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Dynamic Contingency Analysis Tool – Phase 1

November 2015

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U.S. DEPARTMENT OF ENERGY

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Executive Summary

The bulk electric power grid is subject to vulnerabilities from component outages, which in certain combinations (extreme events) might lead to cascading outages. Cascading is a sequential process of disconnecting power system elements such as generators, transmission lines, and loads, potentially leading to a partial or complete blackout that leaves thousands of electricity consumers without electric power. These large blackouts have a great impact on citizens, businesses, the economy, and the government. While such blackouts are rare, they pose a substantial risk to the security and economic health of the country. Much is known about avoiding the first few failures near the beginning of a cascade, but there is a deficit of established methods for directly analyzing the risks and consequences of the longer chains of component outages. Analyzing the risks of cascading failures and devising ways to prevent them is an evolving field of study. This study leverages utility-grade software in partnership with the industry to understand the robustness of the grid against high-order contingencies and to study the resilience of the grid in terms of its response to and recovery from such events. In addition, the development of new methodologies, algorithms, and software tools is needed to incorporate the complexity of the network and assess the impacts of cascading sequences of events. Such a process will help provide an assessment of the overall risk profile associated with extreme events.

The Dynamic Contingency Analysis Tool (DCAT) is an open-platform and publicly available methodology to help develop applications that aim to improve the capabilities of power system planning engineers to assess the impact and likelihood of extreme contingencies and potential cascading events across their systems and interconnections. Outputs from the DCAT will help find mitigation solutions to reduce the risk of cascading outages in technically sound and effective ways.

Overall, the ultimate goal of the DCAT is to bridge multiple gaps in cascading-outage analysis in a single, unique prototype tool capable of automatically simulating and analyzing cascading sequences in real systems using multiprocessor computers. This study has been conducted in close collaboration with grid operators, Siemens Power Technologies International (PTI), and the Electric Power Research Institute (EPRI).

Dynamic Contingency Analysis Tool (DCAT) Objectives

The principal objective and innovation of this project is to equip the power industry with the ability to simulate, understand, predict, and prevent consequences of major disturbances on the grid including cascading events that can lead to widespread power supply interruptions. Despite some recent progress achieved in this area, the main objective of accurately simulating cascading events leading to blackouts has not been accomplished. The simulation component includes the modeling accuracy, speed of computations, and comprehensiveness considerations (which are important because of the multitude of possible causes of cascades and multiple variants of cascade development). Understanding blackouts is essential for mitigating and preventing them. Prediction of blackouts is a very challenging task. It can be addressed by revealing the most frequent (or most probable) potential cascade development scenarios.

One of the additional goals of this study is to overcome the difficulties facing the power industry in implementing the North American Electric Reliability Corporation (NERC) Standard TPL-001-4, “Transmission System Planning Performance Requirements,” that has been partially enforced since the beginning of 2015. The standard states that “studies shall be performed to assess the impact of the

extreme events." This requirement can be addressed by applying the DCAT methodology. The DCAT is an open-platform and publicly available methodology to help develop applications that aim to improve the capabilities of power system planning engineers to assess the impact and likelihood of extreme contingencies and potential cascading events across their systems and interconnections. Outputs from the DCAT will help find mitigation solutions to reduce the risk of cascading outages in technically sound and effective ways. The current prototype DCAT implementation has been developed as a Python code that accesses the simulation functions of the Siemens PSS®E planning tool (PSS/E). It has the following features:

- It uses a hybrid dynamic and steady-state approach to simulating the cascading outage sequences that includes fast dynamic and slower steady-state events.
- It integrates dynamic models with protection scheme models for generation, transmission, and load.
- It models special protection systems (SPS)/remedial action schemes (RAS) and automatic and manual corrective actions.

DCAT Approach Modules

The DCAT approach consists of four main modules: model preparation, initial system aggravation and event screening, dynamic simulation, and post-contingency steady-state analysis. A fifth module is used to process simulation results and log the sequence of cascading events. A flow chart of the DCAT approach modules is shown in Figure ES.1.

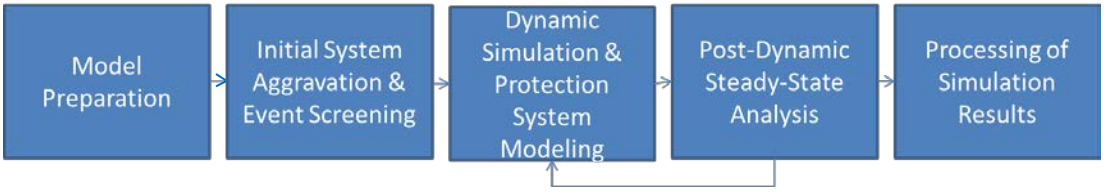

Figure ES.1. A Flow Chart of the DCAT Approach Modules

Model Preparation

The user can provide multiple base planning cases corresponding, for example, to different seasons, different levels of wind and solar penetration, different load levels, variants of possible system reinforcements, etc., reflecting a variety of possible initial system conditions. The base planning cases include both power flow and dynamic system models.

Protection system models are added to the base cases. This integrated planning/protection model is a very important element of the DCAT methodology. Ideally, protection models should be created, tuned, and continuously supported by protection engineers. However, generic protection models available in planning tools can be added with settings that are based on engineering experience and knowledge of general principles and solutions of protection systems. Selected generic relay models in PSS/E have been used in dynamic simulations as follows.

Undervoltage, overvoltage, underfrequency, and overfrequency relays have been modeled for each generating unit. The settings of generating units' protection relays are based on the new NERC Standard PRC-024-1, "Generator Frequency and Voltage Protective Relay Settings." This standard will take effect

in January 2016 for all types of generating units. Out-of-step protection has been implemented through a user-written model that is applied only to synchronous machines.

Typically, transmission line breaker locations are not available in the planning models; rather, they are available in grid models used in protection software packages. In this study, Category B contingency lists based on their definition in the old NERC reliability standards (TPL-003-0b and TPL-004-0a) have been used to determine breaker location for the placement of protection within the transmission network of the full interconnection that has been used in DCAT simulations. Two types of transmission system protection were modeled:

- distance-relay protection (used in dynamic simulation). The suggested relay settings and associated operation of zones of protection are based on best practices.
- overcurrent protection (used in post-dynamic steady-state simulation). The relay settings are based on NERC Standard PRC-023-3, "Transmission Relay Loadability."

Two types of load shedding schemes were modeled:

- underfrequency (frequency-responsive non-firm load shedding)
- underfrequency and undervoltage firm load shedding.

Load-shedding relay settings were provided by the grid operator of the full interconnection used for simulations.

Initial System Aggravation and Event Screening

The stress-pattern application module simulates the system aggravation stage of a blackout. The patterns may include various system stresses, such as increasing load, decreasing wind generation, and some generation and transmission system contingencies (e.g., $N-1$ and non-simultaneous $N-1-1$ contingencies).

To select the initiating events that trigger cascading failures, a steady-state-based contingency/cascading simulation is applied using EPRI's Transmission Contingency And Reliability Evaluation (TransCARE) software package. The prescreening part of the algorithm runs power flow analyses for a list of initiating events. The cascading process is simulated based on the observed overloads and voltage problems, which exceed certain user-specified limits. The outages of protection and control groups, generator disconnections, and load curtailments are simulated based on these violations. This is a simplified representation of the protection system operation. The amount of load loss and the number of cascading steps are recorded to enable the user to rank and select the contingencies for further dynamic simulation.

During the cascading-outage analysis, the branching process is simulated by modeling protection misoperation. An individual cage is created for each base case, aggravation scenario, and initiating event. Later on in the algorithm, some events can result in different outcomes—for instance, in either correct or incorrect breaker operation (breaker failure). Branching is performed based on probabilities of different outcomes, e.g., the probability of breaker failure.

Dynamic Simulation

The dynamic simulation process is internally integrated with the protection system model. At each simulation step, system parameters are checked against dynamics-based protection models. Both successful and unsuccessful (due to a failure) operation of protection are simulated. For the unsuccessful outcome, new dynamic processes (cages) are started. The dynamic simulation runs until a stable point is reached, or it can be stopped if instability is detected. The instability criteria are user defined. For instance, they can include transient voltage and frequency dips, unlimited increase of phase angle differences, etc.

If the process is stable, the system frequency (or frequencies, in stable islands) is logged and a steady-state case is extracted for the subsequent post-dynamic steady-state analysis. During the simulation process, the cascading sequence for generation and transmission line tripping in addition to the load loss due to the action of the protection system and the SPS/RAS action is logged.

Dynamic simulation is a computationally intensive task. An adaptive simulation time module has been implemented to run the dynamic simulation long enough to capture the dynamic response of the system. The appropriate time can be determined by having stability checks at intermediary times that could stop the dynamic simulation. The simulation is initially run for 30 seconds; after that it runs in increments of 5 seconds.

The rotor speeds of all traditional synchronous machines (i.e., excluding wind machines, flexible alternating current (AC) transmission system devices, batteries, solar generators, and direct-current equivalenced generators) in the last two seconds of dynamic simulation periods are used for stability checking. First, the difference between maximum and minimum values in the last two seconds is calculated for each considered speed channel. Next, the maximum of the calculated differences across all considered channels is computed. This computed maximum value is compared with a user-specified tolerance (= 10^{-4} in this study) to determine whether the system has reached a steady state. If the computed maximum value is less than the tolerance, the system is considered to have reached a steady state. Otherwise, the system has not settled down and more dynamic simulation is needed, or if the dynamic simulation has reached the maximum time, T_{max}, a message is printed out to report system status.

Post-Dynamic Steady-State Analysis

If the entire power network or certain islands within it are identified as stable, a post-transient steady-state case is extracted at the end of the dynamic simulation. Even though the dynamic simulation is stable, the extracted case might not be a converged power-flow case. For subsequent analysis with DCAT, a post-transient (governor) power flow is run. Running a governor-response power flow on a “close to converged” case at the end of a stable dynamic simulation assures that both dynamic convergence and steady-state convergence are achieved. The objective of post-dynamic steady-state analysis is to model SPS/RAS response, other automatic controls, and operator manual corrective actions. If these corrective actions fail to eliminate transmission lines and/or transformers overloading, slower overcurrent protection tripping actions are simulated.

The SPS/RAS systems are designed to detect predetermined system conditions and automatically take corrective actions, other than the isolation of faulted components, to meet system performance requirements. These schemes are designed to maintain system stability, address reliability standards, and

prevent unacceptable power flows and voltage violations. In the DCAT implementation, all the SPS/RAS actions that were provided by grid operators for the full interconnection under test were implemented. At the beginning of the post-dynamic analysis, all SPS/RAS responses are checked, and if any predetermined SPS/RAS conditions are met, such as overloading of a certain transmission line, the corresponding SPS/RAS tripping actions are activated. To simulate the effect of the SPS/RAS action, a dynamic simulation run is performed for the current system status and the SPS/RAS action is triggered during the dynamic simulation.

The automatic control actions of transformer tap changes, switching of shunt reactors and capacitor banks, phase shifter, static compensators (STATCOM), and static VAr compensators (SVC) are used to eliminate voltage violations. The DCAT implements these actions using the PSS/E AC corrective actions function, which is part of the Multi-Level AC Contingency Computation (MACCC) application.

Operator manual actions to eliminate line overloading through generation redispatch and load shedding are modeled in the DCAT using the PSS/E AC corrective actions function.

If there are still overloaded lines after all possible corrective actions have been taken, the DCAT will select the line with the highest overloading percentage to be tripped. This process is performed through dynamic simulation as if this tripping is a new initiating event imposed on the current system topology, including all the tripping that occurred in previous cascading steps.

Simulation Results

Steady-state cascading-outage simulations have been performed on a full interconnection grid using TransCARE to preselect initiating events for the DCAT. Hybrid dynamic and steady-state simulations were then performed using DCAT to simulate the cascading-outage sequences. The models used in the DCAT for this full interconnection integrate dynamic models with protection scheme models for generation, transmission, and load. Post-dynamic analysis is performed to model SPSs/RASs and automatic and manual corrective actions.

The following three examples show simulation results of the DCAT. The first two examples contrast situations in which a distance relay operates correctly and incorrectly. In the second example, we show how misoperation of a transfer trip communication channel in a distance relay can result in significant generation outages, in comparison to the first example, where it operates correctly and consequently there are no generation outages. In the third example, we show how non-firm frequency-responsive load can help in maintaining system stability after significant generation loss. The purpose of these examples is to show the importance of performing hybrid dynamic and steady-state simulations with protection modeling to accurately mimic the cascading outage process. They also show how planning engineers can use DCAT for cascading-outage analysis and how the results are reported.

Special attention should be given to Example 3, where a bus fault that lasted for six cycles was introduced at a large substation. A steady-state analysis indicated this extreme event did not converge, and suggested a blackout as the amount of generation loss was higher than the available spinning reserve. Using the DCAT, this extreme event gives a good example of how a non-firm frequency-responsive load-shedding scheme acts and sheds a part of the load to restore the balance between generation and load. This example shows the importance of including dynamic simulations and protection in cascading-outage

analysis. The additional modeling detail enabled by DCAT provides a more realistic assessment of system reliability.

Example 1: Line Fault with a Pilot Scheme (Transfer Trip Enabled)

A line fault is applied on one of the lines connected to Bus X1 at a distance of 90% from Bus Y1 at time t = 10 s, as shown in Figure ES.2.

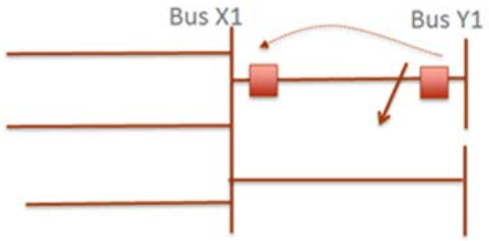

Figure ES.2. Example 1: Line Fault with a Pilot Scheme (Transfer Trip Enabled)

Distance relays are modeled on both ends of the line, each having the ability to send a transfer trip to the other end upon sensing a Zone 1 fault. Though the other end of the line (at Bus X1) sees a Zone 2 fault, this pilot scheme trips the breaker as soon as the other relay times out on the Zone 1 fault. Upon successful operation of both breakers, the fault is isolated, without other tripping actions. Voltages of Buses X1 and Y1 are shown in Figure ES.3.

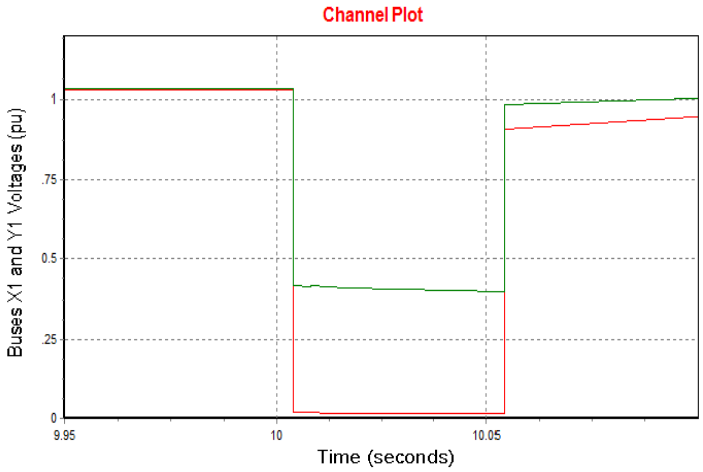

Figure ES. 3. Example 1: Voltages of Buses X1 and Y1

Example 2: Line Fault with Failed Transfer Trip

Example 2 is similar to Example 1, but the communication channel for transfer trip is assumed to have failed; the line fault is applied at time t = 5 s. As a result, the end of the line near to the fault at Bus Y1 trips at Zone 1 settings (4 cycles) and the other end of the line trips at Zone 2 settings (22 cycles). Since the Zone 2 trip persists longer than the Zone 1 trip, timers on many other relays would have started, and some of them had cascaded tripping. Voltages of Buses X1 and Y1 are shown in Figure ES.4.

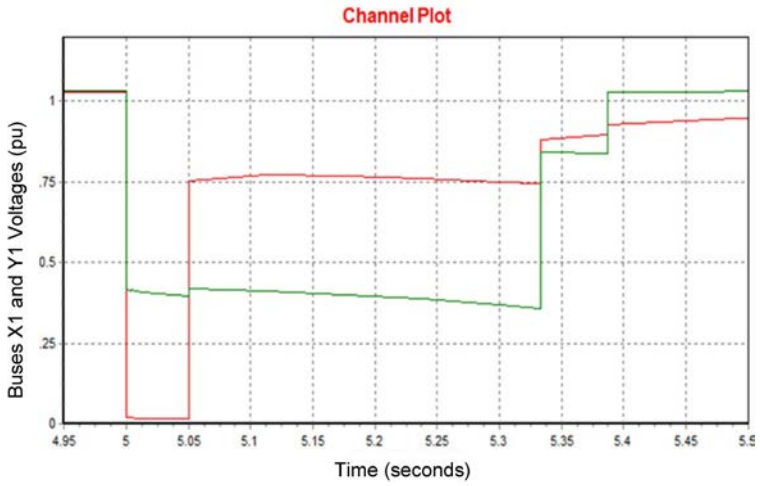

Figure ES.4. Example 2: Voltages of Buses X1 and Y1

The sequence of relay tripping observed during the dynamic simulation is shown in Table ES.1. After the dynamic simulation, no control conditions that could trigger SPS/RAS actions were observed. The line overloads observed on the system were below 130% of Rate A and no voltage violations below 0.9 per unit (pu) were observed. No corrective action was required for this contingency with these protection settings. This contingency resulted in a total of 18 tripping actions with a total generation loss of 3,004 megawatts (MW) and no load loss, as given in Table ES.2.

Table ES. 1. Relay Tripping Sequence for Example 2 (sample output of DCAT)

Relay Type					
DISTR1	TimeOut (s)	Bus from	Bus to	Ckt id	
DISTR1	5.05	X1	X2	1	
DISTR1	5.333	Y1	Y2	1	
VTGTPA	TimeOut (s)	Pgen (MW)	Qgen (MVAr)		
VTGTPA	5.387	1204.9	156.52		
VTGTPA	5.387	1194.9	152.6		
VTGTPA	6.421	68	28.8		
VTGTPA	6.421	67	28.8		
VTGTPA	6.487	17	14.8		
VTGTPA	6.487	17	14.8		
VTGTPA	6.571	15	0		
VTGTPA	6.579	68.99	6.59		
VTGTPA	6.583	70.99	6.59		
VTGTPA	6.583	69.99	6.78		
VTGTPA	6.583	67.99	6.59		
FRQTPA	TimeOut (s)	Pgen (MW)	Qgen (MVAr)		
FRQTPA	9.662	7.53	7.37		
FRQTPA	9.662	5.42	0		
OutOfStep_new	TimeOut (s)	Pgen (MW)	Qgen (MVAr)	AngleThr (degrees)	AngleDev (degrees)
OutOfStep_new	10.1374	0	−12.25	180	180.2261
VTGTPA	16.046	74.67	38		
VTGTPA	16.046	71.61	38		

AngleDev = angle deviation
AngleThr = angle threshold
Ckt id = circuit identification
DISTR1 = distance-relay model
FRQTPA = underfrequency/overfrequency generator disconnection relay
Pgen = generator real power
Qgen = generator reactive power
VTGTPA = undervoltage/overvoltage generator disconnection relay

Table ES.2. Generation and Load Loss Summary for Example 2

Generation Loss (MW)	3,004
Load loss (MW)	0
No. of Total Tripping Actions	18
No. of SPSs/RASs Triggered	0
No. of Overloaded Lines	0
Corrective actions	None

Example 3: Demonstration of the Role of a Non-Firm Frequency-Responsive Load-Shedding Scheme in Maintaining Grid Integrity after an Extreme Event

A bus fault that lasted for six cycles was introduced at a large substation. All elements connected to this substation were then tripped to isolate the fault, including a very large power plant. This extreme event did not converge in TransCARE analysis, because the amount of generation loss was higher than the available spinning reserve. Using the DCAT, this extreme event gives a good example of how a non-firm frequency-responsive load-shedding scheme acts and sheds a part of the load to restore the balance between generation and load.

A significant amount of generation was lost due to this fault, which was followed by significant underfrequency non-firm load shedding. The fault is introduced at time t = 10 seconds into the dynamic simulation. Graphs of frequency at selected load uses are given in Figure ES.5.

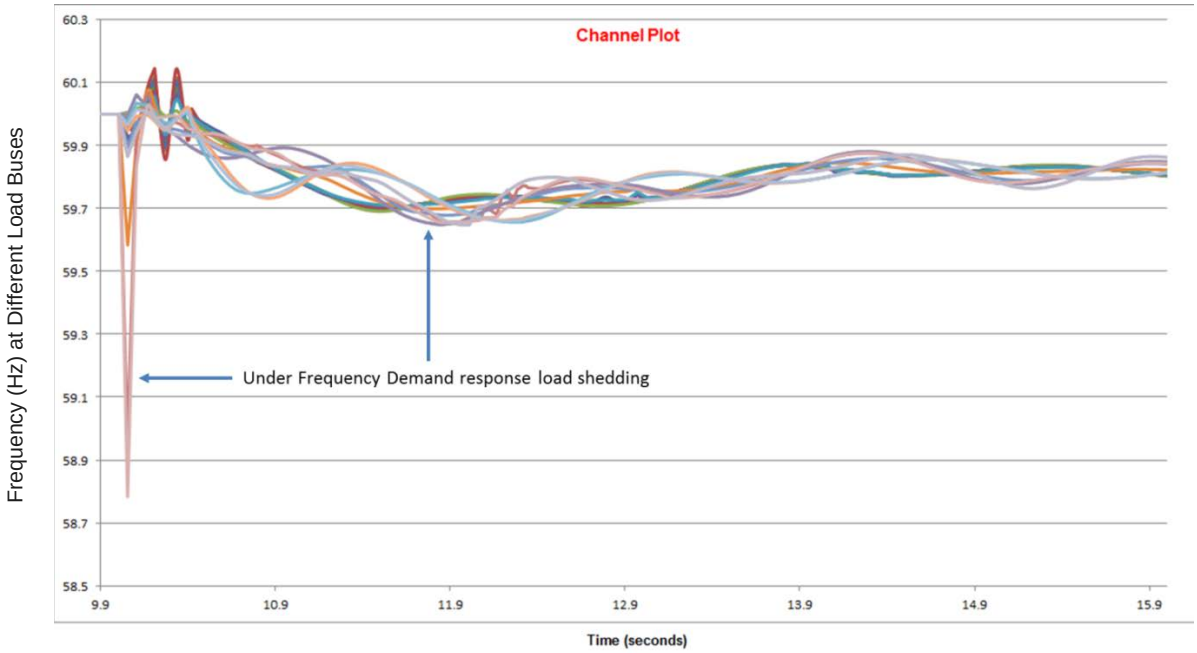

Figure ES.5. Example 3: Tripping of Loads Participating in the Non-Firm Frequency-Responsive Load-Shedding Scheme

A partial list of the relay tripping sequence observed during the dynamic simulation is given in Table ES.3. After the dynamic simulation, no control conditions that could trigger SPS/RAS actions were observed. The line overloads observed on the system were below 130% of Rate A and no voltage violations below 0.9 pu were observed. No corrective action was required for this contingency with these protection settings. This contingency resulted in a total of 84 tripping actions with a total generation loss of 3,900 MW and 1,068 MW load loss, as given in Table ES.4.

Table ES. 3. Partial List of Relay Tripping Sequence for Example 3. (The full table is given in subsection 5.2.3)

Relay Type							
DISTR1	TimeOut (s)	From	To				
DISTR1	10.054	X1	Y1				
DISTR1	10.054	X2	Y2				
FRQTPA	TimeOut	Pgen (MW)	Qgen (MVAr)				
FRQTPA	10.104	70.56	−10.05				
FRQTPA	10.104	70.56	−10.05				
OutOfStep_new	TimeOut	Pgen (MW)	Qgen (MVAr)	AngleThr (degrees)	AngleDev (degrees)		
OutOfStep_new	10.4207	1375	160.03	180	182.5495		
OutOfStep_new	10.4207	1375	180.03	180	181.8143		
LDSH_LDFR	TimeOut	Stage	$P_{shedding}$ (MW)	$Q_{shedding}$ (MVAr)	Shed Load (pu of initial load)	Bus Voltage (pu)	Bus Frequency (Hz)
LDSH_LDFR	11.529	1	13.68	5.97	0.3876	0.97	59.72
LDSH_LDFR	11.633	1	7.92	2.29	0.1646	1.01	59.7
LDSH_LDFR	11.675	1	5.74	2.15	0.6512	0.98	59.71
LDSH_LDFR	11.675	1	2.85	0.91	0.0905	1.03	59.71
LDSH_LDFR	11.687	1	1.99	0.45	0.1585	1.03	59.71

LDSH_LDFR = load shedding
$P_{shedding}$ = amount of real power shed
$Q_{shedding}$ = amount of reactive power shed

Table ES.4. Generation and Load Loss Summary for Example 3

Generation Loss (MW)	3,900
Load loss (MW)	1,067
No. of Total Tripping Actions	84
No. of SPSs/RASs Triggered	0
No. of Overloaded Lines	0
Corrective actions	None

Conclusions and Future Directions

The expected outcome of this project is to equip the power industry with the ability to simulate, understand, predict, and prevent consequences of major disturbances on the grid including cascading, blackouts, and widespread power supply interruptions. The objective of this study is to leverage utility-grade software in partnership with the industry to understand the robustness of the grid against high-order contingencies and to study the resilience of the grid in terms of its response to and recovery from such events. The development of the DCAT framework is an example that will help overcome the difficulties

facing the power industry in implementing the NERC Standard TPL-001-4. The standard states that "studies shall be performed to assess the impact of the extreme events."

The DCAT was developed to realistically model cascading-outage processes in the power grid. It uses a hybrid dynamic and steady-state approach to simulate the cascading-outage process that includes fast dynamic and slower events. The integration of dynamic models used in planning studies with protection scheme models, including generation, transmission, and load protection systems, is a key element. Post-dynamic steady-state analysis was used to model SPS/RAS response as well as automatic and manual corrective actions. Steady-state cascading-outage analyses were performed using TransCARE to prescreen initiating events for the DCAT.

The implemented DCAT in the form of Python code will be made available to interested system planners to overcome the difficulties facing the power industry in implementing extreme-events analysis. Overall, the DCAT tool bridges multiple gaps in cascading-outage analysis and puts solutions in a single, unique prototype tool capable of automatically solving and analyzing cascading processes in large, interconnected power grids using multiprocessor computers. This study has been conducted in close collaboration with grid operators, Siemens PTI and EPRI. While the DCAT has been implemented using PSS/E in Phase I of the study, other commercial software packages have similar capabilities and may be used in future phases or for different aspects of the analysis.

This report presents a detailed methodology for simulating a cascading failure from the aggravated state, followed by a triggering event and subsequent cascading evolution. The final steady state might be a system that has a different configuration with loss of load and/or generation, or several islands. This methodology and its implementation constitute a step forward to address the gaps in existing approaches, which are listed in the Introduction. At the same time, several opportunities for further enhancement remain unaddressed and need further investigation and development. They can be part of future work scope. Detailed explanations for the following potential improvements are given in Section 7 of this report:

- validating the DCAT through the simulation of historical cascading-outage events
- implementing the DCAT using high-performance computing to simulate thousands of extreme events simultaneously
- more accurate modeling of protection and control groups, distance relays, and SPS/RAS
- more realistically representing operators' actions after disturbances
- improving the methods for sampling the initial conditions
- using severity indices to rank initiating events
- calculating probabilities of cascading-outage events
- modeling communication systems
- evaluating the impact of high wind and solar penetration by using hundreds of base power-flow cases under different load, wind, and solar values
- evaluating the impact of high distributed-generation penetration
- periodic deep-dive screening of the U.S. interconnections for cascading events.

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- Ms. Carla Raymond, Project Specialist

Acronyms and Abbreviations

3Ø	three-phase
AC	alternating current
API	application programming interface
CAPE	Computer-Aided Protection Engineering
COI	center of inertia
DC	direct current
DCAT	Dynamic Contingency Analysis Tool
DISTR1	distance-relay model
EMS	energy management system
EPRI	Electric Power Research Institute
FACTS	flexible AC transmission system
FRQTPA	underfrequency/overfrequency generator disconnection relay model
HPC	high-performance computing
Hz	hertz
INLF	inertial response power flow
LDSH	load shedding model
MACCC	Multi-Level AC Contingency Computation
MVA	apparent power, megavolt amperes
MVAr	reactive power, megavolt amperes reactive
MW	megawatts
NERC	North American Electric Reliability Corporation
NR	Newton-Raphson
PCG	protection and control group
PCM	Potential Cascading Modes
PG&E	Pacific Gas and Electric
PNNL	Pacific Northwest National Laboratory
POM	Physical and Operational Margins
PSS/E	Siemens PTI PSS®E Power Flow software
PTI	(Siemens) Power Technologies International
pu	per unit
RAS	remedial action scheme(s)
SOC	self-organized criticality
SPS	special protection system(s)
TB	breaker time
TP	relay pickup time
TransCARE	Transmission Contingency and Reliability Evaluation

TRELSS	Transmission Reliability Evaluation of Large-Scale Systems
VAR	“variable” in PSS/E
VTGTPA	PSS/E undervoltage/overvoltage generator disconnection relay model
WECC	Western Electricity Coordinating Council

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1.0 Introduction

Vulnerability of large power systems to cascading and major blackouts has become evident since the Northeast blackout in 1965, where a chain of cascading events resulted in a power supply interruption up to 13 hours long in Ontario, Connecticut, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont (Task Force on Recent Blackout Experience 2007, Andersson et al. 2005). Based on the analyses of the series of cascading blackouts in the past decade or so, including the recent blackouts in Turkey and Washington, D.C., the industry and the research community realized the urgent need to develop methods, tools, and practices for cascading-outage analysis and mitigation that are easily accessible by utilities planning engineers (U.S.–Canada Power System Outage Task Force 2004, Beck et al. 2011, Makarov et al. 2005, FERC/NERC 2012, Saha et al. 2014, Direskeneli 2015, Davis and Zauzmer 2015).

However, when the Working Group of Understanding, Prediction, Mitigation and Restoration of Cascading Failures (CFWG) recently issued a survey to the power industry about cascading outage analysis; it was clear from the survey results that most utilities do not have the tools to perform such complicated analysis. One important point of feedback from the industry was the need to include dynamic and protection modeling in cascading outage analysis (Vaiman and Papic 2015). While there are a large number of references devoted to the analysis of cascading events and blackouts demonstrating a significant interest in and effort dedicated to these phenomena by practicing engineers and researchers, a core problem remains of providing the right methods, tools, and practices for cascading-outage analysis and mitigation. These solutions must include protection modeling and dynamic simulation that are easily accessible by utilities planning engineers. This problem is addressed by the following technical approaches and changes to existing practices:

- Transition from steady-state models to dynamic cascading models. Dynamic simulations form a more accurate framework for cascading analyses, reflect power system transient stability and system frequency changes, and enable correct protection system model behavior. All these features are essential for correct simulations of major disturbances and awareness of their true consequences (e.g., the resulting load loss and parts of the system that experience blackout).
- Transition from simplified power-flow models [e.g., direct current (DC) models] to full alternating current (AC) power system models. The full AC models are critically important for addressing reactive power controls and voltage stability problems that can be part of cascading processes. DC models do not have this capability.
- Transition from deterministic models to probabilistic models. The strength of probabilistic simulation is that it yields probabilities of events and hence enables quantitative risk analysis. Risk analysis accounts in an objective way for both the frequency and the impact of cascades and blackouts.
- Transition from simplified protection system models to detailed protection system models. Protection system operation or misoperation has a profound impact on system behavior after disturbances. If the protection system is not adequately modeled, this could lead to incorrect conclusions regarding the actual system vulnerability to extreme events.
- Transition from research-grade cascading-outage simulators to commercial-grade cascading-outage simulators.

The importance of these changing approaches (implemented in DCAT) is outlined below.

Steady-State and Dynamic Models

Dynamic simulations form a more accurate framework for cascading analyses. Dynamic simulatiions create the potential for better representation of the protection system, including protective system actions during transient states; reflect frequency variations affecting generation and load, including enabling simulations of under- and overfrequency relaying; and can capture instances of transient instability during cascading. Usually software developers who provide the dynamic option for cascading processes also provide a steady-state model (Paul and Bell 2004, Bhatt et al. 2009, V&R Energy 2010).

The steady-state cascading models are based on a power flow analysis of cascading steps following a serious contingency (triggering event). Transition from one cascading step to the next cascading step is simulated by disconnection of additional system elements (e.g., transmission lines, transformers, generators, loads) caused by protection system action. Power flow is then analyzed for the new configuration. These actions are simulated using simplified criteria, such as line flows exceeding certain limits or voltage magnitudes being above or below certain limits. Examples of the steady-state approach can be found in Kumbale et al. (2008), Miller (2008), and Pfitzner et al. (2011).

Steady-state cascading simulations do not provide accurate representations of real cascading processes. They do not reflect system dynamics and do not allow accurate modeling of the protection system, which is important for detecting and sequencing of cascading trips. They do not capture instances of transient instability. They do not reflect frequency variations that may trigger underfrequency load shedding and generation protection operation, etc. At the same time, these types of analysis play an important role, and they are used in practical studies for the following reasons:

- Steady-state simulations are much faster than dynamic simulations; they can cover many more cascading scenarios within a reasonable simulation time frame.
- They can be used to prescreen extreme contingencies, rank them, and select a limited number of the most severe contingencies for in-depth dynamic simulations.
- They may be suitable for studying slowly developing cascading processes or for an analysis of aggravating system conditions before the actual cascading begins (e.g., random contingencies, load growth, etc.).
- They can be very useful in re-creating post-transient system states, where system operators or special protection systems (SPS)/remedial action schemes (RAS) undertake corrective actions to alleviate unallowable variations of system parameters (frequency, voltage, power flow, etc.).

Applying dynamic simulations to analysis of multi-scenario cascading events requires a very significant, if not computationally prohibitive, effort. With this consideration in mind, the use of parallel methods and high-performance computing (HPC) to run these analyses are very attractive options (Jin et al. 2013, Crow and Ilic 1990, La Scala et al. 1990, Jalili-Marandi et al. 2012, Decker et al. 1996). There is an increasing interest in the use of cloud computing for parallel dynamic simulations (Chen et al. 2014).

A major research effort has been undertaken in the development of faster dynamic analysis methods, including the energy function methods (Pai 1989, Fouad and Vittal 1992, Pavella et al. 2000). Energy

function methods are also called direct methods. This approach can be used as a screening tool to filter critical studies, which are then simulated with full detailed models.

Recently, an approach to implement transient stability-constrained optimal power flow in cascading outages was proposed. The approach detects transient instability due to a cascading chain and prepares transient stability constraints for optimal power flow. The constraints use trajectory sensitivities, which can speed up the analysis by estimating the change in rotor angle response with generation levels (Tang and McCalley 2014).

AC Power Flow Models vs. DC Power Flow Models

Full AC models are critically important for addressing reactive power control and voltage stability problems that can be part of cascading processes. DC models do not have this capability.

Steady-state power flow models can be based on simplified power-flow equations (e.g., DC models) or full AC models. DC models introduce additional limitations to simulation accuracy. Due to AC computational limitations, DC analysis is sometimes used in applications that are time sensitive and do not require significant accuracy.

Probabilistic Models vs. Deterministic Models

The strength of probabilistic simulation is that it yields probabilities of events and hence enables quantitative risk analysis. Risk analysis accounts in an objective way for both the frequency and the impact of cascades and blackouts.

The deterministic framework for extreme-event simulation computes the response of a deterministic power system model to a list of contingencies that stress the power system to a certain extent. The contingencies in the list are judged to be credible worst cases in the sense that they are severe contingencies that have some significant chance of occurring. Examining responses of the power system to all the contingencies can give insights into credible cascades of failures and their mitigation. Moreover, since many of the current North American Electric Reliability Corporation (NERC) reliability standards are deterministic, a deterministic simulation can be used to check compliance with the NERC standards.

The weaknesses of the deterministic approach lie in the difficulty of objectively determining which contingencies are credible, insufficient sampling of power system states and possible outcomes, and the inability to compute event probabilities or risk within the framework. The probabilistic simulation approach is also often slower and requires more knowledge, complicating the analysis.

Probabilistic simulation is needed due to the significant and increasing probabilistic nature of analyzed scenarios and events in the system. Probabilistic analysis selects samples from multiple possible cascades to enable it to evaluate event probabilities and risks. Different samples are selected in different runs of the model so that the outcomes can be different. If the sampling is done properly, the results can be interpreted probabilistically and conclusions about risk can be made.

A weakness common to all simulation approaches is that only a selection of all the possible cascading mechanisms are represented, and the representation is approximate (Morgan et al. 2011).

Detailed Protection System Models vs. Simplified Protection System Models

After the August 2003 blackout, NERC stated that overly conservative relay settings, combined with quick relay systems operation, was one of the causes of this major blackout (U.S.–Canada Power System Outage Task Force 2004).

The key component of a cascading-outage analysis is modeling the protection system and its potential misoperation or failure to operate (Thorp and Wang 2001, Soman et al. 2004). Some commercial-grade software tools allow inclusion of some protection scheme models, but this capability is not usually employed by utility users (Gopalakrishnan et al. 2014). This can result in decreased accuracy of dynamic simulations after major disturbances as well as the inability to trace cascading events accurately. Enabling such capabilities will help bring to light the true consequences of major events and cascading and contribute to their understanding, prediction, mitigation, and prevention.

Tziouvaras (2007) discusses details of the role and performance of protection systems during disturbances using relay and digital fault recorder data, their impact on the system, design, and setting considerations to avoid relay misoperations, and applications of synchrophasors to monitor and mitigate wide-area disturbances. Tziouvaras stresses that protection systems can actually contribute to the spread of blackouts (Zone 3 protection) and that a significant effort is needed to find their settings and develop loadability requirements. On the other hand, proper understanding of protection schemes, careful review of settings, and proper design changes can minimize the extent of disturbances.

1.1 Review of Some Existing Approaches and Developments in Cascading-Outage Analysis

In this section, we discuss in more detail some interesting approaches developed in the area of cascading-outage analysis by the research community to evaluate the extent of propagation of cascading failures, their criticality, and the susceptibility of the power system to large-scale disturbances, and to identify potential cascading chains.

1.1.1 Branching

Branching in the context of cascading outage analysis is defined as estimating the branching process parameter λ that measures the extent to which failures propagate (Dobson et al. 2006). The branching model implies that failures at each step of the cascading process independently produce further failures in the next step, according to a probability distribution with mean λ called the offspring distribution. That is, each failure in each stage produces an average of λ failures in the next stage. If $\lambda < 1$, the failures will die out with the mean number of failures in each step decreasing exponentially. If $\lambda > 1$, it is still possible for the process to die out, but often the failures increase exponentially until the system size or saturation limits are reached.

1.1.2 Self-Organized Criticality

The self-organized criticality (SOC) approach to cascading outage analysis shifts the focus from individual causes of particular blackouts to the dynamics of a complex system in which repeated major disruptions from a variety of causes are a reality (Carreras et al. 2000). In an SOC system, the nonlinear dynamics in the presence of perturbations organize the overall average system state near to, but not at, the state that is marginal to major disruptions.

Therefore, the traditional risk evaluation methods applied to SOC systems are bound to underestimate the risk of large events. In Carreras et al. (2004), the authors analyze a 15-year time series of North American electric power transmission system blackouts for evidence of SOC. They conclude that the blackout data seem to be consistent with the SOC model.

1.1.3 Brittleness

Brittleness reflects the susceptibility of the power system to large-scale disturbances. To compute brittleness, a simplified power system model is used that reflects system topology and operating conditions. The maximum amount of power that would be disrupted for a specific number of disconnected lines is calculated. Then the specific lines involved in the worst-case scenario are determined. These worst-case scenarios help to identify outages to be monitored or further analyzed by more detailed methods (Dobson et al. 2006).

1.1.4 Cluster-Based Approach

A cluster-based approach is described in Vaiman et al. (2012). It helps to quickly identify potential cascading chains due to transmission system overloads. A cluster is a group of buses connected via critical lines (load clusters [sinks]; generator clusters [sources]; and a connecting cluster). Source and sink clusters are identified by using similar minimal cutsets. Line outages in a cutset can cause large overloads on another line in the cutset. If this overloaded line is disconnected by the protection system, cascading may occur.

1.2 Industry Standards for Cascading-Outage Analysis

In the past, planning practices in U.S. utilities have been confined to maintaining system security and stability during the occurrence of contingencies as defined in the NERC planning standard TPL-001-0.1, “System Performance Under Normal Conditions” (NERC TPL-001-0.1).

NERC has developed a new transmission planning reliability standard, TPL-001-4, “Transmission System Planning Performance Requirements” (NERC TPL-001-4). The new standard will be enforced in 2015 and 2016. A similar Western Electricity Coordinating Council (WECC) Regional Criterion, TPL-001-WECC-CRT-3, “Transmission System Planning Performance,” is currently under development in the WECC system (WECC 2014).

In the abovementioned documents, the following new criteria have been introduced:

P0 – no contingencies

P1 – single contingency; generator, transmission line, or transformer

P2 – single contingency; bus section or breaker fault

P3 – loss of element followed by system adjustments

P4 – fault plus delayed clearing

P5 – fault with protection failure

P6 – multiple overlapping single contingencies

P7 – common structure failure, multiple lines on a common structure.

Additionally, special requirements are added for extreme events. For some of the events P1–P7, some non-consequential load loss[1] is acceptable. For some grid operators' planning studies, non-consequential load loss is not allowed, except for the events P2-2 HV, P2-3 HV, P2-4, P4-1 HV, P4-2 HV, P4-3 HV, P4-4 HV, P4-5 HV, P4-6, P5 HV, P6, and other extreme events.

Despite the fact that NERC standards are mandatory in the United States, they are weakly enforced at the moment. Very few of the electric utilities today systematically investigate the consequences of extreme events. Part of the reason for this is the lack of software tools that can properly simulate such outages. Simulating such outages utilizing available power-flow programs is quite cumbersome. The Working Group of Understanding, Prediction, Mitigation and Restoration of Cascading Failures (CFWG) recently issued a survey to the power industry about cascading outage analysis; it was clear from Survey results that most utilities do not have the tools to perform such complicated analysis (Vaiman and Papic 2015).

1.3 Commercially Available Cascading-Outage Analysis Tools

Papic et al. (2011) provide a review of some of the commercially available tools for analyzing cascading failures. This section contains a brief excerpt of the findings from that report. Table 1.1 is reproduced in this report from Papic et al. (2011). Note that there is a new version of Transmission Reliability Evaluation of Large-Scale Systems (TRELSS) software called Transmission Contingency and Reliability Evaluation (TransCARE) (EPRI 2012).

[1] Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault. Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage-sensitive Load, or (3) Load that is disconnected from the System by end-user equipment. "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service." (NERC TPL-001-4)

Table 1.1. Some of the Existing Commercially Available Cascading-Outage Analysis Tools

Cascading Tool	Methodology	AC/DC Power Flow	Max. Number of Buses	Web Address
ASSESS by RTE, France & National Grid, UK	Analytical + Monte Carlo	DC or AC steady state plus dynamic simulation	Practical limit of around 2,000 buses	Yes
CAT by Commonwealth Associates, Inc., USA	Analytical	AC	64,000	Yes
POM-PCM by V&R Energy Systems Research, Inc., USA	Analytical	AC steady state plus dynamic simulation	No limit	Yes
TRELSS (TransCARE) by EPRI, USA	Analytical	AC or DC	70,000	Yes

CAT = Cascade Analysis Tool
EPRI = Electric Power Research Institute
POM-PCM = Physical and Operational Margins – Potential Cascading Modes

1.3.1 ASSESS

Features of ASSESS, from French transmission system operator Réseau de Transport d'Électricité (RTE), in collaboration with England and Wales National Grid, include the following (Papic et al. 2011):

- A security-constrained AC optimal power flow.
- A quasi-steady-state simulator, called ASTRE, that has a simple model of protection of branches.
- A full time-domain simulation, Eurostag, that models controls on the system, including some forms of generator protection and, in some sense, Zone 3 protection on overhead lines.
- A possibility of modeling sequences of events and state of the system in a simulation, and assessing the possibility of cascading outages.

1.3.2 Cascade Analysis Tool

Cascade Analysis Tool (CAT) was developed by Commonwealth Associates, Inc. Features of CAT include the following (Papic et al. 2011):

- Assesses vulnerability to widespread outages and uncontrolled cascading
- Runs AC power flow
- Automatically runs contingencies
- Determines and automatically simulates the load losses
- Uses the criteria thermal overload, low voltage, and voltage change
- Determines the next outage by identifying the worst overload or by dropping load at the bus with the lowest voltage. Only one outage is allowed at each cascading step
- Repeats cascading steps until no more violations occur
- For a divergent power flow, load is dropped and it makes another attempt to solve the case

- Repeats the process until the case is solved without violations, or load drop exceeds certain threshold, or a voltage is low, indicating that load drop is required.

1.3.3 Potential Cascading Modes (POM-PCM)

PCM is a part of POM (Physical and Operational Margins) software. It was developed by V&R Energy Systems Research, Inc. Features of PCM include the following (Papic et al. 2011):

- PCM simultaneously monitors voltage stability, thermal overloads, and voltage violations.
- AC solutions can be found in ~0.1 second for a 50,000-bus case.
- Initiating events and contingencies can be generated either automatically as a result of the "cluster" approach or from user-specified contingency lists.
- Millions of initiating events may be analyzed within one simulation run.
- Cascade chains are automatically identified based on overloads exceeding the branch user-defined tripping threshold, and voltage violation below or above load/generator tripping thresholds.
- The cascading run continues until (1) a solution cannot be found due to voltage instability, or (2) loss of load/generation exceeds a certain threshold value, or (3) islanding occurs with imbalance of load and generation, or (4) a violation of thermal and voltage limits does not occur.
- A vulnerability index, based on the estimated likelihood and impact of cascading events, is computed, helping to rank contingencies based on their severity.
- Optimal remedial actions to prevent and mitigate cascading outages can be determined at each cascading step. Available remedial actions include megawatt (MW) dispatch, megavolt amperes reactive (MVAr) dispatch, transformer tap change, phase shifter adjustment, capacitor and reactor switching, load curtailment, line switching in and out, and new capacitor placement.
- The cascading outages can be also analyzed as a dynamic process.
- Frequency issues and relay operation are included within the transient stability approach.
- Islanding techniques are available, including underfrequency load shedding.

1.3.4 TRELSS/TransCARE

The TRELSS software, and TransCARE, which builds upon TRELSS, include the following (Papic 2011):

- The software captures the cascade path starting from an aggravated system condition and an initiating (triggering) event.
- Threshold values for cascading tripping events, such as the line loading level and threshold low voltage at which a load is dropped, can be specified.
- The software simulates the cascading process as a sequence of quasi-steady-state system conditions.
- TRELSS simulates outages of protection and control groups (PCGs). A PCG is a set of components protected by a common set of breakers.

- TRELSS includes a fast decoupled power-flow algorithm with partial matrix refactorization to modify the system matrix during bus-type switching. Auxiliary solution in the *Q-V* iteration aids in smoothing solution perturbations introduced due to bus-type switching.
- Within each cascading-outage step, generating units can be redispatched using unit margin, generating unit participation factor, and full or fixed-loss economic generation dispatch methods.
- The linear programming module provides a mixed integer solution and incorporates both continuous and discrete controls.
- Control actions include generator MW and MVAr redispatch, transformer-tap and phase-shift adjustment, capacitor and reactor switching, load curtailment, and relaxation of area interchange.
- TransCARE allows the automatic placement of breakers and PCGs. Breaker locations are determined automatically by the program.

1.3.5 Integrated Protection-Planning Simulation Environment

The Integrated Protection-Planning Simulation (IPPS) environment, which links CAPE[2] with PSS/E models for dynamic studies, is described in Gopalakrishnan et al. (2014). The main features of IPPS include:

- An actual protection system operation model with its thousands of relays (distance, overcurrent, out-of-step, frequency, voltage, etc.)
- A transient stability model reflecting interactions between system dynamics and relay operation
- Different contingencies and scenarios, including the ones leading to cascading outages
- Relay performance for balanced and unbalanced faults
- A platform for SPS/RAS.

1.4 Current Industry Practices

A review of the current industry practices for analyzing extreme events is provided in Papic et al. (2011). In that paper, the experiences of Idaho Power, ISO[3] New England, Midcontinent Independent System Operator (MISO), and Southern Company are described. In this report, we provide additional information on the experience of California ISO, FirstEnergy, and Con Edison in cascading-outage analysis (CAISO 2013). These are illustrative examples of cascading-outage analysis.

1.4.1 California ISO Analysis

The potential consequences of extreme events could pose a significant risk to customers in the City and County of San Francisco and the San Francisco Peninsula. The purpose of the California ISO study was to:

- identify the system performance after extreme events

[2] CAPE (Computer-Aided Protection Engineering) is a commercial software package used for protection studies.
[3] ISO = independent system operator

- identify the risk and impacts of such events
- identify mitigation options for the extreme events.

The risks associated with extreme events on the San Francisco Peninsula are significant because:

- this is a seismically active area
- it is dependent on electric imports
- this is an isolated area surrounded by water on three sides.

Seismic issues can affect substations, above-ground cables, below-ground cables, and the transmission system. This California ISO assessment looked at the likelihood that an event would affect facilities on the San Francisco Peninsula, as well as the duration of service outages.

Vandalism and third-party action impacting substations were also evaluated in this assessment. This assessment looked at the likelihood and impact of such events within the area, evaluated the duration of service outages, and examined alternatives for preventive measures.

Assessment of co-located facility failure looked at the frequency of cable or substation equipment failure due to co-located infrastructure such as gas pipelines or water mains, the impact of such a failure, and contingency planning for such events.

Some technical details of this assessment are provided in Appendix D of the 2014-2015 Draft Transmission Plan (CAISO 2015). In Pacific Gas and Electric (PG&E) comments (PG&E 2015), it is stated that "The approach and methodology to analyze the potential unserved customer load based on the seismic integrity, location, and restoration times for damaged facilities provides valuable information about resiliency of the grid after an extreme event." Reliability on the San Francisco Peninsula can be improved by:

- reconfiguring the Martin substation
- certain additional capital improvements to PG&E's existing system
- replacing certain older 115 kV underground cables
- upgrading the 230 kV buses at the San Mateo and Martin substations.

PG&E comments that "With these refinements to PG&E's modernization plan, the San Francisco Peninsula extreme-event assessment indicates that the electric transmission system should maintain the ability to provide reliable service after a major seismic event."

In California Public Utilities Commission comments (CPUC 2015), it is stressed that "The San Francisco Peninsula extreme-event study brought significant rigor and transparency to an inherently difficult and non-transparent planning problem, and the resulting recommendations appear to be prudent and appropriate."

1.4.2 FirstEnergy Cascade Analysis

Information in this section is from FirstEnergy (2014).

FirstEnergy transmission facilities at greater than 200 kV are tested to determine the effects of severe contingencies on the system, including voltage and angular stability. Examples of these contingencies are:

- loss of a generation station
- loss of all lines on a single right-of-way
- loss of a line with three or more circuits
- loss of all lines and transformers of one voltage at a substation or switching station
- dropping of a large load or major load center
- failure of an SPS/RAS to operate
- operation of an SPS/RAS for a condition for which it was not intended to operate.

FirstEnergy cascade analysis is conducted for all scenarios resulting in a transmission loading above 125% of seasonal rating. The 125% level is a proxy for the overload where a protective relay may operate. The steady-state power-flow model is used. After simulation of a contingency, facilities meeting the following criteria are removed from service:

- Transmission facilities loaded to 125% or greater of the seasonal short-term emergency rating for the initial solution immediately following the contingency and 100% or greater than summer short-term emergency for subsequent case solutions.
- Generators with terminal voltages below their minimum voltage provided by plant owners. If no information has been provided, the minimum voltage is assumed to be 95%.
- The process is repeated until the case fails to converge (indicating the potential for a system collapse) or until neither of the two criteria above are violated. This process is limited to three successive steps, after which it is assumed that a system collapse will occur.
- If this steady-state analysis indicates a possible collapse, additional analysis is performed using dynamic analysis for verification.
- Automatic and/or manual load shedding are permitted to prevent a system cascade. If load shedding beyond certain values is required to prevent a system cascade, system reinforcements or modifications needed to limit load shedding to values below those values are implemented.
- When there is potential for a cascading outage, an evaluation is conducted to consider: (1) consequences to the FirstEnergy and adjacent systems; (2) projects to correct the condition; and (3) operating measures to minimize the severity of the disturbance.
- Based on this evaluation, a decision will be made as to whether a capital project or installation of SPS/RAS should be considered to mitigate the potential risk.

1.4.3 Con Edison Experience and Analyses

Koenig et al. (2010) summarizes Con Edison's experience with simulation and mitigation of cascading events.

During the past several years, Con Edison has concentrated on assessment and prevention of cascading outages under several projects aiming to: (1) identify contingencies causing cascading due to thermal overloads, (2) quantify the impact of cascading outages (Bhatt et. al. 2009), (3) identify data requirements, and (4) find actions to prevent or stop cascading outages. In these projects, cascading outages were analyzed using the steady-state approach and based on thermal overloads over a certain threshold. For the purpose of simulating the protection scheme's action, it was assumed that the overloaded branches would trip automatically. After an initiating event, overloaded branches were consecutively tripped until one of the following events occurred:

- divergence due to voltage instability
- loss of load exceeded a certain threshold
- islanding with imbalance within islands occurred
- thermal violations dropped below the tripping threshold value.

Con Edison's approach applies remedial actions at each cascading step to prevent or decrease the spread of cascading outages. POM and Optimal Mitigation Measures (OPM) software developed by V&R Energy Systems Research, Inc. was used for simulations (V&R Energy 2010). The following simulation process was applied:

1. Select $N-1$ and/or $N-2$ contingencies that cause overloads above the threshold.
2. Determine and apply remedial actions to alleviate the overloads.
3. Stop the cascading process if the remedial actions bring the flow on the overloaded branches below the threshold.
4. Continue cascading simulation if the remedial actions do not bring the line flows below the threshold.
5. In the event a cascading outage cannot be stopped, mitigating actions to reduce the consequences of blackouts (e.g., instability) are determined and applied. Table 1.2 shows the remedial actions and their priorities (Koenig et al. 2010).

Table 1.2. Remedial Actions and their Priorities (Koenig et al. 2010)

Remedial Action	Priority
Transformer tap change	1
Transformer phase-shifter adjustment	2
Capacitor and reactor switching	3
MVAr dispatch	4
MW dispatch	5

If the use of preferable priorities is ineffective, the priorities should be changed to select the most effective remedial actions. If the remedial actions listed in Table 1.2 do not prevent cascading, load curtailment is utilized.

A 2007 summer peak New York Independent System Operator (NYISO) power-flow case with about 50,000 buses was used during the study.

A partial NYISO contingency list, consisting of 250 contingencies, including stuck breakers, tower outages, etc., was used as an $N-1$ contingency list. Additionally, $N-2$ contingencies (over 31,000 combinations) were used by POM.

The load curtailment that is necessary to mitigate steady-state stability violations after each cascading step was computed. Cascading outages were ranked based on this criterion and the number of steps in the cascading chain.

1.5 Gaps in Current Research and Industry Practice and Suggestions for Future Research

This section discusses the existing gaps in the industry practice and suggestions for future research based on the collective opinion prevailing in the industry and research community. The gaps include lack of data and adequate models, including protection system, dynamic and probabilistic models, lack of sufficient time and controls to find and apply preventive actions, and lack of predictive indices. These deficiencies are the major obstacles to more comprehensive, focused, successful, efficient, and proactive blackout prevention in power systems. This work addresses the key gaps facing the industry.

There has been a good effort to study cascaded failures, including the tools availableand industry practice (Baldick et al. 2008). It provides a good starting point to identify the gaps in cascading-outage analyses.

Some immediate gaps and needs in the area of cascading-events analysis and simulations are provided in Morgan et al. (2011), Pourbeik et al. (2006), and Vaiman et al. (2012). The existing gaps can be summarized as follows:

- Increased failure rates in aging equipment are not adequately covered by current analysis tools.
- There is a lack of reliable real-time data: the industry data are either not systematically collected or are kept confidential, which complicates simulation of cascading events and validation of results.
- There is a lack of time to take decisive and appropriate remedial action against events unfolding on the system.
- There is a lack of properly automated and coordinated controls to take immediate and decisive action against system events in an effort to prevent cascading.
- Traditionally, planning models are bus-branch models, while energy management system (EMS) models use node-breaker models. This complicates simulations of some types of cascading events, where substation configuration matters.

- Most of the existing approaches use a static system model, whereas many of the major system disturbances are dynamic processes that require dynamic models and simulations.
- The risk of cascading events is determined to a great extent by their probabilities, which are not captured sufficiently well in the existing approaches.
- Many of the existing approaches do not completely and correctly model the protection system, SPSs/RASs, or human intervention.
- Severity indices, which can ultimately be an important tool for industry, would benefit from additional research and from industry input.
- The methodologies should be expanded to include variants of possible cascading events for the same initiating event.
- Divergent cases create “gray areas” in the cascading-event analysis. The key difficulty here is the inability to distinguish the cases where a power-flow solution does not exist from those cases where the divergence is caused by deficiencies in the numerical solution algorithms.

The following developments have been proposed in Morgan et al. (2011) and Vaiman et al. (2012):

- Improved methods for sampling the initial conditions and events that trigger cascades are needed.
- Modeling more cascading processes in increasing detail is required. There is a need for following more variants of cascading process development.
- The breaker location information is critically important for producing an adequate structure of PCGs. Access to this information is one of the most significant near-term improvements needed for the deterministic extreme-events simulation methodology.
- Interoperability of models between operations and planning would significantly improve the accuracy of cascading simulations.
- The substation design and configuration have significant impact on PCG structure and ultimately on the system reliability and cascading sequences. The system model used for cascading failure analyses should reflect the variety of substation configurations as well as the differences in their behavior after disturbances.
- The protection system model consisting of overcurrent, impedance, and remote (Zone 3) relaying should be included in a system model.
- Hidden failure analysis can be part of cascading simulations (Phadke and Thorp 1996).
- There is a need to develop SPS/RAS that help to prevent or restrict extreme events in a power system.
- Future simulation models would benefit from capturing system dynamics. Analysis of a cascading outage from a transient or mid-term stability perspective is needed, including issues related to the increasing penetration of wind and solar photovoltaic generation (voltage control, decreasing inertia and frequency response, relay protection settings, etc.), as well as increasing of power transfers due to market transactions and other reasons.
- Additional types of initiating events should be studied. For instance, the increasing penetration of variable renewable generation resources, demand-side load management, virtual and actual

consolidation of balancing authorities, new performance standards, and other factors should be studied.

- Probabilistic approaches and risk assessment are needed. Multiple random factors influence all phases of blackout process development, including variable system conditions before a blackout, initiating events, development of the cascading process (branching), as well as the final highly dynamic stages of a system blackout.
- Predictive and actionable blackout indices should be developed. They should be predictive from both grid planning and operational perspectives. The indices should also provide information to help select the most effective system reinforcements and make the best control decisions to reduce the risk and potential consequences of cascading events.
- Periodic deep-dive screening of the U.S. interconnections for cascading events could be a good option. One approach could be the use of large-scale computations involving static and dynamic interconnection-level system models.
- Results of cascading analyses should be validated against real data.
- Increasing the speed of computations and multiprocessor computers are essential for massive cascading-outage analyses (Dobson et al. 2010).

Additionally, the project team has discussed the following needs for comprehensive blackout simulations:

- simulation of operators' actions after disturbances
- the use of synchrophasor data for situational awareness
- communication system modeling
- simulation of islanding situations in the cascading model
- collection of statistical information on failure of different equipment to build probabilistic models
- better models for extreme deviations of voltages and frequency during cascading processes
- predictive cascade failure simulations: blackouts are typically analyzed after the fact, rather than beforehand; it would be better to try to predict future events and their probabilities.

Some of the abovementioned gaps have been addressed in various past work and current research and development efforts.

1.6 Mitigation and Prevention

From the literature it is clear that there is no universal strategy to prevent cascading outages. Even if the system is $N-1$ secure, there are many situations that may result in a blackout, as the European Union experience showed during 2006 (Li et al. 2007). Hence, each utility must evolve a strategy based on past experience, analytical tools and methodologies, and clearly defined and reinforced reliability standards. An aspect that can be addressed, however, is to indicate mitigation and prevention strategies.

Pourbeik et al. (2006) state the following needs:

- appropriate technologies to address root causes of blackouts with proper investments

- relevant mandatory reliability standards, backed by penalties for noncompliance
- periodic review of reliability standards, based on experiences from major system incidents and better technologies
- the need for investment for bulk system reliability
- definition of how such expenditure will be recoverable through transmission rates.

Tziouvaras (2007) recommends the following protection system enhancements to reduce the risk and consequences of major system disturbances:

- single-phase tripping and reclosing for all extra-high-voltage transmission lines to improve stability, minimize system impacts, increase power transfer capability, and improve power system reliability
- dual-pilot protection relay systems in all extra-high-voltage and important high-voltage lines, including local backup protection, and direct transfer tripping
- well designed controlled system separation schemes and SPS/RAS
- proper coordination of generator protection relays and excitation control
- out-of-step tripping of large steam generators coordinated with out-of-step tripping schemes; whether units should be tripped during the first slip cycle, or after a number of slip cycles, and whether this should be part of design
- wide-area protection schemes based on extremely flexible and adaptive protection devices, as well as on reliable high-speed communication technologies
- synchrophasor measurement technology for real-time wide-area monitoring, analysis, adaptive protection and control systems
- voltage instability detection and undervoltage load shedding schemes, and adaptive underfrequency shedding schemes to trip only the amount of load necessary for system recovery
- protection for transformers to prevent damage from overexcitation after islanding and load shedding caused by overvoltage.

In Vaiman et al. (2012), some additional mitigation options to prevent cascading are formulated for planning and operations.

1.7 Study Goals and Report Structure

The principal goal of this project is to equip the power industry with an automated tool that helps in simulating, understanding, predicting, and preventing consequences of major disturbances on the grid including cascading, blackouts, and widespread power supply interruptions.

An additional goal of the project is to overcome the difficulties facing the power industry in implementing the NERC requirements for cascading-outage analysis. This is achieved by developing a Dynamic Contingency Analysis Tool (DCAT) to improve the capabilities of power system planners to assess the impact of extreme contingencies and potential cascading events across their systems and interconnections. Outputs from the DCAT will help planners find mitigation solutions to reduce the risk

of cascading outages in technically sound and effective ways. The tool has been developed as a Python code that accesses the simulation functions of the Siemens PSS®E planning tool (PSS/E). The proposed DCAT has the following features:

- It uses a hybrid dynamic and steady-state approach to mimic the cascading-outage process that includes both fast dynamic and slower events.
- It integrates dynamic models with protection scheme models, including generation, transmission, and load protection systems.
- It models SPS/RAS and automatic and manual corrective actions.

Overall, the DCAT bridges multiple gaps listed above and puts solutions in a single, unique prototype tool capable of automatically solving and analyzing cascading processes in real systems using multiprocessor computers.

This first section of the report provides a brief survey of existing approaches, industry practice, tools, and gaps in performing cascading-outage analysis. The DCAT methodology is explained in Section 2. The approach used for adding protection models to the dynamic planning models is given in Section 3. The post-dynamic analysis approach is described in Section 4. Simulation results for a few examples using DCAT on a test system and a full interconnection are given in Section 5. Steady-state cascading-outage analysis using the Electric Power Research Institute's (EPRI's) TransCARE software package is covered in Section 6. Finally, Section 7 provides study conclusions, lessons learned, and suggested future work. Detailed explanations of the protection modeling in PSS/E that is used in the DCAT are provided in Appendices A and B. Some selected implementation Python codes are given in Appendix C.

2.0 DCAT Methodology

2.1 Specific Objectives

The principal objective and innovation of this project is to equip the power industry with the ability to simulate, understand, predict, and prevent consequences of major disturbances on the grid including cascading-outages, blackouts, and widespread power supply interruptions. Despite some recent progress achieved in this area, the main objective is far from having being addressed to any practically significant extent. The simulation component includes the modeling accuracy, speed of computations, and comprehensiveness considerations (which are important because of the multitude of possible causes of cascades and multiple variants of cascade development). Understanding the principle and propagation of blackouts is essential for mitigating and preventing them. This knowledge is very limited at present. Prediction of blackouts is a very challenging task. It can be addressed by revealing the most frequent (or most probable) potential cascade development scenarios. Prevention of blackouts is currently a very limited practice in the industry. There are no systematic, well orchestrated, industry-wide activities in this area.

In this study, we leverage utility-grade software in partnership with the industry to understand the robustness of the grid against high-order contingencies and to study the resilience of the grid in terms of its response to and recovery from such events. The development of the DCAT framework will help in overcoming the difficulties facing the power industry in implementing the NERC Standard TPL-001-4, "Transmission System Planning Performance Requirements" (NERC TPL-001-4) that has been partially enforced since the beginning of 2015. The standard states that "studies shall be performed to assess the impact of the extreme events."

The DCAT is an open-platform and publicly available methodology to help develop applications that aim to improve the capabilities of power system planning engineers to assess the impact and likelihood of extreme contingencies and potential cascading events across their systems and interconnections. Outputs from the DCAT will help find mitigation solutions to reduce the risk of cascading outages in technically sound and effective ways. The current prototype DCAT implementation has been developed as a Python code that accesses the simulation functions of the Siemens PSS®E planning tool (PSS/E). It has the following features:

- It uses a hybrid dynamic and steady-state approach to simulating the cascading-outage sequences that includes both fast dynamic and slower steady-state events.
- It integrates dynamic models with protection scheme models for generation, transmission, and load.
- It models SPSs/RASs and automatic and manual corrective actions.

Overall, the ultimate goal of the DCAT is to bridge multiple gaps in cascading-outage analysis in a single, unique prototype tool capable of automatically simulating and analyzing cascading sequences in real systems using multiprocessor computers. This study has been conducted in close collaboration with grid operators, Siemens Power Technologies International (PTI), and EPRI. While the DCAT has been implemented using PSS/E in Phase I of the study, other commercial software packages with similar capabilities can be used within the DCAT framework. Specific objectives of this study are listed in Figure 2.1.

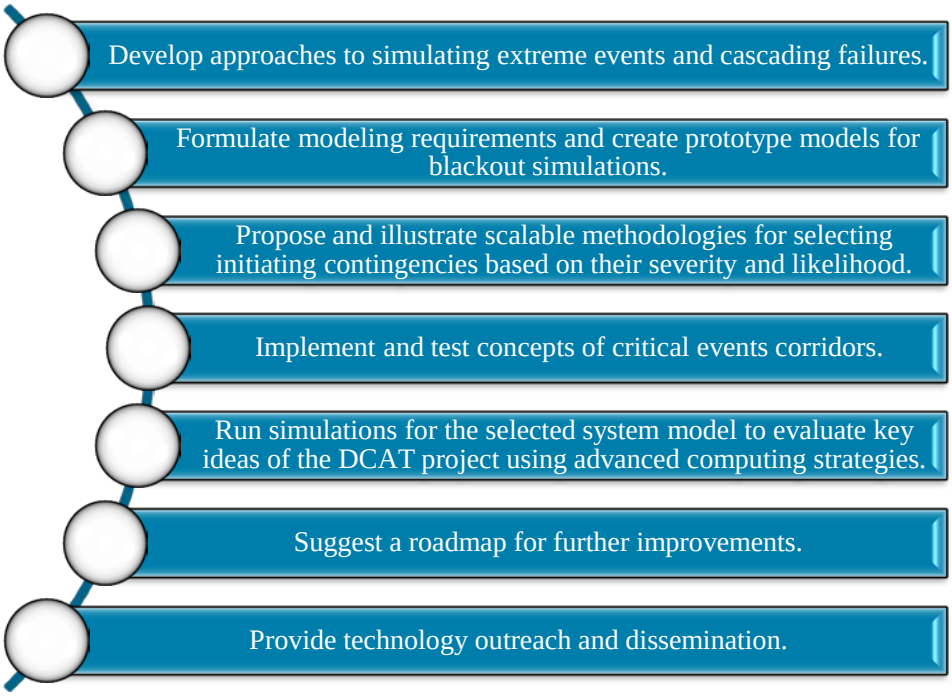

Figure 2.1. Specific Objectives of the Study

The study will develop a solid, well justified open-access platform for probabilistic cascading-events analyses, so that the software vendors can connect their tools to the platform, and by doing so add extreme-event analysis capability to their product. In the Phase 1 implementation, two software products have been selected for the initial DCAT implementation:

- PSS/E, from Siemens PTI, for dynamic and steady-state simulations and protection system modeling
- TransCARE, from EPRI, for cascading simulations based on a steady-state system model.

DCAT will incorporate two modes of analysis, “in depth” and “light.” The objective of the in-depth DCAT mode is to analyze the maximum possible number of cascading events and provide their ranking (based on risk = probability × severity). This mode will provide a more comprehensive cascading-event analysis (~10,000 in Phase 1 and 100,000–10,000,000 and more in subsequent phases). By ranking these contingencies based on their risk, a limited list of contingencies for analyzing using DCAT-light will be formed (1,000–5,000). It is envisioned that DCAT-in-depth will be applied using HPC. End users can use DCAT-light in their routine grid planning and operational planning studies on conventional computers.

2.2 The Generalized Cascading Model

In 2003, four large-scale blackouts were caused by cascading trips of generators and/or transmission facilities. These were (i) the August 14th blackout in the United States and Canada, (ii) the August 28th blackout in London, (iii) the September 23rd blackout in Sweden and Denmark, and (iv) the September 28th blackout in Italy. By analyzing these blackouts, the common scenario of these cascading processes shown in Figure 2.2 can be suggested. In our methodology, we use a generalized cascading model for

shaping the sequence of simulation steps. The content of this section is based on the work reported by Makarov et al. (2005).

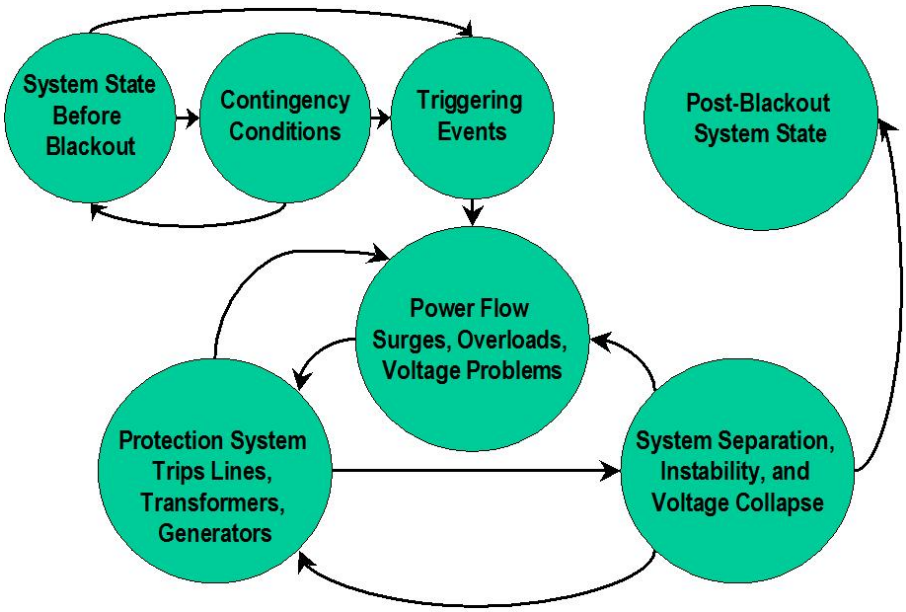

Figure 2.2. Generic Cascade Development Scheme

2.2.1 System State before the Blackout – Aggravation Stage

In all four blackout cases, system parameters remained within their normal operating reliability ranges with no indications of the approaching blackouts. At the same time, some noticeable deviations were observed that could potentially weaken the systems before the actual blackouts.

In Case (i), the U.S.-Canada blackout, there were high electricity demands, heavy power flows, depressed voltages, and frequency variations in the U.S. Eastern Interconnection.

In Case (ii), the Italy blackout, above-schedule power imports from Switzerland to Italy occurred before the collapse of the Italian system.

In the U.S.-Canada and Italian scenarios, some scheduled maintenance on the nearby generators and/or transmission facilities was conducted on the days of the blackouts.

Before the blackouts, the systems were additionally weakened by unscheduled outages. These were outages of the transmission lines in Indiana, the Eastlake 5 generating unit, and the Stuart-Atlanta 345 kV line in Ohio (U.S.-Canada blackout); unplanned disconnection of the Hurst transformer (London blackout), the loss of Unit 3 at Oskarshamn nuclear plant (blackout in Sweden and Denmark), and the trip of the Swiss 380 kV Mettlen-Lavorgo line (blackout in Italy).

2.2.2 Initiating (Triggering) Events

At a certain point in development of each of the blackouts, a triggering event occurred. Apparently, these were the Harding-Chamberlin 345 kV line trip in Ohio (U.S.-Canada blackout); the circuit trip from

Wimbledon to New Cross (London blackout), double busbar fault at the Horred 400 kV substation in Sweden (Sweden-Denmark blackout), and the trip of the Sils-Soazza line (blackout in Italy). Triggering events separate two periods of operation: (1) a period in which multiple "undirected" factors accumulate (factors that contribute to a blackout but are not directly connected to it); and (2) the "blackout-directed" sequence of events (events with clear cause-effect relationships between the subsequent phases).

2.2.3 Cascading Stage

2.2.3.1 Power Flow Surges, Overloads, and Voltage Problems

The triggering event, as well as the subsequent events, in a blackout scenario cause power flow surges, overloads, and frequency and voltage problems. These problems in their turn cause the subsequent events in the sequence.

2.2.3.2 Protection System Trips Lines, Transformers, and Generators

The power system relay protection plays a very important role in blackout scenarios. Its action could be caused either directly by system problems, in which the protective relays react as if the large line flows or low voltages were due to a short circuit, or indirectly, when the system problems cause genuine short circuits or instability, e.g., when the overheated conductors make contact with a fallen tree. The protection system isolates the equipment or a group of equipment from the rest of the network. Some load loss may accompany this process. This can result in more power flow surges, overloads, voltage problems, and so on. The cascading process can be relatively slow, at least at its initial stages.

2.2.3.3 System Separation, Instability, and Voltage Collapse

In the advanced stages of a blackout, uncontrollable system separation, phase angle instability, and voltage collapse can occur. As a result, a significant load loss may occur. Load loss could potentially help to balance generation and load and to relieve system problems in the remaining part of the interconnection and in some isolated islands within the separated grid.

2.2.4 Post-Blackout State

After a number of subsequent phases of the developing cascading process, all analyzed blackouts have resulted in certain post-blackout states. These states are the starting points for the system restoration process.

2.3 Selection of Initiating Events

Our assumption is that $N-1$ contingencies are already routinely analyzed by the utilities and system operators. It is assumed that the system is already protected against such contingencies. These contingencies will be only analyzed in the pre-cascading system state-aggravation modules.

2.3.1 Selection of Initiating Events using Deterministic Criteria

Initiating events that may cause cascading can be user-specified and/or automatically generated by the DCAT.

Automated creation of a comprehensive contingency list for cascading-outage analysis includes:

- flow gates and major transmission interfaces
- historical events
- events provided by the end-user
- random $N-k$ contingencies
- extreme events, such as those defined by NERC in the transmission planning reliability standard TPL-001-4, "Transmission System Planning Performance Requirements" (NERC TPL-001-4). The events defined in this standard are replicated below.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
    a. Loss of a tower line with three or more circuits.[1]
    b. Loss of all Transmission lines on a common Right-of-Way.[1]
    c. Loss of a switching station or substation (loss of one voltage level plus transformers).
    d. Loss of all generating units at a generating station.
    e. Loss of a large Load or major Load center.
3. Wide-area events affecting the Transmission System based on System topology such as:
    a. Loss of two generating stations resulting from conditions such as:
        i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
        ii. Loss of the use of a large body of water as the cooling source for generation.
        iii. Wildfires.
        iv. Severe weather, e.g., hurricanes, tornadoes, etc.
        v. A successful cyber attack.
        vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
    b. Other events based upon operating experience that may result in wide-area disturbances.

[1] Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common right-of-way (Extreme event, steady state 2b) for 1 mile or less.

Stability

1. With an initial condition of a single generator, transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, transmission circuit, single pole of a different DC line, shunt device, or transformer prior to system adjustments.
2. Local or wide-area events affecting the Transmission System such as
    a. 3Ø fault on generator with stuck breaker[1] or a relay failure[2] resulting in Delayed Fault Clearing
    b. 3Ø fault on Transmission circuit with stuck breaker[1] or a relay failure[2] resulting in Delayed Fault Clearing
    c. 3Ø fault on transformer with stuck breaker[1] or a relay failure[2] resulting in Delayed Fault Clearing
    d. 3Ø fault on bus section with stuck breaker[1] or a relay failure[2] resulting in Delayed Fault Clearing
    e. 3Ø internal breaker fault
    f. other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide-area disturbances.

2.3.2 Selection of Initiating Events using Probabilistic Risk Reduction Approach

We cannot analyze *all* possible cascading events, yet we need to be prepared for them. Probabilistic approaches can be used to prune the large number of initiating events to those that are more likely to occur. The idea of our approach is to start with the most probable and most severe events—see the dark brown box in the upper right corner of Figure 2.3. The risk of cascading events is defined as

$$\text{Risk (R)} = \text{Probability (P)} \times \text{Consequences (C)}$$

P is hard to quantify; initially, in our implementation we will use "likelihood" weight coefficients instead. The relative likelihood of events can be determined by our industry partners. For instance, the industry experts can assign relative risk to various events as "*x*" chances out of 100. A better variant is that this information could then be specified as an outage rate, or the number of events over 10 years. This information will be processed by the project team to produce approximate probabilities of various events. In a later phase of this project, the project team will produce a recommended methodology for collecting and pre-processing information, which the industry could consider in the future to enable probabilistic analyses.

[1] A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.

[2] Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

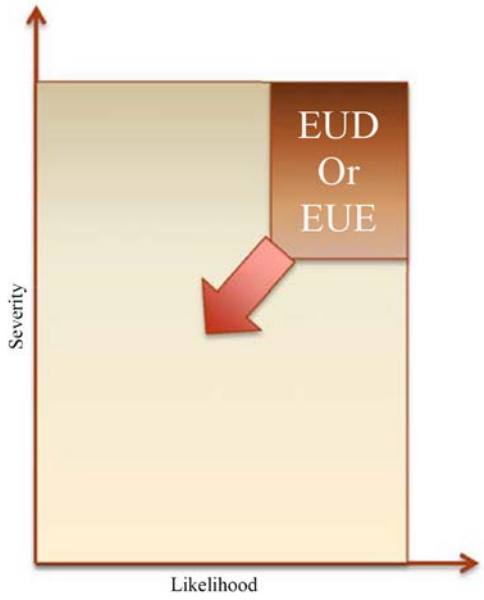

Figure 2.3. Probabilistic Risk Reduction Approach (EUD = expected unserved demand; EUE = expected unserved energy)

The expected severity of events can be initially evaluated in two different ways:

a) by collecting information from experts about the relative severity of different events, e.g., a common right-of-way line outage vs. a substation outage.

b) by prescreening initiating events and resulting cascades using a cascading analysis tool such as TransCARE or V&R Energy Systems Research tools. The severity index can be determined as follows.

$$Index = \frac{Amount\ of\ Load\ Loss + Weighting\ Factor\ x\ Number\ of\ Lines\ Tripped}{Number\ of\ Outage\ Elements\ in\ the\ Initiating\ Event}$$

The consequences of cascading events can be assessed using two metrics related to load loss:

c) unserved demand (MW)

d) unserved energy (MWh).

In the implementation of Phase 1 of this project, we will use the unserved-demand metric only. The unserved-energy metric includes the time of blackout, and its implementation will require building a system restoration model. This could be done in future phases of the DCAT project.

In the future, we will expand the analysis by including more events in the dark brown box of Figure 2.3 with increasing simulation capabilities.

2.4 Steady-State and Dynamic Analysis Sequence and Interactions

Initial stages of blackouts are usually sequences of unrelated events and other changes that aggravate the system state before the actual initiating event starts the cascading process. In the cascading process, events are related as causes and consequences. The aggravation stage is usually a sequence of steady-state system conditions. The cascading stage is more dynamic. After a cascading sequence, the system can reach a steady-state condition again after some load loss, or experience a complete blackout. Islanding is also possible. The system operators attempt to stabilize the system and remove potential violations (e.g., when voltage magnitudes deviate from their normal values by more than 10%). This can be achieved by applying certain corrective actions, including disconnection of loads.

Therefore, the overall simulation sequence will be as follows:

a) Aggravation stage and initiating contingency selection. At this stage, in the general methodology, we will simulate various system states (load levels, dispatches, etc.) and light contingencies, such as $N-1$ contingencies. We will use power flow simulations at this stage. To select the initiating events that trigger cascading, a steady-state-based contingency/cascading simulation can be applied.

b) Cascading analysis will start with a severe initiating event or with arrival at a state where the protection system will definitely operate. The cascading process is a dynamic simulation.

c) The post-contingency stage will again involve a steady-state analysis.

2.4.1 Protection System Modeling

Protection systems in modern power networks have been identified by NERC as a critical reliability issue. After the 2003 North American blackout, based on the U.S.-Canada Power System Outage Task Force report, the NERC stated that one of the major causes of the large-scale blackout was overly conservative relay settings combined with cascading relay operation. Protection system misoperation or incorrect settings can contribute to the spread of blackouts. Better understanding of protection schemes' sequences of operation, careful review of settings, and proper design changes can minimize the extent of disturbances.

The ultimate objective of the overall project is to equip the end user with the capability of simulating the entire protection system in the course of steady-state and dynamic simulations. In the implementation stage of Phase 1, we will use PSS/E capabilities for simulating protection system actions.

Breaker location information will be collected from EMS, other protection system models, and/or contingency lists, if available, as will be explained in Section 3. Otherwise, TransCARE software will be used to identify PCGs in the model. In the implementation stage of Phase 1, some generic rules combined with inferences that may be drawn from contingency definitions will be used to infer breaker location and select relay placement.

In the subsequent phases of the project, the project team intends to explore other options, including the use of protection system simulation tools, such as CAPE (Gopalakrishnan et al. 2014 and ongoing work by Oak Ridge National Laboratory) or Advanced Systems for Power Engineering (ASPEN), along with know-how developed by other parties. We will also develop a metric to evaluate each approach

based on a) simulation time, b) ability to model balanced and unbalanced faults, c) labor and data needed to prepare the integrated planning and protection model, and d) accuracy of protection relay operation modeling.

2.4.2 Caged Simulations

The caged approach to simulations implies running an entire single-cascading chain on one processor to minimize information exchange between parallel processors (a “cage” defines the work to be performed on a single processor). Separate cages will be generated for base cases, different aggravation scenarios, and initiating events.

2.4.3 Critical Event Corridors

No blackouts follow exactly the same sequence, but similar partial sequences of cascading events may exist. Critical event corridors are sequences of cascading outages that occur repeatedly (or are the most probable) for multiple system states and initiating events. By determining critical event corridors, one will be able to address the most probable/most frequently observed sequences by enhancing system protection and SPSs/RASs, as well as by system reinforcements. Critical event corridors can be identified by scanning various initiating events with their probabilities and by simulating the cascading sequences caused by them. Pacific Northwest National Laboratory (PNNL) will develop algorithms to automatically detect these critical corridors. Figure 2.4 illustrates the concept of critical event corridors.

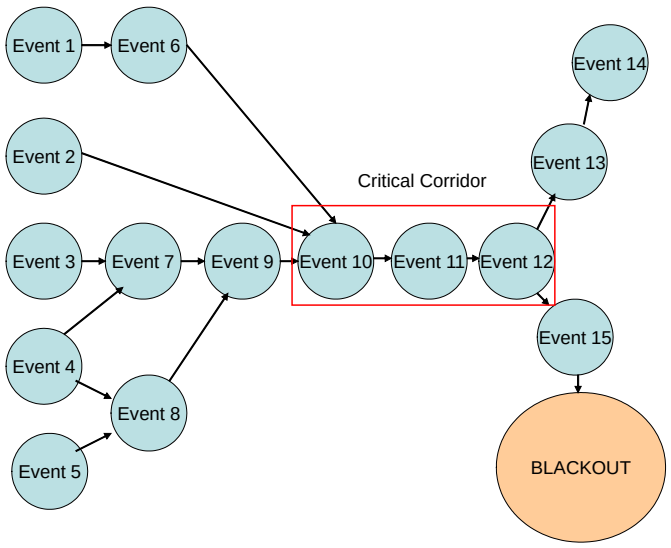

Figure 2.4. Critical Event Corridor

2.4.4 Branching

Branching means following a multivariant tree of multiple cascading scenarios. Examples of branching can be found in Figure 2.4. Events 4 and 12 can result in different outcomes. For instance, Event 4 can result in either a successful or an unsuccessful fault-clearing cycle. Event 12 could be either correct or incorrect (stuck) breaker operation (breaker failure). Branching will be performed based on probabilities of different outcomes, e.g., the probability of breaker failure.

2.5 DCAT Computational Flow Chart

Based on a generic blackout development model, the DCAT flow chart consists of the following four phases (Figure 2.5 and Figure 2.6):

a) Preparation of base cases with integrated protection models

b) Initial system aggravation and event screening

c) Dynamic simulation

d) Post-contingency steady-state analysis.

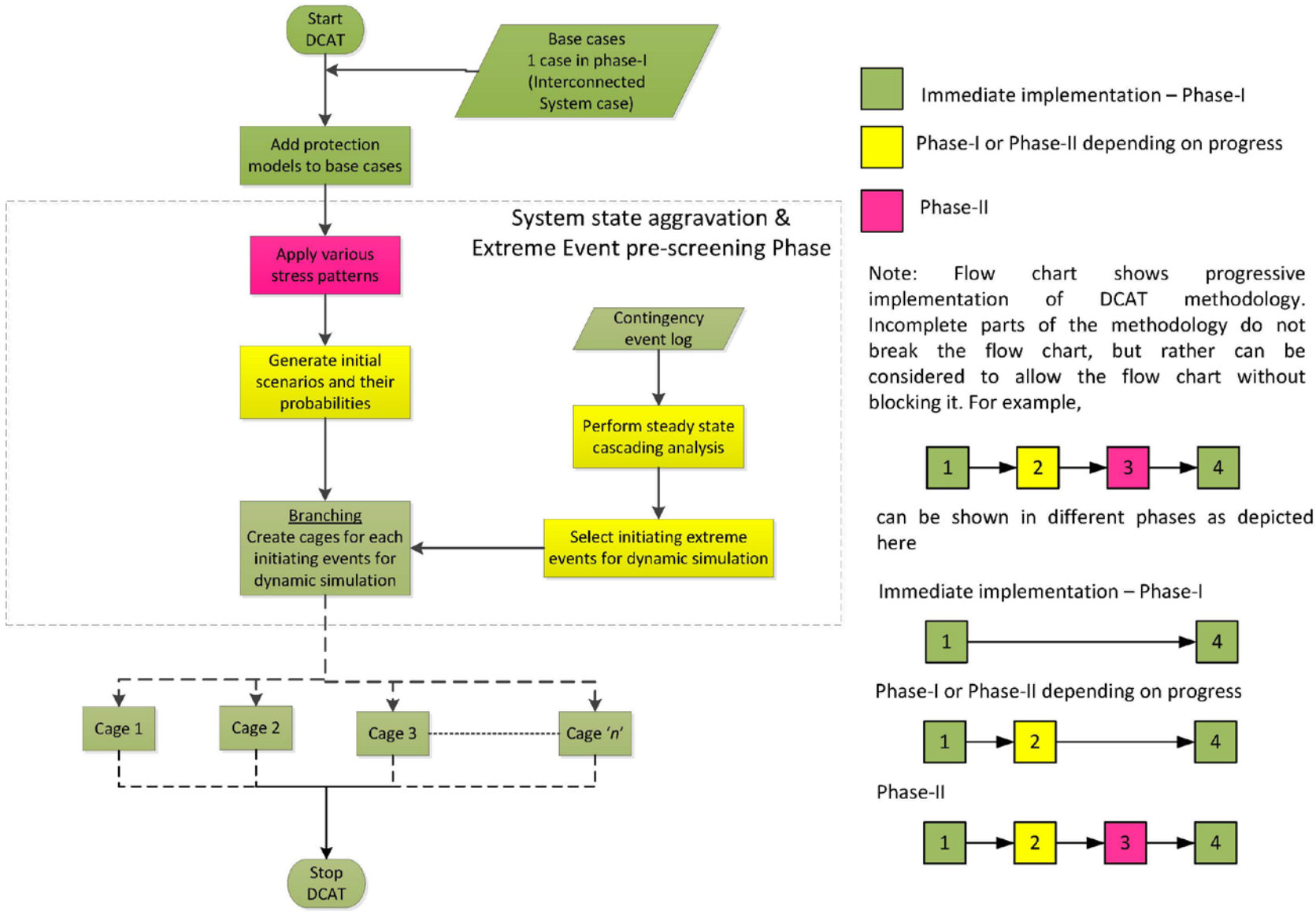

Figure 2.5. DCAT Flow Chart (Part A)

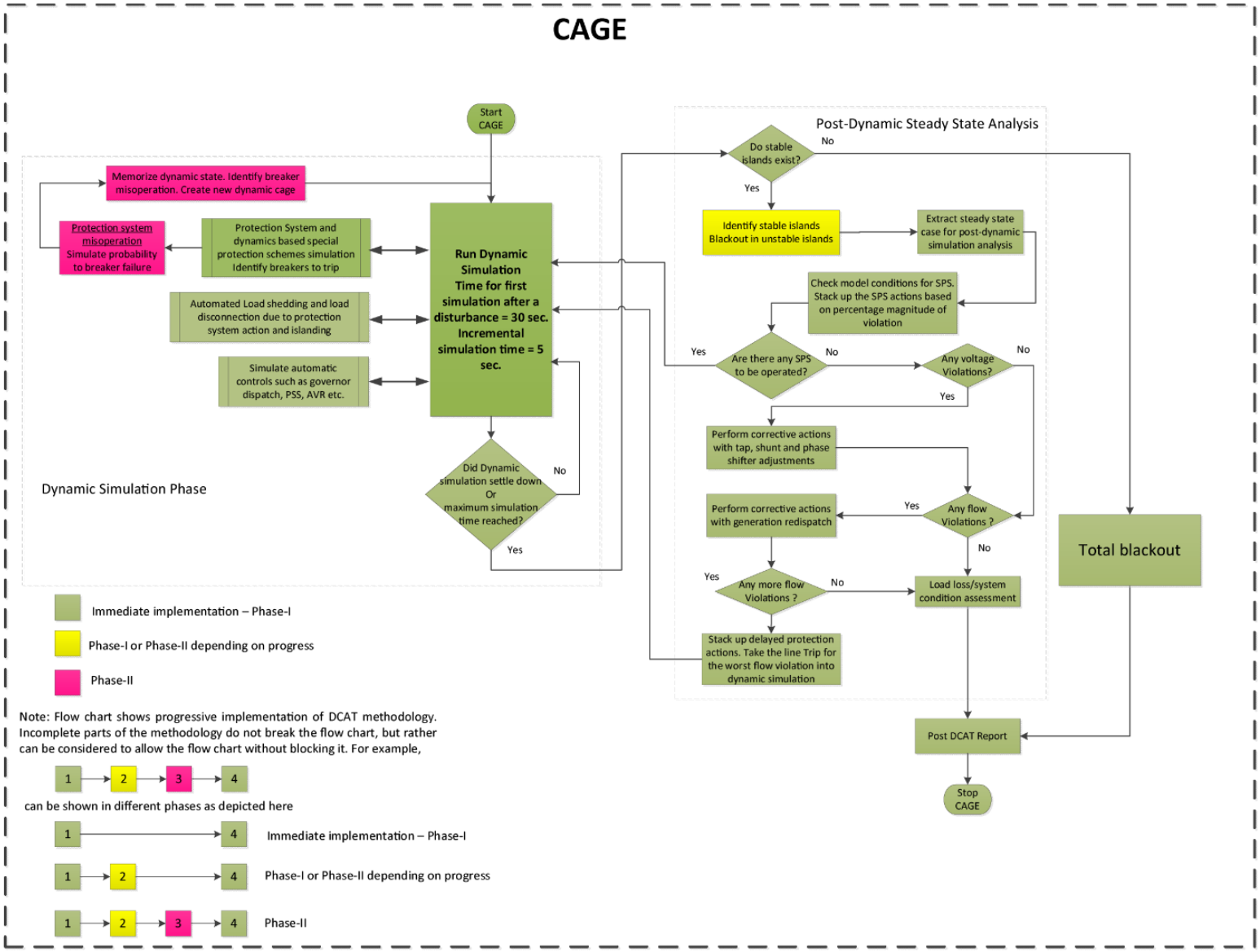

Figure 2.6. DCAT Flow Chart (Part B)

2.5.1 Preparation of Base Cases with Integrated Protection Models

The user can provide multiple base cases corresponding, for example, to different seasons, different levels of wind and solar generation, different load levels, variants of possible system reinforcements, etc., reflecting a variety of possible system conditions. Each case is parenting a new group of simulation cages via branching. The base cases include both power flow and dynamic system models. The base cases can be planning cases or EMS/State Estimation snapshots with added dynamic models. In the first implementation phase, we will consider only one planning base case.

Once a base case is identified, protection system modeling is added to it. This integrated planning/protection model is a very important element of the DCAT methodology. Ideally, this model should be created, tuned and continuously supported by protection engineers. These models are usually not readily available with the interconnection/reliability coordinator/balancing-authority levels. The work of gathering and reconciling this information at the interconnection/reliability coordinator/balancing-authority level should be initiated to enable more accurate extreme-events simulations. An alternative is to use approximate models that are generated based on engineering experience and knowledge of general principles and solutions of protection systems. This approach is taken in the implementation stage of Phase 1 of this project. Selected generic relay models in PSS/E have been used in dynamic simulations as follows:

Undervoltage, overvoltage, underfrequency, and overfrequency relays have been modeled for each generating unit. The settings of generating units' protection relays are based on the new NERC Standard PRC-024-1, "Generator Frequency and Voltage Protective Relay Settings" (NERC PRC-024-1). This standard will take effect in January 2016 for all types of generating units. In addition, out-of-step protection has been implemented through a user-written model that is applied only to synchronous machines.

Typically, transmission line breaker locations are not available in the planning models; rather they are available in grid models used in protection software packages. In this study, Category B contingency lists based on their definition in the old NERC reliability standards (NERC TPL-003-0b and NERC TPL-004-0a) have been used to determine breaker location for the placement of protection within the transmission network of the full interconnection that has been used in the DCAT simulations. Two types of transmission system protection were modeled:

- distance-relay protection (used in dynamic simulation). The suggested relay settings and associated operation of zones of protection are based on best practices.
- overcurrent protection (used in post-dynamic steady-state simulation). The relay settings are based on NERC Standard PRC-023-3, "Transmission Relay Loadability" (NERC PRC-023-3).

Two types of load shedding schemes were modeled as follows:

- underfrequency (frequency-responsive non-firm load shedding)
- underfrequency and undervoltage firm load shedding.

Load-shedding relay settings were provided by the grid operator for the full interconnection used for simulations.

2.5.2 Initial System Aggravation and Event-Screening Phase

At this stage, in the general methodology, we will simulate various system states (load levels, dispatches, etc.) and light contingencies, such as $N-1$ contingencies. We will use power flow simulations at this stage. To select the initiating events that trigger cascading-outages, a steady-state-based contingency/cascading simulation can be applied.

2.5.2.1 Apply Various Stress Patterns

The stress-pattern application module simulates the system aggravation stage of a blackout. The patterns may include various system stresses, such as increasing load, decreasing wind generation, and some generation and transmission system contingencies (e.g., $N-1$ and non-simultaneous $N-1-1$ contingencies). During the implementation stage of Phase 1 of this project, we will not implement this module.

2.5.2.2 Generate Cases with their Probabilities

This module will produce a set of cases corresponding to different base cases, stress patterns, and contingencies used to aggravate the base cases. Each case will be provided with its probability or likelihood as described above.

2.5.2.3 Branching Implementation

Branching means following a multivariant tree of multiple cascading scenarios. In this module, an individual cage is created for each base case, aggravation scenario, and initiating event. Later on in the algorithm, some events can result in different outcomes—for instance, in either correct or incorrect breaker operation (breaker failure). Branching is performed based on probabilities of different outcomes, e.g., the probability of breaker failure.

2.5.2.4 Prescreening of Initiating Events

The prescreening part of the algorithm runs power-flow-based contingency analyses for the log of initiating events. The cascading process is simulated based on the observed overloads and voltage problems, which exceed certain user-specified limits. The outages of PCGs, generator disconnections, and load curtailments are simulated based on these violations. This is a simplified representation of the protection system operation. The amount of load loss and the number of cascading steps are logged to enable the user to rank and select the contingencies for further dynamic simulation. The user will have an option to skip the prescreening process and go directly to the dynamic simulation phase, so that the cascading chains will all be explored based on dynamic models.

2.5.3 Dynamic Simulation Phase

The dynamic simulation process will be internally integrated with the protection system model. At each integration step, system parameters will be checked against the settings of the protection system and dynamics-based protection schemes. Both successful and unsuccessful (due to a failure) operation of

protection will be simulated. For the unsuccessful outcome, new dynamic processes (cages) will be started.

Dynamic simulation is a computationally intensive task. An adaptive simulation time module is implemented to run the dynamic simulation long enough to capture the dynamic response of the system. The appropriate time can be determined by having stability checks at intermediary times that could stop the dynamic simulation. The simulation is initially run for 30 seconds; after that it runs in increments of 5 seconds until reaching a stable point. If instability is detected, the simulation will be stopped. The instability criteria are user defined. For instance, they can include transient voltage and frequency dips, unlimited increase of phase angle differences, etc. If the process is stable, system frequency (or frequencies in stable islands) is logged for the subsequent analysis.

During the simulation process, the load loss inflicted by the protection system, SPS/RAS, and cascading will be logged along with the probability of this loss.

2.5.4 Post-Dynamic Steady-State Analysis

If the dynamic simulation is unstable, the algorithm will search the system topology for islands where the simulation converges to a certain steady-state condition (this is also a check for voltage stability). If no stable islands are identified, the algorithm considers the situation to be total blackout with total load loss. If the entire system or its parts are identified as stable, a post-transient (governor) power flow is run. Additionally, slow-acting SPS/RAS and overcurrent schemes with time delays exceeding the dynamic simulation time limit will be simulated.

If the power flow is divergent, an effort will be made to apply a so-called non-divergent power flow. The non-divergent power flow may use certain more reliable numerical methods such as the continuation power flow method. At a minimum, the solution process should provide information about the power system state that is achievable and closest to the actual solution. All information about the non-divergent power flow will be made accessible to the user for a possible subsequent analysis and corrections.

If the power flow is solvable and additional protection system actions are needed, a new dynamic cage will be created.

The post-transient power flow may have multiple violations that require an operator's action. These actions may include generation redispatch and/or other actions, including possible load shedding. All load drops will be recorded for further analysis and assessment.

2.6 Security Criteria Used in DCAT Implementation

In this section, we describe steady-state and transient performance (reliability) criteria used in DCAT implementation. As explained in Section 1.2, the proposed criteria are based on the new NERC Standard TPL-001-4, "Transmission System Planning Performance Requirements" (NERC TPL-001-4), to be enforced in 2015 and 2016, and a similar WECC Regional Criterion, TPL-001-WECC-CRT-3, "Transmission System Planning Performance," (WECC 2014) currently under development in the WECC system. Our analysis should be also compliant with NERC Standard PRC-023-3, "Transmission Relay Loadability" (NERC PRC-023-3).

Special requirements are added for extreme events. For some of the events P1–P7, some non-consequential load loss[1] is acceptable. For some grid operators' planning studies, non-consequential load loss is not allowed. The NERC TPL-001-4 standard has specific exemptions. The current study guideline uses 300 MW as the load shedding threshold to identify potential critical events that need more detailed analysis. The non-consequential load loss, when it is allowed, should be limited to 300 MW.

The implementation plan is divided into two stages based on security criteria. In the initial implementation stage, we concentrate on extreme events with cascading and load loss due to cascading. Our evaluation is based on the risk of consequential load loss. In the subsequent phase, we will evaluate additional criteria for event categories P0–P7 as described in Section 1.2.

2.6.1 Initial Phase Performance Criteria

Our primary objective is to make sure that for P1–P7 events, we do not see consequential load loss. (Non-consequential load loss may occur for some events.) For extreme events, we will evaluate the consequential load loss during the cascading process.

For transient analysis, the following criteria apply:

a. The largest generator rotor angle deviation with respect to center of inertia (COI) in a single electric island should not exceed 180 degrees in a dynamic simulation.

b. The protection system operation is simulated in PSS/E based on a model developed by PNNL.

c. The transient simulation is stopped when the simulation time exceeds the time limit. PSS/E detects and saves generator rotor angle violations in a log file.

d. If the system is separated into islands, the simulation is conducted for each island. In PSS/E, the dynamic simulations are continued even when islands are created. In the steady-state analysis, it is possible to have islands, but slack buses must be provided for each island. Right now, this is a manual operation that needs to be automated by PNNL.

In an unstable island/system, a complete load loss will be assumed.

In stable islands, a follow-up steady-state analysis will be conducted. System parameters will be checked against criteria formulated in NERC TPL-001-4 and NERC PRC-023-3. Thermal loading will be checked against the NERC PRC-023-3 criterion for non-operation of the protection system under steady-state conditions, i.e., 115% of rating B or 150% of rating A. Based on NERC TPL-001-4, all bus voltages in the stable islands should stay within a range of 0.9–1.1 per unit (pu) If these criteria are violated, the system operator may attempt to redispatch the system or disconnect some loads. Since the overload of 115% of rating B is acceptable for only 15 minutes, these violations will be addressed first.

[1] "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service." (NERC TPL-001-4)

The slower portion of the protection system will be also simulated. If all these actions do not help, some lines, loads, or generators may be disconnected as well. This would trigger another round of dynamic simulations.

2.6.2 Performance Criteria in the Subsequent Phase

Our primary objective is to make sure that for events P1–P7, we do not see consequential load loss. (Non-consequential load loss may occur for some events based on Table 1 of NERC TPL-001-4). For extreme events that we need to evaluate, we will evaluate the consequential load loss during the cascading process. Several additional criteria are suggested to aid the cascading-outage analysis. In a simulation, either steady-state or dynamic, for any type of violation observed, this information will be saved (type, location, time stamps, limiting contingency, etc.) for further processing, if needed.

For steady-state analysis (power flow), the following criteria apply:

a. For normal conditions (P0 events), all bus voltages in the monitored areas stay within a range of 0.95–1.05 pu

b. For post-contingencies (P1–P7 events), all bus voltages in the monitored areas stay within a range of 0.9–1.1 pu

c. For P1 events, the post-contingency voltages of all buses serving loads in the monitored areas shall not exceed ±8% of their pre-contingency values

d. For voltage stability analysis, a positive reactive power (Q) margin is needed so that power flow can be solved at:

    1. 105% of transfer path flow or forecasted peak load, for P0–P1 events

    2. 102.5% of transfer path flow or forecasted peak load, for P2–P7 events

e. Thermal loadings on all the branches in the monitored areas are calculated for P0–P7 contingencies. Thermal loading will be checked against grid operator criteria under steady-state conditions to determine whether it is within 100% of rating B or 100% of rating A.

For dynamic simulation, the following criteria are used:

a. The largest COI-referenced generator rotor angle difference in a single electric island should not exceed 180 degrees in a dynamic simulation.

b. Transient voltage of all monitored buses should recover to at least 80% of their pre-contingency values within 10 seconds.

c. Transient violations will be checked against overcurrent relay settings. These relays will be relied upon to trip lines and a record will be kept of such actions.

d. Transient voltage response will be checked in more detail, e.g., voltage ride-through time duration curve.

e. The transient simulation is stopped when the simulation time exceeds the time limit. PSS/E detects and saves generator rotor angle and voltage recovery violations in a log file.

f. If the system is separated into islands, the simulation is conducted for each island.

g. In an unstable island/system, a complete load loss will be assumed.

h. In stable islands, a follow-up steady-state analysis will be conducted. System parameters will be checked against criteria formulated in NERC TPL-001-4 and NERC PRC-023-3. Thermal loading will be checked against the NERC PRC-023-3 criterion for protection system non-operation under steady-state conditions: 115% of rating B or 150% of rating A. Based on NERC TPL-001-4, all bus voltages in the stable islands must stay within a range of 0.9–1.1 pu. If these criteria are violated, the system operator may attempt to redispatch the system or disconnect some loads. Since the overload of 115% of rating B is acceptable for only 15 minutes, these violations will be addressed first.

i. All bus voltages in the stable islands should stay within a range of 0.9–1.1 pu. If these criteria are violated, the system operator may attempt to redispatch the system or disconnect some loads. The slower portion of the protection system will be also simulated. If all these actions do not help, some lines, loads, or generators may be disconnected as well. This triggers another round of dynamic simulations.

3.0 Protection Modeling

3.1 Introduction

Protective relays and circuit breakers are devices that detect abnormal conditions in a power system and issue appropriate actions to mitigate adverse effects on the system equipment so as to bring the system back to a normal condition as soon as is practical. Another function of protective relaying is to isolate any power system equipment that shows signs of abnormal behavior.

Most relay systems are designed for high dependability, i.e., a system must operate only if a fault is detected in its zone of protection. To make sure all equipment in the system is covered by protection systems, the zone of protection must satisfy two requirements:

1. All equipment must be encompassed by at least one zone.
2. Zones of protection must overlap to prevent any system equipment from being unprotected.

Although the fundamentals of relaying are the same throughout the world, there are differences in implementation depending on the nature of the power system, operating philosophy, experiences, and national standards. For example, power systems that have long transmission lines will have more complicated relays than systems with short transmission lines. In the United States it is more common to open all three phases of a transmission line when a fault occurs in one phase. In the European countries, it is not uncommon for relays to operate on a single phase.

Depending on which equipment (bus, line, generator, transformer, etc.) the relays are designed to protect, appropriate types of relays are chosen.

Protection systems in modern power networks have been identified by NERC as a critical reliability issue. After the 2003 North American blackout, based on the U.S.-Canada Power System Outage Task Force report, the NERC stated that one of the major causes of the large-scale blackout was overly conservative relay settings combined with cascading relay operation. Protection system misoperation or incorrect settings can contribute to the spread of blackouts. Better understanding of protection schemes' sequences of operation, careful review of settings, and proper design changes can minimize the extent of disturbances.

The lack of wide-area consolidated dynamic models with protection relay models incorporated is a major challenge for performing analysis, such as model validation by simulating grid disturbances, performing cascading-outage analysis, and developing RASs/ SPSs. Current practice is to mimic protection actions in dynamic simulations assuming that the fault will be cleared, and identify the elements that will trip due to this fault with a time delay after fault inception. In addition, some grid operators model underfrequency and undervoltage load-shedding relays in their planning models.

Commercial software tools for large-scale power system steady-state and dynamic simulations allow inclusion of some generic protection schemes, but this capability is inadequate and not usually employed by utility planning engineers. Specific software packages designed for coordinating protection relay settings usually use a totally different set of models and simulation approaches with much smaller time steps. These tools are typically used by the protection engineers.

Phase I of the DCAT study focuses on development of a methodology and proof-of-concept testing, and then implementing a simplified and generic protection scheme. A more complex and complete version of protection modeling can be used in future phases, depending on the particular area of investigation. The following sections provide explanations of how protection systems are modeled in the DCAT by using generic relay models in PSS/E that are added to the grid dynamic model for transmission, generation, and load protection. This approach can be used by planning engineers to add protection systems to models used for dynamic simulations.

3.2 Selected Relays for Modeling Transmission Protection

For transmission line protection systems, distance relays are commonly used. Because overcurrent relay tripping actions are generally slow compared to distance relays, overcurrent relays are unlikely to operate during dynamic simulation, if the distance relays operate appropriately. PSS/E imposes a hard limit on the number of relays to be modeled in the transmission system (3,000 maximum). Therefore, we choose not to implement overcurrent relays in dynamic simulation, but rather to monitor line overloading in the post-dynamic analysis. Phase I of the DCAT project uses distance/impedance relays for transmission protection. The initial implementation includes options for (1) distance relays on all lines 100 kV and above, and (2) locations for distance relays on a subset of lines chosen based on NERC Category B contingency definitions. Relaying on some lines below 100 kV may also be added to accurately model particular extreme events.

Distance relays are the most commonly used relays to protect transmission systems. They respond to the impedance between the relay location and the fault location. Variations of this type of relay can be designed to respond to other parameters, such as admittance or reactance between the relay and the fault location.

3.2.1 Methods for Distance-Relay Placement

This section describes the basic approach for generating placement of PSS/E distance-relay model "DISTR1." Two relays are required, one at each end, to fully protect a line. Even ignoring lines below 138 kV, the number of relays required for the full interconnection simulated in this study will exceed the limit imposed by PSS/E. Hence, our approach was to add distance relays for lines at or above 345 kV, and to add relays only at some 138 kV buses based on the location of the initiating event.

A number of approaches were considered for placement of relays in the transmission protection system. In order to perform studies of particular extreme events, ideally the system model would include an integrated, fully accurate protection modeling system, including options for detailed modeling of possible protection failure.

One approach for accomplishing this aspect of the DCAT methodology would be to have a detailed protection model in the software designed specifically for protection modeling (such as CAPE). One form of CAPE and PSS/E model integration for dynamic studies was introduced by Gopalakrishnan et al. (2014). The protection software includes a methodology for populating a grid model with breaker placement in a realistic manner. An even more exact method for determining placement of protective devices is to extract the information from the EMS model, such as from a Common Information Model

(CIM) database. Both approaches were considered for the DCAT project but found to be beyond the scope of Phase I, which focuses mainly on development and demonstration of the tool methodology.

When information about locations of breakers and other protection devices is not available, one possibility is simply to assume that breakers are present on both ends of all the lines listed in the power grid model. This, however, becomes intractable for a sufficiently large system; it may excessively slow down the dynamic simulation, or it may hit a hard limit in the software. This assumption is also unrealistic for all medium- and lower-voltage lines.

Another possibility could be to take advantage of the fact that utilities and balancing authorities collect contingency definitions, and the groupings in Category B contingency definitions may indicate groups of elements that are likely to be tripped together. This can affect relay placement and estimation of where breakers might be located in the system.

For DCAT Phase I, a much generalized approximation is desired. Based on recommendations from industry partners, DCAT Phase I does not model transmission protection below 138 kV, uses some rough approximations for relay placement at 138 kV, and focuses on detail and accuracy for distance-relay placement at 345 kV and above.

3.2.2 Relay Placement Using Category B Contingency Definitions

This section describes how Category B contingency definition files could be used to give insight into where the breaker placement might be in the system and to aid in placement of the DISTR1 relays. In this document, a “Category B grouping” is the set of transmission lines that make up a multiple-line Category B contingency definition.

For the full interconnection system that is used in Section 5.2 simulations, the following rules have been followed for distance relay placement:

- PSS/E will generate an error if a distance relay is placed on a line/branch with very small impedance or a zero-impedance line/branch. Our approach is not to place distance relays on such lines/branches.

- For 345 kV and above, all lines not part of a Category B grouping and not excluded to prevent “zero impedance line” errors have DISTR1 relays placed at each end of the line. Those lines that are part of a Category B grouping have DISTR1 relays placed according to the structure of the grouping.

- The 138 kV lines that are not included in a Category B contingency definition are excluded from having DISTR1 relays. 138 kV lines that are listed in single-line Category B contingency definitions have DISTR1 relays placed at each end of the line. Additional detail may be added to better simulate a particular cascaded sequence based on a certain initiating event. Those lines that are part of a Category B grouping have DISTR1 relays placed roughly according to the structure of the grouping, using generalized assumptions.

The following sections describe some of the structures that could be found in the Category B definitions discussed above, and details placement of DISTR1 relays.

3.2.2.1 Single Branch

As noted in a previous section, for 345 kV and above, all lines not part of a Category B grouping and not excluded to prevent "zero impedance line" errors have DISTR1 relays placed at each end of the line as shown in Figure 3.1. This means that for each such line, two PSS/E DISTR1 relays are added with the only difference between them being how the *from bus* and *to bus* are defined in the corresponding dynamic model of the relays.

Figure 3.1. A Structure Common in Category B Contingency Definitions Consisting of a Single Branch

3.2.2.2 Two Branches in Parallel

Figure 3.2 shows a structure that may be found in Category B contingency definitions consisting of a double branch between the same two buses. For the structure shown in Figure 3.2, the current code adds DISTR1 relays placed at each end of each line as shown in Figure 3.2.

Figure 3.2. A Structure That May Be Found in Category B Contingency Definitions Consisting of Two Branches in Parallel

It may be possible that one of the two branches would be skipped by PSS/E because it generates a "zero impedance line" error in PSS/E, as shown in Figure 3.3.

Figure 3.3. A Structure That May Be Found in Category B Contingency Definitions Consisting of Two Parallel Branches Where One Has Zero Impedance

3.2.2.3 Two Branches in Series

Figure 3.4 shows a common structure that may be found in Category B contingency definitions consisting of two branches in series. For the structure shown in Figure 3.4, the current code adds two relays as shown. The relays are at each end of the structure, with the *from bus* for each relay being the bus at that edge of the structure. The impedance (Z) settings for the two relays are set to treat the length of the structure as the line length: $Z_{relay} = Z_{line1} + Z_{line2}$.

Figure 3.4. A Structure Common in Category B Contingency Definitions Consisting of Two Branches in Series

3.2.2.4 Three Branches Attached to a Single Bus

Figure 3.5 shows a common structure that may be found in Category B contingency definitions consisting of three branches attached to a single bus. For the structure shown in Figure 3.5, the code adds three relays as shown. The *from bus* for each relay is the bus at that edge of the structure. The impedance settings for the relays are set to treat the length of the structure as the line length: $Z_{relay} = Z_{line1} + Z_{line2}$, where Z_{line1} is the impedance of the line that the relay is located on. This means that for any of the three relays, there are two possibilities for Z_{line2}. In this case, Z_{line2} is chosen to be the larger of the two possibilities.

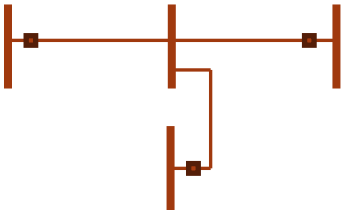

Figure 3.5. A Structure Common in Category B Contingency Definitions Consisting of a Central Bus with Three Attached Lines

3.2.2.5 Three Branches in Series

Figure 3.6 shows a structure that may be found in Category B contingency definitions consisting of three branches in series. For the structure shown in Figure 3.6, the code adds two relays as shown. The relays are at each end of the structure, with the *from bus* for each relay being the bus at that edge of the structure. The impedance settings for the two relays are set to treat the length of the structure as the line length: $Z_{relay} = Z_{line1} + Z_{line2} + Z_{line3}$.

Figure 3.6. A Structure Common in Category B Contingency Definitions Consisting of Three Branches in Series

3.2.2.6 Three Branches in Series with a Single Lateral Branch

Figure 3.7 shows a structure that may be found in Category B contingency definitions consisting of three branches in series with a single lateral branch. For the structure shown in Figure 3.7, the current code adds three relays as shown. The *from bus* for each relay is the bus at the edge of the structure. The impedance settings for the relays are set to treat the length of the structure as the line length: $Z_{relay} = Z_{line1} + Z_{line2} + Z_{line3}$, where Z_{line2} and Z_{line3} are impedances of the two rightmost lines in the structure, and Z_{line1} is chosen to be the larger of the two remaining lines.

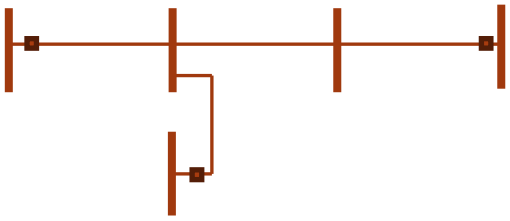

Figure 3.7. A Structure That May Be Found in Category B Contingency Definitions Consisting of Three Branches in Series with a Single Lateral Branch

3.2.2.7 Four Branches in Series

Figure 3.8 shows a structure that may be found in Category B contingency definitions consisting of four branches in series. For the structure shown in Figure 3.8, the current code adds two relays as shown. The relays are at each end of the structure, with the *from bus* for each relay being the bus at that edge of the structure. The impedance settings for the two relays are set to treat the length of the structure as the line length: $Z_{relay} = Z_{line1} + Z_{line2} + Z_{line3} + Z_{line4}$.

Figure 3.8. A Structure That May Be Found in Category B Contingency Definitions Consisting of Four Branches in Series

3.2.2.8 A Sequence of a Single Branch, a Double Branch, and a Single Branch in Series

Figure 3.9 shows a structure that may be found in Category B contingency definitions consisting of a single branch, a double branch, and a single branch, in series. For the structure shown in Figure 3.9, the current code adds two relays as shown. The relays are at each end of the structure, with the *from bus* for each relay being the bus at that edge of the structure. The impedance settings for the two relays are set to treat the length of the structure as the line length: $Z_{relay} = Z_{line1} + (Z_{line2a} || Z_{line2b}) + Z_{line3}$.

Figure 3.9. A Structure That May Be Found in Category B Contingency Definitions Consisting of a Single Branch, a Double Branch, and a Single Branch in Series

3.2.3 Distance-Relay Model Settings

It is fairly typical to set Zone 1 for distance relays at 85–90% of the line length, Zone 2 at 120–150% of the line length, and Zone 3 at 150% of the next line. Operation of Zone 2 of the distance relay for the line must coordinate with Zone 1 of the next line such that Zone 1 of the next line must operate before Zone 2 of the first line does. This coordination delay for Zone 2 is usually of the order of 0.3 s. Similarly, operation of Zone 3 for the line must coordinate in time and distance with Zone 2 of the next line. The operating time of Zone 3 is usually of the order of 1 s (Horowitz and Phadke 2008).

The initial implementation shown in this document uses generic Zone 1 and Zone 2 settings that are similar across all distance relays, with settings based on the values of X and R from the branch table in the PSS/E system model. The Zone 3 protection approach will be added in the next phase of the DCAT project. Detailed model descriptions and implementation of distance relay DISTR1 are given in Appendixes A and B.

3.3 Selected Relays for Modeling Generator Protection

Modeling generation-unit protection in the DCAT uses over/undervoltage and over/underfrequency relays. The relay models are used to protect every single generator (there are options available to disconnect an entire generator bus, but these are not used in this implementation). Out-of-step protection has been implemented through a user-written model that is applied only to synchronous machines.

All the PSS/E generator-protection relay models include the following two parameters:

a) *TP*, which is the relay pickup time in seconds

b) *TB*, which is the breaker time in seconds.

For this project, *TB* is set to 83 ms, which is taken from "IEEE Standard for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis - Preferred Ratings and Related Required Capabilities for Voltages Above 1000 V" (IEEE 2009). The standard states: "The ratings in this column are the maximum time interval to be expected during a circuit breaker opening operation between the instant of energizing the trip circuit and the interruption of the main circuit on the primary arcing contacts under certain specified conditions."

The parameter *TP* is set to a minimum of 50 μs, which is taken from the Schweitzer Engineering Laboratories datasheet, "SEL-700G Family of Generator and Intertie Protection Relays" (SEL 2015). The parameter *TP* is also used to implement different time-delayed settings.

3.3.1 Generating Unit Under/Overvoltage Relay Settings

Settings for tripping over/undervoltage relays are taken from NERC Standard PRC-024-1, "Generator Frequency and Voltage Protective Relay Settings" (NERC PRC-024-1), effective in 2016. The settings used are shown in Table 3.1.

Table 3.1. High- and Low-Voltage Ride-Through Times as Specified in NERC Standard PRC-024-1

High-Voltage Ride-Through Duration		Low-Voltage Ride-Through Duration	
Voltage (pu)	Time (s)	Voltage (pu)	Time (s)
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

3.3.1.1 PSS/E Documentation: Under/Overvoltage Generator Trip Relay: VTGTPA

This is a modified section from the PSS/E Version 32 documentation.

The under/overvoltage model, VTGTPA, is a protection model located at the generator bus that continuously monitors the voltage on that bus or a remote bus specified by the user. It trips the generator for under- and overvoltage conditions on the generator (or remote bus).

The relay timer is started during under/overvoltage conditions, i.e., when voltage is less than, greater than, or equal to the corresponding pickup threshold. The relay resets instantaneously if the voltage restores within the two pickup thresholds. If the relay is not reset, a trip signal is sent to the circuit breaker if the timer reaches its setting. Voltage must have remained in an under/overvoltage condition for the entire time delay for generator tripping to occur. Generator tripping is delayed by the circuit breaker time.

Several relays can be used to simulate the coordinates of the protection system with the voltage/frequency-versus-time function. A detailed model description and parameters of under/overvoltage relay VTGTPA are provided in Appendix A.

3.3.2 Generating Unit Under/Overfrequency Relay Settings

A major concern in the operation of steam turbine generators is the possibility of damage due to prolonged operation at reduced frequency during a system overload condition. Such a condition would result from an under-shedding of load during a system disturbance. Recognizing this possibility, many utilities have used or are considering the application of underfrequency relays and timers to protect steam turbine generators from damage (GE, Undated).

Settings for tripping over/underfrequency relays are taken from NERC (2014), effective in 2016. These are shown in Table 3.2.

Table 3.2. High- and Low-Frequency Duration Times as Specified in NERC Standard PRC-024-1

High-Frequency Duration		Low-Frequency Duration	
Frequency (Hz)	Time (s)	Frequency (Hz)	Time (s)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

Hz = hertz

3.3.2.1 PSS/E Documentation: Under/Overfrequency Generator Trip Relay: FRQTPA

This is a modified section from the PSS/E Version 32 documentation.

The under/overfrequency model, FRQTPA, is a protection model located at the generator bus that continuously monitors the frequency on that bus or a remote bus specified by the user. It trips the generator for under- and overfrequency conditions on the generator (or remote bus).

The relay timer is started during under/overfrequency conditions, i.e., when frequency is less than, greater than, or equal to the corresponding pickup threshold. The relay resets instantaneously if the frequency restores within the two pickup thresholds. If the relay is not reset, a trip signal is sent to the circuit breaker if the timer reaches its setting. Frequency must have remained in an under/overfrequency condition for the entire time delay for generator tripping to occur. Generator tripping is delayed by the circuit breaker time.

Several relays can be used to simulate the coordinates of the protection system with the frequency-versus-time function. A detailed model description and parameters of under/overfrequency relay FRQTPA are provided in Appendix A.

3.3.3 Generator Out-of-Step Protection

In addition to the over/undervoltage and over/underfrequency relays, this project also implements a user-written model, GNSCNANG,[1] that scans all rotor angles at each time step during the dynamic simulation and trips generators that have rotor angles advanced across a specified threshold compared to a chosen reference angle. The operation of this relay mimics the operation of an out-of-step relay.

To detect and properly trip generators that accelerate too much against the rest of the generators in the system, PNNL requested the development of a user-written model due to limitations in the existing PSS/E out-of-step model. This user-written model scans all rotor angles at each time step during dynamic simulation. If a relative rotor angle is greater than a specified threshold, the corresponding generator will be tripped out of service. The reference angle is chosen as the COI angle in this project. This user-written model scans only synchronous generators. It excludes classically modeled generators and all user-written generator models such as wind, solar, battery, flexible AC transmission system (FACTS) devices, and DC equivalence machines. In this project, the threshold is chosen to be 180 degrees, and the reference angle is chosen as the COI angle, which is defined as

[1] GNSCNANG is a PSS®E user-written model developed by Siemens PTI for this project.

$$\delta_{COI} = \frac{1}{H_T}\sum_{i=1}^{N} H_i \delta_i$$

$$H_T = \sum_{j=1}^{N} H_j$$

$$\delta_{COI}^{i} = \delta_i - \delta_{COI}$$

where N = total number of synchronous machines considered

H_j = inertia of the *j*th machine

δ_j = rotor angle of the *j*th machine

δ_{COI} = reference angle in the COI reference frame

δ_{COI}^{i} = relative rotor angle of the *i*th machine in the COI reference frame

As soon as the relative rotor angle in the COI reference frame is greater than the threshold value, the generator should trip. Detailed model description and parameters of generator scan and trip model GNSCNANG are shown in Appendix A.

3.4 Selected Relays for Modeling Load Shedding

In order to fully model a cascaded operation, islanding and load-shedding capability must be present in the model. Underfrequency load-shedding relays drop load on a predetermined schedule to balance load and generation under such circumstances. Typically there is a sequence of shedding increments of load if/as frequency continues to drop. Figure 3.10 shows a sequence of frequency load-shedding points on the frequency (horizontal) axis; time is on the vertical axis.

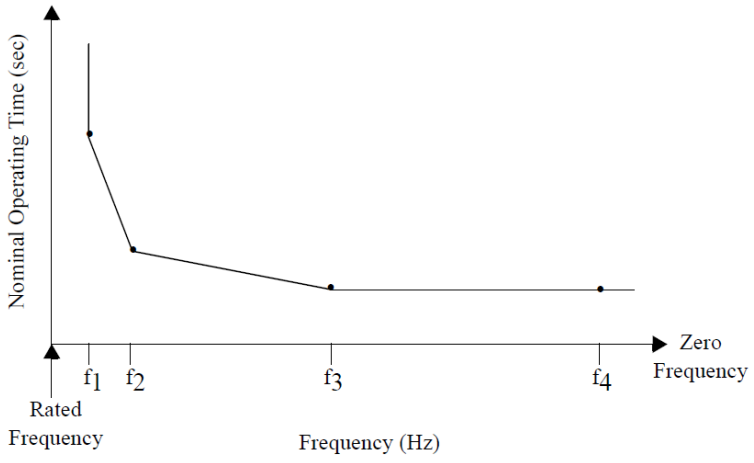

Figure 3.10. Time versus Frequency Curve Showing Load-Shedding Points along the Frequency Axis

In addition, undervoltage load-shedding relays drop load on a predetermined schedule if voltage drops below a certain value. That is typically done in steps.

Two types of load shedding schemes were modeled:

- underfrequency (frequency-responsive non-firm load shedding)
- underfrequency and undervoltage firm load shedding.

Load-shedding relay settings were provided by the grid operator of the full interconnection used for simulation. Detailed model descriptions and parameters of underfrequency and undervoltage load shedding are provided in Appendix A.

4.0 Post-Dynamic Simulation Analysis

Post-dynamic simulation is conducted using PSS/E in Phase I of the DCAT project. However, other tools have similar capabilities and may be used in future phases or for different aspects of the analysis. For illustration purposes, we use the "savnw" test system that is available with the PSS/E software package. The following sections explain how DCAT performs a stability check to stop dynamic simulation, extract a steady-state case, and perform automatic and manual corrective actions. A flow chart for the post-dynamic analysis is shown in Figure 4.1.

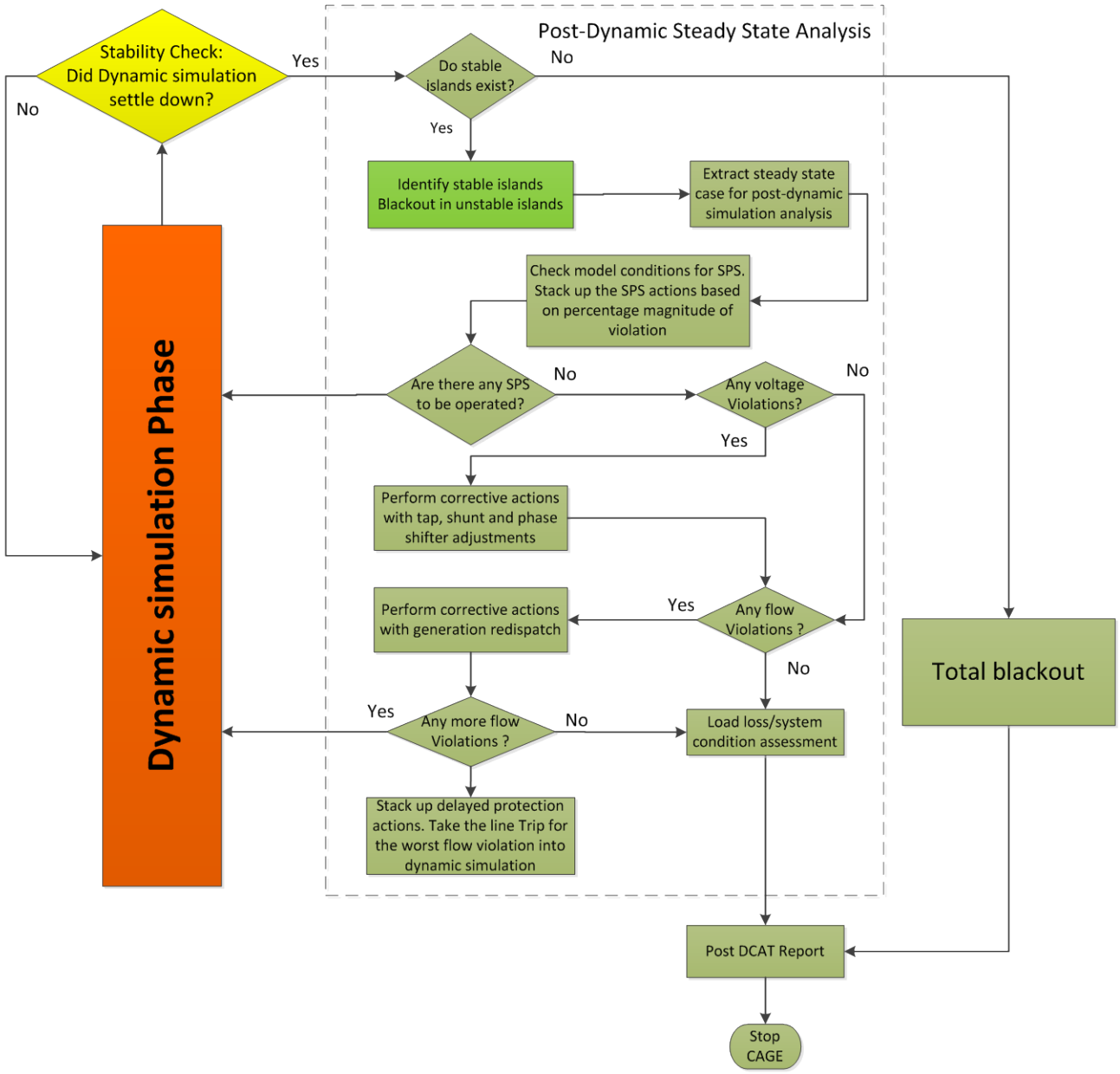

Figure 4.1. Flow Chart of the Post-Dynamic Analysis

4.1 Stability Check to Stop Dynamic Simulation

Dynamic simulation is a computationally intensive task. An appropriate trade-off is necessary to run the dynamic simulation long enough to capture the dynamic response of the system. The appropriate simulation time can be determined by having stability checks at intermediate times that could stop the dynamic simulation. In the DCAT, each dynamic simulation is run for 30 seconds; a stability check is then performed. If the system has not reached a stable point, dynamic simulation is then resumed for another 5 seconds. This process is repeated until a stable point is reached or it is concluded that the system is not stable.

To extract a useful power flow case at the end of dynamic simulation for a corrective action task, it is required that the system reaches a steady state at the end of dynamic simulation. A Python script was written to run the stability check at the end of each dynamic simulation period. The steps are as follows.

Step 1 – Run dynamic simulation for the required period, T_0 (= 30 s in this project)

Step 2 – Run the stability check

Step 3 – If the system reaches a steady state, extract the power flow case and go to the corrective action stage described in Section 4.2;

– Otherwise, if the dynamic simulation period is equal to the maximum time T_{max} (= 60 s in this project), print out the status and save the power flow case. Otherwise, continue to run dynamic simulation for ΔT = 5 more seconds and then go back to Step 2.

The algorithm for stability check is shown in Figure 4.2.

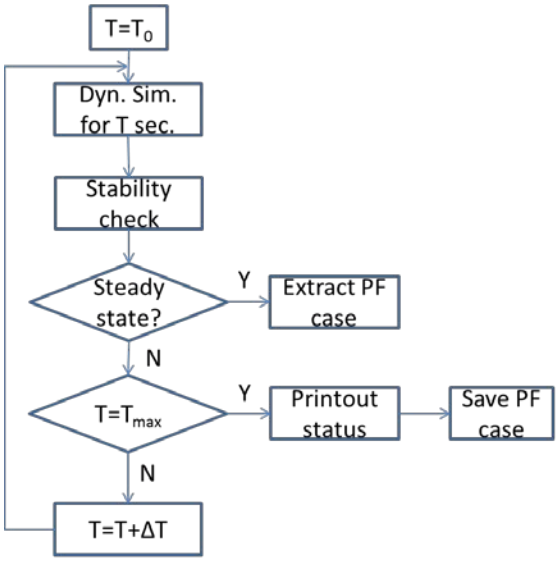

Figure 4.2. Algorithm for Stability Check

4.1.1 Criterion for Stability Check (System Reaches Steady State)

The speeds of all traditional synchronous machines (i.e., excluding wind machines, FACTS devices, batteries, solar generators, and DC equivalence generators) in the last two seconds of dynamic simulation

periods are used in the stability check. First, the difference between maximum and minimum values in the last two seconds is calculated for each considered speed channel. Next, the maximum of the calculated differences across all considered channels is computed. This computed maximum value is compared with a user-specified tolerance (= 10^{-4} in this project) to determine whether the system has reached a steady state. If the computed maximum value is less than the tolerance, the system is considered to have reached a steady state. Otherwise, the system has not settled down and more dynamic simulation is needed, or if the dynamic simulation has reached T_{max}, a message is printed out to report system status.

4.2 Extracting a Power Flow Case at the End of Dynamic Simulation

An important feature of the DCAT is to perform post-dynamic analysis of the system. It is possible that there may be several islands in the post-fault state. The simulation is accomplished using the following steps.

- Step 1: During the dynamic simulation, generator Pelec, Qelec, bus voltage, and angle magnitudes, power flows in lines, and the status of power system components such as generators, buses, branches, transformer taps, switched shunts, etc., will need to be captured for post-processing analysis. This could be accomplished by saving the case at the end of the dynamic simulation. For more information, refer to the PSS/E Program Operation Manual, Section 18.2.
- Step 2: To perform the dynamic simulation, the generators are converted to a current source model using the command “CONG”. A traditional power flow solution cannot be performed when the generators are converted. This process is not automatically reversible. This can be resolved by saving the power flow raw file (i.e., converting the *.sav file to a *.raw file).
- Step 3: Activity CONG converts all power flow Type 3 (swing) buses to Type 2 (PV) (see PSS/E Program Operation Manual, Section 18.3). There is, hence, no swing bus in the *.raw file. To run a Newton-Raphson (NR) power flow, at least one swing bus needs to be identified in every island. There are several possibilities that might result from dynamic simulation:
    a) At least one of the swing buses in the original power flow case is not isolated: one possible way to solve the NR power flow is to restore the bus type of all the original swing buses back to Type 3.
    b) During dynamic simulation, some buses might be isolated (becoming Type 4 buses). It is possible that the identified swing buses are isolated buses after dynamic simulation, but the islands in which they are located have several connected buses. In this case it is necessary to identify some other buses as swing buses to perform NR power flow.
    c) During dynamic simulation, multiple trippings might have created many islands. It is necessary to identify each island and select a swing bus in every island to perform NR power flow.
    d) During a cascading event, if an island has no active generators at the end, then all buses are tripped and thus isolated in the island. This feature of dynamic simulation makes sure that unsupported islands are automatically blacked out.

PSS/E provides several other power flow methods, such as *inertial response* power flow and *governor response* power flow.

a) Inertial response power flow (see PSS/E Program Operation Manual, Section 6.8.3) is intended to indicate system conditions that would exist one-half second after the initiation of an event in a steady-state system condition. In this time frame, it is assumed that generator overcurrent protection and governor effects are minimal, and that changes in generator power levels are influenced principally by machine inertias.

b) The governor-response power flow solution (see PSS/E Program Operation Manual, Section 6.8.4) is intended to indicate system conditions that would exist for at least several seconds after the initiation of an event following a steady-state system condition. In this time frame, it is assumed that voltage-regulator and turbine-governor effects are influential in bringing the system to a new steady-state condition, and that changes in generator power levels are determined by governor droop and damping characteristics.

These power flows have also been analyzed. After the raw case as shown in Step 2 is read, to perform inertial- or governor-response power flows, a “Unit inertia and governor data file” is necessary. This could be extracted when a power flow case and dynamic files are read into PSS/E. This file could be used to perform inertial- and governor-response power flows. One advantage of inertial- and governor-response power flows is that a swing bus need not be selected in every island. The power flows automatically identify all islands and select swing buses in every island.

The purpose of extracting a steady-state case after the dynamic simulation is to make sure that analog states (bus voltages’ magnitudes and angles, generator real and reactive power levels, load levels, etc.) and digital states (statuses of buses, branches, generators, and other components such as ON/OFF switches) are preserved at the end of dynamic simulation. Since the algorithms behind dynamic simulations and steady-state power flows might be different, it is possible that a settled solution at the end of the dynamics might not be a converged solution in the steady state. This could be due to limitations in power-flow algorithms to capture the behavior of generators and other dynamic components.

To verify the best solution approach that matches the results obtained at the end of dynamic simulation, a few tests are performed.

4.2.1 Post-Dynamic Steady-State Case Verification through Flat-Start Dynamic Simulation

The purpose of this task is to compare the power-flow solution of the converted case before a flat-start dynamic simulation (dynamic simulation without any disturbance) and the extracted power flow case at the end of the flat-start dynamic simulation.

The power flow results of the pre-dynamic simulation converted case are compared to the results obtained from post-dynamic simulation and solved with various power flow methods. The comparisons are between A & B and A & C in Figure 4.3. The results are shown in Table 4.1. It can be seen that the power flow results are almost identical, which means extracting a steady-state case at the end of dynamic simulation is a valid approach.

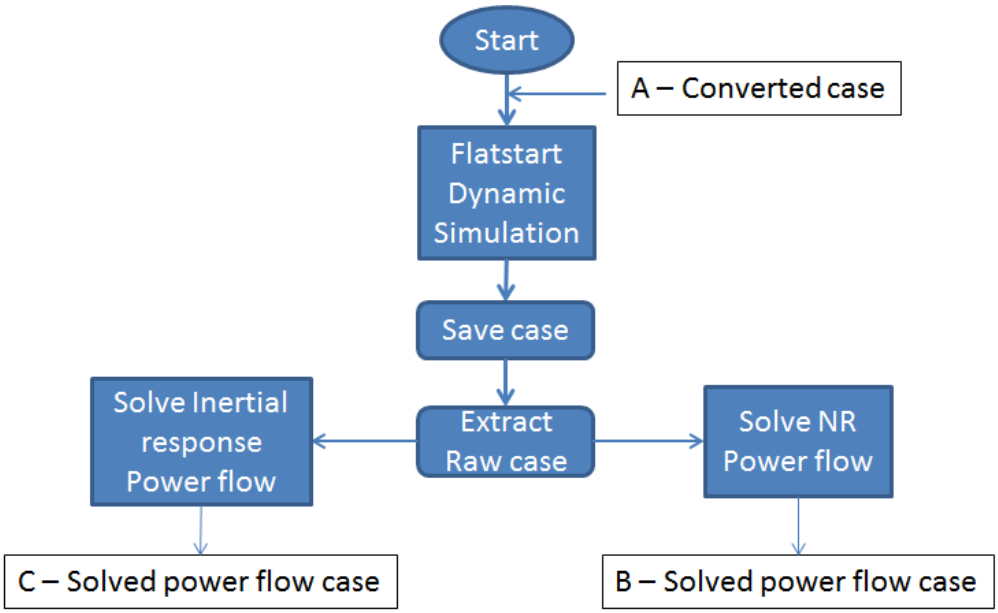

Figure 4.3. Flat-Start Dynamic Simulation for Comparing Various Power Flows

Table 4.1. Flat-Start Comparison for Buses with Maximum Variation in Power Flow Result for the PSS/E "savnw" Case

		Pre-Dynamic		Post-Dynamic NR Power Flow Results for the Extracted Steady-State Case		Absolute Difference		Post-dynamic INLF (Inertial Response) for the Extracted Steady-State Case		Absolute Difference	
		Bus Voltage		Bus Voltage				Bus Voltage			
Bus #	Bus Name	Mag (pu)	Angle (deg)	Mag (pu)	Angle (deg)	Δmag	Δangle	Mag (pu)	Angle (deg)	Δmag	Δangle
3018	CATDOG_G	1.0218	−4.08	1.0218	−4.08	0	0	1.0217	−4.08	0.0001	0

Mag = magnitude

4.2.2 Post-Dynamic Steady-State Case Verification through Fault Dynamic Simulation

A dynamic simulation run is performed by adding a bus fault at one of the substations (Bus 205 in this example) in the PSS/E test system. The bus fault is applied for six cycles and then cleared by isolating the faulted bus. Dynamic simulation results are generated and compared with post-dynamic simulation power flow results as shown in the flow chart in Figure 4.4.

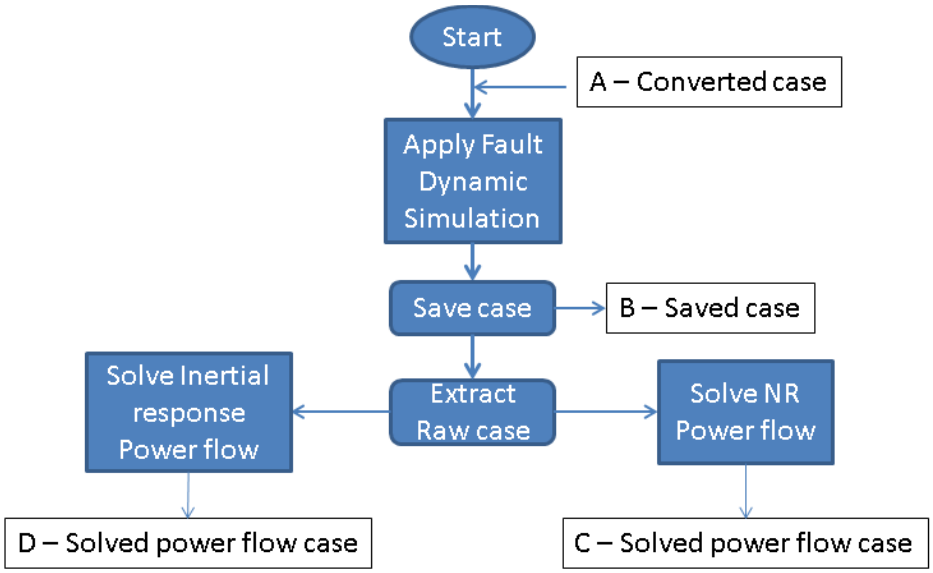

Figure 4.4. Dynamic Simulation with Fault Induced for Comparing Various Power Flows

The system state resulting after the dynamic simulation case and that obtained after solving power flow on the post-dynamic simulation state are compared. The comparisons are between cases B & C and B & D shown in Figure 4.4. The results are shown in Table 4.2 and Table 4.3. It can be seen that the power flow results are almost identical, which means extracting a steady-state case at the end of dynamic simulation and solving it using NR or inertial response power flow (INLF) is a valid approach.

Table 4.2. Comparison of PSS/E "savnw" Case Power Flow Results with Maximum Deviations

		Results at the End of Dynamic Simulation		Post-Dynamic NR Power Flow Results for the Extracted Steady-State Case			
		Bus Voltage		Bus Voltage		Absolute Difference	
Bus #	Bus Name	Mag (pu)	Angle (deg)	Mag (pu)	Angle (deg)	Δmag	Δangle
101	NUC-A	1.0206	−11.62	1.02	−11.25	0.0006	0.37
102	NUC-B	1.0206	−11.62	1.02	−11.25	0.0006	0.37
151	NUCPANT	1.0097	−15.77	1.0085	−15.41	0.0012	0.36
152	MID500	0.9908	−27.68	0.9873	−27.37	0.0035	0.31
153	MID230	0.9609	−30.27	0.9571	−29.98	0.0038	0.29
154	DOWNTN	0.8765	−39.21	0.8706	−38.95	0.0059	0.26
201	HYDRO	1.041	−17.5	1.04	−17.14	0.001	0.36
202	EAST500	0.9868	−26.91	0.9837	−26.58	0.0031	0.33
203	EAST230	0.9399	−32.38	0.9361	−32.08	0.0038	0.3
206	URBGEN	1.0283	143.72	0.98	143.72	0.0483	0
211	HYDRO_G	1.0412	−11.92	1.0425	−11.57	0.0013	0.35
3001	MINE	1.0205	−28.81	1.0204	−28.75	0.0001	0.06
3002	E. MINE	1.015	−29.23	1.0141	−29.13	0.0009	0.1
3003	S. MINE	1.0098	−29.73	1.0087	−29.63	0.0011	0.1
3004	WEST	0.9908	−30.65	0.9872	−30.41	0.0036	0.24
3005	WEST	0.9669	−32.73	0.9624	−32.5	0.0045	0.23
3006	UPTOWN	0.9631	−30.98	0.9591	−30.7	0.004	0.28
3007	RURAL	0.9289	−36.59	0.9221	−36.34	0.0068	0.25
3008	CATDOG	0.9169	−37.54	0.9075	−37.27	0.0094	0.27
3011	MINE_G	1.0384	−27.45	1.04	−27.45	0.0016	0
3018	CATDOG_G	1.0142	−32.4	0.9735	−31.85	0.0407	0.55

Mag = magnitude

Table 4.3. Comparison of Inertial Response Power Flow Results with Maximum Deviations for the PSS/E "savnw" Case

		Results at the End of Dynamic Simulation		Post-Dynamic INLF (Inertial Response) for the Extracted Steady-State Case			
		Bus Voltage		Bus Voltage		Absolute Difference	
Bus #	Bus Name	Mag (pu)	Angle (deg)	Mag (pu)	Angle (deg)	Δmag	Δangle
101	NUC-A	1.0206	−11.62	1.0206	−11.62	0	0
102	NUC-B	1.0206	−11.62	1.0206	−11.62	0	0
151	NUCPANT	1.0097	−15.77	1.0093	−15.75	0.0004	0.02
152	MID500	0.9908	−27.68	0.988	−27.62	0.0028	0.06
153	MID230	0.9609	−30.27	0.9576	−30.22	0.0033	0.05
154	DOWNTN	0.8765	−39.21	0.871	−39.17	0.0055	0.04
201	HYDRO	1.041	−17.5	1.041	−17.48	0	0.02
202	EAST500	0.9868	−26.91	0.9844	−26.85	0.0024	0.06
203	EAST230	0.9399	−32.38	0.9368	−32.33	0.0031	0.05
206	URBGEN	1.0283	143.72	1.0283	143.72	0	0
211	HYDRO_G	1.0412	−11.92	1.0436	−11.95	0.0024	0.03
3001	MINE	1.0205	−28.81	1.0192	−28.78	0.0013	0.03
3002	E. MINE	1.015	−29.23	1.0132	−29.19	0.0018	0.04
3003	S. MINE	1.0098	−29.73	1.0078	−29.69	0.002	0.04
3004	WEST	0.9908	−30.65	0.9872	−30.58	0.0036	0.07
3005	WEST	0.9669	−32.73	0.9623	−32.67	0.0046	0.06
3006	UPTOWN	0.9631	−30.98	0.9595	−30.92	0.0036	0.06
3007	RURAL	0.9289	−36.59	0.9221	−36.52	0.0068	0.07
3008	CATDOG	0.9169	−37.54	0.9077	−37.46	0.0092	0.08
3011	MINE_G	1.0384	−27.45	1.0384	−27.43	0	0.02
3018	CATDOG_G	1.0142	−32.4	0.9737	−32.06	0.0405	0.34

4.3 Corrective Actions

As part of DCAT methodology, after a dynamic simulation is performed, automatic and manual corrective actions are modeled. The automatic control actions of transformer tap changes, switching of shunt reactors and capacitor banks, phase shifters, static compensators (STATCOMs), and static VAr compensators (SVCs) are used to eliminate voltage violations. The DCAT implements these actions using the PSS/E AC corrective actions function, which is part of the Multi-Level AC Contingency Computation (MACCC) application. Operator manual actions to eliminate line overloading through generation redispatch and load shedding are modeled in the DCAT using the PSS/E corrective actions function, which is part of the MACCC application.

If there are still overloaded lines after all possible corrective actions have been taken, the DCAT will select the line with the highest overloading percentage to be tripped. This process is performed through dynamic simulation as if this tripping is a new initiating event imposed on the current system topology, i.e., including all the trippings that occurred in previous cascading steps.

This section discusses the different kinds of strategies that can be used to make sure that a converged solution with no violations for the post-dynamic steady-state case can be achieved.

4.3.1 Generation Redispatch

For computing power flows with respect to contingency analysis, it might be beneficial to use a distributed-slack-based approach for better convergence. The following subsections explain a few available techniques in PSS/E.

4.3.1.1 Newton-Raphson Solution in PSS/E with Inertial/Governor Redispatch

As explained in Section 4.1, PSS/E allows power flows to be solved using either inertial or governor responses. The data needed for this solution can be extracted from the dynamic data file (*.dyr file). These two redispatch options are available in the INLF option of PSS/E.

Inertial Response Power Flow

This is intended to give a quick approximation to system changes in approximately the half second following a disturbance. Generator power is principally influenced by machine inertias. Inertial response is the inherent response of synchronized generators to changes in the system frequency. A generator or load can be considered to contribute to system inertia if a change in system frequency causes a change in its rotational speed and thus its kinetic energy. The power associated with this change in kinetic energy is fed to or taken from the power system, and is known as the inertial response. In this computation, the effects of excitation and governor systems are minimal. Generator changes are assumed to be influenced solely by inertial effects.

Governor-Response Power Flow

The governor-response solution is intended to represent the system several seconds after an event. For this solution, the governor and excitation systems are assumed to have brought the system back to a steady state. New generator power levels are determined by the governor droop and damping characteristics.

4.3.1.2 Participation Factors for Generation Redispatch

In PSS/E, we can choose a set of generators that would participate in a power flow and thus would perform as distributed slack buses. The contribution of each of those generators to the system slack is based on the participation factors. This can be achieved by first defining a subsystem that consists of a set of generators that would participate in the redispatch. A subsystem can be implemented in a *.sub file.

4.3.2 Special Protection Systems / Remedial Action Schemes

To meet system performance requirements, SPSs/RASs are designed to detect predetermined system conditions and automatically take corrective actions, other than the isolation of faulted components. These schemes are designed to

a) maintain system stability

b) address reliability standards

c) maintain acceptable power flows

d) maintain acceptable system voltages.

There are several functions in PSS/E for conducting contingency analysis in a steady state. The procedure outlined below describes the process of evaluation of a multilevel contingency.

Step 1: The AC contingency function calculates full AC power flow for a set of contingencies, and results are stored in contingency solution files.

Step 2: The SPS/RAS monitors “Model Conditions”. In “Model Condition,” choose the type of element to which the condition would be applied and choose the specific object. Define a set of conditions that apply to that object. For example, we may specify the tripping of a combination of lines and generators if the apparent power (MVA) flow on the line between two buses is greater than a specified value.

Step 3: If the action condition of an SPS/RAS model is satisfied (i.e., MVA flow on the specified line is greater than the specified value), all trip actions defined within a trip specification (i.e., tripping of the specified combination of lines and generators in Step 2) will be applied. These actions are used to resolve the system criteria violations caused by a contingency. These actions include but are not limited to

- tripping of generator/bus/transformer
- tripping of sources
- load curtailment or tripping
- system reconfiguration
- changes in MW and MVAr output

This process continues until the number of such power flows performed as part of the SPS/RAS simulation for each contingency reaches a maximum limit.

4.3.3 Implementation of Corrective Actions in PSS/E

In PSS/E, the AC corrective actions function is part of the MACCC application. In PSS/E, AC corrective actions are modeled as an optimal power-flow problem (see the PSS/E Program Operation Manual). The objective function is to minimize the control adjustments needed to remove limit violations in the power system. The constraints include equality and inequality constraints, namely power flow equations and limits of controls and operation conditions. The three constraints available to choose are the branch flows, interface flows, and the bus voltages. The six categories of action controls are generator active power redispatch, phase shifter angle adjustment, load curtailment, off-line generator active power dispatch, tap setting adjustment, and switched shunt reactive power control. Among these, tap setting adjustment and switched shunt control influence the voltages more than the flows. Generation redispatch can influence both flow and voltage violations and the remaining ones mainly influence the flow violations.

Different weights can be chosen for the control actions in the optimal power flow for corrective actions, as shown in Figure 4.5. The corrective action algorithm finds an optimal solution by minimizing the weighted sum of the individual controls. The weight for each control is given by its weighting function. The corrective actions are influenced by these weighting functions and by the relative effectiveness of the respective controls in eliminating the system problems.

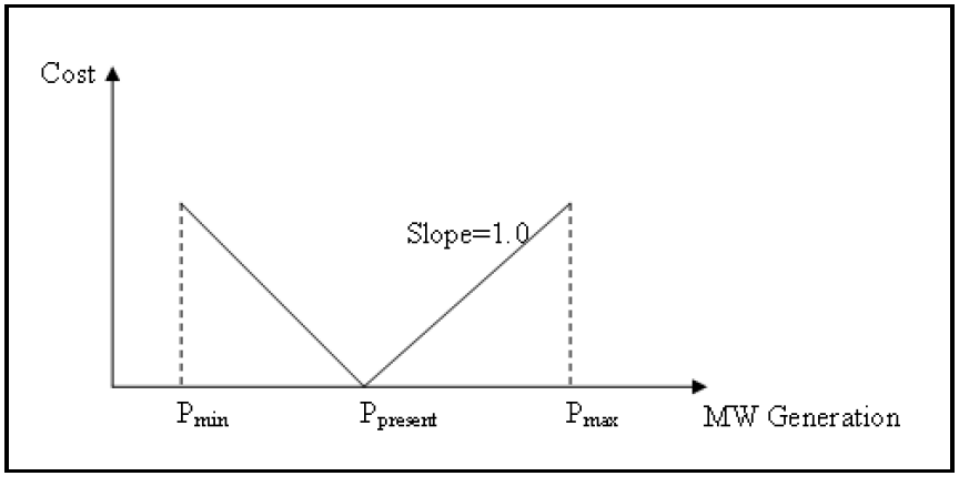

Figure 4.5. Active Power Generation Control Default Weighting Function

This feature has been used to explore possible corrective actions. Since the corrective actions are part of the AC contingency analysis, a contingency definition is necessary to implement the corrective action. To get around this problem we have defined a fictitious contingency by adding a high-impedance branch in parallel with an existing branch and defined this dummy branch as the contingency.

The corrective actions can be performed with several participating units. These units can be generators, phase shifters, tap-changing transformers, switched shunts, loads, etc. The first corrective actions are performed with control phase shifters, tap-changing transformers, and switched shunts. If the voltage and flow violations still remain, generator controls are the next to be used.

NERC standards and utility practices provide a temporary overload of transmission lines up to 130% of Rate A or 115% of Rate B of the transmission facilities including lines and transformers, whichever is smaller. The criteria can be adjusted as the additional detailed information of facilities ratings becomes available and modeled in the study cases based on the loading durations.

When the corrective actions are performed using the MACCC function of PSS/E, it considers one single rating, whether Rate A or Rate B. To make sure we follow the NERC standards, we can update the Rate C for the transmission lines to have the lower of 130% of Rate A or 115% of Rate B. This rating can then be used to perform corrective actions. Since this is a one-time update, it is better to perform this action at the beginning of the simulation.

Finally, a report of the various corrective actions performed is obtained and the corrective actions are applied to the extracted post-dynamic steady-state case. If there are still overloaded lines, the line with the highest violation is tripped. This is simulated by running a new dynamic simulation.

5.0 Simulation Results

Steady-state cascading-outage simulations have been performed on a full interconnection grid using TransCARE to preselect initiating events for the DCAT; simulation details and results for this analysis are given in Section 6. Hybrid dynamic and steady-state simulations were then performed using DCAT to simulate the cascading-outage sequences. The models used in the DCAT for this full interconnection integrate dynamic models with protection scheme models for generation, transmission, and load. Post-dynamic analysis is performed to model SPSs/RASs and automatic and manual corrective actions. This section presents simulation results for DCAT on several examples, using first a PSS/E test system and then a full interconnection. The purpose of these examples is to show the importance of performing hybrid dynamic and steady-state simulations with protection modeling to accurately mimic the cascading outage process. They also show how planning engineers can use DCAT for cascading-outage analysis and how the results are reported.

Table 5.1compares different examples. Special attention should be given to the example in Section 5.2.4 where a bus fault that lasted for six cycles was introduced at a large substation. A steady-state analysis will indicate this extreme event did not converge and suggests a blackout because the amount of generation loss was higher than the available spinning reserve. Using the DCAT, this extreme event gives a good example of how a non-firm, frequency-responsive, load-shedding scheme acts and sheds a part of the load to restore the balance between generation and load. This example shows the important of including dynamic simulations and protection in cascading-outage analysis.

Table 5.1. Comparison between Simulation Examples

Example Section No.	System Type	Initiating Event	First Dynamic Simulation Reaches a Stable Point	SPS/RAS Activated	Corrective Action Needed	Second Dynamic Simulation Reaches a Stable Point	Generator and Load Outage
5.1.1	PSS/E test system "savnw"	3 phase line fault	Yes (30 s) 2 relay actions	N/A	No	N/A	None
5.1.2	PSS/E test system "savnw"	3 phase line fault with distance relay failed to send transfer trip signal	Yes (30 s) 2 relay actions	N/A	No	N/A	None
5.1.3	PSS/E test system "savnw"	3 phase bus fault for10 cycles	Yes (75 s) 2 relay actions	N/A	No	N/A	Gen loss = 600 MW Load loss = 0 MW
5.1.4	PSS/E test system "savnw"	3 phase bus fault for 12 cycles	No (blackout)	N/A	N/A	N/A	Gen loss = 3,259 MW (before system collapses)
5.2.1	Full Inter-connection	3 phase line fault	Yes (30 s) 2 relay action	No	No	N/A	None
5.2.2	Full Inter-connection	3 phase line fault with distance relay failed to send transfer trip signal	Yes (30 s) 18 relay actions	No	No	N/A	Gen loss = 3,004 MW Load loss = 0 MW
5.2.3	Full Inter-connection	3 phase bus fault for 6 cycles	Yes (65 s) 84 relay actions	No	No	N/A	Gen loss = 3,900 MW Load loss = 1,067 MW
5.2.4	Full Inter-connection	3 phase bus fault for 6 cycles	Yes (30 s) 5 relay actions	Yes	No	Yes (30 s) No relay actions	Gen loss = 203 MW Load loss = 0 MW

5.1 Simulation Results on a PSS/E Test System

Simulation tests are performed with the DCAT by considering one of the example test cases (savnw.sav) that is provided with the PSS/E software package. This test system has 23 buses and six power plants. Figure 5.1 shows a one-line diagram of the test system. Four different simulation tests are performed using the test system, and outcomes of each test are presented in the following subsections.

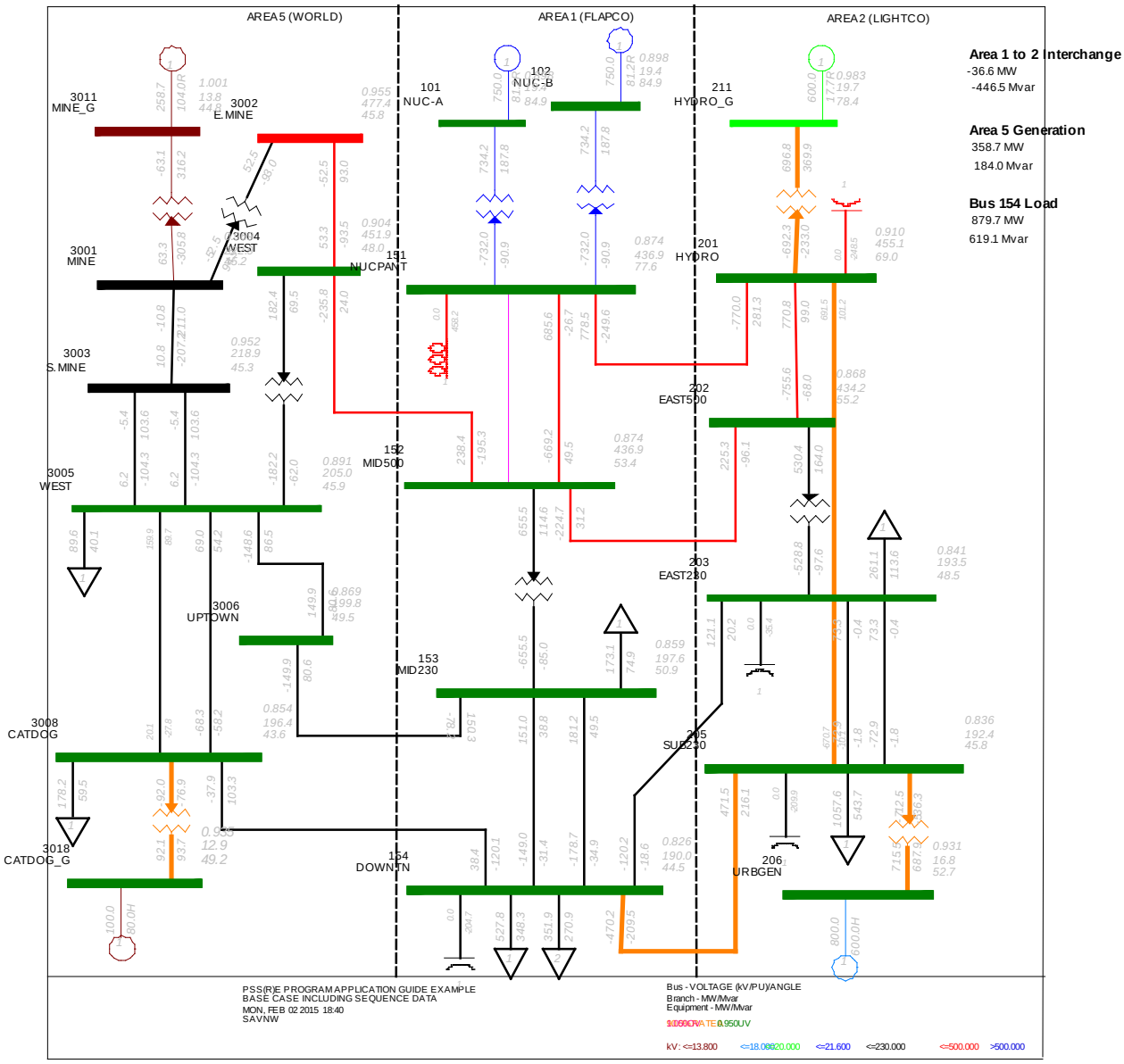

Figure 5.1. One-Line Diagram of the Test System

5.1.1 Test 1: Not a Close-In Fault in Pilot Scheme Line – Using Fictitious Node

A line fault is applied on one of the lines connected to Bus 152 at a distance of 90% from it. Distance relays are modeled on both ends of the line with an ability to send a transfer trip to the other end upon sensing a Zone 1 fault. Though the other end of Line 152 sees a Zone 2 fault, this pilot scheme trips the breaker as soon as the other relay on Bus 152 times out on the Zone 1 fault. Upon successful operation of both breakers, the fault is isolated, and there are no other tripping actions.

To model a fault in PSS/E at any location in a transmission line other than the two line ends, a fictitious node needs to be added, as explained in Appendix B. In this test, to model a fault in the line connecting Buses 151 and 152 that is located at a distance of 0.1 pu of total line length from Bus 151, a new fictitious node (151152) is added between Buses 151 and 152. Figure 5.2 shows the location of the

fictitious bus. Distance relays then need to be associated with the two branches newly created by the fictitious bus addition. That is, one branch is from the near end to the fictitious bus, and the other is from the remote end to the fictitious bus.

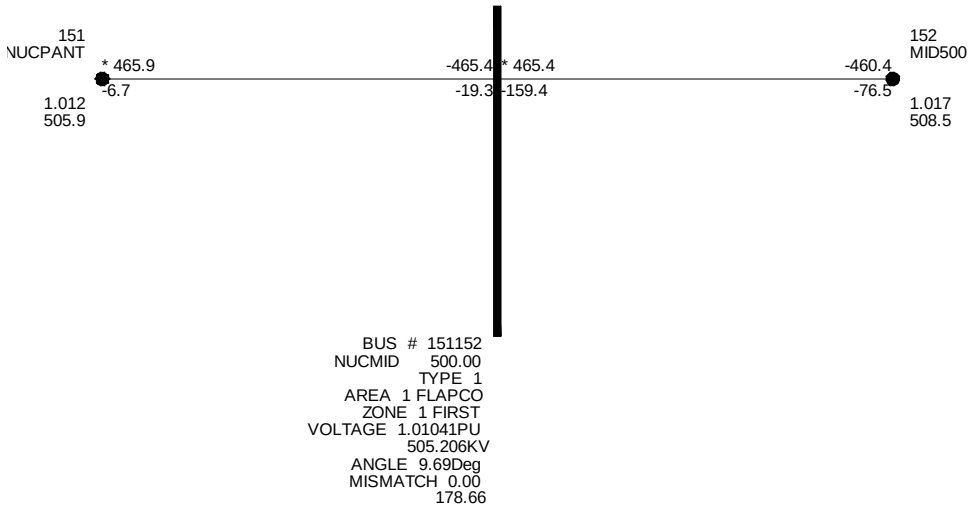

Figure 5.2. A Fictitious Bus between Buses 151 and 152

The bus fault is introduced at the fictitious bus (151152) at t = 5 s and simulation runs until dynamic simulation reaches a steady state. In this test, dynamic simulation reaches a steady state at t = 16 s. The following is the sequence of relay tripping events:

a) Distance relay (DISTR1) at Circuit 1 from 151 to 151152 is activated as Zone 1 and its timer started at t = 5 s.

b) Distance relay (DISTR1) at Circuit 1 from 152 to 151152 is activated as Zone 2 and its timer started at t = 5 s.

c) Zone 1 timer timed out at t = 5.017 s; self-trip breaker timer and also transfer trip and breaker trip timers started at the same time.

d) Circuit 1 from 151 to 151152 tripped at t = 5.05 s and transfer trip timer also timed out at the same time. In this case, the Zone 1 relay accelerates the other relay, and as a result, the other end (Circuit 1 from 152 to 151152) trips at the same time (t = 5.05 s), and soon thereafter the two voltages start to recover.

The channel plot in Figure 5.3 shows that the voltage at Bus 151 collapses more than the Bus 152 voltage. This indicates that the fault is closer to Bus 151.

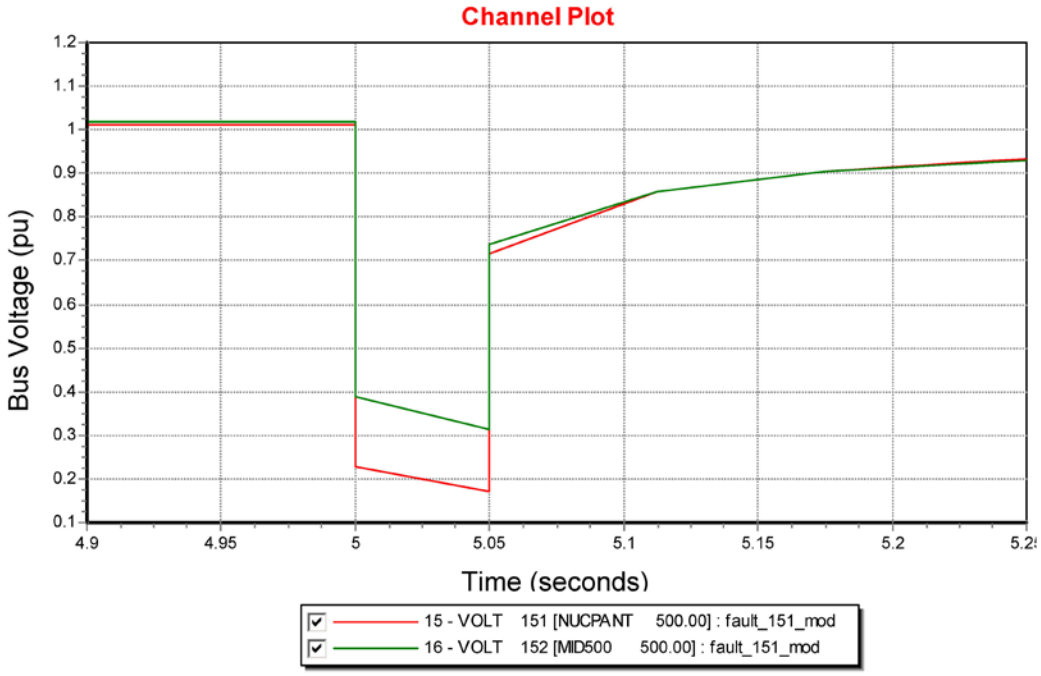

Figure 5.3. Voltage Plots of the Terminal Buses of the Faulted Line for Test 1

5.1.2 Test 2: Not a Close-In Fault in Step Distance Line – Using Fictitious Node

This simulation uses the same procedure and files that were used in Test 1 except that the transfer trip capability of DISTR1 is assumed to have failed. As a result of that, the near end of the line to the fault at Bus 151 trips on the Zone 1 setting (4 cycles) and the other end of the line at Bus 152 trips at the Zone 2 setting (22 cycles).

Each end will trip according to the Zone 1 or Zone 2 delays where appropriate. The bus fault is introduced at the fictitious bus (151152) at t = 5 s and simulation runs until dynamic simulation reaches a steady state. In this test, dynamic simulation reaches a steady state at t = 16 s. The following is the sequence of relay tripping events:

a) Distance relay (DISTR1) at Circuit 1 from 151 to 151152 is activated as Zone 1 and its timer started at t = 5 s.

b) Distance relay (DISTR1) at Circuit 1 from 152 to 151152 is activated as Zone 2 and its timer started at t = 5 s.

c) Zone 1 timer timed out at t = 5.017 s; self-trip breaker timer and breaker timer started at the same time.

d) Circuit 1 from 151 to 151152 tripped at t = 5.05 s.

e) Circuit 1 from 152 to 151152 trips as Zone 2 fault at t = 5.333 s and the channel plot (Figure 5.4) shows the two voltages start to recover after tripping both ends of the branch.

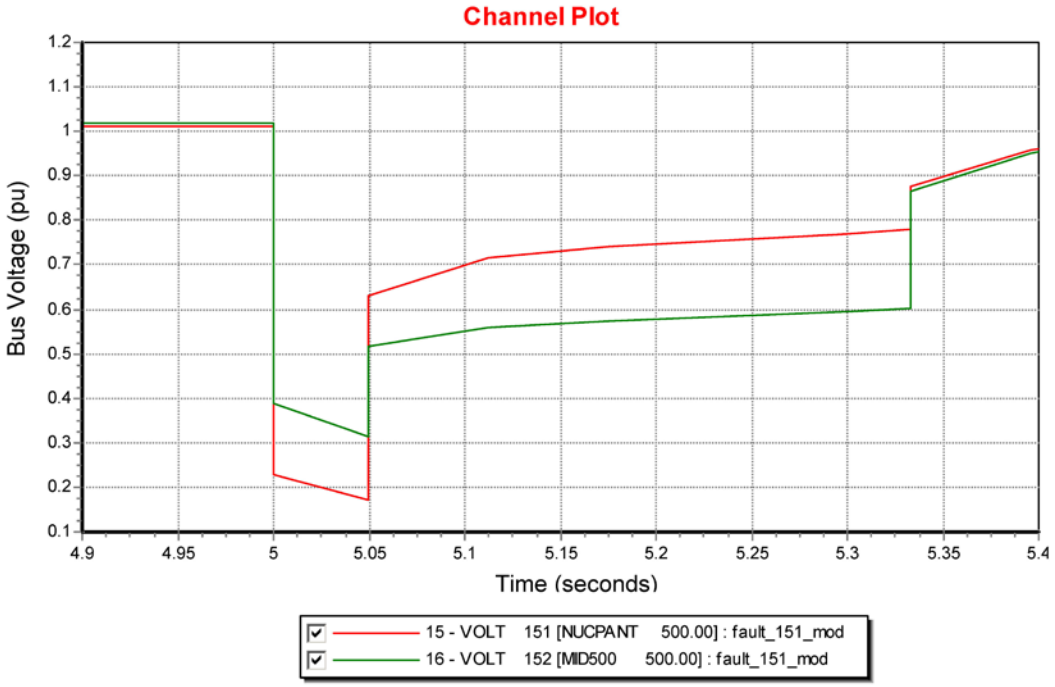

Figure 5.4. Channel Plot for Test 2

5.1.3 Test 3: Bus Fault

In Test 3, a fault is applied at Bus 201 at t = 5 s and the fault is cleared after 10 cycles. The simulation runs until dynamic simulation reaches a steady state. In this test, dynamic simulation reaches a steady state at t = 75 s. Table 5.2 shows a summary. No corrective action was required for this contingency with these protection settings. The details of each tripping action in Test 3 are presented in Table 5.3. Simulation result plots are shown in Figure 5.5 and Figure 5.6.

Table 5.2. Relay Trips Summary of Test 3

Relay Type										
DISTR1	TimeOut	Busfrom	Busto	ckt						
DISTR1	5.1	201	202	1						
VTGTPA	TimeOut	Bus	BusName	BuskV	Pgen (MW)	Qgen (MVAr)	GenBus	GenID	GenName	GenkV
VTGTPA	5.237	211	HYDRO_G	20	600	17.75	211	1	HYDRO_G	20

ckt = circuit
Pgen = generator real power
Qgen = generator reactive power

Table 5.3. Tripping Action Details of Test 3

Relay Type					
DISTR1	TimeOut	Busfrom	Busto	ckt	Details
DISTR1	5.1	201	202	1	• Distance relay (DISTR1) at circuit 1 from 201 to 202 is activated as Zone 1 and its timer started at t = 5 s. • Zone 1 timer timed out at t = 5.067 s; self-trip breaker timer started at the same time. • Circuit 1 from 201 to 202 is tripped at t = 5.1 s. • Channel plots for Bus 201 and 202 are shown in Figure 5.5.
VTGTPA	TimeOut	Bus	BusName	BuskV	Details
VTGTPA	5.237	211	MINE_G	20	VTGTPA at Bus 211: • Pickup timer started at t = 5.004 s. • Breaker timer started at t = 5.154 s. • Breaker timer timed out at time t = 5.237 s. • Channel plot for Bus 211 is shown in Figure 5.6 • Voltage at Bus 211 starts to recover after tripping and reached a steady state around 60 s.

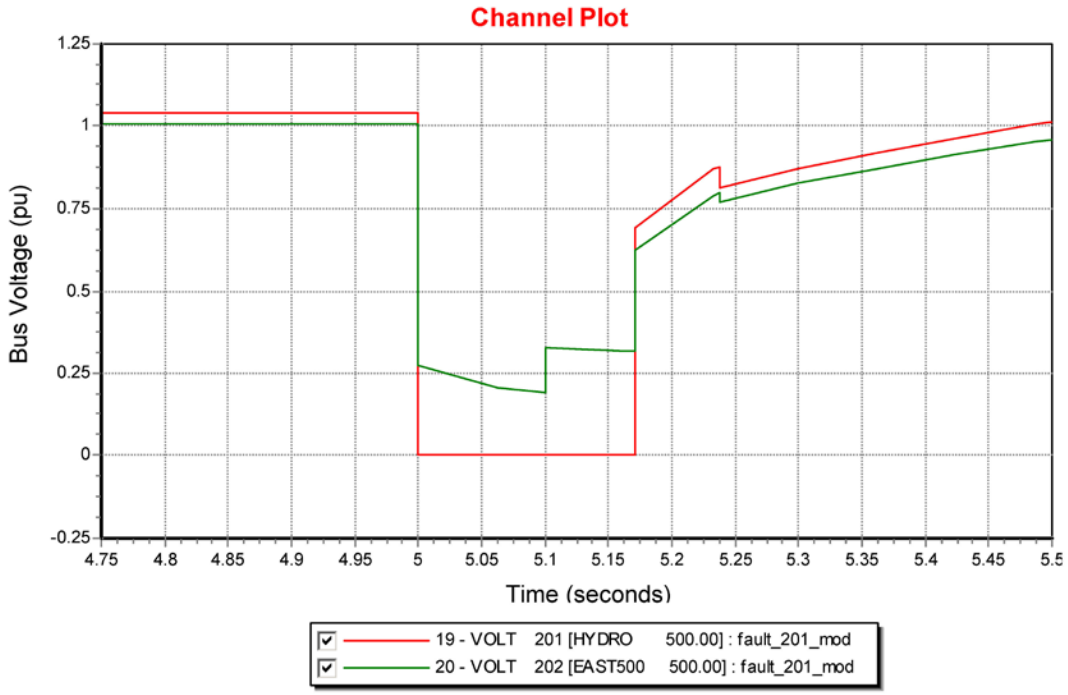

Figure 5.5. Channel Plot for Voltages at Buses 201 and 202

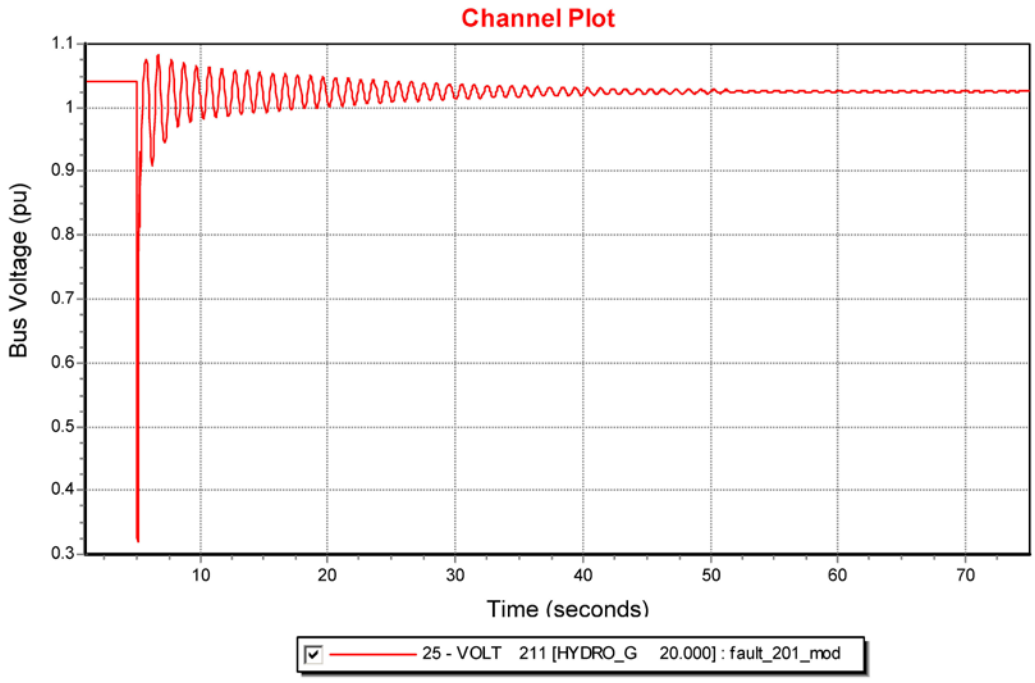

Figure 5.6. Channel Plot for Voltage at Bus 211

5.1.4 Test 4: Bus Fault Leads to Blackout

In this dynamic simulation, a fault is applied at Bus 151 at t = 5 s; the fault is applied for 12 cycles and then cleared. A significant number of undervoltage and underfrequency generator relays were tripped due to this fault, which leads to system blackout. The network did not converge after t = 6.3708 s. A total of seven relays are activated during this dynamic simulation; Table 5.4 shows a summary.

Table 5.4. Relay Trips Summary of Test 4

Relay Type										
DISTR1	TimeOut	Busfrom	Busto	ckt						
DISTR1	5.1	151	152	1						
DISTR1	5.1	151	152	2						
VTGTPA	TimeOut	Bus	BusName	BuskV	Pgen (MW)	Qgen (MVAr)	GenBus	GenID	GenName	GenkV
VTGTPA	5.237	101	NUC-A	21.6	750	81.19	101	1	NUC-A	21.6
VTGTPA	5.237	102	NUC-B	21.6	750	81.19	102	1	NUC-B	21.6
FRQTPA	TimeOut	Bus	BusName	BuskV	Pgen	Qgen	GenBus	GenID	GenName	GenkV
FRQTPA	6.362	3018	CATDOG_G	13.8	100	80	3018	1	CATDOG_G	13.8
FRQTPA	6.371	206	URBGEN	18	800	600	206	1	URBGEN	18
FRQTPA	6.371	3011	MINE_G	13.8	258.66	104.04	3011	1	MINE_G	13.8
FRQTPA	6.383	211	HYDRO_G	20	600	17.75	211	1	HYDRO_G	20

The sequence of tripping is shown in Figure 5.7. It is observed that Tripping 1 is due to a distance relay, Tripping 2 is due to undervoltage at Generators 101 and 102, and the remaining trippings from 3 to 5 are due to underfrequency at Generators 3018, 206, 3011, and 211. The details of each tripping action in Test 4 are presented in Table 5.5. Simulation result plots are shown in Figure 5.8 and Figure 5.9.

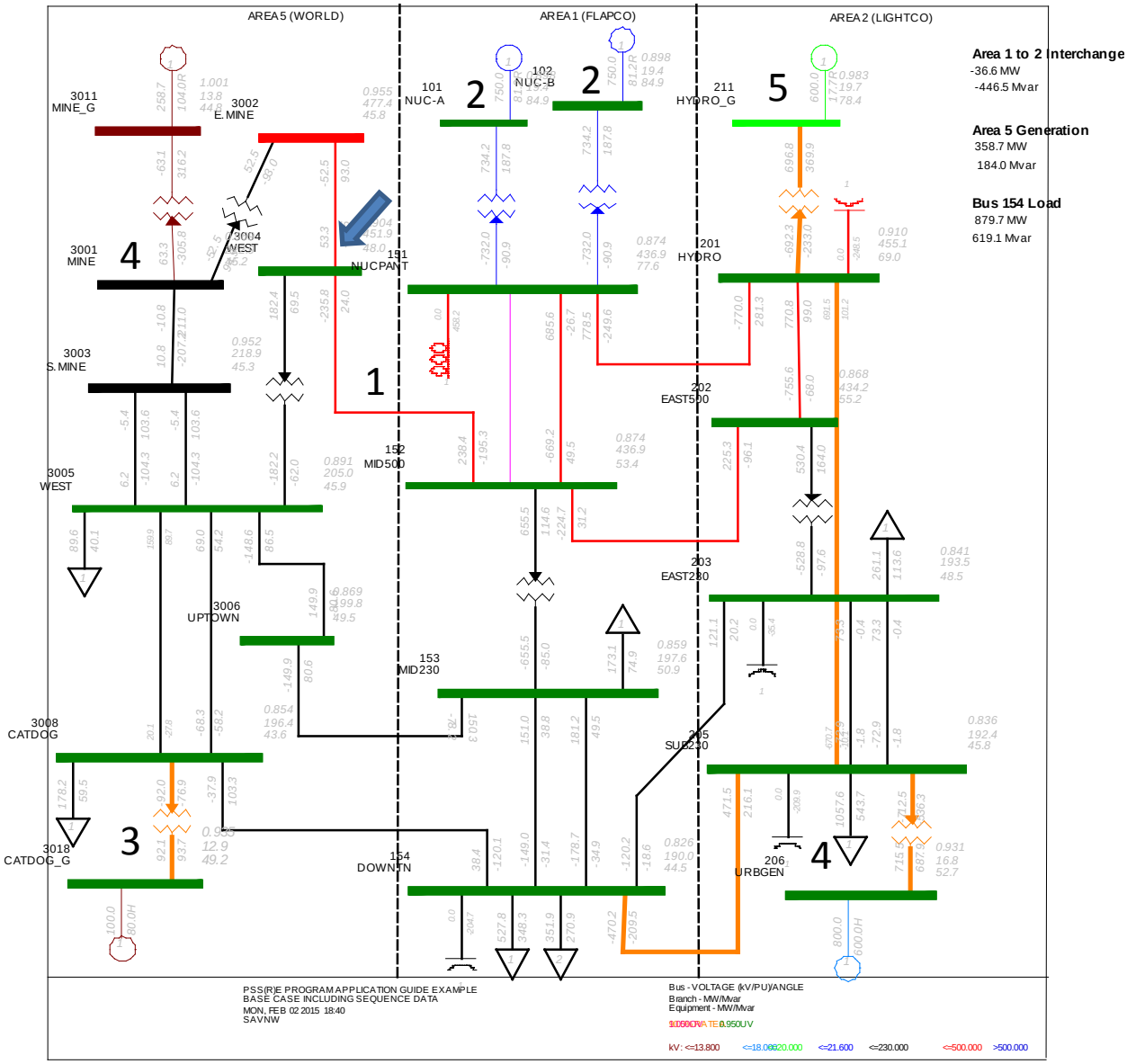

Figure 5.7. One-Line Diagram of Test System to Show Sequence of Tripping

Table 5.5. Tripping Action Details of Test 4

Relay Type					
DISTR1	TimeOut	Busfrom	Busto	ckt	Details
DISTR1	5.1	151	152	1	• Distance relay (DISTR1) at Circuit 1 from 151 to 152 and relay at Circuit 2 from 151 to 152 are activated as Zone 1 and their timers started at t = 5 s. • Zone 1 timer timed out at t = 5.067 s; self-trip breaker timer started at the same time. • Circuit 1 from 151 to 152 and Circuit 2 from 151 to 152 are tripped at t = 5.1 s.
DISTR1	5.1	151	152	2	
VTGTPA	TimeOut	Bus	BusName	BuskV	Details
VTGTPA	5.237	101	NUC-A	21.6	VTGTPA at Buses 101 and 102: • Pickup timer started at t = 5.004 s. • Breaker timer started at t = 5.154 s. • Breaker timer timed out at time t = 5.237 s. • Channel plots for Buses 101 and 102 are shown in Figure 5.8.
VTGTPA	5.237	102	NUC-B	21.6	
FRQTPA	TimeOut	Bus	BusName	BuskV	Details
FRQTPA	6.362	3018	CATDOG_G	13.8	FRQTPA at Bus 3018: • Pickup timer started at t = 6.275 s. • Breaker timer started at t = 6.279 s. • Breaker timer timed out at time t = 6.362 s.
FRQTPA	6.371	206	URBGEN	18	FRQTPA at Buses 206 and 3011: • Pickup timer started at t = 6.283 s. • Breaker timer started at t = 6.287 s. • Breaker timer timed out at time t = 6.362 s.
FRQTPA	6.371	3011	MINE_G	13.8	
FRQTPA	6.383	211	HYDRO_G	20	FRQTPA at Bus 3011: • Pickup timer started at t = 6.296 s. • Breaker timer started at t = 6.300 s. • Breaker timer timed out at time t = 6.383s. • Channel plots for speeds of machines 3018, 206, 3011, and 211 are shown in Figure 5.9.

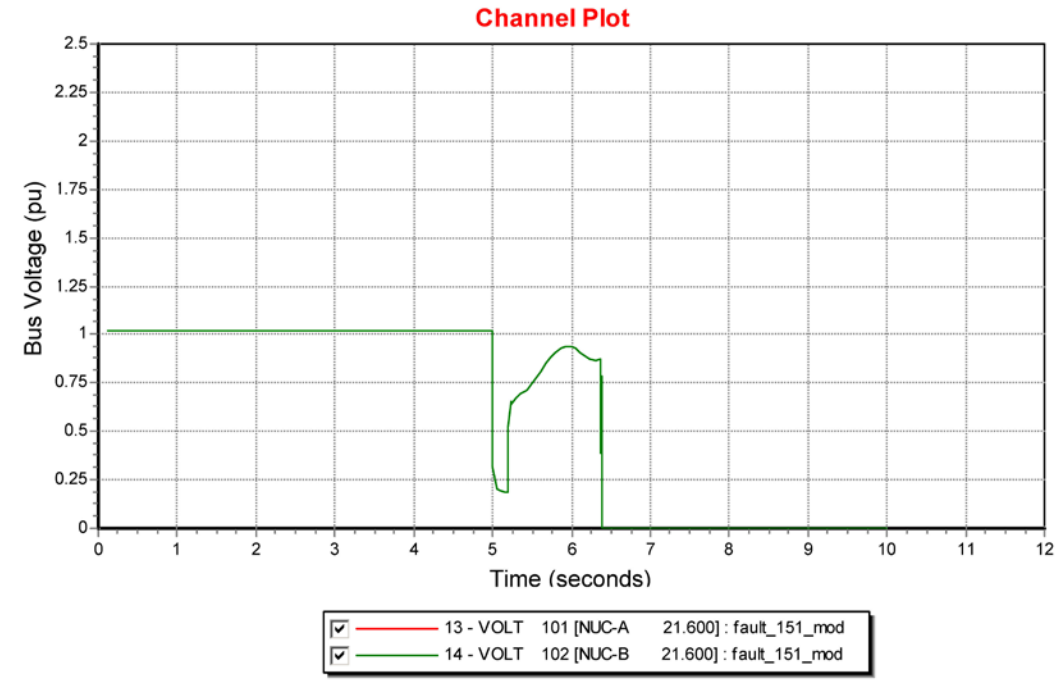

Figure 5.8. Channel Plots for Voltages at Buses 101 and 102

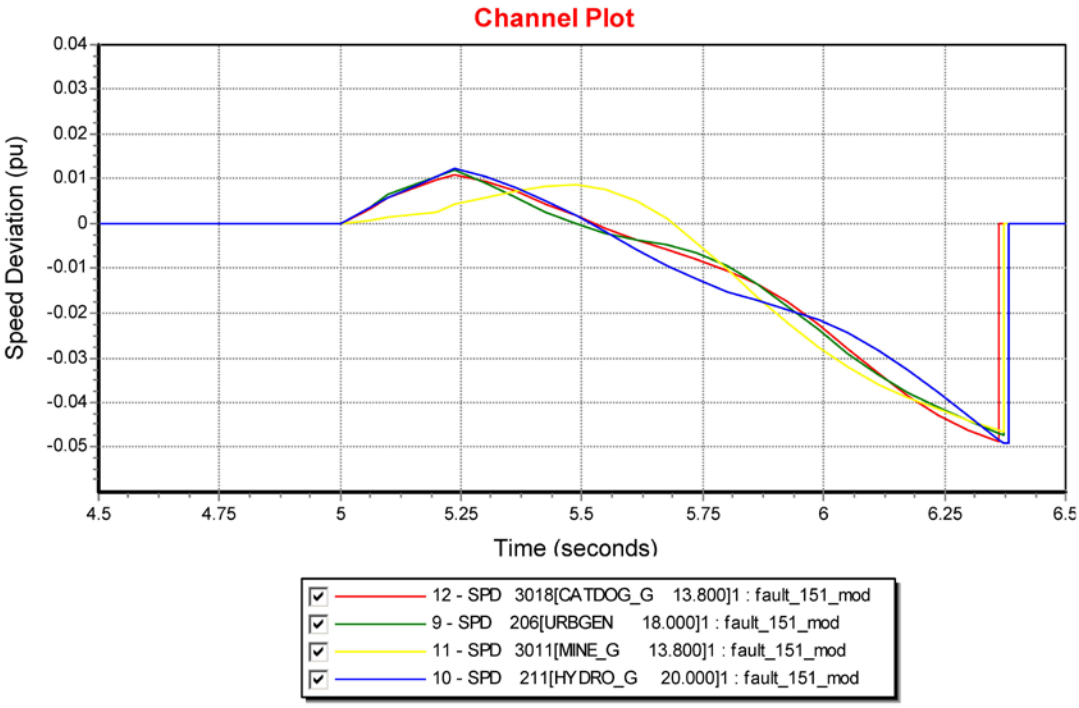

Figure 5.9. Channel Plots for Speeds of Machines 3018, 206, 3011, and 211

5.2 Simulation Results on a Full Interconnection

The following four examples show simulation results of DCAT on a full interconnection considering severe initiating events based on TransCARE analysis. In the second example, we show how

misoperation of a transfer trip communication channel in a distance relay can result in significant generation outages, in comparison to the first example, where it operates correctly and consequently there were no generation outages. In the third example, we show how non-firm, frequency-responsive load can help in maintaining system stability after significant generation loss. In the fourth example, we show how an SPS/RAS action is activated in post-dynamic analysis.

5.2.1 Example 1: Line Fault with a Pilot Scheme (Transfer Trip Enabled)

A line fault is applied on one of the lines connected to Bus X1 at a distance of 90% from Bus Y1 at time t = 10 s, as shown in Figure 5.10.

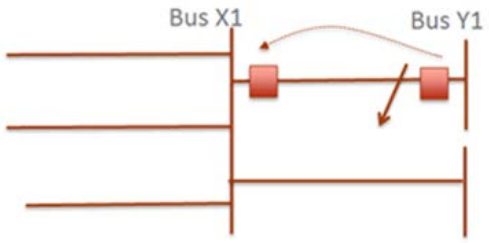

Figure 5.10. Example 1: Line Fault with a Pilot Scheme (Transfer Trip Enabled)

Distance relays are modeled on both ends of the line, each having the ability to send a transfer trip to the other end upon sensing a Zone 1 fault. Though the other end of the line (at Bus X1) sees a Zone 2 fault, this pilot scheme trips the breaker as soon as the other relay times out on the Zone 1 fault. Upon successful operation of both breakers, the fault is isolated, without other tripping actions. The voltages at the two ends are shown in Figure 5.11.

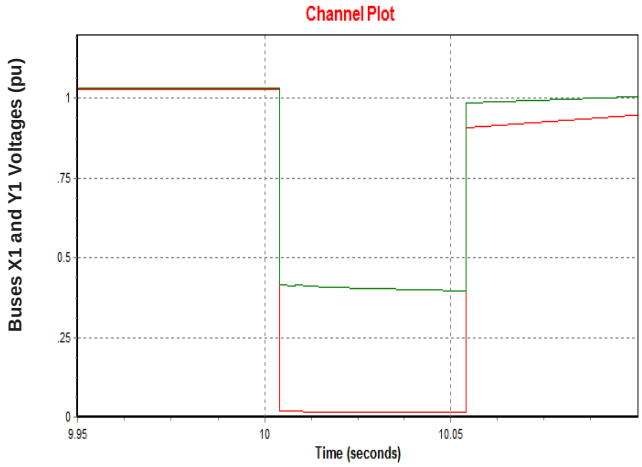

Figure 5.11. Example 1: Voltages of Buses X1 and Y1

PSS/E includes a branch fault, but it cannot be set at a particular distance on the line. To achieve this fault at 90% of the line, a new bus (X3) is created at 90% tap of the line and a bus fault is introduced at this bus. In case the fault is isolated by Zone 1 timing of the two relays at both ends, the impact of the fault on the system will be fairly minimal. The fault is introduced at 10 seconds into the dynamic simulation. The relay trippings observed are given in Table 5.6.

Table 5.6. Relay Trippings for Example 1

Relay Type	TimeOut (s)	Busfrom	Busto	ckt
DISTR1	10.054	X1	X3	1

After the dynamic simulation, no control conditions that could trigger SPS/RAS actions were observed. The line overloads observed on the system were below 130% of Rate A and no voltage violations below 0.9 pu were observed. No corrective action was required for this contingency. This contingency resulted in a total of 1 tripping action with no generation loss and no load loss, as given in Table 5.7.

Table 5.7. Generation and Load Loss Summary for Example 1

Generation Loss (MW)	0
Load Loss (MW)	0
No. of Total Tripping Actions	1
No. of SPSs/RASs Triggered	0
No. of Overloaded Lines	0
Corrective Actions	None

5.2.2 Example 2: Line Fault with Failed Transfer Trip

Example 2 is similar to Example 1, but the communication channel for transfer trip is assumed to have failed; the line fault is applied at time t = 5 s. As a result, the near end of the line to the fault at Bus Y1 trips at Zone 1 settings (4 cycles) and the other end of the line trips at Zone 2 settings (22 cycles). Since the Zone 2 trip persists longer than the Zone 1 trip, timers on many other relays would have started, and some of them had cascaded trippings. Graphs of simulation results are given in Figure 5.12 and Figure 5.13.

The sequence of relay trippings observed during the dynamic simulation is shown in Table 5.8. After the dynamic simulation, no control conditions that could trigger SPS/RAS actions were observed. The line overloads observed on the system were below 130% of Rate A and no voltage violations below 0.9 pu were observed. No corrective action was required for this contingency with these protection settings. This contingency resulted in a total of 18 tripping actions with a total generation loss of 3,004 MW and no load loss, as given in Table 5.9.

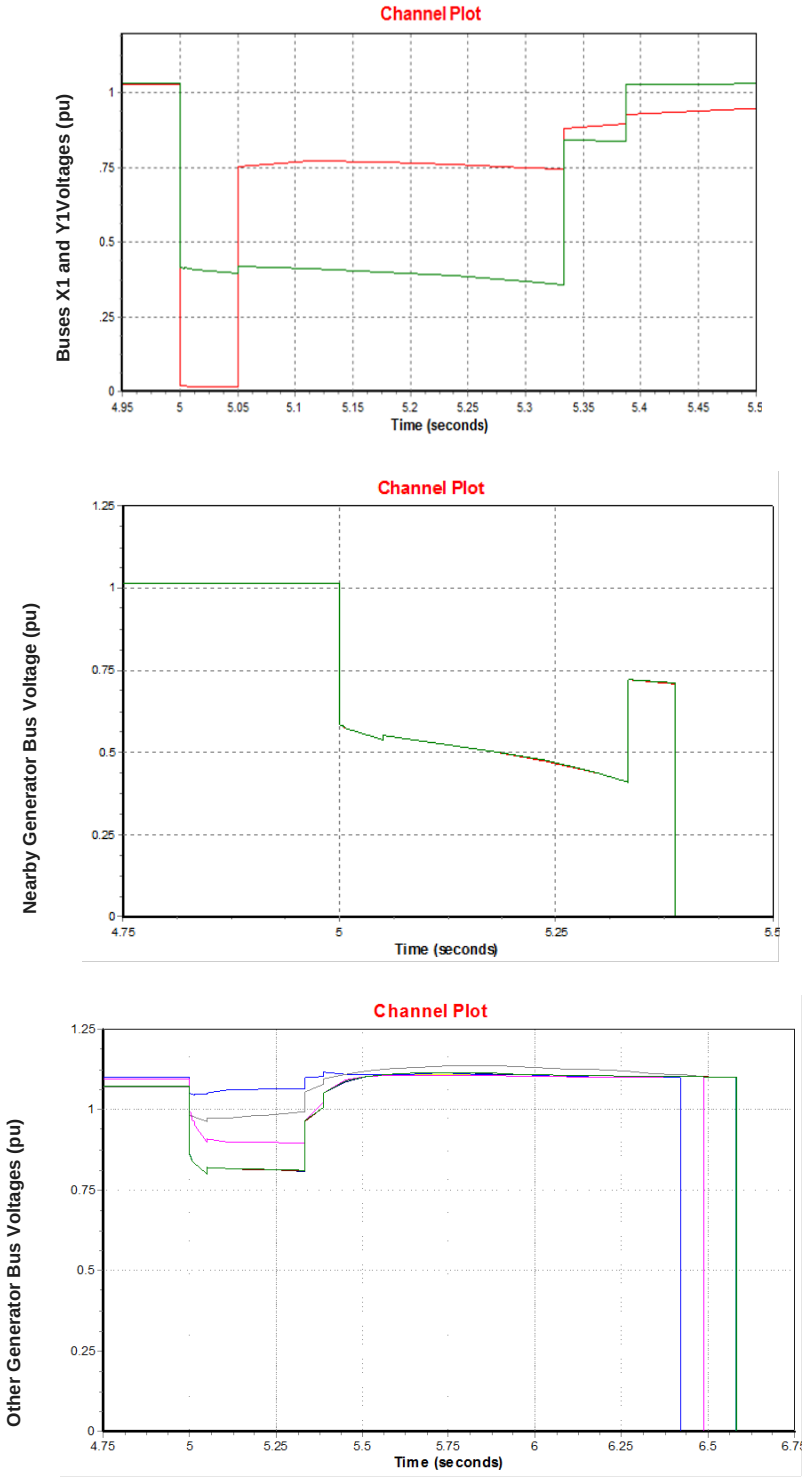

Figure 5.12. Example 2: Buses X1 and Y1 Voltage (top graph) and Generating Units Tripping due to Undervoltage (middle graph) and Overvoltage (bottom graph)

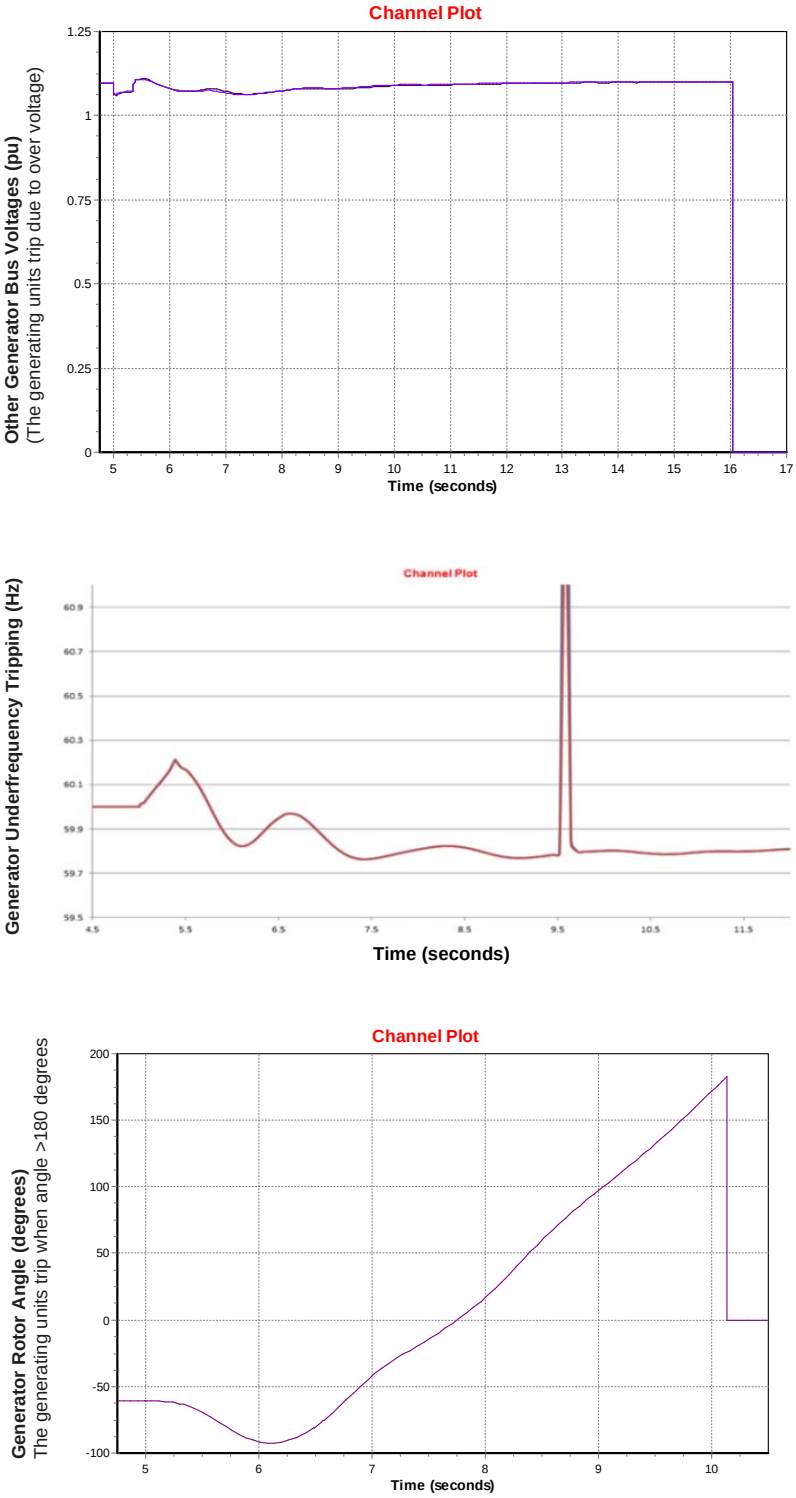

Figure 5.13. Example 2: Generating Units Tripping due to Overvoltage (top graph), Underfrequency (center graph), and Out-of-Step (bottom graph) Conditions

Table 5.8. Relay Tripping Sequence for Example 2 (Sample Output of the DCAT)

Relay Type					
DISTR1	TimeOut (s)	Bus from	Bus to	Ckt id	
DISTR1	5.05	X1	X2	1	
DISTR1	5.333	Y1	Y2	1	
VTGTPA	TimeOut (s)	Pgen (MW)	Qgen (MVAr)		
VTGTPA	5.387	1204.9	156.52		
VTGTPA	5.387	1194.9	152.6		
VTGTPA	6.421	68	28.8		
VTGTPA	6.421	67	28.8		
VTGTPA	6.487	17	14.8		
VTGTPA	6.487	17	14.8		
VTGTPA	6.571	15	0		
VTGTPA	6.579	68.99	6.59		
VTGTPA	6.583	70.99	6.59		
VTGTPA	6.583	69.99	6.78		
VTGTPA	6.583	67.99	6.59		
FRQTPA	TimeOut (s)	Pgen (MW)	Qgen (MVAr)		
FRQTPA	9.662	7.53	7.37		
FRQTPA	9.662	5.42	0		
OutOfStep_new	TimeOut (s)	Pgen (MW)	Qgen (MVAr)	AngleThr (degrees)	AngleDev (degrees)
OutOfStep_new	10.1374	0	−12.25	180	180.2261
VTGTPA	16.046	74.67	38		
VTGTPA	16.046	71.61	38		

AngleDev = angle deviation
AngleThr = angle threshold
Ckt id = circuit identification
DISTR1 = distance-relay model
FRQTPA = underfrequency/overfrequency generator disconnection relay
Qgen = generator reactive power
VTGTPA = undervoltage/overvoltage generator disconnection relay

Table 5.9. Generation and Load Loss Summary for Example 2

Generation Loss (MW)	3,004
Load Loss (MW)	0
No. of Total Tripping Actions	18
No. of SPSs/RASs Triggered	0
No. of Overloaded Lines	0
Corrective Actions	None

5.2.3 Example 3: Demonstration of the Role of a Non-Firm, Frequency-Responsive, Load-Shedding Scheme in Maintaining Grid Integrity after an Extreme Event

A bus fault that lasted for six cycles was introduced at a large substation. All elements connected to this substation were then tripped to isolate the fault, including a very large power plant. This extreme event did not converge in TransCARE analysis, because the amount of generation loss was higher than the available spinning reserve. Using the DCAT, this extreme event gives a good example of how a non-firm, frequency-responsive, load-shedding scheme acts and sheds a part of the load to restore the balance between generation and load.

A significant amount of generation was lost due to this fault, which was followed by many underfrequency non-firm load sheddings. The fault is introduced at time t = 10 seconds into the dynamic simulation. Graphs of simulation results are given in Figure 5.14, Figure 5.15, and Figure 5.16.

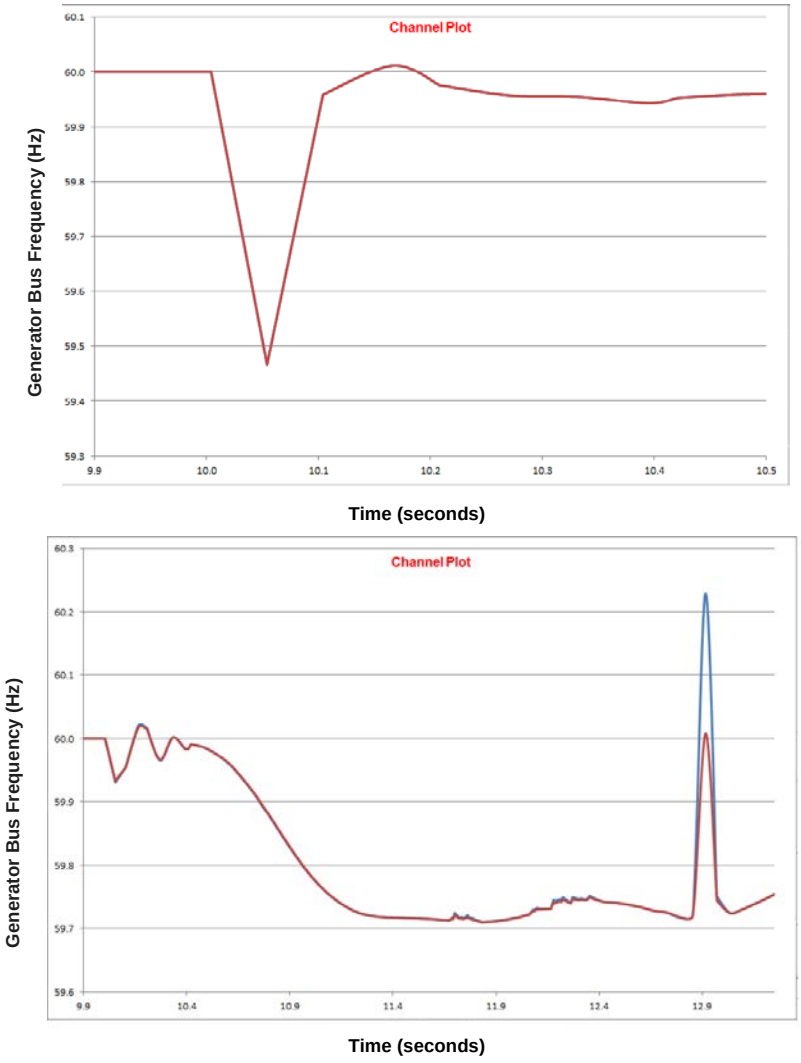

Figure 5.14. Example 3: Generating Units Tripping due to Underfrequency

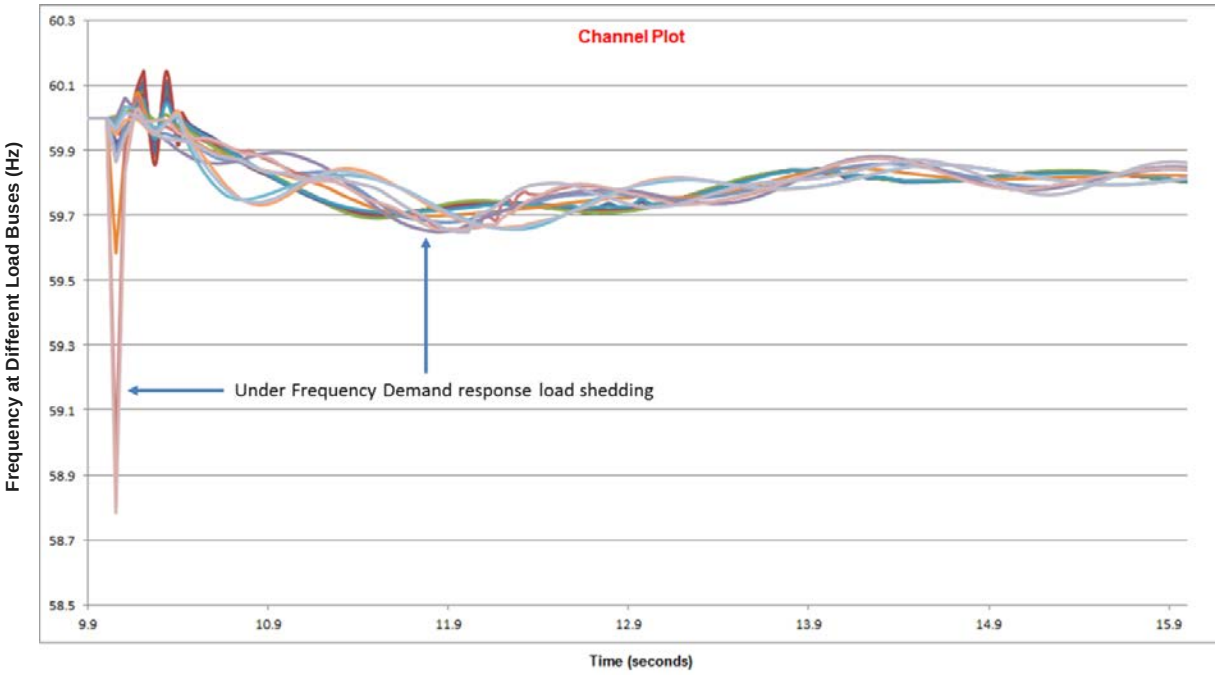

Figure 5.15. Example 3: Tripping of Loads Participating in the Non-Firm, Frequency-Responsive, Load-Shedding Scheme

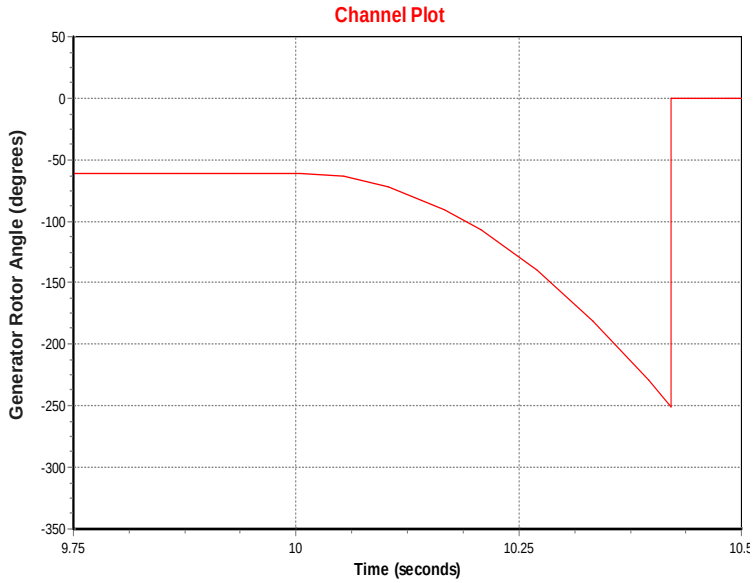

Figure 5.16. Example 3: Generating Unit Out-of-Step Tripping. The generating units trip when the angle exceeds 180 degrees.

A partial list of the relay tripping sequence observed during the dynamic simulation is given in Table 5.10. After the dynamic simulation, no control conditions that could trigger SPS/RAS actions were observed. The line overloads observed on the system were below 130% of Rate A and no voltage violations below 0.9 pu were observed. No corrective action was required for this contingency with these protection settings. This contingency resulted in a total of 84 tripping actions with a total generation loss of 3,900 MW and 1,068 MW load loss, as given in Table 5.11.

Table 5.10. Relay Tripping Sequence for Example 3

Relay Type							
DISTR1	TimeOut (s)	From	To				
DISTR1	10.054	X1	Y1				
DISTR1	10.054	X2	Y2				
FRQTPA	TimeOut	Pgen (MW)	Qgen (MVAr)				
FRQTPA	10.104	70.56	−10.05				
FRQTPA	10.104	70.56	−10.05				
OutOfStep_new	TimeOut	Pgen (MW)	Qgen (MVAr)	AngleThr (degrees)	AngleDev (degrees)		
OutOfStep_new	10.4207	1375	160.03	180	182.5495		
OutOfStep_new	10.4207	1375	180.03	180	181.8143		
LDSH_LDFR	TimeOut	Stage	Pshed (MW)	Qshed (MVAr)	Shed Load (pu of initial load value)	Bus Voltage (pu)	Bus Frequency (Hz)
LDSH_LDFR	11.529	1	13.68	5.97	0.3876	0.97	59.72
LDSH_LDFR	11.633	1	7.92	2.29	0.1646	1.01	59.7
LDSH_LDFR	11.675	1	5.74	2.15	0.6512	0.98	59.71
LDSH_LDFR	11.675	1	2.85	0.91	0.0905	1.03	59.71
LDSH_LDFR	11.687	1	1.99	0.45	0.1585	1.03	59.71
LDSH_LDFR	11.692	1	1.99	0.45	0.1654	0.97	59.71
LDSH_LDFR	11.7	1	1.5	0.35	0.1307	1.03	59.71
LDSH_LDFR	11.721	1	2.13	0.61	0.0392	1.03	59.71
LDSH_LDFR	11.733	1	5.39	1.12	0.2122	1	59.71
VTGTPA	TimeOut	Pgen	Qgen				
VTGTPA	11.737	50	30				
LDSH_LDFR	TimeOut	Stage	Pshed (MW)	Qshed (MVAr)	Shed Load (pu of initial load value)	Bus Voltage (pu)	Bus Frequency (Hz)
LDSH_LDFR	11.754	1	3.28	0.79	0.4316	0.99	59.71
LDSH_LDFR	11.762	1	4.58	1.01	0.237	1.01	59.72
LDSH_LDFR	11.767	2	7.1	2.04	0.1304	1.03	59.72
LDSH_LDFR	11.846	1	23.63	0.07	0.6513	1.01	59.65
LDSH_LDFR	11.896	1	14.24	4.68	0.6513	0.99	59.68
LDSH_LDFR	11.95	1	92.48	37.97	0.6513	1.02	59.66
LDSH_LDFR	12.008	1	0.51	0.1	0.0158	0.98	59.66
LDSH_LDFR	12.008	1	0	0	0.3372	1.02	59.65
LDSH_LDFR	12.008	1	19.51	5.69	0.3372	1.02	59.65
LDSH_LDFR	12.008	1	58.65	17.11	0.3372	1.02	59.65
LDSH_LDFR	12.008	1	78.16	22.8	0.3372	1.02	59.65
LDSH_LDFR	12.058	1	16.67	3.34	0.3799	1.02	59.67
LDSH_LDFR	12.062	2	11.91	2.39	0.2714	1.03	59.67
LDSH_LDFR	12.079	1	23.44	2.57	0.4162	1.02	59.67
LDSH_LDFR	12.083	1	1.31	0.18	0.1267	0.97	59.68
LDSH_LDFR	12.083	1	0.91	0.13	0.1267	0.97	59.68
LDSH_LDFR	12.1	1	26.05	0	0.5555	1.07	59.67
LDSH_LDFR	12.1	1	26.05	0	0.5555	1.07	59.67

Table 5.10. (contd)

LDSH_LDFR	TimeOut	Stage	Pshed (MW)	Qshed (MVAr)	Shed Load (pu of initial load value)	Bus Voltage (pu)	Bus Frequency (Hz)
LDSH_LDFR	12.1	1	26.05	0	0.5555	1.07	59.67
LDSH_LDFR	12.104	2	5.21	0.95	0.0578	1.02	59.67
LDSH_LDFR	12.162	1	1.36	0.33	0.0171	1.02	59.66
LDSH_LDFR	12.167	1	21.79	0	0.6513	1	59.63
LDSH_LDFR	12.167	1	23.54	0	0.6513	0.98	59.67
LDSH_LDFR	12.167	1	26.05	0	0.2821	0.99	59.67
LDSH_LDFR	12.171	1	23.54	0	0.6513	0.98	59.67
LDSH_LDFR	12.179	1	4.56	0.65	0.0756	0.99	59.67
LDSH_LDFR	12.179	1	0	0	0.0756	0.99	59.67
LDSH_LDFR	12.183	1	1.35	0.32	0.0227	1	59.67
LDSH_LDFR	12.196	1	28.06	0	0.3443	1.02	59.66
LDSH_LDFR	12.204	1	42.98	7.83	0.477	1.02	59.66
LDSH_LDFR	12.204	1	24.25	0.6	0.384	1.01	59.67
LDSH_LDFR	12.212	1	2.85	0.74	0.0356	1	59.67
LDSH_LDFR	12.217	2	25.02	0	0.307	1.02	59.66
LDSH_LDFR	12.217	2	16.88	0.42	0.2673	1.01	59.67
LDSH_LDFR	12.217	1	0.77	0.18	0.0061	1	59.67
LDSH_LDFR	12.221	1	1.76	0.11	0.6511	1.02	59.66
LDSH_LDFR	12.225	1	7.74	0.23	0.2851	1.02	59.66
LDSH_LDFR	12.225	1	9.77	3.4	0.2247	1.02	59.66
LDSH_LDFR	12.225	1	3.64	0	0.2247	1.02	59.66
LDSH_LDFR	12.225	1	4.64	0.62	0.0587	0.98	59.67
LDSH_LDFR	12.258	2	9.94	0.29	0.3662	1.02	59.66
LDSH_LDFR	12.262	1	4.88	1.99	0.2781	0.99	59.67
LDSH_LDFR	12.262	1	4.88	1.99	0.2781	0.99	59.67
LDSH_LDFR	12.262	2	5.41	0.73	0.0685	0.98	59.68
LDSH_LDFR	12.271	1	3.26	0.97	0.2778	1.02	59.66
LDSH_LDFR	12.271	1	26.05	0	0.5832	0.99	59.63
LDSH_LDFR	12.271	1	26.05	0	0.5832	0.99	59.63
LDSH_LDFR	12.271	1	26.05	0	0.5832	0.99	59.63
LDSH_LDFR	12.283	1	5.66	1.66	0.6513	1	59.68
LDSH_LDFR	12.3	1	26.05	0	0.4634	1	59.62
LDSH_LDFR	12.3	1	26.05	0	0.4634	0.99	59.62
LDSH_LDFR	12.312	1	123.75	0	0.5625	1.02	59.67
LDSH_LDFR	12.333	1	1.39	0.26	0.141	1.02	59.67
LDSH_LDFR	12.346	1	10.42	4.43	0.4623	1.01	59.66
LDSH_LDFR	12.346	1	10.03	0	0.4623	1.01	59.66
LDSH_LDFR	12.354	1	5.21	1.12	0.0708	1.01	59.66
FRQTPA	TimeOut	Pgen	Qgen				
FRQTPA	12.971	7.53	7.37				
FRQTPA	12.971	5.42	0				

Table 5.10. (contd)

OutOfStep_new	TimeOut	Pgen	Qgen	AngleThr (degrees)	AngleDev (degrees)
OutOfStep_new	13.2457	0	−12.25	180	180.1145
VTGTPA	TimeOut	Pgen	Qgen		
VTGTPA	13.821	392.37	38.87		
VTGTPA	14.05	68	28.8		
VTGTPA	14.05	68	28.8		
VTGTPA	14.05	68	28.8		
VTGTPA	14.05	68	28.8		
VTGTPA	14.05	68	28.8		
VTGTPA	14.05	67	28.8		
VTGTPA	19.651	74.67	38		
VTGTPA	19.688	71.61	38		

Table 5.11. Generation and Load Loss Summary for Example 3

Generation Loss (MW)	3,900
Load Loss (MW)	1,067
No. of Total Tripping Actions	84
No. of SPSs/RASs Triggered	0
No. of Overloaded Lines	0
Corrective Actions	None

5.2.4 Example 4: Activation of an SPS/RAS

In this example, a bus fault that lasted for six cycles was introduced at Bus X5, which was then tripped to isolate the fault. Along with this bus trip, a line within the vicinity was also considered to have tripped due to nuisance tripping. This was one of the extreme events that had the potential to trigger an SPS/RAS. The fault was introduced at t = 5 seconds and the bus was isolated after 10 cycles, along with a line trip during the dynamic simulation. The relay tripping sequence observed during the dynamic simulation is shown in Table 5.12. A graph of the simulation result is shown in Figure 5.17.

Table 5.12. Relay Trippings for Example 4

Relay Type			
DISTR1	TimeOut		
DISTR1	5.333		
DISTR1	5.333		
VTGTPA	TimeOut	Pgen (MW)	Qgen (MVAr)
VTGTPA	6.421	68	28.8
VTGTPA	6.421	68	28.8
VTGTPA	6.421	67	28.8

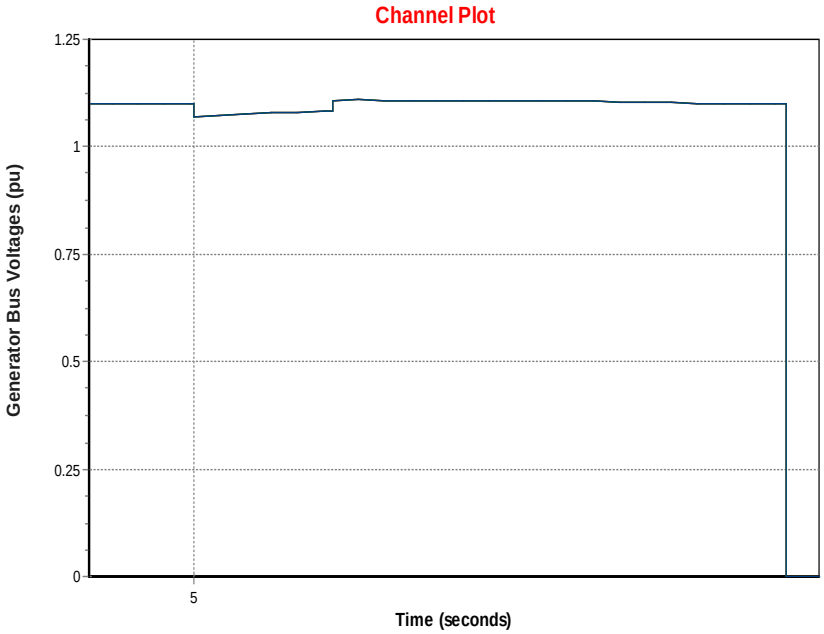

Figure 5.17. Example 4: Generator Overvoltage Trippings. (The generating units trip due to overvoltage.)

After the dynamic simulation, one control condition that could trigger an SPS/RAS was observed in the post-dynamic steady-state case. A second dynamic simulation has been performed to trigger this cascading event.

It is to be noted that during the first dynamic simulation, since there was no system slack bus, the bus angles would have moved away from zero degrees. They could have settled close to 180 degrees. If the second dynamic simulation to implement the SPS/RAS cascade is started from these angle states, there is a great possibility that some of the generators would trip off by out-of-step protection even though they are not out of step. This problem is addressed by forcing the slack bus angle to zero before every dynamic simulation and solving a power flow to obtain a convergent solution. It might be necessary to relax the tolerance of the power flow to about 5 MVA and run a second power flow with the usual tolerance of 0.1 MVA.

No other trippings have been observed during the dynamic simulation where the SPS/RAS event has been triggered. The line overloads observed on the system were below 130% of Rate A and no voltage violations below 0.9 pu were observed. No corrective action was required for this contingency with these protection settings. The sequence of DCAT actions that were performed for this contingency is shown in Figure 5.18. This contingency resulted in a total of 84 tripping actions with a total generation loss of 203 MW and no load loss, as given in Table 5.13.

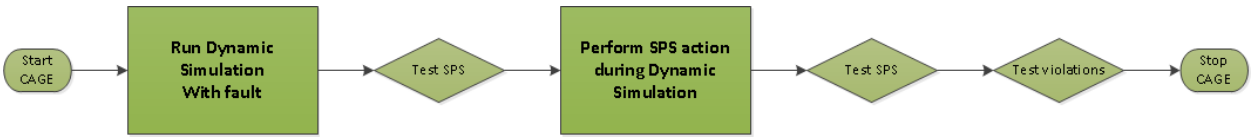

Figure 5.18. Sequence of Events Performed by DCAT for Example 4

Table 5.13. Generation and Load Loss Summary for Example 4

Generation Loss (MW)	203
Load loss (MW)	0
No. of Total Tripping Actions	5
No. of SPSs/RASs Triggered	1
No. of Overloaded Lines	0
Corrective Actions	None

6.0 Steady-State Cascading-Outage Analysis for Preselection of Initiating Events

Given the computational burden of dynamic simulations, we cannot analyze all possible initiating events. Steady-state cascading-outage analysis can be used to prune the large number of initiating events for further investigation using DCAT. In this chapter, steady-state cascading-outage simulations have been performed on the full interconnection grid used in the simulation examples in Section 5.2 using TransCARE to filter and preselect initiating events for the DCAT.

The steady-state-based approach to simulate cascading-outages is introduced using the TransCARE commercial software package. The main theory and assumptions used in TransCARE are provided. The procedures of setting up a study scenario in TransCARE are explained. TransCARE provides an efficient way to quickly screen a large number of contingencies, e.g., tens of thousands of extreme events. Initiating events that may cause potential issues such as load loss, generator tripping, or load shedding can be further analyzed using the DCAT as shown in Section 5.2.

6.1 TransCARE Simulation Overview

The TransCARE simulation method outlined here can be the first step in enhancing our understanding of how cascading failures may propagate through a bulk-transmission network. The method aims to capture the cascade path starting from an aggravated system condition and an initiating (triggering) event. For the purpose of simulating system vulnerability to cascading failures, the term “initiating event” refers to simultaneous outage of transmission lines, transformers, and generating units that may trigger cascading failures, that can potentially cause system instability, or that lead to local or widespread blackouts. The model simulates the cascading process as a sequence of quasi-steady-state system conditions caused by a sequence of tripping events. At present, it is based upon an *a priori* assumption of tripping sequence. For example, it is assumed that given both a heavily overloaded circuit and a load-bus voltage that is below a specified threshold, a voltage-triggered tripping will occur before the overloaded line trips. Admittedly this is a simplified assumption, but it still is reasonable for some types or stages of blackout processes. However, dynamic cascading failures can occur that defy this assumption and the existing method should be extended to include such complexities.

Cascading failures may occur due to a variety of causes such as breaker failures, common tower and common right-of-way circuit outages, and loss of important transmission network facilities. Although the probability of such events may be low, nevertheless they may result in serious consequences leading to local or even widespread load loss. These initiating events are triggered by action of a set of breakers comprising a protection zone. Since several bulk-power transmission system components are protected by a set of breakers, all of these components are taken out of service. When a PCG (a set of components protected by a common set of breakers) goes out of service due to action of the breakers defining the PCG boundary, other components belonging to a different protection zone may also go out of service. These initial outages could in turn cause severe overloads and voltage deviations in transmission facilities, which may trigger further tripping action of other PCGs, and so on. These cascading outages can propagate through the interconnection, incurring significant loss of load and potentially leading to system collapse. The difficulty of this analysis is compounded by the complexity of the models and the multitude of initiating events and propagation scenarios.

6.1.1 Protection and Control Groups

The analysis method that simulates network vulnerability to cascading failures is a part of the TransCARE software and is termed the cascading-outage analysis. TransCARE was developed jointly by EPRI and Southern Company over the past few decades. A realistic simulation of cascading failures must include PCGs because cascading failures may occur in a power system operating under steady-state conditions.

Figure 6.1 demonstrates an example of a PCG as utilized in a TransCARE cascading-outage simulation approach. Four PCGs have been identified in a portion of a system, as shown with dashed lines. If the breakers protecting the line spanning Buses 10 and 22 trip, then not only are the loads at interior Buses 18 and 20 lost, but also the radial loads at Buses 27 and 29. TransCARE identifies the PCGs automatically using a network-trace algorithm based upon breaker location information, which can be determined either automatically based upon a predetermined logic or from the user-specified breaker locations in a positive-sequence network. Breaker locations that are determined automatically by the program can also be modified to match actual breaker locations. The network trace would not only trace the components within a PCG, but also other components and islands that might go out of service as a result of the action of breakers in the primary protection zone. For example, for a fault on the tapped line at Bus 18, circuits 18–24, 24–27 and 24–29 would all go out of service if line section 18–24 is tripped.

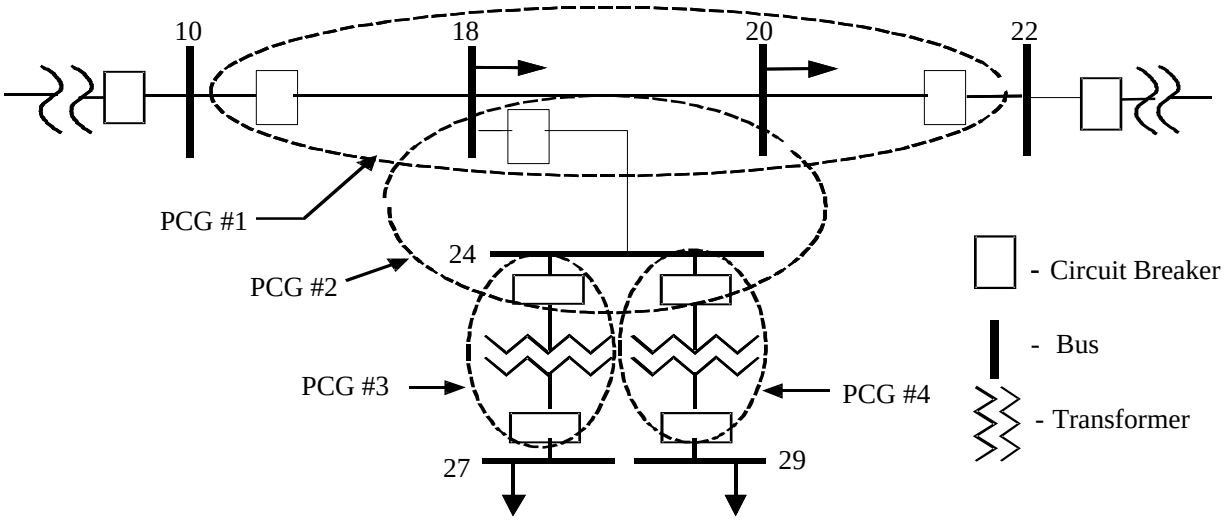

Figure 6.1. Sample Protection and Control Groups

6.1.2 TransCARE Capabilities

Although TransCARE was designed for comprehensive probabilistic transmission network and generation reliability analysis, its main solution algorithms are well suited for simulating cascading failures. Its model allows up to ten base-case scenarios whose analyses form the foundation for computing reliability indices while including the impact of system load variation. These base cases can either be supplied as individual files or the rest of the cases can be created by load scaling from a single supplied base case. TransCARE is capable of performing comprehensive contingency analysis by including:

- PCG outage due to temporary and permanent faults

- enumeration of independent contingencies, a combination of a maximum of five line sections and four generators
- common-mode contingencies
- user-supplied, must-run contingencies
- a two-weather-outage model
- variation of system load.

TransCARE contingency analysis uses a wind-chime enumeration scheme (Meliopoulos et al. 2005) to systematically enumerate independent component outages due to repair. Contingency analysis can be further augmented by supplying additional contingency lists containing common-mode-dependent events and/or must-run contingencies. Independent contingency analysis involves a systematic contingency enumeration utilizing efficient ranking of contingencies, using performance-index-based overload or voltage ranking. While traditional reliability assessment is generally confined to combinations of bus-to-bus line sections and generator outages, TransCARE incorporates a far more detailed assessment that simulates the sequence of component outages commencing from breaker actions when faults occur. In terms of load loss, PCG outages have the greatest impact on network reliability, and exclusion of this model from traditional contingency analysis would severely underestimate impact of contingencies.

TransCARE includes a very fast decoupled power-flow algorithm that implements both partial matrix refactorization and factor update algorithms to modify the system matrix during bus-type switching. An auxiliary solution in the reactive power/voltage (Q-V) iteration aids in smoothing solution perturbations introduced due to bus-type switching. These enhancements have resulted in extremely fast solution speed while enhancing the robustness of the solution algorithm. TransCARE includes a rigorous and robust framework for wide-ranging optimization-based remedial actions. The remedial-actions algorithm determines a set of global control actions while minimizing the vector of available control variables. The linear programming module provides a mixed integer solution and incorporates both continuous and discrete controls. Control actions include generator real and reactive power redispatch, transformer-tap and phase-shift adjustment, capacitor and reactor switching, three classes of load curtailment, and even relaxation of area interchange. The remedial-actions algorithm is based on computing the sensitivity of system constraints, such as overloads and voltage violations, with respect to system controls. The sensitivity computation is exact and uses the full Jacobian matrix.

6.1.3 Generation Redispatch Due to Contingencies

During contingency solution, the dispatch algorithm restores generation-load balance in the system following the outage of one or more generating units. A dispatch error is generated by algebraically summing the generation, load, real shunt flow, and base-case losses apportioned to the buses. Defining the “margin” as the difference between the upper limit and the current generation of a generating unit, unit participation factors are computed and normalized in so that the sum of these participation factors equals one. The resulting dispatch error is then apportioned to each of the generating units that are online to bring the system power balance to a rough equilibrium.

The dispatch error could be for the whole power system or for each interchange area. When area-interchange obligations are to be observed, and in the absence of network islanding, the dispatch will be

by area (only control areas that are in the superset of the study area are dispatched). All areas contained in the study area are classified as part of the dispatch area. The dispatch error is then distributed among the participating units (units with nonzero unit participation factors) in the dispatch area(s).

These initiating events are subjected to cascading-outage analysis as shown in the flow chart in Figure 6.2. The details of the simulation are output in a formatted report that lists not only the initiating events but also the cascading outages, system problems, and load loss that may be triggered as a result.

6.1.4 Cascading-Outage Analysis

The flow chart shown in Figure 6.2 illustrates the method of cascading-outage analysis implemented in TransCARE. The analysis shown is for a single load level; other load levels are simulated in a similar fashion, analyzing the impact of initiating events upon the power system.

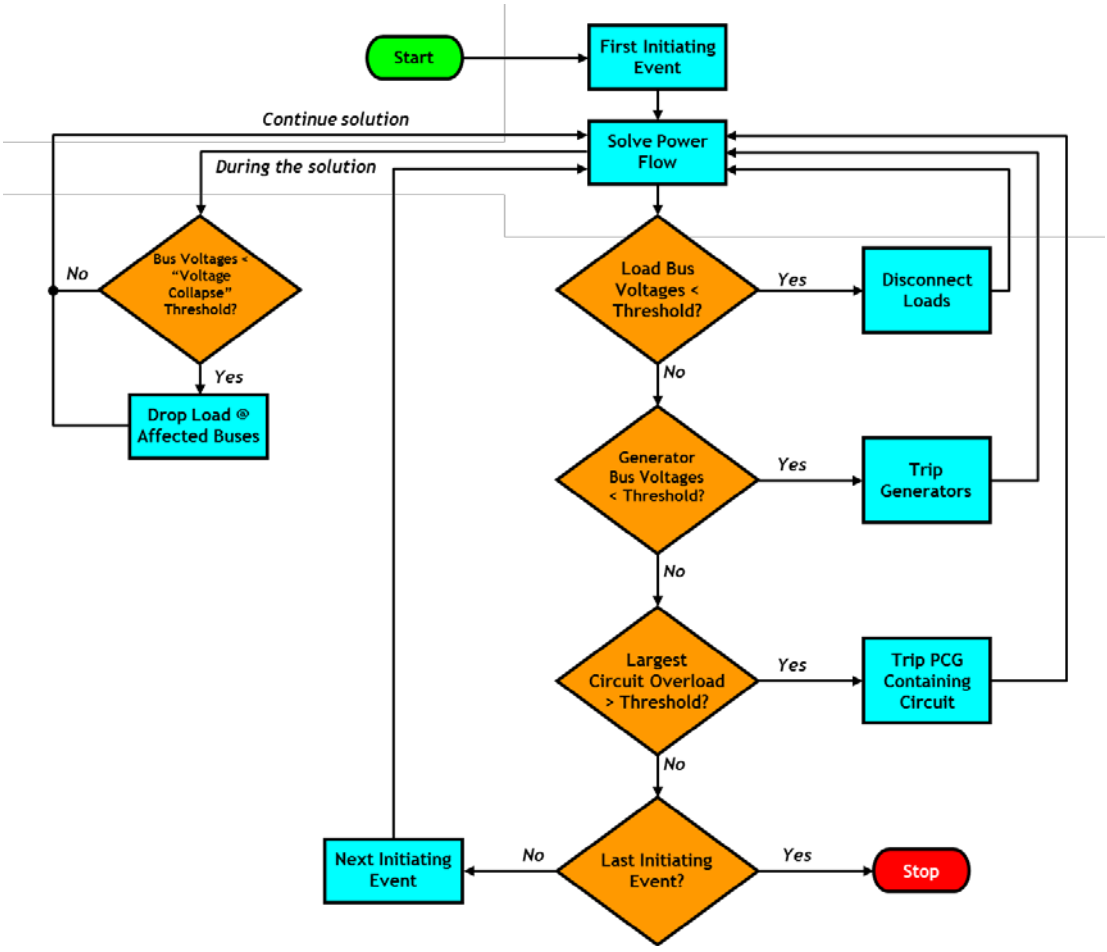

Figure 6.2. Flow Chart of Cascading-Outage Analysis

A list of initiating events supplied by the user serves as the starting point of this analysis. An initiating event can be supplied as a combination of transmission-line, generator, and/or transformer outages. Other than the PCG tripping actions following an initiating event, important user specifications include the following:

- a “voltage collapse” threshold to prevent the power flow solution from diverging
- a load-bus tripping threshold, which to some extent models the setting of a low-voltage relay
- a generator control-voltage tripping threshold
- an overload threshold for tripping overloaded lines.

Starting with the first initiating event, the identified PCGs are simultaneously taken out of service. A power flow solution is attempted; if voltage collapse conditions are detected at certain buses, then the loads at these buses are tripped out of service. This is to make sure that a power-flow solution is reached to the extent possible, given that extreme events comprising outage of a large number of components are being analyzed. The solved power-flow system state is now scrutinized for load-bus voltages that are below the user-specified threshold. If such buses are detected, then the loads at these buses are tripped, mimicking the action of a low-voltage relay or a motor stalling. The resulting system becomes the starting point for the next power-flow solution. If no load-bus voltages are below threshold, generator terminal voltages are examined to identify ones that are below that specified threshold; if any are found, the corresponding generators are tripped and another power-flow solution is attempted. If neither load-bus voltages nor generator terminal voltages are below the respective specified thresholds, then circuits that are overloaded above the specified limit are identified. The PCGs containing the highest-loaded line segment are identified and tripped. This then forms the cascading outage. The tripping sequence is continued until the power-flow solution is unable to converge or a maximum of 20 cascading power flows is reached.

The resulting load loss for each cascade is tabulated and reported, including system violations such as overloads and voltage violations. The amount of load loss for each category of tripping is also reported. This procedure is repeated for each initiating event until the user-specified initiating-event list is exhausted.

6.2 Model Setup in TransCARE

The following subsections give a brief explanation of how the user can perform cascading-outage analysis in TransCARE starting from a planning base power-flow case.

6.2.1 Data Required for Cascading-Outage Analysis

TransCARE requires the following data files to simulate cascading failures:

a) power-flow case, in an appropriate format (typically the PSS/E *.sav file)

b) breaker location data, supplied in the required format

c) traced PCGs utilizing the breaker location data

d) a set of initiating events that act as the trigger for cascading-outage analysis

Typically a single power flow, or a number of power flow cases not exceeding ten system operating states, is (are) supplied, depending on the objective of the study. A single case can be specified if the analysis is only of interest for a particular load level. However, if it is of interest to examine the variation of system failures due to cascading outages with varying load levels, then a number of power flow cases should be supplied. The load scaling feature can also be used to examine how system failures vary with load levels.

The other mandatory input is a file containing breaker locations on the high-voltage network as translated to a bus-oriented positive-sequence network, which can be automatically generated by TransCARE. Once the breaker locations are supplied, PCGs are automatically determined using a robust network-trace algorithm. The PCGs coincide roughly with the primary protection zone in a typical system-protection scheme. The traced PCGs are output into a file that also contains default outage statistics. Both the breaker location file and the traced PCGs are processed with an ancillary file-preparation program that reads the power-flow data and the specified breaker locations and then outputs the traced PCGs.

The other major requirement for performing cascading-outage analysis is a list of initiating events that are simulated individually in order to identify whether any of them cause cascading failures leading to either local or widespread blackouts. The specifications for an initiating event include outages of line sections, transformers, generator units, and/or combinations thereof.

Analysis and tabulation of system problems is restricted to a specified study area. A study area is normally defined by the control area over which a particular utility has jurisdiction and control. The PCGs to which the specified components belong, which were previously identified using a network trace, are first identified; the initiating event is triggered by simultaneously taking out of service all PCGs identified by the network trace.

6.2.2 Power Flow Base Case

Currently, TransCARE supports the power flow files in the format of “*.sav” cases in PSS/E Version 32. Modifications to the base case(s) may be required to run simulations properly in TransCARE. As an example, if the base case has many study areas to be simulated simultaneously, it is necessary to reduce the total number of areas in the model by restricting bus areas to those of interest.

6.2.3 Automatic Breaker Placement

To simulate cascading outages, TransCARE requires information on the location of circuit breakers powering the network, which is normally supplied using existing system-protection maps. This method necessarily involves tedious and time-consuming manual procedures in order to prepare the requisite breaker location data file. However, if the actual breaker locations are not available, the automatic breaker placement module in TransCARE can be used. The breaker placement logic follows existing system-protection practices. A threshold bus voltage level is defined based on user specification, above which all lines emanating from a bus are assumed to be protected by a breaker; e.g., 161 kV. Similarly, all buses of four points or higher are assumed to be protected by placing breakers on all radiating lines. Three-winding transformers are handled assuming that each of the three branches is protected by breakers at

both terminals. In order to confine PCGs to each study area at points where a control area connects to a neighboring utility, both terminals of a tie line are assumed to be protected by breakers.

For branches below the user-specified threshold voltage, each bus is pivoted and every line radiating from it traced. Such tracing identifies lines that are networked and those that are radial. If a radial line is discovered by the topological trace, then a breaker is placed at the farthest point from the line terminal where the line connects to the network. Network lines are lines not having breakers at the pivoted bus. The breaker placement data is written in the required format for automated PCG identification.

6.2.4 PCG Identification

Breaker locations are used to perform a network trace to identify components that belong to a PCG. The trace algorithm also automatically identifies other PCGs that may go out of service outside of the protection zone of a PCG. Identified PCGs and the dependent outages are written to a file containing the components that fall within a PCG and those that are forced out of service by the primary outage.

6.2.5 Selection of Threshold Values for Cascading-Outage Analysis

The following threshold values are very important; they affect the cascading-outage analysis results, which should be based on common practice in the power industry:

- overloaded-circuit tripping threshold: 130% of MVA Rating A values on transmission lines
- low-voltage generator tripping threshold: 0.85 pu
- simulation low-voltage load tripping threshold: 0.85 pu.

It should be noted that the current version of TransCARE does allow tripping due to overvoltage.

6.2.6 Selection of Initiating Events

The selection of initiating events plays a crucial role in accurate simulation and analysis of potentially large-scale power system failures. Successful identification of such events can help effectively identify the most severe disturbances and help system planners propose preemptive system reinforcements that will improve both the security and the reliability of the system. Unlike traditional contingency analysis, which confines outages to bus-to-bus line sections, cascading analysis implements simultaneous outage of several sections of transmission line protected by a set of breakers; it thus mimics the actual outage sequence in a bulk-power transmission system. For example, a substation breaker failure could lead to multiple PCG outages followed by a cascading process. Common-right-of-way transmission lines are more vulnerable to simultaneous trips when the lines are located in different parts of the system.

In addition to the traditional contingency analysis limited to a combination of single-element outages, more initiating events can be studied in TransCARE, including substation outages, loss of two important transmission lines, and loss of two generators, each of which is discussed below. A greater variety of initiating events can be considered in TransCARE.

6.2.6.1 Type 1: Substation Outage

The outage of a substation will result in the loss of all the branches and generators connected to this station. Initiating events of this type are chosen based on the bus voltage level; i.e., the simulation only includes the outage of substations with voltage levels above a certain prespecified threshold, e.g., 100 kV.

6.2.6.2 Type 2: Coincident Loss of Two Generators

In the event of the loss of two large generators at the same time in the system, a generator list is selected first to include all the machines with an apparent power (MVA) output greater than a specified value. With this list, simulations can be run that consider all possible combinations of any two machines in this list.

6.2.6.3 Type 3: Coincident Loss of Two Transmission Lines

In the contingency of the coincident loss of two major transmission lines, a list of transmission lines with MVA flow greater than a prespecified threshold level is created. This list is then used to create a set of initiating events that considers all possible combinations of any two transmission lines in the list.

In accordance with to the above criteria, a MATLAB®[1] code was created to automatically produce the list of initiating events used in TransCARE for any system model. The code can create contingency files with tens of thousands of initiating events based on prespecified criteria.

6.3 Analysis of TransCARE Simulation Results for Identifying Critical Event Corridors

6.3.1 Classification of Initiating Events Based on Output Results

Based on comprehensive analysis of TransCARE simulation results, initiating events can be categorized into several types:

a. initiating events that cannot be solved from the beginning, because power flow is not converging; TransCARE marks these as “Non-convergent case.”

b. other initiating events that cannot be solved from the beginning because power flow is collapsing; TransCARE marks these as “Divergent case.”

c. initiating events that cannot be solved after a certain number of cascades, i.e., the power flow has no solution after a few cascades

d. initiating events that were solved after a certain number of cascades with a certain amount of load curtailment

e. initiating events that cannot be solved from the beginning because of generation deficiency

f. initiating events with no cascading failures.

[1] MATLAB is a product of The Math Works™

6.3.2 Ranking Index of Initiating Events

Ranking the severity of initiating events is needed to identify the critical events, so that remedial actions can be designed to assist the system operator in handling those events and preventing or arresting the occurrence of cascading failures. It is challenging due to the many factors that should be considered. Initiating events that cannot be solved cannot be ranked without further investigation to determine the reasons for the lack of a power-flow solution. For those cases solved in TransCARE, those initiating events with load loss and cascading trippings can be ranked based on a severity index, which would consider the amount of load loss in cascading failures, the number of cascading outages, and the total number of failed elements in the initiating event:

$$Index_{severity} = \frac{L_S + M * N_c}{N_k} \quad (1)$$

where
- L_s is the total amount of load loss in MW
- M is the weighting factor
- N_c is the total number of cascading PCG actions
- N_k is the total number of failed elements in the initiating event.

The weighting factor can be obtained by incremental tests.

6.3.3 Methodology for Identifying Critical Corridors

Although no two blackouts follow the same sequence of events, similar partial sequences of cascading events may exist in a particular power system, such as partial patterns in which transmission lines (PCGs), generators, or buses are forced out in a certain order and can appear more often in a variety of initiating events and system conditions, as shown previously in Figure 2.4. Therefore, these patterns can result from multiple different initiating events and can be seen as parts of different cascading processes. If confirmed, the concept of critical corridors could be used to recommend transmission system enhancements, protection system modification, and remedial actions to help eliminate the most frequently observed, and therefore most probable, critical sequences leading to the most severe consequences such as massive load loss or system collapse.

The main goal of this effort is to develop a methodology for identifying critical corridors in the system and to examine the hypothesis of critical corridors. The methodology is based on searching for common paths, or sequences, that may exist in multiple different cascading-outage events. These critical paths can be ranked according to their frequency of occurrence (or, in future research, based on their probability) and severity. Below is the proposed procedure to identify a critical corridor; a MATLAB script was developed to extract key information from a TransCARE simulation result file.

1) Open the PCG group description file (*.cko) and build a lookup table to store all the lines in this file and their PCG group number.

2) Open a TransCARE result file (*.cdn) and start reading this file.

3) For each line, search for key words:

   i. If the current line contains '= OUTAGE DESCRIPTION FOR INITIATING EVENT NUMBER', this line represents a new event simulation.

   ii. If the current line contains '========= CIRCUITS SWITCHED ==========' and its above line contains '== AUTOMATIC CIRCUIT TRIPPING DUE TO THERMAL LIMIT VIOLATION', this line indicates that there are a few circuits tripped due to thermal violation, shown right after the current line.

   iii. Collect these tripped lines in a matrix, called "TripLine."

   iv. Store their initiating event numbers.

4) Find the PCG group numbers for the tripped circuits.

5) Find cascading events and store them:

   i. For the same initiating event, store all the PCG numbers that are tripped during this simulation.

   ii. Filter the simulation cases with more than one PCG action for the same initiating event; (e.g., for initiating event 17, there are three PCG groups tripped. This case is considered as a cascading event. On the contrary, if for initiating event 20, only one PCG group tripped, this case is not a cascading event. Therefore, this case is not stored).

   iii. Build a matrix to store all the cascading events, including initiating event number and the corresponding PCG actions.

6) Search for critical sequential pairs:

   i. Exhaustively search for all the possible sequential pairs in the cascading-event matrix and count their frequency.

   ii. Rank the pairs according to their frequency.

   iii. Output the most frequently occurring pairs to *.csv (comma-separated value) files.

7) Search for critical triplets (the three sequential PCGs that occur most often); the algorithm is similar to Step 6. (This function will be added in the near future).

8) Search for critical corridor including four PCGs, five PCGs, etc., if necessary.

6.4 Case Studies

Steady-state cascading-outage simulations have been performed on a full interconnection grid using TransCARE to preselect initiating events for the DCAT. Case 1 examines 620 initiating events that were provided by a grid operator, while Case 2 examines more than 9,000 initiating events that were created based on certain criteria. The advantage of steady-state cascading-outage analysis is that hundreds of thousands of initiating events can be examined with much less computational effort than with dynamic simulations.

6.4.1 Case 1

Case 1 provides an initial testing result using TransCARE for cascading-outage analysis using the provided contingency list from a grid operator. The initial power-flow base case was obtained. However, the detailed breaker locations were not available to the research team; therefore, the breakers were automatically generated in TransCARE and PCGs were determined based on the generated breaker locations. The participation factors for redispatching generators were calculated based on the generating unit maximum real power Pmax. An initiating event list was obtained, which was converted from a PSS/E contingency file (*.con) to an initiating event file (*.smd) in TransCARE. A total of 620 contingencies was converted successfully. After the cascading-outage analysis simulation in TransCARE, the detailed simulation results were all saved in a log file (*.cdn file). The MATLAB codes developed by PNNL team were used to read the *.cdn file, and the summary is shown below. (The numbers in parentheses are the percentage of each type of result out of the total number of initiating events).

e) No. of initiating events: 620

f) No. of non-solved cases: 6 (1%)

g) No. of capacity deficiency cases: 0 (0%)

h) No. of divergent cases: 0 (0%)

i) No. of non-solved cases after several power flows: 2 (0.3%)

j) No. of severe cases with load loss or cascading events: 388 (62%)

k) No. of normal cases: 224 (36%).

Figure 6.3 shows the total amount of load loss and number of lines tripping after the initiating event.

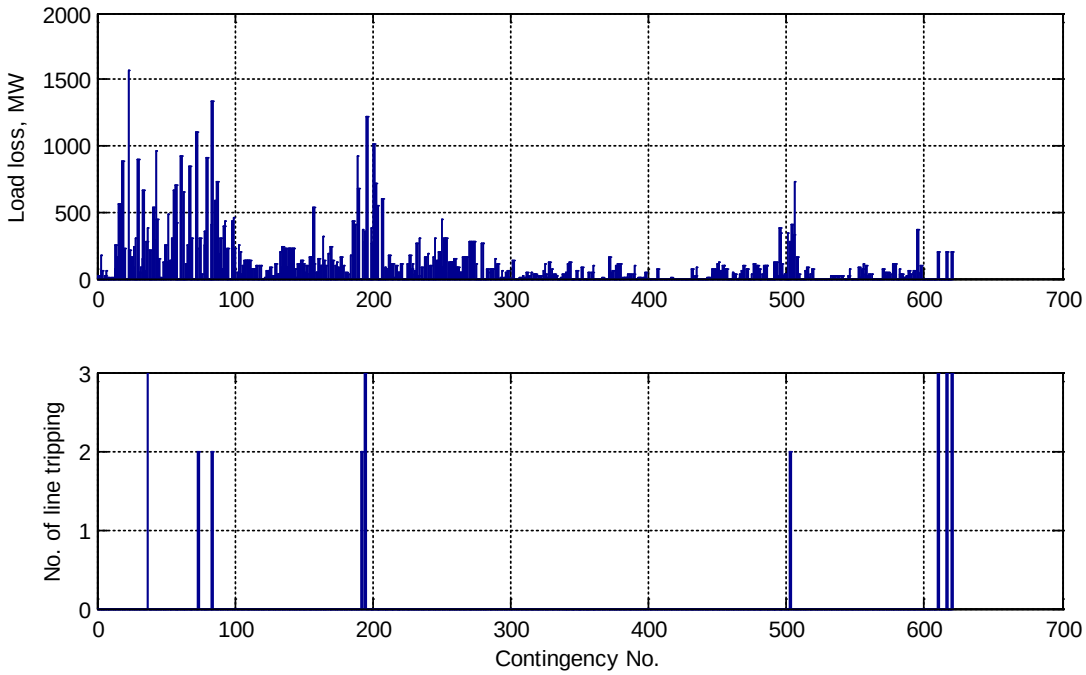

Figure 6.3. Contingency Analysis Results

Critical-corridor analysis was performed to identify the cascading sequences with the highest frequency of occurrence, shown in Table 6.1.

Table 6.1. Critical Event Corridors Identified

First PCG in the Cascading Sequence	Second PCG in the Cascading Sequence	Frequency of Occurrence
PCG04490	PCG04489	5
PCG04026	PCG04490	3
PCG03946	PCG03937	1
PCG03937	PCG02383	1
PCG04048	PCG04036	1
PCG03922	PCG03724	1
PCG03724	PCG03720	1
PCG00421	PCG00422	1

6.4.2 Case 2

In this section, more contingencies are generated using a MATLAB script, including substation outages, $N-2$ generator outages, $N-2$ line outages, random combinations of generator and line outages, etc. The following types of initiating events, along with their thresholds, were used to create a significantly larger number of initiating events for a more comprehensive study:

a) substation outage with voltage level larger than 100 kV

b) random combination of two generator outages, for all machines with active power output larger than 200 MW.

There were 9,133 initiating events created to perform a more comprehensive study. The summary of TransCARE simulation results is shown below. (The numbers in parentheses are the percentages of each type of result out of the total number of initiating events.)

a) No. of initiating events: 9,133

b) No. of non-solved cases: 5 (0.05%)

c) No. of capacity deficiency cases: 0 (0%)

d) No. of divergent cases: 2 (0.02%)

e) No. of non-solved cases after several power flows: 0 (0%)

f) No. of severe cases with load loss or cascading events: 3,943 (43%)

g) No. of normal cases: 5,183 (57%).

Figure 6.4 shows the total amount of load loss and number of lines tripping after each initiating event. Critical event analysis was also performed on the 9,133 cases, and several critical corridors (with two and three sequential PCG outages) were identified; these are shown in Table 6.2 and Table 6.3, respectively.

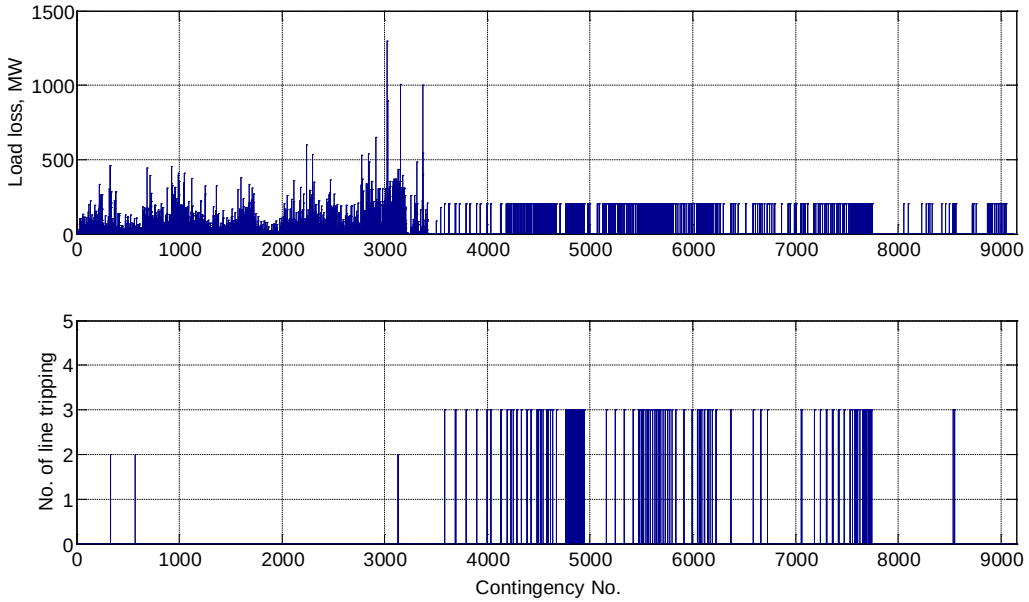

Figure 6.4. Cascading-Outage Analysis for 9,133 Contingencies

Table 6.2. Identified Critical Corridors – Two Sequential PCGs

First PCG in the Cascading Sequence	Second PCG in the Cascading Sequence	Frequency of Occurrence
PCG04490	PCG04489	373
PCG04026	PCG04490	371
PCG00611	PCG00493	1

Table 6.3. Identified Critical Corridor – Three Sequential PCGs

No.	First PCG in the Cascading Sequence	Second PCG in the Cascading Sequence	Third PCG in the Cascading Sequence	Frequency of Occurrence
1	PCG04026	PCG04490	PCG04489	371

As explained earlier in this section, TransCARE adopts a static-analysis method to identify system behavior following severe disturbances. Power flows are performed using a very computationally efficient decoupling method that significantly reduces the computational time of all simulations. For a contingency list with 9,608 initiating events, it only takes 1~2 minutes to obtain all the simulation results on an Intel Core 2 Duo-based machine.

7.0 Conclusions, Lessons Learned, and Future Work

7.1 Conclusions

The DCAT was developed to realistically model cascading-outage processes in the power grid. It uses a hybrid dynamic and steady-state approach to simulate the cascading-outage process that includes both fast dynamic and slower events. The integration of dynamic models used in planning studies with protection scheme models, including generation, transmission and load protection systems, is a key element. Post-dynamic steady-state analysis was used to model SPS/RAS as well as automatic and manual corrective actions. Steady-state cascading-outage analyses were performed using TransCARE to prescreen initiating events for the DCAT.

The developed Python code that represents the DCAT implementation will be made available to grid operators to overcome the difficulties facing the power industry in implementing extreme-events analysis. Overall, the DCAT bridges multiple gaps in cascading-outage analysis and puts solutions in a single, unique prototype tool capable of automatically solving and analyzing cascading processes in large, interconnected power grids using multiprocessor computers. This study has been conducted in close collaboration with grid operators Siemens PTI and EPRI. While the DCAT has been implemented using PSS/E in Phase I of the study, other commercial software packages have similar capabilities and may be used in future phases or for different aspects of the analysis.

7.2 Lessons Learned

During development of the DCAT, several important lessons have been learned that we would like to explain in this section. The main lessons can be summarized as follows:

- A sufficiently detailed modeling of cascading processes is possible in the existing software tools. This capability does exist, but is dramatically underused. There is lack of such experience in the industry and among many vendors. This project demonstrated how this “sleeping” opportunity can be activated and implemented using an example of one of the most popular software tools—PSS/E.
- Close collaboration among national laboratories, utilities and system operators, software vendors, and research organizations has proven again to be very effective for developing new effective solutions, new capabilities, and new tools. This project is a good illustration of this winning approach.
- Integration of steady-state and dynamic simulations is needed. Cascading events should be simulated as a combination of steady-state and dynamic processes to accurately depict slower and faster phases of blackout development and their sequence. In the current industry practice, dynamic and steady-state simulations are usually conducted in a sequence, where the dynamic simulations follow the steady-state runs. This is not an adequate approach to simulate cascading. During cascading, the dynamic processes (if they are stable) result in a post-transient state, where another disturbance can happen and cause a new dynamic process. This requires a combined/integrated steady-state and dynamic simulation engine where the steady-state and dynamic simulation steps are following each other to mimic slow and fast actions during the cascading sequence. A prototype of such an engine is implemented in this project. This prototype sets an example for software developers and users.

- Protection system modeling is vital for accurate cascading-failure simulations. The lack of integrated dynamic models with protection relays in the industry is a major challenge for performing sound cascading-outage analysis. This project has demonstrated how the protection system model can be embedded in an existing dynamic simulation tool.

The following subsections provide more details and some additional thoughts on the lessons learned.

7.2.1 Steady-State vs. Dynamic Analysis

For planning and NERC compliance purposes, there are typically two teams within the grid operator organization: one team handles base power-flow models/contingency lists for steady-state analysis, and another team handles dynamic models with more detailed base power flow cases. Take as an example modeling of a wind power plant in the base power-flow case. For dynamic simulation, the collector system will be presented using several equivalent machines with their associated dynamic models located at several buses; for steady-state analysis, it will be modeled as one single bus. The more-detailed base power-flow cases are more appropriate for use in the cascading-outage analysis. In addition, cascading-outage analysis should use a hybrid dynamic and steady-state approach to simulate fast dynamic and slower steady-state events as implemented in the DCAT.

7.2.2 Convergence of a Steady-State Solution after Extreme Events

For steady-state analysis, two critical components have roles in finding a converged solution after extreme contingencies:

- The modeling of generation redispatch when the extreme events result in a significant mismatch between generation and load can be based on inertial response, governor response, or using a list of generating units with predetermined participation factors.
- The modeling of SPS/RAS is very important because tripping of certain elements can help in reaching convergence.

7.2.3 Modeling of Protection in Cascading-Outage Analysis

The lack of integrated dynamic models with protection relays is a major challenge for performing sound cascading-outage analysis. The current practice is to mimic protection actions by assuming that the fault (initiating event) will be cleared, and identify the elements that will be tripped due to this fault with a certain time delay after fault inception. In addition, some grid operators model underfrequency and undervoltage load-shedding relays. The newly issued NERC Standard PRC-024-1, “Generator Frequency and Voltage Protective Relay Settings” (NERC PRC-024-1), will make the under/overfrequency and under/overvoltage relay settings universal for all generating units. Grid operators should add these relay models to their dynamic models. In addition, modeling of out-of-step protection for generating units is important. For transmission protection, the modeling of distance relays with correct settings could be a challenge because this information is typically set by transmission owners and not available to grid operators. Because overcurrent relay tripping actions are generally slow compared to distance relays, overcurrent relays are unlikely to operate during dynamic simulation if the distance relays operate appropriately. PSS/E imposes a hard limit on the number of relays to be modeled in the transmission

system (3,000 maximum). Therefore, there is no need to implement overcurrent relays in dynamic simulation; instead, monitor line overloading in the post-dynamic analysis.

7.2.4 Modeling of Post-Dynamic Corrective Actions

Longer duration events that are not practical in dynamic simulation need to be considered in cascading-outage analysis. The following actions should be modeled:

- SPS/RAS
- automatic corrective actions for voltage violation corrections
- manual corrective actions for generation redispatch and load shedding
- transmission line trips caused by overloading.

Implementation of SPS/RAS can be of two types. Some SPS/RAS actions that are critical for dynamic stability of the system are performed in the time frame of few cycles up to a few seconds for the safety of the system. Dynamic SPS/RAS actions can be implemented using a relay scheme that operates based on the time settings provided by the planner. For the purpose of dynamic simulation, updating the *.dyr files with the appropriate relay information and performing the simulation can capture the effects of these SPS/RAS actions.

Other SPS/RAS actions, however, are automatically enabled and occur in a time frame longer than a few seconds. These SPS/RAS actions could not be automated during the dynamic simulation similarly to the operation of protection relays. The model conditions for each SPS/RAS are checked using the steady-state case extracted at the end of dynamic simulation. If a model condition is satisfied for an SPS/RAS, this action is performed by running a new dynamic simulation. The steady-state file extracted at the end of the previous dynamic simulation is used to start this new dynamic simulation. The new dynamic simulation is allowed to run for a few seconds for flat start, and the SPS/RAS action is then implemented. The dynamic response of the interconnected system to such SPS/RAS action can then be captured.

7.2.5 Low-Voltage Network Model Details and the Impact on Load Shedding

Low-voltage network models are typically aggregated models, which can affect the accuracy of the amount of load shedding. Some grid operators develop several base cases, with each case being modeled with more low-voltage network details for a certain portion of the system. Using these different base power-flow cases for cascading-outage analysis may result in different amounts of load shedding due to undervoltage and underfrequency relay protection.

7.2.6 Compliance with New NERC Standards

To fully comply with the new NERC Standard TPL-001-4, “Transmission System Planning Performance Requirements” (NERC TPL-001-4), a development of new or modified extreme events analysis tools is very much needed. The capabilities of existing simulation tools are not sufficient to fully address the NERC requirements standard.

The standard has been partially in effect since January 2015 and will be in full enforcement by January 2016.

7.3 Future Work

The project presented in this report made a significant step forward in the ability to simulate, understand, predict, and prevent consequences of major disturbances on the grid, including cascading, blackouts, and widespread power supply interruptions. Despite the significant progress made, further work is needed. It can be organized along the following lines.

The main target of future work should be a significant increase in power system reliability, resiliency, and ability to withstand or recover from major disturbances.

The work reported in this project should be put in a broader context of system survivability and resilience. The work will include both technical and nontechnical issues. Possible directions for future work include the following:

- The analysis could be expanded to cover extreme events of a broader nature, such as earthquakes, hurricanes, geomagnetic storms, and premeditated attacks.
- Interactions between the electric power system and the information technology systems could be considered, as well as interactions with other industries such as the natural gas transportation and storage system, transportation, the military, and others.
- Develop system restoration strategies on the national and interconnection levels. This effort will require the development of new ideas, methods, and situation awareness and decision-support tools and capabilities.
- The ultimate goal is to equip major software tools used by the industry, decision-makers, and policy-makers with the cascading-outage analytical capability and actionable information that will help prevent and mitigate the outcomes of blackouts.
- Continuous attention should be given to industry outreach, partnership, and coordination of multiple activities in the area of cascading-outage simulations.

In this report, a detailed methodology for simulating cascading failures from the aggravated state followed by triggering events and subsequent cascading evolution was presented. The final steady state might be a system that has a different configuration with loss of load and/or generation, or several islands. This methodology and its implementation constitute a step forward to address the gaps in existing approaches listed in the Introduction. At the same time, several significant gaps and opportunities remain unaddressed and need further thorough investigation and development, as explained in the following subsections. They can be part of the future work. The following discussion gives some additional details on future activities.

7.3.1 Improved Methods for Sampling Initiating Events

Improved methods for sampling the initial conditions and events that trigger cascades are needed. Additional types of initiating events should be studied. For instance, the increasing penetration of variable renewable generation resources, battery storage schemes, demand-side load-management schemes, virtual and actual consolidation of balancing authorities, new performance standards, and other factors should be studied. The effects of high distributed-generation penetration and microgrids also need to be investigated.

7.3.2 Modeling of Protection and Control Groups

Breaker location information is critically important for producing an adequate structure of PCGs. Access to this information is one of the most significant near-term improvements needed for the deterministic extreme-events simulation methodology. Substation design and configuration have a significant impact on PCG structure, and ultimately on system reliability and cascading sequences. The system model used for cascading-outage analyses should reflect the various types of substation configurations as well as the differences in their behavior after disturbances. In addition, the modeling of SPS/RAS remains a task that requires further effort.

7.3.3 Greater Knowledge of Probabilities

The risks of cascading events are determined to a great extent by their probabilities. These probabilities are based on the probabilities of component outages, the probabilities of relay protection misoperation, the probabilities of communication system failures, and so on. The variety of events that may lead to cascading is huge. To facilitate the probabilistic approach it is necessary to create, list, and classify such events and determine their probabilities. Based on this, we need to develop procedures to quantify the probabilities of multiple simultaneous events, convolution procedures for continuous and discrete events' probability distributions, and probabilities in the event branching process.

7.3.4 Severity Indices

Cascading (blackout) severity indices should be improved and further developed. They are very important for understanding cascading failures and industry applications. There are quite a few possible criteria for selecting "ideal" severity indices. Some of these criteria could be as follows:

a. **Transparency** – The severity indices should be easy to understand and interpret. This condition is very important for the acceptance of these indices by the electrical utility industry.

b. **Probabilistic Nature** – There is an enormous variety of possible cascading events scenarios. Each of them contributes to the overall assessment of the likelihood and severity of cascading events. The overall severity index cannot just mechanically summarize the characteristics of particular cascading scenarios, such as the load loss. This is because each scenario has a different likelihood. As we have already discussed in this report, risk-based severity indices appear to be a good choice for combining scenario-specific information into an overall cascading-severity assessment. In these indices the severities of particular cascading events are surmised with their weights (probabilities of occurrence of these events).

c. **Backward Traceability** – There is a need to backtrack and compare the most significant contributing factors to the overall cascading-severity index. This feature is related to the sharpness characteristic explained below.

d. **Saturation** – The cascading-severity indices should be able to include additional cascading-events scenarios without major changes in their value each time we add a new scenario. Non-saturated solutions would introduce certain "instability," randomness, and ambiguity into the cascading-events analysis process. Without satisfying the saturation requirement, cascading-events analysis results will be difficult to evaluate or to use in practice. For instance, they can help in making decisions on possible system reinforcements. Of course, this requirement can only be considered when a sufficiently large number of scenarios is covered.

e. **Sensitivity** – The severity indices should be sensitive to changes of system parameters, system configuration, and system reinforcements. A sensitivity index can be developed that will help in identifying the most efficient strategy for mitigating cascades.

f. **Sharpness** – The sharpness concept was proposed by Makarov and Hardiman (2003). "Sharpness" probabilistically quantifies the degree of dominance of certain cascading processes, their parts, and their causes. Zero sharpness means that multiple cascading processes or their parts have similar severities, and that it is difficult to indicate particular processes that are dominant in terms of severity. Greatest attention should be given to the areas with high severity and sharpness.

g. **Predictive and Actionable Information** – Blackouts are typically analyzed after the fact, rather than beforehand; it would be better to try to predict future events and their probabilities. The severity indices should provide information that helps to identify causes of cascading. They should be predictive from both grid planning and operational perspectives. The indices should also provide information to help select the most effective system reinforcements and make the best control decisions to reduce the risk and potential consequences of cascading events. The use of synchrophasor data for situational awareness in simulating a cascading failure is a good area for research and development.

7.3.5 Other Considerations

- Modeling cascading processes in increased detail is needed. The methodologies should be expanded to include variants of possible cascading events that follow the same initiating event.
- As indicated by Lin et al. (2011, 2012) it is important to do co-simulation of the power system dynamics with that of the communication network. This analysis can be extended to extreme events and also performed on a national basis.
- The study of human intervention when a cascade occurs will be useful for modeling cascading-outage sequences. Such studies will concentrate on simulating operator actions after power grid disturbances.
- Evaluating the impact of high wind and solar penetration by performing cascading-outage analysis using hundreds of base power-flow cases under different load, wind and solar values is needed to understand the impact of initiating events under different dispatch and load conditions.
- Periodic deep-dive screening of the U.S. interconnections for cascading events could be a good option. One approach could be the use of large-scale computations involving static and dynamic interconnection-level system models. This analysis could be extended to extreme events and also performed on a national basis. The use of HPC is essential.

- Since the protection system is a critical component in a cascading failure, it may be good to have a screening tool to find which relays are vulnerable by evaluating the relay margins for various contingencies (Dobraca et al. 1990). This may be supplemented by trajectory sensitivity analysis (Bai and Ajjarapu 2007).

7.3.6 Outreach Activities and Partnership

During this project, a strong and effective partnership and collaboration have been established between PNNL, planning engineers of a grid operator, Siemens, and EPRI. This partnership resulted in the development of a near-production-grade tool for cascading-outage analysis in only one year of work. Normally, developments of this complexity require years of work. This is another example of the effectiveness of collaboration between the U.S. Department of Energy, national laboratories, and industry in the matters of innovation, great national importance, and expected outcome. The future outreach effort will include:

- wide dissemination of the project's results and findings, including presentations at industry forums and conferences as well as publications
- expansion of industry outreach activities by establishing cooperation with other entities, including California ISO, PJM, Idaho Power, and other industry organizations that have already expressed interest in this area of research. Results will be communicated to vendors that are developing major software products and are deeply interested in the area
- dramatically improved cooperation with the other national laboratories and universities that have historically been involved and have significant achievements in cascading-outage analysis: Argonne National Laboratory, Los Alamos National Laboratory, Lawrence Livermore National Laboratory, the Massachusetts Institute of Technology, and others
- development of project proposals to support continued funding for future work.

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Appendix A

Protection Models in PSS/E

Appendix A

Protection Models in PSS/E

A.1 Mho, Impedance, or Reactance Distance Relay[1] for Transmission Line Protection

This section is modified from the PSS/E Version 32 documentation.

In PSS/E the (mho, impedance, or reactance) distance-relay model is DISTR1. This model covers all three types of distance relays (impedance, reactance, and admittance). The implementation and parameter description for this model are as follows:

IBUS, 'DISTR1', JBUS, ID, RS, ICON(M) to ICON(M+10), CON(J) to CON(J+23) /

DISTR1 Relay Model Parameter Definitions

Relay is located from bus	#_____	IBUS,
To bus	#_____	JBUS,
Circuit identifier	#_____	ID,
Relay slot (1 or 2)	#_____	RS.
This model uses CONs starting with	#_____	J,
and VARs starting with	#_____	L,
and ICONs starting with	#_____	M.

[1] This section is taken from PSS/E 32.0.5: PSS/E Model Library, Revised October 2010, Chapter 11, Section 11.2.

CONs	Val	Description
J		Zone 1 operating time (cycles)
J+1		Zone 1 reach (diameter or reactance) (pu[1])
J+2		Zone 1 centerline angle in degrees (0 for reactance relay)
J+3		Zone 1 center distance (0 for reactance relay)
J+4		Zone 2 pickup time (cycles)
J+5		Zone 2 reach (diameter or reactance) (pu)
J+6		Zone 2 centerline angle (0 for reactance relay)
J+7		Zone 2 center distance (0 for reactance relay)
J+8		Zone 3 pickup time (cycles)
J+9		Zone 3 reach (diameter)
J+10		Zone 3 centerline angle (degrees)
J+11		Zone 3 center distance (pu)
J+12		Angle of directional unit (only for impedance relay)
J+13		Threshold current (pu)
J+14		Self-trip breaker time (cycles)
J+15		Self-trip reclosure time (cycles)
J+16		Transfer trip breaker time (cycles)
J+17		Transfer trip reclosure time (cycles)
J+18		1st blinder type (±1 or ±2)
J+19		1st blinder intercept (pu)
J+20		1st blinder rotation (degrees)
J+21		2nd blinder type (±1 or ±2)
J+22		2nd blinder intercept (pu)
J+23		2nd blinder rotation (degrees)

VARs	Value	Description
L		Apparent R
L+1		Apparent X
L+2		Current
L+3		
.		
.		VARs required for internal program logic
.		
L+9		

[1] pu = per unit

ICONs	Value	Description	
M		Type 1, mho distance Type 2, impedance distance Type 3, reactance distance	
M+1		0 Monitor 1 Monitor and operate	
M+2		From bus number	
M+3		To bus number	First transfer trip
M+4		Circuit ID	
M+5		From bus number	
M+6		To bus number	Second transfer trip
M+7		Circuit ID	
M+8		From bus number	
M+9		To bus number	Third transfer trip
M+10		Circuit ID	
M+11	X	Permissive flag for self trip[1]	
M+12	X	Permissive flag for transfer trip[2]	
M+13 . . . M+28	X	ICONs required for internal program logic	

[1] Set to 1 and −1 by supervisory relay to block trip and force trip, respectively.
[2] Set to 1 by supervisory relay to block trip.

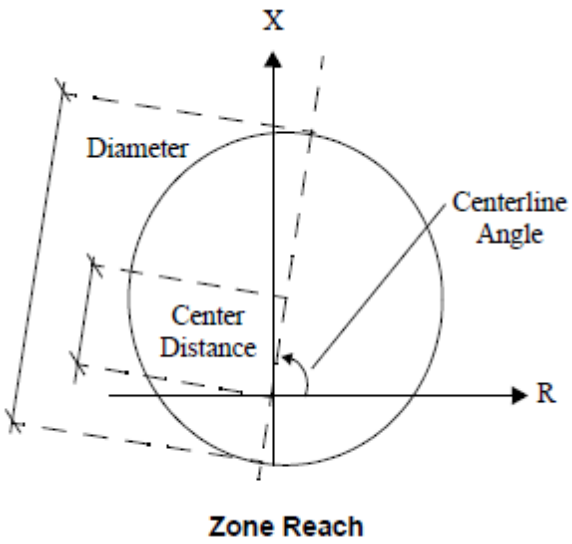


Figure A.1. Zone Reach, Center Distance, Centerline Angle, and Diameter for the DISTR1 Relay Model

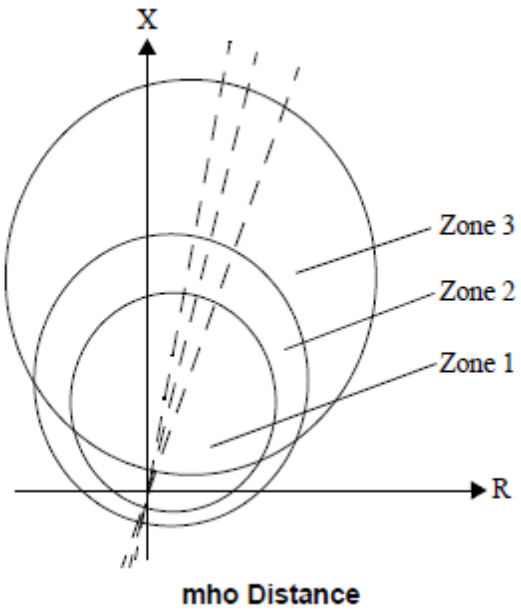


Figure A.2. R vs. X Diagram for a Distance Relay

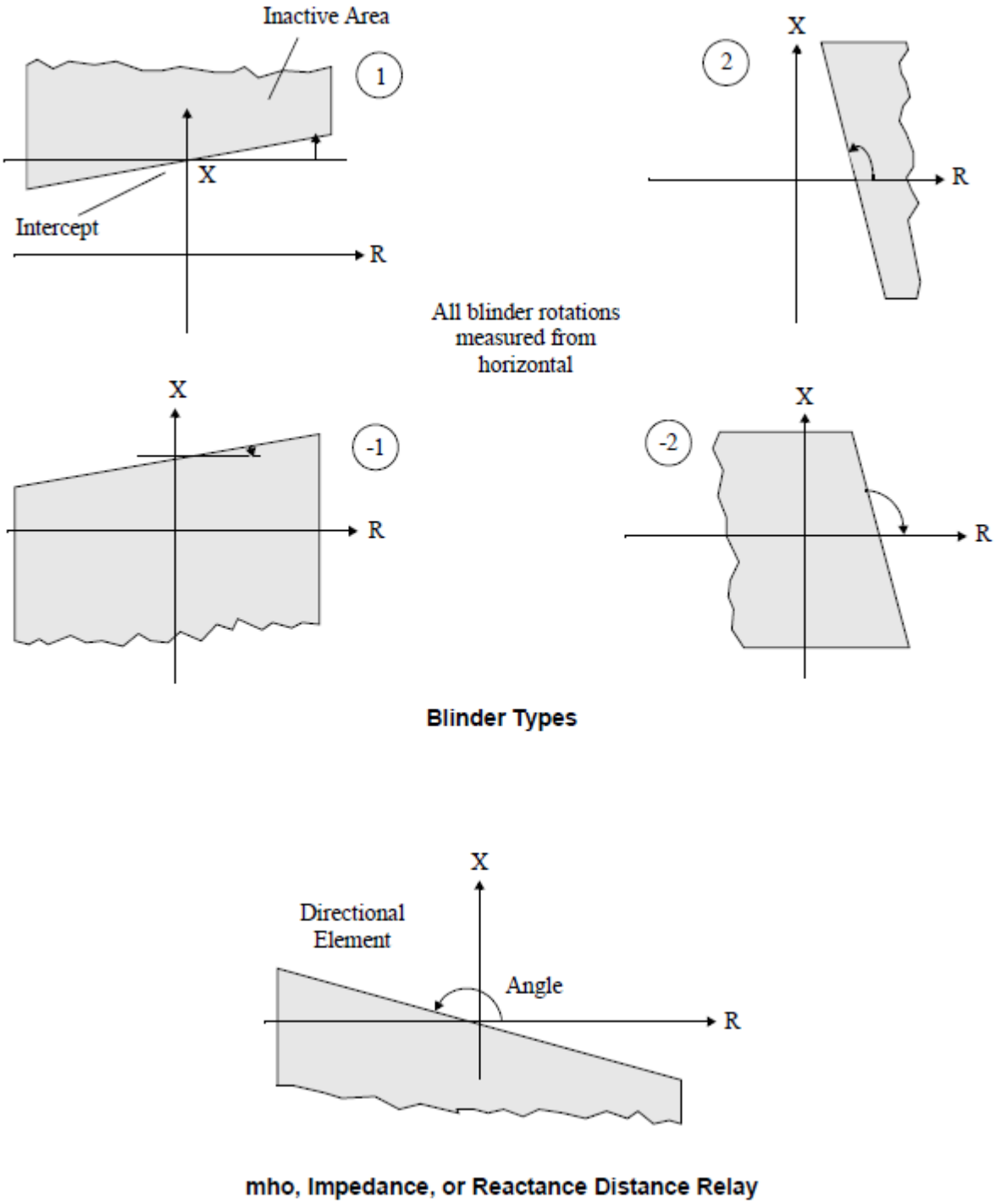


Figure A.3. Blinder Types/Rotations for the DISTR1 Relay Model

The initial implementation uses Zone 1 and Zone 2, with generic parameters as shown in the table of settings for the DISTR1 relay below.

Settings for the DISTR1 Relay

Parameter	Description	Value
IBUS	The *from bus* in the PSS/E model	*frombus*
'DISTR1'	Name of the relay model	'DISTR1'
JBUS	The *to bus* in the PSS/E model	*tobus*
ID	Circuit identifier	*ckt*
RS	Relay slot (1 or 2)	1
M	Type 1, mho distance	1
M+1	1 Monitor and operate	1
M+2	First transfer trip *frombus* number	
M+3	First transfer trip *tobus* number	
M+4	First transfer trip circuit ID	
M+5	Second transfer trip *frombus* number	
M+6	Second transfer trip *tobus* number	
M+7	Second transfer trip circuit ID	
M+8	Third transfer trip *frombus* number	
M+9	Third transfer trip *tobus* number	
M+10	Third transfer trip circuit ID	
J	Zone 1 operating time (cycles)	4
J+1	Zone 1 reach (diameter or reactance) (pu)	80% of |Z|
J+2	Zone 1 centerline angle (degrees)	atan(X/R)
J+3	Zone 1 centerline distance	40% of |Z|
J+4	Zone 2 pickup time (cycles)	35
J+5	Zone 2 reach (diameter or reactance) (pu)	120% of |Z|
J+6	Zone 2 centerline angle (degrees)	atan(X/R)
J+7	Zone 2 centerline distance	60% of |Z|
J+8	Zone 3 pickup time (cycles)	1.00E+06
J+9	Zone 3 reach (diameter or reactance) (pu)	
J+10	Zone 3 centerline angle (degrees)	
J+11	Zone 3 centerline distance	
J+12	Angle of directional unit	
J+13	Threshold current	
J+14	Self-trip breaker time (cycles)	2
J+15	Self-trip reclosure time (cycles)	1.00E+06
J+16	Transfer trip breaker time (cycles)	1.00E+06
J+17	Transfer trip reclosure time (cycles)	1.00E+06
J+18	1st blinder type (1,2, −1,−2)	0
J+19	1st blinder intercept (pu)	0
J+20	1st blinder rotation (degrees)	0
J+21	2nd blinder type (1,2, −1,−2)	0
J+22	2nd blinder intercept (pu)	0
J+23	2nd blinder rotation (degrees)	0

Example for PSS/E *.dyr File Entry for Distance-Relay Model *DISTR1*

Xxxx , 'DISTR1', Yyyy , 1 , 1, 1, 1, 0,0,, 0,0,, 0,0,, 4.0000,0.0005,79.8753,0.0002,
35.0000,0.0007,79.8753,0.0003, 1000000.0000,,,,
,,2.0000,1000000.0000,1000000.0000,1000000.0000,0.0000,0.0000,0.0000,0.0000,0.0000,0.0000 /

Parameter	Description	Value
IBUS	The *from bus* in the PSS/E model	Xxxx
'DISTR1'	Name of the relay model	'DISTR1'
JBUS	The *to bus* in the PSS/E model	Yyyy
ID	Circuit identifier	1
RS	Relay slot (1 or 2)	1
M	Type 1, mho distance	1
M+1	1 Monitor and operate	1
M+2	First transfer trip *frombus* number	0
M+3	First transfer trip *tobus* number	0
M+4	First transfer trip circuit ID	
M+5	Second transfer trip *frombus* number	0
M+6	Second transfer trip *tobus* number	0
M+7	Second transfer trip circuit ID	
M+8	Third transfer trip *frombus* number	0
M+9	Third transfer trip *tobus* number	0
M+10	Third transfer trip circuit ID	
J	Zone 1 operating time (cycles)	4
J+1	Zone 1 reach (diameter or reactance) (pu)	80% of |Z| = 0.0005
J+2	Zone 1 centerline angle (degrees)	atan(X/R) = 79.8753
J+3	Zone 1 centerline distance	40% of |Z| = 0.0002
J+4	Zone 2 pickup time (cycles)	35
J+5	Zone 2 reach (diameter or reactance) (pu)	120% of |Z| = 0.0007
J+6	Zone 2 centerline angle (degrees)	atan(X/R) = 79.8753
J+7	Zone 2 centerline distance	60% of |Z| = 0.0003
J+8	Zone 3 pickup time (cycles)	1.00E+06
J+9	Zone 3 reach (diameter or reactance) (pu)	
J+10	Zone 3 centerline angle (degrees)	
J+11	Zone 3 centerline distance	
J+12	Angle of directional unit	
J+13	Threshold current	
J+14	Self-trip breaker time (cycles)	2
J+15	Self-trip reclosure time (cycles)	1.00E+06
J+16	Transfer trip breaker time (cycles)	1.00E+06
J+17	Transfer trip reclosure time (cycles)	1.00E+06
J+18	1st blinder type (1,2, −1,−2)	0
J+19	1st blinder intercept (pu)	0
J+20	1st blinder rotation (degrees)	0
J+21	2nd blinder type (1,2, −1,−2)	0
J+22	2nd blinder intercept (pu)	0
J+23	2nd blinder rotation (degrees)	0

A.2 Relay Models for Generator Protection

A.2.1 Under/Overvoltage Model in PSS/E[1]

Model Parameter Definitions

This model is located at system bus	#	IBUS,
machine	#	IM,
This model uses CONs starting with	#	J+,
and VARs starting with	#	K,
and ICONs starting with	#	M.

CONs	#	Value	Description
J+			VL, Lower voltage threshold (pu)
J+1			VU, Upper voltage threshold (pu)
J+2			TP, Relay pickup time (s)
J+3			TB, Breaker time (s)

VAR	#	Description
K		Timer memory

ICONs	#	Description
M		Bus number where voltage is monitored
M+1		Bus number of generator bus where relay is located
M+2		Generator ID
M+3		Delay flag
M+4		Timeout flag
M+5		Timer status

Note: ICONs (M+3) through (M+5) are control flags that are not to be changed by the user.

Format:

0 'USRMDL' 0 'VTGTPA' 0 2 6 4 0 1 ICON(M) ICON(M+1) 'ICON(M+2)' 0 0 0 CON(J+) to CON(J++3) /

Note: Model VTGDCA disconnects generator bus (i.e., disconnects all equipment attached to the generator bus). Model VTGTPA disconnects generators only.

[1] This section is taken from PSS/E 32.0.5: PSS/E Model Library, Revised October 2010, Chapter 23, Section 23.27.

Implementation Details for VTGTPA

Multiple instances of the VTGTPA relay are required to implement the settings based on North American Electric Reliability Corporation (NERC) requirements in Table 3.1. For example, the table below shows settings for a single instance of the VTGTPA relay that trips "instantaneously" (after relay pickup time and breaker time).

Example VTGTPA Relay Settings for Instantaneous Tripping

J+	Description	Value
	VL, lower voltage threshold (pu)	0.45
1	VU, upper voltage threshold (pu)	1.2
2	TP, relay pickup time (s)	0.00005
3	TB, breaker time (s)	0.083

An example instance of this relay model would look like

0 'USRMDL' 0 'VTGTPA' 0 2 6 4 0 1 Xxxx Xxxx '1' 0 0 0 0.45 1.2 0.00005 0.083/

In this example, Generator number '1' at Bus Xxxx is taken out of service 0.083 seconds after the voltage at Bus Xxxx becomes higher than 1.2 pu or lower than 0.45 pu for 0.00005 seconds or more.

The PSS/E technical team's suggested approach is to use a separate instance of the relay for each individual setting. Using this approach, the settings would be as shown in the two tables below.

VTGTPA Undervoltage Settings

J+	Description	Relay 1	Relay 2	Relay 3	Relay 4
0	VL, lower voltage threshold (pu)	0.45	0.65	0.75	0.90
1	VU, upper voltage threshold (pu)	5	5	5	5
2	TP, relay pickup time (s)	0.15	0.30	2	3
3	TB, breaker time (s)	0.083	0.083	0.083	0.083

VTGTPA Overvoltage Settings

J+	Description	Relay 5	Relay 6	Relay 7	Relay 8
	VL, lower voltage threshold (pu)	0	0	0	0
1	FU, VU, upper voltage threshold (pu)	1.2	1.175	1.15	1.10
2	TP, relay pickup time (s)	0.00005	0.2	0.5	1.0
3	TB, breaker time (s)	0.083	0.083	0.083	0.083

In this case, the VTGTPA definitions for Generator ‘1’ at Bus Xxxx would look like the following:

0 'USRMDL' 0 'VTGTPA' 0 2 6 4 0 1 Xxxx Xxxx '1' 0 0 0 0.45 5 0.15 0.083/
0 'USRMDL' 0 'VTGTPA' 0 2 6 4 0 1 Xxxx Xxxx '1' 0 0 0 0.65 5 0.3 0.083/
0 'USRMDL' 0 'VTGTPA' 0 2 6 4 0 1 Xxxx Xxxx '1' 0 0 0 0.75 5 2 0.083/
0 'USRMDL' 0 'VTGTPA' 0 2 6 4 0 1 Xxxx Xxxx '1' 0 0 0 0.90 5 3 0.083/
0 'USRMDL' 0 'VTGTPA' 0 2 6 4 0 1 Xxxx Xxxx '1' 0 0 0 0 1.2 0.00005 0.083/
0 'USRMDL' 0 'VTGTPA' 0 2 6 4 0 1 Xxxx Xxxx '1' 0 0 0 0 1.175 0.2 0.083/
0 'USRMDL' 0 'VTGTPA' 0 2 6 4 0 1 Xxxx Xxxx '1' 0 0 0 0 1.15 0.5 0.083/
0 'USRMDL' 0 'VTGTPA' 0 2 6 4 0 1 Xxxx Xxxx '1' 0 0 0 0 1.1 1 0.083/

A.2.2 Under/Overfrequency Model in PSS/E[1]

Model Parameter Definitions

CONs	#	Value	Description
J+			FL, Lower frequency threshold (Hz)
J+1			FU, Upper frequency threshold (Hz)
J+2			TP, Relay pickup time (s)
J+3			TB, Breaker time (s)

VAR	#	Description
K		Timer memory

ICONs	#	Description
M		Bus number where frequency is monitored
M+1		Bus number of generator bus where relay is located
M+2		Generator ID
M+3		Delay flag
M+4		Timeout flag
M+5		Timer status

Note: ICONs (M+3) through (M+5) are control flags that are not to be changed by the user.

Format:

0 'USRMDL' 0 'FRQTPA' 0 2 6 4 0 1 ICON(M) ICON(M+1) 'ICON(M+2)' 0 0 0 CON(J+) to CON(J++3) /

[1] This section is taken from PSS/E 32.0.5: PSS/E Model Library, Revised October 2010, Chapter 23, Section 23.26.

Note: Model FRQDCA disconnects a generator bus (i.e., disconnects all equipment attached to the generator bus). Model FRQTPA disconnects generators only.

Implementation Details for FRQTPA

Multiple instances of the FRQTPA relay are required to implement the settings based on NERC requirements in Table 3.2. For example, the table below shows settings for a single instance of the FRQTPA relay that trips "instantaneously" (after relay pickup time and breaker time).

Example FRQTPA Relay Settings for Instantaneous Tripping

J+	Description	Value
	FL, lower frequency threshold (Hz)	57.5
1	FU, upper frequency threshold (Hz)	61.8
2	TP, relay pickup time (s)	0.00005
3	TB, breaker time (s)	0.083

An example instance of this relay model would look like

0 'USRMDL' 0 'FRQTPA' 0 2 6 4 0 1 Xxxx Xxxx '1' 0 0 0 57.5 61.8 0.00005 0.083/

In this example, generator number '1' at Bus Xxxx is taken out of service 0.083 seconds after the frequency at Bus Xxxx is higher than 61.8 Hz or lower than 57.5 Hz for 0.00005 seconds or more.

The suggested approach of the PSS/E technical team is to use a separate instance of the relay for each individual setting. Using this approach, the settings would be as shown in the two tables below.

FRQTPA Underfrequency Settings

J+	Description	Relay 1	Relay 2	Relay 3	Relay 4
	FL, lower frequency threshold (Hz)	57.5	58.0	58.4	59.4
1	FU, upper frequency threshold (Hz)	100	100	100	100
2	TP, relay pickup time (s)	0.00005	2	30	540
3	TB, breaker time (s)	0.083	0.083	0.083	0.083

FRQTPA Overfrequency Settings

J+	Description	Relay 5	Relay 6	Relay 7
	FL, lower frequency threshold (Hz)	0	0	0
1	FU, upper frequency threshold (Hz)	61.8	61.6	60.6
2	TP, relay pickup time (s)	0.00005	30	540
3	TB, breaker time (s)	0.083	0.083	0.083

In this case, the FRQTPA definitions for Generator '1' at Bus Xxxx would look like the following:

0 'USRMDL' 0 'FRQTPA' 0 2 6 4 0 1 Xxxx Xxxx '1' 0 0 0 57.5 100 0.00005 0.083/
0 'USRMDL' 0 'FRQTPA' 0 2 6 4 0 1 Xxxx Xxxx '1' 0 0 0 58.0 100 2 0.083/
0 'USRMDL' 0 'FRQTPA' 0 2 6 4 0 1 Xxxx Xxxx '1' 0 0 0 58.4 100 30 0.083/
0 'USRMDL' 0 'FRQTPA' 0 2 6 4 0 1 Xxxx Xxxx '1' 0 0 0 59.4 100 540 0.083/
0 'USRMDL' 0 'FRQTPA' 0 2 6 4 0 1 Xxxx Xxxx '1' 0 0 0 0 61.8 0.00005 0.083/
0 'USRMDL' 0 'FRQTPA' 0 2 6 4 0 1 Xxxx Xxxx '1' 0 0 0 0 61.6 30 0.083/
0 'USRMDL' 0 'FRQTPA' 0 2 6 4 0 1 Xxxx Xxxx '1' 0 0 0 0 60.6 540 0.083/

A.2.3 Generator Scan and Trip Model in PSS/E[1]

Model Parameter Definitions

CON	#	Value	Description
J			Angle threshold (degrees)

VAR	#	Value	Description
L			Reference angle

[1] This section is taken from the document *Generator Scan and Trip Model*, provided by Siemens.

ICONs	#	Description
M		Flag: • −1: Disable the model • 0: Monitor only • 1: Monitor and trip
M+1		IBUS, Bus number
M+2		Machine ID (enter within single quote)
M+3		Flag: • 1: Use machine average angle • 2: Use the rotor angle in Center of Inertia (COI) reference frame (See Note 3) • 3: Use angle of machine whose bus number and machine id are specified in ICON(M+4) and ICON(M+5) (See note 4)
M+4		Machine bus number Used when ICON(M+3) is 3, else 0
M+5		Machine id (specified within single quotes) Used when ICON(M+3) is 3, else 0

DYRE record:
0 'USRMDL' 0 'GNSCNANG' 8 0 6 1 0 1 ICON(M) to ICON(M+5), CON(J) /

Notes:

1. The model scans the machine at bus IBUS with machine ID specified in ICON(M+2).
2. The model can either just report, or report and trip, those generators for which the following conditions are met:
    a. machine is a synchronous machine
    b. machine rotor angle is greater than the angle selection [per the flag in ICON(M+3)] by a specified amount [specified in CON(J)].
3. If ICON(M+3) is set to 1 and if there are no synchronous machines (i.e., machines for which the angle has a meaning) in the case, PSS/E will put an error message and the model will be ignored.
4. If ICON(M+3) is set to 2 and if there are no synchronous machines with inertia constant greater than zero in the case, PSS/E will put an error message and the model will be ignored. Also, since the generator inertia values are in the generator dynamic model data record, PSS/E has to know which generator model is attached to this machine. If the generator model attached is not one of the following: GENROU, GENROE, GENSAL, GENSAE, GENDCO, or GENTPJU1 (V32 & V33), GENTPJ1 (for V34), then PSS/E will put an error message and the model will ignore this machine from COI calculation.
5. If ICON(M+3) is set to 3, and if the machine [whose bus number and machine ID are as specified in ICON(M+4) and ICON(M+5)] is not found, PSS/E will put an error message and the model will be ignored.
6. ICON(M) is a flag whose value can be −1, 0, or 1. If ICON(M) is −1, the model scan and trip functionality is disabled; if 0, the model just reports all synchronous machines whose angle exceeds the average angle by the specified threshold; if 1, the model reports and also trips synchronous machines whose angle exceeds the angle [angle selection per ICON(M+3)] by the specified threshold.

7. This model will generate call in subroutine CONEC. Use of this model will therefore require compilation of the conec file (conec.fix or conec.for).

   The table below shows settings for a single instance of the GNSCNANG[1] in this project.

Example GNSCNANG Settings

J+	Description	Value
1	Angle threshold (degrees)	180

An example instance of this model would look like

0 'USRMDL' 0 ' GNSCNANG' 8 0 6 1 0 1 1 Xxxx '1' 2 0 0 180 /

In this example, Generator '1' at Bus Xxxx is taken out of service if the relative rotor angle of this generator is greater than 180 degrees.

A.3 Relay Models for Load Shedding

A.3.1 Underfrequency Load-Shedding Models in PSS/E

A.3.1.1 Underfrequency Load Shedding: LDSHBL, LDSHOW, LDSHZN, LDSHAR, LDSHAL[2]

Model Parameter Definitions

This model uses CONs starting with	#_____	J,
and VARs starting with	#_____	L,
and Reserved ICONs starting with	#_____	N.

[1] GNSCNANG is a PSS®E user-written model developed by Siemens PTI for this project.
[2] This section is taken from PSS/E 32.0.5: PSS/E Model Library, Revised October 2010, Chapter 10, Section 10.3.

CONs	Value	Description
J		f_1, first load shedding point (Hz)
J+1		t_1, first point pickup time (s)
J+2		$frac_1$, first fraction of load to be shed
J+3		f_2, second load shedding point (Hz)
J+4		t_2, second fraction pickup time (s)
J+5		$frac_2$, second fraction of load to be shed
J+6		f_3, third load shedding point (Hz)
J+7		t_3, third point pickup time (s)
J+8		$frac_3$, third fraction of load to be shed
J+9		T_b, breaker time (s)

VARs	Value	Description
L		First timer memory
L+1		Second timer memory
L+2		Third timer memory

Reserved ICONs	Value	Description
N		First point delay flag
N+1		First point timeout flag
N+2		First timer status
N+3		Second point delay flag
N+4		Second point timeout flag
N+5		Second timer status
N+6		Third point delay flag
N+7		Third point timeout flag
N+8		Third timer status

I, 'LDSHxx', LID, CON(J) to CON(J+9) /

LID is an explicit load identifier or may be * for application to loads of any ID associated with the subsystem type.

Model Suffix "xx"	"I" Description
BL	Bus number
OW	Owner number
ZN	Zone number
AR	Area number
AL	0

An example of using the underfrequency load-shedding relay model “LDSHBL” in PSS/E is given below:

Syntax:

Bus Number, 'LDSHBL',LID,freq1,t1,fraction1,freq2,t2,fraction2,freq3,t3,fraction3,Breaker Time

Implementation:

Xxxx, 'LDSHBL',‘1’,59.3,0.5,1.0,0,0,0,0,0,0,0.058/MID230

A.3.1.2 Underfrequency Load Shedding with Transfer Trip: LDS3BL, LDS3OW, LDS3ZN, LDS3AR, LDS3AL[1]

Model Parameter Definitions

This model uses CONs starting with #_____ J,
and VARs starting with #_____ L,
and ICONs starting with #_____ M,
and Reserved ICONs starting with #_____ N.

CONs	Value	Description
J		f_1, first load shedding point (Hz)
J+1		t_1, first point pickup time (s)
J+2		tb_1, first breaker time (s)
J+3		$frac_1$, first fraction of load to be shed
J+4		f_2, second load shedding point (Hz)
J+5		t_2, second point pickup time (s)
J+6		tb_2, second breaker time (s)
J+7		$frac_2$, second fraction of load to be shed
J+8		f_3, third load shedding point (Hz)
J+9		t_3, third point pickup time (s)
J+10		tb_3, third breaker time (s)
J+11		$frac_3$, third fraction of load to be shed
J+12		f_4, fourth load shedding point (Hz)
J+13		t_4, fourth point pickup time (s)
J+14		tb_4, fourth breaker time (s)
J+15		$frac_4$, fourth fraction of load to be shed
J+16		f_5, fifth load shedding point (Hz)
J+17		t_5, fifth point pickup time (s)
J+18		tb_5, fifth breaker time (s)
J+19		$frac_5$, fifth fraction of load to be shed
J+20		ttb, transfer trip breaker time (s)

[1] This section is taken from PSS/E 32.0.5: PSS/E Model Library, Revised October 2010, Chapter 10, Section 10.2.

VARs	Value	Description
L		First timer memory
L+1		Second timer memory
L+2		Third timer memory
L+3		Fourth timer memory
L+4		Fifth timer memory
L+5		Transfer trip timer

ICONs	Value	Description
M		GBUS, bus number of transfer trip generator
M+1		GID, machine ID of transfer trip, -1 if plant
M+2		SC: 0 Do not shed shunt 1 Shed shunt with same fraction as load

Reserved ICONs	Value	Description
N		First point delay flag
N+1		First point timeout flag
N+2		First point timer status
N+3		Second point delay flag
N+4		Second point timeout flag
N+5		Second point timer status
N+6		Third point delay flag
N+7		Third point timeout flag
N+8		Third point timer status
N+9		Fourth point delay flag
N+10		Fourth point timeout flag
N+11		Fourth point timer status
N+12		Fifth point delay flag
N+13		Fifth point timeout flag
N+14		Fifth point timer status
N+15		Transfer trip breaker status
N+16		Transfer trip timer status

I, 'LDS3xx', LID, ICON(M) to ICON(M+2), CON(J) to CON(J+20) /

LID is an explicit load identifier or may be * for application to loads of any ID associated with the subsystem type.

Model Suffix "xx"	"I" Description
BL	Bus number
OW	Owner number
ZN	Zone number
AR	Area number
AL	0

A.3.1.3 Rate of Frequency Load Shedding: DLSHBL, DLSHOW, DLSHZN, DLSHAR, DLSHAL[1]

Model Parameter Definitions

This model uses CONs starting with #_____ J,
and VARs starting with #_____ L,
and Reserved ICONs starting with #_____ N.

CONs	Value	Description
J		f_1, first load shedding point (Hz)
J+1		t_1, first point pickup time (s)
J+2		$frac_1$, first fraction of load to be shed
J+3		f_2, second load shedding point (Hz)
J+4		t_2, second point pickup time (s)
J+5		$frac_2$, second fraction of load to be shed
J+6		f_3, third load shedding point (Hz)
J+7		t_3, third point pickup time (s)
J+8		$frac_3$, third fraction of load to be shed
J+9		T_B, breaker time (s)
J+10		df_1, first rate of frequency shedding point (Hz/s)
J+11		df_2, second rate of frequency shedding point (Hz/s)
J+12		df_3, third rate of frequency shedding point (Hz/s)

[1] This section is taken from PSS/E 32.0.5: PSS/E Model Library, Revised October 2010, Chapter 10, Section 10.1.

VARs	Value	Description
L		First timer memory
L+1		Second timer memory
L+2		Third timer memory
L+3		Memory for derivative of bus frequency
L+4		Bus frequency derivative

Reserved ICONs	Value	Description
N		First point delay flag
N+1		First point timeout flag
N+2		First timer status
N+3		Second point delay flag
N+4		Second point timeout flag
N+5		Second timer status
N+6		Third point delay flag
N+7		Third point timeout flag
N+8		Third timer status

I, 'DLSHxx', LID, CON(J) to CON(J+12) /

LID is an explicit load identifier or may be * for application to loads of any ID associated with the subsystem type.

Model Suffix "xx"	"I" Description
BL	Bus number
OW	Owner number
ZN	Zone number
AR	Area number
AL	0

A.3.1.4 Time Underfrequency Load Shedding: LDSTBL, LDSTOW, LDSTZN, LDSTAR, LDSTAL[1]

Model Parameter Definitions

This model uses CONs starting with #_____ J,
and VARs starting with #_____ L,
and Reserved ICONs starting with #_____ N.

CONs	Value	Description
J		f_1, pickup frequency (Hz)
J+1		z_1, nominal operating time (s)
J+2		f_2, second frequency point (Hz)
J+3		z_2, nominal operating time (s)
J+4		f_3, third frequency point (Hz)
J+5		z_3, nominal operating time (s)
J+6		f_4, fourth frequency point (Hz)
J+7		z_4, nominal operating time (s)
J+8		T_B, breaker time (s)
J+9		frac, fraction of load to be shed
J+10		f_{reset}, reset frequency (Hz)
J+11		t_{res}, resetting time (s)

VARs	Value	Description
L		Frequency (Hz)
L+1		Relay trip contact position
L+2		Breaker timer memory

Reserved ICONs	Value	Description
N		Relay status
N+1		Breaker timer flag
N+2		Breaker timeout flag

I, 'LDSTxx', LID, CON(J) to CON(J+11) /

[1] This section is taken from PSS/E 32.0.5: PSS/E Model Library, Revised October 2010, Chapter 10, Section 10.4.

LID is an explicit load identifier or may be * for application to loads of any ID associated with the subsystem type.

Model Suffix "xx"	"I" Description
BL	Bus number
OW	Owner number
ZN	Zone number
AR	Area number
AL	0

A.3.2 Undervoltage Load Shedding

A.3.2.1 Undervoltage Load Shedding: LVSHBL, LVSHOW, LVSHZN, LVSHAR, LVSHAL[1]

Model Parameter Definitions

This model uses CONs starting with #_____ J,
and VARs starting with #_____ L,
and ICON #_____ M,
and Reserved ICONs starting with #_____ N.

CONs	Value	Description
J		V1, first load-shedding point (pu)
J+1		T1, first point pickup time (s)
J+2		F1, first fraction of load to be shed
J+3		V2, second load-shedding point (pu)
J+4		T2, second fraction pickup time (s)
J+5		F2, second fraction of load to be shed
J+6		V3, third load-shedding point (pu)
J+7		T3, third point pickup time (s)
J+8		F3, third fraction of load to be shed
J+9		T_B, breaker time (s)

[1] This section is taken from PSS/E 32.0.5: PSS/E Model Library, Revised October 2010, Chapter 10, Section 10.6.

VARs	Value	Description
L		First timer memory
L+1		Second timer memory
L+2		Third timer memory

ICON	Value	Description
M		JBUS, remote bus number where voltage is measured[1]

[1]Set JBUS = 0, if remote bus is same as the local bus to which the load is

Reserved ICONs	Value	Description
N		First point delay flag
N+1		First point timeout flag
N+2		First timer status
N+3		Second point delay flag
N+4		Second point timeout flag

Reserved ICONs	Value	Description
N+5		Second timer status
N+6		Third point delay flag
N+7		Third point timeout flag
N+8		Third point status

I, 'LVSHxx', LID, ICON(M), CON(J) to CON(J+9) /

LID is an explicit load identifier or may be * for application to loads of any ID associated with the subsystem type.

Model Suffix "xx"	"I" Description
BL	Bus number
OW	Owner number
ZN	Zone number
AR	Area number
AL	0

An example of using the undervoltage load-shedding relay model “LVSHBL” in PSS/E is given below:

Syntax:

Bus number ,’LVSHBL’,LID,JBUS,v1,t1,frac1,v2,t2,frac2,v3,t3,frac3,Tb,/To-Station name

Implementation:

Xxxx,'LVSHBL','1',0,0.91,3, 1 ,0,0,0,0,0,0,0.08333,/MID230

A.3.2.2 Undervoltage Load Shedding with Transfer Trip: LVS3BL, LVS3OW, LVS3ZN, LVS3AR, LVS3AL[1]

Model Parameter Definitions

This model uses CONs starting with	#_____	J,
and VARs starting with	#_____	L,
and ICONs starting with	#_____	M,
and Reserved ICONs starting with	#_____	N.

CONs	Value	Description
J		f_1, first load-shedding point (pu)
J+1		t_1, first point pickup time (s)
J+2		tb_1, first breaker time (s)
J+3		$frac_1$, first fraction of load to be shed
J+4		f_2, second load-shedding point (pu)
J+5		t_2, second point pickup time (s)
J+6		tb_2, second breaker time (s)
J+7		$frac_2$, second fraction of load to be shed
J+8		f_3, third load-shedding point (pu)
J+9		t_3, third point pickup time (s)
J+10		tb_3, third breaker time (s)
J+11		$frac_3$, third fraction of load to be shed
J+12		f_4, fourth load-shedding point (pu)
J+13		t_4, fourth point pickup time (s)
J+14		tb_4, fourth breaker time (s)
J+15		$frac_4$, fourth fraction of load to be shed
J+16		f_5, fifth load-shedding point (pu)
J+17		t_5, fifth point pickup time (s)
J+18		tb_5, fifth breaker time (s)
J+19		$frac_5$, fifth fraction of load to be shed
J+20		ttb_1, first transfer trip breaker time (s)
J+21		ttb_2, second transfer trip breaker time (s)

[1] This section is taken from PSS/E 32.0.5: PSS/E Model Library, Revised October 2010, Chapter 10, Section 10.5.

VARs	Value	Description
L		First timer memory
L+1		Second timer memory
L+2		Third timer memory
L+3		Fourth timer memory
L+4		Fifth timer memory
L+5		First transfer trip timer
L+6		Second transfer trip timer

ICONs	Value	Description	
M		FBUS1, from bus number	First transfer trip
M+1		TBUS1, to bus number	
M+2		ID1, Circuit ID	
M+3		FBUS2, from bus number	Second transfer trip
M+4		TBUS2, to bus number	
M+5		ID2, Circuit ID	
M+6		SC: 0 Do not shed shunt 1 Shed shunt with same fraction as load	

Reserved ICONs	Value	Description
N		First point delay flag
N+1		First point timeout flag
N+2		First point timer status
N+3		Second point delay flag
N+4		Second point timeout flag
N+5		Second point timer status
N+6		Third point delay flag
N+7		Third point timeout flag
N+8		Third point timer status
N+9		Fourth point delay flag
N+10		Fourth point timeout flag
N+11		Fourth point timer status
N+12		Fifth point delay flag
N+13		Fifth point timeout flag
N+14		Fifth point timer status

Reserved ICONs	Value	Description
N+15		First transfer trip breaker status
N+16		First transfer trip timer status
N+17		Second transfer trip breaker status
N+18		Second transfer trip timer status

I, 'LVS3xx', LID, ICON(M) to ICON(M+6), CON(J) to CON(J+21) /

LID is an explicit load identifier or may be * for application to loads of any ID associated with the subsystem type.

Model Suffix "xx"	"I" Description
BL	Bus number
OW	Owner number
ZN	Zone number
AR	Area number
AL	0

A.3.2.3 Undervoltage and Underfrequency Load Shedding: UVUFBLU1, UVUFOWU1, UVUFZNU1, UVUFARU1, UVUFALU1[1]

Model Parameter Definitions

This model uses CONs starting with	#_____	J,
and VARs starting with	#_____	L,
and ICONs starting with	#_____	M,
and Reserved ICONs starting with	#_____	N.

CONs	#	Value	Description
J			V1, first voltage-based load-shedding point (pu)
J+1			TV1, first voltage-based point pickup time (s)
J+2			FV1, first voltage-based fraction of load to be shed
J+3			V2, second voltage-based load- shedding point (pu)
J+4			TV2, second voltage-based point pickup time (s)
J+5			FV2, second voltage-based fraction of load to be shed
J+6			V3, third voltage-based load-shedding point (pu)
J+7			TV3, third voltage-based point pickup time (s)
J+8			FV3, third voltage-based fraction of load to be shed
J+9			TVB, voltage-based breaker time (s)
J+10			F1, first frequency-based load-shedding point (Hz)
J+11			TF1, first frequency-based point pickup time (s)
J+12			FF1, first frequency-based fraction of load to be shed
J+13			F2,second frequency-based load-shedding point (Hz)
J+14			TF2, second frequency-based point pickup time (s)
J+15			FF2, second frequency-based fraction of load to be shed
J+16			F3, third frequency-based load-shedding point (Hz)
J+17			TF3, third frequency-based point pickup time (s)
J+18			FF3, third frequency-based fraction of load to be shed
J+19			TFB, frequency-based breaker time (s)

[1] This section is taken from PSS/E 32.0.5: PSS/E Model Library, Revised October 2010, Chapter 10, Section 10.7.

VARs	#	Description
L		First voltage-based timer memory
L+1		Second voltage-based timer memory (pu)
L+2		Third voltage-based timer memory
L+3		First frequency-based timer memory
L+4		Second frequency-based timer memory
L+5		Third frequency-based timer memory
L+6		Load fractions already shed in previous stages

ICON	#	Value	Description
M			JBUS, remote bus number where voltage is measured[(a)]

(a) Set JBUS = 0, if remote bus is same as the local bus to which the load is connected.

Reserved ICONs	#	Description
N		First voltage-based point delay flag
N+1		First voltage-based point timeout flag
N+2		First voltage-based timer status
N+3		Second voltage-based point delay flag
N+4		Second voltage-based point timeout
N+5		Second voltage-based timer status
N+6		Third voltage-based point delay flag
N+7		Third voltage-based point timeout flag
N+8		Third voltage-based timer status

Reserved ICONs	#	Description
N+9		First frequency-based point delay flag
N+10		First frequency-based point timeout flag
N+11		First frequency-based timer status
N+12		Second frequency-based point delay flag
N+13		Second frequency-based point timeout flag
N+14		Second frequency-based timer status
N+15		Third frequency-based point delay flag
N+16		Third frequency-based point timeout flag
N+17		Third frequency-based timer status

DYRE Data Record:
I, 'USRLOD', LID, 'UVUFxxU1', 13, IT, 1, 20, 0, 7, 18, JBUS, CON(J) to CON(J+19) /

LID is an explicit load identifier or may be * for application to loads of any ID associated with the subsystem type.

Model Suffix "xx"	"IT" Description	"I" Description
BL	1	Bus number
OW	2	Owner number
ZN	3	Zone number
AR	4	Area number
AL	5	0

Appendix B

Distance-Relay Modeling in PSS/E

Appendix B

Distance-Relay Modeling in PSS/E

Provided by Eli Pajuelo, Ph.D.
Pajuelo Electric, Inc.
January 26, 2015

In the following sections, the system used to illustrate the approach is the "SAVNW" in the sample systems provided by PSS/E.

B.1 Example Line

Line from case "SAVNW" between nodes NUCPANT 151 and MID500 152, at 500 kV level.

Tested in PSS/E V32.

B.2 General Settings

The lists of settings required in the DISTR1 model covering most of the cases are provided in Table B.1 and Table B.2 below.

Table B.1. Settings Required in the DISTR1 Model for M Parameters

Parameter	Value	Description	
M	1	Type Mho	
M+1	1	Monitor and operate	
M+2	(*1)	From bus	
M+3	(*1)	To bus	First transfer trip
M+4	(*1)	Circuit ID	
M+5	0	From bus	
M+6	0	To bus	Second transfer trip
M+7	Empty string	Circuit ID	
M+8	0	From bus	
M+9	0	To bus	Third transfer trip
M+10	Empty string	Circuit ID	

(*1): To be used in internal fault using fictitious node.

Table B.2. Settings Required in the DISTR1 Model for J Parameters

Parameter	Value	Description	
J		Operating time : 345 kV = 1 cycle, 138 kV = 2 cycle	
J+1	80% |Z|	Reach	Zone 1
J+2	Angle(Z)	Centerline angle = line angle in degrees	
J+3	40% |Z|	Center = ½ Reach, no reverse coverage	
J+4	35	Operating time	
J+5	120% |Z|	Reach	Zone 2
J+6	Angle |Z|	Centerline angle = line angle in degrees	
J+7	60% |Z|	Center = ½ Reach, no reverse coverage	
J+8	90	Operating time typically 90 cycles = 1.5 s	
J+9	(*2)	Reach	Zone 3
J+10	Angle |Z|		
J+11	(*2)	Center = ½ Reach, no reverse coverage	
J+12	Angle |Z| + 90 deg	Angle of directional unit (unused here, but this would be the correct value)	
J+13	10% |Line Rated MVA|	Threshold current; it resets the impedance element for low currents as safety feature.	
J+14		Breaker time: 345 kV = 2 cycles, 138 kV = 4 cycles	Self trip
J+15	1.0e+6	Reclosure time (unused)	
J+16	(*1)	Breaker time	Transfer trip
J+17	1.0e+6	Reclosure time (unused)	
J+18	(*2)	Type (1,2, −1, −2) – Blinders described in separate section	
J+19	(*2)	Intercept (pu[1])	1st blinder
J+20	(*2)	Rotation (degrees)	
J+21	(*2)	Type(1,2, −1, −2) – Blinders described in separate section	
J+22	(*2)	Intercept (pu)	2nd blinder
J+23	(*2)	Rotation (degrees)	

(*1): To be used in internal fault using fictitious node.
(*2): To be used when setting Zone 3

B.2.1 Limitations

These settings are applicable for typical low-impedance three-phase faults. Higher impedance faults, or other unbalanced fault types, are not covered by these settings.

B.3 Close-In Faults in Pilot Scheme Line – 345 kV

B.3.1 Considerations

In this case, relays are associated with the branch between both ends of the line.

Line faults can be simulated as close-in faults at either end. Only three-phase faults can be applied in a dynamic study.

The whole line is taken off service as soon as either relay at either end trips. This is equivalent to having breakers at both ends tripping simultaneously.

[1] pu = per unit

A fault resistance value of 0.0001 ohm was tested and works correctly.

B.3.2 Limitations

A zero ohm fault cannot be simulated because it will cause zero volts measurement at the relay closest to the fault. With zero voltage, the distance relay cannot determine whether the fault is internal in the forward direction or external behind it. This implies that the DISTR1 model does not use the stored voltage in the implementation equation.

In a real scenario, the tripping times at each end are not simultaneous and there may be typically around two (2) cycles difference between trippings at each end. This time difference creates problems in some pilot schemes with parallel lines sometimes causing an incorrect trip on the unfaulted parallel line.

B.3.3 Example

Base files: savnw.sav, savnw.sld, savnw.dyr,
Simulation run: close_in_ps.idv, savnw_t2.dyr

B.4 Close-In Faults in Step Distance Line – 138 kV

B.4.1 Considerations

In this case, breakers are represented at each end of the line by using very short branches, thus adding two intermediate nodes to the line.

The small branch needs to have R > 0 in order for this approach to work in PSS/E V32.

Line faults can be simulated as close-in faults in the branch between the two intermediate nodes. The first node specified indicates the location of the close-in fault.

The relays are associated with each of the very short branches representing the breakers at each end using the reach settings for the overall line.

With this arrangement, it is possible to represent the case of one end tripping while the other end remains closed.

B.4.2 Limitation

The relay is designed to use voltage measurement from the first node specified. This is equivalent to having a bus potential transformer measurement for the relay. However, in many cases on a real scenario, the voltage is measured using a potential transformer located at the line side of the breaker.

B.4.3 Example

Base files: savnw.sav, savnw.sld, savnw.dyr,
Simulation run: savnw_t3_bk.dyr, close_in_w_bk_sd.idv

B.5 Not a Close-In Fault – Using Fictitious Node

B.5.1 Considerations

This case applies to the line where the fault is applied.

In this case, a new fictitious node is added at the location where the fault needs to be simulated.

The relays need to be associated with the two branches newly created by the node addition. That is, one is from one end to the tap point, and the other is from the remote end to the tap point.

In case of a pilot scheme being applied, the transfer trip capability of DISTR1 needs to be used to make sure both ends trip simultaneously.

In case of step distance without a pilot scheme, the transfer trip capability of DISTR1 does not need to be used. Each end will trip according to the Zone 1 or Zone 2 delay where appropriate.

B.5.2 Example

Base files: savnw.sav, savnw.sld, savnw.dyr,
For pilot scheme: savnw_t4_fn_ps.dyr, intermediate_case_ps.idv
For step distance: savnw_t4_fn_sd.dyr, intermediate_case_sd.idv

B.6 Zone 3 Setting

B.6.1 Considerations

The objective of a Zone 3 element is to provide backup in case the breaker at the remote bus corresponding to the adjacent line downstream fails to trip for a fault at any point in the adjacent line. In this case, all sources of fault current feeding the remote bus need to be tripped.

The setting selected should be based on all the faults two buses away in the forward direction from the relay of interest.

To comply with North American Electric Reliability Corporation (NERC) requirements, Figure B.1 needs to be followed considering $I_{Emergency}$ the 15-minute line rating.

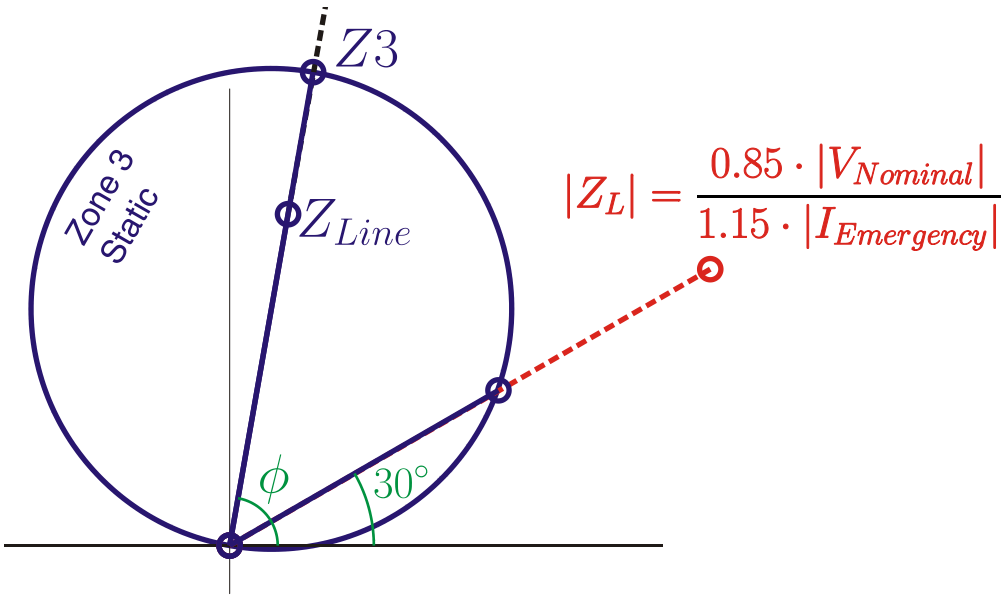


Figure B.1. Load Encroachment Criteria from NERC

B.6.2 Example

In this example, the setting for Zone 3 is selected as the terminal on Bus 152 in Branch 152 to 151.

The Zone 3 at Bus 152 MID500, Branch 152 to 151, can provide backup protection for faults at Buses 101 NUC-A and 102 NUC-B.

However, the Zone 3 from Bus 152 MID500 is unable to provide protection for a fault at Bus 201 HYDRO because the apparent fault impedance is located in the second quadrant far away from the mho Zone 3.

To cover the faults at Buses 101 and 102, a Zone 3 setting of 5.1 × ZL was used, where ZL is the line impedance.

Taking into account the loading criteria from NERC, we find the impedance at 30 degrees is equal to 0.061594 (= 0.85/1.15/12.0). Zone 3 needs to be restricted by using blinders at both sides. Figure B.2, Figure B.3, and Figure B.4 show plots of different zones of protection.

In the simulation runs, it was observed that the power swing was severe and entered Zone 2 and Zone 1 as well. Thus, Zone 3 did not have chance to operate.

Base files:	savnw.sav, savnw.sld, savnw.dyr
To calculate Zone 3 settings:	zone3_problem_b151.idv, zone3_problem_b152
Simulation runs:	zone3_flt_101, zone3_flt_201

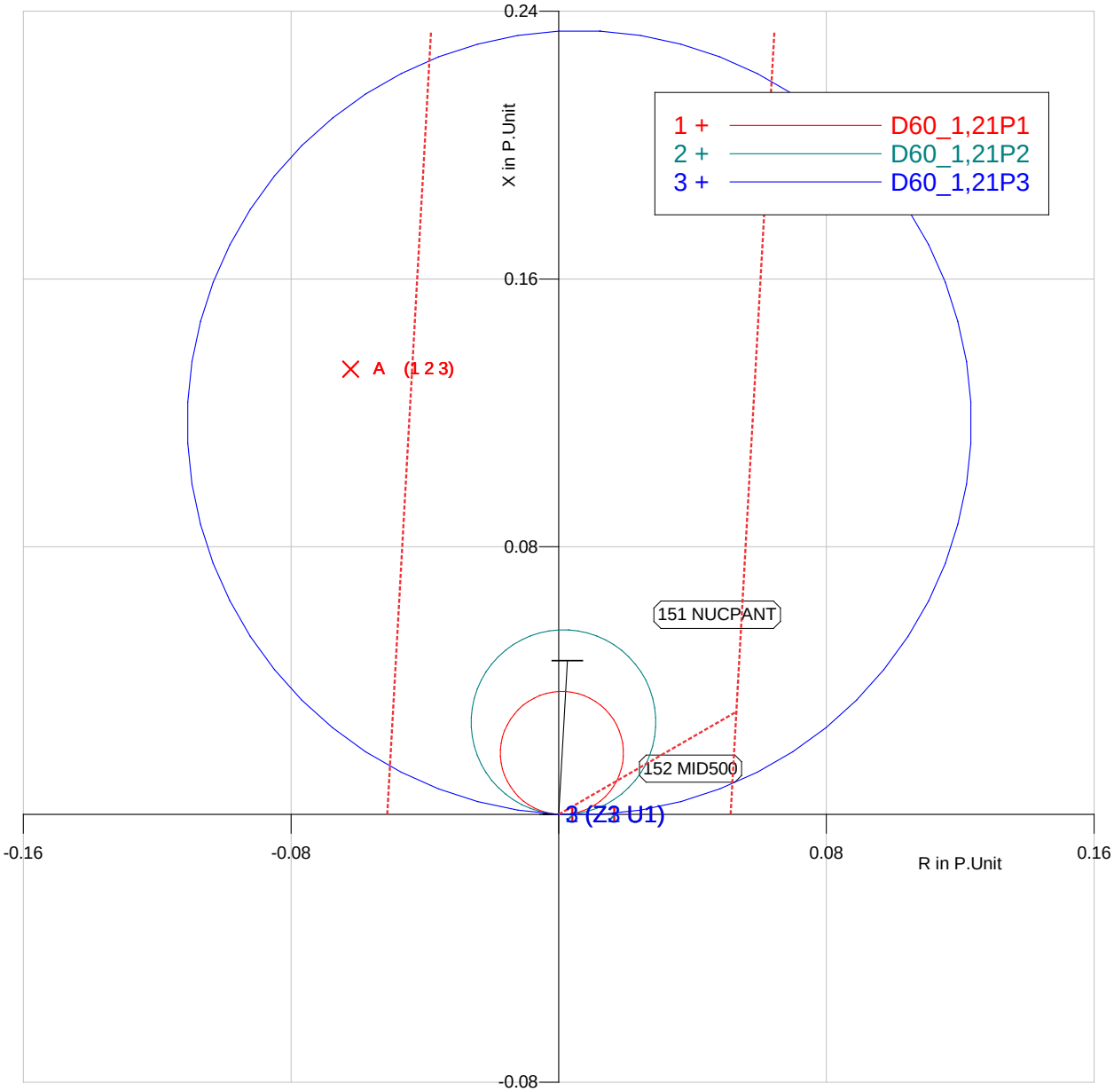


Figure B.2. Fault at Bus 101 as Seen by Relay at Bus 152

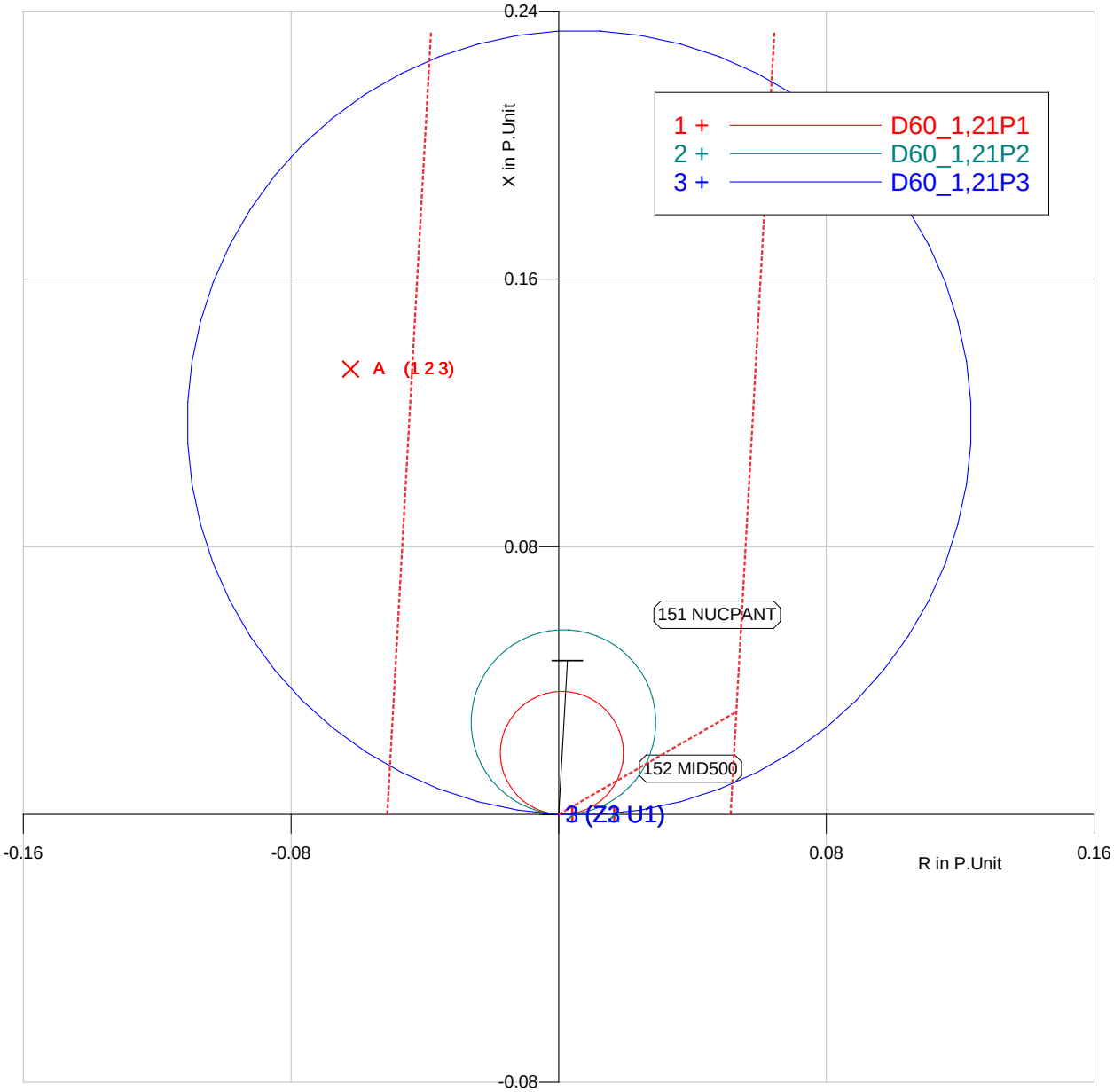


Figure B.3. Fault at Bus 102 as Seen by Relay at Bus 152

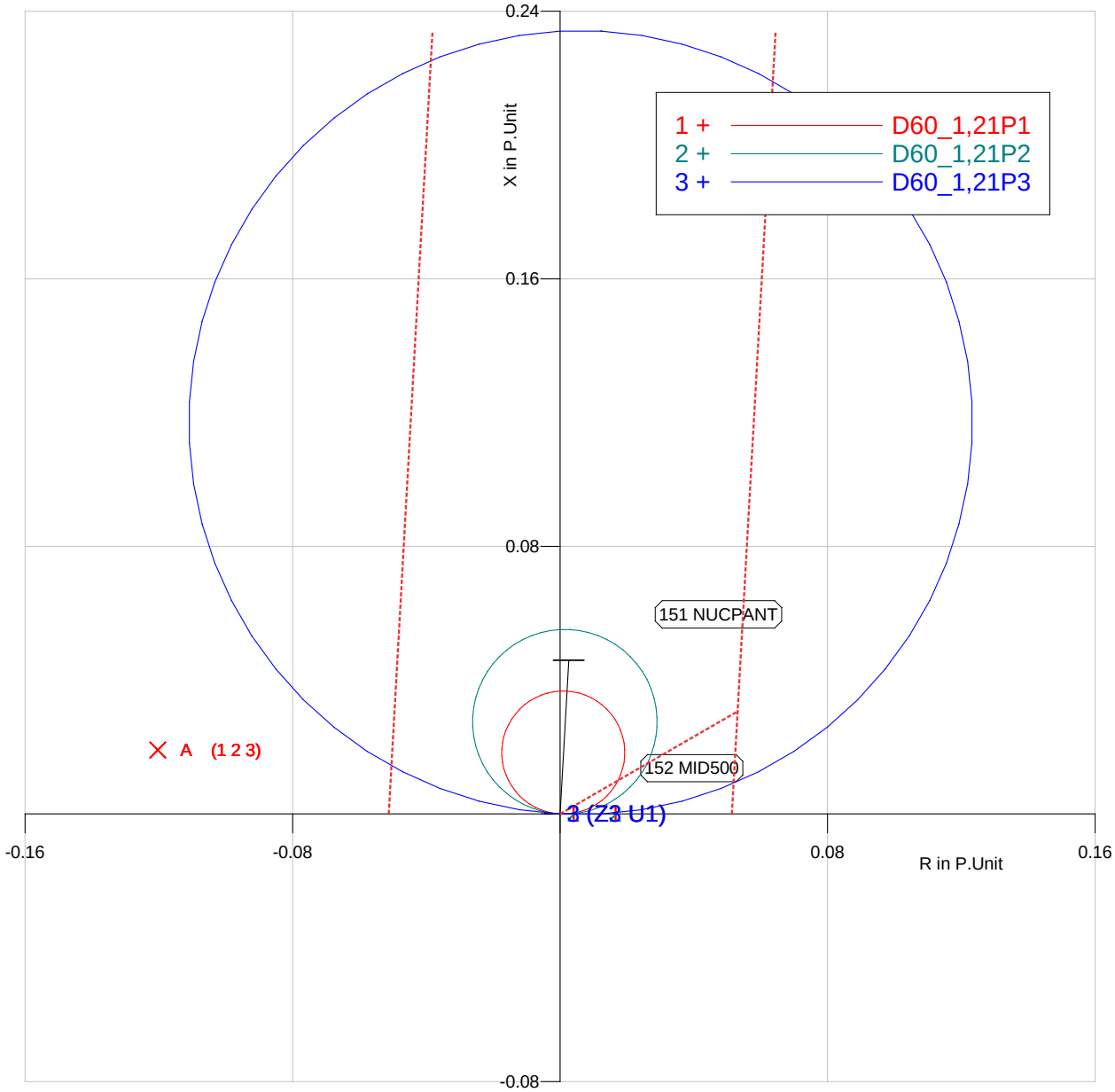


Figure B.4. Fault at Bus 201 as Seen by Relay at Bus 152

Appendix C

Selected Implementation Codes in PSS/E

Appendix C

Selected Implementation Codes in PSS/E

C.1 Security Criteria Implementation in PSS/E

The implementation of the proposed security criteria in the Dynamic Contingency Analysis Tool (DCAT) PSS/E Python code explained in Section 2.6 is as follows:

- Enable or disable the simulation option setting that scans for **generators** for which the **angle** differs from the angular average by more than a specified threshold using application programming interface (API) “set_genang”.

Syntax: set_genang(status, angle)

– Integer STATUS is the value of the option setting. STATUS = 1 enables scanning for generators exceeding angle threshold.

– Real ANGLE is the value of the deviation threshold.

Implementation: *psspy.set_genang(1, 180.0)*

- Enable or disable the simulation option setting that scans **buses** for **voltage** recovery (primary and secondary recovery) using API “set_voltage_rec_check”

Syntax: set_voltage_rec_check (VPRCHK, VSRCHK, VPRTHR, VPRTIM, VSRTHR, VSRTIM)

– VPRCHK is the flag to set voltage primary recovery check. Input if BAT_command or ICODE is 0 or negative (unchanged by default). Output if ICODE is positive. VPRCHK = 1 enables primary recovery check. VPRCHK ≠ 1 disables primary recovery check.

– VSRCHK is the flag to set voltage secondary recovery check. Input if BAT_command or ICODE is 0 or negative (unchanged by default). Output if ICODE is positive. This flag can be set only if the primary recovery check is ON. VSRCHK = 1 enables secondary recovery check. VSRCHK ≠ 1 disables secondary recovery check.

– VPRTHR is the voltage primary recovery threshold in pu. Input if BAT_command or ICODE is 0 or negative (unchanged by default). Output if ICODE is positive.

– VPRTIM is the voltage primary recovery time in seconds. Input if BAT_command or ICODE is 0 or negative (unchanged by default). Output if ICODE is positive.

– VSRTHR is the voltage secondary recovery threshold in pu. Input if BAT_command or ICODE is 0 or negative (unchanged by default). Output if ICODE is positive. VSRTHR has to be greater than VPRTHR.

– VSRTIM is the voltage secondary recovery time in seconds. Input if BAT_command or ICODE is 0 or negative (unchanged by default). Output if ICODE is positive. VSRTIM has to be greater than VPRTIM.

Implementation: *psspy.set_voltage_rec_check(1,0, 0.8, 10.0, 0.9, 1.0)*

- Enable or disable the simulation option setting that expresses the ANGLE array relative to a designated reference angle using API "set_relang"

Syntax: set_relang(SWITCH, ibusex, id)

– SWITCH is the value of the option setting (input if BAT_ command or ICODE is 0 or negative; unchanged by default) (output if ICODE is positive). SWITCH = 1 enables relative angle calculation. SWITCH ≠ 1 disables relative angle calculation (use absolute angles).

Implementation: *psspy.set_relang(psspy.set_relang(1, <bus number>, <bus id>)*

C.2 Extracting a Power Flow Case at the End of Dynamic Simulation

- During the dynamic simulation, generator Pelec, Qelec, bus voltage, and angle magnitudes, power flows in lines, and the status of power system components such as generators, buses, branches, transformer taps, switched shunts, etc., will need to be captured for post-processing analysis. This could be accomplished by saving the case at the end of the dynamic simulation. The command for accomplishing the task is

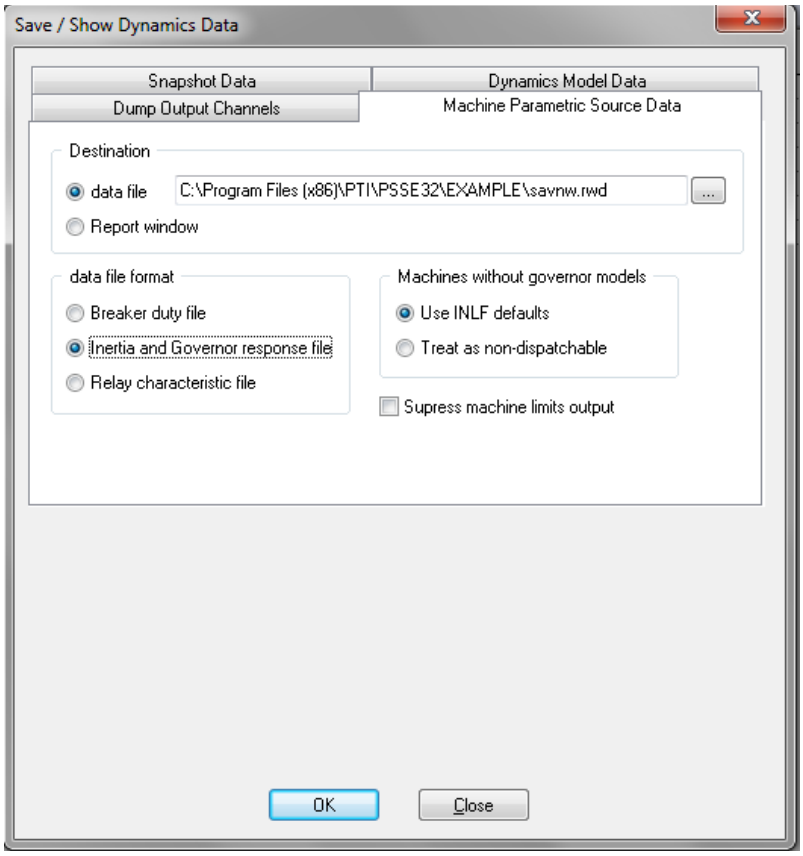
  psspy.save(r"""CASENAME.sav""")

For more information, refer to the PSS/E Program Operation Manual, Section 18.2.

- To perform the dynamic simulation, the generators are converted to a current source model using the command "CONG". A traditional power flow solution cannot be performed when the generators are converted. This process is not automatically reversible. This can be resolved by saving the power flow raw file (i.e., converting the *.sav file to a *.raw file). The command for this conversion is

  psspy.rawd_2(0,1,[1,1,1,0,0,0,0],0,r"""CASENAME.raw""")

After the raw case is read, to perform inertial- or governor- response power flows, a "Unit inertia and governor data file" is necessary. This could be extracted when a power flow case and dynamic files are read into PSS/E. When we select "Save" on the PSS/E graphical user interface, options for saving this file are displayed (see the figure below).



"Save" Option to Extract "Unit Inertia and Governor response file"

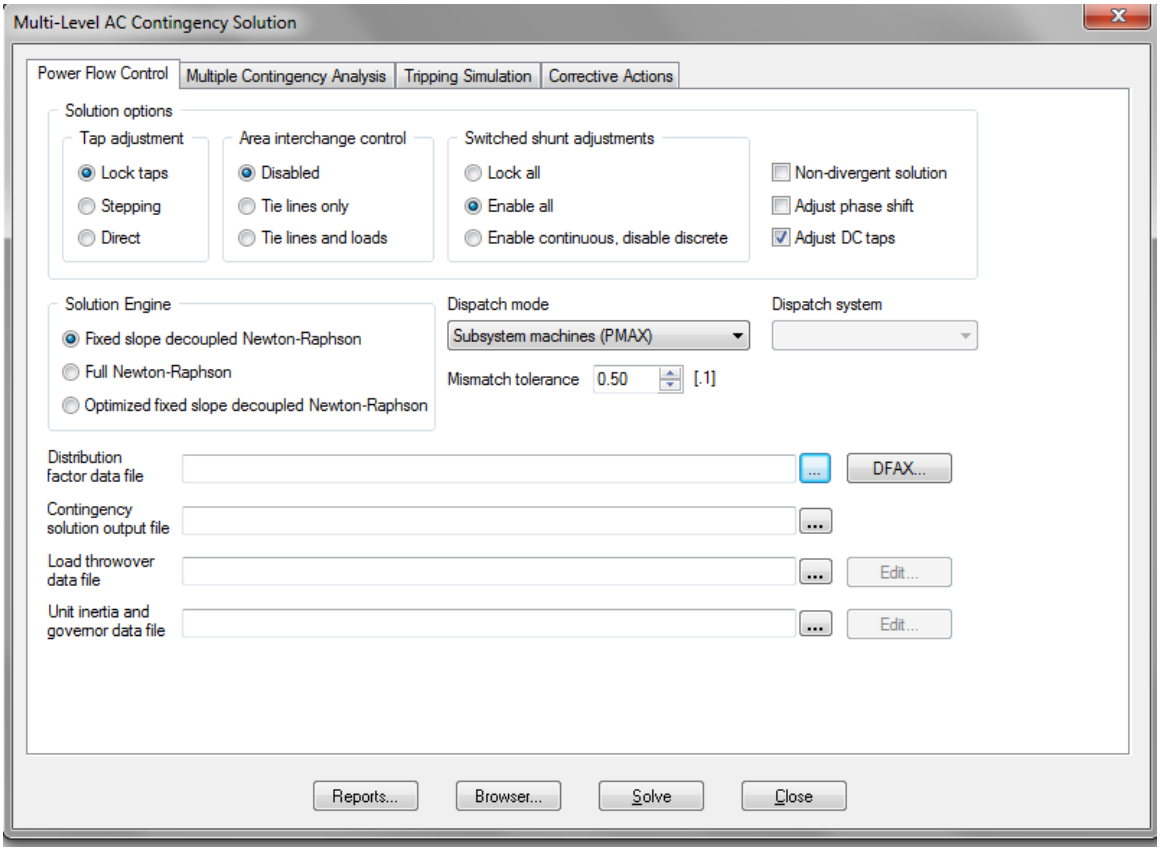
This file could be used to perform inertial- and governor- response power flows. One advantage of inertial- and governor- response power flows is that a swing bus need not be selected in every island. The power flows automatically identify all islands and select swing buses in every island.

C.3 Participation Factors for Generation Redispatch

In PSS/E, we can choose a set of generators that would participate in a power flow and thus would perform as distributed slack buses. The contribution of each of those generators to the system slack is based on the participation factors. This can be achieved by first defining a subsystem that consists of a set of generators that would participate in the redispatch. A subsystem can be implemented in a *.sub file. The *.sub file can be prepared as shown below.

```
SUBSYSTEM 'AGC_NW'
      BUS     ****
      BUS     ****
      BUS     ****
      BUS     ****
      BUS     ****
SUBSYSTEM 'NW'
   JOIN 'GROUP1'
      ZONE ***
      KVRANGE 100.000 400.000
   END
   JOIN 'GROUP2'
      ZONE ***
      KVRANGE 100.000 400.000
   END
```

After generating the DFAX (distribution factors) file with this subsystem and the contingency definitions files, when performing the AC contingency analysis, PSS/E gives options for several dispatch modes, shown in the figure below. These dispatches are based on the subsystems that we have defined above.



Dispatch Modes Available for AC Contingency Analysis

C.4 Special Protection Systems / Remedial Action Schemes

To meet system performance requirements, special protection systems/remedial action schemes (SPSs/RASs) are designed to detect predetermined system conditions and automatically take corrective actions, other than the isolation of faulted components. These schemes are designed to:

a) maintain system stability

b) address reliability standards

c) maintain acceptable power flows

d) maintain acceptable system voltages.

There are several functions in PSS/E for conducting contingency analysis in a steady state. The procedure outlined below describes the process of evaluation of a multilevel contingency.

Step 1: The AC contingency function calculates full AC power flow for a set of contingencies, and results are stored in contingency solution files.

Step 2: The SPS/RAS monitors model conditions. In "model condition," choose the type of element to which the condition would be applied and choose the specific object. Define a set of conditions that apply to that object. For example, we may specify the tripping of a combination of lines and generators if the apparent power (MVA) flow on the line between two buses is greater than a specified value.

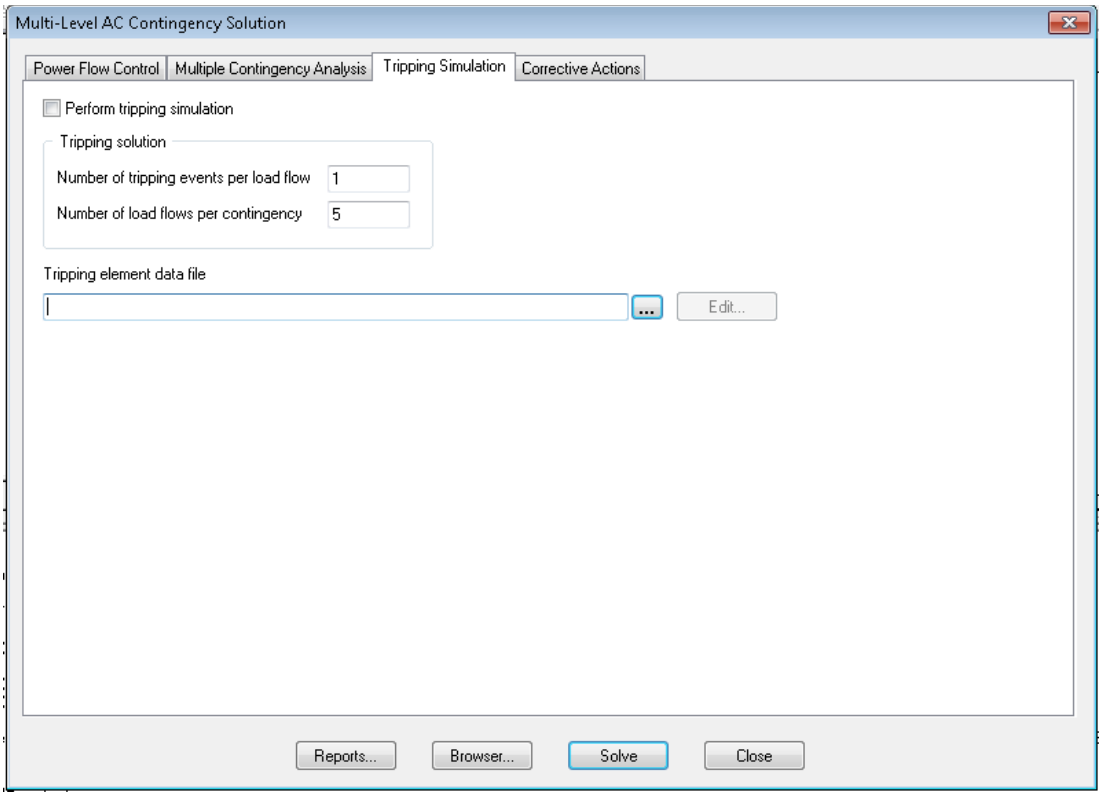
Step 3: If the action condition of an SPS/RAS model is satisfied (i.e., MVA flow on the specified line is greater than the specified value), all trip actions defined within a trip specification (i.e., tripping of the specified combination of lines and generators in Step 2) will be applied. These actions are used to resolve the system criteria violations caused by a contingency. These actions include, but are not limited to:

- tripping of generator/bus/transformer
- tripping of sources
- load curtailment or tripping
- system reconfiguration
- changes in MW and MVAr output.

This process continues until the number of such power flows performed as part of the SPS/RAS simulation for each contingency reaches a maximum limit.

C.5 Implementation of Corrective Actions in PSS/E

Selection of SPSs/RASs can be done in the Multi-Level AC Contingency Solution function as shown in the figure below.



Tripping Simulation Function for SPSs/RASs

In PSS/E, AC corrective actions are modeled as an optimal power flow problem (see PSS/E Program Operation Manual).

This feature has been used to explore possible corrective actions. Since the corrective actions are part of the AC contingency analysis, a contingency definition is necessary to implement the corrective action. To get around this problem, we have defined a fictitious contingency by adding a high-impedance branch in parallel with an existing branch and defined this dummy branch as the contingency. The actions are shown in the Python commands below.

psspy.branch_data(151,201,r"""2""",[_i,_i,_i,_i,_i,_i],[0.1, 0.1,_f, 1500.0, 1500.0, 2000.0,_f,_f,_f,_f,_f,_f,_f,_f,_f])
psspy.fnsl([0,0,0,0,0,0,99,0])

A fictitious contingency is defined with this branch being opened. The *.con file definition is provided here.

CONTINGENCY 'TEMP'
OPEN BRANCH FROM BUS 151 TO BUS 201 CKT 2
END

The corrective actions can be performed with several participating units. These units can be generators, phase shifters, tap-changing transformers, switched shunts, loads, etc. The first corrective

actions are performed with control phase shifters, tap-changing transformers, and switched shunts. If the voltage and flow violations still remain, generator controls are the next to be used.

Syntax:

psspy.dfax([1,1],r"""All.sub""",r"""All.mon""",r"""temp.con""",
r"""test_corrective_actions.dfx""")

- **Corrective actions with phase shifter, tap setting, and switched shunt adjustments**

psspy.accor_2([0,0,0,1,1,1,1,0,0,1,1,0,1],[0.5, 100.0, 0.1,0.0, 1.0, 1.0, 1.0, 1.0, 1.0,
1.0],[r"""ALL""",r"""ALL""",r"""ALL""",r"""ALL""",r"""ALL""",r"""ALL"""],
r"""test_corrective_actions.dfx""")

- **Corrective actions with generator redispatch**

psspy.accor_2([0,0,0,1,1,1,1,1,0,0,0,0,0],[0.5, 100.0, 0.1,0.0, 1.0, 1.0, 1.0, 1.0, 1.0,
1.0],[r"""ALL""",r"""ALL""",r"""ALL""",r"""ALL""",r"""ALL""",r"""ALL"""],
r"""test_corrective_actions.dfx""")

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