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Trial Implementation of the High-Impact, Low-Frequency Power Grid Event Risk Framework to Support Informed Decision-Making

October 2016

A Veeramany
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U.S. DEPARTMENT OF
ENERGY

Prepared for the U.S. Department of Energy
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Pacific Northwest National Laboratory
Richland, Washington 99352

Abstract

In 2015, Pacific Northwest National Laboratory (PNNL) developed a multi-hazard risk-assessment framework for modeling high-impact, low-frequency (HILF) power grid events to support risk-informed decisions for power grid management and emergency planning. The identified framework elements are based on a systematic and comprehensive characterization of hazards to the level of detail required for modeling risk. In 2016, PNNL performed a trial implementation of the framework for a single hazard category and a set of key power grid asset types as a way to test the framework.

A specific realization of a HILF event is referred to as an initiating event, or initiator. An initiating event is the manifestation of a hazard, and can be, for example, an earthquake of specified magnitude at a specified epicenter. Other examples of HILF events include geomagnetic disturbances and pandemics. For this test implementation, grid assets of a benchmark power system transmission network were assigned proxy geographical coordinates associated with Washington State locations; and real-world seismic hazard information was used for those locations. Based on the fragility of the grid assets to events of different severities, the set of possible failure scenarios (i.e., combinations of different asset failures) and their associated probabilities were determined, and recovery of grid assets and restoration of the network were considered. These combinations of failures and their subsequent recovery constitute a HILF event sequence that results in a given level of consequence, such as loss of power over a given geographic area for a given duration. The concurrent quantitative consideration of event probabilities and event consequences characterizes a risk model. For HILF event sequences, risk was expressed as expected unserved energy per year. This implementation demonstrates the feasibility and value of using the HILF event risk framework despite some of the identified challenges. This report discusses this trial implementation and presents risk results and insights from the implementation.

Executive Summary

Pacific Northwest National Laboratory developed a multi-hazard risk-assessment framework for modeling high-impact, low-frequency power grid events to support risk-informed decisions for power grid management and emergency planning. The identified framework elements are based on a systematic and comprehensive characterization of hazards to the level of detail required for modeling risk. The framework is documented in PNNL-24673, Framework for Modeling High-Impact, Low-Frequency (HILF) Power Grid Events to Support Risk Informed Decisions, dated December 2015, and provides the overarching technical basis for development of HILF event risk models that can inform decision-makers. The report acknowledged and identified anticipated challenges in implementation of the framework. One key challenge anticipated during framework development was uncertainty regarding the availability of suitably detailed domain models across different hazard categories and the difficulty in integrating such models. Another key anticipated challenge involved the large number of possible scenarios associated with combinations of potential asset failures and the need for techniques to produce acceptably accurate risk estimates. This report discusses the trial implementation of the framework and presents risk results and insights from the implementation.

A specific realization of a HILF event is referred to in this project using probabilistic risk-assessment terminology as an initiating event, or initiator. An initiating event is a manifestation of a hazard and can, for example, be an earthquake of specified magnitude at a specified epicenter. The initiator begins a sequence of events resulting in an accident sequence. In probabilistic risk-assessment terminology, accident sequences are initiating events followed by a sequence of events - failures (e.g., component or system failures) or successes - that lead to an undesired consequence with a specified end-state. A HILF event sequence involves damage to some combination of grid and supporting infrastructure assets that then results in a given level of consequence, such as loss of power over a given geographic area for a given duration. Risk modeling consists of systematic and comprehensive identification of the accident sequences resulting from initiators, estimation of the likelihood of the occurrence of those sequences, and quantification of the degrees of impact resulting from those occurrences. The concurrent quantitative consideration of event probabilities and event consequences characterizes a risk model. A typical probabilistic risk-assessment results in quantification of the expected value of consequences (e.g., expected loss of life). For HILF event sequences, risk was expressed as expected unserved energy per year.

For this test implementation, grid assets of a benchmark power system transmission network were assigned proxy geographical coordinates associated with Washington State locations; however, real-world seismic hazard information was used for those locations. This process systematically defined, in terms of frequency and magnitude, the distribution of seismic events that could have high impact to the grid, and characterized, for each grid asset location, the severity of the event (i.e., the seismic ground motion stress) to the grid asset. Then, based on the fragility of the grid asset to events of different severities, the set of possible failure scenarios (i.e., combinations of different asset failures) and their associated probabilities were determined. Next, the power grid was analyzed for each scenario and recovery and restoration were considered to determine the consequences of the events in terms of the cumulative unserved energy.

The ability to compare risk estimates across multiple potential initiating events associated with seismic hazards for the study region provides insights for power grid planning and suggests means of allocating the finite resources available to manage HILF event risks. As an enhancement to the risk results, a method to determine the risk-importance of specific grid assets was developed. This importance analysis provides identification of the most risk-significant assets, which could be used to identify asset or system improvements that reduce the vulnerability of the power grid to seismic events. This implementation

demonstrates the feasibility and value of using the HILF event risk framework notwithstanding some of the identified challenges.

Figure ES.1 displays elements of the framework considered in the test implementation. Hazard characterization yields seismic initiating frequency estimates for earthquake events of given magnitudes. Site disturbance characterization describes how the energy is transferred to assets of interest assuming peak ground acceleration as the prime stress parameter. The vulnerabilities of transformers, towers, and buses are probabilistically characterized through asset fragility distributions. A hazard load vs. asset capacity comparison across all assets in the network results in the formulation of number of probabilistically weighted grid asset failure scenarios. These scenarios, when evaluated through grid-simulation (network graph) methods, produce the consequence and restoration time estimates needed to generate risk estimates. Further, importance analysis aids in identifying key assets that, if strengthened, would have the greatest impact on grid resilience.

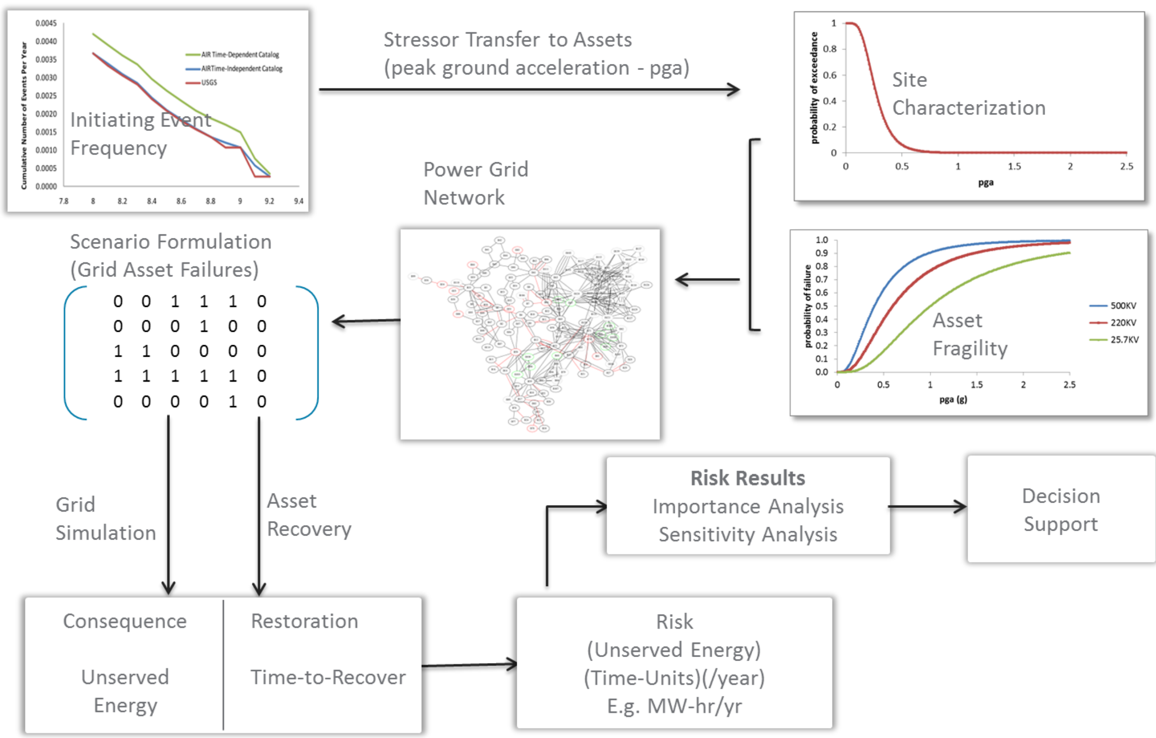


Figure ES.1. Integration of Constituent Models to Assess Seismic Risk to the Power Grid

The framework was tested using an Institute of Electrical and Electronics Engineers (IEEE) 145-bus test system assumed to be vulnerable to seismic hazards with proxy geographic coordinates assigned to asset locations. The network layout is shown in Figure ES.2 with numbered epicenters. A total of 40 seismic initiating events were considered (i.e., four different earthquake magnitudes for ten epicenters). The asset classes that were considered were buses (B), transformers (T), transmission lines (L), and transmission towers (W). The implementation of this element of the framework resulted in formulation of 200,000 scenarios (10 epicenters x 4 magnitudes per epicenter x 5,000 simulation iterations per initiator) similar to the single scenario illustrated in Table ES.1. In this example an earthquake of magnitude 8.45 at epicenter 3 resulted in failure of 45 assets (i.e., 15 transmission lines, 8 buses, and 22 transformers).

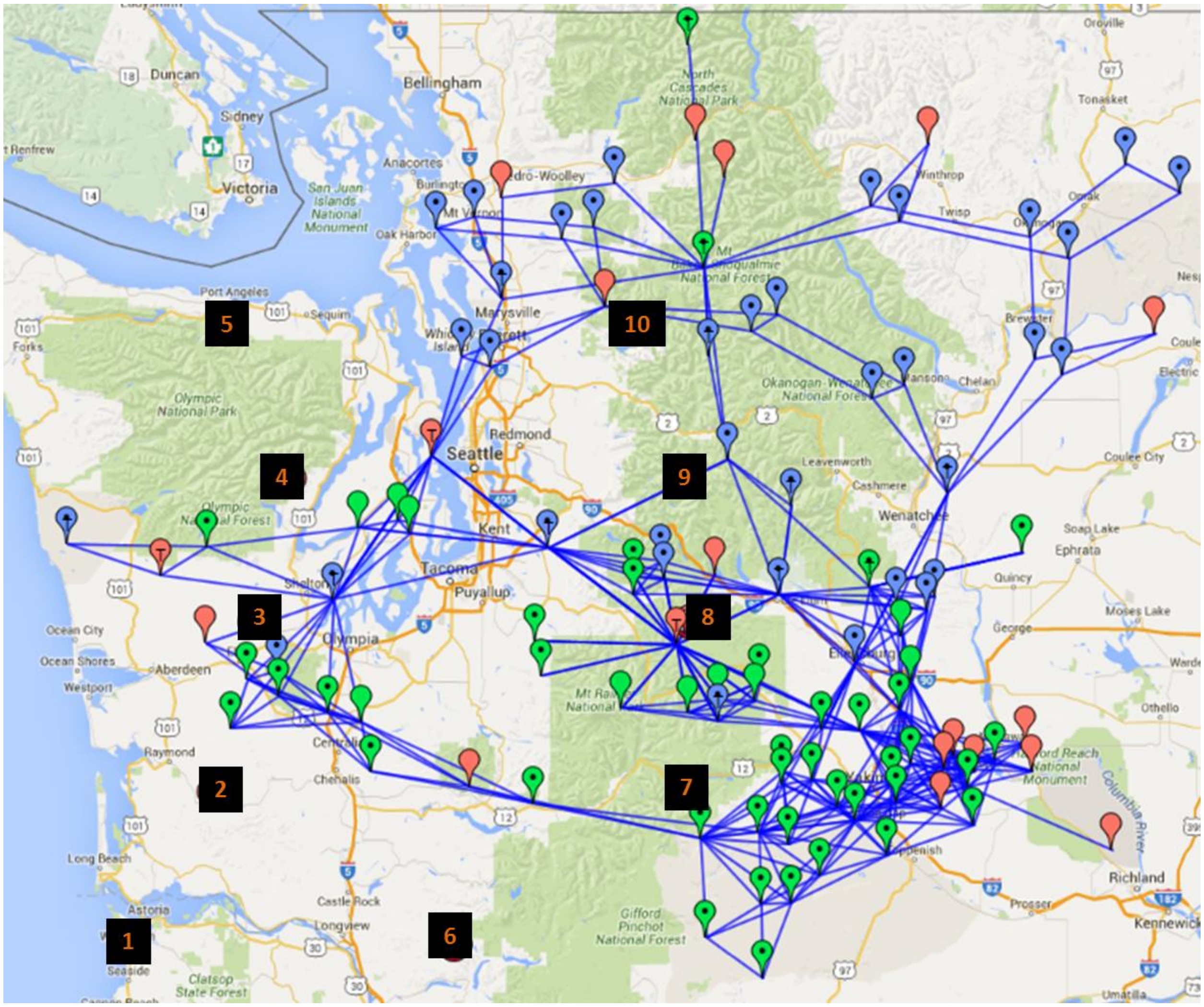
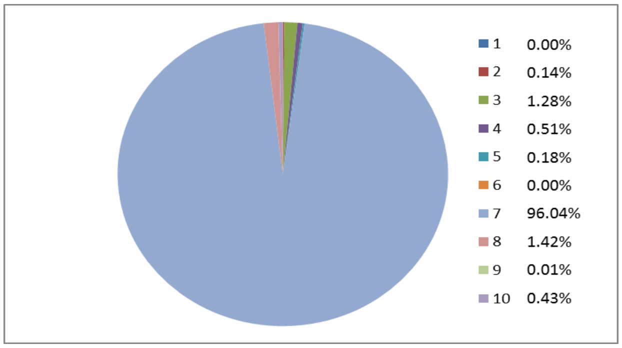


Figure ES.2. The IEEE 145 Bus Test System Overlaid on Geographic Map with Epicenters. (Red: load bus, green: generation bus, blue: load and generation bus, numbered squares: epicenters considered.)

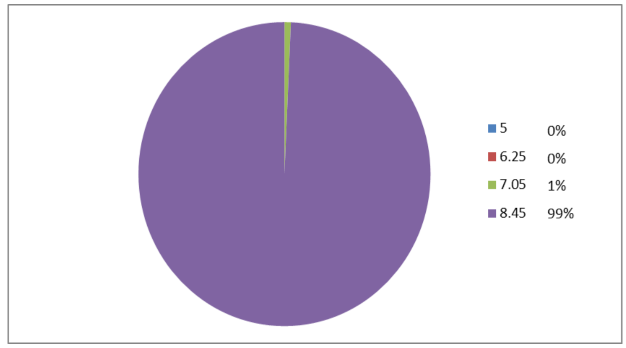
Table ES.1. Example of Scenario for Initiating Event of Magnitude 8.45 at Epicenter 3

Epicenter	Scenario
3	L142, L143, L145, L150, L275, L276, L277, L278, L280, L281, L282, L290, L291, L296, L297, B80, B79, B14, B17, B22, B59, B92, B107, T4, T21, T32, T33, T34, T39, T40, T41, T45, T46, T49, T52, T53, T54, T55, T57, T62, T64, T65, T66, T69, T70

Analysis results are presented in terms of expected unserved energy per year (MW-hr/yr) incorporating the following risk elements: 1) likelihood of seismic scenario including asset failures, 2) extent of load lost, and 3) post-event recovery duration. The risk to the test grid across all seismic initiating events was found to be 25 MW-hr/yr. The contribution to the seismic risk to the test grid as a function of epicenter location and seismic event moment magnitudes is shown in in Figure ES.3. While Figure ES.3(a) indicates that epicenter 7 contributes 96 percent of the risk to the test grid, followed by epicenters 8 and 3 (about 1 percent each), Figure ES.3(b) indicates that an 8.45 magnitude earthquake would contribute the most risk across all epicenters. A magnitude 8.45 earthquake occurring at epicenter 7 would be the primary risk driver affecting two load buses (i.e., B136 and B141) that serve nearly 37 percent of the total load.



(a)



(b)

Figure ES.3. Seismic Risk to the Test Grid (a) Associated With the Considered Epicenter Locations Across Earthquake Magnitudes (b) by Earthquake Magnitudes Across All Epicenter Locations

Figure ES.4 presents random variability (aleatory) in the consequence estimate. Note that a loss of approximately 4.4 percent (283 GW) of the total load for over 24 hours—approximately 300 GW-hours—has a relative exceedance frequency of about 6E-5/yr, or approximately once in 1,600 years.

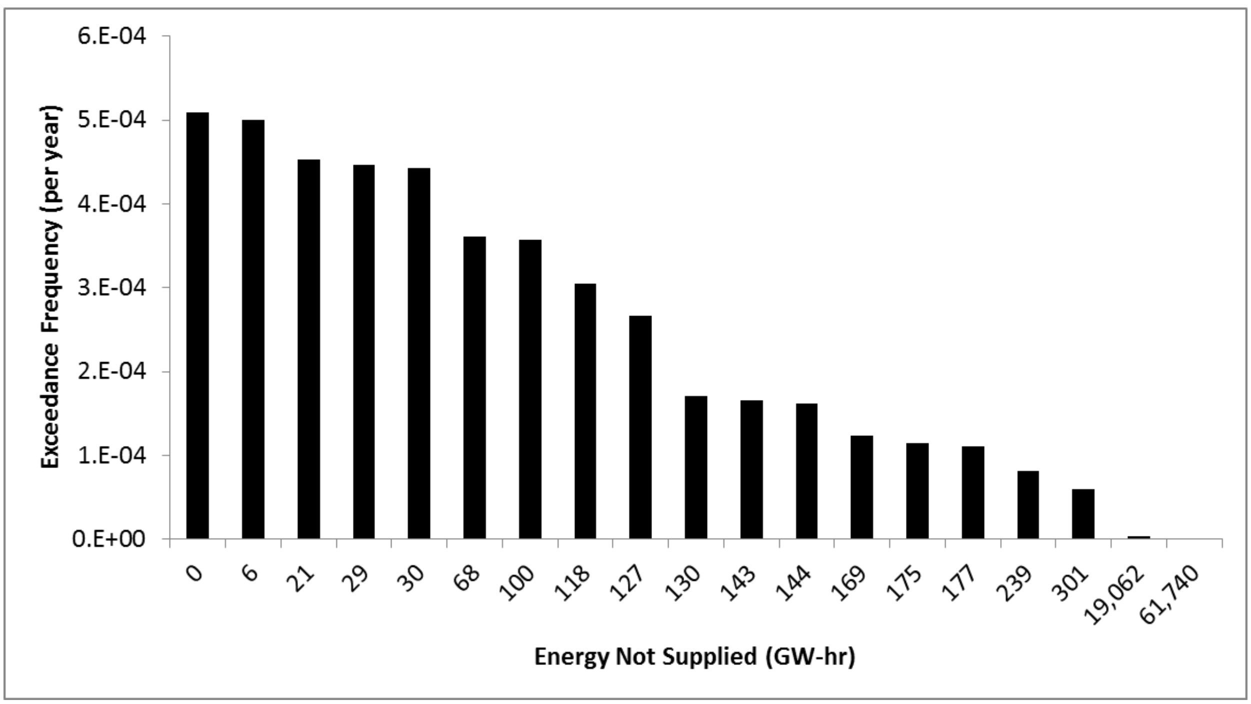


Figure ES.4. Energy Not Supplied (GW-hr) across Epicenters and Magnitudes

The risk associated with scenarios consisting of asset failures that encompass combinations sufficient to cause a load loss was estimated as the sum of the expected value of unserved energy from those scenarios, weighted by the ratio of the frequency of those scenarios to the total frequency. Table ES.2 provides risk contribution of the top scenarios. Table ES.2 indicates that failure contribution of buses B136 and B141 account for 96% of the overall risk to the test grid. Note that some assets (e.g., T65 and B74) fail in multiple scenarios.

Table ES.2. Risk Contribution from Asset Failure Combinations across Initiating Events (rounded up for reporting)

Asset Failure Scenario	% Risk
B136	77
B141,B136	19
B74,L243,B73	0.9
B80,T65,B22,T66	0.5
T65,B22,T66	0.5
B80,T65,B22,B79,T66	0.5
B74,B73	0.5
T65	0.4
B51,B33	0.4
T65,B22,T66,L288	0.1
B51	0.1
B90,T65,T39	0.1
B101,L256,B74	0.04
T65,T66,L288	0.04
T65,B22	0.03
B74	0.01
B81	0.01
L243	0.002
L256	0.002

An asset importance analysis performed as part of the probabilistic risk assessment indicates that strengthening bus B136 (e.g., by reducing the rigidity of the associated structure) or adding redundancy would result in 88 percent risk reduction. Similarly, a 6 percent risk reduction is possible by installing a base isolation device at transformer T65. The top seven risk-significant assets (possible risk reduction of ≥1 percent) are presented in Table ES.3.

Table ES.3. Risk Reduction Achieved by Planning for Top Seven Risk-Significant Assets

Asset	B136	T65	B74	L256	B73	L243	B141
Risk Reduction Achieved (%)	88	6	4	2	2	1	1

The test implementation accounted for restoration and recovery to reduce the total unserved energy. The results indicate that the same insights would be produced using local-, utility-, and state-specific recovery plans.

We found that this analysis demonstrates the feasibility and value of the HILF event risk framework for assessing extreme event risk and informing decision-making for a test power grid vulnerable to seismic hazards. Test implementation results include the following:

- total power grid risk (i.e., expected unserved energy)
- contributions to power grid risk from each initiating event category (i.e., seismic magnitudes and epicenters)
- contributions to power grid risk from each asset failure scenario
- asset importance, ranked by contribution to total power grid risk
- risk reductions achievable through asset strengthening and recovery planning

We found that the model results from the implemented framework provides a broad inventory of risk insights that are likely to help decision-makers ensure that resources are expended where the greatest potential for risk reduction lies.

We contend that one of the greatest benefits of using the framework will be assessment of multiple hazards in a consistent manner. We note that for most locations more than one hazard is likely to pose significant threat to the power grid, which creates complexities for grid and emergency response planners trying to sort out how to manage and allocate resources without comparable risk information integrated across completely different kinds of hazards. We maintain that once implemented across multiple hazards the framework will allow decision-makers to prioritize risk-management activities, helping ensure that the dominant risk drivers are addressed first, and that measures that reduce impact across multiple hazard types can be identified and implemented.

Insights gained from the test implementation provide a strategic roadmap for future research. The platform of models developed for implementation of the framework for the seismic hazard establishes a good foundation to implement the HILF event risk framework across other hazards (e.g., geomagnetic disturbance and electromagnetic pulse events) and to incorporate the impact of HILF events to grid-supporting infrastructure systems. However, additional work is needed in future investigation to expand the test implementation of the HILF event risk framework to address these considerations.

Acknowledgments

This work was funded by U.S. Department of Energy Office of Electricity Delivery and Energy Reliability and was performed under contract DE-AC05-76RL01830.

Acronyms and Abbreviations

B_G	generation bus
B_L	load bus
EENS (EUE)	expected energy not supplied (expected unserved energy)
GMM	ground motion attenuation model
HILF	high-impact, low-frequency
IEEE	Institute of Electrical and Electronics Engineers
IESO	Independent Electricity System Operator
LOLH	loss of load hours
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
OpenSHA	Open-source GMM code available from the U.S. Geological Survey
PGA	peak ground acceleration
PNNL	Pacific Northwest National Laboratory

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1.0 Introduction

1.1 High-Impact, Low-Frequency Event Risk Framework

Pacific Northwest National Laboratory previously developed a risk framework for modeling high-impact, low-frequency (HILF) power grid events to support risk-informed decisions for grid management and emergency planning. Risk from HILF events has been a focus of risk managers and policymakers (Assante 2009)(FERC-NERC 2016), because although HILF events, by definition, rarely occur, they have the potential to cause catastrophic impacts on the electric power system. In this report, we briefly describe the framework and demonstrate its implementation for seismic hazards using a benchmark reliability test system. We describe integration of a collection of models implemented to perform hazard analysis, fragility evaluation, consequence estimation, and post-event restoration. We demonstrate the value of the framework as a means for facilitating risk-informed planning and resource allocation. The research will benefit transmission planners and emergency planners by improving their ability to maintain a resilient grid infrastructure against impacts from major events (NERC 2012).

The elements of the HILF event risk framework, illustrated in Figure 1.1, were described in Veeramany et al. (2015) along with consideration of anticipated challenges and the state of the art of constituent models. In this framework, an initiating event is realization of an extreme event associated with a given hazard. For instance, a magnitude 9.3 earthquake caused by a rupture trace of a fault along the coast of Washington State is a realization of the seismic hazard. An initiating event leads to a sequence of events resulting in disruption of the power grid and its supporting infrastructure network. In the probabilistic risk-assessment community, this sequence of events is referred to as an accident sequence. The consequence of an accident sequence associated with the power grid might be defined as the unserved energy over the affected geographic area for a duration of time until functionally is restored.

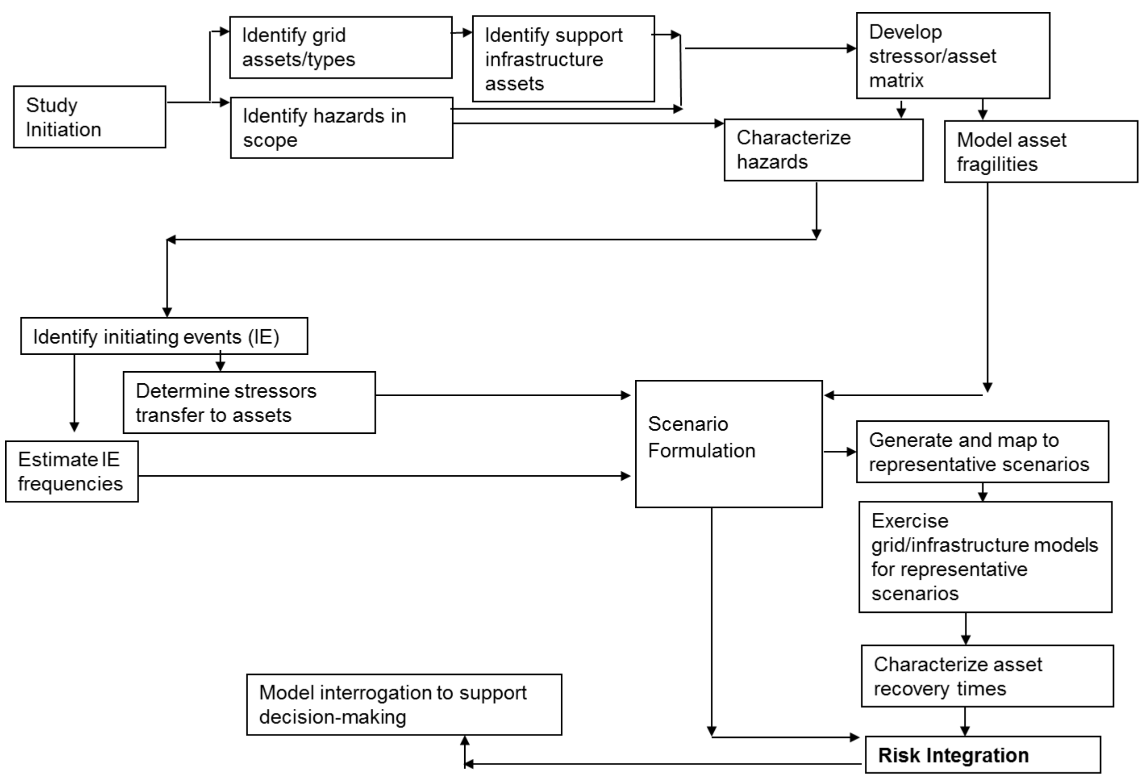


Figure 1.1. Elements of the HILF Event Risk Framework

The development of a risk model involves systematic and, to the extent possible, comprehensive identification of accident sequences, their likelihood of occurrence, and the magnitude of their impact. The essence of risk assessment that makes it useful for planning purposes is this consideration of event likelihood and consequences.

1.2 Elements of the Risk Framework

This section briefly discusses the actions associated with implementing each element of the HILF event risk framework.

1.2.1 Study Initiation

Prior to implementation of the framework, identify the intended audience for the risk information and establish the objective and scope of the modeling required.

1.2.2 Identify Grid Assets/Types

Identify critical power grid infrastructure asset types relevant to the application scope.

1.2.3 Identify Hazards in Scope

Identify the hazards to be addressed in the modeling and the stressors associated with each hazard. For instance, peak ground acceleration (pga) is the predominant stressor associated with a seismic event.

1.2.4 Identify Support Infrastructure Assets

Besides the power grid assets identify the support system assets the grid relies on for reliable functionality. A comprehensive risk model should include the vulnerabilities associated with support system as well as power grid assets.

1.2.5 Develop Stressor/Asset Matrix

Develop a matrix that identifies for each hazard class the potential impact on an asset class and the stressors to which the assets are vulnerable. Distribution lines, for example, may be impacted by meteorological hazard events such as high winds and generated projectiles, while transmission lines may be only impacted by generated projectiles.

1.2.6 Characterize Hazards

Develop a probabilistic characterization of the hazards to be addressed. For example, a hazard characterization for the seismic hazard is a curve that specifies mean annual frequencies of given earthquake magnitudes specified by location.

1.2.7 Model Asset Fragilities

Develop a probabilistic model of each asset's capacity to withstand a stressor of a given intensity. A fragility curve defines the probability of functional failure of the asset conditional on specified stressor magnitudes.

1.2.8 Identify Initiating Events

Choose discrete representative initiating events from the probabilistic characterizations of the hazards (e.g., the hazard curves) to be addressed that will provide the initiator for scenarios potentially resulting in adverse consequences.

1.2.9 Estimate Initiating Event Frequencies

Estimate, based on the hazard curves, the annual frequencies of the selected initiating events. For HILF event sequences, the frequency of the initiating event is also the frequency of the HILF event frequency.

1.2.10 Determine Stressor Transfer to Assets

Define the way the stressor associated with the energy of the initiator is transferred to the asset to impact the asset. For example, a seismic event results in energy release and ground motion that is attenuated between the earthquake epicenter and the power grid assets.

1.2.11 Scenarios Formulation

Formulate scenarios by defining the occurrence of an initiator and the subsequent success and failure of assets. Failure occurs when the associated stressor exceeds the corresponding capacity of the asset to withstand it. A Monte Carlo simulation or similar simulation is a practical approach for formulating scenarios.

1.2.12 Generate and Map to Representative Scenarios

Generate the consequence of scenarios (based on the consequence metric of interest such as power outage duration and geographic extent) using existing grid-simulation models, such as Power Transmission System Planning Software (PSS/E) and map those consequences to representative scenarios. Identification of representative scenarios is needed because scenario simulation run times can render execution a model for every scenario impractical. Identification of representative scenarios consists of identification of scenarios for which the consequences will be calculated and to which the full Monte Carlo sample of scenarios will be mapped.

1.2.13 Exercise Grid/Infrastructure Models for Representative Scenarios

Exercise support infrastructure models, which map loss of supporting assets to loss of grid assets, and grid operability models for the representative scenario set to assess the degrees of impact on the consequences.

1.2.14 Characterize Asset Recovery Times

Estimate recovery times associated with each representative scenario and use those estimates as the basis to adjust the consequence estimates.

1.2.15 Risk Integration

Integrate the frequencies and estimated consequences of the realized representative scenarios to characterize the risk to the electric power grid due to the hazards addressed.

1.2.16 Model Interrogation to Support Decision-Making

Once implemented, interrogate the risk model for insights of interest to decision-makers. Some of the most common means of interrogating a model are identification of principal risk drivers, sensitivity analyses, and cost-benefit analyses to determine how the most cost-effective risk reduction can be achieved.

1.3 Seismic HILF Event Risk Implementation Precedents

Extensive literature is available on various domain models that have varying degrees of applicability to elements of the HILF event risk framework. Candidate and state-of-the-art models were preliminarily identified in the initial HILF event risk framework publication (Veeramany et al. 2015). Additional literature relevant to the test implementation of the framework is discussed below.

A risk assessment on Bonneville Power Administration transmission substations and the associated transmission network under earthquake loading was performed by Eidinger and Kempner (2012). This study includes characterization of the seismic hazard analysis for the considered geographic region, determination of the impact of seismic events of different magnitudes, and determination of the repair times and economic impacts associated with those seismic events. A similar study was performed on the seismic performance of the Western Interconnection using power-flow analysis to determine the impact of grid asset failures to the bulk electric system (Shinozuka et al. 2003). Lin and Adams (2007) provides helpful seismic fragility data of hydropower components. Gjerde et al. (2011) recommend using probabilistic risk assessment to identify the risk to power systems associated with extreme events. In this approach, fault trees, event trees, consequence diagrams, risk diagrams, and bow-tie models are used to structure the analysis in terms of threats, unwanted events, barriers, and consequences. In almost all the studies surveyed herein, the addition of loss-of-power consequence estimates, consideration of infrastructure that supports the power grid, and identification of restoration strategies would make the studies more complete. An Institute of Electrical and Electronics Engineers (IEEE) task force explored methodologies and challenges associated with risk assessment of cascading outages including combinatorics of contingencies and computational complexities (Vaiman et al. 2012). That study pointed out the difficulty of estimating the impact on the grid from a large number of failed assets given that current cascading simulation tools are deterministic. The task force developed a set of criteria to be used in comparing various cascading outage risk-assessment methodologies.

This report focuses on integrating models meeting the functional requirements of elements associated with the risk framework to develop an end-to-end risk model. Although some of the constituent models employed in the framework are simplified at this stage, we anticipate expanding to a more comprehensive demonstration of the framework. However, our current research focuses on evaluating seismic risk to a power grid test system and on evaluating the impact of seismic events on electrical buses, transformers, and transmission lines as the core assets to test the framework. The constituent models of test demonstration address the following:

- seismic hazard analysis
- asset fragility analysis
- consequence analysis
- restoration analysis
- importance analysis.

The integrated demonstration model sets the necessary precedents for developing a more realistic and more comprehensive risk-informed, multi-hazard, decision-support resiliency model. The rest of the report provides more detail on elements of the framework through the trial implementation case study.

2.0 Framework Implementation Approach and Case Study

This section demonstrates application of the risk framework using a case study. The scope of this report is showing the use of risk framework to assess seismic hazard risks to the extent that system vulnerabilities and effective energy restoration strategies can be identified.

In probabilistic risk-assessment terminology and this report, the specific realization of a HILF event is referred to as an initiating event, or initiator. For instance, the initiator of a seismic hazard could be an earthquake of specified magnitude at a specified epicenter. The initiator begins a sequence of events resulting in an accident sequence. In probabilistic risk-assessment terminology, accident sequences are initiating events followed by a sequence of events - failures (such as component or system failures) or successes - that lead to an undesired consequence with a specified end-state. A HILF event sequence involves damage to some combination of grid and supporting infrastructure assets that results in a given level of consequence (e.g., loss of power over a given geographic area for a given duration). Risk modeling consists of systematic and comprehensive identification of the accident sequences resulting from adverse events, estimation of the likelihood of the occurrence those sequences, and quantification of the degrees of impact resulting from those occurrences. It is the concurrent quantitative consideration of event probabilities and event consequences that characterizes a risk model. A typical probabilistic risk-assessment quantifies an expected value, e.g., expected loss of life (Expected value is a predicted value of a variable, calculated as the sum of all possible values each multiplied by the probability of its occurrence.) For HILF event sequences, risk in this report is expressed as expected unserved energy (EUE). Another metric of importance for power system generation adequacy planners is the loss of load hours (LOLH) signifying risk of insufficient generation capacity (Abdel-Karim 2015).

Figure 2.1 shows those elements of the framework considered in the test implementation.

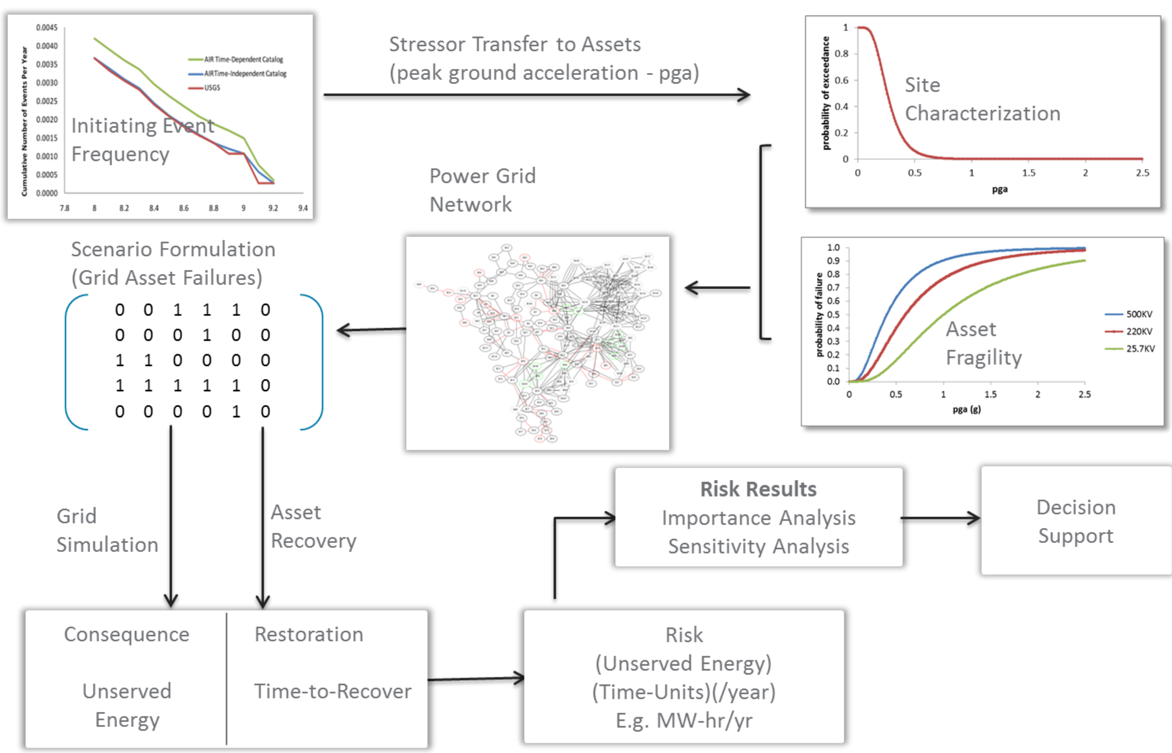


Figure 2.1. Integration of Constituent Models to Assess Seismic Risk to the Power Grid

Hazard characterization yields seismic initiating frequency estimates given an earthquake event and its magnitude. Site disturbance is characterized as how energy is transferred to sites where assets of interest exist or are housed by assuming peak ground acceleration as the prime ground motion parameter. The vulnerabilities of transformers, towers, and buses are probabilistically characterized through asset fragility distributions. A comparison of the hazard load versus the asset capacity across all assets in the network identifies the grid assets that fail and helps formulate the scenarios. These scenarios, when processed through grid simulation and recovery models (network graph), produce consequence and restoration time estimates needed to generate risk estimates. The risk results can then be used to identify risk-significant scenarios and assets to support decision making.

2.1 Study Initiation

The intended audience for this study is assumed to be transmission planners and emergency planners interested in maintaining a resilient grid infrastructure against impacts from major seismic events. The case study assumes an IEEE 145 test bus system overlaid on Washington State vulnerable to seismic hazards associated with the Cascadia Subduction Zone. The objective was to identify critical assets at risk across initiating events, the expected unserved energy (lost load and duration for restoration), and restoration paths for resiliency planning.

The test system has 52 transformers, connects 145 buses through a network of 453 transmission lines and 50 generation assets, and serves approximately 283 GW of load (Vittal and Treinen 1987; Vittal et al. 1992; Shah 2011). This test system was chosen because it has a high average "degree of distribution." Degree of distribution is a graph-theoretic metric that refers to the number of transmission lines to which a node (bus) is connected. A high number—6.25 in this case—means the grid should exhibit a higher degree of robustness to extreme events. Most real power grids have a degree of distribution of about two or three. Another reason this system was chosen is the availability of dynamic test data. Future modeling will include use of a dynamic contingency power-flow tool, which necessitates that dynamic test data be available. Further, the choice to not use a real-world model permits initial validation of the risk framework without generating or disseminating any sensitive information regarding the vulnerability of an actual network.

It is anticipated that geographic coordinates of power grid assets will be known. The test power grid systems typically represent real networks but do not come with coordinate information. Therefore, a method to generate proxy coordinates is necessary in simulate a real system.

Proxy geographic coordinates for the assets in the test grid were generated in a four-step process. First, we developed a network graph of the test system with buses as nodes and transmission lines as edges. Second, we assumed that buses connected to a transformer were at the same location and that buses not connected transformers were at different locations. This assumption is necessary because the test system does not host substation information. Third, we created a bus-branch visual representation of the network using "graphviz" graph visualization software (Ellson et al. 2001) as illustrated in Figure 2.2. Fourth, Cartesian coordinates were transformed into geographic coordinates by overlaying the network on the geographical region of interest.

Figure 2.3 provides the geographical layout of grouped assets used on our demonstration model. The asset positions can vary depending on the "graphviz" filter used for automating the layout. The list of assets along with their characteristics and geographic coordinates are presented in Appendix C.

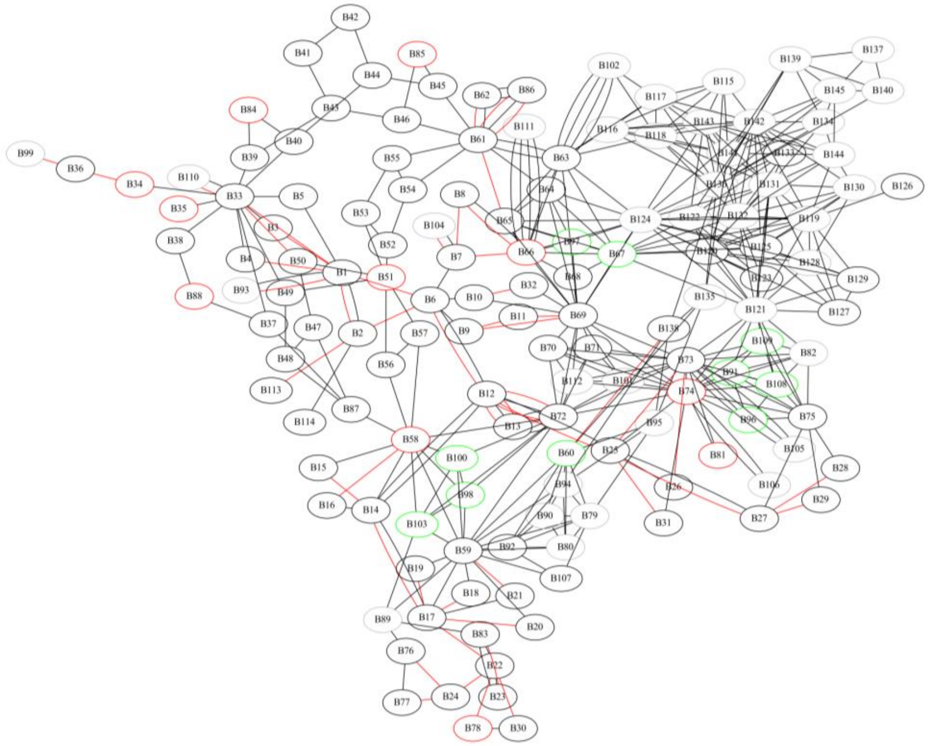


Figure 2.2. Bus-Branch Network Graph View of the IEEE 145 Bus Test System (red node: load bus, green node: generation bus, black node: connectivity bus, red line: transformer)

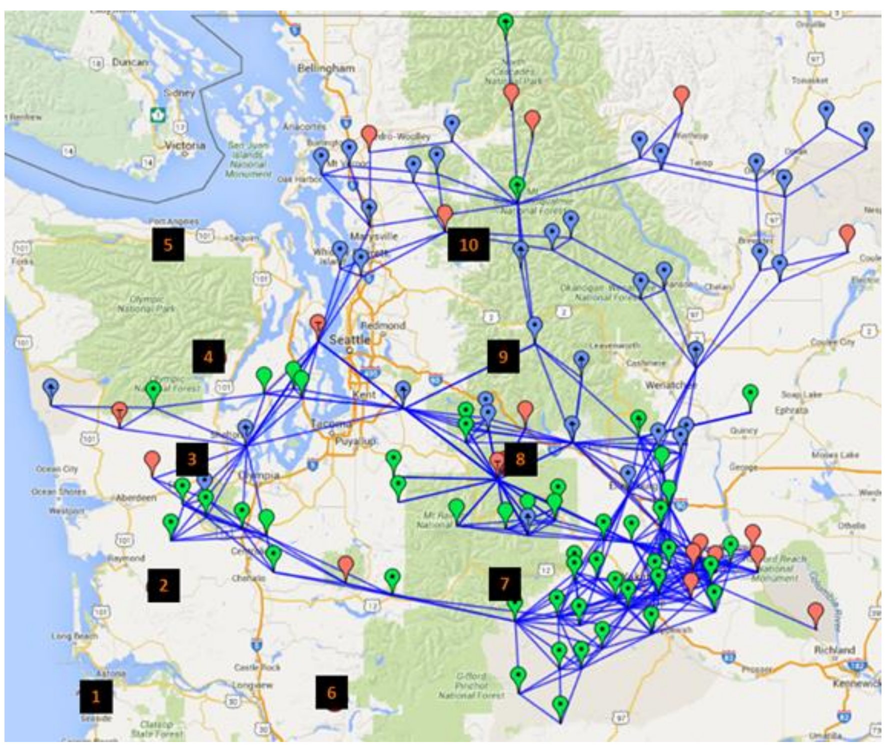


Figure 2.3. IEEE 145 Bus Test System Laid out Geographically on a Map (red: load bus, green: generation bus, blue: load and generation bus, numbered squares: epicenters considered)

2.2 Identify Grid Assets/Types

The power system transmission network connects power generation assets to consumption points (called as loads) through redundant transmission lines (also called branches or tie-lines). The nodal points are buses (i.e., generation buses, load buses, and connectivity buses) typically hosted at substations that also contain other critical assets (e.g., transformers). In terms of loss estimation, these assets account for 40 percent of the substation's economic value (Eidinger and Ostrom 1994).

In the trial implementation we addressed certain important asset classes (i.e., buses, transmission towers and lines, and transformers.) Other asset types (e.g., control systems and support infrastructure) could be accommodated using the appropriate test network model or grid-simulation model supporting these asset types.

2.3 Identify Hazards in Scope

While multiple hazards pose various degrees of potential threat to the network and are location-specific, events that would threaten grid stability and cause widespread impacts requiring multi-jurisdictional coordination (NERC 2014) can be very risk significant even though they have low recurrence frequency. For example, although the likelihood of a seismic rupture in the Cascadia Subduction Zone of at least magnitude 8.0 is only about once in 250 years, the magnitude of the consequences produced by such an event may merit transmission planning and emergency preparedness attention. However, more frequent hazard events (e.g., wind storms and ice loading) to which the Western Interconnection is vulnerable could also be risk significant and could warrant attention. For the test implementation, we considered seismic hazards in the Western U.S. Cascadia Subduction Zone.

2.4 Identify Support Infrastructure Assets

An interruption in support infrastructure (e.g., gas pipeline systems, fuel supply) or logistics can render multiple generation plants non-functional (Shahidehpour et al. 2005). The NERC Severe Impact Resilience Task Force (SIRTF) in their report (NERC 2012) identifies infrastructure that the bulk power system (i.e., the power grid) relies on. However, current industry-scale grid network representation formats do not support incorporation of support assets. To limit the scope of this test implementation, support infrastructure assets were not considered in this test.

2.5 Develop Stressor/Asset Matrix

All asset types (i.e., buses, transmission towers, and transformers) considered in the test grid and study region are vulnerable to ground motions arising from a seismic initiating event. Secondary impacts resulting from the seismic event were not considered. Damage to a power grid asset caused indirectly by other damage (e.g., impact from uprooted trees on lines and other power grid assets) was not modeled.

2.6 Characterize Hazards

Seismic hazard source characterization conducted as part of the Hanford probabilistic seismic hazard analysis (Coppersmith et al. 2013) estimates the mean annual frequency (see Figure 2.4) for various magnitudes of earthquakes associated with the Cascadia Subduction Zone that stretches along and off the coast of the Pacific Northwest.

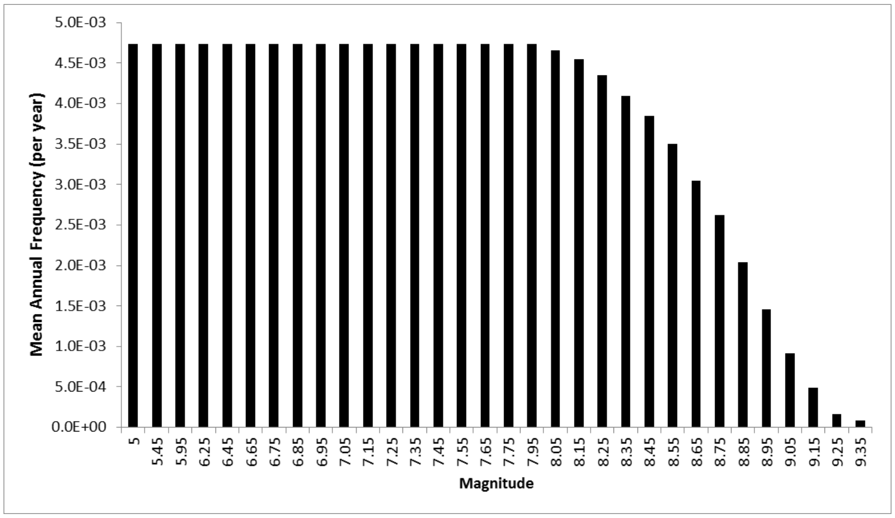


Figure 2.4. Mean Annual Frequency for Seismic Events along the Cascadia Subduction Zone (Coppersmith et al. 2013)

2.7 Model Asset Fragilities

Fragility curves for transformers, buses and transmission towers are illustrated in this section with reference to data sources outlined in Appendix A. Fragility or vulnerability refers to the probability of failure of an asset conditional on the disturbance caused at the site location in response to an initiator. The fragility of an asset can be decreased by mitigative features designed to reduce the impact of a seismic event. Examples of mitigative features include use of flexible bus structures and anchoring transformers with base isolated devices (Knight and Kempner Jr 2009; Saadeghvaziri et al. 2010). Other than in a National Institute of Building Sciences technical manual for earthquake loss estimation methods for electric power utilities (Eidinger and Ostrom 1994), fragility data appear to be sparse. The technical manual presents lognormal distributions for major assets at a transmission substation categorized by asset rated capacity and mitigative features. Fragility curves for transformers and buses are illustrated in Figure 2.5 and Figure 2.6, respectively.

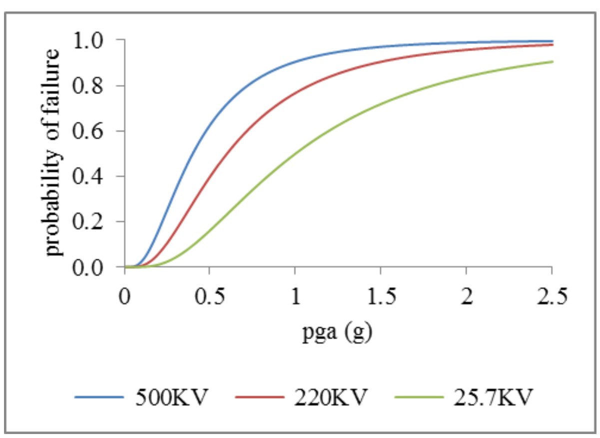


Figure 2.5. Cumulative Distribution Function (Capacity Curves) for Bus Fragility (Eidinger and Ostrom 1994)

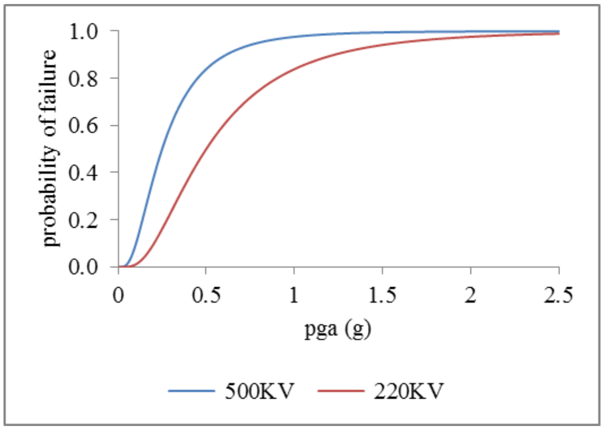


Figure 2.6. Cumulative Distribution Function (capacity curves) for Transformer Fragility (Eidinger and Ostrom 1994)

Transmission towers form the basis for supporting transmission lines and are known to be susceptible to seismic events. The failure of any one tower along a transmission line was assumed to operationally fail that line. In the model, a total of 1,584 towers were placed at set geographical distances along a line length of 7,742 mi to approximate actual transmission towers. The fragility of transmission towers depends on their design and the material used in their construction. We used fragility data associated with the most conservative type of towers analyzed in a study by Park et al. (2015). The model can be expanded to include support infrastructure and various other asset types (e.g., generators, control centers, and protection systems). However, availability of credible fragility data for additional assets and infrastructure could be a sparse, as could be the availability of grid-simulation models that support these asset types.

2.8 Identify Initiating Events

The case study in this report considers 40 representative initiating events (i.e., ten earthquake epicenters, each associated with four different magnitudes) borrowed from the Hanford probabilistic seismic hazard analysis study (Coppersmith et al. 2013).

2.9 Estimate Initiating Event Frequencies

The frequency of occurrence of the specific initiating events considered was obtained from the mean annual frequency distribution identified in Section 2.6. The frequency obtained from the distribution was apportioned across the ten considered epicenter locations.

2.10 Determine Stressor Transfer to Assets

In seismic hazard analysis, ground motion attenuation models (GMMs) characterize the ground motion (i.e., the stressor) for a given earthquake at an asset site. Simple GMM models produce a point estimate of the expected ground motion, and probabilistic seismic hazard analysis studies characterize uncertainties around these estimates. Both methodologies take into consideration wave propagation and an asset location's geological characteristics.

The test used a probabilistic version of a U.S. Geological Survey model. Events were assumed to originate at point-source locations with various earthquake magnitudes. Default values were used for other parameters (e.g., shear wave velocity). Peak ground acceleration probabilistic exceedance (load) curves were output from the model.

The test implementation used the U.S. Geological Survey's GMM implemented in the OpenSHA open-source platform (Field et al. 2003; OpenSHA 2004). This GMM uses several input parameters associated with the event source (e.g., depth, slip type, epicenter, and magnitude) and site characterization (e.g., soil type and site class) to produce a site-specific probabilistic distribution of seismic loading. The site referred to herein is the location of a critical grid asset for which response to a seismic event needs to be evaluated. The trial implementation does not consider the cumulative damage associated with after-shocks. This impact should be addressed in future model development.

Figure 2.7 and Figure 2.8 provide examples of probability of exceedances curves using pga as the ground motion parameter with varying magnitudes and a fixed site location (Figure 2.7) and fixed magnitude and varying site locations (Figure 2.8). The exceedance probability is greater when the site location is closer to the epicenter and earthquake magnitude is relatively larger.

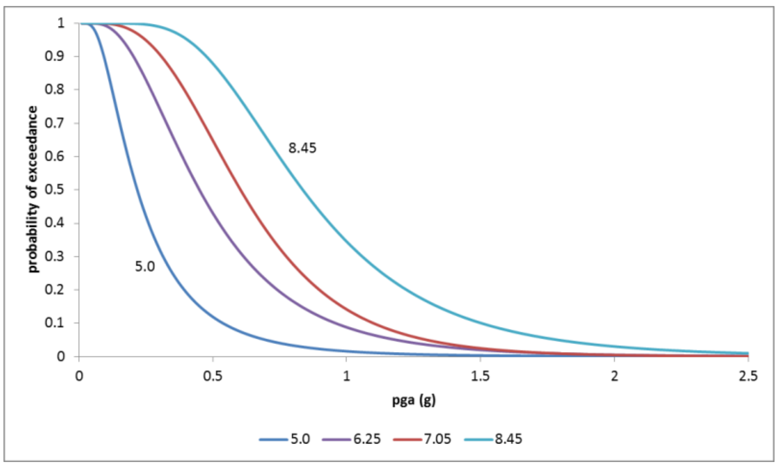


Figure 2.7. Sample Probability of Exceedance (load) Curve at an Asset Site 3 mi from Epicenter 8 for Various Earthquake Magnitudes

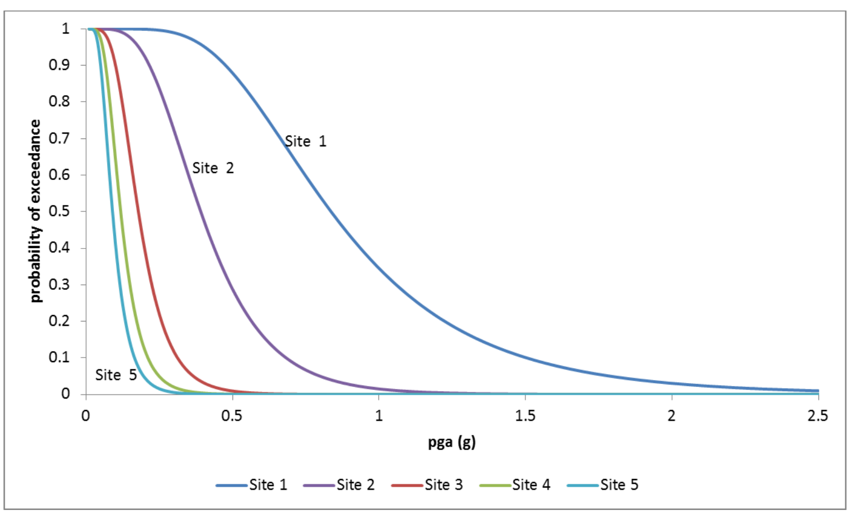


Figure 2.8. Sample Probability of Exceedance (load) Curve at Asset Sites 3 mi (site 1), 15 mi, 40 mi, 61 mi, and 80 mi from Epicenter 8 for a Magnitude 8.45 Earthquake

2.11 Scenarios Formulation

Initiating events can lead to failure of multiple assets associated with the grid infrastructure, depending on event magnitude and asset vulnerabilities. A single realization of the seismic hazard (i.e., an initiating event) and its interaction with the power grid generates a failure scenario and repetition of the process produces a large set of scenarios owing to the random uncertainties inherent in asset vulnerability and ground motion at the site.

Hazard analysis produces site load curves conditional on the event and fragility analysis produces an asset's capacity curve. A comparison of event load to asset capacity from specific realization of these curves determines if an asset fails in response to the initiator. Repeating these steps for every asset in the power network generates a scenario vector that defines assets that have failed and the assets that survived the event. Formulation of scenarios in this manner reflects the probabilistic nature of grid response to an extreme event. We identified three options for addressing this complexity: (1) convolve both the load and capacity curves to get a conditional probability of failure and then go to option (2) or start with option (2) by performing a regular Monte Carlo simulation on the load and capacity curves separately, or option (3) use Monte Carlo simulation with a variance reduction scheme on the load and capacity curves separately. Options (1) and (2) lead to larger variance in the estimated consequences and require a large number of samples. We used Latin Hypercube Sampling techniques (Wyss and Jorgensen 1998) to implement option (3) as demonstrated by Shu and Jirutitijaroen (2011). Though fewer samples are needed, this scheme ensures all segments of the probability scale (0 to 1) are represented in the generated samples. Appendix E presents a more detailed description of use of this sampling technique for the test implementation.

The implementation of this element of the framework resulted in formulation of 200,000 scenarios (10 epicenters x 4 magnitudes per epicenter x 5,000 simulation iterations per initiator) similar to the single scenario illustrated in Table 2.1. In this example an earthquake of magnitude 8.45 at epicenter 3 resulted in failure of 45 assets (i.e., 15 transmission lines, 8 buses, and 22 transformers). Transmission lines were assumed to have failed if at least one of the transmission towers along the line failed due to the event. An additional illustrative set of scenarios developed using simulation methods is presented in Appendix D for reference.

Table 2.1. Example of Scenario for Initiating Event of Magnitude 8.45 at Epicenter 3

Epicenter	Scenario
3	L142, L143, L145, L150, L275, L276, L277, L278, L280, L281, L282, L290, L291, L296, L297, B80, B79, B14, B17, B22, B59, B92, B107, T4, T21, T32, T33, T34, T39, T40, T41, T45, T46, T49, T52, T53, T54, T55, T57, T62, T64, T65, T66, T69, T70

2.12 Generate and Map to Representative Scenarios

A sample of scenarios formulated using the simulation method described above showed us that our approach could generate duplicates scenarios. Such redundancies were grouped during implementation so that consequence and recovery models needed to be run only once per such identified group.

2.13 Exercise Grid/Infrastructure Models for Representative Scenarios

We identified three recognized methodologies to determine HILF event consequence: 1) use of topological graph models, 2) steady-state power-flow analysis, and 3) dynamic power-flow analysis. Any or a combination of the three methods can be used in an implementation of the framework. An important aspect to consequence analysis is identification of a consequence metric suitable to grid planners and other decision-makers who are using risk-informed models. At the transmission level of the power grid, unserved load over a specified period is a metric of interest; megawatt-hours of load shed has been recommended as a metric by some (Vaiman et al. 2012; Watson et al. 2014). From this metric, economic losses can be determined and cost-benefit analyses can be performed.

Cvijic and Ilic (2011) and Hines et al. (2010) explain the limitations of topological models in analyzing power system networks. One advantage of this technique is that it is immune to large asset losses in the network. According to the cited literature, power flow and consequential load estimates are unlikely to be accurate. However, Wegner (2014) subsequently compared network flow models for power grids with power-flow simulation models and showed that graph-theoretical electrical flow models perform well for comparisons. In Wegner’s work, losses were presented as load deviations in megawatt units. Variations of this technique appear to have found widespread acceptance in vulnerability modeling especially for interdependent critical infrastructure failure analysis (Holmgren 2006; Atkins et al. 2009; Poljanšek et al. 2012; Pagani and Aiello 2013).

Steady-state electrical power simulation tools (e.g., MATPOWER by Zimmerman et al. (2011)) analyze the network at a point in time and can rapidly perform power-flow calculations. For example, Pfitzner et al. (2011) used MATPOWER to solve for power flows associated with cascading outages in which one or two lines are initially tripped and then used heuristics to determine outages associated with further line loss to estimate the fraction of load not served. However, when large numbers of assets fail across widespread areas in response to the initiating event, these tools experience non-convergence issues even before the effect of cascading outages is addressed. For these types of scenarios, it is not clear whether the non-convergence is due to grid instability or mathematical intractability.

Dynamic contingency analysis tools (e.g., DCAT by Samaan et al. (2015)) are at the forefront of the state of the art for analyzing the evolution of a contingency and subsequent cascades that can result from an extreme event. Analysis using a dynamic contingency analysis tool involves incorporation of protection systems and operator intervention modeling. A steady-state simulation tool can be initially run to prescreen a list of initiators that potentially could lead to cascading failures. Using these tools, overloads and voltage deviations form the basis for scenario selection and further analysis to estimate load loss.

We used network graph techniques to implement our framework as these are suitable for long-term planning and do not require the complexity of models based on physics of power flow. The results of our consequence analysis do not necessarily reflect what real-world load losses would be or are not necessarily comparable with the results from power-flow models. In our model, buses (i.e., load, generation, and connectivity) were considered to be vertices, and transmission lines and transformer connectivity between buses were considered as undirected weighted edges. Weights of all edges were initially set to zero and then selectively assigned a value of 1.0 in the event of failure of a transmission line or transformer. Dijkstra’s algorithm (Cormen 2009) was used to determine if a load bus could at all be connected to any of the generation buses. In the case of a bus failure, all edges connected to the bus vertex were invalidated by assigning a value of 1.0. This scheme ensures that a path from a load bus to a generation bus, if one exists, has a path weight of zero. If no connectivity exists, the load was assumed to be unserved and to contribute to total consequences quantified for a scenario. Overloads and partial load curtailment were conservatively considered. The unserved load buses were identified and archived for restoration analysis.

The percentage contribution of generation assets to any given load was not modeled, although such models do exist as part of economic dispatch algorithms for deregulated markets (Ghasemi et al. 2003).

These models are partially closed-form as they intermittently rely on power-flow solutions to estimate contributions using sensitivity analysis.

An illustration of the consequence analysis is shown in Table 2.2. One realization of the simulation resulted in loss of 0.04 percent of the total servable load (283 GW) following an 8.45 magnitude earthquake at epicenter 3 and another 30 percent load loss associated with an earthquake of same magnitude at epicenter 7. Load buses potentially affected by the inability to secure generated energy are also shown in the Table 2.2. Note that these buses may not have physically failed but are unable to serve load because of lost assets that could connect them to generation buses.

Table 2.2. Illustration of Consequence Analysis for a Magnitude 8.45 Initiating Event

Epicenter	Scenario	Load Buses Affected	Load Loss (%)
3	L142, L143, L145, L150, L275, L276, L277, L278, L280, L281, L282, L290, L291, L296, L297, B80, B79, B14, B17, B22, B59, B92, B107, T4, T21, T32, T33, T34, T39, T40, T41, T45, T46, T49, T52, T53, T54, T55, T57, T62, T64, T65, T66, T69, T70	B78, B80, B79	0.04
7	L255, L266, L404, L406, L407, L408, L409, L410, L411, L412, L413, L414, L415, L416, L428, L429, L430, L431, L433, B136, B141, B25, B27, B96, T21, T22, T23, T24, T27, T29, T30, T32, T33, T39, T40, T41, T71, T74, T75, T76, T78, T79, T80	B136, B141	30

Random uncertainty (aleatory) exists in the consequence estimate (Figure 2.9). It is interesting to note that a loss of approximately 4.5 percent of the total load (283 GW) for more than 24 hours has a relative exceedance frequency of 6E-5, or approximately once in 1,600 years. Because uncertainty is associated with consequence for each initiating event, a total of 40 uncertainty distributions are associated with all considered initiating events. Figure 2.9 shows the expected value of scenarios grouped by similar consequences (unserved energy measured in GW hours) by summing the frequency of the scenarios in those groupings.

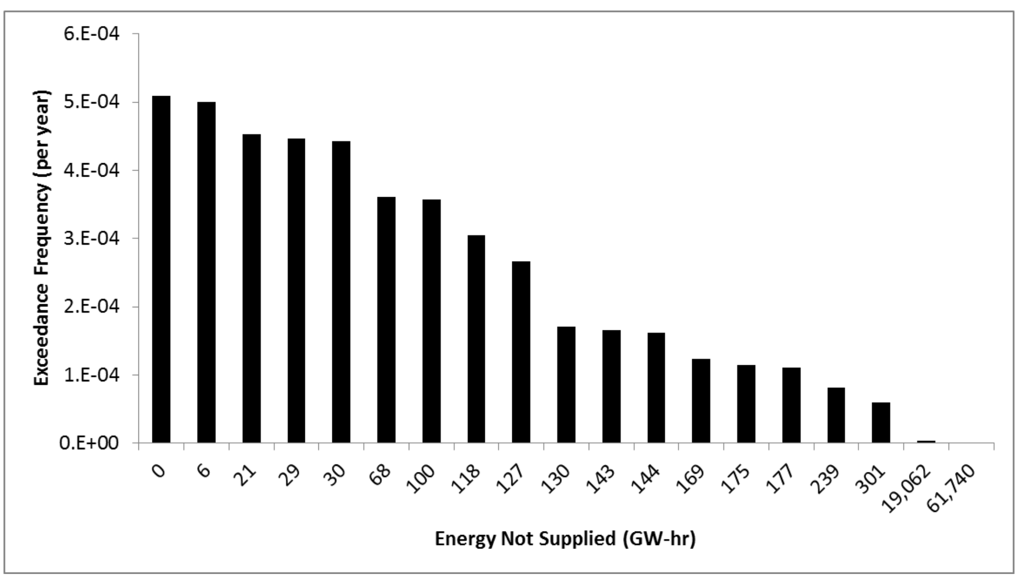


Figure 2.9. Energy Not Supplied (GW-hr) across Epicenters and Magnitudes

2.14 Characterize Asset Recovery Times

A realistic asset recovery model would account for logistics, spares, and crew availability. At the regional grid-planning level, restoration plans would reflect the post-event actions of various power system operators as presented in Appendix F. For the test implementation, we used a simplified model that assumed recovery times for a bus, a transformer, and transmission lines were 360, 768, and 72 hours, respectively (Salmeron et al. 2004). These time units were assigned as weights to edges of the network graph so that, for each disconnected load bus, the least weighted path represents the optimum combination of assets to be restored to reach a servable generator. (The least weighted path cannot be zero because a zero weight indicates that there is no need for restoration.) Repeating this process across all affected load buses helps identify the optimum restoration milestones.

The outcome of asset recovery and grid restoration models is to determine the following:

- time for restoration of an operational grid that serves all the load without necessarily restoring every failed asset
- identification, for each load bus disconnected from generation, of the assets—including generation assets—that restore the load in minimal time
- restoration milestones to partial load recovery and estimated time to reach those milestones
- identification of the minimum set of assets that need to be recovered for each scenario vector.

In addition to failed assets, load buses that were not entirely served were also tracked (e.g., "B81, B74") for each scenario. For each such affected load bus, Dijkstra's algorithms—based on repair time weights—were used to identify a functional generation bus and the minimal number of failed assets needed to be restored to get the load bus reconnected in the least amount of time. These recovery schemes were represented as "[B_L (A_i) B_G](t)(x%)," signifying assets A_i can be restored within *t* time units to connect load bus B_L with generation bus B_G and recover x% of total load lost in the network. Figure 2.10 illustrates this scheme. For each scenario and for each load bus affected in that scenario, a list of such "restoration schemes" was generated to return to 100 percent of the servable load in the network.

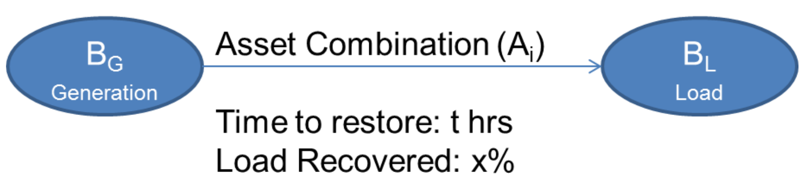


Figure 2.10. Minimal Asset Combinations to Recover to Connect a Pair of Generation and Load Buses.

Along with operational recovery of each load bus, a restoration curve was generated to track the amount of load recovered along with restoration time represented by "t1:x1%; t2:x2%; …tn:100%," signifying that by time t1, x1% of load was cumulatively recovered and so on. An example of such a generated restoration curve is "3:39%;4:78%;5:100%;."

Restoration of service can be enhanced by restoring load buses that rely on recovery of assets that are common to multiple load buses. These unique asset sets were identified and compiled across all restoration schemes for each scenario. The minimal set of assets that need to be recovered to recover a load bus are the same as the minimal set of failures that required to fail a load bus. The minimal set of asset failures required to fail a load bus are referred to here as “minimal scenarios.” We found that, in many cases, many more assets failed than required to fail a load bus. The total recovery time for each of these minimal recovery scenarios was considered to be the scenario recovery time.

Table 2.3 illustrates contrasting examples of restoration analysis on the scenarios presented in Table 2.2. For the first scenario, recovering two transformers (i.e., T66, T65) and a bus (i.e., B22) will enable connectivity between load bus B78 and generation bus B139. This recovery requires 1,896 hours and restores 77 percent of lost load due to the event. For the same scenario, recovery of buses B80 and B79 requires 720 hours and enables restoration of the rest of the lost load. Note that both these buses are generation buses and load buses. For example, bus B80 supports 47 MW of generation and 17 MW of load. The total expected restoration time is 2,616 hours. This assumes one repair crew per asset; however, that assumption can be modified to accommodate a planning entity’s restoration model. The restoration curve for this scenario indicates that by restoring each recovery path, the first 15 percent of the load can be recovered in 360 hours, followed by 23 percent recovery by 1,848 hours as shown in the “restoration curve” column of Table 2.3 and as visualized in Figure 2.11. The order in which restoration paths are selected is not prescribed in this model; although, crews working in parallel on each restoration path are recommended. If such a scheme is not feasible, the planner can risk-inform the order of restoration.

Table 2.3. Illustration of Restoration Analysis for a Magnitude 8.45 Initiating Event

Epicenter	Scenario	Load Loss (%)	Recovery Time (hrs)	Recovery Path	Restoration Curve (hrs:% restored)	Minimal Scenario
3	L142, L143, L145, L150, L275, L276, L277, …	0.04	2,616	[B78{T66,B22,T65,}B139] (1896)(77%) [B80{B80,}B80](360)(15%) [B79{B79,}B79](360)(8%)	360:15%; 1848:23%; 2616:100%	B80, T65, B22, B79, T66
7	L255,L266,L404,L406,L407, …	30	7,20	[B136{B136,}B136](360) (62%) [B141{B141,}B141](360) (38%)	360:38%; 720:100%	B141, B136

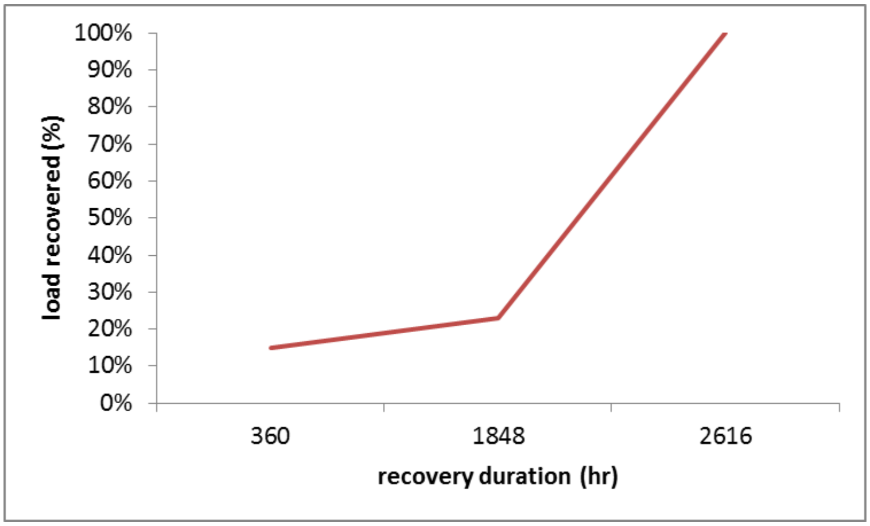


Figure 2.11. Snapshot of Recovery Curve for the Seismic Scenario in Table 2.3 (epicenter 3)

The recovery duration of the assets in this model is not assumed to be proportional to the capacity or nameplate rating of the asset. The restoration time is assumed to be proportional to the number of lost assets; however, this can be customized for a specific restoration model. In the second scenario provided in Table 2.2, only two assets (B136 and B141) are lost, but they contribute 30 percent load loss relative to the total load to be served.

2.15 Risk Integration

In this report, expected energy not supplied (Wang et al. 2010) is combined with the annual frequency of the initiating event occurrence (yr^{-1}) to produce a quantified risk estimate for a seismic event in terms of expected energy not supplied per year (MW-hours/yr).

It should be noted that the objective of this research has been to put the framework to test rather than an accurate quantification of risk. A total of 40 earthquakes with known frequencies were used as seismic initiating events (i.e., ten different epicenters each with four different magnitudes). These served as inputs to the U.S. Geological Survey GMM to characterize stressor transfer to the assets.

The risk integration approach, including the simulation scheme, is illustrated in Figure 2.12. Consideration of each initiating event resulted in as many ground motion exceedance probability curves as the number of unique asset locations conditional on the event occurrence. Similarly, asset fragility characterization resulted in as many fragility curves as the number of unique asset types conditional on ground motion. Latin Hypercube Sampling Monte Carlo sampling (see Appendix E) was used to sample from these curves, and a comparison of sampled values resulted in generation of a single scenario (e.g., L142,B22,…) for a given initiating event. Repeating the process for each initiating event considering various ten epicenters, four magnitudes and 5,000 simulated iterations per event resulted in the generation of 200,000 scenarios. The scenarios were subjected through a topological graph model of the test grid to estimate expected energy not supplied in the units of MW-hr after the estimation of expected consequences (MW) and restoration times (hours) associated with each initiating event. Together with event frequency from hazard characterization, initiating event risk was estimated. The evaluation of seismic risk to the test grid followed from the ensemble of initiating event risk estimates.

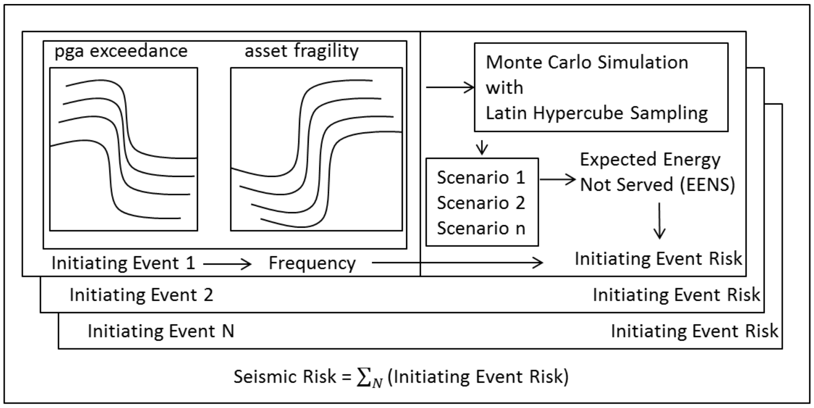
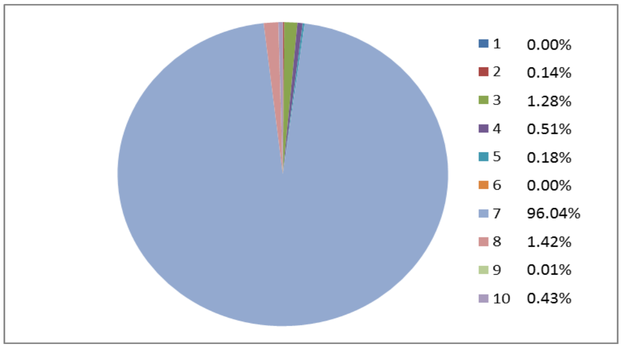
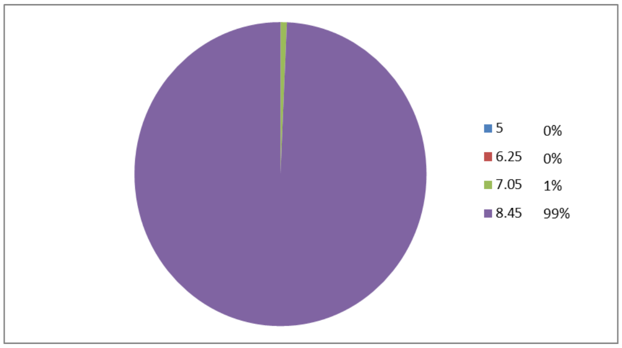


Figure 2.12. Simulation Scheme for Scenario Generation and Risk Integration

The expected seismic risk to the benchmark system was 25 MW-hr/yr with magnitude 8.45 earthquake around epicenter 7 being the primary driver. Contributions of seismic risk to the test grid as a function of earthquake epicenters and seismic moment magnitudes are shown in in Figure 2.13(a) and Figure 2.13(b), respectively. An earthquake of magnitude 8.45 at epicenter 7 was found to be the primary risk driver (96 percent of overall risk) affecting two load buses (B136 and B141) that serve nearly 37 percent of the total load. The number of load buses around epicenter 7 is less (mostly B136 and B141), but their generation and load carrying capacity is large (i.e., 86 GW of load, 90 GW of generation). The risk at epicenter 7 for magnitude 7.05 is 0 MW-hr/yr while being non-zero around other epicenters. This is because, for epicenter 7, the most vulnerable assets leading to load loss are B136 and B141, both of which are 100 KV buses that have a lower probability of failure. Around the other epicenters, there are relatively more assets that have the potential to experience load losses (e.g., transformer T65 around epicenter 2). Table 2.4 shows contributions across the top three risk drivers along with potential load buses that would be affected.



(a)



(b)

Figure 2.13. Seismic Risk to The Test Grid (a) at the Numbered Epicenter Locations across Earthquake Magnitudes (b) by Earthquake Magnitudes across all Epicenter Locations

Table 2.4. Top Three Contributing Epicenters with Risk and Affected Loads for an 8.45 Magnitude Earthquake

Epicenter	Risk (MW-hr/yr)	Load Buses Affected
7	238	B136, B141
3	3	B78, B80, B79
8	2	B81, B74, B101

A further drill-down provides risk insights into minimal asset failure combination scenarios (i.e., minimal set of asset failures required to fail a load bus) that contribute most across all initiating events. Scenario risk for these minimal scenarios was estimated as the expected value of energy not supplied weighted by the initiator frequency summed across all initiating events.

This scenario-level causal analysis, shown in Table 2.5, indicates that buses B136, B141, and failure combinations thereof account for 96 percent of the overall risk to the test grid. Some of the assets (e.g., T65 and B74) are affected across multiple scenarios. A comprehensive causal breakdown of risk drivers and their percentage contributions is presented in Appendix B. While analysis at this level identifies asset combinations contributing to the risk, risk insights described in the next section (Section 2.15) support decision-making through identification of specific assets that, when strengthened, can minimize overall risk to the test grid.

Table 2.5. Contribution from Minimal Scenarios across all Initiating Events (rounded for reporting)

Asset Failure Scenario	% Risk
B136	77
B141,B136	19
B74,L243,B73	0.9
B80,T65,B22,T66	0.5
T65,B22,T66	0.5
B80,T65,B22,B79,T66	0.5
B74,B73	0.5
T65	0.4
B51,B33	0.4
T65,B22,T66,L288	0.1
B51	0.1
B90,T65,T39	0.1
B101,L256,B74	0.04
T65,T66,L288	0.04
T65,B22	0.03
B74	0.01
B81	0.01
L243	0.002
L256	0.002

The challenge associated with the large number of scenarios and resource intensive computing of scenario consequence, restoration path generation (as well as asset importance which is discussed in the next section) were alleviated using high performance computing (HPC) machines at PNNL. However, the focus of this report is on trial implementation of the framework, and so the technical details of the HPC application are considered beyond the scope of this report.

2.16 Model Interrogation to Support Decision-Making

Although risk analysis will generate valuable information for power grid operators and emergency planners, decision-makers have only finite resources and cannot afford to strengthen all vulnerable power grid assets against every hazard. Hence, the value of an importance analysis lies in risk-ranking assets by quantifying the contribution of each asset across the many scenarios analyzed and hazards considered.

An importance analysis can be performed individually for each hazard, each initiating event, or broadly across all hazards.

For each of the power grid assets that failed at least once during the analysis, we re-ran the analysis under the assumption that the asset never failed. The percentage difference in the pre – and post-risk estimates reflect the risk reduction that can be achieved by ensuring that the asset never failed in the first place. Transmission and system state planners can use this kind of information to inform choices and develop strategies (e.g., developing spare reserve programs and establishing asset strengthening initiatives).

The analysis identified 21 assets where strategic resilience planning could reduce overall risk across the considered initiating events ranging between 88 percent and less than 1 percent. Of these, the top seven assets that potentially enable at least a 1 percent risk reduction are presented in Table 2.6. These assets include four buses, one transformer, and one transmission line. For example, if bus B136 never failed due to any of the seismic initiating events, the overall risk would have reduced by 88 percent. Risk-reduction measures such as use of flexible bus structures, installing base isolation devices for transformers, and use of alternative materials for transmission line support structures are among promising solutions to mitigate seismic risk to the power grid. Risk information could also be used to inform recovery and restoration plans including temporary restoration plans.

Table 2.6. Snapshot Results of Importance Analysis – % Risk Reduction Achieved (⩾1%)

Asset	B136	T65	B74	L256	B73	L243	B141
Risk Reduction Achieved (%)	88	6	4	2	2	1	1

A late challenge considered by the project team was consideration of whether the HILF event risk framework could be interrogated to support real-time or near-term risk decision-making, although the framework is designed to support mid – to long-term planning. The project team concluded that while the HILF event framework does not lend itself to use of real-time situational awareness obtained from telemetric data, archived real-world telemetry data could potentially be used as input to a HILF event risk framework model. If archived telemetric precursor data can be identified that indicates the possibility of an upcoming hazard event, then this information might be used together with the HILF event risk framework model to produce a near-prediction of risk. The precursor information would be used to update the frequency and severity of a hazard event. Certainly, however, whether such precursor information exists at all for most hazards and to what extent the HILF event risk framework would need to be adapted to incorporate its use.

3.0 Conclusions: Lessons Learned and Future Direction

This section discusses challenges and lessons learned in the test implementation of the HILF event risk framework, identifies prospective uses of this modeling framework by industry planning organizations, and suggests further development and implementation of the HILF event risk framework.

One of the primary challenges was integration of disparate model types, at a level of abstraction sufficient to serve the applications of the risk model. A number of assumptions were made across different models to reduce the overall modeling complexity to a level consistent with project objectives and available domain models. These simplifications are not considered to affect insights on the key question of the implementability of the risk framework. As more detailed models emerge and greater modeling resources become available, they can be incorporated into the framework. The critical aspect of the framework is considered to be the means by which it allows disparate modeling domains to be integrated to give risk-informed insights. Some simplifications include the following:

- Seismic initiating events were assumed to be point-source events rather than ruptures along the fault geometry.
- Seismicity induced hazards (e.g., tsunamis, liquefaction, landslides, and fires) were not addressed in the test application.
- Fragility distributions assumed that buses were rigid structures and transformers were not anchored.
- Secondary impacts resulting from the seismic event were not considered. Damage to a power grid asset caused indirectly by other damage (e.g., impact from uprooted trees on lines and other power grid assets) was not modeled.
- Topographic models of asset interdependences were used to approximate detailed power-flow models; therefore, grid instability due to imbalance in the physics of power flow was not modeled.
- Support infrastructure was assumed to be available and undisrupted following a HILF event. Though proprietary formats exist, a typical approach for defining an electrical power system network is use of the IEEE bus-branch common data format. IEEE bus-branch common data formats do not allow for the incorporation of a full set of grid assets and support infrastructure and are not as flexible as some proprietary models. Development of a comprehensive HILF event model would require customization and expansion of the IEEE model.

The challenge associated with the large number of scenarios and resource intensive computing of scenario consequence, restoration path generation and asset importance were alleviated using high performance computing (HPC) machines at PNNL. However, the focus of this report is on trial implementation of the framework, and so the technical details of the HPC application are considered beyond the scope of this report.

This analysis demonstrates the feasibility and value of the HILF event risk framework for assessing extreme event risk and informing decision-making for a test power grid vulnerable to seismic hazard, notwithstanding some of the challenges identified. The test implementation produced results that include the following:

- total power grid risk (i.e., expected energy not served) for the hazard considered
- power grid risk by initiating event category (i.e., range of seismic magnitudes at a set of epicenters)
- power grid risk by seismic magnitude
- power grid risk by seismic epicenter

- power grid risk by “minimal scenario” (i.e., minimal set of asset failures that are required to fail a load bus)
- importance of each asset according to its contribution to total power grid risk.

We found the model resulting from the framework to provide a broad inventory of risk insights that are likely to help decision-makers ensure that resources are expended where the greatest potential for risk reduction lies. Based on the current analysis, we anticipate applications of the models based on the HILF event framework to include the following:

- identification of risk-dominant failure scenarios and risk-dominant assets in support of transmission planning and improvement of grid resiliency
- identification of risk-dominant failure scenario information in support of state planning for multi-jurisdictional coordination
- development of risk-informed recovery and restoration options in support of emergency planning
- development of general and location-specific hazard risk in support of high-level resource allocation and planning

We contend that one of the greatest benefits of using the framework will be assessment of multiple hazards in a consistent manner. We note that although an individual hazard may represent a significant risk to the power grid for specific areas of the United States, for most areas more than one hazard is likely to pose significant threat to the grid. This creates complexities for grid and emergency response planners trying to sort out how to manage and allocate resources without comparable risk information integrated across completely different kinds of hazards. Once the framework is applied to multiple hazard categories, we anticipate a significant expansion of insights from the framework, allowing the relative risk-importance of disparate hazards to be assessed. This will allow decision-makers prioritize risk-management activities, ensuring that the dominant risk drivers are addressed first, and that measures that reduce impact across multiple hazard types can be identified and implemented.

Experience gained and insights generated from the test implementation provide a strategic roadmap for future research. The platform of models developed for implementation of the framework for the seismic hazard establishes a strong foundation for implementing HILF event risk framework across other hazards (e.g., geomagnetic disturbance and electromagnetic pulse events). Given that not all modeling associated with different hazards are at the same level of maturity, however, additional work is needed to test implementation of the HILF event risk framework across other hazards. The platform of models developed for implementation of the framework is also a good foundation for incorporating the consideration of the impact of HILF events on supporting infrastructure systems which was not addressed in the test implementation. Again, as with application of the framework to other hazards, enhancement of current work is needed to understand how the HILF event risk framework may need to be expanded or amended.

The following next steps are recommended:

- implementation of the framework for other hazard events including man-made HILF events and comparison of the relative risk across those hazards
- expansion of the framework to incorporate infrastructure support systems and indirect effects from the hazard event on power grid assets and support systems
- development of a complete decision-support system for multi-hazard risk assessment.

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Appendix A

Data Sources

Appendix A

Data Sources

Data sources used for the test implementation were identified and referenced throughout the report. However, this Appendix consolidates all the sources in Table A.1 for easy reference.

Table A.1. Data Sources used in the Report for HILF Power Grid Events Risk Assessment

Benchmark Power System Network	IEEE 145 bus Test System (Shah 2011)
Cascadia Subduction Zone Epicenter Catalog Recurrence Interval for Seismic Events along the Subduction Zone	Hanford probabilistic seismic hazard analysis Study (Coppersmith et al. 2013)
Fragility of Transformers, Buses and Transmission Towers	National Institute of Building Sciences (Eidinger and Ostrom 1994), Transmission Towers in South Korea (Park et al. 2015)
Probabilistic Seismic Hazard Analysis	OpenSHA open-source seismic hazard analysis tool (Field et al. 2003) Implementation of U.S. Geological Survey combined ground motion model (OpenSHA 2004)
Asset Recovery Times	Based on 1996 Reliability Test System (Salmeron et al. 2004)
Graph Visualization	Graphviz for network layout (Ellson et al. 2001)

Appendix B

Risk Estimates

Appendix B

Risk Estimates

The value of risk assessment for decision-making lies in a comprehensive causal analysis and identification of risk drivers. This appendix presents risk outcomes analyzed by asset combination scenarios, epicenters, magnitudes, and initiating events. The breakdown also is shown in terms of percentage of the overall risk aggregate of 24.7 MW-hr/yr to the test grid. Note that in some cases the percentage contribution may not add to 100 percent due to rounding for reporting.

Table B.1. Risk Estimates by Minimal Scenario

Epicenter	Minimal Scenario (Asset Combination)	Minimal Scenario Risk (MW-hr/yr)	Percent Contribution
1	B136	1.9E+01	77
2	B141, B136	4.7E+00	19
3	B74, L243, B73	2.2E-01	0.9
4	B80, T65, B22, T66	1.3E-01	0.5
5	T65, B22, T66	1.2E-01	0.5
6	B80, T65, B22, B79, T66	1.2E-01	0.5
7	B74, B73	1.1E-01	0.5
8	T65	1.0E-01	0.4
9	B51, B33	8.8E-02	0.4
10	T65, B22, T66, L288	2.7E-02	0.1
11	B51	1.8E-02	0.1
12	B90, T65, T39	1.4E-02	0.1
13	B101, L256, B74	1.1E-02	0.04
14	T65, T66, L288	1.1E-02	0.04
15	T65, B22	7.7E-03	0.03
16	B74	2.8E-03	0.01
17	B81	2.3E-03	0.01
18	L243,	4.5E-04	0.002
19	L256,	4.5E-04	0.002
		24.7	

Table B.2. Risk Estimates by Epicenter

Epicenter	Risk (MW-hr/yr)	Percent Contribution
1	0.0E+00	0.0
2	3.5E-02	0.1
3	3.2E-01	1.3
4	1.3E-01	0.5
5	4.4E-02	0.2
6	0.0E+00	0.0
7	2.4E+01	96.0
8	3.5E-01	1.4
9	2.3E-03	0.01
10	1.1E-01	0.4
	24.7	

Table B.3. Risk Estimates by Earthquake Magnitude

Epicenter	Magnitude	Risk (MW-hr/yr)	Percent Contribution
1	5	0.0E+00	0
2	6.25	0.0E+00	0
3	7.05	1.7E-01	0.7
4	8.45	2.5E+01	99.3
		24.7	

Table B.4. Risk Estimates by Initiating Event

Epicenter	Latitude	Longitude	Magnitude	Frequency (per year)	EENS[a] (MW)	Risk (MW-hr/yr)	Percent Contribution
7	46.533	-121.337	8.45	3.8E-04	61910.14	23.77349	96.0
3	47.065	-123.337	8.45	3.8E-04	737.7158	0.283283	1.1
8	47.065	-121.337	8.45	3.8E-04	551.0491	0.211603	0.9
8	47.065	-121.337	7.05	4.7E-04	294.1877	0.139151	0.6
4	47.513	-123.186	8.45	3.8E-04	328.5168	0.12615	0.5
10	47.979	-121.577	8.45	3.8E-04	271.0094	0.104068	0.4
5	47.979	-123.47	8.45	3.8E-04	115.7712	0.044456	0.2
2	46.533	-123.525	8.45	3.8E-04	90.17472	0.034627	0.1
3	47.065	-123.337	7.05	4.7E-04	68.352	0.03233	0.1
9	47.513	-121.379	8.45	3.8E-04	5.9184	0.002273	0.01
10	47.979	-121.577	7.05	4.7E-04	4.2084	0.001991	0.01
1	46.047	-123.915	5	4.7E-04	0	0	0
1	46.047	-123.915	6.25	4.7E-04	0	0	0
1	46.047	-123.915	7.05	4.7E-04	0	0	0
1	46.047	-123.915	8.45	3.8E-04	0	0	0

Table B.4. (contd)

Epicenter	Latitude	Longitude	Magnitude	Frequency (per year)	EENS[(a)] (MW)	Risk (MW-hr/yr)	Percent Contribution
2	46.533	-123.525	5	4.7E-04	0	0	0
2	46.533	-123.525	6.25	4.7E-04	0	0	0
2	46.533	-123.525	7.05	4.7E-04	0	0	0
3	47.065	-123.337	5	4.7E-04	0	0	0
3	47.065	-123.337	6.25	4.7E-04	0	0	0
4	47.513	-123.186	5	4.7E-04	0	0	0
4	47.513	-123.186	6.25	4.7E-04	0	0	0
4	47.513	-123.186	7.05	4.7E-04	0	0	0
5	47.979	-123.47	5	4.7E-04	0	0	0
5	47.979	-123.47	6.25	4.7E-04	0	0	0
5	47.979	-123.47	7.05	4.7E-04	0	0	0
6	46.047	-122.422	5	4.7E-04	0	0	0
6	46.047	-122.422	6.25	4.7E-04	0	0	0
6	46.047	-122.422	7.05	4.7E-04	0	0	0
6	46.047	-122.422	8.45	3.8E-04	0	0	0
7	46.533	-121.337	5	4.7E-04	0	0	0
7	46.533	-121.337	6.25	4.7E-04	0	0	0
7	46.533	-121.337	7.05	4.7E-04	0	0	0
8	47.065	-121.337	5	4.7E-04	0	0	0
8	47.065	-121.337	6.25	4.7E-04	0	0	0
9	47.513	-121.379	5	4.7E-04	0	0	0
9	47.513	-121.379	6.25	4.7E-04	0	0	0
9	47.513	-121.379	7.05	4.7E-04	0	0	0
10	47.979	-121.577	5	4.7E-04	0	0	0
10	47.979	-121.577	6.25	4.7E-04	0	0	0
						24.7	

(a) EENS = expected energy not supplied

Appendix C

Test System Assets

Appendix C

Test System Assets

The IEEE 145 bus system assets and their characteristics are outlined in Table C.1 through Table C.4. Buses and transformers assumed to be located at the same substation share the same geographic coordinates. Identification of assets used a nomenclature where unique number was prefixed with 'B' for buses, 'T' for transformers, 'W' for towers, and 'L' for transmission lines. Transformer connectivity between buses was also assigned a unique label under the category of branches for identification purposes.

Table C.1. Bus Details

No.	Bus Identification	Load(MW)	Generation(MW)	Base KV	Asset Group
1	B1	0	0	500	6
2	B2	0	0	500	1
3	B3	0	0	25.7	6
4	B4	0	0	25.7	6
5	B5	0	0	25.7	6
6	B6	0	0	500	16
7	B7	0	0	500	3
8	B8	0	0	100	3
9	B9	0	0	500	4
10	B10	0	0	500	5
11	B11	0	0	100	4
12	B12	0	0	500	7
13	B13	0	0	100	7
14	B14	0	0	500	8
15	B15	0	0	100	8
16	B16	0	0	100	8
17	B17	0	0	500	9
18	B18	0	0	100	9
19	B19	0	0	100	9
20	B20	0	0	100	9
21	B21	0	0	100	9
22	B22	0	0	500	10
23	B23	0	0	100	10
24	B24	0	0	500	11
25	B25	0	0	500	12
26	B26	0	0	100	12
27	B27	0	0	500	13
28	B28	0	0	100	13
29	B29	0	0	100	13
30	B30	0	0	100	10
31	B31	0	0	100	12
32	B32	0	0	100	5
33	B33	0	0	220	6
34	B34	45.05	0	220	17
35	B35	49.19	0	220	18
36	B36	0	0	220	14
37	B37	0	0	220	15
38	B38	0	0	220	19
39	B39	0	0	220	20
40	B40	0	0	220	21
41	B41	0	0	100	22
42	B42	0	0	100	23

Table C.1. (contd.)

No.	Bus Identification	Load(MW)	Generation(MW)	Base KV	Asset Group
43	B43	0	0	220	24
44	B44	0	0	220	25
45	B45	0	0	220	26
46	B46	0	0	220	27
47	B47	0	0	100	28
48	B48	0	0	100	29
49	B49	0	0	220	30
50	B50	0	0	220	31
51	B51	58.45	0	220	32
52	B52	0	0	100	33
53	B53	0	0	100	34
54	B54	0	0	100	35
55	B55	0	0	100	36
56	B56	0	0	100	37
57	B57	0	0	100	38
58	B58	76.3	0	100	8
59	B59	0	0	100	9
60	B60	0	51	100	39
61	B61	0	0	220	2
62	B62	0	0	100	2
63	B63	0	0	100	40
64	B64	0	0	100	41
65	B65	0	0	100	42
66	B66	102.2	0	100	3
67	B67	0	1486	100	43
68	B68	0	0	100	44
69	B69	0	0	100	5
70	B70	0	0	100	45
71	B71	0	0	100	46
72	B72	0	0	100	7
73	B73	0	0	100	12
74	B74	81.9	0	100	12
75	B75	0	0	100	13
76	B76	0	0	100	11
77	B77	0	0	100	11
78	B78	89	0	100	10
79	B79	9.1	250.2	100	47
80	B80	17.1	47	100	48
81	B81	82.2	0	100	49
82	B82	2.1	70	100	50
83	B83	0	0	100	10
84	B84	24.3	0	100	51
85	B85	27.4	0	100	52
86	B86	0	0	100	2
87	B87	0	0	100	15
88	B88	69	0	100	53
89	B89	0.6	673	100	54
90	B90	4.6	22	100	55
91	B91	0	64	100	56
92	B92	0	0	100	57
93	B93	100.4	700	18.5	6
94	B94	15.4	300	100	58
95	B95	6.7	131	100	59
96	B96	0	60	100	60
97	B97	0	140	100	61
98	B98	0	426	100	62
99	B99	10.46	200	18	14
100	B100	0	170	100	63
101	B101	17.8	310.9	100	64

Table C.1. (contd.)

No.	Bus Identification	Load(MW)	Generation(MW)	Base KV	Asset Group
102	B102	37.6	2040	100	65
103	B103	0	135	100	66
104	B104	30.2	2000	100	3
105	B105	96	1620	100	67
106	B106	64	1080	100	68
107	B107	-17.5	0	100	69
108	B108	0	800	100	70
109	B109	0	52	100	71
110	B110	100.4	700	18.5	6
111	B111	60.4	2000	100	72
112	B112	18.6	300	100	73
113	B113	0	0	24	1
114	B114	0	0	24	1
115	B115	683.5	2493	100	74
116	B116	792.6	2713	100	75
117	B117	485.3	2627	100	76
118	B118	651.9	4220	100	77
119	B119	2094	8954	100	78
120	B120	-408	0	100	79
121	B121	237.7	2997	100	80
122	B122	29.2	1009	100	81
123	B123	-84	0	100	82
124	B124	94.1	3005	100	83
125	B125	-712	0	100	84
126	B126	-333	0	100	85
127	B127	-546	0	100	86
128	B128	4075	12963	100	87
129	B129	-482	0	100	88
130	B130	4328	5937	100	89
131	B131	21840	28300	100	90
132	B132	491.9	3095	100	91
133	B133	-83	0	100	92
134	B134	22309	20626	100	93
135	B135	4298	5982	100	94
136	B136	52951	51950	100	95
137	B137	12946	12068	100	96
138	B138	-363	0	100	97
139	B139	57718	56834	100	98
140	B140	24775	23123	100	99
141	B141	32799	37911	100	100
142	B142	17737	24449	100	101
143	B143	4672	5254	100	102
144	B144	9602	11397	100	103
145	B145	9173	14118.62	100	104

Table C.2. Branch Details

No.	Branch ID	Bus From	Bus To
1	L1	B1	B2
2	L2	B1	B2
3	L3	B1	B3
4	L4	B1	B4
5	L5	B1	B5
6	L6	B1	B6
7	L7	B1	B33
8	L8	B1	B93
9	L9	B1	B93
10	L10	B2	B6
11	L11	B2	B113
12	L12	B2	B114
13	L13	B3	B33
14	L14	B4	B33
15	L15	B5	B33
16	L16	B6	B7
17	L17	B6	B9
18	L18	B6	B10
19	L19	B6	B12
20	L20	B6	B12
21	L21	B7	B8
22	L22	B7	B66
23	L23	B7	B104
24	L24	B7	B104
25	L25	B8	B66
26	L26	B8	B66
27	L27	B9	B11
28	L28	B9	B69
29	L29	B10	B32
30	L30	B10	B69
31	L31	B11	B69
32	L32	B12	B13
33	L33	B12	B13
34	L34	B12	B13
35	L35	B12	B14
36	L36	B12	B14
37	L37	B12	B25
38	L38	B12	B25
39	L39	B12	B72
40	L40	B12	B72
41	L41	B12	B72
42	L42	B13	B72
43	L43	B13	B72
44	L44	B13	B72
45	L45	B14	B15
46	L46	B14	B16
47	L47	B14	B17
48	L48	B14	B17
49	L49	B14	B58
50	L50	B15	B58
51	L51	B16	B58
52	L52	B17	B18
53	L53	B17	B19
54	L54	B17	B20
55	L55	B17	B21
56	L56	B17	B22
57	L57	B17	B59
58	L58	B18	B59
59	L59	B19	B59
60	L60	B20	B59
61	L61	B21	B59
62	L62	B22	B23
63	L63	B22	B24
64	L64	B22	B30
65	L65	B22	B78
66	L66	B22	B83
67	L67	B23	B83
68	L68	B23	B83
69	L69	B24	B76
70	L70	B24	B77
71	L71	B25	B26
72	L72	B25	B27
73	L73	B25	B27
74	L74	B25	B31
75	L75	B25	B73
76	L76	B25	B74
77	L77	B26	B73
78	L78	B27	B28
79	L79	B27	B29
80	L80	B27	B75
81	L81	B28	B75
82	L82	B29	B75
83	L83	B30	B78
84	L84	B31	B74
85	L85	B32	B69
86	L86	B33	B34
87	L87	B33	B35
88	L88	B33	B37
89	L89	B33	B38
90	L90	B33	B39
91	L91	B33	B40
92	L92	B33	B49
93	L93	B33	B50
94	L94	B33	B110
95	L95	B33	B110
96	L96	B34	B36
97	L97	B36	B99
98	L98	B37	B87
99	L99	B37	B88
100	L100	B38	B88
101	L101	B39	B43
102	L102	B39	B84
103	L103	B40	B44
104	L104	B40	B84
105	L105	B41	B42
106	L106	B41	B43
107	L107	B42	B44
108	L108	B43	B46
109	L109	B44	B45
110	L110	B45	B61
111	L111	B45	B85
112	L112	B46	B61
113	L113	B46	B85
114	L114	B47	B48
115	L115	B47	B50
116	L116	B47	B87
117	L117	B48	B49
118	L118	B48	B87
119	L119	B49	B51
120	L120	B50	B51
121	L121	B51	B52
122	L122	B51	B53
123	L123	B51	B56
124	L124	B51	B57
125	L125	B52	B53
126	L126	B52	B54
127	L127	B53	B55
128	L128	B54	B55
129	L129	B54	B61
130	L130	B55	B61
131	L131	B56	B57
132	L132	B56	B58
133	L133	B57	B58
134	L134	B58	B59
135	L135	B58	B72
136	L136	B58	B87
137	L137	B58	B98
138	L138	B58	B100
139	L139	B58	B103
140	L140	B59	B60
141	L141	B59	B72
142	L142	B59	B79
143	L143	B59	B80
144	L144	B59	B89
145	L145	B59	B92
146	L146	B59	B94
147	L147	B59	B98
148	L148	B59	B100
149	L149	B59	B103
150	L150	B59	B107
151	L151	B60	B135
152	L152	B60	B79
153	L153	B60	B80
154	L154	B60	B90
155	L155	B60	B92
156	L156	B60	B94
157	L157	B60	B95
158	L158	B60	B138
159	L159	B61	B62
160	L160	B61	B62
161	L161	B61	B63
162	L162	B61	B63
163	L163	B61	B64
164	L164	B61	B65
165	L165	B61	B86
166	L166	B61	B86
167	L167	B61	B86
168	L168	B62	B86

No.	Branch ID	Bus From	Bus To
169	L169	B62	B86
170	L170	B63	B64
171	L171	B63	B65
172	L172	B63	B66
173	L173	B63	B67
174	L174	B63	B69
175	L175	B63	B102
176	L176	B63	B102
177	L177	B63	B102
178	L178	B63	B102
179	L179	B63	B116
180	L180	B63	B117
181	L181	B63	B118
182	L182	B63	B124
183	L183	B64	B65
184	L184	B64	B66
185	L185	B64	B67
186	L186	B64	B69
187	L187	B64	B97
188	L188	B64	B124
189	L189	B65	B66
190	L190	B65	B67
191	L191	B65	B69
192	L192	B65	B97
193	L193	B65	B124
194	L194	B66	B67
195	L195	B66	B68
196	L196	B66	B69
197	L197	B66	B97
198	L198	B66	B111
199	L199	B66	B111
200	L200	B66	B111
201	L201	B66	B111
202	L202	B66	B124
203	L203	B67	B68
204	L204	B67	B69
205	L205	B67	B97
206	L206	B67	B119
207	L207	B67	B120
208	L208	B67	B121
209	L209	B67	B122
210	L210	B67	B124
211	L211	B67	B125
212	L212	B67	B132
213	L213	B68	B69
214	L214	B69	B70
215	L215	B69	B71
216	L216	B69	B72
217	L217	B69	B73
218	L218	B69	B74
219	L219	B69	B97
220	L220	B69	B101
221	L221	B69	B112
222	L222	B69	B124
223	L223	B70	B71
224	L224	B70	B72
225	L225	B70	B73
226	L226	B70	B74
227	L227	B70	B101
228	L228	B70	B112
229	L229	B71	B72
230	L230	B71	B73
231	L231	B71	B74
232	L232	B71	B101
233	L233	B71	B112
234	L234	B72	B73
235	L235	B72	B74
236	L236	B72	B98
237	L237	B72	B100
238	L238	B72	B101
239	L239	B72	B103
240	L240	B72	B112
241	L241	B73	B74
242	L242	B73	B75
243	L243	B73	B81
244	L244	B73	B82
245	L245	B73	B91
246	L246	B73	B96
247	L247	B73	B101
248	L248	B73	B105
249	L249	B73	B105
250	L250	B73	B105
251	L251	B73	B108
252	L252	B73	B109
253	L253	B73	B112
254	L254	B73	B121
255	L255	B74	B75
256	L256	B74	B81
257	L257	B74	B82
258	L258	B74	B91
259	L259	B74	B96
260	L260	B74	B101
261	L261	B74	B106
262	L262	B74	B106
263	L263	B74	B108
264	L264	B74	B109
265	L265	B74	B112
266	L266	B74	B121
267	L267	B75	B82
268	L268	B75	B91
269	L269	B75	B96
270	L270	B75	B108
271	L271	B75	B109
272	L272	B75	B121
273	L273	B76	B77
274	L274	B76	B89
275	L275	B79	B80
276	L276	B79	B90
277	L277	B79	B92
278	L278	B79	B94
279	L279	B79	B95
280	L280	B79	B107
281	L281	B80	B90
282	L282	B80	B92
283	L283	B80	B94
284	L284	B82	B91
285	L285	B82	B108
286	L286	B82	B109
287	L287	B82	B121
288	L288	B83	B89
289	L289	B89	B103
290	L290	B90	B92
291	L291	B90	B94
292	L292	B91	B96
293	L293	B91	B108
294	L294	B91	B109
295	L295	B91	B121
296	L296	B92	B94
297	L297	B92	B107
298	L298	B94	B95
299	L299	B94	B138
300	L300	B95	B138
301	L301	B96	B108
302	L302	B97	B124
303	L303	B98	B100
304	L304	B98	B103
305	L305	B100	B103
306	L306	B101	B112
307	L307	B102	B117
308	L308	B102	B118
309	L309	B108	B109
310	L310	B108	B121
311	L311	B109	B121
312	L312	B115	B116
313	L313	B115	B117
314	L314	B115	B118
315	L315	B115	B143
316	L316	B116	B117
317	L317	B116	B118
318	L318	B116	B143
319	L319	B117	B118
320	L320	B117	B143
321	L321	B118	B131
322	L322	B118	B132
323	L323	B118	B143
324	L324	B119	B120
325	L325	B119	B121
326	L326	B119	B122
327	L327	B119	B124
328	L328	B119	B125
329	L329	B119	B126
330	L330	B119	B127
331	L331	B119	B128
332	L332	B119	B129
333	L333	B119	B130
334	L334	B119	B131
335	L335	B119	B132
336	L336	B119	B144
337	L337	B120	B121
338	L338	B120	B122
339	L339	B120	B123
340	L340	B120	B124
341	L341	B120	B125
342	L342	B120	B127
343	L343	B120	B128
344	L344	B120	B129
345	L345	B120	B130
346	L346	B120	B131
347	L347	B120	B132
348	L348	B121	B122

No.	Branch ID	Bus From	Bus To
349	L349	B121	B123
350	L350	B121	B124
351	L351	B121	B125
352	L352	B121	B127
353	L353	B121	B128
354	L354	B121	B129
355	L355	B121	B131
356	L356	B121	B132
357	L357	B122	B123
358	L358	B122	B124
359	L359	B122	B125
360	L360	B122	B131
361	L361	B122	B132
362	L362	B122	B133
363	L363	B122	B143
364	L364	B123	B124
365	L365	B123	B125
366	L366	B123	B131
367	L367	B123	B132
368	L368	B124	B125
369	L369	B124	B128
370	L370	B124	B131
371	L371	B124	B132
372	L372	B124	B133
373	L373	B124	B143
374	L374	B125	B127
375	L375	B125	B128
376	L376	B125	B129
377	L377	B125	B130
378	L378	B125	B131
379	L379	B125	B132
380	L380	B127	B128
381	L381	B127	B129
382	L382	B128	B129
383	L383	B128	B130
384	L384	B128	B131
385	L385	B130	B131
386	L386	B130	B132
387	L387	B130	B144
388	L388	B131	B132
389	L389	B131	B133
390	L390	B131	B143
391	L391	B131	B144
392	L392	B132	B133
393	L393	B132	B143
394	L394	B132	B144
395	L395	B133	B143
396	L396	B134	B131
397	L397	B134	B136
398	L398	B134	B139
399	L399	B134	B141
400	L400	B134	B142
401	L401	B134	B144
402	L402	B134	B145
403	L403	B135	B95
404	L404	B135	B136
405	L405	B135	B138
406	L406	B135	B141
407	L407	B136	B115
408	L408	B136	B116
409	L409	B136	B117
410	L410	B136	B118
411	L411	B136	B138
412	L412	B136	B139
413	L413	B136	B140
414	L414	B136	B141
415	L415	B136	B142
416	L416	B136	B143
417	L417	B136	B145
418	L418	B137	B139
419	L419	B137	B140
420	L420	B137	B145
421	L421	B139	B140
422	L422	B139	B141
423	L423	B139	B142
424	L424	B139	B145
425	L425	B140	B145
426	L426	B141	B115
427	L427	B141	B116
428	L428	B141	B117
429	L429	B141	B118
430	L430	B141	B131
431	L431	B141	B132
432	L432	B141	B142
433	L433	B141	B143
434	L434	B141	B144
435	L435	B141	B145
436	L436	B142	B115
437	L437	B142	B116
438	L438	B142	B117
439	L439	B142	B118
440	L440	B142	B119
441	L441	B142	B120
442	L442	B142	B122
443	L443	B142	B124
444	L444	B142	B125
445	L445	B142	B130
446	L446	B142	B131
447	L447	B142	B132
448	L448	B142	B133
449	L449	B142	B143
450	L450	B142	B144
451	L451	B142	B145
452	L452	B143	B144
453	L453	B144	B145

Table C.3. Transformer Details

No.	Transformer ID	Branch ID	Bus From	Bus To
1	T3	L3	B1	B3
2	T4	L4	B1	B4
3	T5	L5	B1	B5
4	T7	L7	B1	B33
5	T8	L8	B1	B93
6	T9	L9	B1	B93
7	T11	L11	B2	B113
8	T12	L12	B2	B114
9	T21	L21	B7	B8
10	T22	L22	B7	B66
11	T23	L23	B7	B104
12	T24	L24	B7	B104
13	T27	L27	B9	B11
14	T28	L28	B9	B69
15	T29	L29	B10	B32
16	T30	L30	B10	B69
17	T32	L32	B12	B13
18	T33	L33	B12	B13
19	T34	L34	B12	B13
20	T39	L39	B12	B72
21	T40	L40	B12	B72
22	T41	L41	B12	B72
23	T45	L45	B14	B15
24	T46	L46	B14	B16
25	T49	L49	B14	B58
26	T52	L52	B17	B18
27	T53	L53	B17	B19
28	T54	L54	B17	B20
29	T55	L55	B17	B21
30	T57	L57	B17	B59
31	T62	L62	B22	B23
32	T64	L64	B22	B30
33	T65	L65	B22	B78
34	T66	L66	B22	B83
35	T69	L69	B24	B76
36	T70	L70	B24	B77
37	T71	L71	B25	B26
38	T74	L74	B25	B31
39	T75	L75	B25	B73
40	T76	L76	B25	B74
41	T78	L78	B27	B28
42	T79	L79	B27	B29
43	T80	L80	B27	B75
44	T94	L94	B33	B110
45	T95	L95	B33	B110
46	T97	L97	B36	B99
47	T98	L98	B37	B87
48	T159	L159	B61	B62
49	T160	L160	B61	B62
50	T165	L165	B61	B86
51	T166	L166	B61	B86
52	T167	L167	B61	B86

Table C.4. Assumed Geographic Locations

Asset Group ID	Latitude	Longitude
1	47.94951	-121.253
2	47.52826	-120.152
3	47.23269	-120.508
4	47.48632	-120.873
5	47.2133	-120.927
6	48.22266	-121.272
7	47.35773	-121.985
8	47.64399	-122.523
9	47.19883	-122.977
10	47.27198	-123.771
11	47.3702	-124.2
12	47.05628	-121.399
13	46.81551	-121.205
14	48.9	-121.345
15	48.12528	-122.202
16	47.63307	-121.162
17	48.61186	-121.308
18	48.49871	-121.177
19	48.47933	-121.681
20	48.36288	-120.372
21	48.41264	-120.503
22	48.44993	-119.08
23	48.53988	-119.327
24	48.25135	-119.594
25	48.31513	-119.774
26	47.94047	-119.748
27	47.89316	-119.624
28	48.3424	-122.504
29	48.37865	-122.328
30	48.34641	-121.78
31	48.30912	-121.923
32	48.10357	-121.726
33	48.02628	-121.055
34	48.07817	-120.933
35	47.81905	-120.499
36	47.86105	-120.349
37	47.951	-122.39
38	47.91546	-122.253
39	46.81098	-122.848
40	47.00038	-120.574
41	47.1618	-120.246
42	47.17725	-120.383
43	46.93376	-120.316
44	47.20497	-120.21
45	47.3165	-121.471
46	47.26002	-121.452
47	46.89512	-123.226
48	46.94526	-123.37
49	47.2767	-121.221
50	46.9379	-121.014

Asset Group ID	Latitude	Longitude
51	48.59855	-120.239
52	48.01866	-119.196
53	48.43603	-122.203
54	47.35941	-123.556
55	46.79237	-123.446
56	46.88174	-121.206
57	46.97382	-123.232
58	46.84271	-123.003
59	46.65719	-122.807
60	46.85641	-121.652
61	47.0818	-120.363
62	47.44354	-122.678
63	47.40387	-122.625
64	47.21311	-121.598
65	46.79295	-120.731
66	47.41957	-122.86
67	47.06597	-122.047
68	46.95605	-122.021
69	47.06074	-123.566
70	46.84316	-121.345
71	46.87929	-121.034
72	47.34422	-119.804
73	47.26965	-121.59
74	46.4252	-120.881
75	46.61537	-120.91
76	46.65635	-120.909
77	46.62962	-120.77
78	46.60754	-120.059
79	46.66423	-120.166
80	46.78481	-120.554
81	46.68052	-120.32
82	46.65557	-120.026
83	46.84762	-120.373
84	46.7052	-120.127
85	46.40703	-119.396
86	46.65816	-119.765
87	46.69609	-119.931
88	46.74662	-119.787
89	46.48548	-120.033
90	46.55716	-120.388
91	46.61976	-120.409
92	46.54091	-120.181
93	46.3265	-120.738
94	46.5562	-122.05
95	46.44382	-121.29
96	46	-121.005
97	46.60609	-122.35
98	46.23785	-121.011
99	46.1313	-121.259

Appendix D

Illustrative Scenarios

Appendix D

Illustrative Scenarios

Example scenarios were illustrated in Table 2.1, Table 2.2, and Table 2.3. In this appendix a few more illustrative scenarios are presented representative of each epicenter resulting in maximum load loss. Recovery path, formatted as [B_L (A_i) B_G](t)(x%), signifies that load B_L can be connected to generation B_G if assets A_i are recovered. The effort is anticipated to recover x% of the load within an expected *t* hours. A restoration curve represented by "t_l:x1%; t_2:x2%; … t_n:x100%" signifying that by time t_1:x1% of the load was cumulatively recovered and so on. The minimal scenario represents a minimal subset of the documented scenario whose recovery functionally restores the grid.

Tables D.1and D.2 provide data for magnitude 8.45 and 7.05earthquake scenarios, respectively. Note that these tables do not provide any risk insights; however, they do allow for formulation of scenarios, and consequence and restoration time estimates. From the samples listed here, magnitude 7.05 earthquakes result in fewer asset failures and consequences relative to those of magnitude 8.45 earthquakes.

Epicenter numbers in the tables refers to one of the numbered locations on the map shown in Figure 2.3. Scenario represents a sample member of a population of asset failure combinations presented as a comma separated list of asset identification numbers. The assets can be identified by their prefixes – B: Bus, T: Transformer, L: Branch. The asset characteristics are detailed in Table C.1 through Table C.4. Load loss refers to the amount (MW) of interruption in the demand due to loss of assets following a HILF event. The corresponding duration is captured under the Recover Time column. Load buses that may potentially lose connectivity with all generation assets are listed under 'Load Buses Affected.' Restoration time is the time to operationally recover the dysfunctional grid.

Table D.1. Scenarios Arising from Magnitude 8.45 Earthquake Originating at Each Epicenter Location Resulting in Maximum Load Loss

Epicenter	Scenario	Load Loss (GW)	Load Buses Affected	Restoration Time (hr)	Restoration Path	Restoration Curve	Minimal Scenario
1	T55,	0					
2	B90, T39, T45, T46, T52, T53, T54, T55, T57, T62, T64, T65, T66, T69, T70, T71, T74,	93.6	B78, B90,	1896	[B78{T39, T65, }B139](1536)(95%); [B90{B90, }B90](360)(5%);	360:5%; 1128:100%;	B90, T65, T39,
3	L142, L143, L145, L150, L275, L276, L277, L278, L280, L281, L282, L290, L291, L296, L297, B80, B79, B14, B17, B22, B59, B92, B107, T4, T21, T32, T33, T34, T39, T40, T41, T45, T46, T49, T52, T53, T54, T55, T57, T62, T64, T65, T66, T69, T70,	115	B78, B80, B79,	2616	[B78{T66, B22, T65, }B139](1896)(77%); [B80{B80, }B80](360)(15%); [B79{B79, }B79](360)(8%);	360:15%; 1848:23%; 2616:100%;	B80, T65, B22, B79, T66,
4	L63, L288, L289, B14, B17, B24, T5, T32, T33, T34, T39, T40, T41, T45, T46, T49, T52, T53, T54, T55, T57, T62, T64, T65, T66, T69, T70, T71, T98,	89	B78,	1608	[B78{L288, T66, T65, }B139](1608)(100%);	1608:100%;	T65, T66, L288,
5	B14, B22, T12, T34, T45, T46, T49, T52, T53, T54, T55, T57, T62, T64, T65, T66, T69, T70, T98,	89	B78,	1896	[B78{T66, B22, T65, }B139](1896)(100%);	1896:100%;	T65, B22, T66,
6	T41, T55, T57, T78, T80,	0					
7	L255, L266, L404, L406, L407, L408, L409, L410, L411, L412, L413, L414, L415, L416, L428, L429, L430, L431, L433, B136, B141, B25, B27, B96, T21, T22, T23, T24, T27, T29, T30, T32, T33, T39, T40, T41, T71, T74, T75, T76, T78, T79, T80,	85750	B136, B141,	720	[B136{B136, }B136](360)(62%); [B141{B141, }B141](360)(38%);	360:38%; 720:100%;	B141, B136,

Table D.1. (contd)

Epicenter	Scenario	Load Loss (GW)	Load Buses Affected	Restoration Time (hr)	Restoration Path	Restoration Curve	Minimal Scenario
8	L72, L73, L214, L215, L217, L218, L219, L220, L225, L226, L229, L230, L231, L235, L242, L243, L244, L245, L246, L247, L248, L249, L250, L251, L252, L253, L254, L255, L256, L257, L258, L259, L260, L261, L262, L263, L264, L265, L292, L293, L426, B74, B101, B6, B7, B9, B10, B12, B25, B26, B27, B31, B71, B73, B91, B108, B109, T3, T5, T11, T12, T21, T22, T23, T24, T27, T28, T29, T30, T32, T33, T34, T39, T40, T41, T45, T49, T52, T55, T57, T71, T74, T75, T76, T78, T79, T80, T94, T166,	182	B81, B74, B101,	792	[B81{B74, L256, }B139](432)(90%); [B74{B74, }B139](360)(45%); [B101{B101, }B101](360)(10%);	360:10%; 792:100%;	B101, L256, B74,
9	L6, L20, L37, L223, L224, L225, L226, L227, L229, L234, L235, L240, L243, L253, L265, B81, B2, B6, B7, B9, B10, B12, B14, B25, B69, B70, B71, T3, T4, T5, T7, T8, T9, T11, T12, T21, T22, T23, T24, T27, T28, T29, T30, T32, T33, T34, T39, T40, T41, T45, T46, T49, T54, T57, T62, T71, T74, T75, T76, T78, T79, T80, T95, T159, T160, T165, T166, T167,	82	B81,	360	[B81{B81, }B139](360)(100%);	360:100%;	B81,
10	L35, L36, B51, B1, B2, B6, B9, B10, B14, B33, B37, B49, B50, B87, B113, B114, T3, T4, T5, T7, T8, T9, T11, T12, T22, T24, T27, T28, T29, T30, T32, T34, T39, T40, T41, T45, T46, T49, T52, T57, T75, T76, T94, T95, T98, T159, T166,	177	B88, B51, B35,	720	[B88{B33, }B139](360)(67%); [B51{B51, }B139](360)(33%); [B35{B33, }B139](360)(67%);	360:33%; 720:100%;	B51, B33,

Table D.2. Scenarios Arising from Magnitude 7.05 Earthquake Originating at Each Epicenter Location Resulting in Maximum Load Loss

Epicenter	Scenario	Load Loss (GW)	Load Buses Affected	Restoration Time (hr)	Restoration Path	Restoration Curve	Minimal Scenario
1		0					
2		0					
3	L150, L281, B17, T52, T53, T54, T55, T57, T62, T64, T65, T66,	89	B78,	768	[B78{T65,}B139](768)(100%);	768:100%;	T65,
4	T46, T52, T53, T54, T55, T57, T62, T65,	0					
5		0					
6		0					
7	L404, L406, B27, T76, T78, T79, T80,	0					
8	L217, L218, L243, L246, L250, L251, L256, L259, L261, L263, B74, B10, B25, B26, B27, B31, B73, T29, T30, T41, T71, T74, T75, T76, T78, T79, T80,	164	B81, B74,	792	[B81{B73, L243, }B139](432)(50%); [B74{B74, }B139](360)(50%);	360:50%; 792:100%;	B74, L243, B73,
9	L225, B6, T11, T28, T30, T34, T41, T71, T75,	0					
10	B51, B2, T3, T4, T5, T7, T8, T9, T11, T12, T94, T95,	58	B51,	360	[B51{B51, }B139](360)(100%);	360:100%;	B51,

Appendix E

Latin Hypercube Sampling

Appendix E

Latin Hypercube Sampling

This appendix uses Latin Hypercube Sampling to sample ground motion parameter from load curves (resulting from ground motion attenuation models (Section 2.10)) and ground motion parameter from capacity curves (generated from asset fragility distributions [Section 2.9]). If the sampled ground motion from a load curve is larger than that from capacity curve for an asset, the asset is assumed to have failed.

The sampling scheme is described in this appendix. Ground motion attenuation models produce a ground motion probability exceedance curve that is a complementary cumulative distribution function. Let the associated cumulative distribution function be $g(X=x)$ at an asset's site. Here, X is the ground motion random variable whose exceedance we seek to characterize probabilistically. Similarly, let the cumulative distribution function associated with an asset's fragility be $f(Y=y)$. Here Y is the ground motion random variable for which we seek to characterize an asset's fragility. The inverse of the cumulative distribution function, both being site specific, are represented as g^{-1} and f^{-1} and yield the ground motion given a probability value. Let there be M asset locations and N assets.

The scenario generation method for a single initiating event and single iteration of the simulation is described here. The process must be repeated for all the other initiating events (40 initiators considered in the implementation) and iterations (K = 5000 iterations considered in the implementation). The probability scale (0 to 1) is stratified at equal intervals, say 10% (K = 10) as seen in 'Strata' column of Table E.1. For each asset site, the ground motion at that site is sampled by taking the g^{-1} of a probability value generated from the corresponding strata. The result of this step is a matrix of sampled ground motion values dimensioned by the asset site and strata as seen in the table. The load curve is the same for a given column (e.g., under site L_1 in the table) and differs from location to location (e.g., L_1 to L_2). Similarly, each asset's fragility distribution is sampled. As before, the fragility curve is the same for a given asset (e.g., under asset A_1 in the table) and differs from asset to asset (e.g., A_1 to A_2).

Table E.1. Latin Hypercube Sampling Scheme for Scenario Generation for a Single Initiating Event

		Load (pga) at site (L_i) given the earthquake				Asset A_i's capacity (pga) given its fragility			
#	Strata	L_1	L_2	…	L_M	A_1	A_2	…	A_N
1	0%-10%	$g^{-1}(p_{11})$	$g^{-1}(p_{21})$	…	$g^{-1}(p_{M1})$	$f^{-1}(q_{11})$	$f^{-1}(q_{21})$	…	$f^{-1}(q_{M1})$
2	10%-20%	$g^{-1}(p_{12})$	$g^{-1}(p_{22})$	…	$g^{-1}(p_{M2})$	$f^{-1}(q_{12})$	$f^{-1}(q_{22})$	…	$f^{-1}(q_{M2})$
…	…	…	…			…	…	…	…
10	90%-100%	$g^{-1}(p_{1K})$	$g^{-1}(p_{2K})$	…	$g^{-1}(p_{MK})$	$f^{-1}(q_{1K})$	$f^{-1}(q_{2K})$	…	$f^{-1}(q_{NK})$

After the matrix of sampled load and capacity curves is set up, each column of the sampled matrices is randomly shuffled so potential correlation is avoided through the comparison of sampled values originating from the same strata. From the modified matrix and using the new indices, if $g^{-1}(p_{ij}) > f^{-1}(q_{ij})$ then the asset A_i is considered failed. The vector of failed assets is considered a failure scenario.

Appendix F

Power System Restoration Planning Guidelines

Appendix F

Power System Restoration Planning Guidelines

To support examination of how implementation of the HILF event risk framework might be used by grid planners, industry planning activity information associated with extreme events were examined. North American Electric Reliability Corporation (NERC) standards require utilities to plan for extreme bulk electric system events resulting in multiple power system assets failing or cascading out of service. Planning events in the NERC standard include the following (NERC 2014):

- significant generation and load loss in a widespread area
- an unstable grid
- circumstances requiring multi-jurisdictional coordination.

Analysis of these events requires consideration of the loss of multiple redundancies (i.e., *N-k* contingency situations). A recent report on power resilience and restoration planning highlighted the need to identify the important concerns and needs after extreme events such as black starts, tie-lines, and supervisory control and data acquisition (FERC-NERC 2016).

The National Association of Regulatory Utility Commissioners defines resilience as the "… robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event" (Keogh and Cody 2013). Along similar lines, the National Infrastructure Advisory Council has defined infrastructure resilience as "… the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event" (Berkeley Iii and Wallace 2010).

In practice, successful grid restoration post-HILF consists of the following equally important basic steps (Goodrich 2015):

- restoration of generation
- energization of transmission lines and
- gradual addition of loads while maintaining grid stability.

Restoration of generation involves identifying, choosing, and activating one or more designated black-start generators given the situational complexities. Transmission line restoration depends on the number of support towers lost and length of the line affected. The entire grid should be gradually restored in isolated islands to begin with, followed by gradual connectivity across regions so that balance is maintained between generation and consumption. These considerations, while significantly beyond the scope of the test implementation, highlight their importance for a realistic energy restoration model. Nonetheless, given the appropriate enhancements in the power grid model, test implementation appears to indicate that, although implementation was performed using assumed restoration and recovery plans for the test bed power grid, the same kind of results could be produced using local-, utility-, and state-specific plans. The restoration plans of various power system operators are presented in this appendix.

F.1 PJM Regional Transmission Organization (PJM 2016)

The PJM Restoration Plan required by NERC Emergency Preparedness and Operations Standards focuses on response to conditions following a disturbance or blackout:

1. Perform a system assessment to determine extent of outage
2. Start black-start units to form islands
3. Build cranking paths to other generating units, nuclear stations and critical gas facilities
4. Restore critical load as defined in Attachment A
5. Synchronize and interconnect islands to form larger islands
6. Connect to outside areas
7. Return to normal operations.

F.2 Ontario Power System Restoration Plan (IESO 2016)

The Ontario Power System Restoration Plan proposes an execution strategy that reflects certain priorities:

1. Restore grid-supplied power to all nuclear sites
2. Restore grid-supplied power to critical power system loads at transmission and generation facilities – to supply station service to allow restoration to proceed
3. Restore grid-supplied power to critical power system loads fed from distributors – to supply telecommunications within their distribution systems needed to facilitate restoration
4. Restore loads needed to control voltage and reload generation units
5. Synchronize islands to each other and the broader Interconnection.

F.3 Midcontinent Independent System Operator (MISO) Power System Restoration Plan (MISO 2015)

The MISO System Restoration Plan conforms to NERC Emergency Preparedness and Operations Standards with the following documented priorities:

1. During the restoration process, the MISO Reliability Coordinator and Transmission Operators will develop restoration strategies with the priority of restoring the integrity of the interconnection.
2. The Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.
3. Restoration priority shall be given to the station supply of power plants and the transmission system (critical substations and inter-ties). These priorities are outlined in Transmission Operator plans.
4. Cranking power to neighboring power plants shall have a priority over restoring internal customer load in a Balancing Authority Area (once sufficient load is established in an island).
5. Customer load shall be restored as generation and transmission equipment becomes available, recognizing that load and generation must remain in balance at normal frequency as the bulk electric system is restored.

Appendix G

Peer Review Comments and Response

Appendix G

Peer Review Comments and Response

This appendix presents comments on the report from three external reviewers: an electrical power grid educator, a senior reliability engineer at NERC, and a former high-level manager at NERC who was the lead author for NERC/DOE report (i.e., High-Impact, Low-Frequency Event Risk to the North American Bulk Power System) cited in this report. While changes were made to the report in light of the comments, the reviewers' insights largely provide focus for future implementation and development of the framework and highlight technical challenges that the authors should keep in mind. Overall, the feedback is extremely helpful. The following presents three sets of review comments along with the author's interpretation of how they will help guide the path forward.

G.1 Comments from Professor Thomas Overbye, Ph.D., power and energy system researcher at the University of Illinois at Urbana-Champaign

Overall I found the report to be a quite useful discussion of an implementation of a framework for the consideration of power system high-impact, low frequency events (HILFs). In this case the report focused on quantifying the impact of earthquakes on the Pacific Northwest grid. The framework, which is nicely summarized in Figure 1.1, seems to be complete. The Chapter 1 descriptions of the framework are rather short, but they are further clarified by the case study provided in Chapter 2. Perhaps a sentence in Section 1.2, letting the reader known additional details are provided in Chapter 2, would be helpful. One issue between Section 1.2.1 and Section 2.1 (Study Initiation) is Section 1.2.1 says to "identify the intended audience for the risk information" yet the audience for the case study is not described. However, overall I found the report provided a good description of the framework, with sufficient detail that a researcher interested in the area (such as myself) could implement the framework. Actually I'm quite looking forward to the publication of the final report so I can utilize this framework in some of my research!

One issue with the report is the load and generation used in the IEEE 145 bus system given in Appendix C were puzzling. I recognize that the report is just intended to be a trial implementation, but still the load and generation values are very unusual. On page 2.2 the system is said to contain 2.83 GW of load, which seems reasonable. However, this does not match the sum of the values shown in Appendix C. For example, a load value of 52.951 GW and a generation value 51.950 GW are given just for bus 136. This is extremely high, especially with a base voltage of 100 kV. Having 96% of the system load at two buses is quite unrealistic. These values should be checked. Obviously the framework could be used with any system, but using such an unrealistic system detracts from what is otherwise a quite useful report. It would also be helpful to include the branch impedance and limit values in Table C.2 (or provide a link to an electronic version of the case) so that others can duplicate the results. Since it is indicated on page 2.2 that the 145 bus system was chosen because of the availability of dynamic test data, it would be useful if the report also provided that data (though it could be included in future work since it isn't used here).

In addition, the reviewer also provided several helpful editorial remarks, grammatical corrections, and identification of typos that are not included here, but were helpful in improving the report.

Authors' Response

The authors appreciate that the reviewer is interested in utilizing the framework in his own research.

As per the reviewer's suggestion, a note was added at the end of Section 1.3 to point out that framework elements are further clarified through the case study in Section 2.0.

The authors agree with the reviewer's comment that intended audience has not been stated as part of following the framework guidelines during the implementation process. In response to the comment, the following was added to Section 2.1: "The intended audience for this study is assumed to be transmission planners and emergency planners interested in maintaining a resilient grid infrastructure against impacts from major seismic events."

The authors thank the reviewer and acknowledge the typo on page 2.2 regarding the total load. It has been revised to be read as 283 GW (same as that stated in the Executive Summary). The sum of load values in Appendix C match that same quantity.

In response to the reviewer's comment to provide a link to the electronic version of the 145-bus power system case along with branch and impedance limits, the authors have provided a link to the original case for download in the bibliography and cited the same in Section 2.1. Dynamic data (not used in this report) is also available at the linked location.

In response to the reviewer's comment regarding concentration of system load at two buses, the authors would like to point out that while it is true that 96 percent of the total risk is concentrated around B136 and B141 given the seismic initiator, the system load clustered around these buses is not more than 40 percent. Moreover, it is worth noting from the developers of the test case (Vittal et al. 1992), and with reference to Shah (2011), that the 145-bus system is modeled around an actual power system.

G.2 Comments from Mike Assante, Consultant and Former Vice President and Chief Security Officer at NERC

1. Page iii – You might want to reference the U.S. Department of Energy/NERC "High-Impact, Low-Frequency Event Risk to the North American Bulk Power System" report.

2. Page iii – You might add a sentence to simply introduce hazard-induced events that have the potential to reach levels of high risk.

3. Page iii – You might also introduce the concept that the event would be profiled by not only area and duration but also the type of response necessary to achieve material restoration of the system.

4. Page iii – Inability to service load. This perspective is certainly a delivery one, but work and collaborations with large integrated utilities has favored 'inability to service load' as the primary measure in non-generation evaluations. A generation-centric view will often focus on the ability to meet contingency reserve levels and straight loss of the ability to supply for some period of time.

5. Page v – Model fidelity, confidence, and the associated data quality are key factors. Physic-models can achieve higher degrees of accuracy but the undermining factor is often the quality of the data associated with both locational data and asset specific information necessary to calculate potential damage curves.

6. Page v – I would assume that newer components with shorter histories associated with specific hazards results in less understanding or data for failure models. An example would be well studied effects on substation bus structures vice newer wind turbine farms, etc.

7. Page v – The terminology is not exclusively associated with probabilistic risk and some HILFs do not involve traditional probabilistic risk hazards. Please consider removing the reference to solely probabilistic risk.

8. Page v – You might footnote the accident sequence with a definition and descriptive example

9. Page v – I believe you should discuss the uncertainty that arises from a collection of initiating events over time—your seismic example includes actual shocks, tremors, and after shocks. The problem is that damage is accumulative and the profile begins to shift from the better known modeled effects of a single shock (hence your reference to the distribution of seismic events) and has to be averaged for the potential after shock tremors over some range of time. Each real earthquake is different in its shock profile for example. This introduces more uncertainty in the damage caused in the tail of the event. You might simply mention that as an accuracy of the damage falls in an acceptable range for

your study. You could avoid this is restoration and recovery were not a part of the study – but a restoration profile will absolutely be impacted by the events in that tail.

10. Page v – and increase the resilience? You might plan for the ability to absorb the damage and erect temporary structures the aid in a quick restoration. An example is the wood and rope/pulley structures used for transmission towers in Peru.

11. Page v – You might note that the restoration time to recover does not take into account secondary consequences that would challenge things like vehicle traffic making it to the substation to begin restoration operations.

12. Page viii – This is loss of non-serviceable load yes? That is load where paths do not exists or sufficient supply is not available. We intentionally lose load based on larger system conditions and events—meaning some of the load lost may not be dependent on the initiated consequences over time but due to logic implemented into protective relays and the manifestation of the condition on the system at the time of the event. It might not be worth calling that out.

13. Page ix – I agree here. It is the element you are able to measure. The actual risk will have other more difficult to measure factors involved. The scope also did not include the potential loss of structures housing control equipment for example.

14. Page 1.2 – All looks good here – should you include a description of assets types that fell outside your scope with the caveat that they too can have an effect on the outage and its restoration?

15. Page 1.4 – Good (as it pertains to the statement "That study pointed out the difficulty of estimating the impact on the power grid from a large number of failed assets given that current cascading simulation tools are deterministic.")

16. Page 2.1 – This hazard lends itself as a probabilistic risk

17. Page 2.2 – I suspect the reader will understand that fragility distributions mean a real world given event may have greater damage profiles for specific real-world assets.

18. Page 2.2 – Did the overlay take into account existing real world load clusters? to distribute the assets and get the proper densities for assets?

19. Page 2.4 – I would be interested in this and our ability to consider the value of a wireless link in a substation over conduit contained wires

20. Page 2.4 – Good to call this out and you might mention damage that may occur from secondary effects is out of scope – although that is mostly implied here. Things like flooding of a substation due to loss of a water containment structure nearby, etc.

21. Page 2.4 – I assume later you characterize damage modeled by asset type although this is direct only as you are using fragility curves – for example out of scope could be the uprooting of trees forcing loss of actual lines or faults.

22. Page 2.4 – Should you include a characterization of the total damage incurred in historic earthquakes specifically calling out damage to assets not considered and damage not accounted for?

23. Page 2.9 – Good section (concerning the advantages and limitation of modeling power grid networks using topographical models.)

24. Page 2.9 – Thank you mentioning this (as it pertains to the difficulty of estimating the impact on the power grid from a large number of failed assets given that current cascading simulation tools are deterministic.)

25. Page 2.9 – Agree it is optimal for system planning and less optimal for operations/restoration plan development.

26. Page 2.11 – Makes sense for the study but results in exceptions when translating into the real world—especially when damage to restoration dependent infrastructure also occurs—for example the availability of heavy equipment and ability to move that equipment to the site.

27. Page 2.11 – Very good approach (as pertaining to the approach of identifying minimal asset combinations to recover load busses.)

28. Page 2.15 – This is a key point! Also, do we have predictive attributes that can aid in quick identification of new construction assets that would fall into this category so that capital plans can be designed to meet these hardening requirements early in the project scoping process?

29. Page 2.15 – This seems buried and might help the paper if it is moved up into the summary section.

30. Page 2.16 – I think could would have to be followed by additional caveats here.

31. Page 3.2 – Agree (as pertaining to the statement in the report: "We found the model from the framework to provide a broad inventory of risk insights that are likely to help decision-makers ensure that resources are expended where the greatest potential for risk reduction lies.")

32. There is an opportunity to refer to the NERC/DOE HILF report (High-Impact, Low-Frequency Event Risk to the North American Bulk Power System) and the NERC Severe Impact Resilience Task Force (SIRTF) report (Severe Impact Resilience: Considerations and Recommendations). I think the SIRTF report could be used to provide the type of planning needs that can be supported. Each report carried with it recommendations to include enhancing models – you should link your work to that so DOE can take some credit helping out.

Authors' Response

The authors appreciate Mr. Assante's insightful comments as they helped improve the report and will provide substantial value in helping future implementation of the framework.

1. The report referred to by the reviewer was cited in the original HILF event framework document (PNNL-24673), but the authors agree that it is appropriate to cite this important work on HILF event impact to the electrical power grid in the current document, so we have added it to Section 1.1.

2. The authors added two examples of HILF events to the Abstract per the reviewer's suggestion.

3. The authors believe that reference to "subsequent recovery" in the cited sentence is adequate for this description.

4. The authors agree with the comment and recognize that the consequence measure of a HILF event is dependent on the interest and perspectives of the stakeholders. The framework can be implemented to address different stakeholder concerns by defining the consequences of interest.

5. The authors agree that model fidelity, uncertainty, and data quality are key considerations for modeling HILF events.

6. The authors agree that there will be less failure data for certain equipment, particularly new equipment such as the wind turbines, as cited by the reviewer.

7. The authors acknowledge that the term "initiating event" is not necessarily exclusive to Probabilistic Risk Assessment (PRA). However, PRA assigns a specific meaning to this term, and treatment of initiating events for this project aligns with that definition.

8. As suggested by the reviewer, the authors added a definition of accident sequence. "An accident sequence is representation in terms of an initiating event followed by a sequence of events - failures (such as component or system failures) or successes and events - that lead to an undesired consequence with a specified end-state" to the Executive Summary and to Section 2.0.

9. The authors agree with, and are appreciative of, the reviewer's observation that seismic events are not necessarily singular events but can involve aftershocks which have the effect of creating more cumulative damage. Acknowledgement of this possibility was added to Section 2.10.

10. The authors agree that risk information could be used not only to reduce component vulnerability but also inform recovery and restoration plan including temporary responses. This acknowledgement was added to Section 2.16. Acknowledgement that risk information could be used to increase power grid resiliency (as well reduce vulnerability) was added to the Executive Summary.

11. The authors agree that the current modeling did not take into account secondary effects such as the impact from increased vehicle traffic. Section 2.4 of the report explicitly discusses the limitation of the current effort in not addressing supporting infrastructure. The authors' aspiration to expand the modeling to address supporting infrastructure is identified in Section 3.0.

12. The authors agree that in an actual event some load lost may be caused by protection systems rather than damage from the initiating event. Advanced modeling involving physics of power flow and response of protection systems can be incorporated using dynamic power grid simulation tools such as dynamic contingency analysis tools (e.g., DCAT) as discussed in Section 2.13 of the report.

13. The authors agree with the comment and, similar to Comment #4, recognize that the consequence measure of a HILF event is dependent on the interest and perspectives of the stakeholders. The authors' aspiration to expand the modeling to address supporting infrastructure (e.g., structures hosting control equipment) is identified in Section 3.0.

14. Section 1.2.2 of the report explains that, per the framework, critical power grid infrastructure asset types relevant to the application scope must be identified. Critical assets actually modeled in the implementation model are identified in Section 2.2 of the report.

15. The reviewer agrees with the statement in the report about the difficulty of estimating the impact on the power grid from a large number of failed assets given that current cascading simulation tools are deterministic.

16. The authors agree that there is a probabilistic nature to hazard events that is fundamental to assessing their risks.

17. The reviewer agrees with the statement in the report about the need to probabilistically characterize asset fragility. Given the real-world uncertainties, there will be deviations in actual damage compared to the assumed damage profiles. For a thorough analysis, an asset's specific fragility should be evaluated.

18. The trial implementation was not intended to mimic any real world load clusters to avoid generation or dissemination of classified information.

19. The authors agree that when the model is expanded to consider support infrastructure that the impact of wireless links and other forms of transmitting control signal to and within substations should be considered. A 'what-if' scenario analysis of HILF scenarios using the model is a way to compare the risk of wired vs. wireless links.

20. The authors agree with the reviewer's concern about the limitations of the current modeling to address secondary effects and this comment in the response to Comment #21 below.

21. The authors agree with the reviewer's observation that damage to a power grid asset can be caused indirectly by other damage (secondary effects) such as impact from uprooted trees on lines or other power grid assets. Acknowledgement of this limitation in the current modeling was added to the discussion in Sections 2.5 and Section 3.0.

22. The authors agree that characterization of total damage from historic hazard events could provide information about impacts not currently modeled that should be modeled and will keep this suggestion in mind for future efforts. The authors added acknowledgement in the report of the need to consider secondary effects in response to Comment #21.

23. The reviewer agrees with the discussion in the report about the advantages and limitation of modeling power grid networks using topographical models.

24. The reviewer agrees with the discussion in the report about the difficulty of estimating the impact on the power grid from a large number of failed assets given that current cascading simulation tools are deterministic.

25. The authors agree with the reviewer's comment that modeling of the power grid using a topographical model is more suitable for long term planning and less optimal for informing operations and restoration, and believe that this view is reflected in Section 2.13 of the report.

26. The authors agree with reviewer's comment that impacts from the event to supporting infrastructure can affect the ability of responders to restore the power grid. Again, Section 2.4 of the report explicitly discusses the limitation of the current effort in not addressing supporting infrastructure. The author's aspiration to expand the modeling to address supporting infrastructure is identified in Section 3.0.

27. The reviewer agrees with the discussion in the report about the approach taken by the authors to identify minimal asset combinations to recover load busses.

28. Section 3.0 of the report states that one of the significant insights gained from implementing the framework is determination of the "importance of each asset according to its contribution to total

power grid risk" and "identification of risk-dominant assets in support of transmission planning and improvement of grid resiliency." The authors agree that this information should be of great value to grid and response planners. The HILF event risk framework supports 'What if' scenario risk analysis which can aid in analyzing sensitivity to incorporation of new construction assets into an existing network.

29. The authors' response to this comment is the same as to Comment #28 above.

30. The authors agree with the reviewer's comments and added further qualifications to statements about the potential use of telemetric precursor data associated with historic extreme events to update the frequency and severity of a hazard event assessed using the framework.

31. The reviewer agreed with the statement in the report: "We found the model from the framework to provide a broad inventory of risk insights that are likely to help decision-makers ensure that resources are expended where the greatest potential for risk reduction lies."

32. The DOE/NERC report referred to by the reviewer was cited in the original HILF event framework document (PNNL-24673), but the authors agree that it is appropriate to cite this important work on HILF event impact to the electrical power grid in the current document; thus, the authors added it to Section 1.1. The authors also added a citation in Section 2.4 of the current report to the NERC SIRTF report concerning infrastructure that the bulk power system relies on.

G.3 Comments from Noha Abdel-Karim, Ph.D., Senior Reliability Assessment Engineer at NERC

1. Page viii – A helpful metric used at NERC is the LOLH/year. Could also show a loss of load in MW/yr if available or as a percent LOL. Providing explanation in regard using a severity scale on how impact LOL to grid reliability.

2. Page viii – Is it a better place here to discuss asset types; vulnerability to risks (i.e., type of buses, loading factors, generation types if any and interconnection level. How much loss of load they cause and its probability and duration)

3. Page ix – A suggestion to improve the readability and the level of understanding of this chart is to split into three horizontal bar charts with thresholds top, medium and low risks grouping ranges.

4. Page ix – This is an important phrase and I would to put in the front section of the exec. summary. Can add examples such as floods, fires to modeling extra externalities.

5. Page 2.8 – More explanation will help the reader gets why they don't provide risk insights

6. Page 2.4 – First time in the report to mention grid stability.

In addition the reviewer also provided editorial remarks, grammatical corrections, and identification of typos that are not included here, but were helpful in improving the report.

Authors' Response

1. The authors agree with the reviewer that loss of load hours (LOLH) is a useful metric for power system generation resource adequacy planners. This has been added to, and acknowledged in, Section 2.0.

2. The authors agree with the reviewer that assessment of the vulnerability of asset types at interconnection level would be very useful for HILF event planners. Of course, the test system used for the trial implementation was defined only for a region (the Pacific Northwest) of the Western interconnection.

3. In response to the reviewer comment regarding readability of Figure ES.5, the authors have replaced the figure with failure scenario risk contribution table (Table ES.1) for better readability.

4. The authors are grateful for, and agree with the reviewer's comment stating that the following is important and needs to be highlighted: "framework for the seismic hazard establishes a good foundation to implement HILF event risk framework across other hazards."

5. The authors agree with the reviewer that "do not yet provide risk insights" is ambiguous. The sentence has been revised. Appendix D is only a subset of the 200,000 scenarios formulated whose synthesis provides risk insights. Aggregated risk output is provided in Appendix B.

6. The authors concur with the reviewer that grid stability is a critical aspect post-event requiring highlighted attention. The use of advanced power system simulation tools such as DCAT will help analyze grid stability.

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