PNNL-29985

Pacific Northwest NATIONAL LABORATORY

Risk-Based Dynamic Contingency Analysis Applied to Puerto Rico Electric Infrastructure

Phase II Report

May 2020

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Executive Summary

The U.S. Department of Energy's (DOE) Office of Electricity and Office of Energy Efficiency & Renewable Energy have funded DOE National Laboratories to perform modeling, analysis, and high-level design of resilience-enhancement options for the power grid of the Commonwealth of Puerto Rico. The Pacific Northwest National Laboratory (PNNL) is one of the national laboratories contributing to the DOE effort. Under this funding, PNNL completed Phase I of their analysis in 2018 [17], which identified high-priority transmission enhancements derived from detailed dynamic cascading analysis of severe contingencies, including a hurricane scenario example. This report describes additional analysis completed under Phase II, which was performed over 2019. The PNNL team applied decades of experience making complex power systems more resilient, reliable, secure, flexible, affordable and sustainable, with partners in government and industry.

In this report, PNNL presents the Phase II analysis, in which a risk-based dynamic contingency analysis approach to evaluate impact of several hurricane scenarios was developed. This approach was used to identify high-priority enhancements and test resilience mitigation actions, including the evaluation of high-solar scenarios developed as a result of the 2019 Puerto Rico Integrated Resource Plan (IRP).

The risk-based dynamic contingency analysis approach developed in this report consists of methodologically linking the following three tools developed at DOE national laboratories:

- Argonne National Laboratory's (ANL) Hurricane Electrical Assessment Damage Outage Tool (HEADOUT)
- PNNL's Electrical Grid Resilience and Assessment System (EGRASS) tool
- PNNL's Dynamic Contingency Analysis Tool (DCAT) – DCAT uses the PSS®E commercial tool as a solution engine, which allows for the use of trusted industry datasets and models

Output data from ANL's HEADOUT was used to create hurricane-related outage scenarios, with probabilities of failure of each electricity asset for a given hurricane event, derived from assets' fragility characteristics. PNNL's EGRASS tool was used to define outage sequences and enable sensitivity studies to obtain a larger or smaller number of assets affected. PNNL's DCAT was improved to analyze hurricane contingencies. This Puerto Rico project has served as one of the main motivations to develop new DCAT capabilities. Software requirements and use cases for testing were provided for modelling hurricane outage sequences automatically in DCAT, as well as for development of new DCAT Analytics, Visualization, and Data Management for processing results.

A new Monte Carlo probabilistic method has been implemented to calculate risk using probabilistic information at two levels:

- Overall probability of occurrence of a hurricane event of a given intensity
- Probability of failure of individual assets for a given hurricane event.

Seven scenarios were studied with ten Monte Carlo realizations of each scenario, and one scenario with twenty realizations, totaling 80 hurricane simulations for this part of the analysis. Each Monte Carlo realization represents a variation of hurricane Maria or Irma. The Monte Carlo approach was used to probabilistically determine many sequences of potential hurricane contingency scenarios. These scenarios are then run in DCAT in order to identify the elements and sequence of elements which, when lost, most compromise the power system. Simultaneously, this probabilistic approach also provides insight into the likelihood of specific element failures. Mitigation strategies and specific system reinforcements that improve resiliency can then be better identified and prioritized based on the results.

Resilience metrics and results analysis of the probabilistic method have been implemented in the new DCAT Analytics, Visualization, and Data Management capabilities.

It is important to highlight that the different tools have been linked from a methodological point of view, and not using a co-simulation software where all tools work together automatically. Instead, this work has focused on methodology improvements and tool improvements to be used within the framework.

The framework can be used to evaluate several hurricane event scenarios in a detailed power system model and identify high-priority grid enhancements and test mitigation actions. The framework has been used to evaluate system performance for a total of 119 hurricane simulations, composed of a total of about 800 contingency sets. Simulations included variations of hurricanes Irma and Maria applied to 15 system configurations, including scenarios for dynamic control settings and corrective actions. In addition, a total of 80 Monte Carlo simulations were run for seven scenarios of study. The framework has been applied to power system model scenarios from the 2019 IRP, 2019 scenario, and 2028 high-solar scenarios.

The framework provides four different levels of detail for results to evaluate the risk of hurricane contingencies:

1) a high-level table with the overall risk for each Monte Carlo hurricane simulation;

2) a table with metrics characterizing each set of contingencies that compose a hurricane event;

3) tables and maps summarizing steady-state electrical variables, contingency definitions, and corrective actions after each set of contingencies that compose a hurricane event; and

4) dynamic evolution of system state as a result of electromechanical transient models containing system control and protection, also as a result of the application of each contingency set composing hurricane events.

Tools and results will be made available to stakeholders by request and after DOE review.

The following observations, conclusions, and recommendations are derived from the analysis in this report:

- Hurricanes Maria and Irma were used to study five hurricane events applied to 15 power system configurations, and 80 Monte Carlo realizations of hurricane contingency sets, resulting in a total of 119 hurricane simulations. Each hurricane event was divided into 5 to 8 groups of contingencies, for an overall total of around 800 groups of contingencies. The developed framework provides detailed results (power flow, dynamics, protection, corrective actions) for each individual contingency and cascading stage. Results are also aggregated at four different levels of detail, from overall risk of hurricanes to detailed impact metrics, and detailed engineering results from steady state and dynamic simulations, including effects of dynamic controllers, protection systems, and corrective actions.
  - The risk-based dynamic cascading analysis framework is well-suited for analyzing high-impact, low-frequency events, including hurricanes, with intuitive user interfaces and flexible integration of grid and weather data sources

- By leveraging probabilistic, stochastic methods, this risk-based dynamic cascading analysis framework enables a full-spectrum analysis for historical hurricane events, and provides solid statistical ground for hurricane contingency formulation and grid equipment failure probability considering different hurricane variations and their unknown characteristics
- The risk-based dynamic cascading analysis framework enables a streamlined process to identify potential grid vulnerability during hurricane events, and a validated and trustable process to evaluate alternative grid enhancement and pre-event preventive strategies

- The results of this study identified Hurricane Maria as presenting the highest risk to Puerto Rico's power system performance, despite the low probability of occurrence for such a large event. This is consistent with the severity observed and experienced by PREPA in Puerto Rico in 2017. Hurricane Irma, with higher probability of occurrence, presented less risk, mainly driven by its lower severity. It is also worth clarifying that while for the actual events, the system was already stressed by Hurricane Irma before Hurricane Maria happened, for the purposes of our analysis, the grid initial conditions were the same for both simulated hurricanes. This can lead to more general conclusions. In other words, the analysis in this report suggests that severe hurricane events, like Maria, even when they do not occur often, could be important enough to guide the power grid planning processes. Even though this conclusion seems obvious, it is important to highlight that the importance of the hurricane events is derived from the technical basis in the proposed framework. For a more complete analysis, an expanded analysis is recommended, using simulations of additional hurricane events.

- Two operational mitigation strategies were studied and found to produce improved system performance in an event like hurricane Maria. The mitigation actions studied were: 1) preventive unloading and 2) preventive splitting of the system into minigrids, as proposed in the 2019 IRP. Preventive unloading of the system consisted of assumed preventive load shedding by operators in advance of the arrival of a hurricane. For preventive splitting into minigrids, it was assumed that the system operator divided the grid into minigrids before the hurricane arrived. It was found that preventive splitting into minigrids is more efficient mitigation action than reducing the system load and keeping the full system connected.

- One maintenance mitigation measure that the Puerto Rico Electric Power Authority (PREPA) should consider is improved vegetation management. In the vegetation sensitivity cases simulated for Hurricane Irma and Maria Lite, increased cascading failure, load loss, and violations were observed under the extreme system conditions, for the cases with line de-rating under poor vegetation management assumption. By increasing vegetation management, risk of outages caused by line sagging during higher levels of thermal loading that occur during extreme events can be reduced. With reduced risk to outages, system resiliency and reduced restoration time will be potentially achieved.

- System performance during disturbances can be significantly increased by activating additional voltage and frequency control and support in all inverter-based solar and energy storage resources. Hurricane simulations indicated a positive impact on load loss and cascading failure with the additional contribution of voltage and frequency support from inverter-based resources.

- Preliminary results show that grid-forming inverters could significantly improve grid stability when compared with currently more common grid-following inverters. Initial stability tests show that grid-forming inverters could potentially eliminate the need for synchronous condensers, which together with grid-following inverters were identified in Puerto Rico's 2019 IRP study.

The initial analysis in this report shows that grid-forming inverters could help operate a Puerto Rico's system with high renewable penetration, however, more modeling, analysis, design, and testing will be needed to confirm this potential.

- Generator frequency and voltage protective relay models were incorporated in dynamic simulations to improve system modeling accuracy; however, the conservative approach taken to model unknown relay settings reduced the number of sequential hurricane contingencies that could successfully solve in the framework developed. For example, under the Maria Lite 2028 day case, the number of contingencies successfully able to solve with added protection models was two, while simulations without relays were able to solve six consecutive sets of hurricane contingencies. Realistic system behavior under these extreme events will fall somewhere between the performance of these two simulation scenarios. Therefore, it is suggested that PREPA acquire and model actual generator protection settings (specifically voltage and frequency) to improve simulation accuracy under extreme contingencies.

- System upgrades in the 2019 IRP that improve resilience against hurricane contingencies are defined in this probabilistic simulation framework. When comparing system performance against Hurricane Maria, Maria Lite, and Irma using the 2019 and future 2028 planning cases (that reflect system upgrades, including undergrounding of selected 230kV transmission facilities), the Puerto Rico grid is able to withstand more hurricane contingencies, with significantly reduced load flow violations, load loss, and generation tripping. In other words, the IRP upgrades can significantly increase grid resiliency and performance during extreme events as validated in our simulations.

The risk-based probabilistic framework described in this report was used to study two historical hurricanes that impacted the island of Puerto Rico. To further this framework and tool demonstration, the following future work and opportunities for enhancement are identified:

- The risk-based dynamic contingency analysis framework proposed here requires infrastructure information that is not commonly available or integrated in power system planning. It is recommended that industry gathers and integrates the following information:

    - Power system planning integrated with operational models, so that operators could quickly put together power flow and dynamic models to analyze current operating conditions, or conditions expected in the near future like in the next hours or next day

    - Power system protection information integrated with planning and operational system models

    - Historical outages of individual pieces of infrastructure, linked with planning and operational models, as well as with Geographic Information System (GIS) information

    - Integrated GIS information of electric infrastructure with improved mapping with planning and operational models

    - Updated fragility information for power system equipment, also linked with GIS, related to the type of equipment stress (such as high wind and flooding) from the events of interest (such as hurricane)

    - Records of historical failure performance of assets for different type of extreme events

- Study additional hurricane scenarios.

- Study additional sensitivities of risk to failure thresholds or fragility of the electric infrastructure, including incorporation of failure probability for wind and solar generation.

- Integrate the developed framework and tools into power system planning processes to include resilience aspects into planning decisions. For example, using developed framework and Monte Carlo simulations, important design *N*-*k* contingencies could be identified and classified to guide the planning process. This task would require a deep dive into Monte Carlo simulation results, covering several event scenarios, and the application of new analytics techniques. Such process could identify design contingencies and their sequences with the highest impact and highest risk, to further support decision making in the planning process.

- Integrate the developed framework and tools into system operations near-term horizon studies, that can be utilized in real-time when hurricane forecasts become available.

- Research the integration of investment capital cost aspects or benefit cost analysis with the risk-based dynamic cascading failure proposed in this report.

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Acronyms and Abbreviations

N-1	*N-1* contingency or contingencies, in which one element is taken out of the starting case
N-1-1	*N-1*-1 contingency or contingencies, in which two elements are taken out of the starting case without having a common outage cause between them
N-2	*N-2* contingency or contingencies, in which two elements are taken out of the starting case due to a single outage cause
ANL	Argonne National Laboratory
BES	Bulk Electric System – includes any transmission assets over 100 kV
DCAT	Dynamic Contingency Analysis Tool
DOE	U.S. Department of Energy
EGRASS	Electrical Grid Resilience and Assessment System
FEMA	Federal Emergency Management Agency
GIS	Geographic Information System
GUI	Graphical User Interface
HEADOUT	Hurricane Electrical Assessment Damage Outage Tool
HUD	Department of Housing and Urban Development
IRP	Integrated Resource Plan
LTEO	Long-term equipment outages/damage
MACCC	Multi-Level AC Contingency Computation
NHC	National Hurricane Center
NOAA	National Oceanic & Atmospheric Administration
PNNL	Pacific Northwest National Laboratory
PREPA	Puerto Rico Electric Power Authority
PSS®E	Siemens PTI PSS®E, a commercial software package
pu	per unit
RAS	Remedial Action Scheme – automated protective actions for maintaining system integrity
STATCOM	Static compensator
STEO	Short-term equipment outage

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1.0 Transmission Resiliency Support to Puerto Rico

Two of the main challenges that the power system planning engineers in Puerto Rico face with respect to extreme events are: 1) the need for analysis tools to support operational planning for the weeks after the event when significant parts of the system are under long-term outage/damage; and 2) the need to analyze extreme contingencies to support long-term planning projects for hardening and reinforcing the transmission system for resiliency to future hurricanes and other extreme events. To offer insight into these challenges, this work develops a risk-based dynamic contingency framework to analyze resiliency of Puerto Rico's grid for dynamic contingencies produced by extreme hurricane related events.

The U.S. Department of Energy's (DOE) Office of Electricity and Office of Energy Efficiency & Renewable Energy have funded DOE National Laboratories to perform modeling, analysis, and high-level design of resilience-enhancement options for the power grid of Puerto Rico. The Pacific Northwest National Laboratory (PNNL) is one of the national laboratories contributing to the DOE effort. Under this funding, PNNL completed Phase I of their analysis in 2018 [17], which identified high-priority transmission enhancements derived from detailed dynamic cascading analysis of severe contingencies, including a hurricane scenario example. This report describes additional analysis completed under Phase II, which was performed over 2019. The PNNL team applied decades of experience making complex power systems more resilient, reliable, secure, flexible, affordable and sustainable, with partners in government and industry.

In Phase II, PNNL has developed a risk-based framework for identifying transmission resilience improvements by classifying and prioritizing high-risk contingencies. The risk-based framework is based on outage definitions with associated probabilities of occurrence from hurricane events, in combination with impact assessment derived from detailed dynamic cascading analysis. The framework makes use of Argonne National Laboratory's (ANL) Hurricane Electrical Assessment Damage Outage Tool (HEADOUT) output data and has adapted and expanded PNNL's Electrical Grid Resilience and Assessment System (EGRASS) and PNNL's Dynamic Contingency Analysis Tool (DCAT) for this application. Figure 1-1 illustrates the developed framework and how the tools interact.

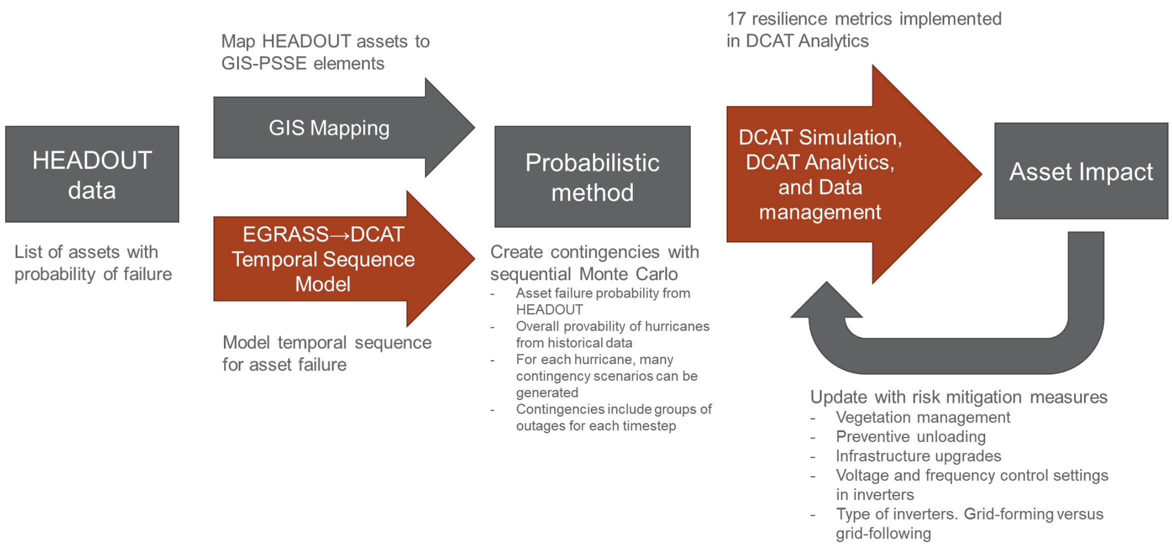


Figure 1-1: Risk-Based Dynamic Contingency Analysis Framework and Interaction of HEADOUT, EGRASS and DCAT tools

PNNL's EGRASS tool was extended, at a prototype level, and incorporated into the risk-based framework. EGRASS was extended to obtain the time sequence of hurricane related outages to complement the output data from the ANL HEADOUT tool. The powerful Geographic Information System (GIS) capabilities of EGRASS were leveraged to derive outage sequences utilizing hurricane wind speed data experienced by each transmission asset, for several historical hurricanes. Figure 1-2 illustrates the prototype expansion of PNNL's EGRASS tool.

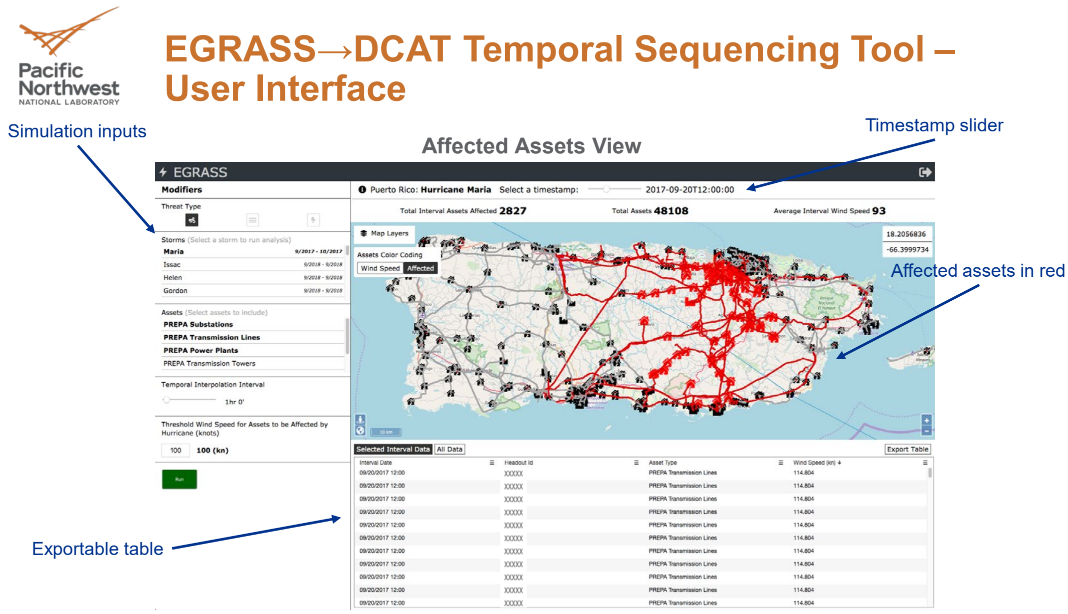


Figure 1-2: EGRASS adapted to provide temporal sequence of hurricane-related outages

Several new capabilities were added and tested in PNNL's DCAT motivated by the Puerto Rico use case. These developments were performed in collaboration with the DCAT High Performance Computing (HPC) project. The Puerto Rico project provided the use case, software requirements, and testing platform for capability refinements, and the DCAT HPC project provided the software development resources. The cascading process in DCAT was specifically automated for hurricane contingencies and other events that evolve over time. DCAT Analytics and Data Management was also improved to support efficient engineering analysis of hurricane and other large events. Figure 1-3 illustrates the DCAT Analytics and Data Management user interface used and adapted for Puerto Rico. The PNNL team has also implemented an overall risk metrics analysis where contingency impacts can be weighted by the overall probability of a particular hurricane magnitude.

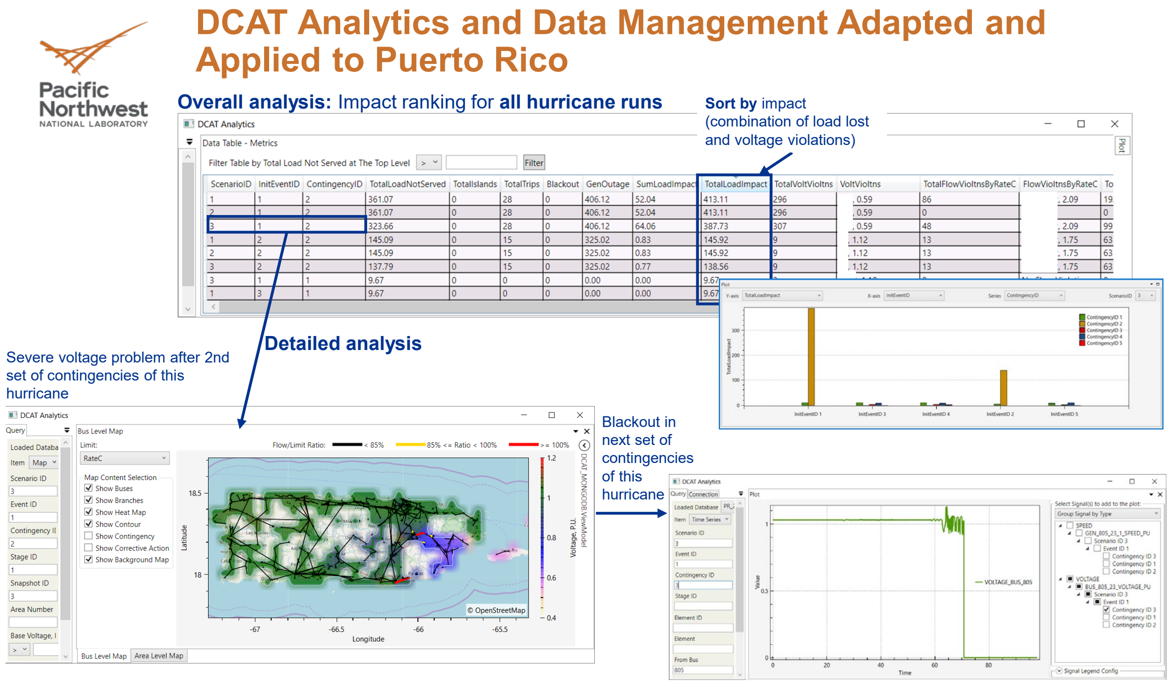


Figure 1-3: DCAT Automation, Analytics, and Data Management interface adapted and applied to hurricane contingencies and to Puerto Rico

1.1 PNNL’s Dynamic Contingency Analysis Tool (DCAT)

PNNL’s DCAT was leveraged in Phase II of this project to analyze dynamic behavior and cascading sequences resulting from generator and transmission related outages caused by a specific hurricane.

DCAT helps provide the utility industry with the ability to simulate, understand, predict, and prevent consequences of major disturbances on the grid including cascading-outages, blackouts, and widespread power supply interruptions. DCAT leverages utility-grade software to understand and characterize the robustness of the grid against high-order contingencies and to study the resilience of the grid in terms of its response to and recovery from such events.

DCAT is an open platform and a publicly available methodology. The current DCAT implementation has been developed as a software package with its own graphical user interface that accesses the simulation functions of the Siemens PSS®E planning tool (PSS®E)[1]. It has the following features:

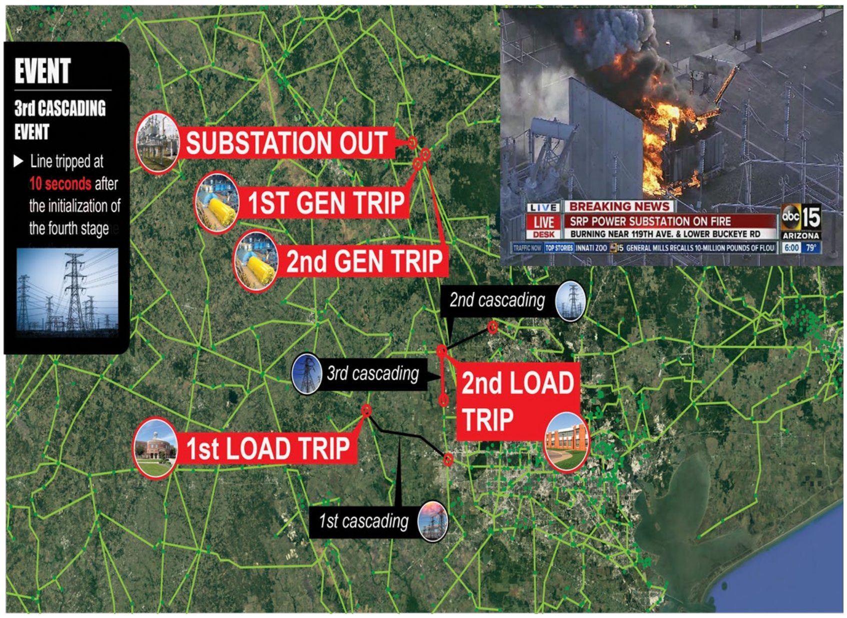
- It uses a hybrid dynamic and steady-state approach to simulating the cascading-outage sequences that includes both dynamic and steady-state events.
- It integrates dynamic models with protection scheme models for generation, transmission, and load.
- It models Remedial Action Schemes (RAS) and automatic and manual corrective actions.

DCAT can assist transmission planning engineers to prepare and plan for extreme events. It combines steady-state and transient stability simulations, manual operator actions, and the effects of protection

[1] A DCAT version that uses PSLF is also available.

systems, starting from an initiating event. The ultimate goal of DCAT is to bridge multiple gaps in cascading-outage analysis in a single tool to automatically simulate and analyze cascading sequences in real systems.

In Phase II of the Puerto Rico project, DCAT was used to simulate a sequence of hurricane contingency scenarios that were identified using the framework developed for this project. How hurricane contingencies were developed, and how they were input into DCAT, are discussed in the following section of this report.



DCAT simulates finer details of cascading events

Figure 1-4: Illustration of DCAT concept of sequential tripping caused by single initiating event

1.1.1 DCAT Methodology

DCAT software uses a generalized cascading model for shaping the sequence of simulation steps. The simulation steps are based on and explained here in a manner similar to the work reported by [6], and also summarized in [7].

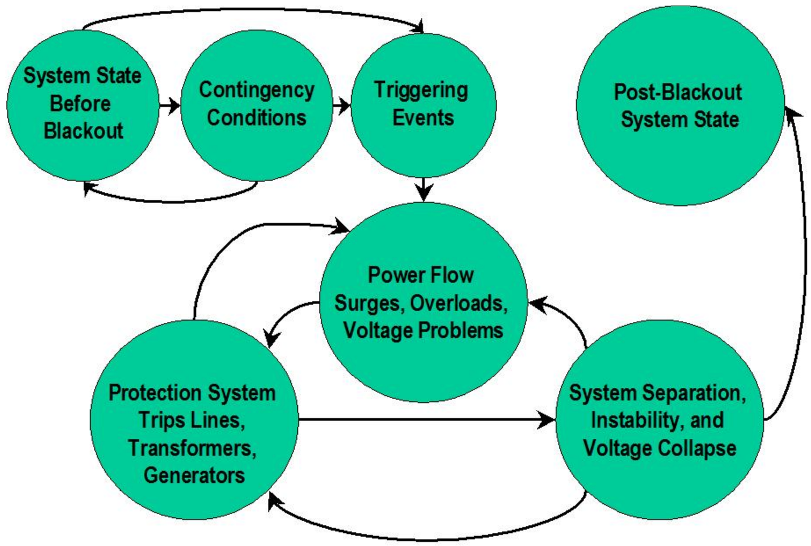


Figure 1-5: Generic cascade development scheme for DCAT, extracted from [7]

Figure 1-5 shows a transition diagram of the stages in a blackout sequence as implemented in DCAT. The stages are described as follows:

- *System State before the Blackout* – The Aggravation Stage: In this stage system parameters remain within normal operating reliability ranges with no indications of the approaching outages. At the same time, some noticeable deviations, such as unusually heavy power flow patterns and/or infrastructure under scheduled and unscheduled outage, can be observed that could potentially weaken the system before the actual cascading outages begin.
- *Initiating (Triggering) Events* – At a certain point in a cascade's development, a triggering event, such as lines tripping, occurs. Triggering events serve as the demarcation between two separate periods of operation; 1) a period in which multiple "undirected" factors accumulate (factors that contribute to a blackout but are not directly causes); and 2) the "blackout-directed" sequence of events (events with clear cause-and-effect relationships between the subsequent phases of the larger event as it unfolds on the system).
- *Cascading Stage*
  - *Power Flow Surges, Overloads, and Voltage Problems* – the triggering event, as well as the subsequent events, in a blackout scenario cause power flow surges, overloads, and frequency and voltage problems. These problems, in turn, cause subsequent events in the sequence.
  - *Protection System Trips Lines, Transformers, Loads and Generators* – The power system automatic protection plays a very important role in blackout scenarios. Protection system actions can be caused either directly by system problems, in which the protective relays react as if the large line flows or low voltages were due to a short circuit, or indirectly, when the system problems cause genuine short circuits or instability, e.g., when the overheated conductors make contact with a tree. The protection system isolates one or more pieces of equipment from the rest of the network, possibly resulting in load loss. This can result in more power flow surges, overloads, and voltage problems, which in turn can lead to further automatic protection system actions, and so on. The cascading process may be relatively slow, at least at its initial stages.
  - *System Separation, Instability, and Voltage Collapse* – In the advanced stages of a blackout, uncontrollable system separation, phase angle instability, and voltage collapse can occur. As a result, significant load loss may occur. Load loss could potentially help to balance generation and

load and to relieve system problems in the remaining part of the interconnection and in some isolated islands within the separated grid.

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

When performing analyses on power systems, it is impossible to accurately model all response options that have been built into the power system. Therefore, some rules and assumption need to be built into any solution method. The following assumptions are usually made when developing DCAT models:

- In the selection of initiating events, it is expected that $N-1$ contingencies are routinely analyzed by the utilities and system operators. It is assumed that the system is already protected against such contingencies. DCAT runs for *N-1* contingencies for most planning models will typically not be sufficiently disruptive to lead to protection system actions and cascading failure. However, cases representing an operational state with many lines out of service following a major storm may be disruptive enough to trigger cascading failure during traditional *N-1* contingencies evaluated in planning studies.
- If the system separates into islands, a simulation is conducted for each island. In PSS®E, the dynamic simulations are continued even when islands are created. In the steady-state analysis, it is possible to have islands, but slack buses must be input for each island.
- In an unstable island or system, a complete load loss is assumed.

Corrective Actions:

As part of the DCAT methodology, after a dynamic simulation is performed, automatic and manual corrective actions are modeled. The automatic control actions of transformer tap changes, switching of shunt reactors and capacitor banks, phase shifters, static compensators (STATCOMs), and static var compensators (SVCs) are used to eliminate voltage violations. DCAT implements these actions using the PSS®E alternating current (AC) corrective actions function, which is part of the Multi-Level AC Contingency Computation (MACCC) application. Manual actions taken by system operators to eliminate line overloading through generation dispatch and load shedding are modeled in DCAT using the PSS®E corrective actions function, which is also part of the MACCC application. At the time of this report, PNNL has no data on RAS for Puerto Rico, but when this information is made available, it could be modeled in DCAT as a part of the cascading analysis in future work.

If there are still overloaded lines after all possible corrective actions have been taken, DCAT will select the line with the highest overload percentage to be tripped. This process is performed through dynamic simulation as though this trip were a new initiating event imposed on the current system topology (i.e., including all trips that occurred in previous cascading steps). This process continues until a converged solution with no violations for the post-dynamic steady-state case can be achieved. Finally, a report of the various corrective actions performed is obtained and the extracted post-dynamic steady-state case with all corrective actions implemented is saved.

1.1.2 DCAT Application to Puerto Rico

DCAT has been used to evaluate impact of hurricanes into grid resilience in Puerto Rico. A large number of simulations were run, including 75,000+ contingencies on single and multiple component failure analysis, as well as time sequences of contingency scenarios that represent hurricane events. This analysis enables power system planners and operators to derive recommendations for transmission hardening, protection coordination, voltage support, control settings for renewable generation, as well as testing for preventive operational actions such as preventive system unloading or intentional islanding.

As an illustration consider Figure 1-4, hurricane events has been defined in DCAT as a time sequences of group of contingencies advancing through the hurricane track as illustrated in the figure. To define each group of contingencies we have used ANL's HEADOUT tool and PNNL's EGRASS. After the contingencies are defined, DCAT automatically runs a full hurricane event. For each group of contingencies, DCAT runs a dynamic cascading simulation, considering various effects: system state right before each contingency group as starting point, dynamic simulation and protection actions, cascading failure originated by the system protections (such as line overload protection) and dynamics, as well as emulation of corrective actions by operators to try to eliminate remaining non severe overloads and voltage problems. When steady state is reached after each contingency group and dynamic cascading simulation, the system is ready to simulate the next contingency group of the hurricane event.

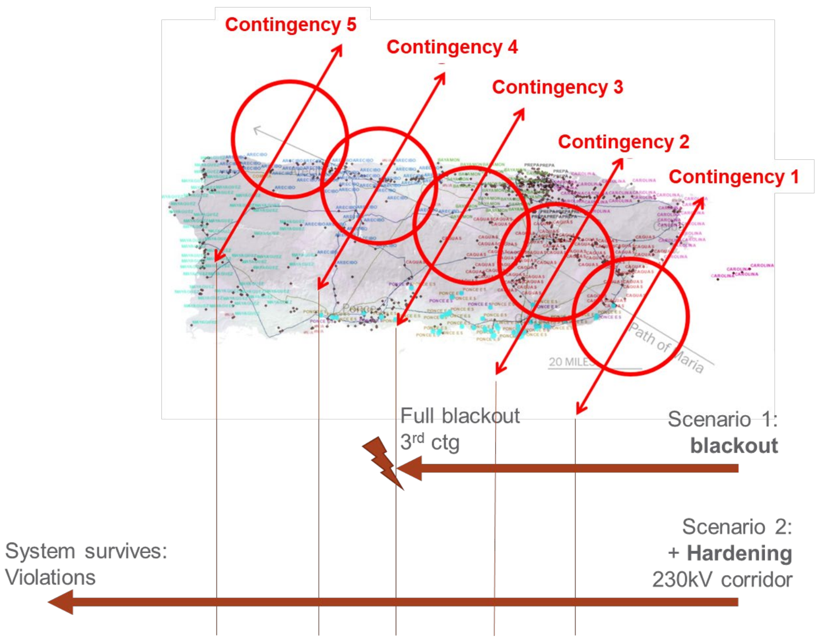


Figure 1-6: Illustration of hurricane event divided into a sequence of contingency groups moving across the island of Puerto Rico that were each simulated as an initiating event in DCAT

Each hurricane event simulation generates a large quantity of result data from steady state (before and after each contingency group, cascading stage, and corrective action), dynamic data, corrective actions implemented automatically to emulate operator's actions, and relay protection actions. The need to analyze a large quantity of data have motivated implementation and adaptations to DCAT.

PNNL's experience in application of DCAT to Puerto Rico study have been one of the main motivations and guides to the development of additional functionalities in DCAT tool. New functionalities include DCAT database module to handle large quantities of result data, and DCAT analytics and visualization for the analysis and support converting the results into actionable recommendations.

1.2 PNNL's Electrical Grid Resilience and Assessment System (EGRASS)

PNNL's EGRASS is a single page web-based geospatial application that was used in Puerto Rico in Phase I [18] to recommend candidate technology deployments for critical end-use loads to improve distribution system resilience. EGRASS is an easy-to-use online tool that was initially developed for map-based distribution system decision support. Target users for this tool include developers, engineers, planners, researchers, and state or local policy makers. In this report, a transmission application of EGRASS was developed to be linked with DCAT. The main objective of the transmission application is to obtain hurricane-related contingency sequences, to model the timing of each asset failure, and to assist on creating contingency groups to feed into DCAT.

For the distribution application, EGRASS was built on Puerto Rico datasets. These data included distribution feeder lines, population estimates, and customer impact, to name a few. It can evaluate the effect of outages on nearby and adjacent distribution lines and associated substations. It also can identify reliability indices associated with grid infrastructure.

For the transmission application, EGRASS was integrated with transmission system GIS information and historical hurricane data to model the impact on grid assets over time. In 2019, it was expanded to obtain the time sequence of hurricane-related outages on the transmission network. The powerful GIS capabilities of EGRASS were leveraged to derive outage sequences utilizing hurricane wind speed data.

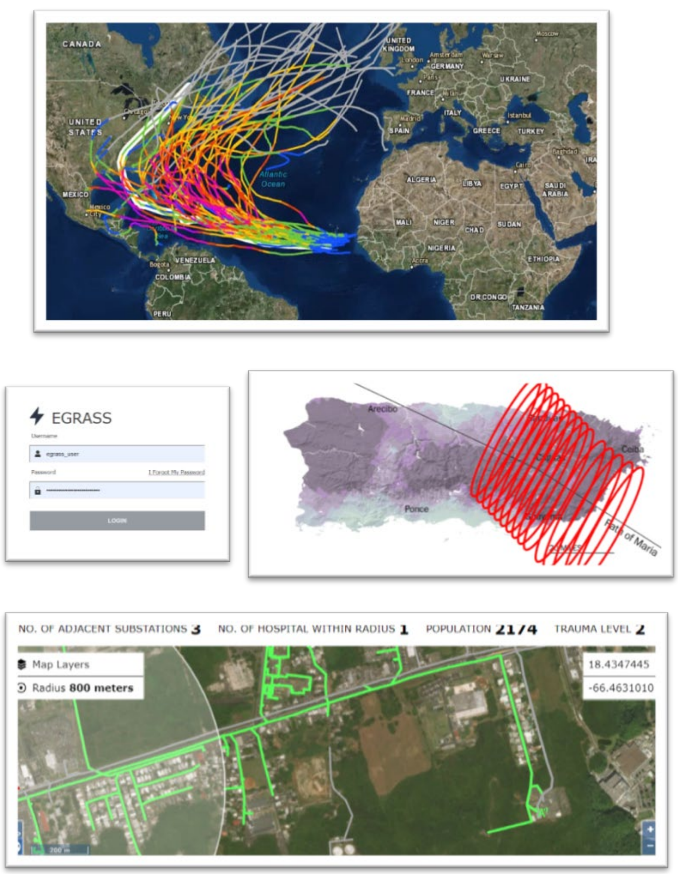


Figure 1-7: Illustration of sample EGRASS visuals

1.3 Argonne National Laboratory's Hurricane Electrical Assessment Damage Outage Tool (HEADOUT)

ANL's HEADOUT was created to provide electrical outage estimates for forecasted hurricanes. Hurricane forecasts are based on National Hurricane Center (NHC) Storm Advisories. In previous research efforts, ANL ran the HEADOUT tool on various historical hurricanes that impacted Puerto Rico. These hurricanes included Hurricane Maria, Hurricane Irma, Hurricane Lenny, and Hurricane San Felipe. The HEADOUT results for these four hurricanes were supplied to PNNL and were used to extract failure probability estimates of generation and transmission infrastructure elements.

In order to utilize ANL's HEADOUT results to create transmission related hurricane continency scenarios, a significant effort to map HEADOUT failure probabilities for individual transmission assets to specific PSS®E elements for DCAT was required. This effort is discussed in more detail in Section 2.

1.4 Combining ANL's HEADOUT, PNNL's EGRASS and PNNL's DCAT into a resilience evaluation framework

The tools briefly described above, ANL's HEADOUT, PNNL's EGRASS, and PNNL's DCAT, were combined in this report into a resilience evaluation framework. PNNL has developed this resilience evaluation framework as a risk-based framework for identifying transmission resilience improvements by classifying and prioritizing high-risk contingencies, as well as for evaluating different scenarios, such as preventing unloading, preventive islanding and future planning scenarios such as those with high renewables. The risk-based framework is based on outage definitions with associated probabilities of occurrence from hurricane events, in combination with impact assessment derived from detailed dynamic cascading analysis. Section 2.0 covers the developed framework in more detail.

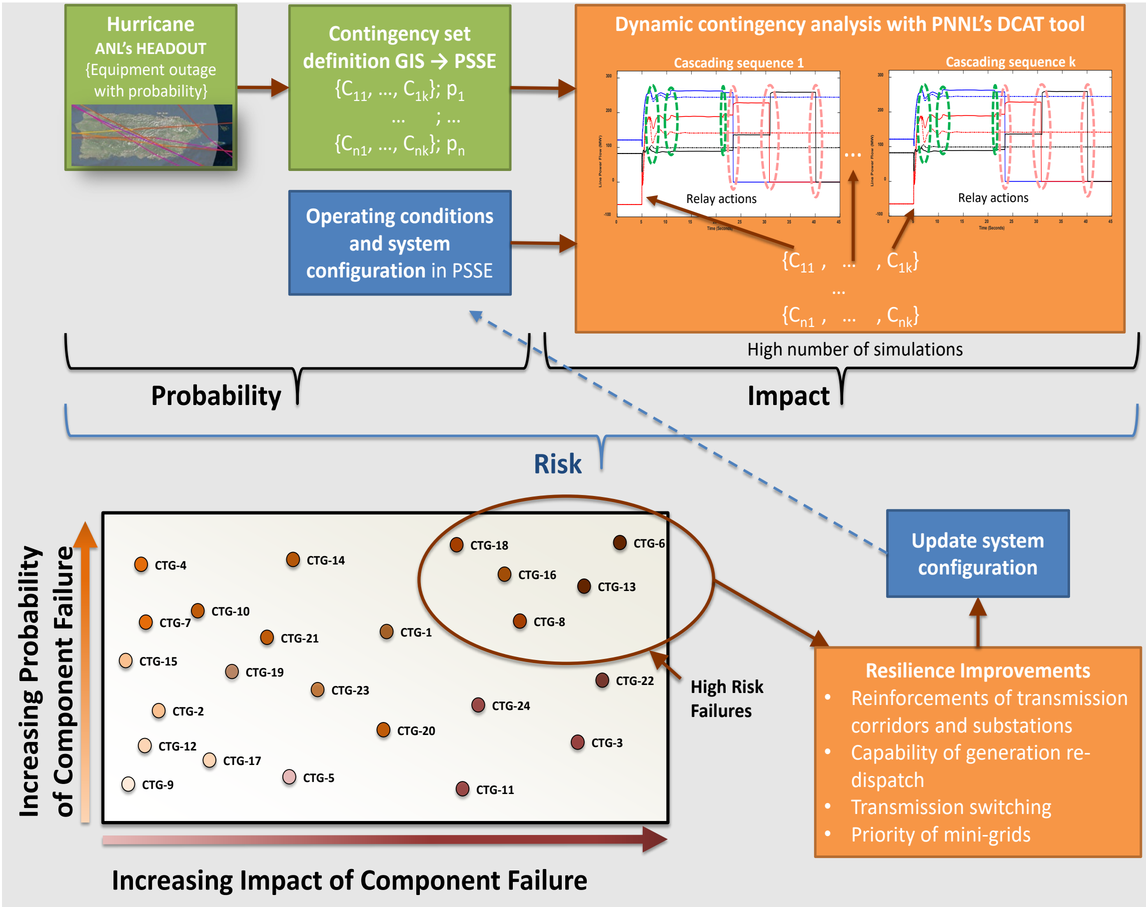
2.0 Risk-Based Dynamic Contingency Analysis Framework

PNNL has developed a risk-based framework for identifying transmission resilience improvements by classifying and prioritizing high-risk contingencies. The risk-based framework is based on outage definitions with associated probabilities of occurrence from hurricane events, in combination with impact assessment derived from detailed dynamic cascading analysis. The framework can be used for evaluating different scenarios, such as preventing unloading, preventive islanding and future planning scenarios like those with high renewables. A combination of three tools from the national laboratories were leveraged and expanded. The framework makes use of ANL's HEADOUT output data and has adapted and expanded PNNL's EGRASS and PNNL's DCAT for this application. Figure 2-1 illustrates the developed framework and how the tools interact.

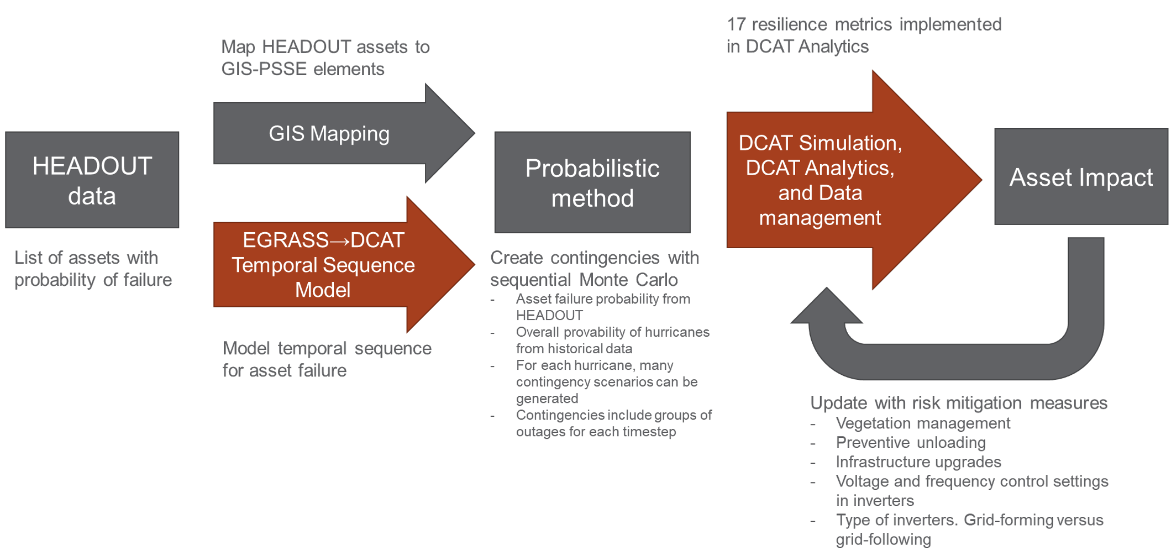
High risk contingencies are identified by obtaining hurricane-related sets of contingencies from ANL's HEADOUT and PNNL's EGRASS enhancements, then by running a high number of dynamic contingency sequences in PNNL's DCAT.

The framework (Figure 2-1 (b)) starts with an estimation of electric infrastructure assets at risk of failure due to hurricane (this could be either an historical hurricane or an upcoming one). ANL's HEADOUT tool is used for this purpose. Results from HEADOUT are fed into PNNL's EGRASS, for the estimation of the timing sequences of outages using hurricane wind speed data and GIS asset locations. The results from HEADOUT are also mapped to the electric power model elements in PSS®E. Results from EGRASS and the GIS mapping are used in a probabilistic method proposed originally in this work. The probabilistic method is a Sequential Monte Carlo method that determines if an asset fails from probability function sampling. The failure samples are translated into contingencies to be taken by DCAT. DCAT generates a large amount of result data. Result data are stored in a new DCAT database module and analyzed by DCAT Analytics framework specifically developed to analyze extreme events. Resilience metrics for this analysis were surveyed and incorporated into the DCAT Analytics framework.

Mitigation strategies, reinforcement, and hardening solutions for base and future scenarios can be studied with this framework. Such solutions could include changes in operational and control strategies, changes in system protection, as well as system upgrades. Longer-term planning decisions in capital projects for building or reinforcing transmission infrastructure, as well as evaluation of intentional islanding strategies, such as the minigrids proposed in the 2019 IRP [16] can also be evaluated using such a framework. The rest of this section describes each component of the framework.



(a)



(b)

Figure 2-1: Risk-Based Dynamic Contingency Analysis Framework: (a) General Illustration and (b) Interaction of HEADOUT, EGRASS and DCAT Tools within the Framework

2.1 Hurricane Contingency Definitions – HEADOUT→ EGRASS→DCAT

To develop hurricane contingency definitions, PNNL utilized HEADOUT data output provided by ANL's team. HEADOUT data consist of asset failure probabilities. PNNL's EGRASS was expanded to identify asset failures and their sequence of failure using wind speed data from historical and geospatial information. These assets were then mapped and translated to PSS®E element (bus or branch) failures. Figure 2-2 illustrates the use of tools and data mapping to create hurricane contingencies.

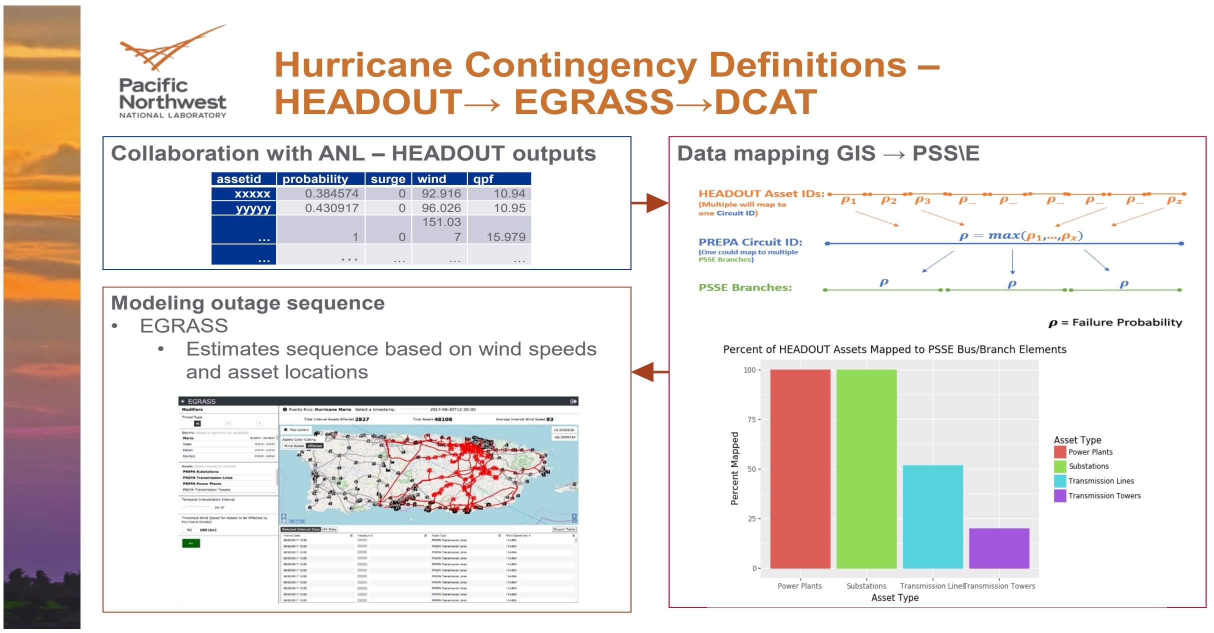


Figure 2-2: Overview of how attaining outage sequence was achieved

2.1.1 Description of HEADOUT Results Utilized as Input

ANL provided HEADOUT results for various hurricanes based on advisory data from the NHC. Typically, HEADOUT results include the number of customers without power for specific regions following a hurricane, but ANL was able to provide PNNL with intermediate results that are generated during the HEADOUT simulation to facilitate modeling with DCAT, which accepts system contingencies as an input. For each hurricane, failure probabilities and GIS data were provided for specific utility assets, including transmission line segments, transmission towers, power plants, and substations. It is important to highlight that failure probabilities for wind and solar generation were not considered in this study, this could be considered in future work. The probabilities were then transformed into sets of contingencies, as described in the following sections.

The failure probability data from HEADOUT represents the probability that a given asset will fail by a fault. For specific assets:

- Transmission Line failure probability represents the likelihood of tripping out on a fault due to wind and debris coming in contact with a line.
- Transmission Tower failure probability represents the likelihood of permanent infrastructure damage, such as a tower falling down and faulting a line.

- Substation and Power Plant failure probability represent the likelihood of an asset becoming completely inoperable from damage caused by flying debris or flooding.

In the GIS dataset provided by ANL, the majority of transmission line and transmission tower assets were associated with a PREPA Circuit ID. Several PREPA's transmission system (115kV and 230KV systems) assets are associated with the same Circuit IDs number. Figure 2-3 and Figure 2-4 illustrate the number of HEADOUT GIS transmission line and transmission tower assets associated with each PREPA Circuit ID.

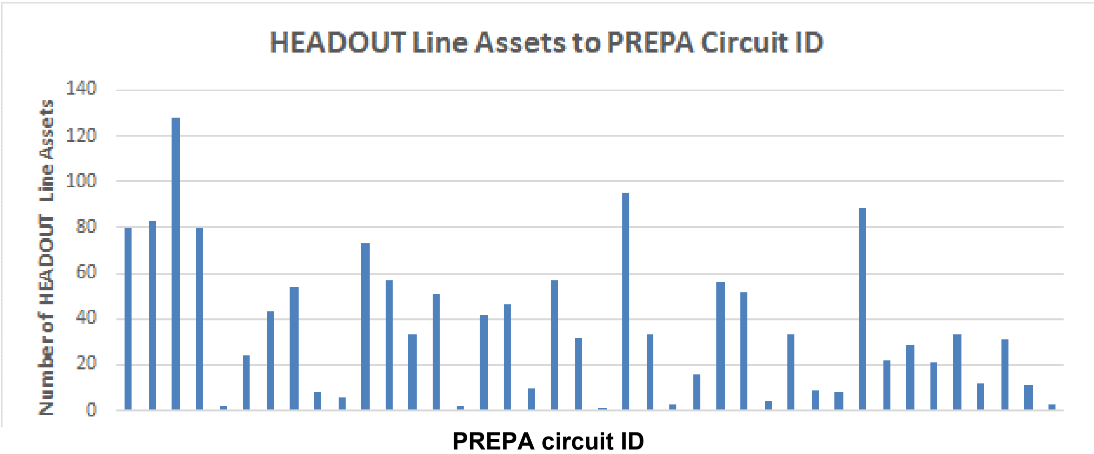


Figure 2-3: HEADOUT 115kV and 230kV Transmission Line Assets Mapped to PREPA Circuit ID

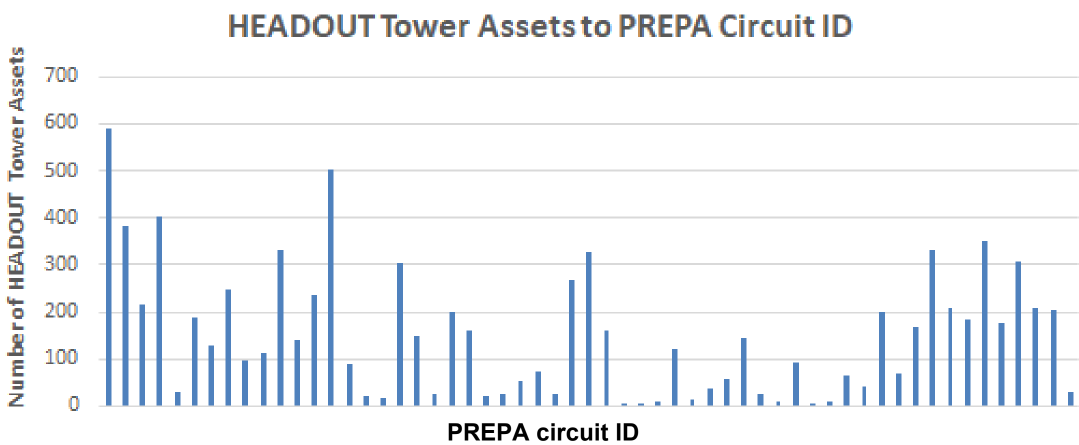


Figure 2-4: HEADOUT Transmission Tower Assets Mapped to PREPA Circuit ID

PREPA Circuit IDs do not directly correspond to PSS®E transmission line branches. PNNL was able to manually map PREPA Circuit IDs to individual PSS®E branches. This effort is discussed in the next section.

2.1.2 Mapping the HEADOUT GIS Assets to PSS®E Elements

The GIS dataset that ANL used as an input to HEADOUT was aggregated in a way that challenged a granular association of probabilities of failure to individual PSS®E model elements. This has introduced modeling uncertainty into the mapping process. This issue has also affected the HEADOUT results interpretation. This section describes how each HEADOUT Asset Type (Transmission Lines, Transmission Towers, Substations, and Power Plants), were mapped back to PSS®E branches and buses. A summary of the mapping challenges is also provided.

The mapping challenges resulted in modeling uncertainty, as discussed below. Potentially, new HEADOUT runs with an improved GIS dataset could result in a more accurate mapping, and reduced modeling uncertainty. The modeling uncertainty analysis in this report is general to also study other sources of modeling uncertainty.

Transmission Line Assets:

HEADOUT provides failure probability for individual transmission line assets. Line assets represent smaller line segments along a PREPA Circuit ID. In the GIS dataset used by ANL in HEADOUT, Transmission Line assets were aggregated into geometries that reflected entire PREPA Circuit ID spans. PREPA circuit ID spans map to more than one branch in the PSS®E model (transmission lines between substations). This posed mapping challenges, because what resulted was HEADOUT failure probabilities that mapped to specific Circuit IDs, rather than the specific GIS line segment location. In order to accurately map GIS line assets to PSS®E line branches, the GIS geometries making up Circuit IDs would have first needed to be disaggregated into individual line segment assets prior to running HEADOUT. This way, each HEADOUT line asset could have been mapped directly to a unique PSS®E branch element. However, this could not be completed with the GIS dataset and HEADOUT results attained from ANL.

Because we were unable to break apart GIS geometries integrated into ANL's GIS dataset, or re-run HEADOUT on a different GIS dataset, PNNL had to resolve this challenge making further assumptions and sensitivity analysis. Figure 2-5 illustrates how HEADOUT failure probabilities were assigned to PSS®E branches. In this figure, the maximum probability along a Circuit ID was assigned to several transmission lines in the electric model (PSS®E branches). Figure 2-6 shows the number of PSS®E branches mapped to PREPA Circuit IDs. This approach consequently over-estimates impact and decreases geographical diversity within hurricane contingency definitions. Appendix A contains more information on HEADOUT failure probability ranges for assets assigned to the same PREPA Circuit ID.

The modeling uncertainty described here also presents an opportunity to quantify the impact of model uncertainty in the proposed framework. We considered sensitivity scenarios by taking the minimum, maximum, or mean probabilities of the multiple assets mapping to electric model branches. Future work could consider defining independent probability functions for each electrical model branch to better model the modeling uncertainty and its effect or quantification on the final results.

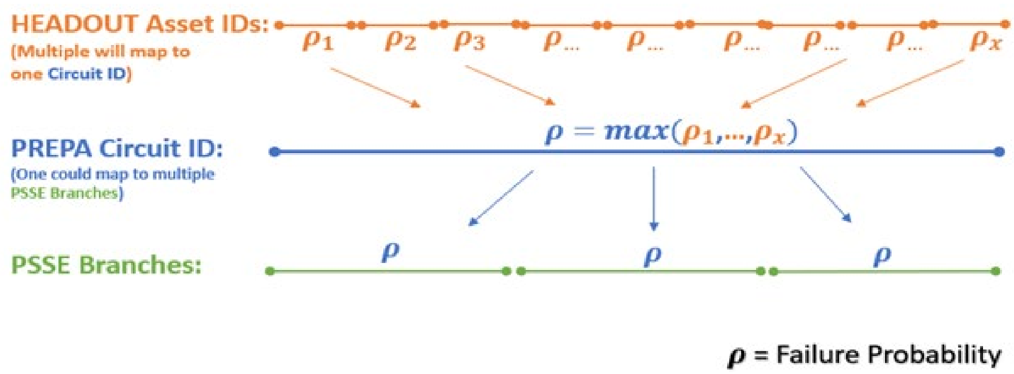


Figure 2-5: HEADOUT transmission line and transmission tower asset failure probability mapping to PSS®E branches

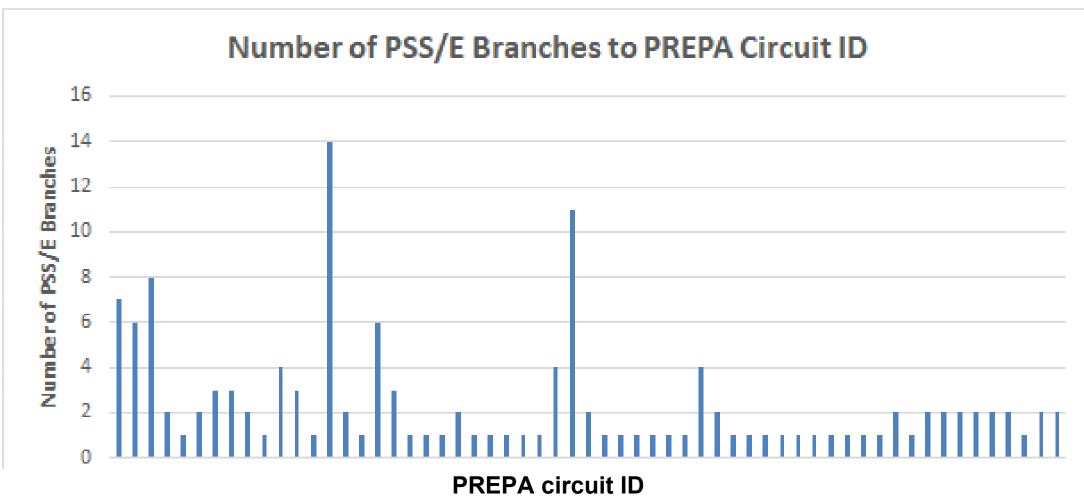


Figure 2-6: Number of PSS®E 115kV and 230kV branches mapped to each PREPA Circuit ID

Transmission Tower Assets:

As mentioned above, each HEADOUT Transmission Line asset maps to a PREPA Circuit ID in the GIS data that ANL provided to PNNL. This Circuit ID was then mapped to PSS®E 230kV and 115kV branches. For Transmission Towers, the GIS data does not readily map to a Circuit ID. Therefore, Transmission Towers were spatially mapped to Transmission Lines using the ArcMap software. By doing this, the Transmission Towers can be mapped to a PREPA Circuit ID, and follow a similar approach for assigning failure probability as for lines. The transmission towers also suffer from the same modeling uncertainty as the lines.

Substation and Power Plant Assets:

Mapping of HEADOUT Substation assets to PSS®E buses was conducted using ArcMap and PREPA GIS data that mapped directly to PSS®E buses. Substations associated with Power Plants were mapped in the same way. The Power Plant asset type was associated to the power plant substation.

Figure 2-7 shows the percentage of HEADOUT assets that were successfully mapped to PSS®E elements. Note that the majority of Transmission Lines and Towers that were not mapped represent low-voltage branches (<100kV). This is because mapping of lower voltage PSS®E branches could not be easily mapped back to GIS line segment assets.

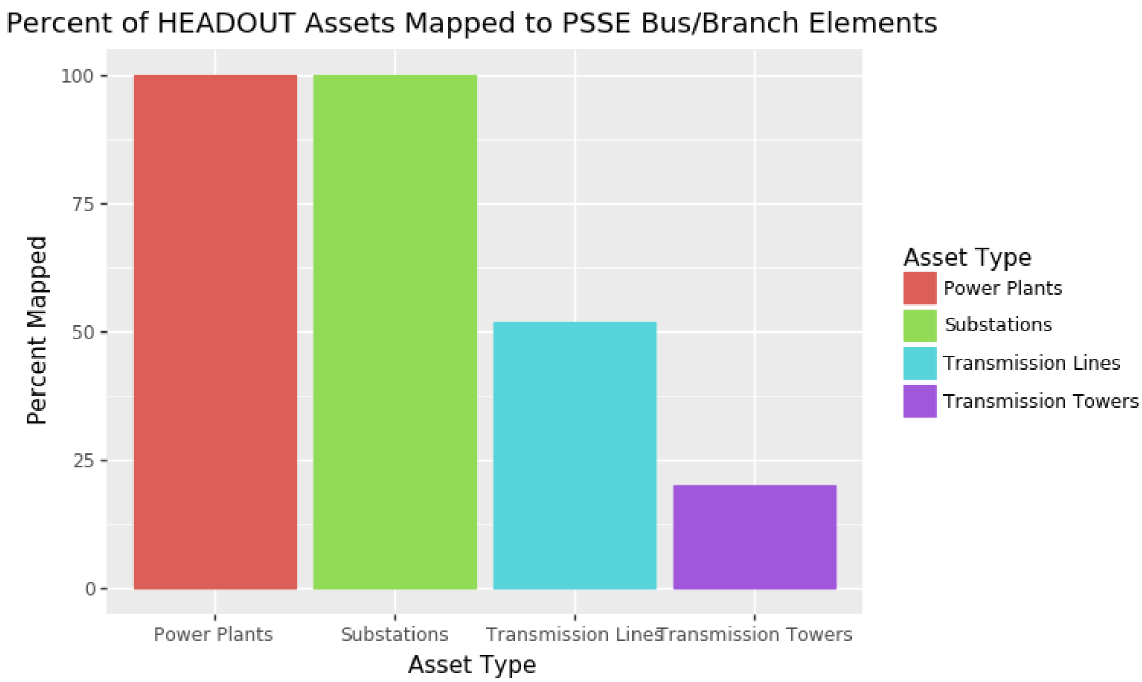


Figure 2-7: The percentage of HEADOUT assets successfully mapped to PSS®E elements by asset type

2.1.3 Sequencing PSS®E Elements Failure based on HEADOUT

A major challenge with the HEADOUT results provided by ANL is that the failure probabilities do not contain any information on failure time or time sequence, which is required to accurately model cascading failures in the DCAT simulations. EGRASS enhancements have been built to address this issue and are discussed in the section below.

2.2 EGRASS Temporal Sequencing Model to Define Timing and Sequence of Asset Outages

HEADOUT data is based on 6-hour National Hurricane Center (NHC) advisories, and the output probabilities themselves do not contain any timestamp or sequencing information. However, for the dynamic cascading analysis in the electric power system model, it is important to understand when assets are affected by a hurricane on the minute-level scale to realistically model power system contingencies. As a result, PNNL's EGRASS tool was extended, at a prototype level, and incorporated into the risk-based framework to model the temporal sequence of asset failures. The Temporal Sequencing Model was built into the EGRASS user interface to allow multiple resilience mapping tools to be co-situated and take advantage of the tool infrastructure already created for EGRASS. The powerful GIS capabilities of EGRASS were leveraged to derive outage sequences using hurricane wind speed data from the NHC.

2.2.1 Tool Inputs and Outputs

In order to align the temporal sequencing with the failure probabilities provided by HEADOUT, the Temporal Sequencing Model uses similar spatial hurricane data obtained from the NHC. This includes 'best-track' GIS data[1], which contains the central location of the hurricane and the edges of the 34, 50, and 64 knot wind fields at 6-hour intervals, and maximum wind speeds from the HURDAT2 database[2]. In the future, this model may be refined by incorporating NOAA wind speed data from weather stations, which will improve the spatial resolution of the model. The model also uses the GIS asset data provided by ANL, which includes an ID assigned by HEADOUT that can be used to match an asset's location to its failure probability.

The tool returns a list of assets that are affected by the hurricane for each timestamp at which they are impacted and the associated wind speed for those timestamps. This list is used to create a subset of the ANL-provided asset probabilities for each timestamp. The subsets serve as input to the probabilistic model (described in section 2.3) which creates contingencies for the DCAT simulation.

The tool uses several tunable parameters. These include the desired output temporal resolution and the wind speed threshold for including an asset in the DCAT contingencies (described further in the following section).

2.2.2 Methodology

First, the NHC wind field and best-track data is linearly interpolated from 6-hours to the user-defined output temporal resolution. Note that there can be additional NHC data points at a shorter temporal resolution than 6 hours. For example, a data point is included at landfall, but most of the data is spaced at 6-hour intervals. Next, the wind speed at each asset location is determined by linearly interpolating the maximum wind speed from the central hurricane location to each of the wind field edges. All assets located outside the 34-knot wind field edge for a given timestamp are not considered to be affected by the hurricane. The resulting wind field is then used to calculate the wind speed of each asset at each timestamp. This process is depicted in Figure 2-8

[1] https://www.nhc.noaa.gov/data/tcr/
[2] https://www.nhc.noaa.gov/data/hurdat/hurdat2-1851-2018-051019.txt

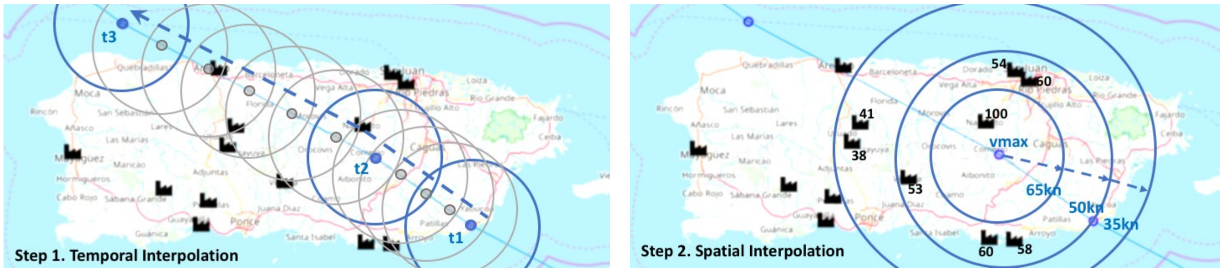


Figure 2-8: Graphic depicting the methodology of the Temporal Sequence Model, showing the interpolation over timestamps in step 1 and the spatial interpolation between wind field edges in step 2

To determine which assets are affected at each timestamp, the user-defined wind speed threshold is used. Any asset which has a wind speed at its location higher than the threshold is considered affected by the hurricane, and therefore included in the subset for the probabilistic model (next step in the overall framework) for that timestamp. In the current implementation of the model, a single threshold is used for all asset types, however, this may be modified in the future.

2.2.3 User Interface

The model was built into the EGRASS user interface to allow a user to visualize which assets are being affected over the course of a hurricane and refine the tunable parameters as necessary. Figure 2-9 shows a screenshot of this tool, along with annotations highlighting how the user interacts with it. A user first selects the threat type (currently, only hurricanes are included), the relevant hurricane, and the utility asset types to include. Both the hurricane data from the NHC and the asset GIS data have been pre-loaded into the EGRASS database. Then, they can choose the temporal interpolation resolution and the wind speed threshold. Once the model is finished calculating, the user can visualize which assets are affected by the hurricane at each timestamp by moving the slider at the top of the screen. They can toggle which assets are shown on the map using the Map Layers legend and view more information on an asset (its ID, type, and wind speed) by hovering over it with the mouse. The total number of assets being modeled, the number of assets that are affected at a given timestamp, and the average timestamp wind speed are shown in the bar on top of the map. In the default view, assets that are affected at a given timestamp are shown in red. It is possible to switch to the wind speed view, which instead color codes the assets by wind speed for each timestamp (see Figure 2-10), which can be useful for tuning the threshold wind speed.

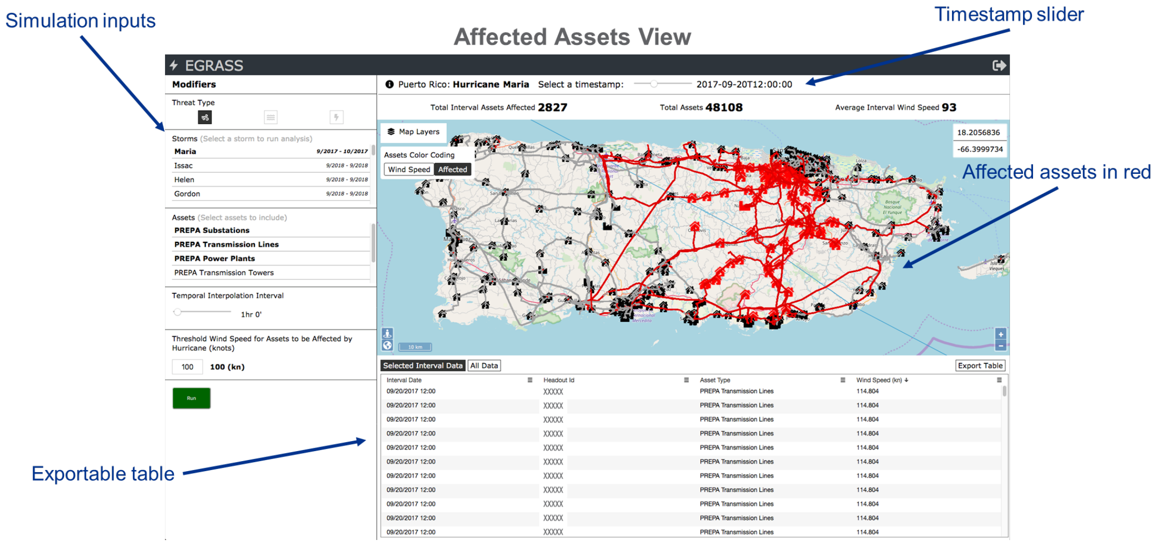


Figure 2-9: The temporal sequencing model user interface with the affected assets view

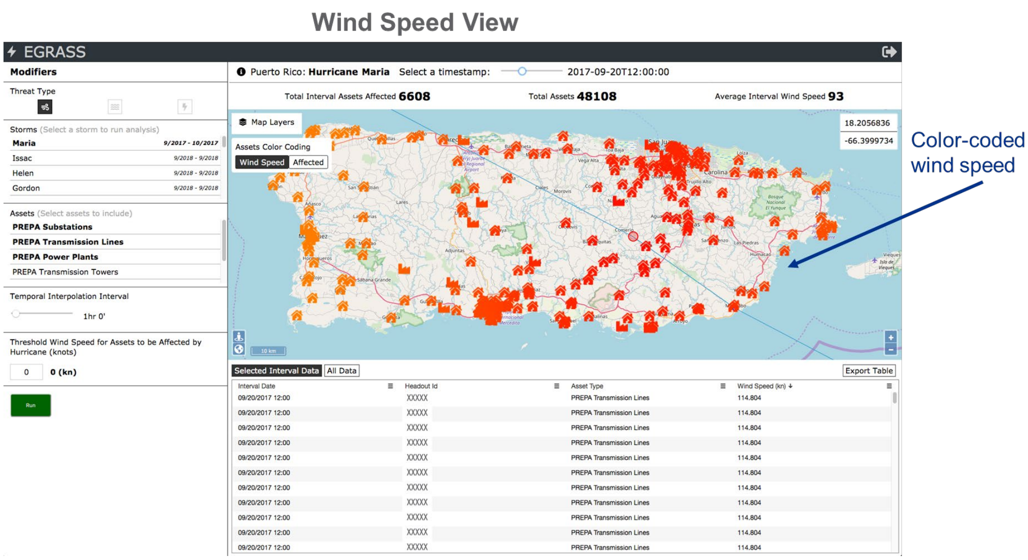


Figure 2-10: The temporal sequencing model user interface with the wind speed view

The table below the map includes a list of assets that are affected for each timestamp with their HEADOUT ID, asset type, and the wind speed at their location for that timestamp. The table can be sorted or filtered by any of the fields, expanded to show data for all timestamps, and exportable to csv format.

2.3 Probabilistic Methodology

A new Monte Carlo probabilistic method has been implemented to calculate risk using probabilistic information at two levels:

- Overall probability of occurrence of a hurricane event of a given intensity
- Probability of failure of individual assets for a given hurricane event.

The methodology to use these two levels of information are explained in this section.

First, at the more granular level, the probability of failure of individual assets for a given hurricane was used as follows. Given HEADOUT failure probabilities, PSS®E branch mapping, and the temporal sequence of asset failure obtained from EGRASS, a Monte Carlo simulation was developed to generate a set of independent contingency realizations caused by a hurricane. These were then used by DCAT to calculate an average impact over those realizations and determine a weighted impact based on the likelihood of a given hurricane occurring.

The Monte Carlo simulation methodology is illustrated in Figure 2-11. First, results generated from the EGRASS temporal sequence model were combined with the GIS asset mappings to obtain a list of PSS®E assets with their corresponding failure probabilities and timestamps at which they are affected by the hurricane. Next, the Monte Carlo method was applied to generate "n" sets of contingencies based on the probabilities of asset failure. The resulting sets of failed assets for each Monte Carlo sampling were then grouped into different DCAT .idv files based on their timestamps, resulting in "n" groupings of .idv files, with each grouping containing a file for each hour.

The generated DCAT .idv files were then used as input to DCAT to simulate the impact of the hurricane on the electric grid. The expected impact from the hurricane was calculated as the average impact from each of the "n" Monte Carlo samples, and the standard deviation of all "n" Monte Carlo samples represents the uncertainty.

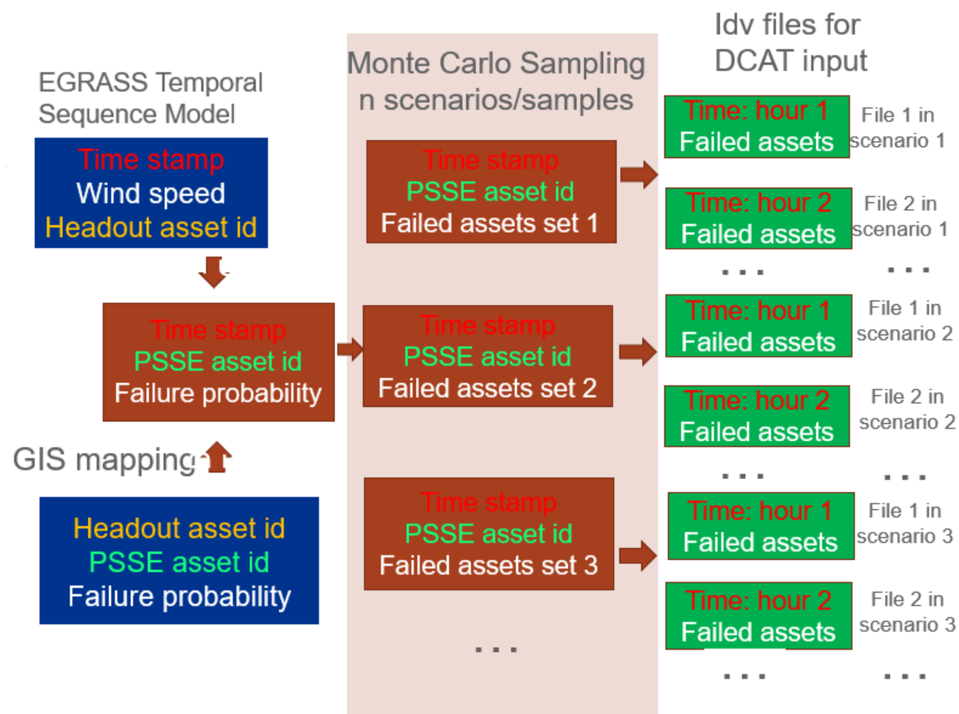


Figure 2-11: An illustration of Monte Carlo sampling method

Second, at a higher level, the overall probability of occurrence of a hurricane event of a given intensity was incorporated as follows. A weighted risk-based hurricane impact was then calculated based on the likelihood of a given hurricane occurring. Figure 2-12 shows a histogram of the maximum wind speed of all hurricanes occurring over Puerto Rico in the past 50 years, which can be used to determine the probability of a given hurricane based on its maximum wind speed. For example, hurricane Maria is high impact, but low probability based on its wind speed. A lower intensity hurricane may have a lower overall impact but a higher probability. The weighted risk-based impact expectation represents the expected impact of a given hurricane considering both its impact on the electric grid and likelihood of occurring.

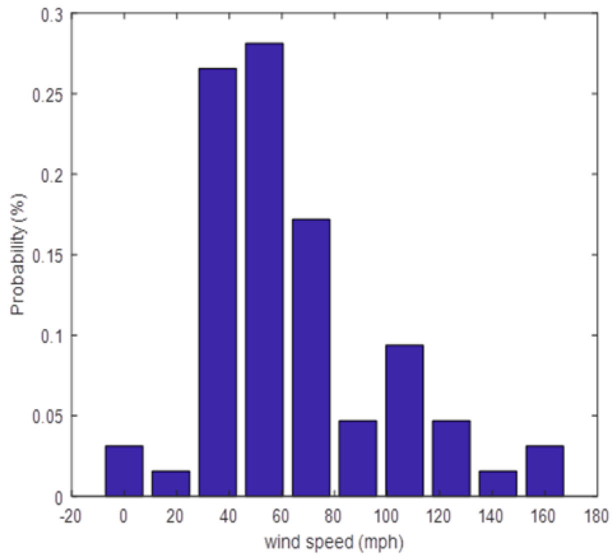


Figure 2-12: Histogram hurricane speeds for all historical hurricanes over Puerto Rico

The overall probabilistic methodology is shown in Figure 2-13. For a given hurricane scenario, the Monte Carlo sampling method was used to generate "n" Monte Carlo samples and associated DCAT .idv files. After the DCAT simulation is complete, the expected impact of the given hurricane was calculated from the average impact of all "n" Monte Carlo samples. Finally, the weighted risk-based impact expectation was calculated by multiplying the expected impact of the given hurricane by the probability of that hurricane occurring based on its maximum wind speed and historical data.

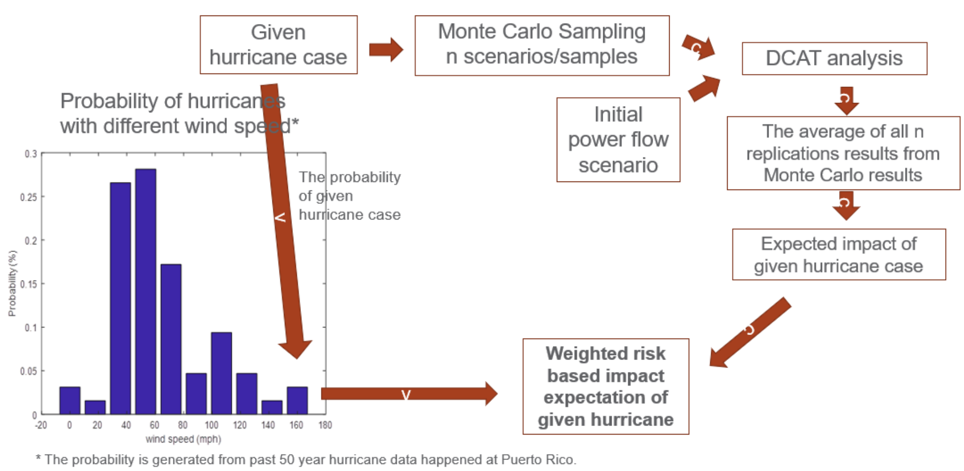


Figure 2-13: An illustration of the probabilistic method

2.4 Resiliency Metrics

The results of the ranking of power system problems is defined based on resiliency metrics results obtained from power flow contingency analysis and DCAT. This ranking is used to identify potential bottlenecks in achieving resilient operation. There are three categories of metrics that were developed in this study, which are given in Figure 2-14.

Category 1. Direct Grid Metrics	Category 2. Preventive Metrics	Category 3. Comprehensive Metrics
a. Total load not served (MW)	a. Total load tripped in advance for preventive action	a. Time of restoration
b. Total # of islands	b. Total generation Redispatch in advance for preventive action (capacity deration?)	b. Load not served with time stamp during each stage of hurricane
c. Total # of tripping events	c. Controlled Islanding (mini grids in IRP)	c. Load not served with load type Considering voltage violation
d. Total # of Voltage violations	d. Installation of new types of protection equipment	d. Total steps in Cascading failure
e. Voltage violations	e. Installation of additional UFLS protection equipment	e. Vegetation metric
f. Total # of Flow violations		
g. Flow violations		
h. System blackout		

Figure 2-14: Resiliency metrics for risk-based dynamic contingency analysis.

For Category 1, there are eight proposed metrics that can be extracted directly from DCAT simulation result files and log files. These metrics include:

- *Total load not served (MW)*: The total amount of load tripped in the DCAT simulation
- *Total # of islands:* The total number of islands existing in the extracted post-contingency power flow case
- *Total # of tripping events*: A summary of all the tripping (including generators and transmission lines) for the current contingency
- *Total # of voltage violations:* The total number of voltage violations that exists in the post-contingency power flow case
- *Voltage violations:* The location and magnitude of the highest voltage violation
- *Total # of flow violations* and *flow violations:* The total number of branch overloads with respect to Rate C and Rate A in the PSS®E planning cases
- *System blackout:* Indication of whether the whole grid is in a state of system blackout

For Category 2, there are five proposed metrics that evaluate alternative preventive strategies and potential system enhancements. These metrics include:

- *Total load tripped in advance for preventive action*: Evaluating how to better prepare grid for any incoming threat with preventive load shedding in advance

- *Total generation redispatch in advance for preventive action*: Evaluating how the generation fleet could be redispatched and optimized to minimize the impacts caused by system disturbances

- *Controlled islanding (mini girds in 2019 IRP [16]):* Evaluating whether the operator controlled islanding and in-advance grid separation could position the whole grid into better status to limit the propagation of system disturbances

- *Installation of new types of protection equipment:* Evaluating how could additional protection equipment could impact the system performance for given study scenarios and events

- *Installation of additional UFLS protection equipment*: Evaluating how under frequency load shedding schemes could improve the grid dynamic behaviors during any severe yet fast grid disturbance

It should be noted that all Category 2 metrics require additional information and utility engineer inputs to facilitate new study scenarios with alternative preventive strategies and potential system enhancements. As a result, the project team would be able perform more evaluations as soon as the required information is received.

For Category 3, comprehensive resilience metrics have been proposed considering composite information; they not only provide the high-level representation of grid status from multiple dimensions, but also make the grid planning more efficient when performing grid analysis and data comparison over a large portfolio of potential scenarios. These metrics include:

- *Time of restoration:* Providing an estimate of the overall grid recovery time considering the impacted grid elements during event

- *Load not served with time stamp during each stage of hurricane:* Providing the aggregated value of tipped load in each contingency during one given hurricane

- *Load not served with load type Considering voltage violation:* Describing the weighted load value considering the negative impact caused by overvoltage and undervoltage conditions

- *Total steps in Cascading failure:* Providing the total number of major events during one cascading failure

- *Vegetation metric:* Describing whether appropriate vegetation practice could help alleviate the grid impacts

2.4.1 Comprehensive Metric Example

The objective of load impact metric is to reflect the potential impact of voltage violation at load bus. Voltage violations might cause damage to the power electronics and service quality for critical load. This metric aims at providing a single, quantifiable metric that combines the impact of load not served with in-service that has been negatively affected by voltage violations. Each load bus has Zone information, and for each Zone a different piece-wise linear function has been defined to determine the impact of voltage violations to load based on violation severity. , These piecewise linear functions are defined by 4 points, $(\boldsymbol{x_1}, \boldsymbol{y_1})$ $(\boldsymbol{x_2}, \boldsymbol{y_2})$ $(\boldsymbol{x_3}, \boldsymbol{y_3})$ $(\boldsymbol{x_4}, \boldsymbol{y_4})$. as a result, at each bus, load impact metric could be calculated by combining the bus voltage violation penalty and impacted load value. An illustration of this is given in Figure 2-15.

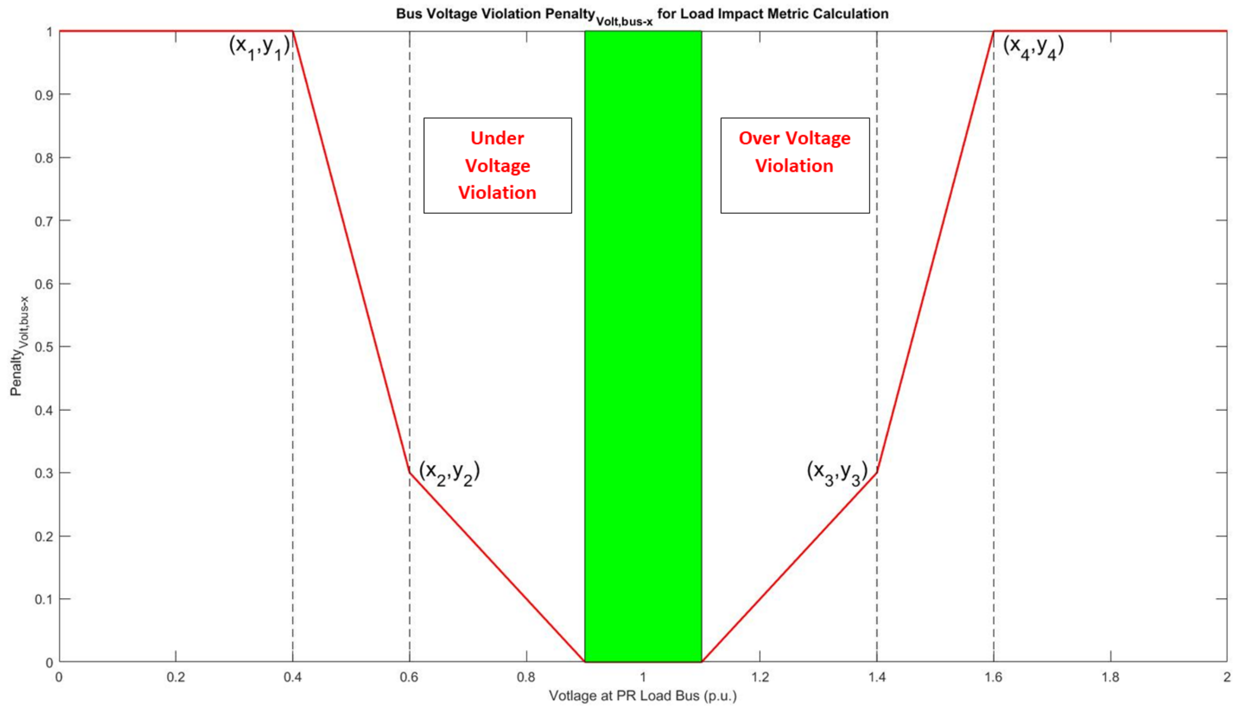


Figure 2-15: An illustration of load impact metric calculation.

The mathematical Expression is given as follows:

$$\boldsymbol{Load\_Impact_{MW,\,Ctg\_i} = Total\ Load\ Not\ Served_{MW,\,Ctg\_i} + \sum(Penalty_{Volt,bus-x} \times Load\ In\ Service_{MW,\,Ctg_i,bus-x})}$$

where $\boldsymbol{Penalty_{Volt,bus-x}}$ is piecewise linear function of voltage deviation, and $Volt_{bus-x}$ is the voltage magnitude at Bus x. It has the following properties:

- When $Volt_{bus-x} \le x_1$, $\quad Penalty_{Volt,bus-x} = 1$
- When $x_1 < Volt_{bus-x} \le x_2$, $\quad Penalty_{Volt,bus-x} = \frac{y_2-y_1}{x_2-x_1} \times (Volt_{bus-x} - x_1) + y_1$
- When $x_2 < VoltDev_{bus-x} < 0.9$, $\quad Penalty_{Volt,bus-x} = \frac{-y_2}{0.9-x_2} \times (Volt_{bus-x} - x_2) + y_2$
- When $0.9 \le Volt_{bus-x} \le 1.1$, $\quad Penalty_{Volt,bus-x} = 0$;
- When $1.1 < Volt_{bus-x} \le x_3$, $\quad Penalty_{Volt,bus-x} = \frac{-y_3}{x_3-1.1} \times (x_3 - Volt_{bus-x}) + y_3$
- When $x_3 < Volt_{bus-x} \le x_4$, $\quad Penalty_{Volt,bus-x} = \frac{y_4-y_3}{x_4-x_3} \times (Volt_{bus-x} - x_4) + y_4$
- When $Volt_{bus-x} > x_4$, $\quad Penalty_{Volt,bus-x} = 1$

For each load bus, the mathematical expression is given as follows:

$$\boldsymbol{Load\_Impact_{MW,\,Ctg_i,\,bus-x} = (Penalty_{Volt,bus-x} \times Load\ In\ Service_{MW,\,Ctg_i,bus-x})}$$

2.5 Enhancements to Dynamic Contingency Analysis Tool (DCAT): DCAT Analytics and Data Management Adapted and Applied to Puerto Rico

Several new capabilities were added and tested in PNNL's DCAT, motivated by the resilience study to Puerto Rico, and to enable the risk-based framework of this work. These developments were performed in collaboration with the DCAT HPC project. The Puerto Rico project provided the use case, derived software requirements from engineering needs, and a testing platform for capability refinements, while the DCAT HPC project provided the software development resources.

The cascading process in DCAT was specifically automated for hurricane contingencies, and also generalized other extreme events that evolve over time. DCAT Analytics and Data Management was also developed and improved to support efficient engineering analysis of hurricane and other large events. Figure 2-16 illustrates the DCAT Analytics and Data Management user interface used and adapted for Puerto Rico.

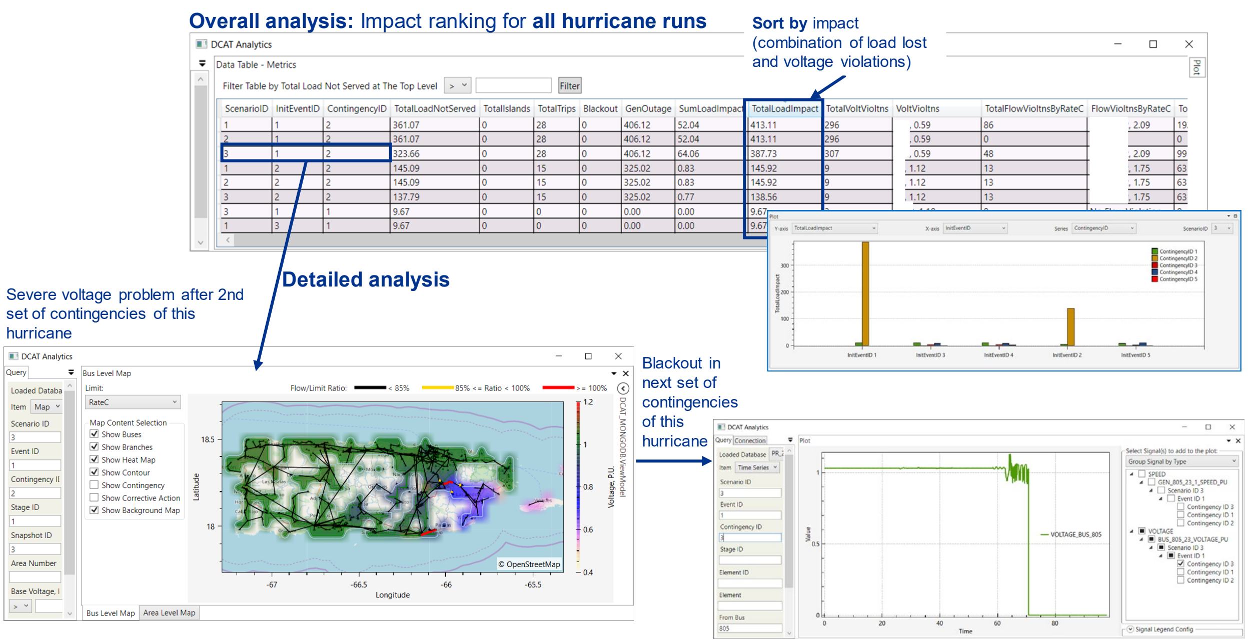


Figure 2-16: DCAT Automation, Analytics, and Data Management interface adapted and applied to hurricane contingencies and to Puerto Rico

The power system industry has increased interest in studying extreme events, such as hurricanes and other natural disasters, with the purpose of analyzing power system resilience. This need is especially important in Puerto Rico due to the recent hurricane events. In addition, the complexity of power systems has increased in recent years due to increased demands and penetration of intermittent resources such as wind, solar, distributed generation, and electric vehicles. These factors, added to the need to evaluate extreme events from natural disasters, create the need to analyze multi-scenario, and multi-contingency scenarios ("*N*-*k*"), beyond commonly studied *N*-1, and *N*-1-1 contingencies. Applying dynamic simulations to analysis of multi-scenario contingency events under uncertainties requires significant effort and may be computationally prohibitive. As shown in the analysis of more than 75,000 "*N*−k" dynamic contingency analysis using Dynamic Contingency Analysis Tool (DCAT) [7] in Puerto Rico, a copious amount of result data is generated. The valuable engineering information can be difficult to extract from the abundant result data.

To help power system engineers thoroughly understand and analyze system behavior under many scenarios and contingencies, a database management module (DBM) was developed that provides full-scale interactive data visualizations by aggregating data from all contingency scenarios to tell a coherent story with valuable, actionable results. Power system engineers need this capability to perform better planning studies.

The rest of this subsection describes the new developments that the Puerto Rico use case supported and how these developments were integrated in the Risk-Based Dynamic Contingency Analysis Framework to obtain new insights about Puerto Rico's grid resilience.

2.5.1 DCAT Simulation Enhancements – Sequential Runs

An automation capability has been developed for DCAT to simulate various hurricane contingencies. A hurricane simulation as defined in this report, involves sequential steps of groups of contingencies that represent the hurricane under study. Figure 2-17 shows the implementation of contingency sequencing approach to model hurricane events in Puerto Rico.

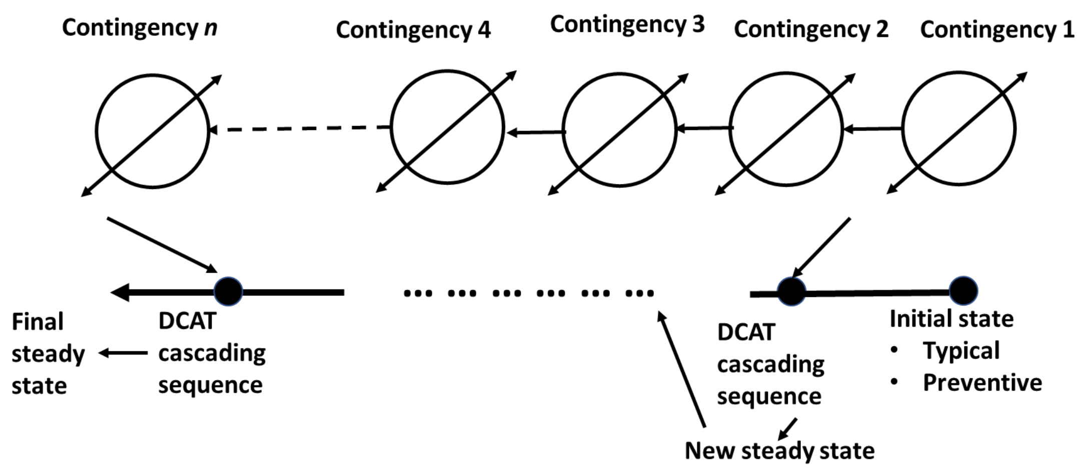


Figure 2-17: Simulation approach for multi-contingency study.

The cascading process in DCAT was specifically automated for hurricane contingencies and other events that evolve over time. Figure 2-18 shows the flowchart of automated multi-contingency study to represent a contingency event. As mentioned before, a hurricane case involves groups of contingencies introduced as sequential steps (these are denoted as contingency groups or hurricane stages), HG in the figure. The first dynamic simulation is initiated considering the first group of hurricane contingencies. DCAT treats each step as a single contingency case and performs simulation. For each step, contingency groups are ingested by DCAT using contingency definition files (idv), while the same DCAT configuration as in the previous DCAT step is adopted for the next step. The final power flow case at the end of the first DCAT simulation is used as an input to run the second hurricane contingency group. The generated power flow data file (sav) from last step is imported as the input power flow data file in current step. The process continues until all the DCAT runs are automatically completed for all listed contingencies or until the system diverges. DCAT saves, dynamic simulations results, summary of actions of protective devices, as well as power flow solutions at various stages of simulation along with the sequence of events.

The simulation process can generate a large amount of result data. The results are stored in using two modes: a series of files and folder and in a database. A series of output folders will be created named after the hurricane contingency file names. The detailed process of sequential DCAT runs along with examples can be found in [14]. A database module was developed and tested as explained in section 2.5.2.

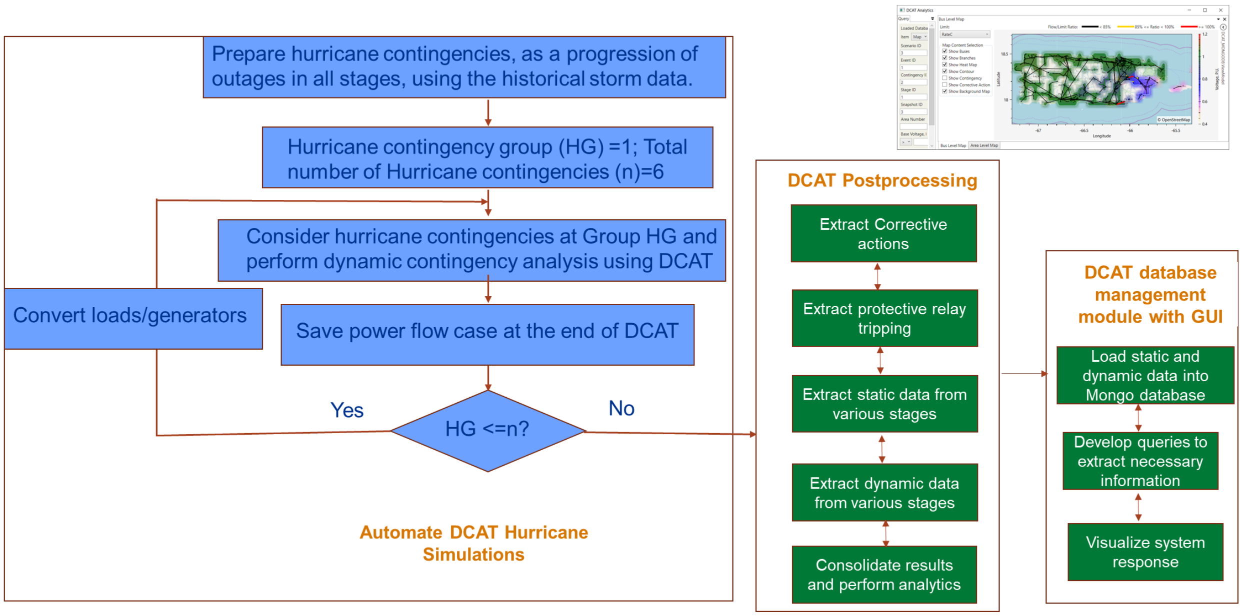


Figure 2-18: Automation of hurricane contingencies

2.5.2 DCAT Database Management Module and DCAT GUI for Analytics and Visualization

To help power system engineers to thoroughly understand and analyze system behavior under many scenarios and contingencies, a DBM was developed for DCAT. An iterative process was used in developing a DCAT result database structure; data structures were designed for specific needs. Figure 2-19 captures the interactive process.

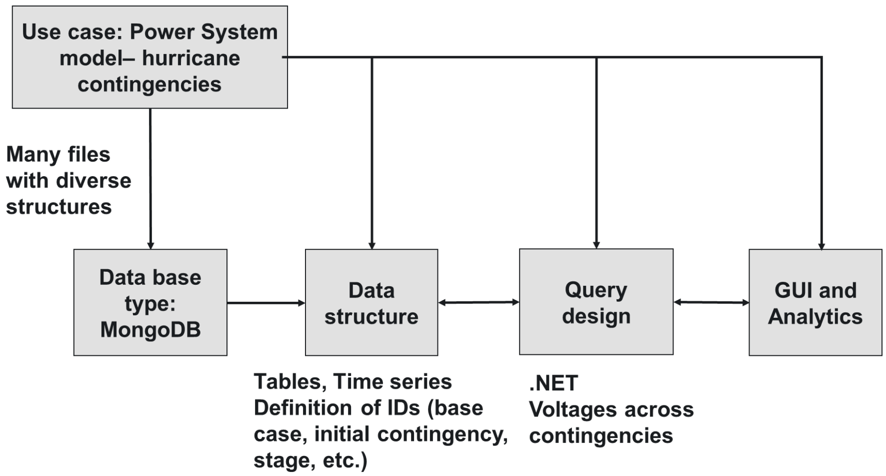


Figure 2-19: Database development iterative process

After the MongoDB database was selected, results from various contingencies were loaded. The team designed an initial data structure, which was improved based on needs for basic data queries. The results of data queries are shown in an analytics graphical user interface (GUI). As more advanced queries are implemented, the team continues to improve the data structure to enable analytics. This iterative process continues, resulting in additional improvements, as the database and analytics continues to be used.

The Puerto Rico example was very important for the development of this data base module. The module is also being updated with experience of application in other interconnections in the continental United States.

2.5.2.1 Data Extraction Module

As mentioned before, DCAT simulations produce large amount of result data; however, actionable information is difficult to extract form these results. The difficulty comes not only from the number of events analyzed, but also from the different types of result data produced in DCAT, such as system intermediate power flow cases, time series from dynamic simulations, corrective actions, and a summary of relay operations. A data extraction module was developed to extract DCAT output information from multiple scenarios and multiple stages of cascading outages and save that data into MongoDB. Figure 2-20 illustrates various data sets that can be extracted using this module.

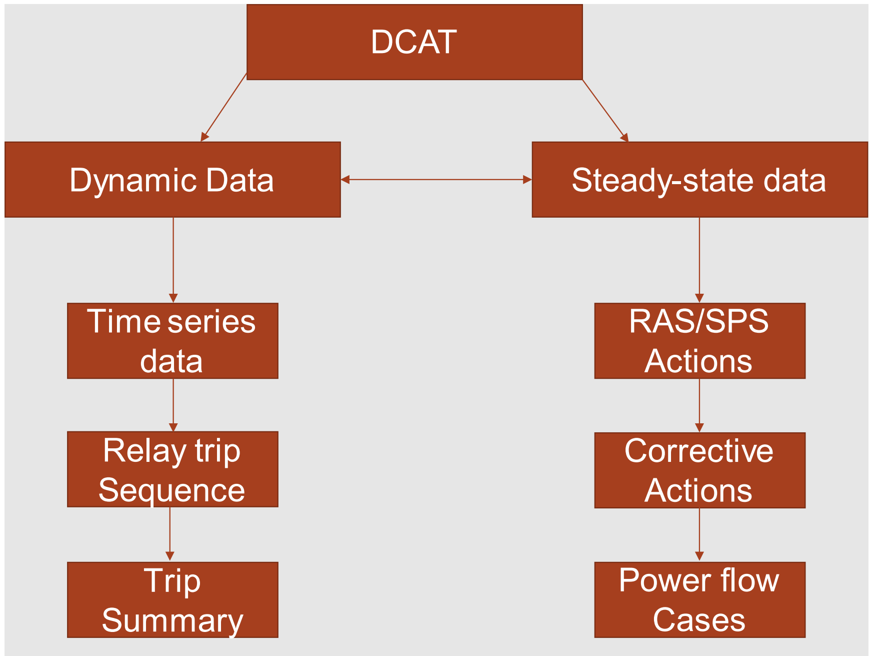


Figure 2-20: DCAT data sets

The data sets illustrated in Figure 2-20 are described below.

1) Time Series Data: This data set has all the time series data for all monitored simulation variables (machine shaft speeds, bus voltages and angles, real and reactive flows) during each contingency during dynamic simulation runs.

2) Relay Trip Sequence and Trip Summary: This summary lists all the tripping information actions immediately following each contingency event that are captured in the dynamic simulation. A summary of the sequence of relay trippings observed during the dynamic simulation is saved for analysis.

3) RAS Actions: A new dynamic simulation is allowed to run for a few seconds from a flat start, and an SPS/RAS action is then implemented. The dynamic response of the interconnected system to such SPS/RAS action is captured and loaded into the database.

4) Corrective Actions: All modifications that the corrective actions have made on the case for each contingency are recorded here. In the current implementation, generation redispatch, shunt switching, transformer tap changing, phase-shifter tap changing, and load shedding transformers taps are considered.

5) Power Flow Cases: Static data from each steady-state case is extracted and saved in the database. This includes bus, branch, load, generator, and interface data.

Commonly Used Parameters in Database Collections

DCAT uses a hybrid dynamic and steady-state approach to simulate cascading outage sequences that include fast dynamic and slower steady-state events. Figure 2-21 shows parameters commonly used in database tables during dynamic and steady-state processes; they are described in 0

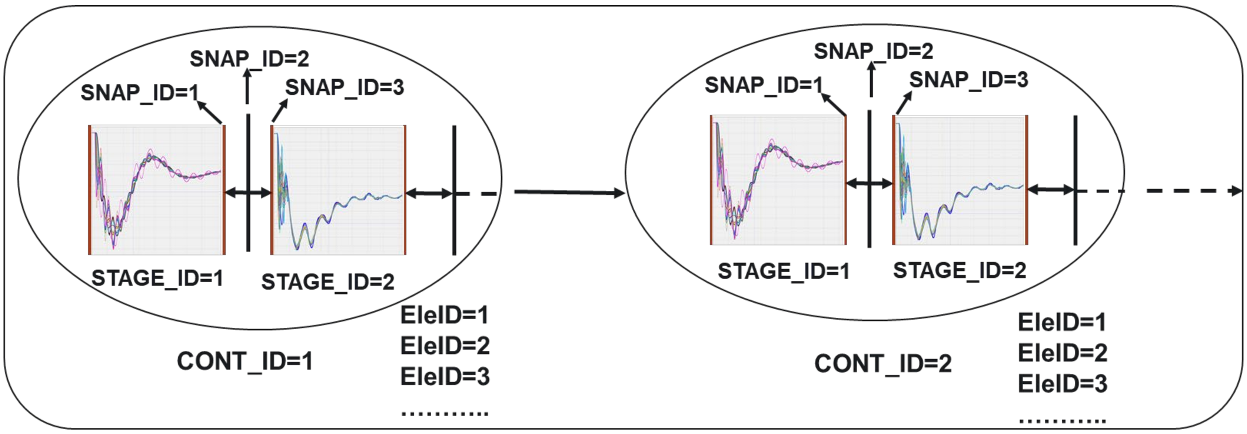


Figure 2-21: DCAT parameters used in database collections

Table 2-1: DCAT Parameters

Parameter	**Description**
INIT_EVENT_ID	Events used in DCAT simulation, such as different hurricanes
SCENARIO	Options applied to DCAT simulation, such as with or without corrective actions
COUNT_ID	Contingency number in hurricane contingency list
STAGE_ID	Dynamic simulation stage, automatically assigned according to result file names
SNAP_ID	Steady-state stage, automatically assigned according to result (1 after DCAT reaches steady state; 2 after RAS actions; 3 After application of corrective actions)

The complete automation capability developed for analyzing hurricane contingencies using DCAT is shown in Figure 2-22.

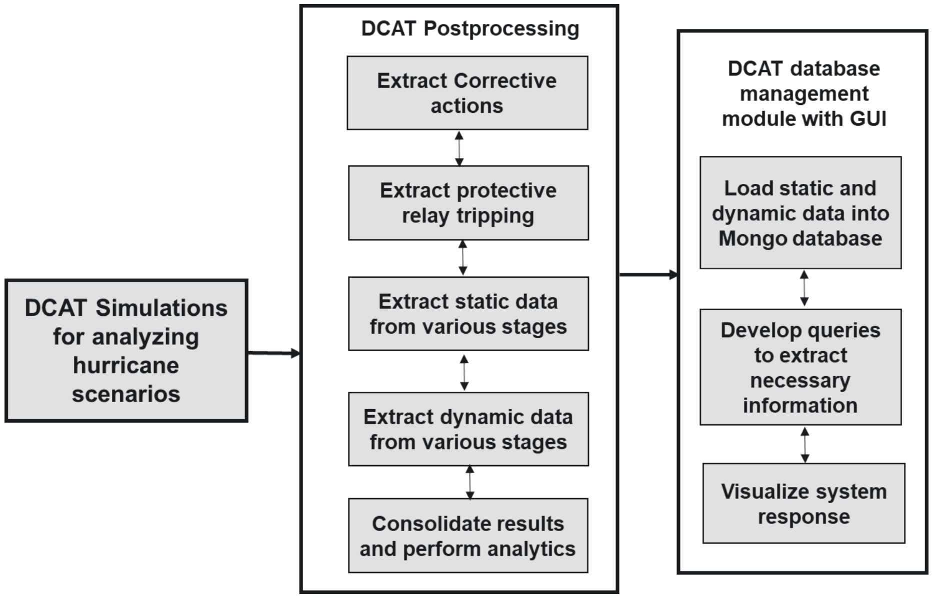


Figure 2-22. Complete automation capability for analyzing hurricane scenarios

2.5.2.2 DCAT Analytics and Visualization - Graphical User Interface

GUI Development

The GUI for DCAT analytics and visualization was developed as a stand-alone Windows application based on a Windows Presentation Foundation (WPF) framework. This application accesses MongoDB displays a list of contingencies, and generates plots illustrating system responses for various initiating events. It also allows the development of queries to extract information from the database. Engineering knowledge and experience analyzing extreme events is factored in the design of the GUI. As shown in Figure 2-23, there are two mains parts of this GUI. The left panel is for database connection and query, which are on two separate tabs: Connection and Query; the right panel is for visualization of the query results. The GUI functionalities are discussed in the rest of this section.

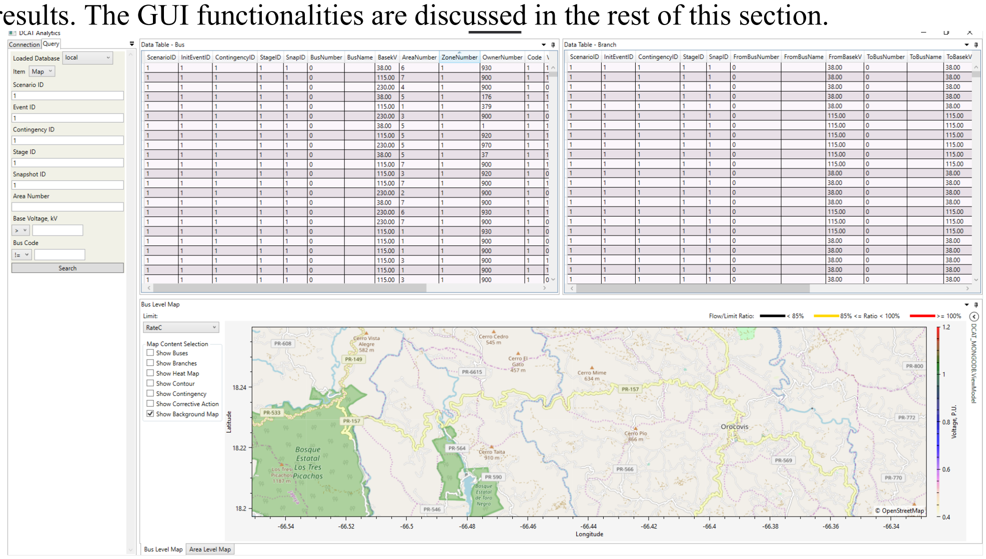
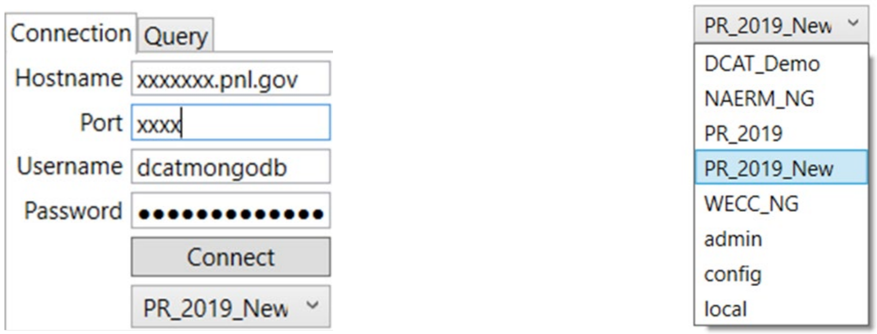


Figure 2-23:Main parts of the DCAT GUI

Database connection

To connect to the MongoDB database server where DCAT simulation results are stored, the hostname of the server, port number, username, and password are required. After the connection is stable, a dropdown menu under the ‘Connect’ button will list all the available databases on the server.

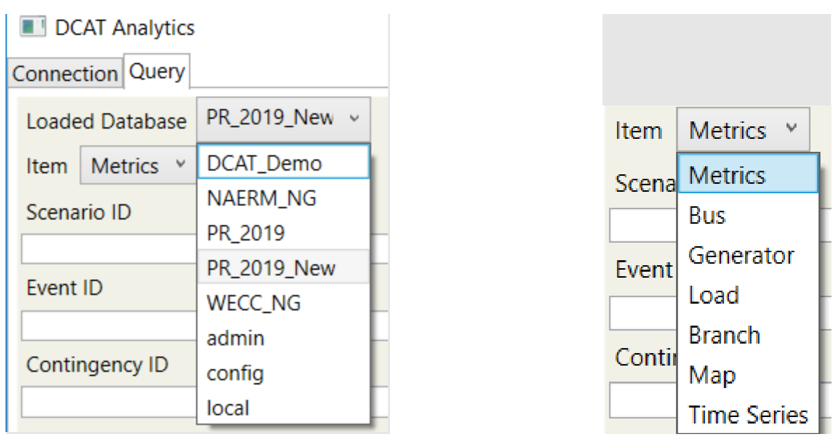


(a) (b)

Figure 2-24: (a) Establish connection between GUI and MongoDB and (b) select database – connection panel

Queries

On the query panel, the user can also choose which database to query against. This selection can be changed anytime during the analysis, as long as the server connection is established. There are seven query items defined in the GUI: Metrics, Bus, Generator, Load, Branch, Map and Time Series. Each of the query items corresponds to one or more actual query(ies) against the selected database and its collection(s). The returned query(ies) results are reorganized for displaying on the right-hand side of the GUI.



(a) (b)

Figure 2-25: (a) database options and (b) available query items – query panel

Parameters

Each of the query item takes some parameters that are field names of the collection(s) in the database and can be specified by the user. None of these parameters are required, but fill in the parameters does help narrow down the queries so it shortens the query time. If none of the parameters are specified, the click on the 'Search' button returns all records in the collection(s). It can take four optional query parameters: Scenario ID, Initial Event ID, Contingency ID and Total Load Not Served by Snapshot ID.

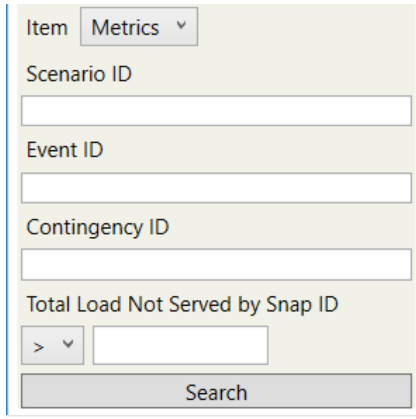


Figure 2-26: Query parameters

The Total Load Not Served by Snapshot ID is specified as a range that is either larger than, equal to or smaller than the specified number. It is the TOT_LOAD_NOT_SERVED field in the STAT table.

Example of Metric Query

The Metrics query serves as a summary for the selected database and gives the user some directions for further analysis. The metrics are defined following the resilience metrics discussed in section 2.4. A summary table is provided summarizing results from three type of data sets: STAT, LOAD, BUS, and BRANCH collections. The metrics table contains summary results such as of load lost and voltage and overload violations. The results are joined by Scenario ID, Initial Event ID, Contingency ID, Stage ID, Snapshot ID and Bus Number, to help the user's analysis.

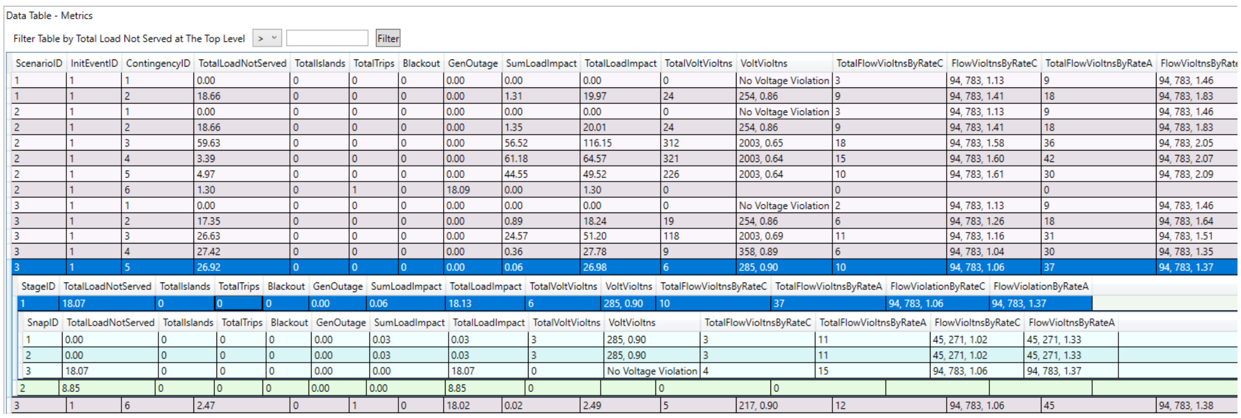
The results are visualized in a three-layer table and a configurable plot, see examples in Figure 2-27 and Figure 2-28.

The table of Figure 2-27 is nested with three layers:

- The top layer of the table summarizes the total results for each contingency group organized by Scenario ID, Initial Event ID and Contingency ID, and some fields are summed, such as TOT_LOAD_NOT_SERVED, TOT_TRIPPINGS, etc.
- The second layer, within each of the above mentioned groups, the records are further grouped by Stage ID, again, fields are summed. Each of these sub-group is shown as sub-tables once a top level row is clicked to expand. The second layer describes detailed results of cascading effects that may result from each event.
- The third layer of records contains details of Snap ID which is the inner most layer and matches the records in the STAT collection. When the row with Stage ID is clicked, the sub-sub-table

expands and rows with Snap ID information shows up. This third layer summarizes information of corrective actions.

The summary table can be sorted by click on the header of each column. The table can be filtered by using the filter above it. This filter filters the table at its top level by Total Load Not Served, i.e. it uses the summed value instead of the individual value of each Snap ID as in the query parameters on the right-hand panel. The user can choose larger than, equal to or smaller than a specified value. By clicking on the row of the table of the first layer, the sub-tables with the second and third layers expand or contract.


Data Table - Metrics

Filter Table by Total Load Not Served at The Top Level > Filter

ScenarioID	InitEventID	ContingencyID	TotalLoadNotServed	TotalIslands	TotalTrips	Blackout	GenOutage	SumLoadImpact	TotalLoadImpact	TotalVoltVioltns	VoltVioltns	TotalFlowVioltnsByRateC	FlowVioltnsByRateC	TotalFlowVioltnsByRateA	FlowVioltnsByRate
1	1	1	0.00	0	0	0	0.00	0.00	0.00	0	No Voltage Violation	3	94, 783, 1.13	9	94, 783, 1.46
1	1	2	18.66	0	0	0	0.00	1.31	19.97	24	254, 0.86	9	94, 783, 1.41	18	94, 783, 1.83
2	1	1	0.00	0	0	0	0.00	0.00	0.00	0	No Voltage Violation	3	94, 783, 1.13	9	94, 783, 1.46
2	1	2	18.66	0	0	0	0.00	1.35	20.01	24	254, 0.86	9	94, 783, 1.41	18	94, 783, 1.83
2	1	3	59.63	0	0	0	0.00	56.52	116.15	312	2003, 0.65	18	94, 783, 1.58	36	94, 783, 2.05
2	1	4	3.39	0	0	0	0.00	61.18	64.57	321	2003, 0.64	15	94, 783, 1.60	42	94, 783, 2.07
2	1	5	4.97	0	0	0	0.00	44.55	49.52	226	2003, 0.64	10	94, 783, 1.61	30	94, 783, 2.09
2	1	6	1.30	0	1	0	18.09	0.00	1.30	0		0		0	
3	1	1	0.00	0	0	0	0.00	0.00	0.00	0	No Voltage Violation	2	94, 783, 1.13	9	94, 783, 1.46
3	1	2	17.35	0	0	0	0.00	0.89	18.24	19	254, 0.86	6	94, 783, 1.26	18	94, 783, 1.64
3	1	3	26.63	0	0	0	0.00	24.57	51.20	118	2003, 0.69	11	94, 783, 1.16	31	94, 783, 1.51
3	1	4	27.42	0	0	0	0.00	0.36	27.78	9	358, 0.89	6	94, 783, 1.04	30	94, 783, 1.35
3	1	5	26.92	0	0	0	0.00	0.06	26.98	6	285, 0.90	10	94, 783, 1.06	37	94, 783, 1.37

StageID	TotalLoadNotServed	TotalIslands	TotalTrips	Blackout	GenOutage	SumLoadImpact	TotalLoadImpact	TotalVoltVioltns	VoltVioltns	TotalFlowVioltnsByRateC	TotalFlowVioltnsByRateA	FlowViolationByRateC	FlowViolationByRateA
1	18.07	0	0	0	0.00	0.06	18.13	6	285, 0.90	10	37	94, 783, 1.06	94, 783, 1.37
2	8.85	0	0	0	0.00	0.00	8.85	0		0	0		

SnapID	TotalLoadNotServed	TotalIslands	TotalTrips	Blackout	GenOutage	SumLoadImpact	TotalLoadImpact	TotalVoltVioltns	VoltVioltns	TotalFlowVioltnsByRateC	TotalFlowVioltnsByRateA	FlowVioltnsByRateC	FlowVioltnsByRateA
1	0.00	0	0	0	0.00	0.03	0.03	3	285, 0.90	3	11	45, 271, 1.02	45, 271, 1.33
2	0.00	0	0	0	0.00	0.03	0.03	3	285, 0.90	3	11	45, 271, 1.02	45, 271, 1.33
3	18.07	0	0	0	0.00	0.00	18.07	0	No Voltage Violation	4	15	94, 783, 1.06	94, 783, 1.37

ScenarioID	InitEventID	ContingencyID	TotalLoadNotServed	TotalIslands	TotalTrips	Blackout	GenOutage	SumLoadImpact	TotalLoadImpact	TotalVoltVioltns	VoltVioltns	TotalFlowVioltnsByRateC	FlowVioltnsByRateC	TotalFlowVioltnsByRateA	FlowVioltnsByRate
3	1	6	2.47	0	1	0	18.02	0.02	2.49	5	217, 0.90	12	94, 783, 1.06	45	94, 783, 1.38

Figure 2-27: Visualization of DCAT analytics

As mentioned before, the summary metrics information can be also shown in a configurable. The plot of Figure 2-28 is interactive and configurable with four dropdown menus. The leftmost dropdown menu specifies the y axis. As it plots the top-level value of the table, to get a unique row, user will have to specify Contingency ID, Initial Event ID and Scenario ID by making choices of the other 3 dropdown boxes.

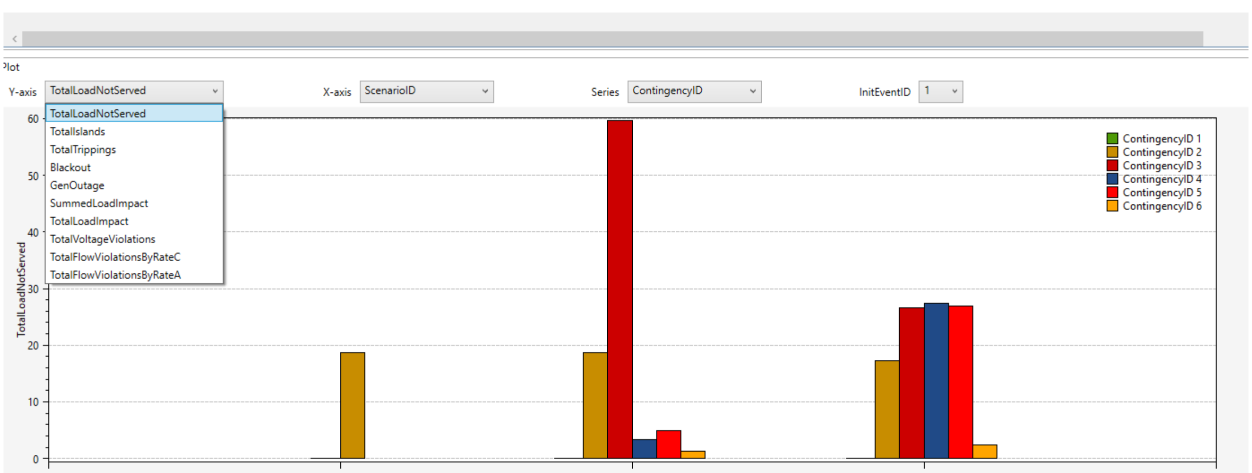
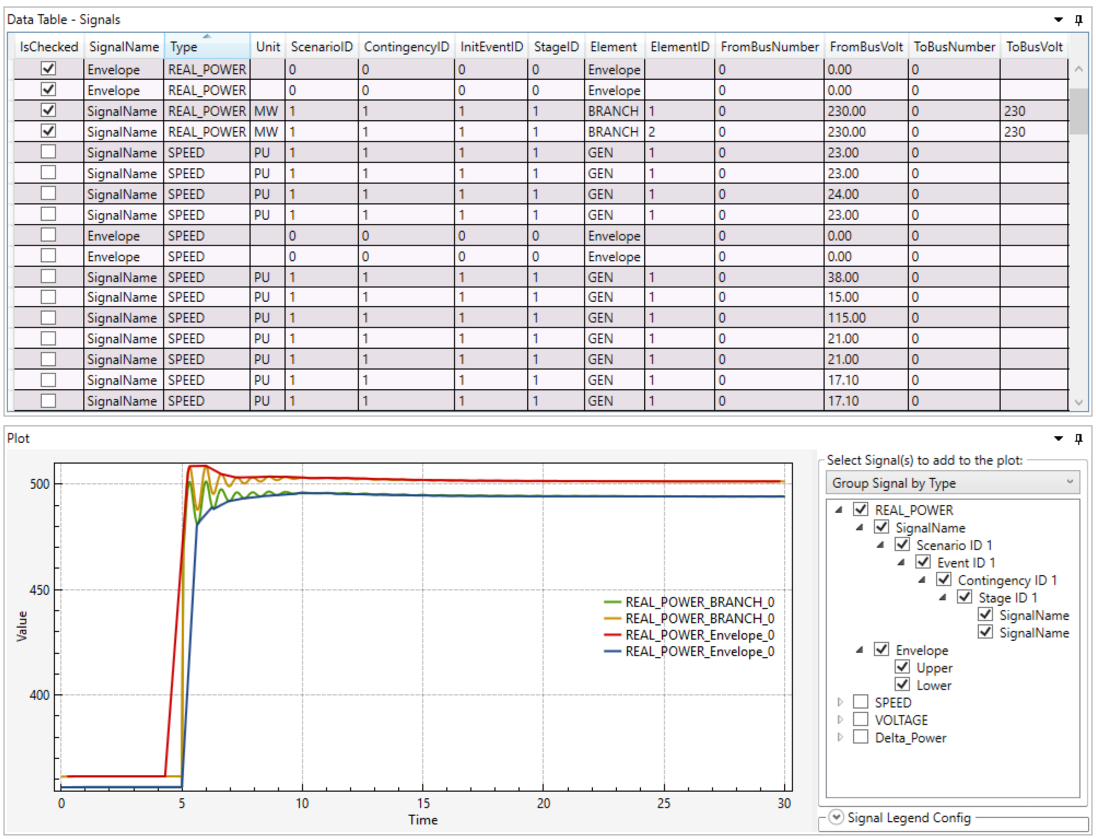


Figure 2-28: Total load not served in all contingencies/scenarios

Dynamic Simulation Results

The results from DCAT dynamic simulations are stored in the database in a collection called TS. The TS results are arranged in a way to facilitate flexible and efficient queries to support engineering analysis. All the TS signals are displayed in a table and can be selected to be plotted in the plot below the table, see Figure 2-29. The dynamic results signals can be queried and filtered in different ways as displayed in Figure 2-30. Both the table and the lower right tree list all signals returned from the query. They are synchronized. Checked signals in the tree of Figure 2-30 will show as checked in the table, and vice versa. A checkbox click selection in the tree will affect all sub-trees. The dropdown box above the lower right signal selection tree let the user choose how the signals should be grouped in the tree. The signals can be grouped by their type, or by the five different IDs. Each type of signals has two envelop signals, upper envelope and lower envelope. The expander below the tree can be expanded and lets the user specify location of the legend for the plot. It also lets the user select what information should be included in the legend



Data Table - Signals

IsChecked	SignalName	Type	Unit	ScenarioID	ContingencyID	InitEventID	StageID	Element	ElementID	FromBusNumber	FromBusVolt	ToBusNumber	ToBusVolt
☑	Envelope	REAL_POWER		0	0	0	0	Envelope		0	0.00	0	
☑	Envelope	REAL_POWER		0	0	0	0	Envelope		0	0.00	0	
☑	SignalName	REAL_POWER	MW	1	1	1	1	BRANCH	1	0	230.00	0	230
☑	SignalName	REAL_POWER	MW	1	1	1	1	BRANCH	2	0	230.00	0	230
☐	SignalName	SPEED	PU	1	1	1	1	GEN	1	0	23.00	0	
☐	SignalName	SPEED	PU	1	1	1	1	GEN	1	0	23.00	0	
☐	SignalName	SPEED	PU	1	1	1	1	GEN	1	0	24.00	0	
☐	SignalName	SPEED	PU	1	1	1	1	GEN	1	0	23.00	0	
☐	Envelope	SPEED		0	0	0	0	Envelope		0	0.00	0	
☐	Envelope	SPEED		0	0	0	0	Envelope		0	0.00	0	
☐	SignalName	SPEED	PU	1	1	1	1	GEN	1	0	38.00	0	
☐	SignalName	SPEED	PU	1	1	1	1	GEN	1	0	15.00	0	
☐	SignalName	SPEED	PU	1	1	1	1	GEN	1	0	115.00	0	
☐	SignalName	SPEED	PU	1	1	1	1	GEN	1	0	21.00	0	
☐	SignalName	SPEED	PU	1	1	1	1	GEN	1	0	21.00	0	
☐	SignalName	SPEED	PU	1	1	1	1	GEN	1	0	17.10	0	
☐	SignalName	SPEED	PU	1	1	1	1	GEN	1	0	17.10	0	

Figure 2-29: Visualization of dynamic response of selected signals

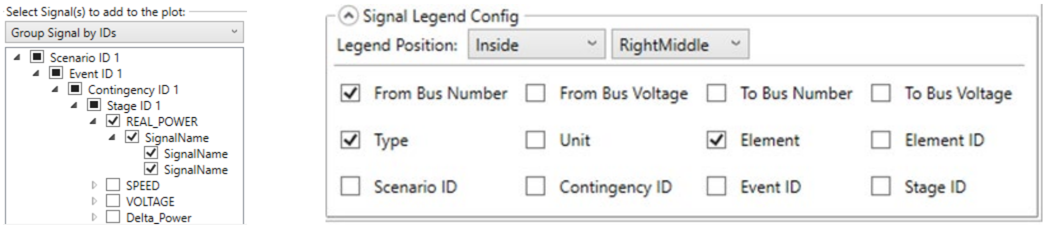


Figure 2-30: Available signal options for querying dynamic results

3.0 Candidate Reinforcements from Previous Studies by Other Institutions

This section compiles potential candidate grid enhancements extracted from the 2019 Puerto Rico IRP [16], and for completeness, this section also lists proposed projects from 2015 Puerto Rico IRP report [10] and other studies. PNNL's hurricane simulations were tested with and without the 2019 Puerto Rico IRP system upgrades to determine how system resiliency and survival improved during hurricane simulations.

3.1 Set of Potential Candidate Reinforcements Based Upon 2019 Puerto Rico IRP Report

The 2019 Puerto Rico IRP [16] proposes sets of candidate lines and substation to reinforce and harden, as well as new proposed transmission lines. These specific reinforcements were designed for minigrid implementation and improved operation. A more detailed discussion on the purpose of Puerto Rico's minigrids and their intended use can be found in Section 4.2.7.

Minigrid upgrades include 140 miles of new 115kV transmission line upgrades. In addition to new lines, another 198 miles of existing 115kV lines were identified as potential candidates for hardening to support minigrid backbones. Additionally, 44 115kV substations and switchyards are up for potential upgrades. Substation upgrades in most cases involve conversion to Gas Insulated Switchgear, that are assumed to be more resistant to hurricane damage caused by wind and surge.

PNNL performed the risk-based hurricane analysis with and without these upgrades in place, using the power grid models from the 2019 IRP. When considering the inclusion of these upgrades, we assumed a zero-failure probability for branch elements and buses associated with these upgrades. Essentially, these elements were removed from contingency definitions utilized in hurricane scenario simulations.

3.2 Set of Potential Candidate Reinforcements from Previous Studies, before 2019 Puerto Rico IRP Report

The Puerto Rico Energy Resiliency Working Group, led by the New York Power Authority and composed of several institutions, proposed a new transmission overlay for Puerto Rico built along main highways to facilitate access by repair crews for rebuilding [8]. The report proposed to build a 345 kV system, to be initially operated in 230 kV. The following list of new lines are proposed and mentioned in [8]:

- Mayaguez to Cambalache along Route 2: Approximately 51 miles
- Cambalache to San Juan along Route 22: Approximately 48 miles
- San Juan to Aguirre along Route 52: Approximately 51 miles
- Aguirre to Costa Sur along Routes 52 and 2: Approximately 40 miles
- Aguirre to San Juan via Humacao, Juncos and Carolina (various highways): Approximately 86 miles
- Costa Sur to Mayaguez along Route 2: Approximately 30 miles

- Caguas to Juncos along Route 30: Approximately 9 miles
- Juncos to San Juan via Carolina (various highways): Approximately 30 miles
- PREPA's new Cambalache to Costa Sur, highlighted as important in report: Approximately 57 miles

Southeast Puerto Rico underground bypass (with HVDC transmission technology) and an alternative conventional AC overhead line are mentioned, however specific points of connection are not given.

Additionally, report [8] proposed several hardening actions with estimated costs for transmission lines, including insulation replacements, hardening against wind damage, and hardening against flooding.

For substations needing reinforcements, report [8], based on an analysis by Navigant Consulting, Inc., identified 230 kV and 115 kV substations with high and medium risks of flooding. Two 230 kV substations and four 115 kV substations were identified as high risk, while one 230 kV substation and eight 115 kV substations were identified as at medium risk of flooding. By crossing-checking the figure provided by Navigant Consulting, Inc. in [8] with the available GIS data from [9], the following lists of substations are identified with the associated levels of risk.

- Aguadilla: High risk
- Añasco: High risk
- Acacias: High risk
- Ponce: High risk
- Aguas Buenas: High risk
- Caguas: High risk
- Bayamón: Medium risk
- Vega Baja: Medium risk
- Dorado: Medium risk
- Caonillas: Medium risk
- Toro Negro: Medium risk

Report [8] estimates costs of several hardening actions for substations, including hardening against wind damage and water damage, replacement of SCADA control equipment, and additional fixes for unreliable operation.

In the 2015 Integrated Resource Planning study [10], several reinforcements and new transmission infrastructure were considered:

- Transmission enhancements identified from previous reliability studies (studies previous to [10]):
  - Bayamón TC: A second transformer of 230/115 kV and 544 MVA
  - Reconstruction of the 115 kV line 36100 Bayamón TC to Barrio Piñas: upgraded to 231 MVA (1192.5 kcmil ACSR conductor)
  - A new 2.5 mile 115 kV underground cable from Humacao TC to Yabucoa TC
  - Capacitor banks at Hato Rey TC (43.05 Mvar) and Berwind TC (46.6 Mvar) to be refurbished and considered in service

- Reconstruction and increase of capacity of the 115 kV line 37800 Cayey TC to Caguas TC to 231 MVA (conductor 1192.5 kcmil ACSR)

- The following transmission enhancements were identified for mitigating the system impacts studied in [10]:
  - Reconstruction of 230 kV lines
  - A new underground 115 kV line between Berwind TC and Sabana Llana TC
  - A new 50 Mvar shunt capacitor bank at Mayagüez TC
  - A new dynamic reactive power compensation in the San Juan area.

In 2013, PREPA envisioned the following transmission projects as priority projects [11].

- A 230 kV line from Costa Sur Plant and EcoEléctrica, L.P. cogeneration plant to Cambalache combustion turbine station: This project envisioned upgrading a line from 115 to 230 kV from Cambalache to Dos Bocas, and constructing a new right of way from Dos Bocas to Costa Sur.
- A new 230 kV line from Aguirre to Aguas Buenas
- A new 230 kV line between Costa Sur and Aguas Buenas, 50 miles
- A planned addition of 230 kV switchgear at Aguirre plant and AES cogeneration facility.
- A planned 115kV line to feed planned Bairoa 115/38kV substation
- A planned 115kV line to from Palo Seco to new Hato Tejas 115/38kV substation
- The report mentions work on several 115/38kV substations.

3.3 Cost Estimates that Could be Applicable to Puerto Rico

Puerto Rico's transmission system has 115 and 230 kV levels. The following cost ranges could be useful for the analysis and are included here for completeness. If more refined cost estimates become available, the values below should be updated.

- Cost of 345 kV lines: although Puerto Rico does not have a 345 kV system, report [8] proposed to build a 345 kV system, to be initially operated at 230 kV. Generic cost information considered in [8] include:
  - $7M/mile for double circuit 345 kV lines
  - $1.25M/mile for 138 kV lines operating at 115 kV
- In 2013, PREPA reported cost estimation and incurred expense of several transmission assets [11]:
  - 230 kV line from Costa Sur Plant and EcoEléctrica, L.P. cogeneration plant to Cambalache combustion turbine station: The project envisioned upgrading a line from 115 to 230 kV from Cambalache to Dos Bocas, and constructing a new right of way from Dos Bocas to Costa Sur. The estimated cost for fiscal year 2014 was $8.1 million; expenditures in fiscal year 2013 were $21.2M. With a total of $29.3M. Using Google Maps to estimate, it appears that the line length would be around 15 miles, which would result in a cost per mile of 29.3/15 = about $2M/mile.
  - New 230 kV line from Aguirre to Aguas Buenas with expenditures of $889,000

- New 230 kV line between Costa Sur and Aguas Buenas, 50 miles, with an estimated cost of $110M
- Expansion of 230 kV switchyards in Costa Sur and Cambalache was $2.8M, and completed in 2012
- Planned addition of 230 kV switchgear at the Aguirre plant and the AES cogeneration facility, with an estimated cost of $3.1M for both projects
- Planned 115kV line to feed the planned Bairoa 115/38 kV substation, with an estimated cost of $7.2M
- Planned 115 kV line to from Palo Seco to new Hato Tejas 115/38 kV substation, with an estimated cost of $10.6M
- The report mentions work on several 115/38 kV substations, providing corresponding budgets
- PREPA installed a 28-mile underground loop of 115 kV transmission cables in the metropolitan San Juan area; the objective of the cable system was to increase resiliency after Hurricane Georges in 1999. The total cost was $195.8M.

4.0 Scenarios of Study: System Conditions and Mitigation Measures

PREPA provided the initial scenarios that were used for current and out-year planning studies in this work. In phase I of this study [17], scenarios were based on provided 2021 and 2019 PREPA planning cases. In phase II (this report), the scenarios of studies are based on planning cases developed by Siemens PTI as part of the 2019 IRP study [16]. An updated 2019 scenario was used. In addition, another 2028 scenario provided by PREPA was also used by PNNL to represent high solar generation. A system high-level summary of those two scenarios are given in Table 4-1

Table 4-1: System summary of 2019 and 2028 scenarios from 2019 IRP used in PNNL study

Case	Total Generation Output; & Load (MW)	Total num. of Bus & Branch	Total num. of 230-kV Bus & Branch	Total num. of 115-kV Bus & Branch
2019	2886.3 & 2820.3	1263 & 1269	17 & 62	124 & 281
2028	2185.9 & 2161.2	1333 & 1332	17 & 43	133 & 273

This study defines sensitivity to system conditions and scenarios for mitigation measures. Scenarios of study are described in this section, including system conditions and configurations, as well as hurricane contingency scenarios.

4.1 Scenarios Provided by PREPA from 2019 IRP

Near-term and long-term planning cases were provided by PREPA to PNNL. The future cases reflected resource plans under the Scenario 4 Strategy 2 (S4S2) plan and the Energy System Modernization (ESM) plan. The base case information provided by PREPA consisted of:

- 2019, day peak and night peak cases, power flow and dynamic models
- 2025, day peak and night peak cases, S4S2 and ESM scenarios, power flow and dynamic models
- 2028, day peak and night peak cases, S4S2 and ESM scenarios, power flow and dynamic models

As described in the 2019 IRP [16], Scenario 4 assumes that *"gas is made available at multiple, new LNG terminals (north, east and west locations) combined with expected (base case) cost of renewable and availability*." And strategy 2 "*reflects a system of more distributed, flexible generation, emphasizing resiliency and closer proximity of generation sources to the customer. The strategy incorporates Micro or Minigrids and hardening of existing PREPA infrastructure. In this strategy, most of the load is supplied from local supply resources that can be isolated form the remainder of the grid during a major event, but still supply all or a portion of the nearby load*."

As described in the 2019 IRP, ESM is [16] "*essentially a derivative of Scenario 4 with the stated purpose to expedite the implementation of a resilient resource plan utilizing procurement options presented by the Public Private Partnership Authority, identify the pricing structure necessary to retain existing natural* *gas fired generation in the south, consider locational alternatives for new large scale CCGTs, and ensure reliable capacity in the San Juan area. The ESM Plan contains provisions for development activities that allow PREPA to install new economic and resilient generation resources should actual load be higher than the IRP's forecast.*"

In this study, the 2019 base case and the 2028 S4S2 cases were used as a base for the analysis. 2019 base case represents the current condition of the grid. While 2028 S4S2 case resulted in a large addition of PV solar generation energy storage and natural gas generation. The day peak 2028 S2S4 case contains 100 % of solar generation, with natural gas plants offline, and retired power plants operated as synchronous condensers to improve stability.

Various sensitivities and mitigation actions have been studied as scenarios in this study. These assumptions for sensitivities are described in the following subsections.

Figure 4-1 shows a map of electric infrastructure in Puerto Rico, as an illustration. This map was created using publicly available data, and it is used here to provide a general idea of the transmission and generation infrastructure in Puerto Rico. However, the details of baseline scenarios are more refined than the map indicates. Figure 4-2 illustrate the 2019 status of the generation assets in Puerto Rico. Figure 4-3 illustrates the 2025 ESM scenario from the 2019 IRP report, and it can also be leveraged to illustrate the 2028 ESM scenario.

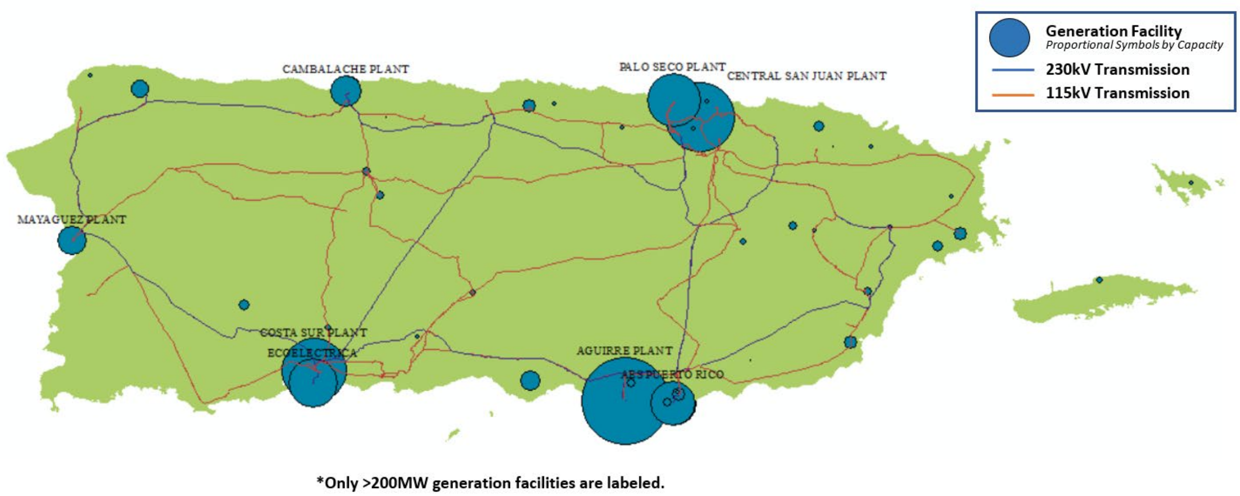


Figure 4-1: Transmission and generation facilities in Puerto Rico (figure based on publicly available GIS information[1]).

[1] Publicly available GIS information from HIFLD Open Data [https://hifld-geoplatform.opendata.arcgis.com]

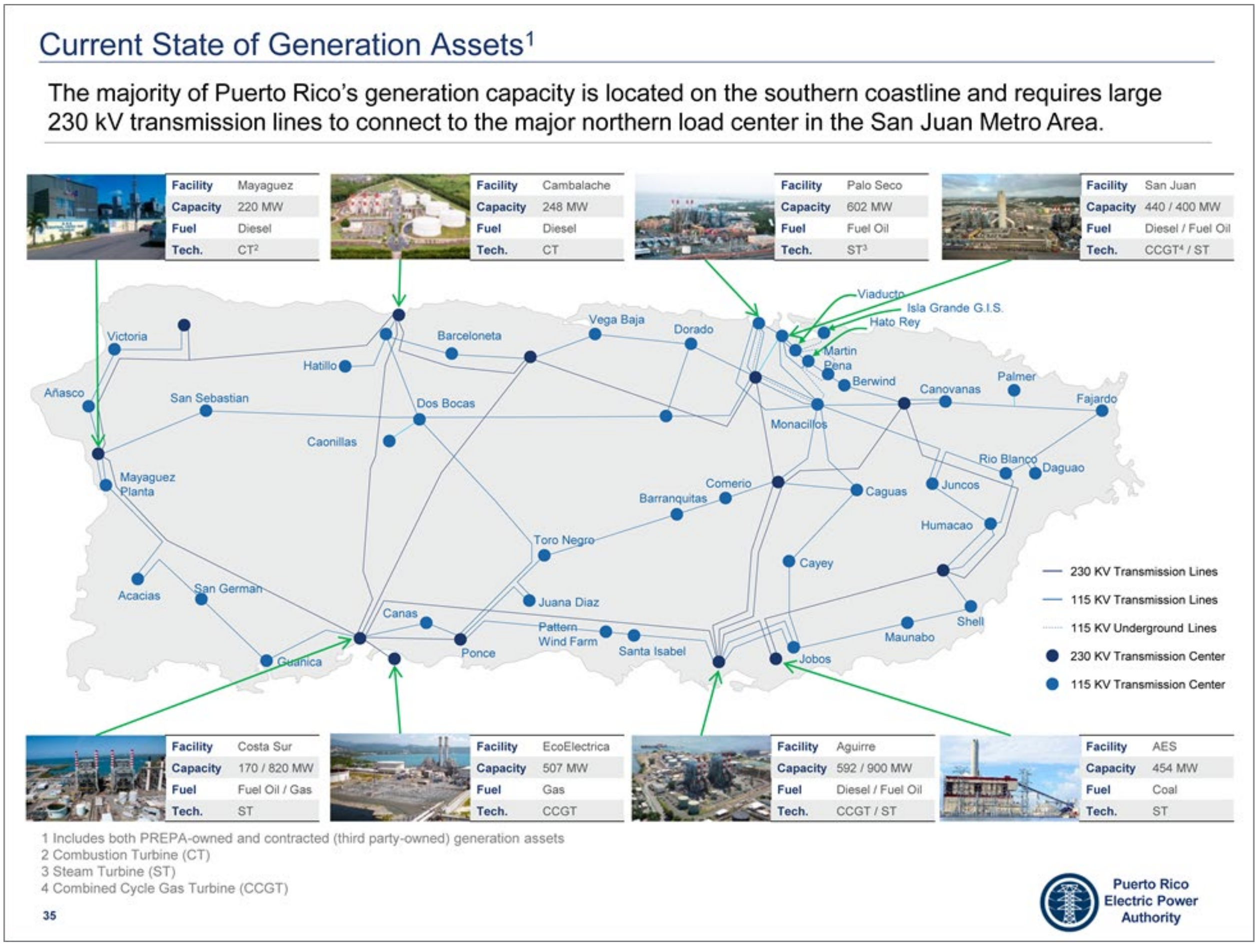


Figure 4-2: 2019 status of generation assets[1]

[1] Source: PREPA's 2019 fiscal plan presentation available online at https://aeepr.com/es-pr/Documents/Exhibit%201%20-%202019%20Fiscal_Plan_for_PREPA_Certified_FOMB%20on_June_27_2019.pdf

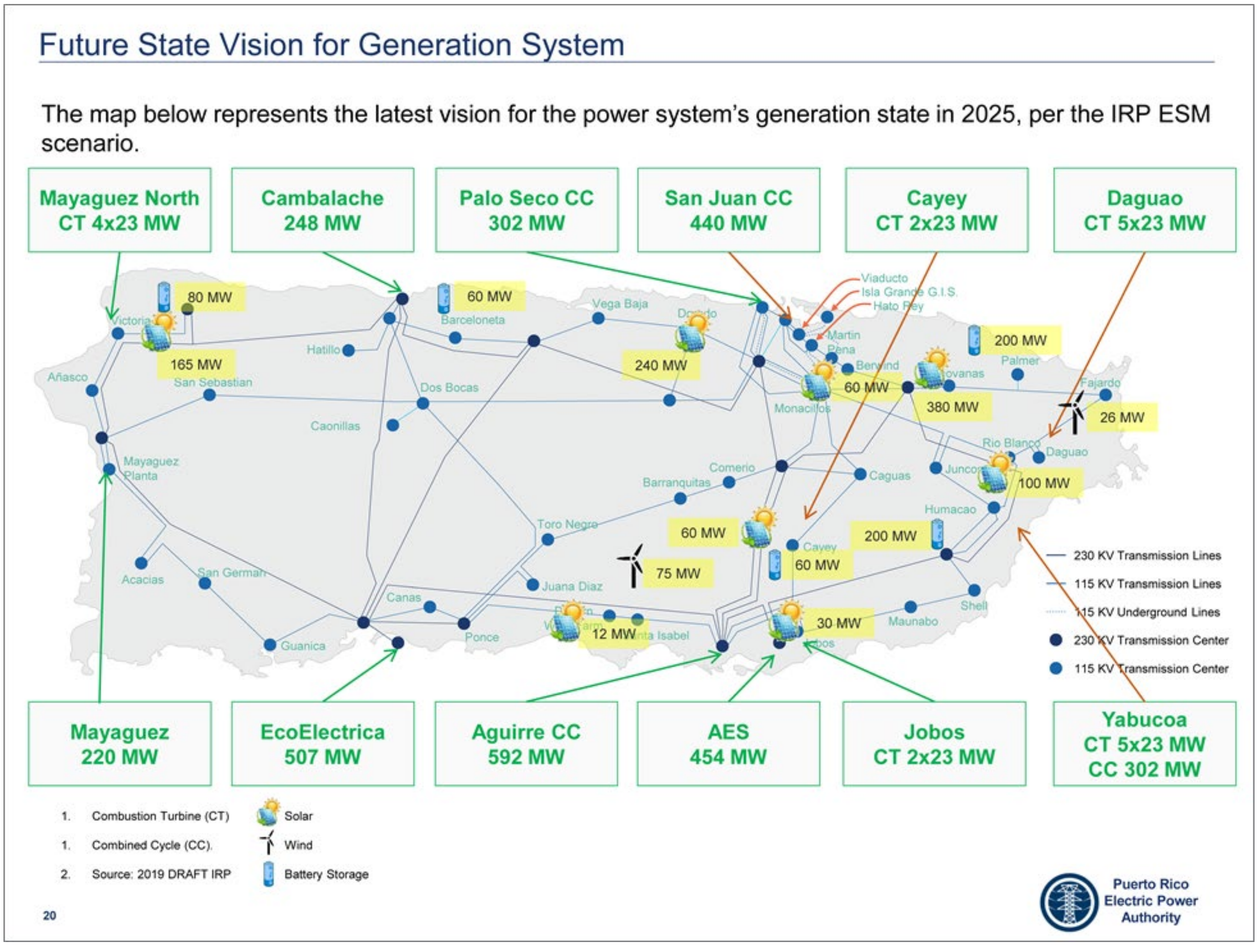


Figure 4-3: 2025 ESM scenario from the 2019 IRP report[1]

[1] Source: PREPA's 2019 fiscal plan presentation available online at https://aeepr.com/es-pr/Documents/Exhibit%201%20-%202019%20Fiscal_Plan_for_PREPA_Certified_FOMB%20on_June_27_2019.pdf

4.2 System Conditions Under Study

DCAT simulations were performed for Puerto Rico to analyze the impacts and resiliency of the transmission network during Hurricane scenarios.

Various system conditions were studied:

- Base cases obtained from PREPA, from the 2019 IRP process (2019 and 2028 scenarios)
- Additional sensitivity cases
    - Sensitivity to corrective actions configurations in DCAT
    - Derating lines due to assumption of lack of vegetation management
    - Sensitivity to asset failure probability, using HEADOUT minimum & average asset failure probability for developing hurricane contingency scenarios
    - Preventive load reduction scenario assuming that the system operator could unload the system as a preventive measure to try to mitigate the impact of a hurricane
    - Addition of generator frequency and voltage protection relays
    - Inverter control configuration for solar PV and energy storage: sensitivity to frequency control settings and type of inverter (grid following versus grid forming inverts) to study stability improvement
    - Minigrid configurations proposed in the 2019 IRP

The following subsections describe the additional sensitivity cases.

4.2.1 Corrective Actions Configuration

Corrective actions are a set of potential control strategies that are used to relief system voltage and line flow violations. The violations thresholds are set to be 0.9 and 1.1 per unit for voltage, and Rate C for line flow in MVA. Four types of corrective actions were employed: switched shunts adjustments, load tap change, generators dispatch, and load shedding. Load shedding has been given a high penalty and the least priority as it is considered the last resort to relief violations.

To investigate the impact of corrective actions on the system performance, three different settings were used to employ the corrective actions on the system after a disturbance simulated by dynamics. The three settings are also listed as three DCAT simulation scenarios, they are:

1. All voltage levels could be utilized to relive violations
2. Only voltage levels of 100 kV and above are allowed
3. No corrective actions at all.

4.2.2 Line Derating Due to Assumed to Lack of Vegetation Management

As lines are lost, increased thermal loading of transmission facilities may result and cause transmission line sagging. When sagging occurs, the distance between energized transmission facilities and underlying vegetation is reduced. This can cause the overloaded transmission facilities to fault out and trip, introducing a dynamic disturbance to an already weakened system. In Puerto Rico, where vegetation management program is lacking, lines tripping offline due to line sagging is a significant concern.

To analyze the impact of lines tripping due to line sagging, lines at risk to underlying vegetation were de-rated in DCAT simulations. The lines identified to be at risk to sagging into vegetation were de-rated by 80%. By de-rating the identified transmission line facilities, DCAT will trip these lines if thermal overloading exceeds the de-rated threshold by an additional 30%.

In order to implement this, a subset of 230kV and 115kV transmission lines in the Puerto Rico PSS®E model was identified where vegetation undergrowth was assumed. In order to identify lines impacted by vegetation undergrowth, a USGS land cover shape file that was based on 2001 satellite imagery was attained. This shape file was overlaid on GIS data of the Puerto Rico power system. Transmission lines mapped on top of denser areas of vegetation were identified as candidates for lines more likely to be impacted by vegetation undergrowth. The lines identified as impacted were mapped back to the Puerto Rico PSS®E power flow case branches. This may be an oversimplified methodology and was chosen due to time constraints and funding. This approach can be improved on in the future for a more accurate approach.

Figure 4-4 shows identified 230kV and 115kV transmission line facilities, highlighted in yellow, assumed to be at risk to underlying vegetation. These line sections were mapped to specific PSS®E line elements. The PSS®E line element ratings were decreased to 80% of their original ratings.

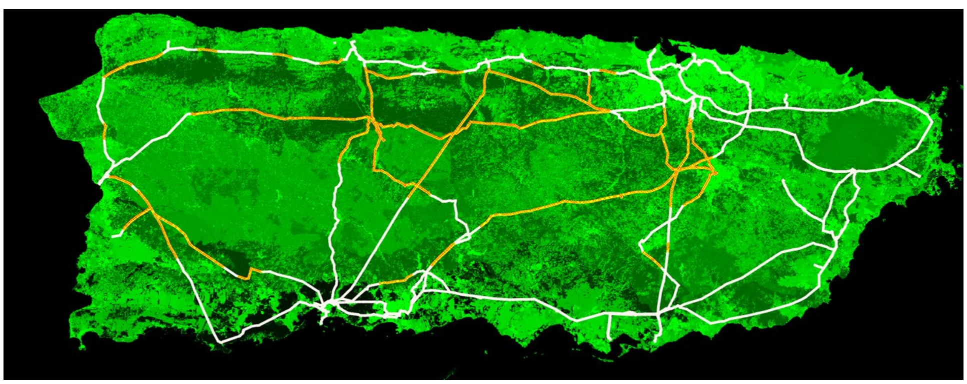


Figure 4-4: Vegetation impacted assets (in yellow) identified by overlaying electric grid GIS on 2001 USGS land cover shape file[1]

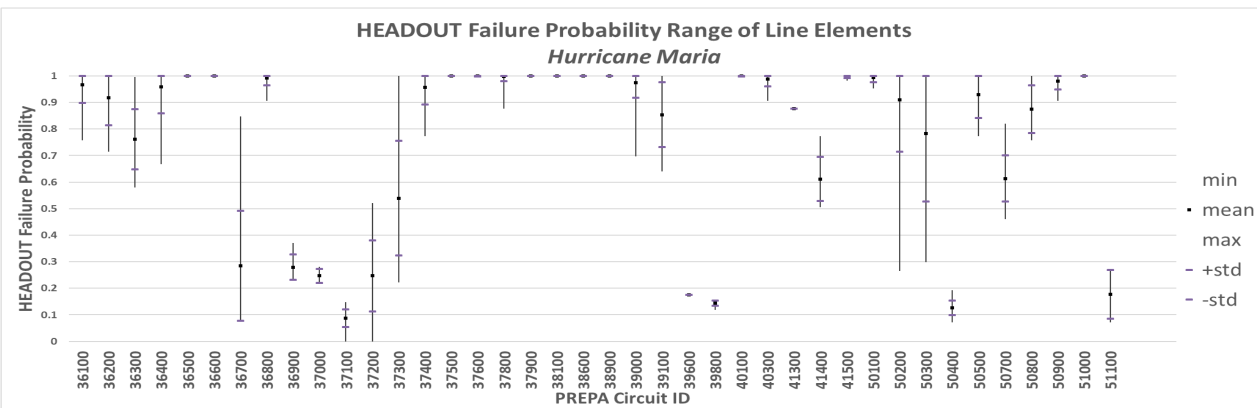
[1] Source: https://www.usgs.gov/core-science-systems/science-analytics-and-synthesis/gap/science/land-cover-data-download?qt-science_center_objects=0#qt-science_center_objects

4.2.3 Using Minimum & Mean HEADOUT Failure Probability

Under the original set of assumptions for mapping HEADOUT failure probability to PSS®E transmission line segments (discussed in section 4.1.1), the worst HEADOUT failure probability along a PREPA Circuit ID was assigned to the associated PSS®E branches. That method represented a worst-case scenario, which is generally the system condition that utilities are required to design and prepare for. As discussed in Section 2.1.2, there is modeling uncertainty due to how the GIS assets were grouped, therefore assumption of worst probability of failure may be too pessimistic. Therefore, in this sensitivity case, the minimum and average HEADOUT failure probability along a PREPA Circuit ID was assigned to the associated PSS®E branches. This was then used to create sets of hurricane contingency scenarios, one using minimum HEADOUT failure probabilities, and the other using average HEADOUT failure probabilities.

By creating hurricane contingency scenarios for DCAT runs based on minimum and mean HEADOUT failure probabilities, insight into less extreme hurricane impact can be assessed. This information can be used to help prioritize system hardening and operational mitigation strategies pre-hurricane impact.

To illustrate the range of HEADOUT failure probabilities along a PREPA Circuit ID, Figure 4-5 below shows the maximum, minimum, mean, and standard deviation of failure probabilities for Hurricane Maria.



PREPA Circuit ID

Figure 4-5: Range of HEADOUT failure probabilities associated with each 230kV and 115kV PREPA Circuit ID for Hurricane Maria

4.2.4 Preventive unloading case

Hurricanes are system-disruptive events that can cause significant damage to the system-grid. Most of the time, information on hurricane path and area of significant impact is known ahead of time through weather forecasting and warnings. Based on this information, some preventive actions could be planned to minimize hurricane impact. The idea here is to implement mitigation measures that can reduce the stress on system infrastructure that is more likely to be damaged by the hurricane. By doing so, the risk of further infrastructure damage and cascading failure can be reduced. In this report, the effectiveness of planned load-shedding has been explored as a preventive action and mitigation strategy. It is assumed that system operators would implement such load-shedding action prior to hurricane impact.

For example, prior to impact, Hurricane Maria was forecasted to have a high probability of damage to electrical infrastructure. Transmission facilities between the southern and northern portions of the grid, that greatly supported system stability, were largely at threat of destruction from Hurricane wind speeds. Transmission corridors between the southern and northern parts of the island provide vital power transfer from the generation heavy Ponce region (located in the south) to the major load centers in San Juan, Bayamon, Caroline and Caguas regions (located in the north).

Figure 4-6 compares the generation and load profiles between the southern and northern regions. Any damage to transmission facilities between these two regions can result in system collapse, especially in the north, triggering disruption of power-supply to all critical and non-critical loads. Therefore, preventive unloading could have been a practical mitigation strategy to reduce power transfer from the south to north prior to hurricane impact, resulting in improved system performance and stability during hurricane impact.

This in one scenario of study performed in the simulation framework developed. It is expected that such a simulation using preventive system unloading would result in improved system response during Hurricane impact. This mitigation strategy can potentially improve the grid’s ability to sustain power-supply to critical and some non-critical loads, even after transmission facilities connecting southern and northern regions are severed. This will largely depend on the generation availability in the northern regions.

In the simulation framework, care has been taken to not unload critical load, such as parts of the PSS®E model designated with zone field names like hospitals. In this report, results are presented for the scenario in which load in the northern regions are reduced by close to 50% with an equivalent amount of generation reduced in the south as shown in Figure 4-6. This preventive unloading measure reduced the power-flow between the southern and northern regions from 602 MW down to 370 MW.

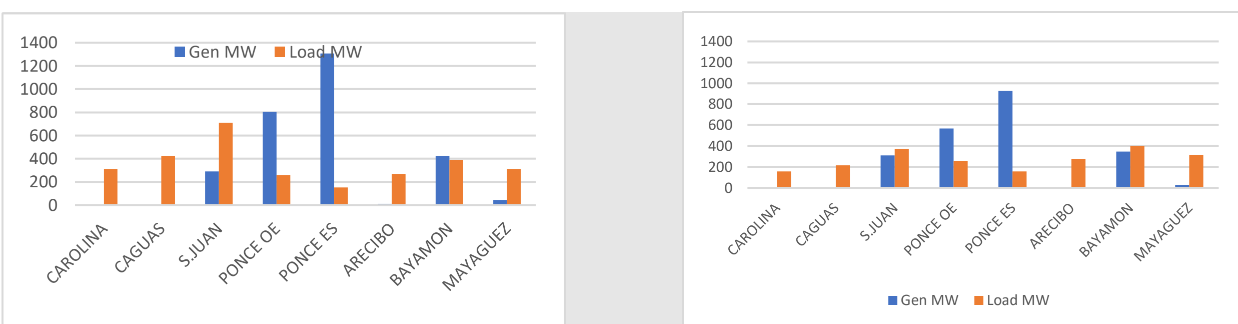


Figure 4-6: Generation and load profile of areas in the North and the South region of Puerto-Rico. A) Base-case B) Light-load case to demonstrate the effectiveness of proposed preventive action

4.2.5 Addition of Generator Frequency and Voltage Relays

A sensitivity study was performed to evaluate the system response with the addition of generator frequency and voltage relays. The PREPA dynamics models received did not contain any generator protection models and therefore new frequency and voltage relay models were added to the dynamic model. The models utilized the FRQDCAT and VTGDCAT dynamic relay models available in PSS®E. The exact relay settings for generator frequency and voltage relays are unknown, however, the settings applied to each generator in PSS®E followed the guidelines specified in an NREL technical report published in 2013[1]. These settings are summarized in Table 4-2..

By applying the settings shown in the table below, a conservative approach at approximating generator settings for frequency and voltage relays is taken. In reality, generator frequency and voltage relays may be set at a wider operational range.

Relays are applied to both conventional and renewable generators as well as to synchronous condensers.

Table 4-2: Generator Frequency and Voltage Relay Set Points added to PREPA Generators in PSS®E

Generator Under-Frequency Relay Set Points	
Setting (Hz)	***Trip Delay***
57.5 Hz	10 seconds
56.5 Hz	Instantaneous Trip
Generator Over-Frequency Relay Set Points	
Setting (Hz)	***Trip Delay***
61.5 Hz	10 seconds
62.5 Hz	Instantaneous Trip
Generator Under-Voltage Relay Set Points	
Setting (p.u.)	***Trip Delay***
0.85 p.u.	3 seconds
0.55 p.u.	2 seconds
0.2 p.u.	0.9 seconds
0.1 p.u.	0.6 seconds
Generator Over-Voltage Relay Set Points	
Setting (p.u.)	***Trip Delay***
1.15 p.u.	3 seconds
1.25 p.u.	1 seconds
1.3 p.u.	0.15 seconds

4.2.6 Inverter control configurations: grid-forming and grid following inverters with frequency and voltage support

PREPA provided 2028 S4S2 scenarios with high penetration of solar and battery storage inverters, from the 2019 IRP study. The models provided considered grid-following generic models for inverters, and they needed the inclusion of synchronous compensators to maintain stability. In this work we considered the following scenarios when it comes to inverter control configurations:

[1] V. Gevorgian and S. Booth, "Review of PREPA Technical Requirements for Interconnecting Wind and Solar Generation," National Renewable Energy Laboratory, Technical Report, NREL/TP-5D00-57089, November 2013 https://www.nrel.gov/docs/fy14osti/57089.pdf

1. IRP cases (as provided by PREPA): grid-following inverters in PV and battery energy storage. Frequency control was considered as part of battery energy storage only with a total capacity of 1400 MW and a droop value of 0.03. The 2019 IRP identified that synchronous condensers where needed to stabilize the system, due to the presence of high penetration of grid-following inverters. It was assumed that retiring generators would be converted into synchronous condensers. Voltage control was considered as part of the grid-following inverter models for both batteries and PV. However, the gain settings provided in the models result in minimum reactive power response. This has motivated the control settings adopted in the other sensitivity scenarios for inverter configurations.

2. 10%PV case: this configuration builds on the 2019 IRP scenarios to enable PV units that are not associated with batteries to provide frequency response within 10% of their rated capacity. Any PVs that are associated with a battery (part of the same plant) are not required to provide frequency control as long as the battery does. These settings comply with the PREPA regulation for distributed energy resources rated above 1MW[1]. This configuration provides additional ~56MW for frequency response. In addition to the frequency response, it was noticed that the voltage control settings on many of the inverters could be improved. The original settings prevented the inverters from providing voltage control and reactive power support that is adaptable to the operating conditions of the system. Voltage control settings were modified to increase the contribution of inverters to the system voltage control. The improvements in the voltage profile are noticeable in the results.

3. All PV case: this configuration extends the previous configuration (10%PV) and allows all PV units to provide frequency response without any limits, whether they are associated with batteries or not. This configuration is thought to be as an extreme and to demonstrate the full potential of the system response in case of emergencies that does not have to comply with regulations. This configuration adds ~174MW (relative to 2019 IRP) for frequency response.

4. Grid forming: a voltage-controlled inverter seen as a controllable voltage source behind a coupling reactance, is known as a grid-forming source. This is much like a synchronous generator, which allows for direct control of voltage and frequency [15]. The use of grid-forming inverters has brought stability improvements in microgrids and could to potentially improve stability in larger grids with high penetration of renewable generation. Grid-forming sources were used to replace original PV plant models, as well as battery units associated with a PV plant. Out of total generation 2023 MW, 1390 MW were replaced with grid-forming inverter models. The remaining units were either identified as wind units, or not enough details were provided about the energy source; the models for both were left as the 2019 IRP configuration. The initial simulations run in this study reflect that with the presence of grid-forming inverters in the system, there is no need for synchronous condensers to stabilize the system. Therefore, all synchronous condensers, considered in the original 2019 IRP scenarios, were disconnected.

[1] Rules for interconnection with PREPA's electric transmission and sub-transmission systems, to participate in net metering programs, https://aeepr.com/es-pr/Site-Servicios/Manuales/Reglamento%20GD%20a%20Transmisi%C3%B3n%20y%20Subtransmisi%C3%B3n%20-%20Depto%20Estado.pdf

4.2.7 MiniGrid Configurations

The 2019 Puerto Rico IRP [16] proposes temporary splitting the Puerto Rico's bulk grid into a subset of eight minigrids. The minigrids are to be activated, as an emergency measure, when critical 230kV and 115kV interconnections are lost after catastrophic events. Approximate geographic locations of these minigrids are shown in Figure 4-7. Each minigrid contains 100-1000MW of peak load, with approximately 40% of this load in each area deemed critical (in need of immediate restoration).

Figure 4-7: Geographic location of minigrids[1].

In this work, the response and performance of minigrid to a hurricane event was studied. It is assumed that the system is split into minigrids as a preventive measure, moments or hours before the hurricane arrives to Puerto Rico.

The proposed risk-based framework (HEADOUT – EGRASS – DCAT) was used to simulate the operation of Puerto Rican grid divided into the smaller mini-grids, when a hurricane occurs. It is to be noted that this minigrid operating scenarios closely aligns with the current practice that PREPA engineers implement to recover the Puerto Rican system after an extreme event. For this analysis, two minigrids, Bayamon-San Juan and Ponce, were considered. These two minigrids have enough generation including thermal and solar to sustain the entire load.

4.2.7.1 Additional background on minigrids

Each minigrid contains Figure100-1000MW of peak load, with approximately 40% of this load in each area deemed 'critical' (in need of immediate restoration). The load in each minigrid is divided into three categories based on its nature: 1) Critical loads – These loads are crucial in nature and include hospitals, airports, fire-stations, etc. These loads must be supplied by thermal generations; 2) Priority loads: These loads are necessary in nature and include loads like shopping centers, gas-stations, etc. These loads can be served by a combination of thermal and solar plants including storage; and 3) Balance of the loads: These loads include rest all other loads in minigrid. These loads can be served by a combination of thermal and solar plants including storage.

Within each minigrid, the 2019 IRP also suggests implementation of microgrids localized to single substations and surrounding facilities and loads. Microgrids would be used when 115kV and 38kV

[1] Source: PREPA's 2019 fiscal plan presentation, page 80, available online: https://aeepr.com/es-pr/Documents/Exhibit%201%20%202019%20Fiscal_Plan_for_PREPA_Certified_FOMB%20on_June_27_2019.pdf

minigrid backbone interconnections are lost. The majority of these microgrids will serve a peak load less than 10MW, based on IRP and acquired historical substation load data.

Minigrid and microgrid designs will require two major elements: 1) local generation that ensures critical and priority loads can be served in isolation, 2) enough grid infrastructure so that generation can be delivered reliably. To serve the load within each microgrid, a combination of thermal and renewable resources is to be considered. Thermal resources to be utilized in microgrid configurations will likely require the flexibility to cycle on-off for renewables during daytime and evening hours. Currently, the IRP considers thermal peaking resources made up of smaller gas turbines to provide minimal thermal supply to minigrids and microgrids in short term.

Currently, there are limited regulatory processes, procedures, and technical requirements, in place for minigrid and microgrid interconnection in Puerto Rico. However, Act 17-2019 requires the development of new regulatory processes to ensure the interconnection of microgrids into the transmission and distribution system are "swift, uniform in all regions, and cost and time efficient in order to promote the development of these projects." Additionally, developments of processes to interconnect minigrids and microgrids under Act 17-2019 may reveal additional technical requirements for generators utilized in these system configurations.

4.3 Hurricane Event Scenarios

The Hurricane event scenarios developed for this study are based on historical data from Hurricanes Maria and Irma which impacted Puerto Rico in 2017. Historical wind field and hurricane track data from the National Hurricane Center were used both to produce utility asset fault probabilities with HEADOUT, see section 2.1.1, and to derive the temporal sequence of outages using the EGRASS Temporal Sequence Model described in section 2.2. These two hurricanes offer a large variation in their impact on the utility infrastructure of Puerto Rico, as the wind speeds and storm surges occurring during Hurricane Maria were much more severe than Hurricane Irma, and this is reflected in the results of this study.

Five event scenarios were developed from Hurricane Maria and Irma data, to allow for modeling of a wide variation in fault propagation on the transmission system. These are:

1. Hurricane Maria – Maximum Failure Probability from HEADOUT
2. Hurricane Irma – Maximum Failure Probability from HEADOUT
3. Hurricane Maria Lite – Maximum Failure Probability from HEADOUT
4. Hurricane Maria – Minimum Failure Probability from HEADOUT
5. Hurricane Maria – Mean Failure Probability from HEADOUT

For both the Maria and Irma base-case scenarios (point 1 and 2 in list above), the EGRASS Temporal Sequence Model was used with a wind-speed cutoff of 50 knots for both hurricanes to determine which assets were affected by the hurricane (and therefore sampled by the Monte Carlo model) at each timestep. In addition, the failure probabilities used for each asset correspond to the maximum probability among all HEADOUT GIS assets assigned to the same Circuit ID, as described in section 2.1.2. In this sense, these scenarios can be viewed as representing the worst-case scenario based on the HEADOUT data.

To provide a contingency scenario that fell somewhere between the base-cases in terms of impact, the Maria Lite scenario (item 3 in list above) was developed. This uses the same data and probabilities as the Maria base-case scenario (item 1 in list above) but employed a wind speed cutoff of 80 knots in the EGRASS Temporal Sequence Model. This had the effect of decreasing the number of assets that could potentially fail for each timestep. This scenario results on a less severe event based on hurricane Maria data.

Finally, in order to provide additional variation in transmission system failure and more fully sample the range in failure probabilities for assets along the same Circuit ID, two additional scenarios were developed, the Maria minimum-probability and Maria mean-probability scenarios (items 4 and 5 in the list of scenarios above). These scenarios take the minimum and mean asset failure probabilities, respectively, for HEADOUT assets assigned to the same Circuit ID, as opposed to the maximum failure probability, as was used in the base-case scenarios (item 1 in list above). Figure 4-5 in section 4.2.3 shows an example of maximum, minimum, mean of failure probabilities for Hurricane Maria. The full range of failure probabilities for each Circuit ID as well as the mean and standard deviation are shown in Appendix A.

Table 4-3. summarizes the key differences between the five event scenarios. For each of the described contingency scenarios, 10 separate scenarios were created from the Monte Carlo sampling model, for a total of 50 simulations.

Table 4-3: Hurricane scenario details.

Event	Hurricane	Wind-speed cutoff (kn)	Failure probability used for Circuit
1. Hurricane Maria – Maximum Failure Probability from HEADOUT	Maria	50	maximum
2. Hurricane Irma – Maximum Failure Probability from HEADOUT	Irma	50	maximum
3. Hurricane Maria Lite – Maximum Failure Probability from HEADOUT	Maria	80	maximum
4. Hurricane Maria – Minimum Failure Probability from HEADOUT	Maria	50	minimum
5. Hurricane Maria – Mean Failure Probability from HEADOUT	Maria	50	mean

In future work, further event scenarios could be developed to provide an even greater range of effects and allow for sensitivity analysis. These could be created by further sampling combinations of parameters used to create the five contingencies discussed here. An additional level of statistical sampling could also be employed to allow for PSS®E elements associated with the same Circuit ID to have different failure probabilities, which will allow for more geographic variation in faults. Additional scenarios could also be created by varying the fragility curves that are used in the HEADOUT model, allowing the tool to model assets of different ages and with varying levels of reliability.

5.0 Simulation Results

Phase II results target two recent hurricanes in Puerto Rico, Hurricane Maria and Hurricane Irma. For each hurricane, different scenarios considering probability and power flow variations were studied using the risk-based dynamic contingency analysis approach developed in this report. Data output from ANL's HEADOUT was mapped to power system models through GIS. PNNL's EGRASS was used to obtain individual outage sequences and for sensitivity analysis. The outage sequences were simulated in PNNL's DCAT platform. The simulation results and corresponding GIS-based visualization were saved and presented in a DCAT Data Management module. DCAT Analytics was used to observe detailed engineering results summarized in this section and used to draw the main findings of this report. This exercise, and the results obtained, indicate that the introduction of grid element failure probability not only assists planning engineers to better understand the impact of historical hurricanes, but also enables a better understanding of the uncertainties inherent in hurricane contingency representations. The Monte Carlo methodology leveraged to perform this more comprehensive, risk-based analysis has been newly developed for this work as part of the framework.

An overview of how simulations were setup to perform the risk-based dynamic contingency analysis for Puerto Rico's electrical infrastructure can be found in Section 2, Section 4, and Appendix B. There, specific information on the base cases used, terminology, and different DCAT sensitivities scenarios are documented.

5.1 Summary of Results

The analysis PNNL performed covers a great volume of simulations of the Puerto Rico Power Grid's performance under different failure scenarios. To begin with, PNNL tested the risk-based dynamic cascading analysis framework on single hurricane event runs for Hurricane Maria and Irma. Furthermore, Monte Carlo simulations were introduced to simulate different variations of Hurricane Maria and Irma, by formulating flexible sequential sets of hurricane contingencies over time and generating dozens of potential independent hurricane threat scenarios for each hurricane event. In addition, information from known historical hurricanes in the past 50 years in Puerto Rico has been leveraged to synthesize and calculate the weighted risk-based impact expectations of possible hurricanes, as described in Section 2.3. This provides an effective way to understand and analyze high-impact low-frequency hurricanes (e.g., Hurricane Maria) and those with lower intensity and potentially higher frequency. Lastly, additional efforts have been focused on the extended benefit evaluation of Puerto Rico Minigrid Strategy and the Solar-based grid forming inverters.

The analysis PNNL performed provides in-depth insights regarding the Puerto Rico Power Grid and related hurricane events, a high-level summary is given as follows:

- Puerto Rico minigrids show potential to improve grid resilience with reduced risk in system collapse and increased preservation of critical loads, and potential faster and more flexible system restoration
- Solar-based grid forming inverters could improve stability for supporting future Bulk Electric System (BES) regarding system frequency stability and voltage stability. The higher percentage of Solar-based grid forming inverters providing voltage and frequency control, the better the BES stability could expect. Scenarios with higher control contribution have better performance in terms of response to single contingencies as well as in terms of response to a hurricane event.

Additionally, the results of this work also provided insights into the particular strengths of the approach taken. In particular:

- The risk-based dynamic cascading analysis framework is suited to analyzing high-impact, low-frequency events including hurricanes, including a user interface and a flexible integration of grid and weather data sources
- Using a Monte Carlo simulation-based approach enables a full-spectrum analysis for historical hurricane events, and provides statistical ground for hurricane contingency formulation and grid equipment failure probability considering different hurricane variations and their unknown characteristics
- The risk-based dynamic cascading analysis framework provides a methodology and process to identify potential grid vulnerability during hurricane events, and a it is applied to evaluate alternative grid enhancement and pre-event preventive strategies, using a detailed technical basis

Even though three tools were used in this work, DCAT is highlighted more in this section, because the results are produced and visualized using newly-developed DCAT capabilities. As illustrated in Figure 5-1 (same as Figure 1-1, repeated here for convenience), the risk-based dynamic cascading analysis is a methodological linking of three DOE national lab's tools (HEADOUT, EGRASS, and DCAT), augmented by a mapping done with diverse GIS data and the development of a new probabilistic methodology to assess hurricane risk at two levels. The last step of this framework involves DCAT simulations and the corresponding analysis also in DCAT data management and analytics modules.

A short summary of anonymized results is described in the following sections. More detailed results can be found in [19]. The following sections will describe the simulation results attained from testing the risk-based framework developed in this project, impact of high solar conditions, and minigrids on hurricane resiliency.

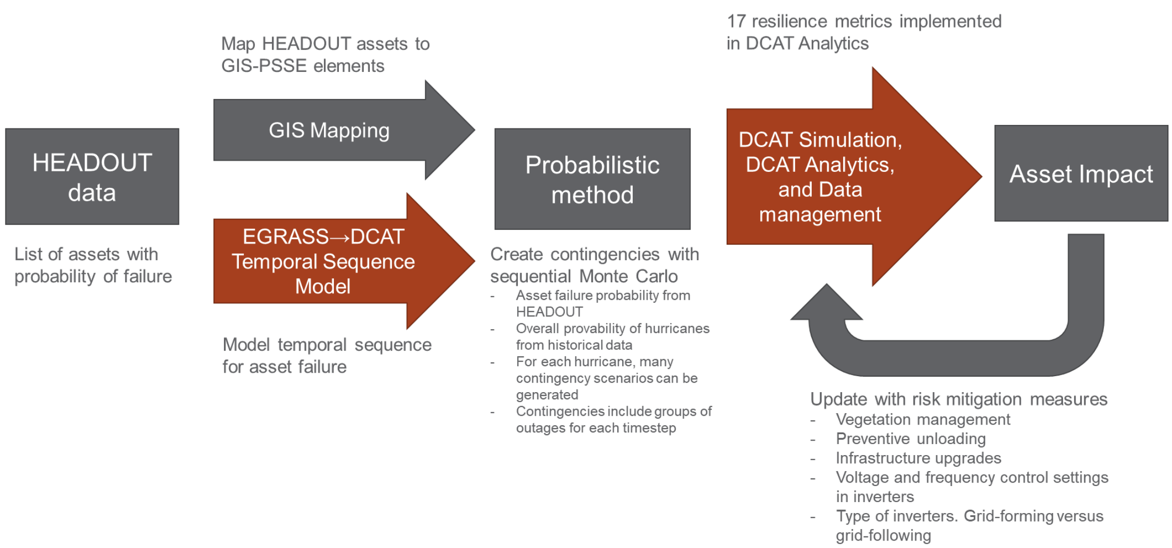


Figure 5-1: Risk-Based Dynamic Contingency Analysis Framework and Interaction of HEADOUT, EGRASS and DCAT tools

5.2 Introductory illustrative example of a simple generic hurricane event

Here one illustrative example is provided to demonstrate the effectiveness of the proposed framework, and to describe the multi-dimensional perspectives used to evaluate pre-hurricane system enhancement/hardening as well as corrective actions taken during the hurricane event. It should be noted that the developed framework incorporates a variety of simulated power quantities from static, dynamic, protection models, and corrective actions simulations. This illustrative example covers a single simulation of a generic hurricane event.

As illustrated in Figure 5-1, the first step consists of obtaining output data from ANL's HEADOUT that generates a list of assets with corresponding probabilities of failure. Performing GIS mapping between datasets allows for the specification of outages in the power system model. PNNL's EGRASS is extended and used to determine the sequencing of system outages. The extension of EGRASS also enables definition of sensitivity scenarios. A probabilistic method based on sequential Monte Carlo generates the final sets of outages to be ingested by PNNL's DCAT. Details of this process can be found in section 2.0. The illustrative example of this section focuses on the last process in the framework in Figure 5-1.

Figure 5-2 shows the DCAT simulations for a generic hurricane event. The generic event uses a track similar to Hurricane Maria, but it is not based on data from this hurricane. The event is divided into 5 contingency groups. In this example, the system experiences a system blackout during the dynamic simulation of Contingency 3. It can be seen in the figure that during Contingency 1, the voltage profile across the Puerto Rico power grid is stable and around 1 p.u. (in green color); but during Contingency 2, the Eastern part of Puerto Rico is experiencing voltage depression, which is around 0.8 p.u. (in dark purple color). Once the simulation continues in Contingency 3, the whole Puerto Rico power grid went into blackout, and the voltage profile in the simulation shows severe undervoltage phenomenon across the island, which is around 0.7 p.u. or even lower.

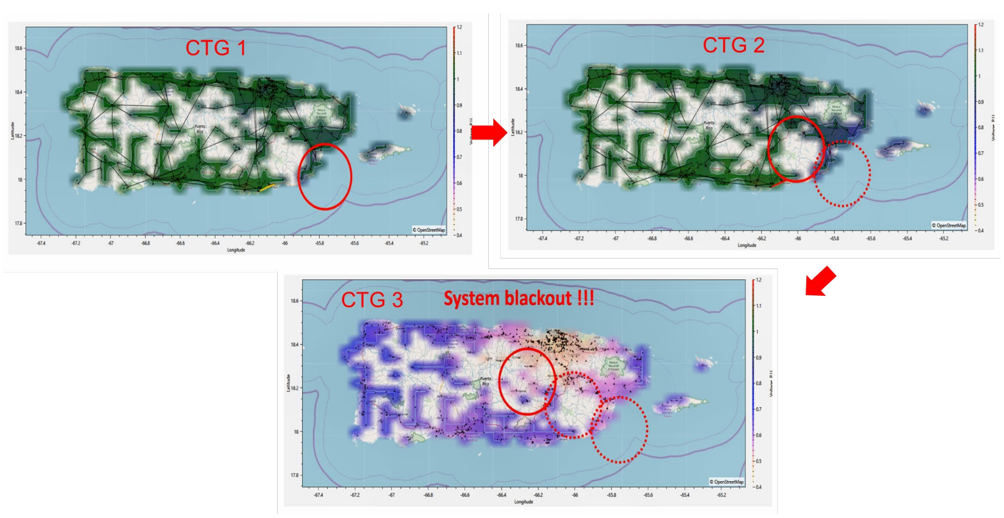


Figure 5-2: Scenario 1 – No Hardening nor Corrective Actions

In comparison, system hardening has been incorporated in the pre-event power flow case, and additional DCAT simulations with same generic hurricane event were performed. The system hardening consisted in assuming that one important transmission line in South-North corridor withstands the hurricane. This assumption could mean that stronger transmission towers have been installed or that the line has been undergrounded, and therefore resisted the hurricane.

Figure 5-3 shows significant improvement in the system's performance when this transmission corridor does not fail. The system is able to survive through the third contingency without experiencing an island-wide blackout and the overall system voltage profile is improved. It should be noted that the Eastern side of Puerto Rico Power Grid still experiences undervoltage phenomenon, which is around 0.8 p.u. (in dark purple color). In other words, even though the system survives the hurricane, severe violations remain in the most critically impacted portion of the island.

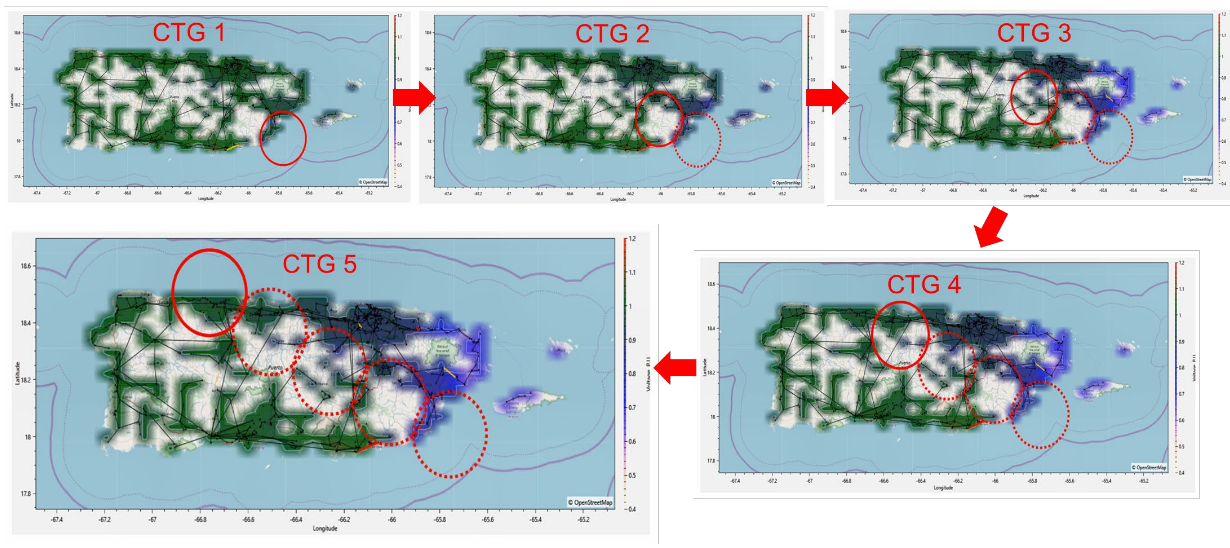


Figure 5-3: Scenario 2 – Hardening Only

The analysis framework can also enable the evaluation of corrective actions taken at the end of each stage of the hurricane contingency simulation. Figure 5-4 shows that by incorporating system hardening sufficient to prevent the loss of the identified, critical North-South corridor and by applying corrective actions, the Puerto Rico power grid could withstand the impact from the generic hurricane event. Corrective actions included generation redispatch and modification of control settings like tap changers as a first measure and load shedding as a last measure to correct the system violations, as described in Section 2.5. The simulation maintained a stable voltage profile across the whole island around 1 p.u. (in green color) and limited undervoltage issues in the Eastern part of the island.

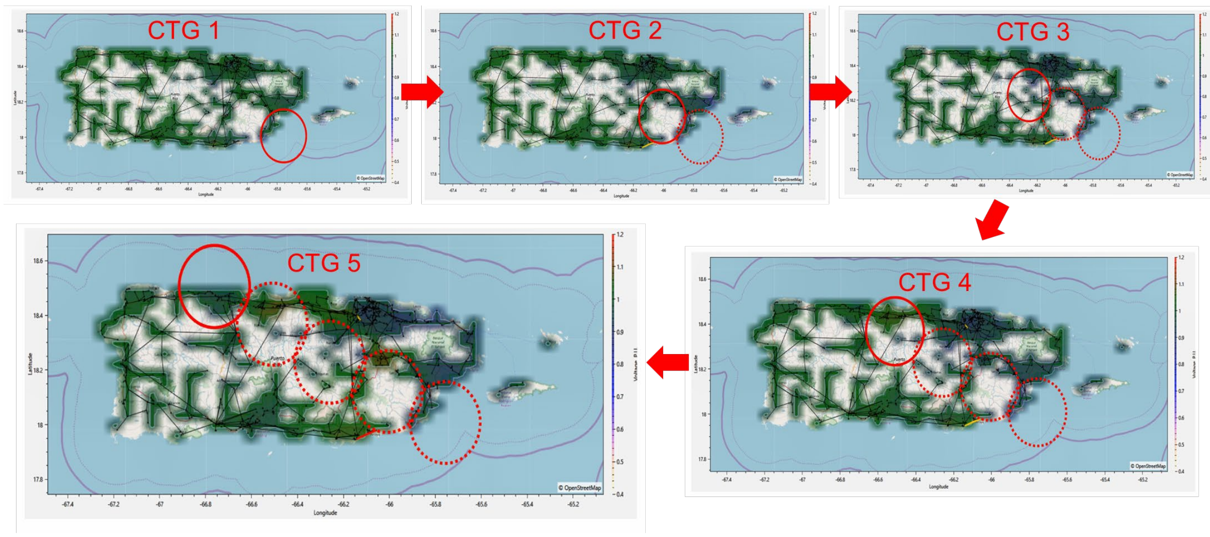


Figure 5-4: Scenario 3 – Hardening + Corrective Actions

Lastly, a cross comparison from the above simulations based on the analysis framework is given in Figure 5-5, showing the final state of the system under each studied scenario. This provides a synthetic, notional example of how the framework could be used to evaluate different mitigation measures including system hardening, topology changes or operational actions to see how they would impact the system's performance under outage scenarios.

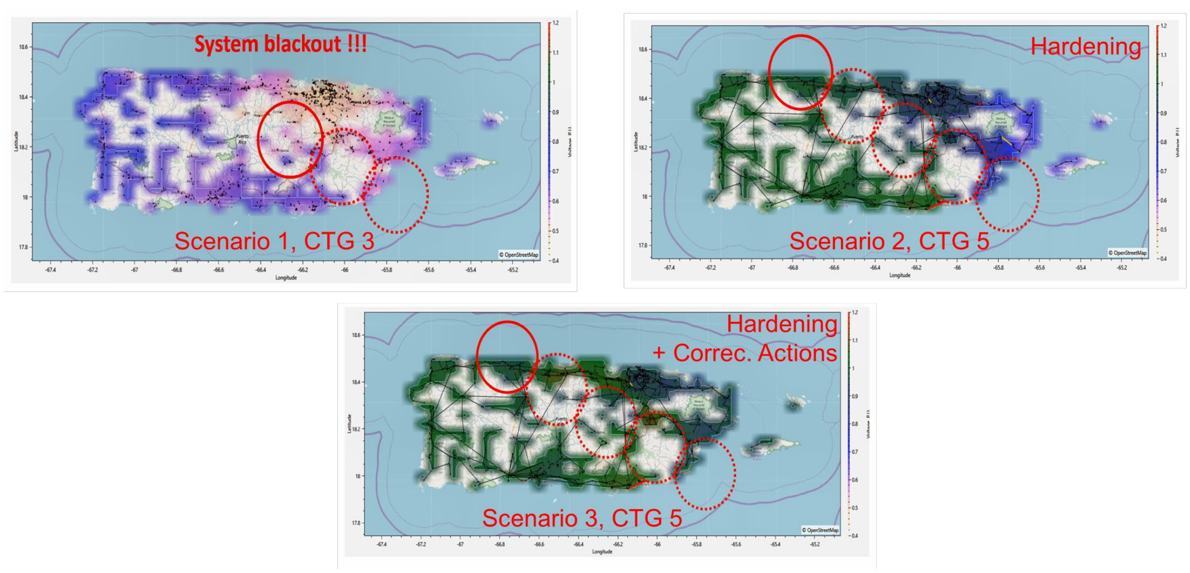


Figure 5-5: Comparison for Different Scenarios

5.3 Single Simulation for Hurricane Scenarios

PNNL initially utilized a single hurricane scenario simulation approach to test the risk-based probabilistic framework prior to increasing the number of runs in Monte Carlo simulations that would generate many potential hurricane scenarios for one event. By starting with a single hurricane scenario, this allowed PNNL to tune and troubleshoot the developed framework, DCAT and EGRASS codes, as well as developing the new probabilistic methodology to be capable of simulating batches of contingencies over time that occur in one hurricane event/scenario.

PNNL has simulated the following single hurricane scenarios with specific pre-event system conditions and various equipment failure probability in contingency formulation, they are:

- Hurricane Maria – Maximum Failure Probability from HEADOUT
- Hurricane Irma – Maximum Failure Probability from HEADOUT
- Hurricane Maria Lite – Maximum Failure Probability from HEADOUT
- Hurricane Maria– Minimum Failure Probability from HEADOUT
- Hurricane Maria– Mean Failure Probability from HEADOUT

For each of these hurricane scenarios, a single set of sequential hurricane contingencies were created using EGRASS, based on HEADOUT output data, mapping efforts, and the probabilistic method discussed in previous sections. Each hurricane scenario included 5 to 8 sets of sequential contingencies, also labeled as "Contingency IDs." Within each Contingency ID, a set of 115kV and 230kV transmission elements were removed from the system due to its failure probability considering hurricane damage. System outages <100kV were not included in these contingency definitions.

Under these hurricane event scenarios, PNNL also used several Puerto Rico power flow base cases to test performance under different system operating conditions and sensitivities. These sensitivities included varying DCAT corrective action capabilities, varying renewable penetration levels, changing system conditions to represent day vs. night loading, and varying amount of grid support from PV plants. By doing this, we were able to better identify what mitigation strategies could be leveraged to improve system performance during a hurricane. System mitigation and reinforcements that improved Puerto Rico system response to the hurricane contingencies included:

- **Preventive unloading:** This improved system response for the extreme Hurricane Maria conditions.
- **2019 IRP [16] system upgrades:** By simulating the hurricane events using a case with IRP upgrades, a significant improvement in system survival throughout the simulated hurricane impact was achieved.
- **Improved frequency response from inverter-based resources**: Severe undervoltage violations occurred at buses in the system that host PV generators after hurricane events. By leveraging these inverter-based resources to provide both frequency response and voltage control, less severe undervoltage conditions were achieved..
- **Preventive system splitting into MiniGrids**: It was assumed that the system operator preventively split the system into minigrids anticipating the hurricane's arrival. It was observed that the San Juan – Bayamon area performed better when disconnected from the rest of the system for Hurricane Maria.

Examples are given as follows to illustrate the simulation process based on the analysis framework, and sample results from the DCAT Database Management Module and DCAT Analytics are provided for an in-depth analysis. As explained in Section 2.5., it should be noted that hurricane event simulation is automated in DCAT, once the contingencies have been defined with the previous processes in HEADOUT and EGRASS, and the simulation results are directly uploaded to the DCAT Database once completed, the user could quickly parse all the simulation results in table and figure format, using the DCAT Analytics user interface. Three examples are given as follows.

5.3.1 Hurricane Maria (Event ID #1)

In order to simulate Hurricane Maria in the analysis framework, the hurricane event was decomposed and represented by a set of six contingency groups, which were then simulated in DCAT. These six contingencies are grouped roughly by time using historical weather information and mapping how the hurricane moved across the island in order to determine the sequence. The results of this analysis showed that the system collapsed during the third contingency stage, resulting in an inability to progress through the remaining three stages. Severe voltage violations begin to occur during the second contingency stage, indicating that after roughly a third of the totally projected equipment failures occur, the system begins to experience critical stress. The system experiences total failure before roughly half of the failures have occurred. Given the severity of Hurricane Maria, this performance was expected and consistent with the historical event. Table 5-1, from DCAT Analytics, lists the Resilience Metrics calculated for Hurricane Maria in a single framework simulation. Figure 5-6 shows the total load not served within each simulated contingency group. Figure 5-7 and Figure 5-8 show the voltage contour profiles for Hurricane Maria Contingency 1 and Contingency 2 respectively. In addition to voltage contour profiles, the figures display equipment in outage for each contingency group (red dashed line), and the applied corrective actions (Letter "G" and/or "L" in Cyan color).

Table 5-1: Example results for Resilience Metrics in Hurricane Maria Analysis – table from DCAT Analytics

InitEventID	ScenarioID	ContingencyID	TotalLoadNotServed	TotalIslands	TotalTrips	Blackout	GenOutage	SumLoadImpact	TotalLoadImpact	TotalVoltVioltns	VoltVioltns
1	2	1	9.67	0	0	0	0.00	0.00	9.67	3	, 1.10
1	2	2	361.07	0	28	0	406.12	52.04	413.11	296	, 0.59

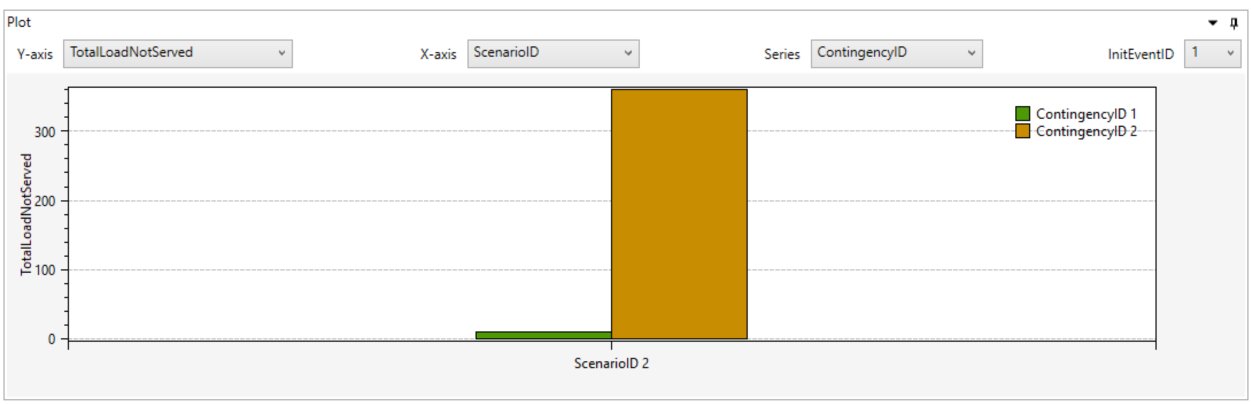


Figure 5-6: Total load not served in Hurricane Maria simulation with 2019 night peak case (corrective actions applied to 100 kV & Above systems) – figure generated by DCAT Analytics

Figure 5-9 shows the dynamic response to Contingency 2 for selected voltages. The instances where the asset outages within Contingency 2 are introduced are observed in the sudden changes observed in the dynamic voltages. The dynamic voltage evolution shows how some voltages start reducing along the evolution until they end in severely low values (0.65 – 0.8 p.u.) for some buses. The voltages in the whole system at the end of the dynamic simulation for Contingency 2 can be observed in Figure 5-8.

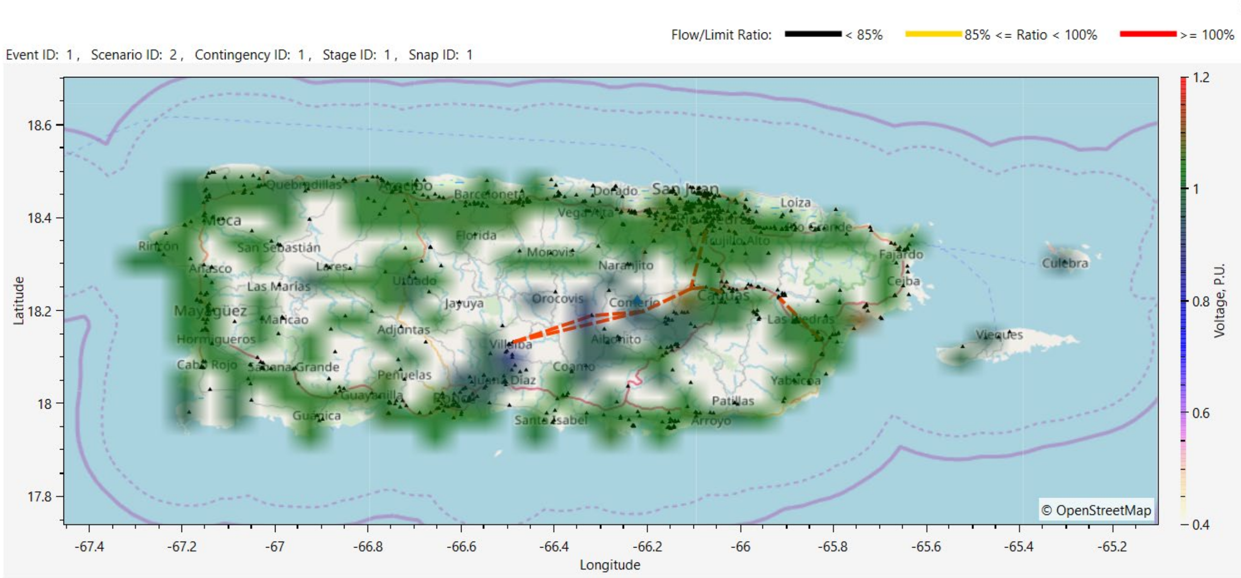


Figure 5-7: Voltage profile plotting for Contingency 1 in Hurricane Maria simulation with 2019 night peak case (corrective actions applied to 100 kV & Above systems) – figure generated by DCAT Analytics

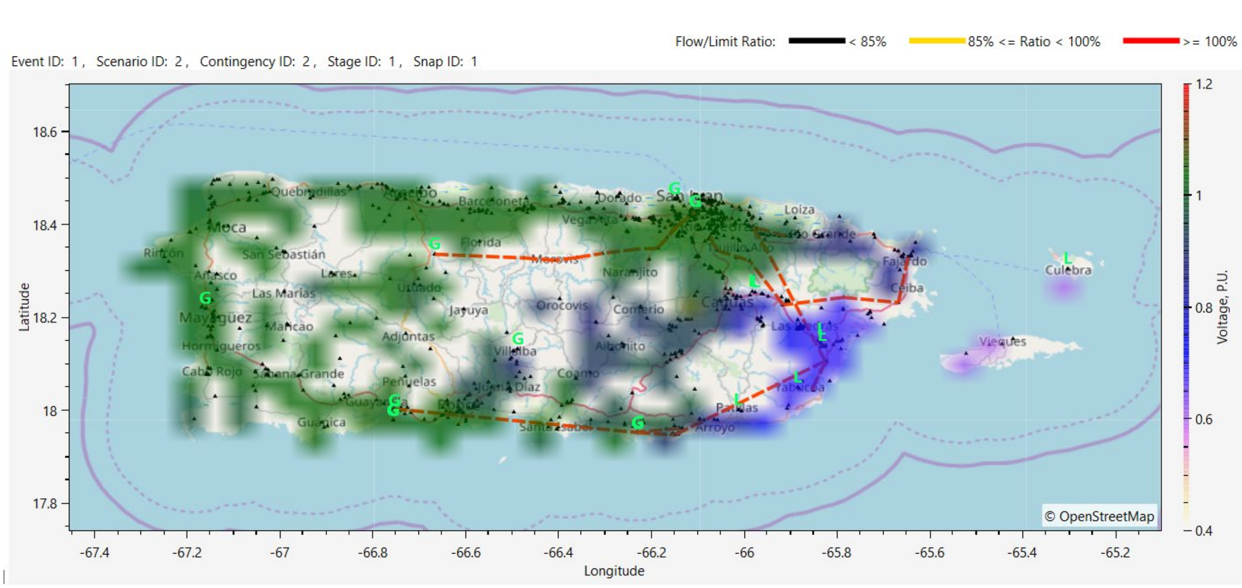


Figure 5-8: Voltage profile plotting for Contingency 2 in Hurricane Maria simulation with 2019 night peak case (corrective actions applied to 100 kV & Above systems) – figure generated by DCAT Analytics

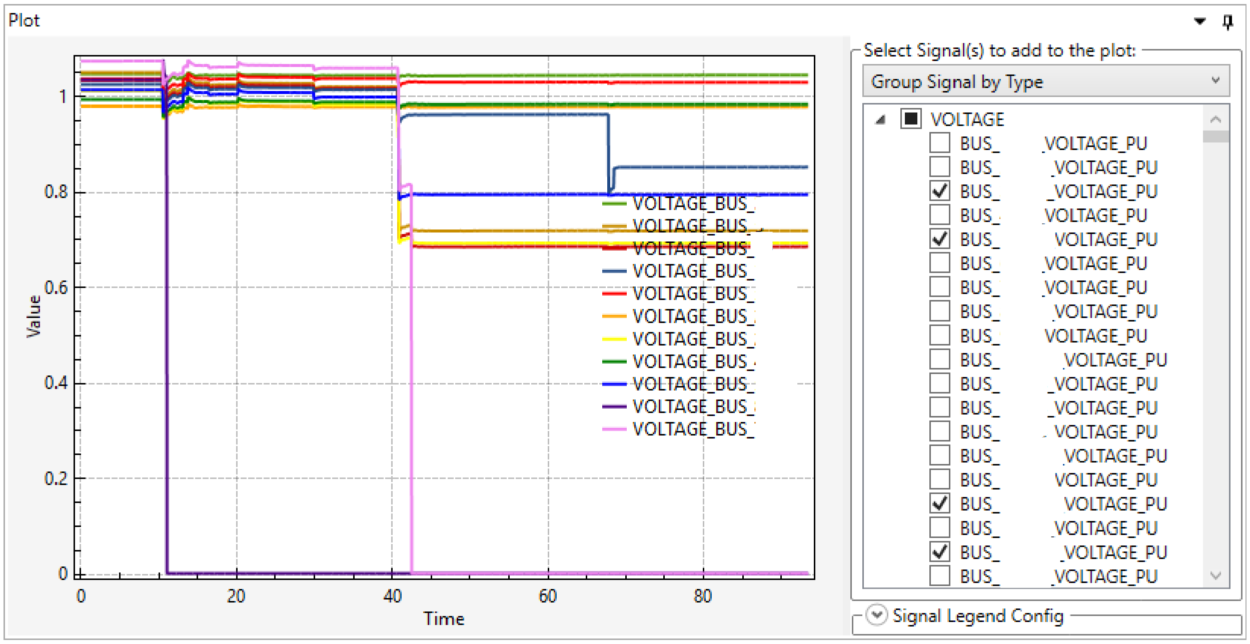


Figure 5-9: Dynamic evolution of voltages in p.u. for Contingency 2 in Hurricane Maria simulation with 2019 night peak case (corrective actions applied to 100 kV & Above systems) – figure generated by DCAT Analytics

5.3.2 Hurricane Maria with Preventive unloading (Event ID 2)

To further explore the Hurricane Maria case and to understand how different mitigation measures could improve system performance, a few additional scenarios were run. The first was to rerun the base analysis described in Section 5.3.1, but to implement preventive unloading prior to simulating the hurricane event. The details of this modification are given in Section 4.2.4.

Similar to the previous results, the simulation for Hurricane Maria with preventive unloading was performed successfully in the first two contingency groups, and failed to proceed through the third due to system collapse.

Table 5-2 lists the Resilience Metrics calculated for Hurricane Maria in a single framework simulation. And Figure 5-10 shows the total load not served within each simulated contingency group. It can be observed that total load not served with preventive unloading are lower as compared to the previous example. The load impact metrics calculated in this case are 0 and 0.83, and the total voltage violations dramatically decrease from 296 to 9 when the preventive unloading is implemented. The alleviation on voltage violation can also be seen in Figure 5-11 and Figure 5-12 (as compared with the original case of Figure 5-7 and Figure 5-8), in which no severe undervoltage was observed, and some substations were showing overvoltage phenomenon.

From the results, it is evident that preventive unloading strategy could better position the Puerto Rico Power grid to withstand the hurricane impact, though the disruptive impact on critical transmission lines and/or equipment by Hurricane Maria was too severe to be fully mitigated by unloading alone.

Table 5-2: Example results for Resilience Metrics in Hurricane Maria with preventive unloading Analysis – table form DCAT Analytics

InitEventID	ScenarioID	ContingencyID	TotalLoadNotServed	TotalIslands	TotalTrips	Blackout	GenOutage	SumLoadImpact	TotalLoadImpact	TotalVoltVioltns	VoltVioltns
2	2	1	4.58	0	0	0	0.00	0.00	4.58	0	No Voltage Violation
2	2	2	145.09	0	15	0	325.02	0.83	145.92	9	, 1.12

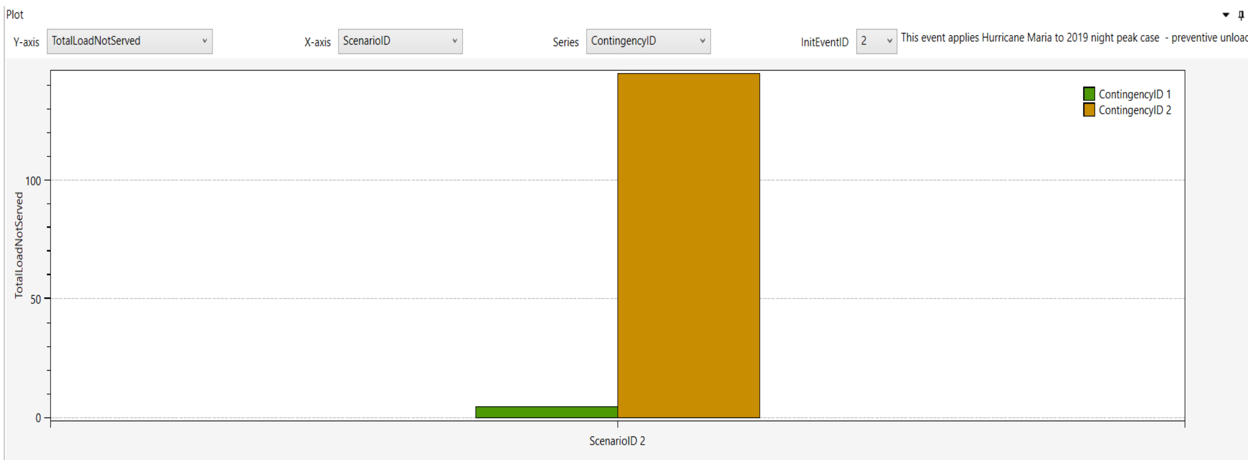


Figure 5-10: Total load not served in Hurricane Maria simulation with 2019 night peak preventive unloading case (corrective actions applied to 100 kV & Above systems) – figure generated by DCAT Analytics

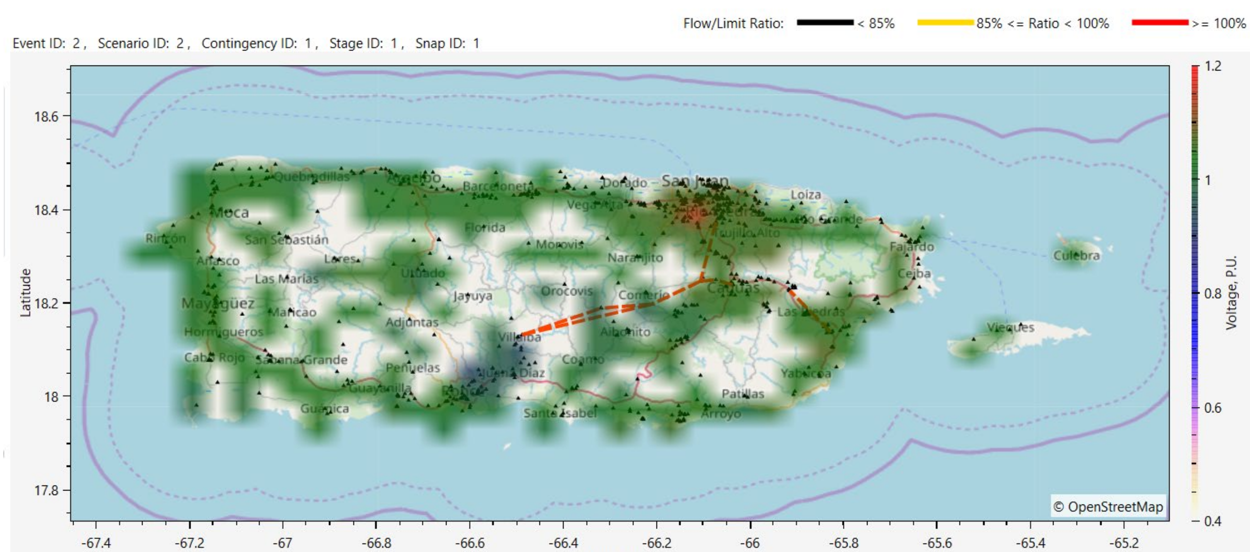


Figure 5-11: Voltage profile plotting for Contingency 1 in Hurricane Maria simulation with 2019 night peak preventive unloading case (corrective actions applied to 100 kV & Above systems) – figure generated by DCAT Analytics

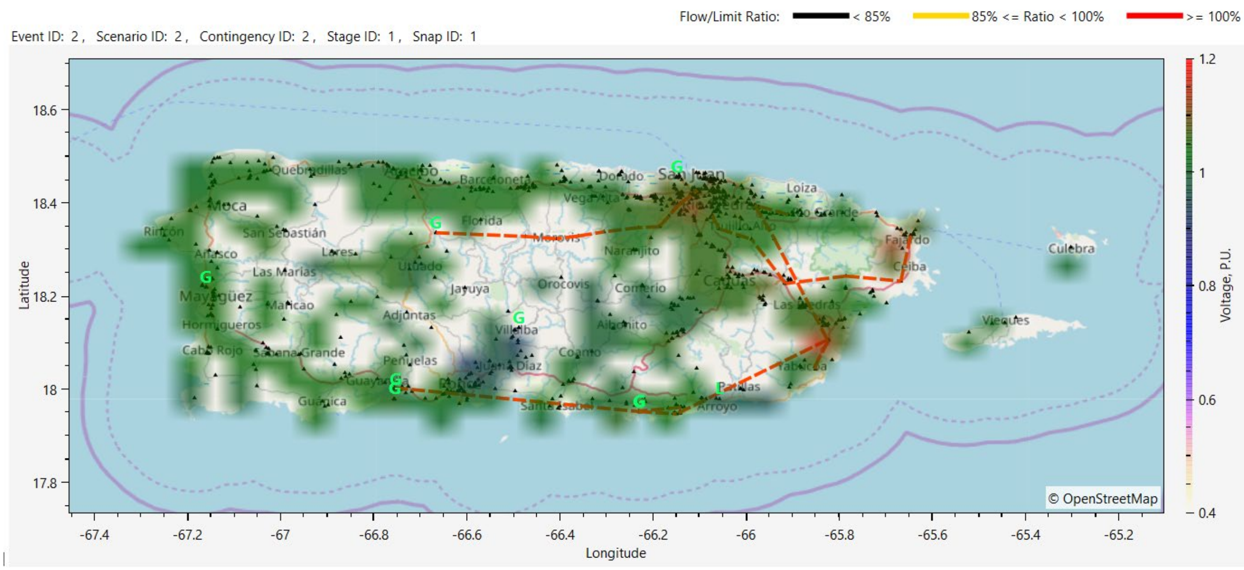


Figure 5-12: Voltage profile plotting for Contingency 2 in Hurricane Maria simulation with 2019 night peak preventive unloading case (corrective actions applied to 100 kV & Above systems) – figure generated by DCAT Analytics

5.3.3 Hurricane Maria with 2019 IRP system upgrades, improved inverter controls, and added generation protection (Event ID 11)

Additional single hurricane simulations were also performed to evaluate scenarios that incorporate 2019 IRP upgrades (see Section 4.1), more detailed protection models (see Section 4.2.5), and increased inverter-based generations (see Section 4.2.6).

Here one specific example is shown to illustrate the effectiveness of the analysis framework when applied to these additional simulations. A 2028 day-peak scenario was adopted, with model configured as used in the IRP, but with additional generator frequency and voltage relays. As mentioned in Section 4.2.6, the IRP model configuration included grid-following generic models for inverters included into the power system dynamic model as well as synchronous condensers to maintain stability.

Table 5-3 provides the Resilience Metrics calculated for Hurricane Maria for this additional analysis. Compared to the simulation results in Section 5.3.1 and Section 5.3.2, the total load not serving in Contingency 2 has been decreased and no voltage violations were observed. This strongly indicates the potential improvements that could be brought through those future efforts. Figure 5-14 and Figure 5-15 also show clear voltage profile improvement throughout the system, and noticeably less corrective actions were required to mitigate such violations.

Table 5-3: Example results for Resilience Metrics in Hurricane Maria Analysis with 2028 day peak case, additional protection models and inverter models – table form DCAT Analytics

InitEventID	ScenarioID	ContingencyID	TotalLoadNotServed	TotalIslands	TotalTrips	Blackout	GenOutage	SumLoadImpact	TotalLoadImpact	TotalVoltVioltns	VoltVioltns
11	4	1	46.74	0	0	0	0.00	0.00	46.74	0	No Voltage Violation
11	4	2	99.18	0	0	0	0.00	0.00	99.18	0	No Voltage Violation

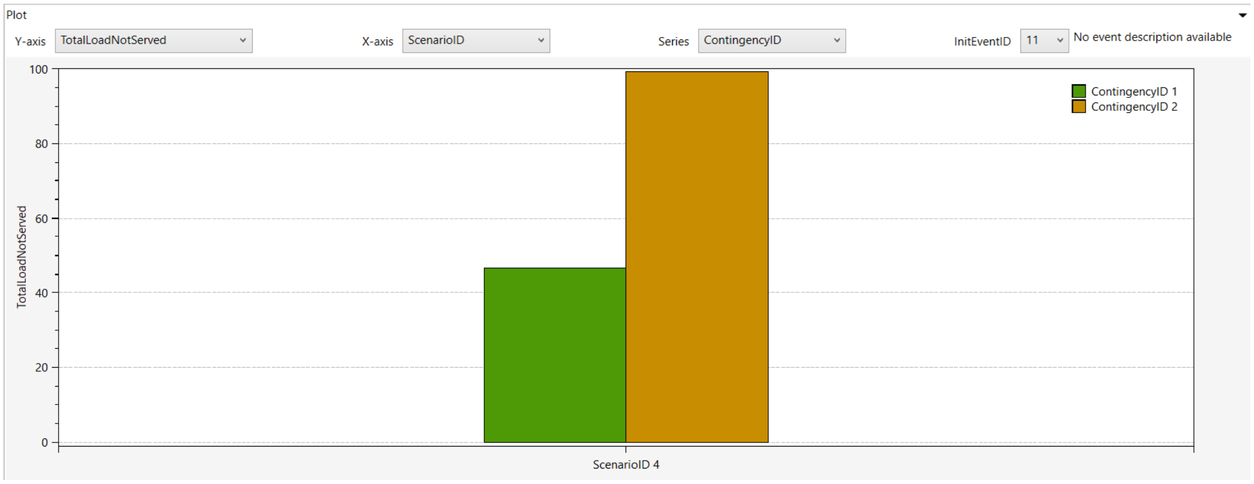


Figure 5-13: Total load not served in Hurricane Maria simulation with 2028 day peak case, additional protection models and inverter models (corrective actions applied to 100 kV & Above systems) – figure generated by DCAT Analytics

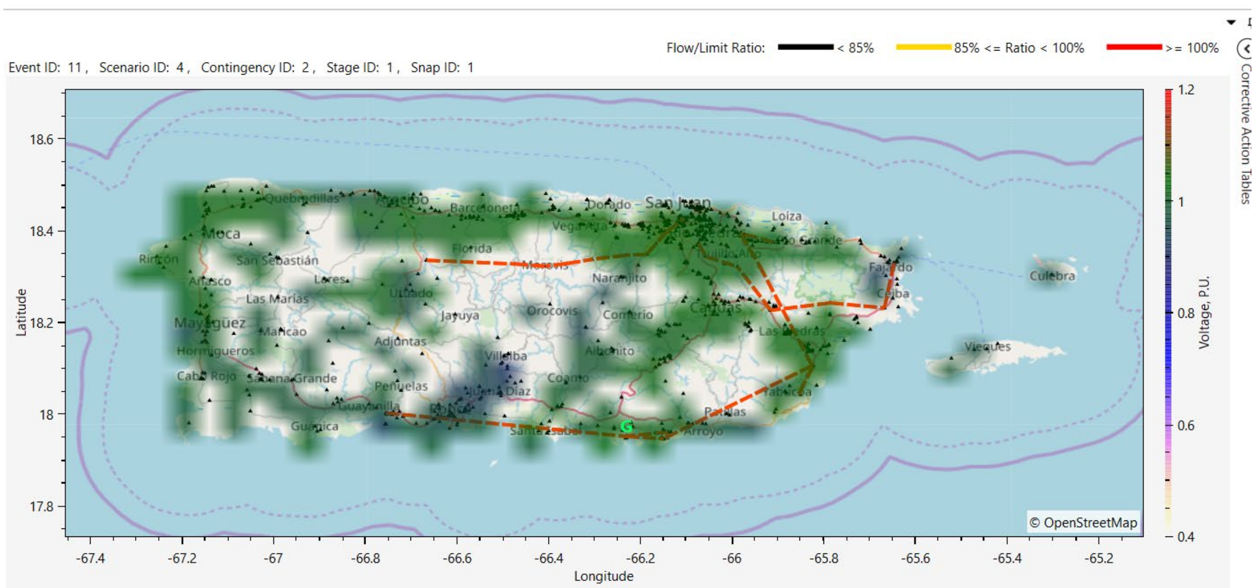


Figure 5-14: Voltage profile plotting for Contingency 1 in Hurricane Maria simulation with 2028 day peak case, additional protection models and inverter models (corrective actions applied to 100 kV & Above systems) – figure generated by DCAT Analytics

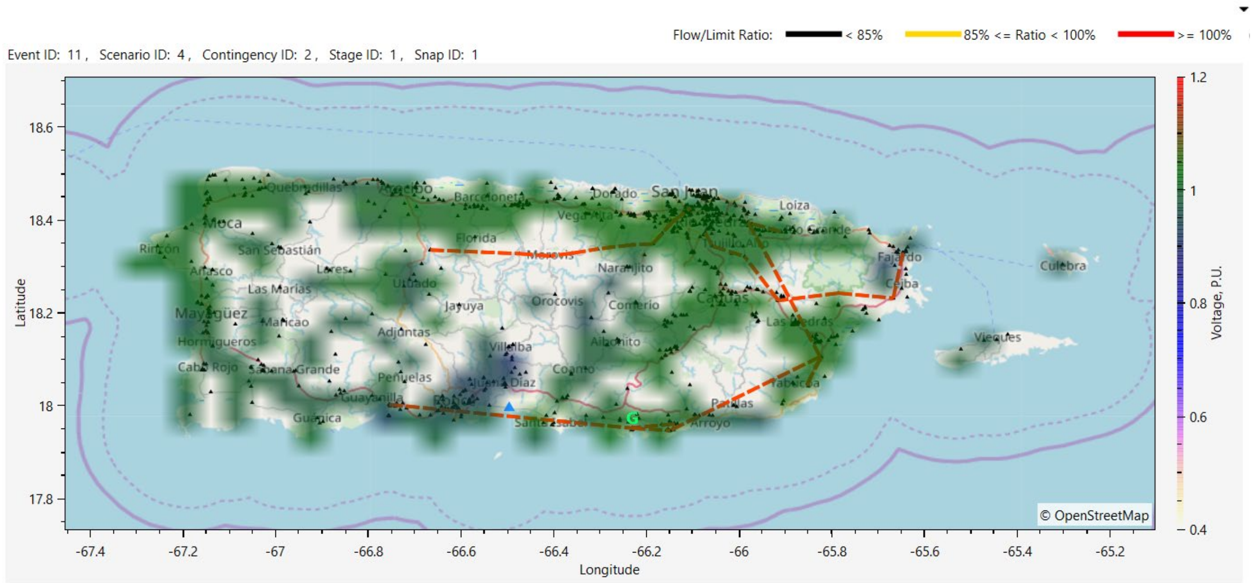


Figure 5-15: Voltage profile plotting for Contingency 2 in Hurricane Maria simulation with 2028 day peak case, additional protection models and inverter models (corrective actions applied to 100 kV & Above systems) – figure generated by DCAT Analytics

5.3.4 Summary for Single Framework Simulation for Hurricane Scenarios

In addition to the single hurricane Maria simulations discussed in sections 5.3.1, 5.3.2, 5.3.3, two additional hurricane event scenarios were simulated. The additional events were Maria Lite and Irma. Maria Lite is a synthetic event based on hurricane Maria but with reduced set of outages. For conciseness, detailed results of Maria Lite and Irma are not included in the main body of report, but are shown in the Appendix C. This section contains a summary of these single event simulations.

A summary of PNNL's simulation results from this effort are described below:

- Simulation results indicated that Hurricane Maria and the associated HEADOUT failure probabilities were very severe. With the 2019 night power flow case, the hurricane contingencies generated were too extreme and abrupt for Puerto Rico's power grid to ride through those initial three sets of hurricane contingency. Even with mitigation strategies in place such as preventive unloading, complete system blackout is inevitable though better voltage profiles were observed prior to system collapse, as discussed in section 5.3.2.

- A Maria Lite scenario was created using PNNL's EGRASS. By filtering the number of electrical infrastructure failures as a function of the hurricane wind speed experienced, the total number of outages were reduced. Under this hurricane scenario, Puerto Rico's power grid was able to ride through 5 out of the 6 sequential contingencies. After the third set of contingencies, the eastern side of Puerto Rico was heavily damaged in simulation and a significant amount of load was lost, ~1000MW. Results from Maria Lite scenario are shown in Appendix C.

- Hurricane Irma was significantly less severe than Hurricane Maria. Simulations were able to run through 5 out of the 6 sequential contingencies, with an ending impact of 20MW load loss with the 2019 night power flow case, and 15MW load loss when occurring over the 2028 day case. Results from Maria Lite scenario are shown in Appendix C.

- In the cases that incorporated lack of vegetation management, increased cascading failure, load loss, and violations were observed.

5.4 Monte Carlo DCAT Hurricane Scenario Simulations

A Monte Carlo approach was used to probabilistically determine many sequences of potential hurricane contingency scenarios. These scenarios are then run in DCAT in order to identify the elements and sequence of elements which, when lost, most compromise the power system. Simultaneously, this probabilistic approach also provides insight into the likelihood of specific element failures. Mitigation strategies and specific system reinforcements that improve resiliency can then be better identified and prioritized based on the results.

Table 5-4 lists all the Monte Carlo simulations that have been performed with the proposed framework, and Figure 5-16, Figure 5-17, and Figure 5-18 provide the comparison of total load not served metric for the first three contingencies across all seven studied events. It is clearly shown that Hurricane Maria (#5) shows the highest impacts, while Hurricane Irma shows more consistency throughout different scenarios, which indicates a less severe impact. More importantly, this comparison based on the proposed framework provides the researchers with better visibility and enhanced confidence, which can be a major challenge whenever analyzing the impact of low-probability, high impact events on the power system.

Table 5-4: Simulation setup for Monte Carlo Simulations

InitEventID:	**5**	**6**	**7**	**8**	**9**	**11**	**12**
Study case:	2019 night	2019 night	2019 night	2019 night	2028 day 10%PV + protections	2028 day 10%PV + protections	2028 day 10%PV + protections
Event Code:	Maria Lite	Irma	Maria	Maria	Maria Lite	Maria	Maria
P(HEADOUT):	Max.	Max.	Min.	Mean	Max.	Min.	Mean

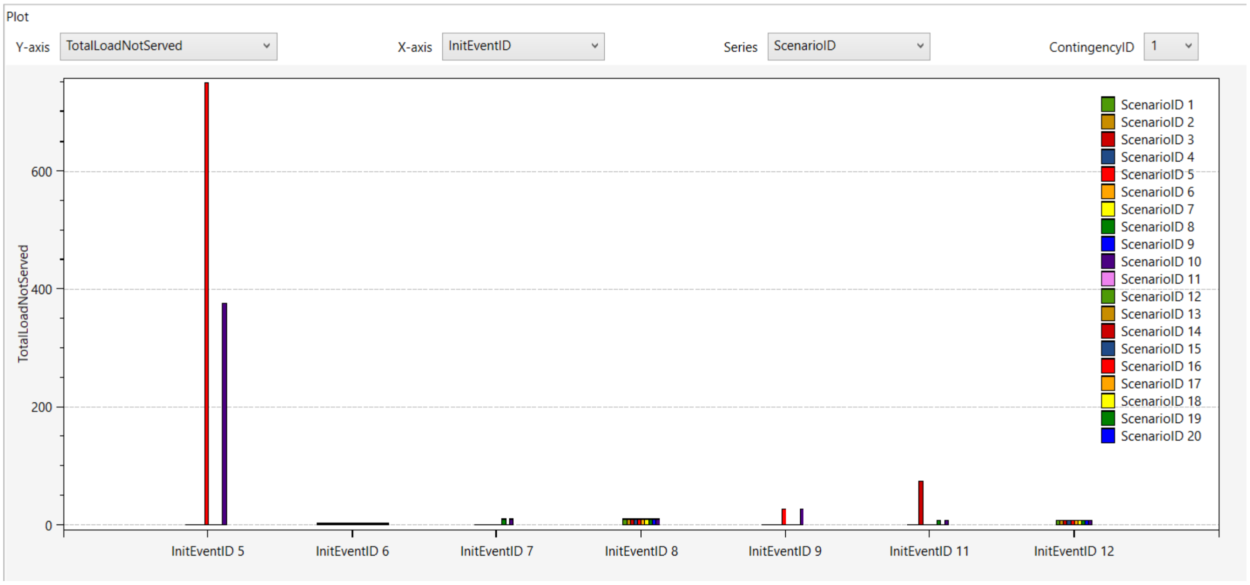


Figure 5-16: Comparison of total load not served in Contingency 1 among different variations of Hurricane Maria and Irma in different Monte Carlo scenarios. – figure generated by DCAT Analytics

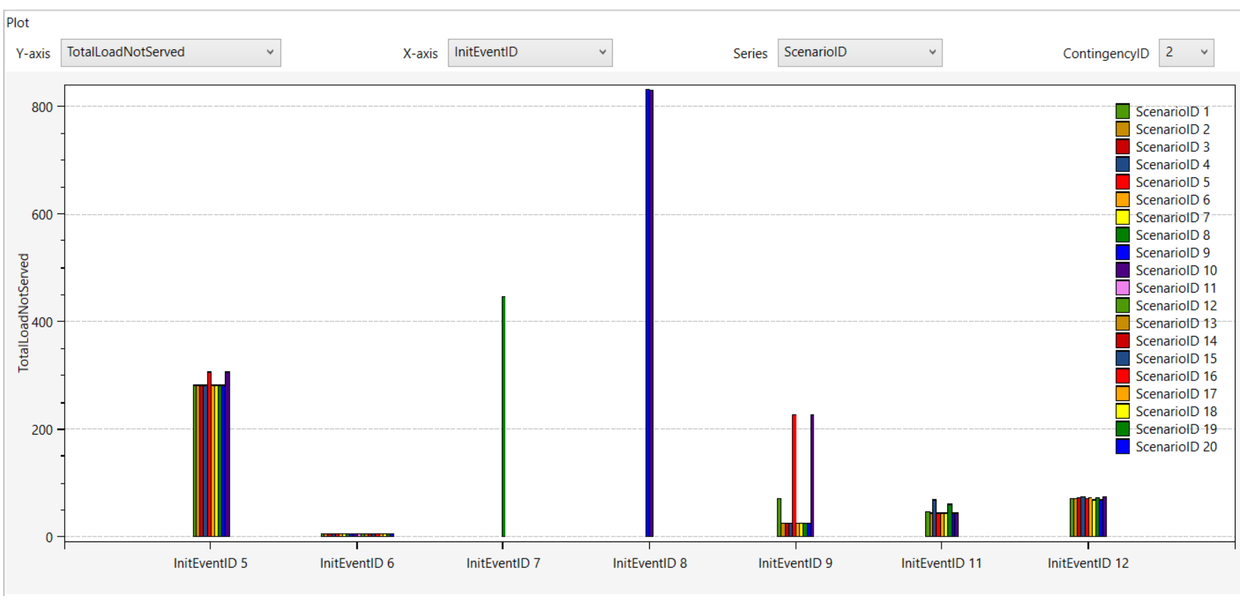


Figure 5-17: Comparison of total load not served in Contingency 2 among different variations of Hurricane Maria and Irma in different Monte Carlo scenarios. – figure generated by DCAT Analytics

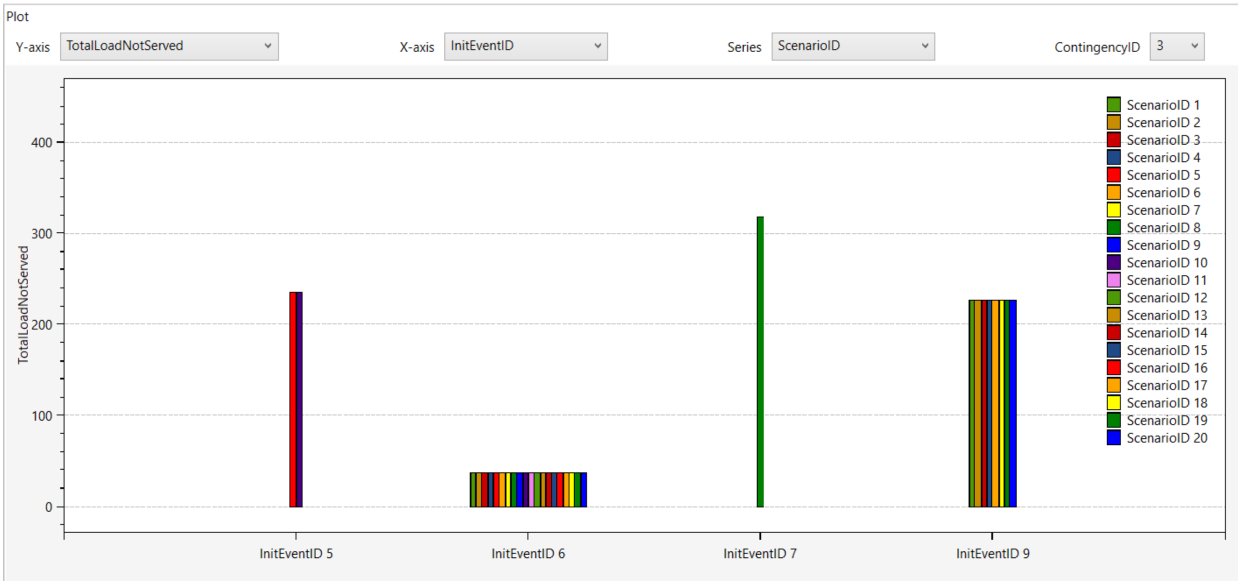


Figure 5-18: Comparison of total load not served in Contingency 3 among different variations of Hurricane Maria and Irma in different Monte Carlo scenarios. – figure generated by DCAT Analytics

Sample results are shown in Figure 5-19 and Figure 5-20 for Hurricanes Maria Lite and Irma. These figures are shown to illustrate the Monte Carlo DCAT hurricane scenario simulations. Maria Lite was chosen because of the severity of the full Hurricane Maria event as described in the previous section.

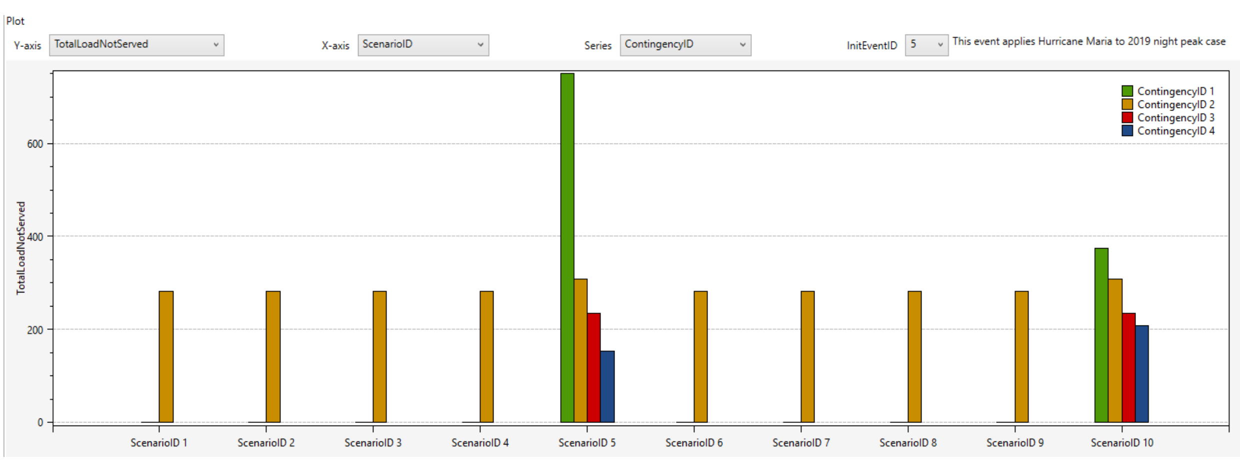


Figure 5-19: Total load not served metric comparison for all 10 Monte Carlo scenarios for Maria Lite. – figure generated by DCAT Analytics

In Figure 5-19, the “Total Load Not Served” metric was calculated for each simulated contingency under different scenarios. One “Scenario” represents one Monte Carlo realization and the corresponding DCAT simulations. In these 10 scenarios, Monte Carlo simulation results for Maria Lite reveal that Scenario 5 and Scenario 10 are the highest impact sequence of contingencies. All other simulations reveal a relatively successful ride-through of the hurricane scenario. Based on observations made from looking at all hurricane scenarios, the infrastructure failures during the first two sets of contingencies are the most detrimental. Additionally, from these results, we can recognize that all simulated hurricane scenarios experienced more than 300 MW load loss.

In Figure 5-20, Monte Carlo simulation results for Hurricane Irma show more consistent impact across different hurricane scenarios, in which all 20 scenarios experienced similar impact during the first three contingencies. Nineteen of 20 scenarios experienced around 70 MW of load loss in the fourth set of contingencies, while Scenario 2 experienced a higher load loss of 115 MW. A system operator or transmission planner might want to take a closer look at this higher impact scenario to identify what sequence of element failures triggered this increased load loss, to prepare a mitigation strategy.

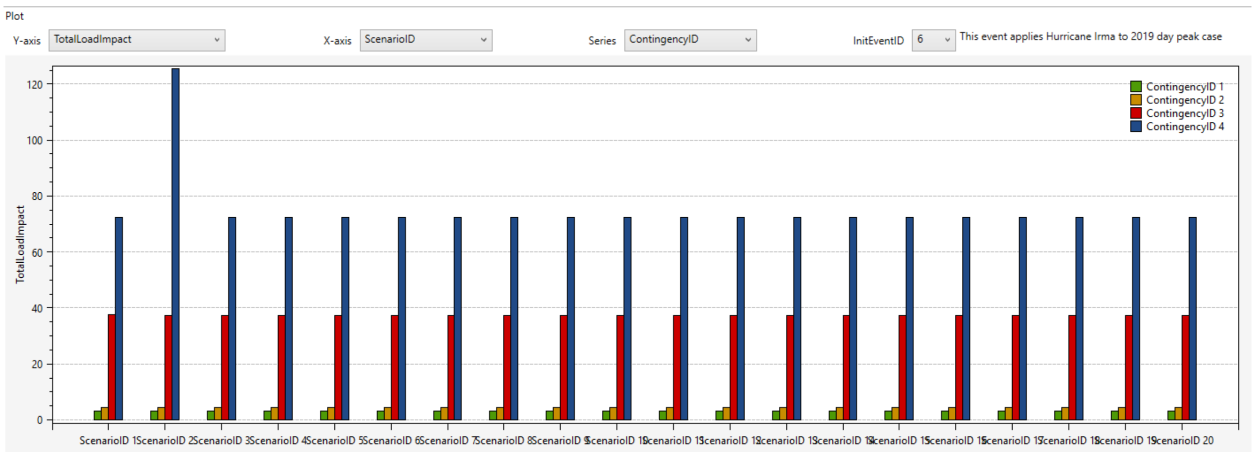


Figure 5-20: Total load impact metric comparison for all 20 Monte Carlo scenarios for Hurricane Irma. – figure generated by DCAT Analytics

Additional metrics were also extracted for each hurricane scenario in the Monte Carlo simulation. These metrics include:

- Total Load Impact
- Total Load Not Served
- Voltage-based Load Impact
- Total Voltage Violations
- Total Line Flow Violations (by Rate A)
- Total Line Flow Violations (by Rate C)
- Total Tripping Events
- Total Generation Outaged

Plots for some of these metrics for hurricanes Maria Lite and Irma can be found in Appendix D.3.

For the more severe Hurricane Maria simulations, a comparison of the Monte Carlo simulation output between using minimum and mean failure probabilities from HEADOUT to formulate hurricane contingencies can be found in Appendix D.4.3.

Performing a deep dive into the differences in element failures and sequence of contingencies between each hurricane scenario was not within the scope this effort. However, in the future, analytical tools to post-process the output of these Monte Carlo simulations could be developed to better understand which specific elements, and their sequence of failure, are higher probability and most detrimental. This could help guide transmission and resource expansion planning, by helping prioritize system reinforcements that yield higher positive impact over others. Additionally, this simulation framework as well as future analytical tools developed from it could also assist near-term system operational planning functions to identify likely or worst-case cascading failures to better prepare mitigation strategies in advance of hurricane impact.

Overall, this Monte Carlo simulation framework demonstrates how system operators and transmission planners can model extreme events, such as historical and forecasted hurricanes. It is a novel approach to modeling and simulating threat scenarios that involve extreme *N-k* contingencies. This tool can be used to better understand uncertainties in hurricane impact, as well as identify sequence of failures that trigger highest impact to customers, power quality, and system stability.

5.5 Impact of High Solar Penetration and Solar-based Grid Services on Hurricane Resiliency

The impact of high solar penetrations on Puerto Rico's future grid was investigated. In the 2019 Puerto Rico IRP [16], simulation considered generic grid-following inverter models with controlled settings assumed for the IRP study. In this section, results of two sensitivities to inverter control settings as well as inverter types are provided. Two types of inverter models are tested in an initial stability test: grid-following (as in the IRP) as well as grid-forming inverters. Grid-forming inverters can bring improved stability to the grid, especially in high penetration scenarios, because they provide a strong reference voltage, as opposed to grid forming inverters which maintain a current source following the grid's voltage. Grid-forming inverter models were configured with voltage and frequency control, in scenarios with and without synchronous condensers in the grid. In addition, the grid-following inverters used in the IRP were studied with added frequency and voltage support. PNNL investigated this even further to validate system performance and determine how solar can be leveraged to improve system performance during hurricane impact. More detail regarding set up of this modeling effort can be found in section 4.2.6.

5.5.1 Initial stability tests for grid-forming inverters

To demonstrate the impact of the inverter model on the system response, a single simulation of generator tripping is used. In this scenario, the outage of the largest PV unit of ~284MW happens at time = 5 seconds. Figure 5-21 shows the frequency response of the system for the three scenarios. Table 5-5 lists the settling frequency and frequency nadir for each scenario.

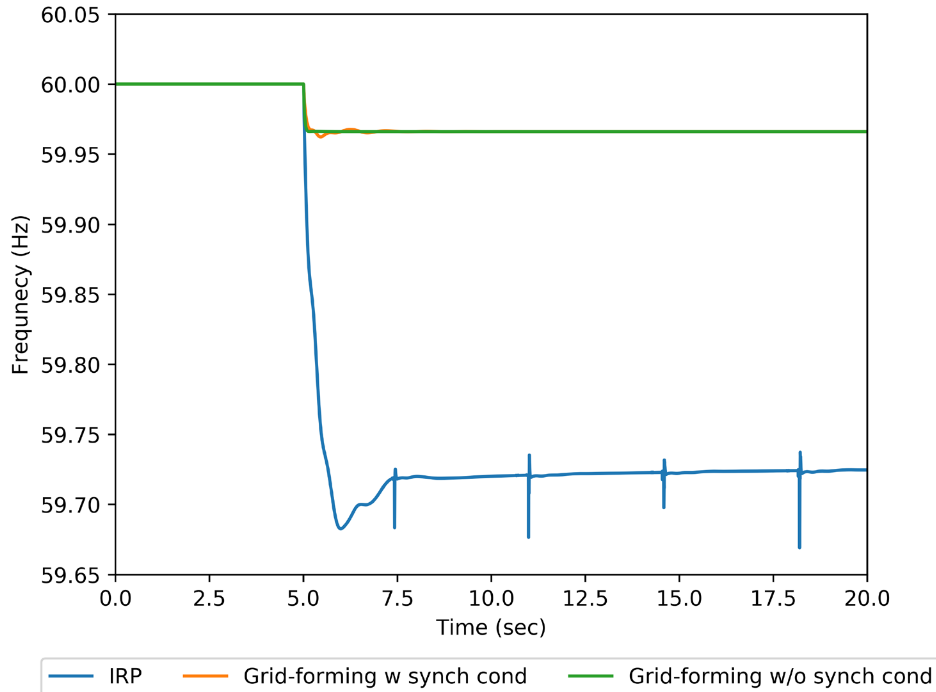


Figure 5-21: Frequency response of the system for the three Solar scenarios.

Table 5-5: The frequency nadir and settling frequency for three solar scenarios.

	Frequency nadir	Settling frequency	Frequency nadir improvement (%)	Settling frequency improvement (%)
IRP	59.66	59.73	-	-
Grid-forming w synch cond.	59.96	59.97	88.82	87.70
Grid-forming w/o synch cond.	59.97	59.97	90.00	87.68

The results show that the frequency response for both cases with grid-forming inverters have significantly better frequency response. This is demonstrated by both frequency nadir and settling frequency. The frequency nadir and settling frequency for both of the grid-forming cases are very close. It can be seen from the figure that synchronous condensers contribute to frequency oscillations in the system that resulted in a slightly lower frequency nadir.

These preliminary results suggest that Puerto Rico could benefit from additional frequency response from grid-forming solar power plants. Additionally, by using grid-forming inverters, the dependence on synchronous condensers for stability could potentially be reduced or eliminated. Potentially, grid-forming inverters could also support system response and grid survival during extreme hurricane contingencies. Additional analysis should be performed.

5.5.2 Hurricane simulations on high-solar 2028 scenarios derived from 2019 IRP (Event ID #8)

Section 5.3.3 shows results of Hurricane Maria in a 2028 scenario from 2019 IRP, with added inverter and synchronous condenser generator protection (for voltage and frequency). In this section, the effect of additional control contribution from solar and battery inverters is studied.

As mentioned in Section 4.2.6, the frequency and voltage support control settings in three scenarios were considered: i) as modeled (dynamically) in the IRP case PNNL received, ii) with added voltage support and frequency response to obtain contributions from 10% of solar output, and iii) activating voltage and frequency support in all solar and energy storage resources. In this section, the system response to a hurricane is compared between scenarios i) and iii). To make the sensitivity to control settings more evident, this comparison does not integrate the generator protection that was considered in Section 5.3.3. Hurricane scenario Maria Lite was used for this simulation.

Figure 5-22. and Figure 5-23. show the results from the hurricane simulation for inverter control scenarios i) and iii). The designation of these scenarios in DCAT Data Management module was Event ID 8 and Scenario ID 4 for i), and scenario iii) is identified as Event ID 8, Scenario ID 6. It can be seen that the addition of voltage and frequency support from inverters (iii) Scenario ID 6) significantly improves the system performance. This improvement can be observed in the total load not served of Figure 5-22. and also in the voltage performance of Figure 5-23.

It is important to note that the absence of generation protection in simulations in this section means that the results are less realistic. However, the simulations in this section illustrate the positive impact of additional contribution from inverter-based resources. For results with generator protection included, see Section 5.3.3.

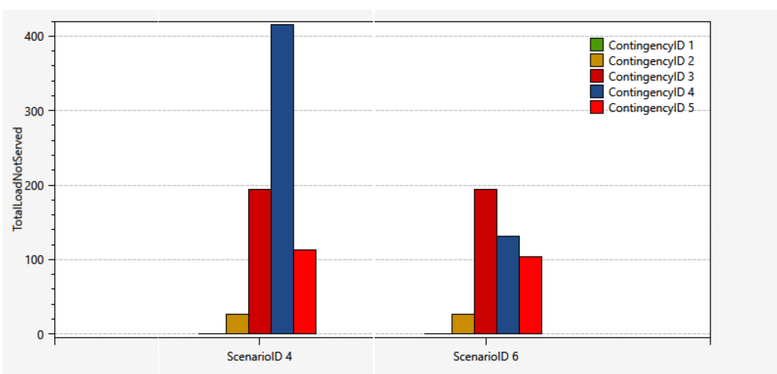
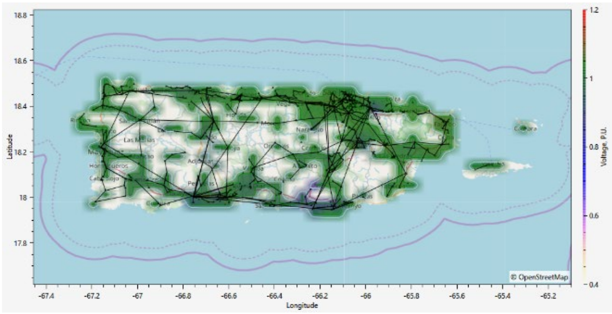
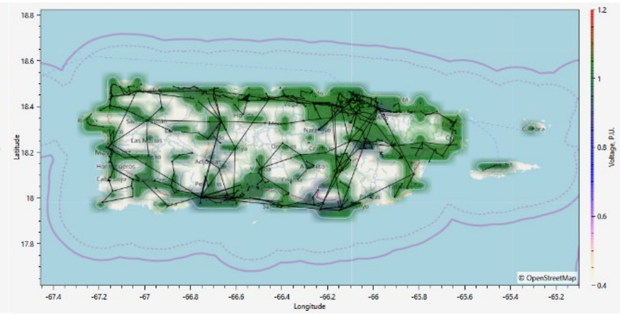


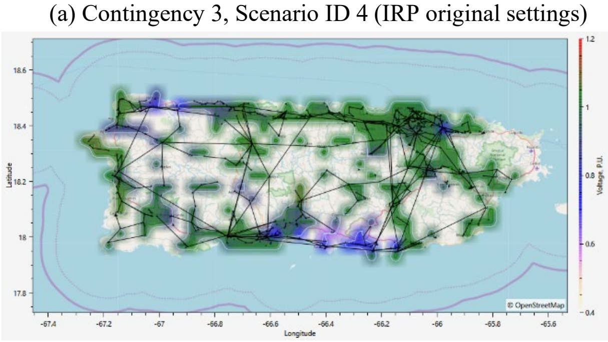
Figure 5-22: Total load impact metric comparison for 2028 high solar scenario with original inverter control settings (Scenario ID 4) and increase voltage and frequency control contributions (Scenario ID 6) for Maria Lite hurricane scenario – figure generated by DCAT Analytics



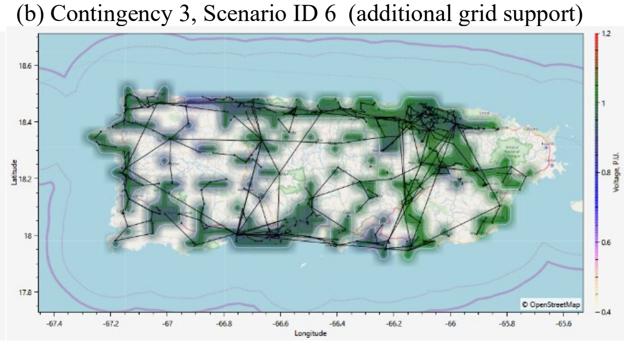
(a) Contingency 3, Scenario ID 4 (IRP original settings)



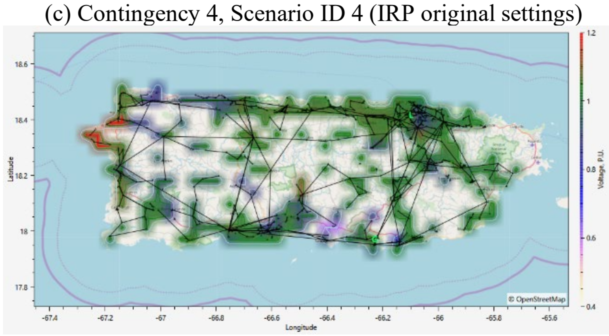
(b) Contingency 3, Scenario ID 6 (additional grid support)



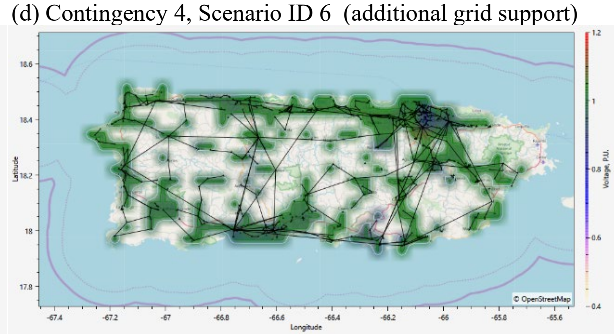
(c) Contingency 4, Scenario ID 4 (IRP original settings)



(d) Contingency 4, Scenario ID 6 (additional grid support)



(e) Contingency 5, Scenario ID 4 (IRP original settings)



(f) Contingency 5, Scenario ID 6 (additional grid support)

Figure 5-23: Voltage profile plotting for Contingencies 3, 4 and 5 in Hurricane Maria Lite simulation with 2028 day peak case, original IRP settings (Scenario ID 4) compared with additional voltage and frequency support from inverter models (Scenario ID 6) – figure generated by DCAT Analytics

5.6 Impact of Puerto Rico Minigrid Strategy on Hurricane Resiliency

As an effort to improve resilience, the 2019 Puerto Rico IRP [16] proposes to split the grid into smaller pieces, called minigrids and microgrids, following a catastrophic event. The system would be operated in this split configuration for a short period of time, such as one month, until the system is restored back together to a full network configuration. Minigrids proposed in the IRP are portions of the transmission system, including hundreds of MW loads, large generation, and 230 kV, 115 kV, as well as 38 kV transmission infrastructure. On the other hand, microgrids proposed in the IRP are smaller localized networks to supply critical loads of up to about 10 to 20 MW, with small local generation, a single substation and in general from low distribution voltage levels up to 38kV transmission.

Approximate geographic locations of the minigrids proposed in the 2019 Puerto Rico IRP are shown in Figure 5-24. Each minigrid contains 100-1000MW of peak load, with approximately 40% of this load in each area deemed 'critical' (in need of immediate restoration).

Figure 5-24: Approximate geographic locations of proposed Minigrids in the 2019 Puerto Rico IRP. Figure extracted from PREPA's fiscal plan[1].

Hurricane simulations, using the developed risk-based dynamic cascading framework were carried out to demonstrate the operation of Puerto Rico divided into smaller minigrids prior to the hurricane event. It should be noted that this operating scenario closely aligns with the current practice of decentralized system recovery used in Puerto Rico. For this analysis, the minigrid for Bayamon-San Juan was considered. This minigrid has enough generation to sustain the entire load.

A new power flow case representing San Juan-Bayamon minigrid was generated based on the IRP S4S2B 2028 power flow case representing the whole Puerto Rico Power Grid, it contains 372 buses and 420 branches. This San Juan-Bayamon minigrid power flow case was analyzed in the proposed risk-based dynamic cascading analysis framework, with the same Hurricane Maria Contingency definition.

Figure 5-25 shows the total load not served in San Juan-Bayamon minigrid from Contingency 1 to Contingency 5, under the Hurricane Maria. By comparison, the previous simulation for the full interconnected Puerto Rico Power Grid cannot survive in Contingency 3 (see section 5.3.3). This comparison demonstrated that preventive splitting into minigrids before the hurricane arrives can improve the system performance for the San Juan – Bayamon areas. This strategy could help San Juan-Bayamon areas avoid the system collapse and help preserve critical load. The improved performance could be especially important to this area because it is a high-density urban area with presence of various public facilities. Additionally, the minigrid strategy could potentially alleviate the restoration burden within each minigrid and speed up the post-event restoration with potentially less coordination effort among different regions.

[1] Source: PREPA's 2019 fiscal plan presentation, page 80, available online: https://aeepr.com/es-pr/Documents/Exhibit%201%20%202019%20Fiscal_Plan_for_PREPA_Certified_FOMB%20on_June_27_2019.pdf

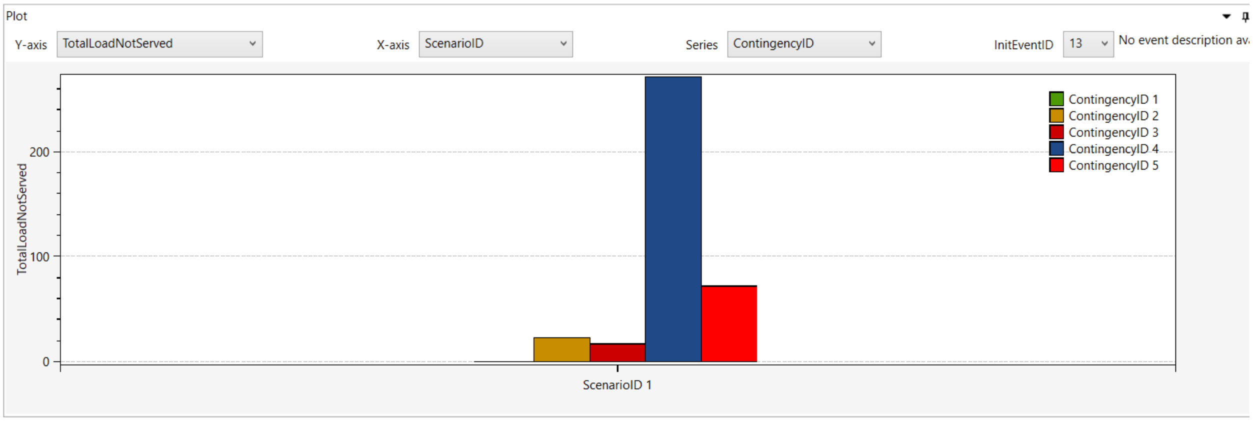


Figure 5-25: Total load not served in San Juan-Bayamon Minigrid simulation for Hurricane Maria. – figure generated by DCAT Analytics

5.7 Risk-based Impact Comparison for Historical Hurricanes

Based on the wind speed of all hurricanes occurring over Puerto Rico in the past 50 years, a histogram of wind speed is shown in Figure 2-12 (Section 2.3) . The histogram of hurricane wind speed represents the chance of hurricanes at different wind speeds to impact Puerto Rico based on historical data. The histogram is then used to calculate the weighted risk-based impact expectation of any given hurricane, within the proposed risk-based dynamic contingency analysis framework. This analysis is also incorporated in DCAT Analytics user interface and DCAT Data Management modules to facilitate the engineering analysis.

For all the events simulated in the proposed framework, Table 5-6 summarizes the information from Monte Carlo simulations as well as the extracted information from the wind speed histogram. The probability of hurricane shows that Hurricane Irma, which has lower wind speed results in a relative higher probability of 0.1; on the other hand, Hurricane Maria has a lower probability of 0.05. However, the Average Total Load Impact and statistical standard deviation of Hurricane Maria are significantly higher than Hurricane Irma, which indicates a more disruptive event to Puerto Rico power grid.

In summary, the weighted risk metric for Hurricane Maria and Hurricane Irma provides a comprehensive method to evaluate the combined impact and probability of impact to the Puerto Rico power grid. This is critical for both long-term grid planning analysis and short-term grid operation and control, and the framework enables such analysis with an effective and efficient way.

Table 5-6 provides a detailed summary for the risk metric for Hurricane Maria and Hurricane Irma and their variations. Major highlights are given as follows:

1) Hurricane Maria (#5) has the largest risk even with a lower probability (0.05) comparing to Hurricane Irma (#6), which has the probability of 0.1, about two times of Hurricane Maria. This is mainly due to the overall impact of Hurricane Maria, in which the average total load not served is 549.19 MW in 10 Monte Carlo simulations

2) Hurricane Maria shows less disruptive impact when simulated with 2028 planning case (#9, #11, #12), in which both the Solar PV generation and additional protection equipment provide essential improvements on system performance

3) Hurricane Maria and its variations with different sensitivities have been simulated, which were all assigned with the same probability of 0.05 in this work. Future studies could explore potential methods to derive specific probability based on various conditions of future hurricanes, which could enable the power system planning engineers to perform long-term future planning studies with the proposed framework.

Table 5-6: A summary of Risk-based grid resilience metrics for historical hurricanes in Puerto Rico – table form DCAT Analytics

InitEventID	AverageTotalLoadImpact	TotalLoadImpactSTD	MaxMaxCont	MinMaxCont	MeanMaxCont	StdMaxCont	ProbabilityHurricane	AverageTotalLoadImpactRisk
5	549.19	454.03	4	2	2.40	0.80	0.05	27.46
6	119.93	11.51	4	4	4.00	0.00	0.10	11.99
7	89.69	250.27	3	1	1.22	0.63	0.05	4.48
8	176.46	333.57	2	1	1.20	0.40	0.05	8.82
9	257.36	13.44	3	2	2.80	0.40	0.05	12.87
11	53.59	11.80	2	1	1.90	0.30	0.05	2.68
12	80.32	2.27	2	2	2.00	0.00	0.05	4.02

6.0 Conclusions, High-Priority Enhancements, and Phase II Recommendations

The previous study, Phase I [17], identified high-priority transmission enhancements derived from detailed dynamic cascading analysis of many severe contingencies, including a hurricane scenario example. Power flow analysis and DCAT were used to analyze dynamic response and cascading sequences initiated by severe outages of multiple elements. Recommendations were provided including the reinforcement of high priority transmission corridors, areas where improved voltage support would be most beneficial, and frequency response improvements.

This study, Phase II, saw the development and demonstration of the risk-based dynamic contingency analysis framework. ANL's HEADOUT and PNNL's DCAT and EGRASS, and DCAT were all linked in a cohesive methodology enabling more comprehensive studies. Additionally, new Analytics, Visualization, and Data Management capabilities were developed to aid in analysis. It is important to highlight that the different tools have been linked from a methodological point of view, and not in a co-simulation software where all tools work together automatically. Instead, this work has focused on methodology improvements and tool improvements to be used within the framework.

A new Monte Carlo probabilistic method has been implemented to calculate risk using probabilistic information at two levels: A) overall probability of occurrence of a hurricane event of a given intensity; and B) probability of failure of individual assets for a given hurricane event. Resilience metrics and results analysis of the probabilistic method have been implemented in the new DCAT Analytics, Visualization, and Data Management capabilities.

The framework can be used to evaluate several hurricane event scenarios in a detailed power system model, to identify high-priority grid enhancements and to test mitigation actions. The framework has been used to evaluate system performance for a total of 119 hurricane simulations, composed of a total of about 800 contingency sets. Simulations included variations of hurricanes Irma and Maria applied to 15 system configurations including scenarios for dynamic control settings and corrective actions settings. In addition, a total of 80 Monte Carlo simulations were run for seven scenarios of study. The framework has been applied to power system model scenarios from 2019 IRP, 2019 scenario and 2028 high-solar scenarios.

The framework provides four different levels of detail in the results enabling the evaluation of risk of hurricane contingencies:

1) a high-level table with the overall risk for each Monte Carlo hurricane simulation;

2) a table with metrics characterizing each set of contingencies that compose a hurricane event;

3) tables and maps summarizing steady-state electrical variables, contingency definitions, and corrective actions after each set of contingencies that compose a hurricane event; and

4) dynamic evolution of system state as a result of electromechanical transient models containing system control and protection, also as a result of the application of each contingency set composing hurricane events.

Tools and results will be made available to stakeholders by request and after DOE review.

The following observations, conclusions, and recommendations are derived from the analysis in this report:

- Hurricanes Maria and Irma were used to study five hurricane events applied to 15 power system configurations, and 80 Monte Carlo realizations of hurricane contingency sets, resulting in a total of 119 hurricane simulations. Each hurricane event was divided into 5 to 8 groups of contingencies, for an overall total of around 800 groups of contingencies. The developed framework provides detailed results (power flow, dynamics, protection, corrective actions) for each individual contingency and cascading stage. Results are also aggregated at four different levels of detail, from overall risk of hurricanes to detailed impact metrics, and detailed engineering results from steady state and dynamic simulations, including effects of dynamic controllers, protection systems, and corrective actions.
    - The risk-based dynamic cascading analysis framework is well-suited for analyzing high-impact, low-frequency events, including hurricanes, with intuitive user interfaces and flexible integration of grid and weather data sources
    - By leveraging probabilistic, stochastic methods, this risk-based dynamic cascading analysis framework enables a full-spectrum analysis for historical hurricane events, and provides solid statistical ground for hurricane contingency formulation and grid equipment failure probability considering different hurricane variations and their unknown characteristics
    - The risk-based dynamic cascading analysis framework enables a streamlined process to identify potential grid vulnerability during hurricane events, and a validated and trustable process to evaluate alternative grid enhancement and pre-event preventive strategies

- The results of this study identified Hurricane Maria as presenting the highest risk to Puerto Rico's power system performance, despite the low probability of occurrence for such a large event. This is consistent with the severity observed and experienced by PREPA in Puerto Rico in 2017. Hurricane Irma, with higher probability of occurrence, presented less risk, mainly driven by its lower severity. It is also worth clarifying that while for the actual events, the system was already stressed by Hurricane Irma before Hurricane Maria happened, for the purposes of our analysis, the grid initial conditions were the same for both simulated hurricanes. This can lead to more general conclusions. In other words, the analysis in this report suggests that severe hurricane events, like Maria, even when they do not occur often, could be important enough to guide the power grid planning processes. Even though this conclusion seems obvious, it is important to highlight that the importance of the hurricane events is derived from the technical basis in the proposed framework. For a more complete analysis, an expanded analysis is recommended, using simulations of additional hurricane events.

- Two operational mitigation strategies were studied and found to produce improved system performance in an event like hurricane Maria. The mitigation actions studied were: 1) preventive unloading and 2) preventive splitting of the system into minigrids, as proposed in the 2019 IRP. Preventive unloading of the system consisted of assumed preventive load shedding by operators in advance of the arrival of a hurricane. For preventive splitting into minigrids, it was assumed that the system operator divided the grid into minigrids before the hurricane arrived. It was found that preventive splitting into minigrids is more efficient mitigation action than reducing the system load and keeping the full system connected.

- One maintenance mitigation measure that the Puerto Rico Electric Power Authority (PREPA) should consider is improved vegetation management. In the vegetation sensitivity cases simulated for Hurricane Irma and Maria Lite, increased cascading failure, load loss, and violations were observed under the extreme system conditions, for the cases with line de-rating under poor vegetation management assumption. By increasing vegetation management, risk of outages caused by line sagging during higher levels of thermal loading that occur during extreme events can be reduced. With reduced risk to outages, system resiliency and reduced restoration time will be potentially achieved.

- System performance during disturbances can be significantly increased by activating additional voltage and frequency control and support in all inverter-based solar and energy storage resources. Hurricane simulations indicated a positive impact on load loss and cascading failure with the additional contribution of voltage and frequency support from inverter-based resources.

- Preliminary results show that grid-forming inverters could significantly improve grid stability when compared with currently more common grid-following inverters. Initial stability tests show that grid-forming inverters could potentially eliminate the need for synchronous condensers, which together with grid-following inverters were identified in Puerto Rico's 2019 IRP study. The initial analysis in this report shows that grid-forming inverters could help operate a Puerto Rico's system with high renewable penetration, however, more modeling, analysis, design, and testing will be needed to confirm this potential.

- Generator frequency and voltage protective relay models were incorporated in dynamic simulations to improve system modeling accuracy; however, the conservative approach taken to model unknown relay settings reduced the number of sequential hurricane contingencies that could successfully solve in the framework developed. For example, under the Maria Lite 2028 day case, the number of contingencies successfully able to solve with added protection models was two, while simulations without relays were able to solve six consecutive sets of hurricane contingencies. Realistic system behavior under these extreme events will fall somewhere between the performance of these two simulation scenarios. Therefore, it is suggested that PREPA acquire and model actual generator protection settings (specifically voltage and frequency) to improve simulation accuracy under extreme contingencies.

- System upgrades in the 2019 IRP that improve resilience against hurricane contingencies are defined in this probabilistic simulation framework. When comparing system performance against Hurricane Maria, Maria Lite, and Irma using the 2019 and future 2028 planning cases (that reflect system upgrades, including undergrounding of selected 230kV transmission facilities), the Puerto Rico grid is able to withstand more hurricane contingencies, with significantly reduced load flow violations, load loss, and generation tripping. In other words, the IRP upgrades can significantly increase grid resiliency and performance during extreme events as validated in our simulations.

The risk-based probabilistic framework described in this report was used to study two historical hurricanes that impacted the island of Puerto Rico. To further this framework and tool demonstration, the following future work and opportunities for enhancement are identified:

- The risk-based dynamic contingency analysis framework proposed here requires infrastructure information that is not commonly available or integrated in power system planning. It is recommended that industry gathers and integrates the following information:
    - Power system planning integrated with operational models, so that operators could quickly put together power flow and dynamic models to analyze current operating conditions, or conditions expected in the near future like in the next hours or next day

- Power system protection information integrated with planning and operational system models
- Historical outages of individual pieces of infrastructure, linked with planning and operational models, as well as with Geographic Information System (GIS) information
- Integrated GIS information of electric infrastructure with improved mapping with planning and operational models
- Updated fragility information for power system equipment, also linked with GIS, related to the type of equipment stress (such as high wind and flooding) from the events of interest (such as hurricane)
- Records of historical failure performance of assets for different type of extreme events

- Study additional hurricane scenarios.
- Study additional sensitivities of risk to failure thresholds or fragility of the electric infrastructure, including incorporation of failure probability for wind and solar generation.
- Integrate the developed framework and tools into power system planning processes to include resilience aspects into planning decisions. For example, using developed framework and Monte Carlo simulations, important design *N*-*k* contingencies could be identified and classified to guide the planning process. This task would require a deep dive into Monte Carlo simulation results, covering several event scenarios, and the application of new analytics techniques. Such process could identify design contingencies and their sequences with the highest impact and highest risk, to further support decision making in the planning process.
- Integrate the developed framework and tools into system operations near-term horizon studies, that can be utilized in real-time when hurricane forecasts become available.
- Research the integration of investment capital cost aspects or benefit cost analysis with the risk-based dynamic cascading failure proposed in this report.

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[18] W Du, PD Royer, KP Schneider, "Improving Resilience of Puerto Rico Electrical Distribution Infrastructure - EGRASS Tool Development," Pacific Northwest National Laboratory, Official Use Only, Technical Report, PNNL-27575 Rev. 3, November 2018

[19] M Elizondo, X Fan, S Davis, B Vyakaranam, X Ke, E Barrett, S Newman, P Royer, P Etingov, A Tbaileh, H Wang, U Agrawal, W Du, P Weidert, D Lewis, T Franklin, NA Samaan, YV Makarov, JE Dagle, "Risk-Based Dynamic Contingency Analysis Applied to Puerto Rico Electric Infrastructure – Phase II Report," Pacific Northwest National Laboratory, Official Use Only Technical Report, PNNL-29842, April 2020

[20] PREPA's 2019 fiscal plan presentation available online at https://aeepr.com/es-pr/Documents/Exhibit%201%20%202019%20Fiscal_Plan_for_PREPA_Certified_FOMB%20on_June_27_2019.pdf

Appendix A: HEADOUT Failure Probability Range

As described in Section 2.1.2, HEADOUT assets were mapped to PSS®E elements, using a circuit ID transmission lines and towers. There was a many to one mapping of HEADOUT assets to circuit IDs, and the ranges of probabilities of failure for each circuit ID are shown in Figure A-1, Figure A-2, Figure A-3 , and Figure A-4 for both Hurricanes Maria and Irma. For the base-case simulations of hurricanes Maria and Irma, the maximum probability among all HEADOUT assets assigned to a circuit ID was used for all PSS®E elements associated with that circuit. In the additional sensitivity analysis described in Section 4.3, the minimum and mean probabilities for hurricane Maria were also used.

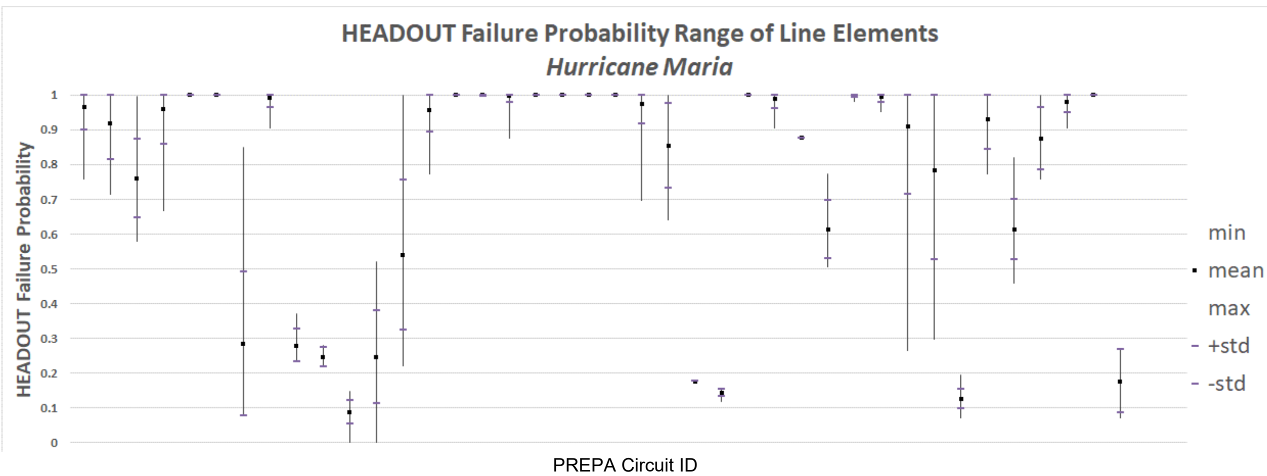


Figure A-1 HEADOUT failure probability range of line elements for Hurricane Maria.

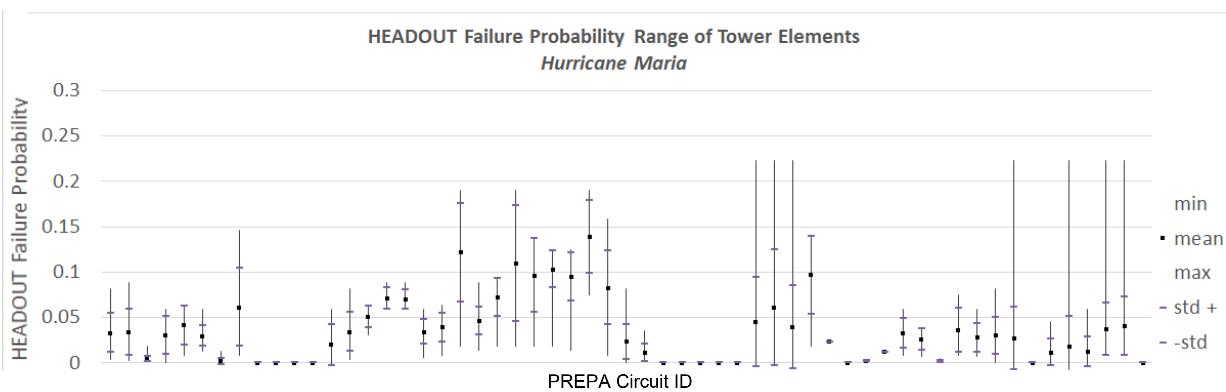


Figure A-2 HEADOUT failure probability range of tower elements for Hurricane Maria.

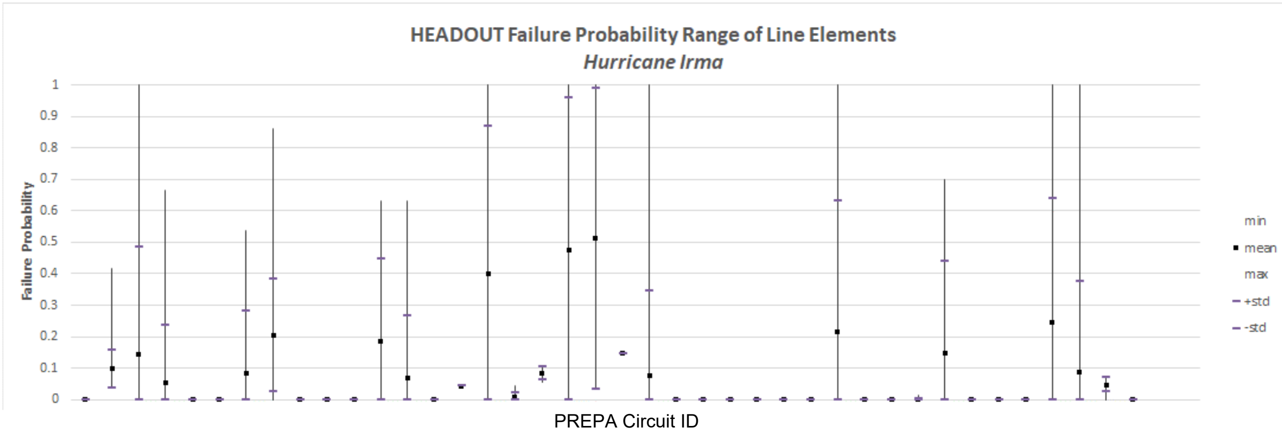


Figure A-3 HEADOUT failure probability range of line elements for Hurricane Irma

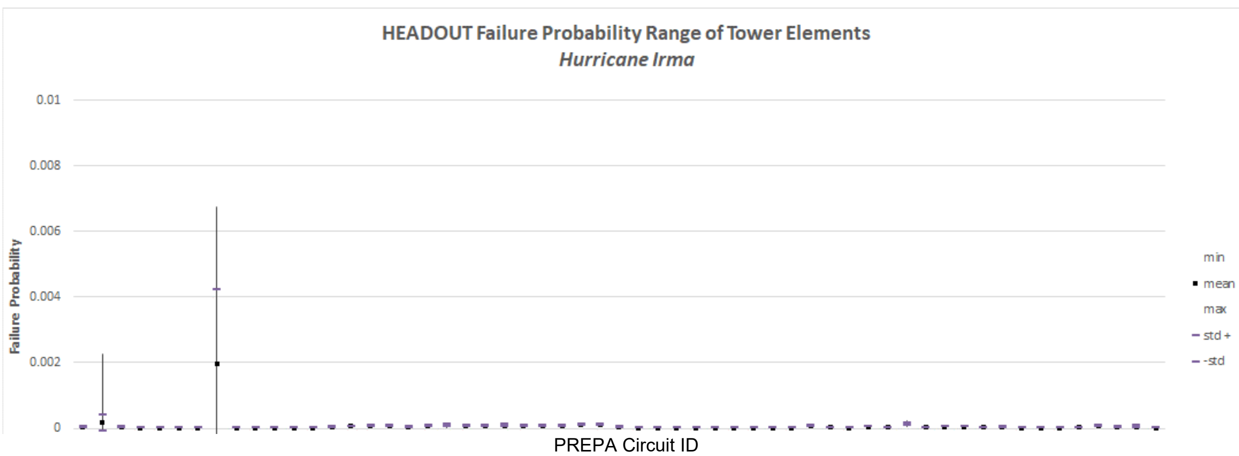


Figure A-4 HEADOUT failure probability range of tower elements for Hurricane Irma

Appendix B: Simulation Setup

The project team performed the risk-based dynamic contingency analysis for Puerto Rico Power Grid, the simulation results cover a great volume of simulations. There are multiple dimensions that those simulations have been aligned with, they can be categorized as follows:

1) Power Flow Case

There are mainly two Puerto Rico power flow cases that have been used in DCAT simulations. They are 2019 base case and the 2028 S4S2 cases. To be more specific, there are also two additional variants of 2019 Night case, which are 2019 Night Preventive Unloading case and 2019 Night Vegetation case. 2019 Night Preventive Unloading case incorporates in-advance load shedding strategy to shift the system to a new operation point with higher generation reserve, while 2019 Night Vegetation case modifies the transmission line rating to reflect vegetation impact.

Section 4.2 provides more details regarding the studied scenario. A high-level summary is given as follows for those additional sensitivity analyses:

- Sensitivity to corrective actions configurations in DCAT
- Derating lines due to assumption of lack of vegetation management
- Sensitivity to asset failure probability, using HEADOUT minimum & average asset failure probability for developing hurricane contingency scenarios
- Preventive load reduction scenario assuming that the system operator could unload the system as a preventive measure to try to mitigate the impact of a hurricane
- Addition of generator frequency and voltage protection relays
- Inverter control configuration for solar PV and energy storage: sensitivity to frequency control settings and type of inverter (grid following versus grid forming inverts) to study stability improvement
- Minigrid configurations proposed in the 2019 IRP

2) Initiating Event (Hurricane)

Both Hurricane Maria and Hurricane Irma are simulated to evaluate their impacts on power grid through DCAT simulations. Based on the combination of different power flow cases and hurricanes, a unique Event ID was assigned to each combination. There are in total nine such combinations those were evaluated in DCAT simulation.

3) Single Hurricane Simulation Scenario

Multiple simulation scenarios have been studied for each *Event ID*, different sensitivity level for DCAT corrective actions and various renewable energy penetration level are considered. Details are given as follows:

1. Apply DCAT corrective actions to all kV level transmission systems

2. Apply DCAT corrective actions only to above 100 kV transmission systems
3. No DCAT corrective actions
4. No additional grid support from Solar Power Plants
5. Additional grid support from 10% of Solar Power Plants
6. Additional grid support from all Solar Power Plants

A summary of all the simulated scenarios for Hurricane Maria and Hurricane Irma are given in Table B-1.

Table B-1 Summary for DCAT simulations regarding Hurricane Maria and Irma

Event	Case	Event ID	Scenario ID
Maria	2019 Night	1	1,2,3
Maria	2019 Night + Preventive Unloading	2	1,2,3
Irma	2019 Night	3	1,2,3
Irma	2019 Night	4	1,2,3
Irma	2019 Night + Vegetation De-rates	5	1,2,3
Irma	2028 Day	6	4,5,6
Maria	2028 Day	7	4,5,6
Maria Lite	2028 Day	8	4,5,6
Maria Lite	2019 Night	9	1,2,3
Irma	2028 Day + Generator Protection	10	4,5,6
Maria	2028 Day + Generator Protection	11	4,5,6
Maria Lite	2028 Day + Generator Protection	12	4,5,6
Maria Lite	2019 Night + Vegetation De-rates	13	1,2,3

4) Monte Carlo Hurricane Simulation Scenario

Monte Carlo methodology is applied to the failure probability of all events in the time series sequence to obtain a series of assets that will fail based on the time series sequential failure probability. Some assets will be “affected” for multiple timesteps in the time series. For those assets, each asset should only come to MC once. For example, asset A has failure probability 0.7, and it appeared 3 time in the time series sequential generated from EGRASS. Then we will only run MC sampling on the asset A only once based on the failure probability 0.7. If it didn’t fail, then we will assume it won’t fail by the overall time series.

The summary of Monte Carlo simulations for those two hurricanes are given in Table B-2 for Monte Carlo Simulation. If not otherwise noted in the “Event” column, the maximum failure probabilities from HEADOUT are used to create the Monte Carlo contingencies for each hurricane.

All the DCAT scenarios listed in Table B-2 were applied with DCAT corrective actions set to monitor only >100 kV transmission systems.

Table B-2 Summary for Monte Carlo simulations regarding Hurricane Maria and Irma

Event	Case	Event ID	Monte Carlo Scenario IDs
Maria Lite	2019 Night	5	1,2,3,4,5,6,7,8,9,10
Irma	2019 Night	6	1,2,3,4,5,6,7,8,9,10,11,12, 13,14,15,16,17,18,19,20
Maria (**Minimum** Failure Probability*)	2019 Night	7	1,2,3,4,5,6,7,8,9,10
Maria (**Mean** Failure Probability*)	2019 Night	8	1,2,3,4,5,6,7,8,9,10
Maria Lite	2028 Day 10%PV	9	1,2,3,4,5,6,7,8,9,10
Irma	2028 Day 10%PV	10	1,2,3,4,5,6,7,8,9,10
Maria (**Minimum** Failure Probability*)	2028 Day 10%PV	11	1,2,3,4,5,6,7,8,9,10
Maria (**Mean** Failure Probability*)	2028 Day 10%PV	12	1,2,3,4,5,6,7,8,9,10

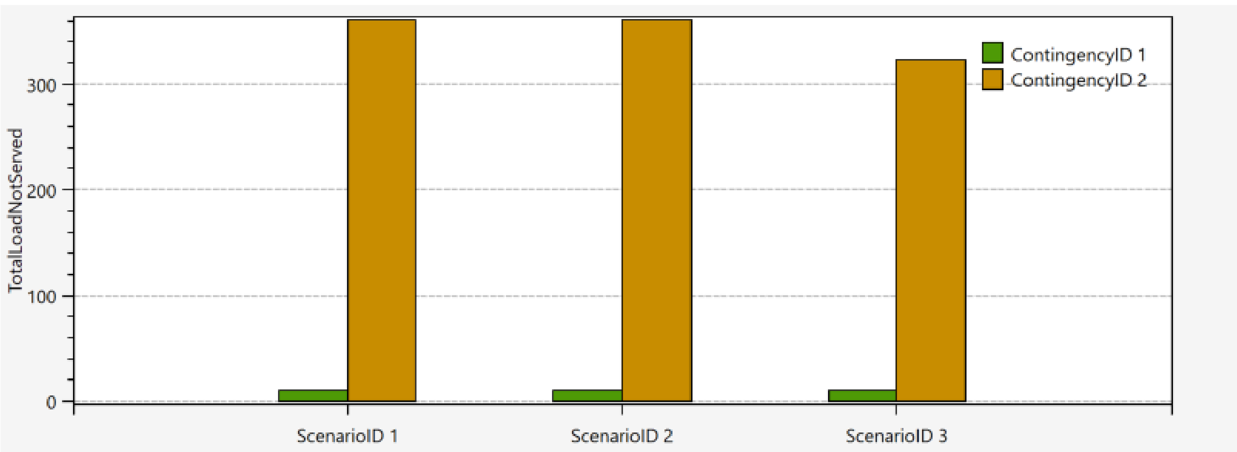
* Using HEADOUT failure probability ranges as identified in Figure 4-5

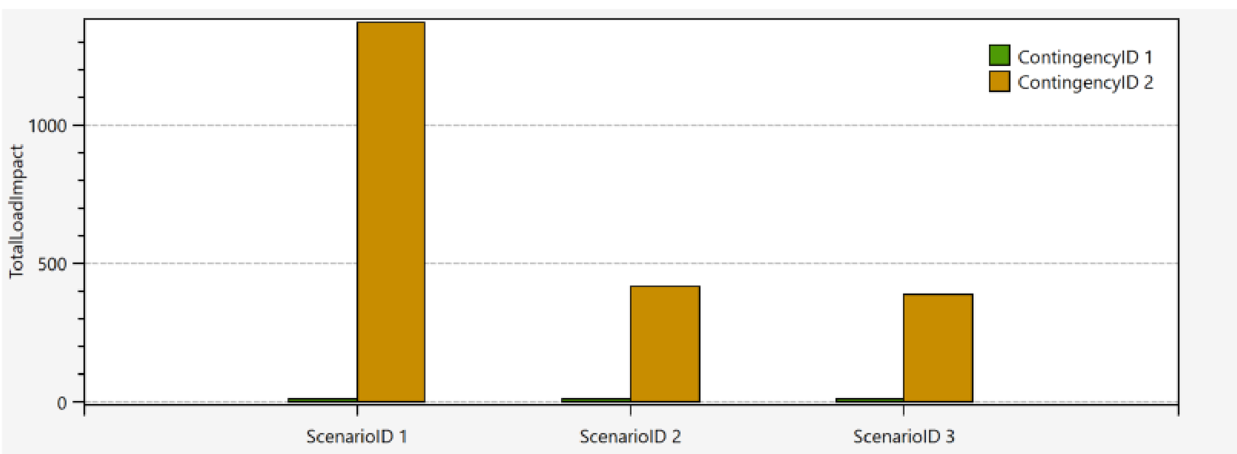
Appendix C: More Results from Single Simulation for Hurricane Scenarios

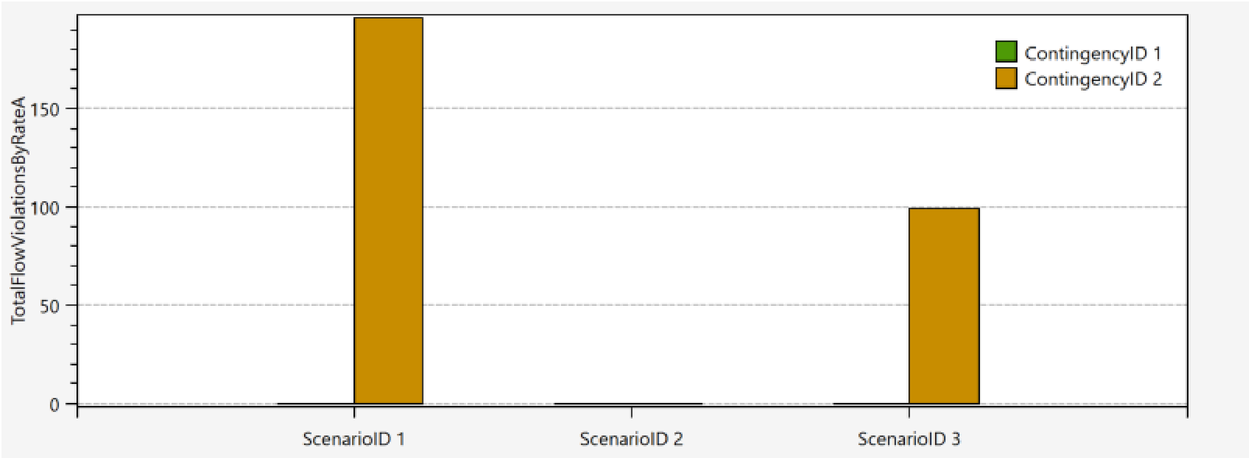
This section provides additional results to complement Section 5.3. The simulation results for Hurricane Maria are saved in DCAT Database Module, which provides the tabular results on resilience metrics, bar charts and GIS-based map visualization. Additional results are given as follows for single simulation for hurricane scenarios.

C.1 Hurricane Maria, InitEventID: 1

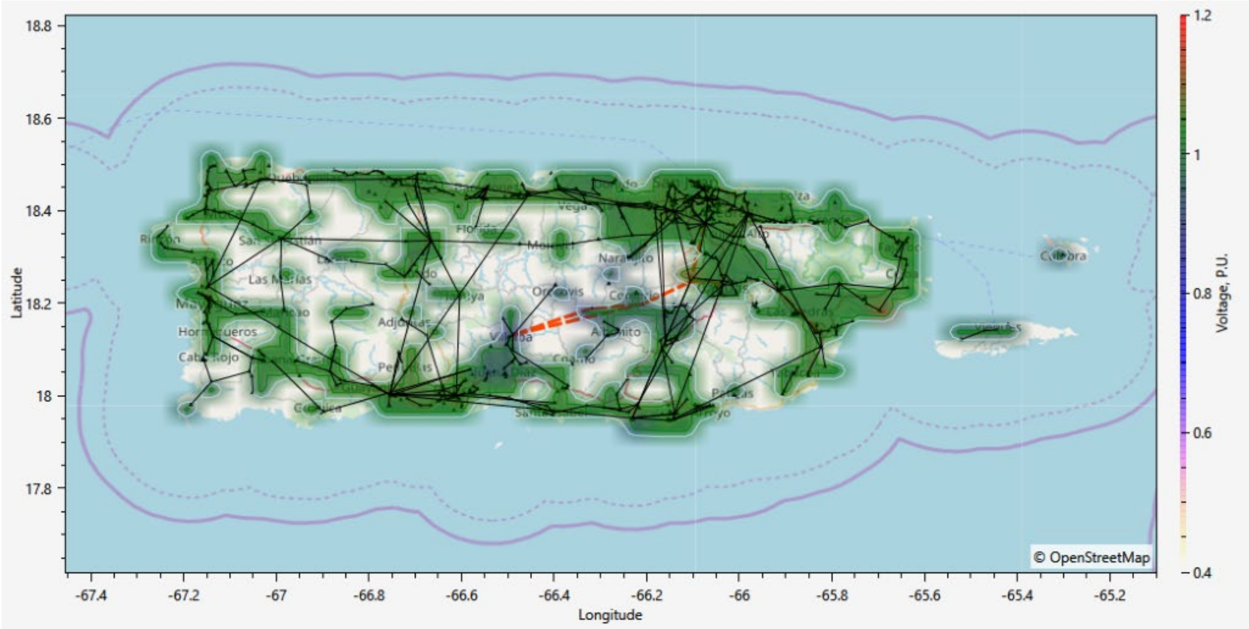
Hurricane: Maria
Case: 2019 Night

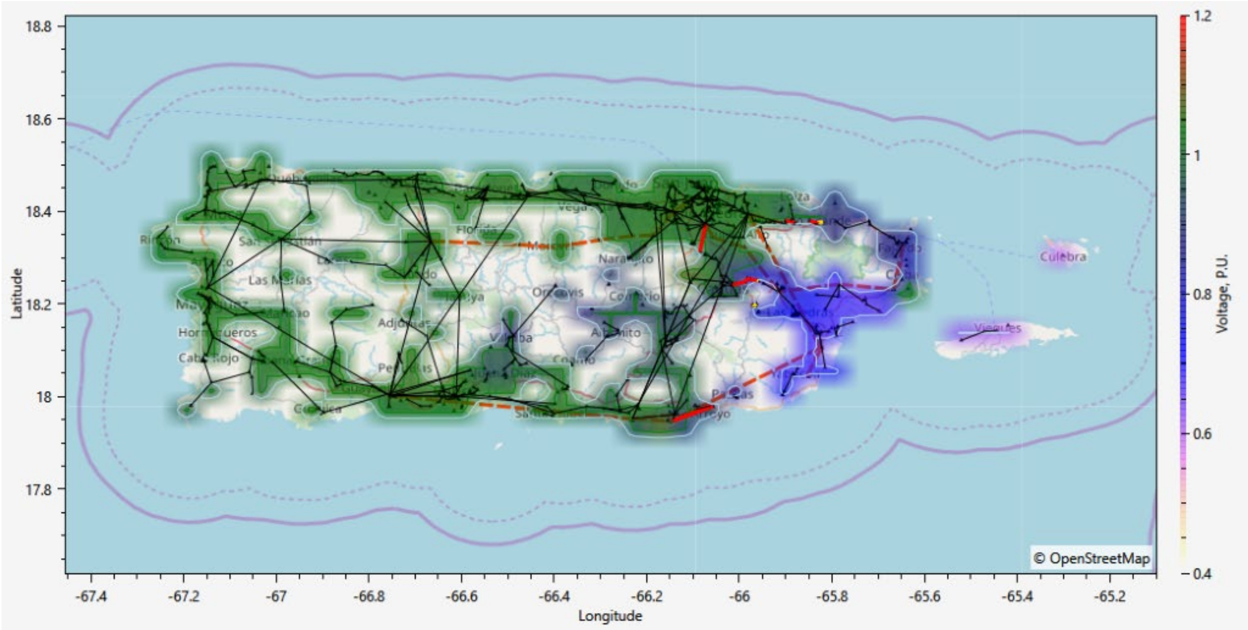






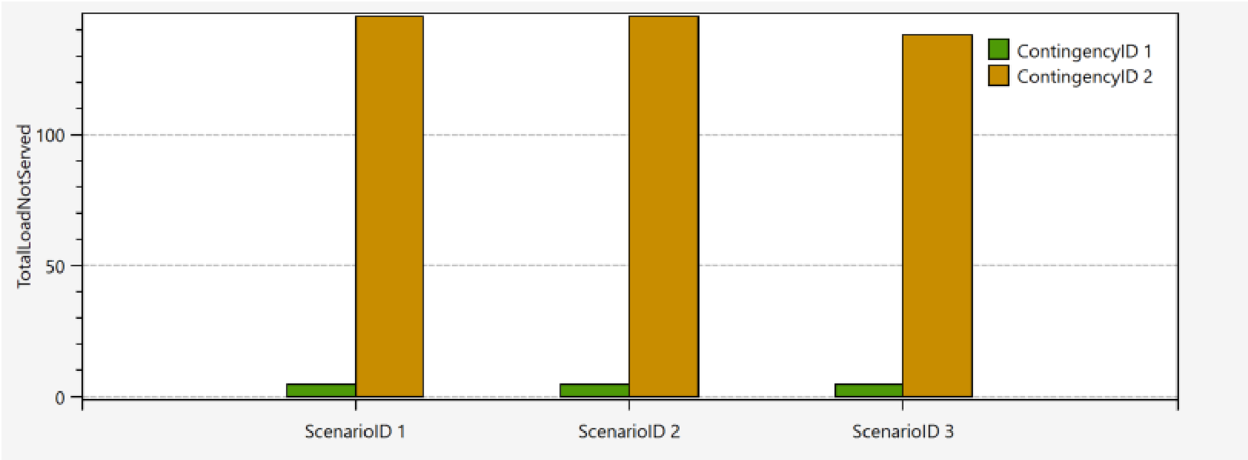
C.1.1 InitEventID: 1, ScenarioID: 2

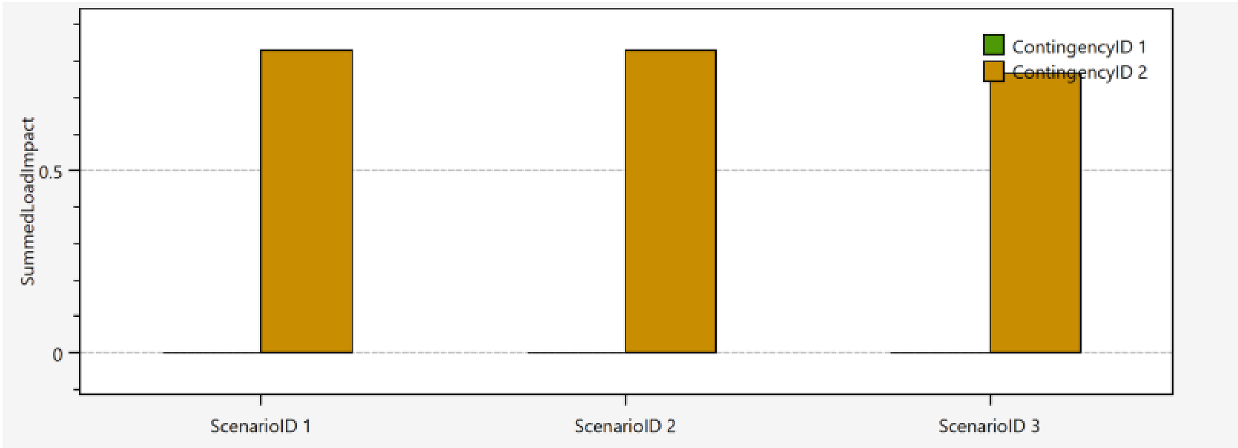


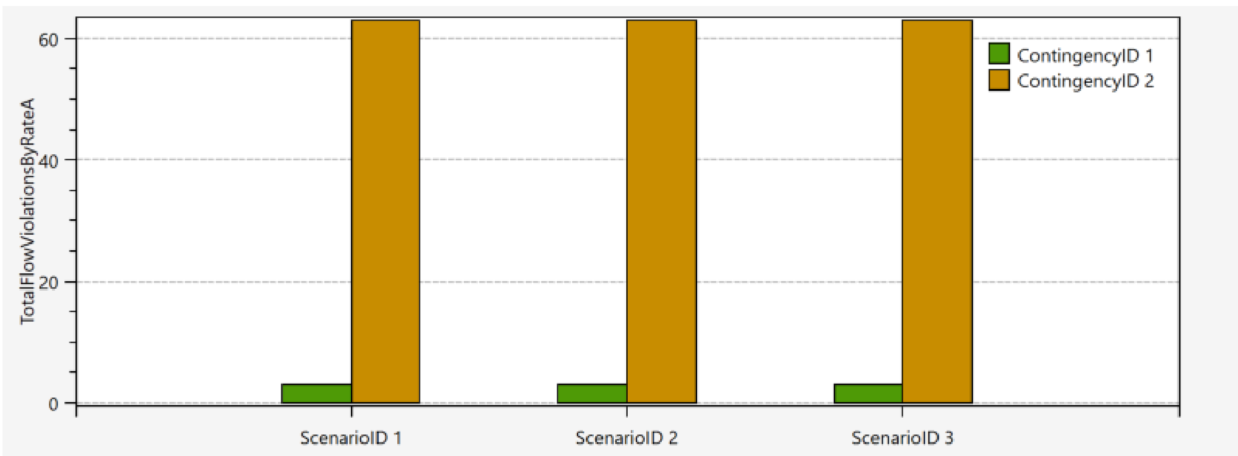


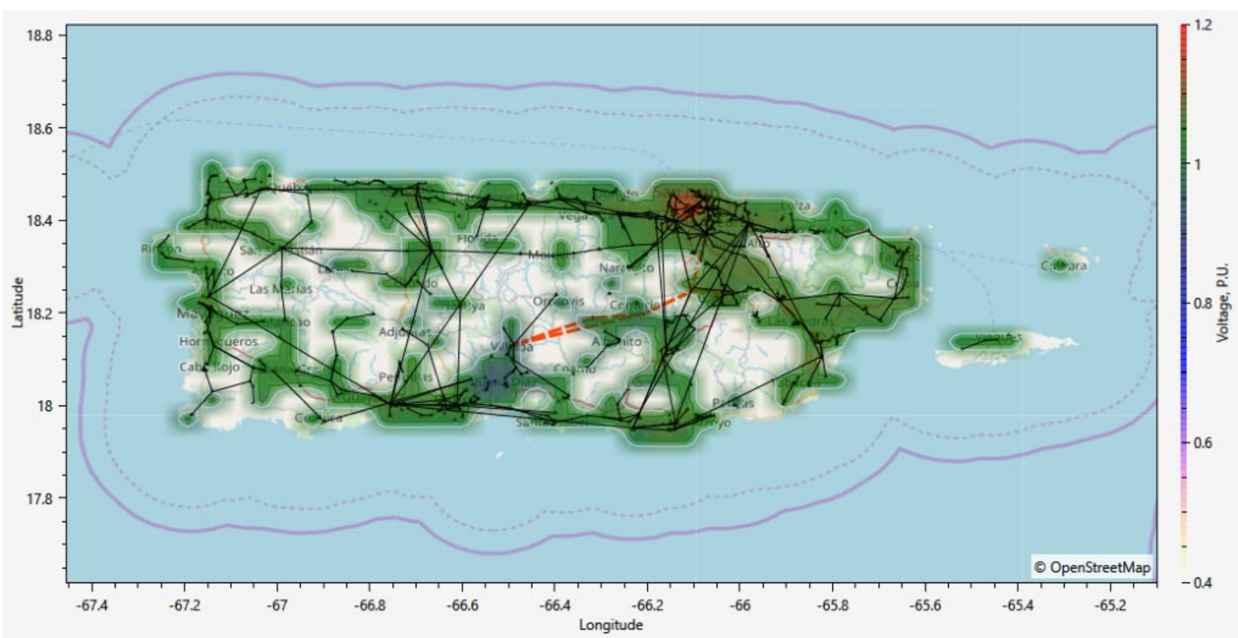
C.2 Hurricane Maria, InitEventID: 2

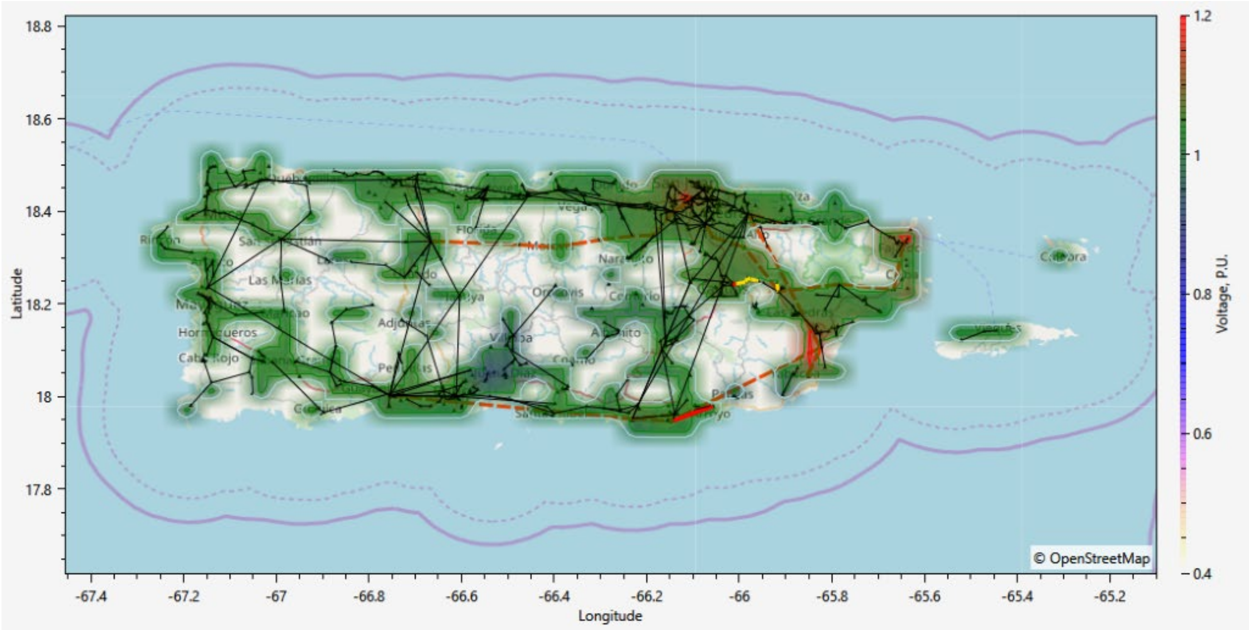
Hurricane: Maria
Case: 2019 Night + Preventive Unloading




SummedLoadImpact
0.5
0
ScenarioID 1
ScenarioID 2
ScenarioID 3
ContingencyID 1
ContingencyID 2

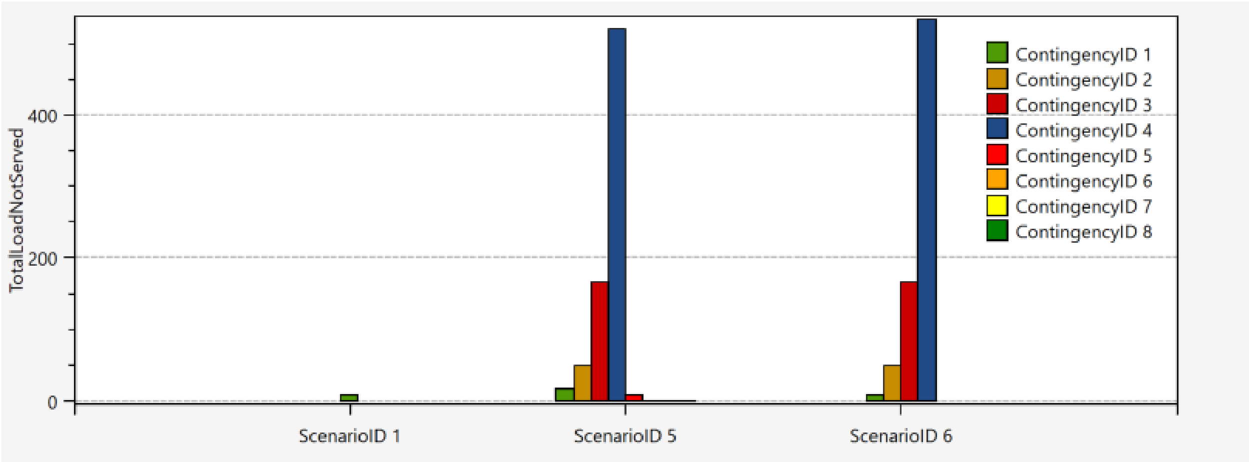

TotalFlowViolationsByRateA
60
40
20
0
ScenarioID 1
ScenarioID 2
ScenarioID 3
ContingencyID 1
ContingencyID 2

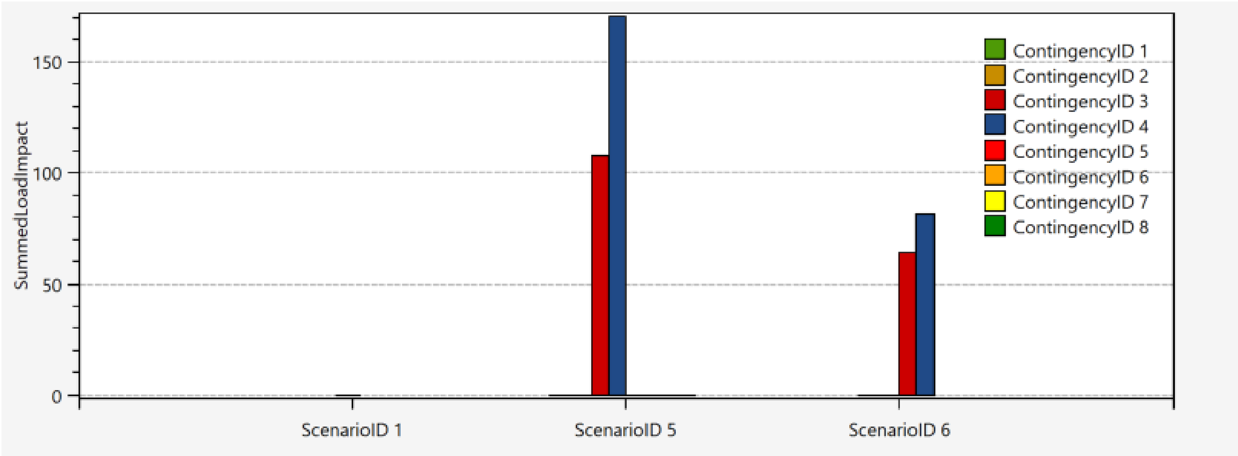

Latitude
18.8
18.6
18.4
18.2
18
17.8
-67.4
-67.2
-67
-66.8
-66.6
-66.4
-66.2
-66
-65.8
-65.6
-65.4
-65.2
Longitude
Voltage, P.U.
1.2
1
0.8
0.6
0.4
© OpenStreetMap

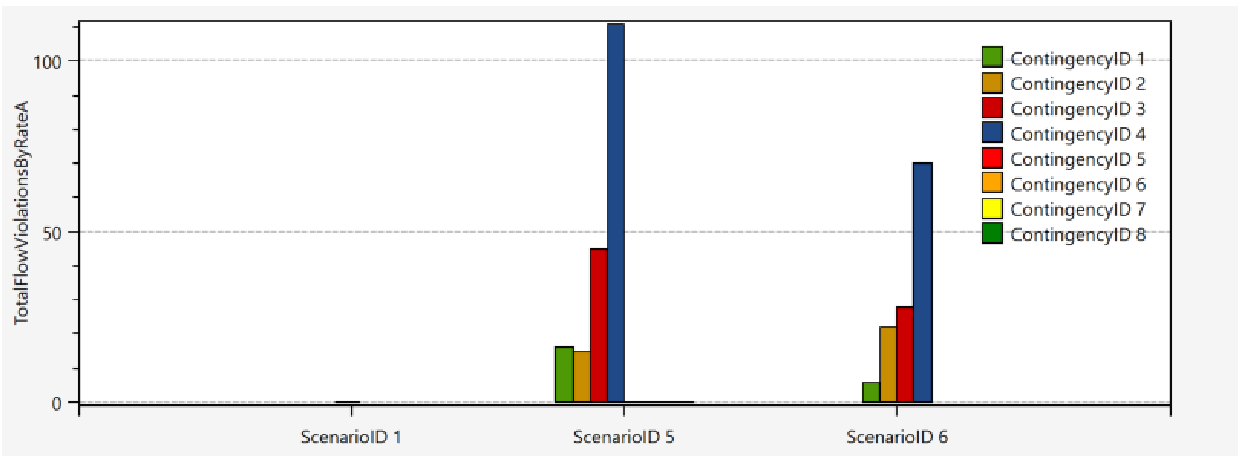


C.3 Hurricane Maria, InitEventID: 7

Hurricane: Maria
Case: 2028 Day

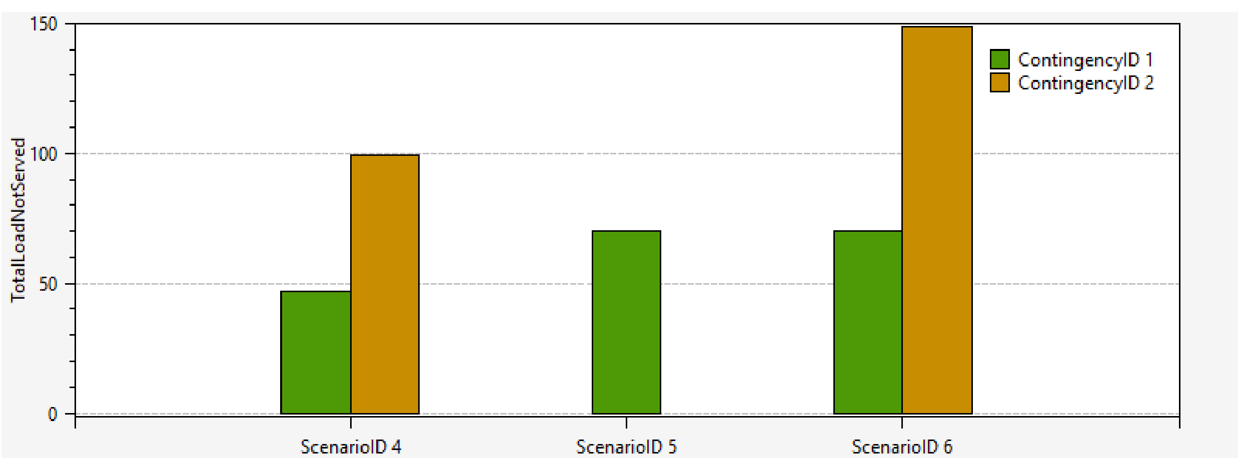


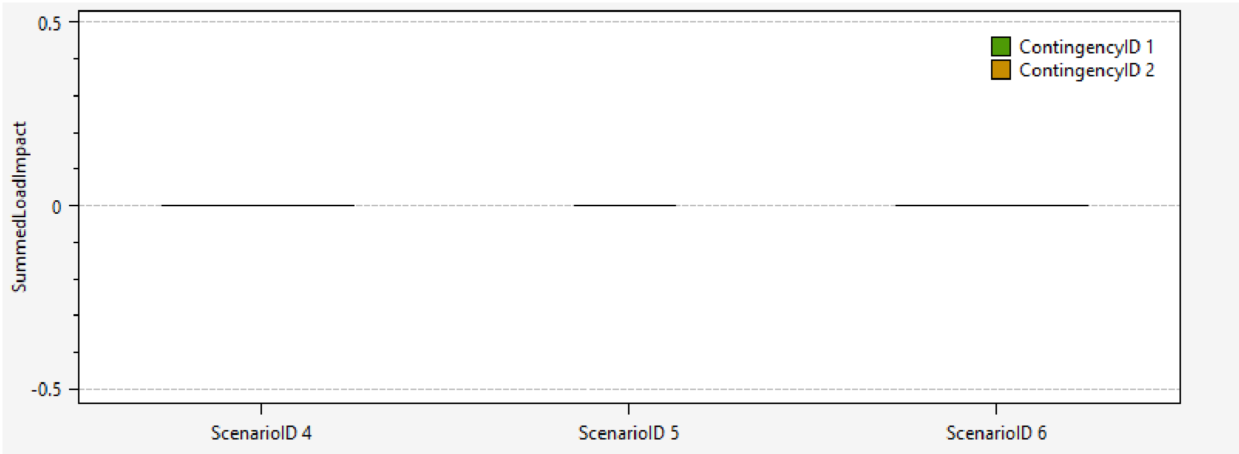


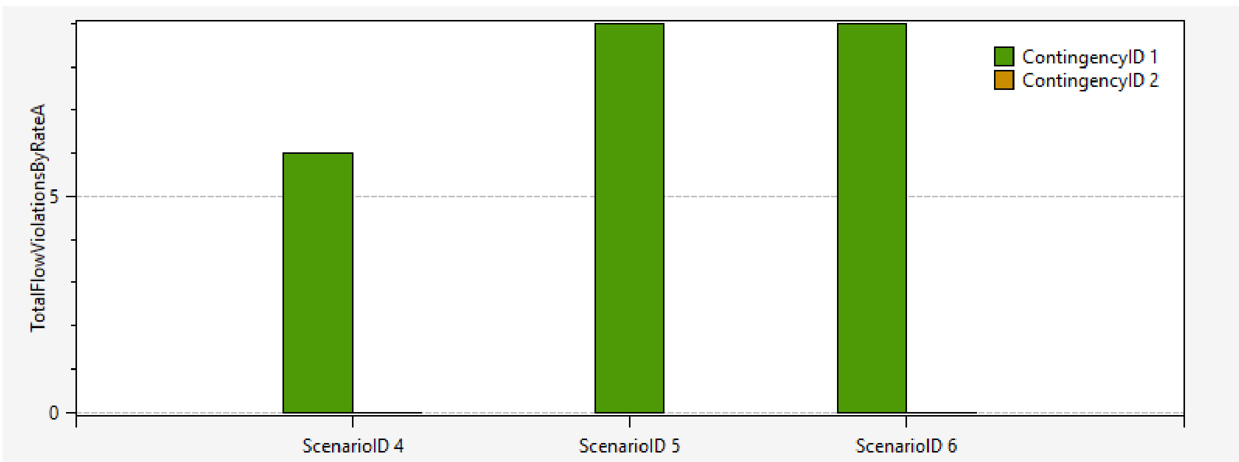


C.4 Hurricane Maria, InitEventID: 11

Hurricane: Maria
Case: 2028 Day + Generator Protection

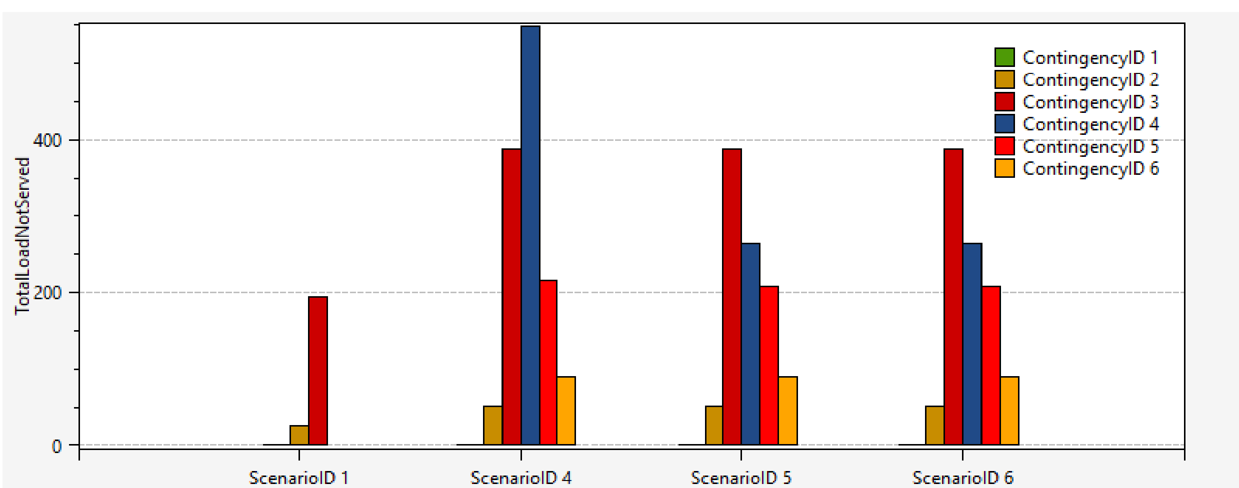


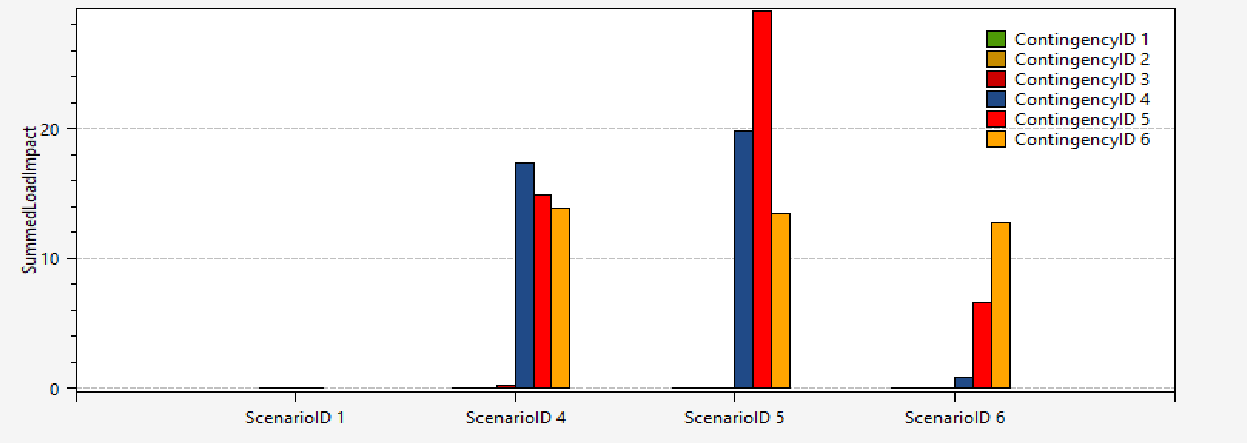


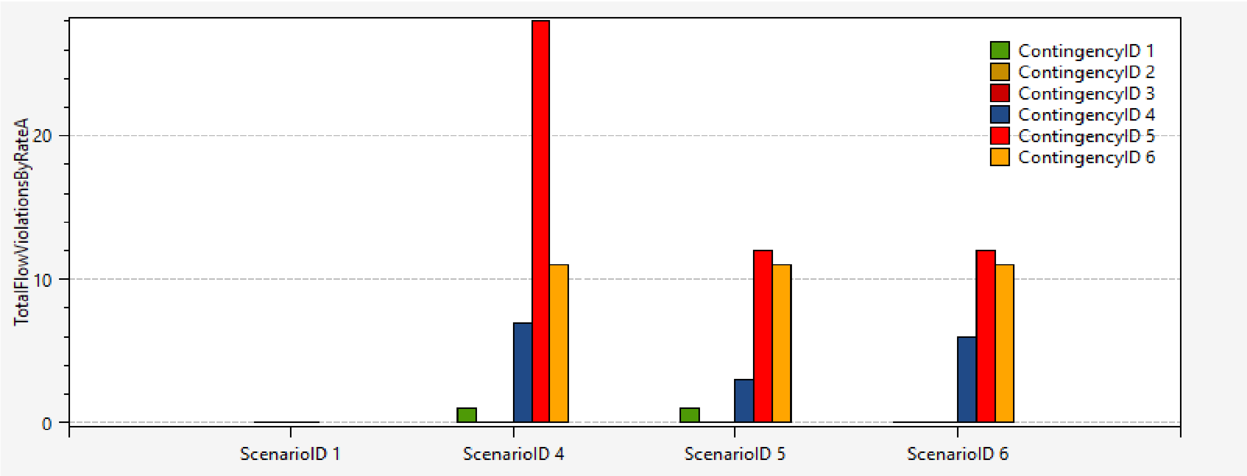


C.5 Hurricane Maria Lite, InitEventID: 8

Hurricane: Maria Lite
Case: 2028 Day

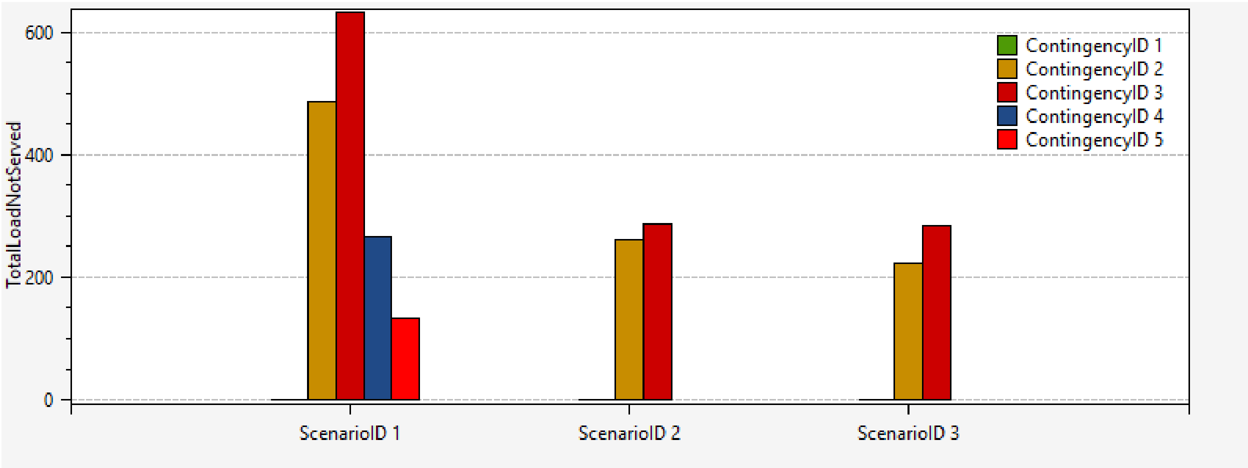


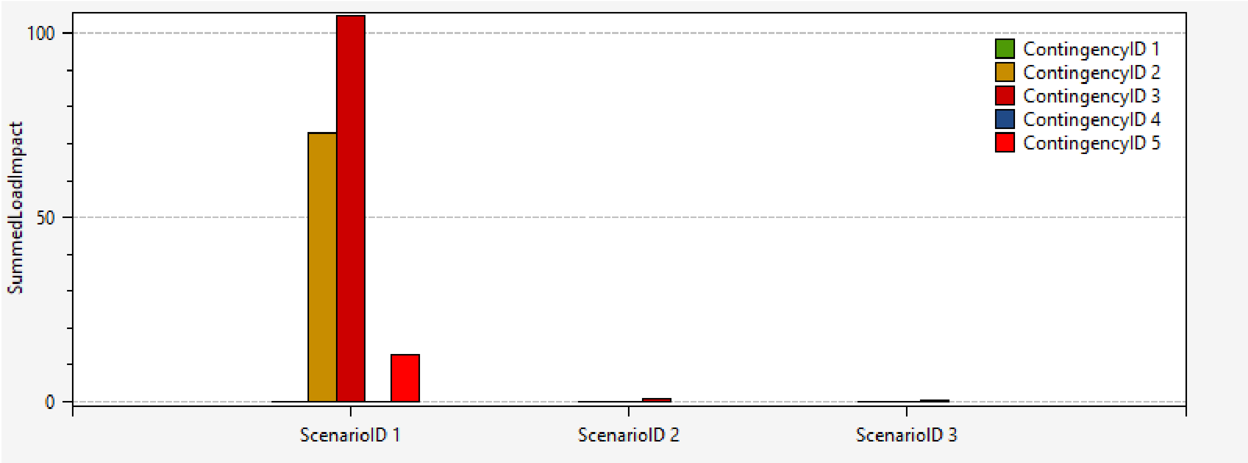


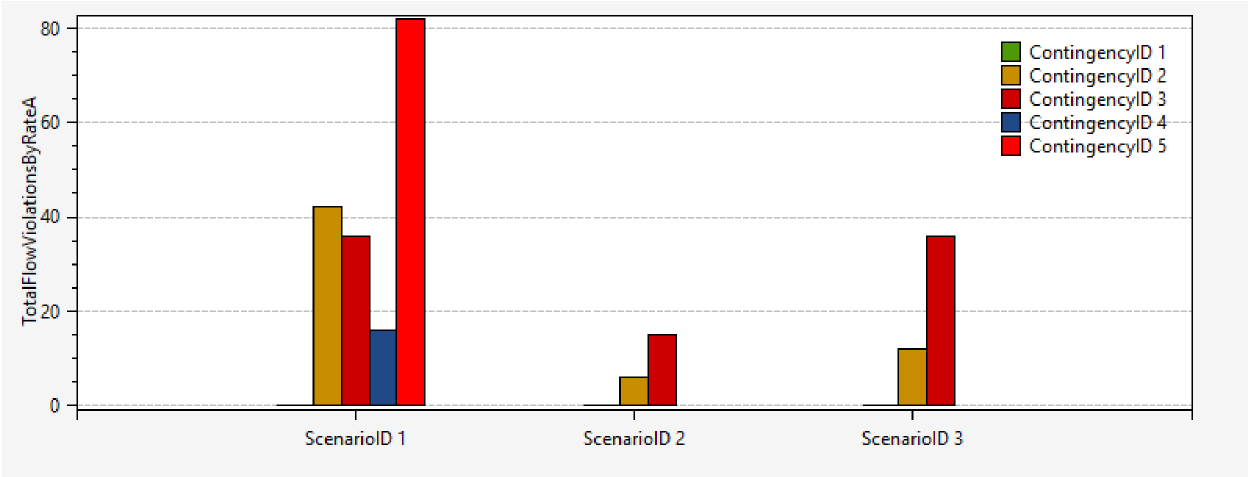


C.6 Hurricane Maria Lite, InitEventID: 9

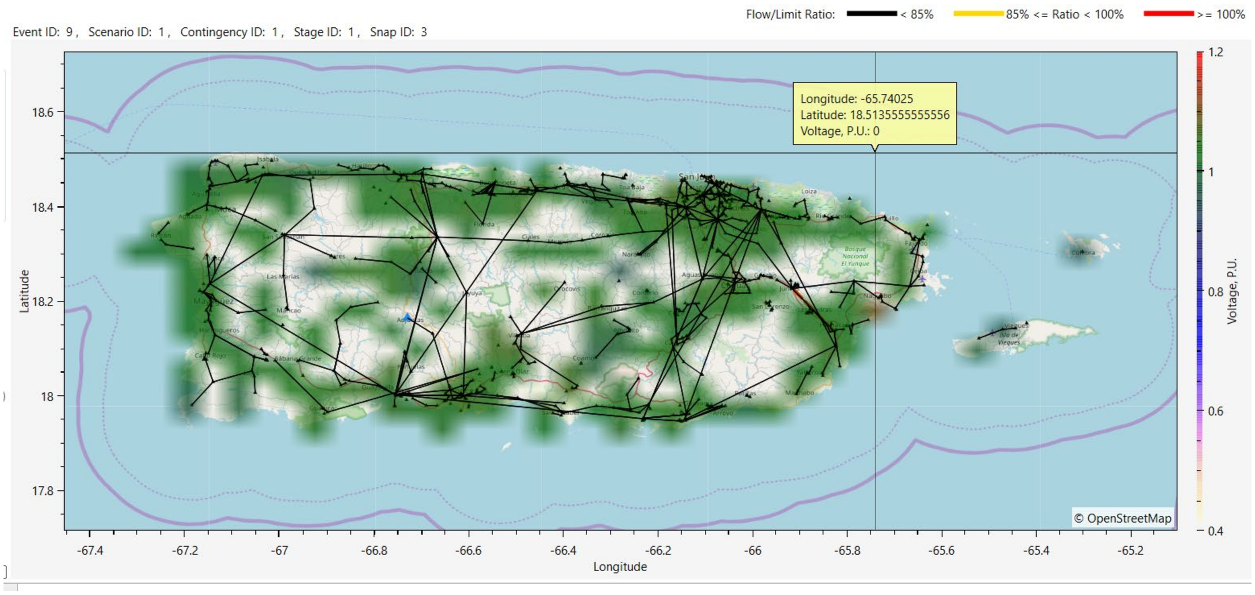
Hurricane: Maria Lite
Case: 2019 Night

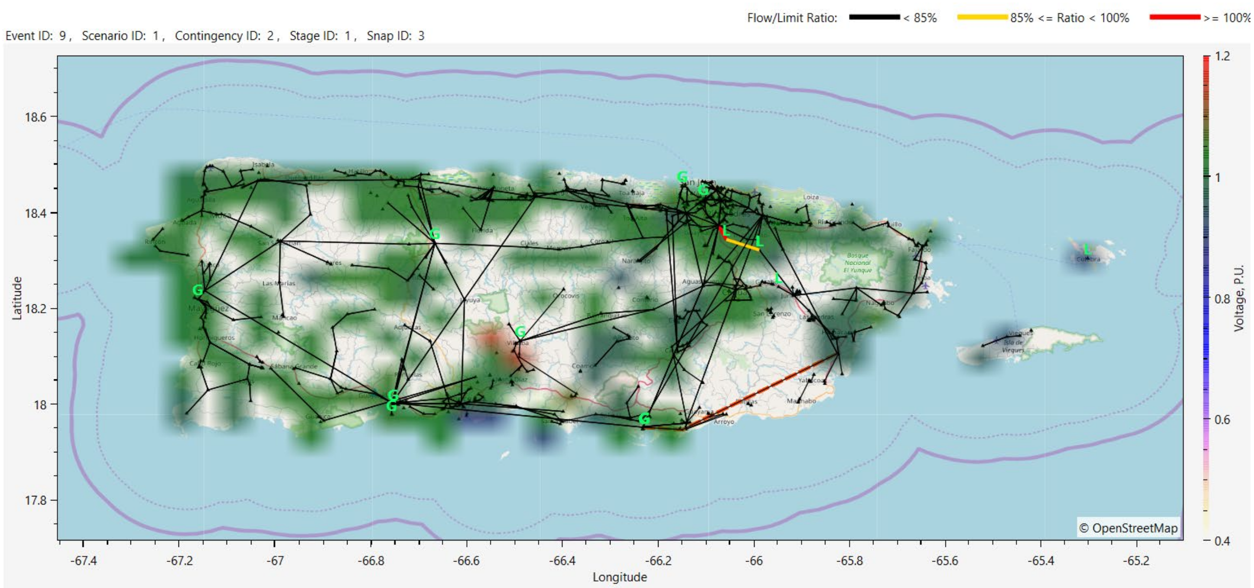

TotalLoadNotServed
600
400
200
0
ScenarioID 1
ScenarioID 2
ScenarioID 3
ContingencyID 1
ContingencyID 2
ContingencyID 3
ContingencyID 4
ContingencyID 5

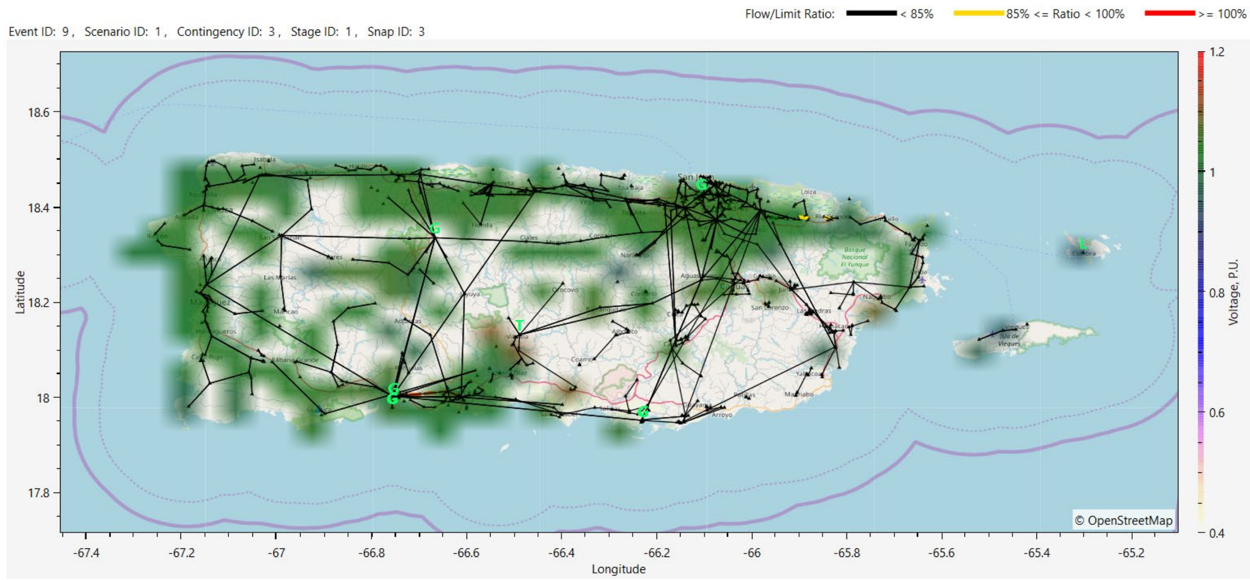

SummedLoadImpact
100
50
0
ScenarioID 1
ScenarioID 2
ScenarioID 3
ContingencyID 1
ContingencyID 2
ContingencyID 3
ContingencyID 4
ContingencyID 5

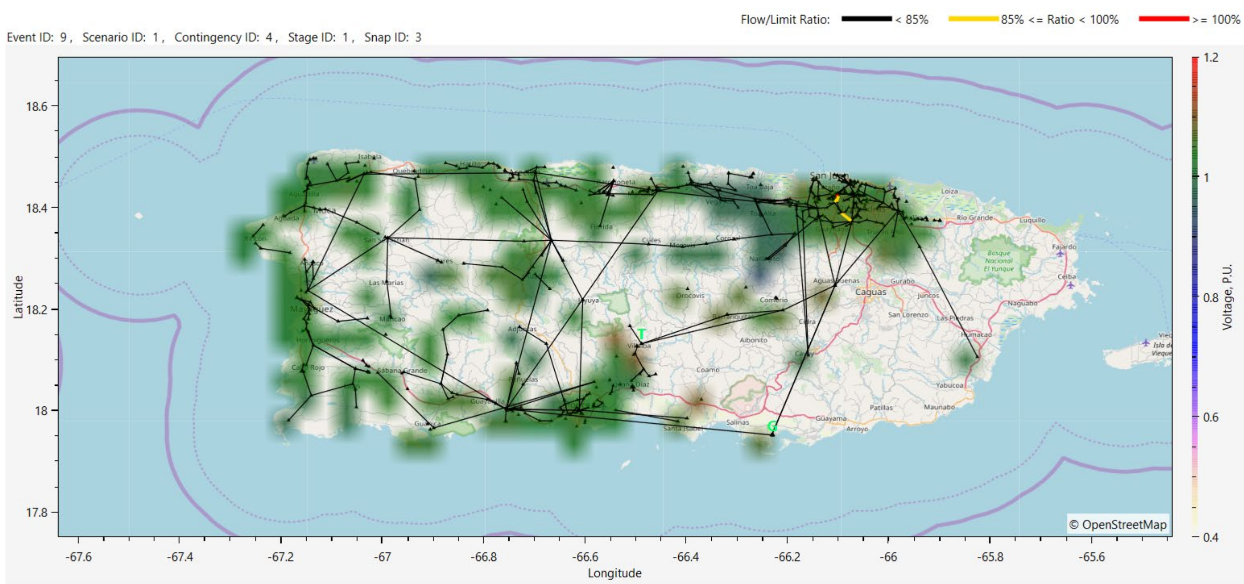

TotalFlowViolationsByRateA
80
60
40
20
0
ScenarioID 1
ScenarioID 2
ScenarioID 3
ContingencyID 1
ContingencyID 2
ContingencyID 3
ContingencyID 4
ContingencyID 5

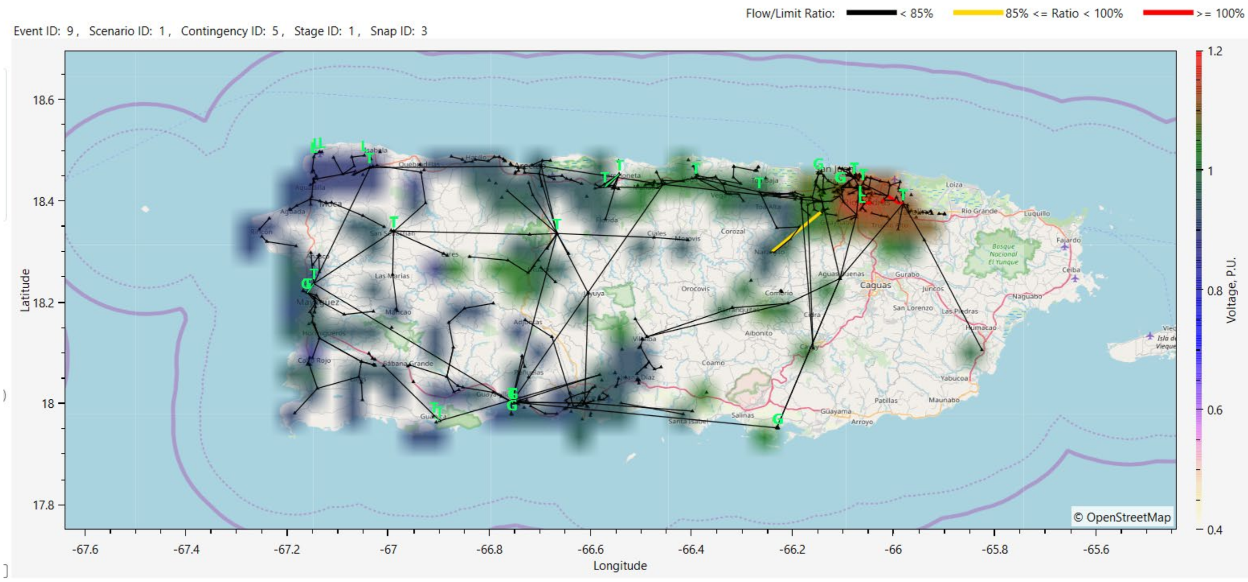
C.6.1 InitEventID:9, ScenarioID: 1





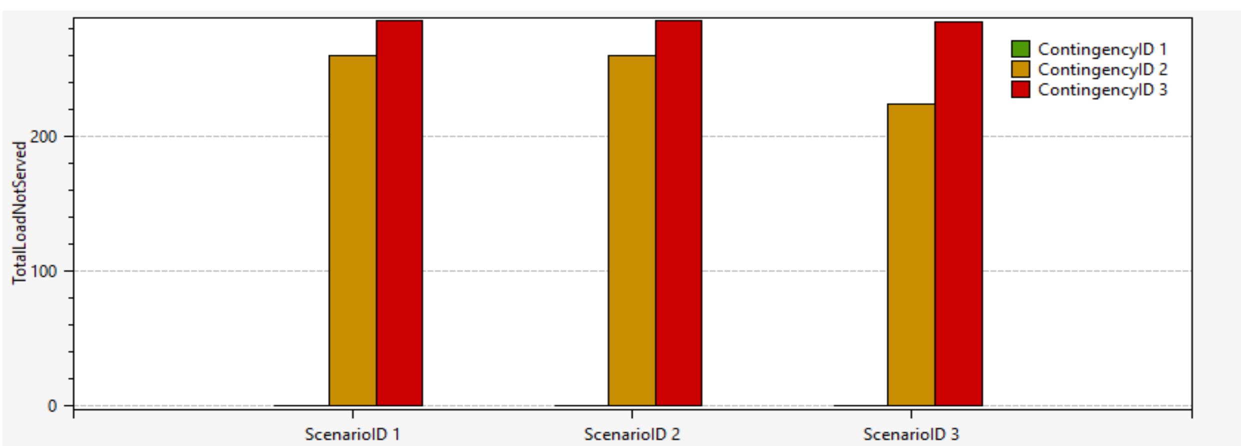

Flow/Limit Ratio: < 85% 85% <= Ratio < 100% >= 100%
Event ID: 9, Scenario ID: 1, Contingency ID: 3, Stage ID: 1, Snap ID: 3
Latitude
Longitude
Voltage, P.U.
© OpenStreetMap

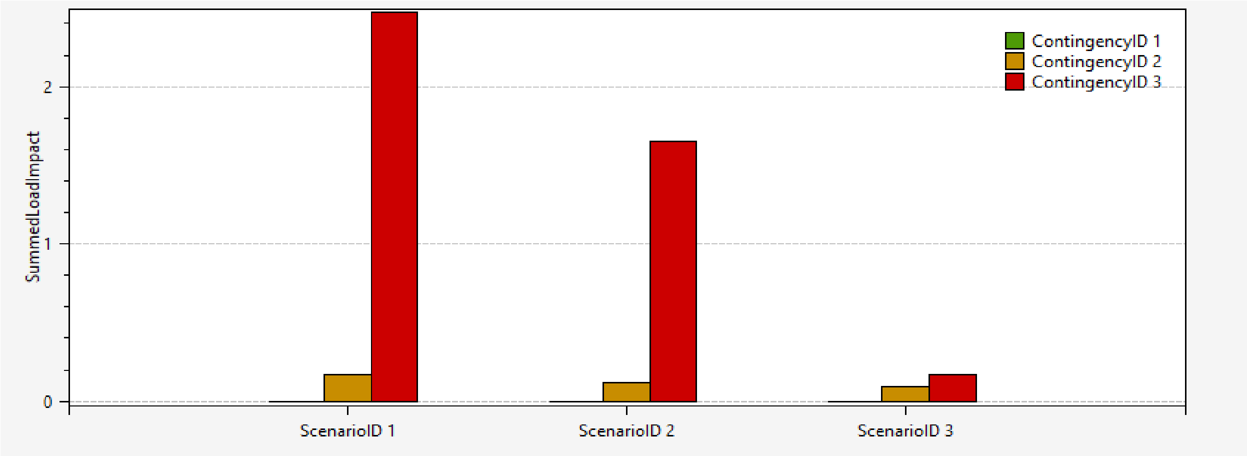

Flow/Limit Ratio: < 85% 85% <= Ratio < 100% >= 100%
Event ID: 9, Scenario ID: 1, Contingency ID: 4, Stage ID: 1, Snap ID: 3
Latitude
Longitude
Voltage, P.U.
© OpenStreetMap

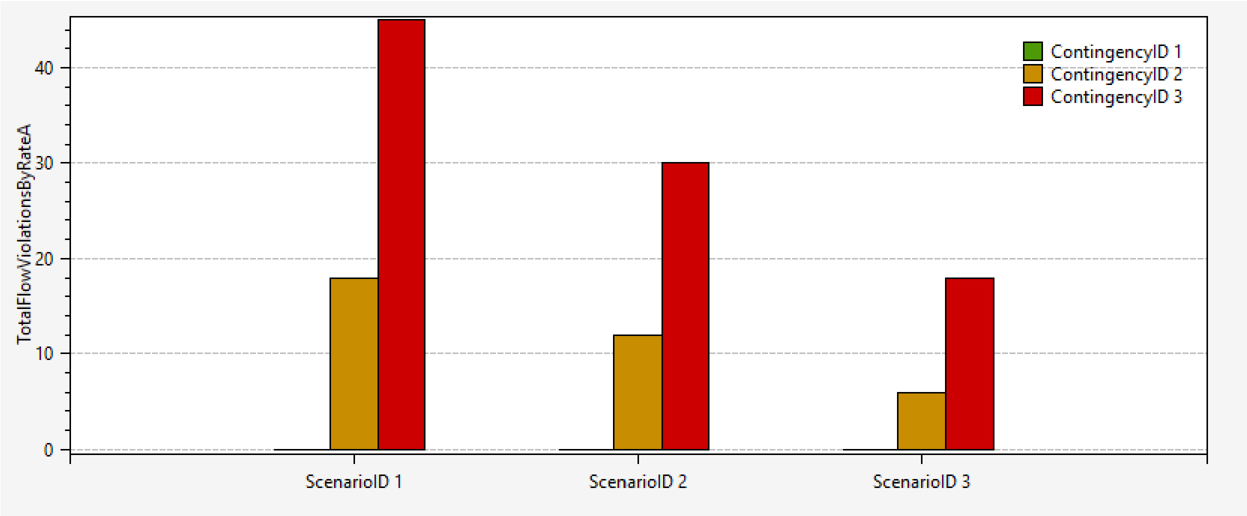


C.7 Hurricane Maria Lite, InitEventID: 13

Hurricane: Maria Lite
Case: 2019 Night + Vegetation De-rates

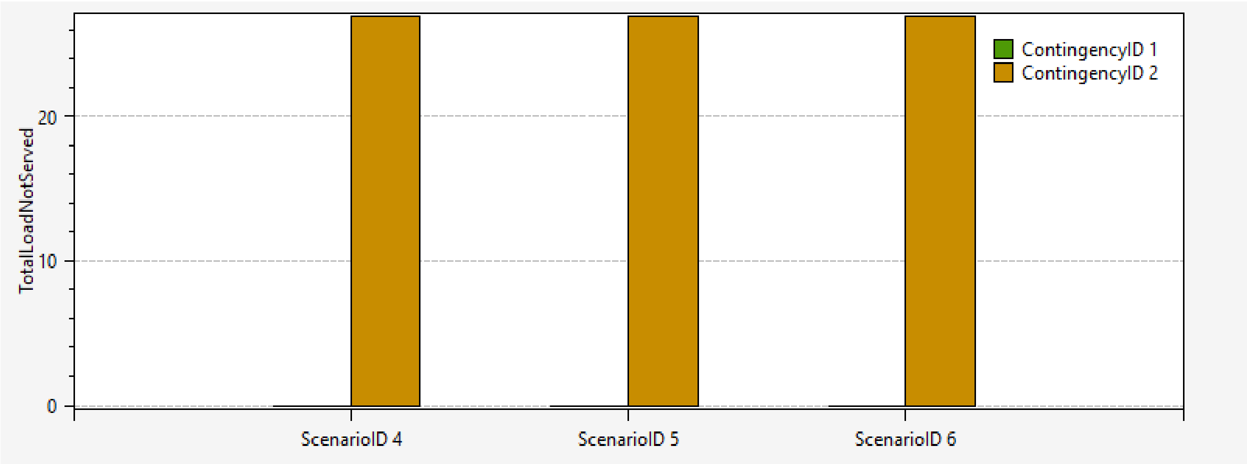


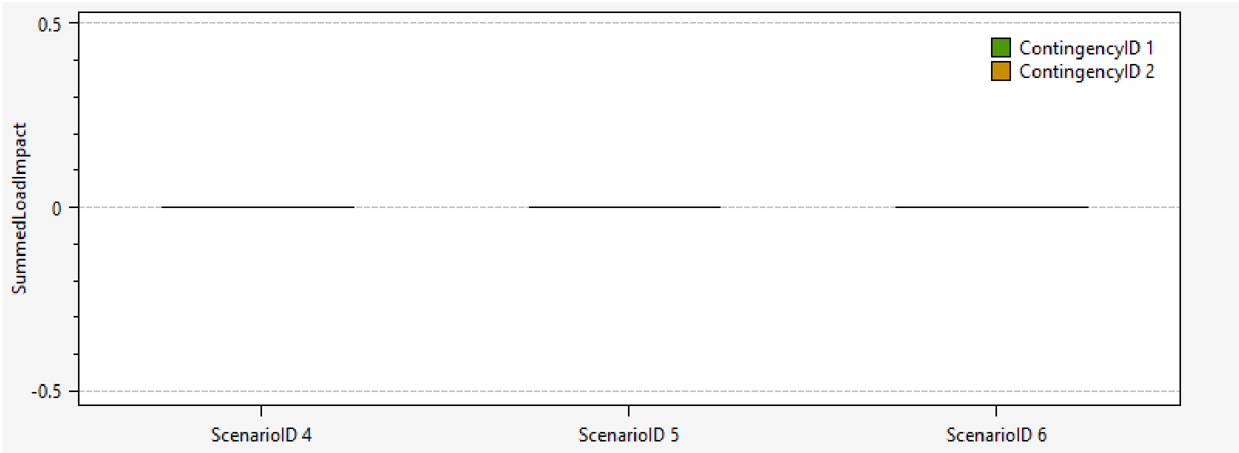


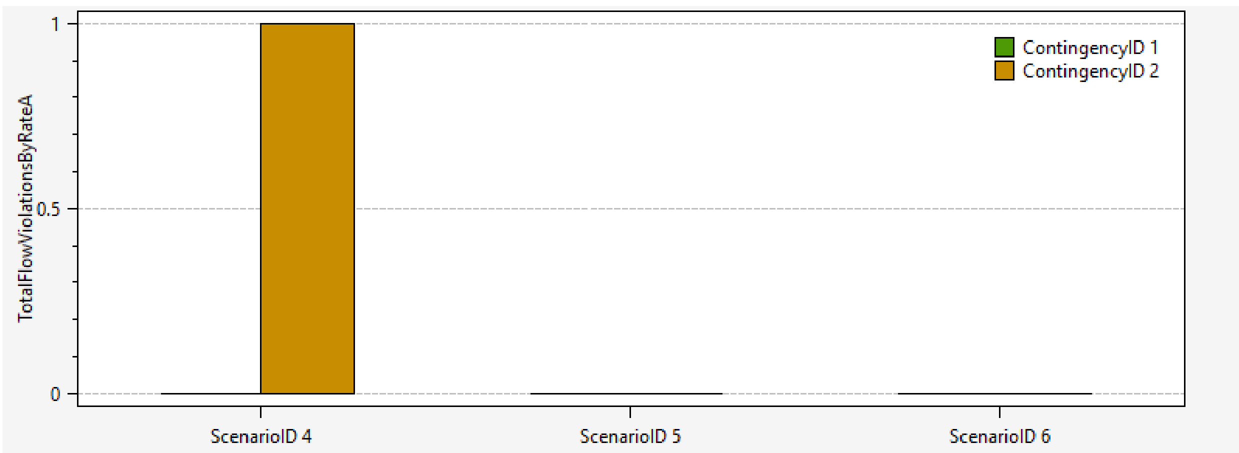


C.8 Hurricane Maria Lite, InitEventID: 12

Hurricane: Maria Lite
Case: 2028 Day + Generator Protection

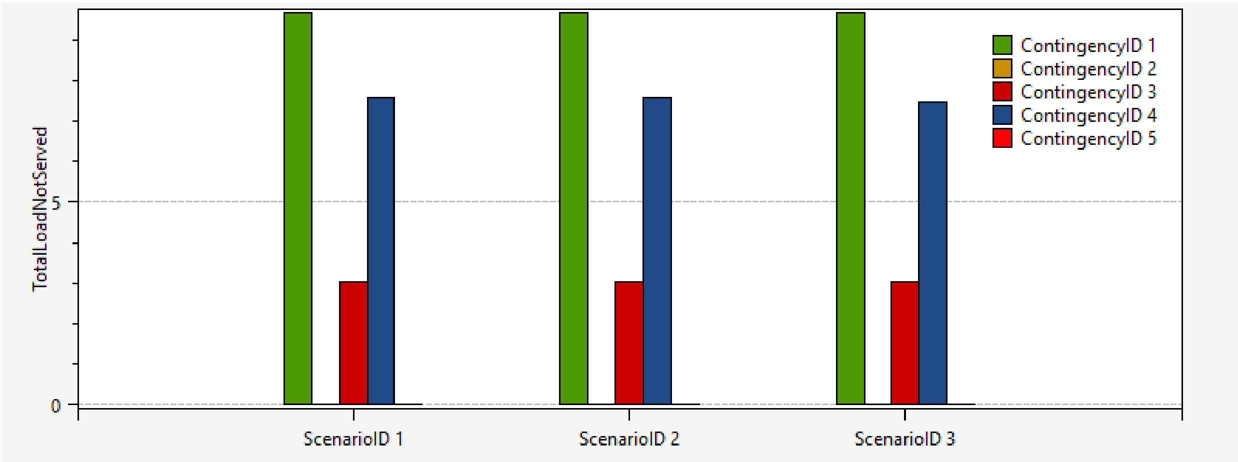


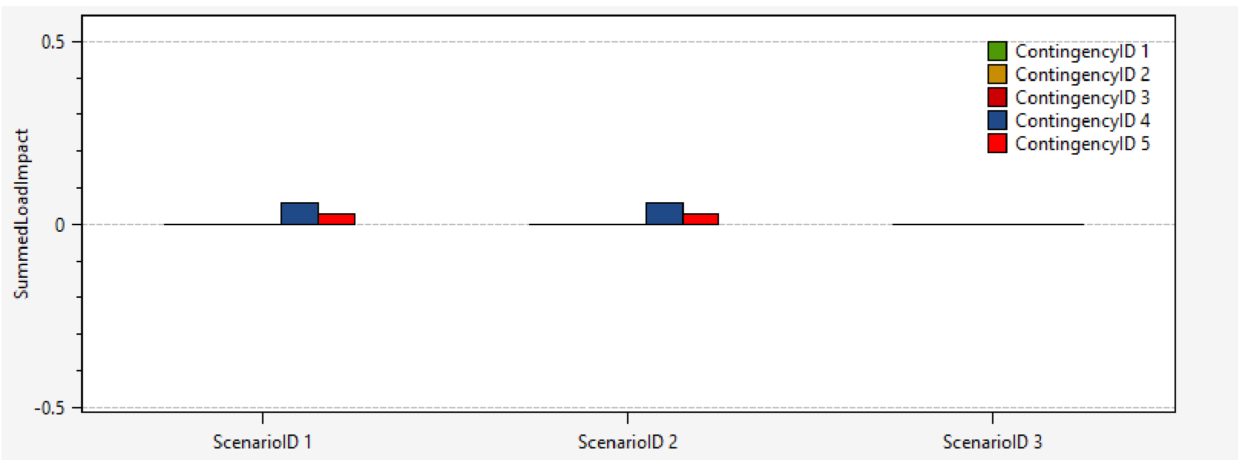


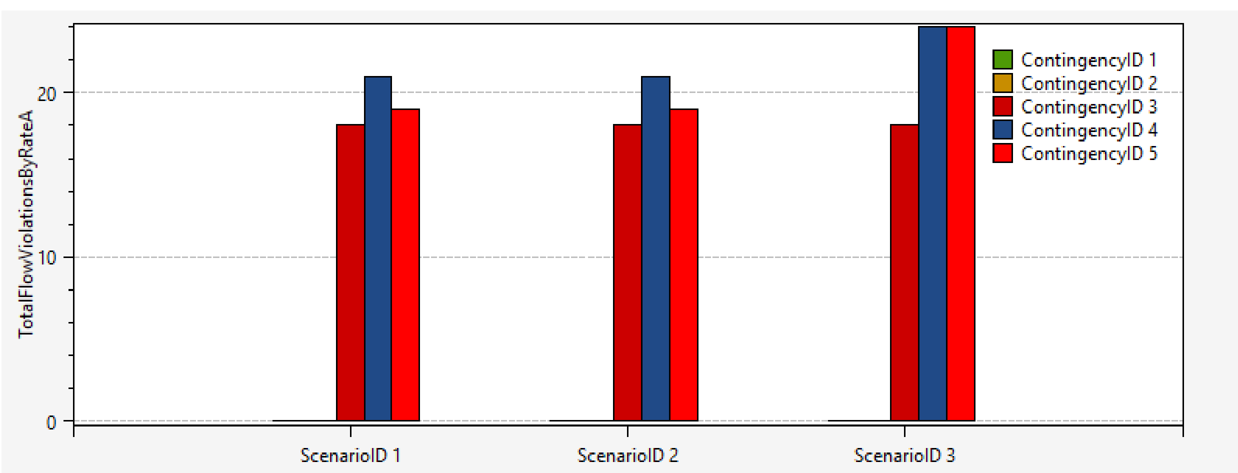


C.9 Hurricane Irma, InitEventID: 3

Hurricane: Irma
Case: 2019 Night

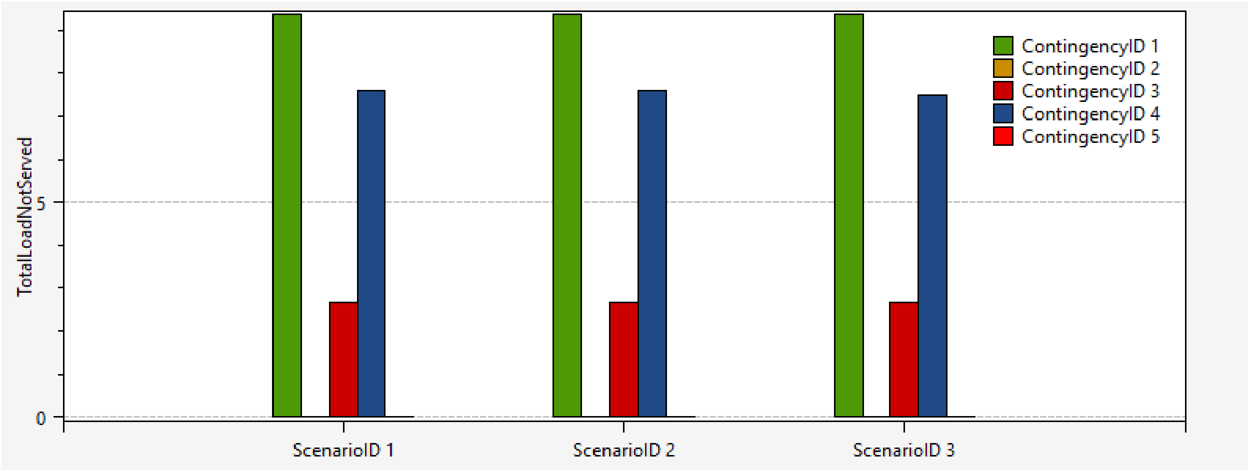

TotalLoadNotServed
5
0
ScenarioID 1
ScenarioID 2
ScenarioID 3
ContingencyID 1
ContingencyID 2
ContingencyID 3
ContingencyID 4
ContingencyID 5

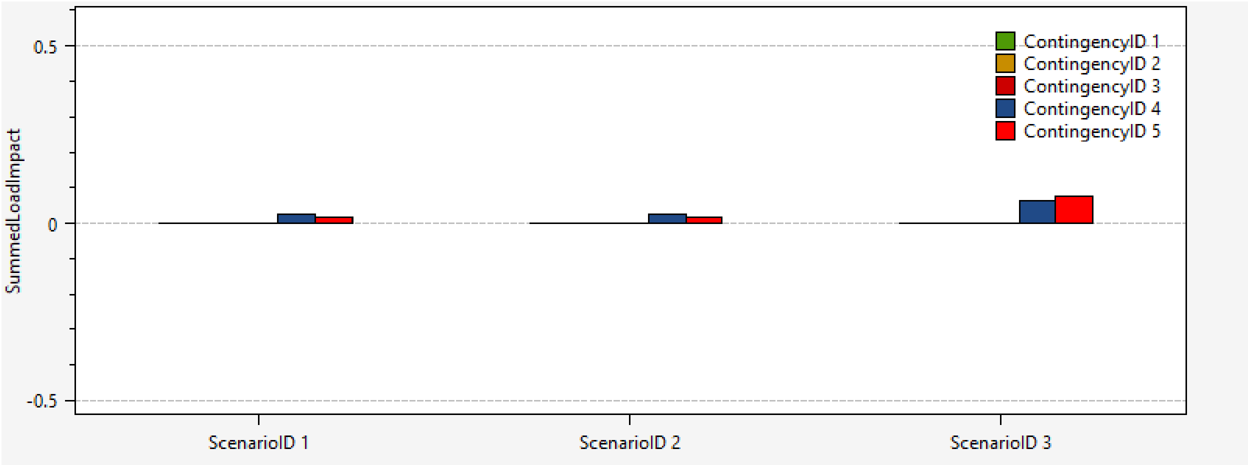

SummedLoadImpact
0.5
0
-0.5
ScenarioID 1
ScenarioID 2
ScenarioID 3
ContingencyID 1
ContingencyID 2
ContingencyID 3
ContingencyID 4
ContingencyID 5

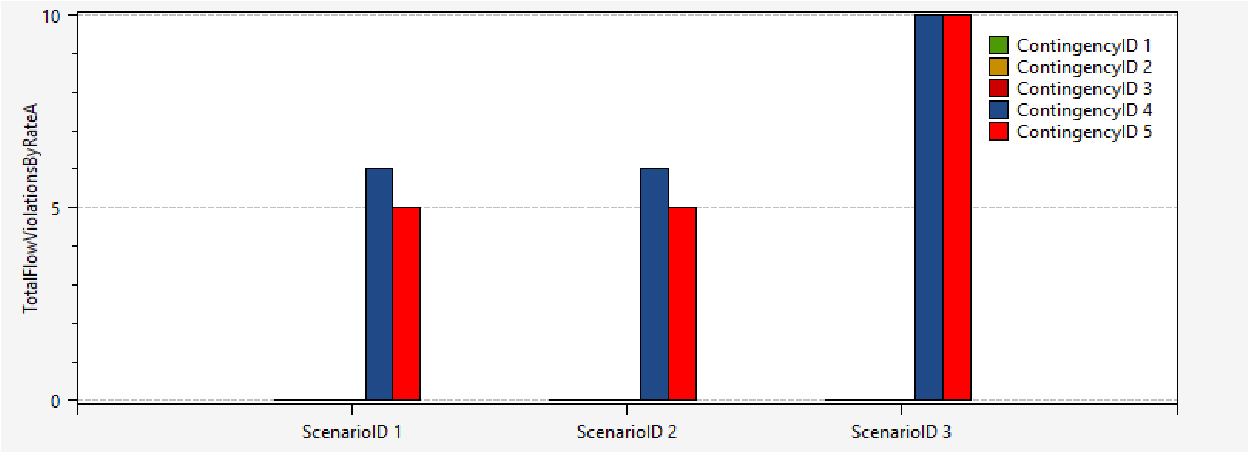

TotalFlowViolationsByRateA
20
10
0
ScenarioID 1
ScenarioID 2
ScenarioID 3
ContingencyID 1
ContingencyID 2
ContingencyID 3
ContingencyID 4
ContingencyID 5

C.10 Hurricane Irma, InitEventID: 4

Hurricane: Irma
Case: 2019 Day

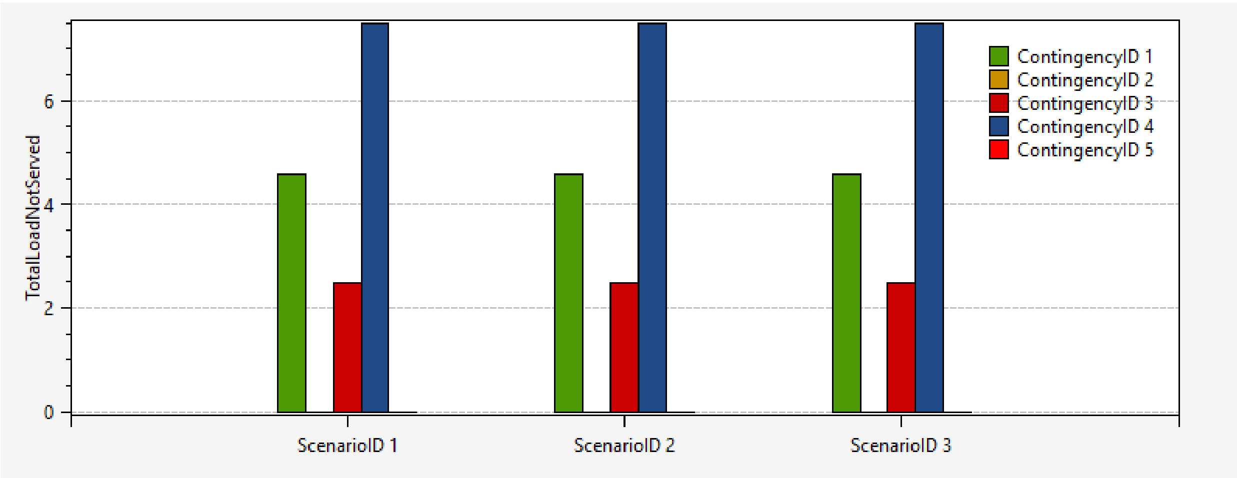


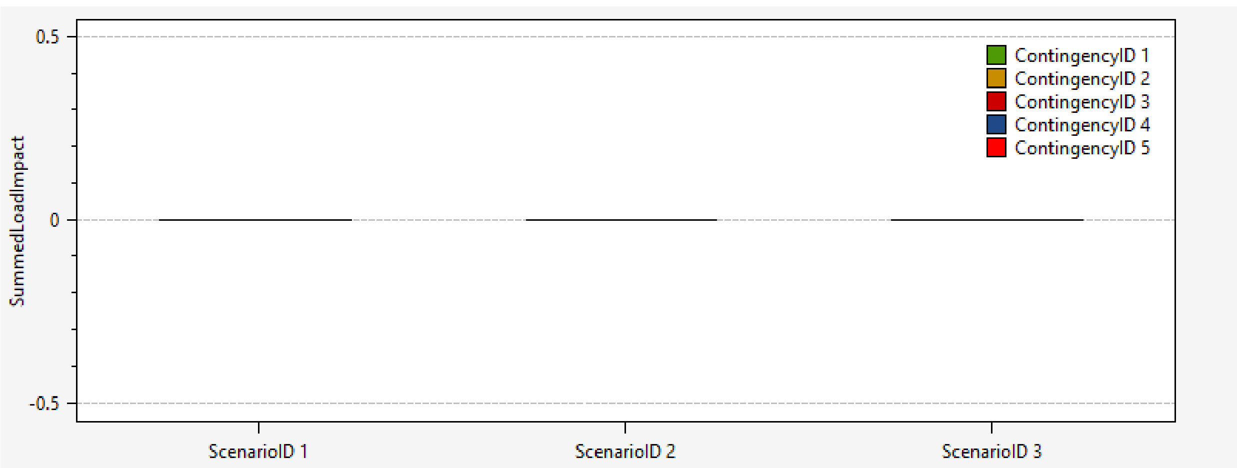


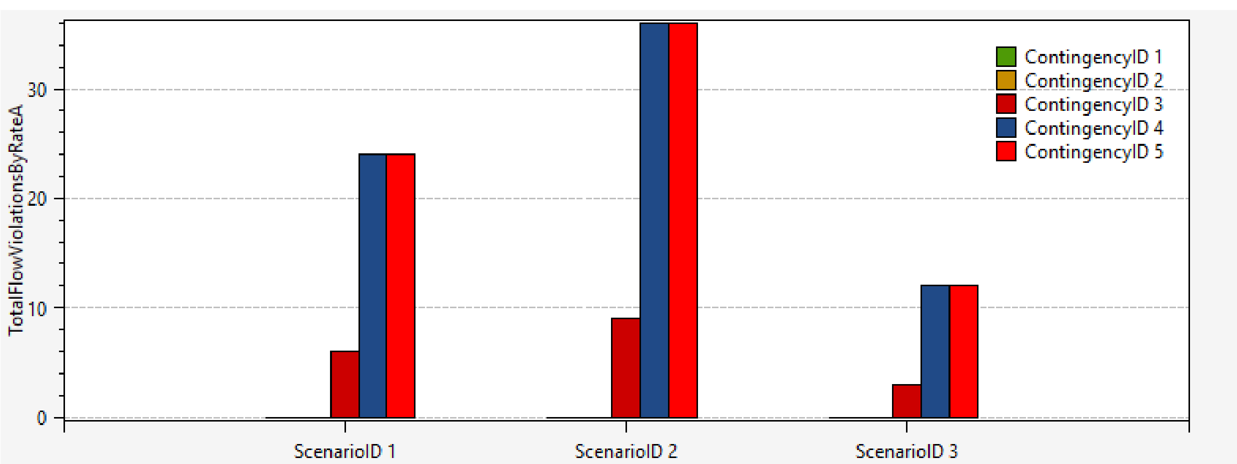


C.11 Hurricane Irma, InitEventID: 5

Hurricane: Irma
Case: 2019 Night + Vegetation De-rates

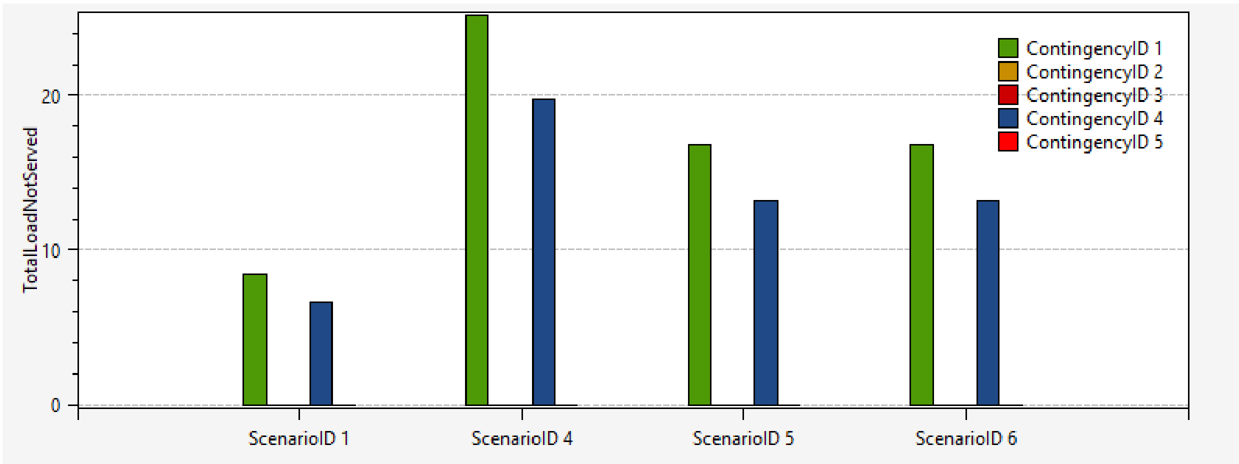


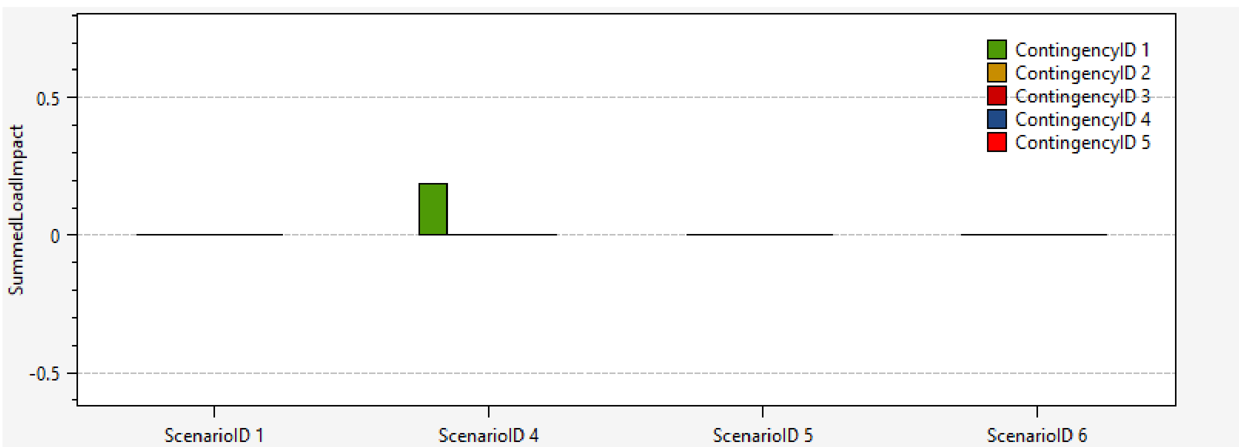


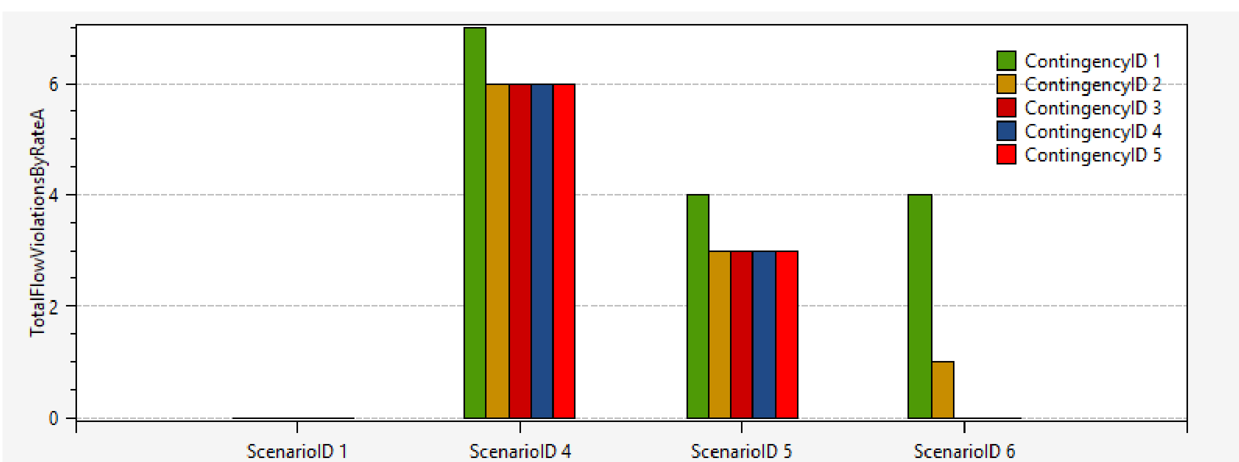


C.12 Hurricane Irma, InitEventID: 6

Hurricane: Irma
Case: 2028 Day

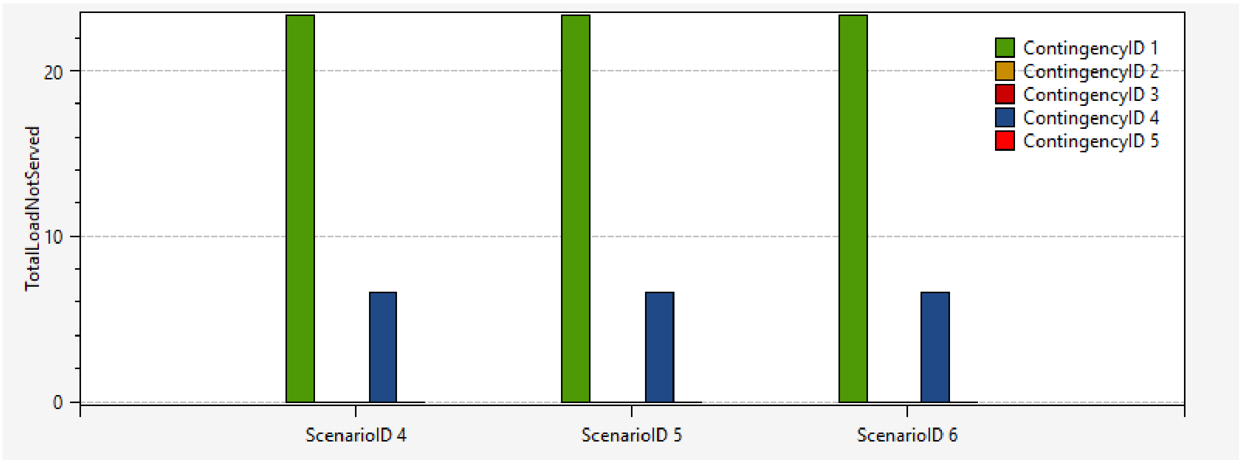


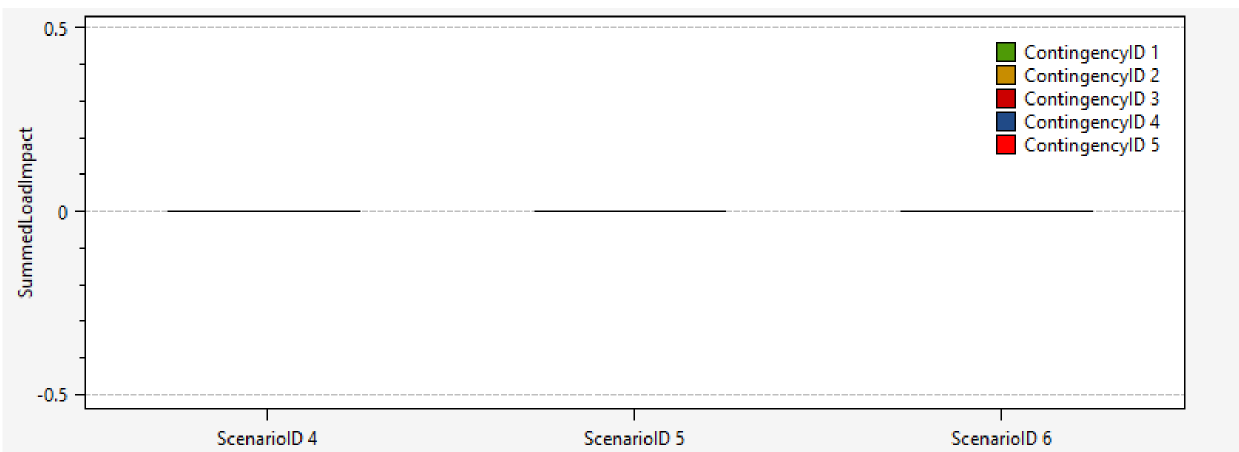


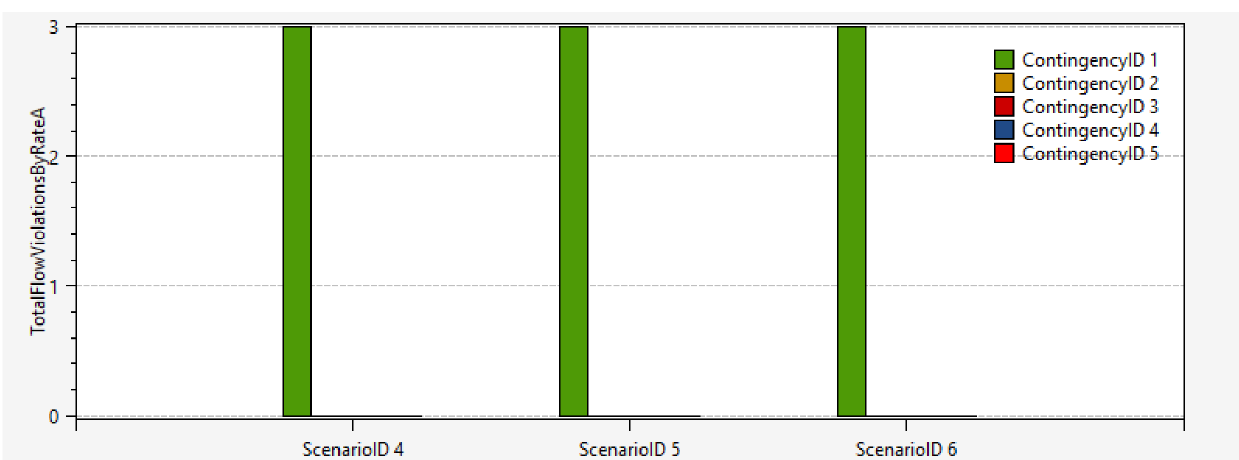


C.13 Hurricane Irma, InitEventID: 10

Hurricane: Irma
Case: 2028 Day + Generator Protection







Appendix D: Monte Carlo DCAT Hurricane Simulation Results

D.1 Monte Carlo Realizations for Hurricane Maria

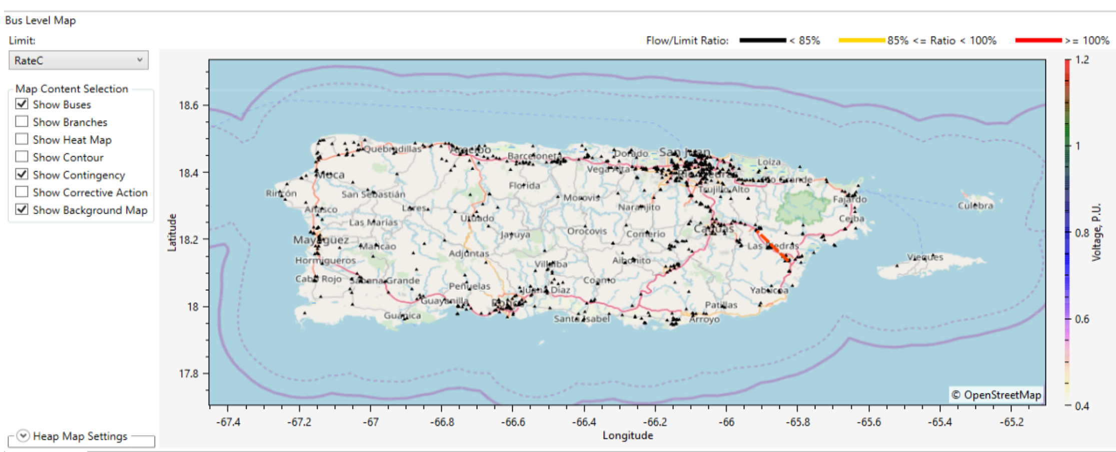
10 contingency realizations for Hurricane Maria were generated using MC method. The contingency sets provide the time series of assets will fail eventually from each scenario. Compare the 10 contingencies, there are around 30% failed assets different from each other because of the sampling from MC method.

A GIS-based contingency visualization is given as follows, each contingency in different scenarios is compared correspondingly in a group, the red lines indicate the transmission line outages represented in that contingency, and the black triangles represent Buses remaining in service.

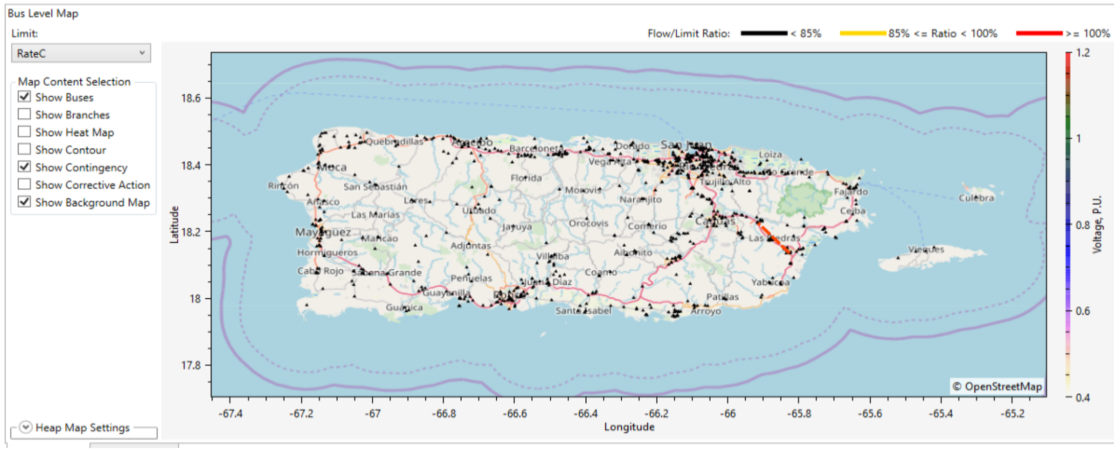
It should be noted that Contingency 1 and 2 were completed for all 10 scenarios, while Contingency 3 and Contingency 4 were completed only for Scenario 5 and Scenario 10. No scenario simulated from Contingency 5 to Contingency 8 as DCAT simulation stopping criteria was met either in Contingency 2 or Contingency 3.

The comparison of Contingency 1 of Hurricane Maria for all scenarios are given as follows:

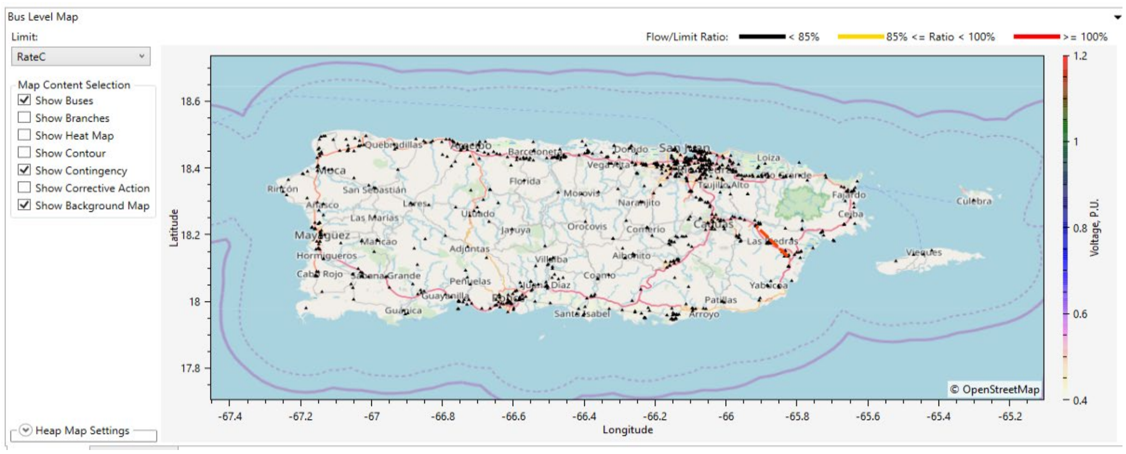
Scenario 1



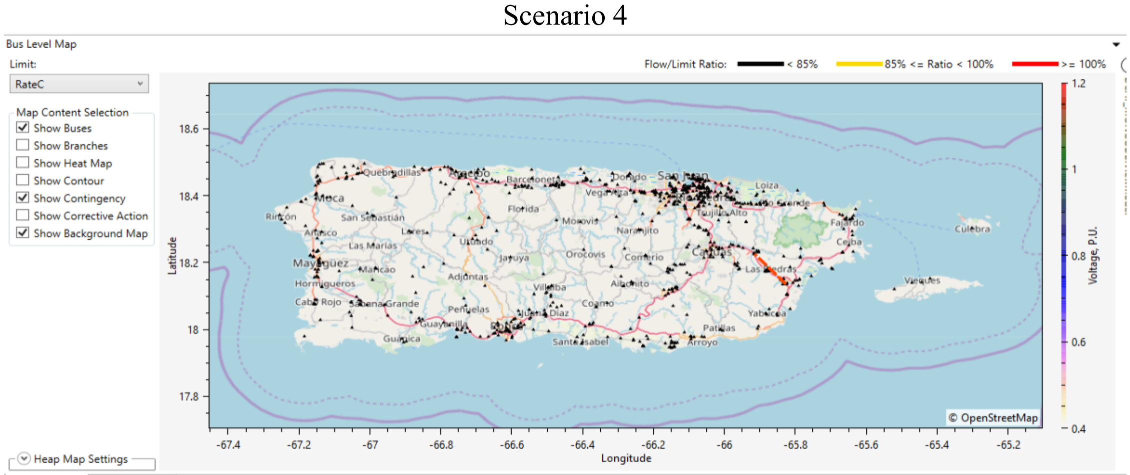
Scenario 2



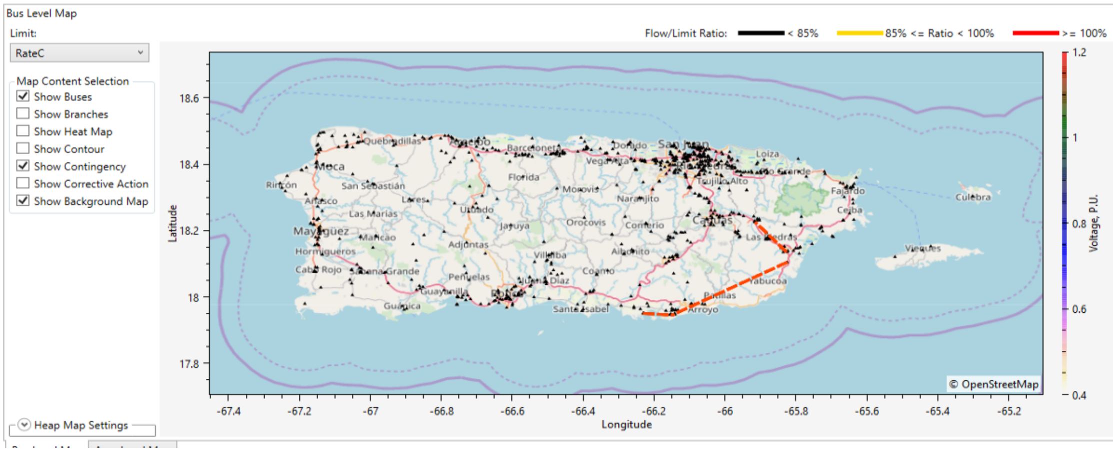
Scenario 3



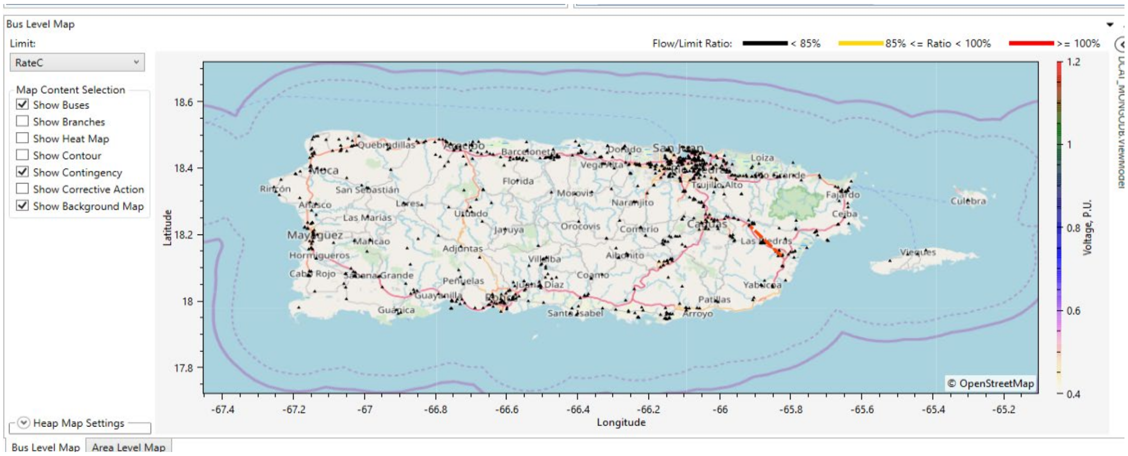
Scenario 4



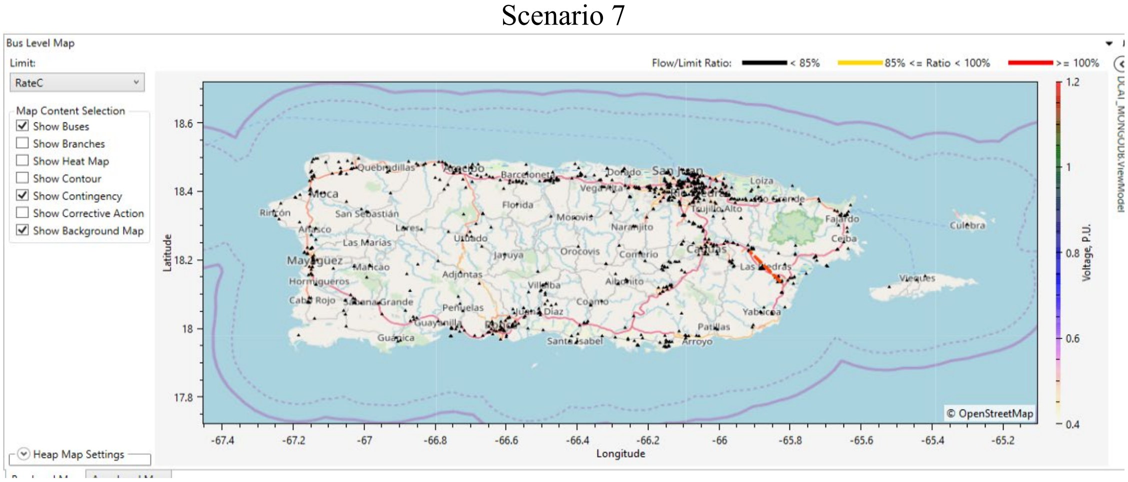
Scenario 5



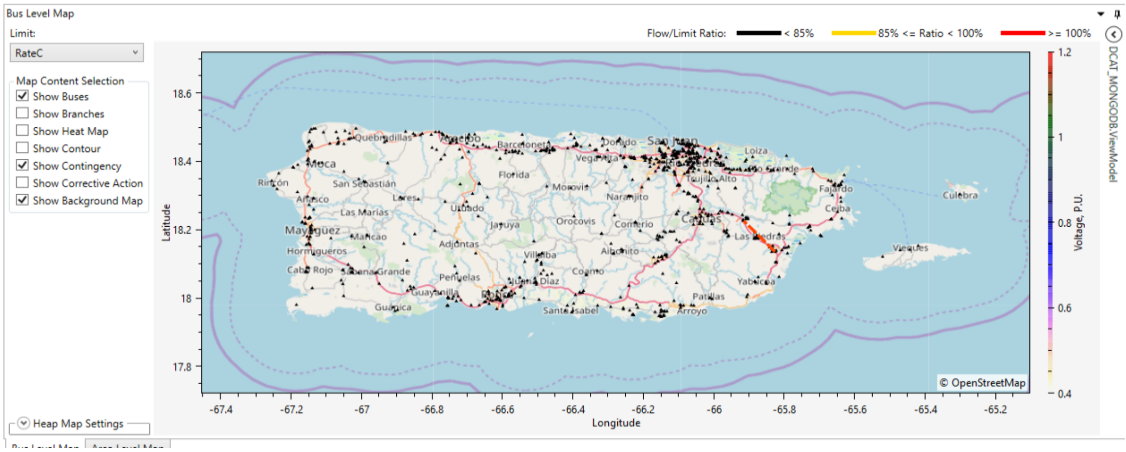
Scenario 6



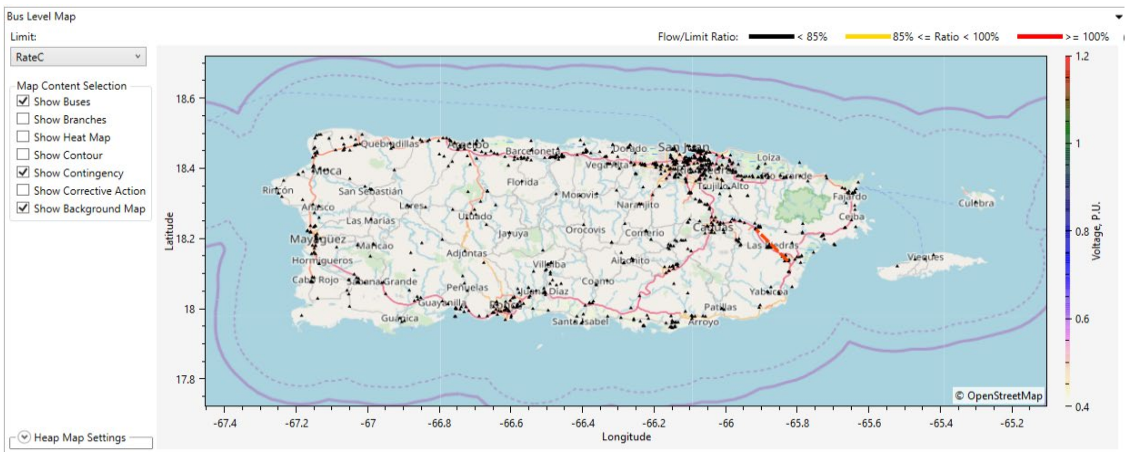
Scenario 7



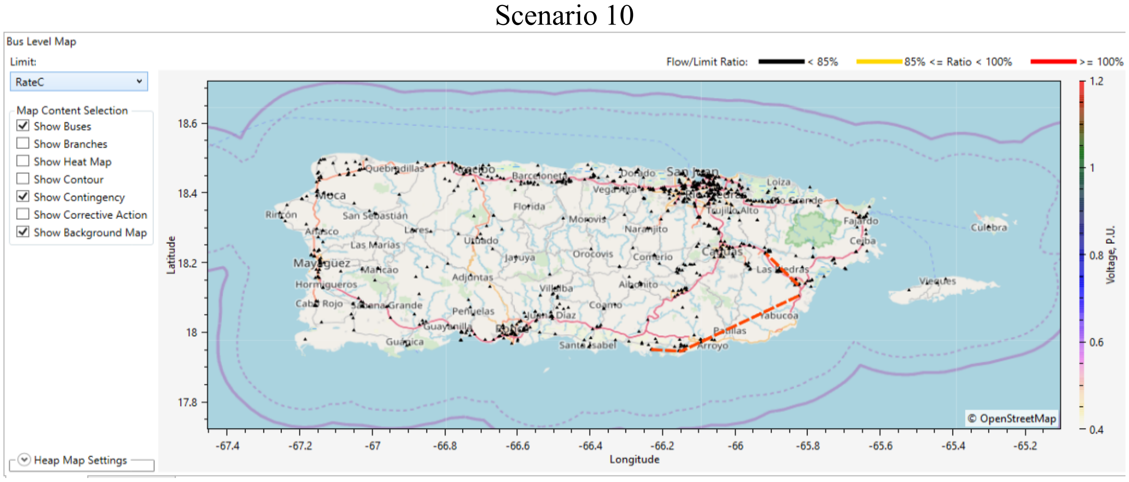
Scenario 8



Scenario 9

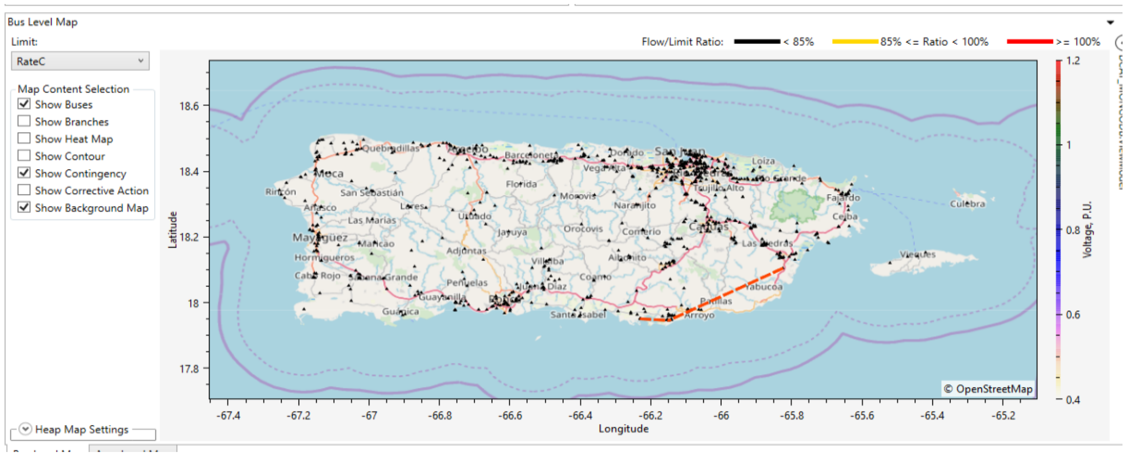


Scenario 10

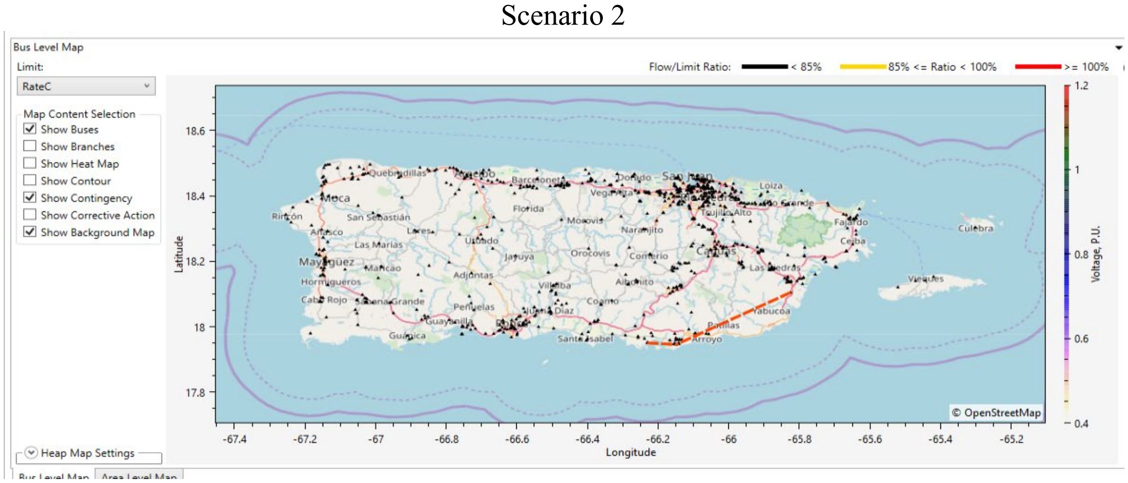


The comparison of Contingency 2 of Hurricane Maria for all scenarios are given as follows:

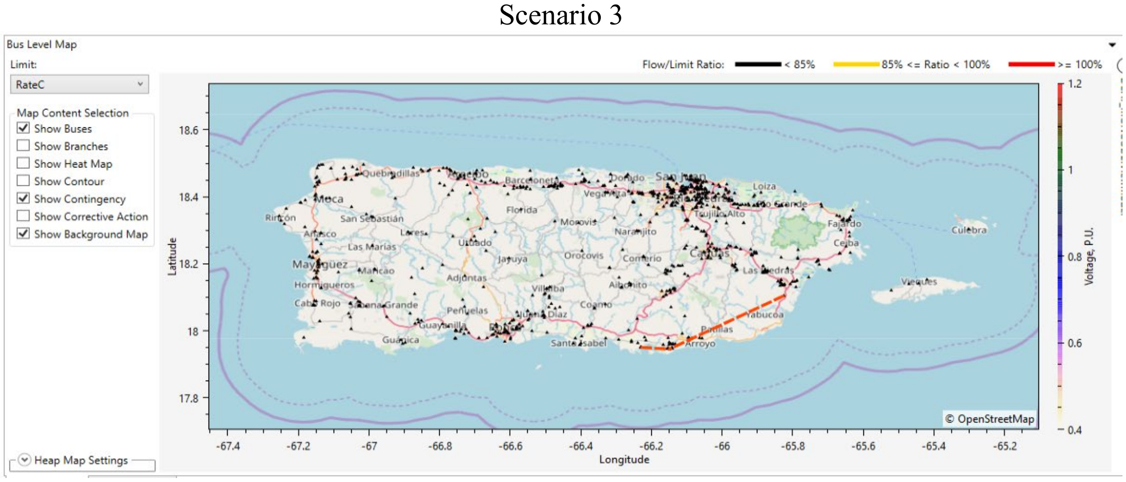
Scenario 1



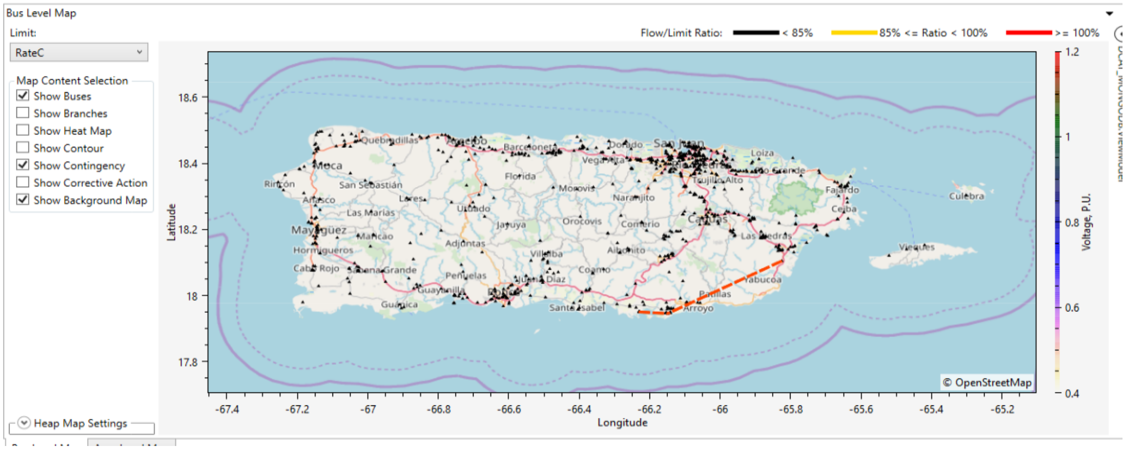
Scenario 2



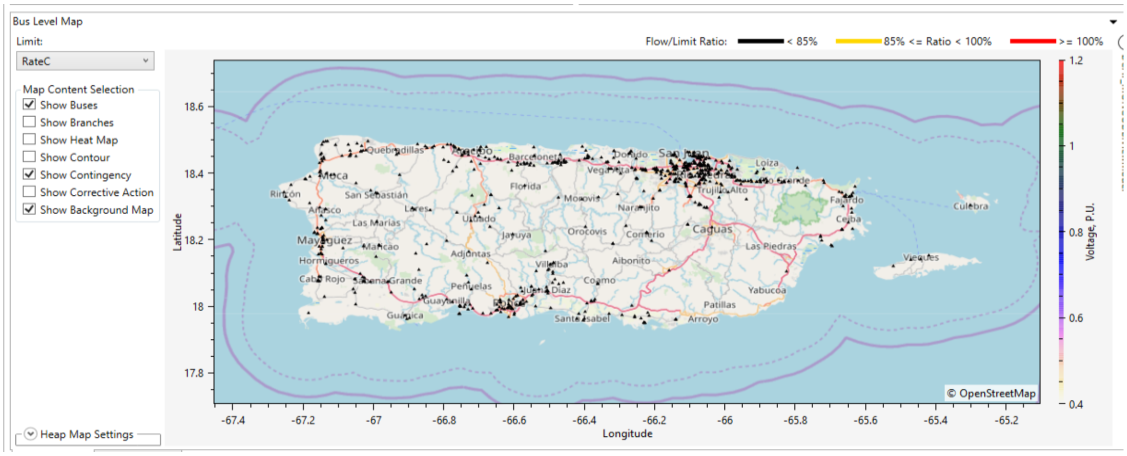
Scenario 3



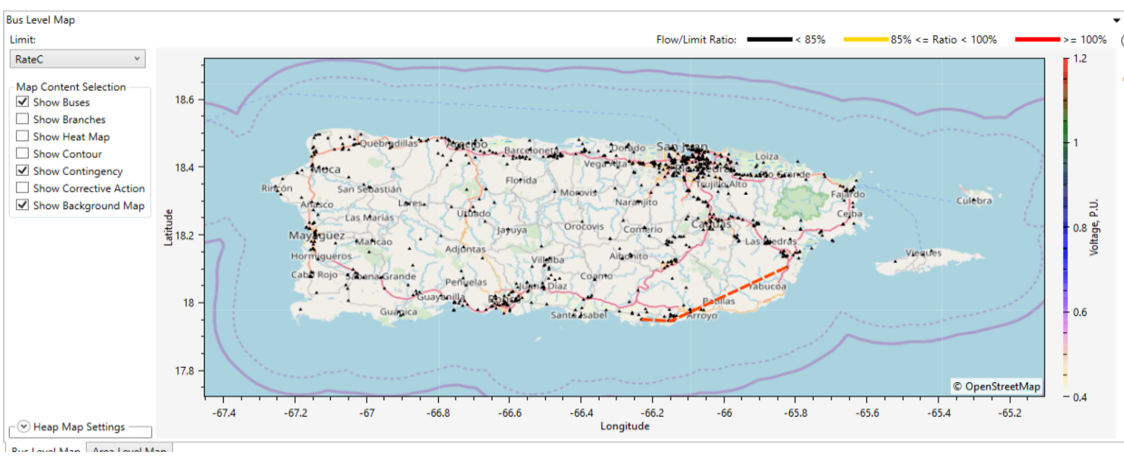
Scenario 4



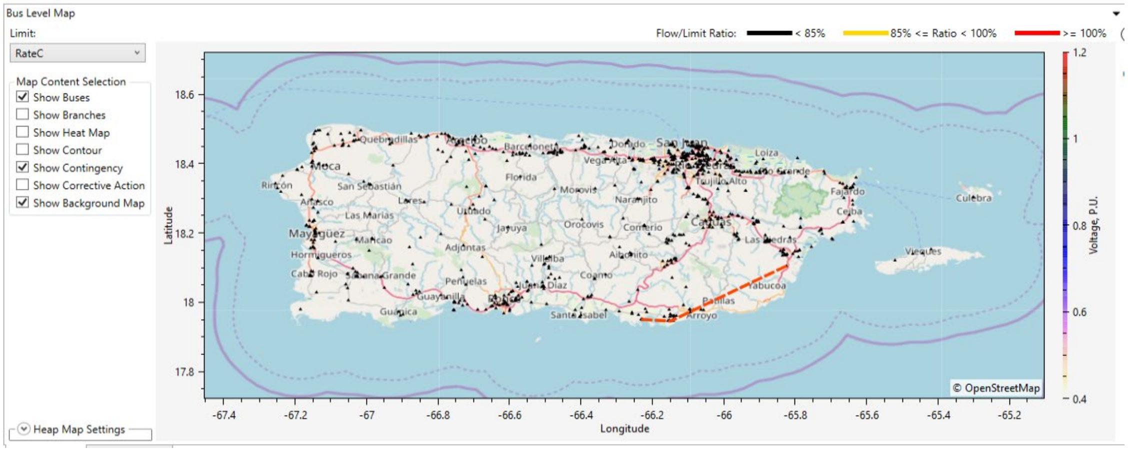
Scenario5



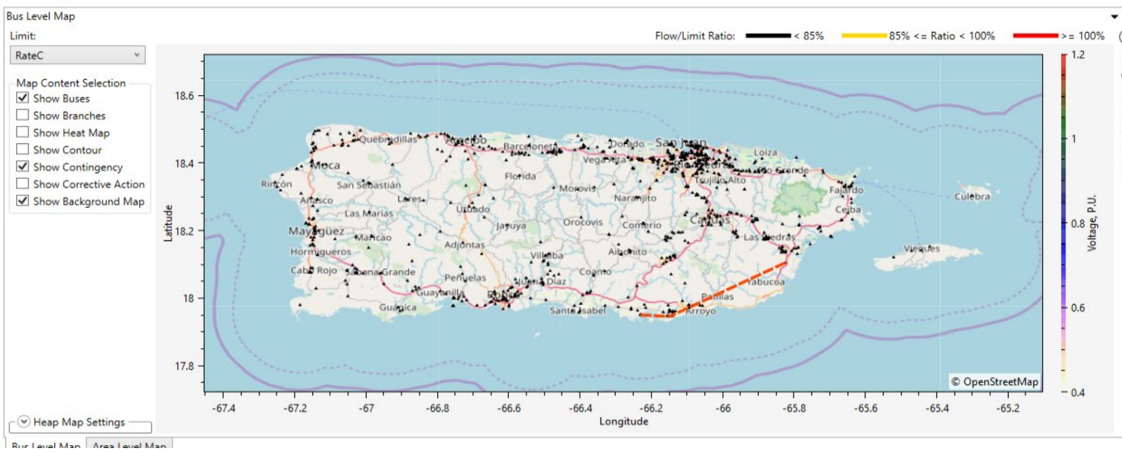
Scenario 6



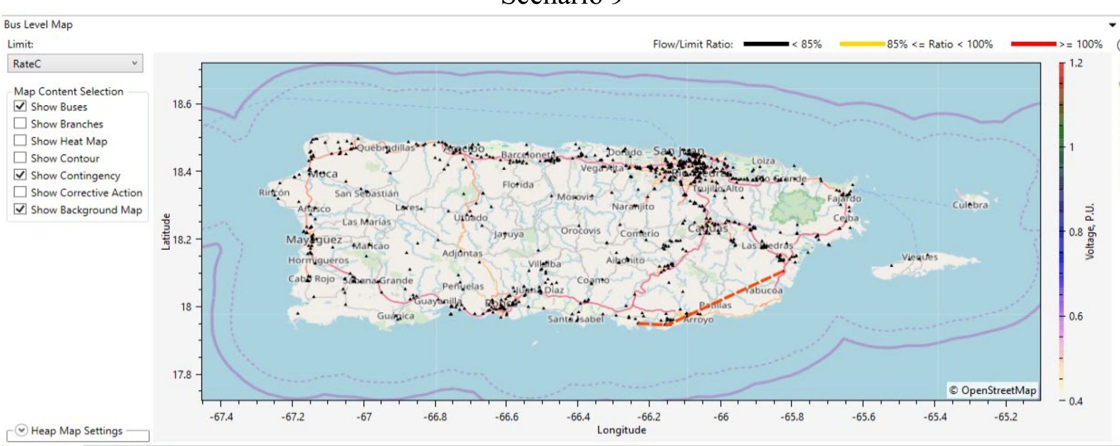
Scenario 7



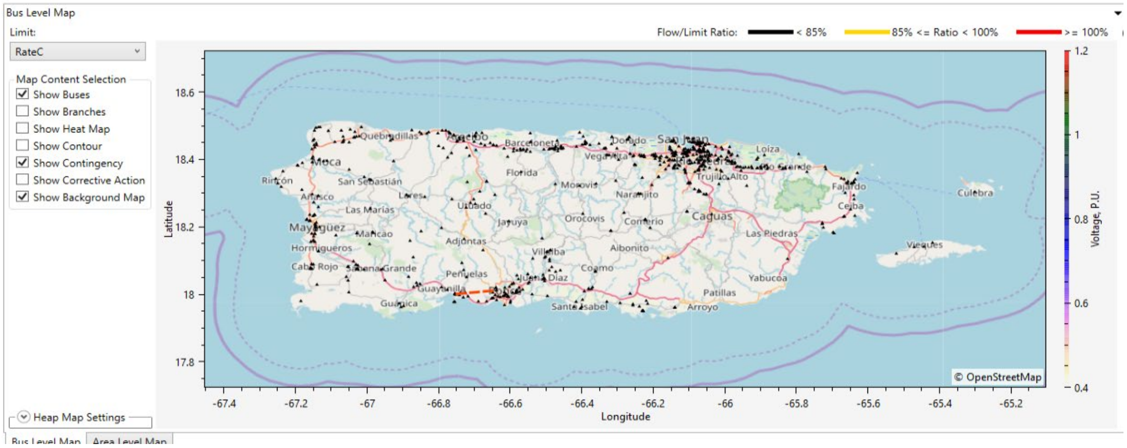
Scenario 8



Scenario 9

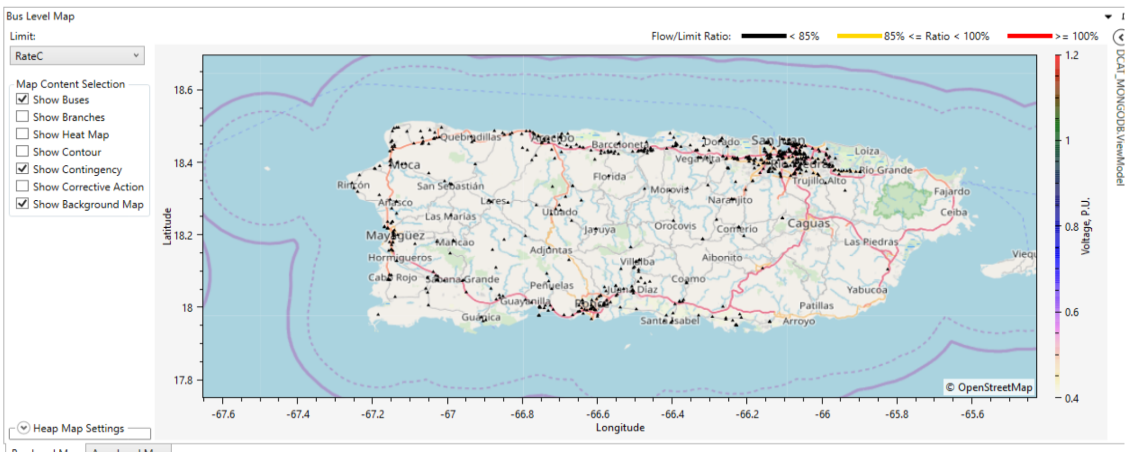


Scenario 10

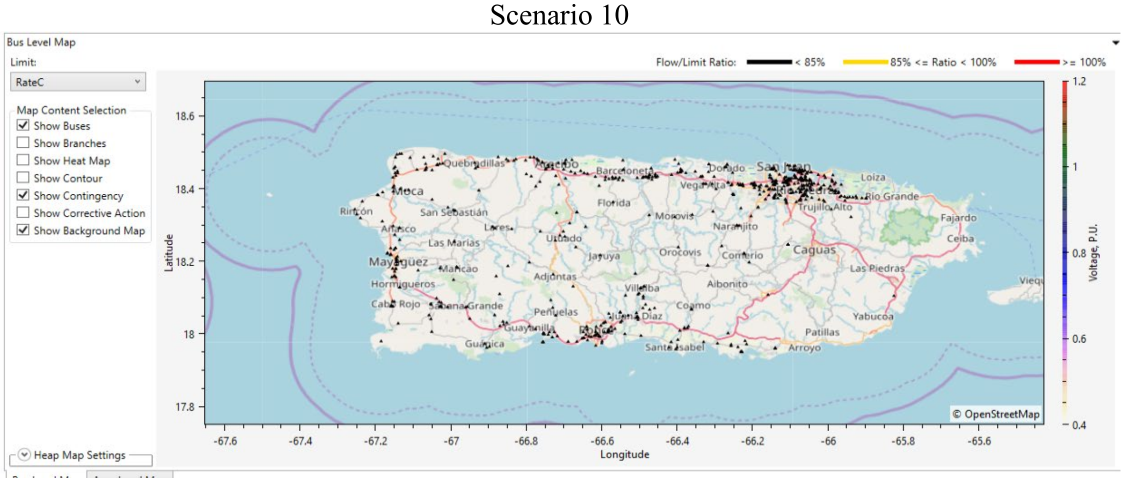


The comparison of Contingency 3 of Hurricane Maria for Scenario 5 and Scenario 10 are given as follows:

Scenario 5

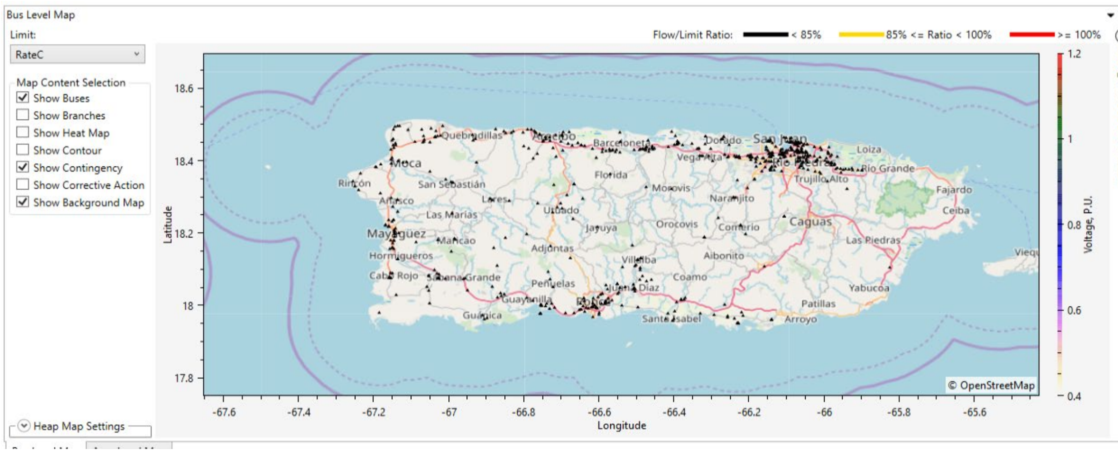


Scenario 10

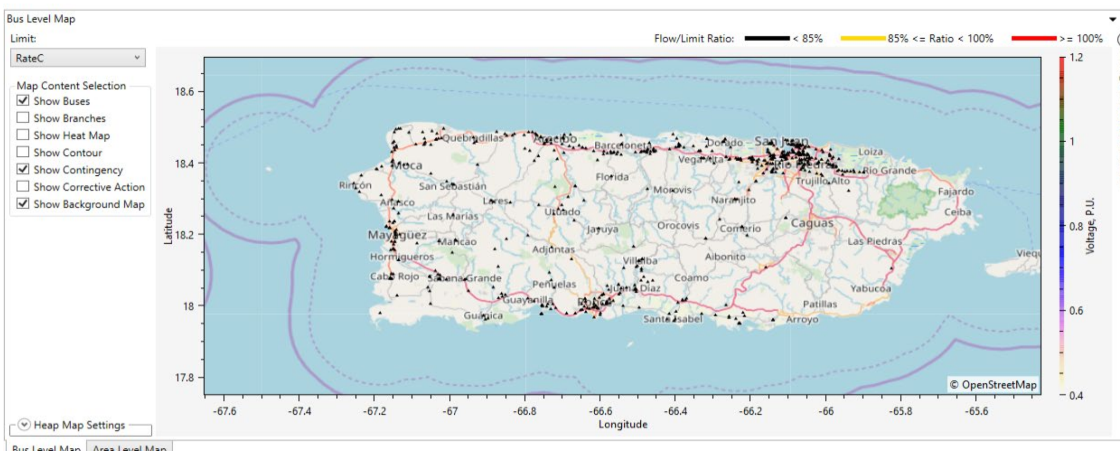


The comparison of Contingency 4 of Hurricane Maria for Scenario 5 and Scenario 10 are given as follows:

Scenario 5



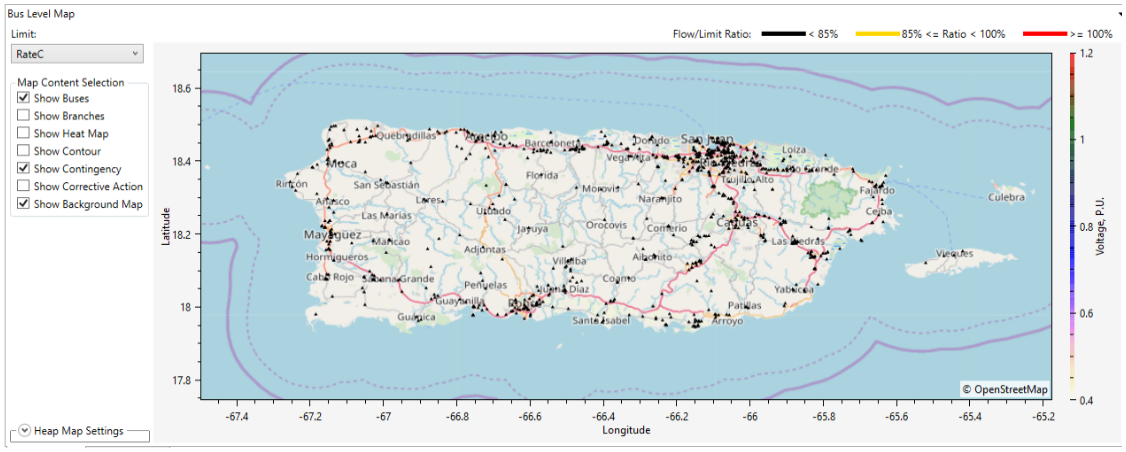
Scenario 10



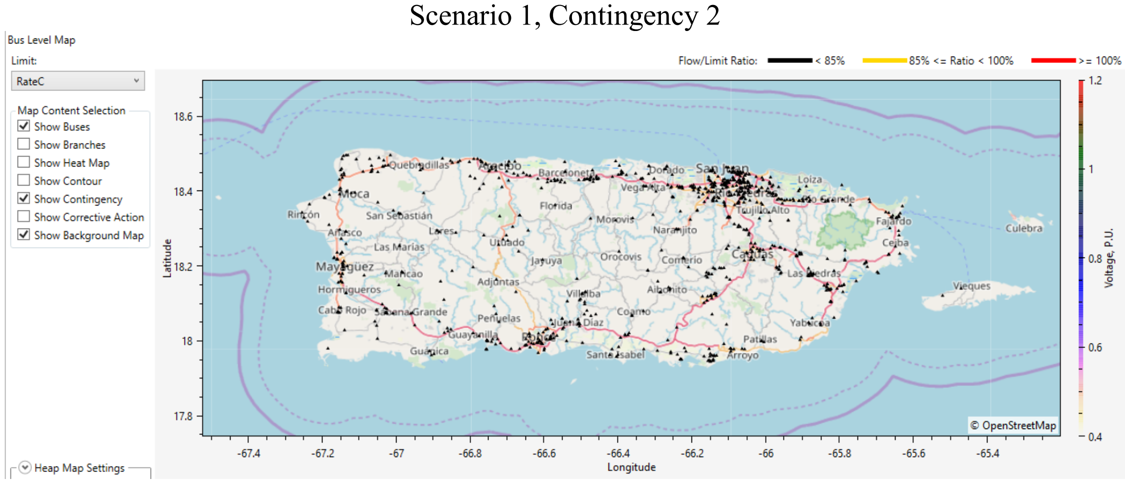
D.2 Monte Carlo Realizations for Hurricane Irma

20 contingency realizations for Hurricane Irma were generated using MC method, Contingency 1 to 4 were completed for all 20 scenarios. Here the contingencies for Hurricane Irma Scenario 1 are illustrated as follows:

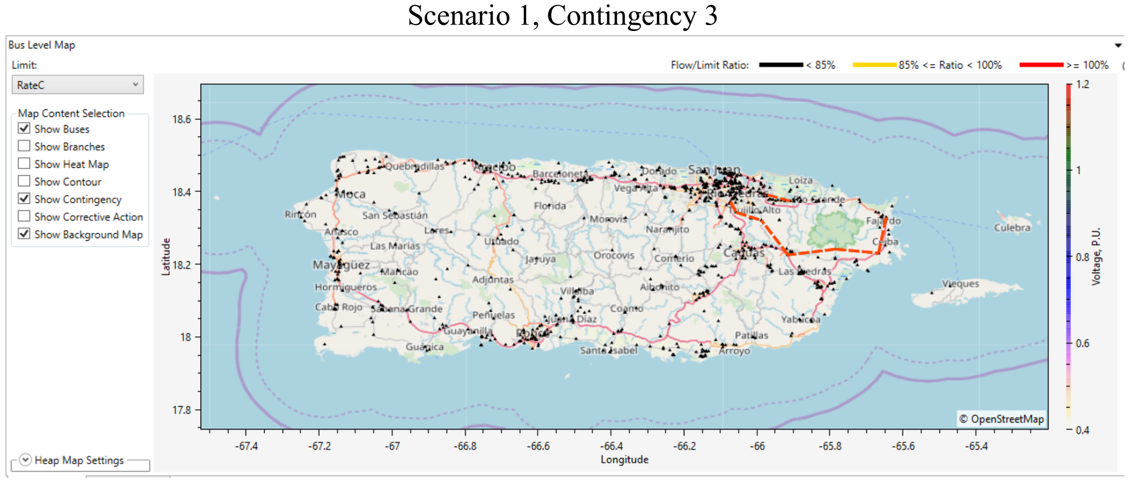
Scenario 1, Contingency 1



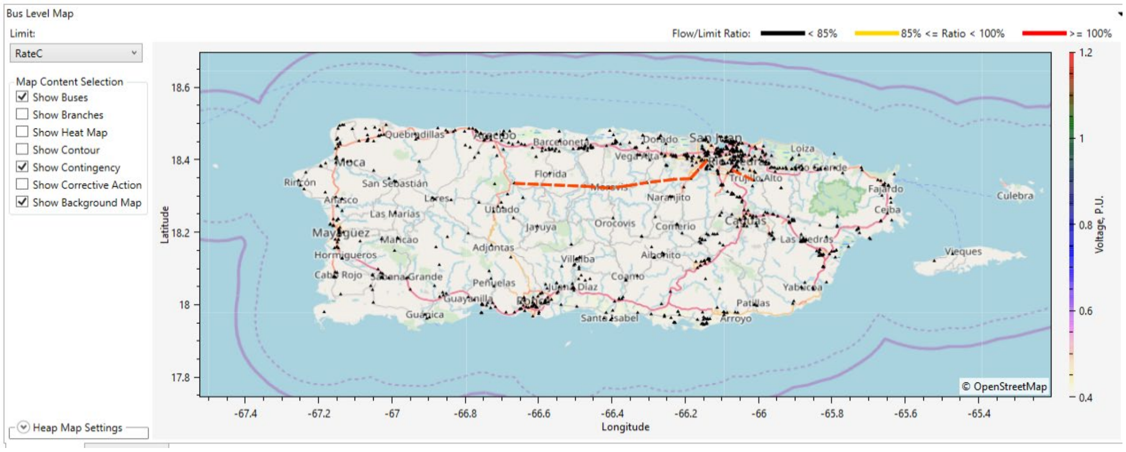
Scenario 1, Contingency 2



Scenario 1, Contingency 3



Scenario 1, Contingency 4

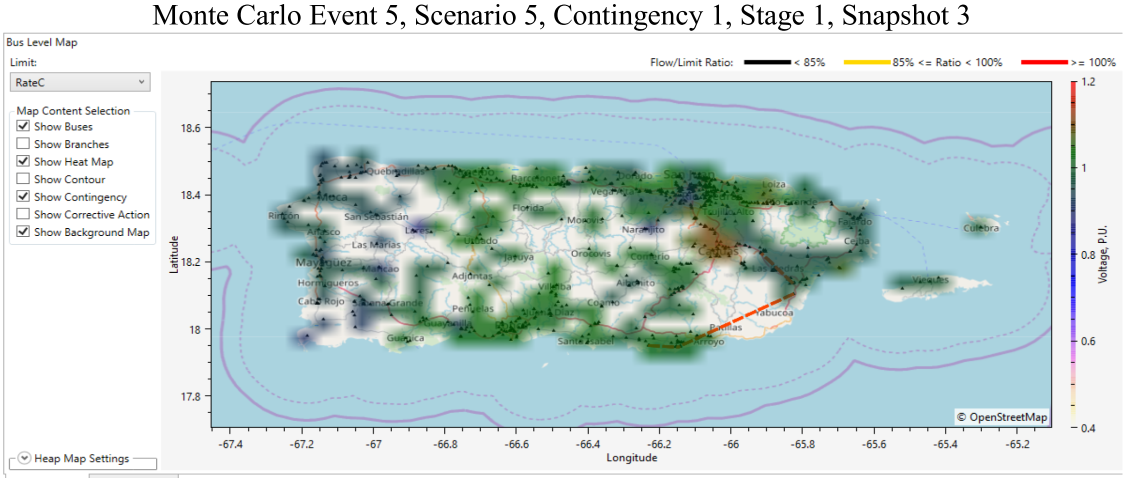


D.3 Monte Carlo Simulation Examples for Hurricane Maria and Irma

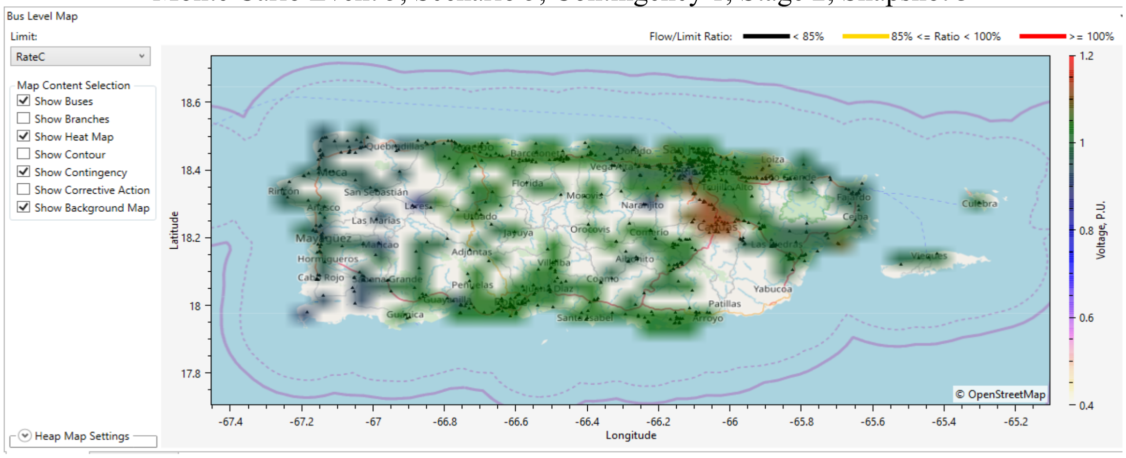
D.3.1 Maria Lite Voltage Heat Maps

The GIS-based voltage heatmaps for Contingency 1, 2, 3, 4 in Maria Lite, Monte Carlo Scenario 5 are given as follows:

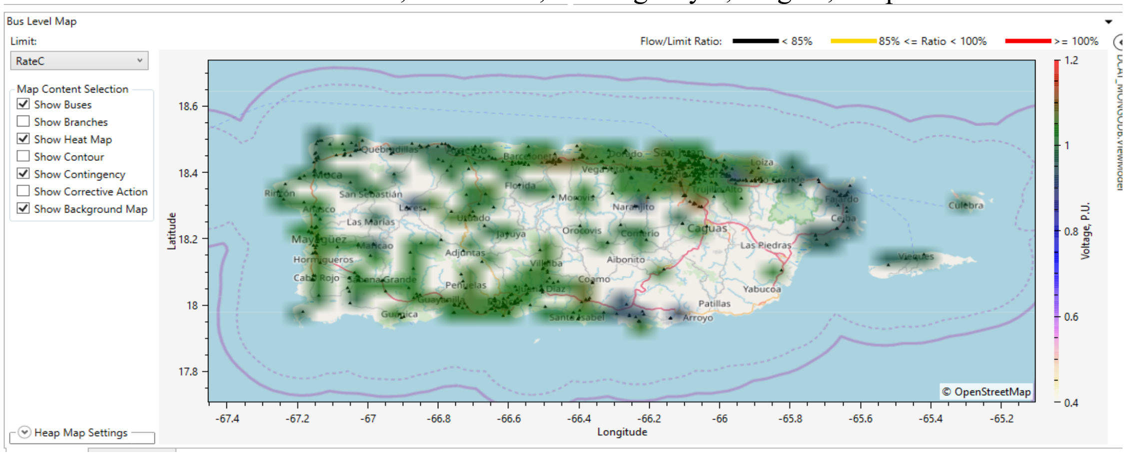
Monte Carlo Event 5, Scenario 5, Contingency 1, Stage 1, Snapshot 3



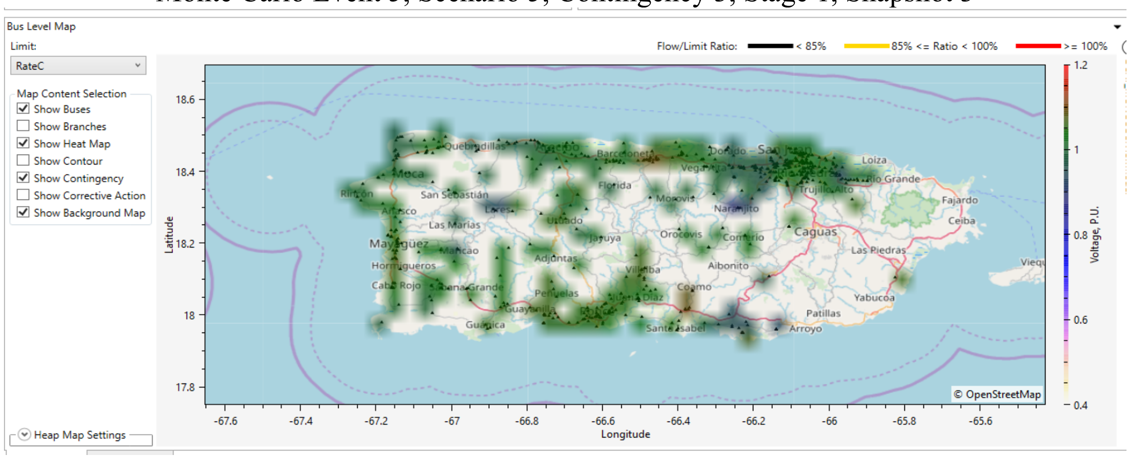
Monte Carlo Event 5, Scenario 5, Contingency 1, Stage 2, Snapshot 3



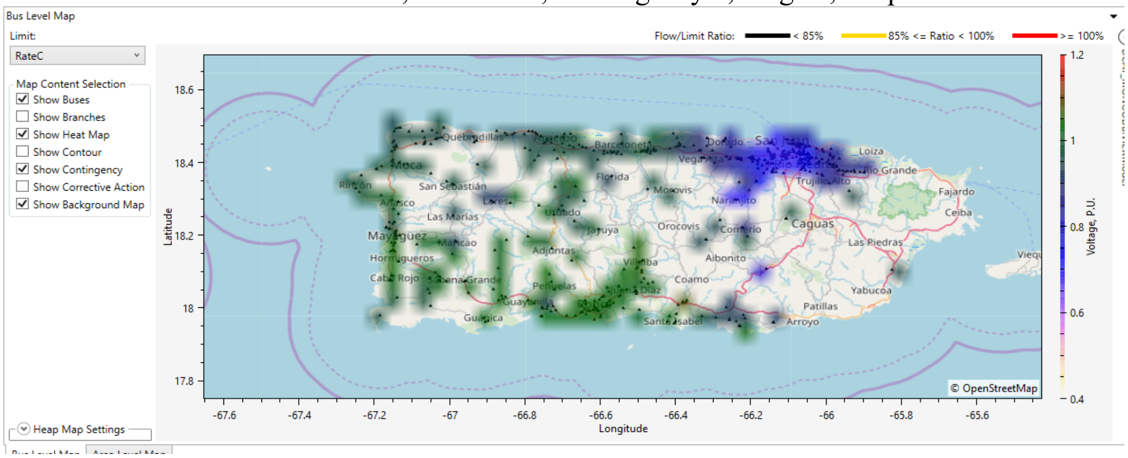
Monte Carlo Event 5, Scenario 5, Contingency 2, Stage 1, Snapshot 3



Monte Carlo Event 5, Scenario 5, Contingency 3, Stage 1, Snapshot 3



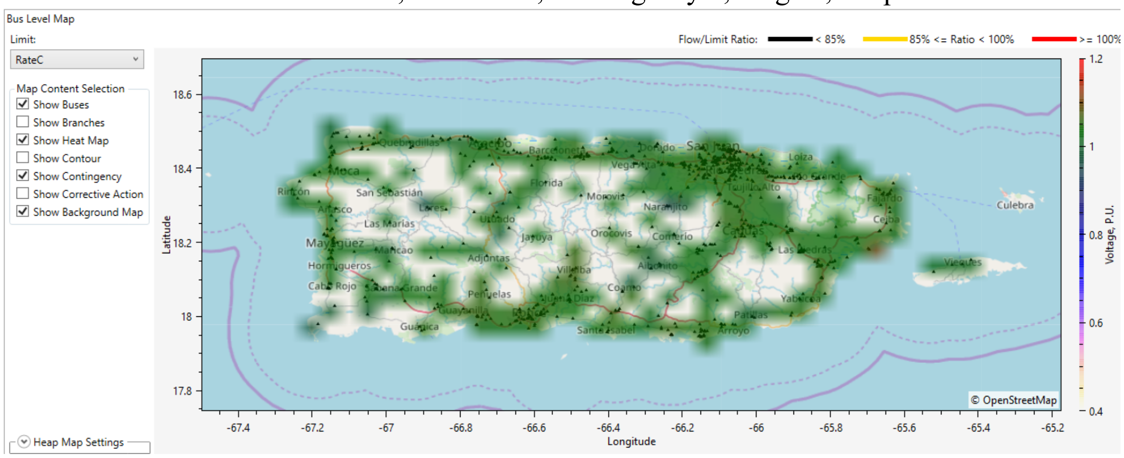
Monte Carlo Event 5, Scenario 5, Contingency 4, Stage 1, Snapshot 3



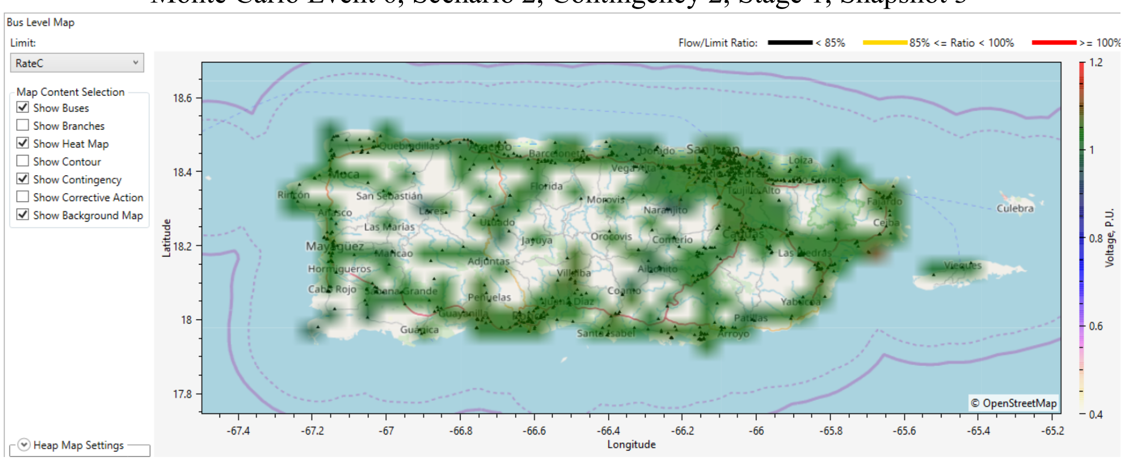
D.3.2 Hurricane Irma Voltage Heat Maps

The GIS-based voltage heatmaps for Contingency 1, 2, 3, 4 in Hurricane Irma, Monte Carlo Scenario 2 are given as follows:

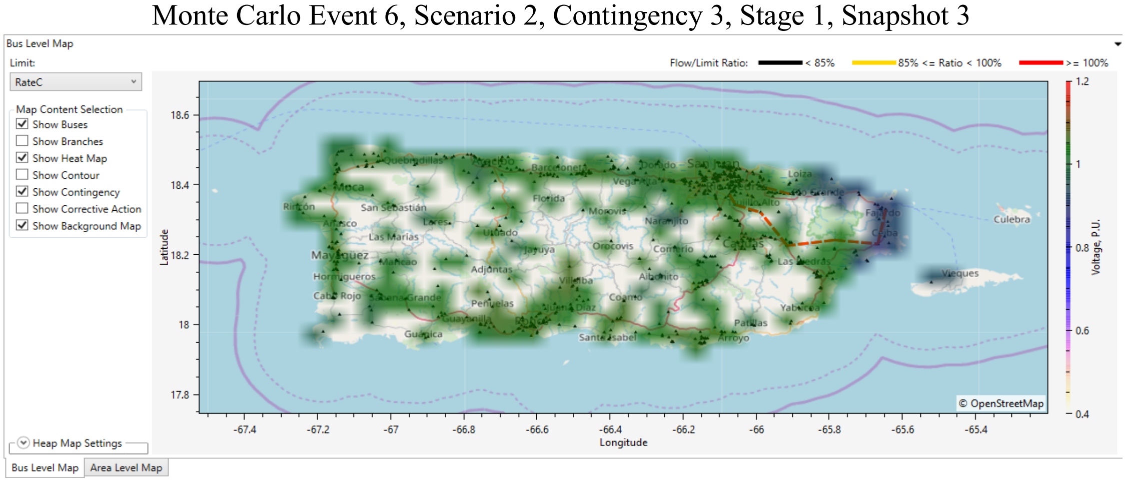
Monte Carlo Event 6, Scenario 2, Contingency 1, Stage 1, Snapshot 3



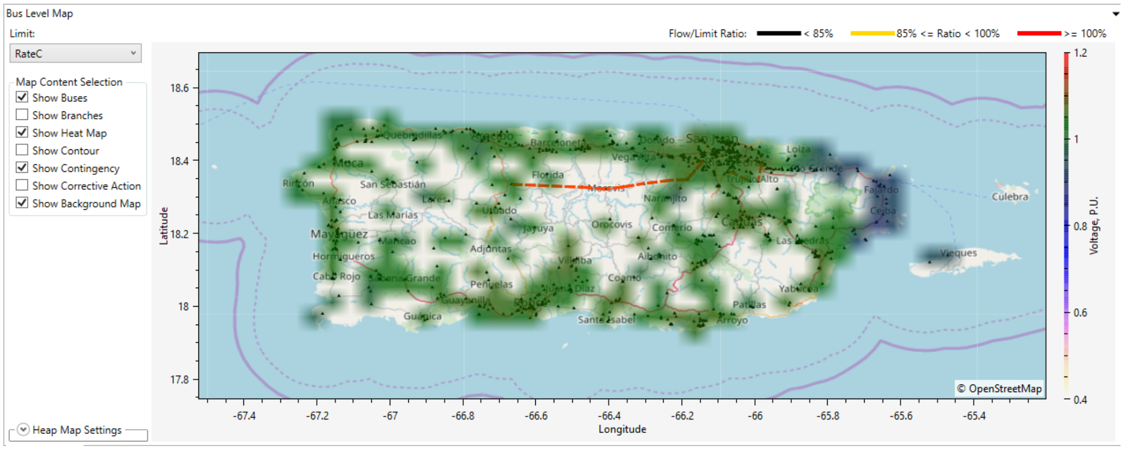
Monte Carlo Event 6, Scenario 2, Contingency 2, Stage 1, Snapshot 3



Monte Carlo Event 6, Scenario 2, Contingency 3, Stage 1, Snapshot 3



Monte Carlo Event 6, Scenario 2, Contingency 4, Stage 1, Snapshot 3



D.4 Detailed Result Comparison

D.4.1 Maria Lite Result Metrics

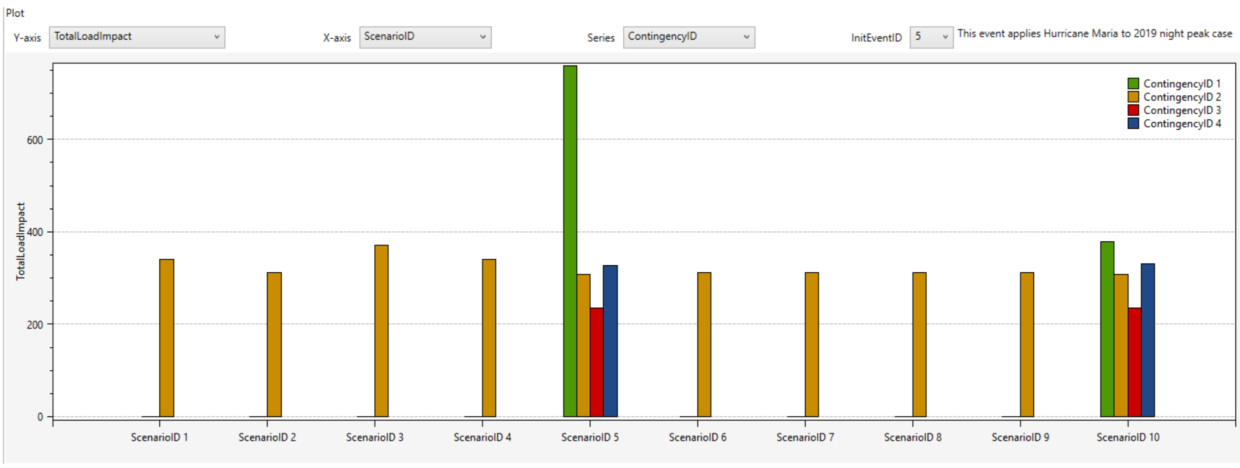


Figure D-1 Total load impact metric comparison for all 10 Monte Carlo scenarios for Maria Lite.

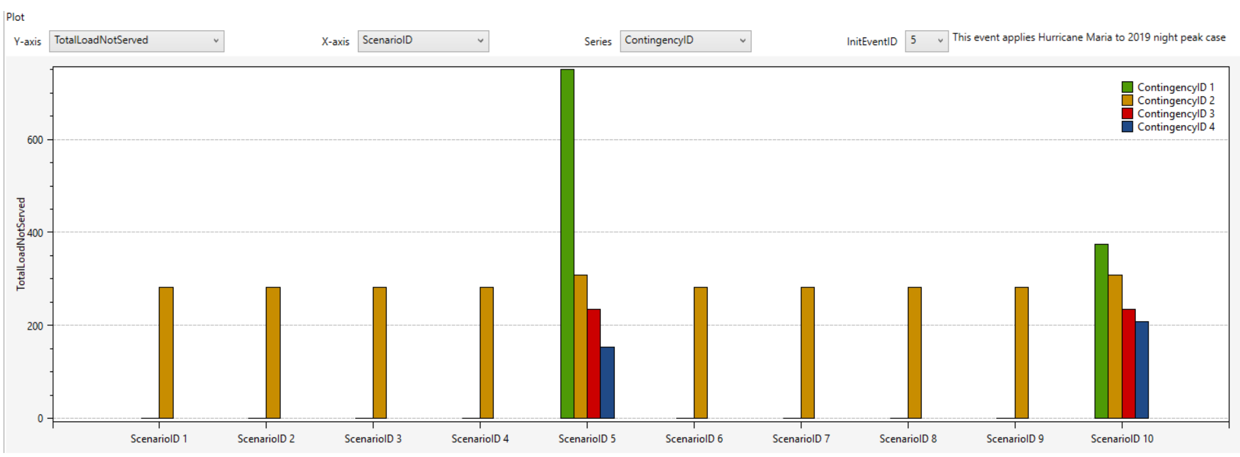


Figure D-2 Total load not served metric comparison for all 10 Monte Carlo scenarios for Maria Lite.

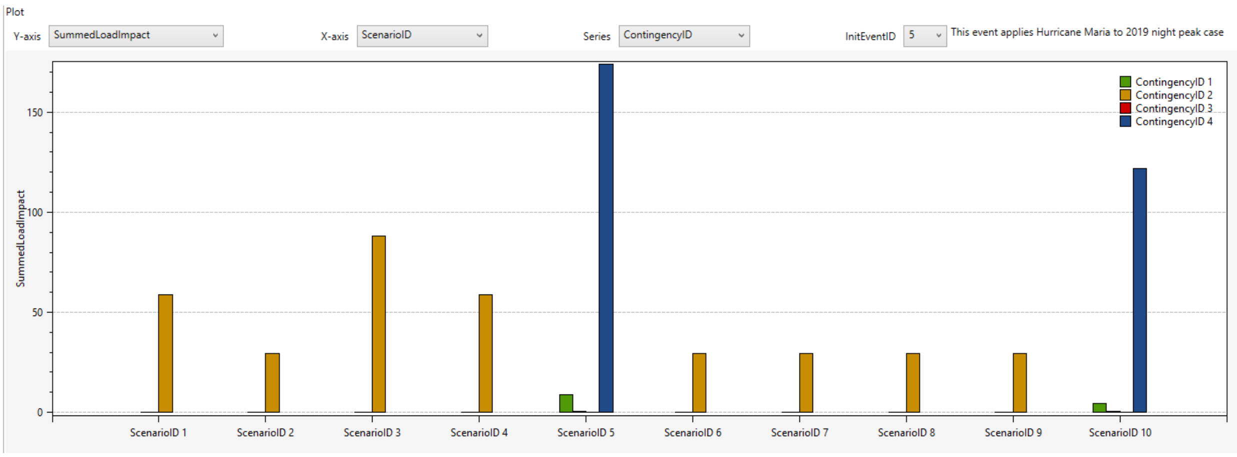


Figure D-3 Voltage-based Load Impact metric comparison for all 10 Monte Carlo scenarios for Maria Lite.

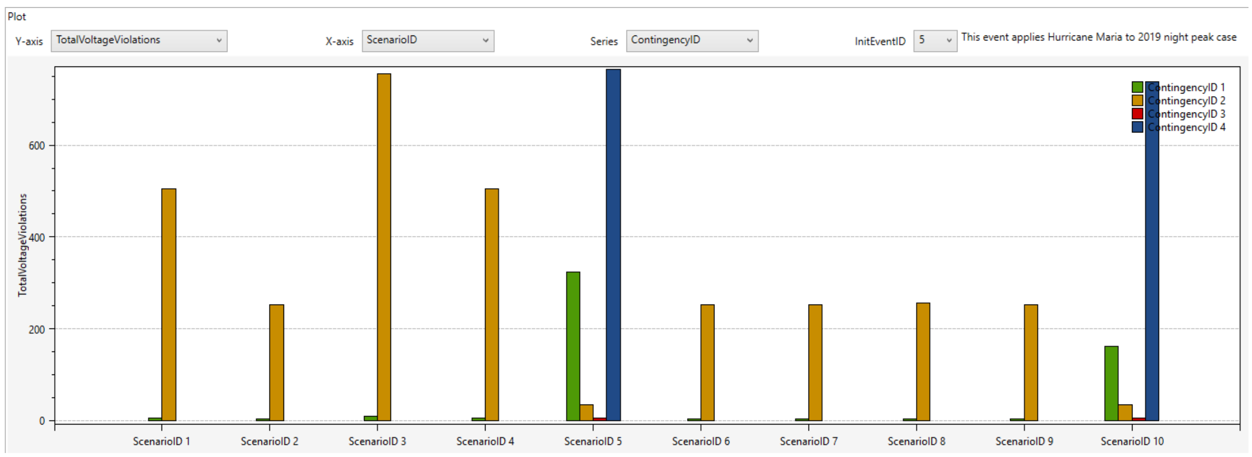


Figure D-4 Total Voltage Violation metric comparison for all 10 Monte Carlo scenarios for Maria Lite.

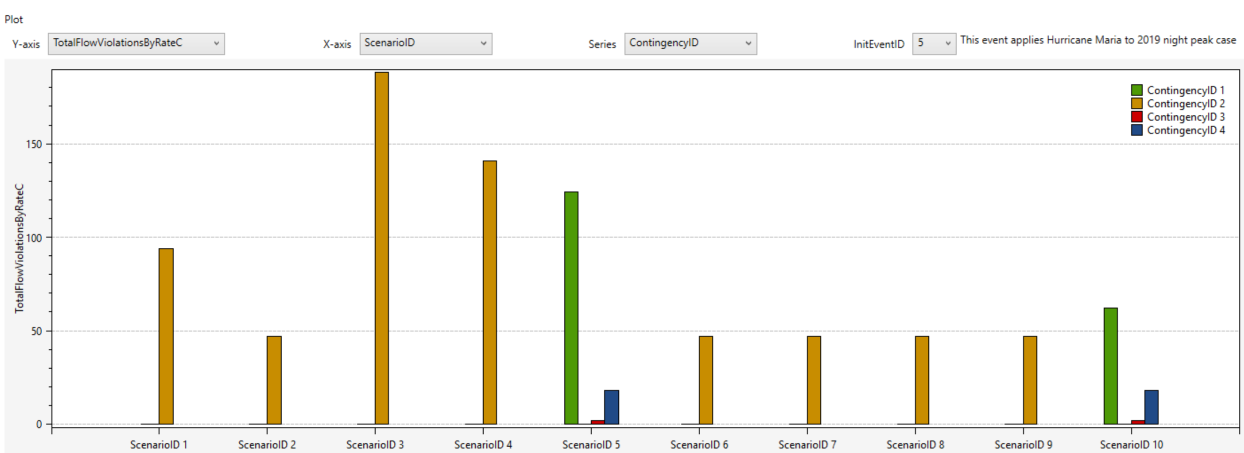


Figure D-5 Total Line Flow Violation (by Rate C) metric comparison for all 10 Monte Carlo scenarios for Maria Lite.

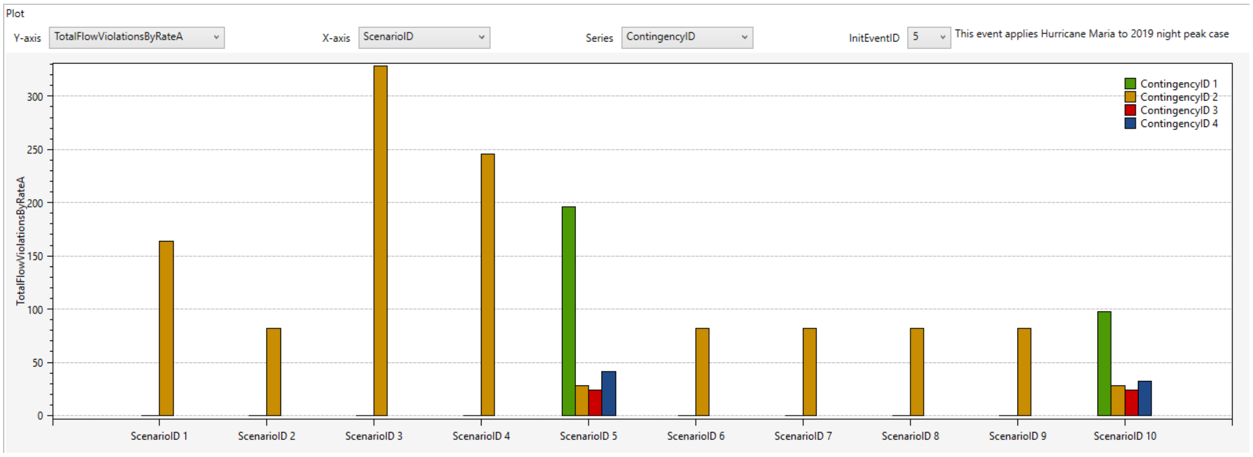


Figure D-6 Total Line Flow Violation (by Rate A) metric comparison for all 10 Monte Carlo scenarios for Maria Lite.

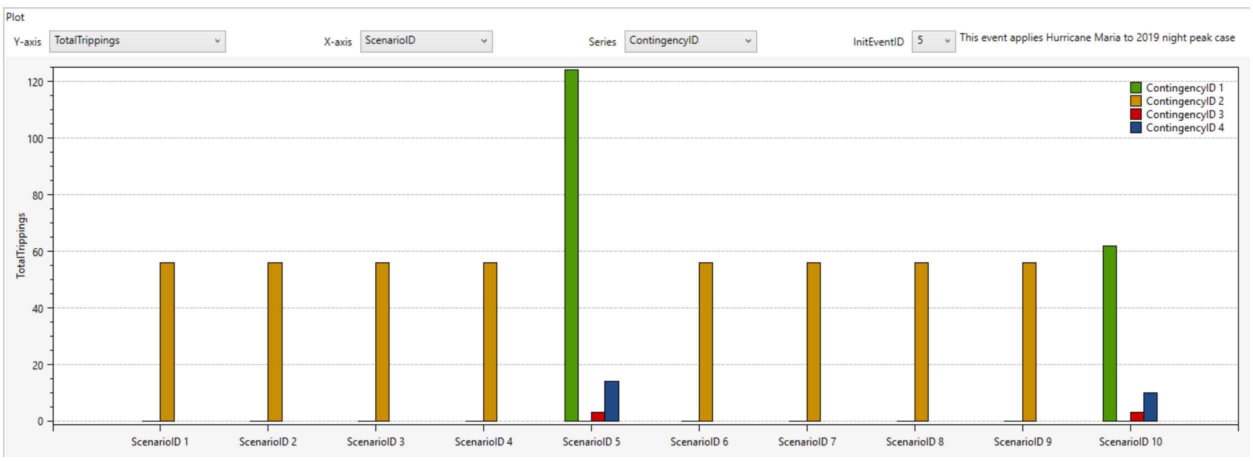


Figure D-7 Total Tripping metric comparison for all 10 Monte Carlo scenarios for Maria Lite.

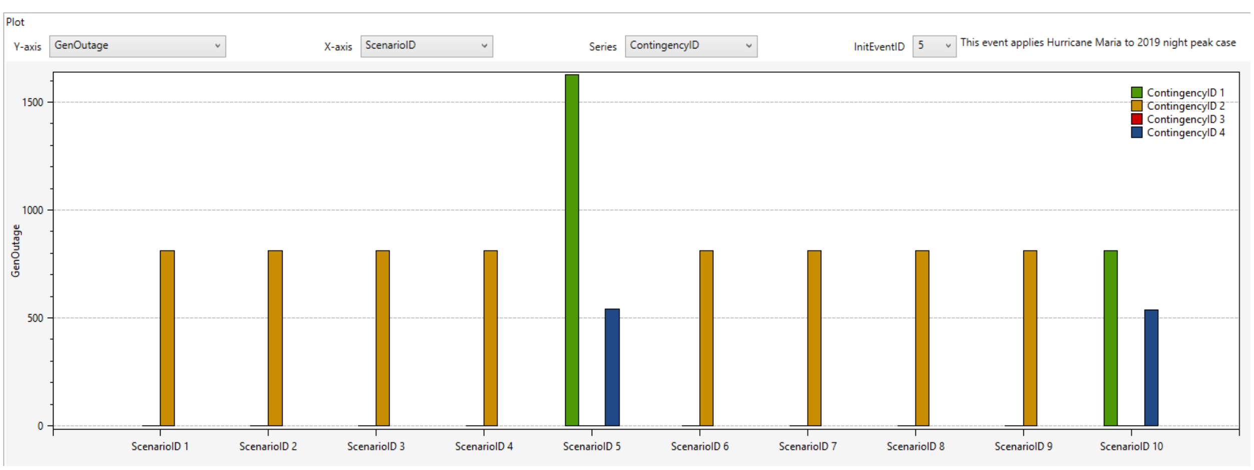


Figure D-8 Total Generation Outage metric comparison for all 10 Monte Carlo scenarios for Maria Lite.

D.4.2 Hurricane Irma Result Metrics

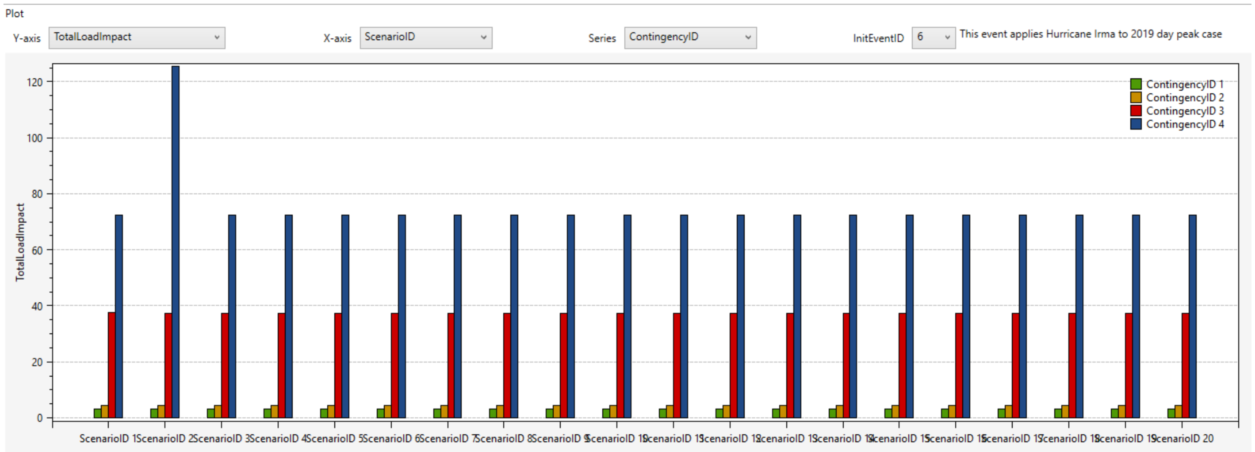


Figure D-9 Total load impact metric comparison for all 20 Monte Carlo scenarios for Hurricane Irma.

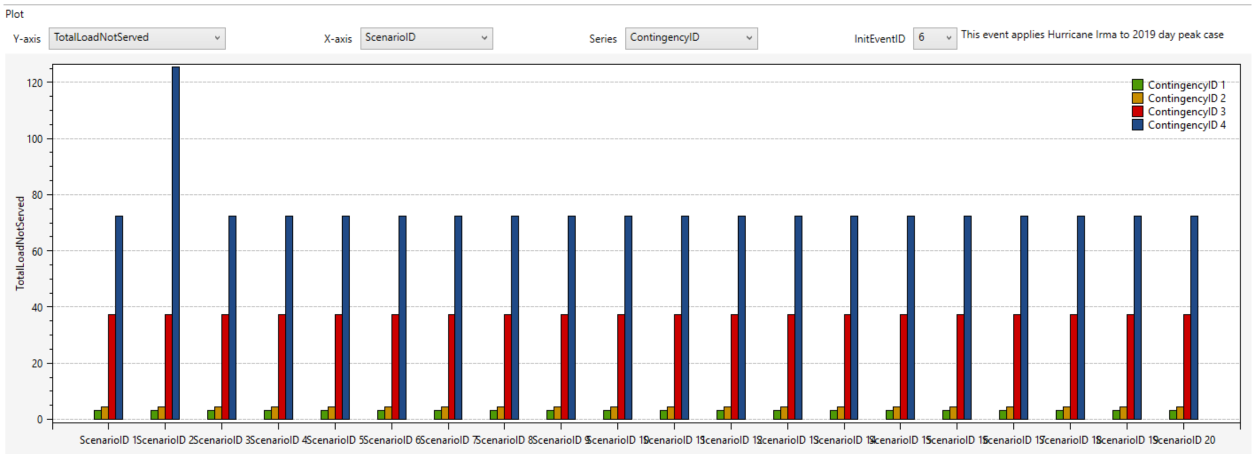


Figure D-10 Total load not served metric comparison for all 20 Monte Carlo scenarios for Hurricane Irma.

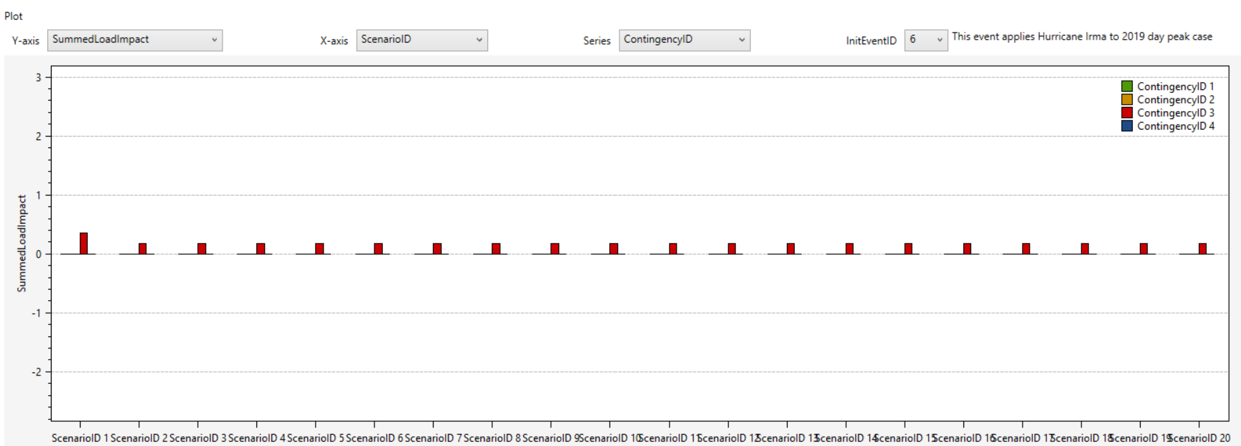


Figure D-11 Voltage-based Load Impact metric comparison for all 20 Monte Carlo scenarios for Hurricane Irma.

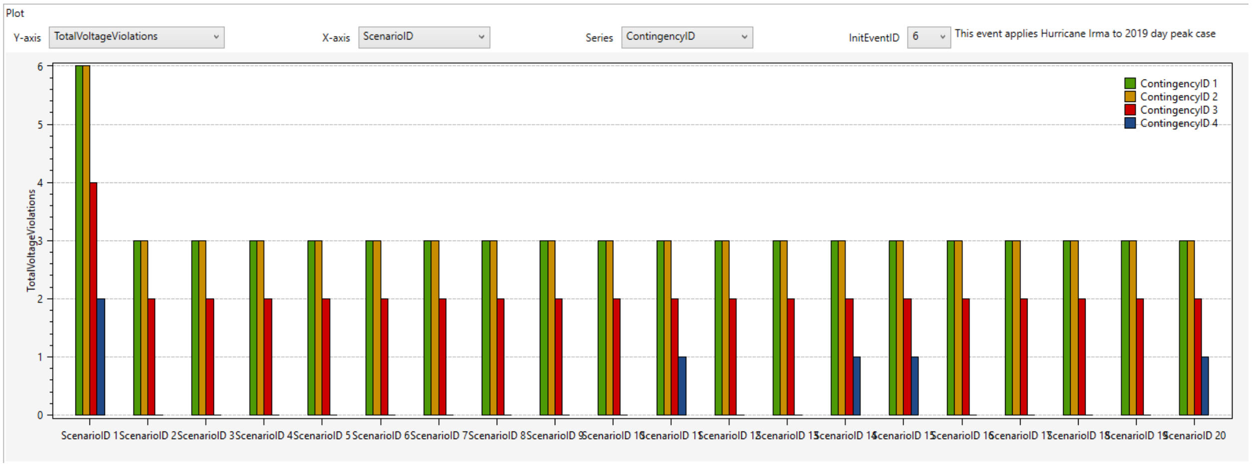


Figure D-12 Total Voltage Violation metric comparison for all 20 Monte Carlo scenarios for Hurricane Irma.

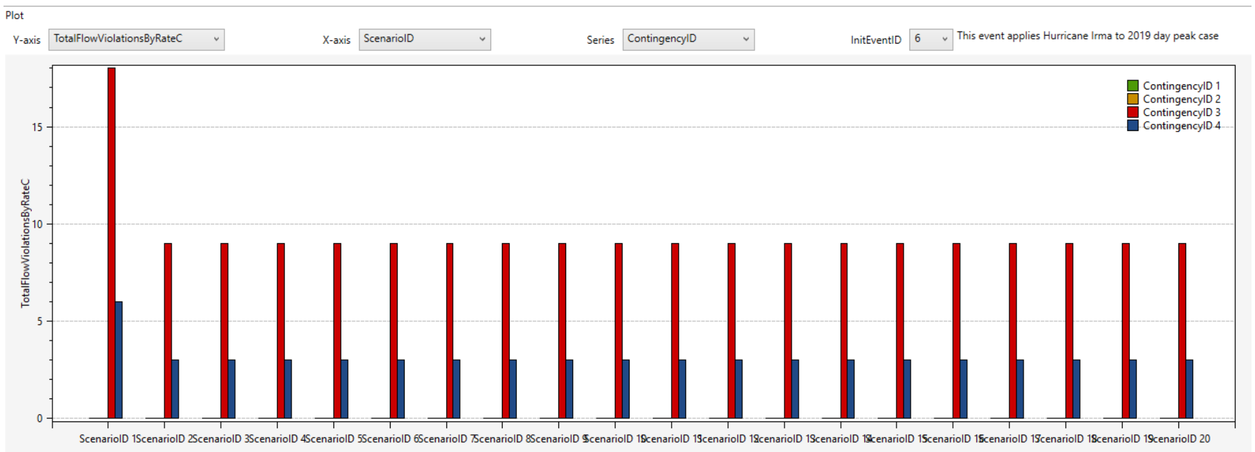


Figure D-13 Total Line Flow Violation (by Rate C) metric comparison for all 20 Monte Carlo scenarios for Hurricane Irma.

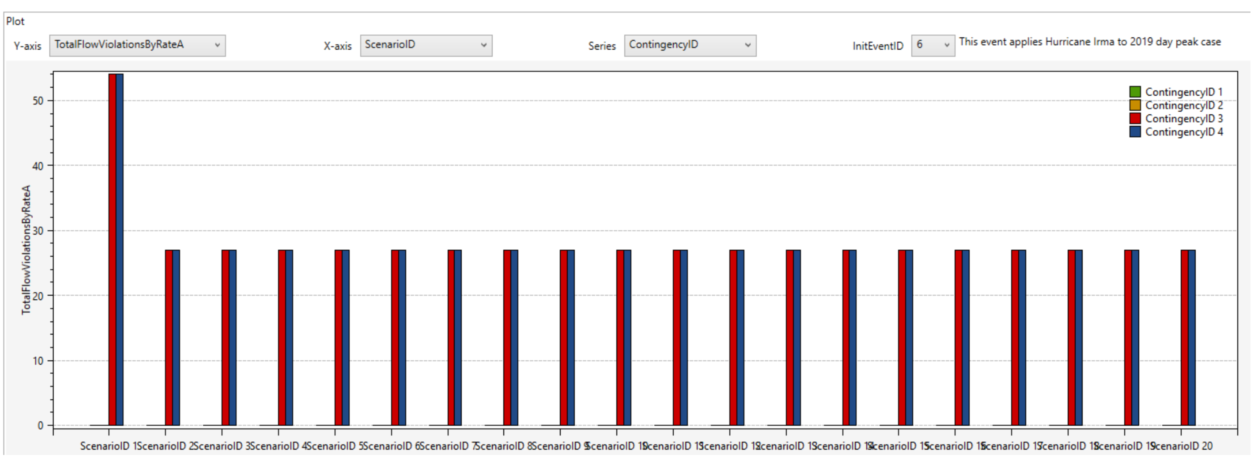


Figure D-14 Total Line Flow Violation (by Rate A) metric comparison for all 20 Monte Carlo scenarios for Hurricane Irma.

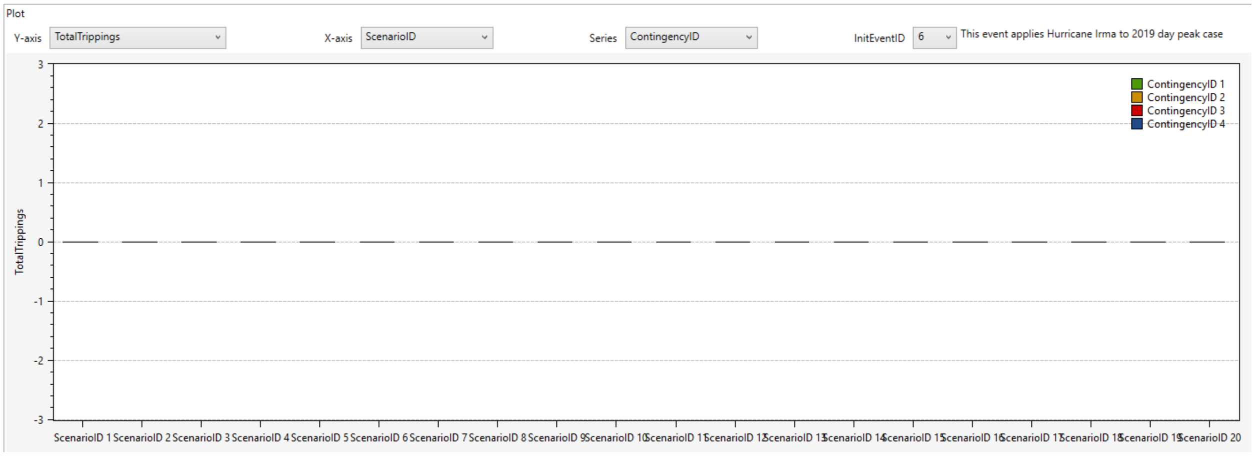


Figure D-15 Total Tripping metric comparison for all 20 Monte Carlo scenarios for Hurricane Irma.

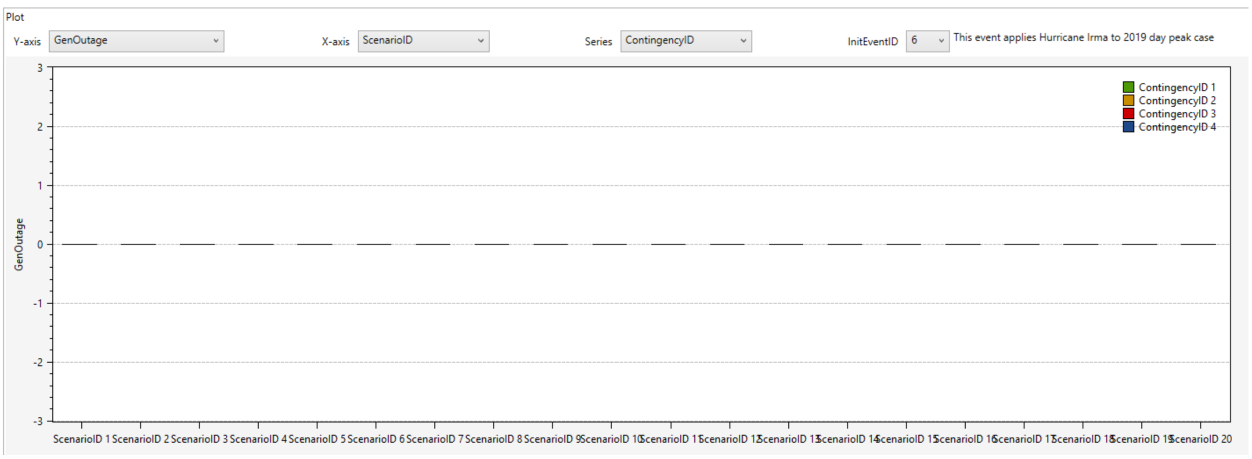


Figure D-16 Generation Outage metric comparison for all 20 Monte Carlo scenarios for Hurricane Irma.

D.4.3 Hurricane Maria: Minimum vs. Mean vs. Maximum Failure Probabilities

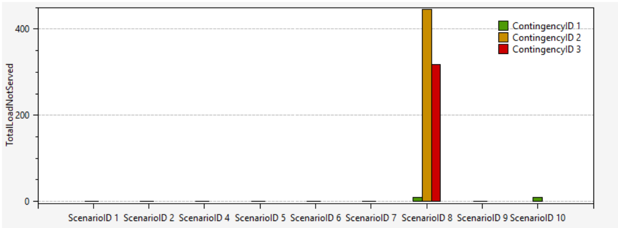
Using the maximum failure probabilities from HEADOUT to create Monte Carlo contingencies for the Hurricane Maria event were too extreme and abrupt for Puerto Rico's power grid to ride through the initial set of contingencies. Therefore, the figures below only compare Monte Carlo simulations between contingencies created using minimum and mean failure probabilities from HEADOUT.

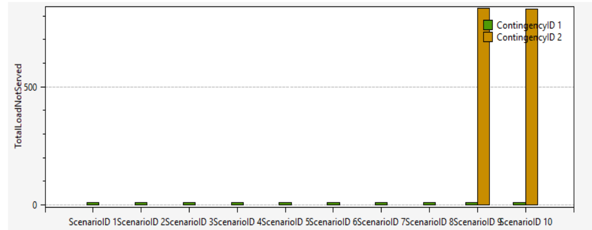
Puerto Rico 2019 Cases

InitEventID: 7
Hurricane: Maria (Min Failure Probability)
Case: 2019 Night

Metric: TotalLoadNotServed

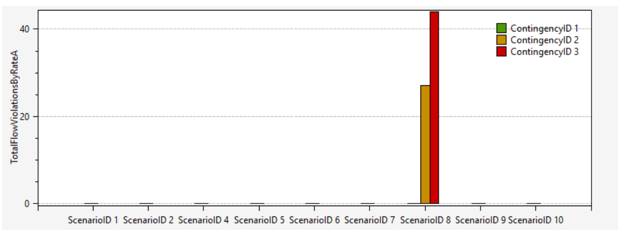
InitEventID: 8
Hurricane: Maria (Mean Failure Probability)
Case: 2019 Night
Metric: TotalLoadNotServed

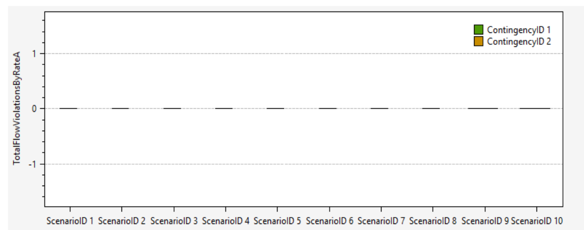




Metric: TotalFlowViolationsByRateA

Metric: TotalFlowViolationsByRateA

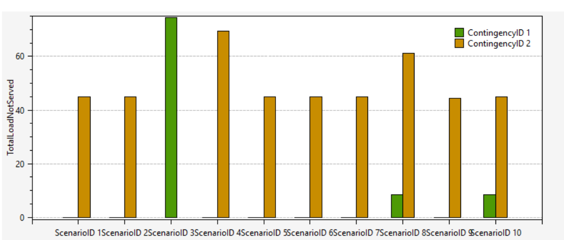




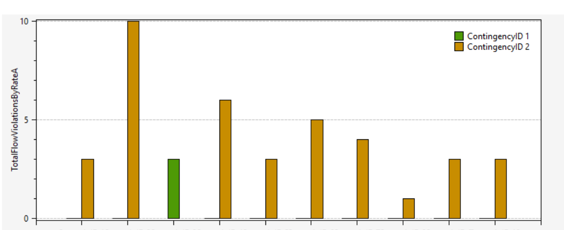
Puerto Rico 2028 Cases

InitEventID: 11
Hurricane: Maria (Min Failure Probability)
Case: 2028 Night

Metric: TotalLoadNotServed

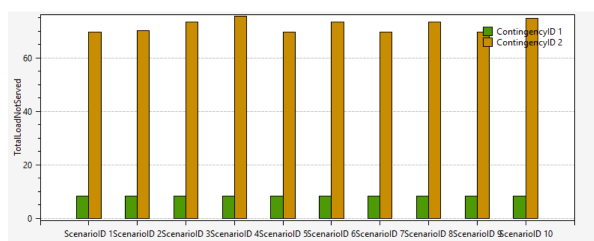


Metric: TotalFlowViolationsByRateA

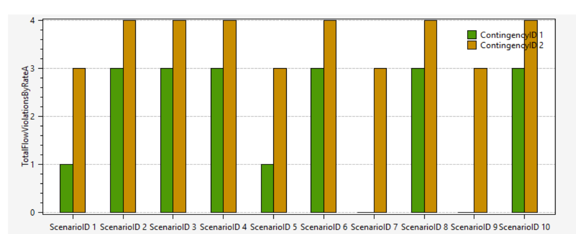


InitEventID: 12
Hurricane: Maria (Mean Failure Probability)
Case: 2019 Night

Metric: TotalLoadNotServed



Metric: TotalFlowViolationsByRateA



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