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Hawaii Electric System Reliability

Cesar A. Silva Monroy and Verne W. Loose

Sandia National Laboratories

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Cesar A. Silva Monroy and Verne W. Loose
Energy Storage and Transmission Analysis Department
Sandia National Laboratories
P.O. Box 5800
Albuquerque, New Mexico 87185-MS1140

Abstract

This report addresses Hawaii electric system reliability issues; greater emphasis is placed on short-term reliability but resource adequacy is reviewed in reference to electric consumers' views of reliability "worth" and the reserve capacity required to deliver that value. The report begins with a description of the Hawaii electric system to the extent permitted by publicly available data. Electrical engineering literature in the area of electric reliability is researched and briefly reviewed. North American Electric Reliability Corporation standards and measures for generation and transmission are reviewed and identified as to their appropriateness for various portions of the electric grid and for application in Hawaii. Analysis of frequency data supplied by the State of Hawaii Public Utilities Commission is presented together with comparison and contrast of performance of each of the systems for two years, 2010 and 2011. Literature tracing the development of reliability economics is reviewed and referenced. A method is explained for integrating system cost with outage cost to determine the optimal resource adequacy given customers' views of the value contributed by reliable electric supply. The report concludes with findings and recommendations for reliability in the State of Hawaii.

ACKNOWLEDGMENTS

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NOMENCLATURE

ACE	Area Control Error
AGC	Automatic Generation Control
BA	Balancing Authority
COPT	Capacity Outage Probability Table
ELCC	Effective Load Carrying Capability
EUE	Expected Unserved Energy
FOR	Forced Outage Rate
HECO	Hawaiian Electric Company
HPUC	Hawaii Public Utilities Commission
Hz	Hertz
IPP	Independent Power Producer
LOEE	Loss of Energy Expectation
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MECO	Maui Electric Company
NERC	North American Reliability Corporation
RSWG	Reliability Standards Working Group
SNL	Sandia National Laboratories

I.   PURPOSE AND BACKGROUND

This report has been prepared in response to requests made by the Hawaii Public Utilities Commission (HPUC) for assistance toward development of reliability standards for the Hawaii electric system. Interest and concern for improved reliability and transparent interconnection requirements have followed the increased investment in renewable energy generation technologies. The State of Hawaii is not required to adhere to established North American Electric Reliability Corporation (NERC) reliability standards.[1] Nevertheless, the HPUC is seeking to establish reliability metrics and measurement for the bulk electric power system. This interest was acted upon by the introduction of Senate Bill 2787 during the 2012 legislative session.[2] The bill would authorize the public utilities commission to develop, adopt, and enforce reliability standards and interconnection requirements; it would authorize the commission to contract for the performance of related duties with a party that would serve as the Hawaii electric reliability administrator. Further, the bill would authorize the collection of a Hawaii electric reliability surcharge to be collected by Hawaii's electric utilities.

A. Plan of the Report

This report begins with a brief description of the Hawaii electric grids and discusses pertinent aspects of the generation, transmission, and distribution assets currently comprising the system. Because there is currently no interconnection between the islands, each grid is a separate entity. Transmission reliability standards and NERC guidelines are identified with appropriate discussion. Transmission reliability metrics are identified and discussed. Then, distribution reliability will be discussed along with metrics appropriate to this portion of the grid. Selected metrics will be chosen and their pertinence to the particular aspects of the Hawaii grids will be discussed. A discussion of the economic perspectives on reliability follows and includes a brief review of economic literature pertinent to gauging how much reliability is desired or necessary. This will include reference to literature in which the economic cost of outages is analyzed. A conceptual economic model of reliability is developed and discussed. The report closes with concluding observations.

B. Description of Hawaii Electric Grids

Hawaii's Electric Grids

Two different sources of design data for the Hawaii electric grid were available for this study. Generation facilities are identified by approximate location, type of fuel and capacity in the HECO Corporate Sustainability Report available on the HECO website.[3] However, this document does not contain information on the transmission facilities that link these generation facilities nor on the distribution substations and systems. The MECO distribution system is briefly described in a booklet entitled Maui Electric Company General Information, dated 2010. Access to more detailed design information would be required to improve the fidelity of the results presented in this study.

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[1] *"*Mandatory Reliability Standards for the Bulk-Power System, Final Rule." Federal Energy Regulatory Commission, DOE. 18 CFR Part 40 (docket No. RM06-16-00; Order No. 693. The exemption for Alaska and Hawaii is contained in the summary statement of the rule.

[2] http://www.capitol.hawaii.gov/measure_indiv.aspx?billtype=SB&billnumber=2787

[3] http://www.heco.com/vcmcontent/StaticFiles/pdf/SustainabilityReport2010.pdf

1. Oahu

The Island of Oahu has the most generating capacity in the State of Hawaii; its fuel sources are diverse as well. Oil plants predominate but there are biofuel, municipal solid waste, coal, and wind sources as well. The plant mix breaks down as follows.

- Oil-fired generation 1471 MW (could be a combination of steam and combustion turbines)
- Waste heat-fired steam turbines 46 MW
- Biofuels 120 MW
- Wind farm 30 MW
- Coal 180 MW

No information on the transmission and distribution system on Oahu was available for this study.

2. Hawaii Island

The Big Island has the following mix of generation technologies:

- Oil-fired generation 259.4 MW
- Geothermal 30 MW
- Wind 31.06 MW
- Hydro 16.45 MW
- Concentrating solar 0.5 MW

No information on the Hawaii transmission or distribution systems was available for this study.

3. Maui

The Maui electric system is comprised of fossil energy-fired internal combustion engines, steam generation, and relatively newly installed wind projects. Plans for future expansion of wind energy will alter the generation capacity mix from mostly conventional technologies to almost half renewable technologies. Currently the grid is comprised of the following components with approximate capacities shown.

- Oil-fired generation 251.6 MW (combination of different fossil technologies)
- Wind farm 30 MW (purchased power)
- Agricultural waste-fired steam and small hydro 16 MW (purchased power)

Maui's transmission system is operated at 69kV and at 23kV. At the Maalaea Generating Station power is stepped up to 69 kV while at the Kahului Generating Station it is stepped up to 23kV. Distribution substations number 67 and step voltages down to a range of distribution voltages between 23 kV and 2.4 kV. Transmission circuits cover about 240 miles and distribution circuits, 1500 miles.

Plans to aggressively expand the capacity of renewable energy are driven by renewable portfolio standards in the form of mandates promulgated by the State. At present wind capacity provides insufficient capacity, together with needed reserves, to completely serve load during off-peak times necessitating running the fossil plants below design set-points during off-peak hours. This creates operational problems for both the wind and fossil plant. However, in terms of reliability,

it means that there may be too much capacity presently on the system thereby reducing capacity utilization overall.

4. Molokai and Lanai

Maui Electric Company owns the generation and distribution facilities on the two small islands with the exception of the solar PV farm on Lanai. Molokai has one 12 MW oil-fired plant and Lanai has an oil plant and purchases power from a 1.2 MW PV solar plant. The distribution systems on Molokai and Lanai are operated at a variety of voltages.

II.   POWER SYSTEM RELIABILITY ASSESSMENT

In a general context, reliability is the ability of a component, device, or system to perform its intended function. Related to power systems, reliability is assessed based on how well the system supplies electrical energy to its customers. There is a tradeoff between how reliable the power system is and the investment needed to achieve or maintain reliability levels. This is illustrated in Figure 1 where the change in incremental cost of reliability is depicted as the ratio of the change in reliability ΔR to the change in investment cost ΔC. It should be noted that a reliability of 100% is never attainable.
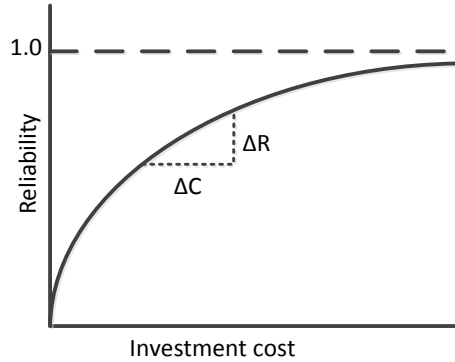
Figure 1: Incremental cost of reliability

In practice, it is extremely difficult to find the true relationship between investment cost and reliability because of the complexity of the power system, the random nature of processes within the system (e.g., unscheduled component outages), and the subjectivity of outage costs. Reliability indices and measures are efforts to quantify reliability in the power system. In order to deal with its complexity, power system reliability assessment divides the system into generation, transmission, and distribution. Probabilistic techniques are employed to plan for uncertainty in the load, component availability, and more recently, output power available from renewable energy sources.

The following sections are a summary of the indices and techniques which are most frequently applied in the reliability assessment of power systems.

A. Resource adequacy
Reliability techniques and indices related to generation capacity are employed in power system planning where long time horizons (i.e., years) are considered. These methods help determine how much capacity is needed in order to meet expected future demand while keeping enough reserves to be able to perform corrective and preventive actions. The issue of whether there is sufficient installed capacity to meet the electric load is known as *resource adequacy*. Descriptions of resource adequacy indices are presented next.

1. Loss of Load Probability (LOLP)
This index estimates the probability that the load will exceed the available generation during a given period. However, it gives no indication as to how severe the condition would be when the load exceeds available generation. For instance, two events can have the same probability of occurring (i.e., the same LOLP value), and the first one can belong to a generation deficiency of

less than 1 MW, while the second one can belong to a generation deficiency of a few hundred MW. LOLP is expressed mathematically as:

$$LOLP = p(A - L < 0) \tag{1}$$

where *A* is the available capacity available to meet the system peak load *L*, and *p* denotes probability. Generally, LOLP is calculated by convolving the capacities and forced outage rates (FOR) of the installed generation fleet (Hsu, 1985). This produces a capacity outage probability table (COPT) that contains the probability of having outages of different MW levels. An example of a COPT is given in Table 1 for a system with 6 generating units and a forced outage rate (FOR) of 0.08 for each unit (NERC, 2011).

Table 1: Example of capacity outage probability for a 6-generator system with FOR of 0.08 for each generator

MW-out	MW-in	Probability	LOLP
0	300	0.60635500	1.0
50	250	0.31635913	0.00000026
100	200	0.06877372	0.07728587
150	150	0.00797377	0.00851214
200	100	0.00052003	0.00053838
250	50	0.00052003	0.00001835
300	0	0.00000026	0.00000026

Alternatively, a Monte Carlo simulation can be employed to calculate the LOLP of a system. Then LOLP can be expressed mathematically as:

$$LOLP = \frac{\sum_{i=1}^{N} S_e}{N} \tag{2}$$

where S_e is a simulation in which at least one significant event occurs. A significant event occurs when load and operating reserve obligations exceed resources or some event threshold limit. *N* is the number of years in the sampling period. Typically, there is one simulation for each hour of each year and LOLP is given as a percentage.

2. Loss of Load Expectation (LOLE)

This index is widely used when evaluating new generation scenarios in the planning process. It is generally defined as the average number of days on which the daily peak load is expected to exceed the available generating capacity (Allan, July 1992). Assuming a Monte-Carlo simulation is employed, LOLE in hours/year can be defined mathematically as (Billinton, 1991):

$$LOLE = \frac{\sum_{i=1}^{N} r_i}{N} \tag{3}$$

where *i* is the sampling year, r_i is the loss of load duration in hours and *N* is the number of years in the sampling period. LOLE and LOLP are directly related. Hence, LOLE has the same weakness as LOLP of providing no information about the severity of the condition.

3. Expected Unserved Energy (EUE) or Loss of Energy Expectation (LOEE)

This index is defined as the expected energy that will not be supplied due to those occasions when the load exceeds the available generation. Assuming a Monte-Carlo simulation is employed, EUE in MWh/year can be defined mathematically as:

$$EUE = \frac{\sum_{i=1}^{N} E_i}{N} \tag{4}$$

where E_i is the energy not supplied in MWh and N is the number of years in the sampling period.

4. Effective Load Carrying Capability (ELCC)

The ELCC is the contribution that a generator makes to overall resource adequacy. It quantifies the additional amount of load that can be served due to the addition of an individual generator (or group of generators) while maintaining the existing reliability level (Keane, 2011). ELCC is also known as *capacity value*. For conventional generators, the ELCC can be calculated based on their respective capacities and FORs. These two are convolved using an iterative method to produce a capacity outage probability table (COPT) that indicates the probability of a given MW outage in the entire system.

Since wind capacity and FOR cannot appropriately describe the available wind power during peak load hours, the ELCC calculation must be modified to accommodate the uncertainty associated with wind. The IEEE preferred method to calculate the capacity value of wind consists of the following steps (Keane, 2011):

1. The COPT of the power system is used in conjunction with the hourly load time series to compute the hourly LOLPs without the presence of the wind plant. The annual LOLE is then calculated. The LOLE should meet the predetermined reliability target for that period. If it does not match, the loads can be adjusted, if desired, so that the target reliability level is achieved.
2. The time series for the wind plant power output is treated as negative load and is combined with the load time series, resulting in a net load time series. In the same manner as step 1, the LOLE is calculated. It will now be lower (and therefore better) than the target LOLE in the first step.
3. The load data is then increased by a constant load ΔL across all hours using an iterative process, and the LOLE recalculated at each step until the target LOLE is reached. The increase in peak load (sum of ΔLs) that achieves the reliability target is the ELCC or capacity value of wind.

The use of Monte-Carlo simulation to evaluate multiple years is recommended in order to minimize the error due to inter-annual variation of wind.

Other methods for assessing the capacity value of wind exist such as using synthetic time series of wind in case there is a limited availability of historical wind data. One of the key factors in this case is to capture the correlation between wind output and load due to underlying weather conditions in the stochastic models of wind and solar plants.

A non-iterative method to approximate the ELCC of wind that requires minimal modeling and is computationally inexpensive was proposed by D'Annunizo and Santoso (D'Annunzio, 2008). This method models a wind plant as a multistate unit that can exist in one or more partial capacity outage states C_j. Hence, a capacity outage individual probability table (COIPT) can be created with multiple discrete power levels (e.g., 0, C_j, $2 \cdot C_j$, $3 \cdot C_j$) up to the total capacity of the wind plant C_A. The probability p_j of a partial capacity outage state C_j is calculated by counting the occurrences when the power output is equal to $C_A - C_j$ divided by the total number of power output data points. This can be expressed mathematically as:

$$p_j = \frac{\text{Number of ocurrences when power output is } C_A - C_j}{\text{Total number of power output data points}} \qquad (5)$$

When a power output value falls between two discrete capacity outage states, it is counted as an occurrence for the highest value.

In addition to the wind plant COIPT, the method uses various load duration curves to determine the relationship between the LOLE of the system and an increase or decrease in the typical load demand. The new load duration curves are produced by taking the original system load curve and shifting it by a given number of percentages (e.g., -20%, 17.5%, -15%, …, 0%, ..., 15%, 17.5%, 20%). Mathematically, this can be expressed as:

$$L_c = L_t \pm c \cdot L_{t_{\text{pk}}} \qquad (6)$$

where L_c is a new load duration curve, L_t is the typical load duration curve with peak load $L_{t\text{pk}}$. Then, the LOLE is computed for each new duration curve. The resulting data points for LOLE as a function of peak load L_{pk} are fitted to an exponential function of the form:

$$LOLE(L_{\text{pk}}) = B \times e^{m \times L_{\text{pk}}} \qquad (7)$$

Thus, an estimated value of m is found. The ELCC can be computed using:

$$\text{ELCC} = \left[-\ln \left[\sum_{j=1}^{k} p_j \times e^{m \times (C_j - C_A)} \right] \right] \times \frac{100\%}{m \times C_A} \qquad (8)$$

where C_j and p_j are the partial capacity outage states (MW) and corresponding individual probability, respectively. The nameplate capacity of the added unit is C_A.

Results from a case study shown in (D'Annunzio, 2008) showed that this method produced accurate results, within 3% of the ELCC value estimated employing the ELCC classical method described at the beginning of this section.

B. Transmission Reliability Indices and Measures

Reliability assessment of the bulk power system (i.e., transmission and generation) is divided into *resource adequacy* and *system security*. The previous section dealt with the issue of resource adequacy. This section now addresses the issue of system security, which refers to the question of whether the transmission system can move energy from generation to bulk supply points, while staying within operational limits and being capable of withstanding disturbances (Allan, Nov. 1992). In other words, the reliability of the transmission system must satisfy both dynamic

conditions (i.e., withstanding a transient disturbance or small signal disturbance) as well as the static conditions (i.e., voltage, frequency, and thermal limits). Past performance indices applied to the transmission system include: system unavailability; unserved energy; number of incidents; number of hours of interruptions; number of voltage excursions beyond limits; and number of frequency excursions beyond limits.

As previously mentioned, the NERC has a very large number of standards that are employed by electric utilities in the mainland and that are oriented towards improving and assessing the reliability of interconnected electric systems. The next section presents a summary of NERC standards that could be applied to electric systems in Hawaii taking into account their islanded nature.

1. Review of NERC Reliability Standards

The following is an overview of a subset of NERC's reliability standards that could be applied to the Hawaiian electric systems. The selection takes into account the fact that each power system in Hawaii is islanded, with no interconnection of any kind, and of relatively small size. All of these standards might be modified to better suit the needs of the Hawaiian electric systems. The standards mentioned below are organized alphabetically, as presented in NERC's complete set of *Reliability Standards for the Bulk Electric Systems of North America* (NERC, 2009).

Real Power Balancing Control Performance (BAL-001.1a)

This NERC reliability standard is aimed at keeping the steady-state frequency within defined limits. It defines the control performance standards (CPS1 and 2). In general terms, these control performance standards are statistical metrics of a balancing authority's ability to closely follow its demand in real time.

In interconnected systems, frequency deviations in combination with scheduled energy interchange values are employed to determine the mismatch between generation and load within balancing authorities. Since Hawaiian electric systems are islanded systems, no energy interchanges exists. However, electrical frequency deviations are used by local utilities in Hawaii to take corrective actions (i.e. increase or decrease generation) during the automatic generation control (AGC) process. Consequently, frequency performance standards could be defined for the Hawaiian electric systems parallel to CPS1 and 2. These frequency performance standards would help quantify the Hawaiian utilities' ability to follow real-time variations of demand and renewable generation.

Automatic Generation Control (BAL-005-0.1b)

This standard establishes requirements for a balancing authority (BA) to calculate the Area Control Error (ACE) necessary to perform AGC. Examples of these requirements are maintaining regulating reserves that can be controlled by AGC, ensuring data acquisition for ACE calculation occurs at least every 6 seconds by having redundant independent frequency metering equipment, performing hourly error checks to determine the accuracy of control equipment, and periodically testing and recharging back-up power for control centers.

Operating Reserves (BAL-STC-002-0)
This standard provides a set of qualitative requirements that defines available operating reserves. These requirements are qualitative and do not set arbitrary operating reserve values, but give BAs a framework to determine reserve capacity necessary for reliable operation (e.g., operating reserves must be able to replace generation and energy lost due to forced outages of generation or transmission).

Cyber Security (CIP-002 to CIP-009)
These standards provide a framework on management and maintenance of cyber assets in power systems. These standards include functions such as identifying assets that are critical for managing the reliability of power systems and the vulnerabilities of those assets.

Telecommunications (COM-001-1.1)
This standard requires each BA to ensure proper functioning of their telecommunication facilities. Additionally, written operating procedures and instructions should be available to enable system operation when a loss of telecommunication capabilities occurs.

Emergency Operations Planning (EOP-001-0)
This standard requires each BA to "develop, maintain and implement a set of plans to mitigate operating emergencies". An example of an emergency is a violation of the system operational limits. In such case, a balancing authority must have a plan to reduce load sufficiently to avoid system failures. Such a plan should include aspects such as communication protocols to be followed, controlling actions to resolve the emergency and staffing levels for the emergency.

Disturbance Reporting (EOP-004-1)
This standard requires BAs to record disturbances or unusual occurrences that result in system equipment damage, interruptions or jeopardize the operation of the system in order to study them and minimize the likelihood of similar events occurring in the future.

System Restoration Plans (EOP-005-1)
This standard requires BAs to develop plans and procedures to ensure that there are resources available for restoring the electric system after a partial or total shut down. Restoration plans include items such as training personnel, verification of restoration procedures through simulation and testing of black start units.

Plans for Loss of Control Center Functionality (EOP-008-0)
Each utility must develop a contingency plan to continue reliability operations in the event that its control center becomes inoperable. This contingency plan includes requirements such as procedures for monitoring and controlling generation, voltage frequency, and critical substation devices; and maintaining basic communication capabilities without relying on data or communication from the primary control center.

Documentation of Black start Generating Unit Test Results (EOP-009-0)
This standard addresses the testing of black start units and its corresponding documentation in order to ensure these units are capable of performing this function.

Transmission Vegetation Management Program (FAC-003-1)
This standard is aimed at minimizing outages and other events due to vegetation located on transmission right-of-ways and maintaining clearances between transmission lines and vegetation. It requires the transmission owner to have and update a formal transmission vegetation management plan.

Modeling and simulation of Interconnected Transmission System (MOD-010-0 and MOD-012-0)
Although there are no interconnected systems in Hawaii, the objective of these standards can still be applied to the Hawaiian electric systems. The main purpose is to establish consistent models to be used in the analysis of the reliability of an electric system. It puts the burden of providing appropriate simulation models on power system component owners. For instance, it requires generator owners provide steady-state and dynamic modeling and simulation data to the regional reliability organization, which is the entity responsible for performing reliability assessments.

Aggregated Actual and Forecast Demand and Net Energy for Load (MOD-017-0.1)
This standard addresses the need for records of past and real-time load and demand-side management data. This data is necessary to forecast load and to perform future system reliability assessment. The standard gives some specifications on requirements such as "integrated hourly demands in MW for the prior year" and "monthly peak hour forecast demands in MW and Net Energy for load in GWh for the next two years".

Reporting of Interruptible Demands and Direct Control Load Management (MOD-019-0.1)
This standard addresses the need for records and forecasts on interruptible loads and direct control loads to be employed in the system reliability assessment.

Verification of Generator Gross and Net Real and Reactive Power Capabilities (MOD-024-1 and MOD-025-1)
This standard makes generator owners responsible for ensuring that accurate information on real and reactive power capability of the units is available. This information is employed in the reliability assessment process. The standard includes requirements on the periodicity of data verification and reporting and the type of information to be reported.

System Personnel Training (PER-005-1)
This standard requires that each balancing authority, reliability coordinator and transmission operator use a systematic approach to training in order to address company specific reliability related tasks. Such training should be updated periodically in order to modify or add new tasks. The training program should also be evaluated periodically.

Analysis and Mitigation of Transmission and Generation Protection System Mis-operations (PRC-04-1)
This standard requires the transmission, distribution and generator owners to analyze protection system mis-operations and implement corrective actions to avoid similar events in the future.

Transmission and Generation Protection System Maintenance and Testing (PRC-005-1)
This standard requires transmission, distribution and generator owners to have a testing and maintenance program for protective devices in their systems. The program should include testing intervals and testing and maintenance procedures. Records of test results and maintenance should be maintained.

Other standards are parallel to this one, but applied to under-frequency load shedding (PRC-008-0) and under-voltage load shedding (PRC-011-0) equipment. These are of particular interest to Hawaiian electric systems since they rely on load shedding due to their islanded nature.

Under-frequency Load Shedding Performance Following an Under-frequency Event (PRC-009-0)
Transmission and distribution owners are required, under this standard, to perform an analysis of each under-frequency event to determine the performance of the under-frequency program. For instance, the cause of an under-frequency event, and load shedding set points and tripping times should be reviewed periodically.

Under-voltage Load Shedding Program (PRC-010-0-PRC-011-0, PRC-021-1-PRC-022-1)
Similarly to the under-frequency load shedding program, the under-voltage load shedding (UVLS) provides preservation measures to avoid voltage instability or collapse. The design and effectiveness of UVLS measures should be evaluated periodically (e.g., every 5 years). The UVLS equipment shall be maintained and tested periodically and data on the technical characteristics (e.g., breaking operating times, voltage set points and clearing times) shall be kept and updated.

Transmission Relay Loadability (PRC-023-1)
This standard requires that transmission operators adjust their relay settings so that they do not limit transmission capability of lines while still performing their protective actions appropriately. The standard gives quantitative guidelines for relay setting such as loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.

Normal Operations Planning (TPO-002-0)
This standard addresses the need for planning in the power system at several time horizons, and communication of these plans or changes during operation between the different parts of the electric system. It requires the system operator to set plans for reliable operation through a "reasonable" future time period; plans to meet unscheduled system changes using a single contingency (i.e., N-1) planning at a minimum; and to perform studies of next-day and current day conditions to determine system operating limits. Additionally, generator owners are required to communicate any changes in real output power capabilities and characteristics of their units.

Monitoring system conditions (TOP-006-1)
This standard requires that critical reliability parameters be monitored in real-time. These parameters include real and reactive power flows, line status, voltage, tap-changer settings, and system frequency. It also calls for weather forecasts and past load patterns to be used by the system operator in order to predict near-term load.

Response to Transmission Limit Violations (TOP-008-1)
This standard requires transmission operators to take immediate actions when system operating limits are violated. It also asks for the transmission operator to collect sufficient information and to use analysis tools to determine the cause of the violations in an effort to mitigate them.

System Performance under Normal to Extreme Conditions (TOP-001-0.1 to TOP-004-0)
These standards address the need for periodic simulation and assessment of system operation in order to ensure the reliability of the system in the long term. This assessment should be made annually using a near-term forecast (i.e., 1-5 years) and a long term forecast (i.e., 6-10 years). The purpose of these studies is to demonstrate that the system is able to perform up to a set of system standards for each of the following conditions:
- normal operation,
- loss of a single bulk electric system element,
- loss of two or more bulk electric system elements,
- and following extreme conditions.

The set of system standards can be found on page 950 of NERC, 2009 and is also attached in appendix A of this document. The transmission operator is required to upgrade or add components in order to meet future system needs and comply with the aforementioned standards.

Assessment Data from Regional Reliability Organizations (TPL-006-0)
This standard requires regional reliability organizations to provide system data, reports and system performance information necessary to periodically assess reliability and compliance. Examples of such data are resource adequacy plans; electric demand forecast and forecast methodologies; assumptions and uncertainties; supply-side resource information; and transmission system information.

Generator Operation for Maintaining Network Voltage Schedules (VAR-002-1)
This standard requires generator owners to provide reactive power control and voltage control necessary to maintain voltage, reactive power flows and resources within specified operating limits. Additionally, it mandates generators to notify system operators of any changes in reactive power capability.

C. Distribution Reliability Standards

There are several metrics employed when evaluating the reliability of distribution systems. These metrics can be divided according to the length of the interruption and other data employed in their calculation as sustained interruption indices, load based indices, and other indices (momentary interruption). A momentary interruption refers to any interruption lasting less than 5 minutes and caused by the operation of an interrupting device such as circuit breakers. Consequently, a sustained interruption is any interruption lasting more than 5 minutes (IEEE, 2004).

Indices based on sustained and momentary interruptions take into account the number of customers affected by the interruption and the time it takes to recover from them. On the other hand, load based indices are those that focus on the load interrupted. The next section presents the most employed sustained interruption indices. Other distribution reliability indices can be found in Appendix B.

1. Sustained Interruption Indices

System Average Interruption Frequency Index (SAIFI)
This index indicates the frequency at which the average customer experiences a sustained interruption in the time interval under analysis (e.g. 1 year). Mathematically, this is given as:

$$\text{SAIFI} = \frac{\sum \text{Total number of customers interrupted}}{\text{Total number of customers served}} \tag{9}$$

System Average Interruption Duration Index (SAIDI)
This index indicates the average time an average customer experiences sustained interruptions in the time interval under analysis. Mathematically, this is given as:

$$\text{SAIDI} = \frac{\sum \text{Customer interruption durations}}{\text{Total number of customers served}} \tag{10}$$

Customer Average Interruption Duration Index (CAIDI)
This index indicates the average time that it takes to restore service after a sustained interruption in the time interval under analysis. In this index, customers with multiple interruptions are counted multiple times. It is expressed mathematically as:

$$\text{CAIDI} = \frac{\sum \text{Customer interruption duration}}{\text{Total number of customers interrupted}} = \frac{\text{SAIDI}}{\text{SAIFI}} \tag{11}$$

Average Service Availability Index (ASAI)
This index indicates the fraction of time that a customer has received power over a predefined period of time.

$$\text{ASAI} = \frac{\text{Customer hours service availability}}{\text{Customer hours service demand}} \tag{12}$$

The denominator is calculated by multiplying the number of customers served by the hours in the predefined period of time.

Customers experiencing multiple interruptions (CEMI$_n$): This is the ratio of total customers that experienced more than n sustained interruptions over the study period. It is expressed mathematically as:

$$\text{CEMI}_n = \frac{\text{Total number of customers that experience} > \text{n sustained interruptions}}{\text{Total number of customers served}} \tag{13}$$

III. ANALYSIS OF FREQUENCY DATA PROVIDED BY THE HPUC

Time series of frequency data for the HECO and MECO electric systems were provided by the Hawaii Public Utilities Commission (HPUC) to SNL. A summary of the findings after analyzing this data is presented in this section. The objective of this analysis is to determine the performance of a couple of power systems in Hawaii, namely HECO and MECO, using their frequency as a proxy.

These time series have an original resolution of 2 seconds and correspond to the years 2010 and 2011. Plots of the time series provided are found in Appendix C.

A. Number of Under-frequency/Over-frequency events

The number of frequency deviations from normal operating limits was assessed. One event is counted as an incident where the frequency goes outside a certain frequency deviation threshold and returns to normal operating limits (i.e. 60 Hz ± 0.03 Hz). This is done so that smaller frequency deviations resulting from larger excursions are not counted as separate events. The events were grouped based on the maximum deviation, and as under-frequency or over-frequency events. Results for consecutive years are shown in the same plot in order to compare performance over the two year period from 2010 to 2011. Five symmetrical frequency thresholds around the normal operating frequency (i.e., 60 Hz.) were chosen. These thresholds were chosen based on important actions taken when under- or over-frequency events occur in the HECO system (HECO, 2011) and do not match one-to-one the thresholds that HECO produces in their filings.

1. HECO Data

A summary of the total number of events in the HECO system is found in Table 2. The under-frequency (U) and over-frequency (O) events are given by year and frequency thresholds.

**Table 2: Summary of events in the HECO system[4]**

	±0.03 - 0.1 Hz				±0.1 - 0.3 Hz				±0.3 - 0.5 Hz				±0.5 - 1.5 Hz				≥ ±1.5 Hz			
	2010		2011		2010		2011		2010		2011		2010		2011		2010		2011	
	U	O	U	O	U	O	U	O	U	O	U	O	U	O	U	O	U	O	U	O
Jan	2,054	2,525	8,601	7,172	1	11	19	52	0	0	0	0	0	0	1	0	0	0	0	0
Feb	2,259	2,912	8,682	6,973	3	4	5	44	1	0	1	0	1	0	0	0	1	0	0	0
Mar	2,824	3,830	8,746	7,377	7	5	19	37	0	0	0	0	0	0	1	0	0	0	0	0
Apr	2,998	3,653	8,506	6,932	1	5	12	41	0	0	2	0	0	0	0	0	0	0	0	0
May	1,988	2,363	8,874	7,514	1	3	11	23	0	0	3	3	0	0	0	1	0	0	0	0
June	2,128	2,462	9,283	6,891	0	0	13	36	0	0	1	5	0	0	1	1	0	0	0	0
July	3,446	3,898	10,508	6,797	0	0	5	14	0	0	1	0	0	0	0	1	0	0	0	0
Aug	4,676	5,264	6,377	5,543	1	17	8	11	0	0	1	0	1	0	0	0	1	0	0	0
Sep	3,699	3,926	6,157	5,257	9	4	4	11	2	2	2	0	1	1	0	0	1	0	0	0
Oct	3,518	3,941	9,232	7,304	6	10	4	9	2	1	0	0	0	0	0	0	0	0	0	0
Nov	4,355	4,487	8,659	7,791	2	10	10	12	1	1	1	0	0	0	0	0	0	0	1	0
Dec	5,961	5,843	7,229	6,647	6	17	7	7	5	1	1	0	2	0	0	0	2	0	1	0

The number of monthly frequency events with deviations between 0.03 Hz and 0.1 Hz is shown in Figure 2 for the HECO system for years 2010 and 2011. Under-frequency or over-frequency deviations of this magnitude usually result in AGC being switched to frequency regulation control ignoring economic operation (HECO, 2011).

The results of the frequency data analysis show that the number of under and over frequency events corresponding to deviations in the range between 0.03 Hz and 0.1 Hz has increased from 2010 to 2011. July 2011 was the month with the highest number of under-frequency events in this range, while November 2011 was the month with the most over-frequency events observed. Every month in 2011 has a higher number of events compared to the same month in 2010. The number of events observed in December 2011 is comparable to the December 2010 events, which is contrasted with the sharp increase observed from the first six months of 2011 to the first 6 months of 2010.

[4] One event refers to a frequency deviation that reaches corresponding threshold and returns to normal operating frequency values without regard of duration. Thus, one event is not equivalent to one 2-second sample but multiple consecutive 2-second samples. This table does not provide information about the duration of the events.
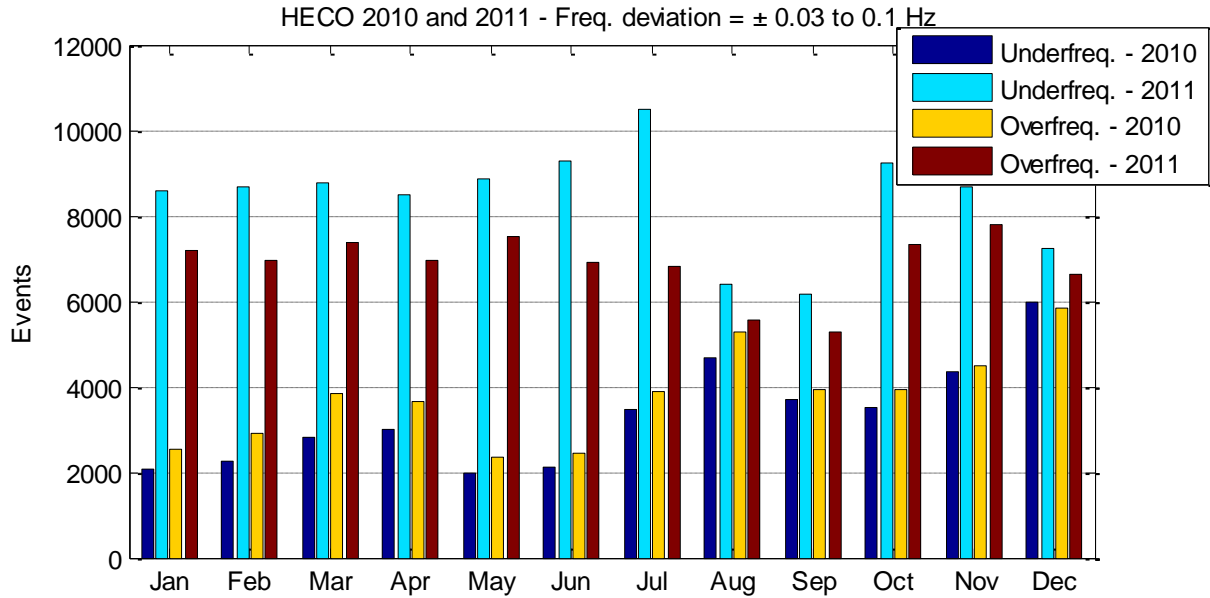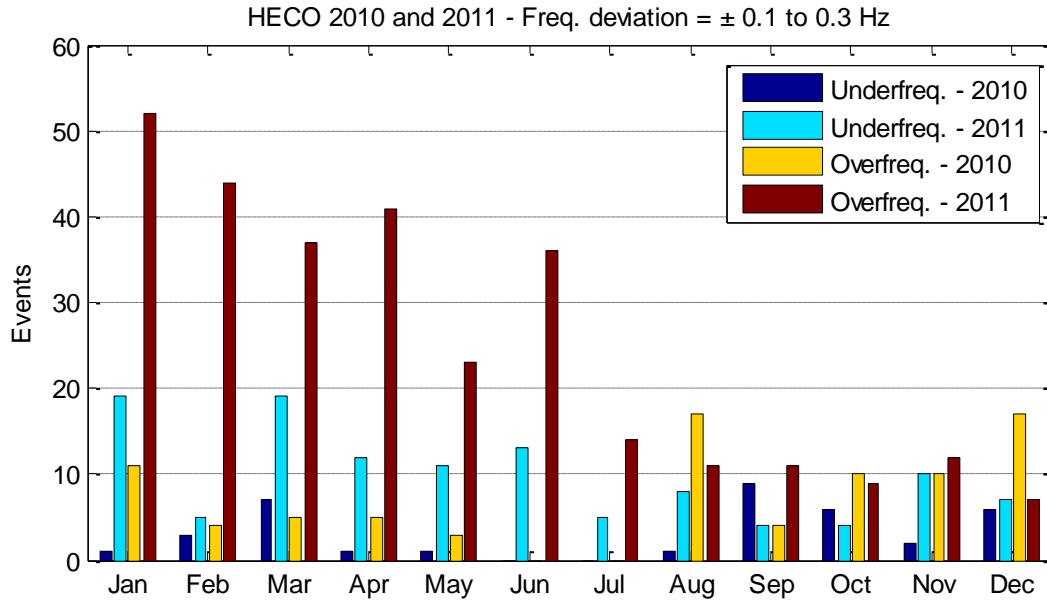
Figure 2: Number of events with frequency deviations between 0.03 Hz and 0.1 Hz in the HECO system in 2010 and 2011

The number of monthly frequency events with deviations between 0.1 Hz and 0.3 Hz is shown in Figure 3 for the HECO system for years 2010 and 2011. Under-frequency or over-frequency deviations of this magnitude result in internal and external frequency alarms being issued (HECO, 2011).

An increase in the total number of under-frequency and over-frequency events with deviations in the range of 0.1 Hz to 0.3 Hz is observed from 2010 to 2011. However, when comparing the same months in years 2010 and 2011 there was a sharp increase in the number of events at the beginning of 2011 compared to number of events in 2010, while the number of events in the last five months is similar. This sharp increase is particularly noticeable in over-frequency events.

Figure 3: Number of events with frequency deviations between 0.1 Hz and 0.3 Hz in the HECO system in 2010 and 2011
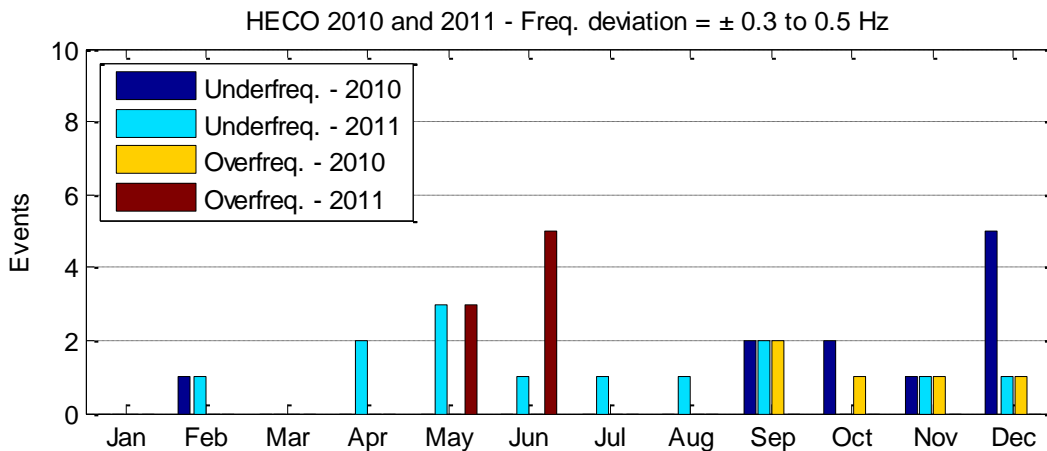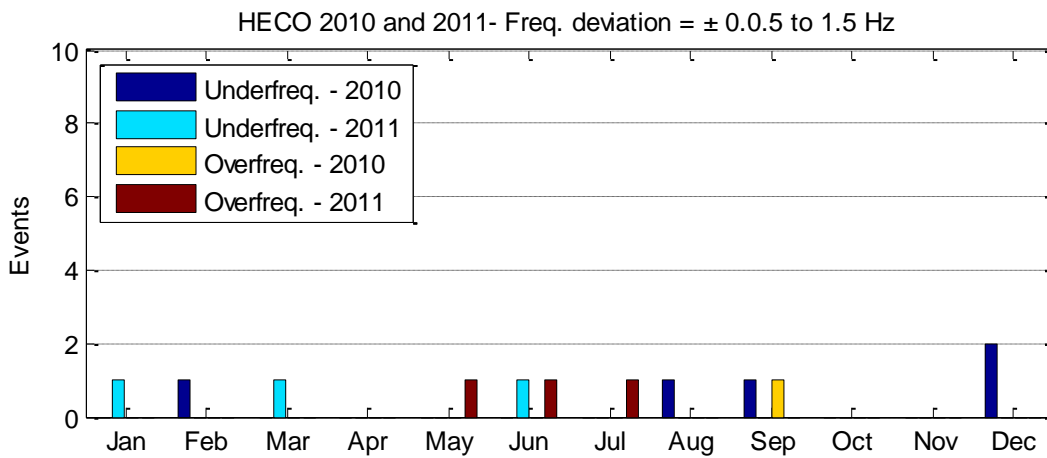
The number of monthly frequency events with deviations between 0.3 Hz and 0.5 Hz is shown in Figure 4 for the HECO system for years 2010 and 2011. Under-frequency deviations of this magnitude (i.e., from 59.5 to 59.7 Hz) result in automatic under-frequency load shedding from the load management program. The number of under-frequency and over-frequency events that falls within these boundaries is comparable for the years 2010 and 2011.

Figure 4: Number of events with frequency deviations between 0.3 Hz and 0.5 Hz in the HECO system in 2010 and 2011

The number of monthly frequency events with deviations between 0.5 Hz and 1.5 Hz is shown in Figure 5 for the HECO system for years 2010 and 2011. When the frequency deviation falls in this range (i.e., 58.5 to 59.5 and 60.5 to 61.5 Hz for under and over-frequency, respectively) generators are switched from AGC to local frequency control for emergency ramping.

Similar trends in the number of events for the years 2010 and 2011 are observed in the HECO system. There are a total of six events in each year. The main difference is that in 2010 the number of under-frequency events was higher than in 2011.

Figure 5: Number of events with frequency deviations between 0.5 Hz and 1.5 Hz in the HECO system in 2010 and 2011

The number of monthly frequency events with deviations greater than 1.5 Hz is shown in Figure 6 for the HECO system for years 2010 and 2011. Under-frequency deviations of this magnitude (i.e., frequency lower than 58.5 Hz) result in automatic under-frequency load shedding of curtailable loads and generators starting to trip as frequency declines. Over-frequency deviations of this magnitude (i.e., frequency higher than 61.5 Hz) result in generators switching controls to avoid over-speed.

The last two months of 2011 presented under-frequency events of this magnitude. Unfortunately the number of samples presented below is insufficient to determine if this is a signal of this type of events occurring more often.
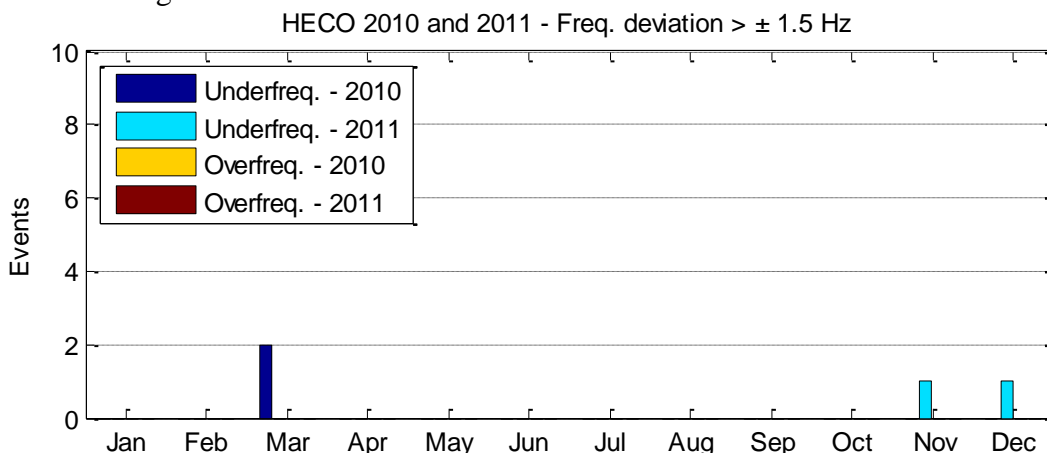
Figure 6: Number of events with frequency deviations greater than 1.5 Hz in the HECO system in 2010 and 2011

2. MECO Data

A summary of the total number of events in the MECO system is found in Table 3. The under-frequency (U) and over-frequency (O) events are given by year and frequency thresholds.

Table 3: Summary of events in the MECO system[5]

	±0.03 - 0.1 Hz				±0.1 - 0.3 Hz				±0.3 - 0.5 Hz				±0.5 - 1.5 Hz				≥ ±1.5 Hz			
	2010		2011		2010		2011		2010		2011		2010		2011		2010		2011	
	U	O	U	O	U	O	U	O	U	O	U	O	U	O	U	O	U	O	U	O
Jan	8,869	7,970	2,335	1,662	54	16	22	16	4	1	1	1	4	0	1	0	0	0	1	0
Feb	7,994	7,207	757	545	40	14	11	9	2	0	1	0	0	1	2	0	0	0	0	0
Mar	12,525	11,779	2,939	2,196	191	65	24	21	2	2	2	2	5	0	1	0	0	0	0	0
Apr	10,474	9,304	2,392	2,114	42	15	16	10	1	0	0	1	4	0	1	0	0	0	0	0
May	11,692	11,021	2,561	2,163	99	26	24	11	2	0	2	0	0	0	0	0	0	0	0	0
June	20,430	20,438	4,826	4,011	342	137	44	15	8	0	3	0	7	3	2	0	0	0	0	0
July	18,356	15,866	4,299	3,227	120	28	48	33	4	1	1	0	0	0	0	0	0	0	0	2
Aug	18,924	17,358	4,861	3,685	305	143	21	9	9	3	3	0	1	0	1	0	0	0	0	0
Sep	13,903	12,408	4,445	3,568	115	24	37	32	4	2	2	3	1	0	2	0	0	0	0	0
Oct	9,080	7,109	4,755	3,653	41	19	29	10	4	0	2	0	5	2	0	0	0	0	0	0
Nov	2,033	1,556	4,886	2,626	15	11	30	11	1	1	1	0	4	1	1	0	0	0	0	0
Dec	1,337	1,051	23,947	1,501	13	5	47	12	0	1	0	3	0	0	0	1	1	1	0	0

The number of monthly frequency events with deviations between 0.03 Hz and 0.1 Hz is shown in Figure 7 for the MECO system for years 2010 and 2011. This corresponds to frequencies between 59.9 to 59.97 Hz for under-frequency and 60.03 to 60.1 Hz for over-frequency. The plot shows that the number of under-frequency and over-frequency events in this range has decreased from 2010 to 2011.

Another important observation is that the number of events in the MECO system in the year 2010 is very high when compared to the events observed in the HECO system. For the year 2011 the number of events in the MECO system is similar to that observed in the HECO system. This is true for all frequency deviations plotted below.

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[5]The data points shown in red were identified by MECO as being invalid late in the course of the study, and have been removed from further review and analysis in this report.
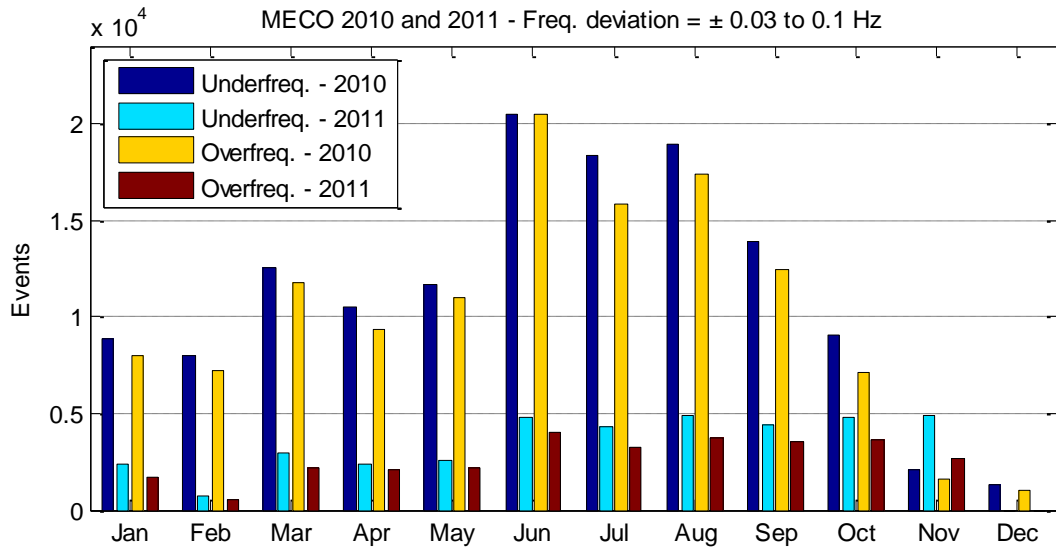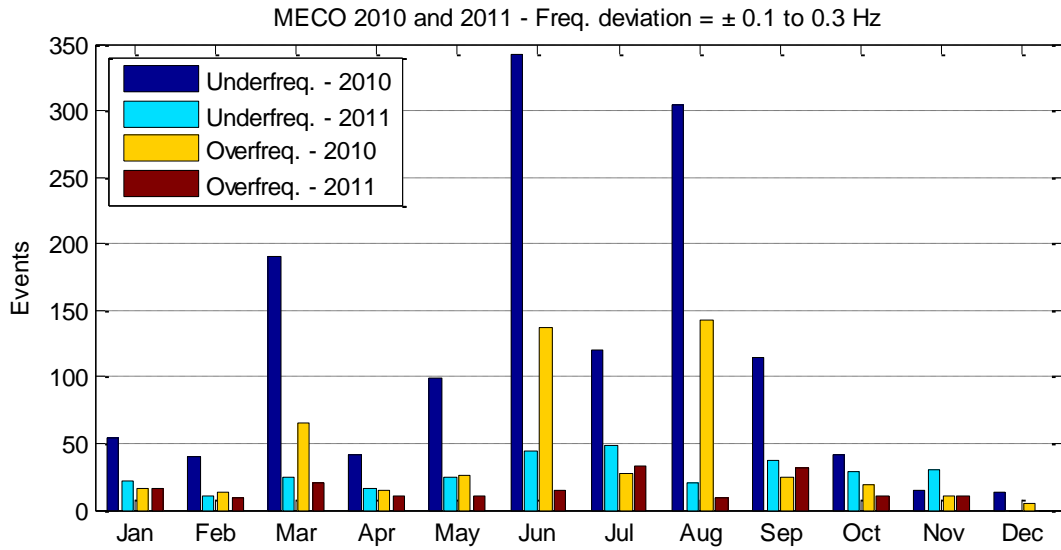
Figure 7: Number of events with frequency deviations between 0.03 Hz and 0.1 Hz in the MECO system in 2010 and 2011

The number of monthly frequency events with deviations between 0.1 Hz and 0.3 Hz is shown in
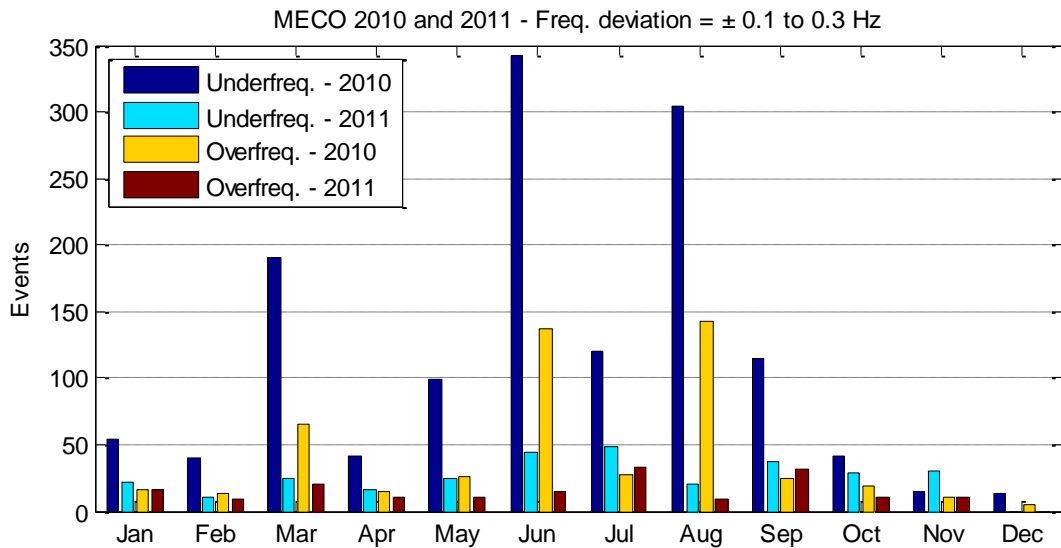
Figure 8 for the MECO system for years 2010 and 2011. This corresponds to frequencies between 59.7 to 59.9 Hz for under-frequency and 60.1 to 60.3 Hz for over-frequency.

As in the previous case, the total number of under-frequency and over-frequency events in this range decreased from 2010 to 2011.

MECO 2010 and 2011 - Freq. deviation = ± 0.1 to 0.3 Hz

Figure 8: Number of events with frequency deviations between 0.1 Hz and 0.3 Hz in the MECO system in 2010 and 2011.

The number of monthly frequency events with deviations between 0.3 Hz and 0.5 Hz is shown in

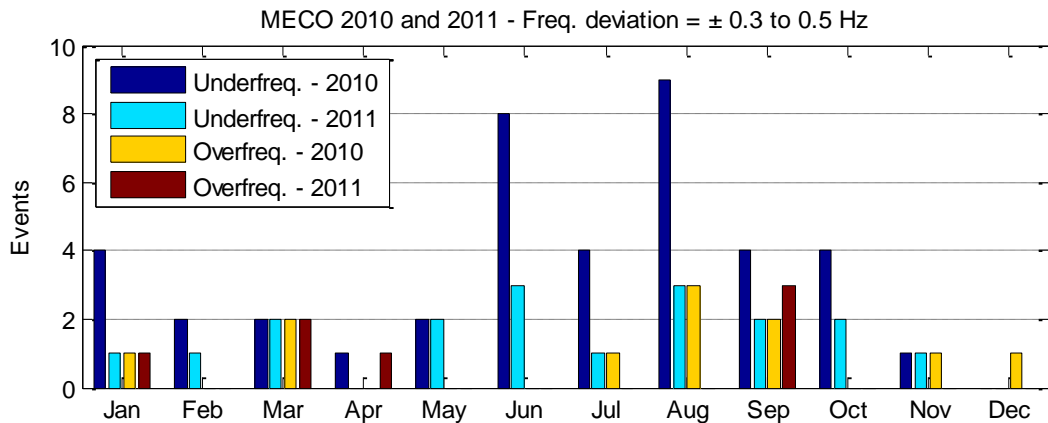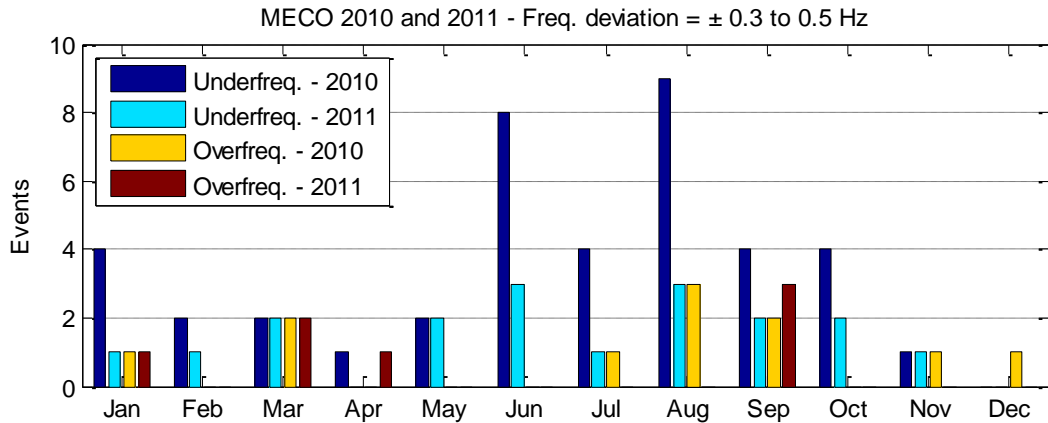MECO 2010 and 2011 - Freq. deviation = ± 0.3 to 0.5 Hz

Figure 9 for the MECO system for years 2010 and 2011. This corresponds to frequencies between 59.5 to 59.7 Hz for under-frequency and 60.3 to 60.5 Hz for over-frequency. The plot shows that the number of events for this frequency range decreased from 2010 to 2011.

Figure 9: Number of events with frequency deviations between 0.3 Hz and 0.5 Hz in the MECO system in 2010 and 2011

The number of monthly frequency events with deviations between 0.5 Hz and 1.5 Hz is shown in
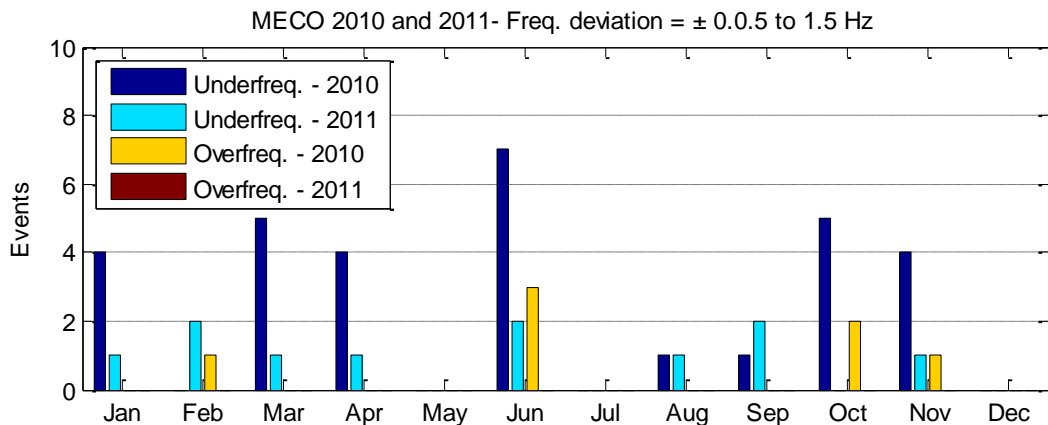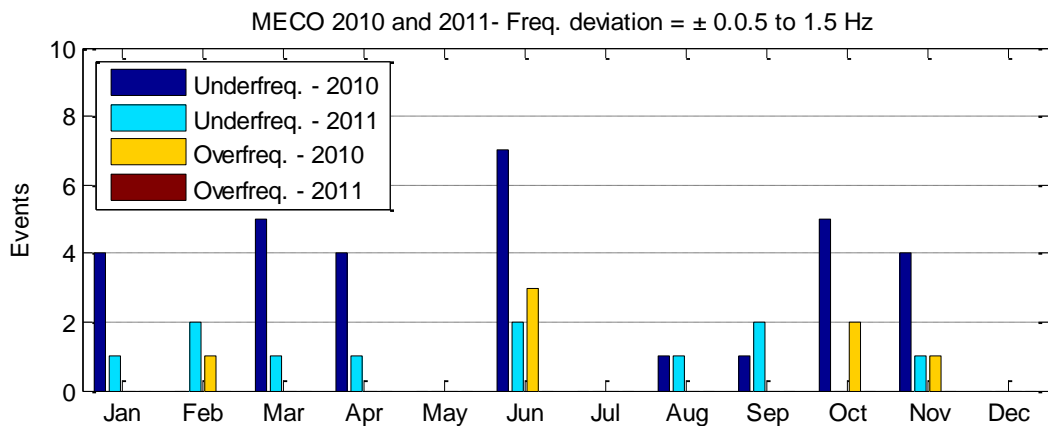

Figure 10 for the MECO system for years 2010 and 2011. This corresponds to frequencies between 58.5 to 59.5 Hz for under-frequency and 60.5 to 61.5 Hz for over-frequency. The plot shows that there was a reduction in the number of events in this frequency deviation range.

Figure 10: Number of events with frequency deviations between 0.5 Hz and 1.5 Hz in the MECO system in 2010 and 2011

The number of monthly frequency events with deviations greater than 1.5 Hz is shown in Figure 11 for the MECO system for years 2010 and 2011, respectively. This corresponds to frequencies lower than 58.5 Hz for under-frequency and higher than 61.5 Hz for over-frequency. The plot shows that the number of severe under-frequency and over-frequency events is similar in 2010 and 2011.
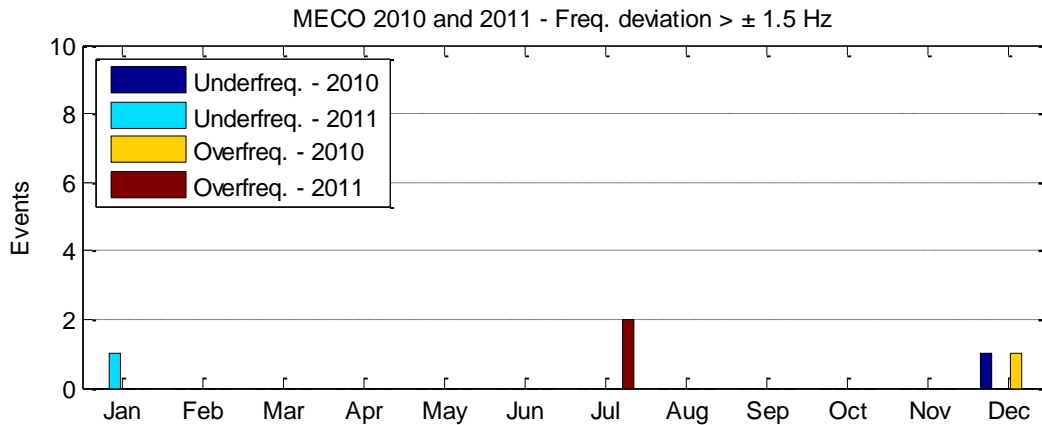
Figure 11: Number of events with frequency deviations greater than 1.5 Hz in the MECO system in 2010 and 2011

IV.   ECONOMIC PERSPECTIVES ON ELECTRIC GRID RELIABILITY

Most of the previous discussion relates to grid reliability measurement in the short-term with existing capacity and resources determined and unchangeable. Not only is the focus of the previous discussion short-term it is completely supply side centric. The issue of optimal reliability is not addressed. In contrast, much of the reliability economics literature pertains to the determination of the optimal level of reliability as desired by electric consumers. This literature is summarized in Appendix E. The incorporation of consumers' views of reliability value into the determination of optimal reliability requires that means are available to quantify this value. Three general techniques for quantifying consumers' values of reliability have been used:

- Market based methods attempt to examine actual customer behavior in response to various service options or investments in reliability to infer customer outage costs as evidenced by customers who sign up for non-firm service rates or install backup generation;
- After the fact measurement of actual outages that have occurred;
- Survey methods use customer responses to postulated outage scenarios to measure outage costs.

Many utility efforts to evaluate the outage costs of their customers have employed survey techniques most frequently and have attempted to elicit responses to:

- Direct costs: customer incurred costs of an outage of specified duration and advance warning time;
- Willingness to pay: customer outlay to avoid an outage of specified duration and advance warning time;
- Willingness to accept: payment received from utility to compensate for an outage of specified duration and advance warning;
- Revealed preference: question elicits customer response regarding specified combinations of increasing price (electric rates) and reliability (reduced outages);

Surveys are popular with utilities because they allow the utility to focus on the particular preferences of their customers and the unique outage and operating characteristics of their utility systems.[6]

An integrated reliability planning conceptual model presented by (Burns and Cross, 1990) is shown in Figure 12. Total system cost, C_{total}, is the sum of system costs, C_s, and outage costs, C_o. Outage costs decline as the level of reliability increases. Correspondingly, system cost increases as investments to achieve increased reliability are made. Other things equal the optimal level of reliability occurs where the marginal increment to system costs needed to achieve an increment to reliability is equal to the incremental decrease in outage costs resulting from this level of

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[6] In contrast, survey methods are not popular with economists, although they are sometimes used. The concern is that consumers will respond to hypothetical questions by interpreting what they believe the interviewer wants to hear, or, based on their supposition of the reason the question is being posed. Or, consumers might try to game the outcome of the survey.

reliability. While it is difficult to discern from the drawing this would occur at the minimum point of the total cost curve.
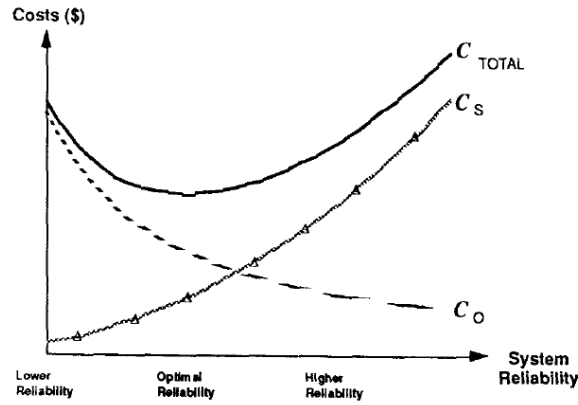
Figure 12: Hypothetical Outage, System, and Total Cost as Functions of Reliability Level

Increased reliability requires increased capacity (larger reserve margin) which increases system costs; but outage costs decline with increased reserve margin, leading to the model shown. A simple mathematical model is derived from specification of these concepts and is manipulated to express marginal changes in expected unserved energy for marginal changes in capacity. This model is reproduced herein with some minor differences in notation.

An aspect of electric system reliability is that, while the regulated utility does not experience directly the costs of outages, its customers do. The utility regulatory commission internalizes the utility customers' costs; but it also internalizes the interests of the subject of its regulation—the utility. Hence, it is appropriate to develop a model that addresses both. An available model results in a reasonably simple framework within which to operationalize the determination of optimal reliability from an engineering-economic standpoint. This model employs the fact that reliability is functionally related to two dependent variables—system costs and outage costs. Reliability is a function of the amount of capacity on the system in relation to peak load. More capacity increases system costs but reduces outage costs. Since these dependent variables are inversely related an optimal capacity (from the societal point of view) can be determined by the capacity that equalizes incremental capacity costs and incremental outage cost reduction.
Total cost for electric service, TC, is determined by system costs, c_s , and outage costs, c_o. System costs include capacity, operation and maintenance, and all other costs to supply energy. Outage costs include costs customers incur during an interruption of service including lost output in all sectors as well as spoiled inventories. This yields,

$$TC = c_s + c_o. \tag{14}$$

Reserve is related to capacity of resources on the system and the peak system load at any point in time as follows

$$R = A - L \tag{15}$$

where R is the margin of reserves, A is the available capacity to meet load and L is peak system load where it is assumed that this is the annual peak load. R, A, and L are all considered random variables. A reliability event takes place whenever L exceeds A and R becomes negative. One measure of the frequency with which this happens (or could happen) is the loss of load probability (LOLP), a statistical measure, as implied by its name. This can be expressed as

$$\boldsymbol{LOLP} \ = \ \boldsymbol{p} \ (\boldsymbol{R} < \boldsymbol{0}), \tag{16}$$

where p denotes probability.

When R becomes negative load shedding, brownouts, or blackouts occur all of which result in some quantity of unserved energy which we designate as u. Then,

$$\boldsymbol{u} \ = \ \boldsymbol{E} \ (\boldsymbol{R} \ < \boldsymbol{0}), \tag{17}$$

where E is interpreted as expectation.

An operational rule of thumb has arisen through repeated use of the reserve margin as a static, point-estimate of system reliability. It is related to R as defined above but is not, strictly, a statistical measure. Using this point estimate we can redefine (17)

$$\boldsymbol{m} \ = \ \boldsymbol{a} - \boldsymbol{l} \tag{18}$$

where a is the total capacity of resources available to meet load and l is the system highest peak load. Equation (18) is closely related to (15) and is the point estimate drawn from a statistical distribution.

For the time period under consideration a is the total quantity of resources available and l is the maximum value of the load random variable. As in equation 4 above, u is related to and, more strongly, a function of m. Any addition of capacity or reduction of peak load increases the reserve margin. As m increases $u(m)$ decreases. Determination of the optimal m, m^* requires the inclusion of outage costs. One interesting feature of this model to note is that there are then, in effect, two options to improve reliability—installing additional capacity and/or reducing peak load. These two options can be operated upon independently. Thus, optimality includes consideration of which of the two options is least expensive to implement. More than likely, at least up to some level of reduction, load shifting from the demand side has the prospect of being more cost effective purely because there is no, or very little, additional capital investment required.[7]

We can now relate marginal capacity to the reserve margin, m. Designate s as marginal capacity cost per MW and let q denote a unit of outage cost represented in units of MWh. Then, assuming that the function u can be evaluated the following can be defined.[8]

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[7] Selective load reduction can be implemented administratively with large electric consumers who could be induced to shift electricity consumption by a variety of financial payments. A fully integrated retail market would require the installation of significant additional infrastructure as is being discussed in Smart Grid programs.

[8] The function can be evaluated either analytically if it is assumed to be continuous and differentiable or can be assessed by "differencing" as suggested by the Burns and Cross.

$$d(m) = \partial u / \partial m, \forall\, m. \tag{19}$$

In utility operational practice system operators will invoke emergency actions to avoid allowing operating reserves to fall to zero. These actions are initiated sequentially presumably in ascending order of cost and include shedding interruptible customers, voltage reductions, and customer appeals for load reduction. The final action is implementation of rotating outages. With each action, i corresponding expected unserved energy u_i can be interpreted as the energy "supplied" but the emergency actions, i. With I emergency actions, the ith being that of rotating blackouts, we can write

$$u = \sum_{i=1}^{I} u_i \tag{20}$$

Then the marginal reduction in outage cost defined in 6 becomes

$$\sum_{i=1}^{I} \frac{\partial u_i}{\partial m}, \forall m = \sum_{i=1}^{I} d_i\,(m) \tag{21}$$

where $d_i(m) = \partial u_i / \partial m$. This expression can be evaluated analytically or by a differencing approach.

The costs per unit of unserved energy, q_i, resulting from each emergency action i are required to complete the model. Then, at the optimal value of m designated as m^*, the following relationship holds,

$$s = \sum_{i=1}^{I} q_i d_i\,(m^*). \tag{22}$$

As mentioned, the evaluation of $d_i(m^*)$ is available from a probabilistic reliability framework or from production cost models. One method of estimating electric consumer outage costs is described below.

With estimates of the value of service to customers, expected unserved energy (kWh) can be converted to dollar values. This process can be carried out explicitly in a production cost modeling framework. Estimated values of service obtained by PG&E for their customer classes are shown in Table 4 Similar techniques could be employed by HECO to estimate customer outage costs by customer class.

Table 4: Direct Cost of a Summer Afternoon Outage with 1 Hour Notice

Customer Class	Average Outage Cost (1988 $/kWh)
Residential	4.05
Commercial	39.69
Industrial	6.78
Agricultural	3.53
System Weighted Average	18.63

Using the derived model and customer outage costs estimates as shown Figure 12 the authors are able to derive a relationship such as that shown in Figure 13.
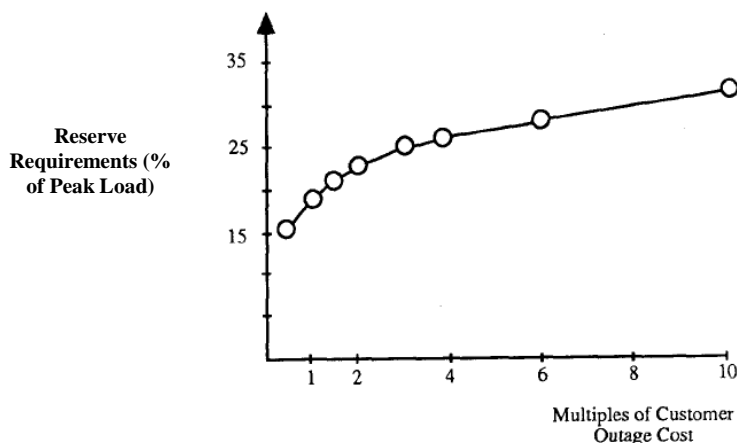
Figure 13: Variation of Reserve Requirements with Respect to Customer Outage Costs[9]

Several interesting observations emerge from this paper. First, the significantly higher outage cost estimates for the commercial sector are notable as compared to all other customer categories that are somewhat closely grouped. While it could be expected to be somewhat higher, to have it be so much greater than the other sectors is surprising. Further, these data are from 1988 so clearly they would not reflect current economic values. Furthermore, there may be economic and social changes that affect the outage costs as seen by consumers. For example, our economy has become significantly more service than manufacturing based. And there might be significantly more home production (telecommuting) today than in earlier years that would increase these customers' views of outage costs. Finally, because we don't include the value of output of "true" home production services (child care, home schooling, grocery shopping, food preparation, cleaning services, etc.) in the national accounts, customers whose households consist of stay-at-home moms and dads may undervalue the cost of outages. These observations suggest that periodic administration of outage surveys and re-estimation of customer outage costs should be performed by utilities. One of the points that Turvey made in his book on electricity economics is that service reliability must be the same for all customers. Burns and Cross also emphasize that their model is based on the assumption of equivalent reliability and cost for all customers. However, they point out that, because customers have distinct needs, a system of uniform power supply reliability is not the most economical means to meet individual needs. And we know from practice that all customers do not, in fact, receive the same level of reliability due to local system effects and differences.

A. Looking Forward

The new focus of reform efforts in the electric industry is to introduce and diffuse market competition as the means of allocating resources needed to supply electricity to customers. Much of this effort is currently focused on the supply side and the introduction and refinement of wholesale markets for electricity supply. Meanwhile, increased interest is evident toward development of retail markets and integration of these markets with the wholesale markets.

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[9] Burns and Cross, 1990

Towards this end there is increased focus on "demand response" as a form of load balancing. The understanding that both demand and supply have the potential to work in concert to balance system supply and demand and can help to improve capacity utilization for the supply system as well as keep electric rates (prices) lower for customers. The concurrent interest in Smart Grid that would provide the platform for customers to express their demand schedule for electricity supports this wholesale/retail market integration. A number of states including Texas and states in the PJM area have programs to elicit demand response. It is possible in this broadened environment to envision a market for reliability that would allow consumers to specify their requirements for power quality. These trends are congruent with observations and findings of market designers who have a goal of making electric power markets more efficient and effective.

(Hogan, 2005) has made the case that reliability levels must be worked out in a market in which every consumer has the option to participate. He brings the value of lost load (VOLL) back into the discussion. (Cramton and Stoft, 2011) have stated this more explicitly: "If reliability is not individualized then individuals know that they will not receive less reliability if they pay less for it, because they can be given less only if everyone is given less. Consequently, everyone will refuse to pay for collective reliability and all will attempt to enjoy a free ride." (p. 24.)

V.   INTEGRATED RELIABILITY INDEX

NERC is developing an integrated reliability index aimed at increasing the transparency of the reliability assessment process. This integrated risk index (IRI) tries to include all aspects of the reliability assessment process and combine them to produce a single number ranging from 0 to 100. This single number indicates the historical risk found in a power system based on three main characteristics: major system events experienced, conditions that indicate if an adequate level of reliability has been attained, and compliance to reliability standards (NERC, 2012).
A review of the integrated risk index calculation proposed by NERC was performed by David Robinson (Robinson, 2011). His findings suggest that there is no connection between the metric proposed by NERC and changes made to a power system in order to improve reliability. This review is found in Appendix D.

VI. FINDINGS AND RECOMMENDATIONS

This report has begun the process of examining reliability benchmarks and metrics for Hawaii. Further work could fruitfully be performed to further this process and institutionalize it within the Hawaii electricity regulatory framework. In particular, the HI PUC could create standards that require electric utilities in Hawaii to supply to the PUC or a reliability regulatory body, the raw data necessary to perform a complete reliability analysis, plans for maintaining reliability within their systems and other relevant information, as described in the review of NERC reliability standards section.

A. Findings

Reliability has short-term and long-term dimensions. In the short-term, when capacity of the system cannot be changed, and load is what it is, the presumption is that the system is operated in an optimal fashion so that total cost, comprised of system cost and outage cost, is minimized. This means that regular maintenance schedules are adhered to, and other activities are undertaken to ensure that the system is maintained in an operable condition. In the long-term, when system capacity can be changed, a different reliability target—*ex ante* reliability—can be established. This is the point at which customer input becomes important.

Increasing reliability comes down to increasing the amount of available, unused capacity on the system and this comes down to a dollars and cents issue. Since each island is a separate system different levels of reliability may be warranted on different islands. For example, on more rural islands such as Kauai a lower level of reliability may be an economical choice. On Oahu, with its fairly large commercial sector, reliability standards might economically be higher. Because of the geography of the islands and the possibility that customers on different islands may view reliability differently, there may be the opportunity to reflect these differences in different reliability standards. It is likely that surveys of customers on the different islands would be helpful to make these comparisons and determinations. It's clear from all of the literature that specification of optimal reliability requires some sort of input from electric consumers. Different reliability standards for different islands would need to be supported by different electric rates or prices—lower rates for places with lower reliability standards and *vice versa* for other islands.

B. Reliability Recommendations for Hawaii

The following are a set of recommendations based on the contents of this report. These recommendations are aimed at providing the HI PUC a perspective on current reliability practices and how they could be applied to electric systems in Hawaii.

- An independent body that oversights, takes part in the reliability evaluation process, collaborates and communicates with the electric utilities in Hawaii should be created.
- Renewable resources are a significant segment of the generation mix. Thus, resource adequacy should be adapted to include renewable energy sources. This can be done using their capacity value based on their statistical properties as explained in the discussion of ELCC.
- Given the small size of the electric systems in Hawaii, implementation of an economic survey to accurately represent the value of reliability is a feasible option. The results of such economic survey will help identify the optimal cost of reliability.

- NERC control performance standards (CPS1 and 2) can be relaxed and applied in the Hawaii electric systems. Because of the islanded nature of these systems, frequency can serve as a good proxy to evaluate the response of the system to different contingencies.
- NERC reliability standards that can be implemented in Hawaii were reviewed. These standards should be adjusted and gradually adopted by the HPUC in order to increase the use of reliability metrics, methods and policies. As more data is gathered, a better understanding the critical factors that affect reliability in Hawaii will be achieved.
- Hawaii electric utilities, the HPUC, Independent Power Producers (IPPs) and other stakeholders have been active in a process called the Reliability Standards working Group (RSWG), with a goal of evaluating the existing utility operations and developing reliability metrics and policies. Their combined experience with implementation of reliability metrics, and their knowledge of the power system can be leveraged for adjusting NERC reliability standards, methods and policies to Hawaii, and for developing new metrics and policies that address problems specific to the Hawaiian electric systems. Hence, collaboration between the HPUC, the electric utilities, IPPs, and other stakeholders is essential to achieving meaningful reliability metrics.
- Develop a model incorporating HI system costs together with outage costs and, using appropriate parameters, make estimates for optimal long term investment to achieve desired reliability.
- Undertake surveys or otherwise develop outage cost and estimates of the value, to HI electric customers of various levels of reliability of service.

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APPENDIX A – NORMAL AND EMERGENCY CONDITIONS AS DEFINED BY NERC

Transmission System Standards – Normal and Emergency Conditions from page 950 of NERC, 2011.

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

APPENDIX B -OTHER DISTRIBUTION RELIABILITY INDICES

Sustained Interruption Indices

Customer Total Average Interruption Duration Index (CTAIDI): This index indicates the average time that a customer who experienced a sustained interruption was without power over the time interval under study. It is calculated as:

$$CTAIDI = \frac{\sum Customer\ interruption\ duration}{Total\ number\ of\ customers\ interrupted}$$

The indices CTAIDI and CAIDI are very similar. The difference is that in CTAIDI customers with multiple service interruptions are counted only once.

Customer Average Interruption Frequency Index (CAIFI): This index represents the average frequency of a sustained interruption seen only by customers who have experienced sustained interruptions. It is expressed mathematically as:

$$CAIFI = \frac{\sum Total\ number\ of\ customers\ interrupted}{Total\ number\ of\ customers\ interrupted}$$

Customers who have experienced multiple service interruptions are counted just once for this calculation.

Load Based Indices

Average System Interruption Frequency Index (ASIFI): This index gives serves as a performance indicator of distribution system performance in areas where industrial and commercial loads are predominant. It is expressed mathematically as:

$$ASIFI = \frac{\sum Total\ connected\ kVA\ of\ load\ interrupted}{Total\ connected\ kVA\ served}$$

In a system with homogeneous load distribution (i.e. kVA load is equal for all customers) ASFI would be equal to SAIFI.

Average System Interruption Duration Index (ASIDI): This index measures the average interruption duration based but as a function of the installed load in the system as opposed to the number of customers.

$$ASIDI = \frac{\sum Connected\ kVA\ duration\ of\ load\ interrupted}{Total\ connected\ kVA\ served}$$

Other Indices (Momentary)

Momentary Average Interruption Frequency Index (MAIFI): This index is the average frequency of momentary interruptions seen by one customer. It is expressed mathematically as:

$$MAIFI = \frac{\sum Total\ number\ of\ customer\ momentary\ interruptions}{Total\ number\ of\ customers\ served}$$

Momentary Average Interruption Event Frequency index (MAIFI$_E$): This index measures the frequency of events that result in momentary interruptions. It is expressed mathematically as:

$$MAIFI_E = \frac{\sum Total\ number\ of\ costumer\ momentary\ interruption\ events}{Total\ number\ of\ customers\ served}$$
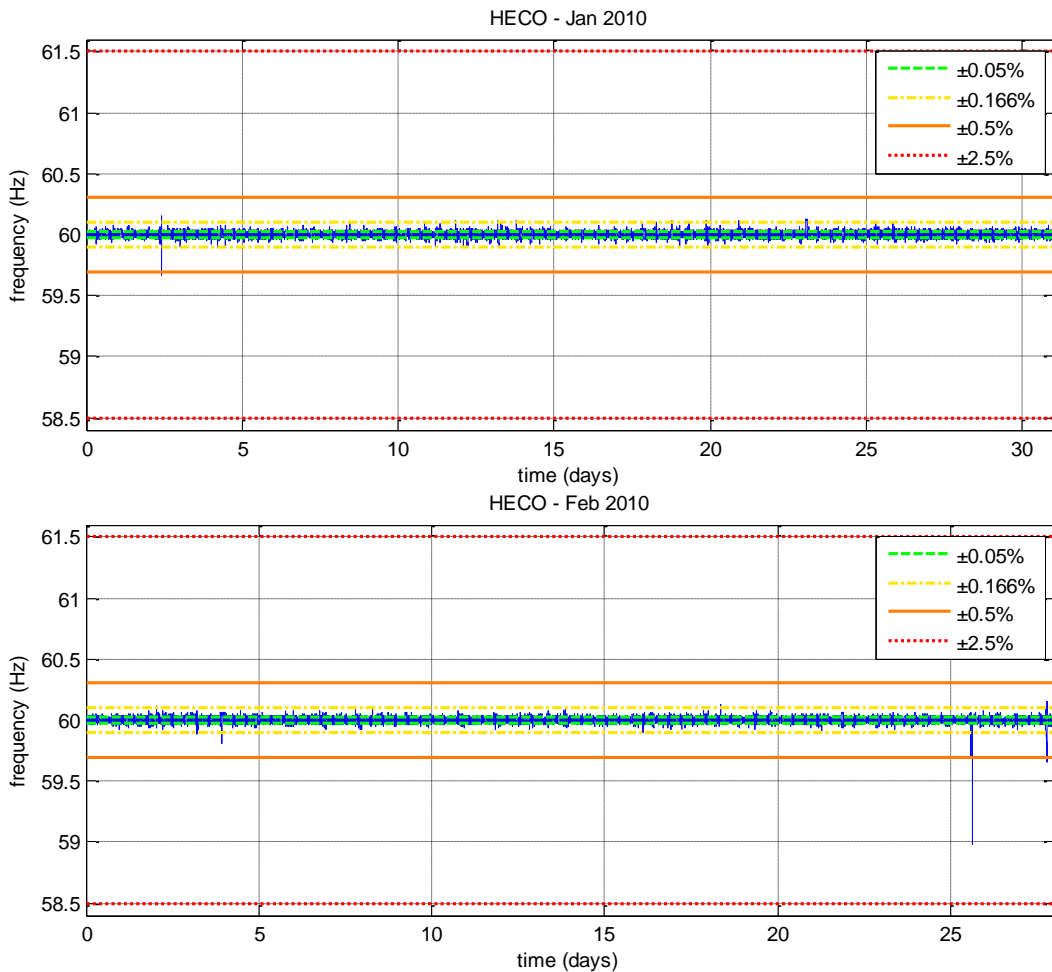
Customers Experiencing Multiple Sustained Interruption and Momentary Interruptions Events (CEMSMI$_n$): This index calculates the fraction of customers that have experience more than n momentary and sustained service interruptions from the total number of customers being served. It is expressed mathematically as:

$$\text{CEMSMI}_n = \frac{\text{total numberf of customers experiencing more than } n \text{ interruptions}}{\text{Total number of customers served}}$$
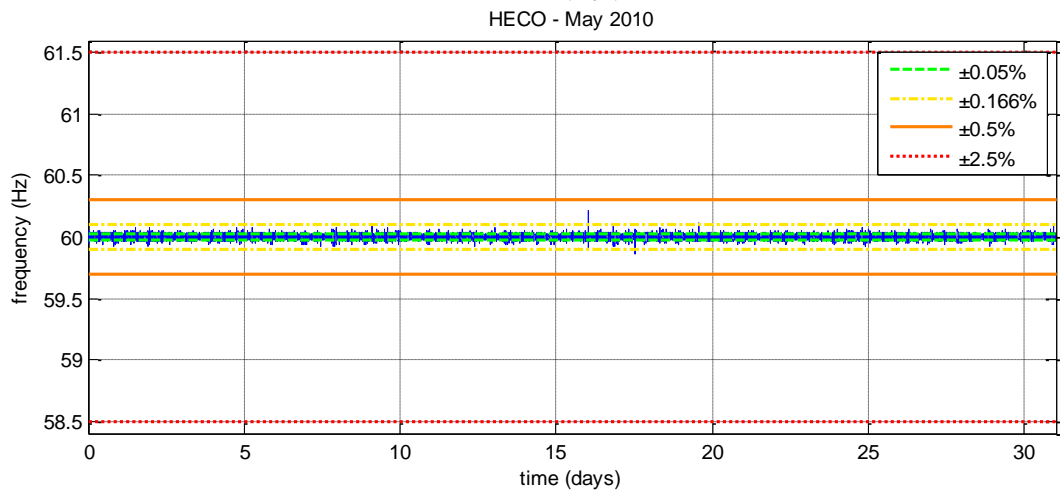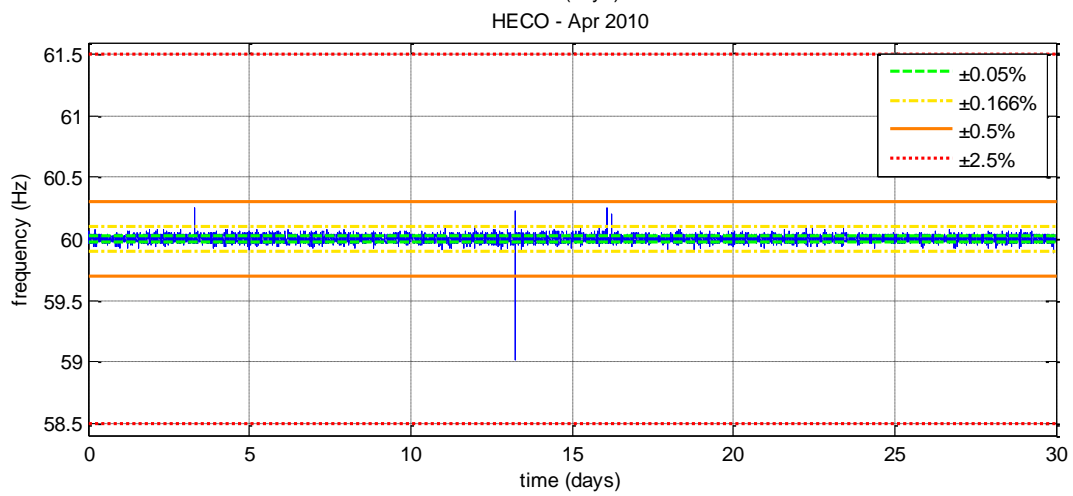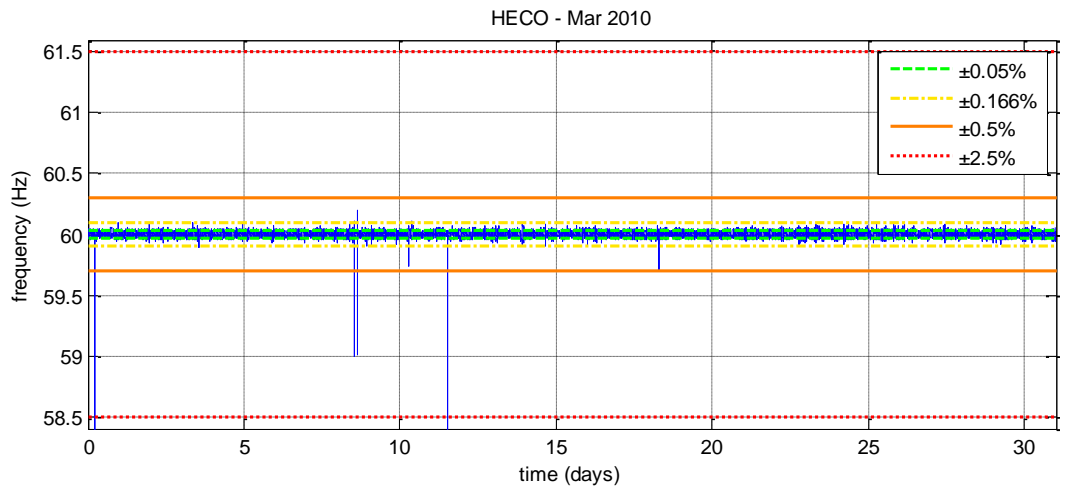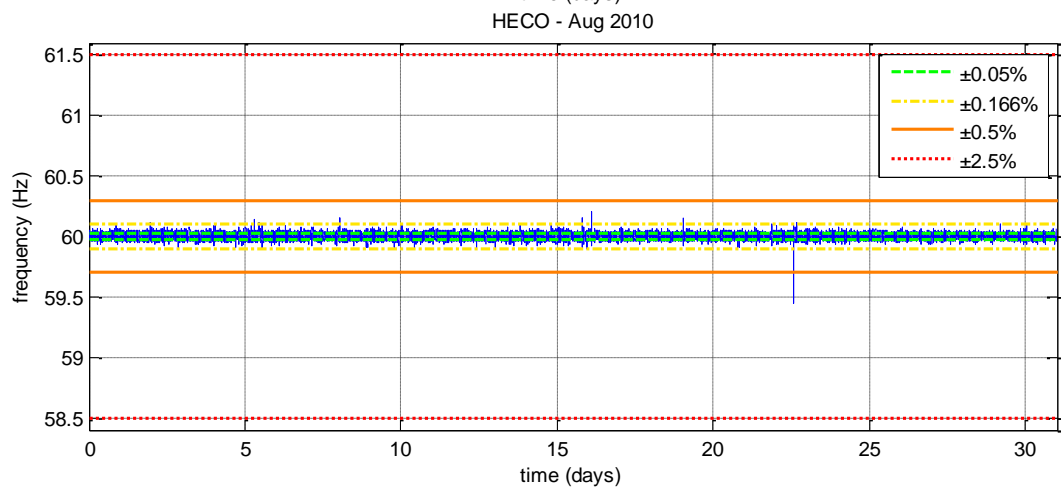
APPENDIX C – TIME SERIES OF FREQUENCY DATA
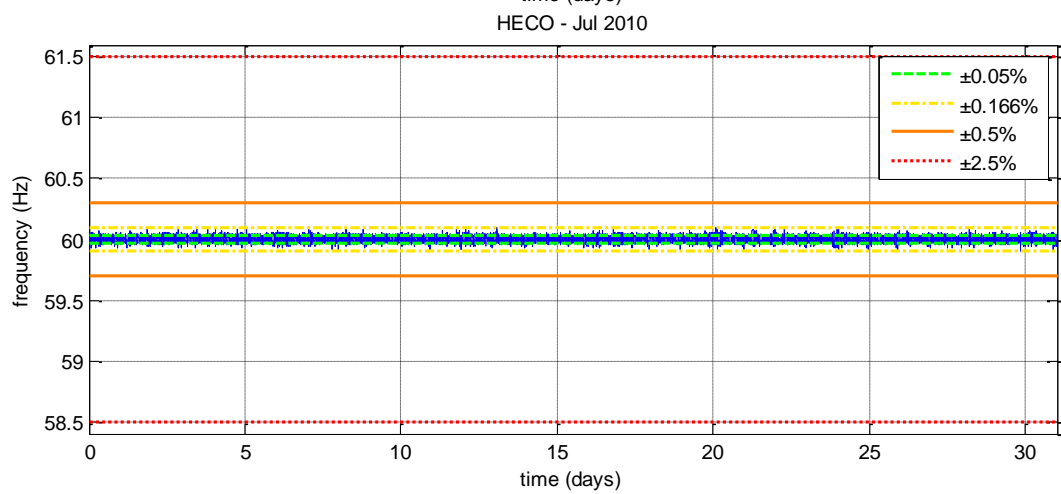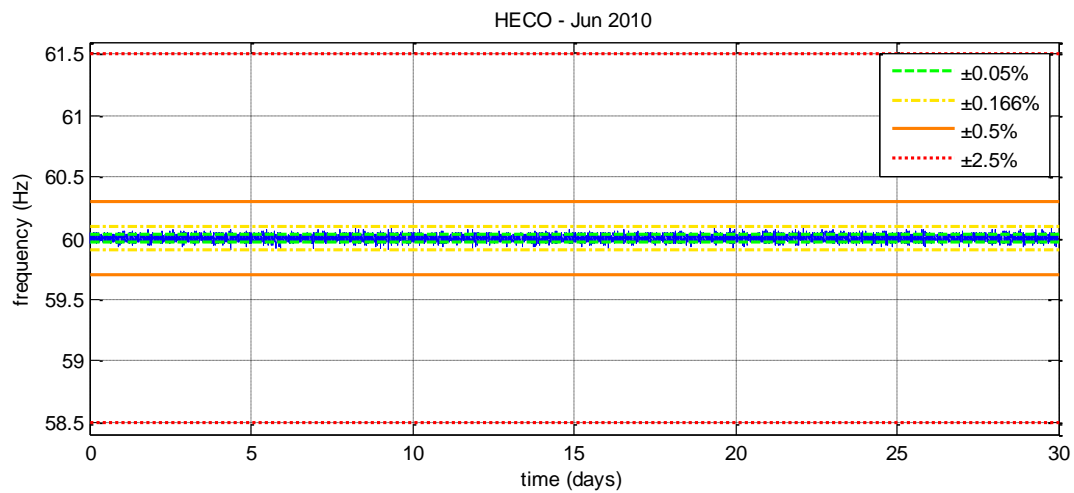
Monthly plots of frequency data time series. Two thresholds are also plotted. The tighter green (± 0.03 Hz) thresholds around 60 Hz correspond to the frequencies at which the AGC is off economic frequency regulation control modes. The looser yellow (±1.5 Hz) thresholds correspond to the frequencies where under-frequency load shedding initiates for values below 60 Hz, and where generator over-speed governors and controls start operating for values above 60 Hz.

HECO 2010

HECO - Mar 2010

HECO - Apr 2010

HECO - May 2010

49

HECO - Jun 2010

HECO - Jul 2010

HECO - Aug 2010

HECO - Sep 2010

HECO - Oct 2010

HECO - Nov 2010

51

HECO - Dec 2010

HECO 2011

HECO - Jan 2011

HECO - Feb 2011

HECO - Sep 2011

HECO - Oct 2011

HECO - Nov 2011

MECO 2010

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MECO - Jul 2010

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MECO - Mar 2011

MECO - Apr 2011

MECO - May 2011

MECO - Jun 2011

MECO - Jul 2011

MECO - Aug 2011

MECO - Sep 2011

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MECO - Nov 2011

MECO - Dec 2011

±0.05%
±0.166%
±0.5%
±2.5%

APPENDIX D – REVIEW OF THE NERC APPROACH FOR MEASURING, MANAGING AND MITIGATING RISK (DRAFT)

date: February 14, 2012

to: Distribution

from: D. G. Robinson, Org. 1464, MS-1327

subject: Review of the NERC Approach for Measuring, Managing, and Mitigating Risk
The North American Electric Reliability Corporations (NERC) mission is to ensure the reliability of the North American bulk power system. (BPS). NERC does not currently have an accepted metric to characterize the reliability of bulk power systems. The scope for the NERC Reliability Metrics Working Group (RMWG), subsequently renamed the Performance Analysis Subcommittee (PAS) includes a task to develop methods that, first, will provide an integrated reliability assessment of BPS reliability and second, provide a means to assess reliability trends.

1 Introduction

Reliability assessment requires three essential elements:
1. A consistent statement of the system being evaluated
2. A consistent characterization of the system operating environment
3. A metric that is consistent with entire system and the operating environment

The system configuration must be representative of the typical operational conditions for the BPS, with specific consideration of generation size and location, transmission capabilities, and location and size of load.

A fundamental goal of this effort is to utilize a periodic reliability assessment to identify, and hopefully anticipate, critical elements within the bulk power system.

2 Background

The RMWG requested Sandia's support to review its proposed BPS reliability monitoring process and provide recommendations for improvement.

This memo summarizes a review based on the following documents:

• Risk Assessment of Reliability Performance Report [1] : http://www.nerc.com/files/2011_RARPR_FINAL.pdf
• Integrated Reliability Index Draft [2]:
http://www.nerc.com/docs/pc/rmwg/Integrated_
Reliability_Index_WhitePaper_DRAFT.pdf
• Integrated Reliability Index Draft Comments [5]: http://www.nerc.com/docs/pc/rmwg/IRI_Whitepaper_Comments.pdf
• Severity Risk Index Document - May 6, 2011 [3]: http://www.nerc.com/docs/pc/rmwg/SRI_Equation_Refinement_May6_2011.pdf

• SRI Dataset (NERC-wide 2008 to 2010):
http://www.nerc.com/docs/pc/rmwg/Event_
Severity_Risk_Index_(SRI)_Curves_with_Benchmark_Days_May_6_2011.xlsx

As noted in [1] *RMWG has advanced the development and understanding of risk attributes impacting reliability performance and the corresponding metrics that provide insight to the performance of the bulk power system*. The critical element identified in the report is need for *measurable components of bulk power system reliability*.

This effort involved review of the Severity Risk Index Model and a review of the Reliability Index Concept.

3 Review of the Severity Risk Index Model

Electric reliability is defined as the continuity of service to and at the interface points of the system. The Severity Risk Index Model, as a performance metric, describes how one configuration of the system performed when subjected to the load and environmental conditions present at that time. The assumption of a linear, additive form carries some strong underlying assumptions. Investigations should be considered with regards to the function (addition versus multiplication of the components) as well as determination whether there is overlap of the components of SRI that might result in double- or triple-counting.

Task 1:
- Review the Severity Risk Index model, from the perspective of risk information coverage that is addressed in the model and recommend, if appropriate, extensions or changes to the model.
- Contrast other risk-based models, for example, BRIIE Index, with the SRI model to identify potential improvements.
- Evaluate whether an event tree/fault tree methodology as used in the Level 1 nuclear plant analysis is needed to address each of the three risk factors used in NERC's severity index.
- Summarize the best practices, using BRIIE model as a starting point, suggest near-term and long-term model enhancements.

3.1 Severity Risk Index

The Severity Risk Index (SRI) for an event is defined:

$$SRIevent = w_L(MW_L) + w_T(N_T) + w_G(N_G) + w_D(H_D) + w_E(N_E) \tag{1}$$

where:

SRIevent: severity risk index for specified event
w_L: weighting of load loss,
w_T: weighting of transmission lines lost,
w_G: weighting of generators lost,
w_D: weighting of duration of event,
w_E: weighting of equipment damage,

MW_L: normalized MW of Load Loss in percent (normalized by the coincident daily peak load)

N_T: normalized number of transmission lines lost in percent,
N_G: normalized number of generators lost in percent
H_D: normalized duration of event in percent
N_E: normalized number of equipment damaged in percent

RPL : load Restoration Promptness Level where: RPL = 1/3 if restoration < 4 hours, RP L = 2/2 if 4 ≤ restoration < 12 hours, RP L = 3/3 if restoration ≥ 12 hours

Refined [3]:
$$SRIevent = RPL[w_L(MW_L)] + w_T(N_T) + w_G(N_G) \qquad (2)$$

3.2 General Discussion

A risk or reliability performance metric should involve consideration for the uncertainty associated with the performance of the system. Generally, this is a cornerstone of common risk and reliability metrics used by NASA, NRC, etc. The goal of these metrics is to characterize the probabilistic performance of the system as it evolves through time with design changes, environmental changes, and changes in operating conditions.

Generally it is advised that the industry create methods to distinguish between "element outage events" and "loss of load events". Currently data collected do not consider these distinctions. According to NERC, power system design recognizes that loss of load may be the Pt operational tactic to avoid more widespread events, as long as it is controlled and conducted in the manner anticipated by the system's design.

3.3 SRI Metric

As stated in Section 3.2, a risk or reliability performance metric should involve consideration for the uncertainty associated with the performance of the system. This metric should refer to a consistent system configuration under observation. Since the uncertainty or probabilistic performance of the system is not considered in SRI, the metrics provided in Equations 1 and 2 are not truly risk or reliability performance metrics.

To explain further, the equations represent utility functions that characterize the impact of an event that is reflected through the BPS and could lead to a loss of load, generating unit or transmission deliverability; the equations may or may not be related to events that could occur within the BPS. The cause-effect relationship with the probability that the BPS operates within acceptable limits is not clear.

In summary, the SRI metric provides limited insight into how changes to the BPS, e.g. operational rules, additional transmission lines, etc. will impact the ability of the system to withstand either an external or internal event.

A key indicator of potential issues with SRI is highlighted by the question: What is the Severity Risk Index for the BPS if there is no failure event? A reliability or risk

metric that reveals the cause-effect relationship should be a characteristic of a system (for a particular configuration) regardless of an event occurrence. Note that in the case of the BPS, a specific operational configuration, e.g. to support simulation of grid operation, will have to be agreed upon so that the cause/effect relationship remains consistent.

A review of a proven risk index might be helpful and a discussion of a measure used by the Nuclear Regulatory Commission is presented in the following section.

4 Baseline Risk Index for Initiating Events (BRIIE)

The BRIIE is a nuclear industry level initiating event performance index (PI) developed to monitor risk significant initiating events in the United States. Performance-based limits are also included for individual initiating events.

The essential elements of a BRIIE analysis are [10,11]:
• Identification of initiating events
• Identification of risk-informed weights for initiating events
• Estimation of performance-based limits for individual initiating events
• Determination of threshold for reporting

There is considerable importance on establishing the proper initiating events. The following are a few of the major references that will be helpful as the discussion moves forward.

NUREG-1753 [9] outlines the basic reasoning behind the development of the NRC risk-based performance indicators and discusses the logic behind construction of the initiating events. NUREG/CR-5750 [8] summarizes the data used to construct the initial estimates of the initiating events.

The following is a very basic discussion provided as a vehicle for discussion. The suggested alternative metrics and other measures are provided as examples only. Additional detail on BRIIE was provided in a presentation to NERC on 1 November 2011 (see attachment).

4.1 Initiating Events

The goal of the U.S. Nuclear Regulatory Commission (NRC) was the development of performance indicators that do not overlap in coverage, highlight the operational risk/reliability, and provided a mechanism for determining the reliability significance of changes in operational performance.

A critical characteristic of any risk metric is the ability to relate a specific system event to the impact on system performance. In the case of the BRIIE metric used by the NRC, the reliability of the system is explicitly available through accepted operational models. The impact of various initiating events can be related directly to the reliability of a nuclear reactor. BRIIE is a critical element in the NRC Reactor Oversight Process for monitoring commercial nuclear power plants.

BRIIE is based on 9 different event categories for Boiling Water Reactors (BWR) and 10 for Pressurized Water Reactors (PWR).

1. Loss of offsite power
2. Loss of vital AC bus
3. Loss of vital DC bus
4. Loss of feedwater
5. Small loss of coolant accident (VSLOCA)
6. PWR/BWR general transient
7. PWR/BWR loss of heat sink
8. PWR/BWR stuck open safety/relief valve
9. PWR/BWR loss of instrument air
10. (PWR only) steam generator tube rupture

The first five are associated with both reactor types and events 6-9 are reported uniquely for PWR and BWR. The tenth event is reported only for PWR reactors. The activities associated with the BRIIE metric help the NRC identify degradation or improvement in industry performance as a whole, and also for the individual reactor types.

In 1999, NRC conducted an initiating event study [8], covering data for a large number of initiating event categories for the period calendar year (CY) 1987 through CY 1995. A subset of these categories has been identified as being risk significant in NUREG-1753 [9].

The term 'event' is a generalization and actually represents a group of component failure events related to a specific type or category of failures. These categories can be generally grouped regarding their functional impact on plant operation. *Also, there is no overlap between these initiating events categories.*

As an example, number 7, Loss of Heat Sink, is composed of a number of component failures (unique to each type of reactor) [8]:
- Inadvertent Closure of All Main Steam Isolation Valve: PWR
- Inadvertent Closure of All Main Steam Isolation Valve: BWR
- Loss of Condenser Vacuum: PWR
- Loss of Condenser Vacuum: BWR
- Turbine Bypass Unavailable

BRIEE inherently depends on the clear understanding of a cause-effect relationship between the initiating events and the nuclear power plant being fully operational. These relationships are captured in complex reliability models for each reactor type.

Some unique BPS characteristics to be considered:
1. BPS performance is not a binary variable like the nuclear reactor. Performance of a BPS may be measured in terms of a continuous variable, such as Megawatts Loss of Load.

2. Another aspect of BPS performance is the <u>cumulative time</u> that the load is lost.
3. Unlike the general configuration of a nuclear reactor, a BPS system is dynamic. A consistent configuration and operational conditions much be established.

Possible solutions might involve the use a DC power flow model of each BPS as replacements for the reacor reliability models used by the NRC. Another alternative is one of the relatively new BPS reliability modeling methods appearing in the literature, for example, Yang, et al [5, 6].

Another possible metric might involve total MW-hours lost and this could be used as a basis for a reliability performance metric. The next step would be to develop a list of the components or combinations of components in the BPS that would result in a change in the MW available (i.e. loss of load). This list could be constructed using historical records from previous loss-of-load events (perhaps including a baseline of weather caused events).

4.2 Risk-informed Weights

Estimating weights involves understanding the impact of each failure event. It is not necessary to capture all possible failure events, only the top events that are most likely to occur. The definition of specific events might be an industry established set, as would the configuration of the system to be used as a baseline.

Continuing the above example, computer simulations can be used to characterize the fraction of load that is dropped (ratio of load lost and coincident daily peak load) as a measure of the impact of the event on BPS reliability. Or, in the case of the methodology suggested by Yang, the risk-informed weights are immediately available.

 The key point is to capture a consistent, *quantifiable measure* for how the reliability of the BPS changes in response to the failure of BPS elements. This change in reliability is the risk-informed weight. *It is critical that these weights be tractable from local, to regional, to national levels of reporting.*

4.3 Performance-based Limits

For BRIIE, the performance-based indicators are:
- Established at the beginning of the year and set an upper bound on expected performance for that year
- Values during the year are monitored and compared to the prediction limits
- Indicators that cross the prediction limits are investigated to determine contributing factors
- Factors are assessed for their safety significance and used to determine an appropriate agency response

For a bulk electric system these performance limits can be established by, for example, a NERC RMWG using historical data. Establishing these limits will likely evolve with the development of the Initiating Events and the Risk-informed Weights. Figure 1. depicts the results for a typical BRIIE indicator. Figure 2. depicts an indicator closely related to BPS reliability, Loss of Offsite Power. The nine events in 2003 were associated with a single blackout event.

BWR Loss of Condenser Heat Sink
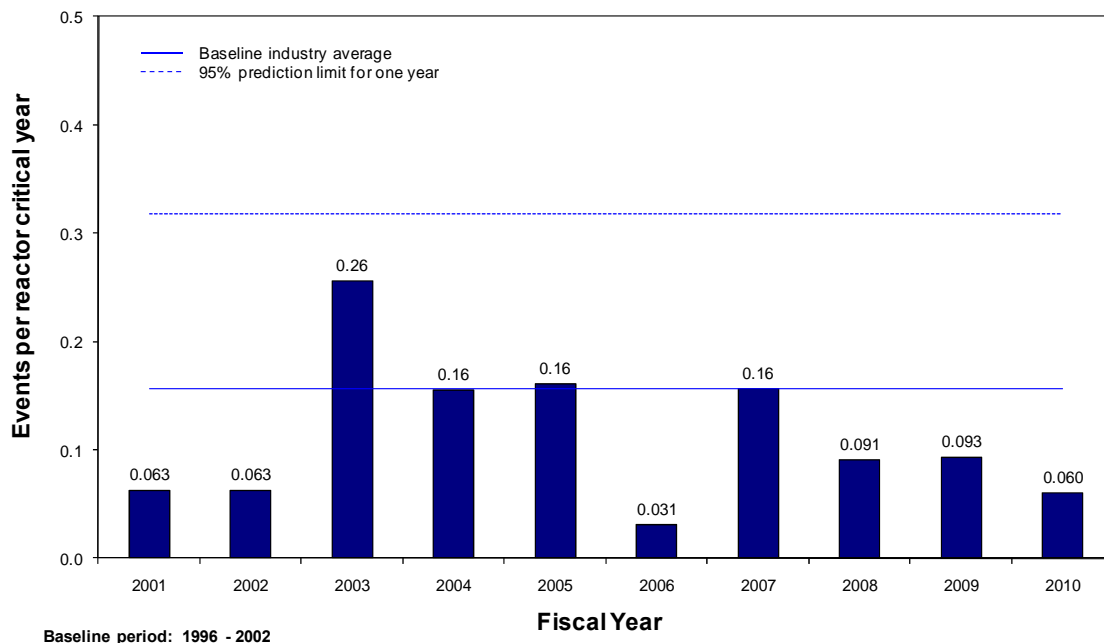
Figure 1. Example of BRIIE Reporting – Loss of Heat Sink (BWR)

Note that the indicators are normalized by reactor critical year. A BPS indicator might be the number of events normalized by, for example, some function of load served. This would allow a fair comparison of different size BPS.

Loss of Offsite Power
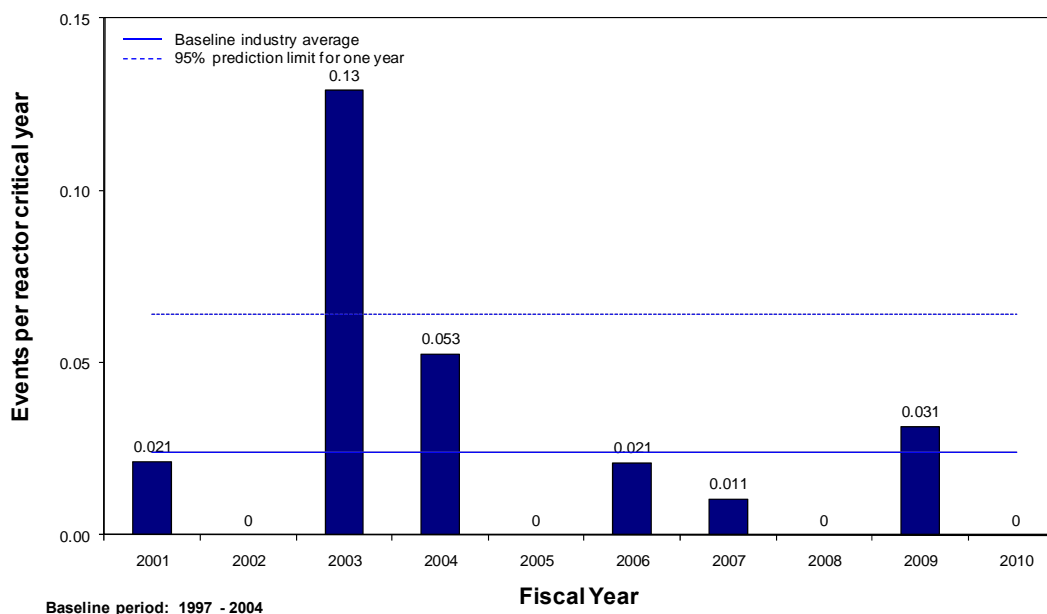
Figure 2. Example of BRIIE Reporting – Loss Offsite Power

4.4 Reporting Thresholds

For BRIIE, thresholds are used to determine there is an industry wide problem that needs to be elevated for consideration and solution. In particular:
- Expert panel decides on the threshold and what is reported to Congress
- BRIIE threshold is a weighted mixture related to mixture of reactor types
- The BRIIE is in the form of a difference from the baseline for each reactor type; this allows comparison across different reactor technologies.
- BRIIE is also available separately for each reactor type, and also industry wide.
- Major contributors and actions taken to address issues are reported.

The performance thresholds are established for local, regional, and industry wide reliability performance of the national system of nuclear reactors. The thresholds are scalable and are relative thresholds and therefore dimensionless; comparison between local and industry values can therefore be directly compared.

For a BPS, it is not clear if it is necessary to establish specific markers or thresholds for action. Continuous reporting of BPS reliability and risk metrics would probably be sufficient, coupled with a yearly summary to FERC. However, as mentioned previously, it will be important that the metrics be scalable.

A proper performance index focuses on events that impact the reliability of the BPS; you want the metric to support decision making on the BPS.

The advantage of using a BRIIE-type reliability performance metric is that it combines very specific, individual initiating events information into a risk-informed indicator at the local or national level.

Current NRC BRIIE industry trend charts can be found at: http://www.nrc.gov/reactors/operating/oversight/industry-trends.html

4.5 SRI Summary

In summary, the Severity Risk Index provides interesting insight into the response of a power system to a severe external event. This makes it possible to compare events and this can be very valuable. However, SRI is not a risk or reliability metric; it is easily dominated by conditions external (and independent) to BPS reliability.

The methodology used by NRC to support the BRIIE reliability performance metric is also not directly applicable. For example, it is theoretically possible to develop a reliability expression for a particular BPS. However, the configuration can change rapidly and therefore the impact of particular components on reliability will change.

Development of a solid metric for BPS would require re-thinking what constitutes a BPS event and building a set of reliability performance indices around those events.

Some observations:

- It is not necessary to capture all possible contingencies; possibly review the past 20 (?) years of operation and identify list of Top X% event *categories* that should be monitored. You are looking for *indicators* of BPS reliability, not a specific reliability quantification. Perhaps look at loss-of-load events and identify the hardware/software that was involved with those events.
- Choose events categories that are meaningful at all levels of grid operation. You will want to use the analysis results to identify where and what the problems might be.
- Reviewed and updated every year to make sure that the analysis is still capturing grid performance.

While the above discussion appears rather negative relative to the Severity Risk Index as a BPS reliability performance metric, SRI appears to appeal to a wide audience. Further, in the case of BRIIE, the reliability performance metrics are not reported alone, but included in a suite of metrics that provide different perspectives or insights into the reliability of nuclear power generation.

5 Review the Integrated Reliability Index

The Integrated Reliability Index was intended to describe the universe of risk and links that calculation to the reliability of the bulk power system [5]. However the linear, additive form does not appear to be support by important validation. Further assessments as to functional relationships, and dependence or independence of factors/indices is strongly suggested.

Task 2:
- Review the proposed Integrated Reliability Index Concept or Reliability Risk Index proposed by NERC relative to the integrated risk components and their associated weighting factors.
- In particular, how should the industry weight SDI (compliance risks) versus EDI (historic event risks) versus CDI (operational metrics) that demonstrate the operational effectiveness of the system?
- Further, are there methods that should be considered to avoid double counting, for example, when a metric migrates from a compliance metric to an operational metric?

The Integrated Reliability Index (IRI) model is defined [5].

$$IRI = w_E(EDI) + w_C(CDI) + w_S(SDI) \qquad (3)$$

where:
w_E : weighting of event component,
w_C : weighting of metric component,
w_S : weighting of standard compliance component,
EDI : normalized Event Driven Index,
CDI : normalized Condition Driven Index,
SDI : normalized Standards/Statute Driven Index

The IRI and SRI share many of the same technical issues. The following discussion will therefore also apply to the SRI Equation 2 which fundamentally involves three power grid attributes: normalized MW of load loss (MW_L), normalized number of transmission lines lost (N_T) and normalized number of generators lost, (N_G). For each event, the realization of those attributes are combined through the use of weights w_L, w_T, and w_G. The load loss is further weighted by the duration of the outages with the factor related to the Restoration Promptness Level, RPL.

In addition, the discussion focuses on SRI and IRI as a *utility performance metrics* rather than a reliability performance metrics. In this context, utility refers to a measure of satisfaction gained from delivery of goods or services.

Inherent in the additive nature of the IRI and SRI functions, is the assumption that a decision maker is independently indifferent to changes in the three attributes. For example, if a farmer is asked to choose his preference for sunshine or rain, the preference for the amount of sunshine will likely depend on the amount of rain that has fallen. In this case, where the preference structure is not independent, an additive function would not be valid. The concern is that a similar preferential or physical relationship may be present between the variables in Equations 2 and 3.

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In addition to establishing the attribute weights, the specific form of the utility function is critical. It is important to check for utility independence, in much the same manner as probabilistic independence is checked in statistical analyses. If the attributes (e.g. EDI) are mutually utility independent, then it remains to determine if the correct form is additive:

$$Utility\ Index = u(x) = \sum_i w_i u(x_i)$$

where $u(x_i)$ are the individual utility metrics such as EDI and w_i is the weight associated with that utility metric. Or if a multiplicative function may be appropriate:

$$1 + ku(x) = \prod [1 + kk_i u(x_i)]$$

The procedure for determining mutual utility independence and the correct form (additive versus multiplicative) is straightforward and can be found in a variety of sources. There are likely more recent publications, but the book by Keeney and Raiffa [7] is very accessible. *If the current SRI and IRI metrics are employed, it is essential that the form of the utility functions be explored in more depth to assure consistency.*

The question naturally arises regarding how to establish the various weights in both expressions. Currently, expert opinion is used to determine the values for the SRI weights w_L= 60%, w_T= 30%, and w_G = 10% and IRI weights: w_E=50%, w_C=25%, and w_S=25%. From the documentation for both metrics, it was not clear if a formal process was used to determine these weights or if the weights were developed in a consensus-seeking environment. It was also not clear how the particular (additive) form of the function was chosen. Following the procedure outlined in Chapter 6 of Keeny and Raiffa will result in an appropriate set of attribute weights that are consistent for whatever particular functional form is used (e.g. linear versus multiplicative).

The use of a fault or event tree methodology was suggested as one method to address the non-independence of attributes. The same issues will arise with any alternative modeling schemes. However, a fault or event tree methodology would not be necessary if the functional form is on strong footing and the weights are constructed using the procedures suggested above.

6 Summary

In summary, the Severity Risk Index appears to capture the major attributes that characterize the performance of bulk power systems. However, it does not capture the necessary BPS characteristics required for a reliability metric. As utility metrics, SRI and IRI should be rigorously reviewed for proper functional form; which would naturally include determination of the appropriate attribute weights.

A BRIEE-type metric is feasible and could provide a valuable monitoring tool for BPS reliability. However, there are limitations regarding existing BPS tools and

data. One option is to construct a reliability model or simulation model to be used as a foundation for a BPS reliability metric. These models would likely be constructed from state and regional models to assure that the resulting metrics scale appropriately. It is understood that these models will have to be based on accepted operational configurations, and it is important to recall that the models need to only provide metrics as indicators, not completely accurate reliability measures. Once these models are established, a procedure similar to that used for BRIIE should be implemented to construct the BPS reliability metric.

The final element in a BRIEE-type metric is the data necessary to populate a reliability model. The availability of this data would need to be confirmed and, if necessary, extended.

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November 2011.

APPENDIX E: ECONOMICS OF RELIABILITY LITERATURE REVIEW

The Early Literature

Economists' interest in electric reliability dates at least to the decade of the 1960s. (Turvey, 1968, 1977) investigated optimal pricing and investment in electricity supply when one of the key features of the industry was considered to be its decreasing long-run average cost (the 'natural' monopoly). (Turvey, 1968) has a short chapter entitled "The Quality of Service" in which he identifies voltage fluctuation, frequency variation, and reliability as key factors. He notes that quality of supply can be provided only at increased Cost. He claims that this choice has two features: (i) that quality of service has to be common for all consumers; (ii) the choice cannot be based on benefits in relation to costs because no marginal conditions formulated to describe the optimal quality level are operational. In other words, consumers' demand function for reliability is unavailable. With finality at the end of this short chapter he concludes that "Determination of the security of supply must rest on judgment rather than upon calculation. Costs will reflect the standards of security chosen." This is where the issue remains even today as the North American Electric Reliability Corporation (NERC) sets, monitors, and enforces reliability standards mostly in terms of engineering criteria rather than what customers express their willingness to pay for.

Nevertheless, investigations into reliability economics continued despite Turvey's conclusion. In the 1970s a number of authors weighed in on the subject including (Telson, 1973), (Crew and Kleindorfer, 1976, 1978), (Munasinghe, 1978, all 3 references). During the 1980s and 1990s economists' suggested the use of the macro-economic costs of outages as a proxy for consumer's willingness to pay for reliability (Sanghvi, 1982; Munasinghe, 1980; and others.) The thinking being that reliability should be improved at added cost but only up to the point where additional reliability (cost outlay) was matched by the cost of outages implied by that level of reliability. This proxy was interpreted more or less as a minimum estimate of the value of reliability to electricity consumers. (Tollefson, 1991) provides an extensive, partially annotated bibliography of the literature published during this era, much of it published in the IEEE Transactions and much of it contributed by engineers.

An excellent example of this research thread is provided by (Munasinghe, 1979). This paper presents a generalized simulation model for optimizing the reliability level by comparing the social benefits and costs of changes in power system reliability. They observe that the supply side costs of increasing system reliability can be determined from straightforward engineering considerations. On the demand side, the benefits to electricity users consist of preserving the benefits of power consumption by averting power failures or outages which may be measured by the disruption of the output streams owing to idle input factors and spoilage. One advance is analytical procedure applied in this paper as compared with its predecessors is the representation of demand for electric power consumption as a demand derived from other production or consumption activities. Therefore, electric power is not demanded for its inherent characteristics—as previous researchers had assumed—but instead is desired for its contribution to other production or consumption activities. The authors conclude that their approach of optimizing the long-run design of the power system so as to minimize total costs (the sum of outage costs plus system costs) to society has the potential to be successful at linking reliability

with outage costs. However, events in the electric power industry, namely—restructuring—have overtaken this aggregated approach to reliability.

Late 20th Century Literature

This provides a convenient segue to the (Burns and Cross, 1990) article that starts from the observation that the value of service reliability needs to explicitly incorporate customer choices regarding reliability "worth" and service costs. Reliability "worth" to customers is interpreted as their "willingness to pay" for incremental improvements in reliability that consumers would interpret as reductions in outage costs they might otherwise incur. This portrayal of reliability planning—involving consumers—is very different from the type of reliability planning that has historically, and is currently in use in the real world industry. While reliability planning has evolved from use of deterministic models to more sophisticated probabilistic models, reliability standards are based primarily on notions of what is 'acceptable' from the point of view of system engineering. Burns and Cross, Turvey, and others, make the point that the methodologies used in determining reliability criteria cannot evaluate the economic impacts of changing levels of reliability for the utility and its customers. Consequently, the optimal level of reliability cannot be determined due to lack of information from consumers on their desired level of reliability. From a societal point of view, using existing methods, a case cannot be made to determine that an LOLP of 1 day in 10 years is superior either to 1 day in 5 years or 1 day in 20 years.
The incorporation of consumers' views of reliability value into the determination of optimal reliability requires that means are available to quantify this value. Three general techniques for quantifying consumers' values of reliability have been used:

- Market based methods attempt to examine actual customer behavior in response to various service options or investments in reliability to infer customer outage costs as evidenced by customers who sign up for non-firm service rates or install backup generation;
- After the fact measurement of actual outages that have occurred;
- Survey methods use customer responses to postulated outage scenarios to measure outage costs.

Burns and Cross make the point that utility efforts to evaluate the outage costs of their customers have employed the survey techniques most frequently and have attempted to elicit responses to:

- Direct costs: customer incurred costs of an outage of specified duration and advance warning time;
- Willingness to pay: customer outlay to avoid an outage of specified duration and advance warning time;
- Willingness to accept: payment received from utility to compensate for an outage of specified duration and advance warning;
- Revealed preference: question elicits customer response regarding specified combinations of increasing price (electric rates) and reliability (reduced outages);

Surveys are popular with utilities because they allow the utility to focus on the particular preferences of their customers and the unique outage and operating characteristics of their utility systems.[10]

Post-Industry Restructuring Literature

It appears that after the early 1990s interest in reliability economics has waned somewhat. Perhaps this is due to a new focus on market design in support of the currently evolving wave of restructuring.[11] But the new markets are again bringing the issue of reliability to the forefront. As the industry works the supply side of the business to wring out all of the available economic efficiencies it becomes clear that the emerging grid will require the development of more effective retail markets and the integration of these with the wholesale markets. Reliability standards remain the result of administrative decree. The National Electric Reliability Corporation (NERC) specifies the required standards, regional reliability entities monitor compliance and provide enforcement, including financial and other penalties. There is limited concern for whether the level of reliability is economic. Indeed, while reliability is specified to be equivalent system-wide, it is true that individual electric consumers experience different levels of reliability due to very local system conditions that vary over time.

"The massive electricity blackout in the northeastern United States and Canada on August 14-15, 2003 rekindled public interest in the reliability of the electricity grid." LaCommare and Eto (2004). They use a simple linear model of aggregate outage cost predicated primarily on the number, frequency, and cost per event by customer class to arrive at the annual aggregate cost of outages across the U.S. Vulnerability of customer classes and type of reliability event are also considered in the estimate. The authors rely on "customer damage functions" estimated by survey technique for a reported large sample of electric consumers conducted by eight electric utilities in the U.S. over a period of slightly more than a decade. The damage functions were estimated from this data using multivariate regression analysis. The aggregate estimates ranged between $22 billion annually and $135 billion annually. In an earlier paper Eto, *et al* (2001) provide an annotated bibliography of literature on the cost of reliability and outages. This is a valuable reference resource.

The new focus of reform efforts in the electric industry is to introduce and diffuse market competition as the means of allocating resources needed to supply electricity to customers. Much of this effort is currently focused on the supply side and the introduction and refinement of wholesale markets for electricity supply. Meanwhile, increased interest is evident toward development of retail markets and integration of these markets with the wholesale markets. Towards this end there is increased focus on "demand response" as a form of load balancing. The understanding that both demand and supply have the potential to work in concert to balance system supply and demand and can help to improve capacity utilization for the supply system as well as keep electric rates (prices) lower for customers. The concurrent interest in Smart Grid

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[10] In contrast, survey methods are not popular with economists, although they are sometimes used. The concern is that consumers will respond to hypothetical questions by interpreting what they believe the interviewer wants to hear, or, based on their supposition of the reason the question is being posed. Or, consumers might try to game the outcome of the survey.

[11] This may also be due to forceful action on the part of FERC and NERC to establish a firm reliability monitoring and enforcement program.

that would provide the platform for customers to express their demand schedule for electricity supports this wholesale/retail market integration. A number of states including Texas and states in the PJM area have programs to elicit demand response. It is possible in this broadened environment to envision a market for reliability that would allow consumers to specify their requirements for power quality. These trends are congruent with observations and findings of market designers who have a goal of making electric power markets more efficient and effective.

(Hogan, 2005) has made the case that reliability levels must be worked out in a market in which every consumer has the option to participate. He brings the value of lost load (VOLL) back into the discussion. (Cramton and Stoft, 2011) have stated this more explicitly: "If reliability is not individualized then individuals know that they will not receive less reliability if they pay less for it, because they can be given less only if everyone is given less. Consequently, everyone will refuse to pay for collective reliability and all will attempt to enjoy a free ride." (p. 24.)

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