NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Essential Reliability Services Task Force Measures Framework Report

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RELIABILITY | ACCOUNTABILITY




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Table of Contents

Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

The North American Bulk Power System (BPS) is undergoing a significant change in the mix of generation resources and the subsequent transmission expansion. Driven by a combination of factors, the rate of this transformation in certain regions is impacting planning and operating of the BPS. For example, environmental regulations are contributing to the acceleration of a significant amount of conventional coal-fired generation retirements while renewable portfolio standards and other factors are driving the development of Variable Energy Resources (VERs). This has resulted in new generation being primarily natural gas fired and an increase in the penetration of wind and solar resources. At the same time, load participation in system operations is increasing through demand response and distributed generation. These changes in the generation resource mix and technologies are altering the operational characteristics of the grid and will challenge system planners and operators to maintain reliability, thereby raising issues that need to be further examined. More specifically:

- **Impact of Retirements:** Conventional units such as coal plants provide frequency support services as a function of their large spinning generators and governor control settings along with reactive support for voltage control. Power system operators use these services to plan and operate reliably under a variety of system conditions, generally without the concern of having too few of these services available.
- **Replacement Resources:** As the generation resource mix evolves, the reliability of the electric grid depends on the operating characteristics of the replacement resources. Gas-fired units, VERs, storage, and other resources are equipped to provide similar reliability services; however, the functionality may not always be installed or made available due to costs or market rules. The controllability of new generator and load resources to maintain the balance between load and generation, especially during ramping periods, is necessary to ensure reliability.
- **Resource Capability and Characteristics:** The reliability of the BPS depends on the operating characteristics of the replacement resources. Merely having available generation capacity does not equate to having the necessary reliability services or ramping capability to balance generation and load. It is essential for the electric grid to have resources with the capability to provide sufficient amounts of these services and maintain system balance.

The purpose of this report is to explore important directional measures to help the industry understand and prepare for the increased deployment of VERs, retirement of conventional coal units, advances in demand response technologies, and other changes to the traditional characteristics of generation and load resources.

The ERSTF is not asserting that it has developed the final answer to this complex transformation; rather, the group is presenting concepts and proposing measures based on discussions with system operators, planners and industry experts studying these issues. The task force looked closely at the BPS, especially areas that are experiencing the greatest level of change in the types of resource used to serve their load. While the behaviors of conventional generators are well documented, the task force also reviewed the capabilities of newer technology such as wind, solar, battery storage and other types of generators. The ERSTF had discussions with CAISO, ERCOT, IESO, and others experiencing significant transitions in generation resource mix. Based on these discussions and other sources of information, the ERSTF has concluded that the generation resource mix transition can and does have a profound impact on the transmission and distribution infrastructure and, while manageable, these impacts have to be accounted for in energy policy making, system planning, and system operations.

In order to maintain an adequate level of reliability through this transition, generation resources need to provide sufficient voltage control, frequency support, and ramping capability—essential components of a reliable BPS.

Creation of the ERSTF

The NERC Planning Committee and Operating Committee jointly created the Essential Reliability Services Task Force (ERSTF) in 2014 to consider the issues that may result from the changing generation resource mix; the committees and the ERSTF released an ERSTF concept paper in October 2014. The committees agreed that it was prudent to identify the essential reliability services, monitor the availability of these services, and develop measures to ensure the industry has sufficient awareness of the change in reliability services in the future. As noted in the concept paper, the key characteristics of a reliable grid can be categorized into two main categories: voltage support and frequency support. The changing generation mix raises a number of potential concerns, and the ERSTF has been asked to identify measures that should be monitored to ensure reliable operation of the BPS.

Objectives of the ERSTF

The purpose of the ERSTF is to develop measures, use data from across North America to assess the validity of these measures, and provide insight into trends and impacts of the changing resource mix. The analysis conducted by the ERSTF is focused on measures that may be monitored by NERC, the appropriate NERC registered entities (such as Balancing Authorities (BAs)), and the industry to identify potential reliability concerns that may result from the changing resource mix. These measures are intended to provide the appropriate NERC registered entities and industry with both a short-term operational view and a long-term planning horizon view that enable the identification of immediate reliability concerns and look into the future for needed adjustments. The ERSTF established three technical sub-teams focusing on 1) frequency support, 2) ramping capability, and 3) voltage support. While ramping is often viewed as an aspect of frequency support, timing differences tend to suggest different measures, and they should be reviewed as separate (but related) topics. The ERSTF also created a fourth sub-team to develop documents, such as this report, to educate and inform industry, policy makers, and regulators.

Summary of Measures and Industry Practices

The task force found that the most important essential reliability services (ERS) for reliability largely focus on the topics of managing frequency, net demand ramping, voltage, and dispatchability. At the highest level, the recommendations can be summarized as:

- **Frequency –** These recommendations relate to restoring frequency after an event such as the sudden loss of a major resource. The frequency within an interconnection will immediately fall upon such an event, requiring a very fast response from some resources to slow the rate of fall, a fast increase in power output (or decrease in power consumption) to stop the fall and stabilize the frequency, then a more prolonged contribution of additional power (or reduced load) to compensate for the lost units and bring system frequency back to the normal level. The task force recommends measures to track the minimum frequency and frequency response following the observed contingency events, track and project the levels of conventional synchronous inertia for each balancing area and the interconnection as a whole, and track and project the initial frequency deviation in the first half-second following the largest contingency event for each interconnection.

- **Ramping –** Ramping is related to frequency, but more in an "operations as usual" sense rather than after an event. Changes in the amount of non-dispatchable resources, system constraints, load behaviors and the generation mix can impact the ramp rates needed to keep the system in balance. The task force recommends a measure to track and project the maximum one-hour and three-hour ramps for each balancing area. Reporting these individual BA values at the NERC level will provide data for industry-wide trending and assessment of the interaction between BAs.

- **Voltage –** Voltage must be controlled to protect the system and move power where it is needed. This control tends to be more local in nature, such as at individual transmission substations, in sub-areas of lower voltage transmission nodes and the distribution system. Ensuring sufficient voltage control and "stiffness" of the system is important both for normal operations and for events impacting normal operations (i.e., disturbances). The task force recommends a measure to track and project the static and dynamic reactive power reserve capabilities to regulate voltage at various points in the system. The task force also recommends that industry monitor events related to voltage performance, periodically review the short circuit current at each transmission bus in the network, and do further analysis of short circuit ratios when penetration of nonsynchronous generation is high or anticipated to increase.

The ERSTF sub-teams worked to define potential measures for study and consideration that will assist in evaluating the impacts on reliability services as a result of the change in generation mix. Each potential measure was assigned a reference number as shown in Table 1. The numbers are solely for the convenience of the task force and are not meant to suggest a priority or level of importance. The general goal when forming each potential measure was to define a value that could measure historical performance, project future performance, and be plotted for the detection and understanding of trends.

After analysis and discussion, the task force recommended that each potential measure be identified as a Measure, Industry Practice, or No Further Action item.

- A Measure means that the task force recommends that values should be calculated by the appropriate entity on a regular basis and tracked by the appropriate NERC committee, subcommittee, or task force going forward.
- An Industry Practice means that the analysis has value for the appropriate entity and its use is recommended, but the value is highly dependent on the context of the specific entity, so it is less useful to report and monitor the values at the NERC level.
- A No Further Action item may provide a useful example, but was not moved forward as a recommendation for the industry at this time.

General Recommendations

Overall, the ERSTF represents a focused approach to understanding system behavior that exists today, how this behavior may change in the future, what the system will require from resources in the future, and how to make the transition in a reliable way. New resources may have different operating characteristics but can be reliably integrated with proper planning, design, and coordination. Maintaining reliability is embodied in the predictability, controllability and responsiveness of the resource mix.

Recommendations include:

1. All new resources should have the capability to support voltage and frequency. Automatic voltage regulators and governors have been standard on conventional generators for decades, and comparable capabilities are currently available for new VERs and other resources. Ensuring that these capabilities are present in the future resource mix is prudent and necessary.
2. Monitoring of the Measures and investigation of trends. The Measures are intended to highlight aspects of reliability that could suggest future reliability concerns if not addressed with suitable planning and engineering practices.
3. Planning and operating entities should use the Industry Practices. While the results of Industry Practices will be system specific and difficult to quantify or compare between different regions, they will help ensure that emerging concerns are addressed with suitable planning and engineering practices.
4. While beyond the formal scope of the ERSTF, the task force recognized that Distributed Energy Resources (DERs) will increasingly affect the net distribution load that is observed by the BPS. The ERSTF recommends coordination of NERC Reliability Standards with DER equipment standards such as IEEE 1547. Pursuant with NERC's reliability assessment obligations, the ERSTF further recommends that NERC

establish a working group to examine the forecasting, visibility, control, and participation of DERs as an active part of the BPS. With prudent planning, operating and engineering practices, and policy oriented to support reliability, DERs should be able to be reliably integrated into BPS operation.

5. Open sharing of experiences and lessons learned. The reliability of the system can be maintained or improved as the resource mix evolves, provided that sufficient amounts of essential reliability services are available.

Recommended Ongoing Efforts

Under the coordination of the NERC Planning and Operating Committees, a clear approach should be established to ensure ongoing analysis and reporting of the Measures and to encourage the use of Industry Practices. The ERSTF believes that the Measures provide useful trends and insights into the current challenges in certain areas of North America as related to the changing resource mix that should be monitored going forward. Additional metrics should also be investigated and monitored as the appropriate subcommittees and working groups continue their review consideration over time. The ERSTF expects to see ongoing enhancements to the Measures and additional recommendations from the other working groups to provide NERC with even greater clarity going forward.

The ERSTF has also developed materials that can be shared with policy makers, regulatory agencies, industry executives, and others to explain the issues and measures. Given the nature of essential reliability services and the significance of such services for energy policy making, system planning, and system operations, NERC should anticipate the need for ongoing information sharing and support for a wide variety of stakeholders. Federal, state, and local jurisdictional policy decisions have a direct influence on changes in the resource mix, and thus can affect the reliability of the BPS. Planning and operations analysis of these emerging changes must be done to ensure continued reliable and economic operation of the BPS.

Summary Table of Recommendations

The ERSTF Measures and Industry Practices are recommended in details below:

Table 1: Summary of Measures and Industry Practices Recommendations

Reference Number	Title	Brief Description	BA or Interconnection Level	ERSTF Recommendation	Ongoing Responsibility
1	Synchronous Inertial Response(SIR) at an Interconnection Level	Measure of kinetic energy at the interconnection level. It provides both a historical and future (3-years-out) view.	Interconnection	Measure	Resource Subcommittee and Frequency Working Group
2	Initial Frequency Deviation Following Largest Contingency	At minimum SIR conditions from Measure 1, determine the frequency deviation within the first 0.5 seconds following the largest contingency (as defined by the Resource Contingency Criteria (RCC) in BAL-003-1 for each interconnection).	Interconnection	Measure	Resource Subcommittee and Frequency Working Group
3	Synchronous Inertial Response at a BA Level	Measure 3 is exactly the same as Measure 1 but performed at the BA level. It provides both a historical and future (3 years out) view and will help a BA identify SIR-related issues as its generation mix changes.	BA	Measure	Resource Subcommittee and Frequency Working Group
4	Frequency Response at Interconnection Level	Measure 4 is a comprehensive set of frequency response measures at all relevant time frames: Point A to C frequency response in MW/0.1 Hz, Point A to B frequency response in MW/0.1 Hz (similar to ALR1-12), C:B Ratio, C:C' Ratio as well as three time-based measures (t_0 to t_C, t_C to $t_{C'}$, t_0 to $t_{C'}$), capturing speed of frequency response and response withdrawal.	Interconnection	Measure	Resource Subcommittee and Frequency Working Group
5	Real Time Inertial Model	Develop a real-time model of inertia including voltage stability limits and transmission overloads as criteria. This is an operator tool for situational awareness and alerts them if the system is nearing a limit and any corrective action is required.	BA	Industry Practice	BA

6	Net Demand Ramping Variability	Measure of net demand ramping variability at the BA level. It provides both a historical and future view.	BA	Measure	Reliability Assessment Subcommittee
7	Reactive Capability on the System	At critical load levels, measure static & dynamic reactive capability per total MW on the transmission system and track load power factor for distribution at low side of transmission buses.	TOP	Measure	Performance Analysis Subcommittee and the System Analysis and Modeling Subcommittee
8	Voltage Performance of the System	Measure to track the number of voltage exceedances that were incurred in real-time operations. This should include both pre-contingency exceedances and post-contingency exceedances. Planners should consider ways to identify critical fault-induced delayed voltage recovery (FIDVR) buses and buses with low short-circuit levels.	No Further Action	No Further Action	No Further Action
9	Overall System Reactive Performance	When an event occurs on the system related to reactive capability and voltage performance, measure to determine if the overall system strength poses a reliability risk. Adequate reactive margin and voltage performance should be evaluated across all horizons (planning, seasonal, real time). This type of post-mortem analysis comports with various requirements in existing and proposed NERC standards.	BA	Industry Practice	Event Analysis Subcommittee
10	System Strength	Based on short circuit contribution considerations, determine if low system strength poses a potential reliability risk. When necessary, calculate short circuit ratios to identify areas that may require monitoring or additional study.	Planning Coordinator	Industry Practice	Planning Coordinator

Detailed Recommendations

The recommendations are fully described in the body of this report and can be summarized as follows:

- Frequency Support Recommendations
  - Calculate the instance of minimal synchronous inertial response (SIR) that occurred in the recent historical study year and its projected value for the next three years (Measure 1 for interconnection and Measure 3 for BAs).
  - At minimum SIR conditions for each of the historical and future years above, determine the frequency deviation that would result within the first 0.5 seconds following the largest contingency of the interconnection (Measure 2 for interconnection).
  - Each interconnection should measure the minimum frequency point (the Nadir) and all aspects of frequency response following observed contingency events (Measure 4).
  - A measure related to situational awareness modeling of available inertia for near-real-time applications when operating the grid (Reference Number 5) was considered. This was identified as an Industry Practice but not recommended as a measure.
- Net Demand Ramping Variability Recommendations
  - Each BA should calculate the historical and projected maximum one-hour-up, one-hour-down, three-hour-up, and three-hour-down net demand ramps (actual load less production from VERs) using one-minute data (Measure 6). Although changes in ramping needs may not indicate a concern, the historical and projected ramp values by BA should be reviewed at both the BA and NERC level to allow for early identification of potential areas for further analysis.
- Voltage Support Recommendations
  - Measures of reactive capability should be calculated and tracked by the appropriate registered entity, including both static and dynamic reserve capability per total megawatt load at peak, shoulder, and light load levels; and load power factor for distribution at the low side of transmission buses at peak, shoulder, and light load levels (Measure 7).
  - The ERSTF considered, but does not recommend, potential measures of voltage performance for tracking voltage exceedances during real-time operations and monitoring buses with low short-circuit strength or susceptibility to fault-induced delayed voltage recovery (FIDVR) conditions (Reference Number 8).
  - The ERSTF discussed a potential measure for reviewing system events that suggest stressed reactive capability or degraded voltage profiles to compare planned performance with real-time operations and evaluate voltage performance (Reference Number 9). This was identified as an Industry Practice but not recommended as a Measure.
  - The appropriate registered entity should measure system strength based on calculating short circuit ratios for sub-areas in the system (Reference Number 10). This was identified as an Industry Practice but not recommended as a Measure.

Frequency Support

Frequency support is the response of generators and loads to maintain the system frequency in the event of a contingency. For the ERSTF's purposes, the frequency support response generally consists of a combination of immediate inertial response, fast frequency response,[1] primary frequency response, and some slow responses to supplement the resources that have responded more quickly.

The task force recommends Measures to track the minimum frequency and frequency response following the observed contingency events, track and project the levels of conventional synchronous inertia in the arresting time frame for each balancing area and the interconnection, and track and project the initial frequency deviation in the first half-second following the largest contingency event for each interconnection. We will look at each of these in turn, focusing first on the Measures of conventional synchronous inertial response, then looking at the system's overall response to a frequency event in the Frequency Response section that follows.

Synchronous Inertial Response Measures

Rotating turbine generators and motors that are synchronously connected to the system store kinetic energy that, during contingency events, is released to the system (also called inertial response). Inertial response provides an important contribution to reliability in the initial moments following a generation or load trip event: determining the rate of change of frequency. In response to a sudden loss of generation, kinetic energy will automatically be extracted from the rotating synchronized machines on the interconnection, causing the machines to slow down and frequency to decline. The amount of inertia depends on the number and size of generators and motors synchronized to the system, and it determines the rate of frequency decline. Greater inertia reduces the rate of change of frequency, giving more time for primary frequency response to fully deploy and arrest frequency decay above under-frequency load shed set points.

SIR is the immediate and thus fastest response obtained from the kinetic energy in the spinning mass of synchronous machines. In order to measure and identify trends in the SIR level with changing generation mix in a system, an inertial response Measure is needed at the interconnection level to show how the interconnections are performing. A second Measure is needed at the BA level to identify changes in contribution toward an interconnection's SIR.

Interconnections with growing amounts of nonsynchronous generation or electrically de-coupled resources should project future SIR trends based on historical SIR information and planned projects in the interconnection queue (e.g., signed interconnection agreements and financial commitments for nonsynchronous generation). These projections will help BAs anticipate decreasing interconnection SIR conditions, which will increase the challenges associated with meeting the interconnection frequency response obligations (IFROs) to preserve reliability.[2] The ability to anticipate the changes in SIR will help BAs develop approaches to offset any decline in SIR to meet their IFRO as required in BAL-003-1.

For systems in which the amount of SIR is decreasing, there are various ways to compensate and maintain reliability, potentially including fast frequency response resources. In some cases, retiring synchronous generators could be converted to synchronous condensers that provide inertia and reactive support, and maintain system stability. During the planning of the BPS, understanding how changes in SIR interact with primary frequency response and locational aspects will be crucial to preserve reliability and determine if a minimum SIR requirement is necessary.

[1] Fast frequency response is high-speed energy contribution such as that from controlled load, storage, synthetic inertia from wind, or other sources.

[2] http://www.nerc.com/pa/Stand/Project%20200712%20Frequency%20Response%20DL/BAL-003-1_clean_031213.pdf

Measure 1: Synchronous Inertial Response at an Interconnection Level

This is a measure of kinetic energy at the interconnection level. It provides both a historical and future (three-years-out) view.

1. For every hour in a year, determine the total available inertial response from all on-line synchronous generators in the interconnection (see boxplots, Figure 1). Identify the instances and conditions that resulted in the minimum inertial response in a year. If an hourly sampling of inertial data for an entire year is not available, then use several historical snapshots that are likely to have yielded low system inertia conditions.
2. Project the minimum inertial response in future years (the next three years). See points corresponding to this response, Figure 1.

Measure 2: Initial Frequency Deviation Following Largest Contingency

This Measure is extrapolated from Measure 1 and applies at the interconnection level.

1. At minimum SIR conditions from Measure 1 for each year, determine the frequency deviation within the first 0.5 seconds following the largest contingency (as defined by the resource contingency criteria (RCC) in BAL-003-1) for each interconnection. The half-second window is sufficient to show the general frequency trend. This initial frequency deviation is not affected by other responses, such as fast frequency response and primary frequency response and therefore illustrates only the effect of system inertia on system frequency deviation.
2. At minimum SIR projections from Measure 1 for future years (the next three years), determine the projected frequency deviation within the first 0.5 seconds following the largest contingency (as defined by the RCC in BAL-003-1) for each interconnection. See Figure 2.

Data Requirements for Interconnection Level Measures 1 and 2

- Historical: generator on-line/off-line status, inertia constant (H) for every synchronous generator, MVA rating for every synchronous generator in the interconnection.
- Future: anticipated nonsynchronous generation in a future year, based on planned projects with signed generation interconnection agreements (GIA) and financial commitments in each BA area of an interconnection.
- Measures 1 and 3 are the same, with Measure 1 at the interconnection level and Measure 3 at the BA level. For the figures shown below, note that ERCOT acts as both the BA and interconnection.

Note on Boxplots

On each box, the central mark (red line) is the median, the edges of the box (in blue) are the 25th and 75th percentiles, the whiskers correspond to +/- 2.7 sigma (i.e., represent 99.3% coverage, assuming the data are normally distributed), and the outliers are plotted individually (red crosses). If necessary, the whiskers can be adjusted to show a different coverage.

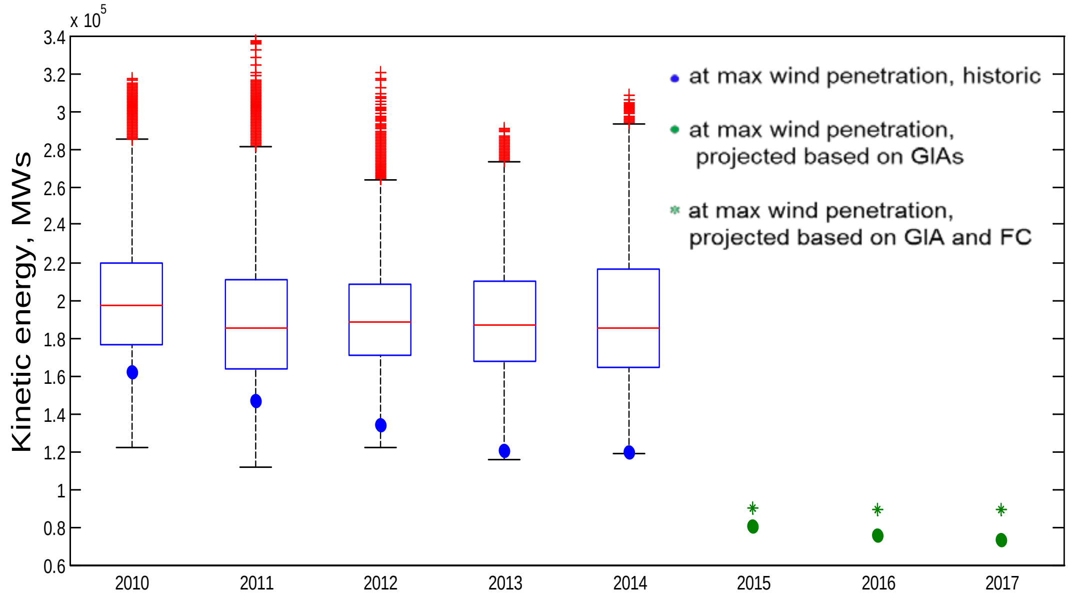


Figure 1: ERCOT historic kinetic energy boxplots (2010–2017)[3]

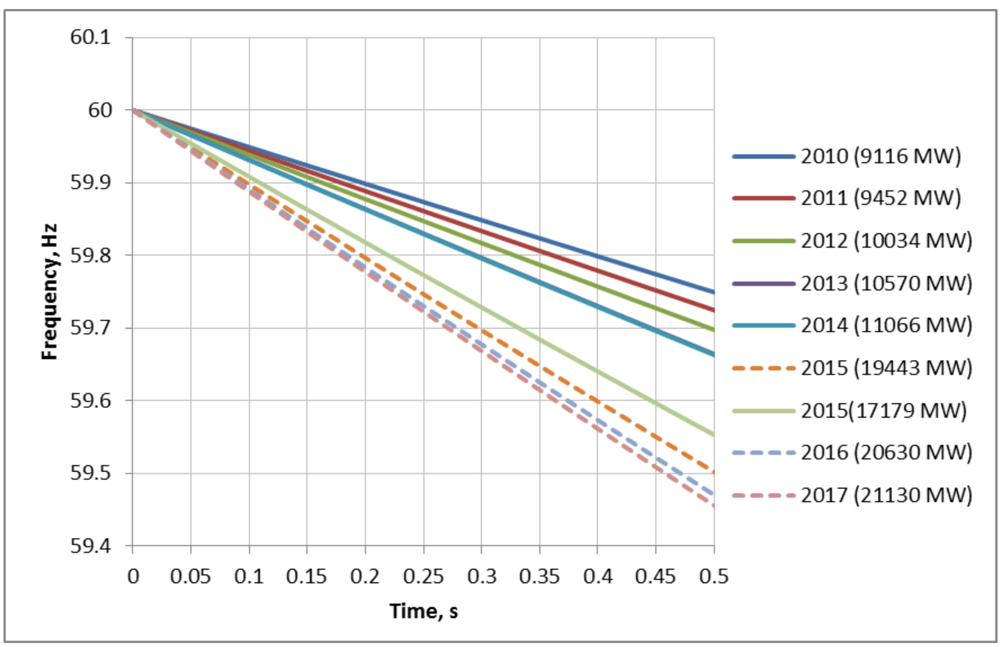


Figure 2: Calculated ERCOT system frequency after 2750 MW generation trip (2010–2017)

[3] On the Figure 1 legend, GIA stands for signed generation interconnection agreements, and FC stands for financial commitments.

Measure 3: Synchronous Inertial Response at BA Level

This Measure is exactly the same as Measure 1 but is taken at the BA level. It provides both a historical and future (three-years-out) view and will help BAs identify SIR-related issues as their generation mixes change.

1. For every hour in a year, determine the total available inertial response (kinetic energy) from all on-line synchronous generators in the BA. Identify the instances and conditions that resulted in the minimum inertial response in a year. If an hourly sampling of inertial data for an entire year is not available, then use several historical snapshots that are likely to have yielded low system inertia conditions.
2. Project minimum inertial response in a future year (the next three years) as shown in Figure 1.

Data Requirements for BA Level Measure 3

1. Historical: generator on-line/off-line status, inertia constant (H) for every synchronous generator, MVA rating for every synchronous generator in the BA.
2. Future: anticipated nonsynchronous generation in a future year based on planned projects with signed generation interconnection agreements in each BA area of an interconnection.

Detailed calculation procedures for Measures 1, 2, and 3 are provided in the Frequency Response appendix.

Summary of Analysis

Selected BAs, WECC, and NERC (for Eastern Interconnection) were requested to submit Measures 1, 2, and 3 for years 2011–2014 along with a three-year projection for years 2015–2017. For Measure 2, projections for years 2015–2017 were based on data gathered for Measure 1. Detail for WECC and each BA that submitted data is available in Appendix A.

Measures 1 & 2

In WECC and the Eastern Interconnection (EI) it was difficult to obtain the data necessary for Measures 1 and 2. In WECC, while the unit status is available from the Peak Reliability State Estimator (West-wide System Model - WSM), the WSM cases were only available for specific snapshots in time. It was also difficult to map generators from WSM cases with corresponding inertia constants.

For EI, dynamic models are available to NERC, and information may also be available on generator unit status from the Parallel Flow Visualization (PFV) project. In addition, the NERC Resources Subcommittee (RS) recently conducted a generator governor survey that requested the generator inertia constant for each machine. That data can be used to calculate Measures 1 and 2 for EI. Mapping between unit names in the generator governor survey and PFV will also be a challenge that will need to be addressed. It was concluded that there appears to be no immediate urgency to calculate Measures 1 and 2 in EI; however, there is a need to begin collecting the data in order to analyze and trend these Measures over time. Overall, generator operators are required under NERC Reliability Standards MOD-012, -026, and -027 to provide machine data to their Planning Coordinators and Transmission Operators; therefore, generator inertia constant data should be available. The main challenge will be mapping of generator parameters with respective generator status from state estimator models.

While it is currently difficult to analyze Measures 1 and 2 at the interconnection level, these Measures, along with Measure 4,[4] will aid in the understanding of the causes of the declining frequency nadir during generator trip events. This understanding will allow the discovery of the most effective solutions to address declining frequency nadir as the generation resource mix continues to change. For example, frequency nadir after a generator trip

[4] Measure 4 - a comprehensive set of frequency response measures at all relevant time frames, discussed further in the report.

may be low because system inertia is too low. Consequently, the rate of change of frequency is too high, and/or there is no fast frequency response available (or the fast frequency response that is available is not sufficiently fast). Frequency nadir may also be low because there is not enough generation with governor response, or generation with fast governor response has been replaced with slower resources, etc. Depending on the cause of low-frequency nadir, the most effective measures to address the issue may vary.

Measure 3

The responses from nine BAs were received and analyzed. A high-level summary is provided in Table 2, and additional supporting details are included in Appendix A. Overall, the BAs found this exercise insightful. While the initial data-gathering effort was challenging, identifying the sources of information will facilitate an easier tracking of Measure 3 in the future. MISO and ERCOT have also set up real-time synchronous inertia calculators to allow for easier tracking of Measure 3.

Table 2: Summary Data for Measure 3

BA/ISO	Installed capacity of nonsynchronous generation (NSG), 2014	2014, nonsynchronous generation penetration peak, in % of load at the time	Installed capacity of nonsynchronous generation 2017	2017, nonsynchronous generation penetration peak, in % of load at the time	Inertia trending down?
ERCOT	11,066	39%	21,130	75%	Yes
ISO NE	3,155*	10%	5,591*	23%	Yes
IESO	4,075*	16%	5,607*	22%	Somewhat
MISO	13,726	16%	18,526	21%	Somewhat
BC Hydro	487.2	13%	667	12%	No (too little NSG)
Southern BA	454	1%	2,324	2%	No (too little NSG)
Duke: DEF	0	0%	0	0%	No (no NSG)
Duke: DEC	136	not significant	232	not significant	No (too little NSG)
Duke: DEP	320	not significant	712	not significant	No (too little NSG)

*Includes HVDC import capacity and renewables (for the areas that import during non-synchronous generation peaks). In 2017, increase in installed capacity of NSG is caused by increase in renewable generation; no HVDC tie capacity increase.

Note that Table 2 shows installed nonsynchronous generation capacity in 2014 and 2017 for the respondents as well as peak of nonsynchronous generation penetration defined as:

$$\max_{t\in[1:8760]} \frac{P_{NSG}(t)}{P_{load}(t)} \cdot 100\%$$

Where $P_{NSG}(t)$ is power production from nonsynchronous generation resources in hour *t* (including imports over HVDC ties), $P_{load}(t)$ is BA load in hour *t.*

Based on experience with wind generation in the ERCOT system, nonsynchronous generation displaces conventional synchronous generation on-line that provides synchronous inertia. In ERCOT, periods with high power production from nonsynchronous generation coincide with low load periods; therefore, the hour of maximum nonsynchronous generation penetration corresponds to the hour with minimum synchronous inertia in a year. However, this conclusion does not necessarily apply to other areas. Analyzing the results from different BAs, it became apparent that the results depend on:

- type of nonsynchronous generation,
- time periods when power production from nonsynchronous generation is high, and
- presence of must-run synchronous generation on a system.

Another indicator may be needed to identify minimum synchronous inertia hour in each year. The proposed indicator for the future projections of a minimum of Measure 1 and 3 is an hour of:

$$\max_{t\in[1\ \ 8760]} \frac{P_{NSG}(t)}{\sum_i MVA_{SG\_i}(t)} \cdot 100\%$$

Where $\sum_i MVA_{SG\_i}(t)$ is a sum of MVA ratings of all on-line synchronous generation resources in hour *t.*

Recommendations

- Measures 1, 2, and 3 should be analyzed once a year along with a three-year projection.
- The task force recommends that values be calculated by the appropriate entity (see Table 1) for trending and analysis by the Resource Subcommittee and Frequency Working Group.
- Measures 1 and 3 should be analyzed on an hourly basis (8760 hours per year). However, if a comprehensive yearly data set is not available, another acceptable method would be to use historical snapshots of hours with low load/high nonsynchronous generation (i.e., low synchronous inertia) provided these snapshots capture minimum inertia.
- Related to Measure 3, a BA's synchronous inertial response will change with a changing resource mix. While BAs normally rely on neighboring BAs for inertial response, the tracking of Measures 2 and 3 is important for potential islanding scenarios.
- Eastern Interconnection (EI) – While there appears to be no immediate need to track Measures 1 and 2 at the interconnection level due to lower penetration levels of nonsynchronous generation at this time, there is a need to begin developing data collection methods necessary for Measures 1 and 2 at the interconnection level and developing the capability of tracking these Measures. Once these Measures are tracked on an interconnection basis, a benchmark related to inertia requirements can be established for future years.
- ERCOT – ERCOT should continue to track Measures 1 and 2 due to high renewable penetration.

- WECC – While the data is available for Measures 1 and 2, mapping between generator inertia constants and generator on-line status information is not available. A process needs to be established to map the inertia constants and on-line status of generators.

Observations

- For Measure 3, it would be a good practice to set up a real-time inertia calculation that will simplify the retrieval of synchronous inertial response data for future analysis.
- For Measure 2, it would be beneficial to capture load damping if this information is available. Without inclusion of the load-damping information, Measure 2 may show a somewhat higher frequency deviation than what may actually be occurring.
- It would also be prudent to:
  - produce a common reporting method for BAs and interconnections to simplify data aggregation and trending;
  - clarify the terminology for data fields in data requests; and
  - identify the responsible groups for data collection and data review going forward.

Frequency Response Measures

Frequency response is the traditional metric used to describe how an interconnection has performed in arresting decline and stabilizing frequency after the loss of resources or load. Figures 3 and 4 use two frequency excursion events—one in the Western Interconnection and one in the Eastern Interconnection—to demonstrate the relevant points and values associated with calculating the Frequency Response Measure and for developing trending metrics for frequency response moving forward. Primary frequency response is measured by relating the size of the resource lost to the resulting net change in system frequency. The period in which stabilizing frequency is determined is defined as the time from t_0+20 to t_0+52 seconds following the initiating event (t_0). (See the explanation of the NERC ALR1-12 metric in the text box below).

The conventional definition of primary frequency response is based on stabilizing frequency (Value B) driven by the fact that performance evaluation has been limited to the BA level. BAs have traditionally only had 2- to 6-second scan-rate data available from their supervisory control and data acquisition (SCADA) systems for frequency and interchange measurements. That fact still governs the periodicity of measurement used for frequency response calculations in NERC Standard BAL-003 where the measurements are evaluated at the BA level.

However, recent advancements in higher-resolution synchronized measurement technology on the power system have unlocked capabilities for examining primary frequency response at the interconnection level and at scan rates much faster than conventional SCADA systems. Therefore, the proposal for Measure 4 on frequency response is based on sub-second resolution measurements from phasor measurement units (PMUs) and frequency disturbance recorders (FDRs). These devices record frequency at rates of 10 to 60 samples per second, affording the capability for far greater fidelity when measuring the frequency nadir, which has always been described as an instantaneous value.

Interconnection-level primary frequency response performance is judged against the Interconnection Frequency Response Obligation (IFRO), which is annually calculated to ensure that frequency excursions caused by loss of large-scale resources do not result in tripping of load by under-frequency load shedding (UFLS) systems. Those systems are designed as a backstop to prevent such events from cascading across the BPS. Primary frequency controls are deemed adequate if, following the sudden loss of largest generation,[5] primary frequency control actions provided by on-line resources successfully arrest and stabilize frequency decline prior to dropping firm customer loads through the UFLS programs. If the frequency nadir(s) (Point C or C') is greater than the highest set point for UFLS, then the primary frequency response sufficiently arrested and stabilized frequency. Otherwise, if frequency falls below the UFLS set points, firm customer loads will be dropped as a precaution to further attempt to arrest frequency decline.

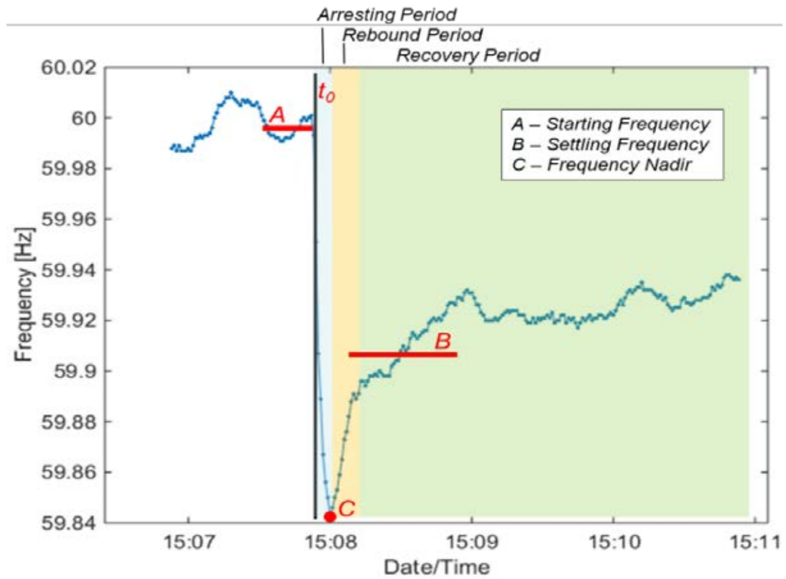


Figure 3. Frequency response example for large disturbance in Western Interconnection

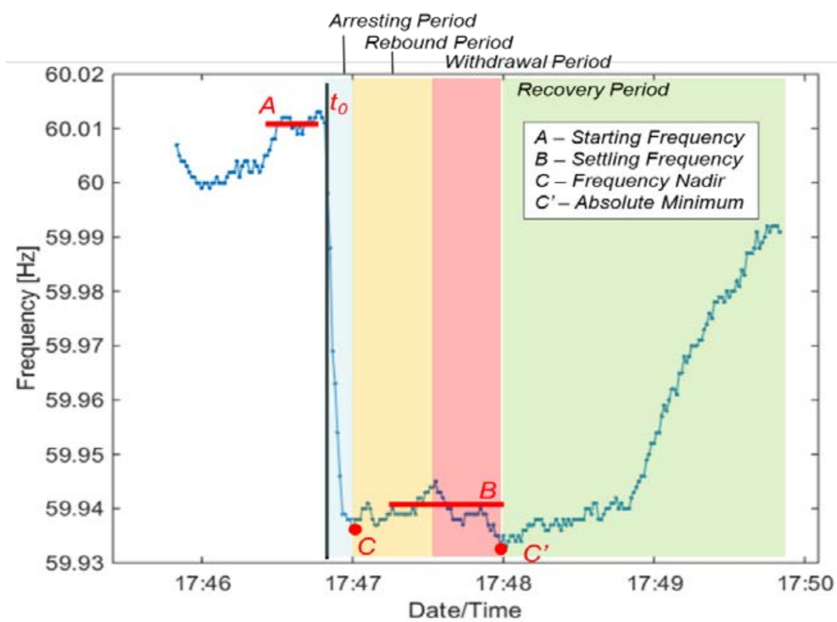


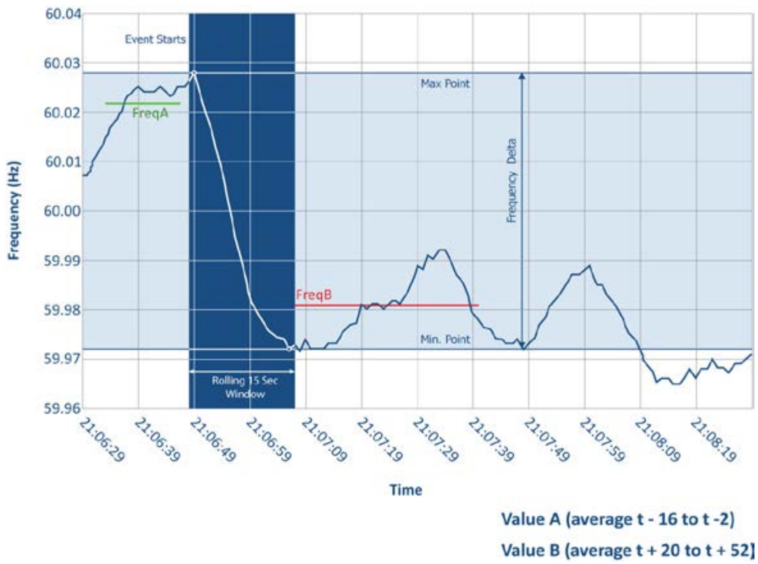
Figure 4. Frequency response example for large disturbance in Eastern Interconnection (with governor withdrawal)

[5] Largest generation loss is defined as largest category C (N-2) event except for Eastern Interconnection, which uses largest event in the last 10 years.

ALR1-12:
This metric is used to track and monitor interconnection frequency response. It is defined as the sum of the change in demand plus the change in generation divided by the change in frequency, expressed in MW/0.1 Hz. The metric measures the average frequency response where frequency drops more than the interconnection's defined threshold (table below). High-resolution frequency measurements from the University of Tennessee, Knoxville (UTK) FNET system are down-sampled to produce 1-second resolution time series data, which is used in ALR1-12 analysis[6].

While the calculations may show trends from year to year, no attempt has been made in this analysis to determine or state what indicates the "acceptable" level of frequency response. Rather, they show the relative performance from year to year and can be a basis for future root-cause analysis.

The figure 5 below shows the criteria for calculating average values A and B; the event starts at time t0. Value A is the average frequency from t0-16 to t0-2 and Value B is the average frequency from t0+20 to t0+52. The difference between A and B is the change in frequency used for calculating frequency response for ALR1-12. The time windows used for calculating these values account for variability in SCADA scan rates, ranging from 2 to 6 seconds between BAs.



Interconnection	ΔFrequency (mHz)	MW Loss Threshold	Rolling Windows (seconds)
Eastern	36	800	15
Western	70	700	15
ERCOT	90	450	15
Quebec	140	450	15

Figure 5. Frequency response example for large disturbance in Eastern Interconnection

[6] See http://www.nerc.com/pa/RAPA/ri/Pages/InterconnectionFrequencyResponse.aspx.

Measure 4: Frequency Response

The following Measures focus on **all** aspects of frequency response and should be trended at the interconnection level to enhance the traditional frequency response metric (ALR1-12). The task force recommends that values be calculated by the appropriate entity on a regular basis and tracked by the Resource Subcommittee and Frequency Working Group. The various components include:

1. **A to B frequency response** captures the effectiveness of primary frequency response in stabilizing frequency following a large frequency excursion. This Measure is the conventional means of calculating frequency response as the ratio of net MW lost to the difference between Point A and Point B.

$$Frequency\ Response_{Current} = \frac{Generation\ Lost\ (MW)}{Frequency_A - Frequency_B}$$

   Trending ALR1-12 in MW/0.1 Hz year to year versus trending only system conditions will provide additional insights concerning primary frequency response levels and characteristics. ALR1-12 metric is already being used. However, trending it versus time does not provide information on how at similar system conditions the response is changing year to year.

2. **A to C frequency response** captures the impacts of inertial response, load response (load damping) and initial governor response (governor response is triggered immediately after frequency falls outside of a pre-set deadband; however, depending on generator technology, full governor response may require up to 30 seconds to be fully deployed). This Measure is calculated as the ratio of net megawatt lost to difference between Point A and Point C frequency.

$$Frequency\ Response_{Nadir} = \frac{Generation\ Lost\ (MW)}{Frequency_A - Frequency_C}$$

   Trending this Measure year to year will capture effects of changes in generation mix and load characteristics and help identify needs for synchronous inertia and/or some forms of fast frequency response (e.g., from battery storage or load resources with under-frequency relays).

3. **C to B ratio** captures the difference between maximum frequency deviation and settling frequency. The C to B ratio is related to governor responsiveness with respect to frequency deviation reading, and its their capability to arrest and stabilize system frequency.

$$C{:}B\ Ratio = \frac{Frequency_C - Frequency_A}{Frequency_B - Frequency_A}$$

   This Measure should also be trended year to year versus trending only system conditions to provide insight into the amount of generation providing primary frequency response compared with the total committed generation on-line.

4. **C’ to C ratio** is the ratio between the absolute frequency minimum (Point C’[7]) caused by governor withdrawal and the initial frequency nadir (Point C).

$$C'{:}C\ Ratio = \frac{Frequency_{C'} - Frequency_A}{Frequency_C - Frequency_A}$$

[7] Point C’ is observed in the Eastern Interconnection following frequency excursions due to large generator trips. Following initial governor response to deviation from set point frequency, generating units’ active power set point control takes over, bringing the unit back to its original operating point. This results in withdrawal of the initial governor response and a consequent decline in frequency due to the decline in injected real power into the system.

In the Eastern Interconnection, the difference between Point C and Point C' is of concern due to governor response withdrawal. While ALR1-12 data does not contain C', original frequency data with 1-second resolution (which captures 300 seconds of an event) can be used. In the Eastern Interconnection, trending the difference between Point C and Point C' for similar-sized events will capture whether Generator Owners are working with vendors to adjust plant Distributed Control Systems load controllers to mitigate the impact of governor response withdrawals.[8]

5. **Time-based Measures** are used to capture the speed in which inertial and primary frequency response as well as governor withdrawal are occurring. These Measures can be trended year to year to identify trends in the rate of change of frequency decline and whether the governor withdrawal phenomena are trending toward improvement or further degradation. These Measures include:
   a. **t_C-t_0 Measure** is the difference in time between the frequency nadir and initial event. It captures the time in which system inertia and governor response arrest declining frequency to its minimum level. Trending this time difference can be useful for ensuring that the defined times for BAL-003-1 fit the actual event data. In addition, trending this with respect to event size and initial frequency can help identify how deadband settings play a role in frequency arrest.
   b. **$t_{C'}$-t_C Measure** is the difference in time between the governor withdrawal minimum and the initial frequency nadir. This Measure captures the time in which governor stabilization and withdrawal occur prior to secondary controls and load responsiveness beginning to return frequency to its initial value.
   c. **$t_{C'}$-t_0 Measure** is the difference in time between the governor withdrawal minimum and the initial event. This provides a comprehensive picture of the overall time in which frequency declines and continues to fall due to the initiating event. While C' should be mitigated and eliminated entirely, the time between the initial event and absolute minimum should also be minimized. In the Eastern Interconnection, it is observed that the minimum frequency level (C' value) due to governor response withdrawal generally occurs 59–78 seconds after an event.

Examples of the proposed frequency response Measures are provided in Appendix A. It should be noted that historical trending of frequency response does not show aggressively degrading frequency response in any of the four interconnections. Efforts related to BAL-003-1 and surveying the Generator Owners regarding governor set point controls have proved effective in communicating the need for primary frequency response. The Measures outlined herein should be tracked for each interconnection such that frequency response can continue to be metricized year to year. If concerns arise and a notable decline in frequency response is observed, then NERC will explore root causes of the declining trends and appropriate action can be taken.

Measure 5: Real-Time Inertial Model

The task force reviewed the development of a real-time model of inertia. As implemented by CAISO, this can include inertia as well as voltage stability limits and transmission overloads as criteria in the model. In CAISO and ERCOT, this type of tool is intended to be an operator tool for situational awareness and alerts them if the system is nearing a limit. The task force decided not to pursue real-time inertia as a measure but, as appropriate, it could be developed and used by a BA as an Industry Practice for those experiencing a decline in system inertia.

[8] The proposed control algorithm to avoid governor response withdrawal was presented during the NERC Frequency Response Initiative webinar on April 7, 2015.

Net Demand Ramping Variability

Changes in net demand require BAs to rely on generators, loads, or other system load-following capabilities. BAs with high penetrations of nondispatchable resources[9] and/or variable energy resources (VERs) may need faster system ramping capability to follow changes in net demand. For example, Figure 6 shows the actual wind (green curve) and solar (yellow curve) production variability experienced by CAISO on March 1, 2014, and Figure 7 shows the actual load (blue curve) and net demand (red curve) for the same day. As shown, the multi-hour ramp during the evening hours partly coincides with sunset. In addition to meeting the increase in load, CAISO must ensure that enough system ramping capability is available to follow the changes in solar and wind production. As BAs integrate more nondispatchable resources and/or VERs into their resource mixes, the need for system ramping capability may increase to ensure compliance with real-time control performance standards. On the other hand, BAs where most VERs and conventional resources are dispatched and responsive to system operator commands may find that they have sufficient flexibility even with growing VER penetrations.

ERSTF analysis found that ramping capability is not currently a challenge for most BAs, but CAISO, with a significant amount of VERs, nondispatchable generation, and base-loaded generation, has found this to be a challenge. CAISO has found that it may not be able to commit more dispatchable resources due to the risk of overgeneration on low demand days, such as on weekends or holidays. It is important to emphasize that the issue is not ramping alone, but the combination of increased ramp rates and limited control of nondispatchable resources and VERs by the system operator.

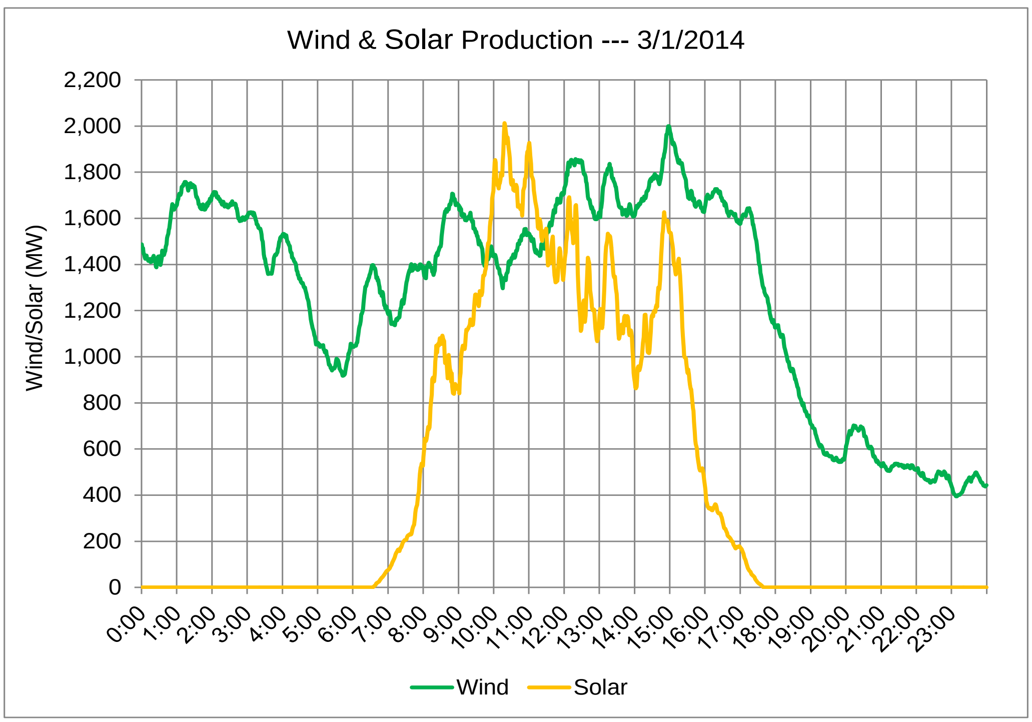


Figure 6: Wind and solar production in CAISO

[9] Nondispatchable generation includes resources for which the BA does not have dispatch authority due physical, regulatory, tariff or contractual reasons, or does not tend to respond to price or dispatch instructions.

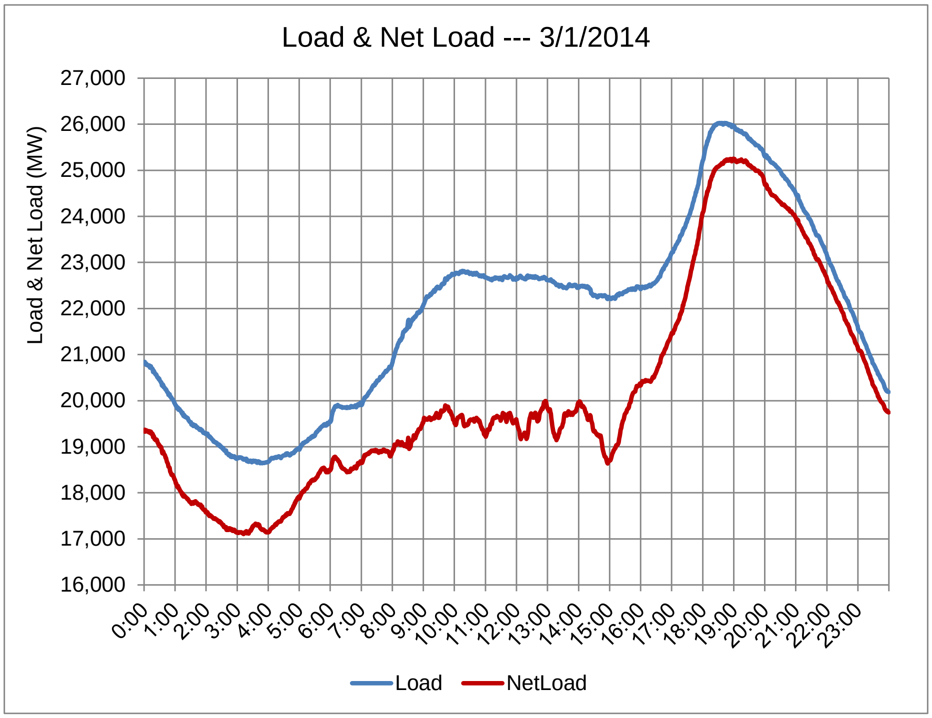


Figure 7: Load and net demand

Measure 6: Net Demand Ramping Variability

This is a measure of net demand ramping variability[10] at the BA level. It provides both a historical and future view of the maximum one-hour-up, one-hour-down, three-hour-up, and three-hour-down net variability. The net variability is generally calculated as the difference between total load and production from VERs, although other variable loads and generation types may be included. This analysis should be done for the current study year, three recent historical years, and a projected year four years in the future (e.g., the 2014 study year would include 2011–2013 historical years and the 2018 future year).

Data Requirements

Calculating the net demand ramping variability measure will generally require one-minute data (or the smallest sample rate available, such as five-minute data) and the creation of a projected build-out of generation and load. The recommended approach is for BAs to use the most current full year of actual load data in one-minute increments and the most current load forecast available from their energy commissions or other forecasts they rely on for system planning studies. Using one-minute load profile data together with one-minute wind and solar production profiles, BAs can develop minute-by-minute net demand profiles by subtracting the wind and solar profiles from the load profiles. BAs can then use this data to identify the maximum one-hour-up, one-hour-down, three-hour-up, and three-hour-down net variability.

Appendix B describes the data, approaches, and details for building the future VER portfolio, including the build-out of load, wind, and solar profile, as well as defining the BA's ramping needs. Examples are provided to show how this is currently being done for both ERCOT and CAISO.

[10] CAISO defines "net demand" as load minus all VER generation, although other variable loads and generation types may be appropriately included depending on their operating characteristics.

Summary of Analysis

Measure 6 outlines a method to evaluate the net demand ramping variability at the BA level. As more resources that exhibit fluctuations in output (such as VERs) are integrated into a BA's resource mix, the BA may be faced with increases or decreases in the amount of demand or generation at certain times during the operating day. This measure provides both a historical and future view of the maximum one-hour-up, one-hour-down, three-hour-up, and three-hour-down net demand variability. A BA expecting an influx of VERs may elect to evaluate variability at different time frames depending on its existing generation mix and/or its scheduling timeline. Ultimately, the BA needs to have adequate resources available to meet the expected demand variability (i.e., the necessary ramping capability).

A recent NERC survey of selected BAs requested historical data as well as expected VERs build-out through 2017. The results of the survey were used to analyze the net demand variability of the three recent historical years and four years in the future. Of the 10 BAs surveyed, only CAISO identified a significant increase in net demand variability or an increased need for flexible capacity in the near-term future years.

For CAISO, this increase in variability is expected to occur during the spring months within the three-hour period prior to the evening demand peaks, which also coincides with the drop-off of production of grid-connected solar resources and rooftop-distributed solar PV. These large three-hour ramps may or may not create operational issues for other BAs depending on the time of their peak demand, amount of nondispatchable resources, and amount of flexible resources within their existing resource mix. The nondispatchable resources within CAISO's existing resource mix are in excess of 10,000 MW (including geothermal, biomass, biogas, and small hydro that count toward California's renewable portfolio standard). When combined with other contractually nondispatchable resources and nuclear resources, nondispatchable conventional resources can exceed 50 percent of supply on low demand days such as weekends. During normal operating conditions, these nondispatchable resources are base loaded and, largely due to contractual rather than physical reasons, can only be curtailed for reliability concerns.

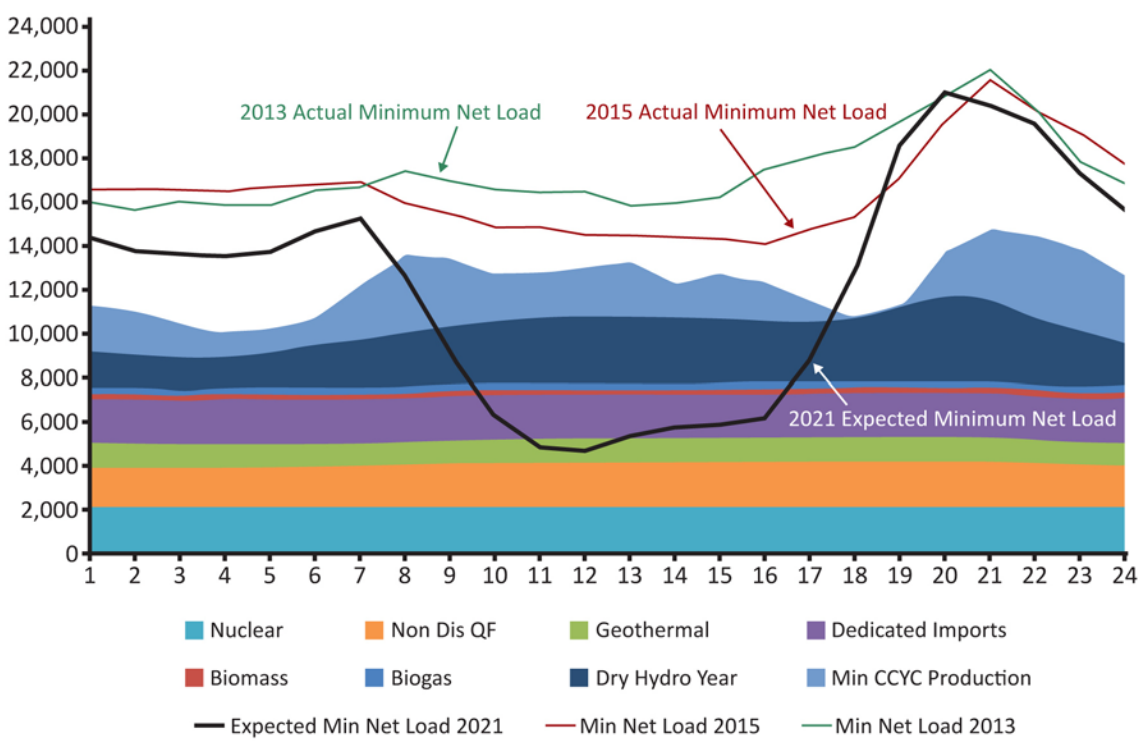


Figure 8: Expected minimum on-line resources in typical spring months, 2021

Recommendations

The ERSTF recommends that Measure 6 be monitored and evaluated at the BA level and the data provided to NERC annually for industrywide trending and analysis by the Reliability Assessment Subcommittee.

Additional considerations for BAs that have or expect to have a high penetration of wind, solar, and nondispatchable resources. BA may choose to:

- Track net demand variability on an annual basis. It is also important to note that rooftop solar PV is netted from demand, so trending of net demand variability may show an increase in variability as more rooftop solar PV is installed.
- Trend their control performance standard 1 (CPS1, see Appendix C) scores on shortened time frames, such as hourly or daily, to identify any correlation between significant intrahour or multihour ramps and CPS1 excursions below 100 percent across the same time frame.
- Begin tracking the frequency and duration when their Balancing Authority ACE Limit (BAAL, see Appendix C) exceeds predefined limits and identify any correlation when these limits are exceeded and insufficient ramping capability exists in the committed fleet.
- Review their net inadvertent interchange to determine if ramping deficiencies within a BA result in inadvertent flows to neighboring entities during ramp deficiencies.
- Develop day-ahead and real-time forecasting tools to better predict VER output changes.

Observations

CAISO, which has high penetration levels of both VERs and nondispatchable resources, provided the following observations:

- Greater risk of overgeneration during periods of low demand because some resources cannot be shut down due to long start-up times or contractual limits.
- Need to mitigate steep intrahour net demand ramps and multihour net demand ramps.
- Need for more flexible resources with ramping capability.
- Need for resources to have the capability to stop and start multiple times per day.
- Greater difficulty in accurately forecasting operating needs of the system.
- Potential for rapid change in the intrahour ramp direction.
- Any nondispatchable resources can exacerbate minimum-generation concerns.

Based on the experience within CAISO, BAs and TOPs with high penetrations of VERs and nondispatchable resources should account for the characteristics of those resources when monitoring and evaluating generation resources included in their unit commitment process or when procuring resources.

Voltage Support

The ability to control the production and absorption of reactive power for the purposes of maintaining desired voltages is critical to the reliable and efficient operation of the power system. Unlike frequency response, which primarily pertains to large regions, voltage issues tend to be local and generally require responses from generators at the appropriate locations or remedial actions such as the installation of static or dynamic reactive resources, addition of series compensation, use of reliability out-of-merit resources, etc. To assess the strength of the system, and to some degree the overall reliability of the system, the industry should consider tracking specific Measures related to voltage support. The Measures can be used to assess the strength of reactive support and to quantify trends that may result from the changing resource mix of both generation and load.

Regional differences may require some flexibility or customization of the Measures. Systems vary widely in their topology and electrical characteristics (e.g., the total level of installed reactive resources, the type of reactive resources, applicable local and regional voltage criteria, etc.). In general, Measures may align with the BA or TOP construct under the NERC functional model, but because of the localized nature of reactive capability, more useful insights should be gained by developing and monitoring the Measures by sub-areas within the BA footprint. Sub-area definitions generally consider system characteristics such as:

- reactive performance within the footprint,
- real power import, export, and flow-through characteristics,
- transmission topology and typical constraints (e.g., surge impedance loading),
- charging from cables or long overhead lines,
- types of resources (i.e., synchronous and/or nonsynchronous/inverter based),
- existing reactive resources (shunt capacitors/inductors, SVCs, STATCOMs, DVARS, generators, HVDC terminals, series compensation, etc.), and
- real and reactive load distribution.

Reactive Power and Sub-Areas:
It is a characteristic of the BPS that reactive power cannot be transmitted long distances. The availability and type of reactive resources also impacts the voltage profile and ability to recover after a contingency. For this reason, planners should consider defining sub-areas or clusters within their footprints that have similar voltage and reactive characteristics. As an example, an urban area that has limited reactive resources relative to its load and must import large amounts of real power may be an appropriate sub-area to analyze. A large rural area with weak transmission, limited load, and significant economic real power resources that are exported may also be an appropriate sub-area to analyze. NERC has produced a whitepaper on this topic. For further information, please reference the *Reactive Support and Control White Paper* developed by the Transmission Issues Subcommittee - Reactive Support and Control Sub-team (May 18, 2009).

Measure 7: Reactive Capability on the System

This Measure tracks static and dynamic reserve capability per total megawatt load at peak, shoulder, and light load levels; and load power factor for distribution at the low side of transmission buses at peak, shoulder, and light load levels. A data request was developed asking for the information on a BA basis for equipment on or connected to the transmission system at 100 kV and above. The measure also offered BAs the option of providing the data by reactive sub-areas if available. The request sought data for the past five years and the current year plus four future years. Several BAs responded to the request.

Observations

Based on the review of the data provided by the participating BAs, it appears that most entities have significant amounts of both dynamic and static reactive margin while maintaining load power factors above 90 percent. There were no cases that showed significant deviations in the year-to-year trends. A few entities did appear to have slightly tighter margins than others; however, these were not considered a significant concern. Review of the data does suggest the value of ongoing monitoring of this Measure.

Recommendations

The results from the data requested in Measure 7 provided insight into the potential reactive strength of the system. It does appear that data provided by individual BAs may impart much more insightful trends if reported on a sub-area basis due to the localized nature of voltage and reactive issues. Entities should consider developing and using a definition of appropriate sub-areas within their footprints to get a clearer picture of system reactive robustness. In order to monitor the continued reactive health of their respective systems, BAs should continue to trend these quantities on an ongoing basis preferably by sub-area to look for new trends and to promote the optimization of dynamic, static, and reactive load. The Measures should be reported and trended based on requirements to be specified by the Performance Analysis Subcommittee and the System Analysis and Modeling Subcommittee.

Measure 8: Voltage Performance of the System

This potential measure would track the number of voltage limit exceedances occurring in real-time operations based on established BA-level voltage criteria (including voltage exceedances during real-time operations) and monitor buses with low short-circuit strength or susceptibility to fault-induced delayed voltage recovery (FIDVR) conditions.

Recommendations

After discussion, the ERSTF decided that there was significant overlap with Measure 9 and no need to pursue this potential measure on a standalone basis.

Measure 9: Overall System Performance

This potential measure would look at events related to a system’s reactive capability and voltage performance to identify if the overall system reactive strength poses a risk to reliability. When an event occurs on the system related to reactive capability and voltage performance, this type of event will most likely fall under the NERC Event Analysis Process. The ERSTF proposed that after this type of event, the reactive margin and voltage performance should be evaluated across all horizons (planning, seasonal, real time). This comparison will provide useful insight into the success of the planning process in designing a robust system, document that the as-built system conforms to the requirements specified in the planning studies, and confirm the ability of Operations to effectively manage those resources in real time. A post-mortem analysis of this nature comports with various requirements in existing and proposed NERC standards.

Recommendations

The ERSTF concluded that this should be considered an Industry Practice, but not a formal Measure that should be tracked at NERC. Because these types of events will fall under the NERC Event Analysis Process, they will still be subject to those reporting requirements. Further analysis and trending would then be undertaken by the Event Analysis Subcommittee.

Measure 10: System Voltage and Reactive Strength Performance

The new TPL-001-4 standard requires the Transmission Planner and the Planning Coordinator to conduct annual assessments of the short circuit capability of the system for the purpose of circuit breaker fault duty analysis. The short circuit data from this assessment can be used to calculate the short circuit ratio (SCR) at buses as defined in IEEE Standard 519-2014. The SCRs can be used as a gauge for identifying areas that may potentially have reliability risks associated with FIDVR-type events and other related voltage stability phenomena. Once low-SCR areas are identified (typically using SCR less than three), entities can utilize traditional study techniques to further analyze the potential for FIDVR and voltage stability issues.

This potential measure is applicable in areas where there is a significant amount of inverter-based resources or other nonsynchronous resources where an additional study process beyond the traditional short circuit ratio calculation is recommended. Study Process Part 1 would serve as a valuable screening tool to identify system areas that would be prone to detrimental inverter based control interactions to the Planning Coordinators. The Planning Coordinators can then utilize Study Process Part 2 to conduct a more detailed analysis of control interactions and develop remedial actions to prevent them.

Observations

Industry studies, most notably in the ERCOT area, have used the study processes documented below. Study Process One has been shown to provide valuable insights into the reactive strength of sub-areas within the network. Study Process Two has then provided additional detail on potential control system interactions that must be addressed in the planning time frame.

Recommendations

- The ERSTF recommends that Planning Coordinators continue to perform traditional short circuit evaluations of their systems per the TPL standard to calculate short circuit ratios and identify weak areas that may require additional traditional voltage and reactive analysis to address potential risks to low-voltage events like FIDVR and voltage instability.
- The ERSTF further recommends that Planning Coordinators employ the suggested additional study processes (Study Process 1 and 2) for areas that either already have or may have significant additions of inverter-based resources or other nonsynchronous resources. The results of this analysis will provide the Planning Coordinators with the necessary information to determine the appropriate reactive support needed and to determine where additional control interaction modifications may be required.
- The Planning Coordinators should strongly consider making the results of these types of studies available to the industry at large as part of an ongoing effort to promote lessons learned for this dynamic and rapidly evolving industry issue.
- The ERSTF proposes that Study Process 1 and 2 be used as an Industry Practice.

Study Process – Part 1

Step 1 – Planners should develop a case that represents anticipated system conditions, including synchronous and nonsynchronous generation commitment at stressed system conditions.

Step 2 – Planners should identify logical voltage/reactive sub-areas within their systems. In general these sub-areas should be based on practical planning and operations experience, and they should typically consider variables such as:

- reactive performance within the footprint,
- real power import, export, and flow-through characteristics,
- transmission topology and typical constraints (e.g., surge impedance loading),
- charging from cables or long overhead lines,
- types of resources (i.e., synchronous and/or nonsynchronous/inverter based),
- existing reactive resources (shunt capacitors/inductors, SVCs, STATCOMs, DVARS, generators, HVDC terminals, series compensation, etc.), and
- real and reactive load distribution.

Step 3 – Planners should then calculate the short circuit ratio for the transmission buses above 100 kV in the sub-areas identified in Step 2 using the following approach. This is a representative indicator of system strength and should be tracked and trended over time.

$$\frac{Lowest\ Short\ Circuit\ Capacity\ in\ a\ sub-area\ _{(MVA)}}{Total\ Nonsynchronous\ Generation\ Capacity\ in\ a\ sub-area\ _{(MW)}}$$

Step 4 – When the short circuit ratio for a sub-area has fallen below 3, system strength is generally considered to be low. This is an indication of potential reliability concerns that may require further investigation, including the control system stability associated with the addition of nonsynchronous or inverter-based resources. An additional assessment of short circuit current and short circuit ratio should be done for weak sub-areas as described in Study Process – Part 2.

Study Process – Part 2

As an additional Industry Practice, further detailed studies are warranted for sub-areas where the short circuit ratio is low and nonsynchronous/inverter-based resources are planned. The planners should calculate the system strength for the identified sub-areas using one of the following approaches:

a. GE's composite short circuit ratio, or
b. ERCOT's weighted short circuit ratio

Planners should also consider using these methods for sub-areas that have traditionally had a high index but are expected to see an increase of nonsynchronous/inverter-based resources.

The study effort to determine relative composite short circuit current and the potential impact on voltage/reactive performance is considered an Industry Practice, and these types of studies should be conducted on a periodic basis or when new nonsynchronous resource additions are planned.

Discussion and Considerations

No industry standard exists for the sub-area short circuit ratio calculation. Further thought and consideration is required to determine the most appropriate short circuit ratio calculation method and the threshold. Actual thresholds should be based on the output of power electronics-based resources instead of capacity.

The increasing penetrations of nonsynchronous resources (including but not limited to wind, solar, and battery storage) could alter system characteristics such as voltage performance and frequency response. These functions have traditionally been provided by synchronous generators, although they can also be provided through fast inverter controls on wind, solar and battery storage plants. However, in situations where the short circuit ratio is low, advanced power electronic devices may not contribute as much as synchronous generators to system strength due to limited short circuit current contribution. A weak grid can also result in potential system stability issues that may cause undesirable oscillation or generation trip during normal or abnormal operations. Therefore, it is important to understand the system strength impact, particularly with changes of generation mix in a region, to ensure that stable operations can be maintained.

From a system assessment perspective, the typical stability analysis using a positive sequence time domain simulation tool focuses on the system response at a frequency less than 10 Hz. The dynamic models applied in such a simulation tool will simplify the high-frequency components, including power electronic controllers, with a fixed time constant or an algebraic equation. Under a weak grid condition, the dynamic stability analysis using the positive sequence simulation tools may not be adequate and the results can be conservatively optimistic. A more detailed analysis may be needed to properly consider all behaviors of the controller under a weak grid condition.

Short circuit ratio is a metric that has traditionally represented the voltage stiffness of a grid. Conventionally, SCR is defined as the ratio of the short circuit capacity, at the bus where the device is located, to the megawatt rating of the device. Based on this definition, SCR is given by:

$$\mathrm{SCR} = \frac{S_{SCMVA}}{P_{RMW}} \qquad (1)$$

where S_{SCMVA} is the short circuit capacity at the bus before the connection of the device and P_{RMW} is the rated megawatt value of the device to be connected.

Equation 1 is the commonly used SCR calculation method when evaluating system strength. The key assumption and limitation of this SCR calculation method is that the studied wind or solar plant does not interact with other such plants in the system. When plants are electrically close to each other, they may interact with each other and oscillate together. In such cases, the SCR calculation using equation 1 can result in an overly optimistic result.

There is currently no industry-standard approach to calculate the proper SCR index for a weak system with high penetration of wind and solar power plants (or other inverter-based resources, such as battery storage). To take into account the effect of interactions between plants and give a better estimate of the system strength, a more appropriate quantity or indicator is needed to assess the potential risk of complex instability. Several approaches, such as GE's Composite Short Circuit Ratio (CSCR) and ERCOT'S Weighted Short Circuit Ratio (WSCR) method, have been proposed to calculate the SCR for a weak system with high penetration of renewable generation. The CSCR and WSCR methods are described in Appendix E.

The values should initially be generated using the past three and future three years of planning and operational data, if such data is available, to test the potential merits of tracking these indices over time and going forward. Once the potential merit has been confirmed, a process for collecting data on future trends should be established.

The low SCR, indicating a weak grid, will serve as a risk indicator to require a more detailed review and modeling for proper reliability assessments. It should be noted that the information obtained in this Industry Practice is to provide an indicator of system strength that will require a more detailed analysis for the identified weak grid condition. It does NOT mean that there is a reliability risk or violation for the identified sub-areas, but instead suggests that additional study and consideration is warranted.

Additional Considerations of the ERSTF

As part of its due diligence, the task force examined the potential impact of Distributed Energy Resources on the BPS. The task force determined DERs should be evaluated to determine any potential impact on the proposed Measures and to identify any necessary follow-up activity that may fall outside the purview of the ERSTF.

Distributed Energy Resources

DERs are becoming a significant element of net load on distribution systems in a few areas of North America. This industry will continue to grow as more announcements are made for future development. From the Bulk Electric System (BES) perspective, distribution load is the combination of connected load and DER generation with the additional influence of DER resources, such as distributed storage, demand-side management, and microgrids, which can both increase and decrease the perceived load at the level of the BES. Although DERs are not explicitly modeled at the BES level today, they will increasingly affect the net distribution load that is observed at the BES level. Taken together, the BES, small resources below the minimum size of BES generator definitions, and net distribution load make up the BPS.

Reliable operation and planning of the BPS requires accurate modeling, forecasting, and measurement of resources, loads, and system topology. The capability of DERs to interact seamlessly with the BPS, such as for frequency and voltage ride-through requirements, is not well coordinated with NERC reliability standards. This lack of coordination can lead to events where the connection and/or disconnection of VERs may abruptly change the net distribution load during frequency excursions or voltage deviations. This may further exacerbate a disturbance on the BPS, while more useful responses from DERs could support the BPS and contribute to reliability and system recovery during disturbances.

A thorough consideration of the reliability coordination and contributions from DERs was beyond the scope of the ERSTF, but the task force considers such activities to be increasingly important and makes the following general recommendations:

- To minimize the possibility of unintended DER impacts on the BPS, DER frequency and voltage ride-through requirements should be considered with regard to NERC Reliability Standards. IEEE Standard P1547, a DER interconnection standard, is currently being revised by the IEEE Standards Association in project IEEE P1547. Efforts to further coordinate IEEE P1547 with NERC Reliability Standard PRC-024-2 (Generator Frequency and Voltage Protective Relay Settings) and other relevant standards should continue with the objective that DERs meet or exceed reliability similar to BES resources to address any unintended consequences that could occur during operation of the BPS. Participation by Transmission Operations and Planning subject matter experts in the IEEE P1547 drafting effort is strongly recommended to provide a BPS perspective to inform the IEEE P1547 drafting team efforts.
- In several regions, DERs are poised to reach levels that will have significant influence on BPS operations either on an individual or aggregated basis. This provides both opportunities and challenges that need to be represented in models, planning activities, and operating practices. Pursuant with NERC's Reliability Assessment obligations, the ERSTF recommends that NERC establish a working group to further examine the ability to forecast, visibility, control, and participation of DERs as an active part of the BPS. With prudent planning, operating, and engineering practices, and policy that is oriented to support reliability, DERs should be able to be reliably integrated into BPS operation.

Summary and Conclusions

The North American BPS is undergoing a significant change in the mix of generation resources. Various factors are leading to a future mix that uses less coal, more natural gas, more wind and solar, and more forms of distributed generation and demand response. NERC created the Essential Reliability Services Task Force in 2014 to consider these changes and identify measures to assess reliable operation of the BPS.

The task force found that the most important essential reliability services largely encompass managing frequency, net demand ramping, voltage performance, and dispatchability. This report describes a set of Measures and Industry Practices in precise detail; this section provides a high-level review of the key findings.

The task force looked closely at the North American BPS, especially those areas that are experiencing the greatest level of change in types of resources used to serve load. While the behaviors of conventional generators are well documented, the task force also reviewed the capabilities of newer technology such as wind, solar, battery storage, and other types of generators. Based on this analysis, a number of Measures and Industry Practices were then identified, with the recommendation that Measures should be tracked and Industry Practices should be used by the appropriate entities as the generation mix changes over the coming years. The Measures and Industry Practices are designed to assist the impacted entity in handling real-time operational concerns as well as comprehensive planning for future resource changes.

Frequency – Many of the Measures relate to restoring frequency after an event such as the sudden loss of a major resource. The frequency within an interconnection will immediately fall upon such an event, requiring a very fast response from some resources to slow the rate of fall, a fast increase in power output (or decrease in power consumption) to stop the fall and stabilize the frequency, then a more prolonged contribution of additional power (or reduced load) to compensate for the lost units and bring system frequency back to the normal level. The task force recommends Measures to track the minimum frequency of a system and frequency response following the observed contingency events, track and project the levels of conventional synchronous inertia for each balancing area and the interconnection as a whole, and track and project the initial frequency deviation in the first half-second following the largest contingency event for each interconnection.

Ramping – Ramping is related to frequency, but more in an "operations as usual" sense rather than after an event. Changes in the level of nondispatchable resources, system constraints, load behaviors, and the generation mix can impact the ramp rates needed to keep the system in balance. The task force recommends a Measure to track and project the maximum one-hour and three-hour ramps for balancing areas that may experience such concerns.

Voltage – Voltage must be controlled to protect the system and move power where it is needed. This tends to be more local in nature, such as at individual transmission substations, in sub-areas of lower-voltage transmission nodes and the distribution system. Ensuring sufficient voltage control and "stiffness" of the system is important both for normal operations and for events impacting normal operations (i.e., disturbances). The task force recommends Measures to track and project the static and dynamic reactive power reserve capabilities to regulate voltage at various points in the system. Industry Practices are also recommended to monitor events related to voltage performance, periodically review the short circuit current at each transmission bus in the network, and do further analysis of short circuit ratios when penetration of nonsynchronous generation (wind, solar, batteries, etc.) is high or anticipated to increase.

The detailed Measure recommendations are summarized as follows:

- Frequency Support Recommendations
  - Calculate the instance of minimal synchronous inertial response (SIR) that occurred in the recent historical study year and its projected value for the next three years (Measure 1 for interconnection and Measure 3 for BAs).
  - At minimum SIR conditions for each of the historical and future years above, determine the frequency deviation that would result within the first 0.5 seconds following the largest contingency of the interconnection (Measure 2 for interconnection).
  - Each interconnection should measure the minimum frequency point (the Nadir) and all aspects of frequency response following observed contingency events (Measure 4).
  - A measure related to situational awareness modeling of available inertia for near-real-time applications when operating the grid was considered. This was identified as an Industry Practice but not recommended as a measure.
- Net Demand Ramping Variability Recommendations
  - Each BA should calculate the historical and projected maximum one-hour-up, one-hour-down, three-hour-up, and three-hour-down net demand ramps (actual load less production from VERs) using one-minute data (Measure 6). Although changes in ramping needs may not indicate a concern, the historical and projected ramp values by BA should be reviewed at both the BA and NERC level to allow for early identification of potential areas for further analysis.
- Voltage Support Recommendations
  - Measures of reactive capability should be calculated and tracked by the appropriate registered entity, including both static and dynamic reserve capability per total megawatt load at peak, shoulder, and light load levels; and load power factor for distribution at the low side of transmission buses at peak, shoulder, and light load levels (Measure 7).
  - The ERSTF considered, but does not recommend, potential measures of voltage performance for tracking voltage exceedances during real-time operations and monitoring buses with low short circuit strength or susceptibility to fault-induced delayed voltage recovery (FIDVR) conditions (Measure 8).
  - The ERSTF discussed a potential measure for reviewing system events that suggest stressed reactive capability or degraded voltage profiles to compare planned performance with real-time operations and evaluate voltage performance. This was identified as an Industry Practice but not recommended as a Measure.
  - The appropriate registered entity should measure system strength based on calculating short circuit ratios for sub-areas in the system. This was identified as an Industry Practice but not recommended as a Measure.

The ERSTF has made an initial effort to encourage industry to think more carefully about what system behavior exists today, how this behavior may change in the future, what characteristics will be needed from resources in the future, and how to make the transition in a reliable way. New resources may have different operating characteristics but can be reliably integrated with proper planning, design, and coordination. Maintaining reliability is embodied in the predictability, controllability and responsiveness of the resource mix. At a higher level, this suggests several general recommendations:

1. Recommend that all new resources have the capability to support voltage and frequency. Automatic voltage regulators and governors have been standard on conventional generators for decades and

comparable capabilities are currently available for new VERs and other resources. Ensuring that these capabilities are present in the future resource mix is prudent and necessary.

2. Recommend the monitoring of the Measures and investigation of trends. The Measures are intended to highlight aspects that could suggest future reliability concerns if not addressed with suitable planning and engineering practices.
3. Recommend planning and operating entities to use the Industry Practices. While the results of Industry Practices will be system-specific and difficult to quantify or compare between different regions, they will help ensure that emerging concerns are addressed with suitable planning and engineering practices.
4. While beyond the formal scope of the ERSTF, the task force recognizes that Distributed Energy Resources (DERs) will increasingly affect the net distribution load that is observed by the BPS. The ERSTF recommends coordination of NERC Reliability Standards with DER equipment standards such as IEEE 1547.
5. Recommend open sharing of experiences and lessons learned. Provided that we act prudently, the reliability of the system can be maintained or improved as the resource mix evolves.

Federal, state, and local jurisdictional policy decisions can have a direct influence on changes in the resource mix and thus can also affect the reliability of the BPS. As the resource mix continues to change, it is necessary for policy makers to recognize the need for essential reliability services in the current and future mix of resources. Analyses of this transformation must be done to allow for effective planning and provide system operators the flexibility to modify real-time operations for reliability of the electric grid. The NERC ERSTF recommendations will assist in informing policy makers of the implications of the changing resource mix and will strengthen the ability of the electric power industry to manage the evolution of the system in a reliable manner.

The Measures and Industry Practices developed and recommended by the NERC ERSTF provide insights into the current challenges in certain areas of North America as related to the changing resource mix. In addition, the Measures will provide means of assessing future trends and engineering solutions to ensure that reliability is not degraded as the resource mix continues to evolve across all of North America. As such, the NERC ERSTF recommendations will assist in informing policy makers and stakeholders of the implications of the changing resource mix and how the system can continue to make this transition in a reliable manner.

Appendix A – Frequency Support

Inertial Response

Rotating turbine generators and motors that are synchronously interconnected to the system store kinetic energy during contingency events that is released to the system, also called inertial response. Inertial response provides an important contribution in the initial moments following a generation or load trip event: determining the rate of change of frequency. In response to a sudden loss of generation, kinetic energy will automatically be extracted from the rotating synchronized machines on the interconnection, causing them to slow down and causing frequency to decline. The amount of inertia depends on the number and size of generators and motors synchronized to the system, and it determines the rate of frequency decline. Greater inertia reduces the rate of change of frequency, giving more time for primary frequency response to fully deploy and arrest frequency decay above under-frequency load shed set points.

With the increasing use of nonsynchronous generation, other electronically coupled resources, and changing load characteristics, synchronous inertial response (SIR) is reduced. Particularly in areas with a high share of renewable resources, this leads to a need to determine minimum amounts of SIR necessary to ensure system reliability as well as the required amounts of primary frequency response based on expected SIR conditions. For systems where the amount of SIR is decreasing, various ways of compensating to maintain reliability are possible, potentially including synthetic inertia from wind turbines (very fast frequency response) and synchronous condensers. In some cases, retiring coal plants could be converted to synchronous condensers that provide inertia and other services without emissions.

Frequency Response (Primary Frequency Control)

Frequency response can be divided into three categories that are applicable to certain operating periods of time:

- Primary frequency control (immediate time frame)
- Secondary frequency control (seconds to minutes)
- Tertiary frequency control (tens of minutes and longer)

Primary frequency control, also known as frequency response, comes from automatic generator governor response, load response, and other devices based on local (device-level) frequency-sensing control systems. In general, frequency response refers to the initial actions provided by the autonomous devices within an interconnection to arrest and stabilize frequency deviations, typically from the unexpected sudden loss of a generator or load.

Primary frequency control is quick and automatic; it is not driven by any centralized control system, and it begins seconds after a system frequency event. Response to a frequency event can be provided by various sources, including generation resources, loads, and storage devices. Each resource type may have different response times, and the level of positive contribution can vary depending on system conditions. Secondary and tertiary control are the centralized, coordinated control of generation, demand response, and storage resources, and these controls are performed by the system operator’s energy management system over minutes to hours to balance generation and load.

Synchronized turbine generator automatic control systems (governors) can sense the decline in frequency and control the generator to increase the amount of energy injected into the interconnection. Frequency will continue to decline until the amount of energy is rebalanced[11] through the automatic control actions of primary frequency

[11] Offsets the amount of energy lost and replaces the amount of kinetic energy supplied by inertia.

response resources. Greater inertia reduces the rate of change of frequency, giving more time for governors to respond. Conversely, lower inertia increases the reliability value of faster-acting frequency control resources in reducing the severity of frequency excursions.

Procedure for calculation of historical and projected system SIR and rate of change of frequency (RoCoF)

The Purpose of this procedure is to:

- Analyze the impact from increasing amounts of nonsynchronous generation on kinetic energy (synchronous inertia) trends of a BA or an interconnection over a number of years.
- Find and analyze hours with lowest system inertia (at BA level or interconnection level).
- Calculate RoCoF after the largest contingency in those hours (only at an interconnection level).
- Project lowest system inertia conditions (highest RoCoF) for future years, based on nonsynchronous generation projections.

1. Historic kinetic energy calculations and trends for future projections for Measure 1 (SIR at an interconnection level) and Measure 3 (SIR at a BA level)

1.1 Data requirements (from BAs in an interconnection)

- Hourly status (on-line/off-line) of all generators and synchronous condensers, if present in a studied system.
- Power production by generator, *i*, for all synchronous generators in a studied system with hourly resolution, $P_i(t)$, for a historic year, if available to supplement unit status information and eliminate some telemetry errors.
- Total nonsynchronous generation (NSG) in a studied system with hourly resolution, $P_{NSG}(t)$, for a historic year.
- Hourly system load (including any HVDC exports/imports) for a historic year $P_{load}(t)$. (Note: In areas with significant HVDC imports, these can be included explicitly as non-synchronous generation $P_{NSG}(t)$.)
- MVA rating of each synchronous generator *i* in a studied system, MVA_i.
- Inertia constant H_i for each generator and synchronous condenser *i* in a studied system (in seconds on machine MVA rating, MVA_i).
- If the inertia constant is not available, typical values based on generation technology may be used as a starting point (e.g., P. Kundur, "Power Systems Stability and Control," p. 134 table with typical inertia constants).

1.2 Additional data requirements (at interconnection level)

- Largest contingency for a studied interconnection (as defined by the Resource Contingency Criteria in NERC BAL-003), ΔP_{MW}.
- Load damping, *D*, expressed in percent per 1 percent frequency change if available (if not available, a 0 load damping assumption represents a more conservative approach). Load damping data can be obtained from the analysis of past generation trip events.

1.3 Calculation procedure

1. Calculate H_i*MVA_i for each generator *i.*

2. For every hour t in a studied historical year, add H_i*MVA_i of all generators that are on-line producing more than a certain threshold (e.g., > 5 MW) and all synchronous condensers that are on-line:

$$KE(t) = \text{sum}(H_i*MVA_i) \tag{1}$$

3. Once kinetic energy is calculated for every hour, construct a boxplot for a studied year (e.g., with boxplot function available in Matlab), Figure A.1.
4. On the boxplot (Figure A.1) each box represents one year of historic kinetic energy data. On each box, the central mark (red line) is the median, the edges of the box (in blue) are the 25th and 75th percentiles, the whiskers correspond to ± 2.7 sigma (i.e., represent 99.3 percent coverage, assuming the data are normally distributed), and the outliers are plotted individually (red crosses). If necessary, the whiskers can be adjusted to show a different coverage.
5. On the same figure, plot system inertia corresponding to NSG penetration peak in a year (blue dots in Figure A.1, which demonstrate downward trend for ERCOT).
6. Determine minimum kinetic energy in a year KE_{min} = min($KE(t)$). Does minimum kinetic energy in a year coincide with NSG penetration peak? These findings can be used for projections of minimum kinetic energy in a future year.

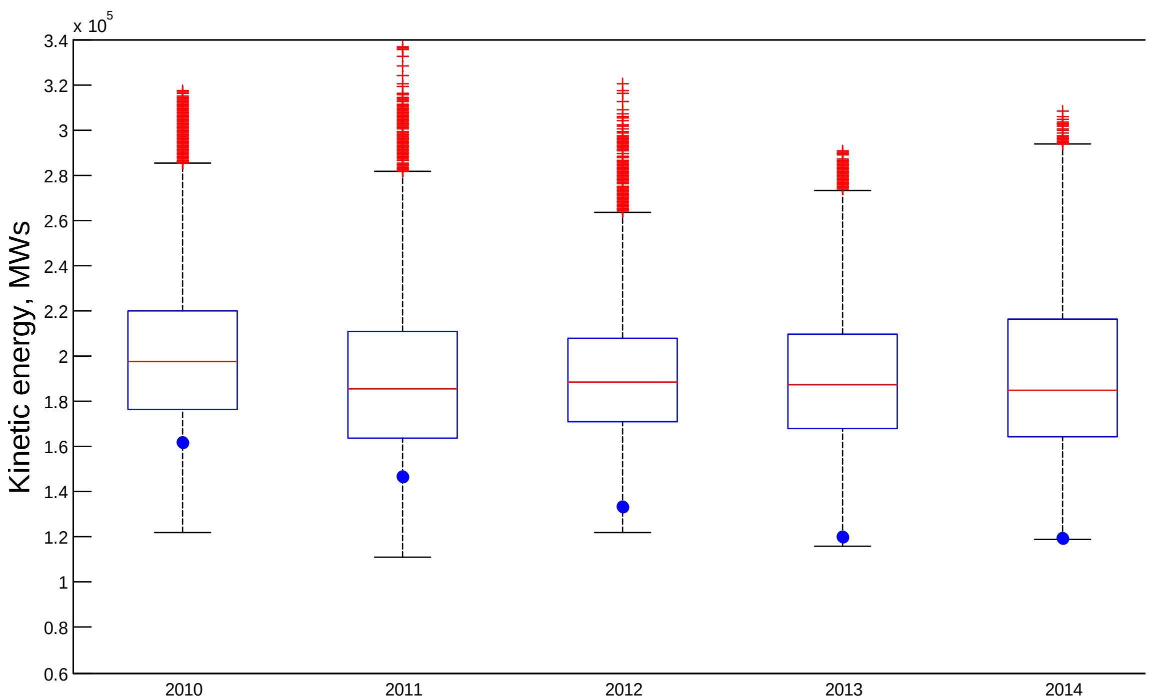


Figure A.1: Boxplot of historic kinetic energy or synchronous inertia (2010–2014)

7. Calculate system net demand as $P_{NL}(t) = P_{load}(t) - P_{NSG}(t)$ for every hour t in a year.
8. Plot hourly system inertia $KE(t)$ vs corresponding net demand $P_{NL}(t)$, and produce a trend line (e.g., linear trend line as $KE(t) = a \cdot P_{NL}(t)+b$), Figure A.2.

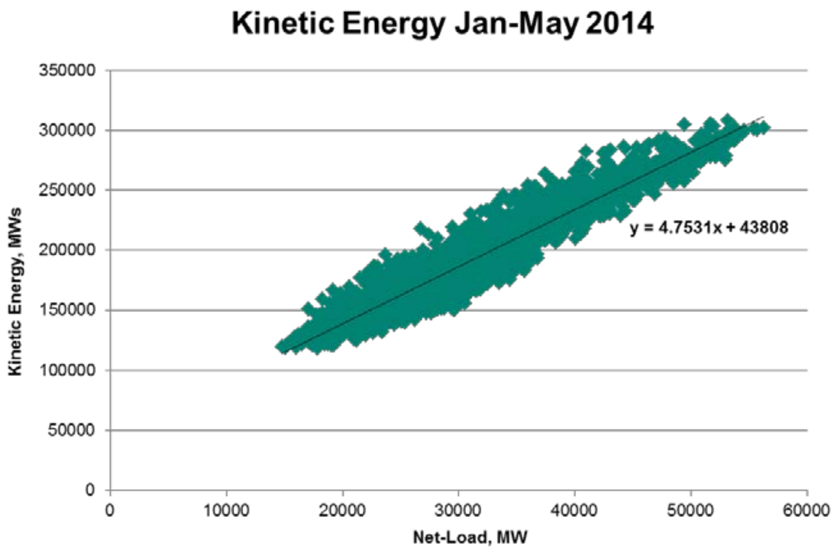


Figure A.2: Hourly system inertia Jan–May 2014 vs corresponding system hourly net demand for ERCOT system with linear trend line

2. Historic rate of change of frequency calculations for Measure 2 (initial frequency deviation following largest contingency at an interconnection level)

1. For each historic year and at minimum kinetic energy conditions KE_{min}, calculate RoCoF over the first 0.5-second window after the largest contingency ΔP_{MW} (as defined by the RCC in BAL-003-1 (e.g., RCC for ERCOT is 2750 MW)).
   Rate of change of frequency over the first 0.5-second window after the contingency is calculated as:
   a. For systems where load damping constant D is not available:

   $$\text{RoCoF} = \Delta P_{MW}/(2^* (KE_{min}\text{-}KE_{RCC}))^*60 \qquad [\text{Hz/s}] \tag{2}$$

   Note: Here with load damping constant *D* assumed to be 0, RoCoF is independent of a time window (for the first few seconds before governor response becomes effective). KE_{RCC} is kinetic energy of the largest contingency, i.e. *H*MVA* of the largest unit(s) as defined by RCC in BAL-003-1.

   b. For systems where load damping constant *D* is available, use the following equation to calculate frequency deviation at 0.5 seconds:

   $$\Delta f_{0.5} = \frac{\Delta P_{MW}}{D \cdot P_{load}} \cdot \left(1 - e^{\frac{-0.5 \cdot D \cdot P_{load}}{2 \cdot KE_{min} - KE_{RCC})}}\right) \cdot 60 \qquad [\text{Hz}] \tag{3}$$

   P_{load} is system load during minimum kinetic energy conditions KE_{min}.

   Corresponding RoCoF is calculated as

   $$\text{RoCoF} = \frac{\Delta f_{0.5}}{0.5} \qquad [\text{Hz/s}] \tag{4}$$

2. Calculate corresponding system frequency as:

$$f_{0.5} = f_o - 0.5*\text{RoCoF} \qquad [\text{Hz}] \qquad (5)$$

f_o is predisturbance frequency, assumed to be 60 Hz.

Example:

- Example date 12/14/2011 4 am
- Load Damping 2.44% per Hz
- Largest Contingency ΔP_{MW}=2750 MW
- P_{load} = 24744.66 MW
- Pre-disturbance frequency f_o=*60 Hz*
- *KE(t)*=sum(H_i*MVA_i) = 147081 MWs for that hour, i.e. sum of H_i*MVA_i for all synchronous generators that were producing more than 5 MW in this hour
- *RoCoF* for this hour (hour 8333 in a year) can be calculated as follows

Calculation procedure

1. Convert Load damping into percent load change per 1 percent frequency change
   1 Hz=1/60=1.67 percent of 60 Hz
   D=2.44/1.67=1.46 pecent per 1 percent frequency change
2. $\Delta f_{0.5} = \frac{\Delta P_{MW}}{D \cdot P_{load}} \cdot \left(1 - e^{\frac{0.5 \cdot D \cdot P_{load}}{2 \cdot KE(t)}}\right) \cdot 60 = \frac{2750}{1.46 \cdot 24744.66} \cdot \left(1 - e^{\frac{0.5 \cdot 1.46 \cdot 24744.66}{2 \cdot 147081}}\right) \cdot 60 = 0.272$
   [Hz]
3. *RoCoF*=0.272/0.5=0.544 Hz/s
4. $f_{0.5}$=f_o-0.5**RoCoF*=60-0.5*0.544=59.728 Hz

3. Plot system frequency after the largest contingency event calculated in step 2, assuming linear trend between time = 0 and time = 0.5 seconds, Figure A.3.

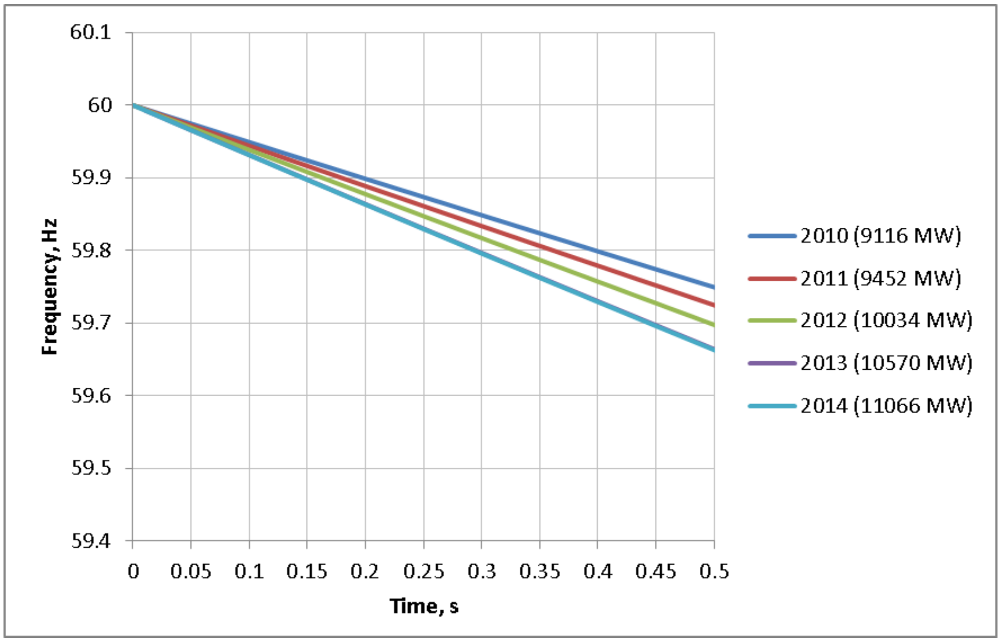


Figure A.3: Calculated system frequency after 2750 MW generation trip, during nonsynchronous generation penetration peak in ERCOT for years 2010–2014

4. Analyze system load and the nonsynchronous generation penetration level during minimum kinetic energy conditions KE_{min} for several years. Derive trends that could be used to project minimum kinetic energy conditions for a future year (e.g., coincidental nonsynchronous generation and load during minimum kinetic energy hour in a future year). In the following sections, kinetic energy and RoCoF projections are made for the highest instantaneous nonsynchronous generation penetration hour in a future year.

3. Analyze hours of highest instantaneous nonsynchronous generation penetration in a number of historic years to calculate future projections.

3.1 Additional data requirements (from BAs in an interconnection)

- Installed capacity of nonsynchronous generation-by-generation technology (e.g., wind-installed MW, PV-installed MW, etc.) in each studied historic year.

3.2 Calculation procedure

1. For each year and in each hour, calculate instantaneous nonsynchronous generator penetration (NSGP) as $\gamma(t) = P_{NSG}(t)/P_{load}(t)$;
2. In a year, find an instantaneous nonsynchronous generation penetration peak, $\gamma(t_{max}) = \max(P_{NSG}(t)/P_{load}(t))$ and an hour t_{max} in which it was encountered

Example:

In ERCOT on March 31, 2014, 2:00 a.m. (hour t = 2139 in a year)

- the system load (including any dc exports/imports) was $P_{load}(2139)$ = 24617 MW.
- total nonsynchronous generation was $P_{NSG}(2139) = P_{wind}(2139)$ = 9699 MW, all provided from wind generation.
- nonsynchronous generation penetration at the time was $\gamma(2139) = P_{NSG}(2139)/P_{load}(2139) = 9699/24617 = 0.394$.

Conducting similar calculations for each hour of 2014, we can see that on March 31, at 2:00 a.m., instantaneous nonsynchronous generation penetration was the highest in the year (i.e., $\gamma(2139) = \max_{2014}(P_{NSG}/P_{load}) = 0.394$, $t_{max} = 2139$.)

3. For the hour of highest nonsynchronous generation penetration, t_{max}, determined in step 2 above, calculate power production from each nonsynchronous generation technology (e.g., wind, PV) as a share of the total installed capacity $\eta(t_{max})$ of this generation technology (e.g., $\eta_{wind}(t_{max})=P_{wind}(t_{max})/P_{installed\_wind}(t_{max})$ for wind generation, $\eta_{PV}(t_{max})=P_{PV}(t_{max})/P_{installed\_PV}(t_{max})$ for PV generation, etc.). If some nonsynchronous generation resources are concentrated in certain geographical areas, η may be calculated separately for each generation technology in each geographic area.

Example:

For ERCOT's example above, wind production, is expressed as a share of the total installed wind generation capacity, $P_{installed\_wind}(2139)$ = 11066 MW during highest nonsynchronous generation penetration hour t_{max} = 2139, is: $\eta_{wind}(t_{max}) = P_{wind}(2139)/P_{installed\_wind}(2139)$ =9699/11066=0.88.

For all studied historical years (2010–2014), $\eta_{wind}(t_{max})$ and $\gamma(t_{max})$ are shown in the table below along with underlying data.

	2010	2011	2012	2013	2014
Installed Capacity, MW	9,116	9,452	10,034	10,570	11,066
Non-synch. gen. penetration peak, $\gamma(t_{max})$	25.5%	27.4%	29.8%	35.8%	39.4%
P_{wind}, MW	6,483	6,772	7,247	8,773	9,699
Wind producion in % of installed capacity, $\eta_{wind}(t_{max})$	71%	72%	72%	83%	88%
P_{load}, MW	25,427	24,745	24,328	24,488	24,617

4 Projecting kinetic energy and RoCoF at renewable penetration peak hour for a future year Additional data requirements (for BAs in an interconnection)

- Expected installed nonsynchronous generation-by-generation technology in a future year based on generation interconnection agreements (GIAs), financial commitments (FCs), and other criteria, e.g., $P_{installed\_wind\_future}$

4.2 Calculation procedure

1. Project system load $P_{load,\ future}$ during nonsynchronous generation penetration peak based on the analysis and findings from Section 1, step 4.

> **Example:**
>
> For the ERCOT system, it was found that during nonsynchronous generation penetration peak hours for years 2011–2014, system load was nearly the same. Therefore, average system load from years 2010–2014, nonsynchronous generation penetration peak hours, was assumed even for projected nonsynchronous generation peak hours ($P_{load,\ future}$ = 24,700 MW) in future years 2015–2017.

2. Apply installed capacity share factor $\eta(t_{max})$ (as calculated in Section 3 step 3) to the expected installed capacity of respective generation technology (and geographical location); e.g., $P_{wind\_future}(t_{max}) / \eta_{wind}(t_{max}) * P_{installed\_wind\_future}$, $P_{PV\_future}(t_{max}) = \eta_{PV}(t_{max}) * P_{installed\_PV}(t_{max})$, etc. This is the projected production by nonsynchronous generation type during a forecast nonsynchronous generation penetration peak in a future year.

   Total nonsynchronous generation during projected nonsynchronous generation penetration peak in a future year is then $P_{NSG\_future} = P_{wind\_future}(t_{max}) + P_{PV\_future}(t_{max})$.

> **Example:**
>
> For the ERCOT system, with the future load assumption P_{load_future} as per the previous example and expected nonsynchronous generation capacity, $\eta(t_{max})$ and corresponding wind production $P_{wind\_future}(t_{max})$ are projected for each year (2015–2017):

	2014	2015	2016	2017
Installed Capacity, MW	11,066	19,443	20,630	21,130
Non-synch. gen. penetration peak, $\gamma(t_{max})$	39.4%	69%	73.2%	75%
P_{wind}, MW	9,699	17,041	18,082	18,520
Wind producion in % of installed capacity, $\eta_{wind}(t_{max})$	88%	88%	88%	88%
P_{load}, MW	24,617	24,700	24,700	24,700

3. Calculate projected net demand, $P_{NL,future} = P_{load,future} - P_{NSG,future}$

4. Calculate projected system kinetic energy during nonsynchronous generation penetration peak based on the trend line obtained in Section 1.3 step 8 (e.g., linear trend line $KE = a \cdot P_{NL} + b$), at $P_{NL} = P_{NL,future)}$.
5. Plot projected kinetic energy on the same figure as boxplots (Figure A.1) to obtain the figure below (which is identical to Figure 1).

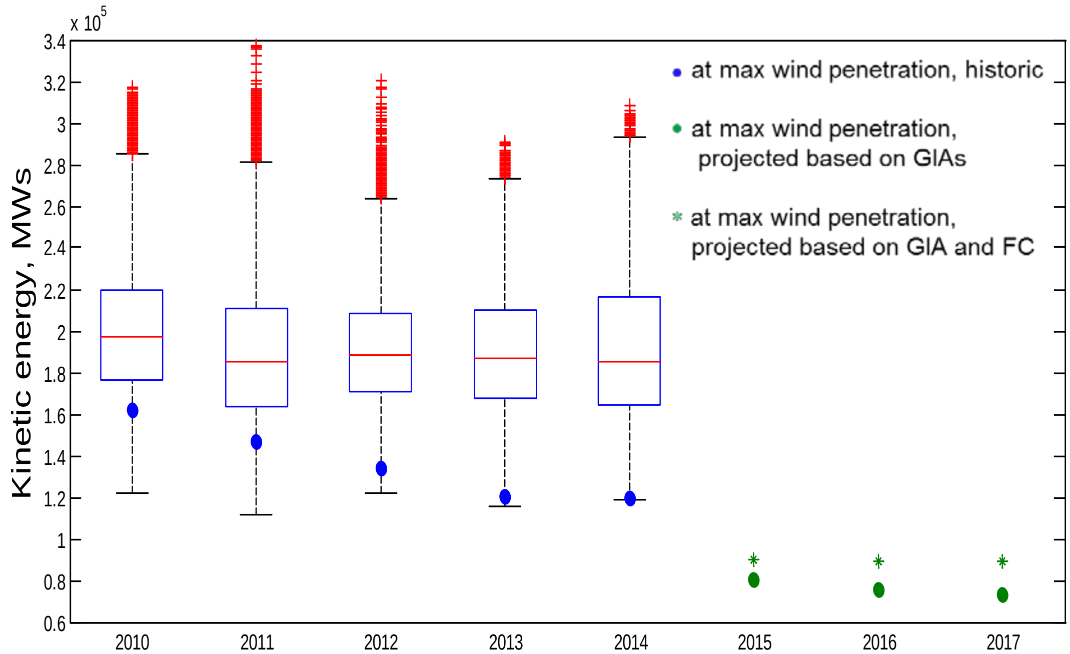


Figure A.4: ERCOT historic kinetic energy boxplots (2010–2017)

6. At an interconnection level, calculate corresponding RoCoF for the largest contingency ΔP_{MW} as described in Section 2, step 1, equation 2 (without load damping) or equations 3–4 (with load damping).
7. Calculate projected system frequency at 0.5 seconds after largest contingency with a RoCoF as calculated in previous step; use equation 5 in Section 2 step 2.
8. Plot projected system frequency after the largest contingency event, calculated in step 7 above, assuming there is a linear trend between time = 0 and time = 0.5 seconds. Plot it on the same figure as historical frequency Figure A.3 to obtain the figure below.

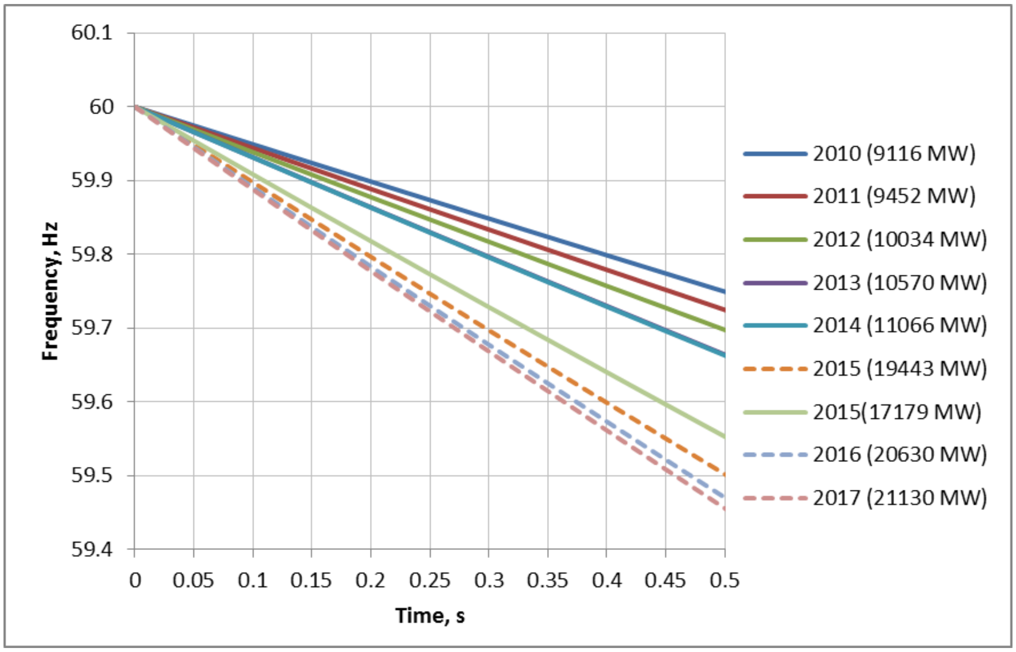


Figure A.5: Calculated system frequency after 2750 MW generation trip (2010–2017)

Results of Analysis

Measure 1: Synchronous Inertial Response at an Interconnection Level

WECC

There is currently not a practical way to find out the minimum inertia hour or the minimum generator capacity hour. Peak Reliability[12] can currently find the hour with minimum generation/load. Peak Reliability determined the minimum generation hour and provided a Westwide System Model (WSM) state estimator case for that time. To determine system-synchronous inertia during the minimum load hour, the WSM generators must be mapped to planning base-case generators. The generator plants (such as wind farms) are not all modeled in the same aggregations, compounding the difficulty of matching them up. As of January 2, 2015, 2913 out of the 3426 generators represented in the current WSM model were mapped to a recent planning base case (see Table A.1). There were still 513 unmapped WSM units represented as generators. The inertia constant and MVA base for the unmapped generators are unknown.

Table A.1: Number of Unmapped Units between WSM and WECC Planning Cases

Cases	WSM Case Units	Unmapped WSM Case Units
Jan 2, 2015	3,426	513
Nov 2, 2014	3,416	526
April 1, 2013	3,164	836

[12] Peak Reliability's two Reliability Coordination (RC) Offices provide situational awareness and real-time monitoring of the Reliability Coordinator Area within the Western Interconnection. Peak Reliability's RC Area includes all or parts of 14 western states, British Columbia, and the northern portion of Baja California, Mexico. Peak Registered Functions: Peak is listed on the NERC Compliance Registry to perform the RC and Interchange Authority (IA) functions as statutory activities.

It is impractical to compare on-line inertia going back in time, because the correspondence between units in the two models is improving with time, so the basis changes for older cases as fewer units were mapped going further back in time. The conclusion is that it will not be practical to try to trend inertia for the Western Interconnection on an ad-hoc basis. Trending will require significant initial effort to assign inertia to each generator unit in the WSM and that would have to be part of the data stored for each unit and maintained with the WSM.

Even though it was not practical to calculate system inertia for historic years 2011–2013 for WECC, Table A.2 shows how installed wind and solar generation capacity was increasing over these years. It also shows historic information for minimum load hours in each year.

Table A.2: Supporting Data for Measure 1 Analysis

	2011	2012	2013	2014
Wind Installed Capacity, P_{wind_inst}	14,046	15,738	18,488	
PV Installed Capacity, P_{PV_inst}				
Supporting Data at Minimum Load Hour				
Date	5/30, 4am	10/14, 4am	4/1, 3am	11/2, 3:48 am
P_{wind}/ P_{load}	4.3%	4.6%	5.6%	
P_{wind}	3,084	3,357	4,161	
P_{load}, MW	70,925	72,898	74,097	
P_{wind}/P_{wind_inst}	22.0%	21.3%	22.5%	

Table A.3: SIR for Different WSM Cases in 2014 and WECC Planning Cases for 2015

Date WSM Cases	System MVA	SIR, MW	Average H	Comment
1-Jul-14	216,536	821,212	3.79	WECC Peak
2-Nov-14	162,444	593,100	3.65	WECC Minimum
Early Nov, 2014	185,777	681,534	3.67	
19-Nov-14	196,883	731,101	3.71	
2015 HS4A1	253,596	932,130	3.68	2015 Heavy Summer
2015 HWA1	228,247	851,119	3.73	2015 Heavy Winter

Measure 2: Initial Frequency Deviation Following Largest Contingency

ERCOT

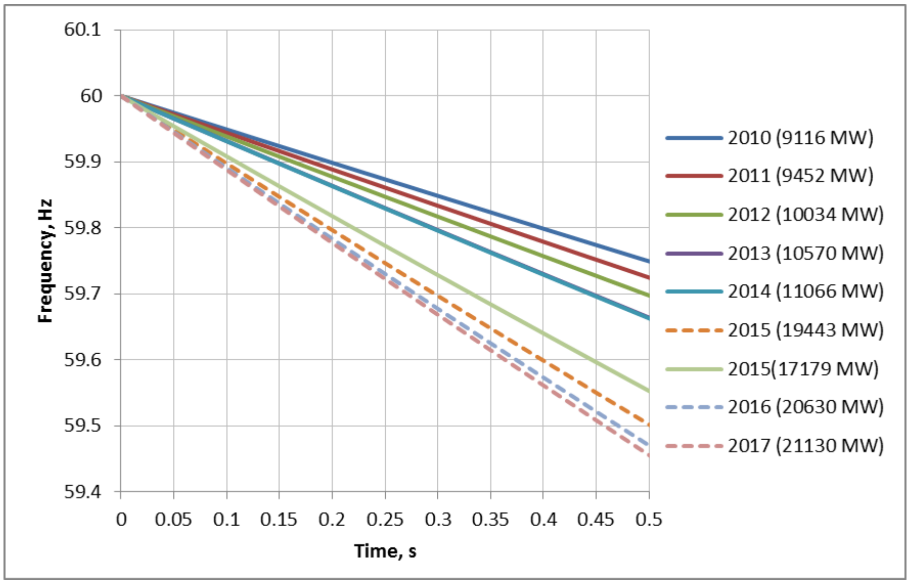


Figure A.6: Calculated system frequency after 2750 MW generation trip (two South Texas Project nuclear units) during nonsynchronous generation penetration peak in ERCOT for years 2010–2014.

Table A.4: Supporting Data for Measure 2 Analysis

	2010	2011	2012	2013	2014	2015 (w. FC)	2015	2016	2017
Installed Capacity (P_{wind_inst}), MW	9,116	9,452	10,034	10,570	11,066	17,179	19,443	20,630	21,130
Installed PV Capacity (P_{solar_inst}), MW	15	42	82	121	159	189	189	394	394
Supporting Data at max nonsynch penetration hour; i.e., an hour with maximum P_{wind}/P_{load} ratio									
P_{wind}/P_{load}	25.5%	27.4%	29.8%	35.8%	39.4%	61%	69%	73.2%	75%
P_{wind}, MW	6,483	6,772	7,247	8,773	9,699	15,057	17,041	18,082	18,520
P_{wind}/P_{wind_inst}	71%	72%	72%	83%	88%	88%	88%	88%	88%
Net Demand, (P_{load}-P_{wind}), MW	18,944	17,973	17,082	15,716	14,918	9,643	7,659	6,618	6,180
Inertia, MWs	161,741	147,081	133,675	120,030	119,604	89,469	80,020	75,066	72,979
Estimated RoCoF after loss of 2x1375 MW, Hz/s	0.501	0.551	0.605	0.672	0.674	0.89	0.996	1.059	1.088

For 2015 the projections are done in two ways: for planned projects with signed interconnection agreements, and for planned projects with both signed interconnection agreements and financial commitments.

WECC

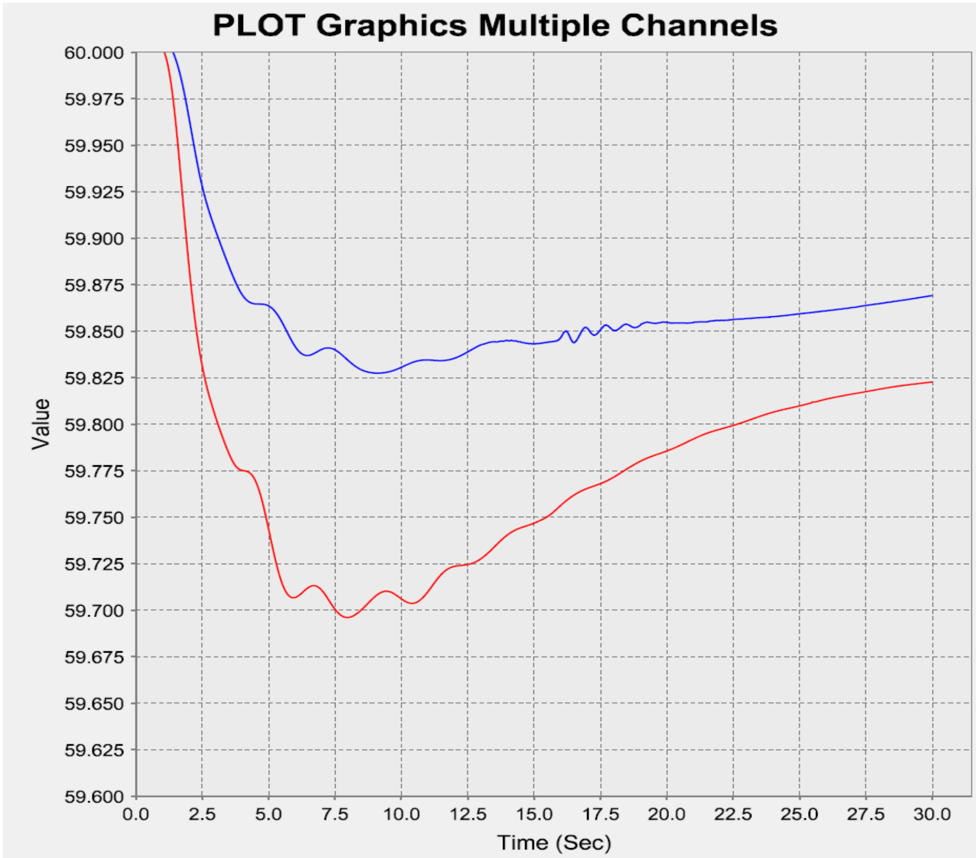


Figure A.7: Simulated WECC system frequency following 2750 MW generation trip

Figure A.7 shows frequency traces from the simulated loss of two Palo Verde units (Resource Contingency Criteria for WECC) for WECC 2014 peak (blue) on July 1, 2014, and the WECC 2014 low load (red) on November 2, 2014 cases. It is interesting to note the large difference the load level makes on the frequency nadir for the two cases.

Eastern Interconnection

The Eastern Interconnection at present has a relatively low penetration of inverter-based resources, so system inertia and frequency response continues to be dominated by load level and the accompanying unit commitment. On August 4, 2007, a major event occurred that included the loss of approximately 4,500 MW of generation. That event was the basis for the EI FRO *NERC Frequency Response Initiative Report*. Events of that size result in frequency excursions on the order of 0.1 to 0.2 Hz. The event in Figure 4 occurred at near-peak-load conditions. Unlike the other interconnections, the EI exhibits a substantially different response characteristic (occasionally referred to as the "lazy L") without a clear nadir and with degrading frequency over the period during which frequency response is calculated according to BAL-003-1. Thus, today in the east, the system inertia is relatively unimportant compared to the primary response of generation. And the overall interconnection frequency response is dominated by automatic load control (governor withdrawal) on the relatively few generators in the EI that have governors enabled for under-frequency response.

At light load, with fewer generators committed, the character of the EI frequency response is similar, but the amplitude of the frequency excursion tends to be worse. For comparison, a simulation of an event similar to that of Figure 3 is included in Figure A.9, but for low load conditions.[13]

Tracking of the status and capability of governors in the EI, including understanding (and modeling) of automatic load control, is critical to understanding frequency response.

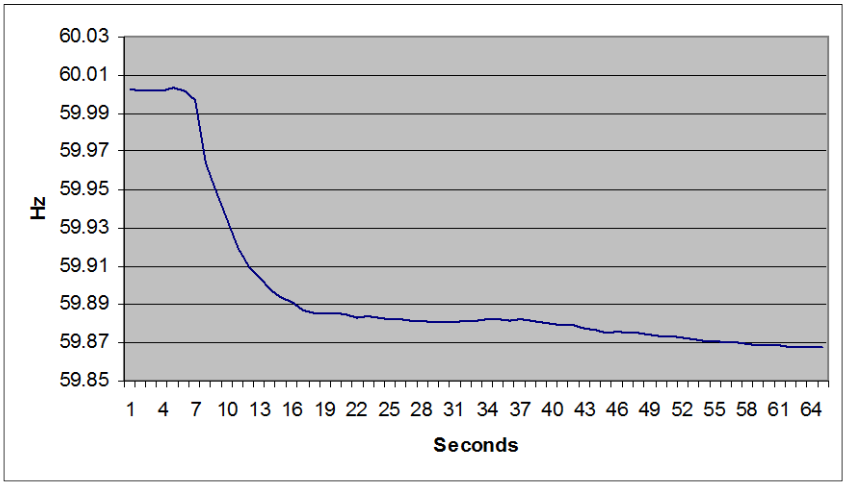


Figure A.8: 4500 MW EI event of August 4, 2007

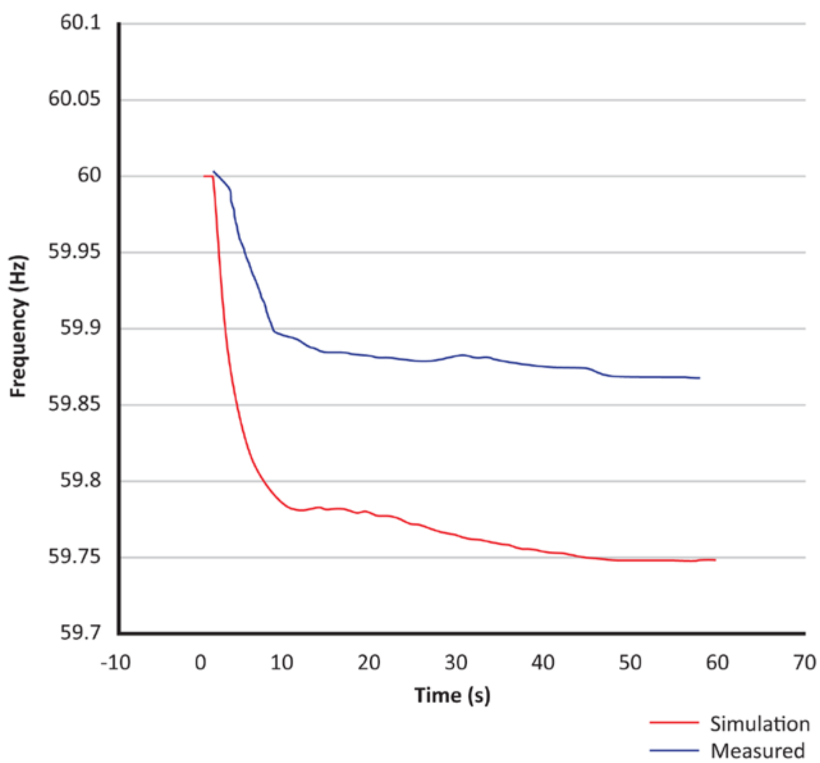


Figure A.9: Measured Event near Peak Load and Simulated Event near Minimum Load

[13] GE Energy (2013). Eastern Frequency Response Study. NREL/SR-5500-58077. Golden, CO: National Renewable Energy Laboratory. May 2013

Measure 3: Synchronous Inertial Response at a BA Level

ERCOT

Figure A.10 shows boxplots for Measure 3[14] (i.e., hourly synchronous inertia (kinetic energy) in MW) for 2010–2014. The blue dots on each boxplot correspond to the nonsynchronous (i.e., wind) generation peak. In the ERCOT system, nonsynchronous generation peaks are encountered predominantly in spring or fall during the early night hours (2–3:00 a.m.). During these hours, wind resources account for over 70 percent of total generation output on the system, displacing more expensive synchronous generation. Note that during times of low load and high wind output, ERCOT is normally exporting power over HVDC ties. Therefore, there is no additional nonsynchronous contribution over the HVDC ties during these periods.

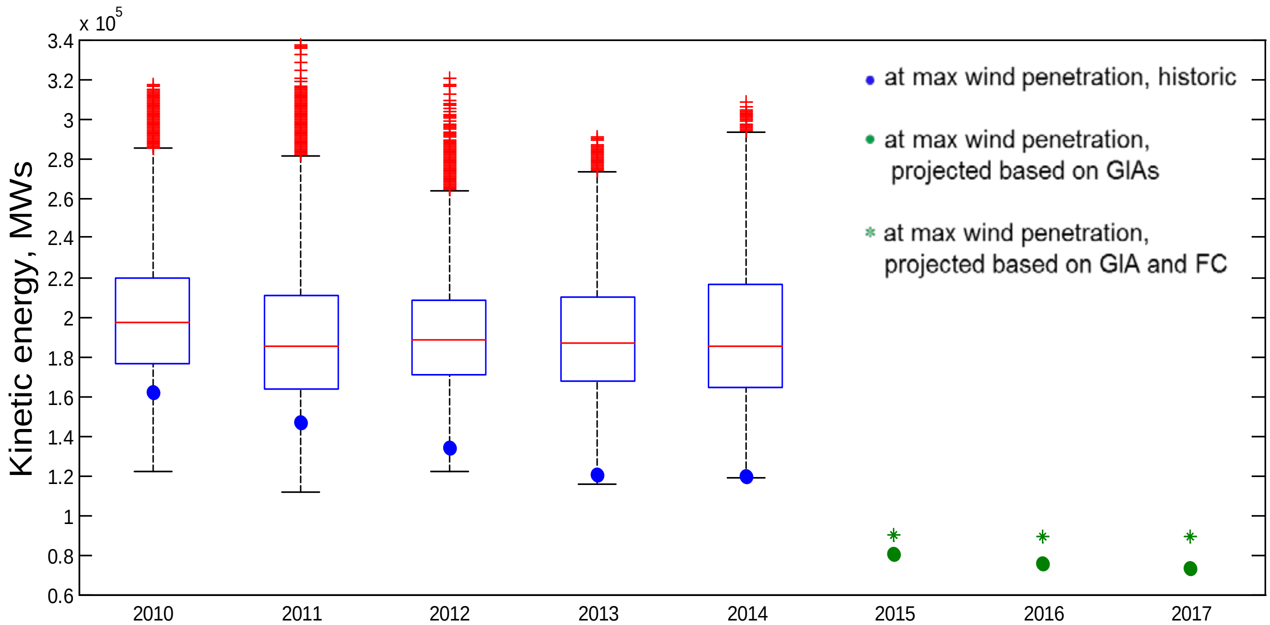


Figure A.10: Measure 1 and Measure 3 for ERCOT historic SIR boxplots and future projections of SIR at peak nonsynchronous generation penetration hour

With installed wind generation capacity increasing from 9 GW in 2010 to 11 GW in 2014, the hour of peak nonsynchronous penetration is also the lowest synchronous inertia hour in the year.

Kinetic energy during the projected peak penetration of wind generation for years 2015–2017 is based on the expected installed capacity of the projects with GIAs and on expected installed capacity of the projects with FCs and GIA. At the end of 2013, many wind generation projects started construction in order to be able to receive the Production Tax Credit. These projects are currently in different stages of construction with expected completion dates between 2015 and 2017.

[14] Note ERCOT is single interconnection and BA, therefore Measure 3 and Measure 1 for ERCOT are the same.

Table A.5: Supporting Data for Measures 1 and 3 Analysis								
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Installed Wind Capacity (P_{wind_inst}), MW	9,116	9,452	10,034	10,570	11,066	19,443	20,630	21,130
Installed PV Capacity (P_{solar_inst}), MW	15	42	82	121	159	189	394	394
Supporting Data at max wind penetration hour; i.e., an hour with maximum P_{wind}/P_{load} ratio								
P_{wind}/P_{load}	25.5%	27.4%	29.8%	35.8%	39.4%	69%	73.2%	75%
P_{wind}, MW	6,483	6,772	7,247	8,773	9,699	17,041	18,082	18,520
P_{wind}/P_{wind_inst}	71%	72%	72%	83%	88%	88%	88%	88%
P_{load}, MW	25,427	24,745	24,328	24,488	24,617	24,700	24,700	24,700

Synchronous Inertial Response (SIR) distribution in years 2010–2014 is largely unchanged; however, beginning in 2013 and 2014, the hour of maximum wind penetration and minimum inertia coincide. This is due to higher levels of installed wind generation and high wind power production during low load hours at night in spring months.

ERCOT found Measure 3 very informative. ERCOT is a single interconnection and relies only on local resources for frequency support. ERCOT has also put in place a real-time synchronous inertia calculator. It is not currently used in the control room, but is used for off-line analysis and future trending.

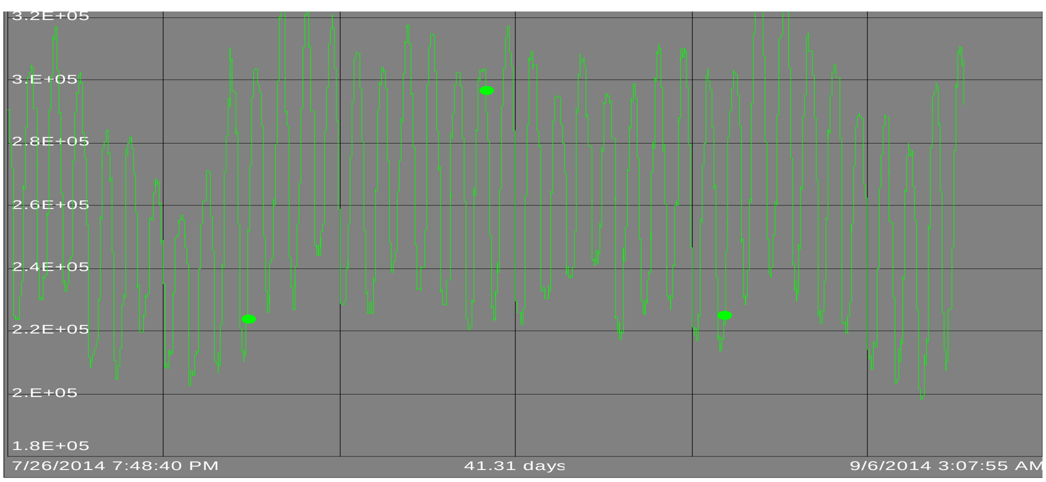


Figure A.11: Snapshot from the real-time SIR calculator in ERCOT

ISO New England

In ISO NE, since a comprehensive data set for an entire year was not readily available, engineering judgment was used to select hours in the year with representative system inertia values. During low inertia hours, ISO NE is importing power over HVDC ties (about 8–9 percent of load at the time). HVDC imports and coincidental wind power production result in up to 4 percent nonsynchronous penetration in historic years 2011–2014.

Future projections are made from the average historical trend due to a full year's data not being available to produce boxplots and find true minimum inertia hours. In future years, installed wind generation capacity in ISO NE is expected to increase from 607 MW to 3043 MW, while HVDC tie capacity remains the same. This leads to projected nonsynchronous penetration of 22 percent of load by 2015 and decline in synchronous inertia.

ISO NE found Measure 3 of value for their system and will continue system inertia tracking since it also aligns with their PFR tracking initiative.

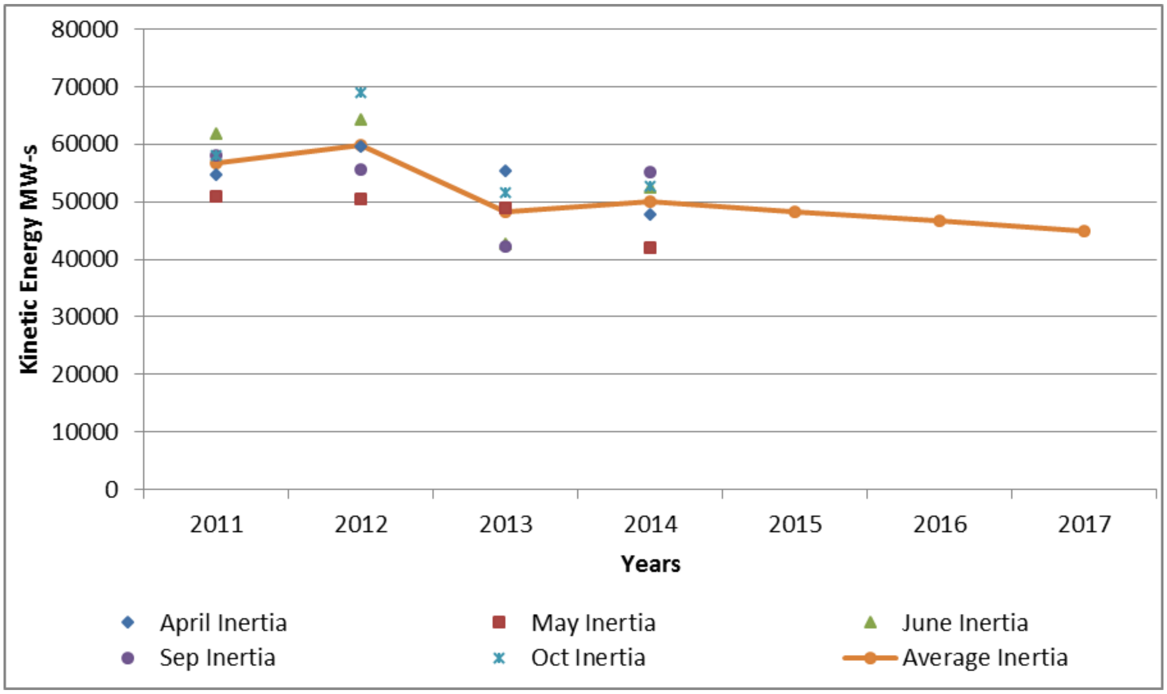


Figure A.12: Measure 3 for ISO NE. Historic SIR based on typical snapshots. Future projections of SIR are based on average SIR conditions in 2014.

Table A.6: Supporting Data Measure 3 Analysis							
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Installed HVDC Capacity (P_{HVDC_inst}), MW	2,548	2,548	2,548	2,548	2,548	2,548	2,548
Installed Wind Capacity (P_{wind_inst}), MW	274	345	607	607	991	2,661	3,043
Total Nonsynch Capacity, MW	2,822	2,893	3,155	3,155	3,539	5,209	5,591
Supporting Data at max nonsynch penetration hour; i.e., an hour with maximum P_{NSG}/P_{load} ratio							
P_{HVDC}, MW - at min inertia	758	738	801	857	857	857	857
P_{HVDC}/P_{HVDC_inst}	30%	29%	31%	34%	34%	34%	34%
P_{wind}, MW - at min inertia	122	90	112	24	257	963	1,219
P_{wind}/P_{wind_inst}	45%	26%	18%	4%	26%	36%	40%
P_{NSG}/P_{load}	10%	10%	10%	10%	12%	20%	23%
P_{load}, MW - at min inertia	9,033	8,654	9,471	9,210	9,210	9,210	9,210

IESO

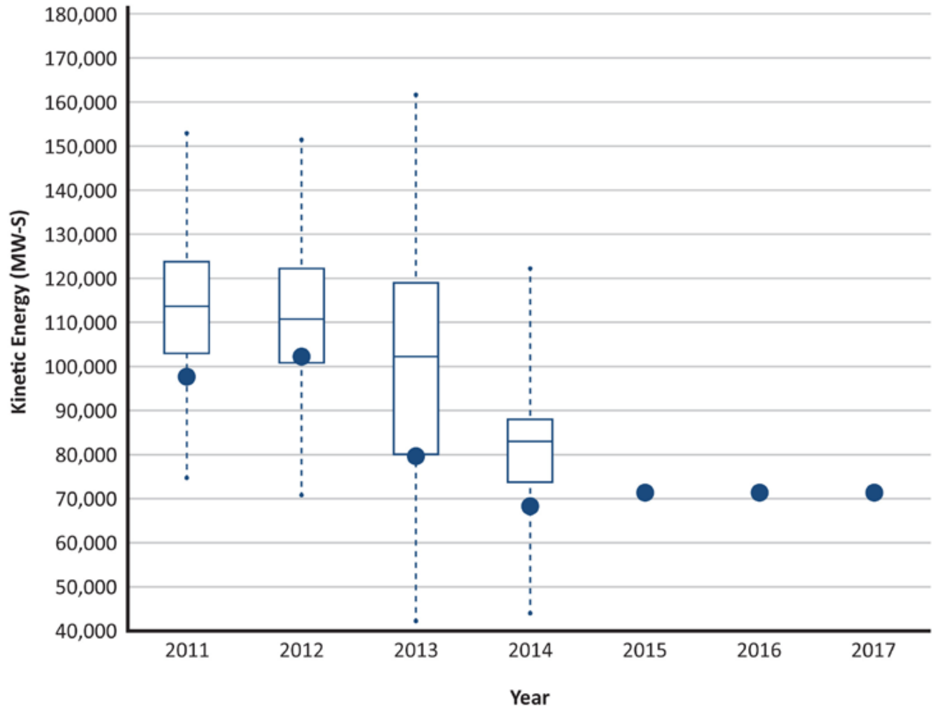


Figure A.13: Measure 3 for IESO. Historic SIR boxplots and future projections of SIR at peak nonsynchronous generation penetration hour. Blue dots correspond to peak nonsynchronous generation penetration hour in each year.

Table A.7: Supporting Data Measure 3 Analysis							
	2011	2012	2013	2014* (Jan - Oct)	2015	2016	2017
Installed Capacity (HVDC line Capability included), MW	2,955	2,955	3,452	4,075	5,607	5,607	5,607
Installed Wind, MW (Maximum during the year)	1,725	1,725	2,222	2,845	4,377	4,377	4,377
Supporting Data at max nonsynch penetration hour; i.e., an hour with maximum P_{NSG}/P_{load} ratio							
Max P_{wind}/P_{load}	11.2%	14.3%	14.6%	16.3%	22%	22%	22%
P_{wind} (HVDC included)	1,794	2,560	3,114	2,735	4,055	4,055	4,055
HVDC imports (interpolated flow values includes off-market transactions)	600	969		664	664	664	664
$P_{wind}/P_{install}$	62%	87%	90%	72%	72%	72%	72%
P_{load}, MW	16,084	17,937	21,335	16,822	18,045	18,045	18,045
Minimum Market Demand	12,605	11,974	12,762	12,741			

IESO historical maximum nonsynchronous penetration hours happened in the early morning or afternoon hours in spring and fall (see Table A.8).

Table A.8: Historic Dates and Times for Maximum Nonsynchronous Generation Penetration		
Date	Hour Ending	Max NSG penetration
11/25/2011	14	11.2%
03/28/2012	7	14.3%
11/18/2013	18	14.6%
04/10/2014	6	16.3%

MISO

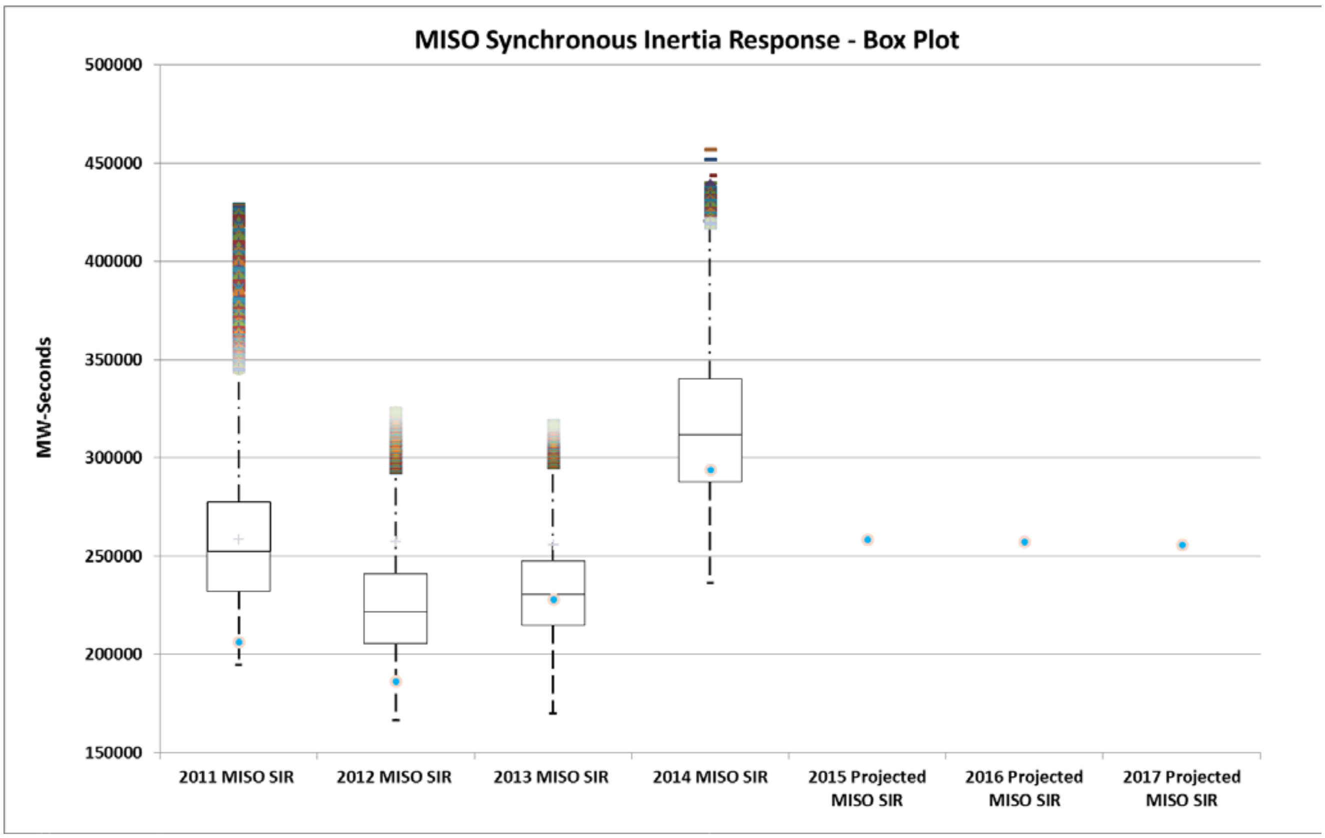


Figure A.14: Measure 3 for MISO. Historic SIR Boxplots and future projections of SIR at peak nonsynchronous generation penetration hour. Blue dots correspond to peak nonsynchronous generation penetration hour in each year.

Table A.9: Supporting Data for Measure 3 Analysis							
	2011	2012	2013	2014	2015	2016	2017
Installed Wind Capacity (P_{wind_inst}), MW	10,628	12,270	13,035	13,726	15,476	17,001	18,526
Supporting Data at max nonsynch penetration hour; i.e., an hour with maximum P_{NSG}/P_{load} ratio							
P_{wind}/P_{load}	16%	25%	21%	16%	18%	20%	21%
P_{wind}, MW	7,665	9,906	9,705	9,653	10,883	11,956	13,028
P_{wind}/P_{wind_inst}	72.12%	80.73%	74.45%	70.32%	70.32%	70.32%	70.32%
P_{load}, MW	49,190	40,191	47,263	59,119	59,711	60,308	60,911

MISO does not have any HVDC ties that cross the BA boundary. Thus, maximum nonsynchronous generation penetration is only driven by wind generation. Over the years, MISO has had some large load changes within the Balancing Authority area during the time frame of this collection, so results and trends do reflect that: First Energy left the MISO BA in June 2011 (less load in the BA, but no change in wind), and the integration of the South Region (added load, no wind) into the MISO BA in December 2013 (including Entergy, Cleco, SMEPA, LAGN). Table A.10 shows minimum and maximum load from 2011 through 2014 for reference.

Table A.10: MISO Minimum and Maximum Load 2011–2014		
	Max MISO Load MW	Min MISO Load MW
2011	10,0795	41,118
2012	94,468	39,049
2013	92,034	36,919
2014	111,318	50,824

Future projections are based on a 1 percent load growth factor and projected wind-installed capacity megawatts. Since the MISO system has undergone some changes in 2011 and 2013, the future SIR projections are based on 2014 inertia trends.

MISO found Measure 3 useful for their system and set up a real-time system inertia calculator. Figure A.15 illustrates real-time system inertia along with wind, load, and generation, calculated every 15 minutes since January 27. Currently it is not displayed for the operators.

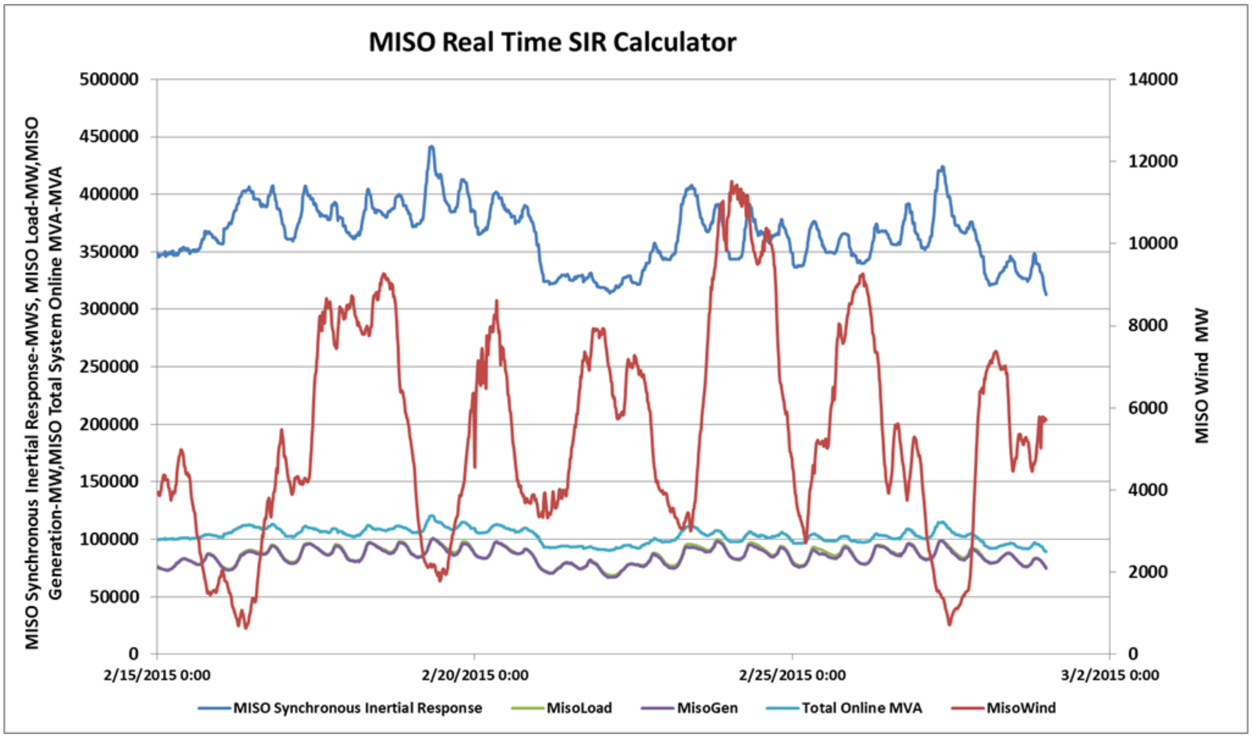


Figure A.15: Real-time SIR Calculator in MISO

BC Hydro

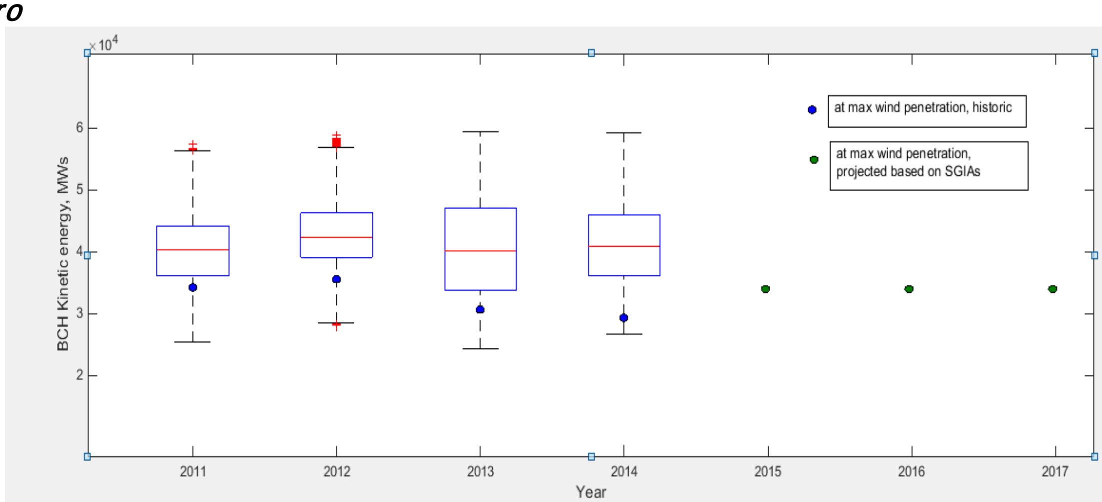


Figure A.16: Measure 3 for BC Hydro. Historic SIR Boxplots and future projections of SIR at peak nonsynchronous generation penetration hour. Blue dots correspond to peak nonsynchronous generation penetration hour in each year.

BC Hydro projected P_{load} is calculated as an average of historical P_{load} from 2011 through 2014.

Table A.11 Supporting Data for Measure 3 Analysis							
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Installed Wind Capacity (P_{wind_inst}), MW	246	388	388	487	487	487	667
Supporting Data at max nonsynch penetration hour; i.e., an hour with maximum P_{wind}/P_{load} ratio							
P_{wind}/P_{load}	5 % (Apr)	6% (Nov)	9% (Apr)	13 % (Sep)	9%	9%	12%
P_{wind}, MW	199	302	330	336	336	336	460
P_{wind}/P_{wind_inst}	81%	78%	85%	69 %	69%	69%	69%
BCH Load, MW (excluding AC import/export)	5,422	5,584	4,914	4463	N/A	N/A	N/A
P_{load} (including AC import), MW	3,938	5,075	3,731	2542	3,822	3,822	3,822

Duke

Duke Energy (Duke) has three separate BAs: Duke Energy Florida (DEF), Duke Energy Carolinas (DEC), and Duke Energy Progress (DEP). For all three Duke Energy areas there is no HVDC export/import capacity, and imports at any hour are zero. All three are part of the Eastern Interconnection and all ties to neighbors are ac.

Duke has been employing variations of these measures for some time and sees promise in them as reliability metrics. Duke intends to refine the data and analyses and has already identified potential improvements in data collection and analysis, and in the measures themselves.
Duke's BAs have varying generation composition and load characteristics, but none currently has or is forecast to have significant penetrations of nonsynchronous generation (NSG) as compared to CAISO and ERCOT. In particular, DEF has no NSG (quantifiable at the bulk level), and none is projected in the coming three-year time frame. Both DEC and DEP have experienced a dramatic rise in NSG (almost completely PV solar) over recent years due to state incentives (in addition to federal ones), but penetration is expected to flatten as the state incentives expire. This impending expiration also drove some apparent anomalous historical results due to significant increases in NSG installation/operation in December of each year.

As Duke continues to refine data collection and analysis for these measures, it is expected that other anomalies will be identified and resolved.

DEF Statistical Analysis of Kinetic Energy and Projected Minima

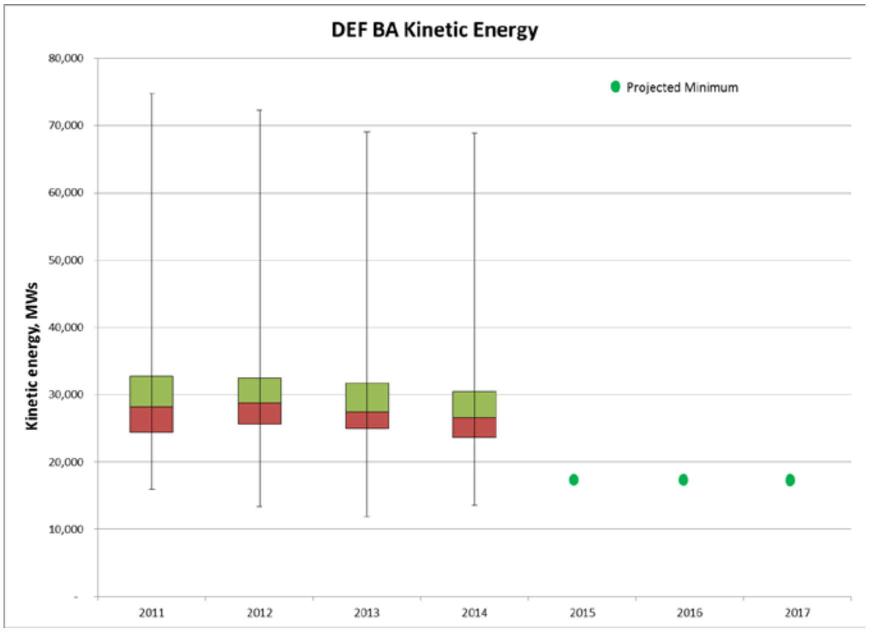


Figure A.17: Measure 3 for Duke Energy Florida. Historic SIR boxplots and future projections of SIR at minimum load.

Note, DEF currently has no measurable NSG penetration and doesn't project any. The future minimum projections of kinetic energy for DEF are based on the lowest value observed over the 2011–2014 time period due to the lack of nonsynchronous generation. Since there is no nonsynchronous generation in DEF, the projected KE minima do coincide closely with load minima.

DEC Statistical Analysis of Kinetic Energy and Projected Minima

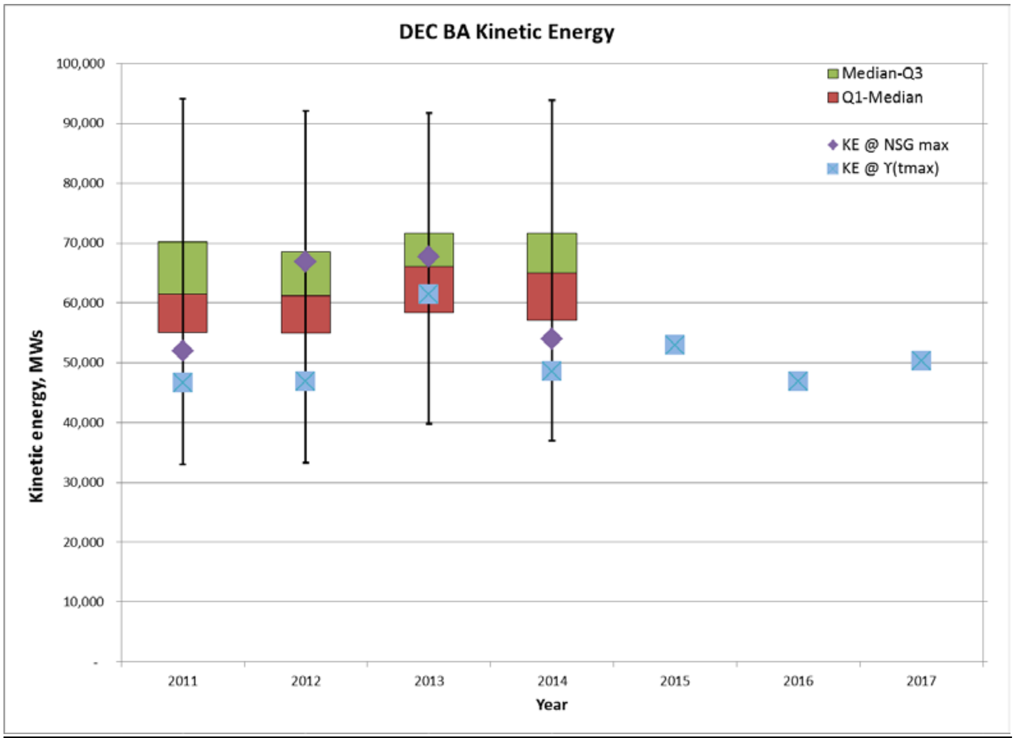


Figure A.18: Measure 3 for Duke Energy Carolinas. Historic SIR boxplots and future projections of SIR at peak nonsynchronous generation penetration hour. Purple dots correspond to peak nonsynchronous generation penetration hour in each year. Blue dots correspond to hours with maximum nonsynchronous to synchronous generation ratio.

For DEC, actual BA loads were not used in the analysis. The understood intent of the analysis was to use total BA generation (i.e., BA load net of imports/exports) as the basis for calculation. The purple dots on Figure A.18 are kinetic energy at maximum production from nonsynchronous generators, kinetic energy at NSG max (historical only). Since practically all of the NSG in DEC is solar, kinetic energy at max NSG max, usually at a time when load is near peak and synchronous generation on-line is high as well (12:00–14:00 local time, depending on time of year). The blue dots (kinetic energy at ϒ(tmax)) correspond to kinetic energy at the maximum ratio of nonsynchronous to synchronous generation (NSG/SG) occur and are not at the same time as NSG peak.

The growth in total synchronous generation is projected using the forecast growth in peak BA load as a percentage of the forecast 2014 peak (an average of approximately 1.35 percent per year).

Table A.12 Supporting Data for Measure 3 Analysis							
	2011	2012	2013	2014	2015	2016	2017
Installed PV Capacity (P_{PV_inst}), MW	48	107	121	136	214	239	232
Supporting Data at max wind penetration hour; i.e., an hour with maximum P_{PV}/P_{SG} ratio							
P_{PV}/P_{SG}	0.2%	0.3%	0.7%	1.2%	1.6%	2.1%	1.7%
P_{PV}, MW	15	25	70	99	147	166	161
P_{PV}/P_{PV_inst}	30.7%	23%	57.8%	73.1%	69.1%	69.6%	69.6%
P_{SG}, MW	9,083	7,847	10,551	8,323	9,262	7,877	8,664

DEP Statistical Analysis of Kinetic Energy and Projected Minima

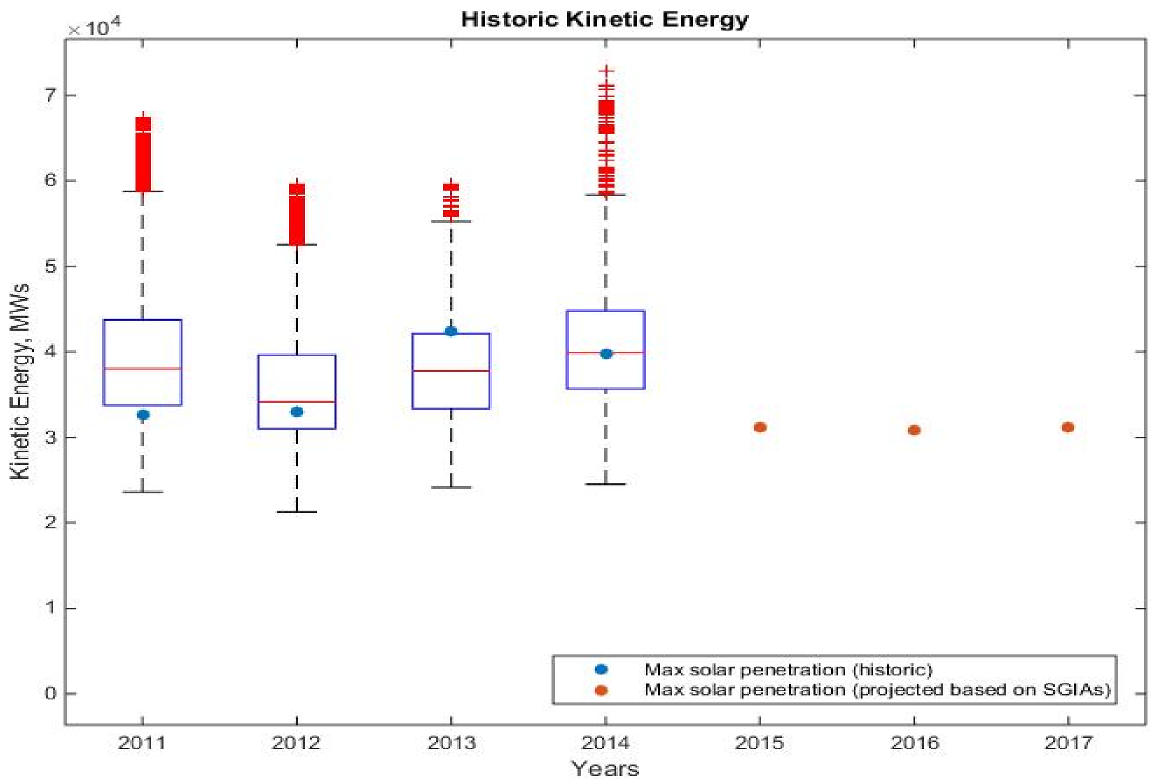


Figure A.19: Measure 3 for Duke Energy Progress. Historic SIR boxplots and future projections of SIR at peak nonsynchronous generation penetration hour. Blue dots correspond to peak nonsynchronous generation penetration hour in each year.

Table A.13 Supporting Data for Measure 3 Analysis							
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Installed PV Capacity (P_{PV_inst}), MW				320	447	712	712
Supporting Data at max wind penetration hour; i.e., an hour with maximum P_{PV}/P_{load} ratio							
P_{PV}/P_{load}				3.4%			
P_{PV}, MW				222	309	495	495
P_{PV}/P_{PV_inst}				69.4%	69.1%	69.6%	69.6%
P_{load}, MW	6,352	6,431	7,681	6,558			

Southern

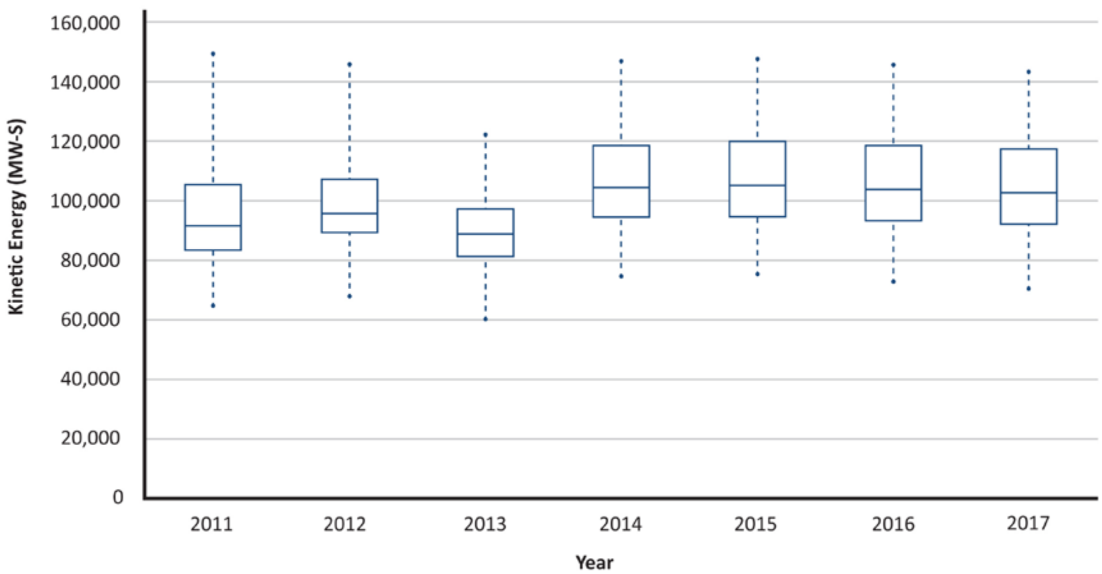


Figure A.20: Measure 3 for Southern Balancing Area historic and future projections.

Southern Company projected P_{load} is calculated as the average of historical P_{load} during 2011–2014.

Table A.14 Supporting Data for Measure 3 Analysis							
	2011	2012	2013	2014	2015	2016	2017
Installed Capacity Nonsynch (P_{NSG_inst}), MW	0	0	248	454	1586	1836	2324
Installed Capacity Wind (P_{wind_inst}), MW	0	0	202	404	404	654	654
Installed Capacity Solar (P_{solar_inst}), MW	0	0	46	50	1182	1182	1670
Supporting Data at max nonsynch penetration hour, i.e. an hour with maximum P_{NSG}/P_{load} ratio							
Nonsynch. gen. penetration peak, P_{wind}/P_{load}	0.0%	0.0%	0.3%	1.1%	1.1%	1.8%	1.8%
P_{wind}/P_{load}	0.0%	0.0%	1.1%	2.2%	2.2%	3.6%	3.6%
P_{wind}, MW	0	0	44	202	202	325	325
P_{wind}/P_{wind_inst}	0.0%	0.0%	21.8%	50.0%	50.0%	49.7%	49.7%
P_{solar}/P_{load}	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%
P_{solar}, MW	0	0	14	0	0	0	0
P_{solar}/P_{solar_inst}	0.0%	0.0%	30.4%	0.0%	0.0%	0.0%	0.0%
P_{load}, MW	17,637	16,691	17,974	18,422	18,422	18,422	18,422

Measure 4: Frequency Response at Interconnection Level

The following examples illustrate the proposed frequency response measures for ERCOT and the Eastern and Western Interconnections. For the reference to Point A, C, B, and C', Figures 1 and 2 from the main body of the report are repeated in this appendix:

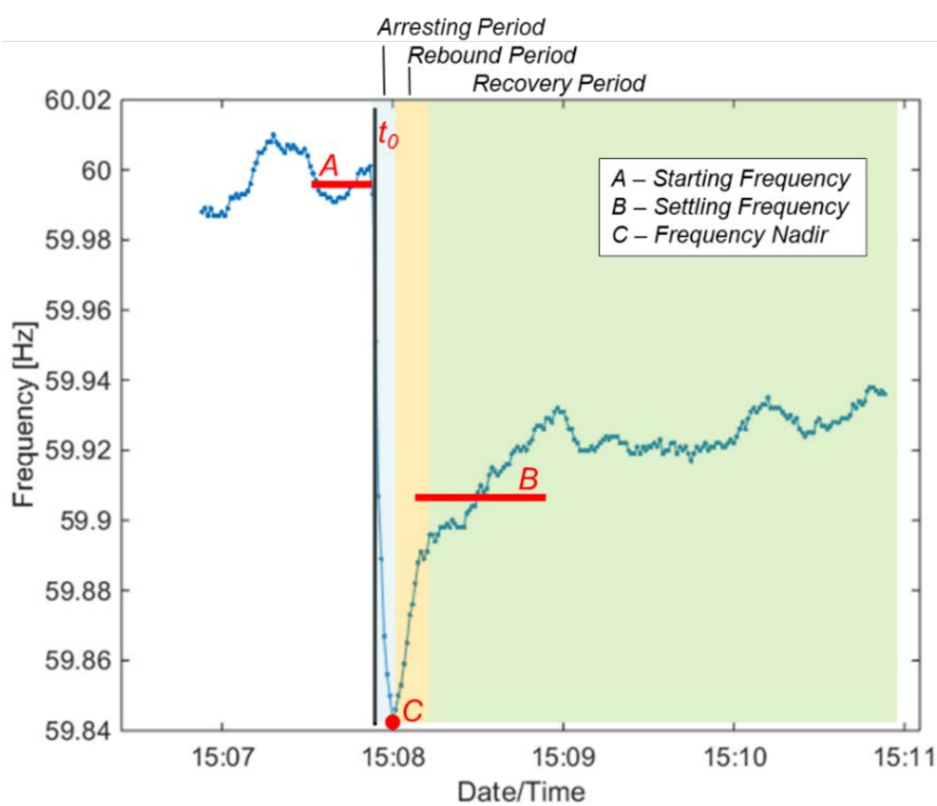


Figure A.21: Frequency response example for large disturbance in Western Interconnection

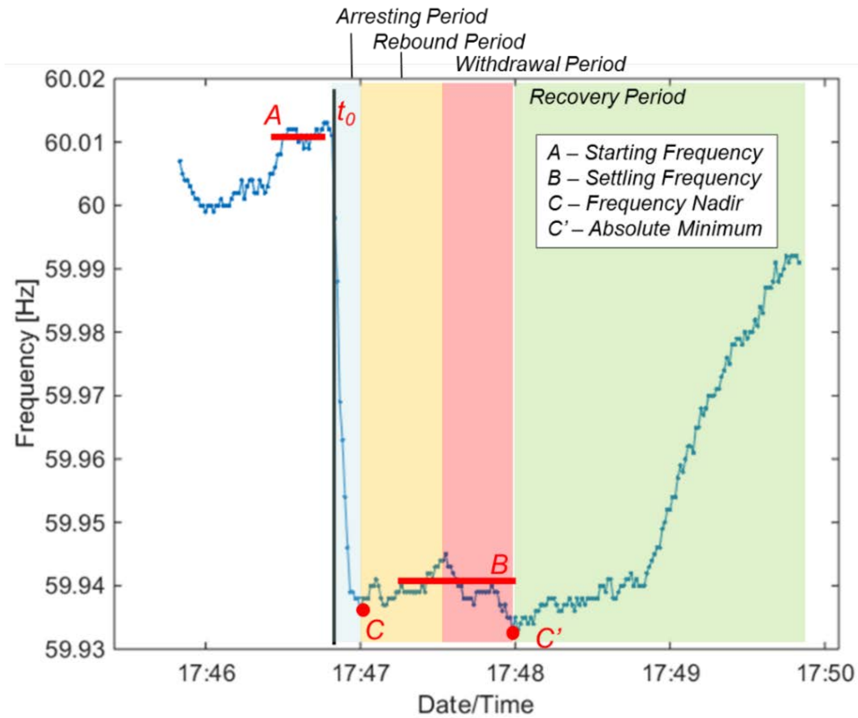


Figure A.22: Frequency response example for large disturbance in Eastern Interconnection (with governor withdrawal)

ERCOT Interconnection Example

The following plots illustrate some of the frequency response measures identified for trending.

A-to-B and A-to-C Frequency Response

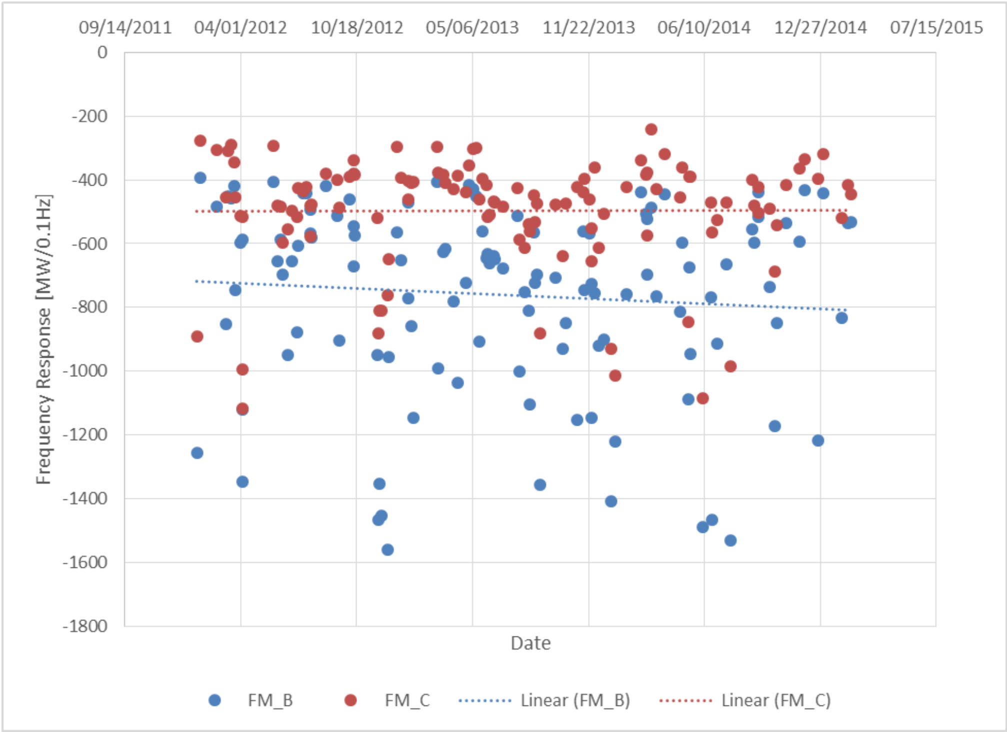


Figure A.23: ERCOT A-to-B frequency response (blue) and A-to-C frequency response (red)

Notice that the trend is toward an increasing absolute value of frequency response (frequency response is actually calculated as a negative number, since generation loss in megawatts in the measure calculation is taken with negative sign; hence larger negative numbers are better). The A-to-B frequency response is improving at a rate slightly better than A-to-C frequency response. This would indicate that there is some improvement in interconnection-wide governor response. Even though Measure 1 (synchronous inertia measure) is trending down due to increasing penetration of nonsynchronous generation, there is slight improvement over time in A-to-C frequency response. This can be explained by some improvements in governor response, which are listed below:

- During transition from zonal to nodal market, extensive governor testing was done at all plants.
- Since March 2012, wind generators are also required to provide governor-like response. This response is faster than governor response from conventional generators. Governor-like response from wind generators is available for overfrequency events any time a generator is in operation and for underfrequency events when wind generators are curtailed. Until completion of the CREZ transmission project (at the end of 2013), wind generation in western Texas was oftentimes curtailed and therefore capable of governor-like response at underfrequency events.
- On January 16, 2014, the BAL-001-TRE standard was approved with an effective date of April 1, 2014, and an implementation plan of 30 months. However, during the development of the standard, many generators tested their governors with narrower governor deadband settings, as prescribed by the standard, and then did not revert to the original settings. Consequently, implementation of the new governor requirements has been accelerated.

If data is available, trending frequency response measures (A to C and A to B) year to year versus trending only system conditions can provide additional insights concerning primary frequency response levels and characteristics. As an example, Figure A.24 shows A-to-C frequency response as a function of system net demand (load minus wind generation) for ERCOT. While Figure A.23 shows slight overall improvement over time in A-to-C frequency response, Figure A.24 provides additional insight, showing in 2013–2014 compared to earlier years the reduction in absolute frequency response at low net demand (due to reduction in synchronous inertia) and improvement at high net demand (due to improvements in governor response described above).

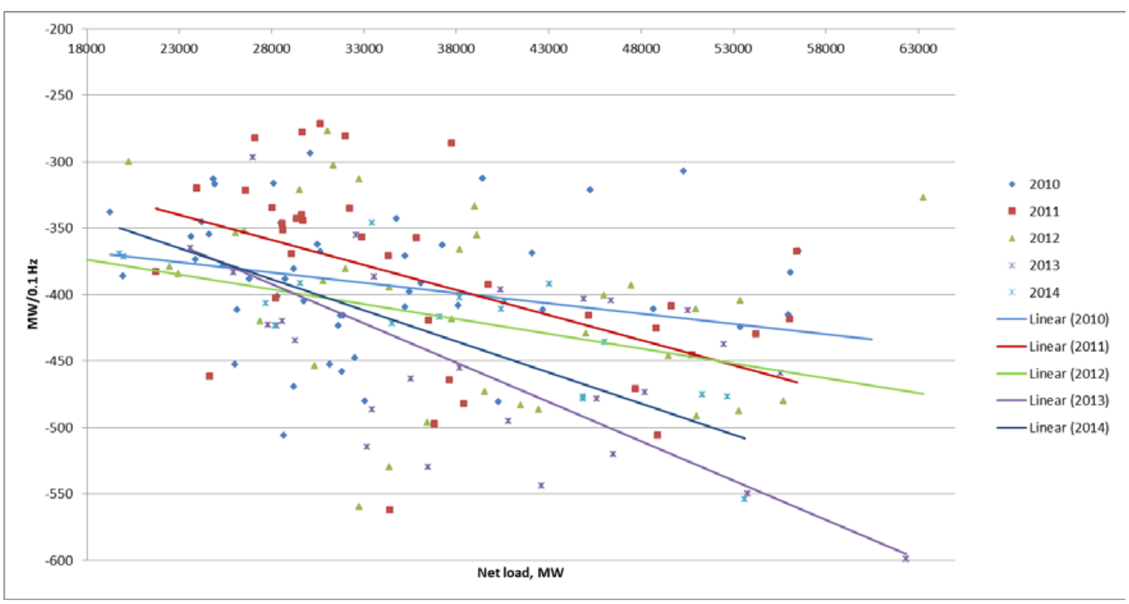


Figure A.24: A-to-C frequency response versus net demand in ERCOT 2010–2014

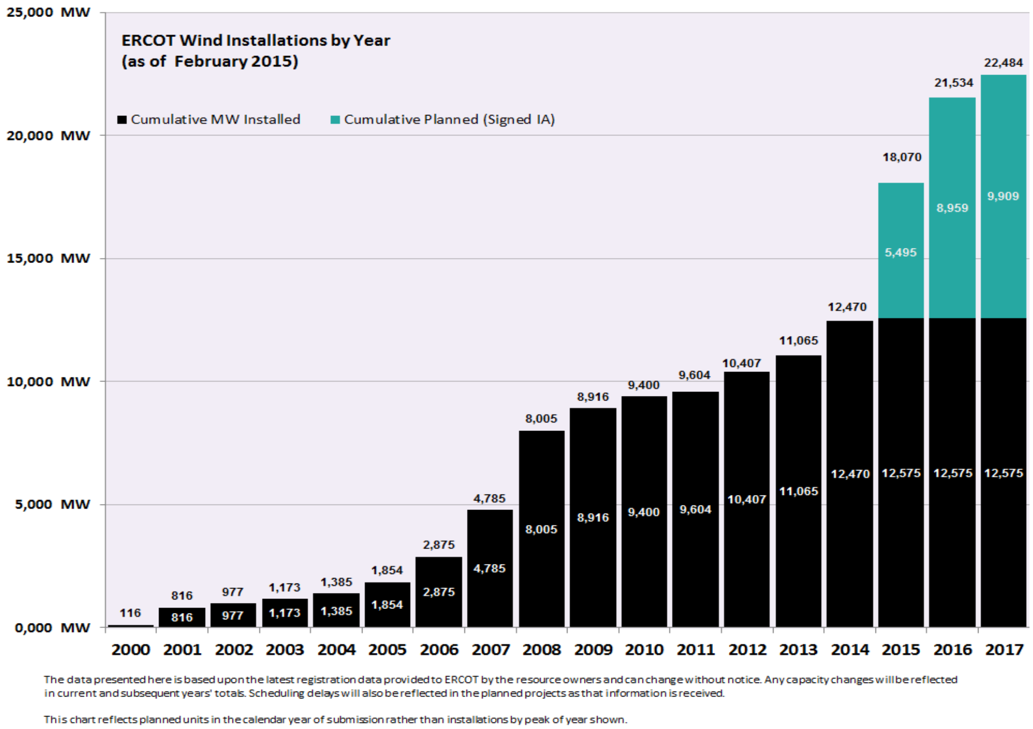


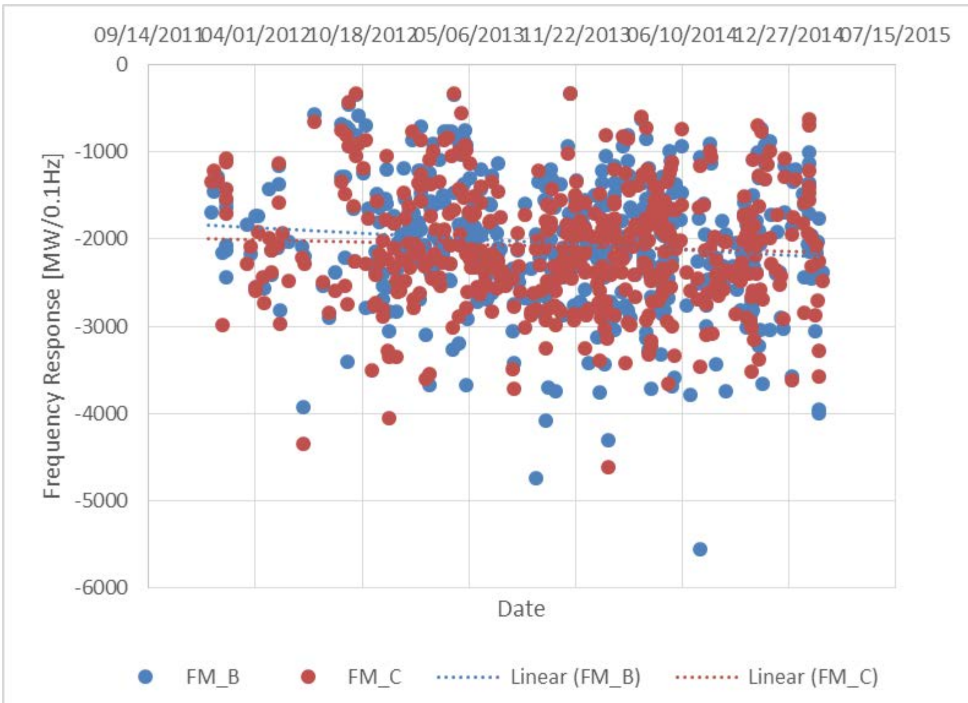
Figure A.25: ERCOT wind generation installations by year (as of February 2015)

Eastern Interconnection Example

The following plots illustrate some of the frequency response measures identified for trending.

A-to-B and A-to-C Frequency Response

Notice the trend toward increasing absolute value of frequency response (frequency response is actually calculated as a negative number; hence, larger negative numbers are better). It is observed from mid-2011 to mid-2014 that the A-to-B frequency response value is improving at a rate slightly better than A-to-C frequency response. This would indicate that there is some improvement in interconnection-wide governor response, as well as a continued inertial and governor response to arrest frequency deviations.



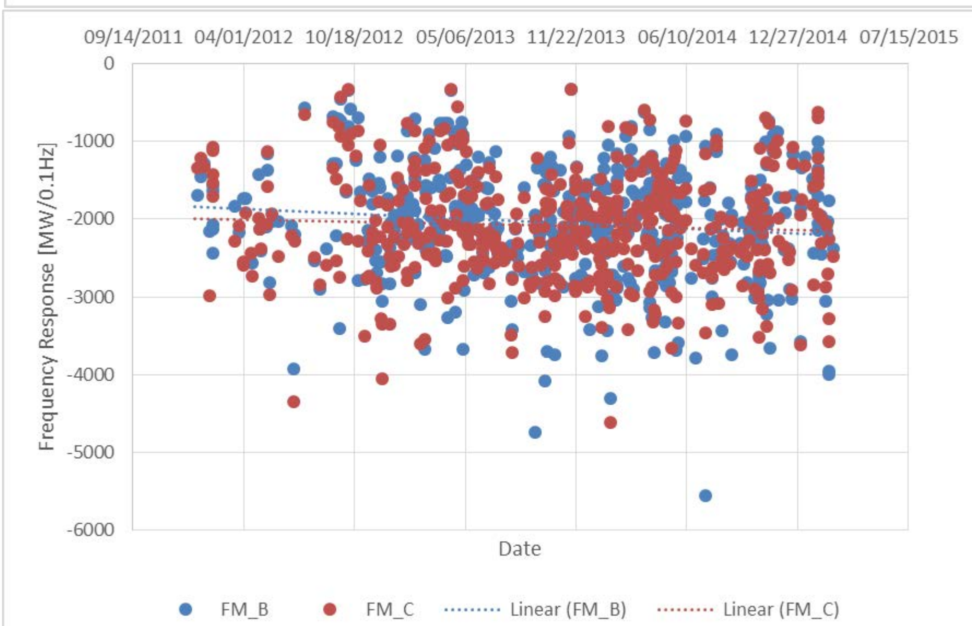


Figure A.26: Eastern Interconnection A-to-B frequency response (blue) and A-to-C frequency response (red)

C-to-B Ratio

The ratio between Point C and Point B in the Eastern Interconnection appears to be trending upward, meaning a larger difference between Points C and B. This either means the frequency nadir is dropping (which is not identified in the previous plots showing A-to-C and A-to-B frequency response measures) or the B value is improving. While this upward trend is a positive sign for reliability and frequency response, it is critical to note the number of data points with ratio < 1.0. This indicates events in which the frequency nadir is higher than the settling frequency calculated as Point B, indicative of the Eastern Interconnection "Lazy L" effect. Efforts put forth by NERC and industry regarding generator governor settings are likely to improve this ratio moving forward, and it is critical to track this measure in conjunction with the A-to-C frequency response measure above.

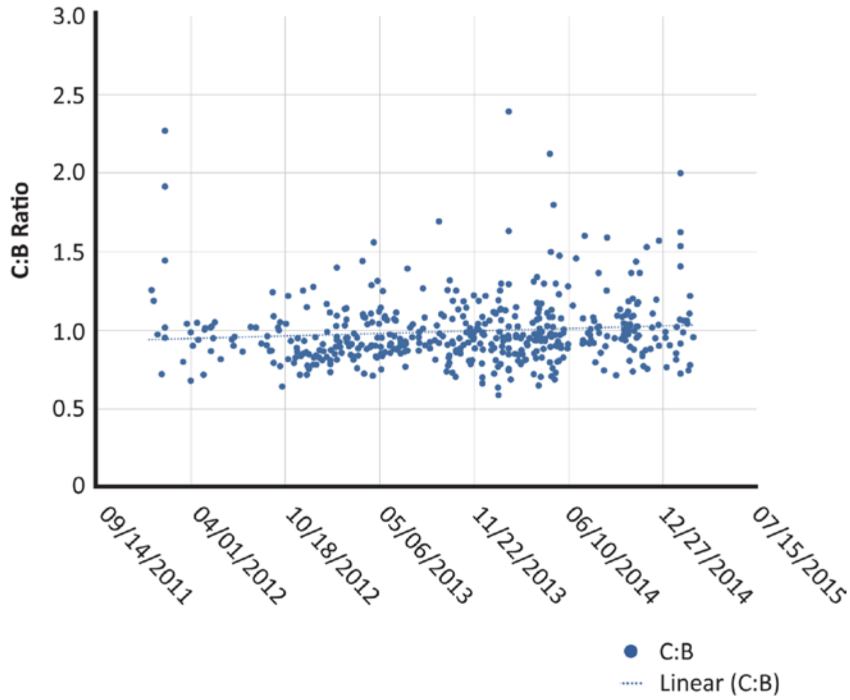


Figure A.27: Eastern Interconnection C-to-B ratio

C'-to-B and C'-to-C Ratios

The ratio of C' to B, if one exists, provides information relative to the extent of governor withdrawal following a frequency excursion event and initial governor response. C' only exists if a frequency minimum exists after the time period for calculating the B value. Hence, it may not exist for every event.

The ratio of C' to C provides similar information regarding the governor withdrawal; however, C' to C provides information relating to the severity of that withdrawal. Ratios larger than 1.0 signify events in which governor withdrawal results in frequency excursions lower than the initial frequency nadir. The goal is to correct the governor response withdrawal issue such that this ration is less than 1.0 and eliminated entirely.

The figure below trends C'-to-B and C'-to-C ratios over the time period of early 2012 to mid-2013. While this data does not cover the entire timespan of interest, it gives illustrative proof of concept regarding what information can be extracted from trending this measure year to year.

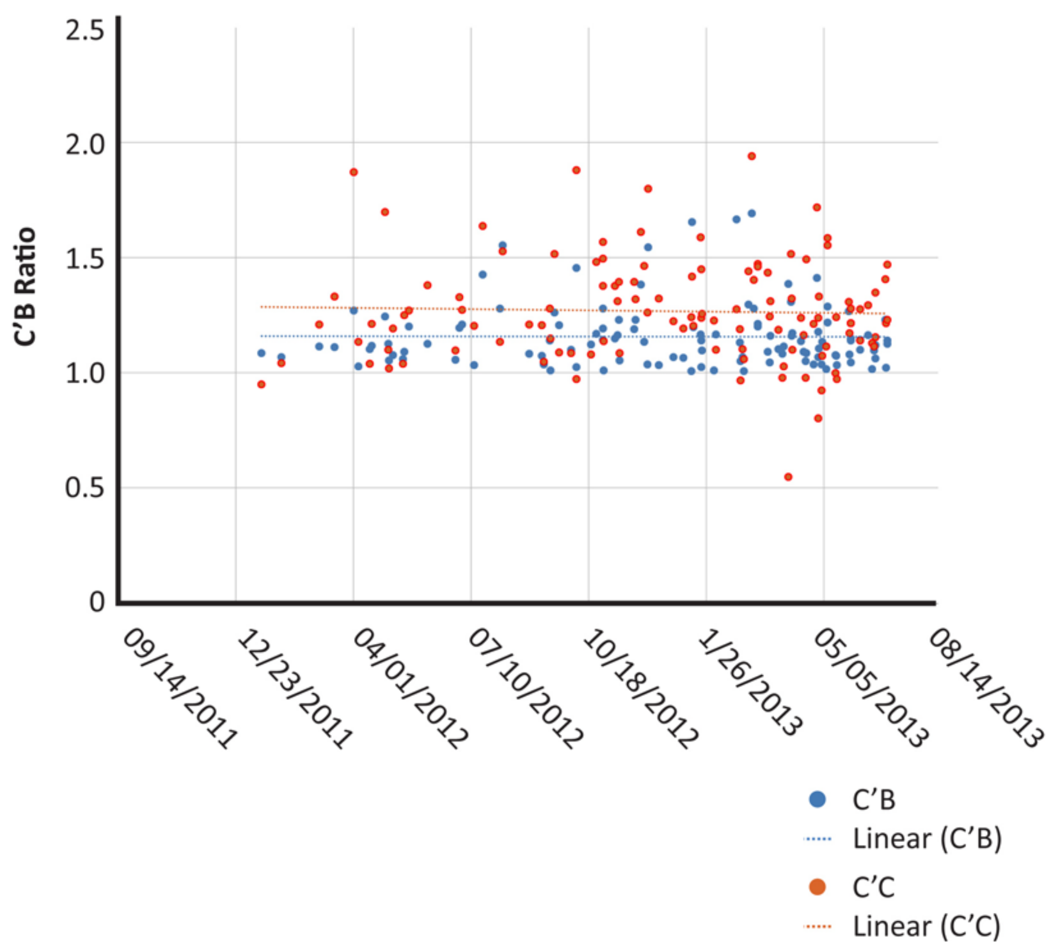


Figure A.28: Eastern Interconnection C'-to-B and C'-to-C ratios

Time-Based Measures

t_C-t_0 Measure

Time difference between the initial frequency nadir and time of event provides information regarding system inertia and governor response arresting frequency decline. The figure below shows chronological trend of this time difference. It is important to note that the time range of t_0 to t_0+12 seconds is used to calculate the frequency value. The figure below shows that this time window may not fit all frequency events in the Eastern Interconnection as many data points hit the upper time limit. Also note that this information is calculated from raw data and needs further investigation to filter out outliers. However, the proof of concept demonstrates the capability to trend this time difference chronologically.

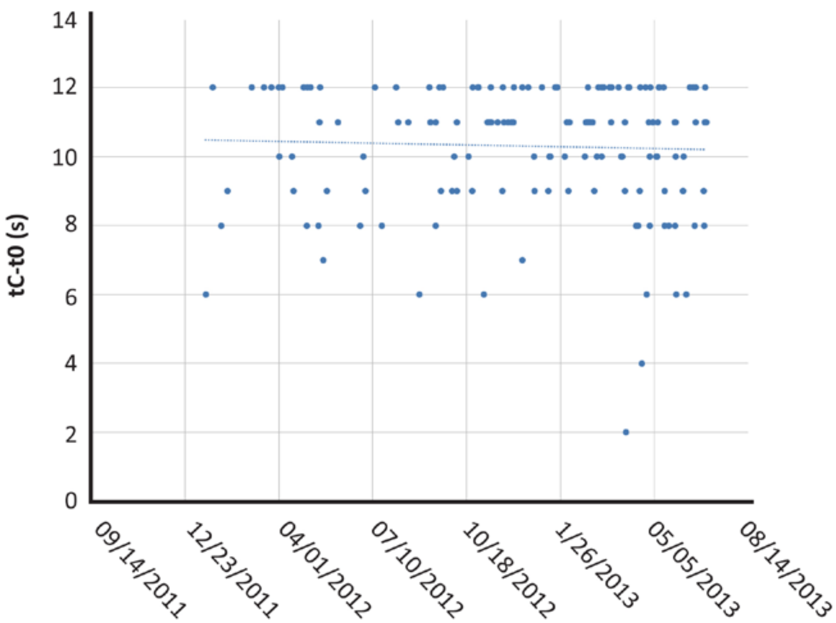


Figure A.29: Eastern Interconnection t_C-t_0 time-based measure

$t_{C'}$-t_0 and $t_{C'}$-t_C Measures

Time difference calculations to the C′ frequency point provide information regarding governor withdrawal and its duration and impact. The figure below shows consistency in duration over the timespan observed in the Eastern Interconnection.

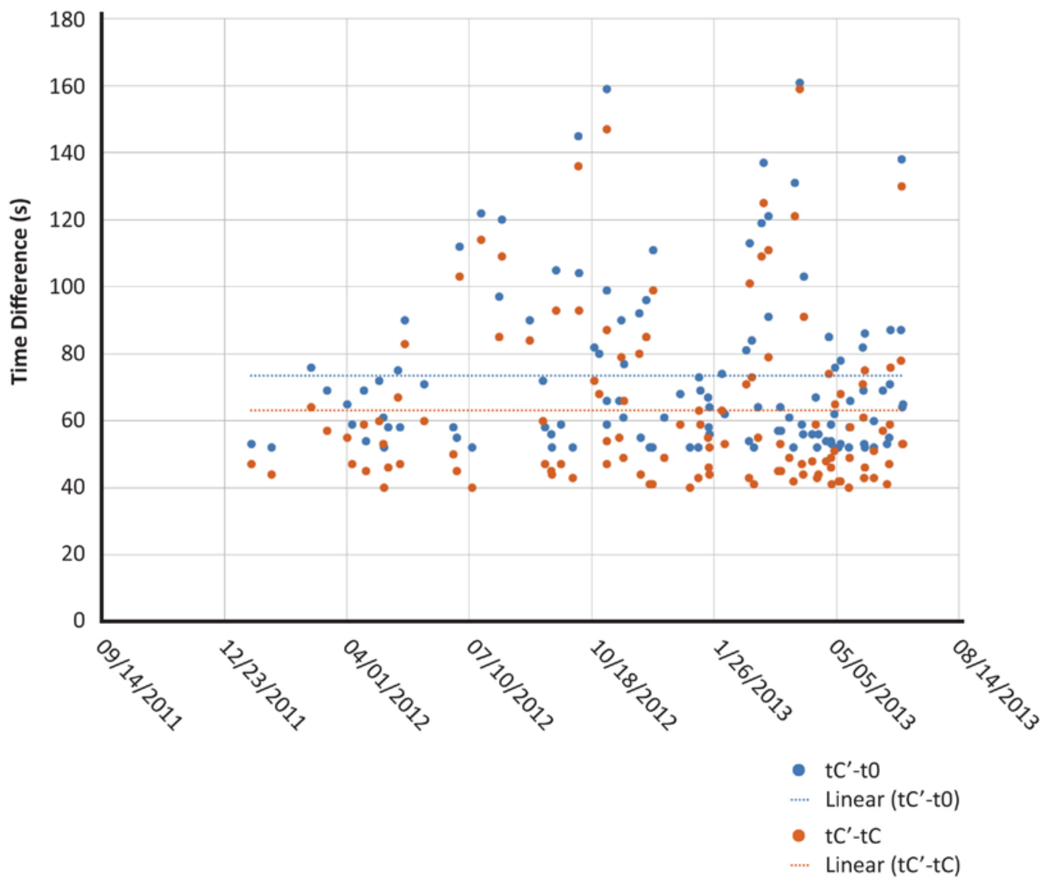


Figure A.30: Eastern Interconnection $t_{C'}$-t_0 (blue) and $t_{C'}$-t_C (orange) time-based measures

Western Interconnection Example

The following plots illustrate some of the frequency response measures identified for tracking.

A-to-B and A-to-C Frequency Response

The Western Interconnection is seeing improved frequency response from the time period of mid-2011 to mid-2014. The data suggests that A-to-B frequency response and A-to-C frequency response track similarly. This also indicates improved interconnection governor response to frequency deviations.

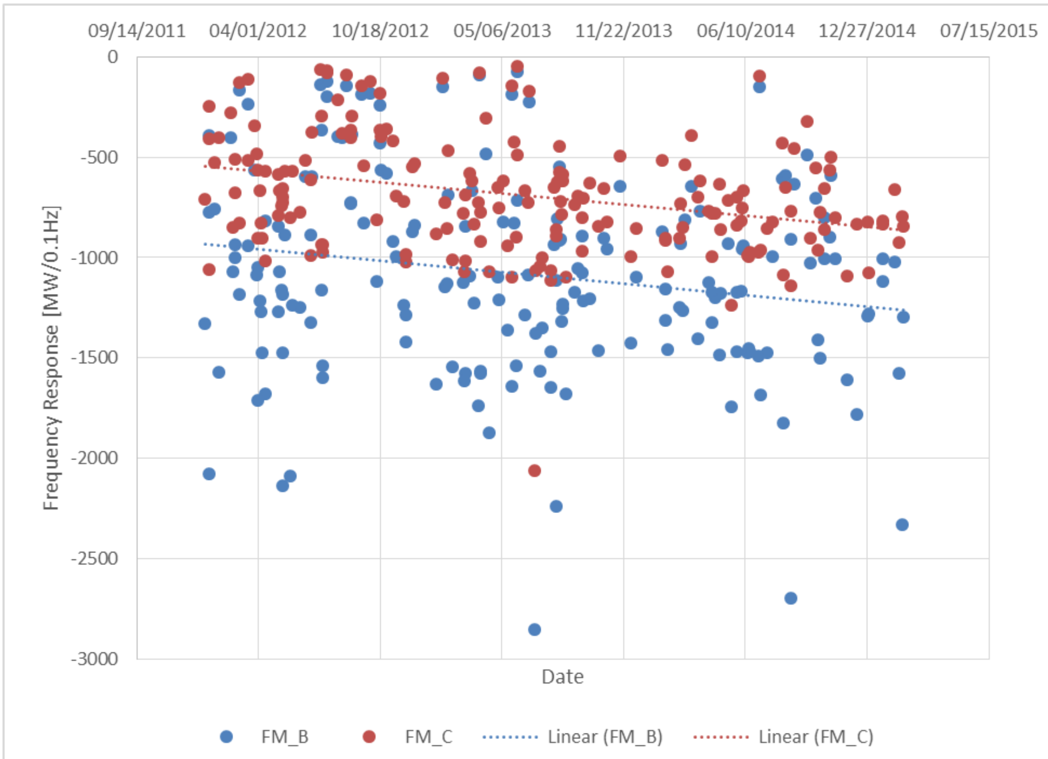


Figure A.31: Western Interconnection A-to-B frequency response (blue) and A-to-B frequency response (red)

C-to-B Ratio

The Western Interconnection is experiencing a slight decline in the ratio from Point C to Point B, meaning the difference in frequency value between Point B and Point C is declining slightly. Note that this proof of concept figure may be skewed to outliers that need further investigation. However, the concept of the C-to-B ratio declining indicates either a decrease in frequency response (not likely, due to a strong response from the frequency response calculation above) or the frequency nadir is increasing, meaning a reliability benefit and movement away from UFLS set points.

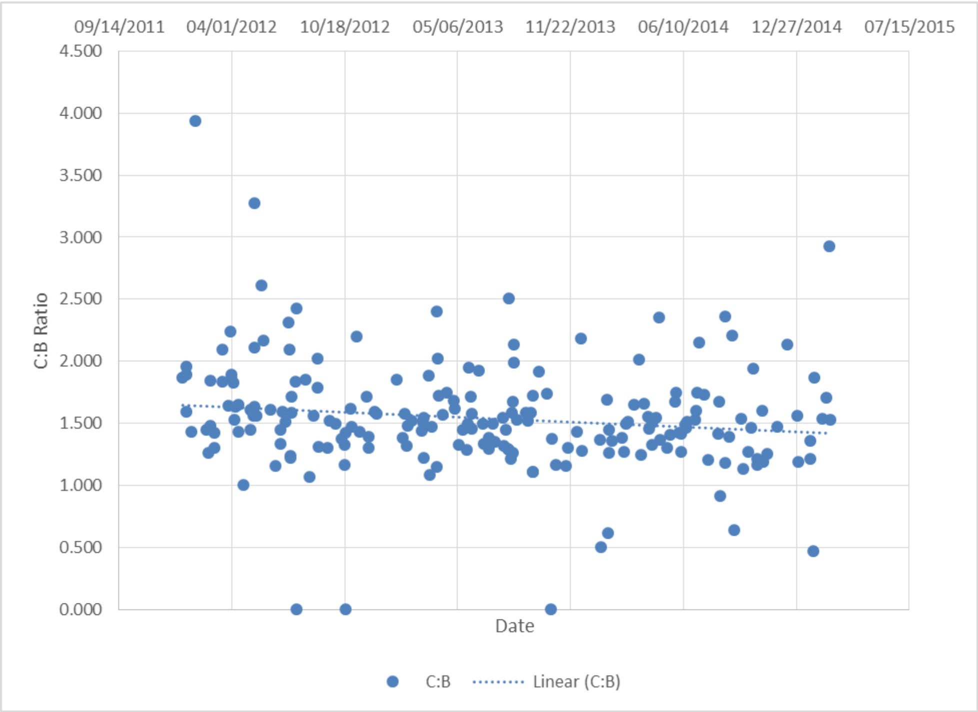


Figure A.32: Western Interconnection C-to-B ratio

C'-to-B and C'-to-C Ratios

The Western Interconnection does not generally have a C' value. Therefore, C' measures are not trended over time.

Time-Based Measures

tC-t0 Measure

Time-to-frequency nadir in the Western Interconnection (WI), though less data is available for this measure in the WI, demonstrates a relatively stable trend in inertia and frequency response arresting declining frequency. Average time difference is trending around approximately 7.5 seconds.

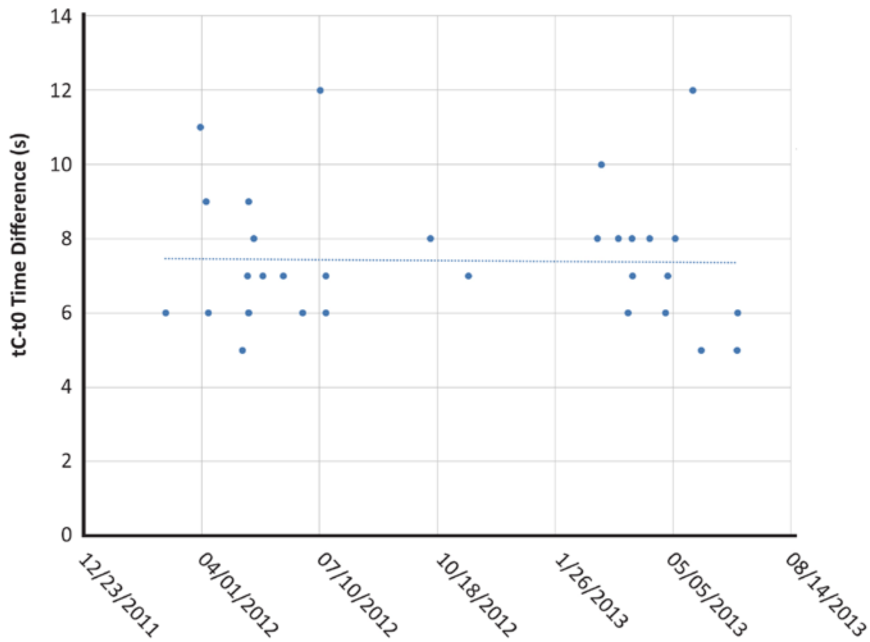


Figure A.33:.Western Interconnection tC-t0 time-based measure

tC'-t0 and tC'-tC Measures

With no C' frequency point for the Western Interconnection, there is no associated tC' value and hence no calculation of these time-based measures.

Appendix B – Net Demand Ramping Variability

The changes to the generation mix and other energy and environmental policies are imposing operational constraints on conventional resources. On the demand side, changes are also occurring, and predicting demand in the day-ahead time frame is becoming more of a challenge due to energy efficiency, distributed solar PV, more variable loads, and plug-in electric vehicles. Demand response and price-responsive loads are providing system operators with additional system-balancing tools.

In order to maintain load-and-supply balance in real time with higher penetrations of variable supply and less-predictable demand, BAs are seeing the need to have more system ramping capability, whether by adding more flexible resources within their committed portfolios or by removing system constraints to flexibility. Flexible resources, as described in this section, refer to dispatchable conventional as well as renewable resources, energy storage devices, and dispatchable loads.

To identify system ramping capability needs, the ERSTF studied data using a simple "net demand" terminology to illustrate the expected variability of the system, assuming there is no curtailment of variable supply. The net demand is calculated by taking the difference between total load and total production from VERs. The Electric Power Research Institute (EPRI) recently published a technical paper called *Metrics for Quantifying Flexibility in Power System Planning* that suggests other useful metrics.[15]

EPRI's Metric for Quantifying Ramping Capability

In response to utility and ISO needs to better understand flexibility requirements, EPRI has been developing metrics, methods, and tools to assist in assessing the operational flexibility of an electric system. These are complementary to other efforts at regulatory agencies, utilities, and consultancies. The EPRI work is described here to provide additional context on how operational flexibility requirements and the ability of the system to provide this flexibility can be measured. This effort is still under development and needs further testing on real systems before being used in utility/ISO practice. This information was presented to the ERSTF and is included here for reference.

A multilevel framework has been proposed with various levels of assessment corresponding to different levels of detail. The framework described is intended as additional analysis or modeling beyond existing planning processes and is mainly aimed at areas likely to have significant operational flexibility requirements. Higher-level screening should suffice for many areas, while the detailed methods may only be needed for those where flexibility has been identified as an issue.

In Level 1, variability measures such as those described in the next section quantify variability over different time frames and for different expected frequencies of occurrence. These can be used to screen for requirements and to understand how this may change based on future load profiles, and how renewable energy, demand response, or other resources may affect the required flexibility requirements.

Level 2 screens the flexibility available from resources on the system; this includes a summary of the ramping ability of the resources, minimum turn-down levels, start and shutdown times, and the minimum up and down times.

In Level 3 of the EPRI approach, more detailed metrics are considered. These metrics are based on post-processing of operational simulations that may already have been carried out for a system or on historical data. Based on expected unit commitment for each interval of the time period studied, the flexibility available from each resource

[15] http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002004243

can be measured for each hour of the study time frame. This is then compared to a flexibility requirement as defined in Level 1 to assess the sufficiency of the system to meet flexibility requirements. The requirement is normally based on the largest expected ramps up to a certain percentile under certain conditions. This results in three different flexibility metrics that can be assessed against system operations and can be calculated for both up and down ramping over different time horizons (typically five minutes to eight or more hours).

1. **Periods of Flexibility Deficit (PFD)**: The PFD is a measure of the number of periods when the available flexible resources were less than the assumed required flexibility. The required ramping is measured based on the type of analysis described elsewhere in this document. This is done over all time horizons. Deficits over shorter time periods can be mitigated by improved short-term forecasting capabilities, dynamic and probabilistic reserve procurement strategies, reserve sharing between connected systems, and new fast-start, high-response resources. Over longer time periods, such as three to eight hours, better long-term forecasts aid in the scheduling of large, slow-starting generation and intertie flows. In both cases, operational practices should be adopted first, but if there is still a flexibility deficit, new resources may be required.

2. **Expected Unserved Ramping (EUR):** EUR measures the amount of ramping that is not met for the system simulated. It is important to recognize that this does not mean the system will be short that much energy, but that this is the cumulative amount of shortfalls for ramping requirements based on large ramps. For example, the 97th percentile of ramp may be used, and the system may be short 20 MW for meeting that ramp over a given time horizon.

3. **Insufficient Ramp Resource Expectation (IRRE):** IRRE is a measure of the frequency of flexibility shortfalls over different time horizons. It differs from PFD in that it uses a probabilistic approach to determine the likelihood of not being able to meet net demand ramps at each time interval. A distribution of ramps is created and compared to a distribution of available flexibility. This is similar to the loss-of-load expectation used in resource adequacy assessment but is adopted for operational flexibility.

In Level 4 of the proposed framework, Level 3 analysis is extended to include a more complex representation of system constraints. While Level 3 considers the system as a whole, Level 4 adds consideration of how transmission may be physically available but contractually unavailable for the deliverability of flexibility. The deliverability over each time horizon and direction of ramping can provide information as to where flexibility constraints are most significant and how new transmission can help the system meet flexibility requirements.

These four levels of analysis are still under development and need further testing on real systems before being used in utility/ISO practice. The Level 3 metrics are data and modeling intensive and dependent on the assumptions made in the modeling of system operations. Therefore, they are suited to issues such as resource expansion and determination of how different resources provide flexibility. Many of the measures are not purely a reliability measure, and instead may focus more on efficiency and economics as to how systems can manage flexibility needs.

Measure 6: Net Demand Ramping Variability

The data requirements and methods for the Measure are described below, using examples from CAISO and ERCOT. The intent is to provide both a historical and future view of the maximum one-hour-up, one-hour-down, three-hour-up, and three-hour-down net demand ramps. The net demand generally means the difference between total load and production from VERs, although other variable loads and generation types may be appropriately included. It is recommended that this analysis be done for the current study year, three recent historical years, and a projected year that is four years in the future. For example, the 2014 study year would include 2011–2013 historical years and the 2018 future year.

Building the Forecast Variable Energy Resource Portfolio

A BA can request the installed capacity for the expected renewable build-out for a study year from load-serving entities (LSEs) representing load within the BA's balancing area. Typical data would include:

- The installed capacity for each wind, solar, and distributed resource that is under contractual commitment to the LSE;
- The location of each resource:
  - External resources: For resources that are external to the BA, additional information would be required to determine if the variability of the resource would be firmed by the sending BA or the receiving BA. For example, if the renewable resource would be imported on a dynamic schedule, then the receiving BA would need to include the variability in its ramping capability needs calculation similar to an internal renewable resource.
- Technology type (e.g., solar thermal, solar PV tracking, solar PV nontracking, or distributed solar PV); and
- The expected on-line date. This is in order to include the flexible needs for the month and year after the resource has been in service.

The above information ensures that the assessment captured the geographic diversity benefits of renewable resources.

Load Build-out

It is recommended that a BA's monthly net demand ramping variability be assessed using the most current full year of actual load data, preferably in one-minute increments. (If one-minute data is not available or the BA does not believe that it is necessary given the nature of their system, five-minute data may be used.) The load growth factor could be obtained from the state's Energy Commission (EC) in which the BA is located or any other reputable forecast provider entity responsible for providing load forecast to the BA for planning studies.

The BA can use the monthly peak load forecast to develop minute-by-minute load forecasts for each month. The BA can scale the actual load for each minute of each month of the most recent year using an expected load growth factor of the monthly peak forecast for the study year divided by the actual monthly peak.

Wind Profile Build-out

Existing Resources

- Use actual one-minute wind production data for the most recent year. For example, 2013 actual one-minute wind production data can be used to build 2018 one-minute wind production data.

Future Study Year

- Extract one-minute actual wind production data for the most recent year (e.g., 2013).
- If the expected wind addition is small compared to the installed capacity of the study year (e.g., 2018), the one-minute wind profile can be created by scaling the one-minute wind production data for 2013 using this factor: expected installed capacity in 2018 divided by the installed capacity in 2013.

$$2018\ W_{\text{1-min}} = 2013\ W_{\text{Actual\_1-min}} * 2018\ W_{\text{Installed Capacity}} / 2013\ W_{\text{Installed Capacity}}$$

- If the expected wind addition is significant, then one-minute wind production data for the study year can be developed using NREL's simulated profiles for a location in close proximity to the expected plant.

$$2018\ W_{\text{1-min}} = 2013\ W_{\text{Actual\_1-min}} + 2018\ W_{\text{Simulated\_1\_min}}$$

Solar Profile Build-out

Existing Solar

- Use actual solar one-minute production data for the most recent year. For example, 2013 actual one-minute solar production data can be used to develop the profile for the study year 2018.

Future Study Year

- ERCOT developed one-minute solar production profiles using NREL's 2005 solar profiles for a competitive renewable energy zone (CREZ) based on the profiles' geographic locations and technology (e.g., solar thermal, solar PV tracking, and solar PV fixed). For example, if there is an existing 50 MW solar PV resource in a CREZ, and a new 25 MW solar PV is scheduled to come on-line during the study year in the same CREZ, the BA can scale up the output of the 50 MW resources by an additional 50 percent to account for the new solar resource. This method maximizes the correlation between the load/wind and load/solar production profiles for a particular year for the vast majority of VERs. For solar resources located in new CREZs, the BA can develop production profiles using NREL's dataset for specific locations based on expected installed capacity. New CREZs would not have the load/solar correlation, but the maximum three-hour ramps during the non-summer months are highly influenced by sunset, which is consistent with existing solar data during the non-summer months.
- Aggregate all new solar one-minute production data by technology.
- Sum the actual one-minute existing solar production data with the aggregated simulated solar data for all new solar installations.

$$\text{Solar 2018}_{\text{1-min}} = 2013_{\text{Actual\_1-min}} + 2018_{\text{Simulated\_1-min data}}$$

Calculating the Monthly Maximum One-hour and Three-hour Net Load Ramps

Using the one-minute load profile and the expected wind and solar one-minute production profiles, the BA can develop minute-by-minute net load profiles by subtracting the one-minute wind and solar profiles from the one-minute load profiles. The monthly one-hour and three-hour ramping needs can then be calculated by any of the three options outlined below. The maximum one-hour up and down ramping needs are determined by calculating the 99.8th percentile for up ramp and the remaining one-fifth percentile for down ramp change, respectively, within each consecutive 60-minute period. The maximum three-hour up and down ramping needs are determined in a similar manner using the largest ramp in each consecutive 180-minute period. As shown in Figure B.1, the maximum three-hour ramp can occur in less than three hours.

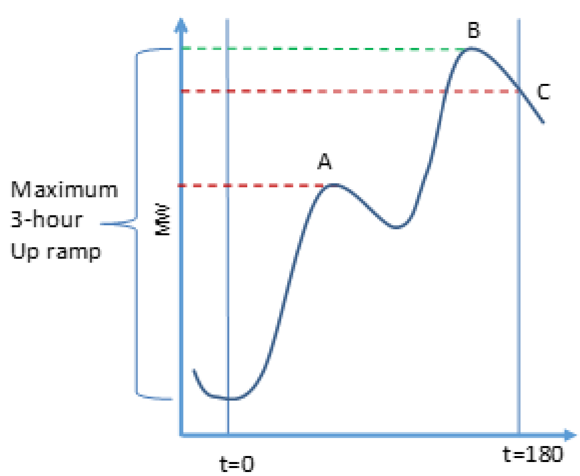


Figure B.1: Maximum three-hour ramp

- The maximum net load change in three hours can occur in less than three hours.
- The maximum monthly three-hour net demand ramp within a three-hour period is the highest megawatt value reached within any three-hour moving window.

The one-hour and three-hour upward and downward net demand ramp capacity can be calculated in several ways. The following are three options:

Option 1 – One-minute moving window

- One-Hour Ramp: NL_{61}-NL_{1}, NL_{62}-NL_{2}, NL_{63}-NL_{3}....NL_{n+61}-NL_{n+1} ....n ≥0
- Three-Hour Ramp: NL_{181}-NL_{1}, NL_{182}-NL_{2}, NL_{183}-N_{L3}....NL_{n+180}-NL_{n}

Option 2 – Five-minute moving window

- One-Hour Ramp: NL_{61}-NL_{1}, NL_{66}-NL_{6}, NL_{71}-NL_{11}....NL_{5n+61}-NL_{5n+1} .... n ≥0
- Three-Hour Ramp: NL_{181}-NL_{1}, NL_{186}-NL_{6}, NL_{191}-NL_{11}....NL_{5n+181}-NL_{5n+1}

Option 3 – Average of one-minute moving window

- One-Hour Ramp or Three-Hour

  Up Ramp **=** Avg(NL_{t+4min}) ≥ Avg(NL_{t-4min})

  Down Ramp **=** Avg(NL_{t+4min}) < Avg(NL_{t-4min})

The results for all three options are fairly close. For simplicity, Option 1 is typically used.

Defining the BA's Net Demand Ramping Variability

Each BA can calculate its one-hour or three-hour ramping capability needs using the following equation. Each BA can exclude the second part of the equation if it elects to neglect the spinning reserve portion of the contingency reserve in the flexible needs determination.

$$Flexibility\ Need_{MTH_y} = Max\left[\left(3RR_{HR_x}\right)_{MTH_y}\right] + Max\left(MSSC, 3.5\% * E\left(PL_{MTH_y}\right)\right) + \varepsilon$$

Where:

$Max[(3RR_{HRx})_{MTHy}]$ = Largest three-hour contiguous ramp starting in hour x for month y

E(PL) = Expected peak load

*Replace $Max[(3RR_{HRx})_{MTHy}]$ with $Max[(1RR_{HRx})_{MTHy}]$ to calculate one-hour ramping needs

MTHy = Month y

MSSC = Most Severe Single Contingency

ε = Annually adjustable error term to account for load forecast errors and variability method

Results of Analysis by BA

CAISO

Table B.1: CAISO's Expected Build-out Through 2018

	2011	2012	2013	2014	2018
Large-Scale Solar PV	182	1,345	4,173	4,512	6,202
Small-Solar PV		367	1,100	2,200	2,630
Solar Thermal	419	419	419	1,051	1,631
Distributed PV					2,400
Wind	3,748	5,800	5,894	5,894	8,557
Total					

The charts in Figures B.2 and B.3 show the one-hour and three-hour net demand ramping variability. As currently defined, the need is expected to increase for future years with the increase being more noticeable during the non-summer months. Figure B.2c shows the distribution of the one-hour up/down net demand ramping variability for 2011–2014 and the expected variability in 2018. Likewise, the charts in Figure B.3 show the distribution of the three-hour up/down variability for 2011–2018. The red shaded areas shown in Figures B.2c and B.3c represent two standard deviations from the mean of the one-hour and three-hour up/down variability, respectively.

CAISO's Historic Net Demand Ramping Variability Calculations and Trend for Future Projections

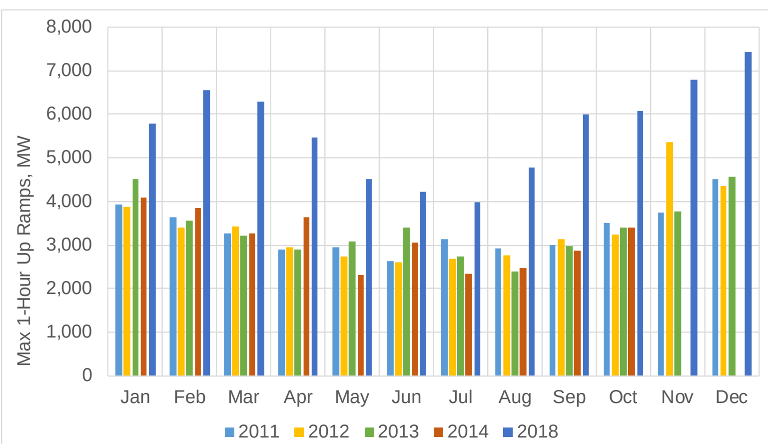


Figure B.2a: Maximum one-hour up ramp

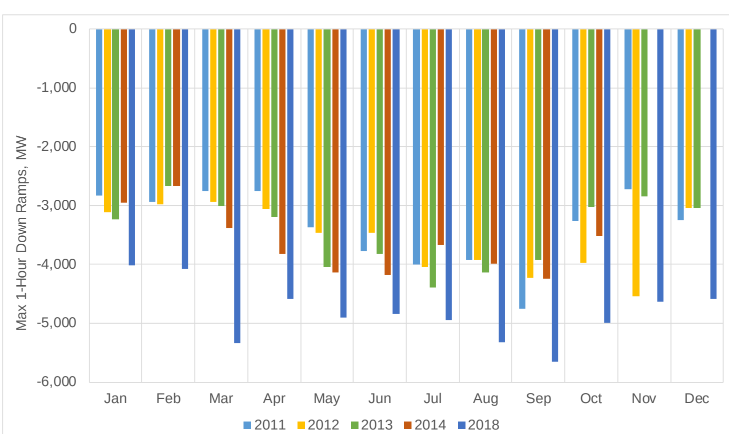


Figure B.2b: Maximum one-hour down ramp

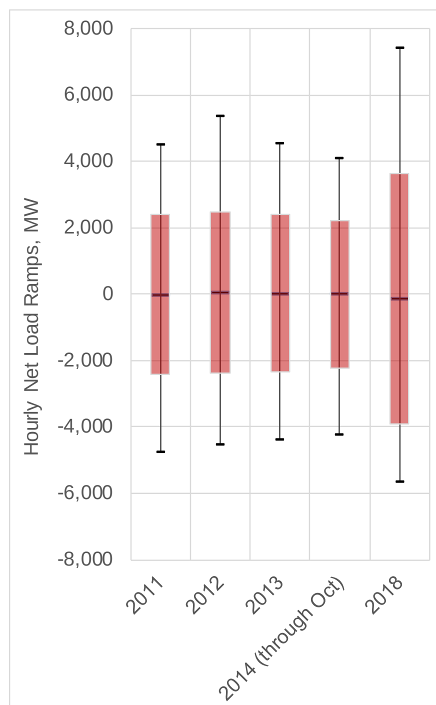


Figure B.2c: Yearly one-hour ramp distribution

Red shaded area represents 2 σ from the mean

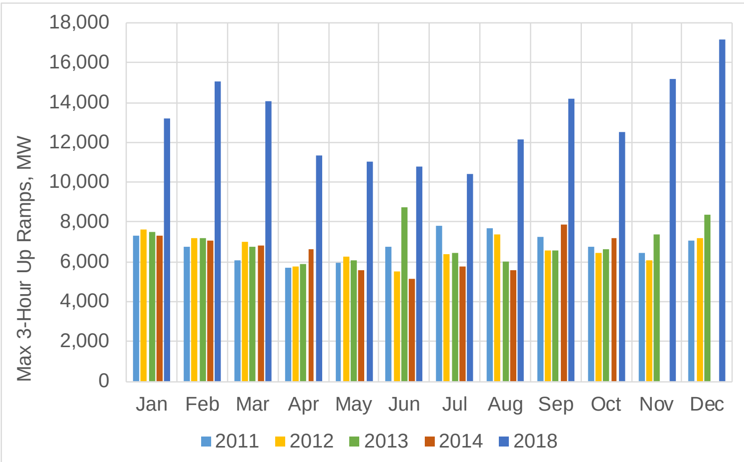


Figure B.3a: Max. monthly three-hour up ramps

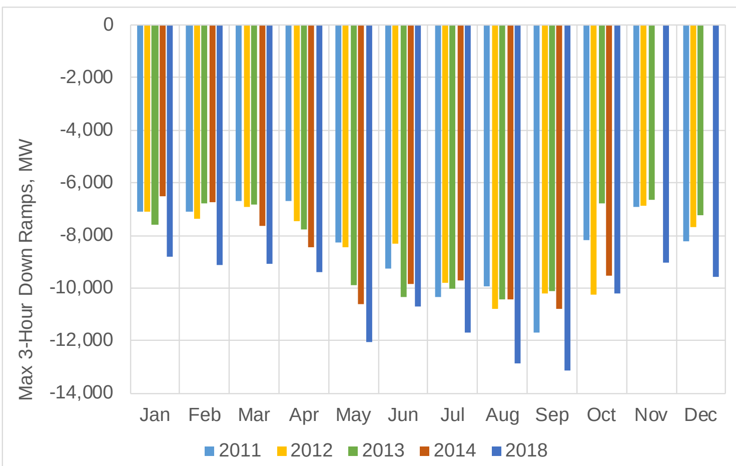


Figure B.3b: Max. monthly three-hour down ramps

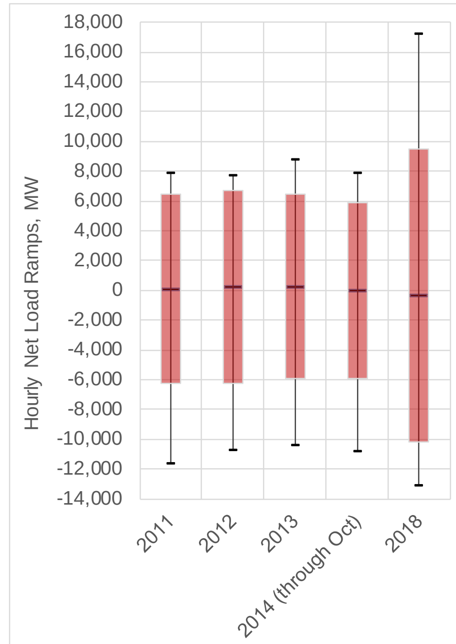


Figure B.3c: Yearly three-hour ramp distribution

Red shaded area represents 2σ from the mean

ERCOT

ERCOT Net Demand Ramping Variability Analysis for 2011–2014 and Predictions for 2018 Data Requirements

1. Total ERCOT system load with one-minute resolution for 2011–2014.
2. Total ERCOT wind power production with one-minute resolution for 2011–2014.
3. Total installed wind generation capacity for each year, 2011–2014,[16] Table B.2. In ERCOT, coastal wind is positively correlated with system load; therefore, the capacities are reported in the table as coastal and non-coastal wind to inform the analysis.

Table B.2 Installed Wind Generation Capacity for 2011–2014 and Projected Wind and PV Generation Capacity for 2018

Year	Wind Capacity, MW	Non-Coast Wind, MW	Coast Wind, MW	PV
2011	9,00	8,433	1,067	
2012	10,458	9,178	1,278	
2013	10,994	9,313	1,681	
2014	11,703	10,022	1,681	
2018	17,340 (with GIAs & FCs)			
2018 with PV	21,130 (with GIAs)			6,341 (Requests)

Calculation procedure and results

1. From historical load and wind generation data, net demand is calculated for every one-minute interval as load minus wind production.
2. One-hour and three-hour net demand ramps are calculated using one-minute moving window, Option 1, as described above.
3. In each studied year, find maximum of net demand up ramps and maximum net demand down ramps for every time frame (i.e., one hour or three hour), as 99.8th percentile and 0.2nd one-fifth percentile of net demand ramp distribution[17] (see Figures B.5–B.8). There is no particular trend in net demand ramps that can be observed based on historical data. This is partially due to the fact that installed wind generation capacity was only increasing by about 500 to 1000 MW a year. Also, it was observed that maximum load ramps are fairly close to maximum net demand ramp values, while maximum wind ramps are much lower (about one-half of maximum net demand ramps of one-hour ramps and about one-third of maximum net demand ramps for three-hour ramps). This means that the highest net demand ramps are “driven” by load ramps rather than wind ramps. The load ramps follow fairly constant diurnal patterns and are not expected to vary substantially from year to year.
4. Projected 2018 net demand ramps are based on projected installed capacity of variable generation (i.e., wind and solar) in 2018.

   For ERCOT, two cases were considered (see Table B.2):

   - **2018 case:** The projected installed capacity of variable generation is based on planned projects with signed interconnection agreements and financial commitments.
   - **2018 with PV case:** The projected installed capacity of variable generation is based on planned wind projects with signed interconnection agreements and all solar projects that requested

[16] Note currently there is only 158.8 MW PV capacity registered with ERCOT.
[17] Note that absolute maximum of net load ramps may be driven by a single event and may not be suitable for comparison between different years and trending.

interconnection with ERCOT. This goal of analyzing this case is to look at potential impacts from rapid solar build-out.

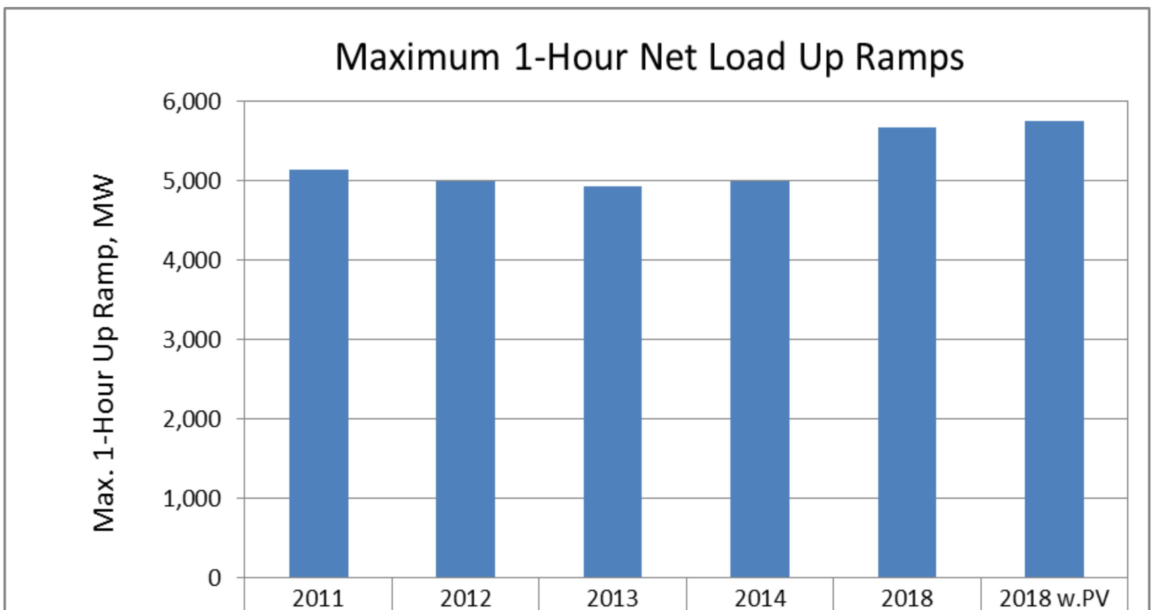
- Note that all wind interconnection requests in ERCOT currently add up to 24.5 GW of additional capacity, and ERCOT believes it is not realistic to assume that all of them will be built by 2018.

AWS True Power provided ERCOT with hourly wind power generation patterns for hypothetical future wind generation plants. Each profile is representative of the historical wind output in a specific county. The profiles were used in this analysis to project hourly production for new wind power plants in 2018.

ERCOT also procured new hourly solar generation patterns. These patterns contain profiles for 254 Texas counties for four different types of solar technologies: single-axis tracking, fixed tilt, solar thermal, and residential. ERCOT selected the single-axis tracking profiles, which were used in this analysis to project hourly production for new solar plants in 2018.

DNV GL (former KEMA) [18] developed the method for creating high-resolution variable power production and load time series from hourly data. The parameters for this method are derived from historically observed variability. This method was used to produce a time series with one-minute resolution for future load, wind, and solar generation.

Figures B.4–B.6 show maximum net demand up ramps and maximum net demand down ramps for 2018 case and 2018 with PV case.



	2011	2012	2013	2014	2018	2018 w.PV
Max 1_Hr_Up	5,148	5,002	4,939	4,994	5,671	5,749

Figure B.4: Maximum (98th percentile) one-hour net demand up ramps 2011–2014 and projected for 2018

[18] http://www.dnvkema.com/Images/EndUseDataStrategy_July2014final.pdf

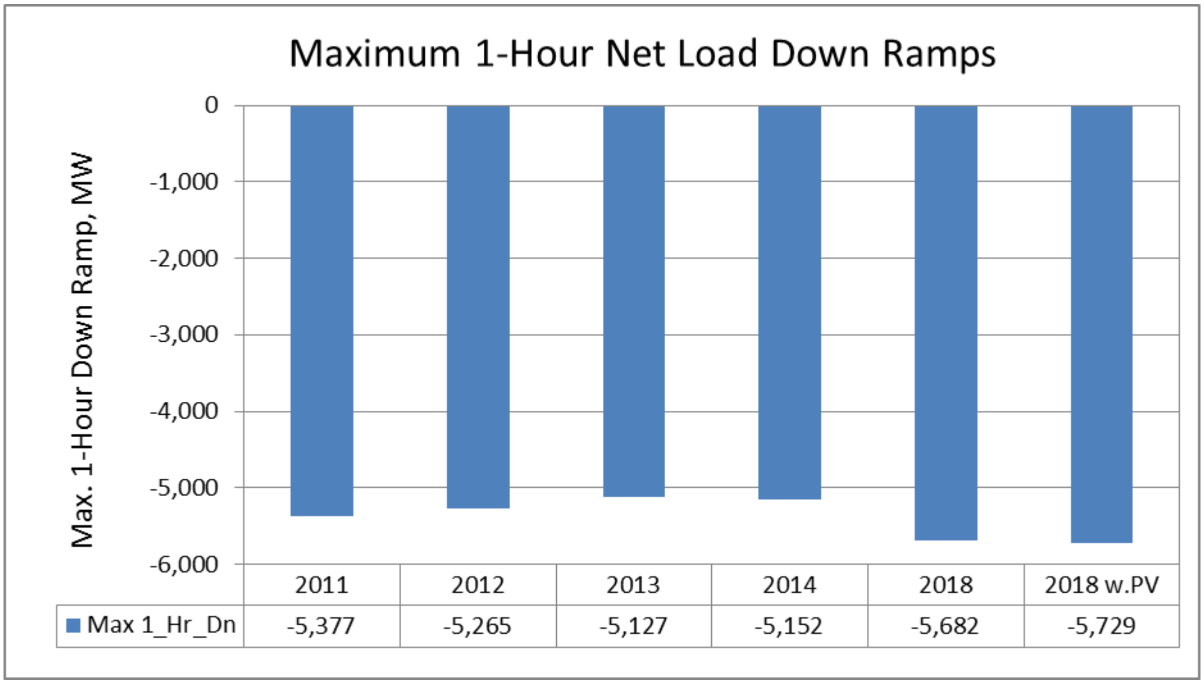


Figure B.5: Maximum (0.2nd percentile) one-hour net demand down ramps 2011–2014 and projected for 2018

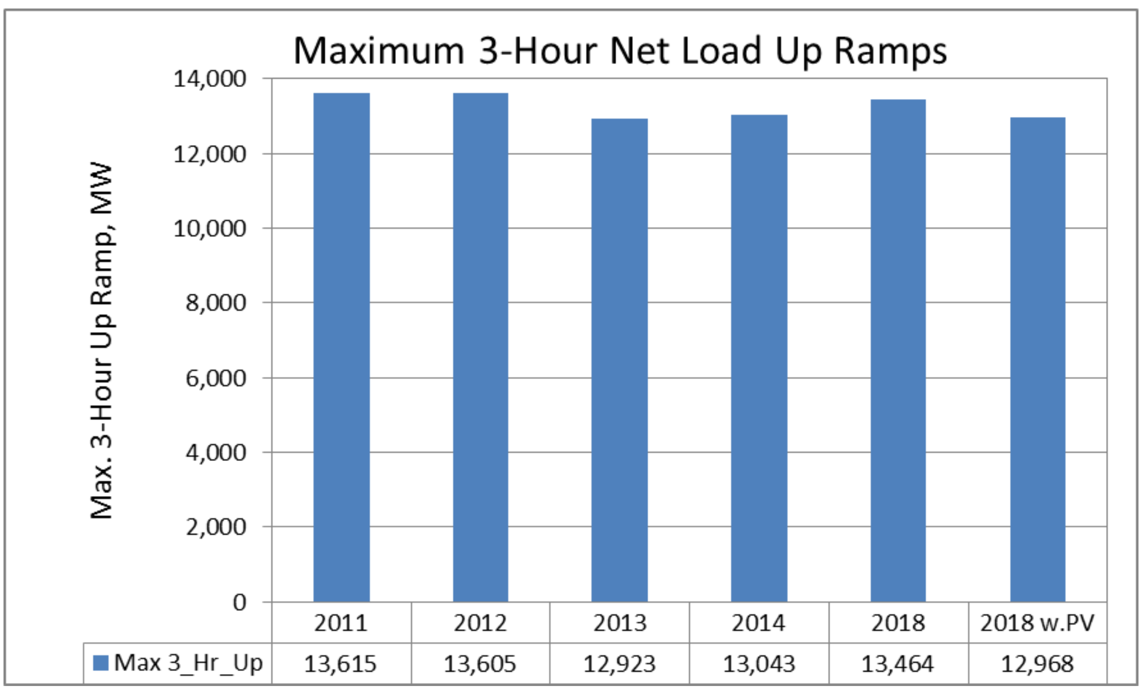


Figure B.6: Maximum (98th percentile) three-hour net demand up ramps 2011–2014 and projected for 2018

5. Figures B.7 and B.8 illustrate boxplots for one-hour and three-hour net demand ramps, respectively, for historical years 2011–2014 and future projections in 2018. Boxplots are a convenient way to compare net demand ramp statistics from several years on one plot.

   On a boxplot, each box represents one year of net demand ramps, as calculated in step 2 or step 3. On each box, the central mark (red line) is the median, the edges of the box (in blue) are the 25th and 75th percentiles, and the whiskers correspond to ± 2.7 sigma, which represents 99.3 percent coverage, assuming the data is normally distributed, and the outliers are plotted individually (red crosses). If necessary, the whiskers can be adjusted to show a different coverage.

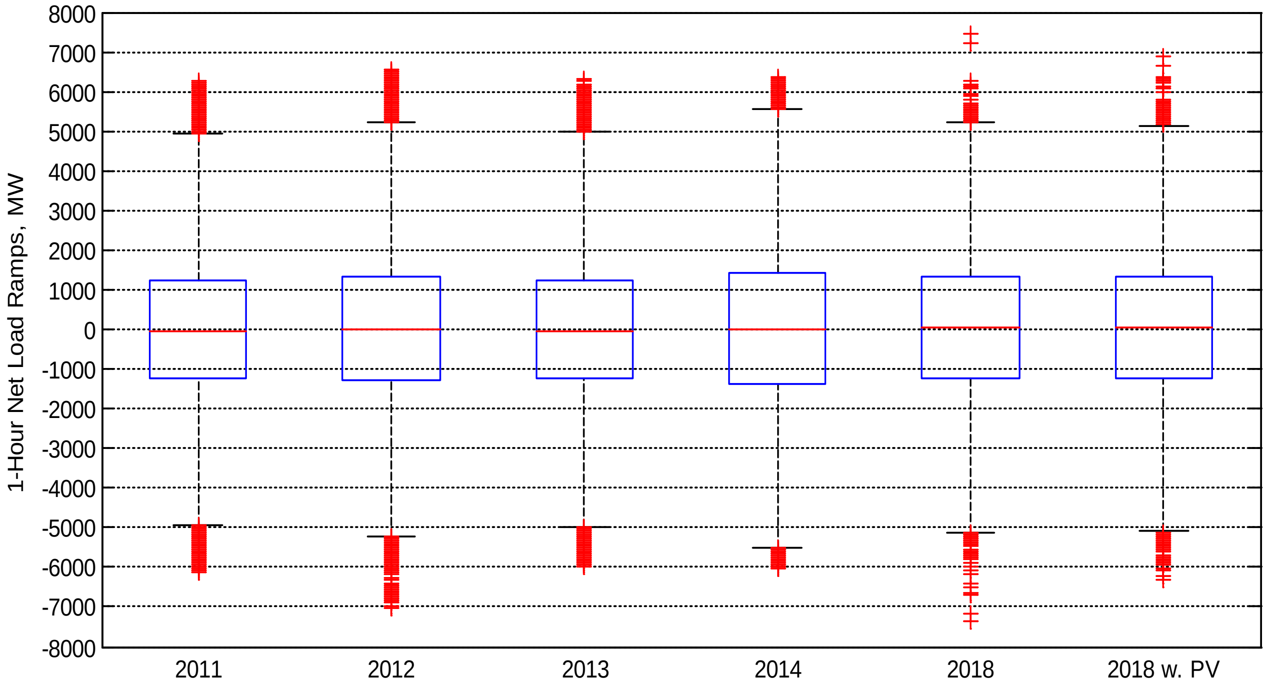


Figure B.7: Boxplots for one-hour net demand ramps 2011–2018

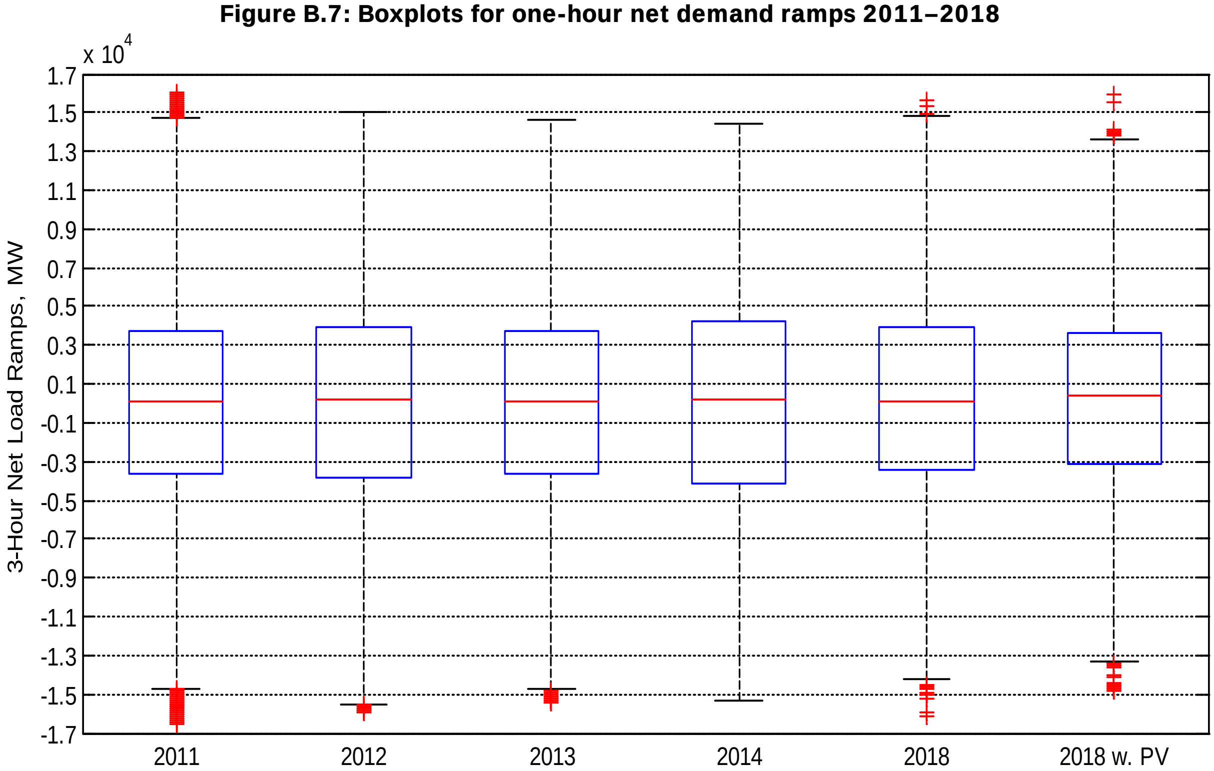


Figure B.8: Boxplots for three-hour net demand ramps 2011–2018

BC Hydro

By the end of 2014, BC Hydro had approximately 487 MW of VERs, which is expected to increase by a mere 180 MW by 2018. Thus, the ramping needs are not expected to show any noticeable difference.

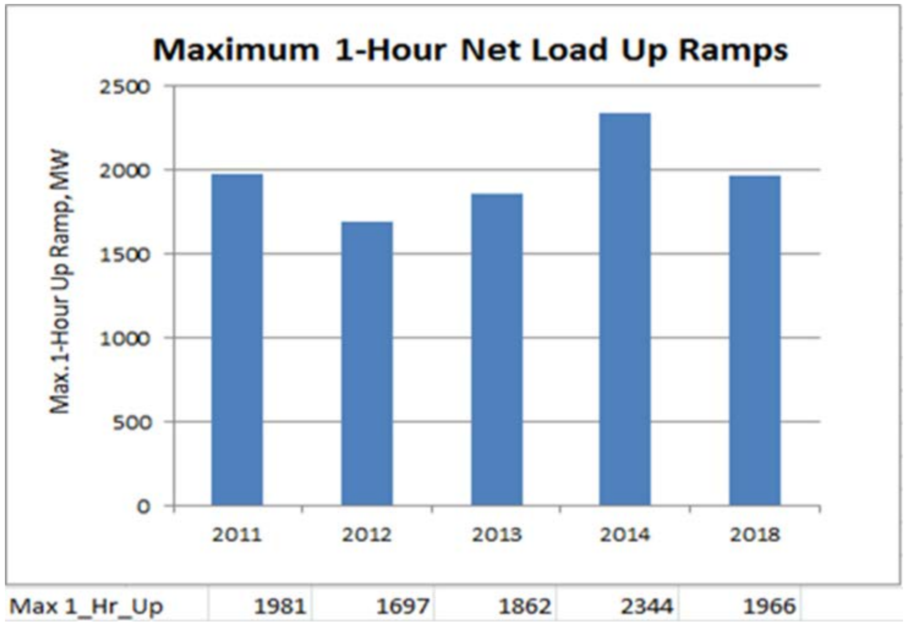


Figure B.9: BC Hydro maximum 1-hour net load up ramps

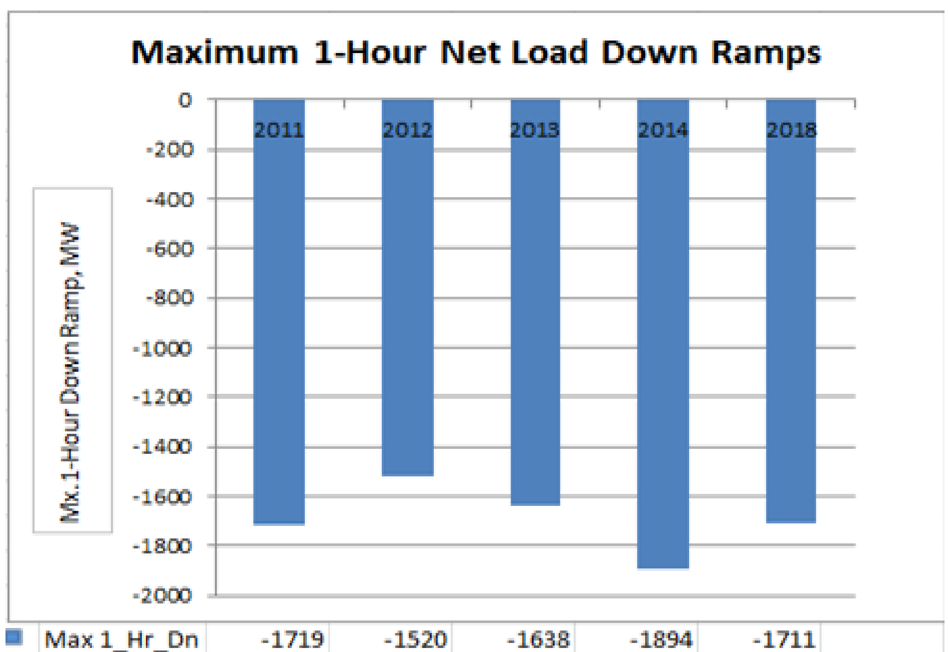


Figure B.10: BC Hydro maximum 1-hour net load down ramps

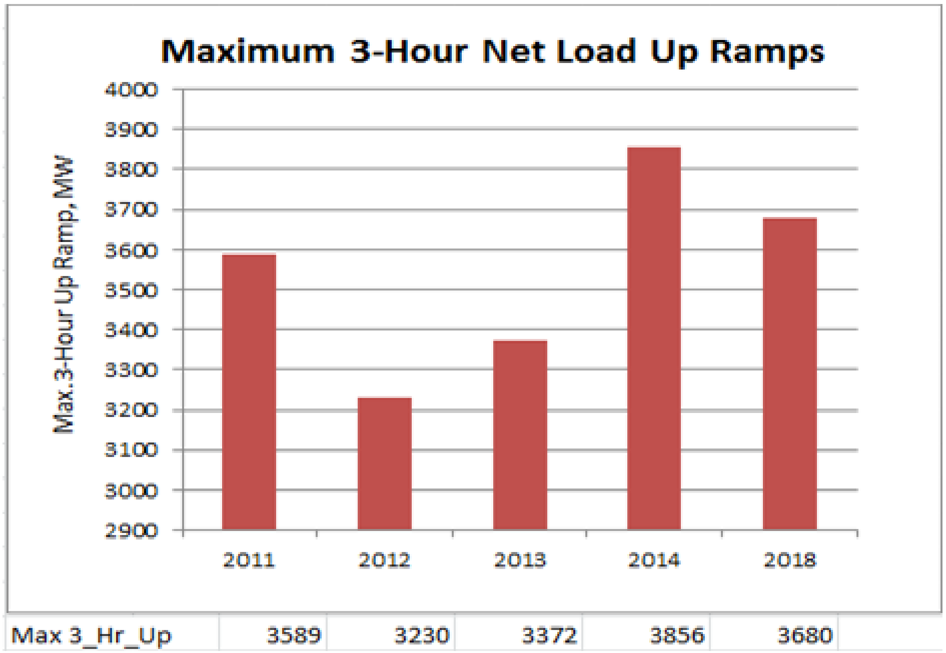


Figure B.11: BC Hydro maximum 3-hour net load up ramps

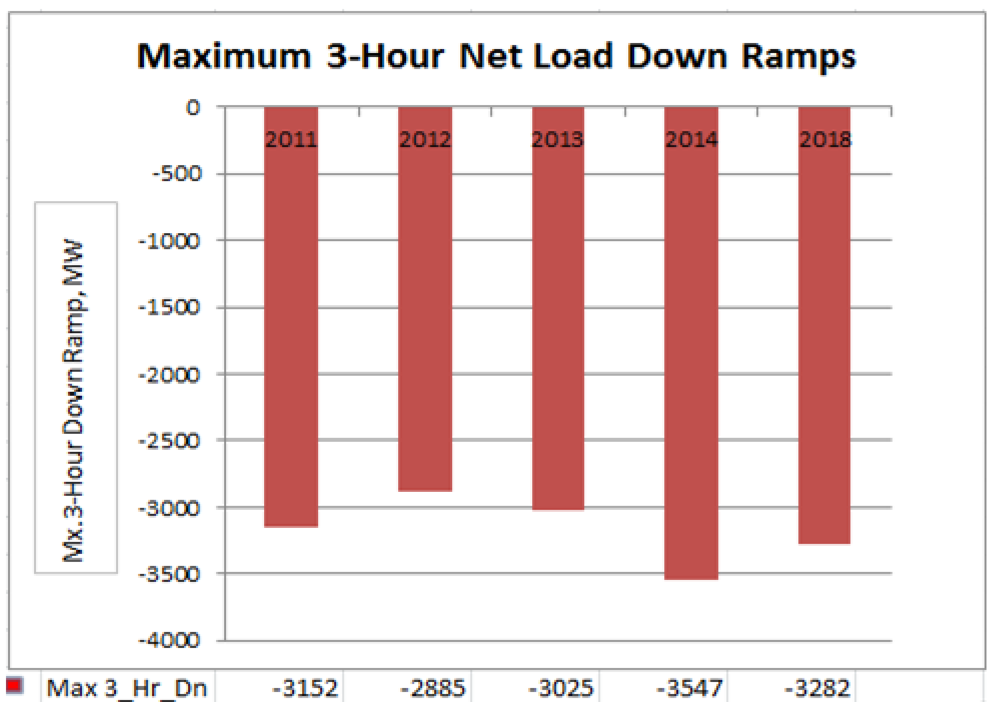


Figure B.12: BC Hydro maximum 3-hour net load up ramps

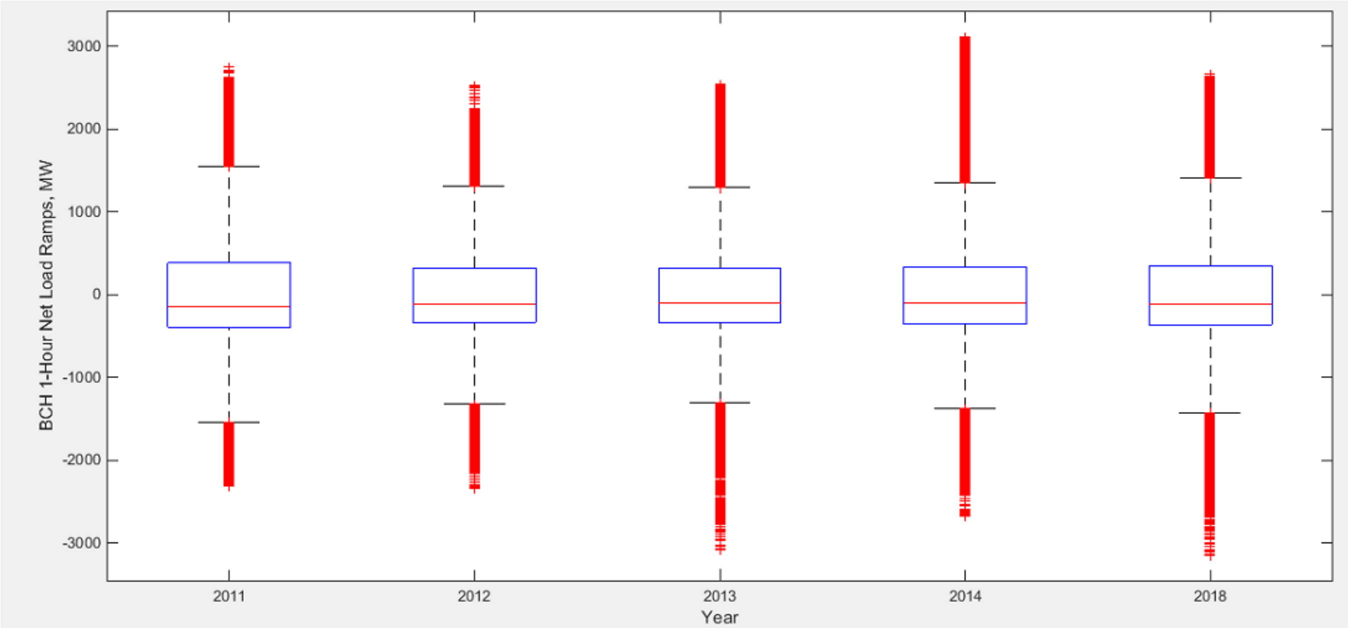


Figure B.13: Boxplot for BCH 1-hour net load ramps 2011–2018

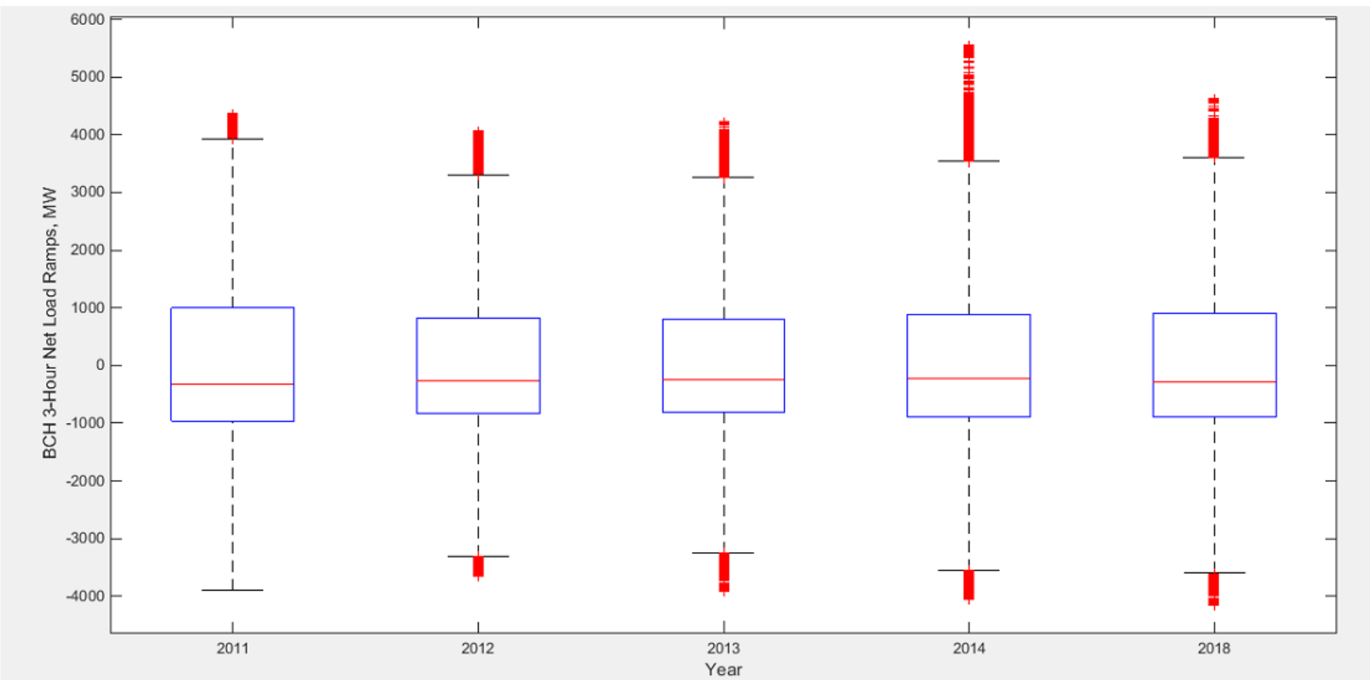


Figure B.14: Boxplot for BCH 3-hour net load ramps 2011–2018

Duke Energy

Duke Energy (Duke) has three separate BAs: Duke Energy Florida (DEF), Duke Energy Carolinas (DEC), and Duke Energy Progress (DEP). For all three Duke Energy areas there is no HVDC export/import capacity, and imports at any hour are zero. All three are part of the Eastern Interconnection and all ties to neighbors are ac.

Duke has previously employed variations of these measures for some time and sees promise in them as reliability metrics. Duke intends to refine the data and analyses and has already identified potential improvements in data collection and analysis, and in the measures themselves.

Duke's BAs have varying generation composition and load characteristics, but none currently has or is forecast to have significant penetrations of nonsynchronous generation (NSG) as compared to CAISO and ERCOT.

As Duke continues to refine data collection and analysis for these measures, it is expected that other anomalies will be identified and resolved.

Duke Energy Florida

<u>**DEF BA Ramp Rates 2013**</u>

Note: Only data for 2013 was available in time for this report. Since there is no measurable NSG projected, no projection for 2018 was needed or made.

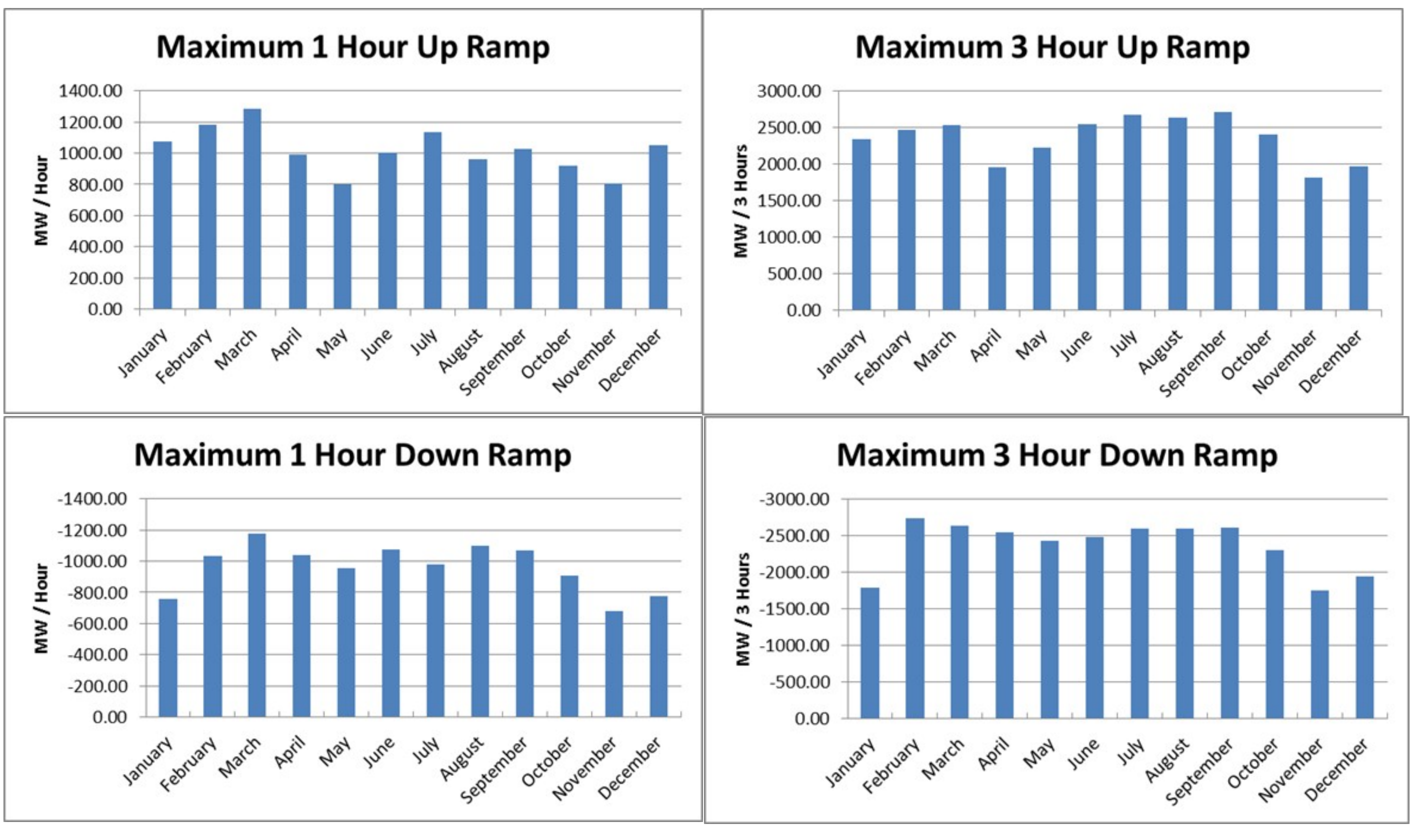


Figure B.15: BC Hydro maximum 1-hour net load up and down ramps

Duke Energy Carolinas (DEC)

Note: Only data for 2014 was available in time for this report. Since there is measurable NSG projected, a projection for 2018 was made.

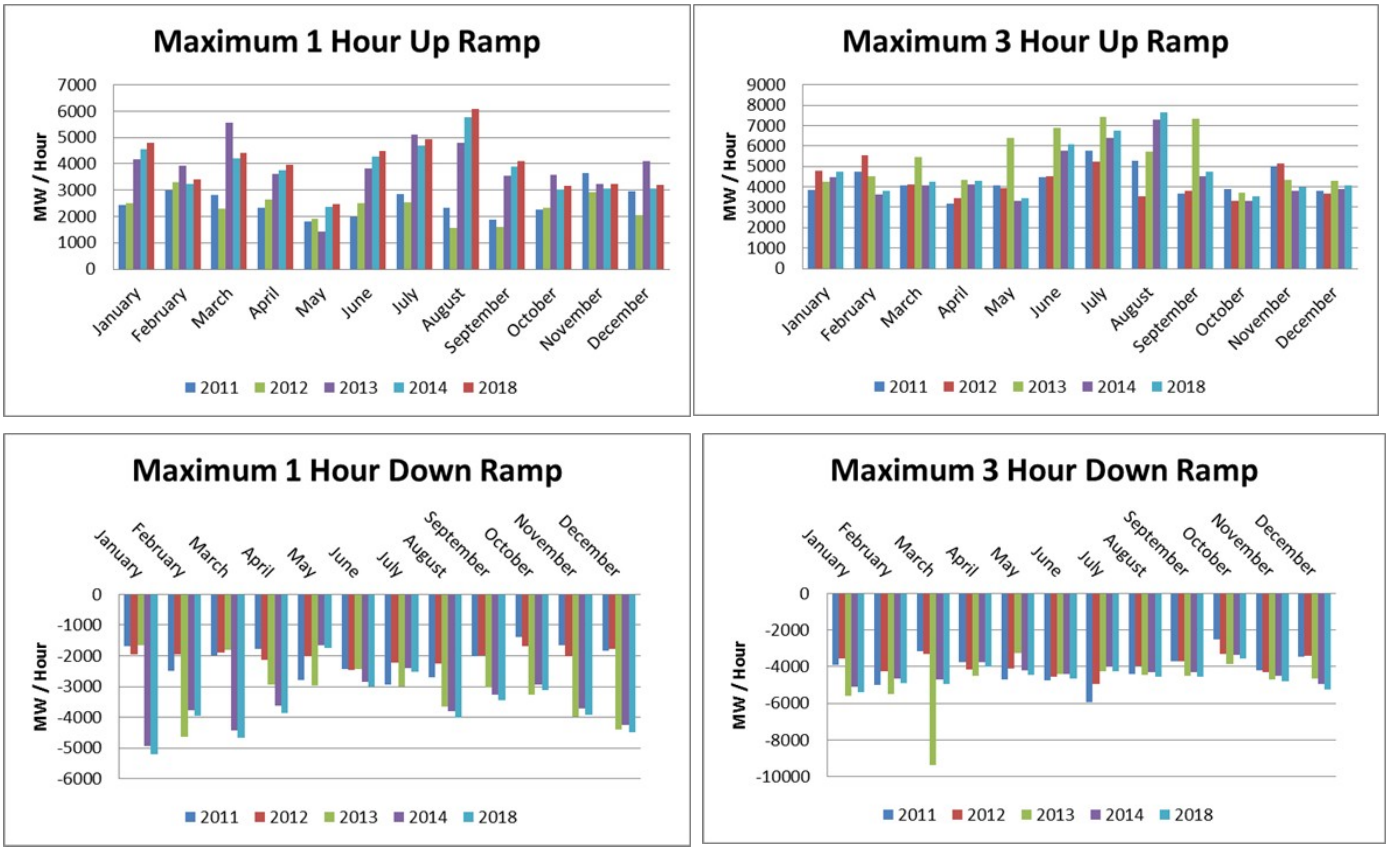


Figure B.16: Duke Energy Carolinas maximum 1- and 3-hour net load up and down ramps

Duke Energy Progress

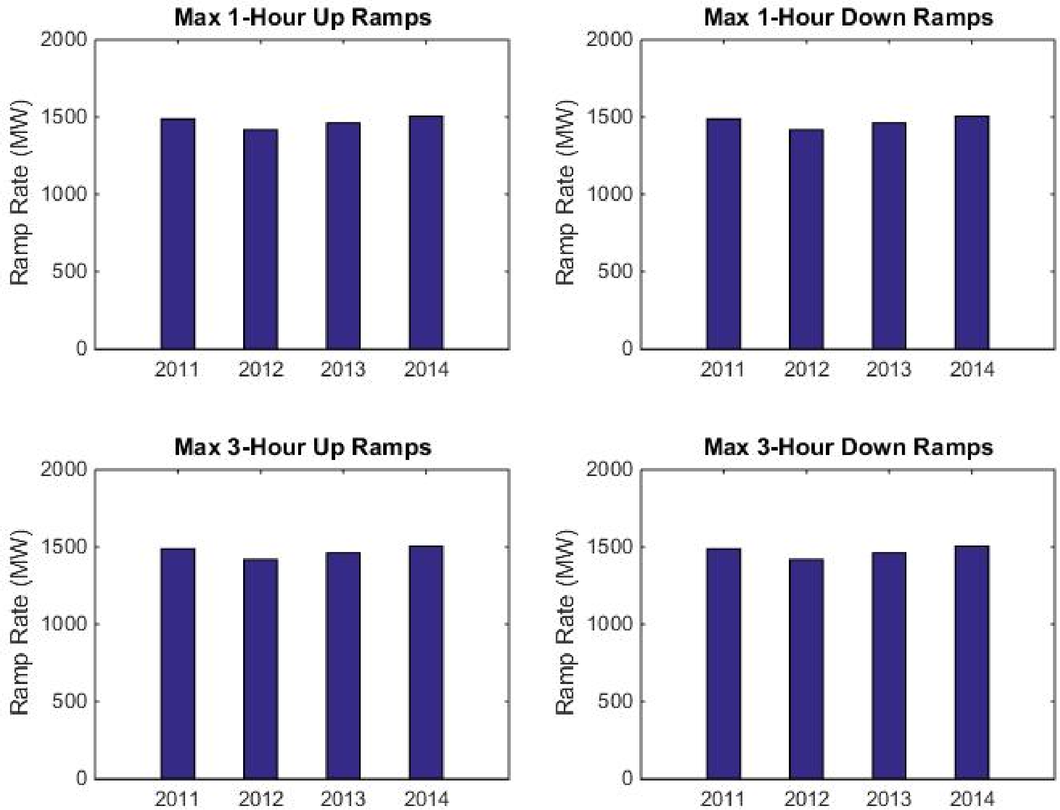


Figure B.17: Duke Energy Progress maximum 1- and 3-hour net load up and down ramps

Southern Company

Through the end of 2014, Southern Company had approximately 454 MW of VERs, which is comprised of 404 MW of wind and 50 MW of solar PV. By 2018, Southern Company expects to see an increase of 250 MW of wind and 1620 MW of solar PV for a total of 2,324 MW of VERs. Even with an increase of 500 percent of VERs between 2014 and 2018, Southern Company does not anticipate any noticeable increase in intrahour or multihour ramps.

Measure 6

Ramping Capability Measures

The historical and projected maximum one-hour-up, one-hour-down, three-hour-up, and three-hour-down net load ramps (actual load less production from VERs) using one minute data.

Year	One hour up	One hour down	Three hour up	Three hour down
2011	6,166	-6,325	11,714	-10,096
2012	5,560	-4,376	10,385	-9,614
2013	4,192	-4,521	9,034	-9,072
2014	4,423	-3,868	9,911	-9,236
2015	4,423	-3,868	9,911	-9,236
2016	4,423	-3,868	9,911	-9,236
2017	4,423	-3,868	9,911	-9,236

NOTE: Values remain unchanged for 2014–2017 because they occur outside of the solar energy operating hours (For example: 3-hour down occurs in hour 23).

Year	Wind Capacity, MW	PV, MW
2011	0	0
2012	0	0
2013	202	46
2014	404	50
2015	404	1,182
2016	654	1,182
2017	654	1,670

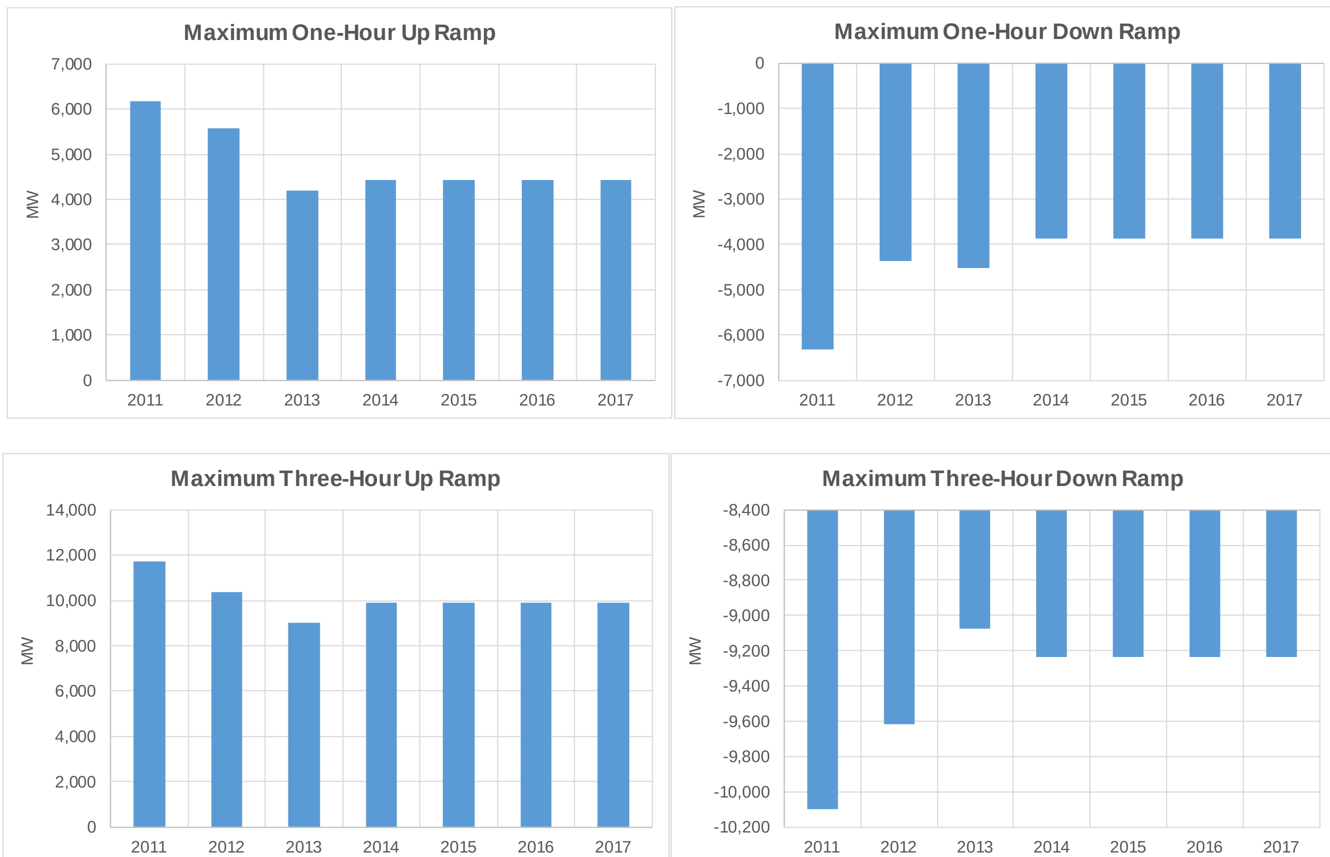
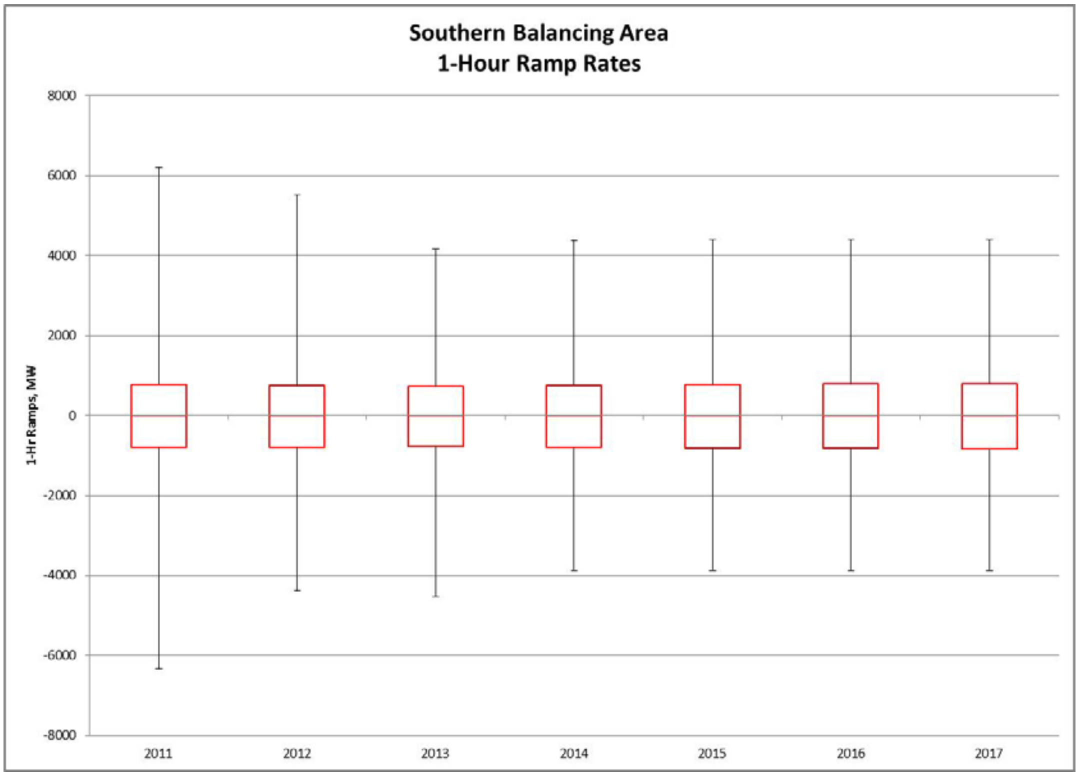


Figure B.18: Southern Company maximum 1- and 3-hour net load up and down ramps



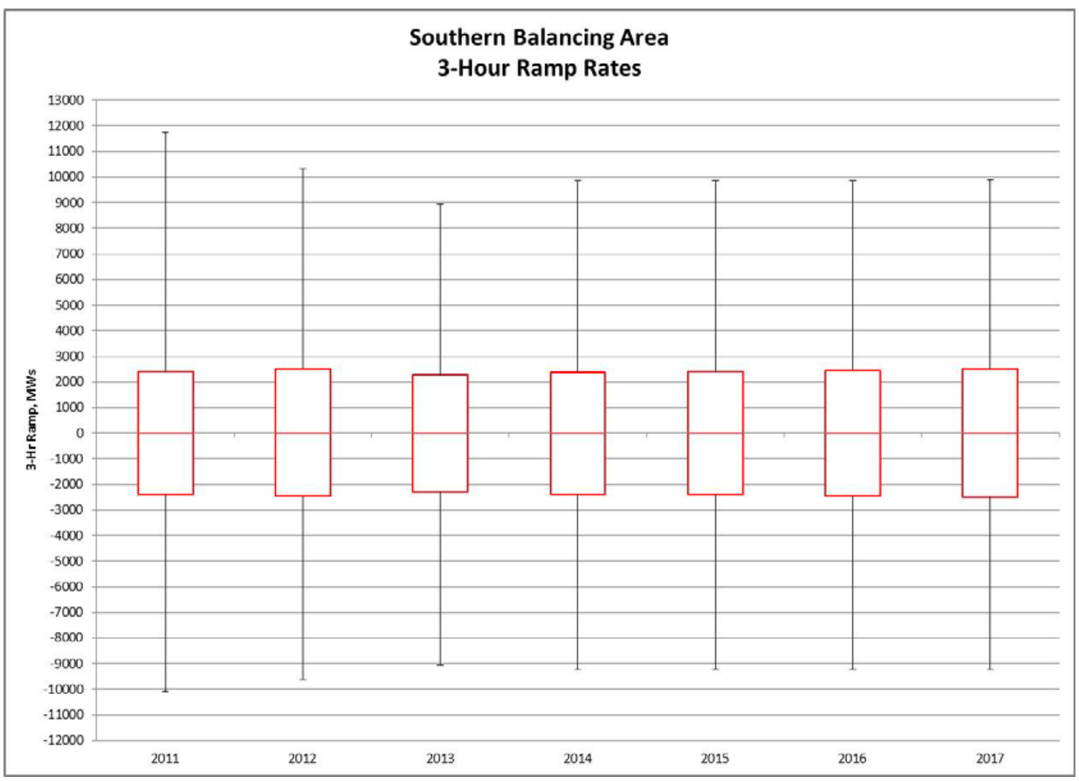


Figure B.19: Southern Company's Maximum 1- and 3-hour net load up and down ramp rates

PJM

By the end of 2014, PJM had approximately 7,029 MW of installed capacity of VERs (approximately 8,810 MW if behind-the-meter is included). This is expected to increase to 15,800 MW by 2018. As shown in Figure B.20, PJM does not expect to see any noticeable increase of ramping needs either in the 1-hour or 3-hour time frame.

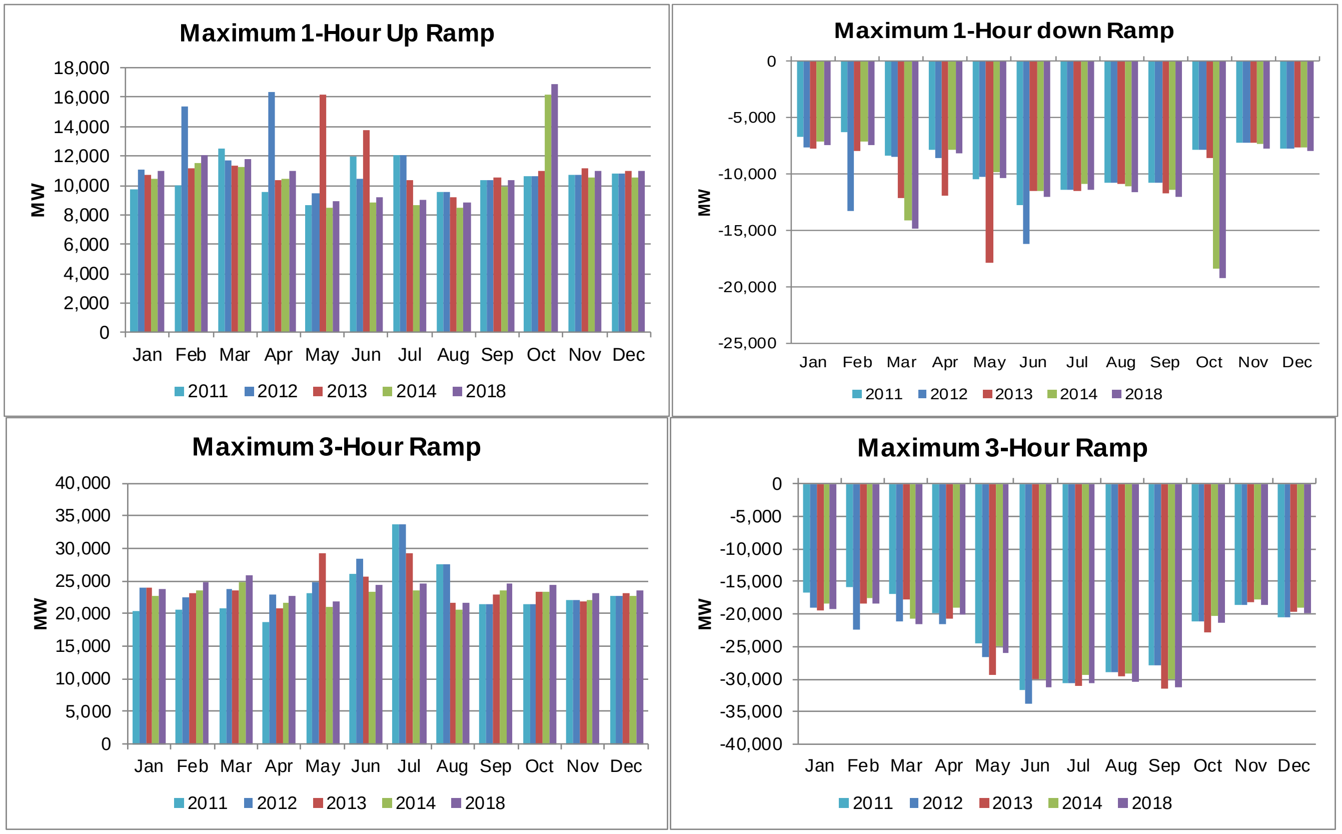


Figure B.20: PJM Maximum 1- and 3-hour net load up and down ramps

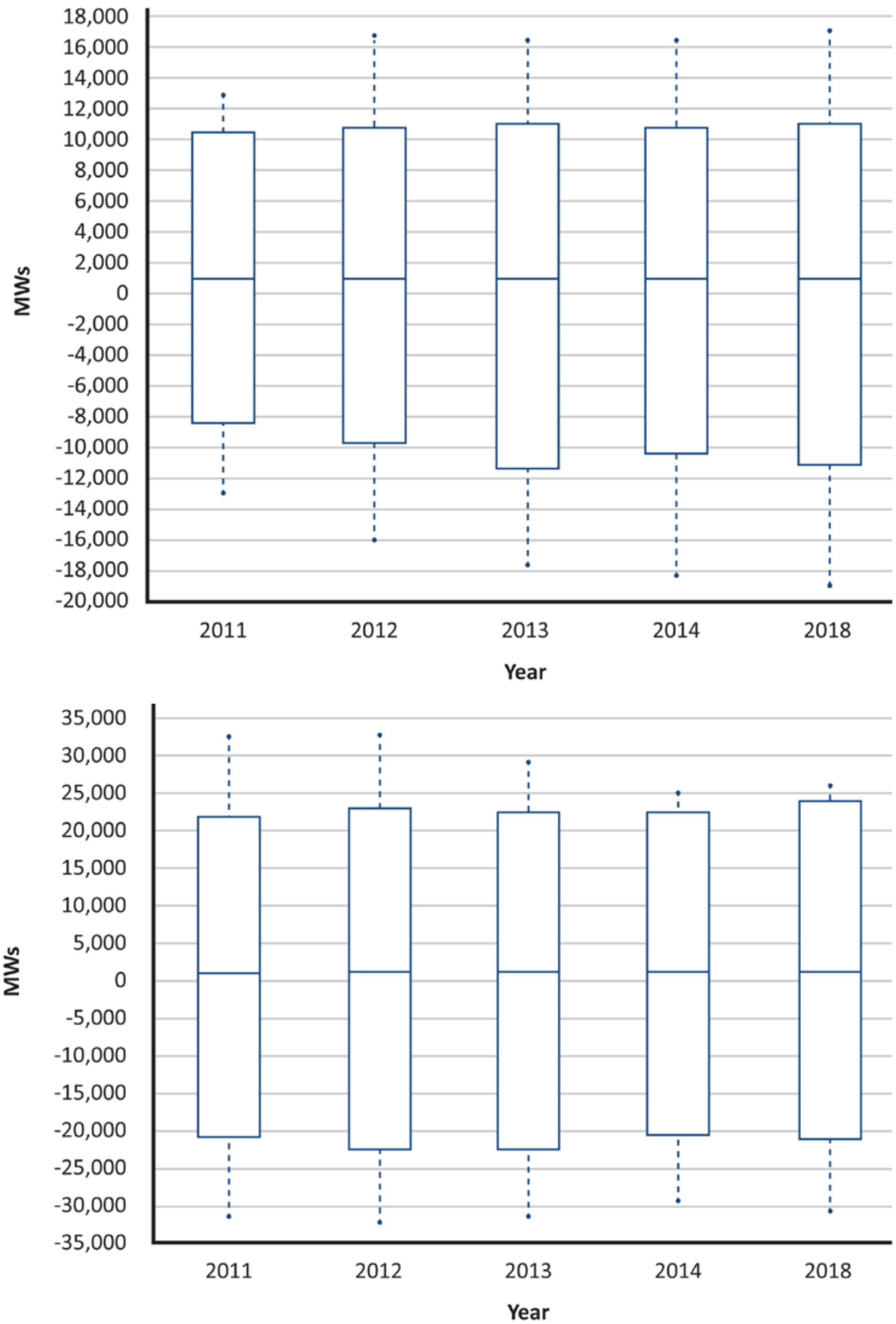


Figure B.21: PJM Maximum 1-hour and 3-hour net load up and down ramps

IESO

By the end of 2014, IESO had approximately 2,845 MW of installed capacity of VERs (wind only). This is expected to increase to 4,377 MW by 2018 (wind and solar). As shown in Figure B.22 IESO is not experiencing any noticeable increase of ramping needs either in the 1-hour or 3-hour time frame. It is important to note that IESO implemented wind dispatch in 2013. As a result, the data will understate the issue of wind ramps adding to the normal ramp requirement. IESO now uses wind to manage much of its ramp requirements due to interchange/demand change. Note that this data is in 10-minute increments with an hourly ramp requirement, which differs from the rolling hour calculation, as done by CAISO.

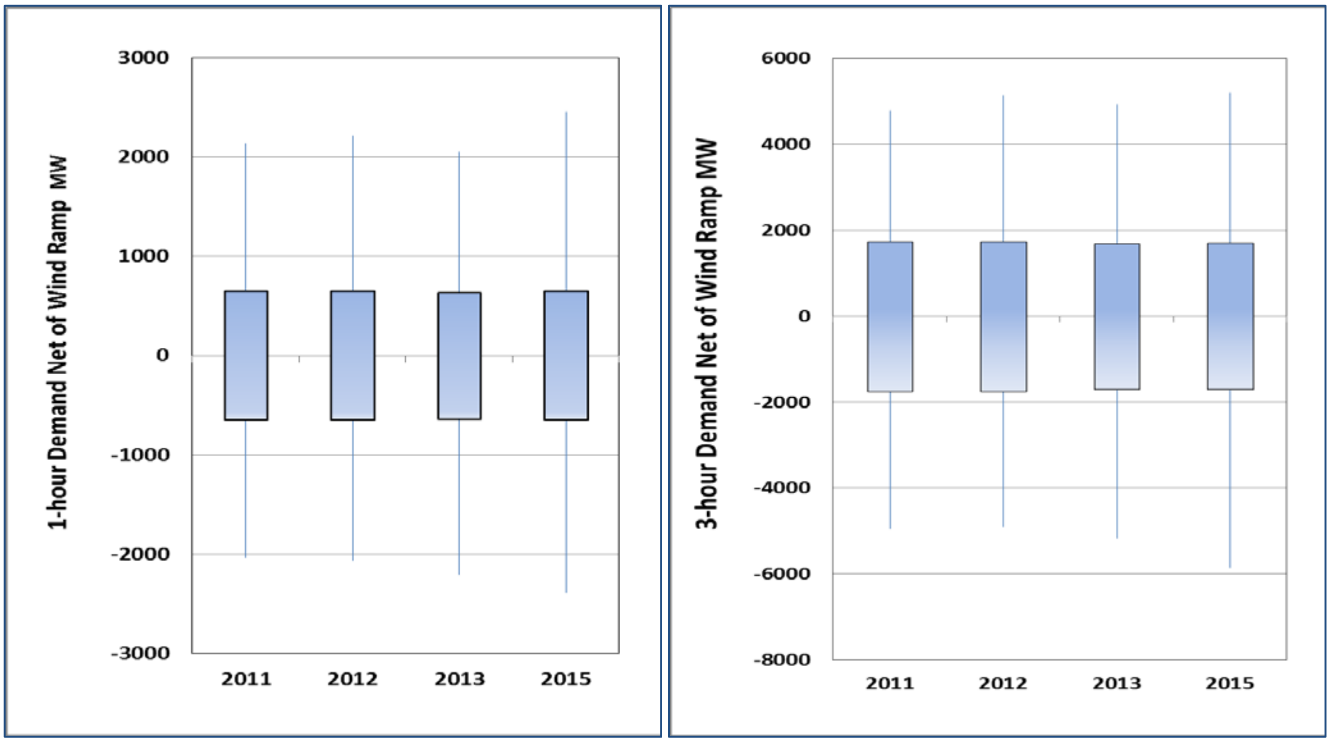


Figure B.22: IESO Maximum 1-hour and 3-hour net load up and down ramps

Appendix C – Control Performance Standards (CAISO Example)

Each BA within an interconnection has an obligation to support the interconnection frequency in real time. A BA's ability to support the interconnection frequency in real time is measured by how well it complies with NERC's Control Performance Standard 1 (CPS1) and Balancing Authority ACE Limit (BAAL) performance measures.

Control Performance Standard 1 (CPS1)

CPS1 is a statistical measure of a BA's area control error (ACE) variability in combination with the interconnection frequency error from scheduled frequency. It measures the covariance between the ACE of a BA and the frequency deviation of the interconnection, which is equal to the sum of the ACEs of all of the BAs. CPS1 assigns each BA a share of the responsibility for controlling the interconnection's steady-state frequency. The CPS1 score is reported to NERC on a monthly basis and averaged over a 12-month moving window. A violation of CPS1 occurs whenever a BA's CPS1 score for the 12-month moving window falls below 100 percent.

As an example, CAISO's CPS1 score for January 3, 2015, was 134.2 percent, which is well above the minimum 100. However, by monitoring the CPS1 score on an hourly basis, CAISO was able to determine the hours when its CPS1 scores dropped below 100 percent and determine the root cause. A closer look revealed that these hours coincided with its steep evening upward net load[19] ramp, shown in Figure C.1. The red curve is the net demand and the blue bars are the average CPS1 scores for each hour. The blue horizontal line represents a CPS1 score of 100 percent. Whenever the blue bars are above the blue line, the BA is supporting the interconnection frequency; when the blue bars fall below the blue line, the BA is leaning on the interconnection.

By analyzing CPS1 performance and performing technical studies, CAISO determined the need for flexible resources to be committed with sufficient ramping capability over a three-hour period to meet the expected increase in load and the simultaneous drop-off in solar production. System operators must rely on ramping capability in both speed and quantity to balance the VERs' production change. Also, any under-forecasting or over-forecasting of demand requires dispatching flexible resources at higher or lower levels, respectively, in order to minimize inadvertent energy flows with neighboring BAs.

[19] Net Load = Load – Wind - Solar

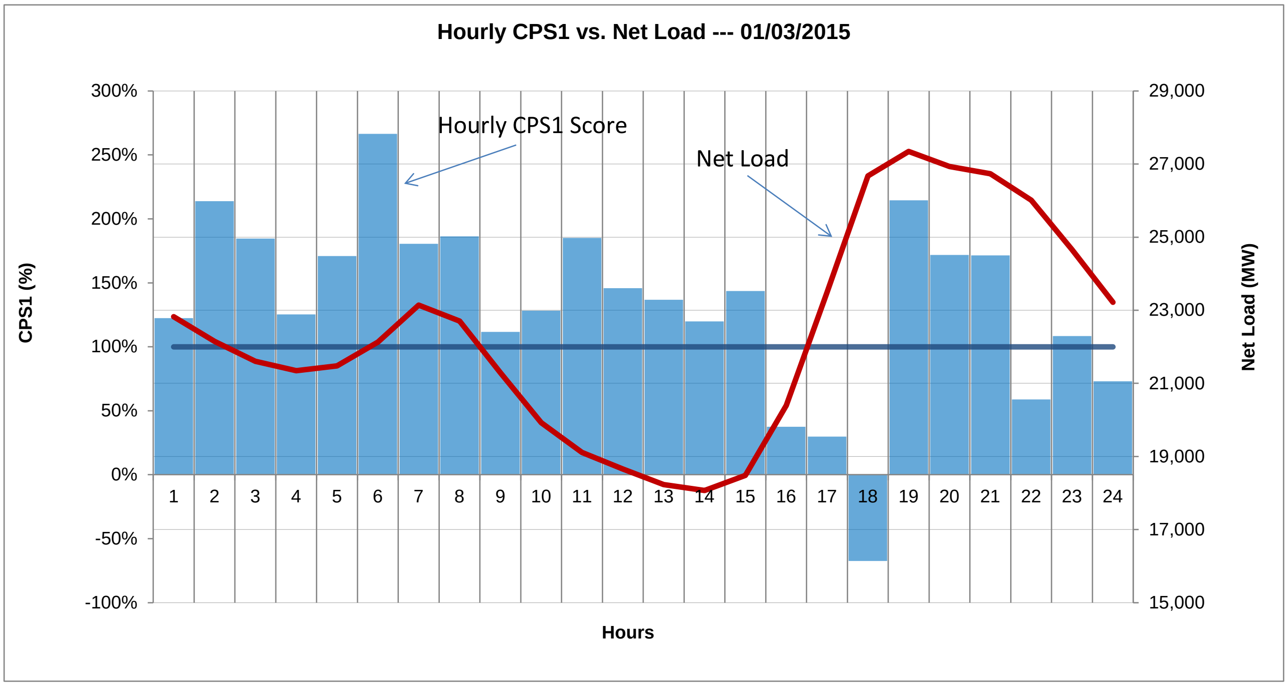


Figure C.1: Net demand vs hourly CPS1 scores 01/03/2015

To help manage the lack of fleet flexibility, CAISO is currently implementing a ramping tool[20] to predict and alert system operators of the load-following capacity and ramping requirements needed on the system in real time. CAISO is also introducing a flexible ramp product[21] to ensure enough dispatchable capacity will be available on a five-minute dispatch basis in the real-time market.

Balancing Authority ACE Limit (BAAL)

BAAL provides each BA with two dynamic ACE limits, each of which is a function of the interconnection frequency. These two dynamic ACE limits—(1) $BAAL_{High}$ and (2) $BAAL_{Low}$—are unique for each BA and are based on a BA's frequency bias and the interconnection's 1-minute frequency error (epsilon 1). As interconnection frequency deviates from scheduled frequency, the ACE limit for each BA becomes more restrictive. BAAL replaced CPS2, which was not designed to address interconnection frequency. A BAAL excursion occurs when the BAAL limit is exceeded for more than 30 consecutive minutes.

Also, by observing the hours when BAAL limits are exceeded, the BA can commit resources accordingly. For example, within CAISO's footprint, during middays with high solar production, there is less need to commit additional resources, but toward sunset an immediate need exists to replace the solar generation to continue meeting consumer demand. Many resources that could replace solar generation must be committed prior to this significant ramp, which begins before sunset. These resources often require several hours to a day or more to fully come on-line, which can result in more generation on-line than consumer demand, causing overgeneration conditions. By 2020, CAISO expects that increased flexibility will be needed to reliably meet two net load peaks, which would require managing approximately 7,000 MW of upward and downward ramps in three-hour time frames, and provide nearly 13,000 MW of continuous up-ramping capability to meet the evening peak, also in a three-hour time frame.

[20] http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-21112.pdf
[21] http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx

Knowing these challenges ahead of time relieves the system operator of real-time surprises and uncertainty.

Figures C.2 and C.3 show the BAAL for each minute of the operating day. As shown, for 14 minutes, the upper BAAL limit was exceeded during hour 18. A closer look at the root cause revealed the system area control error was high because more generation had to be committed to meet the evening three-hour upward ramp.

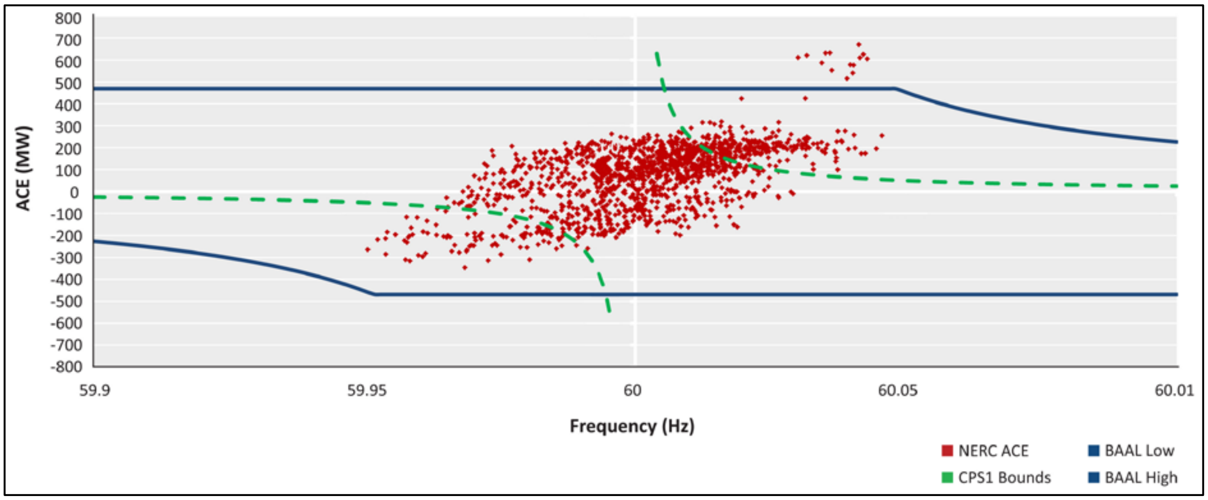


Figure C.2: Frequency of BAAL 1-minute exceedances

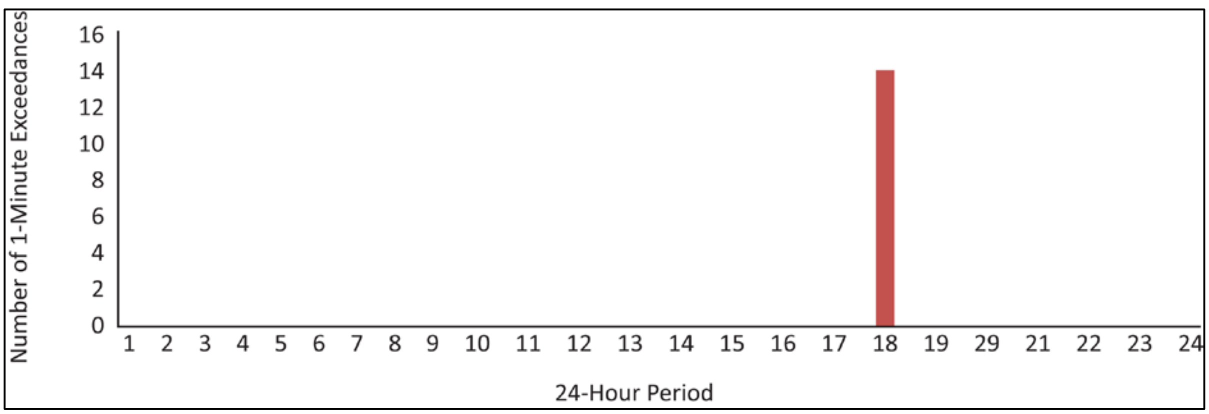


Figure C.3: Frequency of BAAL hourly exceedances

Appendix D – Reactive Power and Voltage Control

Background

The ability to control the production and absorption of reactive power for the purposes of maintaining desired voltages is critical to the reliable and efficient operation of the BPS. The process of controlling voltages and managing reactive power on interconnected transmission systems is well understood from a system planning and operating perspective. Key attributes include the following:

- System planners should design a system that has enough robust dynamic and static reactive capability (including both lagging and leading capability) to withstand the contingencies outlined in the TPL standards, specifically:
  - Determine the appropriate voltage levels and acceptable voltage bandwidths for reliable operation of the system under normal and contingency conditions;
  - Maintain voltages by managing reactive capability throughout the transmission system under normal and contingency conditions, including fault-induced delayed voltage recovery (FIDVR) situations and distributed generation ride-through;
  - Optimize reactive capability and voltages to maximize the efficient transfer of real power to load across the Bulk Electric System (BES) under normal and contingency conditions; and
  - Provide for operational flexibility under normal and abnormal conditions as determined in both steady-state and transient analyses.
- TOs and GOs should construct and maintain facilities that, at a minimum, meet the system design requirements developed in the planning studies.
- The RC, TOP, and GOP should operate the system based on the requirements in the NERC TOP and VAR Reliability Standards.
- The RC and TOP should periodically review reactive and voltage performance of the system to ensure adequate reliability is maintained and to look for potential areas of enhancement moving forward.

Reactive support must be provided locally throughout the power system. Resources are generally controlled centrally because their coordinated operation is essential to maintaining reliability. Centralized control of reactive capability leads to efficient use of resources and ensures that there is an adequate reactive margin (the combination of on-line dynamic and static reactive reserves and off-line available dynamic and static reactive reserves) in response to emerging system conditions and contingencies.

Voltage and reactive power capability is a balancing act between the supply and demand of reactive power and the resultant impact on the voltage profile. Generators and various types of controllable transmission equipment, such as shunt and series devices, synchronous condensers, static VAR compensators, etc., are used to maintain voltages throughout the transmission system and maintain adequate reactive margins. When necessary, these resources are used to inject reactive power into the system to raise voltages or absorb reactive power to lower voltages. Requirements can differ substantially from location to location and can change rapidly due to shifting system conditions and load levels. For example, reactive power requirements will often vary significantly between day and night due to load level and pattern, dispatch, and system transfers.

There are other system devices that, while not directly supplying or withdrawing reactive power, will impact overall reactive and voltage performance of the system. As an example, transformer tap settings at the distribution level can impact the systemwide reactive capability. Likewise, the appropriate switching of series compensation can also have a significant impact.

Controlling the amount of reactive power that the load contributes to or withdraws from the transmission system can be an extremely effective way to manage overall BES voltage and reactive performance. The load power factor can be managed through coordinated adjustments of the step-down transformer taps and low-side voltage schedules as well as strategic placement of capacitors on the distribution system.

Reliability Considerations

Because reactive power requirements can change rapidly—especially under contingency conditions—the impact on voltage can be significant. There are other key considerations besides simply determining the needed amount of reactive capability. Resources with dynamic reactive power control capability (synchronous and converter-fed generators, SVCs, synchronous condensers, etc.) are needed to augment static devices (such as shunt capacitors and reactors) to maintain system reliability.

System planners must determine the optimal mix of dynamic and static reactive resources to handle inherent characteristics of the transmission elements in the power system, such as reactive losses on the BES system when it is heavily loaded (high-surge-impedance loading) and line charging when the BES is lightly loaded. Equally important is the electrical location of those resources on the system. Because reactive power is not very transportable across the transmission system, the physical location must be optimized relative to the type, size, and characteristics of the reactive resources. It is imperative that planners have a coordinated approach to managing reactive power and voltage control across the system that addresses not only supply-side and load-side concerns but also the controllability of voltage schedules, transformer taps, static device switching schedules, etc.

System operators must monitor actual voltages, adjust appropriate voltage schedules, and manage reactive power capability (dynamic and static) just as they must monitor and manage real power. Reliable operation requires the BES be able to withstand sudden disturbances and unanticipated loss of system components, including the loss of the reactive resources. Generation, along with other dynamic and static system resources, must provide stable voltage regulation and adequate reactive capability to ensure that the system can operate securely under steady-state conditions and during a myriad of potential contingencies. It is also important to avoid adverse interactions between voltage-regulating devices in tightly interconnected systems, to identify areas in the grid that are particularly challenging due to weak system conditions, and to mitigate situations where reliability may be jeopardized. It is therefore critical for the RC and TOP to have adequate situational awareness of their current voltages, on-line reactive resources, off-line reactive resources (available and unavailable), reactive loads, system conditions, etc., and understand the predictive voltage and reactive response of their systems to potential contingencies.

Trends in the Industry

Changes in the resource mix of the generation fleet will impact reactive power management and require planning for controlling voltage. Traditional synchronous generators have typically been providers of dynamic reactive support and voltage control. In many cases, these units are being retired and replaced by gas, wind, solar, and demand response. The capabilities of these new generators must be considered and planned into the future system to maintain necessary levels of reactive support throughout the power system.

Some of these new renewable resources have utility-grade inverters such as those used to couple modern wind and PV power plants with the BES, which can provide dynamic reactive power and voltage control capability. New wind and PV power plants are capable of providing dynamic reactive power control whether or not the plant is producing real power, similar to an SVC. As more resources using power electronics (e.g., wind, solar, FACTS devices, etc.) are integrated into the network, it is important that the controls of these resources be coordinated to maintain stable operation under all applicable system conditions.

Adequate analysis of the system characteristics and response will also require coordination with distribution owners and operators. The proliferation of distributed generation on the distribution/sub-transmission system creates an impact on voltage, and while there are evolving NERC standards (PRC, VAR) and IEEE 1547 revisions that will help, the potential impact on reactive performance behind the meter and on the distribution system must be factored in. Another impactful load-changing phenomenon is FIDVR. FIDVR is a voltage condition initiated by a fault and characterized by the stalling of induction motors, such as those commonly used for air conditioner compressor motors, where initial voltage recovery after the clearing of a fault is limited and the recovery typically occurs in a period in excess of two seconds. These impacts on the distribution system can increasingly affect BES voltage performance.

Proposed Measures

As discussed in the body of this report, industry should consider tracking several Measures related to voltage support. The Measures can be used to assess the strength of reactive support and quantify trends that may result from the changing resource mix of both generation and load. Regional differences may require some flexibility or customization of the measures. Systems vary widely in their topology and electrical characteristics (e.g., the total level of installed reactive resources, the type of generation resources, applicable local and regional voltage criteria, etc.). In general, Measures may align with the BA construct under the NERC functional model, but because of the localized nature of reactive capability, more useful insights may be gained by monitoring the Measures for appropriate sub-BA regions.

Data for Measure 7: Reactive Capability on the System

The ERSTF requested and obtained extensive data from system operators for Measure 7. The method is described immediately below and the results from participating system operators follow.

1. Determine the dynamic reactive capability on the transmission system (rotating and non-rotating) per total MW load for the applicable areas at critical load levels (i.e., peak, shoulder, and light load) for the following:

    a. Nameplate installed in the near-term planning study environment

    b. Nameplate installed and actually on-line during real-time operations

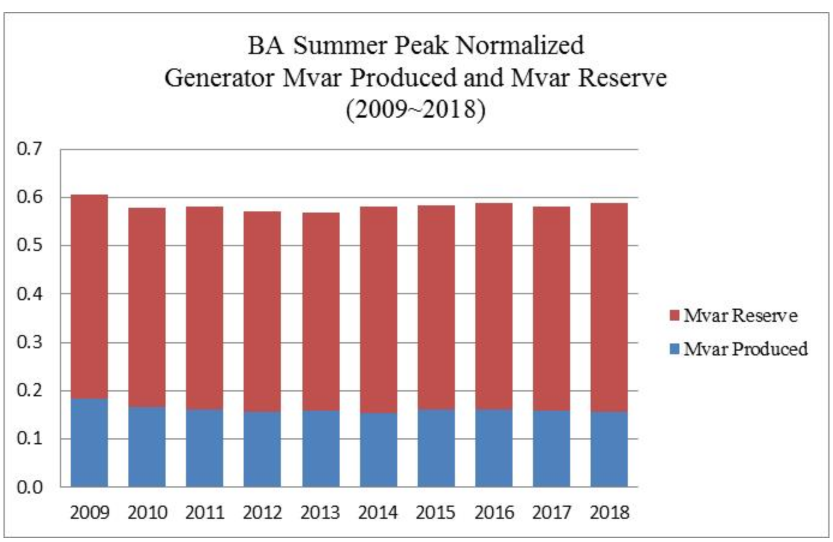


Figure D.1: Generator Mvar – produced and reserve at BA level

2. Determine the static reactive capability on the transmission system per total megawatt load for the applicable areas at critical load levels (i.e., peak, shoulder, and light load) for the following:
    a. Nameplate installed in the near-term planning study environment
    b. Nameplate installed and actually on-line during real-time operations

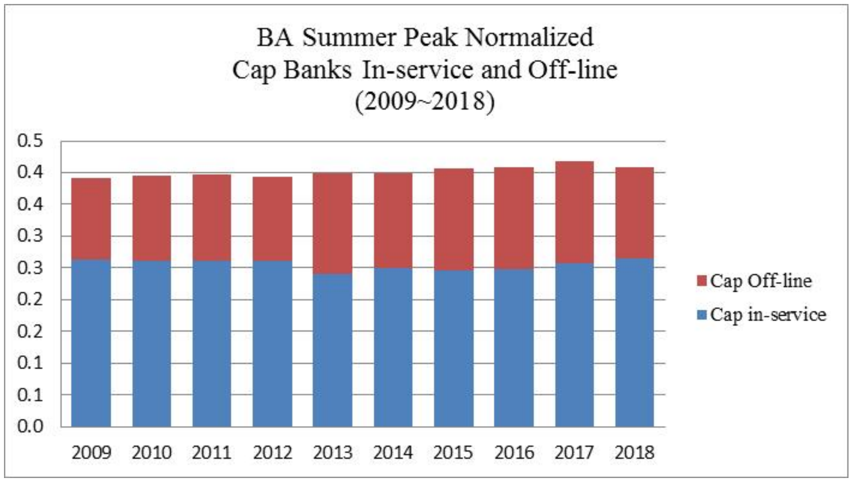


Figure D.2: Capacitor Mvar – off-line and on-line at BA level

3. Track the load power factor for distribution at the low side of transmission buses at the critical load levels (i.e., peak, shoulder, and light load).

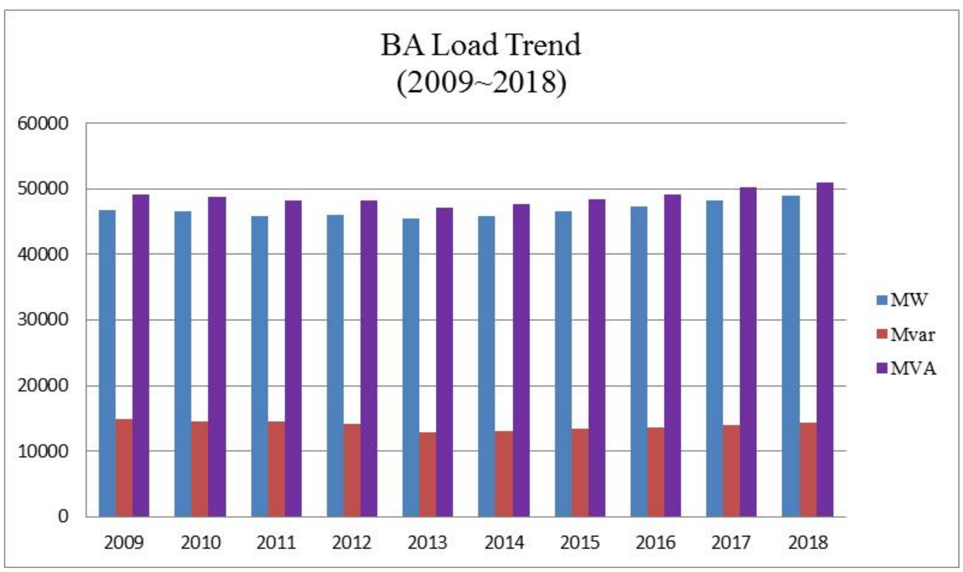


Figure D.3: Load trend at BA level

Results of Analysis by BA

Duke Energy Carolinas – Planning – Dynamic (p.u.)

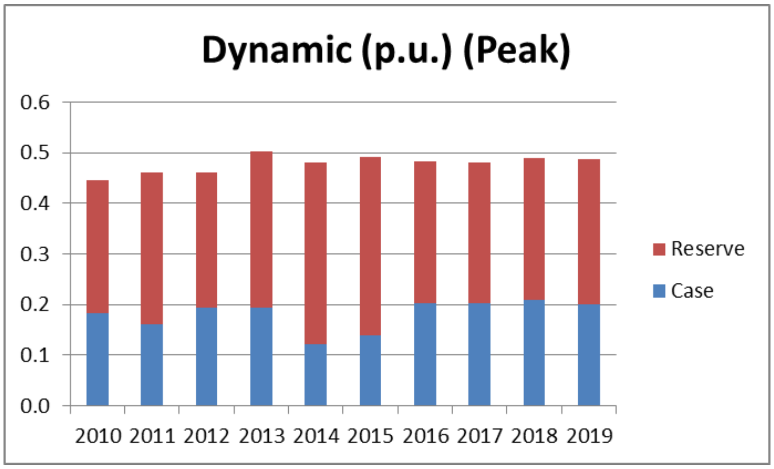


Figure D.4: Duke Energy Carolinas – Planning – Dynamic (p.u.) Peak

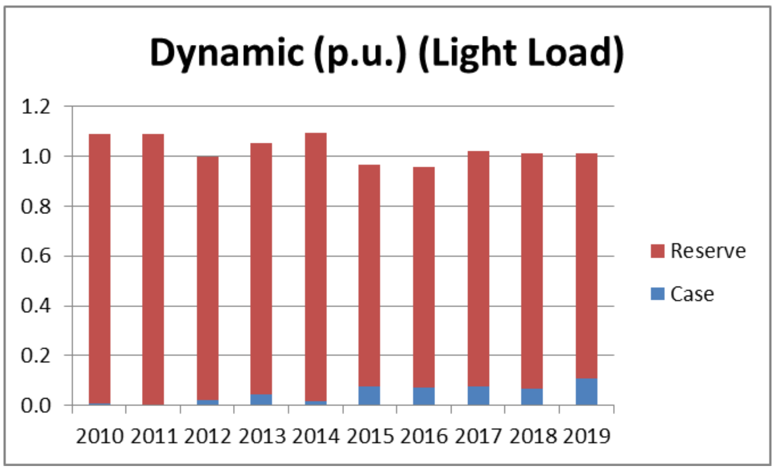


Figure D.5: Duke Energy Carolinas – Planning – Dynamic (p.u.) Light Load

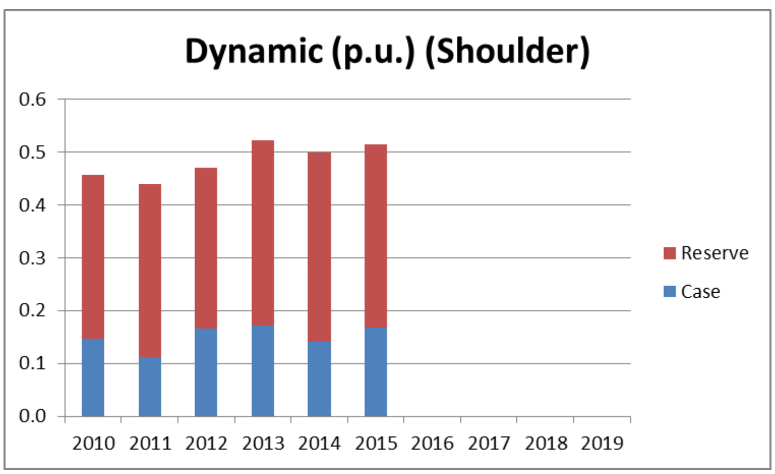


Figure D.6: Duke Energy Carolinas – Planning – Dynamic (p.u.) Shoulder

Duke Energy Carolinas – Planning – Static System (p.u.)

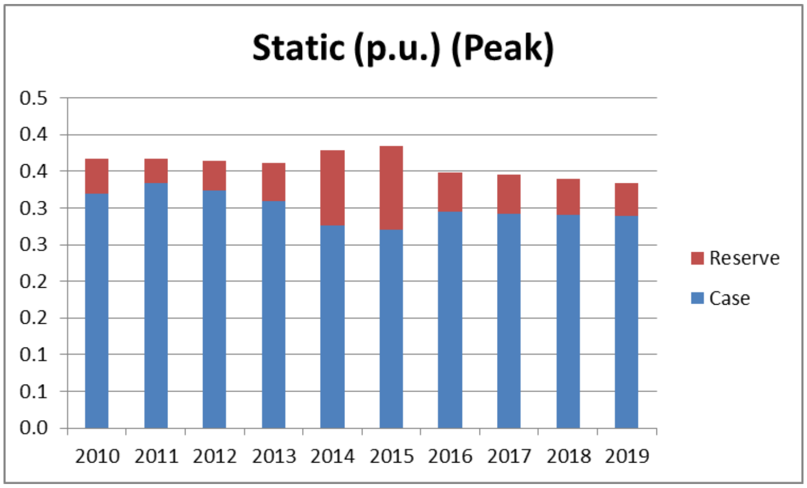


Figure D.7: Duke Energy Carolinas – Planning – Static (p.u.) Peak

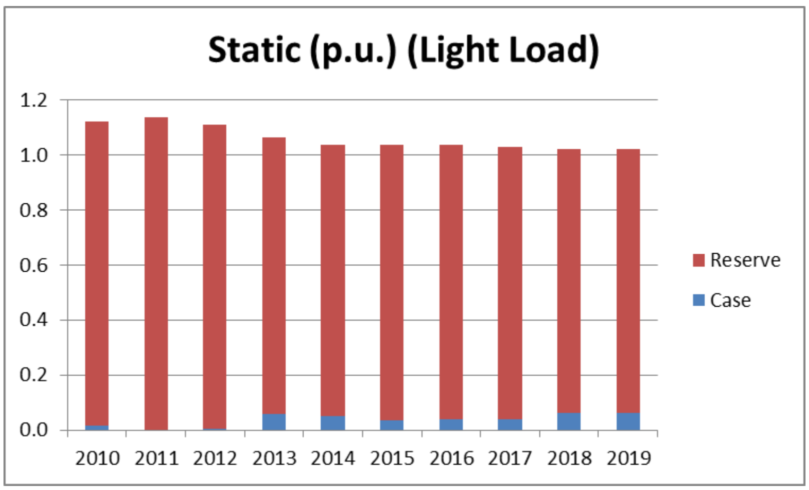


Figure D.8: Duke Energy Carolinas – Planning – Static (p.u.) Light Load

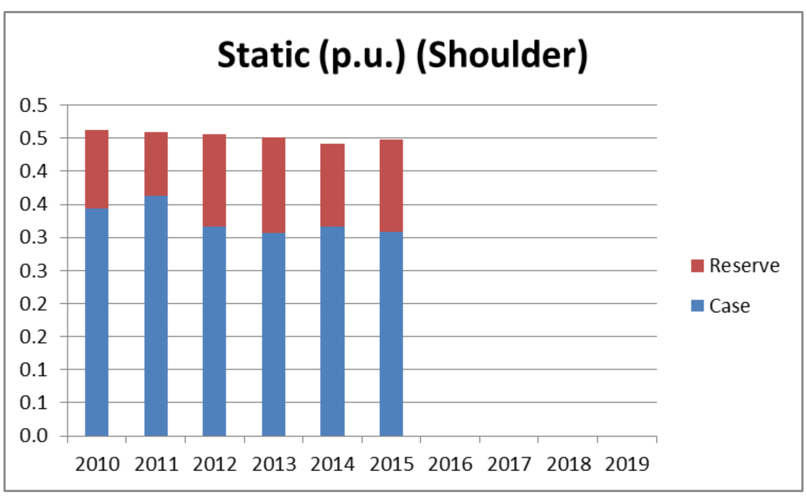


Figure D.9: Duke Energy Carolinas – Planning – Static (p.u.) Shoulder

Duke Energy Carolinas – Planning – Load Trend (MW)

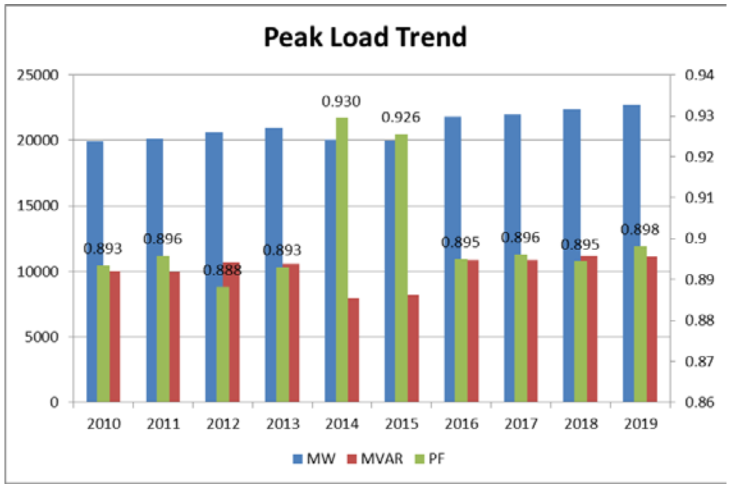


Figure D.10: Duke Energy Carolinas – Planning – Peak Load Trend (MW)

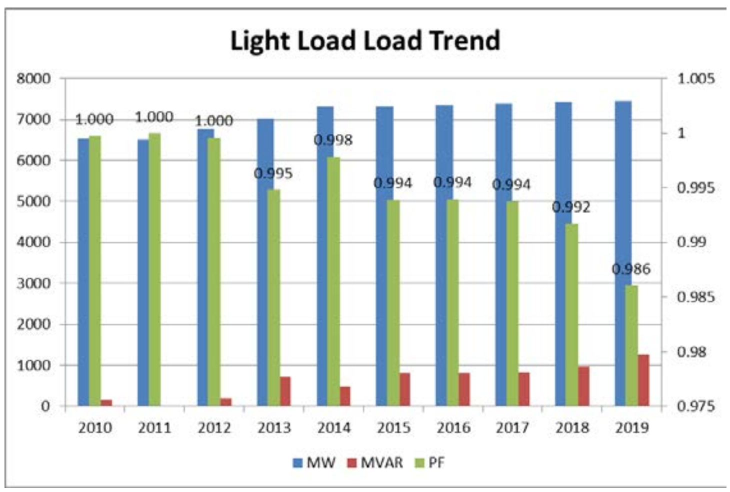


Figure D.11: Duke Energy Carolinas – Planning – Light Load Trend (MW)

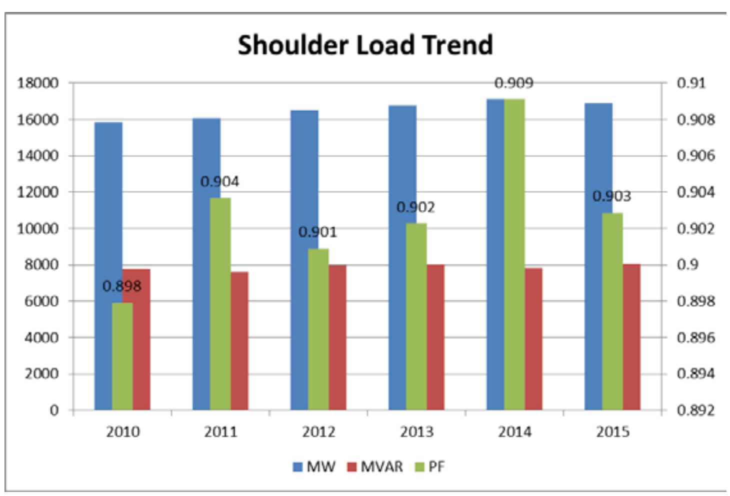


Figure D.12: Duke Energy Carolinas – Planning – Shoulder Load Trend (MW)

Duke Energy Carolinas – Real Time – Dynamic System (MVAR)

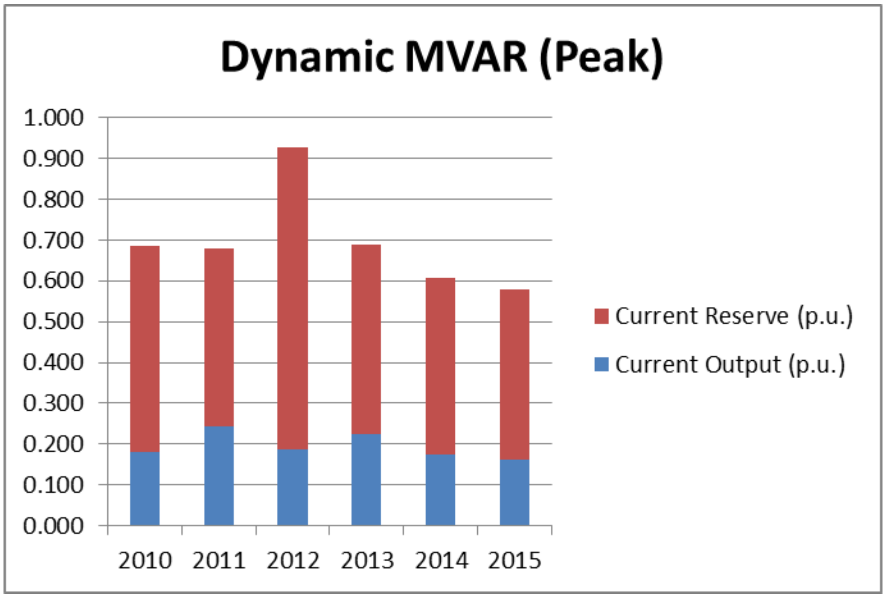


Figure D.13: Duke Energy Carolinas – Real Time – Dynamic MVAR (Peak)

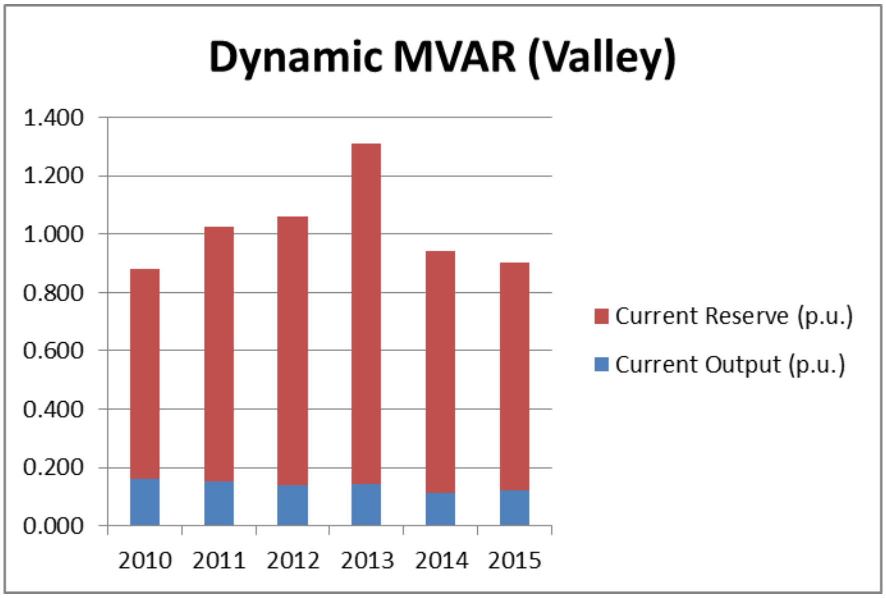


Figure D.14: Duke Energy Carolinas – Real Time – Dynamic MVAR (Valley)

Duke Energy Carolinas – Real Time – Static System (MVAR)

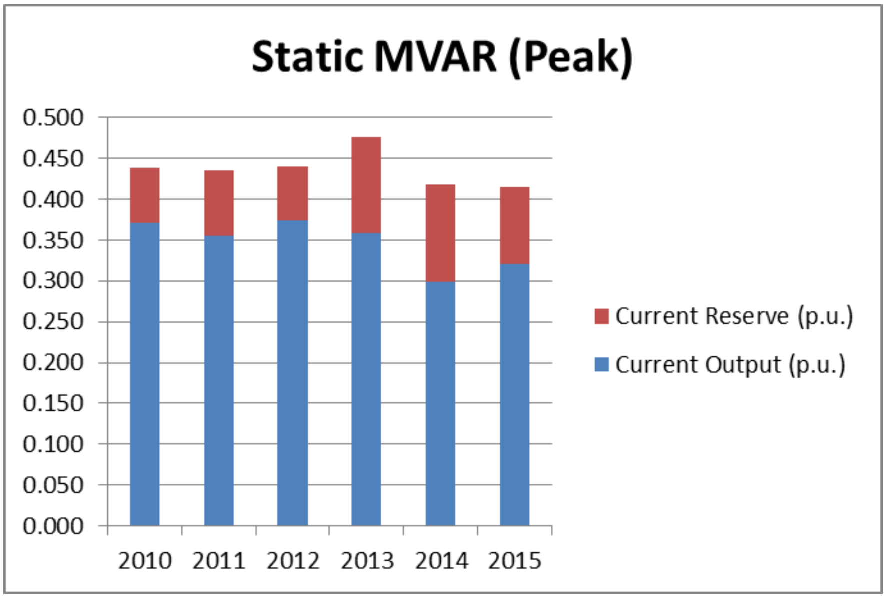


Figure D.15: Duke Energy Carolinas – Real Time – Static MVAR (Peak)

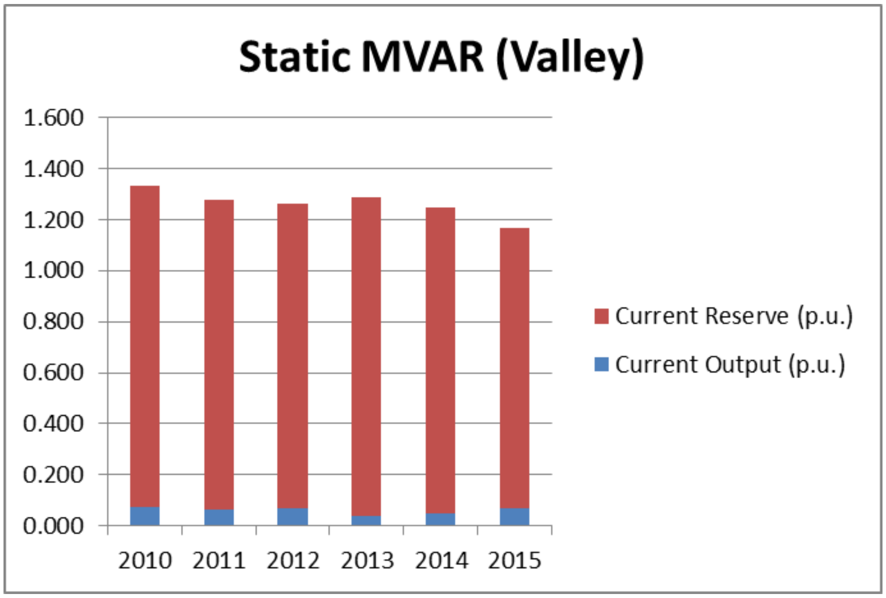


Figure D.16: Duke Energy Carolinas – Real Time – Static MVAR (Valley)

Duke Energy Carolinas – Real Time – Load Trend (MW)

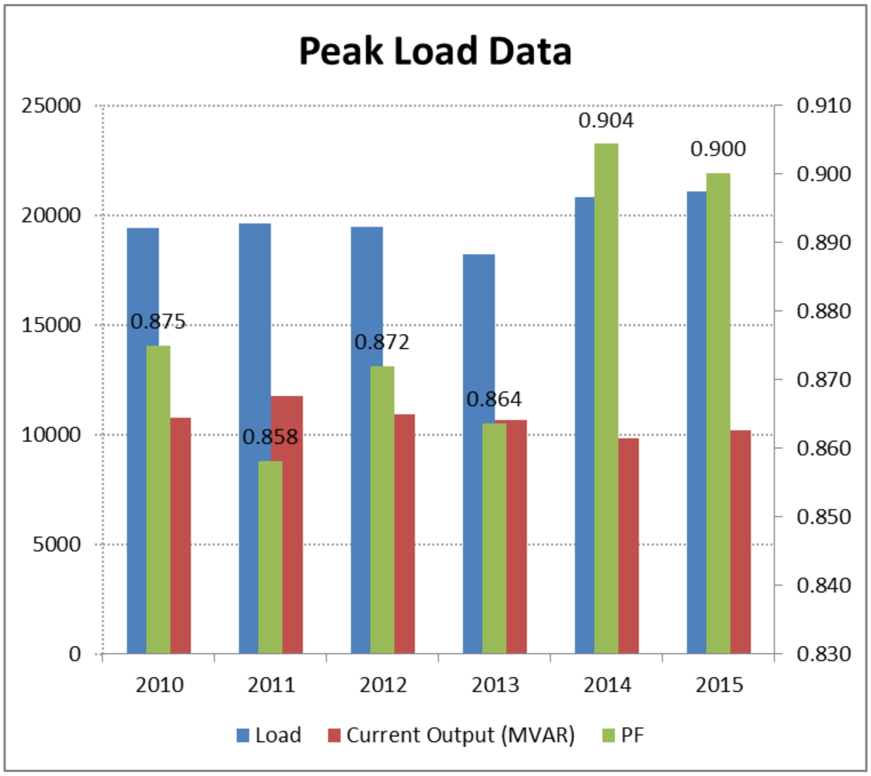


Figure D.17: Duke Energy Carolinas – Real Time – Load Trend (MW)

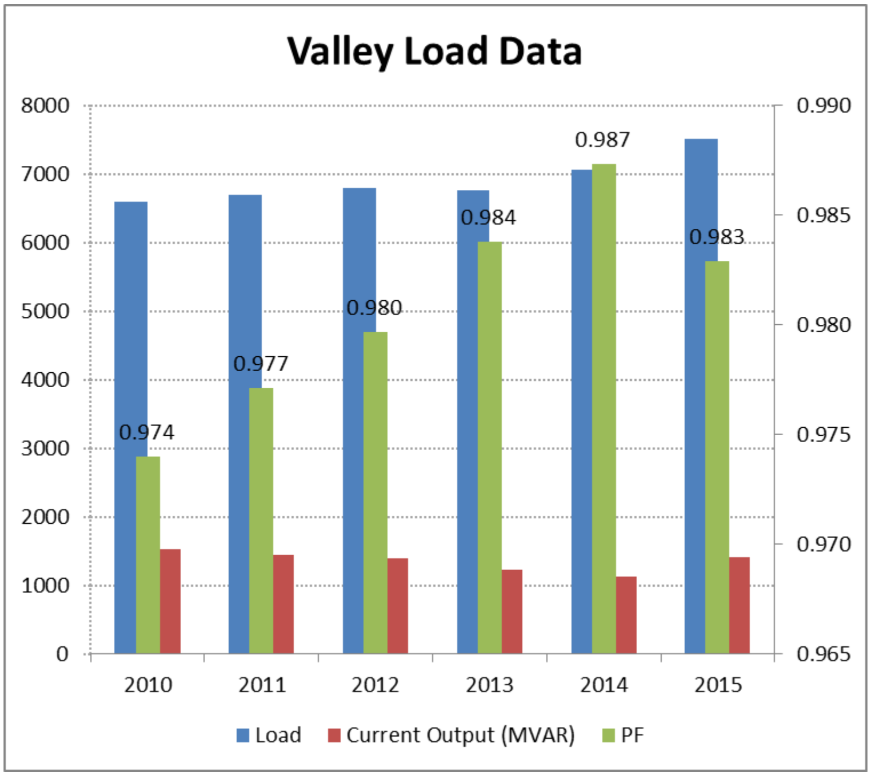


Figure D.18: Duke Energy Carolinas – Real Time – Valley Load Data (MW)

Duke Energy Progress – Planning – Dynamic System (P.U.)

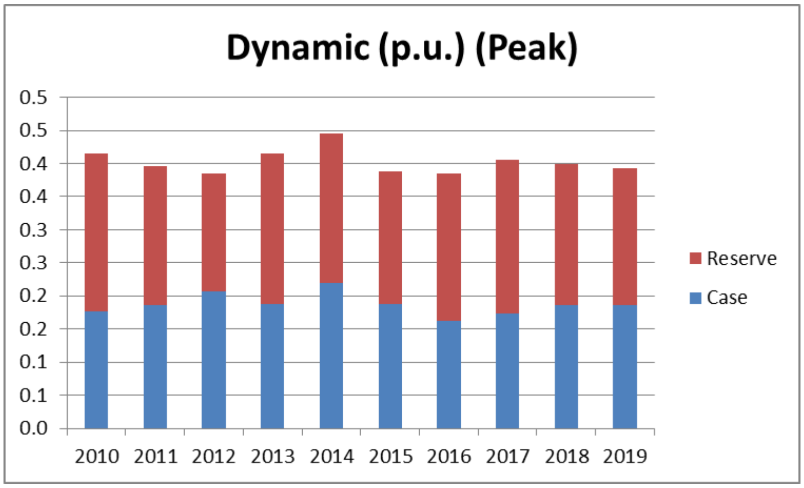


Figure D.19: Duke Energy Progress – Planning – Dynamic System (p.u.) (Peak)

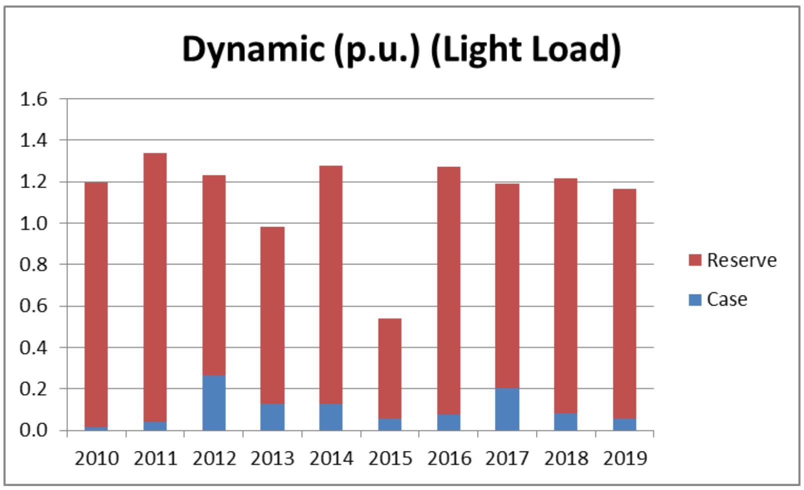


Figure D.20: Duke Energy Progress – Planning – Dynamic System (p.u.) (Light Load)

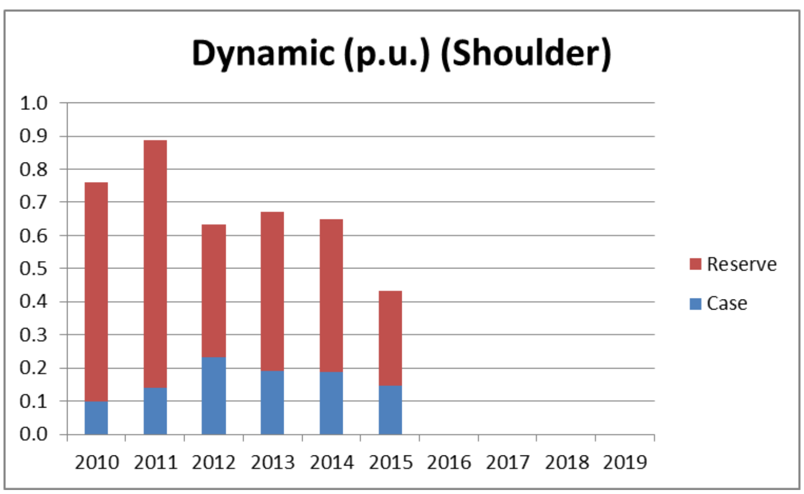


Figure D.21: Duke Energy Progress – Planning – Dynamic System (p.u.) (Shoulder)

Duke Energy Progress – Planning – Static System (P.U.)

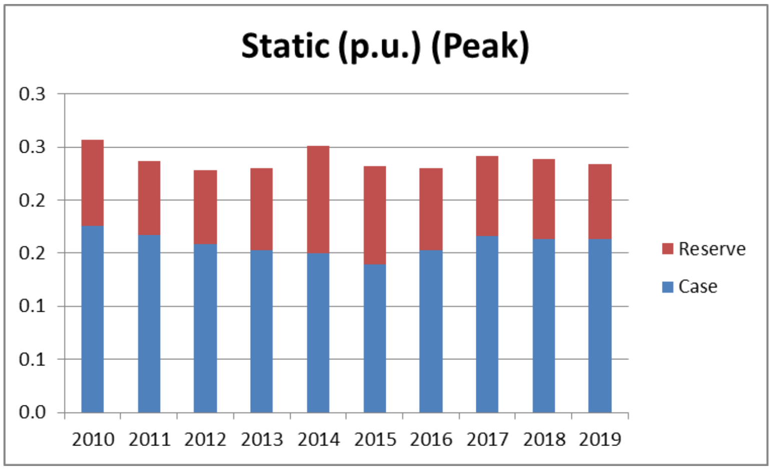


Figure D.22: Duke Energy Progress – Planning – Static System (p.u.) (Peak)

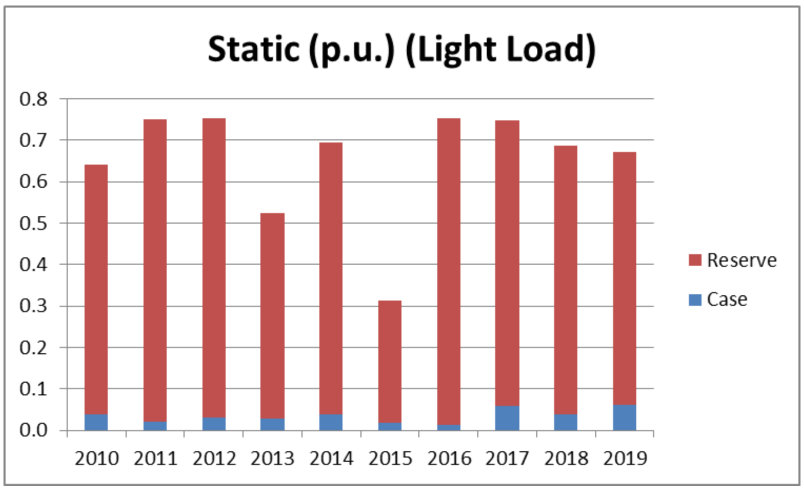


Figure D.23: Duke Energy Progress – Planning – Static System (p.u.) (Light Load)

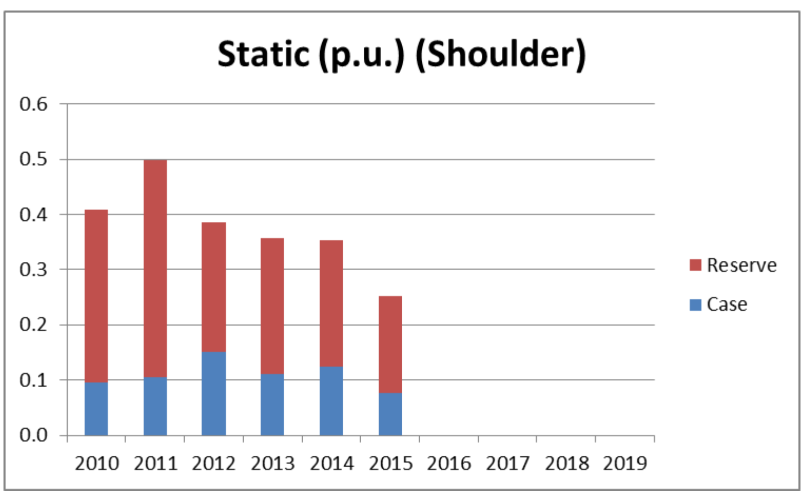


Figure D.24: Duke Energy Progress – Planning – Static (p.u.) (Shoulder)

Duke Energy Progress – Planning – Load Trend (MW)

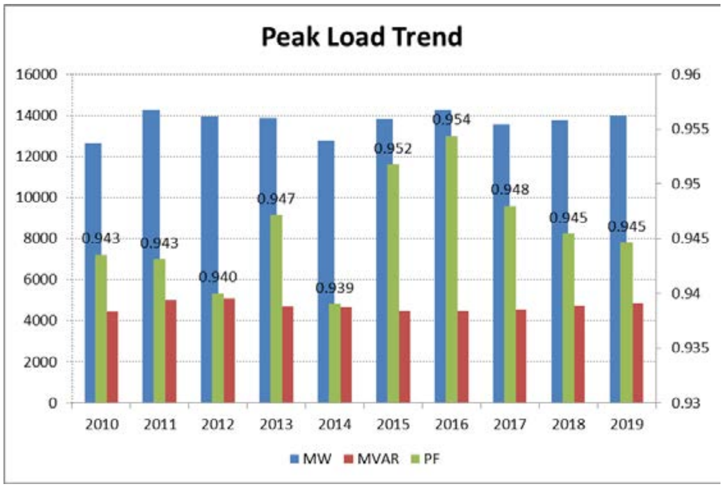


Figure D.25: Duke Energy Progress – Planning – Load Trend (MW) (Peak)

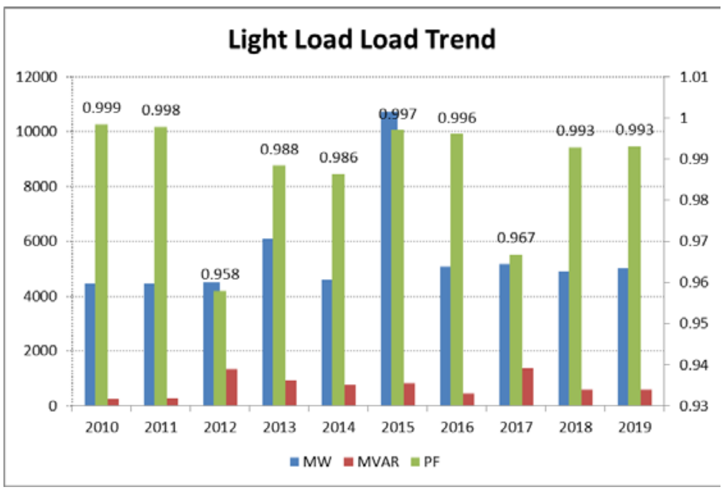


Figure D.26: Duke Energy Progress – Planning – Load Trend (MW) (Light Load)

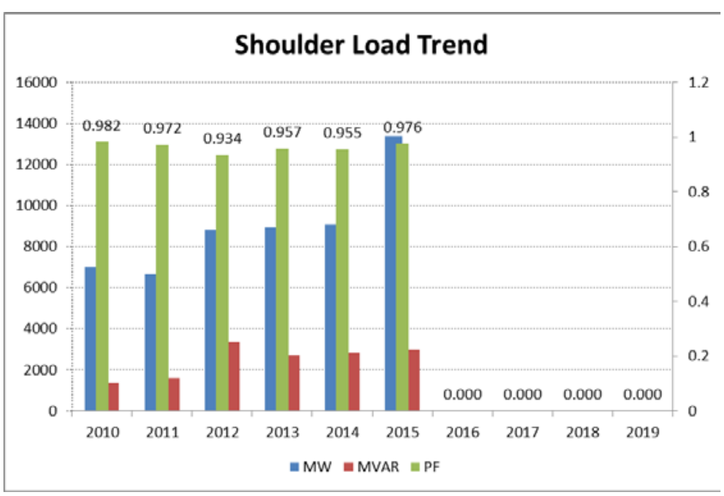


Figure D.27: Duke Energy Progress – Planning – Load Trend (MW) (Shoulder)

Duke Energy Progress – Real Time – Dynamic System (MVAR)

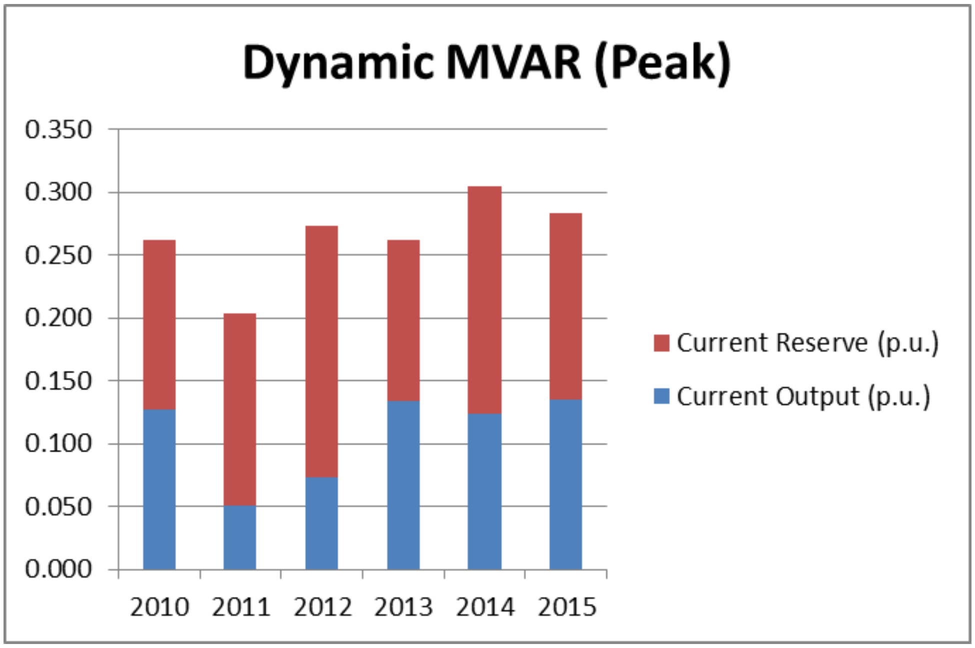


Figure D.28: Duke Energy Progress – Real Time – Dynamic System (MVAR) (Peak)

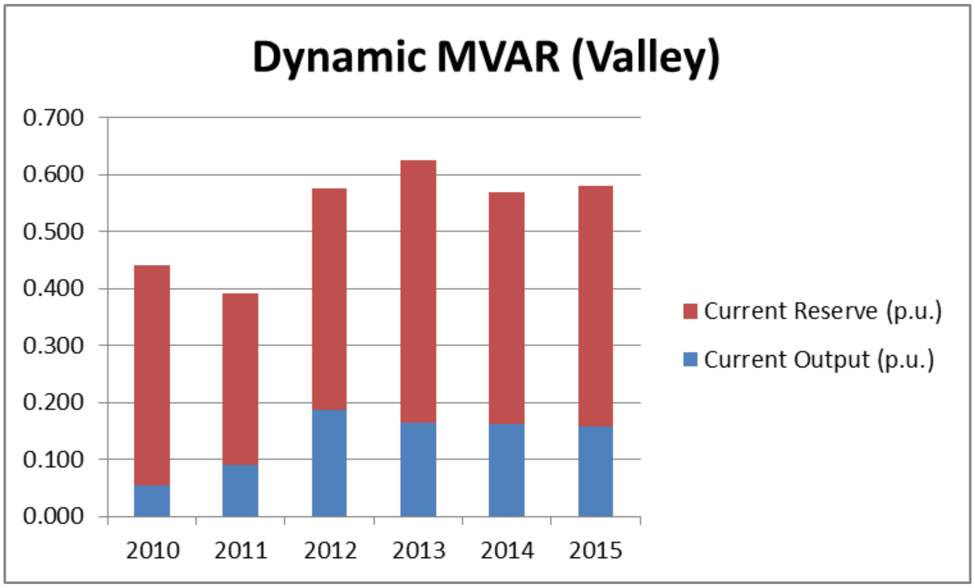


Figure D.29: Duke Energy Progress – Real Time – Dynamic System (MVAR) (Valley)

Duke Energy Progress – Real Time – Static System (MVAR)

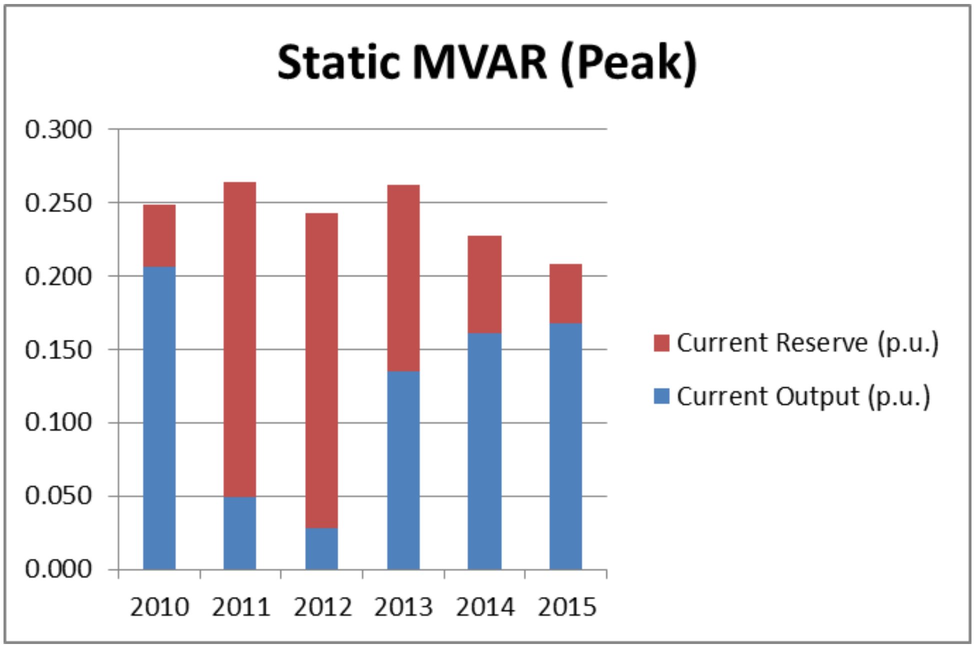


Figure D30: Duke Energy Progress – Real Time – Static System (MVAR) (Peak)

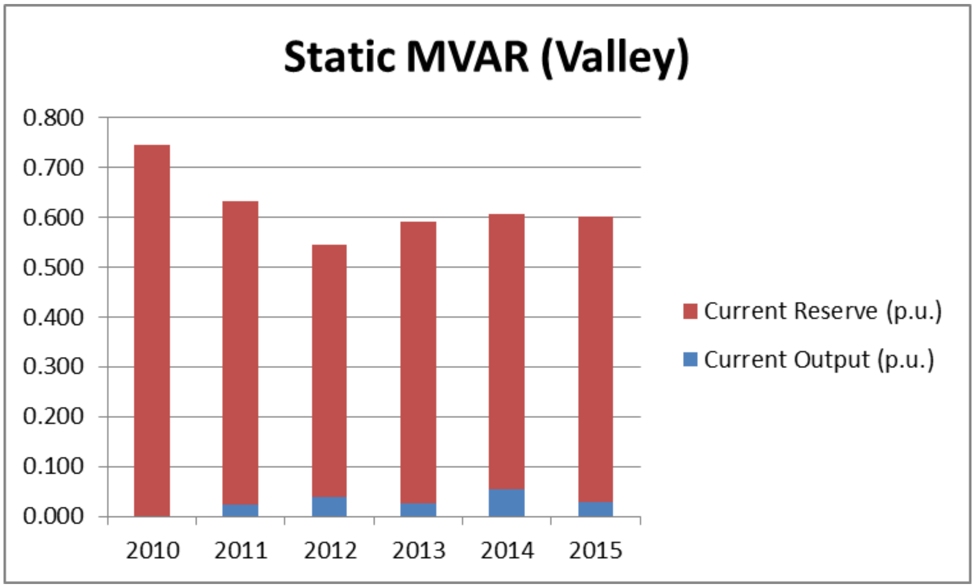


Figure D.31: Duke Energy Progress – Real Time – Static System (MVAR) (Valley)

Duke Energy Progress – Real Time – Load Trend (MW)

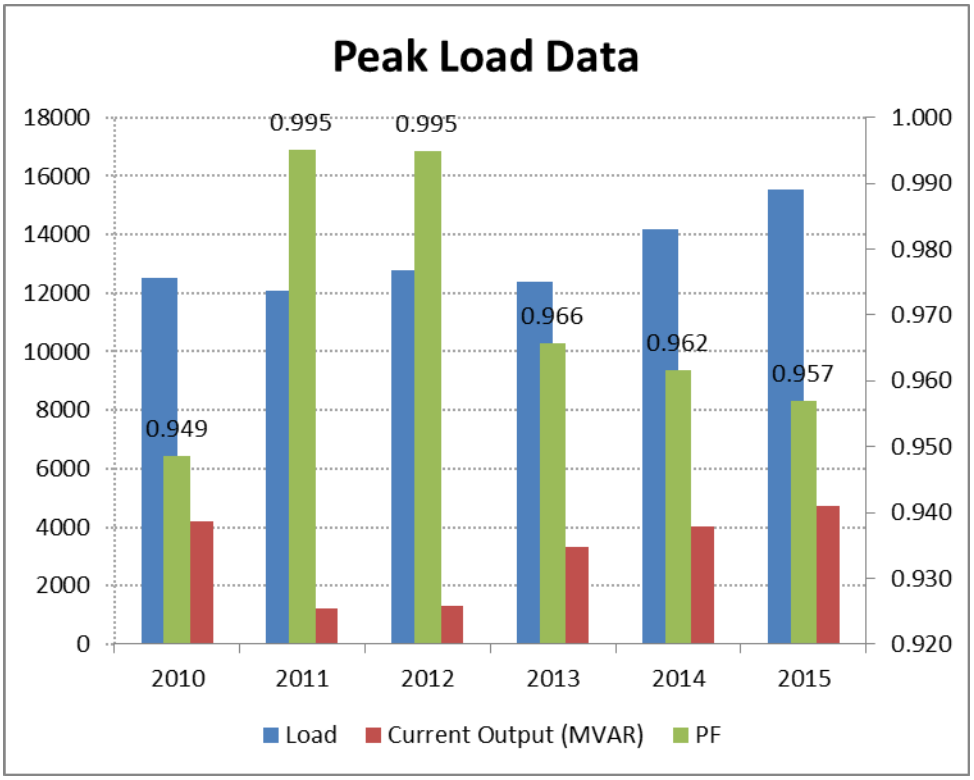


Figure D.32: Duke Energy Progress – Real Time – Load Trend (MW) (Peak)

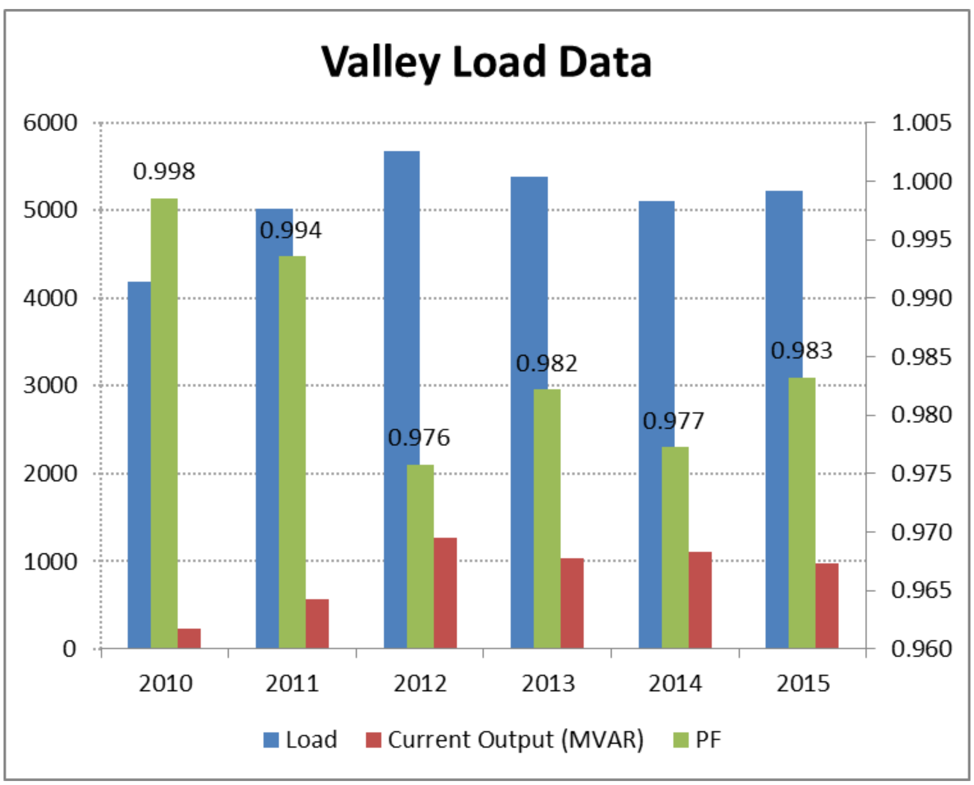


Figure D.33: Duke Energy Progress – Real Time – Load Trend (MW) (Valley)

Duke Energy Florida – Planning – Dynamic System (P.U.)

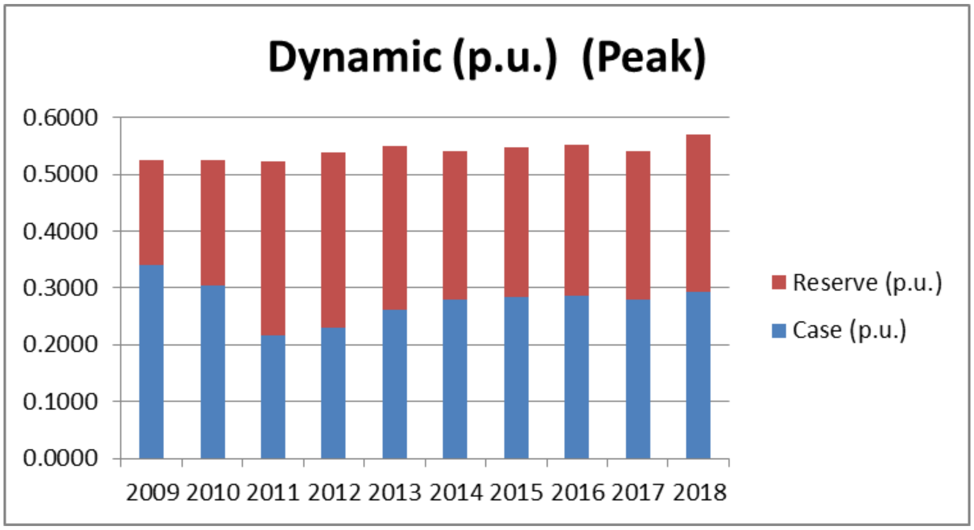


Figure D.34: Duke Energy Florida – Planning – Dynamic (p.u.) (Peak)

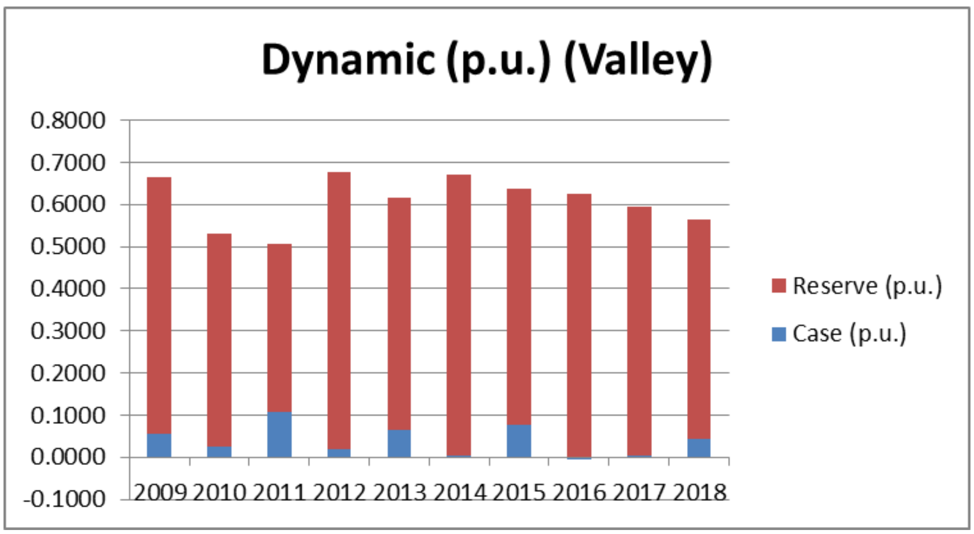


Figure D.35: Duke Energy Florida – Planning – Dynamic (p.u.) (Valley)

Duke Energy Florida – Planning – Static System (p.u.)

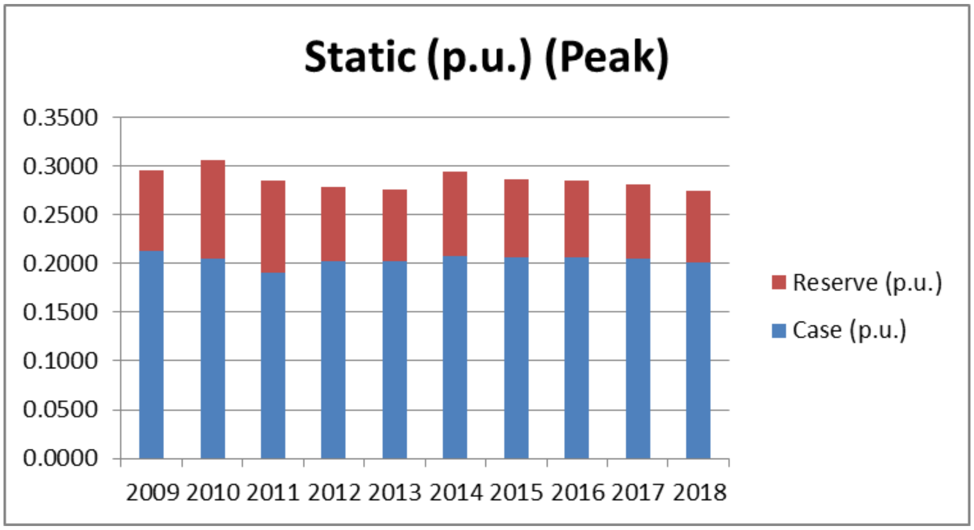


Figure D.36: Duke Energy Florida – Planning – Static System (p.u.) (Peak)

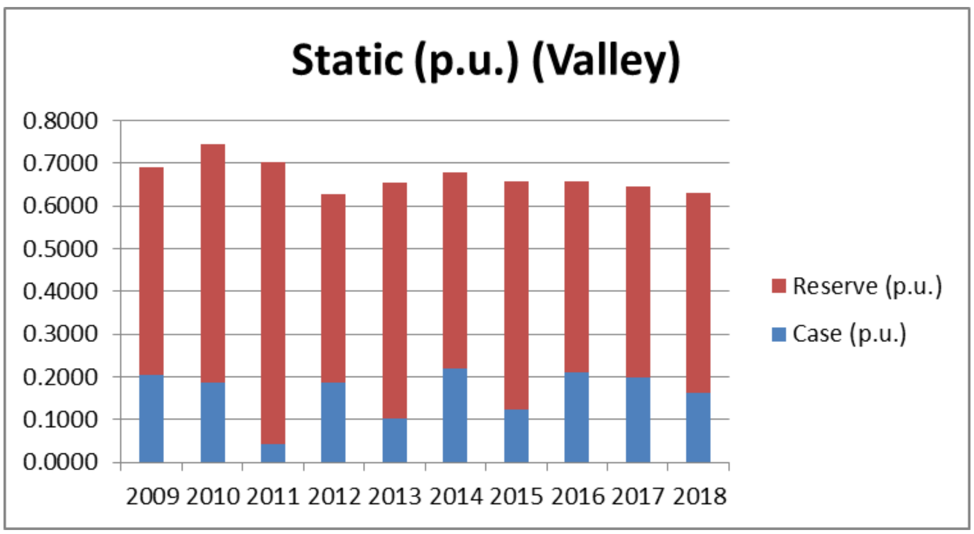


Figure D.37: Duke Energy Florida – Planning – Static System (p.u.) (Valley)

Duke Energy Florida – Planning – Load Trend (MW)

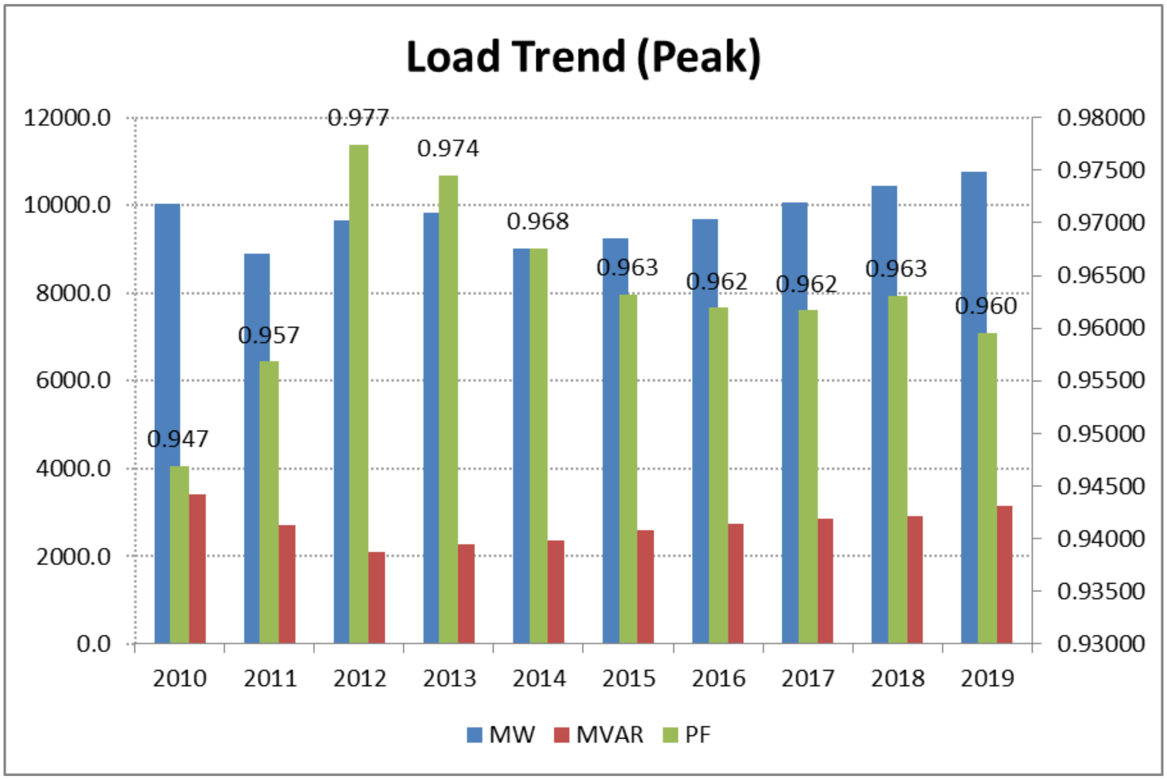


Figure D.38: Duke Energy Florida – Planning – Load Trend (MW) (Peak)

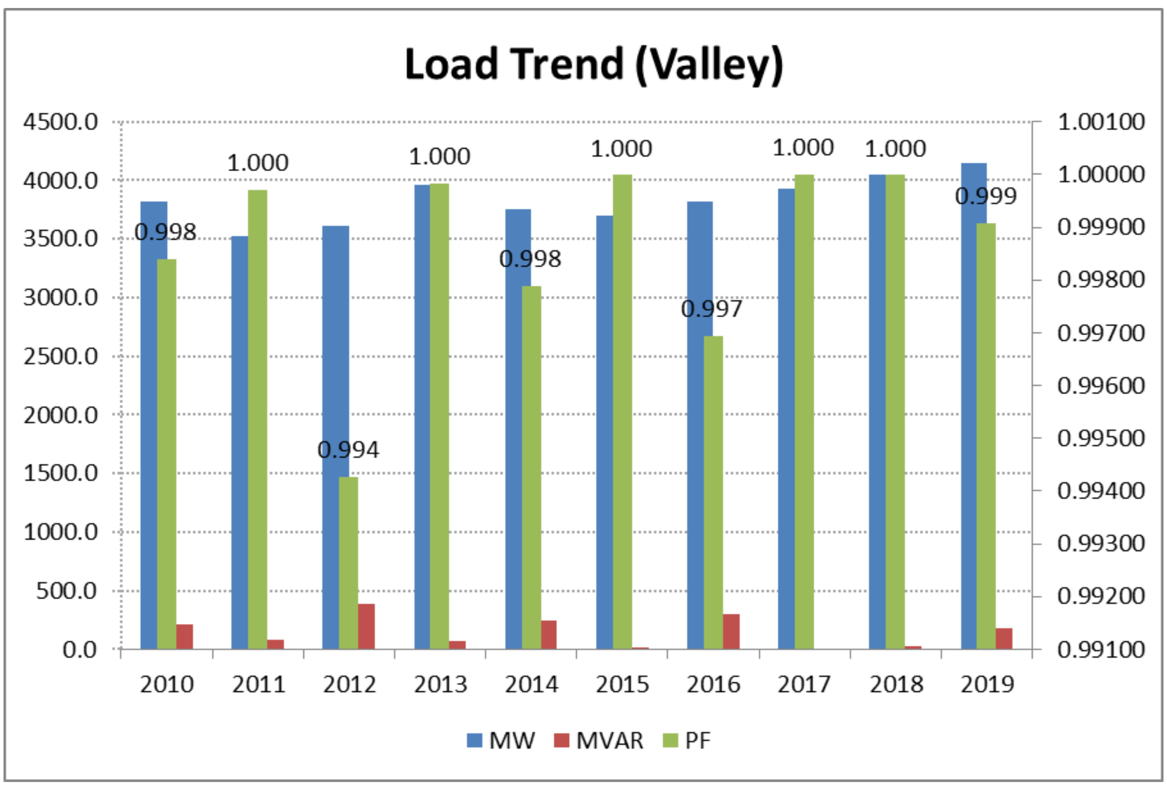


Figure D.39: Duke Energy Florida – Planning – Load Trend (MW) (Valley)

ISO-NE – Planning – Dynamic System (P.U.)

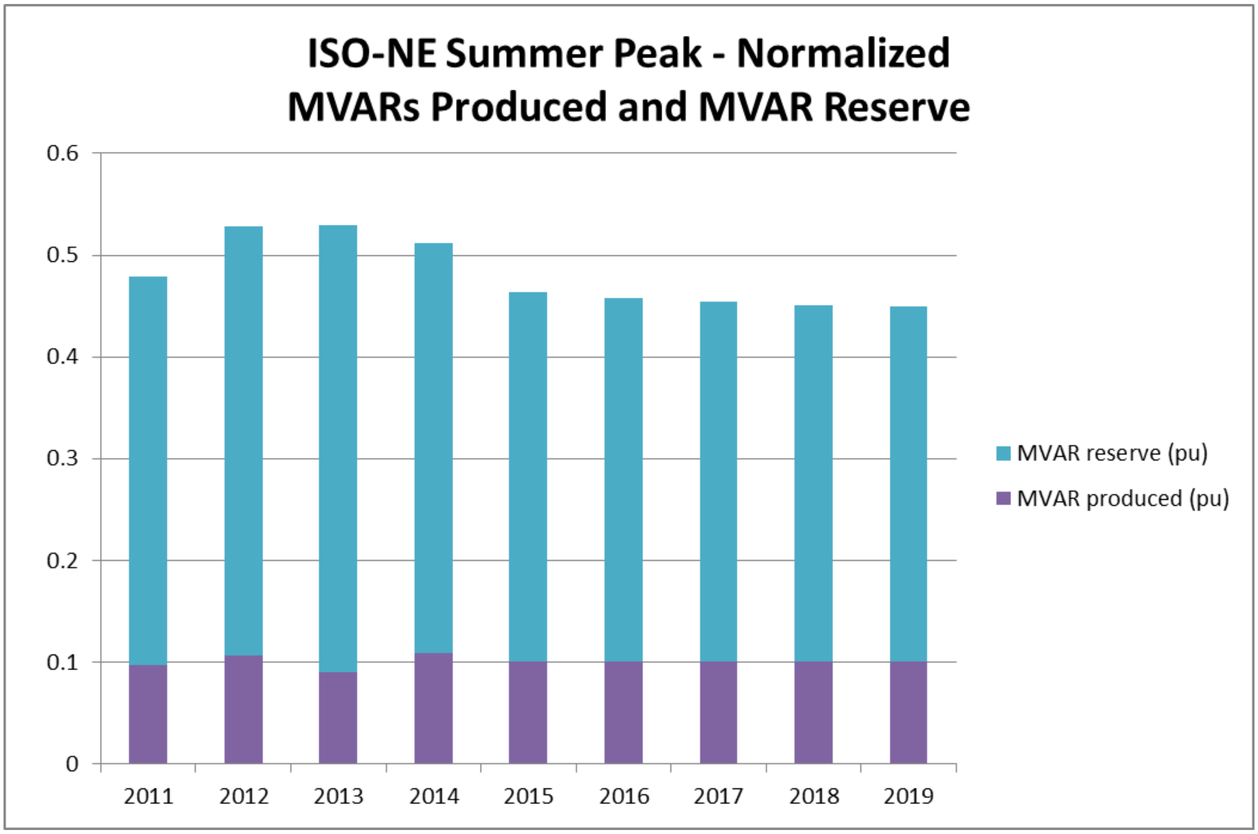


Figure D.40: ISO-NE – Planning – Dynamic System (p.u.) (Summer Peak)

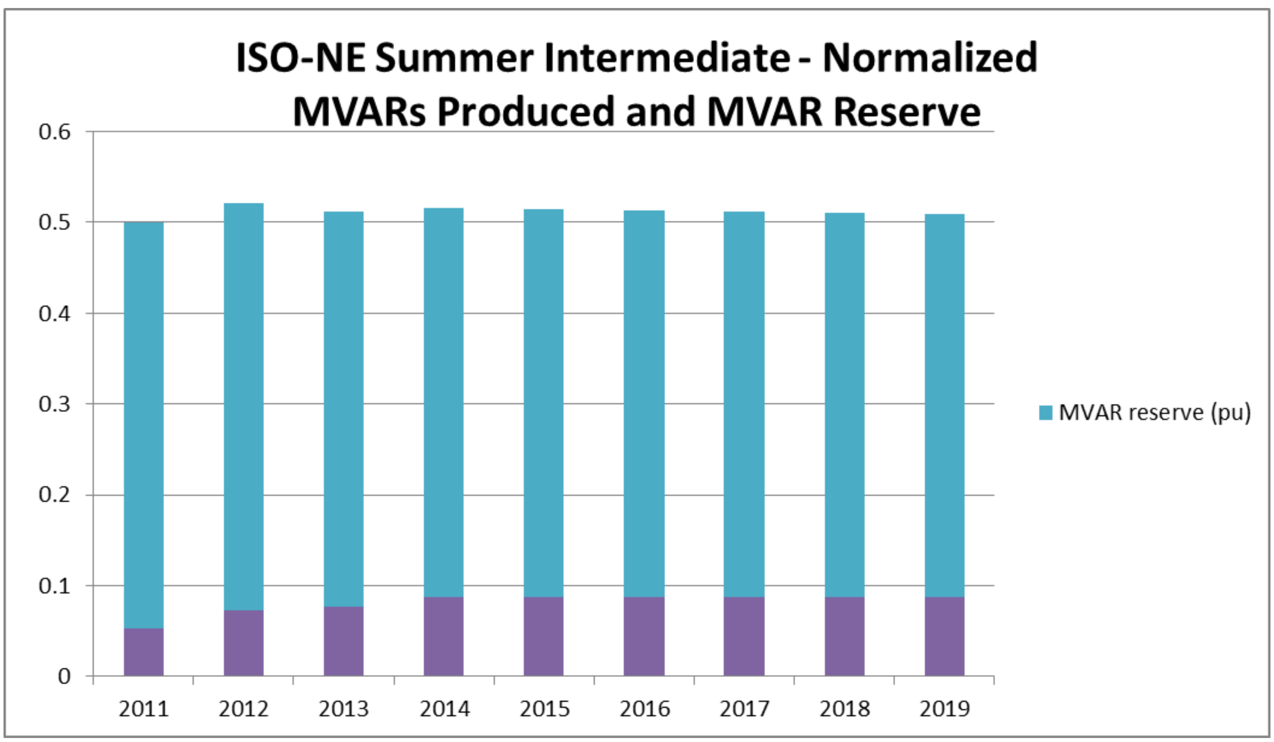


Figure D.41: ISO-NE – Planning – Dynamic System (p.u.) (Summer Intermediate)

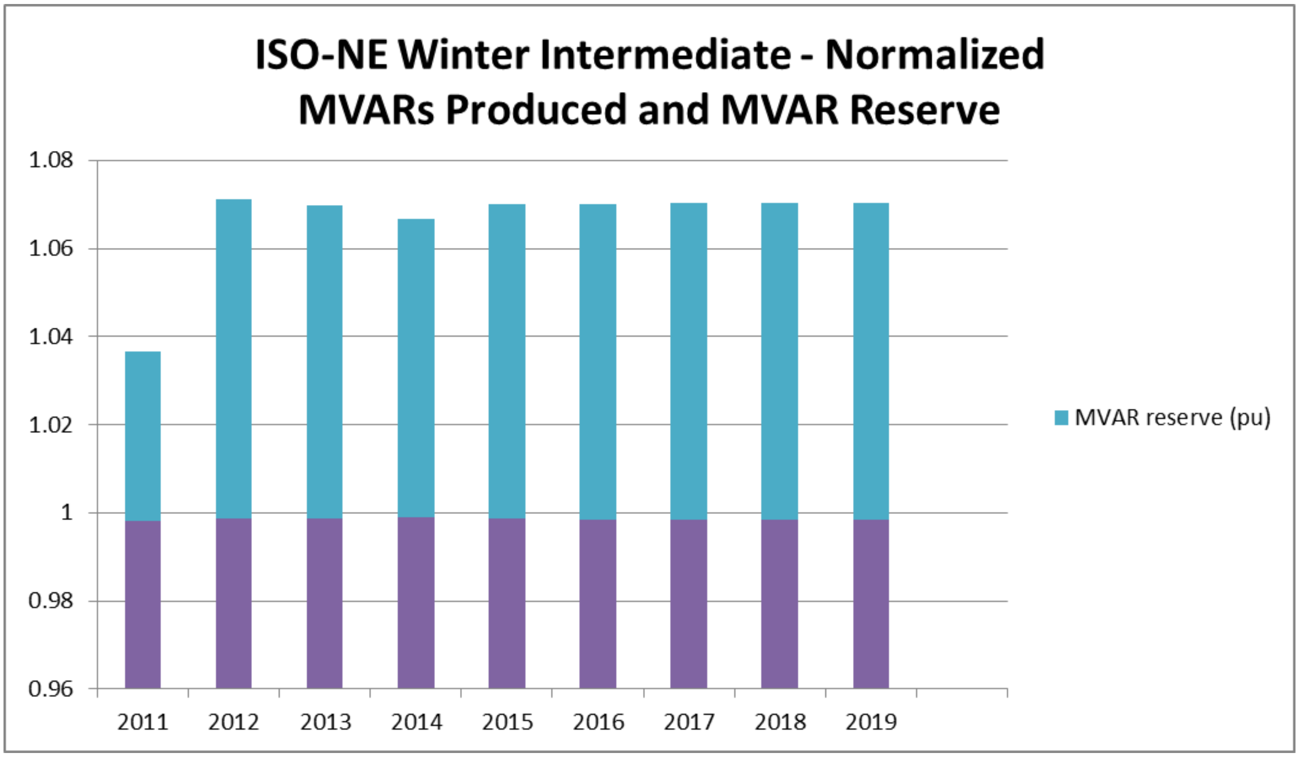


Figure D.42: ISO-NE – Planning – Dynamic System (p.u.) (Winter Intermediate)

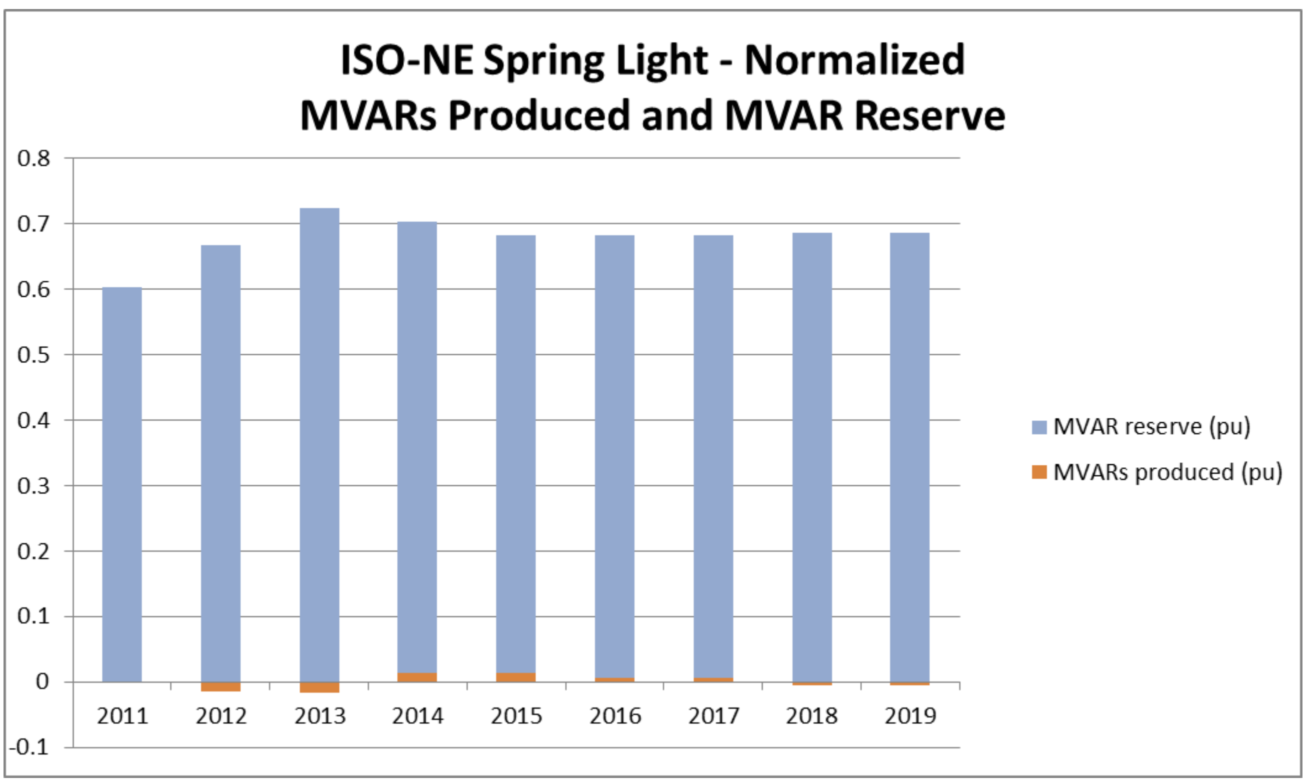


Figure D.43: ISO-NE – Planning – Dynamic System (p.u.) (Spring Light)

ISO-NE – Planning – Static System (p.u.)

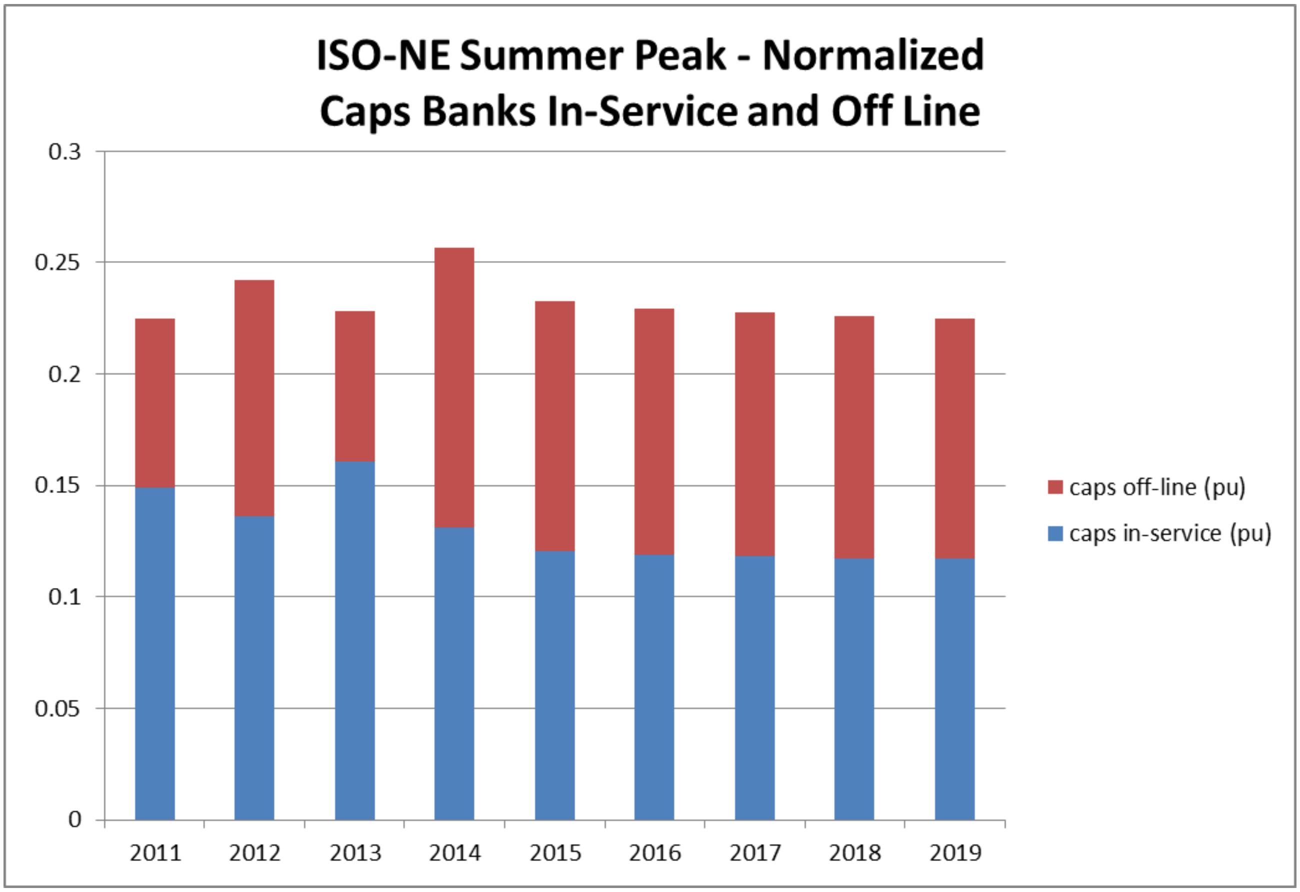


Figure D.44: ISO-NE – Planning – Static System (p.u.) (Summer Peak)

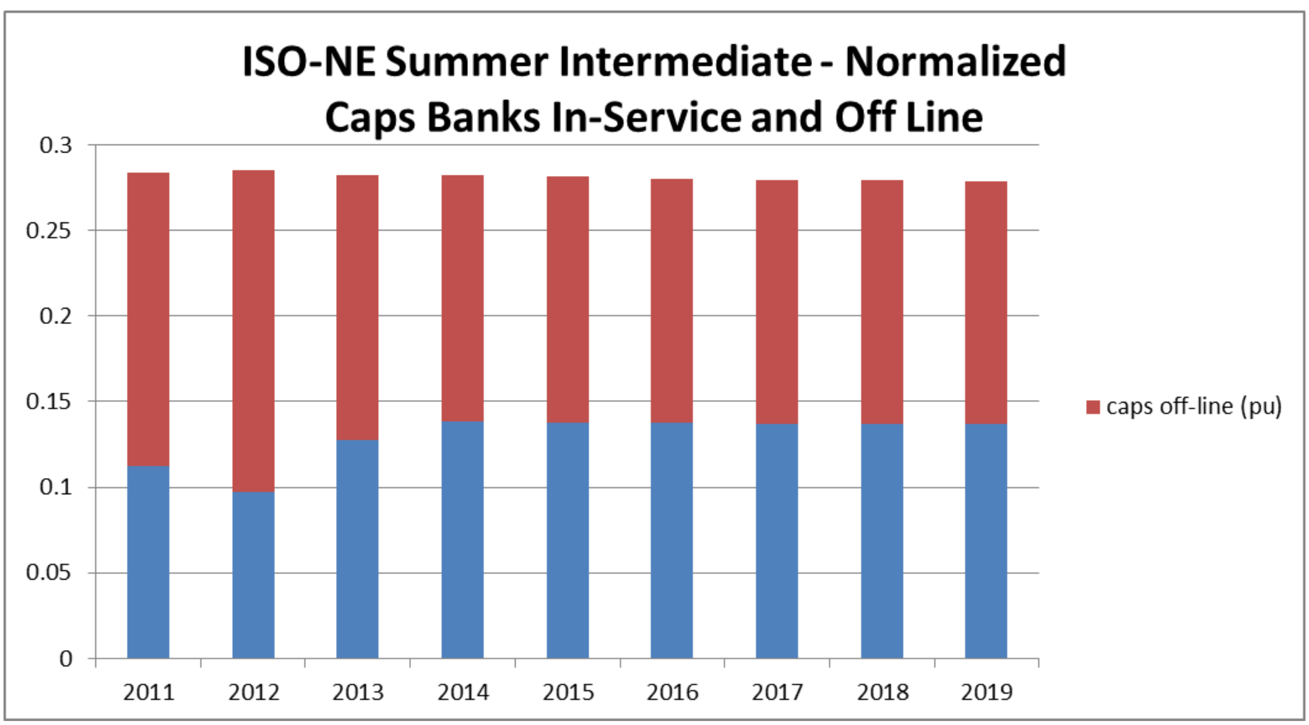


Figure D.45: ISO-NE – Planning – Static System (p.u.) (Summer Intermediate)

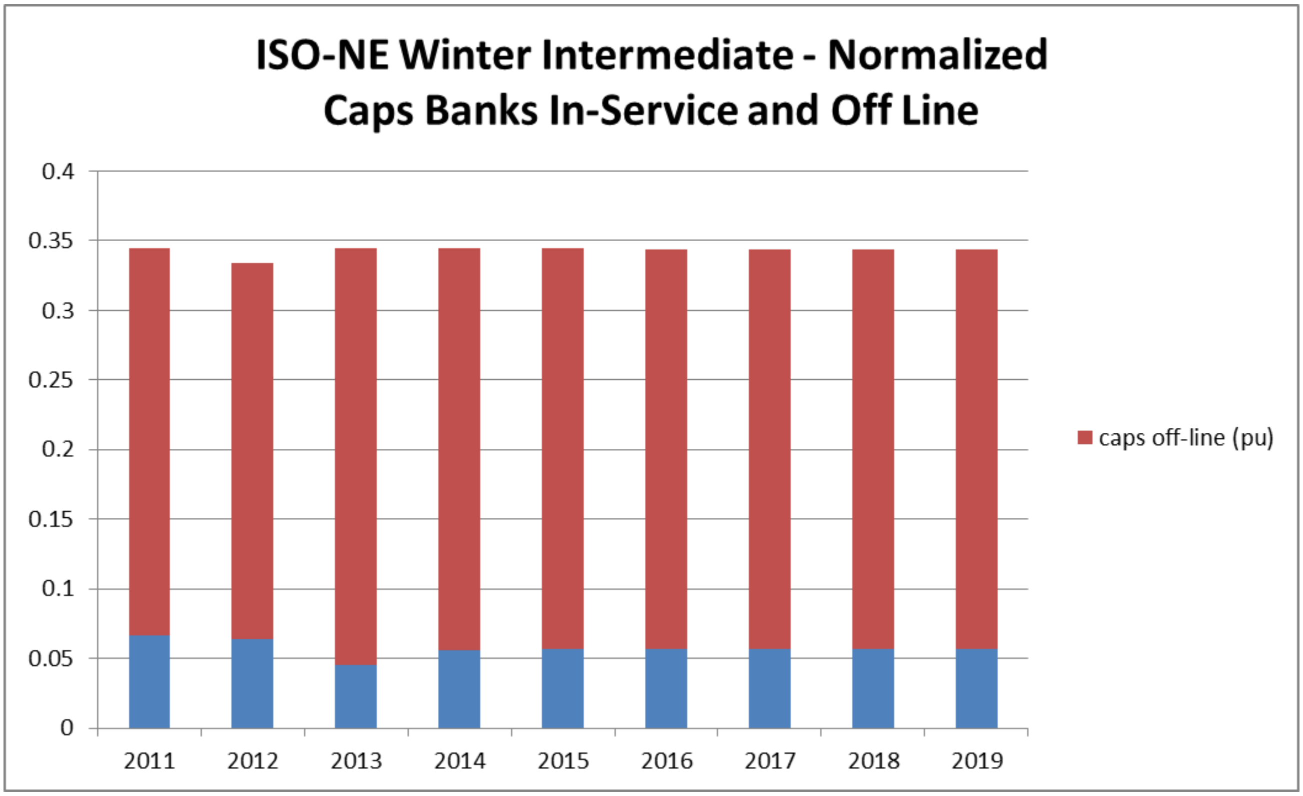


Figure D.46: ISO-NE – Planning – Dynamic System (p.u.) (Winter Intermediate)

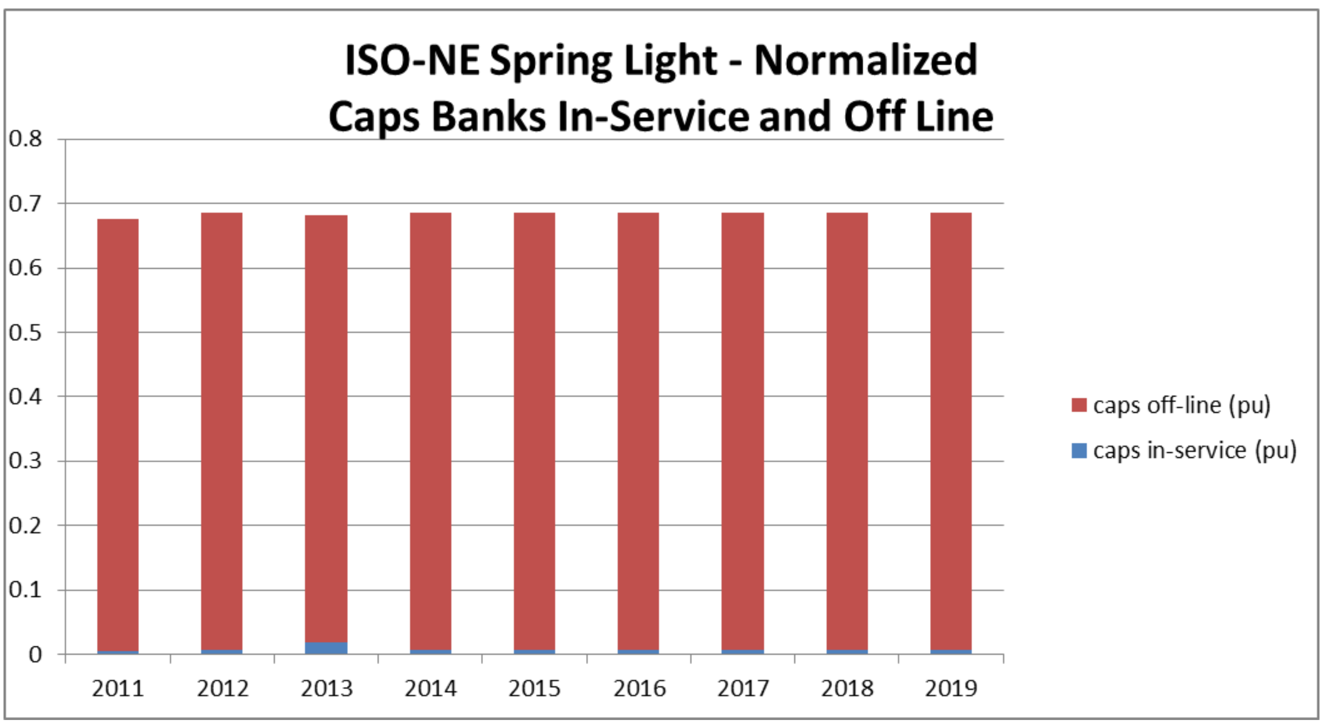


Figure D.47: ISO-NE – Planning – Dynamic System (p.u.) (Spring Light)

ISO-NE – Planning – Load Trend (MW)

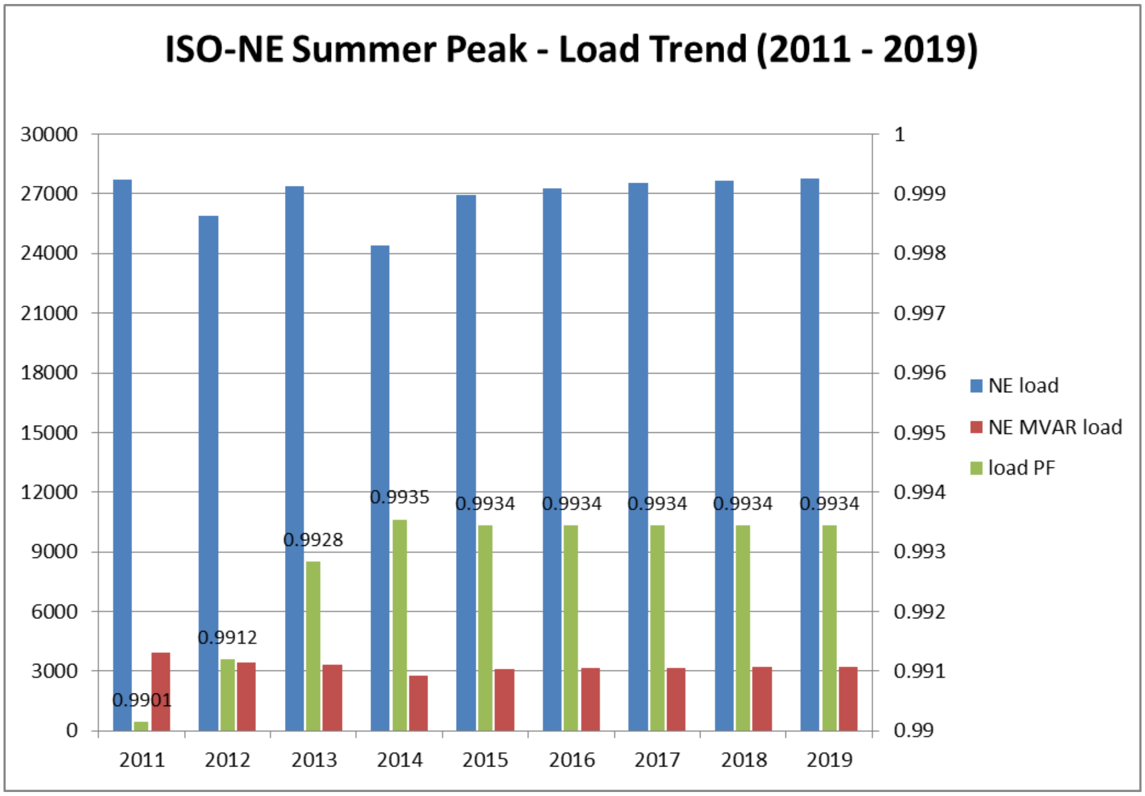


Figure D.48: ISO-NE – Planning – Load Trend (MW) (Summer Peak)

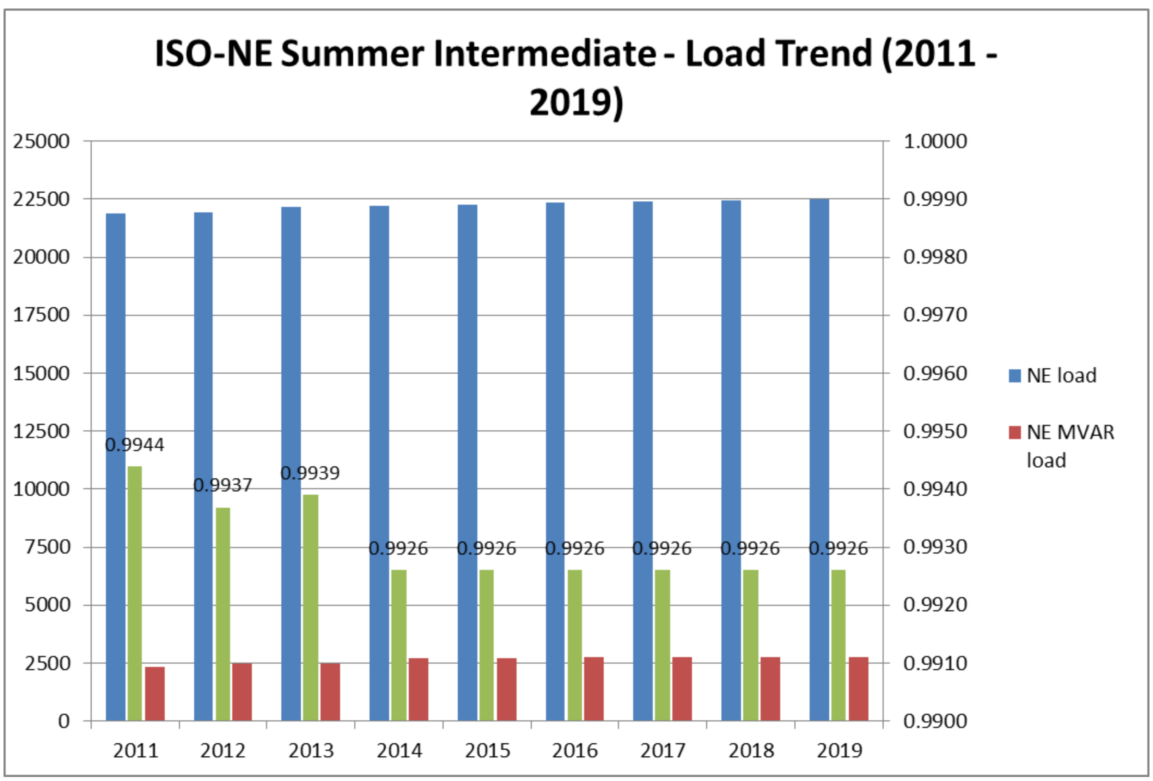


Figure D.49: ISO-NE – Planning – Load Trend (MW) (Summer Intermediate)

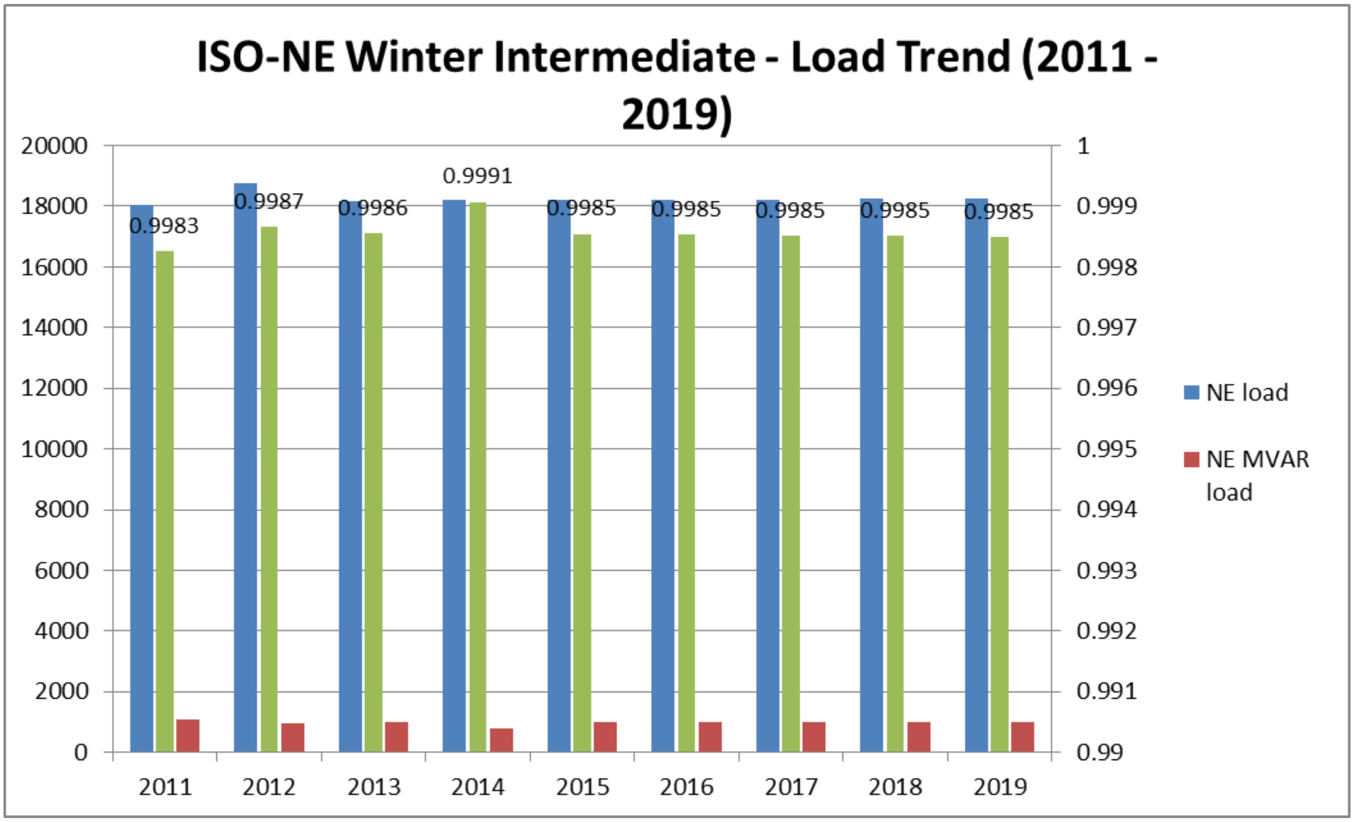


Figure D.50: ISO-NE – Planning – Load Trend (MW) (Winter Intermediate)

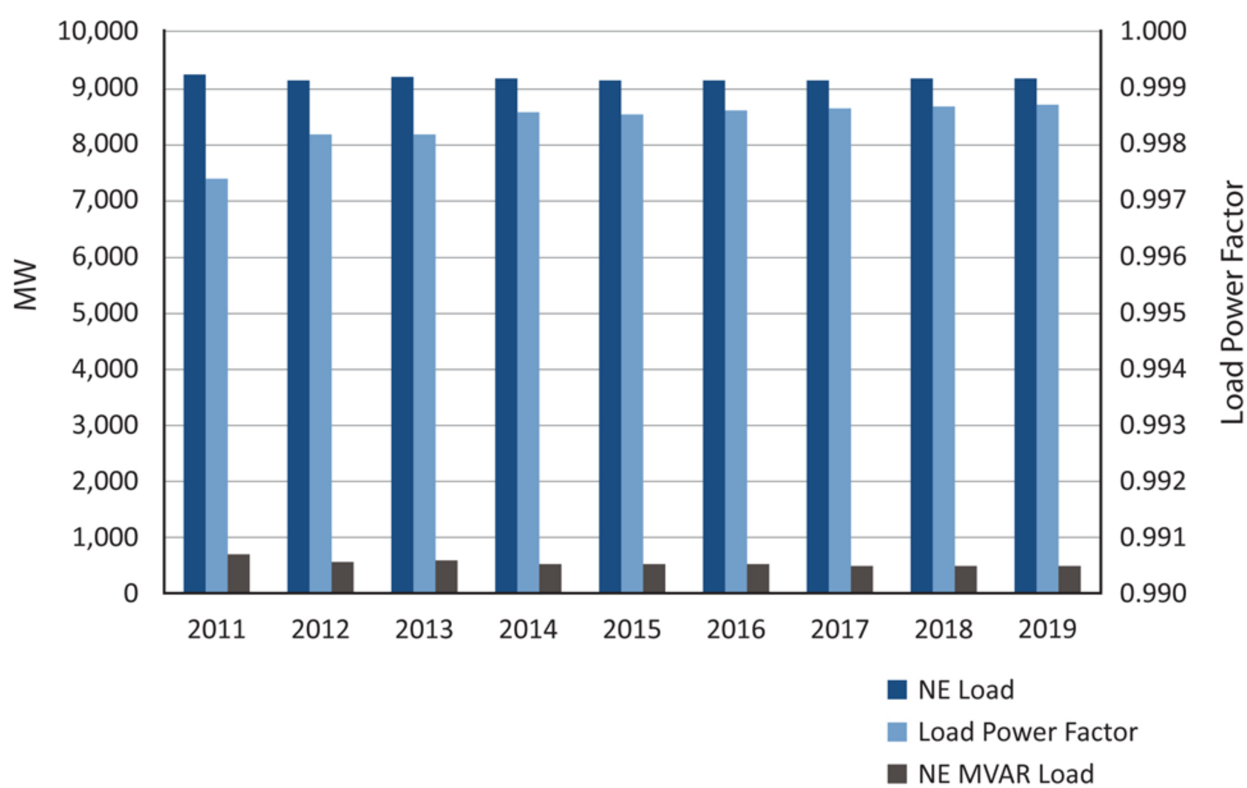


Figure D.51: ISO-NE – Planning – Load Trend (MW) (Spring Light)

ERCOT – Planning – Dynamic System (p.u.)

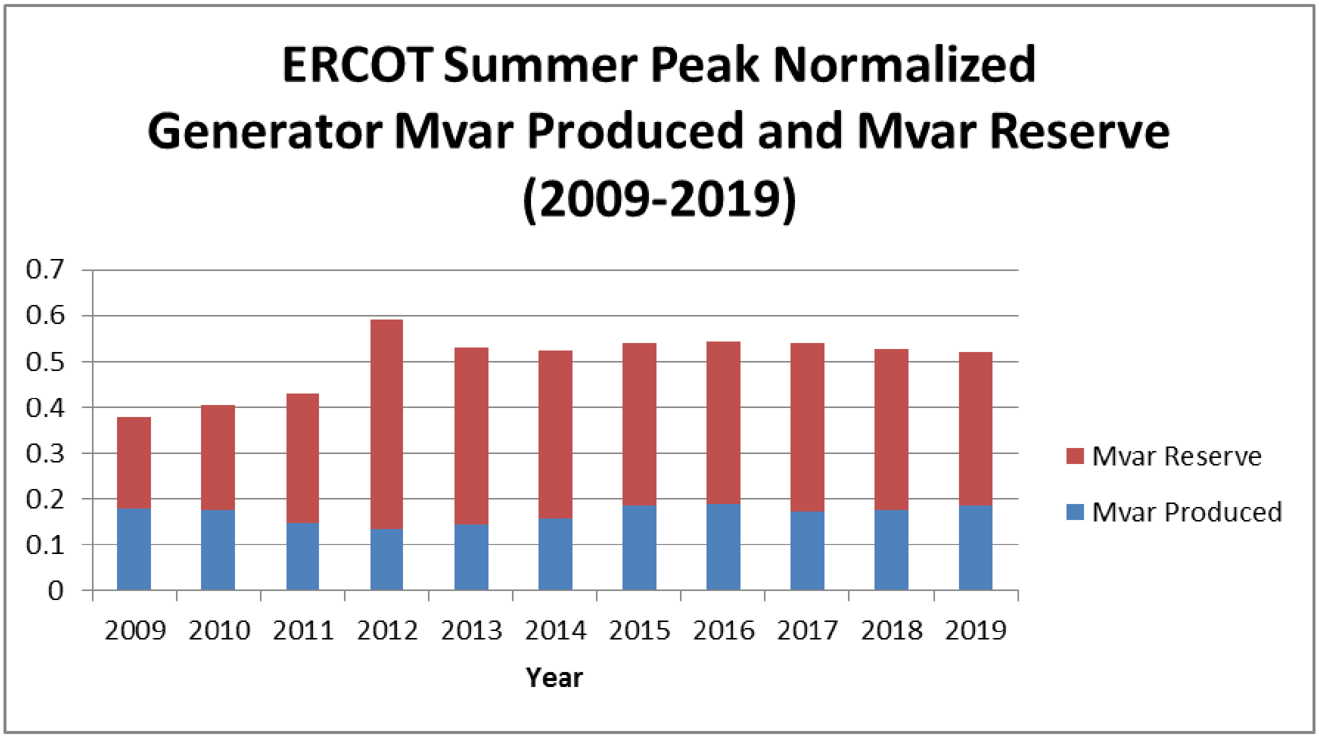


Figure D.52: ERCOT – Planning – Dynamic System (p.u.) (Summer Peak)

ERCOT – Planning – Static System (p.u.)

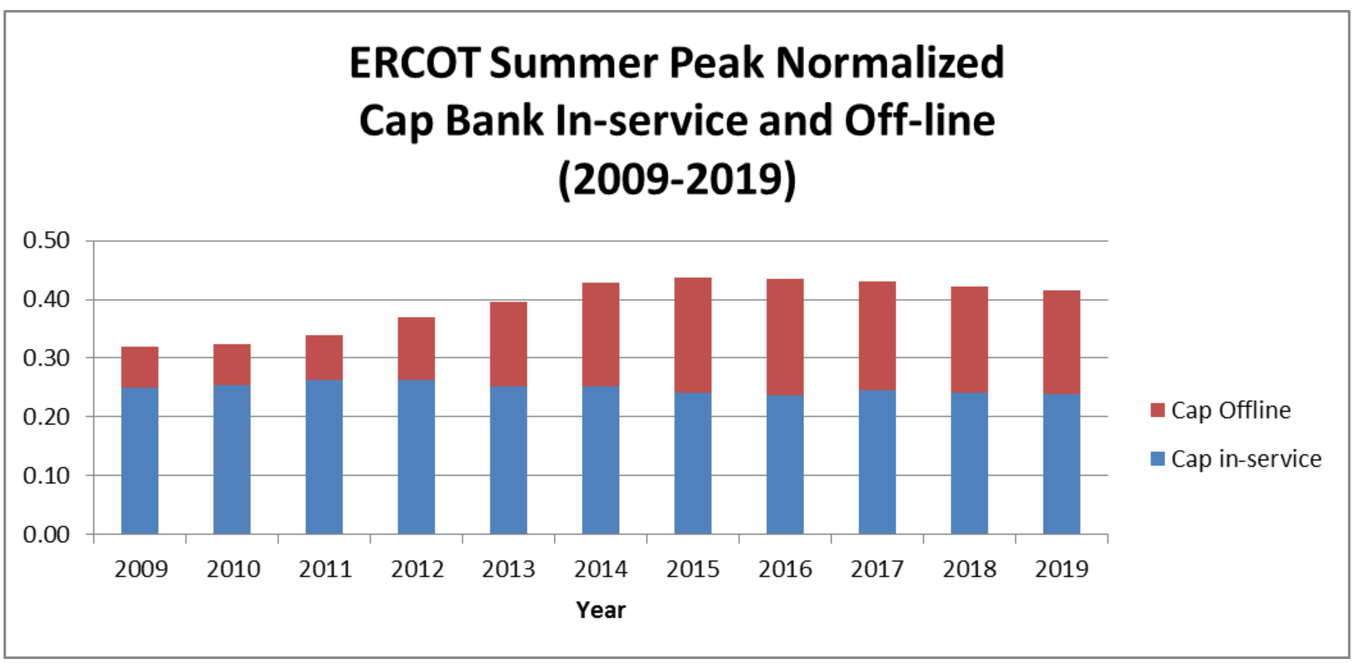


Figure D.53: ERCOT – Planning – Static System (p.u.) (Summer Peak)

ERCOT – Planning – Load Trend (MW)

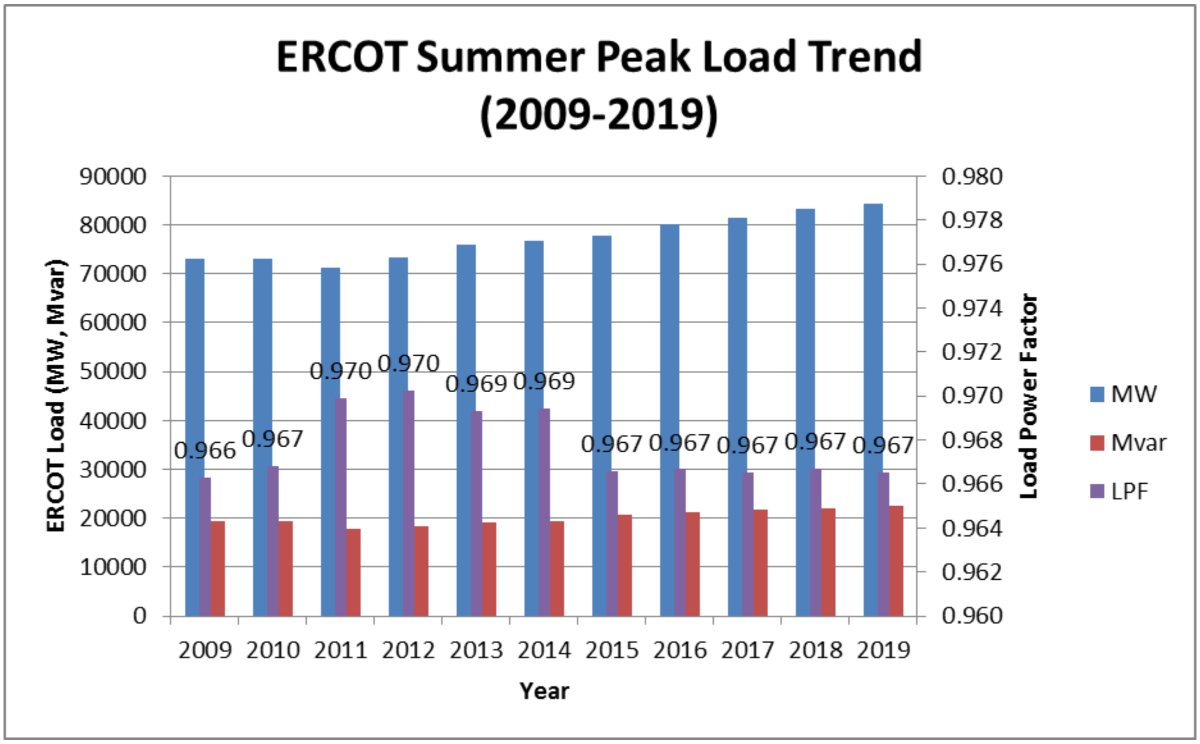


Figure D.54: ERCOT – Planning – Dynamic System (p.u.) (Summer Peak)

IESO – Planning – Dynamic System (P.U.)

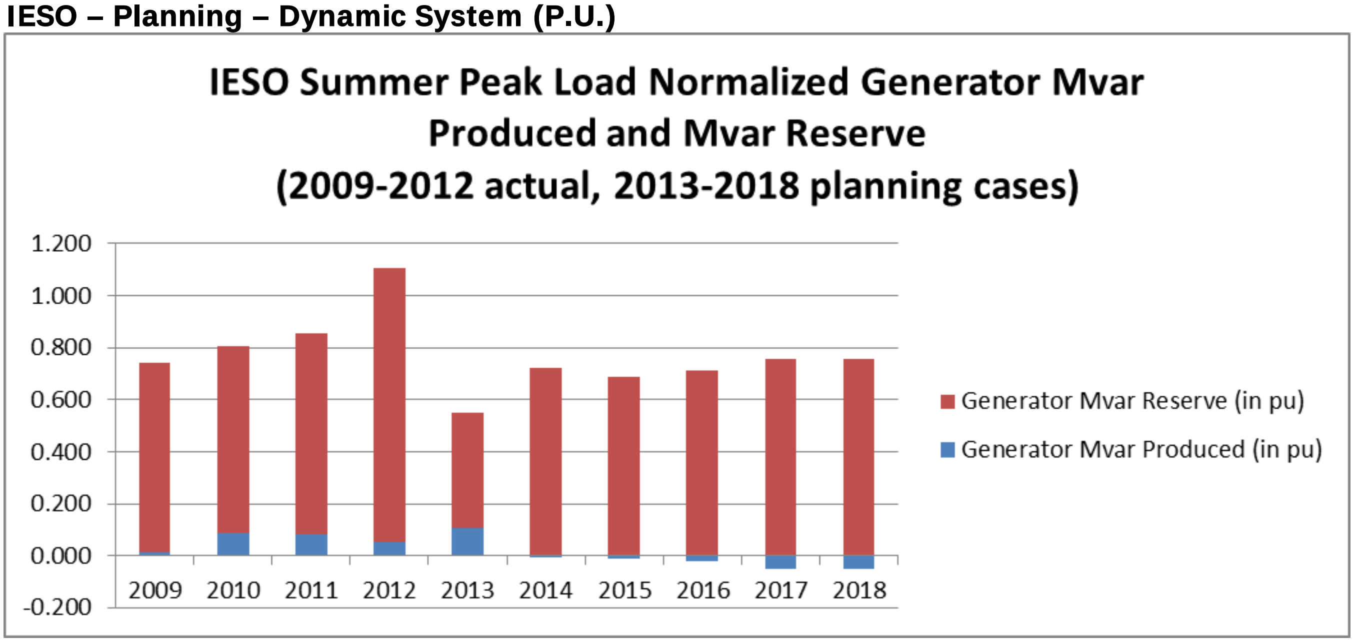


Figure D.55: IESO – Planning – Dynamic System (p.u.) (Summer Peak)

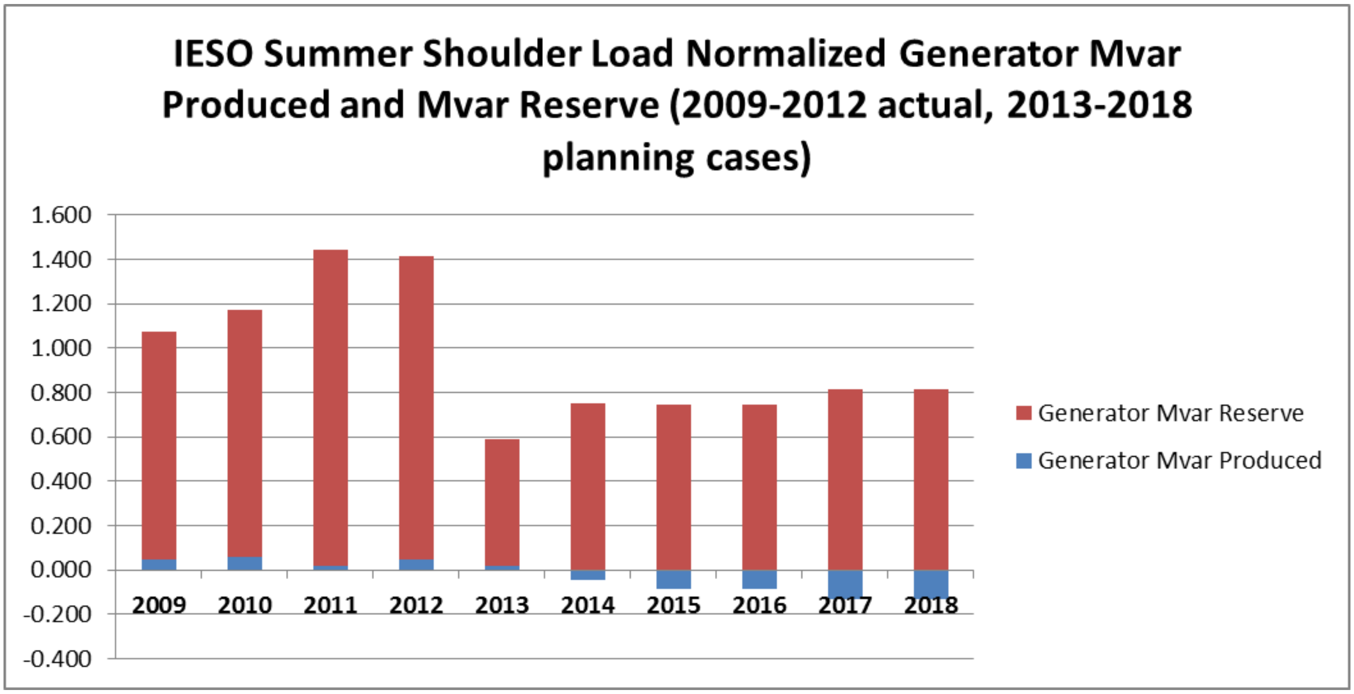


Figure D.56: IESO – Planning – Dynamic System (p.u.) (Summer Shoulder)

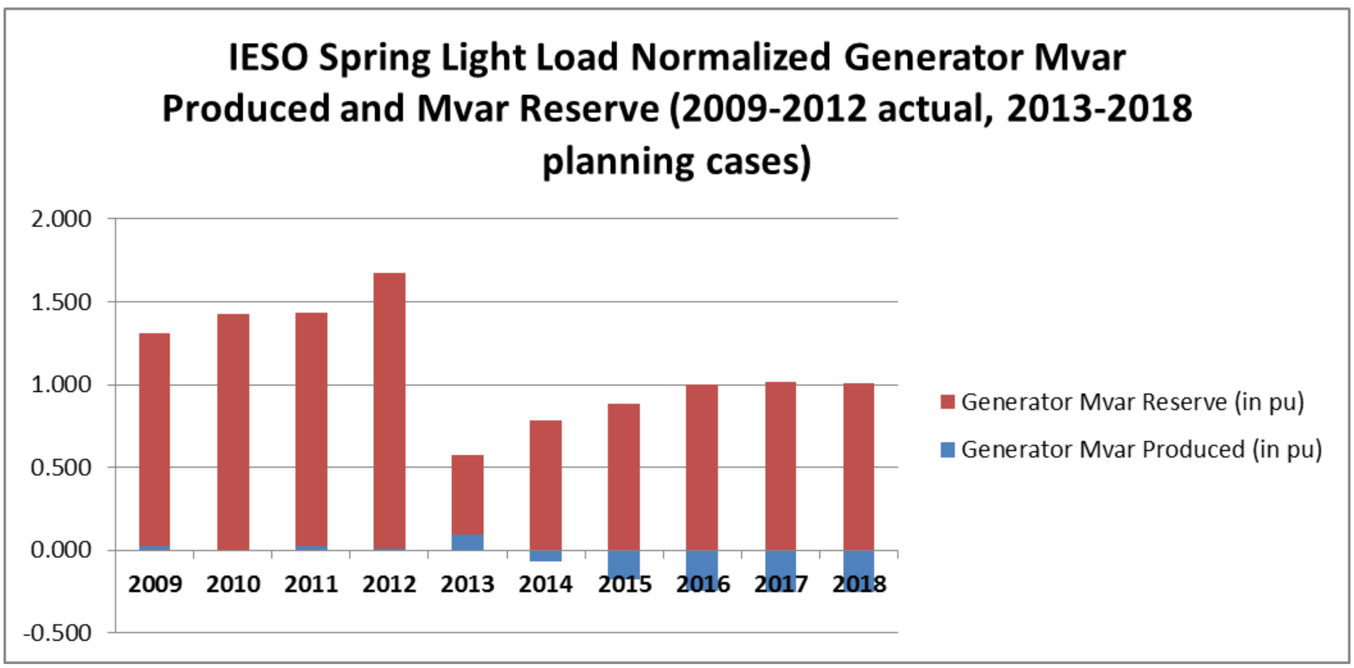


Figure D.57: IESO – Planning – Dynamic System (p.u.) (Spring Light Load)

IESO – Planning – Static System (p.u.)

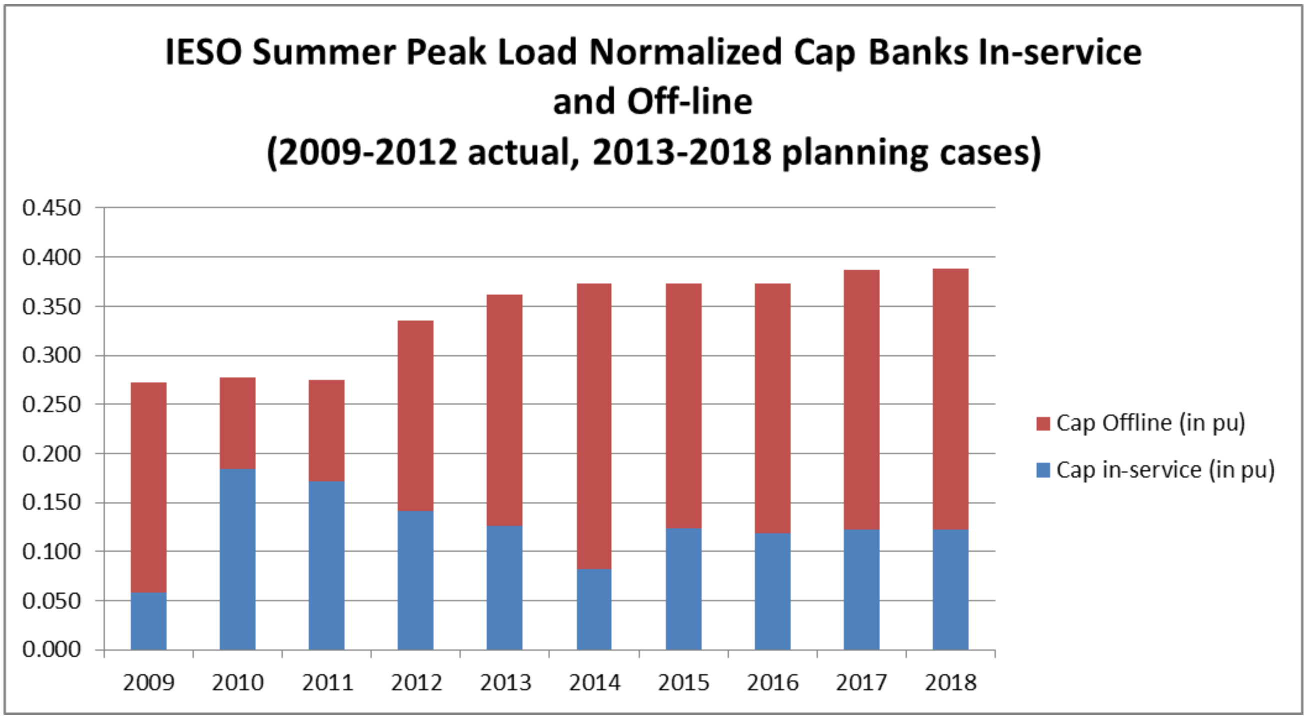


Figure D.58: IESO – Planning – Static System (p.u.) (Summer Peak)

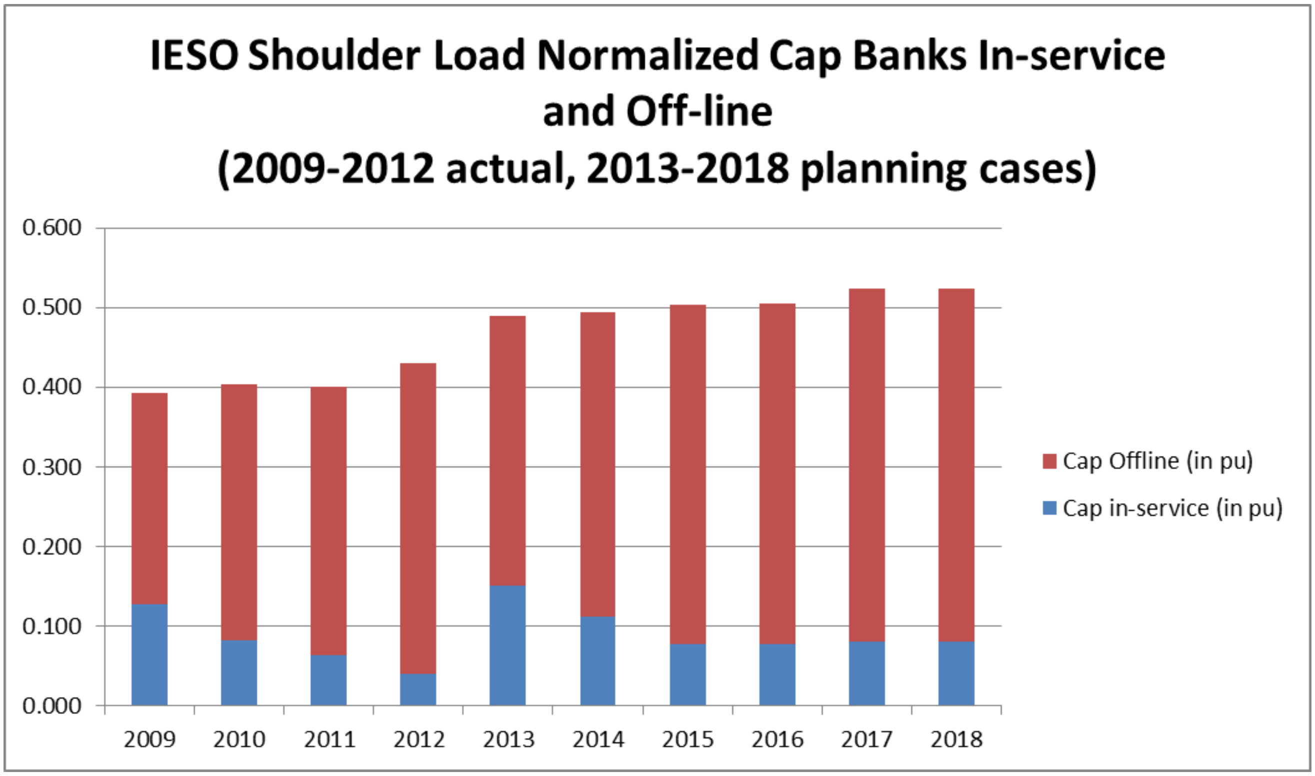


Figure D.59: IESO – Planning – Static System (p.u.) (Shoulder Load)

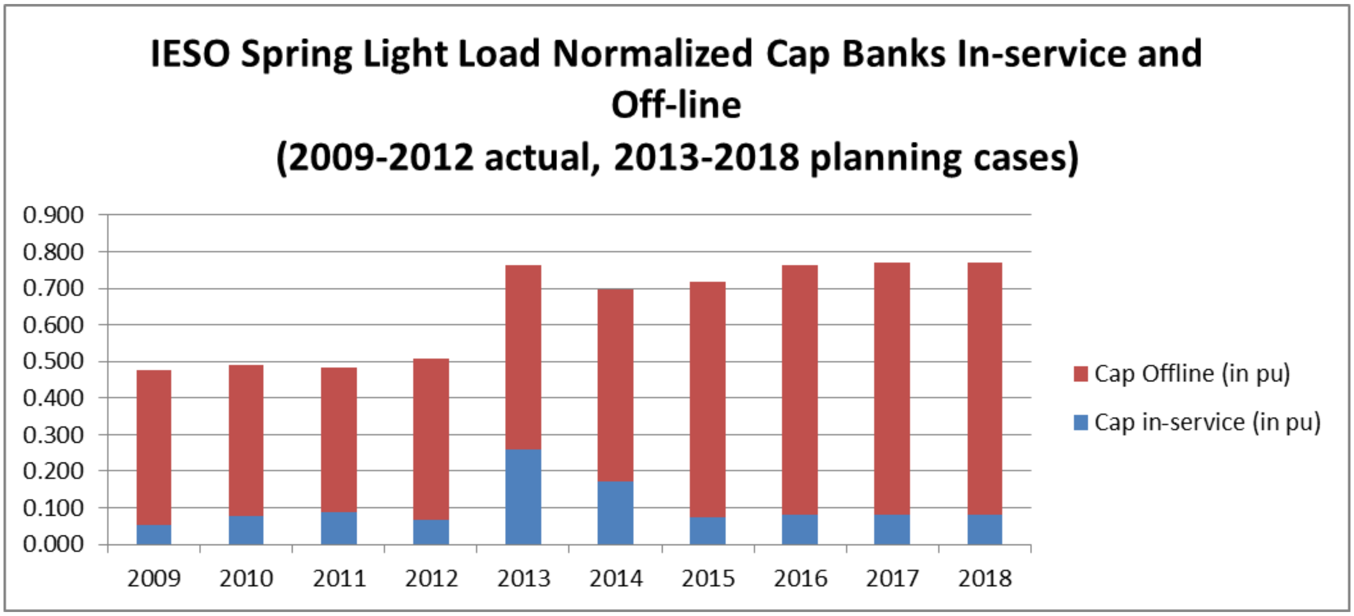


Figure D.60: IESO – Planning – Static System (p.u.) (Spring Light Load)

IESO – Planning – Load Trend (MW)

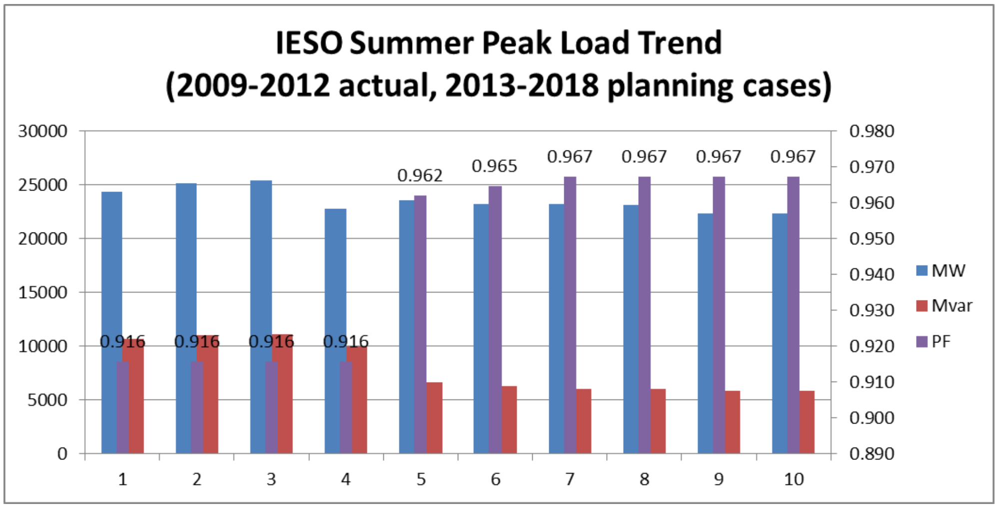


Figure D.61: IESO – Planning – Load Trend (MW) (Peak)

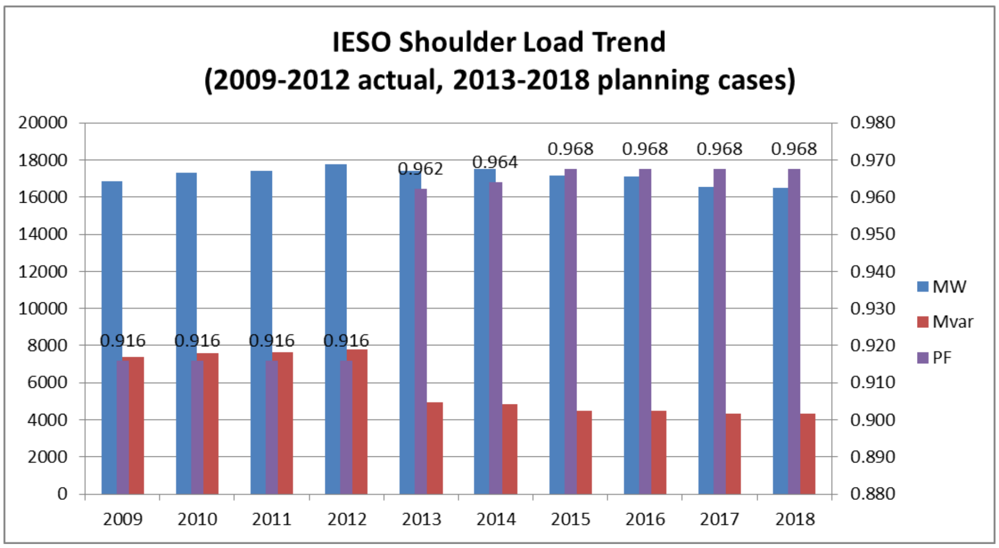


Figure D.62: IESO – Planning – Load Trend (MW) (Shoulder)

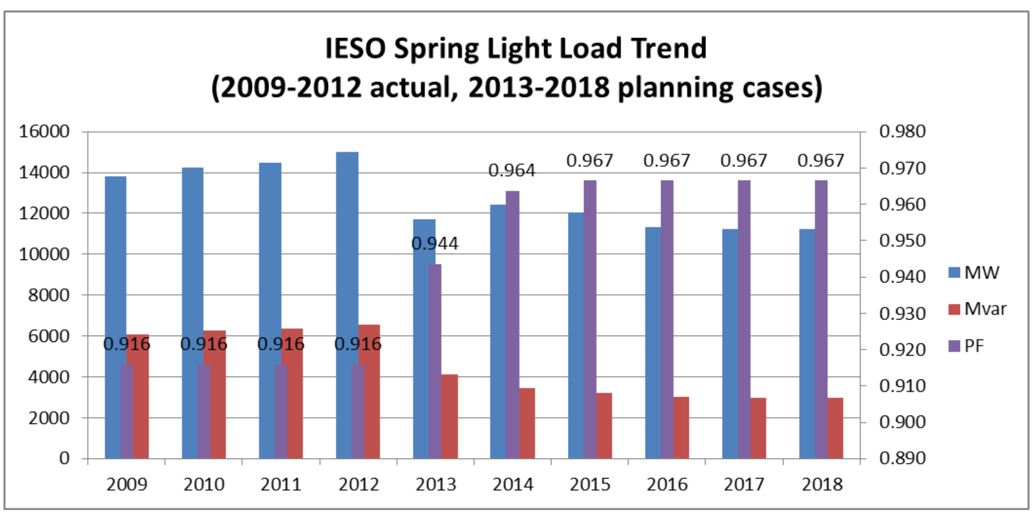


Figure D.63: IESO – Planning – Load Trend (MW) (Spring Light Load)

Hydro-Quebec – Planning – Dynamic System (p.u.)

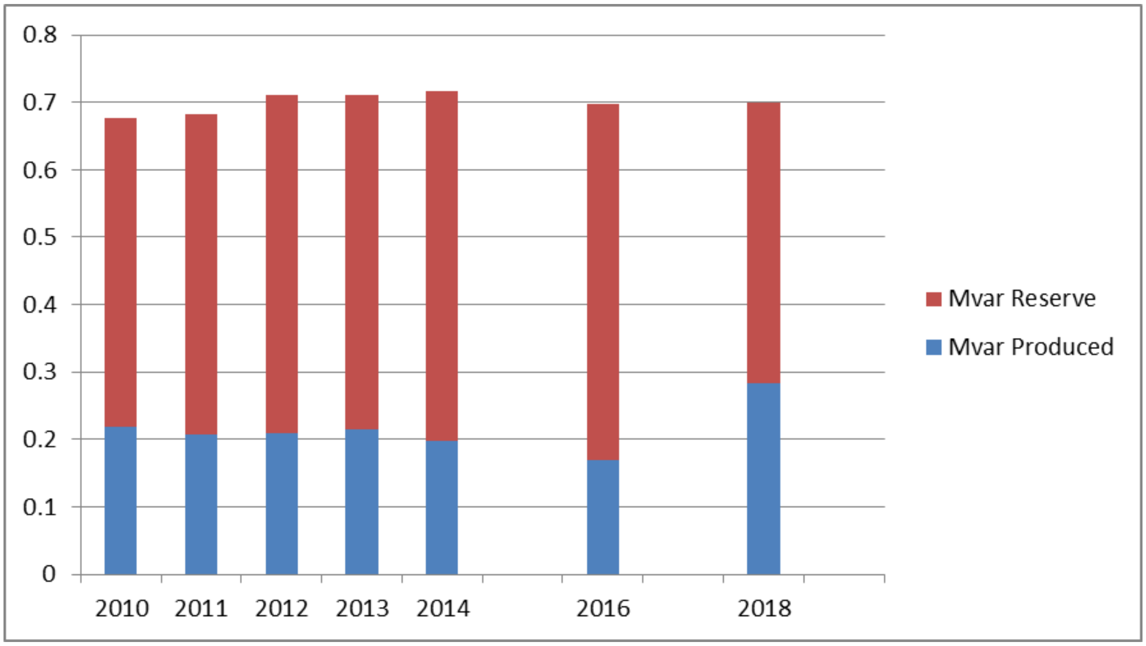


Figure D.64: Hydro-Quebec – Planning – Dynamic (p.u)

Hydro-Quebec – Planning – Static System (P.U.)

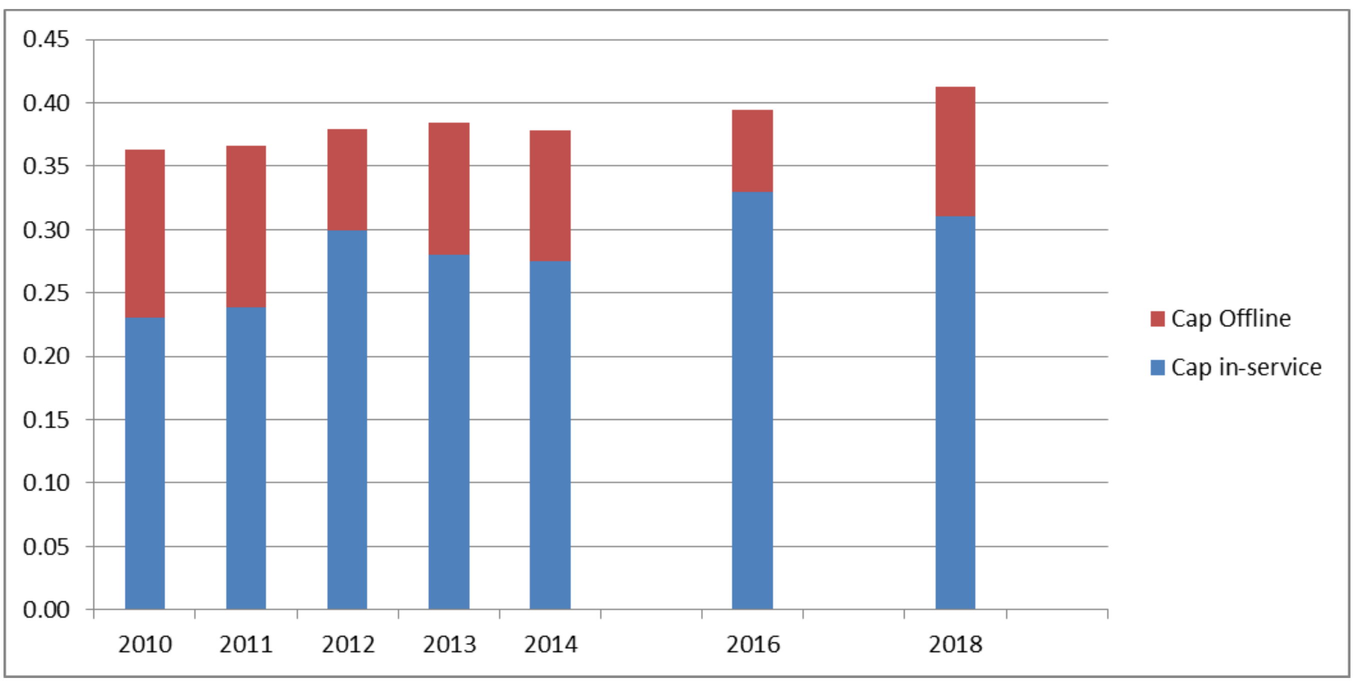


Figure D.65: Hydro-Quebec – Planning – Static System (p.u)

Hydro-Quebec – Planning – Load Trend (MW)

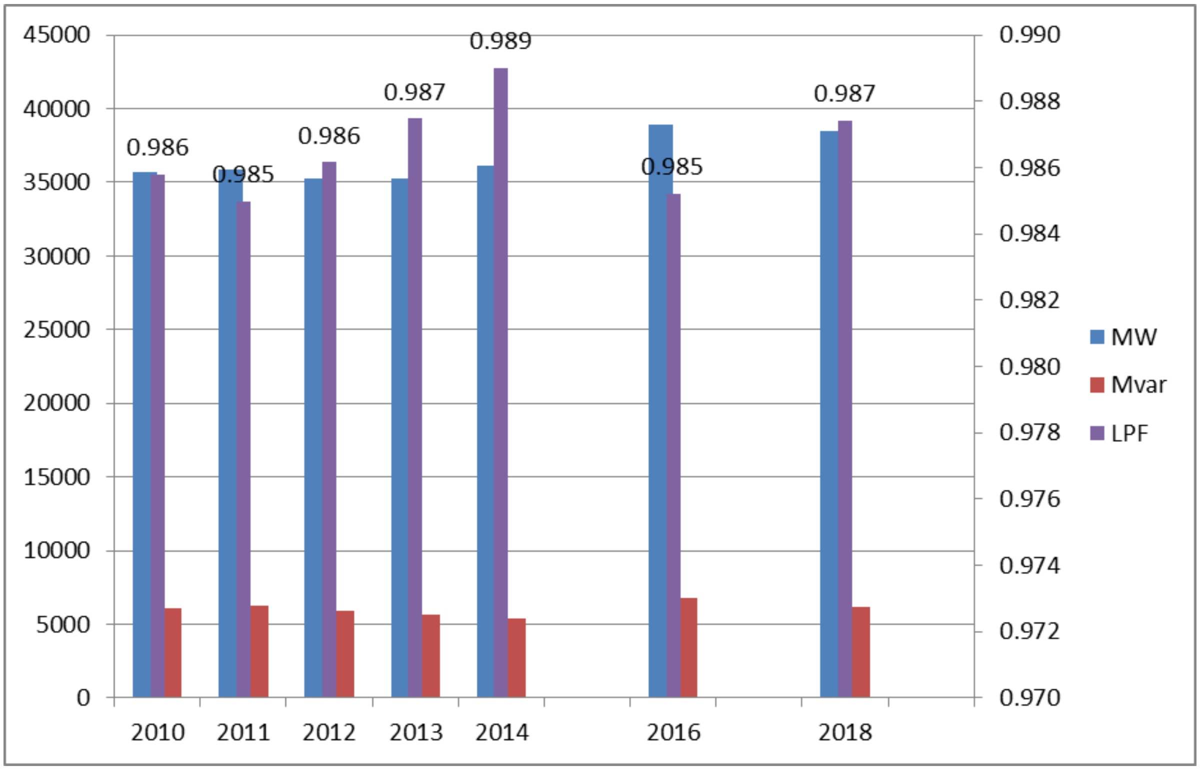


Figure D.66: Hydro-Quebec – Planning – Load Trend (MW)

Southern Company – Planning – Dynamic System (P.U.)

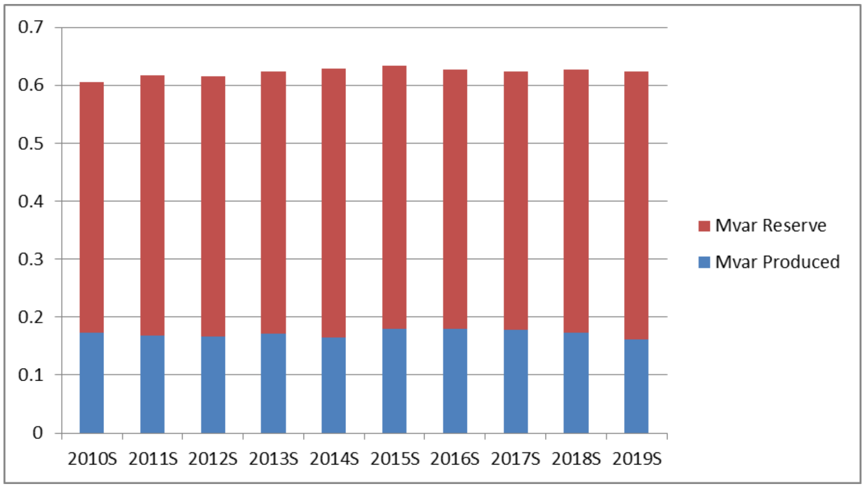


Figure D.67: Southern Company – Planning – Dynamic System (p.u) (Summer Peak)

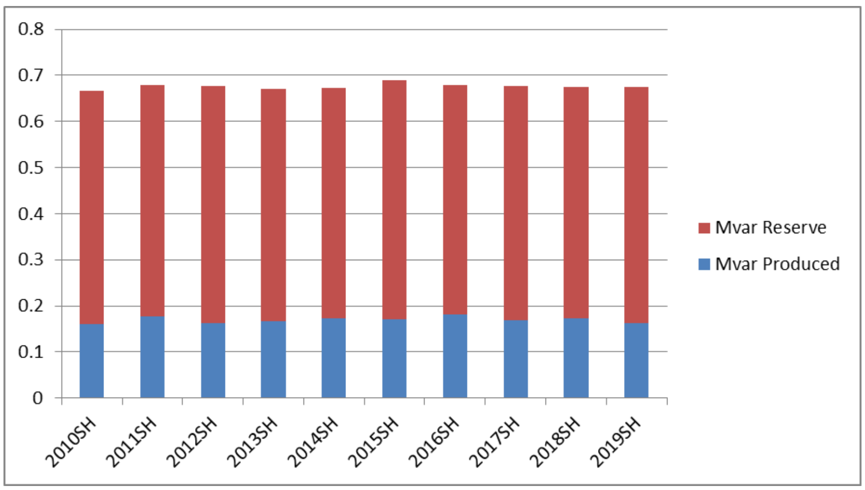


Figure D.68: Southern Company – Planning – Dynamic System (p.u) (Shoulder)

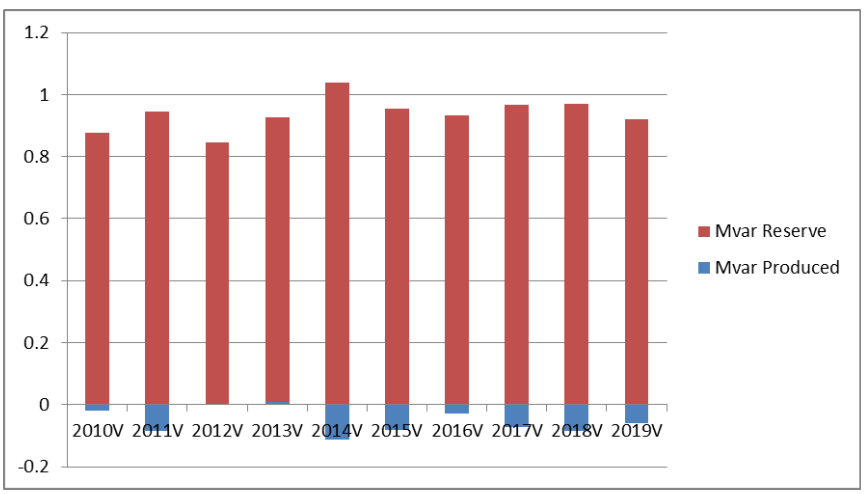


Figure D.69: Southern Company – Planning – Dynamic System (p.u) (Valley

Southern Company – Planning – Static System (P.U.)

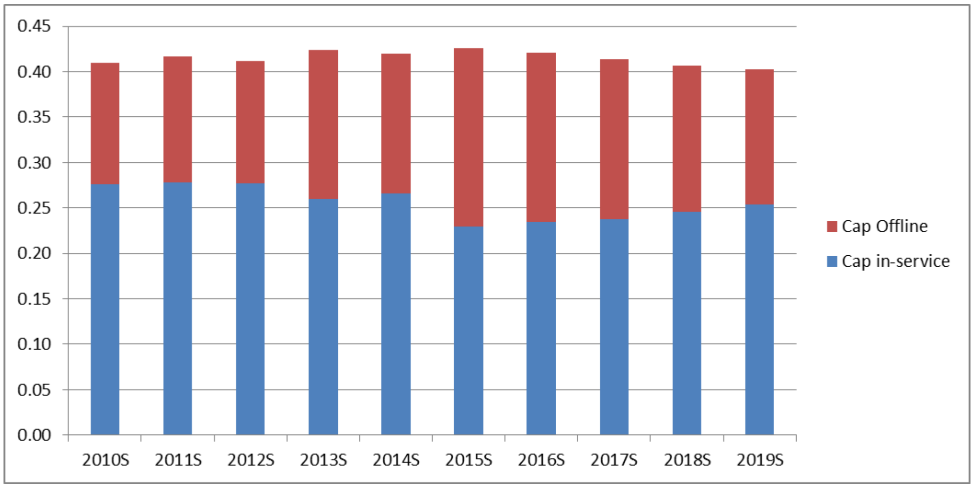


Figure D.70: Southern Company – Planning – Static System (p.u) (Summer Peak)

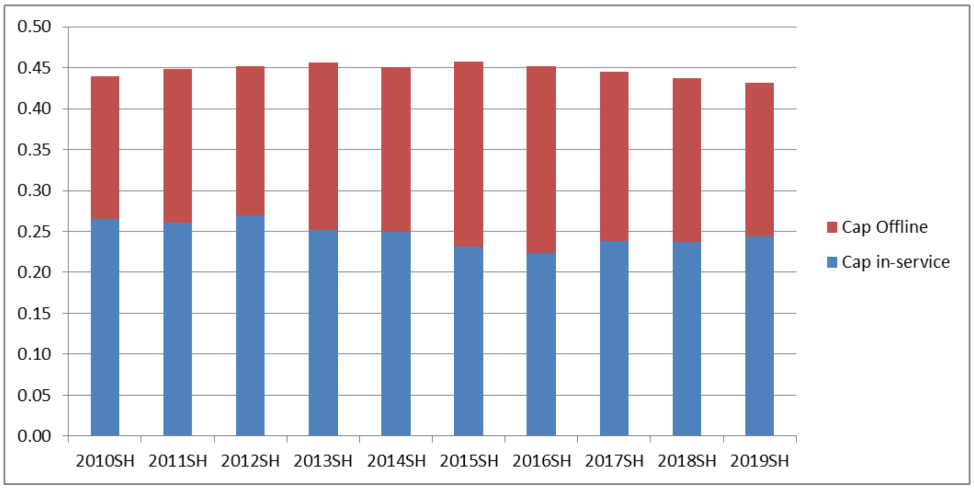


Figure D.71: Southern Company – Planning – Static System (p.u) (Shoulder)

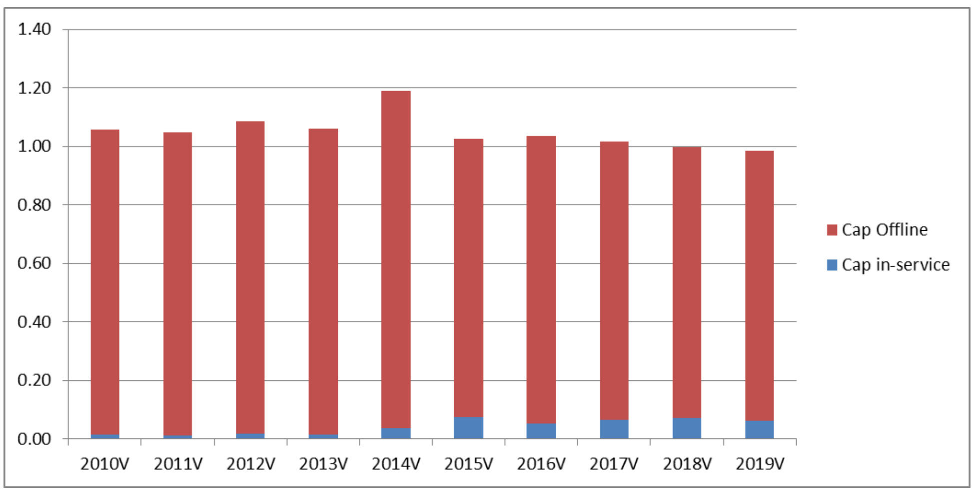


Figure D.72: Southern Company – Planning – Static System (p.u) (Valley)

Southern Company – Planning – Load Trend (MW)

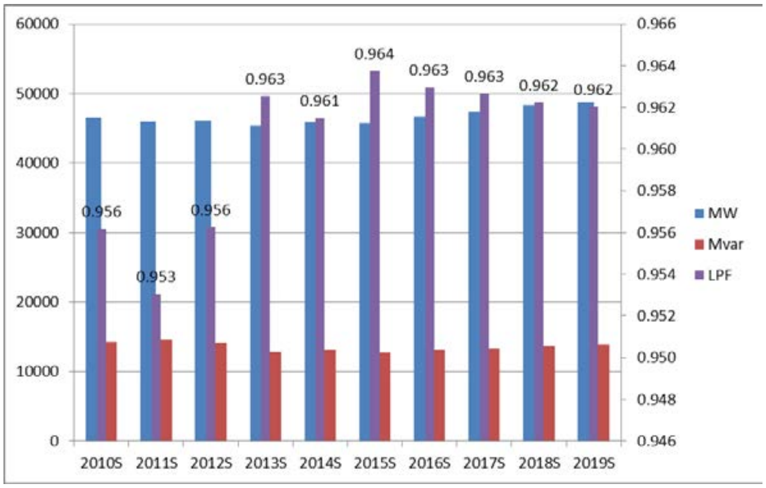


Figure D.73: Southern Company – Planning – Load Trend (MW) (Summer Peak)

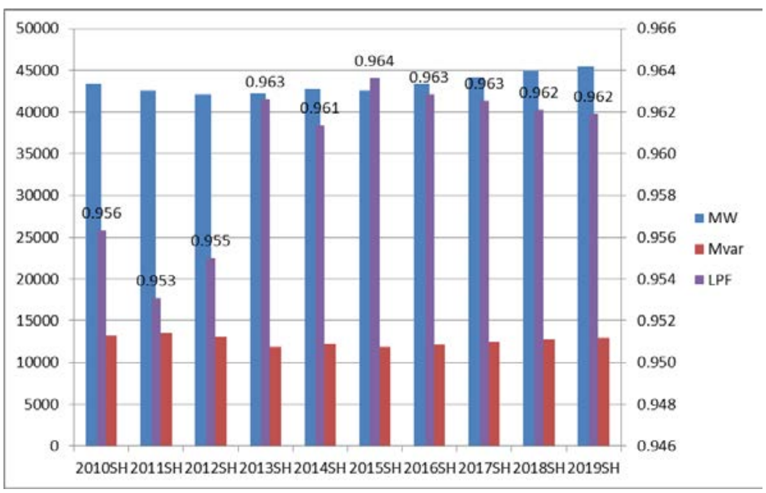


Figure D.74: Southern Company – Planning – Load Trend (MW) (Shoulder)

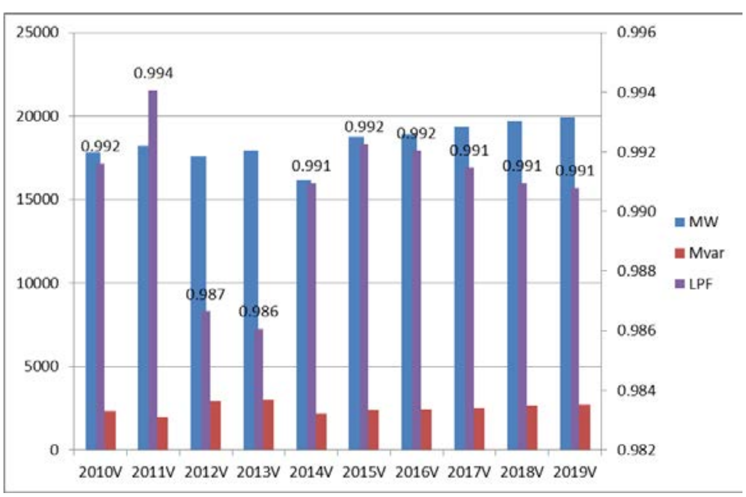


Figure D.75: Southern Company – Planning – Load Trend (MW) (Valley)

Southern Company – Real Time – Dynamic System (p.u.)

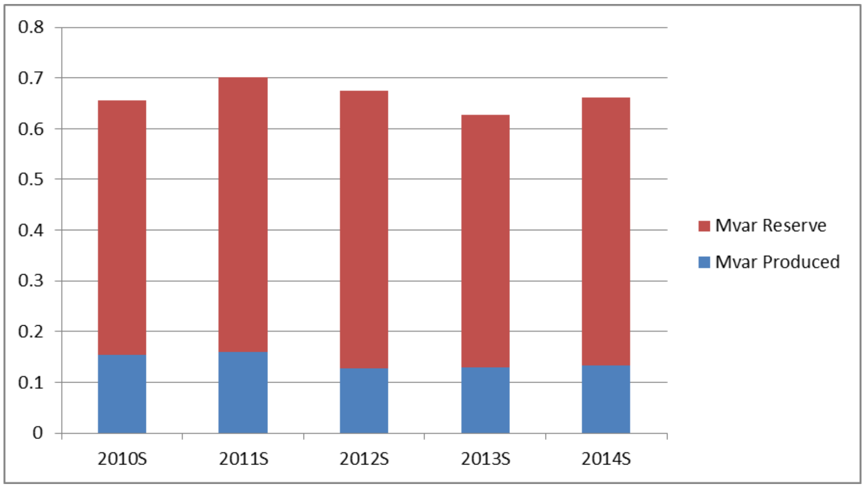


Figure D.76: Southern Company – Planning – Dynamic System (p.u.) (Summer Peak)

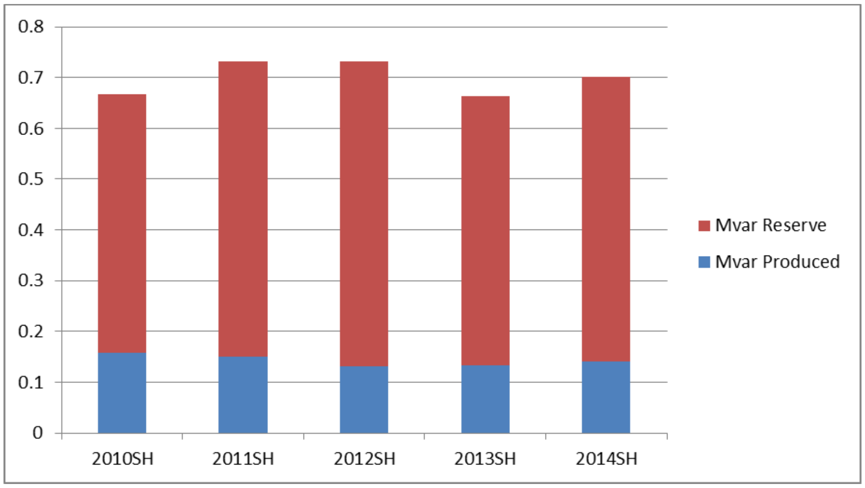


Figure D.77: Southern Company – Planning – Dynamic System (p.u.) (Shoulder)

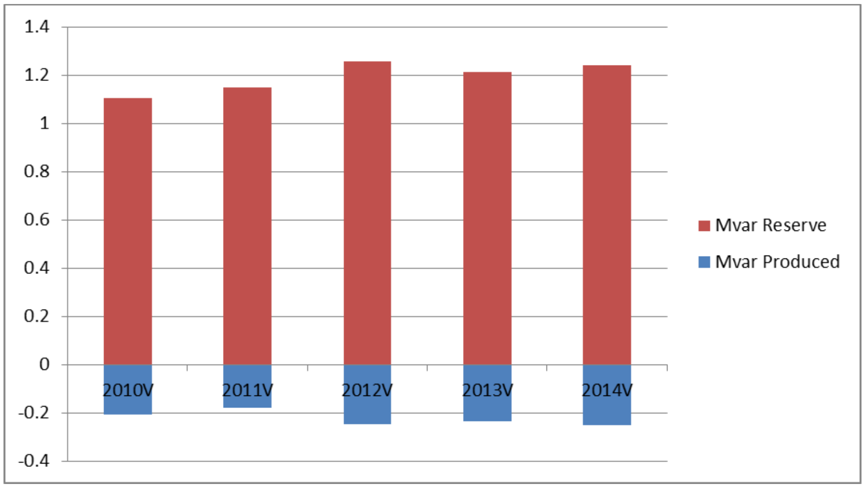


Figure D.78: Southern Company – Planning – Dynamic System (p.u.) (Valley)

Southern Company – Real Time – Static System (p.u..)

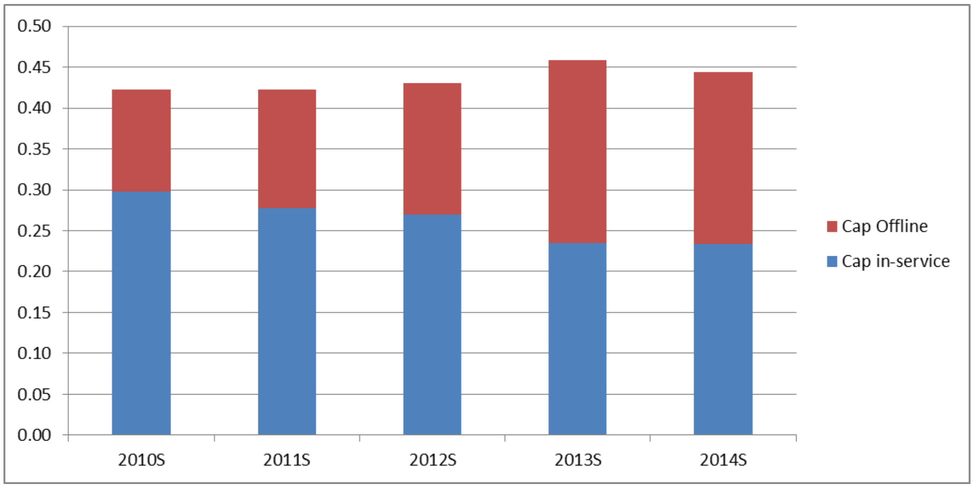


Figure D.79: Southern Company – Planning – Static System (p.u.) (Summer Peak)

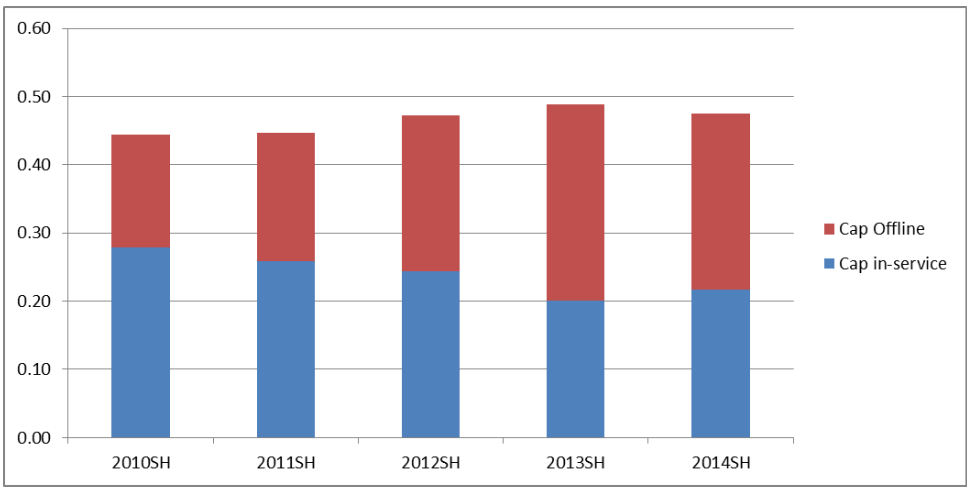


Figure D.80: Southern Company – Planning – Static System (p.u.) (Shoulder)

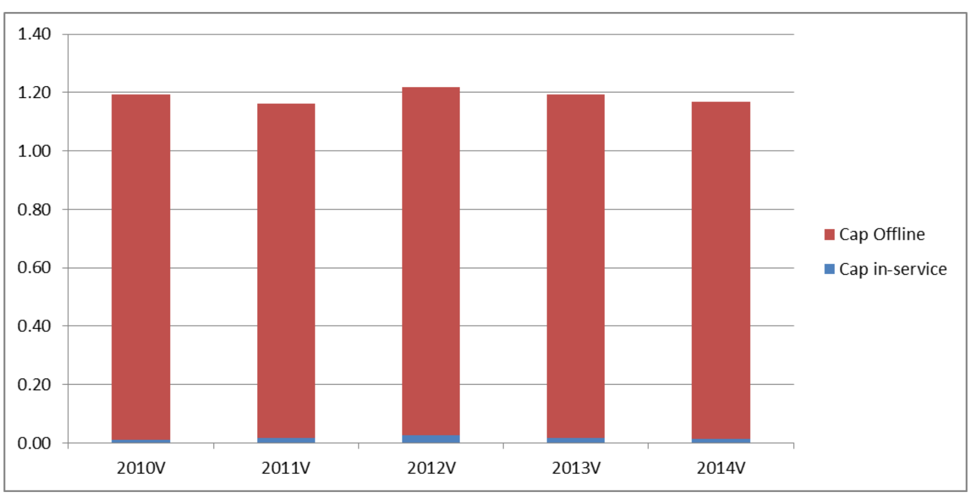


Figure D.81: Southern Company – Planning – Static System (p.u.) (Valley)

Southern Company – Real Time – Load Trend (MW)

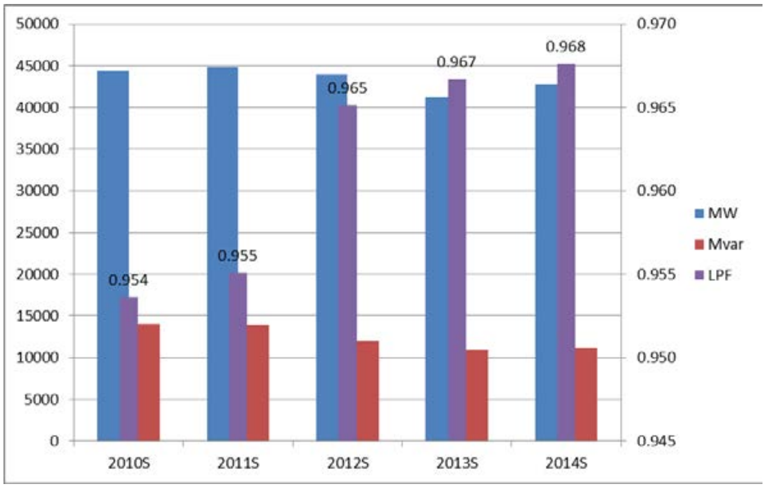


Figure D.82: Southern Company – Planning – Real Time (MW) (Summer Peak)

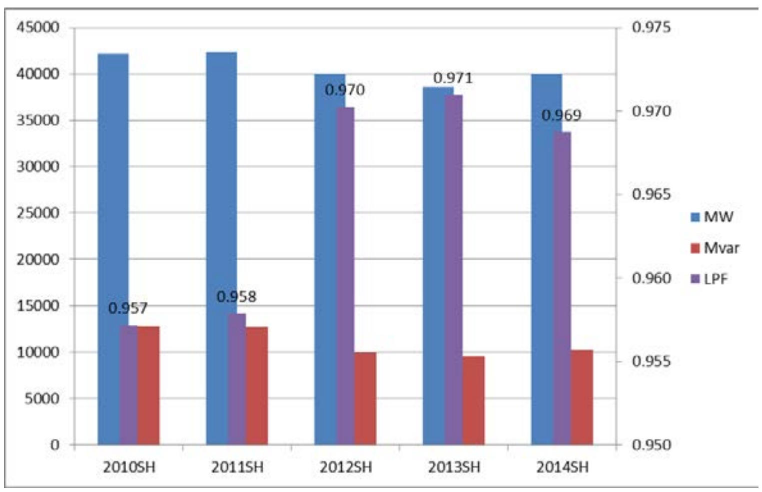


Figure D.83: Southern Company – Planning – Real Time (MW) (Shoulder)

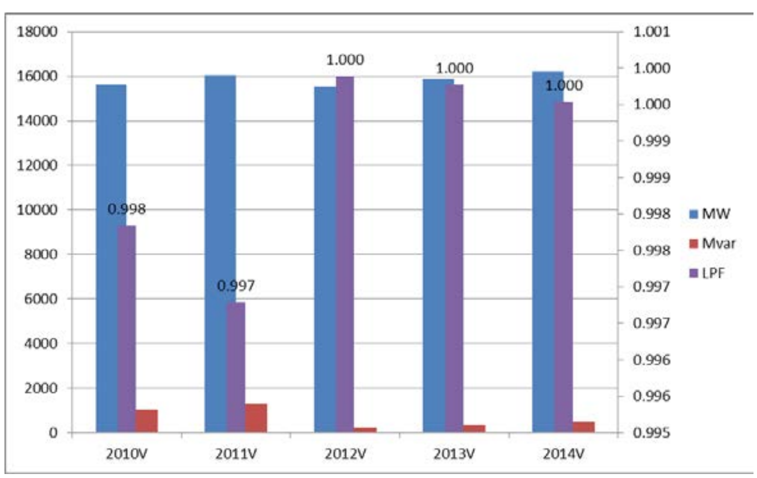


Figure D.84: Southern Company – Planning – Real Time (MW) (Valley)

Appendix E – Short Circuit Ratios for Measure 10 Part Two

Short circuit ratio (SCR) is a metric that has traditionally represented the voltage stiffness of a grid. Conventionally, SCR is defined as the ratio of the short circuit capacity, at the bus where the device is located, to the megawatt rating of the device. Based on this definition, SCR is given by:

$$SCR = \frac{S_{SCMVA}}{P_{RMW}} \qquad (1)$$

where S_{SCMVA} is the short circuit capacity at the bus before the connection of the device and P_{RMW} is the rated megawatt value of the device to be connected.

Equation (1) is the commonly used SCR calculation method when evaluating system strength. The key assumption and limitation of this SCR calculation method is that the studied wind or solar plant does not interact with other such plants in the system. When plants are electrically close to each other, they may interact with each other and oscillate together. In such cases, the SCR calculation using equation 1 can result in an overly optimistic result.

There is currently no industry-standard approach to calculate the proper SCR index for a weak system with high penetration of wind and solar power plants (or other inverter-based resources, such as battery storage). To take into account the effect of interactions between plants and give a better estimate of the system strength, a more appropriate quantity or indicator is needed to assess the potential risk of complex instability. Several approaches, such as GE's Composite Short Circuit Ratio (CSCR) and ERCOT'S Weighted Short Circuit Ratio (WSCR) method, have been proposed to calculate the SCR for a weak system with high penetration of renewable generation.

<u>GE's Composite Short Circuit Ratio (CSCR)</u>
The GE CSCR method is fully described in the following document: *Report to NERC ERSTF for Composite Short Circuit Ratio (CSCR) Estimation Guideline*, GE Energy Consulting: Fernandes, R., Achilles, S., MacDowell, J., January 2015.

<u>ERCOT's Weighted Short Circuit Ratio (WSCR)</u>
The weighted short circuit ratio (WSCR) is defined as:

$$\begin{aligned} WSCR &= \frac{Weighted \quad S_{SCMVA}}{\sum_i^N P_{RMWi}} \\ &= \frac{(\sum_i^N S_{SCMVAi} * P_{RMWi}) / \sum_i^N P_{RMWi}}{\sum_i^N P_{RMWi}} \qquad (2) \\ &= \frac{\sum_i^N S_{SCMVAi} * P_{RMWi}}{(\sum_i^N P_{RMWi})^2} \end{aligned}$$

where S_{SCMVAi} is the short circuit capacity at bus *i* before the connection of nonsynchronous generation plant *i* and P_{RMWi} is the MW rating of nonsynchronous generation plant *i* to be connected. N is the number of wind plants fully interacting with each other and *i* is the wind plant index.

The proposed WSCR calculation method is based on the assumption of full interactions between nonsynchronous generation plants. This is equivalent to assuming that all nonsynchronous generation plants are connected to a virtual point of interconnection (POI). For a real power system, there is usually some electrical distance between each nonsynchronous generation plant's POI, and the nonsynchronous generation plants will not fully interact with each other. The WSCR obtained with this method gives a conservative estimate of the system strength and is considered a proper index to represent the system strength for the studied Panhandle region. A small sample system with four wind plants, as shown in Figure WSCR-1, is used to demonstrate the proposed WSCR concept. The subsystem consisting of four wind plants connects to the main system with weak links. There is no significant electrical distance between each wind plant's POI. Table WSCR-1 shows the wind plant sizes and SCR values calculated using equation 1.

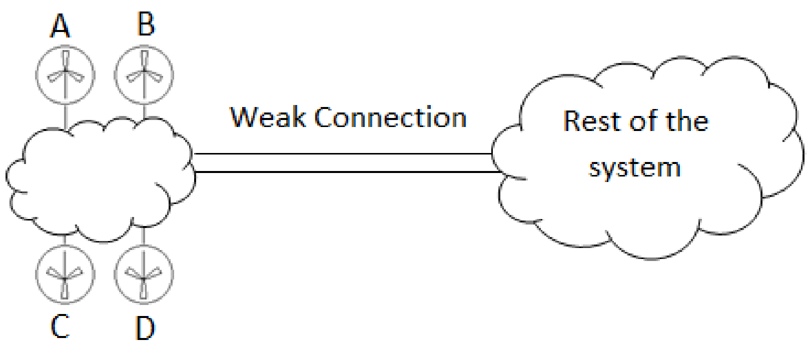


Figure E.1: Four wind generation plants integrated into the system with weak connections

Table E.1: Wind Capacity and SCR Values Assuming No Interaction

Wind plant	Wind Capacity (MW)	Short Circuit Capacity (SCMVA)	SCR
A	1,200	6,500	5.42
B	1,000	8,000	8.00
C	800	8,500	10.63
D	2,000	7,000	3.5

The weighted SCR is calculated using Equation 3.

$$WSCR = \frac{1{,}200 * 6{,}500 + 1{,}000 * 8{,}000 + 800 * 8{,}500 + 2{,}000 * 7{,}000}{(1{,}200 + 1{,}000 + 800 + 2{,}000)^2} = 1.46 \qquad (3)$$

The calculation in equation 3 shows that even though all the SCR values at each individual POI are larger than 3, the WSCR of the equivalent virtual POI to represent the region is only 1.46. This means the actual system strength is much weaker since the wind plants interact with each other.

It is recommended that these values be initially generated using the past few years of planning and operational data, if such data is available, to test the potential merits of tracking these indices over time going forward. Once their potential merit has been confirmed, a process for collecting data on future trends should be established.

Appendix F – Task Force Roster & Contributing Entities

Name	Entity
Gerald Beckerle	Ameren
Dave Canter	American Electric Power
Richard Hydzik	Avista Corporation
Clyde Loutan	California Independent System Operator
J. Holeman	Electric Power Research Institute
Robert Entriken	Electric Power Research Institute
Aidan Tuohy	Electric Power Research Institute
Jack Cashin	Electric Power Supply Association
Brendan Kirby	Electric Power System Consulting
Shun-Hsien Huang	Electric Reliability Council of Texas
Julia Matevosyan	Electric Reliability Council of Texas
Alfred Corbett	Federal Energy Regulatory Commission
Hassan Hamdar	Florida Reliability Coordinating Council
Jason McDowell	General Electric
Nicholas Miller	General Electric
Caroline Beaulieu-Cote	Hydro Quebec
David Devereaux	Independent Electricity System Operator
John Simonelli	Independent System Operator of New England
Michael McMullen	MISO Energy
Paul McCurley	National Rural Electric Cooperative Association
Mark Ahlstrom	NextEra Energy
Noha Abdel-Karim	North American Electric Reliability Corporation
Robert Cummings	North American Electric Reliability Corporation
Michelle Marx	North American Electric Reliability Corporation
John Moura	North American Electric Reliability Corporation
Ryan Quint	North American Electric Reliability Corporation
Pooja Shah	North American Electric Reliability Corporation
Ken Schuyler	PJM Interconnection
Dariush Shirmohammadi	California Wind Energy Association
Ronald Carlsen	Southern Company
K. Chakravarthi	Southern Company
Cindy Hotchkiss	Southern Company
Todd Lucas	Southern Company
Thomas Siegrist	Stone, Mattheis, Xenopoulos & Brew, P.C.
Jagan Mandavilli	Texas Reliability Entity
Kenneth McIntyre	The Anfield Group
Brian Evans-Mongeon	Utility Services
Charlie Smith	UVIG
Anthony Jankowski	WE Energies
Steven Ashbaker	Western Electricity Coordinating Council
Layne Brown	Western Electricity Coordinating Council
Donald Davies	Western Electricity Coordinating Council