Frequency Response Initiative Report

The Reliability Role of Frequency Response

October 30, 2012

RELIABILITY | ACCOUNTABILITY

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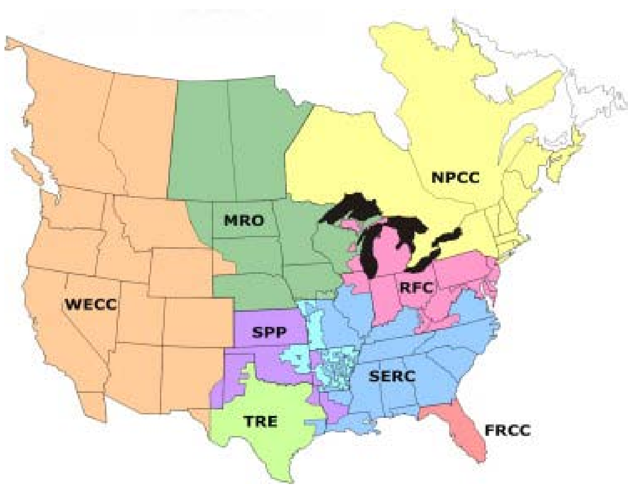
NERC's Mission

The North American Electric Reliability Corporation's (NERC) mission is to ensure the reliability of the North American bulk power system. NERC is the electric reliability organization (ERO) certified by the Federal Energy Regulatory Commission (FERC) to establish and enforce reliability standards for the bulk power system. NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast and summer and winter forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. ERO activities in Canada related to the reliability of the bulk power system are recognized and overseen by the appropriate governmental authorities in that country.[1]

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into eight Regional areas, as shown on the map and table below. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico.



Note: The highlighted area between SPP RE and SERC denotes overlapping Regional area boundaries. For example, some load-serving entities participate in one Region and their associated transmission owner/operators in another.

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

[1] As of June 18, 2007, FERC granted NERC the legal authority to enforce reliability standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro that makes reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. Nova Scotia and British Columbia also have frameworks in place for reliability standards to become mandatory and enforceable. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

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This report was approved by the Planning Committee October 4, 2012, via e-mail vote.

This report was accepted by the Operating Committee October 12, 2012, via e-mail vote.

Introduction

System planning and operations experts are anticipating significantly higher penetrations of renewable energy resources, most of which are electronically coupled to the grid. This presents some new and different technical challenges, particularly in the reduction of system inertia through the displacement of conventional generation resources during light load periods. Load management and other demand-side initiatives also continue to grow. Most importantly, a continued downward trend for frequency response over a number of years has raised concern that credible contingencies may result in frequency excursions that encroach on the first step of under-frequency load shedding (UFLS). Such large frequency excursions could also trigger undesirable reactions from frequency-sensitive smart grid loads and electronically coupled renewable resources. Taken together, it is clear that maintaining adequate frequency response for bulk power system reliability is becoming more important and complex. While the decline in frequency response has lessened in the last couple of years, it is important that the industry understands the growing complexities of frequency control and is ready with comprehensive strategies to stay ahead of any potential problems.

NERC has undertaken various activities over the past few years in an effort to understand the steady decline in frequency response, particularly in the Eastern Interconnection. While some significant insight has been gained and system-wide and technical improvements have been achieved in the Western Interconnection and ERCOT, a deeper and more dedicated effort is needed.

To comprehensively address the issues related to frequency response, NERC launched the Frequency Response Initiative in 2010. In addition to coordinating the myriad of efforts underway in standards development and performance analysis, the initiative includes performing in-depth analysis of interconnection-wide frequency response to achieve a better understanding of the factors influencing frequency performance across North America.

Basic objectives of the Frequency Response Initiative include:

- development of a clearer and more specific statement of frequency-related reliability factors, including better definitions for “ownership” of responsibility for frequency response;
- collection and provision of more granular frequency response data on and technical analyses of frequency-driven bulk power system events, including root cause analyses;
- metrics and benchmarks to improve frequency response performance tracking;
- increasing coordinated communication and outreach on the issue to include webinars and NERC alerts and to share lessons learned; and
- focused discussion on communication of emerging technology issues, including frequency-related effects caused by renewable energy integration, smart grid technology deployment, and new end-use technology.

In March 2011, the NERC Planning Committee tasked the Transmission Issues Subcommittee (TIS, now the System Analysis and Modeling Subcommittee (SAMS)) with determining what criteria should be used to decide the appropriate level of interconnection-wide frequency response needed for reliability. The TIS started with a body of work already underway by the Resources Subcommittee (RS) and the Frequency Working Group (FWG) of the Operating Committee, and the Frequency Responsive Reserve Standard Drafting Team (FRRSDT). The RS produced a position paper on frequency response outlining the method to translate a resource contingency criterion into an Interconnection Frequency Response Obligation (IFRO).

The report on IFRO was approved by the Planning Committee September 2011.[2] Since that time, numerous modifications and improvements have been made to the IFRO determination analysis and calculations. Those changes are reflected in the IFRO section of this report.

This report provides an overview of the work that has been done to date toward gaining understanding of frequency response. It is in support of NERC Standards Project 2007-12 Frequency Response, which is preparing a revised draft standard (BAL-003-1). That standard is intended to codify a Frequency Response Obligation and means for measuring the performance of the Balancing Authorities.

[2] http://www.nerc.com/docs/pc/tis/Agenda_Item_5.d_Draft_TIS_IFRO_Criteria%20Rev_Final.pdf

Executive Summary

Recommendations

1. NERC should embark immediately on the development of a NERC Frequency Response Resource Guideline to define the performance characteristics expected of those resources for supporting reliability. That guideline should address appropriate parameters for the following:

    - Existing conventional generator fleet – In order to retain or regain frequency response capabilities of the existing generator fleet, adopt:

        - deadbands of ±16.67 mHz,
        - droop settings of 3%–5% depending on turbine type,
        - continuous, proportional (non-step) implementation of the response,
        - appropriate operating modes to provide frequency response, and
        - appropriate outer-loop controls modifications to avoid primary frequency response withdrawal at a plant level.

    - Other frequency-responsive resources – Augment existing generation response with fast-acting, electronically coupled frequency responsive resources, particularly for the arresting and rebound periods of a frequency event:

        - contractual high-speed demand-side response,
        - wind and photo-voltaic – particularly for over-frequency response,
        - storage – automatic high-speed energy retrieval and injection, and
        - variable-speed drives – non-critical, short-time load reduction.

2. Instead of using a fixed margin, the calculation of the Interconnection Frequency Response Obligations should use statistical analysis to determine the necessary margin.

3. The starting frequency for the calculation of IFROs should be the frequency 5% of the lower tail of samples from the statistical analysis, representing a 95% confidence that frequencies will be at or above that value at the start of any frequency event, as shown in table A.

Table A: Interconnection Frequency Variation Analysis (Hz)				
Value	Eastern	Western	ERCOT	Québec
Starting Frequency (F_{Start})	59.974	59.976	59.963	59.972

4. The recommended UFLS first-step limitations for IFRO calculations are listed in table B.

Table B: Low-frequency Limits (Hz)	
Interconnection	Highest UFLS Trip Frequency
Eastern	59.5[3]
Western	59.5
ERCOT	59.3
Québec	58.5

5. The allowable frequency deviation (starting frequency minus the highest UFLS step) should be reduced to account for differences between the 1-second and sub-second data for Point C (frequency nadir) by a statistically determined adjustment as listed in table C. Sub-second measurements will more accurately detect Point C.

Table C: Analysis of 1-Second and Sub-Second Data for Point C (CC_{ADJ})				
Interconnection	Number of Samples	Mean	Standard Deviation	CC_{ADJ} (95% Quantile)
Eastern	30	0.0006	0.0038	0.0068
Western	17	0.0012	0.0019	0.0044
ERCOT	58	0.0021	0.0061	0.0121
Québec	0	N/A	N/A	N/A

6. The allowable change in frequency from the IFRO Starting Frequency should be adjusted by a statistically determined value to account for the differences between the Value B and the Point C for historical frequency events as listed in table D.

Table D: Analysis of B Value and Point C (CB_R)				
Interconnection	Number of Samples	Mean	Standard Deviation	CB_R (95% Quantile)
Eastern	41	0.964	0.0149	1.0 (0.989)[4]
Western	30	1.570	0.0326	1.625
ERCOT	88	1.322	0.0333	1.377
Québec[5]	N/A	1		1.550

[3] The highest UFLS setpoint in the Eastern Interconnection is 59.7 Hz in FRCC, based on internal stability concerns. The FRCC concluded that the IFRO starting frequency of the prevalent 59.5 Hz for the Eastern Interconnection is acceptable in that it imposes no greater risk of UFLS operation in FRCC for an external resource loss event than for an internal FRCC event.

[4] CB_R value limited to 1.0 because values lower than that indicate the Value B is lower than Point C and does not need to be adjusted. The calculated value is 0.989.

7. An adjustment should be made to the maximum allowable delta frequency to compensate for the predominant withdrawal of primary frequency response exhibited in an interconnection until such withdrawal is no longer exhibited in that interconnection.

8. The determination of the maximum delta frequencies should be calculated in accordance with the methods embodied in Table E – Determination of Maximum Delta Frequencies.

Table E: Determination of Maximum Delta Frequencies

	Eastern	Western	ERCOT	Québec	Units
Starting Frequency	59.974	59.976	59.963	59.972	Hz
Minimum Frequency Limit	59.500	59.500	59.300	58.500	Hz
Base Delta Frequency	0.474	0.476	0.663	1.472	Hz
CC_{ADJ}[6]	0.007	0.004	0.012	N/A	Hz
Delta Frequency (DF_{CC})	0.467	0.472	0.651	1.472	Hz
CB_R[7]	1.000[8]	1.625	1.377	1.550[9]	Hz
Delta Frequency (DF_{CBR})[10]	0.467	0.291	0.473	0.949	Hz
BC'_{ADJ}[11]	.018	N/A	N/A	N/A	Hz
Max. Delta Frequency	0.449	0.291	0.473	0.949	Hz

5 Based on Québec UFLS design between their 58.5 Hz UFLS with 300 millisecond operating time (responsive to Point C) and 59.0 Hz UFLS step with a 20-second delay (responsive to Value B or beyond) with a 0.05 Hz confidence interval. See the Adjustment for Differences between Value B and Point C section of this report for further details.

6 Adjustment for the differences between 1-second and sub-second Point C observations for frequency events.

7 Adjustment for the differences between Point C and Value B.

8 CB_R value for the Eastern Interconnection limited to 1.0 because values lower than that indicate the Value B is lower than Point C and does not need to be adjusted. The calculated value is 0.989.

9 Based on Québec UFLS design between their 58.5 Hz UFLS with 300 ms operating time (responsive to Point C)and 59.0 Hz UFLS step with a 20-second delay (responsive to Value B or beyond).

10 DF_{CC}/CB_R

11 Adjustment for the event nadir being below the Value B (Eastern Interconnection only) due to primary frequency response withdrawal.

9. The Interconnection Frequency Response Obligations should be calculated as shown in Table F: Recommended IFROs.

Table F: Recommended IFROs

	Eastern	Western	ERCOT	Québec	Units
Starting Frequency	59.974	59.976	59.963	59.972	Hz
Max. Delta Frequency	0.449	0.291	0.473	0.949	Hz
Resource Contingency Protection Criteria	4,500	2,740	2,750	1,700	MW
Credit for LR	–	300	1,400	–	MW
IFRO[12]	-1,002	-840	-286	-179	MW/0.1Hz
Absolute Value of IFRO	1,002	840	286	179	MW/0.1Hz
% of Current Interconnection Performance[13]	40.6%	71.2%	48.7%	23.9%	
% of Interconnection Load[14]	0.17%	0.56%	0.45%	0.50%	

10. NERC and the Western Interconnection should analyze the FRO allocation implications of the Pacific Northwest RAS generation tripping of 3,200 MW.

11. Trends in frequency response sustainability should be measured and tracked by observing frequency between T+45 seconds and T+180 seconds. A pair of indices for gauging sustainability should be calculated comparing that value to both the Point C and Value B.

12. Frequency response performance by Balancing Authorities should not be judged for compliance on a per-event basis.

13. Linear regression is the method that should be used for calculating Balancing Authority Frequency Response Measure (FRM) for compliance with Standard BAL-003-1 – Frequency Response.

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[12] IFRO =

[13] Current Interconnection Frequency Response Performance: EI = -2,467 MW / 0.1Hz, WI = -1,179 MW / 0.1Hz, TI = -586 MW / 0.1Hz, and QI = -750 MW/0.1 Hz.

[14] Interconnection projected Total Internal Demands from the 2010 NERC Long-Term Reliability Assessment: EI = 604,245 MW, WI = 148,895 MW, TI = 63,810 MW, and QI winter load = 36,000 MW.

14. NERC and the Frequency Working Group should annually review the process for detection of frequency events and the method for calculating the A and B Values and Point C. The associated interconnection frequency event database, methods for calculating interconnection metrics on risks to reliability, the associated probabilities, and the calculation of the IFROs using updated data should also undergo review in an effort to improve the process. Throughout this process, NERC should strive to improve the quality and consistency of the data measurements.

15. NERC should address improving the level of understanding of the role of turbine governors through seminars and webinars, with educational materials available to the Generator Owners and Generator Operators on an ongoing basis.

16. When the Eastern Interconnection Reliability Assessment Group Multiregional Modeling Working Group (ERAG MMWG) completes its review of turbine governor modeling, a new light-load case should be developed, and the resource loss criterion for the Eastern Interconnection's IFRO should be re-simulated.

17. Eastern Interconnection inter-area oscillatory behavior should be further investigated by NERC, including the testing of large resource loss analysis for IFRO validation.

Findings

1. Analysis of data submitted by the Balancing Authorities during the field trial indicates that a single-event-based compliance measure is unsuitable for compliance evaluation when based on data that has the large degree of variability demonstrated by the field trial.

2. Analysis of data submitted by the Balancing Authorities during the field trial confirms that the sample size selected (a minimum of 20–25 frequency events) is sufficient to stabilize the result and alleviate the perceived problem associated with outliers in the measurement of Balancing Authority frequency response performance.

3. There is a strong positive correlation between Eastern Interconnection load and frequency response for the 2009–2011 events. On average, when interconnection load changes by 1,000 MW, frequency response changes by 3.5 MW/0.1Hz.

4. Pre-disturbance frequency (Value A) is a statistically significant contributor to the variability of frequency response for the Eastern Interconnection. The expected (mean of the sample) frequency response for events where Value A is greater than 60 Hz is 2,188 MW/0.1 Hz versus 2,513 MW/0.1 Hz for events where Value A is less than or equal to 60 Hz based on data from 2009 through April 2012.

5. There is a statistically significant seasonal (summer/not summer) correlation to the variability of frequency response for the Eastern Interconnection. The expected frequency response for summer (June–August) frequency events is 2,598 MW/0.1 Hz versus 2,271 MW/0.1 Hz for non-summer events based on data from 2009 through April 2012.

6. The difference in average frequency response between on-peak events and off-peak events is not statistically significant for the Eastern Interconnection and could occur by chance.

Frequency Response Overview

To understand the role frequency response plays in system reliability, it is important to understand the different components of frequency control and the individual components of Primary Frequency Control (also known as frequency response). It is also important to understand how those individual components relate to each other.

Frequency Control

Frequency control can be divided into four overlapping windows of time:

Primary Frequency Control (frequency response) – Actions provided by the interconnection to arrest and stabilize frequency in response to frequency deviations. Primary Control comes from automatic generator governor response, load response (typically from motors), and other devices that provide an immediate response based on local (device-level) control systems.

Secondary Frequency Control – Actions provided by an individual Balancing Authority or its Reserve Sharing Group to correct the resource-load unbalance that created the original frequency deviation, which will restore both Scheduled Frequency and Primary frequency response. Secondary Control comes from either manual or automated dispatch from a centralized control system.

Tertiary Frequency Control – Actions provided by Balancing Authorities on a balanced basis that are coordinated so there is a net-zero effect on area control error (ACE). Examples of Tertiary Control include dispatching generation to serve native load, economic dispatch, dispatching generation to affect interchange, and re-dispatching generation. Tertiary Control actions are intended to replace Secondary Control Response by reconfiguring reserves.

Time Control – This includes small offsets to scheduled frequency to keep long-term average frequency at 60 Hz.

Primary Frequency Control – Primary Frequency Response

Primary Frequency Control, also known generally as primary frequency response, is the first stage of frequency control and is the response of resources and load to arrest local changes in frequency. Primary frequency response is automatic, is not driven by any centralized system, and begins within seconds after the frequency changes, rather than minutes. Different resources, loads, and systems provide primary frequency response with different response times, based on current system conditions such as total resource/load mix and characteristics.

The NERC Glossary of Terms defines Frequency Response[15] in two parts:

- **Equipment** – The ability of a system or elements of the system to react or respond to a change in system frequency.
- **System** – The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 hertz (MW/0.1 Hz).

Because the loss of a large generator is much more likely than a sudden loss of an equivalent amount of load, frequency response is typically discussed in the context of a loss of generation.

NOTE: For purposes of this report, the term "frequency response" is considered to be the overall response measured between T+20 and T+52 seconds, as used in the BAL-003-1 draft standard.

Frequency Response Illustration

Many components are included within the defined frequency response. The following simplified example graphically illustrates those components of frequency response and how they react to changes in system frequency. The example is presented as an energy balance problem for the interconnection. It is not intended to be a treatise on governors or other turbine-generator controls or the internal machine dynamics associated with those control actions. For additional information on those topics, see the References on Rotating Machines section in Appendix L.

The example is based on an assumed disturbance event due to the sudden loss of 1,000 MW of generation. Although a large event is used to illustrate the response components, even small events can result in similar reactions or responses. The magnitude of the event only affects the shape of the curves on the graph; it does not obviate the need for frequency response.

The loss of generation is illustrated by the black power deficit line using the MW scale on the left. The interconnection frequency is illustrated in red, using the hertz (Hz) scale on the right. The interconnection frequency is assumed to be 60 Hz when the disturbance occurs.

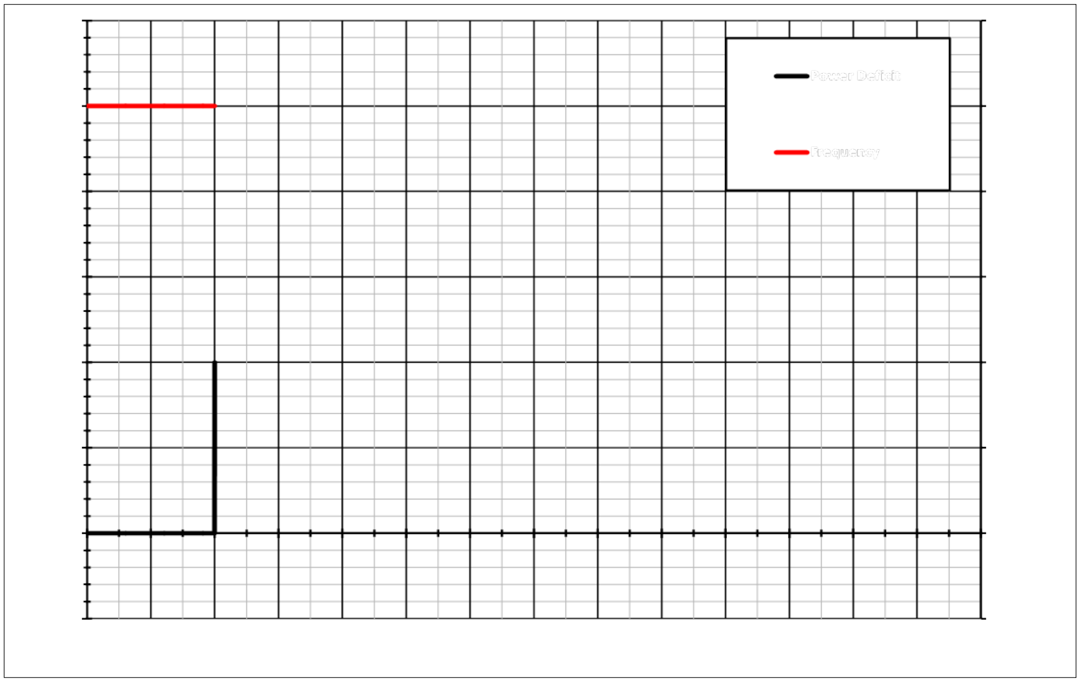
Figure 1 shows the tripping of a 1,000 MW generator. Even though the generation has tripped and power injected by the generator has been removed from the interconnection, the loads across the system continue to use the same amount of power. The Law of Conservation of Energy[16] requires that the 1,000 MW must be supplied to the interconnection if the energy balance is to be conserved. That 1,000 MW of balancing power is provided by extracting it from the kinetic energy stored as inertial energy in the rotating mass of all of the synchronized turbine-generators and motors on the interconnection. It is produced by the slowing of the spinning inertial mass of rotating equipment on the interconnection that both releases the stored kinetic energy and reduces the frequency of the interconnection. The extracted energy

[15] Capitalized as referenced in the NERC Glossary of Terms; lowercased otherwise.

[16] The "Law of Conservation of Energy" is applied here in the form of power. If energy must be conserved, then power—which is the first derivative of energy with respect to time—must also be conserved.

supplies the "balancing inertia"[17] power required to maintain the power and energy balance on the interconnection.

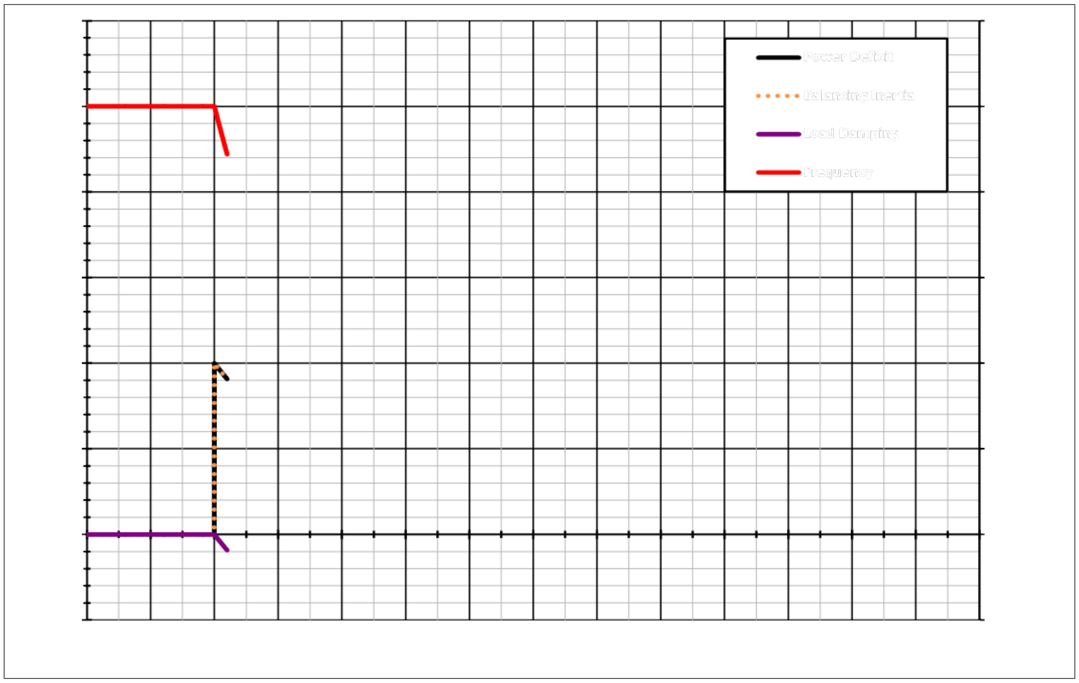
Figure 1: Loss of a 1,000 MW Generator



As this balancing power from inertia is used, the speed of the rotating equipment on the interconnection declines, resulting in a reduction of the interconnection frequency. Synchronously operated motors contribute to load damping; adjustable or variable speed drive motors are effectively decoupled from the interconnection frequency through their electronic controls, and they do not contribute to load damping. In general, any load that does not change with interconnection frequency (such as resistive loads) will not contribute to load damping or frequency response. The balancing inertia is illustrated in figure 2 by the orange dots, which represent the balancing inertia power that exactly overlays and offsets the power deficit. At this point in the example, no other energy injection has occurred through any governor control action.

[17] The term "balancing inertia" is coined here from the terms "inertial frequency response" and "balancing energy." Inertial frequency response is a common term used to describe the power supplied for this portion of the frequency response, and balancing energy is a term used to describe the market energy supposedly purchased to restore energy balance.

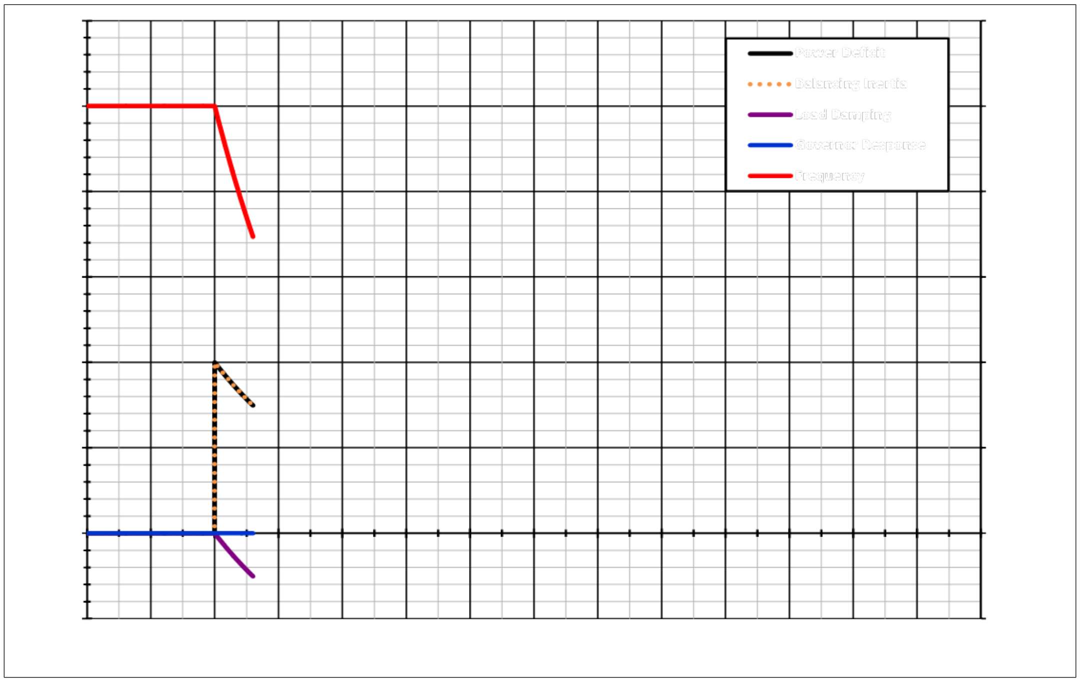
Figure 2: Inertial Energy Extracted from Rotating Mass of Generation and Synchronous Motor Load



As the rotating machines slow down (reflected as a decline of frequency), the generator governors, which are the controls that “govern” the speed of the generator turbines, sense this as a change in turbine speed. In this example, the change in frequency will be used to reflect this control parameter. Governor action then takes physical action, such as injecting more gas into a gas turbine, opening steam valves wider on a steam unit (also injecting more fuel into the boiler), or opening the control gates wider on a hydraulic turbine. This control action results in more combusted gases, steam, or water to impart more mechanical energy to the shaft of the turbine to increase its speed. The turbine shaft is coupled to the generator, where it is converted into additional electric energy. The process of the turbine slowing, the detection of change in speed, and the injection of additional mechanical energy is not instantaneous.

Until the additional mechanical energy can be injected, the frequency continues to decline, due to the ongoing extraction of balancing power from the inertial energy of the rotating turbine-generators and synchronous motors on the interconnection. As frequency continues to decline, the reduction in load also continues as the effect of load damping continues to reduce the load.

Figure 3: Time Delay of Governor Response

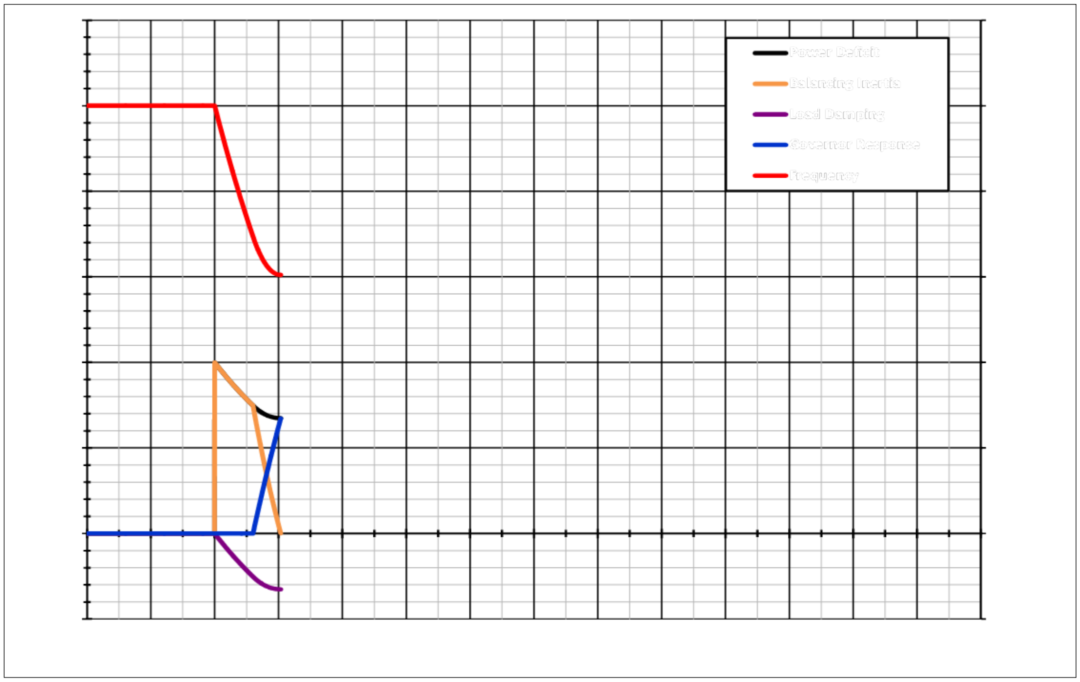


During the initial seconds of the disturbance event, the primary frequency response from the turbine governors has not yet influenced the frequency decline. For this example, primary frequency response from governors that injects additional energy into the system is reflected by the blue line (in MW) on figure 3.

After a short time delay, the governor response begins to increase rapidly in response to the initial decline in frequency, as illustrated in figure 4. In order to arrest the frequency decline, the governor response must offset the power deficit and replace the balancing power that had extracted inertial energy from the rotating machines of the interconnection. At this point in time, the balancing power from inertia is reduced to zero as it is replaced by the governor response. That replacement is shown as the crossing of the orange and blue lines in figure 4. The point at which the frequency decline is arrested is called the nadir, or Point C, and frequency response calculated to that point is “arrested frequency response.”

If the time delay associated with the delivery of governor response is reduced, the amount of balancing power from inertia required to limit the change in frequency for the disturbance event can also be reduced. This supports the conclusion that balancing power from inertia is required to manage the time delays associated with the delivery of primary frequency response. Not only is the rapid delivery of primary frequency response important, but so is the shortening of the time delay associated with its delivery.

Figure 4: Governor Response Replaces Balancing Power from Inertia and Arrests Frequency Decline



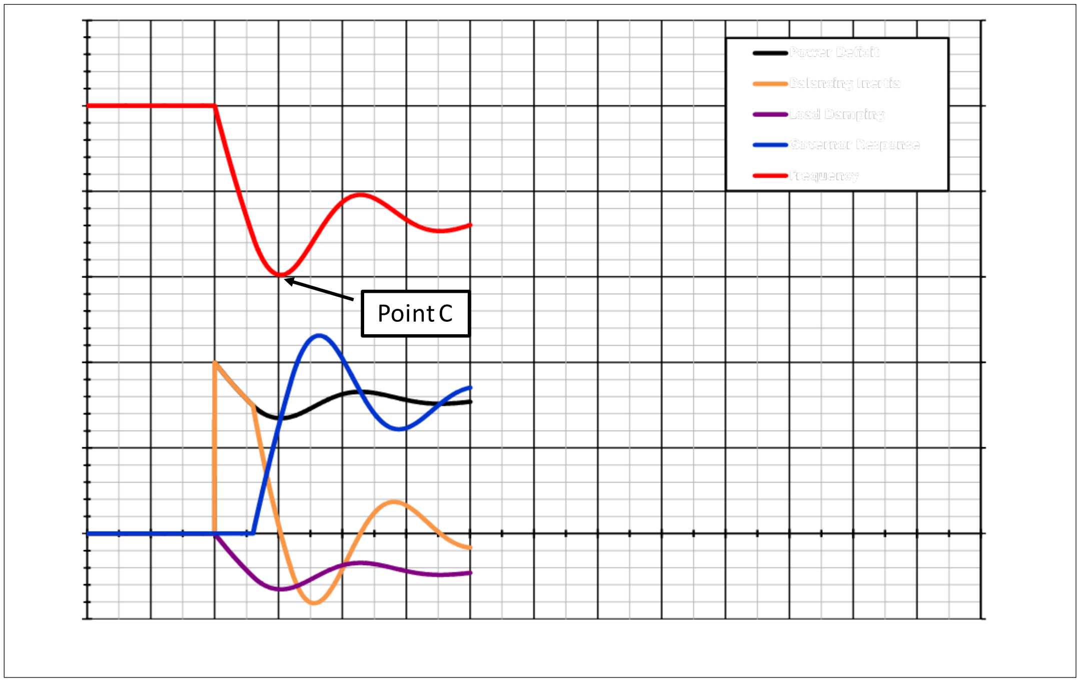
The above components are related to the length of time before the initial delivery of primary frequency response from governors begins and how much of the response is delivered before the frequency change is arrested.

From a system standpoint during this time delay, the amount of inertia on the interconnection, which determines the amount of energy available to be extracted from rotating machines, determines the slope of the frequency decline: the less inertia there is, the steeper the slope. This is important in the relationship between the balancing power from inertia and the time delay associated with the governor response. For a given time delay in primary frequency response from governors, the steeper the slope, the lower frequency will dip before it is arrested. Conversely, for a given balancing power from inertia and slope of frequency decline, the faster governor response can be provided, the sooner the frequency decline is arrested, making the nadir less severe.

Therefore, as traditional rotating generators are replaced by electronically coupled resources, such as wind turbines and solar voltaic resources (which provide less overall system inertia), the speed of delivery of governor response should increase, or other methods should be provided that support fast-acting energy injection to minimize the depth of frequency excursions.

The arrested frequency is normally the minimum (maximum for load loss events) frequency that will be experienced during a disturbance event. This minimum frequency is the frequency that is of concern from a reliability perspective. The goal is to arrest the frequency decline so frequency remains above the under-frequency load shedding (UFLS) relays with the highest settings so that load is not tripped. Frequency response delivered after frequency is arrested at this minimum provides less reliability value than frequency response delivered before Point C, but greater value than secondary frequency control power and energy that is delivered minutes later.

Figure 5: Post-Disturbance Transient Period (0 to 20 seconds)



Once the frequency decline is arrested, the governors continue to respond because of the time delay associated with the governor action. This results in the frequency partially recovering from the minimum arrested value and results in some oscillating transient that follows the minimum frequency (arrested frequency) until power flows and frequency settle during the transient period, which typically ends around 20 seconds after start of the disturbance event. This post-disturbance transient period is shown in figure 5.

The total disturbance event is illustrated in figure 6. Frequency and power contributions stabilize at the end of the transient period. Frequency response calculated from data measured during this settled period is called the "settled frequency response." The settled frequency response is the measure used as an estimator for determining the Frequency Bias[18] setting used in the automated generator control (AGC) systems of the energy management systems (EMS) in energy control centers.

[18] As defined in the NERC Glossary: "A value, usually expressed in megawatts per 0.1 hertz (MW/0.1 Hz), associated with a Balancing Authority Area that approximates the Balancing Authority Area's response to Interconnection frequency error."

Figure 6: Disturbance Event Frequency Excursion

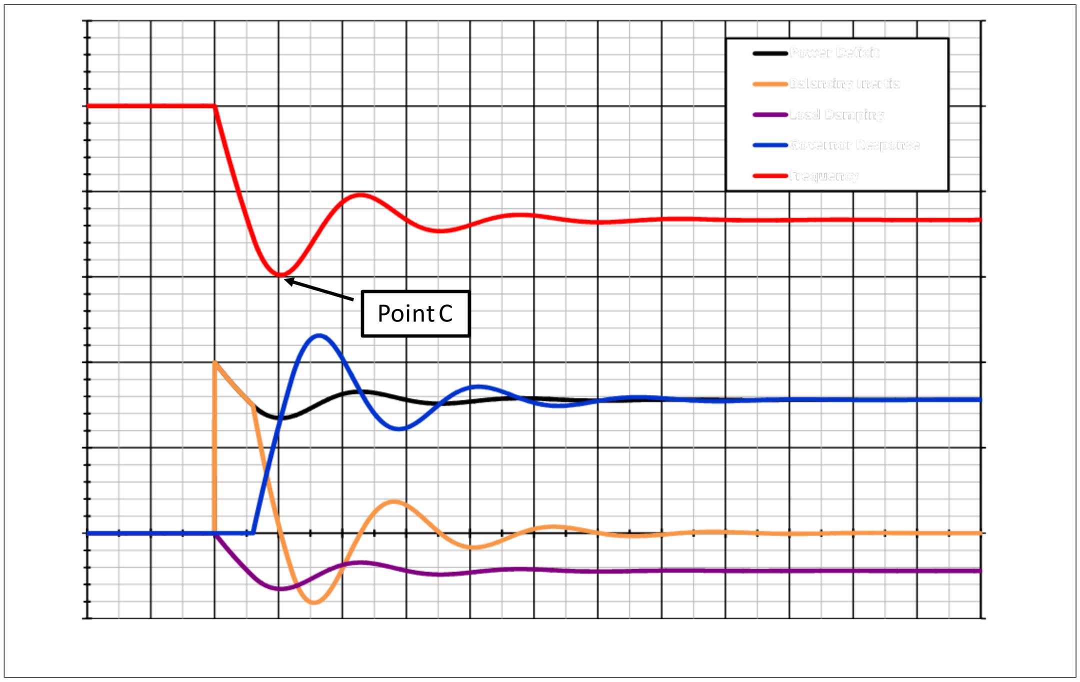


Figure 7: Averaging Periods used for Measuring Frequency Response

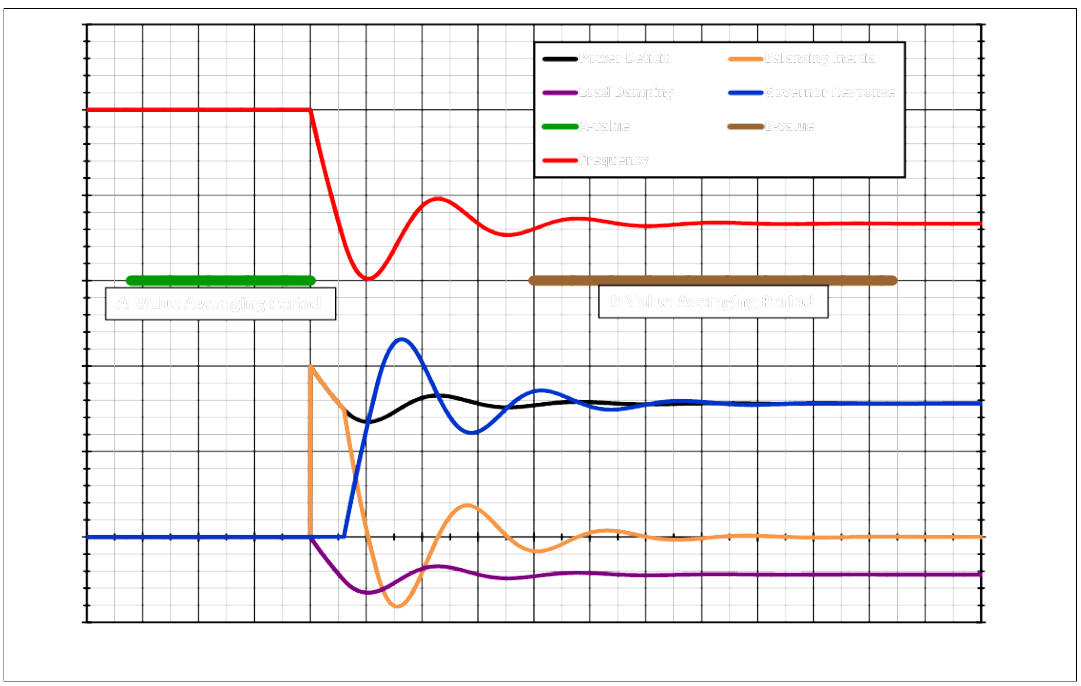


Figure 7 shows the averaging periods used to calculate[19] the pre-disturbance Value A frequency averaging period (T-16 through T+0 seconds) and the post-disturbance Value B frequency averaging period (T+20 through T+52 seconds) used to calculate the settled frequency response. The length of those periods is based on the length of the system control and data acquisition (SCADA) scan rates of the energy management systems (EMS) of the Balancing Authorities.

The calculation of the Value A and Value B frequencies began with the assumption that a 6-second scan rate was the source of the data. Once the averaging periods for a 6-second SCADA scan rate were selected, the averaging periods for the other scan rates were selected to provide as much consistency as possible between Balancing Authorities with different scan rates.

The Value A frequency was initially defined as the average of the two scans immediately prior to the frequency event. All other averaging periods were then selected to be as consistent as possible with this 12-second average scan from the 6-second scan rate method. In addition, the "actual net interchange immediately before Disturbance" was then defined as the average of the same period and same scans as used for Value A averaging.

The Value B frequency was then selected to be an average as long as the average of 6-second scan data as possible, that would not begin until most of the hydro governor response had been delivered, and would end before significant Automatic Generation Control (AGC) recovery response had been initiated as indicated by a consistent frequency restoration slope. The "actual net interchange immediately after Disturbance" was then similarly defined as the average of the same period and same scans as used for the Value B.

Balancing Authority Frequency Response

Disturbances can cause the frequency to either increase from loss of load or decrease from loss of generation; frequency response characteristics of Balancing Authorities should be evaluated for both types of events.

Accurate measurement of frequency response for an interconnection or for individual Balancing Authorities is difficult unless the frequency deviation resulting from a system disturbance is significant. Therefore, it is better to analyze response only when significant frequency deviations occur.

Frequency response considers the following elements of an interconnected transmission system:

1. **Frequency Response Characteristic (FRC)** – For any change in generation/load balance in the interconnection, a frequency change occurs. Each Balancing Authority in the interconnection will respond to this frequency change through:
   - a load change that is proportional to the frequency change due to the load's FRC, and

[19] As proposed in Standard BAL-003-1 – Frequency Response.

- a generation change that is inverse to the frequency change due to turbine governor action. The net effect of these two actions is the Balancing Authority's response to the frequency change; that is, its FRC. The combined response of all Balancing Authorities in the interconnection will cause the interconnection frequency to settle at some value different from the pre-disturbance value. It will not return frequency to the pre-disturbance value because of the turbine governor droop characteristic. Frequency will remain different until the Balancing Authority with the generation/load imbalance (referred to as the "Contingent Balancing Authority") corrects that imbalance, thus returning the interconnection frequency to its pre-disturbance value.

2. **Response to Internal and External Generation/Load Imbalances** – Most of a Balancing Authority's frequency response will be reflected in a change in its actual net interchange. By monitoring the frequency error (the difference between actual and scheduled frequency) and the difference between actual and scheduled interchange, using its response to frequency deviation, a Balancing Authority's automatic generation control (AGC) can determine whether the imbalance in load and generation is internal or external to its system. If internal, the Balancing Authority's AGC should correct the imbalance. If external, the Balancing Authority's AGC should allow its generator governors to continue responding (preserved by its frequency bias contribution in its ACE equation) until the contingent Balancing Authority corrects its imbalance, which should return frequency to its pre-disturbance value.

3. **Frequency Bias versus Frequency Response Characteristic (FRC)** – The Balancing Authority should set its bias setting in its AGC ACE equation to match its FRC. In doing so, the Balancing Authority's bias contribution term would exactly offset the tie line flow error (Ni_A – Ni_S) of the ACE that results from governor action following a frequency deviation on the interconnection. The following sections discuss the effects of bias settings on control action and explain the importance of setting the bias equal to the Balancing Authority's FRC. The discussion explains the control action on all Balancing Authorities external to the contingent Balancing Authority (the Balancing Authority that experienced the sudden generation/load imbalance) and on the contingent Balancing Authority itself.

   While this discussion deals with loss of generation, it applies equally to loss of load, or any sudden contingency resulting in a generation/load mismatch. Each Balancing Authority's frequency response will vary with each disturbance because generation and load characteristics change continuously. This discussion also assumes that the frequency error from 60 Hz was zero (all ACE values were zero) just prior to the sudden generation/load imbalance.

4. **Effects of a Disturbance on all Balancing Authorities External to the Contingent Balancing Authority** – When a loss of generation occurs, an interconnection frequency error will occur as rotating kinetic energy from the generators of the interconnection is expended, slowing the generators throughout the interconnection. All Balancing Authorities' generator governors will respond to the frequency error and increase the

output of their generators (increase speed) accordingly. This will cause a change in the Balancing Authorities' actual net interchange. In other words, the Actual Net Interchange (Ni_A) will be greater than the Scheduled Net Interchange (Ni_S) for all but the contingent Balancing Authority, and the result is a positive flow out of the non-contingent Balancing Authorities. The resulting tie flow error (Ni_A – Ni_S) will be counted as Inadvertent Interchange.

If the Balancing Authorities were using only tie line flow error (i.e., flat tie control ignoring the frequency error), this non-zero ACE would cause their AGC to reduce generation until Ni_A was equal to Ni_S, returning their ACE to zero. However, doing this would not help arrest interconnection frequency decline, because the Balancing Authorities would not be helping to temporarily replace some of the generation deficiency in the interconnection. With the tie line bias method, the Balancing Authorities' AGC should allow their governors to continue responding to the frequency deviation until the contingent Balancing Authority replaces the generation it has lost.

In order for the AGC to allow governor action to continue to support frequency, a frequency bias contribution term is added to the ACE equation to counteract the tie flow error. This bias contribution term is equal in magnitude and opposite in direction to the governor action and should ideally be equal to each Balancing Authority's frequency response characteristic measured in MW/0.1 Hz. Then, when multiplied by the frequency error, the bias should exactly counteract the tie flow error portion of the ACE calculation, allowing the continued support of the generator governor action to support system frequency.

In other words, $BiasContributionTerm = 10B(f_A - f_S)$. ACE will be zero, and AGC will not read just generation.

The ACE equation is then:

$$ACE = (Ni_A - Ni_S) - 10B(f_A - f_S) - I_{ME}$$

Where:

- The factor 10 converts the bias setting (B) from MW/0.1 Hz to MW/Hz.
- I_{ME} is meter error correction estimate; this term should normally be very small or zero.

NOTE: Although frequency response and bias are often discussed as positive values (such as "our bias is 50 MW/0.1 Hz"), frequency response and bias are actually negative values.

If the bias setting is greater than the Balancing Authority's actual frequency response characteristic, then its AGC will increase generation beyond the primary frequency response from governors, which further helps arrest the frequency decline, but increases Inadvertent Interchange. Likewise, if the bias contribution term is less than the actual FRC, its AGC will reduce generation, reducing the Balancing Authority's contribution to arresting the frequency change. In both cases, the resultant control action is unwanted.

5. **Effects of a Disturbance on the Contingent Balancing Authority** – In the contingent Balancing Authority where the generation deficiency occurred, most of the replacement power comes from the interconnection over its tie lines from the frequency response contributions of the other Balancing Authorities in the interconnection. A small portion will be made up internally from the contingent Balancing Authority's own governor response. In this case, the difference between Ni_A and Ni_S for the contingent Balancing Authority is much greater than its frequency bias component. Its ACE will be negative (if the loss is generation), and its AGC will begin to increase generation.

   - Ni_A – drops by the total generation lost less the contingent Balancing Authority's own primary frequency response from governors
   - Ni_S – does not change

   The contingent Balancing Authority must take appropriate steps to reduce its ACE to zero or pre-disturbance ACE if ACE is negative within 15 minutes of the contingency. (Reference: formerly Operating Criterion II.A.) The energy supplied from the interconnection is posted to the contingent Balancing Authority's inadvertent balance.

6. **Effects of a Disturbance on the Contingent Balancing Authority with a Jointly Owned Unit** – In the contingent Balancing Authority where the generation deficiency occurred on a jointly owned unit (with dynamically scheduled shares being exported), the effect on the tie line component (Ni_A – Ni_S) of their ACE equation is more complicated. The Ni_A drops by the total amount of the generator lost, while the Ni_S is reduced only by the dynamic reduction in the shares being exported.

   - Ni_A – drops by the total generation lost less the contingent Balancing Authority's own primary frequency response from governors
   - Ni_S – decreases by the reduction in dynamic shares being exported

   The net effect is that the tie line bias component only reflects the contingent Balancing Authority's share of the lost generation. Most of the replacement power comes from the interconnection over its tie lines from the frequency bias contributions of the other Balancing Authorities in the interconnection.

7. **Effects of a Disturbance on the Non-contingent Balancing Authority with a Jointly Owned Unit** – In the non-contingent Balancing Authority where the generation deficiency occurred on a jointly-owned unit in another Balancing Authority (with dynamically scheduled shares being exported), the effect on the tie line component (Ni_A – Ni_S) of their ACE equation is also complicated. The Ni_A increases by the Balancing Authority's own primary frequency response from governors, while the Ni_S is reduced only by the dynamic reduction in the shares being imported.

- Ni_A – increases by the Balancing Authority's own primary frequency response from governors
- Ni_S – decreases by withdrawn dynamic shares of the jointly-owned unit

The net effect is that the tie line bias component only reflects the contingent Balancing Authority's share of the lost generation. Most of the replacement power comes from the interconnection over its tie lines from the frequency bias contributions of the other Balancing Authorities in the interconnection.

Historical Frequency Response Analysis

History of Frequency Response and its Decline

Interconnection frequency response has been a subject of industry interest and attention since the first two electric systems became interconnected and the concept of frequency bias was adopted. In 1942, the first test to determine the system's load/frequency characteristic was conducted for use in setting bias control. As interconnected systems grew larger and the characteristics of load and generation changed, it became apparent that guidelines were needed regarding frequency response to avoid one system imposing undue frequency regulation burdens on its interconnected neighbors. During the 1970s and 1980s, NERC's Performance Subcommittee (now the Resources Subcommittee of the Operating Committee), which is charged with monitoring the control performance of the interconnections, observed that generators' governor responses to frequency deviations had been decreasing, especially in the Eastern Interconnection. The result was quite noticeable during large generation losses where the frequency deviation was not arrested as quickly as it once was. The industry did not initially recognize that power systems operations could significantly influence primary frequency response.[20]

In 1991, NERC's Performance Subcommittee approached the Electric Power Research Institute (EPRI) with a request to fund and manage a study of the apparent decline in governor response in the interconnections. EPRI agreed and in turn contracted with EPIC Engineering to perform this study. The conclusions were captured in a joint EPRI/NERC report, "Impacts of Governor Response Changes on the Security of North American Interconnections."[21] These studies indicated that the frequency response of the interconnections was declining at rates greater than would be expected with the growth of demand and generating capacity.[22] Although frequency response was declining, the opinion of experts at the time was that the decline had not reached a point at which reliability was being compromised.

The NERC Resources Subcommittee proposed a frequency response standard for comment in 2001. In response to these comments, the Frequency Task Force of the NERC Resources Subcommittee published a Frequency Response Standard white paper[23] intended to create an understanding of the need for a frequency response standard and the technical and economic drivers motivating its development. The paper documented and discussed the decline observed in frequency response in the Eastern and Western Interconnections.

[20] *See* Illian, H.F. *Frequency Control Performance Measurement and Requirements*, LBNL-4145E (December 2010).

[21] EPRI Report TR-101080, *Impacts of Governor Response Changes on the Security of North American Interconnections*, October 1992.

[22] *See* EPRI Report TR-101080, *Impacts of Governor Response Changes on the Security of North American Interconnections*, October 1992 ("An analysis of the 14 Frequency Response Characteristics Surveys conducted by NERC over the 1971 to 1993 period showed that the Frequency Response in percent MW/O. 1Hz has deteriorated. This value in 1971 was between 2.25 and 3.25% (depending on the area) and by 1993 had dropped to 0.75 and 1.25 %.").

[23] Available here: http://www.nerc.com/docs/oc/rs/Frequency_Response_White_Paper.pdf ("Frequency Response Standard Whitepaper").

Projections of Frequency Response Decline

In August 2011, the Transmission Issues Subcommittee[24] of the NERC Planning Committee completed an analysis titled "Interconnection Criteria for Frequency Response Requirements – Determination of Interconnection Frequency Response Obligations."[25] The analysis included comparisons of various Resource Contingency Protection Criteria for loss of resources, including largest potential loss-of-resource event (N-2), the largest total generating plant with common voltage switchyard, and the largest loss of generation in the interconnection in the last 10 years. Also examined in that analysis were the various other factors that must be considered in an IFRO determination: the highest under-frequency load shedding (UFLS) program setpoint within each interconnection, special consideration of demand-side frequency responsive programs in ERCOT, and a reliability margin to account for the variability of frequency due to items such as time error correction (TEC), variability of load, variability of interchange, variability of frequency over the course of a normal day, and other uncertainties. The proposed margin was analyzed using a probabilistic approach based on 1-minute frequency performance data for each interconnection. The Transmission Issues Subcommittee recommended the following IFROs for the four interconnections: Eastern: -1,875 MW/0.1 Hz; Western: -637 MW/0.1 Hz; Texas: -327 MW/0.1 Hz; and Québec: -113 MW/0.1 Hz. The Transmission Issues Subcommittee IFRO report was approved by the NERC Planning Committee in September 2011 and forwarded to the Standard Drafting Team for their consideration.

A similar report had been prepared by the Resources Subcommittee of the NERC Operating Committee in January 2011 titled "NERC Resources Subcommittee Position Paper on Frequency Response."[26] That report used similar Resource Contingency Protection Criteria but used the prevalent 59.5 Hz highest UFLS setpoint for the Eastern Interconnection and a lower 59.3 Hz UFLS setpoint for ERCOT. The Resources Subcommittee analysis also used a 25% reliability margin for all four interconnections. The Resources Subcommittee recommended the following IFROs for the four interconnections: Eastern: -1,406MW/0.1 Hz; Western: -685 MW/0.1 Hz; Texas: -286 MW/0.1 Hz; and Québec: -141 MW/0.1 Hz. The Resources Subcommittee position paper was approved by the Operating Committee in March 2011 and was considered by the Frequency Response Standard Drafting Team. NERC has been tracking the decline of frequency response in the Eastern Interconnection for several years.

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[24] The Transmission Issues Subcommittee is now the System Analysis and Modeling Subcommittee (SAMS).

[25] Available here: http://www.nerc.com/docs/pc/tis/Agenda_Item_5.d_Draft_TIS_IFRO_Criteria%20Rev_Final.pdf.

[26] Available here: http://www.nerc.com/docs/oc/rs/NERC%20RS%20Position%20Paper%20on%20Frequency%20Response%20Final%20(May%2027%202011).pdf.

Figure 8: Eastern Interconnection Mean Primary Frequency Response[27] (March 30, 2012)

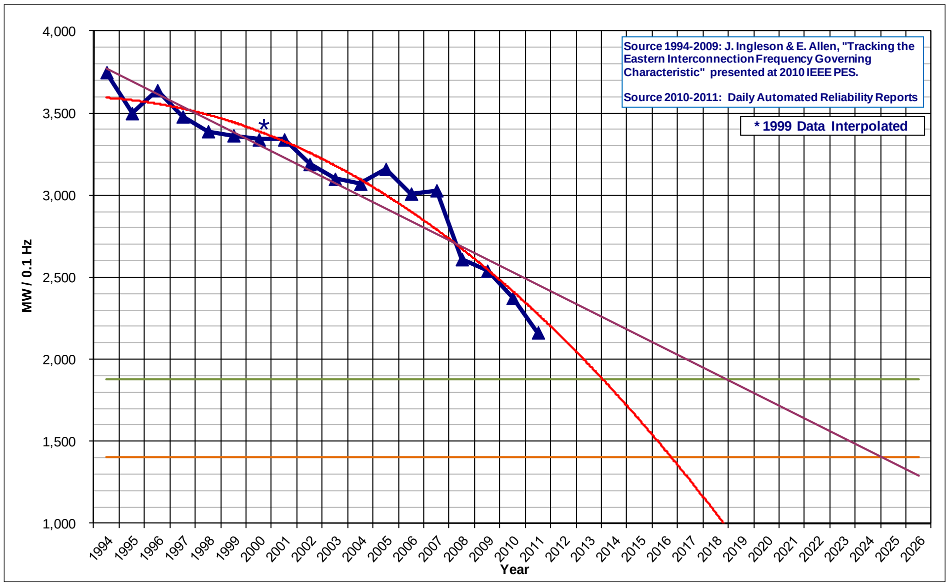


Figure 8 shows how frequency response has declined since 1994, as filed in NERC's "Motion for an Extension of Time of the North American Electric Reliability Corporation" (for the development of Standard BAL-003-1 – Frequency Response).[28] That request for extension of time was granted by FERC in its Order on Motion for an Extension of Time and Setting Compliance Schedule (Issued May 4, 2012).[29]

Comparing the proposed IFROs from those two studies, the Eastern Interconnection IFROs range from about 1,400 MW/0.1 Hz to about 1,900 MW/0.1 Hz, and the linear projection of the frequency response decline intercepts those target IFROs between 2019 and 2024. Even the more pessimistic polynomial projection of the decline intercepts the proposed IFROs between 2014 and 2016. This shows that there was still some time as of that filing for revising BAL-003-1 and responding to the decline in frequency response.

Figure 8 was revised shortly after the March 2012 filing in conjunction with revised frequency response calculation methods used in NERC's 2012 State of Reliability report (May 2012). Figure 9 reflects the revised frequency response calculations for 2009 through 2011.

[27] The Frequency Response data from 1994 through 2009 displayed in figure 2 is from a report by J. Ingleson & E. Allen, Tracking the Eastern Interconnection Frequency Governing Characteristic that was presented at the 2010 IEEE.

[28] Filing available at: http://www.nerc.com/files/MotionExtTime_RM06-16_03302012.pdf

[29] Order available at: http://www.nerc.com/files/Order_Motion_Extension_Time_Compliance_Sched_2012.5.4.pdf

Figure 9: Updated Eastern Interconnection Mean Primary Frequency Response (May 2012)

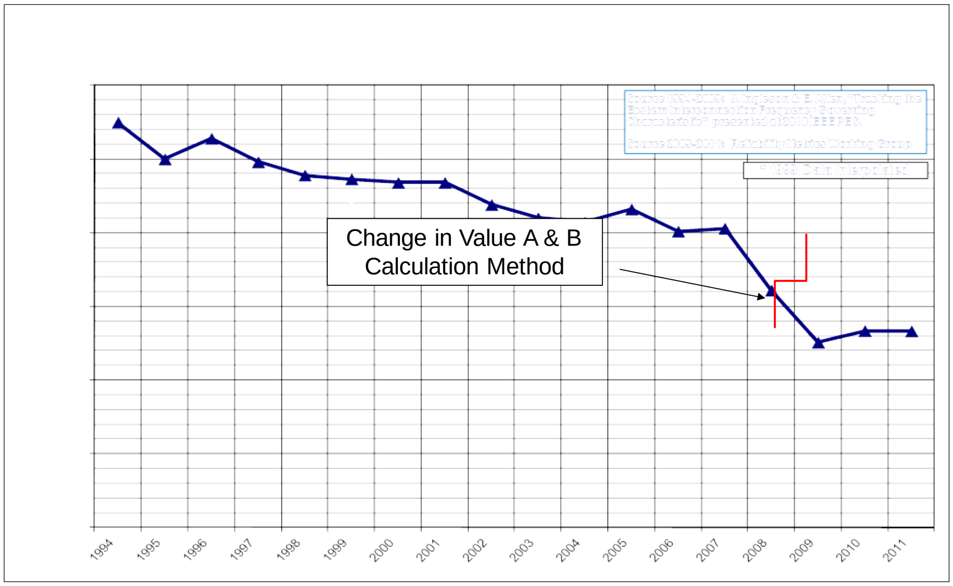


Figure 9 shows an improvement in frequency response in 2009 through 2011 due to alignment of the methods for calculation Values A and B. That method is consistent with the method being proposed in NERC Standard BAL-003-1. The method has since been further refined, as reflected in the Statistical Analysis of Frequency Response section of this report.

Figures 10–13 show the statistical analysis of the frequency response for 2009–2011 for the Eastern, Western, and ERCOT Interconnections from the 2012 State of Reliability report in box plot format (only 2011 data was available for the Québec Interconnection).

Figure 10: Eastern Interconnection Frequency Response Analysis for 2009–2011

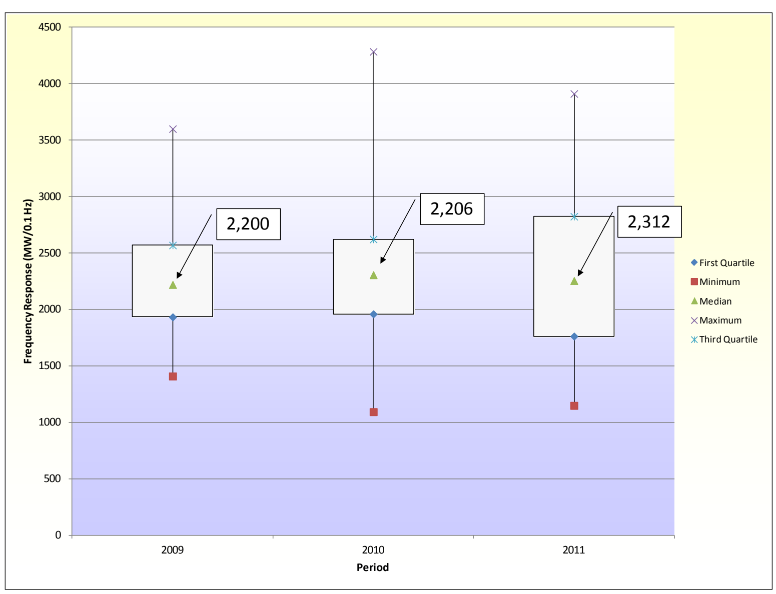


Figure 11: Western Interconnection Frequency Response Analysis for 2009–2011

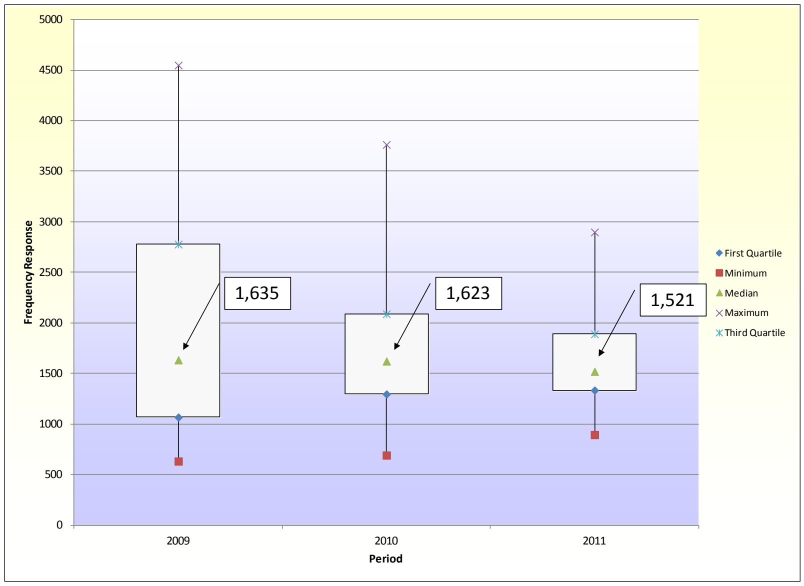
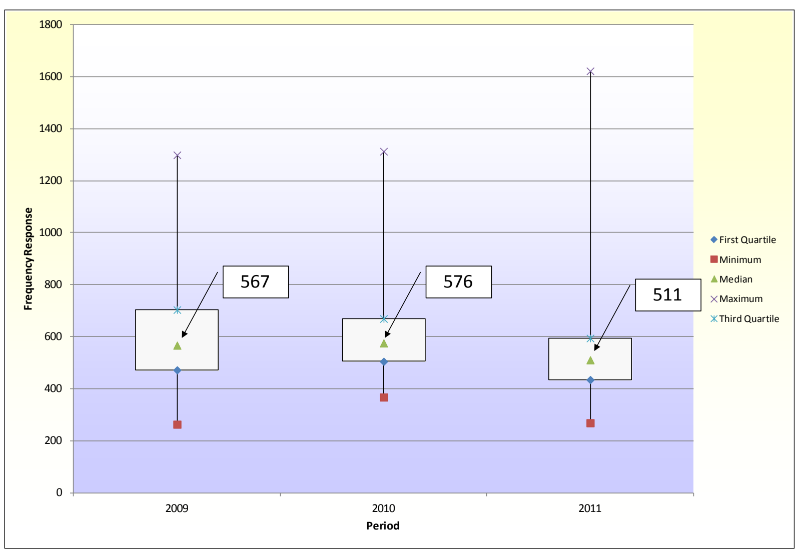
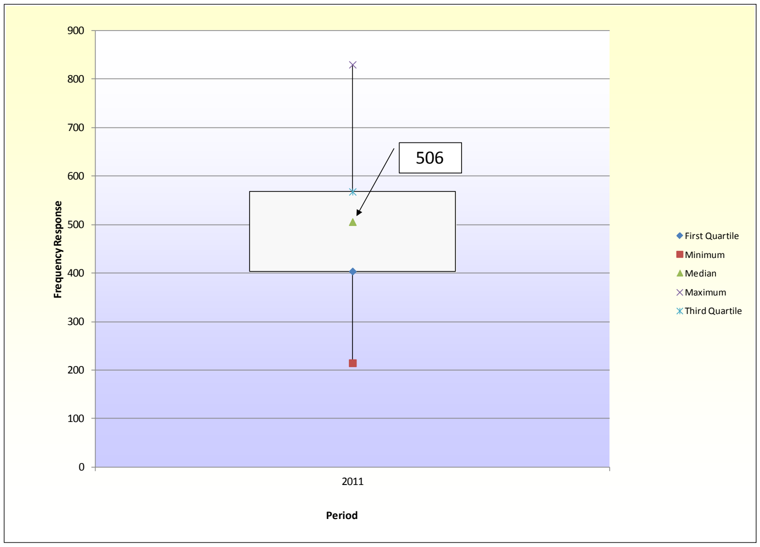


Figure 12: ERCOT Interconnection Frequency Response Analysis for 2009–2011



It is important to note the range of variability of the frequency response for each year. Additional events and modifications to the calculation methods for the A, B, and C values have been made since these values were calculated for the May 2012 report. The new values are reflected in the Statistical Analysis section of this report.

Figure 13: Québec Interconnection Frequency Response Analysis for 2011



Statistical Analysis of Frequency Response (Eastern Interconnection)

In July 2012, a statistical analysis of the frequency response of the Eastern Interconnection was performed for the calendar years 2009–2011 and the first three months of 2012. The size of the dataset was 163 (with 44 observations for 2009, 49 for 2010, 65 for 2011, and 5 for 2012).

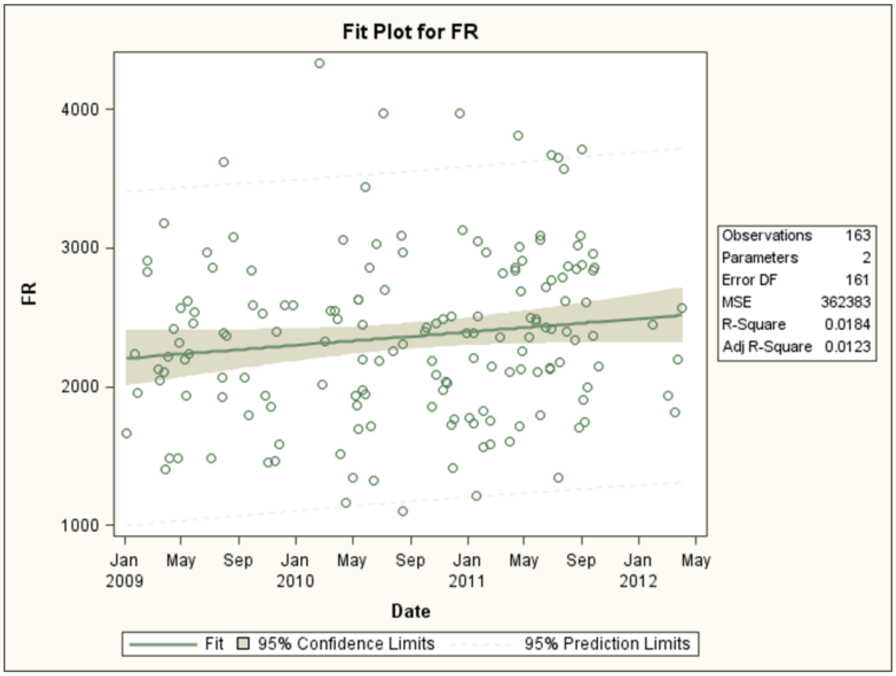
Table 1: Statistical Analysis Dataset			
Sample Parameter	2009	2010	2011
Sample Size	44	49	65
Sample Mean	2,258.4	2,335.7	2,467.8
Sample Standard Deviation	522.5	697.6	593.7

The report on that analysis was updated in August and September 2012 and is contained in Appendix G. Its results are paraphrased here for brevity. For the analysis, frequency response pertains to the absolute value of frequency response.

Key Statistical Findings

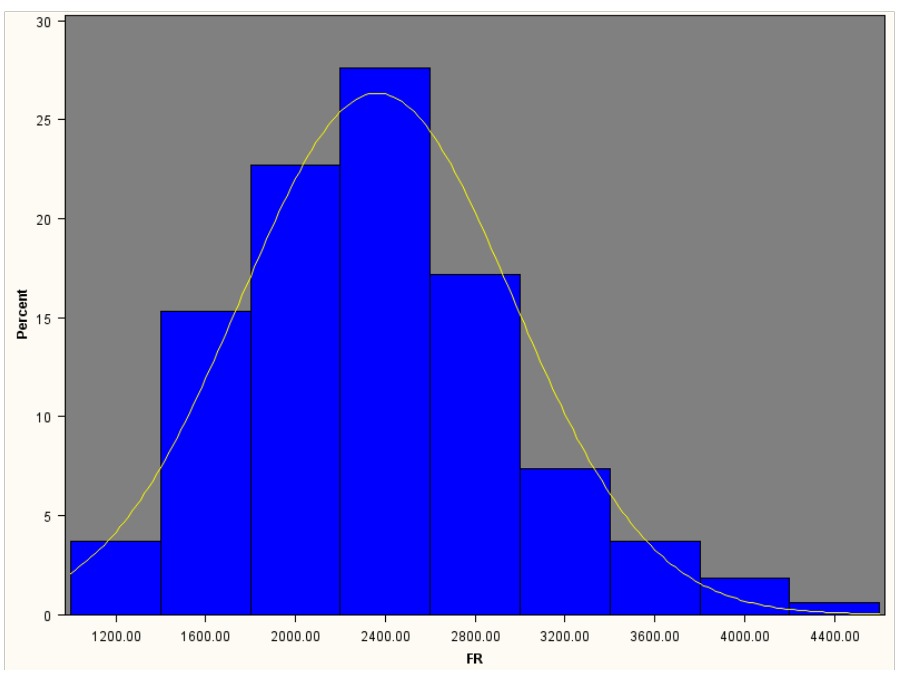
1. A linear regression equation with the parameters defined in Appendix G is an adequate statistical model to describe the relationship between time (predictor) and frequency response (responsive variable). The graph of the linear regression line and frequency response scatter plot is given in figure 14.

Figure 14: Linear Regression Fit Plot for Eastern Interconnection Frequency Response



2. The probability distribution of the whole frequency response dataset is approximately normal, with an expected frequency response of 2,363 MW/0.1 Hz and a standard deviation of 605.7 MW/0.1 Hz as shown in figure 15.

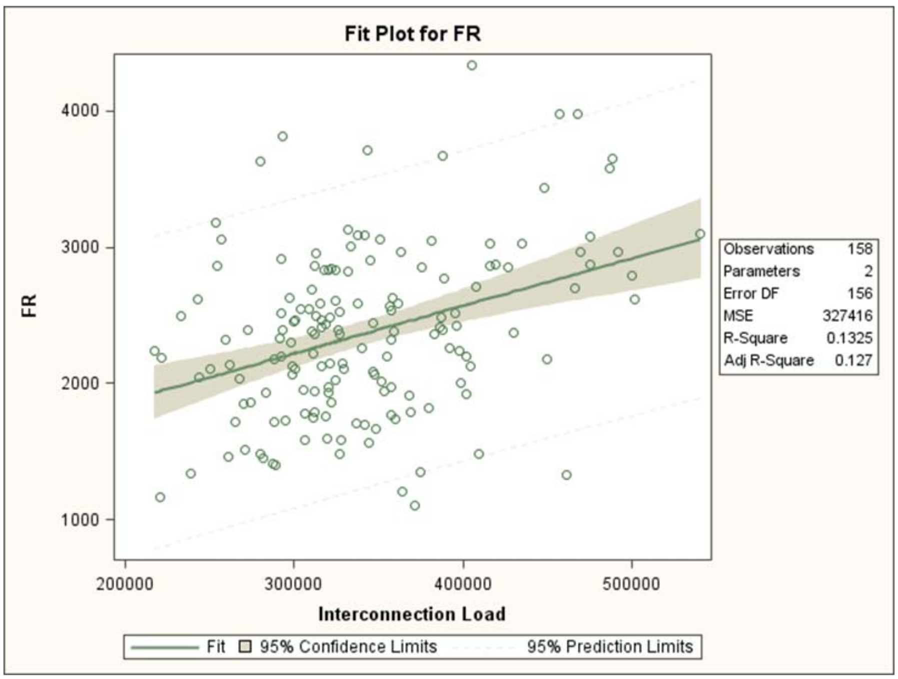
Figure 15: Probability Distribution Eastern Interconnection Frequency Response January 2009–April 2012



3. There is a statistically significant seasonal (summer/not summer) correlation to the variability of frequency response for the Eastern Interconnection. The expected frequency response (mean of the samples) for summer (June–August) frequency events is 2,598 MW/0.1 Hz versus 2,271 MW/0.1 Hz for non-summer events. This is attributable to at least two factors: higher load contribution to frequency response and increased generation dispatch of units with higher frequency response characteristics.

4. Pre-disturbance (average) frequency (Value A) is another statistically significant contributor to the variability of frequency response. The expected frequency response (mean of the samples) for events where Value A is greater than 60 Hz is 2,188 MW/0.1 Hz versus 2,513 MW/0.1 Hz for events where Value A is less than or equal to 60 Hz.

Figure 16: Linear Regression for Frequency Response and Interconnection Load



5. The difference in average frequency response between on-peak events and off-peak events is not statistically significant and could occur by chance. According to the NERC definition, Eastern Interconnection on-peak hours are designated as follows: Monday to Saturday from 07:00 to 22:00 hours (Central Time) excluding six holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. Analysis showed that the on-peak/off-peak variable is not a statistically significant contributor to the variability of frequency response. There is a positive correlation of 0.06 between the indicator function of on-peak hours and frequency response; however, difference in average frequency response between on-peak events and off-peak events is not statistically significant and could occur by chance (P-value—the probability of obtaining a result at least as extreme—is 0.49).

6. There is a strong positive correlation of 0.364 between interconnection load and frequency response for the 2009–2011 events. On average, when interconnection load changes by 1,000 MW, frequency response changes by 3.5 MW/0.1 Hz.

   This correlation indicates a statistically significant linear relationship between interconnection load (predictor) and frequency response (response variable). Figure 16 shows the linear regression line and frequency response scatter plot. For the dataset, the regression line has a positive slope estimate of 0.00349; thus, the frequency response variable increases when interconnection load grows.

7. For the 2009–2011 dataset, five variables (time, summer, high pre-disturbance frequency, on-peak/off peak hour, and interconnection load) were involved in the statistical analysis of frequency response. Four of these—time, summer, on-peak hours, and interconnection load—have a positive correlation with frequency response (0.16, 0.24, 0.06, and 0.36, respectively), and the high pre-disturbance frequency has a negative correlation with frequency response (-0.26). The corresponding coefficients of determination R^2 (the square of correlation) indicate that about 2.6% in variability of frequency response can be explained by the changes in time, about 5.8% is seasonal, 0.4% is due to on-peak/off-peak changes, 13.3% is the effect of interconnection load variability, and about 6.9% can be accounted for by a high pre-disturbance frequency. However, the correlation between frequency response and on-peak hours is not statistically significant, with the probability of about 0.44 having occurred by mere chance (the same holds true for the corresponding R^2).

Table 2: Explanatory Variables for Eastern Interconnection Frequency Response

Variable X	Sample Correlation (X, FR)	P-Value	Linear Regression Statistically Significant	Coefficient of Determination R^2 (Single Regression)
Interconnection Load	0.36	<0.0001	Yes	13.3%
Value A > 60 Hz	-0.26	0.0008	Yes	6.9%
Summer/Not Summer	0.24	0.0023	Yes	5.8%
Date	0.16	0.044	Yes	2.6%
On-Peak Hours	0.06	0.438	No	N/A

Therefore, out of the five parameters, interconnection load has the biggest impact on frequency response followed by the indicator of high pre-disturbance frequency. A multivariate regression with interconnection load and starting frequency (Value A) greater than 60 Hz as the explanatory variables for frequency response yields a linear model with the best fit (it has the smallest mean square error among the linear models with any other set of explanatory variables selected from the five studied). Together these two factors can account for about 20% of the variability in frequency response.

Frequency response is, therefore, affected by other parameters that have low correlation with those studied and account for the remaining share of frequency response variability, minimizing the random error variance.

Note that interconnection load is positively correlated with summer (0.55), on-peak hours (0.45), and time (0.20), but is uncorrelated with starting frequency greater than 60 Hz (P-value of the test on zero correlation is 0.90).

Frequency Response Withdrawal

Withdrawal of primary frequency response is an undesirable characteristic associated most often with digital turbine-generator control systems using setpoint output targets for generator output. These are typically outer-loop control systems that defeat the primary frequency response of the governors after a short time to return the unit to operating at a requested MW output.

Figure 17: Primary Response Sustainability

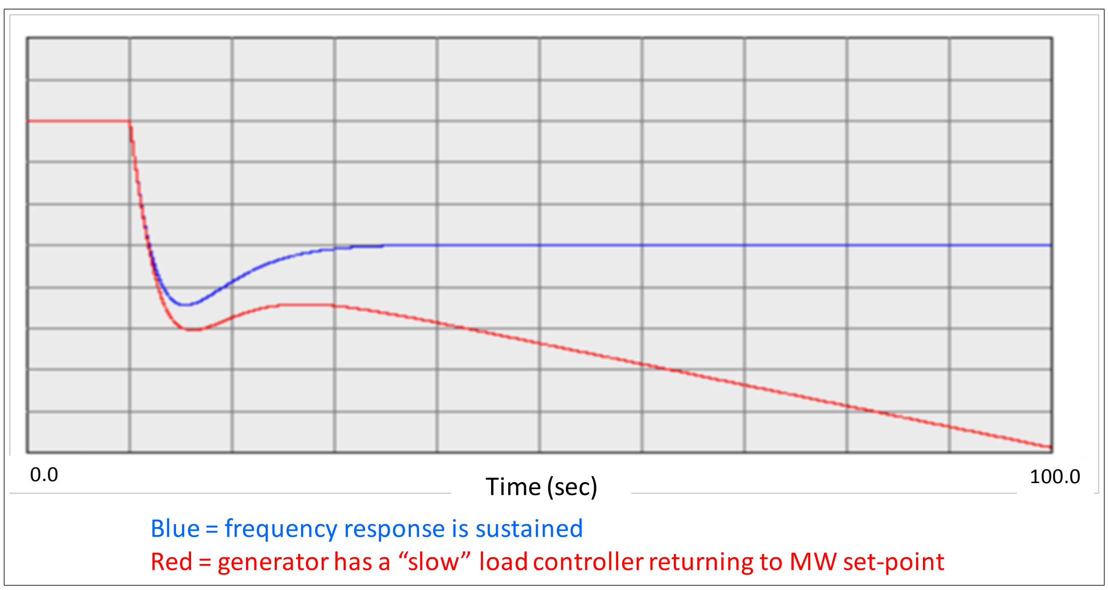


Figure 17 shows how the outer-loop control on a single machine would influence its ability to provide primary frequency response.

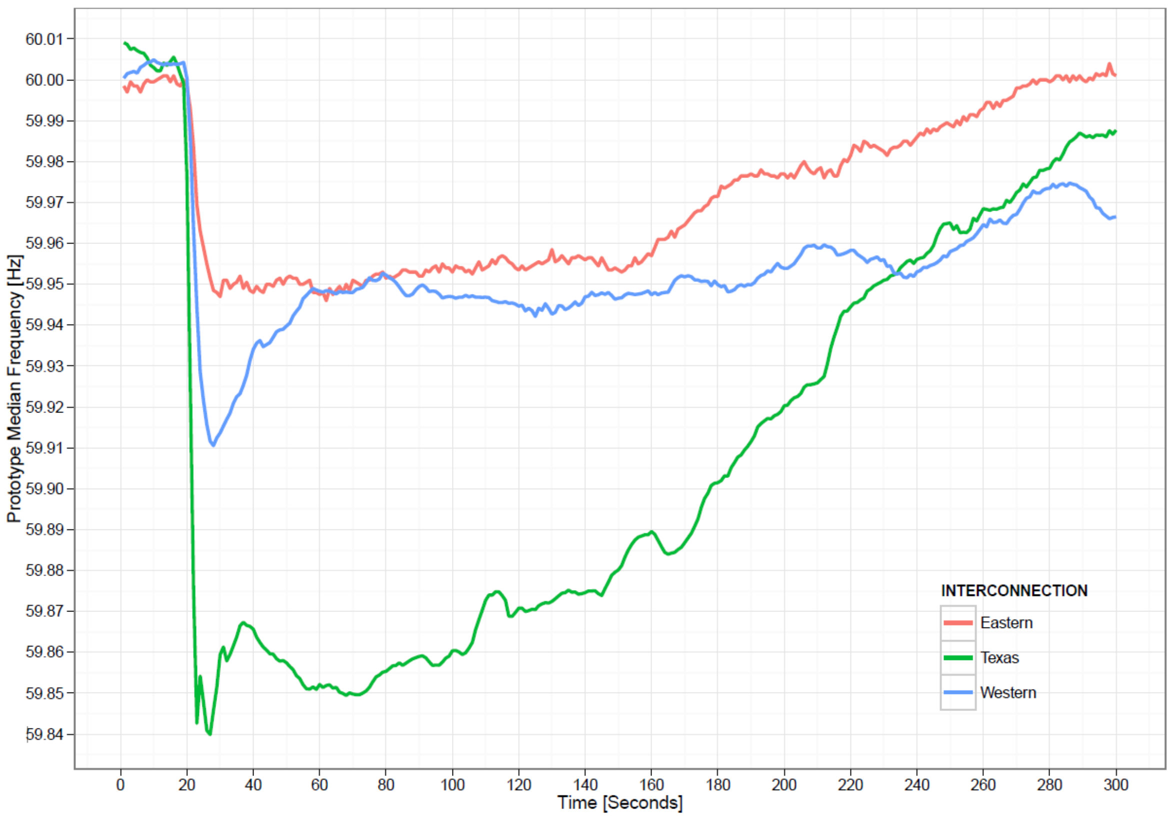
Some of the typical causes of the withdrawal are:

- Plant outer-loop control systems – driving the units to MW setpoints
- Unit characteristics

  - Plant incapable of sustaining primary frequency response
  - Governor controls overridden by other turbine/steam cycle controls
- Operating philosophies – operating characteristic choices made by plant operators
  - Desire to maintain highest efficiencies for the plant

The phenomenon is most prevalent in the Eastern Interconnection and can easily be seen in the comparison of the typical frequency response performance of the three interconnections (figure 18).

Figure 18: Typical Interconnection Responses for 2011[30]



Sustainability of primary frequency response becomes more important during light load conditions (nighttime) when there are generally fewer frequency-responsive generators on-line.

A number of the governor survey questions addressed the operational status and parameters of the governor fleet. The results of the survey show:

- About 90% of the generators were reported to have governors.

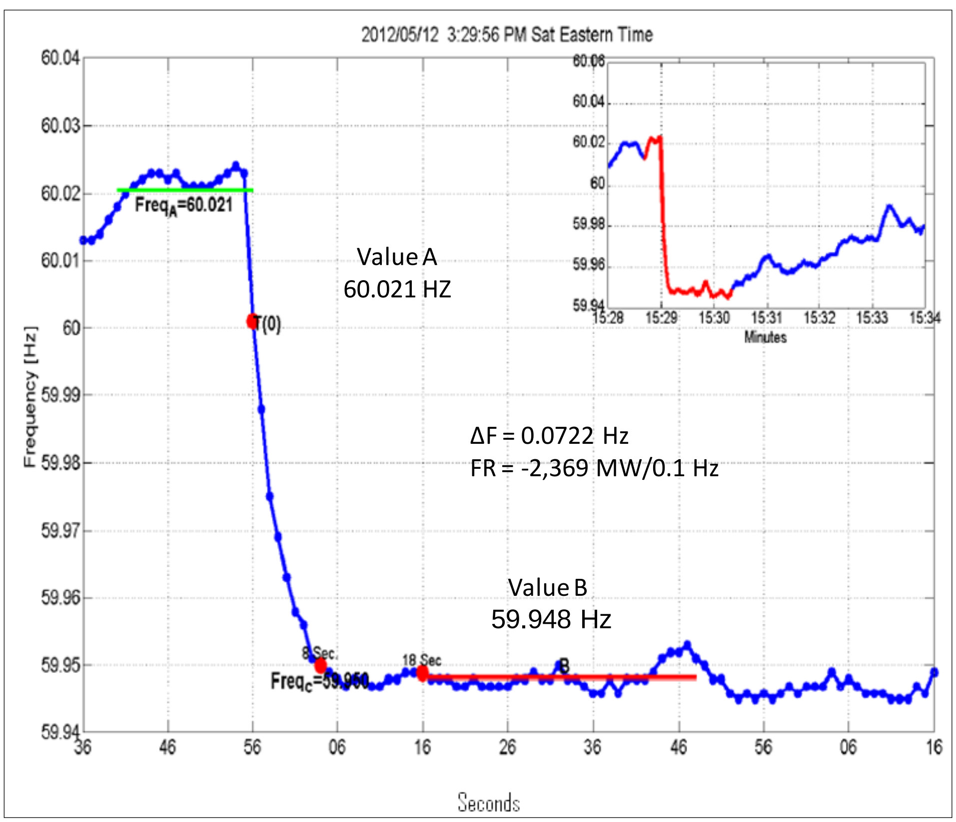
[30] NERC interconnections 2011 typical event frequency patterns using the median of the same second of each RS–FWG selected event – Revised: 09/26/12 provided by Advanced Systems Researchers.

- Virtually all (95–99% by interconnection) of the GOs and GOPs reported that their governors are operational.
- 80–85% (by interconnection) of the governors were reported to be capable of sustaining primary frequency response for longer than 1 minute if the frequency remained outside of their deadband.
- Roughly 50% of the governors reported that they had unit-level or plant-level control systems that override or limit governor performance.

Despite the fact that the majority of generators reported they have operational turbine governors, half of them have unit- or plant-level control systems that override governor responses. These control systems allow the units to return to scheduled output (MW setpoint) or an optimized operating point for economic reasons. These factors heavily influence the sustainability of primary frequency response, contributing to the withdrawal symptom often observed. This is often evident during light load periods in the middle of the night when high-efficiency, low-cost units that operate on MW setpoints are the majority of the generators dispatched to serve load.

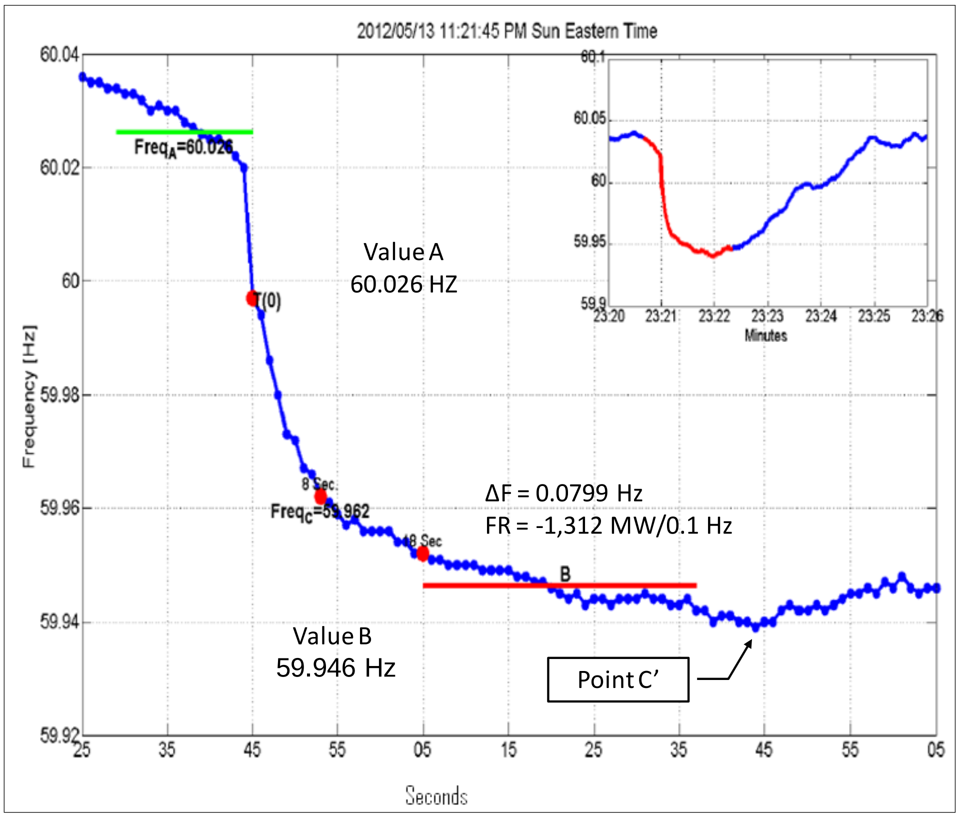
This was exhibited by two events involving generator trips in the spring of 2012 in one weekend. During the first event (figure 19), 1,711 MW of generation was tripped with a typical -2,369 MW/0.1 Hz frequency response.

Figure 19: 3:30 pm Saturday Afternoon 1,711 MW Resource Loss



The second event (figure 20) occurred late Sunday night when load in the Eastern Interconnection was much lighter, and the generators dispatched—probably the most efficient units—were of a different character. Despite the resource loss being almost 700 MW less, the frequency response of the interconnection was significantly reduced and exhibited the "lazy L" of primary frequency response withdrawal. Point C defined to occur during the first 8 seconds (at that time) was 59.962 Hz, while a lower point of about 59.939 Hz occurred about 1 minute after the event.

Figure 20: 11:21 pm Sunday Night 1,049 MW Resource Loss



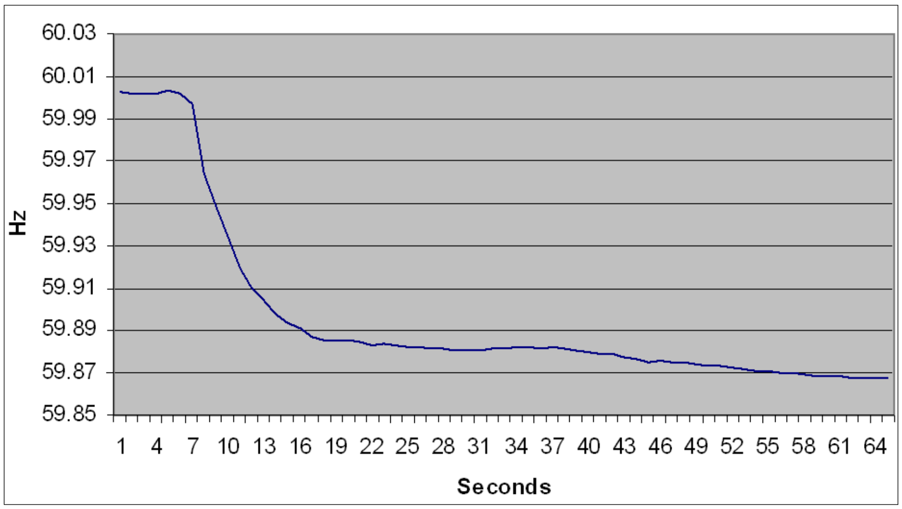
These two events point to the composition of the dispatch and the characteristics of the units on-line as primary elements in the frequency response strength, as well as the key elements in creating withdrawal. Therefore, when calculating an Interconnection Frequency Response Obligation (IFRO), it is important for operational planners and operators to recognize the potential for that withdrawal and the frequency consequentially being lower one to two minutes after the beginning of the event.

A similar withdrawal was experienced during the major frequency excursion of August 4, 2007 (figure 21). During that event some 4,500 MW of generation was lost.

The lowest frequency in the event was 59.868 Hz at about one minute after the start. Recovery to pre-event frequency was about 8 minutes, but the measurement of Value B (20 to 52 seconds) would not capture the lowest frequency. That frequency point is the true frequency event nadir, hereafter referred to as Point C' ("Point C Prime"), and is normally equal to Point C for events that don't exhibit the so-called "lazy L" effect.

It is important that the phenomenon be recorded and trended to determine if it is improving or deteriorating.

Figure 21: Interconnection Frequency – August 4, 2007 EI Frequency Excursion



Recommendation – Measure and track frequency response sustainability trends by observing frequency between T+45 seconds and T+180 seconds. A pair of indices for gauging sustainability should be calculated comparing that value to both Point C and Value B.

Modeling of Frequency Response in the Eastern Interconnection

Modeling of frequency response characteristics has been a known problem since at least 2008, when forensic modeling of the Eastern Interconnection required a "de-tuning" of the existing MMWG dynamics governor to 20% of modeled (80% error) to approach the measured frequency response values from the event.

Figure 22 shows the response comparison for that event analysis. Although the event was an over-frequency problem at that point, it is indicative of the larger problem of governor modeling in the Eastern Interconnection. The problem was further highlighted in the 2010 "Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation," by Ernest Orlando Lawrence Berkeley National Laboratory (LBNL). In that analysis, an attempt was made to simulate a 4,500 MW loss event that occurred on August 4, 2007. Figure 23 shows a comparison of the simulation to the measured frequency from the event.

Figure 22: 2007 Event Frequency Response Forensic Analysis

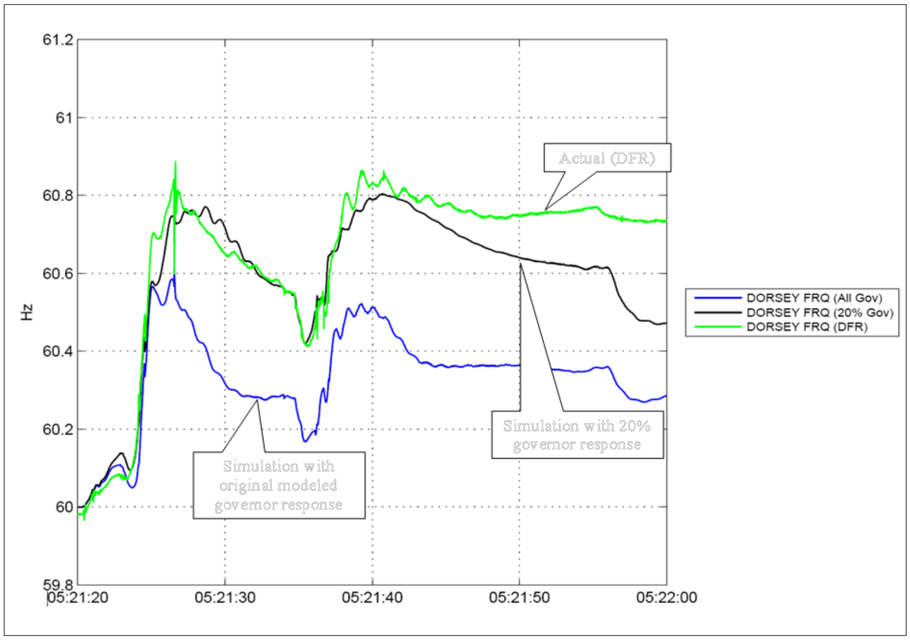
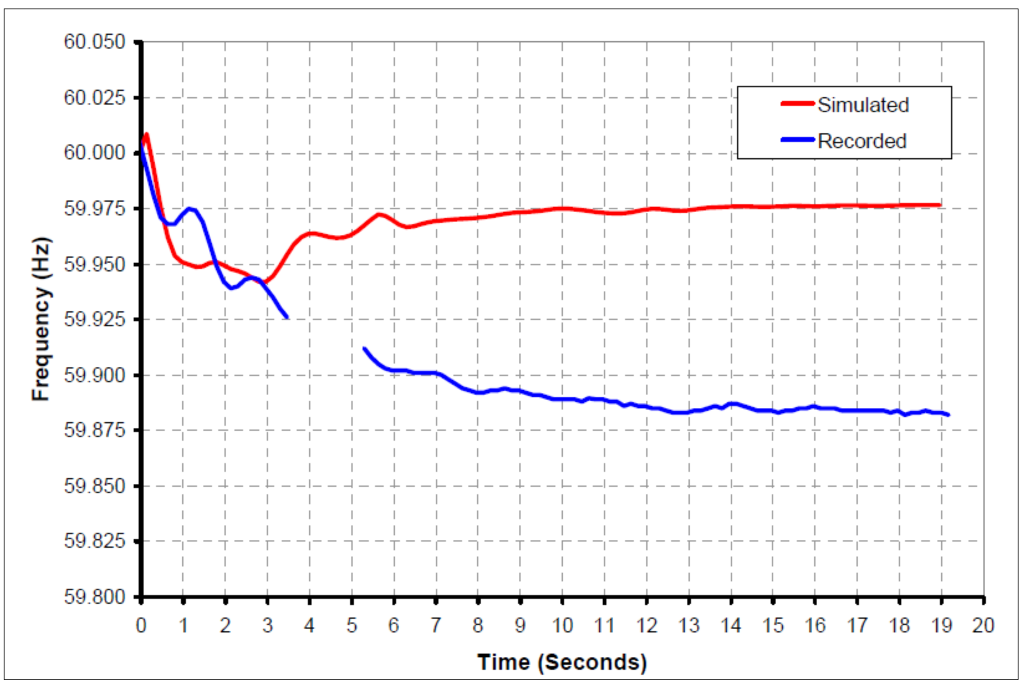


Figure 23: Eastern Interconnection Frequency Response – August 4, 2007 Initial 20 Seconds



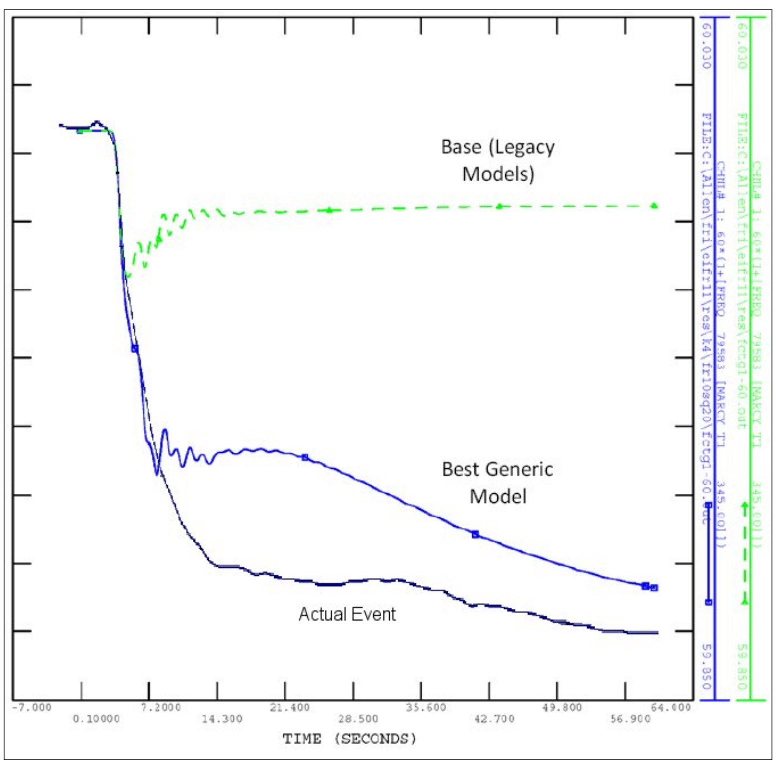
As part of the NERC Frequency Response Initiative and the Modeling Improvements Initiative, NERC collaborated with the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) to perform an analysis of the modeling of overall frequency response in the Eastern Interconnection. That review was a prelude to a plan for thorough examination of the governor models in the Eastern Interconnection dynamics study cases that are assembled by the MMWG. That report stated, "The turbine-governor modeling currently reflected in the MMWG dynamics simulation database is not a valid representation of the frequency control behavior of the Eastern Interconnection."

That project created a "generic case" dynamics model, replacing the turbine governor models in the case with a generic governor model in order to ascertain the basic characteristics of the frequency response of the Eastern Interconnection. Figure 24 shows a comparison of the actual event data and the simulations using the original governor data and the generic case.

The characteristics found in that study were:

- Only 30% of the units on-line provide primary frequency response.
- Two-thirds of the units that did respond exhibit withdrawal of primary frequency response.
- Only 10% of units on-line sustain primary frequency response.

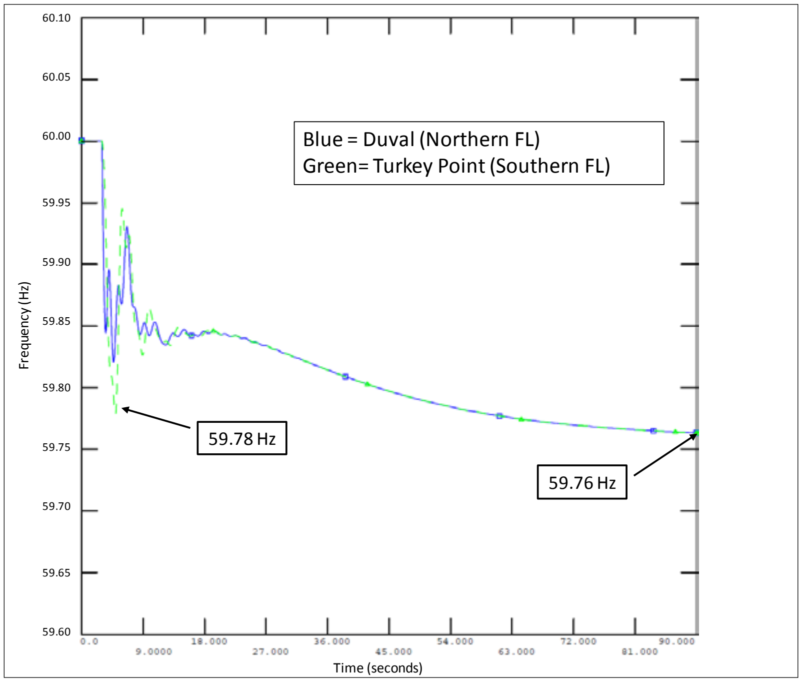
Figure 24: Comparison of Legacy and Generic Simulations to August 4 Event



Following that study, a follow-on analysis was performed by NERC staff to determine the general order of magnitude of a frequency event that could be sustained by the Eastern Interconnection without violating the 59.7 Hz first step UFLS in FRCC. A simulation was run that tripped about 8,500 MW of generation in the southeast United States (north of Florida). Figure 25 shows the result of that testing.

The simulation showed that the lowest frequency would be about 59.76 Hz in southern Florida. The initial nadir of 59.78 Hz in southern Florida is lower than the nadir in northern Florida due to the wave properties of the disturbance.

Figure 25: 8,500 MW Resource Loss Simulation



Although the simulations using the generic governor models are not exact, that analysis is indicative of the Eastern Interconnection's ability to sustain a resource loss event significantly higher than the Resource Contingency Protection Criteria proposed in this report.

Concerns for Future of Frequency Response

There is a growing concern about the future of frequency response in light of a number of factors:

- **Electronically coupled resources** – The incorporation of renewable resources such as wind and solar and the increasing penetration of variable speed motor drives presents a continuing erosion of system inertia; all are electronically coupled to the system. As such, those resources, unless specifically designed to mimic inertial response, do not have inertial response.

- **Electronically coupled loads** – As synchronous motors are replaced by variable speed drives, the load response of the motors is eliminated by the power electronics of the motor controller. This reduces the load damping factor for the interconnection.

- **Displacement of traditional turbine-generators in the dispatch** – Traditional turbine-generators are being displaced in the dispatch, particularly during off-peak hours when wind generation is at its highest and the loads and generation levels are at their lowest.

Such displacement of frequency responsive resources increasingly depletes the inertia of the interconnection at those times.

Role of Inertia in Frequency Response

Inertia plays a crucial role in determining the slope of a frequency decline during a resource loss event.

The slope of frequency excursion is determined by the inertia of the system and a factor to account for the load damping characteristics of the interconnection.

Where:

D = Load Damping Factor

The load damping factor ranges from 0 to 2, where 2 would represent a load of all motors.

H = Inertia Constant of the interconnection

The inertia constant ranges from 2.5 to 6.5

Figure 26 shows the sensitivity of frequency response to changes to system inertia. The lower green curve represents an inertia constant of 2.5, and the lower red curve represents an inertia constant of 5.0.

Figure 26: Frequency Response Sensitivity to System Inertia

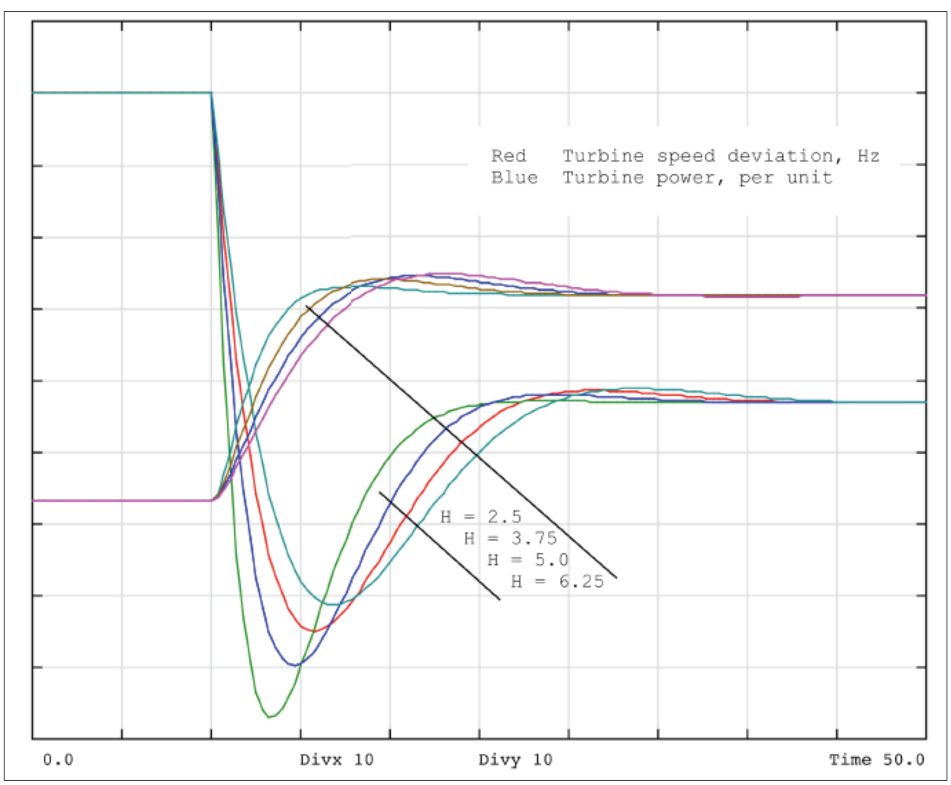
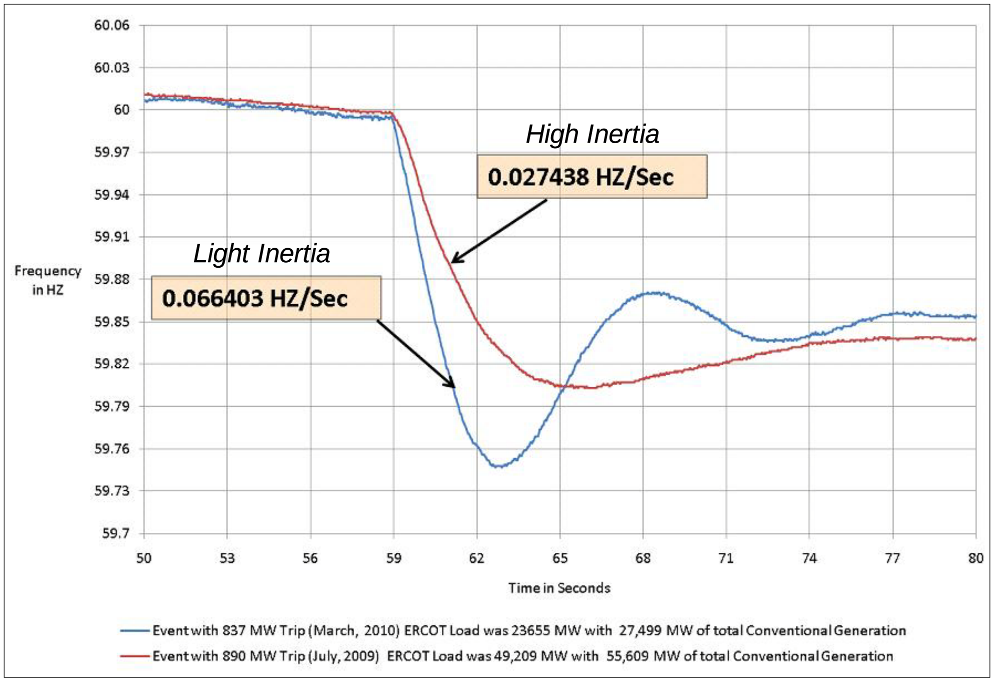


Figure 27 shows an actual example from ERCOT of how frequency response is changed for similarly sized resource loses with differences in inertia. It is clear that when the inertia on the system is lower, a similar resource MW loss creates a much steeper and deeper frequency excursion. This is a good example of the displacement of traditional resources with electronically coupled resources during light load periods.

Figure 27: Inertial Response Sensitivity



Need for Higher Speed Primary Frequency Response

The reduction of inertia drives a need for higher speed response to frequency excursions. If the slope of the frequency decline is steeper, it is necessary for high-speed injection of energy to arrest the decline in order to prevent the excursion from being too deep. Such energy injection can come from a number of sources, such as energy storage devices and wind turbines with modified inverters.

Preservation or Improvement of Existing Generation Primary Frequency Response

Additionally, to further ensure strong overall frequency response, it is important to preserve or improve the primary frequency response of the existing generation fleet. The Role of Governors section of this report discusses the results of the 2010 survey on generator governors. The survey results show that there is a significant portion of the existing generator fleet that has operational governors. However, the reported deadband ranges make those governors ineffective for all but catastrophic losses of resources. Figure 28 shows the reported deadband ranges.

If the existing generator fleet primary frequency response performance can be improved through adjustments in deadbands and implementation of no-step droop responses, a significant improvement in interconnection frequency response could be realized. Further, if all of the existing generators were made capable of response, any generators that are on-line during light load periods would be more able to provide response.

Figure 28: Reported Governor Deadband Settings

The Role of Governors section of this report recommends immediate development of a NERC turbine-generator governor guideline calling for deadbands of ±16.67 mHz with droop settings of 4%–5% depending on turbine type in order to retain or regain frequency response capabilities of the existing generator fleet.

Withdrawal of Primary Frequency Response

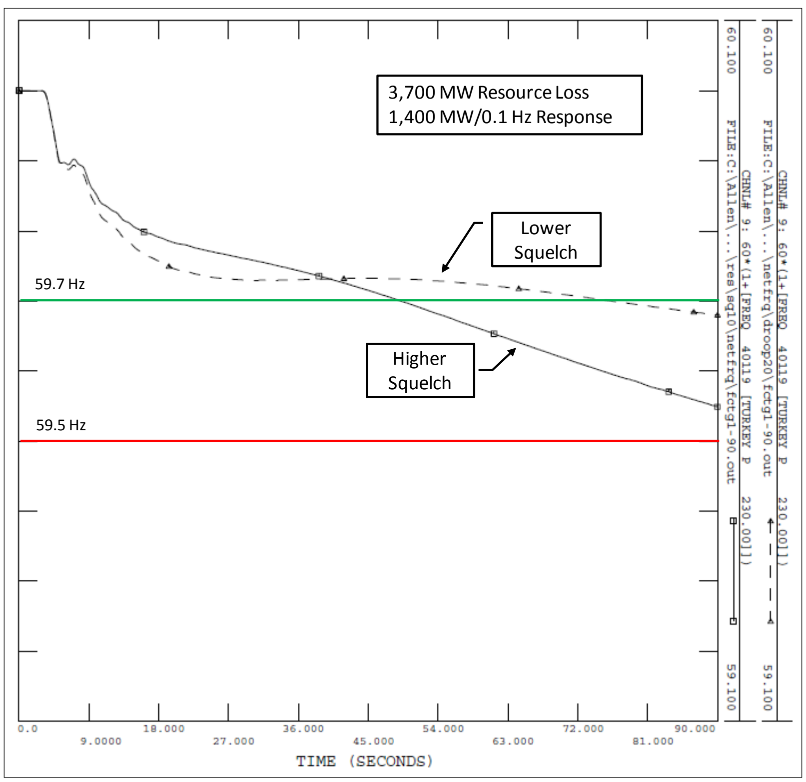
Withdrawal of primary frequency response caused by outer-loop control systems must be addressed. As shown in the Frequency Response Withdrawal section of this report, frequency response during light load periods can be highly influenced by the mix of dispatched resources. Economics of the dispatch dictates that the most efficient, cost-effective generation will remain on-line during those periods. Such generation employs setpoint controls that return generation to AGC-prescribed or efficiency-prescribed generation levels regardless of system frequency. This results in “squelching” of any primary frequency response that the governors may have provided during a frequency event. This withdrawal of primary response before secondary frequency response from AGC becomes effective starting at about T+45 to T+60 seconds, creating the “lazy L” event response prevalent in the Eastern Interconnection.

To illustrate this effect, a dynamic simulation of a 3,700 MW resource loss frequency event was performed for the Eastern Interconnection using the generic dynamics case described in the Modeling of Frequency Response in the Eastern Interconnection section of this report. Two simulation runs were performed to mimic about 1,400 MW/0.1 Hz frequency response (between 20 and 52 seconds), with different combinations of generator dispatch and differing amounts of response "squelch." Figure 29 shows that the effects on frequency response sustainability can be highly influenced by the composition of the resource dispatch, even with the same measured frequency response.

There are potential ways of alleviating this withdrawal symptom, including introduction of a frequency bias into the outer-loop controls systems that would prevent withdrawal of primary frequency response, similar to the frequency bias settings in an automatic generation control (AGC) system.

Recommendation – NERC should include guidance on methods to reduce or eliminate the effects of primary frequency response withdrawal by outer-loop unit or plant control systems.

Figure 29: Simulations of Varying Levels of Primary Frequency Response Withdrawal Eastern Interconnection



Note that these simulation runs were done for illustrative purposes only; the simulations are not yet accurate enough to confidently predict system performance, and AGC secondary frequency response was NOT simulated. Secondary frequency response from AGC becomes effective starting at about T+45 to T+60 seconds.

Interconnection Frequency Response Obligation (IFRO)

Tenets of IFRO

The IFRO is intended to be the minimum amount of frequency response that must be maintained by an interconnection. Each Balancing Authority in the interconnection should be allocated a portion of the IFRO that represents its minimum responsibility. In order to be sustainable, Balancing Authorities that may be susceptible to islanding may need to carry additional frequency responsive reserves to coordinate with their under-frequency load shedding (UFLS) plans for islanded operation.

A number of methods to assign the frequency response targets for each interconnection can be considered. Initially, the following tenets should be applied:

1. A frequency event should not trip the first stage of regionally approved UFLS systems within the interconnection.
2. Local tripping of first-stage UFLS systems for severe frequency excursions, particularly those associated with protracted faults or on systems on the edge of an interconnection, may be unavoidable.
3. Other frequency-sensitive loads or electronically coupled resources may trip during such frequency events (as is the case for photovoltaic inverters in the Western Interconnection).
4. Other susceptible frequency sensitivities may have to be considered in the future (e.g., electronically coupled load common-mode sensitivities).

UFLS is intended to be a safety net to prevent against system collapse from severe contingencies. Conceptually, that safety net should not be violated for frequency events that happen on a relatively regular basis. As such, the resource criteria are selected to avoid violating UFLS settings approved by the Regional Entities.

The Frequency Responsive Reserve Standard Drafting Team (FRRSDT) is proposing an administered value approach for the BAL-003-1 field trial. Eventually, an agreed-upon method of determining the interconnection FRO will be included in a reliability standard, or in the NERC Rules of Procedure.[31]

[31] http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20110412.pdf

Statistical Analyses

Frequency Variation Statistical Analysis

A statistical analysis of the variability of frequency for each of the four interconnections was performed using 1-second measured frequency for the Eastern, Western, and ERCOT Interconnections for 2007–2011 (five years). Data for the Québec Interconnection was only available for 2010 and 2011. Analysis of data showed the Western Interconnection frequency deviations (Epsilon) to be more volatile since the Balancing Authority ACE Limit (BAAL) field trial began there in March of 2010. Therefore, it was decided to limit the analysis to the years 2009–2011 to more accurately portray the current frequency characteristics.

This variability accounts for items such as time error correction; variability of load, interchange, and frequency over the course of a normal day; and other uncertainties, including time error corrections and all frequency events—no large events were excluded. The results of the analysis are shown in table 3.

Table 3: Interconnection Frequency Variation Analysis (Hz)

Value	Eastern	Western	ERCOT	Québec
Timeframe	2009–2011	2009–2011	2009–2011	2010–2011
Number[32] of Samples	91,283,555	90,446,802	85,924,929	34,494,049
Expected Value	60.0000367	59.9999522	59.9999847	60.00002303
Maximum Value	60.3090	60.3575	62.1669	60.8776
Minimum Value	59.0015	59.7364	58.0000	59.1879
Variance of Frequency (σ^2)	0.00024092 Hz^2	0.00022266 Hz^2	0.00060749 Hz^2	0.00035315 Hz^2
σ	0.01552147	0.01492184	0.02464722	0.01879236
2σ	0.03104295	0.02984369	0.04929445	0.03758472
3σ	0.04656442	0.04476553	0.07394167	0.05637708
Starting Frequency (F_{Start}) 5% of lower tail samples	59.974	59.976	59.963	59.972

[32] Numbers of samples vary due to exclusion of data drop-outs and other obvious observation anomalies.

For each interconnection, the distribution of the interconnection frequency fails the normality test (both the chi-square goodness-of-fit and the Kolmogorov-Smirnov goodness-of-fit) at any standard significance level. The combined datasets for the interconnection frequency consist of very large numbers of observations. For such large samples, the empirical distribution can be considered as a very good approximation of the actual distribution of the frequency, and was judged a better predictor than use of standards deviation for predicting the interconnection starting frequencies for an event. The rate of convergence in the Glivenko-Cantelli theorem is $n^{(-1/2)}$, where n is the sample size. Therefore, quantiles of the empirical distribution function can be used directly to calculate intervals where values of frequency belong with any pre-determined probability.

Only resource losses (frequency drops) are examined for IFRO calculations, so the focus is on the one-sided lower tail of the distribution for frequencies that fall outside the upper 95% interval of the overall distribution. Therefore, the starting frequency that should be used for the calculation of the IFROs is the 10% quantile frequency value, which represents a 95% confidence in the prediction for that single tail.

Those starting frequencies encompass all variations in frequency, including changes to the target frequency during time error correction. That eliminates the need to expressly evaluate TEC as a variable in the IFRO calculation.

Recommendation – The starting frequency for the calculation of IFROs should be frequency of the 5% of lower tail of samples from the statistical analysis, representing a 95% confidence that frequencies will be at or above that value at the start of any frequency event.

Figures 30–33 show the interconnection histograms broken into 1-mHz "bins." A complete set of graphs for the four interconnections is located in Appendix D of this report.

Figure 30: Eastern Interconnection 2009–2011 Frequency Histogram

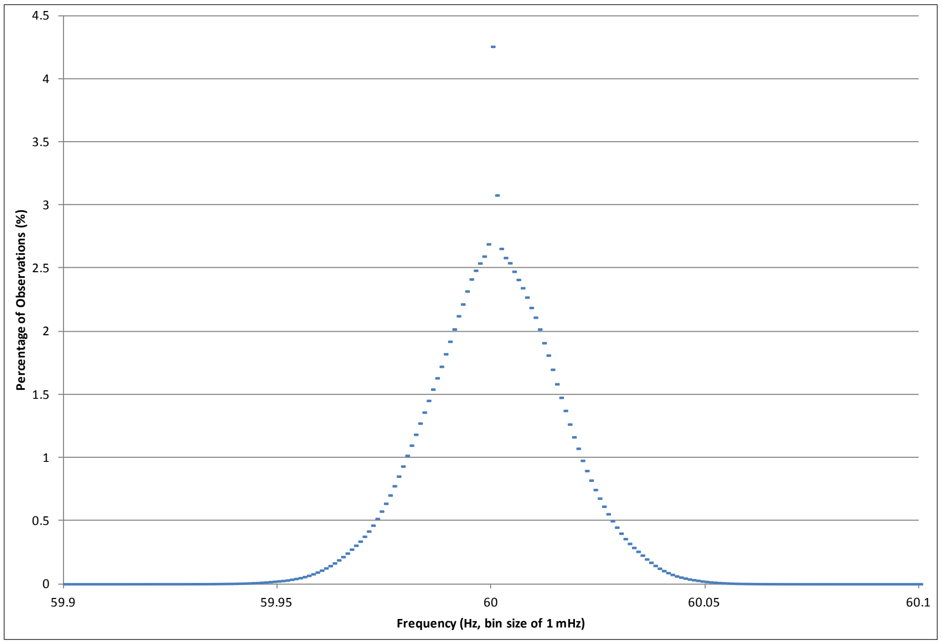


Figure 31: Western Interconnection 2009–2011 Frequency Histogram

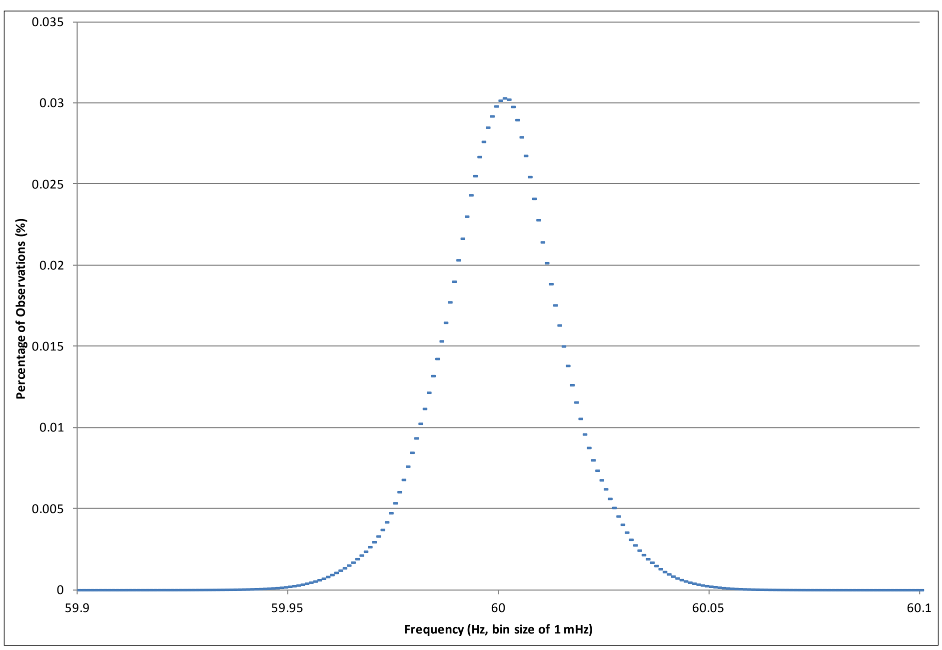
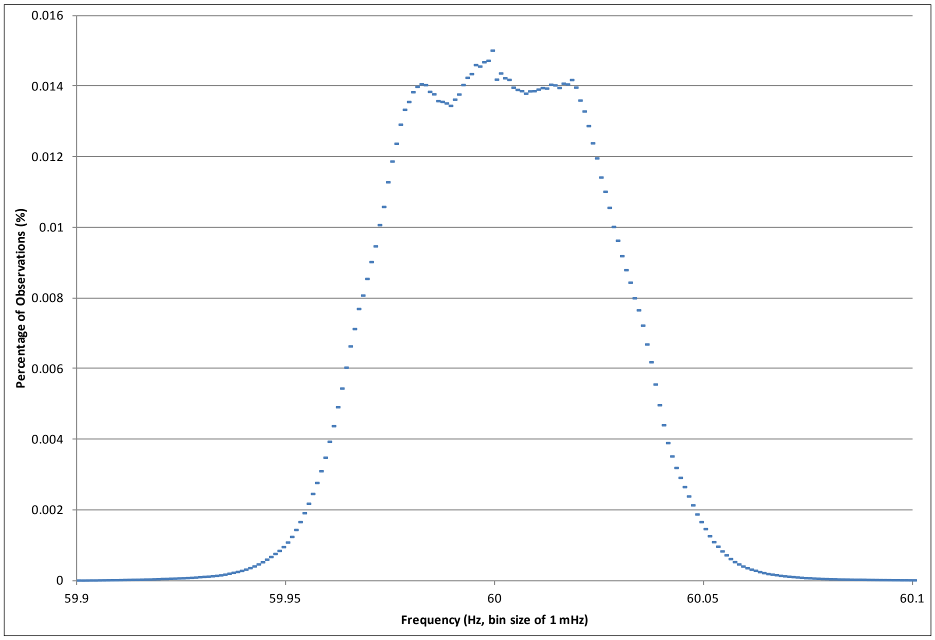
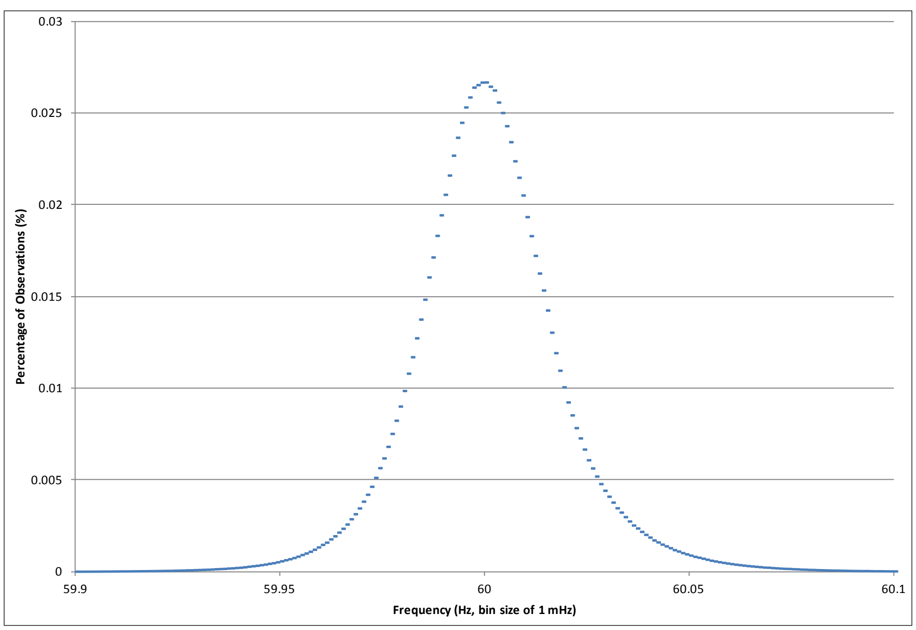


Figure 32: ERCOT Interconnection 2009–2011 Frequency Histogram



Note that the ERCOT frequency histogram displays the influence of the "flat-top" f profile that was common to that interconnection prior to 2008. That phenomenon was caused by a standardized ±36 mHz deadband with a step-function implementation. Additional discussion on that topic is in the ERCOT Experience section of this report.

Figure 33: Québec Interconnection 2010–2011 Frequency Histogram



Point C Analysis – One-second versus Sub-second Data

Additional statistical analysis was performed for the differences between Point C and Value B calculated as a ratio of Point C to Value B using 1-second data for events from December 2010 through May 2012. Although the 1-second data sample is robust, it does not necessarily ensure the nadir of the event was accurately captured. To do so requires sub-second measurements that can only be provided by PMUs or FDRs. Therefore, a "CC" adjustment component (CC_{ADJ}) for the IFRO calculation was designed to account for the differences observed between the 1-second Point C and high-speed Point C measurements.

Table 4: Analysis of One-second and Sub-second Data for Point C (CC_{ADJ})

Interconnection	Number of Samples	Mean	Standard Deviation	CC_{ADJ} (95% Quantile)
Eastern	30	0.0006	0.0038	0.0068
Western	17	0.0012	0.0019	0.0044
ERCOT	58	0.0021	0.0061	0.0121
Québec[33]	0	N/A	N/A	N/A

This adjustment should be made to the allowable frequency deviation value before it is adjusted for the ratio of Point C to Value B. Note: No sub-second data was available for the Québec Interconnection.

Recommendation – The allowable frequency deviation (starting frequency minus the highest UFLS step) should be reduced by the CC_{ADJ} to account for differences between the 1-second and sub-second data for Point C as listed in table B-C9.

Adjustment for Differences between Value B and Point C

All of the calculations of the IFRO are based on protecting from instantaneous or time-delayed tripping of the highest step of UFLS, either for the initial nadir (Point C), or for any lower frequency that might occur during the frequency event. The frequency variance analysis in the previous section of this report is based on 1-second data from 2007 through 2011 (except Québec 2010 and 2011 only).

As a practical matter, the ability to measure the tie line and loads for the Balancing Authorities is limited to system control and data acquisition (SCADA) scan-rate data of 1–6 seconds. Therefore, the ability to measure frequency response of the Balancing Authorities is still limited by the SCADA scan rates available to calculate Point B.

[33] Sub-second data from Québec was not available.

Candidate events from the ALR1-12 Interconnection Frequency Response selection process (Appendix E) for frequency response analysis were used to analyze the relationship between Value B and Point C for the significant frequency disturbances from December 2010 through May 2012. This sample set was selected because data was available for the analysis on a consistent basis. This resulted in the number of events shown in table 5.

Analysis Method

When evaluating some physical systems, the nature of the system and the data resulting from measurements derived from that system do not fit the standard linear regression methods that allow for both a slope and an intercept for the regression line. In those cases, it is better to use a linear regression technique that represents the system correctly.

The Interconnection Frequency Response Obligation is a minimum performance level that must be met by the Balancing Authorities in an interconnection. Such response is expected to come from the frequency response in MWs of the Balancing Authorities to a change in frequency. As such, if there is no change in frequency there should be no change in MWs resulting from frequency response.

This response is also related to the function of the frequency bias setting in the ACE equation of the Balancing Authorities for longer term. The ACE equation looks at the difference between scheduled frequency and actual frequency times the frequency bias setting to estimate the amount of MWs that are being provided by load and generation within the Balancing Authority. If the actual frequency is equal to the scheduled frequency, the frequency bias component of ACE must be zero.

Since the IFRO is ultimately a projection of how the interconnection is expected to respond to changes in frequency related to a change in MW (resource loss or load loss), there should be no expectation of frequency response without an attendant change in MW. It is this relationship that indicates the appropriateness of the use of regression with a forced fit through zero.

Evaluation of data to determine C-to-B ratio:

The evaluation of data to determine C-to-B ratio to account for the differences between arrested frequency response (to the nadir, Point C) and settled frequency response (Value B) is also based on a physical representation of the electrical system. Evaluation of this system requires investigation of the meaning of an intercept. The C-to-B ratio is defined as the difference between the pre-disturbance frequency and the frequency at the maximum deviation in post-disturbance frequency, divided by the difference between the pre-disturbance frequency and the settled post-disturbance frequency.

A stable physical system requires the ratio to be positive; a negative ratio indicates frequency instability or recovery of frequency greater than the initial deviation.

Table 5: Analysis of Value B and Point C (CBR)				
Interconnection	Number of Samples	Mean	Standard Deviation	CB_R (95% Quantile)
Eastern	41	0.964	0.0149	1.0 (0.989)[34]
Western	30	1.570	0.0326	1.625
ERCOT	88	1.322	0.0333	1.377
Québec[35]				1.550

This statistical analysis was completed using 1-second averaged data that does not accurately capture Point C and is better measured by high-speed metering (PMUs or FDRs). Therefore, a separate correction must be used to account for the differences between the Point C in the 1-second data and the Point C values measured with sub-second measurements from the FNet FDRs.

The CB_R value for the Eastern Interconnection indicates that the Value B is generally below the Point C value. Therefore, there is no adjustment necessary for that interconnection.

The Québec Interconnection's resources are predominantly hydraulic and are operated to optimize efficiency, typically at about 85% of rated output. Consequently, most generators have about 15% headroom to supply primary frequency response. This results in a robust response to most frequency events, exhibited by high rebound rates between Point C and the calculated B Value. For the 26 frequency events in their event sample, Québec's CB_R value would be 3.613, or two to three times as high as the CB_R value of other interconnections. Using the same calculation method for CB_R would effectively penalize Québec for their outstanding rebound performance and make their IFRO artificially high. Therefore, the method for calculating the Québec CB_R was modified.

Québec operates with an operating mandate for frequency responsive reserves to protect from tripping their 58.5 Hz (300 ms trip time) first step UFLS for their largest hazard at all times, effectively protecting against tripping for Point C frequency excursions. They also protect against tripping a UFLS step set at 59.0 Hz that has a 20-second time delay, which protects them for Value B low frequency and any withdrawals. This results in a Point C to Value B ratio of 1.5. To account for the confidence interval, 0.05 is then added, making the CB_R = 1.550.

Adjustment for Primary Frequency Response Withdrawal

At times, the nadir for a frequency event occurs after Point C—defined in BAL-003-1 as occurring in the T+0 to T+12 second period, during the Value B averaging period (T+20 through T+52 seconds), or later. For purposes of this report, that later occurring nadir is termed Point

[34] CB_R value limited to 1.0 because values lower than that indicate the Value B is lower than Point C and does not need to be adjusted. The calculated value is 0.989.

[35] Based on Québec UFLS design between their 58.5 Hz UFLS with 300 millisecond operating time (responsive to Point C)and 59.0 Hz UFLS step with a 20 second delay (responsive to Value B or beyond).

C'. This lower nadir is symptomatic of primary frequency response withdrawal, or squelching, by unit or plant-level outer-loop control systems. Withdrawal is most prevalent in the Eastern Interconnection, as described earlier.

As described in the Withdrawal of Primary Frequency Response section of this report, frequency response withdrawal can become important depending on the type and characteristics of the generators in the resource dispatch, especially during light load periods. Therefore, an additional adjustment to the maximum allowable delta frequency for calculating the IFROs was statistically developed. This adjustment should be used whenever withdrawal is a prevalent feature of frequency events. Initially, it is only being applied to the Eastern Interconnection.

Table 6 shows the statistical results of the analysis based on the 34 frequency response events in the Eastern Interconnection. Note that the expected timeframe for the C' nadir to occur is about 82 seconds after the start of the event.

Table 6: Statistical Analysis of the Adjustment for C' Nadir (BC'_{ADJ})

Value	Number of Samples	Mean	Standard Deviation	BC'_{ADJ} (95% Quantile)
Delta Frequency from Value B to Point C' Nadir	34	4.0 mHz	8.2 mHz	17.5 mHz
Seconds from T+0 to C' Nadir	34	38.9 s	26.3 s	82.1 s

This BC'_{ADJ} should be applied to the allowable delta frequency after the differences from Value B to Point C are adjusted. The values driving this adjustment should also be carefully monitored and the adjustment recalculated during the annual review of IFRO calculations.

Variables in Determination of Interconnection Frequency Response Obligation from Criteria

To make a determination of the appropriate Resource Contingency Protection Criteria to protect for a certain kind of event, the MW target value needs to be translated into an Interconnection Frequency Response Obligation (IFRO) for an appropriate comparison. A number of other variables must be taken into consideration.

Low Frequency Limit

The low frequency limit to be used for the IFRO calculations should be the highest setpoint in the interconnection for regionally approved UFLS systems.

Recommendation – Based on the tenet that UFLS should not trip for a frequency event throughout the interconnection, the recommended UFLS first-step limitations for IFRO calculations listed in table 7 should be used.

Table 7: Low-Frequency Limits (Hz)	
Interconnection	Highest UFLS Trip Frequency
Eastern	59.5[36]
Western	59.5
ERCOT	59.3
Québec	58.5

The highest UFLS setpoint in the Eastern Interconnection is 59.7 Hz in FRCC, while the prevalent highest setpoint in the rest of that interconnection is 59.5 Hz. The FRCC 59.7 Hz first UFLS step is based on internal stability concerns and preventing the Florida peninsula from separation from the rest of the interconnection. The FRCC concluded that the IFRO starting point of 59.5 Hz for the Eastern Interconnection is acceptable in that it imposes no greater risk of UFLS operation for an interconnection resource loss event than for an internal FRCC event.

Protection against tripping the highest step of UFLS does not ensure that generation that has frequency-sensitive protection or turbine control systems will not trip. Severe system conditions might drive the frequency to levels that may present protection and control systems with a combination of conditions that may cause the generation to trip, such as severe rate of change in voltage or frequency, which might actuate volts per hertz relays. Similarly, some combustion turbines may not be able to sustain operation at frequencies below 59.5 Hz. Recent laboratory testing by Southern California Edison of inverters used on residential and commercial scale photovoltaic (PV) systems revealed a propensity to trip at about 59.4 Hz, which is 200 mHz above the expected 59.2 Hz prescribed in IEEE Standard 1547 for distribution-connected PV rating ≤ 30 kW (57.0 Hz for larger installations). This could become problematic in areas of high penetration of photovoltaic resources.

Credit for Load Resources (CLR)

The ERCOT Interconnection depends on contractually interruptible demand that automatically trips at 59.7 Hz to help arrest frequency declines. A 1,400 MW Load Resource (formerly Load acting as a Resource – LaaR) credit is included against the Resource Contingency for the ERCOT Interconnection. Similarly, there is a remedial action scheme (RAS) in WECC that trips 300 MW of load for the loss of two Palo Verde generating units.

For the Western Interconnection, if the larger 3,200 MW resource loss activates the RAS and trips the Pacific DC Intertie (PDCI), the 300 MW credit for Load Resources associated with the loss of the two Palo Verde units does not apply.

[36] The highest UFLS setpoint in the Eastern Interconnection is 59.7 Hz in FRCC, based on internal stability concerns. The FRCC concluded that the IFRO starting frequency of the prevalent 59.5 Hz for the Eastern Interconnection is acceptable in that it imposes no greater risk of UFLS operation in FRCC for an external resource loss event than for an internal FRCC event.

For both interconnections, credit for load resources is handled in the calculation of the IFRO as a reduction to the loss of resources, when appropriate.

Interconnection Resource Contingency Protection Criteria

Selection of discrete event protection criteria for each interconnection must be done before the IFRO can be calculated. The protection criteria selected should ensure that Point C would not encroach on the first step UFLS. However, the criteria may need to be different from one interconnection to the other due to the differences in size and design characteristics.

The following potential interconnection event criteria were considered:

- largest N-2 loss-of-resource event,
- largest total generating plant with common voltage switchyard, and
- largest loss-of-resource event in the interconnection in the last 10 years.

Largest N-2 Event

For this approach, each interconnection will have a target Resource Contingency Protection Criteria based on the largest N-2 loss-of-resource event. This should not be confused with a Category C, N-2 event prescribed in the NERC TPL standards; it is intended to reflect a simultaneous loss of the resources without time for system adjustments. As such, these events would be considered Category D events in the current standards.

Table 8: Largest N-2 Event

Interconnection	Basis	MW
Eastern	Nelson DC Bi-poles 1 & 2	3,854[37]
Western	Two Palo Verde Units	2,740[38]
ERCOT	Two South Texas Project Units	2,750[39]

For both the ERCOT and Western Interconnections, that would be the loss of the two largest generating units in the interconnection. However, for the Eastern Interconnection, the largest N-2 loss-of-resource event would be the loss of the two Nelson dc bi-pole converters.

[37] Nelson Bi-poles 1 and 2 are rated 1,854 MW and 2,000 MW, respectively.

[38] Net winter ratings per Form EIA-860 reporting.

[39] Net rating from ERCOT Resource Asset Registration Form (RARF).

Largest Total Plant with Common Voltage Switchyard

Another approach is to examine the largest complete generating plant outage in each of the interconnections, limiting this classification to those generators with a common voltage switchyard. The reasoning for considering such a protection criteria is that despite popular belief, complete plant outages can and do happen on a regular basis; 15 complete plant outages occurred in North America in the 12 months from July 1, 2010 through June 30, 2011.

Table 9: Largest Total Plant with Common Voltage Switchyard		
Interconnection	Basis	MW
Eastern	Darlington Units 1-4	3,524[40]
Western	3 Palo Verde Units	3,575[41]
ERCOT	2 South Texas Project Units	2,750[42]

Note that in the Western Interconnection, multi-plant generation tripping by the operation of the Pacific Northwest remedial action scheme (RAS) results in resource loss of 3,200 MW. That issue is further discussed in the Special IFRO Considerations section of this report.

Largest Resource Event in Last 10 Years

A third approach is to examine the largest complete resource loss event in the interconnection over the last 10 years. Although this method yields a reasonable value for the Eastern Interconnection, the values for the other two interconnections would likely not be sustainable without activating some UFLS. It also results in a larger resource contingency for the Western Interconnection than for the Eastern Interconnection. These single events were not approached in magnitude by any other events in the 10-year period.

Table 10: Largest Resource Contingency Event in Last 10 Years		
Interconnection	Basis	MW
Eastern	August 4, 2007 Disturbance[43]	4,500
Western	June 14, 2004 Disturbance[44]	5,000
ERCOT	May 15, 2003 Disturbance[45]	3,400

[40] Net winter ratings from the NERC Electricity Supply and Demand.

[41] Net winter ratings per Form EIA-860 reporting.

[42] Net rating from ERCOT Resource Asset Registration Form (RARF).

[43] The August 4, 2007 frequency excursion was a complex, multi-faceted event involving nine generators across three states. Of those nine generators, seven tripped because of turbine control actions, and the others tripped on instability. This was not an N-1 event.

[44] The June 14, 2004 disturbance was a complex series of events thattripped ten generators across the western Interconnection as the result of a protracted fault. This was not an N-1 event.

Recommended Resource Contingency Protection Criteria

Because the philosophy is for the criteria to protect against the largest frequency excursion the interconnection can withstand, the contingency criteria may vary significantly between the interconnections. For example, because of its sheer size and generating capacity, the Eastern Interconnection can withstand a greater loss of resources.

Therefore, a blending of Resource Contingency Protection Criteria is recommended (table 4) for the determination of IFROs.

Table 11: Recommended Resource Contingency Protection Criteria

Interconnection	Resource Contingency	Basis	MW
Eastern	Largest Resource Event in Last 10 Years	August 4, 2007 Disturbance	4,500
Western	Largest N-2 Event	2 Palo Verde Units	2,740[46]
ERCOT	Largest N-2 Event	2 South Texas Project Units	2,750[47]

Although the size of a resource contingency that can be sustained by an interconnection should be tested through dynamic simulations, that test can currently be done only for the Western and ERCOT Interconnections.

Recommendation – Dynamic simulation testing of the Western and ERCOT Resource Contingency Protection Criteria should be conducted as soon as possible.

Recommendation – Dynamic simulation testing of the Eastern Interconnection Resource Contingency Protection Criteria should be conducted when the dynamic simulation models of the interconnection are capable of performing the analysis.

[45] The May 15, 2003 disturbance was a complex series of events that tripped six generators due to a protracted fault. This was not an N-1 event.

[46] Net winter ratings per Form EIA-860 reporting.

[47] Net rating from ERCOT Resource Asset Registration Form (RARF).

Comparison of Alternative IFRO Calculations

Each of the proposed resource loss criteria alternatives were compared through development of the corresponding IFROs. The following tables show the calculation of an IFRO for each alternative for the Eastern, Western, and ERCOT Interconnections. The criterion for the Québec Interconnection was kept constant throughout.

IFRO Formulae

The following are the formulae that comprise the calculation of the IFROs.

Where:

- DF_{Base} is the base delta frequency.
- F_{Start} is the starting frequency determined by the statistical analysis.
- UFLS is the highest UFLS trip setpoint for the interconnection.
- CC_{ADJ} is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data.
- DF_{CC} is the delta frequency adjusted for the differences between 1-second and sub-second Point C observations for frequency events.
- CB_R is the statistically determined ratio of the Point C to Value B.
- DF_{CBR} is the delta frequency adjusted for the ratio of the Point C to Value B.
- BC'_{ADJ} is the statistically determined adjustment for the event nadir occurring below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.
- MDF is the maximum allowable delta frequency.
- RLPC is the resource loss protection criteria.
- CLR is the credit for load resources.

- ARLPC is the adjusted resource loss protection criteria adjusted for the credit for load resources.
- IFRO is the interconnection frequency response obligation.

Determination of Maximum Delta Frequencies

Because of the limitation of measurement of the Balancing Authority-level frequency response performance using Value B, the Interconnection Frequency Obligations must be calculated in "Value B space." Protection from tripping UFLS for the interconnections based on Point C (the nadir defined as occurring between T=0 and T+12 seconds in BAL-003-1), Value B (defined as occurring from T+20 seconds to T+52 seconds), or any nadir occurring after point C, within Value B, or after T+52 seconds must be reflected in the maximum allowable delta frequency for IFRO calculations expressed as a Value B.

Table 12: Determination of Maximum Delta Frequencies

	Eastern	Western	ERCOT	Québec	Units
Starting Frequency	59.974	59.976	59.963	59.972	Hz
Minimum Frequency Limit	59.500[48]	59.500	59.300	58.500	Hz
Base Delta Frequency	0.474	0.476	0.663	1.472	Hz
CC_{ADJ}	0.007	0.004	0.012	N/A	Hz
Delta Frequency (DF_{CC})	0.467	0.472	0.651	1.472	Hz
CB_R	1.000[49]	1.625	1.377	1.550[50]	Hz
Delta Frequency (DF_{CBR})[51]	0.467	0.291	0.473	0.949	Hz
BC'_{ADJ}	.018	N/A	N/A	N/A	Hz
Max. Delta Frequency	0.449	0.291	0.473	0.949	Hz

Table 12 shows the calculation of the maximum allowable delta frequencies for each of the interconnections. All adjustments to the maximum allowable change in frequency are made to include:

- adjustments for the differences between 1-second and sub-second Point C observations for frequency events,
- adjustments for the differences between Point C and Value B, and

[48] The highest UFLS setpoint in the Eastern Interconnection is 59.7 Hz in FRCC, based on internal stability concerns. The FRCC concluded that the IFRO starting frequency of the prevalent 59.5 Hz for the Eastern Interconnection is acceptable in that it imposes no greater risk of UFLS operation in FRCC for an external resource loss event than for an internal FRCC event.

[49] CB_R value for the Eastern Interconnection limited to 1.0 because values lower than that indicate the Value B is lower than Point C and does not need to be adjusted. The calculated value is 0.989.

[50] Based on Québec UFLS design between their 58.5 Hz UFLS with 300 ms operating time (responsive to Point C) and 59.0 Hz UFLS step with a 20-second delay (responsive to Value B or beyond).

[51] DF_{CC}/CB_R

- adjustments for the event nadir being below the Value B (Eastern Interconnection only) due to primary frequency response withdrawal.

Recommendation – The determination for the Maximum Delta Frequencies should be calculated in accordance with the methods embodied in Table 12 – Determination of Maximum Delta Frequencies.

Largest N-2 Event

Table 13 shows the determination of IFROs based on a resource loss equivalent to the largest N-2 event in each interconnection. This calculation has been adjusted to include the recommended adjustment for the differences between Value B and Point C, and for the differences in measurement of Point C using 1-second and sub-second data.

Table 13: Largest N-2 Event

	Eastern	Western	ERCOT	Québec	Units
Starting Frequency	59.974	59.976	59.963	59.972	Hz
Max. Delta Frequency	0.449	0.291	0.473	0.949	Hz
Resource Contingency Protection Criteria	3,854	2,740	2,750	1,700	MW
Credit for LR		300	1,400		MW
IFRO[52]	-858	-840	-286	-179	MW/0.1Hz
Absolute Value of IFRO	858	840	286	179	MW/0.1Hz
% of Current Interconnection Performance[53]	34.8%	71.2%	48.7%	23.9%	
% of Interconnection Load[54]	0.14%	0.56%	0.45%	0.50%	

[52] IFRO =

[53] Current Interconnection Frequency Response Performance: EI = -2,467 MW / 0.1Hz, WI = -1,179 MW / 0.1Hz, TI = -586 MW / 0.1Hz, and QI = -750 MW/0.1 Hz.

[54] Interconnection projected Total Internal Demands from the 2010 NERC Long-Term Reliability Assessment: EI = 604,245 MW, WI = 148,895 MW, TI = 63,810 MW, and QI winter load = 36,000 MW.

Largest Total Plant with Common Voltage Switchyard

Table 14 shows the determination of IFROs based on a resource loss equivalent to the largest total plant with common voltage switchyard in each interconnection. This calculation has been adjusted to include the recommended adjustment for the differences between Value B and Point C, and for the differences in measurement of Point C using 1-second and sub-second data.

Table 14: Largest Total Plant with Common Voltage Switchyard

	Eastern	Western	ERCOT	Québec	Units
Starting Frequency	59.974	59.976	59.963	59.972	Hz
Max. Delta Frequency	0.449	0.291	0.473	0.949	Hz
Resource Contingency Protection Criteria	3,524	3,575	2,750	1,700	MW
Credit for LR		300	1,400		MW
IFRO[55]	-785	-1,127	-286	-179	MW/0.1Hz
Absolute Value of IFRO	785	1,127	286	23.9%	MW/0.1Hz
% of Current Interconnection Performance[56]	31.8%	95.6%	48.7%	23.9%	
% of Interconnection Load[57]	0.13%	0.76%	0.45%	0.50%	

[55] IFRO = ———

[56] Current Interconnection Frequency Response Performance: EI = -2,467 MW / 0.1Hz, WI = -1,179 MW / 0.1Hz, TI = -586 MW / 0.1Hz, and QI = -750 MW/0.1 Hz.

[57] Interconnection projected Total Internal Demands from the 2010 NERC Long-Term Reliability Assessment: EI = 604,245 MW, WI = 148,895 MW, TI = 63,810 MW, and QI winter load = 36,000 MW.

Largest Resource Event in Last 10 Years

Table 15 shows the determination of IFROs based on a resource loss equivalent to the largest resource event in the last 10 years in each interconnection. This calculation has been adjusted to include the recommended adjustment for the differences between Value B and Point C, and for the differences in measurement of Point C using 1-second and sub-second data.

Table 15: Largest Resource Event in Last 10 Years

	Eastern	Western	ERCOT	Québec	Units
Starting Frequency	59.974	59.976	59.963	59.972	Hz
Max. Delta Frequency	0.449	0.291	0.473	0.949	Hz
Resource Contingency Protection Criteria	4,500	5,000	3,400	1,700	MW
Credit for LR		300	1,400		MW
IFRO[58]	-1,002	-1,721	-423	-179	MW/0.1Hz
Absolute Value of IFRO	1,002	1,721	423	179	MW/0.1Hz
% of Current Interconnection Performance[59]	40.6%	146.0%	72.2%	23.9%	
% of Interconnection Load[60]	0.17 %	1.16%	0.66%	0.50%	

[58] IFRO =

[59] Current Interconnection Frequency Response Performance: EI = -2,467 MW / 0.1Hz, WI = -1,179 MW / 0.1Hz, TI = -586 MW / 0.1Hz, and QI = -750 MW/0.1 Hz.

[60] Interconnection projected Total Internal Demands from the 2010 NERC Long-Term Reliability Assessment: EI = 604,245 MW, WI = 148,895 MW, TI = 63,810 MW, and QI winter load = 36,000 MW.

Recommended IFROs

Table 16 shows the determination of IFROs based on a resource loss equivalent to the recommended criteria in each interconnection. This calculation has been adjusted to include the recommended adjustment for the differences between Value B and Point C, and for the differences in measurement of Point C using 1-second and sub-second data.

Recommendation – The Interconnection Frequency Response Obligations should be calculated as shown in Table 16 – Recommended IFROs.

Table 16: Recommended IFROs

	Eastern	Western	ERCOT	Québec	Units
Starting Frequency	59.974	59.976	59.963	59.972	Hz
Max. Delta Frequency	0.449	0.291	0.473	0.949	Hz
Resource Contingency Protection Criteria	4,500	2,740	2,750	1,700	MW
Credit for LR		300	1,400		MW
IFRO[61]	-1,002	-840	-286	-179	MW/0.1Hz
Absolute Value of IFRO	1,002	840	286	179	MW/0.1Hz
% of Current Interconnection Performance[62]	40.6%	71.2%	48.7%	23.9%	
% of Interconnection Load[63]	0.17%	0.56%	0.45%	0.50%	

Special IFRO Considerations

The IFRO calculation scenarios for the Western Interconnection do not take into account intentional tripping of generation during the operation of remedial action schemes (RAS). A key example is the Pacific Northwest RAS for loss of the Pacific DC Intertie (PDCI), which trips up to 3,200 MW of generation in the Pacific Northwest when the PDCI trips, depending on the loading of the PDCI. The RAS is intended to avoid system instability, tripping generation, inserting the Chief Joseph braking resistor (for up to 30 cycles), and other reactive configuration

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[61] IFRO =

[62] Current Interconnection Frequency Response Performance: EI = -2,467 MW / 0.1Hz, WI = -1,179 MW / 0.1Hz, TI = -586 MW / 0.1Hz, and QI = -750 MW/0.1 Hz.

[63] Interconnection projected Total Internal Demands from the 2010 NERC Long-Term Reliability Assessment: EI = 604,245 MW, WI = 148,895 MW, TI = 63,810 MW, and QI winter load = 36,000 MW.

changes. However, because the generation in the Pacific Norwest is some of the most responsive to frequency deviations in the Western Interconnection, the RAS also blocks frequency response by a number of generators and Balancing Authorities to avoid overloading the Pacific AC ties (such as the California–Oregon Interface (COI)).

Frequency events caused by the 3,200 MW generation trips from that RAS have not been considered historically as candidate events for the Western Interconnection calculation of frequency bias settings by the Balancing Authorities because of the response blocking. However, from an interconnection perspective, the frequency of the interconnection still must be maintained as a whole, regardless of which Balancing Authorities are responding to the event. This creates a dilemma when calculating an IFRO for the interconnection—the resultant resource loss is larger than the design loss criteria of two Palo Verde units (2,440 MW). Table 17 shows a comparison of the two resource losses in calculating the IFRO for the Western Interconnection.

Table 17: Western Interconnection IFRO Comparison

	2-PV	PNW RAS	Units
Starting Frequency	59.976	59.976	Hz
Max. Delta Frequency	0.291	0.291	Hz
Resource Contingency Protection Criteria	2,740	3,200	MW
Credit for LR	300		MW
IFRO[64]	-840	-1,101	MW/0.1Hz
Absolute Value of IFRO	840	1,101	MW/0.1Hz
% of Current Interconnection Performance[65]	71.2 %	93.4 %	
% of Interconnection Load[66]	0.56 %	0.74 %	

Using a 3,200 MW resource loss criterion in the IFRO calculation increases the obligation by 260 MW but is further complicated when that obligation is allocated to the Balancing Authorities in the interconnection; allocation of FRO to Balancing Authorities whose response is blocked by the RAS is inappropriate. Therefore, a different FRO allocation would be necessary for that IFRO.

Recommendation – NERC and the Western Interconnection should analyze the FRO allocation implications of the Pacific Northwest RAS generation tripping of 3,200 MW.

[64] IFRO =

[65] Current Interconnection Frequency Response Performance: WI = -1,179 MW / 0.1Hz.

[66] Interconnection projected Total Internal Demands from the 2010 NERC Long-Term Reliability Assessment: WI = 148,895 MW.

Comparison of IFRO Calculations

Table 18 shows a comparison of the four criteria analyzed by the TIS, as well as the criteria recommended by the NERC Resources Subcommittee (RS) in their white paper on frequency response. The table also compares the IFROs to current levels of frequency response performance[67] for each of the interconnections. A comparison is also made to IFROs adjusted to include the recommended adjustment for the differences between Value B and Point C.

Table 18: IFRO Calculation Comparison

	Eastern	Western	ERCOT	Québec	Units
Current Interconnection Frequency Response Performance	-2,467	-1,179	-586	N/A	MW/0.1Hz
Largest N-2 Event					
Resource Loss Criteria	3,854	2,740	2,750	1,700	MW
IFRO	-858	-840	-286	-179	MW/0.1Hz
IFRO as % of Current Performance	34.8%	71.2%	48.7%	23.9%	
IFRO as % of Load[68]	0.14%	0.56%	0.45%	0.50%	
Largest Total Plant with Common Voltage Switchyard					
Resource Loss Criteria	3,524	3,575	2,750	1,700	MW
IFRO	-785	-1,127	-286	-179	MW/0.1Hz
IFRO as % of Current Performance	31.8%	95.6%	48.7%	23.9%	
IFRO as % of Load	0.13%	0.76%	0.45%	0.50%	
Largest Resource Event in Last 10 Years					
Resource Loss Criteria	4,500	5,000	3,400	1,700	MW
IFRO	-1,002	-1,716	-423	-179	MW/0.1Hz
IFRO as % of Current Performance	40.6%	146.0%	72.2%	23.9%	
IFRO as % of Load	0.17%	1.16%	0.66%	0.50%	

[67] Based on the frequency response performance calculated in the daily CERTS-EPG Automated Reliability Reports for 2011 through August 16, 2011.

[68] Interconnection projected Total Internal Demands from the 2010 NERC Long-Term Reliability Assessment: EI = 604,245 MW, WI = 148,895 MW, TI = 63,810 MW, and QI = 20,599 MW.

Table 19 compares the recommended IFROs with those recommended by the Resources Subcommittee.

Table 19: IFRO Calculation Comparison					
	Eastern	Western	ERCOT	Québec	Units
Current Interconnection Frequency Response Performance	-2,467	-1,179	-586	N/A	MW/0.1Hz
Recommended IFROs					
Resource Loss Criteria	4,500	2,740	2,750	1,700	MW
IFRO	-1,692	-838	-286	-417	MW/0.1Hz
IFRO as % of Load	0.28 %	0.56 %	0.45 %	2.03 %	
RS Recommendation					
Resource Loss Criteria	4,500	2,740	2,750	1,700	MW
Base IFRO	-1,125	-548	-229	-113	MW/0.1Hz
25 % Margin	-281	-137	-57	-28	MW/0.1Hz
IFRO	-1,406	-685	-286	-141	MW/0.1Hz
IFRO as % of Load	0.23 %	0.46 %	0.45 %	0.68 %	

Allocation of IFRO to Balancing Authorities

The allocation of the IFRO to individual Balancing Authorities in a multi-Balancing Authority interconnection will be done in accordance with the “Attachment A – BAL-003-1 Frequency Response and Frequency Bias Setting Supporting Document,” which can be found at:

http://www.nerc.com/docs/standards/sar/Att_A_Freq_Response_Standard_Support_Document_100611.pdf)

The process is paraphrased here for brevity.

Once the IFROs have been calculated by the ERO, the FRO for each Balancing Authority in a multi-Balancing Authority interconnection is allocated based on the Balancing Authority’s annual load and annual generation to each Balancing Authority by the following formula:

$$FRO_{BA} = FRO_{Int} X \frac{AnnualGen_{BA} + AnnualLoad_{BA}}{AnnualGen_{Int} + AnnualLoad_{Int}}$$

Where:

- Annual Gen_{BA} is the total annual “Output of Generating Plants” within the Balancing Authority Area (BAA), on FERC Form 714, column C of Part II – Schedule 3.
- Annual $Load_{BA}$ is total annual load within the BAA, on FERC Form 714, column E of Part II – Schedule 3.
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection.
- Annual $Load_{Int}$ is the sum of all Annual $Load_{BA}$ values reported in that interconnection.

The data used for this calculation is from the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which used data from 2011. Balancing Authorities that are not FERC-jurisdictional will use the Form 714 instructions to assemble and submit equivalent data to the ERO for use in the FRO allocation process.

Balancing Authorities that elect to form a Frequency Response Sharing Group (FRSG) will calculate an FRSG FRO by summing the individual Balancing Authority FROs. Balancing Authorities that elect to form an FRSG as a means to jointly meet the FRO will calculate their FRM performance for the FRS Form 1 as follows:

- calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- jointly submit each Balancing Authority’s Form 1 with a summary spreadsheet that sums each participant’s individual event performance.

Balancing Authorities that merge or transfer load or generation are encouraged to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation to the interconnection remains the same and so that Control Performance Standard (CPS) limits can be adjusted.

Each Balancing Authority reports its previous year's Frequency Response Measure (FRM), frequency bias setting and frequency bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised frequency bias settings on FRS Form 1. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit FRS Form 1.

Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:

- frequency bias setting
- Frequency Response Obligation (FRO)

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined Balancing Authorities' areas on FRS Form 1 as described in Requirement R4 of the BAL-003-1 standard.

Frequency Response Performance Measurement

Interconnection Process

The process for detection of candidate interconnection frequency events for use in frequency response metrics is described in the ALR1-12 Metric Event Selection Process contained in Appendix W. It is paraphrased here for brevity.

Frequency Event Detection, Analysis, and Trending (for Metrics and Analysis)

Interconnection frequency events are detected through a number of systems, including:

- FNet (Frequency monitoring Network) – FNet is a wide-area power system frequency measurement system that uses a type of phasor measurement unit (PMU) known as a Frequency Disturbance Recorder (FDR). FNet is able to measure the power system frequency, voltage, and angle very accurately at a rate of 10 samplers per second. The FNet system is currently operated by the Power Information Technology Laboratory at Virginia Tech and the University of Tennessee, Knoxville. FNet alarms are received by the NERC Situational Awareness staff and contain an estimate of the size of the resource or load loss and general location description based on triangulation between FDRs.
- CERTS–EPG Resource Adequacy Tool Intelligent Alarms – The Electric Power Group (EPG) operates the Resource Adequacy (RA) tool developed under the auspices of the Consortium for Electric Reliability Technology Solutions (CERTS). The RA tool uses 1-minute frequency and area control error (ACE) SCADA data transmitted to a NERC central database. The RA tool constantly monitors frequency and produces many Smart Alarms for a number of frequency change conditions, but most useful for frequency event detection is the short-term frequency deviation alarm, which indicates when there has been a significant change in frequency over the last few minutes, typically indicating a resource loss.
- CERTS–EPG Frequency Monitoring and Analysis (FMA) Tool – EPG also developed and operates the FMA tool that allows rapid analysis of frequency events, calculating the A, B, and C values for a frequency event in accordance with parameters set by the Frequency Working Group (FWG). Event selection criteria are further discussed in Appendix E of this report.

Those three systems are used in combination by NERC staff to detect and collect data about frequency excursions in the four North American interconnections. The size of resource losses is verified with the Regional Entities for events where FNet estimates of resource loss meet the following criteria:

- Eastern: >1,000 MW (60 mHz excursion)
- Western: >700 MW (80 mHz excursion)
- ERCOT: >450 MW (100 mHz excursion)

Events that are detected and meet the ALR1-12 metric criteria are then considered to be "candidate events" and are used by NERC to calculate interconnection frequency response metrics and trends. Those candidate events are also presented to the Frequency Working Group for consideration to be used as events for calculation of Balancing Authority frequency response and bias setting calculations in accordance with NERC Standard BAL-003-1.

Ongoing Evaluation

The process for detection of frequency events and the calculation of Values A, B, and C and the associated interconnection level metrics will undergo constant review in an effort to improve the process. NERC staff and the Frequency Working Group will perform that review at least annually.

Recommendation –NERC staff and the Frequency Working Group should annually review the process for detection of frequency events and the method for calculating A and B Values and Point C. The associated interconnection frequency event database, methods for calculating interconnection metrics on risks to reliability, the associated probabilities, and the calculation of the IFROs using updated data should also undergo review in an effort to improve the process. Throughout this process, NERC should strive to improve the quality and consistency of the data measurements.

Balancing Authority Level Measurements

A statistical analysis and evaluation was performed on field trial data with similar sample sizes to those specified in the draft Standard BAL-003-1 Frequency Response and Frequency Bias Setting. Field trial data was provided on FRS Form 1 for 2011 for 60 Balancing Authorities on the Eastern and Western Interconnections; the analysis was not performed for either of the single Balancing Authority interconnections, (i.e., ERCOT or Québec). Of the 60 Balancing Authorities that provided data, only 50 provided data of sufficient quality to be used in the analysis. Balancing Authorities that were excluded provided frequency data that was either obviously incorrect (i.e., frequency data in hertz instead of change in hertz) or frequency data that was uncorrelated to the frequency measured in an interconnection.

To protect the confidential nature of the data, the Form 1 data was normalized by dividing the change in actual net interchange by the Frequency Response Obligation (FRO) for each Balancing Authority, based on Interconnection Frequency Response Obligations (IFROs) of -1,215 MW/0.1 Hz and -836 MW/0.1 Hz for the Eastern and Western Interconnections, respectively.[69] This normalization method converts all of the data from the actual frequency response of the Balancing Authority to a per-unit frequency response value where 1.0 indicates that the frequency response is exactly equal to the Balancing Authority's FRO. The process also required the development of the some of the data that would appear on the equivalent of the CPS2 Bounds Report under this revised standard. The required data was extracted from FERC Form 714 reports for the year 2009 and was estimated for those Balancing Authorities that did

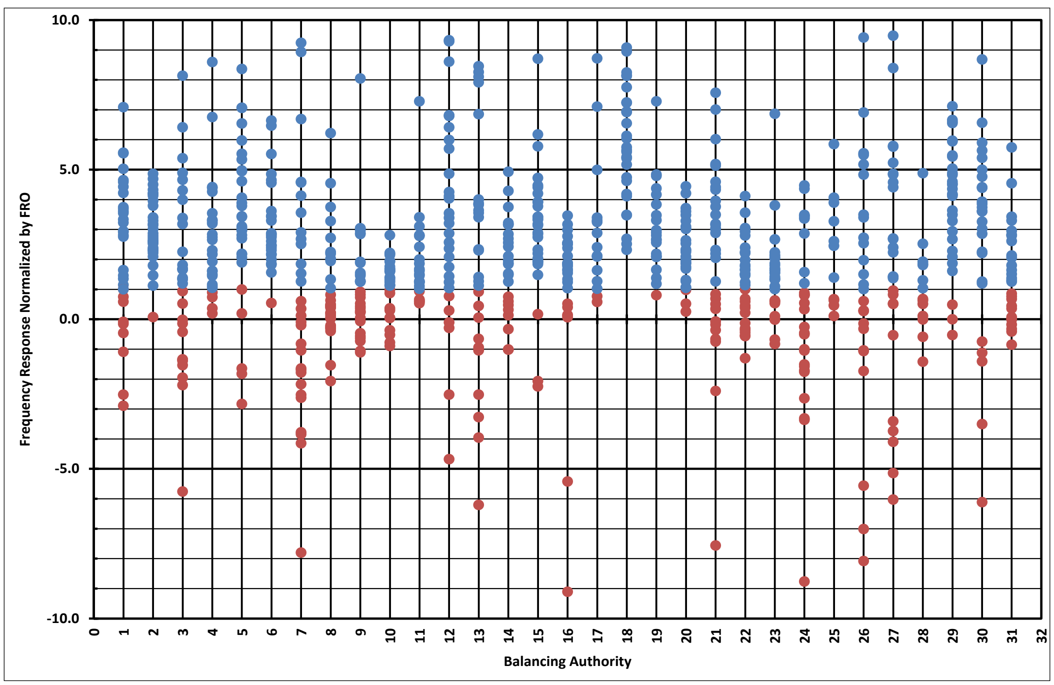
[69] As recommended by the Project 2007-12 Frequency Response Standards Drafting Team during the May 2012 Frequency Response Technical Conferences.

not submit 714 reports from equivalent data based on other sources. The validity of this analysis is not dependent upon the accuracy of the FRO estimates. It is only necessary for these estimates to be close to the actual values for firm conclusions to be drawn from the results and put the results in the proper context. Once the FROs were estimated for all of the Balancing Authorities on the Eastern and Western Interconnections, they were transcribed onto the FRS Form 1 for each Balancing Authority included in the analysis.

Single-Event Compliance

The question was posed whether or not a Balancing Authority's compliance with the proposed BAL-003-1 standard should be measured on each event, through use of the mean, median, or a regression analysis for a 12-month period. The variability of the measurement of frequency response for an individual Balancing Authority for an individual disturbance event was evaluated to determine its suitability for use as a compliance measure. The individual Balancing Authorities' performance disturbance events were normalized and plotted for each Balancing Authority on the Eastern and Western Interconnections.

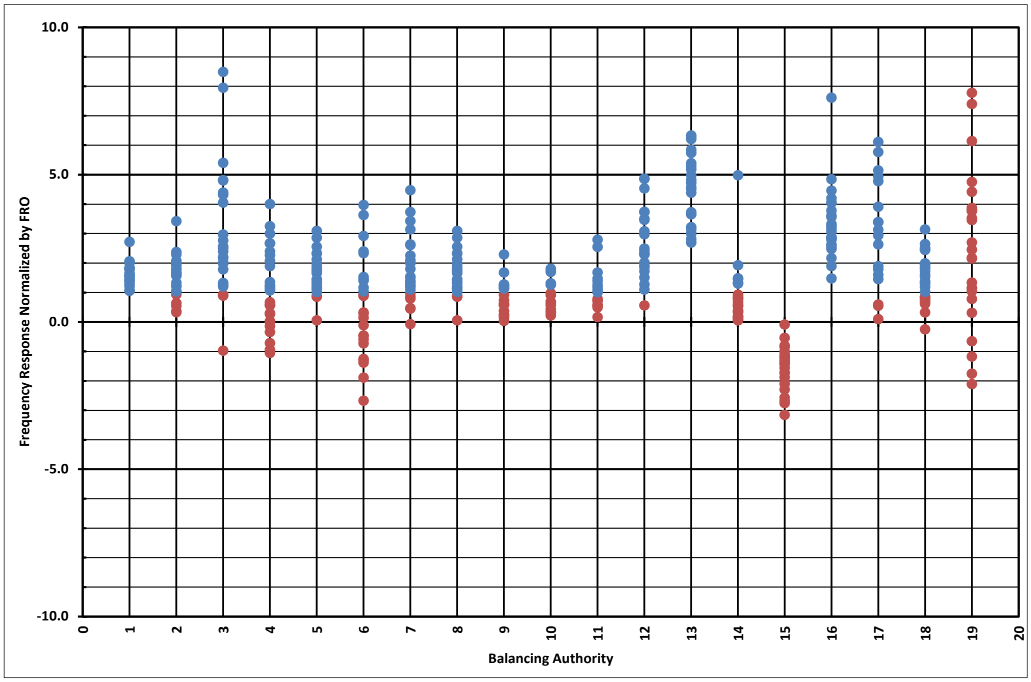
Figure 34: 2011 Normalized Frequency Response Events by BA Eastern Interconnection



On Figures 34 and 35, events that had a measured Balancing Authority's frequency response above its FRO were shown as blue dots, and events that had a measured frequency response below its FRO were shown as red dots.

Analysis of this data indicates that a single-event-based compliance measure is unsuitable for compliance evaluation when the data has the large degree of variability shown in the charts in Appendix 1. Based on the field trial data provided, only three out of 19 Balancing Authorities in the sample (16%) would be compliant for all events with a standard based on a single event measure on the Western Interconnection. Only one out of 31 Balancing Authorities in the sample (3%) would be compliant for all events with a standard based on a single-event measure on the Eastern Interconnection.

Figure 35: 2011 Normalized Frequency Response Events by BA Western Interconnection



Finding – Analysis of the field trial data indicates that a single-event-based compliance measure is unsuitable for compliance evaluation when the data has a large degree of variability.

Recommendation – Balancing Authority compliance with BAL-003-1 should not be judged on a per-event basis. Doing so would cause almost 90% of the Balancing Authorities to be out of compliance.

Balancing Authority Frequency Response Performance Measurement Analysis

Data provided by the Balancing Authorities from the field trial were also analyzed to determine: 1) if the sample size minimum of 20–25 frequency events, as specified for FRM calculation of the draft BAL-003-1 standard, is sufficient to provide stable measurements results; and 2) which of the three candidate FRM measurement methods is most appropriate. These analyses were carried out using the normalized data provided by a number of Balancing Authorities during the field trial.

Event Sample Size

Previous studies have recommended a sample size sufficient to provide a stable measure of frequency response of 20–25 events. These previous studies were performed on limited data and a limited number of Balancing Authorities. The field trial data set is sufficiently large to allow conclusions to be drawn with respect to that sample size recommendation specified for FRM calculation in the draft standard.

Review of the full set of graphs (Appendix H) indicates that the outlier problem, as previously described, did not present itself. There were no Balancing Authorities that had a small degree of variability in the measured single-event frequency response for most of the events that contained a few outliers.

The variability appeared similar for all events for each Balancing Authority, which indicates that the sample size of 20–25 events was sufficient to stabilize the result and eliminate any undue influence from potential outliers. In those Balancing Authorities with large variations in measured single-event response, the sample size was large enough that no single outliers unduly influenced the result. Balancing Authorities with large measurement variation still had enough samples to mitigate the risk associated with outliers. This demonstrates that the sample size chosen was sufficient to stabilize all three methods of measuring FRM. Therefore, it can be concluded that none of the methods are unduly influenced by outliers and the selection of the measurement method should be based on other factors.

Finding – Analysis of data submitted by the Balancing Authorities during the field trial confirms that the sample size selected (a minimum of 20–25 frequency events) is sufficient to stabilize the result and alleviate the perceived problem associated with outliers in the measurement of Balancing Authority frequency response performance.

Measurement Methods – Median, Mean, or Regression Results

All of the normalized data were analyzed using all three candidate methods for measuring FRM.

> **median** – Median is the numerical value separating the higher half of a one-dimensional sample, a one-dimensional population, or a one-dimensional probability distribution from the lower half. The median of a finite list of numbers is found by arranging all the observations from lowest value to highest value and picking the middle one. When the number of observations is even, there is no single middle value; the median is arbitrarily defined as the mean of the two middle values.
>
> In a sample of data, or a finite population, there may be no member of the sample whose value is identical to the median (in the case of an even sample size), and, if there is such a member, there may be more than one so that the median may not uniquely identify a sample member. Nonetheless, the value of the median is uniquely determined with the usual definition. A median is also a central point that minimizes the arithmetic mean of the absolute deviations. However, a median need not be

uniquely defined. Where exactly one median exists, statisticians speak of "the median" correctly; even when no unique median exists, some statisticians speak of "the median" informally.

The median can be used as a measure of location when a distribution is skewed, when end values are not known, or when one requires reduced importance to be attached to outliers; e.g., because they may be measurement errors. A median-unbiased estimator minimizes the risk with respect to the absolute-deviation loss function, as observed by Laplace.[70] For continuous probability distributions, the difference between the median and the mean is never more than one standard deviation. Calculation of medians is a popular technique in summary statistics and summarizing statistical data, since it is simple to understand and easy to calculate. It also gives a measure that is more robust in the presence of outlier values than the mean.

mean – Mean is the numerical average of a one-dimensional sample, a one-dimensional population, or a one-dimensional probability distribution. A mean-unbiased estimator minimizes the risk (expected loss or estimate error) with respect to the squared-error loss function, as observed by Gauss.[71] The mean is more sensitive to outliers for the very reason that it is a better estimator; it minimizes the squared-error loss function.

linear regression – Linear regression is the linear average of a multi-dimensional sample, or a multi-dimensional population. A linear regression unbiased estimator minimizes the risk (expected loss or estimate error) with respect to the squared-error loss function in multiple dimensions, as observed by Gauss.[72] The linear regression is also sensitive to outliers for the very reason that it is a better estimator; it minimizes the squared-error loss function.

Important Considerations

The following issues are important to consider with respect to the selection of the best method for measuring frequency response.

two-dimensional measurement – Two-dimensional measurement of frequency response provides the best representation of the change in MWs divided by the change in frequency and is used to estimate the frequency bias setting, which indicates the frequency response in MWs provided at actual frequency as compared to scheduled frequency.

non-linear attribute of frequency response – The non-linear attribute of frequency response has been demonstrated on all of the North American interconnections and is an important consideration in the representation of frequency response.

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[70] An absolute-deviation loss function is used to minimize the risk of estimate error when dealing with uniform distributions. Appendix 3 provides a description of Uniform Distributions and a derivation of the median.

[71] A squared-error loss function is used to minimize the risk when dealing with normal (Gaussian) distributions. Appendix 4 provides a description of normal (Gaussian) distributions and a derivation of the mean.

[72] Appendix H provides a derivation of the linear regression.

single best estimator – A single best estimator of frequency response is a necessary result for use in compliance evaluation.

linear system – A linear system[73] is assumed in the development of the individual Frequency Response Obligation for each Balancing Authority on a multiple Balancing Authority interconnection and is used to distribute the Interconnection Frequency Response Obligation among the Balancing Authorities on that interconnection. If the system is non-linear,[74] then it cannot be assumed that the total required Interconnection Frequency Response Obligation will be achieved when all Balancing Authorities provide their individual Frequency Response Obligations.

bi-modal distributions – Bi-modal distributions occur whenever a reconfiguration of Balancing Authorities occurs within a compliance year. Unless the method chosen can correctly represent bi-modal distributions, reconfigured Balancing Authorities cannot be effectively measured for compliance.

quality statistics – Quality statistics should be available for use in compliance evaluation. Frequency response is used to determine compliance with minimum provision of the Balancing Authority's obligation for providing its share of frequency response for the interconnection. When using a measure for compliance, one must ensure that the measure fairly represents the Balancing Authority's performance. There is still a presumption that an indication of non-compliance should not occur due to pure chance.

reducing influence of noise – Reducing influence of noise in the data is considered an important attribute in the measurement method. All measurements of frequency response will be affected by noise in the measurement process.

reducing influence of outliers – Reducing influence of outliers in the data is considered the most important attribute in the measurement method. All measurements of frequency response will be affected by true outliers. The risk associated with the reduction in the influence of outliers is that valid information about the measure is also lost when an outlier reduction method is used.

ease of calculation and familiar indicators – Ease of calculation and familiar indicators are important considerations for communication and to promote ease of understanding by the industry.

Appendix H presents the series of graphs indicating results for each Balancing Authority. Each graph shows all of the individual data points use to determine the median, mean, and regression lines.

[73] A linear system is a system in which the sum of the parts is equal to the whole.
[74] A non-linear system is a system in which the sum of the parts is not equal to the whole.

The median line is green, the mean line is blue, and the regression line is red. The value of the normalized frequency response (vertical axis) where the line intercepts the value of frequency (horizontal axis) at a value of 0.1 Hz indicates compliance. Values above 1.0 indicate an FRM above the FRO, and values below 1.0 indicate an FRM below the FRO.

Figure 36 shows an example of a Balancing Authority with a small degree of variability in the measured frequency response for each individual event.

Figure 36: BA with Small Degree of Variability in Measured Frequency Response

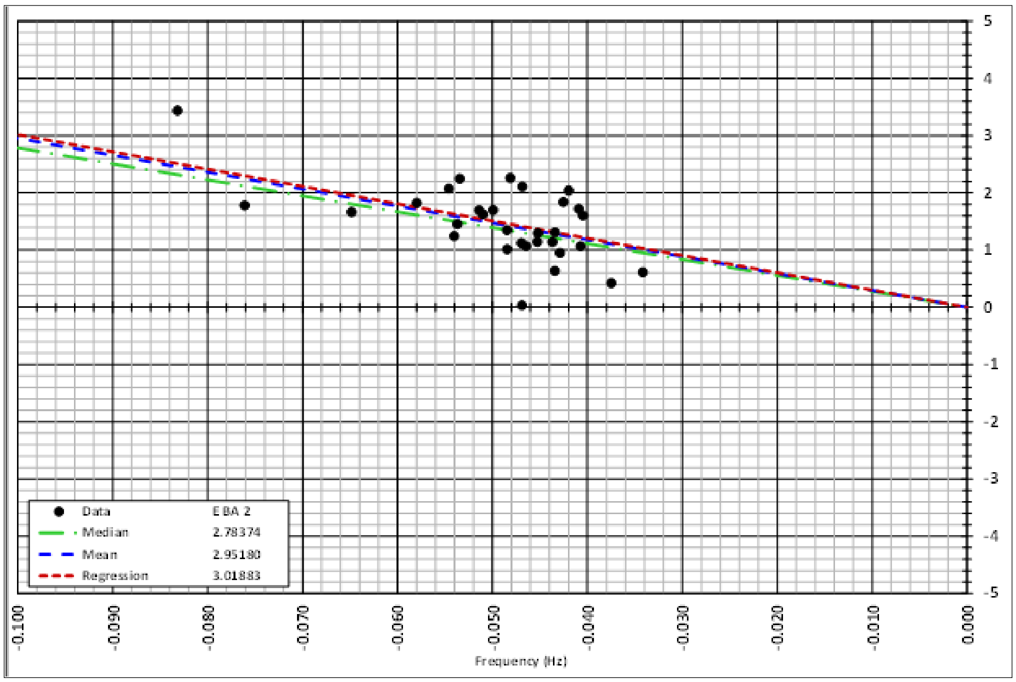
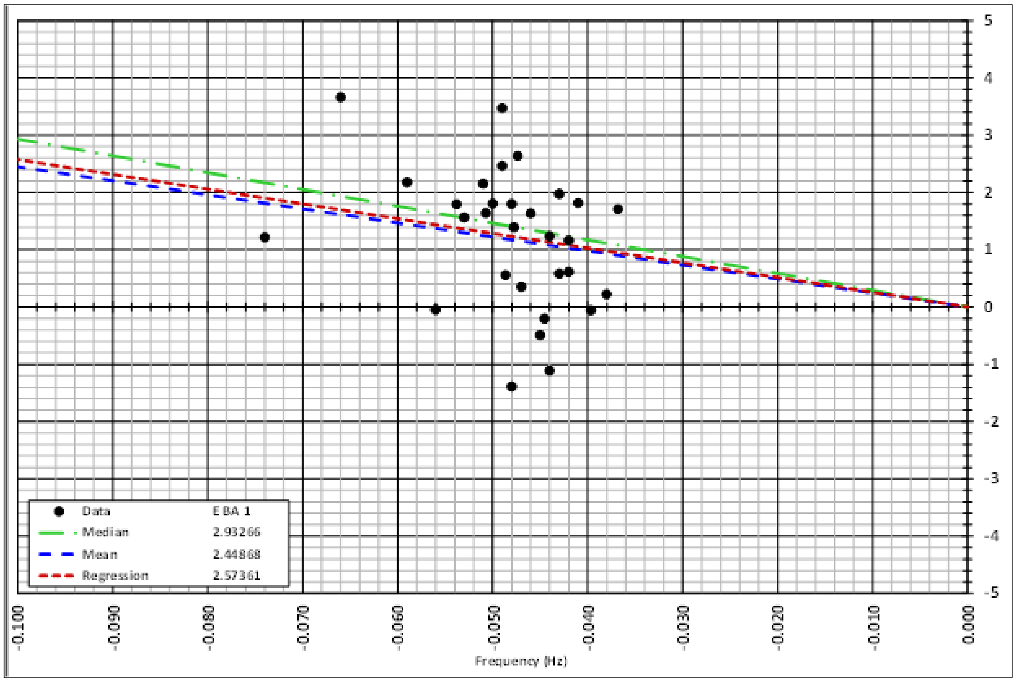


Figure 37 shows an example of a Balancing Authority with a large degree of variability in the measured frequency response for each individual event.

During the analysis, the graphs appeared to show that the regression provided a higher estimate of FRM than the median. Consequently, a comparison was made between the FRM as measured by the median and the FRM as measured by the regression. The results of the regression analysis demonstrate a performance for all samples that is 0.087% of their FRO higher than the median's performance on the Eastern Interconnection and 0.117% of their FRO higher than the median's performance on the Western Interconnection. In an unbiased analysis, one would expect the median and regression to yield the same result. This indicates there is an unknown statistical bias affecting the results of the analysis.

Figure 37: BA with Large Degree of Variability in Measured Frequency Response

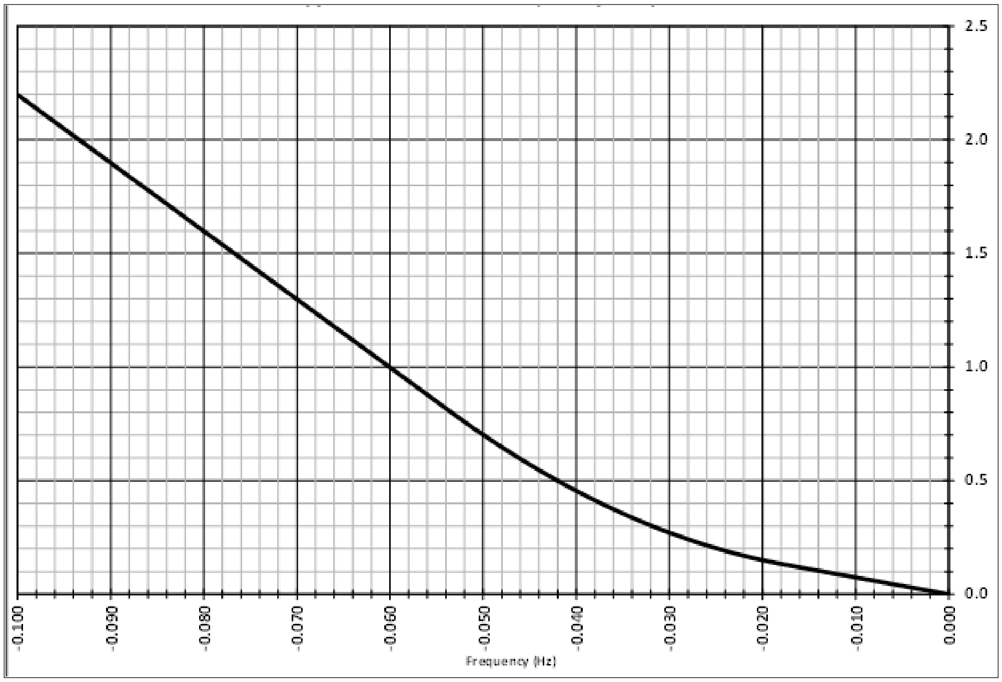


The bias causing the difference between the median and regression results can be explained by an attribute of frequency response. As the frequency deviation increases for larger disturbance events, the frequency response increases, but it does so disproportionately, shown in figure 38. This attribute of frequency response has been demonstrated in technical papers.[75] It has also been implemented in the variable frequency bias settings used by ERCOT, BPA and BC Hydro. In simple terms, the regression includes the effect of this non-linear attribute and the median does not.

The regression accommodates the disproportion on the slope of the regression line. In this case the effect tends to be upward—ever bigger MWs per increment in size of larger frequency error. The median is biased against any disproportionate increase in response per increase in size of frequency error as part of the median's blindness to outliers. The median will give no credit for the ever-growing amount of MWs deployed per added increment in size of frequency error. All the median does is count the number of MW responses regardless of size and, to represent all the MW responses, choose the one that occurred half-way in the sequence of decreasingly negative and increasingly positive frequency errors. Therefore, the median underestimates the FRM because it cannot evaluate the non-linear attribute correctly. It does not see or notice that attribute at all through its blinders regardless of numerical order or placement in a sequence. Regression is the only measurement method that captures the non-linear frequency response correctly.

[75] Hoffman, Stephen P., Frequency Response Characteristic Study for ComEd and the Eastern Interconnection, Proceedings of the American Power Conference, 1997. Kennedy, T., Hoyt, S. M., Abell, C. F., Variable, Non-linear Tie Line Frequency Bias for Interconnected Systems Control, IEEE Transactions on Power Systems, Vol. 3, No. 3, August 1988.

Figure 38: Typical Non-Linear Frequency Response



The advantages of each method of measurement are presented in Table 20 – Median, Mean and Regression Comparison. The alphabetic key is below.

Table 20: Median, Mean, and Regression Comparison

Attribute	Median	Mean	Regression
Provides two-dimensional measurement	A	A	Yes
Represents non-linear attributes	B	B	Yes
Provides a single best estimator (single value)	C	Yes	Yes
Is part of a linear system		Yes	Yes
Represents bi-modal distributions	D	Yes	Yes
Quality statistics available	E	Yes	Yes
Reducing influence of noise	Yes (F)		Partial (G)
Reducing influence of outliers	Yes		Partial (H)
Easy to calculate	Yes	Yes	I
Familiar indicator	Yes	Yes (J)	No
Currently used as the measure in BAL-003-1	No	Yes	No

A. Neither median nor mean can evaluate the two-dimensional nature of frequency response.

B. Neither median nor mean can capture the non-linear attribute of frequency response. Both underestimate the typical non-linear frequency response.

C. Median is arbitrarily defined as the average of the two central values when there is an even number of values in the data set. The decision to further constrain this central range of values to a single value that is the average of the ends of that range is unsupported by any mathematical construct. It is only the desire of those looking for simplicity in the result that supports this singular definition of median.

D. The median fails to provide a valid estimate of frequency response when the distribution of frequency event responses is bi-modal due to Balancing Authority reconfiguration or changes in responsibility for control such as partial-period overlap of supplemental control.

E. The median fails to provide any methods to determine the quality, significance, or confidence associated with the measure.

F. The median reduces the influence of noise in the data, but that noise reduction comes with the cost of eliminating the availability of any quality statistics.

G. Linear regression provides a result that weights the data according to the change in frequency. Since the noise in the data is independent of change in frequency, linear regression provides a method superior to the mean for reducing the influence of noise in the resulting estimate of frequency response.

H. Linear regression is less sensitive to outliers and large data errors than the mean.

I. Linear regression is more complex and requires more effort to calculate, but that additional effort is small when the evaluation process has been automated.

J. Mean is currently used as the measure in the proposed draft BAL-003-1 standard.

After consideration of the mitigating effects of the sample size with respect to outliers, the linear regression method is the preferred method for calculating the frequency response Measure (FRM) for Balancing Authorities for compliance with proposed NERC Standard BAL-003-1 – Frequency Response.

Recommendation – Linear regression is the method that should be used for calculating Balancing Authority Frequency Response Measure (FRM) for compliance with Standard BAL-003-1 – Frequency Response.

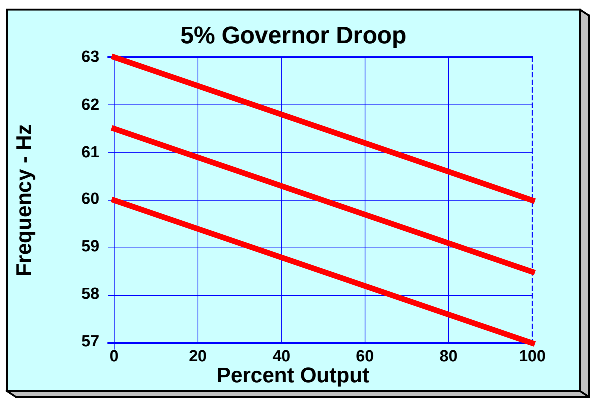
Role of Governors

Deadband and Droop

Turbine-generator units use turbine speed control systems, called governors, to control shaft speed by sensing turbine shaft speed deviations and initiating adjustments to the mechanical input power to the turbine. This control action results in a shaft speed change (increase or decrease). Since turbine-generators rotate at a variety of speeds, outside the power plant it is more appropriate to generally relate shaft speed to system frequency and throttle valve position to generator output power (MW).

The expected response of a turbine-generator's governor to frequency deviations is often plotted on what is known as a governor droop characteristic curve or a droop curve. The curve shows the relationship between the generator output and system frequency. The curve droops from left to right. Simply stated, as the frequency decreases, the generator's output will increase in accordance with its size.

Figure 39: Sample Droop Characteristic Curve



Droop settings on governors are necessary to enable multiple generators to operate in parallel while on governor control while not competing with each other for load changes. Droop is expressed as a percentage of the frequency change required for a governor to move a unit from no-load to full-load or from full-load to no-load. Prior to 2004, NERC Operating Policy 1, Generation Control and Performance, recommended generators with governor control (typically 10 MW and larger) to have a droop setting of 5% for steam turbine (and 4% for combustion turbines, although not explicitly stated in the policy). This means that a 3 Hz (5% of 60.00 Hz) change in system frequency is required to move a generator across its full range. Normally governors respond only to substantial frequency deviations.

Guidelines of the 2004 NERC Operating Policy 1, Generation Control and Performance, section C, stated:

1. Governor installation – Generating units with nameplate ratings of 10 MW or greater should be equipped with governors operational for frequency response unless restricted by regulatory mandates.
2. Governors free to respond – Governors should be allowed to respond to system frequency deviation unless there is a temporary operating problem.
3. Governor droop – All turbine-generators equipped with governors should be capable of providing immediate and sustained response to abnormal frequency excursions. Governors should provide a 5% droop characteristic. Governors should, at a minimum, be fully responsive to frequency deviations exceeding ±0.036 Hz (±36 mHz).
4. Governor limits – Turbine control systems that provide adjustable limits to governor valve movement (valve position limit or equivalent) should not restrict travel more than necessary to coordinate boiler and turbine response characteristics.

Within the Frequency Response Initiative, NERC is considering modifications to those parameters based on the recent advances in frequency response performance in ERCOT and revised governor control parameters.

In 2010, NERC conducted a survey of governor status and settings through Generator Owners and Generators Operators. The results of that survey are summarized in the Generator Governor Survey section of this report. A complete set of the summary graphics of the survey is contained in Appendix K.

ERCOT Experience

The general decline in primary frequency response in all interconnections has prompted regulatory entities to address the issue. Electric grids such as the one in Texas are especially sensitive to frequency regulation and response due to their relatively small overall interconnected capacity compared to the other interconnections. The Texas Regional Entity (TRE) is actively working on a regional standard for frequency regulation.

Frequency Regulation

Electric grid frequency regulation is attained by the response of the turbine governors to deviations from nominal synchronous speed, the operation of the boilers-turbine controls in response to the frequency change, and the actions of the dispatching system.

Frequency regulation success for any given boiler-turbine plant depends on many factors, primarily:

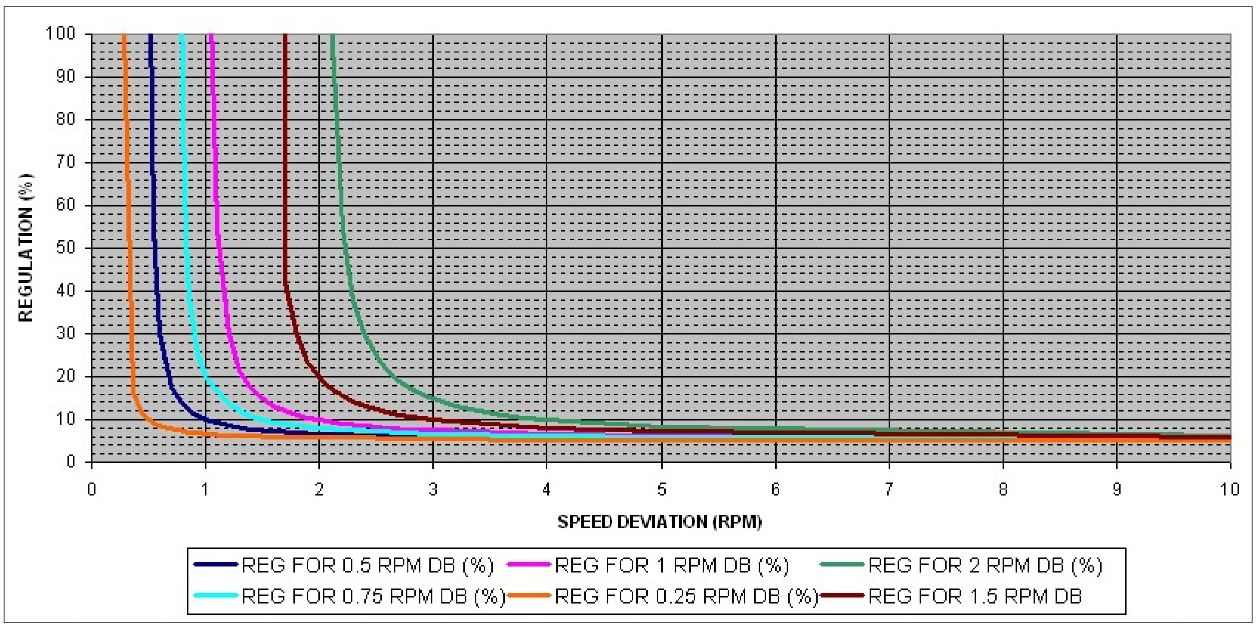
- steady state and dynamic stability of the unit
- load following capability
- linearization of turbine governor valves' steam flow characteristics
- proper calibration and coordination of the boiler and turbine frequency regulation parameters

- proper high and low limiting of the boiler and turbine frequency regulation based on unit conditions
- proper dispatching actions to restore the frequency to its normal operating value

Another factor that influences a unit's capability for frequency regulation is the available boiler energy storage. The larger the storage, the less the initial pressure drop caused by the quick opening of the governor valves, and the better the initial unit frequency regulation.

The standard speed regulation setting for the turbine governors of the boiler-turbine generating units is 5%. This is a ±5% change from rated speed (0.05*3,600 = 180 RPM), which causes the turbine governor to change its valves' position demand ±100 percent. It is also generalized industry practice to add a small deadband (DB) to the calibration of the governor speed error bias in order to minimize the movement for very small speed deviations. The selection of the DB affects the fidelity of the regulation, as shown in figure 40.

Figure 40: Regulation versus RPM Deadbands



The regulation curves of figure 40 are for the noted speed regulation at constant pressure. They are calculated by developing the equation ΔGVD= f (ΔRPM) for each DB, where ΔGVD is the change in the turbine Governor Valve Demand as a function of the change in RPM.

Knowing the ΔGVD for any given ΔRPM enables the regulation calculation via the equation:

$$REG\ (\%) = (100 * \Delta RPM/\Delta GVD)*(100/3{,}600)$$

ERCOT Nodal Operating Guides Section 2 has specific requirements for governor deadband settings. The maximum allowable deadband is ±0.036 Hz, which has been the industry standard for mechanical "fly-ball" governors on steam turbines for many years. With the development of energy markets in the early 2000s, generators with electronic or digital governors began implementing this same deadband in their primary frequency response implementation. Unfortunately, the Guides were not clear on how to implement the droop curve at the deadband. Since the Guides required 5% droop performance, many generators introduced a "step function" or modified "step" once the deadband was reached in order to achieve near 5% droop performance outside the deadband.

As can be seen in figure 40, a 2 rpm deadband on a 3,600 rpm turbine is equivalent to +/-0.033 Hz. Based on the corresponding droop (regulation percent) for this deadband, a generator's performance to typical frequency deviations during disturbances would be much greater than 5% without some "step" function. These governor settings resulted in an abnormal frequency profile for the interconnection.

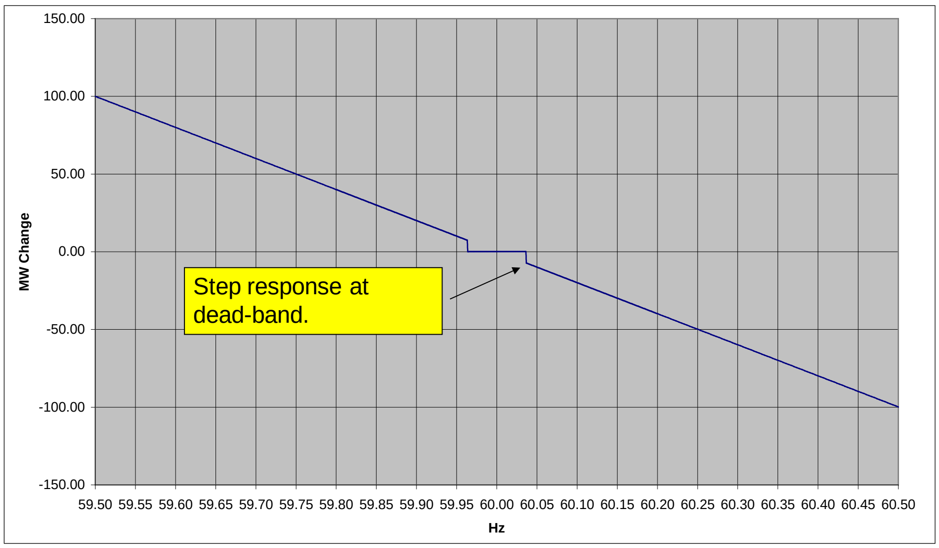
Figure 41: Frequency Profile for March and September 2008
(in 5 mHz bins)

Figure 41 is the ERCOT frequency profile for March and September of 2008. It is clear that the "flat top" of the profile is centered on the ±0.036 Hz deadband. This flat frequency profile created significant problems because frequency spent as much time at the governor deadband points as it did at any point in between. This made it difficult to employ Frequency Regulation to correct frequency to 60 Hz, and for ERCOT to meet the NERC BAL-001-0 — Real Power Balancing Control Performance Requirement 1 (aka, CPS1), since ERCOT had an epsilon-1 limit of 0.030 Hz. The frequency profile also contributed to generator instability at the deadbands with the implementation of the various "step" functions in the governors.

If generators that had implemented governor step functions were to be electrically separated from the grid during an islanding event, they would experience extreme instability. This would be caused by the governor providing excessive frequency response to the island to small generation load imbalances, resulting in large frequency swings and unit instability.

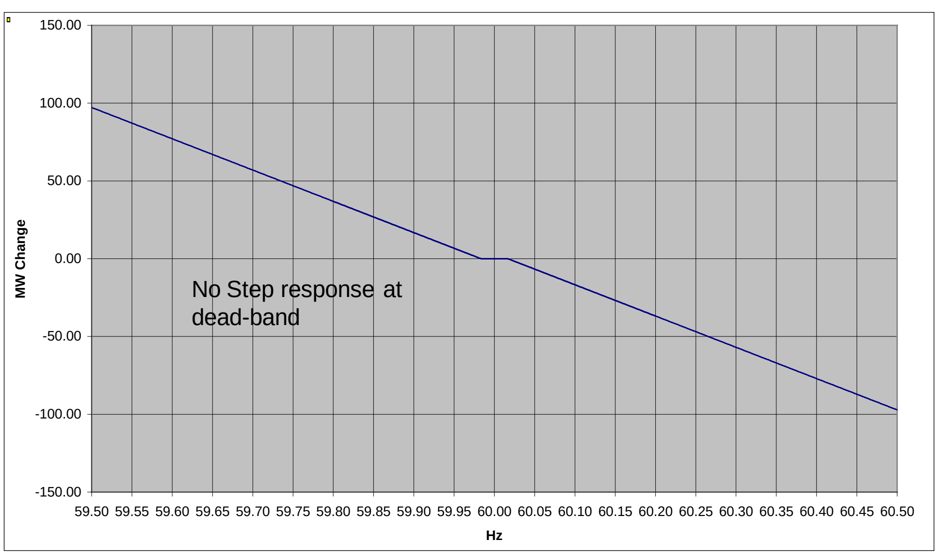
The ERCOT Performance Disturbance and Compliance Working Group (PDCWG) became increasingly concerned about the frequency instability and the realization of the risk of the step function in the governors (see figure 42). Because of their analysis, a member of the PDCWG discussed the issues with one large generating facility that was willing to try different deadband settings along with a specific droop curve implementation. This implementation required a straight linear curve from the deadband to full range of the governor, eliminating any step function shown in figure 43.

Figure 42: Frequency Response of 600 MW Unit ±36.0 mHz Deadband and Step Response



After brief testing of a number of different deadbands, a 1-rpm deadband (± 0.01666 Hz) was chosen. Four turbine governors were set in this manner on November 3, 2008 (about 2,500 MW capacity or 7.5% of the average grid capacity in November).

Figure 43: Frequency Response of 600 MW Unit ±16.67 mHz Deadband and No-Step Response



The possibility of leaving the deadband at ±0.036 Hz and just eliminating the stepped droop response was considered. Analysis showed that the droop performance at 59.900 Hz would be around 7.72% with a ±0.036 Hz deadband but only 5.97% droop with the ±0.0166 Hz deadband. That difference increases at 59.950 Hz, with a 17.64% droop performance for the ±0.036 Hz deadband and a 7.46% droop performance for the ±0.0166 Hz deadband. However, without the primary frequency response of the lower deadband, the frequency profile would return to the "flat top" frequency profile spanning the ±0.036 Hz deadbands, which is a less reliable state (less stable) for the interconnection. Also, with the larger deadband the interconnection or Balancing Authority may not have been able to meet the minimum frequency response requirements.

Turbine-Generator Performance with Reduced Deadbands

The general purpose for using governor deadbands is to minimize generator movement due to frequency regulation. In an interconnection where generators have various deadband settings, the diversity of settings creates diversity in responses to frequency changes. However, when a majority of the generators in an interconnection set the deadband the same and with a step function, the diversity of responses disappears, and frequency will move to the deadband frequently as demonstrated in the profile in figure 41. When the frequency exceeds the deadband, all units react with a stepped response simultaneously.

The amount of generator movement expected for a specific set of deadband settings can be compared by calculating the MW-minute average movement of a hypothetical generator exposed to actual measured frequency using the different governor settings.

Table 21 compares the movement of two generators with different governor settings: one with a ±0.036 Hz deadband and droop step function, and one with a ±0.01666 Hz deadband and no droop step function.

Table 21: Comparison of MW Movement for Response of Different Governor Settings

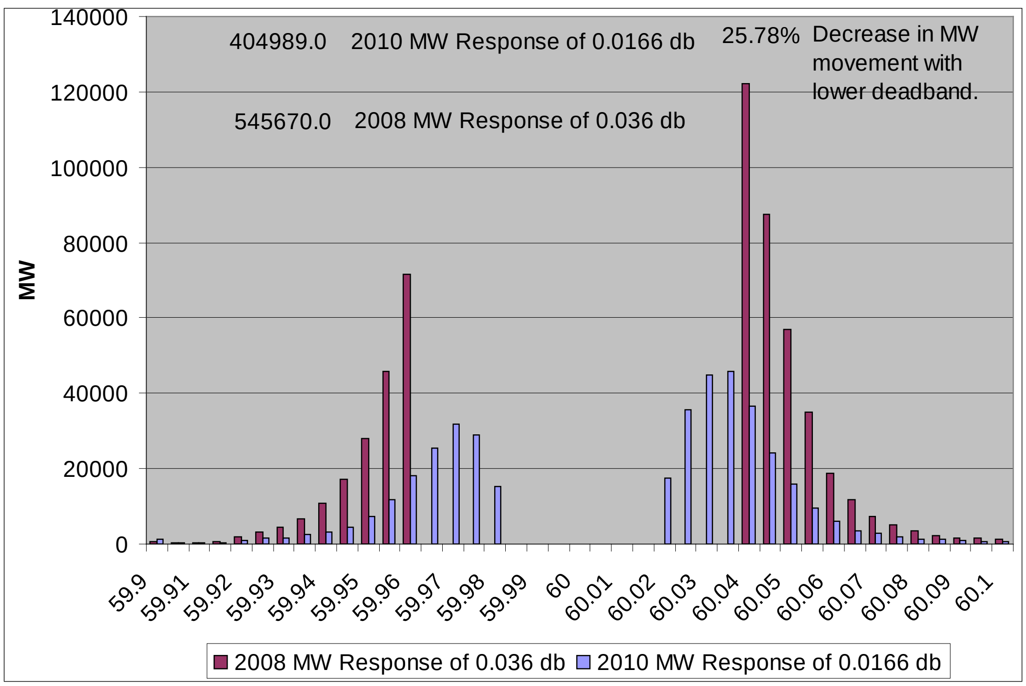
	±0.036 Hz Deadband with Droop Step Function	±0.01666 Hz Deadband with No Droop Step Function	Percent Increase for Smaller Deadband
2008 Frequency Profile	662,574.0 MW-min.	893,164.2 MW-min.	34.80%
2009 Frequency Profile	446,244.0 MW-min.	692,039.8 MW-min.	55.08%

Using the 2008 1-minute average frequency data, the generator with the lower deadband would have had 893,164.2 MW-minutes of primary frequency response while the generator with the larger deadband unit would have had 662,574.0 MW-minutes of primary frequency response. This is a 34.80% increase in movement for the lower deadband generator.

However, if the exact same comparison is made for ERCOT frequency data from 2009, where the new deadbands had an actual impact on frequency, the following observation scan be made. The lower deadband generator would have had 692,039.8 MW-minutes of primary frequency response compared to the larger deadband generator with 446,244.0 MW-minutes, a 55.08% increase in movement for the lower deadband. One observation is that the MW-minute movement of the lower deadband generator is only 4.45% higher than the movement of the larger deadband generator of the previous year (692,039.8 MW-minutes versus 662,574.0 MW-minutes).

Having the lower deadband in service for the entire year greatly reduced the frequency movement of the interconnection and reduced the primary frequency response movement as well. The lower deadband generator MW-minute movement decreased 201,124.4 MW-minutes, or 22.518%, between 2008 and 2009. This indicates the reduced impact on the generator movement with the smaller deadband and the non-step governor droop implementation when the governor becomes active, as compared to the "step" implementation.

Figure 44: MW-Minute Movement of a 600 MW Unit with 5% Droop



This benefit is further emphasized by the comparison in Figure 44, which shows the response of a theoretical 600 MW unit for the 2008 ERCOT frequency profile with a ±0.036 Hz deadband versus the same unit with a ±0.01666 Hz deadband for the 2010 frequency profile. Using the lower deadband, there is a savings of 140,641 MW-minutes of regulation movement because there were a larger number of generators using the ±0.01666 Hz deadband in 2010, which greatly influenced the frequency profile. Figure 45 shows a comparison of the actual January–September ERCOT frequency profiles for 2010 and 2008. The profile changed from a flat response between the ±0.036 Hz deadband to a more normal distribution.

Figure 45: ERCOT 2010 versus 2008 Frequency Profile (Jan.–Sept.)

Conclusion – The benefits of using the smaller ±0.01666 Hz deadband coupled with a non-step governor droop implementation results in the following:

- improved frequency response for small disturbances
- generators responding more often in smaller increments, saving fuel and wear and tear on turbines
- more stable operation when near boundary conditions of deadbands

Recommendation – NERC should embark immediately on the development of a Frequency Response Resource Guideline to define the performance characteristics expected of those resources for supporting reliability. That guideline should address appropriate parameters for:

Existing generator fleet – In order to retain or regain frequency response capabilities of the existing generator fleet, adopt:

deadbands of ±16.67 mHz,

droop settings of 3%-5% depending on turbine type,

continuous, proportional (non-step) implementation of the response,

appropriate operating modes to provide frequency response, and

appropriate outer-loop controls modifications to avoid primary frequency response withdrawal at a plant level.

Other frequency-responsive resources – Augment existing generation response with fast-acting electronically coupled frequency responsive resources, particularly for the arresting and rebound periods of a frequency event:

contractual high-speed demand-side response,

wind and photo-voltaic – particularly for over-frequency response,

storage – automatic high-speed energy retrieval and injection, and

variable speed drives – non-critical, short time load reduction.

Generator Governor Survey

On September 9, 2010, NERC issued a Generator Governor Information and Setting Alert (the alert) recommending that Generator Owners (GOs) and Generator Operators (GOPs) provide information and settings for turbine governors for all generators rated at 20 MVA or greater, or plants that aggregate to a total of 75 MVA or greater net rating at the point of interconnection (i.e., wind farms, PV farms, etc.). The alert was issued as a recommendation to industry, which requires reporting obligations (as specified in Section 810 of the Rules of Procedures) from industry to NERC and, subsequently, from NERC to FERC. Balancing Authorities in North America were the only functional group required to respond to this alert. A copy of the survey instructions is located in Appendix J of this report.

The survey requested three types of information:

1. policies on installation and maintenance, and testing procedures and testing frequency for governors;
2. unit-specific characteristics and governor settings; and
3. unit-specific performance information for a recent, single event.

NERC sent the survey instrument and instructions to 799 GOs and 748 GOPs in North America. Of the 794 GOs that acknowledged receipt of the survey, 749 developed and provided a response. Of the 743 GOPs that acknowledged receipt of the survey, 721 developed and provided a response.

Administrative Findings

NERC staff first reviewed the information submitted by the GOs and GOPs. This initial review led to the following findings from the administration of the survey:

1. There is a wide variety of levels of understanding among GOs and GOPs of the role of turbine governors in maintaining frequency response, including confusion in terminology and a lack of understanding of governor control settings. This indicates a need for education on settings and performance of turbine governors and the governor's role in interconnection frequency response.

Recommendation – NERC should address improving the level of understanding of the role of turbine governors through seminars and webinars, with educational materials available to GOs and GOPs on an ongoing basis.

2. There was a significant amount of duplication of reporting. This was mostly due to dual submittals by entities that are registered both as GOs and as GOPs. NERC staff sought to eliminate as much duplication as possible. However, eliminating duplication was difficult when the entities that own and operate a generator differ, yet both submitted information on the same generator. Hence, there remains some duplication in this analysis.

Summary of the Survey Responses

Table 22 summarizes, by interconnection, the aggregate characteristics of the generators analyzed.

Table 22: Number of Generators as Reported

Interconnection	Total	With Governors	Without Governors
Eastern	4,372 (648.7 GW)	4,217 (630.2 GW)	152 (18.5 GW)
Western	1,560 (171.6 GW)	1,445 (162.9 GW)	114 (8.7 GW)
ERCOT	503 (95.6 GW)	446 (85.6 GW)	53 (9.0 GW)
Totals	6,435 (915.9 GW)	6,110 (878.7 GW)	319 (36.2 GW)

Figures 46–48 summarize the responses on turbine governors for three of the interconnections. Data for the Québec Interconnection is not summarized in this report. The GOs and GOPs reported that governors were operational for 95%, 97%, and 99% of the total number of generating units that were reported as having governors in the Eastern, Western, and Texas Interconnections, respectively.

Figure 46: Eastern Interconnection Generator Responses

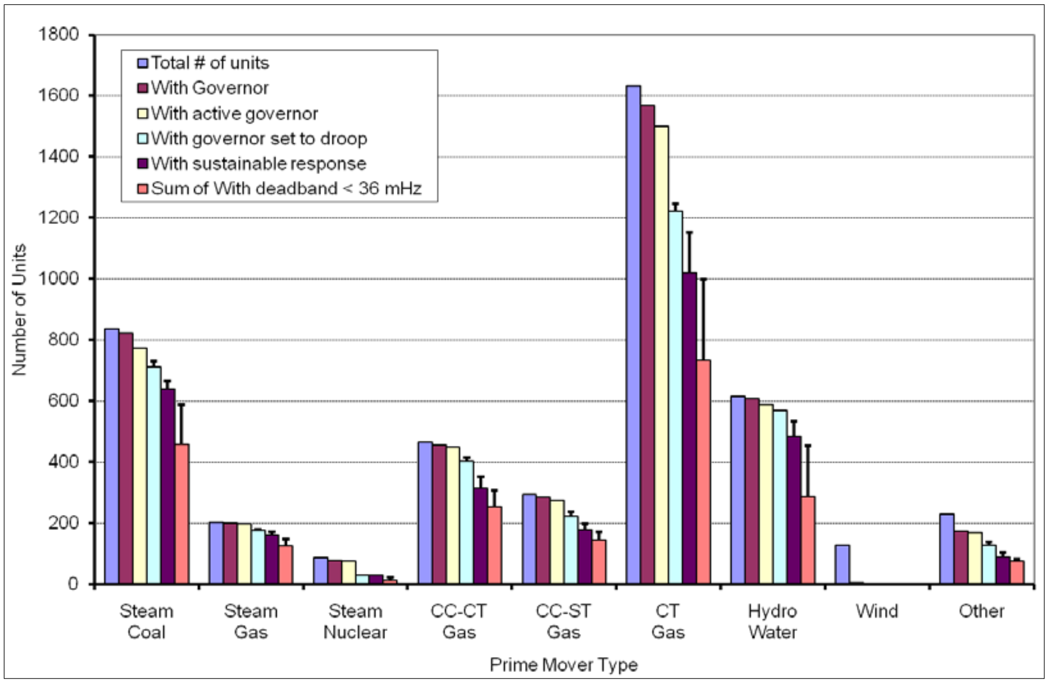


Figure 47: Western Interconnection Generator Responses

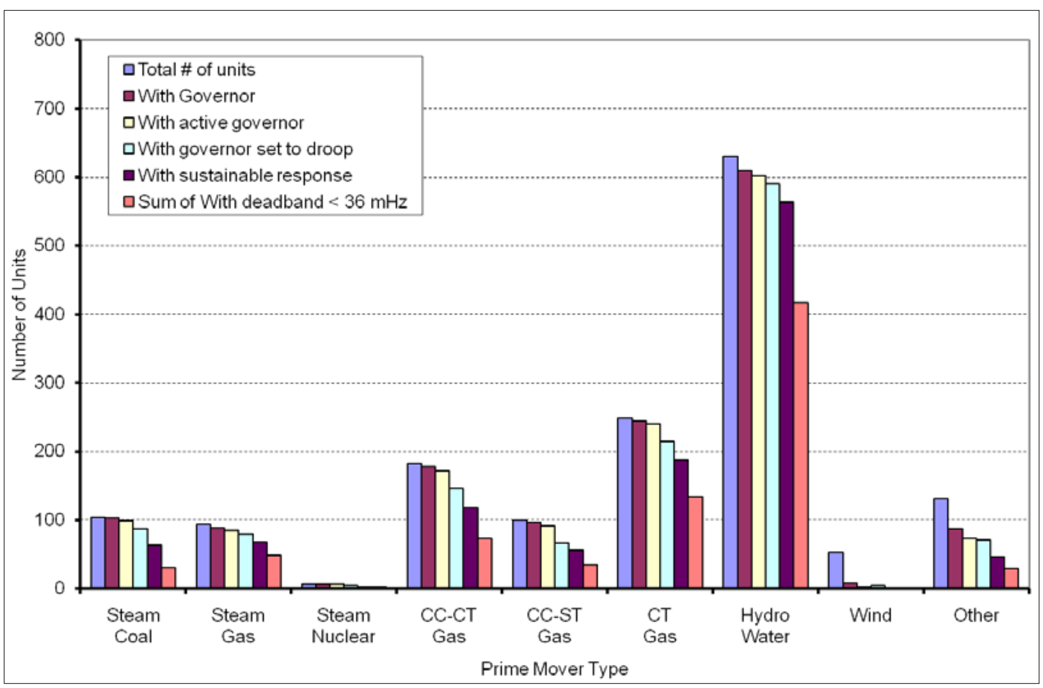
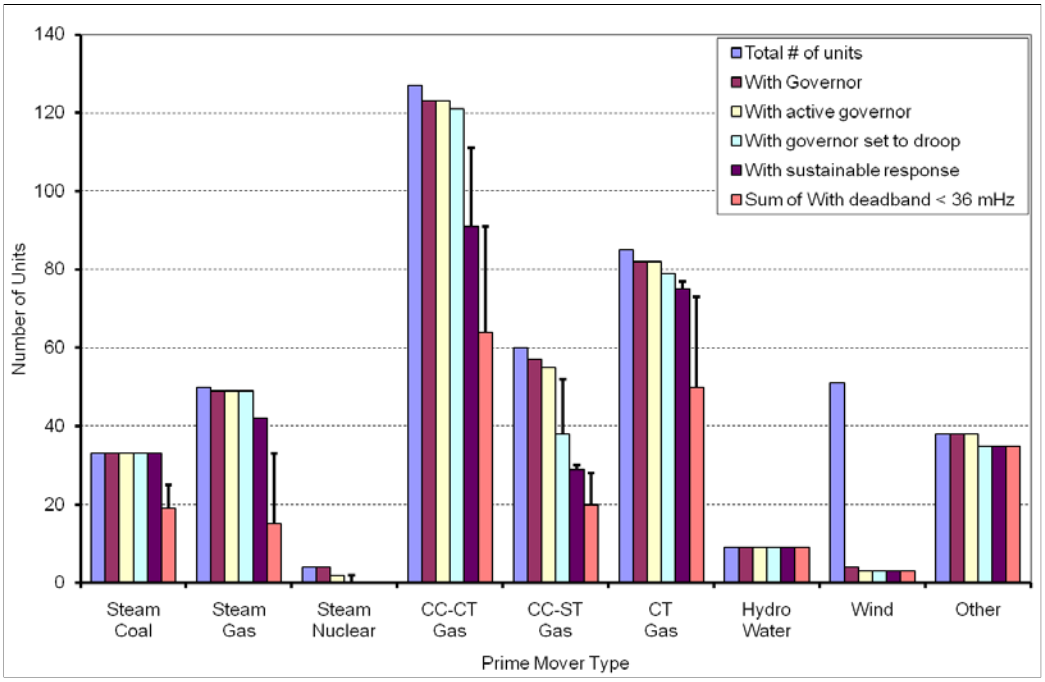


Figure 48: ERCOT Interconnection Generator Responses



Reported Deadband Settings

The deadband setting of a governor establishes a minimum frequency deviation that must be exceeded before the governor will act. Frequency deviations that are less than the setting will not cause the governor to act. Of the information provided by the GOs and GOPs on governor deadbands, 51%, 63%, and 79% of the number of units in the Eastern, Western, and Texas Interconnections, respectively, was usable. Figure 49 summarizes the usability of the deadband data submitted in the survey.

Figure 49: Usability of Information Provided on Governor Deadbands

Figure 50 summarizes the range of deadband settings reported by generating unit size for all three interconnections. The simple average, or mean, of the frequency response values calculated is indicated by the orange dot. A horizontal line inside the green box indicates the median of these values. The upper and lower boundaries of the box are the inter-quartile range, which is the range that contains half the calculated frequency response values. Finally, the end points of the upper and lower vertical lines indicate the lowest and highest calculated frequency response values, respectively.

The use of these descriptive statistics provides additional information on the distribution of values. For example, if the average is lower than the median, it means that the distribution has a small number of low values compared to the main body of values. Similarly, the height of the inter-quartile range (the top and bottom of the box) provides a measure of how widely the values are distributed. The location of the median within the box indicates whether values are evenly distributed on either side of the median (when the median is close to the center of the box) or whether values are disproportionately on one or the other side of the median (when the median is closer to the top or the bottom of the box).

Figure 50: Reported Governor Deadband Settings

Figure 50 indicates:

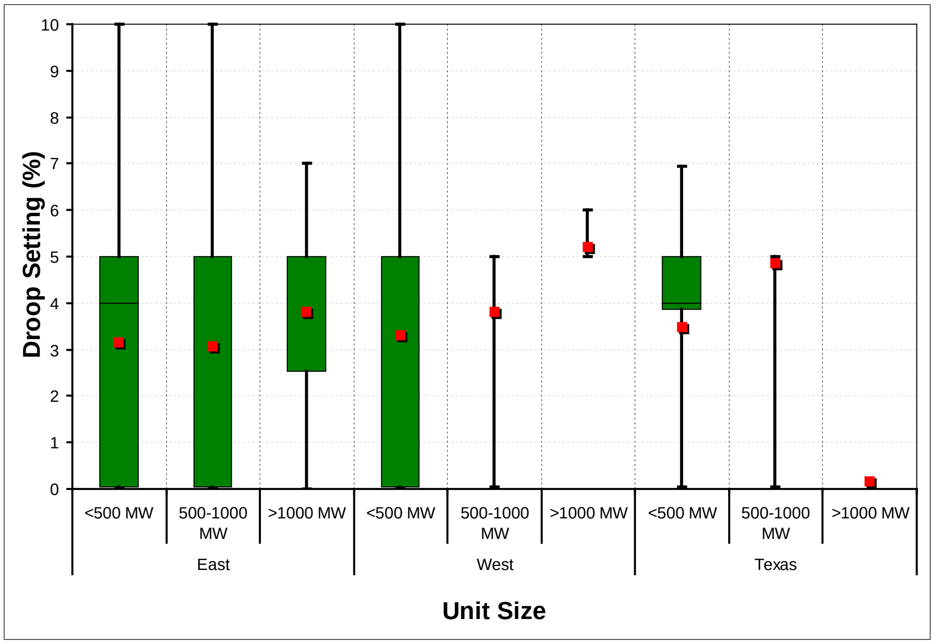
- Eastern Interconnection – Half of the deadband settings are between 0 and 100 mHz, with the smallest generating units having the lowest settings, followed by the mid-size, and then the largest units. The figure also indicates that there are a number of units in all size ranges with very high deadband settings (> 200 mHz).
- Western Interconnection – Half of the deadband settings are between 0 and 50 mHz for the smallest and mid-size generating units. However, the range is considerably broader for the largest units, with half of the settings lying between 0 and more than 300 mHz. The very large deadbands on units greater than 1,000 MW are attributable to the nuclear units.
- Texas Interconnection – The deadband settings are generally less than 50 mHz. There appears to be at least one very high deadband setting for a small generating unit.

Reported Droop Settings

Governor droop expresses the effect of changes in generating unit speed in terms of changes in power output as a function of the amount of frequency deviation from the reference frequency. Of the information provided by the GOs and GOPs on governor droop settings, 89%, 94%, and 87% of the number of units in the Eastern, Western, and Texas Interconnections, respectively, was usable.

Figure 51 summarizes the range of governor droop settings for the interconnections. Generally, the droop settings were in the range of expected values.

Figure 51: Range of Governor Droop Settings by Generating Unit Size



Governor Status and Operational Parameters

A number of the survey questions addressed the operational status and parameters of the governor fleet. As shown in Figure 52, the vast majority of the GOs and GOPs reported that their governors are operational.

Figure 53 shows that the governors also were reported to be able to sustain primary frequency response for longer than 1 minute if the frequency remains outside of its deadband. However, as shown in Figure 54, roughly half of the governors are expected to be overridden or limited by plant-level control schemes. This factor heavily influences the sustainability of primary frequency response, contributing to the withdrawal symptom often observed in the Eastern Interconnection, especially during light load periods.

Figure 52: Operational Status of Governors

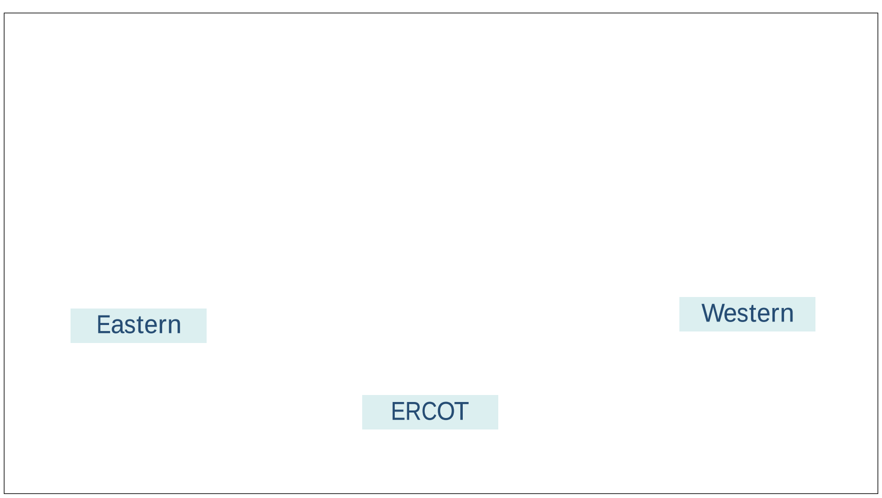


Figure 53: Response Sustainable for More Than 1 Minute if Outside Deadband

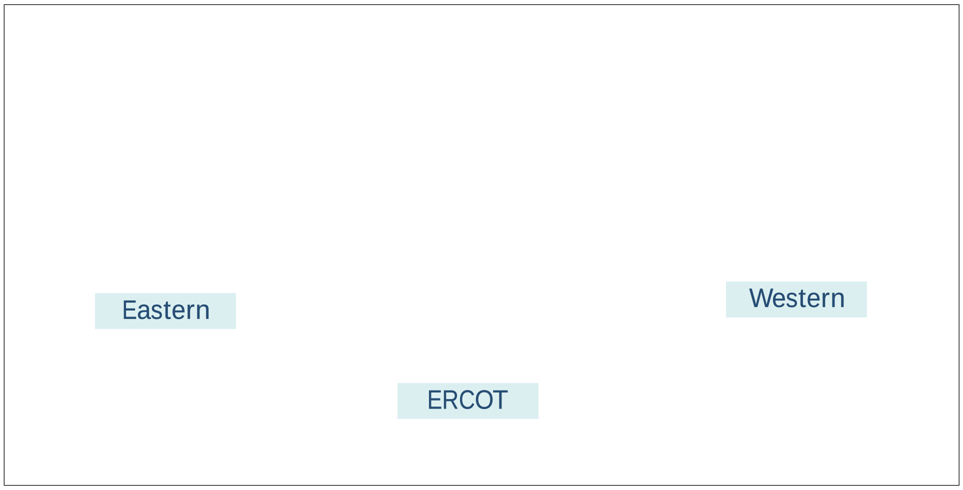
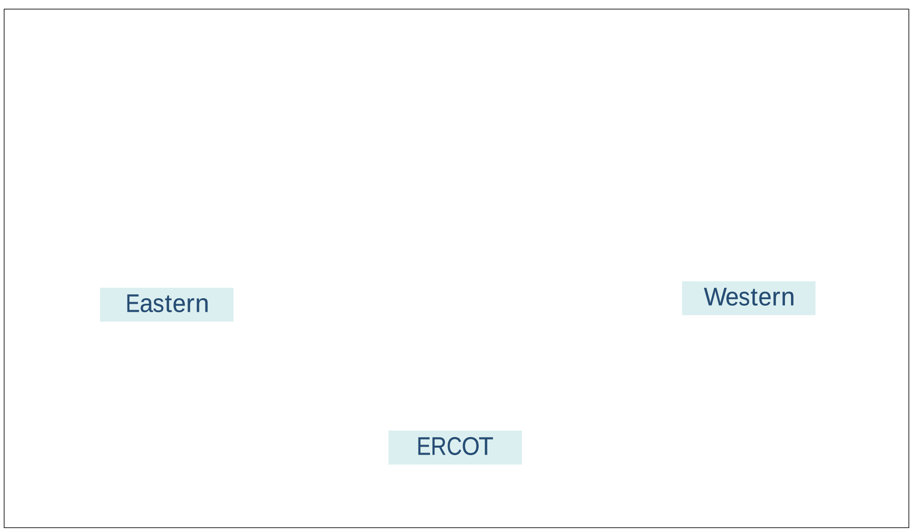


Figure 54: Unit-Level or Plant-Level Control Schemes that Override or Limit Governor Performance



Response to Selected Frequency Events

The GOs and GOPs were asked to provide information on the performance of turbine governors during a selected event in each interconnection. Table 23 lists the date and time of the events selected for the Eastern, Western, and Texas Interconnections (data was not requested from the Québec Interconnection).

Table 23: Selected Events for Provision of Generator Governor Performance Information			
Interconnection	Basis		Frequency
Eastern	8/16/2010	1:06:15 CST	1,200 MW
Western	8/12/2010	14:44:03 CST	1,260 MW
ERCOT	8/20/2010	14:25:29 CST	1,320 MW

Of the interconnections' total generating capacity, 64%, 58%, and 75% of the units were on-line at the time of the event for the Eastern, Western, and Texas Interconnections, respectively.

Figure 55: Governor Response by Total Generating Capacity On-Line

Figure 55 shows:

- Of the total generating capacity on-line, 30%, 44%, and 53% reported responding in the expected direction of response (i.e., to correct the change in frequency) for the Eastern, Western, and Texas Interconnections, respectively.
- Some generation reported no response to the frequency deviations (38%, 35%, and 13% for the Eastern, Western, and Texas Interconnections, respectively).
- Notably, 19%, 17%, and 20% were reported as responding in the opposite direction of the expected response (i.e., not in opposition to the change in frequency) for the Eastern, Western, and Texas Interconnections, respectively.

The values reported for the Eastern Interconnection for capacity providing expected response are in keeping with those calculated from the generic governor simulation of the frequency response to the August 4, 2007 Eastern Interconnection Frequency Disturbance. Those simulations showed that 30% of the capacity on-line responded, and 20% of the capacity on-line withdrew primary support, leaving only 10% of the capacity on-line providing sustained primary frequency response.

Figure 56 shows that for the Eastern Interconnection, total response in the expected direction was 973 MW, while response in the direction opposite expectations was -361 MW, for a total net response of 613 MW. Steam coal and combined-cycle gas turbine units, accounting for 327 MW and 244 MW of the net response, respectively, made the largest contributions. These contributions were made by steam coal and combine-cycle with a total on-line generating capacity of about 180 GW steam coal and about 60 GW combined-cycle gas turbine units, of which about 80 GW and about 10 GW of capacity provided response in the expected direction, respectively.

Figure 56: Eastern Interconnection Generator Governor Performance

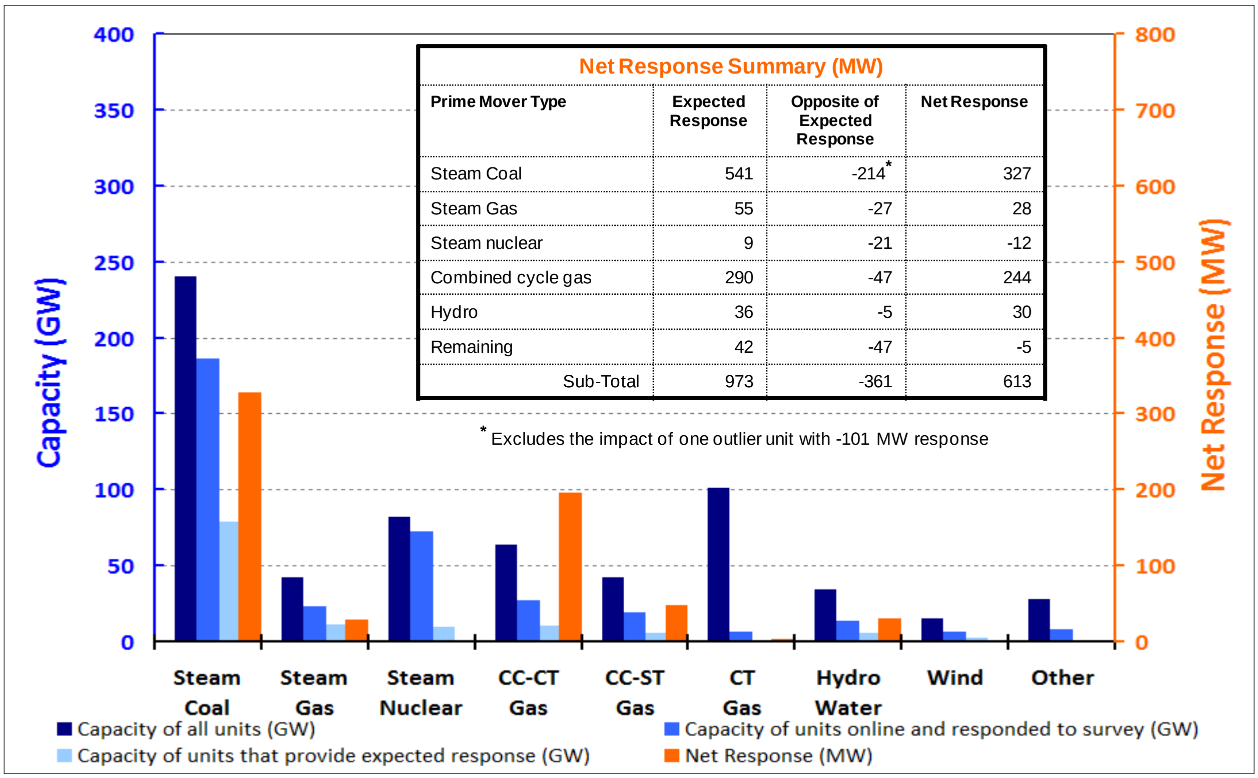
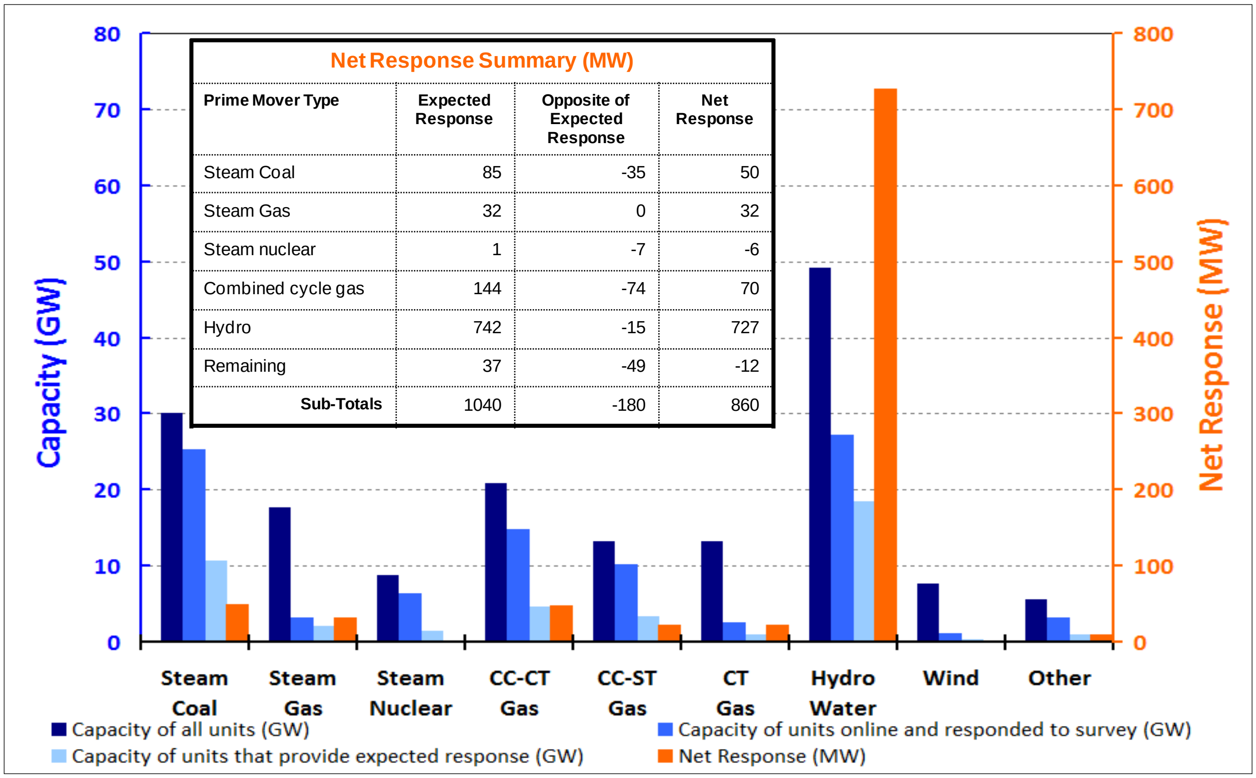


Figure 57 shows that for the Western Interconnection, total response in the expected direction was 1040 MW, while response in the direction opposite expectations was -180 MW, for a total net response of 860 MW. Hydro units, accounting for 727 MW of the net response, made the largest contribution. Hydro units made this contribution with a total on-line generating capacity of about 50 GW, of which about 19 GW of capacity provided response in the expected direction.

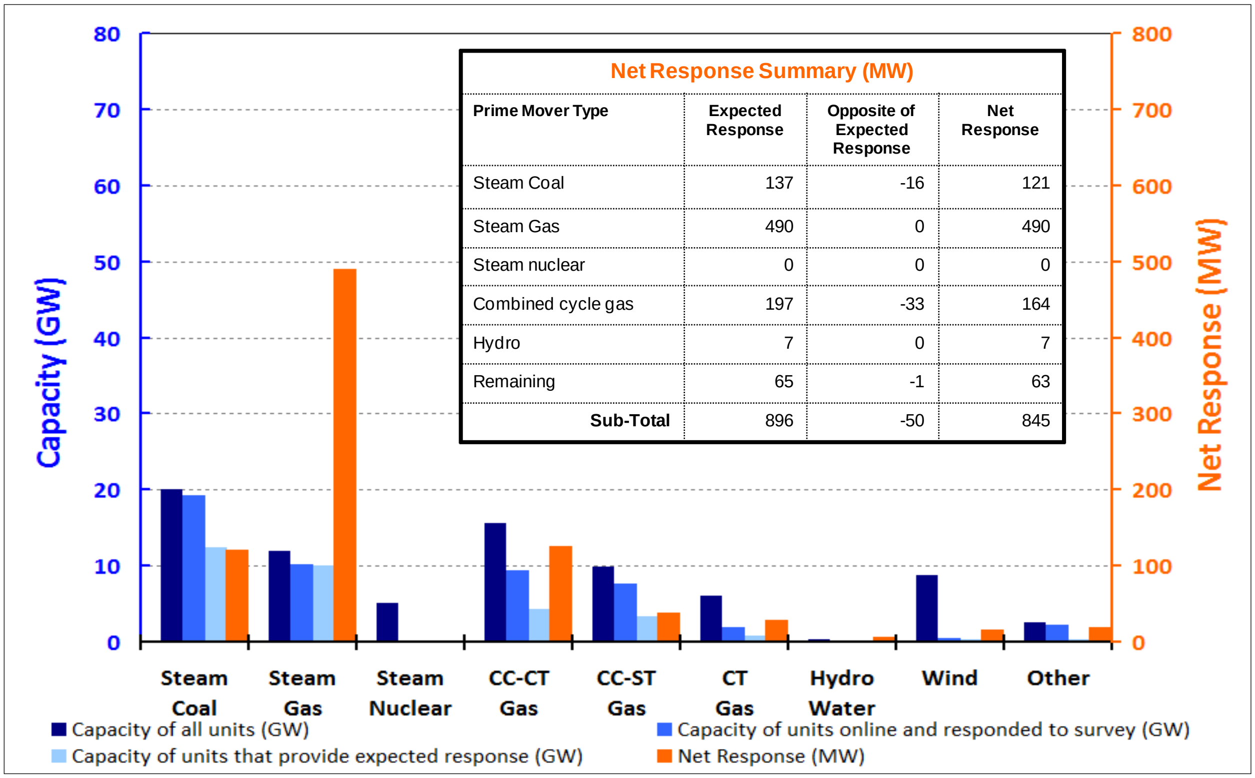
Figure 57: Western Interconnection Generator Governor Performance



Prime Mover Type	Expected Response	Opposite of Expected Response	Net Response
Steam Coal	85	-35	50
Steam Gas	32	0	32
Steam nuclear	1	-7	-6
Combined cycle gas	144	-74	70
Hydro	742	-15	727
Remaining	37	-49	-12
Sub-Totals	1040	-180	860

Figure 58 shows that for the ERCOT Interconnection, total response in the expected direction was 896 MW, while response in the direction opposite expectations was -50 MW, for a total net response of 845 MW. Steam gas units, accounting for 490 MW of the net response, made the largest contribution. Steam gas units made this contribution with a total on-line generating capacity of about 11 GW, of which ~10 GW of capacity provided response in the expected direction.

Figure 58: ERCOT Interconnection Generator Governor Performance



Prime Mover Type	Expected Response	Opposite of Expected Response	Net Response
Steam Coal	137	-16	121
Steam Gas	490	0	490
Steam nuclear	0	0	0
Combined cycle gas	197	-33	164
Hydro	7	0	7
Remaining	65	-1	63
Sub-Total	896	-50	845

Future Analysis Work Recommendations

Testing of Eastern Interconnection Maximum Allowable Frequency Deviations

The stability simulation testing of the Eastern Interconnection resource loss criteria used in the determination of the IFRO was limited to analysis using the generic governor stability case developed by the NERC Model Validation Working Group and the Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group (MMWG) in December 2011 (based on the August 4, 2007 Eastern Interconnection Frequency Disturbance). Simulations using that stability simulation indicated a maximum sustainable generation loss of about 8,500 MW for the Eastern Interconnection. However, that simulation case was not for the light load conditions where system inertia and load response would be expected to be lower than in the generic case.

Recommendation – Dynamic simulation testing of the Western and ERCOT Resource Contingency Protection Criteria should be conducted as soon as possible.

Recommendation – When ERAG MMWG completes its review of turbine governor modeling, a new light-load case should be developed, and the resource loss criterion for the Eastern Interconnection's IFRO should be re-simulated.

Eastern Interconnection Inter-area Oscillations – Potential for Large Resource Losses

During the spring of 2012, a number of inter-area oscillations were observed between the upper Midwest and the New England/New Brunswick areas in the 0.25 Hz family. During one such event, a large generation outage in Georgia instigated that oscillation mode and was interpreted by the FNet frequency monitoring and event detection program as an 1,800 MW resource loss in the upper Midwest. Immediately, the FNet Oscillation Monitoring system detected the 0.025 Hz family oscillations between the upper Midwest and New England/New Brunswick. Investigation into the event showed that it occurred while the Dorsey – Forbes 500 kV transmission line was out of service for maintenance. During that line outage, the transfers on the Dorsey DC line from Northern Manitoba were significantly curtailed, and the oscillation of the Dorsey DC terminal capabilities for damping the 0.025 Hz oscillations were greatly reduced. This made the system more susceptible to such oscillations. In all instances, the energy magnitude under the oscillations was small, well-damped, and of little danger to the reliability of the Eastern Interconnection.

However, the instigation of those oscillations by a generator trip in Georgia seemed unlikely until reviewed in light of the inter-area oscillations detected following the South Florida disturbance of February 26, 2008. During that disturbance, a family of 0.22 Hz oscillations was detected between the Southeast and the upper Midwest. In both cases, the same generation in the upper Midwest has a strong participation in both mode shapes, and since both oscillation modes are close in frequency, the 0.25 Hz family was easily perturbed by an instance of the 0.22 Hz mode oscillations caused by the Georgia generator tripping.

Recommendation – Eastern Interconnection inter-area oscillatory behavior should be further investigated by NERC, including during the testing of large resource loss analysis for IFRO validation.

Appendices Table of Contents

Appendix A – Contributors

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NERC Frequency Response Standard Drafting Team

NERC Frequency Working Group

NERC Resources Subcommittee

NERC System Analysis and Modeling Subcommittee (formerly the Transmission Issues Subcommittee)

[1] Participation made possible through funding provided by the U.S. Department of Energy Office of Electricity and Energy Reliability, coordinated through the Lawrence Berkeley National Laboratory.

Appendix B – Abbreviations

ACE	Area Control Error
ADF	Adjusted Delta Frequency
AGC	Automatic Generator Control
ALR	Acceptable Level of Reliability
ARLPC	Adjusted resource loss protection criteria adjusted for the credit for load resources
BA	Balancing Authority
BAA	Balancing Authority Area
CERTS	Consortium for Electric Reliability Technology Solutions
CPS	Control Performance Standard
CB_R	Ratio of the Point C to Value B to adjust the allowable delta frequency to account for that difference.
CC_{ADJ}	Adjustment to Point C for the differences between 1-second and sub-second measurements
COI	California-Oregon Interface (ac)
D	Load damping factor
dc	Direct current
DCS	Disturbance Control Standard
DF_{Base}	Base delta frequency
DF_{CC}	Delta frequency adjusted for the differences between 1-second and sub-second Point C observations for frequency events
EMS	Energy Management System
EPG	Electric Power Group
ERAG	Eastern Interconnection Reliability Assessment Group
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
F_{Start}	Starting Frequency
FERC	The U.S. Federal Energy Regulatory Commission
FDR	Frequency Disturbance Recorder
FMA	Frequency Monitoring and Analysis tool
FNet	Frequency Monitoring Network (University of Tennessee, Knoxville, and Virginia Tech)
FRC	Frequency Response Characteristic
FRCC	Florida Reliability Coordinating Council
FRM	Frequency Response Measure
FRO	Frequency Response Obligation (FRO_{BA})
FRRSDT	Frequency Response Standard Drafting Team

FR	Frequency Response
FRS	Frequency Response Standard
FRSG	Frequency Response Sharing Group
FWG	Frequency Working Group
GOs	Generator Owners
GOPs	Generator Operators
GVD	Governor Valve Demand
GW	gigawatts (thousands of megawatts)
H	Inertial constant (of the interconnection)
Hz	hertz (cycles per second)
IFRO	Interconnection Frequency Response Obligation (FRO_{Int})
LaaR	Load Acting as a Resource
LBNL	Ernest Orlando Lawrence Berkeley National Laboratory
mHz	millihertz
MMWG	Multi-Regional Modeling Working Group
MVA	megavoltampere
MW	megawatts
N-1	Loss of one system element
N-2	Loss of two system elements
NI_A	Net Interchange Actual
NI_S	Net Interchange Scheduled
PAS	Performance Analysis Subcommittee
PDCI	Pacific Direct Current Intertie
PDCWG	Performance Disturbance and Compliance Working Group (ERCOT)
PMU	Phasor Measurement Unit
PV	Photovoltaic
RA	Resource Adequacy Tool
RARF	ERCOT Resource Asset Registration Form
RAS	Remedial Action Scheme (also known as a Special Protection Scheme – SPS)
RLPC	Resource Loss Protection Criteria
RPM	Revolutions per Minute
RC	Resources Subcommittee
SAMS	System Analysis and Modeling Subcommittee (formerly TIS)
SCADA	System Control and Data Acquisition
SEFRD	Single Event Frequency Response Data
SEFRD	Single Event Frequency Response Data
TIS	Transmission Issues Subcommittee (now SAMS)
TRE	Texas Regional Entity

UFLS	Under-Frequency Load Shedding

Appendix C – Definitions and Terminology

Definitions used in Standard BAL-003-1

Frequency Response Measure (FRM)

The median of all the Frequency Response observations reported annually by Balancing Authorities or Frequency Response Sharing Groups for frequency events specified by the ERO. This will be calculated as MW/0.1Hz.

Frequency Response Obligation (FRO)

The Balancing Authority's share of the required Frequency Response needed for the reliable operation of an Interconnection. This will be calculated as MW/0.1Hz.

Frequency Bias Setting

A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's Area Control Error equation to account for the Balancing Authority's inverse Frequency Response contribution to the interconnection, and discourage response withdrawal through secondary control systems.

Frequency Response Sharing Group (FRSG)

Groups, whose members consist of two or more Balancing Authorities, that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members.

Area Control Error (ACE)*: The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.

Arrested Frequency – Value C – Point C – Frequency Nadir: The point of maximum frequency excursion in the first swing of the frequency excursion between time zero (Point A) and time zero plus 20 seconds.

Arresting Period: The period of time from time zero (Point A) to the time of Point C.

Arresting Period Frequency Response: A combination of load damping and the initial Primary Control Response acting together to limit the duration and magnitude of frequency change during the Arresting Period.

Automatic Generation Control (AGC)*: Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.

Balancing Authority (BA)*: The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

Beta: The factor by which the frequency deviation is multiplied by in the ACE equation to adjust the ACE to protect a BA's Frequency Response.

Contingency Protection Criteria of an interconnection: The selected capacity contingency that an interconnection must withstand at all times without the activation of the first tier of UFLS.

Contingency Reserve*: The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.

Frequency [i]: The rate at which a repeating waveform repeats itself. Frequency is measured in cycles per second or in hertz (Hz). The symbol is "F."

Frequency Bias Setting: The term of the ACE equation that is multiplied by frequency deviation portion. This is a corrective term to offset the tie-line flow error caused by generation/load responding to a frequency deviation.

Frequency Deviation*: A change in interconnection frequency.

Frequency Response*: (Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency. (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 hertz (MW/0.1 Hz).

Frequency Responsive Reserve (a.k.a., dynamic headroom): The capacity of Governor Response and/or Frequency-Responsive Demand Response that will be deployed for any frequency excursion.

Frequency-Responsive Demand Response: Voluntary load shedding that complements governor response. This load reduction is typically triggered by relays that are activated by frequency.

Frequency Sensitive Load: Customer loads that vary directly with changes in frequency or would trip as a result of frequency deviations.

Governor response[§]: The control response of turbine-governors to sensing a change in speed of the turbine as frequency increases or declines, causing an adjustment to the energy input of the turbine's prime mover.

Headroom: The difference between the current operating point of a generator and its maximum operating capability.

Inertia[i]: The property of an object that resists changes to the motion of an object. For example, the inertia of a rotating object resists changes to the object's speed of rotation. The inertia of a rotating object is a function of its mass, diameter, and speed of rotation.

Load damping[¥]: The damping effect of the load to a change in frequency due to the physical aspects of the load such as the inertia of motors and the physical load to which they are connected.

Load following[i]: Commitment of energy based resources (generation or energy schedule) to match the forecast load level for a given period. This is a form of course control for moment-by-moment resource/load matching.

Non-spinning reserve*: 1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.

Off-line Reserve[§]: The off-line capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection.

On-line Reserve[§]: The on-line capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. This can consist of spinning reserve and interruptible load that can act as a resource.

Operating Reserve*: That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. It consists of spinning and non-spinning reserves.

Other On-line Reserves[§]: On-line Resources that can increase their output or connected loads that can decrease their consumption (curtailable loads) in time frames outside the continuum of regulating or spinning reserve (i.e. on four hours' notice).

Other Off-line Reserves[§]: Resources that can be brought to bear outside the continuum of non-spinning reserve (i.e., on four hours' notice).

Plant secondary control[@]: Secondary control refers to controls affected through commands to a turbine controller issued by external entities not necessarily working in concert with frequency management objectives. It is common for a modern power plant to have several distinct modes of secondary control implemented within the plant and to be able to accept secondary control inputs from sources external to the plant.

Primary Control Response Withdrawal: The withdrawal of previously delivered Primary Control Response, through plant secondary controls.

Primary Frequency Control Response: The power delivered to the interconnection in response to a frequency deviation through generator governor response, load response (typically from motors), demand response (designed to arrest frequency excursions), and other devices that provide an immediate response to frequency based on local (device-level) control systems, without human or remote intervention.

Primary Frequency Control Reserves: Frequency-responsive reserves that respond nearly instantaneously (starting in less than 1 second) to oppose any changes in power system frequency.

Quick Start Reserve: A form of non-spinning reserve that can be put on-line and the capacity that can be deployed in ten minutes.

Recovery Period: The period of time from when Secondary Control Response are deployed (typically about zero plus 53 seconds) to the time of the return of frequency to within pre-established ranges of reliable continuous operation.

Regulation[¥]: Controllable resources necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled interchange and interconnection scheduled frequency. Regulation is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes actual net interchange.

Regulating reserve*: An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide a normal regulating margin.

Settling frequency[¥, #]: Refers to the third key event during a disturbance when the frequency stabilizes following a frequency excursion. Point B represents the interconnected system frequency at the point immediately after the frequency stabilizes due to governor action but before the contingent control area takes corrective AGC action.

Secondary Control Response: The power delivered by a Balancing Authority or Reserve Sharing Group in response to a frequency deviation through Secondary Control actions, such as manual or automated dispatch from a centralized control system. Secondary control actions are intended to restore Primary Control Response and restore frequency from the Arrested Frequency back to Scheduled Frequency, or maintain Scheduled Frequency.

Secondary Frequency Control: Actions provided by an individual BA or its Reserve Sharing Group intended to restore Primary Control Response and restore frequency from the Arrested Frequency back to Scheduled Frequency, or to maintain Scheduled Frequency deployed in the "minutes" time frame. Secondary Control comes from either manual or automated dispatch from a centralized control system. Secondary Control also includes initial reserve deployment for disturbances and maintains the minute-to-minute balance throughout the day and is used to restore frequency to normal following a disturbance and is provided by both spinning and non-spinning reserves.

Secondary Frequency Control Reserves: Frequency-responsive reserves that respond over slightly longer time frames (starting in 20-30 seconds). Following the sudden loss of generation, they assist in restoring frequency to the scheduled value after Primary Frequency Control Reserves have been deployed. They also safeguard Primary Frequency Control Reserves (so that primary reserves remain available to respond to these sudden events) by controlling frequency in response to slower imbalances that arise between electricity demand and generation such as the normal rise and fall of system load over the course of a day.

Spinning reserve*: Unloaded generation that is synchronized and ready to serve additional demand.

Tertiary frequency control[§]: Encompasses actions taken to get resources in place to handle current and future changes in load or contingencies. Reserve deployment and Reserve restoration following a disturbance is a common type of Tertiary frequency control.

Under-frequency load shedding[i]: The tripping of customer load based on magnitudes of system frequency. For example, a utility may dump 5% of their connected load if frequency falls below 59.3 Hz, dump an additional 10% if frequency falls below 58.9 Hz, and dump a final 10% if frequency falls below 58.5 Hz. These three steps of load shedding would form this utility's UFLS plan. The purpose of UFLS is a final effort (safety net) to arrest a frequency decline.

Sources:

* NERC Glossary of Terms Used in Reliability Standards, http://www.nerc.com/files/Glossary_of_Terms.pdf

[¥] NERC Reference Document Understand and Calculating Frequency Response (June 19, 2008)

[§] NERC Balancing and Frequency Control (July 5, 2009)

[#] NERC Frequency Response Characteristic Survey Training Document, http://www.nerc.com/docs/standards/sar/opman_12-13Mar08_FrequencyResponseCharacteristicSurveyTrainingDocument.pdf (January 1, 1989)

[@] Undrill, J.M. 2010. *Power and Frequency Control as it Relates to Wind-Powered Generation*. LBNL-4143E. Berkeley: Lawrence Berkeley National Laboratory

[i] Definitions taken from the EPRI Power Systems Dynamics Tutorial. EPRI, Palo Alto, CA: 2009. 1016042

Appendix D – Interconnection Frequency Deviation Duration Plots

Figure D1: Summary of Eastern Interconnection Frequency 2007–2011

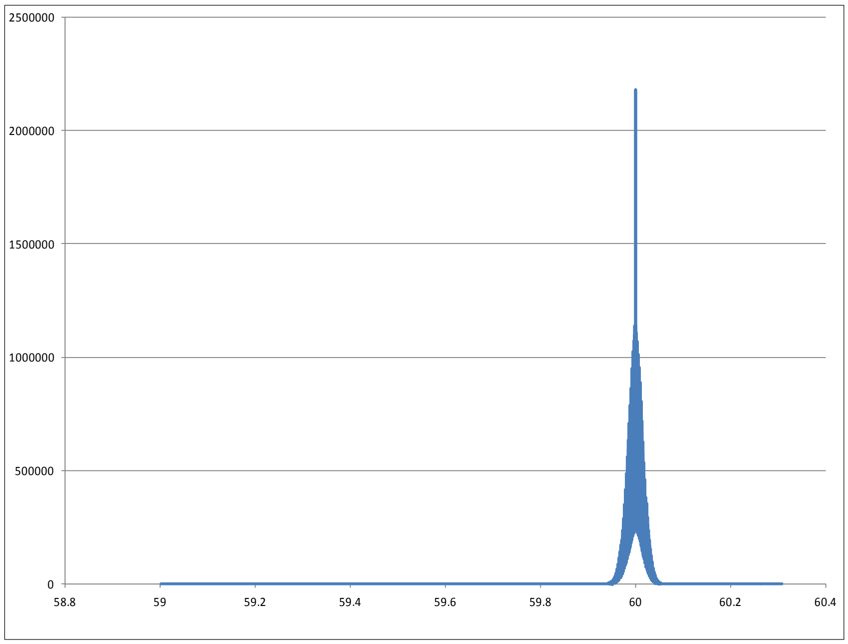


Figure D2: Eastern Interconnection 2007–2011 Frequency Histogram

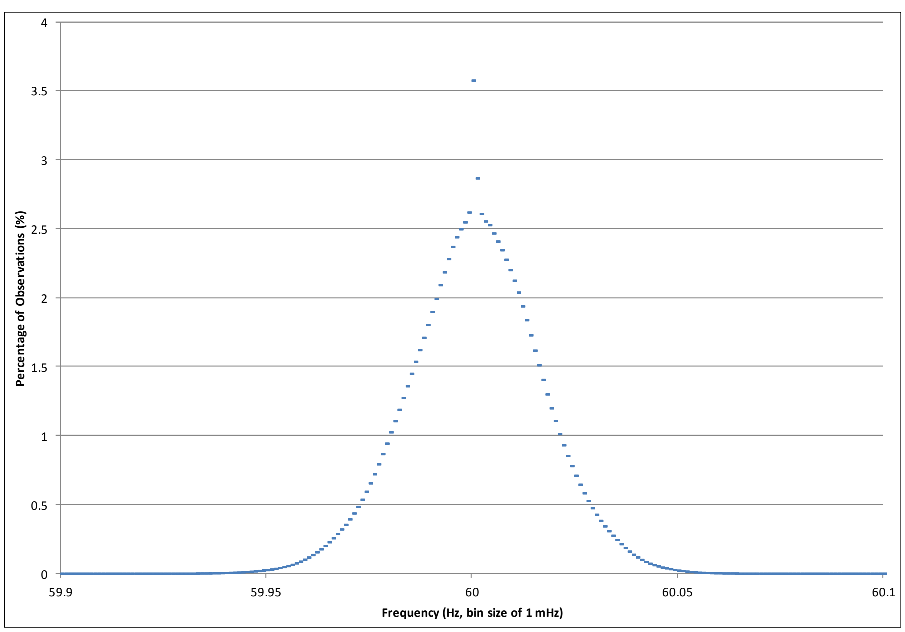


Figure D3: Eastern Interconnection Frequency 2007–2011 Cumulative Distribution

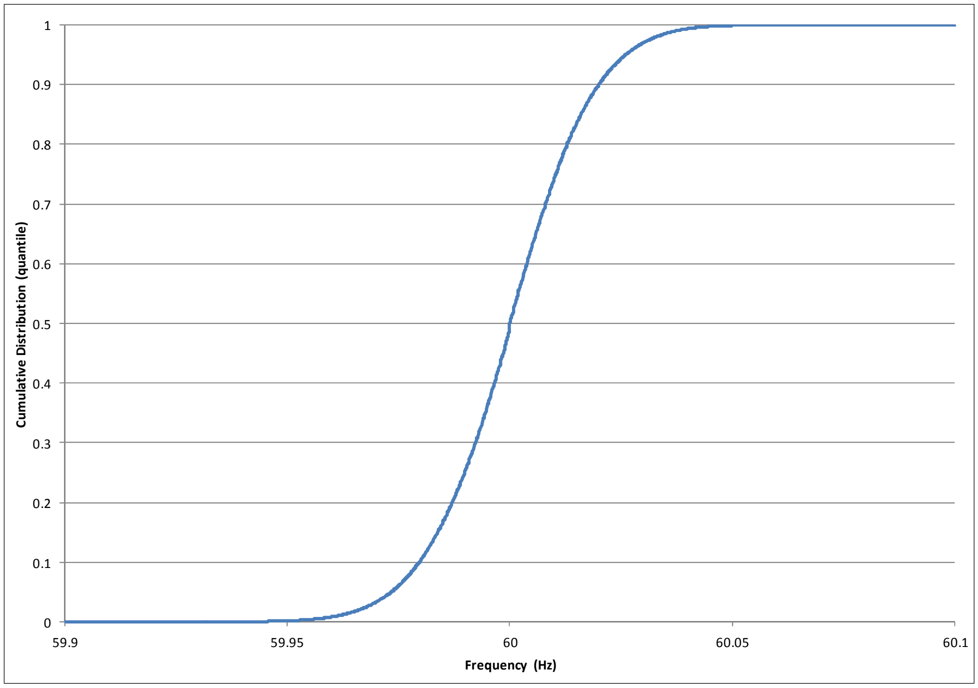


Figure D4: Summary of Western Interconnection Frequency 2007–2011

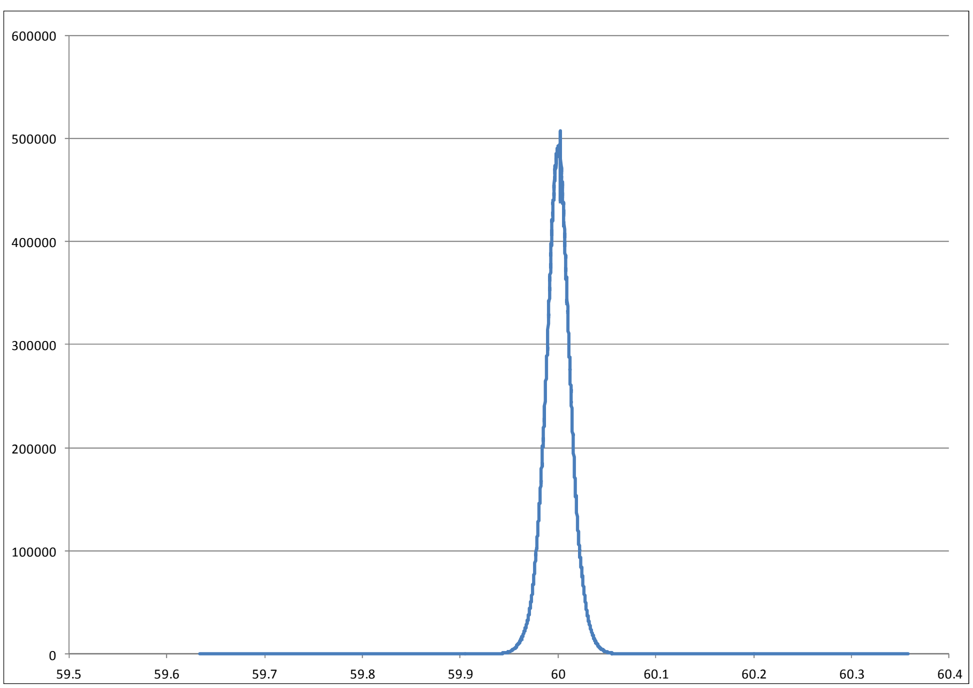


Figure D5: Western Interconnection 2007–2011 Frequency Histogram

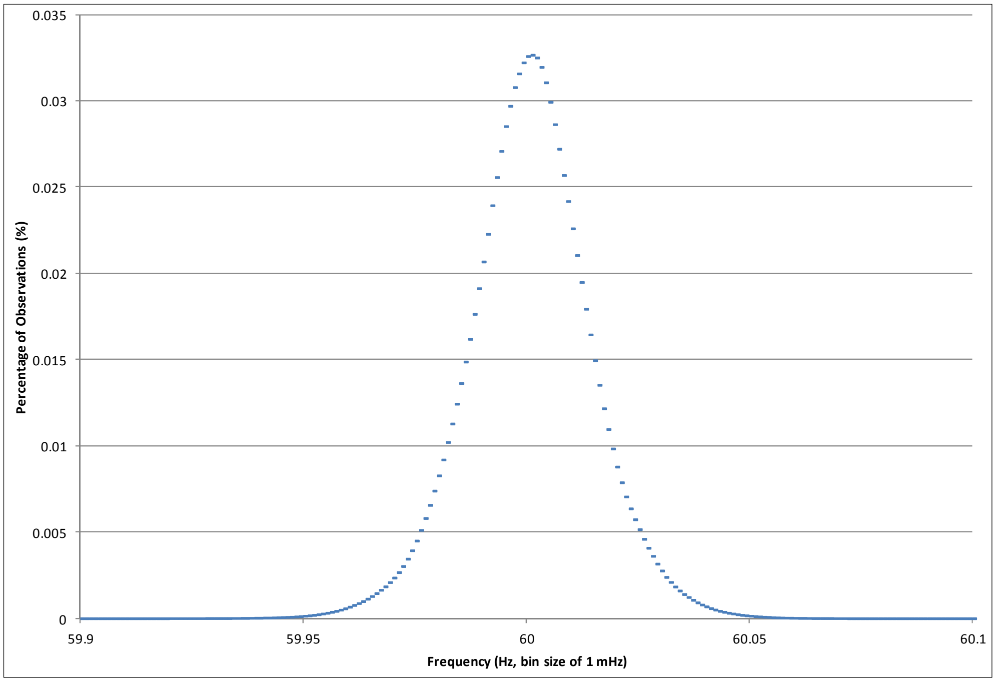


Figure D6: Western Interconnection Frequency 2007–2011 Cumulative Distribution

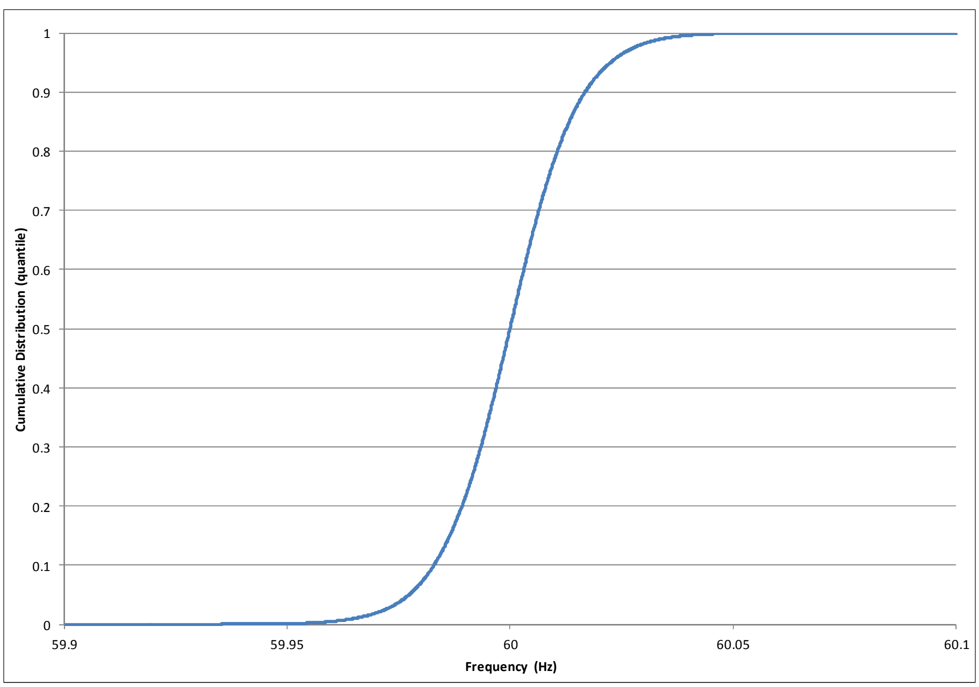


Figure D7: Summary of ERCOT Interconnection Frequency 2007–2011

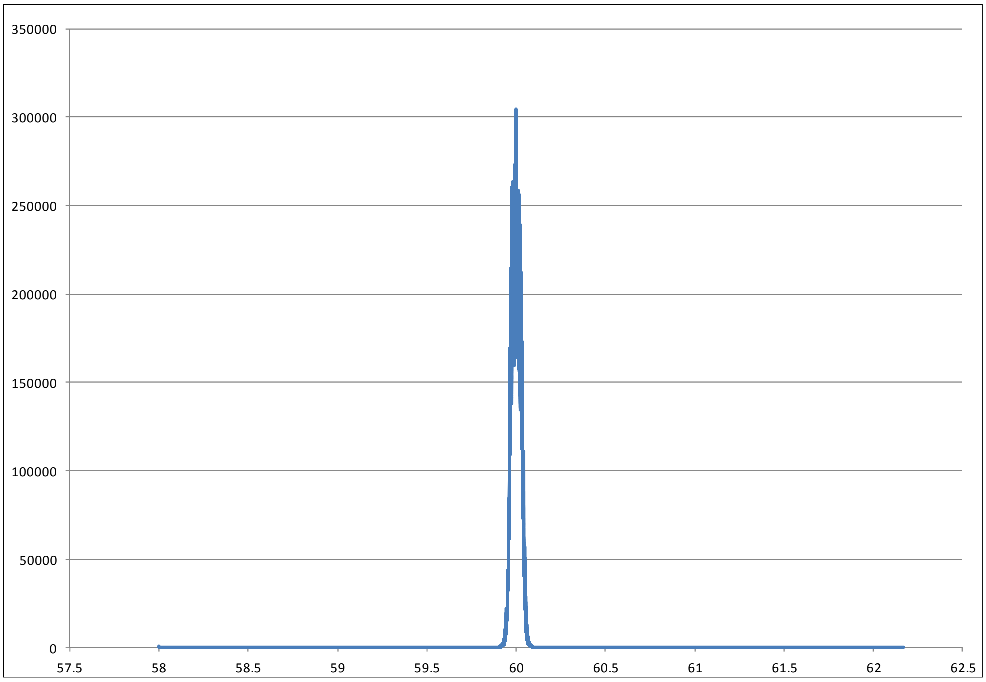


Figure D8: ERCOT Interconnection 2007–2011 Frequency Histogram

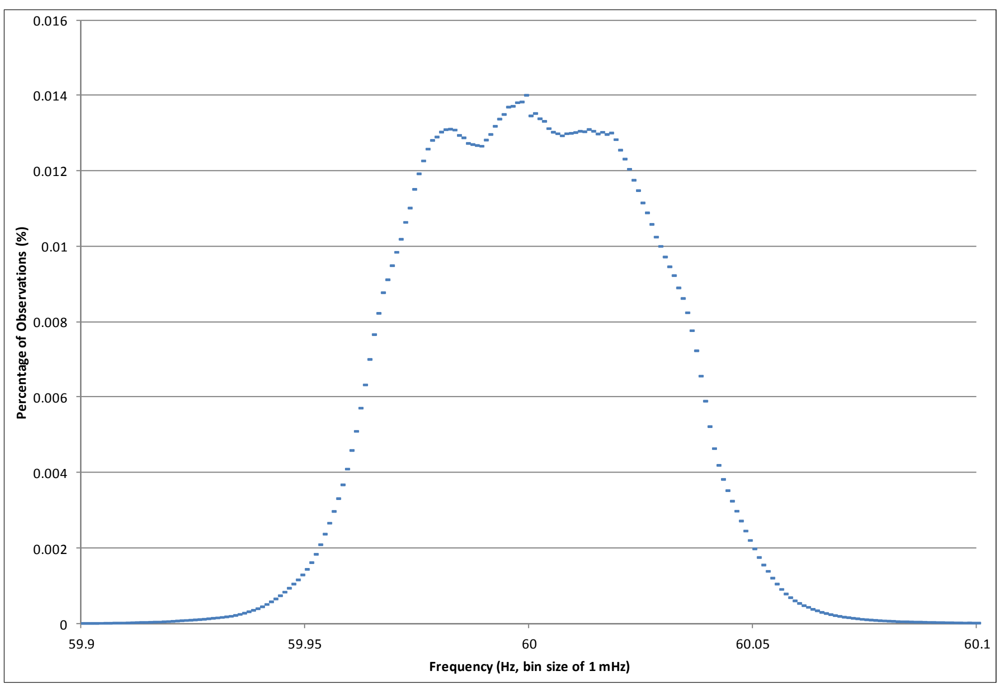


Figure D9: ERCOT Interconnection Frequency 2007–2011 Cumulative Distribution

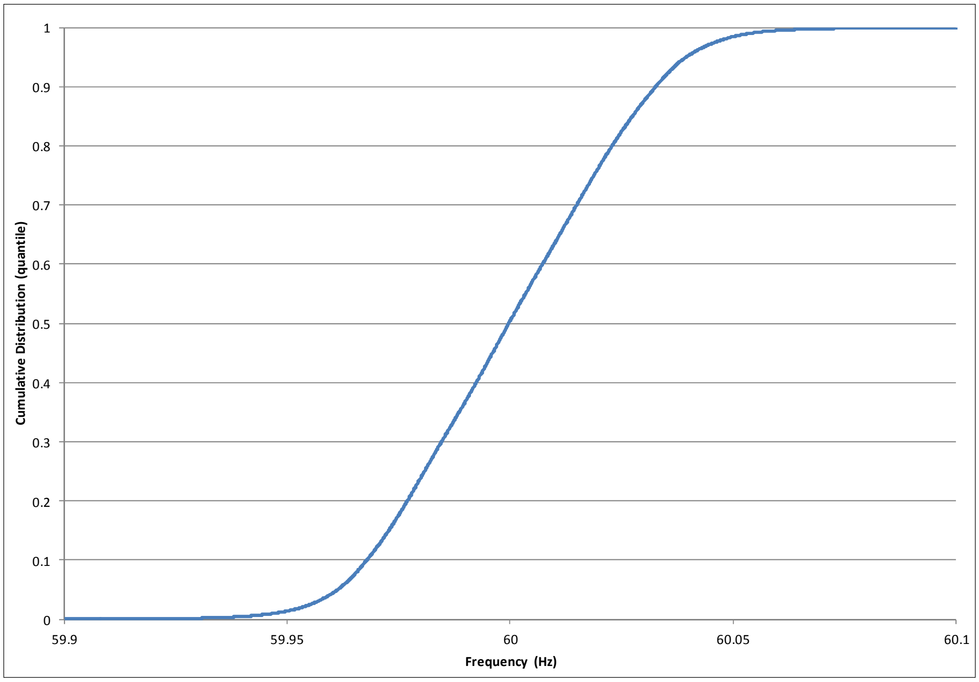


Figure D10: Summary of Québec Interconnection Frequency 2010–2011

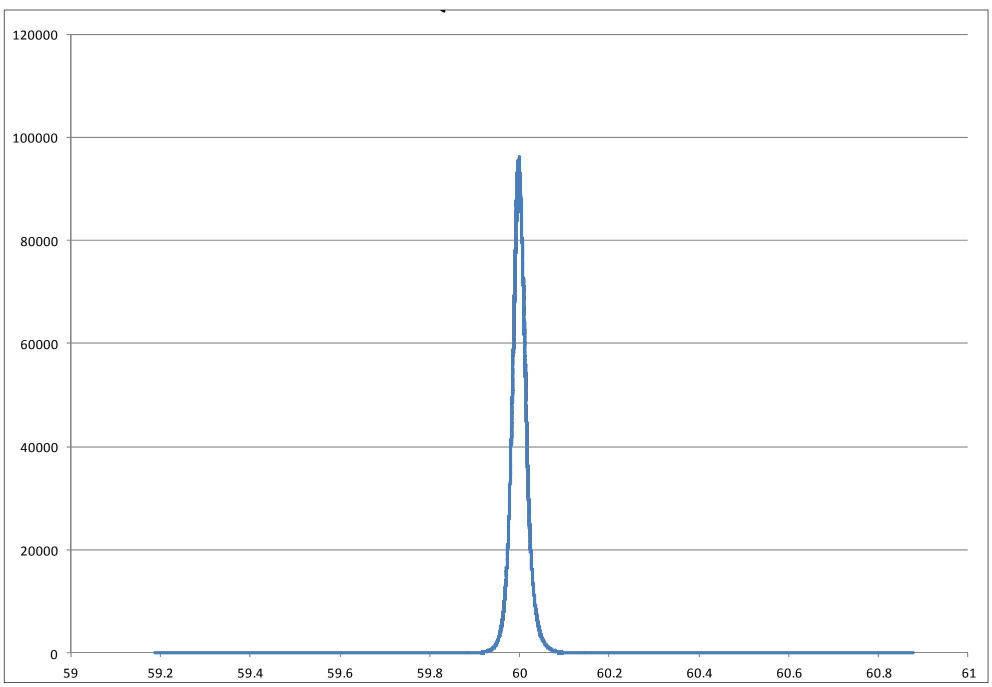


Figure D11: Québec Interconnection 2010–2011 Frequency Histogram

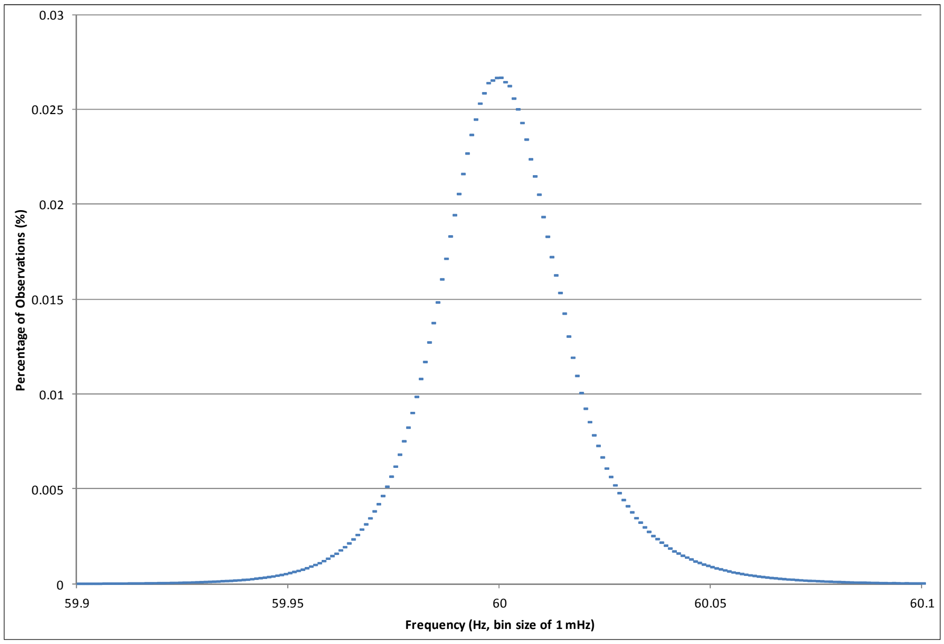
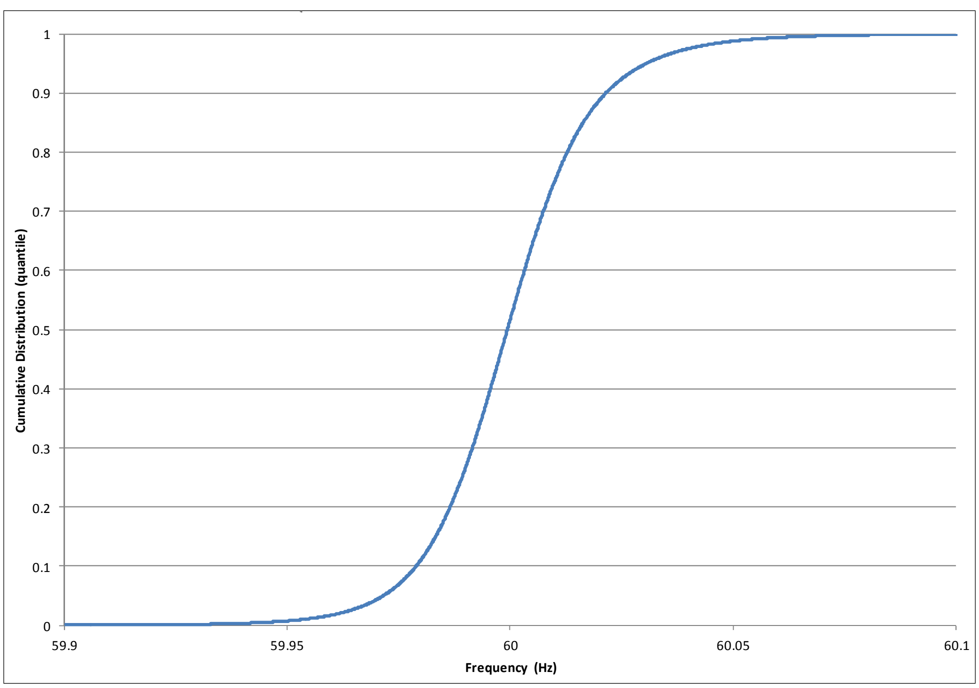


Figure D12: Québec Interconnection Frequency 2010–2011 Cumulative Distribution



Appendix E – ALR1-12 Metric Event Selection Process

1. CERTS-EPG produces a monthly spreadsheet for four interconnections (Eastern Interconnection or EI, Western or WI, ERCOT Interconnection or TI, and Québec). The spreadsheet captures significant frequency events based on the Resources Subcommittee (RS) specified threshold. The Frequency Monitoring and Analysis tool (FMA) gathers and stores the raw data.
2. The spreadsheet is sent by CERTS-EPG to the Frequency Working Group (FWG) on the 15th of each month for the previous month's raw data.
3. The FNET application uses automatic e-mails to flag frequency deviations. Generation loss is estimated.
4. The actual generation loss for the FNET flagged frequency events is determined by the NERC Situation Awareness Coordinator from the Regional Entities and sent to the FWG.
5. The FWG members validate the data and add the actual generation loss values into the spreadsheet.
6. FWG sends the validated monthly sheet to the Resource Subcommittee (RS) and the Performance Analysis Subcommittee (PAS) on the 30th of each month for the previous month's raw data.
7. NERC staff will update the candidate event list on the NERC website that will be used to support the standard. The final official event list for a year will be identified as a subset of the posted candidate list.
8. PAS publishes the quarterly Frequency Response metric data on NERC's Reliability Indicators webpage. The initial trending will be based on annual median/mean and rolling 12 month values.

Background Information

The frequency delta thresholds recommended by RS for the Eastern, Western, ERCOT and Québec Interconnections are shown in Table E1.

Table E1: Frequency delta thresholds recommended by RS

Interconnections	Frequency Delta for events captured in (mHz)	Frequency Delta for Significant events that have a higher Delta	Time Window (Seconds)
Eastern	24	36	15
Western	40	70	15
ERCOT	45	90	15
Québec	140	200	15

The raw statistics for events in 2008, 2009, 2010 and the first half of 2011 are listed in Table E2 below. This was sent by CERTS-EPG to the FWG on August 31, 2011.

Table E2: Raw Statistics for frequency events from 2008 to July 2011

Interconnection	Eastern	Western	ERCOT	Québec
2008	195	102	26	No Data
2009	78	72	85	No Data
2010	132	85	122	No Data
2011 (until July)	70	37	61	159

The statistics for TI from 2008 to 2011 were validated and modified by the FWG. Table E3 shows the statistics for TI that were sent by the FWG to the RS on September 02, 2011.

Table E3: Validated Statistics for TI frequency events from 2008 to July 2011

Interconnections	TI
2008	8
2009	51
2010	67
2011 (until July)	40

The FWG Lead members who will validate the data and add the actual generation loss values into the spreadsheet for the four interconnections are listed in Table E4.

Table E4: Lead members for the four interconnections

Terry L. Bilke	Eastern Interconnection
Don E. Badley	Western Interconnection
Sydney L. Niemeyer	ERCOT Interconnection
Michael Potishnak	Québec Interconnection

In July 2011, CERTS-EPG produced the first of the monthly reports for the FWG. July 2011 has 22 frequency events and a summary is shown in Table E5.

Table E5: Summary of the 1st monthly report produced by CERTS-EPG for the FWG in July 2011

NERC INTERCONNECTION JULY, 2011 FREQUENCY EVENTS – SUMMARY DATA

Eastern Interconnection

Event Time: UTC (t-0) Date / Time (MM/DD/YY HH:MM:SS)	Event Time: Local Time (t-0) Date / Time (MM/DD/YY HH:MM:SS)	Day	Time Zone Pull Dn	Event Frequency Data: A Value Freq Error (from 60)	A Value (t-16 to t-2) average	B Value (t+20 to t+52) average	Hz Delta B-A	Point C (w/in 8 sec after t-0)	Point C delta from Aave	Interconnection Bias Setting MW/0.1 Hz	Resource Information: MW Lost Gross	MW Lost Net	Name BA	Candidate for BA List Y or N	Candidate for beta calc	Load Resources Tripped Before Value B	Point C MW/0.1 Hz
07/02/2011 6:45:21	07/02/2011 2:45:21	Sat	EDT	0.004	60.004	59.956	-0.048	59.969	-0.035	6349		-975	EES				-2024
07/02/2011 14:57:18	07/02/2011 10:57:18	Sat	EDT	-0.003	59.997	59.967	-0.031	59.958	-0.039	6349		-496	TVA				-1600
07/16/2011 7:07:00	07/16/2011 3:07:00	Sat	EDT	-0.007	59.993	59.948	-0.045	59.952	-0.041	6349		-613	TVA				-1370
07/21/2011 1:28:03	07/20/2011 21:28:03	Wed	EDT	0.009	60.009	59.967	-0.042	59.968	-0.041	6349		-902	TVA				-2167
07/25/2011 18:39:08	07/25/2011 14:39:08	Mon	EDT	0.019	60.019	59.989	-0.030	59.978	-0.041	6349		-985	PJM				-3242
07/28/2011 18:47:52	07/28/2011 14:47:52	Thu	EDT	-0.004	59.996	59.946	-0.050	59.947	-0.049	6349		-1242	PJM				-2486
07/30/2011 13:41:21	07/30/2011 9:41:21	Sat	EDT	-0.013	59.987	59.945	-0.042	59.947	-0.040	6349		-1386	PJM				-3337

Western Interconnection

Event ID	Event #	Event Time: UTC (t-0) (MM/DD/YY HH:MM:SS)	Event Time: Local Time (t-0) Date / Time	Day	Time Zone Pull Dn	Event Frequency Data: A Value Freq Error (from 60)	A Value (t-16 to t-2) average	B Value (t+20 to t+52) average	Hz Delta B-A	Point C (w/in 8 sec after t-0)	Point C delta from Aave	Interconnection Bias Setting MW/0.1 Hz	Resource Information: MW Lost Gross	MW Lost Net	Name BA	Candidate for BA List Y or N	Candidate for beta calc	Load Resources Tripped Before Value B	Point C MW/0.1 Hz
		07/03/2011 7:17:08	07/03/2011 0:17:08	Sun	PDT	-0.025	59.975	59.929	-0.046	59.901	-0.074	2024		-255	CISO				-526
		07/11/2011 4:17:33	07/10/2011 21:17:33	Sun	PDT	0.005	60.005	59.952	-0.052	59.911	-0.094	2024		-267	SRP				-496
		07/15/2011 2:46:41	07/14/2011 19:46:41	Thu	PDT	-0.035	59.965	59.928	-0.037	59.873	-0.092	2024		-264	BCHA				-706
		07/30/2011 9:17:34	07/30/2011 2:17:34	Sat	PDT	-0.007	59.993	59.937	-0.056	59.907	-0.086	2024		-426	NWMT				-763

ERCOT Interconnection

Event ID	Event #	Event Time: UTC (t-0) (MM/DD/YY HH:MM:SS)	Event Time: Local Time (t-0) Date / Time	Day	Time Zone Pull Dn	Event Frequency Data: A Value Freq Error (from 60)	A Value (t-16 to t-2) average	B Value (t+20 to t+52) average	Hz Delta B-A	Point C (w/in 8 sec after t-0)	Point C delta from Aave	Interconnection Bias Setting MW/0.1 Hz	Resource Information: MW Lost Gross	MW Lost Net	Name BA	Candidate for BA List Y or N	Candidate for beta calc	Load Resources Tripped Before Value B	Point C MW/0.1 Hz
		07/14/2011 20:53:55	07/14/2011 15:53:55	Thu	CDT	0.023	60.023	59.923	-0.100	59.917	-0.106	653		-259	ERCOT				-259
		07/17/2011 15:18:00	07/17/2011 10:18:00	Sun	CDT	-0.005	59.995	59.894	-0.101	59.879	-0.115	653		-144	ERCOT				-143
		07/18/2011 14:13:00	07/18/2011 9:13:00	Mon	CDT	-0.042	59.958	59.863	-0.094	59.879	-0.079	653		-127	ERCOT				-134
		07/21/2011 0:17:10	07/20/2011 19:17:10	Wed	CDT	0.006	60.006	59.811	-0.194	59.799	-0.206	653		-892	ERCOT				-459
		07/24/2011 16:59:24	07/24/2011 11:59:24	Sun	CDT	-0.025	59.975	59.872	-0.102	59.846	-0.128	653		-167	ERCOT				-163
		07/25/2011 22:57:12	07/25/2011 17:57:12	Mon	CDT	0.013	60.013	59.929	-0.084	59.918	-0.095	653		-306	ERCOT				-363

Hydro Quebec

Event ID	Event #	Event Time: UTC (t-0) (MM/DD/YY HH:MM:SS)	Event Time: Local Time (t-0) Date / Time	Day	Time Zone Pull Dn	Event Frequency Data: A Value Freq Error (from 60)	A Value (t-16 to t-2) average	B Value (t+20 to t+52) average	Hz Delta B-A	Point C (w/in 8 sec after t-0)	Point C delta from Aave	Interconnection Bias Setting MW/0.1 Hz	Resource Information: MW Lost Gross	MW Lost Net	Name BA	Candidate for BA List Y or N	Candidate for beta calc	Load Resources Tripped Before Value B	Point C MW/0.1 Hz
		07/29/2011 2:23:18	07/28/2011 22:23:18	Thu	EDT	0.006	60.006	59.879	-0.127	59.508	-0.498	420		-707	HQ				-559
		07/29/2011 2:23:26	07/28/2011 22:23:26	Thu	EDT	-0.178	59.822	59.891	0.069	59.874	0.052	420		588	HQ				-848
		07/29/2011 5:06:20	07/29/2011 1:06:20	Fri	EDT	-0.030	59.970	60.033	0.064	60.146	0.176	420		329	HQ				-517
		07/30/2011 8:06:58	07/30/2011 4:06:58	Sat	EDT	-0.025	59.975	60.022	0.047	60.109	0.134	420		113	HQ				-239
		07/31/2011 19:32:24	07/31/2011 15:32:24	Sun	EDT	-0.003	59.997	60.081	0.085	60.402	0.405	420		447	HQ				-527

Appendix F – Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard (BAL-003-1)

Event Selection Process

This procedure outlines the ERO process for supporting the Frequency Response Standard (FRS). A procedure revision request may be submitted to the ERO for consideration. The revision request must provide a technical justification for the suggested modification. The ERO will post the suggested modification for a 45-day comment period and discuss the revision request in a public meeting. The ERO will make a recommendation to the NERC BOT, which may adopt the revision request, adopt it with modifications, or reject it. Any approved revision to this procedure will be filed with FERC for informational purposes.

Event Selection Objectives

The goals of this procedure are to outline a transparent, repeatable process to annually identify a list of frequency events to be used by Balancing Authorities (BA) to calculate their Frequency Response to determine:

- whether the BA met its Frequency Response Obligation; and
- an appropriate fixed bias setting.

Event Selection Criteria

1. The ERO will use the following criteria to select FRS frequency excursion events for analysis. The events that best fit the criteria will be used to support the FRS. The evaluation period for performing the annual Frequency Bias Setting and the Frequency Response Measure (FRM) calculation is December 1 of the prior year through November 30 of the current year.
2. The ERO will identify 20–35 frequency excursion events in each interconnection for calculating the Frequency Bias Setting and the FRM. If the ERO cannot identify 20 frequency excursion events in a 12-month evaluation period satisfying the criteria below, then similar acceptable events from the subsequent year's evaluation period will be included with the data set by the ERO for determining FRS compliance.
3. The ERO will use three criteria to determine if an acceptable frequency excursion event for the FRM has occurred:
    a. The change in frequency as defined by the difference from the A Value to Point C and the arrested frequency Point C exceeds the excursion threshold values specified for the interconnection in Table F1 below.
        i. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline.

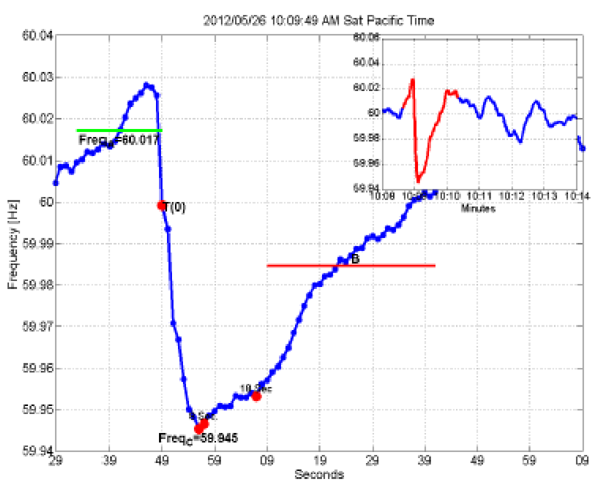
ii. Point C is the arrested value of frequency observed within 12 seconds following the start of the excursion.

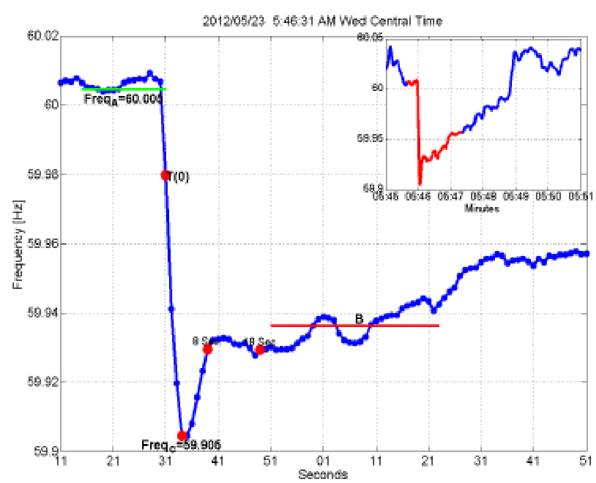
Table F1: Interconnection Frequency Excursion Threshold Values (Hz)			
Interconnection	A Value to Pt C	Point C (Low)	Point C (High)
Eastern	0.04	< 59.96	> 60.04
Western	0.07	< 59.95	> 60.05
ERCOT	0.15	< 59.90	> 60.10
Québec	0.30	< 59.85	> 60.15

b. The time from the start of the rapid change in frequency until the point at which frequency has stabilized within a narrow range should be less than 18 seconds.

c. If any data point in the B Value average recovers to the A Value, the event will not be included.

4. Pre-disturbance frequency should be relatively steady and near 60.000 Hz for the A Value. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline. For example, given the choice of the two events below, the one on the right is preferred as the pre-disturbance frequency is stable and also closer to 60 Hz.





5. Excursions that include two or more events that do not stabilize within 18 seconds will not be considered.

6. Frequency excursion events occurring during periods when large interchange schedule ramping or load change is happening, and frequency excursion events occurring within 5

minutes of the top of the hour, will be excluded from consideration if other acceptable frequency excursion events from the same quarter are available.

7. The ERO will select the largest (A Value to Point C) two or three frequency excursion events occurring each month. If there are not two frequency excursion events that satisfy the selection criteria in a month, then other frequency excursion events should be picked in the following order of priority:

   1) from the same event quarter of the year
   2) from an adjacent month
   3) from a similar load season in the year (shoulder vs. summer/winter)
   4) the largest unused event

As noted earlier, if a total of 20 events are not available in an evaluation year, then similar acceptable events from the next year's evaluation period will be included with the data set by the ERO for determining FRO compliance. The first year's small set of data will be reported and used for Bias Setting purposes, but compliance evaluation on the FRO will be done using a 24 month data set.

To assist Balancing Authority preparation for complying with this standard, the ERO will provide quarterly posting of candidate frequency excursion events for the current year FRM calculation. The ERO will post the final list of frequency excursion events used for standard compliance as specified in Attachment A of BAL-003-1. The following is a general description of the process that the ERO will use to ensure that BAs can evaluate events during the year in order to monitor their performance throughout the year.

Monthly

Candidate events will be initially screened by the "Frequency Event Detection Methodology" shown on the following link located on the NERC Resources Subcommittee area of the NERC website:
http://www.nerc.com/docs/oc/rs/Frequency_Event_Detection_Methodology_and_Criteria_Oct_2011.pdf.

Each month's list will be posted by the end of the following month on the NERC website, http://www.nerc.com/filez/rs.html and listed under "Candidate Frequency Events."

Quarterly

The monthly event lists will be reviewed quarterly with the quarters defined as:

- December through February
- March through May
- June through August
- September through November

Based on criteria established in the "Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard," events will be selected to populate the FRS Form 1 for each interconnection. Each interconnection's Form 1 will be posted on the NERC website, in the Resources Subcommittee area under the title "Frequency Response Standard Resources." The updated Form 1 documents will be posted at the end of each quarter listed above after a review by the NERC RS Frequency Working Group. While the events on this list are expected to be final, as outlined in the selection criteria, additional events may be considered, if the number of events throughout the year do not create a list of at least 20 events. It is intended that this quarterly posting of updates to the FRS Form 1 would allow BAs to evaluate the events throughout the year, lessening the burden when the yearly posting is made.

Annually

The final FRS Form 1 for each interconnection, which will contain the events from all four quarters listed above, will be posted as specified in Attachment A. Each Balancing Authority reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO as specified in Attachment A using the final FRS Form 1. The ERO will error check and use the FRS Form 1 data to calculate CPS limits and FROs for the upcoming year.

Once the data listed above is fully reviewed, the ERO may adjust the implementation specified in Attachment A for changing the Frequency Bias Settings and CPS limits. This allows flexibility in when each BA implements its settings.

Appendix G – Statistical Analysis of Frequency Response (Eastern Interconnection)

Statistical Analysis of Frequency Response

Eastern Interconnection August 7, 2012

Introduction

An interconnected electric power system is a complex system that must be operated within a safe frequency range to reliably maintain the instantaneous balance between generation and load, and is directly reflected in the frequency of the interconnection. Frequency Response is one measurement of how a power system has performed in response to the sudden loss of generation or load. This white paper analyzes the Frequency Response data for the Eastern Interconnection using statistical methods to study the probability distribution of the Frequency Response and its changes from year-to-year, as well as construct a set of variables that strongly influence Frequency Response.

Objectives and Method

The main goals of the statistical analysis of the Frequency Response data for the Eastern Interconnection are to study the:

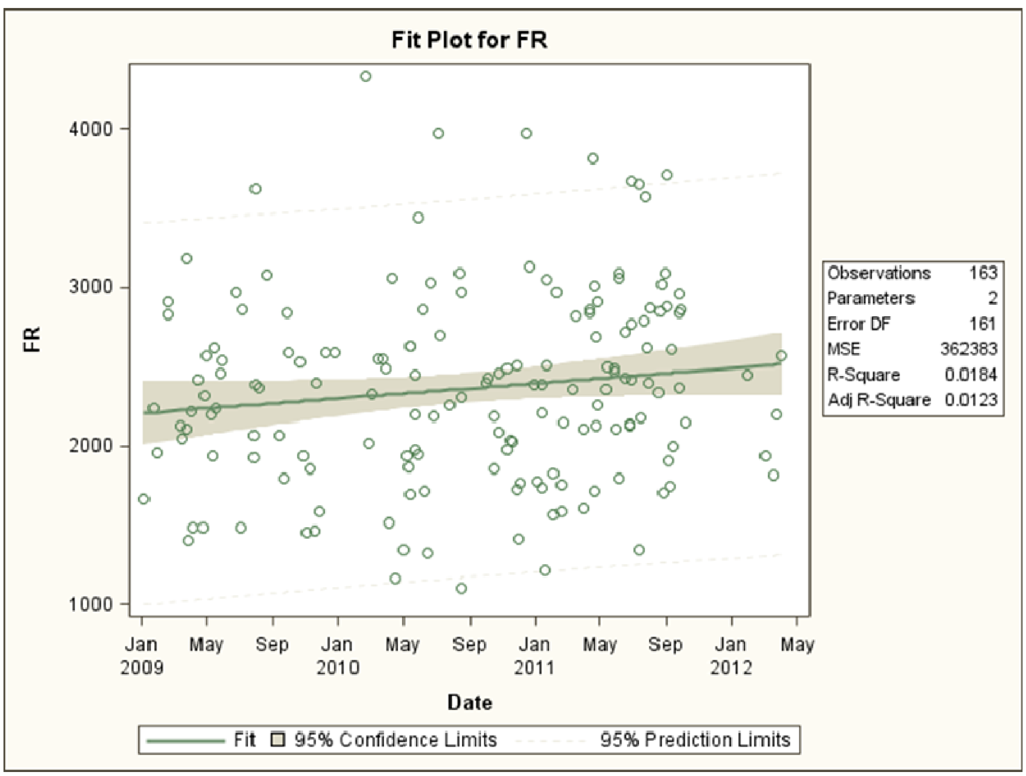
1. time trend of Frequency Response by selecting an appropriate model describing the relationship between a point in time when an event happens and the absolute value of Frequency Response for this event, and to use this model for Frequency Response forecasting with a given confidence level;
2. probability distribution of the Frequency Response and its changes over the years;
3. seasonal changes in Frequency Response distribution and correlation between Frequency Response value and season when the event happened (summer/non-summer);
4. impact of pre-disturbance frequency on Frequency Response;
5. impact of on-peak/off-peak hours on Frequency Response;
6. impact of interconnection load on Frequency Response; and
7. hierarchy of these explanatory factors of Frequency Response.

The analysis uses the Frequency Response dataset for the Eastern Interconnection for the calendar years 2009-2011 and the first three months of 2012. The size of this dataset is 163 frequency events (with 44 observations for the year of 2009, 49 for 2010, 65 for 2011, and 5 for 2012). Since interconnection load data are not yet available for 2012, the part of the study involving interconnection load deals with the 158 Frequency Response events occurred in 2009-2011. For purposes of this whitepaper, Frequency Response pertains to the absolute value of Frequency Response.

Key Findings

1. A linear regression equation with the parameters defined in the Appendix of this whitepaper is an adequate statistical model to describe a relationship between time (predictor) and Frequency Response (response variable). The graph of the linear regression line and Frequency Response scatter plot is given in Figure G1. For the dataset, the regression line has a small positive slope estimate, meaning that the Frequency Response variable has a slowly increasing general trend in time. The value of the slope estimate is 0.00000303805 (the time unit is a second). This means that, on average, Frequency Response increases daily by 0.26 MW/0.1Hz, monthly by 7.87 MW/0.1 Hz, and annually by 95.81 MW/ 0.1Hz (for a month with 30 days , and a year with 365 days). A 90% confidence interval for slope, CI=[-0.00000041605, 0.00000649214], has a negative left-end point (the same is true for a 95% CI and a 99% CI). With new data available the trend line can (a) increase its positive slope, (b) change the positive slope to a slight negative one, or (c) become essentially flat that will correspond to an absence of a correlation between time and Frequency Response.

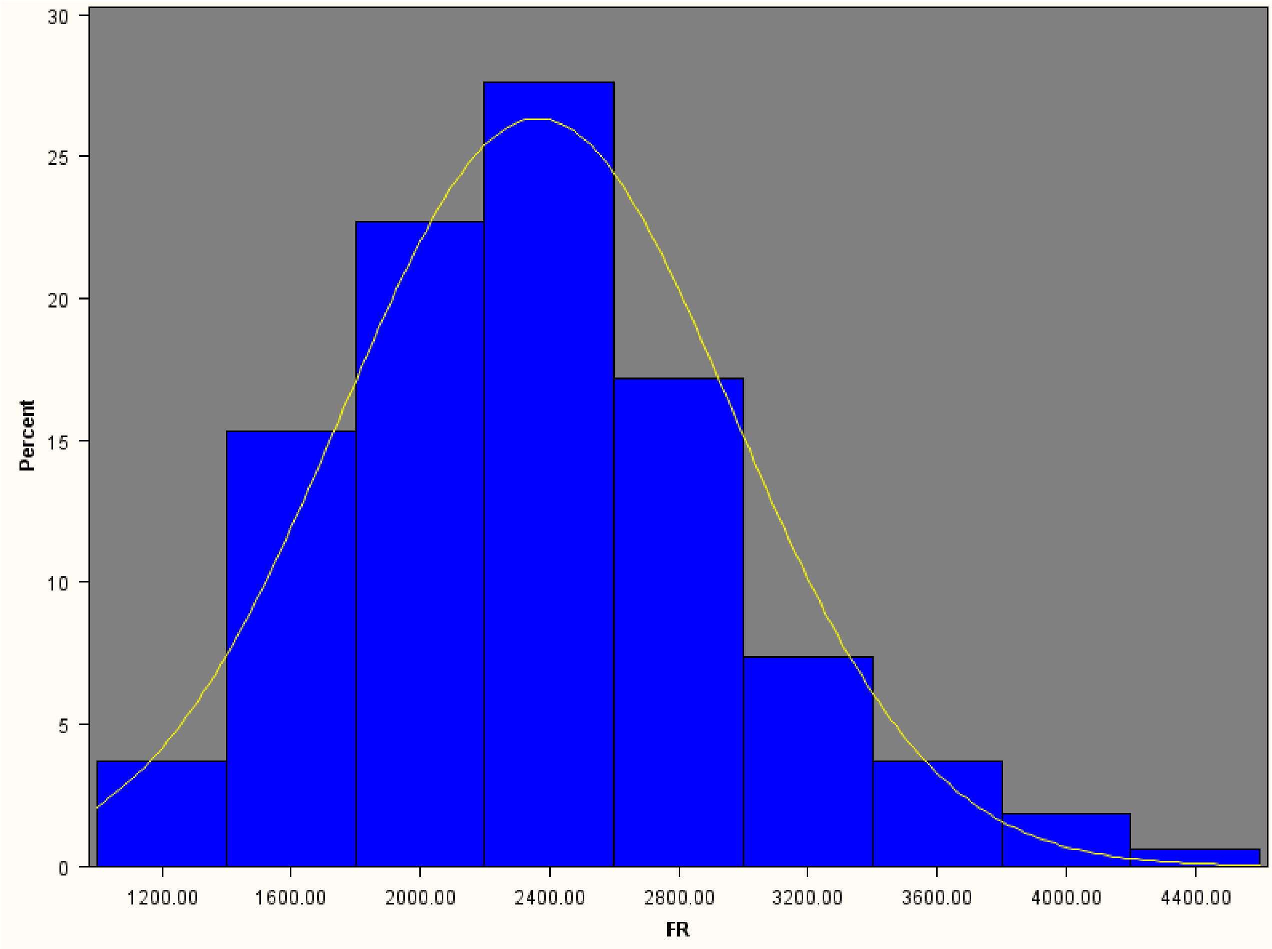
Figure G1: Frequency Response Scatter Plot



2. The probability distribution of the whole Frequency Response dataset is approximately normal with the expected Frequency Response of 2363 MW/0.1 Hz and the standard deviation of 605.7 MW/0.1 Hz as shown in Figure G2. The comparative statistical analysis for every pair of years shows that the changes in the 2010 data versus the 2009 data (and in the 2011 data versus the 2010 data) are not statistically significant enough to lead to the conclusion that the mean value of Frequency Response for any two consecutive years changes. However, the data for 2009 and 2011 differ at the level that results in accepting

the hypothesis that the expected value of Frequency Response for 2011 is greater than for 2009.

Figure G2: Probability Distribution of the Entire Frequency Response Data Set

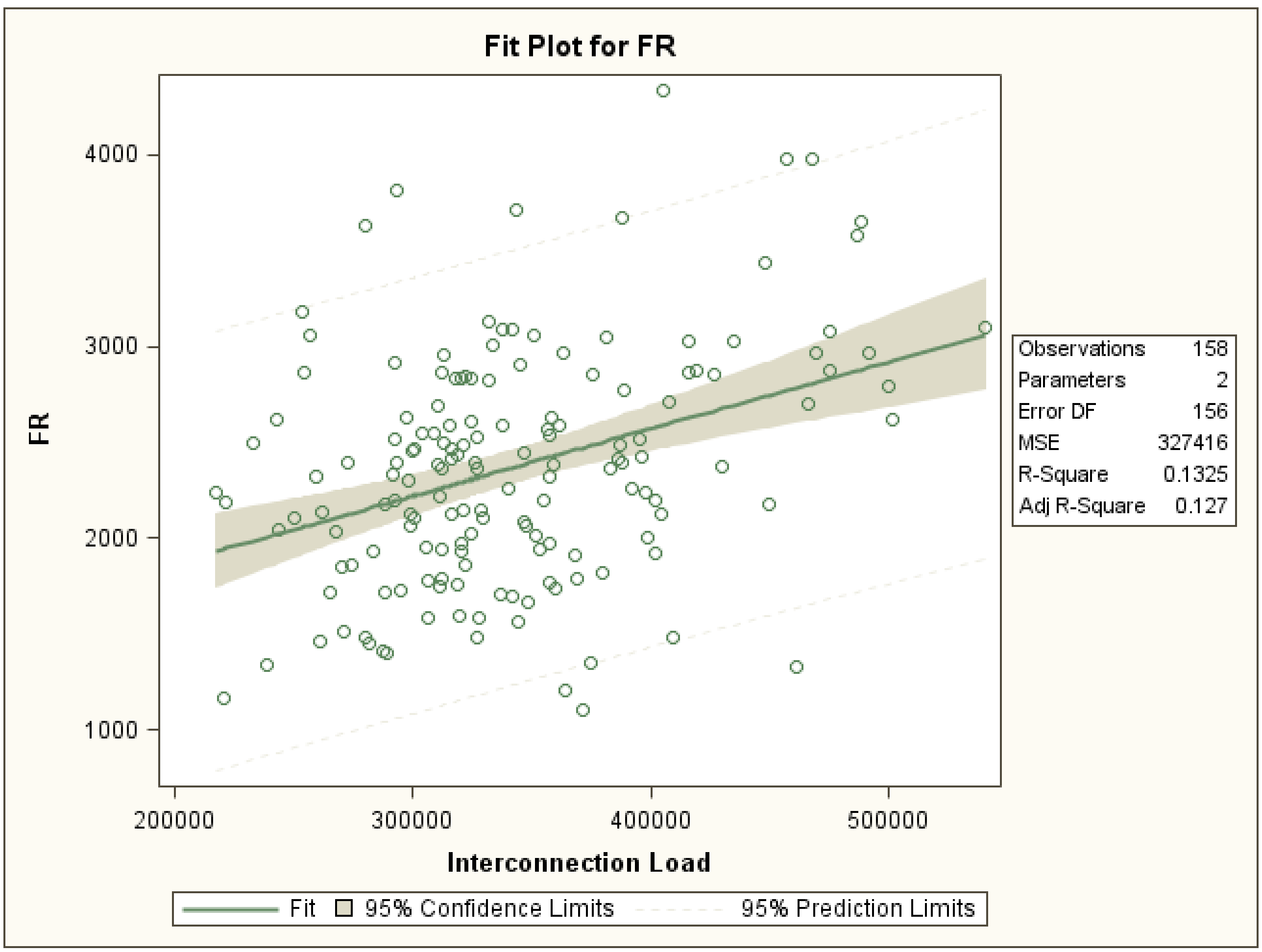


3. A season (summer/non-summer) is a significant contributor to the variability of Frequency Response. There is a positive correlation of 0.24 between the indicator function for summer (defined as 1 for events that occur in June–August and 0 otherwise) and Frequency Response: summer events have a statistically significantly greater expected Frequency Response (the sample mean equals to 2598MW/0.1 Hz) than non-summer events (the mean equals to 2271 MW/0.1 Hz).
4. Pre-disturbance (average) frequency (A) is another significant contributor to the variability of Frequency Response. There is a negative correlation of -0.27 between the indicator function of A>60 Hz and Frequency Response: the events with A>60 Hz have a statistically significantly smaller expected Frequency Response (the sample mean equals to 2188 MW/0.1 Hz) than the events with A≤60 Hz (the mean equals to 2513 MW/0.1 Hz).
5. According the NERC definition, for Eastern Interconnection on-peak hours are designated as follows: Monday to Saturday hours from 0700 to 2200 (Central Time) excluding six holidays (New Year’s Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day). It turns out that on-peak/off-peak variable is not a statistically significant

contributor to the variability of Frequency Response. There is a positive correlation of 0.06 between the indicator function of on-peak hours and Frequency Response; however, difference in average Frequency Response between on-peak events and off-peak events is not statistically significant and could occur by chance (P-value is 0.49).

6. There is a strong positive correlation of 0.364 between interconnection load and Frequency Response for the 2009-2011 events; this correlation indicates to a statistically significant linear relationship between interconnection load (predictor) and Frequency Response (response variable). The graph of the linear regression line and Frequency Response scatter plot is given in Figure G3. For the dataset, the regression line has a positive slope estimate of 0.00349; thus, the Frequency Response variable increases when interconnection load grows. On average, when interconnection load changes by 1000 MW, Frequency Response changes by 3.5 MW/0.1Hz.

Figure G3: Linear Regression for Frequency Response and Interconnection Load



7. For the 2009–2011 dataset, five variables (time, summer, high pre-disturbance frequency, on-peak/off-peak hour, interconnection load) have been involved in the statistical analysis of Frequency Response. Four of these (time, summer, on-peak hours, and interconnection load) have a positive correlation with Frequency Response (0.16, 0.24, 0.06, and 0.36,

respectively), and the high pre-disturbance frequency has a negative correlation with Frequency Response (-0.26). The corresponding coefficients of determination R^2 are 2.6%, 5.8%, 0.4%, 13.3% and 6.9%. These values indicate that about 2.6% in variability of Frequency Response can be explained by the changes in time, about 5.8% of Frequency Response variability is seasonal, 0.4% is due to on-peak/off-peak changes, 13.3% is the effect of the interconnection load variability, and about 6.9% can be accounted for by a high pre-disturbance frequency. However, the correlation between Frequency Response and On-Peak hours is not statistically significant and with the probability about 0.44 occurred by mere chance (the same holds true for the corresponding R^2). Therefore, out of the five parameters, interconnection load has the biggest impact on Frequency Response followed by the indicator of high pre-disturbance frequency. A multivariate regression with interconnection load and A>60 as the explanatory variables for Frequency Response yields a linear model with the best fit (it has the smallest mean square error among the linear models with any other set of explanatory variables selected from the five studied). Still, together these two factors can account for about 20% in variability of Frequency Response. Therefore, there are other parameters that affect Frequency Response, have a low correlation with those studied, together account for a remaining share in Frequency Response variability, and minimize a random error variance. Note that interconnection load is positively correlated with summer (0.55), on-peak hours (0.45), and Date (0.20) but uncorrelated with A>60 (P-value of the test on zero correlation is 0.90).

Explanatory Variables for EI Frequency Response (2009-2011)

Variable X	Sample Correlation (X,FR)	P-value	Linear Regression Statistically Significant?	Coefficient of Determination R^2 (Single Regression)
Interconnection Load	0.36	<0.0001	Yes	13.3%
A>60	-0.26	0.0008	Yes	6.9%
Summer	0.24	0.0023	Yes	5.8%
Date	0.16	0.044	Yes	2.6%
On-Peak Hours	0.06	0.438	No	N/A

Appendix – Background Materials

Frequency Response is a metric used to track and monitor Interconnection Frequency Response. Frequency Response[2] is a measure of an interconnection's ability to stabilize frequency immediately following the sudden loss of generation or load. It is a critical component to the reliable operation of the bulk power system, particularly during disturbances and restoration. The metric measures the average Frequency Response for all events where frequency drops more than the interconnection's defined threshold as shown in Table 1.

Frequency Response Definition

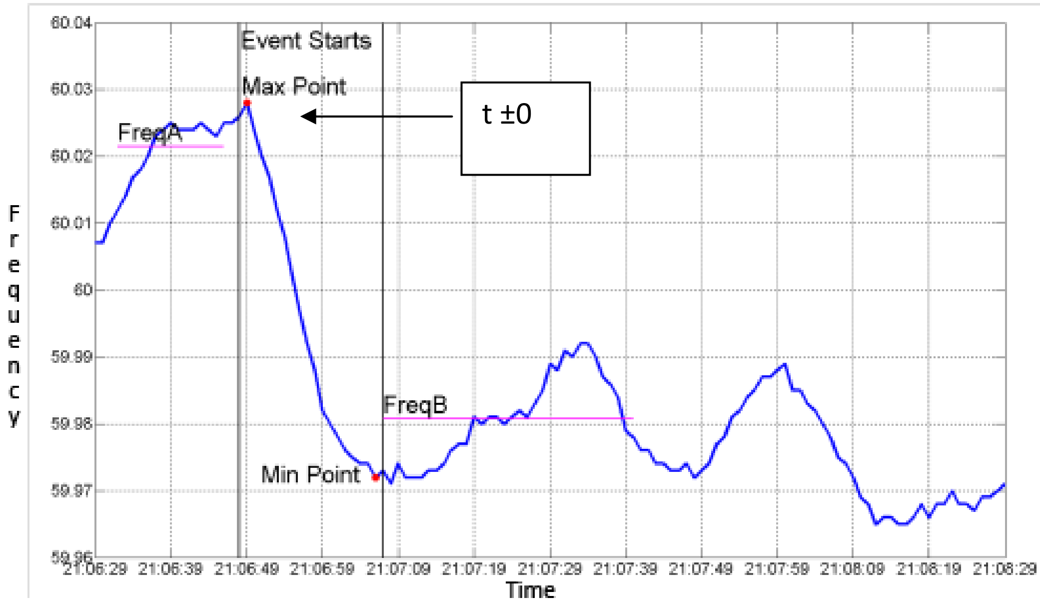
For a given interconnection, Frequency Response is defined as the sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 hertz (MW/0.1 Hz).

Table 1: Frequency Event Triggers for Data Collection			
Interconnection	ΔFrequency (mHz)	MW Loss Threshold	Rolling Windows (seconds)
Eastern	40	800	15
Western	70	700	15
ERCOT	90	450	15
Québec	300	450	15

The change in frequency is the difference between pre-disturbance frequencies A and setting frequency B. Figure 3 shows the criteria for calculating average values A and B. The event starts at time t ±0. Value A is the average from t -16 to t -2 and Value B is the average from t +20 to t +52. These lengths of time used to calculate these values accounts for the variability in Supervisory Control and Data Acquisition (SCADA) scan rates that vary from 2 to 6 seconds in the multiple-Balancing Authority interconnections. For Balancing Authority SCADA data, t ±0 represents the first scan of data that is part of the disturbance. Value A is the average of all SCADA scans between 2 and 16 seconds before t ±0. Value B is the average of all SCADA scans between 20 and 52 seconds after t ±0.

[2] Frequency Response is in fact a negative value. However to reduce confusion for the reader, Frequency Response is expressed in this report as positive values (the absolute value of the actual calculated value).

Figure 3: Criteria for Calculating Value A and Value B



The actual MW loss for the flagged frequency events is determined jointly by NERC and Regional Entity situation awareness staff. Both the change in frequency and the MW loss determine whether the event qualifies for further consideration in the monthly frequency event candidate list.

Statistical Analysis

Linear Regression for Time Trend

Assumptions: Frequency Response and time are related by the following regression equation:

$$FR = A * Time + B + \varepsilon$$

Where:

- $Time$ variable represents a time (year, month, day, hour, minute, second) when a Frequency Response event happened. For each event the Frequency Response is calculated and recorded. This record represents an observation from the dataset. Time is an explanatory variable (predictor, regressor) of the linear regression;
- FR is the Frequency Response value measured in MW/0.1 Hz (response variable of the model);
- A is a slope of the regression line;
- B is an intercept of the regression line; and
- ε is a random error which has a centered normal distribution with variance σ^2.

A SAS program for the linear regression analysis yields the following results shown in figure G3.

(a) The equation of the regression line derived by the least squares method is $y = 0.00000304x - 2493.41315$ with $x = Time(sec)$ elapsed between midnight of January 1, 1960 (the time origin for the date format in SAS) and the time of a FR event;
(b) Estimate for the variance σ^2 of the random error ε is 362,383 and for the standard deviation of ε is 601.98255;
(c) Statistical test for significance of the_regression (based on the analysis of variance approach) is an important part of assessing the adequacy of the linear regression model for time and FR variables. The procedure tests a null-hypothesis that the slope A = 0 versus an alternative hypothesis that it is not 0. Sample value of F-statistic, 3.0170, has P-value of 0.0843 implying that the null hypothesis should be rejected (and the alternative hypothesis accepted) at any significance level above 0.0843. Therefore, the data are statistically significant to support a hypothesis about a linear relationship between time and Frequency Response assuming that the 8.43% significance level (i.e., the probability to reject the null hypothesis when it is true) is appropriate for the model selection. Alternatively, the hypothesis about the correlation coefficient ρ(time, FR) can be tested (with the null hypothesis ρ=0). These tests are equivalent and result in the same P-values for their test statistics.

Another important part of the verification of the linear regression model is testing the assumptions on the random error ε. Student's t-test on location and goodness-of-fit test for normality both result in acceptance the corresponding null-hypothesis (with P-values of 1.0000 and 0.881, respectively).

The linear regression equation with the parameters defined above is an adequate statistical model to describe the relationship between variables time of a FR event and Frequency Response value for this event. For the dataset, the regression line has a small positive slope estimate, meaning that Frequency Response variable has a slowly increasing general trend in time. However, the value of this slope estimate is very small, and confidence intervals for slope at 90%, 95% and 99% levels all have a negative left-end point. By using T-distribution for the slope estimator, we estimate that the probability that the slope of the regression is negative is below 5%.

The coefficient of determination R^2 for the linear regression model equals to 0.0184. This small value indicates very low degree of dependence of Frequency Response on time variable. Essentially, the linear regression model connecting FR and time accounts for 1.8% of variability in the Frequency Response data.

The random error ε has a large estimated variance that makes the "error" term of the linear regression equation a major component of the Frequency Response value. Our next goal is to consider the Frequency Response data as observations of a random variable independent of time and to study properties of its distribution.

Distribution of Frequency Response

Goodness-of-Fit test for normality of the distribution of the Frequency Response data results in acceptance on the null hypothesis at a significance level below 0.177 (including the standard levels of 1%, 5% and 10%). The sample estimate for the expected Frequency Response equals to 2363 MW/0.1 Hz and the sample standard deviation is 605.7 MW/0.1 Hz.

Since for each full year (2009, 2010, and 2011) the sample size of the Frequency Response data exceeds 40, we ran a large-sample test for the difference in the mean Frequency Response for 2009 versus 2010, 2010 versus 2011, and 2009 versus 2011. The null hypothesis that the difference is zero is accepted when the 2009 data are compared to the 2010 data, and when the 2010 data are compared to the 2011 data at any standard significance level (P-values of the two-sided tests are 0.54 and 0.28, respectively). For the 2009 versus 2011 comparison, the test result is not that conclusive (its P-value equals to 0.03 and, therefore, the null hypothesis should be rejected at the 5% and 10% significance levels but is accepted at the 1% level if tested versus an alternative hypothesis that the 2011 mean value is greater than the 2009 mean value).

Seasonal Variability of Frequency Response

Let a function summer be defined as follows: it equals to 1 for Frequency Response events that occur in June-August and 0 otherwise. The FR dataset is therefore divided in two subsets: the Frequency Response data for summer events and non-summer events, respectively. Summer Frequency Response set has 46 observations and non-summer set has 117 observations. The sample mean and the sample variance for the first dataset are 2597.7 MW/0.1 Hz and 675.5 MW/0.1 Hz, respectively. The sample mean and the sample variance for the second dataset are 2270.9 MW/0.1 Hz and 552.2 MW/0.1 Hz. A large-sample test for the difference in the mean Frequency Response for these distributions results in rejection of the null hypothesis that the difference is zero and acceptance of an alternative hypothesis that the expected Frequency Response for summer events is greater than for other events (P-value of the one-sided z-test is 0.0018).

Variables summer and Frequency Response are positively correlated (with the correlation equal to 0.24351), and the coefficient of determination R^2 of the linear regression model is 0.0593. The null hypothesis about zero correlation (no linear relationship between FR and summer) should be rejected (P-value is 0.0017). This analysis indicates that seasonality is a significant factor affecting Frequency Response: almost 6% of its variability is the seasonal variability.

Impact of Pre-Disturbance Frequency

Let a function high pre-disturbance frequency be defined as follows: it equals to 1 for Frequency Response events with A>60 Hz and 0 otherwise. The FR dataset is therefore divided in two subsets: the Frequency Response data for events with A>60 Hz and events with A≤60 Hz, respectively. High pre-disturbance frequency set has 75 observations and its complement has 88 observations. The sample mean and the sample variance for the first dataset are 2187.6 MW/0.1 Hz and 531.5 MW/0.1 Hz, respectively. The sample mean and the sample variance for the second dataset are 2512.8 MW/0.1 Hz and 627.4 MW/0.1 Hz. A large-sample test for the difference in the mean Frequency Response for these distributions results in rejection of the null hypothesis that the difference is zero and acceptance of an alternative hypothesis that the expected Frequency Response for events with A>60 Hz is smaller than for other events (P-value of the one-sided z-test is 0.0002).

Variables high pre-disturbance frequency and Frequency Response are negatively correlated (with the correlation equal to -0.26844), and the coefficient of determination R^2 of the linear regression model is 0.0721. The null hypothesis about zero correlation (no linear relationship between FR and high pre-disturbance frequency) should be rejected (P-value is 0.0005). This analysis indicates that the high pre-disturbance frequency is a factor that accounts for 7.2% of the Frequency Response variability. In fact, out of the four variables involved in this study (time, summer, high pre-disturbance frequency, on-peak/off-peak hours), it is the biggest contributor to the variability of Frequency Response.

Impact of On-Peak/Off-Peak hours

Let a function on-peak hour be defined as follows: it equals to 1 for Frequency Response events occurred during an on-peak hour and 0 otherwise. The FR dataset is therefore divided in two subsets: the Frequency Response data for on-peak hours and off-peak hours, respectively. On-peak set contains 108 observations, and off-peak set has 55 observations. The sample mean and the sample variance for the first dataset are 2386.9 MW/0.1 Hz and 602.9 MW/0.1 Hz, respectively. The sample mean and the sample variance for the second dataset are 2316.6 MW/0.1 Hz and 614.1 MW/0.1 Hz. A large-sample test for the difference in the expected Frequency Response for these distributions results in acceptance of the null hypothesis that the difference is zero and rejection of an alternative hypothesis that the expected Frequency Responses for on-peak events and off-peak events are different (P-value of the two-sided z-test is 0.49).

Variables on-peak hour and Frequency Response are positively correlated (with the correlation equal to 0.005505), and the coefficient of determination R^2 of the linear regression model is 0.0030. However, the correlation is not statistically significant since the null hypothesis about zero correlation (no linear relationship between FR and on-peak hour) should be accepted (P-value is 0.4852). The same is true for the coefficient of determination: there is a high probability that on-peak hours have no explanatory power in the Frequency Response variability. Out of the four variables involved in this study (time, summer, high pre-disturbance frequency, on-peak/off-peak hours), it is the only factor with no statistically significant impact on Frequency Response.

Linear Model that relates Frequency Response to Interconnection Load

Assumptions: Frequency Response and interconnection load are related by the following regression equation:

$$FR = C * IL + D + \varepsilon$$

Where:

- IL is the value of interconnection load (in MW) for a Frequency Response event.
- FR is the Frequency Response value measured in MW/0.1 Hz (response variable of the model);

- C is a slope of the regression line;
- D is an intercept of the regression line; and
- ε is a random error which has a zero mean and variance of σ^2.

A SAS program for the linear regression analysis yields the following results shown in figure G3.:

(a) The equation of the regression line derived by the least squares method is

$y = 0.00349x + 1174.09949;$

(b) Estimate for the variance σ^2 of the random error ε is 327,416 and for the standard deviation of ε is 572.2; and

(c) Statistical test for significance of the regression (based on the analysis of variance approach) is an important part of assessing the adequacy of the linear regression model for interconnection load and FR variables. The procedure tests a null-hypothesis that the slope $C = 0$ versus an alternative hypothesis that it is not 0. Sample value of F-statistic, 23.83, has P-value of 0.0001 implying that the null hypothesis should be rejected (and the alternative hypothesis accepted) at any significance level above 0.0001. Therefore, the data are statistically significant to support a hypothesis about linear relationship between interconnection load and Frequency Response. Alternatively, the hypothesis about the correlation coefficient ρ between interconnection load and Frequency Response can tested (with the null hypothesis ρ=0). These tests are equivalent and result in the same P-values for their test statistics.

The coefficient of determination R^2 for the linear regression model equals to 0.1325. This value indicates high degree of dependence of Frequency Response on interconnection load. Essentially, the linear regression model connecting FR and interconnection load accounts for about 13.3% of variability in the Frequency Response data.

Multiple Linear Regression

A statistically significant linear regression model connects interconnection load and high pre-disturbance frequency (regressors) and Frequency Response (response variable). The estimates of the linear regression coefficients are listed in the Table 2 (P-value of the model is below 0.0001). An error term, ε, has a zero mean and the standard deviation of 551 MW/0.1 Hz. This multiple regression model accounts for 19.96% of the variability in Frequency Response data.

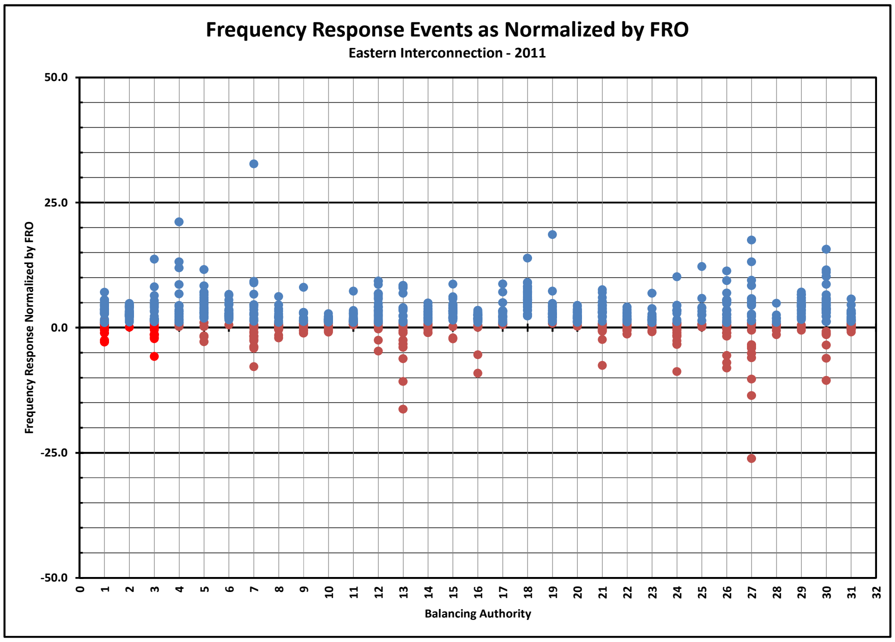
Table 2: Parameter Estimates of Multiple Regression

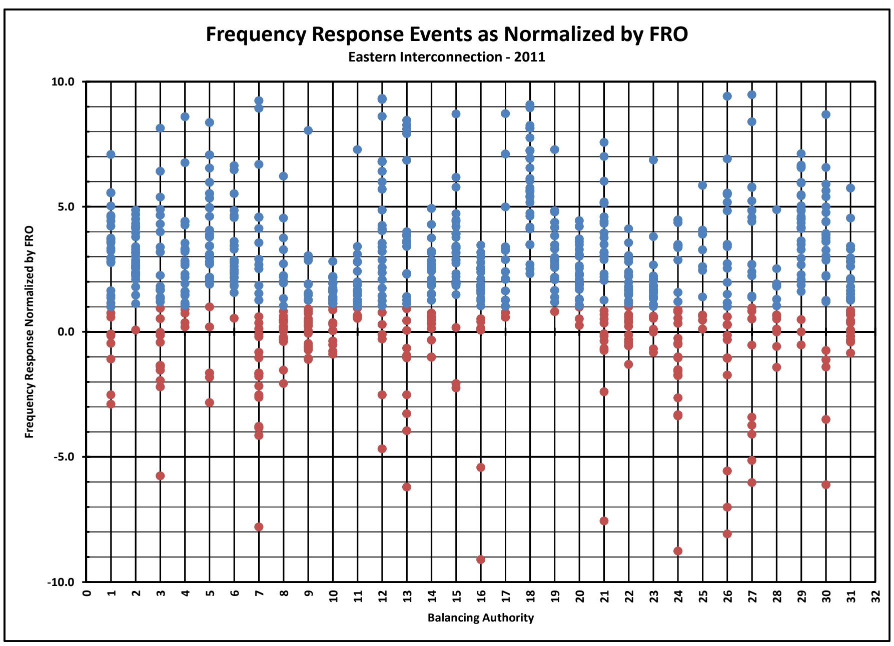
Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	1	1325.96255	243.49079	5.45	<.0001
A>60	1	-317.95091	88.191	-3.61	0.0004
Interconnection Load	1	0.00347	0.00068929	5.03	<.0001

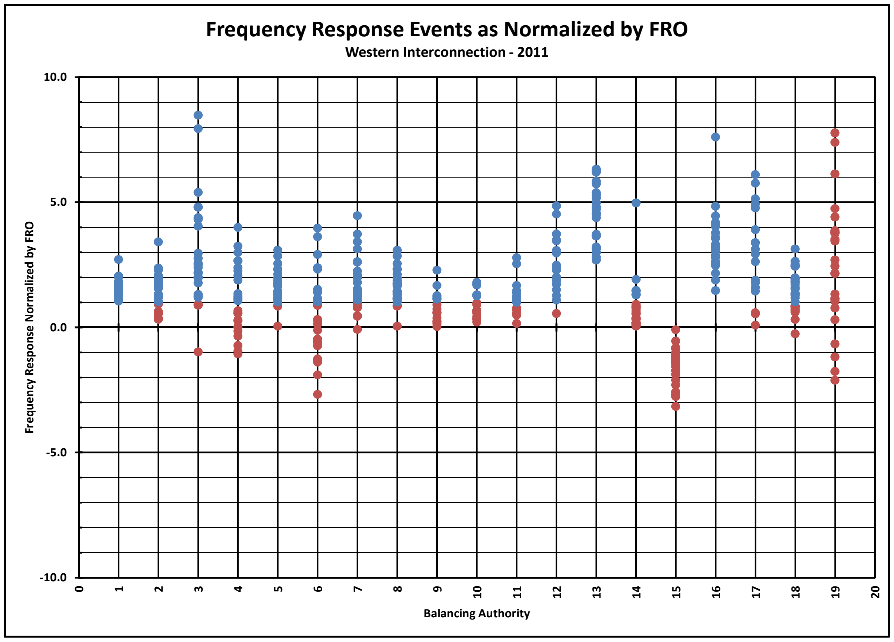
Note that even though time and summer both have a statistically significant positive correlation with Frequency Response, adding one or both of them to the set of explanatory variables does not improve the linear model. This can be explained by a high correlation between interconnection load and summer (0.55) and time (0.20), respectively: addition of these variables does not increase the explanatory power of the model enough to offset an increase of its cumulative error.

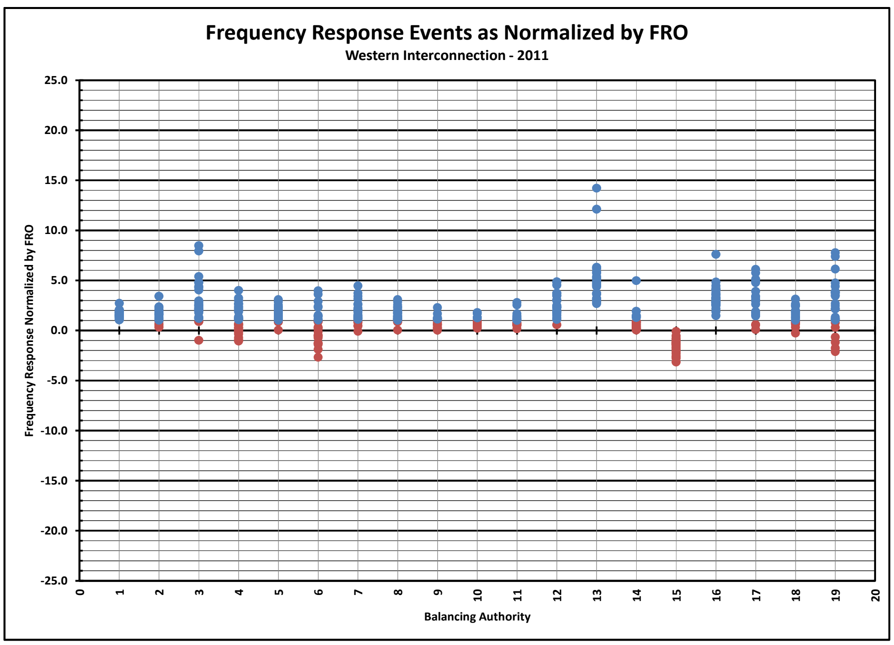
Appendix H – Frequency Response Field Trial Analysis Graphs

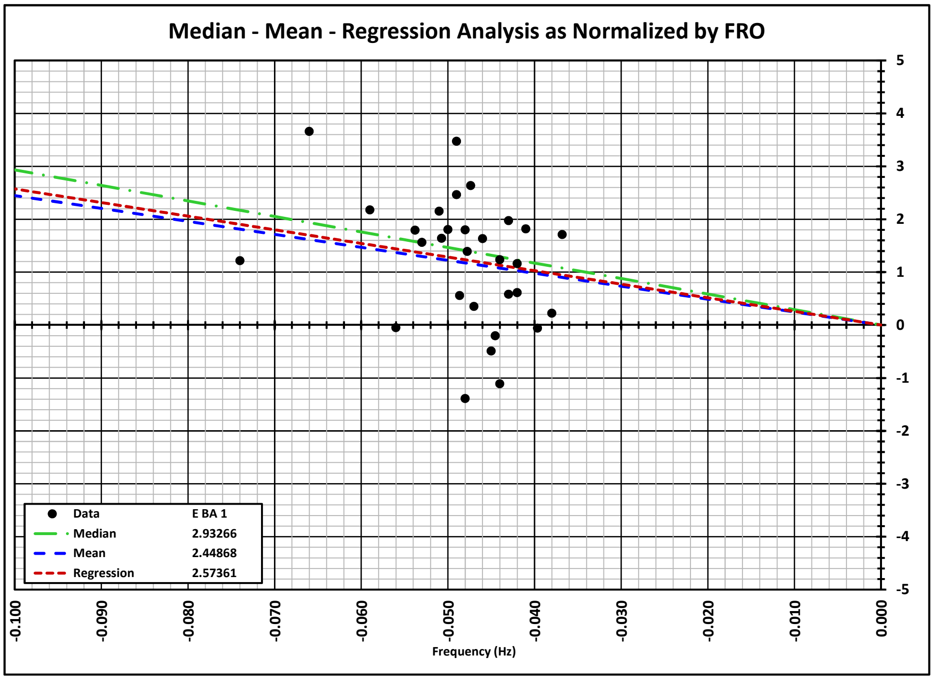
NOTE: These are the background graphics of the Frequency Response Field Trial Analysis of BA performance measurements.

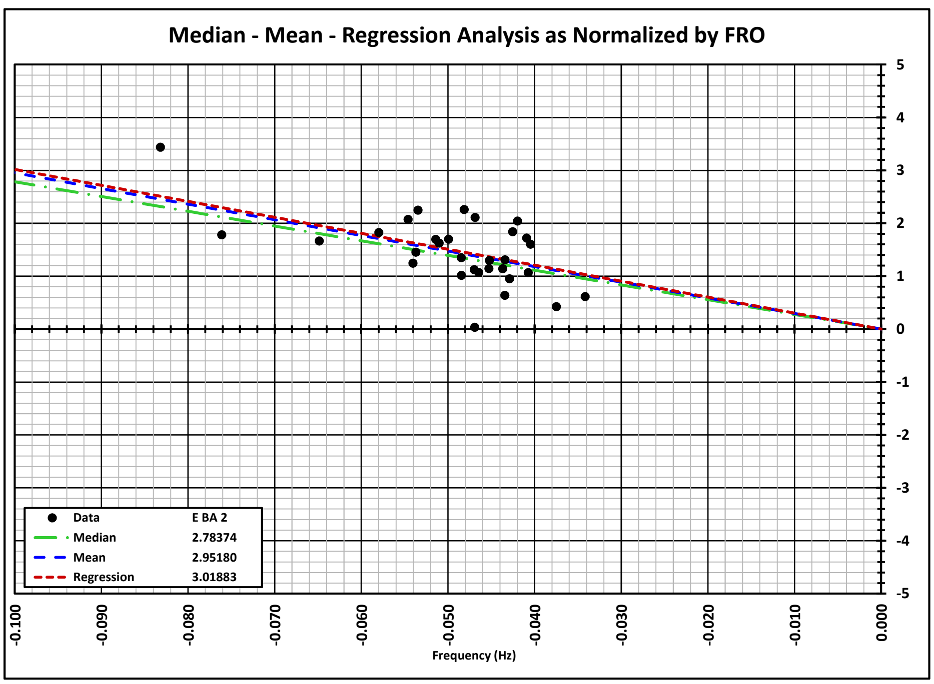


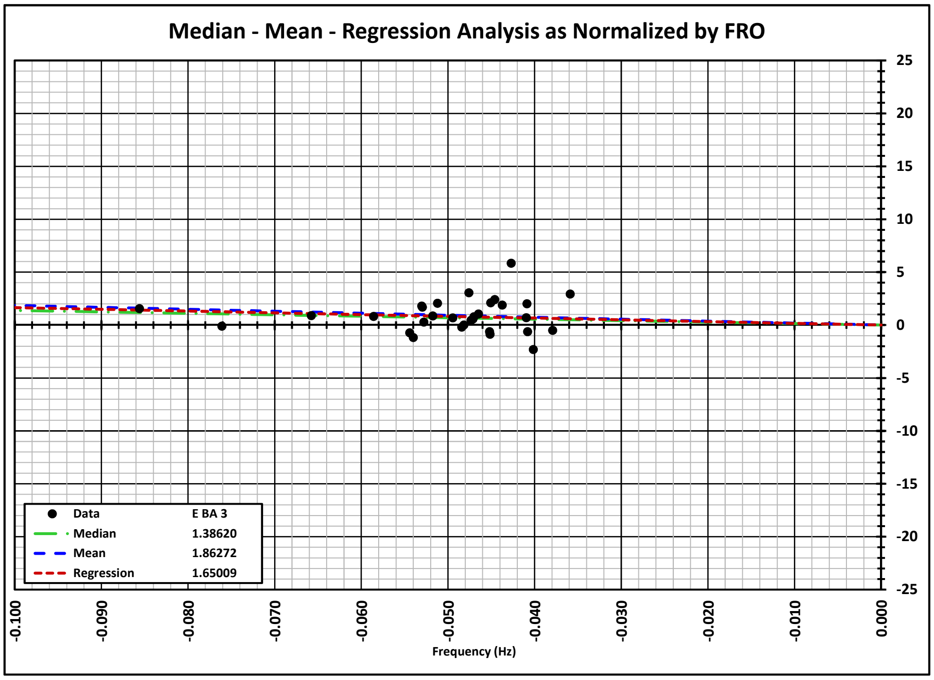


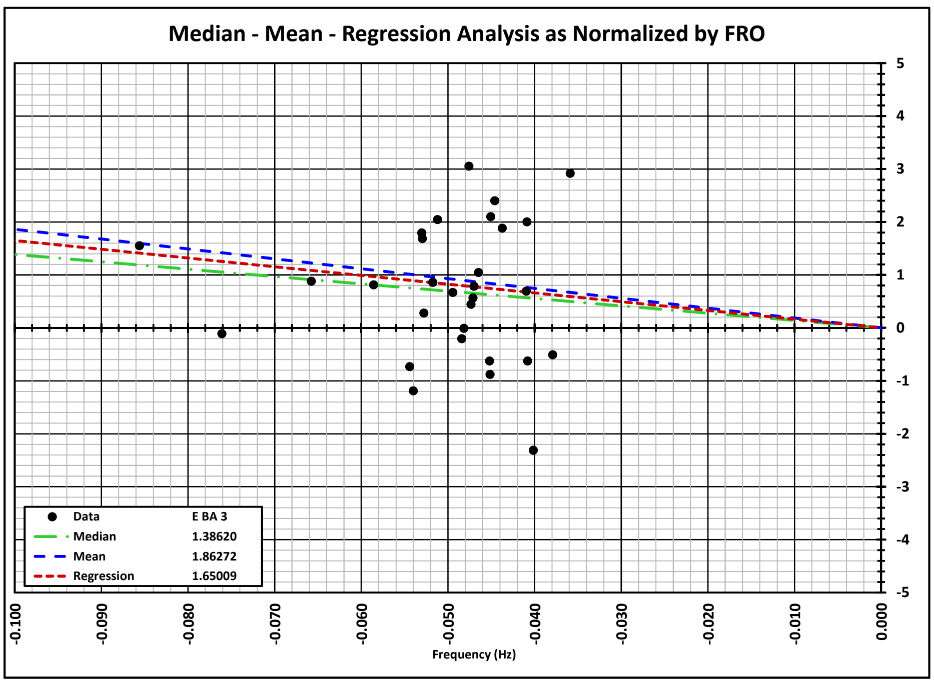

Frequency Response Events as Normalized by FRO
Western Interconnection - 2011
Frequency Response Normalized by FRO
10.0
5.0
0.0
-5.0
-10.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
Balancing Authority

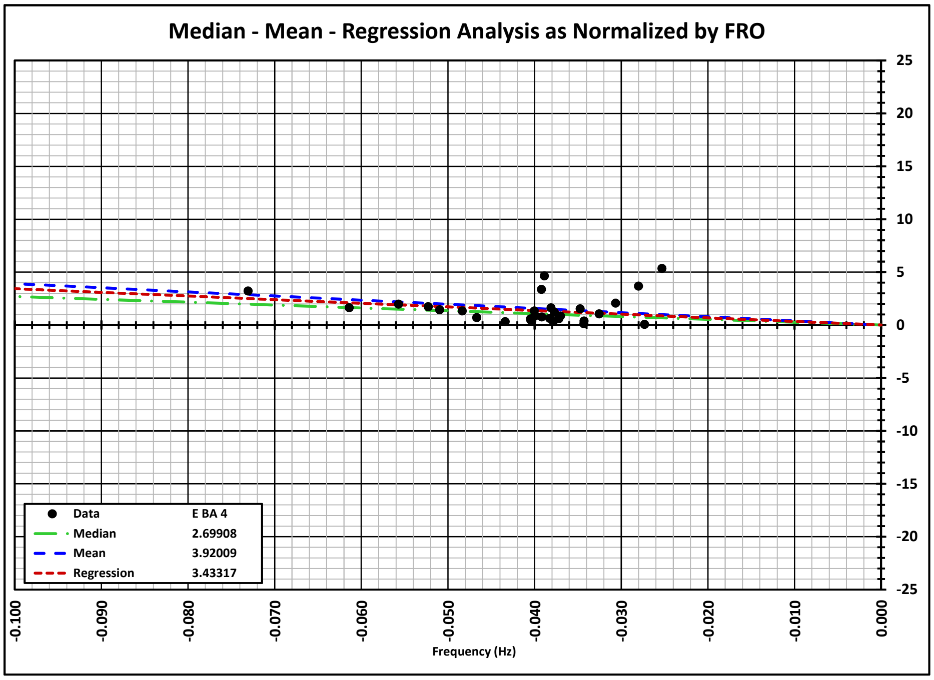

Frequency Response Events as Normalized by FRO
Western Interconnection - 2011
Frequency Response Normalized by FRO
25.0
20.0
15.0
10.0
5.0
0.0
-5.0
-10.0
-15.0
-20.0
-25.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
Balancing Authority

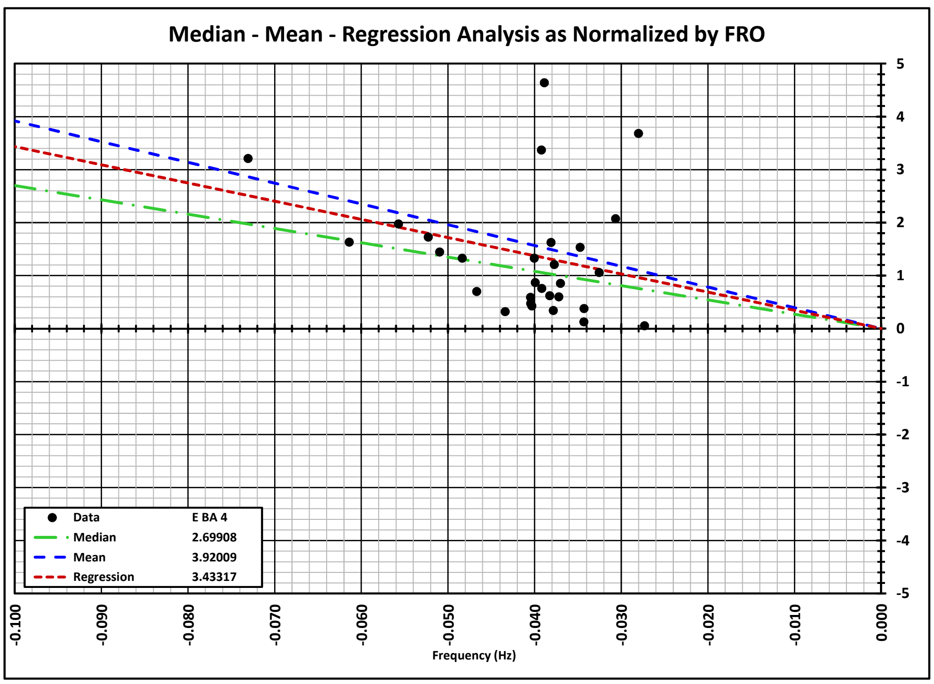

Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 1
Median 2.93266
Mean 2.44868
Regression 2.57361
Frequency (Hz)
-0.100 -0.090 -0.080 -0.070 -0.060 -0.050 -0.040 -0.030 -0.020 -0.010 0.000
5 4 3 2 1 0 -1 -2 -3 -4 -5

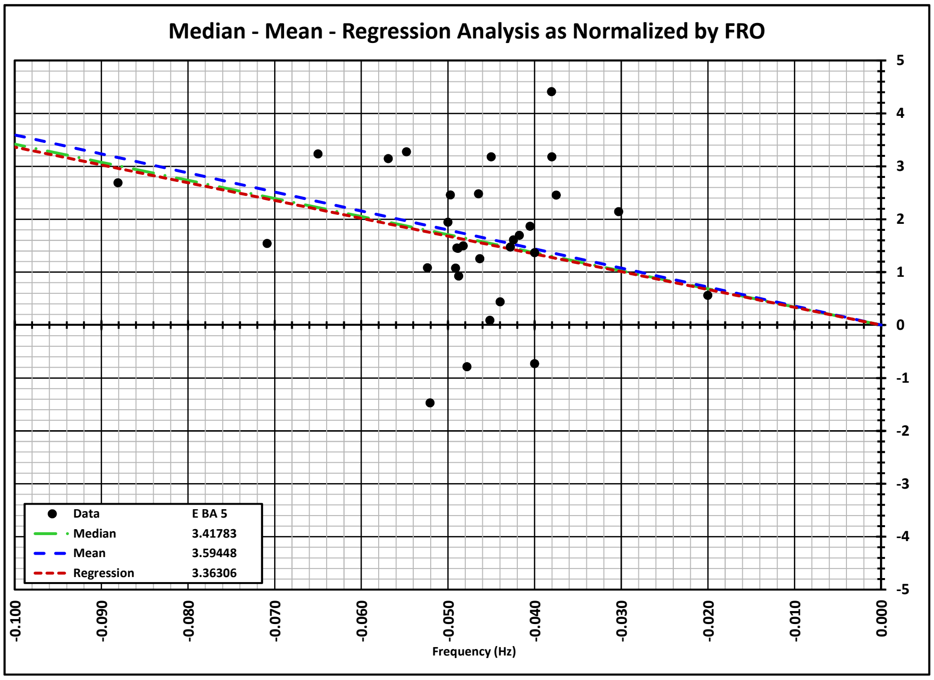

Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 2
Median 2.78374
Mean 2.95180
Regression 3.01883
Frequency (Hz)
-0.100 -0.090 -0.080 -0.070 -0.060 -0.050 -0.040 -0.030 -0.020 -0.010 0.000
5 4 3 2 1 0 -1 -2 -3 -4 -5

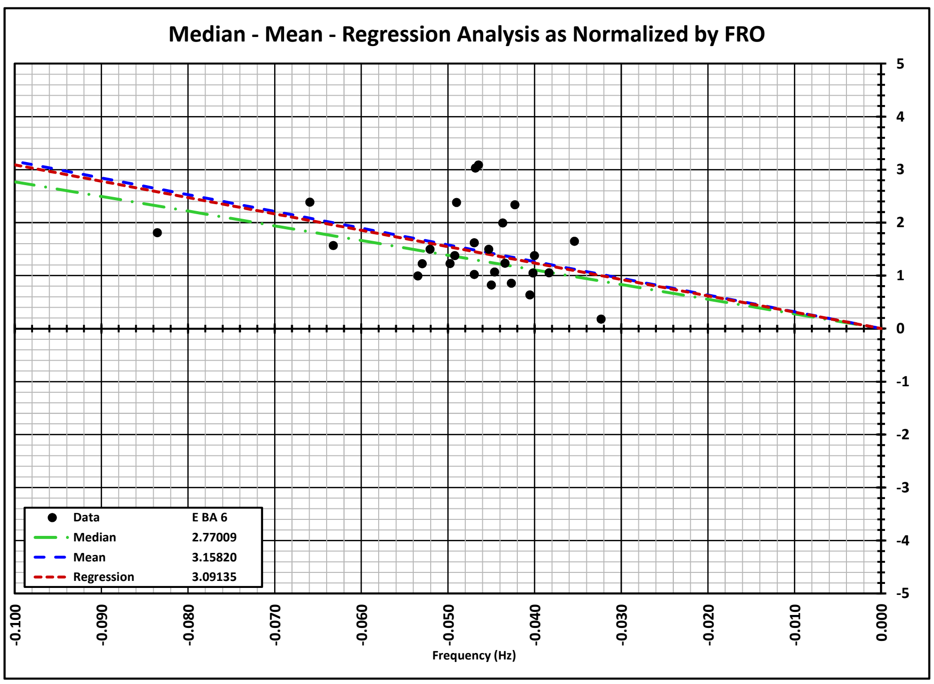

Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 3
Median 1.38620
Mean 1.86272
Regression 1.65009
Frequency (Hz)
25
20
15
10
5
0
-5
-10
-15
-20
-25
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000

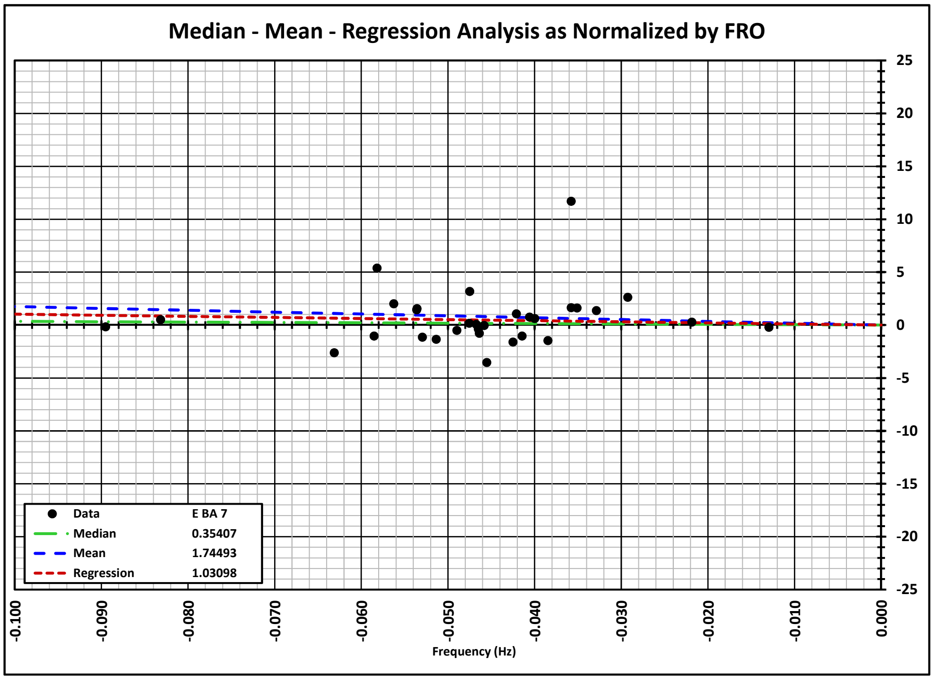

Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 3
Median 1.38620
Mean 1.86272
Regression 1.65009
Frequency (Hz)
5
4
3
2
1
0
-1
-2
-3
-4
-5
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000

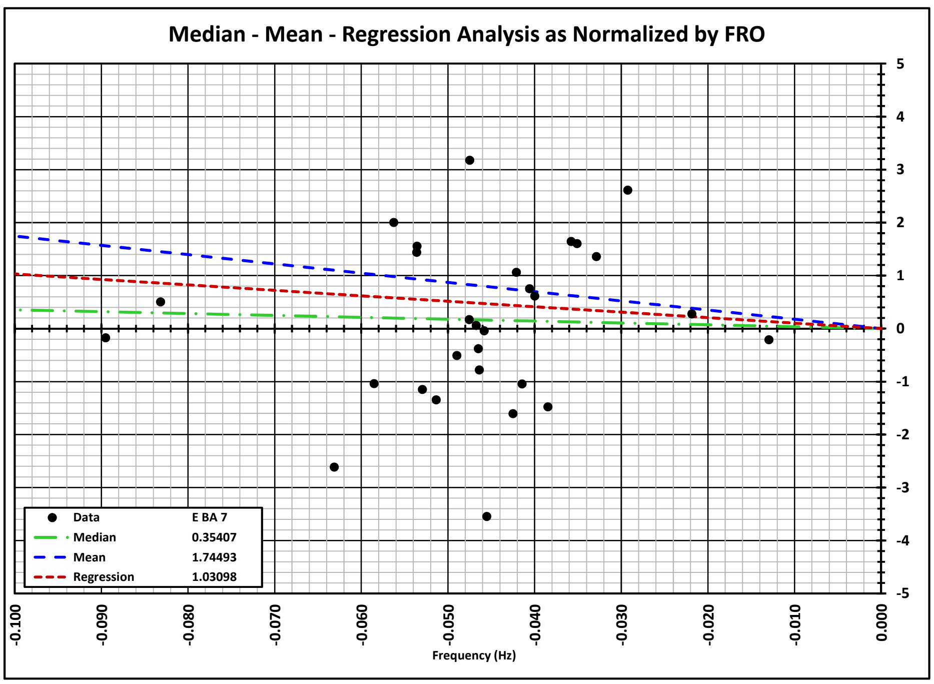

Median - Mean - Regression Analysis as Normalized by FRO
Data
E BA 4
Median
2.69908
Mean
3.92009
Regression
3.43317
Frequency (Hz)
25
20
15
10
5
0
-5
-10
-15
-20
-25
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000

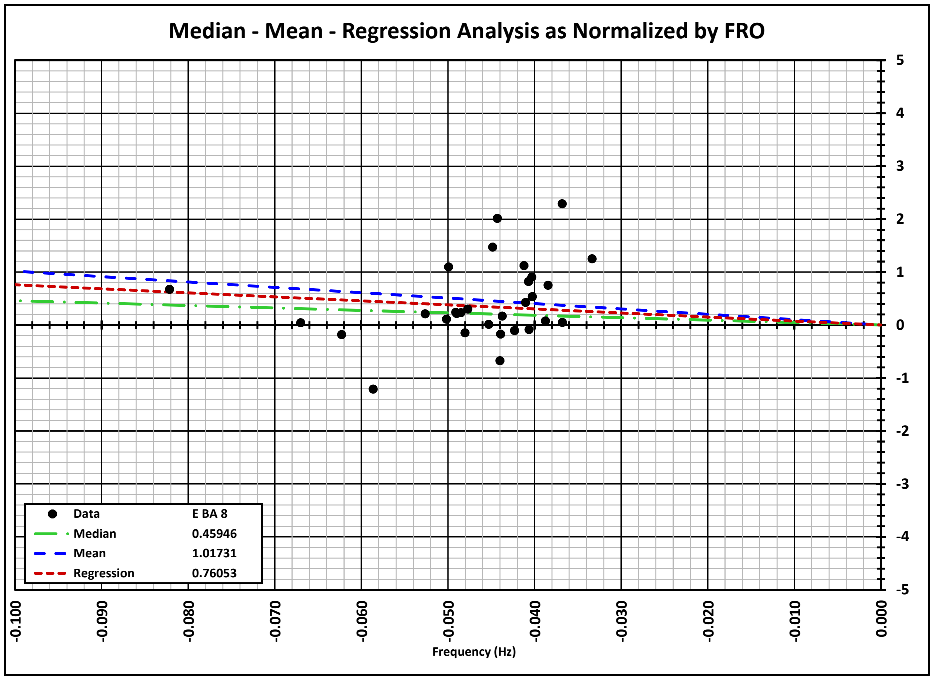

Median - Mean - Regression Analysis as Normalized by FRO
Data
E BA 4
Median
2.69908
Mean
3.92009
Regression
3.43317
Frequency (Hz)
5
4
3
2
1
0
-1
-2
-3
-4
-5
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 5
Median 3.41783
Mean 3.59448
Regression 3.36306
5
4
3
2
1
0
-1
-2
-3
-4
-5
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
Frequency (Hz)

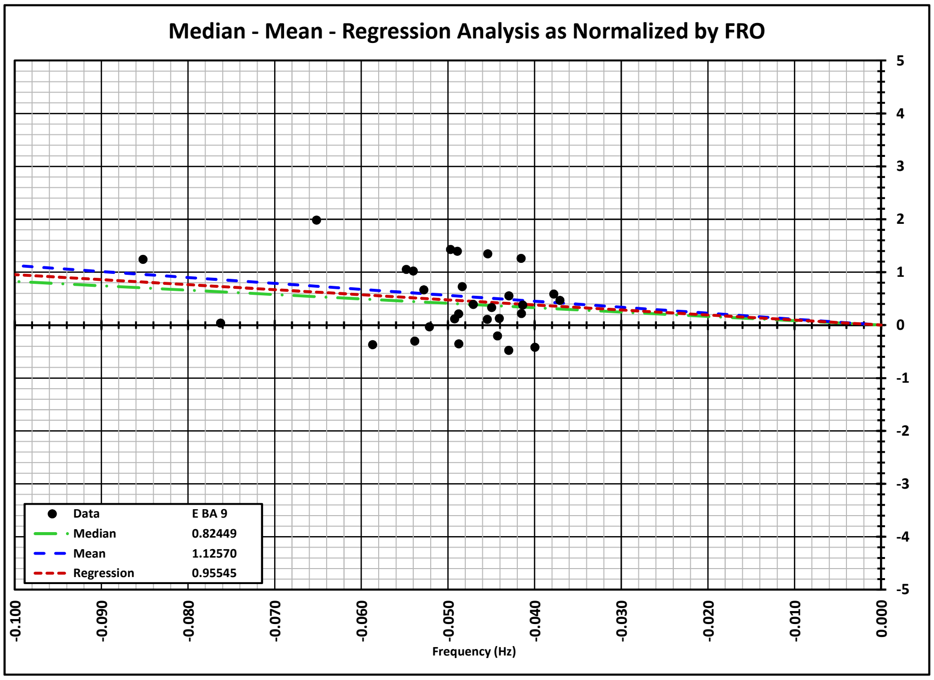

Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 6
Median 2.77009
Mean 3.15820
Regression 3.09135
5
4
3
2
1
0
-1
-2
-3
-4
-5
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 7
Median 0.35407
Mean 1.74493
Regression 1.03098
25
20
15
10
5
0
-5
-10
-15
-20
-25
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
Frequency (Hz)

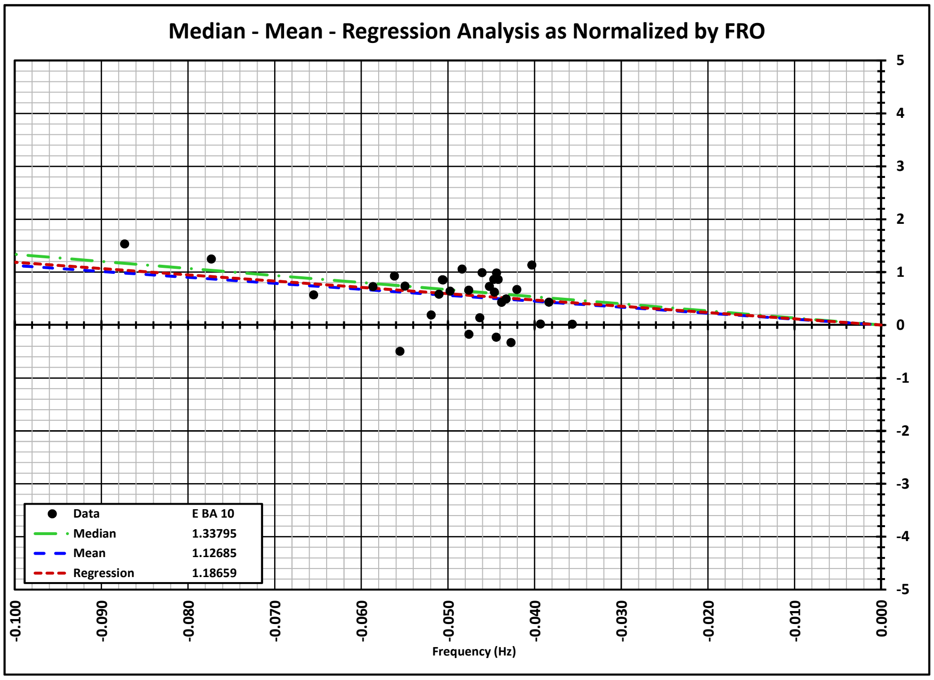

Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 7
Median 0.35407
Mean 1.74493
Regression 1.03098
5
4
3
2
1
0
-1
-2
-3
-4
-5
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
Frequency (Hz)

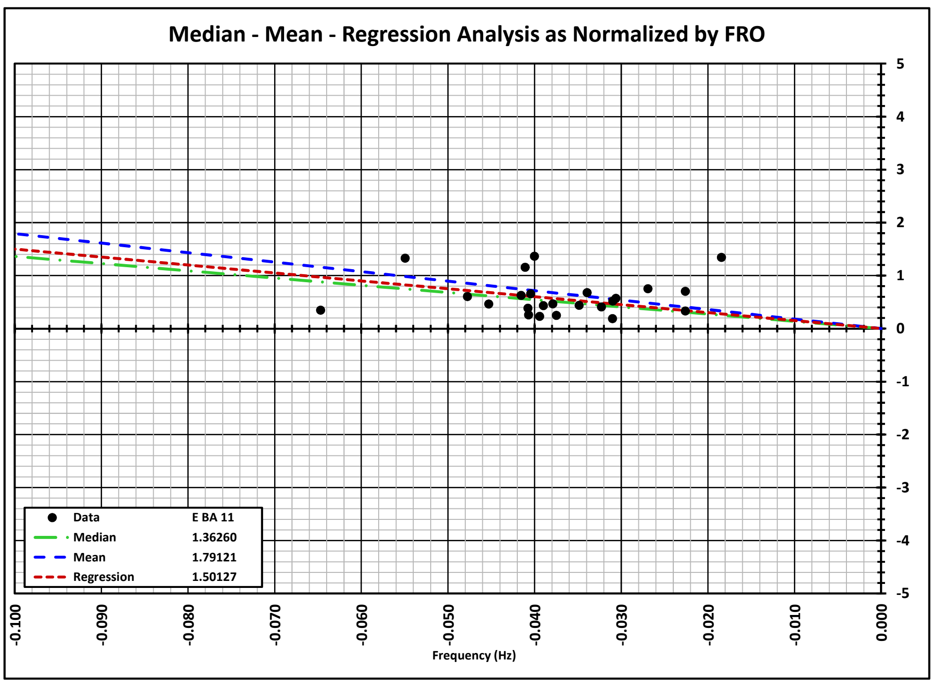


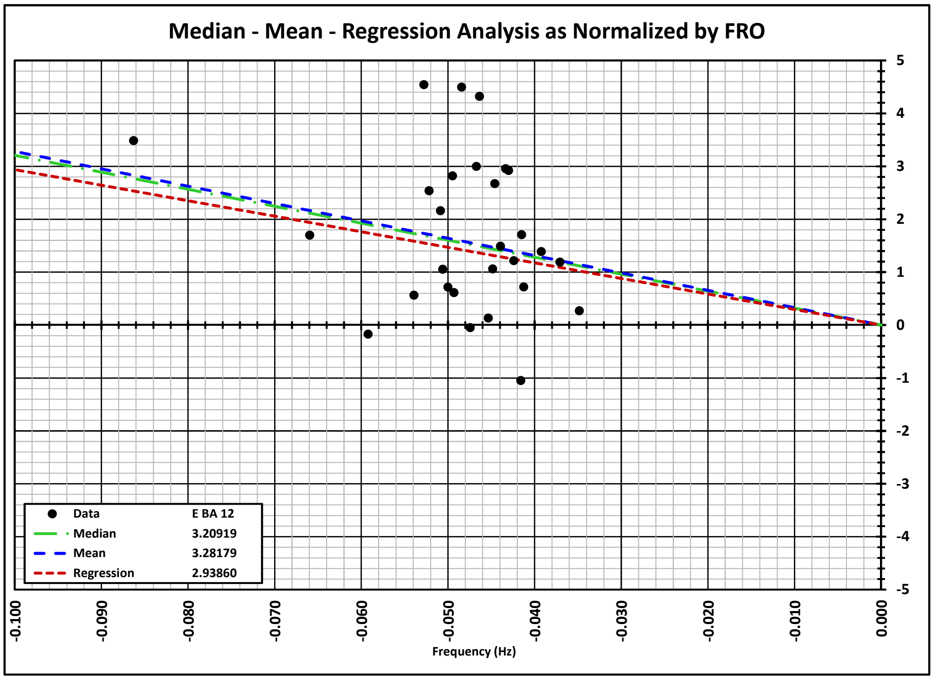
Median - Mean - Regression Analysis as Normalized by FRO
Data
E BA 8
Median
0.45946
Mean
1.01731
Regression
0.76053
Frequency (Hz)



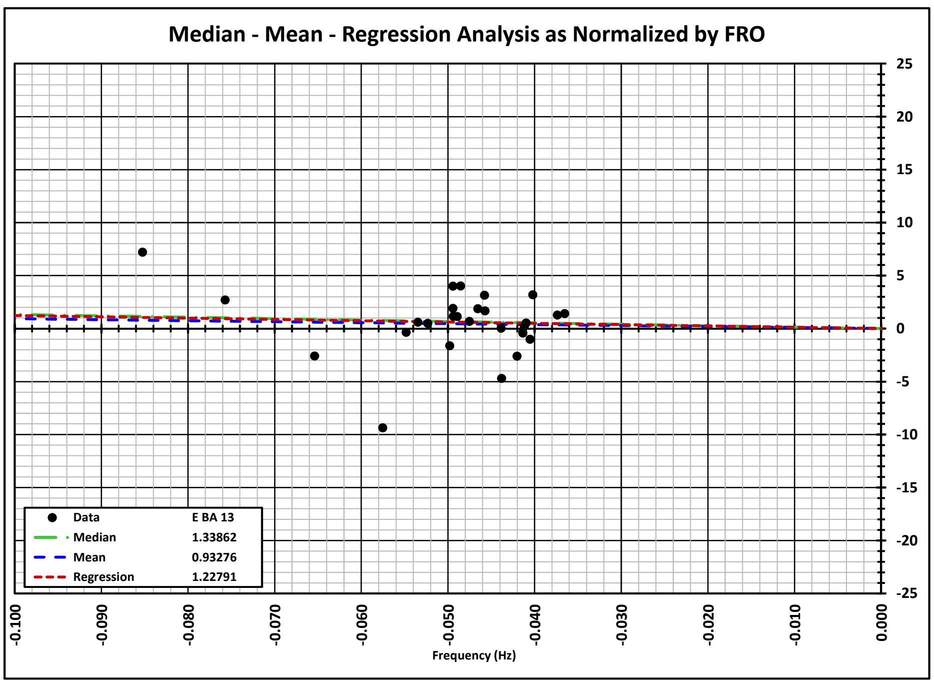
Median - Mean - Regression Analysis as Normalized by FRO
Data
E BA 9
Median
0.82449
Mean
1.12570
Regression
0.95545
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 10
Median 1.33795
Mean 1.12685
Regression 1.18659
Frequency (Hz)
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
5
4
3
2
1
0
-1
-2
-3
-4
-5


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 11
Median 1.36260
Mean 1.79121
Regression 1.50127
Frequency (Hz)
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
5
4
3
2
1
0
-1
-2
-3
-4
-5



Median - Mean - Regression Analysis as Normalized by FRO
Data
E BA 12
Median
3.20919
Mean
3.28179
Regression
2.93860
Frequency (Hz)
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
5
4
3
2
1
0
-1
-2
-3
-4
-5



Median - Mean - Regression Analysis as Normalized by FRO
Data
E BA 13
Median
1.33862
Mean
0.93276
Regression
1.22791
Frequency (Hz)
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
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20
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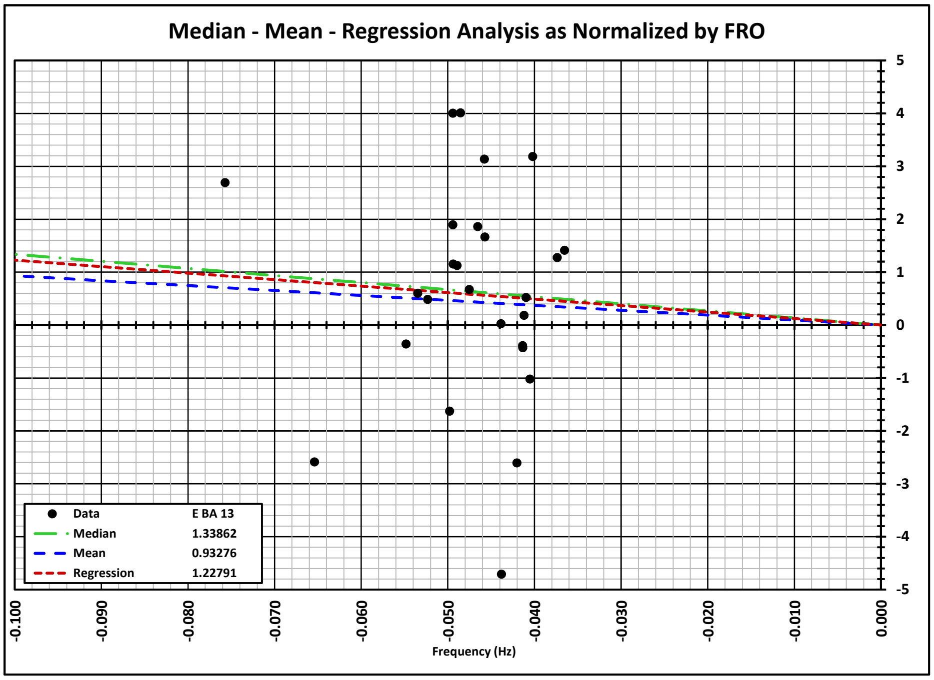
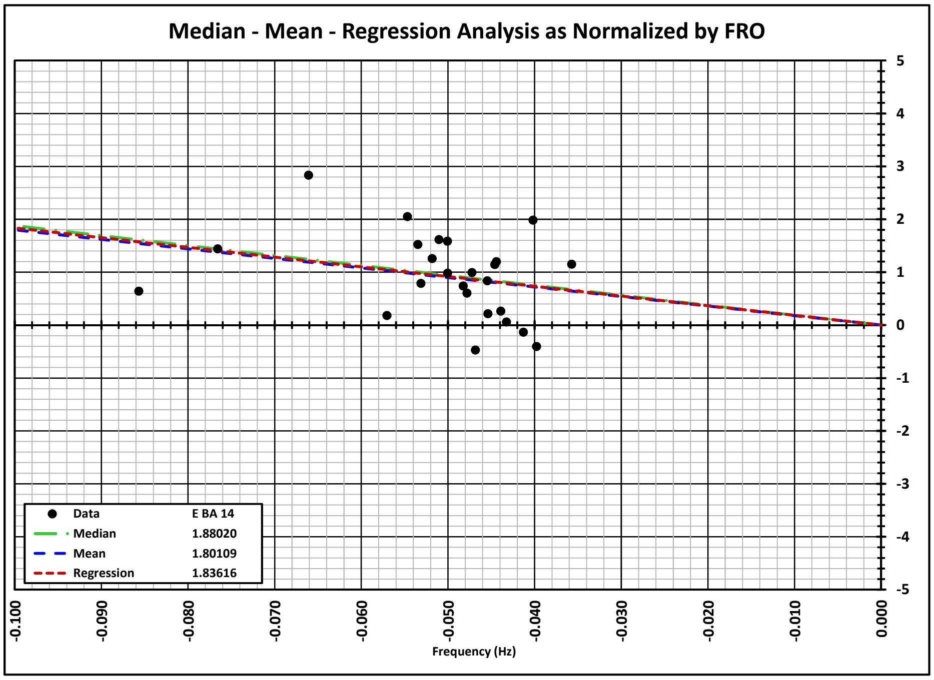
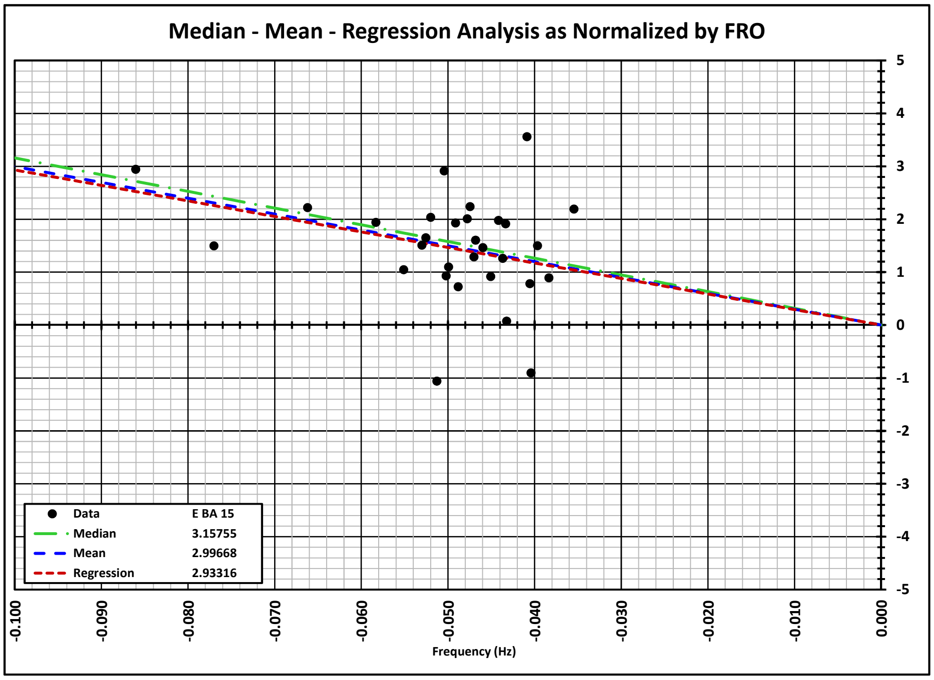
10
5
0
-5
-10
-15
-20
-25


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 13
Median 1.33862
Mean 0.93276
Regression 1.22791
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 14
Median 1.88020
Mean 1.80109
Regression 1.83616
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 15
Median 3.15755
Mean 2.99668
Regression 2.93316
Frequency (Hz)
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-0.060
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-0.040
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-0.010
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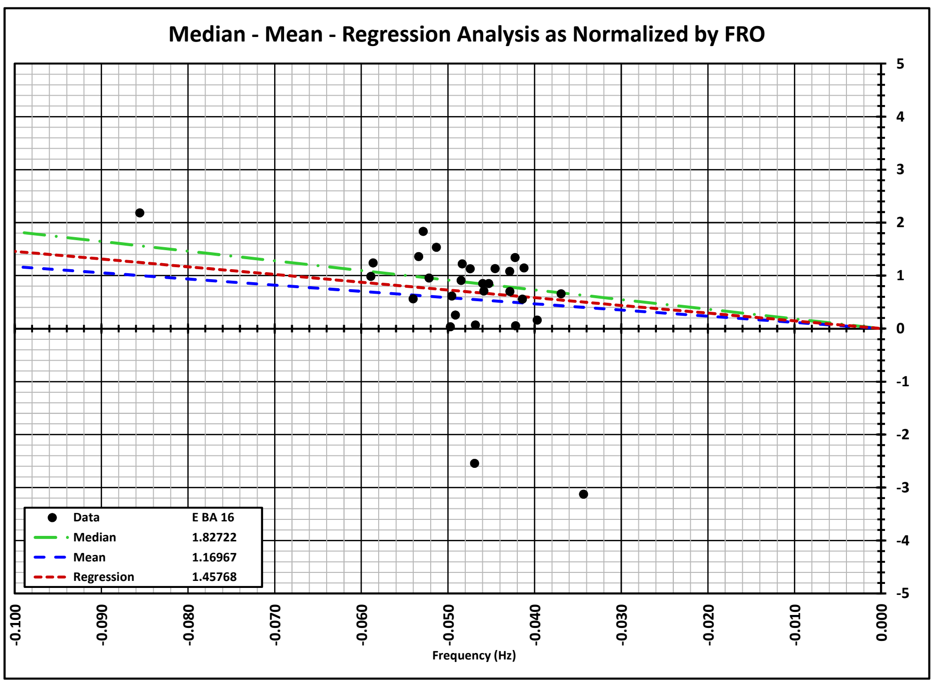
-3
-4
-5


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 16
Median 1.82722
Mean 1.16967
Regression 1.45768
Frequency (Hz)
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-0.040
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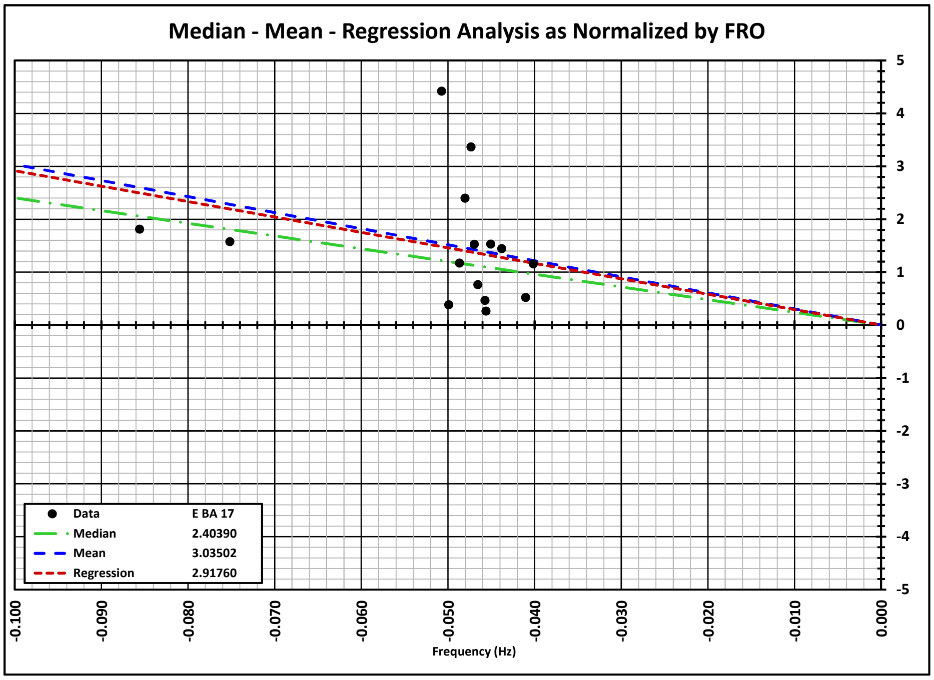
Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 17
Median 2.40390
Mean 3.03502
Regression 2.91760
Frequency (Hz)
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4
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2
1
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-1
-2
-3
-4
-5
-0.100
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-0.060
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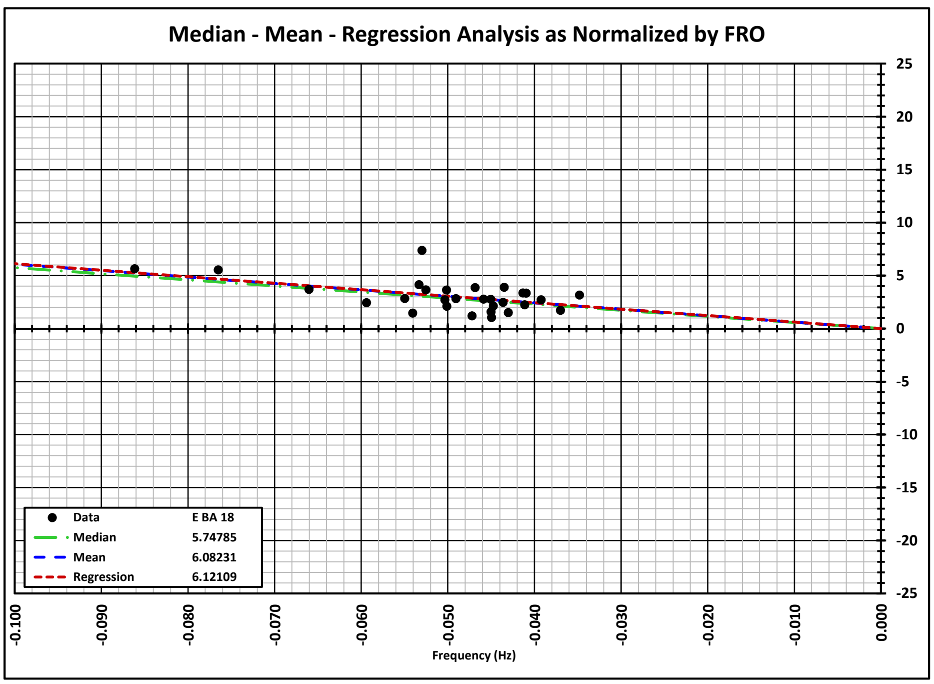
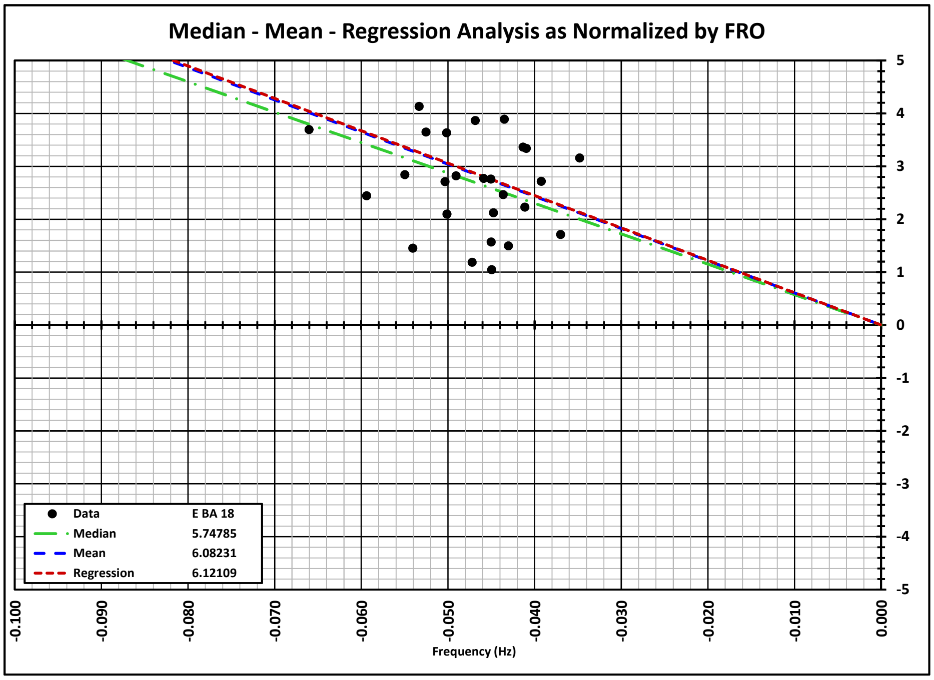

Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 18
Median 5.74785
Mean 6.08231
Regression 6.12109
Frequency (Hz)
25
20
15
10
5
0
-5
-10
-15
-20
-25
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 18
Median 5.74785
Mean 6.08231
Regression 6.12109
Frequency (Hz)
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
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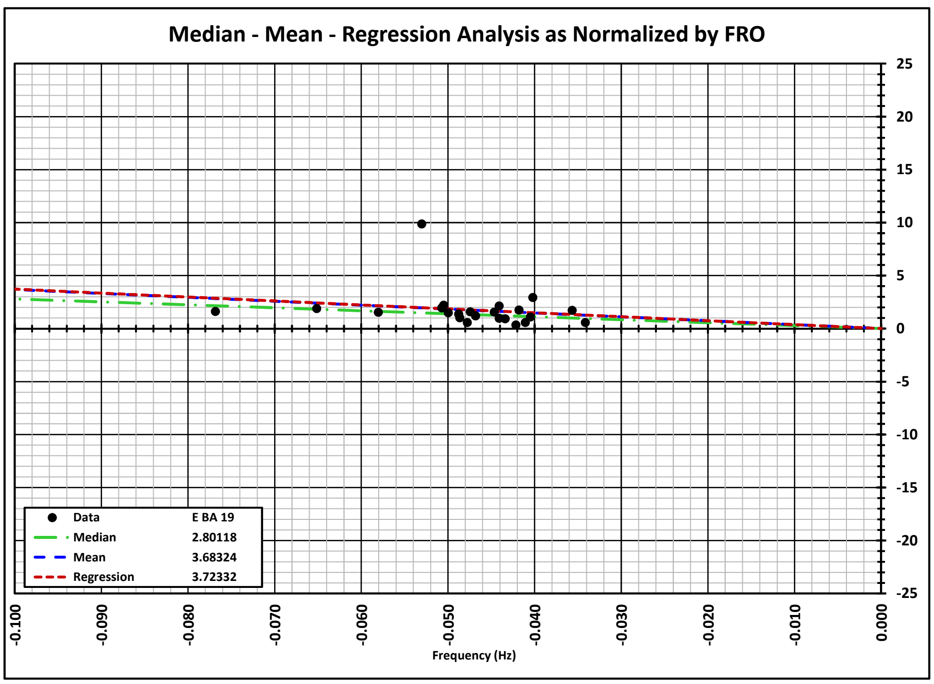
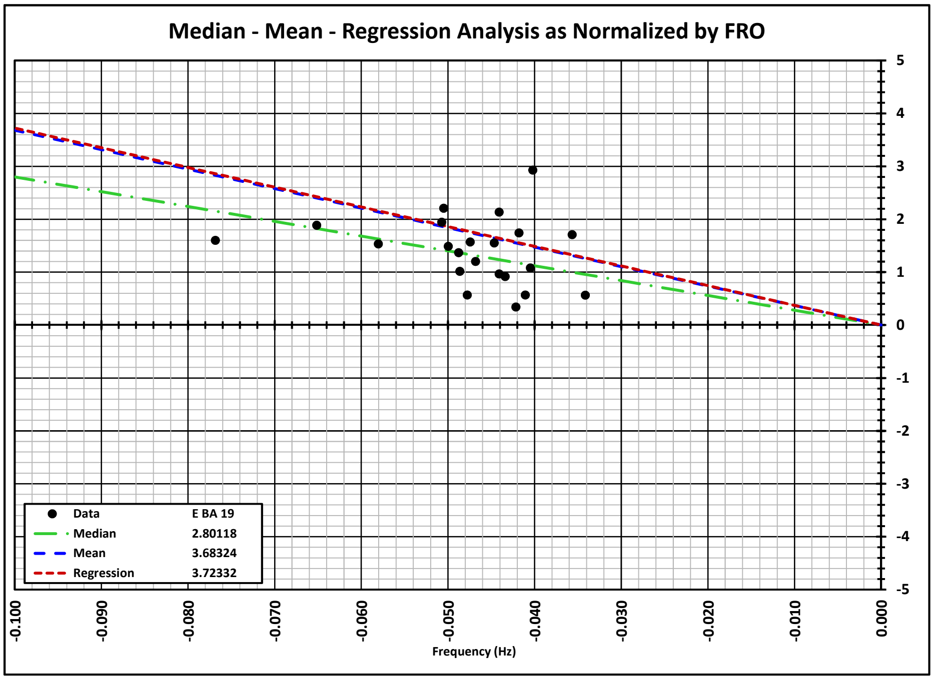
-3
-4
-5


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 19
Median 2.80118
Mean 3.68324
Regression 3.72332
Frequency (Hz)
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
25
20
15
10
5
0
-5
-10
-15
-20
-25


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 19
Median 2.80118
Mean 3.68324
Regression 3.72332
Frequency (Hz)
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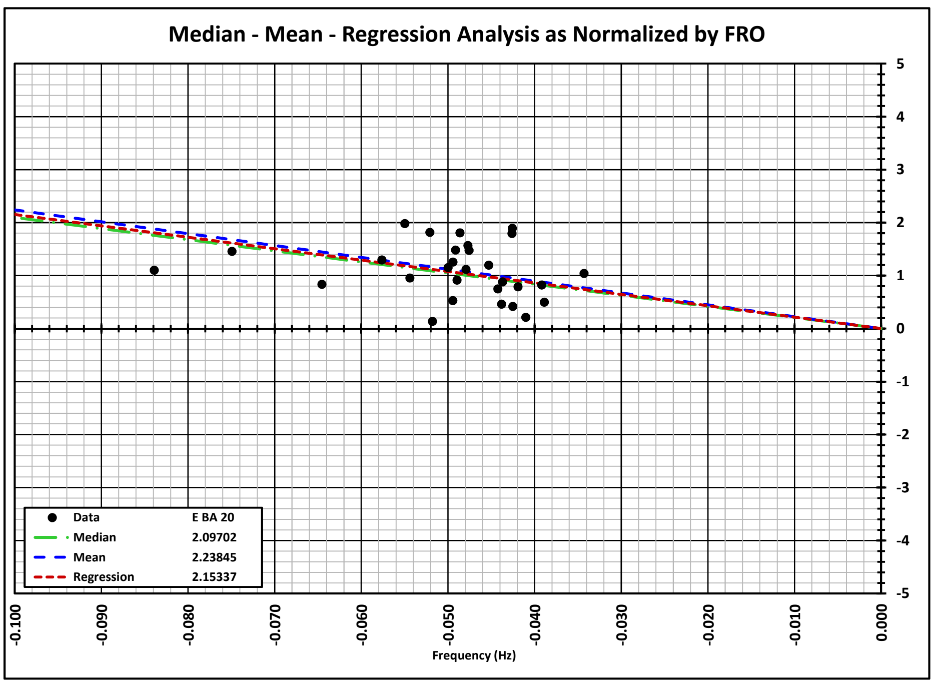
5 4 3 2 1 0 -1 -2 -3 -4 -5


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 20
Median 2.09702
Mean 2.23845
Regression 2.15337
Frequency (Hz)
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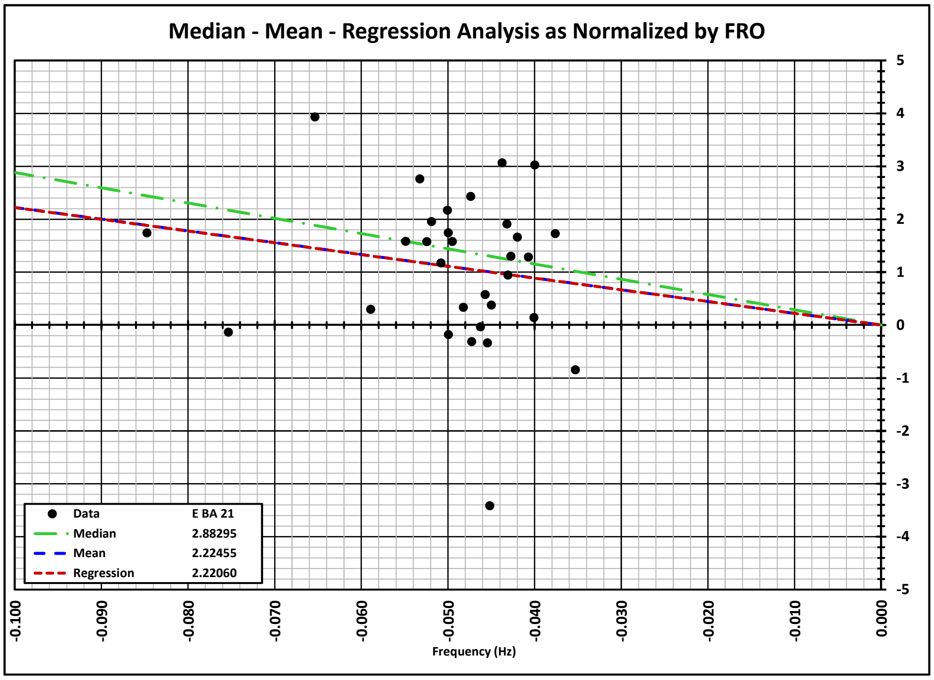
5 4 3 2 1 0 -1 -2 -3 -4 -5


Median - Mean - Regression Analysis as Normalized by FRO
Data
E BA 21
Median
2.88295
Mean
2.22455
Regression
2.22060
Frequency (Hz)
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
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-3
-4
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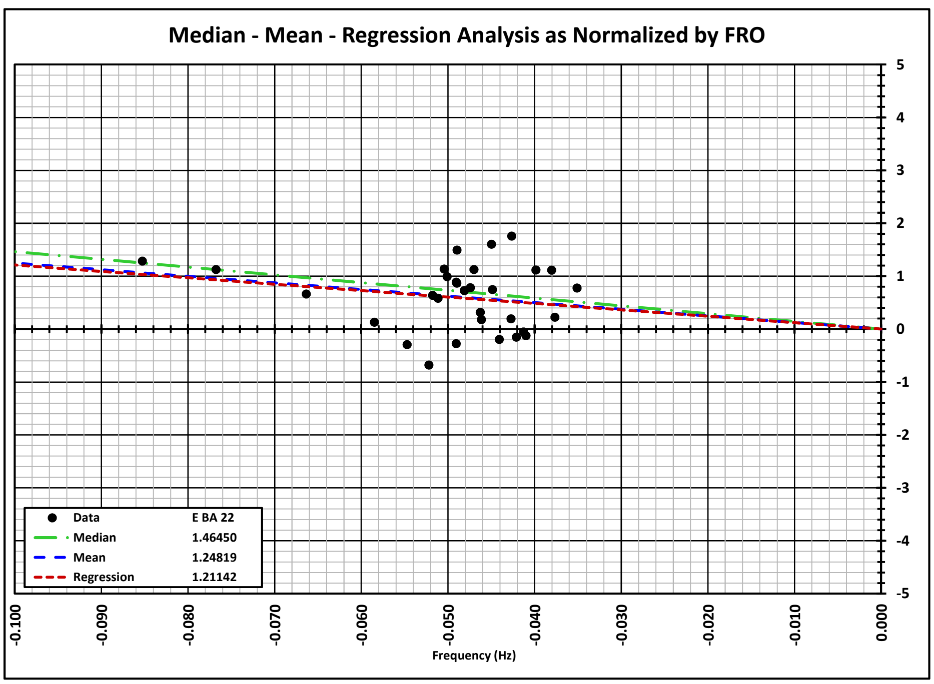
Median - Mean - Regression Analysis as Normalized by FRO
Data
E BA 22
Median
1.46450
Mean
1.24819
Regression
1.21142
Frequency (Hz)
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-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
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-0.010
0.000
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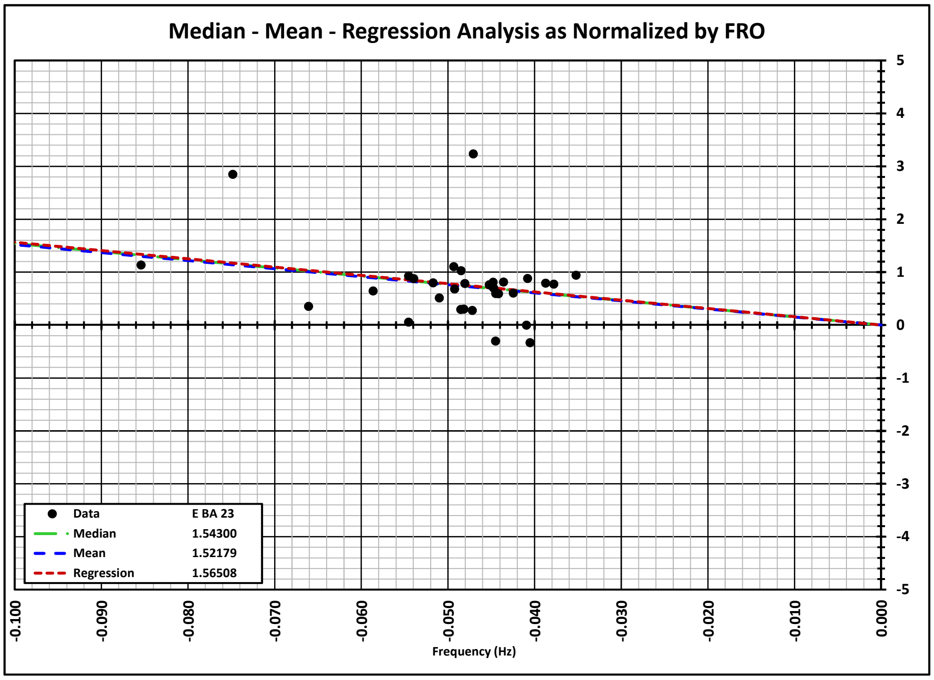
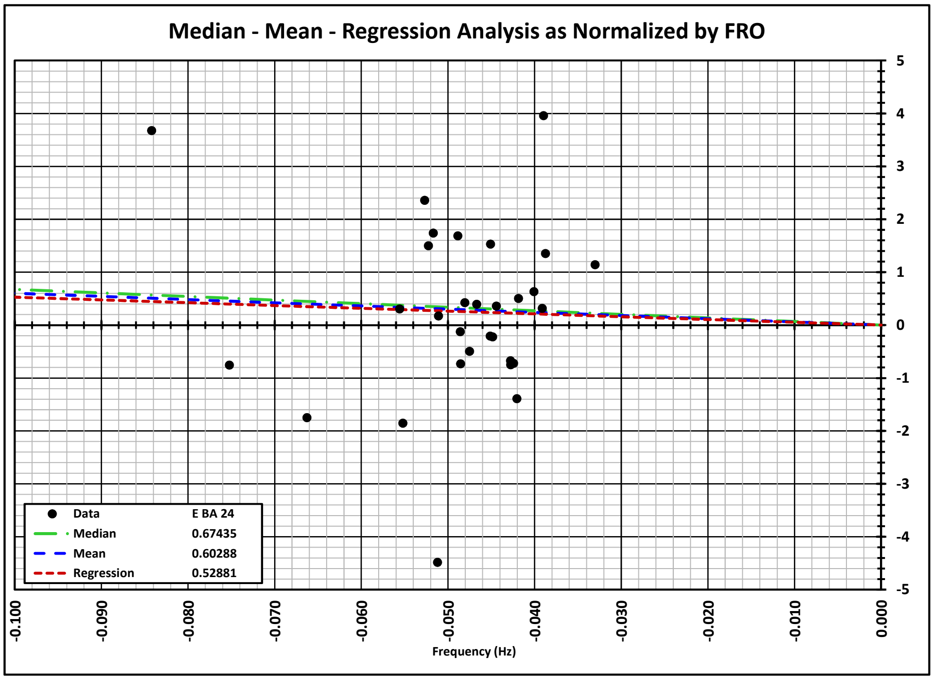
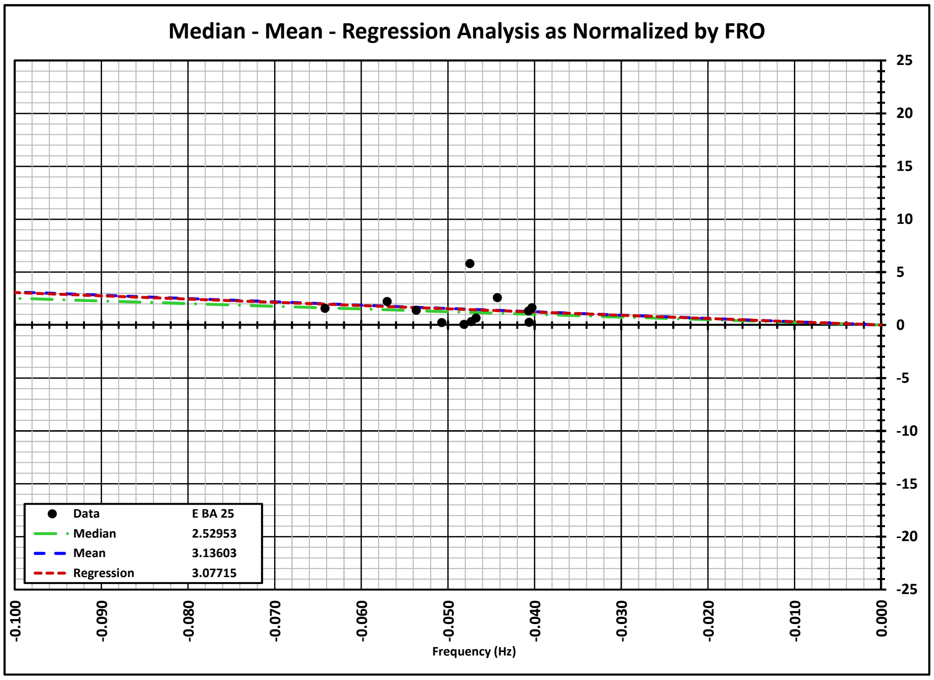
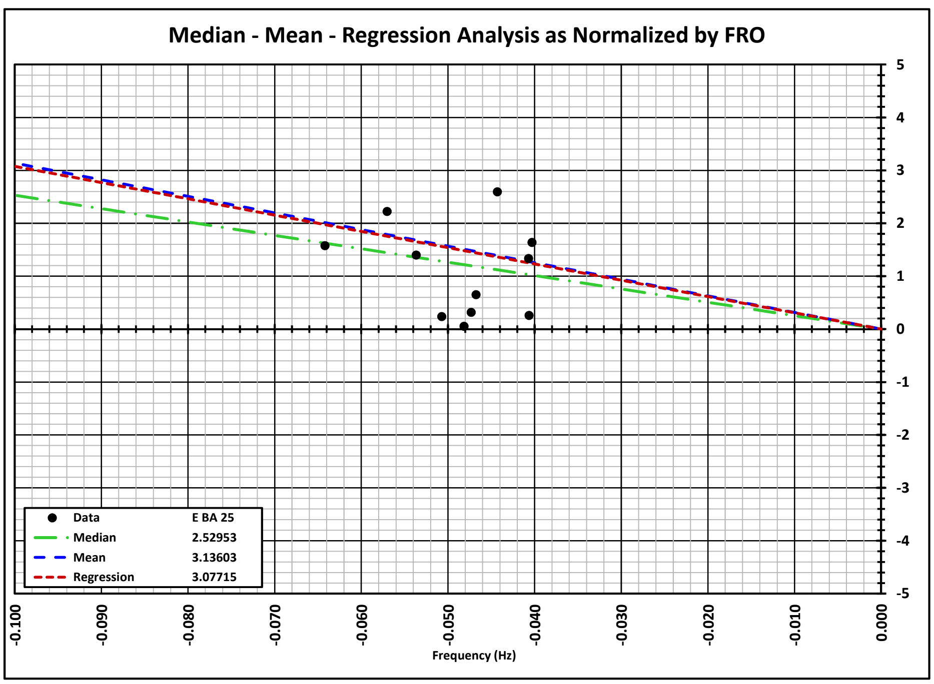
-2
-3
-4
-5


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 23
Median 1.54300
Mean 1.52179
Regression 1.56508
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 24
Median 0.67435
Mean 0.60288
Regression 0.52881
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 25
Median 2.52953
Mean 3.13603
Regression 3.07715
Frequency (Hz)
25
20
15
10
5
0
-5
-10
-15
-20
-25
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 25
Median 2.52953
Mean 3.13603
Regression 3.07715
Frequency (Hz)
5
4
3
2
1
0
-1
-2
-3
-4
-5
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
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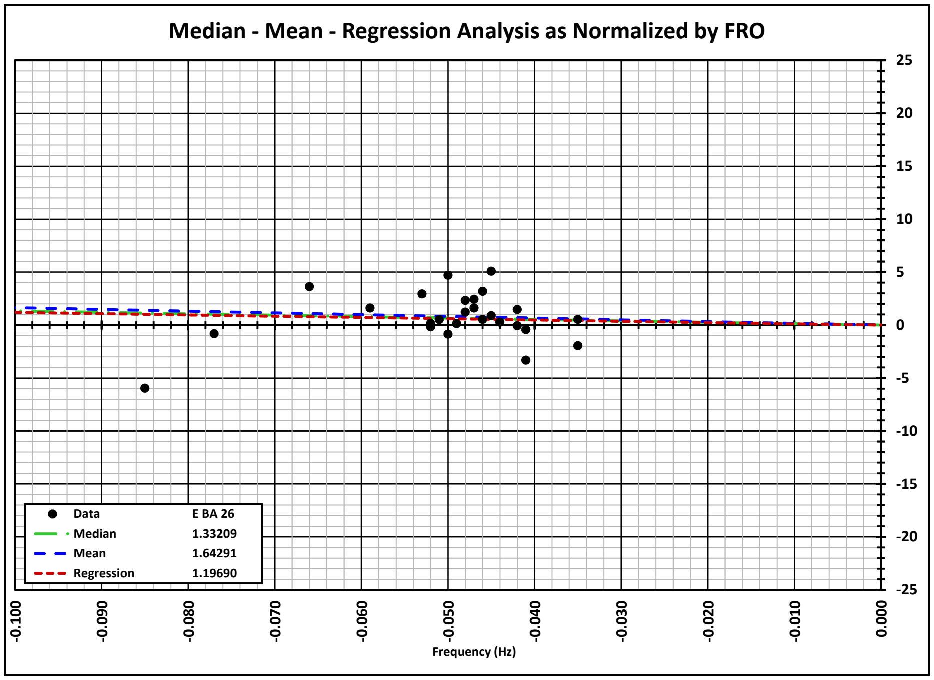
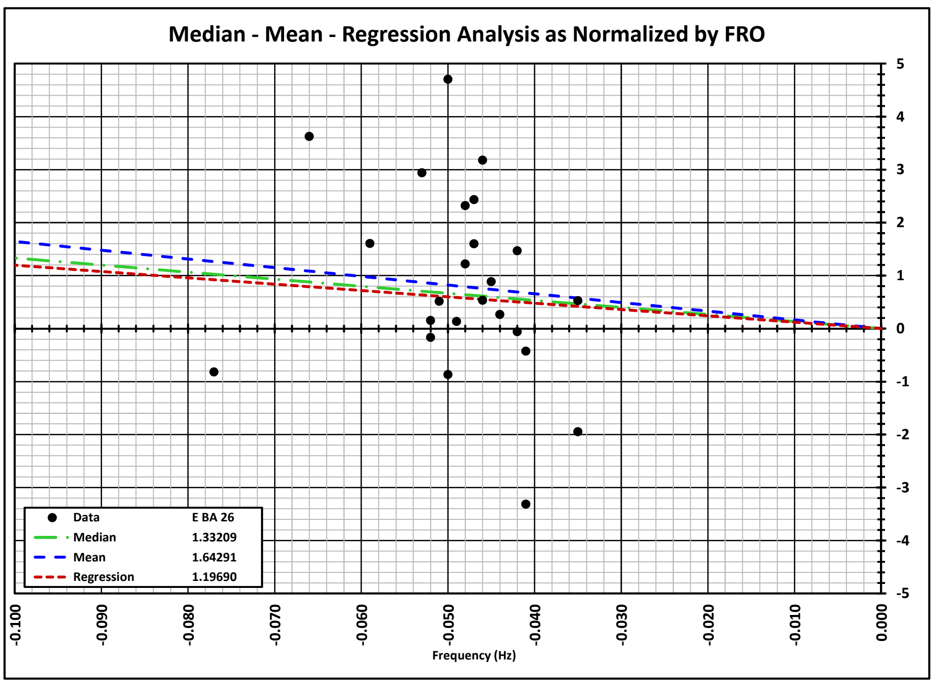
-0.030
-0.020
-0.010
0.000


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 26
Median 1.33209
Mean 1.64291
Regression 1.19690
Frequency (Hz)
25
20
15
10
5
0
-5
-10
-15
-20
-25
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 26
Median 1.33209
Mean 1.64291
Regression 1.19690
Frequency (Hz)
5
4
3
2
1
0
-1
-2
-3
-4
-5
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
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-0.030
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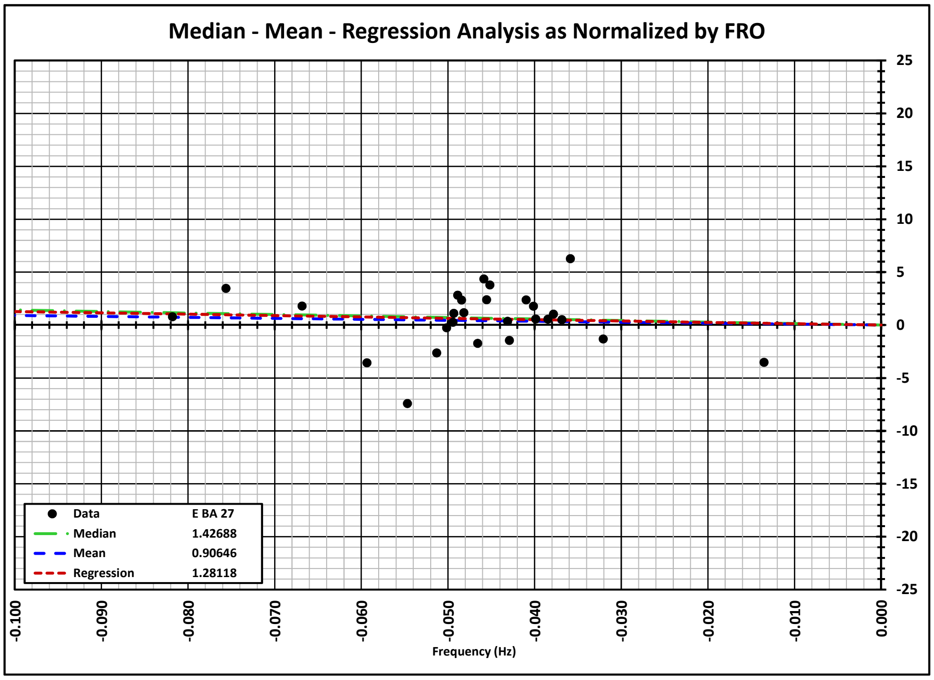
-0.010
0.000


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 27
Median 1.42688
Mean 0.90646
Regression 1.28118
Frequency (Hz)
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
25
20
15
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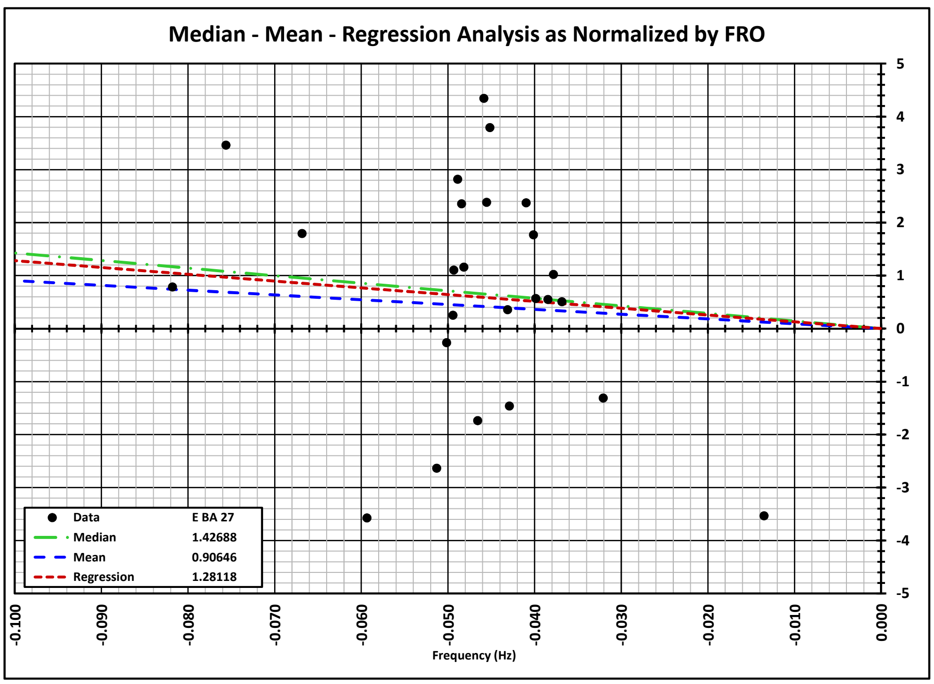
5
0
-5
-10
-15
-20
-25


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 27
Median 1.42688
Mean 0.90646
Regression 1.28118
Frequency (Hz)
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
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0.000
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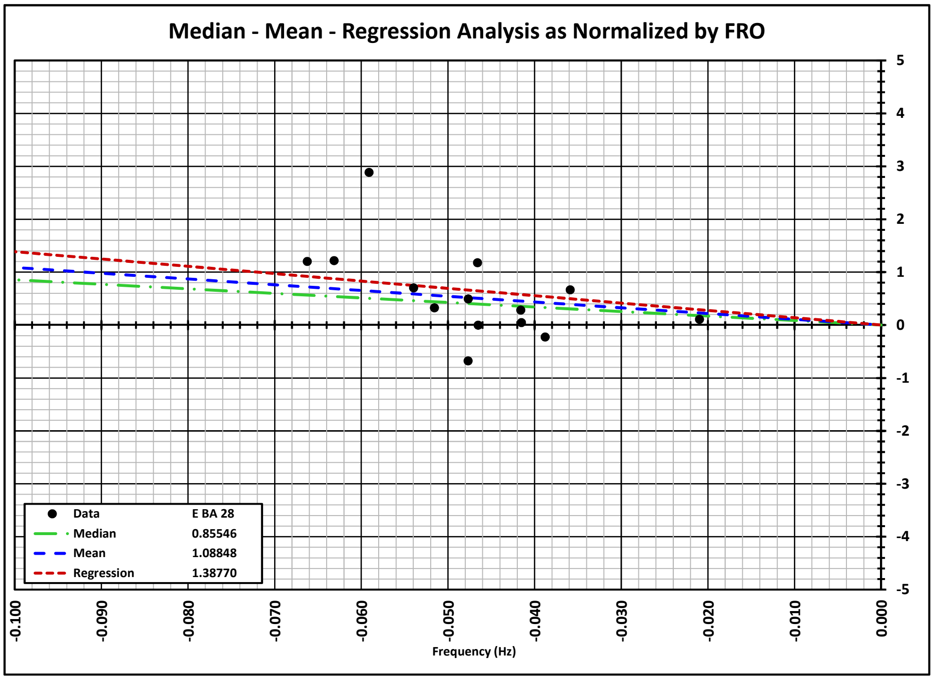
Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 28
Median 0.85546
Mean 1.08848
Regression 1.38770
Frequency (Hz)
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-0.070
-0.060
-0.050
-0.040
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0.000
5
4
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0
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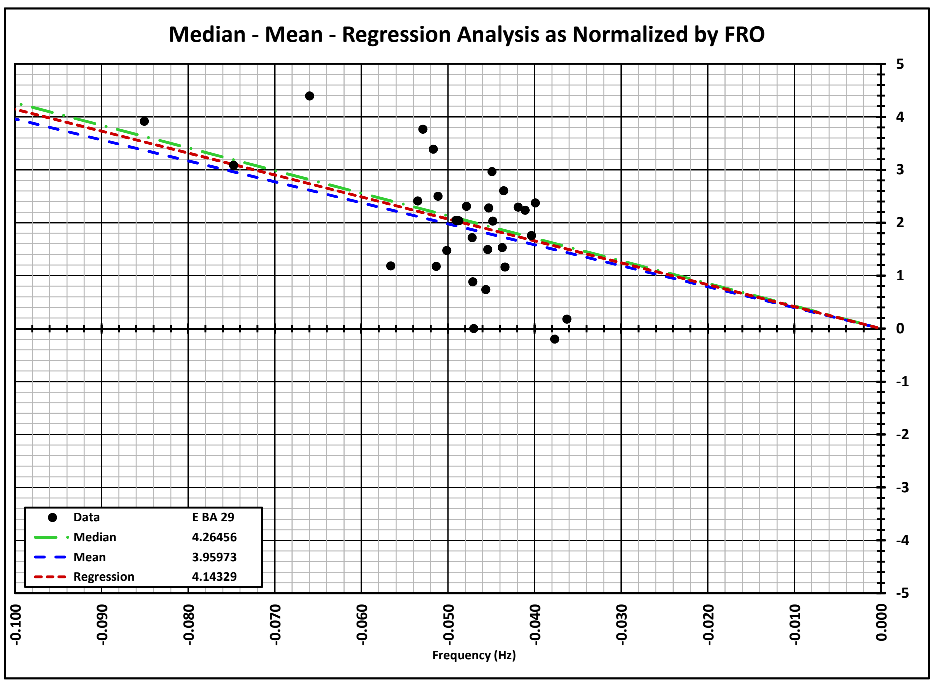
-3
-4
-5


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 29
Median 4.26456
Mean 3.95973
Regression 4.14329
Frequency (Hz)
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-0.080
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-0.060
-0.050
-0.040
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0.000
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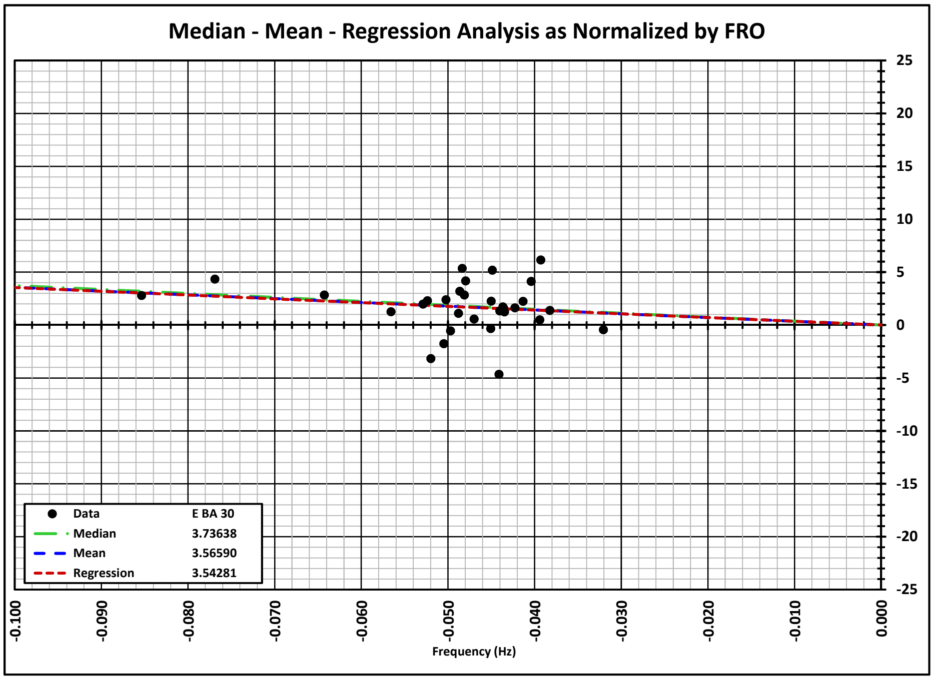
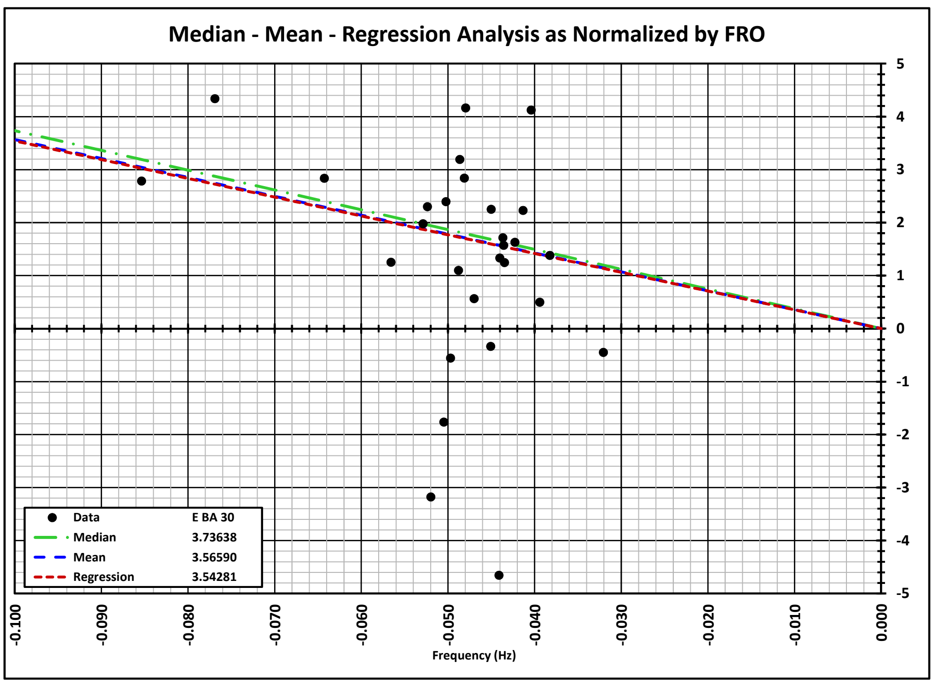
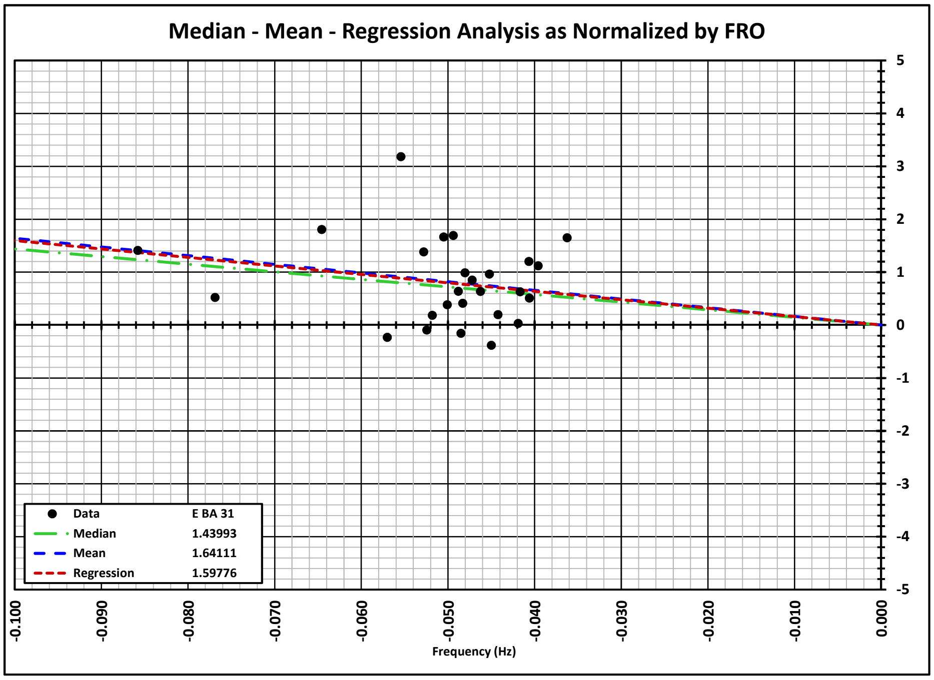
-2
-3
-4
-5

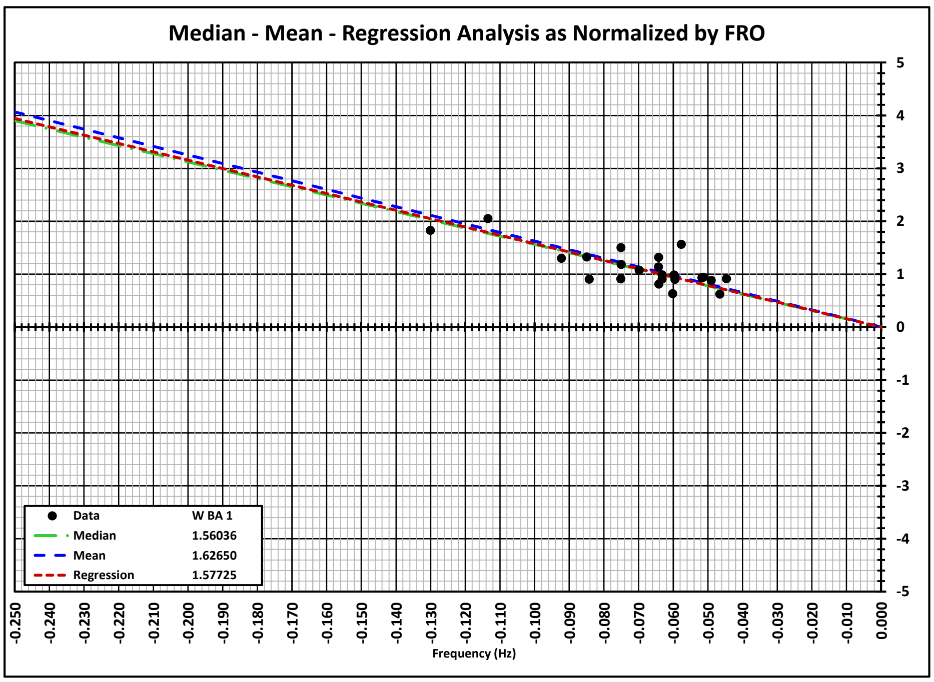


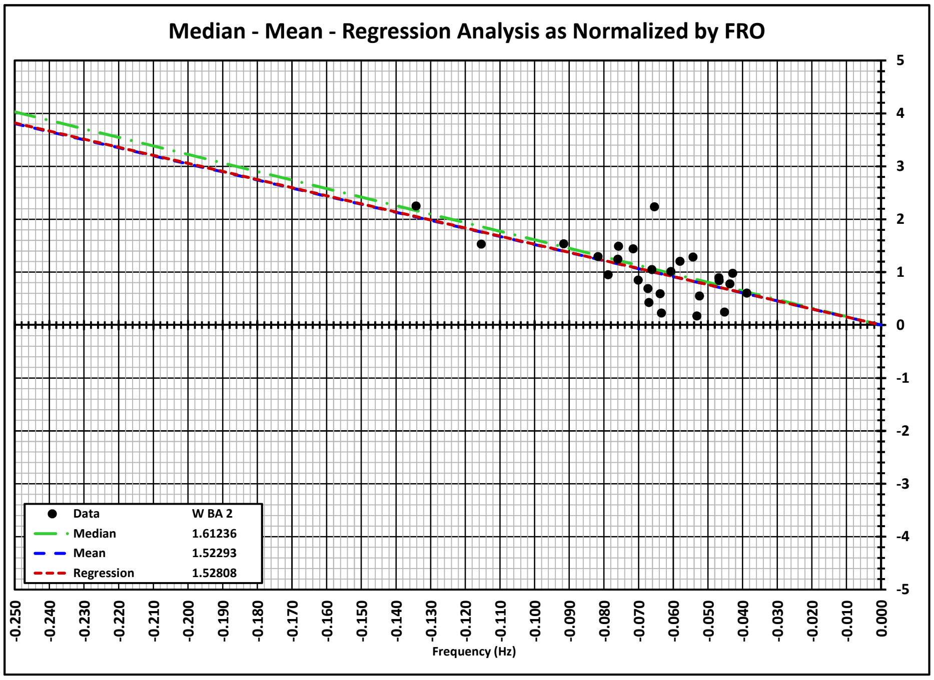
Median - Mean - Regression Analysis as Normalized by FRO
Data
E BA 30
Median
3.73638
Mean
3.56590
Regression
3.54281
Frequency (Hz)

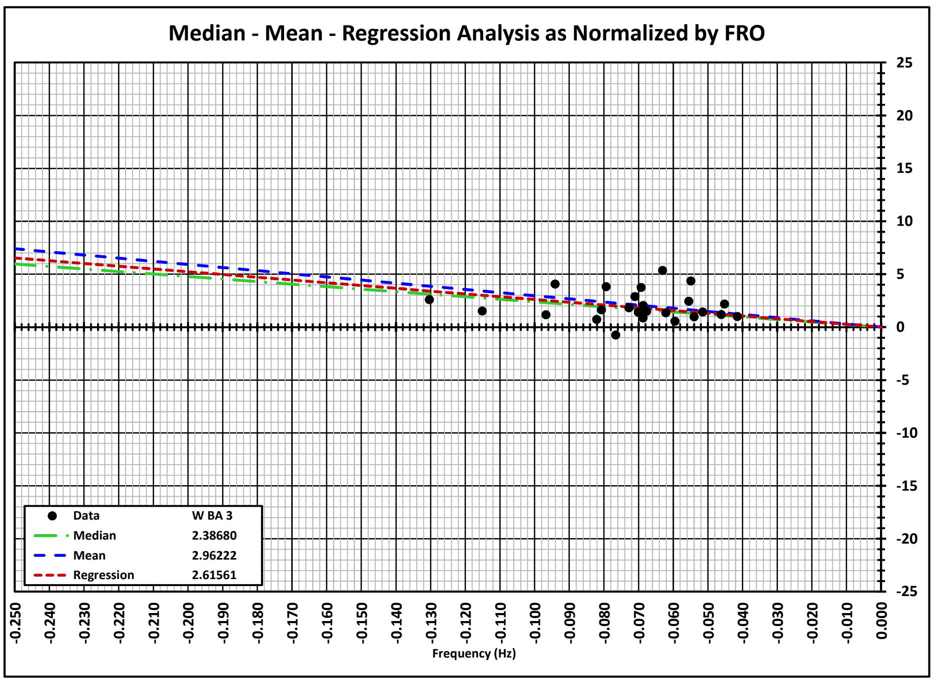


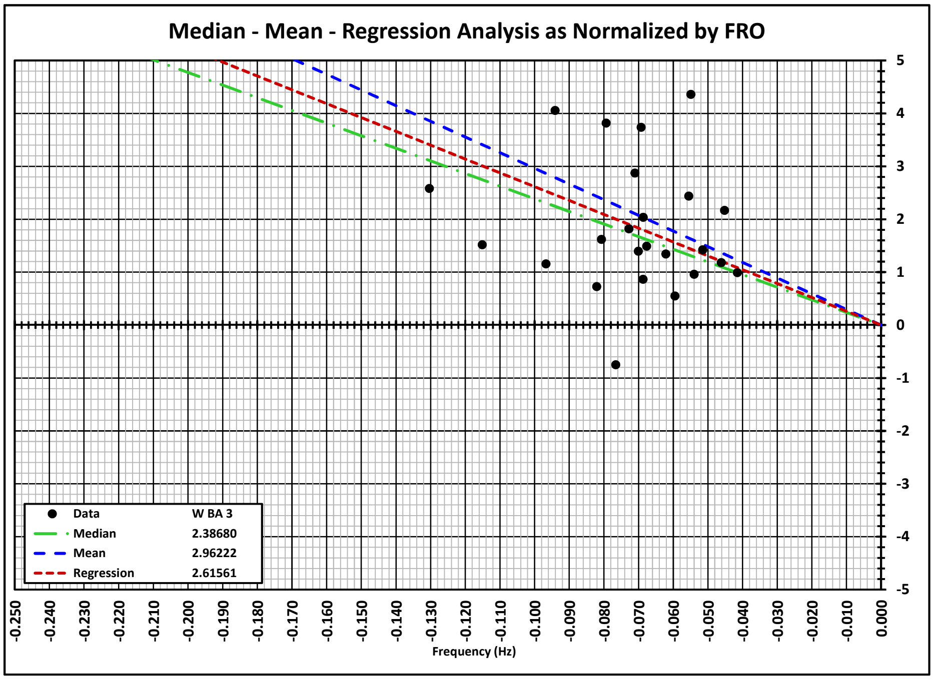
Median - Mean - Regression Analysis as Normalized by FRO
Data
E BA 30
Median
3.73638
Mean
3.56590
Regression
3.54281
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 31
Median 1.43993
Mean 1.64111
Regression 1.59776
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 1
Median 1.56036
Mean 1.62650
Regression 1.57725
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 2
Median 1.61236
Mean 1.52293
Regression 1.52808
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 3
Median 2.38680
Mean 2.96222
Regression 2.61561
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 3
Median 2.38680
Mean 2.96222
Regression 2.61561
Frequency (Hz)
5
4
3
2
1
0
-1
-2
-3
-4
-5
-0.250
-0.240
-0.230
-0.220
-0.210
-0.200
-0.190
-0.180
-0.170
-0.160
-0.150
-0.140
-0.130
-0.120
-0.110
-0.100
-0.090
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-0.060
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-0.030
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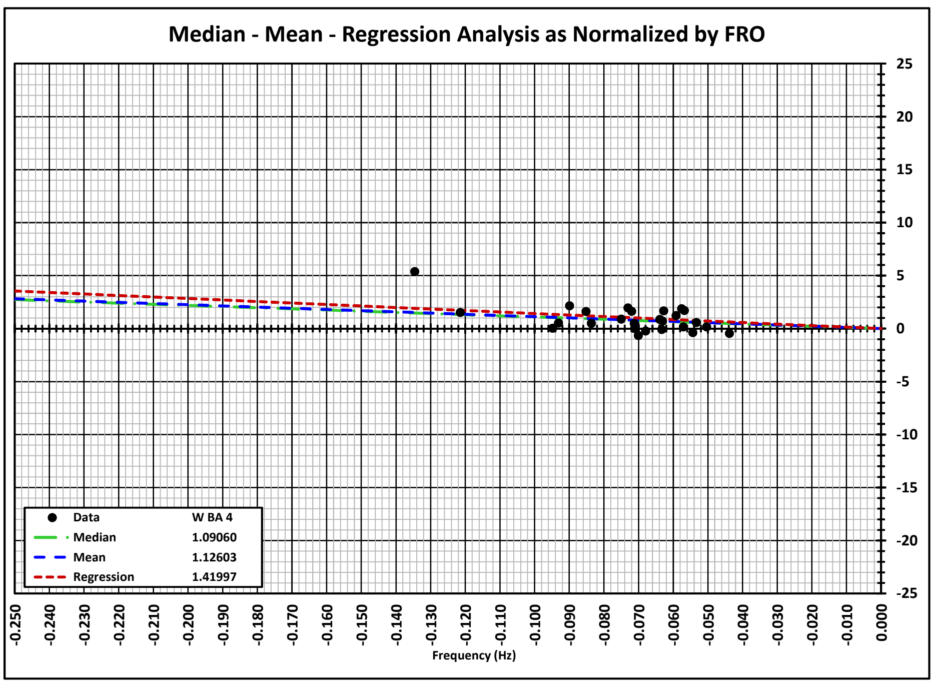
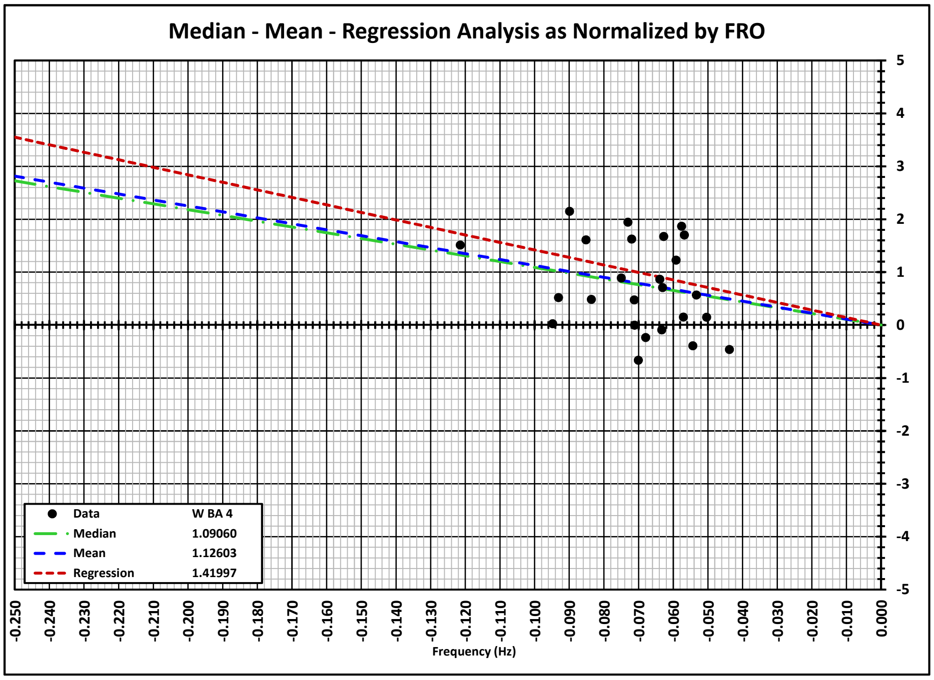
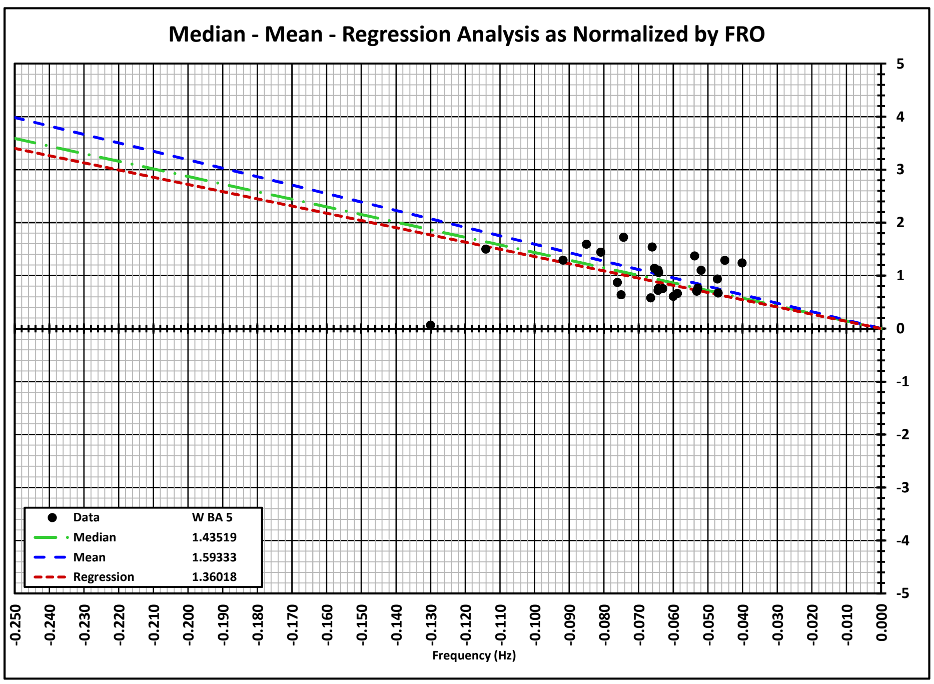
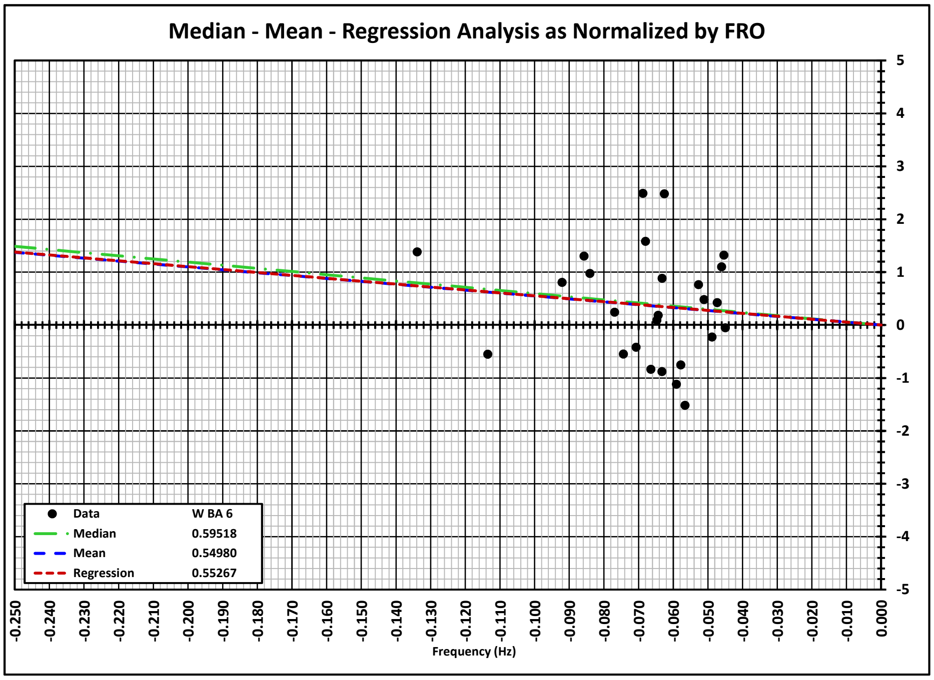
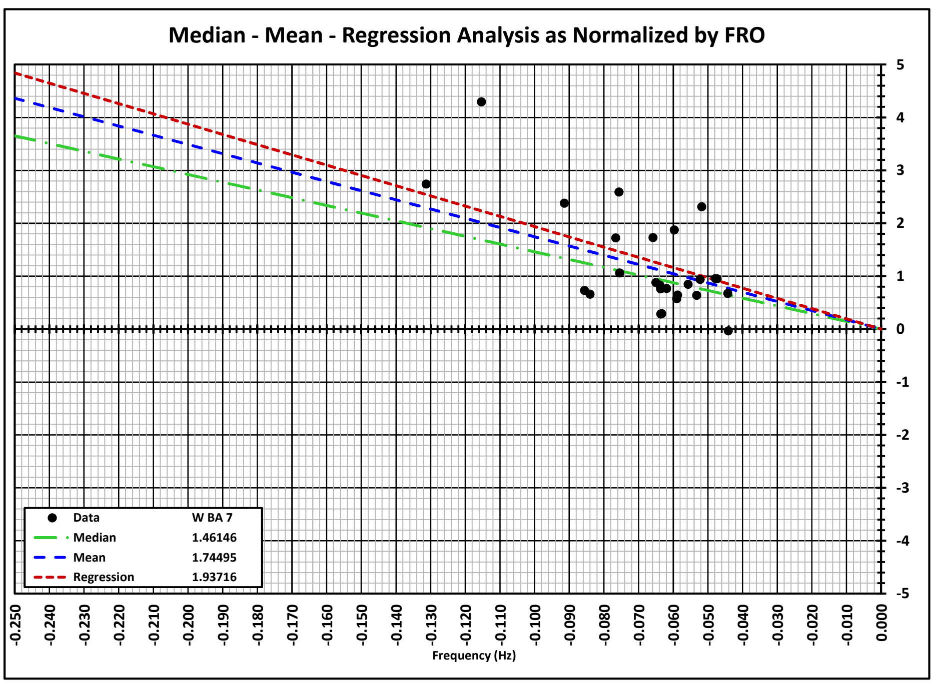
-0.010
0.000

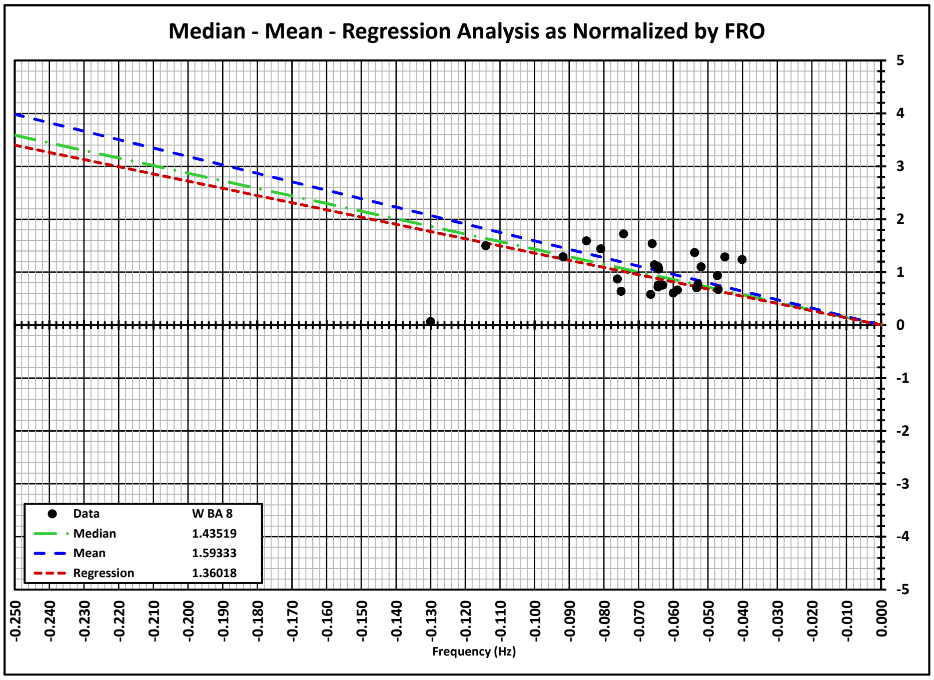

Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 4
Median 1.09060
Mean 1.12603
Regression 1.41997
Frequency (Hz)
25
20
15
10
5
0
-5
-10
-15
-20
-25
-0.250
-0.240
-0.230
-0.220
-0.210
-0.200
-0.190
-0.180
-0.170
-0.160
-0.150
-0.140
-0.130
-0.120
-0.110
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000

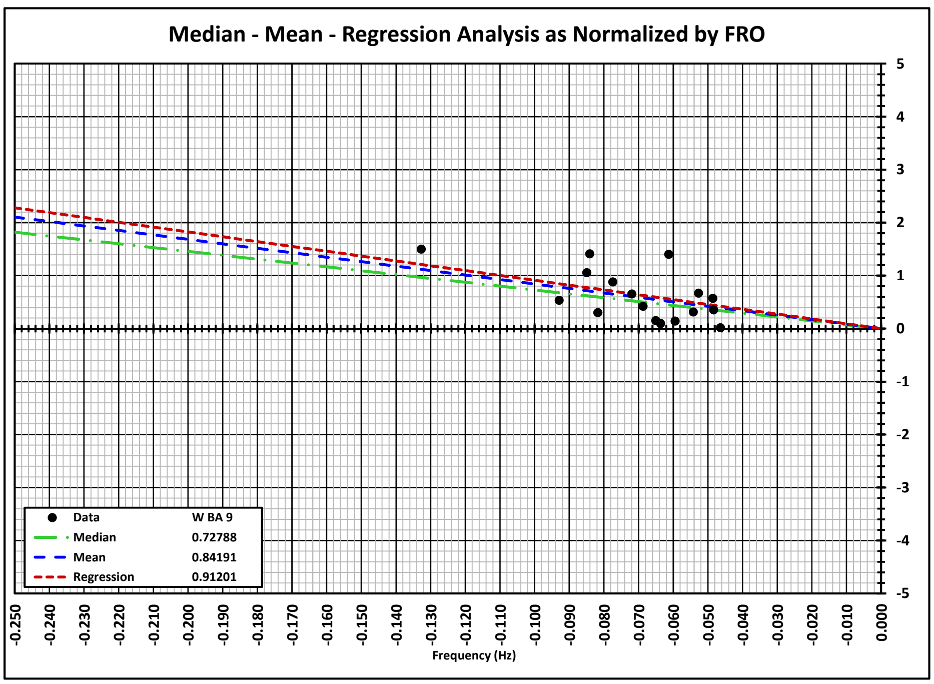

Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 4
Median 1.09060
Mean 1.12603
Regression 1.41997
Frequency (Hz)

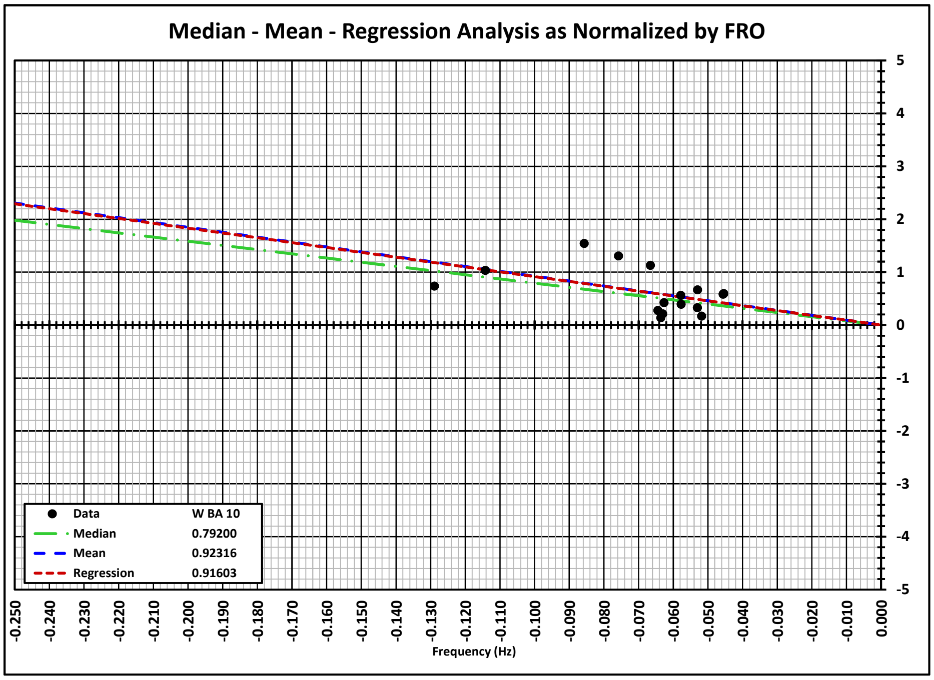

Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 5
Median 1.43519
Mean 1.59333
Regression 1.36018
Frequency (Hz)

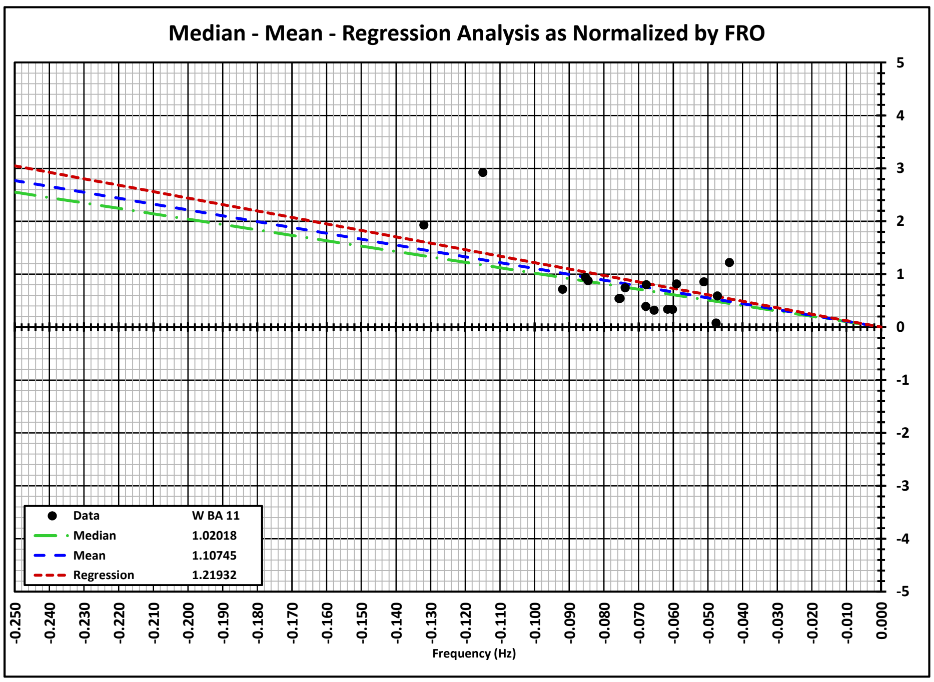

Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 6
Median 0.59518
Mean 0.54980
Regression 0.55267
Frequency (Hz)

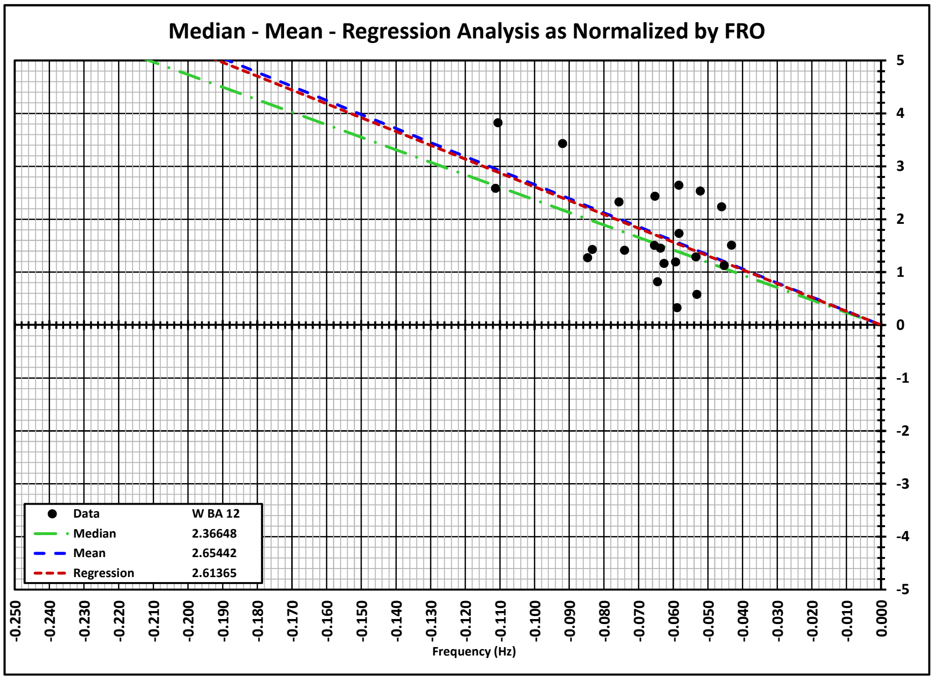

Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 7
Median 1.46146
Mean 1.74495
Regression 1.93716
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 8
Median 1.43519
Mean 1.59333
Regression 1.36018
Frequency (Hz)

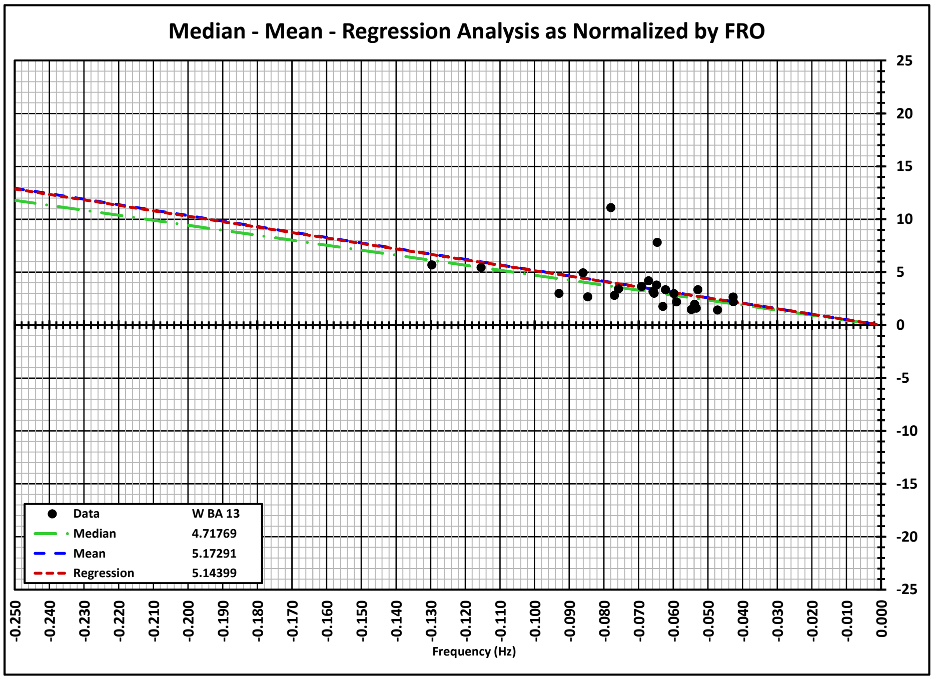

Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 9
Median 0.72788
Mean 0.84191
Regression 0.91201
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 10
Median 0.79200
Mean 0.92316
Regression 0.91603
5
4
3
2
1
0
-1
-2
-3
-4
-5
-0.250 -0.240 -0.230 -0.220 -0.210 -0.200 -0.190 -0.180 -0.170 -0.160 -0.150 -0.140 -0.130 -0.120 -0.110 -0.100 -0.090 -0.080 -0.070 -0.060 -0.050 -0.040 -0.030 -0.020 -0.010 0.000
Frequency (Hz)

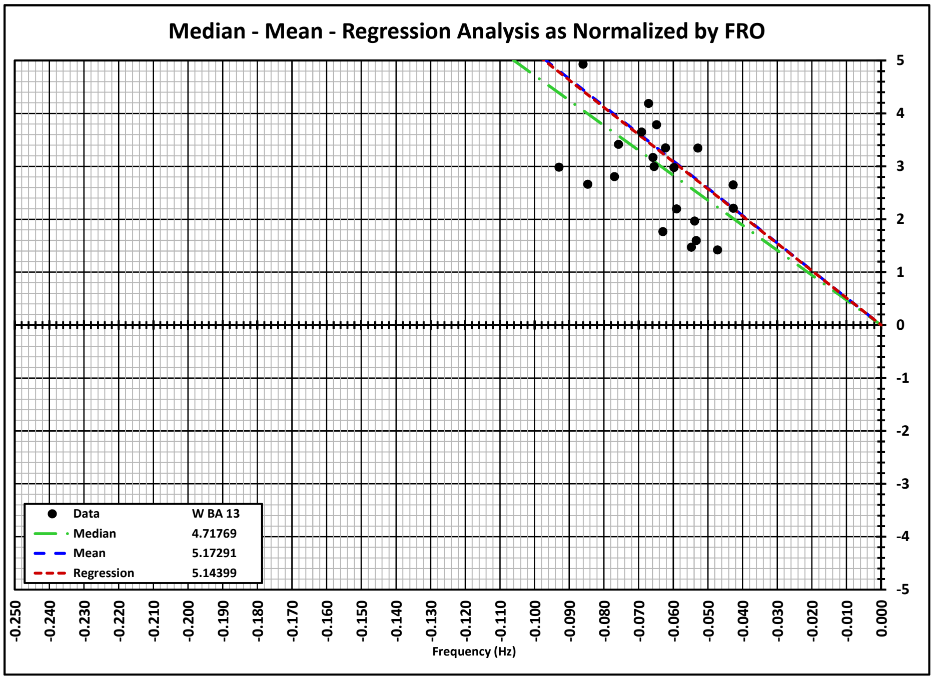

Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 11
Median 1.02018
Mean 1.10745
Regression 1.21932
5
4
3
2
1
0
-1
-2
-3
-4
-5
-0.250 -0.240 -0.230 -0.220 -0.210 -0.200 -0.190 -0.180 -0.170 -0.160 -0.150 -0.140 -0.130 -0.120 -0.110 -0.100 -0.090 -0.080 -0.070 -0.060 -0.050 -0.040 -0.030 -0.020 -0.010 0.000
Frequency (Hz)

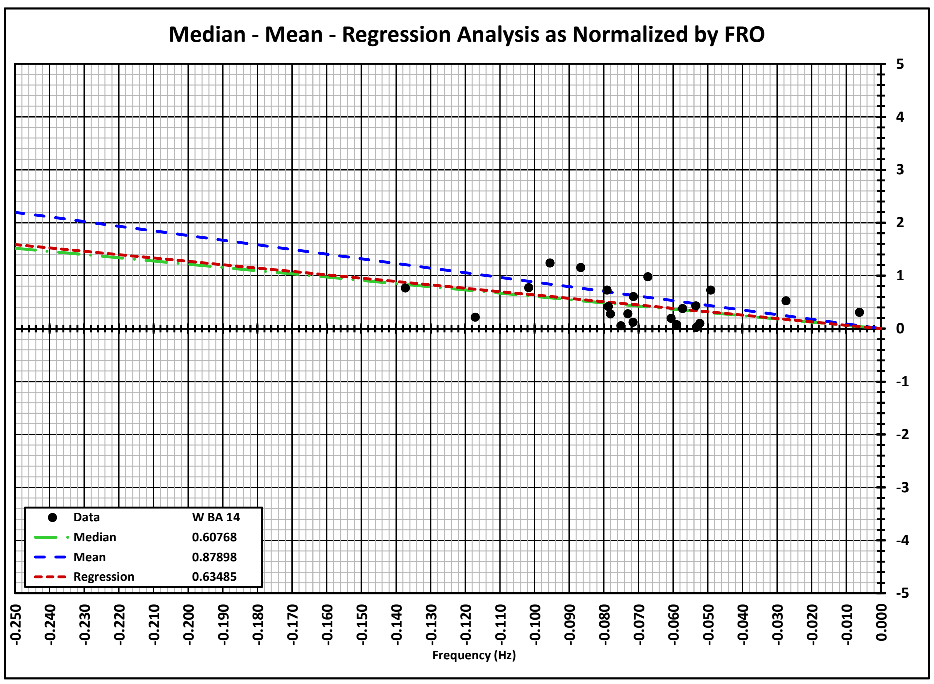


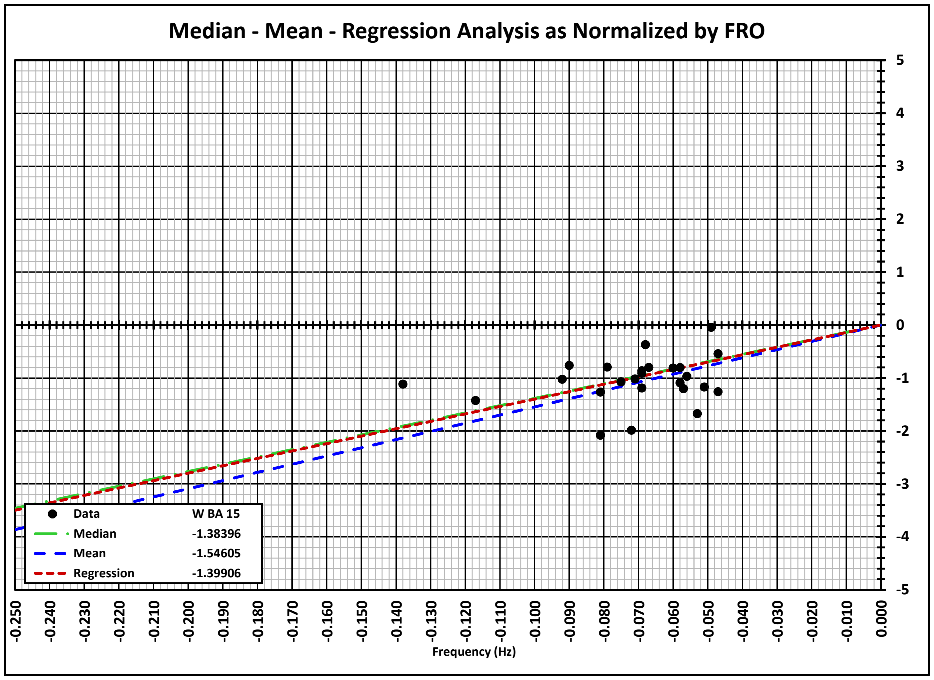
Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 12
Median 2.36648
Mean 2.65442
Regression 2.61365
Frequency (Hz)



Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 13
Median 4.71769
Mean 5.17291
Regression 5.14399
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 13
Median 4.71769
Mean 5.17291
Regression 5.14399
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 14
Median 0.60768
Mean 0.87898
Regression 0.63485
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 15
Median -1.38396
Mean -1.54605
Regression -1.39906
5
4
3
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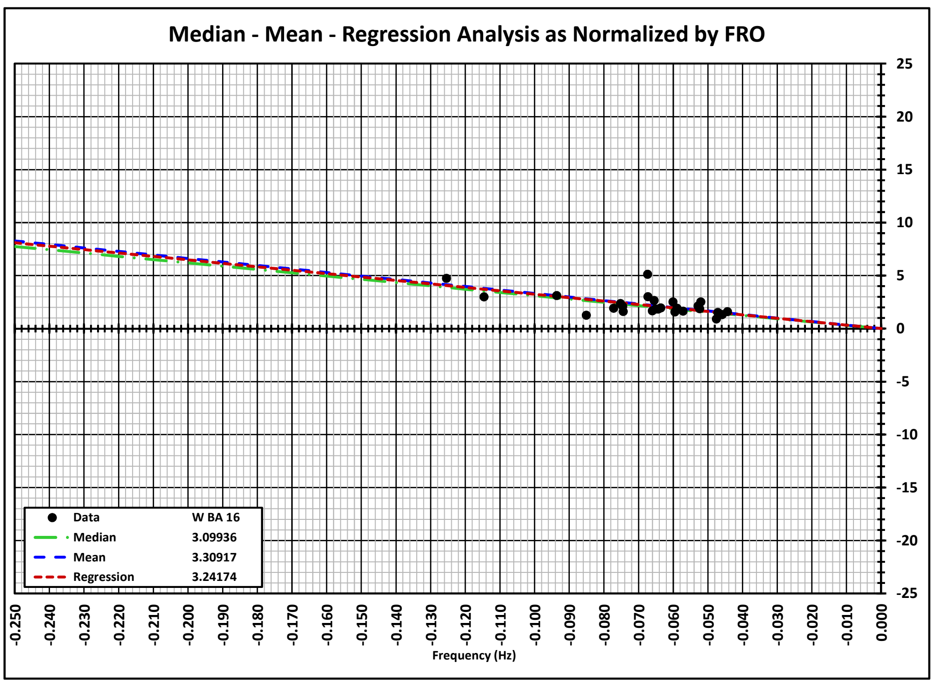
1
0
-1
-2
-3
-4
-5
-0.250
-0.240
-0.230
-0.220
-0.210
-0.200
-0.190
-0.180
-0.170
-0.160
-0.150
-0.140
-0.130
-0.120
-0.110
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 16
Median 3.09936
Mean 3.30917
Regression 3.24174
25
20
15
10
5
0
-5
-10
-15
-20
-25
-0.250
-0.240
-0.230
-0.220
-0.210
-0.200
-0.190
-0.180
-0.170
-0.160
-0.150
-0.140
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-0.120
-0.110
-0.100
-0.090
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-0.070
-0.060
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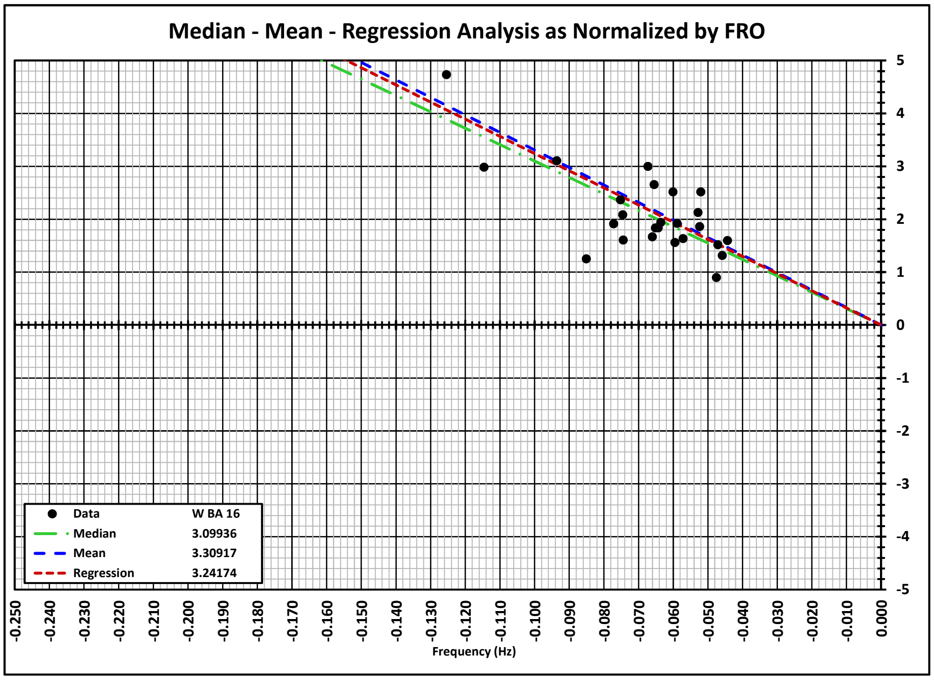
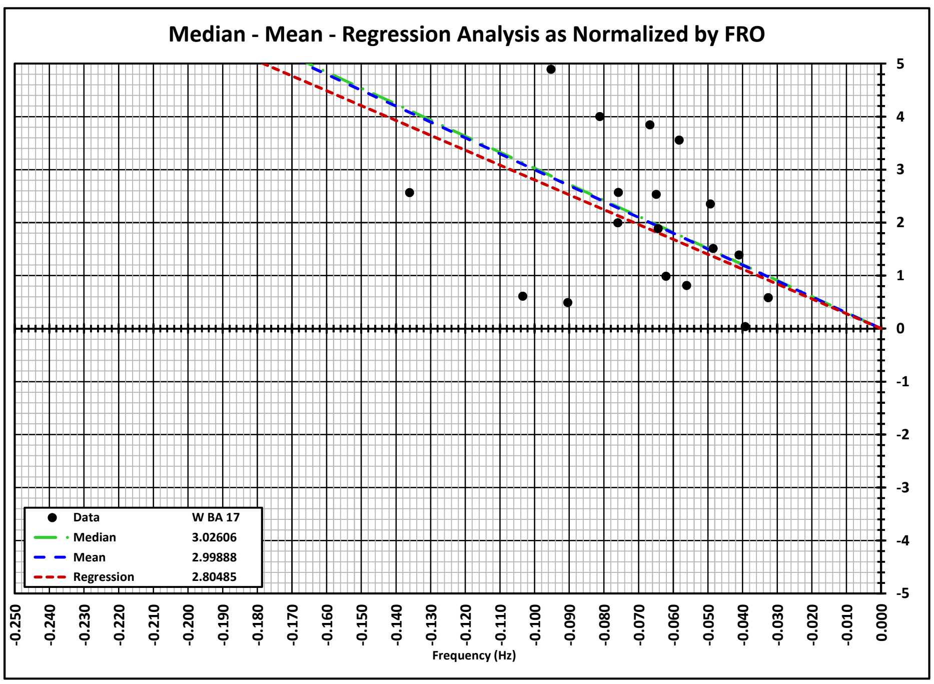
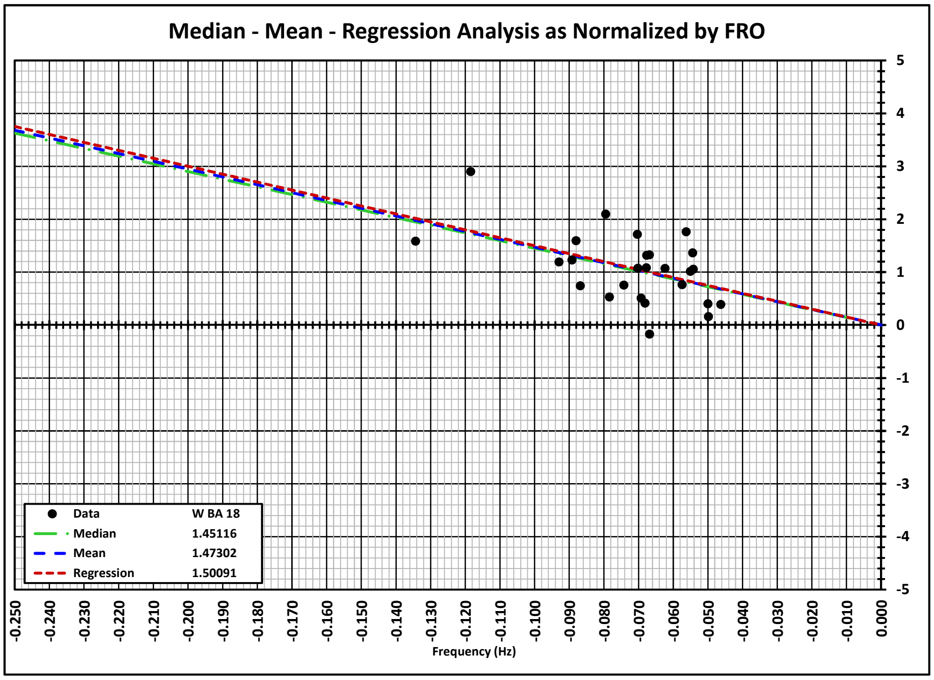
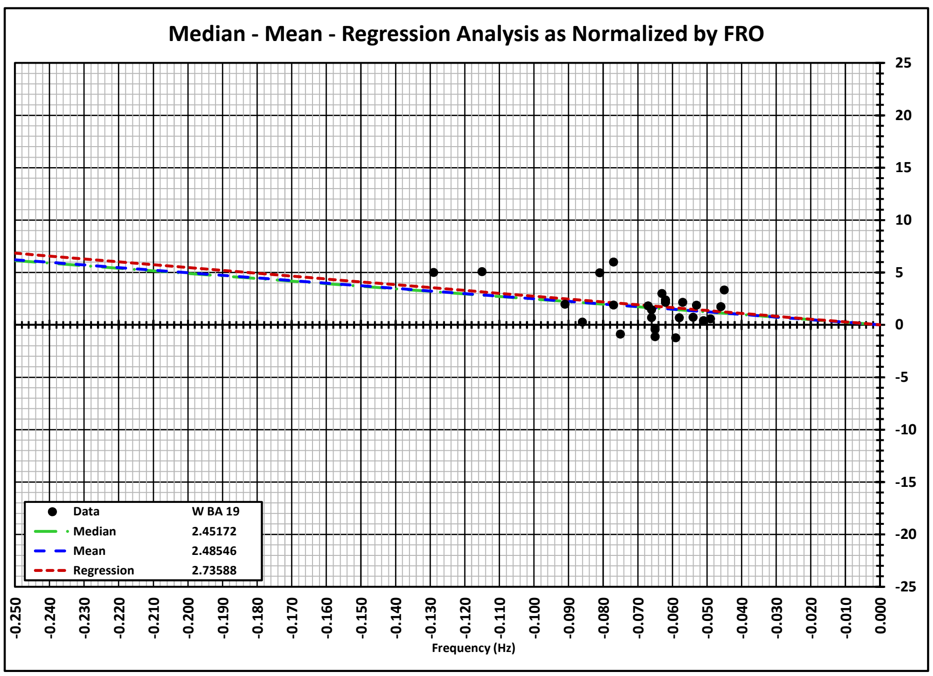
-0.040
-0.030
-0.020
-0.010
0.000
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 16
Median 3.09936
Mean 3.30917
Regression 3.24174
Frequency (Hz)

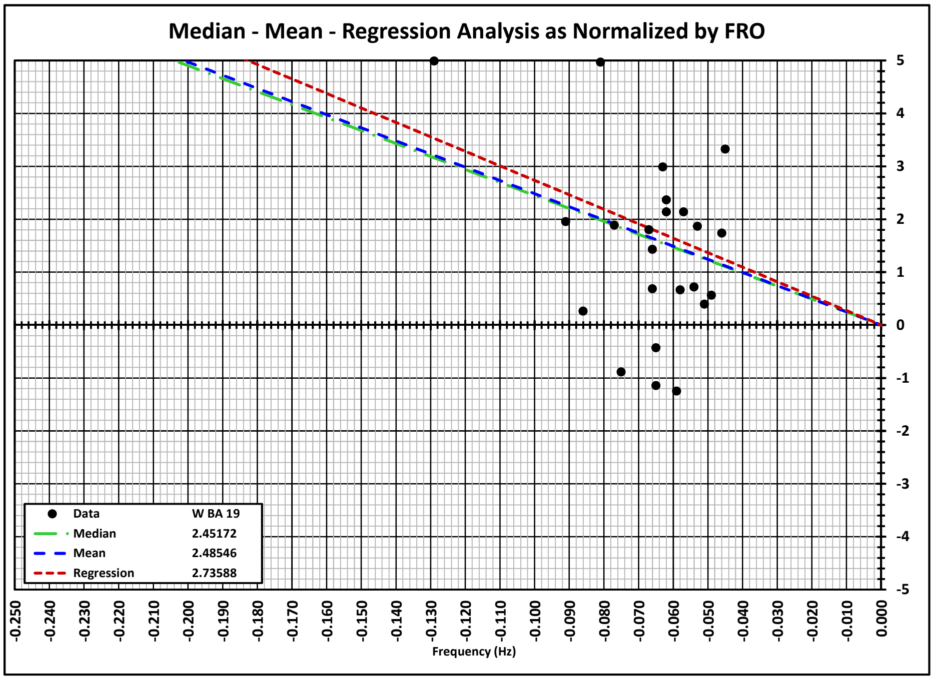

Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 17
Median 3.02606
Mean 2.99888
Regression 2.80485
Frequency (Hz)



Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 18
Median 1.45116
Mean 1.47302
Regression 1.50091
Frequency (Hz)



Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 19
Median 2.45172
Mean 2.48546
Regression 2.73588
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 19
Median 2.45172
Mean 2.48546
Regression 2.73588
5
4
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1
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-1
-2
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-5
-0.250
-0.240
-0.230
-0.220
-0.210
-0.200
-0.190
-0.180
-0.170
-0.160
-0.150
-0.140
-0.130
-0.120
-0.110
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
Frequency (Hz)

Appendix I – Derivation of the Median, Mean, and Linear Regression

Median

The median best represents a uniform one-dimensional dataset.

Uniform Distribution

In probability theory and statistics, the continuous uniform distribution or rectangular distribution is a family of probability distributions such that for each member of the family, all intervals of the same length on the distribution's support are equally probable. The support is defined by the two parameters, a and b, which are its minimum and maximum values.

Median

We have been taught in statistics that minimizing the sum of the differences error term provides the best estimate for the value for a uniform data set. Define a data set as one dimensional with values $\{x_1, x_2, \ldots, x_n\}$. The objective is to select a single value that best represents this data set by minimizing the sum of the residuals.

$$SDE = \sum_{i=1}^{n} \left(x_i - x_m \right)$$

Where: x_m = Best single value to represent the data set.

The result is undefined using calculus. Therefore, other logic must be used.

Organize the data from smallest to largest. Then investigate the change in total difference as the candidate median value is raised from the smallest to the largest value in the data set.

When the candidate median value is raised above the smallest data value the difference between the candidate median value and the smallest value increases, but the difference between the candidate median value and all other data values decreases by an amount equal to the increase in the difference for the smallest value times the number of data values above the candidate median value. As the candidate median value increases, the total difference from all values will decrease until exactly one half of the data values are above the candidate median value and exactly one half of the data values are below the candidate median value. If there are an even number of data values in the set, any change in the candidate median value between the data value immediately below the half and the data point immediately above the half will not change the total difference because the difference change in the increasing direction and the difference change in the decreasing direction offset each other. However, if there are an odd number of data values in the data set, the candidate median value equal to the center data value will result in a minimum of the differences.

This demonstrates that the medianis the best estimate for a set of uniform data because it minimizes the sum of the error terms for the data set.

The real question is not whether the median is an appropriate estimator, but whether the median is an appropriate estimator for the data being analyzed.

Mean

The mean best represents a normal one dimensional dataset.

Normal (Gaussian) Distribution

In probability theory, the normal (or Gaussian) distribution is a continuous probability distribution that has a bell-shaped probability density function, known as the Gaussian function or informally the bell curve, where parameter μ is the mean or expectation (location of the peak) and σ^2 is the variance, the mean of the squared deviation, (a "measure" of the width of the distribution). σ is the standard deviation. The distribution with $\mu = 0$ and $\sigma^2 = 1$ is called the standard normal. A normal distribution is often used as a first approximation to describe real-valued random variables that cluster around a single mean value.

The normal distribution is considered the most prominent probability distribution in statistics. There are several reasons for this:

- First, the normal distribution is very tractable analytically, that is, a large number of results involving this distribution can be derived in explicit form.
- Second, the normal distribution arises as the outcome of the central limit theorem, which states that under mild conditions the sum of a large number of random variables is distributed approximately normally.
- Third, the bell shape of the normal distribution makes it a convenient choice for modeling a large variety of random variables encountered in practice.

For this reason, the normal distribution is commonly encountered in practice, and is used throughout statistics, natural sciences, and social sciences as a simple model for complex phenomena. For example, the observational error in an experiment is usually assumed to follow a normal distribution, and the propagation of uncertainty is computed using this assumption. Note that a normally-distributed variable has a symmetric distribution about its mean. Quantities that grow exponentially, such as prices, incomes or populations, are often skewed to the right, and hence may be better described by other distributions, such as the log-normal distribution or Pareto distribution. In addition, the probability of seeing a normally-distributed value that is far (i.e., more than a few standard deviations) from the mean drops off extremely rapidly. As a result, statistical inference using a normal distribution is not robust to the presence of outliers (data that is unexpectedly far from the mean, due to exceptional circumstances, observational error, etc.). When outliers are expected, data may be better described using a heavy-tailed distribution such as the Student's t-distribution.

Mean

We have been taught in statistics that minimizing the sum of the squares of the error term provides the best estimate for the value for a normal data set. Let's define a data set as one dimensional with values $\{x_1, x_2, \ldots, x_n\}$. The objective is to select a single value that best represents this data set by minimizing the sum of the squares of the residuals.

$$SSE = \sum_{i=1}^{n} (x_i - x_m)^2$$

Where: x_m = Best single value to represent the data set.

$$SSE = \sum_{i=1}^{n} (x_i^2 - 2x_i x_m + x_m^2)$$

$$SSE = \sum_{i=1}^{n} x_i^2 - \sum_{i=1}^{n} 2x_i x_m + \sum_{i=1}^{n} x_m^2$$

$$SSE = \sum_{i=1}^{n} x_i^2 - \sum_{i=1}^{n} 2x_i x_m + nx_m^2$$

Take the derivative of ***SSE*** with respect to x_m, and set that derivative equal to zero.

$$\frac{\partial}{\partial x_m} SSE = \frac{\partial}{\partial x_m}\left(\sum_{i=1}^{n} x_i^2 - \sum_{i=1}^{n} 2x_i x_m + nx_m^2\right)$$

$$\frac{\partial}{\partial x_m} SSE = \frac{\partial}{\partial x_m}\left(\sum_{i=1}^{n} x_i^2\right) - \frac{\partial}{\partial x_m}\left(\sum_{i=1}^{n} 2x_i x_m\right) + \frac{\partial}{\partial x_m}\left(nx_m^2\right)$$

$$\frac{\partial}{\partial x_m} SSE = -2\sum_{i=1}^{n} x_i + 2nx_m = 0$$

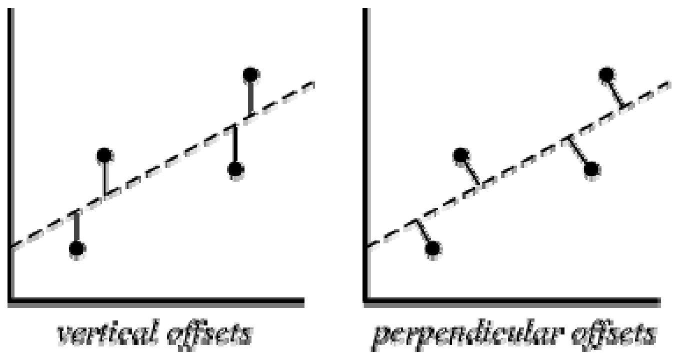
$$\frac{1}{n}\sum_{i=1}^{n} x_i = x_m = \overline{x}$$

This demonstrates that the mean is the best estimate for a set of normal data because it minimizes the sum of the squares of the error terms for the data set.

Linear Regression

A linear regression best represents a normal two dimensional dataset.

As with the one dimensional data set, the objective is to minimize the sum of the squares of the error terms. However, there may be differences that depend upon how we define the error terms.



There are three alternatives available for defining the error term. It can be defined with respect to the dependent variable alone as shown in the vertical offsets plot above. The second is to define the error in terms of the horizontal offsets (not shown). That alternative is the same as the first alternative when the independent variable is exchanged with the dependent variable. The third alternative is to define the error as the perpendicular distance from the best fit line. This is shown in the perpendicular offsets plot above. When the regression is solved using the perpendicular offsets, both variables are considered equal with respect to contribution to error, and the ranking of variables is not necessary.

Solution assuming an independent/dependent variable relationship

In the first example the error term is defined as one dimensional on the dependent variable axis. This is based on the vertical offsets shown above. The result is derived as follows:

$$SSE = \sum_{i=1}^{n} \left(y_i - \hat{y}_i \right)^2$$

Where: $\hat{y}_i$ = Best y value to represent the data set at a given x value.

Substitute a linear equation, $\hat{y}_i = ax_i + b$, for the estimated y value.

$$SSE = \sum_{i=1}^{n} \left(y_i - ax_i - b \right)^2$$

Since we now have two variables, ***a*** and ***b***, the derivative must be taken with respect to each variable. Setting each derivative equal to zero will provide two equations that can be solved for the two unknowns, ***a*** and ***b***.

$$\frac{\partial}{\partial b}SSE = \frac{\partial}{\partial b}\sum_{i=1}^{n}(y_i - ax_i - b)^2 = -2\sum_{i=1}^{n}(y_i - ax_i - b) = 0$$

$$\frac{\partial}{\partial a}SSE = \frac{\partial}{\partial a}\sum_{i=1}^{n}(y_i - ax_i - b)^2 = -2\sum_{i=1}^{n}(x_i y_i - ax_i^2 - bx_i) = 0$$

Rearrange terms and solve the two equations. Solve for b first.

$$-\sum_{i=1}^{n} y_i + a\sum_{i=1}^{n} x_i + nb = 0 \quad \Rightarrow \quad b = \tfrac{1}{n}\sum_{i=1}^{n} y_i - a\tfrac{1}{n}\sum_{i=1}^{n} x_i \quad \Rightarrow \quad b = \bar{y} - a\bar{x}$$

Substitute the result for b into the second equation and solve for a.

$$-\sum_{i=1}^{n} x_i y_i + a\sum_{i=1}^{n} x_i^2 + (\bar{y} - a\bar{x})\sum_{i=1}^{n} x_i = 0 \quad \Rightarrow \quad a = \frac{\sum_{i=1}^{n} x_i y_i - n\overline{yx}}{\sum_{i=1}^{n} x_i^2 - n\bar{x}^2}$$

Calculate the value of a and substitute into the first equation to get the value of b. These are the most common equations used for linear regression. However, they assume that the dependent and independent variables can be identified and that the error in the dependent variable is more important than the error in the independent variable.

Solution without the independent/dependent variable relationship assumption

In this section, the problem is solved using the perpendicular offsets to determine the error terms. This provides a solution that is not dependent upon any assumption concerning the relationship between the variables.

The first step in this solution is to determine the square of the perpendicular offset from the regression line that represents the error term.

$$SSE = \sum_{i=1}^{n}\left(\frac{[y_i - (ax_i + b)]^2}{1 + a^2}\right)$$

Since we again have two variables, a and b, the derivative must be taken with respect to each variable. Setting each derivative equal to zero will provide two equations that can be solved for the two unknowns, a and b.

$$\frac{\partial}{\partial b}SSE = \frac{\partial}{\partial b}\sum_{i=1}^{n}\left(\frac{[y_i - (ax_i + b)]^2}{1 + a^2}\right) = \frac{-2}{1 + a^2}\sum_{i=1}^{n}(y_i - ax_i - b) = 0$$

$$\frac{\partial}{\partial a} SSE = \frac{\partial}{\partial a} \sum_{i=1}^{n} \left(\frac{\left[y_i - (ax_i + b) \right]^2}{1 + a^2} \right)$$

$$\frac{\partial}{\partial a} SSE = \frac{-2}{1 + a^2} \sum_{i=1}^{n} (y_i - ax_i - b) x_i - \sum_{i=1}^{n} \frac{(y_i - ax_i - b)^2 (2a)}{(1 + a^2)^2} = 0$$

Rearrange terms and solve the two equations. Solve for b first.

$$-\sum_{i=1}^{n} y_i + a \sum_{i=1}^{n} x_i + nb = 0 \quad \Rightarrow \quad b = \tfrac{1}{n} \sum_{i=1}^{n} y_i - a \tfrac{1}{n} \sum_{i=1}^{n} x_i \quad \Rightarrow \quad b = \bar{y} - a\bar{x}$$

This is the same result as before. Substitute the result for ***b*** into the second equation and solve for ***a***. The detailed intermediate equations for this solution can be found at http://mathworld.wolfram.com/LeastSquaresFittingPerpendicularOffsets.html. After much manipulation the following equations result:

$$A = \frac{1}{2} \frac{\left(\sum_{i=1}^{n} y_i^2 - n\bar{y}^2 \right) - \left(\sum_{i=1}^{n} x_i^2 - n\bar{x}^2 \right)}{n\bar{y}\bar{x} - \sum_{i=1}^{n} x_i y_i} \qquad \Rightarrow \qquad a = -A \pm \sqrt{A^2 + 1}$$

This solution is somewhat more complex than the vertical offset solution. That is the reason that the vertical offset solution is commonly used. In most cases, the vertical offset solution provides an adequate answer to the problem without the added complexity of the perpendicular offset solution. However, when the vertical offset solution is used, it makes a difference which variable is considered the independent variable and the dependent variable. This can significantly affect the results when the slope is large.

Additional information requires a special case linear regression

The calculation of Frequency Response requires the use of a special case linear regression. Frequency Response is defined as to be equal to zero when the frequency error is equal to zero. This information requires the modification of the linear regression used to provide the best representation of the data. The appropriate linear regression for representing Frequency Response is a regression where the regression line crosses the origin of the axis representing the two variables, frequency and Frequency Response (MW). Therefore, the previously developed general solution to the problem requires modification. This is done by setting the variable that represents the ***y-intercept*** to zero. In the above examples, the ***b*** term must be set to zero.

Special case solution assuming an independent/dependent variable relationship

In the first example the error term is defined as one dimensional on the dependent variable axis. This is based on the vertical offsets but in this case the variable representing the intercept is eliminated. The result is derived as follows:

$$SSE = \sum_{i=1}^{n} \left(y_i - \hat{y}_i \right)^2$$

Where: $\hat{y}_i$ = Best ***y*** value to represent the data set at a given ***x*** value.

Substitute a linear equation, $\hat{y}_i = ax_i$, for the estimated ***y*** value.

$$SSE = \sum_{i=1}^{n} \left(y_i - ax_i \right)^2$$

Since we now have a single variables, ***a***, the derivative must be taken with respect to that variable. Setting the derivative equal to zero will provide an equation that can be solved for the unknown, ***a***.

$$\frac{\partial}{\partial a} SSE = \frac{\partial}{\partial a} \sum_{i=1}^{n} \left(y_i - ax_i \right)^2 = -2 \sum_{i=1}^{n} \left(x_i y_i - ax_i^2 \right) = 0$$

Rearrange terms and solve the equation.

$$-\sum_{i=1}^{n} x_i y_i + a \sum_{i=1}^{n} x_i^2 = 0 \qquad \Rightarrow \qquad a = \frac{\sum_{i=1}^{n} x_i y_i}{\sum_{i=1}^{n} x_i^2}$$

This equation is somewhat simpler than the equation using a non-zero intercept. In the specific case that we are considering, the estimate of Frequency Response, the slope of the regression line is not expected to be large, near vertical. Therefore, the assumption of dependent and independent variables is not important to the solution. In this case, the additional complexity added by considering the horizontal offsets is not significant to the solution and has been eliminated from consideration.

Appendix J – Generator Governor Survey Instructions

NOTE: These were the instructions for the Generators Governor Survey conducted in September 2010.

Frequency Response Initiative

Generator Governor Survey

For the purposes of this survey, governors are defined as any device that implements Primary Frequency Response (speed regulation) for generators.

The survey will be sent to Generator Owners and Generator Operators.

- The survey includes all generators rated 20 MVA or higher, or plants that aggregate to a total of 75 MVA or greater net rating at the point of interconnection (i.e., wind farms, PV farms, etc.), accordance with the Statement of Compliance Registry Criteria, Rev. 5.0.
- Jointly-owned units should be reported by the operating entity.
- For combined-cycle plants, the combustion turbines and heat-recovery (steam turbine) units should be reported separately.
- Wind farms should report on a point-of-interconnection basis.
- If the unit is operable in more than one interconnection, complete the survey for operation in each of the interconnections.

NOTE: The 256-character limitation noted on the spreadsheet is a Microsoft Excel limitation on characters in a cell. If additional space is needed, please supply supplemental documentation as necessary.

When responding, please upload your response and any supporting documentation through the NERC Secure Alerts System

General Questions

1. Does your organization have a formal policy on the installation and operation of generator governors?
2. Does your organization have a testing procedure for governors? If so, how often are they tested?

Unit-Specific Questions

The following questions will all apply to each generator:

1. Unit name and number.

2. Balancing Authority (BA) in which the generator is operated (pull-down).
    a. If operable in more than one, please note all applicable BAs.
    b. If operable in more than one interconnection, complete the survey for operation in each of the interconnections.
3. Unit seasonal Net MW ratings normally reported to NERC for resource adequacy analyses:
    a. Summer Net MW rating
    b. Winter Net MW rating
4. Prime mover (steam turbine, combustion turbine, wind turbine, etc. — pull-down)
5. Fuel type (coal, oil, nuclear, etc. — pull-down)
6. Unit inertia constant (H) as modeled in dynamics analyses – the combined kinetic energy of the generator and prime-mover in watt-seconds at rated speed divided by the VA (Volt-Ampere) base.
7. What are the annual run hours for the unit (data for each of the last 3 years)?
8. What is the continuous MW rating (Pmax) of the unit?
9. What percent of time does the unit run at Pmax or valves wide-open?
    a. 0 to 30%
    b. 31% to 60%
    c. 61% to 100%
10. Equipped with a Governor? (Y/N) If not, no further answers are necessary.
11. If yes, is the governor operational? (Y/N with a comment box) If not, please explain.
    a. Is the governor normally in operation? (Y/N with a comment box) (even if not normally operated, the data on the governor is still needed)
    b. What is the normal governor mode of operation? (pull-down)
    c. Is the governor response sustainable for more than one minute if conditions remain outside of the deadband? (Y/N)
    d. Are there any regulatory restrictions regarding the operation of the governor? This should cover nuclear regulation, environmental restrictions (water temperature, emissions), water flow, etc.
    e. Does the governor respond beyond the high/low operating limit (boiler blocks)? (Y/N)
    f. Is the governor response limited by the rate of change? (Y/N)
    g. Are there any other unit-level or plant-level control schemes that would override or limit governor performance? If yes, please explain.
12. Governor Type?
    - Electronic (analog electro-hydraulic);
    - DEH (digital electro hydraulic);
    - Mechanical;
    - Other — please specify.
13. Governor manufacturer and model?
    a. If mixed vendor equipment is installed, please explain.
14. Governor Deadband setting?
    a. Deadband in(+/-) mHz

i. If in mHz is the deadband centered around a frequency reference (60 Hz or current frequency)?

b. Deadband in (+/-) RPM

i. For RPM specify number of machine poles

ii. If in RPM, is the RPM reference nominal or current RPM?

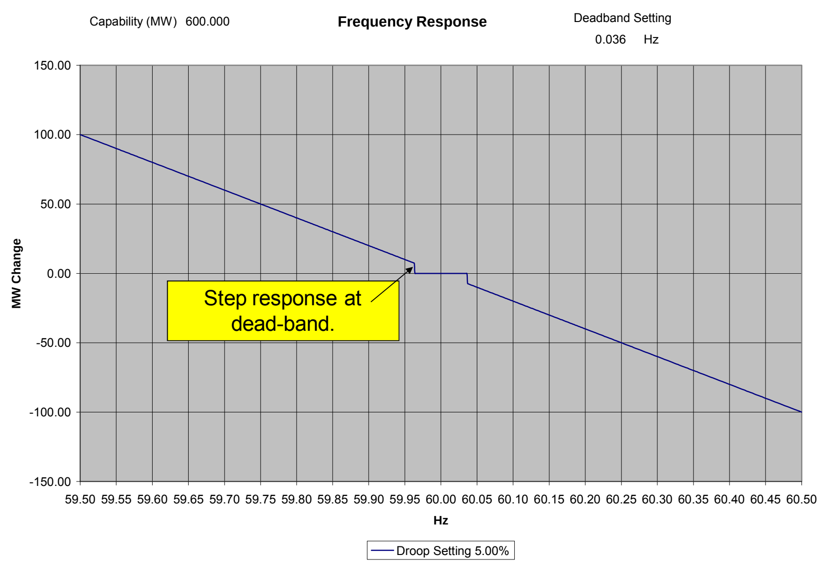
c. What is the basis for this setting?

d. Once activated, what are the conditions for which the governor action is reset?

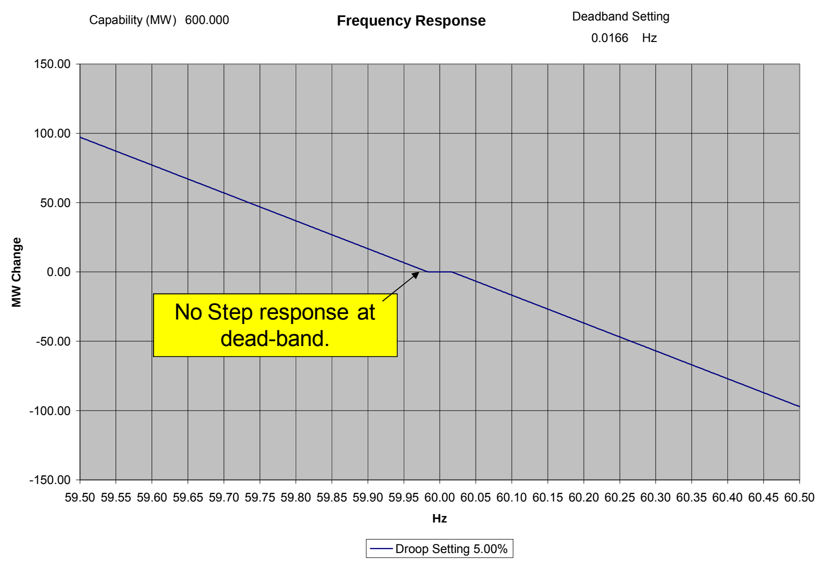
15. What is the percentage (%) droop setting on the governor?

a. What is the basis for the droop setting?

16. Does the unit Frequency Response step into the droop curve or is it linear from the deadband?



Step Implementation (step): When frequency crosses the governor dead-band setting the output of the governor "steps" into the 5% droop curve as if the dead-band did not exist.



Without Step Implementation (linear): When frequency crosses the governor dead-band setting the output of the governor adds proportional output toward the droop curve end point.

17. Prime mover control mode – What is the normally used Turbine Control mode(s)? If more than one is prevalently used, select a primary and explain.
    - Turbine manual
    - Thermally-limited
    - Turbine following
    - Boiler following
    - Part-load
    - Pre-select
    - MW set point
    - Coordinated control
    - Other (please explain) If more than one is prevalently used, select a primary and explain.

18. Do market rules restrict or override governor speed controls? (Y/N) If yes, please explain.

For steam generator controls (boiler controls) or combined cycle central station controls:

19. Does the boiler control or combined cycle central station control have a frequency input? (Y/N) If yes, answer the following questions:
    a. Deadband in(+/-) mHz
        i. If in mHz is the deadband centered around a frequency reference (60 Hz or current frequency)?

b. Deadband in (+/-) RPM
   i. For RPM specify number of machine Poles
   ii. If in RPM, is the RPM reference nominal or current RPM?
c. What is the basis for this setting?

20. Does the control's Frequency Response step into the droop curve or is it linear from the deadband?
21. What is the steam turbine control mode? (boiler following, turbine following, coordinated control)
22. Do the unit or plant controls over-ride governor speed control or are the control parameters supportive? (Y/N)
23. Does the boiler operate under variable/sliding pressure? (Y/N)
    a. What is the control/governor valve position percentage (%) during variable pressure operation?
24. Do unit or plant economic controls over-ride governor speed control? (Y/N)

Event Performance Data

The following five questions are to be answered for each generator to ascertain its performance during the specified frequency events (one per interconnection). The frequency events data to be reported are:

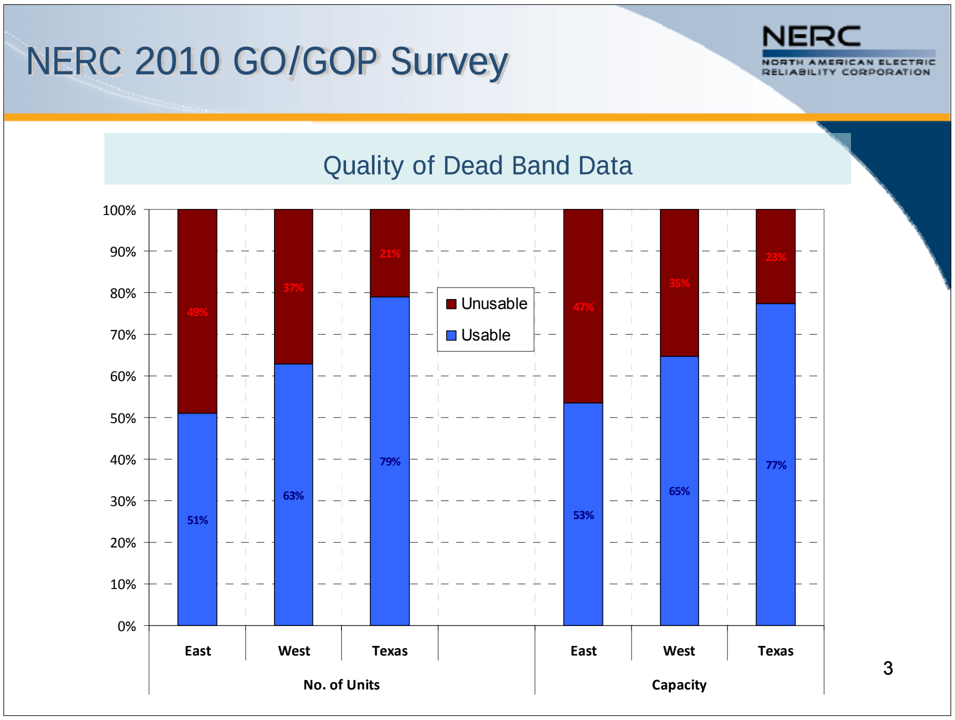
Interconnection	Date	Time	Time Zone
Eastern	8/16/2010	14:25:29	CST
Western	8/12/2010	1:06:15	CST
Texas	8/20/2010	14:44:03	CST
Québec	12/10/2009	15:09:31	EST

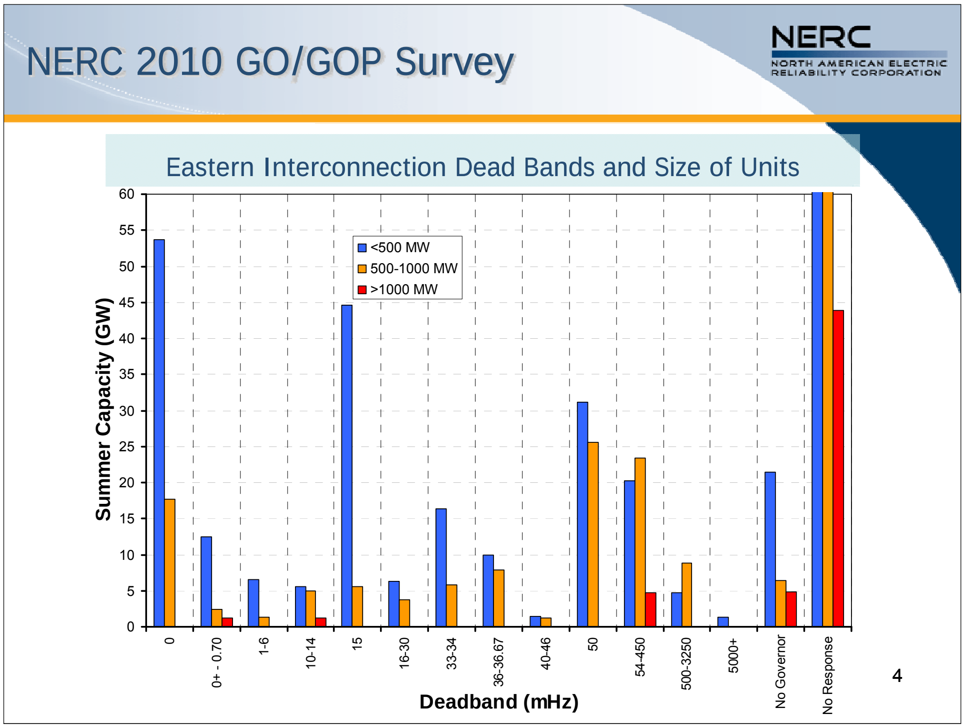
25. Was the unit on-line during the event? (Y/N)
26. Pre-event generation (MW) – Enter the MW output of the generator at the time just before the event began.
27. Post-event generation (MW) – Enter the MW output of the generator after the event that was reflects the response by the governor to the frequency deviation.
28. Time to achieve post-event response (seconds) – Enter the time (in seconds) it took to achieve the MW response noted in question 27.
29. Comments (256 characters) – Enter any comments necessary. If no data is available for the event, note that here.

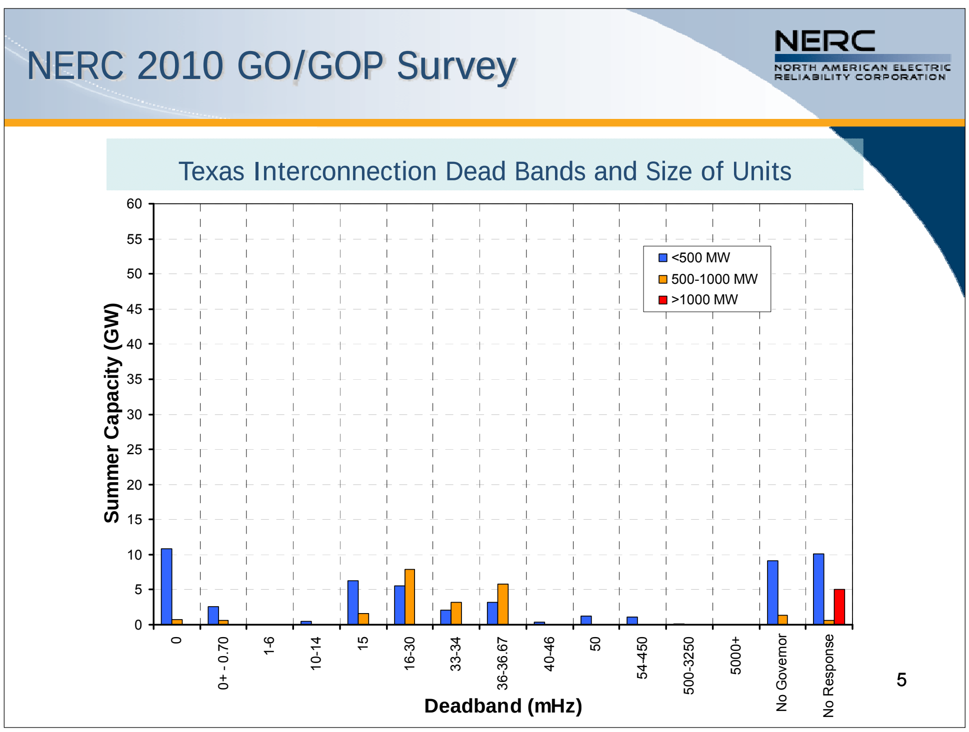
Appendix K – Generator Governor Survey Summary

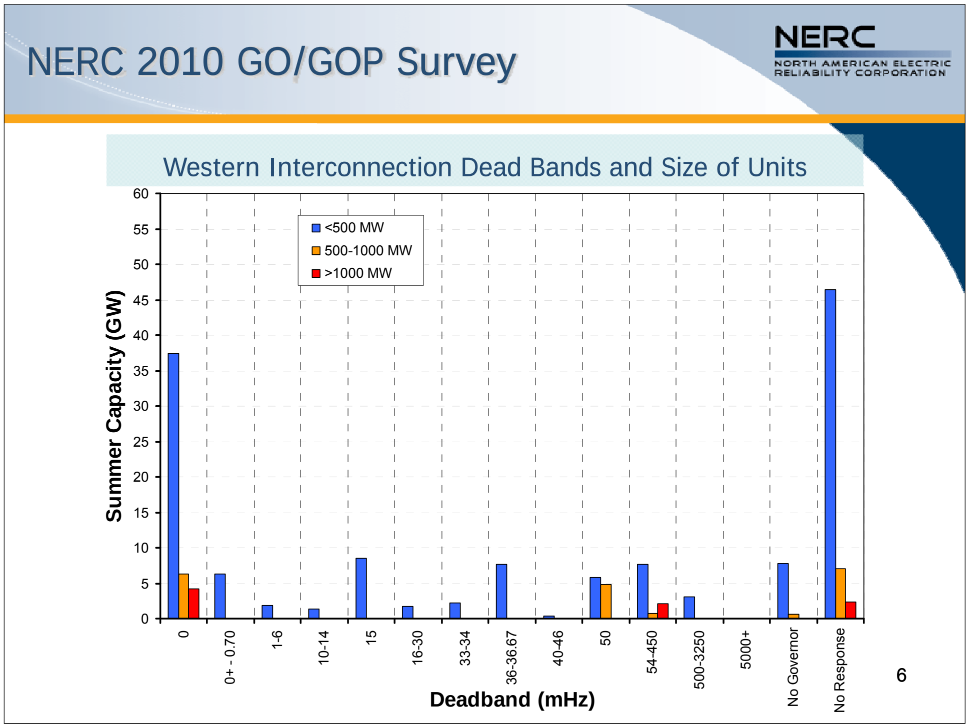
The following are slides that summarize the responses of the 2010 Generator Governor Survey.

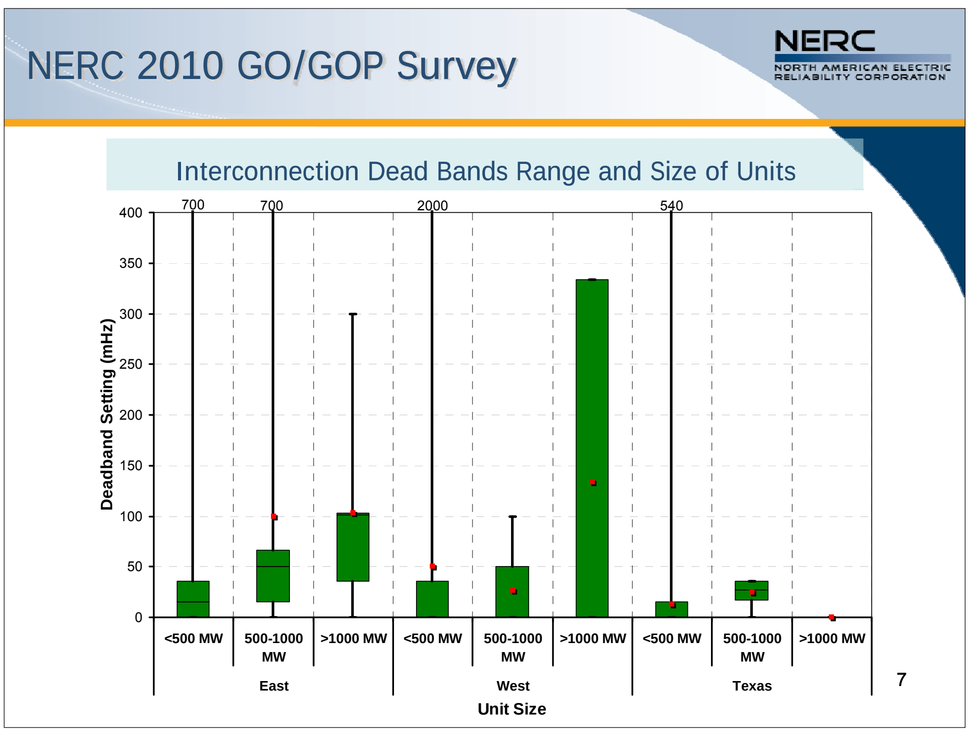
Deadband Settings

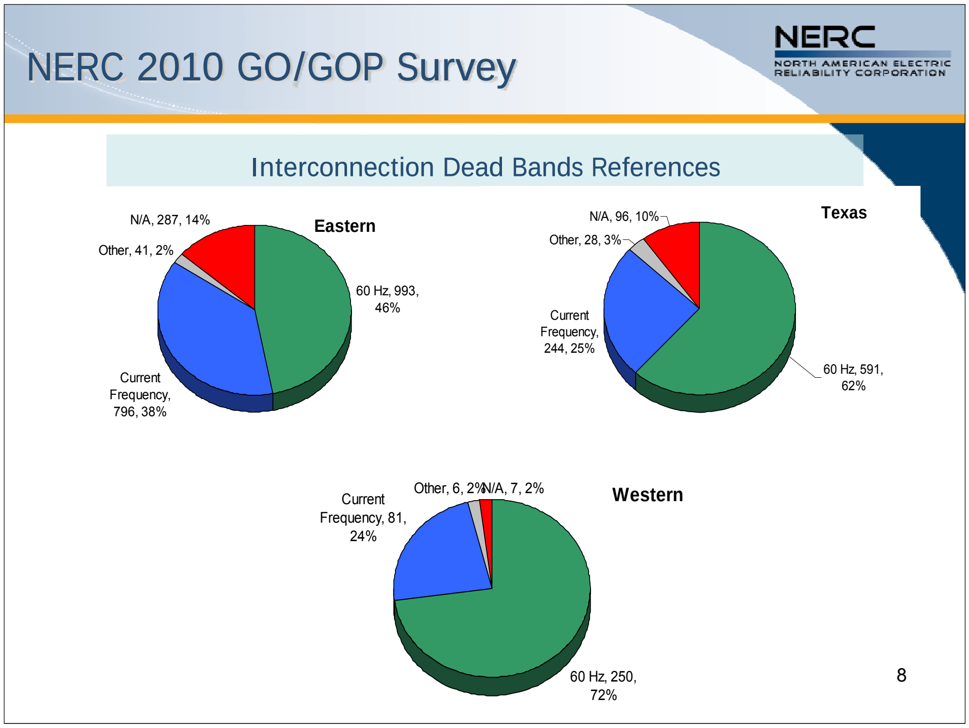



NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Eastern Interconnection Dead Bands and Size of Units
Summer Capacity (GW)
0
5
10
15
20
25
30
35
40
45
50
55
60
<500 MW
500-1000 MW
>1000 MW
0
0+ - 0.70
1-6
10-14
15
16-30
33-34
36-36.67
40-46
50
54-450
500-3250
5000+
No Governor
No Response
Deadband (mHz)
4

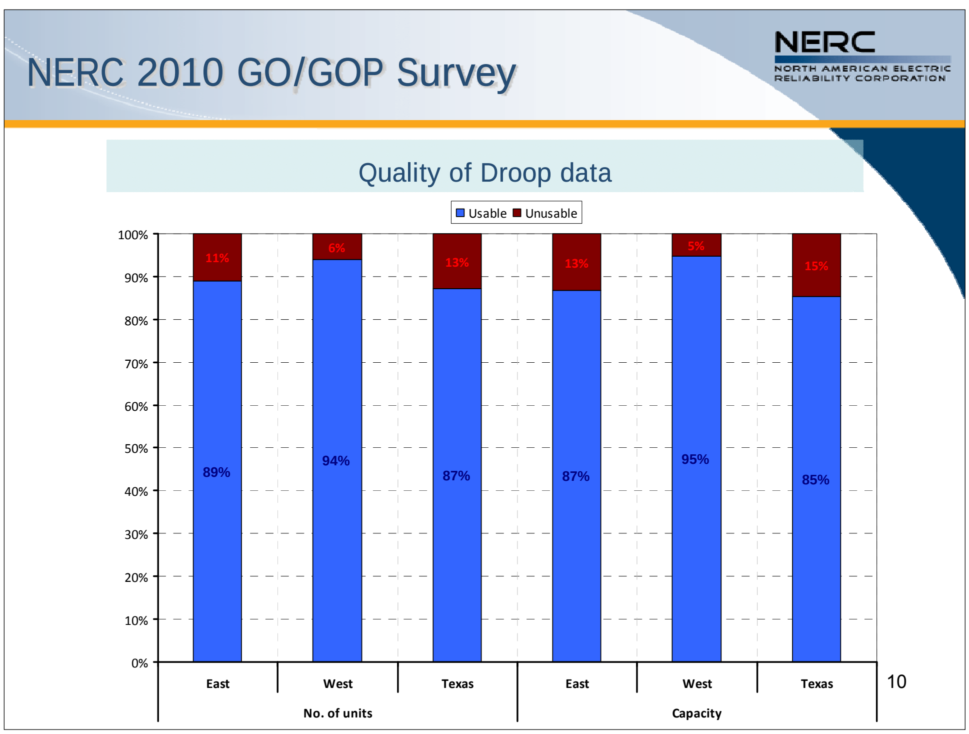

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Texas Interconnection Dead Bands and Size of Units
Summer Capacity (GW)
0
5
10
15
20
25
30
35
40
45
50
55
60
<500 MW
500-1000 MW
>1000 MW
0
0+ - 0.70
1-6
10-14
15
16-30
33-34
36-36.67
40-46
50
54-450
500-3250
5000+
No Governor
No Response
Deadband (mHz)
5

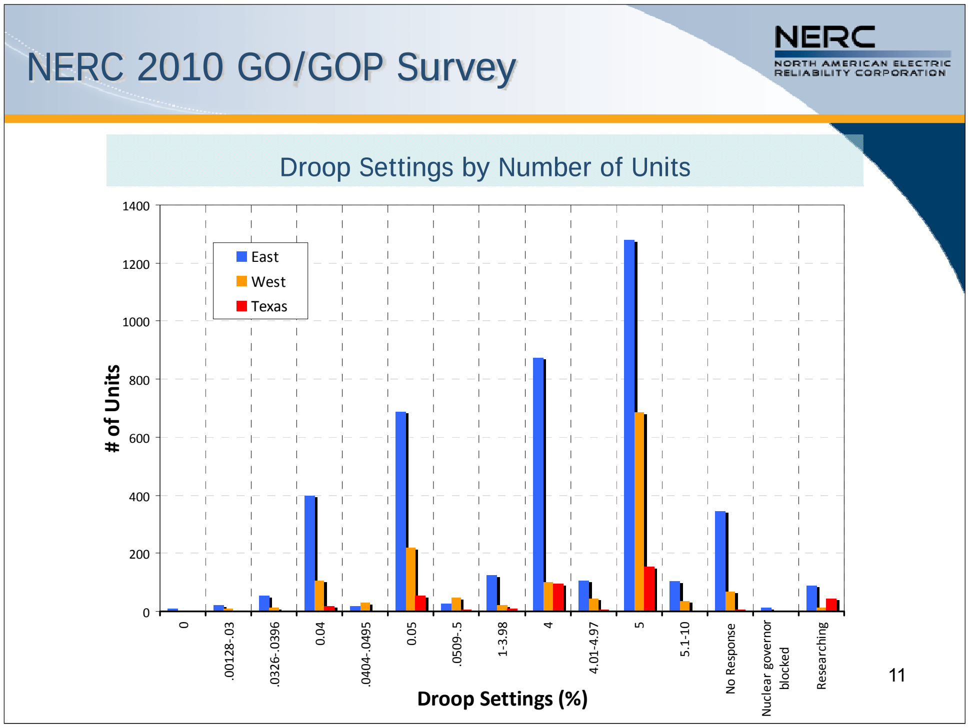

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Western Interconnection Dead Bands and Size of Units
<500 MW
500-1000 MW
>1000 MW
Summer Capacity (GW)
0
0+ - 0.70
1-6
10-14
15
16-30
33-34
36-36.67
40-46
50
54-450
500-3250
5000+
No Governor
No Response
Deadband (mHz)
6

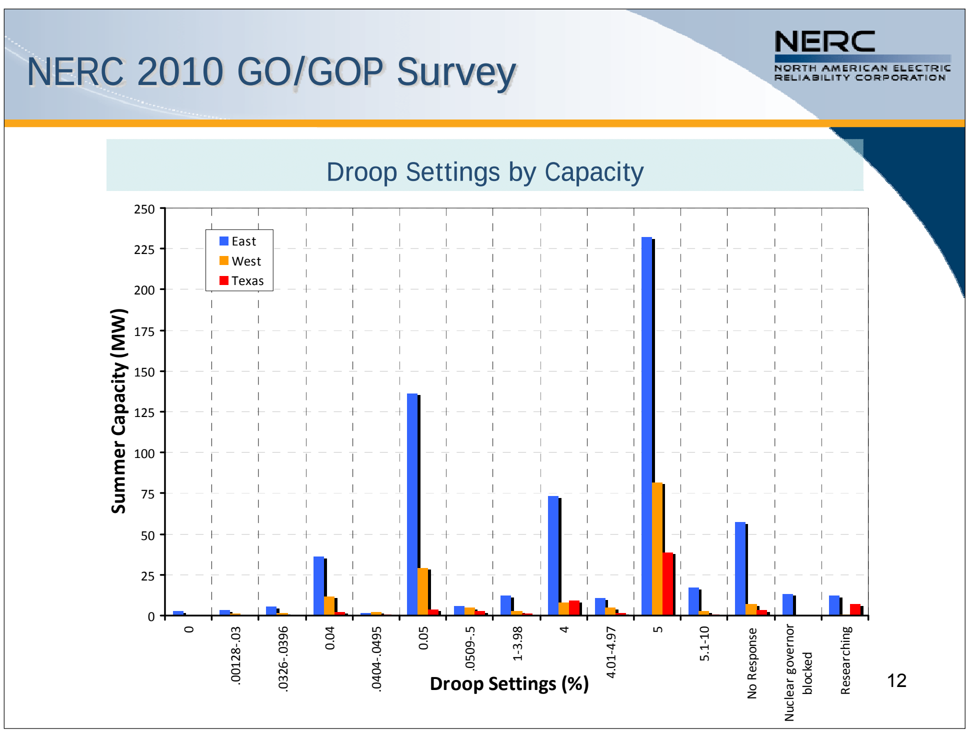

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Interconnection Dead Bands Range and Size of Units
700
700
2000
540
Deadband Setting (mHz)
<500 MW
500-1000 MW
>1000 MW
East
West
Texas
Unit Size
7

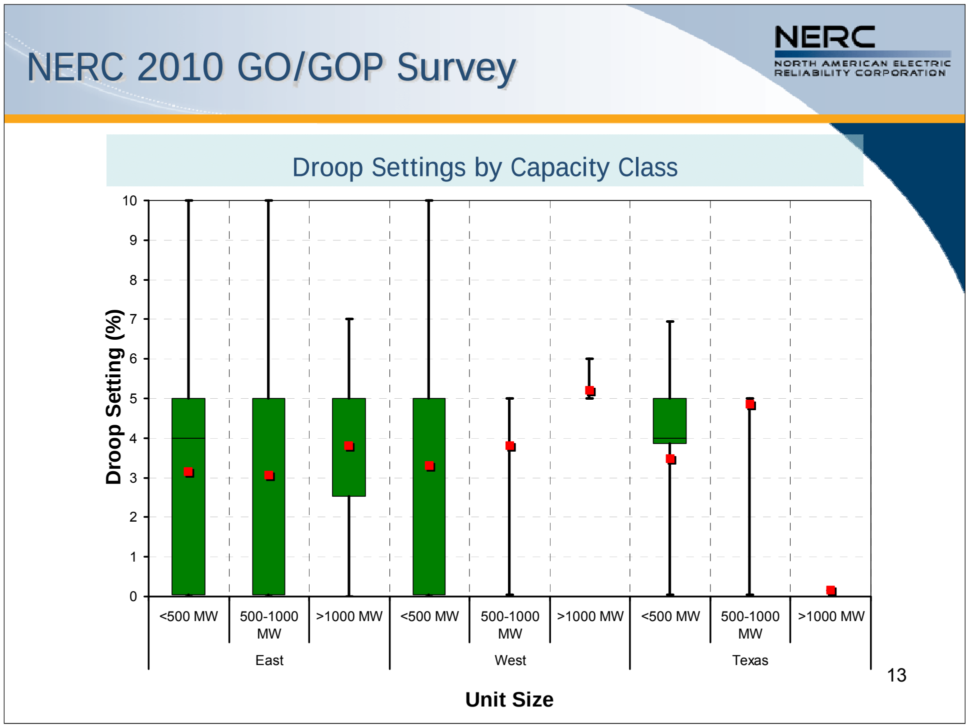


Droop Settings

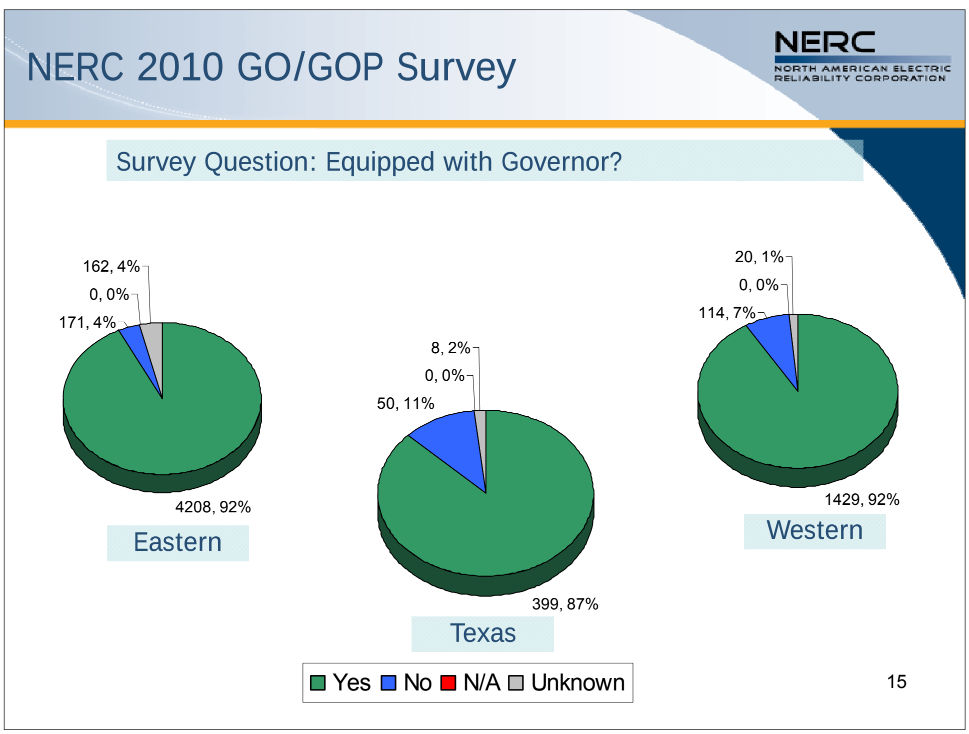


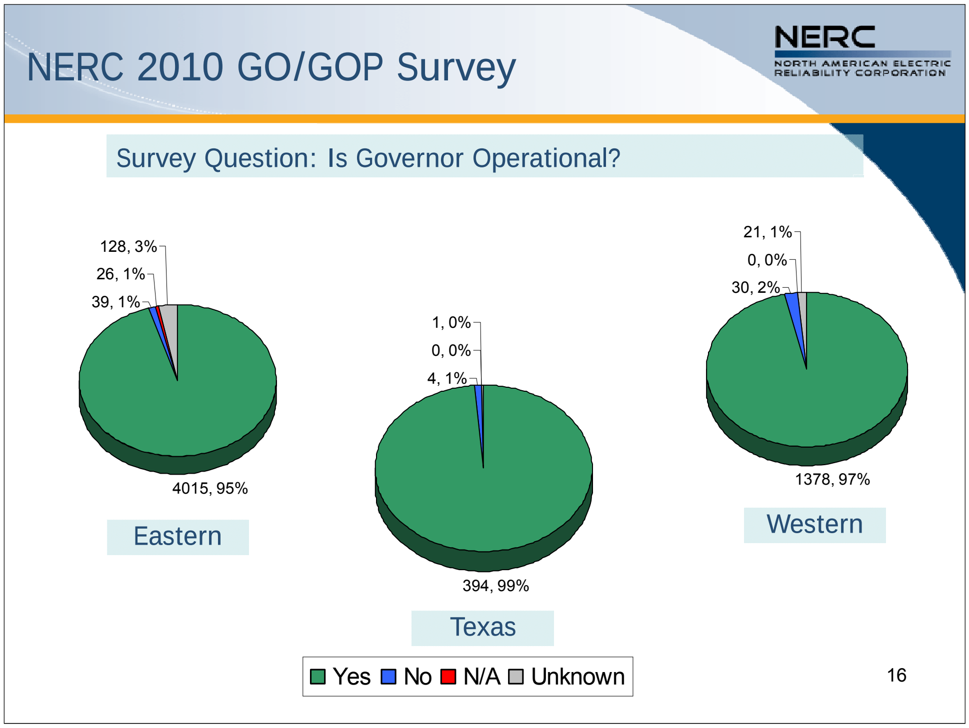

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Droop Settings by Number of Units
# of Units
East
West
Texas
0
.00128-.03
.0326-.0396
0.04
.0404-.0495
0.05
.0509-.5
1-3.98
4
4.01-4.97
5
5.1-10
No Response
Nuclear governor blocked
Researching
Droop Settings (%)
11

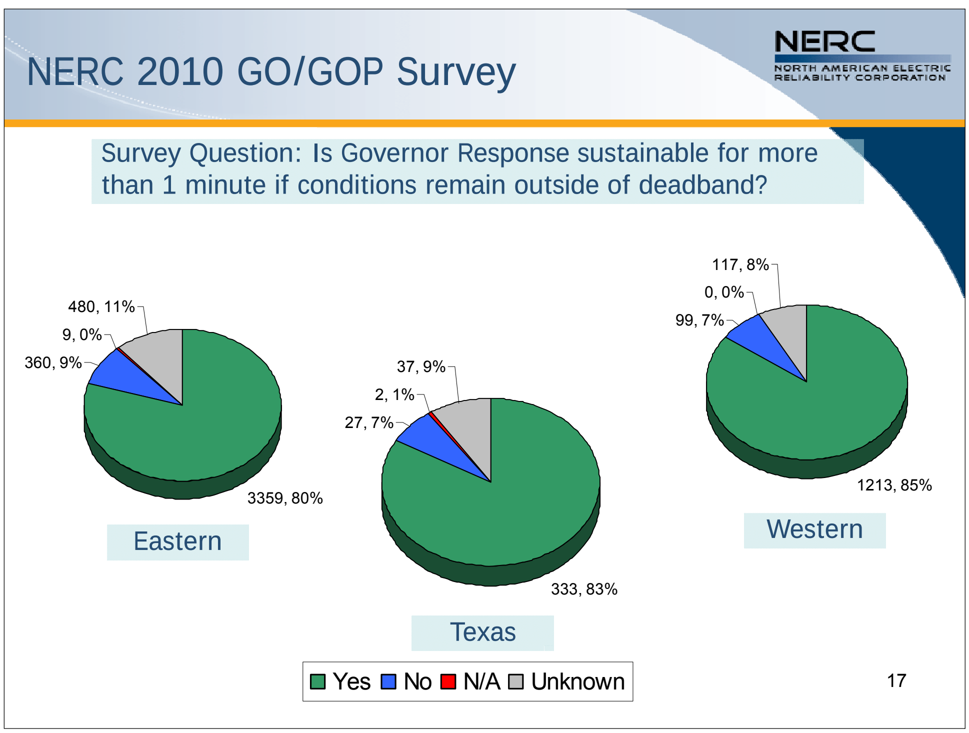

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Droop Settings by Capacity
Summer Capacity (MW)
East
West
Texas
0
.00128-.03
.0326-.0396
0.04
.0404-.0495
0.05
.0509-.5
1-3.98
4
4.01-4.97
5
5.1-10
No Response
Nuclear governor blocked
Researching
Droop Settings (%)
12

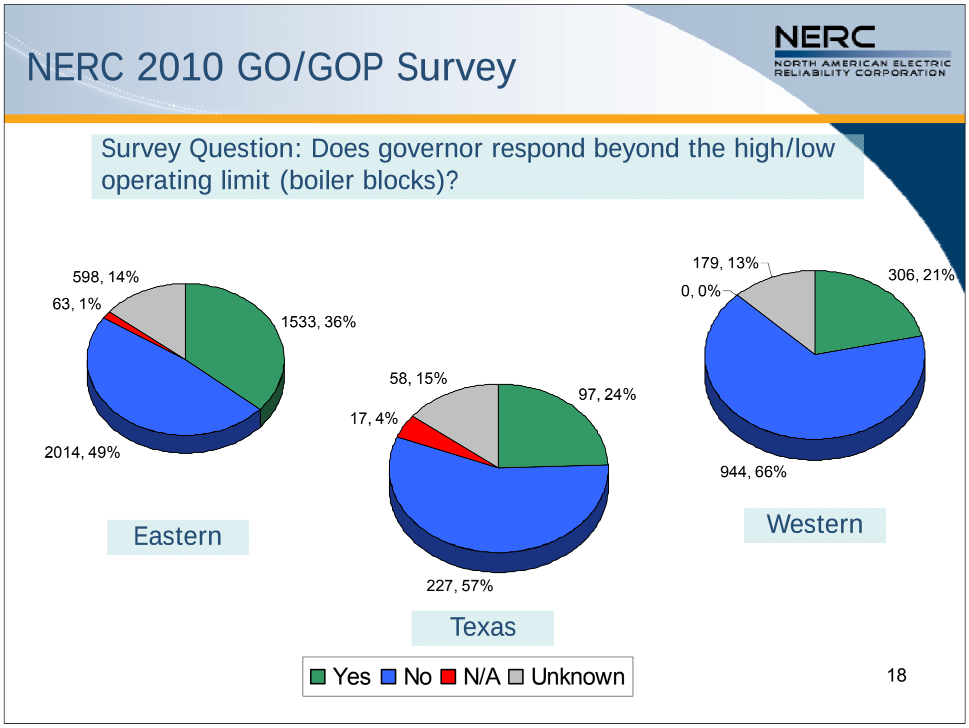


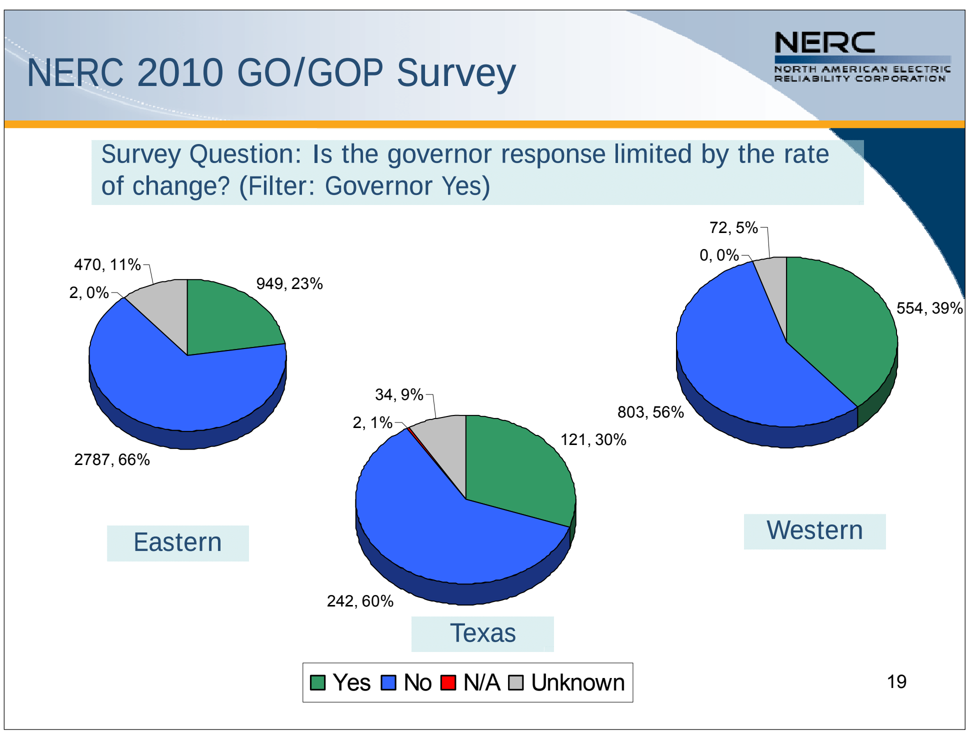
Results of Other Survey Questions

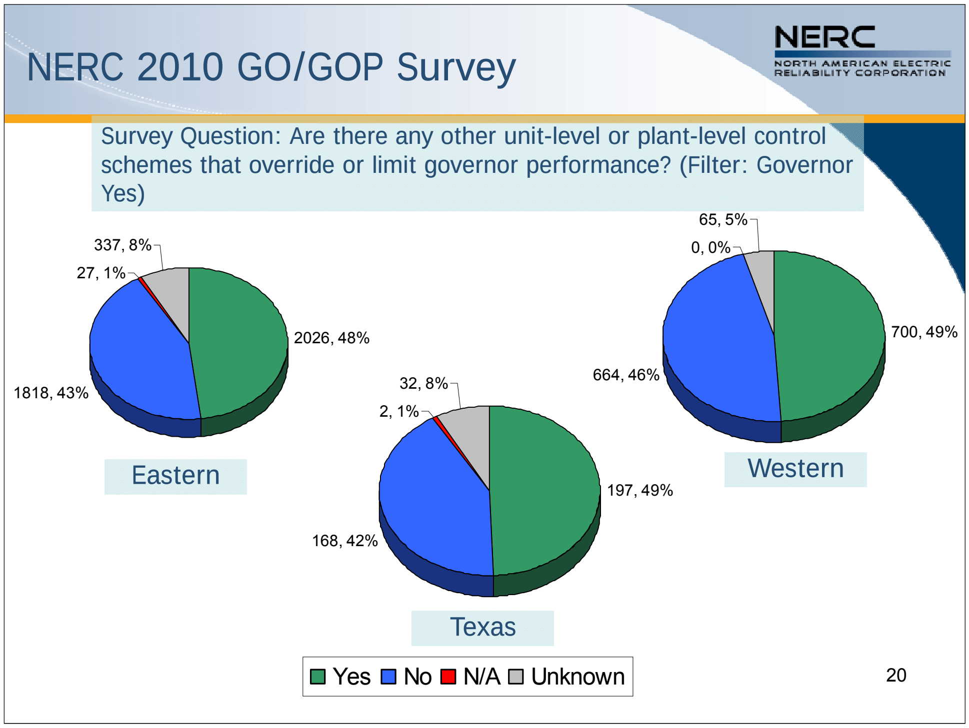


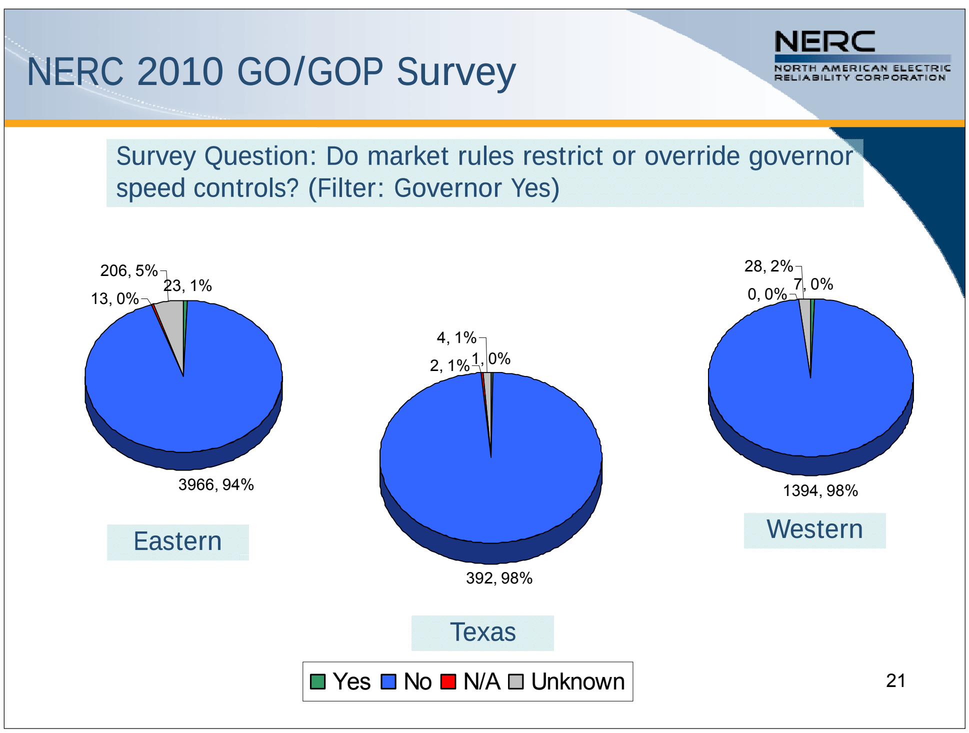

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Survey Question: Is Governor Operational?
128, 3%
26, 1%
39, 1%
4015, 95%
Eastern
1, 0%
0, 0%
4, 1%
394, 99%
Texas
21, 1%
0, 0%
30, 2%
1378, 97%
Western
Yes No N/A Unknown
16

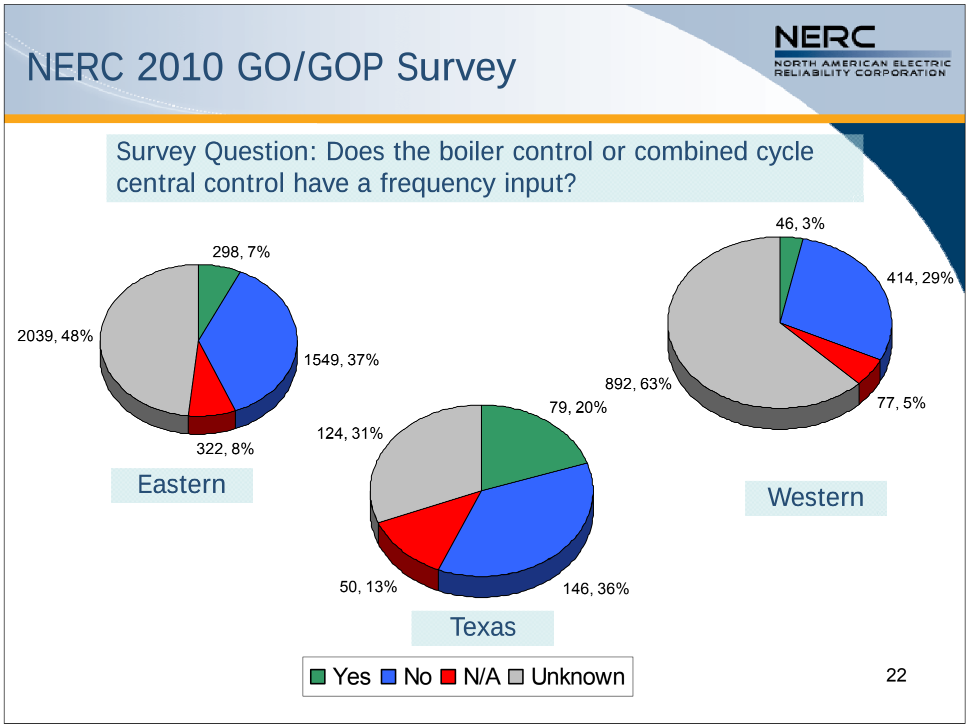

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Survey Question: Is Governor Response sustainable for more than 1 minute if conditions remain outside of deadband?
480, 11%
9, 0%
360, 9%
3359, 80%
Eastern
37, 9%
2, 1%
27, 7%
333, 83%
Texas
117, 8%
0, 0%
99, 7%
1213, 85%
Western
Yes No N/A Unknown
17

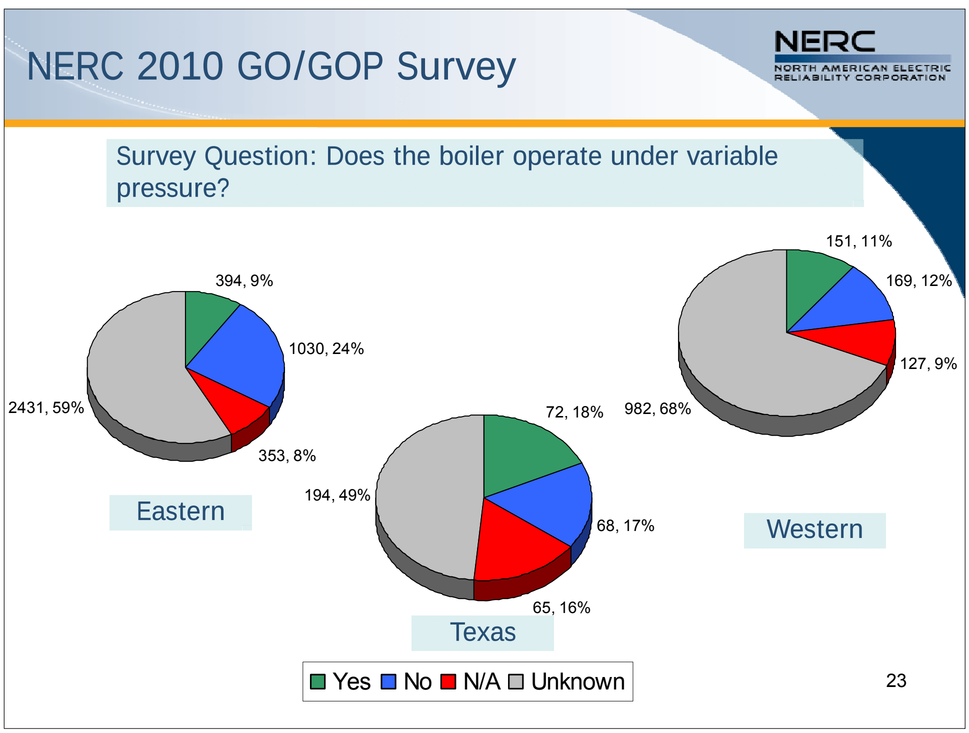

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Survey Question: Does governor respond beyond the high/low operating limit (boiler blocks)?
598, 14%
63, 1%
1533, 36%
2014, 49%
Eastern
58, 15%
17, 4%
97, 24%
227, 57%
Texas
179, 13%
0, 0%
306, 21%
944, 66%
Western
Yes No N/A Unknown
18

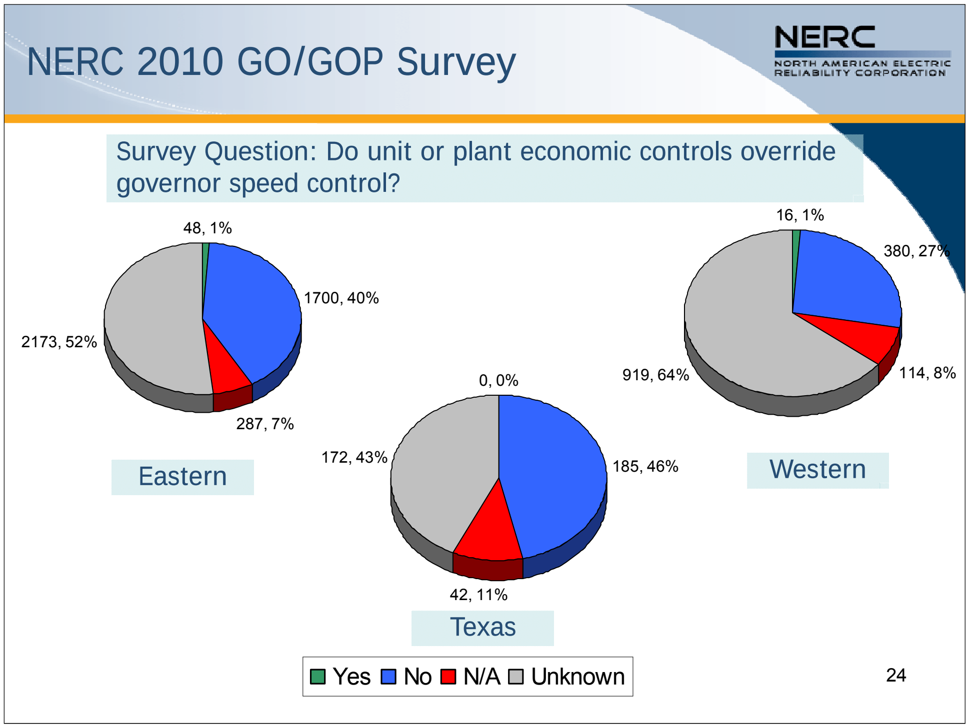

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Survey Question: Is the governor response limited by the rate of change? (Filter: Governor Yes)
470, 11%
2, 0%
949, 23%
2787, 66%
Eastern
34, 9%
2, 1%
121, 30%
242, 60%
Texas
72, 5%
0, 0%
554, 39%
803, 56%
Western
Yes No N/A Unknown
19


NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Survey Question: Are there any other unit-level or plant-level control schemes that override or limit governor performance? (Filter: Governor Yes)
337, 8%
27, 1%
2026, 48%
1818, 43%
Eastern
32, 8%
2, 1%
197, 49%
168, 42%
Texas
65, 5%
0, 0%
700, 49%
664, 46%
Western
Yes No N/A Unknown
20

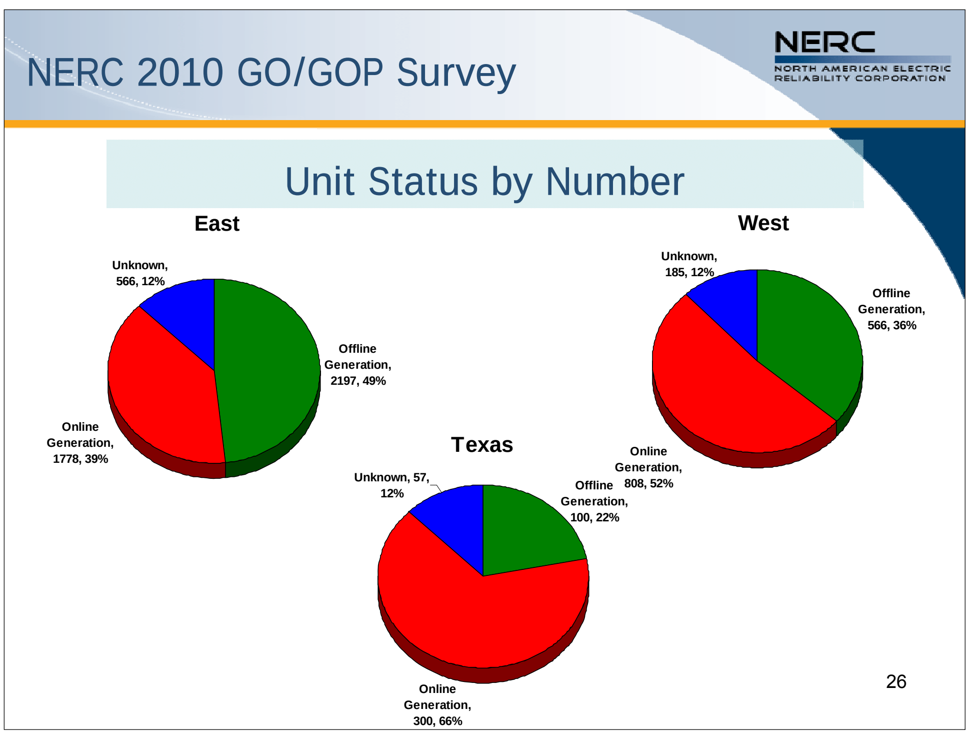

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Survey Question: Do market rules restrict or override governor speed controls? (Filter: Governor Yes)
206, 5%
23, 1%
13, 0%
3966, 94%
Eastern
4, 1%
2, 1%
1, 0%
392, 98%
Texas
28, 2%
7, 0%
0, 0%
1394, 98%
Western
Yes No N/A Unknown
21

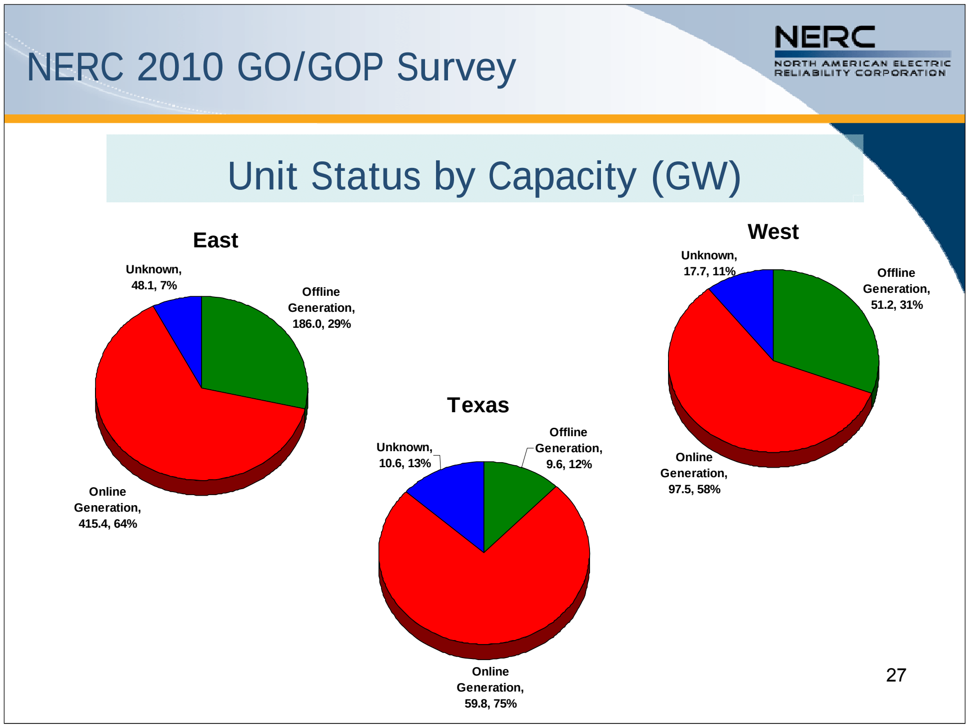

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Survey Question: Does the boiler control or combined cycle central control have a frequency input?
298, 7%
1549, 37%
322, 8%
2039, 48%
Eastern
79, 20%
146, 36%
50, 13%
124, 31%
Texas
46, 3%
414, 29%
77, 5%
892, 63%
Western
Yes
No
N/A
Unknown
22

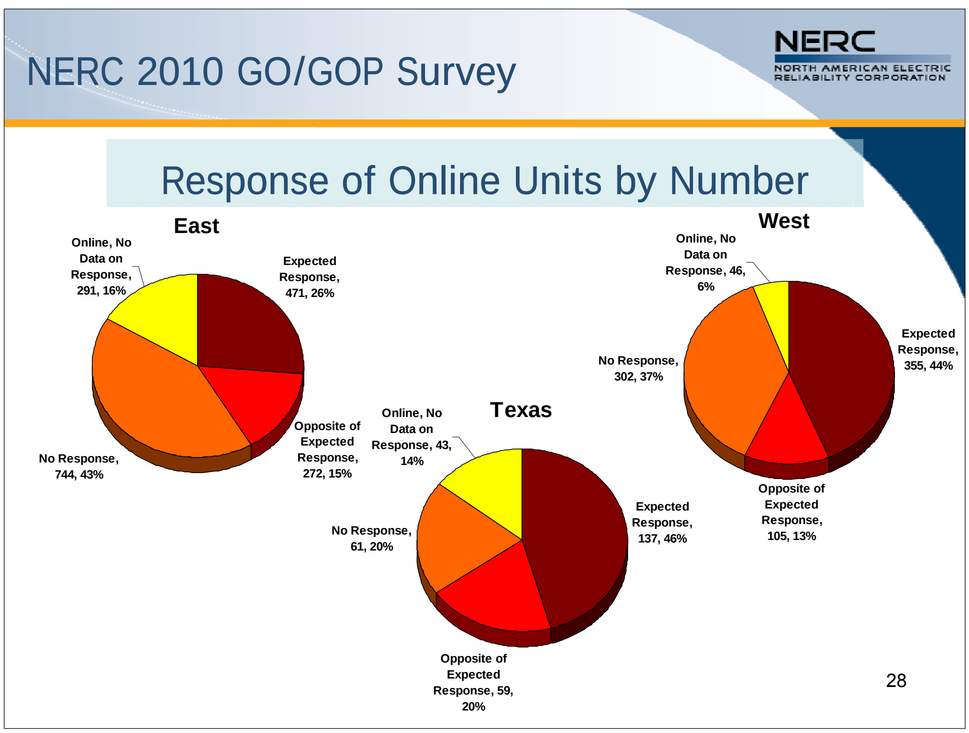

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Survey Question: Does the boiler operate under variable pressure?
394, 9%
1030, 24%
353, 8%
2431, 59%
Eastern
72, 18%
68, 17%
65, 16%
194, 49%
Texas
151, 11%
169, 12%
127, 9%
982, 68%
Western
Yes
No
N/A
Unknown
23

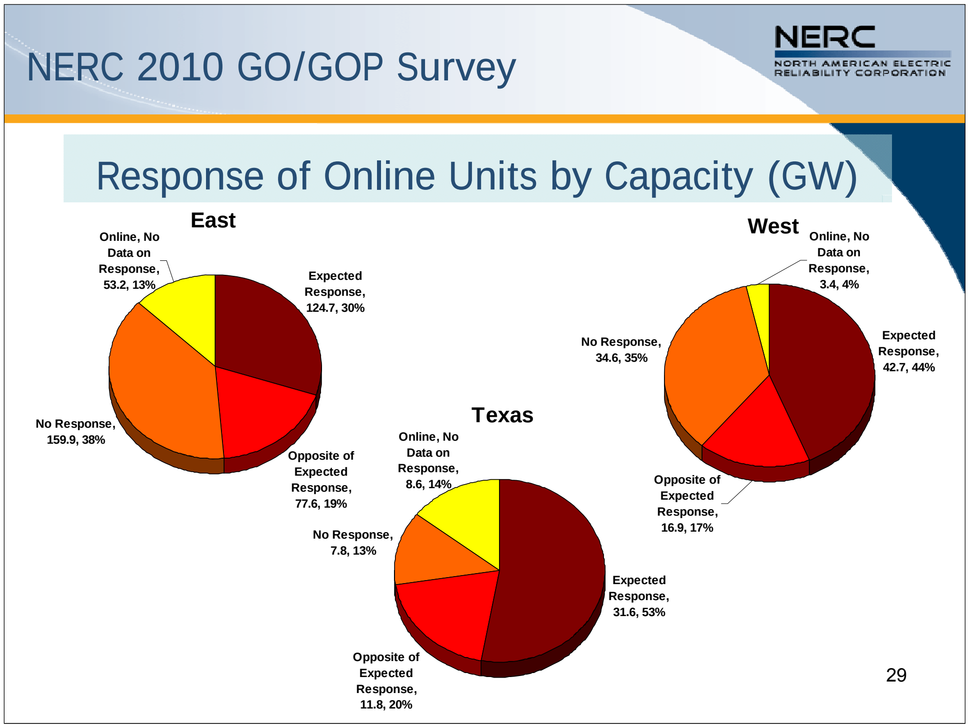


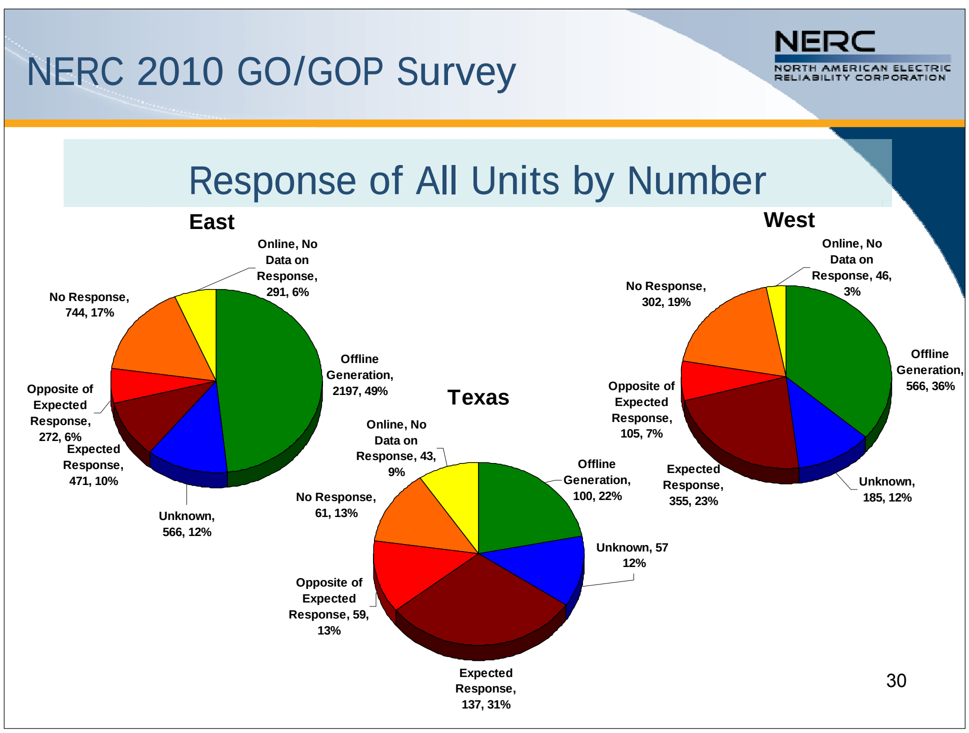
Survey Event Data

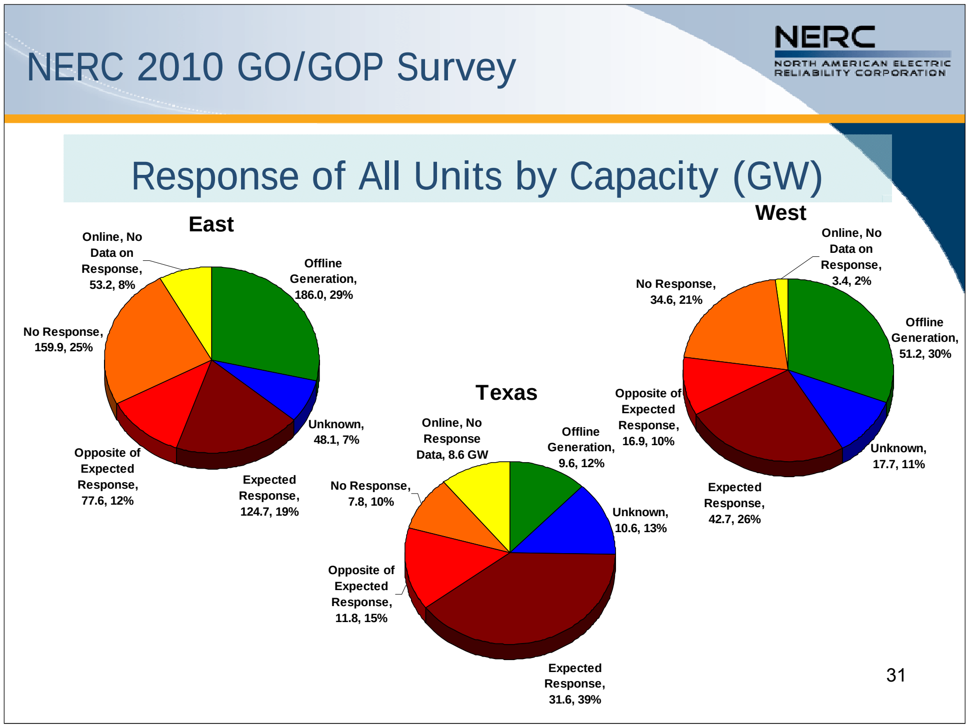



NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Unit Status by Capacity (GW)
East
Unknown, 48.1, 7%
Offline Generation, 186.0, 29%
Online Generation, 415.4, 64%
Texas
Unknown, 10.6, 13%
Offline Generation, 9.6, 12%
Online Generation, 59.8, 75%
West
Unknown, 17.7, 11%
Offline Generation, 51.2, 31%
Online Generation, 97.5, 58%
27


NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Response of Online Units by Number
East
Online, No Data on Response, 291, 16%
Expected Response, 471, 26%
Opposite of Expected Response, 272, 15%
No Response, 744, 43%
Texas
Online, No Data on Response, 43, 14%
Expected Response, 137, 46%
No Response, 61, 20%
Opposite of Expected Response, 59, 20%
West
Online, No Data on Response, 46, 6%
Expected Response, 355, 44%
No Response, 302, 37%
Opposite of Expected Response, 105, 13%
28


NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Response of Online Units by Capacity (GW)
East
Online, No Data on Response, 53.2, 13%
Expected Response, 124.7, 30%
No Response, 159.9, 38%
Opposite of Expected Response, 77.6, 19%
West
Online, No Data on Response, 3.4, 4%
No Response, 34.6, 35%
Expected Response, 42.7, 44%
Opposite of Expected Response, 16.9, 17%
Texas
Online, No Data on Response, 8.6, 14%
No Response, 7.8, 13%
Expected Response, 31.6, 53%
Opposite of Expected Response, 11.8, 20%
29


NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Response of All Units by Number
East
Online, No Data on Response, 291, 6%
No Response, 744, 17%
Offline Generation, 2197, 49%
Opposite of Expected Response, 272, 6%
Expected Response, 471, 10%
Unknown, 566, 12%
West
Online, No Data on Response, 46, 3%
No Response, 302, 19%
Offline Generation, 566, 36%
Opposite of Expected Response, 105, 7%
Expected Response, 355, 23%
Unknown, 185, 12%
Texas
Online, No Data on Response, 43, 9%
No Response, 61, 13%
Offline Generation, 100, 22%
Unknown, 57 12%
Opposite of Expected Response, 59, 13%
Expected Response, 137, 31%
30


NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Response of All Units by Capacity (GW)
East
Online, No Data on Response, 53.2, 8%
Offline Generation, 186.0, 29%
No Response, 159.9, 25%
Unknown, 48.1, 7%
Opposite of Expected Response, 77.6, 12%
Expected Response, 124.7, 19%
Texas
Online, No Response Data, 8.6 GW
Offline Generation, 9.6, 12%
No Response, 7.8, 10%
Unknown, 10.6, 13%
Opposite of Expected Response, 11.8, 15%
Expected Response, 31.6, 39%
West
Online, No Data on Response, 3.4, 2%
No Response, 34.6, 21%
Offline Generation, 51.2, 30%
Opposite of Expected Response, 16.9, 10%
Unknown, 17.7, 11%
Expected Response, 42.7, 26%
31

Appendix L – References

Training Document - Policy 1 Generation Control and Performance, February 24, 2003. NERC

Niemeyer, S. *Frequency Regulation—Is Your Plant Compliant?*
Ibrahim Abdur-Rahman, Sydney & Ricardo Vera, PE

Eto, J.H. et al. 2010. *Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation*. LBNL-4143E. Berkeley: Lawrence Berkeley National Laboratory

Analysis of Eastern Interconnection Frequency Response, February 2011. NERC