UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Mandatory Reliability Standards	**)**	**Docket No. RM06-16-010**
for the Bulk-Power System	**)**	**RM06-16-011**

QUARTERLY REPORT OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION ON STATUS OF DEVELOPMENT OF BAL-003

On March 30, 2012, the North American Electric Reliability Corporation ("NERC") filed with Federal Energy Regulatory Commission ("FERC" or the "Commission") a motion for an extension of time to submit a revised Resource and Demand Balancing ("BAL") Reliability Standard on Frequency Response and Frequency Bias, BAL-003 ("Motion for an Extension of Time"). On May 4, 2012, the Commission issued an order[1] establishing a compliance schedule for NERC to submit a revised BAL-003 consistent with the Commission's directives in Order No. 693.[2] The Commission established a deadline of May 31, 2013, and directed the submission of informational reports on a quarterly basis describing "the progress NERC is making toward completing its analysis and research as well as the progress it is making in completing work on the other issues and filing a revised BAL-003-0 Reliability Standard by May 31, 2013."[3] The instant filing is submitted in compliance with this directive.

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1 *Mandatory Reliability Standards for the Bulk-Power System*, 139 FERC ¶61,097 (2012)("May 4 Order").

2 *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at PP 369-375, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007). *See also Mandatory Reliability Standards for the Bulk-Power System*, 130 FERC ¶ 61,218, *order on reh'g*, 131 FERC ¶ 61,136, *order on compliance filing*, 133 FERC ¶ 61,212 (2010).

3 May 4 Order at P 9.

I. Notices and Communication

Notices and communications with respect to this filing may be addressed to the following:[4]

Gerald W. Cauley
President and Chief Executive Officer
3353 Peachtree Road NE
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Atlanta, GA 30326-1001

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Assistant General Counsel for Standards and Critical Infrastructure Protection

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II. Attachments

Attachment A	Technical Conference Agendas
Attachment B	Presentations from the Frequency Response Technical Conferences
Attachment C	Project 2007-12 – Frequency Response – Drafting Team Meeting Notes
Attachment D	Project 2007-12 – Frequency Response – Project Schedule

III. Status of BAL-003 Standard Development Efforts

NERC notes that it continues to support simultaneous Commission, NERC and industry efforts to develop a market solution in parallel with a frequency response Reliability Standard rather than attempting to resolve this issue in isolation with a Reliability Standard alone.

[4] Persons to be included on FERC's service list are indicated with an asterisk. NERC requests waiver of 18 C.F.R. § 385.203(b) to permit the inclusion of more than two people on the service list.

In the quarter following the May 4 Order, there were (i) two technical conferences with an opportunity to submit comments, and (ii) one drafting team meeting and two conference calls were held as described in further detail below.

As outlined in NERC's Motion for an Extension of Time, technical conferences were held on May 22, 2012, in Arlington, Virginia and on May 24, 2012, in Denver, Colorado. Slides from the presentations are available on the NERC website and the final agenda for both conferences is included herein as **Attachment A**.[5] **Attachment B** includes a selection of the slides presented at the conferences. Following the technical conferences, a comment period on the issues raised at the technical conferences was held from May 30 – June 15, 2012. The Project 2007-12 – Frequency Response standard drafting team met from June 21-22, 2012, in Carmel, Indiana and discussed these comments and the issues raised by attendees at the technical conferences. Specific information regarding the issues discussed at these meetings is included herein at **Attachment C**. Conference calls were held by the drafting team on July 9-10, 2012. Going forward, a drafting team is scheduled to be held from August 2-3, 2012, in Atlanta, Georgia. A project schedule is maintained on the NERC website and is publicly available.[6] *See* **Attachment D**.

Statistical analysis of the variability of frequency for each interconnection are underway using 1-second frequency data from 2007 through 2011, down-sampled from phasor measurement units ("PMUs") and frequency data recorders ("FDRs"). This analysis will be used in the determination of frequency response margins for the interconnection frequency response obligations ("IFROs"). Additional regression analysis of frequency response performance is also underway and will be presented to the frequency response working group and the Resources

[5] Available here: http://www.nerc.com/filez/standards/Frequency_Response-RF.html.

[6] *Id.*

Subcommittee at their July 25-26, 2012 meeting. The results of those analyses will be included in the report "The Reliability Role of Primary Frequency Response" (working title) to be presented for approval to the NERC Planning Committee in September 2012.

Dynamic testing of Eastern Interconnection generation loss scenarios is also underway to examine the susceptibility of the Florida 59.7 Hz UFLS setpoint to large-scale generation trips near the Florida border. This analysis will help determine the minimum frequency target to be used for the Eastern Interconnection IFRO, and will be completed in August, 2012. Additional dynamic verification of the IFROs for each interconnection will be performed when those targets are finalized for the BAL-003 filing.

IV. Conclusion

The North American Electric Reliability Corporation respectfully requests that the Commission accept this Compliance Filing in accordance with the Commission's directive in the May 4 Order.

Respectfully submitted,

/s/ Stacey Tyrewala

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stacey.tyrewala@nerc.net

Dated: July 31, 2012

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 31st day of July, 2012.

/s/ Stacey Tyrewala

Stacey Tyrewala

Attorney for North American Electric Reliability Corporation

Attachment A

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Frequency Response Technical Conference

Tuesday May 22, 2012 | 9:00 a.m. – 5:00 p.m. ET
Crystal Gateway Marriott
1700 Jefferson Davis Highway
Arlington, VA 22202

Welcome and Introduction
Herb Schrayshuen, North American Electric Reliability Corporation

NERC Antitrust Compliance Guidelines and Public Announcement

Agenda

Morning Session

1. **Frequency Response and Frequency Bias Setting Basics**
   a. Presenter - Howard Illian, Energy Mark, Inc.
   b. Bob Cummings, North American Reliability Corporation
   c. Don Badley, Northwest Power Pool
   d. Gerry BecKerle, AmerenReview Bob Cummings Presentation
2. **The Need For a Frequency Response Standard**
   a. Presenter - Bob Cummings, North American Reliability Corporation
   b. David Lemmons, Xcel Energy
3. **Explanation of the Current Version of BAL-003-1**
   a. Presenter - Terry Bilke, Midwest Independent System Operator
   b. Sydney Niemeyer, NRG Energy
   c. Sandip Sharma. ERCOT
   d. David Lemmons. Xcel Energy

4. **Minimum Frequency Bias Setting**
    a. Presenter - Howard Illian, Energy Mark, Inc.
    b. Don Badley, Northwest Power Pool
    c. Terry Bilke, Midwest Independent System Operator
    d. Robert Cummings, North American Electric Reliability Corporation

Afternoon Session

5. **The Responsible Entitiy for Frequency Response**
    a. Presentation - David Lemmons, Xcel Energy
    b. Clyde Loutan, California Independent System Operator
    c. Chris Schaeffer, Duke Energy
    d. Don Tench, Consultant
    e. Ruston Ogburn, PJM
    f. Brendan Kirby, Consultant
6. **Measurement of Frequency Response**
    a. Presentation - Terry Bilke, Midwest Independent System Operator
    b. Howard Illian, Energy Mark, Inc.
    c. Sydney Niemeyer, NRG Energy
    d. Bob Cummings, North American Electric Reliability Corporation
7. **Open Questions/Discussion**
8. **Summary**
    a. Joe Eto, Lawrence Berkeley National Laboratory

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Frequency Response Technical Conference

Thursday May 24, 2012 | 9:00 a.m. – 5:00 p.m. MT
Xcel Energy
1800 Larimer Street, 2nd Floor
Denver, CO 80202

Welcome and Introduction
Herb Schrayshuen, North American Electric Reliability Corporation

NERC Antitrust Compliance Guidelines and Public Announcement

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    d. Bob Cummings, North American Electric Reliability Corporation
7. **Open Questions/Discussion**
8. **Summary**
    a. Stacey Tyrewala, North American Reliability Corporation

Attachment B

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Frequency Response Technical Conference

Frequency Response & Frequency Bias Setting

Howard F. Illian, President, Energy Mark, Inc.

RELIABILITY | ACCOUNTABILITY



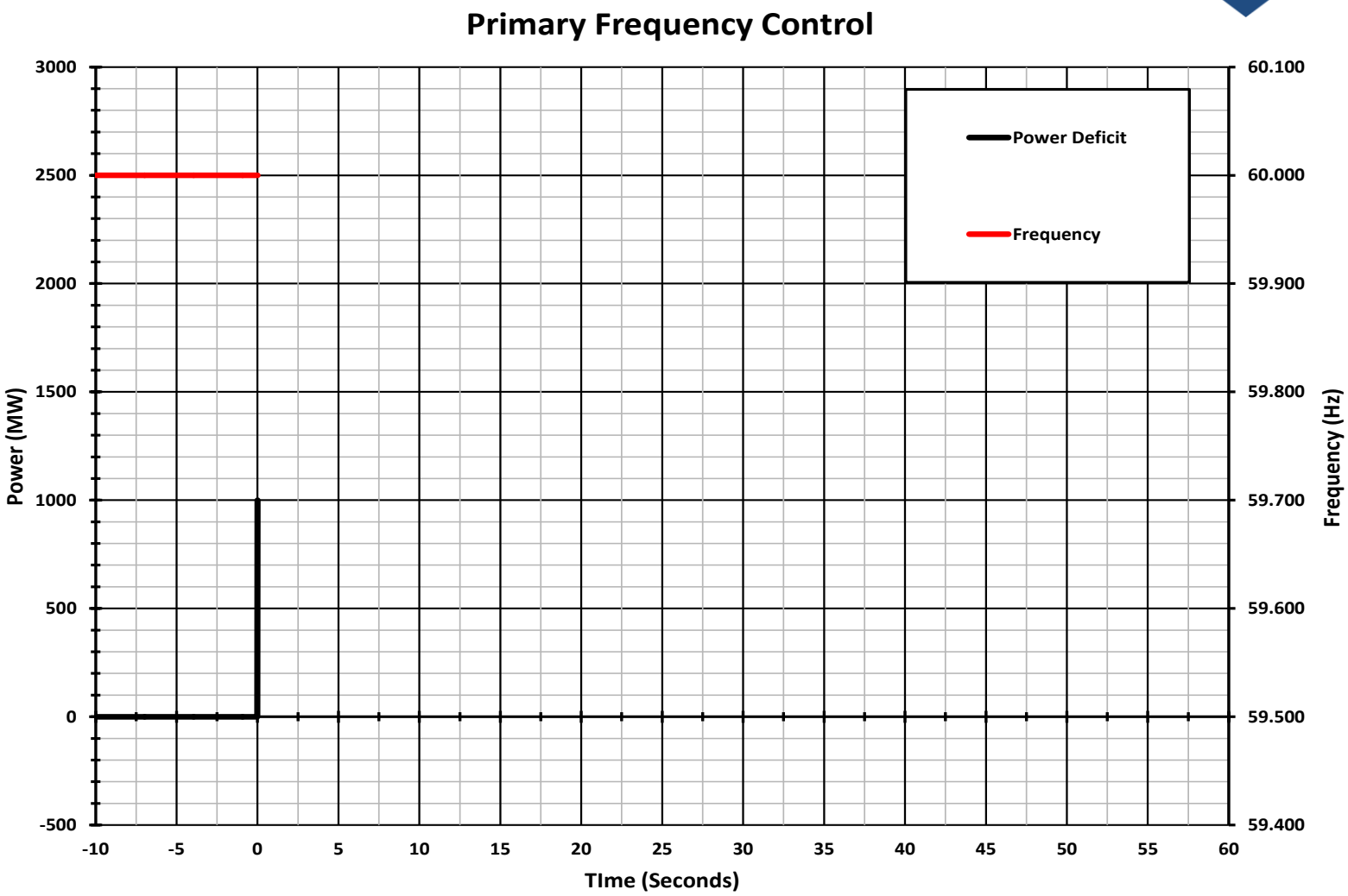

Overview

- Primary Frequency Control (PFC)
  - Disturbance Event
  - Inertial Power & Load Damping
  - Governor Response
  - Arrested Frequency Response
  - Post Disturbance Transient
  - Settled Frequency Response

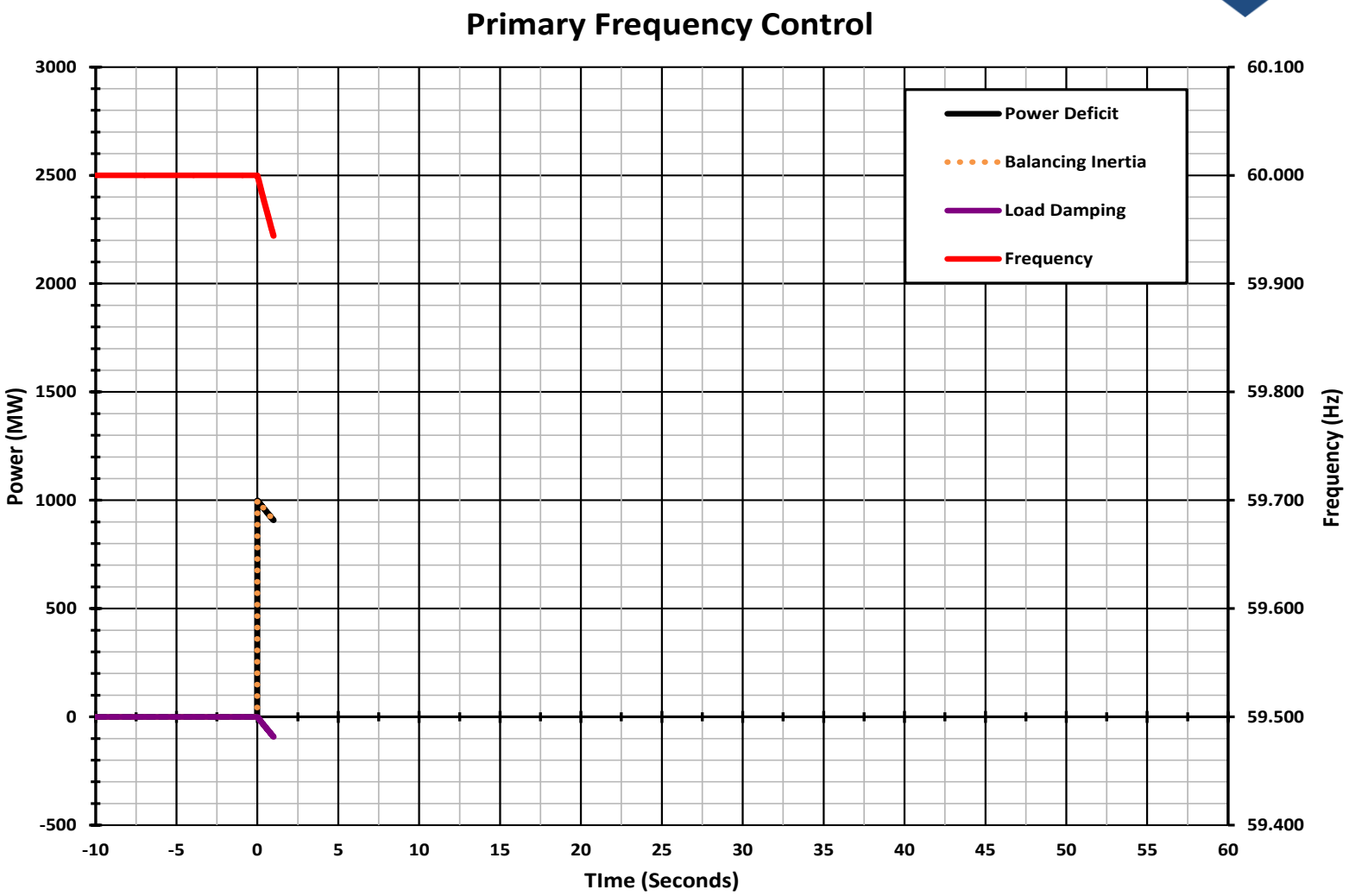
Overview (Cont.)

- Frequency Response Measurement
  - Interconnection Level
  - Balancing Authority Level
  - Individual Provider Level
- Frequency Bias Setting
  - Based on Timing of Secondary Control
  - Best Estimator: Settled Frequency Response
  - Reason for inclusion in ACE and AGC

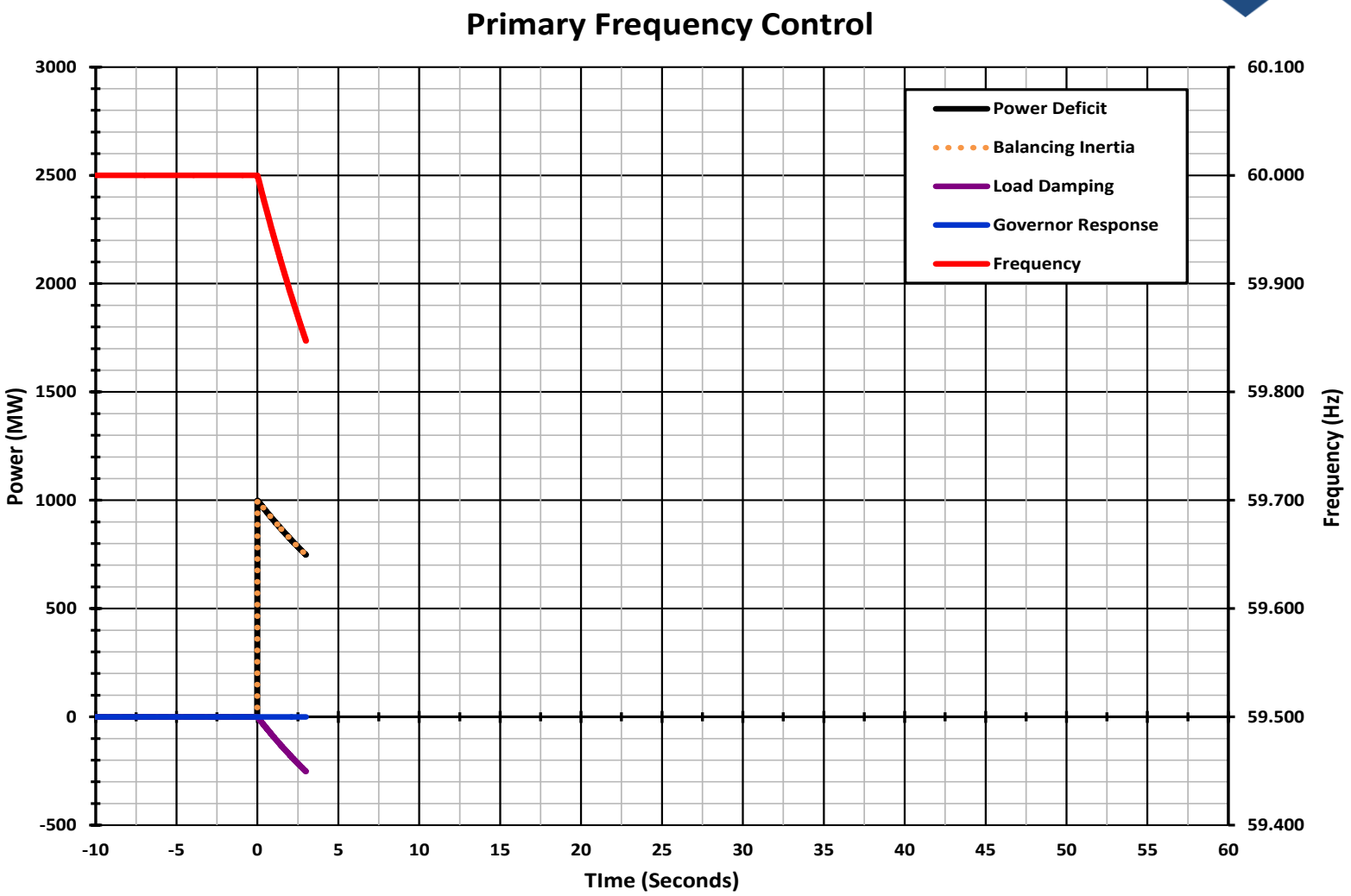
Disturbance Event



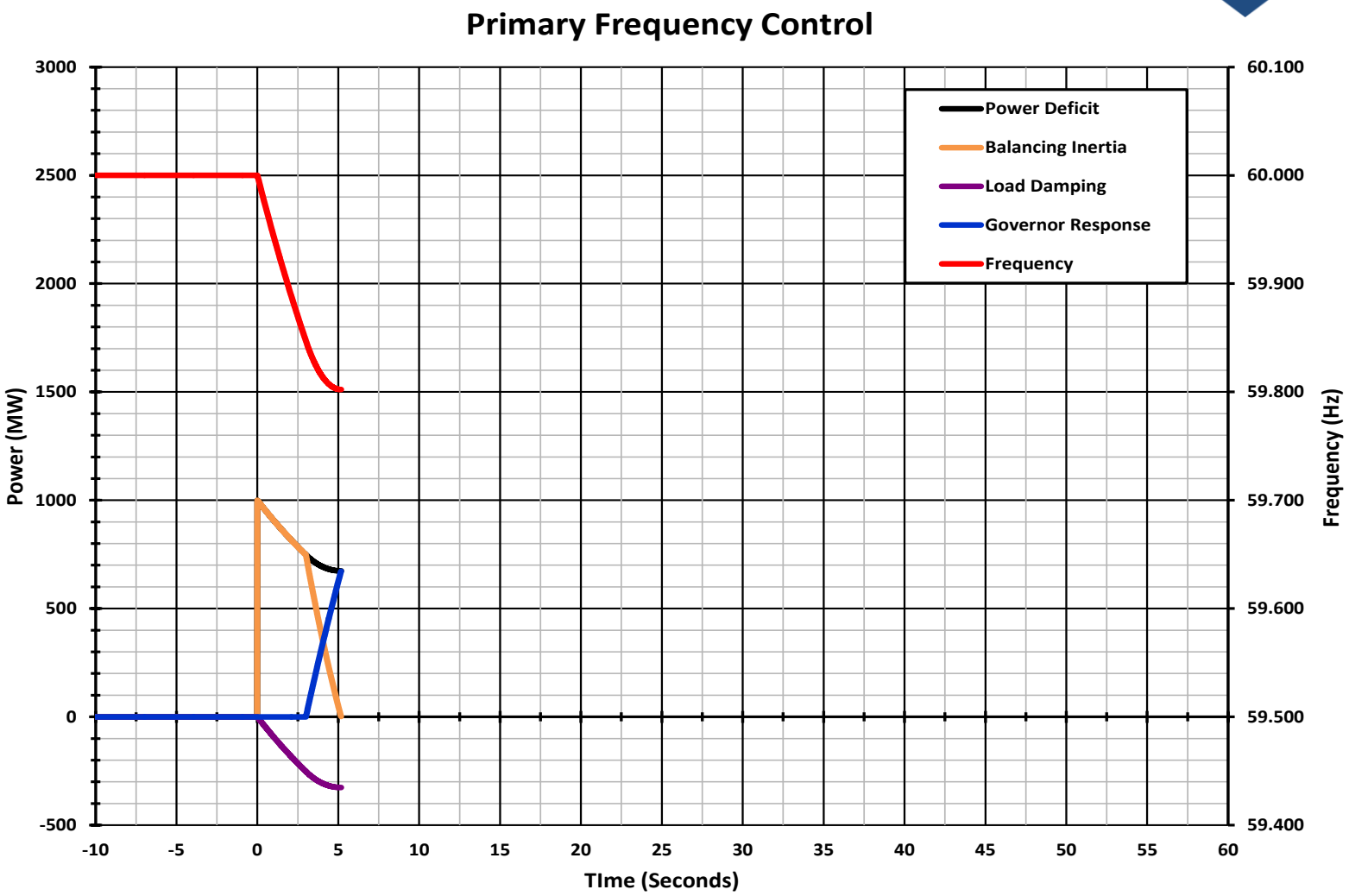
Inertial Power & Load Damping



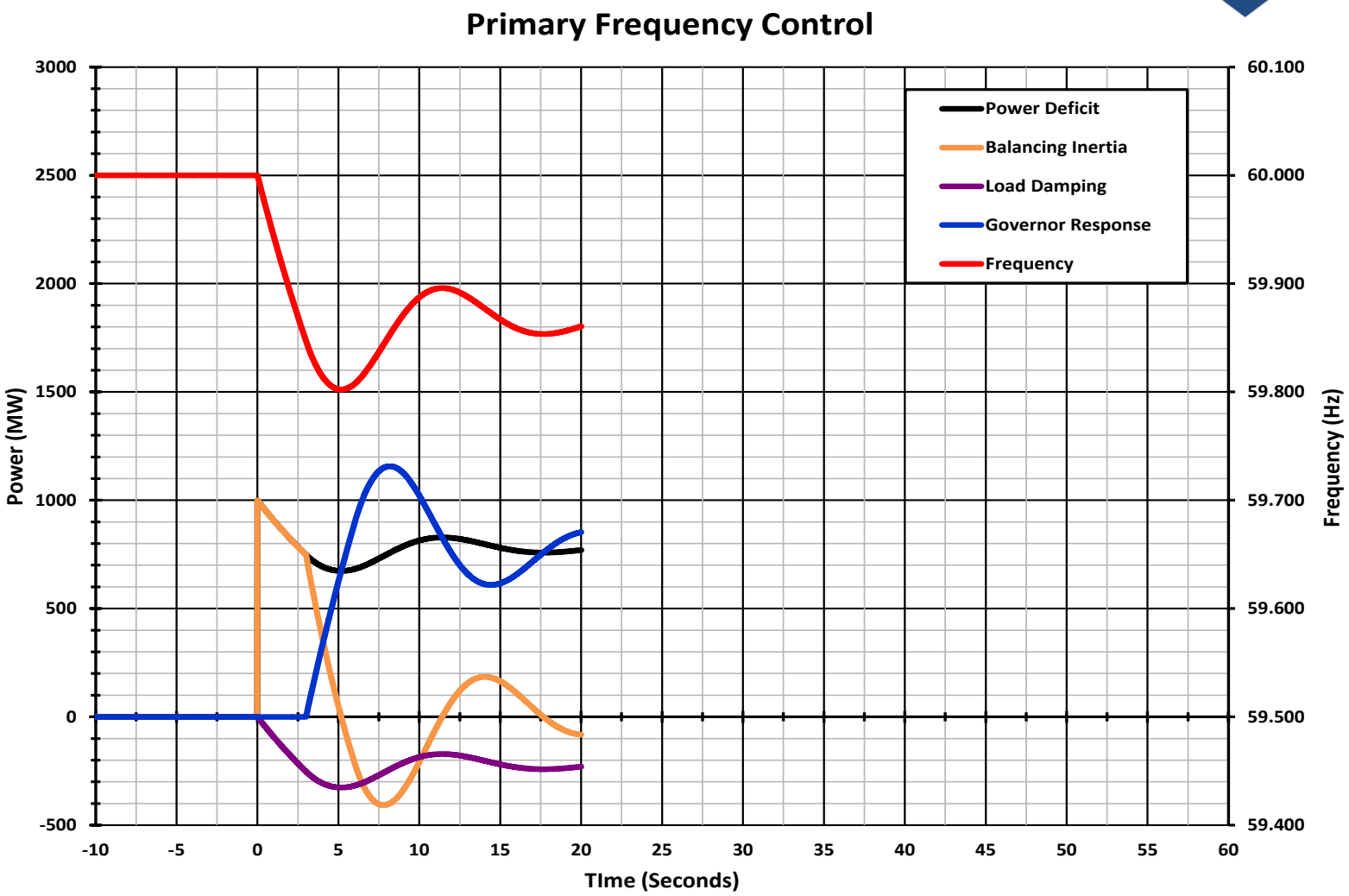
Governor Response



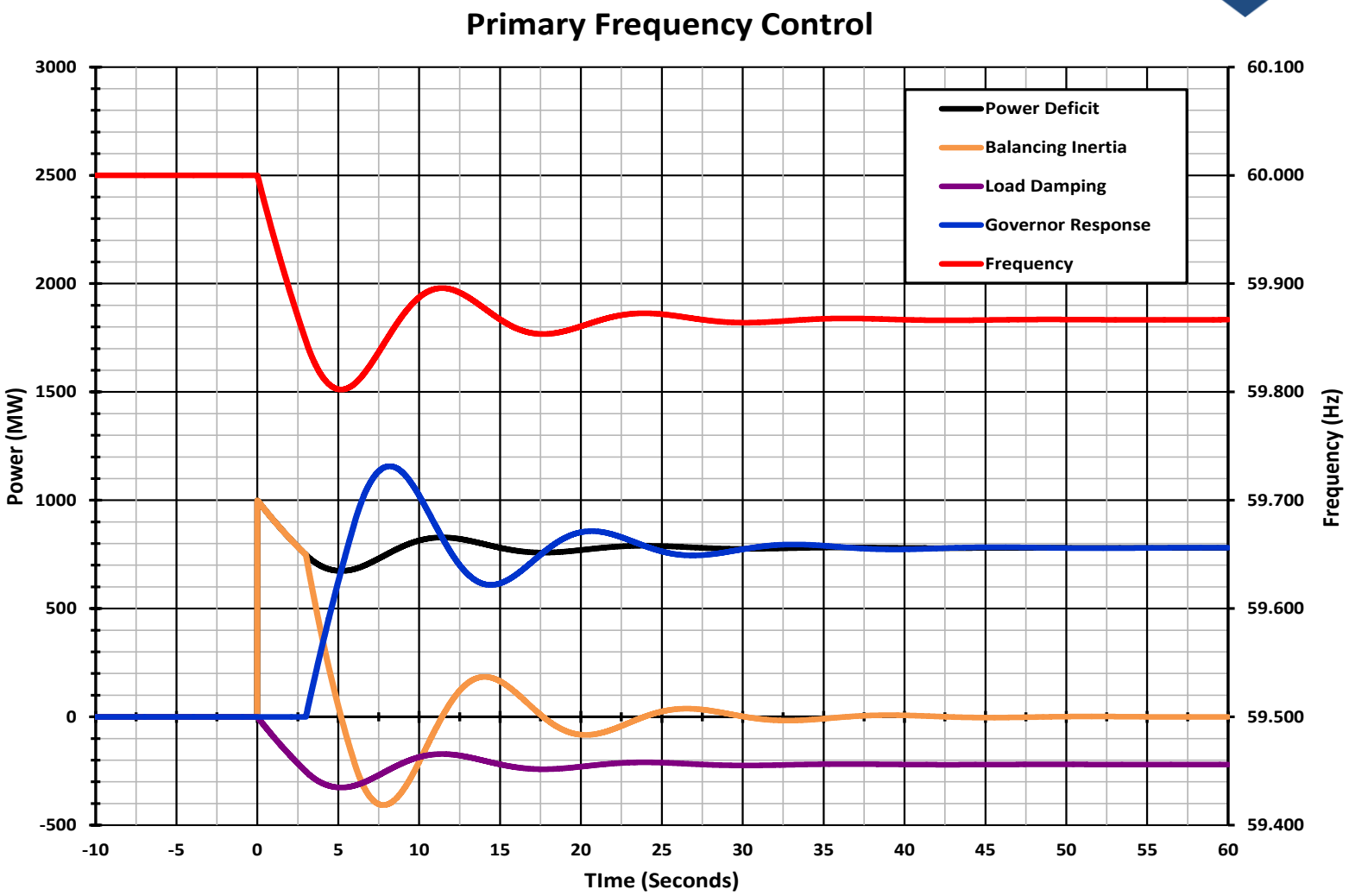
Arrested Frequency Response



Post Disturbance Transient



Settled Frequency Response



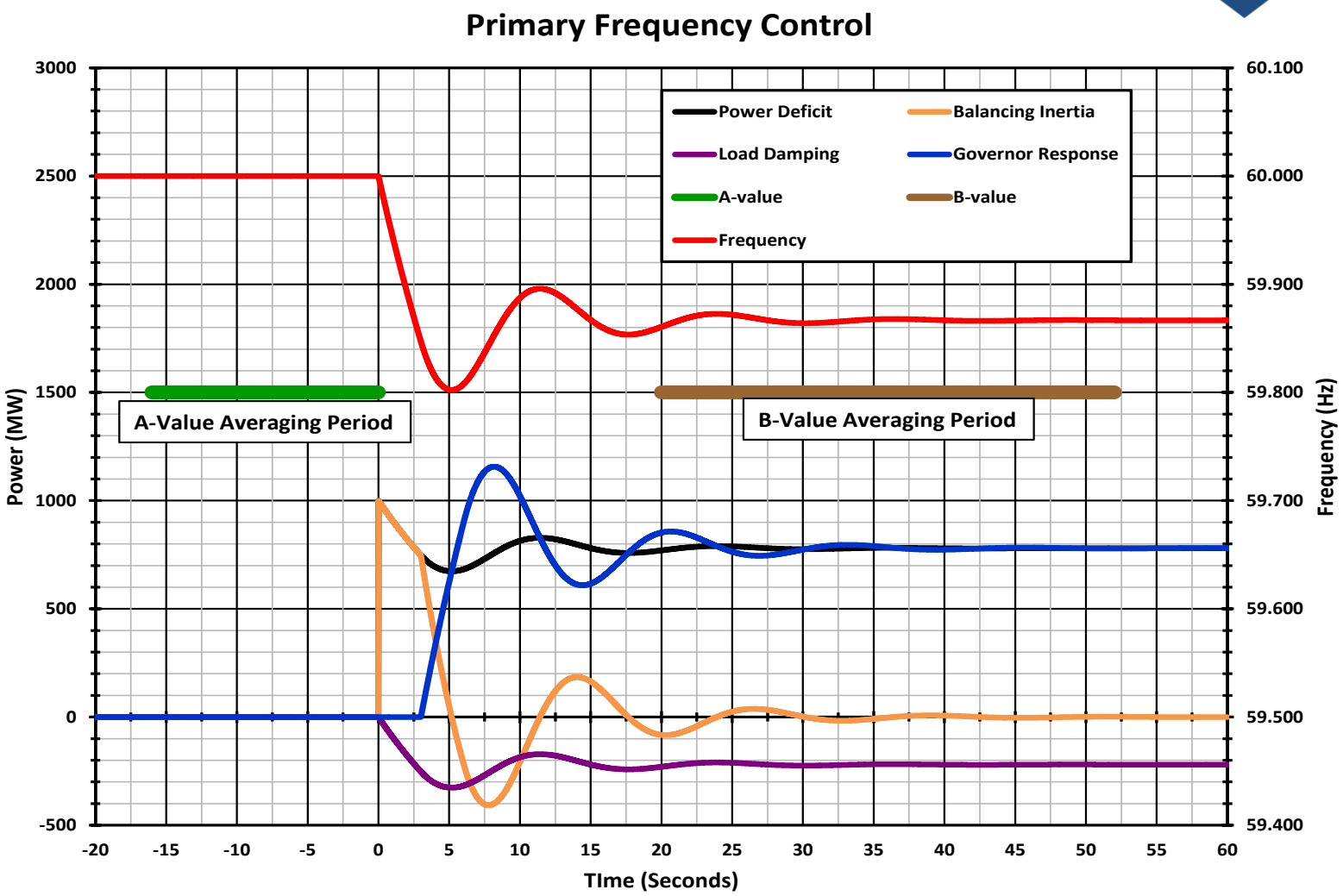
Questions

Response Measurement

- All Frequency Responses are measured as a "Change in Power (MWs)" divided by a "Change in Frequency (Hz)"
- Averaging Periods are standardized for both the Pre-disturbance period (A-Value) and the Post-disturbance period (B-Value) by scan rate*
- Frequency and Power averages use the same averaging periods for measuring a single BA response, about* -16 to 0 seconds before and +20 to +52 seconds after a disturbance

* Averaging periods vary with EMS scan rate

A & B Averaging Periods



Change in Power (MWs)

- Interconnection Level: "Sudden Change" in Generation or Load power as measured from meters local to the disturbance event
- Balancing Authority Level: Change in Actual Net Interchange (ANI) as measured with the sum of the tie-line flows from ACE
- Individual Provider Level: Change in Net Power at the point of interconnection
- Standard Averaging Periods used to calculate A-Value average & B-Value average

Change in Frequency (Hz)

- Average frequency is the same for all regions of an Interconnection for time averages greater than a few seconds
- Change in Frequency (Hz) measured value is similar for measurements at all levels
  - Interconnection
  - Balancing Authority
  - Individual Provider
- Standard Averaging Periods used to calculate A-Value average & B-Value average

Measurement Limitations

- Arrested Frequency Response
  - C-Value can vary from region to region
  - Maximum 6 second scan rate for EMS
  - EMS cannot measure C-value accurately
  - Estimate Arrested Frequency Response from Settled Frequency Response (A-C/A-B ratio)
- Settled Frequency Response used to:
  - Estimate Frequency Response Measure
  - Determine Frequency Response Obligation compliance
  - Estimate Frequency Bias Setting

Frequency Bias Setting

- Based on Secondary Control Timing
  - Begins after Primary Control Transient (+20 seconds)
  - Early Secondary Control risks Frequency Instability
- Settled Frequency Response
  - Used to estimate Frequency Bias Setting
  - Biases the ACE for Dispatcher Situational Awareness
  - Discourages withdrawal of Primary Control by AGC

Questions

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Frequency Response Technical Conference

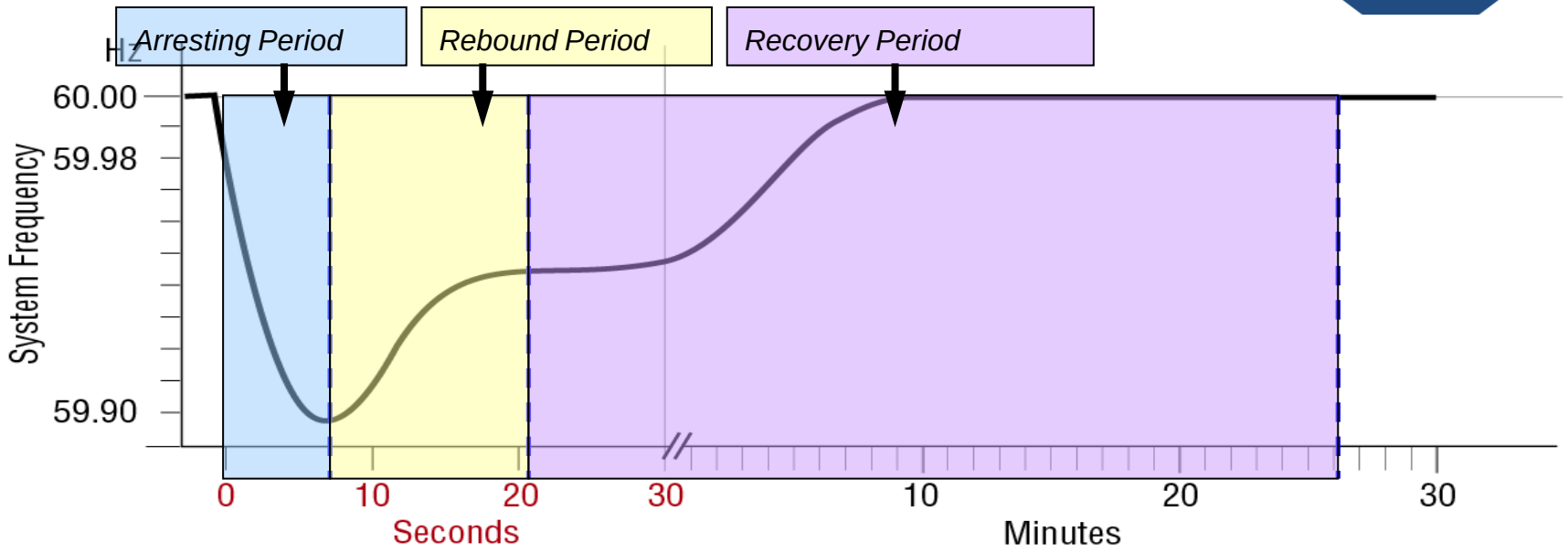
Frequency Response Trends

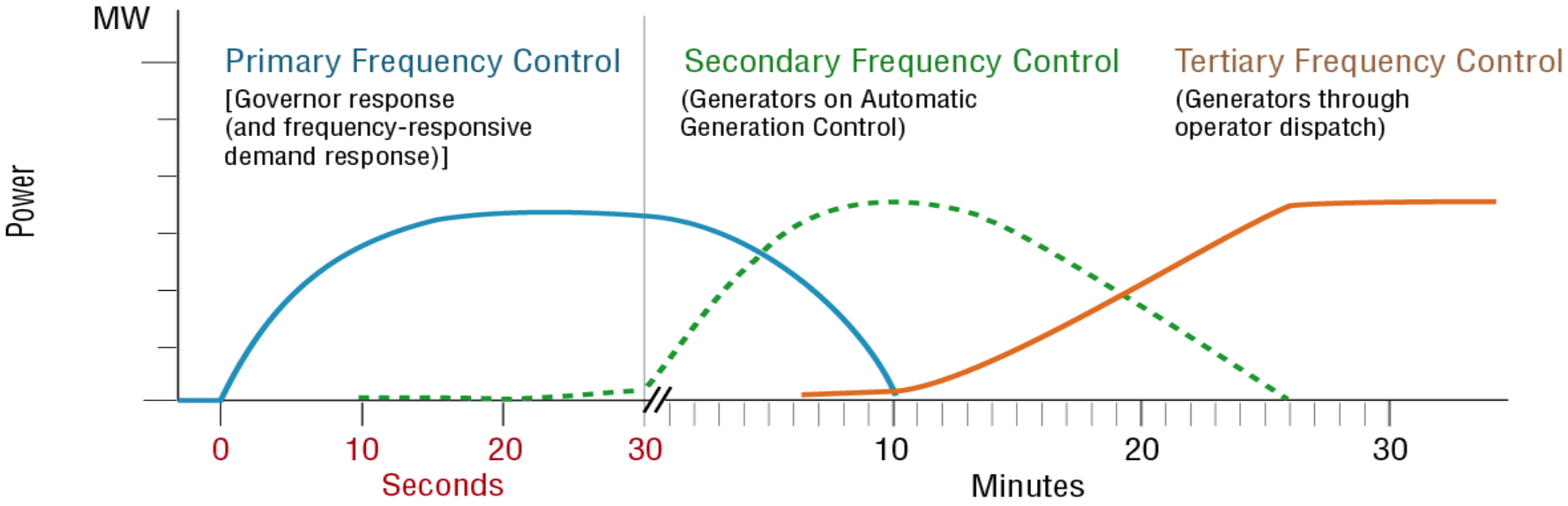
Robert W. Cummings – NERC

RELIABILITY | ACCOUNTABILITY

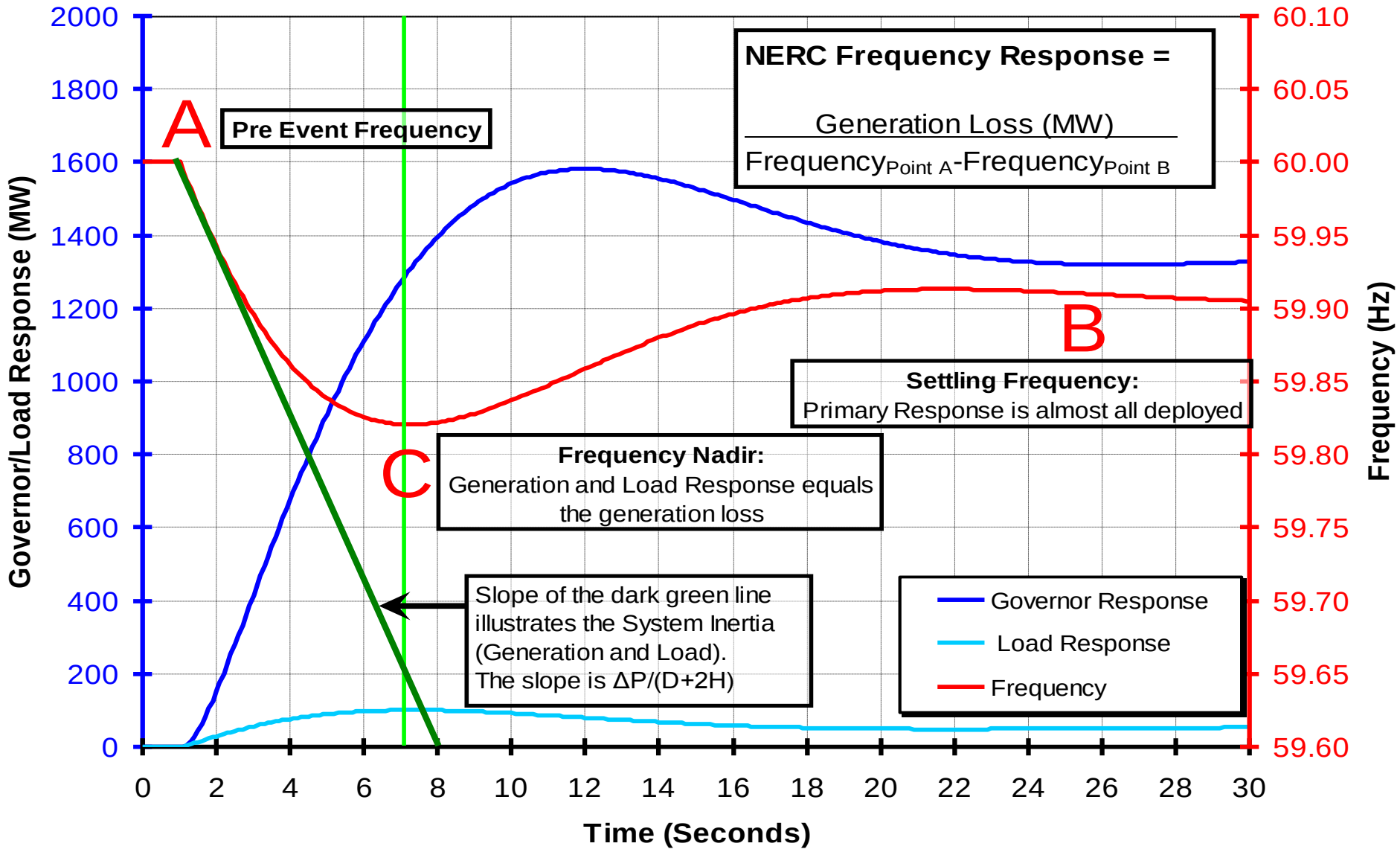



Frequency Response Performance





Frequency Response Basics



Frequency Drop Slope

Slope of frequency excursion – determined by the inertia of the system

$$Slope = \frac{\Delta Power}{D + 2H}$$

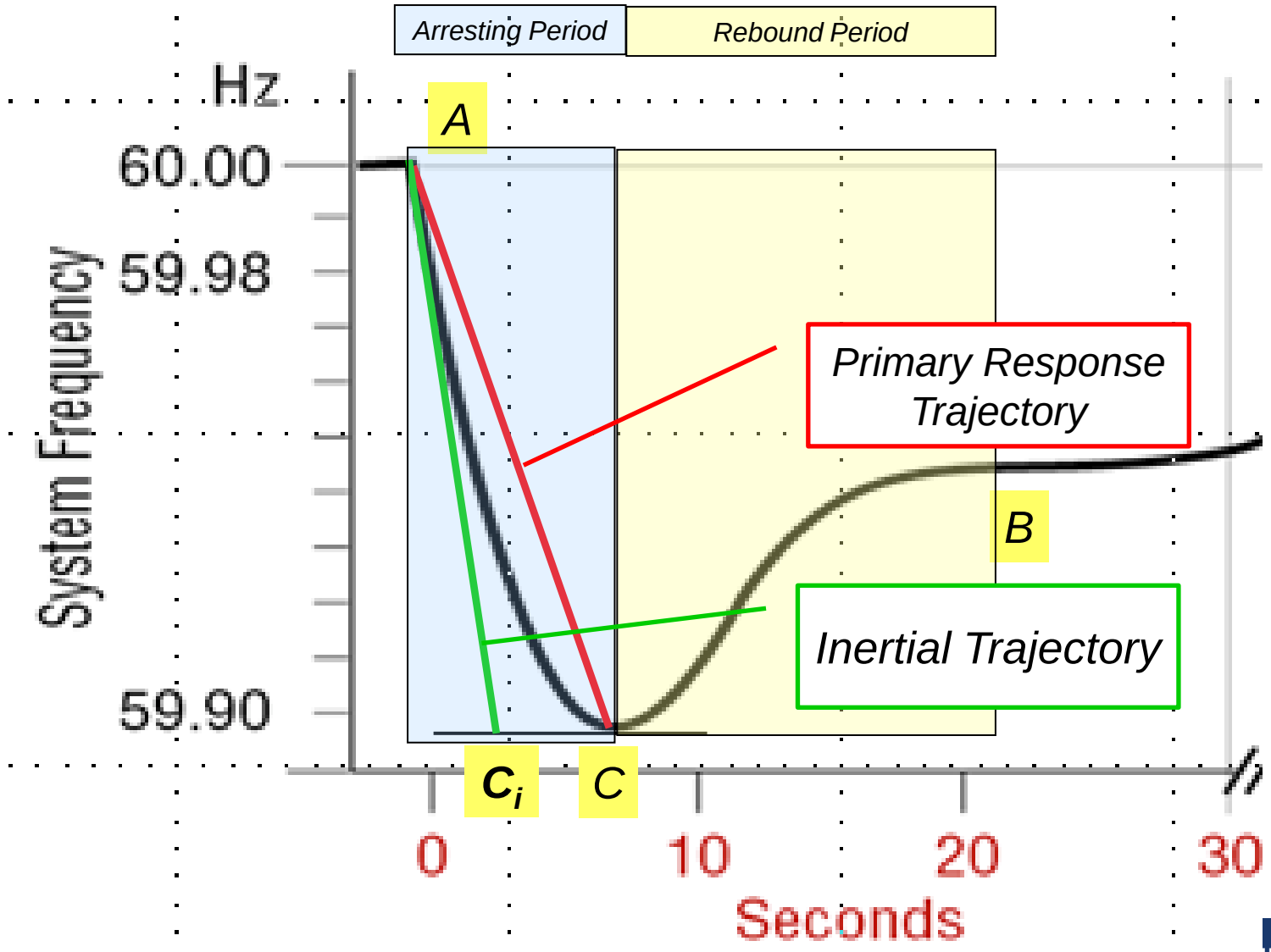
Where D = Load Damping Factor

Range of 0 to 2, where 2 = all motors

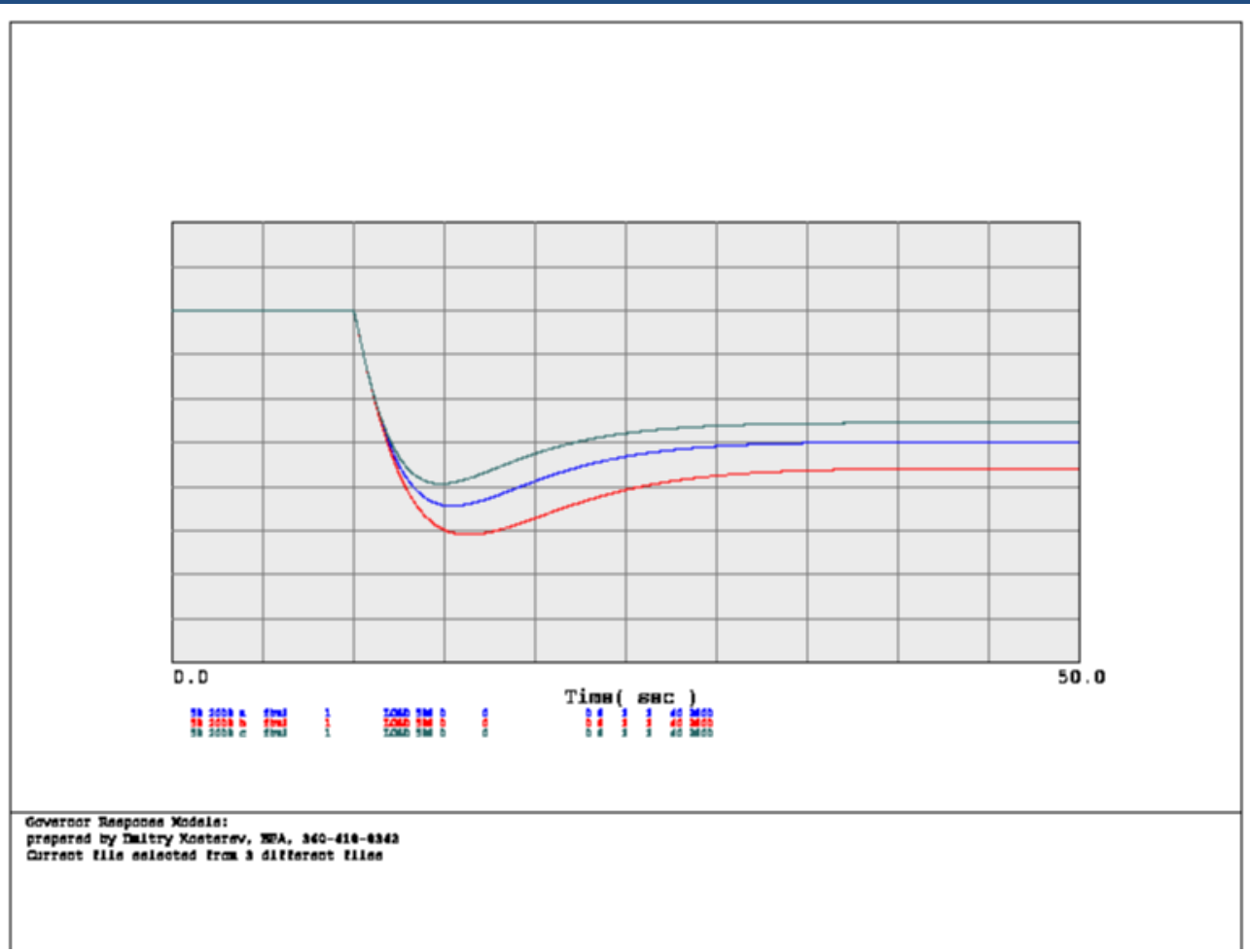
And H = Inertia Constant of the system

Range of 2.5 to 6.5

Arresting Period Analysis



Importance of Deployment Rate

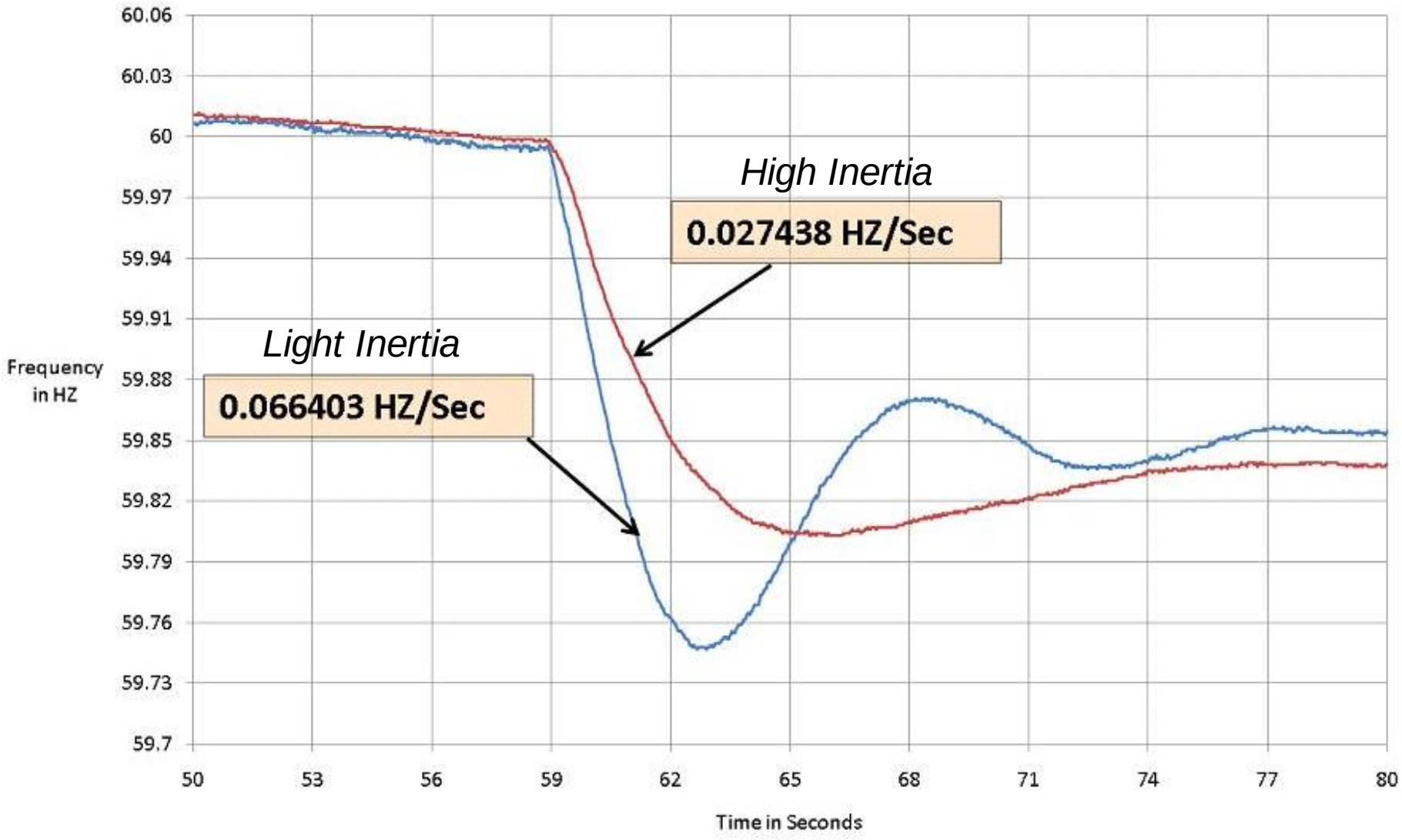


20 GW of generating capacity (red)

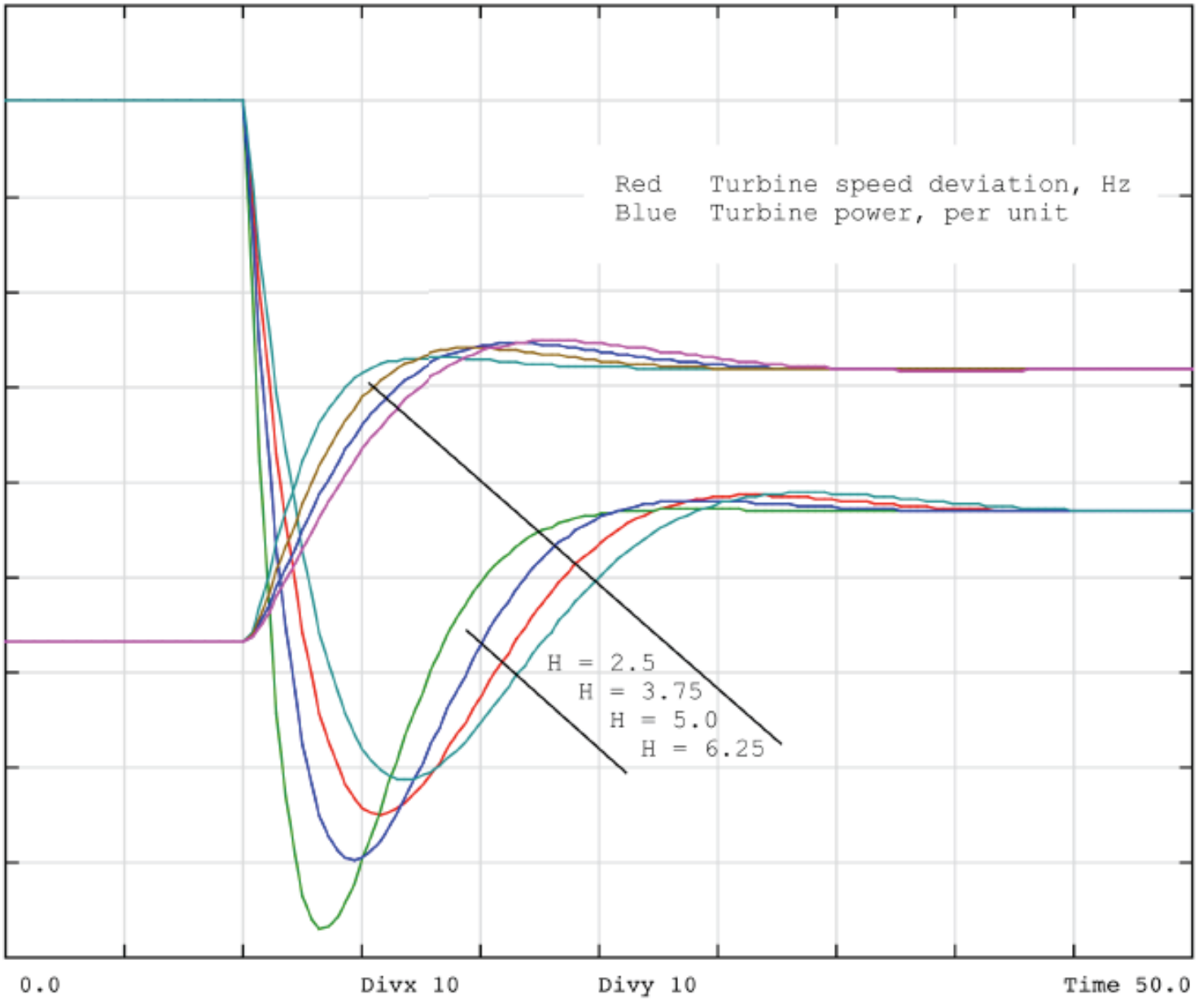
25 GW of generating capacity (blue)

30 GW of generating capacity (green)

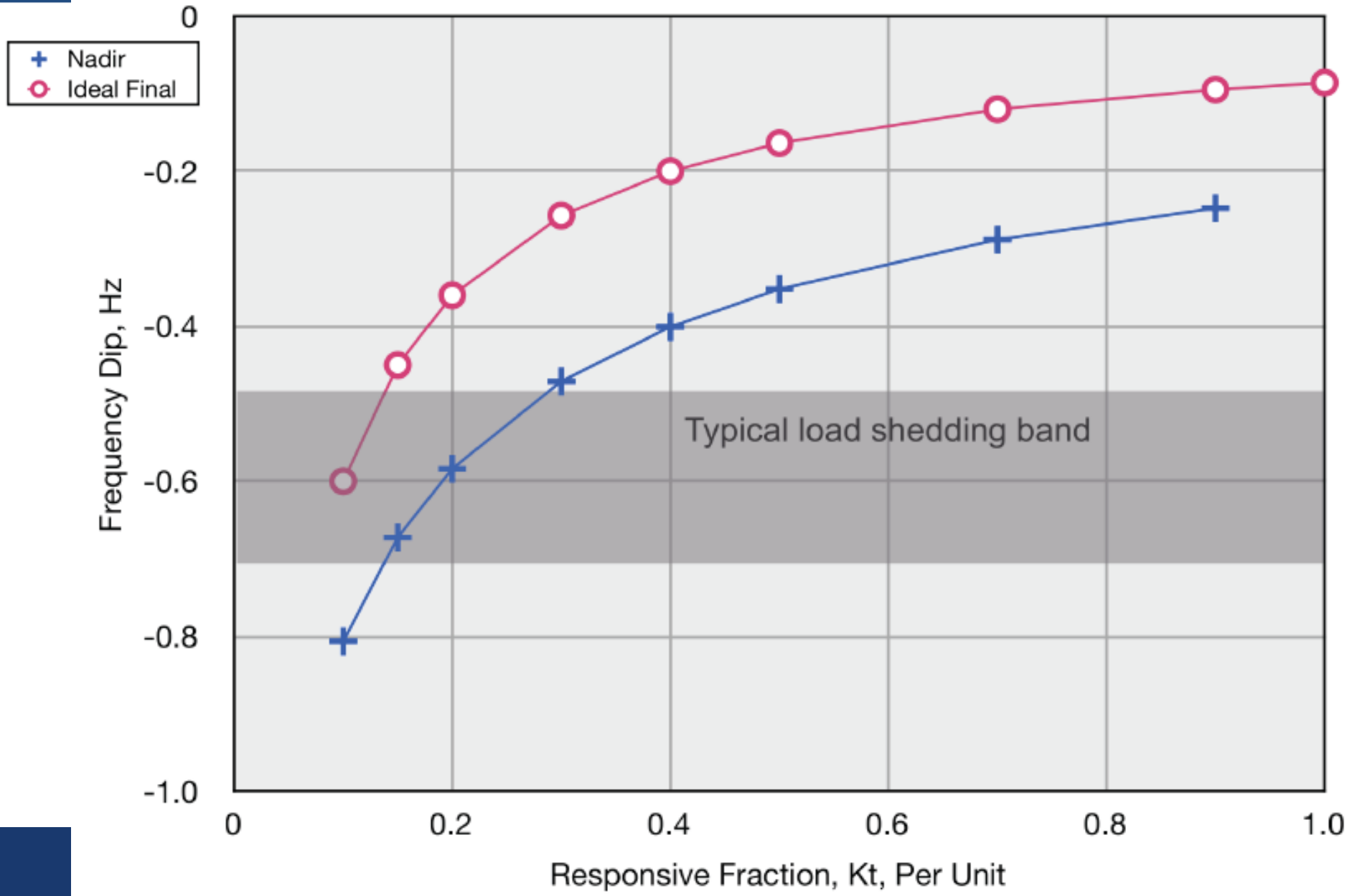
Inertial Response Sensitivity



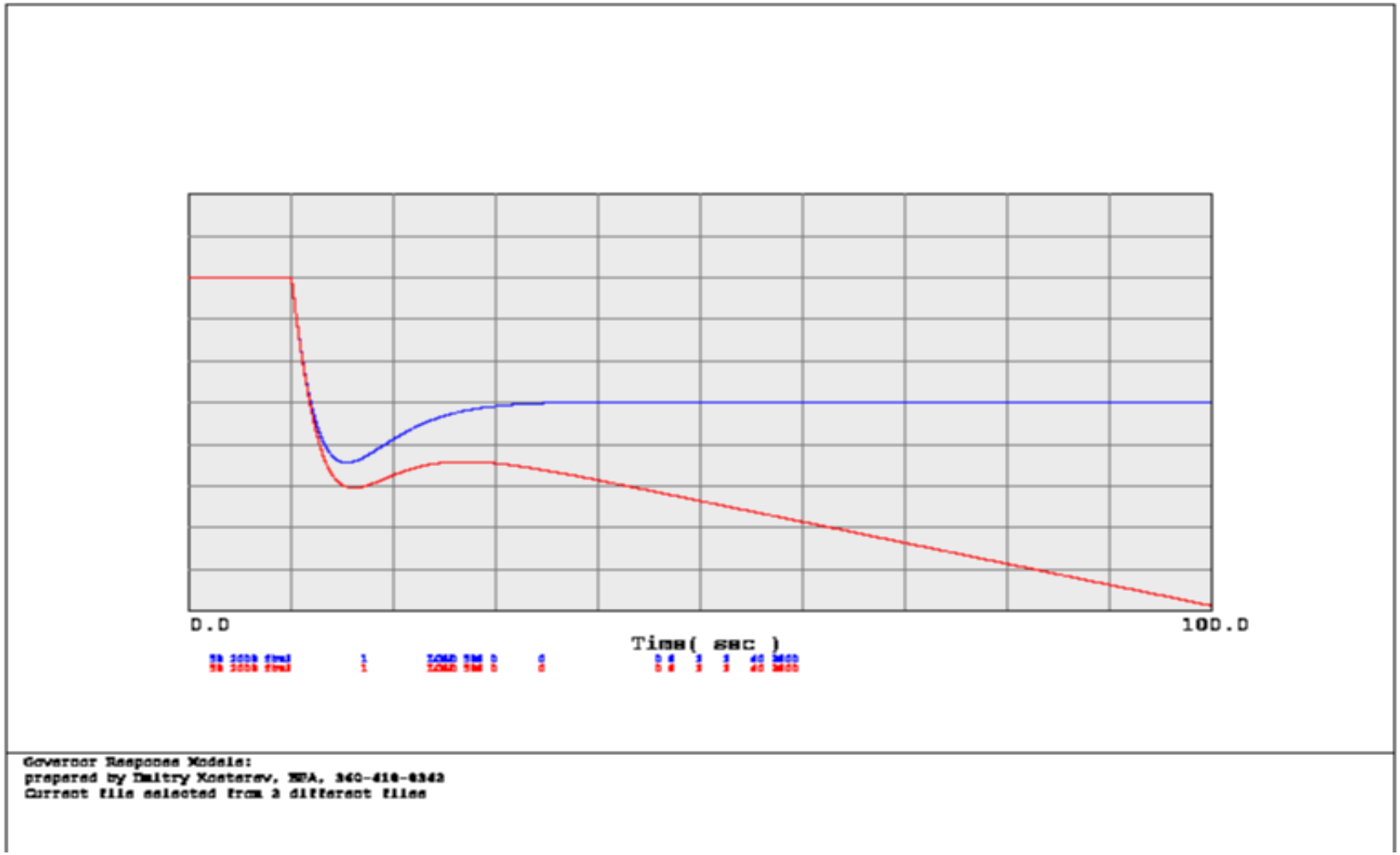
Sensitivity to System Inertia



% of Gen. PFR versus Nadir



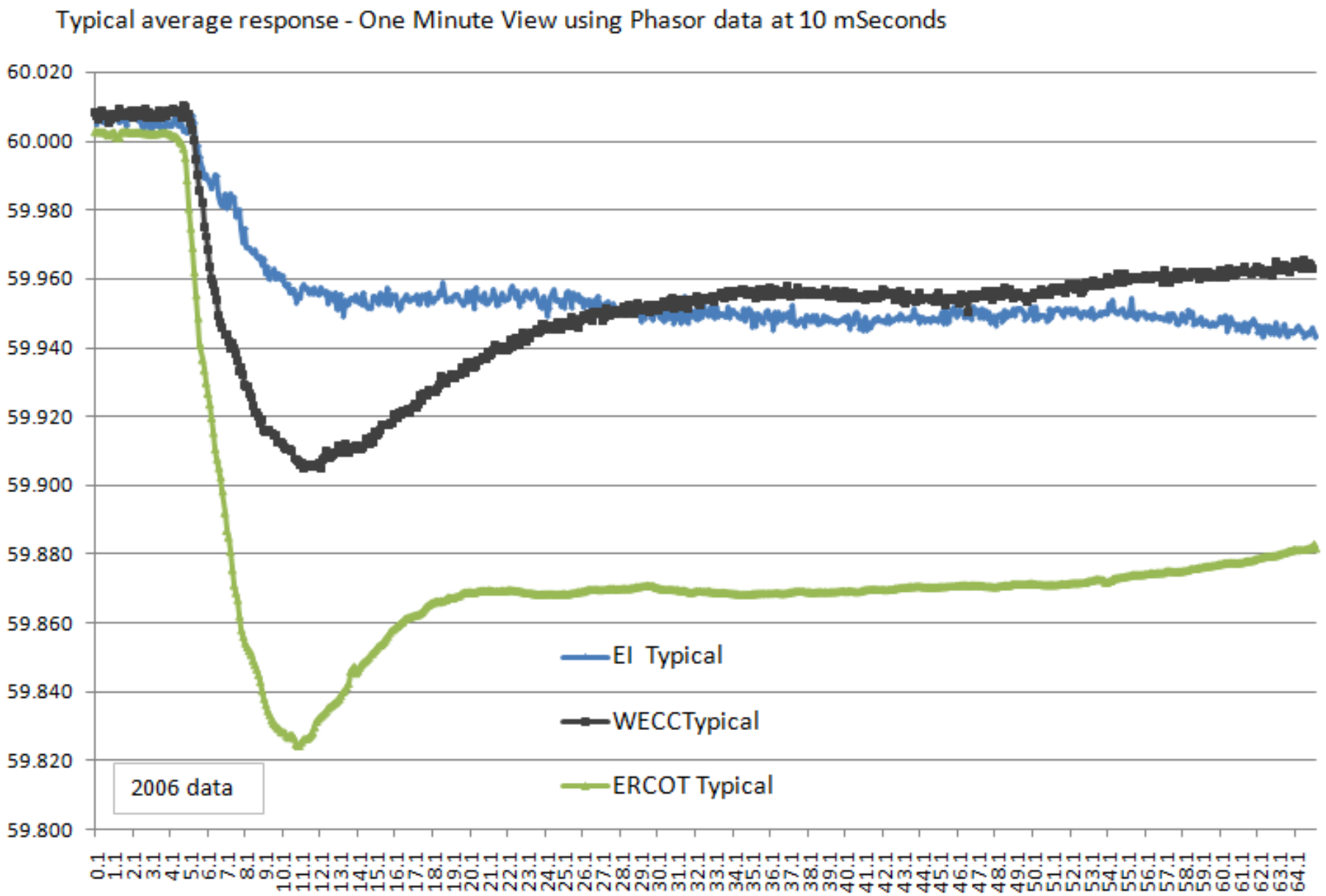
Primary Response Sustainability



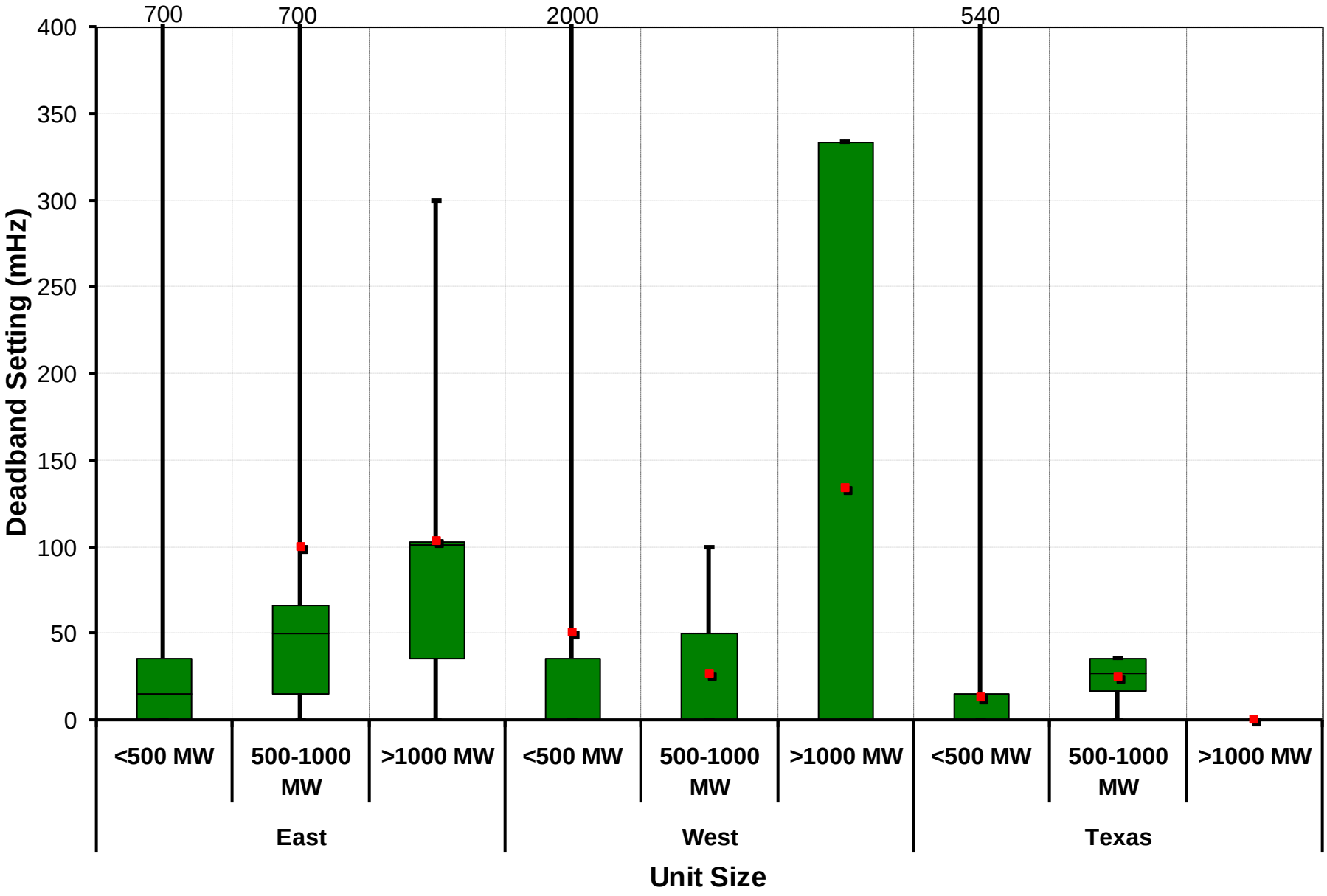
Blue = frequency response is sustained

Red = generator has a "slow" load controller returning to MW set-point

Typical Frequency Responses

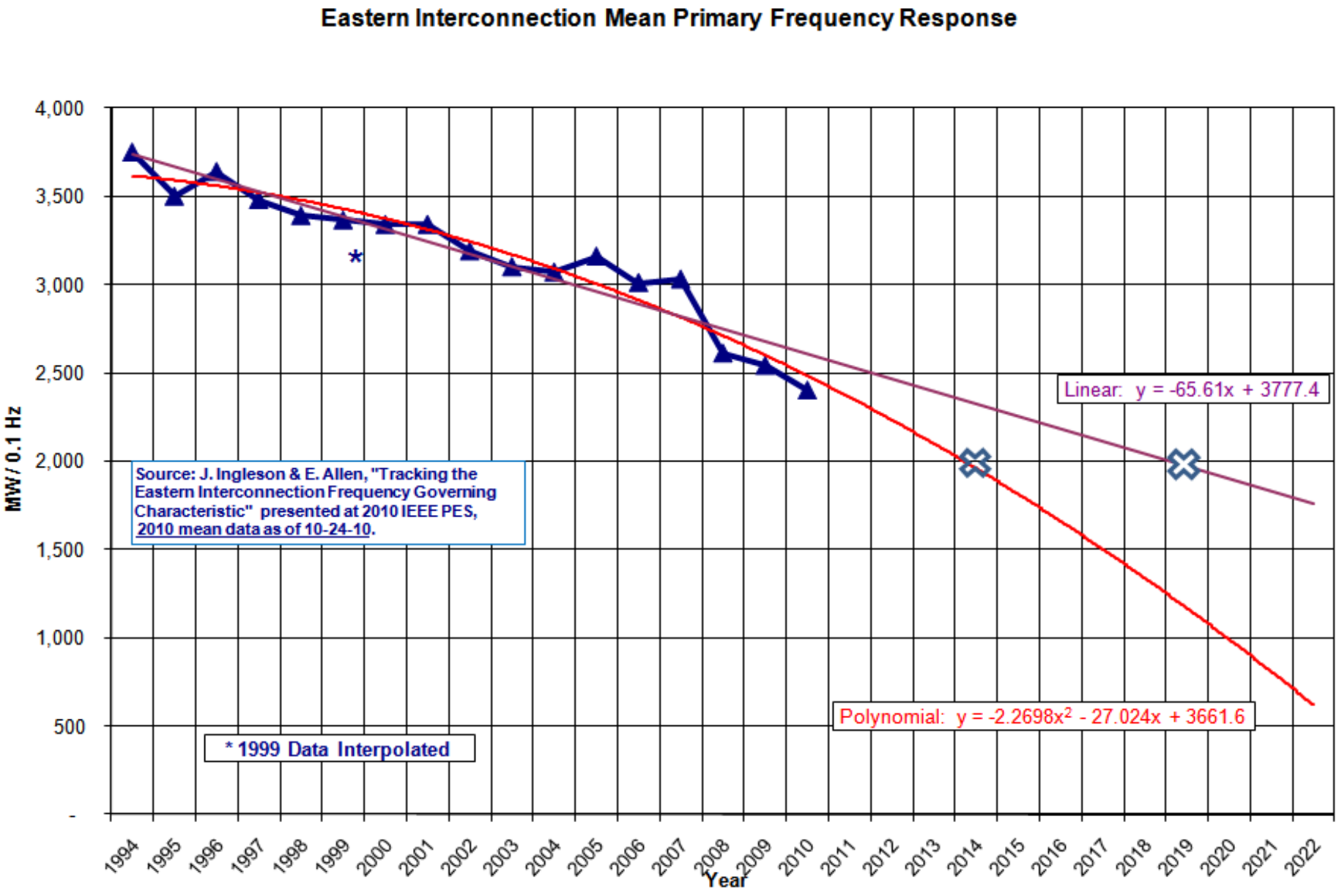


Governor Deadband Settings

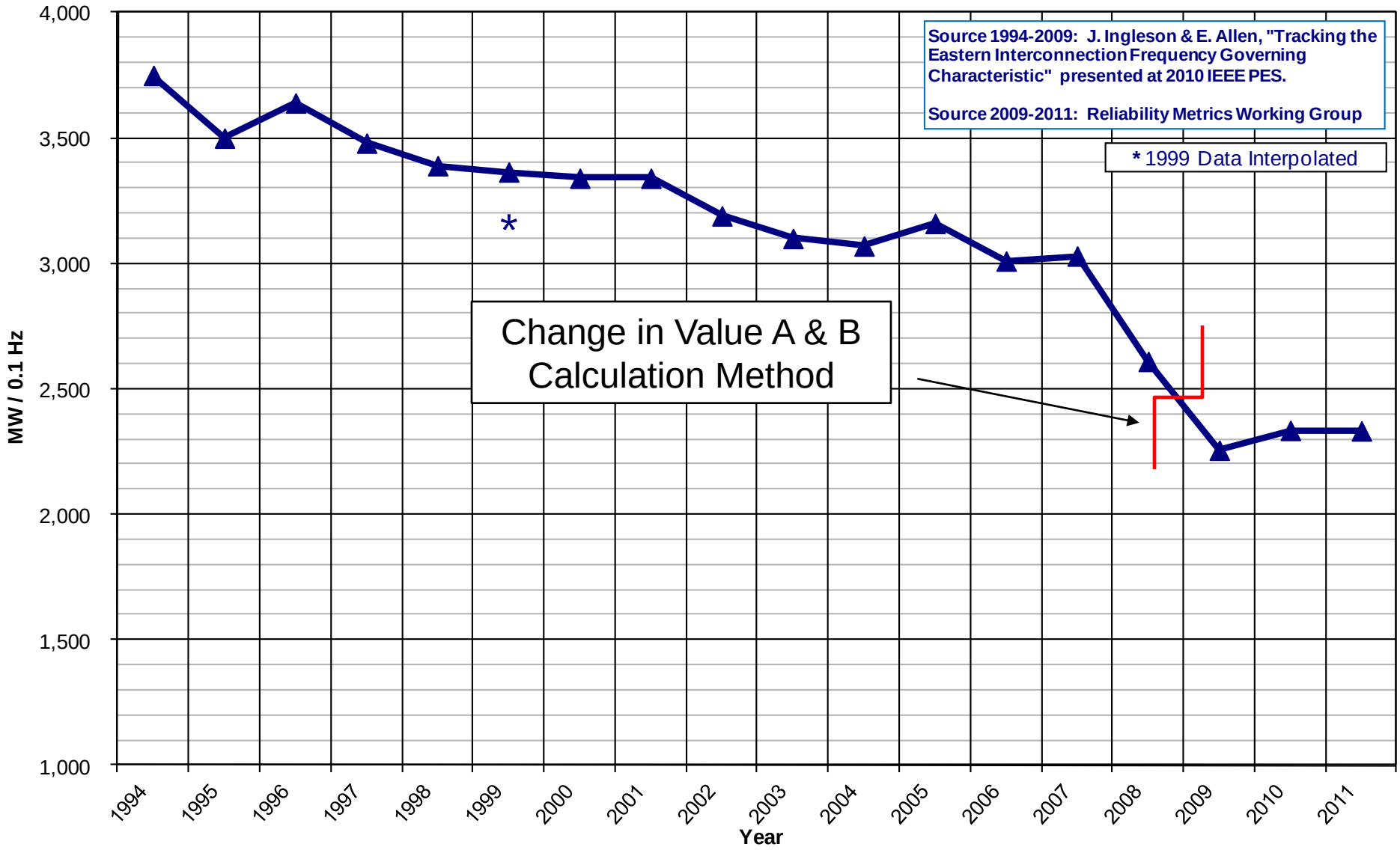


Frequency Response Trends

EI Historical Frequency Response



Updated EI Historical Freq. Response



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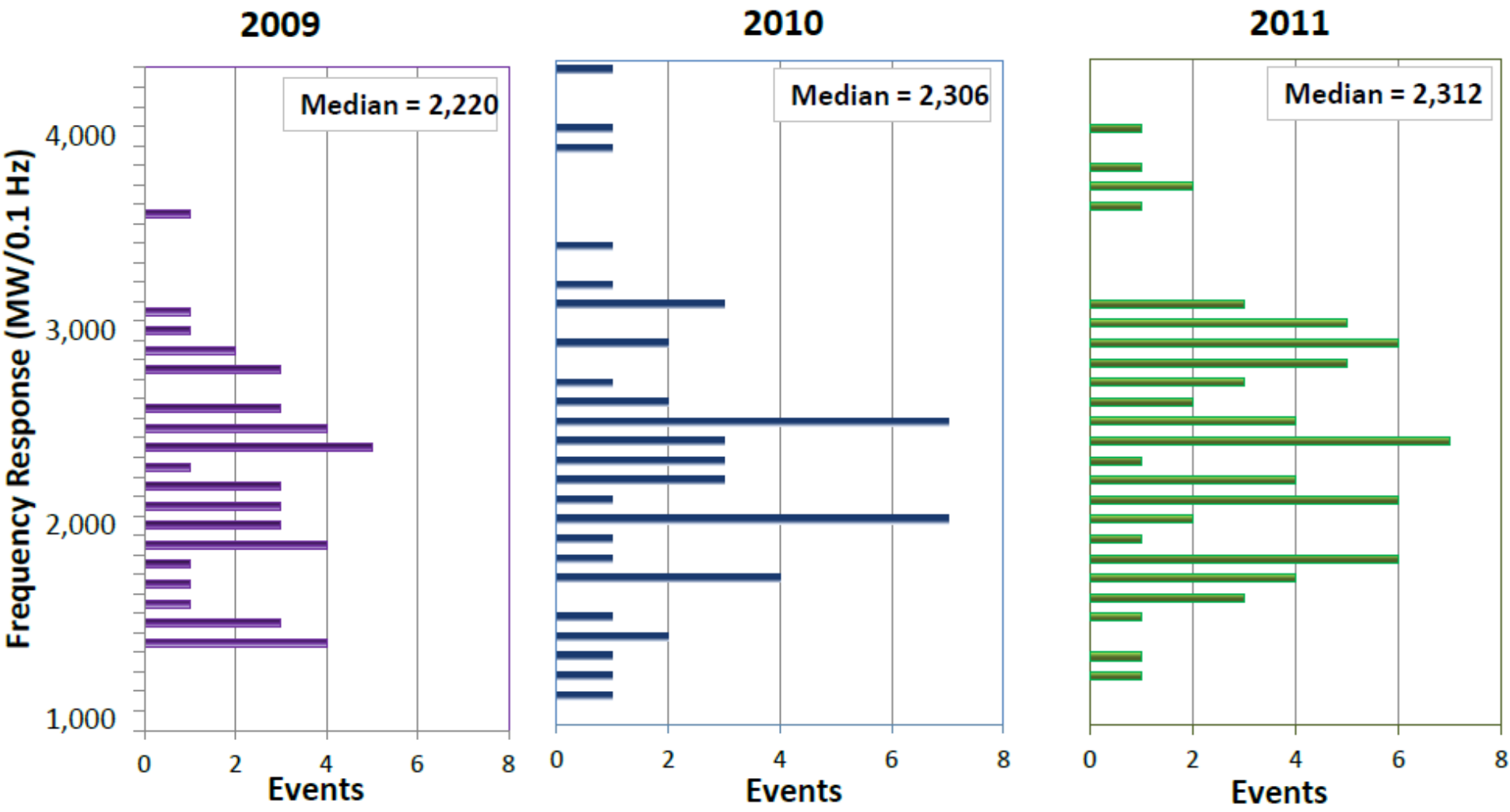
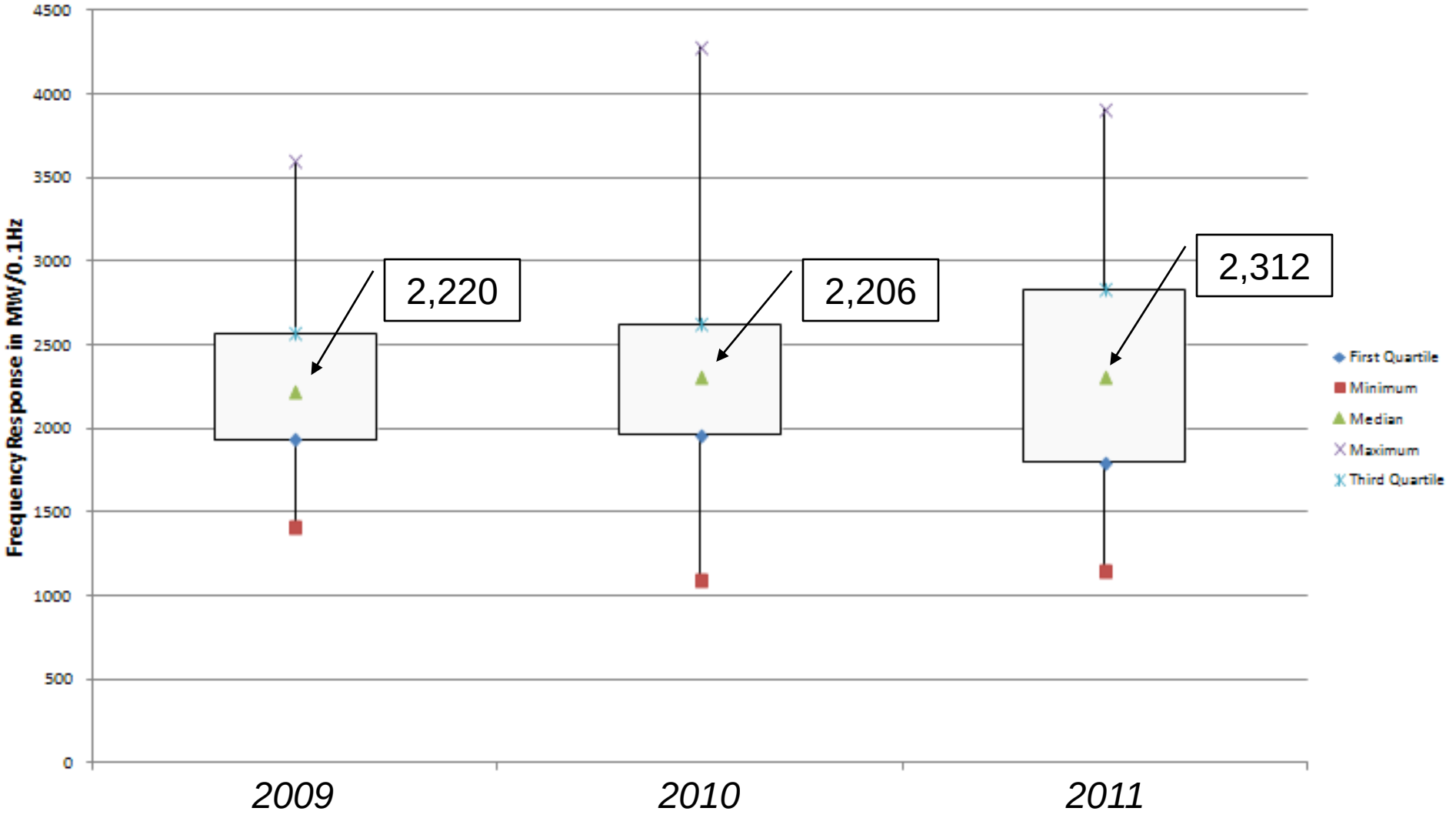
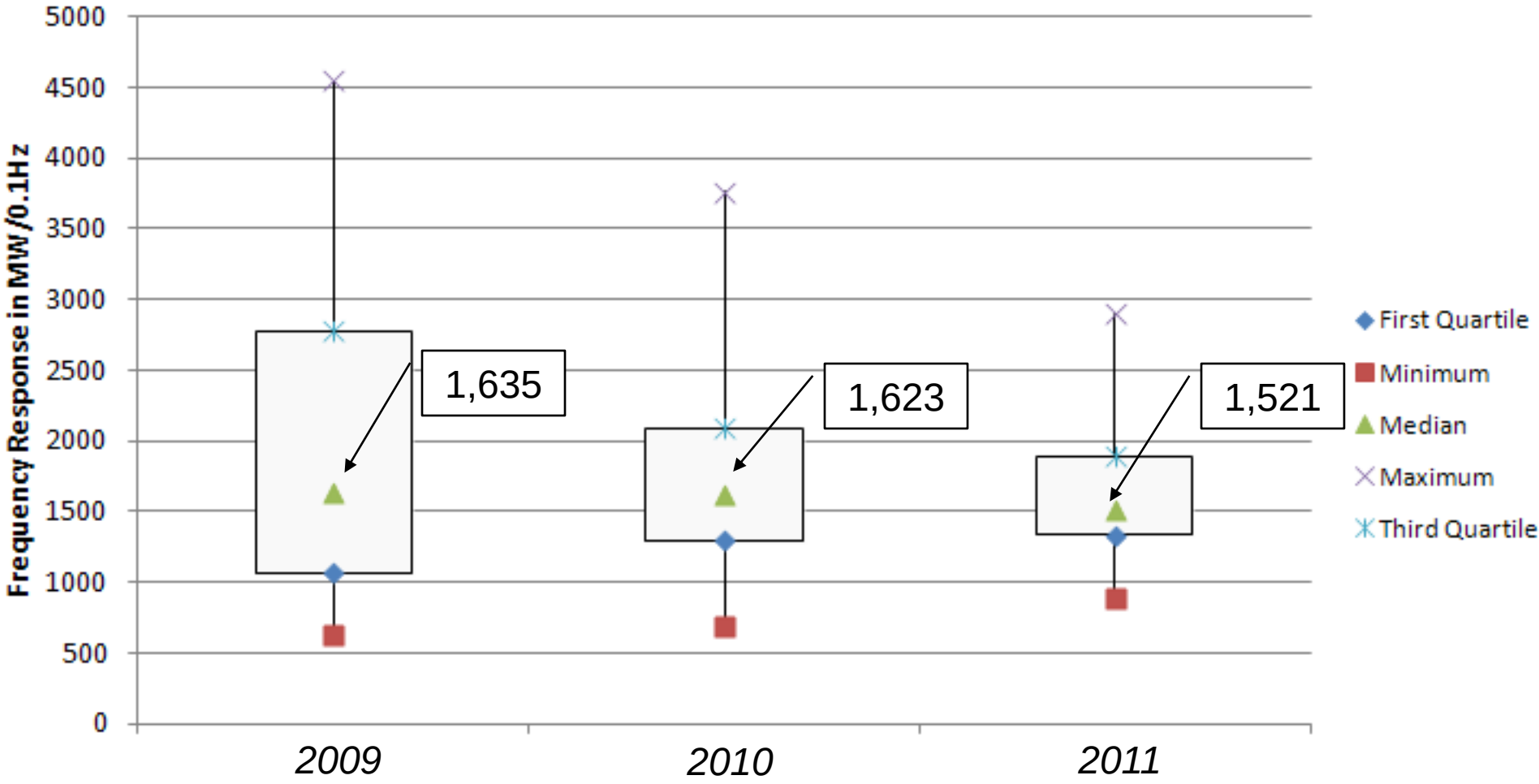
EI Freq. Response Distribution



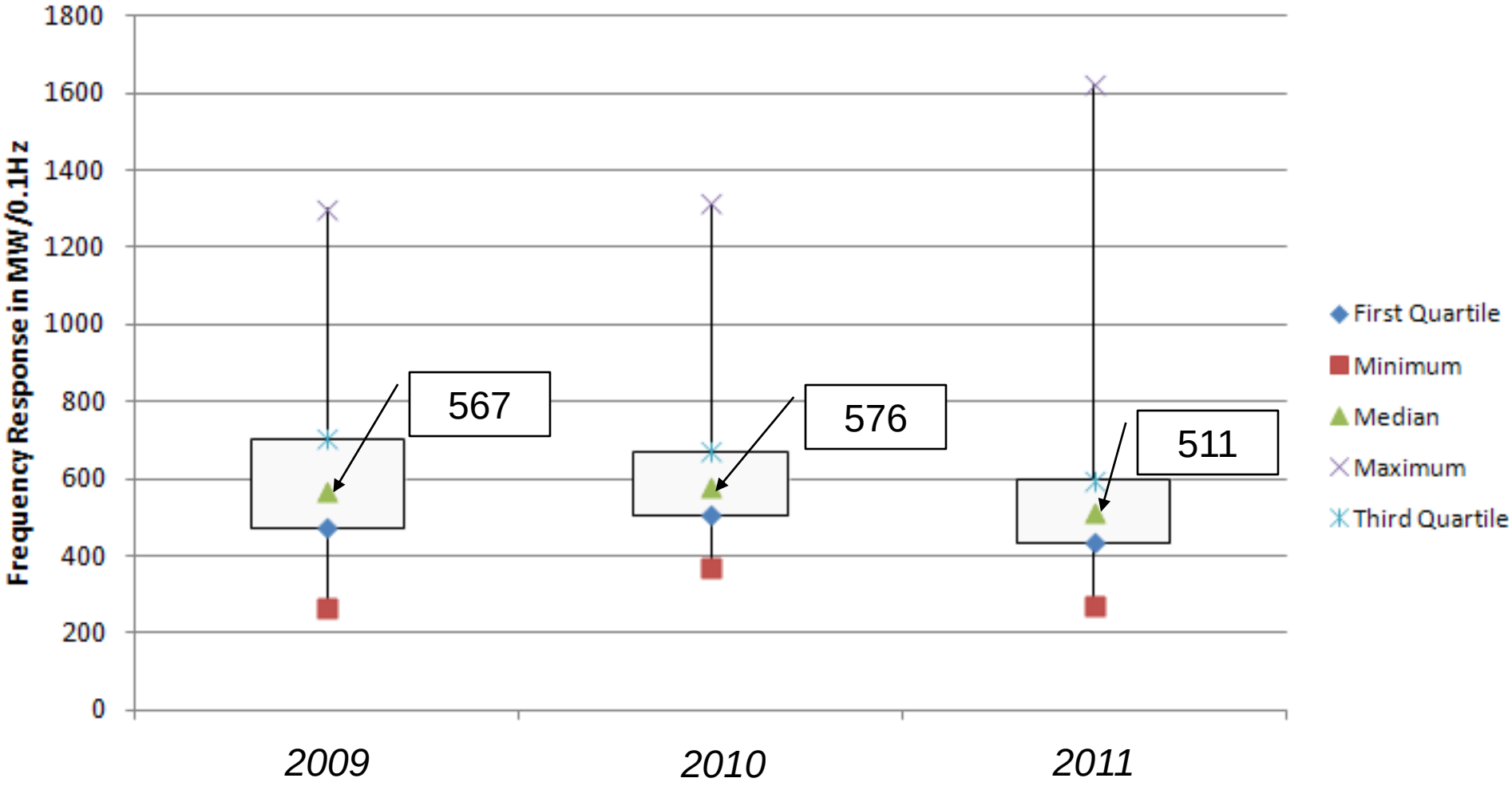
Eastern Int. Frequency Response



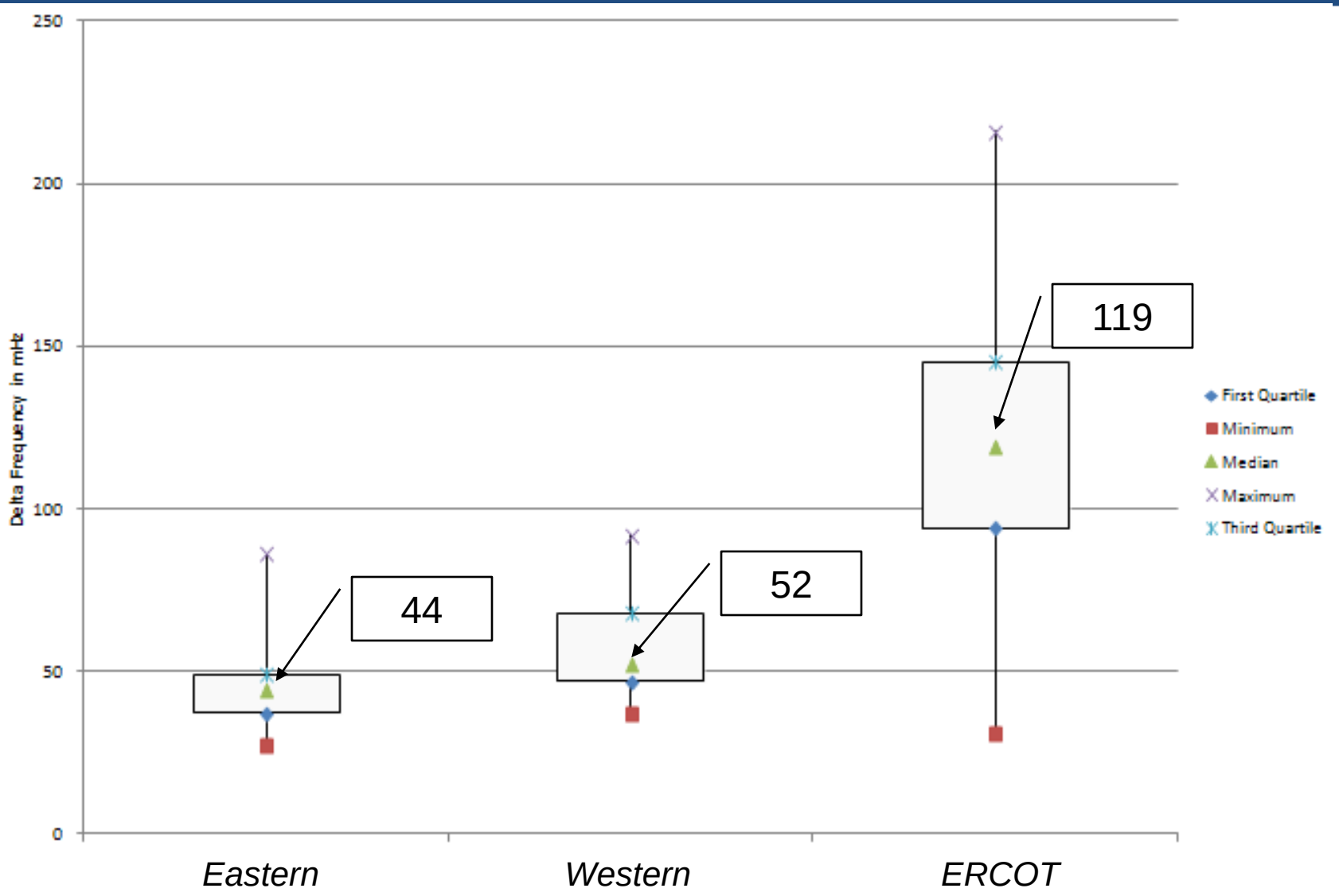
WI Box Plots for Frequency Response



ERCOT Box Plots for Frequency Response

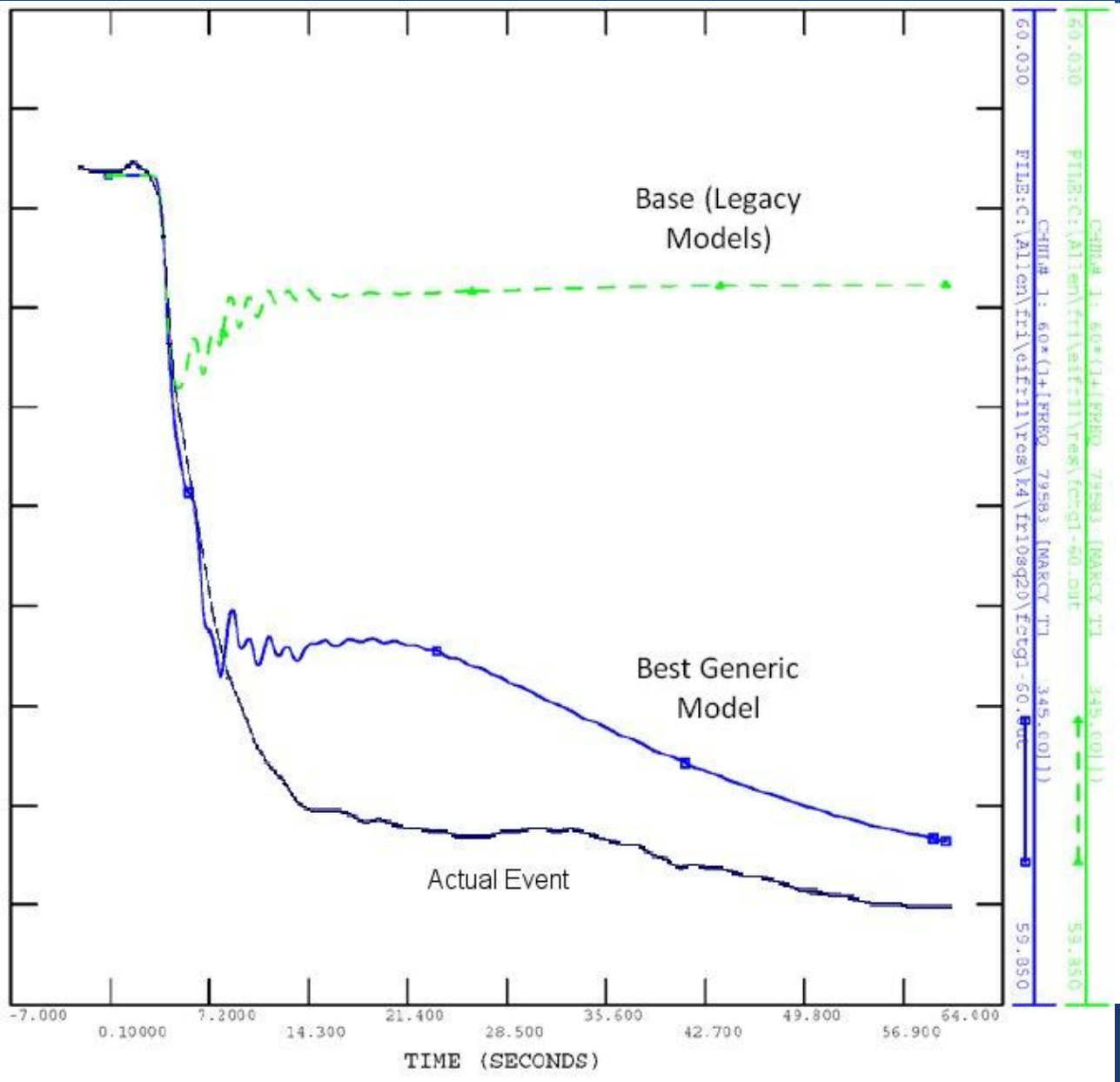


2011 Delta Freq for EI & WI & ERCOT



Modeling Eastern Interconnection Frequency Response

EI FR Modeling



- Based on 4,500 MW loss event
- ~5,400 units above 20 MW

EI ERAG/NERC Modeling Findings

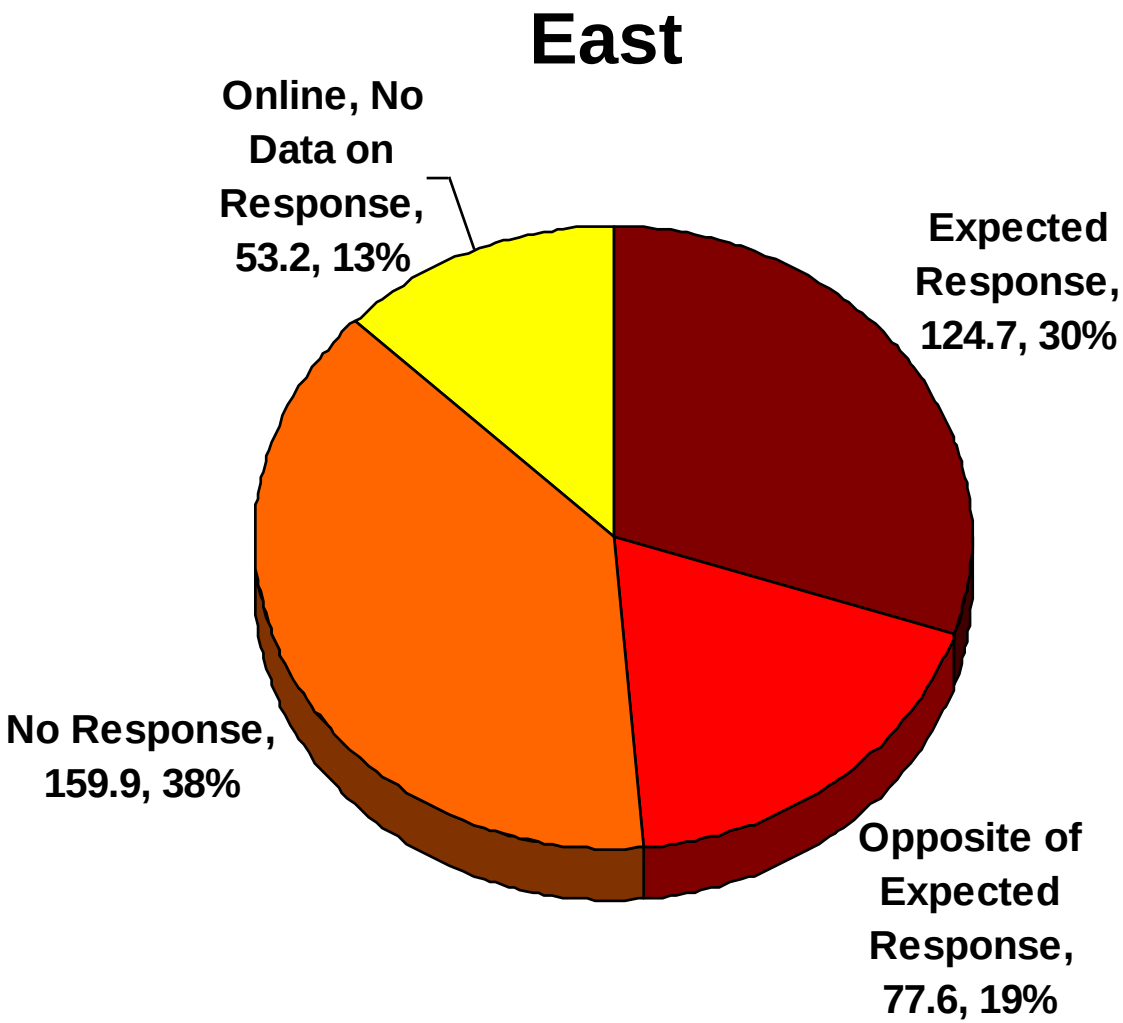
Best match performance characteristics:

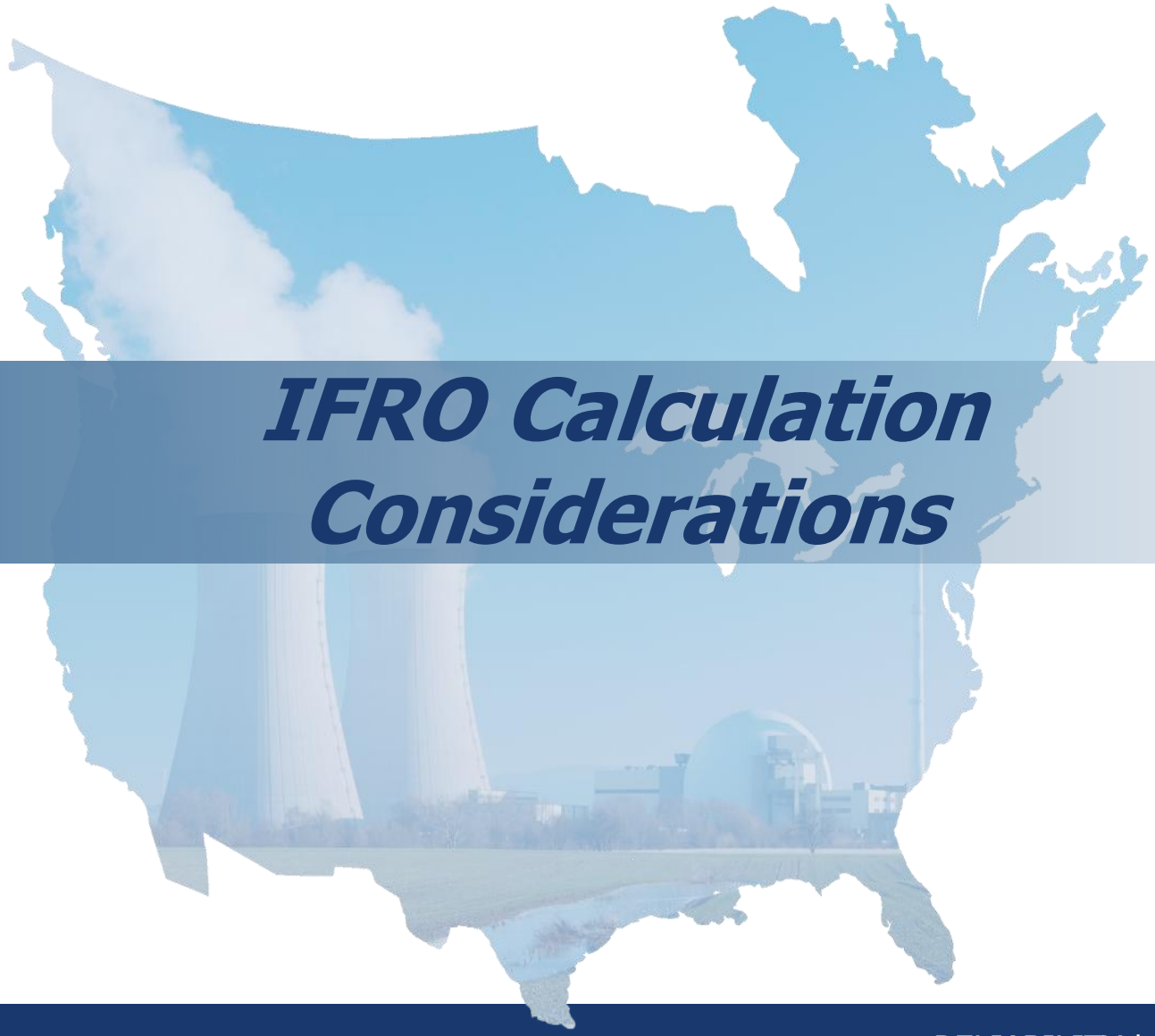
- 30 % of units on line provide primary frequency response
- 2/3 of those units exhibit withdrawal
- 10 % of units on line sustain primary frequency response

Worldwide comparison (per John Undrill)

- 35 % response is typical

EI Governor Response Survey





IFRO Calculation Considerations

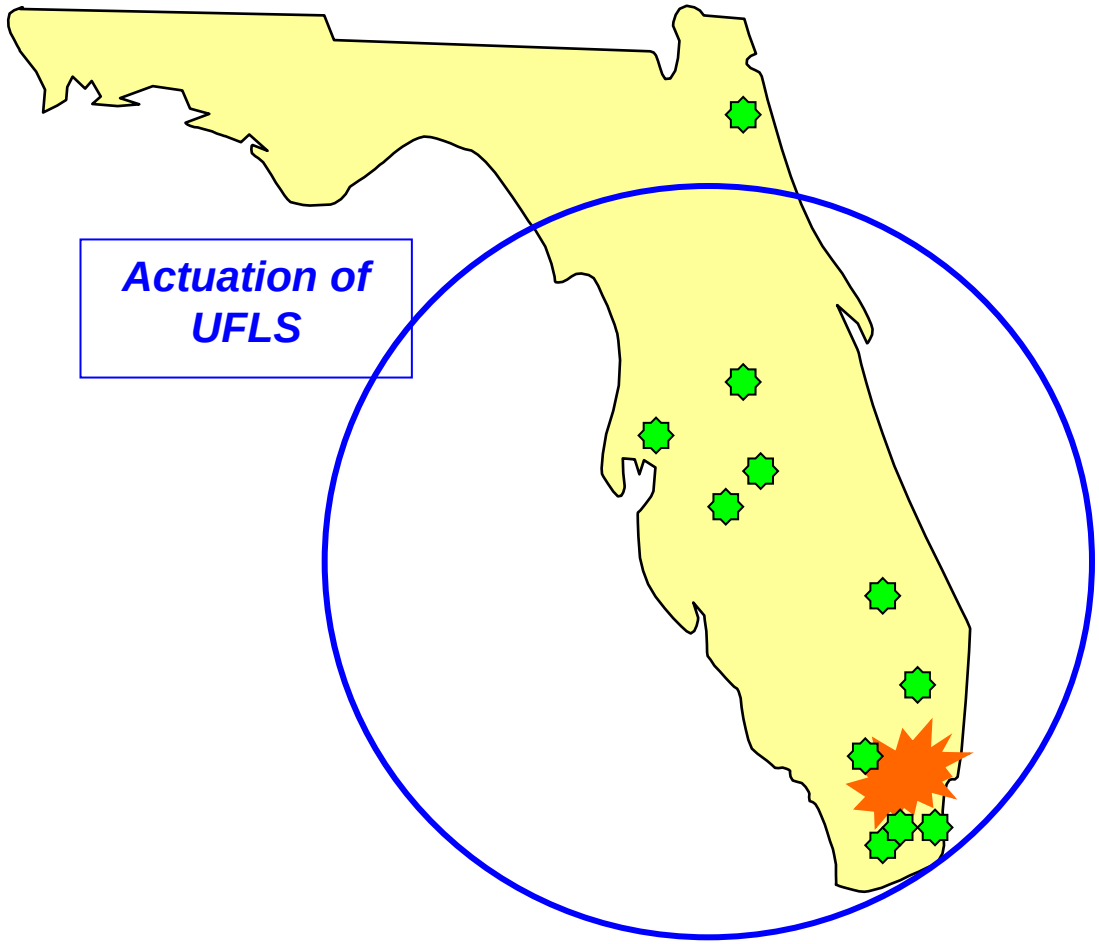
IFRO Tenets

1. Should not trigger first stage of regionally-approved UFLS Systems
2. Unavoidable local tripping of first-stage UFLS systems for severe frequency excursions
   - Protracted faults
   - Systems on edge-of the interconnection
3. Some frequency-sensitive loads may trip
4. Other frequency-sensitivities have to be considered
   - PV inverters tested trip at 59.4 Hz instead of 59.2 Hz specified in IEEE Standard 1547
   - Electronically coupled loads with common-mode frequency sensitivities

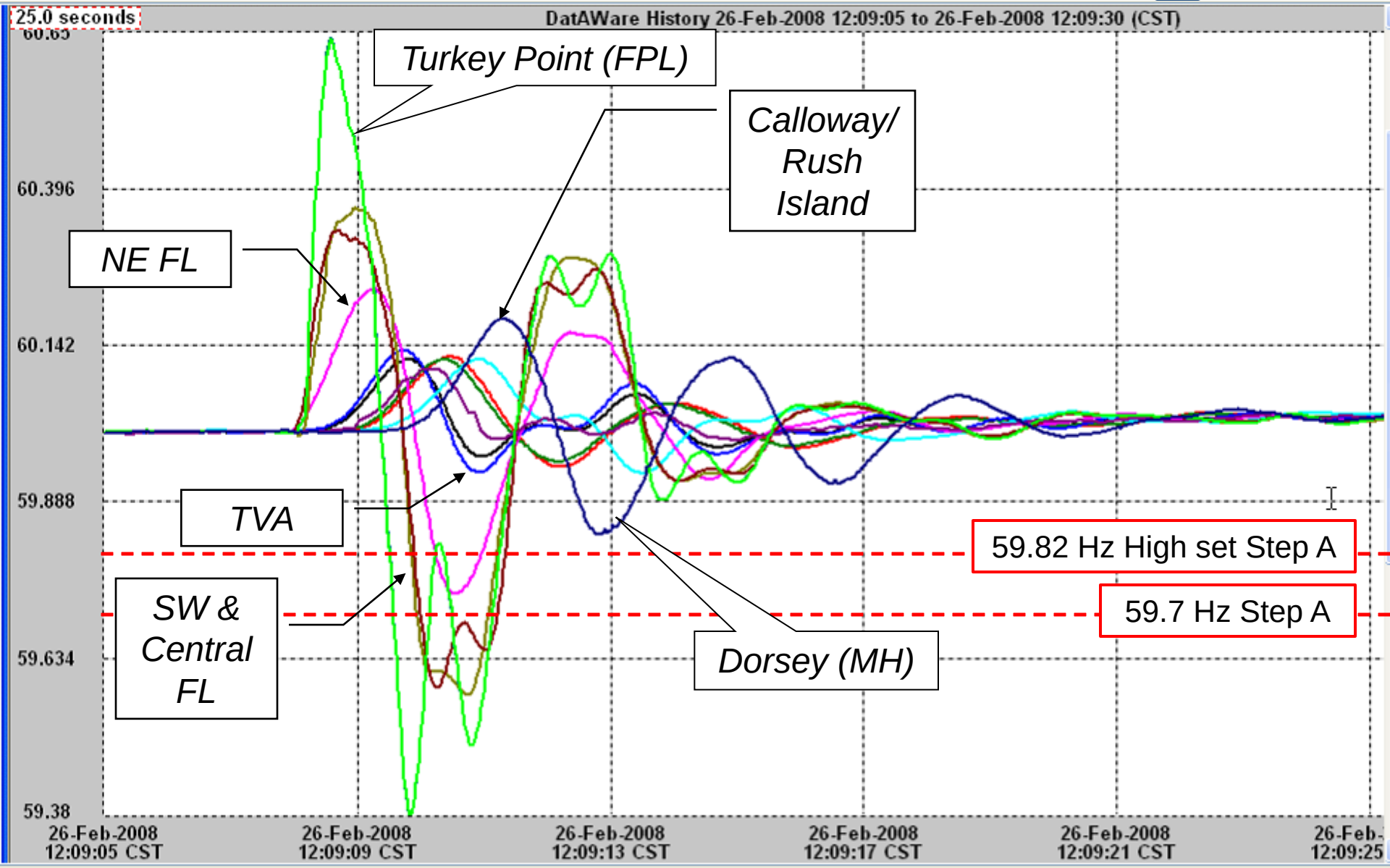
Florida Disturbance Feb. 26, 2008

Generation Trips

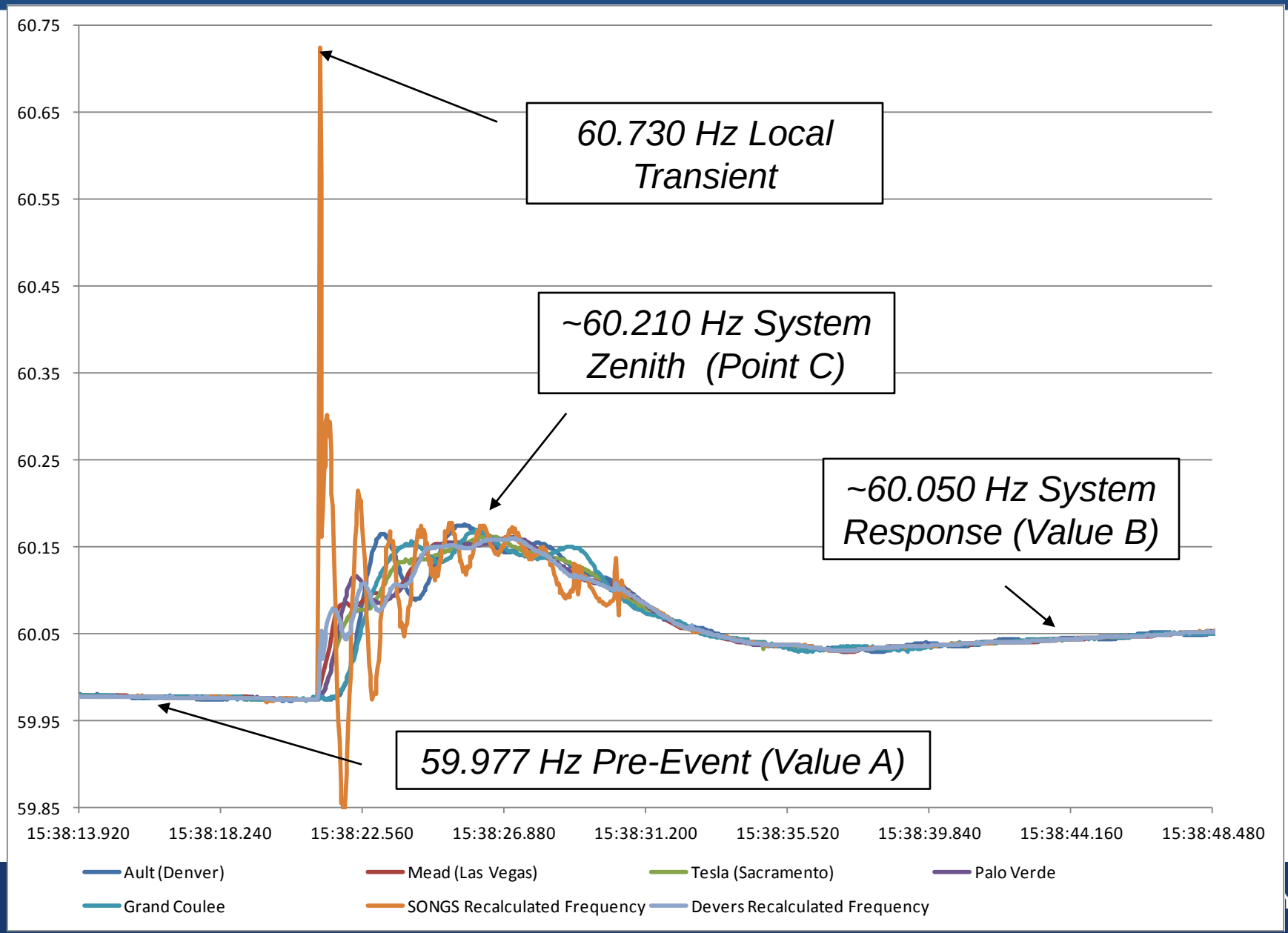
Location of 138 kV – 3θ fault

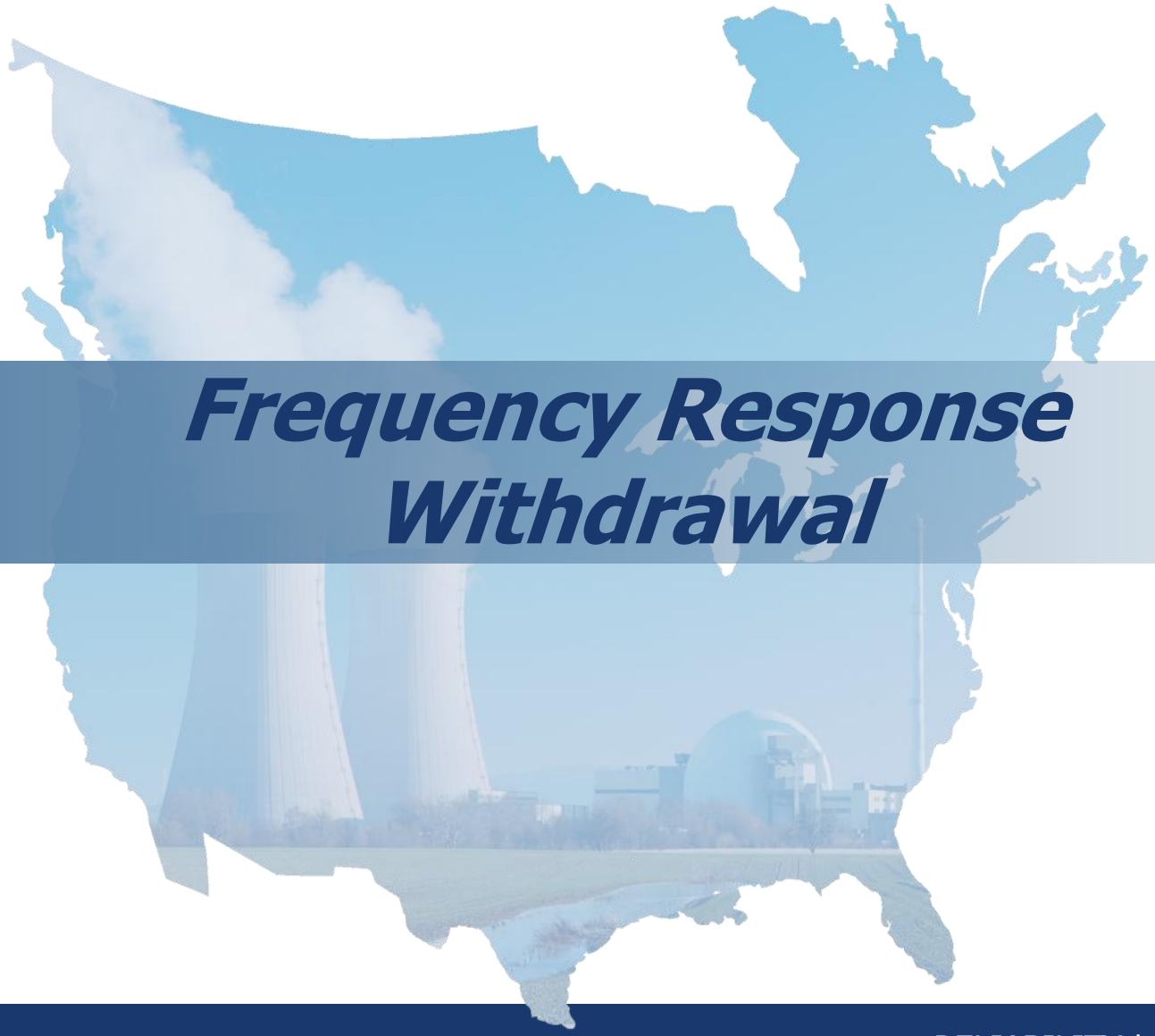


2008 Florida Event Frequency Impacts



PSW 2011 Dist. Frequency Impacts



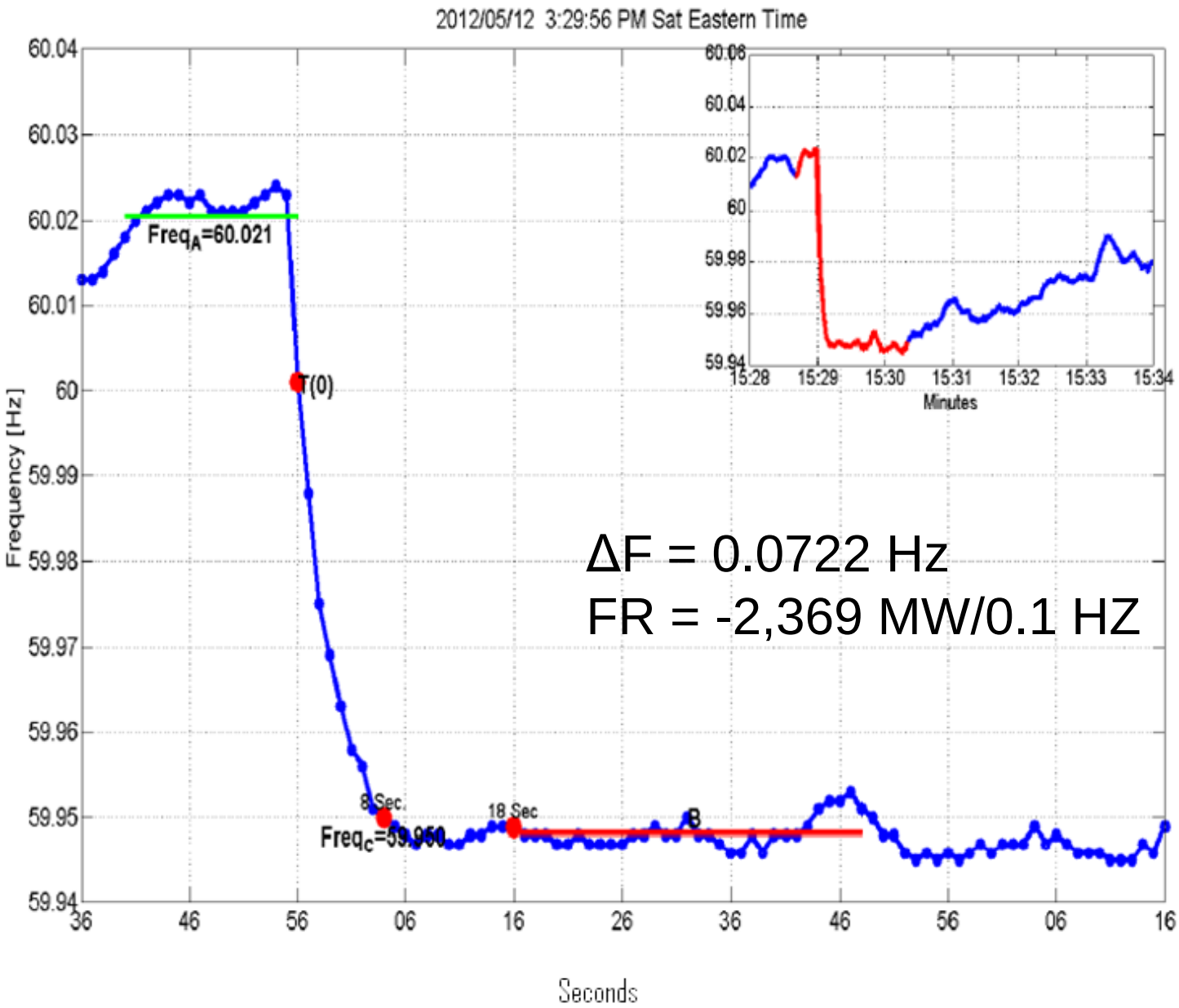


Frequency Response Withdrawal

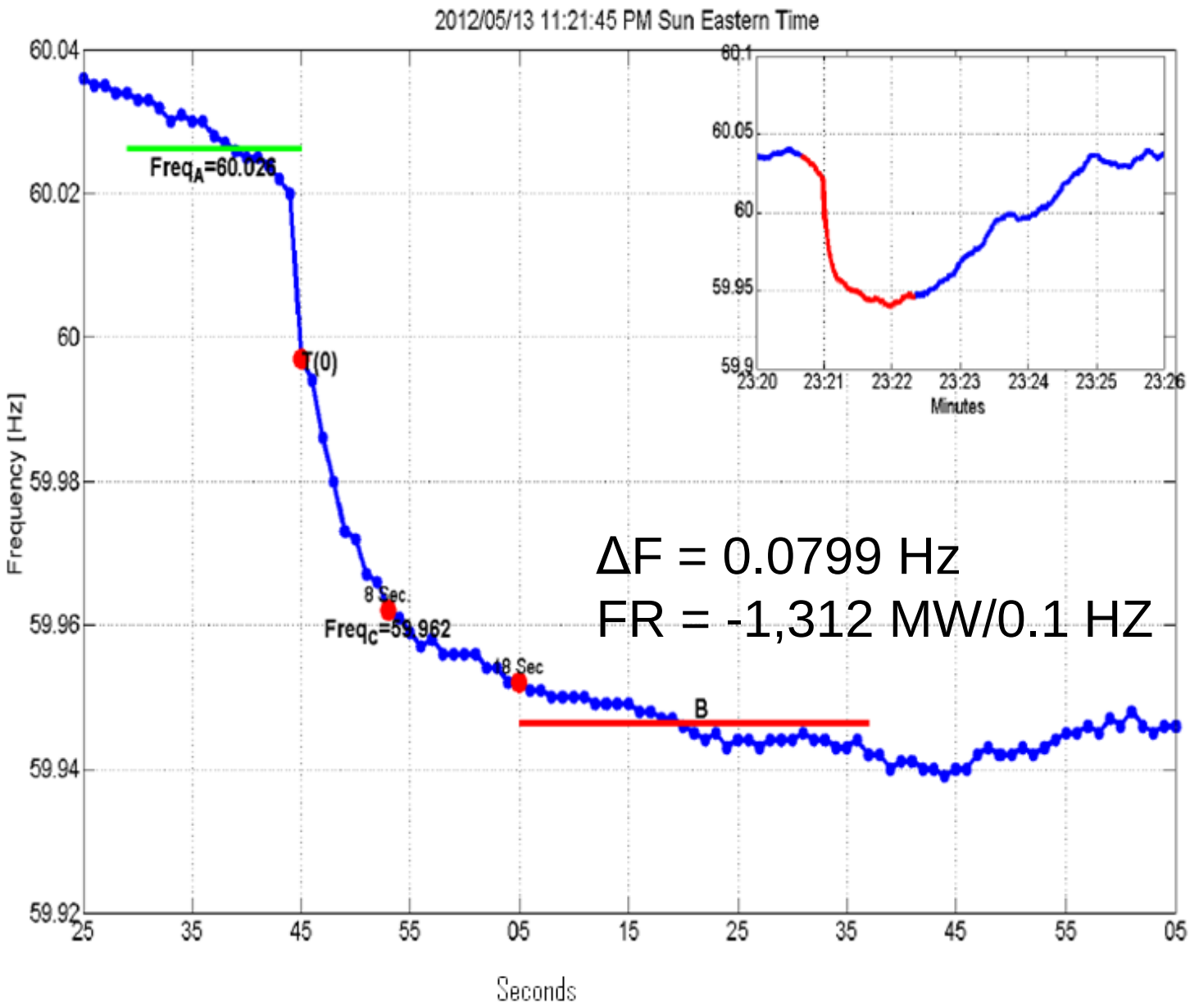
Frequency Response Withdrawal

- Function of dispatch – what types of units are on line and responding
- Typical causes:
  - Plant outer-loop control systems – driving the units to MW set points
  - Unit characteristics
    - Plant incapable of sustaining
    - 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

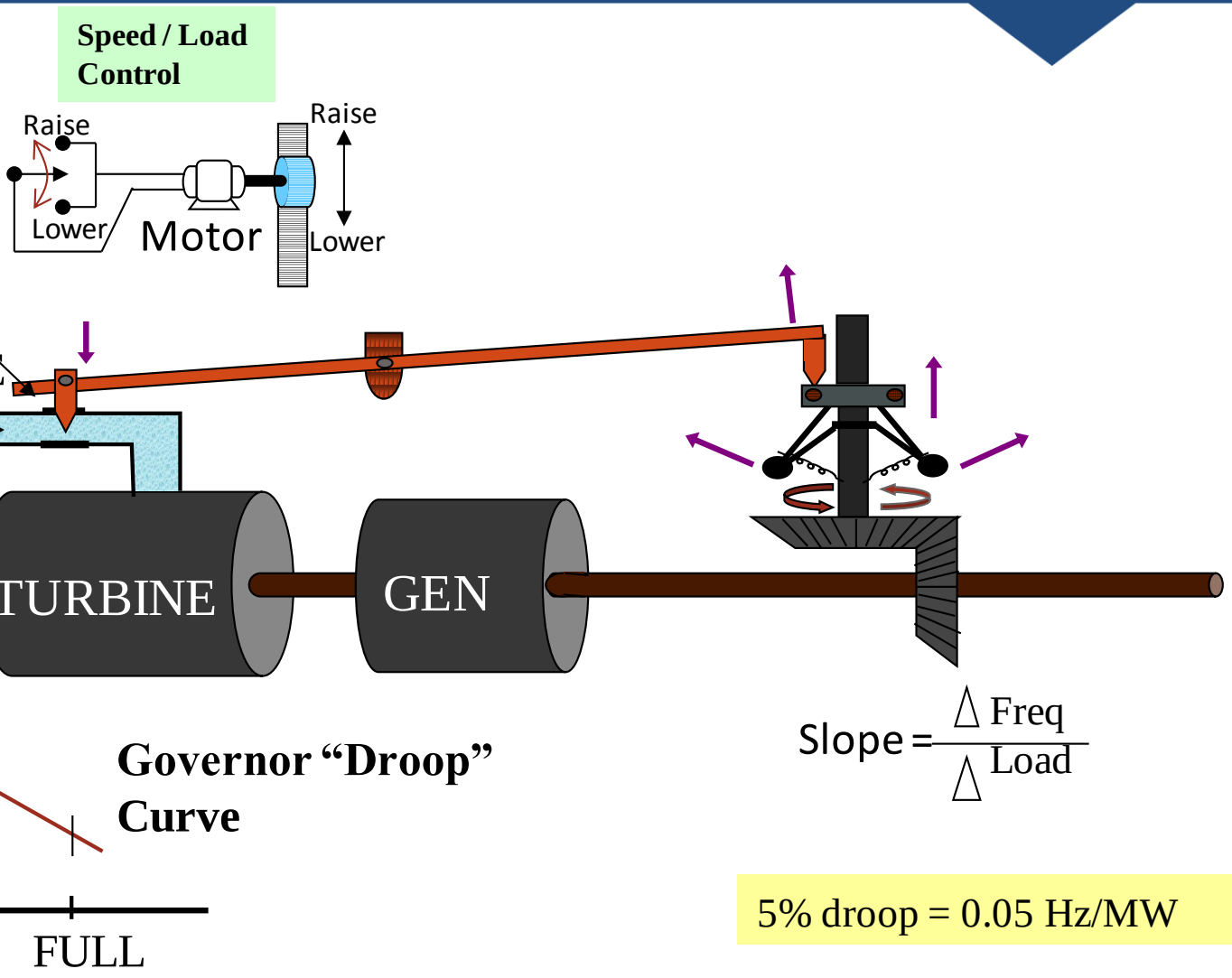
1,711 MW Loss – Sat 3:30 pm EDT



1,049 MW Trip – Sun 11:20 pm EDT



Response from Governors



5% droop = 0.05 Hz/MW

Governor Droop Calculation

Expected Response = -Δ freq / Droop (Hz)
= Δ MW / rated MW

For a 1,000 MW generator

5% droop and Δ freq of 0.1 Hz

To calculate expected MW output change:

Convert the droop (e.g., 5%) to Frequency

0.05 x 60 = 3 Hz

-0.1 Hz / 3 Hz = ΔMW / 1,000 MW

1,000 X 0.1 / 3 = 33 MW

Expected response = 33 MW

Cost of Frequency Response

Energy

1,000 MW turbine generator – 33 MW expected response

- For 70 events per year beyond deadband
- Assume 2 minutes of full response per event
- 77 MWH additional energy (assumes avail. headroom)

Lost opportunity – operating away from full load or highest efficiency operating point

Throttling losses on steam units

Wear & tear caused by unit movement

Reference

For more on generator performance characteristics:

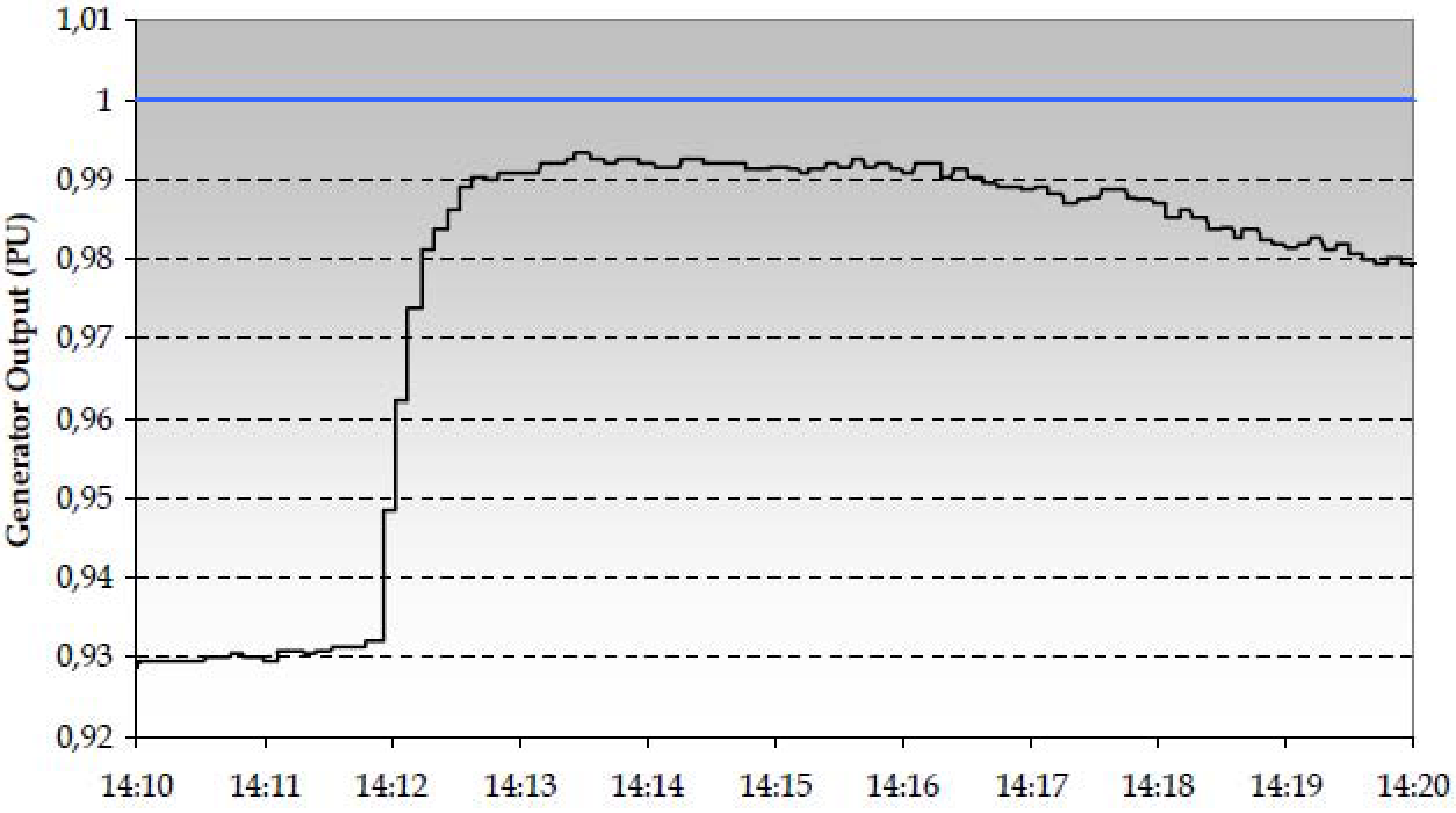
- "Power and Frequency Control as it Relates to Wind-Powered Generation" by John Undrill
- Part of the December 2010 report by Lawrence Berkeley National Laboratories

- Available at:

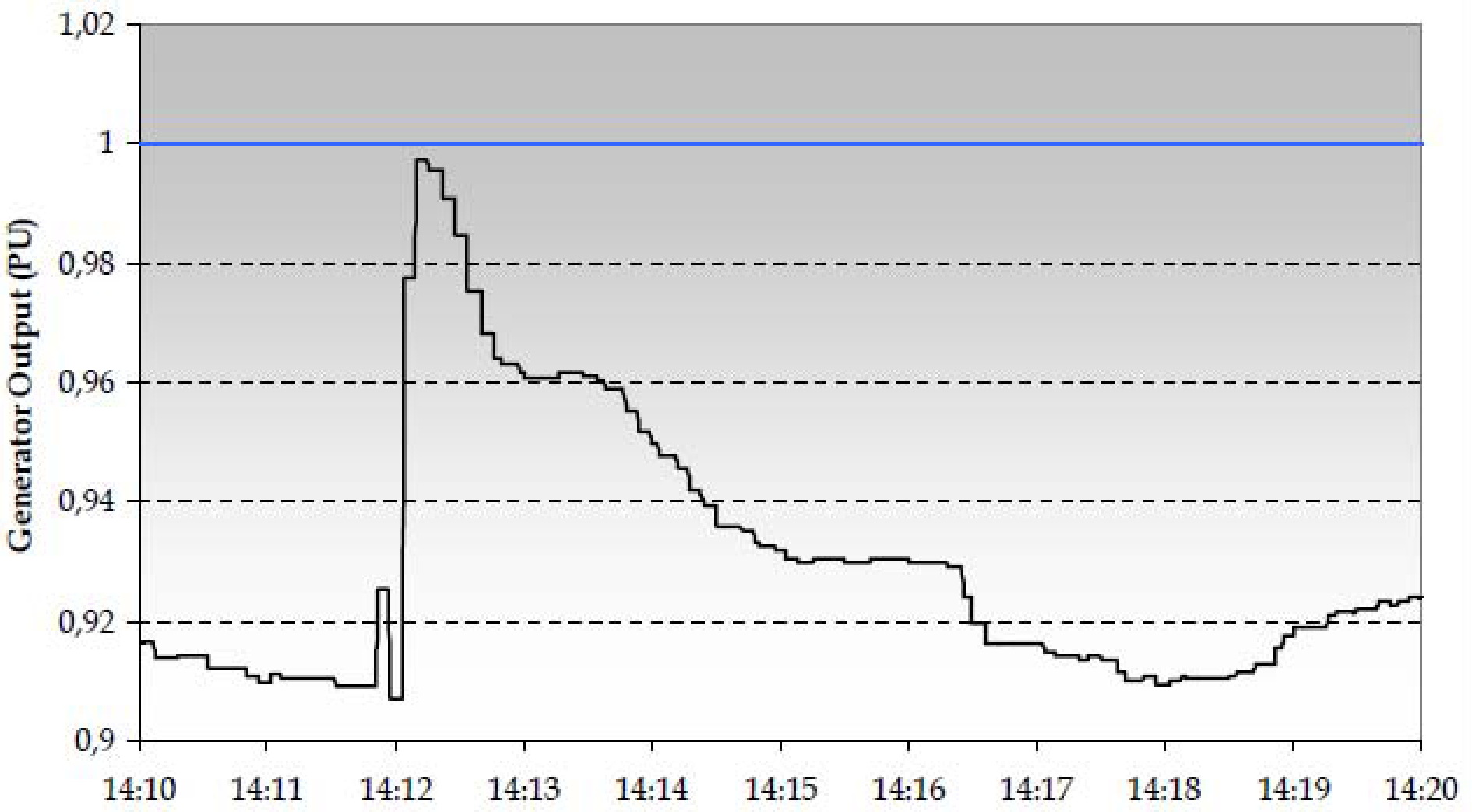
http://www.ferc.gov/industries/electric/indus-act/reliability/frequencyresponsemetrics-report.pdf

Individual Unit Type Performance

Sustained Governor Response Example



Squelched Governor Response Example

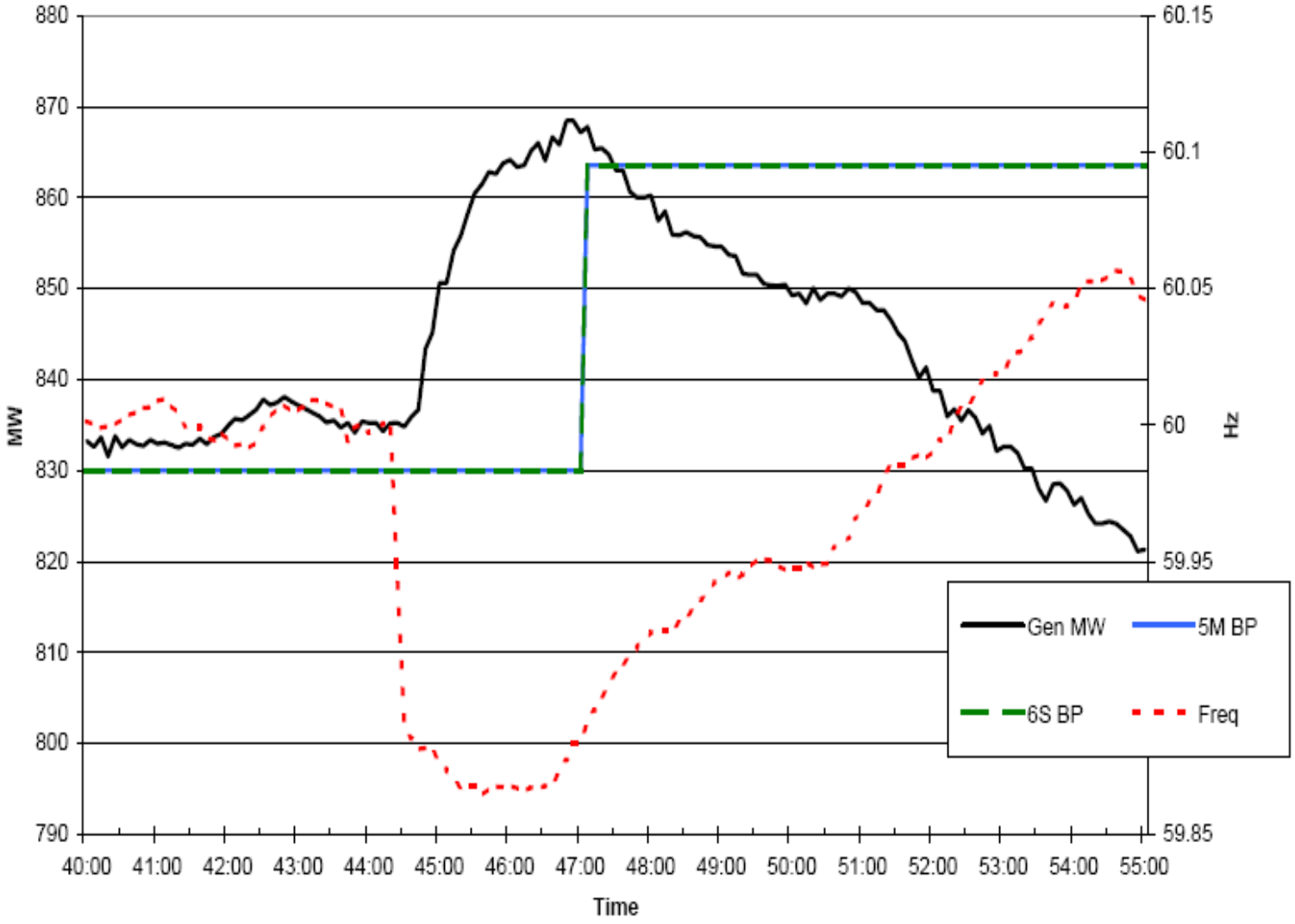


Negative Governor Response Example

Actual Unit Type Performance

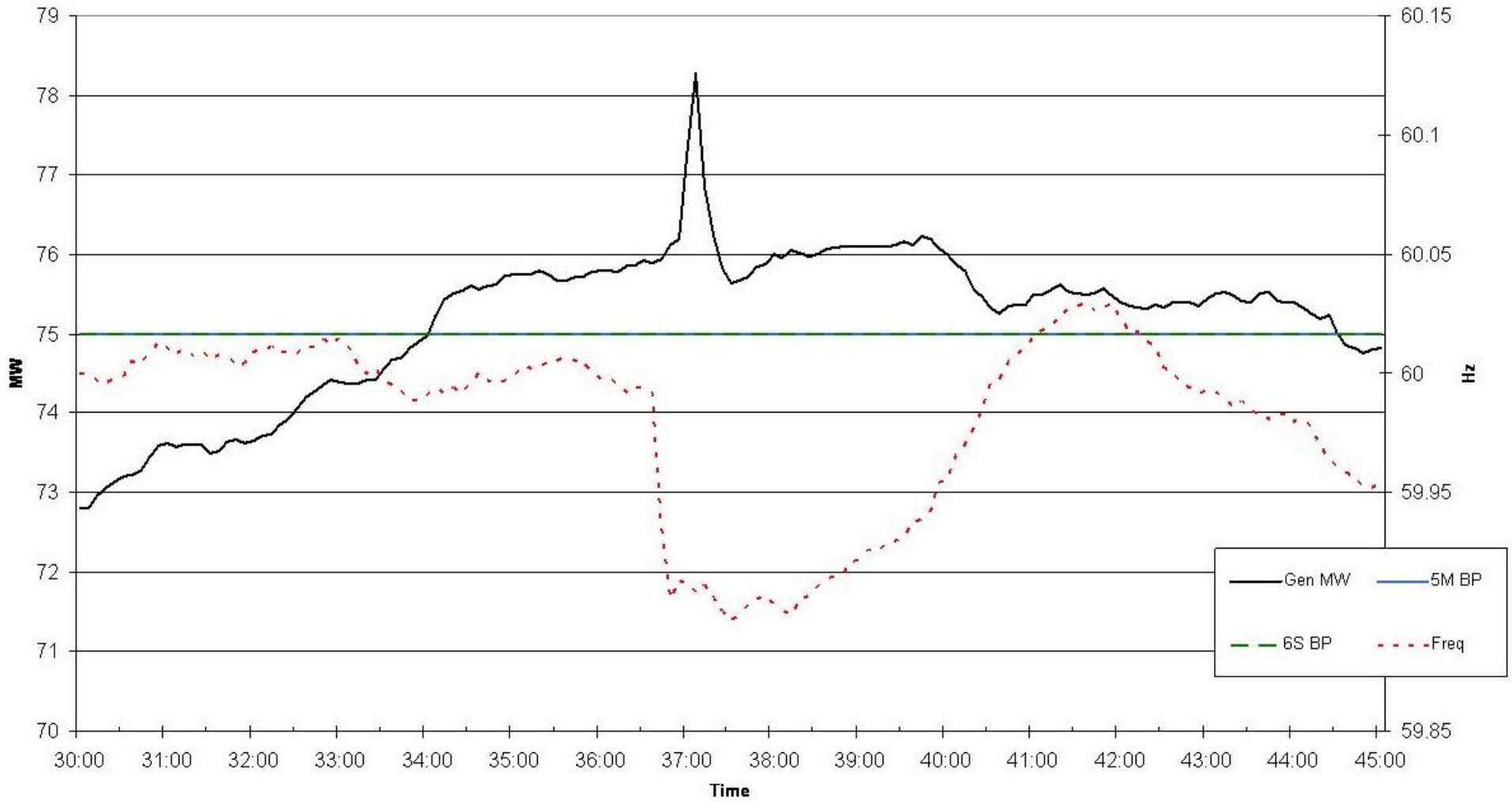
- Actual Primary Frequency Response of generators in Eastern Interconnection
  - Reflect unit operating performance characteristics
  - Reflects operating characteristic *choices* for turbine efficiency
- Examples are based on two different large capacity loss events (8-4-2007 and 4-27-2011)
- Performance for significant frequency events – beyond 36 mHz deadbands
- Governor response varies by:
  - Type of unit – not all units are the same
  - Unit-to-unit – variations between individual units of a given type

Hydro Plant Response



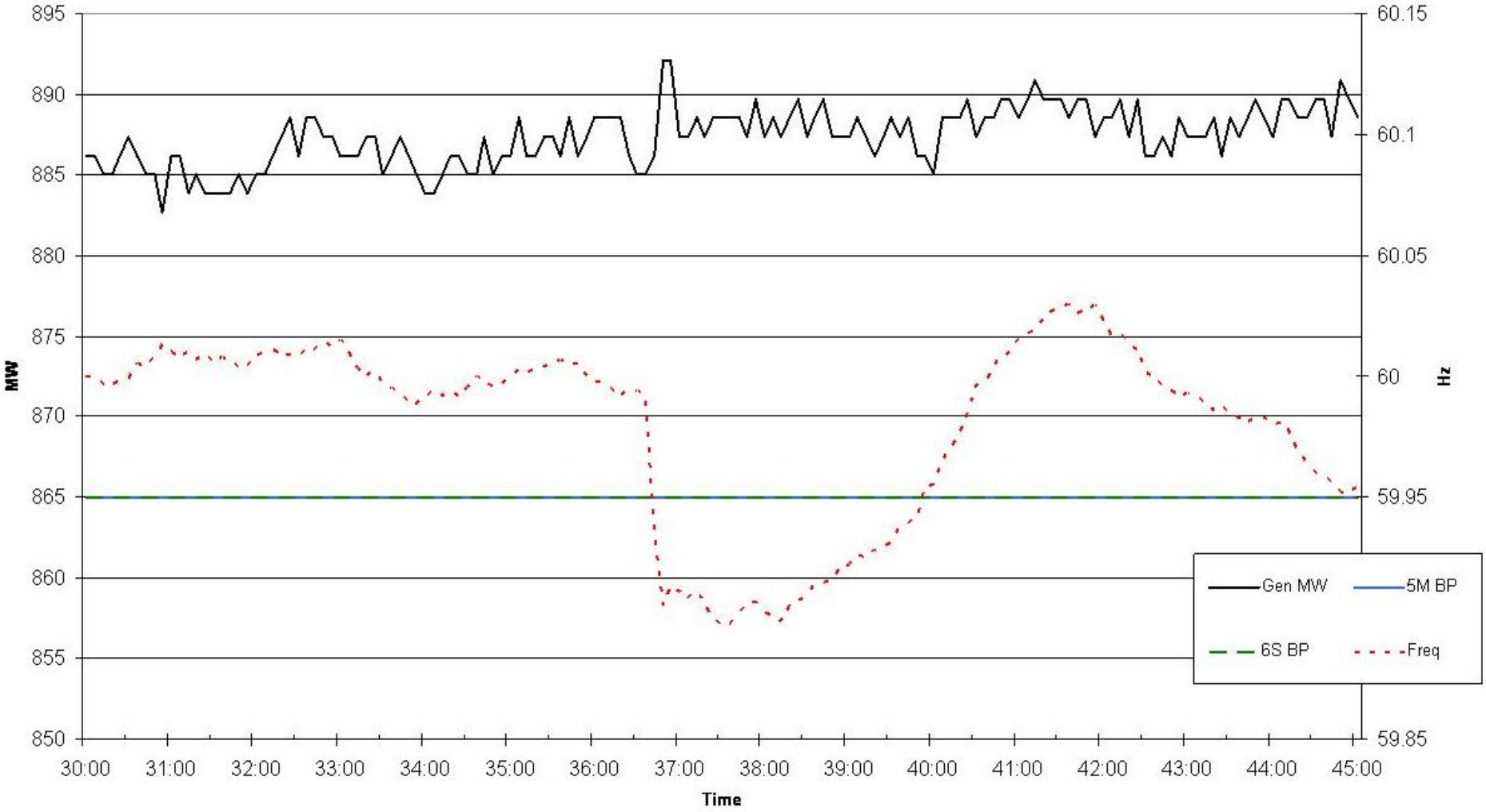
900 MW Unit
5% Droop
33 MW Expected

Small Thermal Unit Response



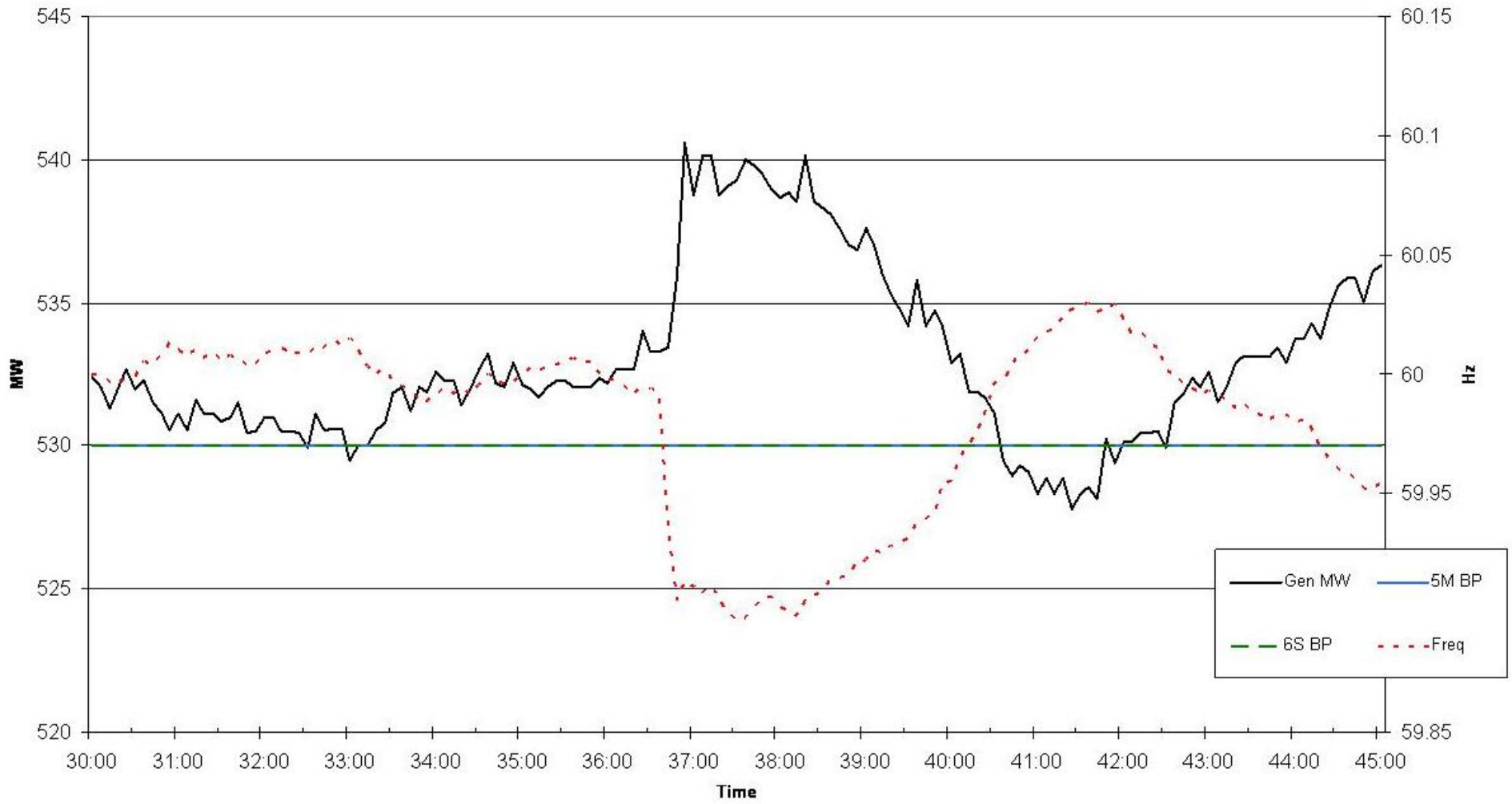
90 MW Unit **5% Droop** **3 MW Expected**

Large Thermal Unit Response



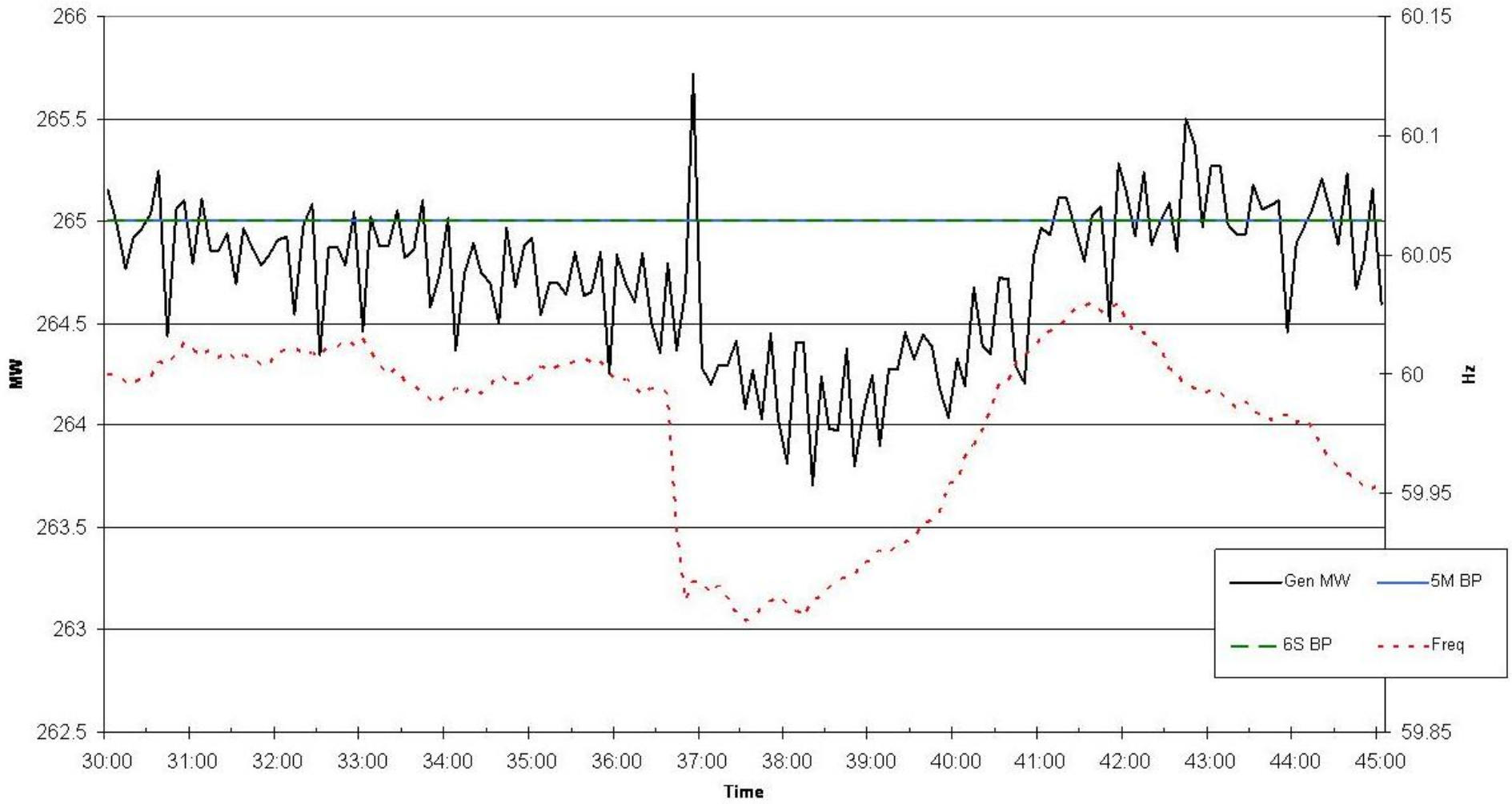
~900 MW Unit **5% Droop** **35 MW Expected** **7 MW Actual**

Large Combined Cycle Response



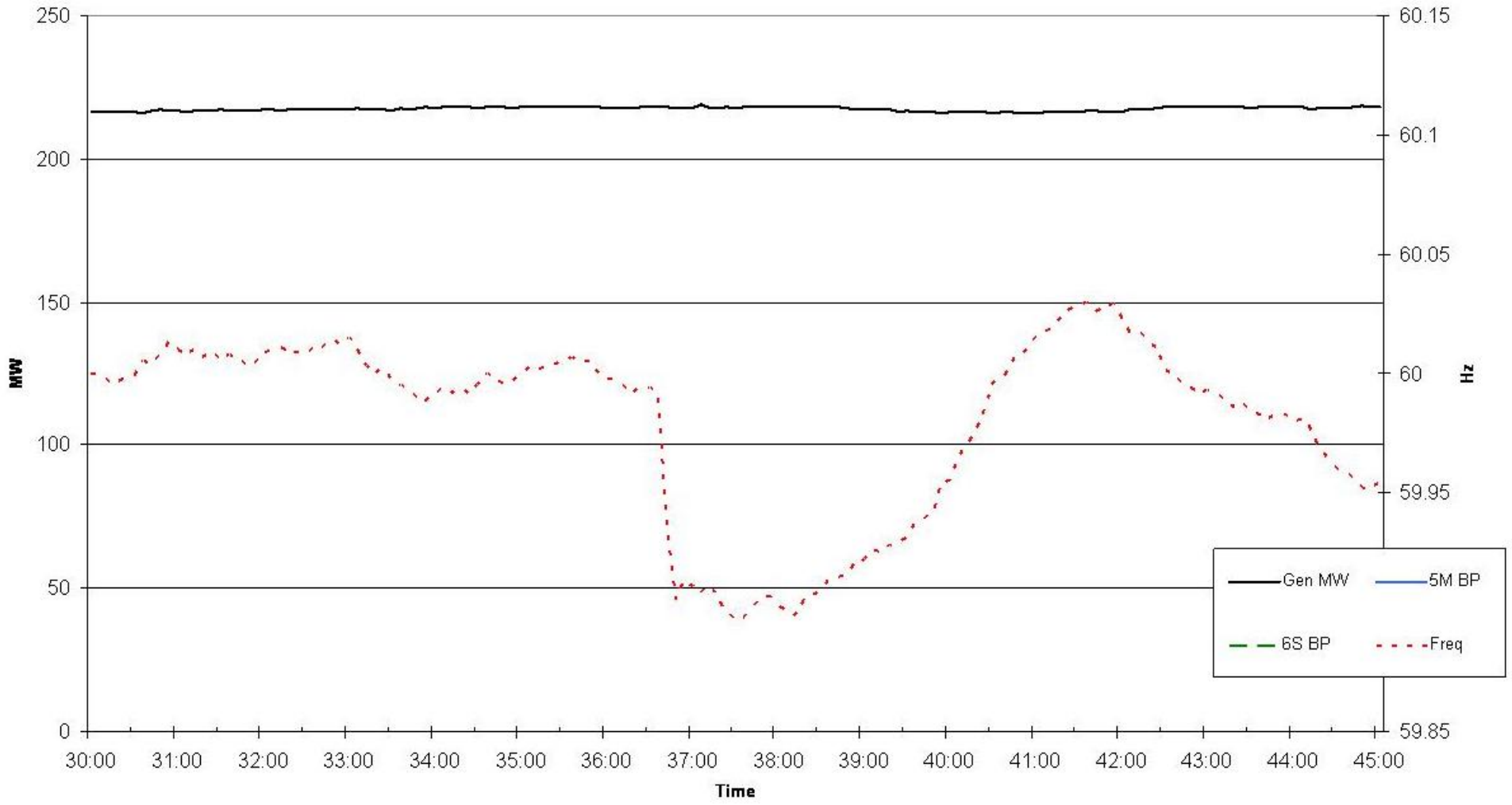
550 MW Unit **21 MW Expected** **7 MW Response**

Spike with Negative Response



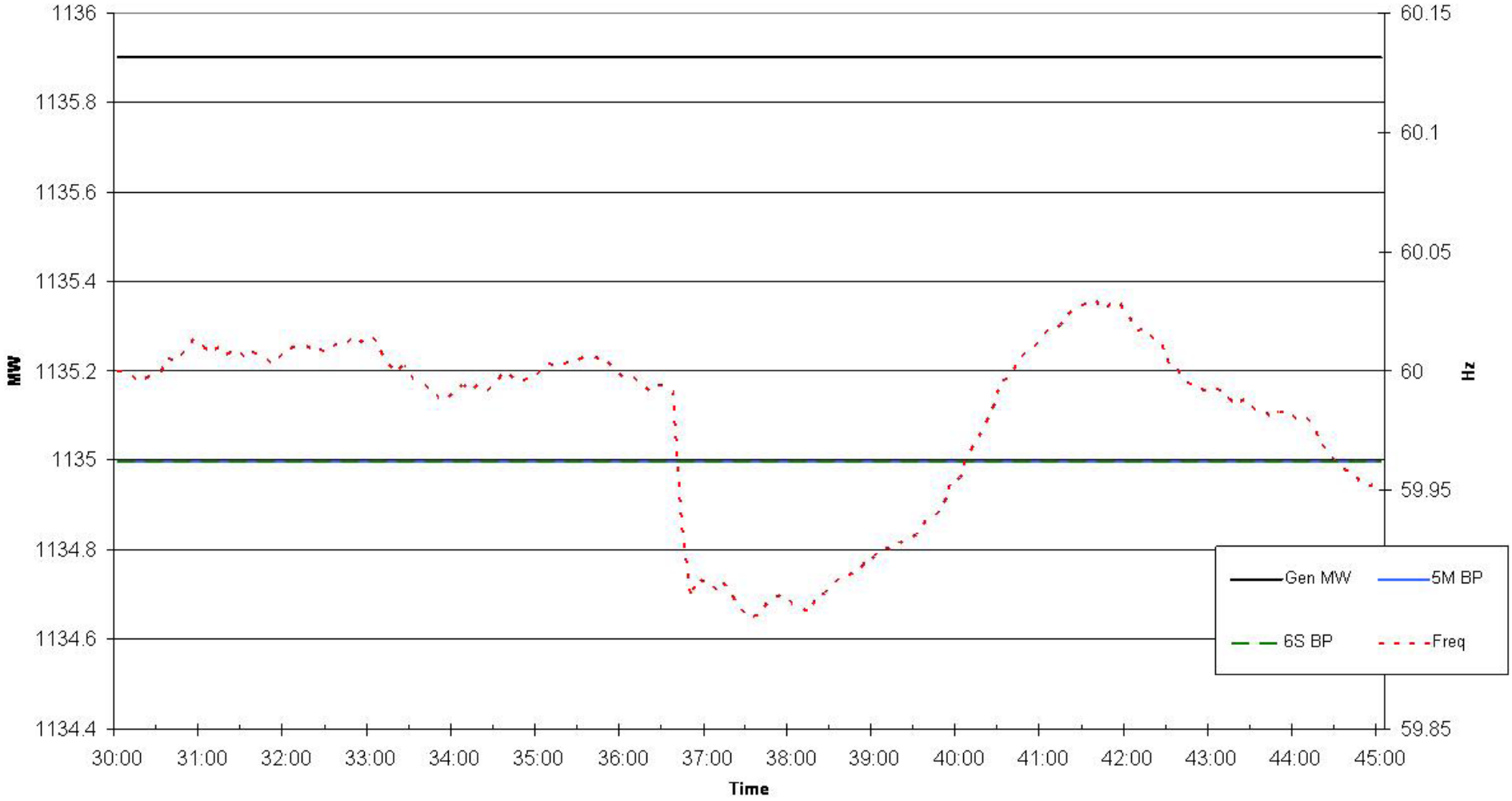
275 MW Unit **11 MW Expected** **~1 MW Response**

Combined Cycle Unit No Response



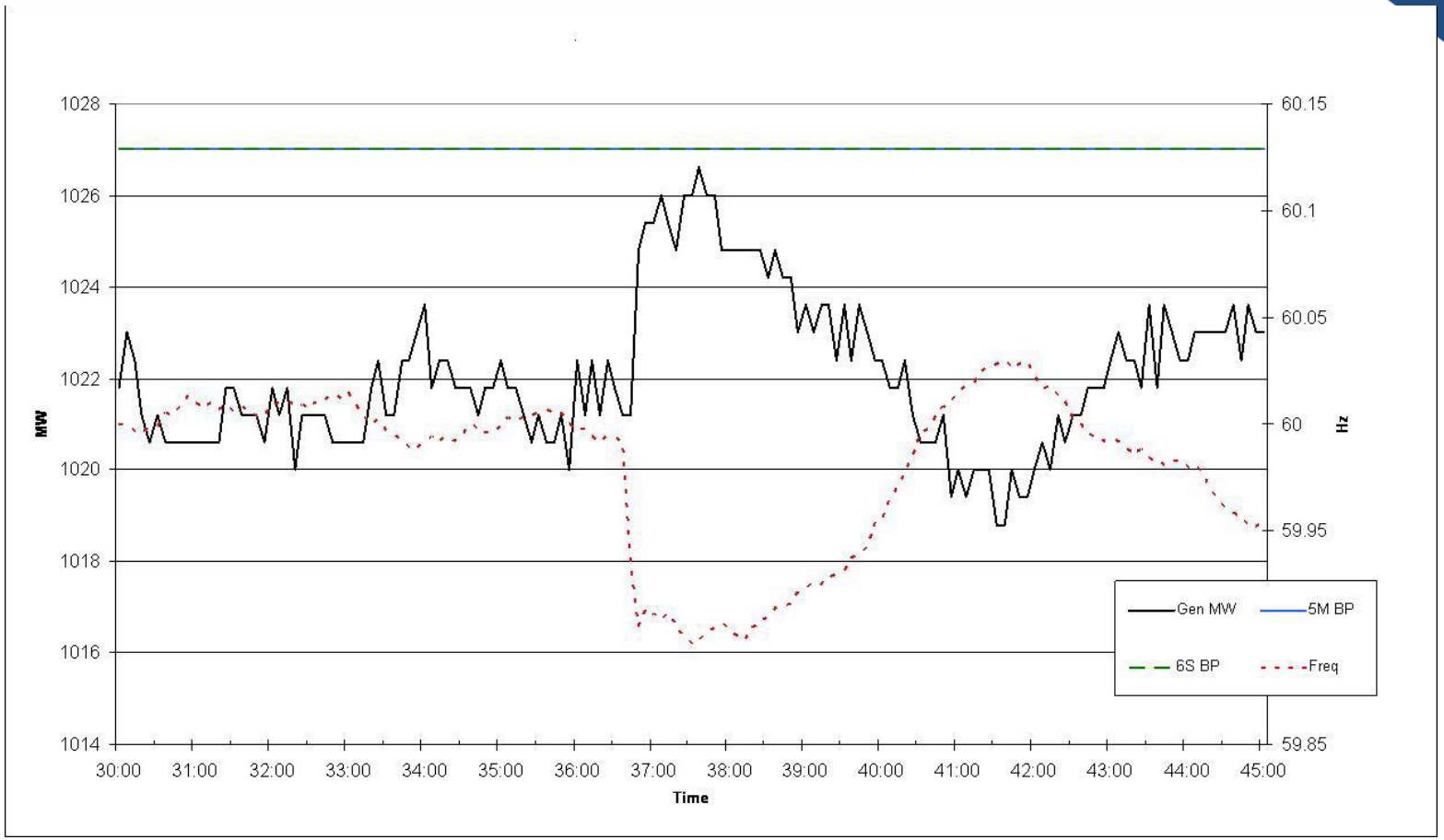
300 MW Unit **6 MW Expected** **No Response**

Non-Responsive Nuclear Unit



1,150 MW Unit **None Expected** **No Response**

Responsive Nuclear Unit



~1,040 MW Unit **None Expected** **4 MW Response**

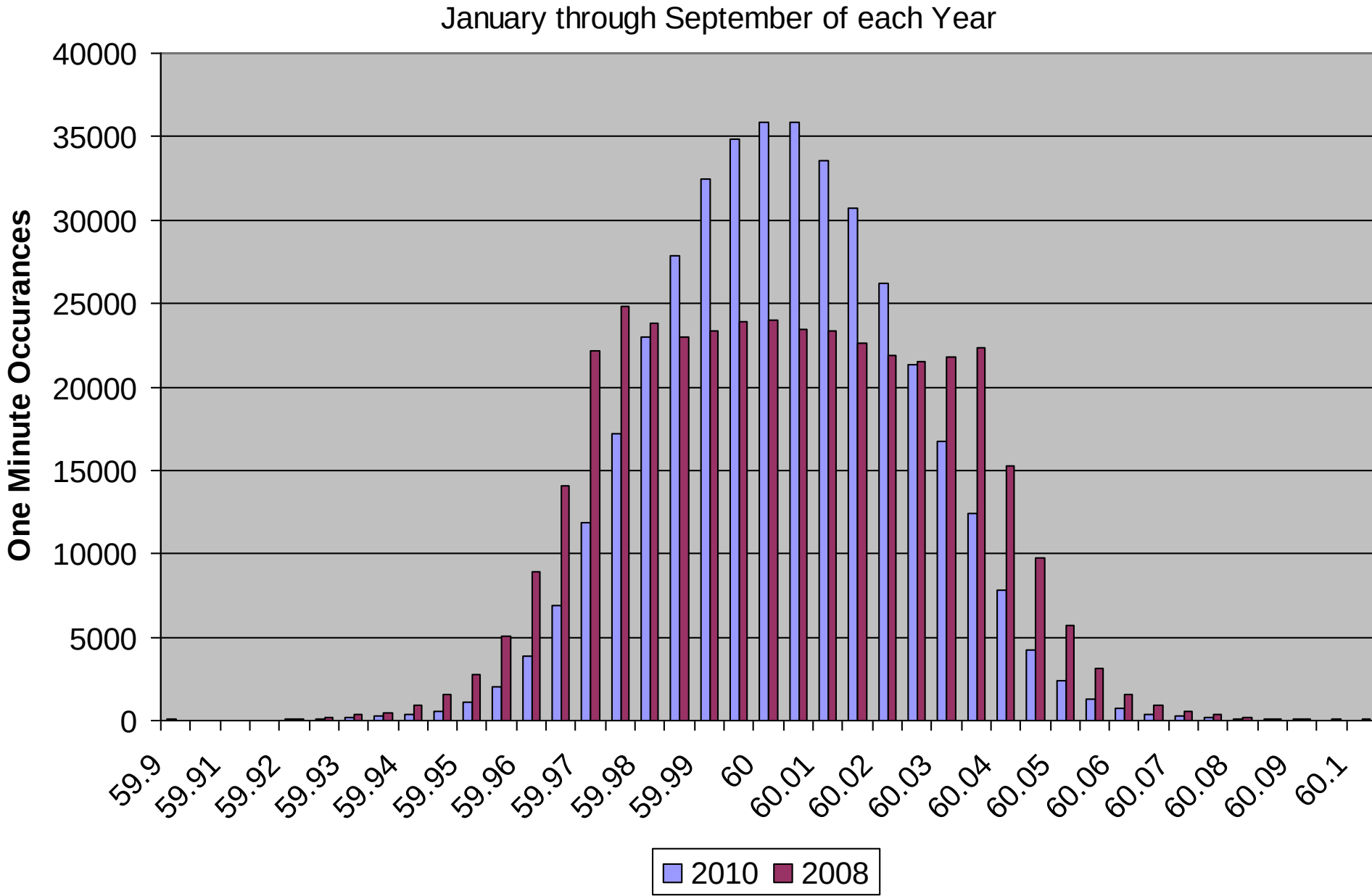
ERCOT Experience with Deadbands

Deadbands in ERCOT

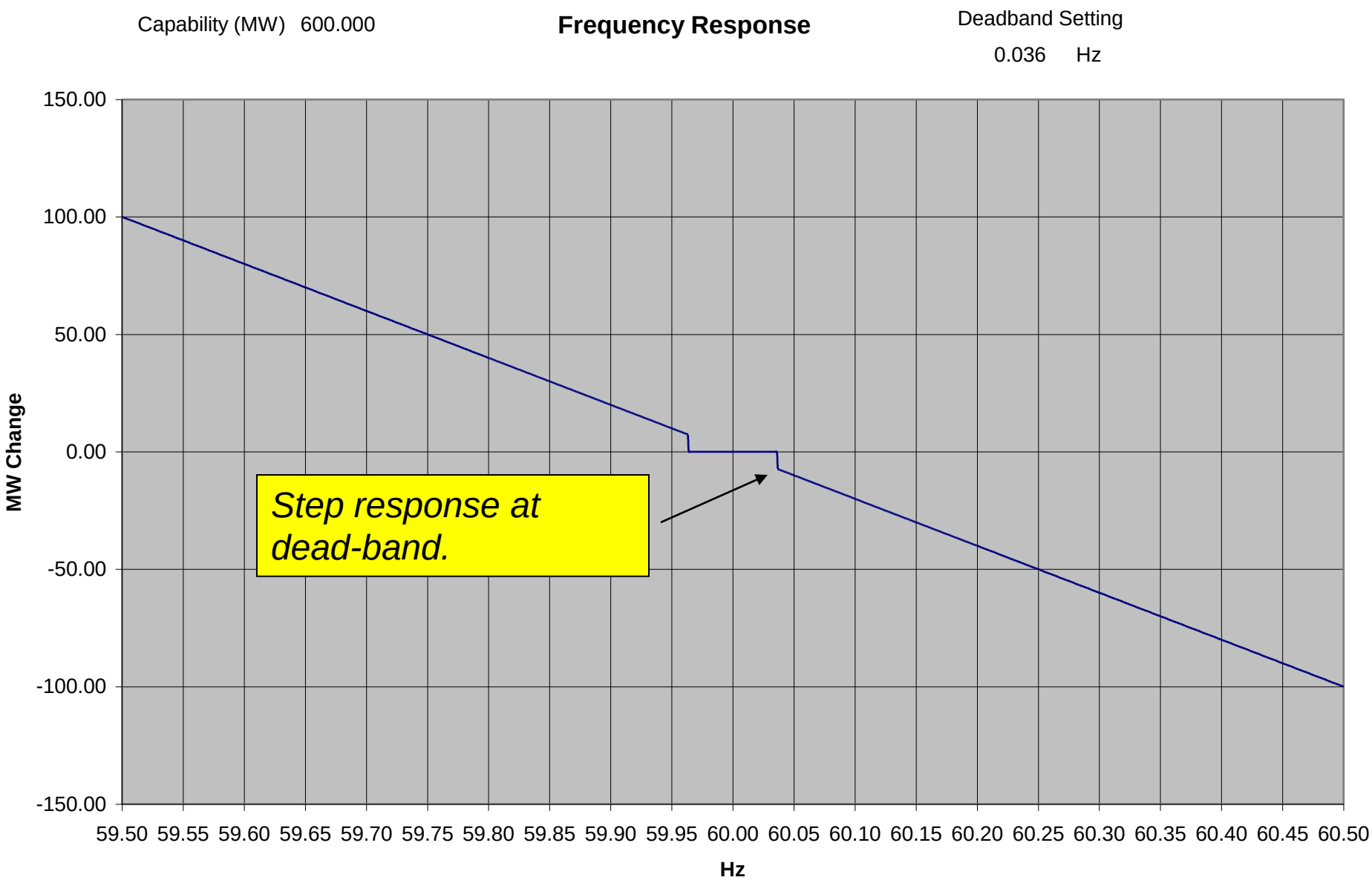
- Initially specified ±36 mHz deadbands (prior to 2010)
- Allowed stepped response at deadband

- Resulted in a flat frequency response for small disturbances
- Resulted in generators trying to respond by larger amounts when deadband was crossed
- Resulted in less stable operation when near boundary conditions of deadbands

ERCOT Frequency Profile



± 36 mHz Deadband – Step Response

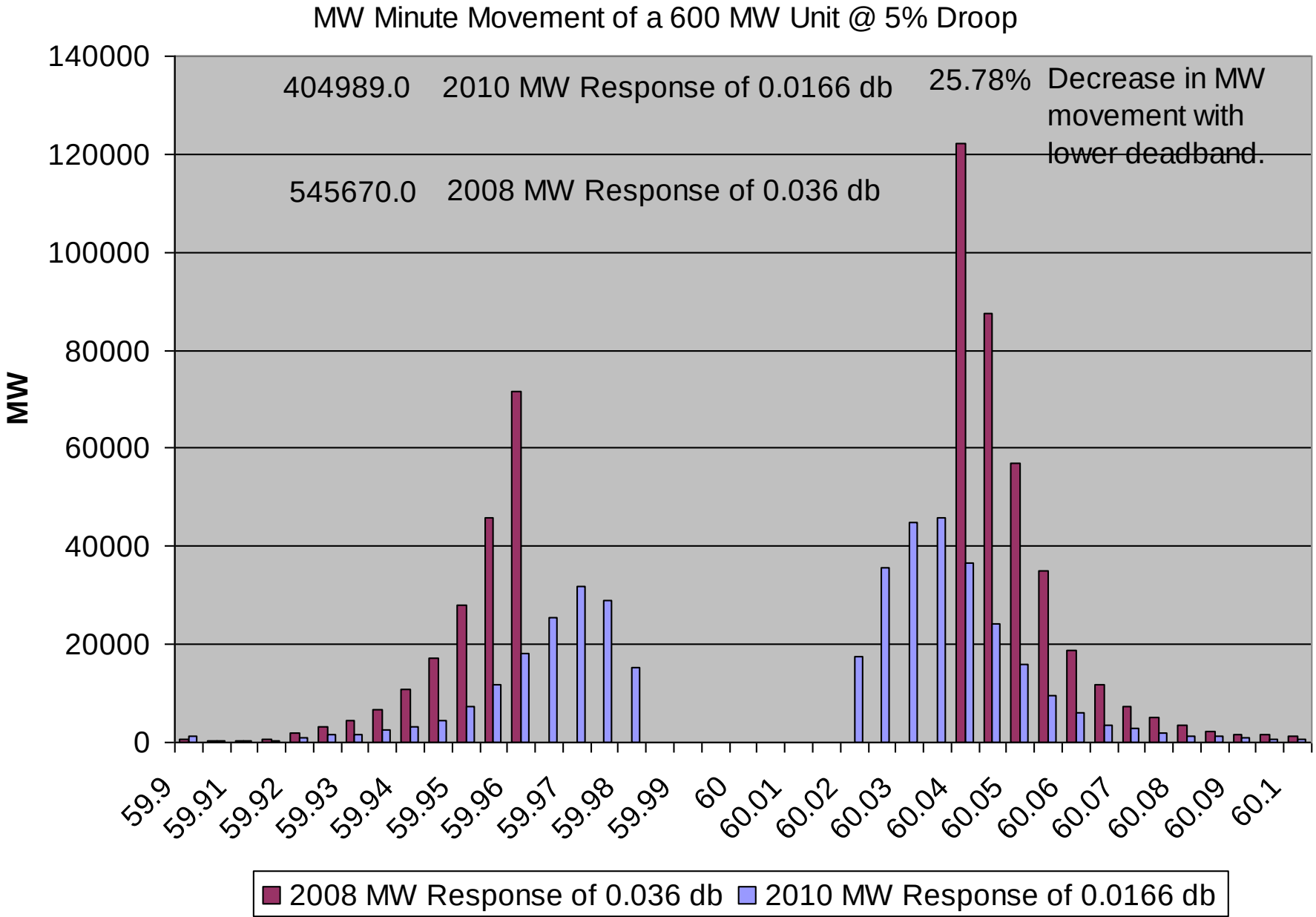


Deadbands in ERCOT

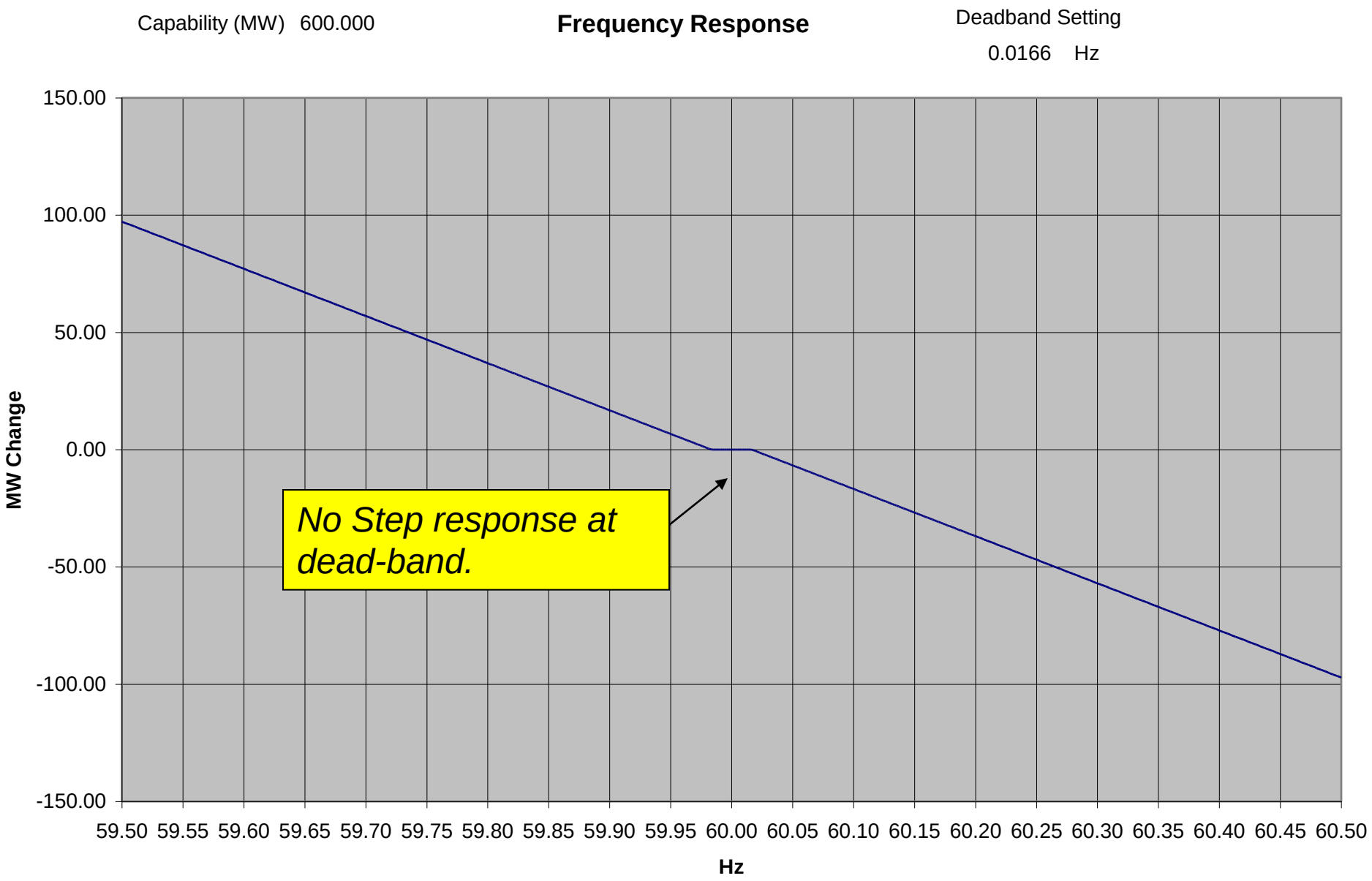
- Moving to ±16.67 mHz deadbands (1 rpm on a 3,600 rpm machine)
- Continuous response (no step) at deadband

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

±0.036 Hz Vs ±0.016 Hz Deadband



± 16.6 mHz Deadband – No Step Response



Questions?

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Frequency Response Technical Conference

BAL-003-1 Overview

Terry Bilke - MISO

RELIABILITY | ACCOUNTABILITY




Agenda

- BAL-003-1 goals
- Bias vs. Beta
- Overview of BAL-003-1
- Changes since last posting
- Differences between version 0 and version 1
- Bias setting process
- Frequency Response Obligation allocation
- Example annual cycle

FRS Goals

- Original SAR
  - Objectively benchmark and track BA and Interconnection performance
  - Establish a better process for developing Bias Settings
  - Enable technically sound decisions on setting any future performance obligations
- FERC Order No. 693 directed additional work
  - Determine the appropriate periodicity of frequency response surveys
  - Define necessary amount of Frequency Response for reliable operations with methods of obtaining response and measuring that the frequency response is achieved

Bias vs. Beta

- Frequency Bias Setting (B) is not the same as Frequency Response (β)
  - Frequency Response is actual MW contribution to stabilize frequency
  - Bias is an approximation of β used in the ACE equation (prevents AGC withdrawal of β)
- Both are negative numbers by convention* (as frequency drops, MW output increases and vise versa)
- Both are measured in MW/0.1Hz
- Bias (absolute value) must be $\geq$ β (absolute value) (stated another way, Bias should be equal to, or more negative than, β)
- In the East, B (absolute value) is about twice as large as β (absolute value)
- Bias (absolute value) under the present standard must be at least 1% of Balancing Authority peak load
- If there is to be a difference between B and β, it is preferable to be over-biased

Note: Some EMS' use a reverse sign convention for ACE and therefore Bias

BAL-003-1 Overview

- Proposed Standard nearly identical to the "Version 0" BAL-003 (only one Requirement is a material change)
  - Frequency Response performance obligation
  - Frequency Bias Setting Implementation
  - Appropriate Frequency Bias Setting for those providing Overlap Regulation Service,
  - Minimum Frequency Bias Setting
- More detail in the following slides

Changes Since Last Posting

- Minimum Bias Setting modified (covered later)
- Clarified the event selection process
- BA responsibility for Frequency Response Obligation (FRO) allocation now based on historic peak data
- Defined Frequency Response Sharing Groups
- Defined upper bound for Frequency Response Obligation

Requirement R1

- BA to provide an average (median) amount of Frequency Response for defined set of events
- Frequency Response Obligation (FRO) is defined for upcoming year (based on BA size)
- BA reports performance at the end of the year for frequency excursions during the year
- With attention, all BAs should be able to meet their FRO
  - Generally sufficient Frequency Response in each Interconnection
  - Standard provides mechanisms to obtain response
  - Field trial data showed good results

R2-R4 Similar to Today

2. Implement Frequency Bias Setting on date specified by NERC
3. Defines how Overlap Regulation providers implement Bias Setting
4. Identifies minimum Bias Setting
   - Drafting team proposes 0.9% of peak/0.1Hz
   - See *"Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard"* (formerly Attachment B) for process to manage changes to the Bias Setting floor

Bias Setting Process

- The Bias Setting process will be very similar to what is done today
- Form 1 will automatically calculate a proposed Bias Setting for the upcoming year
  - The data submitted by the BA will be validated
  - CPS Limits, Bias Settings and FRO for upcoming year will be posted on NERC website
- BAs will be given an implementation date for the new Bias Setting (e.g. March 1 or April 1)

Supporting Documents

- *"Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard"* defines the process NERC will follow to elect events for analysis
- *"Attachment A"* outlines the allocation of the Interconnection's Frequency Response Obligation to BAs
- NERC now publishes lists of events during the year so BAs will have "heads up" on events that will be used
- BAs encouraged to develop local tools to scan for events and capture data for ongoing analysis

Allocation Methodology

- Determine FRO based on the historic annual average monthly peak load and generation (FERC Form 714)
- Formula*:

$$FRO_{BA} = FRO_{Int} \times \frac{Peak\ Gen_{BA} + Peak\ Load_{BA}}{Peak\ Gen_{Int} + Peak\ Load_{Int}}$$

*The Peak Gen and Peak Load numbers above are the average of the twelve monthly numbers

Example Annual Cycle

- January 10, 2013: BAs submit FRS Forms 1 and 2
- January-February 2013: NERC and RS validate data, NERC posts CPS, Bias Setting, FRO
- April 1, 2013: Implement 2013 Bias Settings
- March-November 2013: NERC periodically posts and updates list of candidate events likely to be used for current year's FRM and next year's Bias Setting
- December 7, 2013: NERC posts:
  - Official list of events for Bias Setting and FRM (Forms 1 and 2)
  - BAs notified

Adjusting Minimum Bias Settings

- Present minimum Bias Setting is 1% of peak/0.1Hz
- For most BAs, Frequency Response is < this 1% value
- Control theory says Bias and Frequency Response should closely match
- Proposed field test in 2013 to adjust minimum Bias Settings
  - 0.9% of peak
  - If no issues observed, NERC's procedure will be used to consider further reduction in future years

Questions

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Frequency Response Technical Conference

Minimum Frequency Bias Setting

Howard F. Illian, President, Energy Mark, Inc.

RELIABILITY | ACCOUNTABILITY




Reasons for Minimum Bias

- Original Reasons for Minimum (1964)
  - Assured Frequency Bias Setting above response
    - Actual Frequency Response was much closer to 1% in 1964
    - Based on 1957 Cohn technical paper
      - Did not study Bias Settings above 200% of Frequency Response
      - Partial study of Bias Settings above 150% of Frequency Response
  - Assured all BAs participated in frequency control
    - Requirement set before Secondary Control Standards
      - A1/A2 Secondary Control standard implemented mid-1970s
      - CPS1 & 2 Secondary Control standard revised in late-1990s
      - Developing Primary Control standard currently
    - Assurance of participation no longer needed

1% Minimum Bias Problems

- Problems from Incorrect Frequency Bias Setting
  - Too Low – Causes withdrawal of Frequency Response
  - Too High – Could Cause Frequency Control Instability
- Known Problems with Minimum Frequency Bias
  - Over Bias - East 250% - West 160% - ERCOT - 112%
    - Frequency Control Instability during Eastern disturbance
    - Poor “Situational Awareness” due to over bias
  - Limits flexibility for tuning AGC Systems
  - Min. does not over-bias BAs with bias above min.

Changes to Minimum Bias

- Eliminate minimum for single BA interconnection
  - Provides flexibility for tuning AGC Systems
- Eliminate minimum for variable bias BAs
  - Simplify bias measurement
  - Minimum bias does not improve reliability
- Set minimum from 100% to 125% of FRM
  - Provides flexibility for tuning AGC on multiple BA interconnections
- Slowly reduce interconnection 1% minimum
  - Start at 0.9% and reduce by 0.1% per year max.

Questions

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Frequency Response – Responsible Entity

David Lemmons, Xcel Energy

RELIABILITY | ACCOUNTABILITY




Responsible Entity

- Comments have been received that the BA should not be responsible for FR.
- There is a desire to address the identified reliability issue in a timely manner.
- The SAR could be expanded to address other Responsible Entities, but this will delay the process.
- The Drafting Team recommends that Balancing Authorities have responsibility for Frequency Response under this standard.

Functional Model Support

- Balancing Authority description in Version 5 of Functional Model states:
  - Under Tasks, BA needs to “Operate the Balancing Authority Area to contribute to Interconnection frequency”
  - Under Relationships, BA “Acquires reliability-related services from Generator Operator.”

FM Technical Document

- Maintaining resource-demand balance within the Balancing Authority Area requires … resource management, all of which are the Balancing Authority's responsibility:
  - **Frequency control through tie-line bias**. To maintain frequency within acceptable limits, the Balancing Authority controls resources within its Balancing Authority Area to meet its frequency bias obligation to the Interconnection.

FM Technical Document cont

- **Failure to balance**. The Balancing Authority must take action, either under its own initiative or direction by the Reliability Coordinator, if the Balancing Authority cannot comply with NERC's Reliability Standards regarding frequency control and Area Control Error.

Generator Operator

- The Generator Operator could be given some responsibility for Frequency Response
- Reasons include
  - Majority of Frequency Response traditionally has come from generators
  - Governor control settings significantly impact response from individual generators

Generator Operator

- Functional Model Tasks
  - Operate generators to provide real and reactive power or reliability-related services per contracts or arrangements.
  - Support Interconnection frequency
- Functional Model Real Time Relationship
  - Adjusts real and reactive power ***as directed*** by the Balancing Authority and Transmission Operators. (emphasis added)

Issues with GOP Inclusion

- Some generators may be incapable of responding or have valid reasons not to respond
  - Generator at minimum or maximum, regulatory or environmental limitations, generator may have no governor, etc. all impact a generator's ability to respond.
- Magnitude of measurement process would be expanded significantly
  - 106 BAs registered compared to 4,000 to 20,000 generators, depending on size.
- Other technologies could provide response in the future.
- Response from a subset of generation provides sufficient response to maintain reliability

Additional Issues

- Transmission Tariff Interactions
  - Imbalance Penalties charged to generators due to differences between schedule and actual
  - Order 890 Paragraphs 650 and 672.
- Market Rules/Tariffs can have similar issues
- Ancillary Services rules
- Balancing generator efficiency and interconnection reliability
- Compensation issues

SDT Recommendation

- Move forward with the BAL-003 standard with BA responsibility
  - Allows identified gap to be addressed
- If members of industry believe a standard related to generator control is needed, submit a SAR to begin that process.
  - The current processes related to Generator Verification should be reviewed as part of any effort

Questions

Frequency Response Concerns & Renewable Generation

Brendan Kirby
Consultant
American Wind Energy Association
NERC Frequency Response Conference
May 22, 2012

Who Should Be Responsible For Frequency Response?

- Declining frequency response has been recognized as a serious reliability concern for over a decade
- The problem is most serious in the Eastern Interconnection – the interconnection with the lowest penetration of wind and solar
- Generators differ in their capabilities *and costs* for providing frequency response
  - In a competitive environment uncompensated costs likely lead some frequency response capable resources from providing response
- Frequency response costs are both capital and opportunity
  - Increased cost to make a generator frequency responsive
  - Greater operating costs when poised to provide response
- Costs vary from generator to generator and from hour to hour

Obtaining Reliability Resources and Maintaining Reliability Should Be a BA Responsibility

- The BA is responsible for meeting CPS 1&2 and DCS requirements
  - Obtaining the required reserves
  - Operating to meet the standards
- BA responsibility for assuring sufficient frequency response capability is a logical extension of existing practice
  - The BA is the entity that is aware of current system needs and capabilities
- The BA can select from the available frequency response resources to assure reliability
  - Select the least cost resource mix: It will likely change from hour to hour
  - Utilize all available resources: Generators, Demand Response, Storage

Assuring Frequency Response Capability

- Resources differ in their frequency response capability
  - All technologies have difficulties under certain circumstances: CTs when duct firing, nuclear plants, coal plants when in boiler follow mode.
  - Some loads can provide frequency response, most cannot
  - Some storage resources are ideal for frequency response but others are not
  - The amount of frequency response that each generator, load, or storage facility can provide differs
  - Some new wind turbines can't supply the capability
- Incentives are better than mandatory requirements for reliably obtaining frequency response capability

AWEA's Frequency Response Recommendations

- Address the problem
- Technology neutrality
  - Allow generation, demand response, and storage to participate if they are technically capable
- Use economic incentives rather than mandatory requirements
  - To select the least cost resources in real time
  - To assure capability is installed
  - Pay for performance
- Make full use of existing capability
  - Do not impose retroactive requirements

GO Perspective on Frequency Response Resources

NERC FR Conferences

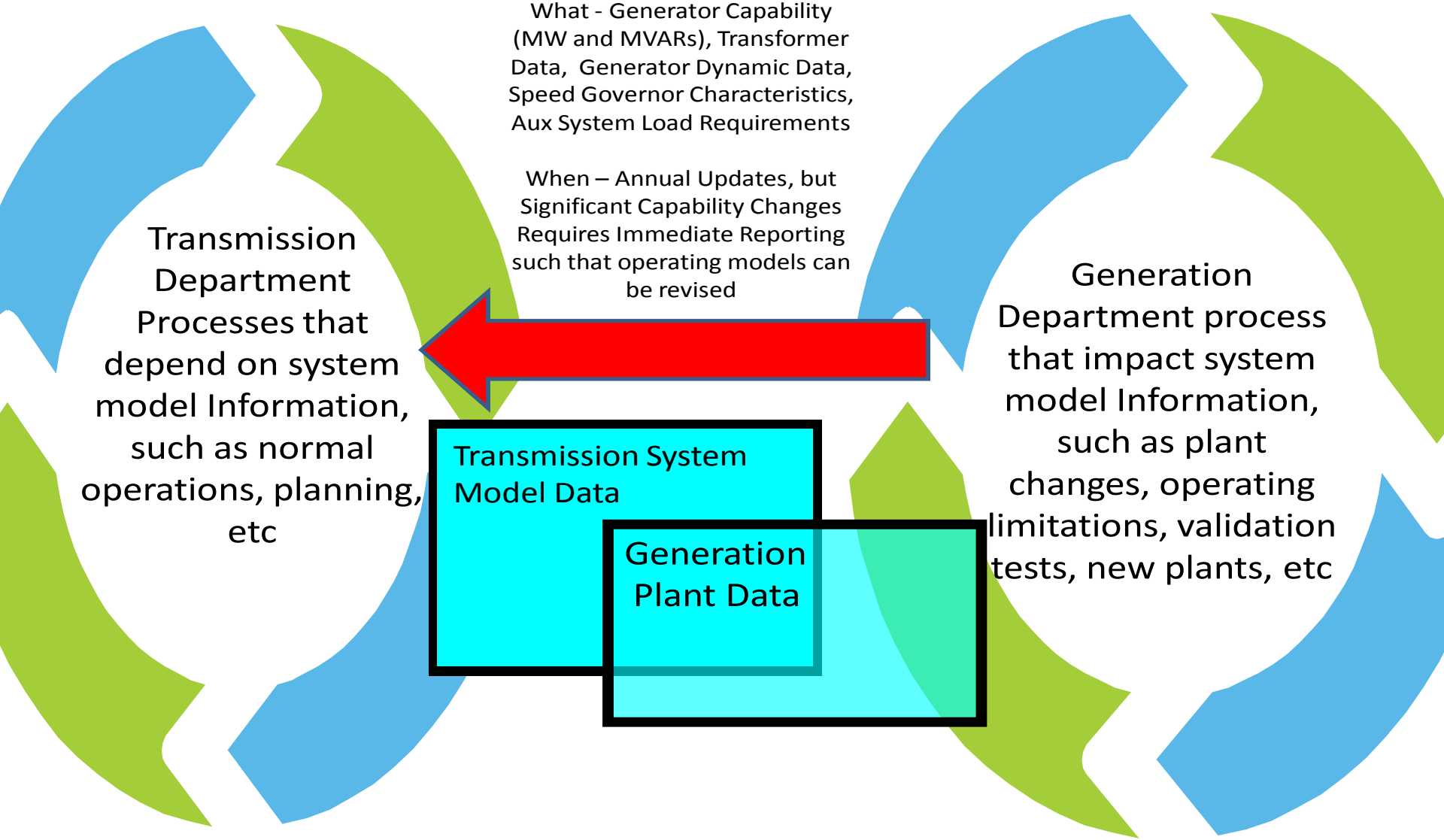
Chris Schaeffer, Sr Engineer, Duke Energy

Chair of EPRI Power Plant NERC Standards MOD Tech Focus Group

NERC Mandated Data Communication

What - Generator Capability (MW and MVARs), Transformer Data, Generator Dynamic Data, Speed Governor Characteristics, Aux System Load Requirements

When – Annual Updates, but Significant Capability Changes Requires Immediate Reporting such that operating models can be revised



Complications

- NERC historically a Transmission focus except for Markets. GO/GOP began to focus after 2007.
- Many different industry structures (vertically integrated vs. IPP/TO) - who is really responsible for what?
- In market based structure, cost cutting, no incentive to maintain equipment expertise - Plants get paid for MWhs. Will follow mandatory NERC standards but maintaining expertise current with evolving issues not considered economic.
- Grids not designed to common “standards”.
- Communication between TO and GOP is hampered by oversensitivity to code of conduct and standards repercussions, especially where an IPP may compete with native generation.
  - This should not be an issue with Frequency Response but...

Recent Trends

- Plant engineering, design, construction and modification outsourcing - less involvement of engineers with understanding of grid issues – not many available.
  - Engineering companies use young (less expensive resources). Minimal graduates in Power Systems. Issues not typically covered in industry initiatives, such as EPRI plant training.
  - No link of recent grid standards with plant design standards (i.e. IEEE, EPRI URD).
  - Controls engineers do not understand “Response Obligations”
- New NERC Focus groups – EPRI and NAGF – no “grid” INPO
- Standard new plants w/o considering local design needs – interconnection studies must identify issues prior to approval.
  - Recent NAGF question – what standard plant features are needed?

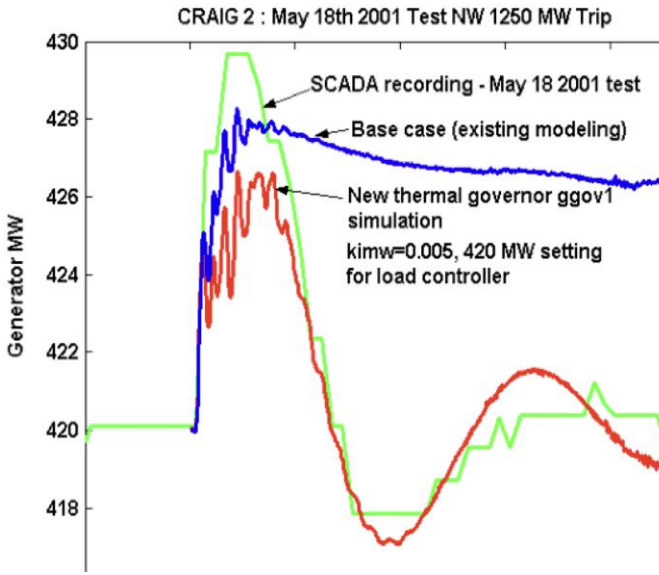
Long Term Legacy (Prior to Mandatory Standards)

- Different MW power sources lead to different technical issues

- Good engineering (ME) ≠ Good engineering (EE). Full operating MW capability of old coal plants may be > designed MW (Prated) in assumed in models.
  - Over time, replacement of worn out turbines with new, more efficient components , tuning steam cycle operating efficiencies based on new knowledge
  - May operate well above original rated MW power levels and thus may be “FR Limited” due to actually operating continuously at the Pmax and Valves wide open (VWO).
  - Boiler output not changed thus, were not considered planned uprates.

Frequency Response and Governors

- Generator MW output responsiveness to Frequency changes
- Early models assumed all units can be modeled as responsive using droop and deadband – invalid assumptions continue which has caused us to miss the big picture - how a unit MW output can be expected to change with frequency.
- Individual Response obligations not well understood
  - Desired response is 1% for 2 minutes?
- Digital governor Max Power Limits
- Plant control system over-rides gov response
- Terminology is key. Ask a GO/GOP
  - How will unit respond to Freq.?
  - Not What is your governor droop and deadband?



Problem – Understanding generator frequency response

- Differences in terminology used by plant vs. model engineers (typically software based), e.g.
  - SERC Regional Criteria – Most utilities employ Power Technologies Inc. (PTI) Power System Simulator for Engineering (PSS/E). Consequently, the various activities in the procedural manual incorporate PTI's procedures and nomenclature in describing these activities. **GO's do not speak this language.**
- Models didn't consider VWO, max power limits, etc.
- Lack of clear definitions and use of different terminology for modeled generation assumptions and terms creates confusion on what is needed
  - New NERC Standards and Glossary do not align

Inconsistent standards terms

- NERC Glossary Term Normal and Emergency Rating, however
  - MOD-024 MW - Verification of Generator Gross and Net Real Power Capability
    - Now moved to MOD-25 after industry comments that this is not needed – more confusion
  - MOD-027 - To verify that the turbine/governor and load control and active power/frequency control model and the model parameters, used in dynamic simulations that assess Bulk Electric System (BES) reliability, that accurately represent generator unit real power response to system frequency variations.
- Need consistent terminology understood by both sides

P-max – Is this "Emergency" Rating?

- **Pmax** – The maximum MW output that is expected to be available in a system emergency and be produced by governor response to frequency dips.
- Plant control system should allow for automatic frequency response if possible. If appropriate, Pmax might = Gross Continuous Capability (GCC – MOD-024 - e.g. the unit has no frequency response capability).
  - Hydro units can accept short periods of cavitations without significant shortening of turbine blade life
    - may be able to provide
    - control system design needs to support – define what is needed?
  - Units with Valves Wide Open could respond if operated below Pmax, but would need to continuously sacrifice MWs to have that ability - what is the incentive/cost for them to do so?
  - Gas plants could use emergency limits, but operation would exceed operating temp limits, shortening time frames to significant rebuild costs – what is the incentive for them to do so?
  - Nuclear units could respond above 100%, but likely would have to change plant licensing basis to do so – what is the incentive for them to do so.

Staged Governor Parameter Testing

- Conditions during Load Rejection ≠ Conditions during full power operation. Thus, staged testing does not accomplish goal yet discussion still exists to require it. Plants consider this a risky evolution.

- Can validate against ambient data from system response (large loss of generation, a system fault, etc), however, this requires a recorder preinstalled to collect generator MW and frequency during an event, e.g. digital fault recorder (DFR).

- EPRI PPPD Software or equivalent (MatLAB) may perform “parameters tuning” to include load control models.

Suggested Initiatives

- Must transition from Knowledge based to Process based Configuration Control Guidelines
  - What should be considered when plant changes might affect models
  - Revise FAC-8 Documentation
  - Integrated change-based revalidations would best assure models and help develop/maintain needed technical expertise.
    - Unit up-rate activities or generator rewinds
    - MOD-26 validations where appropriate
    - Inertia Changes due to Turbine, Generator Rotor or Exciter replacements
    - Include Frequency Response considerations in plant control changes

Suggested Initiatives

- Consensus MW power terms in Glossary, such as
  - Normal (GCC) vs. Pmax Rating
  - Desired Response (obligations) – 1% for 2 minutes?
  - Pmax that respects plant limitations - NRC imposed limits, Thermal Limits (CTs), Operating Valves Wide Open
  - Ramp Rates – how fast can a unit transition from Normal to Emergency Rating if governor response calls for increases.
- Need to be clearly understood and supported by plant design if plant frequency response will be optimized
- NATF initiative for model guidelines with standard definitions.
- GO/GOP Training on System Issues
  - EPRI & NATF collaborate to develop?

Research “Smart” Tools - UNCC ARPA-E Application

- Develop Optimized Platform for System Analyses, Model Configuration Control and Validations to Support Bulk Electric System (BES) Reliability”
  - Consistent definitions, research Generation Aux system load models and transient ride through (PRC-024)
  - On line model tool that can monitor system response though DFR data and alarm when models don’t match. (PPPD model validation on steroids) - AVR/Exciters, Speed Governor, Load Models and Transformers?
  - Integrated analysis tool that can be used to perform all analyses (LF, TS, SC, Real Time, etc) to minimize and simplify database management.
  - Study system and unit/plant controls (Power load Unbalance, MW setpoints, area control actions, generation control loops) within and beyond the transient stability timeframes between 15-25 seconds.
  - Research will be integrated into the UNCC EPIC Engineering curriculum to **train the next generation power system workforce**.
  - Contact Dr Salami @ UNCC EPIC Center if interested in learning more about concept

QUESTIONS?

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Grid Balancing with Demand

Adding a Degree of Freedom for the System Operator

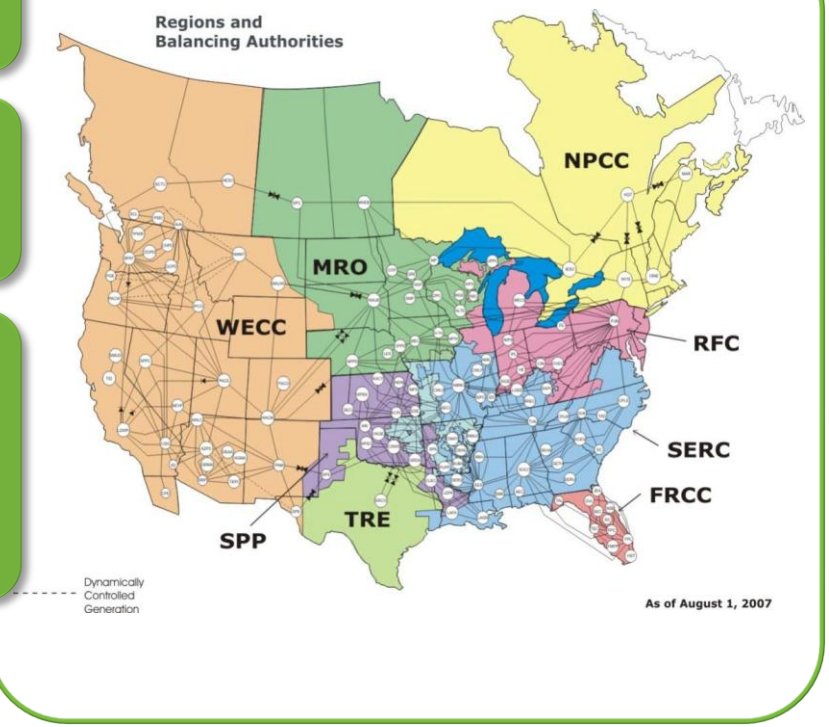
Grid Balancing

Grid Balance is a critical part of electricity generation and distribution

There are over 130 NERC Balancing Authorities (BA's) of varying sizes across North America

Grid Balance is provided in essentially the same way by each individual operator

- Large generator production is constantly adjusted to meet changing electricity demand



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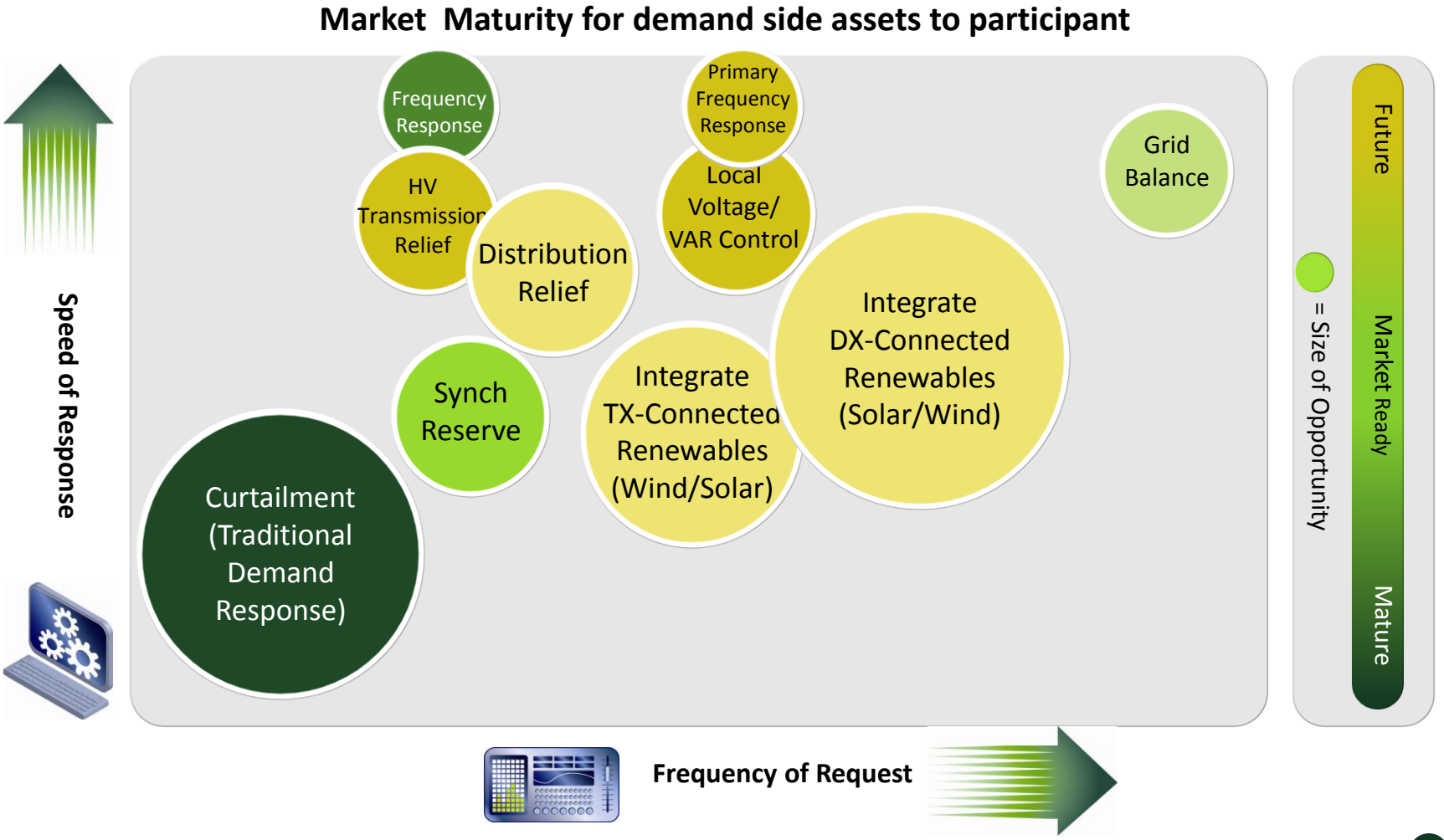
Demand-Side Management Opportunities



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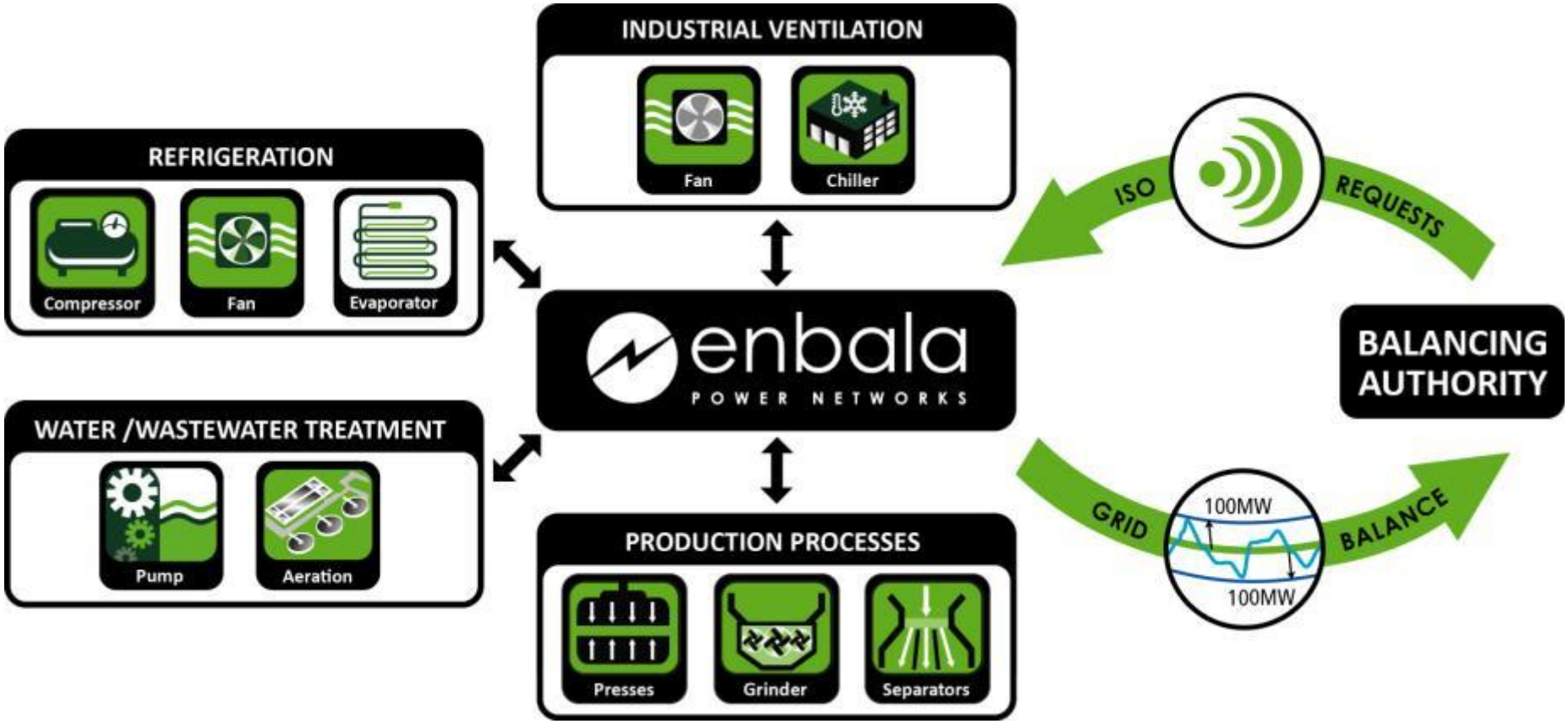
ENBALA Power Network (EPN)



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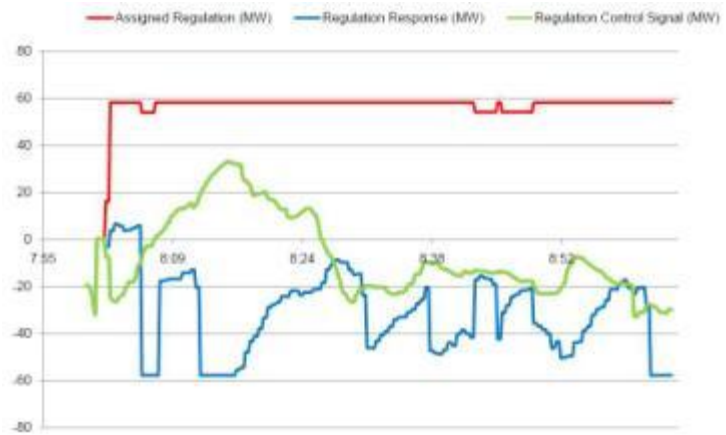
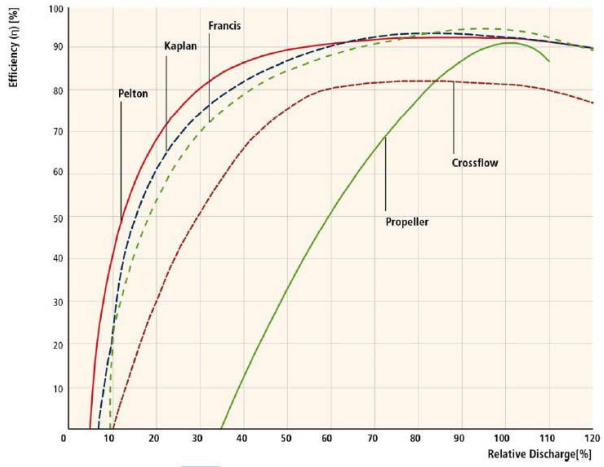
Balancing with Generation

There are many reasons generators can't or prefer not to provide grid balancing

Generating units are limited in their speed of reaction – large mass flow to move

Generator efficiency falls as you move production away from maximum efficient operating point





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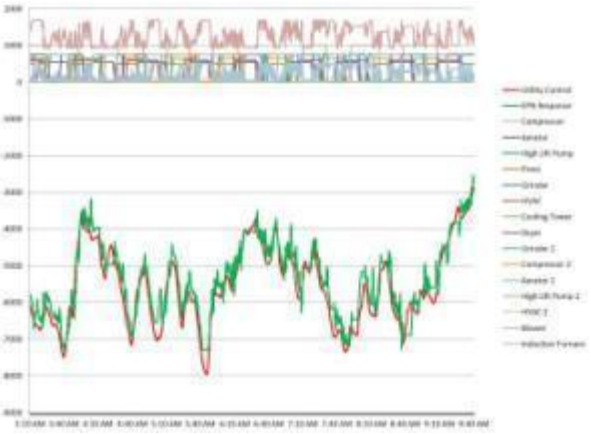
Balancing with Controlled Load is Different

Allow loads to handle volatility, so generators don't have to

A large number of small changes in consumption across a large number of consumers can occur very quickly

Efficiency of load dispatch is flat over short periods - local process storage is used to enable controlled load changes

Production efficiency across the supply fleet can be increased



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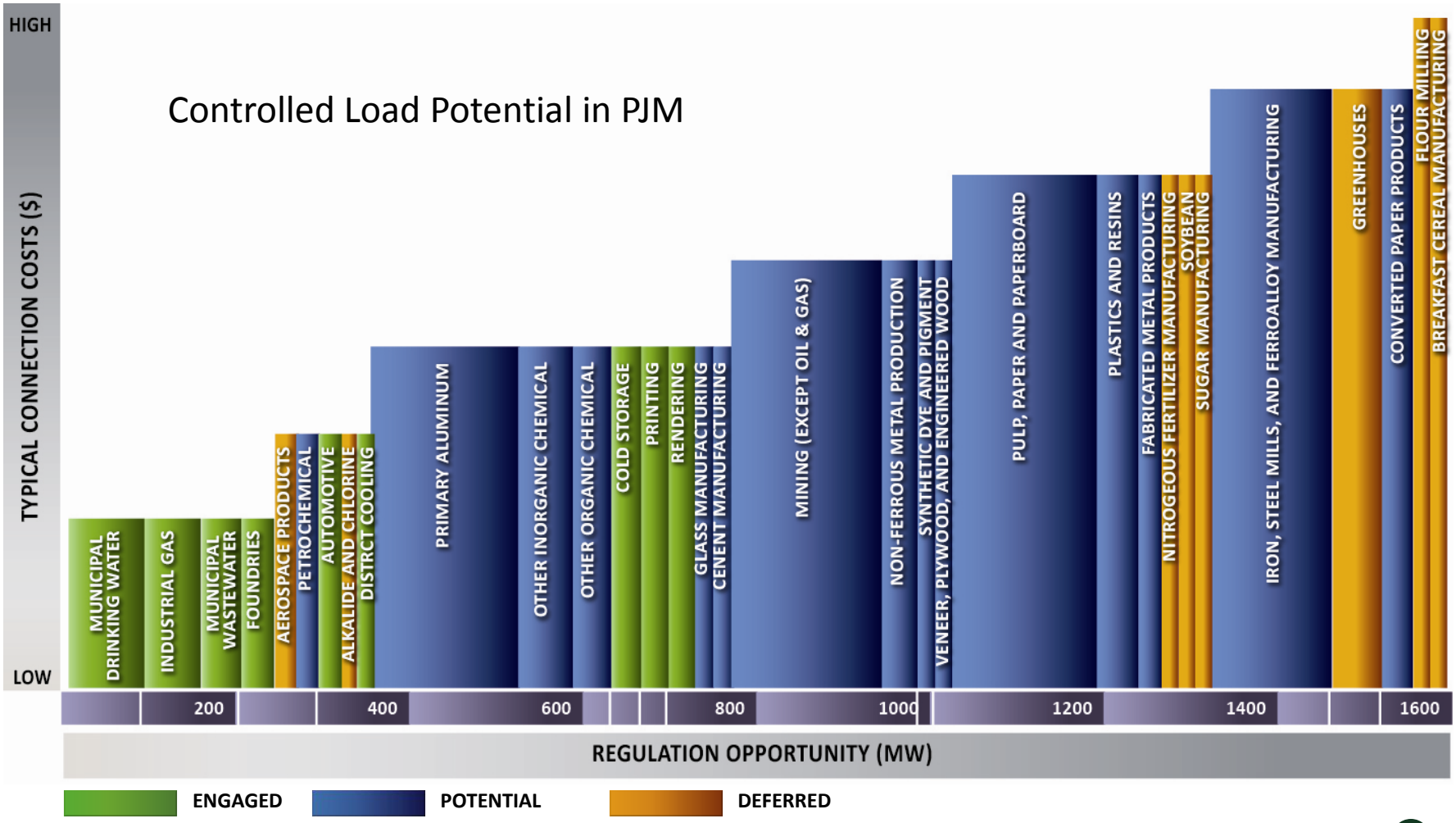
Controlled Loads – Who and How Much?



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EPN Network Performance in PJM

PJM Performance Metric Score: 89.1%

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What we would like to see

- Balancing Authority (BA) be assigned responsibility to ensure sufficient Frequency Response is available
- Ensure that the NERC standard does not define the technology that should provide the response
- BA's procure what they need on an economic basis
- Modify tariff's and/or develop market mechanisms to support the economic selection

- Development along these lines will allow industry to determine the most efficient and effective way to provide necessary Frequency Response

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Thank You

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Frequency Response Technical Conference

Measurement of Frequency Response

Terry Bilke - MISO

RELIABILITY | ACCOUNTABILITY

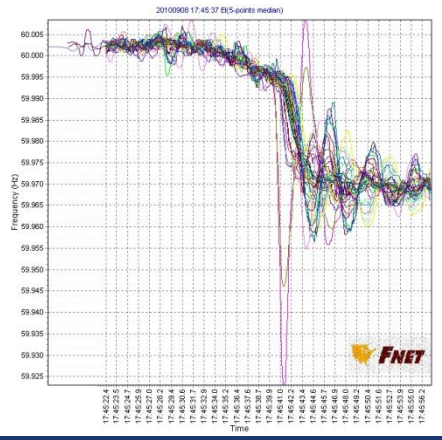



Agenda

- Use of “B value” as the metric
- Median as the measure of annual performance
- Measurement error and data variability
- Proposed Interconnection target obligations
- Estimating your BA’s obligation
- Supplemental discussion (answers to other recently asked questions)
  - Comparison of US-Europe frequency performance
  - Comparison of Interconnections
  - FRS measurement window

B-Value vs. Point C

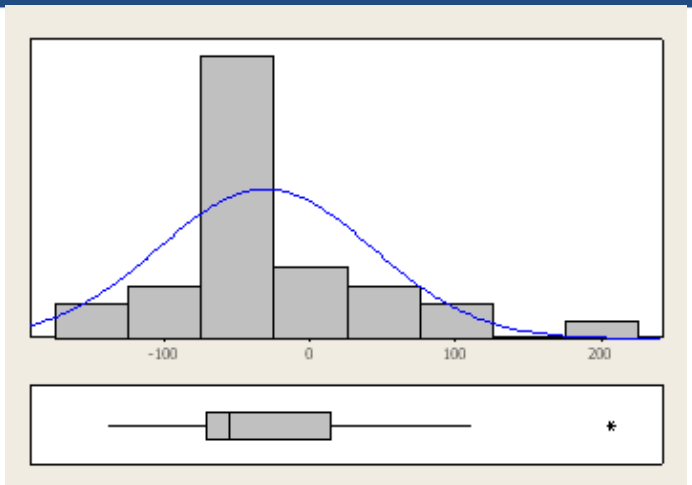
- Much like dropping a stone in a pond, point C is different throughout an Interconnection for the same event and occurs at different times
- The B value is nearly identical among all BAs for the same event
- The ratio of C-B is generally consistent among events within an Interconnection
- Given this, we can use the B value as a metric and apply a correction ratio to measure encroachment on UFLS



Median as the Measure

- The standard uses the median response of about 25 events annually as the measure of a BA's performance
- The frequency response calculation has a very low signal to noise ratio, particularly in a multi-BA Interconnection
  - Governor response is easily masked by minute to minute changes in load
  - Noise causes outliers that corrupt the estimate of frequency response
  - The outliers are not symmetrical and will inflate or underestimate beta
- The median is the preferred measure of central tendency in a population with outliers

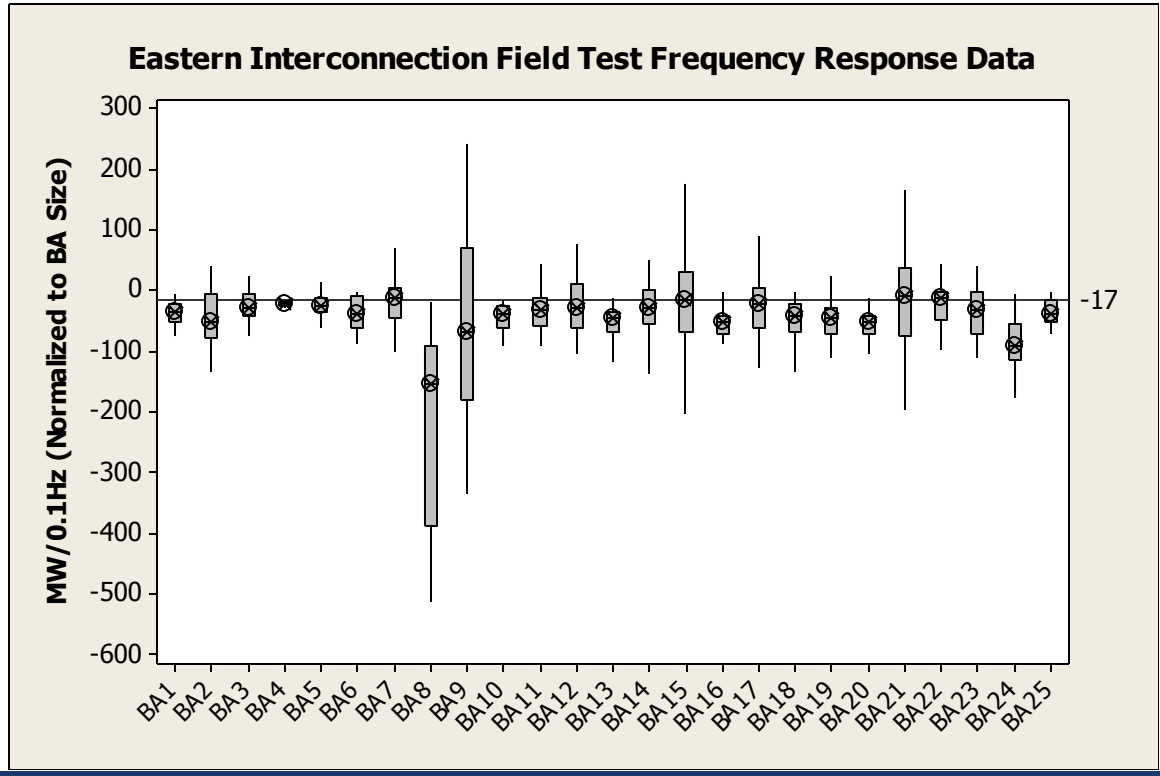
Error induced by Noise



- This graph is typical <u>calculated</u> performance for an Eastern Interconnection BA
- Notice that some values are actually positive
- For the 27 BAs that submitted field trial data, for about 35% of the individual observations, the calculated response is corrupted by the noise to the point of showing low BA frequency response even though Interconnection performed adequately

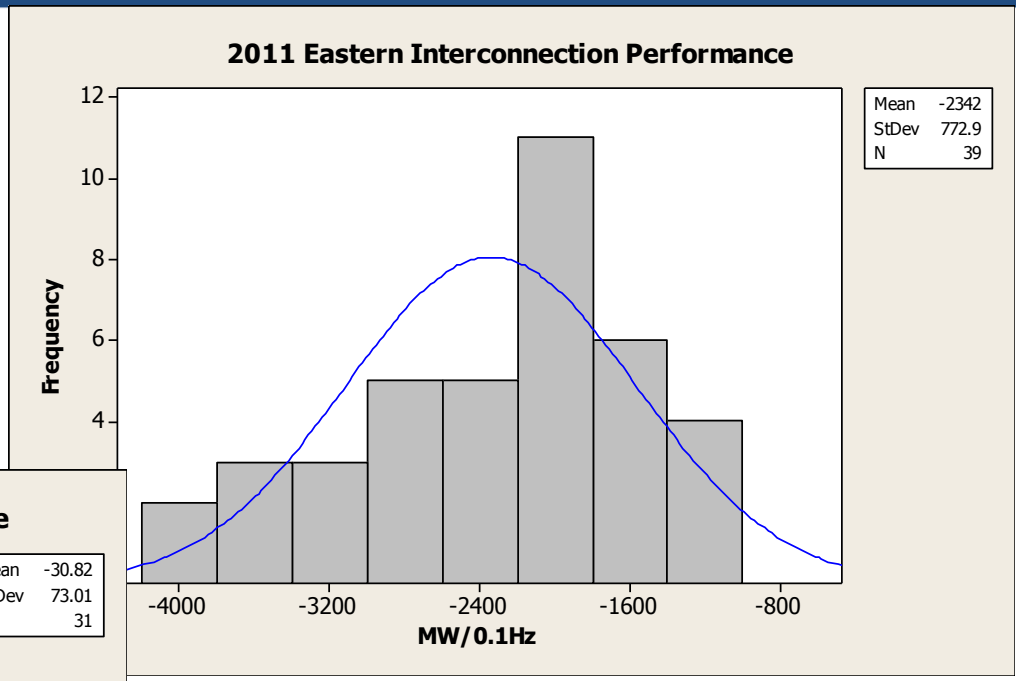
BA Data Variability

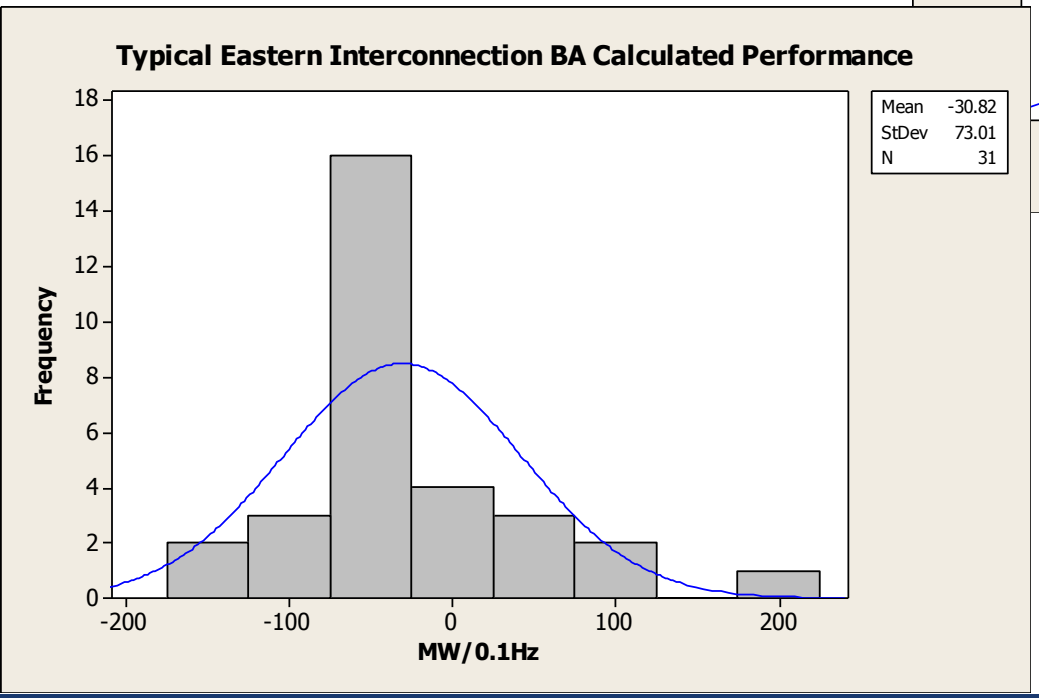
- The graph below shows actual (normalized) data provided by BAs for the field trial
- Note that median performance is OK across the board
- Refer to the previous slide that showed Interconnection performance was acceptable as well for the same period



BA vs. Interconnection

Measurement quality increases when performance is aggregated to the Interconnection level





NERC and the Resources Subcommittee will monitor Interconnection performance for trends

Proposed Interconnection Targets

- The drafting team was asked for further technical justification of the Interconnection target obligations
- The table below outlines the new targets

Interconnection	East	West	Texas	HQ	
Target Protection Criteria	4500	2740	2750	1700	MW
Credit for Load Response		-400	-1400		MW
Prevailing UFLS First Step	59.5	59.5	59.3	58.5	Hz
Frequency Margin (tenths)	5	5	7	15	0.1Hz
Typical C-B Ratio	1.08	1.37	1.24	2.15	
Necessary Frequency Response	-972	-641	-239	-244	MW/0.1Hz
FRO with Reliability Margin (25%)	**-1215**	**-801**	**-299**	**-305**	MW/0.1Hz

Estimating your FRO

1. Use the proposed FRO for your Interconnection (previous slide)
2. Multiply this value by:

$$\frac{\text{Your BA's Bias Setting}}{\text{Your Interconnection's Total Bias}}$$

You can find Bias Setting values at:
www.nerc.com/docs/oc/rs/2012%20CPS2%20Bounds%20Report%20Final(Update20120419).pdf

You can find candidate frequency events at:
www.nerc.com/filez/rs.html

Questions

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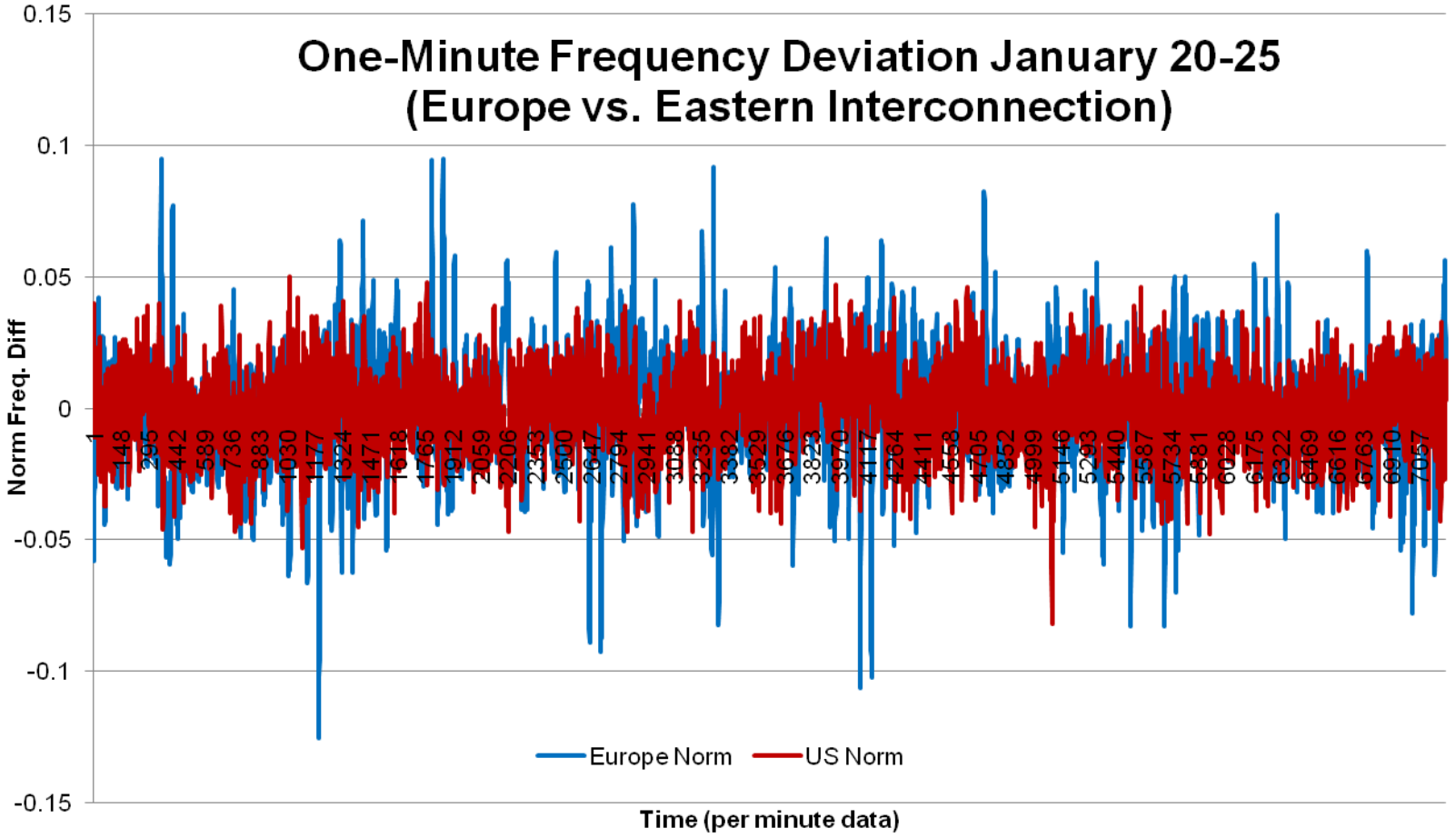
Frequency Response Technical Conference

Other recently asked questions

RELIABILITY | ACCOUNTABILITY

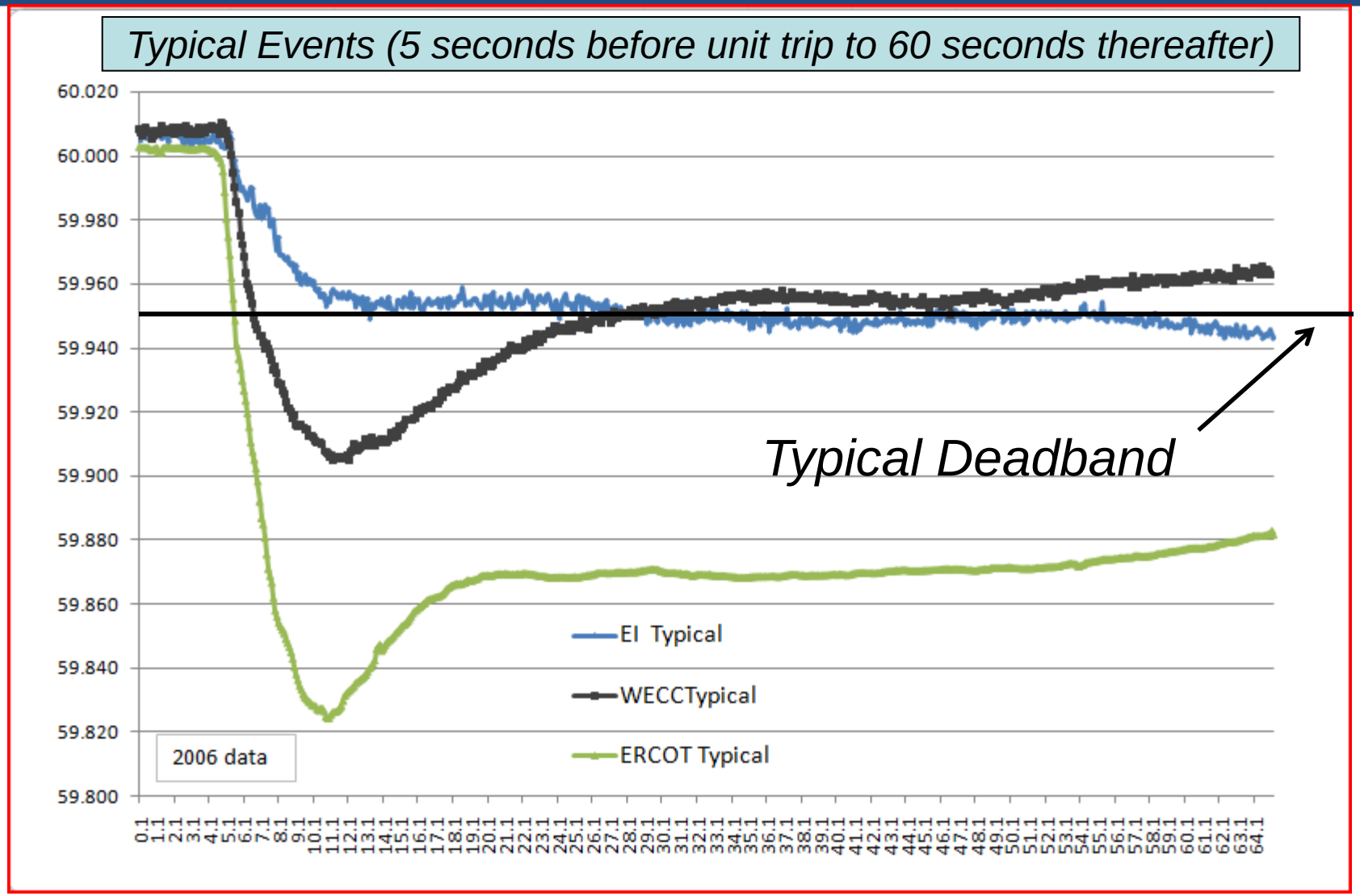


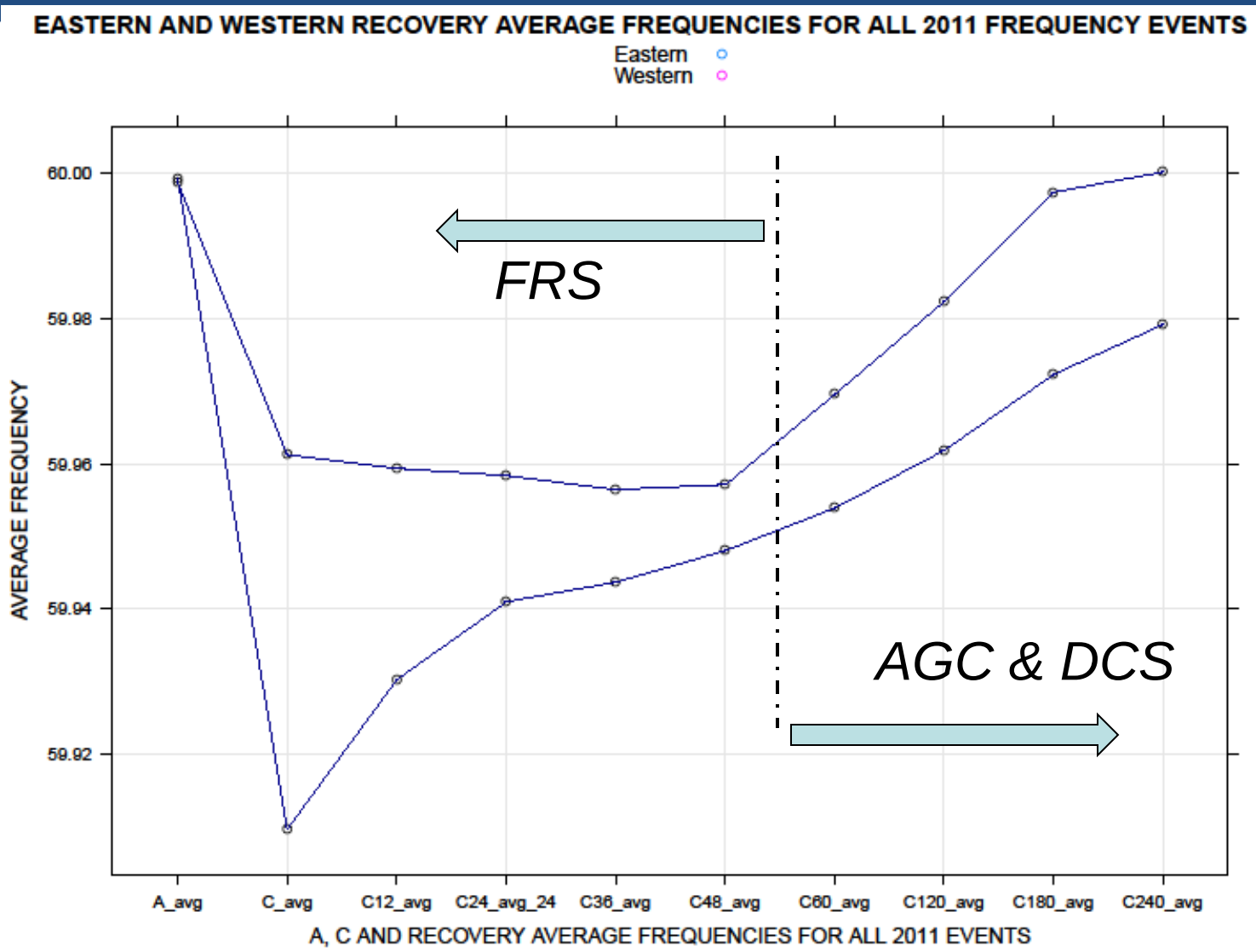

Europe vs. US (EI)



2010 comparison by the Resources Subcommittee

Interconnection Comparison




EASTERN AND WESTERN RECOVERY AVERAGE FREQUENCIES FOR ALL 2011 FREQUENCY EVENTS
Eastern
Western
60.00
59.98
59.96
59.94
59.92
AVERAGE FREQUENCY
FRS
AGC & DCS
A_avg
C_avg
C12_avg
C24_avg_24
C36_avg
C48_avg
C60_avg
C120_avg
C180_avg
C240_avg
A, C AND RECOVERY AVERAGE FREQUENCIES FOR ALL 2011 EVENTS

Attachment C

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Meeting Notes
Project 2007-12 Frequency Response Standard Drafting Team

June 21, 2012 | 8:00 a.m.–5:00 p.m. ET
June 22, 2012 | 8:00 a.m.–Noon ET

MISO Office
720 City Center Drive
Carmel, IN 46032

Administrative

1. **Introductions**

The meeting was brought to order by the Chair, David Lemmons at 8:00 a.m. ET on Thursday, June 21, 2012. The chair provided the team with building and safety information/logistics. Each participant was and those in attendance were:

Name	Company	Member/ Observer	In-person (Y/N)	Conference Call/Web (Y/N)
Don Badley	NWPP	Member	Y	
Terry Bilke	MISO	Member	Y	
Howard Illian	Energy Mark	Member	Y	
David Lemmons	Xcel Energy	Member	Y	
Carlos Martinez	CERTS	Member	Y	
Sydney Niemeyer	NRG Energy	Member	Y	
Mike Potishnak	ISO NE	Member		Y
Darrel Richardson	NERC	Member	Y	

Name	Company	Member/ Observer	In-person (Y/N)	Conference Call/Web (Y/N)
Ena Agbedia	FERC	Observer		Y
Robert Blohm	Consultant	Observer		Y
Neil Burbure	FERC	Observer	Y	
Bob Cummings	NERC	Observer	Y	
Doug Hilsa	Duke	Observer		Y
Stacey Tyrewala	NERC	Observer	Y	

2. **Determination of Quorum**

   The rule for NERC Standard Drafting Team (SDT) states that a quorum requires two-thirds of the voting members of the SDT. Quorum was not achieved as only 7 members were present.

3. **NERC Antitrust Guidelines and public reminder**

   The NERC Antitrust Guidelines and public reminder were read by Darrel Richardson. There were no questions raised.

Agenda

1. **Discussion**

   a. Review summary issues from the Technical Conferences (refer to PowerPoint presentation).

      I. The SDT reviewed the issues raised during the two technical conferences held in May 2012. The major issues raised were as follows:

         1. Is the Frequency Response standard required? The SDT determined that although there appeared to be sufficient Frequency Response at the present time, there has been a decline in the amount of Frequency Response and the development of a standard should alleviate this problem.

         2. Who is responsible for providing Frequency Response? The SDT reiterated their position that the Balancing Authority was the responsible entity for providing Frequency Response. The SDT also felt that they should not define how an entity acquires Frequency Response and that this was not a standard issue but more of a market issue.

3. Would the development of a Frequency Response Market be beneficial? The SDT felt that this would be very beneficial but they also felt that it was not the responsibility of NERC to drive. The SDT believes that this is more of a NAESB issue but FERC involvement would be beneficial.
4. Is the Underfrequency Load Shedding (UFLS) setting for the Eastern Interconnection the proper number to be using? The SDT pointed out that they had discussed the Florida issue with John Sheffer (chair of the Stability Working Group) and that he felt the UFLS setting should not be driven by Florida issues. One member suggested using a weighted table with the weights being a function of control area. Another individual felt that this would create "free riders" and that it should be generic. It was pointed out that this could cause some entities to commit resources for others.

b. Review the comments received during the comment period following the Technical Conferences (refer to the comment report).

I. The SDT reviewed the comments received and the major issues raised were as follows:

1. Others, besides Balancing Authorities should be responsible for providing Frequency Response. The SDT reiterated their position that the Balancing Authority was the responsible entity for providing Frequency Response. The SDT also felt that they should not define how an entity acquires Frequency Response and that this was not a standard issue but more of a market issue.
2. The use of Variable Bias in the standards was not clear and did not seem to be a fair approach. There was a feeling that if the SDT did not include constraints or bounds on the use of Variable Bias that there could be a migration to using Variable Bias and if this happened without bounds it could have impacts on reliability. The SDT decided to modify the standard on the use of Variable Bias and provide additional language in the Background Document concerning Variable Bias.
3. What is the rationale for using N-2 criteria for defining an Interconnection Frequency Response Obligations (IFRO)? The SDT felt that this was explained in the Transmission Issues Subcommittee (TIS) report and will make the report available to the industry.
4. Why does the standard use Peak Load data to calculate a Balancing Authority FRO? The SDT discussed this and decided to modify the calculation to use peak energy data from FERC Form 714 rather than Peak Load data.
5. Doug Hils (Duke Energy) provided a presentation on two methods for allocation FRO and minimum Frequency Bias. The SDT felt that these methods could create conflicts and noted that they seemed reasonable but they lacked technical support. The SDT decided to look at them closer for possible future use.

c. Review questions raised on ReadyTalk during the Technical Conferences: The SDT determined that the inquiries were previously discussed and that no further action was required.

2. **Action Item Review**

   a. There were no action items assigned prior to the meeting.

   b. The following action items were assigned:

      I. Howard Illian to provide additional analysis for use of 25 percent as the "Reliability Margin" for the IFRO. This information will also be compared to the TIS report.

      II. Mr. Illian will provide an analysis of the 2011 data for using a single event measurement versus a multiple event measurement (similar to his work using 2010 data).

      III. Bob Cummings, Carlos Martinez and Neil Burbure will meet to discuss using larger data sets in the different analysis.

      IV. Mr. Lemmons and Gerry Beckerle will provide clarifying language for the event selection criteria in Attachment A.

      V. Don Badley will provide clarifying language for the IFRO in Attachment A.

      VI. Mr. Martinez will provide an analysis for using more than one year for the calculation of frequency response measure.

3. **Future meeting(s)**

   a. There are conference calls scheduled for July 9 and 10, 2012.

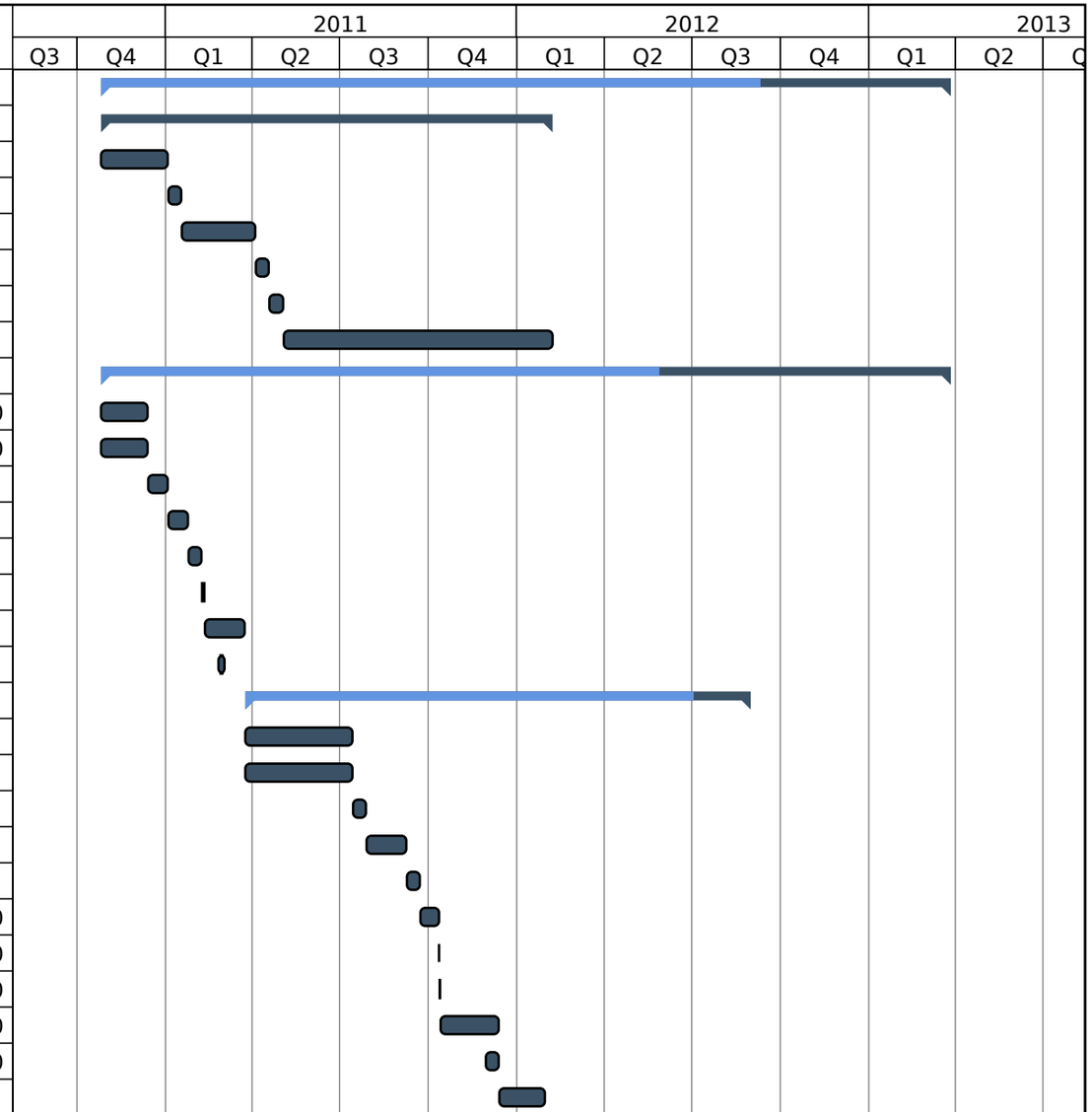
   b. There is a face-to-face meeting scheduled for August 2-3, 2012 in Atlanta, GA.

4. **Adjourn**

   The meeting adjourned at noon ET on Friday, June 22, 2012.

Attachment D

#	Name	Start Date	Completion Date
1	**Project 2007-12 Frequency Response**	10/26/10 9:00 AM	3/27/13 5:00
2	**Field Test**	10/26/10 9:00 AM	2/7/12 5:00
3	Collect data	10/26/10 9:00 AM	1/3/11 5:00
4	Post Official Event List	1/4/11 9:00 AM	1/17/11 5:00
5	Vlaidate Data Submitted on FRS Form 1	1/18/11 9:00 AM	4/4/11 5:00
6	Post Values and Notify BAs	4/5/11 9:00 AM	4/18/11 5:00
7	BAs Implement Bias Values	4/19/11 9:00 AM	5/3/11 5:00
8	Monitor Frequency Performance and Report Monthly	5/4/11 9:00 AM	2/7/12 5:00
9	**Develop Draft Standard**	10/26/10 9:00 AM	3/27/13 5:00
10	Develop Initial Draft of Standard	10/26/10 9:00 AM	12/13/10 5:00
11	Seek Regulatory Clarification on Directives/Other	10/26/10 9:00 AM	12/13/10 5:00
12	Submit Draft Documents for Quality Review	12/14/10 9:00 AM	1/3/11 5:00
13	Revise Documents Based on Quality Review	1/4/11 9:00 AM	1/24/11 5:00
14	Re-submit Draft Documents for Quality Review	1/25/11 9:00 AM	2/7/11 5:00
15	Announce and Post Documents	2/8/11 9:00 AM	2/10/11 5:00
16	First Posting of Documents for Formal Comment	2/11/11 9:00 AM	3/24/11 5:00
17	Industry Webinar on Proposed Standard(s)/Modification(s)	2/25/11 9:00 AM	3/3/11 5:00
18	**Formal Comment and Ballot**	3/25/11 9:00 AM	8/31/12 5:00
19	Develop Reply Comments and Second Draft of	3/25/11 9:00 AM	7/14/11 5:00
20	Seek Regulatory Clarification on Directives/Other	3/25/11 9:00 AM	7/14/11 5:00
21	Submit Draft Documents for Quality Review	7/15/11 9:00 AM	7/28/11 5:00
22	Revise Documents Based on Quality Review	7/29/11 9:00 AM	9/8/11 5:00
23	Re-submit Draft Documents for Quality Review	9/9/11 9:00 AM	9/22/11 5:00
24	Seek SC Approval to move to Ballot	9/23/11 9:00 AM	10/12/11 5:00
25	Project Moved to Balloting Phase	10/12/11 5:00 PM	10/12/11 5:00
26	Announce and Post Documents	10/13/11 9:00 AM	10/13/11 5:00
27	Posting of Documents for Formal Comment and Ballot	10/14/11 9:00 AM	12/13/11 5:00
28	Initial Ballot	11/30/11 9:00 AM	12/13/11 5:00
29	Develop Reply Comments and Third Draft of Standard	12/14/11 9:00 AM	1/30/12 5:00

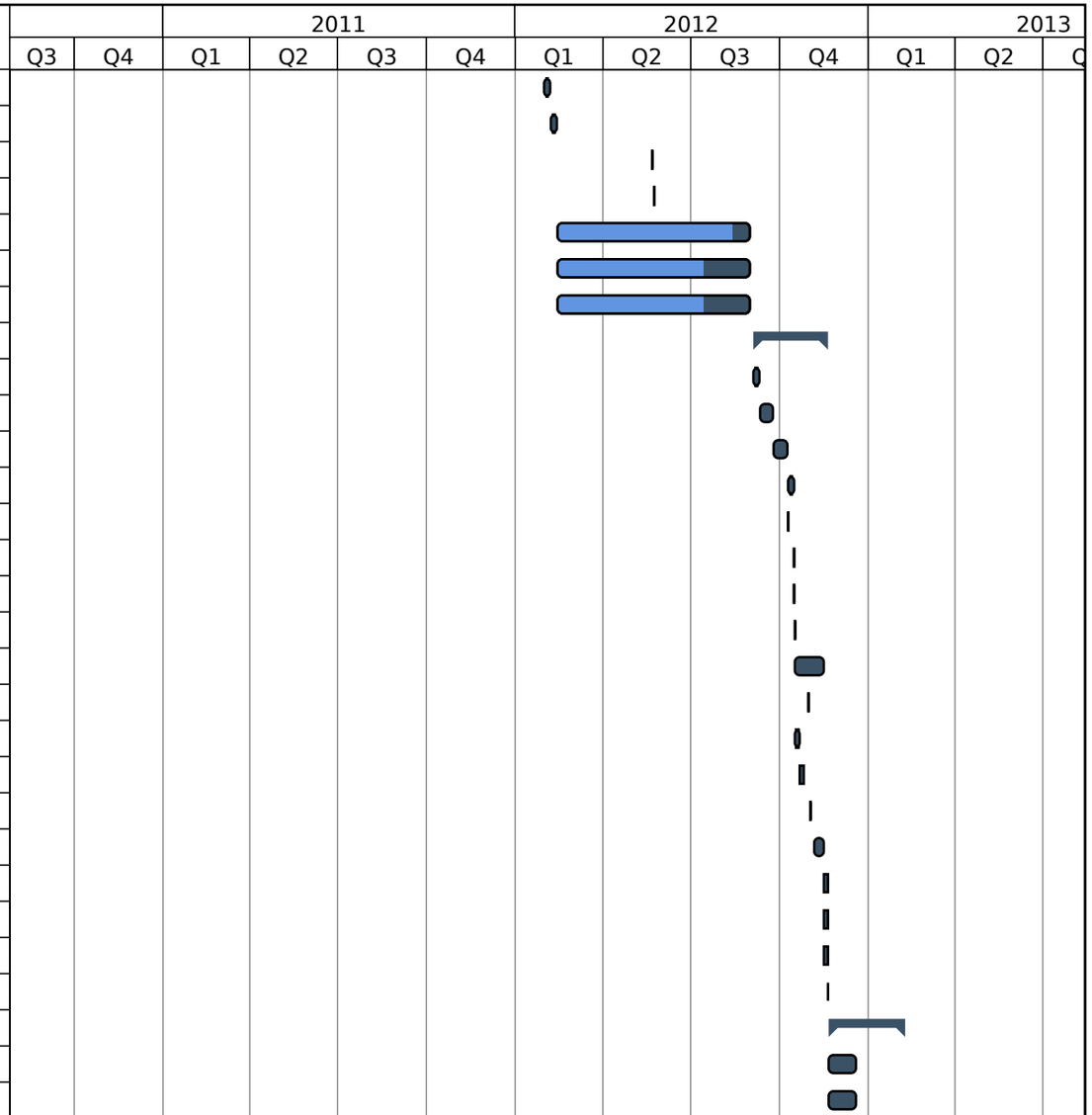


Project: Project 2007-12 Frequency Response
Planned Start: 10/26/10
Projected Start: 10/1/10
Planned Completion: 3/27/13
Projected Completion: 4/8/13
Printed On: 7/23/12

Project 2007-12 Frequency Response and Frequency Bias - Develop a minimum Frequency Response needed for reliable operation and a consistent method for calculating the Frequency Bias Setting.

Planned
Summary
In Progress
Milestone

#	Name	Start Date	Completion Date
30	Submit Draft Documents for Quality Review	1/31/12 9:00 AM	2/6/12 5:00
31	Revise Documents Based on Quality Review	2/7/12 9:00 AM	2/13/12 5:00
32	Conduct First Technical Conference - Washington DC	5/22/12 9:00 AM	5/22/12 5:00
33	Conduct Second Technical Conference - Denver CO	5/24/12 9:00 AM	5/24/12 5:00
34	Review Comments from Technical Conferences	2/14/12 9:00 AM	8/31/12 5:00
35	Draft Version Four of Standard	2/14/12 9:00 AM	8/31/12 5:00
36	Revise Comment Report	2/14/12 9:00 AM	8/31/12 5:00
37	**SUCCESSIVE BALLOT**	9/4/12 9:00 AM	11/20/12 5:00
38	Send Posting Package to SPM for Quality Review	9/4/12 9:00 AM	9/10/12 5:00
39	Perform Quality Review of Posting Package	9/11/12 9:00 AM	9/24/12 5:00
40	Edit Posting Package based on QR and Send to SPM	9/25/12 9:00 AM	10/9/12 5:00
41	Final Pre-Posting Review of Posting Package	10/10/12 9:00 AM	10/16/12 5:00
42	Write Draft Standard Posting Announcement	10/10/12 9:00 AM	10/10/12 5:00
43	Post Draft Standard and Update Web Page	10/16/12 9:00 AM	10/16/12 5:00
44	Post Draft Standard Posting Announcement	10/16/12 9:00 AM	10/16/12 5:00
45	Distribute Draft Standard Posting Announcement	10/17/12 9:00 AM	10/17/12 5:00
46	BAL-003 Comment Period REF_POST_FBS	10/17/12 9:00 AM	11/16/12 9:00
47	Hold Webinar	10/31/12 9:00 AM	10/31/12 5:00
48	Write Successive Ballot Announcement	10/17/12 9:00 AM	10/22/12 9:00
49	Post Successive Ballot Announcement	10/22/12 9:00 AM	10/26/12 5:00
50	Distribute Successive Ballot Announcement	11/2/12 9:00 AM	11/2/12 5:00
51	Conduct Successive Ballot over 10 days	11/6/12 9:00 AM	11/16/12 9:00
52	Assemble Comments on Draft Standard and Send to	11/16/12 9:00 AM	11/20/12 5:00
53	Assemble Ballot Comments on Draft Standard and	11/16/12 9:00 AM	11/20/12 5:00
54	Assemble Ballot Results and Update Web Page	11/16/12 9:00 AM	11/20/12 5:00
55	Successive Ballot Complete	11/20/12 5:00 PM	11/20/12 5:00
56	**RECIRC BALLOT**	11/21/12 9:00 AM	2/8/13 5:00
57	Respond to Comments Received	11/21/12 9:00 AM	12/19/12 5:00
58	Write Draft of Standard	11/21/12 9:00 AM	12/19/12 5:00

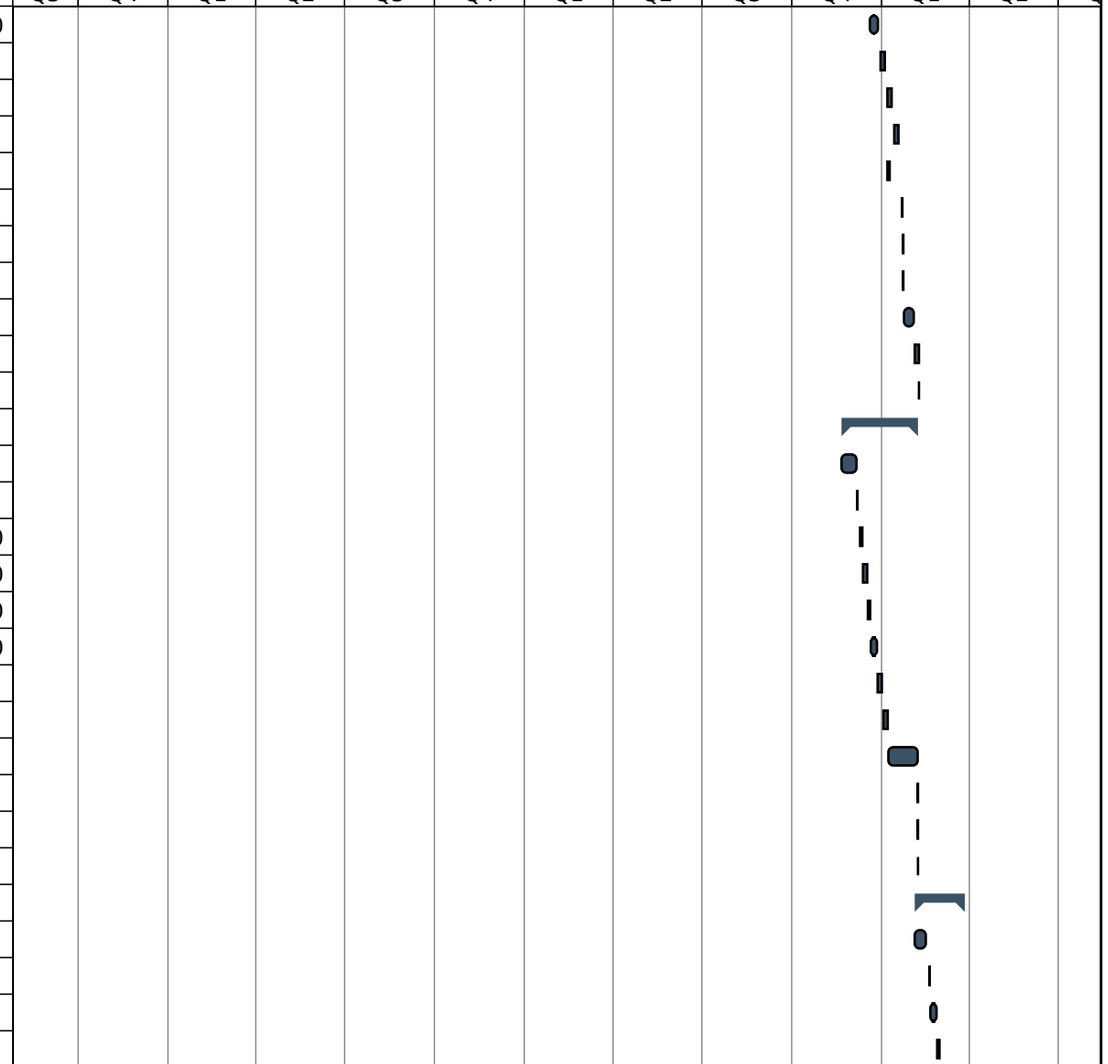


Project: Project 2007-12 Frequency Response
Planned Start: 10/26/10
Projected Start: 10/1/10
Planned Completion: 3/27/13
Projected Completion: 4/8/13
Printed On: 7/23/12

Project 2007-12 Frequency Response and Frequency Bias - Develop a minimum Frequency Response needed for reliable operation and a consistent method for calculating the Frequency Bias Setting.

Planned
Summary
In Progress
Milestone

#	Name	Start Date	Completion Date
59	Send Posting Package to SPM for Quality Review	12/20/12 9:00 AM	12/28/12 5:00
60	Perform Quality Review of Posting Package	12/31/12 9:00 AM	1/4/13 5:00
61	Edit Posting Package based on QR and Send to SPM	1/7/13 9:00 AM	1/11/13 5:00
62	Final Pre-Posting Review of Posting Package	1/14/13 9:00 AM	1/18/13 5:00
63	Write Recirculation Ballot Announcement	1/7/13 9:00 AM	1/9/13 5:00
64	Post Draft Standard and Update Web Page	1/22/13 9:00 AM	1/22/13 5:00
65	Post Recirculation Ballot Announcement	1/23/13 9:00 AM	1/23/13 5:00
66	Distribute Recirculation Ballot Announcement	1/23/13 9:00 AM	1/23/13 5:00
67	Conduct Recirculation Ballot over 10 days	1/24/13 9:00 AM	2/3/13 9:00
68	Assemble Ballot Results and Update Web Page	2/4/13 9:00 AM	2/8/13 5:00
69	Recirc Complete	2/8/13 5:00 PM	2/8/13 5:00
70	**BOT APPROVAL**	11/21/12 9:00 AM	2/7/13 5:00
71	Develop Board Materials	11/21/12 9:00 AM	12/6/12 5:00
72	Send Board Materials to Standards Leadership	12/7/12 9:00 AM	12/7/12 5:00
73	Perform Standards Leadership Review	12/10/12 9:00 AM	12/12/12 5:00
74	Edit Board Materials based on Leadership Review	12/13/12 9:00 AM	12/17/12 5:00
75	Perform Legal Review	12/18/12 9:00 AM	12/20/12 5:00
76	Edit Board Materials based on Legal Review and send	12/21/12 9:00 AM	12/27/12 5:00
77	Perform Exec Mgmt Review	12/28/12 9:00 AM	1/1/13 5:00
78	Edit Board Materials based on Exec Mgmt Review	1/3/13 9:00 AM	1/7/13 5:00
79	Submit Board Materials to Board	1/8/13 9:00 AM	2/7/13 9:00
80	Present Board Materials to Board	2/7/13 9:00 AM	2/7/13 5:00
81	Board Vote on Materials	2/7/13 9:00 AM	2/7/13 5:00
82	BOT Approval Complete	2/7/13 5:00 PM	2/7/13 5:00
83	**FILING**	2/4/13 9:00 AM	3/27/13 5:00
84	Develop Draft Filing	2/4/13 9:00 AM	2/15/13 5:00
85	Send Draft Filing to Standard Regulatory Initiatives	2/19/13 9:00 AM	2/19/13 5:00
86	Perform Standards Regulatory Initiatives Review	2/20/13 9:00 AM	2/26/13 5:00
87	Edit Draft Filing based on SRI Review and send to	2/27/13 9:00 AM	3/1/13 5:00

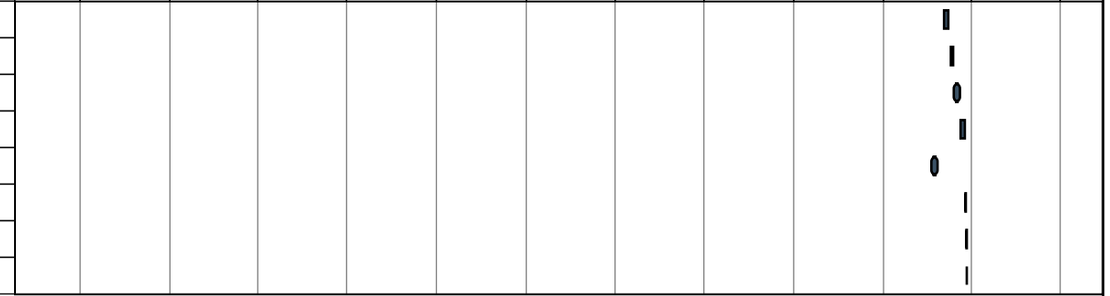


Project: Project 2007-12 Frequency Response
Planned Start: 10/26/10
Projected Start: 10/1/10
Planned Completion: 3/27/13
Projected Completion: 4/8/13
Printed On: 7/23/12

Project 2007-12 Frequency Response and Frequency Bias - Develop a minimum Frequency Response needed for reliable operation and a consistent method for calculating the Frequency Bias Setting.

Planned
Summary
In Progress
Milestone

#	Name	Start Date	Completion Date
88	Perform Legal Review	3/4/13 9:00 AM	3/8/13 5:00
89	Edit Draft Filing based on Legal Review and send to	3/11/13 9:00 AM	3/13/13 5:00
90	Perform Exec Mgmt Review	3/14/13 9:00 AM	3/20/13 5:00
91	Edit Draft Filing based on Exec Mgmt Review	3/21/13 9:00 AM	3/25/13 5:00
92	Assemble development record	2/19/13 9:00 AM	2/25/13 5:00
93	Assemble Final Filing Package	3/26/13 9:00 AM	3/26/13 5:00
94	Submit Final Filing Package	3/27/13 9:00 AM	3/27/13 5:00
95	Filing Complete	3/27/13 5:00 PM	3/27/13 5:00



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Project 2007-12 Frequency Response and Frequency Bias - Develop a minimum Frequency Response needed for reliable operation and a consistent method for calculating the Frequency Bias Setting.

Planned
Summary
In Progress
Milestone