NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Frequency Response Initiative

Industry Advisory – Generator Governor Frequency Response

Troy Blalock – South Carolina Electric and Gas
Bob Cummings – NERC Reliability Initiatives and System Analysis
Rich Bauer – NERC Reliability Risk Management

April 7, 2015

RELIABILITY | ACCOUNTABILITY




Agenda

- Why Primary Frequency Response is important
- Define Primary Frequency Response
- Discuss the NERC Advisory Generator Governor Frequency
- Recommendations for Dead Band and Droop
- Coordination Requirement with Plant DCS
- Step vs. Linear Response
- Frequent Occurring Issues
- Questions

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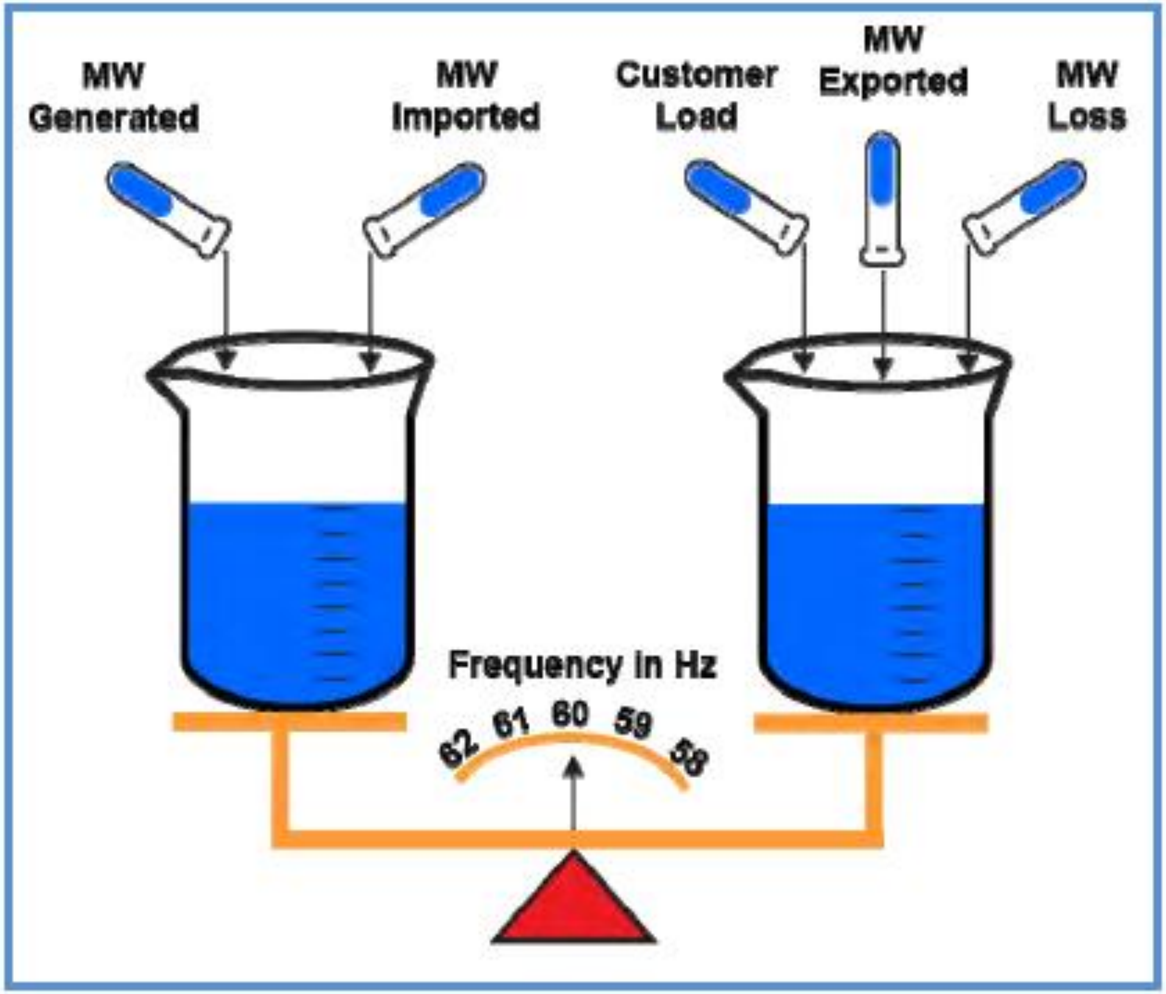
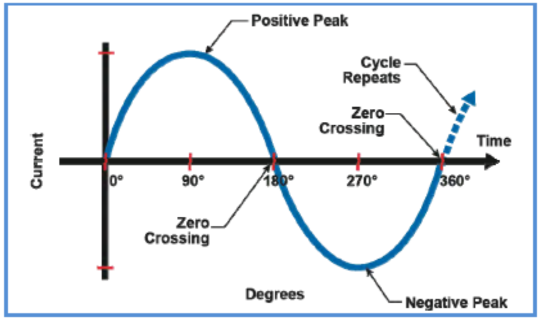
Why Primary Frequency Response Is Important

- Essential for Reliability of the Interconnections
  - Cornerstone for system stability
  - Line of defense to prevent Under Frequency Load Shedding(UFLS)
  - Prevent equipment damage
- Essential for System Restoration
  - Droop response is critical in restoration efforts
- Compliance with NERC Standards BAL-003-1, BAL-001
  - prevent future regulations related to generator frequency response performance
- To accurately predict system events (Transmission Models)

Frequency

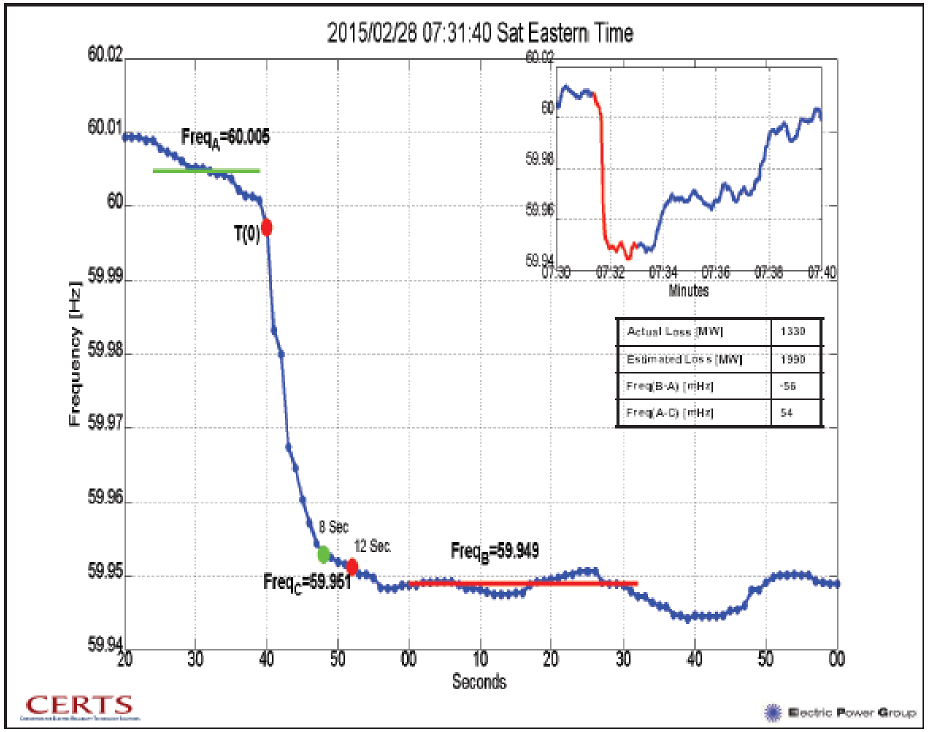

MW Generated
MW Imported
Customer Load
MW Exported
MW Loss
Frequency in Hz
62
61
60
59
58


Positive Peak
Cycle Repeats
Zero Crossing
Time
Current
0°
90°
180°
270°
360°
Zero Crossing
Degrees
Negative Peak


60.0000
MENU
PEAK
RESET
ALARMS
Laurel.

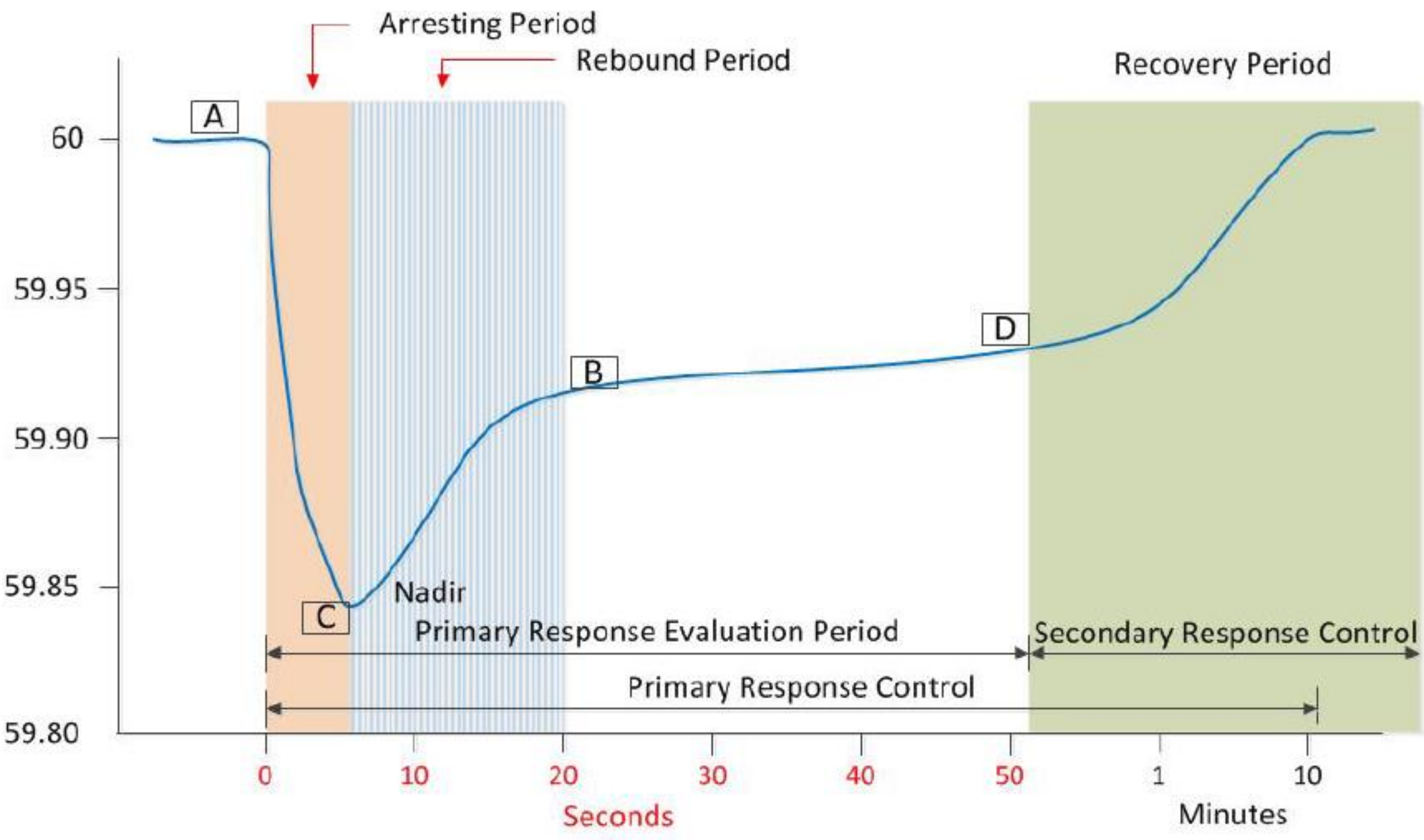
Primary Frequency Response

- Primary Frequency Response are actions to arrest and stabilize frequency in response to frequency deviations. Primary Response comes from generator governor response, load response (motors) and other devices that provide immediate response based on local (device- level) control.
- Generator Governor Response within 0-10 seconds..



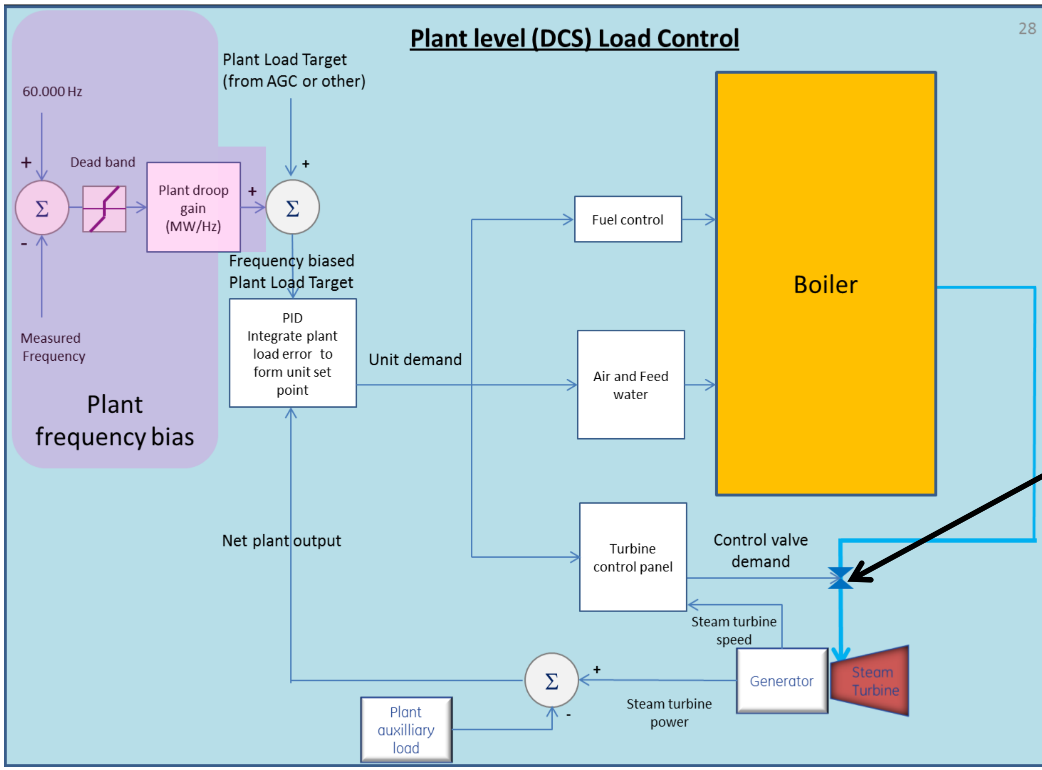
Frequency Point A is the frequency prior to the event
Frequency Point C is the nadir or lowest point
Frequency Point B is the settling frequency

Classic Frequency Excursion Recovery



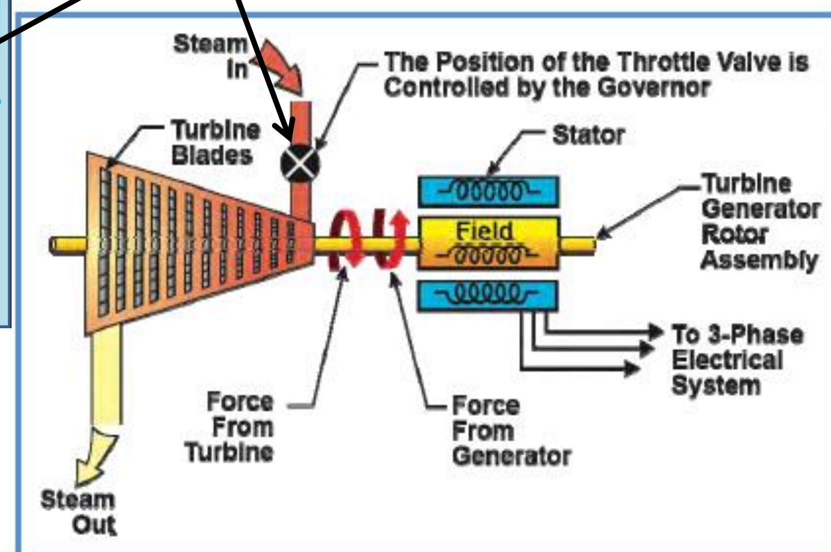
Primary Frequency Response

Generator Response



Graphic from GE info bulletin PSIB20150212

Generator turbine governors either mechanically or electronically control the primary control valves to the turbine. Steam, Water or Fuel is what is regulated.



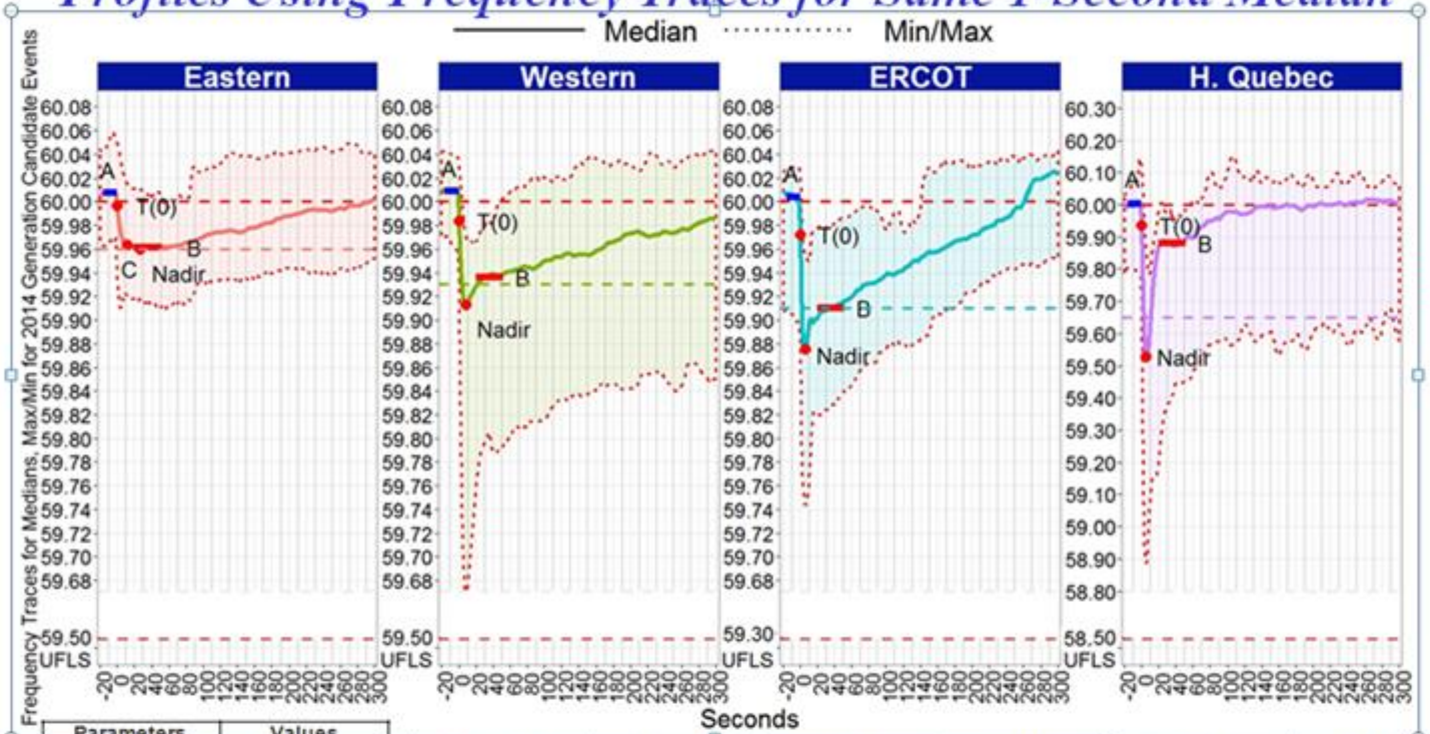
Current Interconnection Profiles

CERTS

ASR
Advanced Systems Researchers

Current Interconnection Profiles

BAL-003 Field Test - Interconnections 2014 Candidate Events Profiles Using Frequency Traces for Same 1-Second Median



Parameters	Values
ValueA	60.007 [Hz]
ValueB	59.961 [Hz]
FreqC	59.963 [Hz]
Nadir	59.960 at 28 Secs
Min-UFLS	409 [mHz]
Risk to Reach ULFS	NA
Generation Events	104

Parameters	Values
ValueA	60.009 [Hz]
ValueB	59.936 [Hz]
FreqC=Nadir	59.913 at 9 Secs
Min-UFLS	171 [mHz]
Risk to Reach ULFS	NA
Generation Events	50

Parameters	Values
ValueA	60.004 [Hz]
ValueB	59.910 [Hz]
FreqC=Nadir	59.875 at 7 Secs
Min-UFLS	444 [mHz]
Risk to Reach ULFS	NA
Generation Events	52

Parameters	Values
ValueA	60.002 [Hz]
ValueB	59.882 [Hz]
FreqC=Nadir	59.529 at 6 Secs
Min-UFLS	388 [mHz]
Risk to Reach ULFS	NA
Generation Events	34

CERTS

ASR Advanced Systems Researchers

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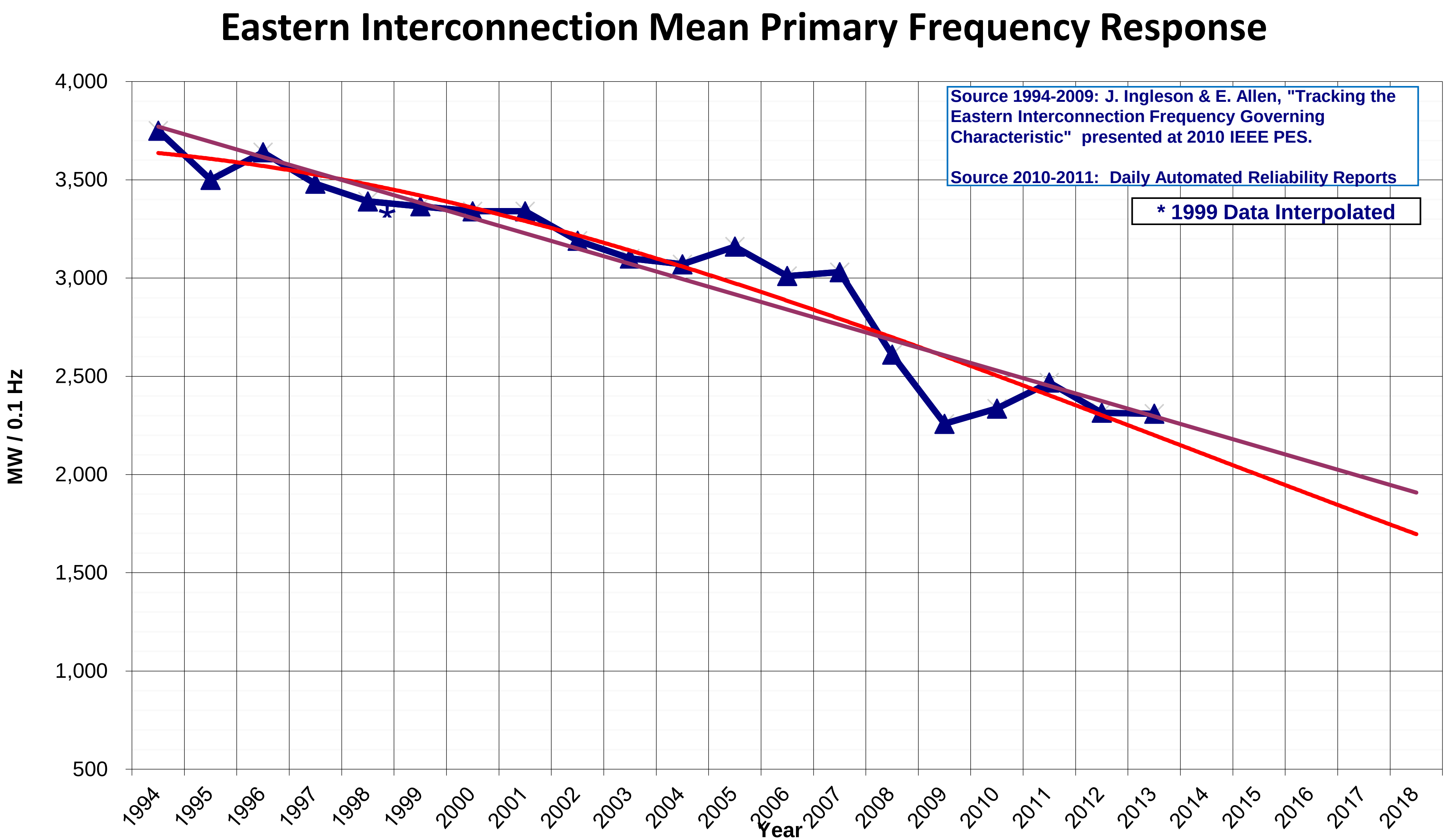
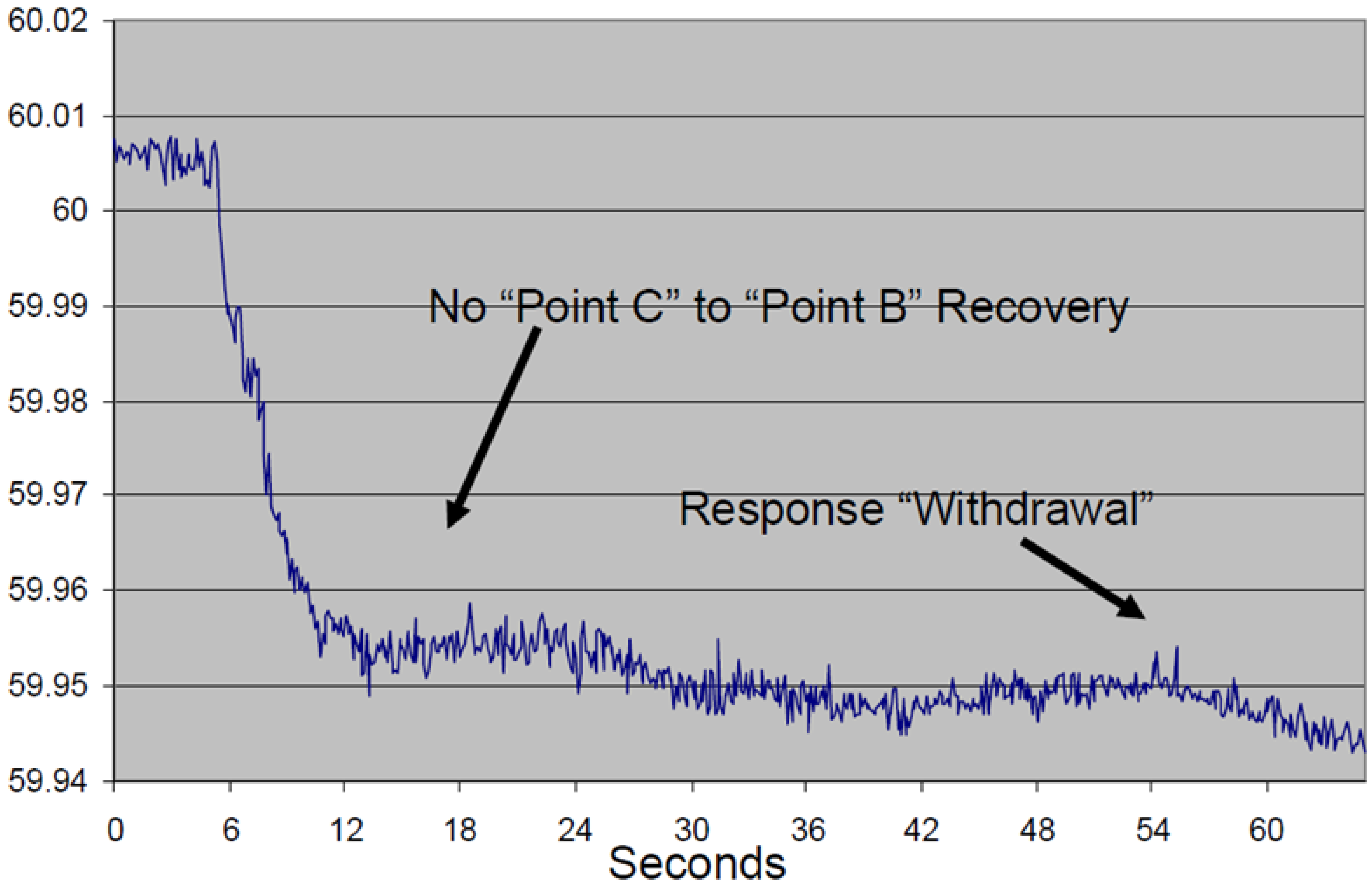
Decline in Eastern Interconnection Frequency Response



Current Eastern Interconnection Frequency Response



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Generator Governor Frequency Response Advisory

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Industry Advisory

Generator Governor Frequency Response

Initial Distribution: February 5, 2015

As a result of the Eastern Interconnection Frequency Initiative, the NERC Resources Subcommittee has determined that a significant portion of the Eastern Interconnection generator deadbands or governor control settings inhibit or prevent frequency response. While this specific work was based on the Eastern Interconnection, in the absence of more stringent regional requirements the following good practice and guidance is applicable to all interconnections. The proper setting of deadbands, droop, and other controls to allow for primary frequency response is essential for reliability of the Bulk Electric System (BES) and critical during system restoration. Further, the accuracy of Transmission Planning models are impacted by incorrect governor data. The purpose of this Advisory is to alert the industry of recommended governor deadband and droop settings that will enable generators to provide better frequency response to support the reliable operation of the Bulk Electric System.

Why am I receiving this? >>
About NERC Alerts >>

Status:	**No Reporting is Required – For Information Only**
	PUBLIC: No Restrictions More on handling >>
Instructions:	NERC Advisories are designed to improve reliability by disseminating critical reliability information and are made available pursuant to Rule 810 of NERC's Rules of Procedure, for such use as your organization deems appropriate. **No particular response is necessary.** This NERC Advisory is not the same as a reliability standard, and your organization will not be subject to penalties for a failure to implement this Advisory. Additionally, issuance of this Advisory does not lower or otherwise alter the requirements of any approved Reliability Standard, or excuse the prior failure to follow the practices discussed in the Advisory if such failure constitutes a violation of a Reliability Standard.
Distribution:	**Initial Distribution:** Balancing Authority, Generator Owner, Generator Operator, Reliability Coordinator, Transmission Operator, Transmission Planner Who else will get this alert? >> What are my responsibilities? >>

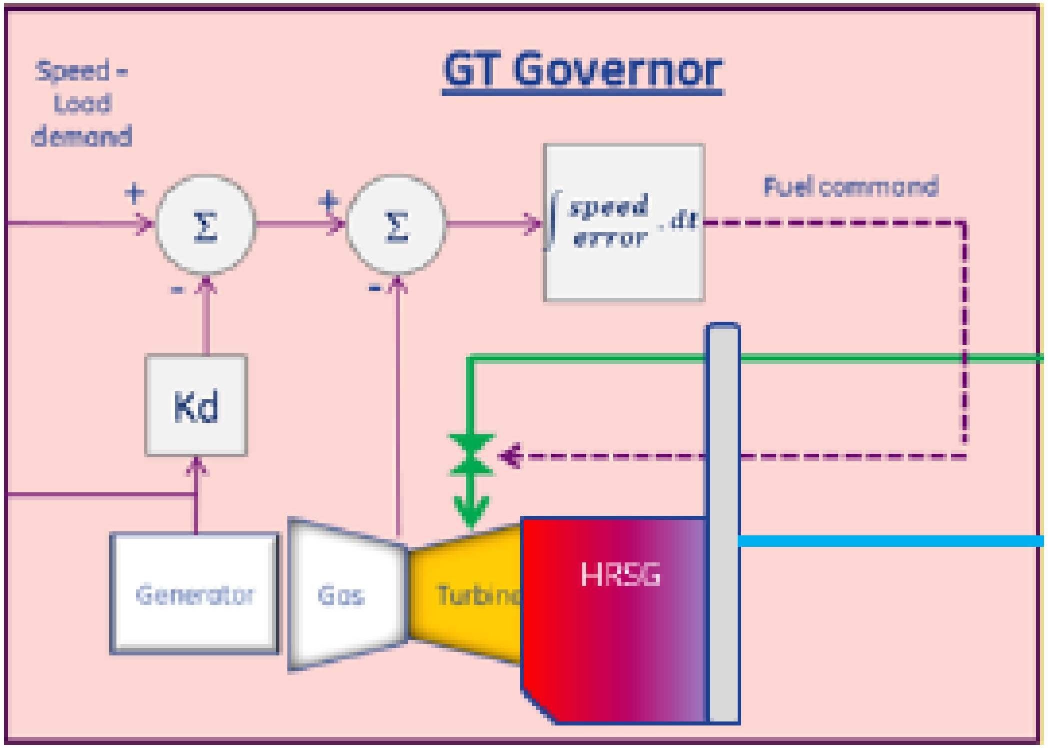
RELIABILITY | ACCOUNTABILITY

- Advisory issued February 5th
- Prompted by NERC Resource Subcommittee
  - Interconnections frequency response has declined
  - Eastern Interconnection Lazy L profile
  - 2010 and 2013 Generator Survey Data

Generator Governor Frequency Response Advisory

What Has Been Learned

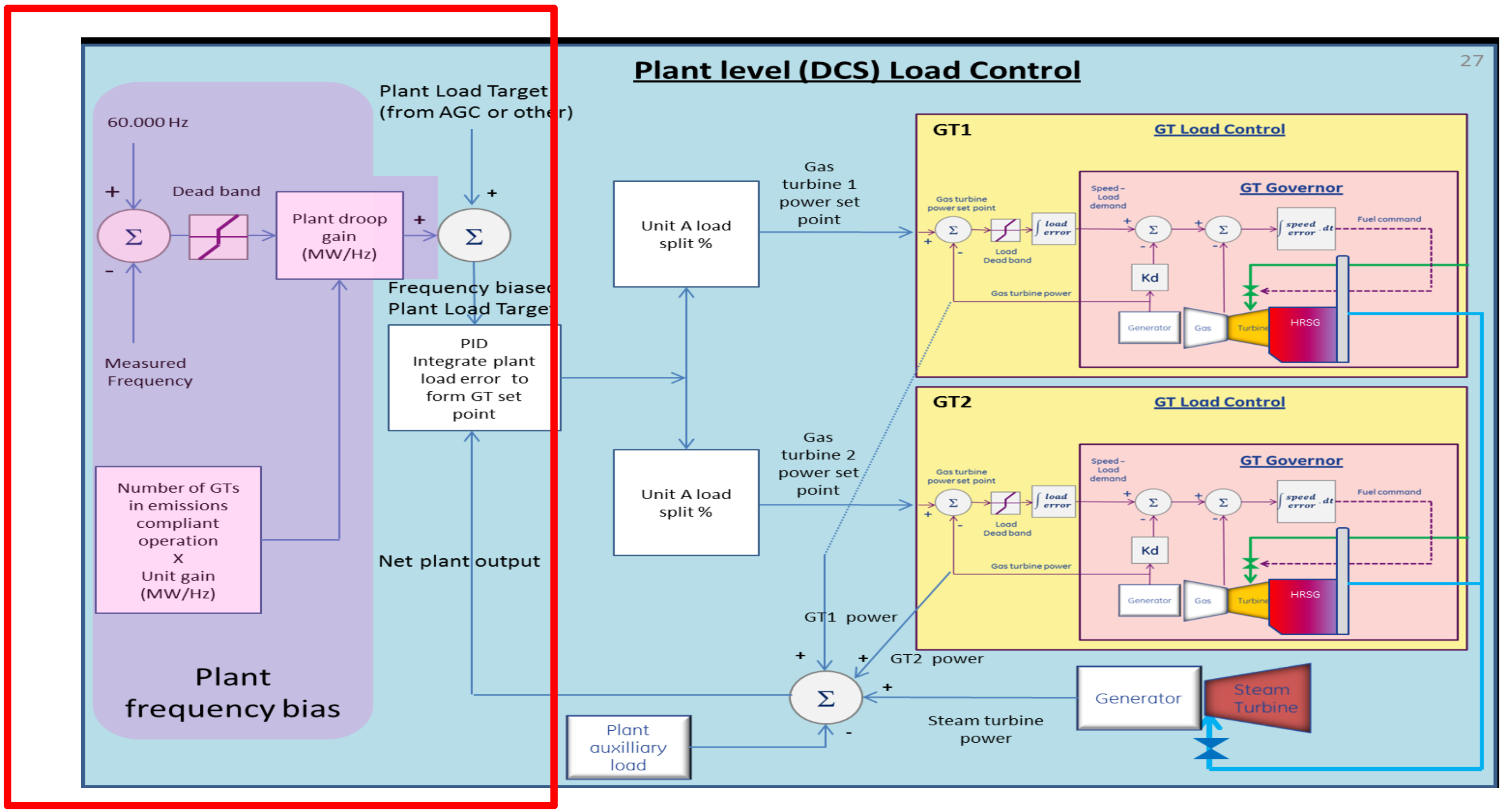
- Primary Frequency Response logic typically resides in the turbine controls.
- Dead Bands Vary
  - Many exceed 36 mHz or 2.16 RPM
- Droops Settings Vary
  - Majority Droops reported 5%



Graphic from GE info bulletin PSIB20150212

What Has Been Learned

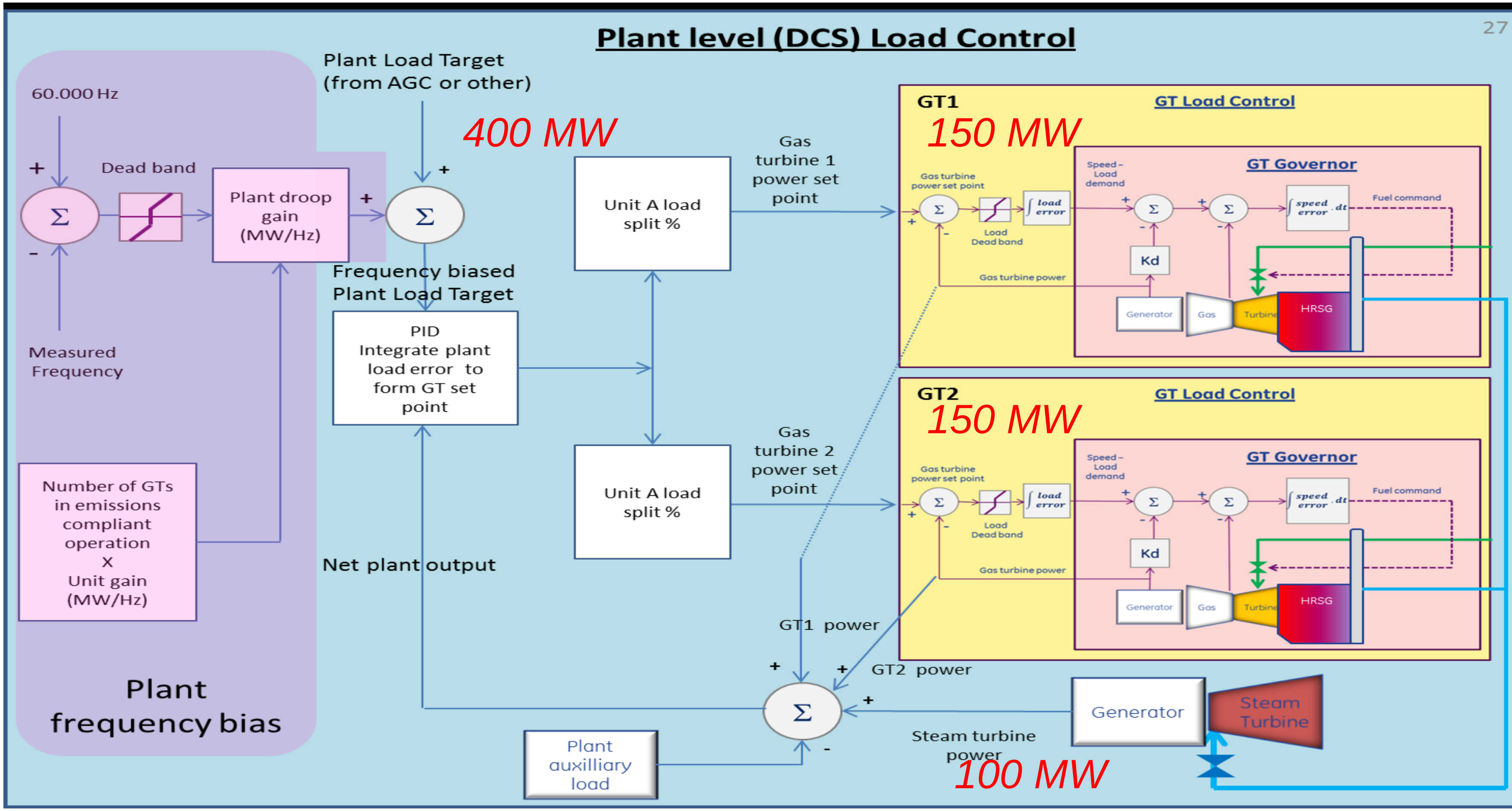
- Coordination with plant DCS is a requirement when operating in MW Set Point Coordinated Control.



Graphic from GE info bulletin PSIB20150212

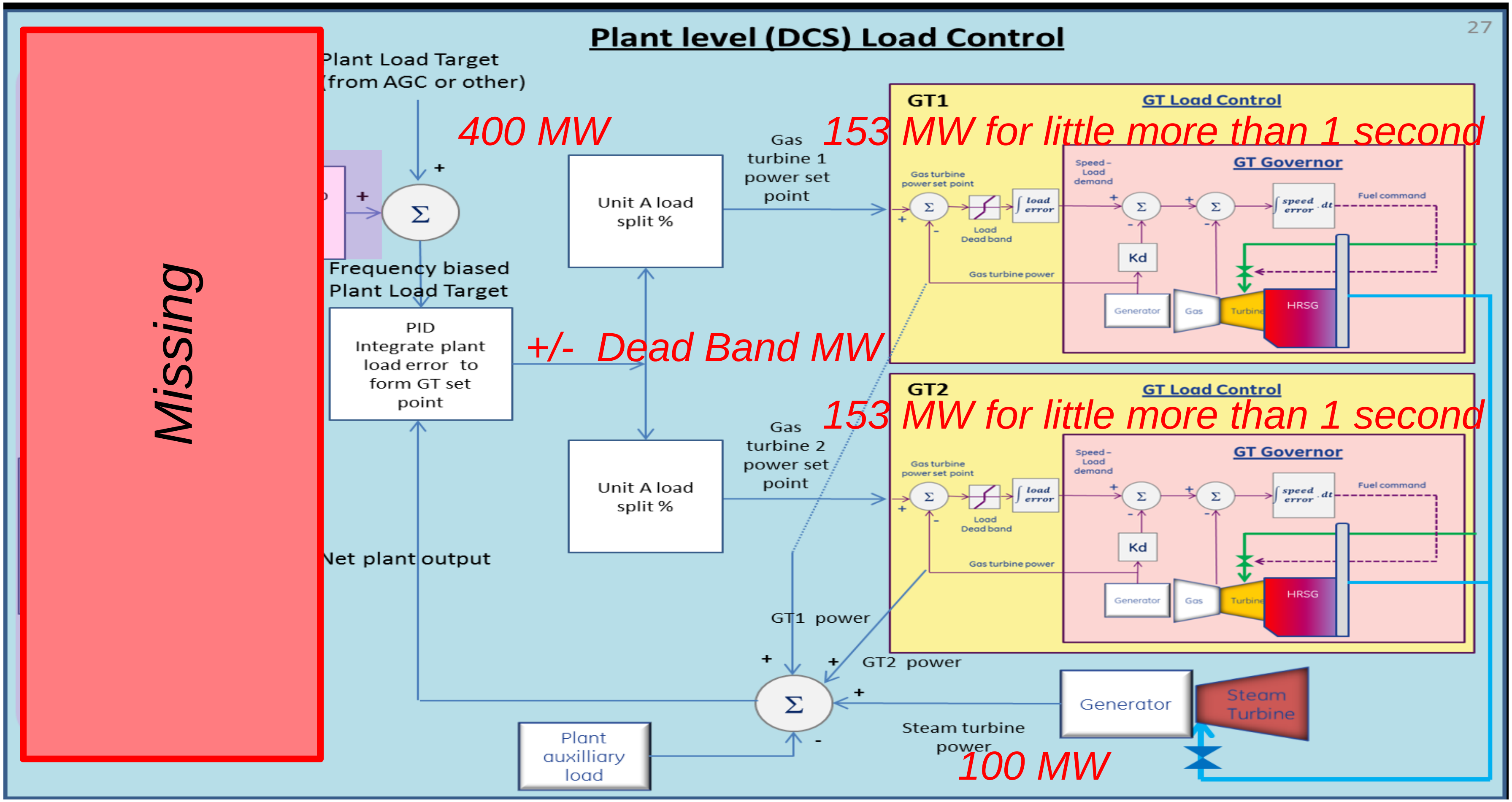
Example

Frequency 60.000 Hz



Graphic from GE info bulletin PSIB20150212

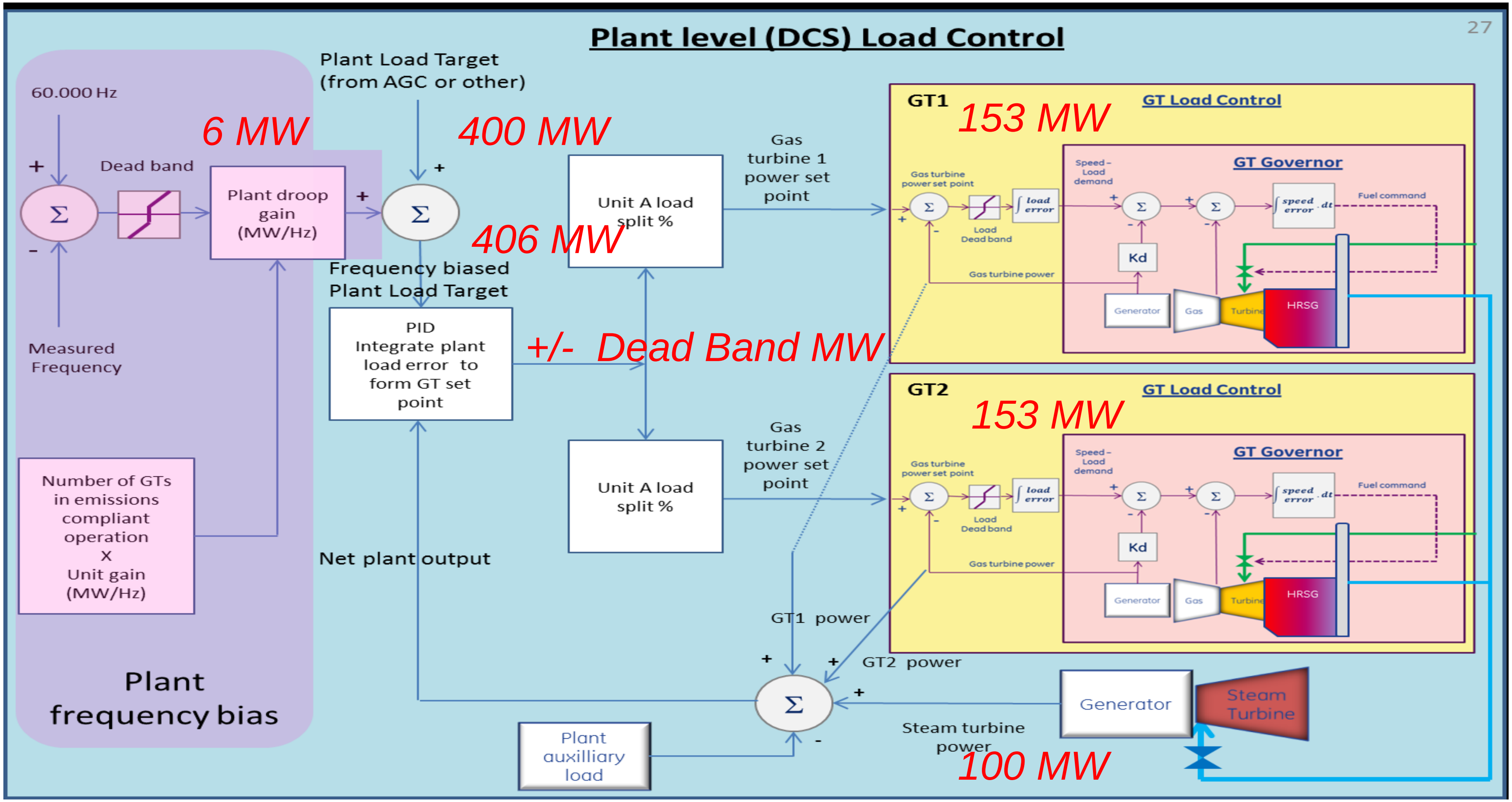
Frequency 59.940 Hz



Graphic from GE info bulletin PSIB20150212

Example

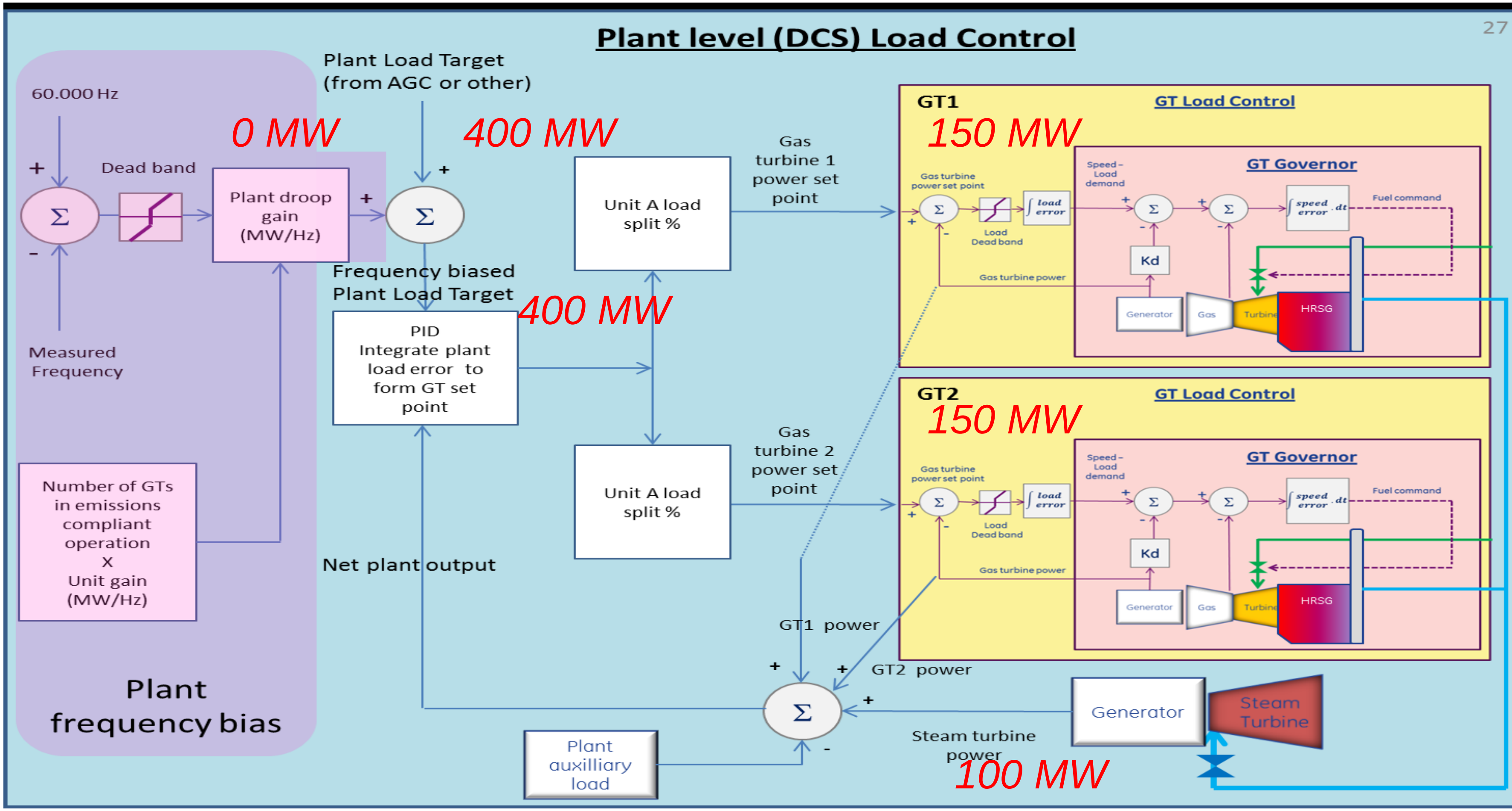
Frequency 59.940 Hz



Graphic from GE info bulletin PSIB20150212

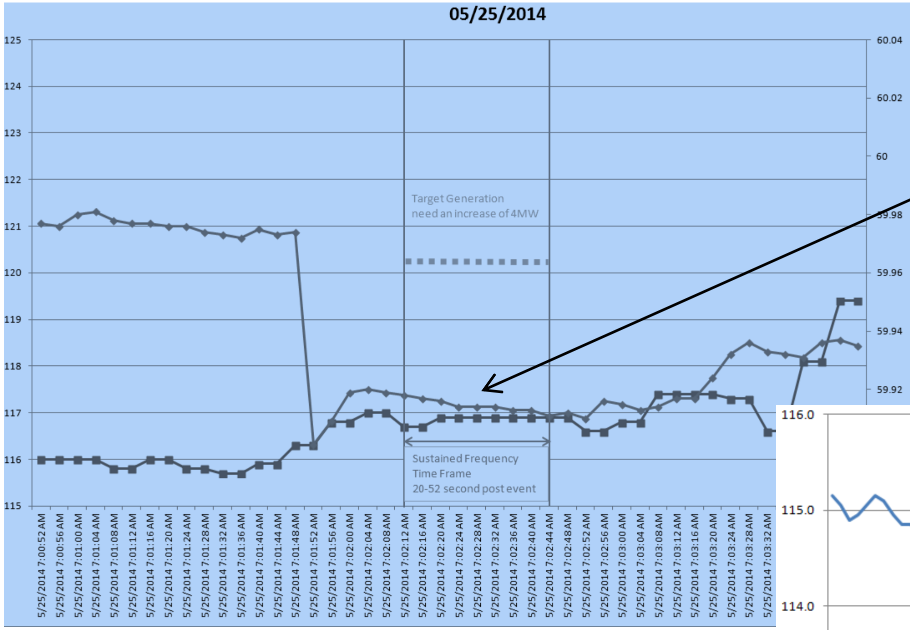
Example

Frequency 60.000 Hz



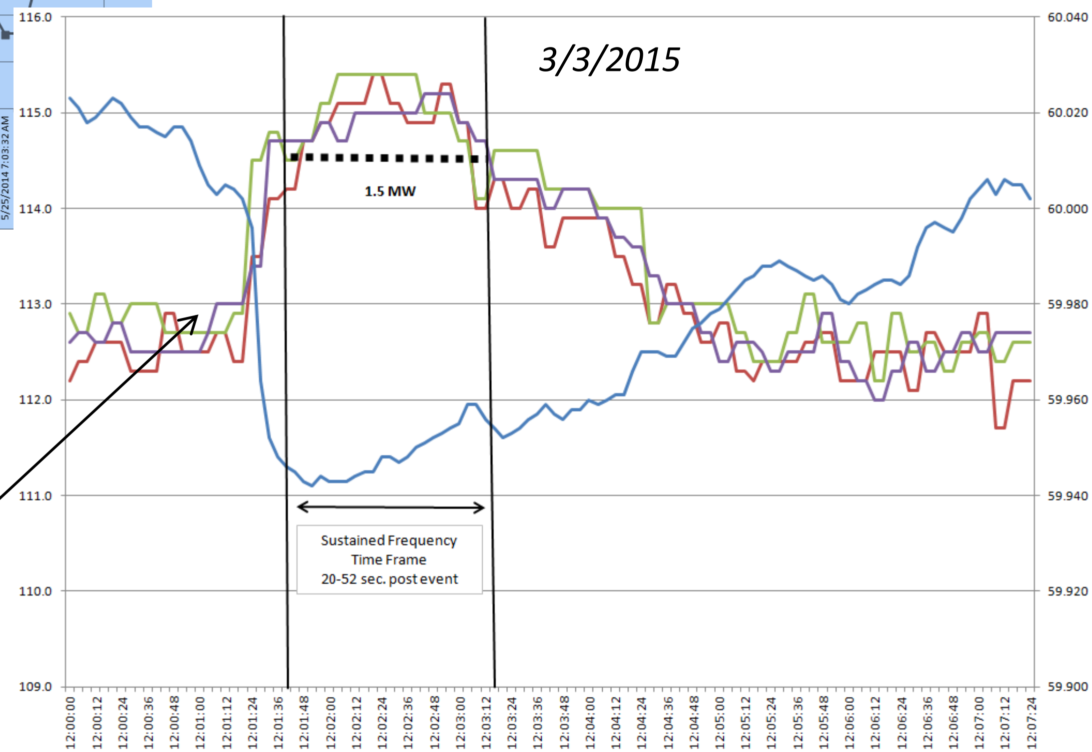
Graphic from GE info bulletin PSIB20150212

Tale of Two Tales



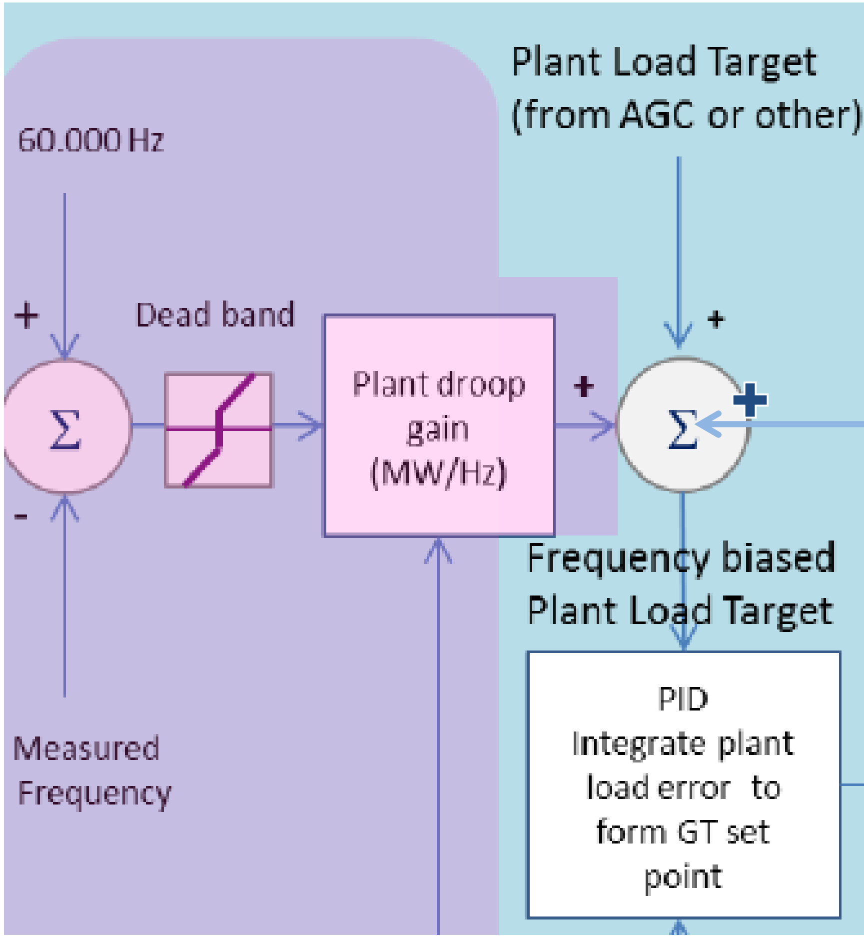
No Frequency Algorithm in DCS

3 -175 MW GE7FA Gas Mark VIe Turbine

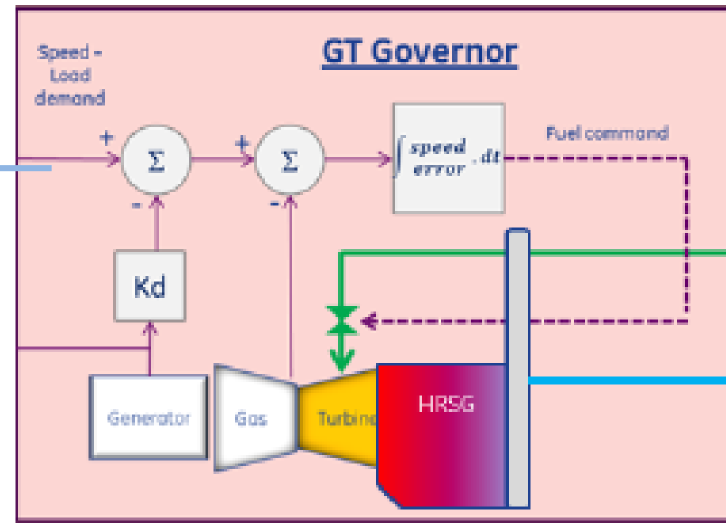


Frequency Algorithm in Plant DCS

The Code



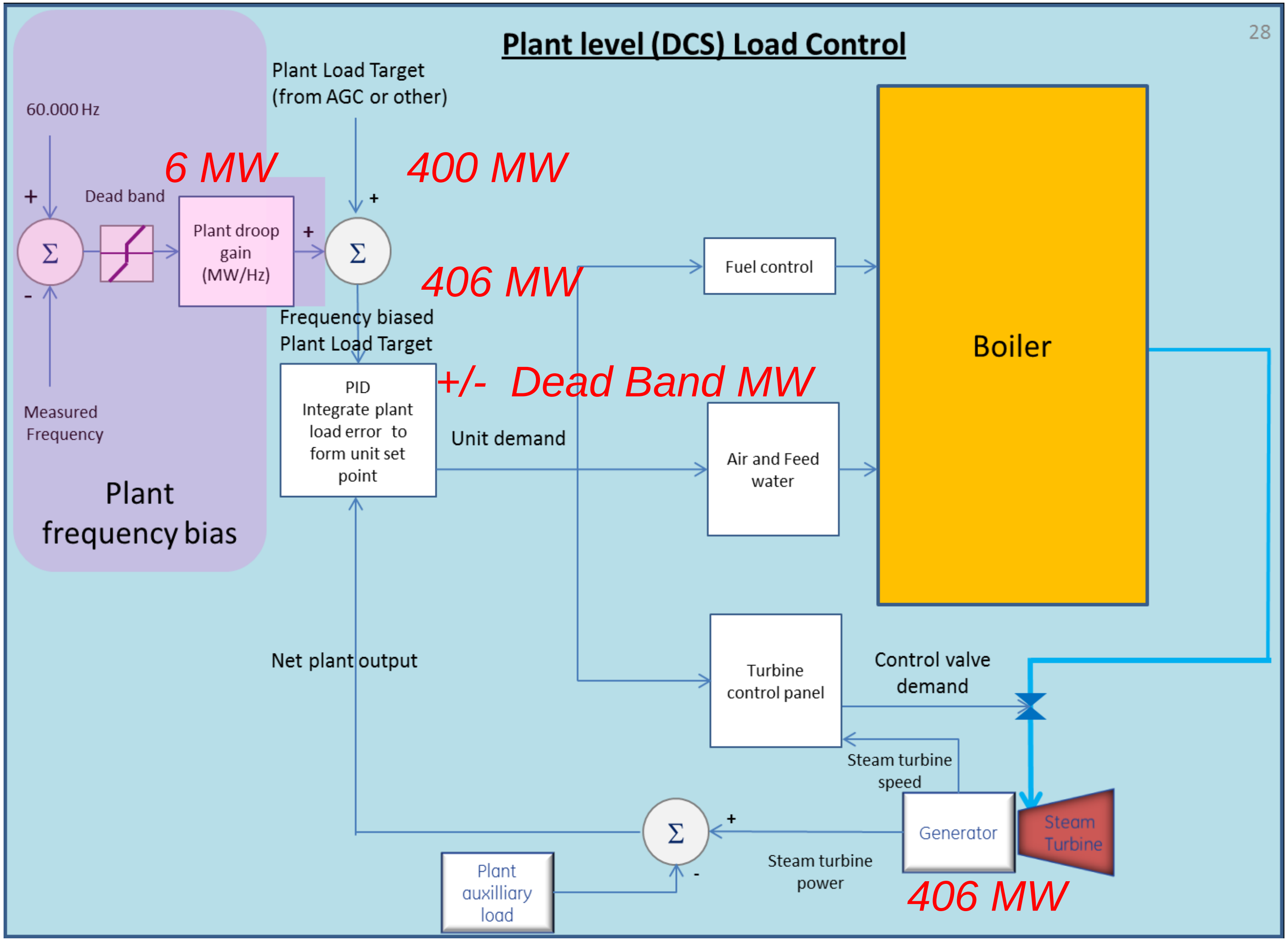
OR



$$MW_{PrimaryControl} = \left[\frac{(HZ_{actual} - 60 + DB)}{(60 * Droop - DB)} \right] * (Frequency\ ResponsiveCapacity) * (-1)$$

Conventional Steam Plant

Frequency 59.940 Hz



Graphic from GE info bulletin PSIB20150212

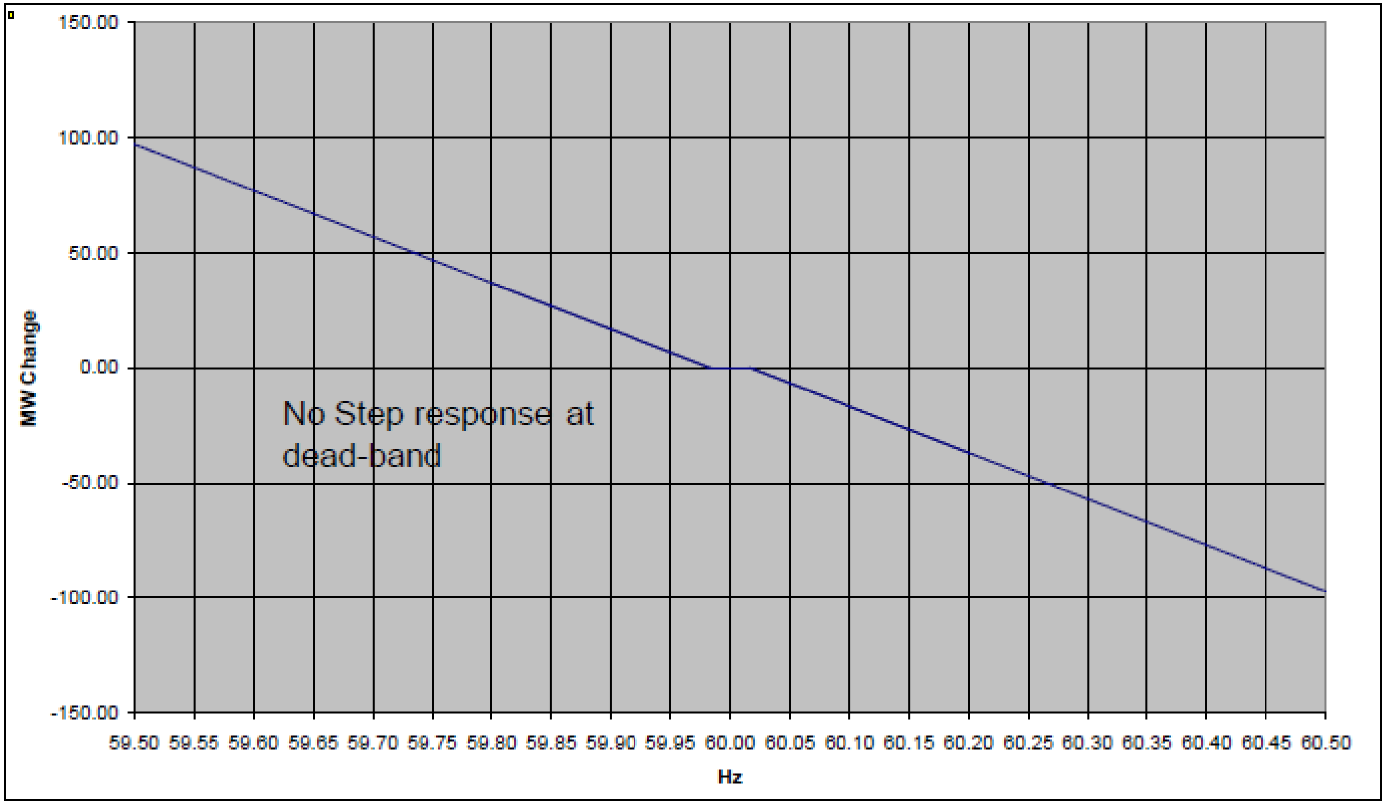
Droop Response Step vs. Linear or Proportional

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

Source: Frequency Response Initiative Report: The Reliability Role of Frequency Response, NERC, Robert Cummings, October 30, 2012

Droop - Linear Response

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

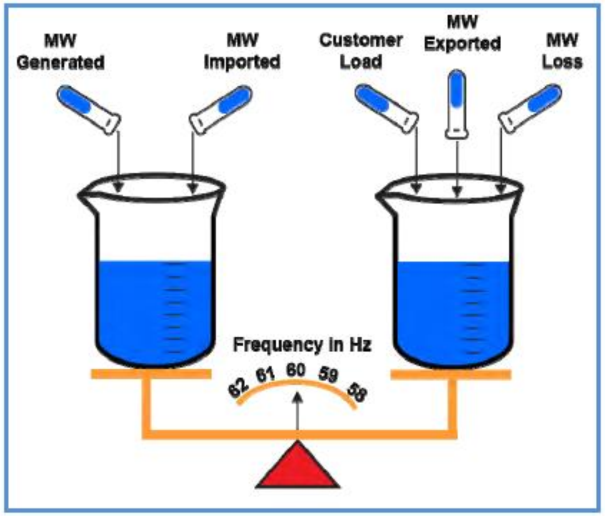


Source: Frequency Response Initiative Report: The Reliability Role of Frequency Response, NERC, Robert Cummings, October 30, 2012

Event Occurrence

Balancing Authority		MyBA
Date/Time (t-0)	BA Time	
BA Time	Zone	DelFreq
12/1/2013 6:13:22	EST	-0.049
12/9/2013 8:46:58	EST	-0.048
1/21/2014 13:50:30	EST	-0.059
1/26/2014 12:09:30	EST	-0.044
2/2/2014 8:59:10	EST	-0.036
2/15/2014 22:54:14	EST	-0.049
2/19/2014 0:33:02	EST	-0.041
2/23/2014 12:32:26	EST	-0.048
3/5/2014 16:24:17	EST	-0.040
4/3/2014 8:36:35	EDT	-0.040
4/3/2014 14:00:37	EDT	-0.033
4/8/2014 4:27:56	EDT	-0.056
4/25/2014 13:30:23	EDT	-0.061
5/1/2014 10:17:00	EDT	-0.051
5/22/2014 12:10:17	EDT	-0.067
5/25/2014 7:01:46	EDT	-0.059
7/24/2014 12:14:01	EDT	-0.060
7/25/2014 15:16:32	EDT	-0.046
7/27/2014 14:09:32	EDT	-0.049
8/13/2014 11:57:44	EDT	-0.042
10/4/2014 4:19:16	EDT	-0.049
10/14/2014 4:41:15	EDT	-0.040
10/20/2014 2:18:39	EDT	-0.049
10/24/2014 18:43:23	EDT	-0.040
10/26/2014 11:31:10	EDT	-0.050
11/1/2014 2:49:38	EDT	-0.046
11/3/2014 14:21:14	EST	-0.059
11/5/2014 10:22:29	EST	-0.067

- The majority of the Eastern events where frequency declines in excess of 36 mHz is when the interconnections are lightly loaded and the majority of generation is dispatch is less than Pmax.



Source: MYBA_2015_FRS_FORM_19a_Eastern Interconnection_Final

Common Generator Frequency Response Issues

	Combustion Turbine	Conventional Steam Unit
No Droop response	Verify that CT has droop logic	Verify that ST droop is enabled
	Verify that the logic is enabled	Determine if ST was rejected from REMOTE mode
	Add plant control frequency bias logic	
Droop response less than 5%	Check CT settings (%, deadband, step)	Compare Coordinated & ST settings (%, deadband, step)
	ST MWs will lag the 4% CT droop	Trend Throttle Pressure and Temperature
Initial response is pulled back	Check plant control logic	Trend boiler master % vs. turbine master %
Response in wrong direction	Check plant control logic	Check Coordinate Control logic for proper math

Other issues

- Some units come out of AGC or MW Set Point Control when frequency response is being provided.
- Conventional Steam Turbines operating in sliding pressure or turbine following mode
- Resolution/quality of speed signal

A Misconception

“If I provide primary frequency response I will be penalized.”

- Interconnection frequency events resulting in deviations below the recommended governor deadband settings are infrequent (about 1 / week)
- Primary frequency response is a relatively small amount of energy for a short period
  - Typically provided for about 120 seconds
  - Roughly 0.5% of capacity
- Tariff provisions vary but typically measure dispatch imbalance or deviation charges based on substantially longer time intervals (on the order of 30 to 60 minutes with a tolerance band of 5-10%)
- Tariff provisions typically allow for exemptions or recourse if a generating resource is subject to imbalance or deviation charges due to providing frequency response
- Contact your Transmission Provider for specific tariff information

Requested Next Steps

Fall Outages 2015/ Spring 2016

- Check and add if necessary Frequency Response Algorithm on Frame Gas Turbines
- Check/ Adjust Dead Bands and Droops
- Check Conventional Steam Unit

Note: Need to make sure dead bands and droop are coordinated to be the same in the Plant DCS as Turbine.

Resources

- NERC Resource Subcommittee
- North American Generator Forum www.generatorforum.org
- Original Equipment Manufacturers
- Industry Trade Associations
- Architect /Engineering Firms
- Balancing Authority

Participating Vendors

★ GE imagination at work

★ Schneider Electric

★ SIEMENS

EMERSON. Process Management

★ ABB Power and productivity for a better world™

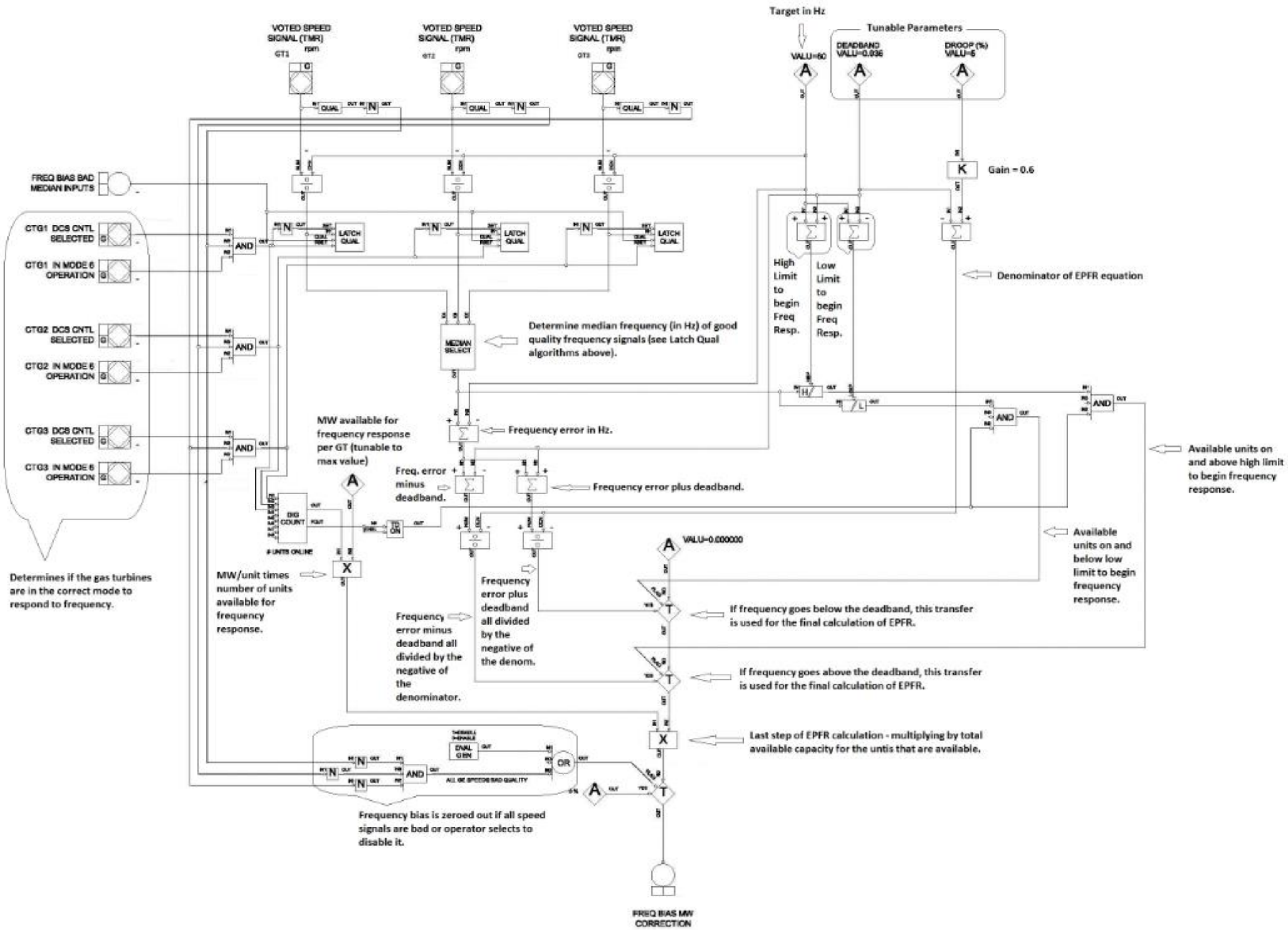
BLACK & VEATCH Building a world of difference.

ALSTOM

* - have developed or are developing a related technical guide

Questions and Answers

Appendix Sample Logic for GT



FREQ BIAS CORRECTION Rev. A — NOT COMMISSIONED 10/14/2014