Primary Frequency Response Stakeholder Education Part 1 of 2

Primary Frequency Response
Sr. Task Force

September 1, 2017

Problem Statement / Issue Charge Summary

Evaluate need for generator Primary Frequency Response (PFR) requirement in PJM

- Primary frequency response is essential for reliability of the Interconnection and is:
  - the first line of defense
  - critical for system restoration
  - needed for accurate modelling and event analysis
  - necessary for compliance to BAL-003-1
- Key work activities:
  - Education on PFR
  - Evaluation of existing state of PFR in PJM and other areas
  - Discussions on potential compensation issues and mechanisms
  - Evaluation of PJM OA, OATT and Manuals

Agenda

<u>Primary Frequency Response Education Part 1 of 2</u>

- **Technical**
  - Power System Fundamentals
  - Importance of Primary Frequency Response (PFR)
  - Terms used in association with PFR
  - Resource and load response to frequency
  - Governor droop and deadband
  - Area Control Error (ACE)
  - Automatic Generation Control (AGC)
  - Interactions between PFR and Ancillary Services
- **Operational**
  - Review control modes
  - Review desired versus observed response
  - Analysis of recent events/unit performance

Agenda Continued

- **Operational (continued)**
  - Reasons for inconsistent response
  - Changing technologies
  - Governor Survey observations
- **Importance of PFR During System Restoration (Blackstart)**
  - Frequency control during normal and restoration operations
  - Review governor modes of operation
  - Review restoration process
  - Reserves during normal and restoration operations

Primary Frequency Response Education Part 2 of 2

- **Current PJM Requirements**
  - Manual requirements
  - Tariff requirements

Agenda Continued

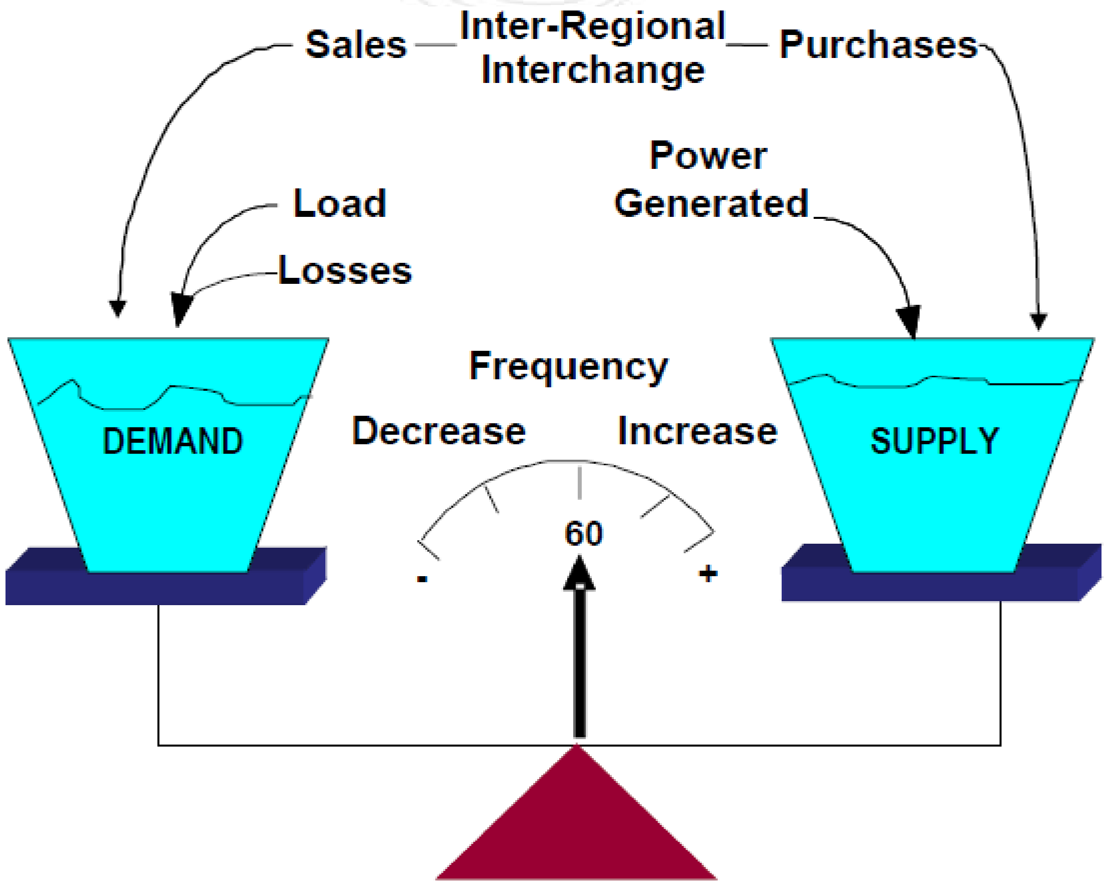
- **Regulatory activities related to PFR**
  - NERC BAL-003 compliance
  - NERC Frequency Response Initiative Report
  - NERC Advisory on Generator Governor Frequency Response
  - NERC Essential Reliability Task Force
  - FERC NOPR on Primary Frequency Response
  - ISO/RTO Council response to FERC NOPR
  - Additional NERC Activity
- **Glossary**
- **References**

Technical Information

Agenda

- Technical
  - Power System Fundamentals
  - Importance of Primary Frequency Response (PFR)
  - Terms used in association with PFR
  - Resource and load response to frequency
  - Governor droop and deadband
  - Area Control Error (ACE)
  - Automatic Generation Control (AGC)
  - Interactions between PFR and Ancillary Services

- Frequency does not change in an Interconnection as long as there is a balance between resources and customer demand (including various electrical losses).



Power Balance

- Normal scheduled frequency across the interconnection is 60 Hz
- Balancing Authority’s (PJM is a Balancing Authority - BA) have the obligation to maintain the scheduled frequency (60 Hz)
- Disturbances can cause the frequency to either increase from loss of load or decrease from loss of generation
- The BA that experienced the disturbance has an obligation to take actions to return the frequency to schedule (60Hz)

- Primary Frequency Control, also known generally as Primary Frequency Response (PFR), is the first stage of frequency control and is the inherent response of resources and load to arrest local changes in frequency.
- Primary frequency response is automatic, ***is not driven by any centralized system***, and begins within seconds after the frequency changes, rather than minutes.

Why Primary Frequency Response Is Important

- Essential for Reliability of the Interconnections
  - Cornerstone for system stability
  - First line of defense to prevent low system frequency which could lead to triggering Under Frequency Load Shedding or ultimately a system blackout
- Essential for System Restoration
  - Response is critical in system blackstart restoration efforts
- Compliance with NERC Standards
  - BAL-001 (Real Power Balancing Control Performance) &
  - BAL-003 (Frequency Response and Frequency Bias Setting)
- Preclude future regulations related to generator frequency response performance

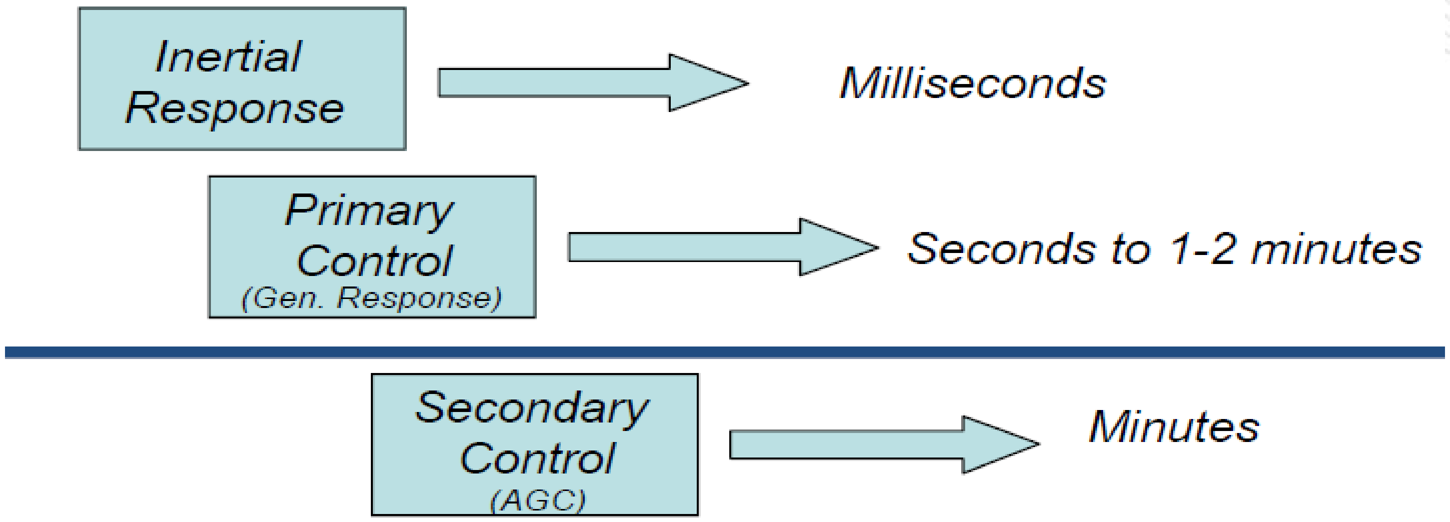
Why Primary Frequency Response Is Important

- Predictability is required for accurate modeling and event analysis
- Observations with current primary frequency response within PJM footprint
  - Large variability from event-to-event basis, many generators not providing PFR
  - Many generators withdraw PFR or respond in the opposite direction
  - Significant portion of frequency response from load

- Occurs within the first few seconds following a change in system frequency (disturbance) to stabilize the Interconnection.
- Primary Frequency Response is provided by:
  - Generator Governor Action
    - Governors on generators are similar to cruise control on your car. They sense a change in speed and adjust the energy input into the generators' prime mover.
  - Load
    - A significant portion of PFR comes from load which cannot be predicted or controlled

- Load (Cont'd)
  - The speed of motors in an Interconnection changes in direct proportion to frequency
    - As frequency drops, motors will turn slower and draw less energy
    - As synchronous motors are replaced by variable speed drives, <u>the load response of the motors is eliminated</u> by the power electronics of the motor controller.
  - Under severe disturbance scenarios, without adequate PFR, firm customer load may be interrupted by automatic under-frequency load shedding to ensure stabilization of the systems

Types of Control



Control	Service	Timeframe
Inertial Control	Inertia	0-10 Seconds
Primary Control	Primary Frequency Response	10-60 Seconds
Secondary Control	Regulation / Reserves	1-10 Minutes
Tertiary Control	System Re-dispatch (SCED)	10-30 Minutes

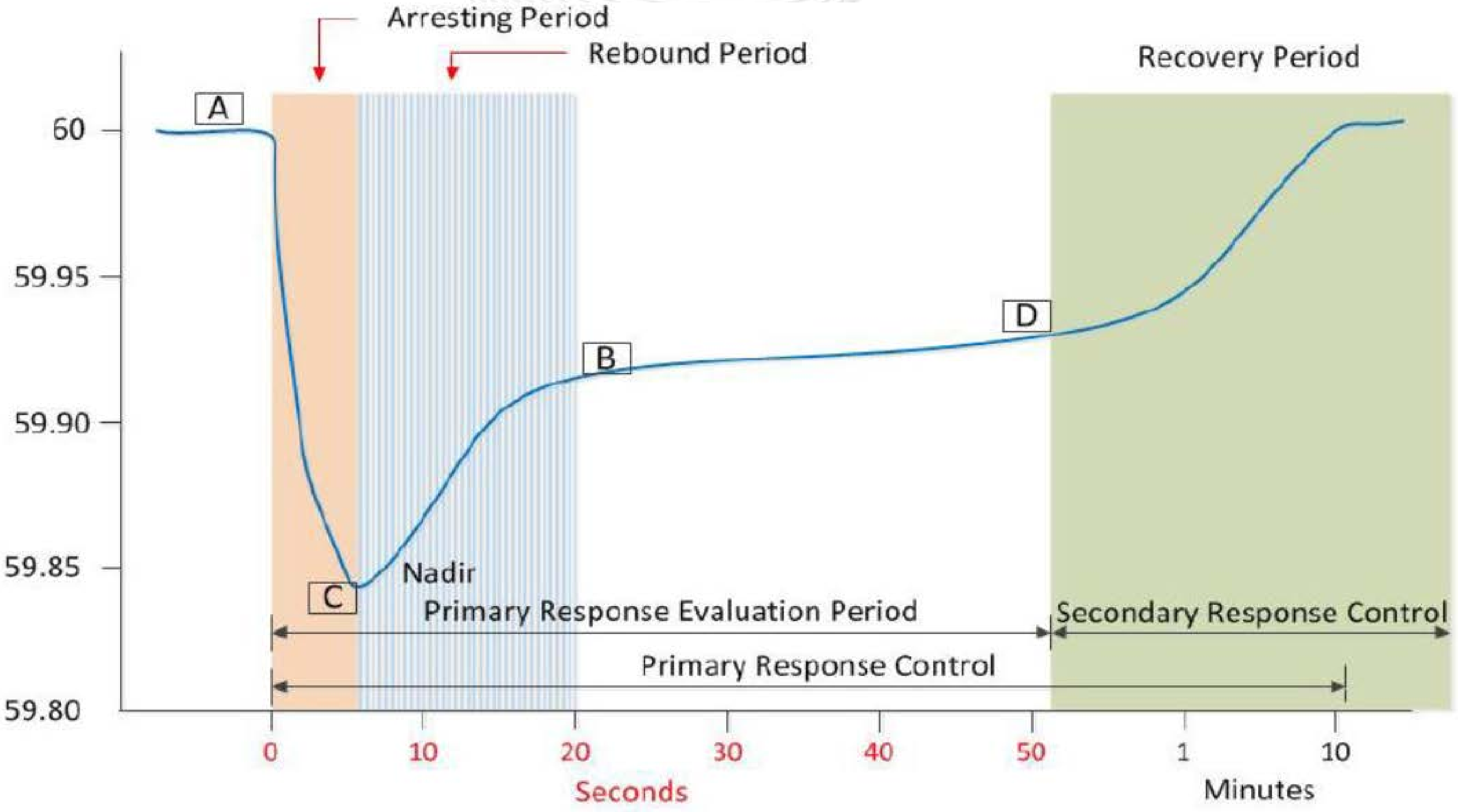
- Kinetic energy stored in the rotating mass of all of the synchronized turbine-generators and motors on the interconnection
- Produced by the slowing of the spinning inertial mass of rotating equipment on the interconnection that both releases the stored kinetic energy and arrests the decline of the interconnection frequency
- Happens immediately following a disturbance

- Secondary Frequency Control - Actions provided by an individual Balancing Authority to correct the resource-to-load imbalance that created the original frequency deviation.
- Restores the system to the scheduled frequency and restores the Primary Frequency Response capability.
- Comes from either manual or automated dispatch <u>from a centralized control system</u> such as Automatic Generation Control (AGC)
  - Includes the deployment of area regulation and synchronized reserves (if required).
- Happens within the recovery period which is 1-10 minutes following a disturbance.

Tertiary (Frequency) Control

- Tertiary Frequency Control - Actions provided by Balancing Authorities on a balanced basis that are coordinated so there is a net-zero effect on Area Control Error (ACE).
- Tertiary Control is best explained as economic dispatch
- Tertiary Control actions are intended to replace Secondary Control Response by reconfiguring reserves.
- Happens within the period of 10 – 60 minutes following a disturbance

Classic Frequency Excursion Recovery



- Essential Reliability Services – Frequency & System Inertia

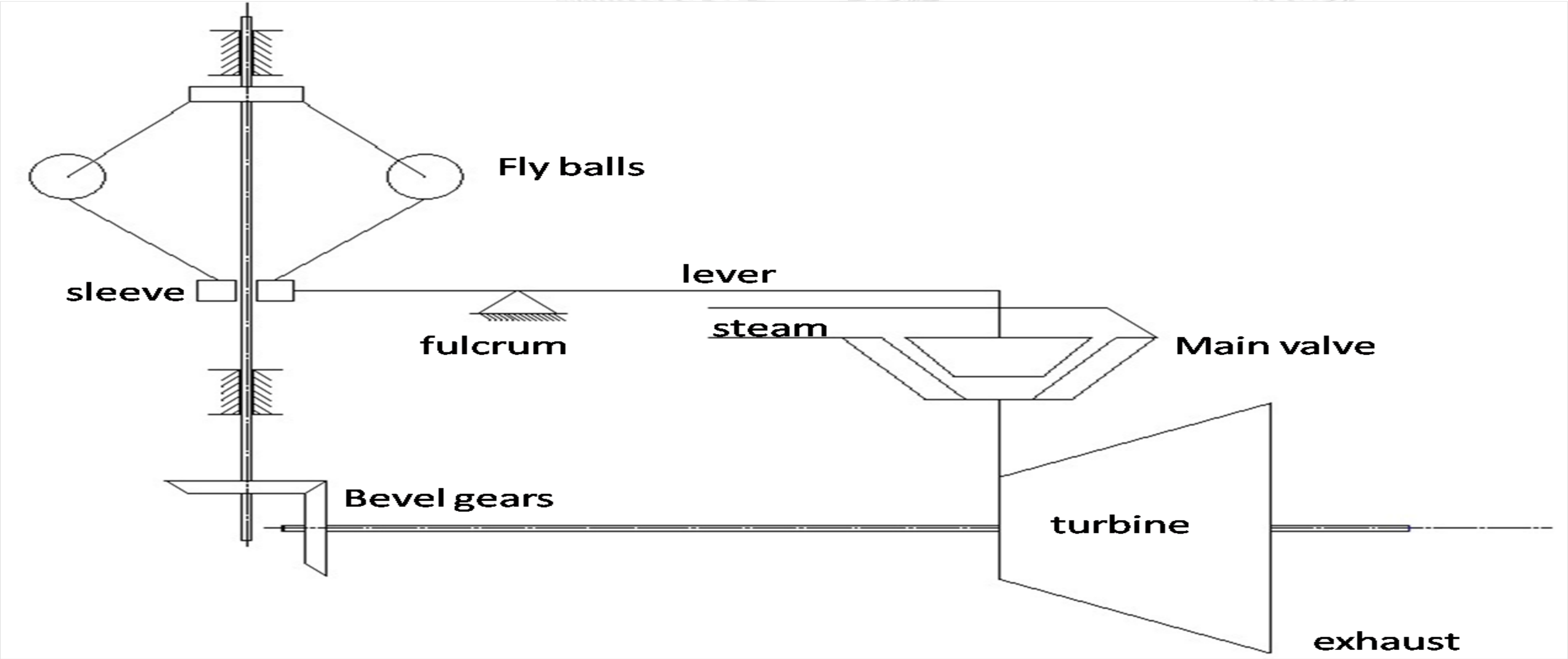
https://vimeopro.com/nerclearning/erstf-1/video/146105419

- Governor
  - Speed control systems for turbine-generators to control shaft speed by sensing turbine shaft speed deviations and initiating adjustments to the mechanical input power to the turbine. This control action results in a shaft speed change (increase or decrease).
- Governor will attempt to adjust a generator's MW output in accordance with its droop setting
  - Governors with a droop setting greater than 0% will arrest a drop in frequency, <u>but not restore or recover it</u>

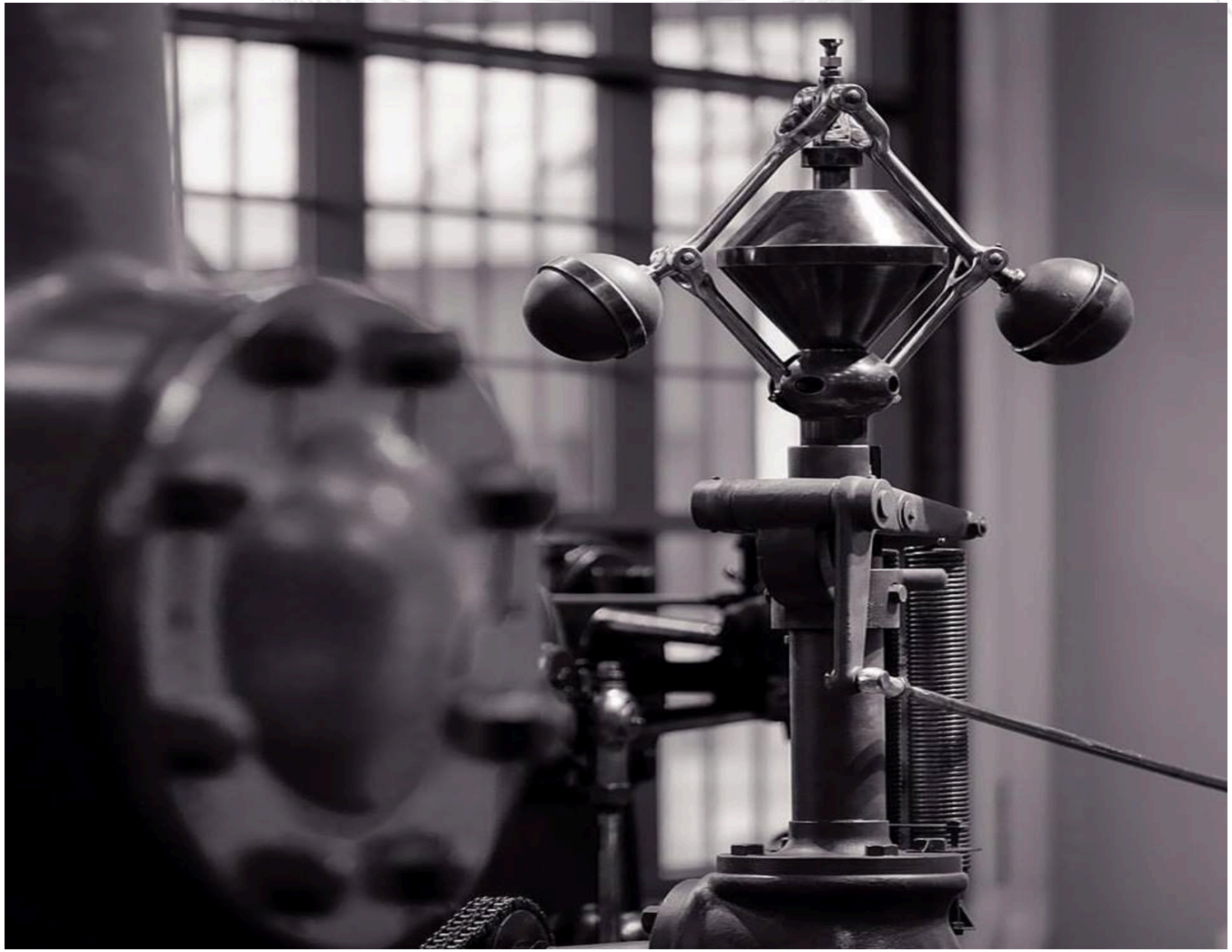
Generator Governor Control (Cont'd)

- MW response of a governor is a function of:
  - Droop setting of the governor
  - Available stored energy of the generator
  - Available generator headroom
  - Type of unit (e.g. steam, hydro, CT, combined cycle, nuclear, intermittent)
  - Control mode of the generator

Schematic diagram of a “fly ball” governor



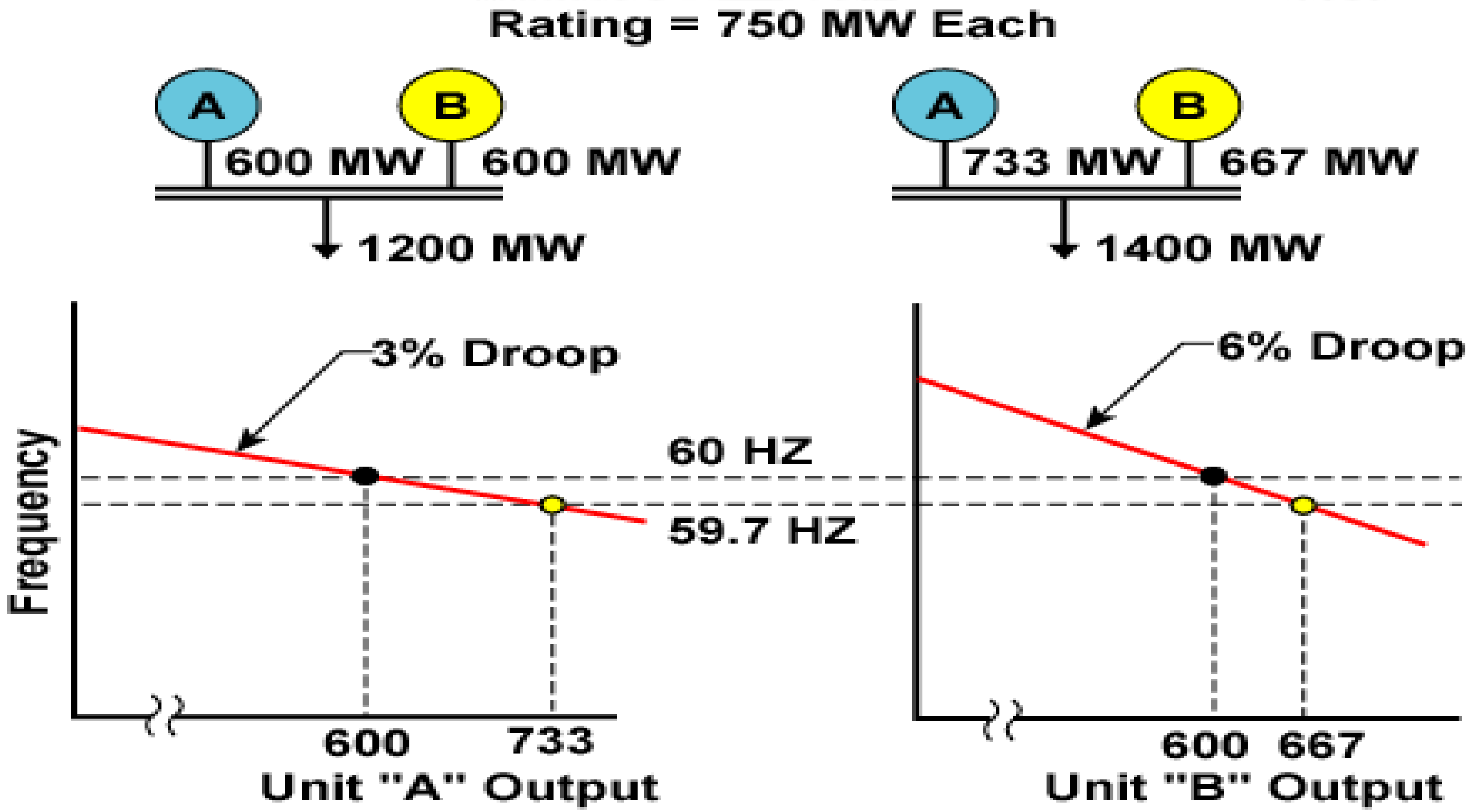
Picture of “fly ball” governor



Generators - Droop

- Turbine Governor Droop, Speed Regulation and Speed Error are common terms used in describing a turbine's response to Changes in Interconnection Frequency (speed)
- Droop Control allows units to operate in parallel so that each unit shares MW response with other generators in the system
  - As load increases, speed decreases
  - The lower the droop setting, the more precise the frequency control
  - Overly precise or sensitive control of frequency can cause MW oscillations or governor instability issues resulting in generator tripping and system shutdowns

- Droop (Cont'd)
  - Now imagine if there was a feature added to the cruise control such that any change in speed and subsequent signal to the cruise control, would be weighted based on the car's engine capacity (droop)
- Example:
  - A trailer is being towed by two cars in parallel.
  - If more load were added to the trailer, both car A and car B would assume more load. However, because of this new (droop) feature, the signal from the cruise control (governor) would be based on the engine sizes of the two cars.
  - Load changes could be more proportionately shared between cars


Rating = 750 MW Each
A
B
600 MW
600 MW
1200 MW
A
B
733 MW
667 MW
1400 MW
3% Droop
60 HZ
59.7 HZ
Frequency
600
733
Unit "A" Output
6% Droop
600
667
Unit "B" Output

- Think about the previous analogy of the two cars on cruise control….
- When a generator synchronizes to the system
  - It couples itself to hundreds of other machines rotating at the same electrical speed.
  - Each of these generators have this Droop feature added to their governor
  - They will all respond in proportion to their size whenever there is a disturbance, or load-resource mismatch.

- Governor Deadband
  - An additional feature included in generator governors
  - A small no-response zone within the calibration of the governor speed control
  - Deadband is the amount of frequency change a governor must see before it starts to respond
  - Deadband serves a useful purpose by preventing governors from continuously “hunting” as frequency varies ever so slightly

Synchronous Generator Characteristics

- Directly connected to the grid via electromagnetism and operating at the same (interconnection) frequency
- Contribute to system inertia
- Examples include steam, CT, combined cycle and hydro units

Non-Synchronous Generator Characteristics

- Generate asynchronous AC voltage which is converted to DC, and then employs inverters and power electronics to generate a 60 Hz AC waveform.
- Electronically connected to the grid
- Examples include wind and solar resources
- Typically do not contribute to system inertia (certain wind turbines may contribute a small amount)
- Energy Storage Systems also connected via inverter based technology

Summary of Important Concepts

- Following a large generator trip or load loss, **Frequency Response will only stabilize the frequency of an Interconnection**, arresting its decline or increase. Frequency will not recover to the scheduled frequency until the contingent Balancing Authority balances generation and load through AGC and reserve deployment.
- **AGC supplements governor control** by controlling actual tie flows and maintaining scheduled interchange at its desired value. It performs this function in the steady-state, seconds-to-minutes timeframe, after transient effects (including governor action) have taken place.
- **Frequency control during restoration is extremely important.** That is why system operators should have knowledge of the generators' governor response capabilities during black start.

- **Area Control Error** is a measure of the imbalance between sources of power and uses of power within the PJM RTO.
  - This imbalance is calculated indirectly as the difference between scheduled and actual net interchange, plus the frequency bias contribution to yield ACE in megawatts.
  - An additional PJM dispatcher adjustment term (manual add) may be included in ACE under certain conditions
    - This provides for automatic inadvertent interchange payback and meter error compensation

- The calculation of Area Control Error (ACE) is given the formula:

$$ACE = (NI_{A} – NI_{S}) – 10B\ (F_{A} – F_{S}) – I_{ME}$$

- Actual Net Interchange – NI_A – the algebraic sum of actual flows on all tie lines
- Scheduled Net Interchange – NI_S – the algebraic sum of scheduled flows on all tie lines
- Actual Frequency – F_A
- Scheduled Frequency - F_S
- Calculated Frequency Bias – B is the Frequency bias setting (MW/0.1 Hz) for the BA. The constant factor of 10 converts the frequency setting to MW/HZ
- Meter Error - I_{ME} – meter error correction factor

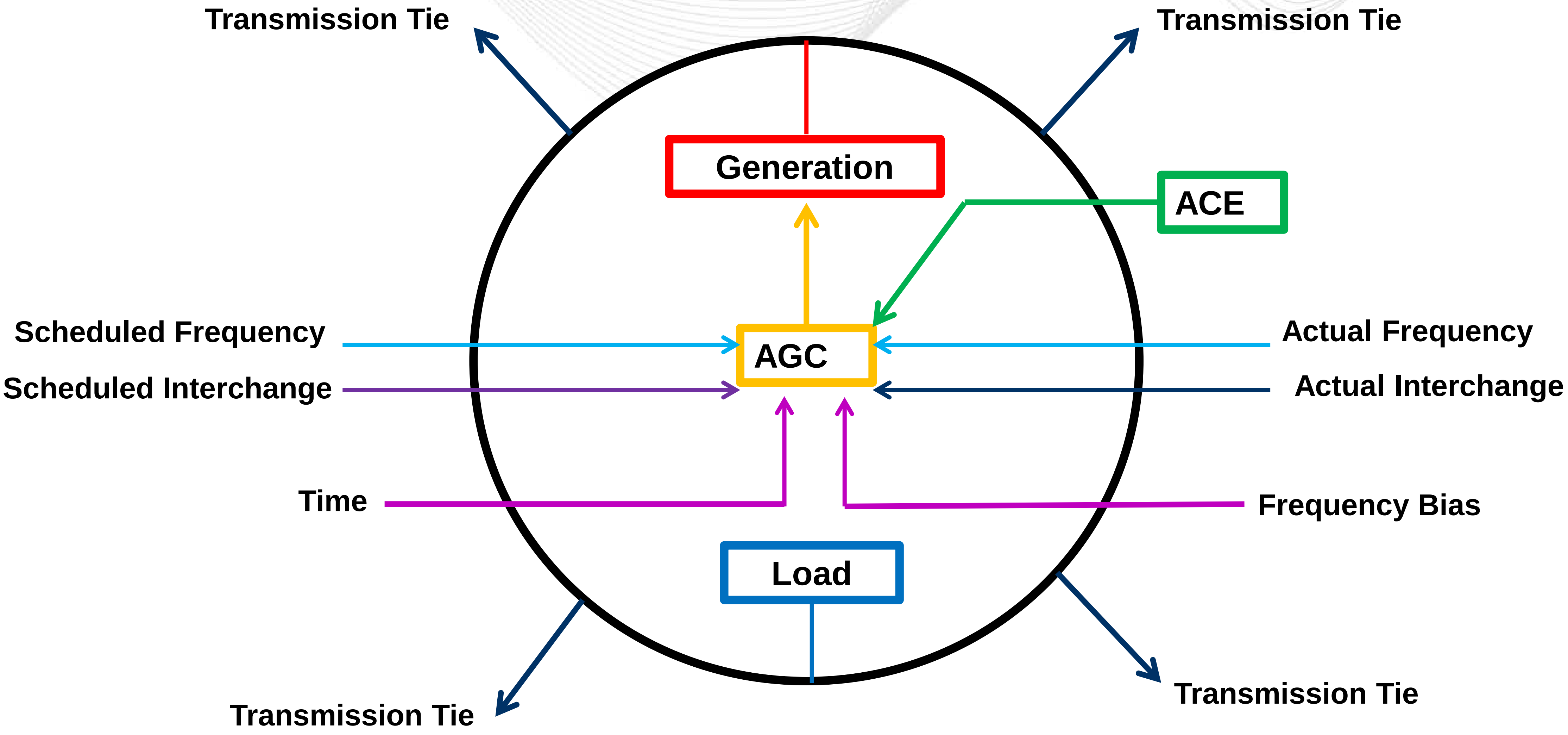
Frequency Bias Component of ACE Equation

- Frequency bias component of ACE is required to ensure that the ACE calculation supports frequency error correction for the Eastern Interconnection
  - For example, if the frequency goes low, each Balancing Authority is required to contribute a small amount of extra generation in proportion to its system’s established frequency bias
- Frequency Bias component of ACE is set annually by NERC based on actual measured frequency response of the BA and Interconnection Minimum as determined by the ERO

Automatic Generation Control (AGC)

- Designed to control within Balancing Authority's boundaries in an interconnected mode
  - Control parameters are continuously monitored and consist of:
    - Actual/scheduled frequency readings
    - Actual/scheduled tie-line MW flows
- AGC operation during normal operations continuously balances:
  - Generation
  - Interchange schedules
  - Load
- While maintaining scheduled frequency
  - Economically dispatches resources
  - Dispatches regulating resources

Automatic Generation Control



Interactions between PFR and Ancillary Services

- Primary Frequency Response is:
  - Inherent response of resources and load to arrest local changes in frequency
  - Automatic, ***is not driven by any centralized system***, and begins within seconds after the frequency changes, rather than minutes
- Regulation and Synchronized Reserves
  - Depend on PJM's Automatic Generation Control System and PJM Dispatch
  - Response within minutes

- Resources assigned Regulation or Synchronized Reserves may inherently react to system frequency deviations.
- Resources may provide Primary Frequency Response depending on the amount of available headroom (if any) and the control mode of the resource.
  - Within one or two minutes following a significant frequency deviation within the PJM Balancing Area as determined by the direction of PJM's Area Control Error Signal:
    - PJM's AGC will adjust the Regulation
    - PJM Dispatch may call for Synchronized Reserves if required.

Operational

- Operational
  - Review control modes
  - Review desired versus observed response
  - Analysis of recent events/unit performance
  - Reasons for inconsistent response
  - Changing technologies
  - Governor Survey observations

- Power plants are equipped with a wide variety of governor and plant control systems
  - In general, all prime movers will utilize some form of speed governor
  - Typically, this is a core part of the machine’s over speed protection as well as the foundation for the speed droop governor

- Modern systems generally incorporate a form of plant or unit load control
  - Can be locally or remotely controlled
  - Can be applied within the turbine control panel, the plant control panel or even remotely from a central dispatch center
  - In each of these control systems, the primary frequency control of the turbine governor must be taken into account to achieve sustained primary frequency response
  - Without coordination of the turbine governor’s response to all speed changes, these additional control systems will react to the primary frequency response as a control error and quickly reverse the action of the governor

Generation Control Modes

- Unit level control
  - Single control system controlling one unit
- Plant level control
  - Single control system controlling multiple units at the same plant (e.g. – combined cycle plant)
- MW set point control
  - Generation output set to AGC-prescribed or efficiency-prescribed generation levels <u>regardless of system frequency</u>.
  - This results in "squelching" of any primary frequency response that the governors may have provided during a frequency event.

- Boiler Follow Mode
  - The boiler is divorced from the generation control, which means the steam turbine utilizes stored energy in the boiler to provide immediate load response.
  - The boiler must then change firing rate to bring pressure back to the prescribed setpoint.
  - This is a less efficient operating mode but does provide small amounts of primary frequency response.

- Turbine Follow Mode
  - Turbine control valves maintain a set pressure while the boiler fires to maintain load.
  - Drawback here is a slower generation response.
  - There are variations with this scheme, in that the turbine control **valves can be fully opened** at higher loads to minimize the energy penalty associated with the differential pressure loss across them. In that case, it has been called **sliding-pressure control**, or cascade control.
  - This mode of operation <u>does not support primary frequency response</u> but is more efficient.

- Coordinated Control
  - In general, various logic schemes are provided to move the steam turbine valves for quick load response, as well as fire the boiler for the anticipated energy requirements of the boiler (generally via an energy balance equation).

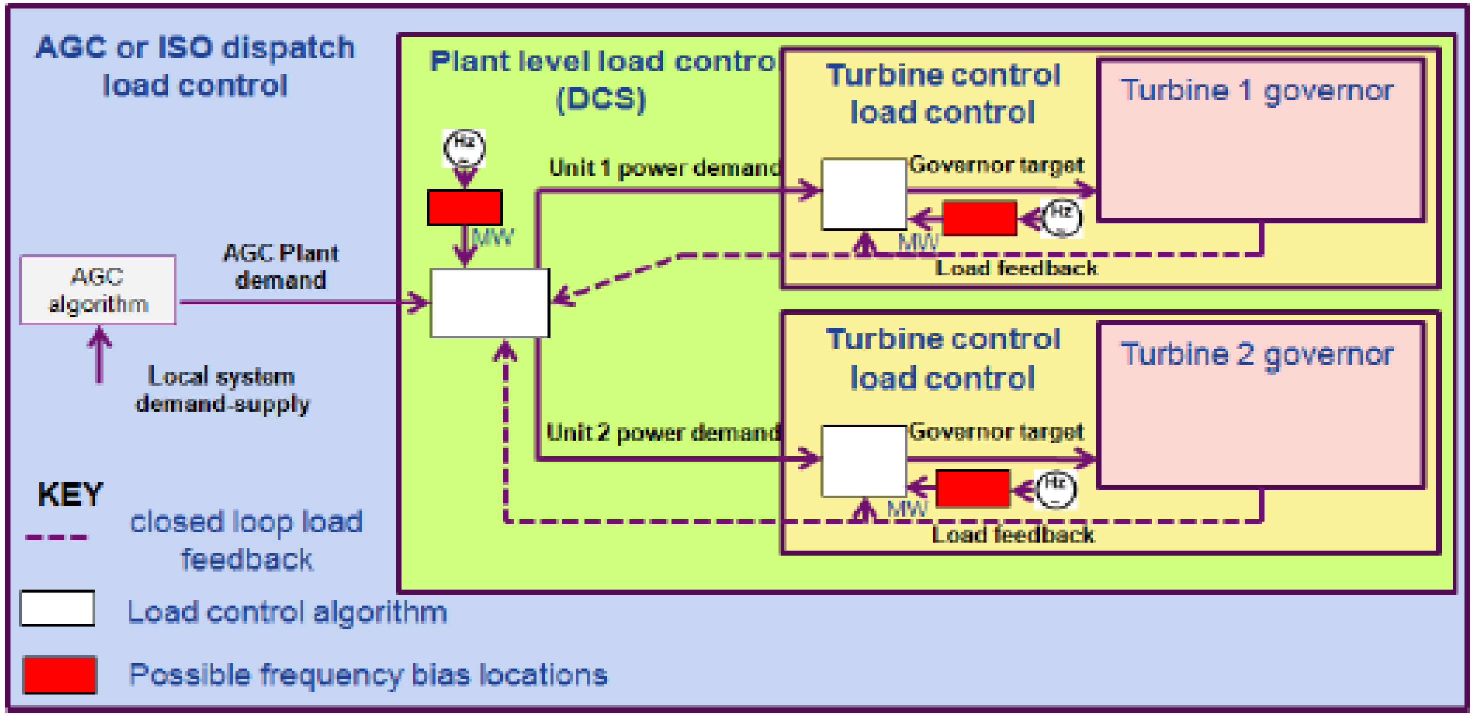
- Withdrawal of primary frequency response is an undesirable characteristic associated most often with digital turbine-generator control systems using setpoint output targets for generator output.
- These are typically outer-loop control systems that defeat the primary frequency response of the governors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

Reasons for response withdrawal

- Outer loop controls “squelching the response”
  - Frequency response algorithm is missing in the majority of the gas turbine fleet when operating in MW Set Point Control
- Lack of coordination with boiler or plant controls
- Mode of operation of generator
- Deadband setting (too wide)
- Other characteristics of the type of resource providing frequency response.

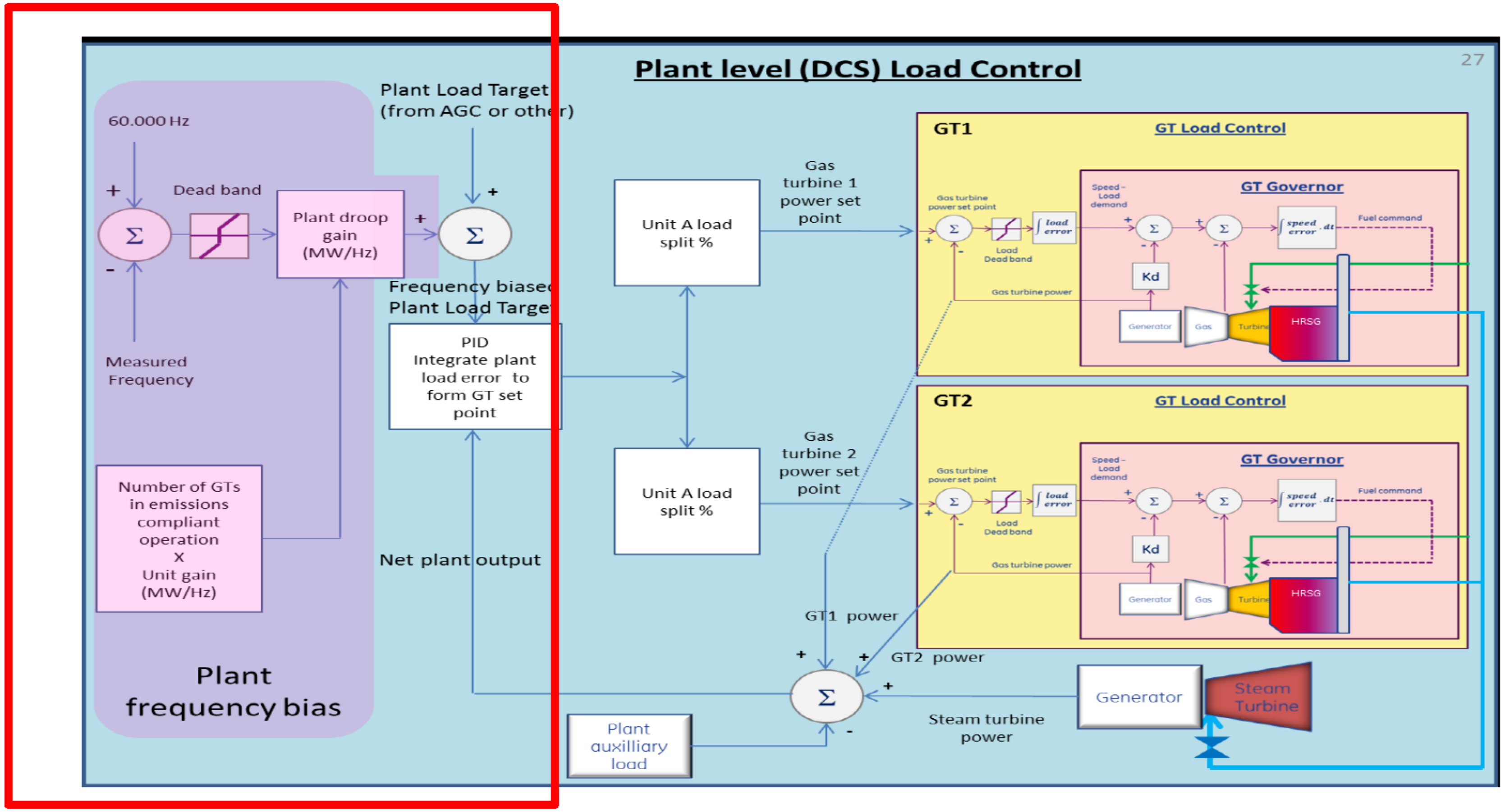
- Any closed-loop load controls can “squelch” or “negate” governor droop response (PFR)
- Must add a frequency bias or simulation component to correct this
- Appropriate outer-loop controls modifications may be required to avoid primary frequency response withdrawal at a plant level

Coordination with plant Distributed Control System (DCS) is a requirement when operating in MW Set Point Coordinated Control



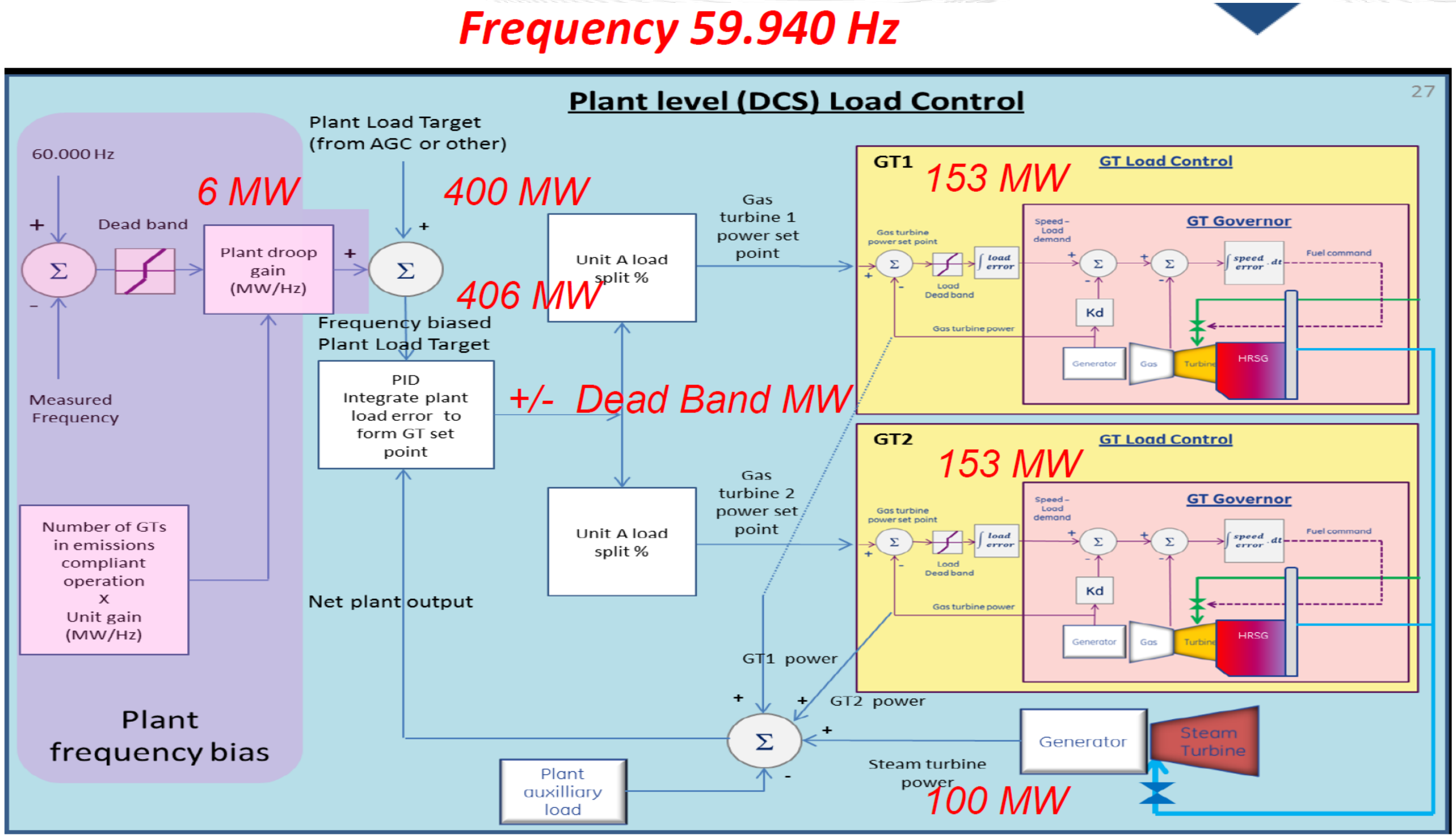
What Has Been Learned (NERC Slide)

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



Graphic from GE info bulletin PSIB20150212

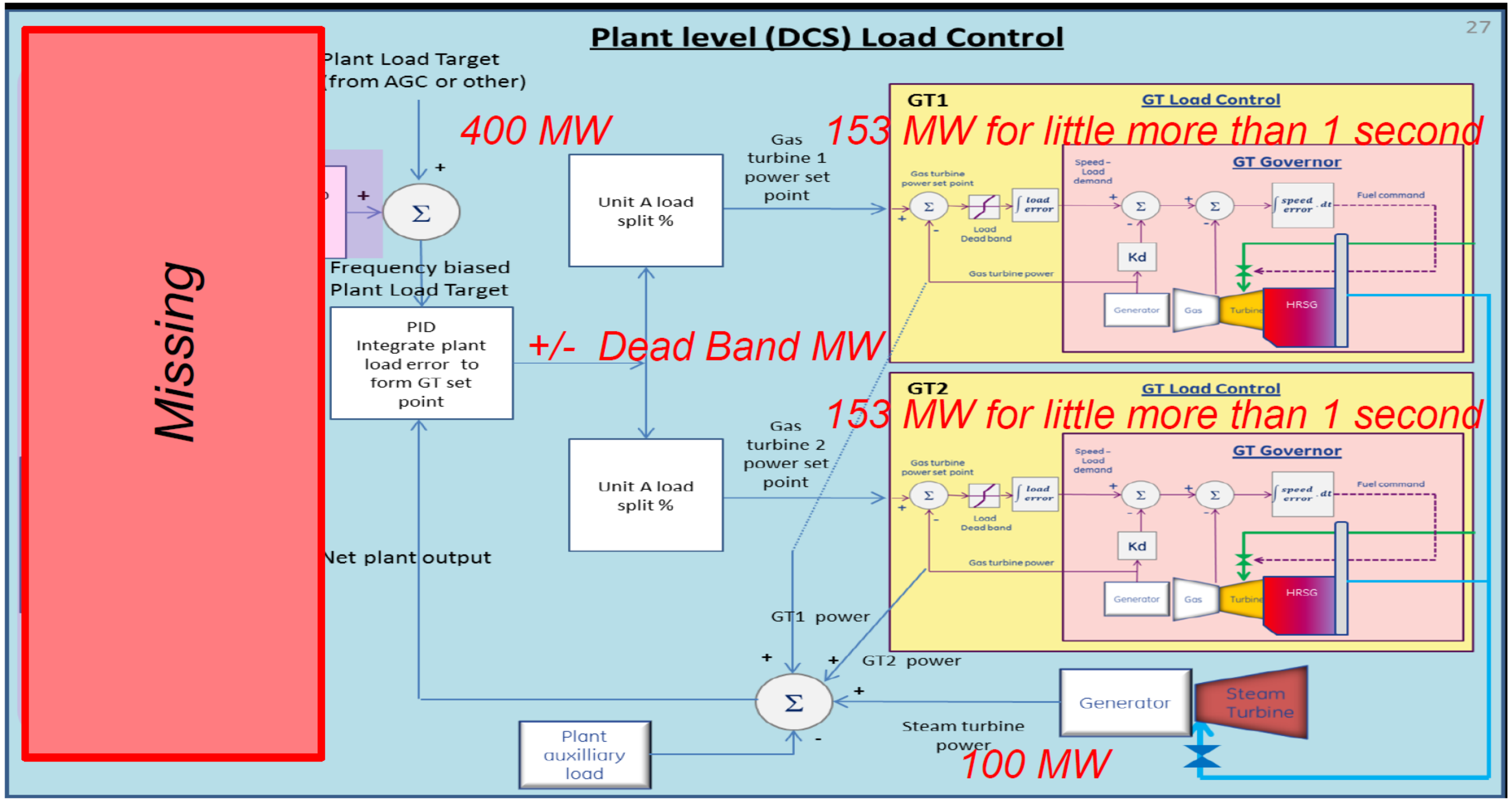
Example – Disturbance With Frequency Input



Graphic from GE info bulletin PSIB20150212

Example – Disturbance Without Frequency Input

Frequency 59.940 Hz

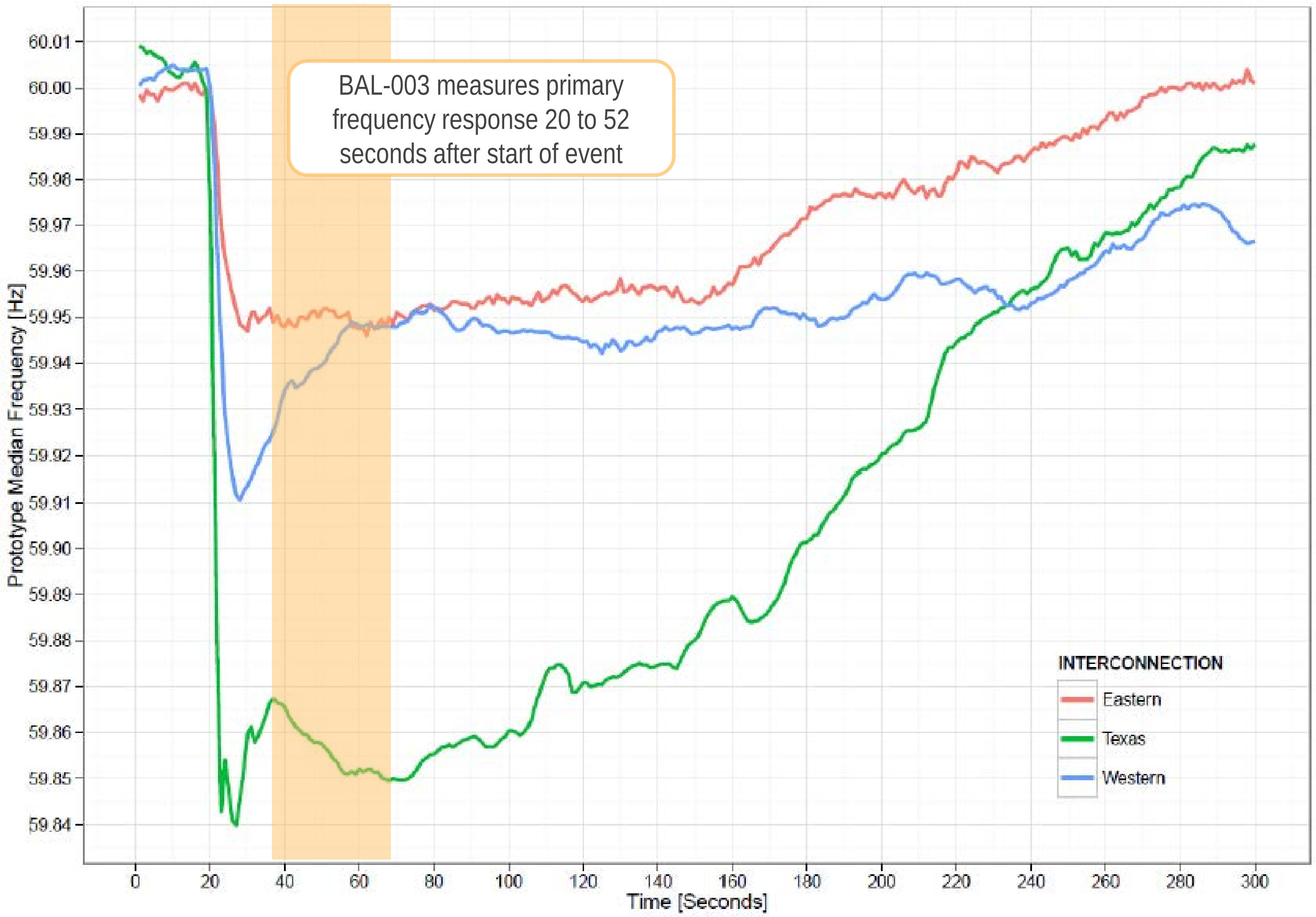


Graphic from GE info bulletin PSIB20150212

Typical Interconnection Responses

Primary Frequency Control comes from automatic generator governor response, load response (primarily motors), and other devices that provide an immediate response based on local control systems.

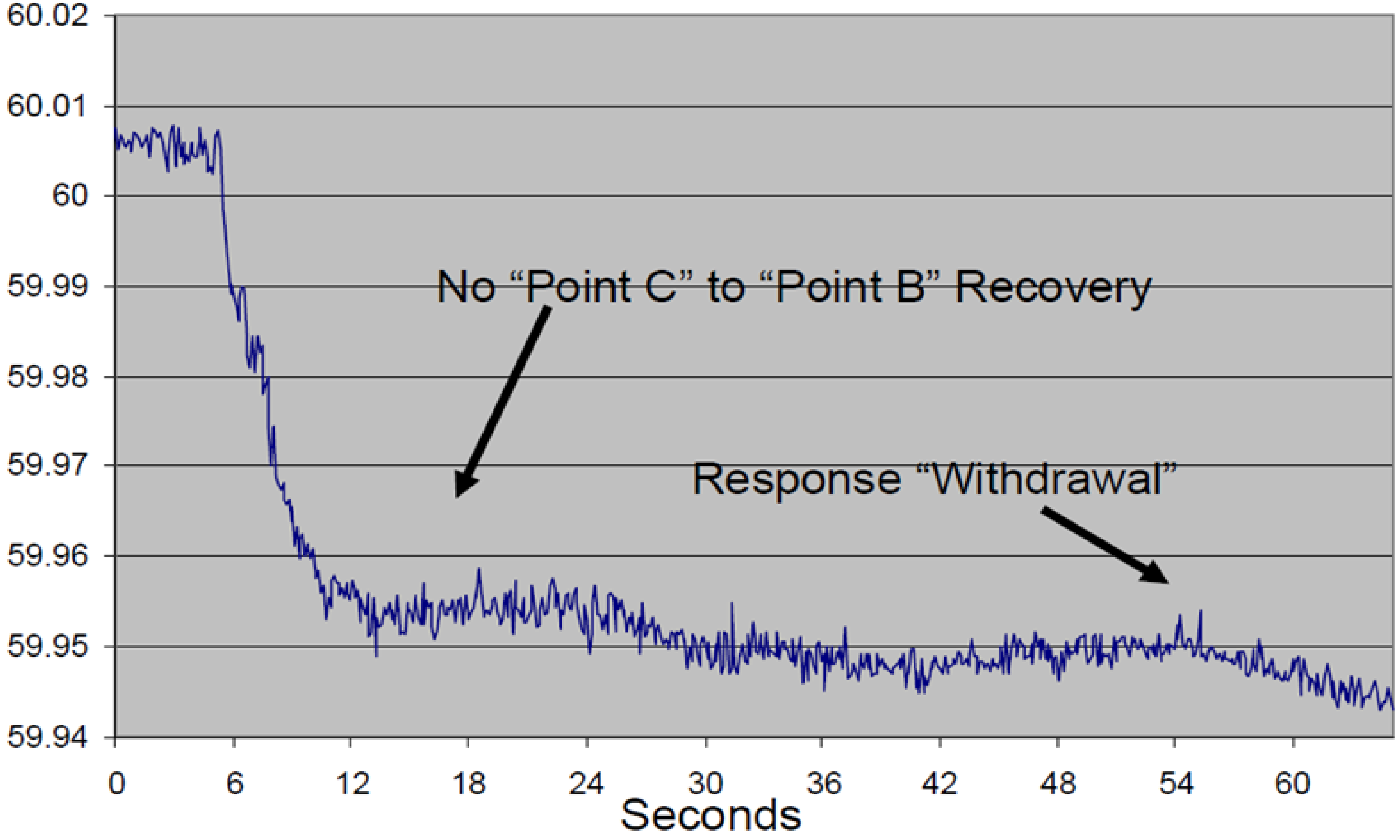
Evidence of frequency response withdrawal seen in the Eastern Interconnection.



Eastern Interconnection "Lazy L"

- The term **“Lazy L”** is a reference to a frequency profile typical of the **Eastern Interconnection** and describes the event frequency profile after a sudden loss of generation.
- Frequency declines to a new lower equilibrium and remains flat for 10 to 30 seconds and then reduces further due to withdraw of primary frequency response from generation.

Eastern Interconnection "Lazy L"



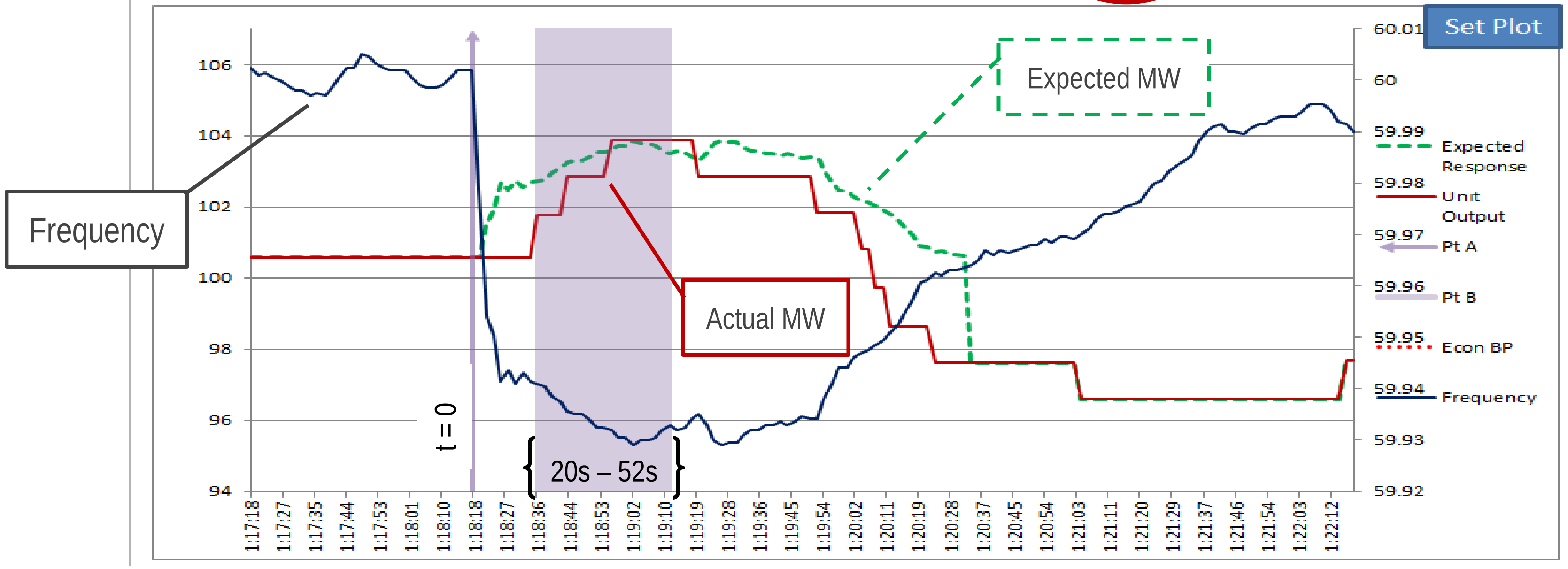
Frequency Response Unit Event Performance Tool

Governor Settings	
Droop (%):	5%
Deadband (Hz):	0.036

Plot Times	
Event Start:	12/29/2012 1:18:18
Plot Start:	12/29/2012 1:17:18
Plot End:	12/29/2012 1:22:18
Interval:	2s

in MW	Actual Resp.	Expected Resp.
Point A =	100.576	100.576
Point B =	103.127	103.459

Actual Response =	3 MW
Expected Response =	3 MW
Deficiency =	0 MW



Unit Actual Response ≈ Expected Response

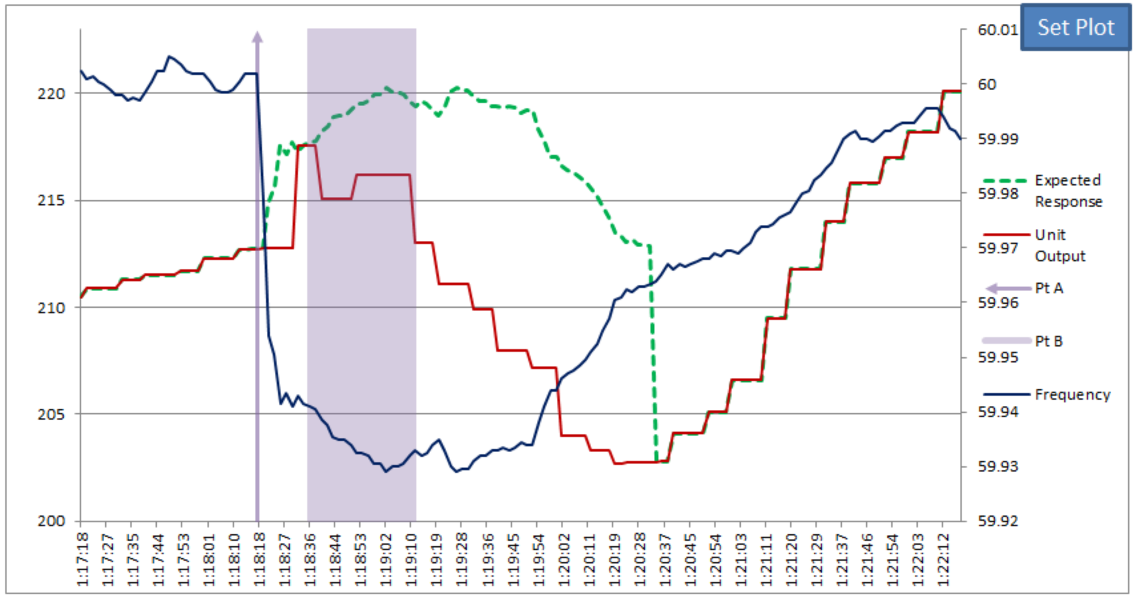
Frequency Response Unit Event Performance Tool

Governor Settings	
Droop (%):	*5%*
Deadband (Hz):	*0.036*

Plot Times	
Event Start:	12/29/2012 1:18:18
Plot Start:	12/29/2012 1:17:18
Plot End:	12/29/2012 1:22:18
Interval:	2s

in MW	Actual Resp.	Expected Resp.
Point A =	212.733	212.733
Point B =	215.894	219.370

Actual Response =	3 MW
Expected Response =	7 MW
Deficiency =	3 MW



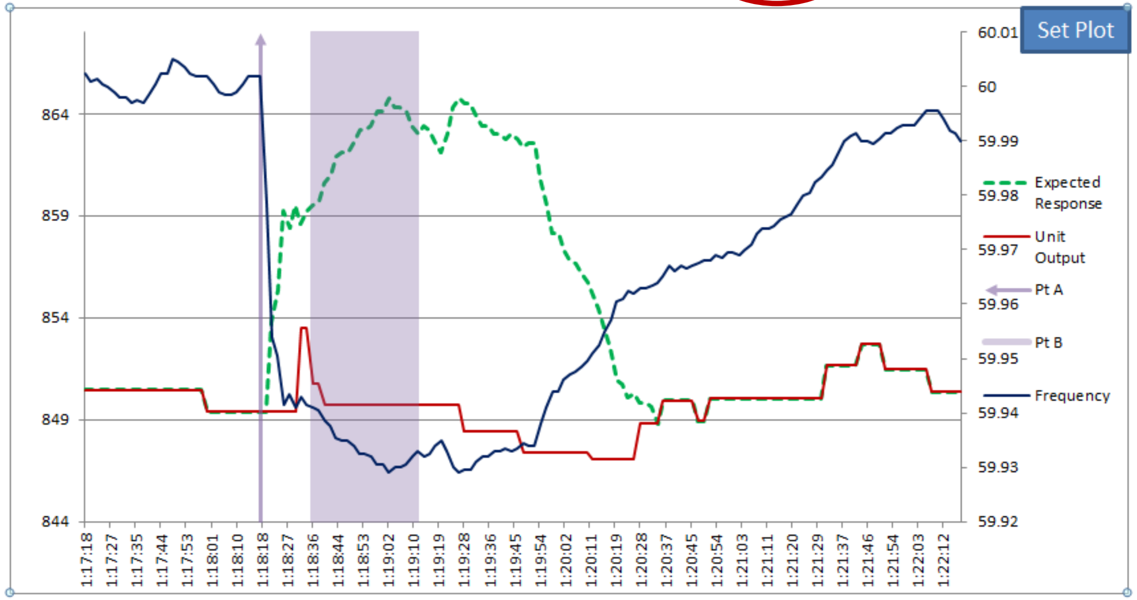
Initial Response with Early Withdrawal

Governor Settings	
Droop (%):	*5%*
Deadband (Hz):	*0.036*

Plot Times	
Event Start:	12/29/2012 1:18:18
Plot Start:	12/29/2012 1:17:18
Plot End:	12/29/2012 1:22:18
Interval:	2s

in MW	Actual Resp.	Expected Resp.
Point A =	849.400	849.400
Point B =	849.814	862.880

Actual Response =	0 MW
Expected Response =	13 MW
Deficiency =	13 MW



No Response

Load Response to Frequency

- Motor load provides frequency response to the Interconnection
  - The rule of thumb is that this response is equal to 1 to 2 % of load
    - This depends on the ratio of motor load to non-motor load within the Balancing Authority boundaries
  - Variable drive motors do not provide frequency response
- "Smart Loads" are being developed to provide additional response
  - A voltage compensator is inserted between the supply and the load
    - The voltage compensator senses a change in grid frequency and as a result changes the supply voltage to the load
    - The power consumption of the load changes as the voltage changes

Active Power Controls for Variable Resources

- Wind turbines and solar arrays connect to the grid via power electronics-based converters (inverters)
- Historically, these inverters were programmed to isolate from the grid during frequency & voltage disturbances
- Currently available “Smart” Inverters have advanced control functions
  - Frequency and Voltage ride-through
  - Frequency-fault ride-through
  - Frequency response
  - Ramp-rate controls

- Wind and solar plants respond best to grid frequency increases, which require a drop in power generation
  - They can provide primary frequency response to frequency drops, which require a power increase, only when they are operating below maximum output levels (headroom required)
- Inertial Response
  - Some wind turbines can provide an inertial response, similar to that of conventional generators, by using energy stored in the rotating blades or capturing more energy from converters

- Barriers to Active Power Controls
  - Economic barriers
  - Upfront equipment costs
  - Lost opportunity costs
  - Potential to increase loading impacts on the turbine components

- Storage Resources (batteries & flywheels) connected to the grid through “smart inverters” are also capable of providing primary frequency response
  - The fast-acting response of flywheel and battery storage systems excel in stabilizing the frequency
  - Need to be equipped with autonomous controls that respond directly to grid frequency
  - Different from providing regulation service, which depends on the PJM AGC signal control

PJM Underfrequency Load Shedding

- As a safety net, portions of firm load may be dropped by under-frequency load shedding programs to ensure stabilization of the system under severe disturbance scenarios.
- Frequency during a severe disturbance must not drop below the UF relay trip settings, otherwise, firm load will be shed
- PJM Control Zone Under Frequency Load Shed (UFLS) Settings as follows
  - Mid-Atlantic: 59.3, 58.9, 58.5 Hz @ 10% increments
  - Western Control Zone: 59.5, 59.3, 59.1, 58.9, and 58.7 Hz @5% increments
  - ComEd: 59.3, 59.0 and 58.7 Hz @ 10% increments
  - Dominion: 59.3, 59.0 and 58.5 Hz @ 10% increments

- February 2016 - PJM Issued a Governor Survey
  - Total of 1440 units surveyed, based on eDART model
  - Consisted of 22 technical questions such as:
    - Is the unit equipped with a governor?
    - Is the governor operational?
    - Droop setting?
    - Deadband Setting?
    - Any control system or regulatory limitations to governor response?

- January 2017 - PJM began an outreach to individual generators to clarify responses to February 2016 survey
  - Initially contacted blackstart and critical load units
  - Followed up by contacting all other units
  - Clarified responses to various questions such as:
    - Status of governor settings
    - Any control system or regulatory limitations to governor response
    - Mode of operation during blackstart (system restoration)
    - Status of training and procedures for blackstart (system restoration)

- **Of the designated Black Start units on the PJM system:**
  - 100% indicated that they have a governor capable of changing output in response to locally detected changes in interconnection frequency
  - 92% were within the guidelines of the NERC advisory for governor dead band settings (governor dead band not to exceed +/- 36 mHz)
  - 100% were within the guidelines of the NERC advisory for governor droop settings (governor droop settings not to exceed 5%)
  - 84% responded that they **do not have any** unit-level or plant-level control schemes or regulatory **restrictions that would override or limit governor response** during normal operation

Summary of PJM Governor Survey data for PJM Critical Load Units following January/February 2017 outreach to units

- **Critical Load unit – a unit with a hot start time of 4 hours or less**
- **Critical Load units will be the first units to get start-up power from the Black Start units**
- **Of the Critical Load units on the PJM system:**
  - 97% indicated that they have a governor capable of changing output in response to locally detected changes in interconnection frequency
  - 79% were within the guidelines of the NERC advisory for governor dead band settings (governor dead band not to exceed +/- 36 mHz)
  - 97% were within the guidelines of the NERC advisory for governor droop settings (governor droop settings not to exceed 5%)
  - 75% responded that they **do not have any** unit-level or plant-level control schemes or regulatory **restrictions that would override or limit governor response** during normal operation

Summary of PJM Governor Survey data for PJM Non Black Start and Non Critical Load Units (a.k.a. – "other units")

- **Of the Other Units:**
  - 69% indicated that they have a governor capable of changing output in response to locally detected changes in interconnection frequency
  - 52% were within the guidelines of the NERC advisory for governor dead band settings (governor dead band not to exceed +/- 36 mHz)
  - 62% were within the guidelines of the NERC advisory for governor droop settings (governor droop settings not to exceed 5%)
  - 63% responded that they **do not have any** unit-level or plant-level control schemes or regulatory **restrictions that would override or limit governor response** during normal operation

Importance of Primary Frequency Response During System Restoration

Agenda

- System Restoration
  - Frequency control during normal and restoration operations
  - Review governor modes of operation
  - Review restoration process
  - Reserves during normal and restoration operations

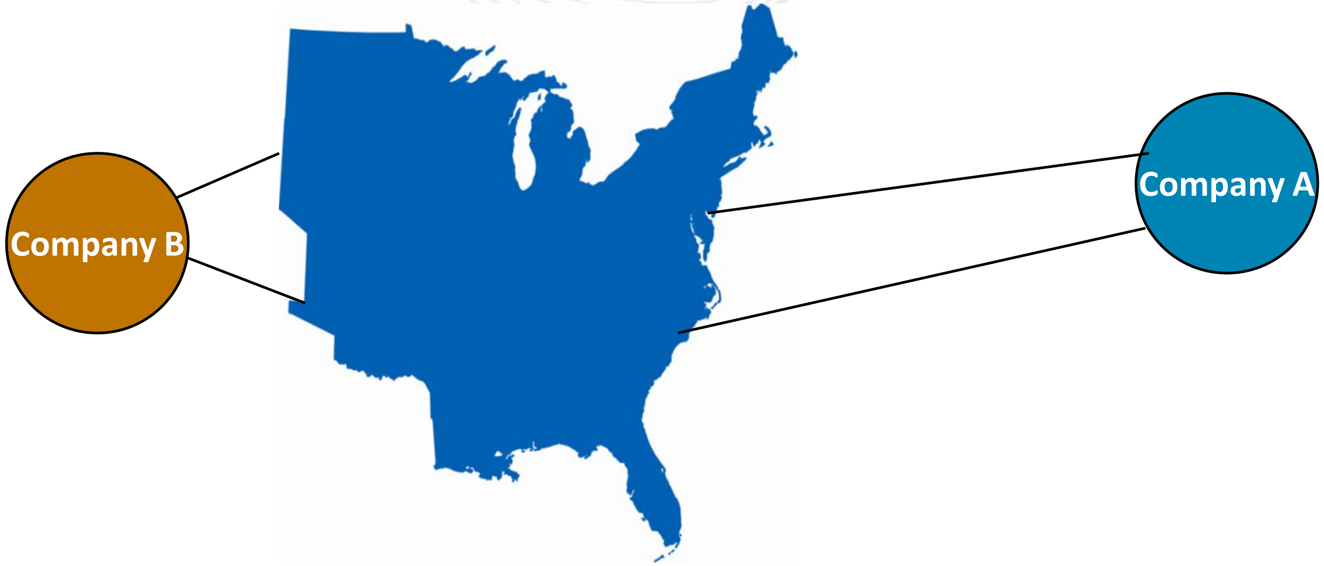
- Tie-Line Bias Control
  - Used when control area to control area tie lines are in service
  - This is the normal control mode
  - Includes Frequency and Tie Line Component

$$ACE = \left(Frequency\ Deviation\ (HZ) * \ Frequency\ Bias\ \left({}^{MW}/_{0.1\ HZ}\right) * 10\right) + \ (Tie\ Schedule - Tie\ Actual)$$

  - Frequency Bias component is set annually by NERC
    - Based on actual measured frequency response of the Balancing Authority, and Interconnection Minimum as determined by the ERO (Reliability First / SERC for PJM RTO)

Normal (Interconnected) Operations

- Two or More Companies with Synchronized Generation



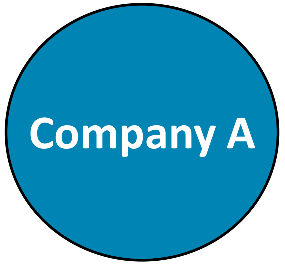
<u>Company B: Tie-Line Bias Control</u>

Requires: Frequency Source, Frequency Bias and Tie-line Schedules Eastern Interconnection and Actual Tie line flows with Eastern Interconnection

<u>Company A: Tie-Line Bias Control</u>

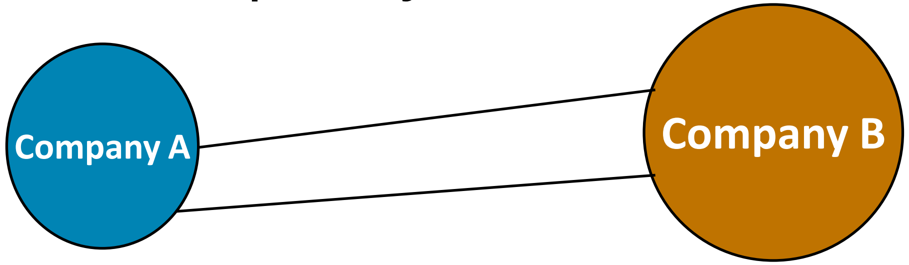
Requires: Frequency Source, Frequency Bias and Tie-line Schedules with Eastern Interconnection and Actual Tie line flows with Eastern Interconnection

- <u>No centralized (PJM) Dispatch Signal Available</u>
- Single Island Control
  - Used in initial stage of system restoration (Blackstart)
  - Utilizes **Flat Frequency Control**
    - Focus is 100% on maintaining scheduled frequency
    - Requires: <u>Frequency Source</u>, Frequency Bias
    - Frequency Bias = (0.01)(Company A Load)



Restoration Control Modes

- <u>No centralized (PJM) Dispatch Signal Available</u>
- Multiple Island Control
  - Company A operates in **Flat Tie Line Control**
    - Controls energy transfer between islands
    - Does NOT account for frequency in either island
  - Company B operates in **Flat Frequency Control**
    - This entity controls frequency in BOTH islands



<u>Flat Tie Line Control</u>

Requires: Tie Line Schedule, Actual Tie line flow

ACE = (Tie Schedule - Tie Actual)

<u>Flat Frequency Control</u>

Requires: Frequency Source, Frequency Bias

Frequency Bias = (0.01)(Total System Load)

Maintaining Frequency Control

- **During normal operation**, frequency control is very manageable
  - Based on the large amount of generation in service
  - Adequate energy and ancillary services managed through markets
  - Stability of the system due to size of the Interconnection
  - <u>PJM controls generation via telemetered or verbal instructions to Generation Owners (GOs) / MOC Dispatchers</u>
  - **During a restoration process**, frequency control is more challenging
  - Based on the small amount of generation in service
  - Potentially multiple small islands within PJM footprint
  - Instability of the system due to low system inertia
  - <u>Transmission Owners control generation via direct communication to GOs / MOC Dispatchers</u>

- Manual 36, System Restoration
  - Section 6.1.7 Blocking Governors
    - During system restoration, **governors must not be blocked** and plant operators must operate the generator in a mode which **allows the governors to respond to frequency deviations** if this mode of control is available.
    - Generating units which cannot meet this criteria **do not contribute to Dynamic Reserves.**

- Black Start units
  - Are first units to be brought online
    - Compensated under Schedule 6A of PJM OATT to provide “Black Start Service” and tested annually
  - Can be started without any external power
  - Must be able to maintain frequency <u>in Isochronous mode</u>
  - Supply start up (cranking) power to Critical Load units
  - Must be able to switch to normal (parallel) droop mode to allow governor to automatically respond to system frequency in proportion to its Droop setting

- Critical Load units
  - Are units that have a hot start time of 4 hours or less as defined in Manual 36, System Restoration, Attachment "A"
    - Hot Start-up Time (from PJM Markets Gateway User Guide)
      - The time interval, measured in hours, from the actual unit start sequence to the breaker close for a generating unit in its hot temperature state.
  - This is not the same designation of "Critical" as defined by NERC
    - NERC historically defined critical assets and critical cyber assets in the context of the Critical Infrastructure Protection (CIP) standards
    - The designation of Critical Load Units is not related to NERC CIP standards

- Isochronous Control refers to a governor droop setting of 0%
- Used by Black Start units during system restoration
  - Frequency is controlled, <u>through governor action alone</u>, to the target value of the governor (60 Hz)
  - Response is rapid and sensitive to even small changes in frequency
  - No external (AGC) signal involved – only local frequency
- Concerns
  - Most effective for a single unit serving an isolated block of load, or when the unit is the only unit responding to changes in load
  - Only one unit can be in the isochronous mode during a restoration

- From Manual 36, System Restoration, Section 5.1.2
  - Needed to ensure that the system, or islands within the system, will remain stable following the largest energy contingency which can be:
    - a single generator or
    - single transmission path from multiple generators
  - Consists of two components:
    - Reserve on generators that are available **via generator governor action** during a frequency disturbance to a level at which generators will normally separate from the system (i.e., 57.5 Hz).
    - System **load with automatic under-frequency trip** levels above the frequency at which generators will normally separate from the system during a frequency disturbance (i.e., 57.5 Hz).

- Dynamic Reserve (Cont'd)
  - Approximately 30% of PJM load is served by feeders equipped with automatic under-frequency relay controls
  - Dynamic Reserves are only calculated and used during system restoration
  - Differ from Synchronized Reserves used during normal, day-to-day operations
    - Does not rely on market parameters
    - Determined by “load pick-up factors” for units paralleled to the system

- Maximum load a generator can pick up, as a percentage of the generator rating (capacity), without incurring a decline in frequency below safe operating levels.
- PJM uses the following load pick-up factors to calculate Dynamic Reserves:
  - 5% for steam units (Including Combined Cycle Units)
  - 15% for hydroelectric units
  - 25% for combustion turbine units
  - Or the unloaded capacity of the unit, whichever is less

Summary

- All generators must have operable governors that:
  - respond to system frequency
  - maintain that response for a defined period of time

- External logic must have a frequency input to bias the plant MW set point during frequency disturbances.

Glossary and Reference Documents

- Glossary of terms used in association with PFR – Posted on PFRSTF website: http://pjm.com/committees-and-groups/task-forces/pfrstf.aspx

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