ECEN 667
Power System Stability

Lecture 12: Compensation, Governors

Prof. Tom Overbye
Dept. of Electrical and Computer Engineering
Texas A&M University
overbye@tamu.edu

Announcements

- Read Chapter 4
- Homework 4 is assigned today, due on Thursday October 18.

Desired Exciter Performance

- A discussion of the desired performance of exciters is contained in IEEE Std. 421.2-2014 (update from 1990)
- Concerned with
  - large signal performance: large, often discrete change in the voltage such as due to a fault; nonlinearities are significant
    - Limits can play a significant role
  - small signal performance: small disturbances in which close to linear behavior can be assumed
- Increasingly exciters have inputs from power system stabilizers, so performance with these signals is important

Transient Response

- Figure shows typical transient response performance to a step change in input

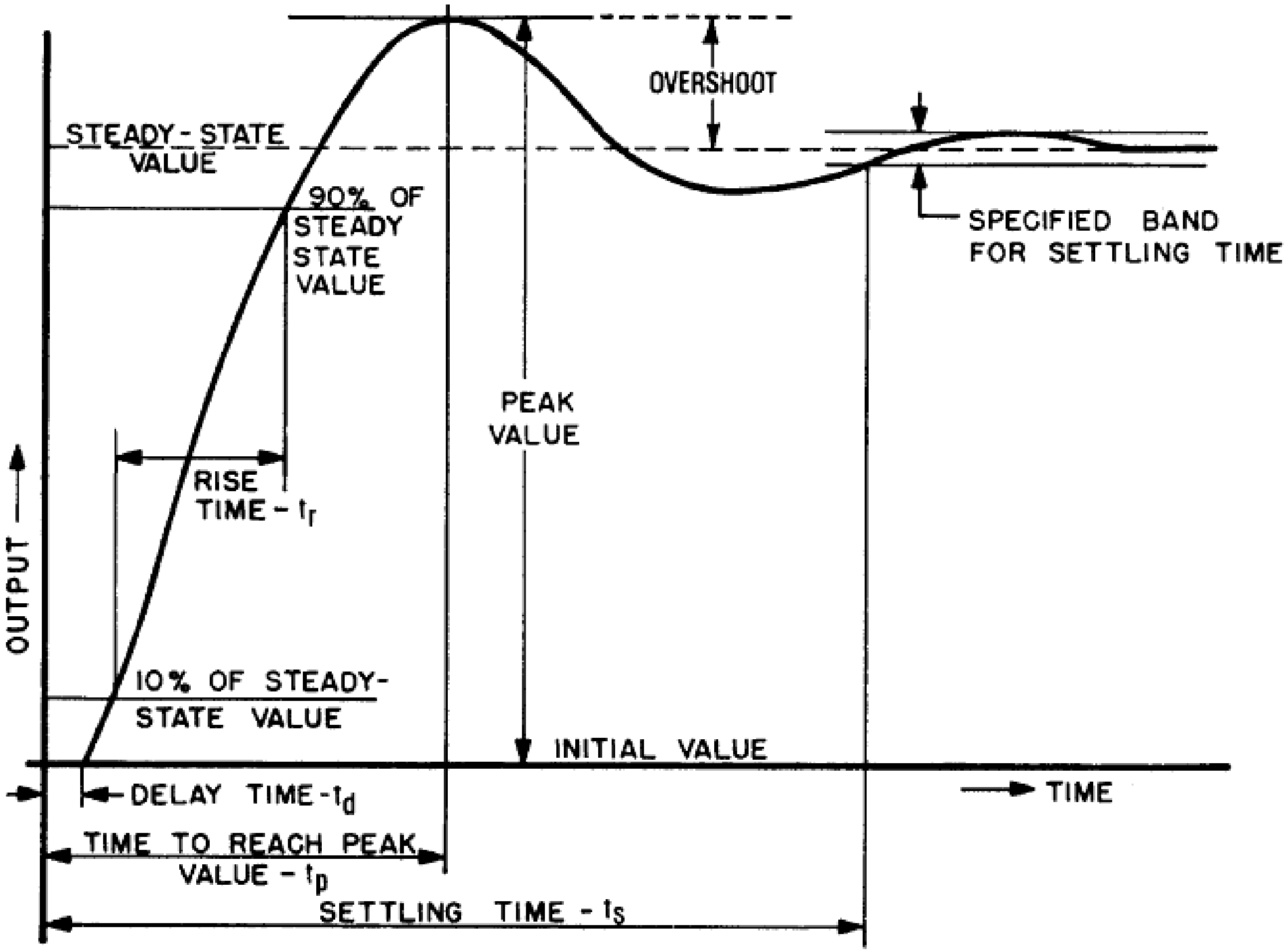


Image Source: IEEE Std 421.2-1990, Figure 3

Small Signal Performance

- Small signal performance can be assessed by either the time responses, frequency response, or eigenvalue analysis
- Figure shows the typical open loop performance of an exciter and machine in the frequency domain

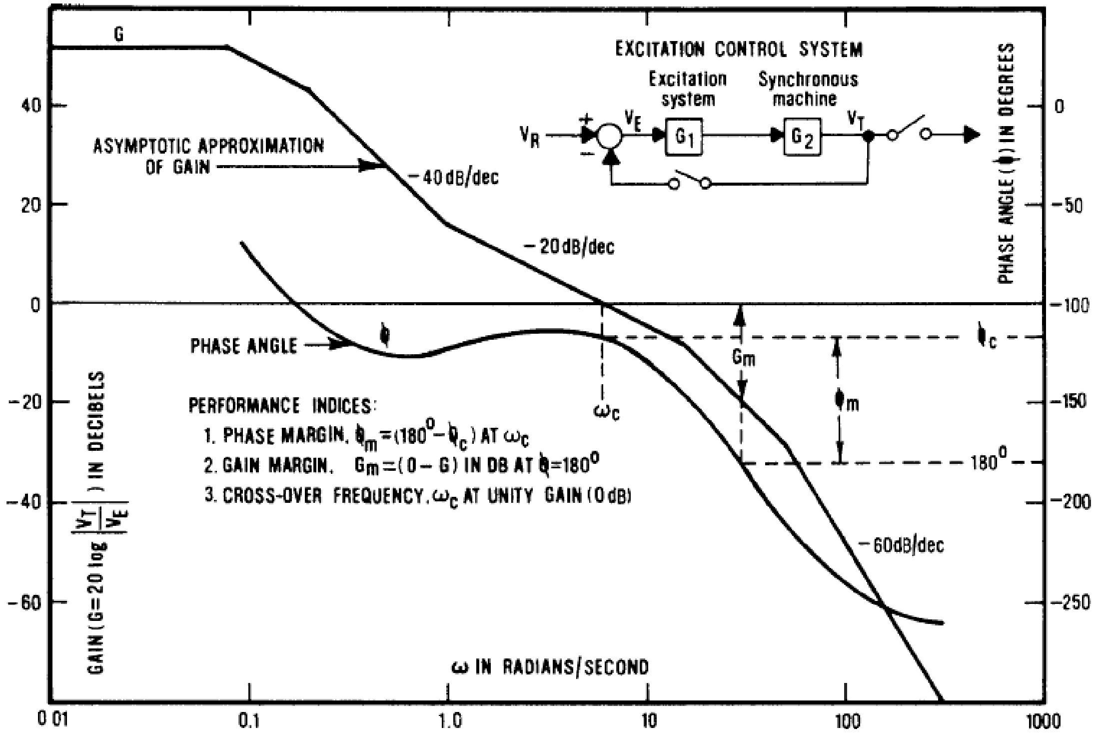


Figure 4—Typical Open-Loop Frequency Response of an Excitation Control System with the Synchronous Machine Open-Circuited

Image Source: IEEE Std 421.2-1990, Figure 4

Exciter Upgrade Example: ABB UNICITER

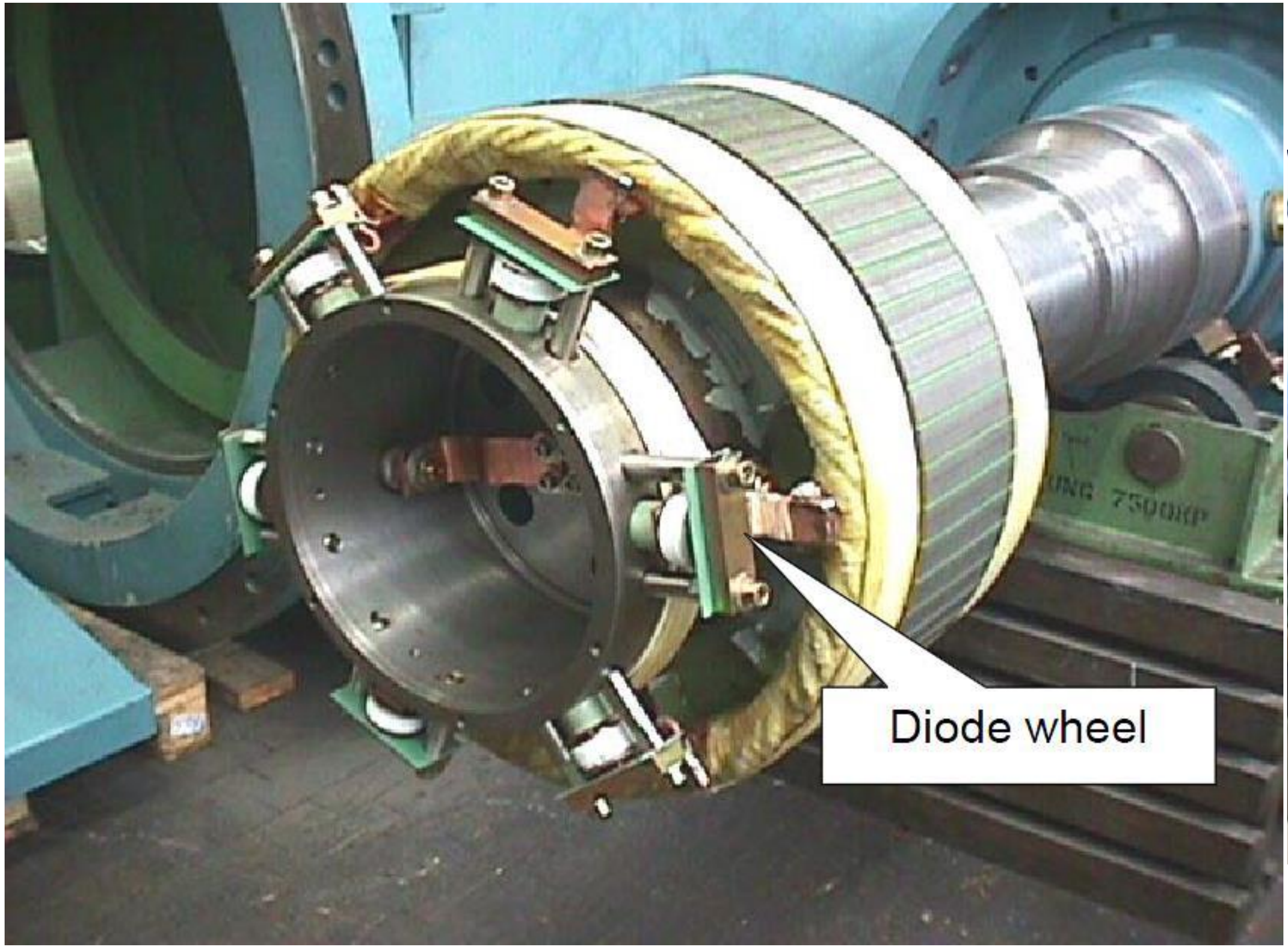
UNICITER® Example
Hydro Power Plant – Horizontal - Switzerland

- Old DC commutator exciter by Brown Boveri
- Date of manufacture: 1960

New UNICITER® by ABB GTSC Birr

Image Source: qdoc.tips/brushlessexcitationsystemsupgrade-pdf-free.html

ABB UNICITER Rotor Field



Exciter Stator Field

Image Source: qdoc.tips/brushlessexcitationsystemsupgrade-pdf-free.html

Compensation

- Often times it is useful to use a compensated voltage magnitude value as the input to the exciter
  - Compensated voltage depends on generator current; usually Rc is zero

$$E_c = \left|\bar{V}_t + \left(R_c + jX_c\right) I_T\right|$$

Sign convention is from IEEE 421.5

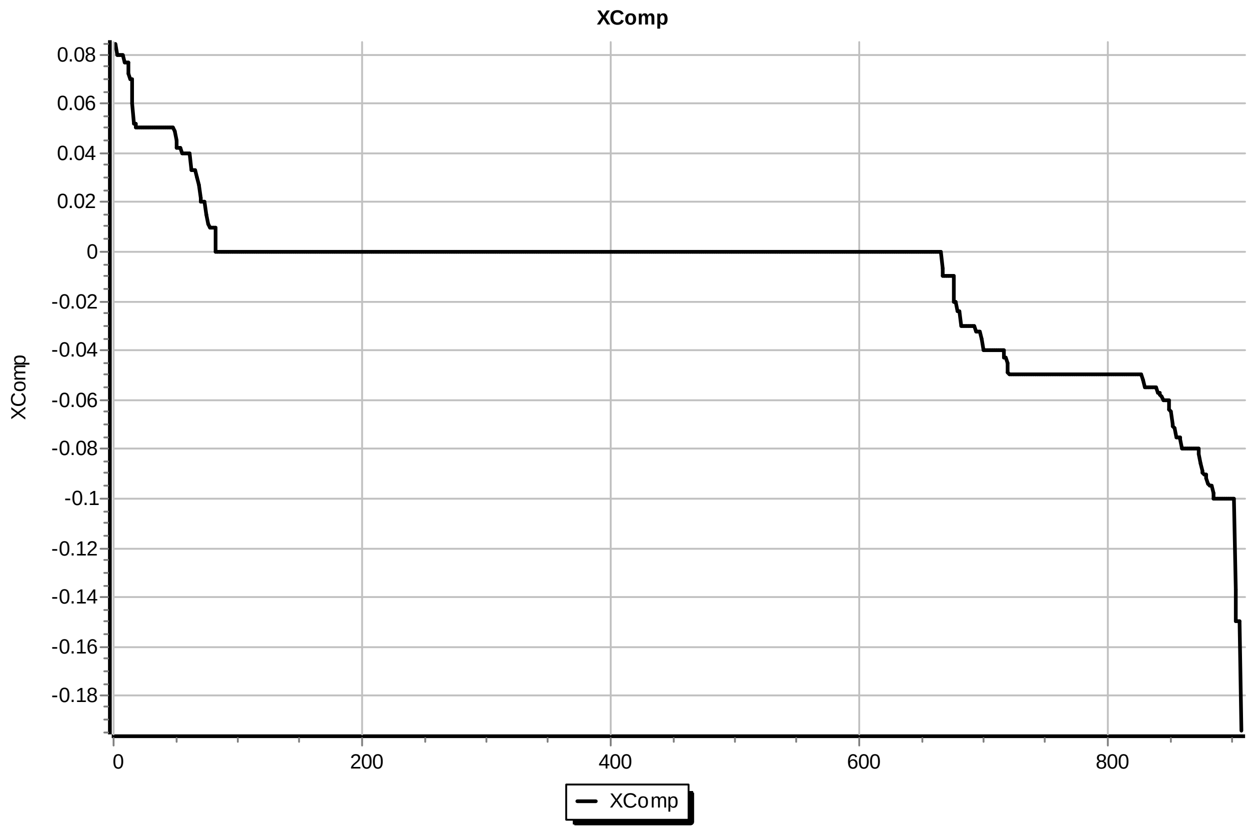
- PSLF and PowerWorld model compensation with the machine model using a minus sign (negative convention)
  - Specified on the machine base
- PSSE requires a separate model with their COMP model also using a negative sign

$$E_c = \left|\bar{V}_t - \left(R_c + jX_c\right) I_T\right|$$

Compensation

- Using the negative sign convention
  - if X_c is negative then the compensated voltage is within the machine; this is known as droop compensation, which is used reactive power sharing among multiple generators at a bus
  - If X_c is positive then the compensated voltage is partially through the step-up transformer, allowing better voltage stability
  - A nice reference is C.W. Taylor, "Line drop compensation, high side voltage control, secondary voltage control – why not control a generator like a static var compensator," IEEE PES 2000 Summer Meeting

Example Compensation Values



Negative values are within the machine

Graph shows example compensation values for large system; overall about 30% of models use compensation

Compensation Example 1

- Added EXST1 model to 4 bus GENROU case with compensation of 0.05 pu (on gen's 100 MVA base) (using negative sign convention)
  - This is looking into step-up transformer
  - Initial voltage value is

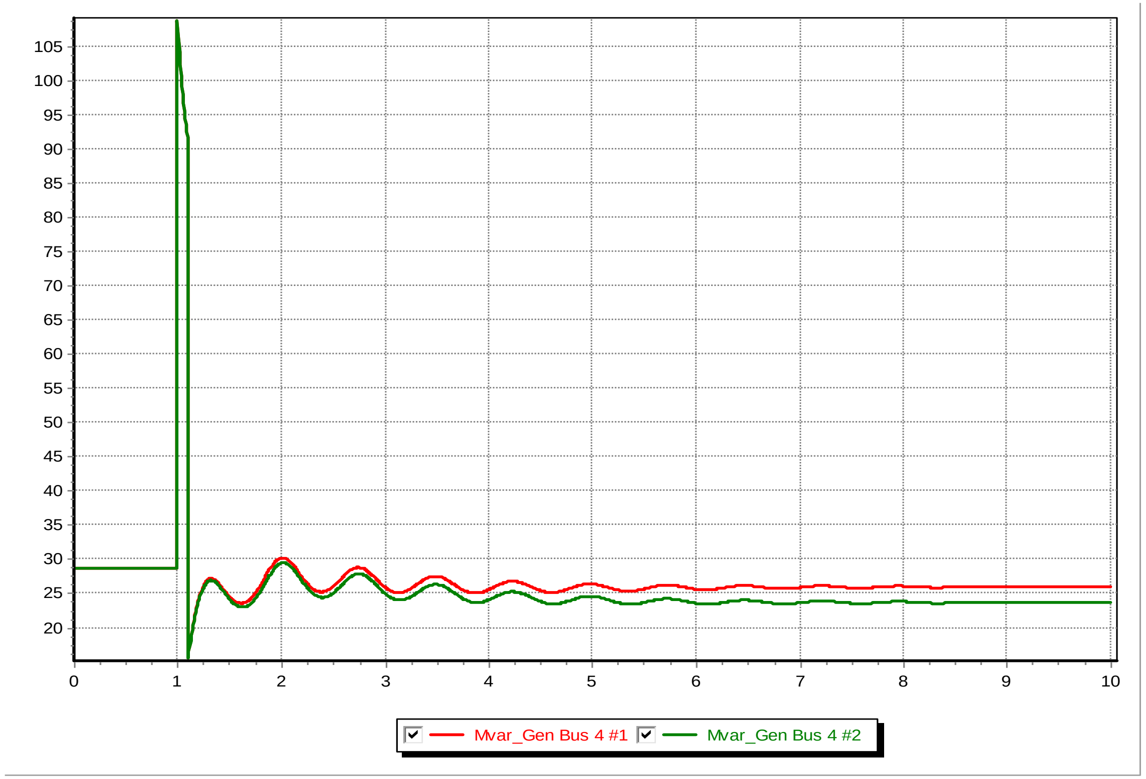
$$V_t = 1.072 + j0.22, \quad I_t = 1.0 - j0.3286$$

$$E_c = \left|1.072 + j0.22 - (j0.05)(1.0 - j0.3286)\right| = \left|1.0557 + j0.17\right| = 1.069$$

Case is **B4_comp1**

Compensation Example 2

- B4 case with two identical generators, except one in Xc = -0.1, one with Xc=-0.05; in the power flow the Mvars are shared equally (i.e., the initial value)

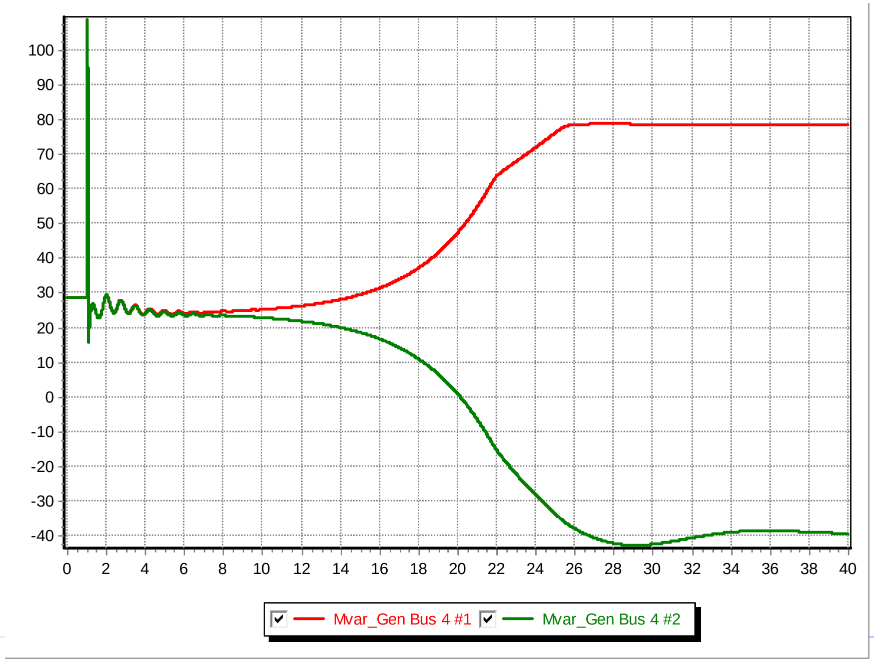


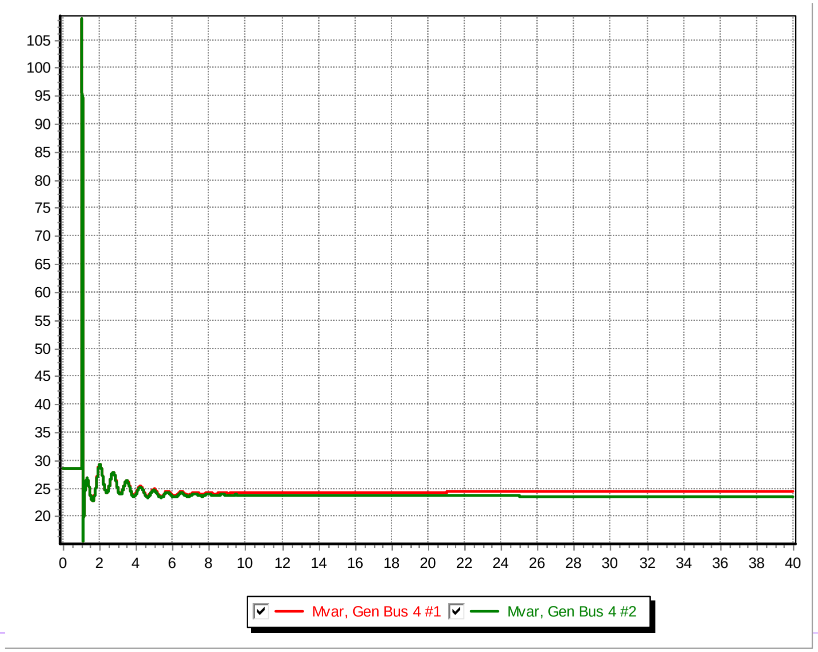
Plot shows the reactive power output of the two units, which start out equal, but diverage because of the difference values for X_c

Case is **B4_comp2**

Compensation Example 3

- B4 case with two identical generators except with slightly different Xc values (into net) (0.05 and 0.048)
- Below graphs show reactive power output if the currents from the generators not coordinated (left) or are coordinated (right); PowerWorld always does the coordinated approach



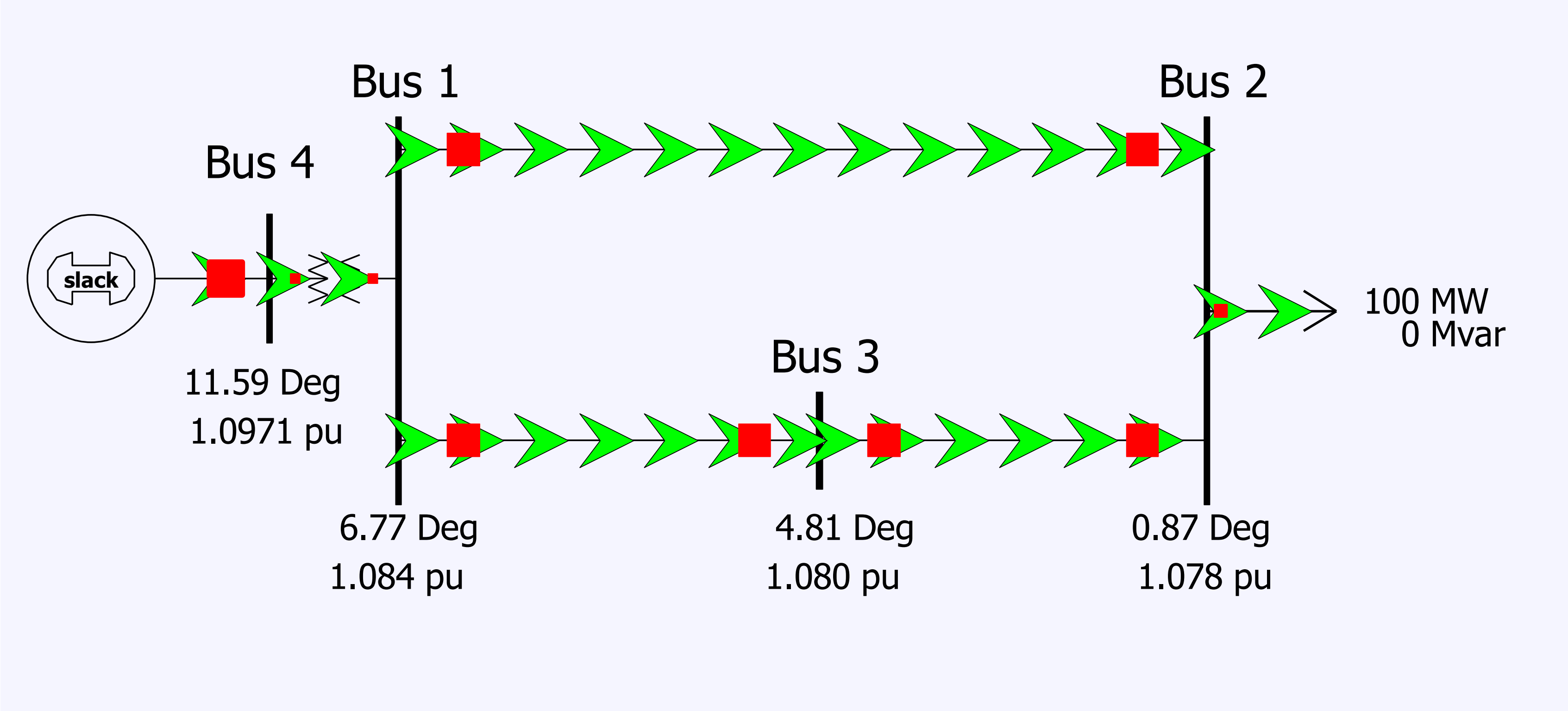


Case is **B4_comp3**

Compensation Benefits

- A reason for using compensation to control voltages in the transmission system is to move the source of voltage support closer to the load

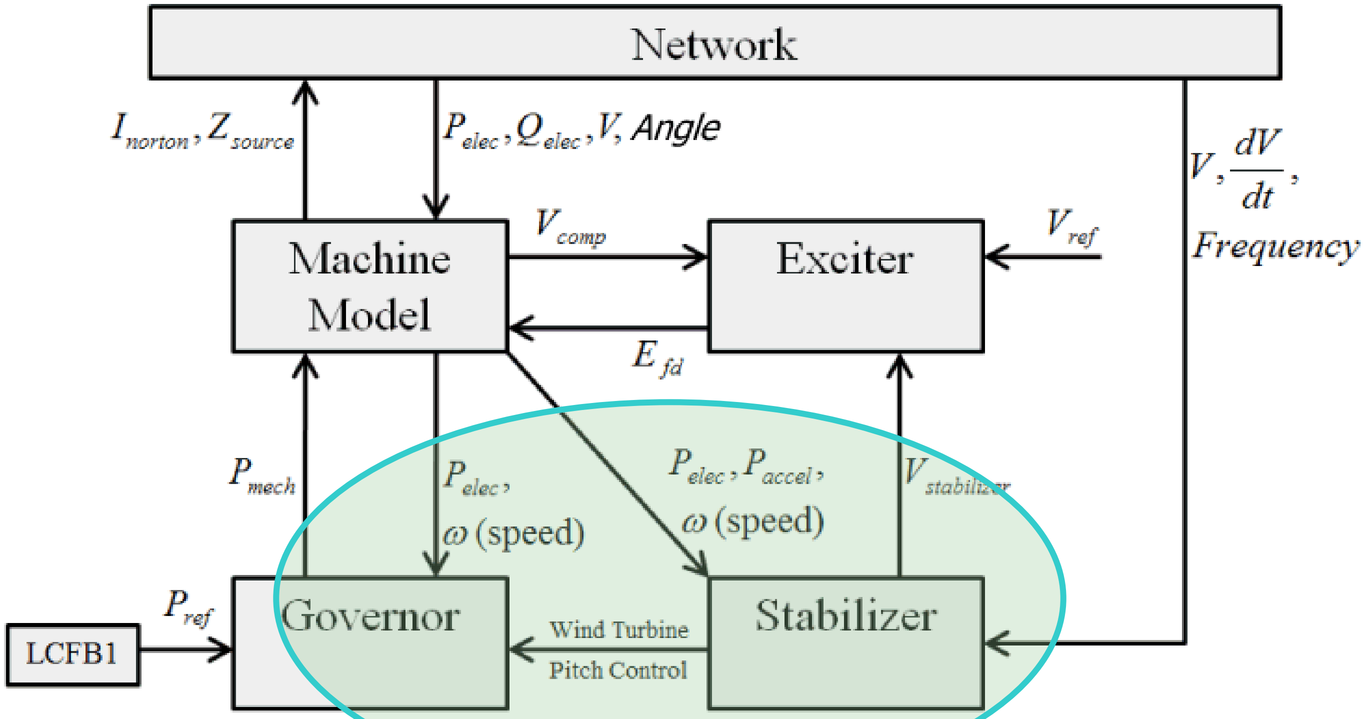
Case is **B4_comp_voltagestability**



Initial Limit Violations

- Since many models have limits and the initial state variables are dependent on power flow values, there is certainly no guarantee that there will not be initial limit violations
- If limits are not changed, this does not result in an equilibrium point solution
- PowerWorld has several options for dealing with this, with the default value to just modify the limits to match the initial operating point
  - If the steady-state power flow case is correct, then the limit must be different than what is modeled

Governor Models



P_{elec} = Electrical Power

Q_{elec} = Electrical Reactive Power

V = Voltage at Terminal Bus

$\frac{dV}{dt}$ = Derivate of Voltage

V_{comp} = Compensated Voltage

P_{mech} = Mechanical Power

ω (speed) = Rotor Speed (often it's deviation from nominal speed)

P_{accel} = Accelerating Power

$V_{stabilizer}$ = Output of Stabilizer

V_{ref} = Exciter Control Setpoint (determined during initialization)

P_{ref} = Governor Control Setpoint (determined during initialization)

Prime Movers and Governors

- Synchronous generator is used to convert mechanical energy from a rotating shaft into electrical energy
- The "prime mover" is what converts the original energy source into the mechanical energy in the rotating shaft
- Possible sources: 1) steam (nuclear, coal, combined cycle, solar thermal), 2) gas turbines, 3) water wheel (hydro turbines), 4) diesel/ gasoline, 5) wind
(which we'll cover separately)
- The governor is used
to control the speed

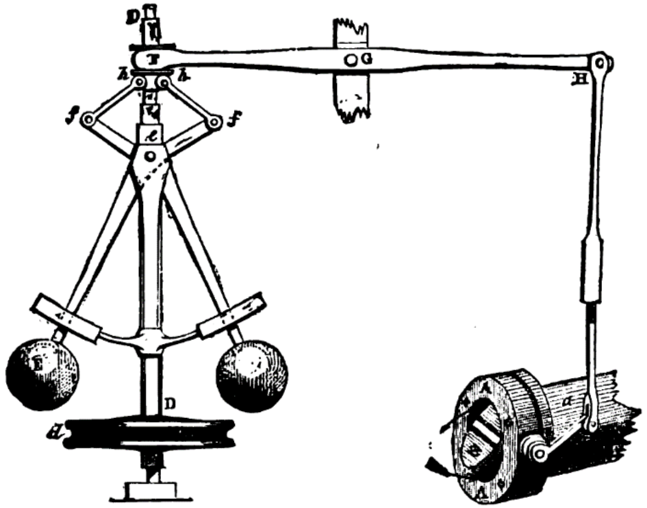


FIG. 4.—*Governor and Throttle-Valve.*

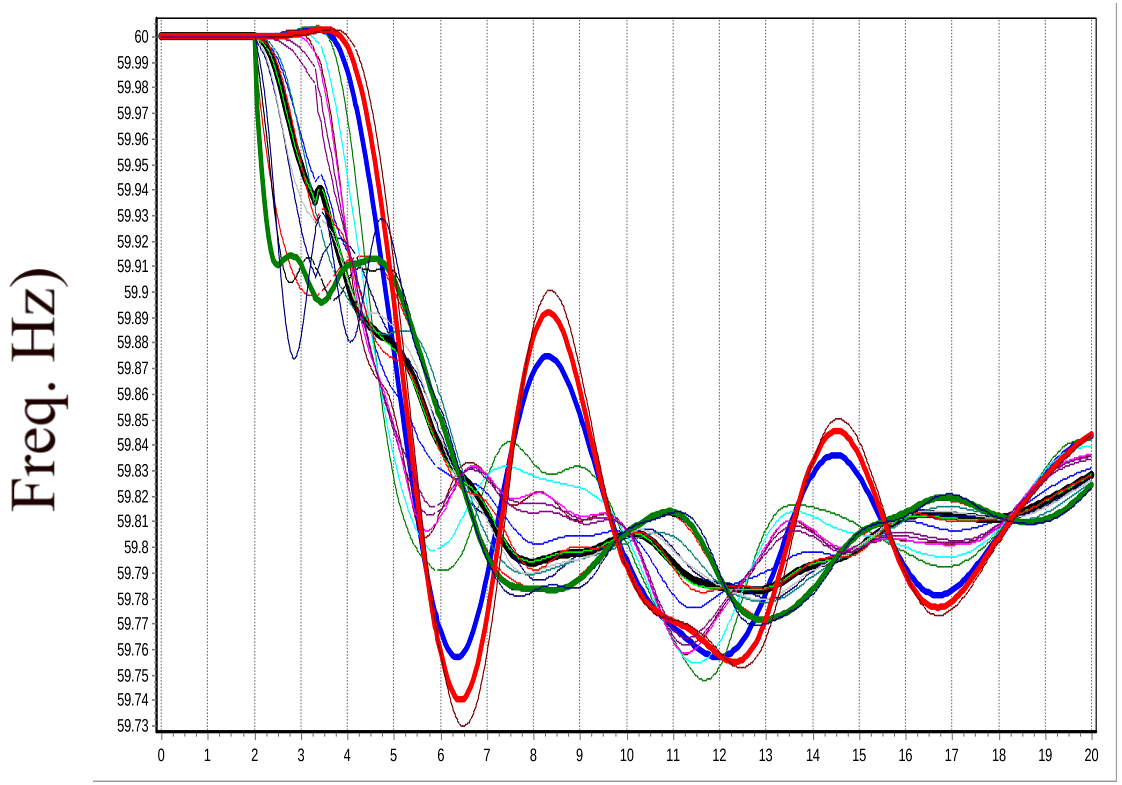
Image source: http://upload.wikimedia.org/wikipedia/commons/1/1e/Centrifugal_governor.png

Prime Movers and Governors

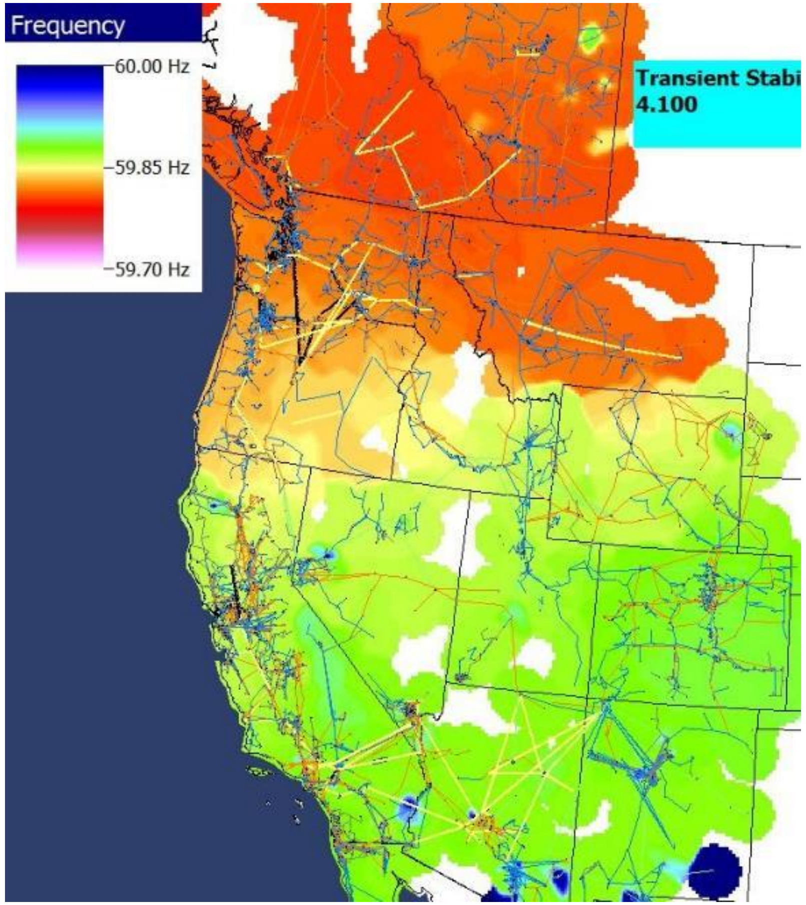
- In transient stability collectively the prime mover and the governor are called the "governor"
- As has been previously discussed, models need to be appropriate for the application
- In transient stability the response of the system for seconds to perhaps minutes is considered
- Long-term dynamics, such as those of the boiler and automatic generation control (AGC), are usually not considered
- These dynamics would need to be considered in longer simulations (e.g. dispatcher training simulator (DTS)

Power Grid Disturbance Example

Figures show the frequency change as a result of the sudden loss of a large amount of generation in the Southern WECC



Time in Seconds



Frequency Contour

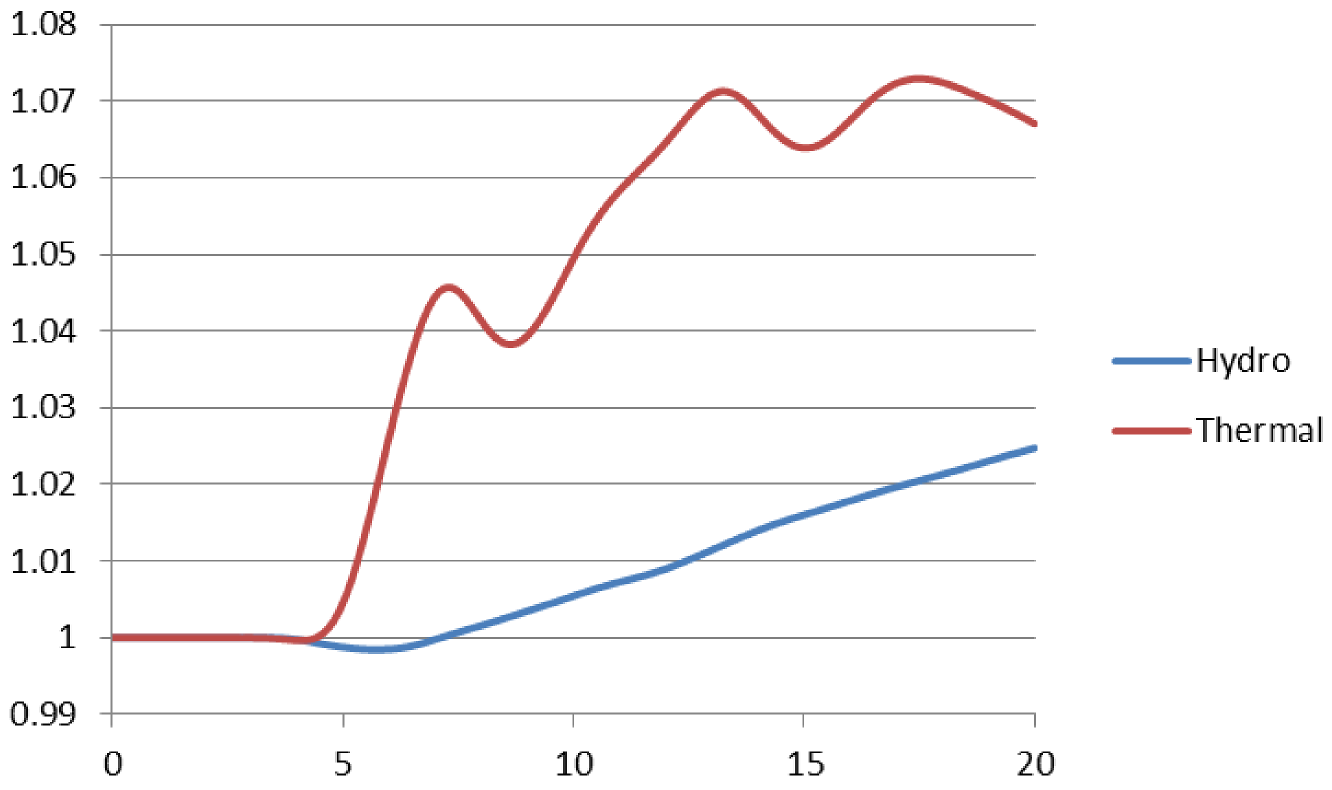
Frequency Response for Generation Loss

- In response to a rapid loss of generation, in the initial seconds the system frequency will decrease as energy stored in the rotating masses is transformed into electric energy
  - Some generation, such as solar PV has no inertia, and for most new wind turbines the inertia is not seen by the system
- Within seconds governors respond, increasing the power output of controllable generation
  - Many conventional units are operated so they only respond to over frequency situations
  - Solar PV and wind are usually operated in North America at maximum power so they have no reserves to contribute

Governor Response: Thermal Versus Hydro

Thermal units respond quickly, hydro ramps slowly (and goes down initially), wind and solar usually do not respond. And many units are set to not respond!

Normalized output

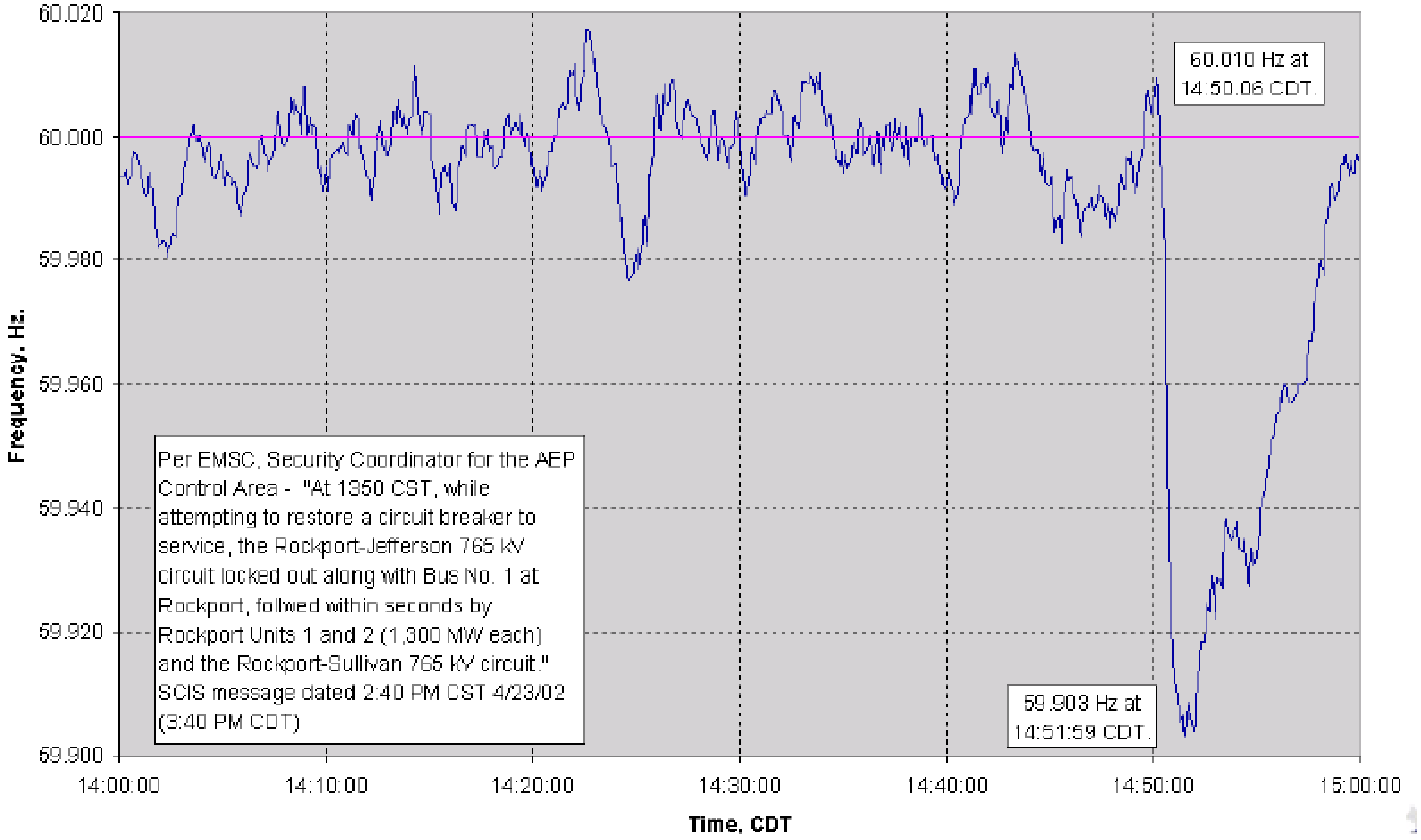


Time in Seconds

Some Good References

- Kundur, *Power System Stability and Control*, 1994
- Wood, Wollenberg and Sheble, *Power Generation, Operation and Control*, third edition, 2013
- IEEE PES, "Dynamic Models for Turbine-Governors in Power System Studies," Jan 2013
- "Dynamic Models for Fossil Fueled Steam Units in Power System Studies," *IEEE Trans. Power Syst.*, May 1991, pp. 753-761
- "Hydraulic Turbine and Turbine Control Models for System Dynamic Studies," *IEEE Trans. Power Syst.*, Feb 1992, pp. 167-179
- NERC, "Reliability Guideline Application Guide for Modeling TurbineGovernor and Active Power-Frequency Controls in Interconnection-Wide Stability Studies," June 2019

2600 MW Loss Frequency Recovery



Frequency recovers in about ten minutes

ERCOT Winter Storm Uri Frequency (2/15/21)

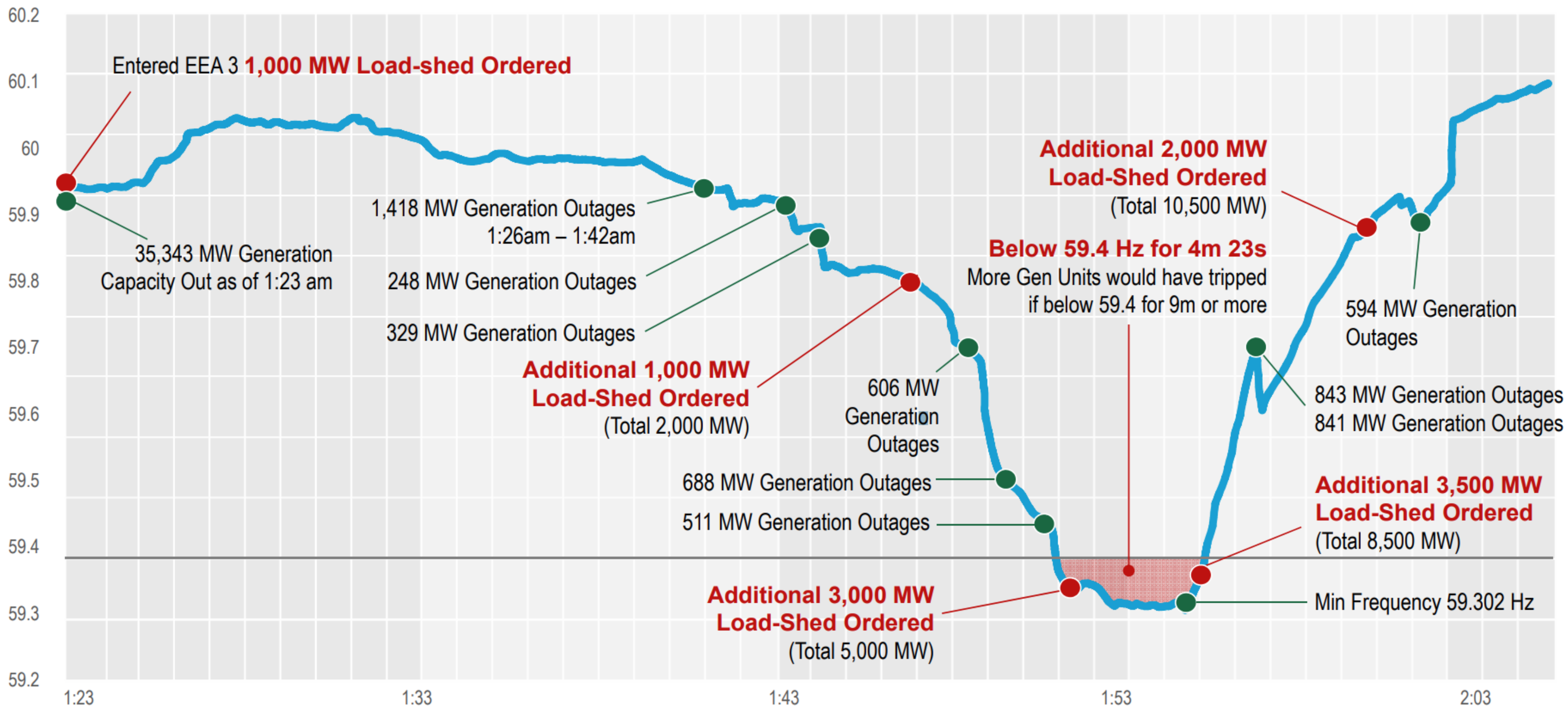
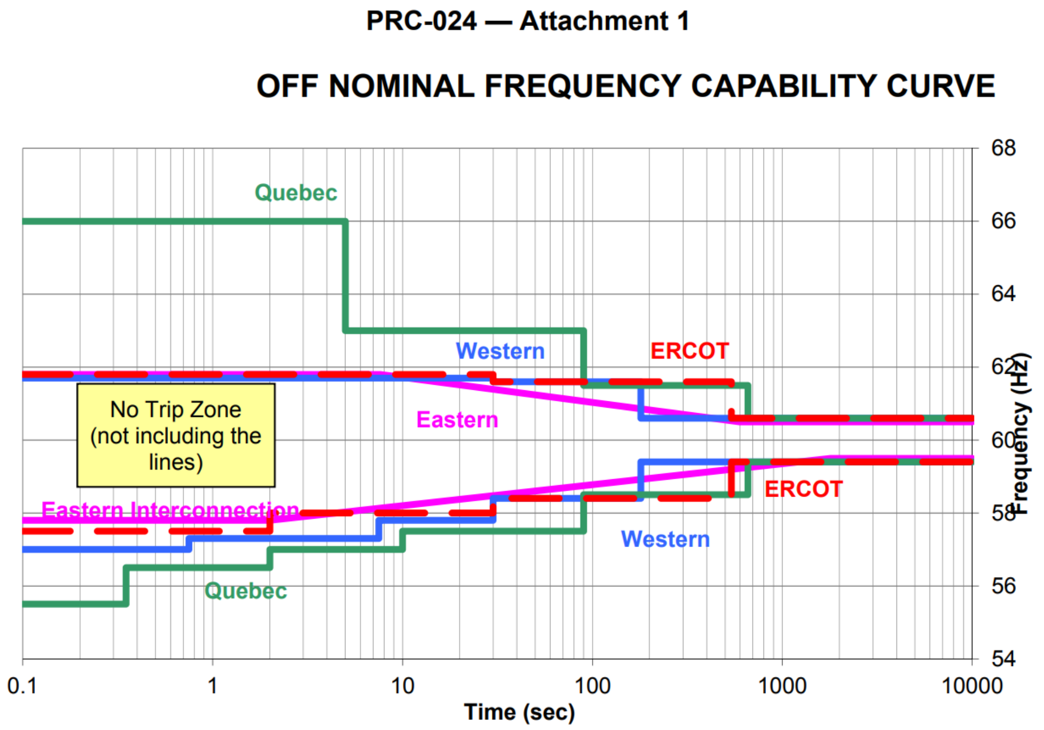


Image source: https://www.ercot.com/files/docs/2021/03/03/Texas_Legislature_Hearings_2-25-2021.pdf

Generator Under and Over Frequency Protection

- Generators have automatic protection systems to trip them if the frequency goes out of range for too long (also their voltage)



NERC Standard PRC-024.1

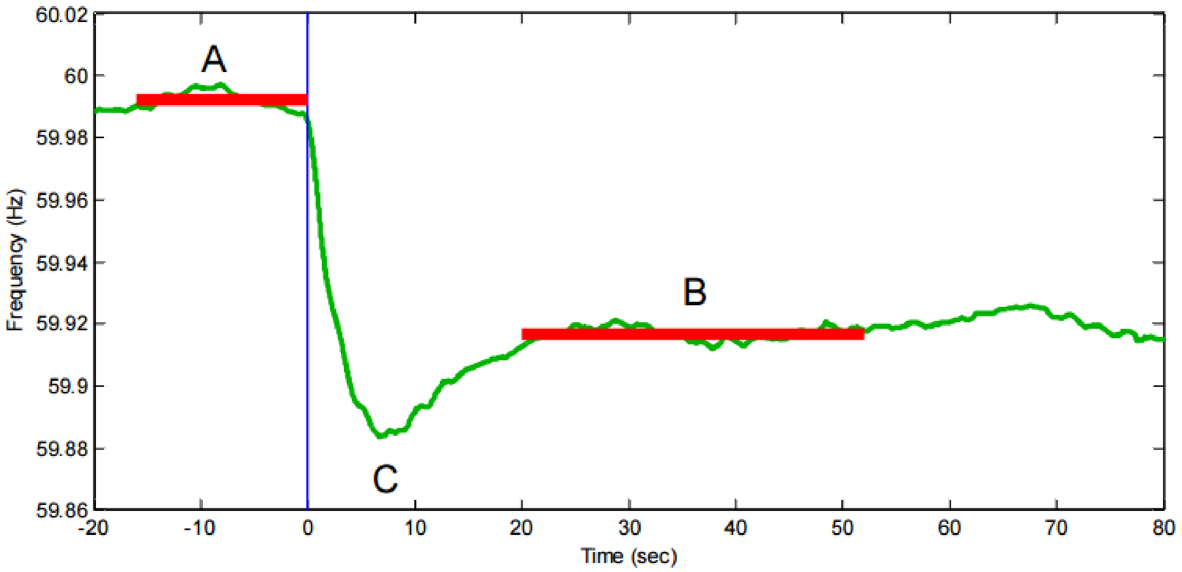
A typical concern with off-nominal frequency operation is the turbine (i.e., not the synchronous machine) operating at close to one of its natural frequencies, resulting in accelerated aging (metal fatigue); this is often shown using a Campbell diagram; see IEEE C37.106.2022

Frequency Response Definition

- FERC defines in RM13-11: “Frequency response is a measure of an Interconnection’s ability to stabilize frequency immediately following the sudden loss of generation or load, and is a critical component of the reliable operation of the Bulk-Power System, particularly during disturbances and recoveries.”
- Design Event for WECC is N-2 (Palo Verde Outage) not to result in UFLS (59.5 Hz in WECC)

Source: wecc.biz/Reliability/Frequency%20Response%20Analysis%20-%20Dmitry%20Kosterev.pdf

Frequency Response Measure



NERC FRM BAL-003-1: Frequency difference between Point A and Point B

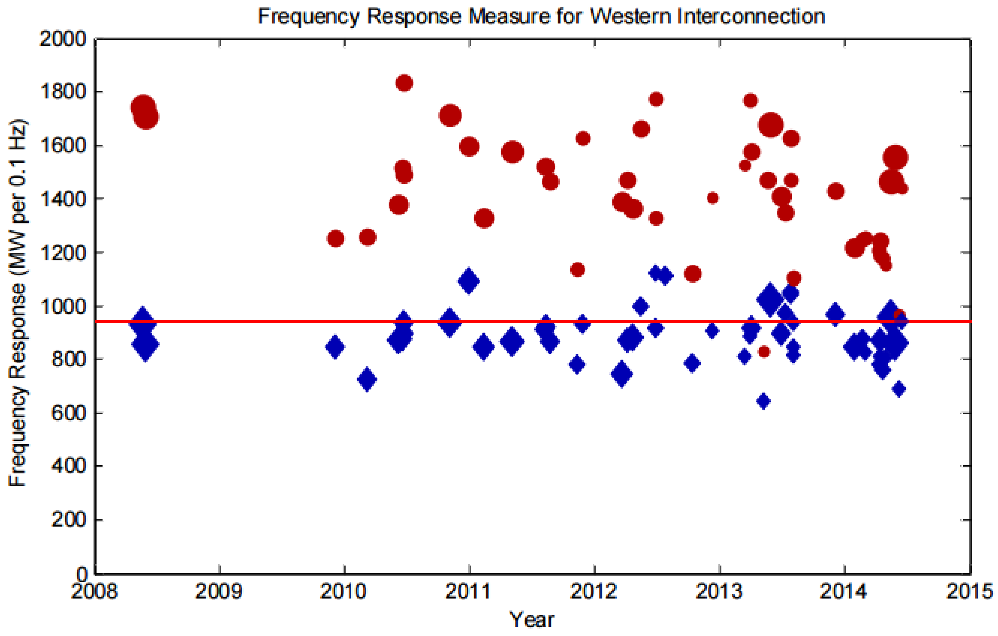
LBNL Metrics: Frequency difference between Point A and Point C

Source: wecc.biz/Reliability/Frequency%20Response%20Analysis%20-%20Dmitry%20Kosterev.pdf

WECC Interconnection Performance

Western Interconnection Performance

WECC IFRO ~950 MW per 01. Hz, WECC IFRM is trending ~ 1,400 to 1,600 MW per 0.1 Hz
Response at nadir: required ~580 MW per 0.1 Hz, actual is about 800 MW per 0.1 Hz



Higher is better since it means a 0.1 Hz drop occurs with the loss of a larger unit

- Red dots – frequency response measured at point B (settling) using NERC FRM methodology
- Blue diamonds – frequency response is measured at point C (nadir)

Source: wecc.biz/Reliability/Frequency%20Response%20Analysis%20-%20Dmitry%20Kosterev.pdf

Control of Generation Overview

- Goal is to maintain constant frequency with changing load
- If there is just a single generator, such with an emergency generator or isolated system, then an isochronous governor is used
  - Integrates frequency error to insure frequency goes back to the desired value
  - Cannot be used with interconnected systems because of "hunting"

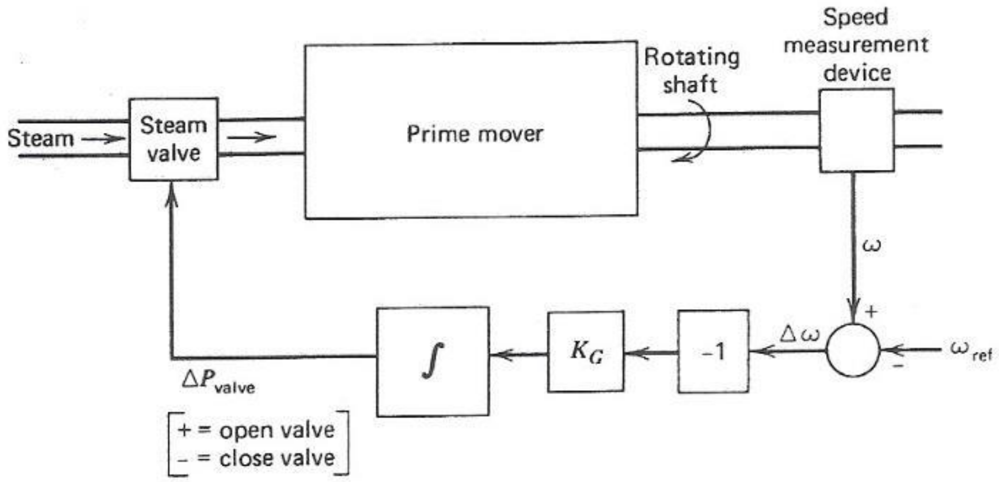


FIG. 9.9 Isochronous governor.

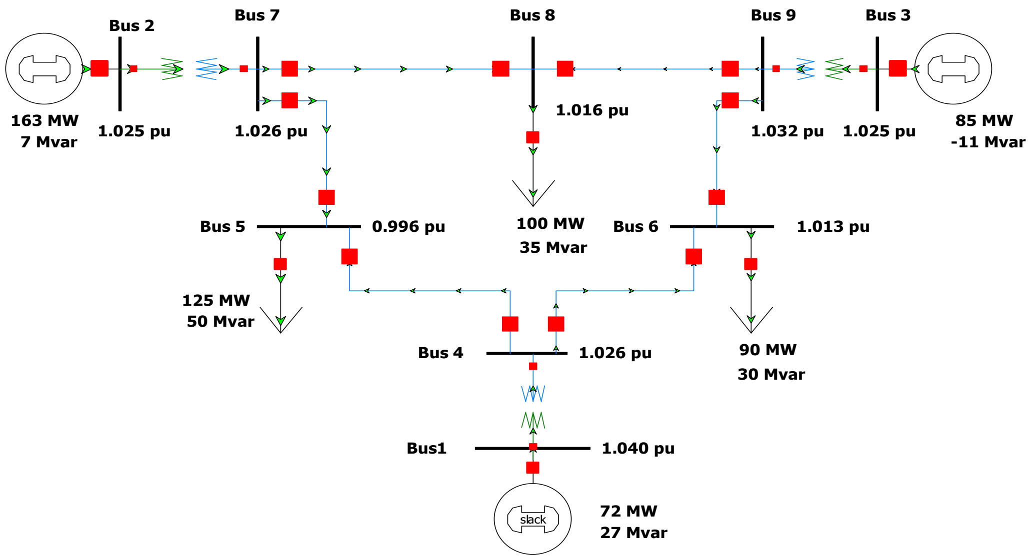
Image source: Wood/Wollenberg, 2nd edition

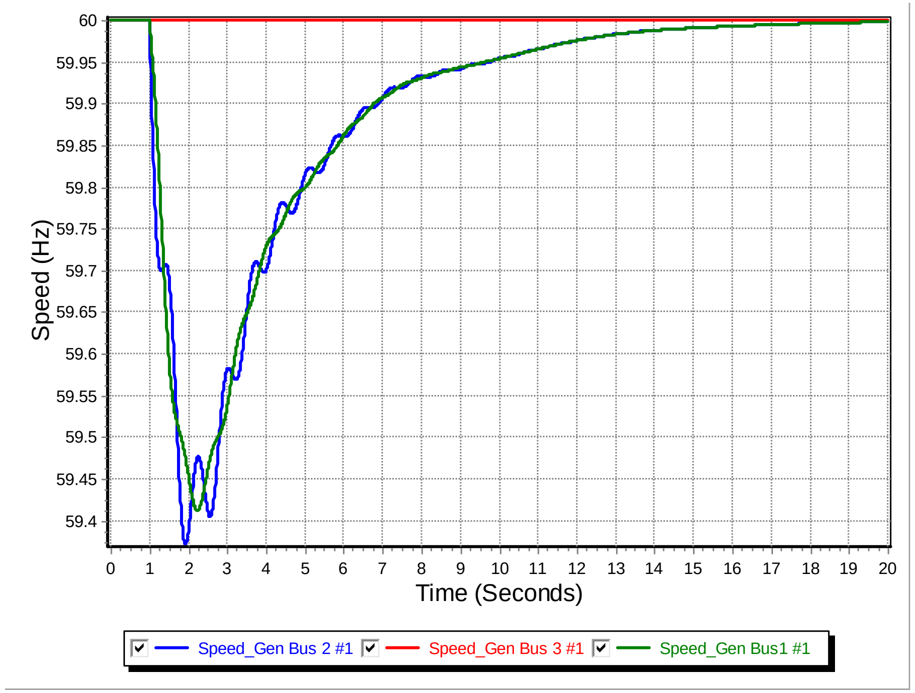
Generator “Hunting”

- Control system “hunting” is oscillation around an equilibrium point
- Trying to interconnect multiple isochronous generators will cause hunting because the frequency setpoints of the multiple generators are never exactly equal.
  - If there are two then one will be accumulating a frequency error trying to speed up the system, whereas the other will be trying to slow it down
  - The generators will NOT share the power load proportionally

Isochronous Gen Example

- WSCC 9 bus from before, gen 3 dropping (85 MW)
  - No infinite bus, gen 1 is modeled with an isochronous generator (PW ISOGov1 model)

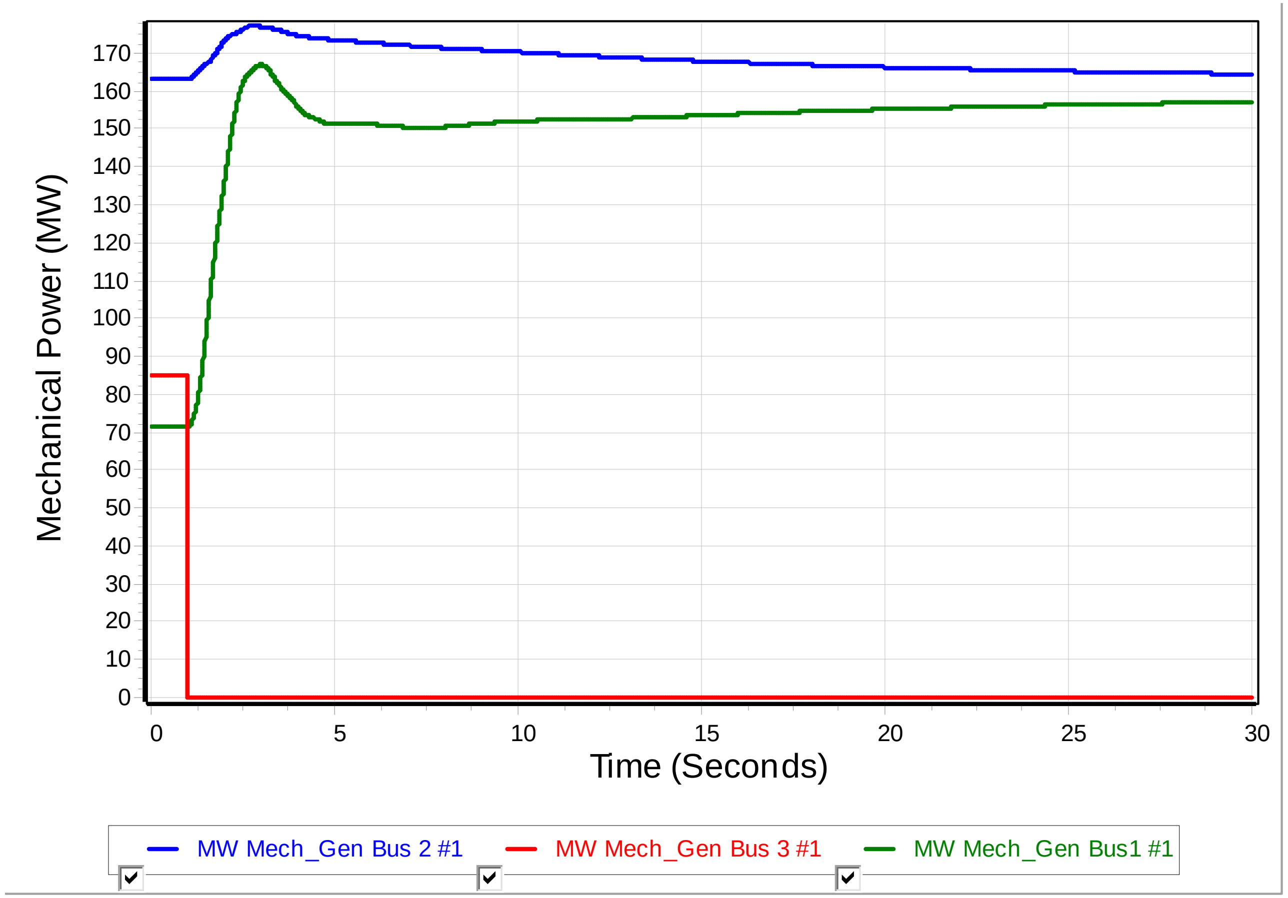




Case is **wscc_9bus_IsoGov**

Isochronous Gen Example

- Graph shows the change in the mechanical output

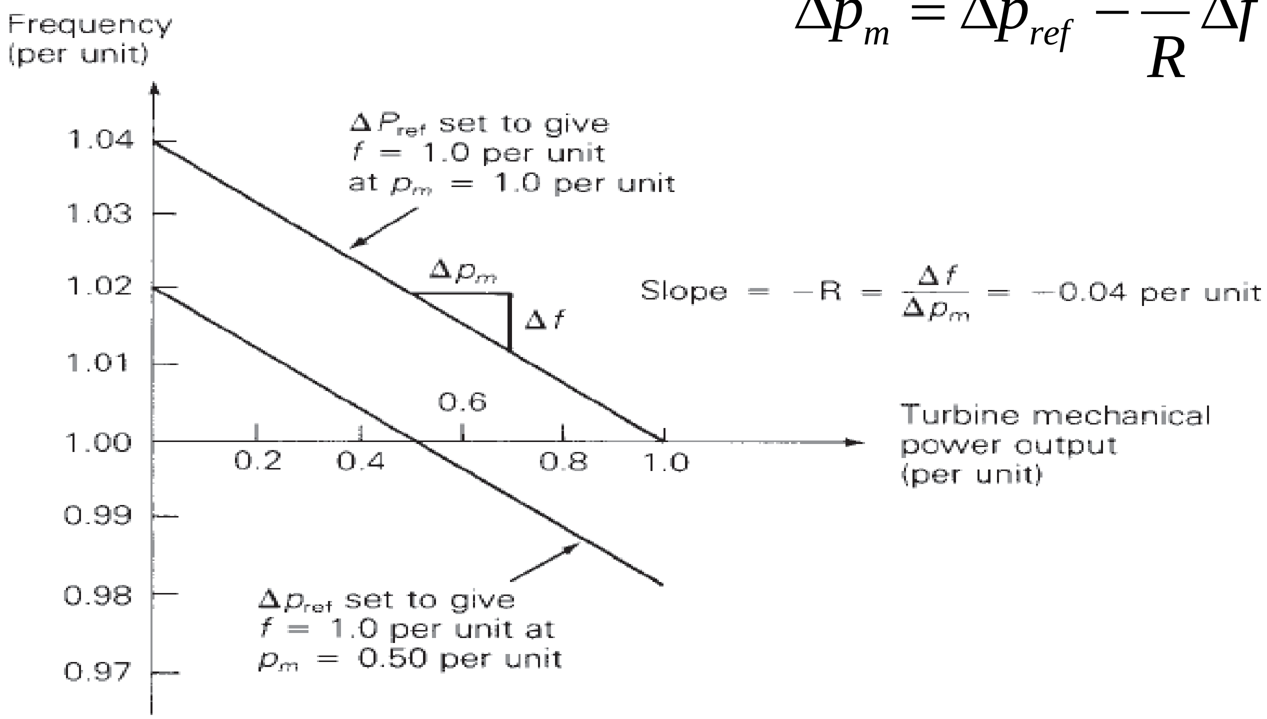


All the change in MWs due to the loss of gen 3 is ultimately being picked up by gen 1

Droop Control

- To allow power sharing between generators the solution is to use what is known as droop control, in which the desired set point frequency is dependent upon the generator's output

$$\Delta p_m = \Delta p_{ref} - \frac{1}{R}\Delta f$$



R is known as the regulation constant or droop; a typical value is 4 or 5%. At 60 Hz and a 5% droop, each 0.1 Hz change would change the output by 0.1/(60*0.05) = 3.33%

WSCC 9 Bus Droop Example

- Assume the previous gen 3 drop contingency (85 MW), and that gens 1 and 2 have ratings of 500 and 250 MVA respectively and governors with a 5% droop. What is the final frequency (assuming no change in load)?

To solve the problem in per unit, all values need to be on a common base (say 100 MVA)

$$\Delta p_{m1} + \Delta p_{m2} = 85/100 = 0.85$$

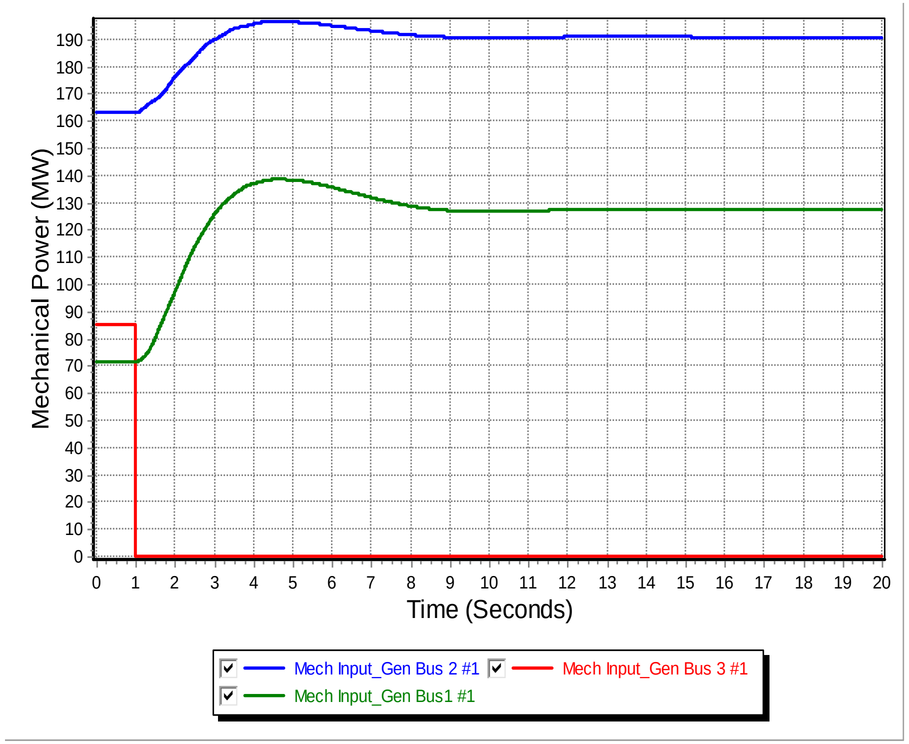
$$R_{1,100MVA} = R_1 \frac{100}{500} = 0.01, \quad R_{2,100MVA} = R_2 \frac{100}{250} = 0.02$$

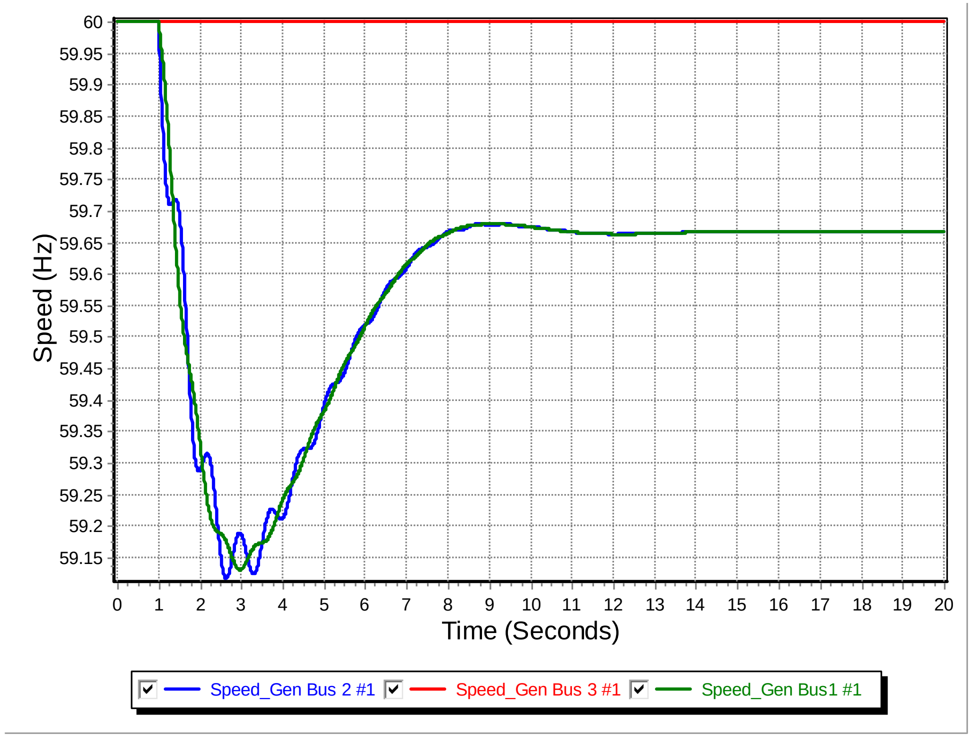
$$\Delta p_{m1} + \Delta p_{m2} = -\left(\frac{1}{R_{1,100MVA}} + \frac{1}{R_{2,100MVA}}\right)\Delta f = 0.85$$

$$\Delta f = -.85/150 = 0.00567 = -0.34 \text{ Hz} \rightarrow 59.66 \text{ Hz}$$

WSCC 9 Bus Droop Example

- The below graphs compare the mechanical power and generator speed; note the steady-state values match the calculated 59.66 Hz value





Case is **wscc_9bus_TGOV1**

Quick Interconnect Calculation

- When studying a system with many generators, each with the same (or close to same) droop, then the final frequency deviation is

$$\Delta f = -\frac{R \times \Delta P_{gen,MW}}{\sum_{OnlineGens} S_{i,MVA}}$$

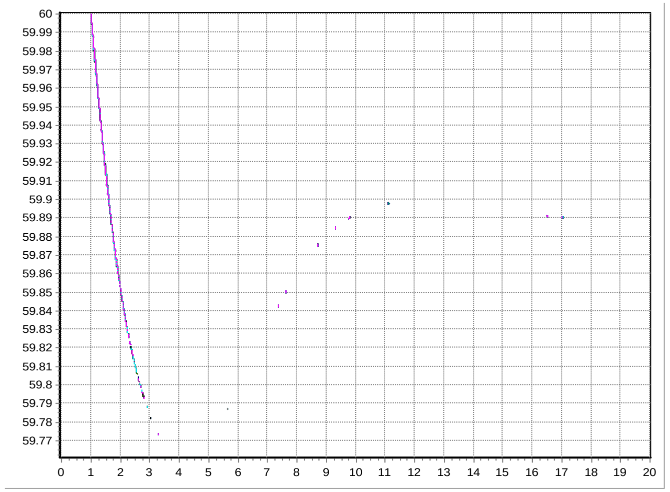
The online generator group obviously does not include the contingency generator(s) that are opened

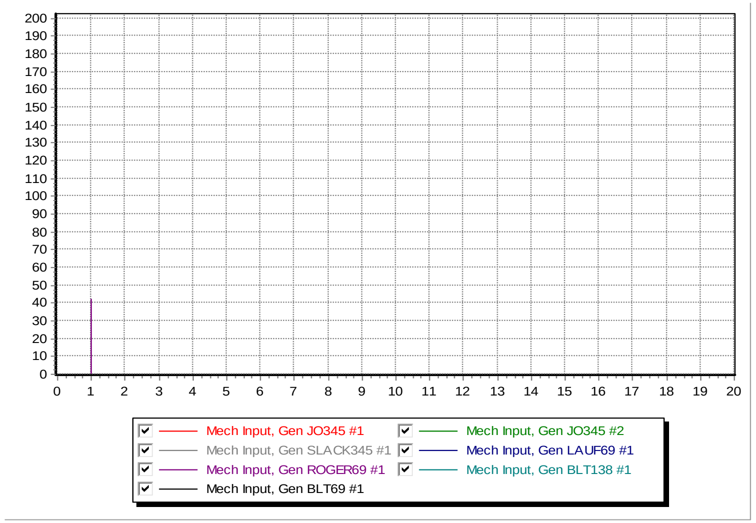
- The online generator summation should only include generators that actually have governors that can respond, and does not take into account generators hitting their limits

Larger System Example

- As an example, consider the 37 bus, nine generator example from earlier; assume one generator with 42 MW is opened. The total MVA of the remaining generators is 1132. With R=0.05

$$\Delta f = -\frac{0.05\times 42}{1132} = -0.00186 \text{ pu} = -0.111 \text{ Hz} \rightarrow 59.889 \text{ Hz}$$





Case is
Bus37_TGOV1