ECEN 667
Power System Stability

Lecture 12: Governors

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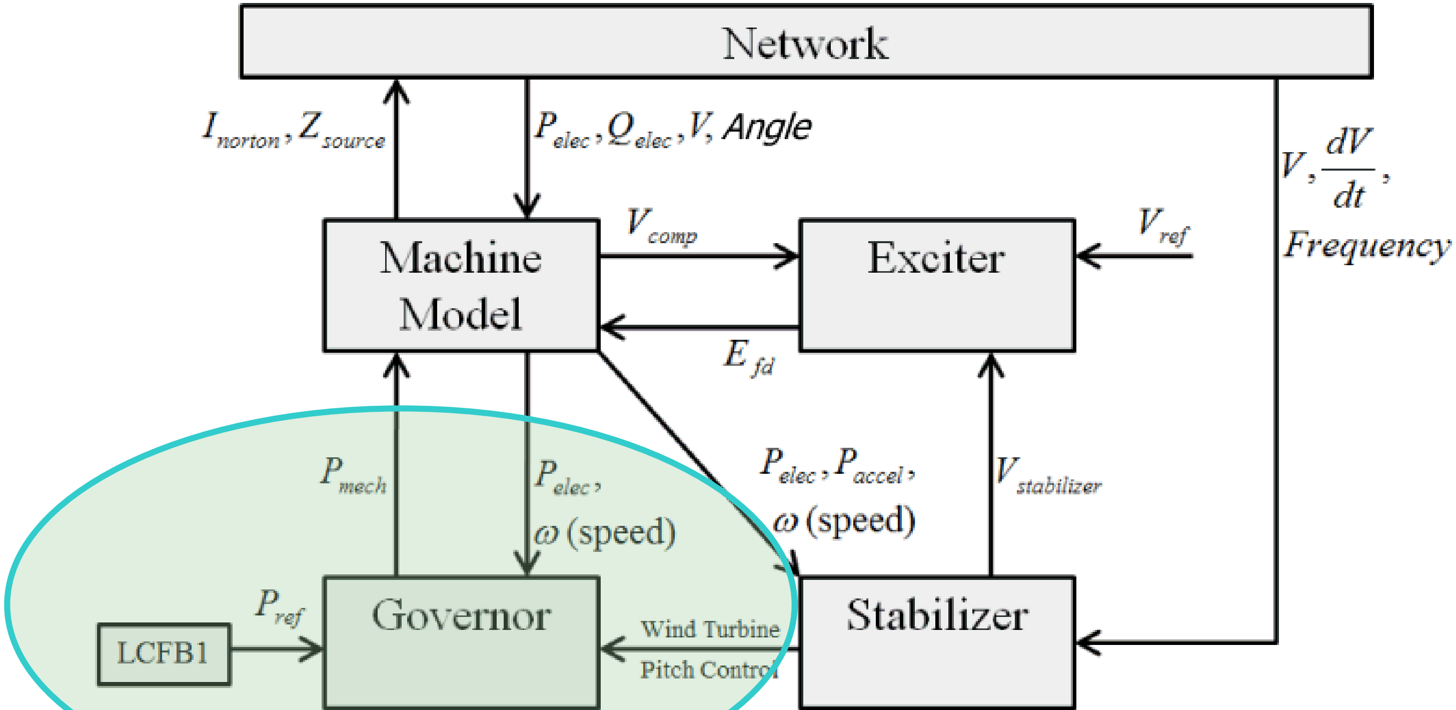
Announcements

- Read Chapter 4
- Homework 3 is due today
- Homework 4 does not need to be turned in, but should be completed before the first exam
- Exam 1 will be on Oct 14 in class
  - For the distance learners we usually use Honorlock (though I know for some that won't work)
  - Exams are closed book, closed notes, but you can bring in one 8.5 by 11 inch note sheet and can use calculators
  - My first exam from 2019 (with the solution) is available on Canvas, keeping in mind, Past performance is no guarantee of future results."

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

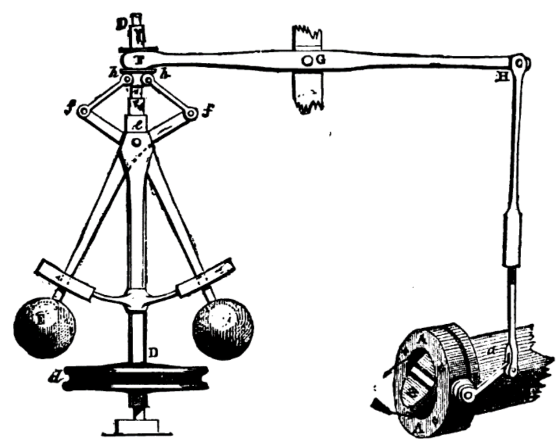


FIG. 4.—*Governor and Throttle-Valve.*

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

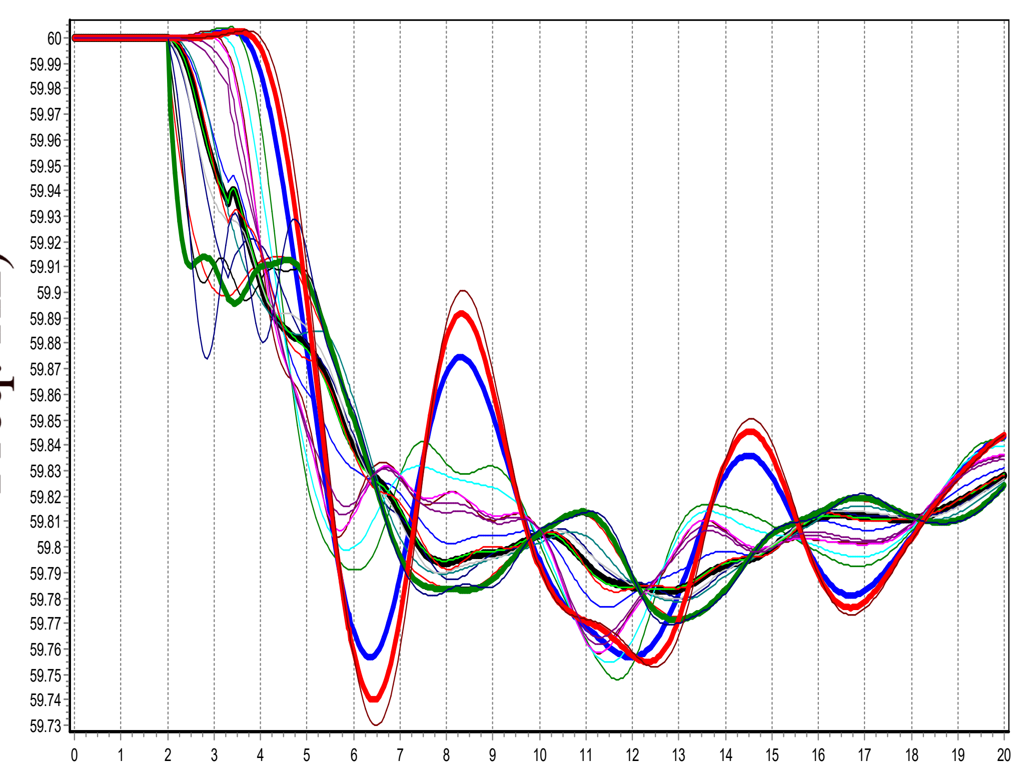
Prime Movers and Governors

- 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)

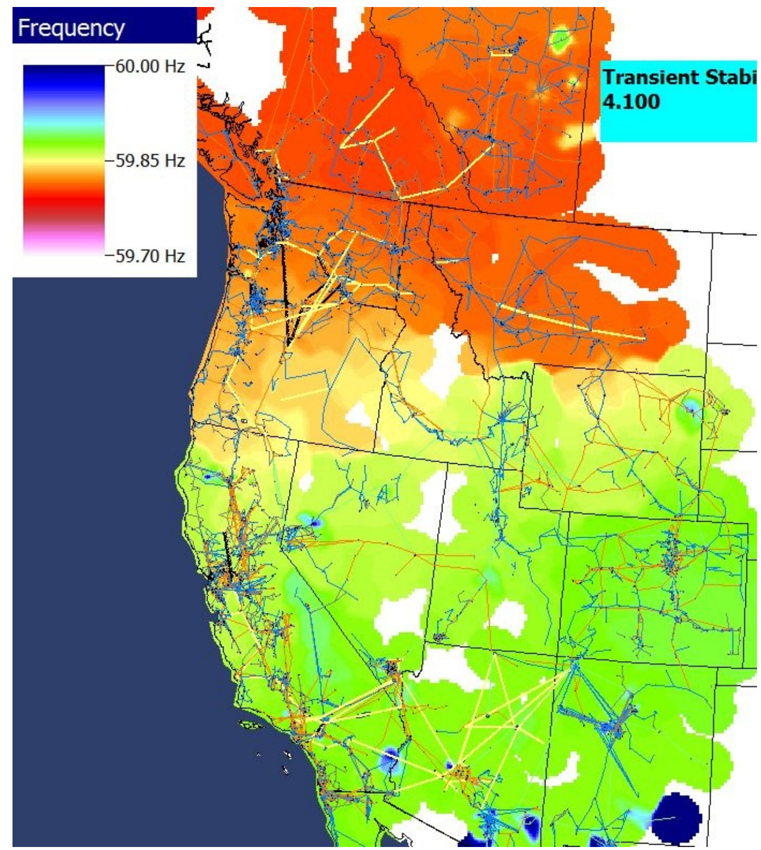
Power Grid Disturbance Example

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

Freq. Hz)



Time in Seconds



Frequency Contour

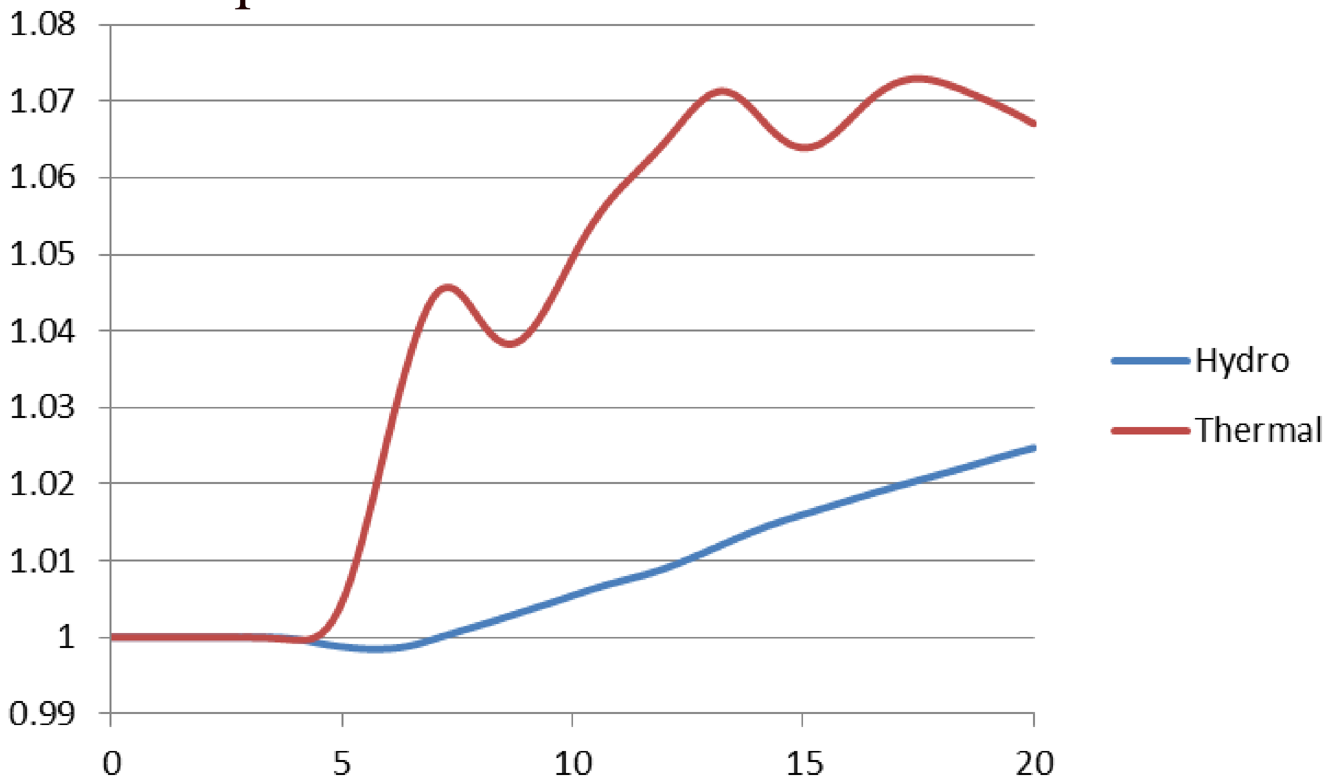
Frequency Response for Generation Loss

- 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

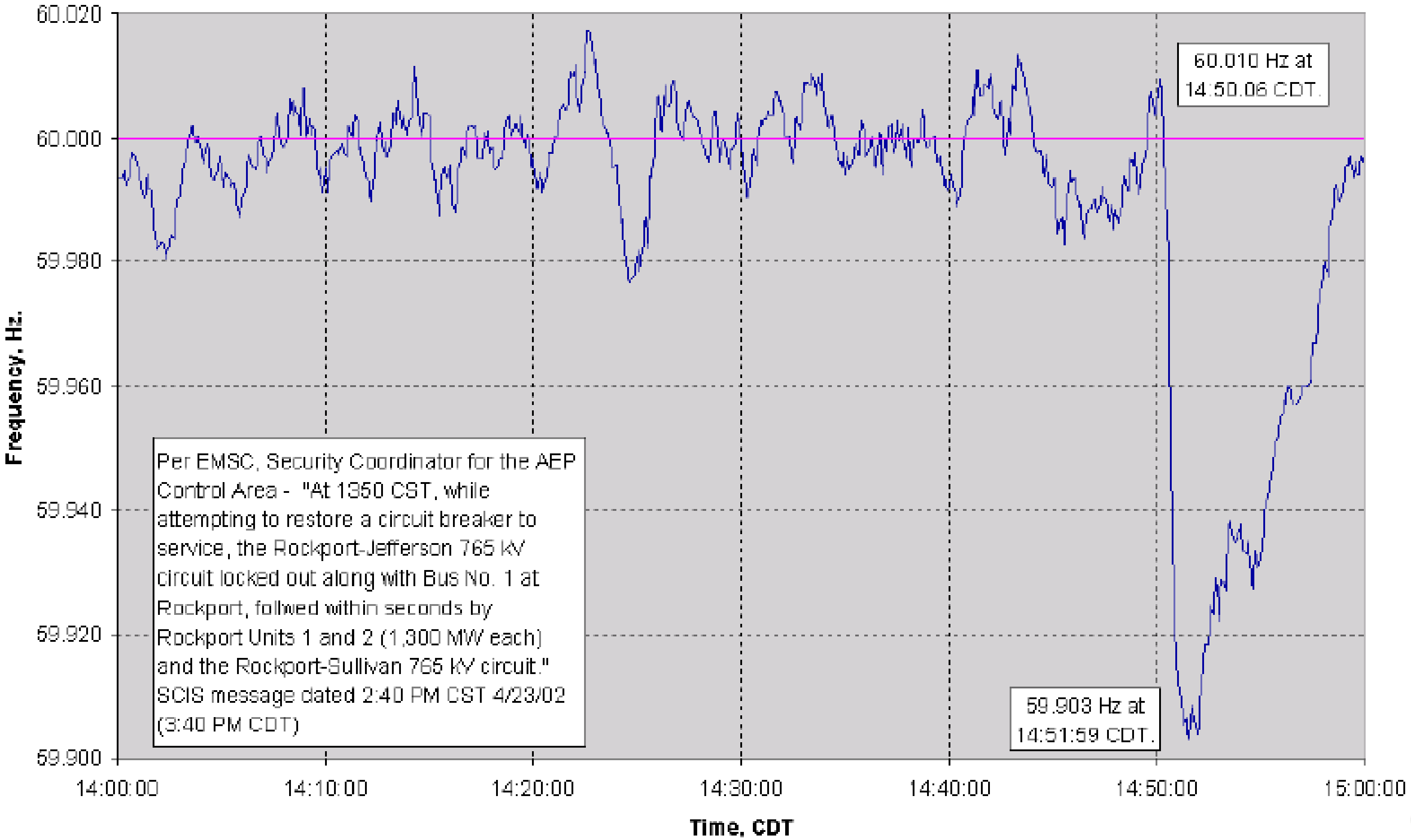


Time in Seconds

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

2600 MW Loss Frequency Recovery



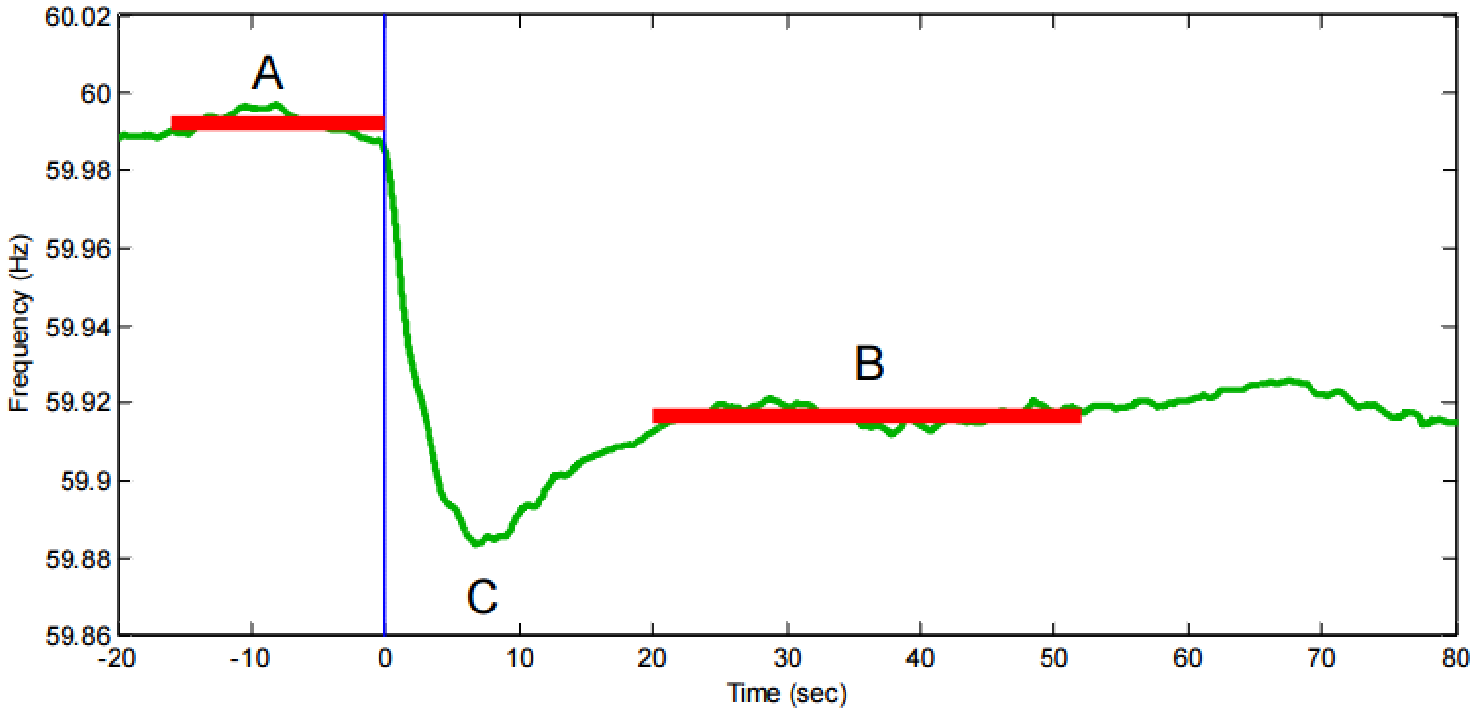
Frequency recovers in about ten minutes

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

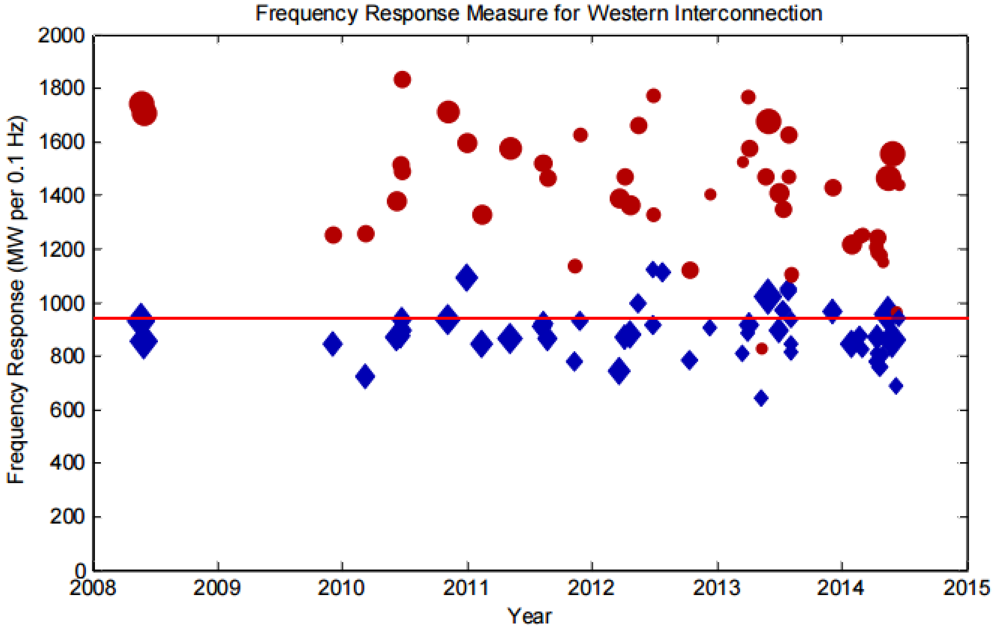
LBNL Metrics: Frequency difference between Point A and Point C

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"

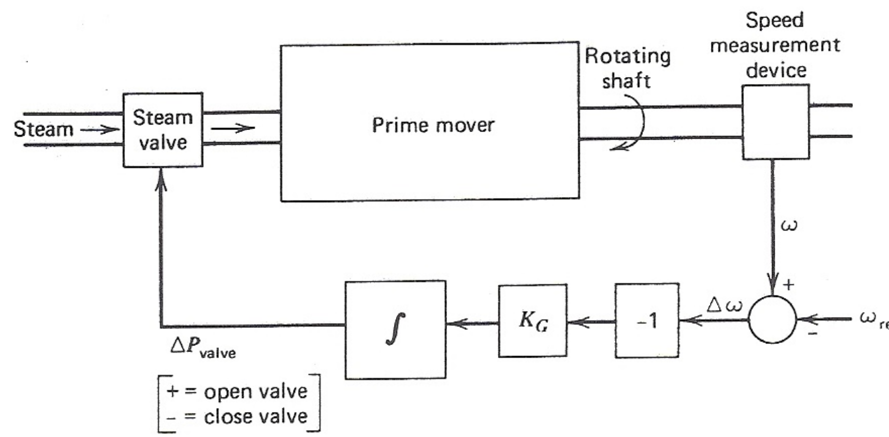


FIG. 9.9 Isochronous governor.

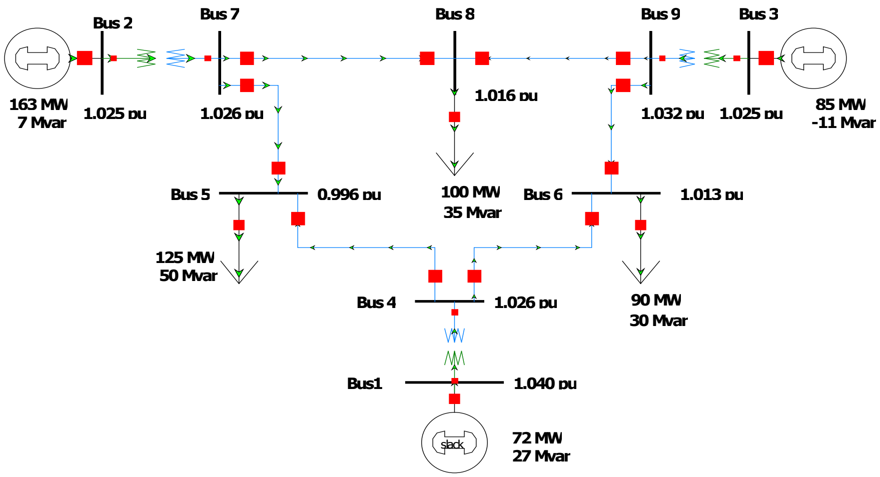
Image source: Wood/Wollenberg, 2nd edition

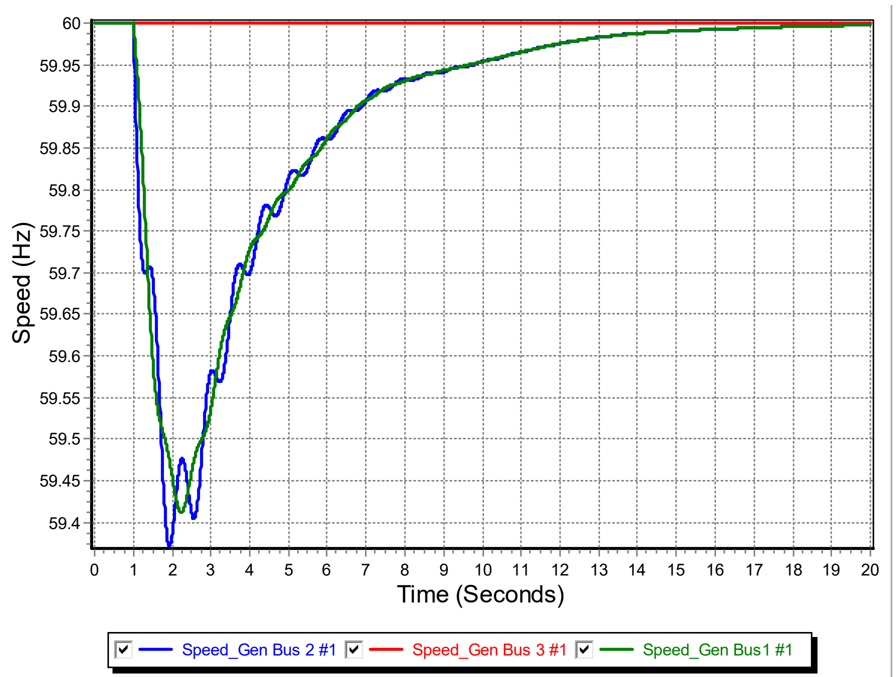
Generator "Hunting"

- 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)

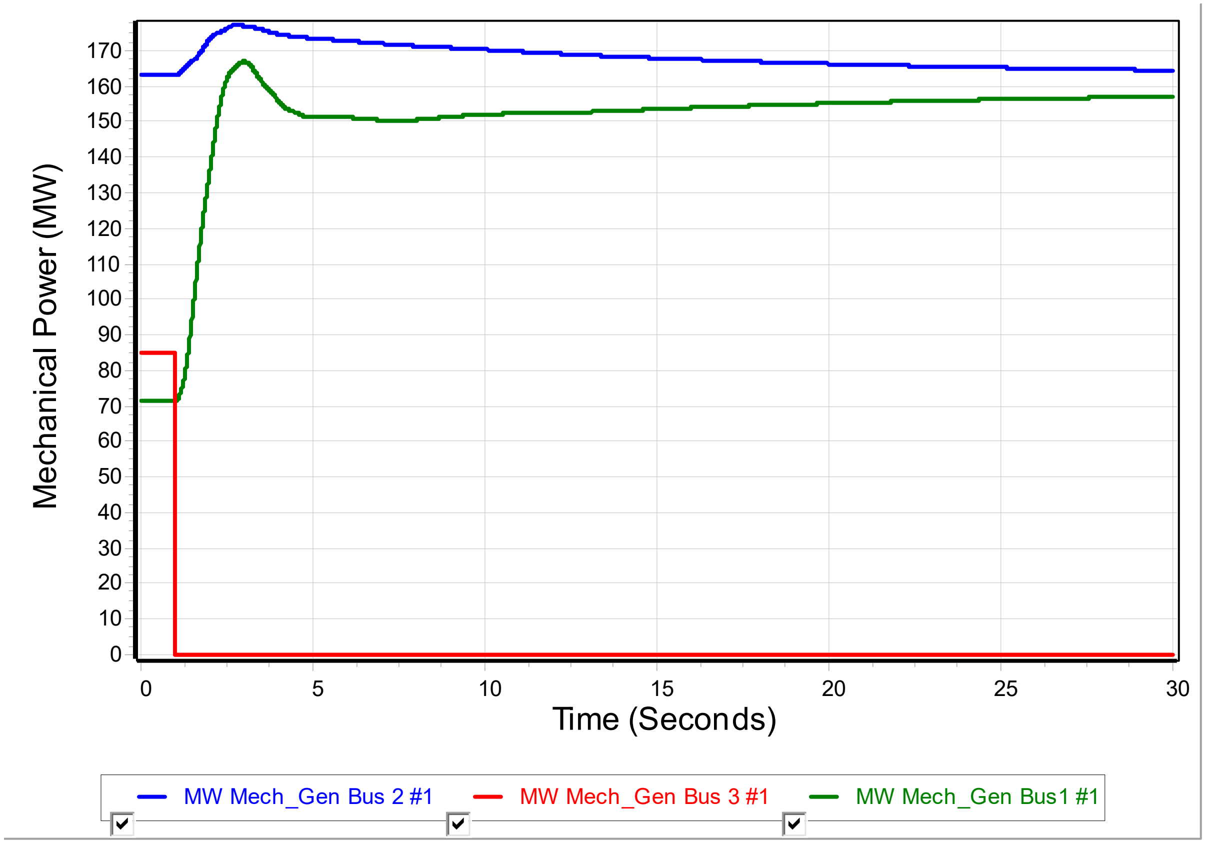




Case is **wscc_9bus_IsoGov**

Isochronous Gen Example

- Graph shows the change in the mechanical output

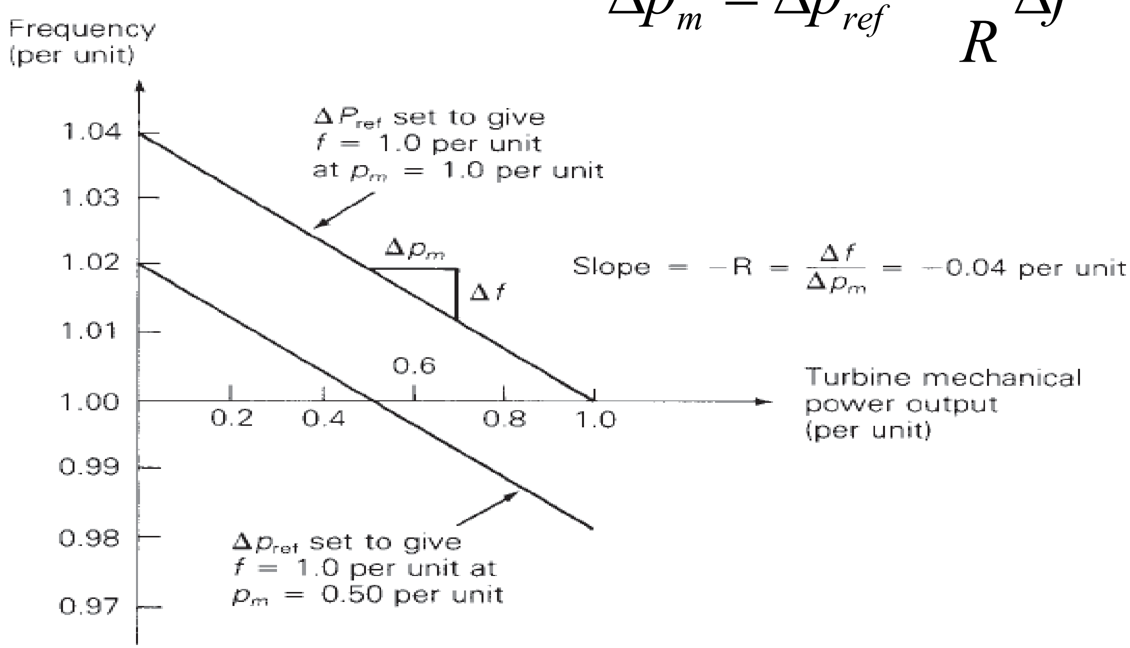


All the change in MWs due to the loss of gen 3 is ultimately being picked up by gen 1

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)

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

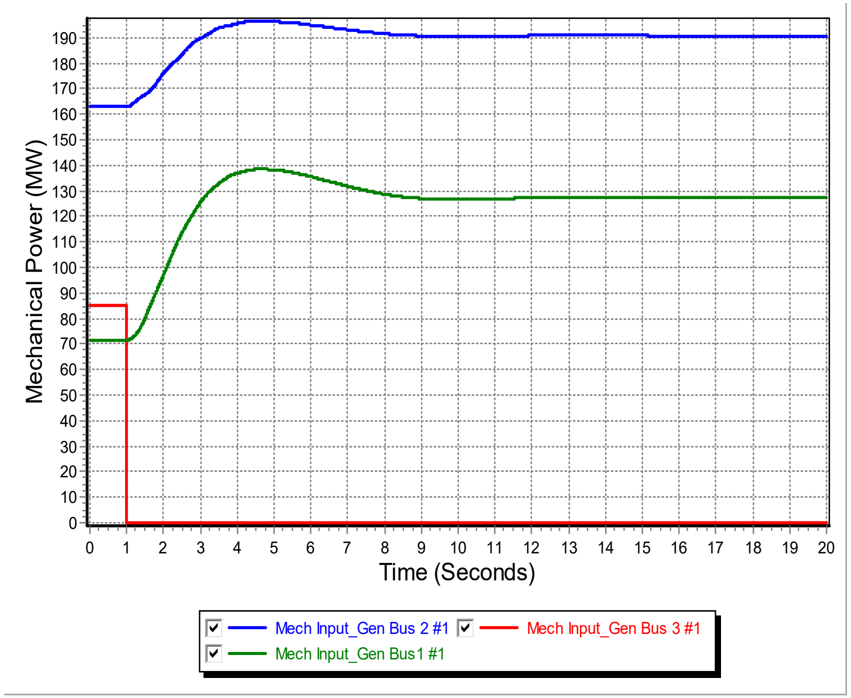
$$R_{1,100MVA} = R_1 \frac{100}{500} = 0.01, \quad R_{2,100MVA} = R_2 \frac{100}{250} = 0.02$$

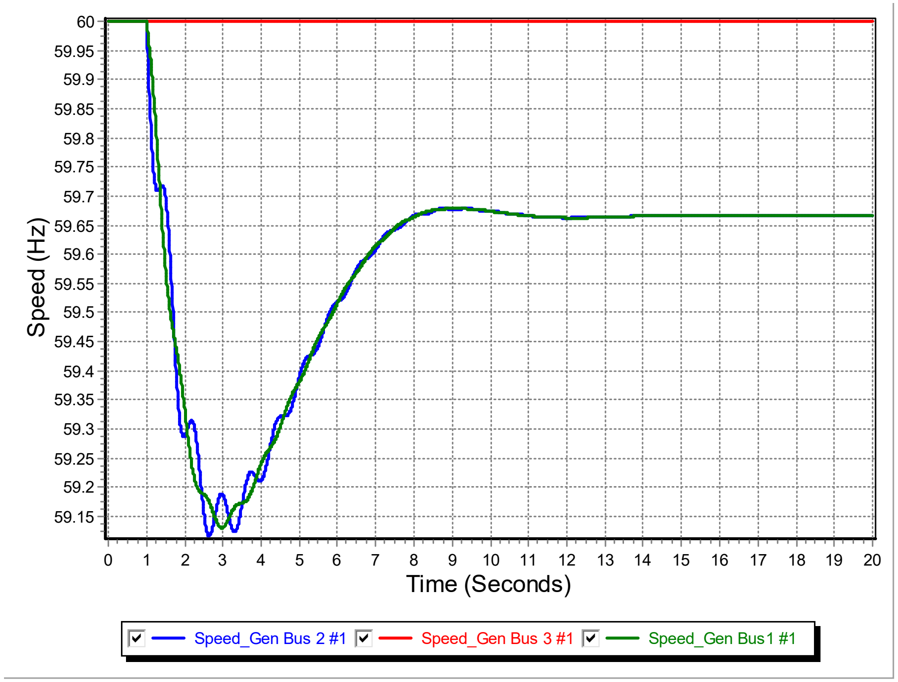
$$\Delta p_{m1} + \Delta p_{m2} = -\left(\frac{1}{R_{1,100MVA}} + \frac{1}{R_{2,100MVA}}\right)\Delta f = 0.85$$

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

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

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

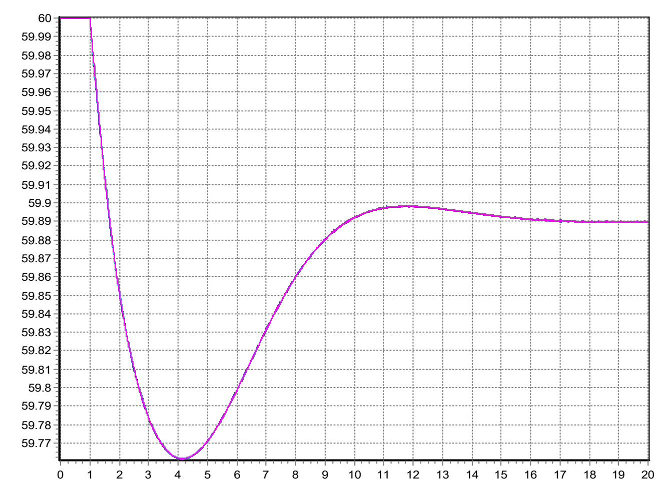
The online generator group obviously does not include the contingency generator(s) that are opened

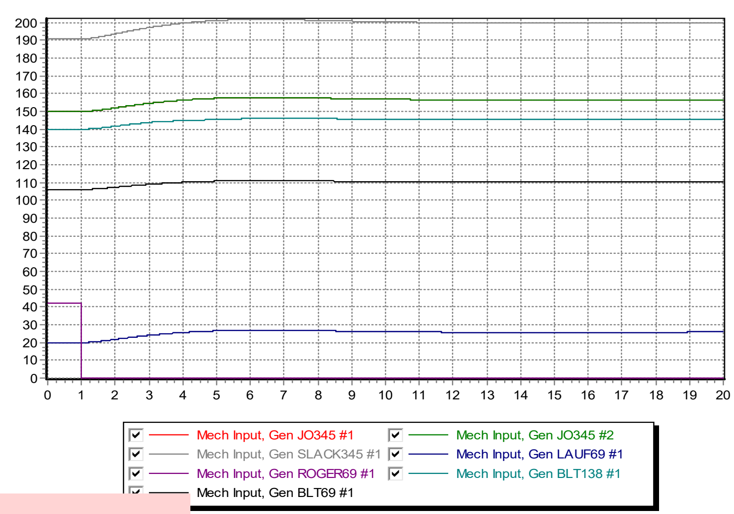
- The online generator summation should only include generators that actually have governors that can respond, and does not take into account generators hitting their limits

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

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

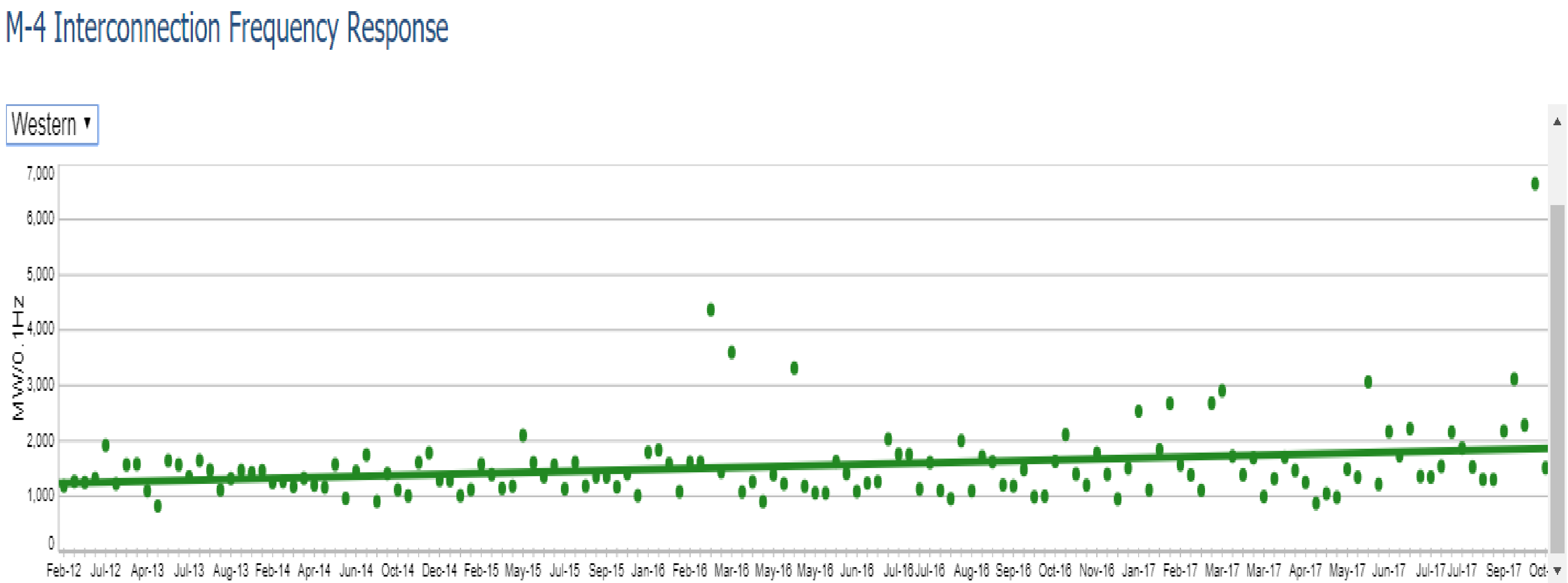




Case is **Bus37_TGOV1**

WECC Interconnect Frequency Response

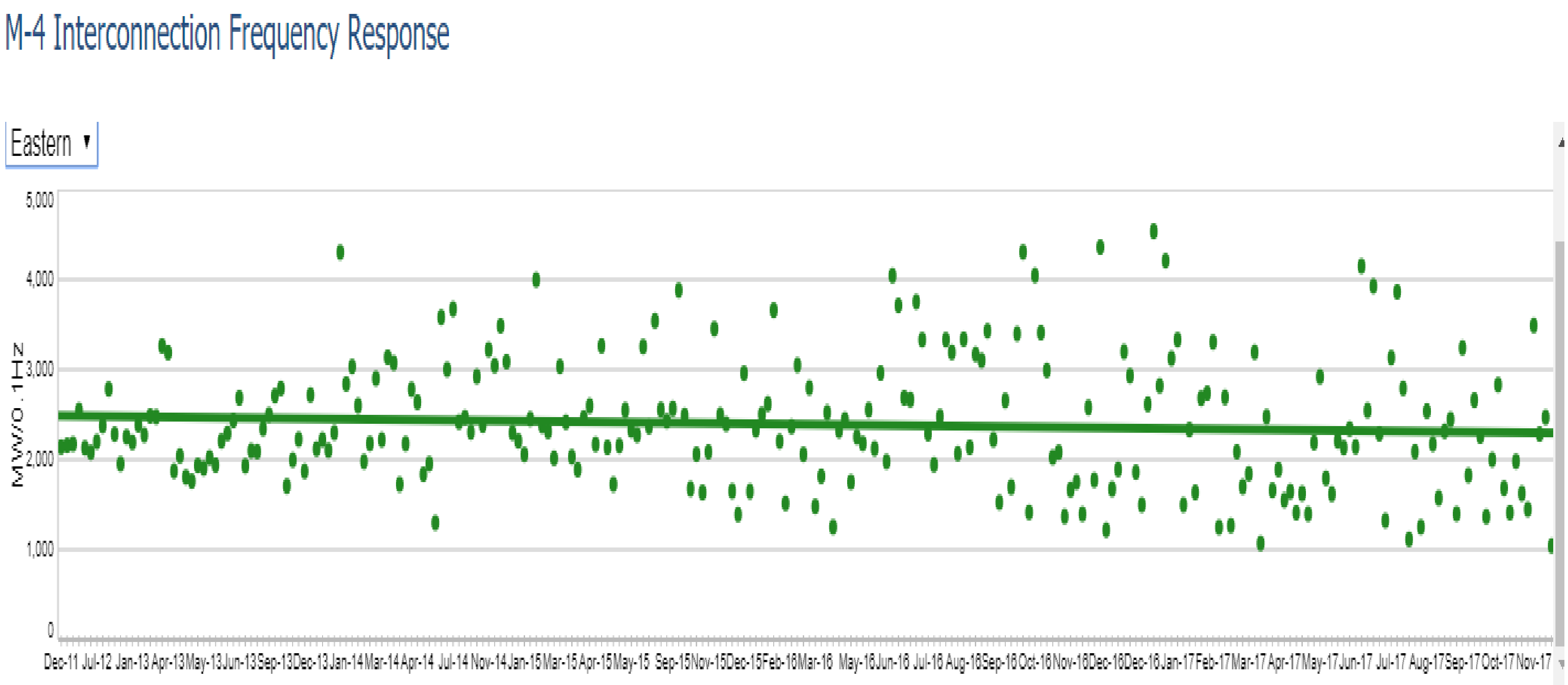
- Data for the four major interconnects is available from NERC; these are the values between points A and B



A higher value is better (more generation for a 0.1 Hz change)

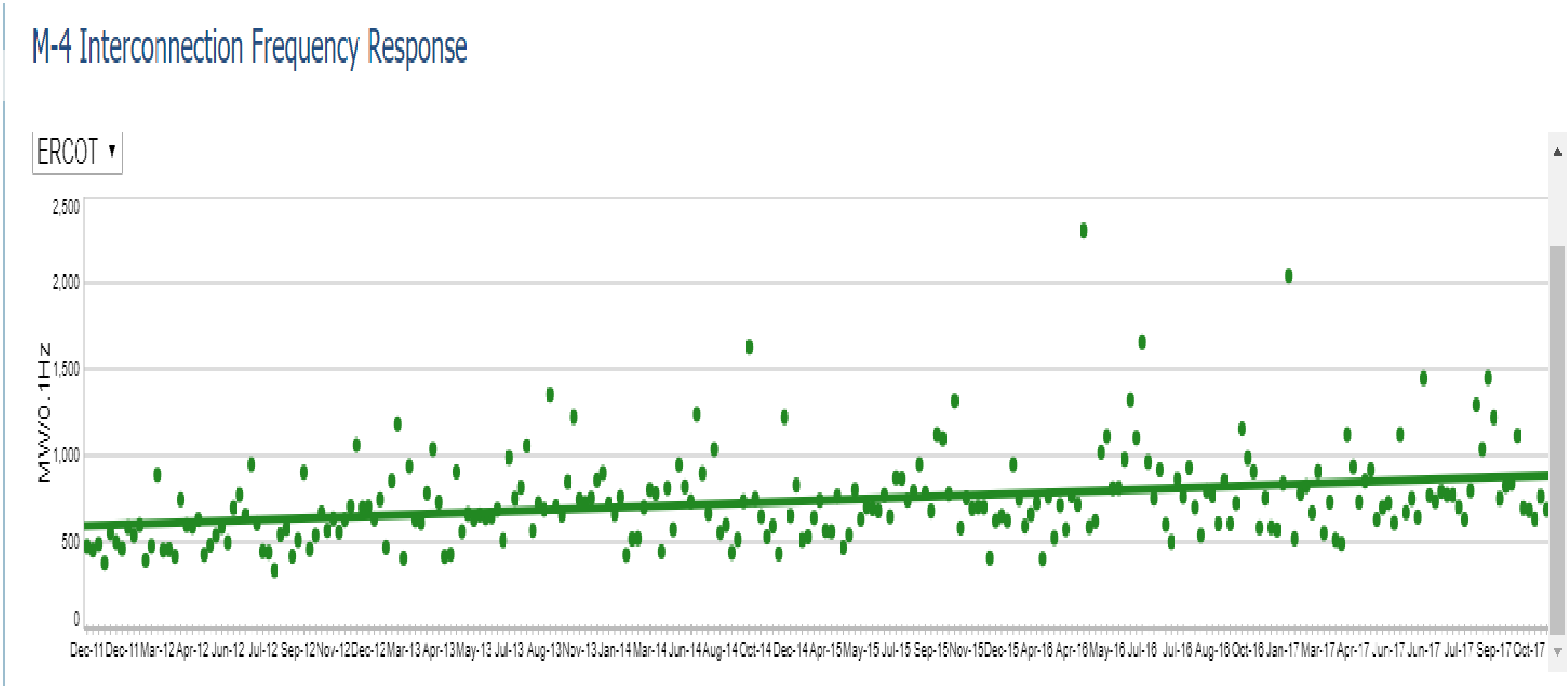
Source: www.nerc.com/pa/RAPA/ri/Pages/InterconnectionFrequencyResponse.aspx

Eastern Interconnect Frequency Response



The larger Eastern Interconnect on average has a higher value

ERCOT Interconnect Frequency Response

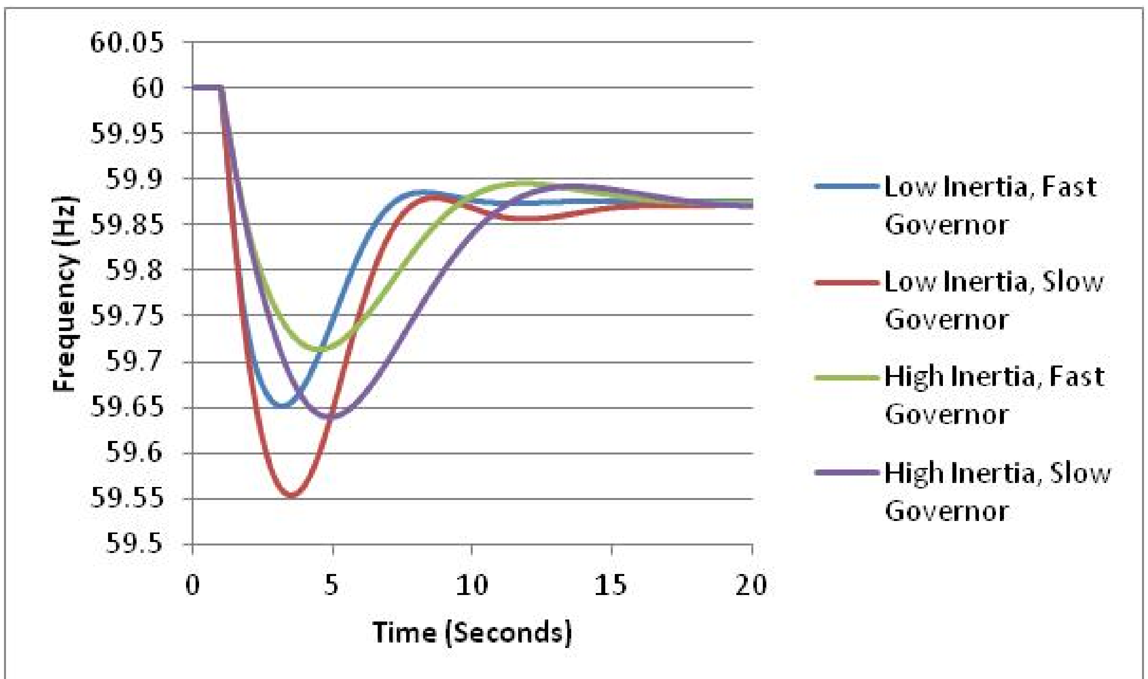


The ERCOT values are usually lower

Source: www.nerc.com/pa/RAPA/ri/Pages/InterconnectionFrequencyResponse.aspx

Impact of Inertia (H)

- Final frequency is determined by the droop of the responding governors
- How quickly the frequency drops depends upon the generator inertia values



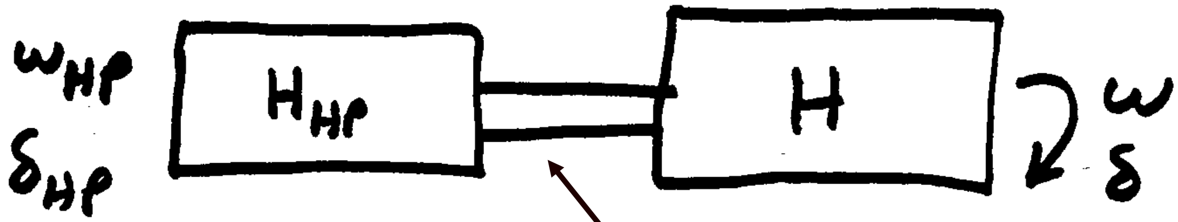
The least frequency deviation occurs with high inertia and fast governors

Restoring Frequency to 60 (or 50) Hz

- In an interconnected power system the governors to not automatically restore the frequency to 60 Hz
- Rather this done via the ACE (area control error) calculation. Previously we defined ACE as the difference between the actual real power exports from an area and the scheduled exports. But it has an additional term
  $ACE = P_{actual} - P_{sched} - 10\beta(freq_{act} - freq_{sched})$
- β is the balancing authority frequency bias in MW/0.1 Hz with a negative sign. It is about 0.8% of peak load/generation

This slower ACE response is usually not modeled in transient stability

Turbine Models



model shaft "squishiness" as a spring

$$\frac{d\delta}{dt} = \omega - \omega_s$$

$$\frac{2H}{\omega_s}\frac{d\omega}{dt} = T_M - T_{ELEC} - T_{FW}$$

$$T_M = -K_{shaft}\left(\delta - \delta_{HP}\right) = T_{OUT}$$

Usually shaft dynamics are neglected

$$\frac{d\delta_{HP}}{dt} = \omega_{HP} - \omega_s$$

$$\frac{2H_{HP}}{\omega_s}\frac{d\omega_{HP}}{dt} = T_{IN} - T_{OUT}$$

High-pressure turbine shaft dynamics

Steam Turbine Models

Boiler supplies a "steam chest" with the steam then entering the turbine through a value

$$T_{CH} \frac{dP_{CH}}{dt} = -P_{CH} + P_{SV}$$

Assume $T_{in} = P_{CH}$ and a rigid shaft with $P_{CH} = T_{M}$

Then the above equation becomes

$$T_{CH} \frac{dT_M}{dt} = -T_M + P_{SV}$$

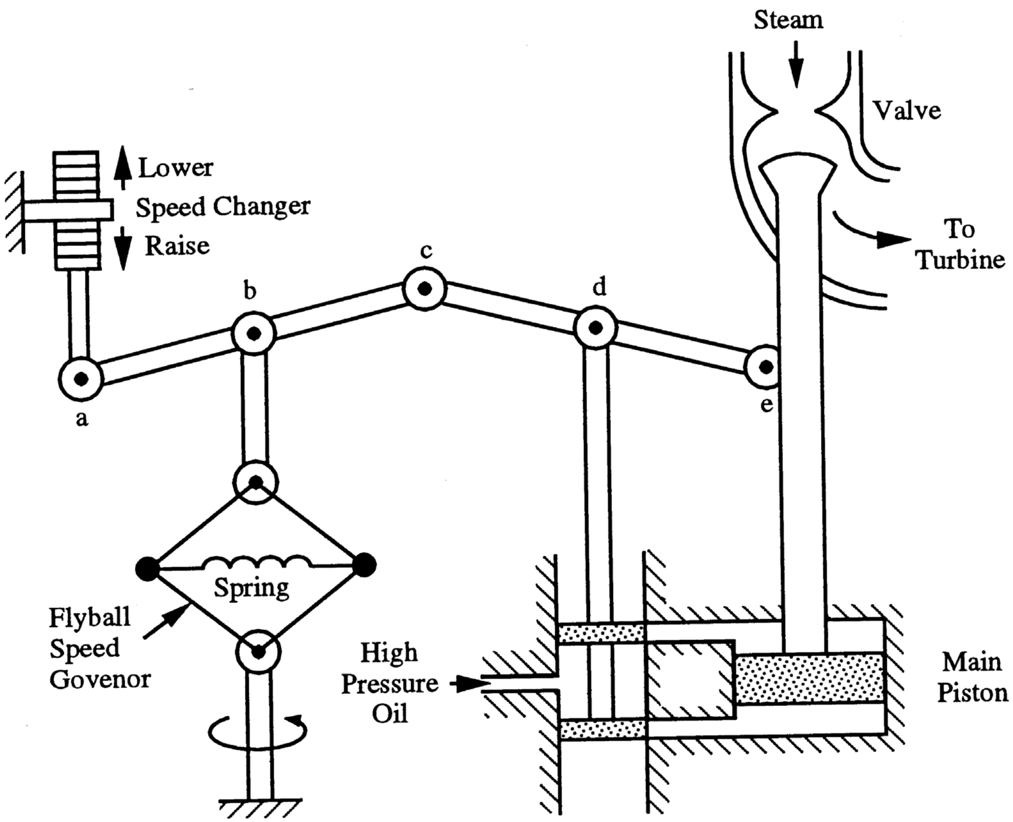
And we just have the swing equations from before

$$\frac{d\delta}{dt} = \omega - \omega_s$$

$$\frac{2H}{\omega_s} \frac{d\omega}{dt} = T_M - T_{ELEC} - T_{FW}$$

We are assuming $\delta = \delta_{HP}$ and $\omega = \omega_{HP}$

Steam Governor Model



Steam Governor Model

$$T_{SV}\frac{dP_{SV}}{dt} = -P_{SV} + P_C - \frac{1}{R}\Delta\omega$$

$$\text{where } \Delta\omega = \frac{\omega - \omega_s}{\omega_s}$$

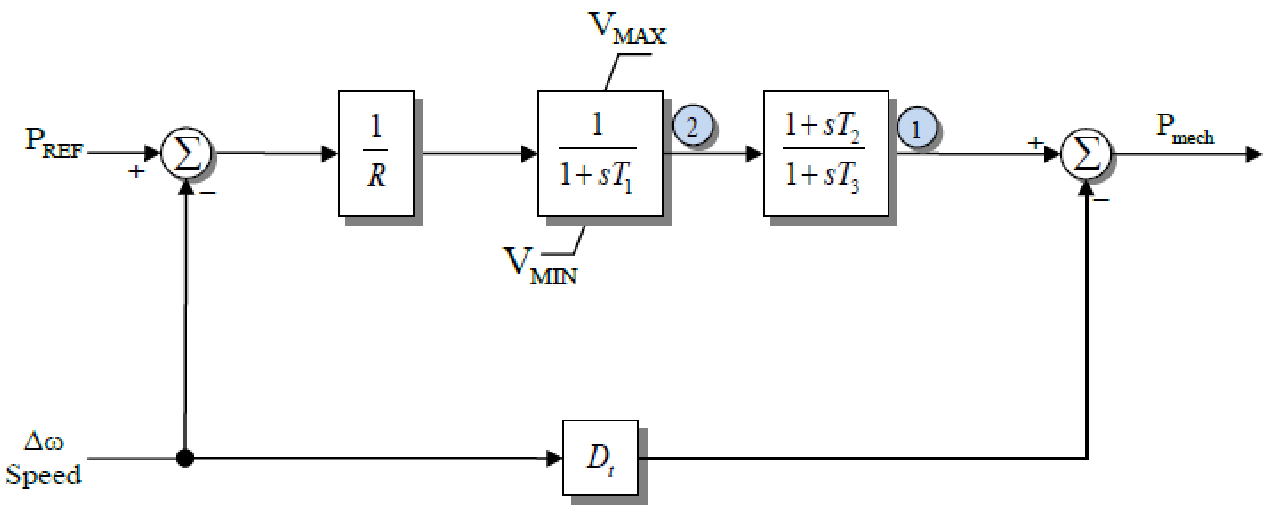
$$0 \le P_{SV} \le P_{SV}^{\max}$$

Steam valve limits

R = .05 (5% droop)

TGOV1 Model

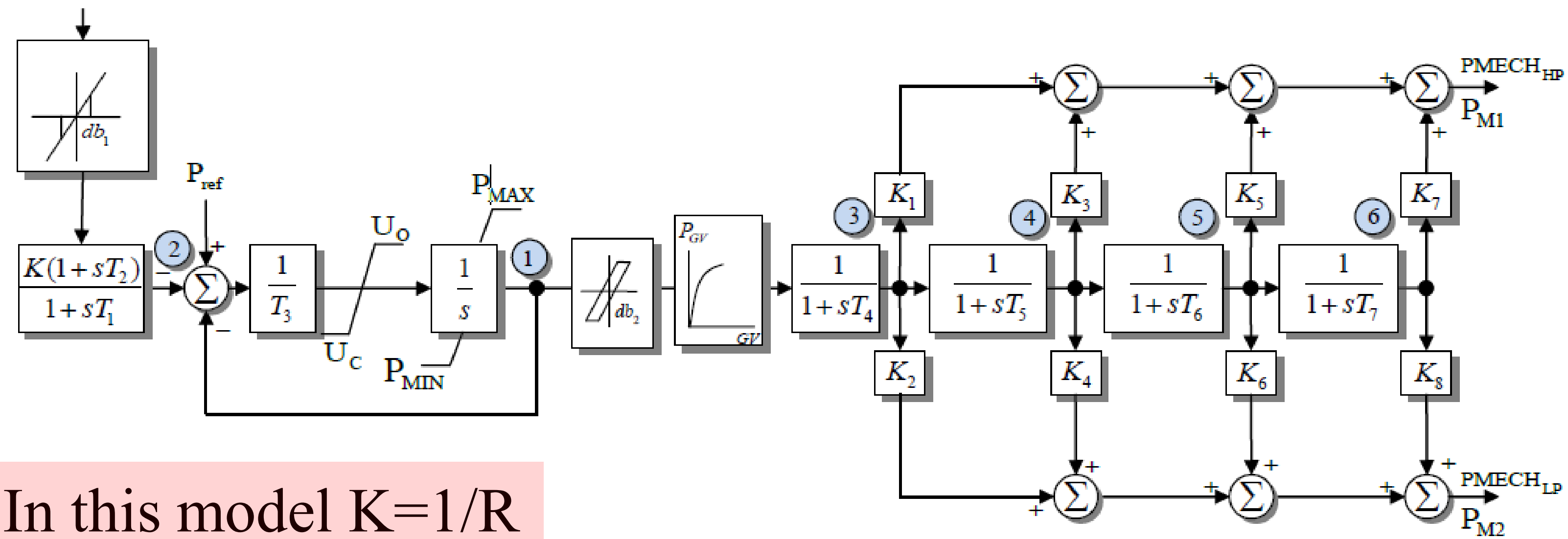
- The standard model that is close to this is the TGOV1



About 12% of governors in a 2015 EI model are TGOV1; R = 0.05, T_1 is less than 0.5 (except a few 999's!), T_3 has an average of 7, average T_2/T_3 is 0.34; D_t is used to model turbine damping and is often zero (about 80% of time in EI)

IEEEG1 Model

- A common stream turbine model, is the IEEEG1, originally introduced in the below 1973 paper



In this model K=1/R

U_o and U_c are rate limits

It can be used to represent cross-compound units, with high and low pressure steam

IEEE Committee Report, "Dynamic Models for Steam and Hydro Turbines in Power System Studies," Transactions in Power Apparatus & Systems, volume 92, No. 6, Nov./Dec. 1973, pp 1904-15

IEEEG1

- Blocks on the right model the various steam stages
- About 12% of WECC and EI governors are currently IEEEG1s
- Below figures show two test comparison with this

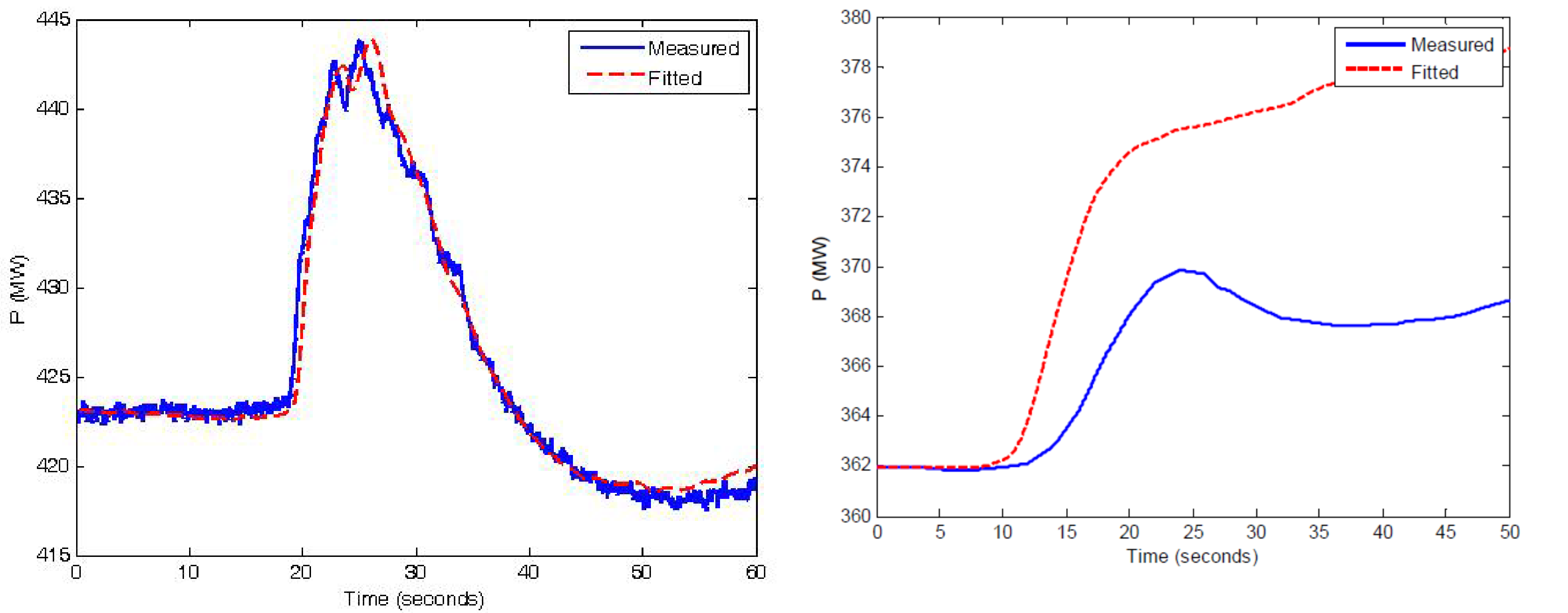


Image Source: Figs 2-4, 2-6 of IEEE PES, "Dynamic Models for Turbine-Governors in Power System Studies," Jan 2013

Deadbands

- Before going further, it is useful to consider deadbands, with two types shown with the IEEEG1 model and described in the 2013 IEEE PES Governor Report
- The type 1 is an intentional deadband, implemented to prevent excessive response
  - Until the deadband activates there is no response, then normal response after that; this can cause a potentially large jump in the response
  - Also, once activated there is normal response coming back into range
  - Used on input to IEEEG1