ECEN 460
Power System Operation and Control
Spring 2025

Lecture 20: Power System Stability

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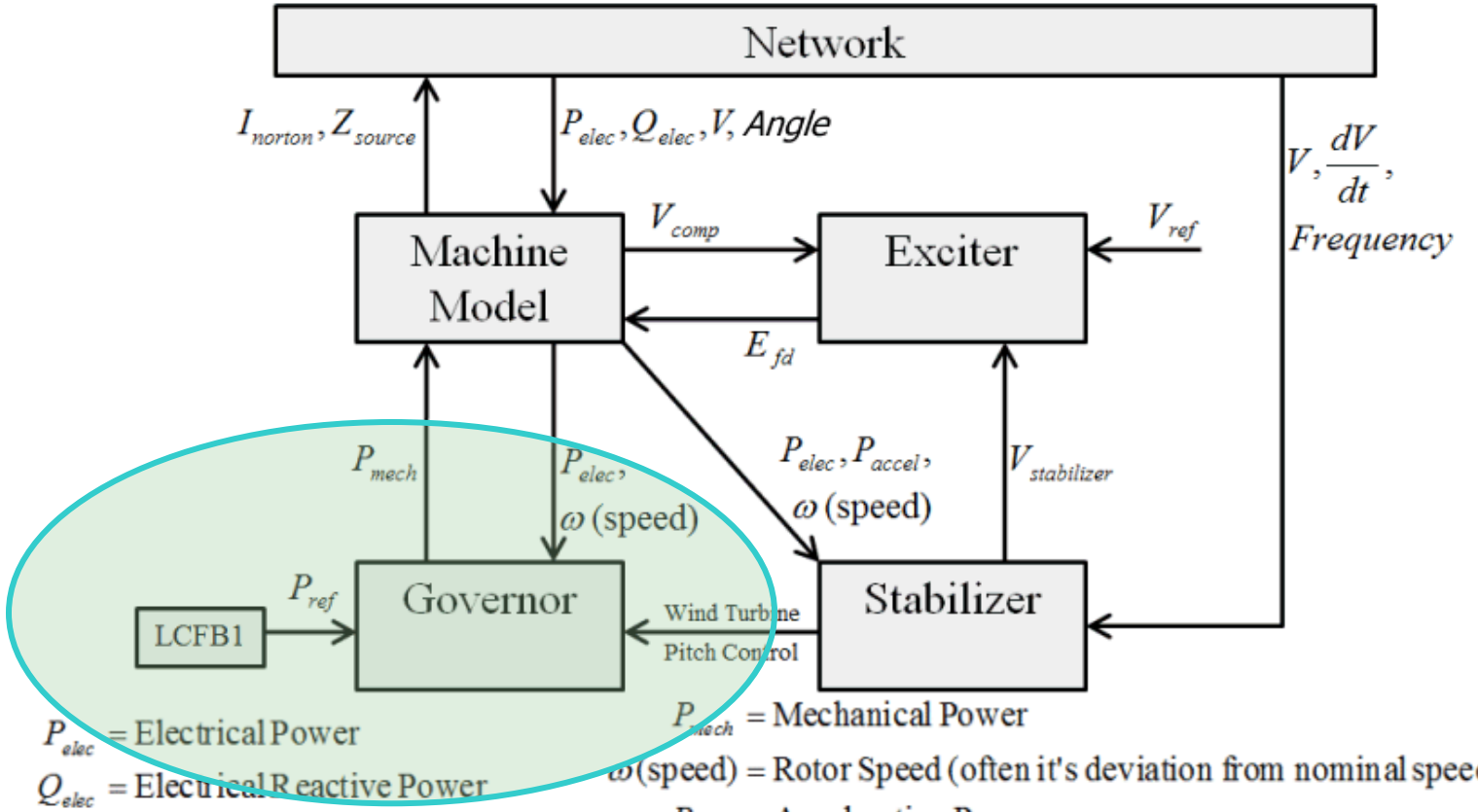
TEXAS A&M UNIVERSITY

Announcements

- Please read Chapter 13
- By April 9 do Problem Set A
- Schedule for the rest of the semester is
  - Lab 9 this week
  - Lab 10 week of April 7, which will include time for the design groups to meet
  - Lab 3 week of April 14 (optional, ungraded machine lab)
  - Lab 11 (project presentations) by the individual teams to their TA before the end of classes (on or before April 29)
  - Exam 2 on Wednesday April 23 during class
  - Design project due at 9:30 am on May 1 (i.e., at the end of our final slot; no final)

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

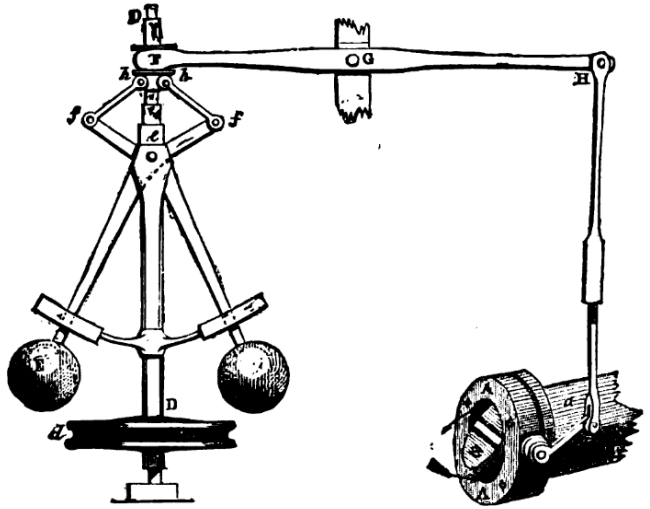


FIG. 4.—*Governor and Throttle-Valve.*

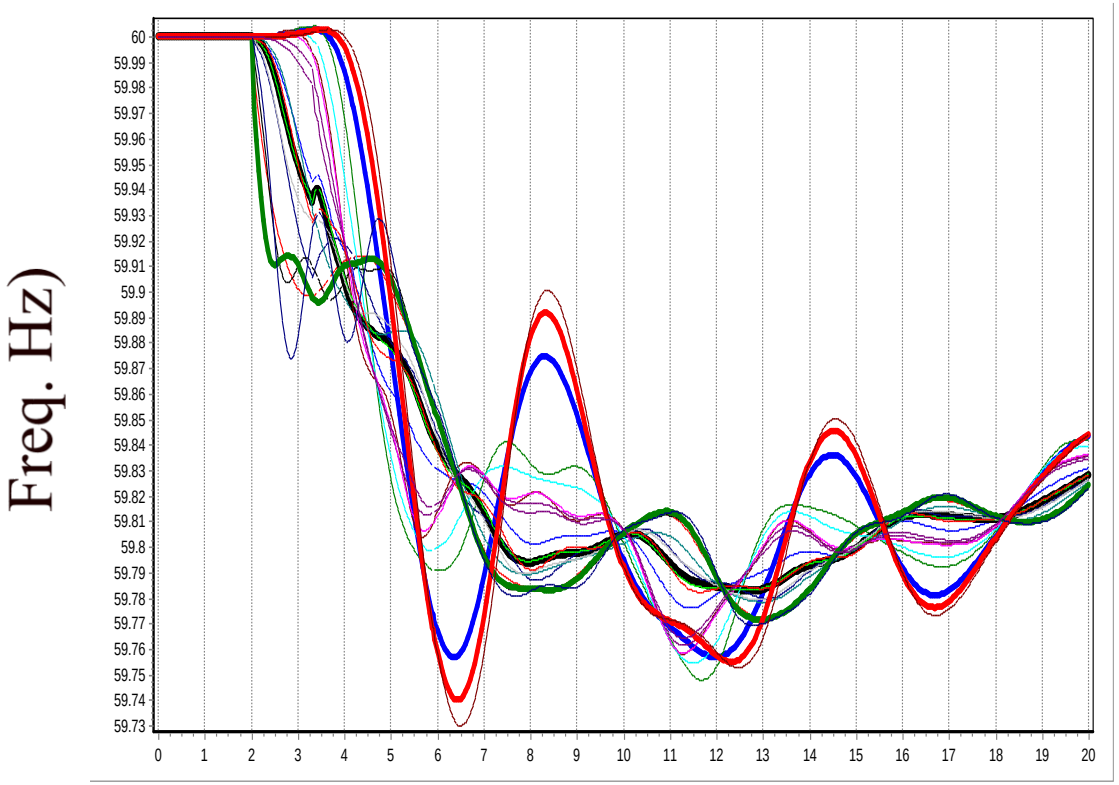
Image source: http://upload.wikimedia.org/wikipedia/commons/1/1e/Centrifugal_governor.png

Prime Movers and Governors

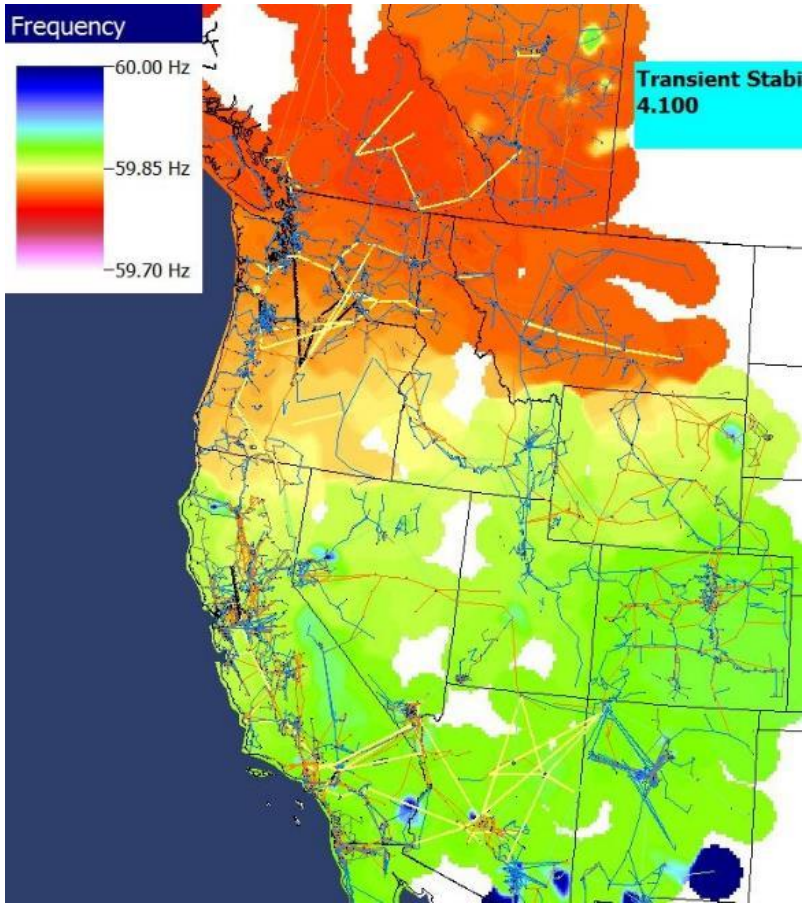
- In transient stability collectively the prime mover and the governor are called the "governor"
- As has been previously discussed, models need to be appropriate for the application
- In transient stability the response of the system for seconds to perhaps minutes is considered
- Long-term dynamics, 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



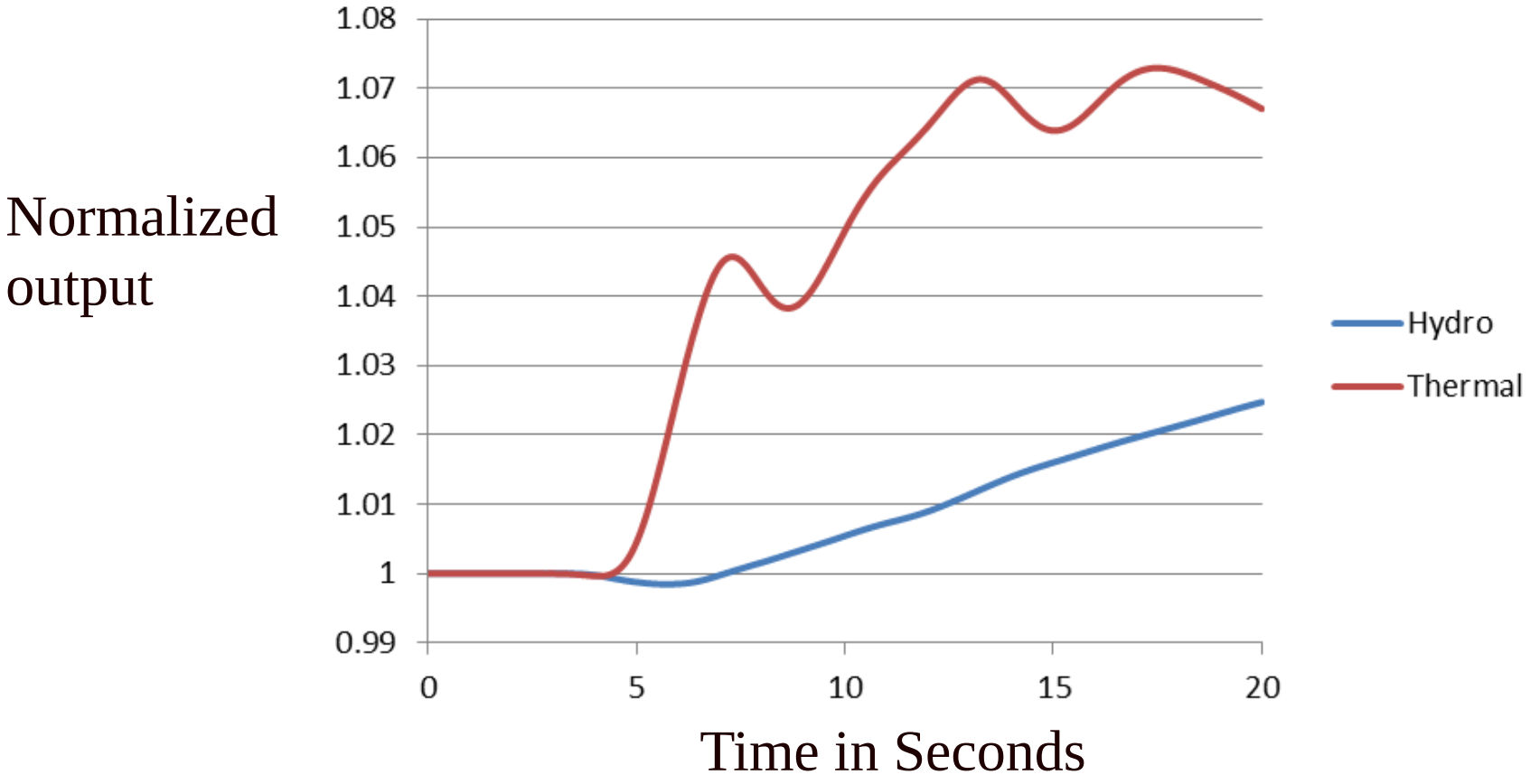
Frequency Contour

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!



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"

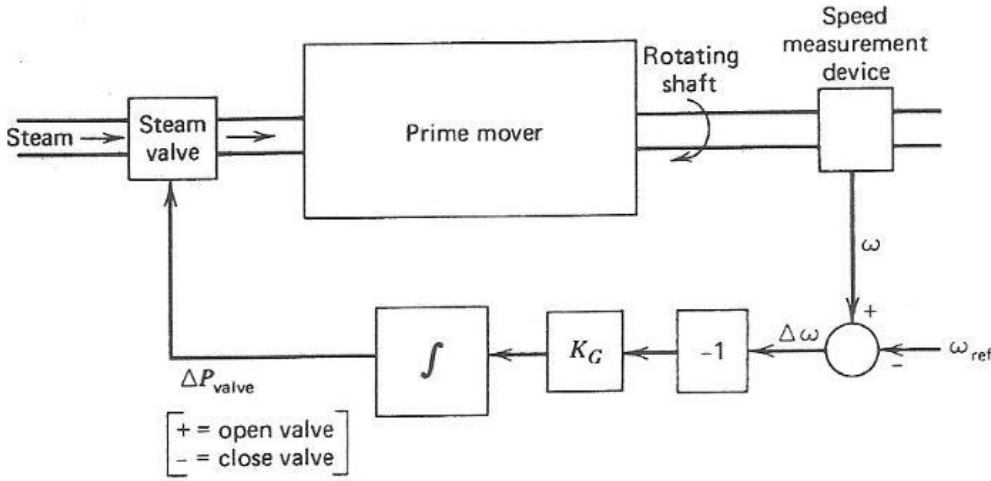


FIG. 9.9 Isochronous governor.

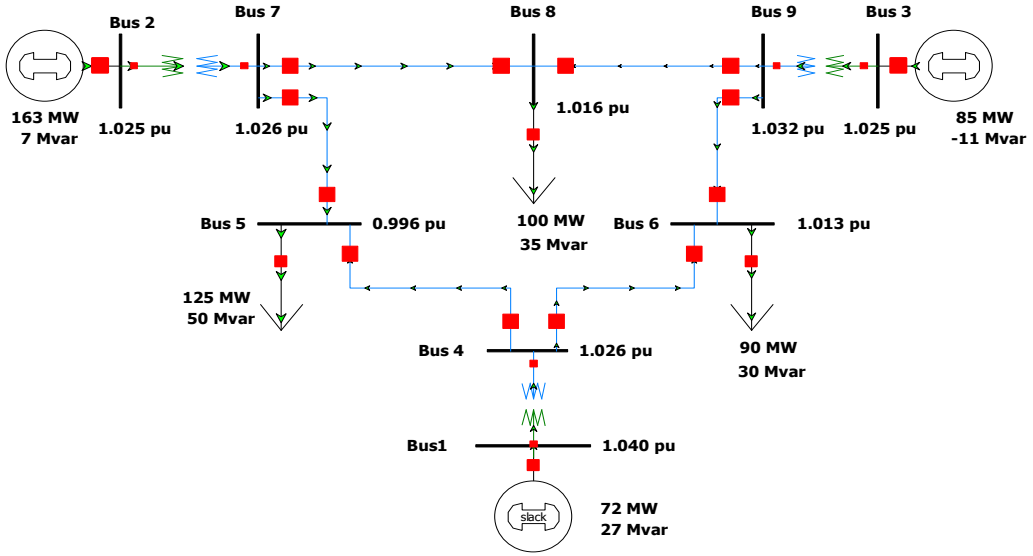
Image source: Wood/Wollenberg, 2nd edition

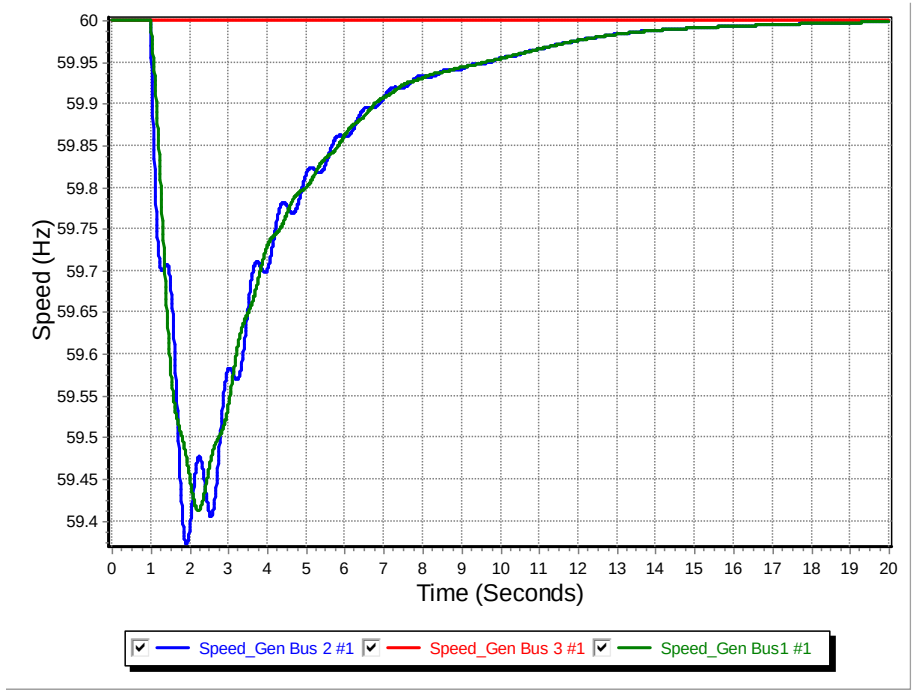
Generator “Hunting”

- 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)

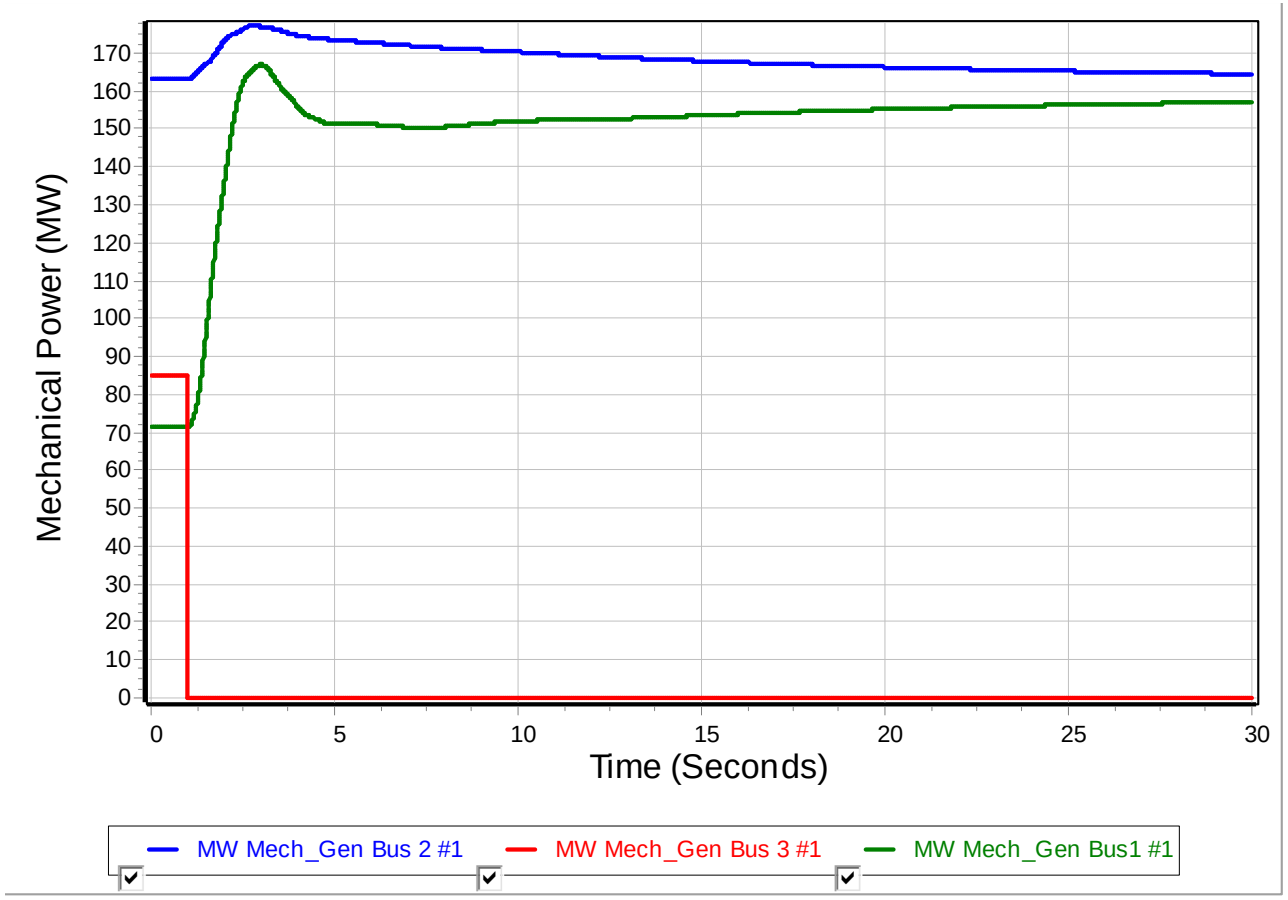




Case is **wscc_9bus_IsoGov**

Isochronous Gen Example

- Graph shows the change in the mechanical output

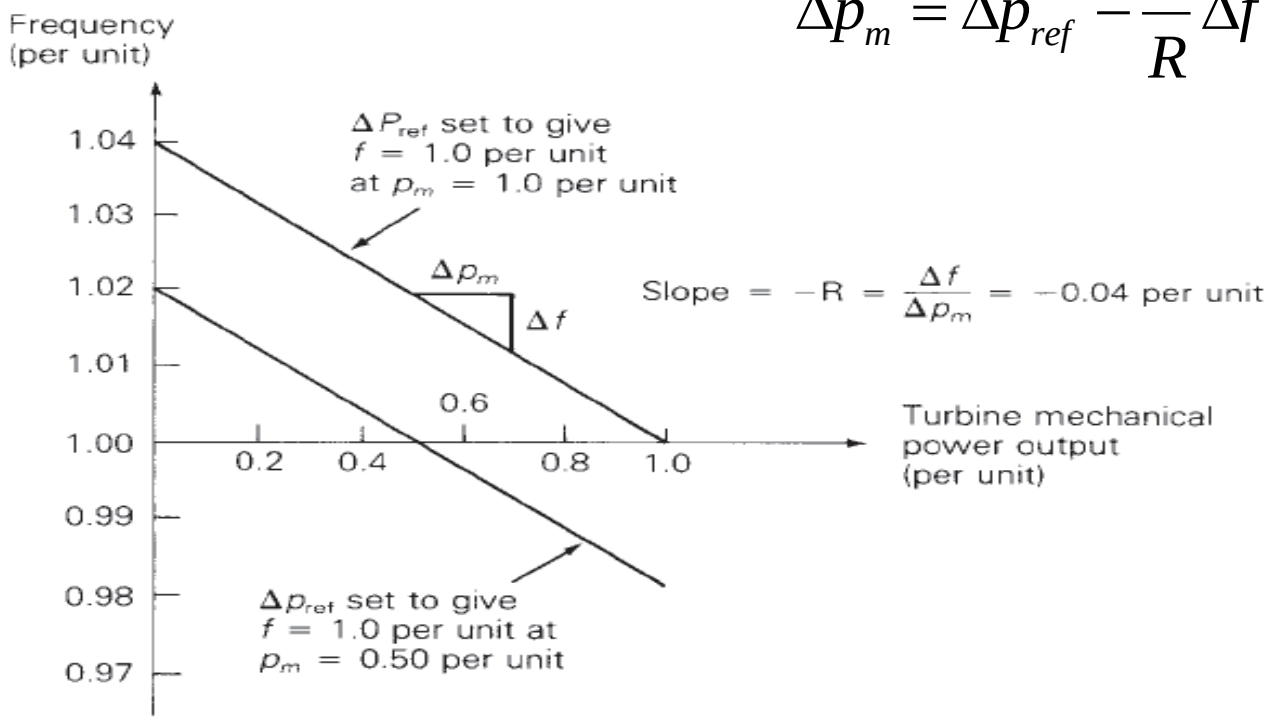


All the change in MWs due to the loss of gen 3 is ultimately being picked up by gen 1

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)

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

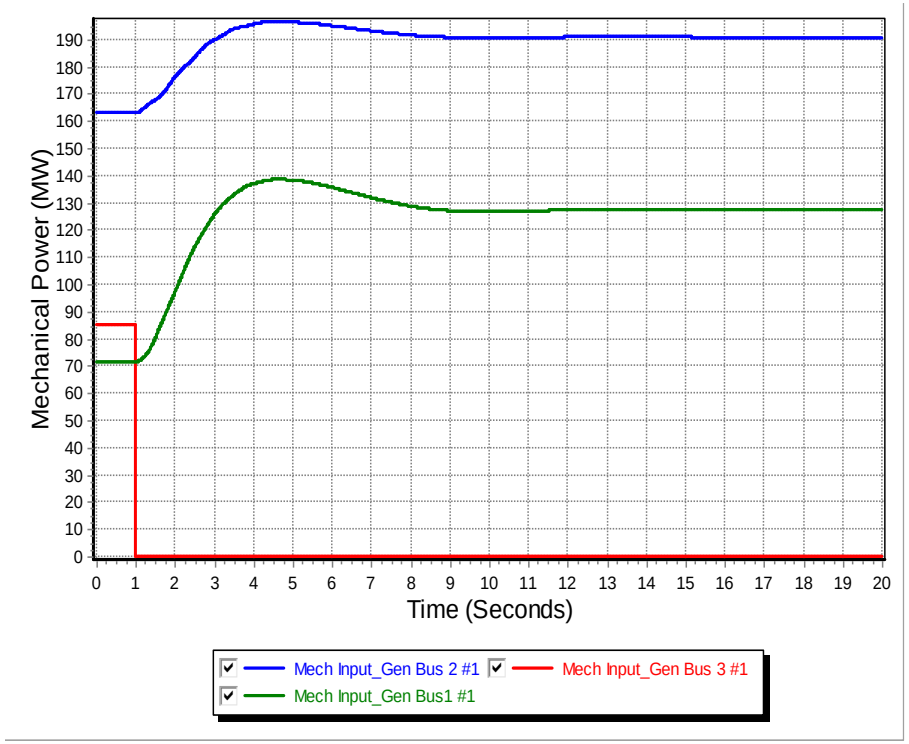
$$R_{1,100MVA} = R_1 \frac{100}{500} = 0.01, \quad R_{2,100MVA} = R_2 \frac{100}{250} = 0.02$$

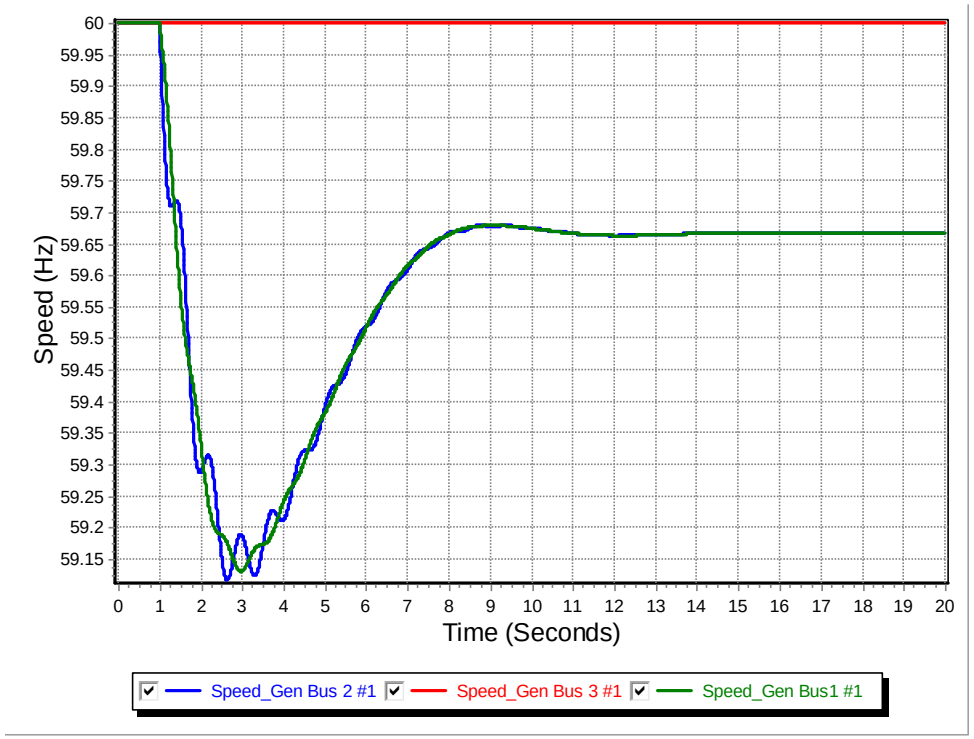
$$\Delta p_{m1} + \Delta p_{m2} = -\left(\frac{1}{R_{1,100MVA}} + \frac{1}{R_{2,100MVA}} \right) \Delta f = 0.85$$

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

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

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

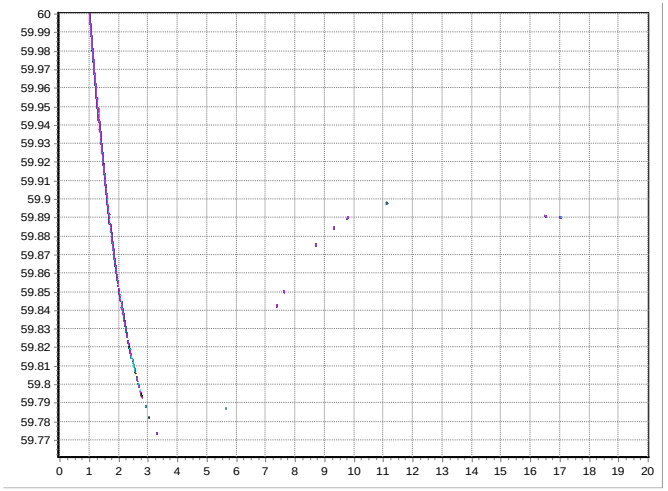
The online generator group obviously does not include the contingency generator(s) that are opened

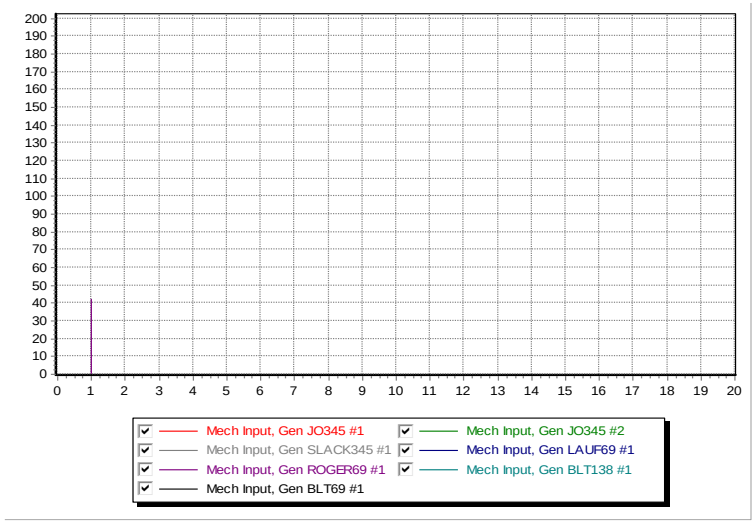
- The online generator summation should only include generators that actually have governors that can respond, and does not take into account generators hitting their limits

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

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





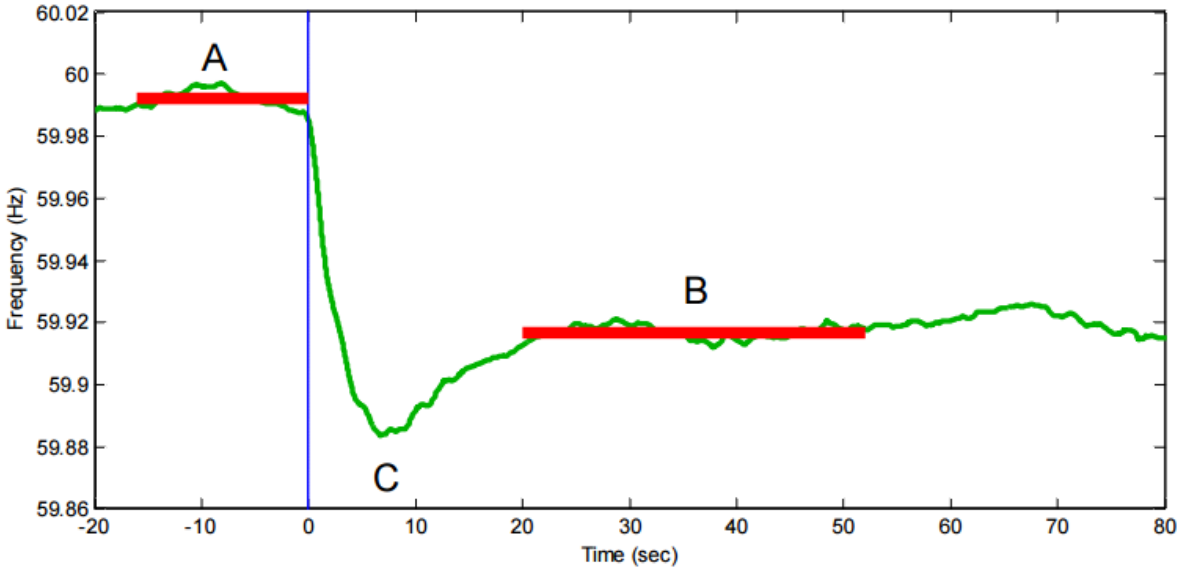
Case is **Bus37_TGOV1**

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

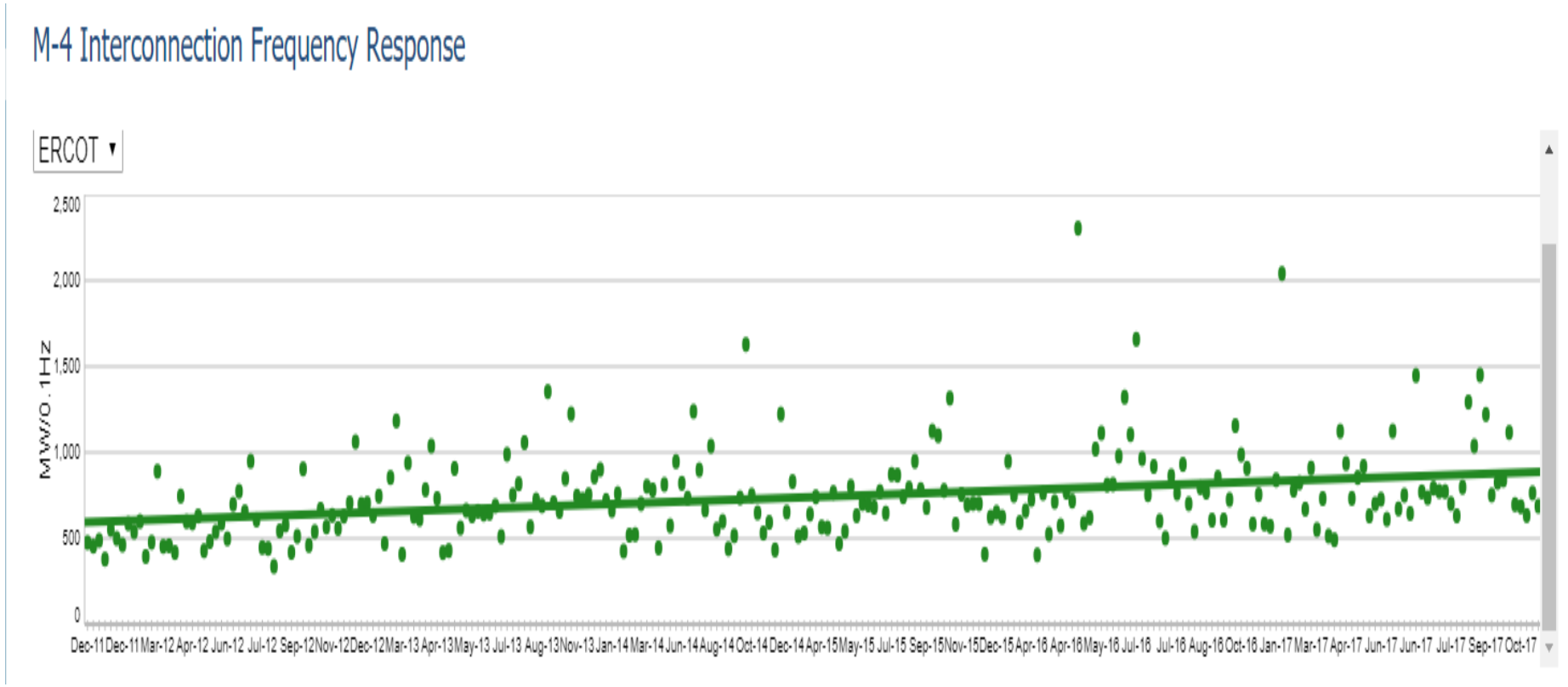


NERC FRM BAL-003-1: Frequency difference between Point A and Point B

LBNL Metrics: Frequency difference between Point A and Point C

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

ERCOT Interconnect Frequency Response

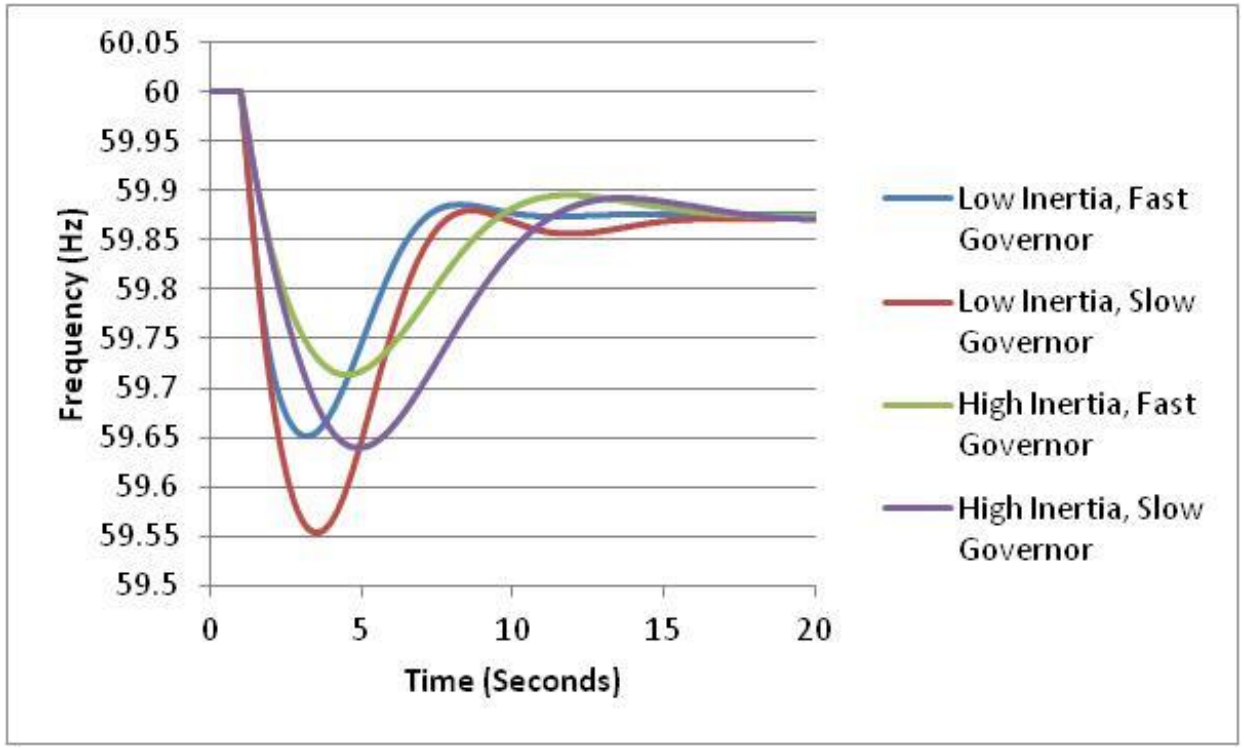


The ERCOT values are usually lower

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

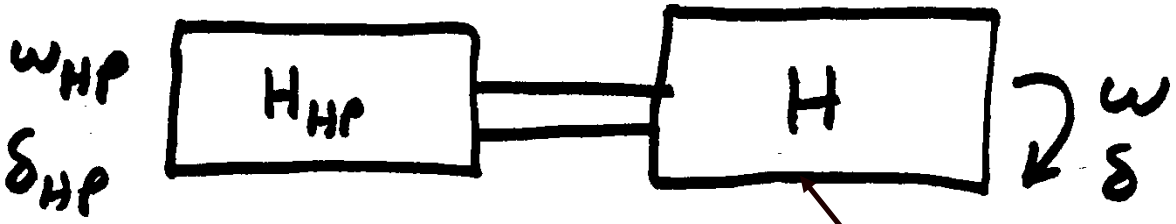
- In an interconnected power system the governors to not automatically restore the frequency to 60 Hz
- Rather this done via the ACE (area control error) calculation. Previously we defined ACE as the difference between the actual real power exports from an area and the scheduled exports. But it has an 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 most stability simulations

Turbine Models



model shaft "squishiness" as a spring

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

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

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

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 Governor Model

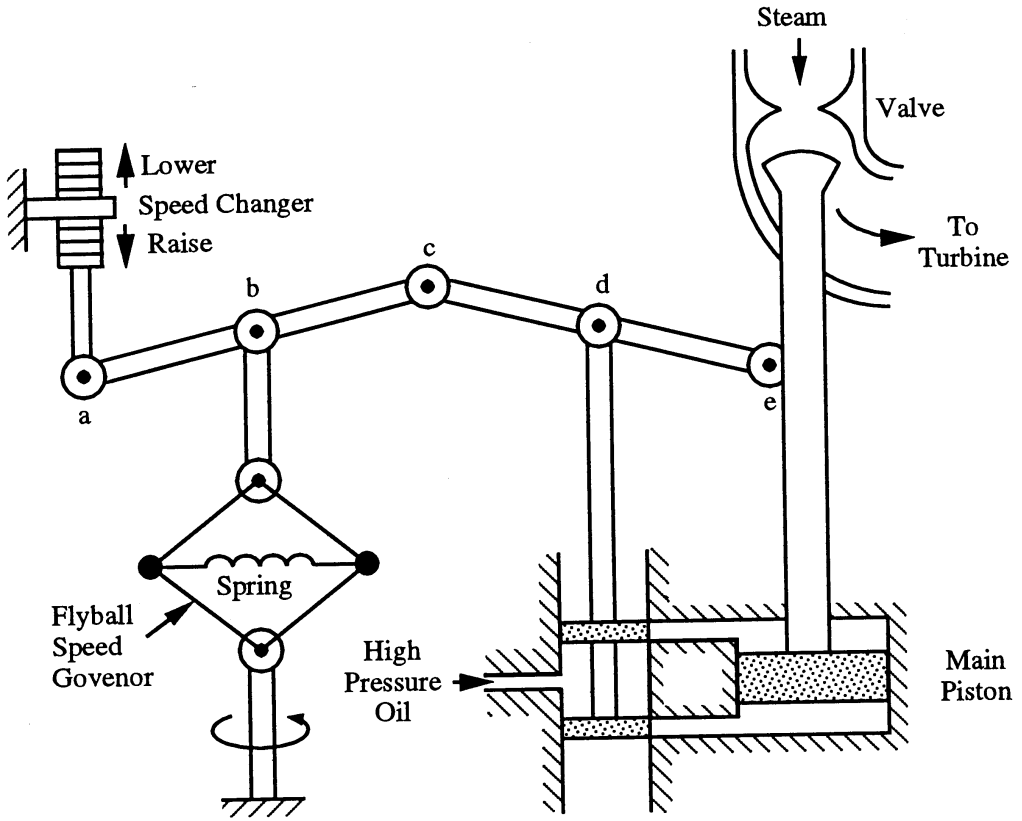
$$T_{SV}\frac{dP_{SV}}{dt} = -P_{SV} + P_C - \frac{1}{R}\Delta\omega$$

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

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

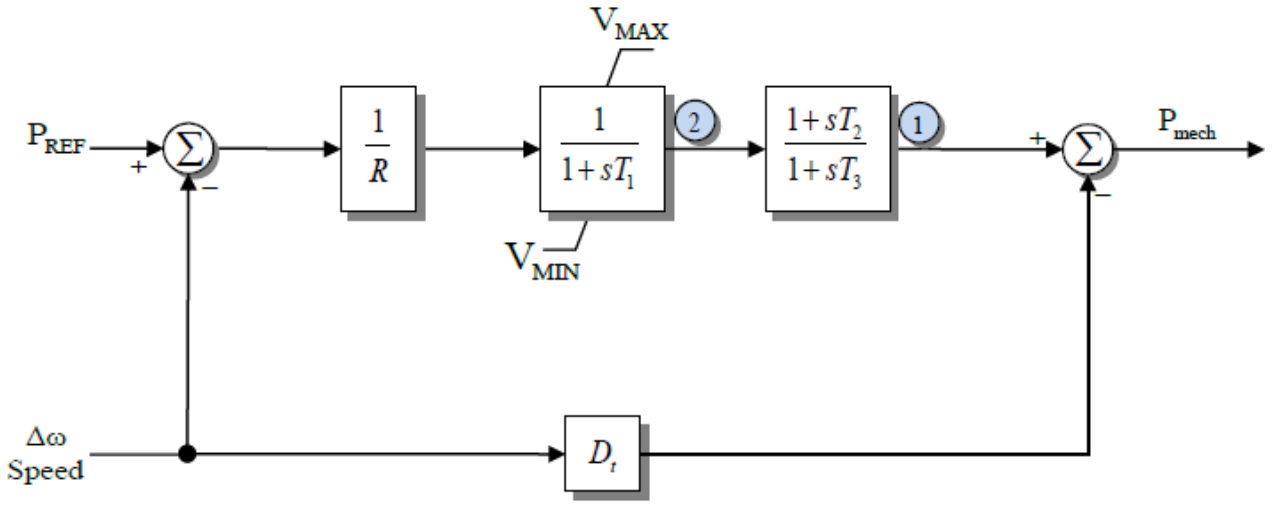
Steam valve limits

R = .05 (5% droop)



TGOV1 Model

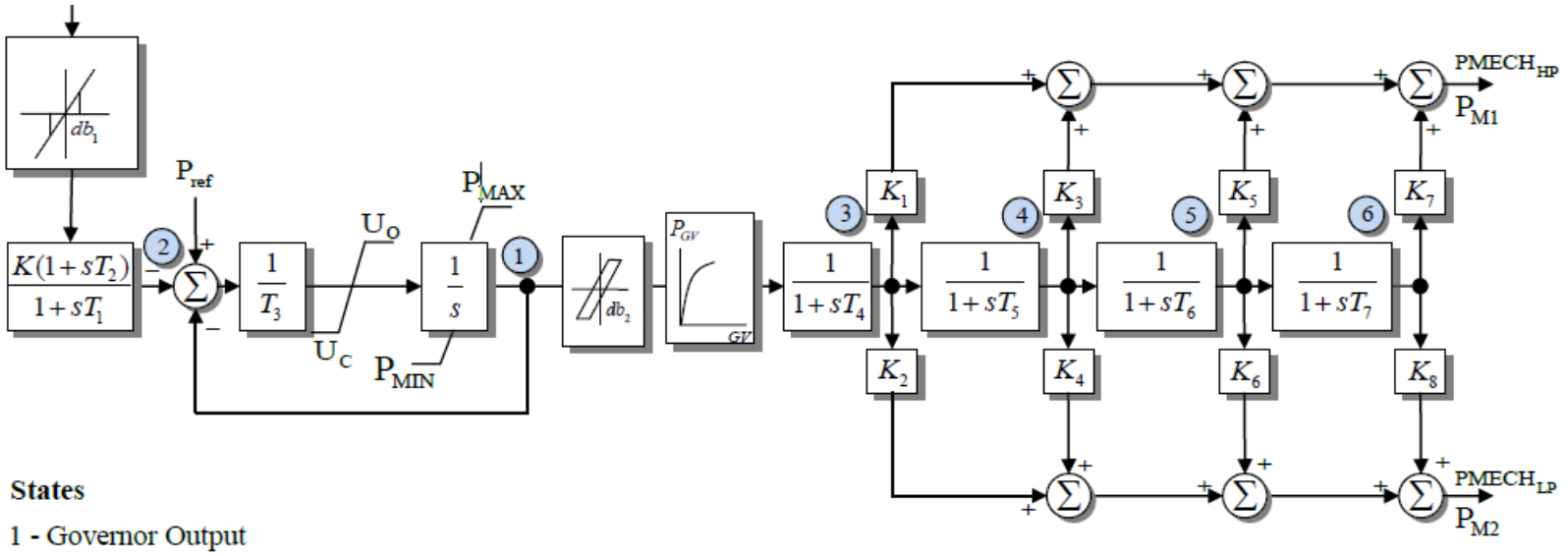
- The standard model that is close to this is the TGOV1



About 3% of governors in the 2022 EI/WECC model are TGOV1; R is about 0.05, T_1 is less than 0.5 (except for one 999!), T_3 has an average of 6, average T_2/T_3 is 0.34; D_t is used to model turbine damping and is often zero (about 90% of the time)

IEEEG1 Model

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



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

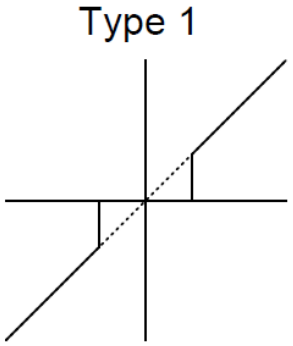
U_o and U_c are rate limits

In this model K=1/R

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

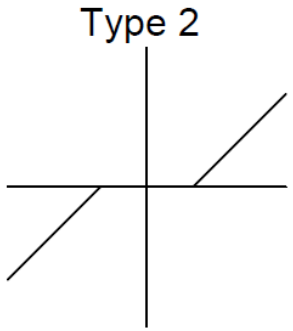
Deadbands

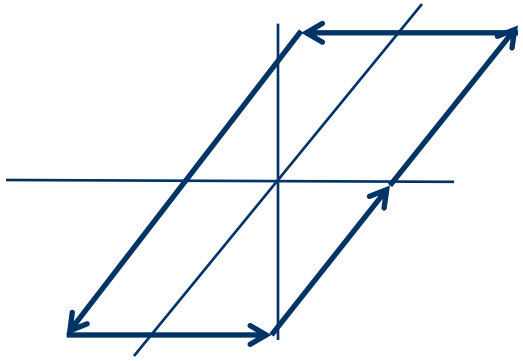
- Before going further, it is useful to briefly consider deadbands, with two types shown with IEEEG1 and described in the 2013 IEEE PES Governor Report
- The type 1 is an intentional deadband, implemented to prevent excessive response
  - Until the deadband activates there is no response, then normal 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



Deadbands

- The type 2 is also an intentional deadband, implemented to prevent excessive response
  - Difference is response does not jump, but rather only starts once outside of the range
- Another type of deadband is the unintentional, such as will occur with loose gears
  - Until deadband "engages" there is no response
  - Once engaged there is a hysteresis in the response





When starting simulations the deadbands usually start at their origin

Gas Turbines

- A gas turbine (usually using natural gas) has a compressor, a combustion chamber and then a turbine
- The below figure gives an overview of the modeling

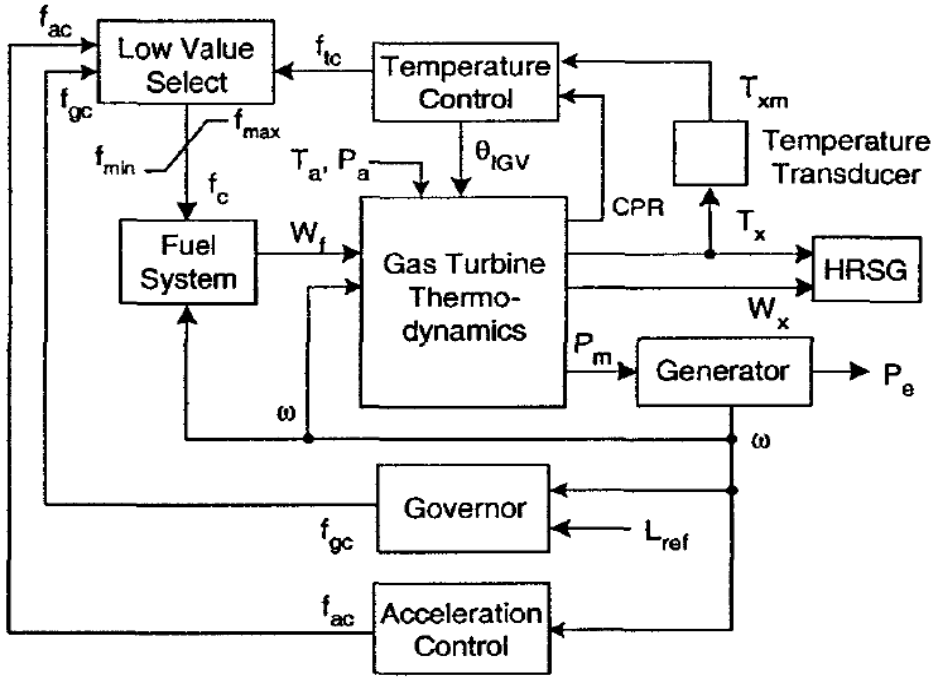


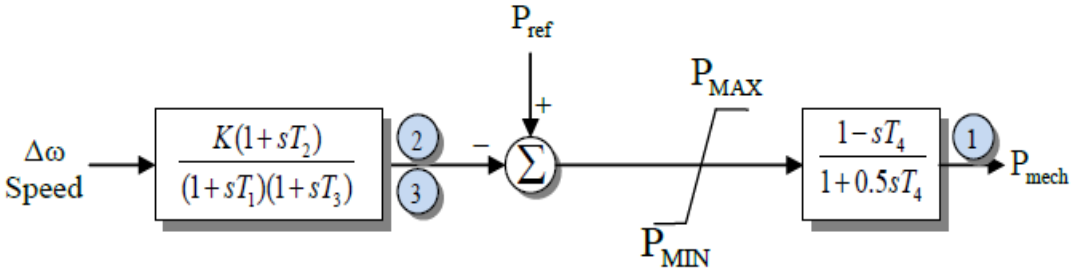
Figure 3-3: Gas turbine controls [17] (IEEE© 2001).

HRSG is the heat recovery steam generator (if it is a combined cycle unit)

Image from IEEE PES, "Dynamic Models for Turbine-Governors in Power System Studies," Jan 2013

Hydro Units

- Hydro units tend to respond slower than steam and gas units; since early transient stability studies focused on just a few seconds (first or second swing instability), detailed hydro units were not used
  - The original IEEEG2 and IEEEG3 models just gave the linear response; now considered obsolete
- Below is the IEEEG2; left side is the governor, right side is the turbine and water column



For sudden changes there is actually an inverse change in the output power

Washout Filters

- A washout filter is a high pass filter that removes the steady-state response (i.e., it "washes it out") while passing the high frequency response

$$\frac{sT_w}{1+sT_w}$$

- They are commonly used with hydro governors and (as we shall see) with power system stabilizers
- With hydro turbines ballpark values for T_w are around one or two seconds

Basic Nonlinear Hydro Turbine Model

- Basic hydro system is shown below
  - Hydro turbines work be converting the kinetic energy in the water into mechanical energy
  - assumes the water is incompressible
- At the gate assume a velocity of U, a cross-sectional penstock area of A; then the
  volume flow is A*U=Q;

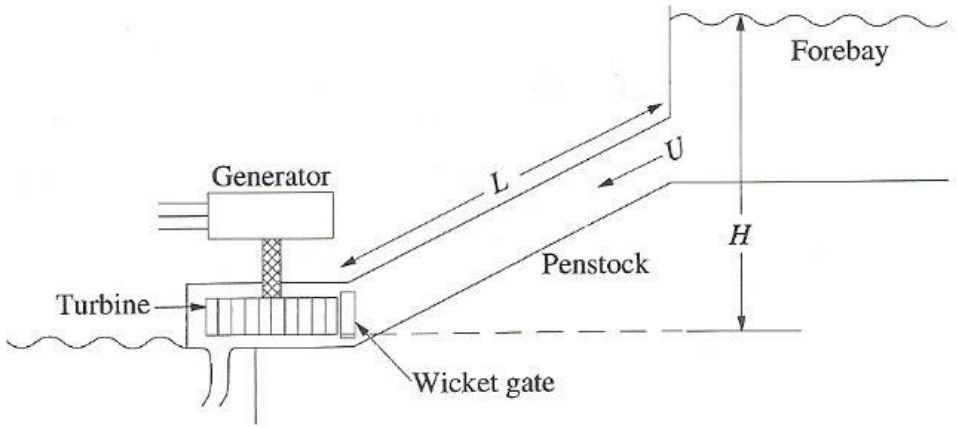


Figure 9.2 Schematic of a hydroelectric plant

Source: 9.2, Kundur, *Power System Stability and Control*, 1994

Basic Nonlinear Hydro Turbine Model

- From Newton's second law of motion the change in the flow volume Q

$$\rho L \frac{dQ}{dt} = F_{net} = A\rho g\left(H - H_{gate} - H_{\text{loss}}\right)$$

where ρ is the water density, g is the gravitational constant, H is the static head (at the drop of the reservoir) and H_{gate} is the head at the gate (which will change as the gate position is changed, H_{loss} is the head loss due to friction in the penstock, and L is the penstock length.

- As per [a] paper, this equation is normalized to

$$\frac{dq}{dt} = \frac{\left(1 - h_{gate} - h_{\text{loss}}\right)}{T_W}$$

T_W is called the water time constant, or water starting time

[a] "Hydraulic Turbine and Turbine Control Models for System Dynamic Studies," *IEEE Trans. Power Syst.*, Feb, 92

Basic Nonlinear Hydro Turbine Model

- With h_{base} the static head, q_{base} the flow when the gate is fully open, an interpretation of T_w is the time (in seconds) taken for the flow to go from stand-still to full flow if the total head is h_{base}
- If included, the head losses, h_{loss}, vary with the square of the flow
- The flow is assumed to vary as linearly with the gate position (denoted by c)

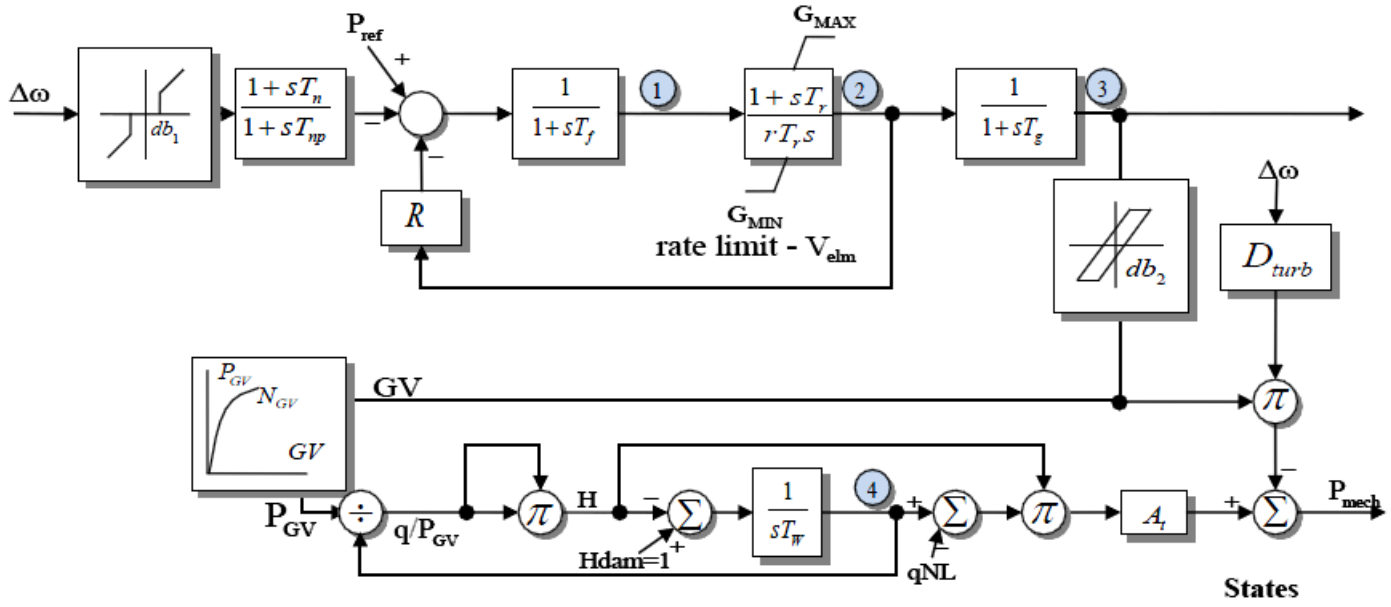
$$q = c\sqrt{h} \text{ or } h = \left(\frac{q}{c}\right)^2$$

- Power developed is proportional to flow rate times the head, with a term q_{nl} added to model the fixed turbine (no load) losses
  - The term A_t is used to change the per unit scaling to that of the electric generator

$$P_m = A_t h\left(q - q_{nl}\right)$$

Model HYGOV

- This simple model, combined with a governor, is implemented in HYGOV



H_{loss} is assumed small and not included

About 6% of WECC governors use this model; average T_W is two seconds

The gate position (GV) to gate power (P_{GV}) is sometimes represented with a nonlinear curve

PID Controllers

- Governors and exciters often use proportional-integral-derivative (PID) controllers
  - Developed in 1890's for automatic ship steering by observing the behavior of experienced helmsman
- PIDs combine
  - Proportional gain, which produces an output value that is proportional to the current error
  - Integral gain, which produces an output value that varies with the integral of the error, eventually driving the error to zero
  - Derivative gain, which acts to predict the system behavior. This can enhance system stability, but it can be quite susceptible to noise

PID Controller Characteristics

- Four key characteristics of control response are
  1) rise time, 2) overshoot,
  3) settling time and
  4) steady-state errors

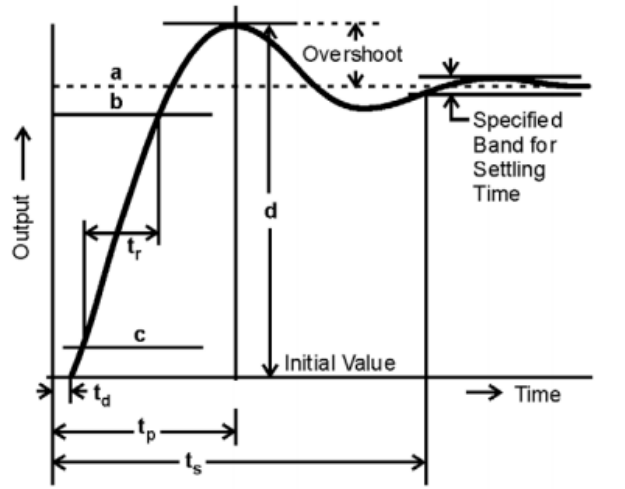


Figure F.1—Typical dynamic response of a turbine governing system to a step change

Increasing Gain	Rise Time	Overshoot	Setting Time	Steady-State Error
K_P	Decreases	Increases	Little impact	Decreases
K_I	Decreases	Increases	Increases	Zero
K_D	Little impact	Decreases	Decreases	Little Impact

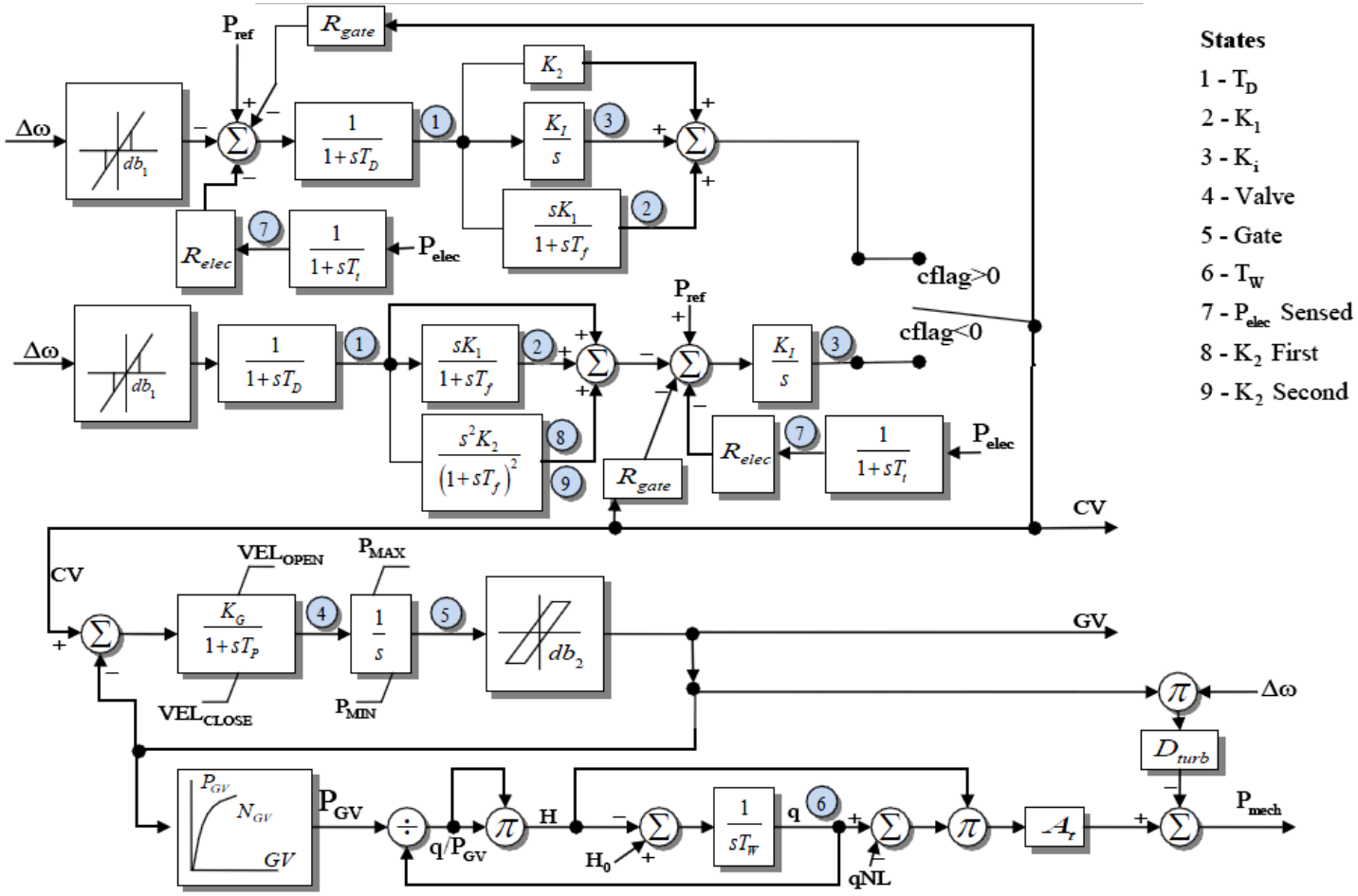
Image source: Figure F.1, IEEE Std 1207-2011

PID Example: Car Cruise Control

- Say we wish to implement cruise control on a car by controlling the throttle position
  - Assume force is proportional to throttle position
  - Error is difference between actual speed and desired speed
- With just proportional control we would never achieve the desired speed because with zero error the throttle position would be at zero
- The integral term will make sure we stay at the desired point
- With derivative control we can improve control, but as noted it can be sensitive to noise

HYG3

- The HYG3 models has a PID or a double derivative



States
1 - T_D
2 - K_1
3 - K_i
4 - Valve
5 - Gate
6 - T_W
7 - P_{elec} Sensed
8 - K_2 First
9 - K_2 Second

Looks more complicated than it is since depending on cflag only one of the upper paths is used

About 15% of current WECC governors at HYG3

Load Modeling

- The assumed model for the load can have a significant impact on simulation results, particularly the voltage response
- Constant power loads are, in general, not a good choice
- Traditionally load models have been divided into two groups
  - Static: load is a algebraic function of bus voltage and sometimes frequency
  - Dynamic: load is represented with a dynamic model, with induction motor models the most common
- The simplest load model is a static constant impedance
  - Has been widely used
  - Allowed the $\mathbf{Y}_{bus}$ to be reduced, eliminating essentially all non-generator buses
  - Presents no issues as voltage falls to zero
  - No longer commonly used

ZIP Load Model (Static, can be used in Power Flow)

- The most common static load model is the ZIP, in which the load is represented as

$$P_{Load,k} = P_{BaseLoad,k}\left(P_{z,k}\left|\bar{V}_k\right|^2 + P_{i,k}\left|\bar{V}_k\right| + P_{p,k}\right)$$

$$Q_{Load,k} = Q_{BaseLoad,k}\left(Q_{z,k}\left|\bar{V}_k\right|^2 + Q_{i,k}\left|\bar{V}_k\right| + Q_{p,k}\right)$$

Constant impedance is a special case of this model

- Some models allow more general voltage dependence

$$P_{Load,k} = P_{BaseLoad,k}\left(a_{1,k}\left|\bar{V}_k\right|^{n1} + a_{2,k}\left|\bar{V}_k\right|^{n2} + a_{3,k}\left|\bar{V}_k\right|^{n3}\right)$$

$$Q_{Load,k} = Q_{BaseLoad,k}\left(a_{4,k}\left|\bar{V}_k\right|^{n4} + a_{5,k}\left|\bar{V}_k\right|^{n5} + a_{6,k}\left|\bar{V}_k\right|^{n6}\right)$$

The voltage exponent for reactive power is often > 2

Discharge Lighting Models

- Discharge lighting (sending electricity through a gas such as fluorescent lamps) have been at major portion of the load (10-15%) though now it is getting increasingly replaced by LEDs
- Discharge lighting has been modeled for sufficiently high voltage with a real power as constant current and reactive power with a high voltage dependence
  - Linear reduction for voltage between 0.65 and 0.75 pu
  - Extinguished (i.e., no load) for voltages below

$$P_{Discharge Lighting} = P_{Base}\left(\left|\bar{V}_k\right|\right)$$

$$Q_{Discharge Lighting} = Q_{Base}\left(\left|\bar{V}_k\right|^{4.5}\right)$$

May need to change with newer electronic ballasts – e.g., reactive power increasing as the voltage drops!

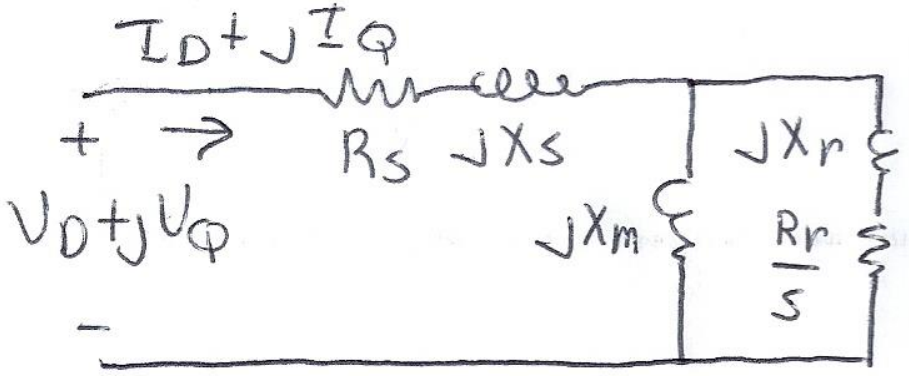
Dynamic Load Models

- Most stability models now include a combination of static models with dynamic models
- The major dynamic component of the load has been induction motors
- Induction motors operate close to synchronous speed, but not a synchronous speed; a key value is their slip, s; the slip then is a parameter in their circuit model

$$s = \frac{N_s - N_{act}}{N_s}$$

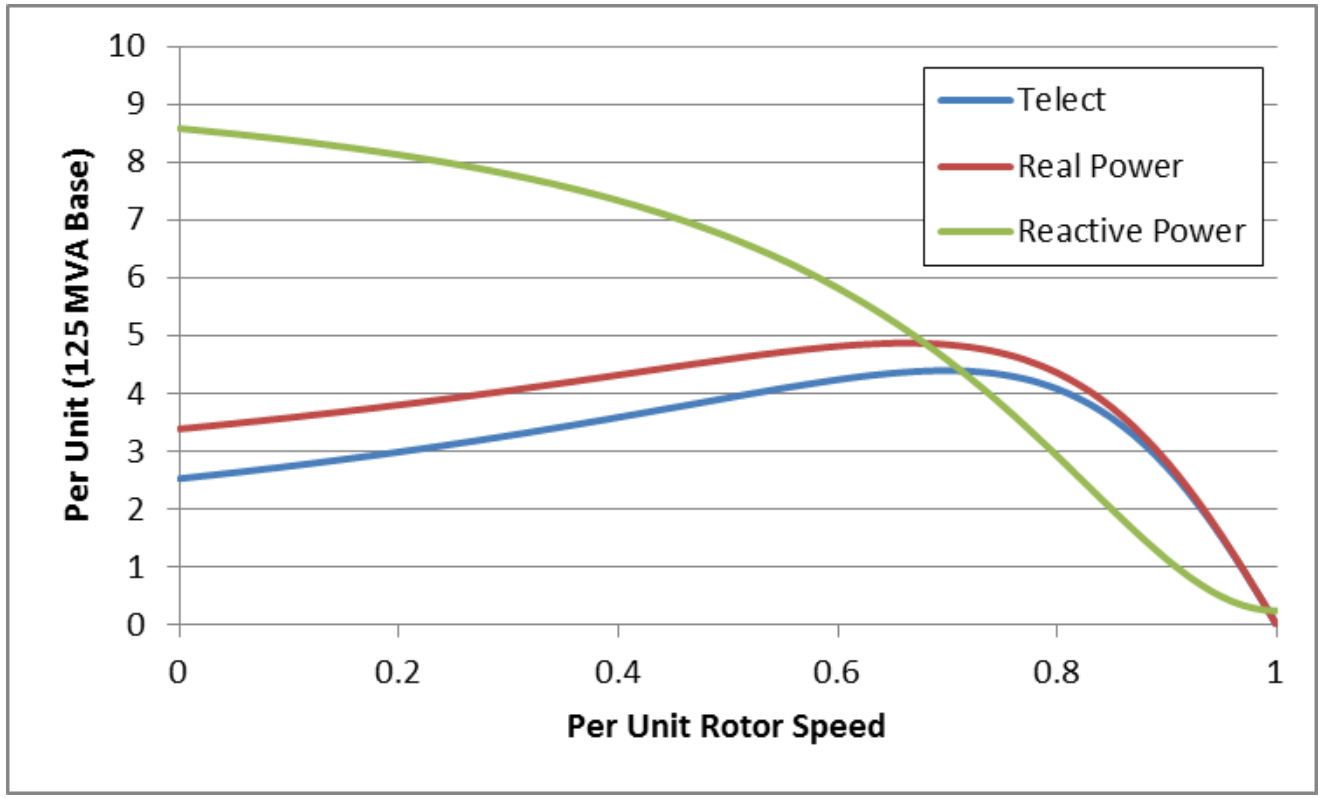
where N_s is the synchronous speed, and

N_{act} is the actual speed (in RPM)



Induction Model Torque-Speed Curves

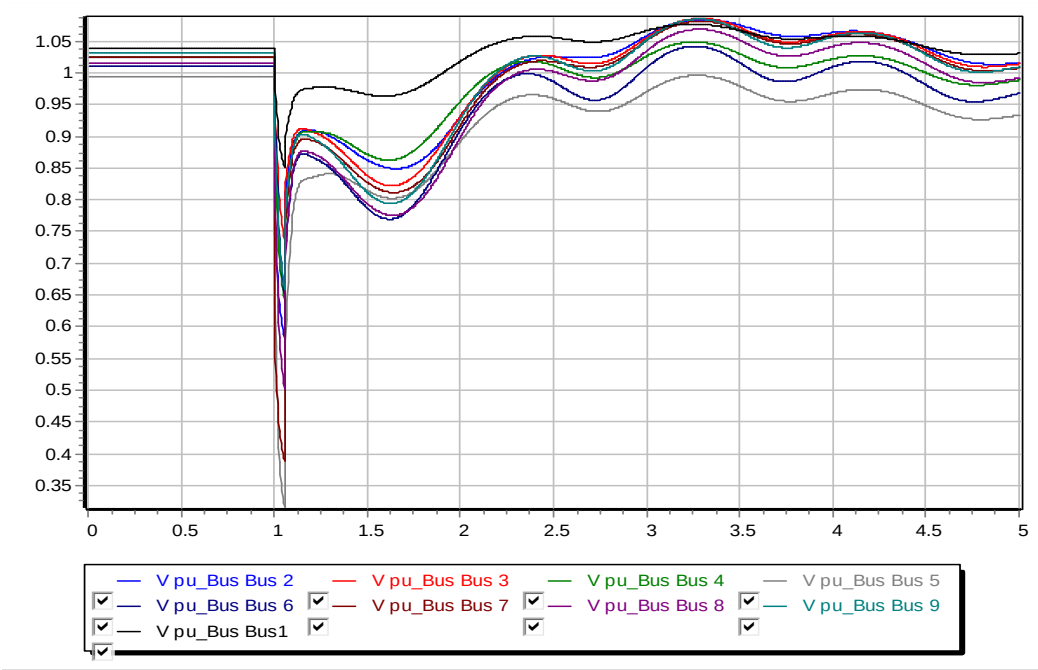
- The below graph shows the torque-speed curve for this induction machine; note the high reactive power consumption on starting (which is why the lights may dim when starting a cloth dryer!)



From the graph you can see with a 100 MW load (0.8 pu on the 125 MW base), the slip is about 0.025

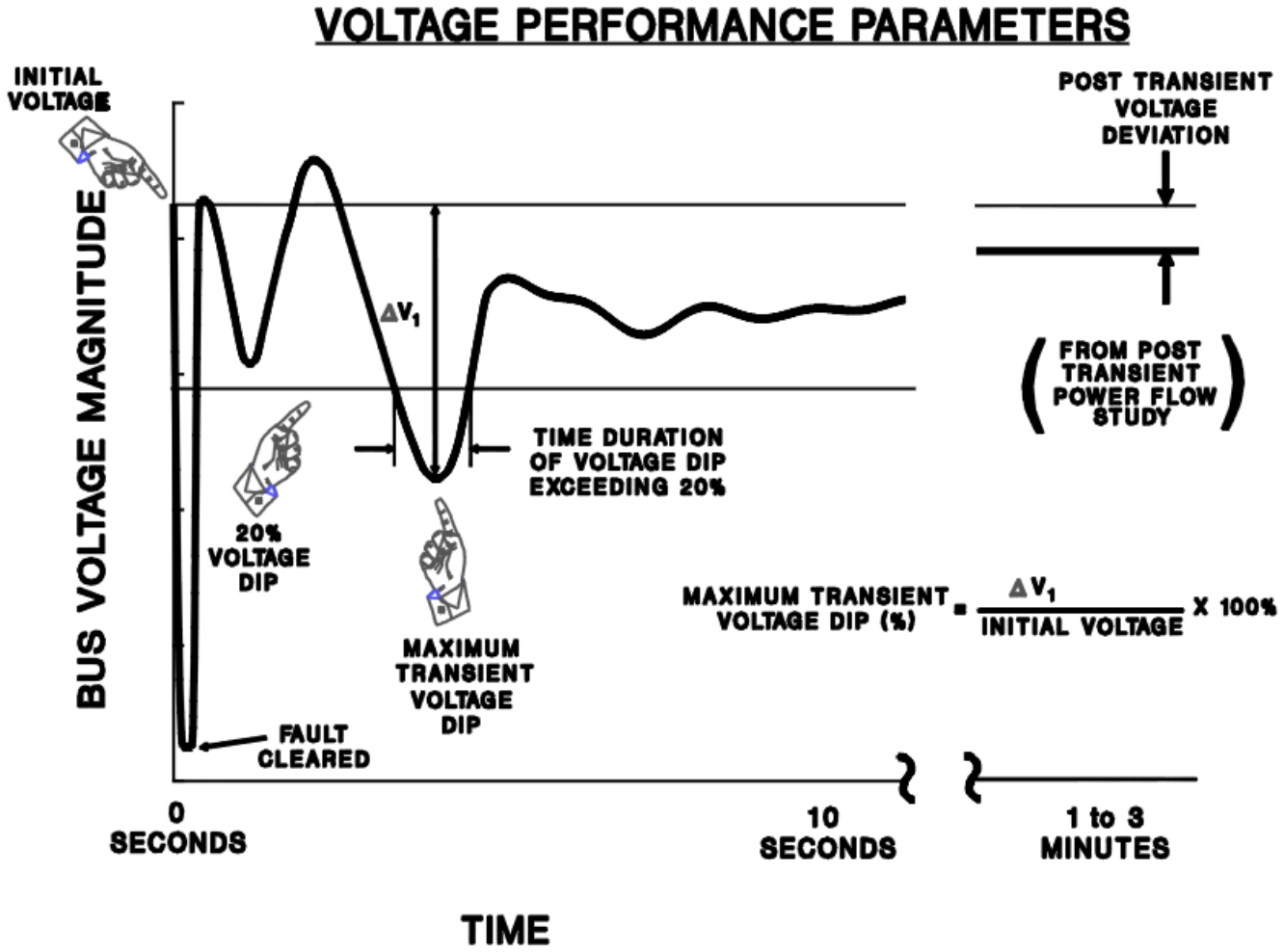
Induction Motor Stalling

- Height of the torque-speed curve varies with the square of the terminal voltage
- When the terminal voltage decreases, such as during a fault, the mechanical torque can exceed the electrical torque
  - This causes the motor to decelerate, perhaps quite quickly, with the rate proportional to its inertia
  - This deceleration causing the slip to increase, perhaps causing the motor to stall with s=1, resulting in a high reactive current draw
  - Too many stalled motors can prevent the voltage from recovering



Transient Limit Monitors

- During a transient contingency how fast the voltage recovers is a key metric



Similar performance criteria exist for frequency deviations

Image from WECC Planning and Operating Criteria