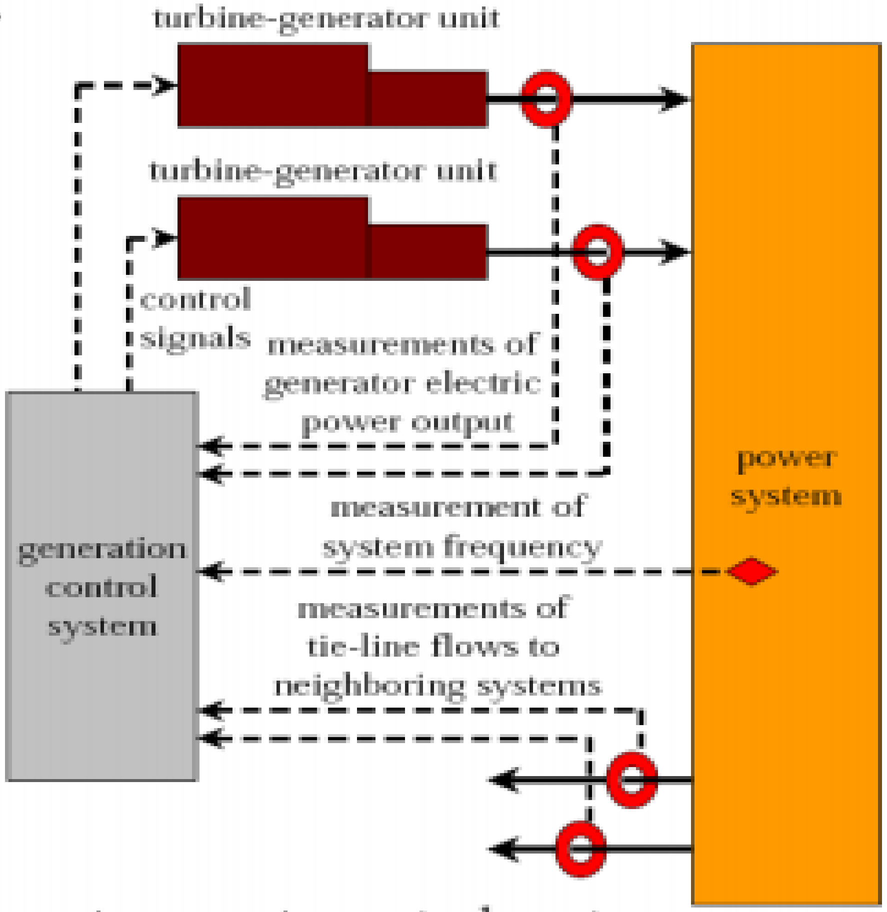
Control of Generation

Generation Control

- Optimal dispatch and scheduling of generation establishes the best operation point with respect to economics
- The operating point must be implemented via generation control
    - local generator control for each individual generator
    - energy control center for the control of a large utility and the flow of power across interconnections to other utilities
    - regional control over several utilities and the Independent Power Produces, IPP's
        - ISO - Independent System Operator
        - RTO - Regional Transmission System Operator

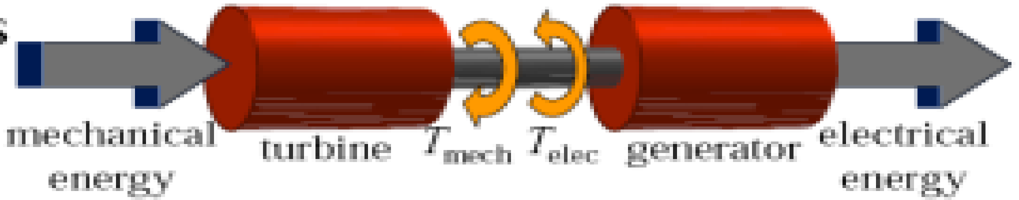
Overview of Control Problem

- Many generators supply power to the transmission system
  - consumer loads are constantly changing the power level
  - some control means needed to allocate the load changes to the generators
    - a governor on each unit maintains mechanical speed (electrical frequency)
    - supplementary control acts to allocate generation
      - influences the power output
      - control signal usually originates at a remote control center



Generator Model

- Definition of important terms



  - ω = rotational speed
  - α = rotational acceleration
  - δ = phase angle of a rotating machine
  - T_{net} = net accelerating torque in a machine
  - T_{mech} = mechanical torque exerted on the machine by the turbine
  - T_{elec} = electrical torque exerted on the machine by the generator
  - P_{net} = net accelerating power
  - P_{mech} = mechanical power input
  - P_{elec} = electrical power output
  - I = moment of inertia for the machine
  - M = angular momentum of the machine
    - all quantities, except for the phase angle, are expressed in per unit on the machine base and/or the standard system frequency base
    - steady-state and nominal values have a "0" subscript added

Generator Model

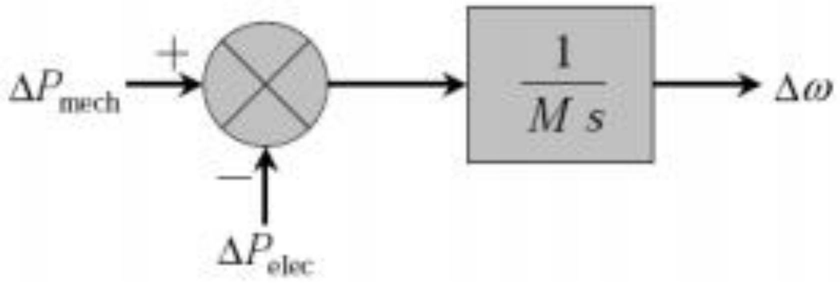
- Basic relationships
  - acceleration principle: $T_{net} = I\,\alpha$
  - momentum principle: $M = \omega\, I$
  - power equation: $P_{net} = \omega\, T_{net} = \omega(I\,\alpha) = M\,\alpha$
- Phase angle deviation
  - general shaft equation: $\omega = \omega_0 + \alpha\, t \quad \delta = \delta_0 + \omega_0\, t + \frac{1}{2}\alpha\, t^2$
  - deviation from nominal: $\frac{d}{dt}(\Delta\delta) = \Delta\omega = \alpha\, t$
  - relationship to torque: $T_{net} = T_{mech} - T_{elec} = I\,\alpha = I\,\frac{d^2}{dt^2}(\Delta\delta)$
  - deviation of power: $P_{net} = P_{mech} - P_{elec} = \omega\, T_{net} = \omega\, I\,\frac{d^2}{dt^2}(\Delta\delta)$
  - the resulting swing eq.: $P_{mech} - P_{elec} = M\,\frac{d^2}{dt^2}(\Delta\delta) = M\,\frac{d}{dt}(\Delta\omega)$

Generator Model

- Laplace transform of the dynamic power equation

$$T_{mech0} = T_{elec0}$$
$$T_{net} = T_{mech0} - T_{elec0} + \Delta T_{mech} - \Delta T_{elec} = \Delta T_{mech} - \Delta T_{elec}$$
$$P_{net} = \omega T_{net} = \omega \Delta T_{mech} - \omega \Delta T_{elec} = \Delta P_{mech} - \Delta P_{elec}$$
$$\Delta P_{mech} - \Delta P_{elec} = M \tfrac{\mathrm{d}}{\mathrm{d}t}(\Delta\omega)$$
$$\Delta P_{mech} - \Delta P_{elec} = M\, s(\Delta\omega)$$

- Block diagram model



Load Model

- Electrical loads consist of a variety of devices
  - purely resistive devices
  - power electronics
  - motor loads
    - motor loads dominate the mix of loads
- Motors exhibit a variable power-frequency characteristic
  - model of the effect of a frequency change on net load drawn

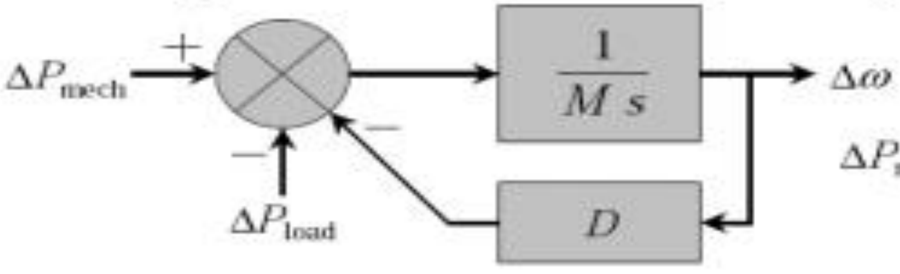
    $$\Delta P_{L(freq)} = D \cdot \Delta\omega$$

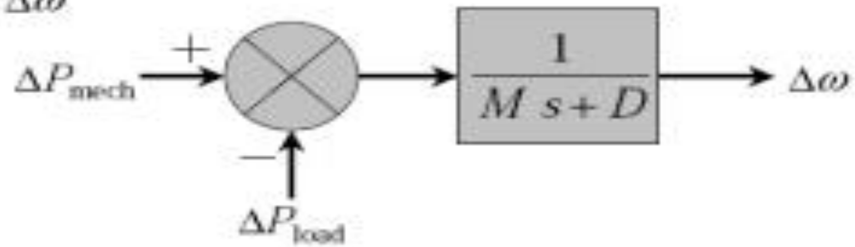
  - D is expressed as a percentage change in load per percentage change in frequency on the motor's power base
  - the value of D must be converted to the system power base for system studies

Load Model

- Block diagram modeling
  - basic frequency dependent load

  - rotating mass and load as seen by prime mover output

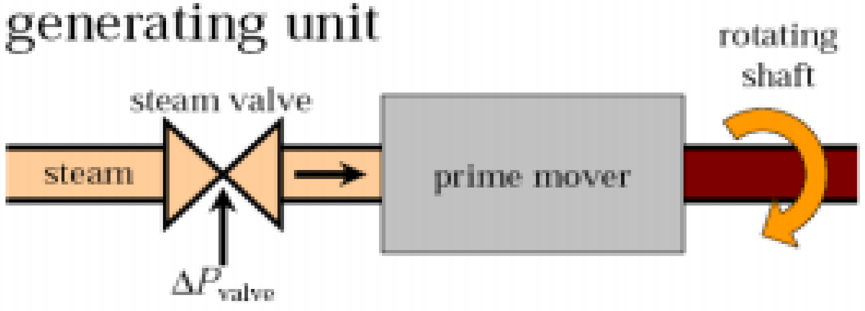


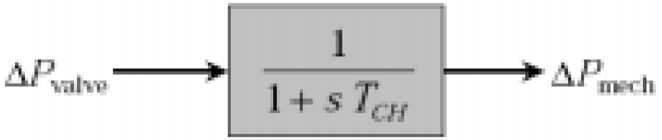


    - the net change in the electrical power load, P_{elec}, is
      $$\Delta P_{elec} = \Delta P_L + D\,\Delta\omega$$
      - where ΔP_L is the non-frequency-sensitive load change

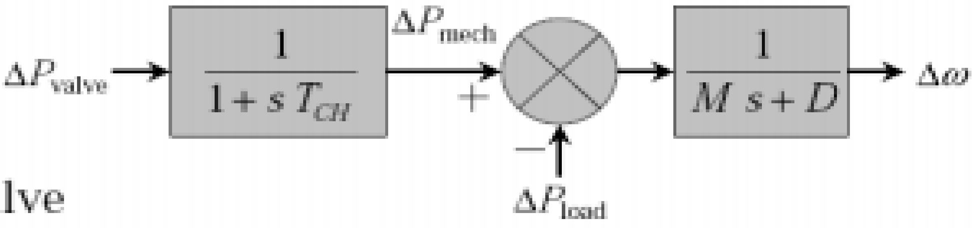
Prime-Mover Model

- The prime mover drives the generating unit
  - steam turbine
  - hydroturbine
- Modeling must account for control system characteristics
  - e.g., boiler and steam supply
- Model of the non-reheat turbine
  - relates the steam valve position to the output power
    - "charging time" time constant, T_{CH}
    - per unit change in valve position from nominal, ΔP_{valve}





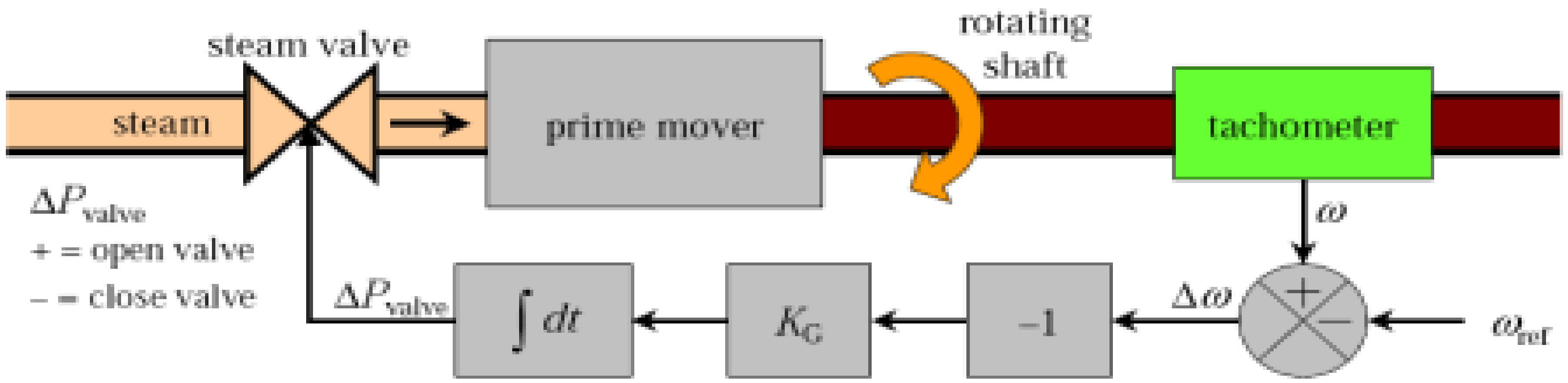
Prime-mover model



Prime-mover-generator-load model

Governor Model

- The governor compensates for changes in the shaft speed
  - changes in load will eventually lead to a change in shaft speed
  - change in shaft speed is also seen as a change in system frequency
  - simplest type of control is the isochronous governor

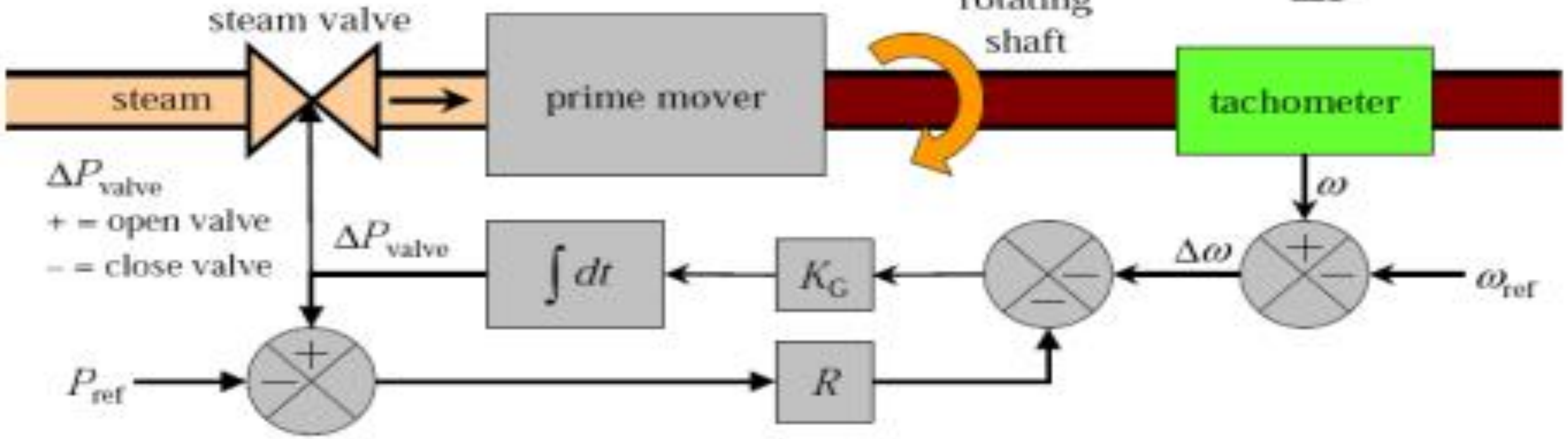


Governor Model

- The isochronous governor
  - to force frequency errors to zero requires the use of an integration of the speed error
  - the isochronous governor can not be used when two or more generators are electrically connected to the same system
    - fighting between generator governors for system frequency
    - problems with load distribution between generators
- A load reference control provides settings for both the frequency and the desired output power
  - a new input, the load reference signal, controls the desired power output
  - feedback loop contains a gain R that determines a speed-droop characteristic

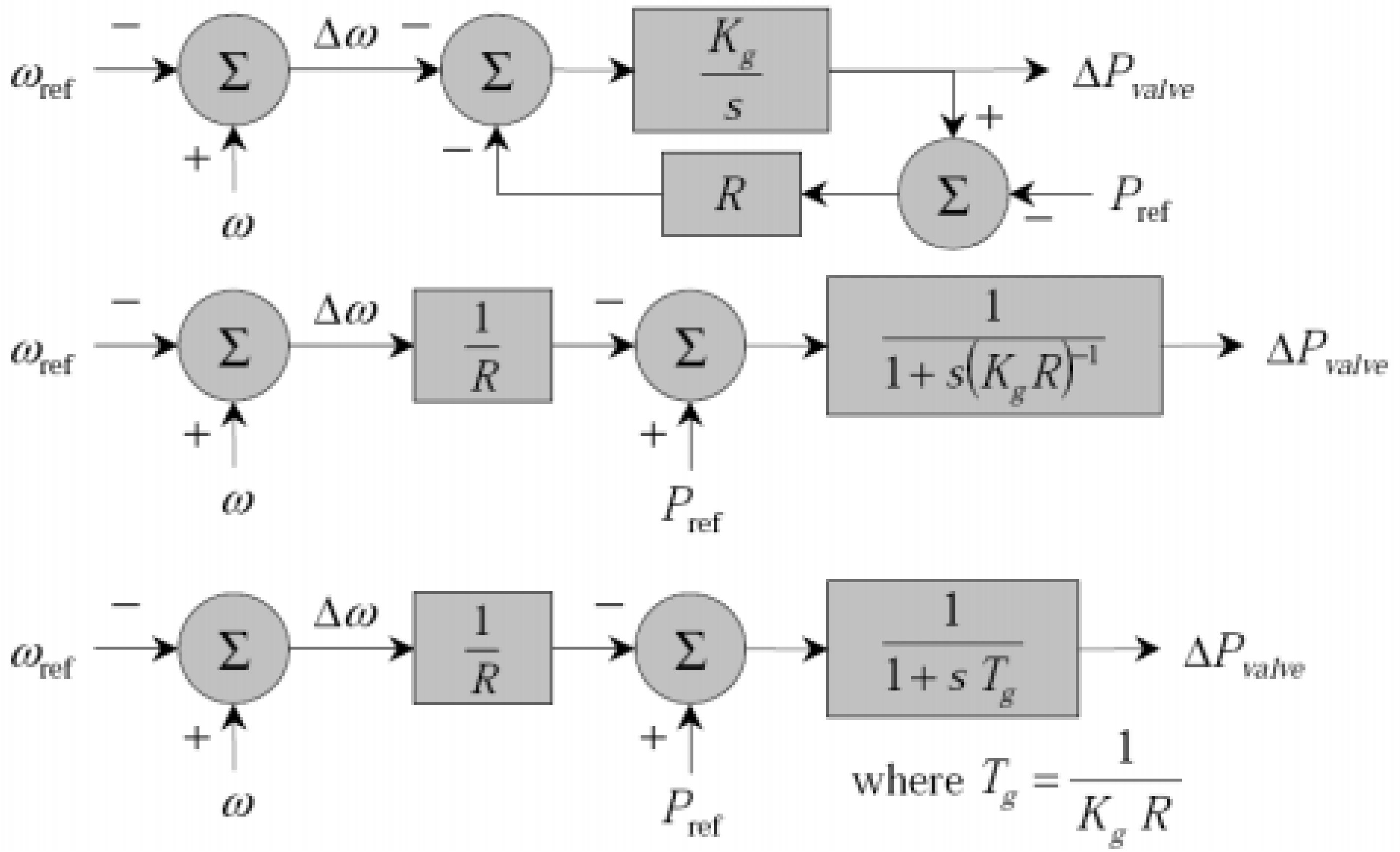
Governor Model

- Load reference control
  - the speed-droop function handles the load sharing between generators
    - there will always be a unique frequency at which the system loading will be shared among the generators
    - the gain R is equivalent to the per unit change in frequency for a 1.0 p.u. change in power: $R = \frac{\Delta\omega}{\Delta P}$ pu



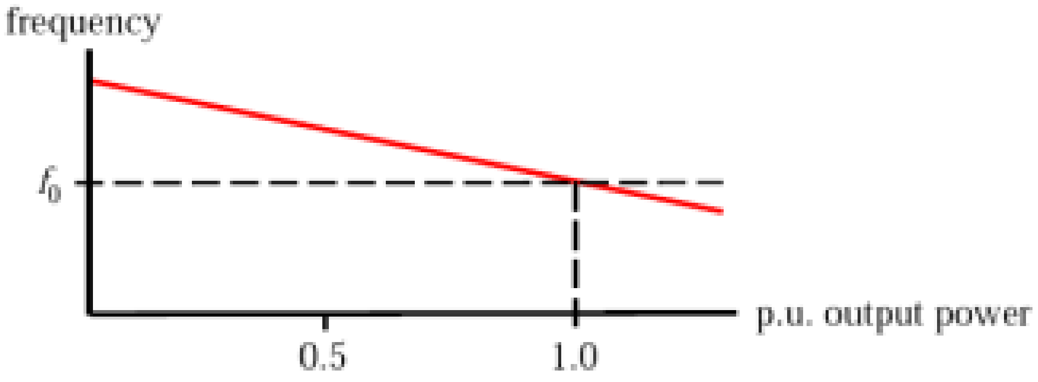
Governor Model

- Simplification of the block diagram model

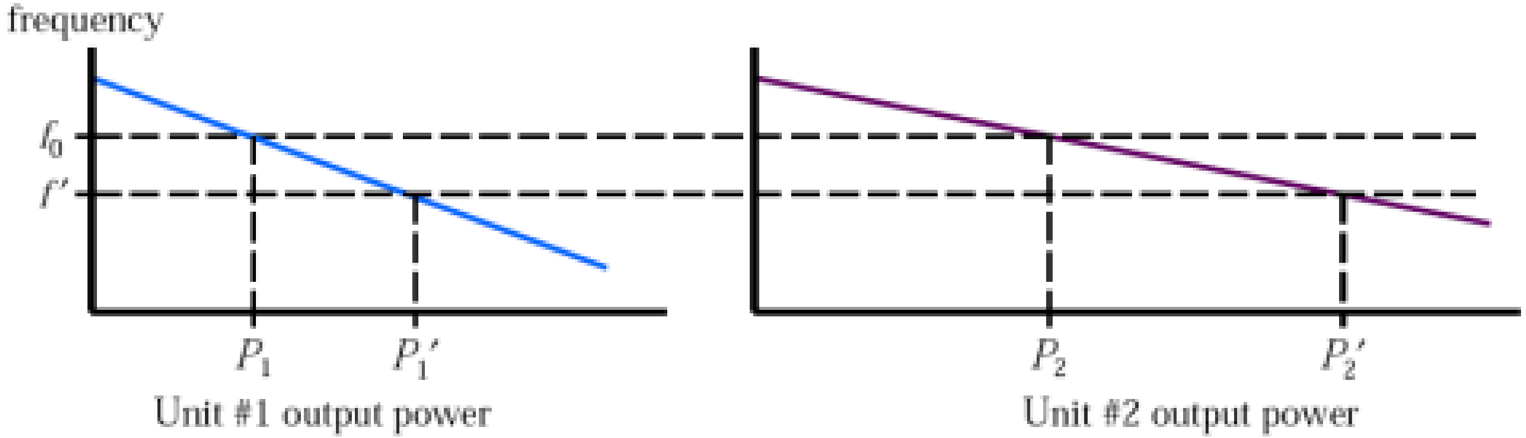


Governor Characteristics

- Speed-droop characteristic

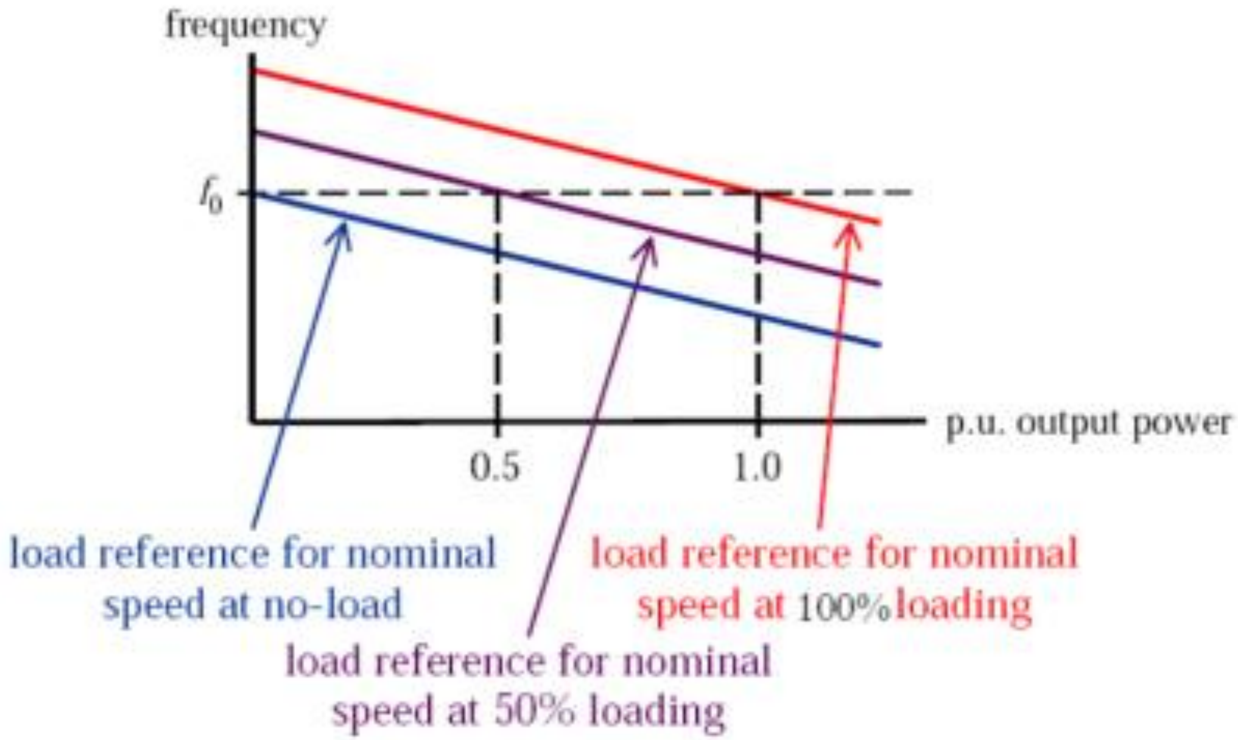


- Allocation of unit outputs with governor droop



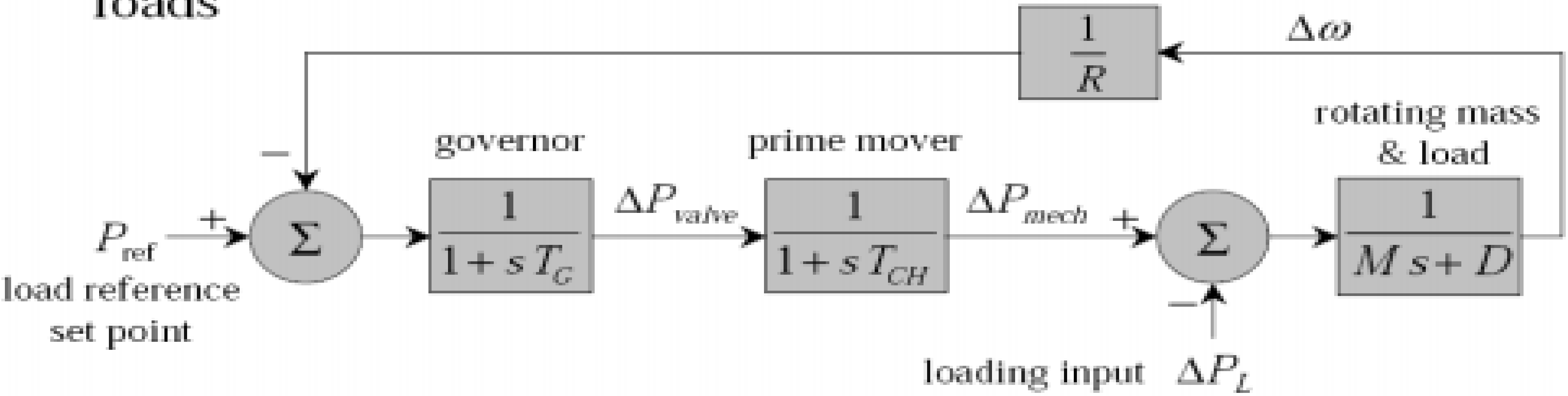
Governor Characteristics

- Speed-changer settings



Complete Generator Model

- Block diagram of governor, prime mover, rotating mass, and loads



  - transfer function of generator

$$\frac{\Delta\omega(s)}{\Delta P_L(s)} = \left[\frac{\dfrac{-1}{Ms+D}}{1+\dfrac{1}{R}\left(\dfrac{1}{1+sT_G}\right)\left(\dfrac{1}{1+sT_{CH}}\right)\left(\dfrac{1}{Ms+D}\right)} \right]$$

Complete Generator Model

- Steady state behaviors
  - final value of the transfer function
    - using Laplace method

$$\Delta\omega\big|_{t=\infty} = \lim_{s\to 0}\left[s\,\Delta\omega(s)\right] = \Delta P_L\left[\frac{\frac{-1}{D}}{1+\left(\frac{1}{R}\right)\left(\frac{1}{D}\right)}\right] = \frac{-\Delta P_L}{R^{-1}+D}$$

  - for several generators connected within the system

$$\Delta\omega = \frac{-\Delta P_L}{1/R_{G1} + 1/R_{G2} + \cdots + D}$$

Tie-line Model

- The power flow across a tie-line can be modeled using a linear load flow approach
  - steady-state or nominal flow quantity: $P_{\text{tie flow}} = \frac{1}{X_{tie}}(\delta_1 - \delta_2)$
  - deviation from the nominal tie-line flow

$$P_{\text{tie flow}} + \Delta P_{\text{tie flow}} = \frac{1}{X_{tie}}[(\delta_1 + \Delta\delta_1) - (\delta_2 + \Delta\delta_2)] = \frac{1}{X_{tie}}(\delta_1 - \delta_2 + (\Delta\delta_1 - \Delta\delta_2))$$

$$\Delta P_{\text{tie flow}} = \frac{1}{X_{tie}}(\Delta\delta_1 - \Delta\delta_2)$$

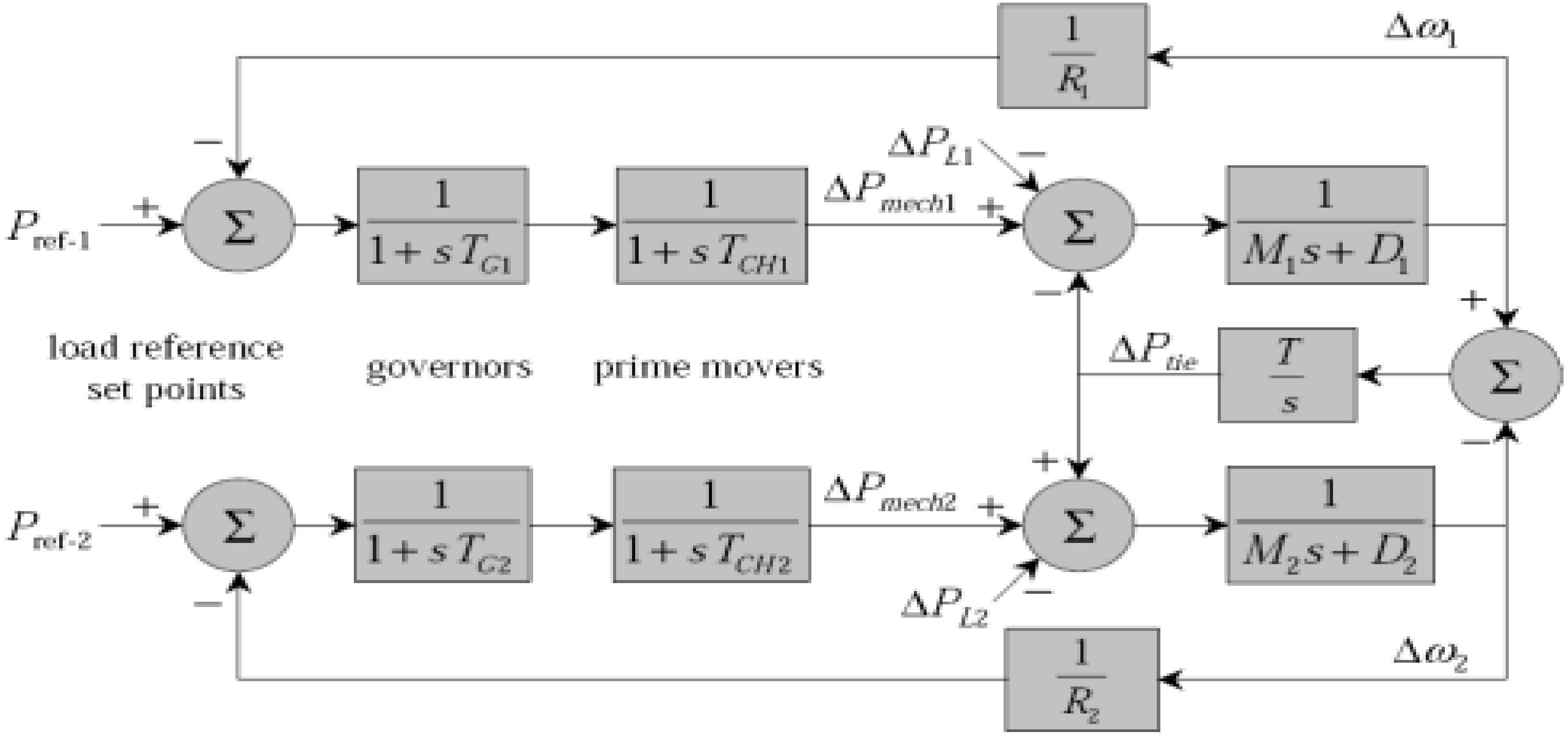
  - where $\Delta\delta$ must be in radians for ΔP_{tie} to be in per unit
- using the relationship for speed and $\Delta\delta$: $\Delta\delta = \frac{\omega_0}{s} \cdot \Delta\omega$

then $\Delta P_{\text{tie flow}} = \frac{\omega_0}{s} \frac{(\Delta\omega_1 - \Delta\omega_2)}{X_{tie}} = \frac{T}{s}(\Delta\omega_1 - \Delta\omega_2)$

  - where $T = 377 / X_{\text{tie}}$ for a 60-Hz system

Tie-line Model

- Simplified control for two interconnected areas



Tie-line Model

- Consider two areas each with a generator
  - the two areas are connected with a single transmission line
  - the line flow appears as a load in one area and an equal but negative load in the other area
  - the flow is dictated by the relative phase angle across the line, which is determined by the relative speeds deviations
  - let there be a load change ΔP_{L1} in area 1
  - to analyze the steady-state frequency deviation, the tie-flow deviation and generator outputs must be examined

Tie-line Model

- after the transients have decayed, the frequency will be constant and equal to the same value in both areas

$$\Delta\omega_1 = \Delta\omega_2 = \Delta\omega \quad \rightarrow \quad \frac{\mathrm{d}(\Delta\omega_1)}{\mathrm{d}t} = \frac{\mathrm{d}(\Delta\omega_2)}{\mathrm{d}t} = 0$$

$$\Delta P_{\text{mech}-1} - \Delta P_{\text{tie}} - \Delta P_{L1} = \Delta\omega \cdot D_1 \qquad \Delta P_{\text{mech}-1} = \frac{-\Delta\omega}{R_1}$$

$$\Delta P_{\text{mech}-2} + \Delta P_{\text{tie}} = \Delta\omega \cdot D_2 \qquad \Delta P_{\text{mech}-2} = \frac{-\Delta\omega}{R_2}$$

- applying substitutions yields

$$-\Delta P_{\text{tie}} - \Delta P_{L1} = \Delta\omega\left(D_1 + \frac{1}{R_1}\right)$$

$$+\Delta P_{\text{tie}} = \Delta\omega\left(D_2 + \frac{1}{R_2}\right)$$

Tie-line Model

- additional simplification yields

$$\Delta\omega = \frac{-\Delta P_{L1}}{\frac{1}{R_1} + \frac{1}{R_2} + D_1 + D_2}$$

$$\Delta P_{\text{tie}} = \frac{-\Delta P_{L1}\left(D_2 + \frac{1}{R_2}\right)}{\frac{1}{R_1} + \frac{1}{R_2} + D_1 + D_2}$$

- Notes
  - the new tie flow is determined by the net change in load and generation in each area, but not influenced by the tie stiffness
  - the tie stiffness determines the phase angle across the tie

Tie-line Model

- Example
  - consider two areas, each with a generator, motor loads, and a single tie-line connecting the two areas.
    - area 1: $R_1 = 0.01$ pu, $D_1 = 0.8$ pu, Base MVA = 500
    - area 2: $R_2 = 0.02$ pu, $D_2 = 1.0$ pu, Base MVA = 500
  - a load change of 100 MW (0.2 pu) occurs in area 1
  - find the new steady-state frequency and net tie flow change

$$\Delta\omega = \frac{-\Delta P_{L1}}{\frac{1}{R_1} + \frac{1}{R_2} + D_1 + D_2} = \frac{-0.2}{\frac{1}{0.01} + \frac{1}{0.02} + 0.8 + 1.0} = -0.001318$$

$$f_{new} = 60 + (-0.001318)(60) = 59.92 \quad \text{Hz}$$

$$\Delta P_{tie} = \Delta\omega\left(\frac{1}{R_2} + D_2\right) = (-0.001318)\left(\frac{1}{0.02} + 1\right) = 0.06719 \text{ pu} = 33.6 \text{ MW}$$

Tie-line Model

- Example
  - change in the prime movers

$$\Delta P_{mech1} = -\Delta\omega/R_1 = 0.001318/0.01 = 0.1318 \quad (65.88\text{ MW})$$

$$\Delta P_{mech2} = -\Delta\omega/R_2 = 0.001318/0.02 = 0.0659 \quad (32.94\text{ MW})$$

  - change in the motor loads

$$\Delta P_{L1(motor)} = \Delta\omega\, D_1 = -0.001318\cdot 0.8 = -0.001054 \quad (-0.527\text{ MW})$$

$$\Delta P_{L2(motor)} = \Delta\omega\, D_2 = -0.001318\cdot 1.0 = -0.001318 \quad (-0.659\text{ MW})$$

  - change in tie flow

$$\Delta P_{tie} = \Delta P_{mech2} - \Delta P_{L2(motor)} = 0.0672 \quad (33.6\text{ MW})$$

  - change in apparent loading

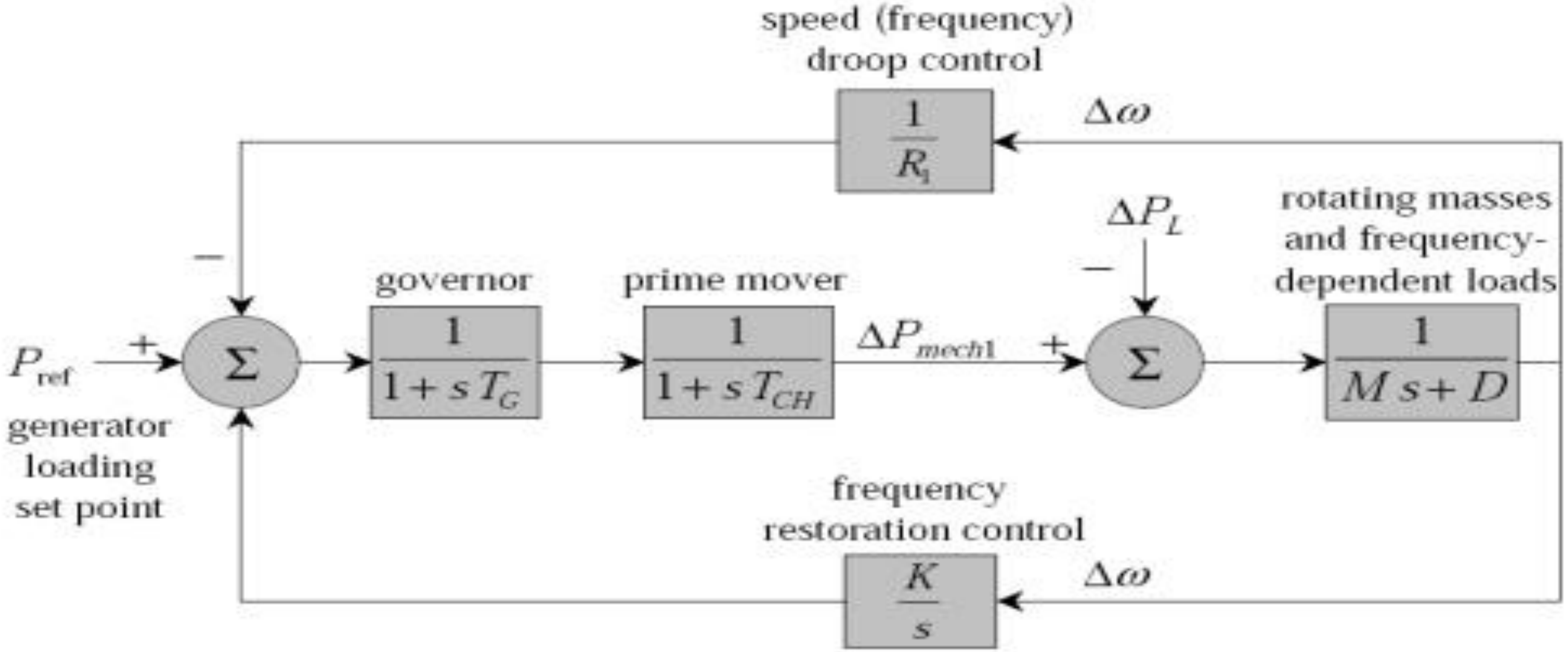
$$\Delta P_{L1} = \Delta P_{mech1} - \Delta P_{L1(motor)} + \Delta P_{tie} = 0.200 \quad (100\text{ MW})$$

Generation Control

- Automatic Generation Control (AGC) is a control system that has three major objectives
  - hold the system frequency at or very close to a specified nominal value (e.g., 60 Hz)
  - maintain the correct value of interchange power between control areas
    - enforce contracts for shipping or receiving power along the tie-lines to neighboring utilities
  - maintain each generating unit's operating point at the most economic value

Generation Control

- Supplementary control action



Generation Control

- Tie-line control
  - two utilities will interconnect their systems for several reasons
    - buy and sell power with neighboring systems whose operating costs make the transactions profitable
    - improvement to overall reliability for events like the sudden loss of a generating unit
    - provide a common frequency reference for frequency restoration
  - define tie flows and tie flow changes
    - total actual net interchange: $P_{\text{net int}}$
      - $+$ for power leaving the system; $-$ for power entering the system
    - scheduled or desired value of interchange: $P_{\text{net int sched}}$
    - change in tie flow: $\Delta P_{\text{net int}} = P_{\text{net int}} - P_{\text{net int sched}}$

Generation Control

- Tie-line control
  - interconnections present a challenging control problem
    - consider a two-area system
      - both areas have equal load and generator characteristics ($R_1 = R_2$, $D_1 = D_2$)
      - assume that area 1 sends 100 MW to area 2 under an interchange agreement between the system operators of the two areas
      - let area 2 experience a sudden load increase of 30 MW, then both areas see a 15 MW increase in generation (because $R_1 = R_2$) and the tie flow increases from 100 to 115 MW
        - the 30 MW load increase is satisfied by a 15 MW increase in generation #2 plus a 15 MW increase in tie flow into area 2
      - this is fine, except that area 1 contracted to sell only 100 MW
        - generation costs have increased without anyone to bill
    - a control scheme is needed to hold the system to the contract

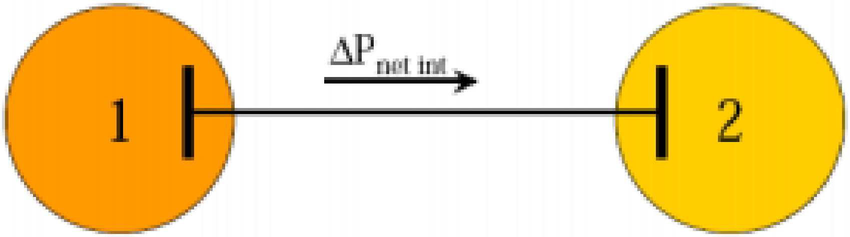
Generation Control

- Tie-line control
  - such a control system must use two pieces of information
    - the system frequency
    - the net power flow across the tie line
  - a few possible network conditions include
    - if the frequency decreases and net interchange power leaving the system increases, a load increase has occurred outside the area
    - if the frequency decreases and net interchange power leaving the system decreases, a load increase has occurred inside the area
  - define a control area
    - part of an interconnected system within which the load and generation will be controlled
      - all tie-lines that cross a control area boundary must be metered

Generation Control

- Tie-line control
  - control scheme actions

$\Delta\omega$	$\Delta P_{\text{net int}}$	ΔP_{L1}	ΔP_{L2}	Resulting control action
–	–	+	0	increase P_{gen} in area 1
+	+	–	0	decrease P_{gen} in area 1
–	+	0	+	increase P_{gen} in area 2
+	–	0	–	decrease P_{gen} in area 2



ΔP_{L1} = Load change in area 1
ΔP_{L2} = Load change in area 2

Generation Control

- Tie-line control
  - for the first row of the control response table, it is required that

$$\Delta P_{gen1} = \Delta P_{L1}$$
$$\Delta P_{gen2} = 0$$

    - the required change is known as the *area control error* (ACE)
    - the equations for the ACE for each area

$$ACE_1 = -\Delta P_{\text{net int}1} - B_1\,\Delta\omega$$
$$ACE_2 = -\Delta P_{\text{net int}2} - B_2\,\Delta\omega$$

    - B_1 and B_2 are the frequency bias factors, and are set accordingly

$$B_1 = \frac{1}{R_1} + D_1$$
$$B_2 = \frac{1}{R_2} + D_2$$

Generation Control

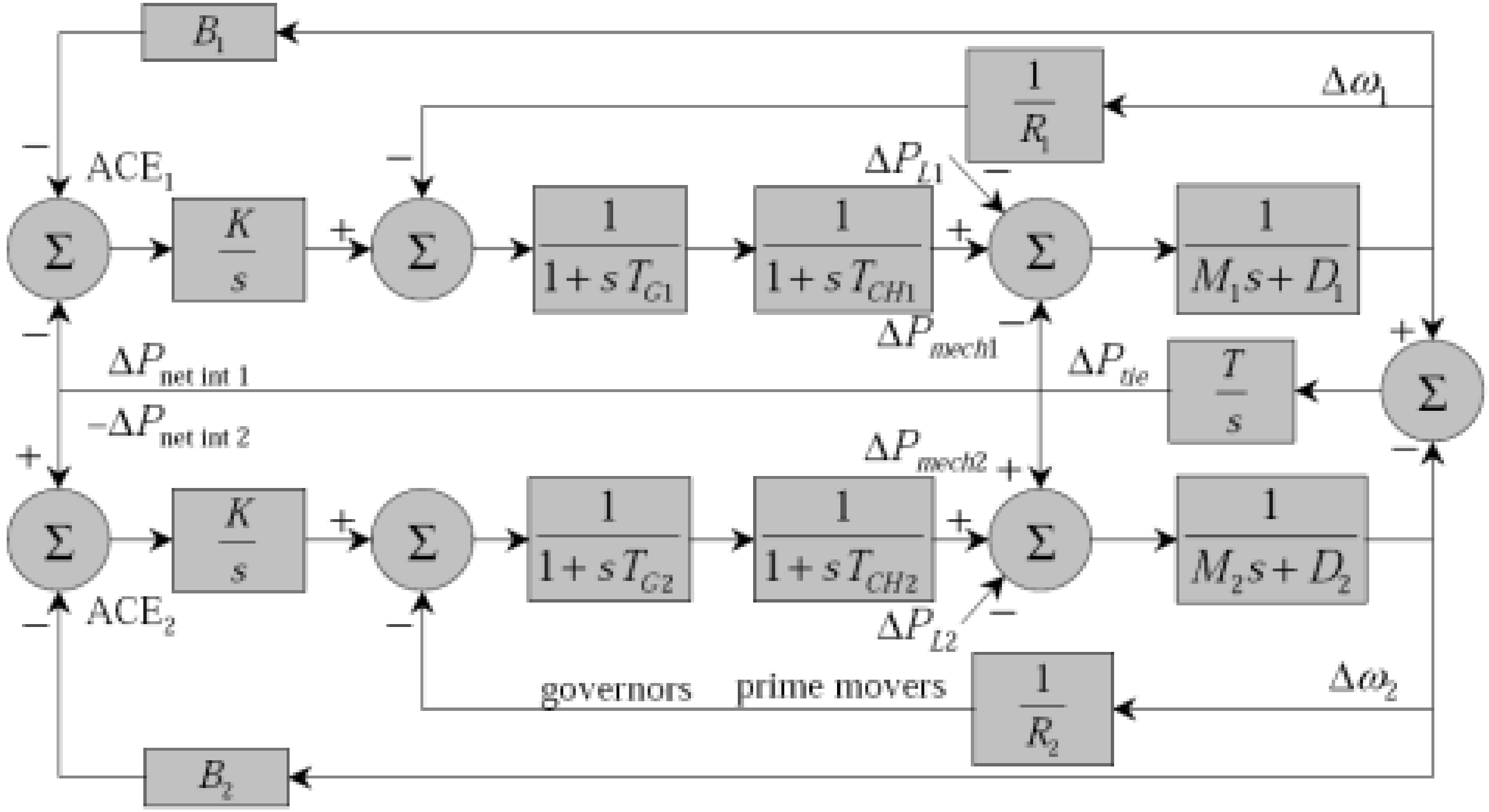
- Tie-line control
  - combining the ACE functions with the tie flow equations results in

$$ACE_1 = \frac{\Delta P_{L1}\left(\frac{1}{R_2} + D_2\right)}{\frac{1}{R_1} + \frac{1}{R_2} + D_1 + D_2} - \left(\frac{1}{R_1} + D_1\right)\frac{-\Delta P_{L1}}{\frac{1}{R_1} + \frac{1}{R_2} + D_1 + D_2} = \Delta P_{L1}$$

$$ACE_2 = \frac{\Delta P_{L1}\left(\frac{1}{R_2} + D_2\right)}{\frac{1}{R_1} + \frac{1}{R_2} + D_1 + D_2} - \left(\frac{1}{R_2} + D_2\right)\frac{-\Delta P_{L1}}{\frac{1}{R_1} + \frac{1}{R_2} + D_1 + D_2} = 0$$

Generation Control

- Tie-line bias supplementary control for two areas



Generator Allocation

- A typical control area contains many generators
  - the individual outputs must be set according to economics
    - the solution of the economic dispatch must be coupled to the generation control system
    - the input consist of the total generation required for the area
      - in order to satisfy the load demand and maintain contractual power flows across the tie lines
    - the output is the power distribution across the outputs of all the generators within the control area
  - continuously varying system load demand
    - a particular total generation value will not exist for a very long time

Generator Allocation

- Economic generator control
  - it is impossible to simply specify a total generation, calculate the economic dispatch schedule, and give the control system the output schedule for each generator
    - unless such a calculation can be made very quickly
    - for digital control system it is desirable to perform the economic dispatch calculation at intervals of 1 to 15 minutes
  - independent of the calculation schedule
    - the allocation of generation must be made instantly whenever the required area total generation changes
    - the allocation control of generation must run continuously
    - a rule must be provided to indicate the generation allocation for values of total generation other than that used in the economic dispatch

Generator Allocation

- The allocation of individual generators over a range of total generation values
  - accomplished using *base points* and *participation factors*
    - for period k, the economic dispatch sets the base-point generation values for the total generation value measured at the start of the period
    - the base-point generation for the ith unit, $P_{i\,\text{base}}$ is the most economic output for the particular total generation value
    - the participation factor, pf_i, sets the rate of change of the ith unit's power output with respect to a change in total generation
    - the base points and participation factors are used as follows

$$P_{i\,\text{scheduled}}(t) = P_{i\,\text{base}}(k) + pf_i \cdot \Delta P_{\text{total}}(t)$$

$$\Delta P_{\text{total}}(t) = P_{\text{actual}}(t) - \sum_{i \in \text{all gen}} P_{i\,\text{base}}(k)$$

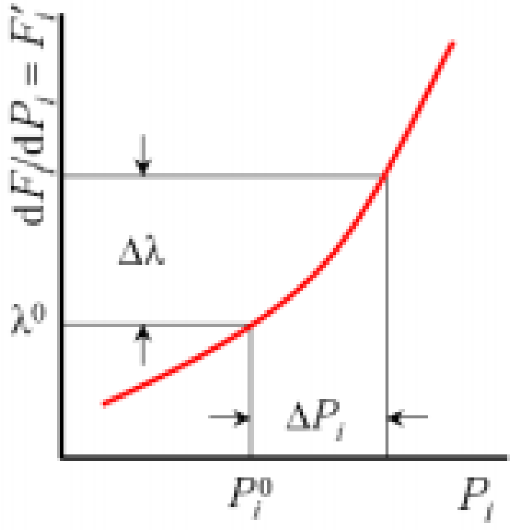
Generator Allocation

- Base points and participation factors
  - participation factors are determined from a generator's cost function
    - assume that both the first and second derivatives exist for the cost function
    - the change in the system's incremental cost as a function of the change in power output on the *i*th generator

$$\Delta\lambda_i = \Delta\lambda_{\text{system}} \cong F_i''(P_i^0)\cdot \Delta P_i$$

    - the change in system incremental cost equaling the unit's incremental cost is true for all generating units

$$\frac{\Delta\lambda}{F_1''} = \Delta P_1,\quad \frac{\Delta\lambda}{F_2''} = \Delta P_2,\ \cdots \frac{\Delta\lambda}{F_N''} = \Delta P_N$$



Relationship of $\Delta\lambda$ and ΔP_i

Generator Allocation

- Base points and participation factors
  - the total change in generation must equal the change in the total system demand, and is the sum of all the individual unit changes

$$\Delta P_D = \Delta P_1 + \Delta P_2 + \cdots + \Delta P_N$$
$$= \Delta\lambda \cdot \sum_{i \in \text{all gen}} \frac{1}{F_i''}$$

  - the participation factor for each generating unit is then found as

$$pf_i = \frac{\Delta P_i}{\Delta P_D} = \frac{\frac{1}{F_i''}}{\sum_{i \in \text{all gen}} \frac{1}{F_i''}}$$

Generator Allocation

- Example
  - Consider a three generator system
    - the cost functions for the three generators

$$F_1(P_1) = 561 + 7.92P_1 + 0.001562P_1^2$$
$$F_2(P_2) = 310 + 7.85P_2 + 0.00194P_2^2$$
$$F_3(P_3) = 78 + 7.97P_3 + 0.00482P_3^2$$

    - an economic dispatch has been conducted for a total load demand of 850 MW
      - the system's incremental cost is \$ 9.148 / MWh
      - the dispatch is: P_1 = 393.2 MW, P_2 = 334.6 MW, & P_3 = 122.2 MW
    - calculate the participation factors for the current dispatch, and calculate the dispatch for a new total load of 900 MW

Generator Allocation

- Example
  - participation factors

$$pf_1 = \frac{\Delta P_1}{\Delta P_D} = \frac{(0.003124)^{-1}}{(0.003124)^{-1} + (0.00388)^{-1} + (0.00964)^{-1}} = \frac{320.10}{681.57} = 0.47$$

$$pf_2 = \frac{\Delta P_2}{\Delta P_D} = \frac{(0.00388)^{-1}}{681.57} = 0.38$$

$$pf_3 = \frac{\Delta P_3}{\Delta P_D} = \frac{(0.00964)^{-1}}{681.57} = 0.15$$

  - new dispatch

$$\Delta P_D = 900 - 850 = 50$$

$$P_1 = P_{1\,\text{base}} + pf_1 \cdot \Delta P_D = 393.2 + (0.47)(50) = 416.7$$

$$P_2 = 334.6 + (0.38)(50) = 353.6$$

$$P_3 = 122.2 + (0.15)(50) = 129.7$$

Generator Control

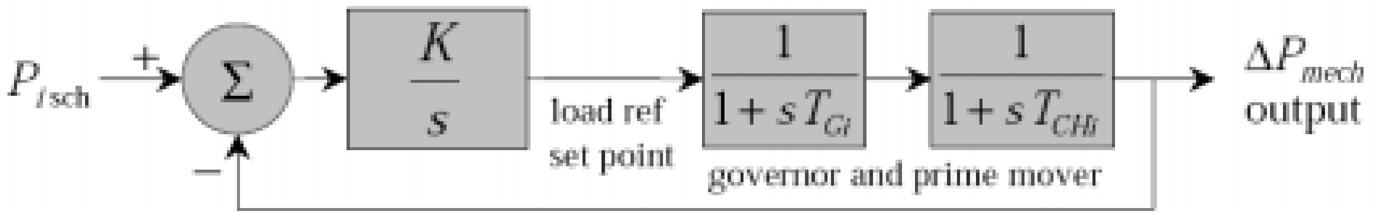
- Automatic generator control implementation
  - the AGC schemes are usually centrally located at a control center
    - system measurements, taken at the major substations, other information and data are telemetered to the control center
      - unit megawatt power output for each committed generating unit
      - megawatt power flow over each tie line to neighboring systems
      - system frequency
    - control actions are determined in a digital computer
    - control signals are transmitted to the generation units at remote generation stations over the same communication channels
      - raise / lower pulse signals change a generating unit's load reference point up or down

Generator Control

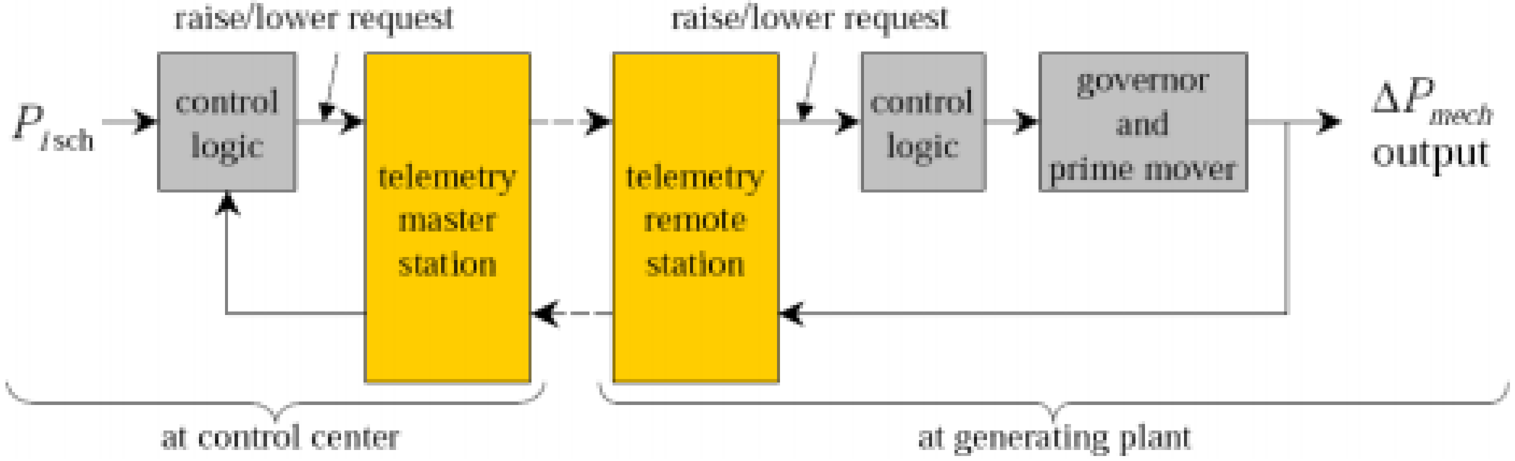
- Automatic generator control implementation
  - the basic reset control loop for a generating unit consists of an integrator with gain K
    - the integrator insures that the steady-state control error goes to zero
  - the scheduled power value is the control input
    - a function of the system frequency deviation, net interchange error, and the unit's deviation from its scheduled economic output

Generator Control

- Automatic generator control implementation
  - the basic generating unit's power output control loop

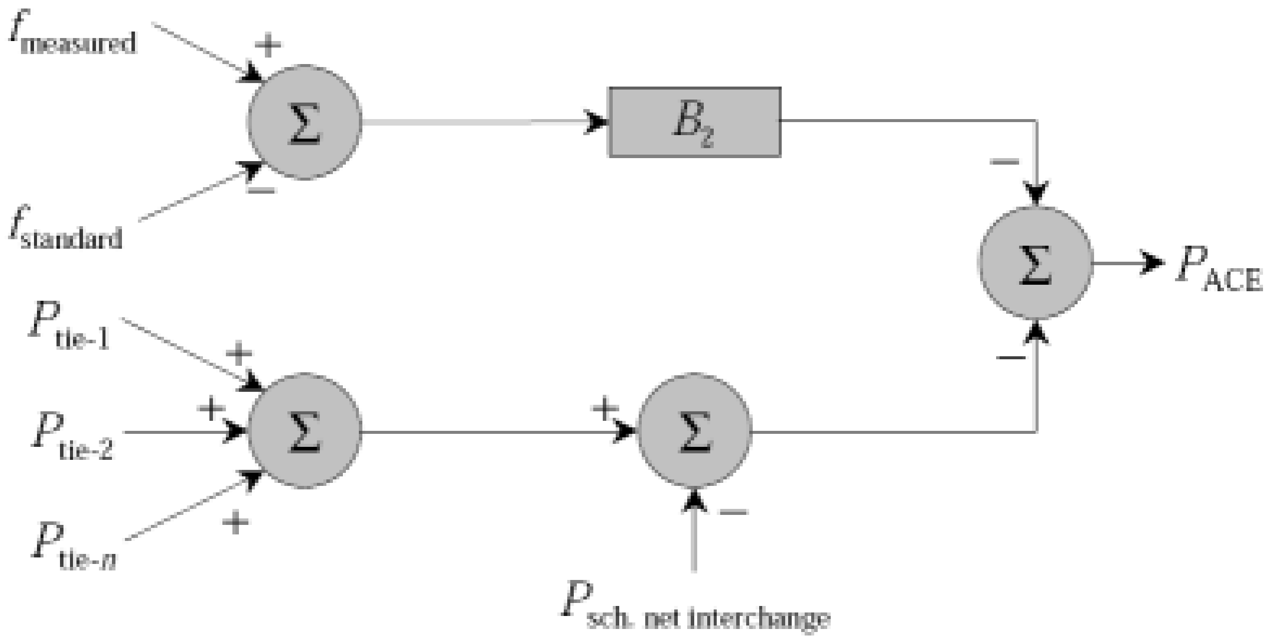


  - implementation via telemetry



Generator Control

- The AGC calculation
  - the input to the AGC combines the inputs of the various tie-flows errors with the frequency deviation
    - the resultang is the area control error

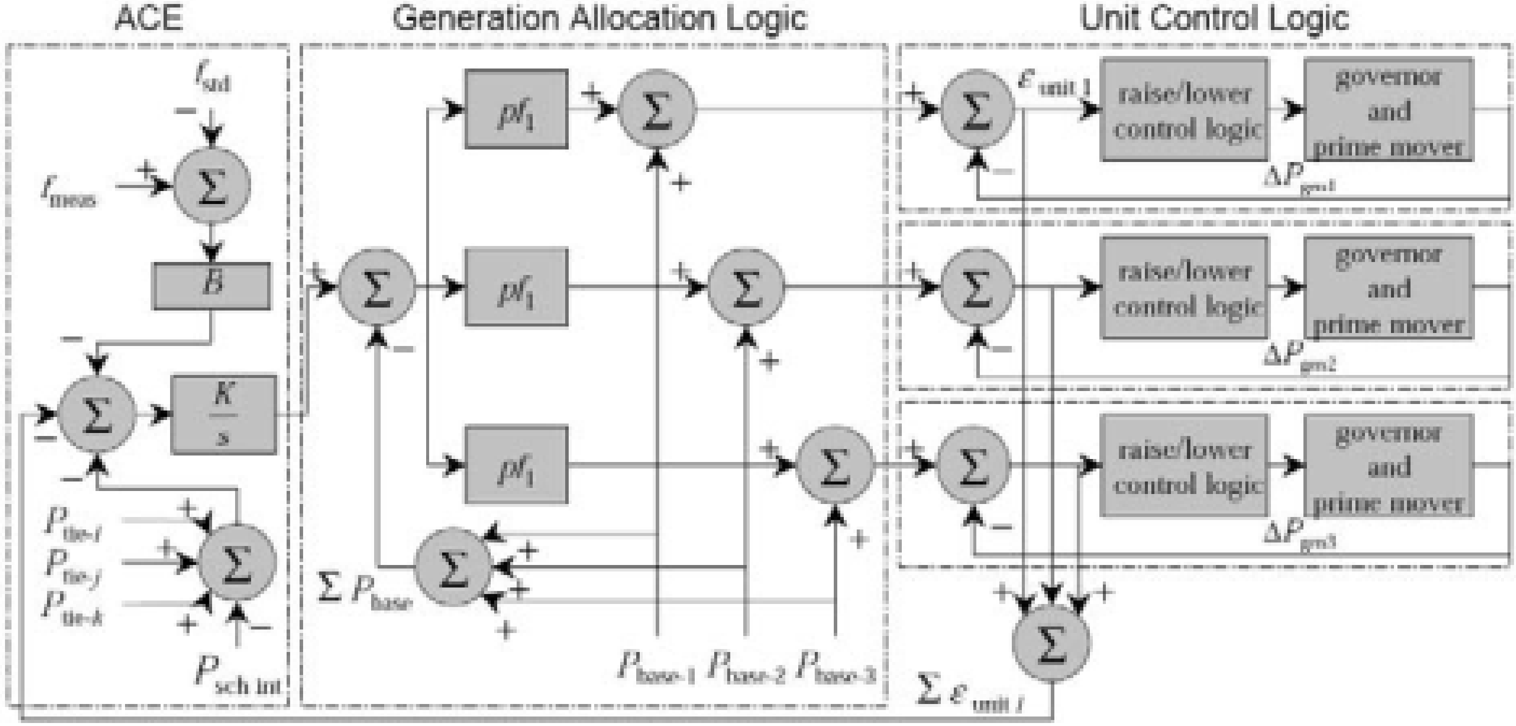


Generator Control

- The AGC calculation
  - the control must also drive the generating units to obey the economic dispatch in addition to pushing the frequency and tie flow errors to zero
    - the sum of the unit output errors is added to the ACE to form a composite error signal
    - the generation allocation calculation is placed between the ACE and the governor control / unit control loop

Generator Control

- Automatic generator control implementation
  - a typical layout



Generator Control

- Automatic generator control implementation
  - good design requirements
    - the ACE signal should be kept moderate in size
      - the ACE is influenced by random load variations
      - the standard deviation of the ACE should be small
    - the ACE should not be allowed to drift
      - the integral of the ACE should span an appropriate, but small time period
      - drift has the effect of creating system time errors or inadvertent interchange errors
    - the control action should be kept to a minimum
      - many errors are simple random load changes that should not cause any control action
      - chasing these random variations only wears out the unit's speed-changing hardware