ELEC0014 - Introduction to electric power and energy systems

Frequency control

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Introduction

Frequency must remain close to its nominal value:

- for the correct operation of loads (rotating machines)
- because it is an indication that the (active) power production balances the (active) power consumption (including network losses).

Link between frequency and active power balance ?

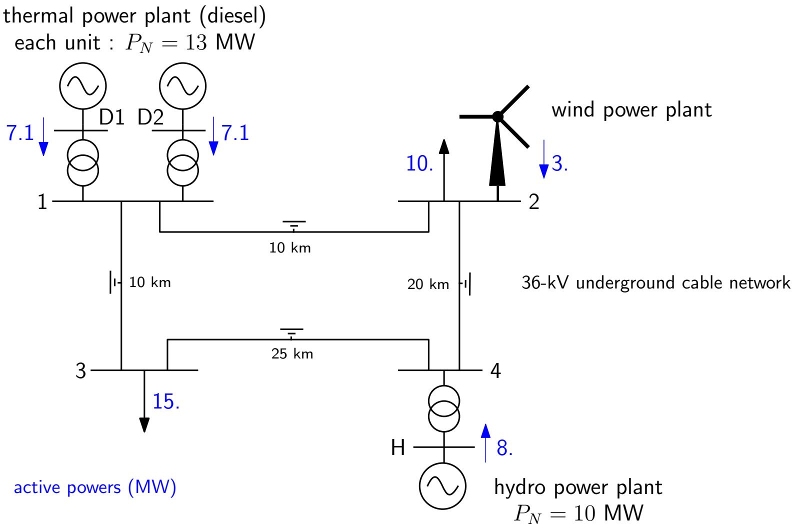
- Electrical energy cannot be stored; it is produced when it is requested
- in the very first instants after a disturbance: the missing (resp. excess) amount of energy is taken from (resp. stored into) the rotating masses of the synchronous machines
- this causes a variation of their speed of rotation, and hence of frequency
- this is sensed by the *speed governors*[1], which adjust the steam/water/gas flow in the turbines to correct the speed deviation.

Frequency correction is performed in two steps:

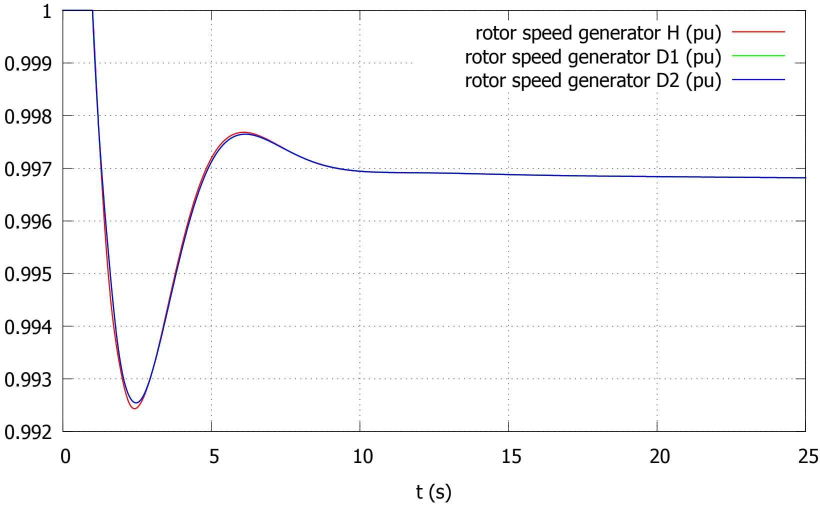
- *primary* (in a few seconds): local: speed control in power plants
- *secondary* (in a few minutes): centralized: corrections of generator power setpoints.

[1] en français: régulateurs de vitesse

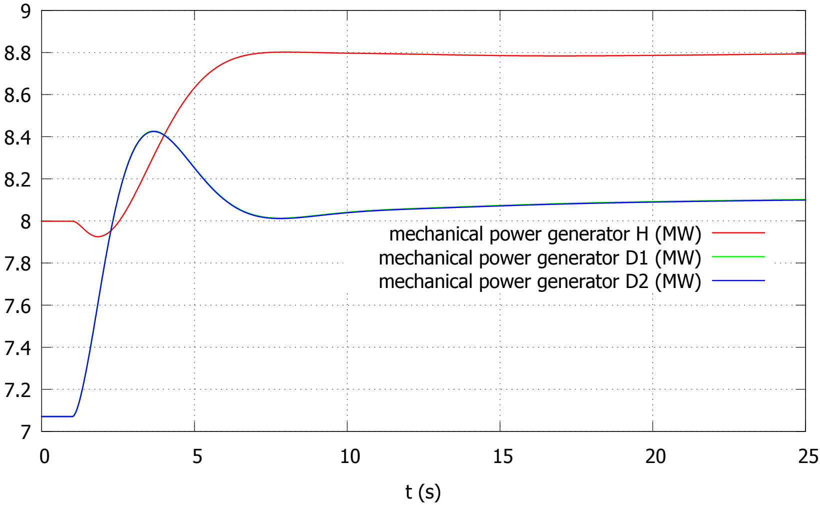
An illustrative example : the Van Cutsem island



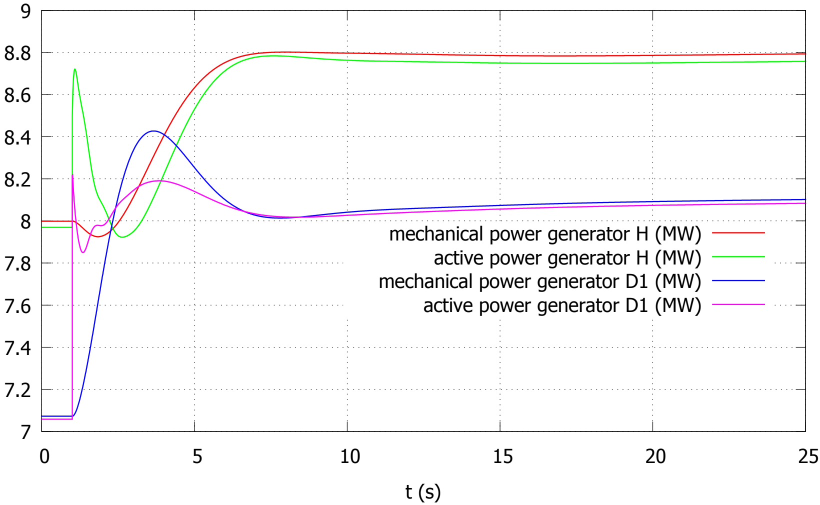
Incident: tripping at $t = 1$ s of the wind power plant at bus 2



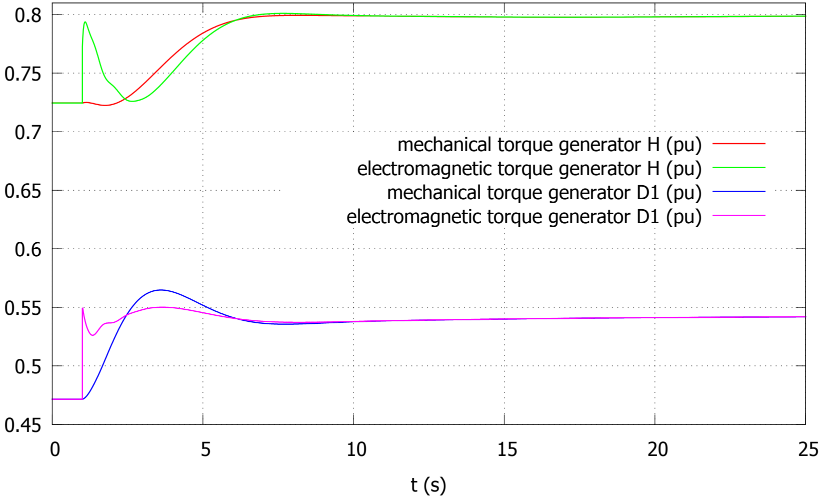
Rotor speeds of generators (pu)



Mechanical powers of generators (MW)



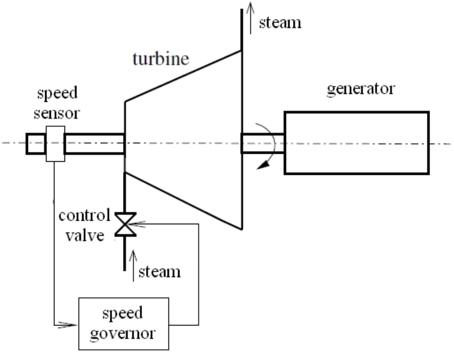
Active powers and mechanical powers of generators (MW)

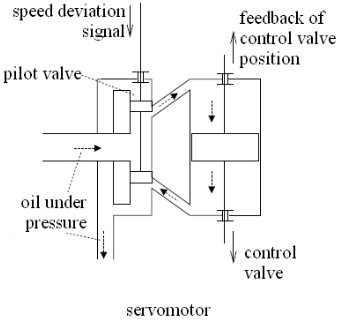


Electromagnetic torques T_e and mechanical torques T_m of generators (pu)

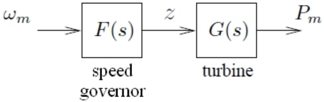
The speed governor

Description





Bloc diagram



ω_m : speed of rotation

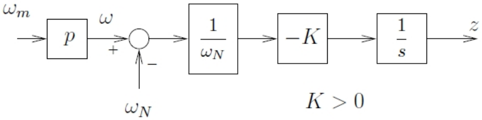
z : fraction of opening of the turbine control valves ($0 \leq z \leq 1$)

P_m : mechanical power produced by the turbine

$G(s)$: transfer function between z and P_m

$F(s)$: transfer function between ω_m and z.

First type of speed governor: the isochronous regulator



p : number of pairs of poles of generator

$\omega = p\,\omega_m$: electrical speed

$=$ angular frequency of AC voltages in steady state

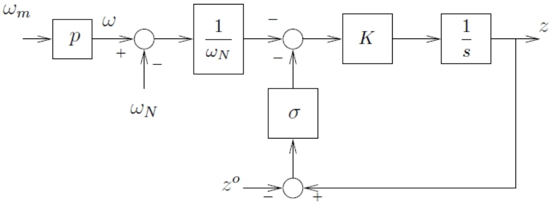
ω_N : nominal angular frequency

Servomotor: represented by the gain K and the integrator

In steady state: $\omega = p\omega_m = \omega_N$: cancellation of the frequency error

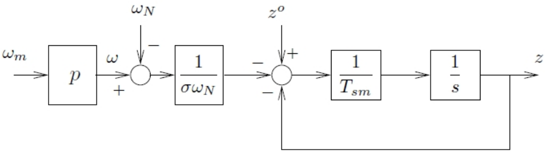
- a single generator can be equipped with an isochronous regulator
- that generator will alone ensure the active power balance of the whole system
  $\Rightarrow$ inappropriate for a large network !

Second type of speed governor



feedback of the control valve position z

z^o : valve opening setpoint (to modify the power production of the generator).



$T_{sm} = 1/(K\,\sigma)$: time constant of the servomotor

$$z = \frac{1}{1 + s\,T_{sm}} \left(z^o - \frac{\omega - \omega_N}{\sigma\,\omega_N} \right)$$

Steady-state characteristic of a turbine-governor set

In steady state :

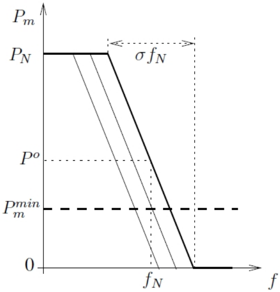
$$\begin{aligned} P_m &= G(0)z \\ z &= \left(z^o - \frac{\omega - \omega_N}{\sigma\, \omega_N} \right) \end{aligned}$$

For $z = 1$, $P_m = P_N =$ nominal power of turbine (MW)

$$P_N = G(0).1 \quad \Rightarrow \quad P_m = P_N z$$

$$\Rightarrow \quad P_m = P_N z^o - \frac{P_N}{\sigma} \frac{\omega - \omega_N}{\omega_N} = P^o - \frac{P_N}{\sigma} \frac{f - f_N}{f_N}$$

P^o : power setpoint of generator



Speed droop[2]

Ratio between the relative frequency deviation and the relative power deviation:

$$|\frac{\Delta f/f_N}{\Delta P_m/P_N}| = |\frac{\Delta\omega/\omega_N}{\Delta P_m/P_N}| = \sigma$$

$\sigma =$ *speed droop* of the speed governor. Typical values: 4 - 5 %

A frequency deviation $\Delta f = \sigma f_N = 0.04 \times 50 = 2$ Hz would result in a variation of mechanical power $\Delta P_m = P_N$.

Infinite speed droop: the machine operates at constant power, and does not participate in frequency control.

The speed controller is of the proportional type

- it leaves a steady-state frequency error, but ...
- this is precisely the signal allowing to share the effort over the various generators.

[2] en Français: *statisme*

Primary frequency control

Variations of the frequency and the productions after an active power disturbance?

Modelling assumptions

- system has come back to steady state
  $\Rightarrow$ all machines have the same electrical speed $= 2\pi f$
- the network is lossless
- the mechanical power produced by the turbines is completely converted into electrical power
- load is sensitive to frequency:

$$\begin{aligned} P_c &= P_c^o \, p(f) \qquad\qquad \text{with} \;\; p(f_N) = 1 \\ &= P_c^o \left(p(f_N) + \left.\frac{dp}{df}\right)_{f=f_N} (f - f_N) \right) = P_c^o \left(1 + D\,(f - f_N)\right) \end{aligned}$$

  D : sensitivity of load to frequency (1/Hz)[3]
- the system initially operates at the nominal frequency ($f = f_N$), for simplicity.

[3] also called "self-regulation of load"

Share of power variation among the generators

The steady-state characteristics of the various generators can be combined into:

$$P_m = \sum_{i=1}^{n} P_{mi} = \sum_{i=1}^{n} P_i^o - \frac{f - f_N}{f_N} \sum_{i=1}^{n} \frac{P_{Ni}}{\sigma_i}$$

Expressing that load is balanced by generation:

$$\sum_{i=1}^{n} P_i^o - \frac{f - f_N}{f_N} \sum_{i=1}^{n} \frac{P_{Ni}}{\sigma_i} = P_c^o \left(1 + D\left(f - f_N\right)\right)$$

In particular, at the initial operating point: $\sum_{i=1}^{n} P_i^o = P_c^o$

Disturbance: increase ΔP_c of consumption, the setpoints P_i^o being unchanged

$$\sum_{i=1}^{n} P_i^o - \frac{f - f_N}{f_N} \sum_{i=1}^{n} \frac{P_{Ni}}{\sigma_i} = P_c^o \left(1 + D\left(f - f_N\right)\right) + \Delta P_c$$

$$-\frac{f - f_N}{f_N} \sum_{i=1}^{n} \frac{P_{Ni}}{\sigma_i} = P_c^o D\left(f - f_N\right) + \Delta P_c$$

$$\Delta f = f - f_N = -\frac{\Delta P_c}{\beta} \qquad \text{with} \qquad \beta = DP_c^o + \frac{1}{f_N}\sum_{i=1}^{n}\frac{P_{Ni}}{\sigma_i}$$

β : *composite frequency response characteristic* (MW/Hz) [4]
characterizes the accuracy of primary frequency control.

Variation of power of j-th generator: $$\Delta P_{mj} = -\frac{\Delta f \; P_{Nj}}{f_N \; \sigma_j} = \frac{\Delta P_c \; P_{Nj}}{f_N \; \beta \; \sigma_j}$$

- The steady-state frequency error allows a predictable and adjustable sharing of the power variation over the various (participating) generators
- all speed droops being fixed, the larger the nominal power of a generator, the larger its participation
- all nominal powers being fixed, the smaller the speed droop of a generator, the larger its participation
- the larger the number of generators participating in frequency control, the smaller the frequency deviation.

[4] also called "network power frequency characteristic" or "stifness of system". En français: énergie réglante

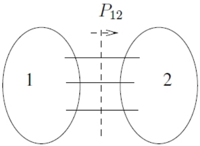
Primary reserve

- only a fraction of the total number of generators participate in primary frequency control
- to participate, the generator must have a *primary reserve*, i.e. it must produce less than its maximum power
- this is not desirable:
  - for generators using a renewable energy source
  - for units whose power cannot (easily) be varied: e.g. nuclear units

- primary reserve = service offered by the producer on the corresponding dedicated market
- if it is selected, the generator is paid:
  - for making the reserve available (even if it is not activated)
  - as well as for the activation of the reserve:
    - amount paid to the producer for an increase of power
    - $\neq$ amount paid to the producer for a decrease of power.

Secondary frequency control

Primary frequency control of an interconnection: example with 2 networks



With the same modelling assumptions as in slide # 1 :

- generators of network 1 : $P_{m1} = \sum_{i \in 1} P_i^o - \frac{f - f_N}{f_N} \sum_{i \in 1} \frac{P_{Ni}}{\sigma_i}$
- load of network 1 : $P_{c1} = P_{c1}^o + D_1 P_{c1}^o (f - f_N)$
- power balance in network 1 : $P_{m1} = P_{c1} + P_{12}$
- generators of network 2 : $P_{m2} = \sum_{i \in 2} P_i^o - \frac{f - f_N}{f_N} \sum_{i \in 2} \frac{P_{Ni}}{\sigma_i}$
- load of network 2 : $P_{c2} = P_{c2}^o + D_2 P_{c2}^o (f - f_N)$
- power balance in network 2 : $P_{m2} = P_{c2} + P_{21} = P_{c2} - P_{12}$
- power balance of whole system : $P_{m1} + P_{m2} = P_{c1} + P_{c2}$

Scenario :

- the whole system operates initially at frequency f_N
- the load power in network 1 increases by ΔP_{c1}.

Applying the relations of primary frequency control :

$$\begin{aligned} \text{to network 1 :} \quad -\beta_1 \Delta f &= \Delta P_{c1} + \Delta P_{12} \\ \text{to network 2 :} \quad -\beta_2 \Delta f &= -\Delta P_{12} \end{aligned}$$

β_1, β_2 : composite frequency response characteristics of networks 1 and 2.

Hence the frequency changes by : $\Delta f = -\dfrac{\Delta P_{c1}}{\beta_1 + \beta_2}$

the tie-line power changes by : $\Delta P_{12} = -\dfrac{\beta_2}{\beta_1 + \beta_2} \Delta P_{c1} \quad < 0$

- the power flow from network 1 to network 2 decreases, due to the support provided to network 1 by the generators of network 2
- the larger β_2 with respect to β_1, the more pronounced this effect.

Objectives and principle of secondary frequency control

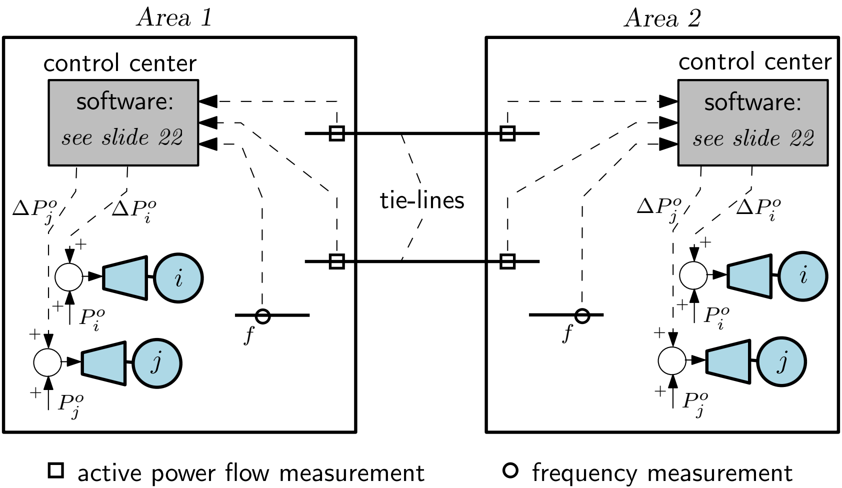
- eliminate the frequency error inherent to primary frequency control
- bring the power exchange between networks to the desired value (contracts)
- restore the generator primary reserves

In our two-network example :

- increase the production of some generators in network 1, where load increased
- the powers of the generators in network 2 need not be adjusted !

Implementation of secondary frequency control

- acts in pre-defined *control areas* :
  - corresponding to a country, to the network managed by a transmission operator, etc.
- measurements are gathered in each control area :
  - frequency
  - sum of power flows in the tie-lines linking the area to the rest of the system
- power set-point corrections ΔP_i^o are sent to dedicated generators in the area.



Control distributed in the various areas :

- measurements from one area gathered by the control center of that area
- no exchange of real-time measurements between areas

Two-network example, assuming network 1 $\equiv$ area 1 and network 2 $\equiv$ area 2:

Area Control Error (ACE)

$$\begin{aligned}\text{in area 1 : } ACE_1 &= P_{12} - P_{12}^0 + \lambda_1 (f - f_N) = \Delta P_{12} + \lambda_1 \Delta f \\ \text{in area 2 : } ACE_2 &= P_{21} - P_{21}^0 + \lambda_2 (f - f_N) = -\Delta P_{12} + \lambda_2 \Delta f\end{aligned}$$

λ_1, λ_2: *bias factors*

Generator power correction: output of Proportional-Integral controller:

$$\begin{aligned}\text{in area 1 : } \Delta P_1^o &= -K_{p1}\, ACE_1 - K_{i1} \int ACE_1\, dt \qquad K_{i1}, K_{p1} > 0 \\ \text{in area 2 : } \Delta P_2^o &= -K_{p2}\, ACE_2 - K_{i2} \int ACE_2\, dt \qquad K_{i2}, K_{p2} > 0\end{aligned}$$

Distribution over the generators participating in secondary frequency control:

$$\text{for the } i\text{-th generator of area 1 : } P_i^o + \rho_i \, \Delta P_1^o \qquad \text{with} \quad \sum_i \rho_i = 1$$

$$\text{for the } j\text{-th generator of area 2 : } P_j^o + \rho_j \, \Delta P_2^o \qquad \text{with} \quad \sum_j \rho_j = 1$$

When the system comes back to steady state, the integral control imposes:

$$ACE_1 = 0 \quad \Rightarrow \quad \Delta P_{12} + \lambda_1 \Delta f = 0$$
$$ACE_2 = 0 \quad \Rightarrow \quad -\Delta P_{12} + \lambda_2 \Delta f = 0$$

whose solution is : $\Delta f = 0$ and $\Delta P_{12} = 0$

both objectives of secondary frequency control are met !

Choosing the bias factors λ_i

- They do not impact the final system state but the dynamics to reach it
- It is appropriate to choose: $\lambda_1 = \beta_1 \quad \lambda_2 = \beta_2$

  Indeed, in the above example:

  $$ACE_2)_{\lambda_2=\beta_2} = -\Delta P_{12} + \beta_2 \Delta f = 0 \quad \Rightarrow \quad \Delta P_2^o = 0$$

  no adjustment of the generators in zone 2 $\leftarrow$ that's what we wanted !
- the more λ_2 differs from β_2, the more the generators in zone 2 are uselessly adjusted by the secondary frequency controller.

Choosing the K_i and K_p gains of the PI controllers

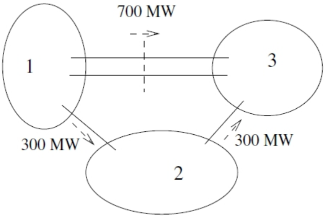
- They influence the dynamics, in particular the speed of action of secondary frequency control
- secondary frequency control must not act too promptly, in order not interfere with primary frequency control (which is the "first line of defense")
- quite often, $K_p = 0$ (integral control only).

Choosing the participation factors ρ_i

- ρ_i coefficients: distribute the correction signal ΔP_1^o (or ΔP_2^o) on the participating generators, which must have *secondary reserve*
- for both primary and secondary frequency controls, the power variation that a participating unit commits to provide, in a given time interval, must be compatible with its maximum rate of change:

  $\simeq$ a few $\% P_N$ / min for thermal units
  $\simeq P_N$ / min for hydro units.

Extension to more than two control zones



Example

1 want to sell 1000 MW to **3**
2 does not want to sell nor to buy power

Settings of the secondary frequency controllers:

$$P^o_{12} + P^o_{13} = 1000 \text{ MW} \qquad P^o_{21} + P^o_{23} = 0 \text{ MW} \qquad P^o_{31} + P^o_{32} = -1000 \text{ MW}$$

After all 2ndy freq controllers have acted:

$$ACE_1 = 0 \Rightarrow \quad (P_{12} + P_{13}) - (P^o_{12} + P^o_{13}) + \lambda_1 \Delta f = P_{12} + P_{13} - 1000 + \lambda_1 \Delta f = 0$$

$$ACE_2 = 0 \Rightarrow \quad (P_{21} + P_{23}) - (P^o_{21} + P^o_{23}) + \lambda_2 \Delta f = -P_{12} + P_{23} + \lambda_2 \Delta f = 0$$

$$ACE_3 = 0 \Rightarrow \quad (P_{31} + P_{32}) - (P^o_{31} + P^o_{32}) + \lambda_3 \Delta f = -P_{13} - P_{23} + 1000 + \lambda_3 \Delta f = 0$$

$$\Rightarrow \qquad \Delta f = 0 \qquad P_{12} + P_{13} = 1000 \qquad P_{12} = P_{23} \qquad P_{13} + P_{23} = 1000$$

Note. Secondary frequency control does not control individual power flows !