The frequency active power control simulation for the electrical power systems in radial network interconnected

MIRCEA PAUL MIHAI¹, GABRIEL IOVAN², MIRCEA ION¹

¹Department of Electrical Engineering, Energetics and Aerospace, University of Craiova
107, Blvd. Decebal, Craiova
²Energy Dispatching Territorial Center Craiova - C.N. Transelectrica S.A
1, Blvd Nicolae Titulescu, Craiova
ROMANIA
mmircea@elth.ucv.ro, gabiovan@yahoo.com, imircea@elth.ucv.ro

Abstract: In the paper is presented the simulation of the frequency-active power control composed by the load frequency control, acting in the first 30 seconds after the disturbance and the automatic generation control, acting in the next 15 minutes in order to restore the imbalance between production and consumption. The model is realised used two power systems in radial network interconnection. The used model for simulating the load frequency control between the two interconnected power systems is realized by the interconnection between the primary machine model and the system represented by oscillating equation model of the rotors expressed in relative units of frequency. The automatic generation control is represented by a simplified model of the central controller currently used in the Romanian power system. In the paper is described the realization of the mathematical models related to the primary machine composed of the automatic speed regulator model in series with the turbine model.

Key-Words: - Simulation, power systems, primary machines, radial network, mathematical models.

1 Introduction
The primary control LFC (load frequency control) is a decentralized automatically readjusted with static characteristic distributed on a large number of generating units and provides the rapid correction (within 30 seconds) of the different between production and consumption at a stationary frequency difference from the scheduled value. Is an automatic function of the ASR (automatic speed regulator) to change the power produced by a generator due to a frequency deviation. The LFC stabilize the system frequency in maximum 30 seconds, not necessarily on the rated value, and it represent a speed control performed at each of the individual groups in the system.

The secondary control AGC (automatic generation control) is a centralized automatic control of active power generating of the designated units for restoring the balance and the frequency deviation on the scheduled values in the power system in 15 minutes [1]. The secondary control action restores the primary control reserve, because the primary control does not cancel the frequency deviation and brings balance (the algebraic sum of active power on the interconnection tie lines) to the scheduled value. Because the system operator (the dispatcher) intervention can not be done in real time has developed a dedicated system/plant secondary control comprises a central regulator mounted on the Central Dispatcher and a number of local controllers installed in some power plants called the adjustable plants. In terms of the central regulator it’s represents territory actuators controlled via dedicated communication channels and devices.

2 Defining the power systems and the physical variables that occur in the models
For an average value of production in the European Power System EPS of about 306000MW the participation factor C of the NPS for LFC will be:

\[ C_{NPS} = \frac{P_{\text{avr.NES}}}{P_{\text{avr.EPS}} - P_{\text{avr.NPS}}} \]  

\[ C_{NPS} = \frac{8248\text{MW}}{(306000 - 8248)\text{MW}} \approx \frac{1}{36} = 0.027 \]
For the Romanian Power System RPS is used the data available to the system transport operator (the central dispatcher) [1] according to UCTE (Union for the Coordination of Transmission of Electricity in Europe) presented in the Table 1:

<table>
<thead>
<tr>
<th>Reference value</th>
<th>Specific values</th>
<th>Dating</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rated frequency</td>
<td>50 Hz UCTE</td>
<td></td>
</tr>
<tr>
<td>The minimum frequency deviation for LFC acting</td>
<td>± 20 mHz UCTE</td>
<td></td>
</tr>
<tr>
<td>The frequency deviation for entire LFC power reserve acting</td>
<td>± 200 mHz UCTE</td>
<td></td>
</tr>
<tr>
<td>The medium damping coefficient D</td>
<td>1%u.r./HZ UCTE</td>
<td></td>
</tr>
<tr>
<td>Maximum power consumption in NPS</td>
<td>9206 MW 2010</td>
<td></td>
</tr>
<tr>
<td>Rated power frequency characteristic of NPS</td>
<td>560 MW/Hz 2010</td>
<td></td>
</tr>
<tr>
<td>Average power production in NPS</td>
<td>8248 MW 2010</td>
<td></td>
</tr>
</tbody>
</table>

On the frequency bias value B used for the central controller, one can determine the global frequency power characteristic \( \beta \) set for RPS (according to theorem Darrieux) [2], [3]:

\[
B_{RPS} = \beta_{RPS} = 56 MW / 0.1 Hz = 560 MW / Hz
\]

Applying the principle of contribution the frequency-power characteristic can be determined for the interconnected power system IPS, given the participation factor (1):

\[
\beta_{EPS} = \beta_{RPS} = \frac{B_{EPS}}{C_{EPS}} = 560 \cdot 36 = 20160 MW / Hz
\]

To establish the mechanical power mobilized in the primary control for the reference incident \( \Delta f = 0.2 Hz \) using aggregate characteristics [3]:

\[
\sum \frac{1}{R_i} + D_{echiv} = \frac{1}{R_{echiv}} + D_{echiv} = \beta_{echiv}
\]

The set statism R is determined according to the primary control reserve, and it must be fully mobilized [1], [5] to the frequency deviation \( \Delta f = 0.2 Hz = 0.004 \) p.u. In RPS the primary reserve is set:

\[
P_{Reg} = +/- 1.25% P_N \text{ for the reference frequency deviation from:} \]

\[
\Delta f = 0.2 Hz = 0.4 \% \text{ p.u.} \quad (3)
\]

The value of \( 1/R \) u.r. becomes:

\[
\frac{1}{R_{echiv}} = \frac{P_{Reg} \text{ p.u.}}{\Delta f \text{ p.u.}} = 1.25\% / 0.4\% = 2.9 \text{ p.u.}
\]

The equivalent damping coefficient \( D_{echiv} \):

\[
D_{echiv} = \frac{1}{R_{echiv}} \frac{P_N}{\Delta f} = \frac{1}{0.4\%} = 1\% / 2\% = 0.5 \text{ p.u.}
\]

Were the rated frequency and power are:

\[ P_N = 8248 MW (RPS \text{ production}) \]

\[ F_N = 50 Hz \]

For the coefficients expressed in [MW / Hz] p.u. is realised:

\[
\left( \frac{1}{R}, D, \beta \right) = \left( \frac{MW}{Hz}, \frac{Hz}{MW}, \frac{MW}{[Hz]} \right) = u.f.
\]

The mechanical power mobilized in RPS for a quasi-stationary frequency deviation of 200MHz and a damping factor of 1% \( P_N/Hz \) will be:

\[
\Delta P_{mechRPS} = \frac{1}{R_{echivRPS}} \Delta f = 477.52 \cdot 0.2 = 95.5 MW
\]

The mechanical power mobilized in RPS for a quasi-stationary frequency deviation of 200MHz and a damping factor of 1% \( P_N/Hz \) will be:

\[
\Delta P_{mechIPS} = \frac{1}{R_{echivIPS}} \Delta f = 17190.7 MW / Hz
\]

and:

\[
\Delta P_{mechIPS} = \frac{1}{R_{echivEPS}} \Delta f = 3438.1 MW
\]

The data are summarized in Table 2.

<table>
<thead>
<tr>
<th>Data</th>
<th>RPS</th>
<th>IPS</th>
</tr>
</thead>
<tbody>
<tr>
<td>( P_N )</td>
<td>8248 MW</td>
<td>296769 MW</td>
</tr>
<tr>
<td>( \beta )</td>
<td>560 MW/Hz</td>
<td>20160 MW/Hz</td>
</tr>
<tr>
<td>( 1/R )</td>
<td>477.52 MW/Hz</td>
<td>17190.7 MW/Hz</td>
</tr>
<tr>
<td>( D/Hz )</td>
<td>82.48 MW/Hz</td>
<td>2967.69 MW/Hz</td>
</tr>
</tbody>
</table>

The ideal frequency-power characteristic for RPS is a straight line given in Fig.1 by the equation:
\[ \Delta P = \beta_{\text{SEN}} \cdot \Delta f = 560 \cdot (50 - x); x \in [49.8 \text{ to } 50.2] \]  \hspace{1cm} (7)

\text{with the slope:}
\[ \tan \alpha = \frac{1}{\beta_{\text{SEN}}} = \frac{1}{560 \cdot [\text{MW} / \text{Hz}]} = 0.0017 \text{ [Hz / MW]} \]  \hspace{1cm} (8)

\[ H_{TB}(s) = \text{the transfer function of the equivalent turbine.} \]

In steady state, as the final value theorem 
\( s \rightarrow 0, G_m(s) \rightarrow 1 \) it’s results:
\[ \Delta P_m = \Delta P_e - \frac{1}{R} \Delta \omega \]  \hspace{1cm} (10)

From the swinging equation of the rotor results \( P_M = \text{ct.} \)
The acceleration power is:
\[ P_m - P_e = P_a = 0 \]
with
\[ M \frac{d\omega}{dt} + D \cdot \Delta \omega + T_{12} \cdot \Delta \delta = 0 \]  \hspace{1cm} (11)

where:
- \( P_m \) is the mechanical power
- \( P_e \) is the electric power
- \( P_a \) is the acceleration power
- \( D \) is the damping constant \text{p.u.} / \text{Hz}
- \( T_{12} \) is the synchronization constant.
- \( M \) is the moment of inertia.

The first term represents the angular speed inertia. The second term represent the damping power and the last term is the synchronization power. The inertia constant is:
\[ M = \frac{2 \cdot E_c}{2 \pi \cdot f_s} = \frac{2 \cdot H}{\omega_s} \cdot \text{[u.r. / rad / s^2]} \]  \hspace{1cm} (12)

In [7] the inertia constant \( 2H \) is obtained by dividing to the nominal apparent power \( S_n \):
\[ H = \frac{E_c}{S_n \cdot \text{[p.u.s]}} \]  \hspace{1cm} (13)

The variation of the power angle is:
\[ \Delta \delta = \int \Delta \omega \cdot dt = \int (\Delta \omega_1 - \Delta \omega_2) \cdot dt \]  \hspace{1cm} (14)

The swinging equation of the rotor becomes:
\[ \frac{2H}{2\pi \cdot f_s} \frac{d\omega}{dt} + D \cdot \Delta \omega + T_{12} \cdot \int (\Delta \omega_1 - \Delta \omega_2) \cdot dt = 0 \]  \hspace{1cm} (15)

Expressed in frequency the equation (15) for:
\[ \Delta \omega = 2 \cdot \pi \cdot \Delta f \]  \hspace{1cm} (16)

it becomes:
\[ \frac{2H}{f_{s1}} \frac{df}{dt} + D \cdot \Delta f + 2\pi \cdot T_{12} \cdot \int (\Delta f_1 - \Delta f_2) \cdot dt = 0 \]  \hspace{1cm} (17)

and in the p.u. according to the synchronous frequency:
The undamped frequency oscillations to the small perturbations [5], [8]:

\[ \frac{df}{dt} = \frac{2\pi \cdot T_{12} \cdot f_0}{2H} \]

\[ D = \% \ \text{u.r./Hz} = 0.5 \ \text{p.u.} \] \hspace{1cm} (19)

The typical values of the inertia constant \( H \) [7] are represented in Table 3.

### Table 3. Typical values of the inertia constant \( h \) [5]

<table>
<thead>
<tr>
<th>No.</th>
<th>The generators type</th>
<th>( H ) [sec]</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Hydro generators</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Low speed (&lt; 200rot/min)</td>
<td>2 – 3</td>
</tr>
<tr>
<td></td>
<td>High speed (&gt; 200rot/min)</td>
<td>2 – 4</td>
</tr>
<tr>
<td>2</td>
<td>Thermal generators</td>
<td></td>
</tr>
<tr>
<td></td>
<td>With condensing (1500rot/min)</td>
<td>6 – 9</td>
</tr>
<tr>
<td></td>
<td>With condensing (3000rot/min)</td>
<td>4 – 7</td>
</tr>
<tr>
<td></td>
<td>Without condensing (3000rot/min)</td>
<td>3 – 4</td>
</tr>
<tr>
<td>3</td>
<td>Synchronous motors for heavy shareholders</td>
<td>2</td>
</tr>
</tbody>
</table>

The synchronization constant \( T_{12} \) (sync torque) [5] is represented „the rigidity” connection between the power systems:

\[ T_{12} = \left( \frac{U \cdot E_q}{X_T} \cos \delta^{(0)} \right) \left( \frac{\partial P}{\partial \delta} \right)_{\delta=\delta^{(0)}} \] \hspace{1cm} (21)

where:

- \( \delta \) is the power angle.
- \( \delta^{(0)} \) - the power angles were the linearization is made.
- \( E_q \) - the electromotive voltage.
- \( U \) - the network voltage.
- \( X_T = X_{\text{direct}} + X_{\text{block transformer}} + X_{\text{network}} \) representing the total reactance across the generator terminals.

The generator active power pre-disturbance is:

\[ P = \left( \frac{U \cdot E_q}{X_T} \right) \sin \delta^{(0)} = P_{\text{max}} \cdot \sin \delta^{(0)} \] \hspace{1cm} (22)

The calculated values for \( T_{12} \) in p.u. are summarized in Table 4.

### Table 4. The synchronization constant in p.u. depending on power \( \delta \)

<table>
<thead>
<tr>
<th>Power angle ( \delta^{(0)} )</th>
<th>0(^{\circ})</th>
<th>10(^{\circ})</th>
<th>15(^{\circ})</th>
<th>20(^{\circ})</th>
<th>25(^{\circ})</th>
</tr>
</thead>
<tbody>
<tr>
<td>( T_{12} ) u.r.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6 tie lines parallels</td>
<td>1.86</td>
<td>1.83</td>
<td>1.79</td>
<td>1.74</td>
<td>1.7</td>
</tr>
<tr>
<td>5 tie lines parallels</td>
<td>1.55</td>
<td>1.52</td>
<td>0.49</td>
<td>1.45</td>
<td>1.4</td>
</tr>
<tr>
<td>4 tie lines parallels</td>
<td>1.23</td>
<td>1.22</td>
<td>1.20</td>
<td>1.16</td>
<td>1.14</td>
</tr>
<tr>
<td>3 tie lines parallels</td>
<td>0.93</td>
<td>0.92</td>
<td>0.9</td>
<td>0.86</td>
<td>0.84</td>
</tr>
<tr>
<td>2 tie lines parallels</td>
<td>0.62</td>
<td>0.61</td>
<td>0.59</td>
<td>0.58</td>
<td>0.56</td>
</tr>
</tbody>
</table>

To study the frequency stability and the behavior of the interconnected systems in the primary control the following simplifying assumptions are used:

- The loads are represented by admittance.
- Synchronous machines are represented as ideal voltage sources and equal to \( E_q \) behind their internal synchronous reactance \( X_d \) and the internal reactance of the machine is equal with transient reactance \( X_d' \) [5].
- The generator terminals voltage is constant.

Depending on the total reactance at the terminals will operate in the undisturbed system at different load angles, thus obtaining different values for the constant \( T_{12} \). As seen from (19) the moment of inertia and the values of the synchronization constant will influence the dynamic behaviour of frequency.

### 4. The modelling of the primary machines

The static speed regulator is of type P.I.

The practicality model of the static speed regulator is represented in diagrams from Fig.3, according to [4],[5].

Figure 3. The static regulation loop model.

a) The basic diagram; b) The bloc diagram; c) The equivalent bloc diagram

where:
IA is the intermediate actuator.
PC - the confinement power variation
ASR - the standardized automatic speed regulator (I, PI, PID)
R - the permanent statism.
K. the regulator proportionality factor [MW/Hz]

The proportionality factor K [MW/Hz] given in the general structure of the RAV must be proportional with 1/R:

\[ K = \frac{K_1}{R} \text{ [MW/Hz]} \quad (23) \]

The general mathematical models for hydro and thermal primary machines are represented in the Fig. 4 and Fig.5.

![Figure 4. The general model of the thermal primary machine.](image)

![Figure 5. The general model of the hydro primary machine.](image)

The related transfer functions of the primary machine model in Fig. 4 and Fig. 5 are made according to the schemes presented in Fig. 1 with the following features:

1. For steam turbines – by using the data for the thermal ASR (the CTE Turceni model) type PI with: \( K_p = 1; \ T_1 = 1.5 \text{ s}, \ T_{SI} = 1.25 \text{ s} \Rightarrow K_1 = 5, \ R = 0.33 \text{ p.u.} \)

The ASR (automatically speed regulator) transfer function of the thermal generator is:

\[ H_{ASR}(s) = \frac{1 + T_{HP} s}{(1 + T_{HP} s)(1 + T_{CH} s)} \]

2. For hydro-generators
The power droop function (transient droop) is [4], [8]:

\[ G_c(s) = \frac{1 + T_p s}{1 + \frac{R_p}{R} T_p s} \]

The following general transfer function of speed controllers used in hydro-generators results:

\[ H_{RAVS} = \frac{(1 + T_p s)}{(1 + T_c s)(1 + \frac{R_p}{R} T_p s)} \]

where:
\[ T_c = \frac{1}{K_1} \text{ is the time constant [2] between [0.2-1] s.} \]

\[ R_p = [2.3 - (T_w - l) \cdot 0.15] \frac{T_w}{M} \text{ p.u.} \quad (29) \]

The transient statism \( R_T = [0.58- 1.16] \text{ p.u. for water time constant } T_w = 2.2 \text{ s and } M = [2 - 4] \text{ s [7].} \)

The transfer function of the hydro generator speed regulator is:

\[ H_{ASRH}(s) = \frac{1}{R} \frac{1.4 s + 0.14}{s^2 + 5.029 s + 0.14} \text{ p.u.} \quad (30) \]

For: \( R_T/R = 3.56; \ T_r = 9.6 \text{ [sec]}; \ K_1 = 5. \)

The turbine transfer function is [6]:

\[ H_{TBH}(s) = \frac{1 - 2 R s}{1 + 1.1 s} \]

The small power system RPS is represented by aggregating the primary machine mechanical characteristics for a representative equivalent hydro and thermal generator during the time constant of
the system considered $2H = 8s$. The large system EPS is represented by an equivalent thermal machine being considered $2H = 10s$. (in Fig.3). In order to get the SIMULINK model the general diagram in Fig.6. [4], [5] is used.

5. The modelling and the simulation of the automatic generation control (AGC)

The purpose of secondary control (AGC) is to cancel the area signal error (global deviation control) designated by the acronym ACE (Area Control Error) [4], [5], [7] obtained by a linear combination between power exchange deviations on interconnections tie lines and quasi-stationary frequency deviation $\Delta f$ resulted from primary control action of the form:

$$ACE = \Delta P_{SCH} + B \cdot \Delta f$$  \hspace{1cm} (32)

where:
- $B_{EPS} = B_{EPS}$ is the balancing factor (frequency bias) [MW / Hz]
- $\Delta P_{SCH}$ - power exchange deviations on interconnections tie lines [MW] (node feature)
- ACE constitutes the error signal to the central controller area looked like a node with scheduled consumption feature (neutral, consumer or producer) that must be preserved if the disturbance is external.

The current control system meaning the central controller, achieves a proportional-integral control.

The correction signal, [5], called control order reported to the total available regulation band will be:

$$Y = -\frac{B_k}{\sum B_{RGK}} (C_p \cdot ACE + \frac{1}{T_i} \int ACE \cdot dt) \cdot 100 \%$$ \hspace{1cm} (33)

or:

$$Y = -PFI \cdot (C_p \cdot ACE + \frac{1}{T_i} \int ACE \cdot dt) \cdot 100 \%$$ \hspace{1cm} (34)

where:
- $PFI = \sum B_k$ is the participation factor for the regulating generator $k$
- $\sum B_k$ - the available secondary regulating band.
- $B_K$ - the secondary regulating band for unit K
- $C_p$ - the proportionality constant
- ACE - the area control error
- $T_i$ - the integration constant

The UCTE recommendation [1] for the secondary regulating band is between 200MW and 400 MW (based on maximum consumption forecast). So the secondary control reserve will be between 100MW and 200 MW (the upper half of secondary control band).
\[ R = \sqrt{a \cdot L_{\text{max}} + b^2} - b \]  

(35)

where:

- \( R \) is the recommended secondary control reserve (MW)
- \( L_{\text{max}} \) - maximum load expected in (MW) to the area
- \( a, b \) - empirical parameters set with the following values as the UCTE recommendations:
  - \( a = 10 \text{MW} \)
  - \( b = 150 \text{MW} \)

For maximum value the forecast consumption in the RPS is \( L_{\text{max}} = 9206 \text{ MW} \). This will determine the maximum secondary control reserve for the RPS:

\[ R_{\text{max,RPS}} = \sqrt{10 \cdot 9206 + 150^2} - 150 = 188\text{MW} \]

So the maximum secondary regulating band will be:

\[ \left( \sum B_k \right)_{\text{max}} = 2 \cdot R_{\text{max,RPS}} \approx 376\text{MW} \]

In the Laplace variable the (33) control order will become:

\[ Y(s) = -\frac{ACE(s)}{B_{R_{\text{max}}}} \left( C_p + C_i \cdot \frac{1}{s} \right) \cdot 100 = \pm 50\% \text{ p.u.} \quad (36) \]

where:

- \( B_{R_{\text{max}}} \) is the secondary control regulating band p.u.
- \( R_{\text{Rmax}} \) - the secondary control regulating reserve p.u.
- \( T_i = 1/C_i \quad [\text{s}] \) - the integration time constant
- \( C_p = 0.4 \text{ u.r. normal for } ACE < +/- 100\text{MW} \)
- \( C_p = 0.6 \text{ assist/ urgency for: } +/- 100\text{MW} < ACE \leq +/- R_{\text{Rmax}} \)
- \( T_1 \in (T_{\text{min}}, T_{\text{max}}) = [43.2 \text{;} 200] \text{ s} \)
- \( C_i \) si \( C_p \) the integration and proportional constants

The simplified SIMULINK model of the secondary regulator and the simplified diagram of the secondary loop are represented in the Fig. 6 and Fig. 7:

**Figure 6. The SIMULINK model for AGC regulator.**

The low pass filter LPS, serially with the central controller output provides a real pole (additional poles in the loop PI regulator). In addition to filtering order it provide the stabilization of the secondary control loop in Figure 7.

**Figure 7. The simplified diagram of the AGC loop**

where:

\[ \sum_{i=1}^{n} PF_i = 1 \text{ u.r. is the participations factor of the regulation power plants.} \]

- \( B = \beta \) (the LFC slope characteristic) - the balancing coefficient (the slope of the AGC characteristic).
- \( \Delta P_{\text{SCH}} = \Delta S \) - the power exchange deviation.
- \( ACE = B \cdot \Delta f + \Delta P_{\text{SCH}} \) - “area control error” (the regulation binomial control).
- \( LPS \) - the low pass filter.
- \( PLC \) - the plant controller.
- \( P_{\text{REG}} \) - the control order.
- \( P_{\text{REF}} \) - the power set point (from the energy market).
- \( P_C \) - the nominal set point.

The trumpet curves families may be obtained in MATLAB - SIMULINK, depending on the desired maximum dynamic deviation and the dead band of the central controller (+ / -20MHz). The following
The transfer function is simulated by applying a unit step input signal:

\[ H_f(s) = f_0 \pm \Delta f_{\text{dinmax}} \pm \frac{\Delta f_{\text{dinmax}} - \Delta f_c}{T_s s + 1} \]  

(37)

where:

- \( f_0 = 50 \) Hz is the rated frequency (eventually 49.95 to 50.05 for the synchronous time correction)
- \( \Delta f_{\text{dinmax}} = (0.1 – 1) \) Hz (the maximum frequency deviation) for example will use \( \Delta f_{\text{dinmax}} = +/-0.8\)Hz and +/-1Hz
- \( \Delta f_c = 0.02\)Hz - the regulation dead band assumed for the AGC

\( T_s = 255 \) sec \( t/4 = 900/4 \) s - the time constant for the trumpet curve for the rated during of the permanent regime \( t_s = 15 \) min = 900 sec.

Different trumpet curves can be approximated for different frequency disturbances. The mathematical model used for tracing trumpet curve is shown in the figure 8. Are drawn two curves for two maximum frequency dynamic deviations, is shown in Fig.9.

\( \Delta f_{\text{dinmax1}} = +/-0.8 \) Hz, \( \Delta f_{\text{dinmax2}} = +/-1 \) Hz and \( f_0 = 50 \) Hz.

Given the above further modelling, is presented the general test SIMULINK model for the power frequency control in Fig.10. Depending on the synchronizing coefficients \( T_{12} \), inertia constants \( M \), the evolution and primary machine, the primary control factor \( C_{\text{RPS}} \) from (1) of RPS we obtain the dynamic frequency evolution, the ACE deviation and the mobilization of the secondary control reserve represented in Fig. 11 and Fig.12.

![Figure 8. The SIMULINK model for trumpet curves](image)

![Figure 9. The simulation of the trumpet curves.](image)

![Figure 10. The SIMULINK model of the LFC + AGC control in the two radial interconnected power systems.](image)

For the evaluation of the power-frequency control quality the trumpet curve Fig. 9 is used at the \( \Delta f_{\text{dinmax}}= +/-0.8 \) Hz according to UCTE specifications [1].

Next the AGC simulations framed in "trumpet curve" will be presented for typical disturbances in RPS:

- ACE = +/-50MW specific for the normal load fluctuation.
- ACE = +/-100MW for disturbances related to accidental loss of small capacity production (boiler accidental breakage, transient faults on drain tie lines, etc.) or onset of the medium consumer areas.
- ACE > +/-100MW (220MW, 300MW, 600MW, 700MW) for large disturbances related to the loss of a big hydro or thermal power generator in a big power plant, loss of a drain buss bar or the largest group of the nuclear unit, or a large focused consumer.

The data used in the AGC simulations are presented in Table 5.

Since the control order is applied reversed to the input of the central regulator for more suggestive representation in diagrams, the area control error was represented with changed sign that (-) ACE.

The automatic speed regulators are not included in the power control loop of the regulating power plants.
Table 5. The general data simulations RPS/EPS

<table>
<thead>
<tr>
<th>p.u. = P_{EPS} = 8248 [MW]</th>
<th>RPS</th>
<th>EPS</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>a.u.</td>
<td>p.u.</td>
</tr>
<tr>
<td>C_{EPS/EP}</td>
<td>1</td>
<td>-</td>
</tr>
<tr>
<td>P_{n} [MW]</td>
<td>8248</td>
<td>1</td>
</tr>
<tr>
<td>f_{0} [Hz]</td>
<td>50</td>
<td>1</td>
</tr>
<tr>
<td>1/R [MW/Hz]</td>
<td>477.52</td>
<td>2.9</td>
</tr>
<tr>
<td>1/R thermo = 70% [MW/Hz]</td>
<td>334.26</td>
<td>2</td>
</tr>
<tr>
<td>1/R hydro = 20% [MW/Hz]</td>
<td>143.26</td>
<td>0.9</td>
</tr>
<tr>
<td>D = 1%/Hz [MW/Hz]</td>
<td>82.48</td>
<td>0.5</td>
</tr>
<tr>
<td>B = 1/R + D [MW/Hz]</td>
<td>560</td>
<td>3.4</td>
</tr>
<tr>
<td>R_{Rmax} [MW]</td>
<td>188</td>
<td>0.0227</td>
</tr>
<tr>
<td>B_{Rmax} = 2R_{Rmax} [MW]</td>
<td>376</td>
<td>0.045</td>
</tr>
<tr>
<td>T_{12}/T_{21} [MW]</td>
<td>8825</td>
<td>1.07</td>
</tr>
<tr>
<td>C_{f}</td>
<td>-</td>
<td>0.4/0.6</td>
</tr>
<tr>
<td>C_{p} [s]</td>
<td>100</td>
<td>-</td>
</tr>
<tr>
<td>P_{H} (hydro power share)</td>
<td>-</td>
<td>0.7</td>
</tr>
<tr>
<td>P_{T} (thermo power share)</td>
<td>-</td>
<td>0.3</td>
</tr>
<tr>
<td>\Delta P_{L1} = ACE_{1} [MW]</td>
<td>700</td>
<td>0.0848</td>
</tr>
<tr>
<td>(\Delta f = 0.034Hz = 0.00069 u.r.) one nuclear unit</td>
<td></td>
<td></td>
</tr>
<tr>
<td>\Delta P_{L2} = ACE_{2} [MW]</td>
<td>600</td>
<td>0.0727</td>
</tr>
<tr>
<td>(\Delta f = 0.03Hz = 0.00059 u.r.) Drain buss bar In a big power plant</td>
<td></td>
<td></td>
</tr>
<tr>
<td>\Delta P_{L3} = ACE_{3} [MW]</td>
<td>300</td>
<td>0.0363</td>
</tr>
<tr>
<td>(\Delta f = 0.015Hz = 0.00029 u.r.) One big power generator</td>
<td></td>
<td></td>
</tr>
<tr>
<td>\Delta P_{L4} = ACE_{4} [MW]</td>
<td>100</td>
<td>0.0121</td>
</tr>
<tr>
<td>(\Delta f = 0.005Hz = 0.00001 u.r.)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Figure 11. The simulation of the primary and the secondary frequency- power control in the RPS for the disturbances according to table 3. (RPS generators are PSS compensated; R_{Rmax} = +/- 200MW), t = 250s

a) \Delta P_{LRPS} = 700MW, b) \Delta P_{LRPS} = 600MW, c) \Delta P_{LRPS} = 300MW, d) \Delta P_{LRPS} = 100MW, e) \Delta f_{EPS}, f) trumpet curve

Thereby the loading of the secondary control reserve, according to the control order is carried out according to the gradient of loading / unloading of the power plants. For loading 100% of the thermo secondary reserve approx. 15 min are necessary.

B_{RS} = 10\%P_{N}, R_{RS} = B_{RS} / 2 = \pm 5\% P_{N}, where P_{N} is the rated power.

The secondary control reserve mobilization from the analysed disturbances is shown in Fig.11. The oscillation period is about 6-7 s.
Figure 12. The frequency deviation detail EPS / RPS (t = 15s) after the primary and secondary control action in RPS for disturbances according to table. 3. (R_{RmaxRPS} = + / - 200MW)

- a) ΔP_{LRPS} = 700MW,
- b) ΔP_{LRPS} = 600MW,
- c) ΔP_{LRPS} = 300MW,
- d) ΔP_{LRPS} = 100MW,
- e) Δf_{EPS},
- f) The trumpet curve

6. CONCLUSION

Only in theory the primary and the secondary control are studied separately in time. In reality they are carried out simultaneously with different intensity and duration.

The main problem in optimal and stable operating of the frequency power regulating is subject to the principle Darrieux and correct sizing of primary and secondary control reserves.

If the slope of the power frequency characteristics are different from those of secondary regulation lead to a malfunction [5], the secondary control will work correctly in terms of goal but secondary control reserve mobilization will be inadequate and is reflected in the exchanges inaccuracies (which are monitored by the SCADA platform, supervisory control and data acquisition).

For proper operation of the secondary control the integration in time of the power exchange inaccuracies $\varepsilon(\Delta P_{ae})$ must be zero:

$$\int_0^t \varepsilon(\Delta P_{ae}) \cdot dt = 0$$

(38)

If the disturbance is occurs in EPS the secondary control in RPS will not remain passive and respond incorrectly: jointly if $\beta < B_i$ and reverse if $\beta > B_i$, ordering the downloading of the regulating generators even if the frequency decreases.

The optimizing of the secondary control is achieved by adjusting the time and the proportionality constants of the central controller and for the local plant controller PLC in order to obtain an optimal speed charge / discharge of the secondary control reserve depending on ramps for loading / unloading of the power generators and on the amplitude of the area control error ACE.

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