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An MPC Strategy for Automatic Generation Control with Consideration of Deterministic Power Imbalances

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Abstract

This paper presents a Model Predictive Control (MPC) approach for Automatic Generation Control, suitable for tackling deterministic frequency deviations in a multi-area interconnected power system. The current Proportional-Integral (PI) controllers were compared to the implementation of MPC in a single area and also in all areas of an interconnected system. In a direct comparison, the MPC-based frequency control proved to be superior to the traditional PI control scheme. Moreover, the effect of inaccuracies between the MPC model and the dynamic model of the power system was studied. The proposed controller was found to be robust against inaccuracies of the model and possible external disturbances.

I. Introduction

For a stable operation of power systems, keeping the balance between production and consumption is necessary. Constant changes in power demand and cases of power plant or large consumer outages affect this balance and can lead to frequency oscillations that, if too large, can endanger the normal operation of the system. Furthermore, in today's power systems, there is a strong tendency to incorporate an increasing amount of decentralized power generating units and to liberalize the power markets, thus introducing uncertainties in generation and complicating the control strategy. Large unpredictable power fluctuations from renewable energy sources, e.g. wind power, require efficient and fast acting controllers [1], [2]. In addition, frequency deviations in interconnected systems affect the power interchanges between areas over the tie-lines. Secondary frequency control (or Load Frequency Control) is a mechanism which aims at keeping this balance. The main objectives of the secondary frequency control are to restore the system frequency at its nominal value and to maintain the scheduled power interchanges between the different areas. In case secondary frequency control is done automatically, it is referred to as Automatic Generation Control (AGC) [3].

The AGC controller of an area adjusts the power reference values of the generators participating in it, so as to restore the balance between power generation and consumption after a disturbance [4]. The state-of-the-art implementation is to use a proportional-integral (PI) controller due to the relatively simple construction and robust performance. The gains of a PI controller are usually obtained through extensive field testing [5]. The main disadvantage of a PI controller is that it is a feedback system with constant parameters and therefore no direct knowledge of the controllable process. Consequently, a PI controller may not, in general, provide an optimal control policy, while this basic limitation can be faced with a Model Predictive Control (MPC) scheme [6], [7].

As illustrated in [8] and [9], in the last few years practically all synchronous areas of the European interconnected system have been experiencing increasing frequency variations, centred at the change of the hour, corresponding to the standardised time interval for cross border schedule changes. The hourly transit period for generation schedule is currently not explicitly defined between all market participants. This results in power imbalances and consequently imposes an extra burden on the AGC of each area [8]. The solutions proposed to face the deterministic frequency deviations problem consist of either changing the market rules from hourly changes to smaller time intervals, e.g. every 15 minutes, or changing the formulas of imbalance netting in order to give incentives to the generators to realize the schedule changes ramp-like instead of step-wise at the change of the hour [9].

MPC, also called receding horizon control, is a control strategy widely recognized as highly effective and practical. The control input is obtained by solving a discrete-time optimal control problem over a given horizon, producing an optimal open-loop control input sequence. The first control in that sequence is applied.

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At the next sampling instant, a new optimal control problem is formulated and solved based on the new measurements [7]. MPC is very popular and has many applications in the process control industry because the actual control objectives and operating constraints can be represented explicitly in the optimization problem that is solved at each control instant [10].

In the literature there are many studies that examine various centralized or decentralized approaches of MPC in power systems [5]-[7], [11]-[14]. To improve the control performance and to deal with influences of the hourly products on control areas, we propose an MPC-based AGC scheme. The contributions of this paper are as follows:

- The proposed approach is applicable to a real system as it was tested with the best available real data to the Swiss TSO.
- The predictable component of power imbalances was introduced into the prediction model of MPC.

The proposed MPC framework was simulated in order to prove the robustness of the proposed scheme and to identify benefits from the implementation of MPC for AGC in an interconnected power system.

This paper is organized as follows: In the next section the definition of AGC is given. Then the dynamic model of the power system is presented where a distinction between areas with hydro and thermal power plants is done. In the section IV the Model Predictive Control framework is given, while in the section V the test system as well as the simulations performed and their respective results are presented. The final section presents the conclusions of the conducted analysis.

II. Automatic Generation Control

Following a disturbance, the mismatch between generation and production is available at the area control center and it is indicated by the Area Control Error (ACE), which is a combination of both frequency deviation and tie-line power exchange deviation. ACE is the input to the AGC controller and is calculated in (1) [3].

$$ACE = \Delta P_{tie} + B_f\ \Delta f\ , \qquad (1)$$

where ΔP_{tie} is the difference between the scheduled and actual interchanges with adjacent areas, B_f is the frequency bias factor and Δf is the frequency deviation from the nominal value. The task of AGC is to bring the ACE back to zero.

III. Dynamic model of the power system

The mathematical description used for the dynamic representation of the power system is a state space formulation [3]. The generic description of a state-space model is given in (2):

$$\begin{cases} x_{k+1} = Ax_k + Bu_k \\ y_k = Cx_k \end{cases} , \qquad (2)$$

where x_k, u_k, and y_k denote state, input, and output at time instant k, respectively. Matrices A, B, and C are of appropriate size and denote state matrix, input matrix, and output matrix, respectively.

To obtain the dynamic model of a generic control area, it was assumed that the individual electrical connections within an area are so strong, at least in comparison to the tie-lines between adjoining areas, that each area may be represented by a single frequency, i.e. all generators in a single area swing together [15]. Furthermore, an appropriate transfer function was used for the lumped representation of individual power plant components (governors and turbines

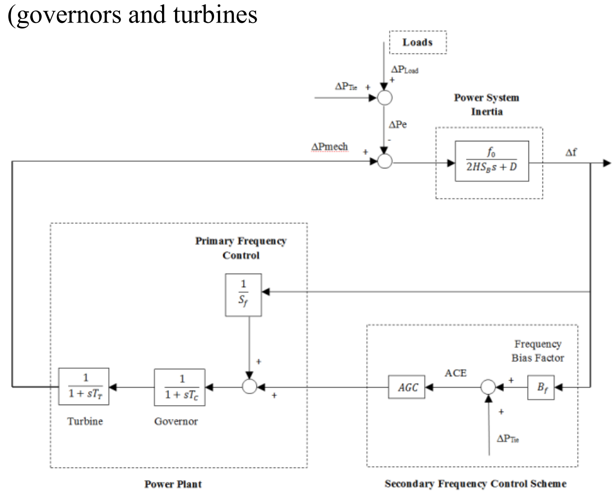

Figure 1. An area modeled with a thermal power plant.

Frequency dynamics of power systems are described by (3). The system inertia that includes the generators dynamics and the area load damping coefficient is given by (3):

$$\dot{\Delta f} = \frac{f_0}{(2\,H\,S_B\,s + D)}(\Delta P_{mech} - \Delta P_e)\ , \qquad (3)$$

where f_0 is the nominal frequency, H is the total inertia constant, S_B is the total rating of the control area, D is the area load damping coefficient and the indices *mech* and *e* stand for mechanical and electrical power, respectively.

Since $\Delta P_e = \Delta P_{load} + \Delta P_{tie}$, one achieves:

$$\dot{\Delta f} = \frac{[\Delta P_{mech} - (\Delta P_{Load} + \Delta P_{tie})]\ f_0 - D\,\Delta f}{2\,H\,S_B} \quad , \qquad (4)$$

where ΔP_{Load} is the load deviation.

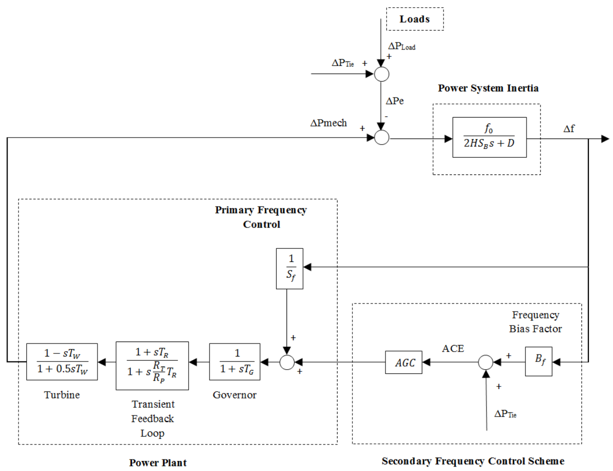

Figure 2. An area modeled with a hydro power plant.

The tie-line power for small deviations between areas *i* and *j* is given by (5):

$$\Delta P_{\text{tie}} = \sum_{\substack{j=1 \\ j\in\Omega_i}}^{N} \frac{U_i\,U_j}{X_{ij}}\, cos\left(\varphi_{0,i} - \varphi_{0,j}\right)\ \left(\Delta\varphi_i - \Delta\varphi_j\right) \quad , \qquad (5)$$

where X_{ij} is the equivalent reactance of the tie line and Ω_i denote a set containing all areas *j* connected to area *i*.

Since $\Delta\dot{\varphi}_i = 2\pi\,\Delta f$, it can be derived:

$$\Delta\dot{P}_{\text{tie}} = 2\pi \sum_{\substack{j=1 \\ j\in\Omega_i}}^{N} \frac{U_i U_j}{X_{ij}}\, cos\left(\varphi_{0,i} - \varphi_{0,j}\right)\left(\Delta f_i - \Delta f_j\right) \quad , \qquad (6)$$

where Δf_i and Δf_j are the frequency deviations of areas *i* and *j* ,respectively [3].

The representation of the turbine and the governor dynamics in power systems are associated with the type of power plant [3]. A thermal power plant can be described by two first-order transfer functions, representing its governor and the turbine dynamics as given in (7) and (8), respectively

$$\Delta\dot{P}_{Vt} = \frac{\Delta P_{AGC} - \frac{1}{S_f}\Delta f - \Delta P_{Vt}}{T_C} \quad , \qquad (7)$$

where ΔP_{Vt} is the output signal of the thermal turbine controller, ΔP_{AGC} is the setpoint sent from the secondary frequency controller, S_f is the speed droop characteristic of the representative generator in the area and T_C is the thermal turbine's governor time constant.

$$\Delta\dot{P}_{Tt} = \frac{\Delta P_{Vt} - \Delta P_{Tt}}{T_T} \quad , \qquad (8)$$

where ΔP_{Tt} is the thermal turbine output and T_T is the thermal turbine time constant.

A hydro power plant is described by hydro governor dynamics and turbine dynamic. If linearization by small signal analysis is considered, governor dynamics are described by (9) and (10), while (11) presents the turbine dynamic [16].
Hydro Governor:

$$\dot{F} = \frac{\Delta P_{AGC} - \frac{1}{S_f}\Delta f - F}{T_G} \quad , \qquad (9)$$

where F is the hydro-governor's first stage output and T_G is the governor time constant.

$$\Delta\dot{P}_{Vh} = \frac{F + \dot{F}T_R - \Delta P_{Vh}}{\left({R_T}/{R_P}\right)\ T_R} \quad , \qquad (10)$$

where ΔP_{Vh} is the second stage's output of the hydro governor, T_R is the reset time, R_T is the temporary droop and R_P is the permanent droop.

Turbine:

$$\Delta\dot{P}_{Th} = \frac{\Delta P_{Vh} - \Delta P_{Th} - T_W \Delta\dot{P}_{Vh}}{0.5\ T_W} \quad , \qquad (11)$$

where ΔP_{Th} is the hydro turbine output and T_W is the water starting time.

Based on the aforementioned equations the state vectors for a control area represented by a thermal and a hydro power plant are given in (12) and (13), respectively.

$$x_t = [\Delta f \quad \Delta P_{Tie} \quad \Delta P_{Vt} \quad \Delta P_{Tt}\ ]^{\mathrm{T}} \qquad (12)$$

$$x_h = [\Delta f \quad \Delta P_{Tie} \quad \Delta P_{Vh} \quad \Delta P_{Th} \quad F]^{\mathrm{T}} \qquad (13)$$

The output and control vectors for both representations are:

$$y = ACE \qquad (14)$$
$$u = \Delta P_{AGC}$$

IV. Model Predictive Control framework

A. *Theoretical background*

The basic procedure of the MPC relies in solving an optimal control problem by including system dynamics and constraints on the system input and output variables. The whole control scheme is based on a system model for predicting the future system behaviour over a prediction horizon p at every sampling interval. A sequence of future control policies for a control horizon m is calculated aiming at the minimization of a specific index. The first control policy of this sequence is actually implemented in the system and the same procedure is repeated in the next sampling interval, when new measurements are available. Given the dynamic model and the state space representation of the power system, we formulate the MPC setup in the following subsections.

B. Prediction Model

The prediction model (15) is based on the step response model (16), derived from the state space representation. The goal would be to predict how the control action (Δu) taken at the sample time k would influence the system output along the prediction horizon p. This is done with the help of the step response matrix S.

$$\hat{Y}(k+1|k)=M\hat{Y}(k+1|k-1)+S\Delta U(k|k)+P(y_m-\hat{y}_{k|k-1}) \quad (15)$$

where $\hat{Y}$ is the predicted system output, ΔU is the sequence of control actions, y_m is the measured system output at the sampling time k, $\hat{y}_{k|k-1}$ is the predicted output for the sampling time k based on the calculation of the previous step (k-1). The error term $y_m - \hat{y}_{k|k-1}$ accounts for imperfections in the model and possible unmeasured disturbances [5].

$$S=\begin{bmatrix} s_1 & 0 & 0 & \cdots & 0 \\ s_2 & s_1 & 0 & \cdots & 0 \\ s_3 & s_2 & s_1 & \cdots & 0 \\ \vdots & \vdots & \vdots & \ddots & \vdots \\ s_p & s_{p-1} & s_{p-2} & \cdots & s_{p-m+1} \end{bmatrix}$$

$$s_p= \sum_{i=1}^{p} CA^{i-1}B \quad (16)$$

$$M=\begin{bmatrix} 0 & 1 & 0 & \cdots & 0 \\ 0 & 0 & 1 & \cdots & 0 \\ \vdots & \vdots & \vdots & \ddots & \vdots \\ 0 & 0 & 0 & 0 & 1 \\ 0 & 0 & 0 & \cdots & 1 \end{bmatrix} \qquad P=[1 \quad \cdots \quad 1]^{\mathrm{T}}$$

C. Optimization Setup

The MPC generates control policies by minimizing a performance index (J). The performance index (J) is in quadratic form and penalizes (at every sampling time k) the weighted sum of the predicted output deviations from the reference trajectory and the control moves taken. The constrained optimization problem can be written in matrix form as follows:

$$\min_{\Delta U(k|k)} J =$$

$$\min_{\Delta U(k|k)} \left\{ \begin{matrix} [\hat{Y}(k+1|k)-Y_r(k+1|k)]^{\mathrm{T}} Q [\hat{Y}(k+1|k)-Y_r(k+1|k)] \\ +[\Delta U(k|k)]^{\mathrm{T}} R [\Delta U(k|k)] \end{matrix} \right\}$$

$$\text{s.t.} \qquad \Delta U_{min} \leq \Delta U(k|k) \leq \Delta U_{max} \quad (17)$$

$$U_{min} \leq U(k|k) \leq U_{max} \, ,$$

where Y_r is a defined reference trajectory, Q and R are the weighting coefficients' matrices in appropriate dimension. Matrices ΔU_{min} and ΔU_{max} describe the constraints imposed on the control moves, whereas U_{min} and U_{max} are saturation constraints (e.g. maximum procured secondary frequency control reserve).

D. Forecast of power imbalances in the prediction model

The power imbalances in the Swiss transmission network contain a deterministic and a stochastic component. The deterministic component can be forecasted by taking into account generation schedules, load forecast and cross border schedule changes [9], [17]. To take advantage of the predictive nature of the MPC, we adjusted the prediction model to incorporate the deterministic component of power imbalances. This component is inserted as a disturbance into the state space as follows:

$$\begin{cases} x_{k+1}=Ax_k+Bu_k+B_w w_k \\ y_k=Cx_k \end{cases} , \quad (18)$$

where w_k is the deterministic component of power imbalances and B_w is the disturbance matrix.

Therefore the prediction model can be expressed by (19):

$$\hat{Y}(k+1|k)=$$

$$M\hat{Y}(k+1|k-1)+S\Delta U(k|k)+S_w\Delta W(k|k)+P(y_m-\hat{y}_{k|k-1}) \quad , (19)$$

where

$$S_w=\begin{bmatrix} s_{w1} & 0 & 0 & \cdots & 0 \\ s_{w2} & s_{w1} & 0 & \cdots & 0 \\ s_{w3} & s_{w2} & s_{w1} & \cdots & 0 \\ \vdots & \vdots & \vdots & \ddots & \vdots \\ s_{w\,p} & s_{w\,p-1} & s_{w\,p-2} & \cdots & s_{w1} \end{bmatrix}$$

$$s_{w\,p}= \sum_{i=1}^{p} C \cdot A^{i-1} \cdot B_w \quad (20)$$

$$\Delta W(k|k) = \begin{bmatrix} \Delta w(k|k) \\ \Delta w(k+1|k) \\ \Delta w(k+2|k) \\ \vdots \\ \Delta w(k+p-1|k) \end{bmatrix}$$

V. Simulation of Test System and Discussion

For testing and validation of the proposed framework, a five area interconnected system was simulated using Matlab/Simulink. As mentioned in section III, each area was modeled as a representative power plant, with interconnections to other areas as shown in Fig. 3. Since the majority of power plants that participate in the secondary frequency control in Switzerland are hydro power plants, this area (denoted as Area 4) was modeled as such a plant using the best available model of the Swiss power system to Swissgrid. For the neighboring areas (Areas 1, 2, 3 and 5) the thermal power plant model was used.

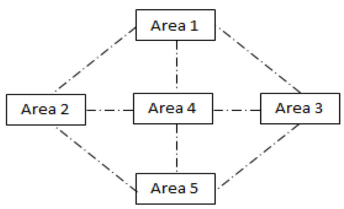

Figure 3. Graphical representation of the interconnected system's model.

A. Large step load increase

Initially, a load increase of 300 MW in area 4 was considered. The system was simulated for 5 minutes with the load deviation occurring at t = 50 sec. Three different control schemes are compared: PI controllers in all areas, MPC scheme implemented only in Area 4 (single MPC) and MPC-based controllers in all areas.

As illustrated in Fig. 4, one can conclude that the introduction of MPC-based controllers in the AGC framework has positive effects in bringing the ACE of the affected area more quickly to zero, compared to the PI controllers. Also, frequency deviations stabilize fast to zero by using the MPC scheme as depicted in Fig.5.

In order to account for the fact that the actual system parameters may be unknown during the design of the MPC controller, a 15% discrepancy has been inserted between the parameters of the system inertia and the damping coefficient of the loads used in the predictive

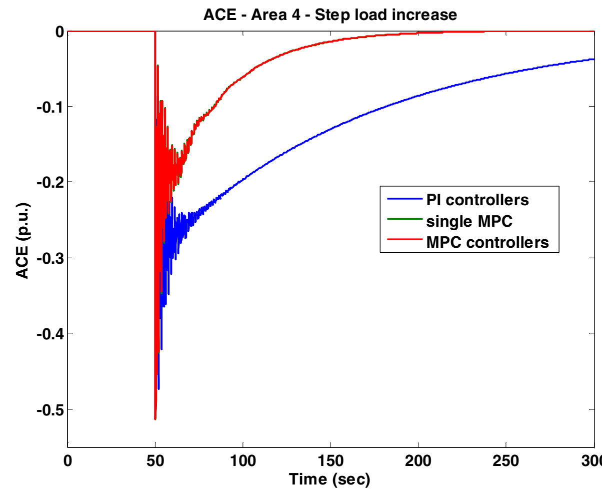

Figure 4. ACE in Area 4.

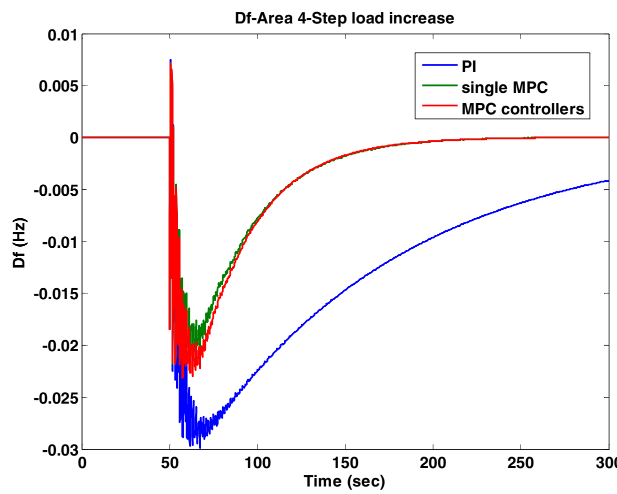

Figure 5. Frequency deviation in Area 4.

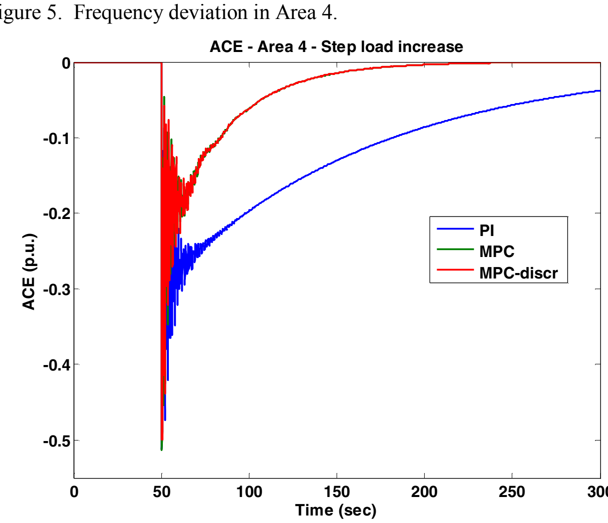

Figure 6. ACE in Area 4: PI controller, MPC controller in Area 4 with correct parameters (MPC) and MPC controller with different parameters between model and actual system (MPC-discr)

model of the controller and those in the dynamic system. This modification did not have any effect on the general evaluation of the two types of controllers described above, as shown in Fig. 6.

B. *Mixed-controller implementation*

In this section, we compare performance of MPC and PI controllers when a large load increase occurs in a neighboring control area. A step load increase of 500 MW occurring in Area 2 at t = 50 is assumed for the following scenarios. According to scenario 1 all control areas have PI controllers, for scenario 2 the only area with MPC is Area 2 and for scenario 3 the MPC framework is accommodated only in Area 4. Table I summarizes the specifications of the different scenarios.

Table I. Combination of control schemes for simulations

Scenario	Area 1	Area 2	Area 3	Area 4	Area 5
1	PI	PI	PI	PI	PI
2	PI	MPC	PI	PI	PI
3	PI	PI	PI	MPC	PI

Figure 7 demonstrates the output signals of the respective controllers in Areas 2 and 4. One can observe that with a mixed-controller implementation in the interconnected system, the 'non-interactive control' concept still holds. With the MPC implementation, the response of the AGC signal in the affected Area (Area 2) is faster, whereas controllers in other Areas (e.g. Area 4) do not react in any case.

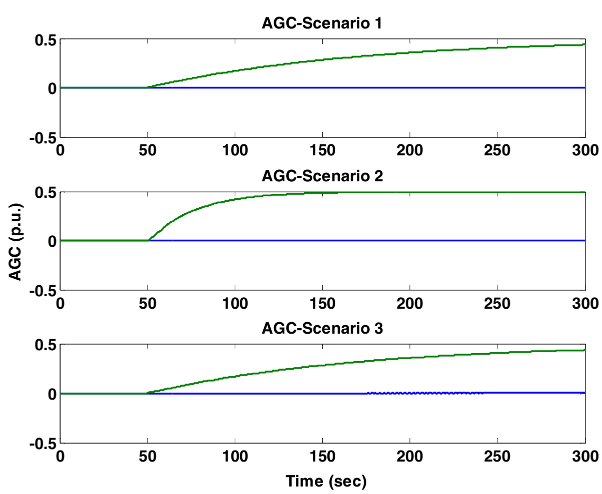

Figure 7 AGC signal in Areas 2 (green) and 4(blue) for all 3 scenarios.

C. *Hourly schedule changes*

Due to the hourly auctions of the European Spot energy Markets, generation schedules change in step form at full hours. However, power consumption changes are not step-, but rather ramp-like. Therefore, it is common to observe spikes in control signal at the full hours [8]. To cover these hourly spikes, the MPC scheme was complimented with the imbalances forecast feature, as presented in section IV-D. Assuming that load increase of 300 MW in Area 4 is scheduled, the difference between the step in the generators schedule and the ramp change of the loads can be forecasted and inserted as a disturbance (Δw) in the MPC formulation.

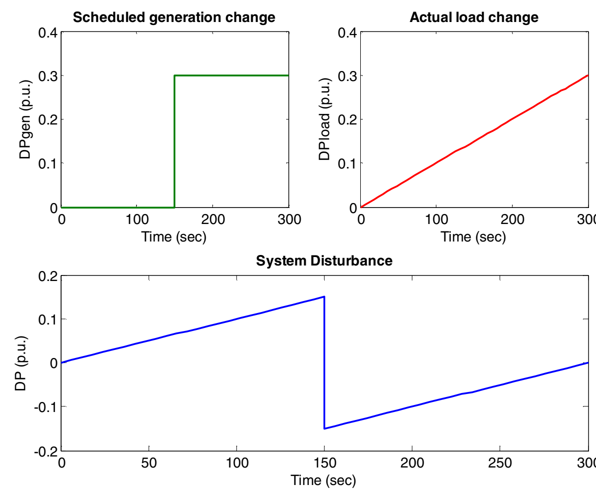

Figure 8. Disturbance in the system inserted through the difference between scheduled and actual load change.

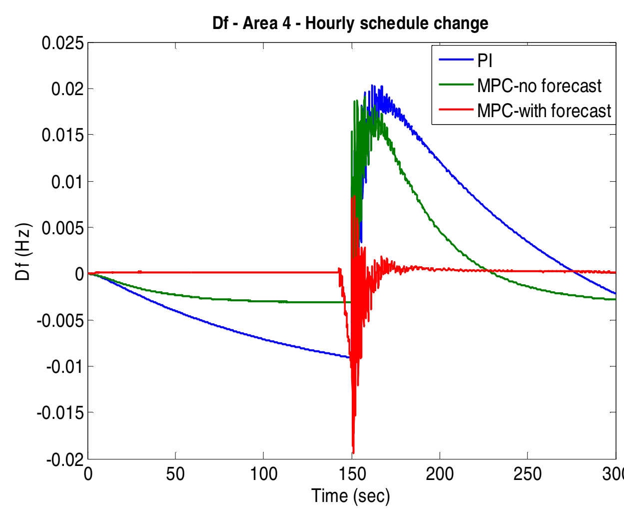

Figure 9. Frequency deviation in Area 4 for different control schemes.

The frequency deviation and the ACE for the PI scheme and the MPC with and without the forecast feature are presented in Fig. 9 and 10 respectively. It is evident that the introduction of the power imbalances forecast in the prediction model results in a better performance of the MPC scheme. The controller anticipates the predicted disturbance and thus takes actions in advance. This leads

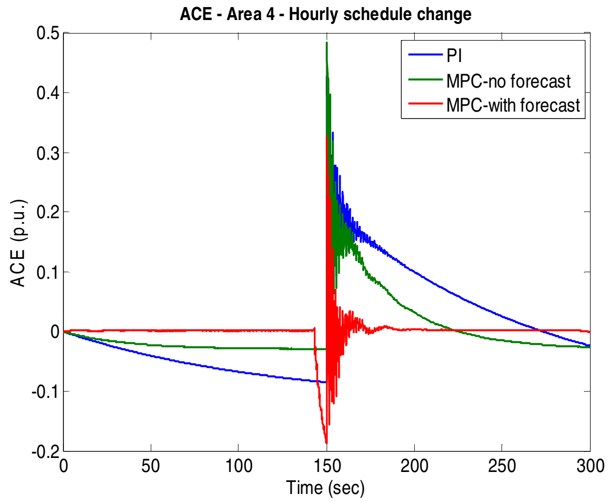

Figure 10. ACE in Area 4 for different control schemes

to smaller frequency excursions and a more stable ACE, since it stays at zero even if the disturbance has already begun.

In order to evaluate the effect of forecasting errors in the presented control strategy, the simulation was run again with an additional discrepancy between the load deviation imposed to the power system and the predicted disturbance inserted in the MPC.

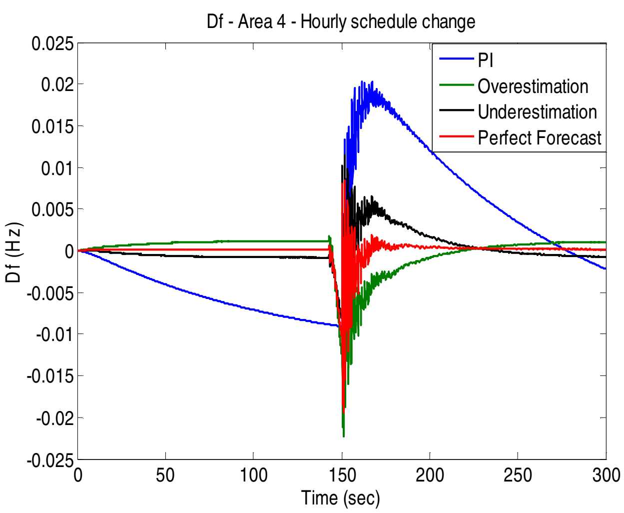

Figure 11. Frequency deviation in Area 4 comparing PI with MPC having perfect forecast of the coming disturbance, overestimation and underestimation of the disturbance.

Fig. 11 presents the resulting frequency deviation comparing the PI scheme with those of MPC with perfect forecast and with 30 % over- and underestimation of the disturbance. It can be observed that in spite of larger frequency deviations due to the forecast errors, the MPC response is still preferable to the PI.

VI. Conclusion

In this paper an MPC-based scheme for the secondary frequency control was proposed, based on work stipulated in literature. An improvement was introduced, considering predictable deterministic disturbances. In a direct comparison, MPC-based frequency control proved to be superior to the traditional PI control scheme. The MPC-based controller proved to be robust against model design inaccuracies in the model and possible external disturbances. The proposed controller has shown also a very good performance and promising results for tackling deterministic deviations. These may be e.g. hourly schedule changes in the continental Europe interconnected system.

In order to achieve the highest positive effect of the MPC scheme, this should be adopted from the area(s) experiencing these disturbances. It is important to stress out that this specific scheme relies on a non-interactive principle.

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