Sensitivity Analysis of the Interaction between Power System Dynamics and Unit Commitment

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***Abstract*—This paper provides a sensitivity analysis of the interaction between the dynamic response of power systems and the unit commitment problem. A sub-hourly, mixed-integer linear programming Security Constrained Unit Commitment (SCUC) with a 24-hour rolling horizon is considered to cope with the uncertainty introduced by the large-scale penetration of non-synchronous, stochastic renewable energy sources (RES). The SCUC is then integrated into Time Domain Simulations (TDS) and a sensitivity analysis with respect to different frequency controllers/machine parameters and different scheduling time intervals is carried out. Simulation results based on the 39-bus system show that shorter scheduling periods of the SCUC leads to lower operating cost and lower frequency variations.**

***Index Terms*—Unit commitment, sensitivity analysis, time domain simulation, power system dynamics, frequency stability.**

I. Introduction

A. Motivation and Literature Review

The decarbonisation of the electricity sector means that large conventional synchronous generators are being replaced with mainly small non-synchronous, stochastic renewable energy sources (RES). The safe integration of RES requires detailed studies that takes into account stability issues (e.g., frequency stability) of power systems [1]. However, a drawback of most studies carried out so far is that they use hourly data that makes difficult to observe any transient beahviour occuring within each hour [2]. This is of particular importance nowadays as higher penetrations of RES increase the uncertainty and volatility of the net load, reduce the inertia, and, in turn, significantly impact on the stability of power systems [3], [4].

A way to tackle these challenges is to make use of a sub-hourly Unit Commitment (UC) problem [5]–[8]. Transmission System Operators (TSOs) have acknowledged the need for short scheduling timescales (less than an hour) in order to better accomodate the variable net load [9]. Another possibility is to include dynamic constraints into the UC formulation [10]–[14], or use the solution of the UC, to study the impact of RES with respect to power imbalances [8] and instability issues [15].

While the works cited above can help define robust scheduling from the stability point of view and/or give a good overview of system security, they all have a major drawback, namely the fact that the dynamics of the system are oversimplified. On the other hand, other authors have proposed enhanced frequency regulation controllers, e.g., Automatic Generation Control (AGC), in order to respond to systems with fast and persistent fluctuations caused by RES [16].

B. Contributions

The goal of this paper is to present a simulation platform that takes into consideration all the above works, including their advantages and limitations, and perform a sensitivity analysis of the interaction between the dynamic response of power systems and UC. This is achieved through the use of a sub-hourly, mixed-integer linear programming Security Constrained Unit Commitment (SCUC) with a rolling time horizon. The SCUC is gelled into time domain simulations (TDS), and then relevant sensitivity analyses with respect to different frequency controller/machines parameters, e.g., different inertia of the synchronous machines, different droops of the turbine governors (TGs) and different scheduling time periods are carried out.

C. Paper Organization

The rest of the paper is organized as follows. Section II describes the mathematical formulation of the SCUC and the power system model for transient stability analysis. The case studies on the modified IEEE 39-bus system and the respective results are discussed in Section III. Conclusions and outlines on future work are given in Section IV.

II. Modeling

This section briefly outlines the SCUC problem (Subsection II-A) and the transient stability model of power systems (Subsection II-B) considered in this paper. How the SCUC and the dynamic models are intertwined together is discussed in Subsection II-C.

A. Unit Commitment Formulation

The UC is an optimization problem utilized by system operators to economically and securely plan and operate the system. This is done by scheduling the generator units based on their cost and at the same time making sure that technical and network constraints are not violated. Due to the need to model start-up and shut-down of generators, the UC problem is

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generally formulated as a Mixed-Integer Linear Programming (MILP) [17]. In this work, we use a MILP SCUC problem based on [18]. The mathematical model of the SCUC is presented below.

1) Objective function: The total cost to be minimized includes the fixed, variable, start-up and shut-down costs of the generating units, as follows:

$$\sum_{t\in\mathcal{T}}\sum_{g\in\mathcal{G}}(C_g^F z_{g,t}^F + C_g^V p_{g,t} + C_g^{SU} z_{g,t}^{SU} + C_g^{SD} z_{g,t}^{SD}) \quad (1)$$

where t represent the time period in the planning horizon; g is the index for the generating units; $\mathcal{T}$ is the set of time periods, e.g., $\{1,\ldots,24\}$ hours; $\mathcal{G}$ is the set of generating units; $z_{g,t}^F$ is the binary variable that represents the status of the units in time period t, e.g., 1 if ON; $z_{g,t}^{SU}$ and $z_{g,t}^{SD}$ are the binary variables that represent the status of the units at the beginning of time period t, i.e., $z_{g,t}^{SU} = 1$, $z_{g,t}^{SD} = 0$ if the generator is up and $z_{g,t}^{SU} = 0$, $z_{g,t}^{SD} = 1$ is the generator is down; and $p_{g,t}$ is the continuous variable representing the active power production during time period t.

2) Binary variable constraints: The binary variables need to be consistent with each-other. For instance, the sum of the start-up and and shut-down binary variables cannot be greater than one:

$$z_{g,t}^{SU} - z_{g,t}^{SD} = z_{g,t}^F - z_{g,t-1}^F, \quad \forall g \in \mathcal{G}, \forall t \in \mathcal{T}, \quad (2)$$

$$z_{g,t}^{SU} + z_{g,t}^{SD} \le 1, \quad \forall g \in \mathcal{G}, \forall t \in \mathcal{T}, \quad (3)$$

$$z_{g,t}^F, z_{g,t}^{SU}, z_{g,t}^{SD} \in \{0,1\} \quad \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \quad (4)$$

It is relevant to note that for the first time period, the initial status of the unit, namely $z_{g,0}^F$ has to be known in (2). Then, when the model steps forward (i.e., rolling approach) the status of the units of the previous horizon serve as an initial status for the next horizon.

3) Generation limits: When online, generating units have a maximum and minimum available capacity limit, as follows:

$$P_g^{\min} z_{g,t}^F \le p_{g,t} \le P_g^{\max} z_{g,t}^F, \quad \forall g \in \mathcal{G}, \forall t \in \mathcal{T}, \quad (5)$$

where, $P_g^{\min}$ and $P_g^{\max}$ are the minimum and maximum active power limits, respectively.

4) Ramping limits: Between two successive time periods a unit output is bounded by a maximum ramp-up rate. Similarly, when a unit start-up at the beginning of the time period its power output is limited by the relevant start-up rate. The same logic applies for the ramping-down and shut-down ramping limits. These constraints are:

$$p_{g,t} - p_{g,t-1} \le R_g^U z_{g,t-1}^F + R_g^{SU} z_{g,t}^{SU}, \ \forall g \in \mathcal{G}, \forall t \in \mathcal{T}, \quad (6)$$

$$p_{g,t-1} - p_{g,t} \le R_g^D z_{g,t}^F + R_g^{SD} z_{g,t}^{SD}, \quad \forall g \in \mathcal{G}, \forall t \in \mathcal{T}, \quad (7)$$

where, $R_g^U, R_g^{SU}, R_g^D, R_g^{SD}$ are the ramping-up, start-up ramping, ramping-down and shut-down ramping limits, respectively. In general, ramping limits are given in per hour, but since we are using a sub-hourly UC we divide the hourly data by the relevant sub-hourly scheduling interval, e.g., by 4 in the 15 min case. Note again that $z_{g,0}^F$ has to be assigned for the first time period.

5) Power balance: One of the basic constraints of the UC that ensures the active power balance at every node of the network:

$$\begin{aligned}&\sum_{g\in\mathcal{G}_n} p_{g,t} - \sum_{j\in\mathcal{D}_n} d_{j,t} = \\ &\sum_{m\in\mathcal{L}_n} B_{nm}(\delta_{n,t} - \delta_{m,t}), \ \ \forall n \in \mathcal{L}, \ \ \forall t \in \mathcal{T},\end{aligned} \quad (8)$$

where $d_{j,t}$ is the forecasted demand located at node n; $\mathcal{L}$ is the set of all branches; B_{nm} is the susceptance of transmission line $n-m$; and $\delta_{n,t}$ and $\delta_{m,t}$ are the voltage phase angles at nodes n and m, respectively. The set $\mathcal{G}_n$ indicates the generators connected to bus n. Similarly, $\mathcal{D}_n$ and $\mathcal{L}_n$ are the demands and lines, respectively, connected to bus n.

6) Transmission lines limits: These constraints ensures that the power through a transmission line does not violate its physical limits (i.e., thermal):

$$\begin{aligned}&-P_{nm}^{\max} \le B_{nm}(\delta_{nt} - \delta_{mt}) \le P_{nm}^{\max}, \\ &\forall n \in \mathcal{L}, \ \ \forall m \in \mathcal{L}_n, \ \ \forall t \in \mathcal{T}_n,\end{aligned} \quad (9)$$

where, $P_{nm}^{\max}$ is the capacity limit of the line.

7) Security constraints: Due to security reasons, spinning reserves are required in order to deal with unforeseen event in the system (e.g., unscheduled outage):

$$\sum_{g\in\mathcal{G}_r} P_g^{\max} z_{g,t}^F \ge \sum_{j\in\mathcal{D}}(d_{j,t} + R_{j,t}), \quad \forall r \in \mathcal{R}, \forall t \in \mathcal{T}, \quad (10)$$

where $d_{j,t}$ is the system total forecasted demand; $R_{j,t}$ accounts for reserves; and $\mathcal{G}_r$ is the set of generators that provides reserve (in the following, we assume $\mathcal{G}_r \equiv \mathcal{G}$). For simplicity, the amount of reserve is assumed to be a percentage of the total demand. This value is lower for shorter scheduling timescales assuming that better forecast is available [19].

8) Reference angle: Finally, the voltage phase angle at some node of the network has to be assigned:

$$\delta_{n,t} = 0, \quad \forall t \in \mathcal{T}, \quad (11)$$

where n is the node chosen to be the reference angle.

9) Remarks on the UC model: Equations (1)-(11) form a conventional model of SCUC. The goal, in fact, is not to propose a novel formulation of the UC but rather to show how the UC can be embedded into the dynamic model of power systems and then used for different stability studies (i.e., sensitivity analysis with respect to different frequency controllers parameters). In the following, the SCUC is modeled using two different sub-hourly time periods, 15 and 5 minutes, respectively. Moreover, a rolling (moving window) approach with a planning horizon of 24 hours is considered to account for better forecast. In other words, the SCUC problem (1)-(11) is solved at every time period t for the next 24 hours.

The average demand of each load is assumed to vary as a nonlinear function. To simulate uncertainty, the values $d_{j,t}$ utilized to solve the SCUC problem at each period differ from the actual demand of the loads by a given percentage. A normal distribution function with different standard deviations per period, say, σ_t, is used to generate the forecast error. The value of the standard deviation increases linearly as a function of t. Specifically, σ_t is null for current loading condition, i.e., $t = 0$, and is maximum for the last period of the planning horizon $\mathcal{T}$.

B. Power system model

Power system dynamics are modeled as a set of hybrid differential algebraic equations (HDAEs) [20], as follows:

$$\begin{aligned} \dot{\boldsymbol{x}} &= \boldsymbol{f}(\boldsymbol{x}, \boldsymbol{y}, \boldsymbol{u}, \boldsymbol{z}) \\ \boldsymbol{0} &= \boldsymbol{g}(\boldsymbol{x}, \boldsymbol{y}, \boldsymbol{u}, \boldsymbol{z}) \ , \end{aligned} \tag{12}$$

where $\boldsymbol{f}$ are the differential equations, $\boldsymbol{g}$ are the algebraic equations, $\boldsymbol{x}$, $\boldsymbol{x} \in \mathbb{R}^n$ are the state variables (e.g., generator rotor speeds), and $\boldsymbol{y}$, $\boldsymbol{y} \in \mathbb{R}^m$, are the algebraic variables (e.g., bus voltage angles); $\boldsymbol{u}$, $\boldsymbol{u} \in \mathbb{R}^q$, are the inputs (e.g., load forecast, generator bids); and $\boldsymbol{z}$, $\boldsymbol{z} \in \mathbb{R}^p$, are the discrete variables (e.g., status of the machines).

Equations (12) represent the conventional model of power systems for angle and voltage stability analysis. They includes dynamic models of synchronous machines, turbine governors (TGs), automatic voltage regulators, automatic generation control (AGC), and the discrete model of SCUC, just to mention some. In particular, the TGs are modelled as a conventional droop (R) and a lead-lag transfer function, whereas the AGC is a simple integrator with gain k_o. These models are not further discussed here for space limitation. The interested reader is referred to [20] for a detailed description of such models.

C. Interaction between UC and HDAEs

The solution of the SCUC, namely $p_{g,t}$, $\forall g \in \mathcal{G}$, is utilized to change the power set point of the turbine governors of the power plants. Figure 1 shows the connection and the interactions between SCUC, turbine governors, generators, demands and the rest of the grid.

The SCUC is implemented in the Python language and solved using Gurobi [21], while all simulations are obtained using Dome, a Python-based software tool [22].

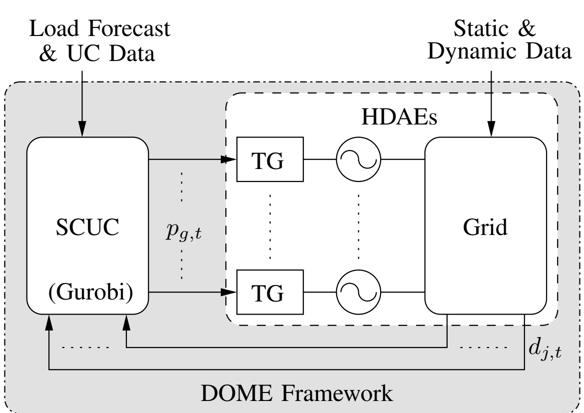

Fig. 1: Interaction between the SCUC problem and the dynamic model of the turbine governors, the synchronous machines and the grid.

III. Case Study

In this section, a sensitivity analysis with respect to net-load volatility and control/machine parameters is carried out. Four case studies are considered on the modified IEEE 39-bus system. The first two scenarios use a 15-minute scheduling period while the last two use a 5-minute scheduling period. Each scenario is characterized by a different amount of load stochastic variations.

The base case (reference) machine/control parameters are set as follows: gain of the AGC is $k_o = 50$, droop of the TGs is $R = 0.05$, and the inertia of the synchronous machines is taken equal to the original values, say M_o, used in [23]. When solving the sensitivity analysis, these parameters are varied, one at a time, and their impact on the standard deviation of the frequency of the system (σ) is observed.

The data of the SCUC are taken from [24]. Since these data differ from that of the dynamic IEEE 39-bus system [23] (e.g., different loading levels), we have scaled relevant dynamic data of the IEEE 39-bus system to that used in the UC problem given in [24].

The SCUC is solved at every time period (i.e., 15 or 5 minutes) using a rolling 24-hour horizon. For simplicity, in all scenarios, we focus only in the first hour of the planning horizon. This hour has a demand forecast of 700 MW. Next, in order to simulate uncertainty, in all scenarios, the load is assumed to differ from the forecast by a maximum of 30% in the first hour. In other words, the load in the last period of the first hour is chosen to be 30% higher than the forecast and it is proportionally lower for other periods of this hour.

The total number of state and algebraic variables of the system for all scenarios are 169 and 223, respectively. The average computing time for each simulation is about 5 minutes.

A. Scenario 1 – 15-Minute Scheduling with High Noise

Stochastic white noise is added to the load power consumptions as proposed in [25]. The standard deviation of the white noise for this scenario is 1% of the base case load. During the first hour, the SCUC is solved four times (i.e., 4 periods of 15 minutes) and the average value of the objective function for these 4 periods is found to be $561,784.79. It is relevant to note that this cost is lower compared to the one found in some other works [26], [17]. This is mainly due to the fact that since we are using a 15 minute scheduling interval, the value of the total reserve is taken 2.5% of the total demand and so proportionally lower compared to the above works that use a value of 10%.

Simulation results of this scenario are shown in Table I. These indicate that, as the gain k_o of the AGC increases, the standard deviation of the frequency decreases. Also, as expected, if the droop of the TGs increases, the standard deviation of the frequency increases. Interestingly enough though, decreasing the inertia of the system leads to slightly lower standard deviations of the frequency. This is due to the fact that the distribution of the frequency is not exactly

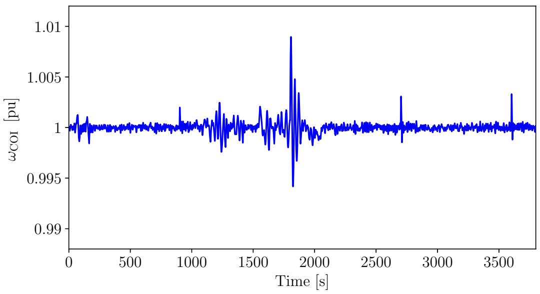

Fig. 2: Frequency of the center of inertia for 15-minute scheduling, high noise and $M = M_o$.

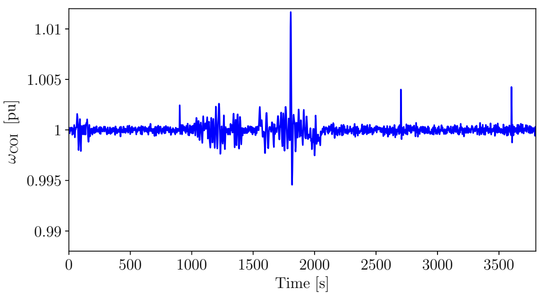

Fig. 3: Frequency of the center of inertia for 15-minute scheduling, high noise and $M = 0.5M_o$.

a Gaussian distribution because of the jumps of the power imposed by the SCUC [27].

Figures 2 and 3 show the frequency of the center of inertia ($\omega_{\rm COI}$) for the case when $M = M_o$ and $M = 0.5M_o$, respectively. These figures show that the higher variations of the frequency actually occur for $M = 0.5M_o$ but, since the frequency takes a longer time (i.e., slower dynamics due to the higher inertia) to return to its nominal value when $M = M_o$, the standard deviation of $\omega_{\rm COI}$ is slightly lower for $M = 0.5M_o$ than for $M = M_o$.

Finally, Fig. 4 depicts the mechanical power of the relevant synchronous machines that are turned ON during the first hour of the time horizon. Significant electro-mechanical oscillations occur every 15 minutes due to a change in the operating point of the synchronous machines enforced by SCUC.

TABLE I: 15-minute scheduling with high noise – Standard deviation σ of the frequency for different control/machine parameters

k_o	σ 10^{-4} pu	R	σ 10^{-4} pu	M	σ 10^{-4} pu
25	9.73	0.02	4.39	$2M_o$	6.85
50	7.5	0.05	7.5	M_o	7.5
100	5.09	0.08	9.26	$0.5M_o$	7.43

B. Scenario 2 – 15-Minute Scheduling with Low Noise

The standard deviation of the load noise in this scenario is chosen to be 5 times lower compared to Scenario 1. The average value of the objective function is found to be $559,191.47 and hence lower than Scenario 1. This is due to the fact that the net load volatilty is lower. The simulation

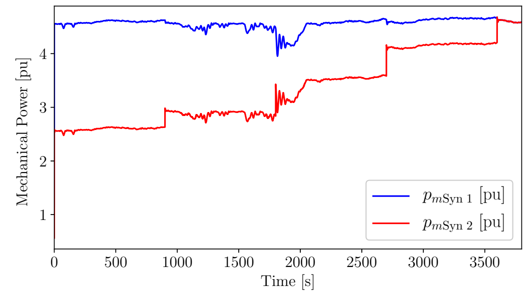

Fig. 4: Mechanical power of two relevant machines for the 15-minute scheduling and high noise.

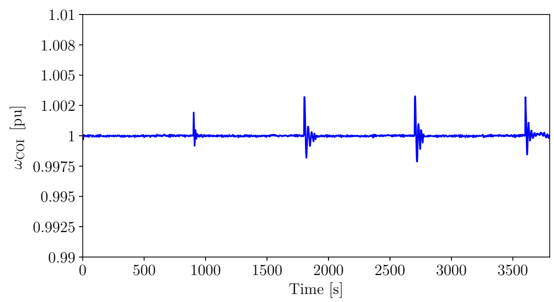

Fig. 5: Frequency of the center of inertia for 15-minute scheduling and low noise.

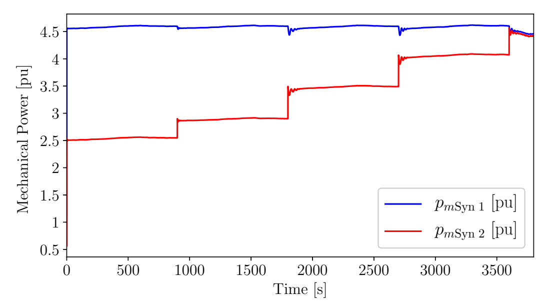

Fig. 6: Mechanical power of two relevant machines for the 15-minute scheduling with low noise.

results of the sensitivity analysis are shown in Table II. As expected, increasing the gain k_o of the AGC decreases σ; increasing the droop R of TGs leads to higher values of σ; and decreasing the inertia M of synchronous machines increases the standard deviation of the frequency.

TABLE II: 15-minute scheduling with low noise – Standard deviations σ of the frequency for different control/machine parameters

k_o	σ 10^{-4} pu	R	σ 10^{-4} pu	M	σ 10^{-4} pu
25	3.74	0.02	1.57	$2M_o$	2.84
50	2.98	0.05	2.98	M_o	2.98
100	2.31	0.08	3.99	$0.5M_o$	3.01

Figures 5 and 6 show the $\omega_{\rm COI}$ and the mechanical power, respectively, of the synchronous machines. It is evident from these two figures that the oscillations significantly decreases compared to Scenario 1.

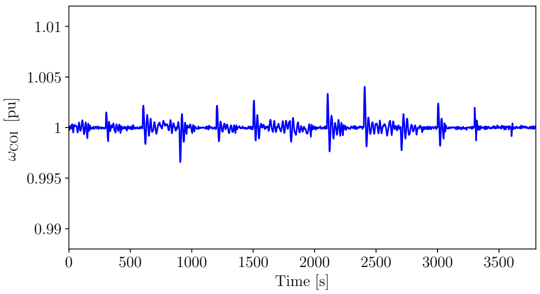

Fig. 7: Frequency of the center of inertia for 5-minute scheduling and high noise.

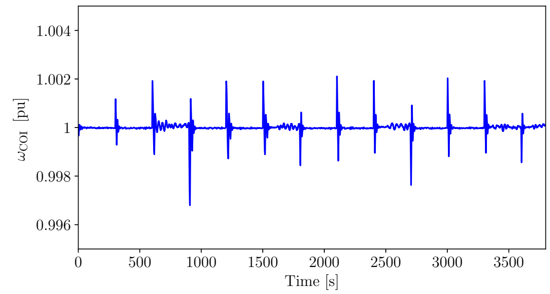

Fig. 9: Frequency of the center of inertia for 5-minute scheduling, low noise and $M = M_o$.

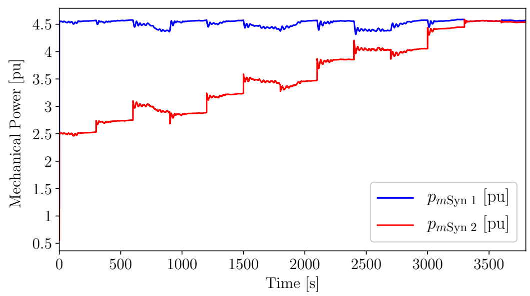

Fig. 8: Mechanical power of two relevant machines for the 5-minute scheduling with high noise.

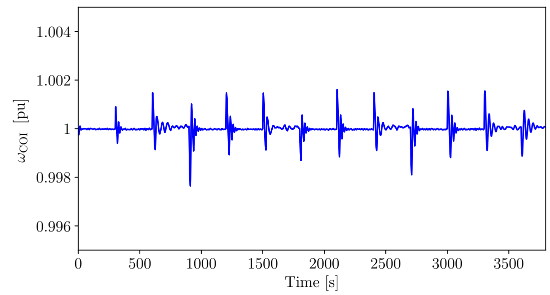

Fig. 10: Frequency of the center of inertia for 5-minute scheduling, low noise and $M = 2M_o$.

C. Scenario 3 – 5-Minute Scheduling with High Noise

In this scenario, load noise is proportionally lower to scenario one. The average value of the objective function is found to be $557,373.86 and hence lower than the other two scenarios. This is the result of lower reserves, and lower noise and uncertainty of the net load. Therefore, it can be said that shorter scheduling periods of the UC leads to lower operating costs. On the other hand, the sensitivity analysis with respect to different parameters is shown in Table III. Similar to scenario one, increasing the gain $k0$ of the AGC decreases σ; increasing R leads to higher values of σ; and decrasing inertia M increases the value of σ.

Figures 7 and 8 show the ω_{COI} and the mechanical power of synchronous machines. Frequency variations and electromechanical oscillations are significant but lower than what obtained for Scenario 1. These results support the conclusion above that shorter periods of the UC are not only better from the economic point of view but also improve the dynamic behaviour of the system.

TABLE III: 5-minute scheduling with high noise – Standard deviations σ of the frequency for different control/machine parameters

k_o	σ 10^{-4} pu	R	σ 10^{-4} pu	M	σ 10^{-4} pu
25	6.68	0.02	3.71	$2M_o$	3.84
50	5.29	0.05	5.29	M_o	5.29
100	4.71	0.08	6.97	$0.5M_o$	6.33

D. Scenario 4 – 5-Minute Scheduling with Low Noise

The white noise of the load is reduced 5 times with respect to Scenario 3. The objective function is found to be $556,421.26 and, hence, lower than all other scenarios. It can be concluded that the shorter the scheduling period of the UC (i.e., lower uncertainty) the lower the total operating costs. Moreover, the sensitivity analysis is shown in Table IV. Again, similar to Scenario 1, increasing the inertia leads to a higher frequency standard deviation. Following the same rationale discussed in Scenario 1, a higher value of σ with high inertia is due to the fact that, after each SCUC scheduling, the frequency takes a longer time to recover to its nominal value. To support this statement, Figs. 9 and 10 show the ω_{COI} for the case when $M = M_o$ and $M = 2M_o$, respectively.

Finally, Fig. 11 depicts the mechanical power of the synchronous machines for the base case of Scenario 4 (i.e., $k_o = 50$, $R = 0.05$ and $M = M_o$). Based on simulation results, this is the scenario that shows both the lowest costs and the lowest frequency variations.

TABLE IV: 5 minute scheduling with low noise – Standard deviations $\sigma$of the frequency for different control/machine parameters

k_o	σ 10^{-4} pu	R	σ 10^{-4} pu	M	σ 10^{-4} pu
25	3.8	0.02	1.73	$2M_o$	2.99
50	2.79	0.05	2.79	M_o	2.79
100	2.16	0.08	3.62	$0.5M_o$	2.87

IV. Conclusions

This paper carries out a sensitivity analysis of the interaction between power system dynamic response and UC. A MILP SCUC is used in order to incorporate the uncertainty and variability of the net load. Then, different frequency controllers/machines parameters (e.g., droop of the TGs) and

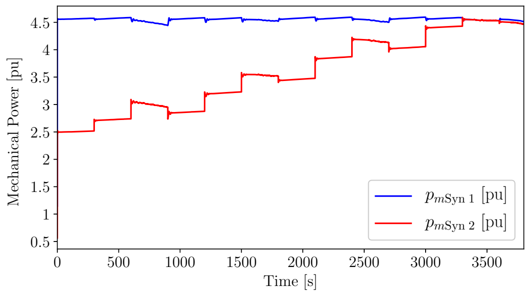

Fig. 11: Mechanical power of two relevant machines for the 5-minute scheduling with low noise.

different scheduling time intervals of the UC (e.g., 15 minutes) are used to study their impact on the dynamic behaviour of the system. The focus was on frequency variations following a UC schedule and different values of control/machine parameters. The main message from the case studies is that a shorter scheduling period of the UC leads to a decrease in cost and lower variations of the frequency of the system. This has to be taken into account by system operators as power systems are expected to integrate more and more RES. Future work will focus on the evaluation of the dynamic interaction of the UC and various schemes of primary and secondary frequency controllers.

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