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Impact of Frequency Control Reserve Provision by Storage Systems on Power System Operation

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Abstract: Batteries can be used to provide ancillary services, such as primary frequency response. However, their energy capacity is limited. Therefore, set-point adjustments are necessary and the energy for this has still to be provided by power-plants that do not face energy constraints. This paper investigates various aspects of and potential benefits for power system operation and stability, if energy-constraint units are allowed to participate in the ancillary service markets.

Keywords: Ancillary Services; Frequency Control Reserves; Battery Energy Storage Systems (BESS).

1. INTRODUCTION

In any electric power system, production and consumption of electric energy has to be in balance at any time. This is usually guaranteed by automatic control schemes adjusting production of some power plants to meet the current demand. These control schemes also have to be able to handle contingencies, such as the failure of a plant or the outage of a line. If there is a power mismatch, system frequency f will change as the rotating mass in generators will be either accelerated, thus increasing f, if too much electric energy is produced, or decelerated, thus decreasing f, if the load is bigger than the production. The inertia of the rotating mass of generators defines the rate of frequency change when a power mismatch is present. While the rotational inertia prevents the system frequency from making sudden jumps, it cannot contain a contingency by itself — if no action is taken and the power mismatch remains, system frequency will diverge until a critical point is reached, resulting in a black-out.

In the European electricity transmission grid, three levels of control are being used to prevent this. 1) Primary control, a distributed control scheme that adapts power plant production proportionally to the frequency deviation from nominal system frequency and thus limits the frequency change. However, a steady-state deviation from the nominal frequency remains. 2) Secondary control, which has a central controller with an integral part and can thus bring back the frequency to nominal valuers. And finally, 3) Tertiary control, which is activated manually and used for re-dispatch of production to relieve secondary control when necessary. Similar schemes with different nomenclature are in place in all major power grids.

While above control scheme is well able to guarantee security and reliability of the European grid, when considering the increasing share of renewable generation it might be necessary to rethink the adequateness of power plants for primary control reserves. There are two issues:

1) Power plants participating in primary control have currently up to 30 s to react to a frequency deviation. With current levels of inertia, this time is sufficient to keep the system frequency within acceptable levels even after a big contingency, such as the outage of a major line. However, renewable energy sources have usually low or no rotational inertia as they are coupled to the grid by converters. As their share is increasing and conventional power plants are being disconnected, the inertia within the grid is reduced and the frequency will drop faster after an outage. It might therefore be necessary to considerably increase the ramp rates of units providing primary control reserves. It is also often assumed that faster ramp rates of units providing primary control would lead to generally lower frequency deviations. Such fast ramp rates could be provided by many storage technologies, such as batteries and flywheels – as well as by Demand Response (DR). In fact, provision of primary frequency control with distributed loads, such as freezers and electric water heaters, was proposed as early as 1980 by (Schweppe et al., 1980), and further investigated by, e.g., (Xu et al., 2011) and (Molina-García et al., 2011)

2) Assume now a system with a very high share of renewable generation. At many times, conventional power plants will run solely to provide ancillary services, even though enough energy is already produced from renewable sources. Relying on this *must-run generation* contradicts the aim of an economic dispatch and of reduction of carbon-dioxide emissions, and is costly.

For these two reasons, the power systems research community is increasingly looking at provision of ancillary services with storage units and DR. There are some challenges on the way. Usually, ancillary service signals are not zero-mean over any reasonable time period. The battery therefore has to either charge or discharge for a prolonged period, meaning that storage capacity limits are hit. An appropriate recharge strategy is needed, which guarantees that the storage system is able to follow the ancillary services signal at all times. Such strategies are discussed in more detail in Section 2. The off-set energy may either be bought at intra-day markets, or it is consumed in form of balancing energy acquired from secondary control reserves.

So far, research in this topic was focused on storage system operation, while grid-wide issues and effects on system stability due to the altered behavior of one of the fastest levels of frequency response has not yet been studied in detail. This paper aims at closing this gap. Specifically, we investigate the effect of the set-point adjustment strategies on overall system stability.

The paper is organized as follows: In Section 2, several recharge algorithms are discussed, and the one used in this paper is explained in detail. In Section 3, the simulation setup used to identify system-wide effects of the recharge strategy is described. The use of faster units for primary control is motivated with a simulation in Section 4. Results for a contingency analysis are given and discussed in Section 5, and for a simulation on historic data in Section 6.

2. RECHARGE STRATEGIES

Various recharge strategies have been discussed in the past. A brief overview will be given in the following paragraphs.

Scheduled recharging. (Künisch et al., 1986) describe a pilot project for a battery providing frequency control for the then islanded system of West-Berlin. From the experience gained in that project, they proposed recharging three times a week during low-load hours – at those times the battery does not provide frequency control.

Deadband recharging. Primary frequency control reserves are usually activated outside of a dead-band around nominal system frequency. In the continental European grid, the dead-band is $\pm 10\,\mathrm{mHz}$. (Oudalov et al., 2007) and (Mercier et al., 2009), recharge or discharge the battery while the system frequency is within this dead-band, outside of the dead-band no set-point adjustments are done. Additionally, if the State of Charge (SoC) of the battery is too high, resistors are shortened to dissipate excess energy. Under this approach, the battery offers exactly the expected response when the system frequency diverges from nominal values, but there are no guarantees that the SoC limits will always be kept. (Oudalov et al., 2007) could show that the SoC stays within constraints for a one-month period of historic data.

Online recharging. Recently, two strategies relying on online set-point adjustments were presented by (Borsche et al., 2013) and (Mégel et al., 2013). The offset adjustment has to have considerably slower dynamics than the original signal, in order to guarantee proper provision of the service. Regulatory frameworks are not definite in this respect, but generally it is legitimate for power plants to make changes in their schedule known to the Transmission System Operator (TSO) with short notice. The online strategy can also be seen as a filtering of the input signal, guaranteeing that the input signal is zero-mean.

(Mégel et al., 2013) propose set-point adjustments whenever the battery reaches specific SoC levels. The set-point adjustments have ramps with limited slope, and also a time-delay to allow for procurement of the off-set energy from an alternative source is discussed. This approach was shown to have minimal costs in terms of energy cycled compared to both the strategies by Oudalov and Borsche. Also, the SoC can be guaranteed to stay within certain limits. However, SoC measurements are far from exact, and the non-linear behavior close to the SoC limits triggering a recharge can lead to widely differing responses from two identical sets of batteries.

The approach from (Borsche et al., 2013) is similar, but uses a moving average to recharge the battery and to adjust for losses during charging and discharging. Let P^1 be the power requested by the primary control, which is computed using the system frequency deviation Δf and the droop S

$$P^1 = -\frac{1}{S}\Delta f \quad . \tag{1}$$

The battery output P^{bat} is then adjusted by an offset P^{off}

$$P^{\mathrm{off}}(k+d) = \frac{1}{a}\sum_{j=k-a}^{k}\left(P^{\mathrm{loss}}(j) - P^1(j)\right) \quad , \tag{2}$$

$$P^{\mathrm{bat}} = P^1 + P^{\mathrm{off}} \quad . \tag{3}$$

Parameter a defines the averaging period, increasing a reduces the ramp rate of the offset, and thus the ramp rate required by the second-tier service providing the recharge energy. d is a delay, which might be useful if the power is bought at intra-day markets, or if a power plant is to be started up to provide the offset energy. P^{loss} are the losses of the battery, which can be measured or estimated.

The battery response is deterministic and can easily be predicted by measuring system frequency only. There is an analytic limit for worst-case energy capacity requirements, and tests on historic time series make the case that considerably smaller storage sizes are sufficient, see (Borsche et al., 2013) for details. Note, that $|P^{\mathrm{bat}}|$ may be higher than $|P^1|$, the required battery power is somewhat larger than the amount of offered reserves.

MPC-based strategies Model Predictive Control was used effectively for the dispatch of a pool of conventional power plants and time-variant electric vehicles providing control reserves, see (Ulbig et al., 2010), and more recently for inertia mimicking and control reserve provision with general power system units that are defined by their respective constraints in ramp rate, power and energy capacity, see (Ulbig et al., 2013). Such control schemes applied to the problem at hand might further reduce the amount of energy cycled by taking into account hourly and daily patterns usually observed in system frequency, and can inherently handle the inter-temporal energy constraints of storage systems. However, any control scheme based on such a complex controller would not be deterministic and handling uncertainties associated with system frequency predictions is non-trivial.

While this paper focuses on decentralized primary control services, similar concepts are in place or under investigation at various TSOs. E.g., PJM offers the RegD-signal, a high-pass filtered signal for the secondary control

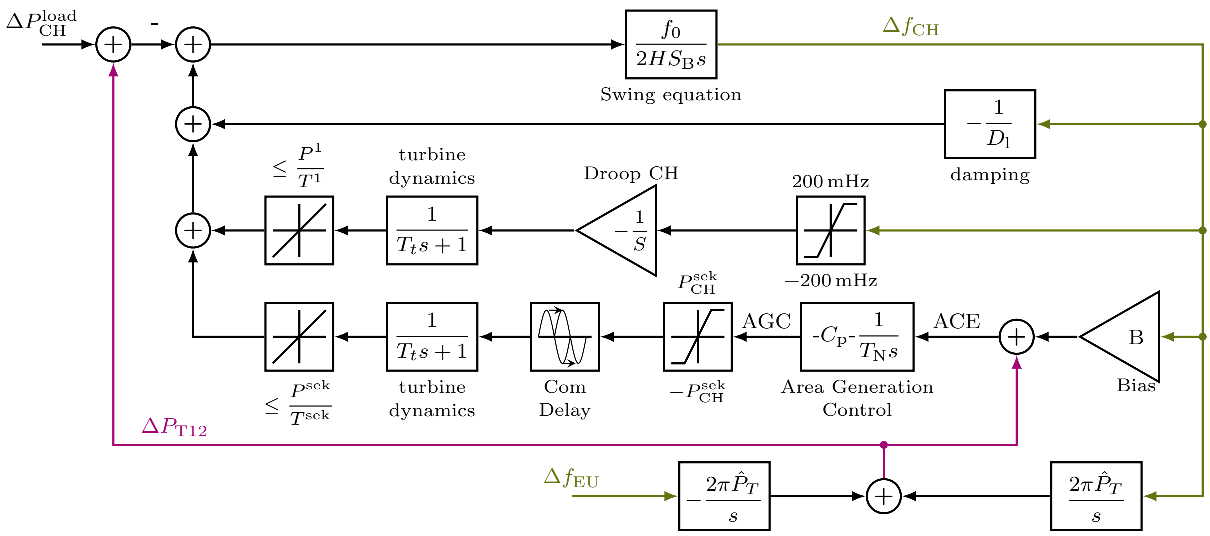

Fig. 1. One-half of the two-area system used for the simulation. Batteries not included.

equivalent ancillary service (Pilong, 2013, Sec 3.1.2). This signal is designed specifically for "dynamic or fast-response resources".

3. SIMULATION SETUP

A simulink model for the synchronous grid of continental Europe is used to analyze the effect of batteries providing primary control reserves on the frequency evolution. Motivated by the available data and the research interest of the authors, the grid is modeled as a two-area system – one area representing the Swiss control area, and the other area representing the remaining European grid.

Inputs to the two-area system are the power-mismatches in both areas, $\Delta P_{\mathrm{CH}}^{\mathrm{load}}$ and $\Delta P_{\mathrm{EU}}^{\mathrm{load}}$. Figure 1 shows one area of the two-area system. The parameters used in the simulation are given in Table 1, and are based on data published in (Weissbach and Welfonder, 2008). The general model is well studied, see, e.g., (Kundur, 1994). The heart of the model is the swing equation,

$$\frac{\mathrm{d}}{\mathrm{d}t}\Delta f = \frac{f_0}{2HS_{\mathrm{B}}}\left(\Delta P - \frac{1}{D_{\mathrm{l}}}\Delta f\right) \quad , \tag{4}$$

with H the rotational inertia, S_{B} the nominal power of the system and D_{l} the damping by frequency dependent loads. The additional blocks describe turbine limits and saturation of primary and secondary control reserves. The governor and turbine dynamics are modeled using a simple low-pass filter, which represents the dominant dynamics. Additionally, ramp rates are specified that agree with the regulation for the ancillary services – that is full primary control activation after 30 s and full secondary activation after 120 s in Switzerland and 300 s in the remaining control areas.

Secondary control reserves are activated by the Automatic Generation Control (AGC). The AGC has the Area Control Error (ACE) as input. The ACE is computed by

$$\mathrm{ACE}_i = \Delta f B + \sum_j \Delta P_{\mathrm{T}ij} \quad . \tag{5}$$

B is the bias factor, and $\Delta P_{\mathrm{T}ij}$ are unscheduled exports from area i to areas j. In turn, the AGC usually is implemented as PI-controller of the form

$$\mathrm{AGC} = \left(-C_{\mathrm{p}} - \frac{1}{sT_{\mathrm{N}}}\right)\mathrm{ACE} \quad . \tag{6}$$

Table 1. Parameters used in the simulation of the two-area system.

parameter	variable	value CH	value EU
inertia	H	6 s	6 s
base power	S_{B}	8 GW	240 GW
Primary control reserves	P^1	80 MW	2920 MW
Primary Response Time	T^1	30 s	30 s
droop	$1/S$	$400\ \frac{\mathrm{MW}}{\mathrm{Hz}}$	$14600\ \frac{\mathrm{MW}}{\mathrm{Hz}}$
Secondary control reserves	P^{sek}	400 MW	14000 MW
Secondary response Time	T^{sek}	120 s	300 s
AGC parameters	C_{p}	0.17	0.17
	T_{N}	120 s	240 s
Load-frequency damping	D_{l}	$\frac{1}{120}\ \frac{\mathrm{Hz}}{\mathrm{MW}}$	$\frac{1}{3750}\ \frac{\mathrm{Hz}}{\mathrm{MW}}$

The model simplifies in many respects. While assuming two areas, the European grid consists of many more control zones. Also, no detailed information about the AGC system in the various control zones is available to the authors, an exception being the Swiss system. Nevertheless, we are confident that the chosen modeling approach gives a realistic-enough representation of the overall system behavior, including the evolution over longer time-spans, as well as frequency dynamics and activation of control reserves.

4. FREQUENCY EVOLUTION IN SYSTEMS WITH LOW INERTIA

If the inertia H is reduced, the system frequency will deviate faster and thus more further out after a contingency. Figure 2 shows this effect after a 3 GW change in load. This is the reference case used for primary frequency control reserve dimensioning in the ENTSO-E grid. While such an event is rare, (Weissbach and Welfonder, 2009) argues that large changes in production are observed at every full hour, leading to considerable frequency changes. If the response time T^1 of primary frequency control is too slow, the frequency may deviate beyond acceptable levels. Reducing the response time in turn can alleviate this issue, and may even lead to a reduced maximal deviation. (Mercier et al., 2009) argue that a similar effect due to the low base load is common in small island grids and that it can be addressed using batteries.

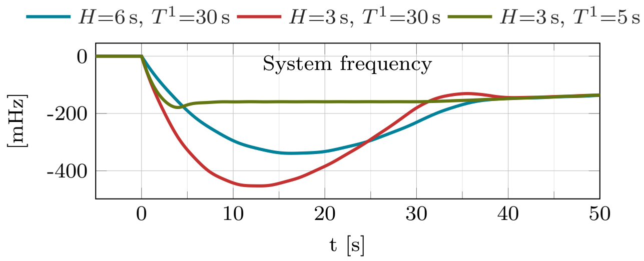

Fig. 2. Frequency change after a deviation depends on the inertia H and response time T^1 of the primary control. Reduced inertia might lead to problems for grid operation in the future.

Other factors impacting on the frequency evolution are the dead-time of the secondary control, and the frequency dependency of the load. Latter again is connected to the total system load. Critical situations might occur especially during low-load situations, when a high share of renewable energy leads to reduced system inertia.

5. CONTINGENCY ANALYSIS

This section gives results of the system and battery behavior after a contingency. We are interested in the following questions: How does the frequency evolve if energy constrained units provide primary frequency control? Is it necessary to explicitly communicate the required recharge energy to the secondary control system? How does the recharge energy required affect the system frequency, and what effect do the averaging period a and delay d have?

Figure 3 shows how the batteries fit into the control scheme. Equations governing the offset P^{off} and the battery output P^{bat} are given in (2) and (3). The parameter β governs what share of the primary control reserves are provided by batteries.

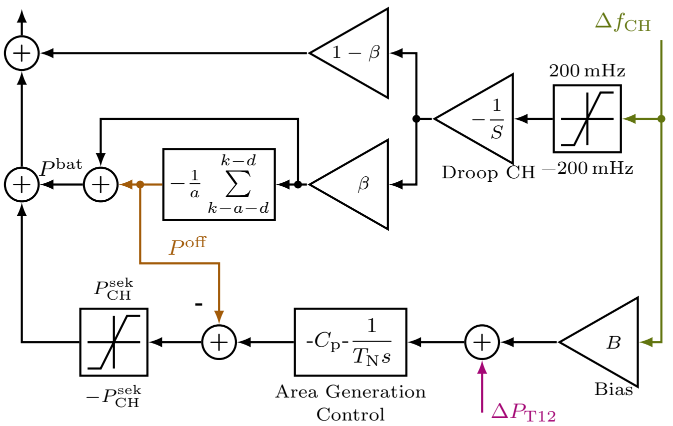

Fig. 3. Batteries as part of the control reserve framework, with recharging algorithm and explicit communication of the offset. Turbine dynamics and rate limits omitted.

Communication of recharge energy. All recharge strategies described in Section 2 assume that the required energy is provided by *some other service.* If the energy is not bought explicitly at an energy market, it has to be provided by the secondary control reserves. The amount of energy required might either be communicated *explicitly* by adding the offset to the AGC signal, or secondary control can be triggered *implicitly* via the system frequency.

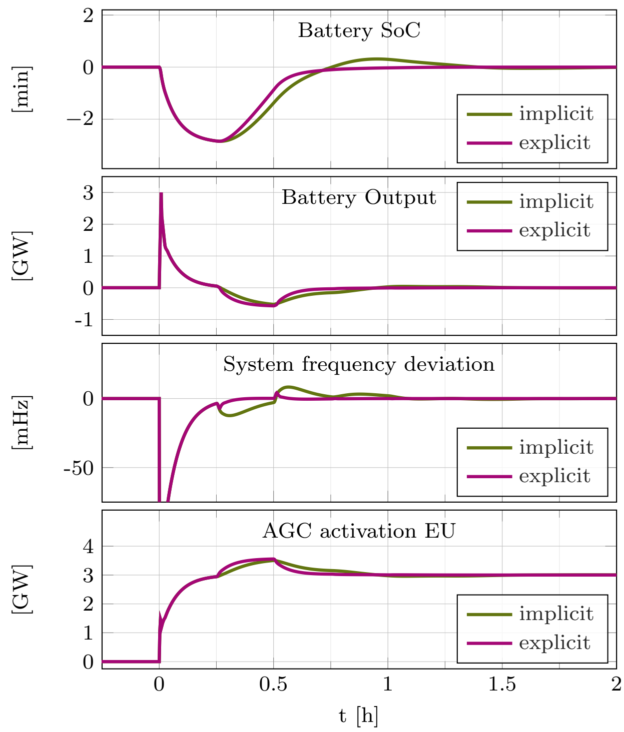

Fig. 4. Effect of communication of the battery offset to the secondary control. Communicating the offset both implicitly via the system frequency and explicitly lead to a rather smooth response.

Figure 4 shows results for a simulation of a 3 GW loss of production, and 100 % primary control provision by energy constrained units, i.e., $\beta = 1$. a and d are both set to 15 min. The green lines show the behavior if the offset is not communicated, purple lines when the offset is added to the AGC signal. Latter approach exhibits a more favorable dynamic, with minimal effect on the system frequency and no overshoot of the battery SoC. However, the difference between adding and not adding the offset is rather small. It seems, that communicating the offset is favorable, but not necessary. As the communication channels might potentially fail, it is reassuring to see that they are only a nice-to-have rather than an essential feature.

Sensitivity to Averaging Period and Delay. Both delay d and averaging period a are parameters of the recharge strategy. The storage capacity requirements of a battery providing primary control are related to both a and d, reducing these values is thus in the interest of the battery owner. However, choosing the values too small might be contrary to system needs. For the following simulations, the offset was not explicitly communicated.

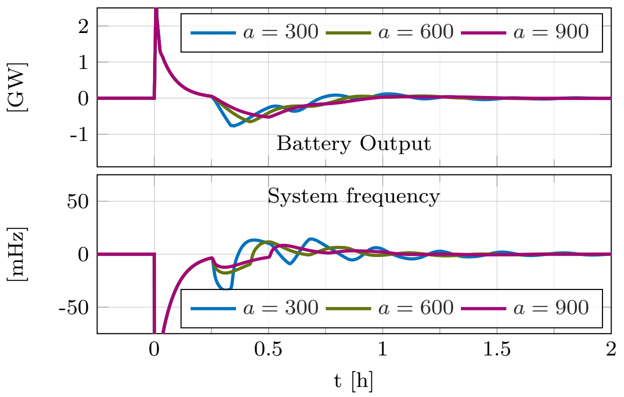

Fig. 5. Effect of averaging period a on system response, if offset is not communicated. Decreasing the averaging period leads to more pronounced oscillations.

Figure 5 gives battery output and system frequency after a contingency. With an averaging period of 15 min, both f and P^{bat} are quite smooth. Reducing the averaging period leads to oscillations during recharging of the battery, which also translates into system frequency oscillations. It seems, that shorter averaging periods lead to an unwanted interaction between the battery and the secondary control. Changing the delay does not show such a pronounced effect on the system behaviour. On the contrary, reducing the delay even to zero offers a rather smooth frequency evolution. With no delay, the battery is being relieved earlier, leading to a slightly faster activation of secondary control reserves, at the same time less offset energy is required.

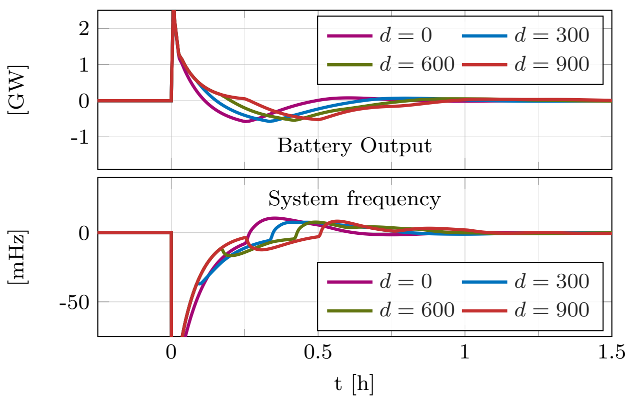

Fig. 6. Effect of delay d on system response, if offset is not communicated. Reducing the delay has no major effect on system frequency or battery output.

6. LONG-TERM SIMULATION

The contingency analysis in the previous section investigated behavior in extreme situations, this section is dedicated to normal power system operation. To receive somewhat robust results, simulations cover a period of one year. The simulation is based on historic frequency and AGC data measured in the Swiss control zone, namely system frequency and Swiss secondary control activation. Both data sets are available in 10 s resolution, the frequency is discretized with 10 mHz. The data available has its limitations, as the dynamics of the swing equation are within seconds and mHz. Using the frequency data, historic primary control activation and damping by frequency dependent loads can be computed, while the AGC signal leads to secondary control activation and, together with frequency, gives also information about tie-line power. With this information, the power mismatch $\Delta P^{\mathrm{load}}_{\mathrm{CH}}$ can be computed. A similar approach is used to get the power mismatch in the remaining European grid, $\Delta P^{\mathrm{load}}_{\mathrm{EU}}$. We will examine how energy constrained units for primary control affect system frequency and AGC activation, and how much storage capacity is needed. Also, we investigate how the system frequency changes if inertia is reduced.

Table 2. Sensitivity of battery and AGC usage on design parameters. Results of one-year simulation. Colourings highlight correlation between parameters and outcome.

Parameters				AGC,CH		Battery response		
β [s]	offset	a [s]	d [s]	$E^{\mathrm{pos}}_{\mathrm{CH}}$ [GW h]	$E^{\mathrm{neg}}_{\mathrm{CH}}$ [GW h]	Δ SoC [min]	$\lVert P^{\mathrm{off}}\rVert_\infty$ [p.u.]	$\lVert P^{\mathrm{bat}}\rVert_\infty$ [p.u.]
0	-	-	-	317.1	-506.2	–	–	–
0.5	yes	900	900	317.7	-509.9	22.91	0.61	0.91
1	yes	900	900	318.5	-513.9	22.91	0.61	0.91
1	no	900	900	318.2	-513.7	22.94	0.61	0.91
1	yes	600	900	319.0	−514.3	20.81	0.64	0.93
1	yes	300	900	319.9	−515.1	18.87	0.66	0.91
1	yes	900	600	319.5	−515.0	18.49	0.61	0.92
1	yes	900	300	320.8	−516.6	14.03	0.61	0.92
1	yes	900	0	321.3	−517.7	8.85	0.61	0.84

Normal operation. Results detailing the sensitivity to parameters battery quota β, averaging period a and delay d are given in Table 2. For each simulation run, the amount of positive control energy $E^{\mathrm{pos}}_{\mathrm{CH}}$ and negative control energy $E^{\mathrm{neg}}_{\mathrm{CH}}$ requested by secondary control services in Switzerland is given. Additionally shown is the resulting required storage capacity of the battery Δ SoC, which is the difference between the maximal and minimal SoC reached, as well as the maximum offset power ΔP^{off} and total battery power ΔP^{bat}. Latter defines the power capacity requirements of the battery. Note, that the highest primary control reserve activation in the simulation period was at 0.78 p.u..

Replacing traditional primary control reserves with batteries leads to a slight increase of energy requested from secondary control reserves, but this is on the order of 1 % of the total energy cycled. In this respect, there is no difference between implicitly and explicitly communication the recharge energy. The necessary battery capacity, given in minutes, is slightly reduced when using short averaging periods, but is more than halved when reducing the delay. Also reducing the delay reduces the minimal power capacity which the storage system has to offer, however this effect is small and seems to be dependent on specific characteristics of the time series. Nevertheless, together with Section 5, it can be recommended to set d to 0 s and a to 15 min.

Reduced Inertia. Table 3 shows secondary control activation and the minimum f^{min}, mean μ^f, standard deviation σ^f and maximum f^{max} of the system frequency observed in the one-year simulation. It can be seen that using

Table 3. Frequency deviations and secondary control activation over one year, depending on use of batteries and inertia.

Set-up				AGC,CH		System frequency			
β []	H [s]	T^1 [s]	offset	E^{pos} [GW h]	E^{neg} [GW h]	$f^{\min}$ [mHz]	μ^f [mHz]	σ^f [mHz]	$f^{\max}$ [mHz]
0	6	30	–	317.1	−506.2	−155.96	2.88	22.11	142.88
1	6	30	yes	318.5	−513.9	−156.17	2.88	22.13	143.00
0	3	30	–	317.1	−506.2	−156.63	2.88	22.25	142.48
0	1	30	–	317.1	−506.2	−157.51	2.88	22.39	144.66

energy constrained units and the associated recharging have only minimal effect on the frequency evolution, with the differences being in the range of µHz. It was further assumed, that a reduction in inertia leads to notably higher frequency deviations in the system. However, this could not be observed in our simulation. There are two possible explanations for this: 1) As long as the change in load mismatch is rather slow, primary control reserves can follow the resulting frequency change well. Maximal frequency deviations are thus limited by the available *amount* of damping and primary control reserves, rather than by the inertia and *rate* of primary activation. 2) The data used for the simulation has a time resolution of 10 s. The load mismatch is interpolated, and thus has a ramping rather then a step behavior. This might be a correct assumption in many situations, but may also be the reason that little dependency between inertia and frequency deviations is observed. With the available data, it is not possible to identify whether 1) or 2) is true. In any case, behavior after a contingency can be well studied with a contingency analysis as in Section 4, where the advantages of fast primary control were clearly shown.

7. CONCLUSION

The effects of primary frequency control provision by energy constrained units, such as batteries or DR on the operation of power systems were investigated. Secondary control has to provide some additional energy, so that the batteries can recharge and keep their SoC constraints. System frequency is not noticeably affected by this. The needed recharging energy can be explicitly communicated to the secondary control, or can be implicitly communicated via the system frequency. A contingency analysis showed the advantages of faster primary control reserves in power systems with low inertia. The adequateness of batteries was proven in every investigated scenario.

Neither additional communication channels nor increased secondary control reserves are necessary, making primary control based on energy constrained units as reliable as traditional primary control. The fast ramp rates that can be provided by batteries are as much an operational benefit as the decoupling of control power provision and energy production.

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