THE EFFECTS OF VERY FAST RESPONSE TO FREQUENCY FLUCTUATION

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Abstract
In power system, as any inequality between production and consumption results in an instantaneous change in frequency from nominal, frequency should be always monitored and controlled. Traditionally, frequency regulation is provided by varying the power output of generators which have restricted ramp rates. New energy storage technologies such as flywheels or batteries can rapidly change their outputs and provide frequency regulation with very fast response to frequency fluctuations. This paper presents the effects of using storage on dynamic behavior of the system. Simulation results show the potential adverse effects of these resources on the system performance.

1. Introduction
Energy storage systems provide the opportunity to store energy for use at a later time. Therefore, they can play a useful role in power system when electric power is most needed and most valuable. There are a number of available or emerging technologies for storing energy, from mechanical storage (e.g., flywheels), to chemical storage (e.g., batteries), to thermal storage (e.g., ice) [1]. Energy storage has the potential to decrease air pollution by decreasing the use of fossil-fueled peaking power plants and enabling integration of renewable resources into the grid. With increasing penetration of wind and other renewable generation resources, the volatility of supply will increase in the system and therefore the need for more frequency regulation service in power system may increase as a result. Energy storage systems have great potential to remedy this problem. The “fast response” nature of some energy storage technologies, like batteries and flywheels, can make them suitable resources to provide ancillary services such as frequency regulation.

Some studies showed that storage can be more effective than conventional generation in providing regulation service [2, 3, 4], meaning that a MW of energy storage is not equivalent to a MW of conventional generation in frequency regulation. A study by the Pacific Northwest National Laboratory (PNNL) defines an “ideal” fast responding resource as one with “instantaneous response, perfect accuracy, and unlimited energy.” [3] PNNL observes that such an ideal resource would be 2.7 times more efficient than a combustion turbine. Despite the energy limitations of some energy storage technologies, such as flywheels, they could provide more effective regulation compared to combustion turbines, steam
turbines, or combined-cycle turbines [1]. A recent study prepared for California Energy Commission (CEC) further supports these claims, concluding that “on an incremental basis, storage can be up to two to three times as effective as adding a combustion turbine to the system for regulation purposes.” [4] This means that a 100 MW energy storage system can be as effective as 200-300 MW of combustion turbine capacity dedicated to provide regulation. [1].

FERC order number 755 [5], observes that because faster ramping resources may be able to replace conventional resources for providing regulation, RTOs and ISOs may be able to procure less regulation capacity, thus lowering costs to load. FERC argued that “the current compensation methods for regulation service in RTO and ISO markets fail to acknowledge the inherently greater amount of frequency regulation service being provided by faster-ramping resources.” [5] Faster ramping results in more accurate response to the AGC signal and avoids overshooting. On the other hand, ramping too slowly may cause the resource to work against the needs of the system and impose the need to commit additional regulation resources. As the current compensation method, which is solely based on the capacity reserved for regulation, does not acknowledge the greater amount of frequency regulation service being provided by faster-ramping resources, FERC order [5] forced all RTOs and ISOs to have a two level payments based on capacity and performance which have to consider the accuracy in following the AGC dispatch signal.

Before deciding to have any additional payment to faster ramping resources because of their performance and accuracy, we should investigate to see if there is any adverse effect of very fast response to frequency fluctuations. Based on these effects we can decide about the real value of these resources. In this paper, we studied these effects by modeling the dynamic behavior of power system.

The rest of the paper is organized as follow. Section 2 describes the frequency control in power system. Section 3 introduced a model for system. Simulations results will be discussed in section 4, and the conclusion and future work are presented in section 5.

2. Frequency Control

Due to the physics of the synchronous machine, the electrical frequency of the generator voltage and the mechanical rotational speed of the generator are in fixed proportion to one another, therefore, any variation in frequency results in rotational speed deviation from the desired steady state. Also, a synchronous region in AC power system should have the same frequency at every node; i.e. all interconnected generators rotating at the same (normalized) speed.

A large frequency deviation can have undesirable effects on power system like damaging equipment, degrading load performance, causing the transmission lines to be overloaded, interfering with system protection schemes and eventually, leading to an unstable condition for the power system. Thus, controlling frequency is an essential task for the power system operator. For keeping the frequency of a power system within a required range, the generation and demand should be kept in balance. In spite of considerable effort for forecasting electricity demand, making a completely accurate prediction is impossible. Second-to-second and minute-to-minute fluctuations are very difficult to foresee, which may result in a difference between load and dispatched generation. [8]
Any mismatch between consumption and production, in fact, is a change in the balance between applied mechanical shaft power and electrical power extracted at the synchronous generator terminals. Based on the rotational Newton’s law, traditional synchronous generators provide counter response over a several seconds timeframe whenever there is a mismatch between mechanical supply and electrical demand. This type of response of generators is called inertial frequency response. Therefore, any sudden change in load or generation is initially compensated by addition or extraction of kinetic energy from the rotating inertia of all synchronous generators [6,7,8,9].

Beyond this natural response, three levels of controls are generally used to achieve the desired frequency control, which are called primary, secondary and tertiary frequency control. In the rest of this section, these three control frequency mechanisms will be defined.

2.1. Primary Frequency Control

A turbine prime mover of a conventional generator is typically equipped with an external control loop called governor control. Governor control system regulates the rotation speed of the shaft by changing the supply to the turbine and thus control frequency. This type of control is traditionally called primary frequency control. [6]

This type of control is designed to keep the stability of the power system in contingency conditions like large generation or load outages. The governor response is started almost instantaneously, although a governed generator generally needs some time to achieve the output level dictated by governor control system.

The gain of the feedback loop in the primary frequency controller, which is called speed droop, is defined as follows [10]:

\[ R = -\frac{df/f_o}{dp/p_o} \quad (1) \]

where \( f_o \) is the nominal frequency and \( p_o \) is the generator capacity. In the other words, droop is the percent change in frequency which would cause the unit’s output to change by 100% of its capacity.

The governor dead-band, which is a region around normal frequency where the governor is not activated, is also a very important issue in frequency control. Dead-band was really a natural feature of the earliest governors caused by their physical characteristics. Intentional dead-bands which are usually bigger than the physical ones are used to reduce the governor activity in normal conditions of power system.

2.2. Secondary Frequency Control

Inertial frequency response and primary frequency control are decentralized and only able to limit and stop frequency excursions but not well suited to bring the frequency back to its target value. Instead, secondary frequency control is a centralized automatic control which is able to restore the frequency to its set point.
Within the UCTE, secondary frequency control is also called load-frequency control (LFC), while the term automatic generation control (AGC) is preferred in North America. However, within the UCTE, the term AGC designates the combination of dispatching and secondary frequency control. [10]

Maintaining frequency and controlling the net power interchanges with neighboring control areas at the scheduled values are main objectives of LFC. For meeting these objectives, a control error signal, called the area control error (ACE), is measured. ACE is a linear combination of net interchange and frequency deviations and includes a frequency bias term which requires each balancing area to increase generation when system frequency is low and decrease generation when frequency is high. The bias is established in MW/0.1 Hz and is based on the MW size of the balancing area. [11] After measuring and filtering the ACE, it is used as an input for a controller which is usually a proportional integral (PI) controller. Based on the characteristics of control area, the resulting output signal is conditioned by limiters, delays and gain constants. Then based on the resulted control signal and the participation factors of all the LFC participant units, the new set points are calculated and sent to the generators by means of the automatic generation control (AGC) system. [12]

This control mechanism provides excellent frequency control under normal conditions but is too slow to respond to major contingencies when the system frequency moves outside the governor dead-band, as shown in figure 1 [11]. In the context of electricity markets, controlling the frequency by using the on-line generators, which are equipped with AGC and participate in LFC, is called frequency regulation, which is a type of ancillary services.

2.3. Tertiary Frequency Control

Tertiary frequency control refers to manual and automatic changes in the dispatching and commitment of generating units. This control is used to restore the primary and secondary frequency control reserves, to manage congestions in the transmission network, and to bring the frequency and the interchanges back to their target value when the secondary control is unable to perform this last task. [10]

3. System Modeling

This section is based on the chapter 2 of [12]. For studying the effects of using fast ramping resources for providing regulation service, we need to construct an appropriate dynamic model for frequency control. Despite the highly non-linear and time-varying nature of power system, for the purpose of frequency control synthesis and analysis a simple low-order linearized model is enough. This simple model should be built based on the frequency control mechanisms which were described in section 2. In this section, a multi-area power system is considered and a simplified frequency response model for each of the control areas is described. Each area is modeled with one generator. The schematic block diagram of the model is shown in figure 2. In the rest of this section, the models of different blocks are discussed.
3.1. System Inertia Model

Inertial frequency response of a power system is due to physics of synchronously rotating mass in the system (includes synchronous generation and motor load). The dynamic relationship between the mismatch power and the frequency deviation can be expressed as:

\[ \Delta P_g(t) - \Delta P_L(t) = 2H \frac{d\Delta f(t)}{dt} + D\Delta f(t) \]
where $\Delta f$ is the frequency deviation, $\Delta P_g$ the generation power change, $\Delta P_L$ the load change, $H$ the inertia constant and $D$ is the load damping coefficient which is usually expressed as a percent change in load for a 1% change in frequency.

Using the Laplace transform, equation (2) can be written as

$$\Delta P_g(s) - \Delta P_L(s) = 2Hs\Delta f(s) + D\Delta f(s)$$  \hspace{1cm} (3)

Therefore, the transfer function of the system inertia model is:

$$\frac{1}{D + 2Hs}$$

### 3.2. Generator Model

For analysis of power system frequency, a number of low order models for representation of generator dynamics have been proposed. These models usually ignore the slow system dynamics of the boiler and the fast generator dynamics.

The block diagram and the transfer functions of generator model appropriate for frequency control analysis is shown in figure 3 and table 1.

![Figure 3: The schematic block diagram of generator model appropriate for frequency control analysis (based on [12])](image)

<table>
<thead>
<tr>
<th>Non-reheat Steam Unit</th>
<th>Governor Transfer Function</th>
<th>1/(1 + $T_g s$)</th>
<th>Turbine Transfer Function</th>
<th>1 + $T_{tr} s$/(1 + $T_r s$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reheat Steam Unit</td>
<td>1/(1 + $T_g s$)</td>
<td>1/(1 + $T_g s$)</td>
<td>1 + $T_{tr} s$/(1 + $T_r s$)</td>
<td></td>
</tr>
<tr>
<td>Hydraulic Unit</td>
<td>1/(1 + $T_g s$ + $h T_{gh} s$)</td>
<td>1 + $T_{th} s$/(1 + 0.5 $T_{th} s$)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 1: The transfer functions of generator model appropriate for frequency control analysis for using in block diagram shown in figure 3 (based on [12])
For studying the effects of fast responses to frequency fluctuations, the generators’ ramp rate should also be included in the model. Non-reheat thermal units usually have a higher generation ramp rate compared to reheat units which have a generation ramp rate of 3-10% (pu MW/min). For hydro-units, the rate is of the order of 100% continuous maximum rating (CMR) per minute.

3.3. LFC model

A multi-area power system consists of areas that are interconnected by tie-lines. Based on our discussion in section 2.2., The LFC system in each control area of an interconnected power system should control the interchange power with the other control areas as well as its local frequency. Therefore, a control error signal which is called area control error (ACE) is defined for each area. ACE is a linear combination of frequency and tie-line power changes of the area:

$$ACE_i = \Delta P_{tie,i} + \beta_i \Delta f_i$$

(4)

where $\beta_i$ is a bias factor of area $i$.

ACE is used as an input for a controller which is usually a proportional integral (PI) controller.

4. Simulation Results

In this section, the effects of using storage resources for providing regulation will be studied by simulating the response of power system to load disturbances. The results for two different examples are presented.

The North American Electric Reliability Council (NERC) has defined two control performance standards (CPS 1 and 2) to assess the performance of an area to maintain frequency and control the interchanges with other areas at the scheduled values. We will use CPS1 in our study. CPS1 can be calculated based on a compliance factor (CF1) as below [13]:

$$CF1 = \frac{1}{\varepsilon^2} \left( \frac{ACE}{10 \beta} \right)_1 \{\Delta f\}_1$$

(5)

$$CPS1 = 100(2 - [CF1]_t)\%$$

(6)

where $\{x\}_t$ means average of $x$ over a minute and $\{x\}_t$ means average of $x$ over $t$. For reporting purposes usually “$t$” is equal to one month but for compliance measure “$t$” is twelve month. Also, $\varepsilon$ is a constant defined by NERC for each interconnection.

Based on the definition of ACE (equation 4), for an isolated system CF1 can be simplified to:

$$CF1 = \left( \{\Delta f\}_{1 \ min} \right)^2 / \varepsilon^2$$

(7)

For each area, a CPS1 score over a rolling 12 months should be at least 100% to meet the compliance requirement of NERC. The maximum score is 200%. [13]
4.1. Example 1

For this example, we select a system from chapter 2 of [12] which consists of a generator and a load. The system model parameters are given in table 2.

We also consider a 10% (pu MW/min) ramp rate for the turbine.

<table>
<thead>
<tr>
<th>LFC System</th>
<th>Governor Model</th>
<th>Governor Speed Droop</th>
<th>Turbine Model</th>
<th>System Inertia</th>
</tr>
</thead>
<tbody>
<tr>
<td>$k(s)$</td>
<td>$\frac{1}{1+T_g s}$</td>
<td>$R$</td>
<td>$\frac{1}{1+T_t s}$</td>
<td>$\frac{1}{D + 2H s}$</td>
</tr>
<tr>
<td>$-0.3/s$</td>
<td>$T_g = 0.08$</td>
<td>$R(\text{Hz/pu}) = 3.00$</td>
<td>$T_t = 0.40$</td>
<td>$D \ (\text{pu/Hz}) = 0.015$</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$2H \ (\text{pu s}) = 0.1667$</td>
</tr>
</tbody>
</table>

Table 2: system model parameters of example 1

In addition to the traditional generator with limited ramp rate, the system is supposed to have the unlimited capacity of ideal storage resources which can respond to LFC signal instantaneously. The LFC system will share the amount of deployed regulation between storage resources and the traditional generator based on a fixed ratio named $\alpha$. Therefore, storage will always generate the $\%\alpha$ of deployed regulation. LFC signal is sent through AGC system every 2 seconds.

The dynamic response of the system to a step load disturbance is plotted in figure 4. The simulations are done for three different participation factors of storage.

It is obvious in figure 4 that using storage changes the dynamic response of the system. In case of $\alpha=\%50$, the frequency comes back to its nominal value sooner in compare to case $\alpha=\%0$ and $\alpha=\%100$. It seems when $\alpha=\%50$, the frequency restoration improves by taking advantage of both traditional generator and storage.

In the real world, the electric load changes continuously and its fluctuations are more similar to a sequence of load disturbances than a step load disturbance. Hence, a simulation is done for a 5-minute sequence of load disturbances. A 1-minute dynamic response of the system to the mentioned load is plotted in figure 5. The behavior differences in different cases are easily recognizable but for quantitative purposes, an index is needed. CPS1 could be a good index because any system needs to meet the NERC’s requirement of having at least 100% CPS1 in a year. Therefore, any behavior that can improve CPS1 is more desirable. As the CPS1 is dependent on the CF1, the CF1 can show the contribution of each minute of frequency response in CPS1. Smaller CF1 for each minute is more desirable as it helps CPS1 to improve.

Figure 6 shows the CF1 values for each minute of the system frequency response to a sequence of load disturbances over 5 minutes. As shown in figure 6, using storage increases CF1 in some intervals. Also, using more storage sometimes results in bigger CF1.

In summary, the results show that using storage for providing regulation can change the dynamic behavior of system and the resulted changes in frequency is not always desirable.
Figure 4: The dynamic response of example 1 to a step load disturbance of 0.002 pu for (a) $\alpha = 0\%$, (b) $\alpha = 50\%$ and (c) $\alpha = 100\%$.
Figure 5: The dynamic response of example 1 to a sequence of load disturbances for (a) $\alpha = 0\%$, (b) $\alpha = 50\%$, and (c) $\alpha = 100\%$. 
For modeling the ERCOT system, the data from a contingency in January 2010 is used. The frequency changes during the first seconds after a contingency are mostly because of inertial response of the system and the governor response is negligible at that time. In this range of time, frequency changes linearly with the time and the inertia constant can be calculated based on the frequency rate of change.

We model the ERCOT system with one generator and one load. For identifying the parameters for governor and turbine model, which assumed to be a second order linear model, used the minimum square based identification method and the data from the mentioned contingency in January 2010. The governor deadband is set at 36 mHz.

The controller in the LFC model of ERCOT is a “proportional” controller with gain that varies with ACE based on Table 3. As the ERCOT is a synchronously isolated system, ACE is defined as “β. Δf”, without any contribution from interchanges, and β is equal to 6670 MW/Hz. Also, ε for calculating CF1 is 30 mHz for ERCOT.

| Condition |  | 62 ≤ | 90 ≤ | 334 ≤ |
|-----------| | ACE≤ | ACE≤ | ACE≤ |
| LFC Controller Gain | 0 | 0.3 | 0.4 | 0.8 |

Table 3: LFC controller gain in ERCOT

The simulation is done for three different values for storage participation factor (α) and a 10-minute sequence of load disturbances. The results are plotted in Figures 7 and 8.
Figure 7: The dynamic response of example 2 to a sequence of load disturbances for (a) $\alpha=\%0$, (b) $\alpha=\%50$ and (c) $\alpha=\%100$
Comparing CF1 values for different storage participation factors through several minutes shows that using storage could have adverse effect on the system performance.

For more reliable results, the simulation should be done for a longer periods of time. To achieve this goal, more operational data is needed for constructing the system model in different situations. As the model here is constructed based on a contingency, the model parameters (like inertia constant and governor and turbine model parameters) is good only for that combination of generators. Hence, the model is not suitable for longer period of time when the combination of dispatched generators will change.

Another issue is that the resources should respond to LFC signal without considering their response effect on CPS1. Meeting the NERC’s requirement is the responsibility of system operator. Therefore, system operator may need to change the LFC method to calculate an appropriate AGC signal for fast response resources to avoid their adverse effect.

5. Conclusion and Future Work

Previous studies [2,3,4,5] showed that fast response resources can result in more accurate response to LFC signal, higher regulation efficiency, less regulation capacity procurement and more economic efficiency. However, increasing the share of these resources could have adverse effects on the system performance. In this paper, this problem is studied by dynamic simulation of frequency control in power systems.
The results showed that an ideal storage resource with unlimited capacity and instantaneous response to LFC signal has the potential to change the frequency response of the system. It seems that the changes in the system frequency as a result of using storage depend on the ratio of regulation provided by storage to the total deployed regulation. These changes could result in reduced CPS1. Hence, storage has the potential to worsen the performance of power system in frequency control.

Future work may consider a more accurate model (for example in case of ERCOT) by using more detailed operational data. Furthermore, the constraints of storage resources (like limited capacity) should be taken into account.

New reasonable indices may enable us to better compare the dynamic frequency response of the system. On the other hand, the effects of using storage could depend on the LFC method used in the system. Therefore, by using an appropriate method the system may take more advantages of storage and decrease their adverse effects. Defining new reasonable indices and finding an appropriate LFC method should be investigated.

6. References


6. Christopher L. DeMarco, Chaitanya A. Baone, Yehui Han, and Bernie Lesieutre, “Primary and Secondary Control for High Penetration Renewables,” PSERC Publication, March 2012.


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