

Sizing of Energy Storage Systems for Grid Inertial Response

Atri Bera, Michael Abdelmalak*, Saad Alzahrani, Mohammed Benidris*, and Joydeep Mitra

Department of Electrical & Computer Engineering
Michigan State University, East Lansing, MI, USA
{beraatri, alzahr21, mitraj}@msu.edu

*Department of Electrical & Biomedical Engineering
University of Nevada, Reno, NV, USA
mabdelmalak@nevada.unr.edu, mbenidris@unr.edu

Abstract—Although the deployment of renewable energy sources (RES) alleviates several concerns related to energy, natural resources, and climate change, their lack of rotational kinetic energy is a key challenge to the stability and resilience of future power grids. Energy storage systems (ESS) hold the potential to compensate for this lack of rotational kinetic energy with *virtual inertia*—such a system is called a *virtual synchronous generator* (VSG). Determining optimal sizes of VSGs is a key factor to develop strategies that efficiently assure the capability of VSGs in maintaining the stability of future power systems. This paper proposes an approach for sizing ESS for grid inertial response in the presence of RES. Time domain simulations are used to determine the minimum inertia required by a power system to maintain its stability. A stochastic method involving Monte Carlo simulation is developed and utilized to determine the low frequency events for a given time period. A stability index is also developed to quantify the probability of occurrence of low inertia events in the system. The ESS is then sized accordingly to compensate for the lost inertia. The proposed method is demonstrated on the reduced Western System Coordinating Council 9-bus test system. The results show that VSG can compensate for the lack of rotational kinetic energy for a wide range of fault clearing times and penetration of RES.

Index Terms—energy storage systems, Monte Carlo simulation, renewable energy, transient stability, virtual inertia

I. INTRODUCTION

The penetration of renewable energy sources (RES) in the modern-day power grids is increasing at a fast pace due to environmental concerns and economic incentives. However, high penetration of these sources poses some serious challenges to the stability of power systems due to their low inertia characteristics. Conventional generators possess the inherent capability of providing inertial support during frequency imbalance conditions. On the other hand, RES, like wind and solar, lack the ability to provide grid inertial support as they are connected to the grid via power electronic converters. Several studies have shown that the replacement of conventional generators with RES causes reduction of system inertia, which leads to increased rate of change of frequency (RoCoF) and lower frequency nadirs [1], [2]. A reduction in frequency response has also been reported by North American Electric Reliability Corporation (NERC) [3] due to increase in the penetration of RES. Therefore, it is becoming increasingly important to compensate for this lack of inertia to avoid critical operating conditions and contingencies in the presence of RES.

The concept of synthetic or virtual inertia has been proposed to improve the dynamic response of power systems [4], [5]. Virtual inertia can be defined as the controlled contribution of electrical torque from a unit that is proportional to the RoCoF at the terminals of the unit [6]. The impact of virtual inertia on enhancing the frequency response of power systems has been discussed in [7]. Controllers have also been developed to minimize frequency disturbances [8] arising due to reduced inertia in the system.

In the absence of adequate conventional generators, fast-acting devices such as energy storage systems (ESS) can inject active power into the system and arrest frequency deviations. The authors of [9]–[11] have studied the utilization of various ESS to enhance grid inertia and improve system reliability considering frequency security. The sizing of ESS for providing virtual inertia has been studied in [12], [13]. Authors of [12] have presented a method to estimate the size of ESS to enhance inertial and frequency responses of power system in the presence of high wind penetration level and have used the inertia constant and droop characteristics for evaluation and comparison. A probabilistic method for sizing ESS under high solar penetration level has been proposed in [13].

Although there is no mechanism at present to provide economic incentives or payback for synthetic inertia, it is possible that markets or other payment schemes can emerge as displacement of inertial generation increases and regulatory requirements evolve. Although a part of generation from renewable resources is sometimes withheld to provide reserve for frequency regulation [14], some utilities such as Hydro-Quebec mandate the use of synthetic inertia [15]. Moreover, in recent times, markets for frequency regulation have been established in some RTOs, and markets for ramping capability are under consideration; it is quite possible that a market for synthetic inertia may emerge in future. Our work anticipates these developments and provides a technical approach to sizing ESS for synthetic inertia.

This paper adds to the prior art by developing a new methodology to size ESS considering the reduction of system inertia due to both RES penetration and various contingencies including component failures. In this study, a sequential Monte Carlo simulation (MCS) based method is presented to estimate

the size of ESS for transient stability enhancement in the presence of RES. The approach takes into consideration the component failures as well as the reduction of system inertia due to various transmission line contingencies. The proposed methodology is generic and hence can be applied to any electric power system integrated with RES with predefined inertial characteristics. First, a minimum inertia level for maintaining system stability is determined using time-domain simulation (TDS) for all contingencies at all points of time of the study period. The critical clearing times (CCT) are also determined for the disturbances. Then, sequential MCS is performed to determine the expected inertia of the system considering component failures. Finally, the expected size of the ESS is evaluated based on the minimum inertia level needed to maintain the stability of the system during disturbance events.

The rest of the paper is organized as follows. Section II discusses the mathematical model of frequency response of the grid and the method to determine a minimum inertia level for maintaining stability according to grid regulations. Section III describes the sequential MCS based approach to determine the ESS size required for providing inertial support to the grid. Section IV demonstrates some case studies and results while section V provides some concluding remarks.

II. MODELING OF GRID FREQUENCY RESPONSE

Frequency response plays a vital role in overall system dynamic performance. An imbalance in real power leads to frequency deviation from the nominal values and might result in load shedding. The control of frequency and power generation is commonly referred to as load frequency control (LFC). It consists of the following stages: inertial response, primary frequency response (PFR), secondary frequency response (also known as automatic generation control or AGC) and tertiary frequency response [16].

A. Modeling of System Inertia

One of the most important components of frequency response is the inertia constant of a conventional generator, H , which is defined as follows [17].

$$H = \frac{1}{2} J \omega^2 \quad (1)$$

where J is the moment of inertia and ω represents the rotational speed of the rotor. In other words, H is a measure of the amount of kinetic energy stored in the rotor of a synchronous generator. Also, the equivalent inertia constant of a system composed of n generators can be determined as follows [12].

$$H_{eq} = \frac{\sum_{i=1}^n H_i S_i}{S_{eq}} \quad (2)$$

where H_i and S_i are the inertia constant and nominal power of the i^{th} unit and S_{eq} is the total rated power of the system. The swing equation, which describes the motion of a machine, can be expressed as follows [18].

$$\frac{2H_{eq}}{f_s} \frac{df}{dt} = \frac{P_m - P_e}{S_{eq}} = \frac{\Delta P}{S_{eq}} \quad (3)$$

where f_s is the nominal frequency of the system, $\frac{df}{dt}$ is the RoCoF, P_m and P_e are the mechanical power input and the electrical power output, respectively.

B. Minimum Level of Inertia

Power systems should possess adequate inertia to withstand disturbances such as generator outages, short-circuits, and other fault conditions. The behavior of synchronous generators tends to deviate from the stable operating point as a result of disturbances. For example, generators accelerate when a large amount of load is suddenly disconnected [19]. Low inertia leads to frequent instabilities [5].

To emulate the impact of RES on system stability, the inertia of some generators is gradually decreased with a scaling factor until the system becomes unstable for the given fault conditions. This scaling factor can be determined either using the TDS or direct methods [20].

TDS is used in this study to determine the scaling factor of system inertia. This method is applicable for predefined fault locations, fault duration, and post-fault configuration. The inertia constants of the generators are gradually reduced to perturb the system inertia until it becomes unstable. The step size chosen for this operation is 0.01. The scaling factor varies with the system and fault parameters such as CCT and loading factor. The process is repeated for different clearing times, loading factors, and failure contingencies.

C. Contribution of the ESS towards Inertial Response

Let the minimum inertia level that is required to maintain frequency stability at time t be $H_{min}(t)$. Also, let the inertia for a system at time t be $H_{sys}(t)$. If $H_{sys}(t) < H_{min}(t)$, then an ESS may be deployed that can inject active power into the system at a sufficiently high rate to maintain stability. Hence, the inertia that the ESS needs to provide at any time t , if $H_{sys}(t) < H_{min}(t)$, can be defined as follows.

$$H_{ESS}(t) = H_{min}(t) - H_{sys}(t) \quad (4)$$

Therefore, using the swing equation of (3), H_{ESS} at time t can be defined as [12]:

$$H_{ESS}(t) = p_{int}(t) \frac{f_s}{2} \left(\frac{df}{dt} \right)^{-1} \quad (5)$$

where $p_{int}(t)$ is the amount of power generated by the ESS at time t to provide the required inertia. Equation (5) also implies that the inertia required from the ESS is a function of time and the ESS should be sized as a mean value of all the obtained sizes. The RoCoF for this study has been assumed to be equal to 0.5 Hz/s [12].

III. MONTE CARLO SIMULATION TO DETERMINE REQUIRED INERTIA

A probabilistic approach based on MCS is implemented in this study to determine the required inertia of the system to maintain stability. Sequential MCS is used to emulate the system behavior in presence of RES and to calculate system inertia for all time intervals. The calculated inertia is then compared with minimum inertia required to determine the

amount of inertia to be supplied by ESS. A new index is proposed to represent the probability of occurrence of low inertia events in the system.

A. Monte Carlo Simulation Strategy

System components are modeled in this study using Markov chains with a finite number of states. System components include conventional generators, wind turbine generators (WTGs), solar PV units and the electric load. Conventional generators are modeled as two-state units, while wind and PV farms are modeled as multi-state units consisting of multiple WTGs and PV modules. Failure and repair rates of all components, including the forced outages of wind turbines and PV modules, have been considered while emulating the system behavior.

Mixed-timing MCS is utilized in this study. Mixed-timing consists of both synchronous and asynchronous timing controls [21] and involves traversing an hourly load curve over the period of interest, while asynchronously advancing states of system components. In the initial state, all components are assumed to be in the up state. Then, the duration of each component in its current state is determined. The value of the state duration of component i (T_i) is calculated using an exponential distribution as follows.

$$T_i = -\frac{1}{\lambda_i} \ln(U_i) \quad (6)$$

where λ_i represents the failure rate of component i at the up state, and the repair rate at the down state, and U_i is a uniform random number.

Once the system state has been determined for a particular time t , the total inertia of the system is calculated and compared with $H_{min}(t)$. If the system inertia falls below $H_{min}(t)$, that state is recorded as a low inertia state $LH(t)$, which be defined as follows.

$$LH(t) = \begin{cases} 1, & \text{if } H_{sys}(t) < H_{min}(t) \\ 0, & \text{otherwise} \end{cases} \quad (7)$$

An index is defined to represent the probability of the system being in a low inertia state. This index is called the low inertia event probability (LIEP) and can be defined as the expectation of the number of low inertia events. Mathematically, it can be expressed as follows.

$$LIEP = \sum_{x \in X} LH(x)P(x) \quad (8)$$

where $P(x)$ is the probability of the system being in a low inertia state $LH(x)$, and X the set of all such states.

A convergence criteria is also defined to calculate the LIEP index at the steady state. The system is said to have converged when the index attains a certain stable value. The stabilization of the value of an index i is measured by its standard error [22]:

$$\eta = \frac{\sigma_i}{\sqrt{n_c}} \quad (9)$$

where σ_i is the standard deviation of the index i and n_c is the number of simulated cycles. Convergence is said to have

occurred when the standard error drops below a pre-specified fraction, ϵ , of the index i , i.e., when

$$\eta \leq \epsilon i \quad (10)$$

The simulation is said to have converged if the above criterion is satisfied.

B. ESS Sizing

The ESS is sized based on the expected value of H_{ESS} which is obtained from the simulation using (4). The convergence of the index LIEP is crucial for determining the expectation of H_{ESS} . The power rating of the ESS can be obtained using $E[H_{ESS}]$ and (5).

The energy capacity of the ESS can be determined based on the duration for which it needs to provide inertial support. The time-frame for this application is typically a few seconds, i.e., the interval between a disturbance and the PFC to respond. Hence, the ESS should have high power and low energy capacity.

If the time required for the ESS to support inertial response is t_{ESS} seconds, and its power rating is p_{ESS} MW, the energy capacity of the ESS, S_{ESS} , can be expressed as follows.

$$S_{ESS} = \frac{p_{ESS} \times t_{ESS}}{3600} \text{ MWh} \quad (11)$$

C. Replacement of Conventional Generation with RES

In this study, it is assumed that the entire available renewable energy is first utilized to serve the load. The remaining load or the net load is then served by conventional generators. Also, if the net load of the system falls below the total minimum capacity of conventional generators, the generator with the lower inertia constant is first retired. This ensures that the system has the maximum inertia possible at all times.

IV. CASE STUDIES AND RESULTS

This section describes the test system and test cases, and discusses the results. The proposed approach is summarized in the flowchart as shown in Fig. 1.

A. Test System

The proposed method is tested and validated using a modified version of the reduced Western System Coordinating Council (WSCC) 9-bus test system. Generator data for the original system is obtained from [17]. The system consists of three synchronous generators, nine buses, and six transmission lines. Forced outage rates of system components can be found in [23]. A single line diagram of the test system is shown in Fig. 2.

In the modified WSCC 9-bus test system, the conventional generator at bus 3 is replaced by a wind farm of size 200 MW and a solar farm of size 67 MW. The wind farm consists of 25 identical wind turbines of 8 MW each. The wind turbine failure data are obtained from [24] and the wind speed data are extracted from [25]. The solar generation data are obtained from [26] and the related reliability data can be found in [27]. Outages of wind and solar farms are also considered in this

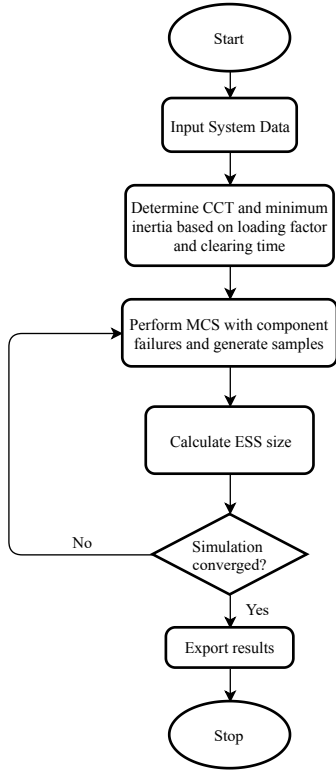


Fig. 1. Flowchart summarizing the proposed approach

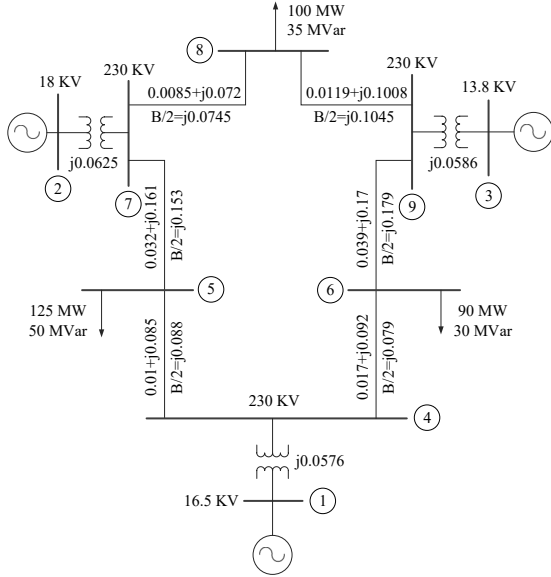


Fig. 2. Single line diagram of the WSCC 9-bus test system

study. It should be noted that the wind and solar resources do not contribute to the system inertia due to the decoupling through power electronic converters.

B. Case Studies

Six possible fault locations were considered for the test system. The system can be reconfigured after any failure and thus for the six locations, there exists a total of 12 possible

configurations. TDS has been used to determine the CCTs for all possible contingencies as presented in Table I.

TABLE I
CRITICAL CLEARING TIMES FOR THE WSCC 9-BUS SYSTEM

Contingency Number	Fault Location	Line Removal From	To	CCT (s)
1	4	4	5	0.319
2		4	6	0.310
3	5	5	7	0.325
4		4	5	0.407
5	6	6	9	0.396
6		4	6	0.451
7	7	7	8	0.184
8		5	7	0.168
9	8	8	9	0.305
10		7	8	0.276
11	9	6	9	0.219
12		8	9	0.234

It can be observed from Table I that the CCT of cases 7, 8, and 11 are the lowest among all cases. This implies that the system is more prone to instability in these cases compared to the other cases. Hence, these cases are chosen while sizing the ESS. Also, three different clearing times for the faults have been assumed for these cases: 100 ms, 150 ms, and 200 ms. Therefore, a total of nine cases have been simulated.

C. Results and Discussion

The results for the different case studies are provided in the Table II. It can be observed from the results that the ESS size is the largest for the fault with the lowest CCTs. The fault with the lowest CCTs is also more prone to instabilities than the other faults. Hence, a large ESS is needed to provide inertial support for that case. Also, it can be observed that the ESS size increases with the fault clearing time. This can be explained as follows. Higher clearing time implies that the ESS needs to support the system longer as more inertia is required.

TABLE II
ESS SIZES FOR ALL CASES

Clearing Time (ms)	Fault No.	H_{ESS}	P_{ESS} (MW)	S_{ESS} (kWh)
100	7	1.5284	2.5474	42.46
	8	2.2034	3.6724	61.21
	11	1.7772	2.9621	49.37
150	7	2.0184	3.3641	56.07
	8	2.746	4.5767	76.2785
	11	2.5636	4.2727	71.21
200	7	Unstable		
	8	Unstable		
	11	4.0894	6.8158	113.59

The energy capacity (S_{ESS}) of the ESS is decided based on the assumption that the ESS will be able to support the system for one minute. However, in most cases, the ESS will not be needed for more than a few seconds.

The values of the LIEP index for different clearing times are shown in Table III and the convergence of the index is shown in Fig 3. From the results it can be observed that the probability of a low inertia event increases with increasing clearing times, hence the LIEP index is higher for higher

TABLE III
LIEP FOR DIFFERENT CLEARING TIMES

Fault Clearing Time (ms)	LIEP
100	0.7628
150	0.7633
200	0.7821

clearing times. Also, the value of the LIEP index is high since the equivalent inertia of the system is low compared to the system size. The equivalent inertia went down as one of the three conventional generators were replaced by RES.

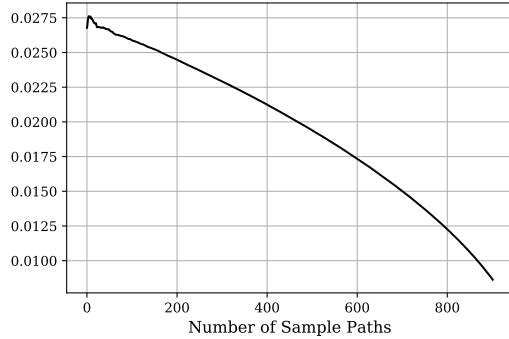


Fig. 3. Error vs. sample paths for the index LIEP

V. CONCLUSION

This paper has proposed a new approach for sizing energy storage systems for grid inertial support. All potential line contingencies have been simulated to determine the critical clearing times and minimum inertia required for each case. Sequential Monte Carlo simulations have been performed to determine system inertia at different points of time considering mean time to failure and mean time to repair of transmission lines. Expected sizes of energy storage systems were determined by comparing the minimum required inertia and the system inertia at any point of time. The results show that large energy storage systems are required for long clearing times and low critical clearing times. A new index for low inertia event probability (LIEP) has been also proposed which quantifies the probability of low inertia events. Results show that the LIEP increases with the increase in clearing times. The proposed methodology can be utilized for power system planning for grid inertial support.

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