Effects of Generator Ratings on Inertia and Frequency Response in Power Systems

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Abstract. The increasing share of renewable generation integrated in the traditional power systems network has brought new challenges to the utility. More specifically, the high penetration of solar energy in the network will reduce the total system inertia which could jeopardize the system’s stability during contingency. The lack of inertia in the power system will increase the Rate of Change of Frequency (RoCoF), which is harmful in the event of sudden load change. In this regard, this paper analyses the effects of generator ratings on system’s inertia and frequency response. The IEEE 9-BUS test system has been utilized in this paper to model the system’s inertia response under various contingency scenarios. The results show that small rating of generators can achieve 20% higher inertia response as compared to the case with larger generator ratings. This implies that system with smaller generators can better recover the system’s frequency than the large-scale generators of similar total rating.

1. Introduction

Fossil fuel power stations release about 2.2 billion tons of carbon dioxide CO$_2$ to the air annually in the United States [1]. The major causes of environmental pollution in the world are acid rain and global warming [2]. These problems have prompted governments and agencies around the world to set new goals in increasing the renewable energy sources (RES) share in their electrical generation mix [3]. For example, China has set a goal of generating over 15% of its total power from renewable energy sources by 2020 with 30 GW of biomass, 200 GW of wind, 50 GW solar and 420 GW of hydro. These strategies are critical to address the large rise in world energy demand while at the same time decreasing the quantity of pollutions. However, the reliability of the whole electrical system may decrease due to the high integration of intermittent RESs which may influence the stability of the system’s frequency [4]. The inertial response in RESs is naturally low for wind turbines or nonexistent for PV solar systems with no rotational parts [5].

For instance, the unstable speed wind turbines are connected to the grid across a converter. This has efficiently decoupled the wind turbine inertia from relieving system transients. In addition, photovoltaic systems do not have any inertia response contribution to the power system. Consequently, the total inertia of the entire power system will decrease when the share of renewable energy increases. In [6], the authors have reported that the growing number of RESs in the United Kingdom could decrease the inertia constant by up to 70% from 2013 to 2033. The Rate of Change of Frequency (RoCoF) of the power system will be sufficiently high to trip the frequency relay during load-shedding due to the low system’s inertia. Therefore, the decreasing of the inertia constant may lead to network blackout during contingency. Study in [7] shows that whenever the percentage of RES installed capacity increases, the
inertial constant will be decreased. This will increase the RoCoF of the power system. Moreover, the number of generation units that provide reserve capacity for primary and secondary frequency response will decrease when the penetration level of the RESs increases. This will lead to the increase in frequency deviation, which is undesirable.

This paper presents the impact of generator ratings on system’s inertia constant and the associated frequency response. The IEEE 9-BUS system has been utilized as the test system and simulated in DlgSILENT PowerFactory software. This paper is organized in the following order: Section 2 presents the concept of the swing power equation with inertia constant and the rate of change of frequency. Section 3 shows the IEEE 9-BUS test system. Moreover, the methodology of the case study will be presented in this section. Section 4 discusses and analyzes the results of the case study. The findings and summary of this paper are summarized in Section 5.

2. Swing equation
Assume a three-phase synchronous alternator is motivated by a prime mover, the machine rotor motion equation can be written as follows [8]:

\[ J \frac{d^2 \theta}{dt^2} = T_m - T_e = T_a \]  (1)

Where J is total inertia of the rotor mass in kgm², \(T_m\) is mechanical torque of the prime mover in N-m, \(T_e\) is electrical torque output of alternator in N-m, and \(\theta\) is the angular position of the rotor in rad.

By neglecting the losses, the net accelerating torque, \(T_a\), is generated by the difference between the mechanical and electrical torque. The electrical torque is equivalent to the mechanical torque in the steady-state; hence the acceleration of power will be equal to zero. In this time the rotor will rotate at synchronous speed \(\omega_s\) in rad/s. The angular position \(\theta\) is measured with a stationary reference frame. The \(\theta\) in term of the synchronous rotating frame is given as follows:

\[ \theta = \omega_s t + \delta \]  (2)

where, \(\delta\) is angular position in radians. Taking the time derivative of the above equation with respect to the synchronous rotation reference frame can be written as follows:

\[ \frac{d\theta}{dt} = \omega_s t + \frac{d\delta}{dt} \]  (3)

Defining the angular speed of the rotor as

\[ \omega_r = \frac{d\theta}{dt} \]  (4)

It can be elaborate (3) as the following equation:

\[ \omega_r - \omega_s = \frac{d\delta}{dt} \]  (5)

Therefore, the rotor angular speed is equal to the synchronous speed only when \(d\delta/dt\) is equal to zero. Taking the derivative of (3) and substitute into (1), the torque equation can be written as follows:

\[ J \omega_r \frac{d^2 \delta}{dt^2} = P_m - P_e = P_a \]  (6)

Multiplying both sides by \(\omega_r\),

\[ J \omega_r \omega_r \frac{d^2 \delta}{dt^2} = P_m \omega_r - P_e \omega_r = P_a \omega_r \]  (7)

Where \(P_m\) is mechanical power in MW, \(P_e\) is electrical power in MW and \(P_a\) is accelerating power in MW.

2.1. Inertia constant
The kinetic energy stored in a single generator shaft is often expressed as proportional to its power rating. It is called the inertia constant H. Inertia can be known as the resistant to change and it prevents
the frequency from changing rapidly. The inertia constant is measured in seconds and it falls typically in the range of 2-9s. For large power plants, the inertia constant is inversely proportional to the power rating. That means when the generator rating increases the inertia constant will decrease as reported in [9] and as shown in Figure 1.

Two factors mainly affect the system inertia, i.e., the inertia of each generator and the number of operating generators in the system. In the conventional power plants, the synchronous generators can provide the inertia to the system given the strong coupling between electrical frequency and the rotational speed [10].

![Figure 1. Inertia constant for conventional generators [9].](image)

The equation of motion of the machine rotor is given as below, that consider inertial constant of a machine as [11],

\[ H = \frac{\text{Stored Energy at rated speed in MWS}}{\text{Generator MVA rating}} \]  

(8)

\[ K.E. = \frac{1}{2}J\omega^2 \]  

(9)

From Equation (7) and (8)

\[ H = \frac{\frac{1}{2}J\omega^2}{\text{MVA}} \]  

(10)

Where H is inertia constant in MWs/MVA, J is the moment of inertia of the rotating mass in kgm², \( \omega \) is the nominal speed of the rotation in rad/s and MVA is nominal generator rating. The total system inertia is calculating from the equation below:

\[ H_{sys} = \sum_{i=1}^{n} H_i S_i \]  

(11)

Where \( H_{sys} \) is total system inertia, \( H_i \) is generator \( i \) inertia in second and \( S_i \) is generator \( i \) rating in MVA.

2.2. Rate of change of frequency (RoCoF)

The time derivative of the power system frequency (df/dt) is known as RoCoF. In a traditional power system, RoCoF was not generally taken into consideration because of the nature of the network without any integrated RESs and small distributed generators. The RoCoF value is not necessary for the conventional power system, but by increasing the penetration of RES into the power system, the RoCoF can play an important role to control the frequency of the network. Moreover, RoCoF can be used for knowing the mismatch power generation and load consumption. The mismatch can be caused by the disconnection of either large loads or generators. The high amount of RoCoF might be observed because of the low system inertia caused by the integration of a high penetration level of uncertain generation
such as PV system or Wind turbines. The rate of change of frequency is calculated from Equation (12) [12, 13].

\[
\frac{df}{dt} = \frac{\Delta p \times f_0}{2H \times S}
\]  

(12)

Where \( \frac{df}{dt} \) is the rate of change of frequency in Hz/s, H is total system inertia in MWs/MVA, \( \Delta p \) is generator loss in MW, \( f_0 \) is generator rated frequency in Hz and S is total generators rating in MVA.

3. Methodology

The IEEE 9-BUS test system is used in this paper, to highlight the effects of inertia constant and the generator rating MVA on the frequency response after contingencies. The system has 9 buses, 3 generators, 3 transformers and 6 transmission lines. It consists of 3 general loads which total up to 315 MW and 115 MVar. A turbine governor and AVR exciters are equipped to all the generators. Figure 2 shows the IEEE 9-BUS system single line diagram in DlgSILENT PowerFactory software. The generators data used in this simulation are shown in Table 1 [14]. The inertia constant H which is shown in Table 3 based on the system rated power MVA that has been calculated from the stored energy at nominal speed from Equation (10).

![Figure 2. IEEE 9-BUS system single line diagram.](image)

| Gen. No. | S (MVA) | P (MW) | J (kgm²) | H (s) | Q (MVar) | V (pu) |
|---------|--------|-------|---------|------|---------|-------|
| G1      | 247.5  | 71.6  | 9160.1  | 2.63 | 27      | 1.04  |
| G2      | 192    | 163   | 1115.8  | 4.13 | 6.7     | 1.03  |
| G3      | 128    | 85    | 8592    | 4.77 | -10.9   | 1.02  |

Table 1. Generators data.

Three scenarios have been considered in this study. Each scenario considers a generator to be disconnected from the system and the other two generators remain in operation. The details are as shown in Table 2.

| Scenario No. | G1 | G2 | G3 |
|--------------|----|----|----|
| 1            | Off| On | On |
| 2            | On | Off| On |
| 3            | On | On | Off|

Table 2. Generators operation scenarios.

Each scenario consists of three cases. The data in Case 2 is the IEEE standard power rating. In Case 1 the power rating is decreased for all the generators by -20% from Case 2 to see the change in Inertia. Opposite of Case 1, the power rating in Case 3 is increasing by +20% to compare with Case 2.
shows the data used in each scenario for all cases. Figure 3 shows different values of generators power rated with inertia constant calculated by Equation (10).

![Inertia constant in different power rated MVA](image)

**Figure 3.** Inertia constant in different power rated MVA.

**Table 3.** Power and inertia data used in scenarios for each generator.

| Case No. | Scenario 1 | Scenario 2 | Scenario 3 |
|----------|------------|------------|------------|
|          | G1         | G2         | G3         |
|          | P (MVA)    | H (s)      | P (MVA)    | H (s)      | P (MVA)    | H (s)      |
| 1        | 200        | 3.25       | 150        | 5.29       | 100        | 6.10       |
| 2        | 247.5      | 2.63       | 192        | 4.13       | 128        | 4.77       |
| 3        | 300        | 2.6        | 250        | 3.18       | 200        | 3.05       |

4. Result and discussion

Numerical results from DIgSILENT Power Factory simulation shows that, when the power rating of the generator is increased, the inertia constant $H$ of the generator is decreased. This scenario has led to a high change in the RoCoF of the whole system and the system will be in critical status. The RoCoF in all the scenarios is calculated from Equation (12). The total system inertia before and after disconnecting the generators are calculated from Equation (11). The data and results for each scenario are shown in the following sub-sections.

4.1. Scenario 1

Generator 1 (G1) with the capacity of 71.6 MW is equivalent of approximately 22% of total system generation. This generator disconnected from the network after 1 second. The other generators will keep on continuing the operation, but the power rating and inertia constant data of all generators are changed based on Case 1, 2 and 3 respectively as shown in Table 4.

**Table 4. Result of Scenario 1.**

| Case No. | Total inertia before disconnecting G1 (MWs) | Total inertia after disconnecting G1 (MWs) | RoCoF (Hz/s) | Freq nadir (Hz) | Steady state (Hz) |
|----------|------------------------------------------|------------------------------------------|--------------|-----------------|------------------|
| 1        | 2053.5                                   | 1403.50                                  | 0.479        | 52.54           | 52.96            |
| 2        | 2054.4                                   | 1403.52                                  | 0.564        | 59.19           | 59.73            |
| 3        | 2185.0                                   | 1405.0                                  | 0.628        | 59.89           | 59.95            |

Figure 4 shows that the frequency is unstable before tripping G1 in Case 1 due to the mismatch between generation and load. In other words, if the demand is higher than the rated generation, the frequency dropped. However, after contingency, the frequency is dropped to 52.546 Hz in Case 1, which
result in a drastic change in RoCoF by 0.479 Hz/s just after the contingency. It can be observed from Figure 4 that the system collapse at approximately 0.5 s. That is because of the shortage of active power MW in the system due to the small generator rating MVA and the large load.

In Case 2 which is IEEE standard base case system, the system is recovered (59.379 Hz) in the steady-state after contingency which the frequency nadir is 59.199 Hz. The system is stable because of the balance between the supply and the demand.

In Case 3 the total generator's rating is 450 MVA as shown in Table 4. In this case, G1 is disconnected and the system inertia is low which led to high RoCoF. As a result, the frequency in steady-state is 59.954 Hz and frequency nadir is 59.893 HZ so the system is stable after contingency.

Figure 4. Result of inertia and frequency for Scenario 1.

4.2. Scenario 2

In this scenario, G2 is disconnected after 1 second from the rest of the network. The loading of G2 is 163 MW which is about 51% of total system generation. Like Scenario 1, due to mismatch between generation and demand, the frequency dropped to 53.829 Hz in Case 1 and it tried to recover the frequency during the secondary frequency response. However, the RoCoF experiences the extreme change of 1.210 Hz/s just after the occurrence of the contingency. This is because of the shortage of active power MW in the system due to the small generator rating MVA and the large load. Figure 5 shows that the system failed to recover the network frequency to the nominal range, and the network has collapsed.

In Case 2 which is IEEE standard base case, the system frequency is recovered to 59.816 Hz in the steady-state after contingency which the frequency nadir is 58.702 Hz. The system is stable because of the balance between the load and the generation.

In Case 3 the total generator's rating is 550 MVA as shown in Table 5. In this case, G2 is disconnected and the system inertia is low which led to high RoCoF. As a result, the frequency in steady-state is 59.841 Hz and frequency nadir is 59.049 Hz so the system is stable after contingency as shown in Figure 5.

Table 5. Result of scenario 2.

| Case No | Total inertia before disconnecting G2 (MWs) | Total inertia after disconnecting G2 (MWs) | RoCoF (Hz/s) | Freq. nadir (Hz) | Steady state (Hz) |
|---------|-------------------------------------------|-------------------------------------------|--------------|-----------------|-----------------|
| 1       | 2053.5                                    | 1260.0                                    | 1.210        | 53.829          | 57.421          |
| 2       | 2054.45                                   | 1261.49                                   | 1.284        | 58.702          | 59.816          |
| 3       | 2185.0                                    | 1390.0                                    | 1.336        | 59.049          | 59.841          |
4.3. Scenario 3

This scenario is almost similar to Scenario 2 as shown in Figure 6, except it operates with higher generator rating. In this scenario, G3 is disconnected after 1 second. Therefore, the network will face the lack of 85 MW (approximately 26% of total generation) that must be compensated by G1 and G2. Thus, as shown in Figure 6 and Table 6, the increasing generator rating value has a significant negative impact on the total inertia constant H of the system. For instance, the increasing of inertia constant from Case 1 with a total of 300 MVA of generation is 8.9768 s in Scenario 2 that compare to 350 MVA with 9.9613 s inertia in Scenario 3.

In Case 1, the frequency nadir is 55.022 Hz and the frequency reach to steady-state with 58.197 Hz. The RoCoF is 0.568 Hz/s, in this case, because of the high inertia of the system. Case 2 is the best in term of inertia because the increased in MVA rating of all generators with total 439.5 MVA. The steady-state frequency, in this case, is 59.917 Hz and the nadir is 59.589 with RoCoF 0.669 Hz/s. Case 3 the RoCoF is high due to the decrease of inertia. The system frequency nadir is 0.775 Hz/s and the system became stable at 59.882 Hz.

### Table 6. Result of Scenario 3

| Case No | Total inertia before disconnecting G3 (MWs) | Total inertia after disconnecting G3 (MWs) | RoCoF (Hz/s) | Freq. nadir (Hz) | Steady state (Hz) |
|---------|--------------------------------------------|-------------------------------------------|--------------|-----------------|------------------|
| 1       | 2053.5                                     | 1443.5                                    | 0.568        | 55.022          | 58.197           |
| 2       | 2054.45                                    | 1443.89                                   | 0.669        | 59.589          | 59.917           |
| 3       | 2185.0                                     | 1575.0                                    | 0.775        | 59.177          | 59.882           |

![Figure 6](image_url). Result of inertia and frequency for Scenario 3.
5. Conclusion
This paper presents the analyses on the rotational inertia of conventional power system, specifically on the impact of generator ratings on the system’s inertia constant and the associated frequency response. In general, the analysis shows that the lack of inertia in the power system increases the Rate of Change of Frequency (RoCoF).

The IEEE 9-BUS test system utilized in this paper as a case study to module the inertia response. Three different scenarios have been considered in this study that each scenario consists of three cases. The results show that the small rating of generators produces the highest inertia in the power system, which helps to recover the system frequency better than the large generators. As the findings of this paper, the integration of small rotational generators that can deliver high inertia rate could help to recover the system during the contingency within the primary frequency response. Based on the three scenarios presented, the range of the generator power rating required to get optimal inertia response is between 100 to 400 MVA.

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