Article

Determination of the required Power Response of Inverters to provide fast Frequency Support in Power Systems with low Synchronous Inertia

Alejandro Rubio [1,†,‡], Holger Behrends [1,‡] and Stefan Geißendörfer [2,*]

[1] Affiliation 1; e-mail@e-mail.com
[2] Affiliation 2; e-mail@e-mail.com
* Correspondence: e-mail@e-mail.com; Tel.: (optional; include country code; if there are multiple corresponding authors, add author initials) +xx-xxxx-xxx-xxxx (F.L.)
† Current address: Affiliation 3
‡ These authors contributed equally to this work.

Version November 24, 2019 submitted to Journal Not Specified

Abstract: Decommissioning of conventional power plants and the installation of inverter-based renewable energy technologies decreases overall power system inertia. This reduction in system inertia has an impact in the power system frequency response when an imbalance between generation and load occurs, increasing the rate of change of frequency (RoCoF) of the system. In a future scenario where renewables are predominant in power systems and due to the natural variability of the resource, imbalances of 40% or more are prompt to happen. When a system is islanded or operates as such and combined with low inertia, it may lead to frequency collapse. This expected high values of RoCoF shorten the response time needed before load shedding or generation curtailment take place and a subsequent possible black out occurs. Through the simulation of two scenarios with different primary reserve response, the requirements for the fleet of connected inverters was determined in terms of activation time and total power to be provided in order to avoid load shedding. This activation time was determined to be the time at which frequency would reach the load shedding value, known as critical time. With such value and knowing the time required for the synchronous reserve to deploy the imbalance power, a simple expression based on nullifying RoCoF at the critical time was obtained for the required inverter based fast power reserve. It was obtained that full activation time for inverter fast power reserve with penetration above 80% of inverter based generation would need to be between 50-500 ms for imbalances up to 40%; meaning that current frequency measurement techniques and renewable deployment times would not ensure system stability under the foreseen future possible power system conditions. A power ramp in the order of 300% the load per second is necessary for fast power reserve to maintain frequency within the allowed limits.

Keywords: frequency support, flexibilization, renewables, inverters

0. How to Use this Template

1. Introduction

2. Results

In this section a deeper look is given to the obtained results out of the simulated cases. In order to allow understandable comparisons between each approach and models; the chapter is divided in three main sections, in which the main results of the simulations will be discussed. This chapter is divided in the following sub-sections: Analysis of critical time. Analysis of Synthetic Inertia and Fast Power Reserve Synchronizing effect and lack of damping torque.

2.1. Analysis of Critical Time

Due to the nature of the swing equation, which describes the frequency response in synchronous machines, a reduction of the available time for the inverters to react to perturbations was found as RoCoF increases. As it was expected, the frequency response is highly dependent on the primary reserve response (governor response). When the IEEE 9 bus model is simplified to one machine and losses are disregarded; critical time deviations from the full dynamic extended model are observed to reach values up to 34%. From the fit plots it can be noticed that the highest deviations occur at high system acceleration constants and in the low range of RoCoF, allowing primary reserve to take effect. Therefore, it can be stated that the simplifications in the model have a greater influence on the results for low RoCoF and IBG penetration values; in this sense, the simplifications become less significant as the RoCoF increases in such a manner that the activated synchronous primary reserve is not relevant in frequency support. Despite the discrepancy in the critical time between both approaches in the IEEE 9 bus model; the power ramp calculated for the simplified model and the extended model does not differ from each other in a great manner as exhibit later in Figure 5 2. It is then inferred that the discrepancy in critical time estimation is compensated by the factor of nadir time, which due to non-linearity characteristics considered in the Extended model, varies upon change in inertia and load imbalance (perturbation); contrary as the linear simplified model in which the nadir time is invariable for perturbations. In the theory section, the typical frequency measurement time and technologies activation time were discussed [14]. Figure 5 1 contrasts the critical times obtained from the models with the required time for frequency measurement and full power activation from different technologies.

It is observed that in the range higher than 2 Hz/s; the critical time trend for the European island and the simplified IEEE model get closer each to other as RoCoF increases. In the same way the extended model but for very high values. Therefore, it is infered that under high RoCoF conditions in any of the models, the primary reserve does not significantly counteract the frequency drop [16]. Figure 5 1 demonstrates that primary reserve can be neglected for determination of the critical time when the combination of inverter based generation and load imbalances would lead to high values of RoCoF (>2 Hz/s); as RoCoF increases, the approximation of critical time as 1(Hz)/RoCoF narrows the difference with the results obtained from simulations [14]. Nevertheless such simplification is applicable to the simplified IEEE model and the European island. Hence, the influence of all the dynamics and machine components, such as generator exciter and armotisour windings, seems to improve the critical time; extending up to a 34% the calculated time with the simplified approach. Damping torque in swing equation [7, 8] was not considered for the IEEE simplifed model; the inclution of such may lead to more precise times when comparing with the extended model. Also it is then stated the need of a fast power response to avoid frequency collapse of islanded micro-grid or an electric island in the European scale. Even assuming that power reserve can immediately fully activated after RoCoF reading, the 100 ms limitation is a constraint for high unbalanced islands with high penetration of IBG in the European case as demonstrated in the result section. Additionally, the direct measurement of RoCoF in the 100 ms interval can lead to misleading readings [14]. In general, when penetration of IBG is higher than 90%; for the 40% imbalance an activation time between 30 and 50 ms would be needed to keep frequency within the allowed limits. Due to the fact that the characteristics of the interconnected scenario provided by ENTSOE were assumed to be the same than the resulting islands after a severe event; the results for the European island can be understood as the behavior of the whole European system with bigger perturbations. The dimensioning scenario assumes a power imbalance of 3 GW, which corresponds to a 2% of the 150 GW load [1]. If in future a bigger dimensioning case is utilized, then synchronous response would not be enough to balance the system before load shedding occurs. Table 5 1 exhibits the required time when the dimensioning scenario is increased up to 10% for different IBG penetration. IBG share (3 4 5 6 7 8 9 10 20 - - 6.081 4.517 3.629 3.050 2.638 2.316 40 - 6.226 4.169 3.215 2.628 2.222 1.934 1.705 60 7.142 3.639 2.623 2.062 1.698 1.451 1.263 1.122 80 2.753 1.744 1.277 1.018 0.843 0.722 0.628 0.559 92 1.109 0.700 0.514 0.406 0.338 0.288 0.252 0.224 95 0.697 0.436 0.322 0.254 0.211 0.179 0.157 0.140 Table 5 1: Critical times for European case in seconds.

Scenarios with higher imbalance than the reference scenario combined with high penetration of renewables will require fast power reserve as indicated in Table 5 1. Even though it was assumed enough synchronous reserve, this is too slow under such conditions. Nadir freq. Nadir for 3 cases with no support: behavior of governor response Nadir for 2 cases with synthetic inertia/critical time improvement with synthetic inertia Nadir for 3 cases with inverter based fast power reserve

2.2. Analysis of Synthetic Inertia and Fast Power Reserve

2.2.1. Effect of Ramp Response on Frequency

When the power ramp required to meet the power load imbalance at the critical time was calculated in chapter 3; the contribution from the ramping power in diminishing system RoCoF during the inception of the perturbation until the critical time was disregarded. Therefore the fast inverter based power response values at the critical time correspond to the accelerating power at that time. Assuming an instant switching of the IBFPR at critical time, the frequency nadir would be 49 Hz (no ramping power before critical time). Nevertheless, a ramp power response was assumed instead. Therefore the calculated power ramp, when applied to the unbalanced system, commonly exhibits a frequency nadir higher than 49 Hz, due to the contribution of the ramping period. In this sense, it can be inferred that the longer the ramping period (shorter measuring time), the higher frequency nadir will be obtained. Here again the relevance of the prompt activation in time of the IBFPR. On the other hand, with the faster IBFPR activation, the ramp slope and the steady power output (Inverter based power reserve) can be diminished compromising frequency nadir. When the activation does not takes place instantaneously, frequency nadir and therefore system stability can be compromised for some combination of system inertia and load imbalance as demonstrated in the result section. In order to assure stability a stepper ramp slope is required in order to meet the required power before critical time. That is achieved by changing equation 3-2 by the adjusted expression: Equation 5 1 Where td is the time delay needed to start the activation of IBFPR. When a comparison is established beween all the calculated power ramp slopes in per unit (pu), it is noted that with high penetration of non-synchronous power in the power system, the required power to ensure no UFLS have a consistent trend between the three models, and a close proximity in the values for RoCoF in the range of 2 to 5 Hz/s is observed between both IEEE models. Such trends can be seen in Figure 5 2. A bigger amount of power ramp slope is needed in all the range of RoCoF for the European case. After inspecting Equation 3-2, it is noticed that the IBFPR is affected by the factor(1-t$_{c}rt_{n}adir), thenasnadirtimeincreases, IBFPRincreasesaswell. ThenadirtimefortheEuropeancase, duetotheactionoft$ $regulationandprimaryreservedeploymentof30seconds, isintherangeof3 - 12seconds(6secondsfor80\%IBGpenetration)whereasthenadirtimeforthesimplifiedIEEEmodelisbetween1 - 3seconds. SeeAppendixIIIformoredetailsinregardsofnadirtime. FastPowerReserve$

So far, the power ramp required to avoid load shedding has been found for the IEEE 9 bus model with a fast governor response and for the European island with conventional primary reserve response. Hence, the investigated inverter based fast power response at critical time which remain constant afterwards, would be accounted as the fast power reserve. Similarly as primary reserve estimations are performed considering the loss of generation at certain level; for fast power reserve the results are presented for the scenarios in which imbalance could reach even 40%.

Figure 5 3 shows the results of the needed fast power reserve for each case under 80% of IBG penetration. A linear behavior is exhibit by the simplified model and the European.

A proportion of almost one to one is observed for the European model, this is caused by the slow primary reserve. Therefore for imbalances higher than 3% the fast power reserve has to cover all the imbalance. The observed offset from the one to one relation is due to the load reduction caused by the frequency drop (load self-regulation). The dashed line represents the one to one proportion. In the case of the IEEE grid; the simplified model exhibits a permanent offset from the dashed line of around 0.05 pu, this due to the action of a faster governor response. Therefore, it can be said that in such scenario, the conventional governor response of synchronous machines would cover 5% of the imbalances starting at 8%. Since the values for nadir time are not independent from the imbalance in the Extended model, due to the non-linearity of the model, the calculated power reserve tend to equalize the whole imbalance. As imbalance increases, the critical time decreases and the nadir time increases, this makes the reducing factor tcr/tnadir from Equation 3-2 to decrease and narrows the difference between the calculated reserve and power imbalance. Similarly as critical time was presented in Table 5 1 the required fast power reserve in the European context is shown in Table 5 2 for extraordinary events

Table 5 2: Fast power reserve in per unit for European case IBG share (3 4 5 6 7 8 9 10 20 - - 0.025 0.038 0.049 0.060 0.070 0.081 40 - 0.016 0.030 0.041 0.052 0.063 0.073 0.083 60 0.005 0.024 0.035 0.045 0.056 0.066 0.077 0.087 80 0.016 0.028 0.039 0.049 0.062 0.070 0.080 0.09 92 0.021 0.033 0.043 0.054 0.064 0.074 0.084 0.094 95 0.024 0.035 0.045 0.055 0.065 0.075 0.085 0.096

As IBG increases the closer to the imbalance the fast power reserve needs to be. As it was demonstrated in the result section; with a faster conventional reserve, reduction in fast power reserve can be observed.

2.3. Synchronizing effect, lack of damping torque and implications

When the IEEE model was implemented using SIMULINK-SIMSCAPE blocks, in order to incorporate all system component dynamics; system instability was found for low inertia values in the system and due to high imbalances (with no IBFPR). In non-linear systems, the stability is not only determined by the equivalent transfer function but also it is dependent on the inputs or sources [7, 22]. In this sense the loss of stability due to huge load imbalances is explained by the non-linearity of the system. When the system is perturbed by a small change in one of the state variables in such a way that the system returns to its initial state or remains close to it; a linearization of the system can be performed and a so called small signal stability analysis can be performed [7]. In the simulations it was found how the extended model is unstable for imbalances above 15% with a penetration of non-synchronous generation of 85%, corresponding to a system acceleration time constant of 2.1 seconds. The diminishing of synchronous machines, and the dependency of system frequency and voltage signal from them, lead to a very weak network, where synchronizing and damping torque, which are inherent characteristics of synchronous machines are not enough to stabilize the system (assuming that such excursion of frequency and rotor speed would be allowed to happen) [7]. Although the implementation of IBFPR contributes keeping synchronous machine on step , low frequency oscillations in the rotor speed/frequency response are observed. This oscillations are created by the lack of damping torque which is provided mainly by the synchronous machines, through damping windings, field exciter and Power System Stabilizer (connected to the machines exciter). For the simplified IEEE model and the European island, only transfer functions describing an equivalent system governor were modeled. Hence in such approaches, the effect and dynamics of synchronous generator's exciters and inter-machine interaction were not taken into account. The before mention factors influence greatly small signal stability [7, 8] Even though the scoop of this thesis is to analyze the power-time characteristics needed to avoid frequency collapse; oscillations associated to big perturbation were observed but they could not been addressed by the simple injection of power to the system. Also in the IEEE model, when a penetration of 95% of inverter based generation and 2% of load imbalance are considered, UFLS is not reached but the system becomes unstable as shown in Figure 5 6 and Figure 5 5. From penetrations levels above 85% complete frequency stability is not ensure with the injection of fast power reserve, only UFLS on the first 10 seconds approximately. Then the system becomes unstable with increasing amplitude oscillations. It is important to note that ENTSOE in its EUROPEAN interconnected scenario, determined that there is no UFLS when an unbalance of 2% with high contribution of non-synchronous generation occurs. Nevertheless, no inter-machine interaction was considered and therefore a similar effect as the one in Figure 5 6 could be experienced.

3. Discussion

Authors should discuss the results and how they can be interpreted in perspective of previous studies and of the working hypotheses. The findings and their implications should be discussed in the broadest context possible. Future research directions may also be highlighted.

4. Materials and Methods

The transitory frequency response of the system and therefore its stable and reliable operation after a perturbation, depends on the inherent characteristics of the power system and the counteraction measurements engaged automatically by the power system. As the share of inverter based generation increases, the more sensible to instability the power system becomes. In this sense the added inverter based fast power reserve must be capable of maintaining transitory frequency value within the allowed limits. Two terms commonly found in the literature of power system stability will be used along this section:

- **Inertia constant (H)**: It has units of seconds (s) and it is the ratio of the kinetic energy stored in the rotating masses of the generators (E_k in MWs) and its nominal capacity (S_{nom} in MVA).

- **Acceleration time constant ($\mathbf{T_a}$)**: It also has the units of seconds (s) but this is the ratio of double the kinetic energy (MWs) and generators nominal power output (P_{nom} in MW).
  Acceleration time constant is a measure of the robustness before disturbances of the system. It could be interpreted as the required time to remove the kinetic energy from the rotating masses of the generators connected in a grid at the rate of the supplied power load. Hence, the higher the time constant, the higher the kinetic energy available. As the share of synchronous generations decreases, this constant decreases proportionally.

With f as frequency, f_0 as nominal frequency and ΔP as power imbalance the swing equation can be expressed as follows:

$$\frac{df}{dt} = \frac{\Delta P * f_0}{2 * H * S_{nom}} = \frac{\Delta P * f_0}{T_a * P_{nom}} = \frac{\Delta P * f_0}{2 * E_k} \tag{1}$$

In this paper, the inertia constant H is used for the description of synthetic inertia in wind turbines, whereas the system acceleration constant T_a is used to express the whole system inertia related to the load in terms of real power.

4.1. Synthetic Inertia

Synthetic inertia is one of the new techniques that manufactures and researchers are considering to tackle with the low inertia problem in power systems [7][6]. Frequency support through synthetic inertia was considered with the following assumptions [3][12]:

1. Power output from synthetic inertia is limited to 10% of wind turbine nominal power.
2. Due to mechanical and thermal stresses, the additional power can be delivered only for a maximum time of 10 s.
3. It is assumed that all wind turbines operate at its maximum power output. The value of 1.5 MW was selected for such purpose.
4. In order to avoid wind turbine stall, the removed kinetic energy from the blades (injected to the grid in electrical form) it is limited to half [4].

An adequate control system is needed so the stored energy in the rotating blades can be extracted from the wind turbine. From the expression of power as the derivative of energy stored in the blades

(2), the rate of energy extracted from the wind turbine can be obtained, considering that the rotational speed changes in time ref.

$$P_{pu}(t) = 2 * H_{wt} * \omega_{pu}(t) * \frac{d\omega_{pu}(t)}{dt} \tag{2}$$

Where H_{wt} is the turbine inertia constant and ω_{pu} the rotational speed in per unit.

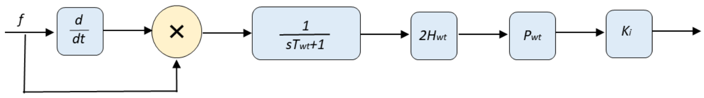


Figure 1. Representation of equation (2) in the model. In the figure it can be seen the insertion of a filter at the output of the multiplication block. A constant block K_i adjusts the initial response in the model. Since equation (2) is given in pu, the output is multiplied by a constant P_{wt} representing the rated power of the turbine.

Typical values for inertia constant of wind turbines are not openly available from the manufacturers to the public. Hence an approximate value was calculated with the utilization of an equation which relates nominal power and inertia constant for wind turbines [8].

$$H_{wt} \approx 1.87 * P_{nwt}^{0.0597} \tag{3}$$

For a wind turbine with nominal power output of 1.5 MW the value of H corresponds to 4.37 s [17]. It is assumed that all the wind turbines deliver their nominal power output. A rated rotational speed of 18 rev/min was considered [28]. To avoid the wind turbine to stall, a reduction of 5 rev/min it is allowed by the implementation of the control system. This change of rotational speed equals a change of 3 MWs reduction on kinetic energy out of a total of 6 MWs.

Table 1. : Constants for implementation of synthetic inertia

$\mathbf{T_{wt}}$	$\mathbf{H_{wt}}$ **(s)**	$\mathbf{P_{wt}}$ **(MW)**	$\mathbf{K_i}$
1	4.37	$1.5*n_{wt}$[1]	10

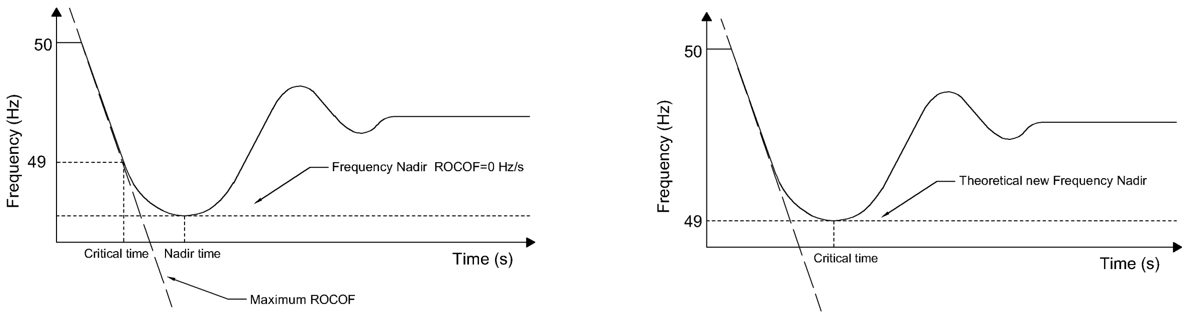
4.2. *Inverter based fast Power Reserve*

When a power system is subjected to a negative power imbalance and it is assumed that no load is rejected at UFLS frequency, this continues dropping below 49 Hz. The time at which the system frequency equals the UFLS value is then called critical time. This is the maximum available time for the inverter based reserve to deploy the required power to the system.

In the critical condition that would lead to load shedding, it is expected from the IBFPR to at least to counteract the RoCoF at the critical time, as illustrated in Figure 2b. Recalling equation (1); it is necessary that the machine's accelerating power (power imbalance) become zero at the critical time.

$$P_a(t_{cr}) = P_{mech} - P_{elec} + P_{IBFPR} = 0 \tag{4}$$

Where P_a is accelerating power, P_{mech} is mechanical power, P_{elec} is electrical power load, t_{cr} is the critical time and P_{IBFPR} is inverter based fast power reserve. From the assumption of a linear mechanical power deployment is given from the synchronous machines governors, the rate of change in mechanical power, after a power imbalance ΔP, is given by $\Delta P/t_{nadir}$, where t_{nadir} represents the time at which the frequency nadir occurs. Given the power balance at the critical time, t_{cr}; the IBFPR response must be equal to $P_{elec} - P_{mech}$, being P_{elec} equal to ΔP.



(a) Typical frequency response leading to UFLS **(b)** Desired frequency response avoiding UFLS

Figure 2. In (**a**) the frequency response goes below the 49 Hz leading to UFLS at the critical time, whereas in (**b**) the IBFPR is applied avoiding ULFS. In this case the power imbalance is compensated at the critical time by the inverters.

Substituting P_{mech} by $\Delta P * t_{cr}/t{nadir}$ and P_{elec} by ΔP in (4), the following expression is obtained for the P_{IBFPR} at time t_{cr}:

$$P_{IBFPR}(t_{cr}) = \Delta P * (1 - t_{cr}/t_{nadir}) \tag{5}$$

It is assumed that P_{IBFPR} remains with a constant power output after t_{cr} long enough to stabilize the system frequency. The result of the previous equation represents the slope of the power output since the inception of the incident until the critical time, which with the implementation of IBFPR, it will be not any longer critical but rather it will be the new desired frequency nadir time.

$$P_{IBFPR}(t) = \frac{\Delta P * (1 - t_{cr}/t_{nadir}) * t}{t_{cr}} \tag{6}$$

According to the obtained expression; it can be realized that the desired power response from the inverters depends exclusively on parameters which cannot be directly measured from the grid connection point. In a real situation the values of ΔP, t_{nadir} and t_{cr} cannot be known in advance, representing this factors a challenge in the implementation of this ideal power response. Those values are dependent on the grid characteristics, the primary conventional reserve deployment time and the overall system inertia [14]. Thus two main cases are considered for the remaining analysis with the intent of covering a wider range of systems with different characteristics and dimensions.

4.3. Simulation Cases

As presented in the previous section, the values of critical time and frequency nadir time depend on the system imbalance and primary reserve deployment time. In spite of assessing the influence of the grid size and the primary reserve characteristics, two main cases are considered. In both cases is assumed that the initial steady frequency is the nominal 50 Hz.

- **Small scale grid case:** For the evaluation of this case typical governor data is considered in a well-known and studied benchmark grid topology as the WSCC model, also known as the IEEE 9 bus model. Synchronous reserve deployment is in the order of a few seconds due to governor response [11][15].

  Scenario A - Simplified Model: The power system is represented by an equivalent single machine model in which losses are neglected. It is investigated the critical time for inverters' activation and the required IBFPR is also determined. Furthermore, the impact of synthetic inertia and the frequency measurement delay in frequency response is analyzed.

  Scenario B - Extended Model: All the power system components (transmission lines, transformers, exciters and governors of the three generators) and its dynamic characteristics are considered in the IEEE 9 bus model.

- **Large scale grid case:** The European grid scale in which all the synchronous machines are modeled and simplified as one single machine, provided with the characteristic expected from the overall system. Synchronous primary reserve deployment is in the order of ~ 30 s [5][10]. Island frequency response is assumed to be the same that the European response analyzed by ENTSOE [5].

4.4. Simplified IEEE 9 bus Model

As a first step to evaluate the impact of inverter based generation and power imbalances in the grid, the whole system is simplified as one single generating unit; neglecting all losses in the system (Transformers, transmission lines and generators) with the assumption that the mechanical output of the prime mover is the same than the electrical power output at generator terminals. Table 2 provides a summary of the elements comprising the base model.

Table 2. :Elements of the IEEE 9 bus model.

	Quantity
Buses	9
Transformers	3
Transmission Lines	6
Generators	3
Load	315 MW

Figure 3 is the block representation of the swing equation (1), it only differs in the fact that blocks representing the inverter based generation have been included. The mechanical power is represented by the output of a steam turbine governor model, which is used to represent the synchronous machine [1]. When equilibrium is lost, the accelerating power is multiply by the transfer function $1/(2 * H * S)$, where H is the machine's inertia constant and S is the machine's power rating. From (1) this product equals the derivative of frequency, therefore an integrator block is added to obtain the frequency response [11][9][13]. A feedback loop is added and an error signal obtained from the reference frequency so the synchronous machine can react as frequency deviates from nominal.

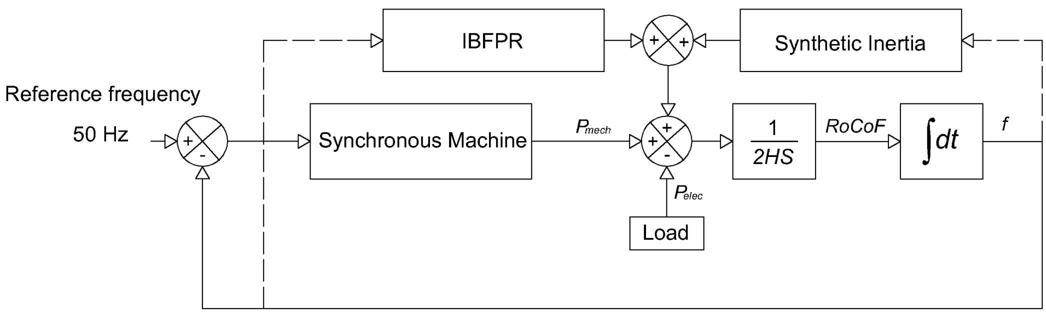


Figure 3. Simplified representation of the IEEE 9 bus model. Blocks linked by the solid line represent the conventional swing equation given by (1). Represented with doted lines, the respective frequency signals to the blocks of IBFPR and synthetic inertia, which add power to the system.

The values of kinetic energy and time constants of a synchronous machines of 835 MVA were selected to represent the synchronous response, with the load of 315 MW the system acceleration time constant is 14 s [8], which is approximately today's Europe acceleration constant [5]. This is the base scenario where an 100% synchronous generation is assumed . For the sake of evaluating the impact of the penetration of inverter based generation; the values of lower capacity generators were selected, diminishing in the sense the total system inertia [1][8].

Even though load imbalances up to 40% were simulated in each inertia scenario, for estimation of the critical time the power capacity limit of the generators was disregarded. The negative imbalance was simulated by increasing the system load. A block diagram representing the system shown in Figure 3 was implemented in SIMULINK with different combinations of power imbalance and system inertia.

4.5. Extended IEEE 9 bus Model

Since it is desired to compare the results obtained in 4.4 against some model that takes into account the whole system components, losses and dynamics; An extended representation of the IEEE 9 bus model was implemented in SIMULINK [2]. In this representation, simulations for different values of system inertia and load imbalance were performed, similarly as it was done with the simplified representation of the model. Figure 4 shows the extended IEEE 9 bus grid architecture with IBG added. In order to evaluate the validity of the equation describing the IBFPR needed to avoid ULFS, the IEEE

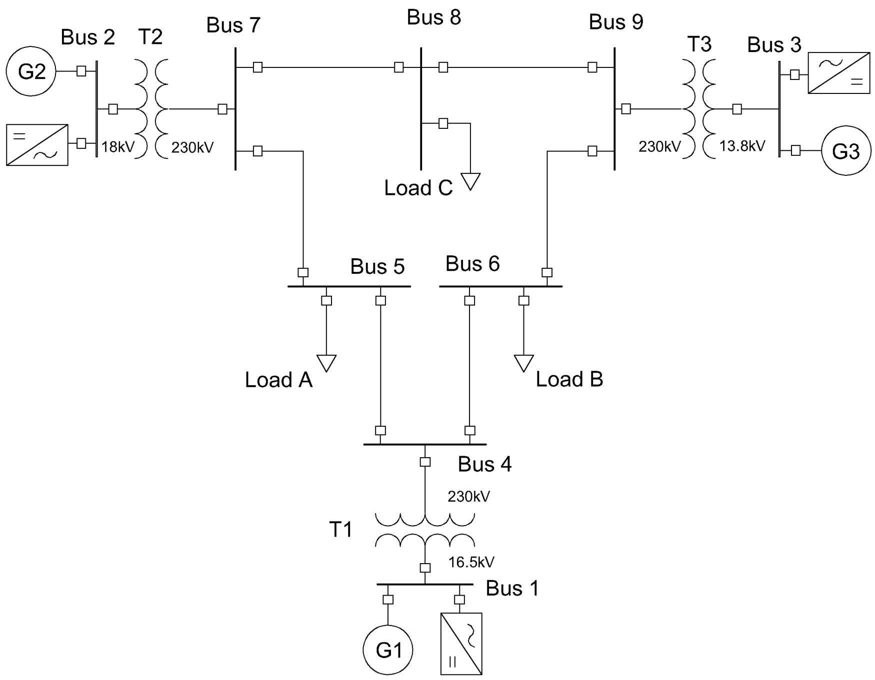


Figure 4. One line diagram of the IEEE 9 bus model. The inverter based frequency response has been added At the same bus of the generating units.

model was modified with the insertion of ideal controlled power sources blocks, which were set up to inject power into the grid accordingly to the simulated scenario. Therefore, no means of frequency measurement were included and only IBFPR was assessed. Similarly as it was done in section 4.4, the total acceleration time constant of the system equals 14 s. Hence the same kinetic energy should be distributed among the three generators' rotating masses in the extended model as in the simplified representation. From (7) it can be easily calculated that the system kinetic energy with 14 s is 2205 MWs (100% synchronous generation).

$$T_{sys} = (2 * E_k)/P_{load} \tag{7}$$

Due to the fact that inverter based generation reduces the system kinetic energy; for different levels of inverter based generation, the generators nominal capacity values were kept constant and the inertia constant of each machine multiplied by the synchronous share factor fss. The total kinetic

energy of the system is the summation of all units. In such manner the synchronous generators in the initial state of equilibrium represent both power sources, inverter based plus synchronous.
In order to start the simulations in steady state, a load flow calculation of the grid was carried out with the objective of calculating the initial conditions for the exciter and prime mover models. Table 3 summarizes the main values for setting system initial conditions; acquired from the power flow tool provided by SIMSCAPE.

Table 3. : Steady state initial conditions of the system

Bus number	Bus Type	Voltage (pu)	Active Power (MW)	Reactive Power (MVAr)
1	Slack	$1.04 \angle 0°$	72.2	25.64
2	PV	$1.025 \angle 9.83°$	163	8
3	PV	$1.025 \angle 4.63°$	85	-9.41
5	PQ	$0.9949 \angle -4.42°$	125	50
6	PQ	$1.01211 \angle -4.16°$	90	30
8	PQ	$1.0172 \angle 0.17°$	100	35

4.5.1. IBFPR Representation

The IBFPR was modeled as controlled current sources. These controlled sources inject active power according to the load imbalance and system inertia simulated. The continuous measurement of voltage is required in order to determine the amount of current needed to supply the requested power. The IBFPR will have symmetrical and balanced characteristics. Due to this reason, the magnitude and angle of the current phasor will be obtained from the positive sequence of the measured voltage. From the definition of complex power and voltage symmetrical components in three phase systems (8), the positive sequence component of phase voltage and line current are obtained [9].

$$S^1_{3\varphi} = 3 * V^1_{LN} * \bar{I_L}^1 \tag{8}$$

This equation is valid for RMS values of voltage and current; nevertheless the measured voltage values and the sought current values are given in peak values, the equation for power and current become:

$$S^1_{3\varphi} = \frac{3 * V^1_{LNpeak} * \bar{I}_{Lpeak}^{\,1}}{2} \tag{9}$$

$$I^1_{Lpeak} = \frac{2 * \bar{S}^1_{3\varphi}}{3 * V^1_{LNpeak}} \tag{10}$$

With the help of the **a** operator ($-0.5 + j\sqrt{3}$ or $1\angle 120°$) the values of the positive sequence component of phase voltage can be obtained.
From $V_a + V_b + V_c = 0$ and $V^1_a = \frac{V_a + aV_b + a^2V_c}{3}$:

$$\begin{aligned} V^1_a &= \frac{V_a + aV_b - a^2V_b - a^2}{3} \\ &= \frac{V_a * (1 - a^2) + aV_b * (1 - a)}{3} \end{aligned}$$

Since $V^1_{an} = \frac{V^1_a}{\sqrt{3}\angle 30°}$, $\sqrt{3}\angle 30° = 1 - a^2$ and $\sqrt{3}\angle -30° = 1 - a$ then after some algebraic manipulation the expression for V^1_{an} becomes:

$$V^1_{an} = \frac{V_a - a^2V_b}{3} \tag{11}$$

With the obtained expressions for the positive sequence of phase voltage (11) and complex power (9), the needed current (10) to supply the IBFPR related to the measured voltages can be implemented in SIMULINK as depicted in FIGUREXXX. The ramping function will last until the critical time is reached, afterwards, the IBFPR output will remain constant.

4.6. Large Scale Case: Europe Power System

Under normal operation ENTSOE has reported values of RoCoF in the range of 5-10 mHz/s for power outages of 1 GW in the current interconnected power system. If an imbalance event of more than 3 GW occurs with depleted primary reserve, extraordinary values of frequency and RoCoF might be reached. After serious disturbances the Continental European Power System has experienced RoCoF between 100 mHz/s and 1 Hz/s. Imbalances of 20% or more along with RoCoF greater than 1 Hz/s have been determined by experience to be critical [5]. ENTSOE has determined that under the case of the reference scenario (The loss of 3 GW generation with 150 GW load and 2%/Hz self-regulation) in the interconnected operation, the influence of inverter based generation, and therefore the reduction of system inertia would not jeopardize system stability. Due to the expected increase of non-synchronous generation in the future, international power trade and renewables variability; ENTSOE estates in its future split reference scenario that the power system must be capable of withstanding imbalances greater than 40% with RoCoF of 2 Hz/s or higher. Under these circumstances the resulting islands must avoid load shedding. Hence, only the split scenario is considered for further analysis.

When considering the system blackout of November 4th 2006, in which four electric islands resulted from the European system split; system blackout due to under frequency was experienced in the so known western area. This island, at the moment of split, had approximately a load of 190 GW (27% more than the low load scenario of ENTSOE) [16]. For its comparable 'size' and the uncertainty of knowing beforehand the resulting islands after a major contingency, the selected load for simulation was the same as the ENTSOE reference scenario as well as the primary reserve deployment time. To simulate the behavior of the resulting island in the European split scenario; a simplified approach was selected. Similarly as it was done with the simplified block model for the IEEE 9 bus model, in the equivalent European representation all the synchronous generation will be represented by a single machine, which will provide governor response when a perturbation takes place. Additional to the synchronous response, a load response of 2% was added to the model, which means that for every Hertz reduced or augmented, the load will reduce or increase by a 2% [5].

In order to fit the behavior of the system to the modeled by ENTSOE, an additional block was added the IEEE simplified model in the steam turbine governor; this was done with the intention of adjusting the time response of the primary reserve as much as possible to the desired one. With this approach, the primary power reserve can be easily tuned with the assistance of the Control System Tuner App available in MATLAB. The period of time of utmost interest for analysis is from the inception of the power imbalance and the nadir time. Therefore, the system must perform as similar as possible in this region compared to the ENTSOE reference, whereas after the nadir time, the disparity between responses can be neglected. In the European scale the reserves must be completely deployed within 30 s after the occurrence of the disturbance.

4.6.1. System Parameters

A power system of n number of synchronous machines is assumed; having each of them a capacity S in MVA, a nominal power P_{nom} in MW. Assuming that each machine operates at a de-load factor dl of P_{nom}; with an acceleration constant equal to T_{nom} then the number of machines n, for the load $P_{syncload}$, served by synchronous machines is:

$$n = \frac{P_{syncload}}{P_{nom} * dl} \tag{12}$$

Then the time acceleration constant of the system T_{sys} can be obtained as follows:

$$\begin{aligned} T_{sys} &= \frac{\sum_{i=1}^{n} P_i * T_i}{P_{LOAD}} \\ &= \frac{nP_{nom} * T_i}{P_{LOAD}} \\ &= \frac{P_{syncload} * T_{nom}}{P_{LOAD} * dl} \\ &= \frac{Syncshare * T_{nom}}{dl} \end{aligned} \tag{13}$$

In this sense the system time acceleration constant can be calculated with a synchronous share of 100%, resulting in $T_{sys} = 12.5$ s with values of $T_{nom} = 10$ s [5][1], and a de-load factor $dl = 0.8$. The values of the additional block in the model are set in order to have a step response with 2% overshoot and a time constant of 8 seconds [13]. Considering only the swing equation, as done in the model, it can be demonstrated that the RoCoF and therefore the frequency response of the system is only dependent on the percentage of load imbalance and the system acceleration time constant. From the definition of RoCoF as $\frac{df}{dt} = \frac{\Delta P * f_0}{2 * E_k}$ and $T_{sys} = \frac{2 * E_k}{P_{LOAD}}$:

$$\begin{aligned} \frac{df}{dt} &= \frac{\Delta P * f_0}{P_{LOAD} * T_{sys}} \\ &= \frac{\Delta P_{pu} * f_0}{P_{LOAD} * T_{sys}} \end{aligned} \tag{14}$$

In (14) the value of ΔP_{pu} is the normalized value of power imbalance having as base power the value of load P_{LOAD}. As shown in the equation, when only the swing equation is considered, the frequency response is only dependent on system acceleration constant and the relative value of imbalance. This relative value of imbalance varies during time, depending on load response to change on frequency and the response of primary reserve of the system.

5. Conclusions

This section is not mandatory, but can be added to the manuscript if the discussion is unusually long or complex.

6. Patents

This section is not mandatory, but may be added if there are patents resulting from the work reported in this manuscript.

Author Contributions: For research articles with several authors, a short paragraph specifying their individual contributions must be provided. The following statements should be used "conceptualization, X.X. and Y.Y.; methodology, X.X.; software, X.X.; validation, X.X., Y.Y. and Z.Z.; formal analysis, X.X.; investigation, X.X.; resources, X.X.; data curation, X.X.; writing–original draft preparation, X.X.; writing–review and editing, X.X.; visualization, X.X.; supervision, X.X.; project administration, X.X.; funding acquisition, Y.Y.", please turn to the CRediT taxonomy for the term explanation. Authorship must be limited to those who have contributed substantially to the work reported.

Funding: Please add: "This research received no external funding" or "This research was funded by NAME OF FUNDER grant number XXX." and and "The APC was funded by XXX". Check carefully that the details given are accurate and use the standard spelling of funding agency names at https://search.crossref.org/funding, any errors may affect your future funding.

Acknowledgments: In this section you can acknowledge any support given which is not covered by the author contribution or funding sections. This may include administrative and technical support, or donations in kind (e.g., materials used for experiments).

Conflicts of Interest: Declare conflicts of interest or state "The authors declare no conflict of interest." Authors must identify and declare any personal circumstances or interest that may be perceived as inappropriately influencing the representation or interpretation of reported research results. Any role of the funders in the design of the study; in the collection, analyses or interpretation of data; in the writing of the manuscript, or in the decision to publish the results must be declared in this section. If there is no role, please state "The funders had no role in the design of the study; in the collection, analyses, or interpretation of data; in the writing of the manuscript, or in the decision to publish the results".

Abbreviations

The following abbreviations are used in this manuscript:

MDPI	Multidisciplinary Digital Publishing Institute
DOAJ	Directory of open access journals
TLA	Three letter acronym
LD	linear dichroism

Appendix A

Appendix A.1

The appendix is an optional section that can contain details and data supplemental to the main text. For example, explanations of experimental details that would disrupt the flow of the main text, but nonetheless remain crucial to understanding and reproducing the research shown; figures of replicates for experiments of which representative data is shown in the main text can be added here if brief, or as Supplementary data. Mathematical proofs of results not central to the paper can be added as an appendix.

Appendix B

All appendix sections must be cited in the main text. In the appendixes, Figures, Tables, etc. should be labeled starting with 'A', e.g., Figure A1, Figure A2, etc.

References

[1] P. M. Anderson and A. A. Fouad. *Power system control and stability*. 2nd ed. New York and Chichester: Wiley, 2002. ISBN: 0-471-23862-7.
[2] Atieh Delavari, Innocent Kamwa, and Patrice Brunelle. "Simscape power systems benchmarks for education and research in power grid dynamics and control". In: *2018 IEEE Canadian Conference on Electrical & Computer Engineering (CCECE)*. IEEE. 2018, pp. 1–5.
[3] Mohammad Dreidy, H Mokhlis, and Saad Mekhilef. "Inertia response and frequency control techniques for renewable energy sources: A review". In: *Renewable and sustainable energy reviews* 69 (2017), pp. 144–155.
[4] E. Muljadi, V. Gevorgian, and M. Singh: NREL and S. Santoso: University of Texas - Austin. "Understanding Inertial and Frequency Response of Wind Power Plants: Preprint". In: (2012).
[5] ENTSOE. "Frequency Stability Evaluation Criteria for the Synchronous Zone of Continental Europe". In: (2016). URL: www.entsoe.eu.
[6] General Electric International. *GE Wind Plant Advance Controls*. 2013.
[7] Vahan Gevorgian and Yingchen :. NREL Zhang. *Wind Generation Participation in Power System Frequency Response*. Tech. rep. National Renewable Energy Lab.(NREL), Golden, CO (United States), 2017. URL: www.nrel.gov.
[8] A. G. González Rodriguez, A. González Rodriguez, and M. Burgos Payán. "Estimating wind turbines mechanical constants". In: *Renewable Energy and Power Quality Journal* 1.05 (2007), pp. 697–704. DOI: 10.24084/repqj05.361.
[9] John J.. Grainger and William D Stevenson. *Power system analysis*. Vol. 67. McGraw-Hill New York, 1994.
[10] Christian Hultholm and Niklas Wägar. "Optimal reserve operation in Turkey–frequency control and non-spinning reserves". In: *Power-Gen Europe*. 2015.
[11] Prabha Kundur, Neal J Balu, and Mark G Lauby. *Power system stability and control*. Vol. 7. McGraw-hill New York, 1994.

[12] Beate Nesje. “The need for Inertia in the Nordic Power System”. MA thesis. NTNU, 2015.
[13] Katsushiko Ogata. *Ingenieria de Control Moderna (Spanish Edition)*. Prentice Hall, 1999.
[14] Erik Ørum et al. “Future system inertia”. In: *ENTSOE, Brussels, Tech. Rep* (2015).
[15] Dinakar Sundaram and Mohammad Bhuiyan. “Comparing and Evaluating Frequency Response characteristics of”. In: (2008).
[16] UCTE UCTE. *Final report system disturbance on 4 November 2006*. 2007.
[17] Lei Wu and David G. Infield. “Towards an Assessment of Power System Frequency Support From Wind Plant—Modeling Aggregate Inertial Response”. In: *IEEE Transactions on Power Systems* 28.3 (2013), pp. 2283–2291. ISSN: 0885-8950. DOI: 10.1109/TPWRS.2012.2236365.

Sample Availability: Samples of the compounds ...... are available from the authors.