Is Real Inertia Always Better? Synchronous Condensers, Fast Frequency Response, and Virtual Inertia in Isolated Hybrid Power Systems

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***Abstract*—Blackout incidence and their potential damage has been rising exponentially over the past few decades due to the continuous replacement of synchronous generators with renewables and other power electronics-interfaced units. The available scientific literature recommends the inclusion of synchronous condensers, fast frequency response (FFR) and virtual inertia (VI) strategies in order to mitigate such risks. However, are they interchangeable? What are their advantages and disadvantages? Is real inertia always better? Or can FFR and VI become a technological advancement instead of a replacement? This paper aims to explore these questions by conducting a study considering the isolated system of São Vicente island, in Cape Verde. There, three increasingly dangerous sudden load increase scenarios considering a 50% renewable penetration are modelled and studied based on the different available solutions. The results point toward the necessity of transmission system operators to reconsider relay sensitivity, and selectivity of load shedding schemes during under-frequency events in low inertia systems.**

I. Introduction

The ongoing energy transition is radically transforming power grids worldwide. Traditional synchronous units are increasingly phased-out in favour of stochastic renewable energy sources (RES) coupled via power electronics (PE). These are effectively decoupled from the grid, not contributing to maintain the system inertia and its stability. In short, low inertia systems present faster dynamics, which limits the time frame to apply corrective measures and narrows the admissible error bandwidth, thus threatening power security.

While this is not particularly problematic with low RES penetration levels, risks grow exponentially once rates exceed 20% [1]. For instance, in 2003 the connection between Switzerland and Italy was lost due to an overload of the lines. After the lines tripped, the large European system presented a short transitory without requiring the activation of load shedding schemes and continuing the operation without major issues. However, the Italian system fell even after activating load shedding schemes as this was not enough to stabilize their system. Berizzini [1] concluded that a combination of insufficient infrastructure and lack of coordination between international system operators (SO) were contributing factors, while the root cause was probably the unsuitability of responding to such an event only with load shedding. Another example is the 2016 blackout of the South Australian system, where two simultaneous tornadoes 170 km apart damaged two different 275 kV lines. Their tripping provoked a chain reaction. First, a number of voltage dips caused the disconnection of wind farms (WF) with a 456 MW output in less than 7 seconds. This altered the power flow in a large interconnector which tripped 700 ms after the power loss. Then, the South Australian system was separated into two synchronous areas, and finally both ended up in black-out as one could not provide enough power and the other one had overproduction. The report released by the Australian SO [2] pointed directly to the incapability of synchronous generators to bear the full responsibility for grid stability and recommended grid support from renewable assets.

The previous were simply two relevant examples of blackouts affecting isolated grids due to insufficient inertial response provision. Nevertheless, this situation is expected to increasingly affect power systems worldwide due to the energy transition [3]. Solutions available in scientific literature focus on maintaining inertia levels. For instance, by substituting traditional generation units with other less polluting but based on synchronous generation such as natural gas, biomass or geothermal [4]. Other authors propose re-purposing decommissioned synchronous generators (SG) as synchronous condensers (SC) [5], [6]. Another option would be to integrate virtual inertia (VI) strategies into the different RES and energy storage systems (ESS) available in the system [7].

Island systems present additional blackout risks due to their limited natural damping caused by their smaller size compared to continental systems. All in all, their reduced size and high operational complexity makes island systems an excellent testing ground for new methods, approaches, and technologies. For example, Canary Islands and Madeira have already been extensively studied in the research field, which has boosted their transition towards nearly fully renewable systems. However, the last of the Macaronesian archipelagos, Cape Verde, has not received such attention.

In this work, we use an isolated power system from the Cape Verde reference system [8] as benchmark to study frequency evolution after a sudden power mismatch. The purpose is to compare the system performance with its original configuration, including SC, and with VI provided from a battery energy storage system (BESS). The aim is to start clarifying thresholds favoring one approach over the other and support future decision making regarding system planning.

II. Inertial Systems Modelling

The advantages of mechanical inertia via synchronous condensers (SC) are related to their relatively simple plug and play setup, well proven technology, easy control, and capability to support short circuit capacity [9]. However, they present additional operating costs and only provide support during the first few instants of a frequency excursion. On the other hand, fast frequency response (FFR) and frequency containment reserve (FCR) are generic ancillary services that can be provided by both renewable generators and energy storage systems [10]. FFR and FCR cover the full spectrum of a frequency excursion's recovery; while they are complex to implement, still suffering rapid development and representing additional costs either as additional installation or loss of production. FFR and FCR provision are expected to become more profitable in the near future via tailored markets to motivate their development; yet, this is not currently the case in most of the countries.

FFR response can be formulated as a droop similar to the traditional primary frequency response as in (1), or Fig. 1. The main advantage of FFR is its capacity to release energy at much faster rates than the turbine-governor response.

$$\Delta P = -k_{FFR}\, \Delta f \tag{1}$$

where ΔP, k_{FFR}, and Δf stand for generation-load active power mismatch, FFR gain and frequency error, respectively.

Then, VI is presented in (2) and Fig. 2 [11], which is usually defined based on the rate of change of frequency (RoCoF), as derived from the classic swing equation (4).

$$\Delta P = -k_{VI}\, \frac{df}{dt} \tag{2}$$

where f_n, H, and S stand for the nominal frequency, inertia constant and apparent power, respectively.

Lastly, (3) and Fig. 3 define SC contribution to the system's total inertia.

$$\Delta P = 2\,(H_{SG} + H_{SC})\, \frac{df}{dt} \tag{3}$$

where H_{SG} and H_{SC} stand for the inertia constant of the SG and the SC, respectively.

$$RoCoF = \frac{df}{dt} = \frac{\Delta P\, f_n}{2\, H\, S} \tag{4}$$

Fig. 1: FFR block diagram.

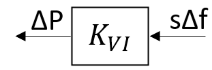

Fig. 2: VI block diagram.

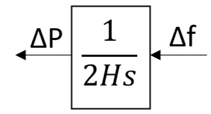

Fig. 3: SC block diagram.

From the equations it can be understood how FFR does not contribute to system inertia, but limits the frequency drop and its nadir. VI contributes in terms of RoCoF limitation similarly to actual inertia as provided by a kinetic storage such as SC.

III. Methodology

In order to evaluate the contributions, advantages, and disadvantages of different frequency control approaches, we study the dynamic performance of a low inertia, isolated power system under different premises. The system is reduced to a classic stability model including governor-turbine architectures of SG, SC, and BESS for FFR and VI support as depicted in Fig. 4, hence defining 4 cases. A Base-Case used as benchmark in which only SG contribute to frequency support, two more using a BESS to enable either FFR or VI, and a last one including SC. The performance of these different cases, which are sometimes mixed in the existing academic literature, is evaluated in three different step load increase regimes: 0.5, 3 and 8%; referred to as Scenarios 1 to 3, summarised in Table I.

TABLE I: Scenario summary.

Scenario	1	2	3
Load Step [%]	0.5	3	8

IV. Study System

The system under study corresponds to the island of São Vicente in Cape Verde, whose single line diagram (SLD) is depicted in Fig. 5. It contains 3 fossil fueled generators of 8, 9 and 13 MW, but also a 7 MW WF. The system operator envisions the inclusion of a BESS in the system whose size has not been decided yet. However, based on our previous work regarding optimal generation expansion planning for the same island [12], we estimate the size of this battery in 5 MW and 20 MWh. Then, since São Vicente's daily peak load is around 15 MVA, the current installed power is quite oversized due to multiple redundancies. Note that all the data mentioned in

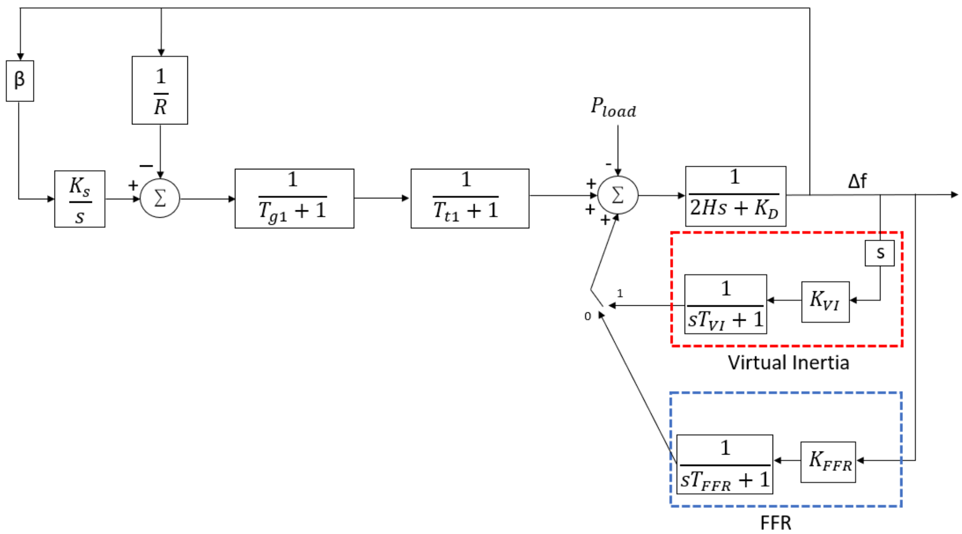

Fig. 4: Combined dynamic model of governor-turbine system with inertia and VI compensation.

this paper is made openly accessible to the interested reader via the Cape Verde Reference System [13].

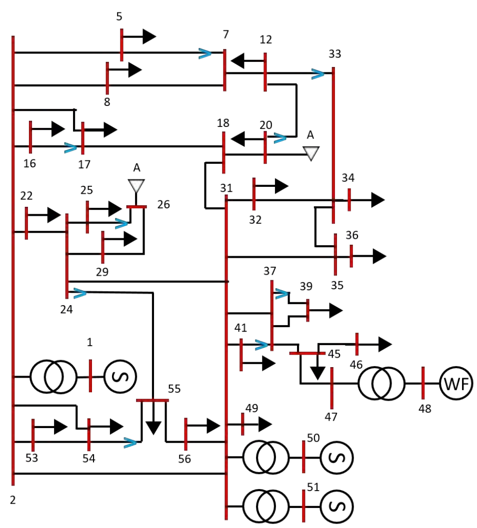

Fig. 5: São Vicente Island's Network, reproduced from [13]

V. Scenario 1

Figure 6 shows the results of Scenario 1 for the different study cases, that is after a 0.5% load step-up. There is no significant difference between the Base-Case, FFR and SC in terms of nadir frequency. On the contrary, VI schemes present a lower nadir frequency due to its RoCoF limiting effect which also provides additional time buffering the contribution of other units. Therefore, the VI scheme presents a much better RoCoF performance compared to the rest of the cases due to its direct effect similar to the SC. However, higher inertia from the SC must be introduced in order to have a significant impact. Lastly, regarding BESS-based power injection VI supports with 0.03 p.u. where the FFR is around 0.005 p.u.. Then, we can see how VI is oversized given the low impact on nadir and RoCoF for the VI scheme.

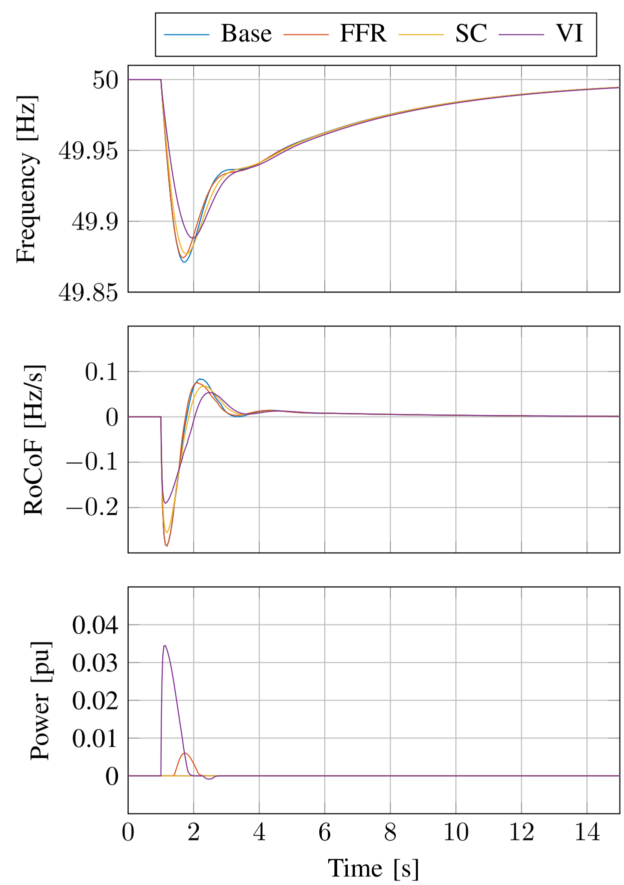

Fig. 6: Scenario 1: Frequency, RoCoF and Power injection.

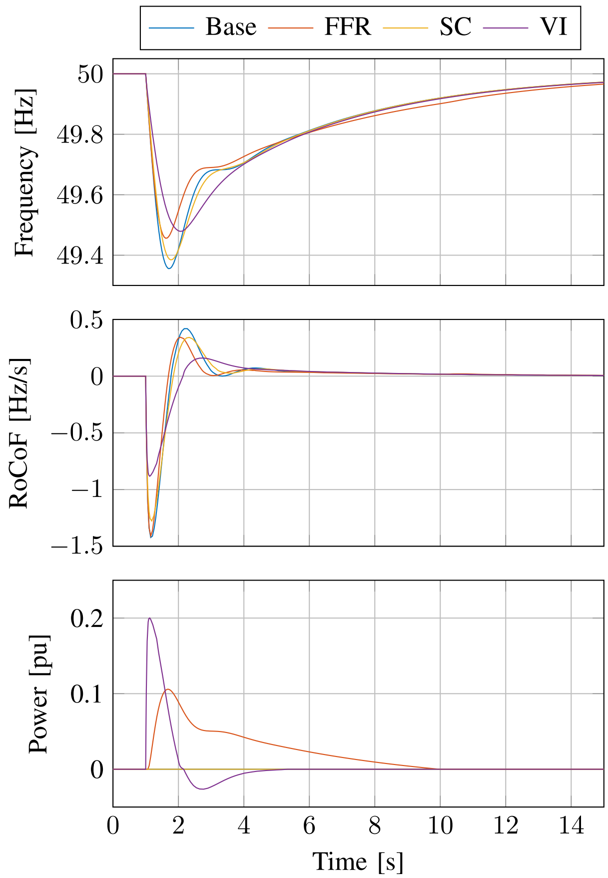

Fig. 7: Scenario 2: Frequency, RoCoF and Power injection.

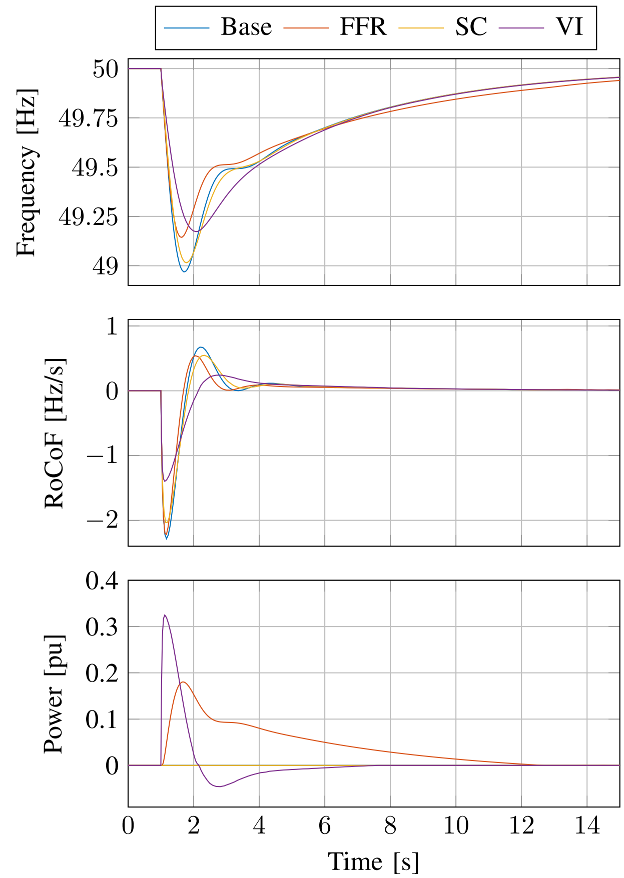

Fig. 8: Scenario 3: Frequency, RoCoF and Power injection.

VI. Scenario 2

This scenario is the consequence of a sudden load step of 3%. Due to the low inertia of the power system, such power variation provokes a major frequency drop.

The dynamics of Scenario 2 are depicted in Fig. 7. Regarding the nadir, FFR and VI schemes present nearly identical values, although displaced in time. This delay is explained by the faster action of the FFR as it directly acts upon Δf, while VI requires additional time to activate the SG action. Conversely, SC provides almost no variations compared to the Base-Case, and it would require a higher inertia constant in order to appreciate a meaningful contribution. Then, regarding the RoCoF, VI provides the highest support as it reduces its value from 1.45 Hz/s to 0.85 Hz/s. Thus, it prevent the relays from tripping, which would cause local blackouts. Nevertheless, VI requires a larger power rating compared to the FFR, which relays more on energy capacity. This is due to the fact that FFR is equivalent to a primary control scheme, hence energy dependent; while VI requires a nearly instantaneous current delivery in order to mimic SG dynamics.

VII. Scenario 3

The results of both Scenario 2 and 3 are equivalent as seen from Fig. 7 and 8. As expected, the higher load increase of 8% experienced in Scenario 3 causes a lower nadir and higher negative RoCoF values, but the conclusions extracted from the different responses are the same. Therefore, TSOs must consider low inertia scenarios in their proposal for RoCoF triggering, load shedding sizing, and relay selectivity requirements.

VIII. Conclusions

The insufficient inertial response available in modern power systems due to the high penetration of power electronic-interfaced generators rises blackout incidence and potential damage. Some authors propose favouring SG-based renewables such as geothermal and others suggest re-purposing SG as SC after they are decommissioned. Meanwhile, the provision from RES and energy storage systems comes in the form of FFR and VI. However, these tools are not equivalent or interchangeable, but tools used to ensure power system security.

This paper presents the effects of the aforementioned techniques on the low inertia, isolated network of São Vicente, Cape Verde. In general, both VI and SC improve the RoCoF response. However, the latter requires large mechanical inertia in order to appreciate significant effects. In the case of São Vicente, where the SC are assumed to be re-purposed SG originally coupled to relatively small diesel generators, such mechanical requirement is not met and their effect is minor compared to VI. Large enough SC can contribute in terms of both nadir and RoCoF improvement, but also other aspect such as short-circuit current. However, the full exploitation of these technologies might not happen in island systems as their original SG were already small to begin with. The re-purposing of SG into SC might be more appropriate in larger continental systems. On the other hand, FFR affects mostly the frequency nadir, as its contribution to RoCoF results fairly limited. Then, a combination of FFR and VI, contributed by power electronic-interfaced units, has a high system stabilizing potential by simultaneously tackling nadir and RoCoF challenges. In this sense, VI and FFR require large power and low energy capacities and vice versa.

Future work involves the development of coordinated FFR-VI schemes provided by different RES, ESS and demand responsive units; along with validation in hardware-in-the-loop laboratories and real microgrid setups.

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