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Coordinated Inertia Supervision for Grid-Forming BESS: A Headroom Aware Approach

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Abstract

The global transition toward inverter-based resources is driving a progressive reduction in power system inertia, jeopardizing frequency stability. While Battery Energy Storage Systems (BESS) equipped with Virtual Synchronous Machine (VSM) strategies offer a solution, they are fundamentally constrained by the rigid limits of power electronics. Conventional implementations frequently overlook these constraints, potentially resulting in inverter saturation or disconnection during critical frequency events when the BESS operates near its rated capacity.

This thesis addresses this reliability gap by introducing a coordinated inertia supervision logic integrated within a Power Plant Controller (PPC). The proposed method continuously estimates the available active power of parallel inverter units and adjusts synthetic inertia provision to ensure operation remains within the Safe Operating Area (SOA). Additionally, the logic coordinates active power dispatch among parallel units to prevent unequal loading and saturation.

The effectiveness of the proposed strategy is assessed using time-domain simulations in DlgSILENT PowerFactory, beginning with a simplified Single-Machine model and advancing to a modified IEEE 9-Bus network. The simulation results indicate that, whereas standard approaches do not maintain stability during critical frequency disturbances (such as -1.0 Hz/s RoCoF), the proposed supervision logic effectively limits the inertial response to the available headroom. This capability guarantees that the BESS can provide continuous grid support under severe stress conditions.

Key-words: Heterogenous BESS, GFM, VSM, Synthetic Inertia, Headroom Supervision, PPC.

Abstract in italiano

La transizione globale verso risorse basate su inverter sta guidando una progressiva riduzione dell'inerzia del sistema elettrico, compromettendo la stabilità della frequenza. Sebbene i sistemi di accumulo a batteria (BESS) equipaggiati con strategie di Macchina Sincrona Virtuale (VSM) offrano una soluzione, essi sono fondamentalmente vincolati dai rigidi limiti dell'elettronica di potenza. Le implementazioni convenzionali trascurano frequentemente questi vincoli, portando potenzialmente alla saturazione o alla disconnessione dell'inverter durante eventi critici di frequenza, qualora il BESS operi vicino alla sua capacità nominale.

Questa tesi affronta tale lacuna di affidabilità introducendo una logica di supervisione coordinata dell'inerzia integrata all'interno di un Controllore di Impianto (PPC). Il metodo proposto stima continuamente la potenza attiva disponibile delle unità inverter in parallelo e adatta la fornitura di inerzia sintetica per garantire che il funzionamento rimanga all'interno della Safe Operating Area (SOA). Inoltre, la logica coordina il dispacciamento della potenza attiva tra le unità in parallelo per prevenire sbilanciamenti di carico e saturazione.

L'efficacia della strategia proposta è valutata mediante simulazioni nel dominio del tempo in DIgSILENT PowerFactory, iniziando con un modello semplificato a singola macchina e passando a una rete IEEE 9-Bus modificata. I risultati indicano che, mentre gli approcci standard non mantengono la stabilità durante disturbi critici di frequenza (come un RoCoF di -1.0 Hz/s), la logica di supervisione proposta limita efficacemente la risposta inerziale al margine disponibile. Questa capacità garantisce che il BESS possa fornire un supporto di rete continuo in condizioni di severo stress.

Parole chiave: BESS, GFM, VSM, Inerzia Sintetica, Supervisione dell'Headroom, PPC.

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List of Acronyms

AC	Alternating Current
AGC	Automatic Generator Control
BESS	Battery Energy Storage System
CIS	Converter-Interfaced Sources
DER	Distributed Energy Resource
DFIG	Doubly Fed Induction Generator
ESS	Energy Storage System
FCR	Frequency Containment Reserve
FF	Feed Forward
FFR	Fast Frequency Responses
FRT	Fault Ride-Through
FSM	Frequency Sensitive Mode
GBGF-I	Great Britain Grid Forming Inverter
GFL	Grid-Following
GFM	Grid-Forming
HV	High Voltage
IBR	Inverter-Based-Resource
LFSM-O	Limited Frequency Sensitive Mode Over-frequency
LFSM-U	Limited Frequency Sensitive Mode Under-frequency
MV	Medium Voltage
NERC	North American Electric Reliability Corporation
OCV	Open Circuit Voltage
PCC	Point of Common Coupling

PFC	Primary Frequency Control
PLL	Phase-Locked Loop
PMU	Power Measurement Unit
POC	Point of Connection
PPC	Power Plant Controller
PWM	Pulse Width Modulation
PV	Photovoltaic
RES	Renewable Energy Sources
RoCoF	Rate of Change of Frequency
SCADA	Supervisory Control and Data Acquisition
SCR	Secondary Frequency Control
SCR	Short Circuit Ratio
SOA	Safe Operating Area
SOC	State of Charge
TFR	Tertiary Frequency Response
TSO	Transmission System Operator
UFLS	Under-Frequency Load Shedding
VSM	Virtual Synchronous Machine

1 Introduction

Recently, global energy policies strongly encourage investments in power generation from clean generation sources like wind and photovoltaic (PV). The urgent need to tackle climate change and reduce greenhouse gas emissions is causing the global energy sector to change rapidly. Over the past ten years, Renewable Energy Sources (RES), especially solar photovoltaic and wind, have grown remarkably. Nearly half of the installed electricity capacity worldwide, or 46% of it, came from renewable sources by the end of 2024 [1]. With the installation of 585 gigawatts (GW) of renewable energy, 2024 saw the biggest rise in renewable energy capacity to date, with solar and wind power accounting for the largest part. With a record 452 GW added throughout the year, solar power alone accounted for more than three-quarters of renewable installations, while wind energy contributed 113 GW [1]. Furthermore, it is expected that the share of renewable power capacity will increase to 11 TW by 2030 to reach the target set at COP 28, which is trebling the installed renewable power capacity [1].

However, integrating such a high share of variable renewables poses technical challenges. Wind and solar generation are intermittent and connected via power electronics, so they do not inherently provide the spinning inertia of traditional generators [2]. Without this physical inertia, the grid's frequency becomes more sensitive: any imbalance between generation and load causes faster and larger frequency swings. In effect, a drop in system inertia raises the initial Rate of Change of Frequency (RoCoF) for any disturbance [3]. Thus, system operators must enhance the grid's dynamic response. In modern power systems, improving inertial response and deploying fast frequency response (FFR) services (rapid injections of active power)

is a major research and operational focus to arrest these rapid deviations [3]. In practice, battery storage and other inverter-based resources are often utilized to deliver this quick-acting support.

Maintaining frequency within its nominal value (50/60 Hz) is critical for grid stability. When generation exceeds demand, frequency rises, and when demand exceeds generation, frequency falls. Small imbalances are normally balanced by generators' governor and Automatic Generator Control (AGC) controls, but large or rapid disturbances can overwhelm these mechanisms. If the frequency deviates too far from mandated limits, protection systems will trip generators or shed loads, potentially causing wide-area blackouts. Therefore, the total generation must continually match total load (plus losses) to keep frequency steady. In practice, this requires very fast corrective action when inverter-based renewables (which lack inherent inertia) cause abrupt swings. This need motivates the use of "synthetic inertia," where sources like batteries or grid-forming inverters momentarily mimic the kinetic energy of spinning machines by injecting power during a frequency event [4]. In other words, these resources provide an ultra-fast frequency response that emulates traditional inertia, helping to stabilize the system during the crucial seconds following a disturbance. Indeed, NERC and other grid authorities now consider fast frequency response an essential service in high-renewables grids [3].

Energy storage, and especially Battery Energy Storage Systems (BESS), is a key technology for addressing these issues. Batteries can absorb excess renewable energy when generation is high and release it when needed, effectively buffering the variability. For example, a BESS can store surplus solar or wind energy during off-peak times and inject it during peaks or when frequency dips. Batteries are well-suited for primary frequency support and other ancillary services, Because of their very fast response times (on the order of milliseconds). This capability is currently utilized in numerous power grids, as utility-scale batteries are routinely employed for frequency regulation and grid stability [4]. Furthermore, advancements in battery technology

and manufacturing have resulted in significant cost reductions; globally, the installed cost of battery storage has decreased by approximately 93% between 2010 and 2024. As storage costs decline, renewables-plus-storage solutions are becoming increasingly competitive with conventional generation, which has generated substantial interest in deploying BESS for grid support [5].

Grid-Forming (GFM) control has become a critical technology for ensuring the stable operation of low-inertia power systems. In contrast to conventional Grid-Following (GFL) inverters, which depend on an external voltage and frequency reference, GFM converters autonomously establish voltage and frequency at the point of connection. By emulating the electromechanical behaviour of synchronous machines through virtual inertia and damping, GFM-controlled BESS can inherently contribute to frequency stability and system strength. This capability enables BESS plants to deliver synthetic inertia, rapid frequency response, and black-start functionality, which are especially valuable in power grids with significant integration of inverter-based renewable generation. As power systems move towards a reduced dependency on synchronous generation, GFM control is increasingly regarded as a fundamental technology for maintaining stable frequency dynamics and ensuring reliable operation in weak-grid and islanded environments [6].

The efficient operation of a multi-unit BESS plant requires the implementation of precise control strategies to balance battery usage. When multiple batteries are connected in parallel to several inverters, differences in battery capacity can lead to uneven current distribution. For example, a battery with lower capacity will charge or discharge more rapidly than one with higher capacity, causing it to reach its operational limits sooner. This process accelerates the aging of the lower-capacity battery and reduces overall system performance. Although existing Power Plant Controllers (PPCs) attempt to balance these loads using state-of-charge (SOC)-based weighting, they do not explicitly consider the dynamic power headroom required for

synthetic inertia. Consequently, a major limitation in current literature is that if one inverter approaches its limit, it can no longer contribute to frequency support, potentially leading to a total loss of plant-level inertia provision during critical events.

Against this background, a critical technical gap remains in the coordination of multi-unit BESS plants: conventional dispatching strategies, whether fixed or SOC based, fail to guarantee grid-forming stability services when individual inverters operate near their power ratings. Inverter saturation results in the loss of synthetic inertia provision, which increases grid vulnerability during frequency disturbances. This study proposes a novel supervisory PPC logic that preserves the 0.2 p.u. power headroom necessary for a 1 Hz/s RoCoF response, as required by the GBGF-I grid code [7]. The core contribution of this thesis is a dynamic dispatching algorithm that transitionally shifts from SOC-based balancing to a power-sharing 'Convergence Mode' as units approach their limits. This ensures that the multiple-unit BESS plant remains grid-compliant and capable of providing critical stability services across its entire operational range.

The primary contributions of this thesis are:

- **Identification of the 'Inertia-Saturation' Gap:** Analyzing the ways in which conventional BESS weighting methods compromise grid stability by permitting inverters to reach their power limits.
- **Design of a Novel Supervisory Logic:** Proposing a dynamic weighting strategy that preserves a specific 0.2 p.u. power headroom for RoCoF compliance .
- **Performance Validation:** Demonstrating via simulation that the proposed controller maintains frequency support where traditional SOC-based and energy-based methods fail

This report is structured into five chapters, advancing from an analysis of the theoretical limitations of current BESS control to the validation of the proposed supervisory logic. Chapter 1 presents the motivation for the research, emphasizing the

reduction of system inertia in current power grids. It presents the specific issue of inverter saturation in multi-unit BESS plants and identifies the research gap concerning the loss of frequency support. The chapter concludes by outlining the research objectives and specifying the unique contributions of this study.

Chapter 2 presents a critical review of frequency regulation schemes, investigating in detail the operational principles and control architectures of currently implemented strategies. It analyses the role of BESS in providing frequency stability and introduces the concept of Synthetic Inertia. It investigates how the system's operating point and the severity of an event can lead to inverter saturation. Consequently, compromising inertial support, a problem not yet fully addressed in existing coordination methods. The chapter also establishes a theoretical foundation by comparing GFL and GFM technologies. It concludes by presenting a general scheme for the Supervisory PPC, combining the findings of the literature review to explicitly define the research gap that justifies the proposed control logic.

Chapter 3 establishes the technical framework and describes the primary contribution of the thesis. The chapter starts with an overview of the BESS plant topology, describing the interactions among the PPC, power inverters, and battery units. Moreover, it provides a detailed characterization of all plant components: inverters, transformers, and loads. After that, the mathematical model of the battery circuits and their associated parameters is presented.

The VSM is introduced with a clear explanation of how it operates. The chapter then discusses how to tune the VSM and how to choose important parameters like the inertia constant (H), damping coefficient (D_p), and low-pass filter time constant (T_{lpf}). It includes a sensitivity analysis of the open-loop transfer function to check system stability.

Additionally, this chapter provides a comprehensive overview of the proposed supervisory PPC logic, which is developed to address the research gap concerning the

loss of synthetic inertia provision during inverter saturation. The functional components of the PPC are analysed to clarify their respective roles in ensuring grid compliance. Additionally, two conventional dispatching strategies, namely SOC-based and nominal energy-based weighting, are introduced for comparative performance analysis of the proposed logic.

Chapter 4 focuses on the validation of the models and the proposed logic using DIgSILENT PowerFactory. It presents first the results of the sensitivity analysis, evaluating how variations in VSM parameters such as inertia, damping, and low-pass filter time constant affect the system's response and stability. Then, it analyses the proposed logic against traditional methods under realistic grid disturbances through a simplified grid topology and a modified IEEE 9-Bus case study. This chapter quantitatively demonstrates how the new controller successfully prevents inverter saturation and ensures compliance with 1 Hz/s RoCoF requirements.

The final chapter, chapter 5, summarizes the key findings of the research and confirms the fulfilment of the initial objectives. It highlights the importance of the proposed PPC logic for the stability of future low-inertia grids beside suggesting potential directions for future research, such as scaling the logic for hybrid renewable plants.

2 BESS INTEGRATION FOR ANCILLARY SERVICES

Frequency regulation services are critical for maintaining grid frequency within acceptable limits to ensure power system stability and reliability. Any imbalance between generation and demand leads to frequency deviations, which—if not promptly mitigated—may result in equipment damage, protection trips, or even large-scale blackouts. Multiple layers of frequency control, operating across various time horizons, address these deviations. These layers include inertial, primary, secondary, and tertiary control actions. Figure 2.1 illustrates the typical temporal characteristics of frequency regulation services and highlights the necessity for fast-acting resources that can respond immediately to sudden power imbalances.

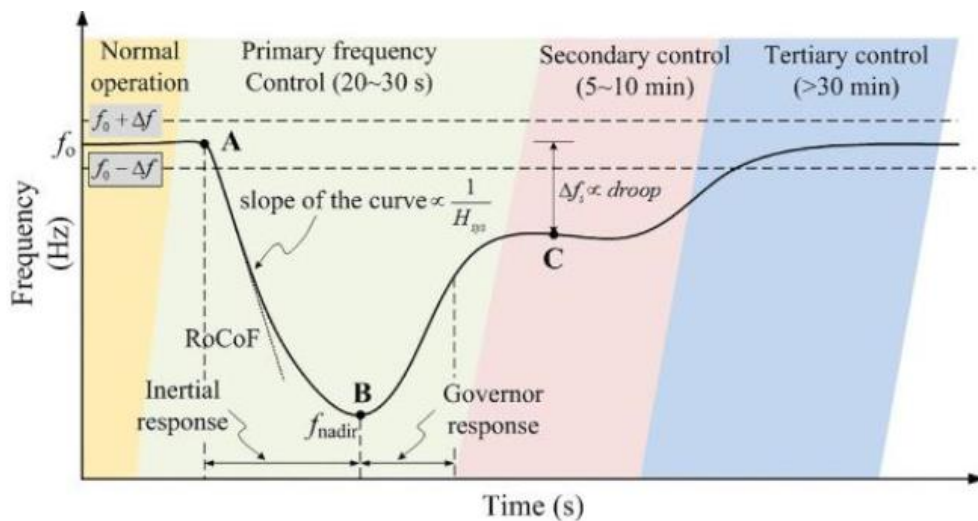


Figure 2.1, Time frame plot of a system's frequency response

The integration of BESS with RES yields significant economic benefits via facilitating participation in electricity and ancillary service markets. This integration reduces dependence on conventional power generation for frequency regulation and supports lower carbon emissions. BESS helps minimizing RES energy wastage by reducing curtailment operations, therefore enhances RES integration. By controlling active and reactive power and mitigating voltage swings brought on by wind and photovoltaic generation, the BESS stabilizes the grid. To acquire those functions, BESS operates in various modes and supports different applications, each tailored to specific grid requirements. For instance, through fast and flexible frequency control, BESS can help in restoring frequency deviations during sudden power imbalances. Compared to traditional generation units, this approach is significantly more responsive, since the former suffers from slow reaction times [8].

2.1. Frequency Response

To maintaining power system stability, it is required to constrain key metrics of frequency, such as the RoCoF, frequency nadir, and steady-state frequency. These constraints are critical to preventing cascading failures like load shedding, system collapse, or brownouts. Frequency nadir is the lowest frequency point after a disturbance before the system starts to recover. On the other hand, frequency zenith describes the maximum frequency point for an over-generation event. The main elements influencing the frequency nadir are system inertia and the power imbalance. Moreover, RoCoF, defined as the derivative of system frequency deviation, is inversely related to system inertia. Maintaining a RoCoF below 1.1 Hz/s (within a 400 ms window) is critical, especially in scenarios with high solar penetration, to prevent under-frequency load shedding (UFLS) and ensure stability [9].

2.1.1. Primary Frequency Control (PFC)

PFC or Frequency Containment Reserve (FCR) serves as the first line of defence against frequency deviations. It is activated within 0–30 seconds following a sudden imbalance between supply and demand, such as from generator or load failures, and lasts up to a minute until slower response mechanisms take over. Conventional generating units or renewable energy systems, that are equipped with frequency support capabilities, could provide PFC by automatically adjusting their output. Generally, through droop control, PFC could be achieved. Through allowing generating units to increase or decrease power output in response to grid frequency changes. The droop control operates by adopting a deadband region of certain mHz. A deadband refers to the range within which frequency or voltage controllers remain inactive, and the power output of the Energy Storage System (ESS) remains zero, as illustrated in Figure 2.2. Smaller deadbands enable quicker and more accurate responses, while larger deadbands result in greater frequency deviations. Selecting appropriate deadband sizes is crucial for improving grid stability and extending the Energy Storage System's (ESS's) lifespan.

For renewable energy sources, wind turbines and solar PV systems can contribute to PFC by employing de-loading techniques or fine-tuning inverter settings [9].

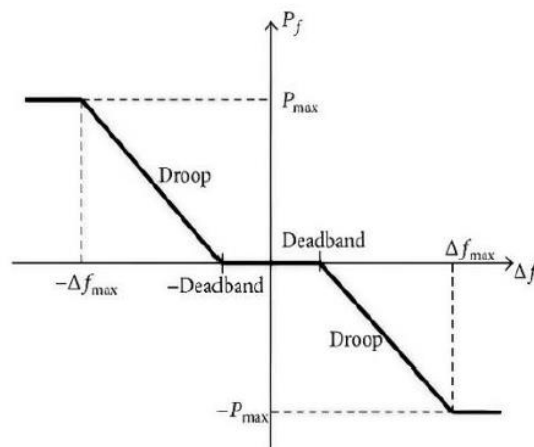


Figure 2.2, Regulation Curve of Droop Control

2.1.2. Secondary Frequency Control (SFC)

Secondary control restores frequency to its nominal value (50 Hz or 60 Hz), after primary control stabilizes the system frequency. This is done through Centralized AGC or PPC sends setpoints to units, after frequency is received from PMU or SCADA. Secondary control operates on a timescale of seconds to minutes, adjusting the set points of generation units or ESS to fine-tune power output and maintain balance. BESS has the capabilities to participate in SFC. However, conventional SFC techniques present two distinct challenges that must be carefully addressed [10].

First, if not properly designed, SFC strategies, particularly those employing aggressive virtual inertia or high-frequency gain, can introduce adverse control interactions and negative damping. These effects may result in oscillations or system instability, particularly in weak or low-inertia grids. This risk increases when multiple Inverter-Based-Resources (IBRs) provide synthetic inertia simultaneously without sufficient coordination or damping design [11].

Second, from an energy management perspective, repeated frequency support actions can cause a BESS to exceed its SoC operational limits. Unlike synchronous machines, BESS have finite energy capacity, and continuous power injection or absorption during frequency events can drive the SoC toward saturation. In consequence, reducing availability for future disturbances or accelerating battery degradation. Consequently, SFC schemes must be complemented by appropriate SoC management and supervisory control to ensure long-term operability and reliable frequency support [12].

2.1.3. Tertiary Frequency Response (TFR)

When secondary reserves are insufficient or when there is a need to restore depleted reserves, tertiary control is activated. It is typically slower and involves either manual intervention or automated control to bring the system back to full operational balance. The activation of this control generally takes several minutes (typically 15-30 minutes) and can last for several hours. BESS and other fast-response resources may also participate in TFR to provide reserve capacity to some extent.

2.1.4. Fast Frequency Response (FFR)

A transmission reliability service called FFR (Fast-Acting Frequency Regulation) is intended to stop and recover from frequency decay brought on by disturbance events. FFR is particularly useful in grids with high penetration of RES, as these grids have reduced mechanical inertia, making them more prone to rapid frequency deviations. FFR can be provided by converter-interfaced sources (CIS), such as BESS, solar PV, and wind turbines. These sources, which are predominantly based on electronic dynamics, offer a rapid response when needed. As depicted in Figure 2.3, FFR operates faster than PFC from synchronous generators, but slower than the inertial response of the system.

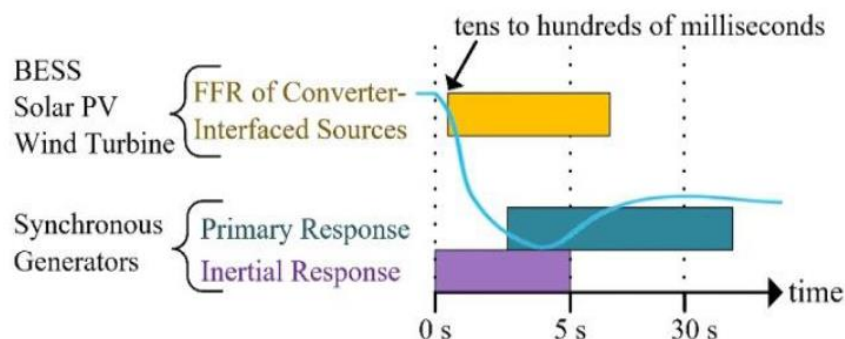


Figure 2.3, Time of Inertial Response, FFR and PFR

2.2. GFM vs GFL

The operation of BESS relies on two power electronic inverter control paradigms, namely GFL and GFM. GFL inverters behave as controlled current sources with high impedance in parallel and synchronize to the grid through a phase-locked loop (PLL) as shown in Figure 2.4 (a). Injecting active power while providing limited reactive power support is the main role of GFL inverters. Thus, they are suitable in case the main grid already provides voltage and frequency reference. However, this scheme relies on external grid conditions and experiences delays during disturbances, leading to weaker performance in low-inertia systems [13].

On contrary, GFM inverters perform as controlled voltage sources with low impedance in series as illustrated in Figure 2.4 (b). They establish voltage magnitude and frequency internally without depending on a PLL, enabling them to operate stably in weak grids or even in islanded conditions. GFMs can provide fast active and reactive power support during disturbances since they directly manage voltage phasors. This capability results in tighter voltage regulation ($\pm 3\%$ vs. $\sim 6\%$ for GFL during transients) and better frequency stability [9]. The trade-off is that GFM designs require more energy storage capacity and oversizing to accommodate inertia emulation and fault currents, which increases cost and design complexity. This distinction is critical in BESS integration: although GFL-BESS can efficiently inject energy, GFM-BESS provides system-level services such as inertia, black-start, and fault ride-through. This makes GFM especially important for grids with decreasing synchronous generation and increasing renewable penetration.

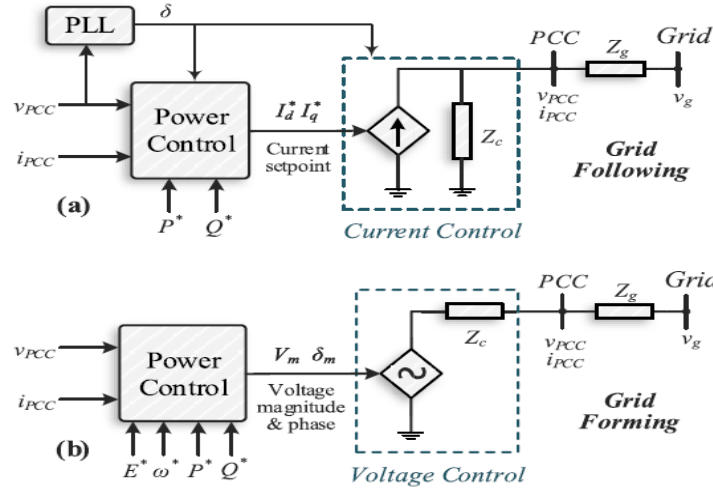


Figure 2.4, Comparison of control and approximation of (a) GFL and (b) GFM

Grid-forming control offers up a number of advanced storage system services. The BESS can quickly arrest frequency variations and imitate synchronous machines by first enabling synthetic inertia and frequency support. Second, even in weak grids, GFMs improve voltage regulation by keeping PCC voltages within small margins. Third, they have the capacity to "black-start," which is a highly desirable characteristic in restoration scenarios since it allows local networks to be powered without the need for external references. By supplying protective systems and injecting short-term overcurrent, GFMs can potentially enhance fault ride-through (FRT) [9]. By simulating synchronous generator behaviour and facilitating smooth islanding operations, GFM-based storage helps stabilize renewable-heavy grids, as demonstrated by real-world examples like Australia's Dalrymple BESS project. These advantages make GFMs increasingly central to utility-scale storage design, especially in heterogeneous BESS where synchronized SOC depletion must be balanced with inertia provision.

GFM Inverters abandon the PLL and instead behave as controlled voltage sources. The key component is a voltage and frequency reference generator, often implemented through droop equations or a VSM block that emulates the swing equation. This block dictates the internal oscillator producing the inverter's voltage phasor. An inner

voltage controller ensures the commanded magnitude and phase are tracked, while an outer power-sharing loop can adjust frequency and voltage based on load or SOC conditions. Like GFL, GFM also rely on a DC-link capacitor and PWM stage [13].

2.3. Synthetic Inertia from GFM BESS

Synthetic inertia describes the extent to which a GFM battery energy storage system can emulate the inertial response of a synchronous generator through controlled active power modulation. From a control perspective, this behaviour is typically derived from the swing equation, shown in Equation (2.1), where frequency dynamics are governed by the balance between power imbalance, inertia, and damping.

$$P_m - P_e = 2H \cdot \frac{dw}{dt} + D \cdot \Delta w \quad (2-1)$$

Where P_m and P_e represent mechanical and electrical power, H is the inertia constant, $\frac{dw}{dt}$ is the RoCoF, and D represents the damping coefficient. In GFM BESS implementations, this relationship is reproduced virtually by linking measured frequency or RoCoF to active power injection via VSM or equivalent control structures. The control algorithm calculates the necessary active power injection (P_{inj}) required to oppose frequency deviations, effectively modifying the inverter's power reference (P_{ref}) according to the control law:

$$P_{out} = P_{ref} - \left(2H \cdot \frac{dw}{dt} + D \cdot (w_{grid} - w_{ref}) \right) \quad (2-2)$$

Consequently, the BESS behaves as a voltage source behind an impedance, instantaneously exchanging power with the grid to counteract frequency drifts. However, unlike physical inertia which is limited only by the stored kinetic energy and thermal time constants, synthetic inertia is strictly bounded by the instantaneous capabilities of power electronics. The inertial power contribution is directly proportional to the severity of the disturbance (RoCoF); therefore, a steep frequency drop demands a significant and immediate power surge. This creates a hard physical

constraint: the summation of the pre-disturbance operating point (P_{op}) and the required inertial response must not exceed the inverter's maximum current and power ratings (P_{max}). This dependency on the available power headroom means that the inertial support is not guaranteed but is instead defined by a dynamic capability envelope, as illustrated in the following section [14].

A typical synthetic inertia capability curve for a GFM BESS is shown in Figure 2.5. Synthetic inertial contribution from a GFM BESS varies depending on various factors such as operating point, contingency size, BESS parameters and overload capability. The synthetic inertia capability curve may be asymmetric depending on the operating point, magnitude and the direction of frequency event, available headroom and charging and discharging capacity [15].

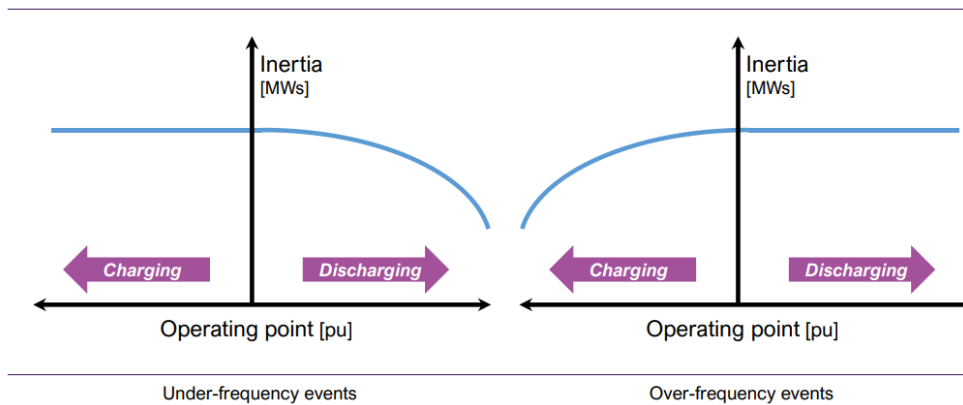


Figure 2.5, Inertia capability curve

2.3.1. Pre-disturbance point of operation

The amount of synthetic inertia provided by the BESS is influenced by the pre-disturbance operating point as shown in Figure 2.6. This could be due to the plant's available energy buffer, types, and limits applied to the inverters. The following are the impacts of the pre-disturbance operating point on the synthetic inertia [15]:

- When an inverter is operating at lower (closer to zero active power) pre-disturbance operating points, it may have sufficient headroom to change its active

power in response to a change in the frequency. Otherwise (at higher pre-disturbance operating points), the synthetic inertia provided by the GFM BESS starts to reduce due to lower available headroom before the BESS hits its current limit. For instance, when a GFM BESS is discharging at 0.8 pu (with respect to MW base), it has less headroom to provide inertial response for an under-frequency event compared to an operating point of 0.5 pu. However, when a GFM BESS is charging at the same operating point (-0.8 pu), it has more headroom to provide inertial response for the same under-frequency event.

- Furthermore, an additional capability, also known as overload capability, enables a GFM BESS to operate temporarily at a current output greater than its continuously rated capacity. The extent to which different operating points can affect the synthetic inertia provided by a GFM BESS thus depends on the inverter overload capability, with lower overload capability being associated with a higher likelihood of a limited inertia contribution at higher pre-disturbance operating points.

Figure 2.6 shows a typical synthetic inertia capability curve of a GFM BESS at different operating point for a fixed contingency size [15].

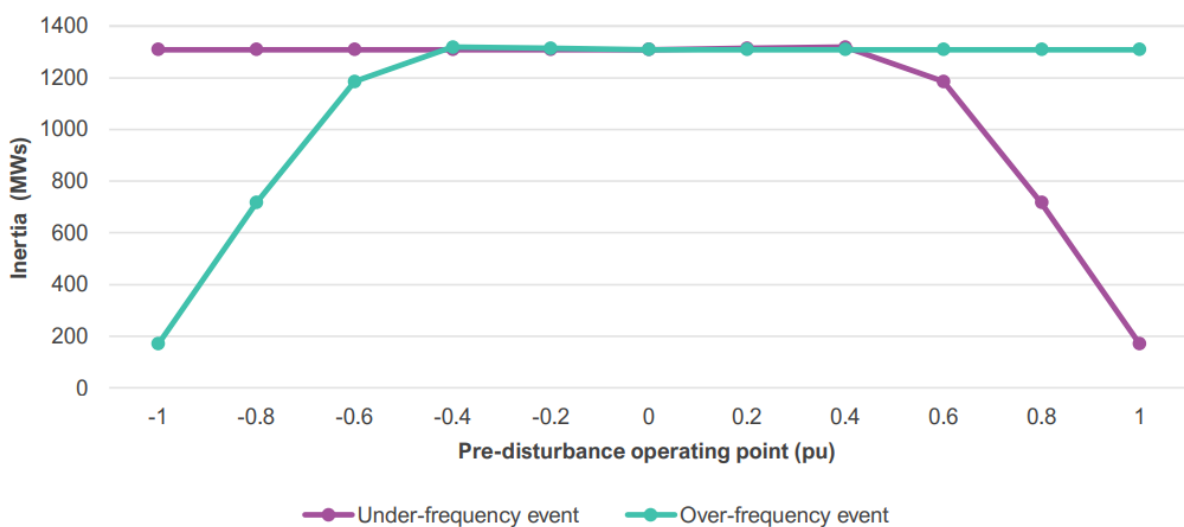


Figure 2.6, Synthetic inertia of a GFM BESS at different operating point for a fixed contingency size

2.3.2. Contingency size and rate of change of frequency

The contingency size, resulting from circuit breaker opening due to line tripping, and the resultant RoCoF is identified as a key contributing factor in quantifying synthetic inertia provided by the BESS. This is primarily because, other things being equal, larger contingency results in larger RoCoF, which results in a higher magnitude of response from the BESS [15]. This can result in a higher likelihood of hitting the current limit. Figure 2.7 shows the impact of contingency size/RoCoF on quantification of synthetic inertia supplied by a BESS. Summarized below the impact of contingency size on quantification of synthetic inertia [15]:

- At lower operating points, a large contingency size (which would generally result in high RoCoF) may lead to a significant reduction in the ability of a BESS to provide a synthetic inertial response. On the other hand, at higher operating points, a small contingency size may also result in a limited synthetic inertial contribution from a GFM BESS. Thus, a larger contingency size/higher RoCoF in conjunction with higher operating points can increase the likelihood of hitting the current limit and thus reduce the inertial contribution from a GFM BESS.

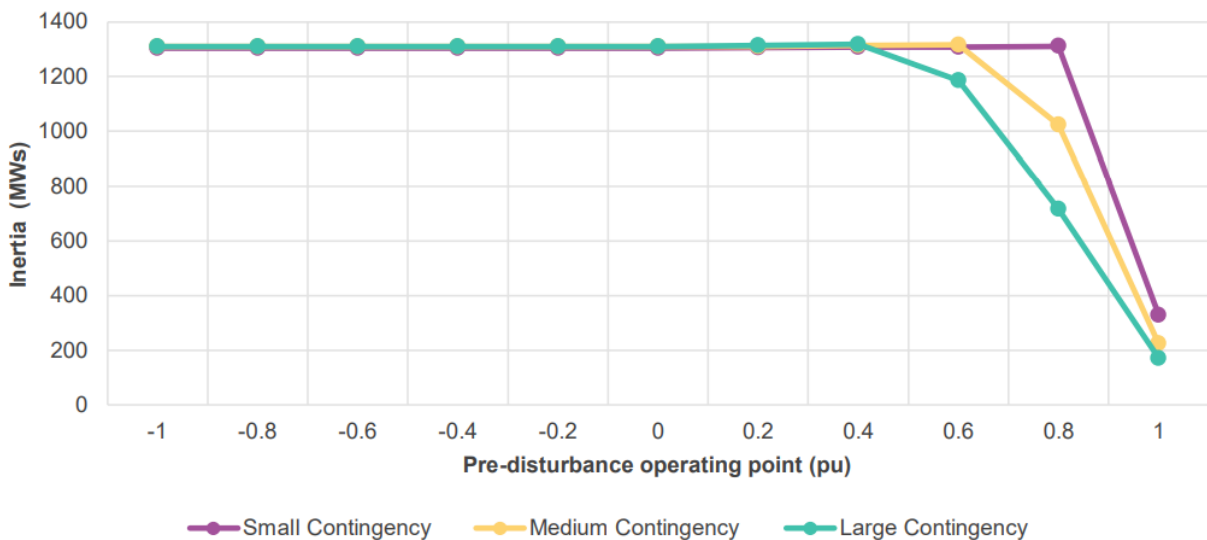


Figure 2.7, Contingency size impact on synthetic inertia from a GFM BESS - under frequency event

2.3.3. BESS Parameters

The amount and quality of inertia that a BESS can provide are fundamentally constrained by its physical ratings and control parameters. In particular, the nominal power rating of the BESS limits the maximum active power that can be injected or absorbed during a frequency event, directly constraining the achievable inertial response. Likewise, the nominal energy capacity determines the duration over which inertial and frequency support can be sustained without violating SoC limits. Beyond these physical constraints, the effective inertia delivered to the grid is strongly influenced by the VSM control parameters, especially the virtual inertia constant and damping coefficient. The virtual inertia parameter affects the initial rate of power injection in response to frequency deviations and to a RoCoF. The damping term affects the transient behavior by reducing oscillations and enhancing system stability. Improper selection of these parameters can result in insufficient frequency support, excessive power saturation, or oscillatory frequency dynamics. As a result, a coordinated tuning of BESS power and energy ratings, along with VSM inertia and damping parameters, is critical to ensure reliable inertia provision and stable frequency response in inverter-dominated power systems [16].

2.4. Power Plant Controller (PPC) (General Overview)

The growing integration of inverter-based renewable generation has made the role of supervisory coordination increasingly critical. PPCs were originally developed for large PV and wind power plants to coordinate multiple inverters and ensure grid code compliance [17]. Today, as BESSs are deployed at utility scale, PPCs are being extended to storage applications where they must not only fulfil conventional active and reactive power control requirements but also manage SoC, emulate inertia, and enable advanced services such as black-start and FRT. In essence, the PPC transforms a heterogeneous collection of batteries and converters into a single, controllable, grid-compliant entity at the point of common coupling (PCC).

The design of a PPC is usually layered as shown in Figure 2.8. At the base, measurement and communication systems collect real-time data on voltage, frequency, active and reactive power, and SOC at the PCC and from local controllers. This information feeds into a reference computation block that determines setpoints in accordance with transmission system operator (TSO) requirements or contractual limits. These setpoints are processed by control algorithms that handle voltage regulation, frequency support, and ramp-rate limiting, and are then dispatched proportionally to inverters and other plant assets. For BESS, an additional SOC management layer must be included, since unlike PV or wind inverters, batteries have finite and unequal energy capacities that must be carefully coordinated to avoid premature depletion of one unit.

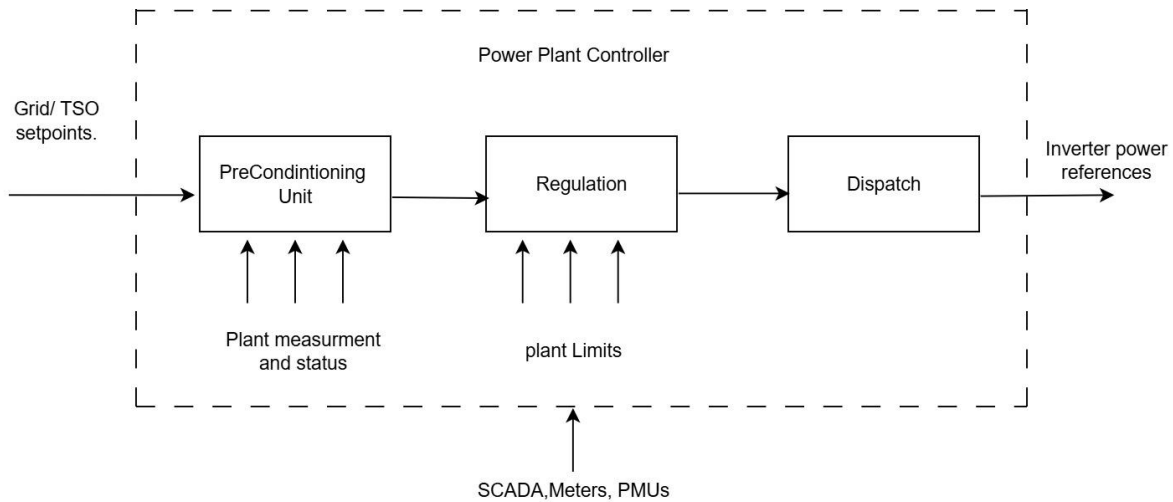


Figure 2.8, General Scheme of PPC

Active power control is one of the fundamental functions of a PPC. The aggregated active power setpoint, P^* , is determined at the PCC and must then be distributed among multiple inverters. The dispatch is typically proportional to nominal ratings [17]. Therefore, allowing heterogeneous inverters to respond to a common control signal, simplifying dispatch. When storage is present, the PPC can also enforce ramp-rate limitations, smoothing transitions to prevent rapid fluctuations. This capability is

particularly important in weak grids or when the TSO imposes maximum ramp rates to avoid stressing transmission assets.

Reactive power and voltage control are also central PPC services. Moreover, PPC can prevent abrupt oscillations due to the ramp-rate constraint capability, which results in smooth transition from one state to another. In weak grids or where the TSO mandates maximum ramp speeds to prevent overloading transmission assets, this capacity is crucial.

Central PPC services also include reactive power and voltage control. Grid codes often mandate plants to run in one of three modes: reactive power setpoint mode, voltage droop mode, or power factor mode. In the former, the PPC applies a droop law of the form

$$Q = Q_{ref} - K_q(V - V_{ref}) \quad (2-3)$$

where Q is reactive power, V is measured voltage, V_{ref} is the reference voltage, and K_q is the droop coefficient. The deadband, which is usually between 0.98 and 1.02 p.u., where no corrective action is taken, is a defining aspect of this system. Reactive power is linearly proportional with voltage change beyond this range. Perhaps the most significant contribution of BESS PPCs is frequency regulation and inertia functions. Frequency support is often implemented using active power–frequency droop,

$$P = P_{ref} - K_p(f - f_{ref}) \quad (2-4)$$

where P is active power, f frequency, f_{ref} nominal frequency, and K_p the droop coefficient. The curve is again characterized by a deadband around nominal frequency, within which no adjustments are made, and sloped segments outside it where power output is increased during under-frequency and curtailed during over-frequency events. Unlike PV-only plants, which cannot deliver additional power above their maximum available generation, BESS PPCs can allocate energy reserves and thus

participate in both over- and under-frequency control. Furthermore, when integrated with grid-forming inverters, the PPC can provide synthetic inertia. This is achieved by embedding VSM control in the local inverters, allowing them to respond to a RoCoF in addition to steady-state deviations.

FRT is another critical requirement addressed through PPC coordination. Local inverter controls handle the immediate sub-cycle fault dynamics, injecting reactive current as required by grid codes. However, the PPC ensures the plant-wide response aligns with operator requirements during and after the fault. For example, it guarantees that sufficient reactive power is injected, that ramping back to pre-fault conditions respects limitations, and that plant stability is not compromised by communication delays. In essence, the PPC guarantees coordinated recovery across heterogeneous assets.

Real-world projects provide evidence of PPC effectiveness. The Dalrymple BESS (30 MW / 8 MWh) in South Australia demonstrated the capability of grid-forming batteries, controlled by a PPC, to provide steady islanding operation, inertia, and black-start [18]. In summary, the functions of synchronous machines are replicated. Similarly, in South Africa, PPCs were utilized in a PV+BESS hybrid plant due to strict grid regulations that demand ramp-rate limitation. Mainly the storage operated to offer frequency reserves and to smooth the output [19]. Analytical studies have further quantified the response capabilities of utility-scale battery storage when coordinated for frequency support. For example, another article modeled a 100 MW/100-200 MWh utility-scale BESS, representative of the Hornsdale Power Reserve in Australia, to evaluate its fast frequency response and headroom-dependent active power contribution during the August 2018 separation event, illustrating how high-capacity storage can significantly enhance frequency stability when controlled appropriately [20]. These case studies illustrate the development of PPCs from basic supervision systems to enablers sophisticated system service. Power Plant Controller encounters a

couple of challenges. For example, in centralized PPC, Communication delays may compromise fast frequency support or FRT compliance due to the fact that this architecture is inherently vulnerable to those delays. To improve this weakness point, hybrid approaches that combine local autonomy with centralized supervision are therefore being explored. Furthermore, another concern is scalability, since larger fleets of distributed batteries will require hierarchical PPC structures with cluster-level controllers. Moreover, as storage becomes increasingly valuable for both grid stability and market participation, PPCs must balance technical requirements with economic optimization. Thus, coordinating batteries not only for grid code compliance but also for revenue stacking through arbitrage, reserve markets, and congestion relief. It is expected in the future that advanced PPCs will integrate predictive algorithms, artificial intelligence and machine learning to anticipate renewable generation fluctuations, SOC trajectories, and grid disturbances in order to optimize dispatch proactively.

Grid-interactive BESS with parallel inverters must ensure all units share load currents in proportion to their ratings. In practice, parallel inverters operate at the same AC voltage and frequency and use droop-based or weighted-sharing schemes so that each unit contributes a fair share. For example, [21] propose a “current-weighting” scheme in which each inverter’s controller multiplies its reference current by a gain based on its rating; this yields weighted output currents and balanced sharing even when units have different capacities [21]. More recent approaches adapt these weights dynamically. In one hierarchical MPC framework, supervisory logic computes time-varying weighting factors (α_i , β_i) for each converter to allocate power setpoints in proportion to capacity and state-of-charge, ensuring equitable sharing while respecting thermal/SoC limits [22]. Complementarily, several works augment droop control with energy management: for instance, to use conventional P–f droops plus a “frequency restoration” loop and strategic deloading of PV/DFIG to let battery

inverters instantly absorb imbalances. Simulation of their scheme shows precise, fast load sharing among diverse DERs, with BESS supporting frequency while others adjust power [23]. Overall, the literature provides many multi-inverter dispatch strategies – from simple droop-sharing to weighted-MPC schemes – that coordinate power among GFMs and GFLs [21] [22].

Mixed GFM/GFL operation adds complexity. Grid-forming inverters autonomously regulate voltage and frequency and can emulate machine inertia, whereas grid-following units simply inject commanded P/Q and rely on the grid for angle reference. Thus, conventional droop sharing does not directly balance power between GFM and GFL devices. A proposed approach to address this is to design complementary controllers for each inverter type: both use active-power–frequency and reactive-power–voltage droops but add secondary loops so that a GFM still stabilizes the grid while GFL units adjust their injections. This guarantees proportional power sharing and simultaneous voltage/frequency regulation in an islanded microgrid [24]. Other schemes take a centralized approach: for example, a fleet of GFM inverters can be “dispatched” by shifting each unit’s frequency-droop intercept. Starting from equal per-unit sharing (identical droop slopes), the controller shifts one inverter’s interception up and another’s down by calculated amounts. This reassigns power (one inverter absorbs more load, the other less) while holding the overall frequency constant [25]. In all of these cases, the GFM units still provide a synthetic inertial response via their droop/VSG dynamics, and additional filtering effectively adds inertia and damping to the inverter behavior. In practice, tuning multiple GFMs for appropriate droop and virtual-inertia constants is nontrivial [26].

Existing literature primarily focuses on optimizing battery longevity or achieving energy balancing under steady-state conditions; however, it does not explicitly account for the operational boundary when an individual inverter reaches its power limit. This represents a significant research gap: in multi-unit BESS plants, reaching

this power ceiling effectively 'mutes' the unit's ability to provide synthetic inertia. If a high-severity frequency event occurs while an inverter is saturated, the lack of dynamic power headroom prevents the required inertial response, thereby compromising the stability of the entire grid. Consequently, there is an urgent need for a supervisory coordination logic that can dynamically preserve this headroom to ensure grid-code compliance, a challenge that this thesis addresses in the following chapters.

Building upon this identified gap, the following chapter details the design and mathematical formulation of a novel Supervisory Power Plant Controller designed to prevent such saturation and ensure continuous grid compliance.

3 Modelling and Control

This chapter starts with introducing the structure and the components of the BESS used for the analysis. It presents the flow of commands and the interaction between different system components such as batteries, PPC, and inverters. After that, the utilized equivalent circuit model of the battery will be introduced alongside the parameters of the model. Moreover, the single line diagram of the implemented VSM of the grid-forming inverter is explained. The open loop transfer function is computed in detail to be able to apply, later, a sensitivity analysis to select the parameters (inertia constant, Damping, and low-pass filter time constant) of the VSM. Finally, the block diagram of the designed PPC is explained in detail including reference computation, regulator and weigh factors calculation. The proposed control logic for power dispatching is computed with a reasoning for the selected approach. Two other control methodologies will be introduced briefly to be used later for a comparison with the proposed approach.

3.1. System topology

Figure 3.1 presents a single line diagram of a hybrid power system topology of the where the BESS is connected to the external grid. In the hybrid system, each battery energy storage unit is connected to the network through its own grid-forming inverter operating with VSM control. These inverters are placed on the low-voltage side behind the MV/LV transformer and are modeled as ideal voltage sources behind a series virtual impedance. A central PPC monitors the AC voltage and current at the POC via sensors, using this feedback to compute active power commands. The PPC then issues

active power setpoints (P^*) to each inverter model, ensuring that their combined output meets the grid-side requirements at the POC.

At each inverter, the VSM-based control loop (including its virtual impedance) directly regulates the AC output voltage and frequency to deliver the commanded power. In practice the inverter has no separate dq-axis inner loops: it simply behaves as an adjustable voltage source whose amplitude and phase change to meet the requested power. The BESS itself is reduced to its power-converter dynamics (since the fast active-power response is dominated by the inverter control and the battery only limits energy availability). In other words, the PPC's P^* command is realized by slightly adjusting the inverter's internal frequency/voltage reference (emulating the VSM's inertia-droop response), and the local voltage-control loop maintains the AC terminal voltage accordingly. In summary, the hierarchical control is the PPC dispatches real-power setpoints to each inverter based on POC measurements, and each grid-forming inverter then regulates its AC voltage (after the virtual impedance) to produce that power while stabilizing the coupling-point voltage.

Table 3.1 describes the parameters of each component alongside the measuring unit and its value.

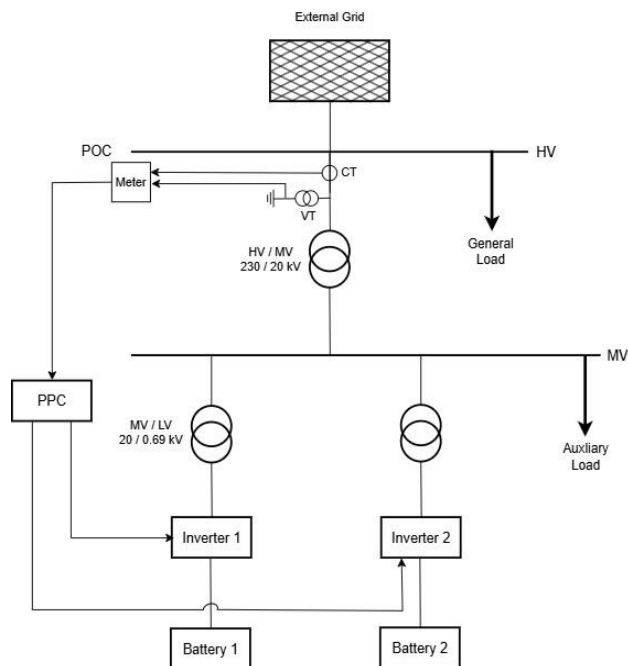


Figure 3.1, Single line diagram of the analyzed BESS.

Table 3-1, Parameters of the plant components

Variable	Unit	Value
Short Circuit Ratio (SCR)		10
High Voltage (HV)	kV	230
Medium Voltage (MV)	kV	20
Low Voltage (LV)	kV	0.69
HV/MV transformer rating	MVA	200
MV/LV transformer rating	MVA	100
HV/MV transformer reactance	%	0.12
MV/LV transformers reactance	%	8
HV/MV transformer efficiency	%	99.5
MV/LV transformers efficiency	%	99
Inverter Rating	MVA	100
Inverter power factor		0.9
General Load power	MW	400
Auxiliary Load power	MW	1.8
Auxiliary Load power factor		0.8

3.2. Battery model

It is essential to design a model that depicts the key parameters of the battery. It should depict the terminal voltage and the internal resistance which are a function of several intern-related variables such as the Battery SOC, the age and temperature of the battery. To balance computational efficiency with dynamic accuracy for frequency stability analysis, a simplified DC voltage source model is adopted, as detailed below. A simplified lead-acid battery model from DigSilent PowerFactory is utilized as shown in Figure 3.2 [27]. The battery is modeled as a controllable voltage source connected behind an internal resistance. The terminal voltage (U_{DC}) is dynamically calculated based on the SOC and the load current (I_{bat}). The governing equation implemented in the simulation is:

$$U_{DC} = U_{max} \cdot SOC + U_{min} \cdot (1 - SOC) - I_{bat} \cdot Z_i \quad (3-1)$$

Where:

- U_{max} and U_{min} represent the internal cell voltages at fully charged (100% SOC) and fully discharged (0% SOC) states, respectively.
- Z_i represents the internal ohmic resistance of the battery pack.
- I_{bat} is the DC current (positive for discharge).

The State of Charge is updated continuously via Coulomb counting:

$$SOC(t) = SOC_{initial} - \frac{1}{C_{nom}} \int_0^t I_{bat}(\tau) d\tau \quad (3-2)$$

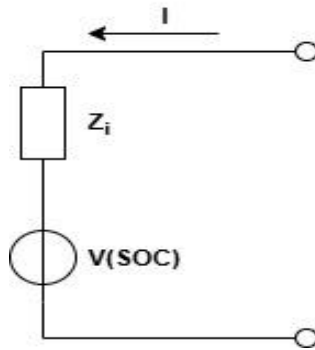


Figure 3.2, Equivalent Circuit Model of the implemented batteries.

While electrochemical batteries (such as Li-Ion or Lead-Acid) exhibit non-linear voltage characteristics—specifically the exponential potential drop in the "cutoff" region and the rapid voltage rise in the "exponential" region—a linearized voltage model is utilized in this study. This simplification is justified for three important reasons:

- **Linear Voltage Dependency:** The internal open-circuit voltage is assumed, in the proposed model, to be linearly dependent on the SOC. While electrochemical cells typically exhibit non-linear behavior at the extreme ends of the discharge curve. This simplification is valid due to the operational range of the proposed strategy. The frequency regulation logic is designed to operate the BESS within a restricted SOC window (e.g., 20% to 80%). Within this mid-range, the Open Circuit Voltage (OCV) curve of practical battery chemistries is predominantly linear, making the linear approximation robust for this application.
- **Constant Internal Resistance:** The internal ohmic resistance (Z_i) is modeled as a constant parameter, neglecting the effects of temperature and current magnitude. This is justified by the timescale of interest since the research focuses on inertial response and primary frequency control, which occur on a timescale of seconds to minutes. Complex long-term phenomena, such as thermal-dependent internal resistance variations, have negligible effect on the short-term power injection capability required for grid stability.
- **Constant Capacity:** The battery capacity is presumed to be constant, independent of the discharge rate. Although the Peukert effect mandates that effective capacity decreases at high discharge currents, this phenomenon is critical only for energy-intensive applications (long-duration discharge). Since this study analyzes power-intensive frequency events (short duration), the total energy throughput is small relative to the total capacity. Therefore, the

reduction in effective capacity does not significantly influence the voltage dynamics or the availability of power headroom during the simulated events.

To verify the validity of the adopted model, a discharge simulation was performed. The BESS model was discharged at a constant nominal power ($P=1$ p.u.) from 100% to 0% SOC.

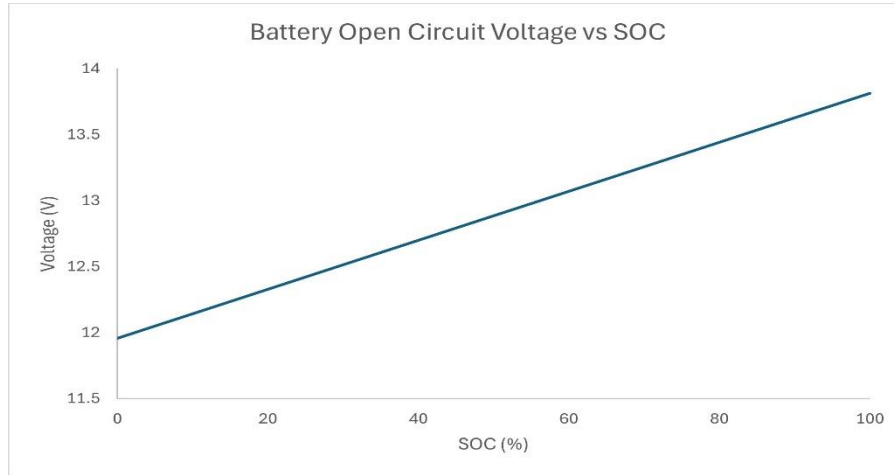


Figure 3.3, Terminal voltage profile against SOC during constant power discharge ($P=1$ p.u.)

As illustrated in Figure 3.3, the voltage profile exhibits a strictly linear decay across the entire SOC range. This behavior aligns perfectly with the governing mathematical formulation (Eq. 3.1) and confirms the model is operating as intended.

The simplified model captures the macroscopic power-energy-voltage dynamics required for grid-forming control analysis. By neglecting complex non-linear electrochemical phenomena (such as the Butler-Volmer kinetics or hysteresis), the simulation burden is significantly reduced without compromising the accuracy of the inertial response, which is driven by the inverter's control loop rather than the battery's micro-dynamics.

Table 3.2 explains the parameters of Equation (3.1) in addition to the values used for the analysis. It is important to mention that for the analysis there are two heterogeneous batteries; one has twice the capacity of the other. The battery with twice

the capacity will be referred to as Battery2 (so as its corresponding inverter), while the lower capacity one is referred to as Battery1 (so as its corresponding inverter). The two BESS units are intentionally sized with unequal capacities, with one battery having twice the nominal capacity of the other. This configuration is adopted to represent a heterogeneous BESS plant, which is typical in practical installations due to design constraints, or unequal aging of battery units. More importantly, the asymmetric sizing creates different power and energy headroom among the inverters, leading to non-simultaneous saturation during frequency events. This allows a meaningful assessment of the PPC dispatching strategy, particularly its ability to reallocate power and preserve synthetic inertia when one inverter reaches its limits while others still reserve available capacity. If identical units were analysed, saturation and inertia loss would occur uniformly, concealing control challenges addressed in this thesis. Furthermore, it should be noted that the capacities of the cells are low. The reason for choosing those values is just for running a small simulation time while still being able to see the effect of the approaches and the visibility of SOC's deviation.

Table 3-2, Description of battery elements and their assigned values.

Variable	Unit	Description	Value
U_{max}	V	Voltage of an empty module	13.85
U_{min}	V	Voltage of a full module	12
Z_i	Ohm	Internal resistance per cell (average value).	0.001
Cells Capacity 1	Ah	Capacity of one cell for the used discharge current of 1 st battery	40
Cells Capacity 2	Ah	Capacity of one cell for the used discharge current of 2 nd battery	80

SOC	—	Current state of charge of the cell	
U_{DC}	V	Voltage rating of the connected DC-busbar.	

3.3. Virtual Synchronous Machine (VSM)

The VSM is a type of grid-forming control that emulates the mechanical part of a synchronous machine, which is also referred to as the swing equation. It is essential to include a functional VSM controller for the sake of analysis. The VSM implemented in this BESS model is a template from DigSilent Powerfactory. A VSM can be represented by the approximated synchronous machine per unit balance in the Laplace domain as given by Equation (3.2),

$$T_a \cdot s \cdot \omega = p_{set} - p_{mea} - D_p \cdot (\omega_r - \omega_{set}) \quad (3-3)$$

where T_a is the mechanical time constant, p_{set} is the active power set point and p_{mea} is the measured active power output. The rotating speed of the VSM is given by ω_r , ω_{set} is the frequency set point and D_p is the damping coefficient.

The VSM controller is illustrated in Figure 3.3, In addition to the swing equation, a low-pass filter $\left(\frac{\omega_c}{\omega_c + s}\right)$ is applied in the damping term. This allows for inertia provision during transients, while eliminating the impact of the damping term at steady state. f_{nom} is the nominal frequency (50 Hz) which gets multiplied by 2π to get nominal angular frequency ω_{nom} . f_{set} is the reference frequency and θ_u is the output voltage angle.

The difference between the set and measured active power ($P_{set} - P_{mea}$) is scaled by the inverse of the power–frequency time constant $1/T_a$ and integrated to produce a corrective frequency deviation. This term works alongside a proportional droop element D_p and filtered feedback of the measured frequency f_{mea} , forming a closed-loop response that mimics primary frequency control. The resulting signal is combined with the nominal angular frequency ($2\pi f_{nom}$) and the set frequency f_{set} , while subtracting the measured frequency f_{mea} to align the

internal dynamics with the grid's actual operating point. The summed output defines the instantaneous reference speed ω_r , which is then integrated to obtain the electrical angle θ_u . Finally, the angle is wrapped by a modulo 2π function to ensure a bounded phase suitable for RMS-based phasor calculations.

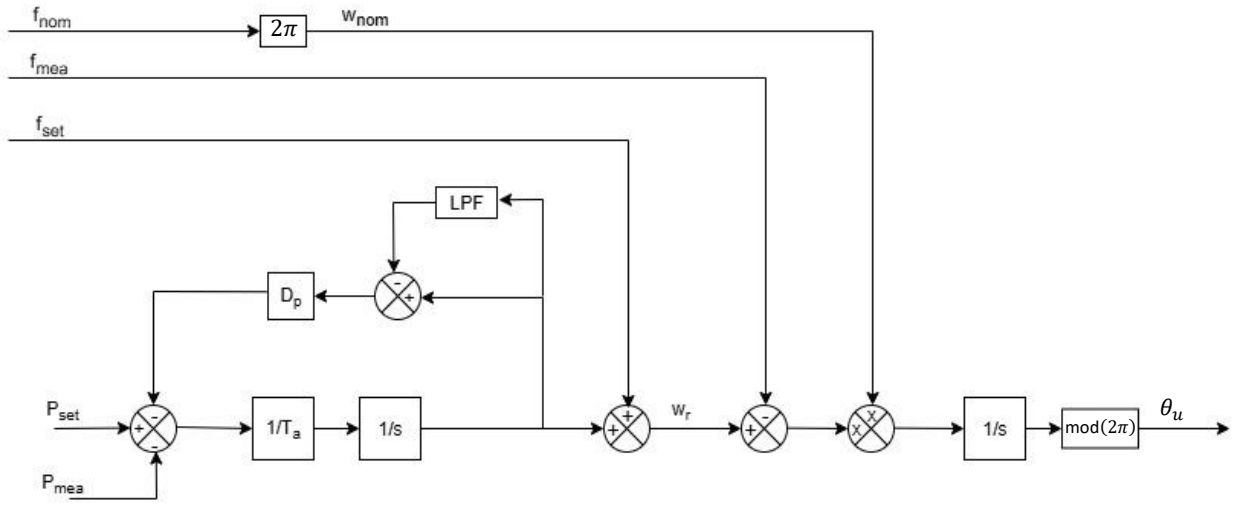


Figure 3.4, Single Line Diagram of the utilized VSM

3.3.1. VSM Parameters Tuning

Tuning and optimization will aid in outlining the parameters that have a significant effect on the final response of the output signal. The aim is to achieve a specific equivalent Time constant T_a , while varying several parameters such as D_p , T_{lpf} , and H . A block diagram that represents the full system from P_{ref} to P_{mea} is shown in Figure 3.4. It includes the swing equation emulation of the VSM and the Power angle equation to get to the measured power.

The power angle equation is presented as follows:

$$P_{mea} = \frac{V_{inv} V_g}{X_{eq}} = K_{sync} \quad (3-4)$$

It is assumed that inverter Voltage V_{inv} and grid voltage V_g are 1 p.u, while equivalent impedance X_{eq} of the grid includes the transformers' reactance and the virtual impedance of the inverter model.

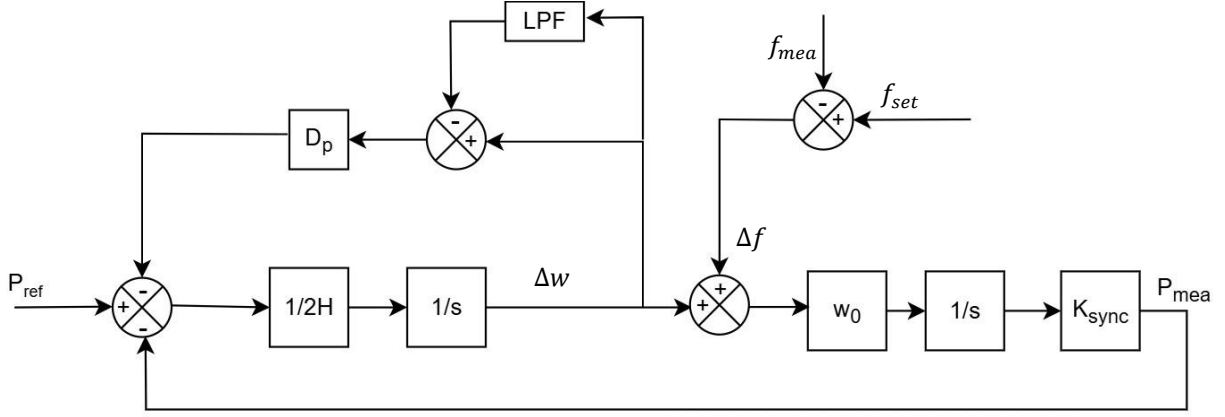


Figure 3.5, Block diagram of the VSM in addition to the Power angle equation.

Two transfer functions are to be computed, one which depicts the relation between the measured power P_{mea} and the reference one P_{ref} . The other one is to present the response of the measured power ΔP due to an external disturbance of the frequency Δf .

Transfer Function is computed as follows starting from swing equation:

$$2H \frac{dw}{dt} = \Delta P - D_p \left(\Delta w - \Delta w \cdot \frac{1}{s \cdot T_{LPF} + 1} \right) \quad (3-5)$$

Convert all the elements into s domain:

$$2H \cdot \Delta w \cdot s = \Delta P - D_p \left(\Delta w - \Delta w \cdot \frac{1}{s \cdot T_{LPF} + 1} \right) \quad (3-6)$$

$$2H \cdot \Delta w \cdot s = \Delta P - D_p \cdot \Delta w \left(\frac{s \cdot T_{LPF}}{s \cdot T_{LPF} + 1} \right) \quad (3-7)$$

Move all the Δw to the left side:

$$\left(2H \cdot s + D_p \cdot \frac{s \cdot T_{LPF}}{s \cdot T_{LPF} + 1} \right) \Delta w = \Delta P \quad (3-8)$$

$$\left(\frac{2H \cdot T_{LPF} \cdot s^2 + (2H + D_p \cdot T_{LPF}) \cdot s}{s \cdot T_{LPF} + 1} \right) \Delta w = \Delta P \quad (3-9)$$

$$P_{mea} = K_{sync} \cdot \theta \quad , \quad \text{where } \theta = \Delta w \cdot \frac{w_0}{s}$$

Substituting θ by Δw to get a direct relation between P_{mea} and Δw :

$$\Delta w = P_{mea} \cdot \frac{s}{K_t} \quad (3-10)$$

$$\text{where,} \quad K_t = K_{sync} \cdot w_0$$

Substitute Equation 3.9 into Equation 3.8:

$$\left(\frac{2H \cdot T_{LPF} \cdot s^2 + (2H + D_p \cdot T_{LPF}) \cdot s}{s \cdot T_{LPF} + 1} \right) P_{mea} \cdot \frac{s}{K_t} = \Delta P \quad (3-11)$$

Get open loop transfer function between the measured power and the reference one

$$\frac{P_{mea}}{P_{ref}} = \frac{K_t}{s} \cdot \frac{s \cdot T_{LPF} + 1}{(2H \cdot T_{LPF} \cdot s^2 + (2H + D_p \cdot T_{LPF}) \cdot s)} \quad (3-12)$$

$$H_{op}(s) = K_t \cdot \frac{s \cdot T_{LPF} + 1}{(2H \cdot T_{LPF} \cdot s^3 + (2H + D_p \cdot T_{LPF}) \cdot s^2)} \quad (3-13)$$

To get the closed loop transfer function:

$$H_{cl}(s) = \frac{H_{op}(s)}{1 + H_{op}(s)}$$

Following the same procedure to simplify the closed loop transfer function, this is the final format:

$$H_{cl}(s) = K_t \cdot \frac{T_{LPF} \cdot s + 1}{2H \cdot T_{LPF} \cdot s^3 + (2H + D_p \cdot T_{LPF}) \cdot s^2 + K_t \cdot T_{LPF} \cdot s + K_t} \quad (3-14)$$

As shown in the last equation, there is a zero in the negative part of the s-plane that depends on the time constant of the low-pass filter. Moreover, it is a third-order system which has 3 poles. Those poles depend on four parameters: H , D_p , T_{LPF} , and K_t . For this analysis, the connection between the inverters and the grid can be assumed constant and non-variable, so does K_t .

To get the closed loop transfer function between the change in power ΔP due to the change of frequency Δf , block diagram reduction methodology is followed.

First, the damping part is reduced to:

$$D_p \cdot \frac{T_{lpf} \cdot s}{T_{lpf} \cdot s + 1}$$

Then it will be feedbacked to $\frac{1}{2H \cdot s}$, to get

$$G(s) = \frac{1}{2H \cdot s + D_p \cdot \frac{T_{lpf} \cdot s}{T_{lpf} \cdot s + 1}} = \frac{T_{lpf} \cdot s + 1}{2H \cdot T_{lpf} \cdot s^2 + (2H + D_p \cdot T_{lpf}) \cdot s} \quad (3-15)$$

The reduced block diagram is shown in Figure 3.5,

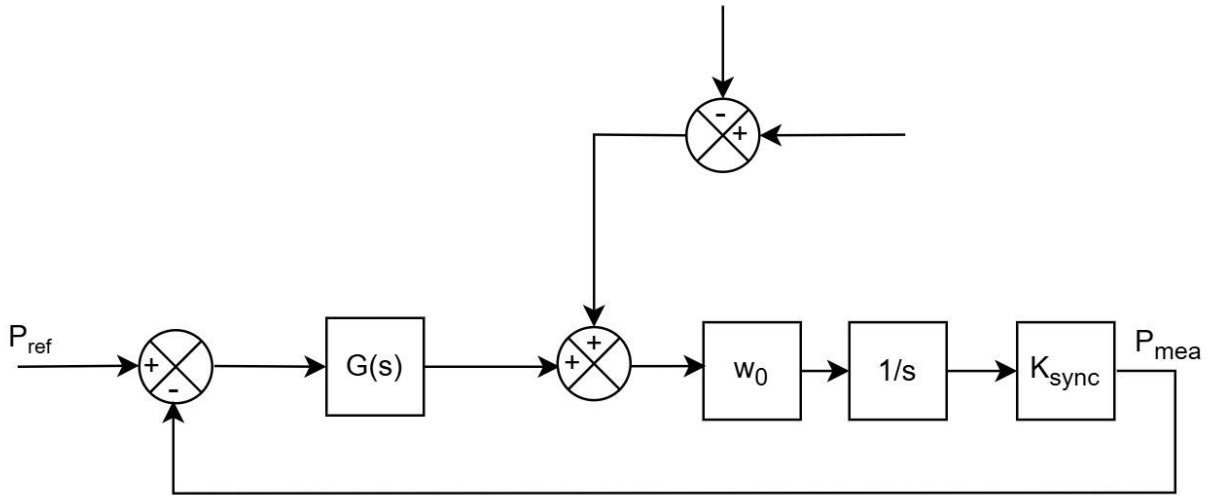


Figure 3.6, Block diagram reduction after feedbacking the damping term

The open loop transfer function between ΔP and Δf is:

$$T_{op}(s) = \frac{K_t}{s} \quad (3-16)$$

The closed loop one after following the same procedures followed before:

$$T_{cl}(s) = \frac{\Delta P}{\Delta f} = K_t \cdot \frac{2H \cdot T_{lpf} \cdot s^2 + (2H + D_p \cdot T_{lpf}) \cdot s}{2H \cdot T_{lpf} \cdot s^3 + (2H + D_p \cdot T_{lpf}) \cdot s^2 + K_t \cdot T_{lpf} \cdot s + K_t} \quad (3-17)$$

Compared to the previous closed loop between P_{mea} and P_{ref} , this one has one extra zero at the origin, while the other zero is function of the three parameters, not just the time constant of the LPF. They have the same poles.

The transfer function used for the sensitivity analysis represents a linearized small-signal model of the system around a given steady-state operating point. The model is

structured as a linear time-invariant (LTI) representation that relates frequency-related disturbances (RoCoF) to the active power output of the VSM. Nonlinear effects such as converter saturation, current limits, and switching dynamics are neglected, and the system is assumed to operate in the small-signal regime. Under these assumptions, the dominant inertial dynamics of the VSM can be captured accurately, making the model suitable for parametric sensitivity analysis of the inertia constant, damping factor, and filter time constant.

3.4. PPC (Applied Scheme)

PPC, as mentioned in the previous chapter, is the brain of the plant. It receives the measured power at the POC and compares it with the reference power, calculated from the TSO requirements and the droop as shown in Figure 3.6. The error passes through a regulator to calculate the new required setpoint to decrease this error. Before sending the setpoint to the inverters, there is a logic function which distributes the power among the inverters based on their current dispatched power and the SOC of their corresponding batteries.

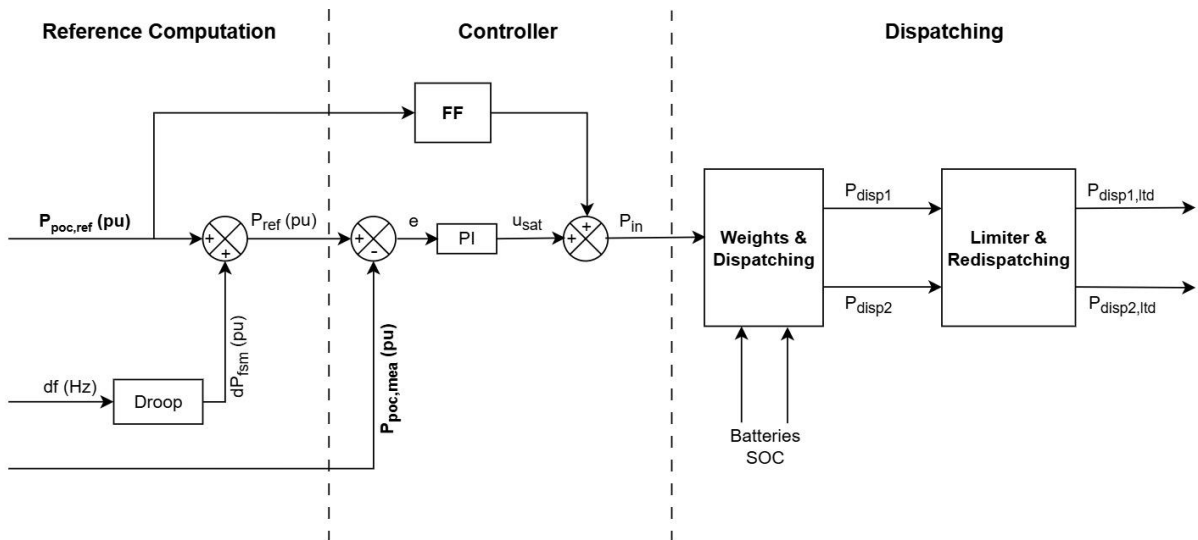


Figure 3.7, Block diagram structure of PPC

3.4.1. Reference Computation

To compute the reference power, two signals are added: reference power required at the POC, which can be a request from the TSO for instance, and Droop change of power in case of a frequency event. The former is just constant, while the latter is a result of droop equation as given in Equation (3.17):

$$\Delta P = -\frac{\Delta f}{R} \quad (3-18)$$

Where R is the droop coefficient and Δf is the difference between the measured frequency and the nominal frequency. Therefore, in case of an increase in the frequency, the power output of the inverters will decrease to stabilize the frequency at a new steady state value.

Figure 3.7 illustrates the functional structure of the Frequency Sensitive Mode (FSM) controller implemented in the converter model. The measured system frequency f_{mea} is compared with the nominal frequency f_n . The resulting deviation $\Delta f = f_{\text{mea}} - f_n$ is processed through three parallel control paths:

- LFSM-O (Limited Frequency Sensitive Mode Over-frequency),
- FSM (normal frequency sensitivity with deadband),
- LFSM-U (Limited Frequency Sensitive Mode Under-frequency).

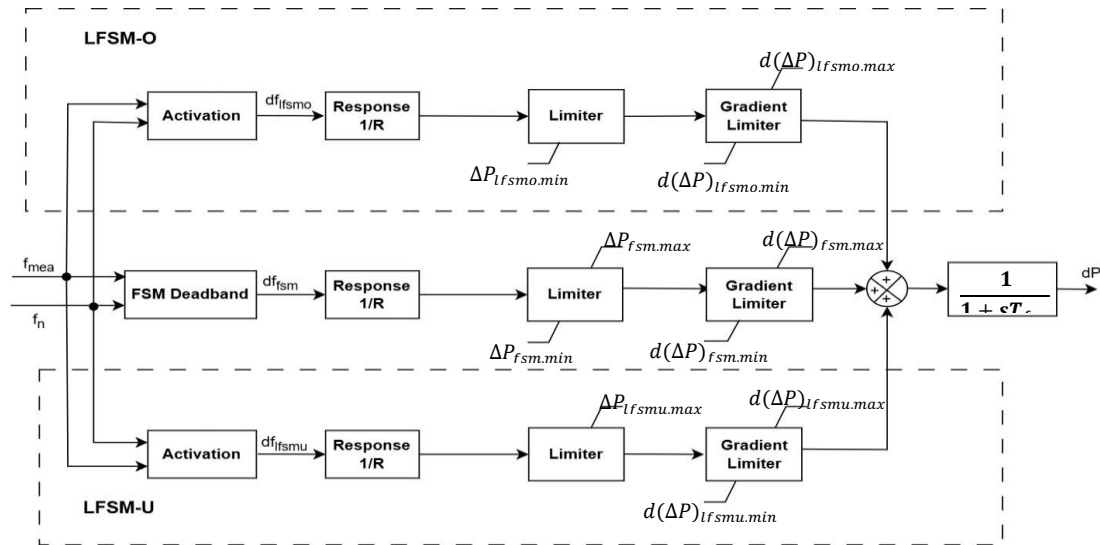


Figure 3.8, Block diagram of FSM

In the FSM path, a deadband (typically ± 20 mHz) defines the frequency range in which no corrective action is taken, so the reference power remains equal to the TSO-defined set-point. Outside this range, the controller produces an active-power variation proportional to the frequency deviation according to a defined droop R . The proportional response passes through two limiters:

1. a power limiter constraining the magnitude of ΔP between $\Delta P_{\min}$ and $\Delta P_{\max}$, and
2. a gradient limiter that bounds the rate of change $d(\Delta P)/dt$ within specified limits $(d(\Delta P)_{\min}, d(\Delta P)_{\max})$.

The LFSM-O and LFSM-U branches become active when the frequency exceeds 50.2 Hz or drops below 49.8 Hz, respectively. Each branch follows the same droop characteristic $1/R$ as the FSM path, ensuring consistent frequency-power sensitivity across the operating range. Before being summed with the FSM output, their outputs are likewise constrained by magnitude and gradient limiters.

The total power variation ΔP is therefore the sum of the contributions from all active branches, each filtered through its respective limiter chain. A low-pass filter with time constant T_{fsm} is subsequently applied to attenuate high-frequency components and measurement noise before the signal is dispatched to the converter control system.

Table 3.3 summarizes the key parameters and limits referenced in the figure, including the droop setting, deadband width, activation thresholds, and limiter values used in the simulations.

Table 3-3, Parameters description and values of the FSM

Variable	Unit	Description	Value
Deadband	mHz	Upper and lower frequency deadband	± 20
R	%	Droop	4
T_{fsm}	s	Output smoothing time constant	0.02
$dP_{fsm,max}$	%	Maximum additional power FSM	100
$dP_{fsm,min}$	%	Minimum additional power FSM	-100
$ddP_{fsm,max}$	%/s	Maximum rate of change of dP_{fsm}	100
$ddP_{fsm,min}$	%/s	Minimum rate of change of dP_{fsm}	-100
$dP_{lfsmo,min}$	%	Maximum power reduction LFSM-O	-100
$ddP_{lfsmo,max}$	%/s	Maximum rate of change of dP_{lfsmo}	100
$ddP_{lfsmo,min}$	%/s	Minimum rate of change of dP_{lfsmo}	-100
$dP_{lfsmu,max}$	%	Maximum additional power LFSM-U	100
$ddP_{lfsmu,max}$	%/s	Maximum rate of change of dP_{lfsmu}	100
$ddP_{lfsmu,min}$	%/s	Minimum rate of change of dP_{lfsmu}	-100

3.4.2. Controller

The active power regulation in the PPC is governed by a proportional–integral (PI) controller that minimizes the instantaneous power error:

$$e(t) = P_{ref}(t) + P_{droop}(t) - P_{POC}(t) \quad (3-19)$$

The control output $u_{unsat}(t)$ represents the total active power command, before saturation, distributed among the battery inverters. The PI equation in continuous time is:

$$u_{unsat}(t) = K_p \cdot e(t) + x(t) \quad (3-20)$$

$$\dot{x}(t) = K_i \cdot e(t) \quad (3-21)$$

where K_p and K_i are the proportional and integral gains, respectively, and $x(t)$ is the integrator state.

During normal operation, the PI behaves as a linear regulator with constant loop gain. However, when the requested power exceeds the inverters limit the PI output is saturated. In such conditions, the integral term can continue accumulating error in the wrong direction (“wind-up”), causing delayed recovery or oscillations once the system re-enters its feasible range. To prevent this, an anti-windup mechanism is integrated into the PPC controller.

The anti-windup implemented in this work operates by directly constraining the integrator state as shown in Figure 3.8.

$x(t)$ represents the integral state, and $e(t)$ is the control error. The derivative $\dot{x}(t)$ integrates the proportional error through the gain K_i . Then, there is saturation enforced on the integrator state between the constant bounds y_{min} and y_{max} . When the state reaches either limit, its derivative is automatically set to zero, preventing further integration in that direction until the error reverses sign. Furthermore, an additional

constraint for the total output $u_{sat}(t)$ ensures that the controller output itself also remains within the same physical limits.

This approach implements an implicit anti-windup: the integrator cannot accumulate beyond its operational range, eliminating the typical lag or overshoot that arises when the controller exits saturation. It is simple and robust, as it requires no tuning of an additional feedback gain. It guarantees consistent recovery after inverter saturation events, maintaining smooth transition of the power command as the system returns to its linear operating region.

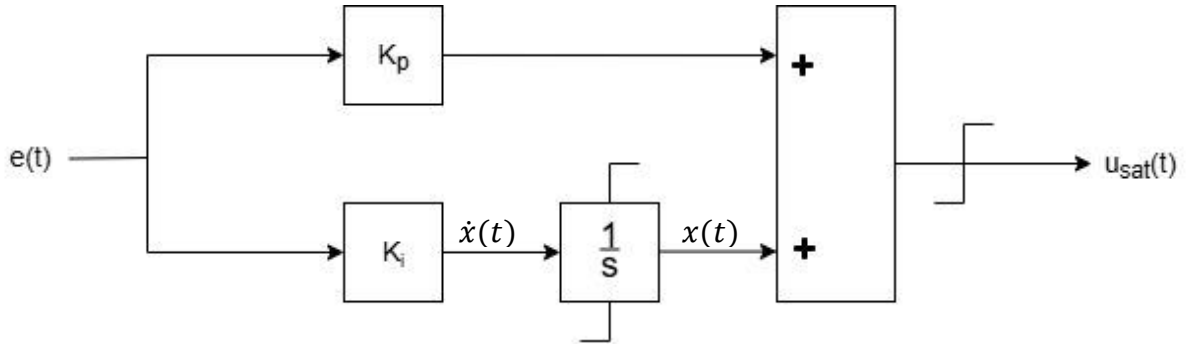


Figure 3.9, PI controller design with anti-windup.

Furthermore, a Feed Forward (FF) block is added to the output of the PI $u_{sat}(t)$ to get P_{in} which is the input to the dispatching control logic. Adding FF helps to reduce the load on the PI, so the PI parameters can be low. This will help during a RoCoF event to avoid the activation of PI during this event since it will oppose the inertia support provided by the inverter. Additionally, FF makes it faster for the measured signal to follow the reference power when there is a change in the reference signal.

3.4.3. Dispatching and weights

BESS are frequently deployed as synthetic or virtual inertia providers to mitigate these effects, as their power-electronic interfaces can emulate inertial response through fast active-power control. In configurations where multiple inverters operate

in parallel, coordination of inertia provision becomes critical to ensure both stability and fair utilization of available resources.

The output of the PI controller, u_{sat} , represents the total active-power command delivered by the PPC. This signal is then distributed among the inverters through the weighting-factor block, whose role is to allocate power proportionally to each battery's available energy and operational headroom. Various methods have been proposed in literature to determine how the reference power contribution is shared among converters. Some approaches use constant weighting factors, as given Equation (3.21), based on rated capacity or nominal power limits:

$$w_i = \frac{E_i}{\sum_j E_j} \quad (3-22)$$

This approach is straight forward, simple but inflexible; in cases where one unit is near SOC limits or approaching constraints, it may over-contribute and destabilize itself.

To remedy the rigidity of fixed weights, others use dynamic weighting depending on operating conditions, notably SOC. The idea: an inverter with higher remaining capacity or SOC should take on more of the power burden to avoid pushing weaker units. In effect:

$$w_i = \frac{\text{SOC}_i E_i}{\sum_j (\text{SOC}_j E_j)} \quad (3-23)$$

That formula ensures that as SOC_i falls, its weight shrinks. This approach respects battery constraints and adapts to changing conditions. On the other hand, it may overreact in fast transients, or cause oscillations in sharing if SOC's fluctuate too fast. Additionally, it doesn't guarantee, in case of multiple inverters BESS, that all the inverters can provide inertia. One inverter with the higher SOC will inject maximum

power while the other, with lower SOC, will output below its power limits. Thus, inertia provision is lost from the former inverter.

3.4.4. Thesis Proposal

According to the latest publication by NESO [7], a Great Britain Grid Forming Inverter (GBGF-I) should have the following characteristics:

- For a RoCoF of magnitude equal to or less than 1 Hz/s, the active inertia power is provided without the activation of current limiting functions.
- The maximum inertia constant allowed is 25 MW·s/MVA.

Moreover, the plant should ensure to provide inertia response based on the following equation:

$$H = \frac{\Delta P \cdot f_0}{2 \cdot \text{RoCoF}} \quad (3-24)$$

Where:

- ΔP is the Active Inertia Power of the Grid Forming Plant for a frequency event of 1Hz/s (MW).
- RoCoF is the Rate of Change of Frequency (RoCoF) in Hz/s
- f_0 is the pre-fault System Frequency (50Hz)

Following those requirements, the calculation of the required headroom is conducted as follows, considering that the inertia of the proposed system is $H = 5$ s:

$$\Delta P = \frac{2.5 \text{ s} \cdot 1 \text{ Hz/s}}{50 \text{ Hz}} = 0.2 \text{ p.u.} \quad (3-25)$$

Therefore, a headroom of 0.2 p.u. should be available for inertia provision without exceeding the active power limits of the inverters.

The proposed approach aims at dividing the operating region into three different zones: normal operation zone, linear convergence zone, and constant weight zone. Figure 3.9 illustrates the dependency of the inverter weighting factor on power and battery state of charge. Below a lower threshold $P_{th,low}$, the distribution is SOC-dependent to preserve proportional energy and avoid the depletion of one battery over the other. Between $P_{th,low}$ and $P_{th,high}$, the weights transition linearly towards a common average value W_{avg} to ensure balanced participation in inertia provision by both inverters instead of only one inverter. Beyond $P_{th,high}$, the weights remain fixed at the average value, reflecting the convergence required for high-power operation. Those numbers refer to the discharge case, but also the same applies for the case of charging. The figure highlights how the SOC-dependency dominates at low operating points, while the linear convergence region provides smooth and stable transition to the uniform-weight regime. Additionally, when the SOC is 0%, not depicted in the graph, the weights become zero since the battery cannot provide any more active power.

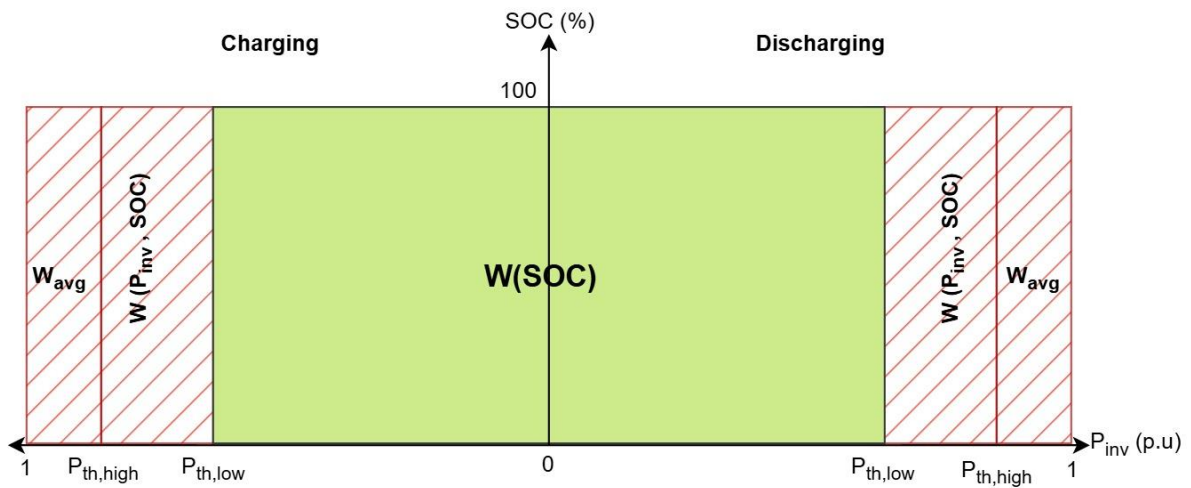


Figure 3.10, Weighting factor variation depending on the inverter output power.

To achieve this solution and control logic, the following equations are implemented:

$$W = \frac{E_i \cdot SOC_i}{\sum_{i=1}^m E_i \cdot SOC_i} + \beta \cdot \left(W_{avg} - \frac{E_i \cdot SOC_i}{\sum_{i=1}^n E_i \cdot SOC_i} \right) \quad (3-26)$$

Where:

- E_i is the nominal capacity of the battery
- SOC_i is the current SOC of the battery.
- m is the number of batteries.
- W_{avg} is the average weighting factor and is equal to $\frac{1}{n}$, n is the number of inverters.
- β is the slope that results in the linear convergence to the average weighting factor.

When the output of any of the inverters is equal to or below $P_{th,low}$, β is zero, as shown in Figure 3.10. Therefore, the weights are function of the available energy in the battery through the first term of Equation (3.25). For example, if the SOC's are the same, the battery with a higher capacity will have higher weight and will dispatch more power. This part is important to avoid the depletion of one battery faster than

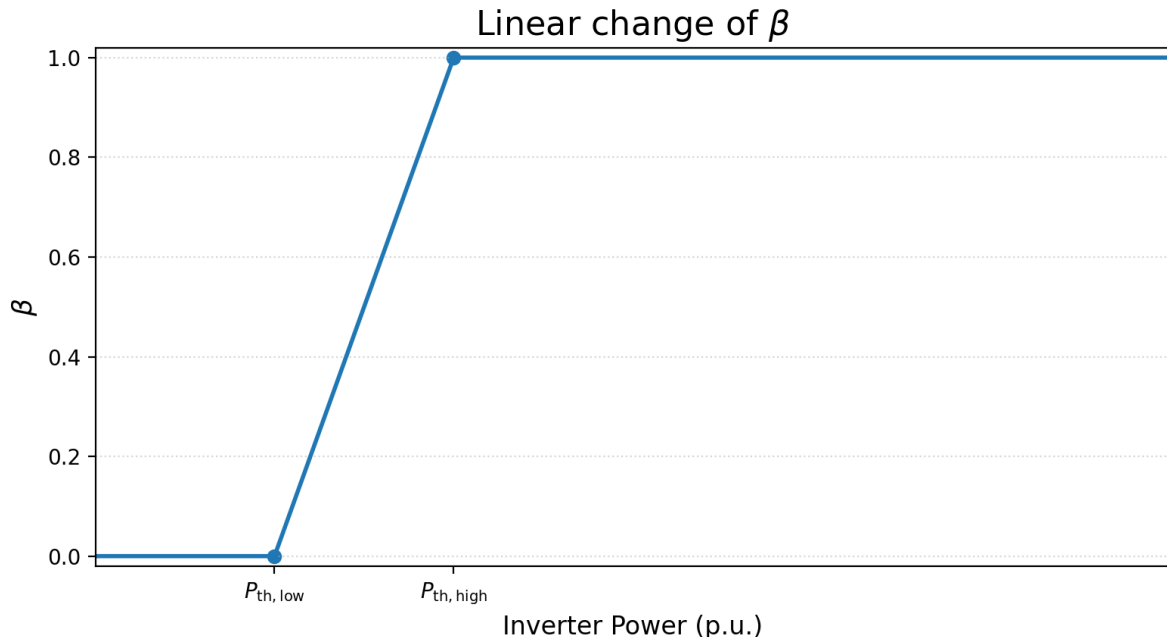


Figure 3.11, Value of β as a function of the output power of the inverter

the other one. Additionally, when the SOC is zero the resultant weight is zero which sounds since the battery cannot provide more active power.

From $P_{th,low}$ to $P_{th,high}$, β starts to change linearly from 0 to 1. As a result, the weights converge linearly to W_{avg} . During this interval of convergence, the weights are function of the SOC and the current dispatched power of the inverters. It can be noted that the transition from one phase to another is smooth and there is no discontinuity.

Finally, when the output power reaches $P_{th,high}$, β becomes 1 and W converges to W_{avg} . Hence, both inverters dispatch the same power. To achieve this, β is calculated through the following equation,

$$\beta = \min \left(\frac{\max(\alpha, P_{th,low}) - P_{th,low}}{\gamma}, 1 \right) \quad (3-27)$$

α is function of the dispatched power, as shown in Equation (4.11), of the inverter and it is considered the triggering factor that decides in which interval the weights are.

$$\alpha = \max (|P_{inv2}|, |P_{inv1}|) \quad (3-28)$$

The absolute value is applied to consider also the case of charging the batteries. Once one inverter reaches $P_{th,low}$, its weight will decrease linearly towards an average weight while the other weight will increase linearly towards the same average weight.

The power is computed from $P_{in}(t)$, resultant of FF and PI summation, as presented in Equation (3.28). This method can be scaled to larger number of inverters.

Additionally, it does not require any communication between the inverters and the PPC so that delays are avoided and complexity are avoided. Therefore, the dispatched power is calculated as follows:

$$P_{inv,i} = P_{in}(t) \cdot \frac{S_{plant}}{S_{inverter}} \cdot \frac{E_i \cdot SOC_i}{\sum_{i=1}^m E_i \cdot SOC_i} \quad (3-29)$$

The calculations inside the PPC are in p.u. , so all the variables should have the same base. Thus, the output power of the regulator is multiplied by $\frac{S_{plant}}{S_{inverter}}$ to map it to the same base as the inverters. Then it is multiplied by the weighting factor of the inverter to get the actual output inverter power.

$\max(\alpha, P_{th,low}) - P_{th,low}$, this term ensures that β is never a negative value. When the dispatched power is equal to or below $P_{th,low}$, this term becomes zero and so does β . When the dispatched power exceeds $P_{th,low}$, the result of this term becomes

$$\alpha - P_{th,low} .$$

As long as the dispatched power of the inverter is $P_{th,low}$ or below, Equation (3.28) results in the actual output of the inverter. On contrary, when the power is above $P_{th,low}$, the result of this equation is higher than the actual output of the inverter. This is because above $P_{th,low}$, the weights are no more function of just the available energy but also the dispatched power. In other words, β is no more zero and the output power of the inverter is lower than the calculated one in Equation (3.28) which computes the power as a function of just the available energy.

So the main aim now is to ensure that β becomes 1 when the output power reaches $P_{th,high}$. This is accomplished by adding the parameter γ , which has the following form:

$$\gamma = P_{th,high} \cdot \frac{S_{plant}}{S_{inverter}} \cdot \max\left(\frac{E_1 \cdot SOC_1}{\sum_{i=1}^m E_i \cdot SOC_i}, \frac{E_2 \cdot SOC_2}{\sum_{i=1}^m E_i \cdot SOC_i}\right) - P_{th,low} \quad (3-30)$$

It can be noted here that the first term is P_{inv} , mentioned in Equation (3.28), but substituted with the $P_{th,high}$ instead of $P_{in}(t)$. This is to ensure that β will be 1 at $P_{th,high}$ and the weights will converge to the average value. This way the computed power can be mapped to be the actual injected power of the inverter. K_{soc} is used to

calculate the power instead of W because it would have resulted in an algebraic loop in the system.

Finally, the outer $\max()$ function is utilized to ensure that β becomes 1 at $P_{th,high}$. Otherwise β will continue increasing linearly.

Regarding the last block in the PPC diagram which is called Limiter and Re-dispatching. Its main purpose is to ensure that the required power is supplied even if some of the inverters are saturated. As long as there are some inverters with available headroom, the required power should be provided. This is achieved through a While loop where the system will not exit the loop unless one of those conditions are met:

- All the required power is dispatched.
- All the inverters saturate

The power is distributed among the inverters according to the weights. If one inverter saturates, it will be excluded from the weight distribution, it will generate its maximum value. The leftover power will be distributed among all the other inverters in operation.

Once all the inverters saturate and there is still power to be provided, a signal is sent to the PI to stop integrating and stop the accumulation of errors.

Table 3-4, Summary of the utilized parameters

Parameter	Description	Unit	Value
T_a	Effective Inertia time constant of the inverters	s	10
$P_{th,low}$	Lower threshold at which the convergence starts	p.u.	0.7
$P_{th,high}$	Higher threshold at which the convergence ends	p.u.	0.8
W_{avg}	The average weighting factor	-	0.5
E_1	Nominal capacity of the battery connected to inverter 1	MWh	25
E_2	Nominal capacity of the battery connected to inverter 2	MWh	50
m	Number of batteries	-	2
n	Number of inverters	-	2
S_{plant}	Rated power of the plant	MVA	200
$S_{inverter}$	Rated power of each inverter	MVA	100

4 Results and Discussion

This chapter will present the results of the sensitivity analysis applied for selecting the parameters of the VSM such as inertia constant, Damping, and low-pass filter time constant. The followed criteria and simulation results will be presented. Moreover, the case study and the events applied for conducting a dynamic simulation to test the efficiency of the proposed approach. Furthermore, a comparison between the proposed approach, nominal Energy-based, and SOC-based approaches is presented.

4.1. VSM Sensitivity Analysis

The parameters of the VSM are selected following a sensitivity analysis on the open loop function. The analysis is performed on MATLAB by checking the effect of each parameter on the zeroes and poles of the last transfer function $T_{cl}(s)$. First, each parameter will be changed while maintaining the other two constants. Then, the effect on the poles and zeroes positioning will be captured. After that an optimization method using MATLAB is performed to get the best parameters for specific settling time, damping, and overshoot. At the end the response of the chosen parameters will be compared to that of power factory.

As shown in Figure 4.1, values of H are analyzed: $H=0.05$ s in red, $H = 2$ s in blues, and $H = 5$ s in black. The other parameters were maintained constants at $D_p = 50$ and $T_{lpf} = 0.168$ s Increasing H results of the following effect

- All the poles and zeroes move closer to the imaginary axis, which results in a slower response since the exponential decay of those poles will last longer.

- Damping ratio of the dominant poles (complex ones) decreases. Thus, the overshoot increases
- The zero gets closer to the real pole so it reduces its weight and its effect on the final response. This should be avoided since this pole has the highest damping and the fastest response so its contribution should be maintained.

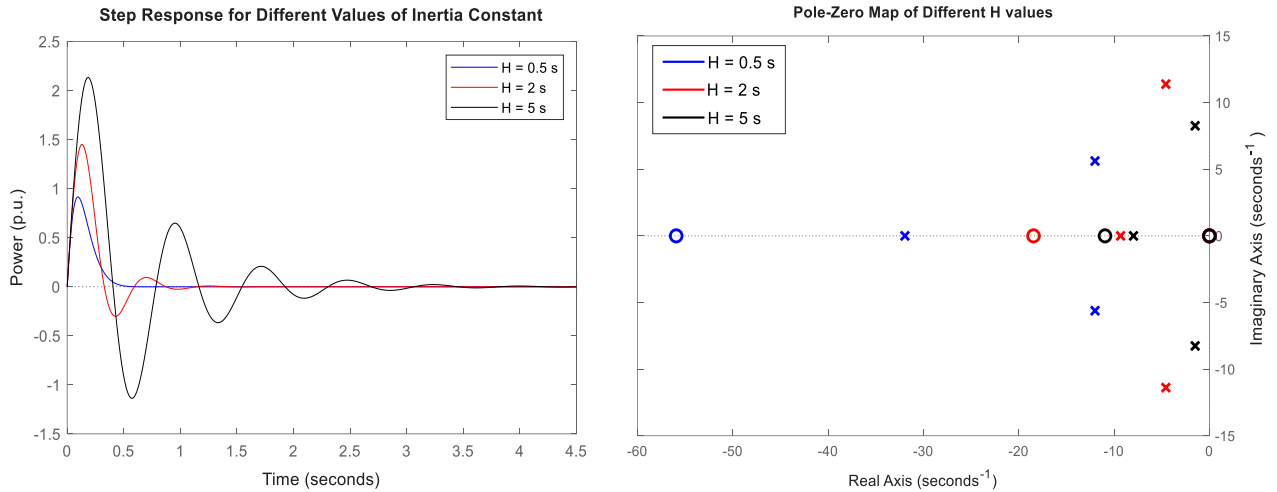


Figure 4.1, the effect of H variation on a step response and on poles positioning and the characteristics of the system response

The influence of the variation of the damping term D_p on the system response is shown in Figure 4.2. Three values are tested: $D_p = 20$, $D_p = 60$, and $D_p = 100$, while $H = 0.5$ s and $T_{lpf} = 0.168$ s. Increasing D_p resulted in the following conclusion:

- From $D_p = 20$ to $D_p = 60$, the complex pairs moved significantly closer to the real axis, while maintaining almost the same real part. Therefore, it results in a higher damping ratio and lower overshoot. reflects a faster response expectation of the system.
- From $D_p = 60$ to $D_p = 100$, the poles moved closer to the imaginary axis, while maintaining almost the same imaginary part. Therefore, the damping ratio decreased which indicates that increasing damping beyond a certain value will cause more oscillations and instability.

- In the three cases, the real poles and the zeroes move away from the imaginary axis, but with different effect on the final system response. $D_p = 100$ has a real pole so far from the complex one so its effect decays quickly and can be neglected. For $D_p = 60$ the real pole is almost 5 times more than the complex pairs so it will have a minor effect, especially that there is a zero close to it. $D_p = 20$ has the real pole almost on the same plane as the complex, but closer to the zero, this results in a unpredictable response, but most probably a low damped system since the complex pairs are much further from the zero.

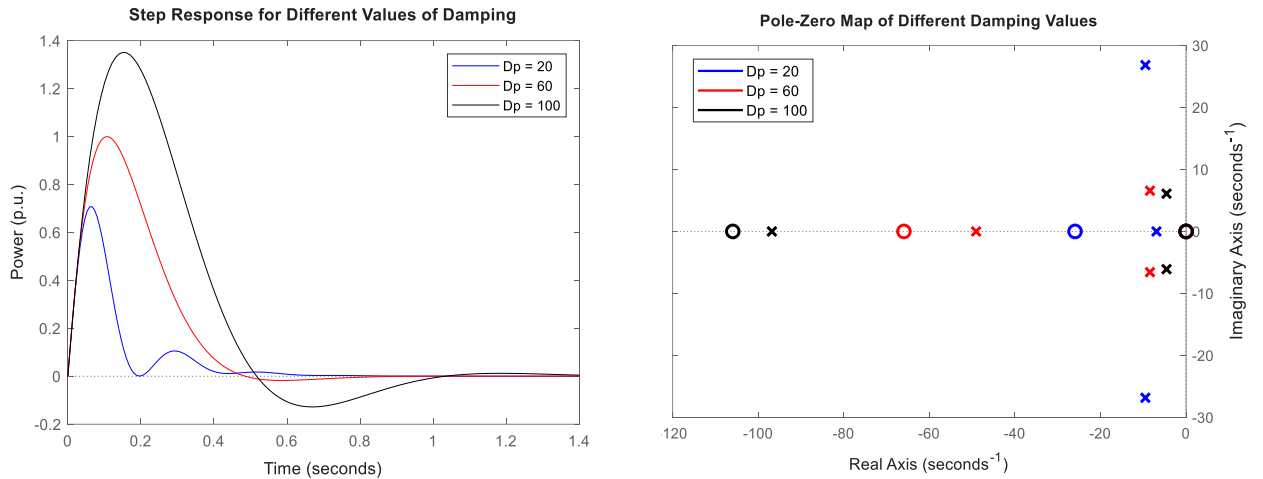


Figure 4.2, the effect of D_p variation on a step response and on poles positioning and the characteristics of the system response.

Finally, time constant of the LPF is changed between three values: 0.1s, 0.5 s, and 1s, as shown in Figure 4.3. H and D_p were maintained constant at 0.5 s and 50, respectively. Increasing T_{lpf} resulted in the following:

- Real poles move closer to the imaginary axis and become the dominant one instead of the complex pairs. Therefore, the response is well damped, but it will be slower. On the other hand, lower time constant will be faster but less damped. So it will be a matter of tradeoff among the parameters.

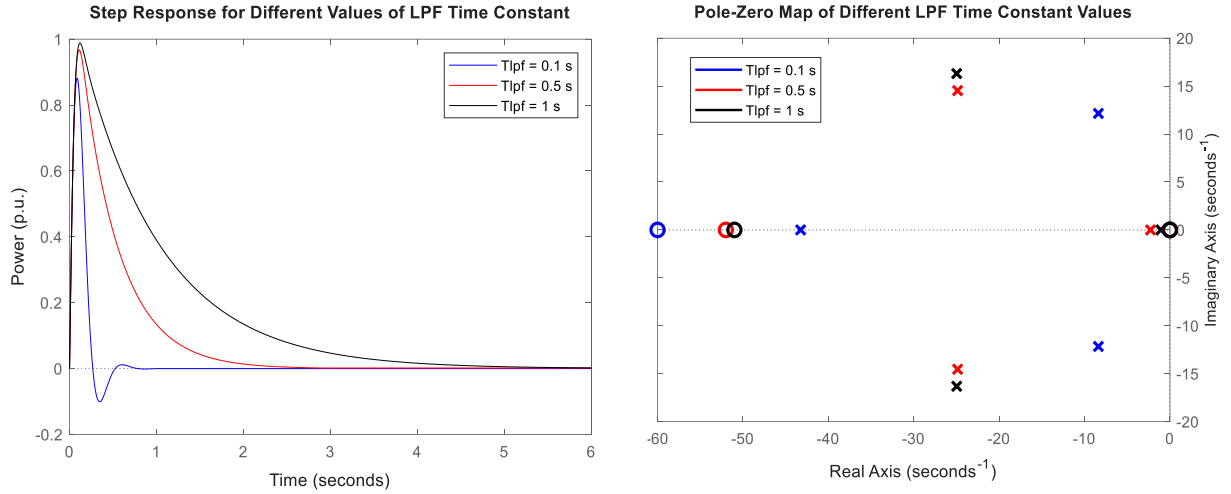


Figure 4.3, the effect of T_{lpf} variation on a step response and on poles positioning and the characteristics of the system response.

It is not clear for certain parameters how changing their values will affect the final response of the system. Increasing the damping blindly can cause instability, while for the LPF time constant, there is a tradeoff between faster response and better damping. For that reason, a code is performed on MATLAB to optimize those 3 parameters to get the best possible response in terms of damping, overshoot, and settle time while maintaining equivalent inertia of 10 s.

The utilized equations for the calculation of damping ratio, overshoot and settle time are presented below. In addition to the constraint equation that forces the equivalent inertia to be equal to 10 s.

$$\text{Damping ratio, } \zeta = \frac{-R(s)}{\sqrt{(R(s))^2 + (Im(s))^2}} \cdot 100 > 15\%$$

$$\text{Overshoot, } OS = \frac{-\zeta \cdot \pi}{\sqrt{1 - \zeta^2}} \cdot 100 < 5\%$$

$$\text{settle time, } T_s = -\frac{4.16}{R(s)} < 1 \text{ s}$$

$$T_a = 2H + D_p \cdot T_{LPF} = 10 \text{ s}$$

The equation used for the settle time is for the criteria of 2%. The 2% settling time criteria is the interval required for a system's transient response to enter and remain

within $\pm 2\%$ of its final steady-state value, effectively indicating that oscillations have decayed [28]. The mentioned equation of settling time assumes an underdamped second-order response or a higher-order system that can be well approximated by dominant pole dynamics [29]. The final transfer function is a higher order with a pole pair dominating the response of the system, as shown in Figures 4.1, 4.2, and 4.3. Therefore, the system can be approximated as a second order and this formulation is valid. That said, some combinations of the three parameters result in all the three poles being close to each other. Thus, if a combination of the parameters resulted in very close settling time, both will be tested to avoid this approximation and to ensure the right selection of the parameters.

The obtained optimized parameters from MATLAB were as follows:

$$H = 0.8 \text{ s} \quad D_p = 50 \quad T_{lpf} = 0.168 \text{ s}$$

A comparison between a ramp response on MATLAB and power factory is applied and shown in Figure 4.4 after inserting the output parameters of the optimization. Both have the same response with minor error, both have almost the settle time with an error of 0.01s. Table 4.1 presents the final utilized values of the VSM parameters

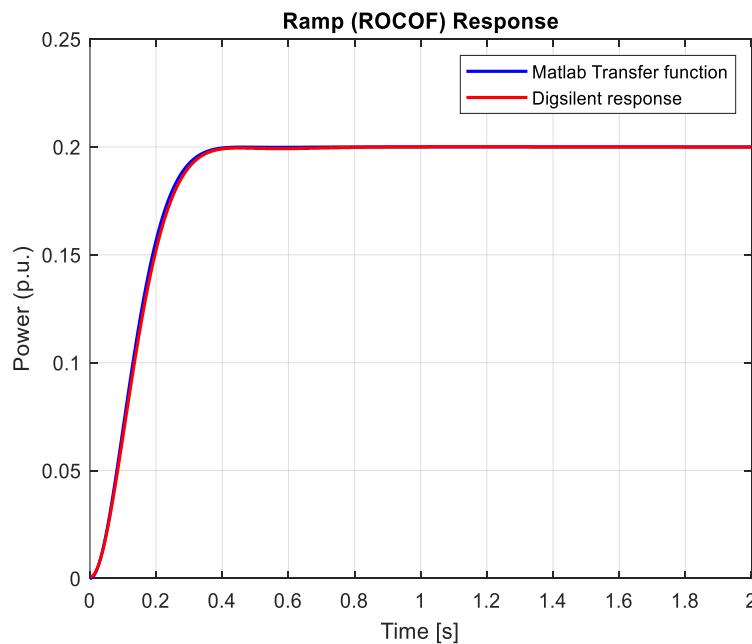


Figure 4.4, comparison between simplified transfer function on MATLAB and powerfactory model for a ramp RoCoF of -1 Hz/s

Table 4-1, Parameters of the VSM and their values.

Variable	Unit	Value
f_{nom}	Hz	50
f_{set}	p.u.	1
H	s	0.8
D_p	p.u.	50
T_{lpf}	s	0.168

4.2. Case Study A: A Simplified System Validation

To evaluate the proposed control logic, the system is subjected to a sequence of events designed to force operation near the inverter thermal limits. This scenario specifically targets two critical performance factors:

1. **Headroom Constraints:** Verifying the inertial response when the BESS is already dispatched at high active power levels.
2. **Adaptive Weighting:** Assessing how the controller assigns asymmetric active power setpoints when an inverter operates below 0.7 p.u to maintain the same SOC. Subsequently, as one inverter reaches 0.7 p.u., the test verifies the stable transition to symmetric load sharing (Linear Convergence).

For this case study, both battery units are initialized with identical SOC levels to isolate the control dynamics from SOC disparity effects. The system begins in an unequal dispatch state to test initial convergence:

- Inverter 1: 25 MW
- Inverter 2: 50 MW

- Total Power: 75 MW (0.417 p.u.)

The simulation timeline, illustrated in Figure 4.5, proceeds as follows:

- $t = 70$ s (Loading Ramp): An external power reference command increases the total output from 75 MW (0.417 p.u.) to 180 MW (1.0 p.u.). This pushes the inverters to their rated capacity, saturating the headroom.
- $t = 120$ s (Deloading Ramp): The power reference is decreased to 135 MW (0.75 p.u.). This establishes a high-load base point (75% loading) just prior to the frequency disturbance.
- $t = 150$ s (Inertial Stress Event): A RoCoF event of -1.0 Hz/s is applied for 5 seconds. This causes a sudden demand for inertial power injection while the BESS is already operating at high power, serving as the primary comparative test between the proposed and standard approaches.
- $t = 170$ s (Recovery): A positive RoCoF event of $+1.0$ Hz/s is applied to restore the grid frequency to 50 Hz and conclude the dynamic test.

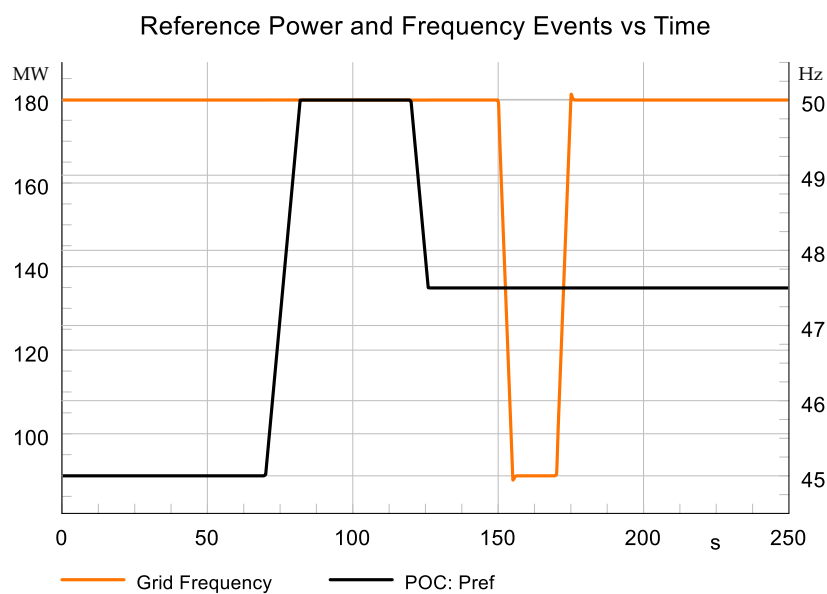


Figure 4.5, Applied events to the external power reference and grid frequency

For the next part, each interval will be analyzed separately to determine the behavior and the performance of the PPC. First interval will be before the occurrence of any event to check the effect of SOC on weight distribution. Second one is during the ramp increase and decrease of the external power reference to check the convergence of the weights to an average value. Third interval is during the RoCoF event to check the inertia provision by the inverters. Moreover, A comparison between three approaches is presented. Those three approaches are: thesis proposal, nominal Energy-based weighting, and SOC-based weighting.

Presented in Figure 4.6 the first interval which is before the occurrence of any events. It depicts the essential parameters for evaluating the efficiency of the proposed approach as a response to the applied case study. As shown in Figure 4.6 (c), the weights are calculated based on energy availability in the batteries. Thus, battery 2, with higher capacity, dispatches more active power. Inverter 2 injects twice the power of inverter 1 as shown in Figure 4.6 (a). Both inverters are dispatching more than the actual requested power (75MW) to account for the losses. Therefore, the measured power at the POC is the same as the reference power requested, as shown in Figure 4.6 (b). Moreover, because of the weight dispatching, the reduction of SOC of both batteries is the same as illustrated in Figure 4.6 (d). As can be noted, all the approaches have the same performance because proposed approach and SOC-based approach are dispatching based on the SOC in this interval. Regarding Energy-based approach, it performs the same because of the same SOC initialization. If the SOC initialization was different, this approach will result in different weights compared to the other two approaches, as illustrated in Figure 4.7 (a). Battery 2 is initialized from 50 % and battery 1 from 40 %. For the nominal Energy approach, battery 1 SOC reduction is faster than battery 2. Additionally, it is faster than that of the other two approaches.

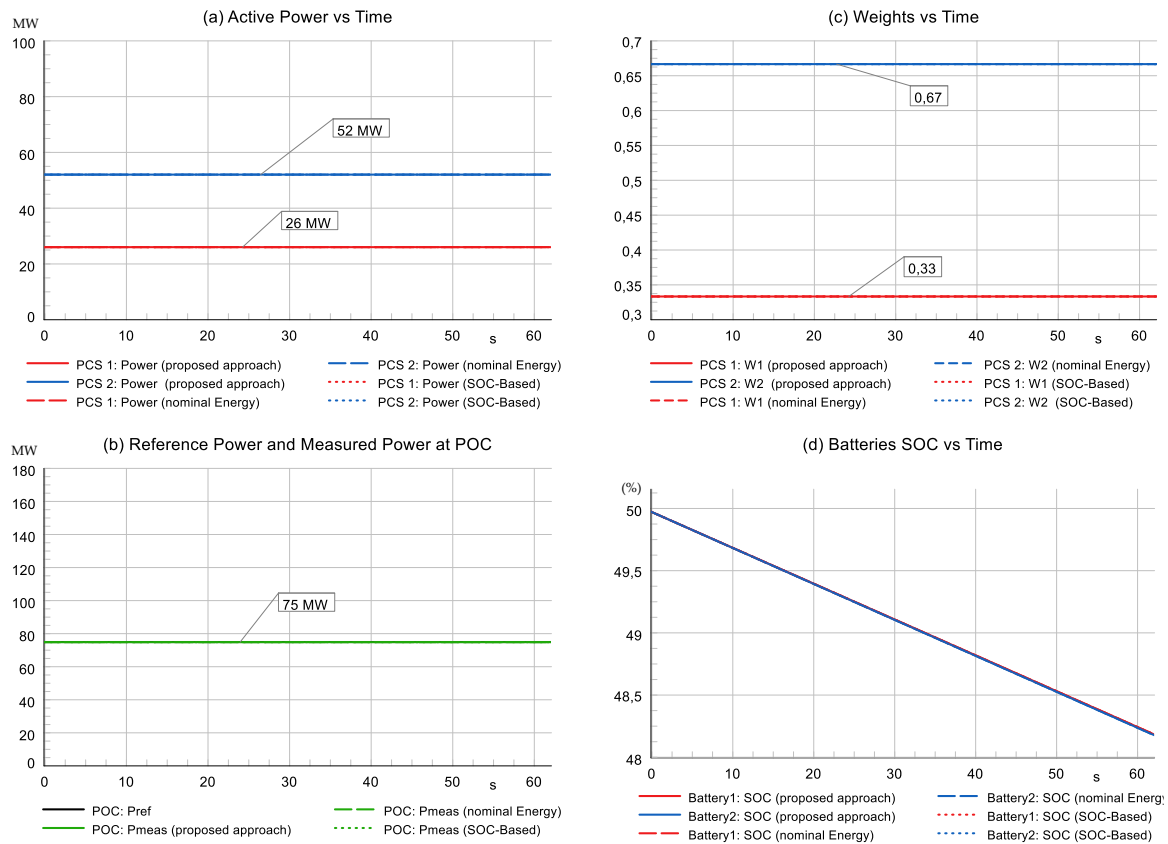


Figure 4.6, Dynamic response of metrices (a) inverter power (b) POC reference power and measured (c) weights (d) SOC before applying any events.

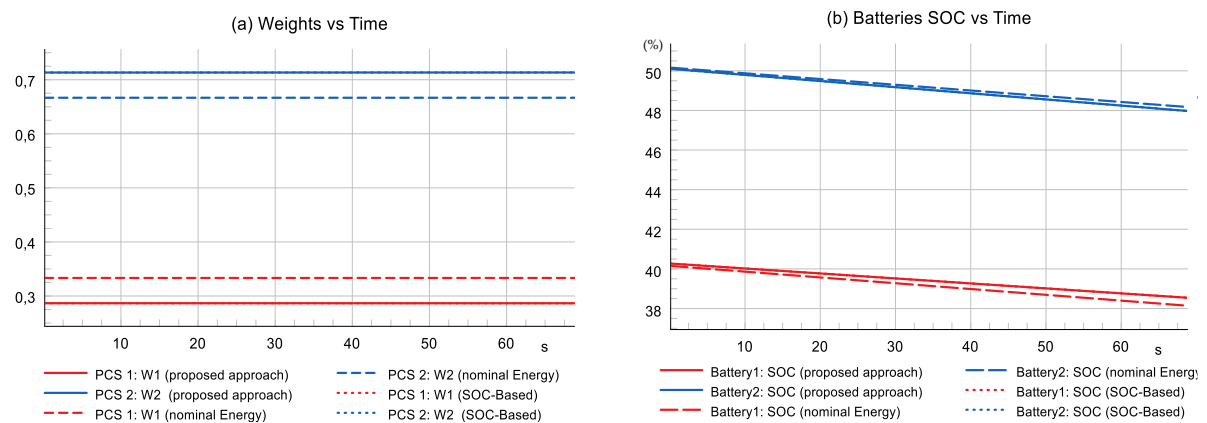


Figure 4.7, Weights differences on different SOC initialization before the occurrence of events

Moving to the next interval, a ramp increase (at 70s) and decrease (at 120s) of the external power reference are applied. The profile of the delivered power at the POC compared to the reference one is the same among all three approaches during the ramp up and ramp down, as depicted in Figure 4.8 (b). It can be noted the effect of the Feed Forward which makes the measured power follows, with less delay, the reference one. As shown in Figure 4.8 (a), the power response of the inverters for SOC-based and nominal Energy-based approaches are the same. In those approaches, once inverter 2 saturated, dispatching rate of inverter 1 increased because of the Re-dispatching block in the PPC. The rest of the power that inverter 2 is supposed to inject is redispached to be injected by inverter 1. On the other hand, the proposed approach performs differently; inverter 2 starts to decrease its rate of power generation at 63 MW (0.7 p.u.), while the injection rate of the same inverter is faster for the other approaches. On the other hand, inverter 1 dispatching rate starts to increase at 63 MW in the proposed approach and becomes faster in comparison to its dispatching rate of the other approaches. This happens since the weights start to converge towards an average value in the proposed approach while maintaining almost the same value in the other two approaches, as shown in Figure 4.8 (c). At approximately 79 s, where the power reaches 72 MW (0.8 p.u.), the weights reach the same value 0.5 and both inverters start to dispatch at the same rate. Meanwhile, for all the approaches, the SOC of the batteries starts to deviate and battery 1 is reduced faster because the injection of equal amount of power 90 MW (1 p.u.), as shown in Figure 4.8 (d). It should be mentioned that the nominal capacities of battery 1 and battery 2 are 25 MWh and 50 MWh, respectively. Therefore, the SOC's reduce fast during a small period. The reason for choosing those values is just for running a small simulation time while still being able to see the effect of the approaches and the visibility of SOC's deviation. Furthermore, the SOC's profile of the proposed approach is different from that of the other two approaches at the beginning of the convergence towards an average weight. Battery 1 is reduced faster

while battery 2 is slower since the dispatching rate, the weights, is the same. During the convergence, the SOC of all the approaches are reduced at the same rate.

During the ramp down, inverter 2 remains injecting 90 MW while inverter 1 injects the rest required to follow the reference power, for SOC-based and nominal Energy-based approaches. On contrary, the proposed approach forces inverter 2 to decrease its dispatching with inverter 1 until 72 MW to maintain a headroom of 0.2 p.u. for inertial support in case of a RoCoF event of 1 Hz/s. For the proposed approach, it can be noticed that the weights are not the same nor are they based on SOC because they are function of both SOC and dispatched power. Additionally, it can be noted that SOC reduction rate decreased in all approaches. Furthermore, the SOC reduction rate is slower in the other two approaches compared to that of the proposed approach. Because the proposed approach gives more priority to inertia provision instead of SOC calibration.

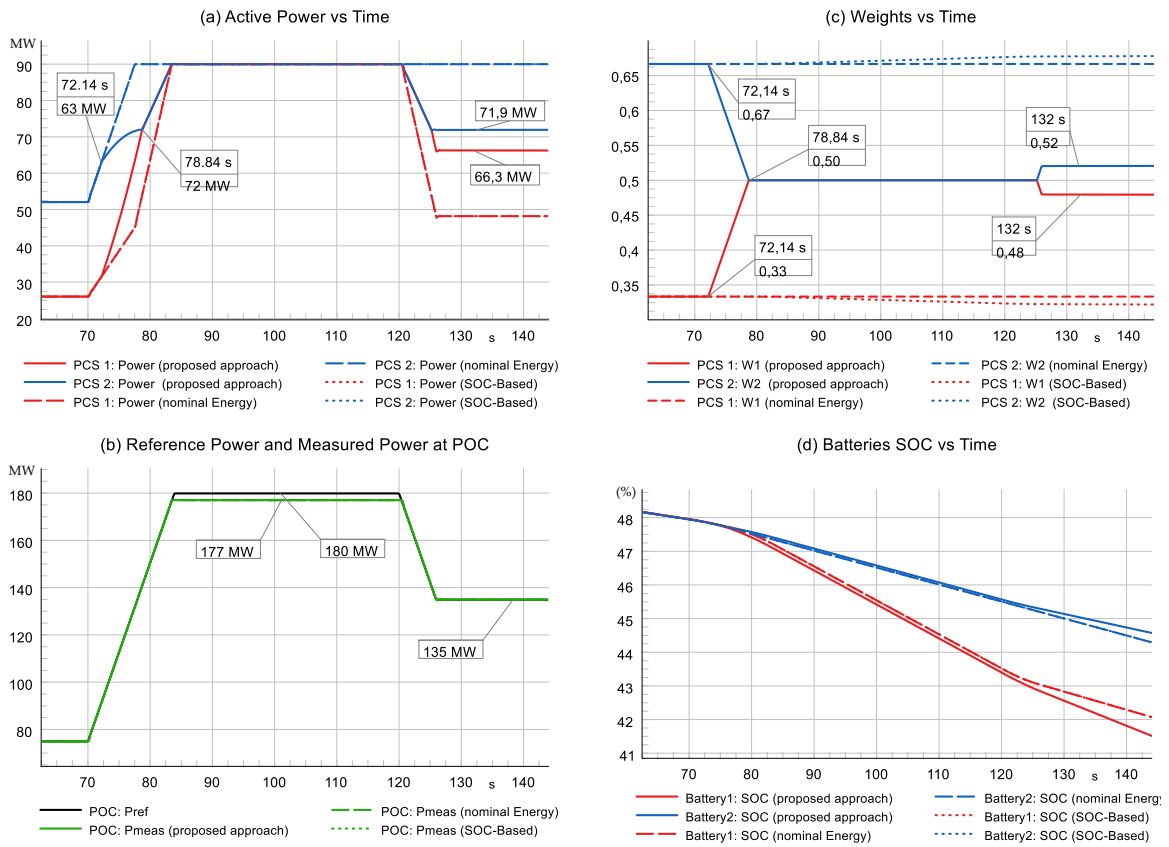


Figure 4.8, Dynamic response of metrics (a) inverter power (b) POC reference power and measured (c) weights (d) SOC during ramp changing the external reference power.

Figure 4.9 illustrates the last interval where RoCoF events take place from as represented in Figure 4.9 (d). First, a RoCoF event of -1 Hz/s takes place between 150 s and 155 s. It should be noted that the droop is deactivated since the main aim is to check the inertia provision of the inverters. As depicted in Figure 4.9 (b), inertia provision by the proposed approach is around 0.2 p.u (36 MW) so the measured power at the POC reached around 171 MW. Additionally, this inertia provision is double than that of the other 2 approaches. This is since inverter 2 saturated for the SOC-based and nominal Energy-based approaches, as shown in Figure 4.9 (a). On contrary in the proposed approach, inverter injected the required inertia since it had a headroom of 0.2 p.u. Furthermore, Inertia support by inverter 1 exists in all three approaches, as shown in Figure 4.9 (a). The power injected by inverter 1 is 0.2 p.u. (18 MW) since the inertia of the VSM is designed to provide 0.2 p.u. for a RoCoF event of 1 Hz/s . It can be seen that the weights are almost constant even in the proposed approach, as shown in Figure 4.9 (c). This is because of the low PI parameters, and this is the advantage of the Feed Forward. Otherwise, if the PI parameters were higher, the regulator will try to oppose the change in power. Thus, the measured power at the POC will not reach a steady state value, but it will be decreasing and will get below the reference power before matching it.

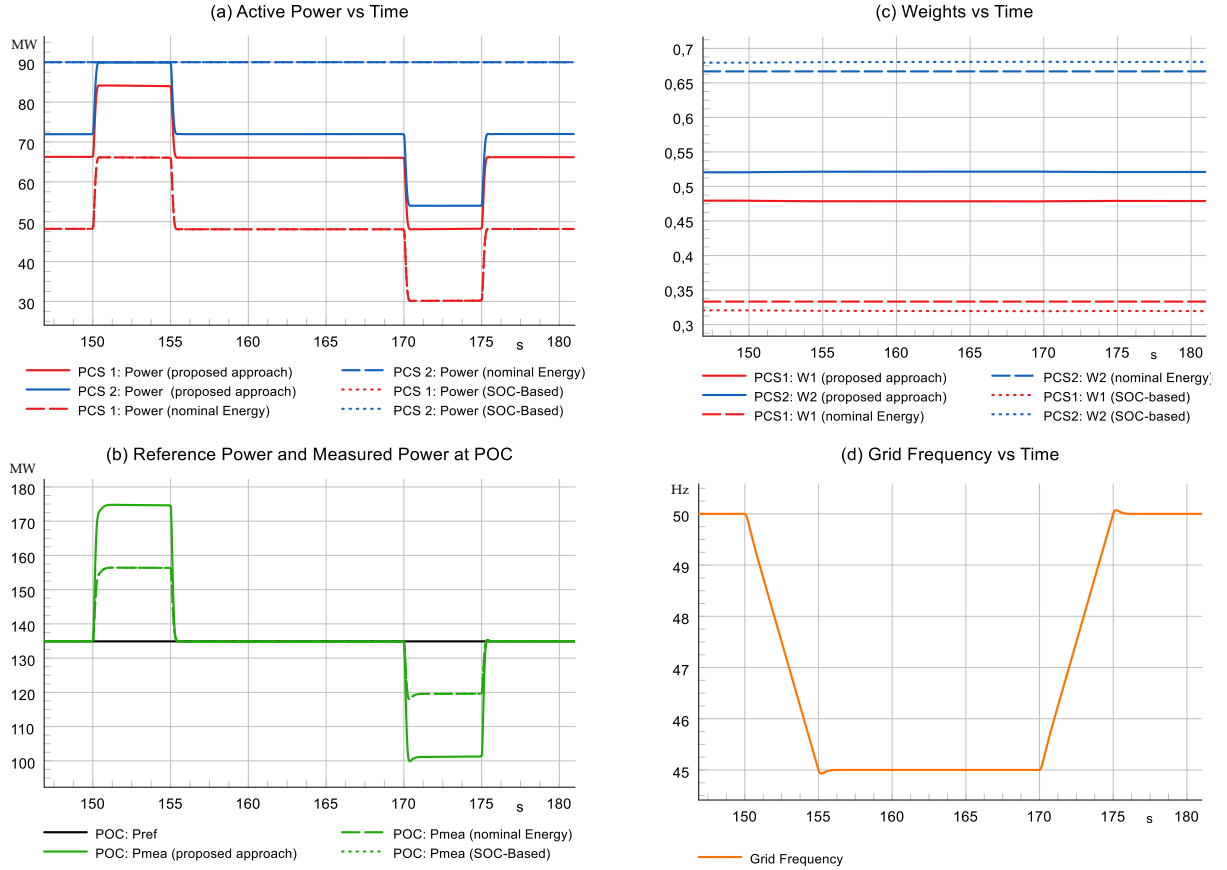


Figure 4.9, Dynamic response of metrics (a) inverter power (b) POC reference power and measured (c) weights (d) SOC during RoCoF event of 1 Hz/s

4.3. Case Study B: Modified IEEE 9-Bus System Integration

The validation of the proposed control strategy is conducted on a modified version of the standard IEEE 9-Bus Test System [30]. The standard topology, widely used in power system stability analysis, consists of three synchronous generators and three aggregated loads interconnected via a 230 kV transmission network.

To investigate the performance of the proposed Battery Energy Storage System (BESS) under future low-inertia grid scenarios, three specific topological modifications were applied to the standard benchmark. The single-line diagram of the modified system is presented in Figure 4.10.

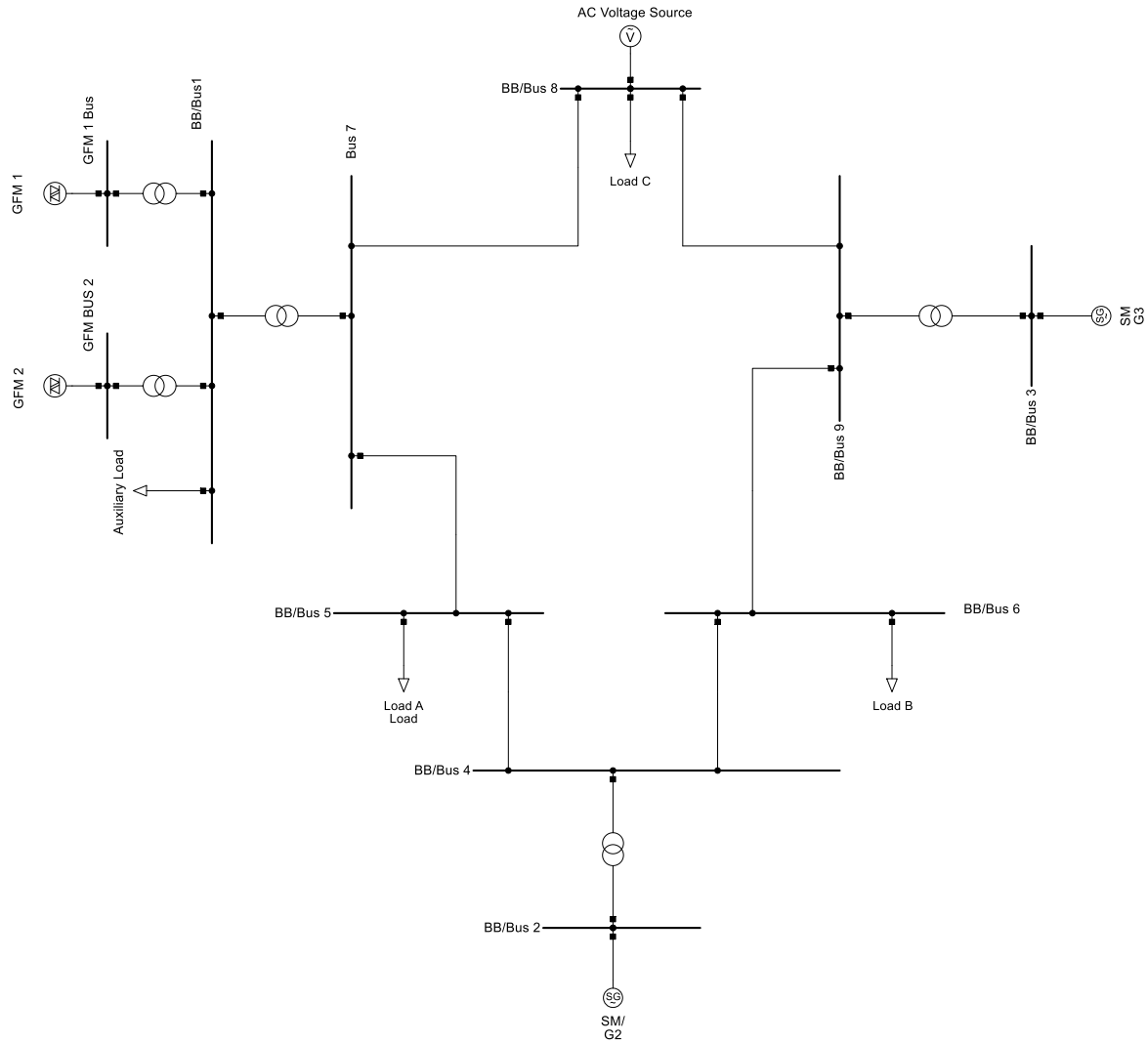


Figure 4.10, Modified IEEE 9-Bus with the integration of the designed BESS.

- **Integration of BESS (System Under Test)**

The conventional synchronous generator (G1) located at Bus 1 was replaced by the proposed BESS model, connected at Bus 1. This location was selected to simulate a scenario where a centralized fossil-fuel power plant is deactivated

and replaced by a utility-scale battery storage facility. The BESS is modeled as two parallel Voltage-Sourced Inverters (VSIs) sharing a common DC link and POC. The total installed capacity of the BESS is 200 MVA, controlled via the proposed VSM strategy with the coordinated dispatch logic described in Chapter 3.

- **Low-Inertia Scenario (Generators G2 & G3)**

To replicate a "weak" or "low-inertia" grid environment characteristic of high renewable penetration, the inertia constants (H) of the remaining synchronous generators (G2 at Bus 2 and G3 at Bus 3) were significantly reduced from their standard values. This reduction lowers the total system kinetic energy, thereby increasing the RoCoF during load disturbances. This modification is essential to stress-test the inertial response of the BESS.

- **Controllable Grid Emulator (Bus 8)**

An ideal AC Voltage Source was integrated at Bus 8 to function as a Controllable Grid Emulator. Unlike a passive infinite bus, this element serves a dual purpose in the simulation:

1. **Decoupling Dynamics:** During power dispatch tests, it maintains a fixed 50 Hz frequency, isolating the BESS active power dynamics from grid frequency feedback loops.
2. **Deterministic Disturbances:** For inertia validation, the source is programmed to execute precise frequency ramps (e.g., Hz/s), allowing for the characterization of the BESS response to specific RoCoF values independent of load stochasticity.

The electrical parameters of the active generation units in the modified system are summarized in Table 4.2.

Table 4-2, Modified Synchronous Generator and BESS Parameters.

Unit	Bus ID	Rated Power (S_{nom}) [200 MVA]	Nominal Voltage [kV]	Inertia Constant (rated to P_{gn}) [s]
BESS	1	200	20	5 (Virtual)
Generator 2	2	120	16.5	3
Generator 3	3	128	13.8	1

To ensure a valid comparison between the two study cases, the IEEE 9-Bus system is subjected to the exact same operational timeline detailed previously in Section 4.2. As illustrated in Figure 4.5, the sequence includes the initial power ramp to saturation (180 MW), the partial deloading to 135 MW, and the final -1.0 Hz/s RoCoF injection at $t = 150$ s. For brevity, the detailed event parameters are not repeated here.

Figure 4.11 illustrates the system response, in the IEEE study case, to an increase and then a decrease in power reference. The total measured power at the POC in all the three approaches follows the reference power, as shown in figure 4.11 (b). The difference between the reference power and the measured one is due to the active power losses between the BESS and the POC. On inverter level, Nominal Energy-based approach and SOC-based approach have the same profile, where both inverters increase at the same rate till inverter 2 reaches the limit then the dispatching rate of inverter 1 increases, as depicted in Figure 4.11 (a). On the other hand, in then proposed approach, inverter 2 decreases have a lower dispatching rate than inverter 1 till they reach 72 MW (0.8 p.u.). After that, they continue at the same rate. During the power decrease, in SOC-based and Nominal Energy-based approaches, inverter 2 continues dispatching at 90 MW (1 p.u) where inverter 1 dispatches the rest. Where, in the proposed control logic, inverter 2 dispatches at lower limit (0.8 p.u) to maintain a headroom of 0.2 p.u while inverter 1 generates the rest.

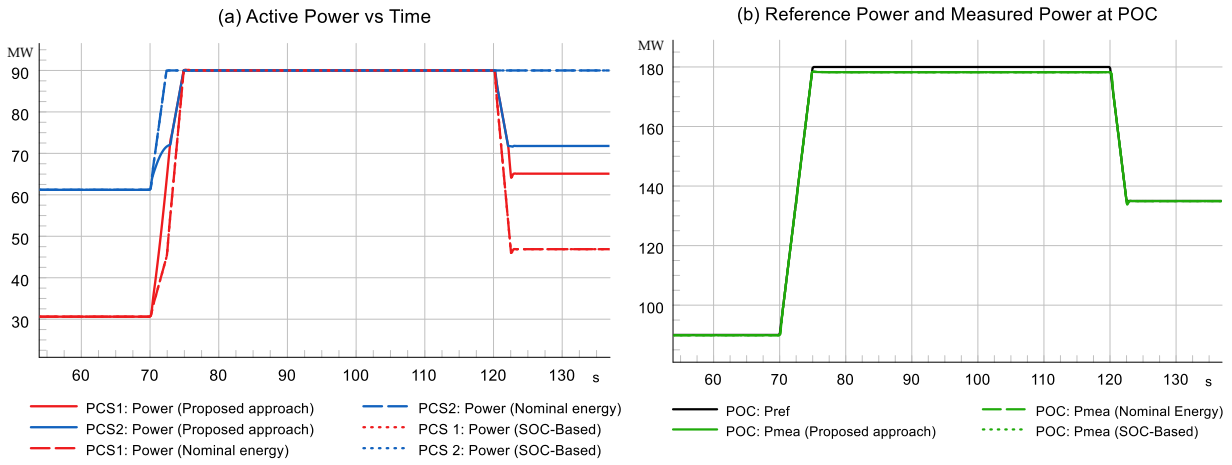


Figure 4.11, BESS response to a change in power reference in IEEE study case

During the RoCoF event of -1 Hz/s, the inertial power provided by the BESS at the POC is shown in Figure 4.12 (b). It can be noticed that the proposed approach injects double the inertia amount than the other 2 approaches. The reason for that is the saturation of the inverter 2, thus it cannot provide its share of the inertia support. It can be proven by checking Figure 4.12 (a) where inverter 1, in the other two approaches, is the only inverter that can provide inertia. On the other hand, in the proposed approach, both inverters injected the same amount of inertia because inverter 2 maintained a headroom of 0.2 p.u.

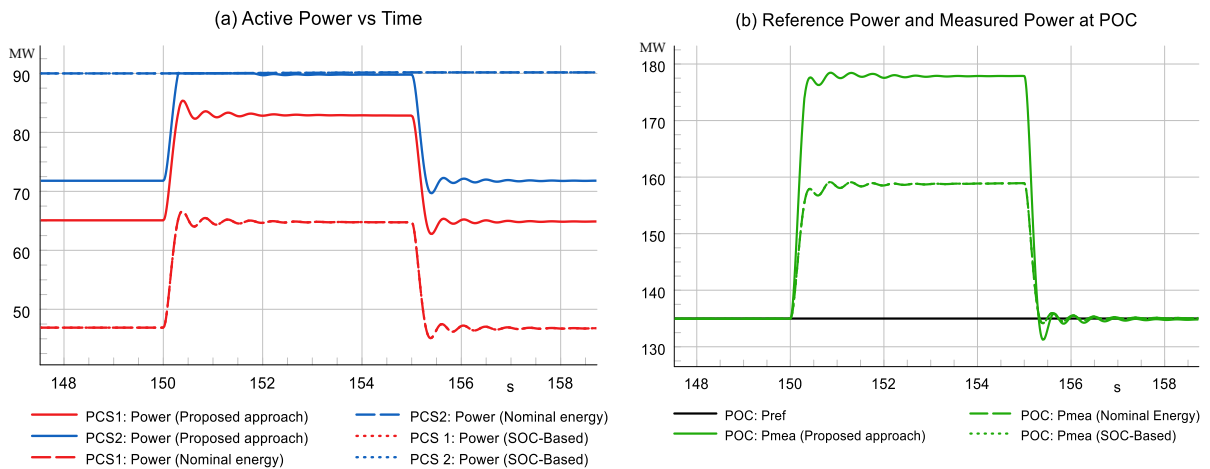


Figure 4.12, BESS response to a RoCoF of -1 Hz/s in IEEE study case

It is observed that the inertial response in the IEEE 9-Bus system Figure 4.12 exhibits slightly higher oscillatory behavior compared to the simplified single-machine case. This is an expected consequence of the network topology. Unlike the simplified setup, the modified IEEE 9-Bus model introduces physical transmission line impedances and transformer reactances between the BESS and the Grid Emulator.

These physical impedances interact with the VSM's virtual impedance and the power calculation filter delays, altering the effective open-loop transfer function of the system. While the controller successfully maintains stability, a refined tuning of the active power loop damping (D_p) or the virtual impedance (R_v, X_v) would be required to perfectly match the smooth profile of the simplified case. However, for the purpose of this study, the current tuning is sufficient to demonstrate the headroom-limiting logic.

Simulation results, from both the simplified single-machine model and the modified IEEE 9-Bus network, demonstrate the robustness and efficacy of the proposed control strategy. The analysis confirms that standard dispatch methods, whether SOC-based or Nominal Energy-based, are susceptible to 'Headroom Blindness'. Therefore, inverter reaches saturation during high-power dispatch and leads to inadequate support during critical frequency events. The proposed Coordinated Power Plant Controller addresses this issue by dynamically reserving power margins according to each unit's capacity. Crucially, the IEEE 9-Bus results validate that this logic holds true even in complex network topologies with coupled impedance interactions. By prioritizing dynamic security over simple proportional dispatch, the proposed approach ensures that the BESS remains a reliable source of inertial support even when operating near its thermal limits.

5 Conclusion and Future Development

5.1. Conclusion

As power systems transition away from synchronous generation toward high penetrations of inverter-based renewable energy resources (IBRs), the degradation of system inertia has emerged as a critical stability concern. Although BESS employing GFM control strategies, particularly VSM, offer a promising approach to restoring inertial capability, standard control implementations frequently neglect the headroom constraint for inertial support during frequency events. This thesis investigates the issue of "Headroom Blindness" in conventional GFM strategies, wherein the pursuit of optimal inertial support may unintentionally cause inverter saturation or tripping under high-load conditions. This research primary contribution is the development and validation of a coordinated inertia supervision logic integrated within a PPC. This strategy focuses on dynamically estimating the available active power headroom of parallel inverter unit. Therefore, adjusting the facility's inertial response to ensure operation within the SOA.

The proposed control strategy was validated through a two-stage simulation approach, progressing from a simplified single-machine-infinite-bus model to a realistic modified IEEE 9-Bus transmission network. The key findings of this research are summarized as follows:

1. **Headroom-Aware Stability:** The core hypothesis was confirmed: standard VSM implementations fail when the BESS is dispatched near its rated capacity (e.g., 90% loading). In comparative simulations, the standard control attempted to inject inertial power exceeding the inverter's current limits during a -1.0 Hz/s RoCoF event, leading to saturation and loss of grid support. Conversely, the proposed supervision logic successfully clamped the inertial response to the

available headroom (e.g., limiting output to 1.0 p.u.), thereby preventing overcurrent trips while delivering the maximum safe level of support.

2. **Effective Coordination of Parallel Units:** The introduction of the PPC successfully decoupled the dispatch dynamics from the inertial response. In scenarios with unequal initial loading, the logic coordinated the ramp rates of parallel inverters, preventing the premature saturation of highly loaded units. This ensures that the aggregate capacity of the BESS plant is utilized efficiently, rather than being bottlenecked by the weakest or most loaded unit.
3. **Robustness in Realistic Grids:** The transition to the modified IEEE 9-Bus system demonstrated that the control strategy remains robust in the presence of complex network impedances. Although the coupling between transmission lines and the virtual impedance introduced slight oscillatory modes in the inertial response, the fundamental protection mechanism remained effective. The system successfully survived severe frequency disturbances that caused the benchmark controllers to fail.

In conclusion, this thesis demonstrates that while BESS capability to provide synthetic inertia is valuable, it must be subordinate to the physical constraints of the hardware. The proposed supervision logic shifts the paradigm from "Emulate Synchronous Machines at all costs" to "Emulate Synchronous Machines safely," ensuring that BESS assets remain online and supportive during the critical moments of a grid fault.

5.2. Future Development

Although the fundamental principles of inertia supervision logic have been validated in this thesis, further research is recommended to improve the precision and applicability of the proposed solution:

- **Integrated Reactive Power and Voltage Control:** The current PPC implementation focuses exclusively on active power dispatch and inertial supervision. Future iterations should expand the control architecture to include a centralized Reactive Power (Q) or Voltage (V) controller. This would allow the PPC to manage the BESS's full P-Q capability curve, optimizing reactive power sharing among parallel units. Furthermore, this extension would necessitate the development of a dynamic priority logic (e.g., prioritizing support during deep voltage sags vs. support during frequency events) to resolve conflicts when the total apparent power limit (S_{max}) is reached.
- **Communication Latency Analysis:** The current simulation assumes ideal, instantaneous communication between the central PPC and the local inverter controllers. In a real-world utility-scale plant, communication delays (latency) can range from 10 ms to 100 ms. Future work should investigate the impact of these delays on the coordination logic, particularly during fast transient events, to determine the maximum tolerable latency for stable operation.
- **Optimization of Virtual Impedance Tuning:** The IEEE 9-Bus results indicated that network coupling can introduce oscillations in the inertial response. Developing an adaptive or auto-tuning mechanism for the VSM's virtual impedance and damping coefficients could be the proper strategy for that challenge. This would allow the BESS to automatically adjust its damping characteristics based on the estimated grid SCR, providing a smoother response across different grid topologies.

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