DISSERTATION

ANALYSIS OF FREQUENCY CONTROL AND GRID STORAGE EFFECTIVENESS FOR A WEST AFRICAN INTERCONNECTED TRANSMISSION SYSTEM

Submitted by

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ABSTRACT

ANALYSIS OF FREQUENCY CONTROL AND GRID STORAGE EFFECTIVENESS FOR A WEST AFRICAN INTERCONNECTED TRANSMISSION SYSTEM

The West Africa Power Pool (WAPP) Interconnected Transmission System (WAPPITS) has faced challenges with frequency control due to limited primary frequency control reserves (PFR). Battery Energy Storage Systems (BESS) have been identified as a possible solution to address frequency control challenges and to support growing levels of variable renewable energy in the WAPPITS.

This dissertation examines existing frequency control challenges in the West African Power Pool Interconnected Transmission System and evaluates the effectiveness of Battery Energy Storage Systems (BESS) as a solution to enhance grid stability and resilience amid growing ambitions to increase variable renewable energy (VRE) penetration.

To carry out this assessment, three studies were conducted - the first study assesses the effectiveness of BESS in providing primary frequency reserves (PFR) using open-loop simulations based on real WAPPITS frequency data. Results from this study suggest that droop-based BESS control strategies can mitigate fast frequency variations. In addition, it demonstrates that integrating BESS alone into the grid will not solve the frequency control challenges in WAPPITS, requiring the need for a revision of frequency control provision, including mandatory participation of traditional power plants in the provision of the service.

The second study investigates primary and secondary frequency control challenges in WAPPITS using surveys from Transmission System Operators, field tests on power plants as well as analysis of events in the grid. Results reveal critical challenges: inadequate PFR reserves, reliance on under-frequency load shedding, and a lack of automatic secondary frequency control via automatic generation control (AGC). The study recommends (1) enforcing mandatory PFR compliance and (2) establishing an ancillary services market to incentivize reserve provision.

The third study uses PSS/E dynamic simulations to assess primary frequency response provision using different mixes of BESS and conventional generation in responding to the maximum N-1 contingency (400MW loss). Simulation results suggest that BESS -only PFR provision outperforms conventional generation-only PFR in fast frequency response across the frequency metrics analyzed. However, a hybrid mix of BESS and conventional reserves achieves adequate performance on all metrics and is more cost effective.

The research demonstrates that BESS can significantly improve frequency stability in WAPPITS, but to successfully achieve this, there is need for technical and regulatory reforms, including:

- Mandatory PFR participation for conventional plants,
- Ancillary services markets to mobilize reserves, and
- Implementation of hybrid PFR provision by BESS and conventional power plants.

This research provides policy makers and technical experts with insights to guide the implementation of frequency control service provision, underscoring the need for institutional and market reforms coupled with technological innovations to solve the existing frequency control challenges in WAPPITS.

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I am also profoundly grateful to my wife, Monsiba Amira, for her unwavering support, encouragement, and understanding. Her support has been the foundation of my strength. To our sons, Jayden, Ethan, and Zane—thank you for cheering me on and reminding me of what truly matters. I would also like to thank my mum and siblings for their support. Finally, I would like to thank my friends and colleagues for their continued support, camaraderie, and encouragement throughout this process.

DEDICATION

To my wife, Monsiba Amira; our sons, Jayden, Ethan, Zane; my mother; and my siblings.

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Chapter 1

Introduction

1.1 Background and Motivation

Maintaining frequency stability is one of the most critical operational requirements in operating a bulk interconnected power system. Frequency control ensures that generation and demand remain balanced in real-time, preventing cascading failures and widespread blackouts after the occurrence of disturbances. In modern power systems, frequency control is implemented through a hierarchical framework including primary frequency response (PFR), typically provided by automatic governor action of synchronous generators, and secondary and tertiary responses delivered through automatic generation control (AGC) and reserve dispatch mechanisms. These frequency control operational practices are well established in advanced power systems such as PJM, CAISO, and the European Network of Transmission System Operators (ENTSO-E), where frequency regulation and ancillary service markets in general are critical in reinforcing operational reliability [1-5].

By contrast, the West Africa Power Pool Interconnected Transmission System (WAPPITS) presents a unique and complex frequency control challenge. Despite decades of investment in transmission infrastructure and interconnection projects across 14 ECOWAS countries, frequency control across WAPPITS remains ineffective. National Transmission System Operators (TSOs), although interconnected, often operate independently based on system-specific operational rules and practices, and frequency reserves, especially primary reserves—are either inadequately maintained or entirely absent. The current limitations to primary frequency control and other essential frequency services are basically due to many power plants signing ‘take-or-pay’ power purchase agreements (PPA’s) without provision for frequency control reserves. Plant owners have no interest or incentive in producing below full capacity to address system reliability needs. The absence of a functional ancillary services market and the lack of regulatory enforcement which would mandate power plants to provide Primary Frequency Response (PFR) has led to significant deficiency in primary control and the absence of automatic generation control in WAPPITS. As a result, under-frequency load shedding (UFLS) is routinely used as a primary means for maintaining frequency stability, rather than last resort for system protection [6 - 8].

The increasing integration of variable renewable energy (VRE) sources such as solar PV and wind is expected to exacerbate the frequency control problem. This is already evident in some WAPPITS TSO areas that have higher VRE penetration and entirely absent primary frequency control reserves.

Unlike conventional synchronous generation, inverter-based renewable generators do not inherently contribute inertia or governor response, making the grid more sensitive to disturbances. WAPP's long-term ambition to raise VRE penetration increases the urgency to shift from current frequency control practices, improve frequency control mechanisms and develop sustainable grid-balancing and control strategies.

Amid these challenges, Battery Energy Storage Systems (BESS) have emerged globally as a promising technology for fast-response frequency regulation. Additionally, there is a growing interest in BESS among development partners and regional stakeholders as an alternative to the existing frequency control problems without considering the operational practical realities of WAPPITS. However, while BESS is often deployed in well-developed, advanced and mature power systems as a complement to already deployed, well-established, robust frequency control provision from conventional power plants, the WAPPITS context is entirely different: BESS must potentially substitute for frequency reserves that do not yet exist. This difference calls for context-specific studies that do not merely assume baseline frequency control mechanisms and capabilities but examine the realities of operations in WAPPITS.

This dissertation assesses frequency control challenges in WAPPITS and analyzes the effectiveness and cost implications of BESS development in WAPPITS. It highlights the unique trade-offs in systems like WAPPITS, where BESS alone may not enhance frequency control cost-effectively unless strategically deployed together with primary frequency control reserves from conventional power plants. The research provides recommendations tailored to WAPPITS, where primary frequency control from conventional power plants is limited and, in some areas, entirely absent, and variable renewable energy ambitions are high, helping to guide realistic and cost-effective pathways for implementing frequency control.

1.2 Description of Study Plan

This dissertation is organized around three major studies, each, building upon the findings of the previous one and contributes to better understanding and addressing the frequency control problem in WAPPITS.

1.2.1 Study 1 - BESS Primary Frequency Control Strategies for West African Power Pool

This study assesses the effectiveness of various BESS control strategies for primary frequency control, including dynamic system behavior and state-of-charge (SOC) restoration under actual WAPPITS grid conditions. The study is conducted based on a first-order numerical analysis using simplified open-loop models and historic WAPPITS frequency data.

The study demonstrates that, while BESS can technically provide fast frequency response, deploying BESS alone may not represent the most technically and economically viable solution under current system conditions with chaotic frequency fluctuations and weak regulatory arrangements in enforcing frequency control. It proposes dynamic and hybrid control strategies to ensure service continuity and effective frequency response.

1.2.2 Study 2 - Analysis of primary and secondary frequency control challenges in an African transmission system

This study diagnoses the unique frequency control implementation challenges specific to the WAPP grid, which differs significantly from how they are implemented in well-established and developed grids. The study is conducted using questionnaires to assess the current state of implementation of frequency control in each of the TSOs and the use of frequency control tests and event-based frequency response analysis using data primarily sourced from Phasor Measurement Units (PMUs). This mixed approach provides a techno-operational view of WAPPITS' current challenges.

The study identifies operational gaps in frequency control, highlights inconsistencies in implementation across TSOs, and frames the problem as a socio-technical challenge.

1.2.3 Study 3 - Analysis of Grid Scale Storage Effectiveness for a West African Interconnected Transmission System

This study simulates and evaluates the effectiveness and cost trade-offs of different contributions of BESS and conventional power plants providing primary frequency response (PFR) across the WAPPITS system using PSS®E static and dynamic models of the WAPPITS.

This study provides a framework for decision making, comparing various BESS deployment strategies and highlighting scenarios under which BESS investments can be strategically deployed paired with conventional power plants to provide cost-effective frequency control.

1.3 Current Frequency Control Practices in Bulk Interconnected Power Systems

Frequency response is a measure of a power system's reaction to generation-demand imbalance either through a change in generation, change in demand or a system event [2][9][10]. To maintain a reliable bulk power system, it is important that interconnected system frequency is maintained within pre-defined, safe, and acceptable operating limits. This implies that, the power system should at all times be operated in such a way that it can be able to respond rapidly to generation-loss events to prevent frequency decline below pre-defined and acceptable operating limits and further prevent automatic triggering of emergency load shedding and cascading blackout [10] .

Frequency control concepts and the main types of frequency control in power systems are identified and explained in this section.

1.3.1 Overview of frequency control concepts

The frequency of an interconnected system is directly related to the instantaneous balance between generation and load [11-12]. Operating a reliable interconnected power system requires maintaining system frequency within acceptable pre-defined limits or ranges recommended in the Network Code. In West Africa, this means that system frequency is required to be maintained at or very close to 50 Hz, with an acceptable quasi – steady state frequency deviation of 200 mHz (49.8 – 50.2 Hz).

This requires that there are always adequate resources available to continuously maintain generation – load balance and restore system frequency to nominal values following occurrence of expected, unexpected or unplanned events such as generator trips or a major transmission line outage. The loss of a large generator for example, would result in total load exceeding generation.

This generation-load imbalance leads to a decline in system frequency as shown in figure 1.1. It is important that the grid is always designed to withstand such events. The next sections walk through the frequency control domains shown in the figure.

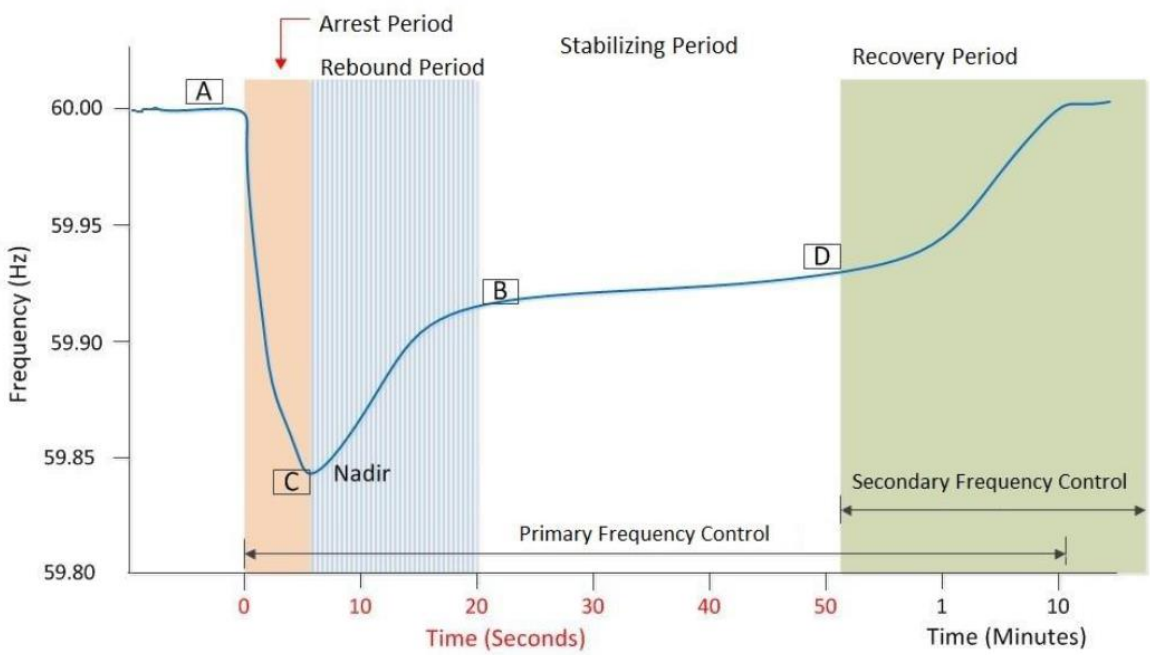


Figure 1.1. Frequency Response Curve

1.3.2 Primary Frequency Control

Primary Frequency Control (PFC) involves an automatic, autonomous and rapid (almost immediate) response of primer governors to frequency deviations. Primary Frequency Control action causes a generator to change its output (either by increasing or decreasing) in response to sudden changes such as generator loss or major transmission line outage. PFC through governor action in an interconnection seeks to arrest, recover and stabilize frequency in response to such sudden deviations or changes. This action takes place usually within 20 seconds or less [2]. When a generator is in PFC mode, a certain amount of its capacity is classified as 'reserve power' and load on the generator is set to allow automatic increase or decrease in power to counter changes in grid frequency [2][4][13][14] .

In the power system, primary frequency response is provided not only by governor action but also by rotational inertia in different resources, including motor loads and synchronous generators, or by fast ramping of inverter-based resources connected to energy storage systems. Primary response systems are typically designed with a mix of different response times based on system conditions such as total generation/load mix, characteristics, and transmission line structure and length [2].

1.3.3 Fast frequency response

Fast Frequency Response (FFR) is "the power injected to (or absorbed from) the grid in response to changes in measured or observed frequency during the arresting phase of a frequency excursion event to improve the frequency nadir or initial rate-of-change of frequency" [15]. As the power system shifts from conventional generation plants to inverter-based generation, inertia of the grid reduces significantly due to reduction of power dispatched from synchronous machines which have large rotating masses [16]. Traditionally, primary frequency control action is deployed to arrest frequency decay following an event [2] [4][13][14] [15]. However, with increasing penetration of inverter-based generation, as the size of a disturbance increases, with decreasing system inertia, the quantity and speed of primary frequency control reserves (required by the grid to arrest the decline of system frequency before it reaches levels that will result in involuntary operation of UFLS relays) also increases [15]. This need has given rise to the concept of FFR. FFR does not replace PFC but complements it. It is like PFC but it acts much faster by providing power during the arresting phase. The objective of FFR is to provide arresting power before the frequency nadir thus contributing to enhancing grid security by improving the dynamics of the power system's response to disturbance [15][16][17]. BESS systems are one type of FFR.

1.3.4 Secondary Frequency Control

Secondary Frequency Control is a centralized task performed by Balancing or Load Frequency Control (LFC) areas to correct generation – load imbalances that result in frequency deviation [2]. Secondary Frequency Control restores both scheduled frequency and primary frequency response. Secondary Control can be done either manually or automated dispatch from a centralized control system. In modern power system, LFC is implemented using Automatic Generation Control (AGC). Power plants that provide Secondary Frequency Control service receive a centralized signal (AGC signal) from the System Operator. Based on a dynamically defined secondary reserve, an AGC signal requires power plants to provide secondary frequency regulation/control as part of the frequency coordination process after disturbances that result in generation- load imbalance [60]. In most implementations, secondary frequency control actions are not activated until $\approx$30 seconds or more following the loss of generation; full activation takes from 5 to 15 minutes (or more) to restore frequency to the nominal value [2] [13], and to restore PFC units, which were stabilizing the frequency prior to SFC compensation, to setpoint values.

1.3.5 Tertiary Frequency Control

Tertiary Frequency Control is also a set of centrally coordinated actions deployed over longer time scale (minutes to ten of minutes) to restore the reserves that were used to provide primary and secondary frequency control [13] [18]. The objective is to put the power system in a position that it can response to subsequent frequency deviations following an event such as a generator loss.

Tertiary Control actions are based on unit commitments. A generator is dispatched downward, usually referred to as Downward Tertiary Reserve to restore its reserve capability whilst another is dispatched upward, usually referred to as Upward Tertiary Reserve to replace the power provided by the first whilst maintaining system frequency [2] [18]

Figure 1.2 below shows the sequential action of primary, secondary and tertiary frequency control following a generator loss event.

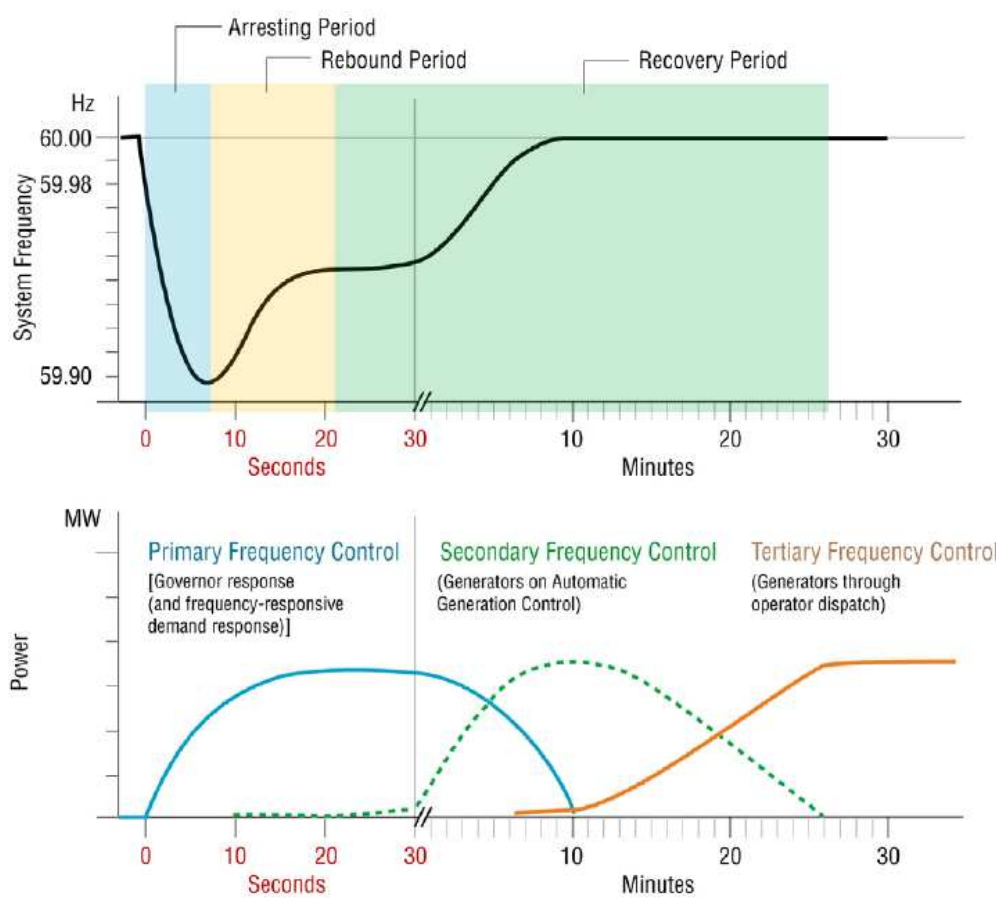


Figure 1.2. Action of Primary, Secondary and Tertiary Controls in a Sequential Order [13]

1.4 Document Summary

The subsequent sections of the dissertation are structured and organized as follows:

- Chapter 2 analyzes BESS primary frequency control strategies in WAPPITS.
- Chapter 3 assesses primary and secondary frequency control challenges in WAPPITS.
- Chapter 4 evaluates grid scale storage effectiveness for a West African Interconnected Transmission System,
- Finally, Chapter 5 summarizes key insights and findings, and presents the overall conclusion of the study.

Chapter 2

BESS Primary frequency control strategies for the West African Power Pool

The content of this chapter was published in MDPI Energies in February 2022 [7].

2.1 Introduction

The integration of renewable energy sources (RES) into the West Africa Power Pool (WAPP) Interconnected Transmission System (WAPPITS) has increased significantly; between 2016 and 2021, about 439 MW of solar PV was installed, representing 1.9% of the total installed generation capacity. The total energy generated from solar PV now represents 0.7% of the energy that is generated in the subregion. The installed capacity of solar PV and wind power is expected to grow to about 40% of the total generation capacity between 2030–2033 in order to fulfill the regional goal of increasing electricity access for the citizens of the Economic Community of West Africa States (ECOWAS) [19]. The WAPPITS' list of regional priority generation projects has RES projects (including hydro) representing 68.9% (10.67 GW) of all expansion projects, of which 29.5% (3.15 GW) involve solar and wind power [19].

The increasing penetration levels of RES will likely create operational challenges for the dynamic behavior of the WAPPITS [19,20]. Notable among the operational challenges is the impact of RES on frequency stability. Since wind and solar RES resources are generally inverter-based, these generators reduce system inertia relative to generation capacity, making the system frequency very susceptible to any loss of generation, transmission line or load [12,21 -24]. The variability and uncertainty of the output of RES generation also results in an increase in the variability and uncertainty of net load in the short term [25]. This requires a greater amount of flexibility and an increase in the need for primary frequency control reserves, which are typically provided by conventional or hydropower generation plants.

The WAPPITS has faced frequency stability challenges due to the lack of the active and reliable participation of conventional power plants in primary frequency control. Currently, the WAPPITS operates as three independent, synchronous blocks and primary frequency control has been identified as one of the main reasons that the WAPPITS cannot synchronize these blocks so as to operate as an interconnected transmission system [11,26-27].

Whilst efforts are being made to address these challenges, it has also been recommended that the WAPPITS deploy Battery Energy Storage Systems (BESS) for frequency regulation, especially with the ongoing effort to increase RES penetration [28]. This is based on the ability of BESS to provide grid services, such as primary frequency control due to the fast dynamic response of these systems, offer generation–demand balance alternatives to grid operators, provide other ancillary services able to stabilize the grid and provide high power capability relative to stored energy capacity [29–31]. Several studies have also indicated that BESS installations are a credible alternative for frequency regulation in maintaining grid stability with a high penetration of RES generation [32–41].

One of the most important studies devoted to analyzing the integration of BESS in the WAPP is the assessment of battery storage applications in the WAPP utilities and countries, which was performed by the World Bank in [28]; however, the study has some limitations. Only the technical performance of the WAPP Power System, with and without BESS, was analyzed. The study primarily assumed the existence of reasonably adequate frequency control reserves and assessed the capability of BESS to stabilize the system in a dynamic/transient domain given by its fast response capabilities. The analysis fell short of evaluating the impact of the possible existing frequency control challenges (based on actual frequency data) on the inherent performance of BESS, its effective application for frequency regulation in the WAPPITS and the possible control strategies to be deployed to ensure BESS services are provided without interruption.

An analysis of the impact of existing frequency behavior on BESS effectiveness (inherently and on the grid) is important, since when comparing BESS and conventional power plants, it must be noted that the operational range and duration of BESS installations are limited by their energy storage (EU Network Codes define BESS as Limited Energy Reservoirs) [42]. In addition, round-trip storage losses when the state of charge (SOC) fluctuates create a fundamental power offset when BESS is used in primary frequency regulation. Hence BESS systems require constant input power that is proportional to the round-trip efficiency multiplied by the power produced/consumed in order to prevent service interruption due to BESS SOC saturation [29].

Research and studies on the application of frequency control and SOC restoration logic to effectively utilize BESS installations for primary frequency control have been conducted using empirical battery models, which were developed using either MATLAB/Simulink or DigSilent and actual frequency measurements from the grid as the input [29,43–47].

These studies primarily used numerical simulations that were based on actual frequency measurements from the transmission system operator (TSO) to size and locate BESS for primary frequency control, both in an interconnected and an isolated system [34,48-56]. The performance and effectiveness of BESS have also been investigated with respect to a range of frequency control and SOC restoration strategies; these analyses have primarily focused on the ability of BESS installations to assure effective frequency control and guarantee service continuity [30,31,34,47-64].

However, the listed studies used frequency measurements from mostly European and Asian countries as the reference data. None of them concentrated on proposing an effective strategy for BESS operation in the WAPPITS, whose critical and unique grid condition could lead to different considerations.

For the purposes of this study, the primary topic of consideration is the application of control strategies for both frequency regulation and SOC restoration. The frequency regulation strategy determines the limits at which the BESS attempts to restore system frequency. The SOC regulation strategy is necessary to avoid BESS saturation at maximum or minimum SOC. Researchers have conducted similar analyses using control strategies such as the frequency and deadband dependent strategy, hybrid SOC and frequency dependent charging strategy, dynamic strategies and the model predictive control (MPC) strategy.

i. Frequency and deadband dependent strategy: The charging and discharging of BESS is dependent on the grid frequency and whether it is within a specified frequency deadband around the nominal (desired) frequency [46,57]. For example, BESS is discharged when $f < f_{min} = f_{nom} - \delta f$ and charged when $f > f_{max} = f_{nom} + \delta f$. f is the measured frequency value, f_{nom} is the nominal frequency, f_{min} is the specified minimum frequency value, f_{max} the specified maximum frequency value and the deadband is δf.
ii. Hybrid SOC and frequency dependent charging strategy: This control strategy utilizes a frequency control similar to (i) but with BESS charge/discharge limits that depend on the SOC. For example, a simple strategy requires that the battery charges when the SOC is less than a specified SOC and discharges when the SOC reaches a certain maximum SOC, typically with a deadband on SOC limits so as to avoid oscillation [29,44,47,57].

iii. Dynamic strategies: In these strategies, the BESS compensates for fast frequency deviations—i.e., discharging or charging in response to high deviations in frequency—while also applying a time-dependent offset to the frequency control signal in order to drive the BESS SOC to within specified thresholds. A similar model uses a frequency setpoint that is based on a moving average of a pre-defined time window to determine the charging and discharging setpoints [30,31,44,47]. All variations of this method build the SOC restoration strategy into the frequency regulation settings.

iv. Model predictive control (MPC) strategy: In this strategy, the power system is characterized by uncertainties related to load forecasting, RES forecasting and system dynamics and, therefore, it requires input data that are capable of predicting such uncertainties. The MPC predicts control uncertainties (future events and operational changes) and makes appropriate decisions to minimize their impact on grid stability. MPC strategies are based on internal models and use optimization methods to fit the control variables to historical data over a specified time horizon. MPC has been used to predict near-optimal locations for where BESS should be sited in order to compensate for major disturbances [44,60]. This approach also helps to make timely and optimal decisions on grid operations, such as storing energy before peak times, altering the settings of a slow acting power plant or bringing additional power plants online in advance of dispatch [60].

v. Dynamic strategies are of particular interest compared to the classical frequency and deadband dependent strategies for the WAPPITS area, which is characterized by large fluctuations that are hardly manageable by BESS alone. The present work investigated alternative dynamic and restoration strategies that are able to optimize BESS behavior for balancing fast frequency fluctuations and compared them not according to economic criteria, as proposed in the majority of works, but in terms of technical feasibility and based on technical performance indicators.

More specifically, the objective of this paper is to contribute to the literature by (i) analyzing and highlighting the application and effectiveness of BESS in providing primary frequency control in the WAPPITS, (ii) analyzing the impact and effectiveness of previously studied BESS frequency control logic when applied to a weak grid system, (iii) analyzing SOC restoration logic that can ensure service continuity and effective frequency regulation and (iv) determining the optimal size of BESS installations in order to accomplish the goal in (i) by means of a combination of MILP optimization and a dynamic grid model. The analysis used the WAPPITS as a case study, represented as a simplified open-loop BESS/grid model that was developed in MATLAB/Simulink and driven by frequency measurements from the WAPPITS.

This paper is organized as follows Section 2 presents an analysis of frequency trends in the WAPPITS; Section 3 introduces the proposed methodology; Section 4, 5 and 6 describes the development of a Simulink BESS simulation model, frequency and state of charge restoration controls; approach to estimate power imbalance of the grid, the MILP model and Section 7 presents the simulation results and discussion.

2.2 Statistical Analysis of Frequency Trends in the WAPPITS

The WAPPITS is currently composed of nine separate power systems that connect fourteen countries. The nominal grid frequency is 50 Hz, with an allowable frequency deviation limit of 200 mHz [12]. As stated earlier, the WAPPITS currently operates as three separate synchronous blocks, as shown in Figure 2.1. While it would be desirable to synchronize all of the blocks, global synchronization has been challenged by multiple problems, including significant frequency fluctuations within and between the blocks. Figure 2.2 depicts the frequency trend of the three synchronous blocks that was measured during a one-month period in the dry season [27]. The left panel in Figure 2.2 illustrates one month of data; the right panel shows data for four days. While shown together, note that each block records frequency at different sample rates (Block 1 at 60 s, Block 2 at 4 s and Block 3 at 10 s).

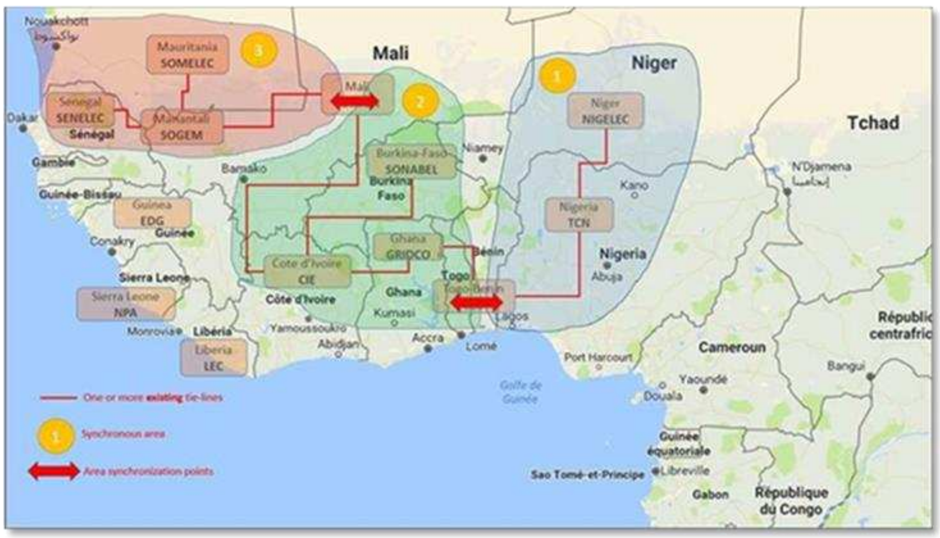
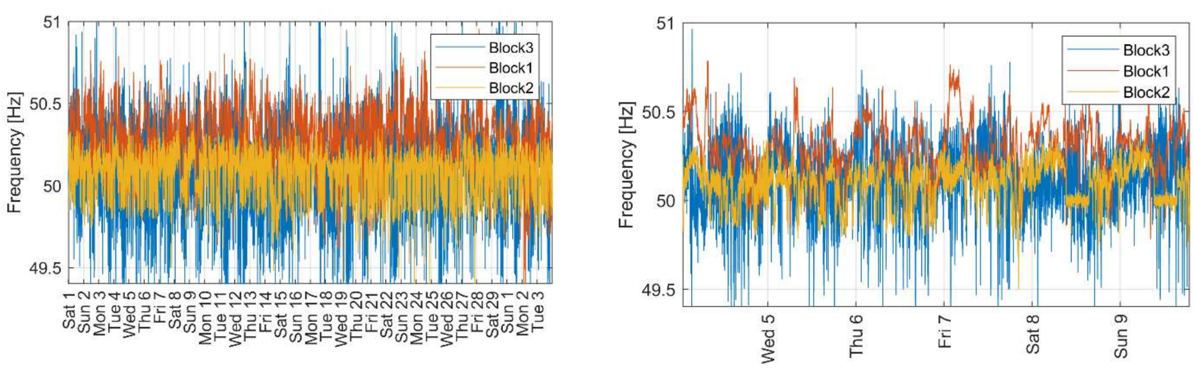


Figure 2.1. The WAPPITS showing the three synchronous blocks



(a) (b)

Figure 2.2. The frequency profiles of the three blocks. (a) one month frequency profile (b) 5 days frequency profile

Figure 2.3 shows the probability distribution of the measured frequency over one month of the measured data. Figure 2.4 shows the variation in frequency by hour as a cloud plot of the daily frequency profile (light color) superimposed over the average hourly frequency. Figure 2.5 summarizes the data for both the hour of the day (left) and the day of the month (right).

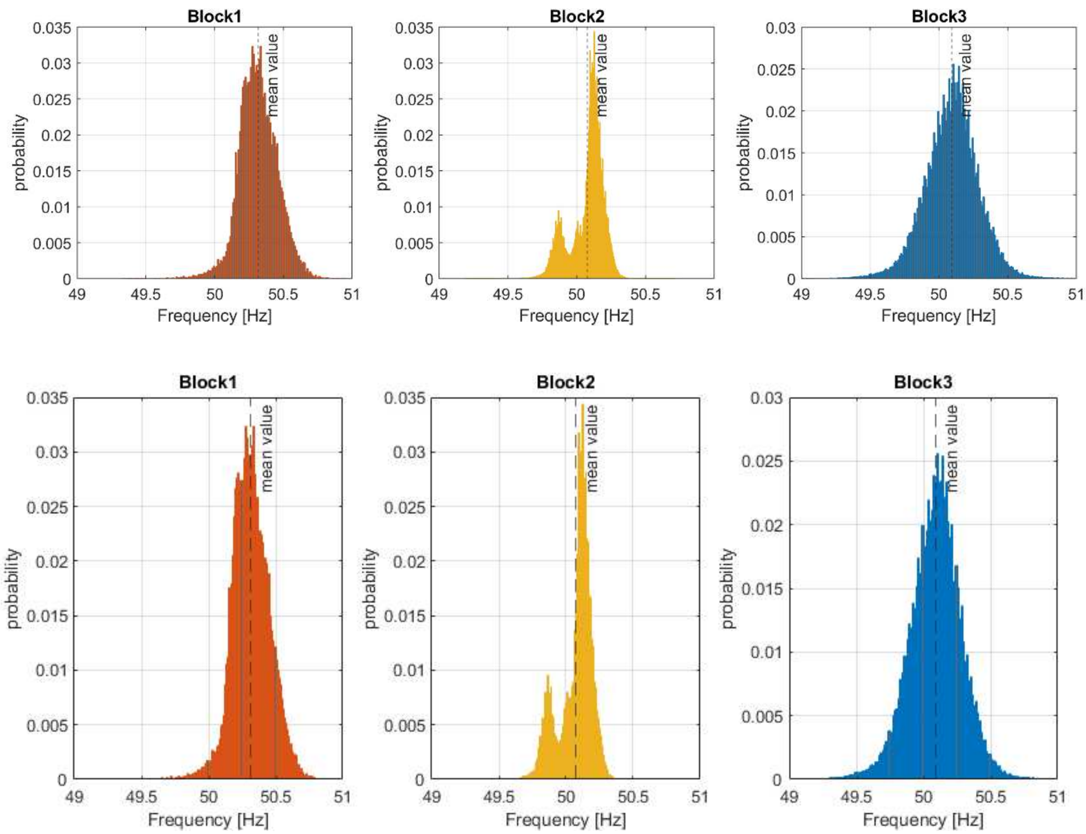


Figure 2.3. The distribution of frequency values of the three blocks. Block 1, Block 2 and Block 3 are probability distribution of the measured frequency over one month

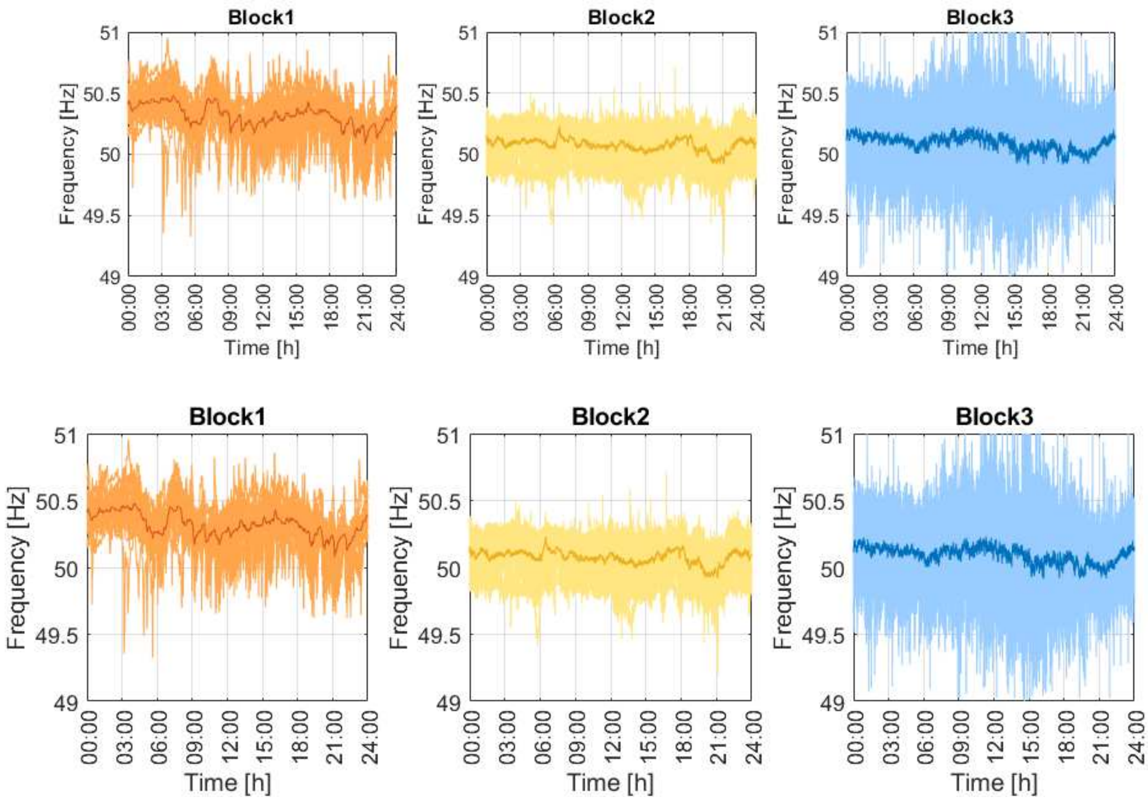
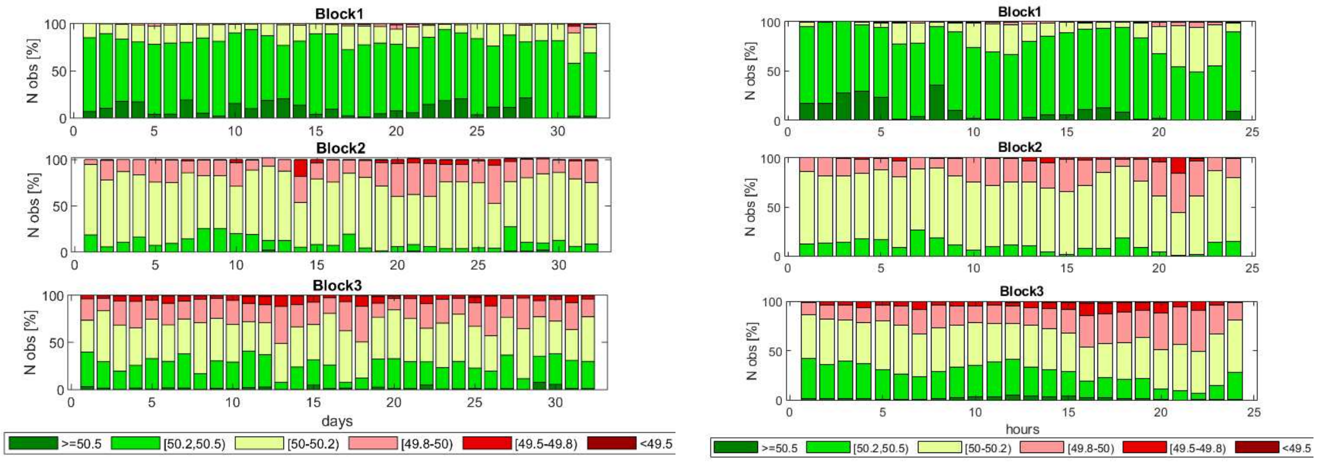


Figure 2.4. The daily and mean daily frequency profiles of the three blocks. Block 1 was sampled at 60 s, Block 2 at 4 s and Block 3 at 10 s.



(a) (b)

Figure 2.5. The percentage of observation in each frequency band for each hour (a) and day of the month (b).

Synchronous Block 1

The frequency was measured over a one-month time period with a sampling time of 60 s. The frequency was within the acceptable target of 50 ± 0.2 Hz 16.9% of the time, the lowest in-control fraction of any block. This block also tended toward over frequency (83.0% of measurements) while it was underfrequency 0.15% of the time; the mean frequency was 50.3 Hz. The very unstable and chaotic variation in frequency and the bias in the mean frequency value could indicate the incorrect configuration of the primary frequency regulation services/assets within the block.

Synchronous Block 2

The frequency data for Block 2 were sampled every 4 s. The frequency fluctuated rapidly and chaotically and was not at the nominal frequency for the majority of the time. The probability distribution (Figure 3, center) was bimodal with modes at approximately 49.9 Hz and 50.1 Hz, which resulted in the frequency being within the ± 0.2 Hz limits 85.1% of the time with a mean frequency of 50.08 Hz. When outside the acceptable range, the system tended toward over frequency (13.1%) rather than underfrequency (1.8%). The bimodal frequency distribution could indicate that secondary regulation was insufficient to restore the frequency to nominal.

Synchronous Block 3

The frequency was sampled every 10 s for one month. Similar to the frequency trend in the other two synchronous blocks, the frequency changed rapidly and showed some signs of instability, but with larger excursions than the other two blocks. The frequency was within the ± 0.2 Hz limits 68.8% of the time. When outside the acceptable range, it was over frequency 26.6% and underfrequency 4.6% of the time. The mode of the probability distribution was at 50.1 Hz, which was within the acceptable operating range, with a mean of 50.09 Hz. While the frequency deviations appeared to be symmetrically distributed, the deviations occurred randomly with no obvious pattern for either time of day or day of month.

All three synchronous blocks of the WAPPITS showed fast oscillations in frequency, indicating inadequate or ineffective primary and secondary frequency control. Additionally, there was a higher probability of over frequency than underfrequency operations. The prevalence of over frequency operation could be caused by the grid operator overscheduling production or by load shedding schemes, which prematurely shed load and lead to excess generation. The rapid frequency oscillations might also be due to the improper implementation of primary and secondary frequency controllers in operational power plants and/or a lack of frequency control reserves in the WAPPITS to manage frequency. Finally, it should be noted that the high frequency spikes might be attributed to major faults in power distribution or the operation of underfrequency load shedding (UFLS) schemes that shed too much load in too short a period.

Given the deviations from the desired nominal behavior, one or more interventions would be needed to stabilize the frequency. Conventionally, this would be provided by proper contracting with, and control strategies for, conventional swing generators. However, it has been suggested that, because of the increasing RES penetration in the area, new BESS technologies could be installed to provide primary and secondary frequency regulation by relying on the fast dynamic response of BESS installations and incidentally using these systems to deal with the current frequency control issues.

This study considered the question of whether BESS is well-suited for this type of frequency control, given what is known about the frequency control issues within the WAPPITS. The study addressed the need for a fast, first-order analysis to assess the potential of BESS deployments prior to a more in-depth, and costly, study of BESS sizing and displacement. This would include analyzing and identifying which BESS control strategies would provide effective regulation services, given what is known about the current frequency instability in the WAPPITS. The methodology used here could also be utilized to answer similar questions, e.g., planning for a rapid expansion of electric vehicles, prior to more detailed planning.

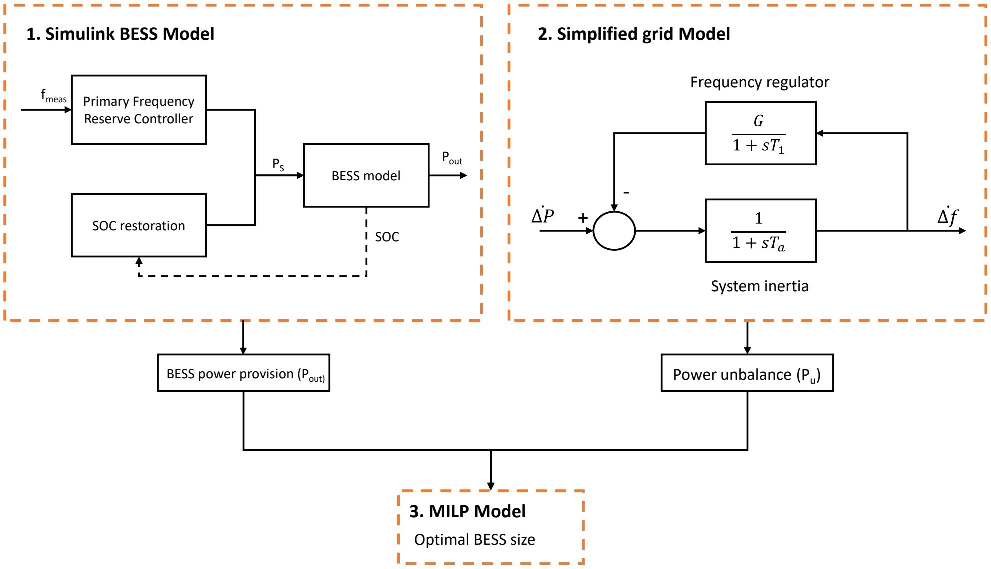
2.3. Proposed Methodology

The proposed methodology was used to assess BESS suitability for the provision of frequency control in the WAPP area. The model adopted consisted of three main modules as shown in Figure 2.6:

Simulink BESS model: This module aimed to simulate, with an open-loop MATLAB/Simulink model, BESS behavior for frequency reserve provision in the WAPP area. Different parameters and control logics were tested to evaluate which would be the best BESS regulating strategy;

Simplified grid model: By means of a simplified single machine model, the instantaneous power mismatch between generation and demand in the synchronous area was computed, taking the measured frequency deviations as the input;

MILP model: This last module takes the BESS power provision with different control strategies, simulated in the first module, and the grid power imbalance as the input. By means of a mixed integer linear programming (MILP) model, the optimal size of batteries that should be installed in the system to compensate the power imbalances was identified.



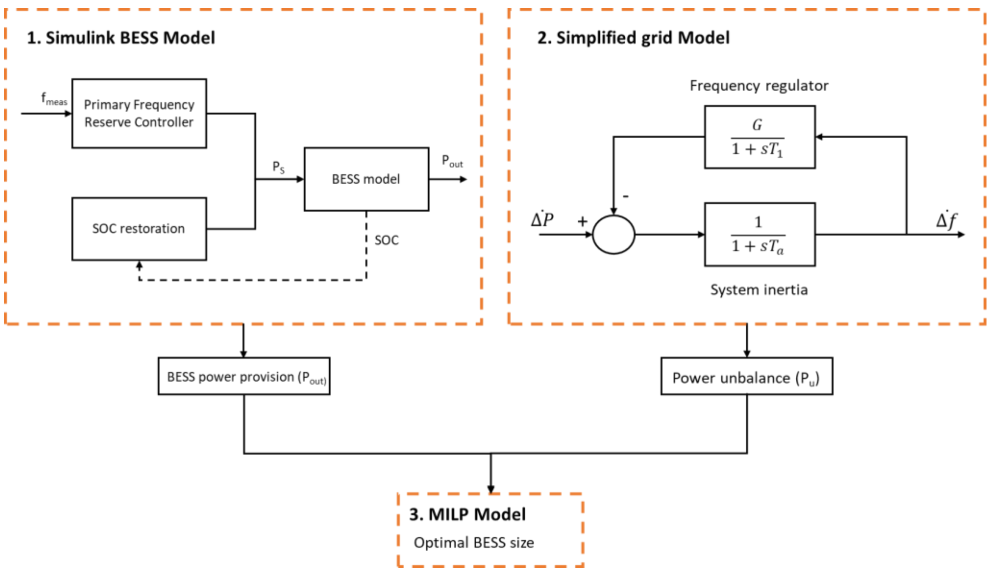


Figure 2.6. A schematic representation of the proposed methodology.

2.4 Simulink BESS Model

To compare different BESS control strategies for primary frequency regulation, this study implemented an open-loop MATLAB/Simulink BESS model. The model evaluated the ability of BESS to provide frequency control services. The BESS was operating by itself, i.e., it was not connected to an external grid. The effectiveness of each control model was assessed (see Figure 2.7).

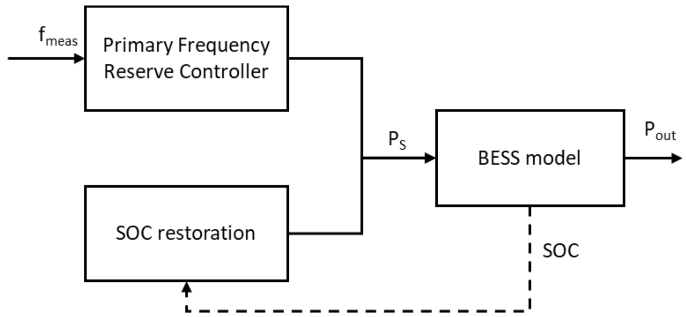


Figure 2.7. The open-loop simulation of the WAPPITS system (in Simulink).

The analysis used the following assumptions:

The input to the BESS controller was the frequency measurement time series that was collected from the WAPPITS grid.

The frequency input was not affected by the power output of the BESS, i.e., detailed grid characteristics were not implemented in the model. This provided a fast method to simulate BESS behavior given a known grid behavior, allowing multiple control approaches to be explored at low computational cost. The results of this preliminary study will allow a down-selection of control approaches and a subsequent phase of this study will simulate the WAPPITS grid in order to understand the dynamic response of the grid to the BESS inputs.

The following paragraphs describe the blocks that compose the Simulink model from Figure 2.7.

2.4.1. Primary Frequency Reserve Controller

The primary frequency reserve controller (PFRC) defined the power setpoint according to the PFRC requirements. The objective of the PFRC was to stabilize the system frequency at nominal value by ensuring that the power balance was maintained in the grid. This analysis only simulated frequency control; operating reserves for contingency situations were not included. The controller followed a defined droop control model, as shown in figure 2.8. The PFRC's input was the frequency measurements obtained from the WAPPITS. Based on the frequency deviation from the nominal frequency ($\Delta f = f - f_{nom}$), the BESS injected or absorbed power according to the droop curve. The droop controller used the following parameters:

Deadband (DB), which is the range of Δf, where the BESS does nothing;

Droop (σ), which is the slope of the droop curve, assumed to be symmetrical for injecting and absorbing power for this analysis;

Regulation band (ΔP_{max}), which is a dimensionless parameter defined as $\Delta P_{max} = \frac{P_{reg}}{P_n}$

where P_{reg} is the regulating power, i.e., the contractual power that the battery makes available for PFRC $P_{reg} = [-P_{min}, P_{max}]$, and P_n is the nominal power of the battery.

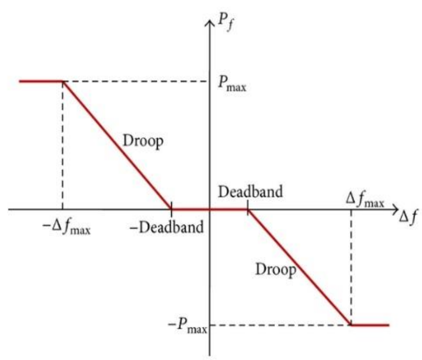


Figure 2.8. The general droop curve for the primary control reserve provision.

The droop value is expressed as:

$$\sigma = \frac{\Delta f / f_{nom}}{\Delta P / P_n} \cdot 100 \qquad (2.1)$$

For this study, Δf, the input for the droop control curve, was computed using one of two methods. First, the classical approach (labelled "Logic A") calculated the frequency deviation as the near-instantaneous deviation of the frequency from the desired frequency ($\Delta f = f_{meas} - f_{nom}$ where

$f_{nom} = 50$ Hz). The second approach used a dynamic or sliding method ("Logic B") where the frequency deviation was computed relative to a moving average, over a given time interval, of the measured frequency ($\Delta f = f_{meas} - f_{aver}$ where f_{aver} is a moving average over the given time interval).

The first approach was tested on the system with different deadband and droop values as a reference case. However, since the WAPPITS experiences large frequency oscillations and the mean frequency is biased toward over frequency, any practical BESS would have insufficient storage to compensate for the prolonged imbalance (excess generation) across the system. Therefore, the second model forces the BESS to compensate for the rapid frequency deviations while ignoring the long-term (typically high) bias in the system's frequency.

The definition of "rapid frequency variation" is set by the transfer function of the f_{aver} calculation, a moving average filter that is applied to the previous N data samples. For a filter of this type, the transfer function is:

$$|H(f)| = \frac{1}{N}\frac{|\sin \pi f_s N|}{|\sin \pi f_s|} \tag{2.2}$$

where f_s is the sampling frequency. As an example, for Block 2, the frequency was sampled at 10 s (0.1 Hz) and a 15-min (900 s) moving average implied $N = 90$. Taking the usual −3 dB as the filter roll off (half-power point), the moving average filter attenuates changes that happened more rapidly than 149 s by 0.5 or more. Subtracting $\Delta f = f_{meas} - f_{aver}$ inverts the low-pass filter to a high-pass filter. Therefore, "rapid" in this example corresponded to system frequency excursions with (sampled) frequencies in excess of ≈ 7 mHz.

The implementation of this model on the BESS installations assumed that other control improvements would provide the necessary positive control to restore long-term mean system frequency to, at or near the desired nominal value for all frequency excursions happening slower than the cutoff frequency of Δf. Logic B was also tested with a range of droop and deadband values and, additionally, with a range of moving average windows.

2.4.2. SOC Restoration

Two SOC restoration strategies were also implemented:

Logic α: When BESS reached a minimum or maximum state of charge, the frequency control provision was interrupted and replaced by a charging or discharging current, at a pre-set C-rate, to restore the SOC to the operational range;

Logic β: This modified the Δf signal to make it proportional to the ΔSOC:

$$f_{aver}^{*} = f_{aver} - |f_{aver} - f_{meas}| \cdot \frac{f_{nom} - SOC \cdot 100}{G} \qquad (2.3)$$

where G is a selected gain parameter.

Logic α, the classical restoration strategy, had the disadvantage of interrupting the BESS' service provision when the SOC fell outside of the operational range. Additionally, charging or discharging at the desired C-rate during restoration might be suboptimal relative to the state of the grid during restoration. Logic β overcame this disadvantage by conditioning the available BESS power to never (with the proper setting of G) allow the SOC to move outside of the operational range.

2.4.3. Empirical BESS Model

In order to provide realistic data, a proper BESS model was required. This study utilized the empirical BESS model described in reference [18] and was derived from the experimental measurements of a BESS for stationary application in JRC's Smart Grid and Interoperability Laboratory (SGILab) in Ispra (Italy). The experimental unit was a Li-ion nickel–manganese–cobalt (NMC) battery pack with a nominal energy capacity (E_n) of 570 kWh and a nominal power (P_n) of 250 kW.

The main parameters characterizing the BESS numerical model were:

Nominal power P_n;

Nominal energy E_n;

Nominal energy to power ratio (EP_r): $EP_r = E_n/P_n$;

Minimum/maximum SOC: SOC_{min}, SOC_{max};

A maximum C-rate, the discharge current normalized to battery capacity, function of SOC and of EP_r, shown in Figure 2.9: $Crate_{,max}$; A variable charging and discharging efficiency function of SOC and of the C-rate, as shown in Figure 2.10: η_c and η_d; the figure, resulting from the experimental characterization of the battery pack, shows the value of battery round-trip efficiency when cycling with different C-rate values and SOC. Efficiency results were compromised at very low C-rate and extreme SOC values (above 80% and below 20%).

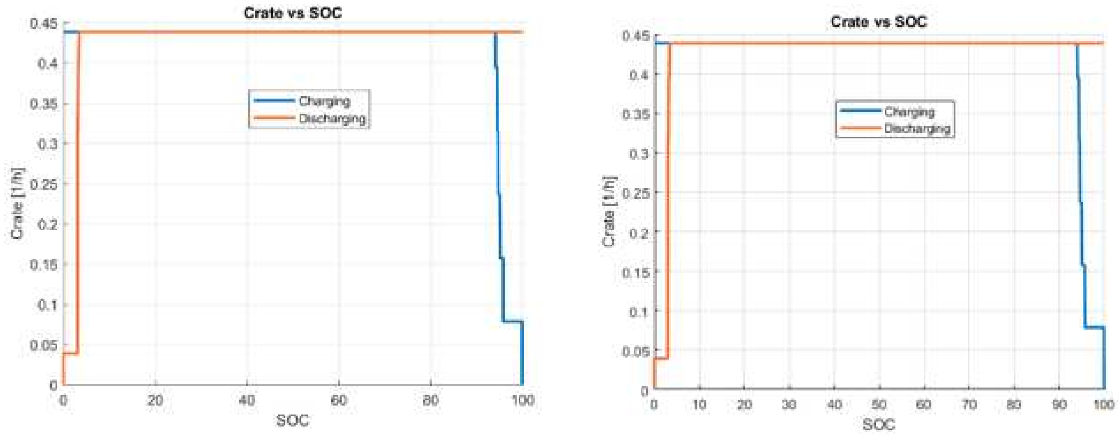


Figure 2.9. C-rate maximum vs. SOC.

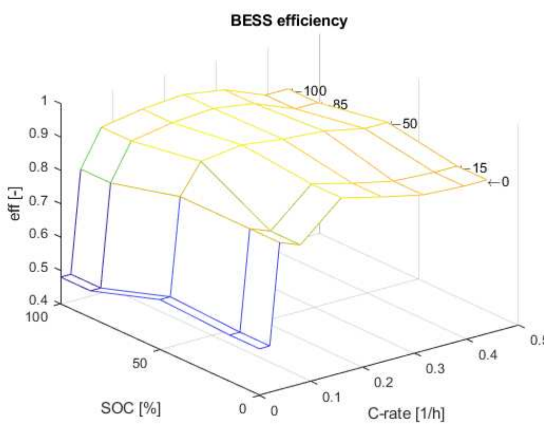


Figure 2.10. The control surface of the BESS efficiency.

The empirical BESS model simulated a quasi-steady-state operation by computing the energy flow to/from the battery and updating the state of charge at each time step. The model received the power setpoint P_s from the PFRC as its input. P_s was negative when the battery charged and positive when it discharged. Based on P_s , the battery updated its SOC accordingly. The real power required from the battery was computed based on the charging and discharging efficiencies of the battery, which were a function of the SOC and the battery C-rate. The real power required from the battery was computed using the expression:

$$\mathrm{P}_B = \begin{cases} \eta_c \mathrm{P}_s, & \mathrm{P}_s < 0 \\ \mathrm{P}_s/\eta_d, & \mathrm{P}_s \geq 0 \end{cases} \qquad (2.4)$$

The state of charge (SOC) variation of the BESS at each time step was given as

$$\Delta \mathrm{SOC} = \int_t^{t+1} \frac{\mathrm{P}_B dt}{E_n} \qquad (2.5)$$

The output power P_{out} provided by the battery to the system was normally equal to P_S and it was equal to 0 when the battery reached the SOC limits (SOC_{min}, SOC_{max}); the maximum power output provided by the battery decreased when the battery was close to saturation and the maximum C-rate was lower than the nominal.

$$|\mathrm{P}_{out}| = \min\left(Crate_{,max} \cdot E_n, |P_S| \right) \qquad (2.6)$$

The model also calculated some metrics:

1) The regulating energy E_{PCR}, which is the total energy required by the frequency controller within a defined time interval (between the starting time (ts) and ending time (te)):

$$E_{PFRC} = \int_{t_s}^{t_e} |P_s| dt \qquad (2.7)$$

2) The energy provided by the battery to the system was computed as the integral of the output power (P_{out}):

$$E_{out} = \int_{t_s}^{t_e} |P_{out}| dt \qquad (2.8)$$

3) The loss of regulation (LoR) indicates the amount of energy that the BESS was unable to provide. It was expressed as the ratio of the energy not provided by the battery to the regulating energy required from the BESS:

$$LOR = \frac{E_{out}}{E_{PFRC}} \qquad (2.9)$$

4) Number of full charge–discharge cycles $N_{cycles:}$

$$\text{Ncycles} = \frac{\int_{t_s}^{t_e} |P_B\,| dt}{E_n \cdot 2} \qquad (2.10)$$

2.5. Power Imbalance Estimation

The simplified grid model adopted to estimate the instantaneous power imbalance (P_u) on the national grid was based on a single synchronous machine dynamic model. The relation between the power imbalance and the frequency deviations is a function of the system inertia and the speed governor (i.e., frequency regulator) characteristics [65,66]. The model depended on the total capacity of active generators in the interconnected system (regulating energy G), the equivalent time constant of the system (T_a), the time constant of the speed governor (T_1), the transfer function equations for the speed governor and system inertia (Figure 2.11). In the proposed approach, the frequency sampled in the WAPPITS was taken as the input and the corresponding power imbalance was calculated. The model was implemented and run in the Matlab environment.

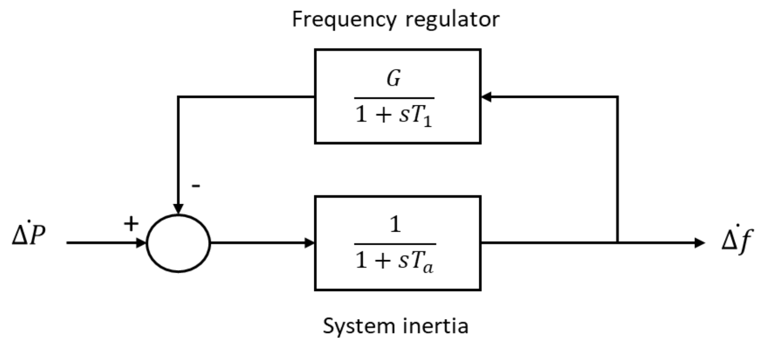


Figure 2.11. The single bus power system model.

The equivalent time constant of the system (T_a) was computed as the average of the time constant of each of the connected generators (T_i), taken from the WAPP data, and weighted according to their capacity (P_i). P_{tot} was the total capacity of the generators connected to the system and $Ngen$ was the total number of generators:

$$T_a = \sum_{i=1}^{Ngen} \frac{P_i T_i}{P_{tot}} \qquad (2.11)$$

The model allowed us to compute the per unit power imbalance ($\Delta\dot{P}$) starting from the measured per unit frequency deviation ($\Delta\dot{f} = \Delta f / f_{nom}$). The power imbalance at each time step, expressed in watts, was then computed as follows:

$$P_u = \Delta\dot{P} \cdot P_{tot} \qquad (2.12)$$

2.6 MILP Model for Optimal BESS Sizing

In this section, the simple MILP optimization model that was used to find the optimal size of the batteries to be installed in the system (P_{BESS}) is described. The goal of the model was to identify the quantity and optimize the size of the batteries to provide the maximum possible service to the grid whilst assuring that the power provided by the batteries could be accepted by the grid.

The input parameters were the power imbalance of the system at each time step $P_{u,t}$, computed as described in the previous paragraph, and the per unit power output of the batteries providing primary frequency control in the system, according to the different control logics described in Section 0: $\dot{P_{out}} = P_{out}/P_n$. The time interval of each timestep t (which was the only independent index) was subsequently set to 1 s.

The objective function (O_f), described in equation 12, was the minimization of the absolute sum of the differences between the power provided by the total installed batteries and the total required by the grid at each time step t. The power provided by the installed batteries was given by the total installed capacity (P_{BESS}), the dependent variable of the problem, multiplied by the power provided by a battery with unitary power $\dot{P_{out}}$.

$$O_f = min \sum_{t=ti}^{te} |P_{out,t} \cdot P_{BESS} - P_{u,t} \tag{2.13}$$

Given the necessity of linearization, a new positive variable z(t) was defined and the model was expressed as:

$$\dot{P_{out,t}} \cdot P_{BESS} - P_{u,t} \geq -z_t \tag{2.14}$$

$$\dot{P_{out,t}} \cdot P_{BESS} - P_{u,t} \leq z_t \tag{2.15}$$

$$O_f = min \sum_{t=ti}^{te} z_t \tag{2.16}$$

The model did not directly consider the BESS parameters. The parameters were already taken into account in characterizing battery behavior, as detailed in the previous Simulink model. The MILP model received the BESS power output as its input. This simplified the MILP optimization to achieve an optimal feasible solution.

The model was coded in Python language with the package pyomo and run with the academic license of the solver “gurobi”.

2.7 Simulation Results and Discussion

This section presents the simulation results for the BESS performance assessment in the WAPPITS. The three modules of the proposed procedure were run for several scenarios considering different BESS PFCR control strategies. The frequency control logics (A and B) and system restoration logics (alpha and beta) were tested using the Simulink model (module 4.1). The results of the simulation helped to characterize battery behavior using one-month actual frequency measurements from the WAPPITS. The details of the simulations’ settings are reported in Table 2.1 and 2.2. A step function was used to pass from the 0.25 Hz sampling time to the 1 Hz time step of the simulations.

Table 2.1. A summary of the simulations without SOC restoration.

Scenario	Droop (%)	DB (Hz)	Scenario	Window Size (s)	Droop (%)	DB (Hz)
Case “1”	0.075	0.02	Case “10”	600	0.075	0.02
Case “2”	0.075	0.05	Case “11”	600	0.2	0.02
Case “3”	0.075	0.1	Case “12”	600	0.4	0.02
Case “4”	0.2	0.02	Case “13”	1800	0.075	0.02

Scenario	Droop (%)	DB (Hz)	Scenario	Window Size (s)	Droop (%)	DB (Hz)
Case “5”	0.2	0.05	Case “14”	1800	0.2	0.02
Case “6”	0.2	0.1	Case “15”	1800	0.4	0.02
Case “7”	0.4	0.02	Case “16”	3600	0.075	0.02
Case “8”	0.4	0.05	Case “17”	3600	0.2	0.02
Case “9”	0.4	0.1	Case “18”	3600	0.4	0.02

Table 2.2 A summary of the simulations with the SOC restoration strategy.

Scenario	Rest Logic	Window Size (s)	Droop (%)	DB (Hz)	Gain
Case “19”	Alpha	600	0.075	0.02	-
Case “20”	Alpha	600	0.2	0.02	-
Case “21”	Alpha	600	0.4	0.02	-
Case “22”	Beta	600	0.2	0.02	10
Case “23”	Beta	600	0.2	0.02	50
Case “24”	Beta	600	0.2	0.02	100
Case “25”	Beta	600	0.2	0.02	200

The different control models were tested using the frequency measurements of Block 2, which were sampled at 4 s (the highest rate). The frequency behavior of Block 2 was more representative of the typical power system with some reasonable frequency control compared to the other blocks, which were sampled at 10 s and 60 s (lower rates). Given the similarities between the frequency trends of the blocks, the conclusions can assumably also be extended to Block 1 and Block 3.

The simulations were run for a battery with the same characteristics as that tested in the laboratory (EPR ratio of 2.28 h) but with a unitary nominal power P_n of 1 MW to simplify the analysis. The regulating power of the battery P_{reg} was the maximum available that was equal to $(-P_n, P_n)$. The SOC limits were set as: $SOC_{min} = 0$; $SOC_{max} = 100$. The numerical values of the variable efficiency and maximum C-rate were those reported in Figures 9 and 10.

After computing the power imbalance in the grid according to procedure 4.2, the optimal BESS size to be installed in the Block 2 area was estimated using the procedure of module 4.3. Each run of this last procedure corresponded to a different setting of the PFCR, previously simulated in Simulink.

2.7.1 PFRC Control Logic A

The BESS behavior was assessed by running the Simulink model with control logic A. Table 1 summarizes the scenarios (cases 1–9) that were analyzed based on a range of droop and deadband settings. The typical ranges of droop and DB that were used were selected from the ENTSO-E (European Network of Transmission System Operators for Electricity) area, as well as relaxed values, which were suggested as a reference for the WAPP region.

Figure 2.12 and 2.13 show the results of the SOC over time and the SOC distribution, respectively, for each of the analyzed cases. The results using control logic A show that the battery saturated at 100% SOC in less than 3 h (around 10,000 s) in all analyzed cases without being able to discharge and hence, its role of providing services for primary frequency response was almost non-existent.

The loss of regulation recorded was around 60% in all nine simulated cases. The observed battery behavior was due to the predominantly high frequency values recorded in the region.

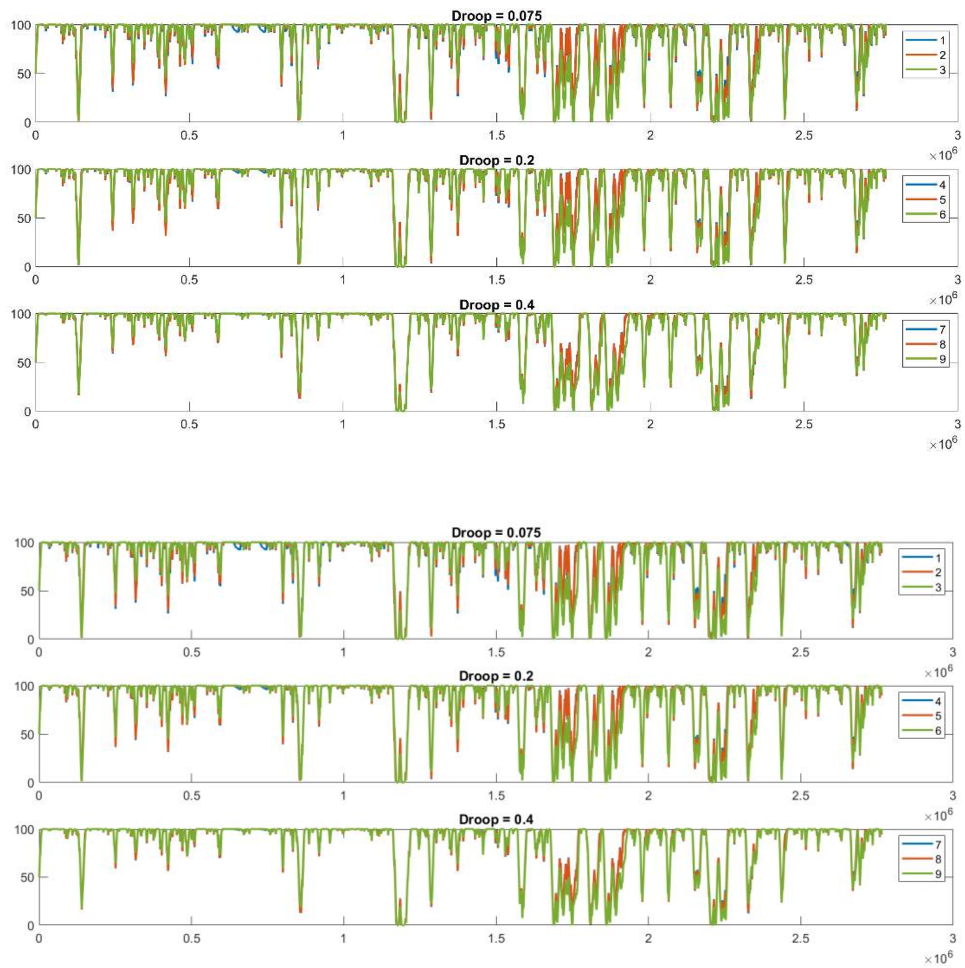
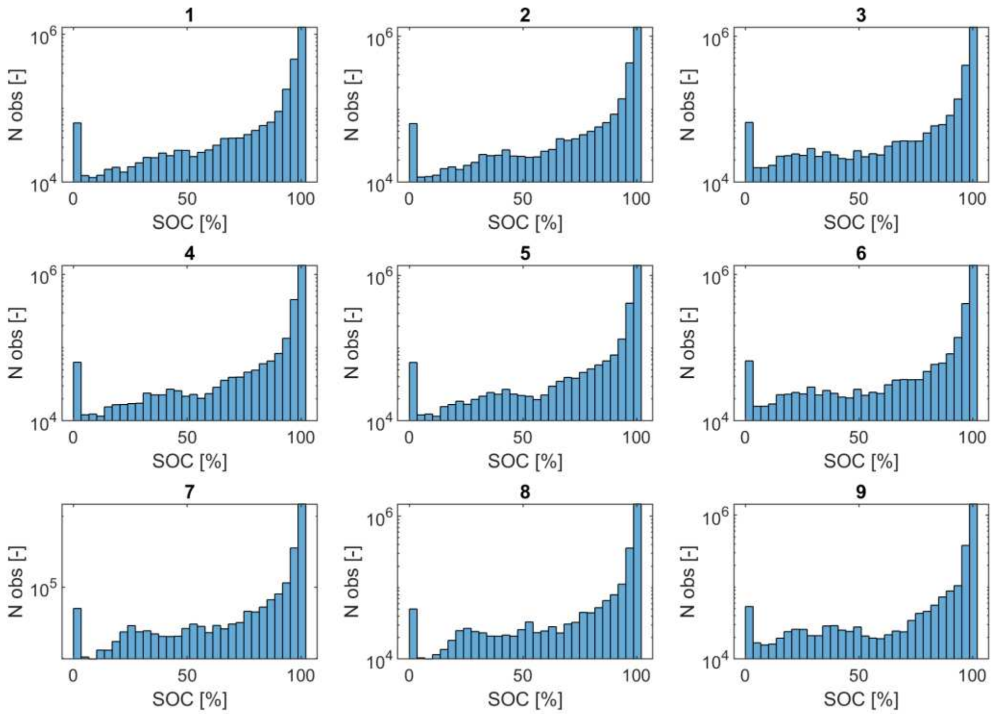


Figure 2.12. The SOC trend over time (cases 1–9).



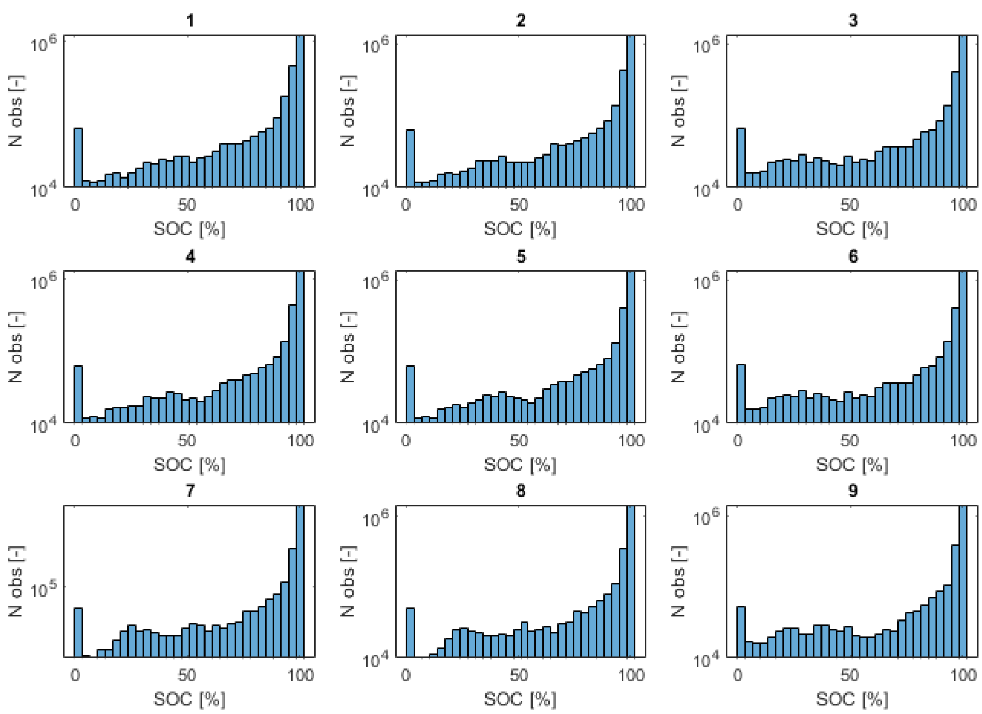


Figure 2.13. The SOC distribution (cases 1–9).

The results also show that neither the width of the deadband nor the droop values had much influence on the battery behavior. This can be seen from a comparison of the root mean square error (RMSE) values of the SOC profiles. The RMSE did not exceed 10% for scenarios with same droop but different deadbands (e.g., 1, 2 and 3) or for scenarios with same deadband but different droops (1, 4 and 7).

2.7.2 Frequency Control Logic B

The frequency control logic B was based on filtering the measured frequency in order to isolate the higher frequency variations from slower fluctuations, as described previously. Figure 14 shows an example of the fast and slow frequency fluctuations that were filtered from the measured frequency data. The study tested frequency control logic B with three different moving average windows sizes (600, 1800 and 3600 s) and three different droop values (0.075, 0.2 and 0.4). The scenarios (cases 10–18) that were analyzed are shown in Figure 2.14.

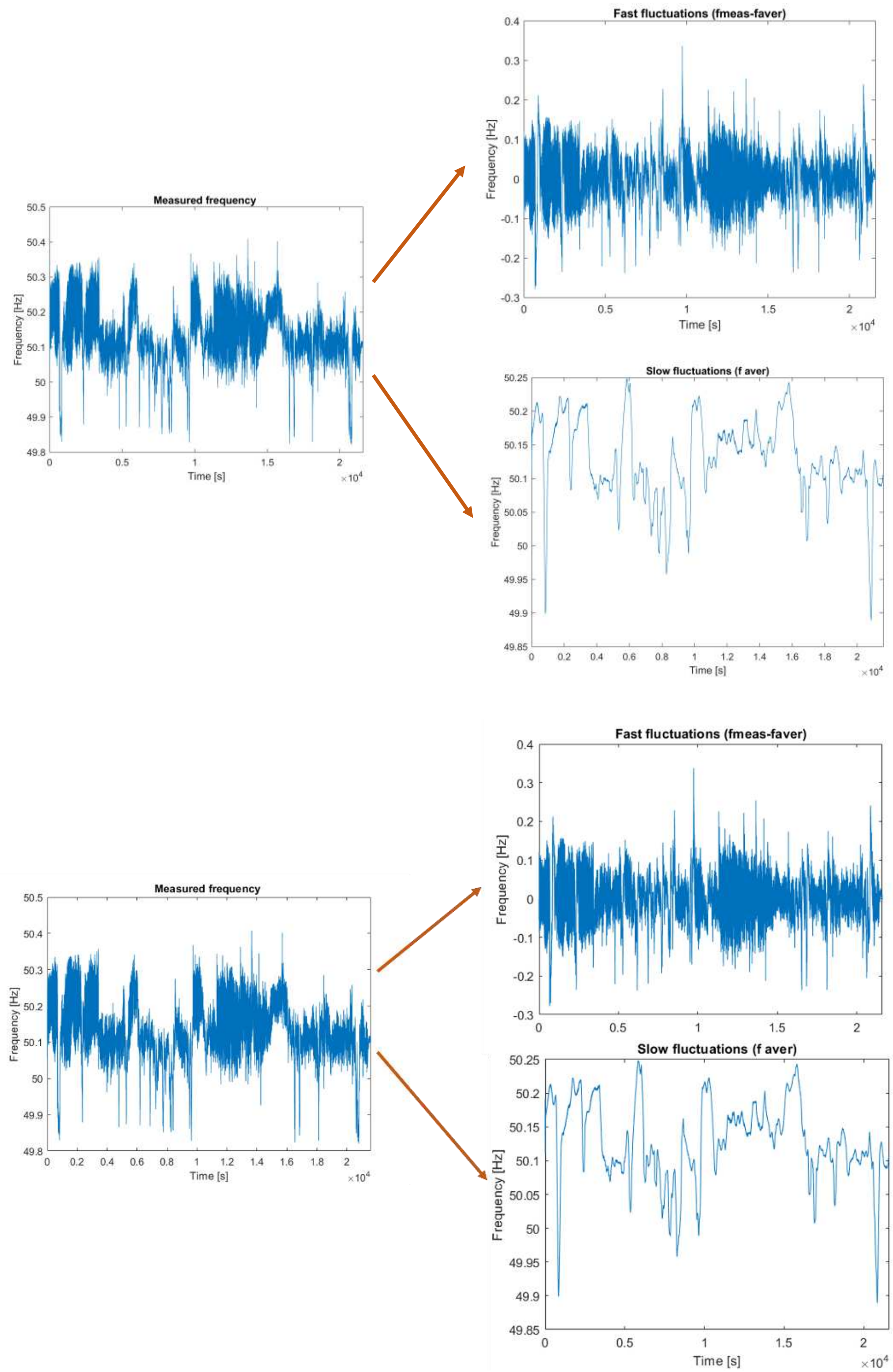
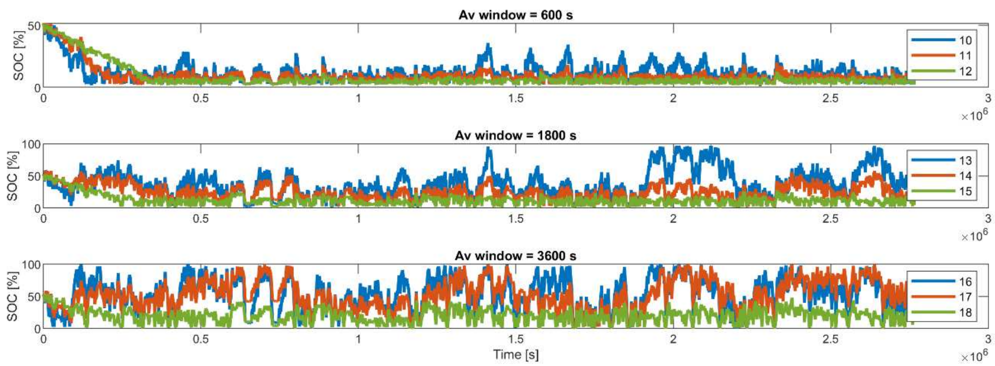


Figure 2.14. The decomposition of the frequency trend into fast and slow fluctuations.

Figures 2.15 and 2.16 show the frequency control logic B simulation results for the SOC over time and the SOC distribution, respectively. Given the symmetrical frequency fluctuations to be compensated by the battery, it tended to discharge and reach SOC values of close to 0%. This was due to batteries' internal losses when charging and discharging (modeled by charging and discharging efficiencies), which resulted in a higher power output than input (such behavior will be fixed by adopting a proper SOC restoration strategy, i.e., logic α or logic β). The results also show that the droop values influenced the speed at which battery was discharged. For example, with a moving average window of 600 s, the time to reach 0% SOC passed from 15,000 s with a droop of 0.075 to 20,000 s and 30,000 s with droops of 0.2 and 0.4.



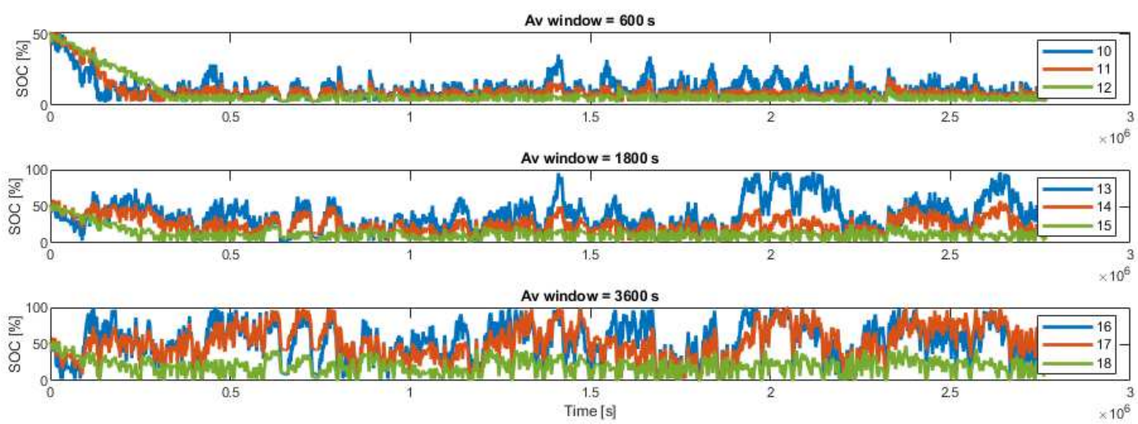
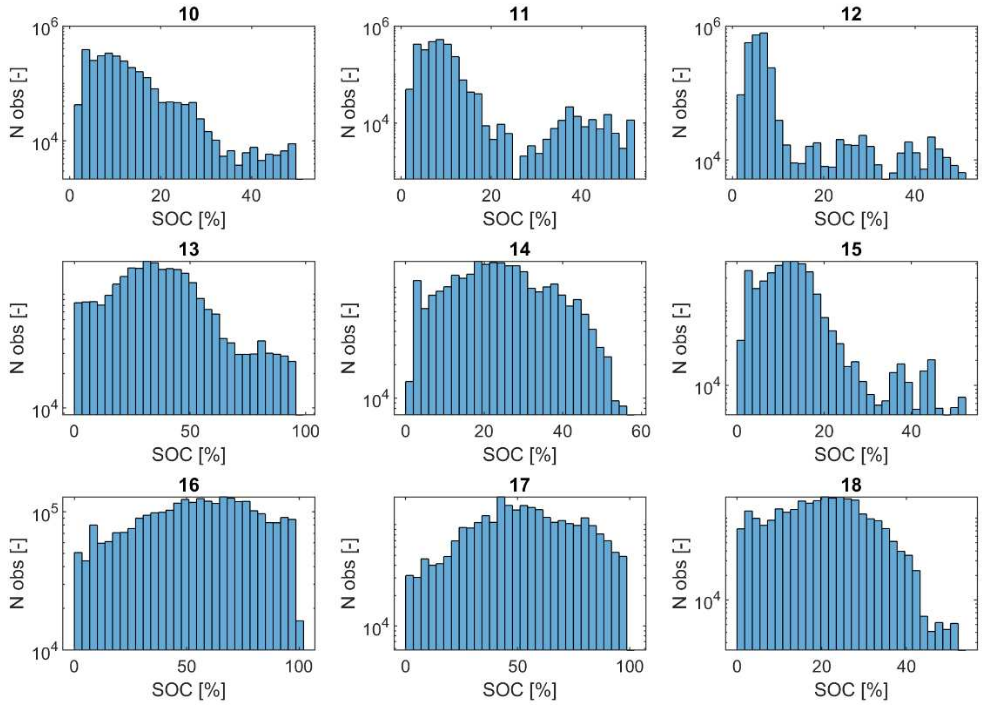


Figure 2.15. The SOC trend over time (cases 10–18).



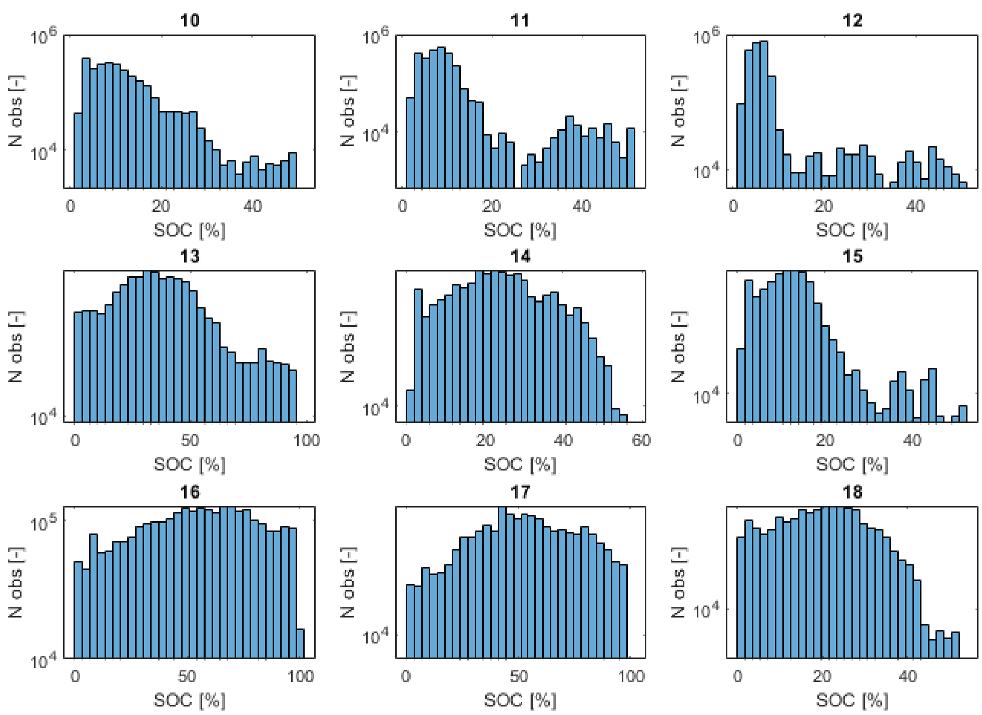
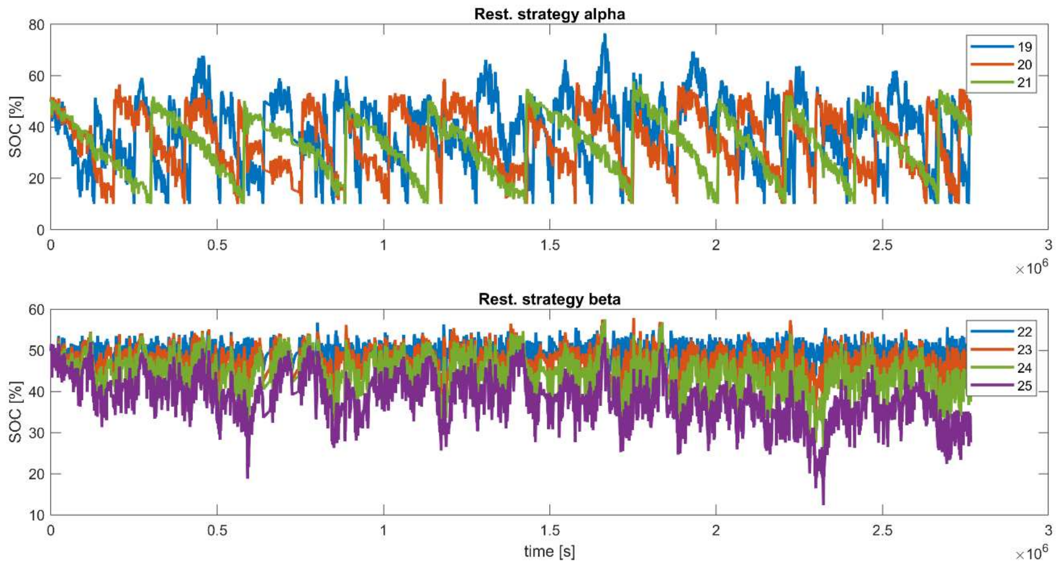


Figure 2.16. The SOC distribution (cases 10–18).

This trend was less visible when the moving average window was increased due to the higher amplitude fluctuations and the higher amount of energy that the battery had to provide. For example, the total energy requested by the PFRC from the battery during the test time period in case 18 was 253 MWh with a moving average window of 3600 s compared to 218 with a moving average window of 1800 s in case 15 and 152 MWh with a moving average window of 600 s in case 12. Consequently, while the BESS tended to stay at SOC < 20% (case 12) for 90% of the time with a small moving average window, this reduced to 50% in case 18. Since the purpose of the study was to analyze the ability of BESS to stabilize fast and small amplitude fluctuations, all subsequent analyses in this study utilized a 600 s moving average window. The average absolute value of power requested by the PFRC was 0.2 MW in case 12 compared to 0.3 MW in case 18.

2.7.3 SOC Restoration Strategies

The two SOC restoration logics previously described (α and β) were tested using a moving average window of 600 s. Logic α was simulated with different droop values and logic β was simulated with different values for the gain. Figures 2.17 and 2.18 show results of the SOC over time and the SOC distribution, respectively. The average SOC distribution in both cases was approximately 50%. The BESS did not saturate and thus, continuously provided the required service for the primary frequency response. For logic α, the BESS would need to be recharged to the target 50% SOC about 10 times per month. This is based on the assumption that the BESS is recharged at the nominal value. This results in a BESS unavailability of 23 h per month. For Logic β, the sum of relative differences between the power provided by the battery and power required to regulate the fast frequency oscillations increased as the gain increased. For example, 16% of the total power for case 22 compared to 5% for case 25 and 6% for case 20. The results show that this restoration logic effectively managed the SOC whilst also ensuring there was no interruption in the energy provision from the BESS for the primary frequency response.



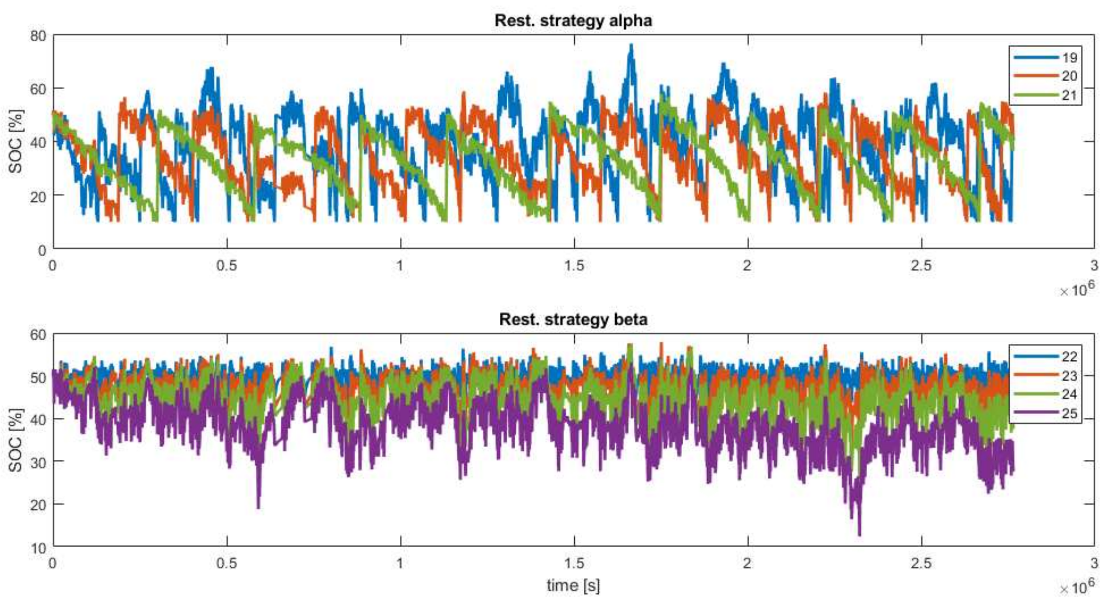
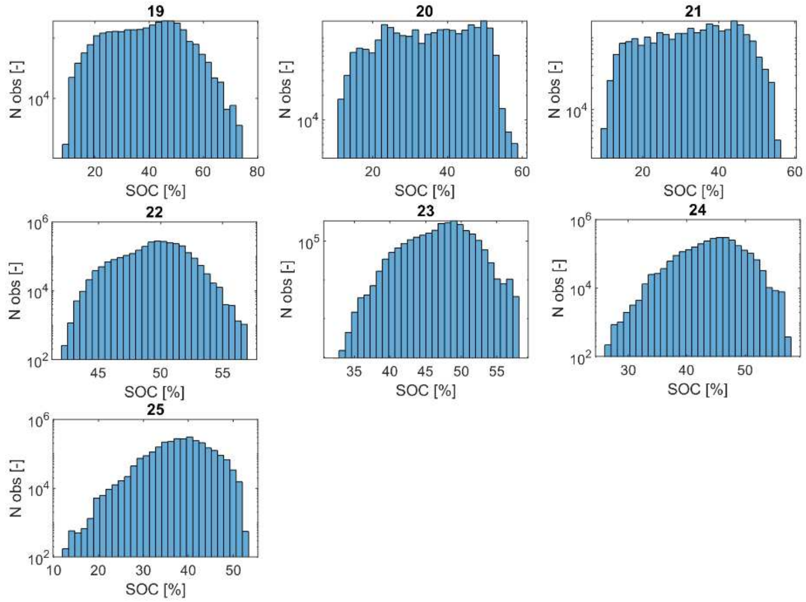


Figure 2.17. The SOC trend over time (cases 19–25).



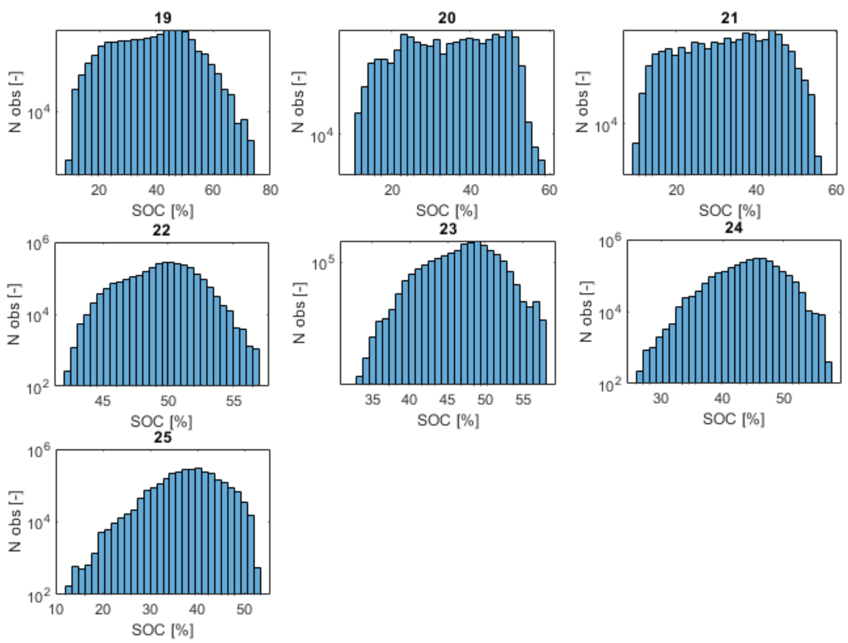


Figure 2.18. The SOC distribution (cases 19–25).

The effectiveness of the proposed frequency control logic was also assessed on the basis of the number of cycles provided by batteries, the total loss of regulation and the energy provided to the system (proportional to the number of cycles).

For frequency control logic A, the loss of regulation was approximately 60% of the total energy required. The loss of regulation was not significantly influenced by changing the droop and deadband values. This is because the battery reached saturation. Frequency control logic B was comparatively responsive to a change in droop values. Changing the droop values could double the total number of cycles provided by the battery. For example, the number of cycles increased from 55 cycles in case 10 for a droop of 0.075 to 111 cycles in case 12 for a droop of 0.4. The loss of regulation was almost null in logic B compared to logic A (2% against 60%). A lower loss of regulation enabled the BESS to provide the required service for more than 95% of the time in all cases, with or without SOC restoration. Restoration logic α allowed the battery to work 99% of the time (actually, the remaining 1% was caused by the recharging period and, if this were accurately planned then it could be further reduced, e.g., in moments when the frequency is inside the deadband). This logic allowed an increase in the number of cycles that the battery was able to operate. For example, comparing cases with the same settings, the number of cycles was 89 in case 10 and 97 in case 19. Figure 2.19 shows the simulation results for the number of cycles, the loss of regulation and the energy provided by the battery to the system.

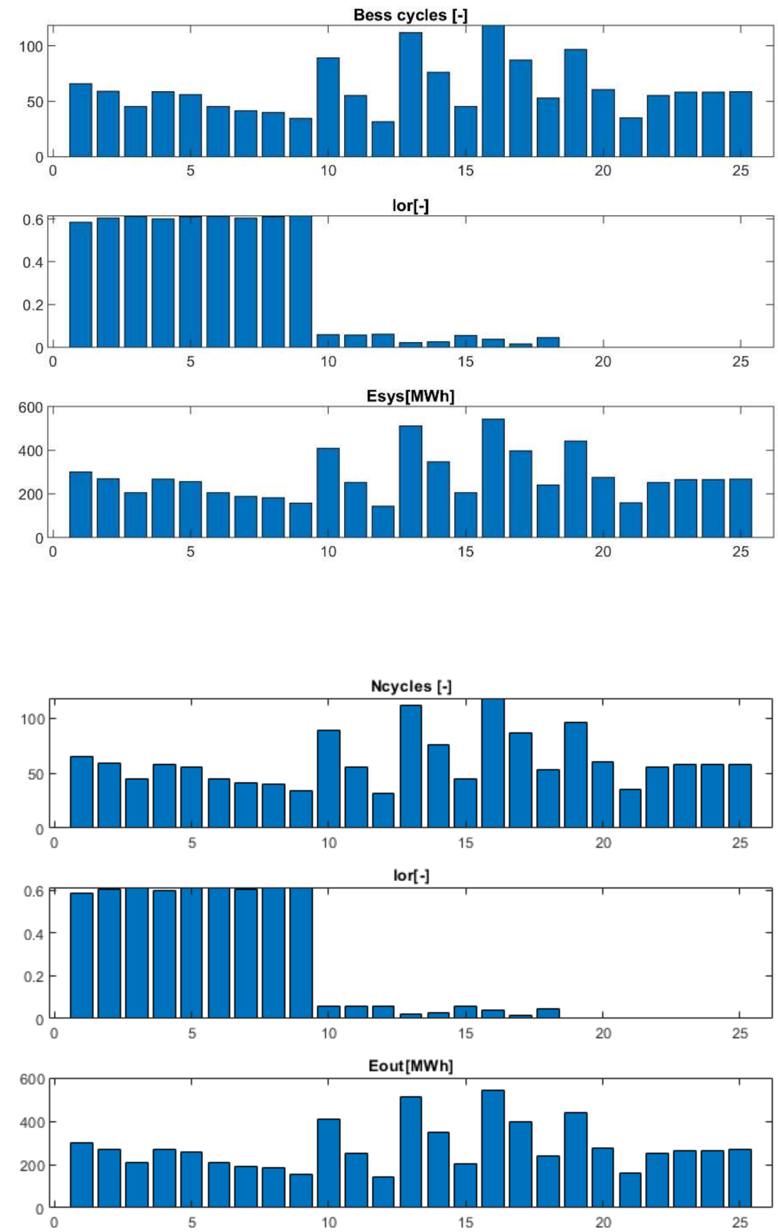


Figure 2.19. A comparison of the indicators in the different simulations.

2.7.4 BESS Sizing

Given the measured frequency deviation on the grid, the active power imbalance was estimated by means of the model shown in Figure 2.11., with the parameters reported in Table 2.3. The values of T_1 and G were taken from the literature and corresponded to the typical values of hydro generators. T_a and P_{tot} were instead evaluated from the WAPP data. The results are shown in Figure 2.20.

Table 2.3. The parameters for power imbalance estimation.

1. Parameter	2. Value	3. u.m.
4. Ta	5. 7	6. s
7. T_1	8. 1	9. s
10. G	11. 1	12. p.u.
13. P_{tot}	14. 8329	15. MW

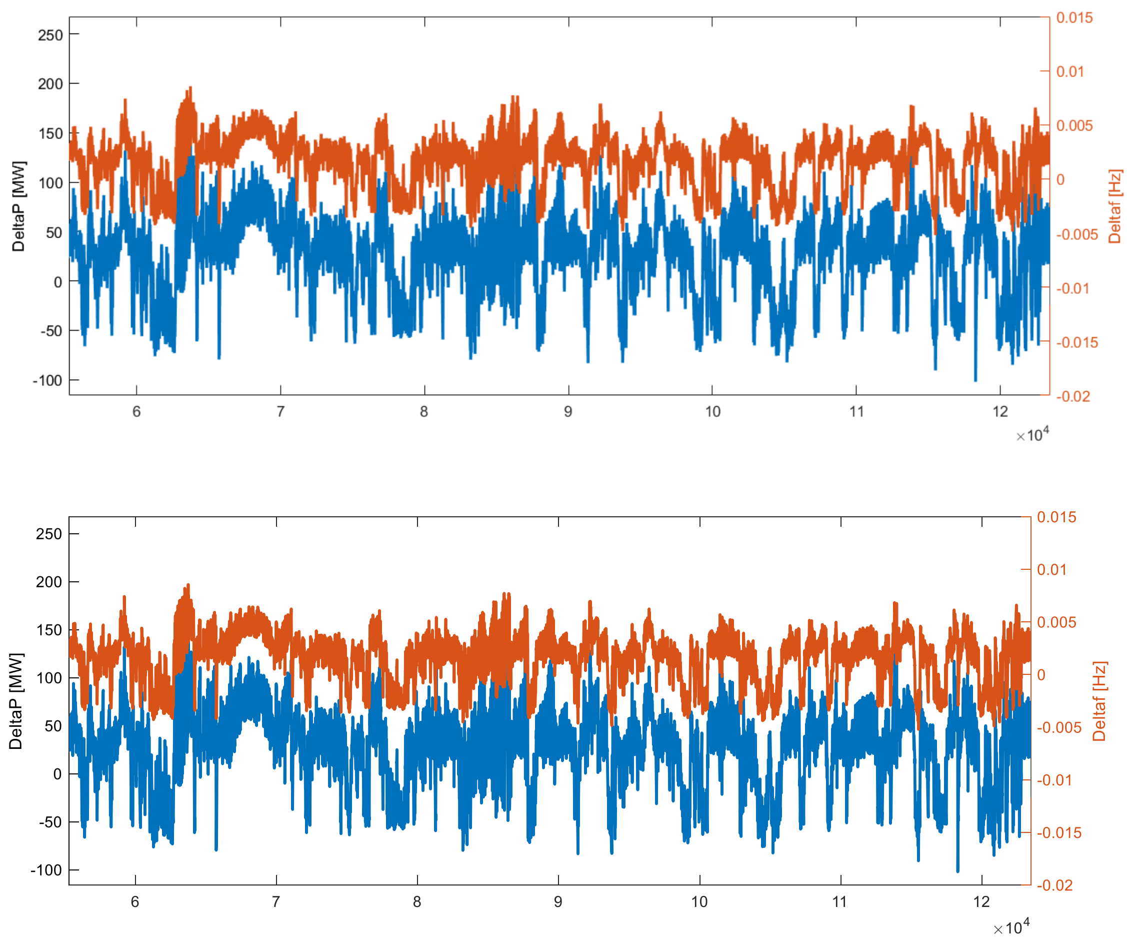


Figure 2.20. Delta P vs. Delta f.

The estimated power imbalance oscillated between a minimum of −50 MW and a maximum of 100 MW. The optimal size of the BESS in terms of power (P_{BESS}) and energy (E_{BESS}) that could supply such an imbalance, found by means of the minimization of power fluxes (as described earlier), is reported in Table 2.4 with each line corresponding to a different case. For the sake of simplicity, only the results for the moving average window of 600 s are reported. The non-supplied energy (NSE) indicator was computed as the difference between the installed batteries' energy output and the total energy requested by the system. This differs from the LoR since it depends not only on battery saturation, but also on the chosen battery size (when the installed BESS are too small, this indicator increases). The column called "NSE service" represents the NSE considering the total energy required by the specific control logic (A or B). Logic B had a lower required energy because it only required the regulation of faster fluctuations. "NSE tot" is the NSE with respect to the total power imbalance in the system (in the case of logic A, it was equal to "NSE service"). The last two columns show the percentage of NSE with respect to total energy required.

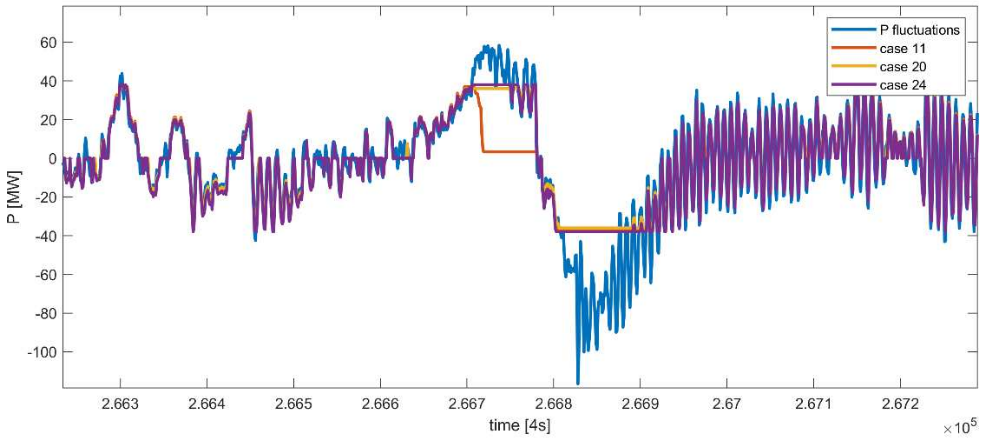
Table 2.4. The MILP optimization results.

Case	P_{BESS} (MW)	E_{BESS} (MWh)	NSE Service (MWh)	NSE Tot (MWh)	NSE Service (%)	NSE Tot (%)
1	43	98	22,503	22,503	68%	68%
2	45	103	22,827	22,827	68%	68%
3	50	114	23,960	23,960	72%	72%
4	46	105	22,381	22,381	67%	67%
5	46	105	22,753	22,753	68%	68%
6	50	114	23,960	23,960	72%	72%
7	68	155	20,888	20,888	63%	63%
8	68	155	21,299	21,299	64%	64%
9	69	157	22,938	22,938	69%	69%

Case	P_{BESS} (MW)	E_{BESS} (MWh)	NSE Service (MWh)	NSE Tot (MWh)	NSE Service (%)	NSE Tot (%)
10	20	46	5258	25,730	43%	77%
11	37	84	3535	25,191	29%	76%
12	69	157	2872	25,227	23%	76%
19	19	43	4938	25,350	40%	76%
20	36	82	3106	24,542	25%	74%
21	68	155	2324	24,447	19%	73%
22	40	91	3303	24,789	27%	74%
23	38	87	3019	24,610	25%	74%
24	38	87	3024	24,617	25%	74%
25	37	84	3031	24,619	25%	74%

For scenarios 1–9, where the actual frequency measurement was used as the input for the BESS model (control logic A), a relatively large battery size was required. This was due to the higher amplitude of oscillations that needed to be balanced. The total energy not supplied with respect to that required by the system was above 60% in all scenarios. When control logic B was applied (scenarios 10–25), the required battery size did not always change significantly from that of scenarios 1–9. Comparing the simulations with the same DB and droop settings: from scenario 1 to 10, the size of the battery was more than halved; for scenarios 4 to 11, the battery size reduced by 20%; and for scenarios 7 to 12, battery size remained almost the same. On the contrary, the energy not supplied relative to that required by the system to balance the fast oscillation reduced significantly. In case 1, the NSE was 68%, while it was 43% in case 10, 67% in case 4, 29% in case 11, 63% in case 7 and 23% in case 12. When a SOC restoration logic was applied, the battery size was further optimized and was able to reduce the NSE to a minimum of 19% in case 21, corresponding to restoration logic α and a droop of 0.4. The simulation results show that in order to have an optimally sized battery at a reduced cost with a lower NSE, the BESS should be designed with control logic B and a SOC restoration logic to ensure the effective provision of a regulation service.

Figure 2.21 provides details of the behavior of the installed BESS with different control models when the droop = 0.2 and DB = 0.02 Hz. The installed battery was of a similar size (37, 36 and 38 MW) and it was able to provide regulation for the fast fluctuations in all cases, until time = 2.667 × 10^5 (4 s). At that moment, in case 11, i.e., the scenario without SOC restoration, the BESS had a SOC of 3% and the C-rate was limited at 0.034 1/h. For this reason, there was a higher amount of NSE with respect to cases 20 and 24, where the SOC was still at 44% and the C-rate could reach 0.45 1/h. However, since power imbalances were higher than the installed BESS capacity in the three cases, the picture shows plateaus in the power output from time 2.667 × 10^5 (4 s) to 2.669 × 10^5 (4 s), which indicates that energy was not supplied. Instead of using the MILP model, BESS could have been sized to be able to respond to all power peaks, but this would have caused an oversizing of the system that would have resulted in a large capacity of the BESS not being fully utilized for the majority of time.



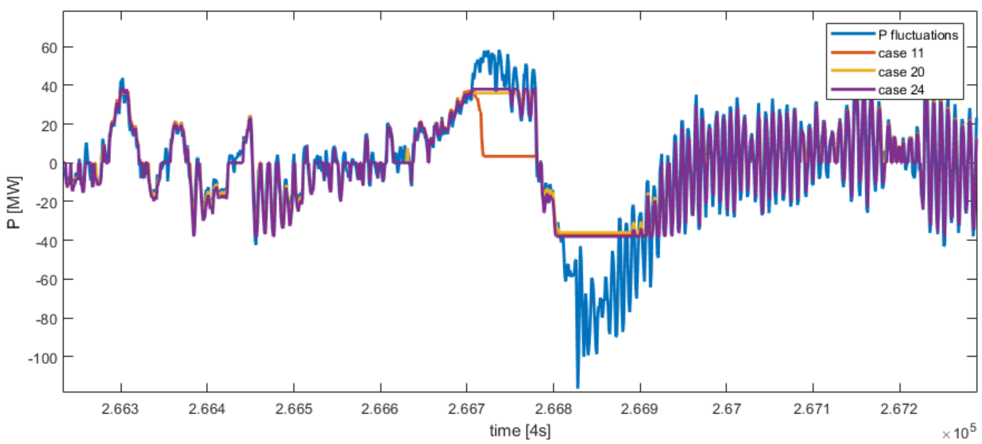


Figure 2.21. The power provided by the BESS vs. the power imbalance fluctuations.

2.8 Conclusions

In this paper, the application and effectiveness of a Battery Energy Storage System (BESS) in providing primary frequency control reserves in the WAPPITS was analyzed. Based on numerical simulations that were performed using simple open-loop BESS modeled in MATLAB/Simulink, the paper analyzed two frequency controls and state of charge restoration logics for the better utilization, performance and effectiveness of BESS using actual frequency measurements from the WAPPITS.

For the BESS frequency control logic analysis, the simulation results show that the use of the moving average frequency control logic decomposed the frequency trend into fast, smaller oscillations and slow, wider oscillations with only the faster oscillations being regulated. This frequency control logic would be an effective way of using the BESS to provide regulation service in the WAPPITS, considering the existing frequency trend.

For the BESS SOC restoration strategy control logic analysis, the BESS charged and discharged quickly due to the chaotic nature of the frequency in the WAPPITS. The SOC restoration strategy, which was based on the change in frequency being proportional to the SOC, was effective in ensuring a guaranteed availability and a higher BESS regulating service continuity.

The simulation results also show that, with the existing frequency trend in the WAPPITS, a BESS may not be the solution to the current frequency control challenges and, therefore, call for the need to put in place the necessary regulatory and technical frameworks that would require conventional power plants to provide some significant amount of primary frequency control. The deployment of BESS without solving the fundamental frequency control issues would require huge BESS sizes to provide balancing services. This is shown by the results of the optimal BESS sizes established in the paper. A possible overreliance on BESS for frequency regulation in the WAPPITS would lead to an increase in battery average C-rate and BESS life cycles and the need to frequently replace the BESS.

A limitation of the present analysis is the use of discrete values for the parameters in the input to the Simulink model (e.g., the droop and deadband settings). A sensitivity analysis with a continuous variation of their values or a Monte Carlo sampling could be useful to further investigate the different control strategies. Moreover, this paper adopted an open-loop BESS model that is already present in the literature, without modeling the entire WAPPITS. Further analysis on the application and effectiveness of BESS will be carried out using a comprehensive power flow and a dynamic model of the WAPPITS.

Chapter 3

Analysis of primary and secondary frequency control challenges in an African transmission system

The content of this chapter has been submitted to MDPI Energies, journal, special issue on "energy storage technologies and applications for smart grids" on February 18, 2025. The initial submission was revised in accordance with reviewers' feedback and recommended for acceptance and publication. It is currently awaiting the final decision from the editor.

3.1 Introduction

The frequency of an interconnected system is directly related to the instantaneous balance between generation and load. Frequency response is the ability of an interconnected system to arrest frequency excursions and stabilize frequency when subjected to disturbances such as sudden loss of generation or load [1-5]. To reliably operate a bulk power system, system operators should maintain system frequency within pre-defined limits, typically specified in a grid code. In the West Africa Power Pool (WAPP), system operators are required to keep a quasi – steady state frequency deviation of <200 mHz (49.8 – 50.2 Hz) as specified in the network standards.

The WAPP interconnected power system comprises of the power systems of 14 countries: Benin, Burkina Faso, Cote d'Ivoire, Gambia, Ghana, Guinea, Guinea Bissau, Liberia, Mali, Niger, Nigeria, Senegal, Sierra Leone, Togo. The WAPP is established to develop generation and transmission infrastructure as well as coordinate power exchange among member states. Its broader mandate is to integrate the national power systems into a unified regional electricity market with the goal of providing reliable and competitive electricity to citizens of West Africa.

Historically, national TSOs operated their grids independently, based on their own operational procedures, frequency control practices, and grid codes. Prior to the establishment of regional coordination mechanisms, frequency control provision was either non-existent or minimal. Only a few TSOs implemented primary frequency control, while most systems operated without automatic frequency response. The lack of integrated control severely limited regional reliability and system security during disturbances.

Over the past two decades, interconnection efforts have accelerated, leading to the interconnection of the power system of all fourteen (14) mainland ECOWAS countries. Integration of the power systems has also led to the need to gradually integrate frequency control mechanisms such as primary control, fast frequency reserves, secondary and tertiary control. This is expected to enable a more coordinated and dynamic frequency regulation in WAPPITS. Additionally, the development of a regional grid code consolidates efforts to harmonize operational practices and lay the foundation for the implementation of a regional ancillary services framework

The currently installed generation capacity is approximately 29 GW with average generation availability of 17 GW (60%). WAPPITS operates as three (3) synchronous areas, labelled here as Area 1-3. The WAPP transmission network has more than 42,993 circuit kilometers of high voltage transmission lines with voltage levels of 90-330 kV. Figure 3.1 shows the current and future high voltage transmission network and interconnection projects of WAPP.

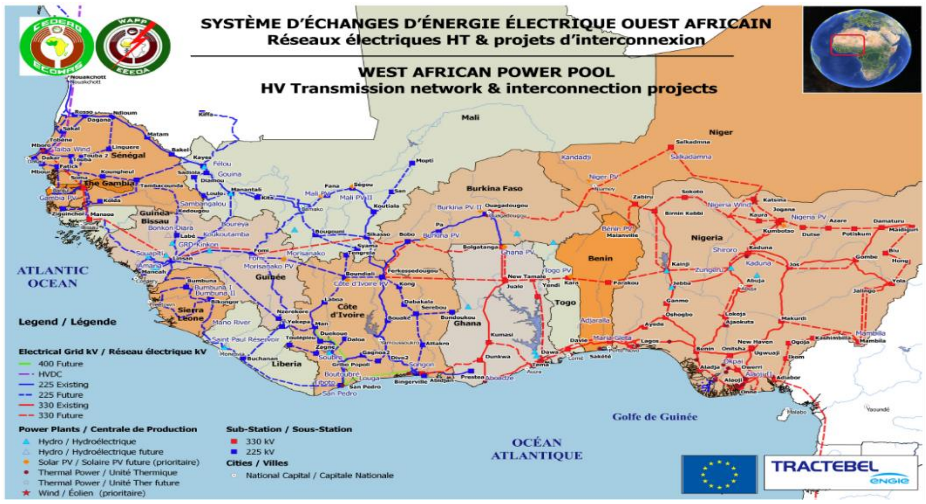


Figure 3.1. WAPP High Voltage Transmission Network and Interconnection Project.

Maintaining frequency within acceptable limits requires a system operator to have adequate available generation resources to continuously keep generation-load balance. Also, the system operator would also be expected to have sufficient resources to restore frequency after the occurrence of expected, unexpected, or unplanned events such as generator trips or a major transmission line outage.

In modern power systems, power systems operators have implemented well-established frequency control types such as primary control, fast frequency control reserves, and secondary and tertiary frequency control to ensure system stability following disturbances [2-5, 15-18]. The two core capabilities consist of primary frequency response, typically provided by automatic governor action on the prime movers of conventional power plants, and secondary frequency response, commonly managed through AGC. These methods are widely adopted in developed power systems, for example, in the continental European grid, the North American Eastern Interconnection, and systems operated by ISOs like PJM, CAISO, and ERCOT—where clear roles are defined for each balancing area and frequency reserves are procured through structured ancillary services markets.

In contrast, whilst a traditional frequency control structure has been defined in some national grid codes in WAPPITS, and also in a recently proposed yet to be adopted regional grid code, practical implementation remains inconsistent. Unlike developed systems that have implemented well-defined reserve obligations, WAPPITS faces persistent challenges in maintaining frequency stability, particularly due to non-uniform operational practices, lack of standardized ancillary services framework, especially frequency control reserves, and minimum enforcement of frequency response obligations across TSOs. In practice, WAPPITS' recent operation demonstrates persistence challenges with frequency control [6-7]. As a result, WAPPITS is operated as the three separate synchronous blocks mentioned earlier. There has been substantial discussion about, but no final conclusions on, why frequency control has been a problem in WAPPITS.

From a purely technical perspective, the operation of system frequency control is not only well-understood, but also widely implemented globally. From the discussion above, it is apparent that issues in WAPPITS represent a socio-technical challenge where technical, economic, and socio-political factors interact to obscure the fundamental causes of WAPPITS' frequency control issues. Therefore, this study used a socio-technical approach to decompose system issues. We used questionnaires sent to system operators to understand how the frequency control system was implemented in practice, and an analysis of field measurements to confirm certain points from the questionnaires with operational data. Combining methods provides unique insights into the operation of a large power system in the developing world that is expected to incorporate VRE generation at penetration rates that have challenged the most developed power systems in the world [67-70]. The novelty of this paper lies in its focus on diagnosing and highlighting the unique frequency regulation challenges specific to the WAPP grid, which differs significantly from those encountered in well-developed grids. Unlike existing studies that assume certain baseline conditions typical of mature systems, our approach identifies foundational issues that must be addressed before advanced solutions, common in developed networks, can be effectively implemented. This perspective is critical for designing realistic and context-appropriate solutions tailored to the actual operational environment.

The paper is structured as follows: Section 1 presents the introduction, Section 2 outlines the methodology used for the study, Section 3 discusses the results, Section 4, the discussions and Section 5 presents the conclusions.

3.2 Methodology

The methodology of the paper includes two parts - a questionnaire to assess the current state of operations in each of the TSOs and confirmatory study of these responses using frequency control tests and frequency response analysis based on metrics calculated using data primarily sourced from Phasor Measurement Units (PMUs) deployed in the Wide Area Monitoring System (WAMS). The combination of methods provides a techno-operational view of WAPPITS' current challenges. The questionnaires provided observations from TSO personnel which are based upon broad experience but are still subject to observational biases by the observers. To confirm questionnaire responses - i.e. to check on biases in the responses - WAPPITS conducted frequency control tests in the WAPP grid by performing governor compliance verification tests on power plants.

3.2.1. TSO questionnaires

The primary data source for this analysis was responses provided by ten (10) TSOs to questionnaires covering key frequency control systems. The questionnaire was sent via email to technical representatives in each TSO who were familiar with central control operations. The first author followed up with representatives to assure a response and spoke with several to clarify why the questionnaire was sent, what answers were expected, and why responding was important. During this process, the first author was careful to avoid biasing the answers by suggesting or diagnosing potential responses. While individual TSOs required different levels of engagement, responses were received from all TSOs. Questionnaire responses were received via email.

Once responses were received, the first author coded answers to the questions as follows:

i. **Primary Frequency Control:** TSOs were required to answer "Yes" or "No" to whether power plants provide primary frequency control (PFC) service and if the reserve amounts are adequate during a typical operating day. A "1" was assigned to a "Yes" response and a "0" to a "No" response.

ii. **Secondary Frequency Control:** TSOs were required to provide a "Yes" or "No" to whether secondary frequency control is provided by power plants, if secondary frequency control reserves are adequate or not and whether control is implemented manually or automatically. A "1" was assigned to a "Yes" response to implementation of secondary frequency control and a "0" to a "No" response.

iii. **AGC Implementation:** TSOs were required to provide a "Yes" or "No" answer to whether secondary frequency control has been implemented in the TSO control room using AGC. Responses were coded considering both the response to whether secondary frequency control is implemented and whether AGC was implemented, resulting in three codes:

"1" indicates neither secondary frequency control nor an AGC system was implemented.

"2" indicates secondary frequency control was implemented but without an operational AGC system.

"3" indicates secondary frequency control implemented using AGC.

iv. **Cost Recovery and Pricing:** TSOs were required to answer a "Yes" or "No" to whether cost recovery and pricing mechanisms are in place for frequency control services. A "1" was assigned to a "Yes" response and a "0" to a "No" response.

v. **Penalties for Non-Compliance:** TSOs were required to answer a "Yes" or "No" to whether penalties are applied for not providing the required frequency control services. A "1" was assigned to a "Yes" response and a "0" to a "No" response.

The Yes/No responses requested in the questionnaire were intentionally designed to force respondents to use their experience operating the system to make a yes/no judgement of whether a particular subsystem was *operationally* present. In some cases, this judgement and the *stated technical condition* of the system match: For example, there may be no AGC system implemented. However, this judgment may also differ substantially from the technically documented or stated condition of the system. For example, power plants may have *stated* a provision of primary frequency control, but in the experience of the TSO operator, no – or insignificant quantity of – primary frequency response was available *in practice.* The coded answers to the questionnaire should therefore be considered encoded judgements by TSO operational personnel capturing day-to-day operational realities.

Table 1 and 2 show the numerical assignments for responses from TSOs.

3.2.2 Analyze frequency control implementation with field testing

Questionnaire responses were compared with a field test to measure the response of a subset of generation units that were self-identified as supplying primary frequency control services. Testing consisted of exercising the governors of these generating units to determine if settings were compliant with the required droop, intentional deadband and frequency response requirements specified in the applicable grid code. The following parameters were assessed:

- Permanent droop setting – The required droop setting for the hydro and gas turbine generators is 4% and for other generator units is 5%.
- Intentional dead band setting: The required intentional dead band setting is ≤ 0.05Hz.
- Primary Frequency Response – the active power output increase/decrease due to frequency change should occur within 15sec and 30sec from steady initial condition. In addition, primary frequency response provided by TSOs should be sustained for at least 20min after a frequency deviation.

A third-party company was engaged to perform tests by the injection of a test signal to the unit's governor to simulate a frequency event that would result in an increase/decrease in the power output of the unit. Using the recordings from these tests, droop, intentional deadband and primary frequency response information were computed and compared to the required settings.

3.2.3 Analyze response of generating units during selected events in WAPPITS

Performance parameters reported by TSOs in the questionnaire and measured in the field were then compared to observed frequency control during three selected events that occurred in WAPPITS. Frequency response curves were generated using data extracted from selected PMUs in the WAMS application installed in the WAPP regional control center. To analyze frequency response effectiveness, the minimum frequency metric, known as nadir frequency (FC), estimated time to arrest frequency (nadir time (tC)), nadir-based frequency response, and rate of change of frequency (ROCOF) were computed and analyzed [10, 71-80].

The purpose of this analysis was to confirm data indicated by the two prior analyses.

3.2.4 Synthesis process

Results of all three analyses were analyzed to identify agreement or disagreement between the results of each analysis. This synthesis process identified if the experience of TSO operational personnel reflected observed frequency control and response characteristics seen in field measurements.

3.3 Results

This section presents analysis of the results.

3.3.1 Results of Analysis of Response to Questionnaires

Analysis of questionnaire responses provided insight into the aggregate experience each TSO has with their frequency control reserves.

In Table 3.1, eight (8) of ten (10) TSOs indicated that primary frequency control service was implemented in the TSO, but nine (9) of 10 TSOs indicated that reserves provided were inadequate to meet system needs. With 80% of the TSOs responding positively to implementing primary frequency control, the grid is generally well-equipped to handle minor disturbances across the service territories of these TSOs. However, the lack of PFC implementation in 2 TSOs could potentially create localized instability in those areas, making the grid more vulnerable to frequency deviations during generation-demand imbalance. Without sufficient primary frequency control reserves, it will be practically difficult to maintain frequency within acceptable limits, particularly at higher penetration of VREs.

The absence of PFC, or insufficient PFC resources, a generation loss will likely trigger automatic under frequency load shedding (UFLS) and local blackouts. If load shedding is insufficient or too slow, a total system collapse is likely. TSO responses confirm that the current approach to frequency management in the WAPP region is heavily reliant on under frequency load shedding to keep the system intact since primary frequency control reserves are often less generation loss. This approach to frequency control is typically not the best practice from either a customer satisfaction or system control perspective; generally, UFLS should be a last resort for primary frequency response. During some historical events, in the WAPP region, UFLS was unable to deal with fast frequency decline, sometimes leading to system partial or total blackouts [15].

Again, referring to Table 3.1, five (5) of ten (10) respondents answered "yes" to the provision of secondary frequency control service, while only one (1) indicated secondary reserves were adequate. Lack of secondary frequency control in 50% of the TSOs poses a risk of sustained frequency deviations in those sections of the grid. Prolonged and sustained frequency deviations shift base frequency from nominal frequency, increasing the risk of unexpected UFLS, damaging customer equipment, and increasing the risk of system instability.

In Table 3.2, three (3) TSOs indicated they have AGC installed in the control room, but none have implemented it for secondary frequency control – i.e. secondary frequency control is performed manually by control room operators. Two (2) TSOs indicate that secondary frequency control is implemented but have no AGC in the control room, implying that secondary frequency control is entirely manual. Without automatic secondary frequency control via AGC, system operators must manually intervene to perform secondary frequency control.

Manual intervention for secondary frequency control is largely non-existent in more developed control systems. In practice, manual intervention has a substantial time delay, as operators must observe a generation issue, decide on a course of action, contact generation operators, and wait for the generator(s) to react. As a result, the system reacts slowly to sustained frequency deviations. In some instances, whilst manual interventions are ongoing, additional frequency deviations may occur, leading to further frequency decline, UFLS, and cascading outages. From a control dynamics perspective, the controlled system dynamics – i.e. the power grid – are as faster or faster than the control system – i.e. manual load balancing for secondary frequency control. This is a recipe for instability.

The red box in Table 3.2 i indicates that only 1 of 10 TSOs indicated that either reserve type was both provided *and* adequate for system needs. Interestingly, one TSO indicated that they had not implemented primary frequency control but had implemented secondary frequency control. This combination is unusual. It is evident that frequency control structure and implementation within the WAPP grid is an important topic that must be discussed and addressed.

Table 3.1. Heatmap of questionnaire responses related to adequacy of primary and secondary frequency control services

Question	TSO										Total
	1	2	3	4	5	6	7	8	9	10	
Primary FC Implemented	1	1	1	1	1	0	1	0	1	1	8
Adequate Primary FC	0	0	0	1	0	0	0	0	0	0	1
Secondary FC Implemented	0	0	1	1	1	0	0	1	1	0	5
Adequate Secondary FC	0	0	0	1	0	0	0	0	0	0	1
Legend:	Yes	1	No:	0							

Table 3.2. Heatmap of questionnaire responses related to installation and implementation of AGC and secondary control

Question	TSO										Total		
	1	2	3	4	5	6	7	8	9	10	None	One	Both
AGC Installed in Control Room	0	0	2	1	1	0	0	2	2	0	5	2	3
AGC Implemented for Secondary FC	0	0	1	1	1	0	0	1	1	0	5	5	0
Automatic Secondary FC	0	0	1	1	1	0	0	1	1	0	5	5	0
Legend:													
	0	Secondary FC not implemented and no AGC											
	1	Secondary FC implemented but no AGC (entirely manual control)											
	2	Secondary FC implemented and AGC in control room (assisted manual)											
		TSO indicated adequate primary and secondary reserves											

All TSOs indicated that there are no cost recovery and pricing mechanisms for the provision of primary and secondary frequency control services. As a result, revenue for generation operators is constrained to payments for energy delivered. Likely, generators may prioritize meeting demand requirements of its customers, thus maximizing income, rather than reserving capacity for system reliability. While this cannot be confirmed, generation operators may have concluded that lost revenue due to load shedding and blackouts is less than lost revenue from reserving capacity for primary or secondary frequency control purposes.

Similarly, all TSOs indicated there are no penalties for *not* providing frequency control services. This is not surprising since the framework and structure that will enable the mandatory or market-based provision of these services are not in place. The regulators cannot penalize power plants for not providing the services.

Summary: Questionnaire responses highlight significant challenges in the implementation of frequency control in the WAPP grid. In most developed grids, power system operations require the availability of well-defined primary and secondary frequency control reserves. These large interconnected systems deploy AGC to restore frequency and maintain interconnection schedules.

In contrast, TSO operations staff indicate that these reserves and the required control systems are not *practically* available in the WAPP grid, likely because these reserves are not prioritized. Primary frequency response and reserves are limited, leading to ongoing frequency variability and large frequency deviations during events. Secondary frequency response requires manual intervention by control room personnel. The resulting, obvious, frequency control problems raises concerns about the assumptions being made to increase the share of inverter-based generation in the WAPP grid. Unlike other developed grids where traditional frequency control approaches have been adopted and implemented, this assumption cannot be made for the WAPP grid.

3.3.2 Results of Analysis of Field Testing of Generating Units

Observations from TSO personnel are based upon broad experience, but are still subject to observational biases by the observers. To confirm questionnaire responses, WAPPITS conducted frequency control tests for in the WAPP grid by performing governor compliance verification tests. Tests were performed pre-selected power plants that had indicated they were either providing some limited primary frequency regulation or have the capability to provide frequency response. Power plant selection was not based on its location in a specific TSO area. The analysis in this section examines how well existing droop, intentional deadband and governor control modes have been implemented on these generation units; see Table 3.3.

Table 3.3. Droop and deadband of pre-selected existing power plants

No.	Plant Type	Nominal Power (MW)	Existing Droop (%)	Droop Active	Existing Deadband (Hz)	Deadband within Standard	Primary FR within Standard	Governor Control Mode	Setting Effective for PFR
1	Hydro	173	4%	1	±0.1	0	0	Load Controller (Preselect)	Yes
2	Thermal	115	-	0	0	0	0	Load Controller (Preselect)	No – no droop
3	Thermal	131	-	0	0	0	0	Load Controller (Preselect)	No – no droop
4	Hydro	137	4%	0	±0.3	0	0	Opening Regulating Mode OR Power Regulating Mode	No – excessive deadband
5	Thermal	147	4%	0	±0.01	1	0	Droop inactive	No – effectively 0 droop
6	Hydro	120	-	0	-	0	0	Frequency Mode / Opening Mode / Power Mode	No
7	Hydro	92	-	0	-	0	0	Frequency Mode / Opening Mode / Power Mode	No
8	Hydro	108	4%	1	±0.2	0	0	Smooth operation	Yes
9	Hydro	81	-	0	±0.2	0	0	Active power setpoint mode / Gate position setpoint mode	No – looks like it is manual
10	Hydro	94	-	0	±0.3	0	0	MW Control Mode (Primary Frequency Response Disabled)	No – power only mode
Total Count:			**4**	**2**		**1**	**0**		
Fraction		**5%**	**40%**	**20%**		**10%**	**0%**		
Total Power:		1198					0		

Six (6) of ten (10) generating units do not have droop settings implemented – i.e. 60% of generating units that have stated primary frequency response will not respond to changes in system frequency. Of the four (4) generating units that had droop settings implemented, two (2) had their droop control active. Therefore, only 20% of the generating units are actively enabled to provide primary frequency control. These two (2) units have a total nominal power of 281 MW, less than the 440 MW primary frequency control reserves required in WAPPITS. Assuming, these generating units agree to provide their entire output for primary frequency control, which is not technically feasible, there are still inadequate primary frequency control reserves for regulation. Therefore, UFLS will be the primary resource for primary frequency response for any disturbance equivalent to the 440 MW primary frequency control reserve requirement. The analysis in the next section indicates that frequency response during recorded events was likely provided primarily by UFLS.

Similarly, nine (9) out of the ten (10) generating units analyzed have deadband settings outside the predefined value. Analyzing the droop and deadband settings, neither of the two (2) generating units with active droop control had a correct deadband setting – one had a deadband setting of 100 mHz, the other a setting of 200 mHz. This means no frequency control action will be taken until frequency excursions exceed at least 20 times the predefined deadband value.

Considering that the frequency in the WAPP grid should be maintained within ±200 mHz, governors of generating units should be responsive to events that cause deviations within this range. In addition to decreasing the response from primary reserves, the wider deadband also increases the effective response time of these units. As noted earlier, this contributes to a control system which operates slower than the dynamics of the system being controlled. As a result, the delay in response, coupled with insufficient primary frequency reserves, further increases frequency deviations, fails to arrest frequency decline, and likely triggers UFLS as a primary means of prevent system collapse.

In summary, the assessment of governor control mode reveals that the primary frequency response contribution from a selected subset of generation units is almost non-existent, supporting observations made by TSOs in the questionnaire phase of this study.

3.3 Frequency response analysis of selected events

A final analysis of field data applied frequency response metrics to recorded data using Grid Digital's Phasoranalytics™ software. Phasoranalytics imports historical phasor data from WAMS to perform frequency response analysis. Based on frequency plots, selected frequency metrics were used to analyze frequency response. The first author performed three case studies developed from one generation loss event in each of WAPPITS synchronous areas.

3.3.3 Event-based frequency response analysis

3.3.3.1 Case 1/Figure 3.2: Frequency Response for 300 MW generation trip in Synchronous Area 1

A generation loss of 300 MW in Synchronous Area 1, caused frequency to drop from 50.2 Hz to an initial nadir frequency of 49.3 Hz and then to second nadir of 49.03 Hz, the UFLS threshold. Initial frequency was higher than the grid standard due to over-generation and slow reaction of generator controls to regulate frequency. Subsequently, TSO actions (i.e. manual load shedding) to recover frequency worked briefly, followed by an additional frequency drop to 48.63 Hz. Frequency then recovered to 49.10 Hz through further manual load shedding. The total load shed was unknown as reported by TSO. This event supports questionnaire responses indicating inadequate frequency control reserves, and also likely illustrates that using a combination of automatic and manual UFLS to restore frequency compounded frequency deviations.

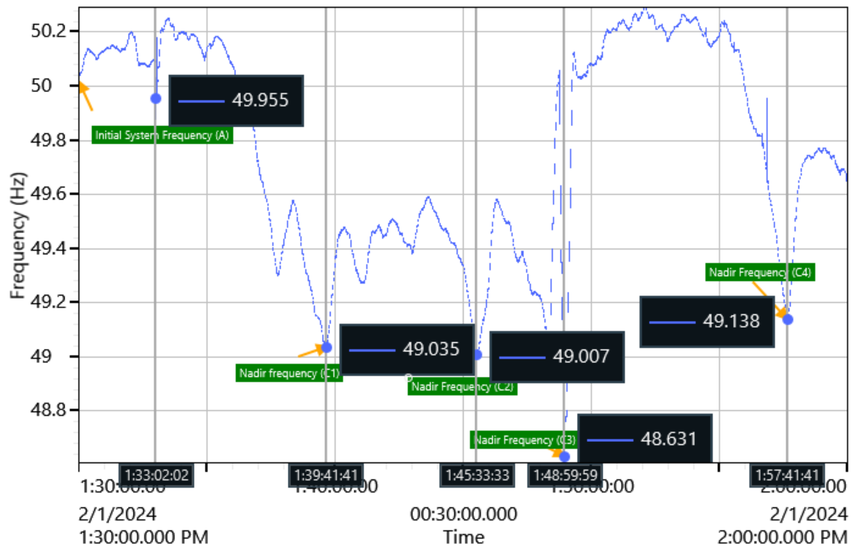


Figure 3.2. Frequency response for 300 MW generation trip which occurred on 1st February 2024.

3.3.3.2 Case 2/Figure 3.3: Frequency Response for 200 MW generation trip in Synchronous Area 2

A 200 MW generation trip in Synchronous Area 2 caused a rapid frequency drop to a nadir of 49.33 Hz that triggered automatic UFLS of 150 MW which helped recover frequency to ≈50.2 Hz. During this event, units involved in primary response appeared to have played no significant role in frequency recovery, a strong indication of the lack of adequate primary frequency control reserves in WAPPITS.

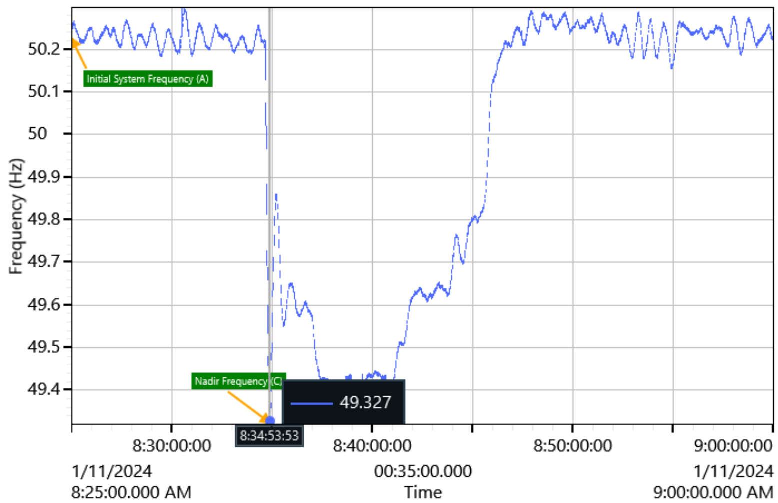


Figure 3.3. Frequency response for 200 MW generation trip which occurred on 11th January 2024.

3.3.3.3 Case 3/Figure3.4: Frequency Response for 90 MW Generation trip in Synchronous Area 3

A 90 MW generation trip occurred on 1st April 2024, resulting in a nadir frequency of 49.24 Hz accompanied by an automatic UFLS of 66 MW, which helped recover frequency to about 50.1 Hz. However, frequency was highly variable for the next 25 minutes, marked by a frequency decline to another nadir of ≈49.30 Hz. The reason for the decline was unreported but could have been caused by loss of additional generation units tripped by the frequency or voltage deviations or re-engagement of load shed circuits before adequate secondary reserves were online. The time between the first and second nadirs was likely sufficient for operational personnel to execute load balancing actions required for secondary frequency control. Given the extended period with highly variable and decreasing frequency, these control actions were insufficient to arrest frequency instability, likely indicating the control room personnel were struggling to understand and respond to the situation. This phenomenon is a clear demonstration that lack of adequate primary frequency control, and to a large extent a lack of AGC for secondary control, makes manual frequency control difficult in a system as large as a WAPPS synchronous area.

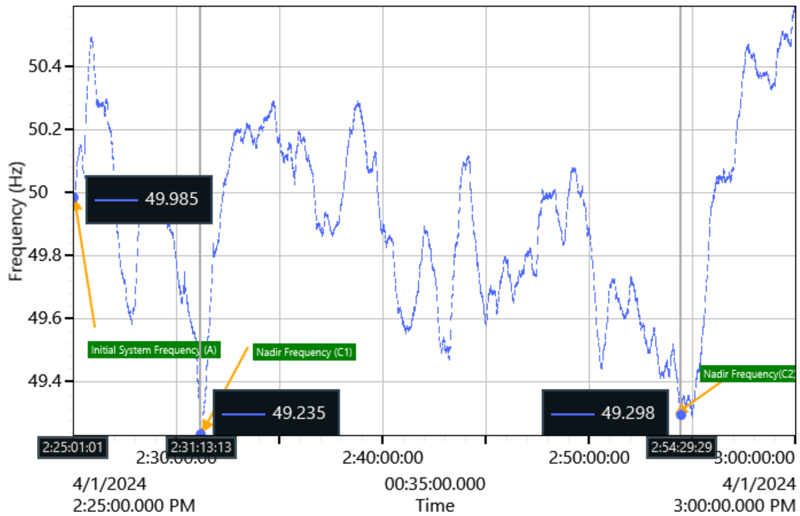


Figure 3.4. Frequency response for 90 MW generation trip which occurred on 1st April 2024

3.4 Discussion

Summarizing the analysis work, this section outlines the problems identified in the analysis of frequency control challenges in WAPPITS and proposes solutions to address these problems.

The following key problems have been identified:

i. A significant deficiency in primary frequency control reserves, which leads to reliance on under-frequency load shedding (UFLS) for maintaining system stability.

ii. Absence of an ancillary services market limits incentives for generators to provide frequency control reserves, leading to prioritization of energy delivery over system reliability.

iii. Variability in frequency control practices among different Transmission System Operators (TSOs) indicates a lack of uniformity and coordination within the WAPP grid.

iv. The combination of inadequate primary and secondary frequency control resources, coupled with manual interventions, poses a risk of cascading outages and total system collapse.

To address the identified problems, the following solutions are proposed:

i. *Development/Implementation of Grid Codes:* Uneven implementation of reserves indicates that TSOs should align frequency control requirements in national grid codes with the WAPP Grid Code. Additionally, national regulators will need to collaborate with TSOs to ensure enforcement of frequency control requirements.

ii. *Implementation of Ancillary Services Market*: This study indicates that generators are likely prioritizing energy delivery, as evidenced by persistent over-frequency conditions within WAPPITS. This behavior is likely due to a lack of incentives to provide reserves, as many independent power producers have power purchase agreements to deliver full capacity. In most developed grids, an ancillary services market is used to procure primary and secondary frequency control reserves and is likely needed in the WAPPs grid as well.

iii. *Mandatory Provision of Primary Frequency Control*: Prior to the implementation of an ancillary services market, frequency control would be improved by implementing a mandatory requirement for the power plants to support primary frequency control. The class, type, or size of the plants required to implement PFC capability would need to be identified. A framework to periodically test (governor compliance verification test, frequency response tests tec.) power plants to assess and evaluate the effectiveness of frequency control post implementation will have to be put in place.

3.5 Conclusions

This study was conducted against the backdrop of increasing pressure on the grid operator(s) to incorporate higher penetration of VREs. VRE penetration in WAPPITS is modest with significant growth projected over the medium to long term. VREs typically lack inherent inertia and traditional governor-based frequency response, which may exacerbate existing issues such as low primary frequency reserves and reliance on manual interventions. Different European demonstration projects have shown interest in the use of battery energy storage systems and other control systems as a possible solution to mitigate the variability of VREs and at the same time provide ancillary services to the grid [78]. However, most of these technologies have been developed on large, stable, power systems with robust frequency control systems. The purpose of this study was to clarify the current state of control systems within WAPPITS, in contrast to other, internationally recognized control methodologies.

While there is a tendency to use only technical methods to analyze system response, to implement any control system, both technical and social factors must be addressed. Technical systems cannot be implemented without robust regulatory guidance (grid code) and controls (enforcement), and with sufficient economic investment (ancillary markets). Additionally, the practical experience of control room operators is often discounted: After all, they are able to keep the system running a substantial portion of the time, albeit with highly variable frequency characteristics.

This study started with the techno-social experience of control room operators, which indicated a near total absence of primary, and automatic secondary, frequency control reserves and concomitant control systems. Since human inputs inputs may be biased, the subsequent technical analyses was used to confirm the operators' observations: In practice, no primary response units had workable governor settings, and in typical events, automatic and manual UFLS was the primary means of arresting frequency drops.

Two recommendations can be made for WAPPITS to operate reliably at higher penetration levels of inverter-based resources: (1) Adopt and enforce primary frequency response requirements through regional regulation, and (2) mobilize secondary frequency control resources and other frequency control products through an ancillary services market. Additionally, when an ancillary services market is in place, TSOs should be obliged to procure and use ancillary services in their generation scheduling and dispatch and during real time system operations.

Chapter 4

Analysis of Grid Scale Storage Effectiveness for a West African Interconnected Transmission System

The content of this chapter has been submitted to Energies journal, special issue on “modeling of energy storage systems for future power grids” and under review.

4.1 Introduction

The frequency of an interconnected system is directly related to the instantaneous balance between generation and load. Frequency response is the ability of an interconnected system to arrest decline and stabilize frequency when subjected to disturbances such as sudden loss of generation or load [1][2][3][4][5]. To reliably operate a bulk power system, system operators must maintain system frequency within pre-defined limits specified in the relevant grid code. In the West Africa Power Pool (WAPP), the frequency requirement specified in the network standards is a quasi-steady state frequency deviation of <200 mHz (49.8 – 50.2 Hz).

Maintaining frequency within acceptable limits requires the system operator to have adequate available generation resources to maintain generation-load balance and to restore system frequency after the occurrence of expected, unexpected, or unplanned events such as generator trips or a major transmission line outage.

In modern power systems, primary frequency response is typically provided by automatic governor action on the prime movers of conventional thermal or hydro power plants; secondary frequency response is provided by automatic generation control (AGC). This frequency control structure is well established in mature grids such as those operated by PJM, CAISO, and the continental European grid, where frequency control provision has been implemented over decades, with ongoing innovations supported by regulatory frameworks and ancillary services markets [2-8,15,19,81].

However, in WAPPITS, there have been persistent challenges with frequency control. WAPPITS experiences chaotic frequency fluctuations and has a patchwork of country-level regulatory requirements, unlike more developed grid operators. These issues have raised questions about the underlying causes of inadequate frequency control in WAPPITS. The authors established in [6, 7, 8] that, due to a lack of primary frequency control reserves in WAPPITS, operators systematically use under-frequency load shedding as a primary means of regulating frequency. Longer-term plans for WAPPITS include rapid increase of renewable resources. This increase makes frequency control requirements a topical subject, as the integration of inverter-based resources does not readily provide system inertia and primary frequency response [15-18,73-77]. Technical and financial partners have strongly encouraged BESS implementations for primary, in some cases, secondary, frequency control in WAPPITS. These entities commonly reference experience with system operations in developed countries, where primary and secondary frequency control has a long operational history.

While developed grids are now exploring the integration of BESS to complement or enhance frequency control—often in response to growing shares of inverter-based renewables, WAPPITS faces a fundamentally different challenge: The absence of frequency control reserves from a grid with predominantly conventional power plants such as hydro and thermal (gas and crude). This context presents a unique opportunity to examine frequency control not as modification of an existing, well-established and functional, system, but as a system-defining tradeoff between conventional and storage-based resources such as BESS.

In [7], the authors presented a first-order numerical analysis using simplified open-loop models and historic WAPPITS frequency data. That study examined the role and effectiveness of BESS in providing primary frequency response. The findings suggested that, while BESS can technically respond quickly to frequency variations, it may not represent a cost-effective solution under current system conditions. The study recommended changes to regulatory and technical frameworks to require conventional power plants to provide sufficient primary frequency control reserves.

This paper builds upon the analytical foundations laid in [6], [7] and [8] using simulations to assess mixes of conventional and BESS primary frequency reserves (PFR) in WAPPITS. The study uses PSS®E simulations of a fully interconnected WAPPITS grid model. The model had been recently tuned using field-test data. The study is restricted to *primary* frequency response; secondary frequency response is not simulated or analyzed. Simulations provide a 1st order analysis of the techno-economic tradeoff between frequency control effectiveness and cost for a range of BESS/conventional mixes.

This approach acknowledges the growing interest in BESS among development partners and regional stakeholders but also grounds the evaluation in the practical realities of WAPPITS. Specifically, prior studies of this topic were primarily conducted on developed grids, evaluating BESS as a new component within a well-established frequency control mechanisms. In contrast, this study examines a BESS in the context of WAPPITS: relatively weak grid characterized by lower energy intensity, constrained investment, and a large and marginally interconnected geographical coverage. Currently, WAPPITS has few functioning PFRs. Thus, the study represents a ‘green field’ analysis of how to implement a PFR system: Conventional, BESS, or a mixture of the two?

The study (a) examines the effectiveness of BESS as PFR in a grid with limited (practically non-existent) primary frequency control reserves from traditional conventional power plants, and (b) develops the techno-economic tradeoffs between combinations of convention and BESS deployments. The analysis highlights the unique trade-offs in systems like WAPPITS, where BESS alone may not enhance frequency control cost-effectively unless paired with strategic deployment of conventional PFR through the implementation of regulatory and market reforms. Finally, the paper provides context-specific recommendations tailored to WAPPITS to guide realistic and cost-effective pathways for implementing frequency control.

The paper is organized as follows: Section II presents frequency control in the WAPPITS, Section III the methodology, Section IV results, and finally Section V presents the conclusions.

4.2 Frequency control in the WAPP Interconnected Transmission

The WAPP interconnected power system comprises of the power systems of 14 countries: Benin, Burkina Faso, Cote d'Ivoire, Gambia, Ghana, Guinea, Guinea Bissau, Liberia, Mali, Niger, Nigeria, Senegal, Sierra Leone, Togo. The currently installed generation capacity is approximately 29 GW with average generation availability of 17 GW (60%). The WAPP transmission network has more than 42,993 circuit kilometers of high voltage transmission lines with voltage levels of 90-330 kV. Figure 4.1 shows the current and future high voltage transmission network and interconnection projects of WAPP.

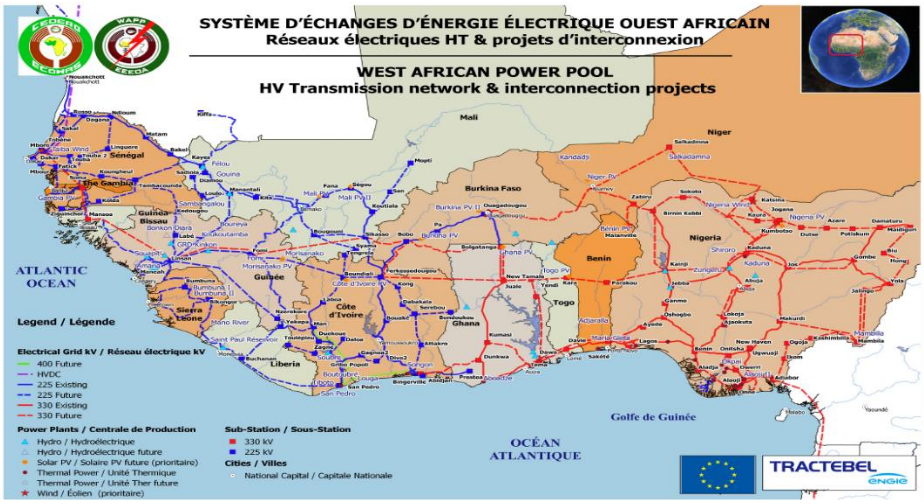


Figure 4.1. WAPP High Voltage Transmission Network and Interconnection Project [19]

Prior to having the power system of all fourteen (14) mainland ECOWAS countries interconnected and a single entity (WAPP Information Coordination Center) coordinating regional reliability efforts, national TSOs operated their grids independently, based on their own operational procedures, frequency control practices, and grid codes. Frequency control provision was either non-existent or minimal. Only a few TSOs implemented primary frequency control, while most systems operated without automatic frequency response. The lack of frequency control exposed WAPPITS to disturbances, often requiring under frequency load shedding [6-8].

WAPPITS' inherent challenges are illustrated by comparison the California ISO. CAISO has a similar length of transmission line (41,850 km) to service a land area 7% of WAPPITS' area (340,000 versus 5 million km^2), with a peak generation 3 times that of WAPPITS (88 GW), all within one sub-national political jurisdiction. WAPPITS long lines, widely distributed power plants and highly dispersed loads, produce exceptional grid control challenges. Additionally, CAISO has a well-developed ancillary services market providing the full range of services; WAPPITS only operates an energy provision market [6].

4.3 Methodology

This section discusses the methodology adopted to simulate and analyze frequency control in WAPPITS.

3.1 Simulation Models

- Modified WAPP Interconnected Network Model: For the purposes of this research, the simulations and analysis were performed using a slightly modified static (.sav) and dynamic (.dyr) model of the WAPP Power System. Dynamic data from selected power plants were updated using field test measurements to enhance their dynamic response and bring their dynamic behavior closer to actual operating conditions.

- PSS/E Generic Models: To simulate dynamic behavior of the BESS, generic generator/converter model (REGC_A), electrical control model (REEC_C) and energy plant controller (REPC_A) in the PSS/E Model Library [81] were used. For synchronous generators, PSS/E standard models used are GENROU for round rotor machines and GENSAL for salient pole machines. For turbine/governor models, the PSS®E standard models HYGOV, TGOV1, GAST and DEGOV1 have been used for hydro, steam, gas, and diesel units respectively with typical parameters and the droop parameter, where available. Other models such as PIDGOV, IEEEG1 and IEESGO provided by TSOs have also been used. The turbine load controller model LFCB1 is used for load frequency control modelling.

4.4 BESS Modeling

A complete Battery Energy Storage System (BESS) comprises of three (3) major components as shown in figure 4.2. The battery module stores electrical energy, the power electronic converter converts DC to AC which is injected into the grid. The digital controls of the BESS provide the various functionalities of the BESS system.

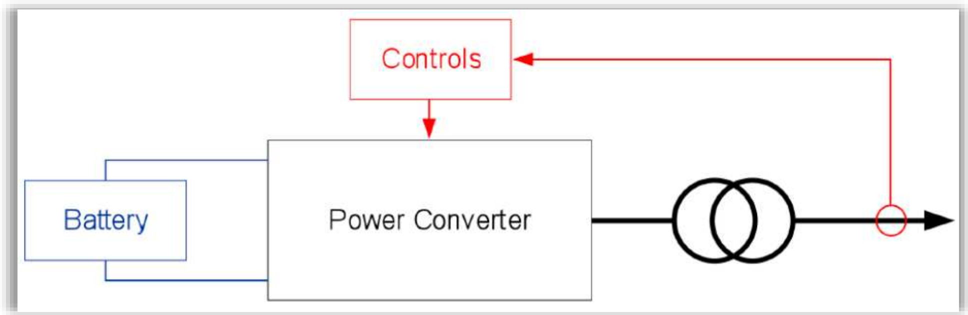


Figure 4.2. Components of a BESS

The BESS was modelled using a single renewable machine that is connected to the grid in steady-state operation.

PSS/E generic models shown in figure 5 were used to assess BESS dynamic behavior. The model consisted of three (3) modules, namely:

- *REGC_A* – the renewable energy generator/converter model, version a.
- *REEC_C* – the renewable energy electrical controls model, version c.
- *REPC_A* – the renewable energy plant controller, version a.

The Generator/Converter Model (REGC_A) in PSS/E processes the currents, Ipcmd and Iqcmd, from the electrical controller (REEC_C), and sends an active output (Ip) and reactive (Iq) currents into the grid. The Ipcmd and Iqcmd are used to help simulate how the converter will respond to grid conditions or setpoints in dynamic simulations.

REEC_C is the electrical controller module that can operate in the four quadrants of the P-Q diagram. It receives active, Pref, and reactive, Qref, power reference inputs from the plant controller (REPC_A) with feedback from the generator output and the voltage terminal. Its output is the active, Ipcmd, and reactive, Iqcmd, currents which are inputs to the generator/converter module (REGC_A).

The plant controller, REPC_A processes active power and the frequency to model the active power control or the frequency response. It processes the reactive power and the voltage to model the reactive power control or voltage regulation, and then sends output active, Pref, and reactive, Qref, power references to the electrical controller (REEC_C).

All simulations calculated the frequency response using the maximum N-1 contingency scenario for the combined WAPPITS system: The loss of 400 MW generation unit. Simulations extended after the contingency event until frequency stabilized, typically at a frequency below the grid frequency of 50 Hz. Secondary response *was not* simulated; secondary response would bring the frequency back to nominal.

4.5 Metrics for Primary Frequency Response Analysis

Common metrics for frequency response were used to assess simulations (see Table 4.1): nadir frequency, nadir time, settling frequency, settling time and rate of change of frequency (ROCOF) [15-18,77-77].

Table 4.1. Frequency Performance Metrics

Metric	Description	Units	Typical Use
Nadir Frequency	Lowest frequency observed post-disturbance	Hz	Indicates critical frequency dip
Nadir time	Time from incident to lowest nadir frequency	s	Indicates how quickly frequency decline is arrested
Rate of Change of Frequency (RoCoF)	How fast frequency changes after a disturbance	Hz/s	Indicates how quickly a power system reacts to a disturbance; it may also indicate if inertia is sufficient or not.
Settling Frequency	Final steady-state frequency after oscillations	Hz	Shows a new stable frequency without considering secondary frequency control actions.

Metric	Description	Units	Typical Use
Settling Time	Time taken for frequency to enter and stay within a tolerance band (e.g., ±0.05 Hz) around the settling or steady state frequency	s	Indicates system recovery speed

4.6 Cost Analysis

To evaluate cost-effectiveness over a 5-year period, the study utilized a basic model for utility scale BESS implementation developed by the U.S. National Renewable Energy Laboratory (NREL). The cost model considered capital investment and operations and maintenance costs for PFR units [82, 83]. Typically, to fully estimate the cost and performance of a battery storage system, in addition to the capital costs, other parameters such as the operations and maintenance costs (O&M), degradation, lifetime and round-trip efficiency assumptions are included. The cost model in [82], allocated all operating costs to the operations and maintenance cost value with the assumption that the battery performance has been guaranteed over the lifetime such that the battery, while operating, does not incur any costs to the battery operator. In [82], a high O&M value was adopted, consistent with providing approximately one SOC cycle per day and based on the assumption that the O&M cost assumptions include degradation, such that the system will be able to perform at rated capacity through an assumed lifetime of 5 years. While longer evaluation periods are possible, a 5-year horizon was selected because it aligns with the expected period during which the BESS can deliver its full technical capability without significant degradation. This timeframe allows for a meaningful cost-performance comparison with conventional technologies, particularly in the context of early-stage deployment scenarios where asset performance and operational certainty are highest.

The cost model used also assumes 1 cycle per day. This would be correct only if a robust frequency control market has been implemented. If this is not implemented, the batteries cycle more often, likely multiple times per day, to restore chronic frequency deviations to reasonable levels. In the current WAPPITS operation, the system does not return to 50 Hz at any time. In [7], it was observed that only enormous battery sizes would be able to provide effective frequency control under chronic frequency deviations and many cycles per day. The storage capacities considered here would be insufficient to correct chronic frequency control problems, causing the BESS units to be at maximum or minimum SOC much of the time. Therefore, *a priori* for modeling, we assume that some combination of actions will control the frequency to near 50 Hz at all times except for the N-1 contingency events considered here. For scenarios with mostly conventional resources and minimal BESS, this reduces the cycling of the battery, resulting in no more than 1 cycle/day, on average. For scenarios with mostly battery resources, this is not the case, and the BESS units may complete partial cycles multiple times per day, as BESS would need to contribute to routine frequency control as well as N-1 contingency response.

As a result, our assumption about degradation rates under-estimates degradation for scenarios with high reliance on BESS, and likely over-estimates degradation for scenarios with low reliance on BESS (i.e. mostly conventional). We have, in effect, picked a 'middle of the road' degradation estimate from modeling done by NREL – i.e. 1 cycle per day.

Table 4.2 presents the cost assumptions. Total cost for assets capable of power output of $P\ (kW)$:

$$C = P \cdot [(C_c \cdot 8760 + C_o) \cdot (5\ years)] \qquad (4.1)$$

For BESS, CAPEX is a combination of the battery storage costs, which scales by hours at full power (storage duration), plus the cost of the inverter power unit, which scales by the maximum power output.

Table 4.2. Cost Assumptions [82,83]

Plant Type	Description	Variable Name	Assumption
Existing conventional power plant			
	CAPEX	X	None (Already Existing)
	Capacity payment (10% of average energy cost)	C_c	$0.001 \frac{\$}{kW}$
	Operations and Maintenance Cost (O&M) for Natural Gas Retrofit for Existing plants	C_o	$68 \frac{\$}{kW \cdot year}$
BESS (1-hour duration, advanced technology)			
	CAPEX for a storage duration of 1 hour	$X = C_p + \chi \cdot C_e + 5 \cdot C_o$	
	BESS energy-power ratio	χ	1 hours
	Power-drive CAPEX Cost	C_p	$233 \frac{\$}{kW}$
	Battery Energy Cost	C_e	$252 \frac{\$}{kWh}$
	Operations and Maintenance Cost (O&M) for Advanced Utility Scale Advanced BESS	C_o	$18 \frac{\$}{kW \cdot year}$

4.7 Description of Scenarios Analyzed

Scenarios were defined to change the mix of PFR assets while holding the total PFR available to the N-1 contingency requirement of 400 MW. The reference case (Scenario 0, case 0) is the current conditions in WAPPITS – approximately 150 MW of conventional PFR with the remaining 250 MW provided by under-frequency load shedding (UFLS). Scenario 1, cases 1-5 simulate a mix ranging from fully conventional to full BESS resources, under the assumption that pre-disturbance frequency was near 50 Hz. Scenario 2, cases 6-10 repeat the mix of PFR assets, under the current condition where the pre-disturbance frequency is chaotically different from 50 Hz. Scenarios are summarized in Table 4.3.

Table 4.3. Description of Scenarios and Cases Analyzed

Scenarios	Cases	Primary Frequency Response Provision (MW)		System Condition
		BESS	**Conventional**	
Scenario 0	Case 0	0	150	Status quo – limited PFR
Scenario 1	Case 1	0	400	Pre-disturbance frequency: 50 Hz Disturbance: Loss of 400 MW Generation
	Case 2	100	300	
	Case 3	200	200	
	Case 4	300	100	
	Case 5	400	0	
Scenario 2	Case 6	0	400	Pre-disturbance frequency: frequency variations below 50 Hz Disturbance: Loss of 400 MW Generation
	Case 7	100	300	
	Case 8	200	200	
	Case 9	300	100	
	Case 10	400	0	

4.8 Results and Analysis

Figure 4.3 below shows frequency response and load shedding (MW) for Case 0, status quo with limited primary frequency control reserves. The lack of sufficient primary frequency control reserves caused frequency to drop quickly after the disturbance and reached the UFLS threshold of 49.5 Hz. At this point, automatic under frequency load shedding relays triggered to shed 250 MW in two stages, which arrested the arrest frequency decline at 49 Hz.

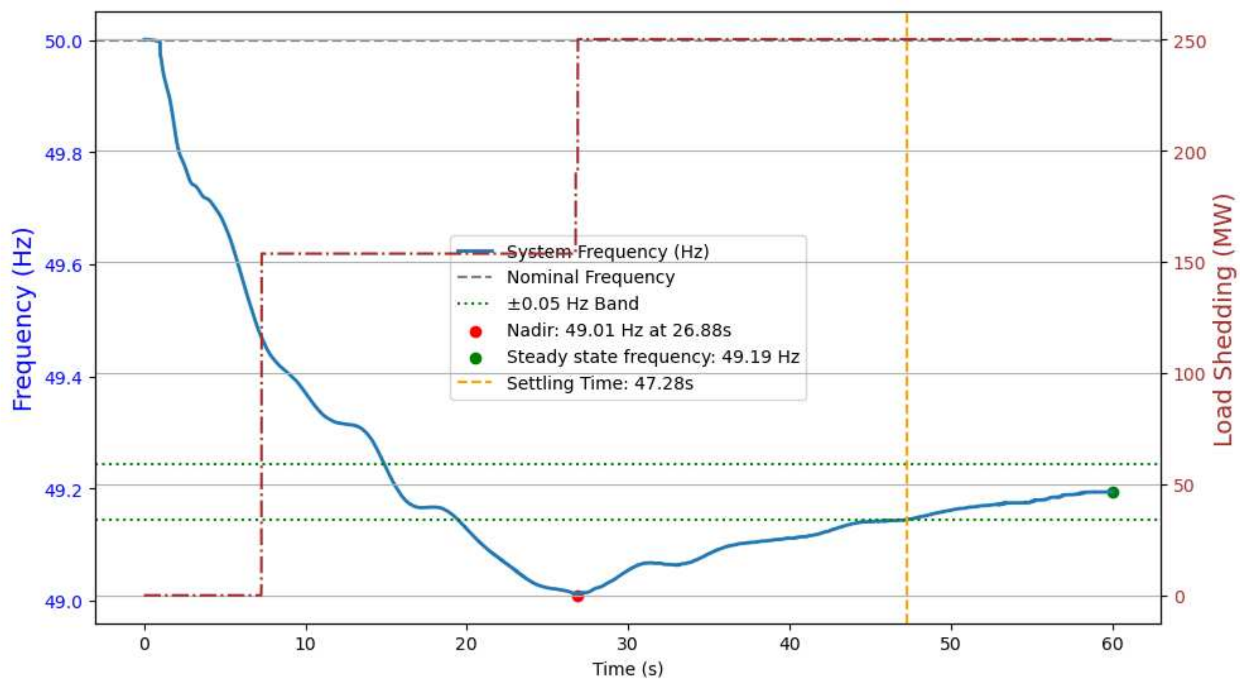


Figure 4.3. Frequency response with respect to load shedding in Case 0

Figure 4.4 – 4.8 shows frequency performance for various mixes of PFR for scenario 1. Figures 4.4 and 4.8 illustrate system performance at the extreme mixes for Cases 1-5 – Figure 4.4: Case 1, all conventional PFR, and Figure 4.8: Case 5, all BESS PFR. The metrics in Table 1 were extracted from these results and compiled into Table 4. Selected results are also shown plotted against system cost in Figures 4.9 and 4.10.

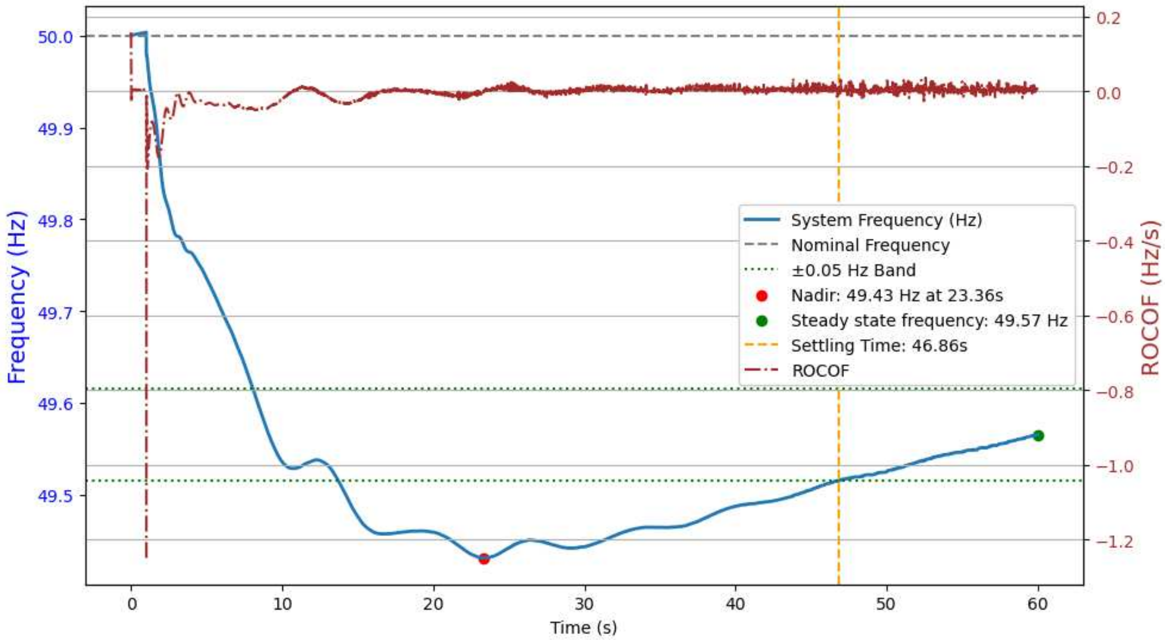


Figure 4.4. Frequency response of the WAPPITS under the conditions of Case 1

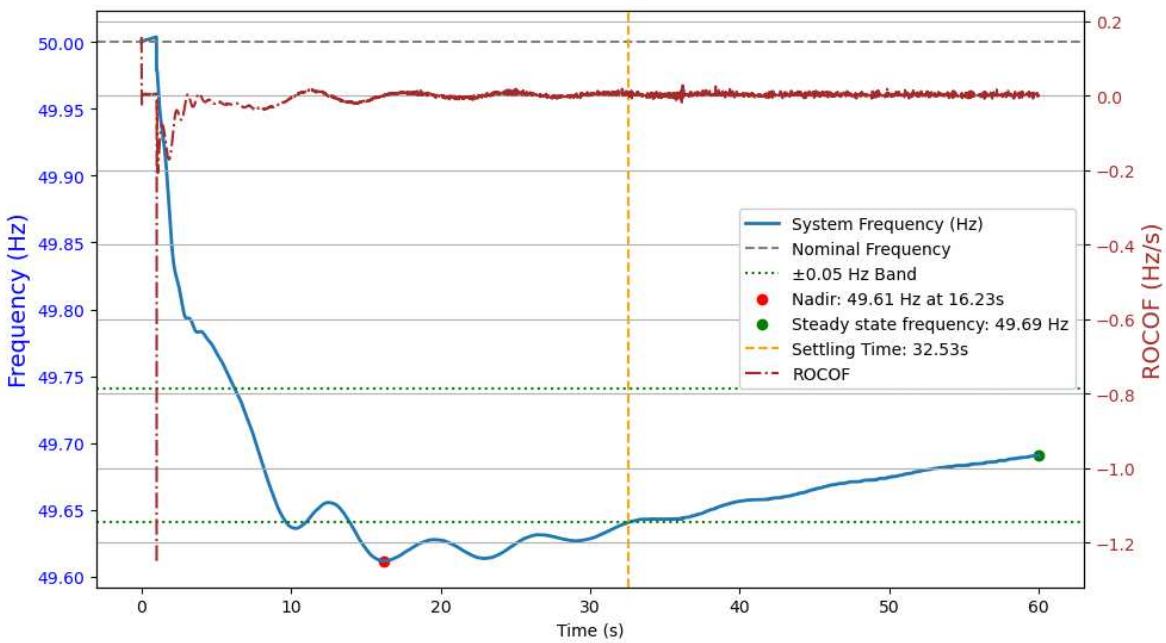


Figure 4.5. Frequency response of the WAPPITS under the conditions of Case 2

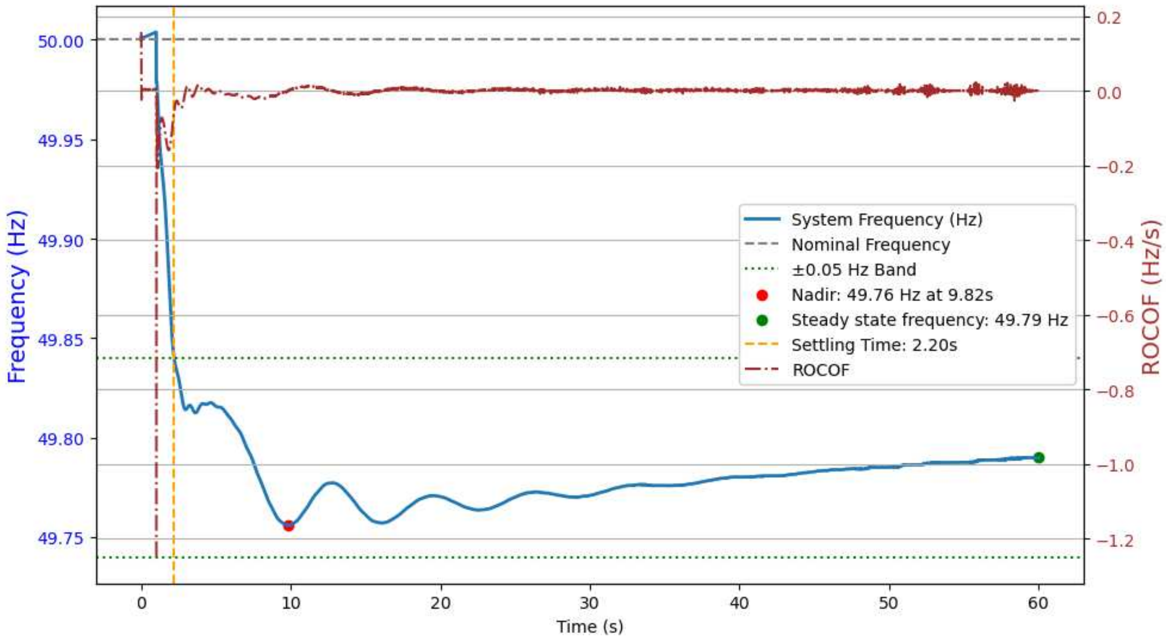


Figure 4.6. Frequency response of the WAPPITS under the conditions of Case 3

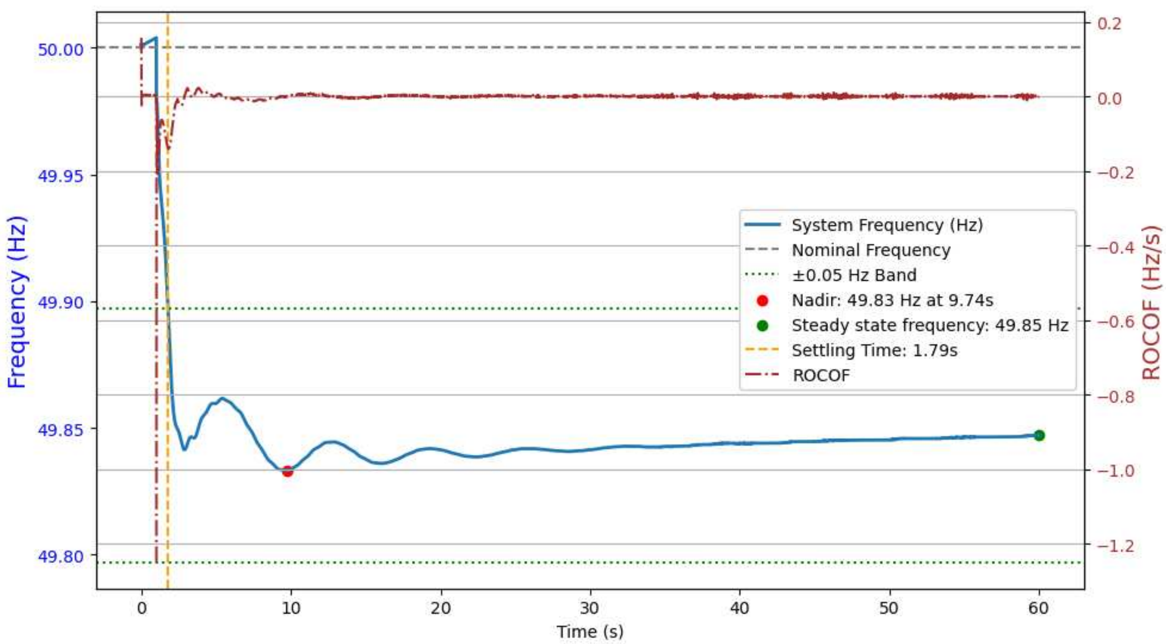


Figure 4.7. Frequency response of the WAPPITS under the conditions of Case 4

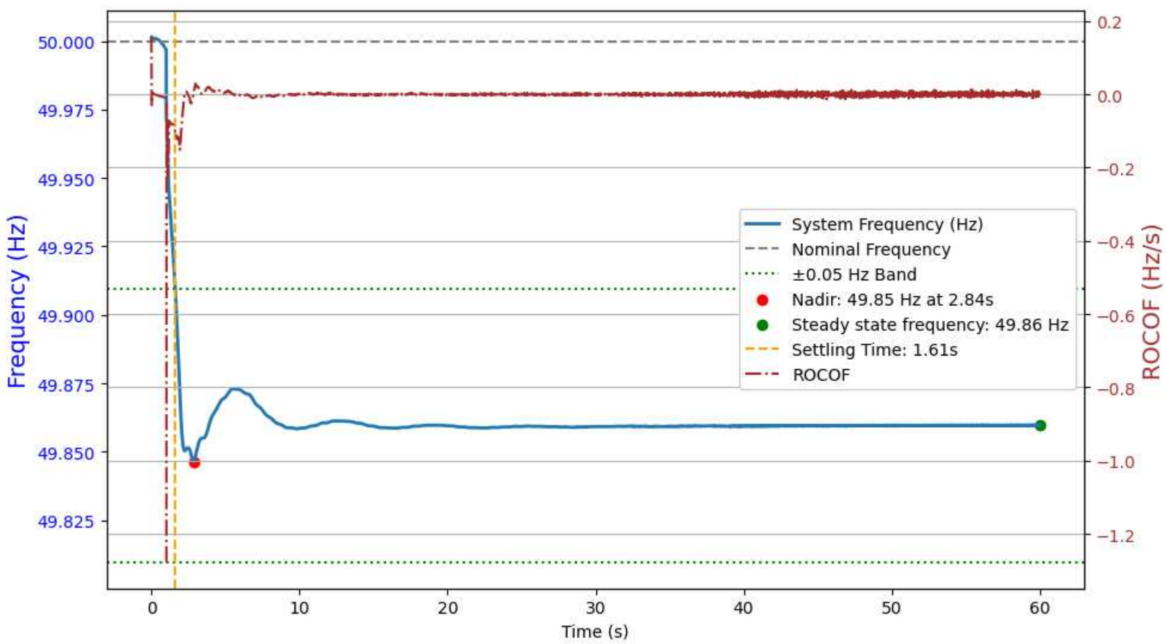


Figure 4.8. Frequency response of the WAPPITS under the conditions of Case 5

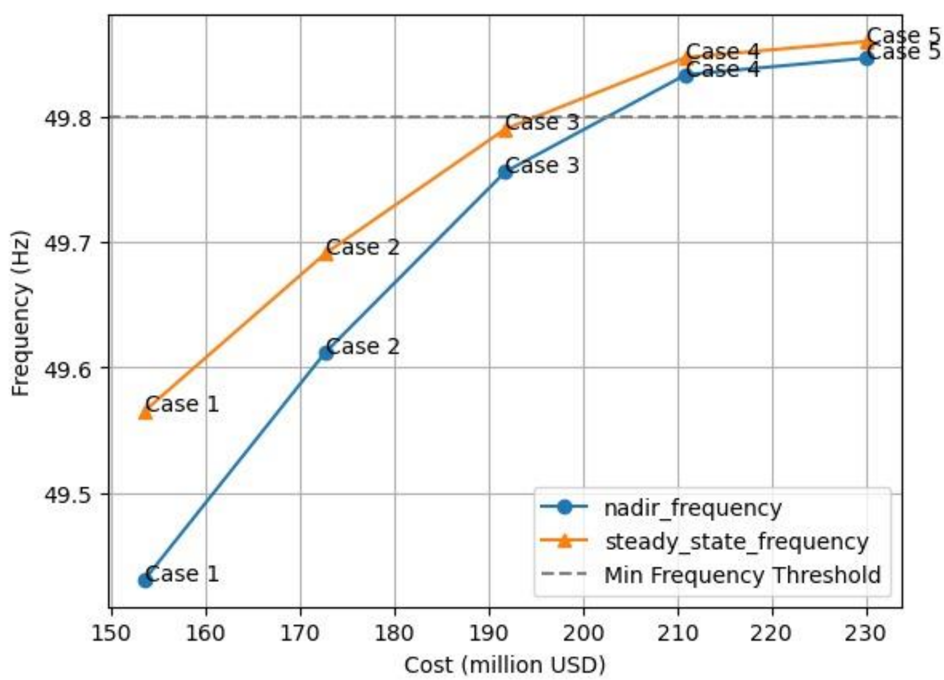


Figure 4.9. Cost-performance comparison of primary frequency response options – Nadir and settling frequencies

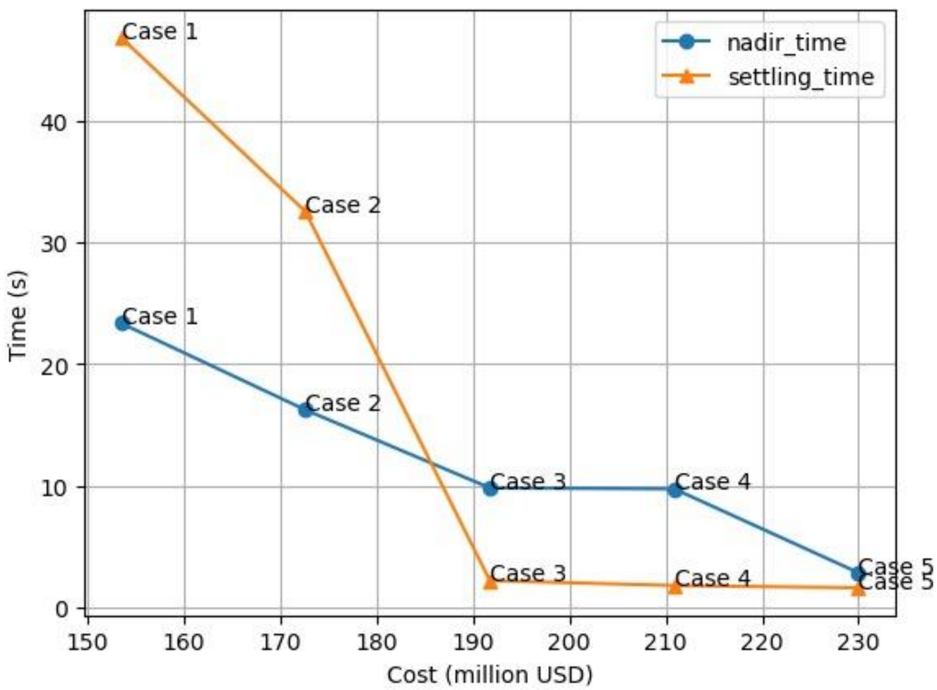


Figure 4.10. Cost-performance comparison of primary frequency response options – Nadir and settling times

Table 4.4. Frequency response metrics for Scenario 1, Cases 1-5

Cases	Frequency Response Reserve Mix (MW)			Nadir Frequency (Hz)	Nadir Time (s)	Steady-state Frequency (Hz)	Settling Time (s)	Initial RoCoF (Hz/s)	Cost (MUSD)
	Conventional	BESS	Load Shed						
Case 0	150	0	250	49.01	26.88	49.19	47.28	-1.26	-
Case 1	400	0	0	49.43	23.36	49.57	46.86	-1.25	153.52
Case 2	300	100	0	49.61	16.23	49.69	32.53	-1.25	172.64
Case 3	200	200	0	49.76	9.82	49.79	2.20	-1.25	191.76
Case 4	100	300	0	49.83	9.74	49.85	1.79	-1.25	210.88
Case 5	0	400	0	49.85	2.84	49.86	1.61	-1.28	230.00

Observations:

As the fraction of PFR from BESS assets increases, all relevant metrics improve, as expected. This is unsurprising, as fast reaction to the disturbance tends to improve all metrics, and the primary attractive attribute of BESS assets is BESS's capability to respond faster and more accurately than conventional units. The faster response is driven by BESS' use of inverters coupled to low-impedance energy storage, compared to conventional power plants which are limited by mechanical inertia and shock limits for hydropower and governor response delays for thermal units.

From case 1 to case 5: Nadir Frequency improves (rises) from 49.43 Hz (Case 1) to 49.85 Hz (Case 5), all substantially better than the status quo 49 Hz. Nadir Time decreases from 23.36 s (Case 1) to 2.84 s (Case 5). Settling time reduces significantly from 46.86 s (Case 1) to 1.61 s (Case 5) – in Cases 3 through 5, the fast-acting BESS causes the frequency to start settling even before reaching its Nadir.

Steady-state frequency improves progressively, from 49.57 Hz (Case 1) to 49.86 Hz (Case 5). BESS asset's ability to rapidly arrest frequency decline tends to stabilize system frequency faster, closer to 50 Hz than conventional plants. This arrest is fast enough in Cases 4 and 5 to settle system frequency within the regulatory-prescribed 49.8 – 50.2 Hz margin. However, it is important to note that the battery system is limited to 1 hour capacity; secondary response must replace batter output within that time.

Finally, all cases show similar, high, initial RoCoF values; this metric degrades from 1.25 Hz/s in Cases 1-4 to 1.28 Hz/s for the 100% BESS Case 5. This is due to the inertia of the online generation units which are predominantly synchronous machines. While these machines do not exhibit governor response (i.e. PFR), they provide inertial response. Case 5, with no conventional PFR assets, has a higher RoCoF due to a reduction in the online inertia.

Figure 4.9 and 4.10 captures these metric trends against a cost estimate for the PFR assets. As previously indicated, Case 5 (all BESS) offers the best technical performance. However, the marginal improvement from Case 3 to Case 5 is significantly smaller than the improvement from Case 1 to Case 3. The zeroth increment, from Case 0 to Case 1 eliminates use of load shedding for PFR, a requirement for WAPPITS moving forward, at an incremental cost of ≈150M USD. Each subsequent case represents a 12% increase in the total cost of providing PFR. Considering nadir frequency, the first and second investment increments (Case 1 to 2, and Case 2 to 3) reduce the frequency drop by similar amounts (43% and 36% of the total possible improvement). The final two increments, together, provide 22% of the possible improvement (17% and 5%, respectively). Case 3 also brings the system response close to, but slightly below, the target frequency nadir (0.2 Hz). Similar observations can be made for the other metrics in Figures 4.7 and 4.8.

These results indicate that a hybrid solution with a balance of conventional and BESS assets likely produces the best cost-benefit performance for acquiring PFR assets. A hybrid solution provides a cost-effective strategy for primary frequency response without compromising significantly on reliability or stability.

In practical terms, converting existing conventional assets to PFR would require both regulatory changes and, likely, an ancillary services market to pay for these reserves. BESS implementation could be developed directly by WAPPITS or provisioned using an ancillary services market; in either case these represent new assets which need to be financed, constructed, and maintained. The current study makes one assumption about the location of PFR assets. A fully developed plan would acquire PFR assets strategically positioned within the WAPPITS system, which may impact cost and operational control strategies.

Scenario 2

In this scenario, we mimic a typical variable frequency condition observed currently in the daily operation of WAPPITS. By considering a chaotic frequency condition, the simulation stresses the operation of the PFR assets prior to the N-1 contingency trip at 360 seconds. Figures 4.11-4.15 show frequency response for different mixes of PFR under scenario 2. As with the previous scenario, Figures 4.11 and 4.15 show the frequency response for the two extremes of PFR asset mix – Case 6, all conventional, and Case 10, all BESS. Figures for all cases 6 through 10 are included in the supplementary material. Table 4.5 documents the metrics extracted from the simulations, and Figures 4.16 and 4.17 show those metrics plotted against total cost.

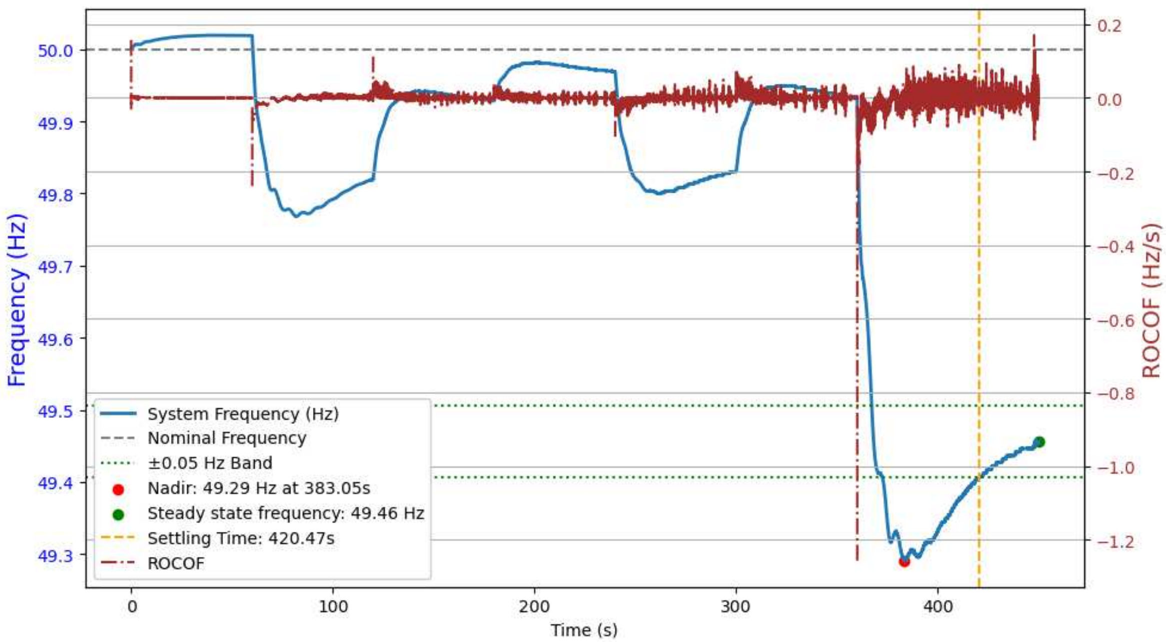


Figure 4.11. Frequency response of the WAPPITS under the conditions of Case 6

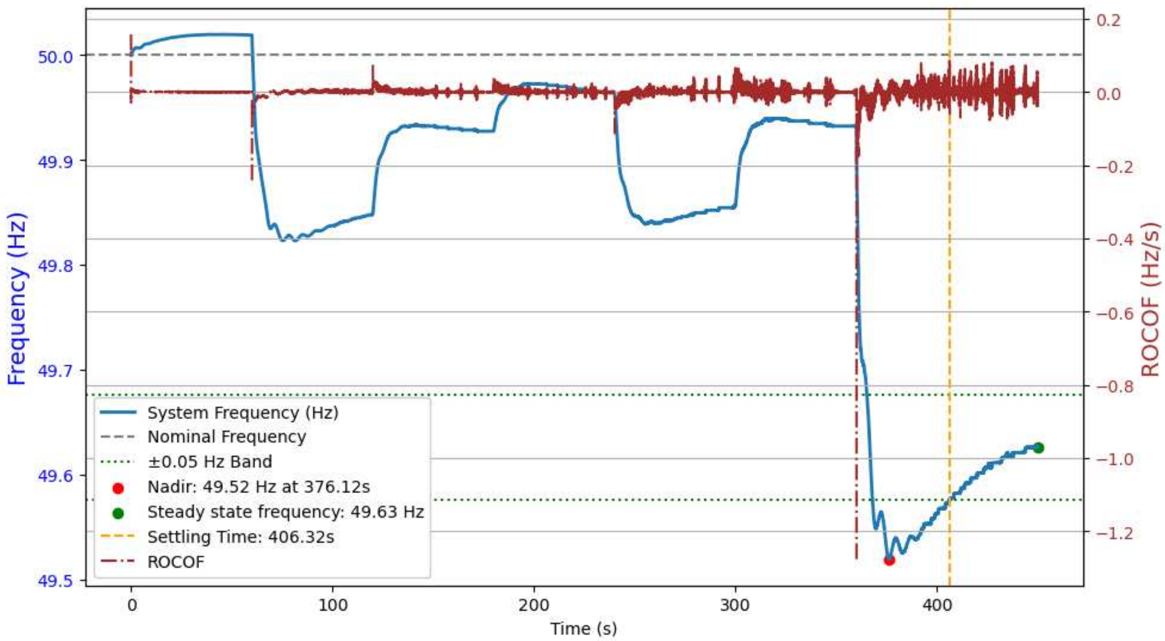


Figure 4.12. Frequency response of the WAPPITS under the conditions of Case 7

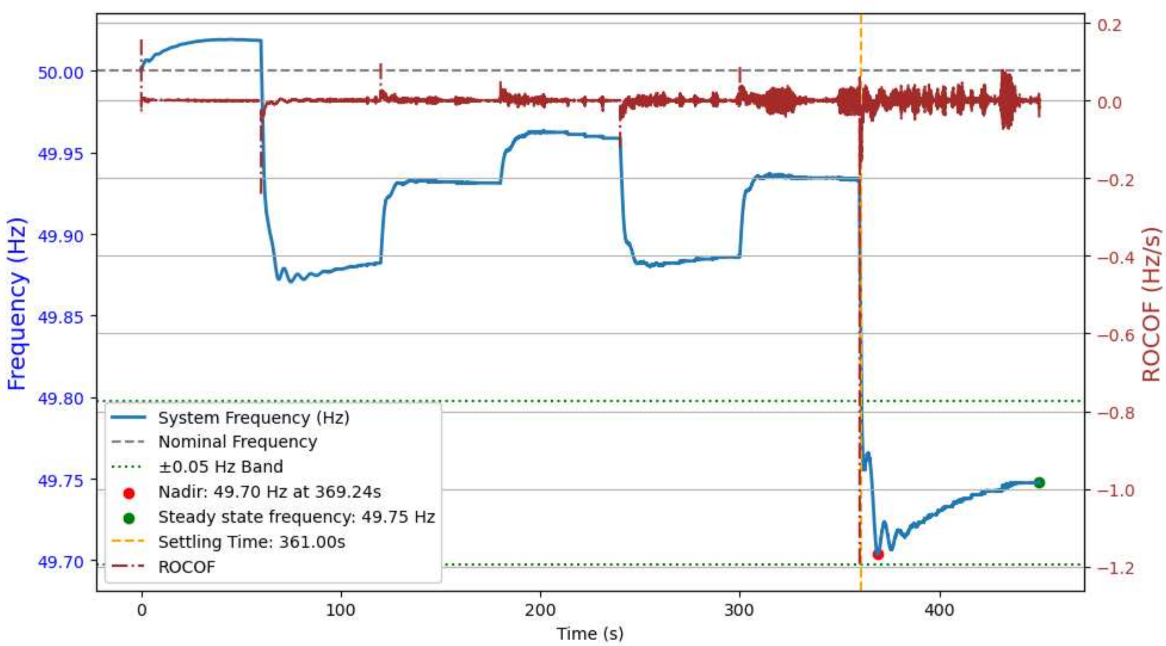


Figure 4.13. Frequency response of the WAPPITS under the conditions of Case 8

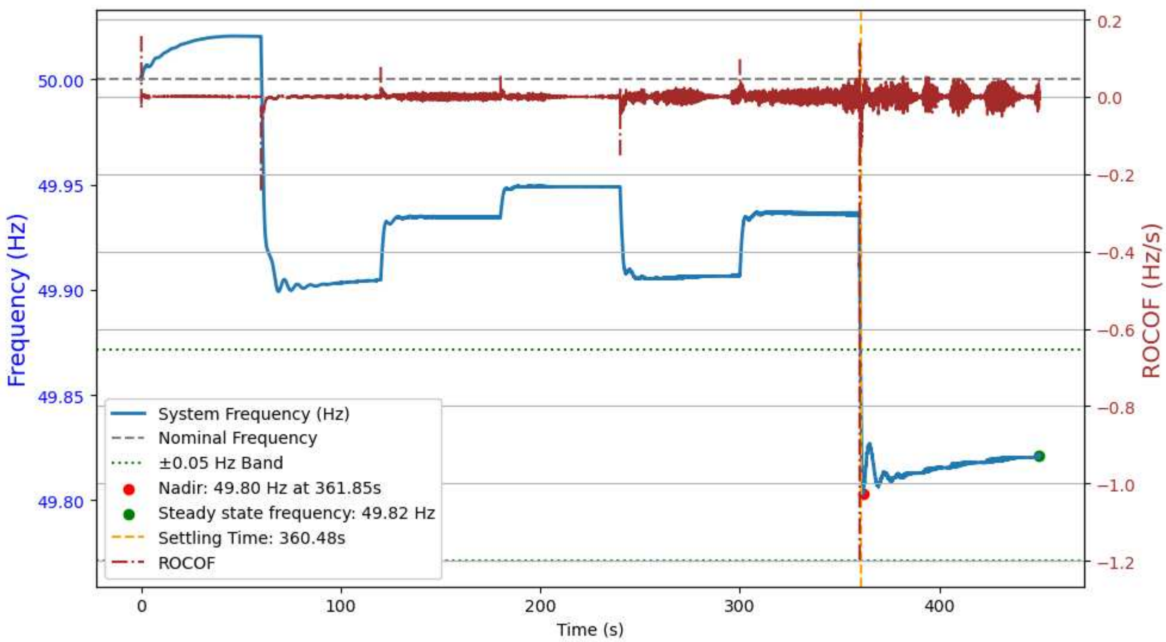


Figure 4.14. Frequency response of the WAPPITS under the conditions of Case 9

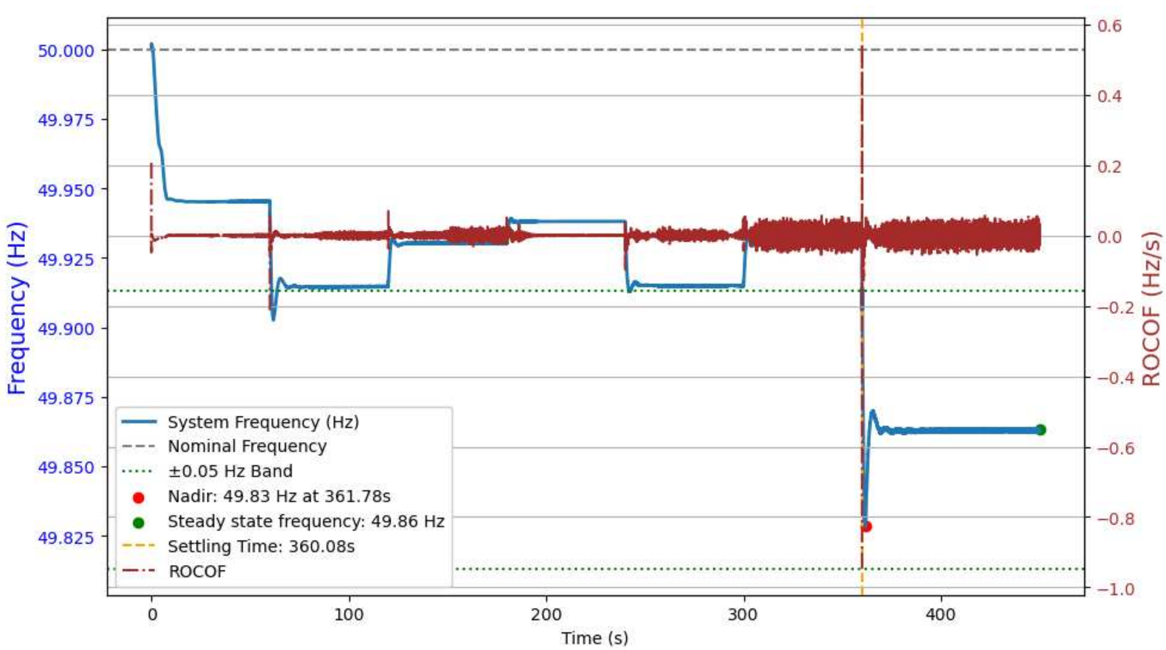


Figure 4.15. Frequency response of the WAPPITS under the conditions of Case 10

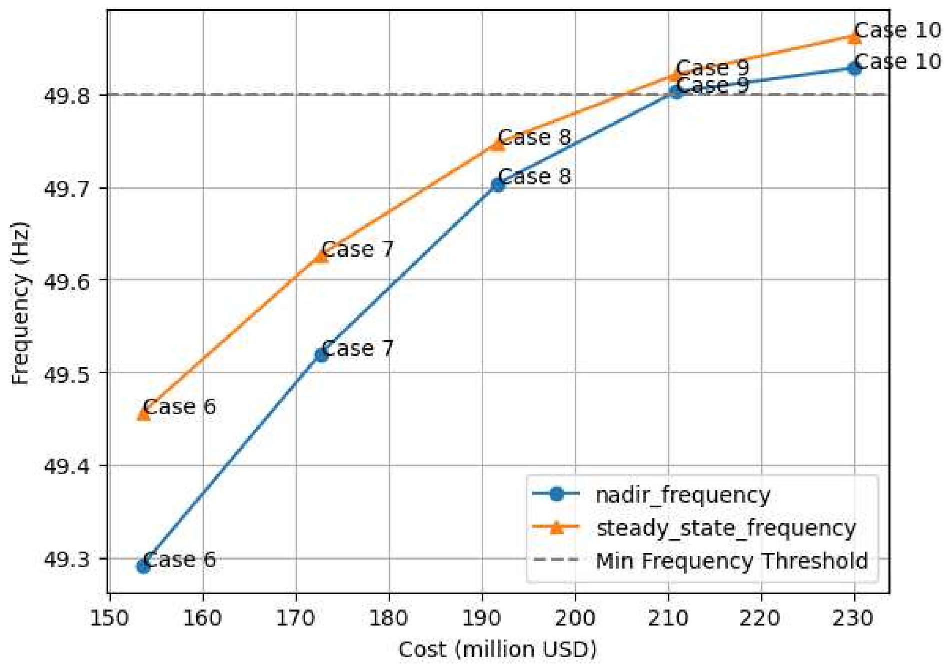


Figure 4.16. Cost-performance comparison of primary frequency response options – Nadir and settling frequencies (Scenario 2)

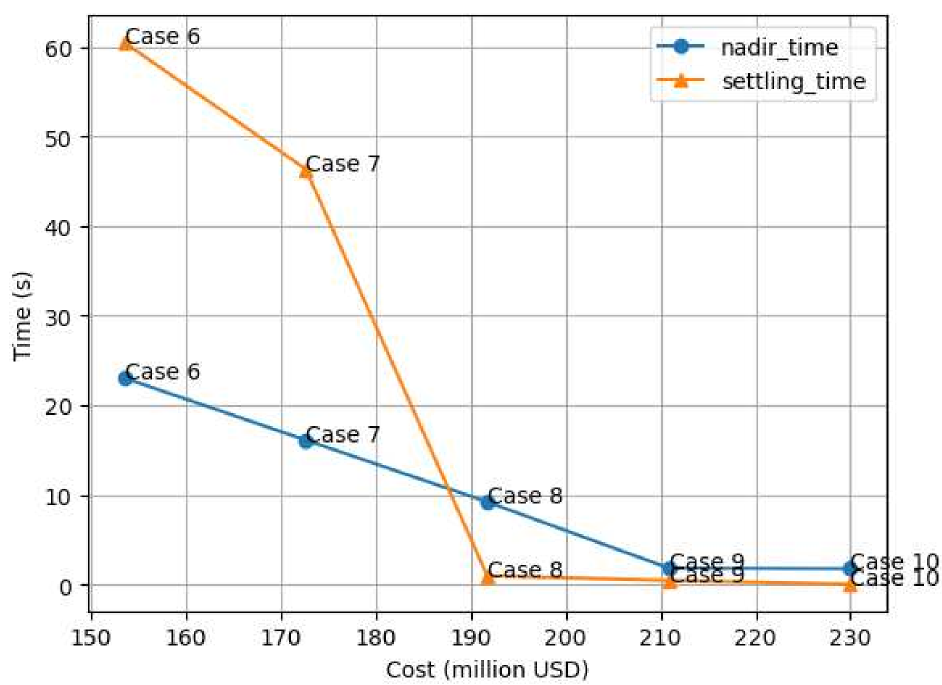


Figure 4.17. Cost-performance comparison of primary frequency response options – Nadir and settling times (Scenario 2)

Table 4.5. Frequency response metrics (Scenario 2)

Cases	Frequency Response Reserve Mix (MW)		Nadir Frequency (Hz)	Nadir Time (s)	Steady-state Frequency (Hz)	Settling Time (s)	Initial RoCoF (Hz/s)	Cost (MUSD)
	Conventional	BESS						
Case 6	400	0	49.29	23.05	49.46	60.47	-1.26	153.52
Case 7	300	100	49.52	16.12	49.63	46.32	-1.28	172.64
Case 8	200	200	49.70	9.24	49.75	1.00	-1.19	191.76
Case 9	100	300	49.80	1.85	49.82	0.48	-1.20	210.88
Case 10	0	400	49.83	1.78	49.86	0.08	-1.00	230.00

A quick inspection of the figures and table indicates that the system response after the disturbance in Scenario 2 closely resembles that of Scenario 1. Nadir frequency and settling time are somewhat worse for the fully-conventional scenario (Case 6 compared to Case 10). The remaining metrics are essentially unchanged. These data indicate that the introduction of variable frequency does not impact the PFR performance, assuming the BESS system has not been pushed toward either full charge or full discharge prior to the event. Maintaining BESS capacity will likely require additional control design, as well as the implementation of a robust secondary response (AGC) system.

Given similar metrics, the incremental improvement for incremental investment in Scenario 2 tracks that of Scenario 1. Again, a PFR system design between Case 8 (50/50 split) and Case 9 (25/75 BESS) split provides control that meets the target nadir of 0.2 Hz, while minimizing total cost. These data indicate a balanced reserve mix (approximately 50% BESS, 50% conventional) provides the best compromise between technical and economic feasibility, provided that secondary frequency reserve resources are available to sustain and improve the frequency recovery, as is common in developed grid systems.

4.9 Conclusions

WAPPITS represents a unique environment to design, from basic assumptions, primary and secondary frequency response systems for a large, complex, interconnected grid system. In developed systems, large investments in conventional resources represent sunk costs with well-understood ancillary services costs. In that environment, BESS investments must compete against established players and known costs.

In contrast, conventional units in WAPPITS *could* provide primary response, but are not currently incentivized to do so. The required incentive payments, likely in the form of an ancillary services market, represent a significant operational cost that is not yet committed by the grid operator, and therefore does not represent a current contractual or political commitment. No BESS units exist currently; all require significant CAPEX but have lower O&M costs than conventional assets.

These competing costs set up a classic cost-benefit optimization between conventional and BESS investments that would be difficult to consider in established, highly developed, grid systems. As a result, in developed systems, BESS has been primarily considered as a solution to stabilize problem areas within the grid or to compensate for high penetrations of variable renewable energy sources.

The analysis performed here does not consider all possible variables. Significant design constraints were not considered, including the location and interconnection of BESS units, the availability and location of conventional units willing to participate in PFR, local and corridor capacity and stability issues. The study also did not consider a future with higher penetration of variable renewable generation sources. However, this high-level analysis provides a reasonably clear answer to a fundamental question: What mix of PFR resources would *likely* produce adequate control while minimizing cost over a 5-year study period?

Results indicate that (a) a hybrid approach, near a 50/50 split between conventional and BESS assets, would likely provide adequate frequency control at minimum total cost. Such a hybrid solution would provide significant advantages to WAPPITS. First, contracting for fewer conventional assets would make an ancillary services market more competitive, potentially lowering the cost of services and/or providing more flexibility in the selection of those resources. Due to the large size and limited interconnection of WAPPITS, location will be a significant factor in designing primary response systems.

Second, BESS units could be contracted through an ancillary services market *or* implemented directly by WAPPITS in selected substations throughout the grid. These options provide additional design and operational flexibility for WAPPITS.

Finally, the results presented here are highly reliant on implementation of an active secondary frequency control system, commonly referred to as automatic generation control. AGC services would also need to be contracted via an ancillary services market. AGC services will compete with the PFR services in those markets. Generation assets in WAPPITS vary in age, control system quality, and other factors. Currently, it is not entirely clear how readily units can be adapted for both PFR and AGC. A hybrid approach provides flexibility to tradeoffs between conventional and BESS assets in response to market offers when those markets initiate.

Chapter 5

Conclusion

This dissertation has presented a comprehensive and multifaceted analysis of frequency control challenges in WAPPITS and assessed the cost-effectiveness of deploying BESS for the provision of primary frequency response in the West African Interconnected Transmission System.

The research adopted a socio techno-economic analysis approach to provide a holistic evaluation of WAPPITS frequency control challenges and proposes technological, policy and regulatory solutions to solving the frequency problems including deployment of BESS.

Through three chapters, namely BESS Primary frequency control strategies for the West African Power Pool (Chapter 2), Analysis of primary and secondary frequency control challenges in an African transmission system (Chapter 3), and Analysis of Grid Scale Storage Effectiveness for a West African Interconnected Transmission System

(Chapter 4)—a comprehensive evaluation of frequency control and deployment of BESS in WAPPITS was developed. This chapter combines findings from all three chapters and highlights key insights, policy and market implications and provides guidance for a more structured and pragmatic approach for frequency control and BESS deployment.

Chapter 2 analyzed the effectiveness of BESS for primary frequency control based on MATLAB/Simulink simulations using actual frequency data extracted from PMUs installed in WAPPITS. Finding from the analysis demonstrated the effectiveness of BESS in providing fast frequency response. However, in a system like the WAPPITS with chaotic frequency variations, BESS may not be effective in the absence of primary frequency control reserves from conventional power plants. Under the current frequency control regime where primary frequency control reserves are either limited or non-existent, notable chaotic frequency fluctuations could lead to a depletion of BESS energy and consequently make render it ineffective when required unless control strategies like frequency control logic using moving average as an input to BESS instead of actual frequency and state of charge control strategies are implemented. This insight highlights the fact that BESS alone cannot completely resolve the frequency control problems in WAPPITS unless they are deployed in large sizes which would be expensive. It underscores the critical importance of implementing basic frequency control services before large-scale deployments of BESS.

Chapter 3 expanded the scope of analysis to an assessment of institutional, regulatory, technological, and human factors influencing frequency control in WAPPITS. Based on survey responses and insights from control room operators, it is noted that Transmission System Operators rely heavily on under-frequency load shedding (UFLS) schemes in the absence of adequate primary or secondary frequency reserves. The lack of frequency reserves is seen not merely as a technical problem but due to the lack of appropriate regulatory framework, weak and inconsistent enforcement, and the absence of ancillary service markets.

The chapter highlights the importance of: (a) implementing and enforcing primary frequency response (PFR) requirements via regional grid codes, and (b) establishing an ancillary service market to procure and operationalize primary frequency control provision through automatic governor response and secondary frequency control via automatic generation control (AGC). In the absence of these reforms, BESS deployment may not be economically viable.

Chapter 4 conducted analysis of the effectiveness of BESS using the WAPPITs grid model, building on earlier analysis performed using a simplified open-loop model in MATLAB/Simulink in chapter 2. The analysis demonstrated that a hybrid approach, combining PRF from conventional power plants and BESS could achieve optimal cost-effectiveness. A 50/50 provision of PFR by BESS and conventional units minimized total costs while maximizing grid reliability.

The study highlighted BESS' key advantage of providing rapid frequency response capability compared to conventional units with slower response times. By balancing the strengths of both technologies, fast frequency response from BESS and inertia from conventional units, WAPPITS could mitigate the risks associated with relying exclusively on BESS. Additionally, a hybrid solution would provide significant benefits to WAPPITS. Contracting for fewer conventional assets would make an ancillary services market more competitive, potentially lowering the cost of services and/or providing more flexibility in the selection of those resources.

Based on the findings above, this dissertation has demonstrated that, while BESS is a promising alternative to improving frequency control and stability in WAPPITS, its success and effectiveness depends on institutional, regulatory, market, and operational reforms. BESS alone is not a solution to the frequency control challenges in WAPPITS; it must be integrated considering a well thought out adaptive technical and regulatory framework.

As WAPPITS goes through the evolving complexities of operating a synchronized interconnected power system, decision makers, with the support of technical and financial partners may be tempted to quickly adopt advanced innovative technologies like BESS, which are currently being deployed in advanced and matured grids like in the US and Europe without considering the unique environment of WAPPITS. Although BESS can enhance frequency stability, its deployment should not be an attempt to solve problems through quick technological fixes without considering systemic readiness, context-specific challenges and the socio-political realities of WAPPITS.

The deployment of BESS should not be seen as another quick opportunity to adopt advanced innovations without first addressing the existing grid operation challenges and regulatory enforcement weaknesses. Rather than implementing innovative and new technological solutions on top of existing problems, WAPPITS must treat BESS deployment as an opportunity to deeply revise its frequency control structure from the foundational level. This approach is different from the usual energy transition strategies being implemented in more developed grids, which center on technological solutions. WAPPITS-specific context requires developing a well-organized frequency control environment from the current fragmented, inconsistent baseline, different from the sophisticated and well-established automatic frequency control environments in advanced and matured grids.

WAPPITS has a unique opportunity due to the absence of sunk-cost infrastructure in conventional power plants. With proper focus, WAPPITS could adopt a forward-looking system design that leverages both the fast responsiveness and flexibility of BESS and the capacity and inertia of conventional power plants. The tradeoff between deploying a fast-responsive BESS requiring capital-intensive energy storage and slow-responding but already existing conventional power plants is not a constraint; it is a systems engineering design opportunity.

This dissertation proposes a hybrid strategy —combining the fast responsiveness of BESS with conventional generation in a manner that is aligned with WAPPITs realities. A hybrid deployment strategy, combining PFR from BESS and conventional units is the most technical and economically viable in the near term. This strategy is appropriate as it optimizes and balances flexibility, cost, reliability, and readiness. BESS deployment should be gradual and incremental as technical and policy makers implement the necessary technical, regulatory and market reforms. It is important that policy makers adopt and enforce appropriate regulatory frameworks prior to, or in parallel with, any BESS deployment to ensure proper and effective application and cost recovery. In addition, ancillary service markets are necessary to provide incentives to both conventional power plants and BESS to support essential grid reliability services like frequency control.

Based on the findings from the research, the current state of frequency instability in WAPPITS reflects an important reality: the system is getting the level of reliability it is paying for. With many power plants signing ‘take-or-pay’ power purchase agreements (PPA’s) without provision for frequency control reserves, plant owners have no interest or incentive in producing below full capacity to address system reliability needs. With the absence of a functional ancillary services market and the lack of regulatory enforcement which would mandate power plants to provide Primary Frequency Response (PFR), the consequence is a near-complete absence of critical frequency services and poor frequency performance. This produces a tradeoff / hybridization between three fundamental choices: First, WAPPITS could mandate PFR provision through regulatory changes and strict enforcement, compelling "take-or-pay" producers to generate below full capacity to provide frequency support. While this may be effective, power producers would likely increase their costs using this "stick-only" approach, leading to higher consumer tariffs. Second, WAPPITS could consider making an investment in PFR assets such as BESS or hybrid solutions. This approach may however require substantial financing, which may not be available, and would require WAPPITS to compete with other power producers, as the PFR resources must be producing some amount of generation to be ‘online.’.

The most balanced and sustainable path going forward may lie in a third option: creating a functioning ancillary services market where PFR and other essential reliability services like secondary and tertiary frequency control can be procured from qualified power plants. This market-based approach will provide the necessary incentives to improve frequency stability. It is evident that irrespective of the approach adopted by WAPPITS, one thing is clear—ensuring frequency stability will require substantial investment. However, this investment will improve grid stability, reduce overreliance on under-frequency load shedding (UFLS), and enhance the flexibility and resiliency of WAPP, laying a better foundation for increasing penetration of variable renewable energy. WAPPITS must come to a realization that frequency stability is not a technical afterthought—it is a public good that must carefully be planned for, paid for, and managed just like energy supply itself.

WAPP, the ECOWAS Regional Regulatory Authority (ERERA), National Regulatory Authorities and Transmission System Operators should work collaboratively to establish an ancillary services market, including specific products for primary frequency control.

In conclusion, WAPPITS does not need to necessarily adopt the approach and energy transition path of advanced and matured grids, it should adopt its own strategy and chart its own course by developing a system and context-specific solution.

Future research could explore the following key areas to provide a deep understanding of BESS integration in the WAPP Interconnected Transmission System (WAPPITS):

- Development of simulation models, accounting for varied grid topologies, seasonal variations, and contingency scenarios to assess system-wide performance under dynamic conditions.
- Optimal sizing and placement of BESS units across the network to enhance system resilience, improve economic efficiency, and frequency regulation effectiveness.

- Assessment of different VRE penetration levels to determine the corresponding impacts on BESS performance, stability requirements, and system inertia.
- Detailed analysis of BESS degradation and lifecycle cost modeling under high cycling frequency, particularly under scenarios with high VRE variability.

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