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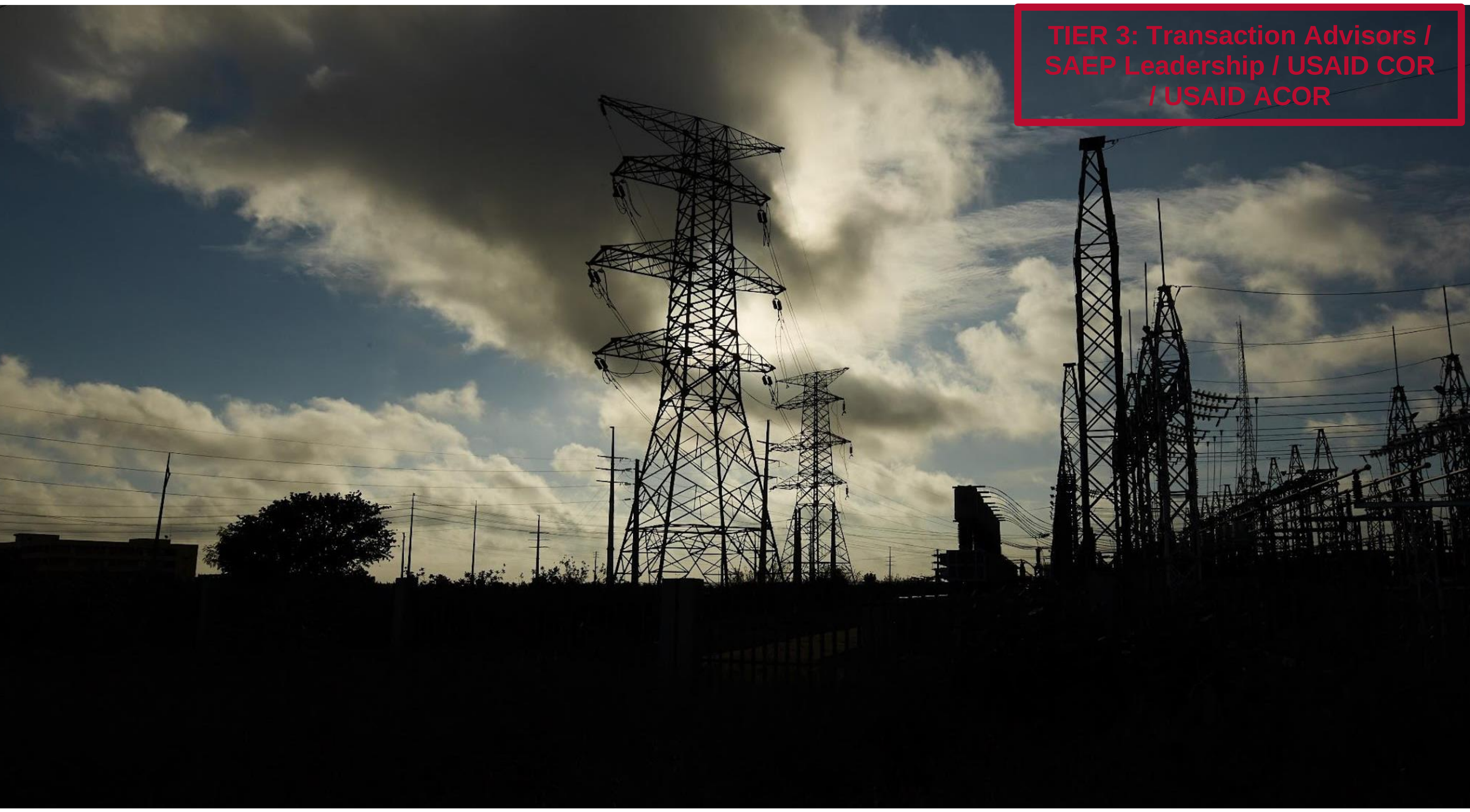

Scoping Report for the Malawi Ancillary Services Market Activity

November 4, 2022

ACRONYMS

Acronym	Definition
AGC	Automatic Generation Control
AVR	Automatic Voltage Regulation
BESS	Battery Energy Storage System
CAS	Control Area Services
COO	Chief Operating Officer
DAM	Day-Ahead Market
DOF	Director of Finance
DOSMO	Director of Market and System Operator
DOT	Director of Transmission
EGENCO	Electricity Generation Company
EMS	Energy Management System
ESCOM	Electricity Supply Corporation of Malawi Limited
GE	General Electric
GDAT	Generation Dispatch Analysis Tool
HCB	Hidroeléctrica de Cahora Bassa
Hz	Hertz
IPP	Independent Power Producer
IR	Instantaneous Reserve (Primary Frequency Control)
MERA	Malawi Energy Regulatory Authority
MCR	Maximum continuous rating
MVA	Megavolt-ampere
MSOM	Markets and System Operations Manager
MVar	Megavolt-ampere reactive
MW	Megawatt (1,000 kW)
MWh	Megawatt hour (1,000 kWh)
NCC	National Control Centre
PML	Power Market Limited
PPA	Power Purchase Agreement
PV	Photo-voltaic
RoCoF	Rate of Change of Frequency
RR	Regulating Reserve (Secondary Frequency Control)
RTU	Remote Terminal Unit
SAEP	Southern Africa Energy Program
SAPP	Southern African Power Pool
SCADA	Supervisory control and data acquisition

SCO	Synchronous Condenser
SO	System Operator
TSO	Transmission System Operator
UFLS	Under frequency load shedding
SVC	Static var Compensator
USAID	United States Agency for International Development
VRE	Variable renewable energy (solar PV and wind)
WACC	Weighted Average Cost of Capital

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SCOPING REPORT FOR THE MALAWI ANCILLARY SERVICES MARKET ACTIVITY

1 INTRODUCTION

The Electricity Supply Corporation of Malawi Limited (ESCOM) requested the USAID Southern Africa Energy Program (SAEP), a Power Africa initiative, to assist the utility with studies on the possibility of establishing an ancillary services market in Malawi. ESCOM has a total of 80 megawatts (MW) of solar photovoltaic (PV) installed, consisting of the 60 MW Salima solar PV plant and the 20 MW Golomoti solar PV plant. The variability introduced by the solar PV plants, worsened by the unplanned outage of the Kapichira Hydropower Plant, has caused frequency excursions that often result in under-frequency load shedding, and hydropower units tripping due to high frequency. Ancillary services are required to improve the integrity of the power system, ensuring that the Under Frequency Load Shedding (UFLS) protection, which is meant to be one of the last lines of defense for the grid, stops operating multiple times a day, as is currently the case.

SAEP's scope of work (SOW) under the Malawi Ancillary Services Market Activity required:

a. Planning for and conducting a scoping study for the Malawi ancillary services market activity

b. Facilitating a workshop on ancillary services for ESCOM executives and technical staff

c. Producing a report based on the scoping study

A. Task 1: Scoping study and workshop

SAEP travelled to Malawi from 26 to 30 September 2022 to meet with stakeholders and conduct a workshop on ancillary services markets. The workshop was on setting up and running an ancillary services market. The primary audience for the workshop was ESCOM's system operations and planning engineers, managers and executive leadership. Workshop material, among others, included:

- Cost estimates of the technologies that can provide different ancillary services and sourced from the private sector or from assets that ESCOM procures, owns and operates
- Information on the management capacity, organizational structure and processes and procedures required to successfully procure, schedule and dispatch the ancillary services

B. Task 2: Produce a report based on the scoping study

Produce a report that:

- Clearly outlines the scope and timelines for the activity up to the point of ESCOM going to market to procure 1) ancillary services from Independent Power Producers (IPPs) or 2) ESCOM-owned assets from Engineering, Procurement and Construction management contractors
- Gives ESCOM an indication of how long it will take to procure the services or assets
- Analyzes ancillary services in the context of the development and eventual commissioning of the Mozambique-Malawi interconnector

SAEP held a workshop with ESCOM and key stakeholders from 27 to 29 September 2022, focusing on the ancillary services market development for Malawi, discussing solutions for addressing the prevailing frequency stability challenges and proposing a structure for a future ancillary services market appropriate for Malawi. A total of 20 participants attended the workshop, including ESCOM operations and planning engineers and representatives from Power Market Limited (PML), Malawi Energy Regulatory Authority (MERA), Electricity Generation Company (EGENCO), Ministry of Energy, Global Energy Alliance for People and Planet (GEAPP) and the Malawi University of

Business and Applied Science (MUBAS). The workshop served as a critical input to this report on the ancillary services market development.

SAEP also visited the ESCOM National Control Centre (NCC) to fully understand the issues being dealt with on a daily basis. On 30 September 2022, further clarification meetings were held with EGENCO and PML. The meeting with EGENCO focused on the possible implementation of Automatic Generation Control (AGC) on the Nkula B and Tedzani hydropower stations.

This report covers Task 2.

2 MALAWI ANCILLARY SERVICES

The requirements for ancillary services are defined in the Malawi Grid Code, which makes allowances for the following ancillary services:

1) Operating reserves, which consist of:
   a Spinning reserve (for primary frequency control)
   b Regulating reserve (secondary frequency control under AGC)
2) Quick reserve (tertiary frequency control)
3) Black start and islanding
4) Reactive power compensation and voltage control from units
5) Near 50 Hertz (Hz) resonance control service

The requirements for each category of ancillary services are described in the Malawi Grid Code section 15.1.

Section 15.2 of the Malawi Grid Code describes the methods to determine the ancillary service technical requirements for each ancillary service. The section details the quantity of operating reserves required when not connected to the Southern African Power Pool (SAPP). Specifically, the section mentions the requirements to increase operating reserve levels with increasing variable renewable energy (VRE) power plants.

Section 15.3 of the Malawi Grid Code describes the technical requirements for participants to provide each of the ancillary services. The code requires that primary frequency control is mandatory from all generators and will need to be updated when Malawi is interconnected to SAPP and mandatory primary frequency control will not be required.

Section 15.4 of the Malawi Grid Code describes the scheduling and dispatch requirements for operating reserves and requires the co-optimization of energy and ancillary services. Specifically, the code details the functions of the market operator and the system operator when it comes to scheduling and dispatch.

Appendix A provides the detailed grid code sections referred to above.

The Malawian Grid Code will require updating when the SADC Regional Grid Code is approved. Specifically, the code will have to introduce frequency rate of change requirements with diminishing inertia and sub-second fast frequency control to ensure frequency rate of change limits are not exceeded.

3 CURRENT SITUATION ON ANCILLARY SERVICES IN MALAWI

3.1 OVERVIEW

ESCOM's installed conventional generation capacity is 370 MW, consisting of about 350 MW hydro and 20 MW diesel generators (Malawi IRP, 2017). The Kapichira Hydropower Station with an installed capacity of 128 MW is currently off and according to EGENCO, is expected to be back in service by December 2022. There is 80 MW of PV installed with the 60 MW Salima and 20 MW Golomoti solar PV plants

Malawi is currently operating as an island and is not interconnected to SAPP. The power line from Mozambique to Malawi (the Mozambique–Malawi interconnection project) is under construction and due for completion by the end of 2023.

3.2 FREQUENCY CONTROL SERVICES

A single generating unit of the Kapichira Hydropower Station, at 32 MW, is the largest conventional unit in the Malawi network. The primary and secondary frequency control criteria were specified with this largest unit. Hydropower plants are reasonably reliable and do not trip often. The result is that the system has been designed to have 32 MW of spinning reserve, which is only meant to be activated a few times a year.

The introduction of the 60 MW Salima solar PV plant has caused frequency excursions, sometimes resulting in UFLS and units tripping on a high frequency. A solar power plant can quickly drop in power from full output to 20% when there is cloud cover. There can be many power dips on a partly cloudy day as one-minute data recorded by ESCOM NCC on 27 August 2022 showed. In Figure 1, the Salima solar power output is seen dropping by 40 to 50 MW in less than 3 minutes. The large frequency drops measured on the day correlate to the drop in power from the Salima PV plant. On one or two occasions the power drops simultaneously at both the Salima and Golomoti solar power plants. Note there are also occasions where the Salima and Golomoti plants are moving in opposite directions and counteracting each other resulting in less impact on frequency.

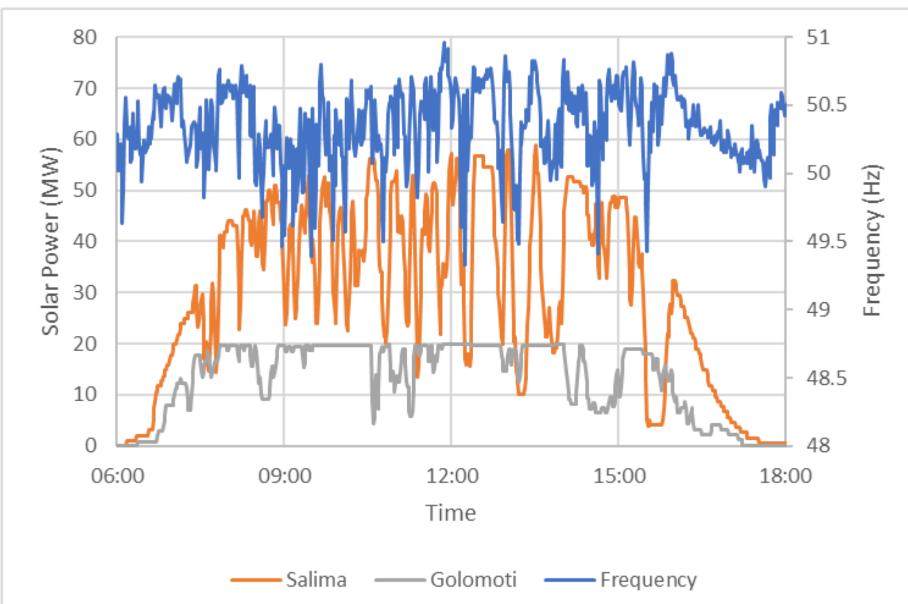

Figure 1 Solar power plant MW output and Malawi system frequency on 27 August 2022

Figure 2 shows the Malawi network frequency measured every minute from 22 to 29 August 2022. The Grid Code requires the frequency to be controlled between 49.7 and 50.3 Hz under normal conditions. The current frequency control strategy cannot meet these normal frequency control requirements; however, the requirements in the grid code are too tight for a network the size of Malawi. It would be more realistic for the normal frequency range to be 49.5 to 50.5 Hz. Note that the current strategy is also to keep the frequency around 50.5 Hz. This is understandable to ensure that when the solar PV power plants output drops, there is room for the controllers at the Nkula control centre to react and manually increase the hydropower plants before the frequency drops below 49.0 Hz. If the frequency drops below 49.0 Hz, load is shed automatically by the UFLS scheme designed to prevent a system black-out.

Chapter 5 looks at alternative frequency control strategies to understand if the frequency control can be improved.

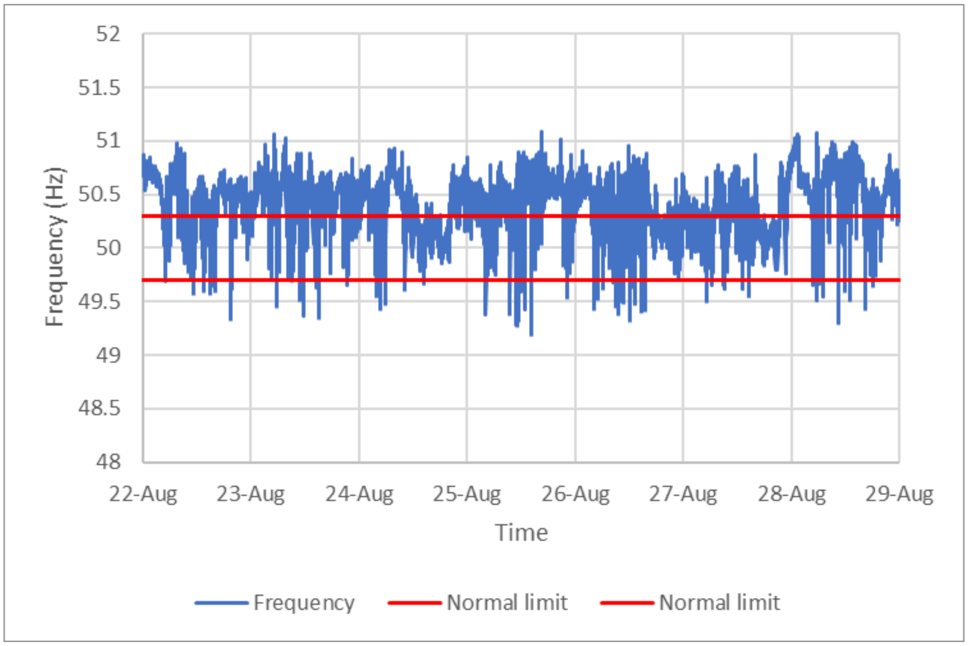

Figure 2: Malawi frequency measured every minute from 22 to 29 August.

3.3 VOLTAGE CONTROL SERVICES

Voltage control is provided by synchronous generators and solar power plants. These power plants are all in voltage control, meaning they change their reactive power production to maintain the voltage setpoint - at the generator terminals, for synchronous generators, and at the point of connection, for solar power plants. The voltage is controlled satisfactorily at sections of the network near power plants. Remote parts of the network with no synchronous generators or solar power plants have voltage control issues.

3.4 BLACK START

The Malawian grid does experience frequent blackouts, which is common for small networks with large single contingencies. The result is that black start facilities are tested often and sufficient facilities and knowledge on how to restart the network exists.

The NCC, generator and network staff all know what to do when restarting the system without referencing the black start procedures. However, the current black start procedure needs reviewing to ensure it is accurate.

4 WORKSHOP ON ANCILLARY SERVICES MARKET DEVELOPMENT FOR ESCOM

SAEP traveled to Malawi from 26 to 30 September 2022 to conduct a workshop with ESCOM and key stakeholders, focusing on the ancillary services market development for Malawi, discuss solutions for addressing the prevailing frequency stability challenges, and propose a structure for a future ancillary services market appropriate for Malawi. The workshop would be critical to this report on ancillary services market development for ESCOM.

The trip was split into three parts:

Part I (26 September): Meeting with the ESCOM COO for introductions and brief discussions on the existing operational challenges and a high-level discussion on what the workshop would cover and a visit to the NCC to engage with the operations staff on their current challenges

Part 2 (27 – 29 September): Workshop with ESCOM and stakeholders

Part 3 (30 September): Closeout meetings with ESCOM System Operator (SO), PML and EGENCO

1. Part 1 (26 September) - Meeting the ESCOM COO and a visit to the NCC

The 26 September meeting with the ESCOM COO, Maxwell Mulimakwenda, Director of System Operations, Charles Kagona, and the Senior Transmission Planning Engineer, Julia Nchilamwela, focused on the following:

- The state of the current power system with a focus on frequency control challenges. A mention was made of probable voltage control issues
- The workshop program and objectives The workshop participants with the COO following up with some key stakeholders to make sure they attended

The visit to the national control center focused on the following discussions:

- The frequency challenge issues and the possible solutions in the short-term (frequency control from hydro units), medium-term (Battery Energy Storage System [BESS]) and long-term (Mozambique-Malawi interconnector)
- Whether voltage control is a major concern – the engagement with operations staff indicated that the voltage control strategy employed at the Salima (60 MW) and Golomoti (20 MW) PV plants. The operators confirmed that the PV plants are on voltage control mode, which was confirmed with the IPPs.

2. Part 2 (27 – 29 September) - Workshop with ESCOM and stakeholders

The workshop objectives were to share knowledge on:

- International experiences with ancillary services
- Impact of wind and solar power on the provision of ancillary services
- Ancillary services for Malawi
- An ancillary market for Malawi
- Ancillary service quantities, costs, processes, procurement and markets
- Role of hydropower plants and BESS in providing ancillary services

A total of 20 participants attended the workshop, including ESCOM operations and planning engineers and representatives from PML, MERA, EGENCO, Ministry of Energy, GEAPP and MUBAS. The stakeholders actively participated in the workshop discussions. SAEP shared practical examples of the modeling done using the ESCOM 30-minute data to demonstrate frequency control challenges and the needed control. ESCOM expressed the need to have a clear **roadmap** to guide them on the preparation they need to make and the capacity (skills and training) they need to operate the end state of the power system with the Mozambique-Malawi interconnector.

The following themes and group discussions were covered:

Day 1: An introduction to ancillary services – Relevance to ESCOM

<u>Group discussion topic:</u> Discussion of how ancillary services can assist with current ESCOM issues

Questions covered in the group discussions:

- What are the most urgent requirements for ancillary services in Malawi?
- Should ancillary services be charged separately to energy for ESCOM generation?
- Should operating reserves be co-optimized with energy in the day-ahead schedule?

Day 2: Determining ancillary service quantities and operating reserves – the Salima PV plant case

Group discussion topic: Discussion on the determination of ancillary services quantities and operating reserves

Questions covered in the group discussion:

- What is the largest single unit and demand in Malawi? From these values, what amount of primary frequency reserve is required for Malawi before interconnecting to SAPP?
- How can the SAPP methodology be used to determine the requirements for spinning reserve for Malawi when Malawi is interconnected to SAPP?
- How much extra regulation reserve is Salima adding to the Malawi system?

Day 3: Ancillary service markets and processes for Malawi: Market design options

Group discussion topic: Discussion of applicability of ancillary services markets and processes to Malawi

Questions covered in the group discussion:

- What does the group think is an appropriate ancillary service market for Malawi?
- How will the ancillary services market in Malawi be impacted when Malawi is interconnected with SAPP in a few years?
- Should the single buyer be the procurer of ancillary services or should some services be procured competitively?

3. **Part 3 - Closeout meetings with ESCOM SO, PML and EGENCO**

Meeting with ESCOM SO:

The meeting with ESCOM involved a second trip to the national control to assist the ESCOM SCADA engineer, Chimwemwe Thomson Khonje, set up the General Electric (GE) SCADA system to capture 4-second data from the power plants. The ESCOM COO joined the meeting briefly to offer his support around engaging EGENCO to set up AGC on the hydropower plants. SAEP, with help from Eskom South Africa and GE, assisted ESCOM to configure the SCADA to capture 4-second data. This information will be used to confirm the initial simulations that were done using 30-minute data.

Meeting with PML:

The meeting with PML Senior Contracts Manager, John Thawi, and Contracts Officer, Isaac Chitedze, focused on PML's current requirements for IPPs to have BESS as part of their PV plants. The BESS capacity is sized at 40% of the PV plant's capacity. There were discussions on the number of PV plants and other Power Purchase Agreements (PPAs) that PML is signing without a clear national plan or strategy to procure IPPs. The engagements with PML highlighted that PML needs a lot of support since they are currently making decisions without the necessary technical analysis and their decisions have lasting financial and economic implications for ESCOM and electricity customers.

Meeting with EGENCO:

The meeting with EGENCO CEO, William Liabunya, focused on requesting EGENCO's permission and support to implement AGC on Nkula and Tedzani hydro plants. EGENCO agreed to the proposal but requested that the SOW and costing for the AGC implementation be taken through the approval processes within EGENCO and ESCOM . ESCOM and EGENCO have expressed their commitment to implementing the AGC as a quick-win project.

The outcomes of the workshop and the trip can be divided into three phases:

Phase 1 (short-term solution – AGC on hydro plants; quick-win)

- Signals from AGC Remote Unit Terminal to be wired to Nkula B and Tedzani units
- Commission AGC signals to Nkula B and Tedzani power plants. Kapichira has already been commissioned. The target is to have at least 48 MW on AGC
- Optimize AGC at the NCC to control the system frequency using Nkula B and Tedzani power plants

- ESCOM indicated that they will send SCADA engineers to scope out the works for generator units at Nkula B and Tedzani III to have AGC capability

Phase 2 (medium-term solution – BESS)

- Activate primary frequency control on BESS with a droop of 0.4% or less. A drop of 0.4% means a 0.2 Hz frequency change will result in a 100% change in active power from the BESS
- Optimize AGC at the NCC for a smoother, more economic control and use backup BESS should it not be available

Phase 3: (long-term solution; the Mozambique-Malawi interconnector)

- The interconnector will take over frequency control and as a result BESS primary frequency control needs to be changed to be a backup should the interconnector trip
- Optimize AGC at the NCC for a smoother, more economic control
- Train the NCC to optimize Malawi generation and interconnector power flows to Mozambique (buying and selling in the SAPP electricity markets)

Chapter 5 details the frequency control studies that SAEP performed using the Generation Dispatch Analysis Tool (GDAT).

5 FREQUENCY CONTROL STUDIES

5.1 SECONDARY FREQUENCY CONTROL STUDIES TO CATER FOR MINUTE-TO-MINUTE BALANCING

This chapter provides the frequency control strategy studies that were performed using the GDAT to investigate improving frequency control. With the GDAT, SAEP used the measured data from 22 to 29 August 2022 and simulated different control strategies using this original data to understand if frequency control can be improved and determine the economic impact for each strategy.

The GDAT is a product developed in MATLAB© & Simulink©.

The GDAT is used for six main purposes:

1. Determining the benefits for controlling network frequency using different primary (governor) and secondary (AGC) control strategies
2. Analyzing the impact of non-dispatchable renewable energy on frequency control
3. Analyzing the benefits of storage on frequency control
4. Tuning automatic generation controllers
5. Analyzing SO controller dispatch performance
6. Auditing SO dispatch

The GDAT was developed in 1998 for the optimization of AGC settings for improved secondary frequency control, economic dispatch and interchange power control, as shown in Figure 3. Since 2007, the tool has been refined for intermittent resource management and used for minute-to-minute wind farm integration studies in Mauritius and small island systems. The GDAT has also been used for system operation studies and system operator audits in South Africa, Tanzania, Thailand and Abu Dhabi.

The GDAT model also has the capacity to incorporate battery storage systems. For instance, the GDAT model for Pacific Islands (part of the small island systems mentioned above) was improved to include battery storage systems for system security studies and for energy storage analysis.

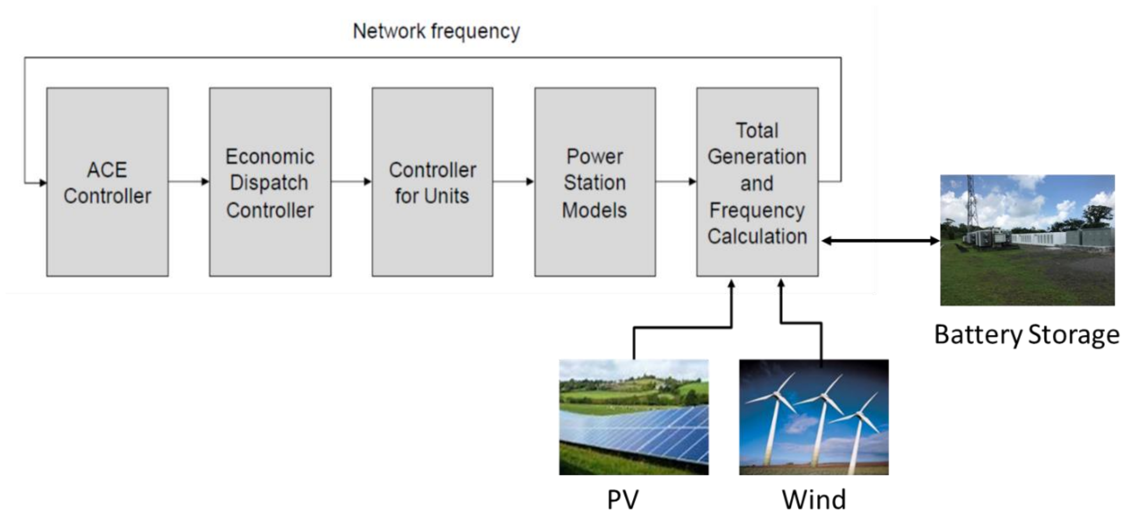

Figure 3 Generation Dispatch Analysis Tool with wind, solar and battery storage inputs added

The studies undertaken in GDAT use original recorded second-to-second generation, demand and frequency data from SCADA as the starting point for the studies. The technical parameters for power plants such as ramp rates, network dynamics and frequency control capability are modelled from the data provided for the system being studied and typical parameters for the power plants. Studies can be done to determine the appropriate level of automatic control to ensure frequency control with increasing VRE with and without using BESS for frequency control and storage.

The user can select the options for the study, including which units to use for frequency control and the required controller settings, the reserve levels and the demand and power plant technical parameters.

GDAT calculates the resultant frequency with the various configurations of controller settings and calculates the cost of dispatch from the cost curves entered into the model. The model is designed to commit units to ensure sufficient spinning reserve level or de-commit to ensure too many units are not operating.

The cost of dispatch can be used to analyze the economic impact of the options selected to study.

5.2 MALAWI SECONDARY FREQUENCY CONTROL STUDIES

5.2.1 INTRODUCTION

ESCOM NCC provided SAEP with one week's one-minute data recorded from 22 to 29 August 2022. The data included each hydropower plant unit's power and each solar power plant's power and frequency.

Figure 4 shows the one-minute recorded frequency, which varies between 49.5 to 51 Hz.

Figure 5 shows the recorded one-minute power output at the solar power plants for the recorded week.

The one-minute frequency is currently controlled by EGENCO generation control center at Nkula B Power Station. EGENCO generation controllers manually instruct hydropower plants to increase or decrease their power output as required to control the frequency. The bulk of the control is performed by Nkula B power station units 4 to 8 (Figure 6). The Nkula A units1 to 3 (Figure 6) and Tedzani units (Figure 7) are used less for minute-to-minute frequency control and are dispatched more to follow the load.

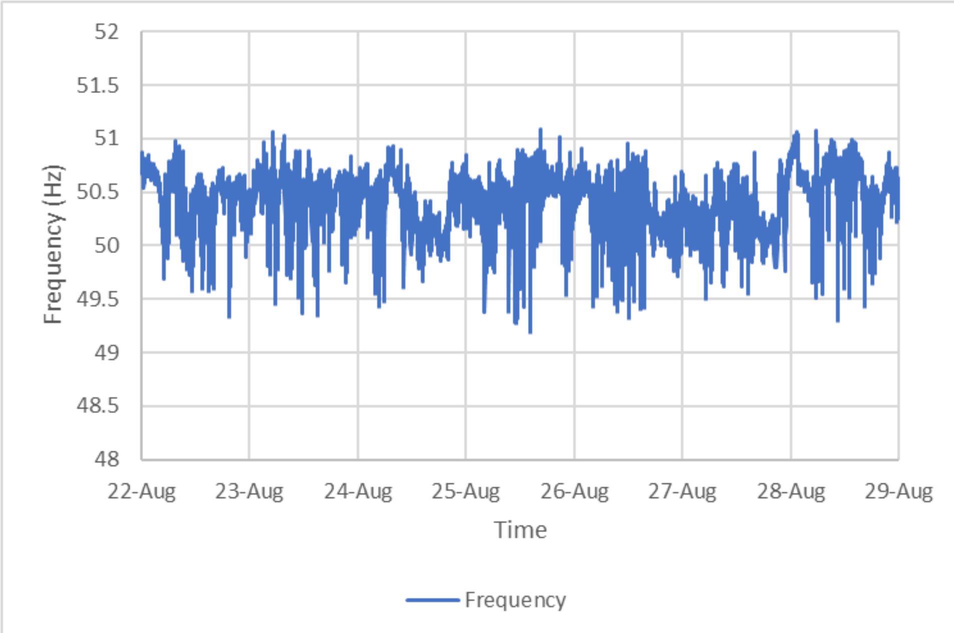

Figure 4 Malawi recorded minute-to-minute frequency

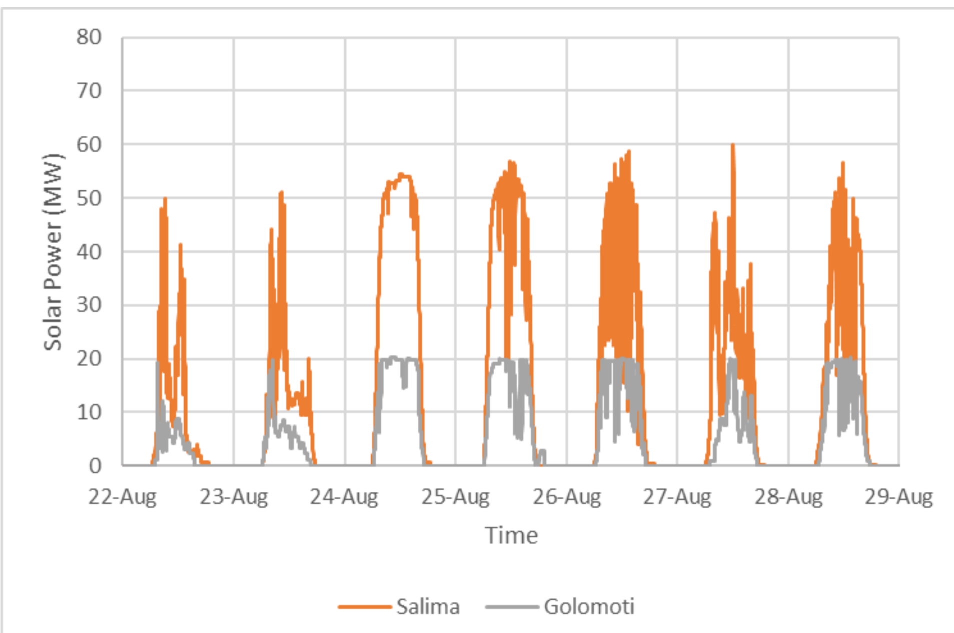

Figure 5 Salima and Golomoti solar PV plant recorded minute-to-minute power output

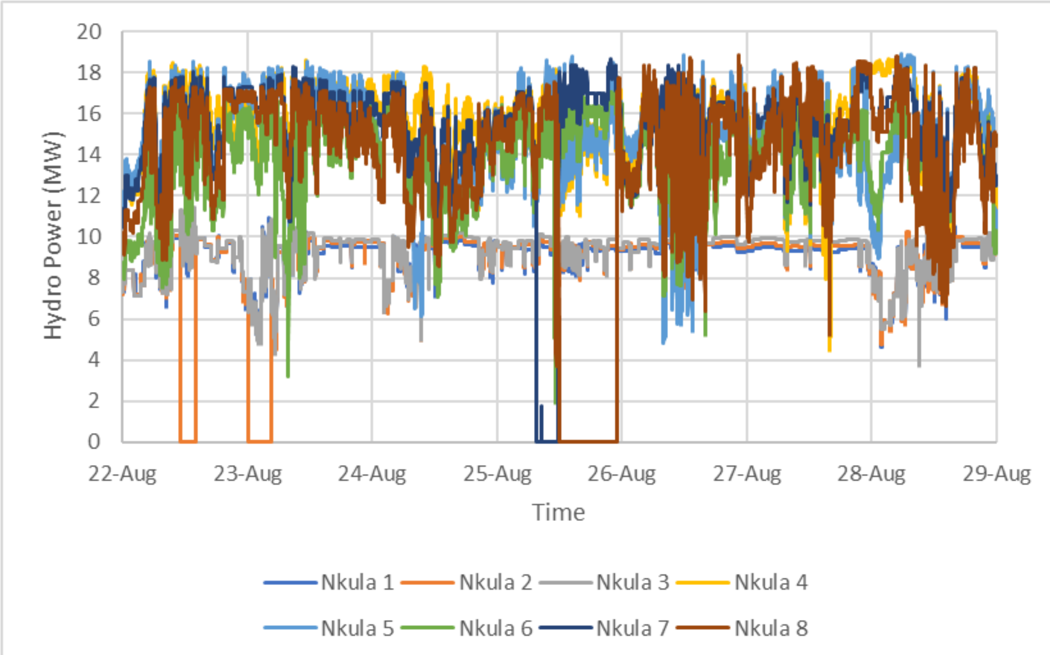

Figure 6 Nkula A and B power plant recorded minute-to-minute power output

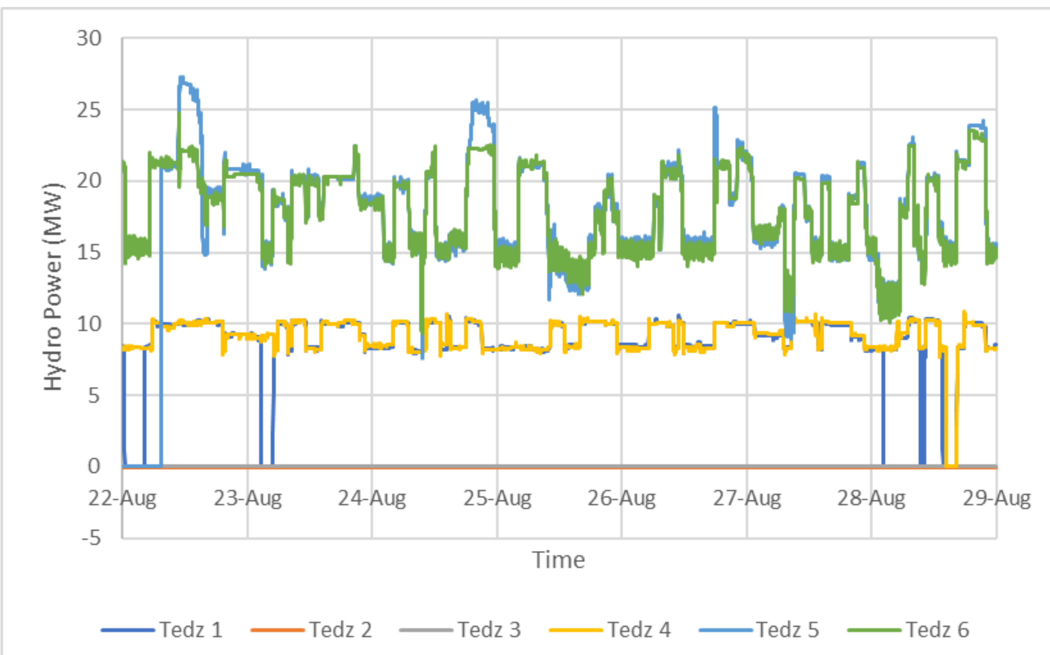

Figure 7 Tedzani power plant recorded minute-to-minute power output

5.2.2 SIMULATION STUDIES WITH NKULA B AND TEDZANI POWER PLANTS ON AGC

ESCOM NCC has a GE Energy Management System (EMS) with the capability to perform AGC. Kapichira Power Station was tested to be on AGC by GE when they were commissioning the EMS system.

Nkula B and Tedzani power stations have the required telecommunications and remote terminal unit (RTU) for AGC. The power stations' unit control systems are able to receive AGC commands. All that is still required is wiring from the RTU to the unit control system.

A simulation was conducted to check if minute-to-minute frequency control could be improved if Nkula B and Tedzani power stations were put on AGC. The technical parameters for the power stations were put into the GDAT model. Nkula B and Tedzani power stations were set to AGC control. Figure 8 shows GDAT unit parameters with Nkula B and Tedzani power stations were set to AGC control.

Figure 9 shows that the frequency can be controlled within ±0.2 Hz of 50 Hz with Nkula B and Tedzani power stations on AGC. Figure 10 shows the simulated MW output with Nkula B and Tedzani power stations on AGC on 24 August 2022. Not many dips from the solar power plants are experienced on this day and thus the hydropower plants do not have to perform many control actions. Figure 11 shows a partly cloudy day with many dips in power specifically from the Salima solar plant. The hydropower plants ramp up and down often on this day. Hydropower plants have the capability to ramp up and down many times a day without significant wear-and-tear and, as will be discussed later, this strategy is only required for a short period until BESS is installed.

Overview | Batch

Unit Name	Nkula 1	Nkula 2	Nkula 3	Nkula 4	Nkula 5	Nkula 6	Nkula 7	Nkula 8	Tedz 1	Tedz 2	Tedz 3	Tedz 4	Tedz 5	Tedz 6	Salima	Golo
Model type	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Solar	Solar
MCR	8	8	8	20	20	20	20	20	10	10	10	10	31	31	60	
Unit Inertia	4.5000	4.5000	4.5000	4	4	4	4	4	3.1000	3.1000	3.1000	3.1000	2.9000	2.9000	0	
Ramp Rate	8	8	8	20	20	20	20	20	3	3	3	3	31	31	60	
Maximum Generation	8	8	8	20	20	20	20	20	10	10	10	10	31	31	60	
Minimum Generation	0	0	0	8	8	8	8	8	8	8	8	8	14	14	0	
Spinning Capability	2	2	2	5	5	5	5	5	2.5000	2.5000	2.5000	2.5000	5	5	0	
Nonspinning Capability	8	8	8	20	20	20	20	20	10	10	10	10	26	26	0	
AGC On	☐	☐	☐	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☐	☐
Model Name	IEEEG1	IEEEG1	IEEEG1	IEEEG1	IEEEG1	IEEEG1	IEEEG1	IEEEG1	IEEEG1	IEEEG1	IEEEG1	IEEEG1	IEEEG1	IEEEG1	RecordedData	RecordedDa
Frequency deadband	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040	0.1000	0.10
Lower frequency limit	-0.2000	-0.2000	-0.2000	-0.2000	-0.2000	-0.2000	-0.2000	-0.2000	-1	-1	-1	-1	-1	-1	0	
Upper frequency limit	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000	1	1	1	1	1	1	1	
Droop (R)	0.0200	0.0200	0.0200	0.0500	0.0500	0.0500	0.0500	0.0500	0.0400	0.0400	0.0400	0.0400	0.0400	0.0400	0.0400	0.04

Figure 8 GDAT unit parameters with Nkula B and Tedzani power stations were set to AGC control

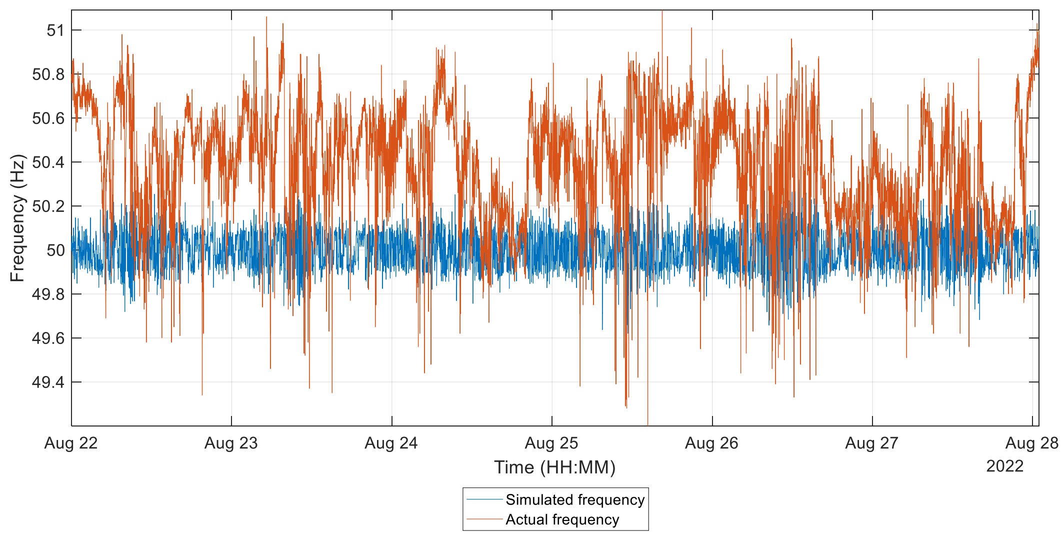

Figure 9 Simulated and measured frequency with Nkula B and Tedzani power stations on AGC

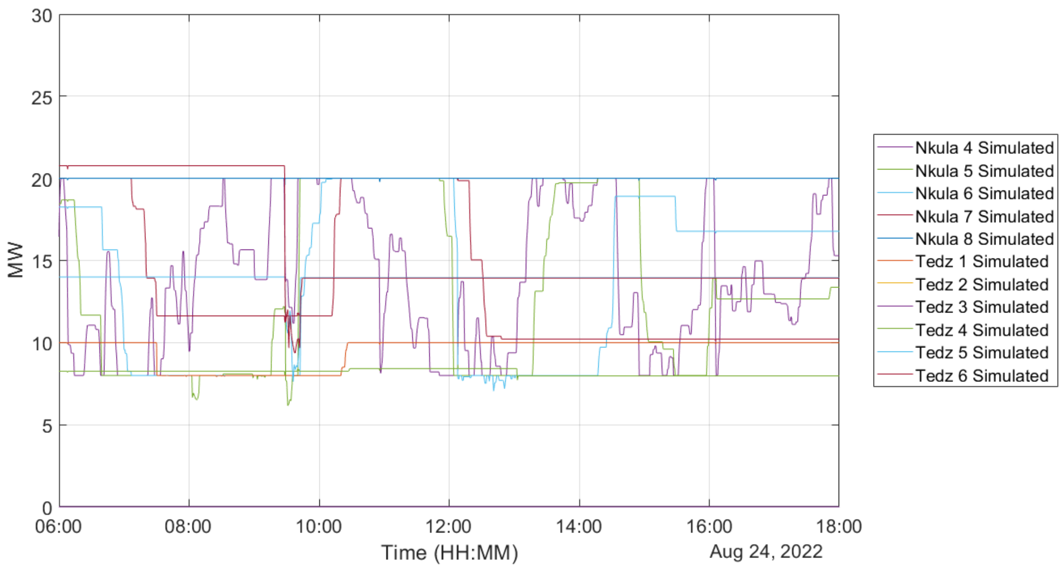

Figure 10 Simulated MW output with Nkula B and Tedzani power stations on AGC on 24 Aug 2022

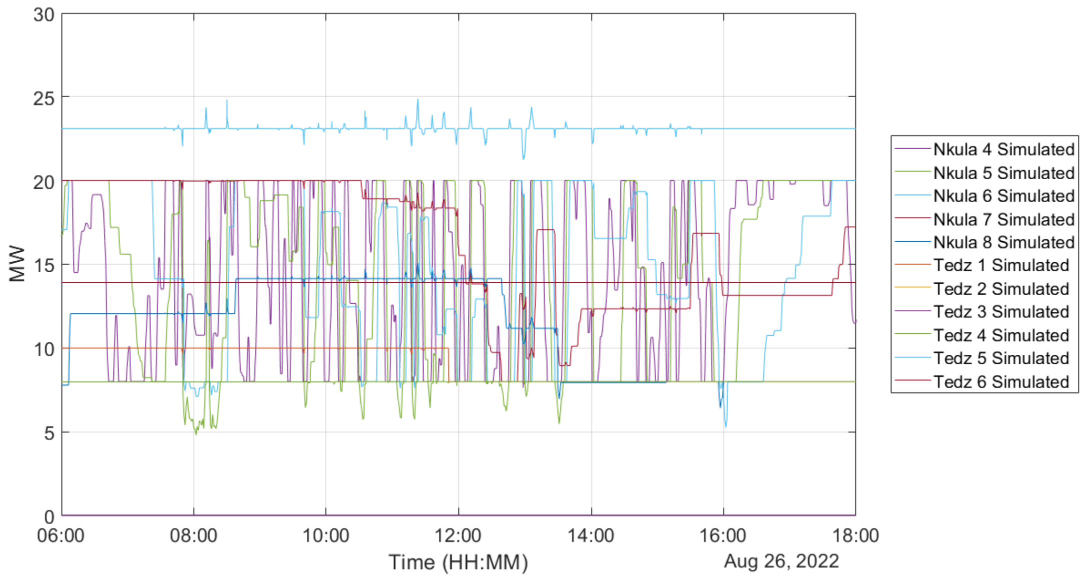

Figure 11 Simulated MW output with Nkula B and Tedzani power stations on AGC on 26 Aug 2022

5.2.3 SIMULATION STUDIES WITH 5 MW OF BESS ON PRIMARY FREQUENCY CONTROL AND WITH NKULA B AND TEDZANI POWER STATIONS ON AGC

The second scenario simulated uses the exiting 5 MW BESS to initially provide primary frequency control and thereafter use Nkula B and Tedzani power stations on AGC for when the BESS cannot control the system frequency.

BESS is ideally suited to provide primary frequency control as it can respond within a second to frequency changes. The control action is not only fast but can also be done with very little degradation to the battery life if the battery does not charge and discharge rapidly. The battery life is measured on the number of full discharges and Li-ion batteries typically are designed to have more than 3,000 full discharges.

The BESS is set to provide aggressive primary frequency control through setting the droop to 0.4%. The BESS controller is set up to provide full power output of 5 MW (discharging) with a 0.2 Hz drop in frequency (49.8 Hz) and full power consumption (charging) with a 0.2 Hz increase in frequency (50.2 Hz).

Figure 12 to Figure 16 show the results when 5 MW BESS is on primary frequency control and thereafter using Nkula B and Tedzani power stations on AGC for the times when the BESS cannot control the system frequency.

Figure 12 and Figure 13 show the frequency is satisfactory and a significant portion of the frequency control is performed by the 5 MW BESS. Figure 19 shows the battery charge does not vary much throughout the week and hence no significant life from the battery is consumed. As will be noted later, aggressive primary frequency control will not be required when Malawi is interconnected to the SAPP network.

Figure 15 and Figure 16 show the reduced frequency control requirements from Nkula B and Tedzani power plants on AGC. Note that the simulation model is swapping hydro units around, which would not be the practice by the controllers.

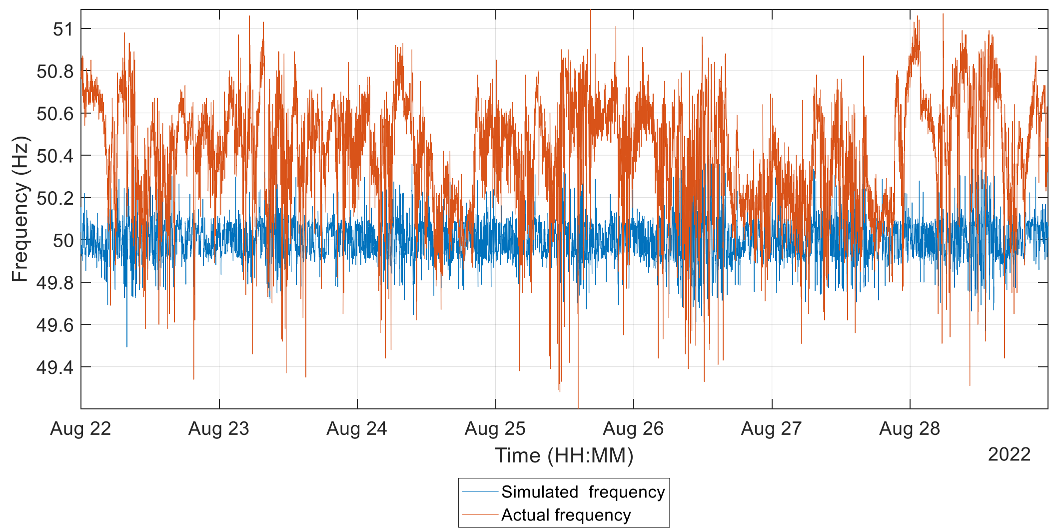

Figure 12 Simulated and measured frequency with 5 MW of BESS on primary frequency control assisted by Nkula B and Tedzani power plants on AGC

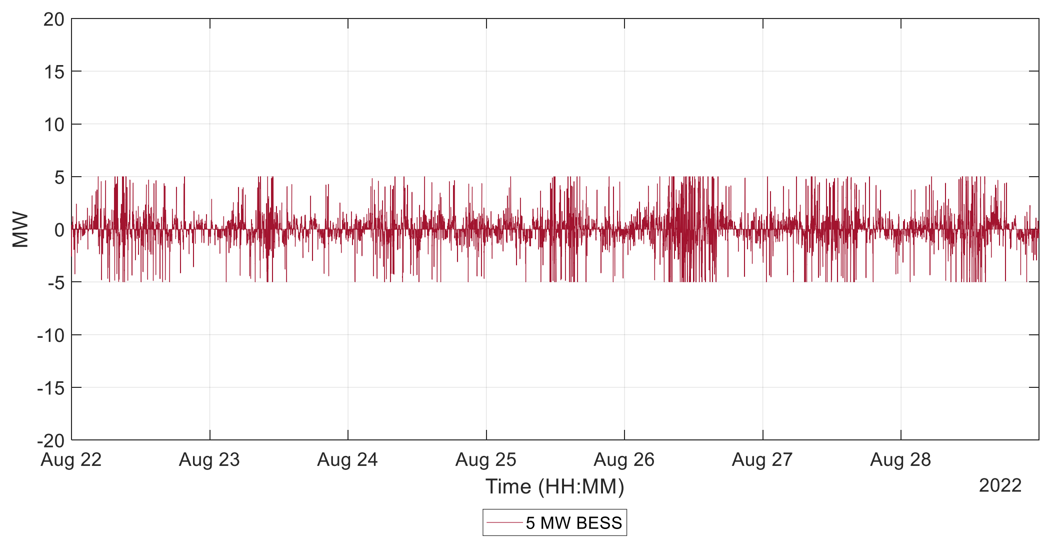

Figure 13 Simulated BESS power with 5 MW BESS on primary frequency control assisted by Nkula B and Tedzani power plants on AGC

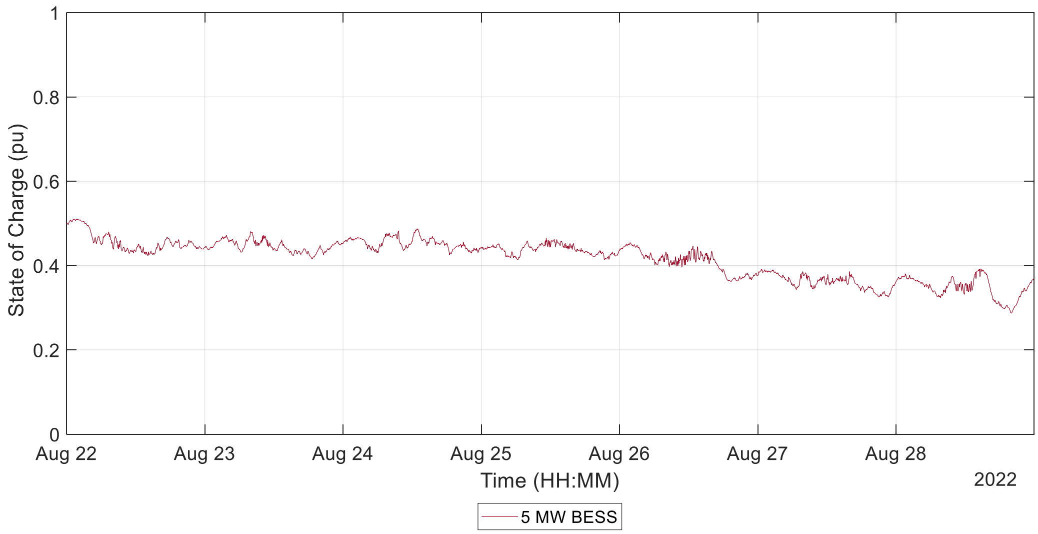

Figure 14 Simulated BESS state of charge with 5 MW BESS on primary frequency control assisted by Nkula B and Tedzani power plants on AGC

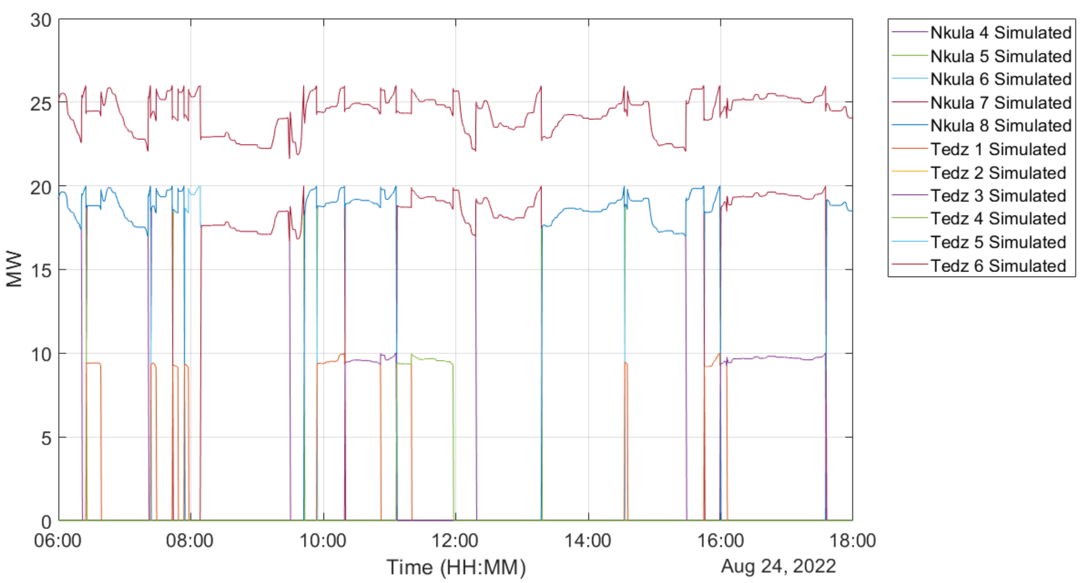

Figure 15 Simulated assisted by Control Nkula B and Tedzani power plants power with 5 MW of BESS on primary frequency control Nkula B and Tedzani power plants on AGC for 24 Aug 2022

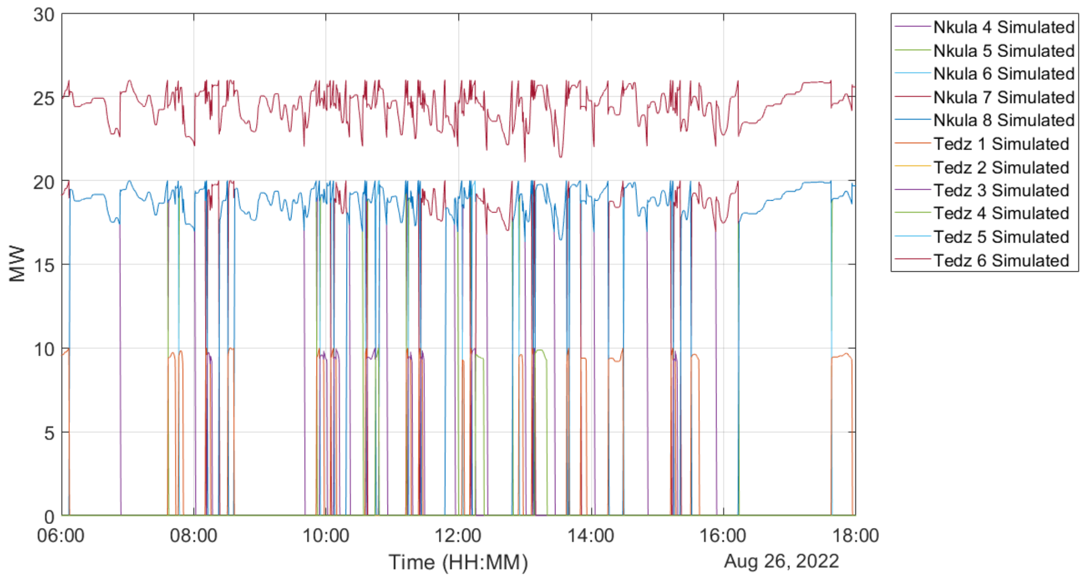

Figure 16 Simulated assisted by Control Nkula B and Tedzani power plants power with 5 MW of BESS on primary frequency control Nkula B and Tedzani power plants on AGC for 26 Aug 2022

5.2.4 SIMULATION STUDIES WITH 25 MW OF BESS ON PRIMARY FREQUENCY CONTROL AND WITH NKULA B AND TEDZANI POWER PLANTS ON AGC

The third scenario simulated uses the existing 5 MW BESS plus the proposed new 20 MW BESS to provide the 'first' primary frequency control and use Nkula B and Tedzani Power Plants on AGC for times when the BESS cannot control the system frequency.

The BESS is set to provide aggressive primary frequency control through setting the droop to 0.4%. The two BESS controllers are set up to provide a combined full power output of 25 MW (discharging) with a 0.2 Hz drop in frequency (49.8 Hz) and full power consumption of 25 MW (charging) with a 0.2 Hz increase in frequency (50.2 Hz).

Figure 17 and Figure 18 show that the frequency is controlled well within ±0.2 Hz and most of the frequency control is performed by the 25 MW of BESS. Figure 19 shows that the battery charge is not varying much throughout the week and hence no significant life from the battery consumed. As discussed previously, the battery life is determined by the number of full discharges. As will be noted later, aggressive primary frequency control will not be required when Malawi is interconnected to the SAPP network.

Figure 20 and Figure 21 show that the frequency control requirements from Nkula B and Tedzani Power Plants on AGC are further reduced when BESS is commissioned. Note that the simulation model is swapping hydro units around, which would not be the practice by the controllers.

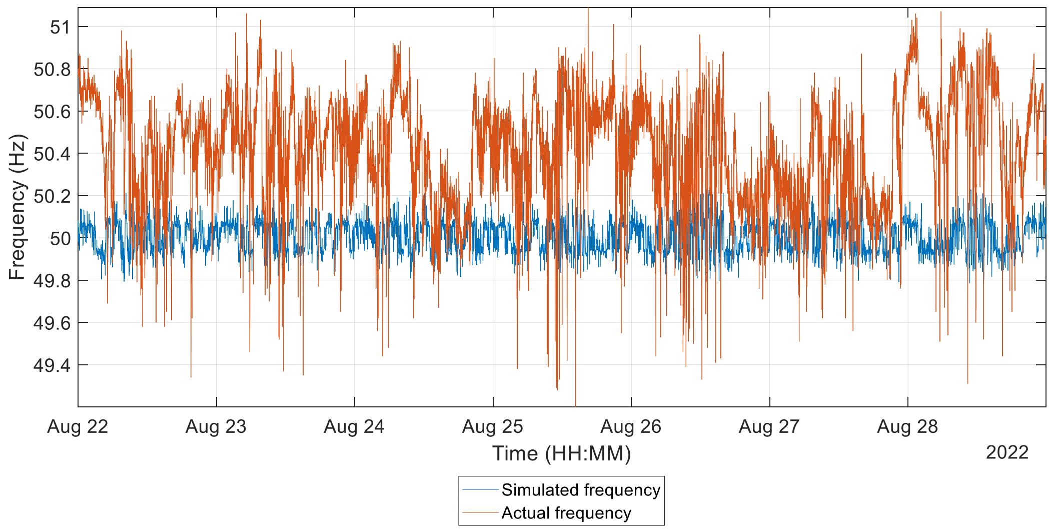

Figure 17 Simulated and measured frequency with 25 MW of BESS on primary frequency control assisted by Nkula B and Tedzani power plants on AGC

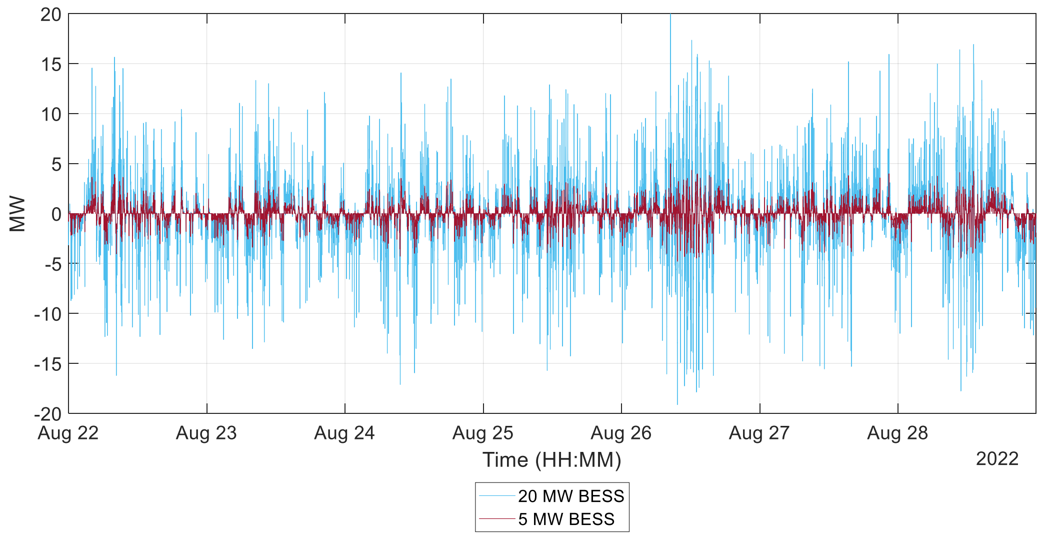

Figure 18 Simulated BESS power with 25 MW BESS on primary frequency control assisted by Nkula B and Tedzani power plants on AGC

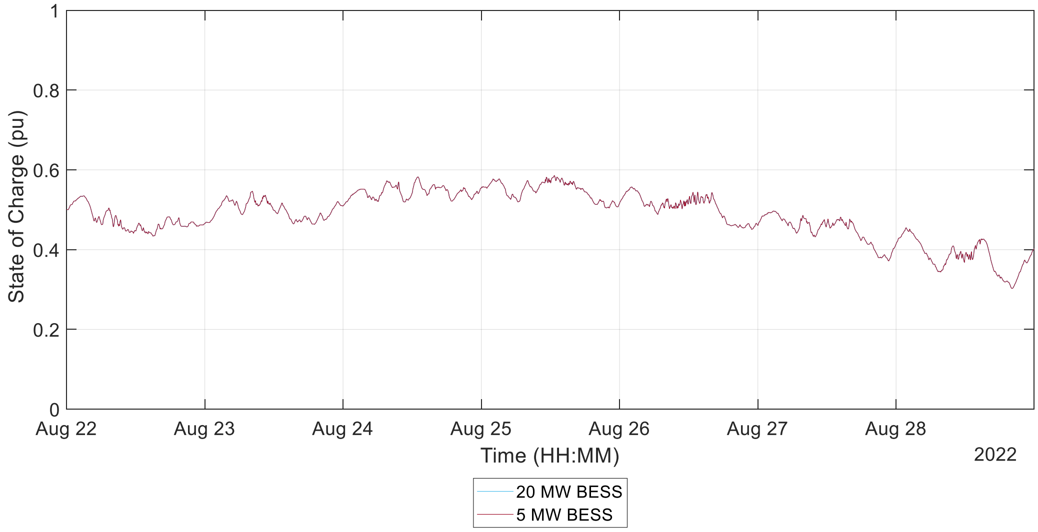

Figure 19 Simulated BESS state of charge with 25 MW BESS on primary frequency control assisted by Nkula B and Tedzani power plants on AGC

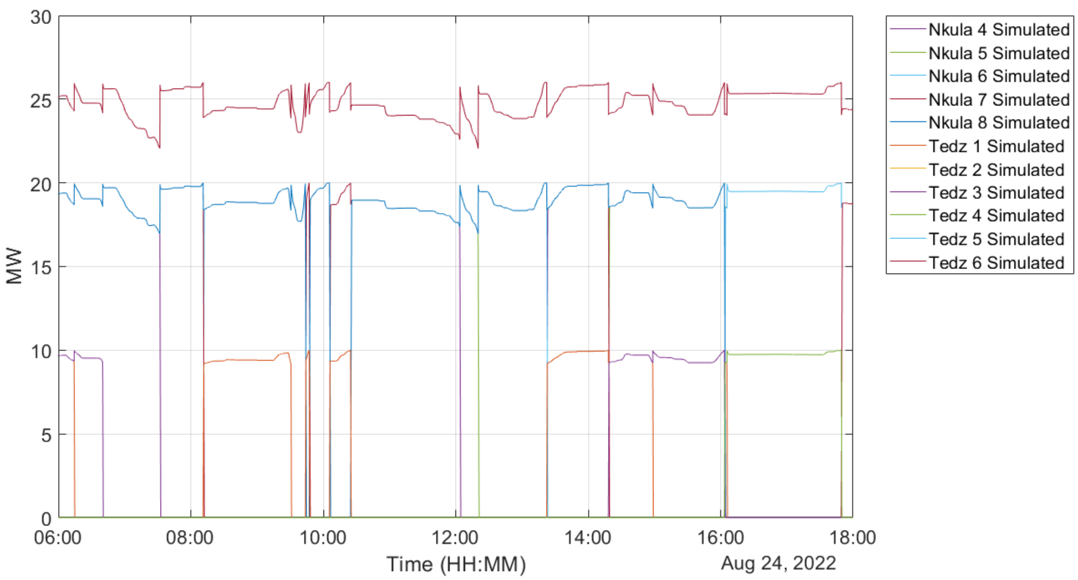

Figure 20 Simulated assisted by Control Nkula B and Tedzani power plants power with 25 MW of BESS on primary frequency control Nkula B and Tedzani power plants on AGC for 24 Aug 2022

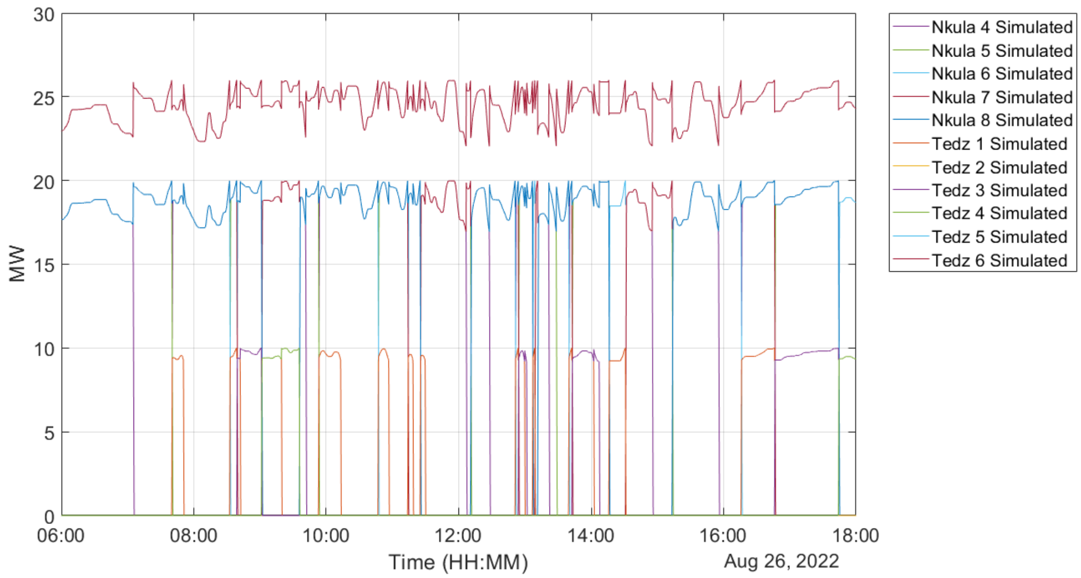

Figure 21 Simulated assisted by Control Nkula B and Tedzani power plants power with 25 MW of BESS on primary frequency control Nkula B and Tedzani power plants on AGC for 26 Aug 2022

5.2.5 SIMULATION STUDIES WHEN MALAWI INTERCONNECTED TO SAPP THROUGH MOZAMBIQUE

The fourth scenario is to simulate the primary and secondary frequency control requirements when Malawi is interconnected to SAPP through Malawi-Mozambique 400 kV line. The line is due to be completed by the end of 2023.

Once the interconnector is in place, Malawi will no longer be able to significantly change the SAPP network frequency. To change the frequency by 0.1 Hz requires more than 150 MW. However, any mismatch between supply and demand within Malawi will result in a change in the power flow on the Malawi-Mozambique 400 kV line.

The scenario simulated is that Mozambique hydro units (Hidroelectrica de Cahora Bassa (HCB)) will provide control area services, including primary and secondary frequency control reserves. Malawi hydro units are run at optimal power levels maximizing the hydropower availability and are not required to provide any primary and secondary frequency control reserves. The simulation's AGC is set up to only become active if the power flow on the interconnector exceeds 40 MW from the contracted power flow, assuming Mozambique is providing 40 MW of operating reserve. The exact amount of operating reserve provided by Mozambique will have to be negotiated as detailed in the roadmap in Chapter 7.5.

The BESS is set up to provide frequency control should the interconnector trip and for these simulation studies the dead band is set to 0.5 Hz. The final frequency control settings for the BESS will need to be determined from DIgSILENT Powerfactory studies. The hydropower plants dead band is also set to 0.5 Hz for these simulation studies.

Figure 22 shows the SAPP interconnected frequency, which is maintained within ±0.15 Hz of 50 Hz for the simulation period. The BESS and hydropower plants thus provide no primary frequency control.

Figure 23 shows the simulated interchange error exceeds the 40 MW threshold a few times a day. Figure 24 shows the Nkula B and Tedzani power plants are only required to assist with AGC control once or twice a day.

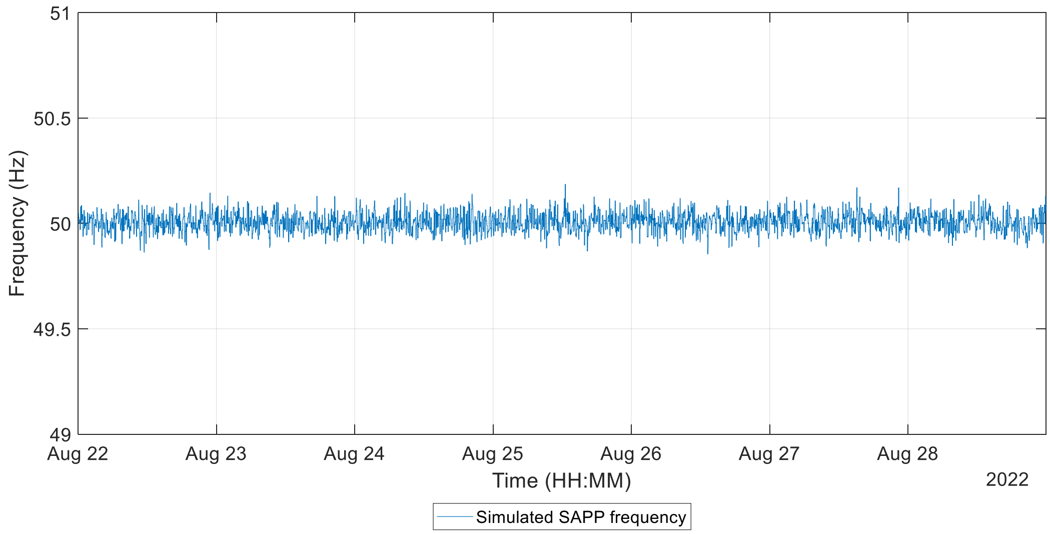

Figure 22 Simulated SAPP frequency with first 40 MW of control performed by Mozambique and then assisted by Nkula B and Tedzani power plants on AGC

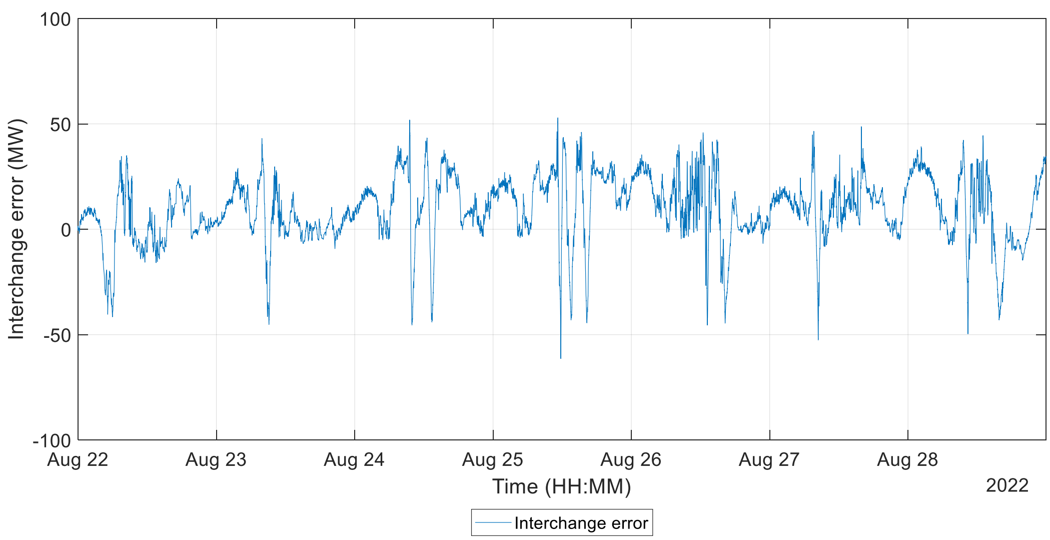

Figure 23 Simulated interchange error with first 40 MW of control performed by Mozambique and then assisted by Nkula B and Tedzani Power Plants on AGC

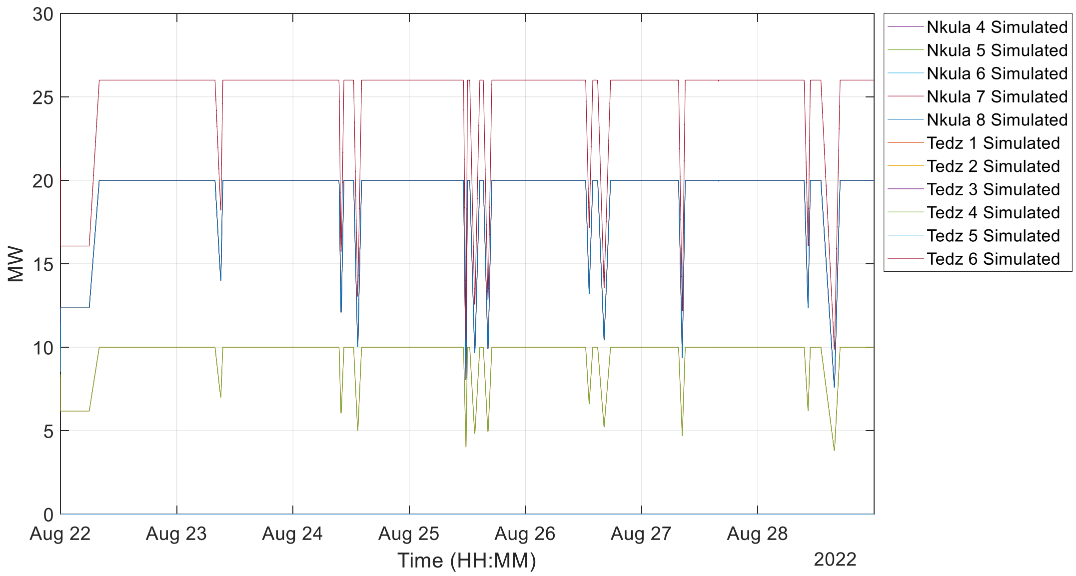

Figure 24 Simulated Nkula B and Tedzani power plants power when on AGC with first 40 MW of control performed by Mozambique

5.3 CONCLUSION OF FREQUENCY CONTROL STUDIES

The simulation studies conclude that satisfactory frequency control can be achieved while Malawi is not interconnected to SAPP using two strategies:

1. Commissioning Nkula B and Tedzani power plants to be on AGC
2. Setting BESS to provide primary frequency control

Once interconnected, the hydropower stations can be on AGC and will be required to balance the system once or twice a day. If a control area agreement can be reached with HCB, the Malawi hydropower plants can be operated without providing primary and secondary frequency control reserves. The hydropower plants can be optimized for efficiency, maximizing the energy available, and selling excess power into the SAPP markets. The BESS primary frequency control settings will need to be changed to ensure they only operate for large frequency deviations, which will be experienced when the interconnector to Mozambique trips or is not available.

6 ANCILLARY SERVICE PROCUREMENT OPTIONS

Ancillary services markets are required to compensate suppliers of ancillary services not already compensated for in the energy market or in the PPA.

The costs for providing ancillary services can be broken down into three distinct categories:

1. Standing costs are the fixed costs which cover the capital costs to allow the provider to provide the service.
2. Holding costs cover the costs for keeping the service available. These include costs for manpower, loss of profit, testing, maintenance and operating costs.
3. Usage costs are the costs when the service is activated such as fuel, maintenance and operating costs.

The calculation of capital costs typically uses the rate of return on asset which is calculated as the Weighted Average Cost of Capital (WACC) where:

*WACC = % equity * equity return + % debt * interest on debt*

Asset value = Asset replacement costs

The annualised cost is derived from the mortgage type payments

The payment function in Excel can be used in the formulas provided. **PMT**(**rate**,**nper**,**pv**), where:

- **rate** is the WACC
- **nper** is the asset lifetime
- **pv** is the present value of the asset

Cost of capital per annum = -PMT (WACC, Plant life, Asset cost)

The SAPP proposed asset values in the SAPP Operating Guidelines for each Ancillary Service are:

1. Reactive (Unit) - Unit replacement costs or generator and exciter costs
2. Reactive Synchronous Condenser Operation (SCO) - Cost of unit with SCO - Cost of unit without SCO or Cost of converting unit to have SCO
3. Reactive (SVC) - SVC replacement costs
4. Secondary frequency control under AGC - AGC equipment cost + additional costs for control system
5. Primary frequency control – For a generator the percentage cost for governor equipment + additional costs for control system and for a demand side participant the cost UFLS equipment, data recording, storage and communication equipment
6. Black Start - Method 1: actual costs, cost difference with and without black start or cost of converting to black start and method 2: Estimated black start capital costs at purchasing TSO unit.
7. Control Area Services – The cost of AGC, telecommunication and telemetering.

For the loss of profit a reference price is required to determine income lost when real power production is reduced as a consequence of providing ancillary services.

The Day-Ahead Market (DAM) price was the proposed reference for SAPP ancillary services. The loss of profit calculation is the difference between the price of the energy that could have been sold and the marginal cost of production, noting that if the marginal cost is higher than DAM, there is no loss of profit.

The method for apportioning ancillary service costs in SAPP is shown in Table 1. These methodologies are documented in the SAPP Operating Guidelines. ESCOM should refer to these methodologies when discussing control area services to be provided by HCB.

Table 1 Method for apportioning Ancillary Service costs in SAPP

Reactive (Unit)	(TSO MVAr(production + reserve))^2 / (Unit MVA) ^{2}
Reactive (SCO)	TSO MVAr(production + reserve) / SCO MVAr
Reactive (SVC)	TSO MVAr(production + reserve) / SVC MVAr
RR	TSO RR range / Total RR range
IR	TSO IR range / Total IR range
TR	TSO TR range / Total TR range
Black start	Method 1: Time to get power to first unit / Time to get power to TSO first unit Method 2: Not required
CAS	Max (TSO_{GC} , TSO_{PD}) / Max (CA_{GC} , CA_{PD}) where GC is generating capacity and PD is peak demand

The current IPP PPAs do not have separate ancillary service cost provisions and it will be nearly impossible to change these existing agreements. Ancillary services that are mandated by the grid code are deemed to be provided at no additional cost.

The ancillary service costs for EGENCO generators can be calculated using the EPRI TR107270 series, which is available on the EPRI web site. It is important to calculate the cost savings when dispatching power plants in Malawi without providing operating reserves. This can be relatively easily to study using the PLEXOS simulation platform.

The proposed approach is for ESCOM to first obtain the costs from HCB to provide all the required control area services, including operating reserves and then to determine if this is cheaper than providing the services internally in Malawi. If it is more affordable, there is no need to start an ancillary services market in Malawi for operating reserves.

The procurement of black start and reactive power should be done through long-term contracts where the requirements are tendered out, noting that BESS is one of the potential providers for such services.

7 CONCLUSION AND RECOMMENDATIONS

The workshop concluded that there is no urgent need to procure ancillary services for reactive power and black start because once interconnected to SAPP, black start from hydro power plants will be infrequently required. The interconnector with Mozambique should be very reliable and even if the interconnector trips there is a remote possibility that the Malawi network will be blacked out. Even in this remote case, the Malawi system can be easily restarted through the interconnector. It is recommended that the black start procedure for restarting Malawi's network from Malawi's hydropower plants is carefully documented so system controllers in the future can know how to restart the Malawi system.

The objective of the workshop and the frequency control studies was to improve the frequency control in Malawi initially using hydropower stations on AGC, then have BESS providing primary frequency control. The final task is to determine the AGC and BESS parameters for interconnected operations.

The recommended tasks (Task 1 to 4 below) and scope outlined in this report provide a high-level roadmap of what needs to be done immediately (a quick-win) to manage the prevailing frequency control challenges and to prepare the staff for operating in the future interconnected system once the Mozambique-Malawi interconnector is commissioned.

As requested by ESCOM at the workshop, the roadmap for interconnected operation provided by ESCOM was reviewed by SAEP and recommendations to update the roadmap are provided in Table 2 below in section 7.5.

7.1 TASK 1: COMMISSION HYDRO UNITS TO BE ON AGC

7.1.1 TASK 1A: COMMISSIONING SIGNALS TO AGC CONTROLLER TO AND FROM THE HYDRO UNIT

AGC gets real-time data from SCADA and sends control commands to power plants through SCADA.

The interface to the units on the Power Station is either through a RTU or via a gateway. The gateway is via a bus and the for the RTU the signals are hardwired to the unit control system.

Main AGC inputs from the units are:

1. Local/remote status of controlled units (AGC will only send control commands to units in Remote control)
2. MW generation of unit (which is already commissioned for units at Nkula and Tedzani)
3. Setpoint feedback (if under setpoint control)
4. Circuit breaker status ON/OFF (which is already commissioned for units at Nkula and Tedzani)
5. Unit high limit (not required for hydro units as this is a static value)
6. Unit low limit (required for hydro units as this is a static value)
7. Unit ramp rate (not required for hydro units as this is a static value)

Main AGC outputs are:

MW control signal – Setpoint to the units (or this could be raise / lower commands).

Responsible persons:

1. ESCOM under the supervision of EGENCO engineers to wire signals from RTU to unit
2. ESCOM NCC SCADA engineers to check signals are correctly mapped into EMS (RTGEN) and signals are refreshed correctly. Refresh threshold should be set to at least 0.5% of full scale for setpoint feedback and 0.5% – 1% for MW feedback.

7.1.2 TASK 1B: SENDING TEST SETPOINT SIGNALS TO UNIT

The AGC unit PLC has a test function where test set point (or raise/lower command) can be sent to the unit. The set point and power on the unit should change according to the signals sent.

Figure 25 shows the test signals and the unit's response. More information can be obtained from the GE RTGEN Application Programming Guide.

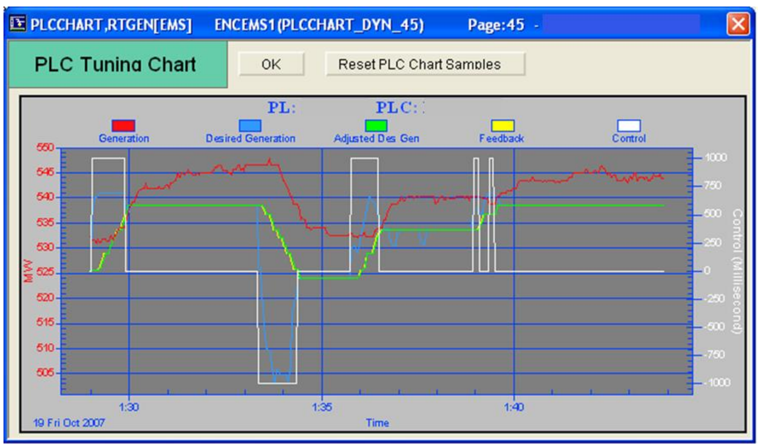

Figure 25: PLC graph for unit response

Responsible persons:

1. Power station staff to switch AGC to remote control at the unit being tested
2. NCC to set the unit on AGC and in test mode
3. NCC to send test set points (or 1 – 7 raise or lower commands) and check the unit responds correctly

7.2 TASK 2: COMMISSIONING AND TUNING AGC WITH HYDRO UNITS ONLY

7.2.1 TASK 2A: DETERMINE INITIAL SETTINGS FOR AGC

SAEP to determine the initial AGC controller settings and gains from the 4-second data received.

The initial controller parameters are developed using the GDAT model.

Responsible persons:

1. SAEP to determine and document the initial AGC controller parameters.

7.2.2 TASK 2B: INITIAL TUNING OF AGC

SAEP to tune AGC controller at the NCC in Blantyre for one week. This will cover all periods during the day and night and the weekend to ensure the controller works well for a typical week.

The final parameters will be documented.

Responsible persons:

1. SAEP to travel to Blantyre for a full week to implement AGC controller parameters and fine tune these.
2. ESCOM NCC SCADA engineers to load final AGC controller parameters in RTGEN (both main and backup systems

7.2.3 OPTIONAL TASK 2C: FINAL TUNING OF AGC (IF REQUIRED)

NCC will operate the AGC and report to Dr Chown any problems experienced with operating the unit on AGC. During this period a decision will be made if it is necessary to return to Blantyre to perform any additional tuning.

Responsible persons:

1. NCC operate the system with hydro units on AGC and report any issues to SAEP.
2. If required, SAEP to travel to Blantyre for a full week to retune AGC controller parameters.

7.3 TASK 3: COMMISSIONING AND TUNING AGC OF HYDRO UNITS WITH BESS PROVIDING PRIMARY FREQUENCY CONTROL

7.3.1 TASK 3A: DETERMINE FREQUENCY CONTROL SETTINGS FOR BESS

Studies to be performed with GDAT and DigSilent to determine suitable settings for the BESS to perform the primary frequency control and revised parameters for AGC. The team will document the expected outcomes with BESS on primary frequency control and revised parameters for AGC.

Responsible persons:

1. SAEP and team to determine and document the primary frequency control settings from BESS and revised AGC controller parameters.

7.3.2 TASK 3B: IMPLEMENT FREQUENCY CONTROL SETTINGS FOR BESS

The primary frequency control settings for BESS are implemented and revised AGC parameters to reduce control to hydropower stations to be implemented.

Responsible persons:

1. NCC and BESS OEM to implement settings in the BESS software.
2. NCC to change the AGC parameters to reduce control to hydro power stations and monitor the performance of both.

7.3.3 OPTIONAL TASK 3C: RETUNING OF AGC WITH BESS

The AGC parameters are returned to smoothen the hydropower station control on AGC, after the BESS is providing primary frequency control. NCC will operate the AGC and report any problems experienced with operating the hydro units on AGC and BESS on primary frequency control. During this period a decision will be made if it is necessary for SAEP to return to Blantyre to perform any additional AGC/BESS retuning.

Responsible persons:

1. SAEP to travel to Blantyre to retune AGC or revise BESS primary frequency control setting.
2. NCC will operate the AGC and report to SAEP any problems experienced.

7.4 TASK 4: STUDIES TO DETERMINE AGC AND BESS SETTINGS FOR INTERCONNECTED OPERATION

If a control area agreement can be reached with HCB, the Malawi hydropower plants can be operated without providing primary and secondary frequency control reserve. The hydropower plants can be optimized for efficiency, maximizing the energy available, and selling excess power into the SAPP markets. The BESS primary frequency control settings will need to be changed to ensure they only operate for large frequency deviations as will be experienced when the interconnector to Mozambique trips or is not available.

Studies will be performed with GDAT and DigSilent PowerFactory to determine the AGC and primary frequency control parameter settings for interconnected operation.

Report and training to be provided.

Controllers to be trained to perform control with interconnected operation.

7.5 ROADMAP FOR INTERCONNECTED SYSTEM OPERATIONS

ESCOM has developed a roadmap, which has been updated in Table 2.

The updates to the table are:

1. Item # 4 Control Area Services should be purchased from HCB. HCB has a Grid Master Power Controller (GMPC) that controls the power flowing on the Songo-Bendura 400 kV line to Zimbabwe. Hence, the GMPC balances the supply and demand in Central Mozambique, and this will include Malawi when Malawi is interconnected to Central Mozambique. Any control actions by the Zimbabwe Electricity Supply Authority (ZESA) will be overridden by the GMPC controller. It would be a major change for HCB to change this functionality. Also note that the Songo-Bendura 400 kV line is congested most of the time, so it is also not technically possible for ZESA to provide Control Area Services. If the Control Area Agreement is with HCB there is no need for the complex Wheeling Arrangements as power is not wheeled through any third-party country.

2. Item # 5 Inter-Control Centre Communications Protocol (ICCP) is only required to SAPP and, in SAEP's opinion, not an urgent item as it will be information passed only. EDM/HCB will be able to see the interconnector and interconnector power flows and other data using their own SCADA systems.

3. Item # 6 SCADA functions - Scheduling and dispatch functionality in the GE system is not as good as the results from PLEXOS. It would be better to use PLEXOS for all scheduling and dispatch.

4. Item # 7 The NCC engineers need to be trained on how to use PLEXOS to optimize generation scheduling and dispatch. This includes the year-ahead schedule, week-ahead schedule, day-ahead schedule and (if required) an updated on-the-day schedule should there be a major change.

5. Item # 8 The NCC controllers and engineers need to be trained on interconnected operations, interchange power control, engaging with SAPP members and 'new' frequency control requirements.

6. Item # 9 BESS control strategy studies for interconnected operations are required to determine the primary frequency control settings needed for frequency control when interconnected and (if required) to protect the Malawi system should the interconnector trip.

7. Item # 10 Hydropower control strategy studies for interconnected operations are required to determine the primary frequency control settings and secondary frequency control strategy for frequency control when interconnected and (if required) to protect the Malawi system should the interconnector trip.

Table 2 Updated roadmap for interconnected system operations

#		Item	Activity	Responsible	Timelines	Status
1		SAPP Rules	To review SAPP documents to familiarize and identify gaps/requirements such as Operating Guidelines, Market Rules DAM Book of Rules	DOSMO MSOM	31-Dec-2022	Partially done
2		Mozambique-Malawi Network Operation	To review commercial agreement on operating arrangements provisions (Wheeling Agreement, Operating Agreement, Maintenance Agreement, Implementation Agreement, and Power Purchase Agreement)	COO DOSMO MSOM	01-Jan-2023	Partially done
3	a)	Preparedness for Trading	Identification/recruitment of traders	DOSMO MSOM	31-Jan-2023	Not done
	b)		Training and certification of traders and controllers	DOSMO MSOM	1 Feb - 31 Aug 2023	Ongoing
	c)		Trading account and guarantee for competitive trading	DOSMO/DOF	30-Nov-2023	Not done
	d)		Providing facilities, tools and equipment for traders and controllers	DOSMO	30-Jun-2023	Not done
4		Control Areas Services	Engage HCB on commercial arrangement/agreement for Control Area Services	DOSMO	30-Jan-23	Not done
5		ICCP	To establish ICCP and signals sharing with—SAPP—to facilitate information exchange	DOSMO/DOT	30-Jan-23	Not done
6		SCADA Functions Activation and Training	To activate SCADA functions such as state estimators, forecasting and scheduling and provide training for control engineers to use these functions	DOSMO	31-Dec-22	Not done
7		Plexos Training	To train NCC engineers on forecasting tools to enhance accuracy in power trading and optimize generation scheduling and dispatch. This includes the year-ahead schedule, week-ahead schedule, day-ahead schedule and if required an updated on-the-day schedule should there be a major	DOSMO	31-Dec-22	Not done

#	Item	Activity	Responsible	Timelines	Status
		change			
8	NCC Controller Training	To train NCC controllers and engineers on interconnected operations, interchange power control, engaging with SAPP members and 'new' frequency control requirements	DOSMO	31-Mar-23	Not done
9	BESS Control Strategy Studies for Interconnected Operations	To determine the primary frequency control settings required for frequency control when interconnected and (if required) to protect the Malawi system should the interconnector trip	DOSMO	31-Mar-23	Not done
10	Hydropower Control Strategy Studies for Interconnected Operations	To determine the primary frequency control settings and secondary frequency control strategy for frequency control when interconnected and (if required) to protect the Malawi system should the interconnector trip	DOSMO	31-Mar-23	Not done

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APPENDIX A MALAWI GRID CODE SECTIONS ON ANCILLARY SERVICES

SECTION 15: ANCILLARY SERVICES (NOT CURRENTLY ON THE MARKET)

15.1. ANCILLARY SERVICES CATEGORIES

15.1.1. The following services are defined as Ancillary Services:

a) Operating reserves

b) Black Start and Islanding

c) Reactive power compensation and voltage control from units

d) Near 50Hz Resonance Control Service

15.1.2. Operating reserves

Operating reserves are required to secure capacity that will be available for reliable and secure balancing of supply and demand. There shall be three categories of operating reserves: Spinning Reserve (Primary Reserve), Regulating Reserve (Secondary Reserve) and Quick Reserve (Tertiary Reserve).

a) Spinning Reserve (Primary Reserve)

Spinning (Primary) reserve is the reserve provided by Generating Units which is activated automatically in case of frequency changes due to the action of the speed governors.

b) Regulating Reserve (Secondary Reserve)

Regulating Reserve is reserve that is under AGC control and can be activated within 10 seconds and be fully deployed within 10 minutes of activation. The Generation Units providing Regulating Reserve shall operate under AGC and shall be able to alter their generation or load under AGC to the performance requirements specified by the System and Market Operator.

15.1.3. Quick Reserve (Tertiary Reserve)

Quick Reserve (Tertiary Reserve) is a reserve that can be activated, on request, within 10 minutes and must be sustainable for at least two hours. Quick Reserve can be provided either by synchronized Generating Units or by Fast Start Generating Units;

15.1.4. Black start and Islanding

a) Islanded units shall be capable of running in the islanded state for at least two hours and of re-connecting to the network.

b) All units capable of Islanding are required to provide the service to the System and Market Operator. Units capable of Islanding shall be certified by the System and Market Operator.

c) To ensure optimal operation of the IPS, the System and Market Operator may deploy network Islanding schemes on the network, e.g. an out-of-step tripping scheme.

d) The System and Market Operator shall determine the minimum requirements for each black start supplier and ensure that the contracted suppliers are capable of providing the service.

15.1.5. Reactive power compensation and voltage control from units

a) Voltage control and the supply or consumption of reactive power is inter-related in the sense that the voltage is affected by changes in the reactive power flow. System stability depends on the voltage profile across the system. In view of these considerations, it is necessary from time to time to employ certain Power Stations to supply or consume reactive power whether or not they are producing active power, for the purpose of voltage control.

b) The amount of reactive power supplied or consumed shall be controlled by the System and Market Operator. This may be done directly through the Energy Management System or by telephone.

c) When a unit is generating or pumping, reactive power supply is mandatory in the full operating range as specified in the Network Code.

15.1.6. Near 50 Hz Resonance Control Service

Some plant may be required to run in Synchronous Condenser (SCO) mode in order to add fault level to the TS. The main reason for this is to assist with the shifting of the near 50 Hz resonance in the network upwards from 50 Hz. The Contracts with plants which will be able and selected by the SB to provide this service shall reflect the cost of this provision in the Contract financial clauses.

15.2. ANCILLARY SERVICES REQUIREMENTS

15.2.1. Reference Incident.

a) Every year, the System and Market Operator shall define and propose to MERA for approval, the Reference Incident which, if considered appropriate, could be different in cases of peak and load demand.

b) This Reference Incident will be used by the System and Market Operator to size the needs of Spinning (Primary), Regulating (Secondary) and Quick (Tertiary) Reserves.

15.2.2. Amount of Reserves required when not connected to the SAPP

a) The amount of Spinning (Primary) Reserve will be, at least, the power generation needed to maintain the frequency, after the occurrence of the Reference Incident between 49.5 and 50.5 Hz.

b) The minimum amount of Regulating (Secondary) Reserve shall be:

b.1) The amount of power generation needed to continuously balance generation and load, under the control of the AGC, while keeping frequency as close as possible to its nominal value (50 Hz), while the system is in Normal State; or

b.2) The amount of power generation needed to compensate the short-term fluctuation of VRE Generation plus the errors in the VRE Generation forecasts; or

b.3) The amount of power generation needed to restore Spinning (Primary) Reserve within 10 minutes after the occurrence of the Reference Incident;

whichever is larger.

c) The amount of Regulating (Secondary) plus Quick (Tertiary) reserve will be the power generation needed to recover the frequency to nominal value (50 Hz) in 30 minutes or less, after the occurrence of the Reference Incident.

15.2.3. Voltage control

15.2.4. The *System and Market Operator* is responsible for the voltage control in the Transmission System as well as at the interface between the *Transmission Licensee* and its *Users*;

15.2.5. The System and Market Operator shall determine the amount of Reactive Power needed to be absorbed or supplied by Generating Units in order to control voltage in the Transmission System.

15.2.6. The System and Market Operator shall also utilize all available equipment from the Transmission Licensee to control voltage across the Transmission System. This equipment may include, among others, on-load transformer tap changers, shunt reactor or capacitors, SVC, et.

15.2.7. Amount of Reserves required when interconnected to the SAAP

a) In the event of interconnection with SAPP, the Spinning (Primary) and Regulating (Secondary) Reserve requirement shall be governed by the ABOM and the SAPP Operating guidelines.

15.3. TECHNICAL REQUIREMENTS FOR PROVIDING ANCILLARY SERVICES

15.3.1. Regulating (Primary) Reserve: To provide regulation reserve a generator must be capable of varying its output, up or down, in response to a deviation in system frequency by the action of the unit speed governor. This Ancillary Service is mandatory for all Generating Units, unless exempted by the System and Market Operator.

15.3.2. Regulating (Secondary) Reserve: To provide Regulating (Secondary) reserve a generator must be able to ramp up or down its generation, to its full output power or technical minimum, in response to an automatic signal provided by the System and Market Operator. The SMO will specify the technical conditions requested to units and specially the minimum ramp up or down speed (MW/min) and the minimum reserve margin to raise or lower (MW). The SMO will also specify the technical conditions of the signal, send to the RTU and to be integrated to the unit control system.

15.3.3. Quick (Tertiary) Reserve: To provide Quick (Tertiary) Reserve a generator must:

a) Be capable to ramp up or down its generation, within 15 minutes, after receiving an order by the System and Market Operator; and

b) Be synchronized (on-line) or have Fast Start capability

15.3.4. Voltage regulation: To provide reactive power a generator must be capable of varying the reactive power output in response to a request from the SMO. Participation of the units into the Voltage Control is mandatory for all Generating units. Also, the Transmission Licensee shall facilitate the tap changers and shunt devices participation into de Voltage Control, which is mandatory.

15.3.5. Black Start: To provide black start a generator must be capable of starting its generation from cold without any external power supply, and capable of connecting to and supplying the Transmission System with electricity once started. The Single Buyer, in consultation with the SMO will specify the units that shall be required to provide this service which is not remunerated.

15.4. SCHEDULING OF GENERATION AND ANCILLARY SERVICES PROCUREMENT

15.4.1. The System and Market Operator shall determine the minimum amount (numerical values) of Spinning (Primary), Regulating (Secondary) and Quick (Tertiary) Reserves required to securely operate the system, under different operational conditions. These values shall be submitted to MERA for approval.

15.4.2. The System and Market Operator shall provide a day-ahead demand forecast for the IPS.

15.4.3. The System and Market Operator will develop the daily twenty-four hours (24) day-ahead energy schedule from 16:00CAT each day, in accordance with the prescriptions of the Market Rules. Should a deviation exist between the scheduled and actual load conditions the System and Market Operator shall be responsible for taking remedial action.

15.4.4. The System and Market Operator shall produce the Day Ahead dispatch, as required by the Market Rules, taking due consideration of the amounts of Spinning (Primary), Regulating (Secondary) and Quick (Tertiary) Reserves required.

15.4.5. The System and Market Operator shall continuously monitor the amount of reserves existing during real time operations and it may produce the necessary changes or re-dispatch if Spinning, Regulating or Quick reserves fall below the required values.

15.4.6. Ancillary services procurement shall be the responsibility of the Single Buyer, provided that during the Single Buyer Phase, as indicated in the Market Rules, the Ancillary Services provided by generators will be included in the PPAs signed between the Single Buyer and the generators. The Single Buyer shall procure the required Ancillary Services that are economically efficient and needed to provide the required reliability, following the recommendations of the System Operation and in accordance with the Market Rules.

15.4.7. Ancillary services scheduling and execution shall be a System and Market Operator responsibility.

15.4.8. Rescheduling of Ancillary Services during unplanned events shall be undertaken by the System and Market Operator as necessary to maintain system reliability, security and safety.