A Techno-Economic Study of a Battery Energy Storage System (BESS) at Vales Point Power Station (VPPS)

Coal Innovation NSW Fund

Project: RDE493-26 Final Report

July 2020

Vales Point Power Station, Lake Macquarie, New South Wales.

Date	Prepared by	Version	Comments
2.3.2020	A.Callen	1.0	Issued for review.
30.3.2020	A.Callen/Wayne Moulday	2.0	Issued for release.
6.7.2020	A.Callen/Wayne Moulday	2.1	Updated with CI NSW comments.

1.0 Acknowledgement and Disclaimer

Delta Electricity acknowledges that this project was funded by Department of Regional NSW through the Coal Innovation NSW Fund, which is administered by the Minister for Regional NSW, Industry and Trade.

Any views expressed herein do not necessarily reflect the views of Coal Innovation NSW, the Department of Regional NSW, the Minister for Regional NSW, industry and Trade, or the NSW Government.

I, the undersigned, being a person duly authorized by the Grantee, certify that:

a) the information in this report is true and complete;

b) the expenditure of the Funding received to date has been solely used on the Project; and

c) there is no matter or circumstances of which I am aware that would constitute a breach by the Grantee, or, if applicable the End Recipient and subcontractors, of any term of the Funding Deed.

Anthony Callen

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2.0 Executive Summary

This project completed a techno-economic assessment of a battery energy storage system (BESS) integrated with an existing synchronous generator at Vales Point Power Station (VPPS). The objective of the project is to determine the technical feasibility and financial viability of the BESS installation and to identify and assess the risks associated with the project.

VPPS is located on the NSW Central Coast at the southern end of Lake Macquarie, about 35km south of Newcastle. VPPS is a coal fired power station with two 660MW generators and is owned and operated by Sunset Power International Pty Ltd trading as Delta Electricity (Delta). The station is currently planned to operate until 2029.

The proposed BESS installation was designed to provide frequency control services and synthetic spinning reserve capacity to support the National Electricity Market (NEM). The innovation of the project is the application of the BESS behind the behind-the-meter to provide network energy support without changing the generation capacity at the network connection point resulting in a reduction in the load cycling and ramping of the coal units, as well as providing additional frequency support services to the market. Further, these additional network support services can be provided by the BESS at a time of diminishing system strength and inertia.

A review of energy storage technologies was completed to identify the most cost-effective and commercially available that would be suitable to procure and construct the project within a 12-month period. Lithium ion battery costs, round trip efficiency and energy density advantage make it the best fit technology for the BESS at VPPS. In addition to technical advantages, the manufacturers of lithium ion batteries have the balance sheets, experience, quality control and commercial availability to provide owners, financiers, and other stakeholders confidence that they can stand behind their guarantees and operate safely.

The study developed a 40MW/20MWh concept design for a BESS integrated with each synchronous generator (ie. 80MW/40MWh station total) connected at the 6.6kV/23kV unit station services transformer. This connection point represents the most cost-effective integration that minimises any impacts to existing electrical equipment and protection systems and can be installed within the time-constraints of the current station outage maintenance program schedule.

Modelling studies based on the Australian Electricity Market Operator (AEMO) requirements for network connection were completed to simulate the connection of the integrated BESS and synchronous generator to the network. AEMO guidelines require a Power Systems Simulator for Engineering (PSS®E) Software package as its primary simulation tool for connection studies, as well as Power Systems Computer Aided Design (PSCAD™) for modelling and simulating sub-cycle dynamic responses. The PSS/E models interrogates the impacts of new or modified applications on the wider network whereas the PSCAD models provide a more detailed investigation of dynamic response at the connection point under different operational and fault conditions.

A preliminary analysis using a generic PSCAD model was completed to identify if there is any unwanted interaction between the BESS system and the existing synchronous generator at the VPPS substation. For this purpose, the system is subjected to symmetrical and unsymmetrical faults at the point of connection to assess the BESS and generator responses for different operating conditions. The study identified that the BESS system is not creating any unwanted interaction with the existing synchronous generator during various faults. Moreover, BESS is actively participating to support the generator during these events responding to faults by providing reactive power to bring up the voltage.

Several Generator Performance Standard (GPS) compliance assessments were performed in PSSE to investigate the dynamic behaviour of the BESS and the interactions between the VPPS generator and the BESS under any grid disturbances, contingencies or other abnormal grid conditions. The GPS studies confirm that the integration of the BESS will not result in an adverse impact on the VPPS since no unwanted interactions between the generator and the BESS have been observed due to grid disturbances, contingencies or other grid abnormal conditions. Rather, the BESS provides active support to the generator by providing reactive power for regulating the grid voltage.

The financial analysis identified potential revenue streams that focus on power-orientated BESS services including spinning reserve management, reducing off target performance and provision of network frequency support services. The net present value assessment demonstrated a negative return over the 10-year project term. A greenhouse gas reduction of 65,000 t-CO_2e per year or 650,000 t-CO_2e over the project life was identified.

The study acknowledges that equivalent FCAS market support services could be provided by a free-standing BESS installed elsewhere in the network or a BESS co-located with renewable energy generation. This report aims to highlight the advantages of a behind-the-meter BESS installation at VPPS including the opportunity to reduce the emissions from existing coal-fired generators and identifies an efficiency improvement from reduced equipment wear and tear from a reduction in the load cycling and ramping of the units. These additional benefits would not be achieved by a BESS installed at greenfield locations within the network.

This feasibility study has demonstrated that the integration of a BESS with an existing synchronous generator is technically feasible and would not compromise the co-located thermal unit or network. Furthermore, the BESS has been shown to support the exiting generator during network fault conditions by providing reactive power for regulating the grid voltage. Unfortunately, the cost for large scale energy storage has been shown to outweigh the anticipated revenues from this BESS configuration during the relatively short 10-year project life. Without additional market mechanisms to value and support the provision of energy capacity, spinning reserve or other emerging market services, it is unlikely that this configuration of a BESS and synchronous generator will be realised in the NEM. Alternatively, the installation of a demonstration project at VPPS operationally supported by Delta, with capital funded by Coal Innovation NSW, would promote development of the technology and provide real scale investigation of the proposed business model. If proven successful, this demonstration project would provide sufficient knowledge sharing for a broader roll-out of the technology across all coal-fired units in NSW.

2.1 Project Overview

The objective of the project was to determine the technical feasibility and financial viability of a battery energy storage system (BESS) integrated with an existing synchronous generator at Vales Point Power Station (VPPS).

VPPS is located on the NSW Central Coast at the southern end of Lake Macquarie, about 35km south of Newcastle. VPPS is a coal fired power station with two 660MW generators and is owned and operated by Sunset Power International Pty Ltd trading as Delta Electricity (Delta). The station is currently planned to operate until end 2029.

The proposed BESS installation was designed to provide frequency control services and synthetic spinning reserve capacity to support the National Electricity Market (NEM). The innovation of the project is the application of the BESS behind the behind-the-meter to provide network energy support without changing the generation capacity at the network connection point resulting in a reduction in the load cycling and ramping of the coal units, as well as providing additional frequency support services to the market. Further, these additional network support services can be provided by the BESS at a time of diminishing system strength and inertia.

Modelling studies based on the Australian Electricity Market Operator (AEMO) requirements for network connection were completed to simulate the connection of the integrated BESS and synchronous generator to the network. The studies confirm that the integration of the BESS will not result in an adverse impact on the VPPS since no unwanted interactions between the generator and the BESS have been observed due to grid disturbances, contingencies or other grid abnormal conditions. Rather, the BESS provides active support to the generator by providing reactive power for regulating the grid voltage.

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3.0 Table of Contents

4.0 Figures and Tables

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5.0 Abbreviations

2phfault	2-phase fault
3phfault	3-phase fault
A-CAES	Advanced compressed air energy storage
AC	Alternating current
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGC	Automatic Generation Control
AS/NZS	Australian Standards/New Zealand Standards
AUD	Australian dollars
AVR	Automatic voltage regulation
BESS	Battery Energy Storage System
BMS	Battery management system
BNEF	Bloomberg New Energy Finance
BOP	Balance of Plant
BTM	Behind the meter
Bus	Busbar
c.f.d	Cumulative frequency distribution
CAL20XX	Calendar year 20XX
CAPEX	Capital expenditure
CI NSW	Coal Innovation NSW
DC	Direct current
DCS	Distributed control system
DI	Dispatch interval
DNSP	Distribution network service provider
DoD	Depth of discharge
DSO	Distribution system operator
EBITDA	Earnings before interest, tax, depreciation and amortisation
EMS	Energy management system
EMT	Electro-magnetic transient simulations
ENA	Energy Networks Australia
EoL	End of life
EP&A Act	NSW Environmental Planning and Assessment Act 1979
ESB	Energy Security Board

f.d	Frequency distribution
FCAS	Frequency Control Ancillary Services
FEED	Front End Engineering and Design
GJ	Giga joules (10^9 joules)
GPS	Generator Performance Standard
HV	High voltage
HVRT	High voltage ride through
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
ISEPP	Infrastructure SEPP
kV	Kilovolt (10^3 volts)
LCA	Life cycle analysis
LCO	Lithium cobalt dioxide
LEP	Local Environmental Plan
LFP	Lithium-iron phosphate
LGA	Local Government Area
Li-ion	Lithium ion
LLG	Line-line-ground
LLLG	Line-line-line-ground (occurs due to breakdown of insulation between all the phase as well as to the earth)
LMO	lithium manganese oxide
LReg	Lower regulation service
LTO	Lithium titanate oxide
LVRT	Low voltage ride through
Max	Maximum
Min	Minimum
MJ	Megajoules (10^6 joules)
MLF	Marginal loss factor
MPa	Megapascal (10^6 pascal)
MV	Medium voltage
MVA	Mega volt amp (10^6 volt amp)
MVAr	Mega volt amp reactive power (10^6 volt amp reactive power)
MW	Megawatt (10^6 Watt)
MWh	Megawatt-hour
NCA	lithium nickel cobalt aluminum oxide

NCM	lithium nickel cobalt manganese oxide
NEM	National Electricity Market
NER	National Electricity Rules
NOFB	Normal operating frequency band
NPV	Net present value
NSCAS	Network Support & Control Ancillary Services
NSP	Network Service Provider
NSW	New South Wales
OFGS	Over frequency generation shedding
OPEX	Operational expenditure
P	Power
PCS	Power conversion system
PEA	Preliminary Environmental Assessment
PIB	Phase isolated bus
PLC	Programmable Logic Controller
POC	Point of Connection
PPC	Power Plant Controller
PSCAD	Power Systems Computer Aided Design
PSS	Power Systems Simulator
PSSE	Power Systems Simulator for Engineering
PV	Photovoltaic
Q	Reactive power
QLD	Queensland
RMS	Root mean square
RoCoF	Rate of change of frequency
RReg	Raise regulation service
RTE	Round trip efficiency
SA	South Australia
SCADA	Supervisory control and data acquisition
SCR	Short circuit ratio
SEARs	Secretary’s Environmental Assessment Requirements
SEPP	State Environmental Planning Policy (NSW)
SG	Synchronous generator
SLD	Single Line Diagram
SMIB	Single machine infinite bus

SoC/min/thr	State of Charge/minimum/threshold
SoL	Start of Life
SRAS	System Restart Ancillary Services
SSD	State Significant Development
TAS	Tasmania
TNSP	Transmission network service provider
TSO	Transmission service operator
t-CO_2e	Tonne carbon dioxide equivalent
UFLS	Under frequency load shedding
UK	United Kingdom
UPS	Uninterrupted power system
US	United States (of America)
USD	United States dollars
USE	Unserved energy
V	Voltage
VIC	Victoria
VP5	Vales Point Power Station Generator Unit 5
VP6	Vales Point Power Station Generator Unit 6
VPPS	Vales Point Power Station
VRE	Variable renewable energy
VRFB	Vanadium-redox flow battery
WACC	Weighted average cost of capital
ZBFB	Zinc-bromine flow battery

6.0 Introduction and Study Objectives

6.1 Background and Rationale

The Australian Energy Market Operator (AEMO) is responsible for operating the National Electricity Market (NEM). The reliability and stability of the NEM requires the real time balancing of electricity generation supply and demand. AEMO utilises several services that are provided by dispatchable synchronous generators, known as frequency control ancillary services (FCAS), to maintain the frequency of the system. In recent years, the system frequency has been diverging and, as conventional synchronous generators retire, and the operating capacity of intermittent variable renewable energy generation increases as part of state and national efforts to reduce greenhouse gas emissions, it is expected that the movements in the remaining synchronous generation in trying to correct system frequency will increase in amplitude, rate of change of frequency and regularity of individual excursions.

Coal-fired power plants are typically designed to operate most efficiently and cost effectively under steady baseload conditions with some ramping up or down during peak and off-peak times. The increased volatility of FCAS regulation services will require the existing fleet of coal-fired power stations to operate with increased flexibility to maintain system reliability and stability. This mode of operation will likely place additional mechanical and electrical stress on plant and equipment which may affect the emissions intensity and reliability of the coal units that, in turn, could affect the energy security in the NEM.

VPPS is located on the NSW Central Coast at the southern end of Lake Macquarie, about 35km south of Newcastle. VPPS is a coal fired power station with two 660MW turbo-generators (1320MW nameplate capacity) and is owned and operated by Sunset Power International Pty Ltd trading as Delta Electricity (Delta). The power station is planned to operate until 2029.

The BESS project at VPPS proposes to investigate the technical feasibility and financial viability of the coupling of a battery storage system to the terminals of a generator to charge and discharge the battery to reduce ramping of the generator. The BESS will provide frequency control services and synthetic spinning reserve capacity to support the National Electricity Market (NEM). The innovation of the project is the application of the BESS 'behind the meter' to provide network energy support without changing the generation capacity at the network connection point resulting in a reduction in the load cycling and ramping of the coal units, as well as providing additional FCAS services to the market.

In a similar way to the operation of regenerative braking on electric motor vehicles, it is proposed to assimilate a battery and inverter into the output of existing generating units and control battery discharge and charge cycling at precise moments in time to reduce in amplitude and regularity the required movements in the turbo generator and its primary governing process. This will result in a controlled unit ramp rate due to the battery providing a fast response to dispatch requirements while the conventional generator continues to approach the overall target and eventually remove the battery input once the dispatch target is reached.

The conventional market systems of energy and FCAS dispatch can be supported by the proposed BESS. Unique to this proposal, however, the battery would be controlled locally, as part of an existing generator and its dispatch instructions, to enhance the performance of the unit in response to those instructions and reduce the impacts of any delay in performance response that exists as a result of inherent design limitations of such units. A BESS will be expected to fill in the void on any shortfall in energy and FCAS response and to be able to do so in rapid time in comparison to the current setpoint controls of boiler steam plant in combination with turbo-generators.

The Project technology is transferable and could be implemented throughout the network and at several different scales. The work is considered to have elements that are attractive to network stakeholders such as generators, regulators, as well as state and federal government agencies.

6.2 Objectives and Structure of the Report

This project provides a techno-economic assessment of a battery energy storage system integrated with an existing synchronous generator at VPPS. The objective of the project is to determine the technical feasibility and financial viability of the BESS installation, and identify and assess the risks associated with the project.

The study focuses on two streams of work, namely:

i. the BESS System Integration Study (technical feasibility); and

ii. business case development (financial viability).

Section 7 reviews the potential energy storage technologies considered for this study and provides an insight into the selection of Li-ion battery systems as the preferred technology.

Section 8 details the engineering studies completed for the study including front-end engineering and design (FEED) work, investigations into the requirements for electrical protection systems, control system integration, network modelling and performance testing requirements, and market system integration.

Section 9 outlines a legal review of the development of a BESS at an existing power station in NSW to determine the appropriate approvals pathway.

Section 10 provides a financial evaluation and business case summary for the project and Section 11 examines the project from a Life-Cycle Analysis perspective.

Section 12 completes a high-level risk assessment for the project and the conclusions and recommendations are discussed in Section 13.

6.3 Milestone Summary

Table 6.1 lists the project milestones that have been achieved as detailed in this final report.

Table 6.1: Milestone Status Summary Table

	Title	Status	Relevance to project and achievement
1	i. Contract execution and project commencement.	100%	Contract executed and project commenced in January 2019.
2	i. Completion of electrical protection studies. ii. Completion of dynamic modelling studies. iii. FEED complete. iv. Control system integration underway. v. Submission of quarterly summary report.	100%	Key engineering studies were completed to evaluate the proposed BESS design. Quarterly Report submitted March 2019.
3	i. Control system integration complete. ii. Business case completed. iii. Submission of quarterly summary report.	100%	Financial evaluation completed to determine commercial viability. Quarterly Report submitted June 2019.
4	i. Development of approvals action plan complete. ii. Market systems integration study complete. iii. Submission of final report.	100%	Appropriate approvals pathway identified and Quarterly Report submitted Sept 2019. Final report submitted February 2020.

7.0 Energy Storage Technology Review

7.1 Energy Storage Market

The current trend of shifting electrical power generation from fossil fuels and nuclear power to renewable energy sources has given rise to network challenges that positions energy storage as a key technology in the transition. Even though energy storage does not represent a new concept, with more than 140GW of pump-turbine storage installed and operational in over 40 countries, the energy storage market is experiencing strong growth that will likely be sustained by this energy transition.

Energy demand, and the global component of electricity in total energy demand, have both doubled over the last 40 years. In this context, energy storage installations around the world are predicted to increase from 9GW/17GWh deployed as of 2018 to 1,095GW/2,850GWh by 2040, according to the latest forecast presented in the Bloomberg New Energy Finance (BNEF) *Energy Storage Outlook 2019*. This is estimated to require $662 billion of investment that will be made possible by further sharp declines in the cost of lithium-ion batteries, on top of an 85% reduction in the 2010-18 period.

The BNEF report predicts a further halving of lithium-ion battery costs per kilowatt-hour by 2030, as demand takes off in two different markets – stationary storage and electric vehicles. The report goes on to model the impact of this on a global electricity system increasingly penetrated by low-cost wind and solar.

Just 10 countries are on course to represent almost three quarters of the global market in gigawatt terms, according to BNEF's forecast. South Korea is the lead market in 2019, but will soon be overtaken by developments in China and the U.S. The remaining significant markets include India, Germany, Latin America, Southeast Asia, France, Australia and the U.K as shown in Figure 7.1.

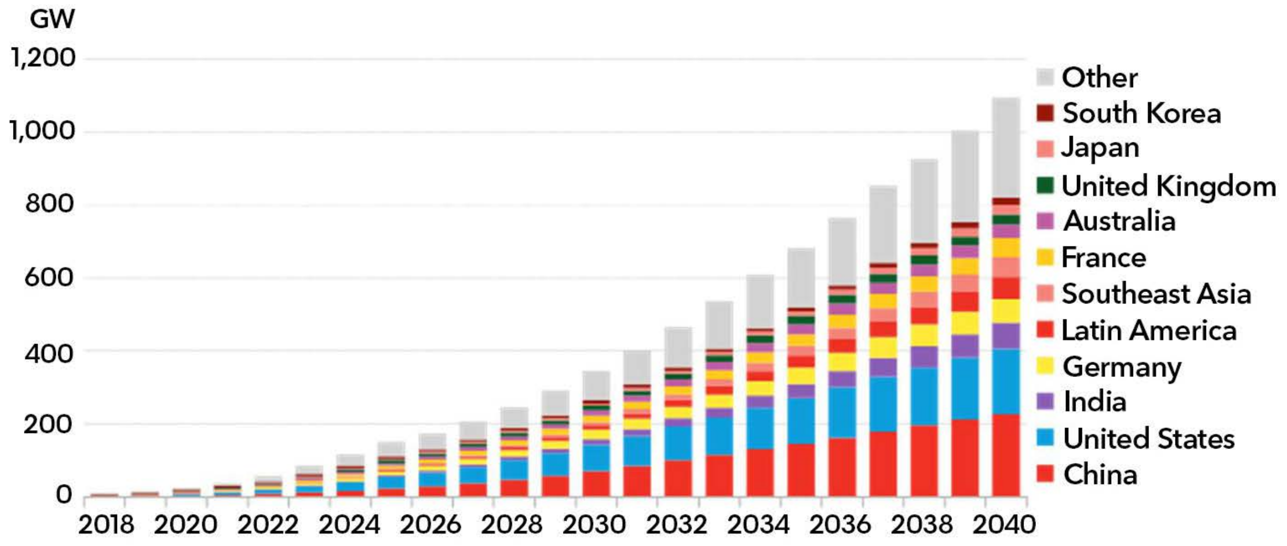

Figure 7.1: Global cumulative energy storage installations (Source: BNEF *Energy Storage Outlook 2019).*

In Australia, the BNEF Report has forecasted approximately 35GW of storage deployments including 60% installed as behind-the-meter storage. Over a half of this capacity will be installed by households – alongside 44GW of rooftop PV – the other half on commercial and industrial sites. Figure 7.2 shows the expected Australian energy storage annual build for various applications throughout 2040.

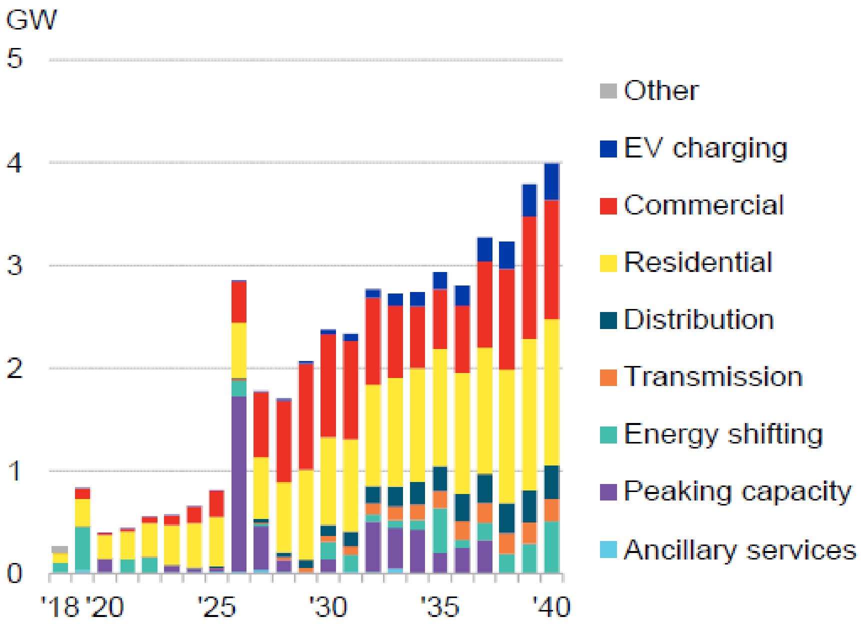

Figure 7.2: Australia energy storage annual build (Source: BNEF *Energy Storage Outlook 2019).*

In Australia, the largest utility scale battery storage project is the Hornsdale Power Reserve (100MW/129MWh, South Australia) which is currently undergoing a 50% expansion to be completed in 2020. Other installations include Gannawarra Energy Storage System (25MW/50MWh, Vic.), Ballarat Terminal Station (30MW/30MWh, Vic.) Dalrymple North (30MW/8MWh, South Australia) and Lincoln Gap (10MW/10MWh, South Australia).

As the energy system transitions to higher proportions of variable renewable generation the demand for storage will increase to balance the new dynamic supply and demand mix. Additional energy storage deployments as a practical alternative to new-build electricity generation or network reinforcement as well as behind the meter applications will also support demand for energy storage and batteries in the foreseeable future.

7.2 Battery Technology Overview

Battery technologies are essential not only to enable the energy transition, but also for the growth and new advances in mobility and electronic devices. Different storage applications call for different battery performance criteria, such as power density, capacity, lifetime, energy density, capital cost, charging time, reliability and safety. The following section provides a review of the main commercially available BESS technologies relevant to the application of energy storage at VPPS. Alternative energy storage technologies such as pumped hydro, mechanical energy storage (eg. fly wheels) and thermal energy storage may have opportunities for integrated energy storage with synchronous generators but are considered outside the scope of this study.

7.2.1 Lead-based Battery

Lead-acid batteries are the oldest commercial rechargeable battery chemistry[1]. Lead-based batteries are characterised by a relatively short lifetime and a low energy density as shown in Table 7.1. While this technology is outdated, it is still one of the most widely used technologies (eg. automotive batteries) due to low capital cost and ability to operate efficiently even at low temperatures.

Materials used in lead battery manufacture are damaging to the environment, which necessitates the adoption of special disposal measures at the end of the battery lifecycle. Lead-acid batteries have a 99% recyclability

[1] Energy Storage Technology and Cost Characterization Report, Hydrowires, US DoE, 2019.

rate, which offers another incentive over competing technologies[1]. Alternatives to lead-acid such as lead-carbon and lead-silicon batteries are available but are not priced competitively with Li-ion.

In comparison with other battery technologies, lead-acid cells do not operate well in a partially charged state, have a shallow depth of discharge and relatively short lifespan. Typically, lead-acid installations are <10MW.

7.2.2 Lithium Ion Battery

Li-ion batteries have an unmatchable combination of high energy and power density, making it the technology of choice for portable electronics, power tools, and electric vehicles [2]. There are different variants of the Li-ion battery by varying the three main components, namely, anode, cathode, and electrolyte system.

Li-ion batteries are commonly classified by their cathode chemistry[3], including:

i. lithium cobalt dioxide (LCO) - the most mature cathode chemistry, which made the commercialization of Li-ion possible;

ii. lithium-iron phosphate (LFP) - this technology is already very near its maximal theoretical performance for power and cycle lifetime;

iii. lithium nickel cobalt aluminum oxide (NCA) - primarily used by Tesla;

iv. lithium nickel cobalt manganese oxide (NCM) - used by the other EV manufacturers; and

v. lithium manganese oxide (LMO) - similar to LFP, as it can deliver high power and lacks energy density but is significantly cheaper as it is less stable (Nissan's recent shift away from using the technology due to continued battery malfunctions).

Li-ion classification by anode chemistry, includes:

i. carbon-based anodes - cheap and with high energy capacity and low voltage versus lithium ions; and

ii. lithium titanate oxide (LTO) anodes - can charge extremely fast and reach full charge in five minutes.

Lithium-ion is well suited for both energy and power-oriented applications and continues to be the preferred technology for utility scale applications[4]. With battery pack prices decreasing by 70% over the last 5 years (2020 ~$1300/kW), lithium-ion has benefited from the economies of scale in manufacturing fostered by the electric vehicle uptake. The rapid decline in costs is mainly the result of the increase in scale across all steps of the manufacturing value chain, increase in cell performance and a decrease in cell costs on a cost/kWh basis.

Importantly, as the primary technology in electric vehicles, lithium-ion will benefit from investments in R&D and manufacturing capacity that will not be matched by other technologies that are limited to stationary storage applications. Further progress is expected from next-generation technologies such as silica anodes, solid-state electrolytes and advanced cathodes.

The typical life of a lithium-Ion battery will vary depending on their thermal environment and how they are charged and discharged. Small scale applications such as mobile phones and computers would be expected to perform for 500-1500 charge cycles[1], whereas utility scale operations would expect to change out battery cells after 10 years based on a daily full charge/discharge cycle.

7.2.3 Flow Battery

Flow batteries use liquid electrolyte solutions to flow through battery stacks of electrochemical cells during charge and discharge cycles[5]. An electrochemical reaction allows electrons to flow through the electrodes. Energy can be varied by changing the electrolyte volume and power can be varied by changing the size of the

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[2] J.M. Tarascon, M. Armand, Nature, 414 (6861) (2001), p. 359.

[3] Utility Energy Storage – A Review, May G.J. et. al, Journal of Energy Storage, 15(145-157) (2018).

[4] Fluence Energy https://blog.fluenceenergy.com/energy-storage-company-fluence-launches-with-unparalleled-suite-of-capabilities-for-customers-in-over-160-countries (accessed 4.7.2020).

[5] https://www.chiefscientist.gov.au/wp-content/uploads/Energy-storage-paper.pdf (accessed 4.7.2020)

stack of the electrochemical cells. This technology is suitable for power applications in the range of 10kW to 10MW and for energy application in the range of 500kWh to 100MWh. Flow batteries are an emerging technology that provides an exceptional lifetime of up to 10,000 cycles.

Flow batteries have two distinct categories including pure flow batteries with all active components stored separately from the cell, and hybrid flow batteries, in which one of the active materials is stored inside the cell. Currently, the most mature technologies within pure flow batteries is the vanadium-redox flow battery (VRFB) and the zinc-bromine flow battery (ZBFB) within the hybrid flow category.

The main disadvantage with flow batteries is footprint. This technology is characterised by a low energy density due to large electrolyte tanks and complex control system that needs ongoing maintenance.

7.2.4 Sodium Sulfur Battery

This technology was one of the most popular large-scale battery storage systems in the past thanks to its high power and energy density but due to its high operating cost (2x Li-ion batteries), it is rapidly losing market share to Lithium-ion.

7.2.5 Nickel Battery

Once favoured for their safety, power and energy, nickel-based batteries have been replaced by Li-ion batteries in most applications.

7.3 Preferred Battery Technology Selection

As shown in Figure 7.3, the majority of non-pumped hydro utility scale energy storage projects have installed lithium ion battery technology. The balance of installations includes mechanical systems such as fly wheels as well as the other minor battery chemical technologies described in Section 7.2. It is noted that there are several other developing technologies such as underground or surface compressed air energy storage and thermal energy storage systems (eg. molten salts, liquid metals) that are at an early stage of development and considered not suitable due to commercial readiness for this study.

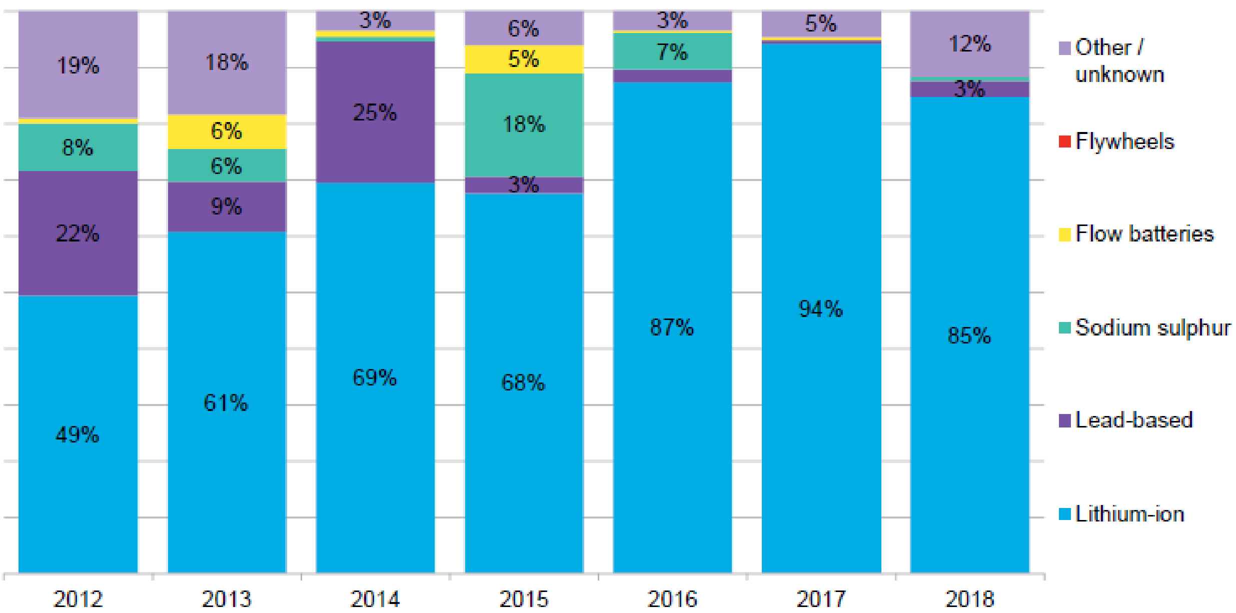


Figure 7.3: Utility scale (non-hydro) technology mix (Source: BNEF *Energy Storage Outlook 2019).*

A comparison of the energy storage technologies considered for this project is provided in Table 7.1.

Lithium ion battery cost, round trip efficiency and energy density advantages make it the best fit technology for the BESS at VPPS. In addition to technical advantages, the manufacturers of lithium ion batteries have the balance sheets, experience, quality control and commercial availability to provide owners, financiers, and other stakeholders confidence that they can stand behind their guarantees and operate safely.

Table 7.1: Comparison of storage technologies (from "Energy Storage Technology and Cost Characterization Report" Hydrowires, US DoE 2019).

Parameter	Li-ion	Lead Acid	Sodium Sulfur	Redox Flow Battery
Max. Power Rating (MW) [a]	100	100	100	10
Discharge Time (hours) [a]	0-8	0-8	0-8	0-8
Capital Cost (AUD$/kW)	1300	2200	3625	3450
Energy Density (Wh/kg) [b]	120 - 230	50-80	150	20 - 70
Round Trip Efficiency (RTE)	90%	80-90%	75%	60 – 85%
RTE Annual Degradation Factor	0.5	5.4	0.35	0.4
Cycles at 80% Depth of Discharge	3500	900	4000	10000
Life (years)	10	2.5	13.5	15

[a] EESI Factsheet https://www.eesi.org/papers/view/energy-storage-2019
[b] "Energy Storage" – Environmental and Energy Study Institute, 2019.

8.0 Engineering Studies

The operation of the National Electricity Market (NEM) is governed by the National Electricity Rules (NER). Under the NER, to establish or modify a connection to the transmission or distribution networks, the applicant must liaise with the connecting Network Service Provider (NSP). The Australian Electricity Market Operator's (AEMO) role as the Market and System Operator is to assess and negotiate performance standards that could affect power system security.

AEMO requires modelling information to represent the physical arrangement of the generating system and its connection to the network. AEMO also requires that simulation models are sufficiently accurate to demonstrate the performance of the generating plant under all expected operating conditions. AEMO uses modelling data and simulation models to assess technical performance standards, to determine power system operational limits, as well as to assess the connection requirements for future Generators.

AEMO uses the Power Systems Simulator for Engineering (PSS®E) Software package to carry out RMS (root mean square – referring to the fundamental frequency response of a power system) type studies as its primary simulation tool for connection studies, as well as Power Systems Computer Aided Design (PSCAD™) for EMT (Electro-magnetic transient simulations used for modelling and simulating sub-cycle dynamic responses) modelling.

The difference between EMT and RMS is that EMT always considers instantaneous values of voltage and current, whilst RMS only considers the fundamental frequency values. This means that EMT simulations can also be used to model very high frequency phenomena such as lightning or switching surges. The PSS/E models interrogates the impacts of new or modified applications on the wider network whereas the PSCAD models provide a more detailed investigation of dynamic response at the connection point under different operational and fault conditions.

This section reviews the design of the proposed BESS and investigates the integration of the battery with the existing synchronous generator using both PSS/E and PSCAD models to determine if there is any adverse interaction between the two units and the network during operation.

8.1 Existing Synchronous Generator

8.1.1 Vales Point Power Station Generating Unit (VP5/VP6) Configuration

VPPS consists of two 660MW generating units designated VP5 and VP6. Both units are essentially identical and design modifications are therefore interchangeable. For simplicity, the following discussion will reference a single unit VP5 noting that all findings could be duplicated on the other generator.

VP5 has a nameplate rating of 776 MVA which corresponds to 660MW at a power factor of 0.85. The unit has a short-term rating (<10 minutes) at 680MW subject to ambient conditions including air and cooling water temperature. VP5 is connected to the Vales Point 330kV Switchyard as shown in the single line diagram (SLD) in Figure 8.1. It is noted that the schematic focuses on the generator and connection point and does not include the boiler plant and supporting systems.

The key plant areas to note include:

i. Generator – this is a steam turbine driven generator (turbo-generator). Pressurised steam turns the turbine blades which rotates the coiled wires in the generator inside a magnetic field to create an electric current to supply the 23kV station busbar (bus);

ii. Generator transformers 23kV/330kV– The generator transformer is the largest transformer on a power station and connects the generator output to the grid at 330kV. This step-up transformer is critical equipment and therefore a duplicate transformer is installed for redundancy;

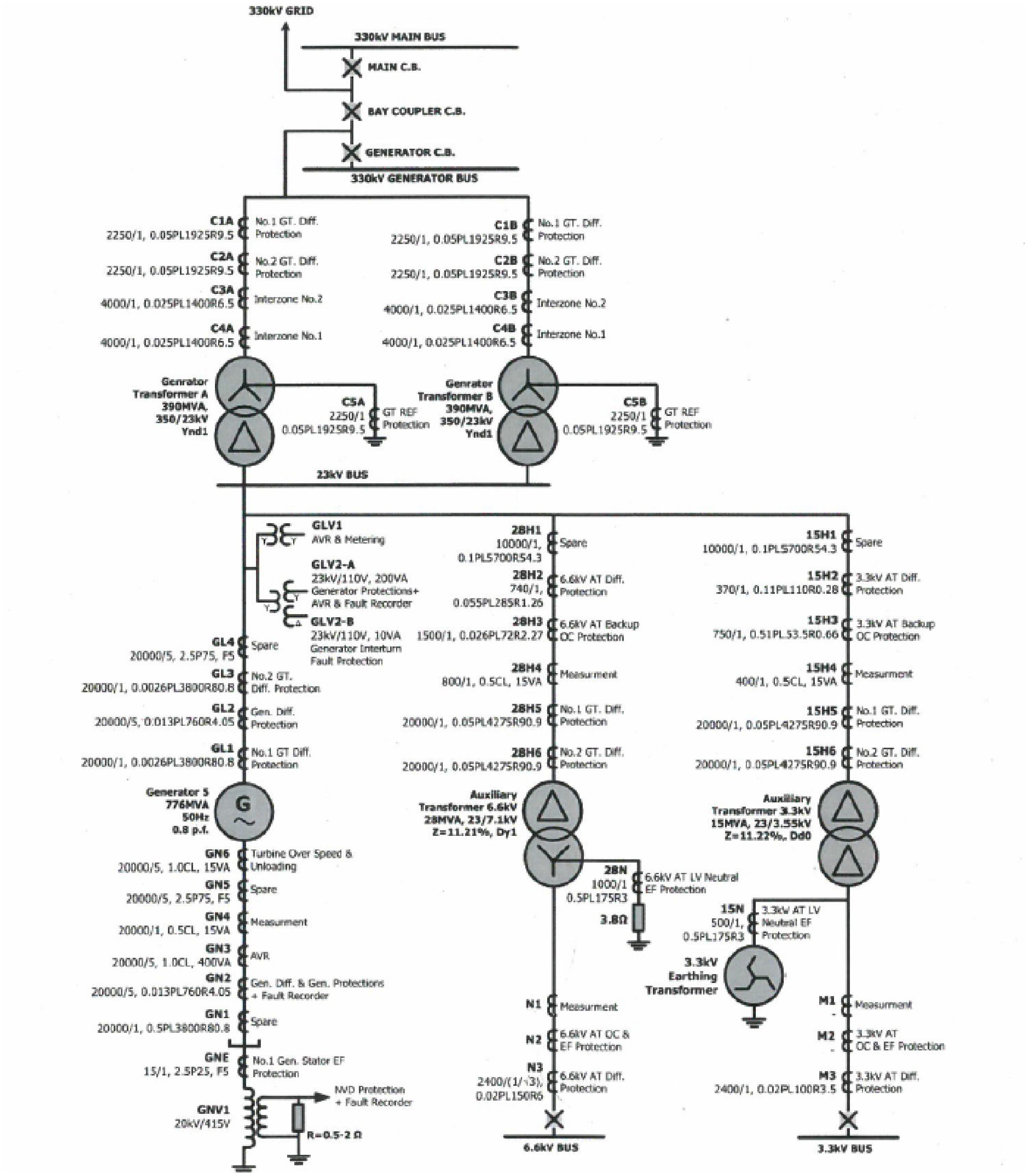


Figure 8.1: Single line diagram of Vales Point Power Station (VPPS) unit VP5.

iii. Auxiliary transformers (23kV/6.6kV and 23kV/3.3kV) – both aux transformers are connected to the 23kV bus and supply power to auxiliary switchboards at either 6.6kV or 3.3kV to power equipment such as pumps and fan motors;

iv. Phase isolated bus (PIB) - A PIB is a method of construction for circuits carrying very large currents between the generator and step-up transformer. Each phase current is carried on a separate conductor (usually hollow aluminium tubes or aluminium bars, supported within the housing on porcelain or polymer insulators) enclosed in a separate grounded metal housing to provide a high degree of electrical protection. The PIB is located within the station automatic voltage regulation (AVR) electrical zone which contains a cascading arrangement of electrical protection devices to ensure safe operation of the unit and auxiliary electrical supplies that are provided from the PIB. Modification to the PIB is considered problematic due to physical restraints preventing substantial changes and the costs and required plant outages to complete the work. The VP5 PIB is shown in Figure 8.2.

Figure 8.2: Image of Gas-Insulated 23kV feeder lines from the main 23kV bus to auxiliary transformer (smaller gauge gas insulation casing assumed to carry lower-rated 23kV cable).

8.1.2 Participation in National Electricity Market

8.1.2.1 Energy Market

The output of a steam generator is driven by the steam pressure in the turbine which is controlled by the main steam or throttle valve. With the throttle valve fully open, the furnace, boiler, steam piping and turbine operate in unison under different temperature and pressure conditions to generate a certain load according to the natural sliding pressure curve. Figure 8.3 shows the turbine natural pressure curve which illustrates the steam turbine operating range (approx.11MPa – 14.5MPa) with throttle valve wide open. Most NSW coal-fired units operate by overfiring the boiler with the steam pressure throttled to achieve the correct pressure for the required turbine set point. The overfiring is used as "spinning reserve" to provide fast response additional generating capacity by increasing the power output of generators already connected to the network. The amount of spinning reserve required is governed by the generator performance standard (GPS) agreement with the Network Operator and is typically in the range 5-10% for NSW generators. Pure sliding-pressure operation does not offer this kind of load or frequency response and is therefore generally not practiced

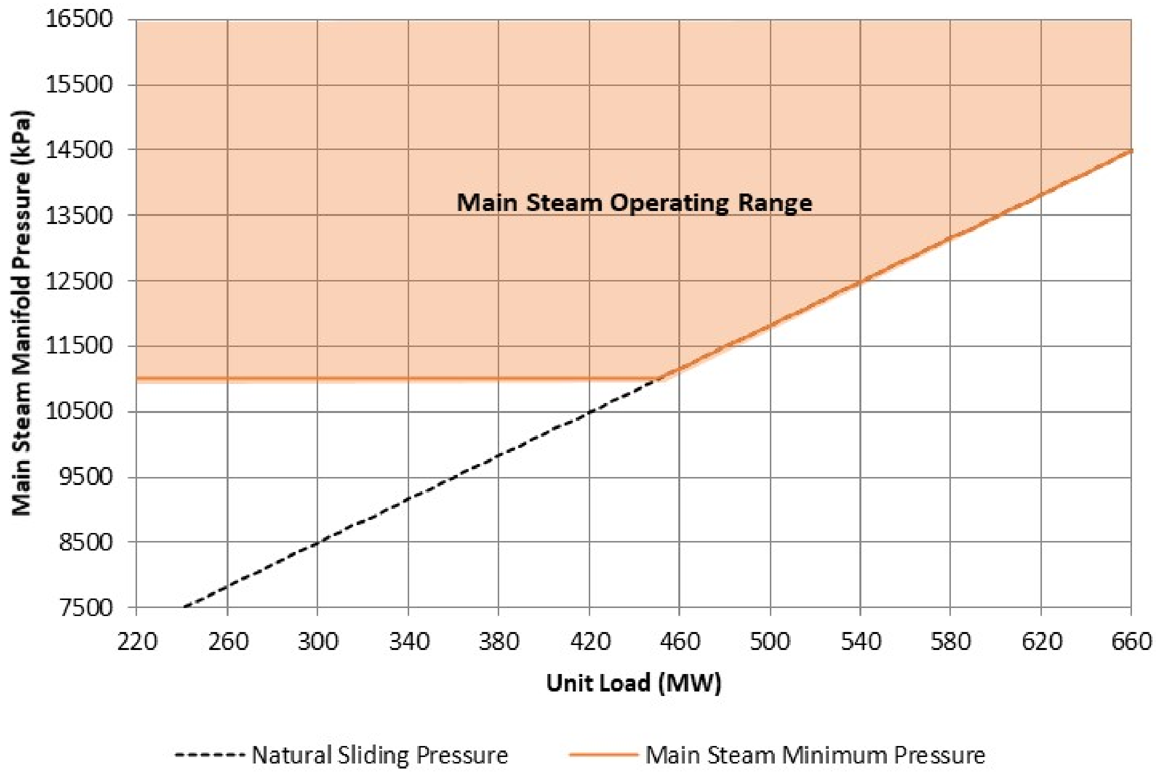


Figure 8.3: Natural pressure curve and main steam operating range.

The NEM is a wholesale commodity exchange for electricity across the five interconnected states (Queensland, NSW, Victoria, Tasmania, South Australia). Energy storage is limited within the NEM where power supply and demand are matched in real time through a centrally coordinated dispatch process. Generators offer to supply the market with specified amounts of electricity at specified prices for set time periods. AEMO ranks the bid offers and deploys generators in a merit order to ensure electricity is provided at the cheapest cost.

8.1.2.2 Ancillary Services Market

AEMO controls the NEM system frequency and voltage through ancillary services. The services include:

i. Frequency Control Ancillary Services (FCAS);
ii. Network Support & Control Ancillary Services (NSCAS); and
iii. System Restart Ancillary Services (SRAS).

FCAS is utilised to maintain the system frequency of the electrical system to 50Hz whereas NSCAS is used to control the network voltage to within prescribed standards. SRAS are reserved for contingency events where the network needs to be restarted from a complete or partial blackout. NSCAS is typically provided by transmission network service providers (TNSP). SRAS is generally provided by gas plants that have diesel powered startup capabilities or hydroplants although all generators have performance management conditions to meet during black start events to restore the system. Although a BESS could theoretically provide black start capability services, VPPS does not currently participate in this market and therefore this study focuses on the provision of FCAS as the primary function.

FCAS has two categories:

i. Regulation frequency control – this is the correction of generation/demand in response to minor variations in system load or generation; and
ii. Contingency frequency control - this is the correction of generation/demand following a major contingency event such as the loss of a generating unit or large industrial load from the system.

The regulation frequency control services are provided by generators on Automatic Generation Control (AGC). The AGC system allows AEMO to continually monitor the system frequency and to send control signals out to generators providing regulation in such a manner that the frequency is maintained within the normal operating band of 49.85Hz to 50.15Hz. These control signals alter the megawatt (MW) output of the generators in such a manner that corrects the demand / generation imbalance. Regulation services are split into two categories, namely, regulation raise (RReg) and regulation lower (LReg), that are used to correct a minor drop or rise in frequency, respectively.

Under the NEM frequency standards AEMO must ensure that, following a credible contingency event, the frequency deviation remains within the contingency band and is returned to the normal operating band within five minutes. There are six contingency frequency control categories that include both raise and lower services within 6s, 30s and 300s timeframes.

Generators that can provide FCAS bid the services into the market and are dispatched in a merit order by AEMO in a similar fashion to the energy market. It is noted that, all payments to FCAS providers are recovered from market participants according to the recovery rules. As contingency raise requirements are set to manage the loss of the largest generator on the system, all payments for these three services are recovered from generators. On the other hand, as contingency lower requirements are set to manage the loss of the largest load / transmission element on the system, all payments for these three services are recovered from customers.

Recovery for contingency services is pro-rated over participants based on the energy generation or consumption in the trading interval. The recovery of payments for the regulation services is based upon the “Causer Pays” methodology. Under this methodology the response of measured generators and loads, to frequency deviations, is monitored and used to determine a series of causer pays factors. Participants whose measured entities operate in a manner that assists in the correction of frequency deviations would be assigned a low causer pays factor while those whose measured entities operate in a manner that cause the frequency to deviate would be assigned a high factor. The causer pays mechanism provides commercial incentive for generators to minimise operation outside of expected dispatch levels.

Coal-fired power plants are typically designed to operate most efficiently and cost effectively under steady baseload conditions with some ramping up or down during peak and off-peak times. The increase of variable renewable energy generators in the network has increased the need for FCAS regulation services which requires the existing fleet of coal-fired power stations to operate with increased flexibility to maintain system reliability and stability. This mode of operation will likely place additional mechanical and electrical stress on plant and equipment which may affect the emissions intensity and reliability of the coal units that, in turn, could affect the energy security in the NEM.

In this project, the BESS will be installed in parallel with an existing turbo-generator to provide frequency control services and synthetic spinning reserve capacity to the NEM. The innovation of the project is the application of the BESS ‘behind the meter’ to provide energy support without changing the generation capacity at the network connection point as well as reducing the load cycling and ramping of the coal unit. This is achieved by operating the turbo-generator with the throttle valve wide open resulting in a controlled unit ramp rate due to the battery providing a fast response to dispatch requirements while the conventional generator continues to approach the overall target and eventually remove the battery input once the dispatch target is reached.

The following sections consider the application of the BESS and design constraints to determine the optimal size and duration of the battery system.

8.1.3 VP5 Power Production Profiles

Figure 8.4 shows a general daily power production profile generated from the 5-minute data. The profile shows the unit cycles through a morning and evening peak period with a generation generally lower during the daytime and significantly lower overnight. The settlement energy price ($/MWh) is also included.

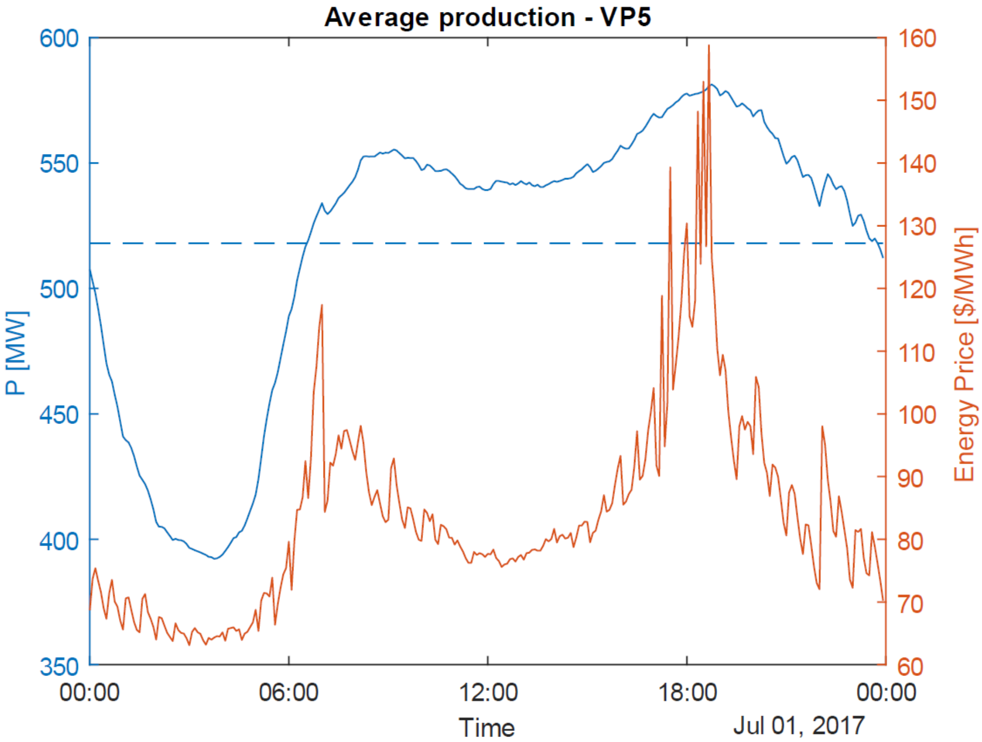


Figure 8.4: Typical power production (VP5) and average energy price (July 2017).

Figure 8.5 shows the difference between the actual power production versus the target set point for dispatch referred to as the MWerror. The flat line data correspond to the maintenence outage periods where the unit is not operating.

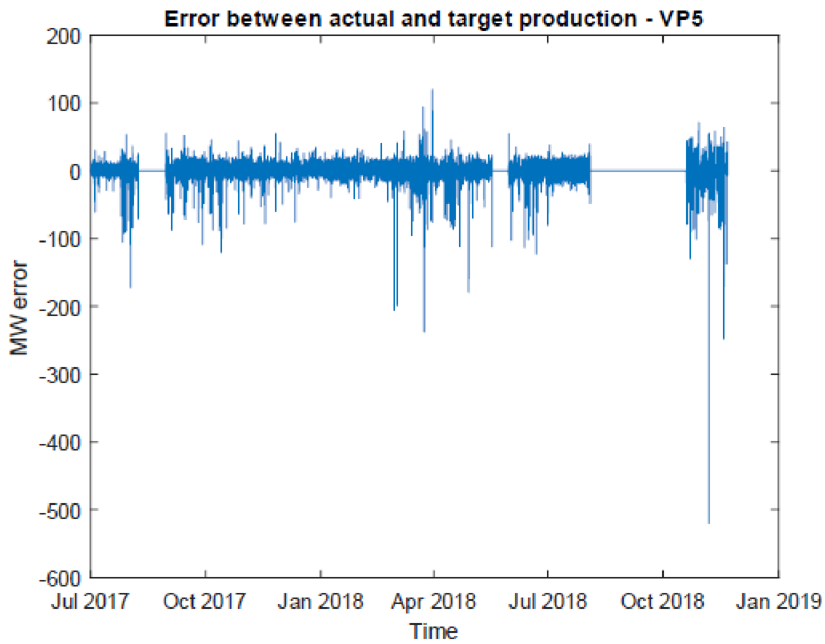


Figure 8.5: Error between actual and target production (MWerror) for period 1/7/2017 – 31/12/18.

Figure 8.6 depicts the percentage frequency distribution (f.d) of power differentials versus the set point, in order of increasing magnitude and includes the cumulative frequency distribution (c.f.d) of off-target events.

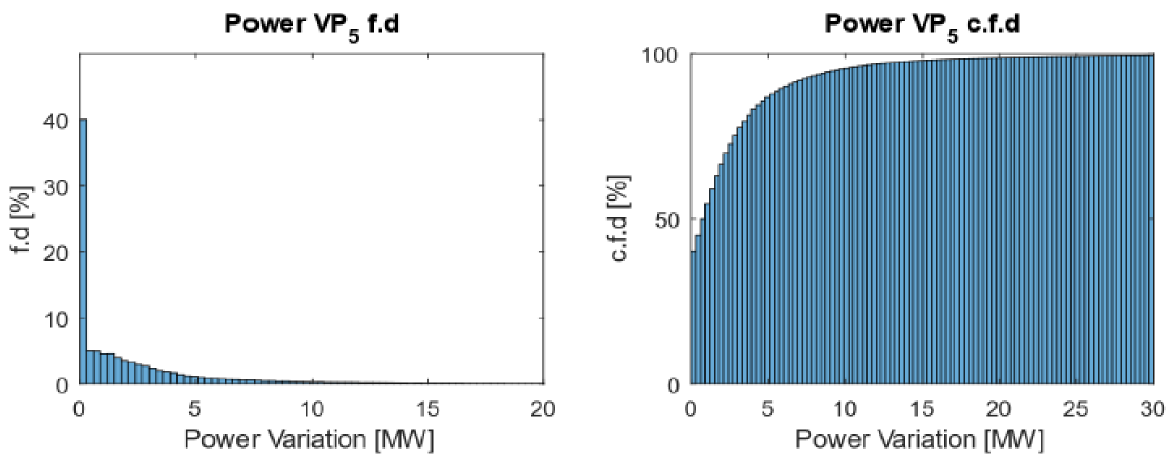


Figure 8.6: Power variation of VP5 and VP6 with respect to the production target (1/7/2017 – 31/12/18).

As shown, almost all power variations with respect to the target production are lower than 20MW, and the relative majority are lower than 2.5MW with few instances of differentials higher than 5MW observed. This analysis indicates a 5MW battery would be suitable for power error compensation to reduce off-target performance and FCAS expenditure (causer pays).

Further analysis of events out of normal operating frequency band (NOFB) was performed to support the FCAS Contingency revenue stream assessment. Figure 8.7 shows the ordered curves of the single under-frequency events and over-frequency events which shows that 96% of under frequency events and 99% of over-frequency events last less than 1 minute. The short single event duration time lends itself to a power orientated BESS.

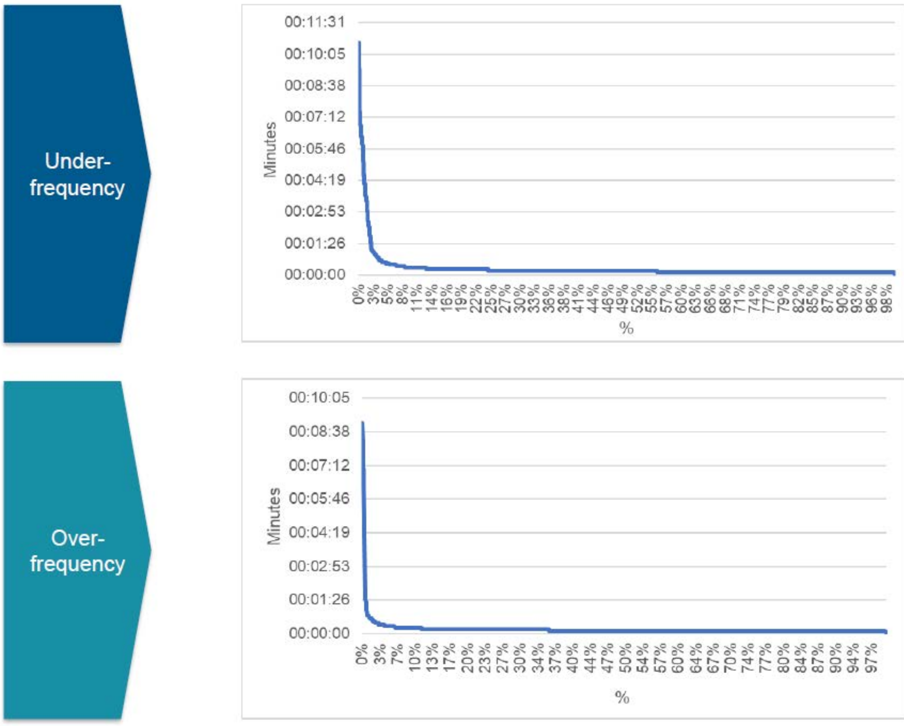


Figure 8.7: Out-of-NOFB single event statistics for period 1/7/2017 – 31/12/18.

To assess optimal BESS sizing constraints, the ordered duration curve of frequency events summed on a daily basis and the curves split into under and over-frequency events as shown in Figure 8.8.

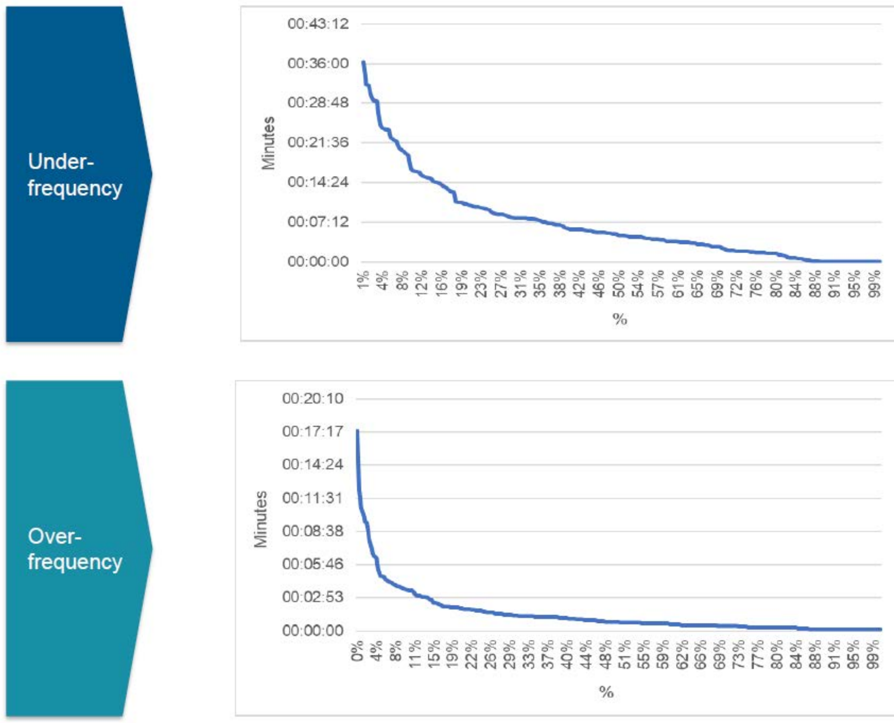


Figure 8.8: Out-of-NOFB daily event statistics for period 1/7/2017 – 31/12/18.

It is observed that in the worst case, the maximum energy required to charge (or to discharge) a BESS to recover from multiple daily frequency events is 36 minutes for recharging at full power and 17 minutes for discharging at full power. Moreover, 90% of the cumulated frequency events are shorter than 15 minutes (under-frequency) and 2 minutes (over-frequency) which implies a limited number of charge and discharge cycles required. As an important upside, frequency events in the opposite direction during the same day can further improve the charging strategy as they compensate each other without the need to modify the unit set point.

Finally, the total number of equivalent hours of out-of-NOFB events have been calculated to show a total of approximately 37.5 hours and 6.5 hours of under-frequency and over-frequency events, respectively during the period 1.7.2017 to 31.12.2018.

8.1.4 Potential BESS Applications at Vales Point Power Station (VPPS)

Grid-side systems, in turn, can be either regulated grid assets, owned by the Transmission/Distribution System Operator (TSO/DSO) where regulation allows so, stand-alone unregulated assets (either contracted to the TSO/DSO or merchant, operating on the spot segments of energy and ancillary services markets), or alternatively co-located with conventional power generation or renewable power plants.

In general, the applications of any BESS can be usefully classified in:

i. Power-oriented: systems with limited autonomy at nominal power capacity, used for frequent, irregular, partial charge/discharge cycles;

ii. Energy-oriented: systems with two-six hours of autonomy at nominal power capacity, used for regular, full intra-day cycling; or

iii. Capacity-oriented, used in extreme circumstances, as energy supply of last resort.

Power-intensive BESS can provide frequency regulation services, operating reserve and substitution reserve, in addition to voltage support to the network. Energy-oriented BESS, instead, can be used to defer transmission and distribution system level investment by alleviating grid congestion issues in critical network nodes, as well as *peakers*, to time-shift off-peak energy to a different time of day to when it is produced.

In some markets (such as the US and UK), BESS capacity is also remunerated through capacity payment schemes or by participation in capacity markets (normally receiving only a portion of the nominal remuneration, to account for limited autonomy), or where black-start capabilities are rewarded either through long-term market contracts (as is the case in Australia), or via bi-lateral agreements with the grid operators.

Power-oriented BTM BESS, in addition to providing frequency regulation, operating reserve and substitution reserve like a grid-side BESS would, can also improve power quality and address grid perturbances (voltage dips and sags, etc.) for the user. Energy-oriented BESS can be used for time-of-day tariff arbitrage, demand charge reduction by peak-shaving the load, and to optimise captive power generation. BESS can further enable revenue generation by rendering the load uninterruptible, and hence eligible for remuneration by the grid operator, as well as act as a uninterrupted power supply (UPS) to back-up critical loads or serve as standby back up.

With reference to BESS co-located with conventional power plants, such as VPPS, systems have been mostly installed targeting the following revenue streams:

i. Primary frequency regulation. The US and European experience shows the economic advantage of providing upwards primary reserve (and in general fast frequency response) with BESS vs. constraining the operation of conventional power plants. This is a compelling proposition for power plants with high load factor and low marginal cost of production (such as VPPS), in markets where frequency regulation services are compulsory and/or well remunerated;

ii. Contingency reserves. the adoption of a BESS to provide fast-response capabilities allows conventional plants not dispatched on the energy market to provide fast contingency reserve starting from cold stand-by (and therefore without incurring fuel costs). This is particularly relevant when contingency reserve is otherwise provided by high-variable cost spinning resources;

iii. Black-start. In case of a blackout, BESS can power the auxiliary loads in islanded-mode to re-power the conventional plant that then powers the grid. The black start remuneration (usually a flat rate to encourage provision or competitive procurement) is on top of remuneration for ancillary service in normal conditions;

iv. Imbalance charge reduction. In order to complement ancillary service remuneration, BESS can drastically reduce the imbalance penalties suffered by conventional plants due to their inertia. This is especially relevant for coal-fired power plants, as their ramp rates are slower than those of gas-fired generators.

Services that can be performed by a power-oriented BESS at VPPS include:

i. Spinning Reserve. Spinning reserve is fundamental to provide a fast system power-response when a frequency event out of the NOFB is being registered. Delta must guarantee a 5% spinning reserve band and is currently reserving 10% of spinning reserve capacity to guarantee the 5% under any environmental conditions. In order to guarantee the 10% spinning reserve capacity, the boilers of both units are operated at a higher pressure set point than the one required to match the power production dispatching target. The overpressure is generated in the boiler, storing additional steam which is released to the turbine when needed by means of a throttle valve. Consequently, units operate at a reduced efficiency, leading to an increased fuel consumption. A BESS would be a valid alternative to provide the spinning reserve as it can be sized to provide the required 5% band while allowing to operate the boilers at an optimal pressure. BESS installation would therefore allow VP5 and VP6 to operate at a higher efficiency.

   As per the data provided by Delta spinning reserve is not statistically required for time intervals longer than 11 minutes. In terms of BESS energy sizing, a fully charged 33MW/16.5MWh system for each VPPS unit could address two consecutive frequency variation events, each lasting 15 minutes.

ii. Power error compensation and Causer Pays Factor reduction. The difference between the actual and the target production is a power error evaluated with a 5-minute step as shown in Figure 8.5. This power error affects the amount of Regulation FCAS recovery payments that VPPS incurs according to the Causer Pays mechanism. A 5 MW BESS for each of VP5 and VP6 (i.e. 10 MW total for VPPS) would cover most of the registered errors in terms of power variations. However, a BESS sized to only provide error balancing would not be economically viable since the achievable revenue stream would be limited.

iii. Contingency FCAS. The final revenue stream considered stems from providing the Contingency FCAS Raise and Lower services with higher availability rates compared to the current VPPS capability. To address this, we made extensive use of the analysis of frequency events. The main strategy adopted to fully exploit this capacity-based revenue stream is based on coupling the functioning of the BESS with that of VP5 and VP6: BESS provides the initial frequency response, while the conventional units ramp up/down slowly once the BESS, as an effect of an extended frequency response event, reaches a Threshold State of Charge (SoC).

The optimal strategy for business case profitability is to address the different services by means of the same BESS. Therefore, two sets of mergeable and non-superimposing services in terms of capacity have been identified, namely:

i. Spinning reserve + Contingency FCAS. Spinning reserve is a mandatory service because the units must be able to face unpredicted frequency variations out of the NOFB. Additionally, when the frequency moves out of the NOFB, FCAS contingency services can be activated. BESS can therefore offer both services at the same time.

ii. Power error compensation + Causer Pays Factor reduction. As error compensation is strictly related to the Regulation FCAS expenditures, any compensation would imply a reduction of the regulation expenditures incurred.

To provide all the listed services a special BESS control strategy is required, and, for each BESS, battery capacity has to be divided for the two considered sets of services, namely:

i. Spinning reserve + Contingency FCAS. BESS and VPPS work in conjunction. This is done by identifying a critical minimum/maximum BESS SoC level, where reaching it triggers the unit ramp-up/ramp-down with respect to the actual power production set-point. The critical SoC is defined to allow the VPPS to substitute the BESS in terms of power production upon a complete BESS discharge. This allows, for every dispatching interval, to bid for all the Contingency FCAS services. In terms of power, a minimum value of 33 MW shall be considered as a constraint for the required spinning reserve.

ii. Power error compensation + Causer Pays Factor reduction. This logic allows the BESS to recharge and discharge if VPPS is in over or under production with respect to the dispatch target setpoint. The error compensation is allowed within the critical minimum SoC and the critical maximum SoC previously defined. In terms of power a minimum BESS power of 5 MW is required.

On the basis of the BESS operational logic described above, the minimum BESS power is therefore identified as 40 MW (33 MW required for the spinning reserve, 5MW for the power error compensation and approx. 2 MW buffer that’s being considered to account for the inverter, battery and transformer losses for each of VP5 and VP6 (i.e. a total of 80MW of installed BESS power for VPPS). Energy requirements are not a limiting factor for the considered system as VP5 and VP6 would step in once BESS reaches a critical SoC threshold. A 2C system – (where 2 represents the ratio between battery storage power – in MW - and energy capacity – in MWh) – is currently assessed as the most cost-effective solution for power intensive applications, thus leading to the BESS sizing of 40MW/20MWh for each unit.

8.2 BESS Concept Design

Previous sections defined the optimal BESS size for VPPS. This section provides an indicative BESS technical configuration in order to assess the interconnection and footprint constraints.

8.2.1 BESS Technical Configuration and Specification

A containerised BESS comprises of three container types, namely:

i. A PowerHouse containing the power conversion system (PCS);

ii. An EnergyHouse containing the batteries and the energy management system (EMS);

iii. A ComHouse containing the medium voltage switchgear.

For each BESS connected to VP5 and VP6, the power and energy management would be handled within the limits identified in Table 8.1.

Table 8.1: BESS management constraints.

Service	Reserved Power (MW)	State of Charge (SoC)
Spinning Reserve + Contingency FCAS	35 MW	SoCmin<SoC<SoCmax
Power error compensation + Regulation FCAS	5 MW	-SoCthr<SoC<+SoCthr

For each BESS connected to VP5 and VP6, the power and energy management would be handled within the limits identified in Table 8.1. SoCmin and SoCmax refer to the limit SoC defined by the battery supplier while +SoCthr and -SoCthr refer to the threshold SoC that triggers the slow ramp up/down of VP5 and VP6, enabling their combined operation with the BESS. This combined operation can be activated only in the case of a contingency event occurrence. For error compensation purposes the threshold is not exceeded.

Table 8.2 lists a generic performance specification for the proposed BESS.

Table 8.2: Proposed BESS parameters (to be confirmed during detailed design).

Item	Details
Rated Power	40MW (per unit)
Rated Energy	20MWh (per unit)
Equipment rated Discharge Duration	0.5 Hour
Usage case/Duty cycle	Max 1 cycle per day (or MWh throughput equivalent) with 99.5% resting state of charge (SoC)
Technical availability	98%
Round Trip Efficiency	88% at SoL/82% at EoL (10 years)
System response time	200ms
Ramp Rate (0% to 100%)	Resting to max power in <2s
Enclosure Type	Modular containers – 40ft customized shipping container
BESS Footprint	2500 m^2 (per 40MW/20MWh)
Metering location	MV switchgear (BOP losses to metering location 1.25%)
BESS Fire Suppression System	FIREPRO, Aerosol or equivalent
Design Life	Equipment: 20 years Batteries based on usage case: 10 years

8.2.2 BESS Integration with Existing Synchronous Generator

To capture the spinning reserve value stream the BESS must be connected behind the connection point at VPPS, and ideally in parallel with the existing generation assets. To minimise efficiency losses and costly replication of high voltage (HV) assets (eg. switchyard protection and HV transformers), the BESS would need to be installed at the highest viable voltage. Consideration of the 22kV system at VPPS was made but this approach presented physical challenges to connect given the space and access challenges at the 22kV PIB level at the station and the complexity involved with adjustments required for existing operational systems as the AVR.

A further iteration of the concept design was required to accommodate these considerations and resulted in location of the BESS connection between the 6.6/22kV aux transformer and the 6.6kV Aux Switchboard which is illustrated in the single line diagram (SLD) in Figure 8.9. Advantages of this design include:

i. Minimising impacts and augmentation of the PIB and AVR zone;
ii. Utilisation of the existing 6.6/22kV transformer to step up the voltage and reducing the size of the BESS transformers; and
iii. Capacity to complete the majority of the installation works outside the planned maintenance outage program with only the final connection required during the outage period.

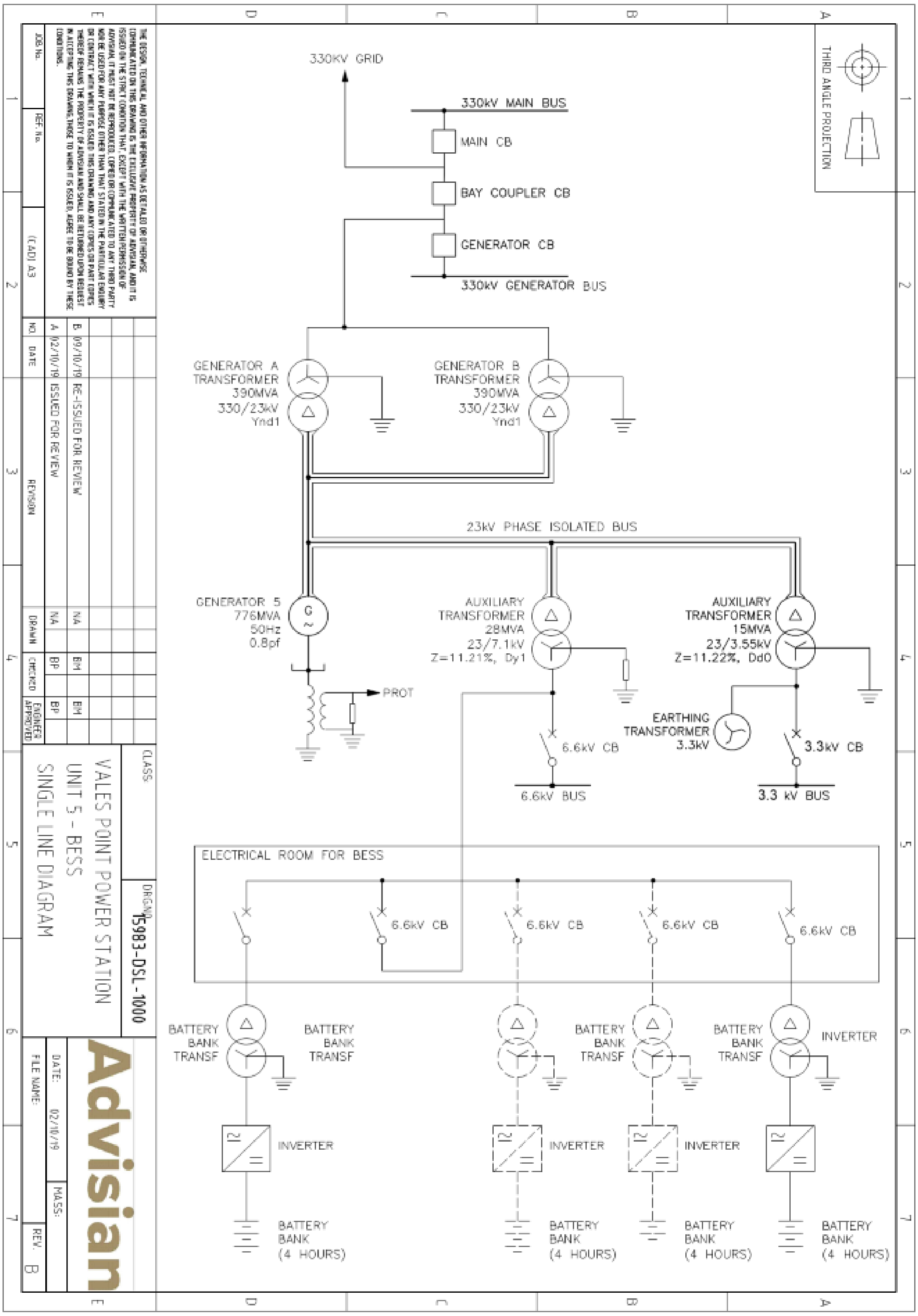


Figure 8.9: Single line diagram for proposed BESS configuration at VPPS.

The main disadvantages of using a lower voltage connection is the requirement for larger cables between the BESS and the connection point to accommodate the expected current. This may be partially avoided as the short duration of battery charging and discharging events is unlikely to create thermal issues in the cables, which will be resolved during the final detailed design review.

The BESS is proposed to operate on a frequency droop with configurable settings inside a parameter window to provide synthetic spinning reserve and network frequency response. Droop speed control is a control mode used for AC electrical power generators, whereby the power output of a generator reduces as the frequency increases. It is commonly used as the speed control mode of the governor driving a synchronous generator connected to an electrical grid. It works by controlling the rate of power produced by the prime mover according to the grid frequency. With droop speed control, when the grid is operating at maximum operating frequency, the prime mover's power is reduced to zero, and when the grid is at minimum operating frequency, the power is set to 100%, and intermediate values at other operating frequency. The BESS will be configured to respond only when substantial deviations in frequency or rate of change of frequency occur (ie. events where spinning reserve is required) and restore frequency to the dead band region.

8.2.3 BESS Footprint and Construction Program

Indicatively, each BESS (40MW/20MWh) would comprise:

i. N. 4 40ft. PowerHouses of 12MVA each, containing 4 Power Conversion System (PCS) of 3MVA;

ii. N. 10 40 ft. EnergyHouses; and

iii. N. 2 40 ft. ComHouses.

The indicative estimated footprint for each BESS installation site is 2,500 square metres.

The feasibility project will focus on the installation footprint for the BESS on a narrow (~5000m^2) area on the former Vales Point A-station site as shown in Figure 8.10. This would enable efficient access to the units via existing cable tunnel infrastructure and allow a straightforward connection between the BESS and the station earth grid. Although this location provides a cost-effective connection and would have negligible impact on existing operations, the BESS could be split and installed in two separate locations in the vicinity of each unit should the A-station site become unavailable. A final decision on the installation location would not be required until the development approvals process has commenced.

A proposed construction program is included in Figure 8.11. The key risks include the achievement of the connection agreement as a modification of the existing GPS, definition of the commissioning and testing program. The integration of this installation program with the existing VPPS maintenance outage program would need to be considered. The least impact would include completion of the majority of the civil, mechanical and electrical install outside of the outage program with the final connection, commissioning and testing program to be completed as part of a scheduled outage and return to service program.

Figure 8.10: Proposed BESS location as a single installation on the former A-station site or split installation for each unit.

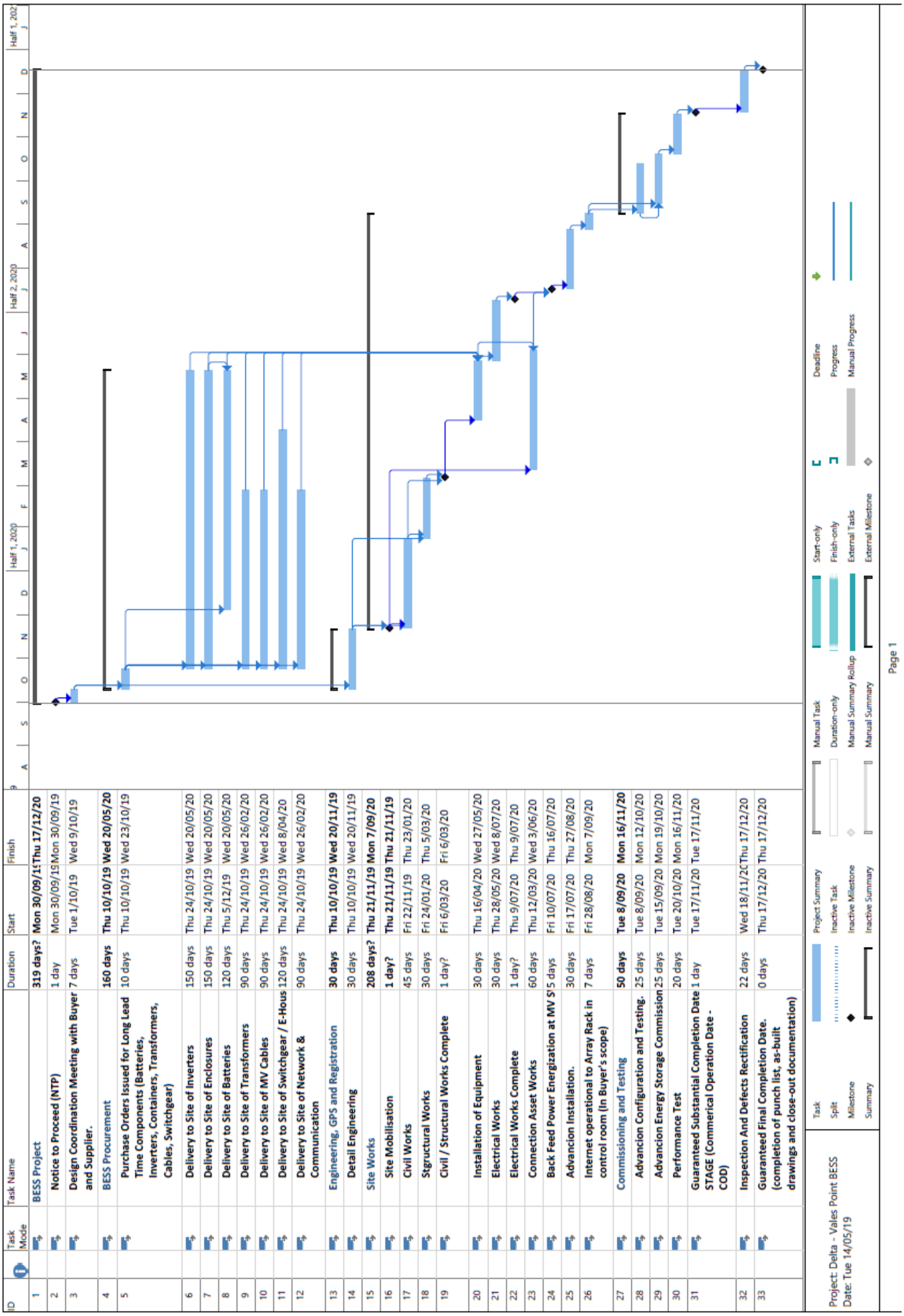


Figure 8.11: Proposed BESS installation program.

8.3 Control System Strategy

8.3.1 Overview

This section describes the strategy behind providing Contingency FCAS services with a BESS that is integrated with VPPS. This configuration exploits some unique characteristics that stem from coupling a BESS with the slow ramp conventional power plants, making Contingency FCAS provision a more reliable revenue stream in terms of service availability with respect to a stand-alone BESS.

For the purposes of this evaluation, all Continency FCAS markets have been considered (Raise 6s, Raise 60s, Raise 5min and Lower 6s, Lower 60s, Lower 5min) therefore allocating a fast BESS power response for frequency events outside the NOFB to exploit the slow ramp capabilities of the power plant in normal operation (no overpressure) to replace the power provided by the battery in SoC-limit situation caused by prolonged frequency event in one direction (under-frequency or over-frequency).

According to the Contingency FCAS bid structure and constraints imposed by AEMO rules on FCAS services, the bids for a Dispatching Interval (DI) are selected within the DI prior to that of the actual delivery. In a worst-case frequency event occurring over an accepted bid period for all three services for a 5-minute DI, the maximum time required to sustain the reserved capacity is equal to 15 minutes (6- second ramp rate at the beginning of the event, the maximum time given by the 5m service).

The rationale behind this approach is based on the short term capacity provided by the BESS for both Raise and Lower FCAS Contingency bids for all three services (6s, 60s, 5min) by the integration of the governor and DCS actions of VPPS, which are currently used to provide Contingency FCAS services. Fast BESS capacity reserve can guarantee an increased number of bidding dispatching intervals throughout the year when compared to the current VPPS capabilities. The increased number of capacity bids is rendered possible by three main factors:

i. The short average duration of the majority of out-of-NOFB events;

ii. The reduced average cumulated duration of out-of-NOFB events throughout the day; and

iii. The possibility to leverage a low gradient ramp-up or ramp-down of VPPS in order to cover SoC limits of the battery in case of prolonged frequency events. This kind of operation is titled *Internal Replacement Reserve* mechanism.

In connection to the mechanism described above, prompt response following the allocation of BESS power capacity for FCAS Contingency service allows to avoid high ramp-up or ramp-down gradients for VPPS. For ramp-up (in particular for providing Raise 6s FCAS Contingency), BESS would enable to avoid providing spinning reserve though pressure increase in the boiler drum thus allowing optimal steam pressure-flow conditions to follow normal set-point operations.

In order to demonstrate that the BESS allows for low ramping that can sustain almost every Contingency FCAS out-of-NOFB event, a dedicated simulation was completed, built on the following assumptions:

i. A strong underfrequency event lasting 20 minutes (stating from minute 02:00 of the simulation) take place and the system responds to a Raise FCAS contingency accepted bid on all the three services (6s, 60s, 5min) and across all of the dispatching intervals that are included in the frequency event (4 DI taking into account the delayed effect of the 5m Raise service);

ii. A shorter frequency event lasting 5 minutes takes place 8 minutes after the ending of the main frequency event;

iii. 35 MW of FCAS contingency are reserved with BESS coupled with one of the VPPS units;

iv. A low ramp-up gradient of the VPPS of 5 MW/minute which avoids boiler drum overpressure for spinning reserve provision. It is assumed that the power plant is already operating at a set-point level established by spot market price below 660 MW (at least below 660-35 = 625 MW);

v. A Threshold SoC which equals 5 minutes of discharge at 35 MW power (2.91 MWh). When the threshold is exceeded, the slow ramp-up gradient of the power plant is triggered in addition to normal set-point in order to provide Internal Replacement Reserve for the discharging battery facing a long-lasting NOFB event and allowing the battery to not exceed normal operational SoC limits (set at 10%);

vi. Energy to recharge the BESS up to a SoC level greater than the Threshold SoC. After the Threshold SoC is reached in the recharging phase, the power plant reduces progressively its production according to the same power gradient of -5 MW/minute; and

vii. The Initial SoC is set equal to the Threshold SoC.

Simulation results are shown in Figure 8.12.

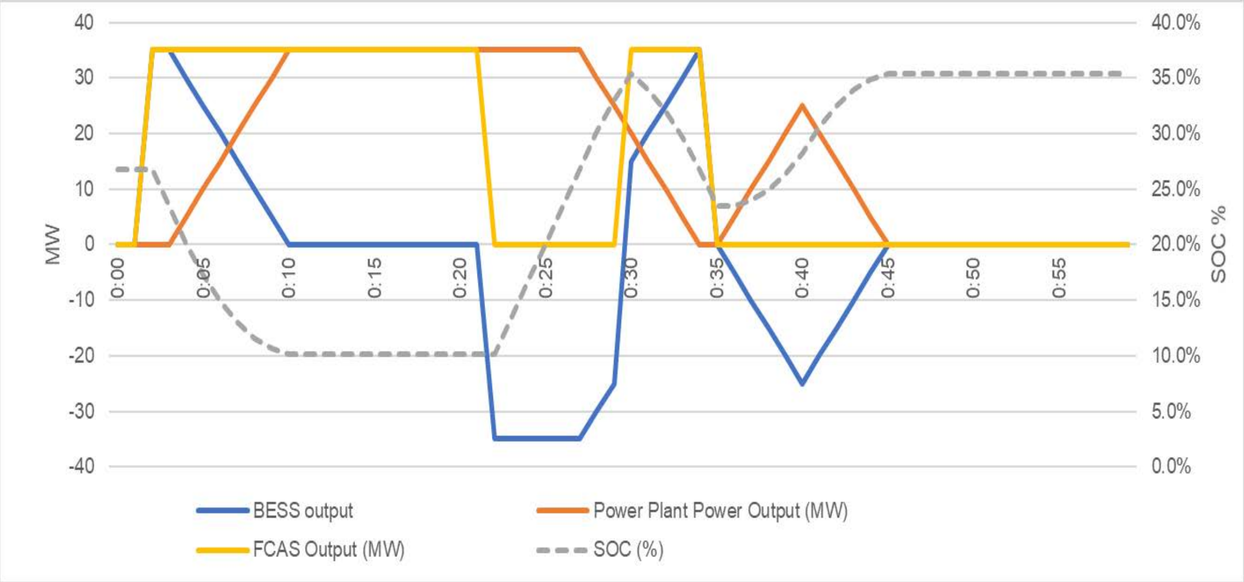


Figure 8.12: Proposed BESS control strategy during Raise FCAS Contingency worst-case simulation event.

The simulation shows that the FCAS event (yellow line) is sustained for all its duration by a combined action of the BESS (blue line) and the power plant (orange line). The Threshold SoC condition is exceeded after the first minute of FCAS Contingency action and triggers the low ramp-up of the power plant which gently replaces the BESS output providing the full FCAS contingency request in a continuous fashion. The SoC never exceeds the 10% operating limit (grey dashed line).

After the FCAS Contingency event ceases, the additional power provided by the power plant set-point variation is used to recharge the BESS. The minor frequency event further discharges the BESS and triggers a new recharge action from the power plant and demonstrates the FCAS requirements are fully met.

A similar worst-case mirrored scenario logic applies for FCAS Contingency lower service. Results are depicted in Figure 8.13. In this example:

i. Lower FCAS Contingency reserved capacity is -35 MW;

ii. The running power plant output set-point is 35 MW above the technical minimum of the plant;

iii. In a similar way to the Rise case the upper threshold SoC that triggers the slow ramp-down of the power plant (orange line) is set to 5 minutes of charge;

iv. The initial SoC is set at the Threshold SoC; and

v. The combined action of the BESS (charge and power plant output reduction allow the SoC level not to exceed the blue line) exceed the maximum operating limit usually set at 90% of the nominal battery capacity.

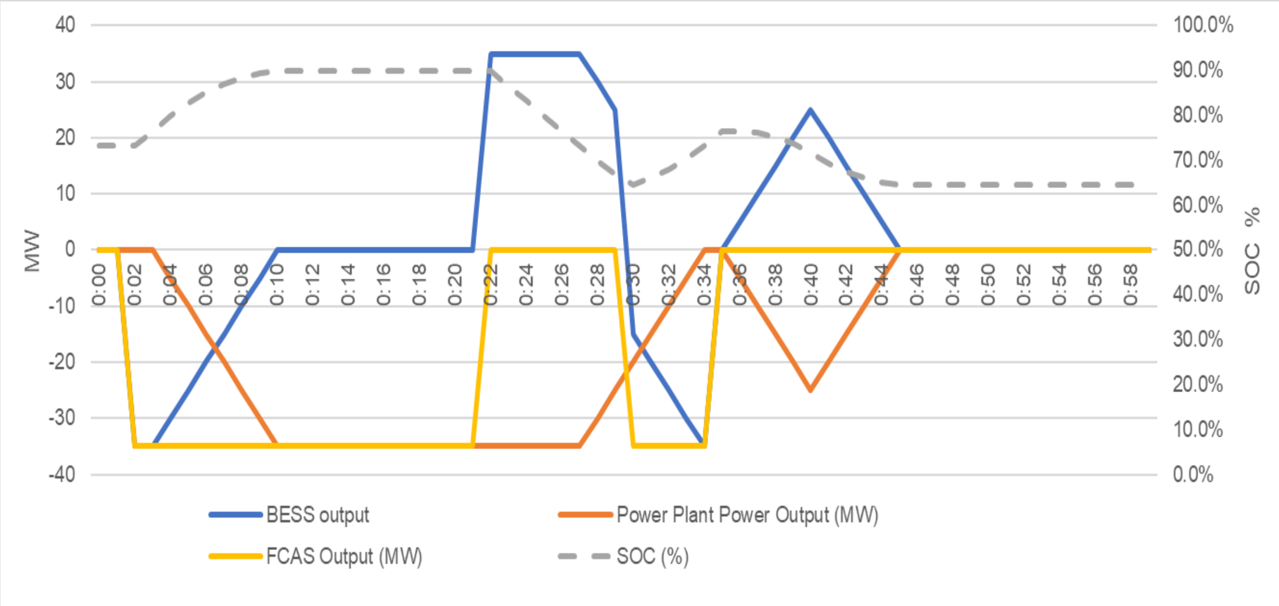


Figure 8.13: Lower Contingency FCAS worst-case simulation event mirrored from the Raise case.

As shown before, the combined action of BESS and slow power plant ramping allows the FCAS Contingency bidding on all six services for any power plant operating level, excluding the out of service period (for which a limited bidding strategy is still possible) and the operating condition for which the power plant output is close to maximum power or to a technical minimum, for which the Contingency FCAS capacity must be reduced accordingly.

8.3.2 Voltage Control Strategy

The BESS will be designed to run automatically and unmanned, receiving and responding to control signals from a variety of inputs on a cascade of hierarchy to consume or provide electrical energy (and potentially other services, such as voltage control) as required for market trading, market ancillary services or network backup services. It will employ an algorithm to determine and optimise commercial outcomes for the asset owner and service off-takers, while keeping the BESS within acceptable operational ranges, and will be capable of remote control should system requirements dictate a change in operational algorithm.

The basic design philosophy of the BESS will include consideration of:

i. Safe operation within the environment in which it is sited;
ii. Compatibility and operability within the NSW Transmission environment; and
iii. Optimal commercial use of the BESS within the engineering capability of the technology employed.

The BESS asset will have the ability to island its supply bus following an upstream line fault, or when called upon manually by the Principal, and service the local load. It will do so without interruption to that load at any time.

Note that during all events a significant amount of local PV may be also generating and dynamically reacting within the supply system, and there is currently no control of this nor is any intended. The BESS Control System must maintain stability of the entire islanded system by sourcing and sinking energy into the battery. The system may also include electrical load dumps, but the preference is to avoid these. A demand side management control element may also be possible, but again the preference is to avoid such.

It would be expected that once the transmission outage is resolved that the BESS would sense restoration of the grid, synchronise the island with the grid and reconnect seamlessly, again without any supply interruptions. In the circumstances where the Principal has manually called for the island to reconnect to the grid, it will only do so if the transmission system is operating correctly and such an operation is safe.

The focus of the project with the latest analysis indicates that the following services will likely form the focus of the BESS operational algorithm:

i. Cap trading revenue – that is, being called to provide MW during system pool pricing peaks;

ii. Expected unserved energy (USE) reduction – that is, the island function described above; and

iii. Improvement in NSW – Victoria or NSW-Queensland interconnector transfer limits – that is, being called on to provide MW during certain system contingencies to prevent transmission elements being overloaded and assist with voltage and power swing stability.

Other services which are likely to result in asset revenue but are challenging to quantify in the current market framework (these may be considered for demonstration purposes):

i. System frequency support (FCAS);

ii. Arresting high Rate of Change of Frequency (RoCoF) – virtual inertia, assisting under frequency load shedding (UFLS) and over frequency generator shedding (OFGS);

iii. Short term spinning reserve; and

iv. Targeted dispatch of all VPPS generation systems.

Other services which can be provided by the BESS but are unlikely to bring asset revenue in the foreseeable future include:

i. Network augmentation deferral

ii. Grid support cost reduction

iii. Voltage control and power quality

iv. Implication of potential new standards, e.g. ramping limitations

v. Fault ride-through assistance

vi. Energy trading revenue (time shifting of energy through charging and discharging)

vii. Marginal Loss Factor (MLF) impact for VPPS generation

viii. Local generator constraint reduction

ix. Avoided FCAS obligation

8.3.3 Earthing Strategy

Provision of adequate earthing of electrical equipment is essential for the safety and protection of operational staff and equipment. The objective of the earthing system is to provide a uniform potential and near zero absolute earth potential.

The earthing system is required to manage any hazardous potential differences to which personnel or members of the public may be exposed. These potential differences include:

i. Touch Voltages (including transferred touch voltages);

ii. Step Voltages; and

iii. Hand-Hand Voltages

These voltages can be present on metallic equipment within substations, associated with substations or equipment associated with power lines or cables, or even on non-power system plant items nearby (and not associated with) the electrical system. The soil potential relative to the metallic equipment needs to be carefully considered. For a hazardous situation to arise, a power system earth fault must be coincident with a person being at a location exposed to a consequential hazardous voltage.

VPPS has a subsurface earth grid consisting of a grid of copper strap that provides protection for personnel and plant equipment. As shown in Figure 8.14, the BESS can be integrated with the existing earth grid. The earthing system concept design includes an earth ring around each battery unit and connection to the existing station earth grid. A step and touch potential design analysis will be required during the final detailed design and safety review.

A grounding electrode system comprising a buried ring consisting of bare cable will be installed at each unit comprising the Energy Storage Device. If the earthing system is excluded from the Proponent's scope of works, the Proponent is to specify minimum requirements.

The earthing system must be designed in accordance with the latest version of the following standards and guidelines, including:

i. IEEE Standard 80, Guide for Safety in AC Substation Grounding;

ii. IEEE 837/2002, IEEE Standard for Qualifying Permanent Connections Used in Substation Grounding;

iii. ENA EG1-2006 Substation Earthing Guide;

iv. ENA EG-0 Power System Earthing Guide;

v. AS/NZS 3000, Wiring Rules;

vi. IEEE 81: IEEE Guide for Measuring Earth Resistivity , Ground Impedance and Earth Surface Potentials of Ground System;

vii. AS 1746: Conductors – Bare overhead – Hard-drawn copper;

viii. AS 1125: Conductors in insulated electric cables and flexible cords;

ix. AS 2067: Switchgear assemblies and ancillary equipment for alternating voltages above 1 kV;

x. IEC 60479-1 Effects of current on human beings and livestock Part 1 General aspects;

xi. IEC 60479-5 Effects of current on human beings and livestock Part 5 Touch Voltages threshold values for physiological effects;

xii. AS 4853 Electrical Hazards on Metallic Pipelines; and

xiii. AS/NZS 3835.1 Earth Potential Rise - Protection of telecommunications network users, personnel and plant.

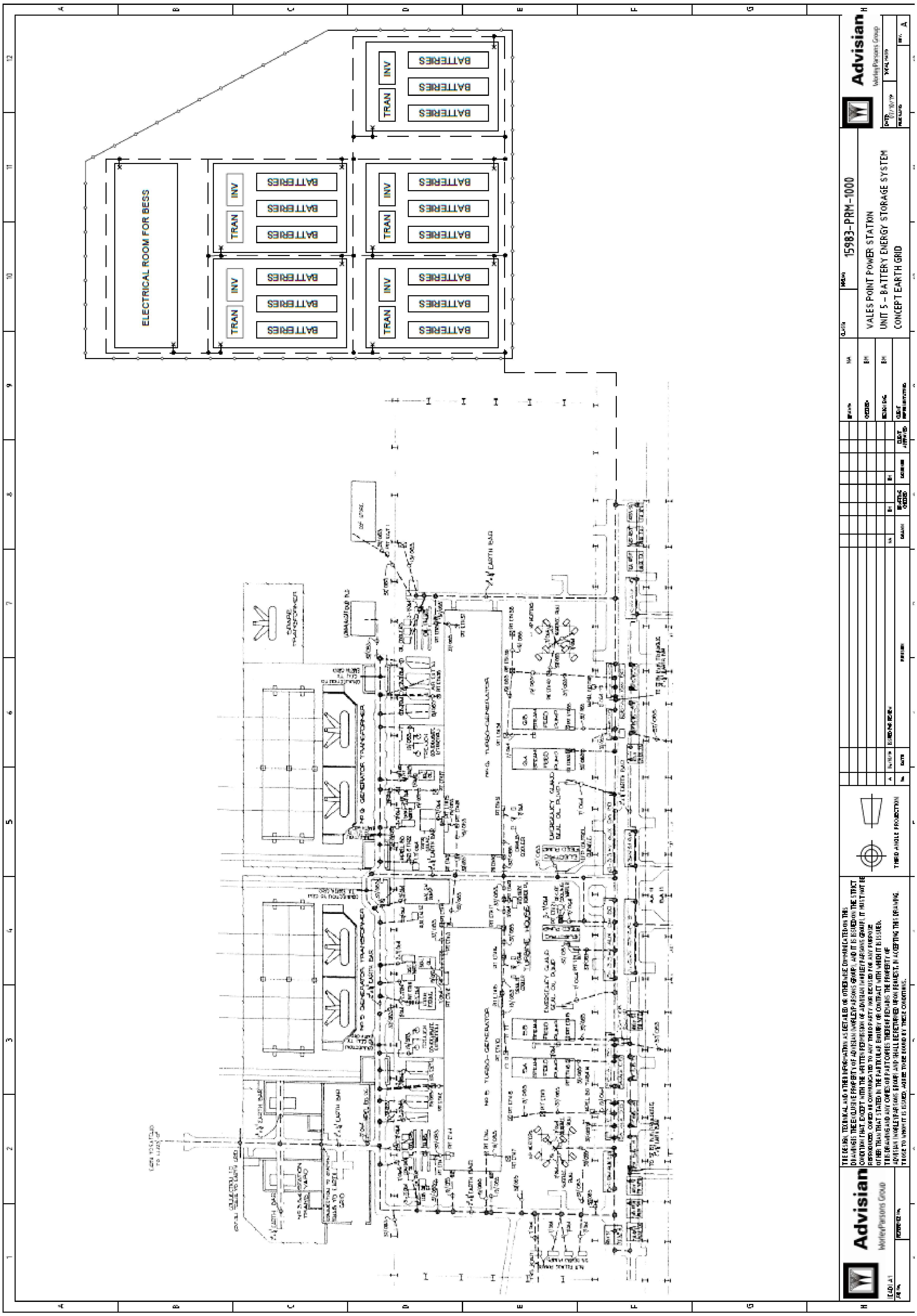


Figure 8.14: Proposed BESS earth protection design integrated with VPPS earth grid.

8.3.4 Control System Integration Requirements

The SCADA system will be based on a main controller which will include a computer-based algorithm that uses these control parameters to constantly evaluate incoming market, generation fleet and network status data to action and optimise operation. This algorithm will have the ability to run autonomously, semi-autonomously or manually, and include the following basic SCADA structure:

i. An industrial Programmable Logic Controller (PLC) based Central Processor, which provides overall plant control and interface to remote sensors or slave control units, and remote peripherals;

ii. Either a backup PLC controller or the ability to default to a safe mode of operation in the event of main PLC failure;

iii. A Battery Management System (BMS) either within the central processor or specifically part of the Energy Storage Medium;

iv. A data storage and collation medium to allow storage, retrieval and regular automatic and manual collated reporting of plant performance (including faults), operational staff log-in details and system changes;

v. A human to machine interface, allowing visibility of operational performance parameters, the scrutiny of logged performance data, the scrutiny and clearing of fault flags and through suitable password control the adjustment of operational parameters, peripheral device locations/numbers/setups, and security level control for operational staff and remote control/visibility units.; and

vi. Through an appropriate data connection technology, provide connection to remote control/visibility units, including VPPS, Transgrid, AEMO and operational contractors.

8.3.5 Dispatch Philosophy and Protocols

The control system will include a settable hierarchy to decide which control mode has precedence in a given situation. It is envisaged that the hierarchy that will apply will be:

i. Dispatch to maximise revenue from FCAS market and minimise causer pays charges to VPPS;

ii. Dispatch to support the network; and

iii. Dispatch for cap trading or time shifting energy.

8.4 Interaction between BESS and Synchronous Generator (SG)

8.4.1 Overview and Dynamic Model (PSCAD)

The main aim of this report was to conduct a preliminary analysis to identify any unwanted interaction between the BESS system and the existing synchronous generator at the Vales Point substation. For this purpose, the system was subjected to symmetrical and unsymmetrical faults at the point of connection (POC) to assess the BESS and SG responses for different operating points and Short circuit Ratios (SCR). SCR is the conventional metric for system strength and is a measurement of the available fault current at a given location. In broad terms, the lower the value of SCR, the weaker the power system will be, and vice versa. Studies were repeated for four different points of the SG capability curve and for SCR ratio 4 and 10. The following initial operating points were considered and are shown in Figure 8.15:

i. Point 1 (P=Pmax, Q=Zero);

ii. Point 2 (P=Pmax, Q=Qmin);

iii. Point 3 (P=Pmax, Q=Qmax); and

iv. Point 8 (P=Pmin, Q=Zero).

where P and Q refer to active power and reactive power, respectively.

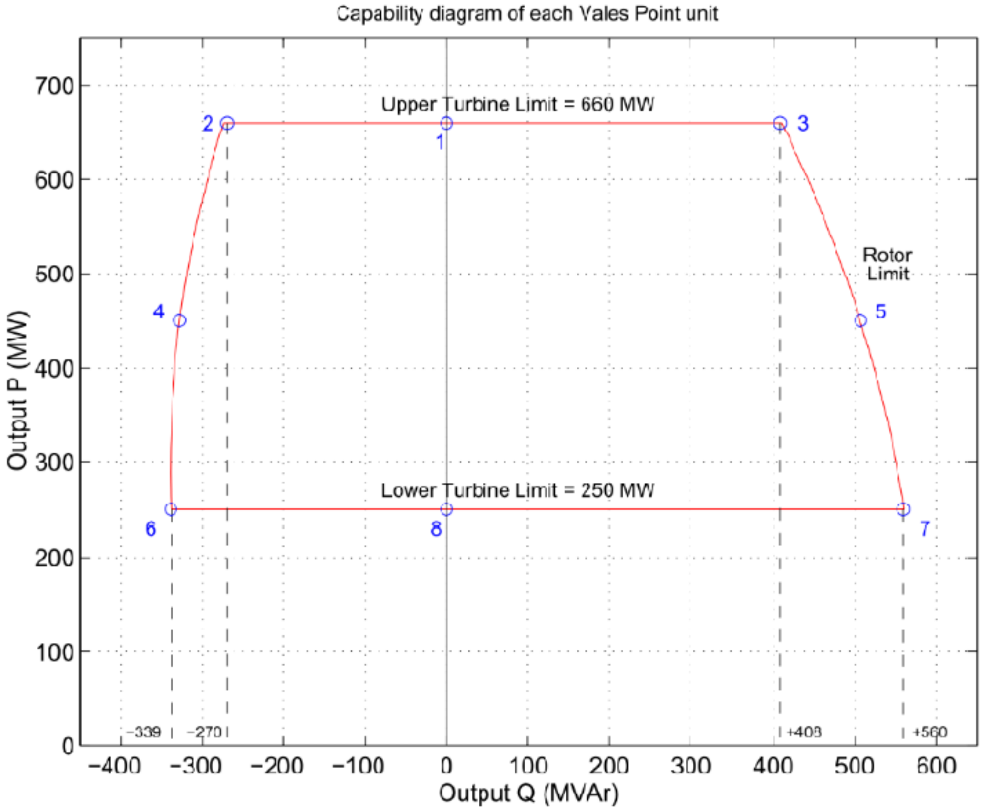


Figure 8.15: Generator capability diagram.

A PSCAD model was developed to represent the VPPS generating station in PSCAD. Figure 8.16 shows the PSCAD representation of the VPPS. It is noted that Unit-6 was not modelled in this study.

PSCAD library model standards were utilised to represent the AVR and PSS in the model and the performance was tuned to match with the PSSE model. The turbine governor model based on the block diagram is shown in Figure 8.17. Synchronous generator (SG) used is an exact replica of the PSSE model.

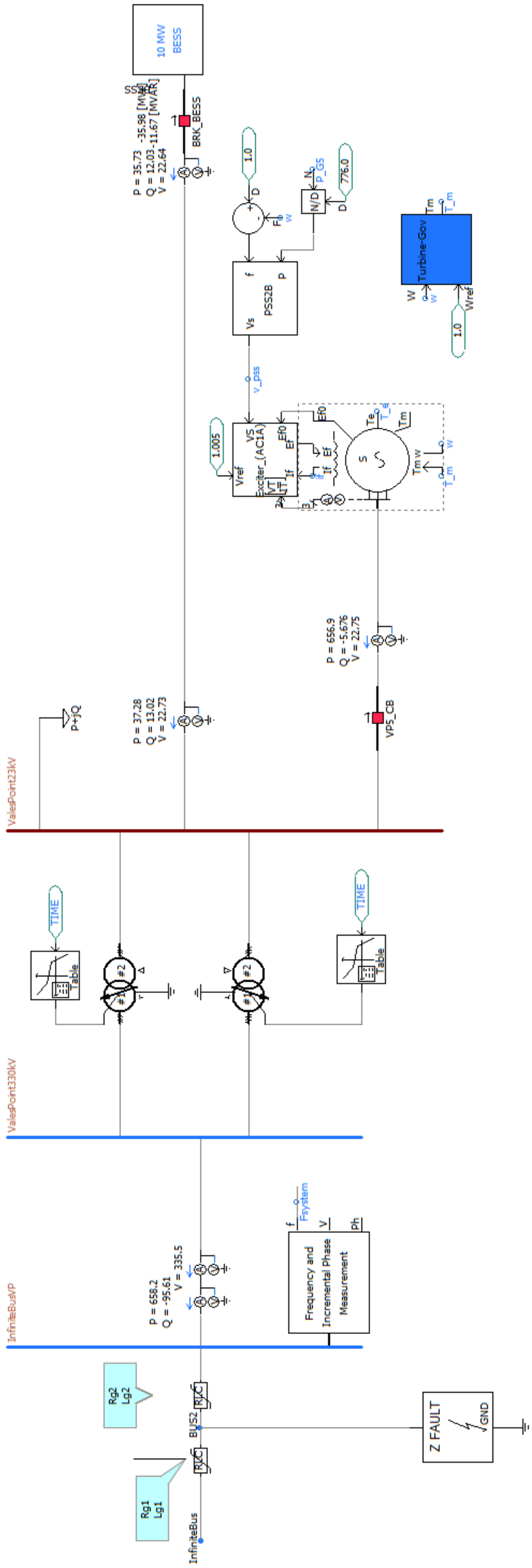


Figure 8.16: PSCAD representation of Vales Point Power Station (VPPS).

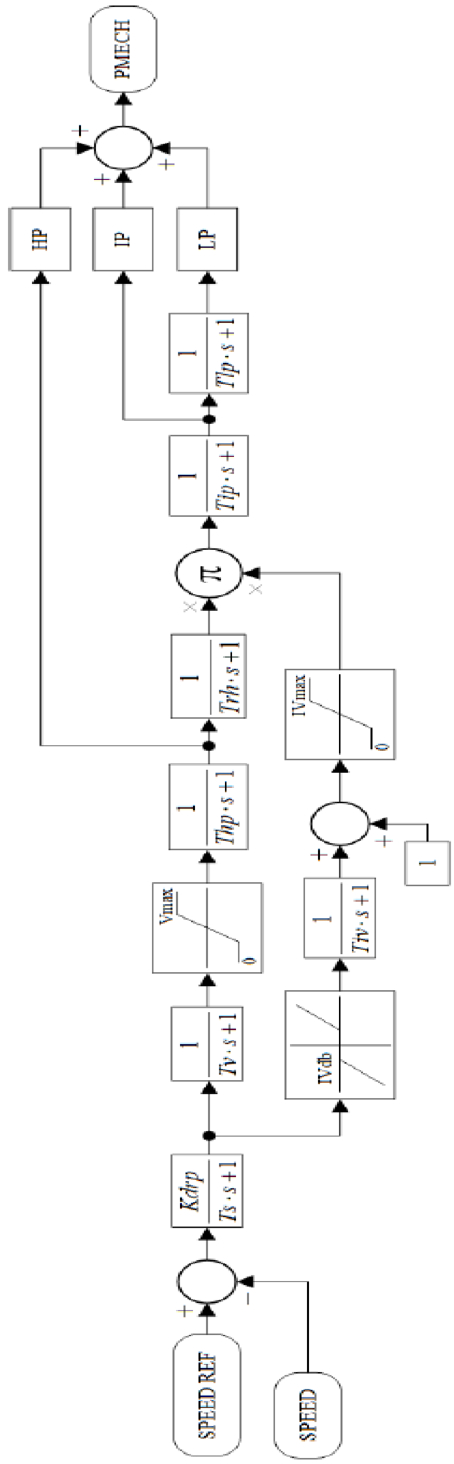


Figure 8.17: Vales Point Power Station (VPPS) turbine governor model.

Identical models for representing the BESS were used in both PSSE and PSCAD. Here, the BESS was connected to the 23-kV generator bus. The BESS was comprised of a battery and an inverter. The battery was modelled using algebraic and dynamic equations of battery energy and state of charge. A power plant controller was developed to control active and reactive power references to the battery inverter model. The active power controller was responsible for providing the active power reference to the inverter. Reactive power controller was set to operate in voltage droop control mode. In this mode, the controller compares the actual bus voltage with a set point value to provide a reactive power command to the inverter controller.

8.4.2 Simulation Results

This section provides two examples of the simulation results of the fault analysis conducted for various generator operating points and short circuit level of the grid. The detailed study is included as Attachment A.

Symmetrical and asymmetrical faults were simulated using the PSCAD model to verify the performance of BESS system. The initial active power output of BESS was kept at 20 MW. Voltage droop control regulates the voltage at BESS terminals by varying the reactive power output. Two SCR ratio were considered in this analysis to assess the BESS performance under weak and strong grids.

Three Phase fault considered in this analysis has a fault impedance of 0.001 and fault duration of 120 ms. For all three phase fault cases considered in the analysis, the system remained stable. For the cases where the SCR ratio is 4, settling time is slightly higher than cases with SCR 10 which is expected due to the relative system strengths.

Initial Point	SCR	Fault Type	Fault Impedance (Ω)	Fault duration (s)
PmaxQmin	10	3phfault	0.001	0.12

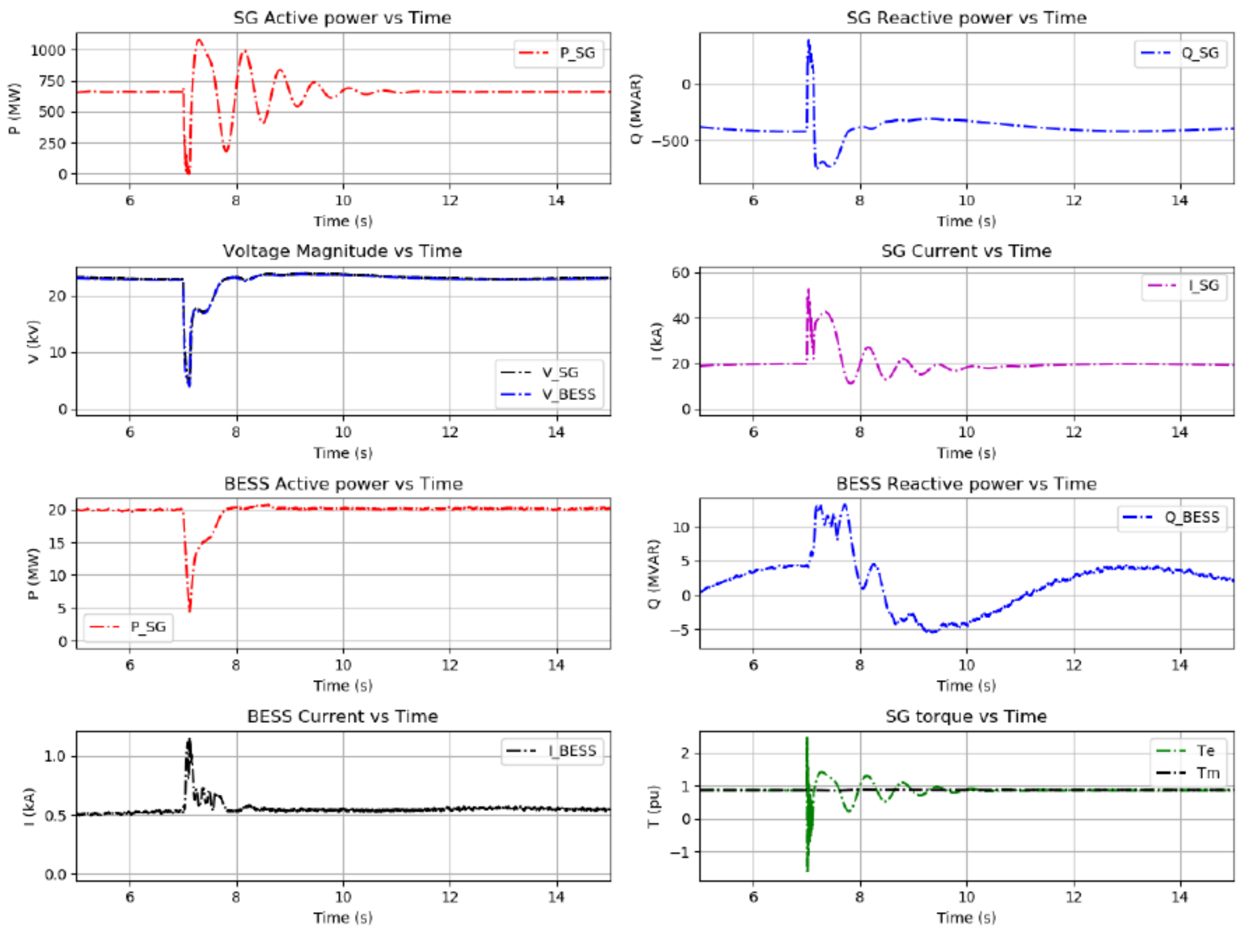


Figure 8.18: Simulation results for case 3phfault-PmaxQmin-SCR-10 showing BESS actively participating by providing reactive power during the fault condition.

On the other hand, the two phase fault considered in this analysis has a fault duration of 240 ms. Two phase faults created much more oscillations in the system compared to three phase faults when SG operates at P=Pmax and Q= Qmin. With SCR 4, this operating point caused the BESS system to trip with its voltage protection activated. For the rest of the operating points, the system remained stable.

Initial Point	SCR	Fault Type	Fault Impedance (Ω)	Fault duration (s)
PmaxQmin	4	2Phfault	0.001	0.24

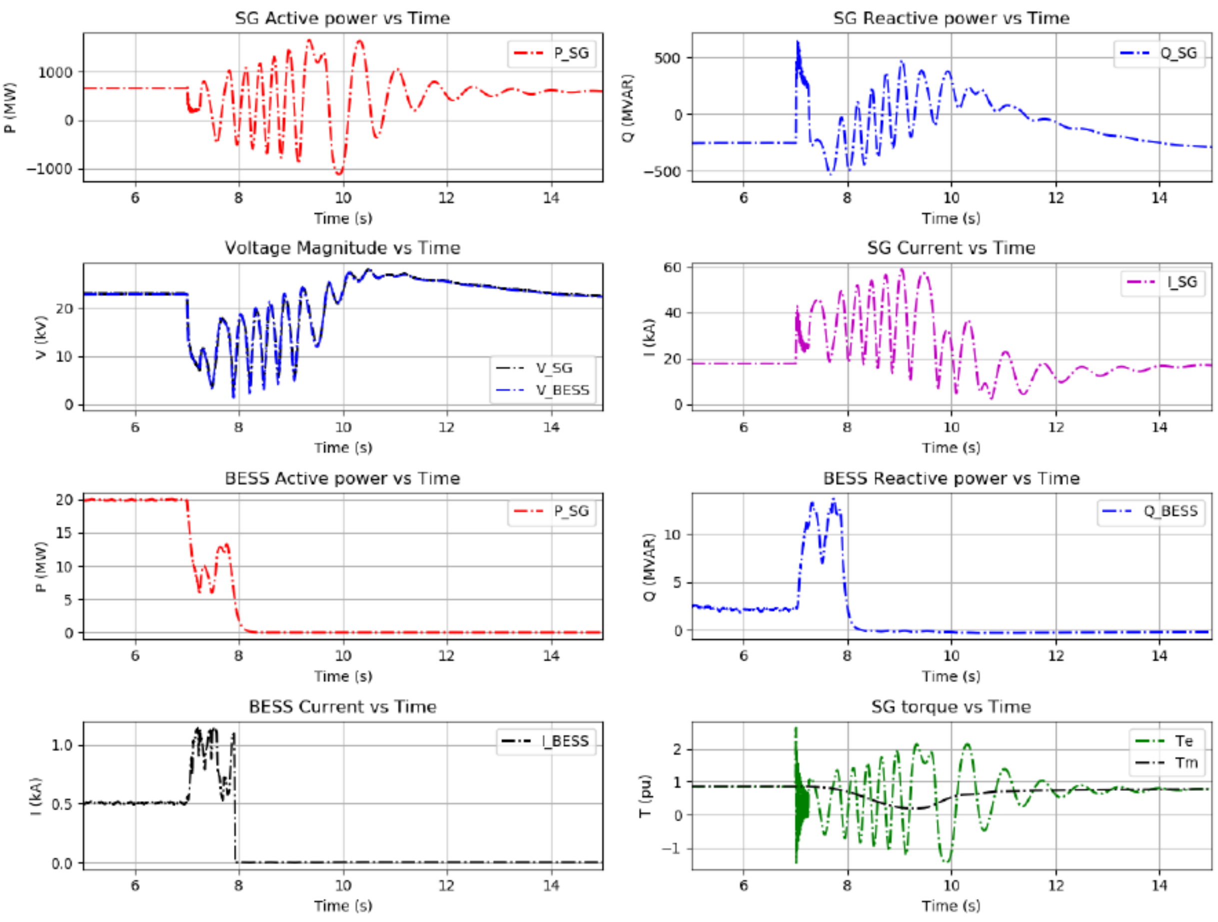


Figure 8.19: Simulation results for case 2Phfault-PmaxQmin-SCR-4 demonstrating the BESS protection systems triggered under this fault condition.

8.4.3 Fault Analysis Discussion

From this preliminary analysis, it is identified that the BESS system is not creating any unwanted interaction with the existing synchronous generator during various faults. Moreover, BESS is actively participating to support the SG during these events. It is noted that BESS is responding to faults by providing reactive power to bring up the voltage. It should be noted that the performance of BESS can be optimized by choosing proper control parameters to meet power station performance requirement.

8.5 Generator Performance Standard (GPS) Compliance Assessment

8.5.1 Overview

A preliminary analysis was conducted to identify if there would be any adverse interaction between the BESS and the existing synchronous generator. In this study, the total plant response was assessed during various fault conditions. The BESS was modelled with a total capacity of 40 MW and connected to the National Electricity Market via TransGrids 330 kV network. The purpose of the BESS is to provide synthetic inertia support for primary frequency response. The BESS considered in this analysis comprises of 24 battery units with a power rating of 1.872 MVA each. The battery operates at a terminal voltage of 0.48 kV AC. Battery unit transformers connect to each unit and step up the terminal voltage to 6.6 kV. The batteries are then connected to one of the auxiliary transformers in the generating station. which steps up the voltage to 23 kV and connects to the generator bus. The single line diagram for the proposed system was previously shown in Figure 8.9. Several Generator Performance Standard (GPS) compliance assessments have been performed in PSSE to investigate the dynamic behaviour of the BESS and the interactions between the VPPS generator and the BESS under any grid disturbances, contingencies or other abnormal grid conditions.

The VPPS model was extracted from the AEMO network snapshot, namely 'SummerHi-20190125- 163118-34 SystemNormal'. A standard BESS model of the rating of 40 MW has been integrated with inverter and power plant controller (PPC) specifications to facilitate the intended studies. The VPPS has been connected to a single-machine infinite bus (SMIB) system. For the assessment of dynamic network capability, a simplified representation of the plant is modelled in PSSE as shown in Figure 8.20. The model comprises a lumped representation of the collector network, the BESS inverter transformers (23 / 0.48 kV), the BESS (connected at bus 20857), the grid transformers (330/23 kV), and the synchronous generator (connected at bus 20855). The generator has a maximum capacity of 660 MW. The grid representation generator (SMIB) at bus 1 is connected to the POC bus number 21854 via a line representing an SCR of 4.5 and X/R of 3.0.

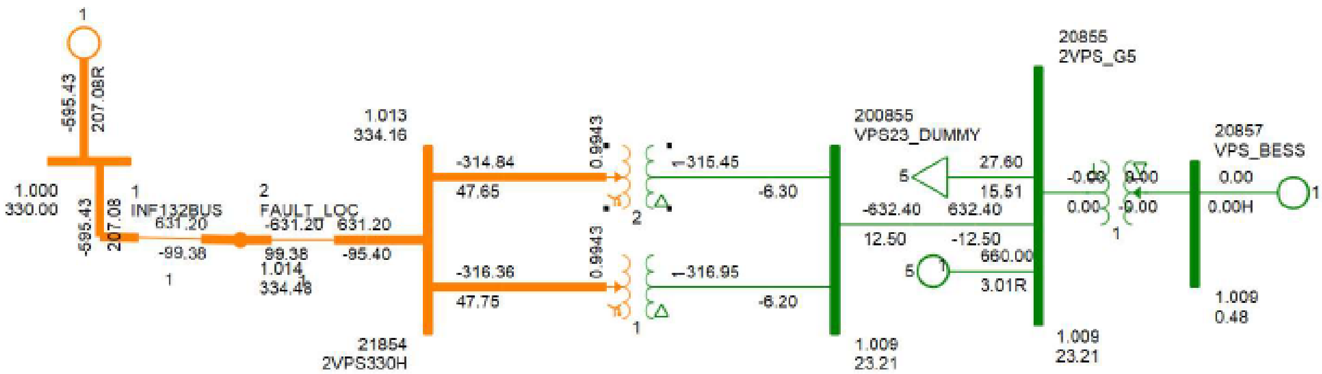


Figure 8.20: Vales Point Power Station (VPPS) single machine infinite bus PSSE model including BESS.

The GPS compliance assessment was performed in PSSE under Chapter 5 of the NER (revision 132). The objective of this study is not to demonstrate the compliance of the VPPS generator with integration of the BESS with the assessed GPS, rather to investigate the dynamic behaviour of the BESS and interactions between the SG and the BESS under any grid disturbances, contingencies or other abnormal grid conditions.

Following GPS compliance assessment has been performed:

i. S5.2.5.3 Generating Response to Frequency Disturbances;
ii. S5.2.5.4 Generating Response to Voltage Disturbances;
iii. S5.2.5.5 Generating System Response to Disturbances following Contingency Events;
iv. S5.2.5.13 Voltage and Reactive Power Control; and
v. S5.2.5.14 Active Power Control.

Under each scenario, the BESS protection system was chosen in compliance with the automatic access standard that corresponds to the relevant clause. This was to minimise negotiation parameters for the GPS modification. For each scenario the response of the BESS and synchronous generator (SG) were modelled with the interaction between the two systems indicated by the response at the point of connection (POC). The response to the disturbance was also investigated during both charging and discharging cycles of the BESS. The following sections summarise the findings of the GPS compliance assessment with the full details included as Attachment B.

8.5.2 Generating Response to Frequency Disturbances (S5.2.5.3)

The performance of the VPPS generator is evaluated with the integration of the BESS against the frequency disturbances. For the study, the SG has not been equipped with any protection system. Meanwhile, the under-frequency and over-frequency protection system for the BESS has been chosen in compliance with automatic access standard to clause S5.2.5.3 as depicted in Figure 8.21.

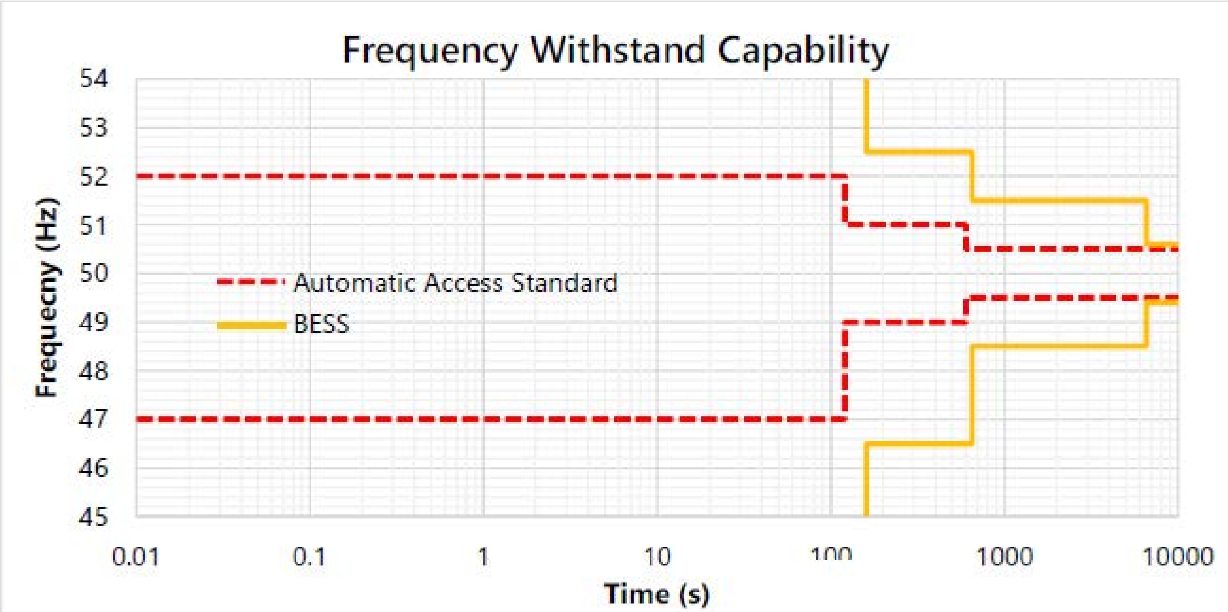


Figure 8.21: BESS frequency withstand capability.

The plant capability is demonstrated by simulation on a controlled voltage and frequency source. The impedance of the grid representation has been for a SCR of 4.5 and X/R ratio of 3.0 (X/R in the generator reactance to resistance ratio, which is used to determine resistance values in short circuit studies). The voltage at the point of connection is set to 1.01 pu. The active power is set to the maximum output of the VPPS generator.

The first test follows the over-frequency profile of the automatic access to clause S5.2.5.3 as indicated by the upper dashed red line of Figure 8.21, and the second test follows the under-frequency profile of the automatic access to clause S5.2.5.3 as indicated by the lower dashed red line of Figure 8.21.

The performance of the VPPS generator for a high frequency event during charging states of the BESS is shown in Figure 8.22 and Figure 8.23. The results demonstrate that the BESS is able to successfully ride-through the high and low frequencies without having any adverse impact from the VPPS generator. Similarly, the response of the BESS and SG to low frequency events are demonstrated through Figure 8 – Figure 11 in Attachment B.

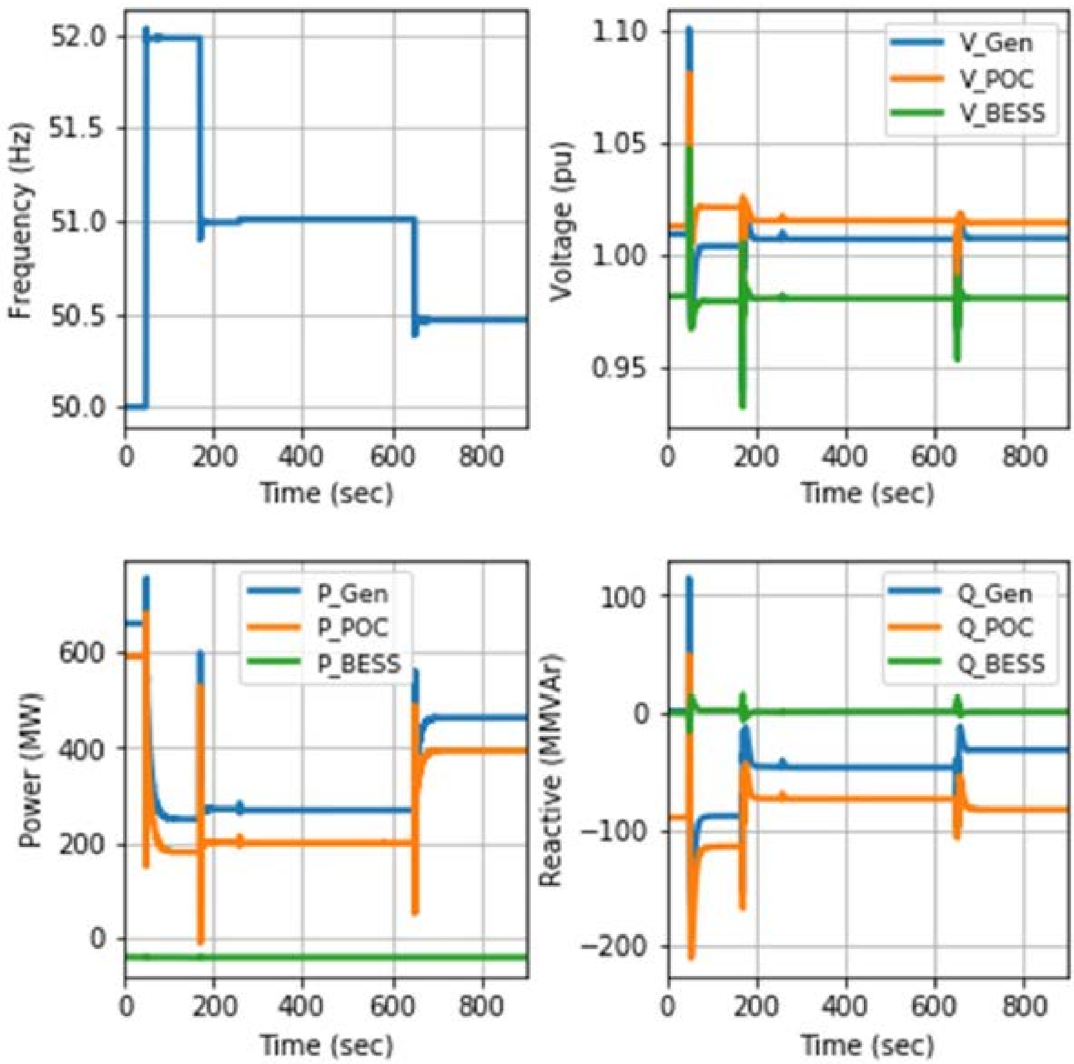


Figure 8.22: Response to high frequency during BESS charging.

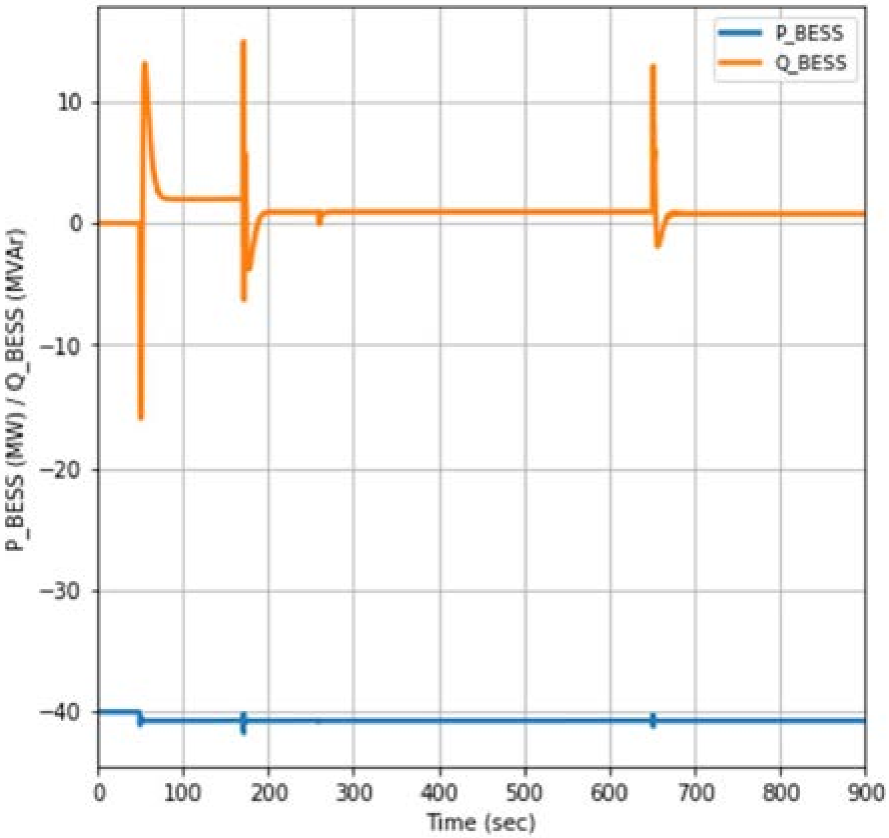


Figure 8.23: BESS response to high frequency during charging.

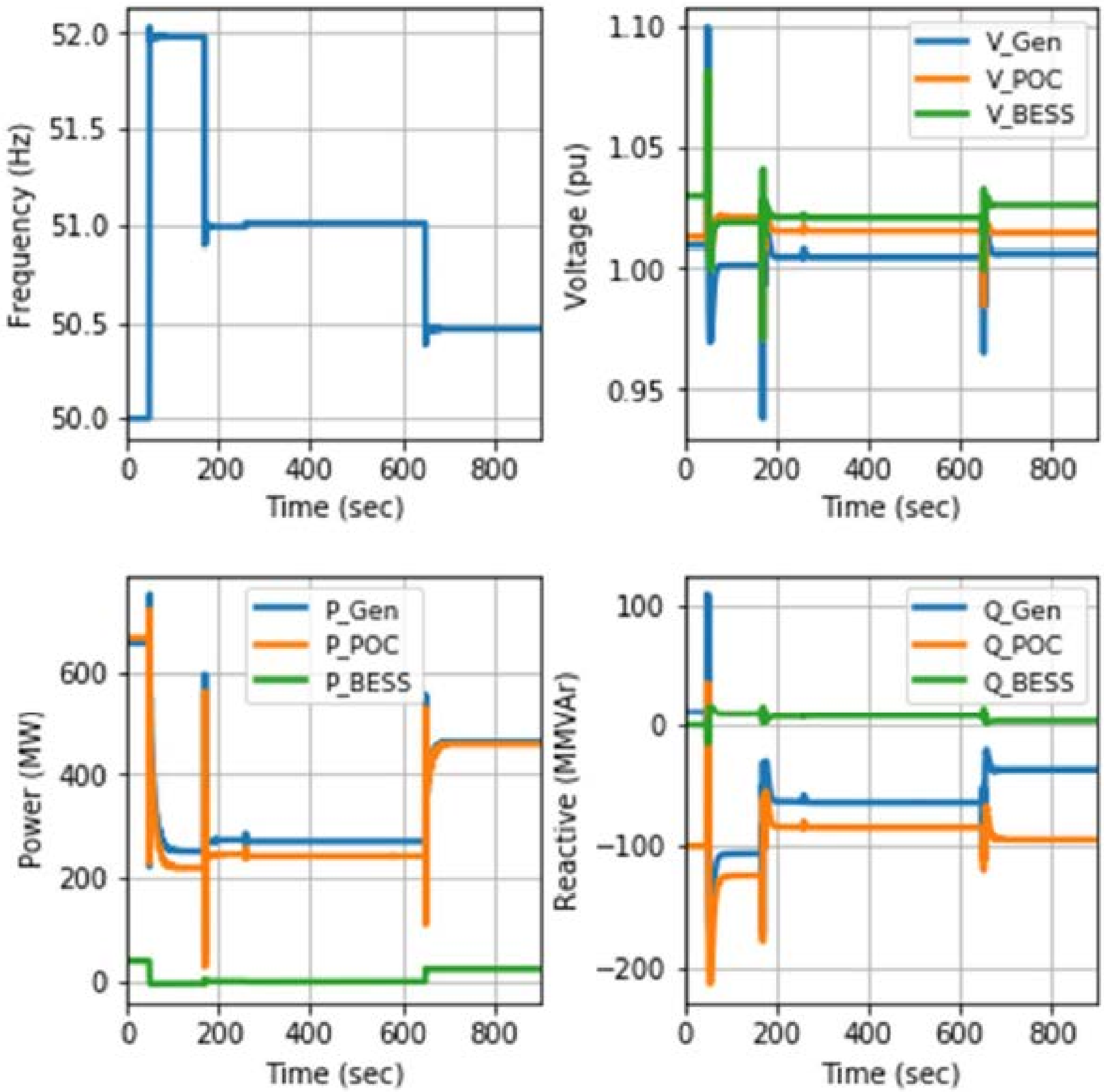


Figure 8.24: Response to high frequency during BESS discharging.

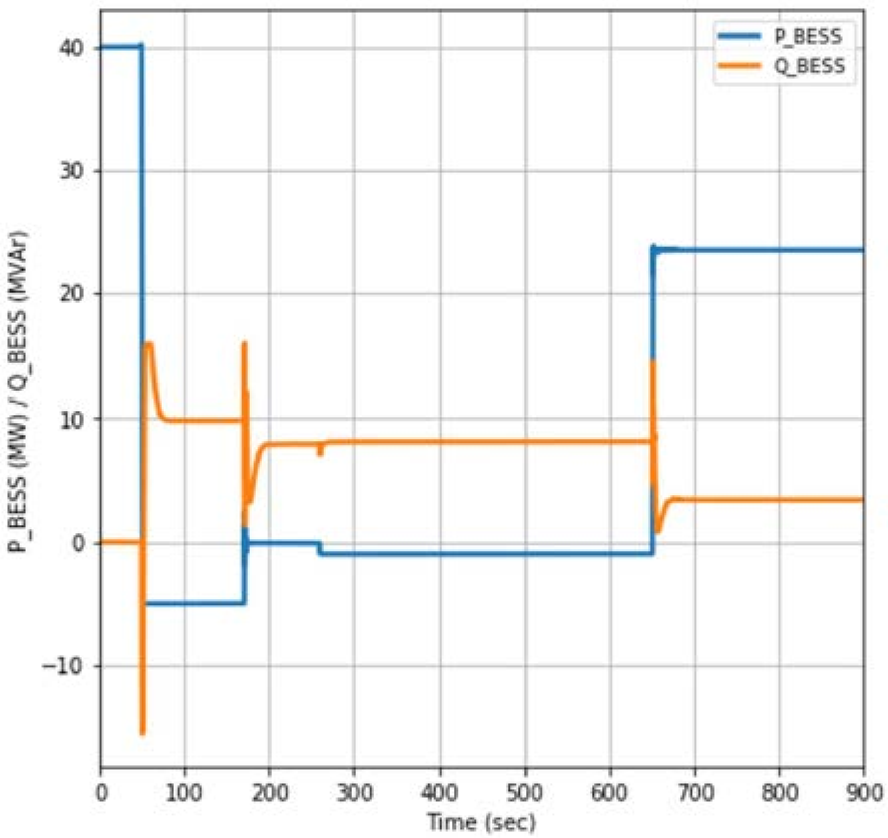


Figure 8.25: BESS response to high frequency during discharging.

8.5.3 Generating Response to Voltage Disturbances (S5.2.5.4)

The performance of the VPPS generator was evaluated with the integration of the BESS against the voltage disturbances. For the study, the VPPS generator was not been equipped with any protection system. Meanwhile, the under-voltage and over-voltage protection system for the BESS was chosen in compliance with automatic access standard to clause S5.2.5.4.

The plant capability was demonstrated by connecting the combined VPPS Generator model with the BESS to a voltage and frequency controllable source which controls the 330 kV POC bus through a very low impedance line (R=0, X=0.0001). The simulation was initialized at 660 MW / 400 MVAr at the VPPS generator terminal.

Simulation results were plotted as shown in Figure 8.26 (High voltage) and Figure 8.27 (Low voltage). The BESS was able to ride through the disturbances and provides a continuous uninterrupted operation. Active power returns to the pre-disturbance value when the voltage returns to 90%-110% of the normal voltage. The VPPS generator is shown to successfully support the grid voltage without resulting in any adverse impact to the BESS.

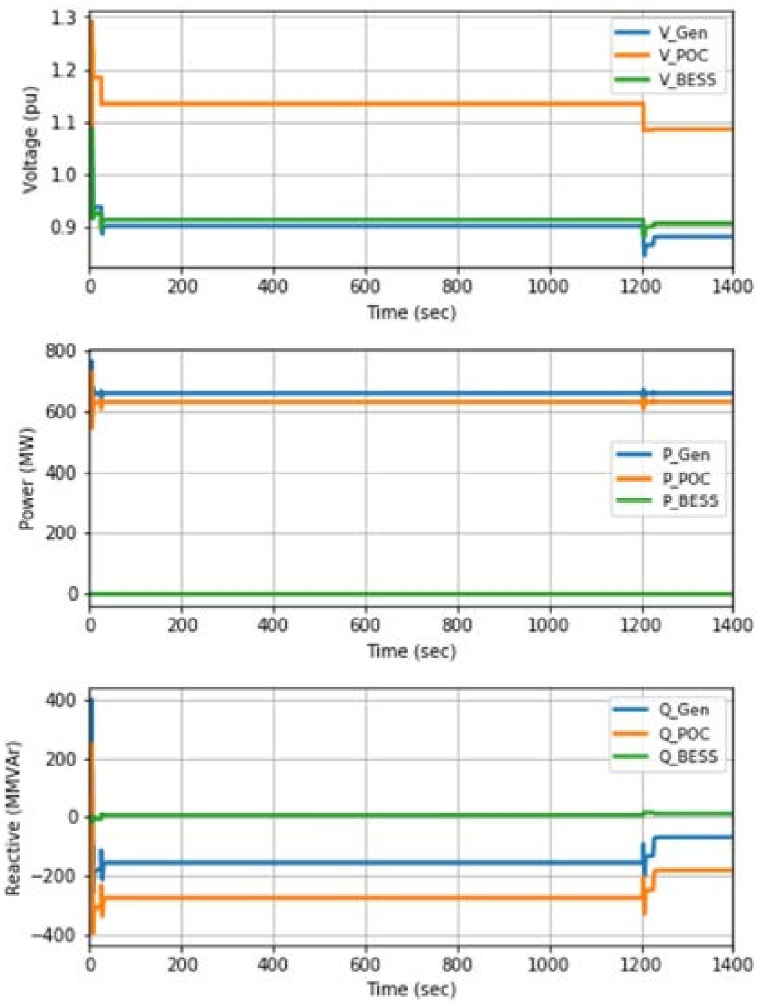


Figure 8.26: High voltage ride through (HVRT) response.

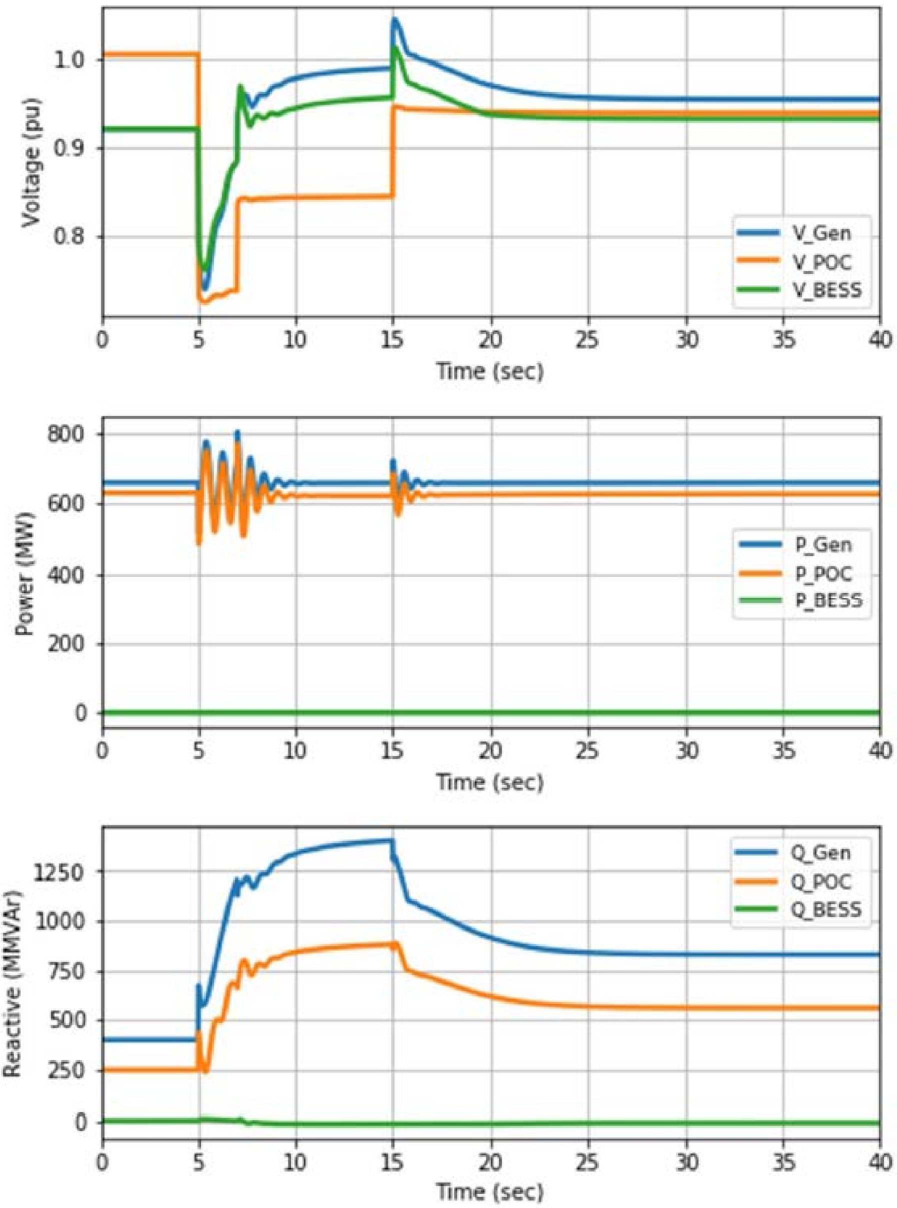


Figure 8.27: Low voltage ride through (LVRT) response.

8.5.4 Generating Response to Disturbances following Contingency Events (S5.2.5.5)

The performance of the VPPS generator was evaluated with the integration of the BESS against the disturbances following contingency events. The study was conducted by simulation on a controlled voltage and frequency source. The impedance of the grid representation has been for a short-circuit ratio of 4.5 and X/R ratio of 3.0. The active power is set to the maximum output of the VPPS generator. The contingencies listed in Table 8.3 have been applied at t = 1 s.

Table 8.3: Contingency specifications.

Fault Type	Fault clearance time (ms)	Fault resistance (Ω)
Three-phase short circuit (LLLG) fault	120	1
Double circuit (LLG) fault	240	0.001

The simulations have been initialised at six different operating points at the VPPS generator terminal. These are:

Point 1-> 660 MW / 0 MVAr

Point 2-> 660 MW / -250 MVAr

Point 3-> 660 MW / 40 MVAr

Point 4-> 250 MW / -339 MVAr

Point 5-> 250 MW / -560 MVAr

Point 6-> 250 MW / 0 MVAr

As observed from the simulation results plotted in Figure 8.28, the system remains stable for all the operating conditions. Moreover, the BESS system does not make any unwanted interaction with the VPPS generator during various faults, rather it actively participates in supporting the generator to restore the post fault voltage by providing reactive power.

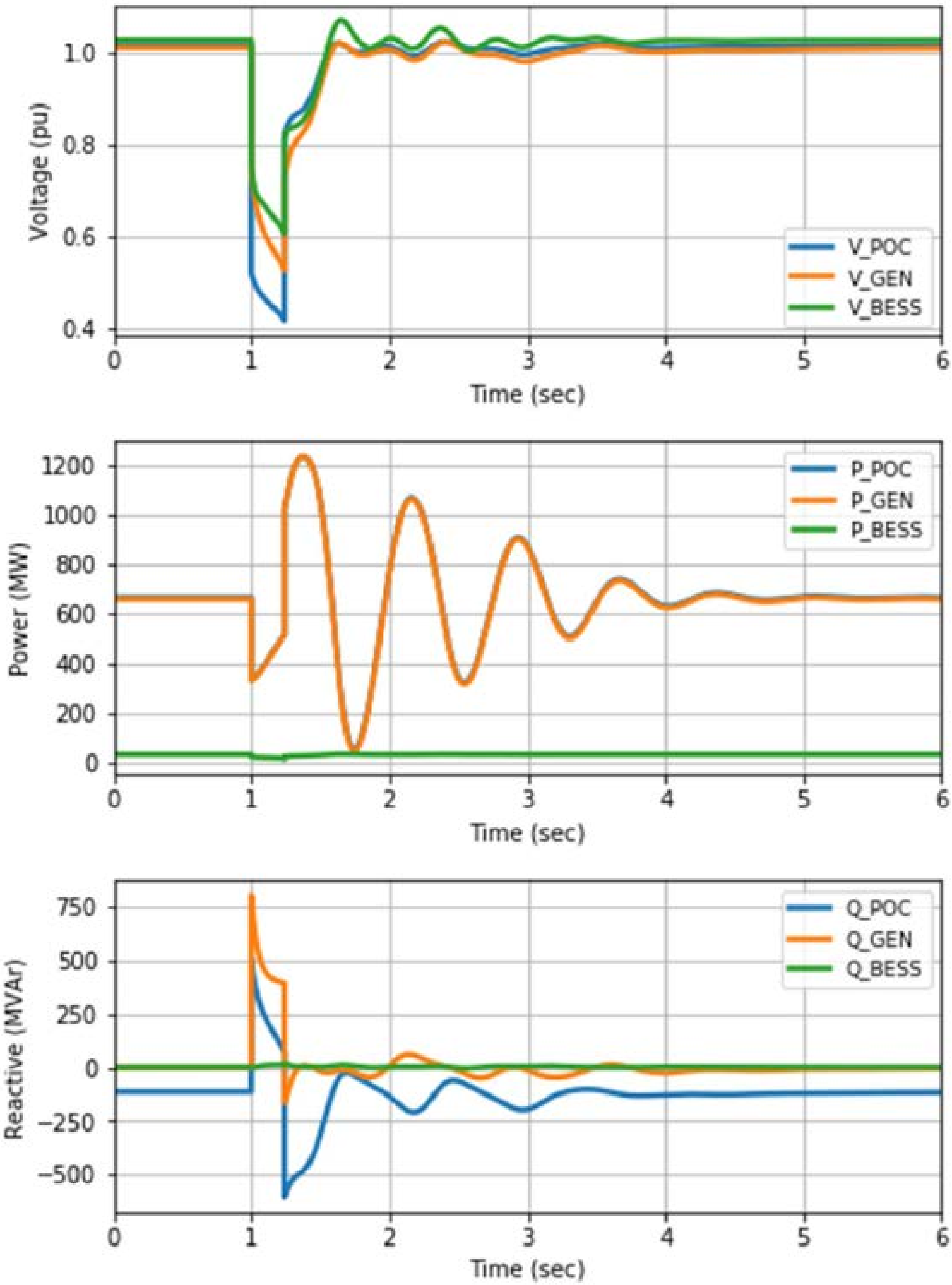


Figure 8.28: Fault response for a line-line-ground (LLG) fault at Point 1.

Similarly, the fault response of BESS and SG at the other operating points are demonstrated in Attachment B.

8.5.5 Voltage and Reactive Power Control (S5.2.5.13)

The interaction between the VPPS generator and the BESS was evaluated with stepping the voltage command up or down. Capability of the voltage control mode has been assessed for both the BESS discharging and charging cases. Voltage command change of ±5% were applied to both the BESS and the VPPS generator separately to demonstrate the interaction between them. VPPS generator has been set to operate in its maximum output.

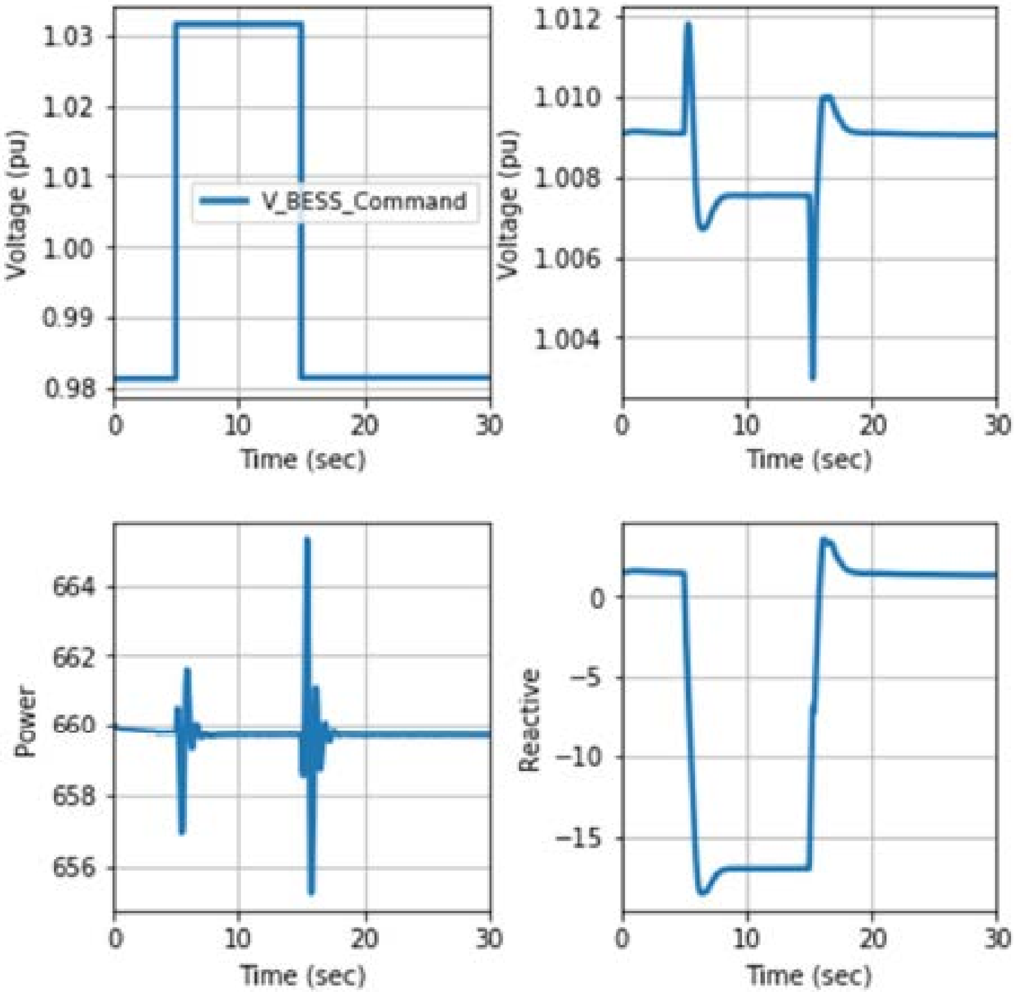


Figure 8.29: Generator response for BESS voltage command step by +5% when BESS is charging (see Attachment B, Figure 42-57 for further examples).

As shown as an example in Figure 8.29 and Figure 8.30, this study shows the power and voltage profiles at the generator terminal and the BESS for a series +5% voltage command steps. When a change in voltage command occurs to either the BESS or the generator, the BESS and the generator respond by supplying or absorbing reactive power and thus maintain the grid voltage.

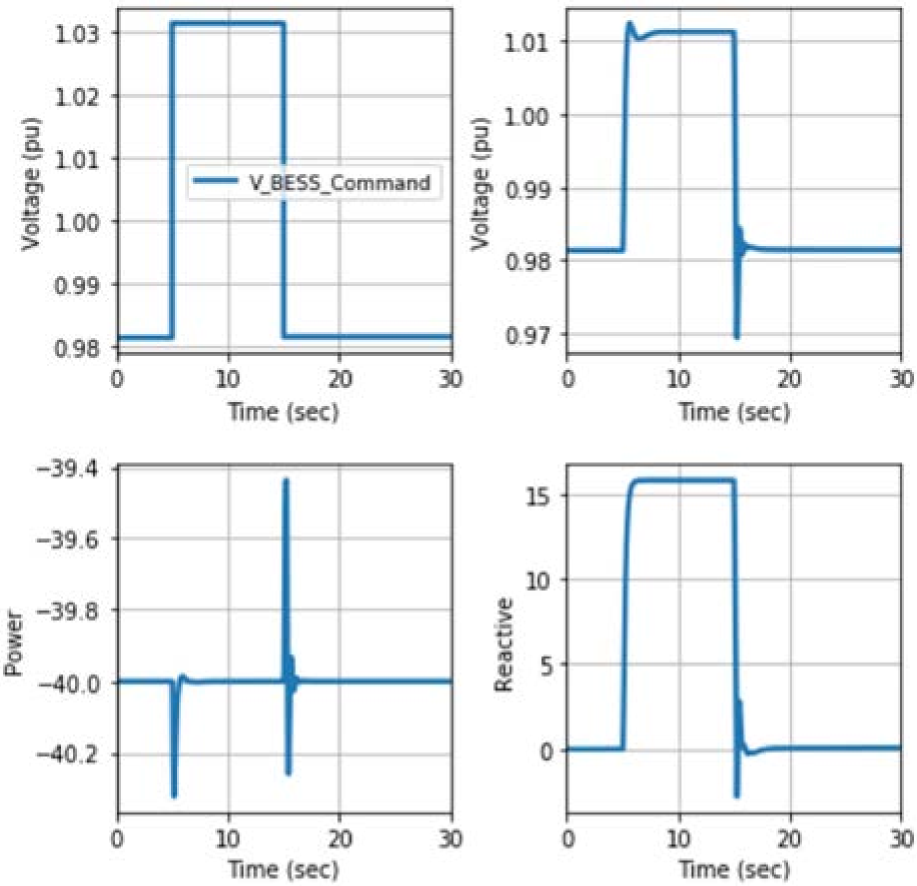


Figure 8.30: BESS response for BESS voltage command step by +5% when BESS is charging (see Attachment B, Figure 42-57 for further examples).

8.5.6 Active Power Control (S5.2.5.14)

The interaction between the VPPS generator and the BESS is evaluated with changes in the active power command of the BESS. The capability of the active power control has been assessed by changing the active power command of the BESS to demonstrate the interaction between the VPPS generator and the BESS. The VPPS generator active power output was set to remain at its maximum throughout the simulation.

Figure 8.31 shows the power profile of the generator and the BESS when active power command is applied to the BESS PPC. As observed from the figure, the active power command of the BESS was changed every several seconds and the BESS successfully responded to active power signals updated with every transition. The generator responded to the command as well without having any adverse impact.

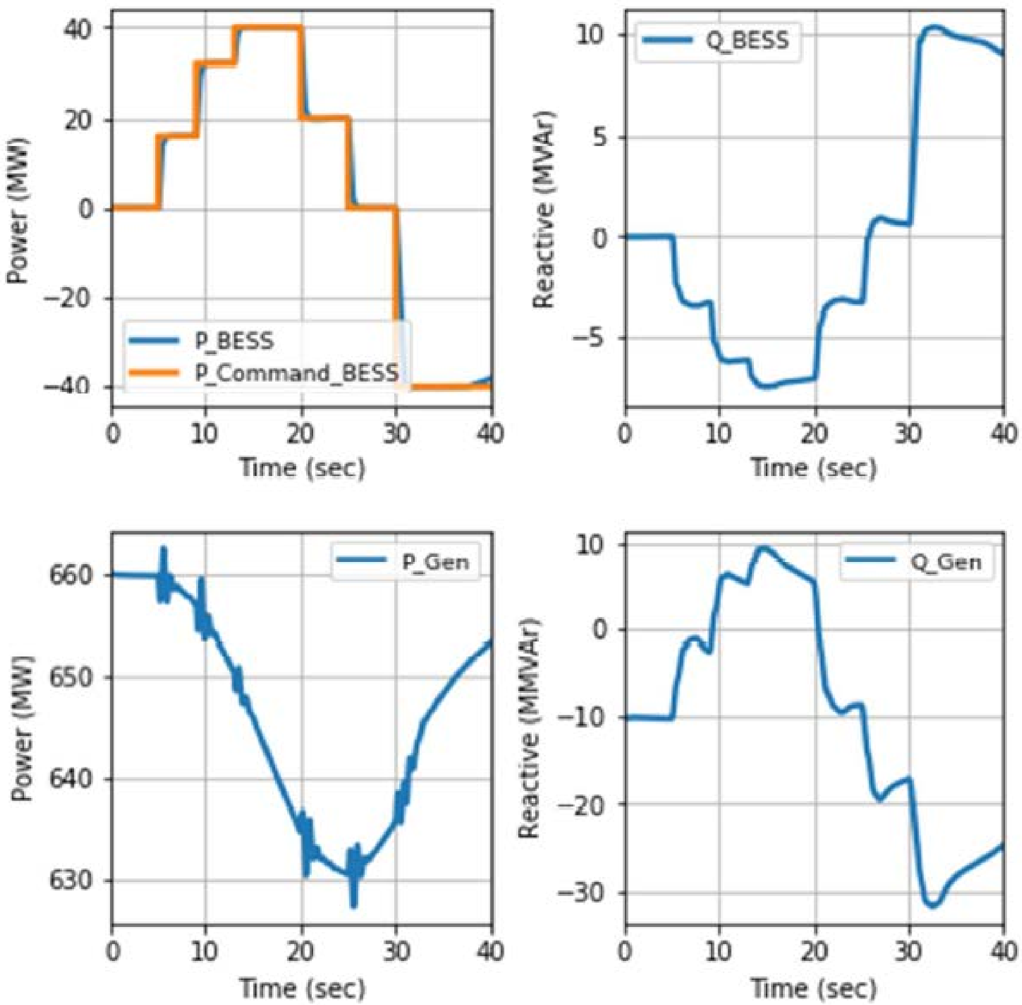


Figure 8.31: Response for BESS active power command step.

8.5.7 Summary of GPS Compliance Assessment

In this report, a number of Generator Performance Standard (GPS) compliance assessments have been performed in PSSE to investigate the dynamic behaviour of the BESS and the interactions between the VPPS generator and the BESS under any grid disturbances, contingencies or other abnormal grid conditions. For the assessment, the VPPS model in PSSE from the snapshot provided by AEMO was extracted and incorporated the standard governor model for the synchronous generator and the 40MW BESS system.

It should be noted that the performance of BESS can be optimised by choosing proper control parameters to meet power station performance requirements. This analysis has not considered parameter tuning which would be completed with a vendor-specific BESS model.

The GPS studies confirm that the integration of the BESS will not result in an adverse impact on the VPPS since no unwanted interactions between the generator and the BESS have been observed due to grid disturbances, contingencies or other grid abnormal conditions. Rather, the BESS provides active support to the generator by providing reactive power for regulating the grid voltage.

9.0 Regulatory Review

9.1 Land Tenure

VPPS is owned and operated by Sunset Power International trading as Delta Electricity. For the purpose of this study, the proposed BESS will be located within the property of VPPS on land zoned *SP2 Infrastructure* located within the Central Coast Council Local Government Area (LGA).

The Objectives of the SP2 zone are to:

- provide for infrastructure and related uses;
- prevent development that is not compatible with or that may detract from the provision of infrastructure;
- recognise existing railway land and to enable future development for railway and associated purposes;
- recognise major roads and to enable future development and expansion of major road networks and associated purposes; and
- recognise existing land and to enable future development for utility undertakings and associated purposes.

The only development types permitted within the zone are roads and the purpose shown on the Land Zoning Map (in this case Energy Generation Works) including any development that is ordinarily incidental or ancillary to development for that purpose. The BESS Project meets the definition of Energy Generation Works and as such is permissible with development consent.

9.2 Planning Approvals

Delta has completed a legal review of the planning consent requirements for the development of a BESS at an existing power station in NSW to determine the appropriate approvals pathway. The *Environmental Planning and Assessment Act 1979 (NSW) (EP&A Act*), the *Environmental Planning and Assessment Regulation 2000 (NSW)* and associated environmental planning instruments (including State Environmental Planning Policies (SEPPs) and Local Environmental Plans (LEPs)) provide the framework for the assessment of the environmental impact of development proposals in New South Wales.

The proposed BESS at VPPS is likely to be considered development for the purpose of electricity generating works as defined under the *Standard Instrument (Local Environmental Plans) 2011*. Under the *Wyong Local Environmental Plan 2013* (Wyong LEP), which is the appropriate local planning instrument, development for the purpose of electricity generating works is permissible with consent within the SP2 portion of VPPS.

State Environmental Planning Policy (Infrastructure) 2007 (ISEPP) also prescribes electricity generating works as permissible with consent (clause 34) or permissible without consent (clause 36). Development in connection with electricity generating works will generally only be permissible without consent if that development is being carried out by or on behalf of a public authority. Delta Electricity does not fall within the definition of a public authority for the purposes of the *EP&A Act*, and therefore, the BESS will not fall into any category of development permissible without consent.

The project would likely have a capital investment value of greater than $30 million and, as such, would be assessed as State Significant Development (SSD). This is assessed in accordance with *Division 4.1 of Part 4 of the EP&A Act* requiring the preparation of an Environmental Impact Statement addressing the Secretary's Environmental Assessment Requirements. The NSW Minister for Planning would be the consent authority in this instance and a summary of the key steps is shown in Figure 9.1. It is noted that a "public authority" completing an identical project may elect to seek approval under the self-assessment and determination provisions of *Part 5 the EP&A Act* for works permissible without consent.

Figure 9.1: SSD Pathway (source: NSW Planning https://www.planningportal.nsw.gov.au/major-projects/assessment/state-significant-development/ssd-process).

The SSD approvals pathway is considered the appropriate approvals pathway and would require the proponent to prepare an environmental impact statement, undergo a period of public exhibition and respond to submissions prior to assessment by the Department. The key elements identified to be undertaken as part of the environmental assessment include:

i. stakeholder consultation (ongoing and meaningful consultation with key regulatory and community stakeholders);

ii. biodiversity and heritage assessment (may be minimal due to negligible impacts on native vegetation and heritage aspects of a brownfield project);

iii. construction activities including transport management, noise and vibration, air quality, land and soil impacts;

iv. noise and vibration impacts for operation periods;

v. assessment of project greenhouse emissions (noting that a BESS is a net load to the system); and

vi. hazardous development assessment (the initial environmental assessment would also require the completion of a preliminary risk screening in accordance with *SEPP 33 – Hazardous and Offensive Development* as Li-ion batteries are classified as Class 9 Dangerous Goods. If the risk screening indicates the development is “potentially hazardous” then a detailed Hazard Analysis would be required).

A cost estimate to complete the environmental assessment is in the order of $100-150k and could be completed within 20 weeks depending on the required seasonal biodiversity studies. A definitive list of studies for assessment is determined during the first step of the SSD approvals process via the proponent’s preparation of the Preliminary Environmental Assessment (PEA) and Secretary’s Environmental Assessment Requirements (SEARs) prepared by the Department.

In April 2020, NSW amended legislation to allow for stand-alone battery storage systems. Under the SEPP (Infrastructure) Amendment (Energy Storage Technology) 2020, the definition for electricity generating works was modified to include:

> *Purpose of –*
>
> *(a) making or generating electricity, or*
>
> *(b) electricity storage.*

This amendment identifies a clear pathway to enable utility providers to construct electricity storage as part of improvement works to transmission and distribution networks and allow for large-scale battery storage systems to be built in permitted zones across NSW.

9.3 Network Connection Agreement and Commissioning Program

AEMO has a key role to assess and negotiate performance standards that could affect power system security. AEMO is also involved in assessing simulation models of power system plant and associated control systems, and commissioning and post-commissioning activities. Table 9.1 shows a high-level summary of the network connection process.

Table 9.1: Overview of technical information requirements for network connection (modified from Technical Information requirements for generator Connections (AEMO).

Connection Stage	Information
Pre-feasibility	General location, size and type of transmission and distribution connection and whether the project will be completed in stages
Connection Enquiry	Information as specified in Schedule 5.4 of the Rules
Connection Application	Generating system data including: • Standard Planning Data (S) • Detailed Planning Data (D) • Diagram of connecting plant configuration • Simulation and modelling data for generation connections (Clause S5.2.4 of the Rules) • Proposed performance standards
Contracts	Agreed performance standards Finalised data regarding connecting plant and its configuration
Construction	Construction schedule information and coordination Factory acceptance test data Regular progress updates
Completion	**Registration:** Generating system and connecting plant data including Registered Data (pre-connection, R1), factory acceptance test data, an acceptable model based on the finalised design data and in accordance with the modelling guidelines, NEM registration documents and agreed performance standards. **Commissioning:** Commissioning program and coordination as per Clause 5.8.4 of the Rules, on-site test data and regular progress updates. **Post Commissioning:** Registered data from post-connection tests (R2) Data and simulation model validation and performance verification

The installation of the BESS "behind the connection point" at VPPS as proposed in this study would be considered an alteration to the existing unit Generator Performance Standard (GPS). For alterations to generating systems across the NEM, the technical information requirements depend on the nature of the alteration.

Clause 5.3.9 of the Rules describes the procedure to be followed by a generator proposing to alter a generating system. In general, Clause 5.3.9 applies where an alteration to an existing generator will, in AEMO's reasonable opinion:

i. affect the performance of the generating system;

ii. have an adverse system strength impact; and

iii. affect network capability, power system security, quality or reliability of supply, inter-regional power transfer capability or the use of a network by another Network User.

The technical information requirements for each stage of the alteration process will be a subset of the requirements detailed in Table 9.1 which are generally assessed on a case-by-case basis. Section 8 in this report has demonstrated that the integration of the BESS will not result in an adverse impact on the VPPS since no unwanted interactions between the generator and the BESS have been observed due to grid disturbances, contingencies or other grid abnormal conditions. As previously noted, this study has utilised generic model parameters to investigate the performance of the BESS integrated with a SG. This analysis would need to be repeated for an active generator modification application to include the vendor specific BESS models and the full turbine protection system analysis.

In August 2019, AEMO submitted a rule change proposal to more efficiently accommodate increasing numbers of connections where bi-directional electricity flows occur (ie. charging and discharging cycles) and business models where there are a mix of technology types connected behind a connection point. AEMO proposes to create a new registered participant category, termed a Bi-directional Resource Provider, in NER Chapter 2 and integrate this through the rest of the NER. Under this proposal, the VPPS BESS could be considered as a hybrid facility containing two scheduled generators behind the connection point which would require additional metering. This requirement may be avoided as the VPPS BESS does not charge from the network and does not impact the system reliability at the connection point. Further considerations and clarification from AEMO would be required once the rules have been redrafted and formalised which is expected in 2020.

A commissioning and testing program, referred to as the R2 Test Plan, would need to monitor performance under both BESS load and generator cycles to replicate the performance predicted by the PSCAD and PSSE modelling submitted with the connection modification application. The R2 Test Plan is likely to be extensive for a first-of-a-kind system and would be negotiated in consultation with AEMO and the NSP.

9.4 Stakeholder Engagement

A key focus of the regulatory approvals process is engagement with all key stakeholders during preparation of the environmental impact statement. Stakeholder groups, with an interest in the project are expected to include:

- NSW Department of Planning and Environment (DPE);
- NSW Roads and Maritime Services;
- NSW Office of Environment and Heritage;
- NSW Environment Protection Authority;
- Transport for NSW;
- Central Coast Council;
- Local land owners and nearby residents; and
- Aboriginal stakeholders.

A detailed consultation plan for the environmental impact assessment would be prepared once SEARs are received, with the outcomes of consultation included in the impact assessment and relevant technical studies. The purpose of the consultation plan is to ensure ongoing and effective communication with key stakeholders and the community.

9.5 Greenfield v Brownfield Site Considerations

There are several possible configurations available for integration of BESS into the network. These include:

i. Co-location with an existing generator (either VRE or SG); or
ii. Embedded in the network as a stand-alone load and generator.

There are several advantages and disadvantages for project deployment co-located with an existing generator (brownfield) or installed as a stand-alone unit (greenfield) as summarised in Table 9.2. It is well known that the development costs and timescales for renewable projects in Australia can be significant barriers for renewable projects, placing pressure on the upfront investment requirements of developers[6]. Each co-location project must balance the interplay between generation profile to maximise long term energy yield, whilst simultaneously exploiting commercial synergies found in the development, design, construction and operation of developing co-located generators.

Table 9.2: Comparison of greenfield and brownfield deployment for stand-alone BESS and co-located with existing generator.

	Stand-alone Embedded generator	Co-located with VRE or SG
Approvals Process	• Maximum design flexibility and infrastructure can be purpose built at optimum location. • Greenfield location may require resolution of land tenure and extensive environmental assessment.	• Potential leverage off existing permitting activities including a reduction or sharing in environmental studies. • Appropriate land zoning in place. • Connection point is generally well understood. • Challenging metering arrangement may be required.
Network Connection Infrastructure	• Likely to be installed adjacent to existing network infrastructure in strong network areas.	• Relative ease of network connection via existing infrastructure (assuming capacity available). • May be located in weak network areas.
Operation	• BESS charging at grid emissions intensity. • No reliance on site generation. • No reduction in BESS balance of plant costs.	• Possible impact on cross warranties and existing assets. • Potential MLF impacts if located in weak network regions. • Co-location with VRE may provide firming, reduce curtailment and mitigate network constraints.

[6] AECOM "Co-location of Investigation - A study into the potential for co-locating wind and solar farms in Australia" – ARENA funded report, 2016.

The key operational difference between co-location with an existing VRE or SG generator relates to the relative marginal loss factors (MLF). A MLF represents the transmission losses in electrical power flow between the connection point and the regional reference node. An MLF less than 1.0 indicates that an incremental increase in power flow from the connection point to the node would increase total losses in the network, whereas a MLF greater than 1.0 indicates the opposite. Loss factors are calculated and fixed annually to facilitate efficient scheduling and settlement processes in the NEM[7].

Within the NEM, most renewable generators have a MLF < 1.0 due to the installation location distance from the load centres of the network[8] as shown in Figure 9.2. Existing thermal generators are typically located in proximity to regional nodes and load centres and have MLF ~1.0. The value of the MLF has a direct impact on BESS revenues where a MLF difference of 0.05 corresponds to a 5% reduction in revenues compared with a BESS located in a strong area of the network with MLF~ 1.0. Further discussion on the commercial impacts of MLF is included in Section 10.3.

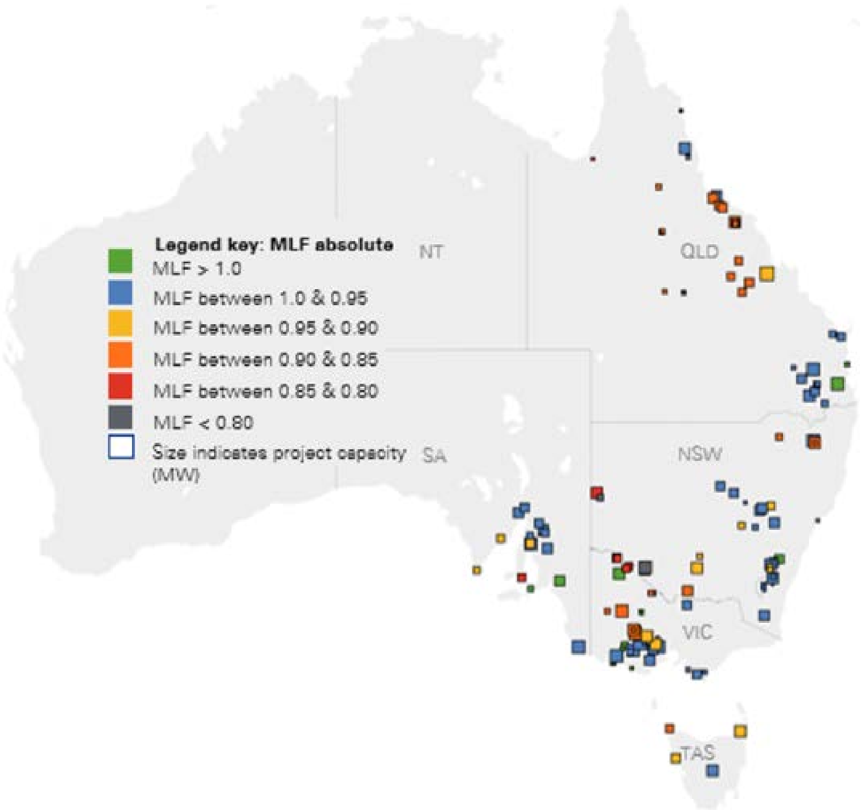


Figure 9.2: 2020-21 MLFs for a range of renewable generators[7].

[7] https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries

[8] https://www.energycouncil.com.au/analysis/marginal-loss-factors-the-state-of-play-in-australia/

10.0 Financial Evaluation

10.1 Capital and Operating Costs

The Project engaged with several BESS providers and determined a cost estimate for the 2 x 40MW/20MWh system in the range AUD$500-$650/kW. The total project CAPEX cost estimate is $51.5m (+/- 30%) and includes batteries, enclosures, inverters, balance of plant (BOP) and mechanical/electrical integration to be firmed during the detailed design phase of the project. The following financial analysis assumes a capital cost of AUD$575/kW. This cost estimate compares favorably with the Lazard Levelised Cost of Storage Report 5.0 (2019) range USD$280-500 (battery only ie. no BOP included) although at the upper end of the range which is reflective of a first of a kind application of the technology.

Operational expenditure for the proposed BESS are AUD$8m (~1.5% of Battery CAPEX) total for the 10-year period. This includes preventative and reactive maintenance, full battery core warranty (batteries, inverters, enclosures, control system), 24/7 BESS monitoring, software maintenance, and spares. It is noted that no battery replacement is required for the 10-yr project lifetime assuming that the number of equivalent battery cycles per day is managed within specification operational limits.

Table 10.1 summarises the project costs used in the financial evaluation.

Table 10.1: Project costs summary.

Item	Cost Estimate ($'000)
Capital Expenditure	
Battery Core (Batteries, enclosures, inverters)	$32,000
Balance of Plant (BOP)	$19,500
Total CAPEX	$51,500
Engineering Costs	
Concept Design	$129
Pre-feasibility	$258
FEED	$773
Detailed Engineering	$2,575
Procurement	$1,030
Survey/Civils	$258
Approvals	$127
Total Engineering Costs (10% CAPEX)	$5,150
Project Costs	$56,650
OPEX (1.5% CAPEX) over 10-year life	$7,725 ($772,500 pa)

10.2 Revenue Streams

A BESS system may provide additional revenue streams above current VPPS revenues due to anticipated market trends and improved operation, including:

10.2.1 Energy Arbitrage

The BESS has the capability to provide short-term energy arbitrage. Arbitrage is best supplied by an energy-orientated BESS as described in Section 8.1.4. Although the increase of VRE generation is expected to produce more price volatility, arbitrage opportunities would be limited for this project due to the short battery cycle number and duration and therefore not considered as a potential revenue stream.

10.2.2 Additional FCAS Capability and Revenues

VPPS provides FCAS to the market. The BESS project as currently contemplated has no increase in the VPPS grid connection capacity. However, the BESS would increase materially VPPS's capability to provide FCAS services to the market.

Assuming the 80MW/40MWh BESS concept design was deployed, the BESS therefore could add up to 40MW per unit of FCAS capability. The NEM FCAS market is not especially deep. Therefore, any additional FCAS capacity bid aggressively into the FCAS market could reasonably be expected to adversely impact FCAS prices.

10.2.2.1 FCAS Market Size and Trends

Figure 10.1 shows the total annual FCAS costs across the NEM for the period 2009-2018.

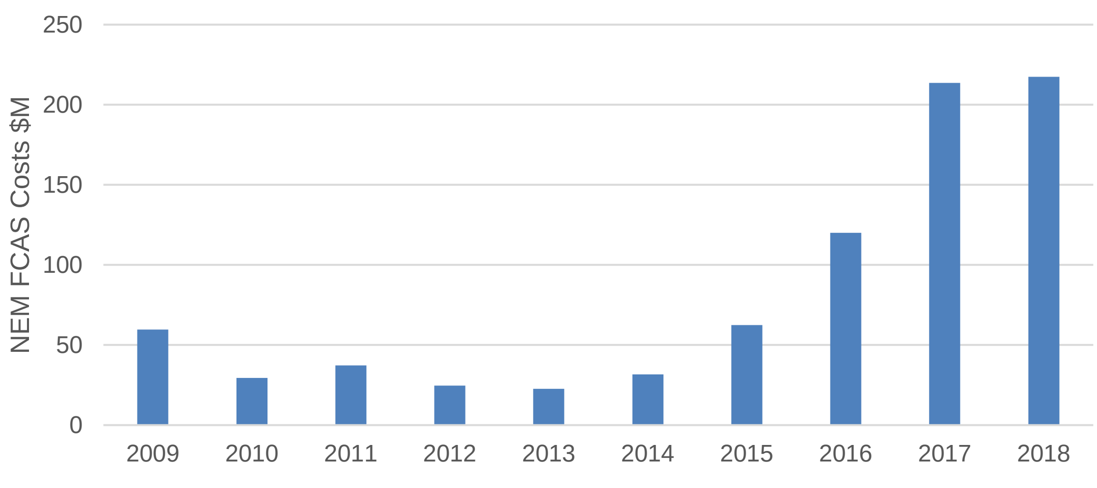


Figure 10.1: Annual NEM FCAS costs (Source: AER, AEMO).

At the time, annual FCAS costs in the NEM in 2017 were the highest on record at $214 million, representing a 77% increase on 2016 levels and a 308% increase on the five-year average. This coincided with the retirement of some FCAS suppliers from the market (such as Hazelwood, Northern, and Wallerawang power stations) and an increase in the price of offers from incumbent providers. A similar level of costs was experienced in 2018.

It is also noted that storage and demand response technologies are continuing to capture progressively larger shares of FCAS markets, particularly in the higher-priced Raise FCAS markets. During Q4 2018 storage and demand response captured 10% and 17% of these markets respectively, resulting in FCAS payments of around $4 million (AEMO Quarterly Energy Dynamics – Q4 2018).

Table 10.2 and Table 10.3 detail the total annual revenue based on data between 1 January 2018 and 3 April 2019.

Table 10.2: Cost/revenue for FCAS by region ($k).

	LReg	L6s	L60s	L5min	RReg	R6s	R60s	R5min	All
NSW	4,945	5	32	172	11,102	11,681	8,804	31,671	68,411
QLD	4,437	1,485	1,895	546	17,508	7,084	6,731	6,521	46,208
SA	3,353	85	208	146	12,685	7,921	4,742	7,536	36,677
TAS	2,548	346	39	96	4,157	13,091	3,266	3,334	26,878
VIC	433	4	44	313	2,210	5,788	4,050	7,785	20,626
ALL	**15,715**	**1,926**	**2,218**	**1,273**	**47,663**	**45,564**	**27,593**	**56,846**	**198,799**

Table 10.3: NSW FCAS price and volume.

	LReg	L6s	L60s	L5Min	RReg	R6s	R60s	R5Min
Average NSW FCAS $/MWh	11.56	0.02	0.07	0.30	25.45	9.68	7.18	13.51
Average NSW enablement MW	49	15	31	69	45	138	138	260
Min NSW Enablement MW	0	0	0	0	0	0	0	6
Max NSW Enablement MW	269	150	243	302	224	373	385	459
Std Dev NSW Enablement MW	23	21	30	36	27	52	56	63

10.2.2.2 Vales Point Power Station (VPPS) FCAS Capability and Revenues

The current AEMO registration of the VPPS units for FCAS services is summarised in Table 10.4 below.

Table 10.4: Vales Point Power Station (VPPS) registered FCAS capability.

	Max Cap	Min MW Level	Max Upper Angle	Max MW Level	Max Lower Angle
R6	33	245	90	660	45
R60	33	245	45	660	90
R5Min	20	245	45	660	90
RReg	50	250	45	660	90
L6	60	245	90	665	45
L60	100	245	90	665	45
L300	40	300	90	665	45
LReg	50	250	90	660	45

As an example of the impact of a BESS, Figure 10.2 below provides an example of potential FCAS capability (assuming 40MW per unit battery) for the R6 service.

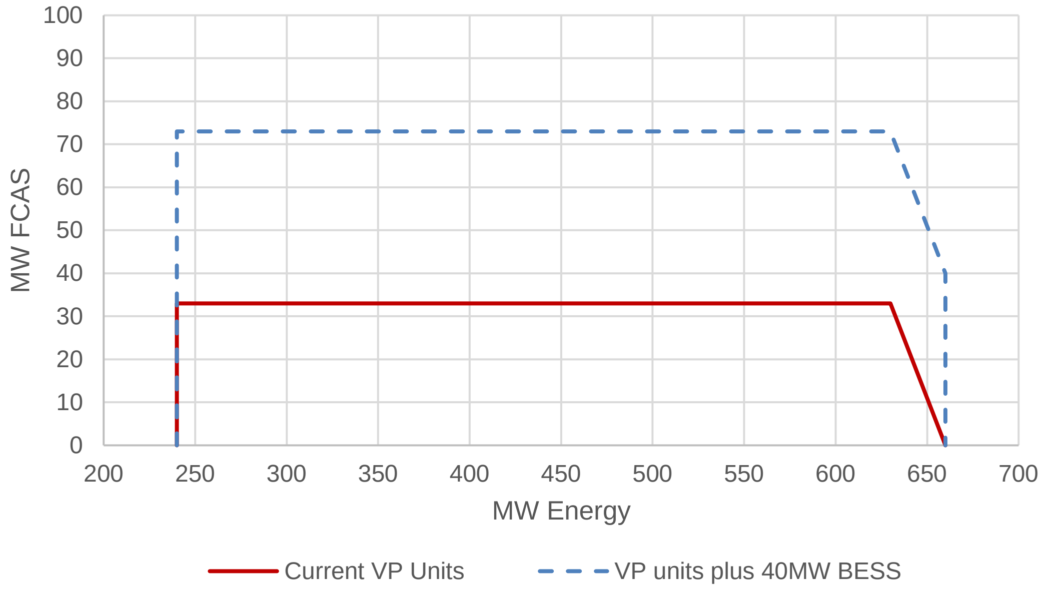
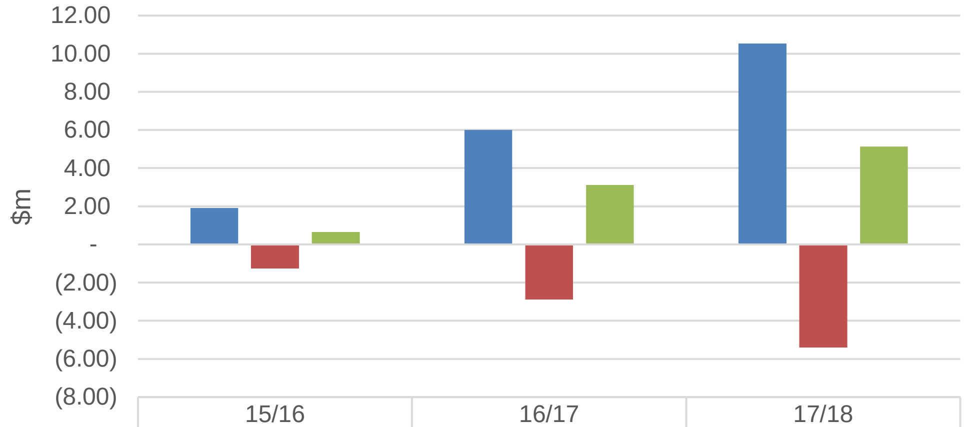


Figure 10.2: Vales Point Power Station (VPPS) Unit FCAS Registered Capability for R6s and R60s.

The VPPS units (VP5 and VP6) are currently registered as generators in the NSW wholesale electricity market and actively bid into the FCAS markets. For each dispatch interval, AEMO's dispatch engine determines a market clearing price for each of the eight FCAS markets. This price is used to determine the payments to the FCAS providers. The payments for FCAS are then recovered from market participants with Delta's expenditure determined by the contribution factor based on off-target performance and retail components as shown in Figure 10.3.



	15/16	16/17	17/18
FCAS Revenue	1.91	6.00	10.53
FCAS Expense	(1.25)	(2.89)	(5.41)
Net FCAS Revenue	0.66	3.11	5.13

Figure 10.3: Vales Point Power Station (VPPS) FCAS Revenues and Expenses.

Figure 10.4 shows a more detailed review of VPPS net revenues for each FCAS market where over 80% value arises from the Raise Reg, Raise 5 min and Raise 6 second services. Further Lower services have been of negligible revenue to VPPS.

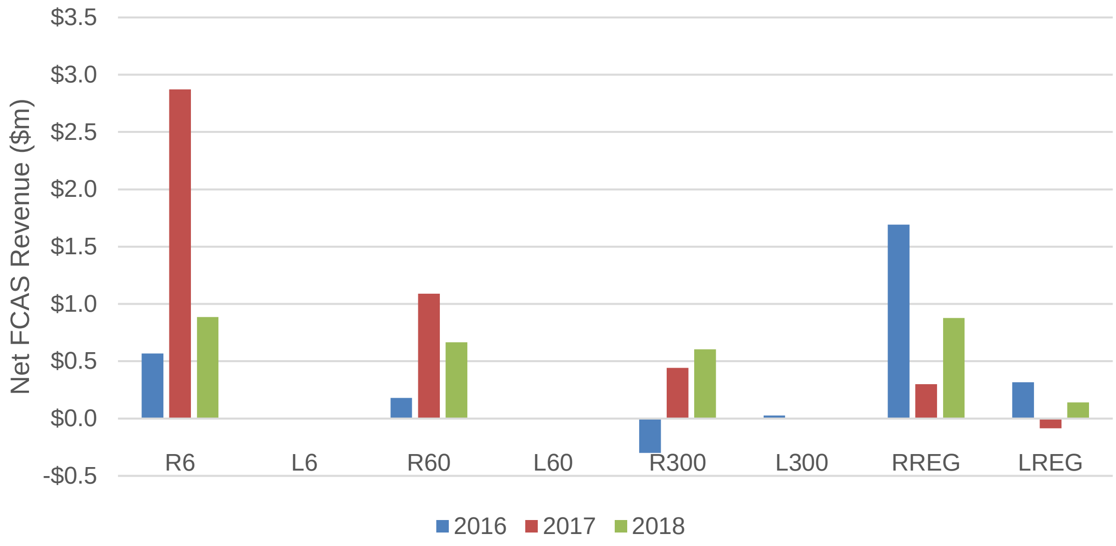


Figure 10.4: Vales Point Power Station (VPPS) FCAS Net Revenues by Market Category.

10.2.2.3 NSW FCAS and Revenue Estimate of Market Share

As outlined above, given the majority of the value of these service to Delta is contained to a few raise services, those services will be the basis for this initial estimate of revenues. To further analyse potential revenue contribution from each service, this estimate is based on an initial review of the supply curves and average NSW region FCAS enablement requirements for each of:

i. Raise 5 minute service (R5min);

ii. Raise 6 second service (R6s);

iii. Raise 60 second service (R60s)

iv. Raise regulation service (Rreg); and

v. Lower services in aggregate.

Raise 5 Minute

In order to initially estimate average price and volume effects of the proposed battery project, in respect of the R5min service, Figure 10.5 shows an indicative supply curve and Table 10.5 shows the typical FCAS providers and volumes.

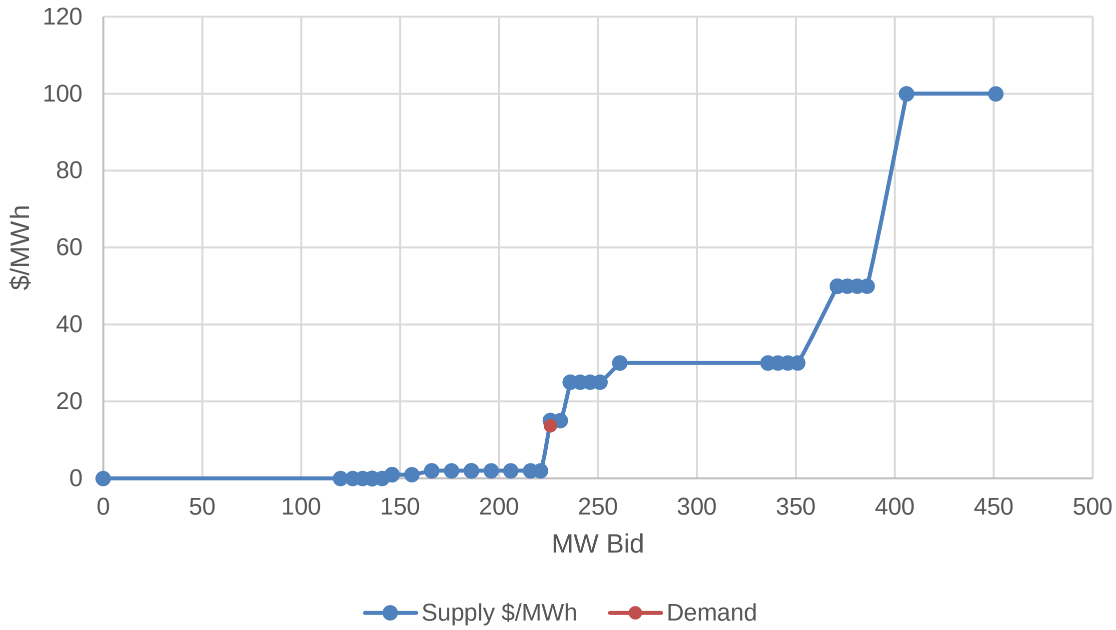


Figure 10.5: Raise 5 Minute.

Table 10.5: Typical FCAS Providers.

	R5Min MW
Snowy	126
Bayswater	30
Eraring	30
Mt Piper	0
VPPS	40
Total	**226**

Snowy typically supplies around half of the average 260MW of NSW Raise 5Min FCAS with the other half shared reasonable equally between the coal fired stations. The supply curve is very flat at prices generally less than $2/MWh which will drop the average price from $13.51/MWh to less than $2/MWh for additional volumes as small as 5MW trying to bid in unless other suppliers pull back to hold up prices.

It will be assumed that the VPPS battery will be able to supply 40MW of this service whilst the current average price of $13.51/MWh will be maintained. This gives an annual revenue estimate of $3.6m.

Raise 6 Second

In order to initially estimate average price and volume effects of the proposed battery project, in respect of the R6s service, Figure 10.6 shows an indicative supply curve and Table 10.6 shows the typical FCAS providers and volumes.

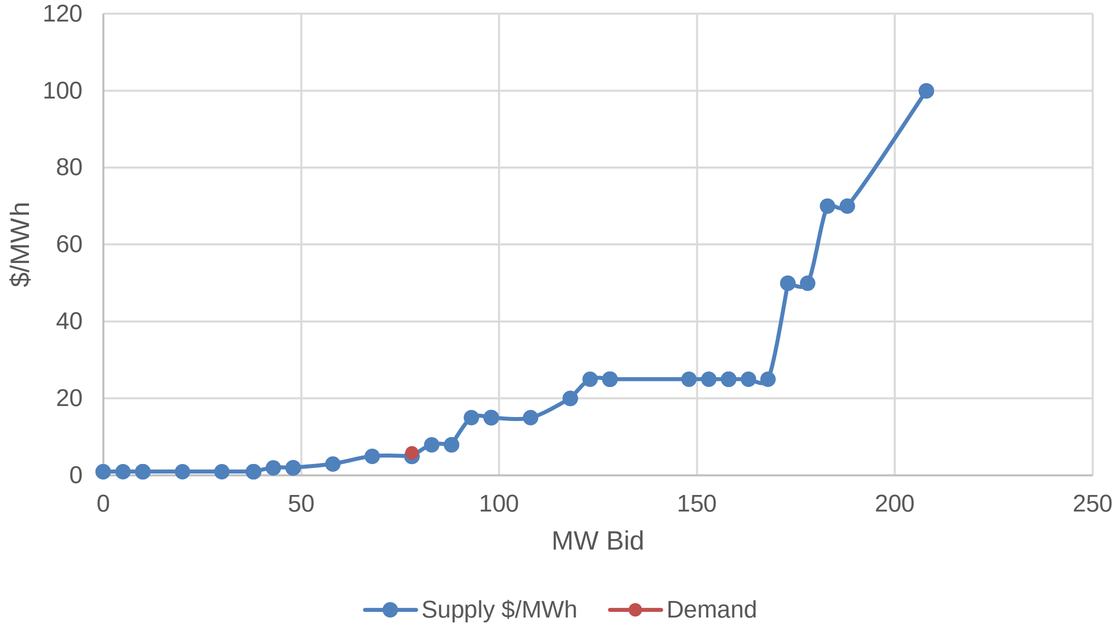


Figure 10.6: Raise 6 Second.

Table 10.6: Typical NSW FCAS Providers.

	R6Sec MW
Snowy	0
Bayswater	10
Liddell	28
Eraring	30
Mt Piper	0
VPPS	10
Total	**78**

The average enablement for this service is 138MW at an average price of $9.68/MWh. The coal fired stations typically provide this service and with no dominant player it would likely be difficult to squeeze too much volume into this service without impacting price.

It will be assumed that the VPPS battery will be able to supply 20MW of this service whilst the current average price of $9.68/MWh will be reduced to $5/MWh with the additional capacity. This gives an annual revenue of $0.9M.

Raise 60 Second

The average enablement for this service is 138MW at an average price of $7.18/MWh.

Based on analysis for the similar Raise 6 Second service, it will be assumed that the VPPS battery will be able to supply an average of 20MW of this service at an average price of $5/MWh. This gives an annual revenue of $0.9M.

Raise Regulation

In order to initially estimate average price and volume effects of the proposed battery project, in respect of the Raise Regulation service, Figure 10.7 shows an indicative supply curve and Table 10.7 shows the typical FCAS providers and volumes.

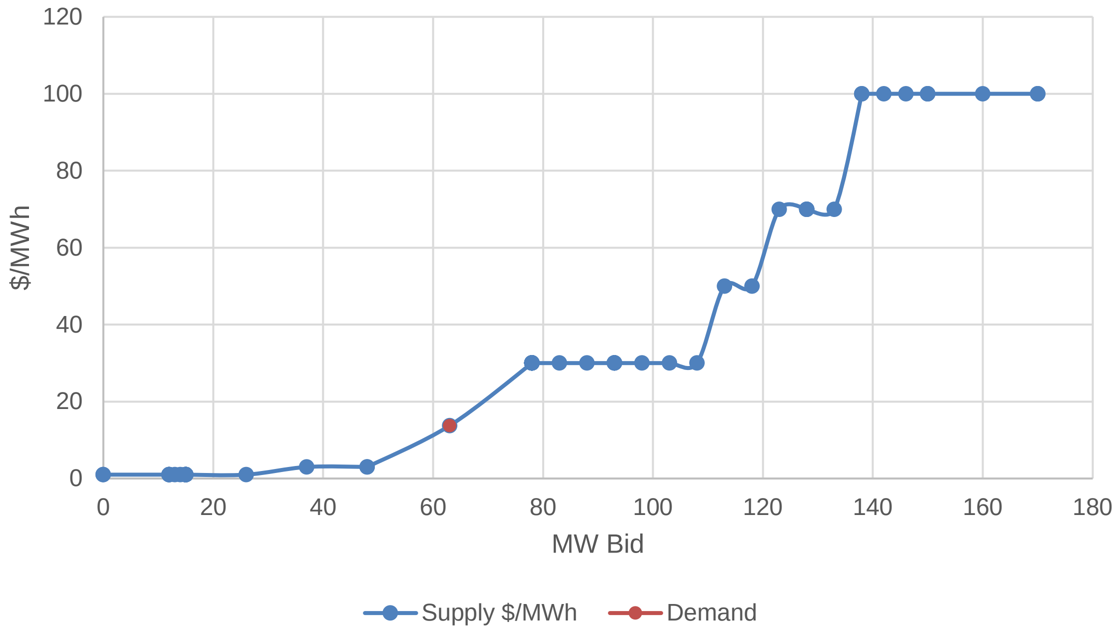


Figure 10.7: Raise Regulation.

Table 10.7: Typical NSW FCAS Providers**.**

	RReg MW
Snowy*	0
Bayswater	62
Liddell	3
Eraring	75
Mt Piper	0
VPPS	30
Total	170

Note Snowy often provides this service but not in the typical period examined. The average enablement for this service is 45MW at an average price of $25.45/MWh. Snowy and the coal fired stations typically provide this service and it would likely be difficult to squeeze too much volume into this service without impacting price.

It will be assumed that the VPPS battery will be able to supply an average of 10MW of this service whilst the current average price of $25.45/MWh will be reduced to $15/MWh with the additional capacity. This gives an annual revenue of $1.3m.

Lower Services in Aggregation

The average enablement for this service is 49MW at an average price of $11.56/MWh.

Based on analysis for the Raise Regulation service, it will be assumed that the VPPS battery will be able to supply an average of 10MW of this service whilst the current average price of $11.56/MWh will be maintained. This gives an annual revenue of $1.0M.

FCAS Expenditure

In 2018, VPPS had approximately $5m in FCAS expenditure which was driven by the contribution factor and off-target performance. The business case assumes that these costs remain the same, and we can drive our “causer pays” down to near zero for the BESS.

10.2.3 Throttling Valve Losses and Heat Rate Improvement

A key element in this study was to determine any greenhouse gas savings generated by the integration of a BESS with an operating generator. Most NSW coal-fired units operate by overfiring the boiler with the steam pressure throttled to achieve the correct pressure for the required turbine set point. The overfiring is used as “spinning reserve” to provide extra generating capacity by increasing the power output of generators already connected to the network. The amount of spinning reserve required is governed by the generator performance standard (GPS) agreement with the Network Operator and is typically in the range 5-10% for NSW generators.

In a perfect engineering world, steam throttling is an adiabatic process (ie. constant enthalpy) and therefore heat, energy and mass losses are negligible across the valve. In the real world there are minor losses due to friction, pressure drop and temperature reduction. This study estimates the energy losses due to steam throttling. Figure 10.8 shows the turbine natural pressure curve which illustrates the steam turbine operating range (approx. 11MPa – 14.5MPa) with throttle valve wide open.

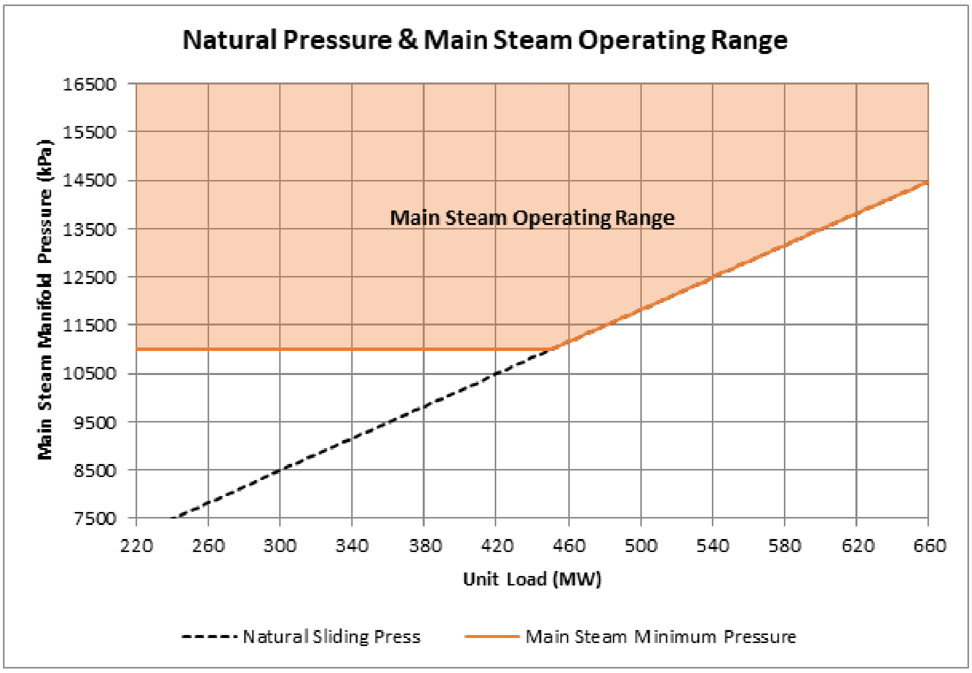


Figure 10.8: Natural turbine sliding pressure curve and main steam operating range.

The overfiring results in a modified sliding pressure curve that is parallel to the natural sliding pressure line and limited to an absolute minimum and maximum steam pressure as shown in Figure 10.9.

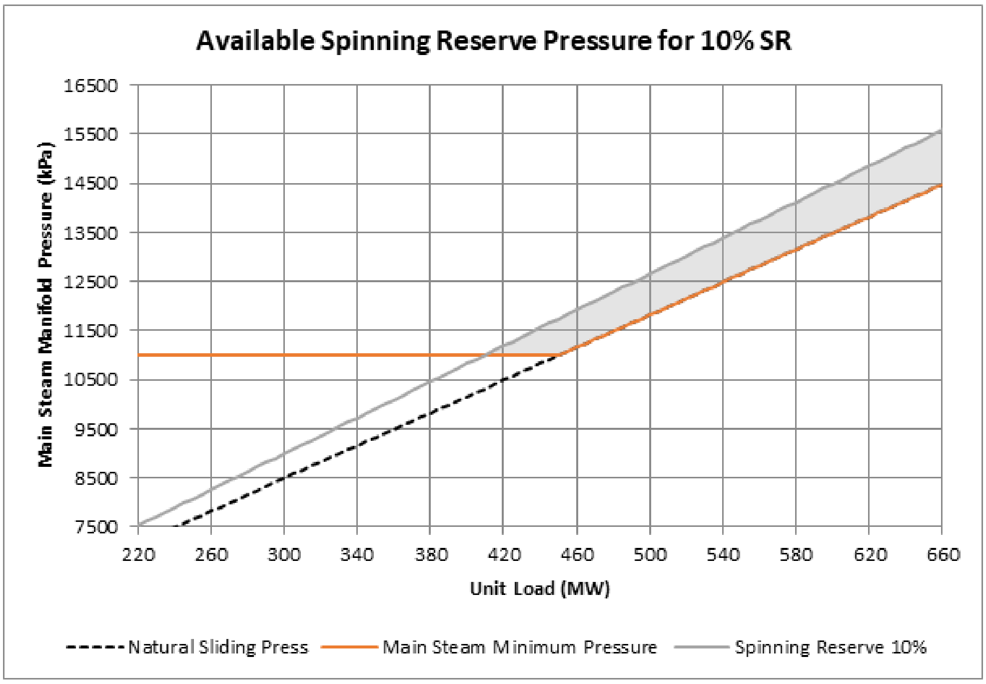


Figure 10.9: Modified sliding pressure for 10 % spinning reserve.

The modified curve shows that the 10% spinning reserve corresponds to 7.5- 8.0% increase in steam pressure required. For example, at 540MW, the pressure difference is 1000 kPa which is 8.0% of the natural sliding pressure of 12500 kPa.

Using the Toshiba heat rate performance curve shows that a +7.5% change in pressure results in a 1% change in heat rate as shown in Figure 10.10.

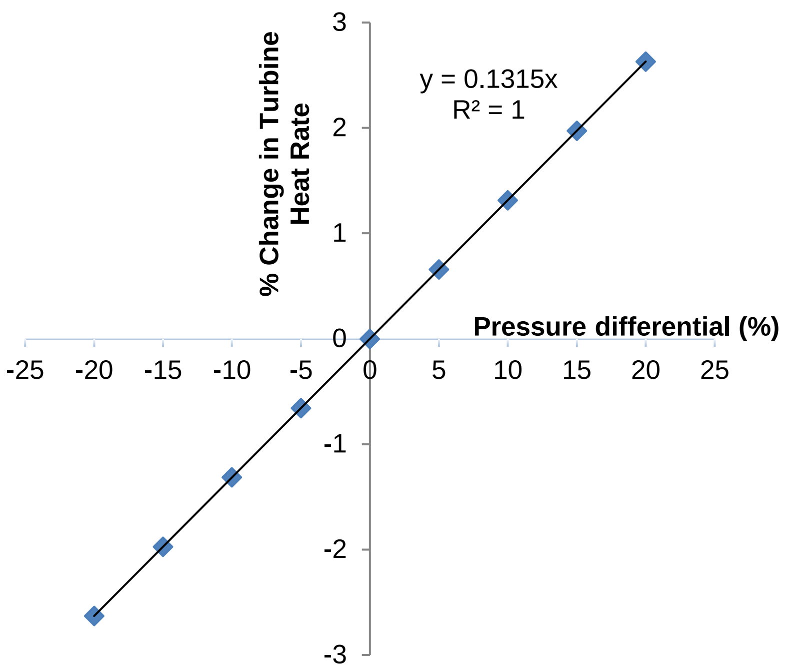


Figure 10.10: Percentage change in turbine heat rate as a function of change in pressure.

A 1% change in heat rate corresponds to approximately 103 kJ/kWh (1% of 10300 kJ/kWh) which is around 30,900 tonne coal per year total for two generating units. This represents approximately 1% reduction in coal usage which is equivalent to ~ 65,000 t-CO_2/year. In commercial terms, this reduction in coal usage corresponds to a savings of approximately $2.4m assuming coal costs at $80/tonne with 25MJ/kg (ie $3.2/GJ) and 7500 GWh annual generation for the station. It is also noted that coal savings would scale with coal prices and market requirements for generation.

Coal-fired units typically throttle the main steam valve to control the turbine output to match the generation target required. Additional coal is burned to produce energy without additional output sold on the market. A key focus of the study will be to monetise the energy not sold.

Additionally, any reduction in throttling losses should result in improved efficiency with a further decrease in heat rate achieved via the additional load required during the BESS charging cycle.

10.2.4 Reduced Wear and Tear on Plant

The electricity system is transitioning from primarily dispatchable generators to an increasing reliance on renewable intermittent sources. With output largely dependent on atmospheric conditions, it is adding both variability and uncertainty to the system. General electricity production profiles for coal, wind and solar power plants are shown in Figure 10.11.

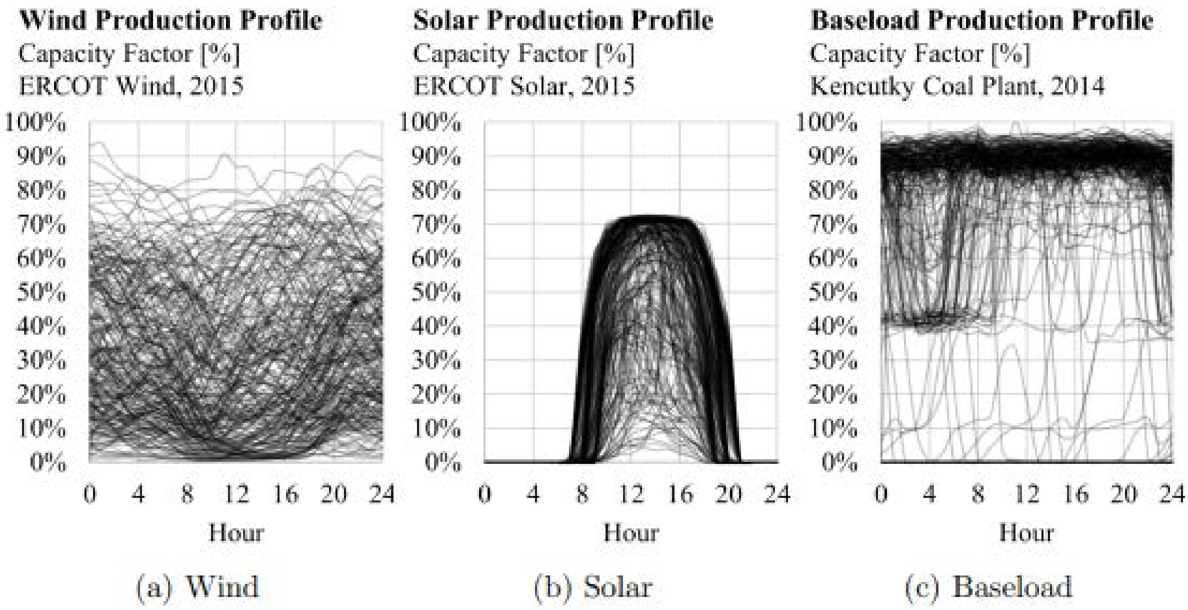


Figure 10.11: Typical production profiles for different sources of generation (Source: “Effects of Intermittent Generation on the economics and operation of prospective baseload power plants”, Massachusetts Institute of Technology, 2017).

The effect of this on the system, specifically with solar (including residential PV), causes a decrease in generation demand during the day and creates what is referred to as the duck curve as shown in Figure 10.12. Solar electricity production can lead to an over generation risk during mid-day and increases the ramp needed from baseload power generators like coal fired power stations during night demand peaks.

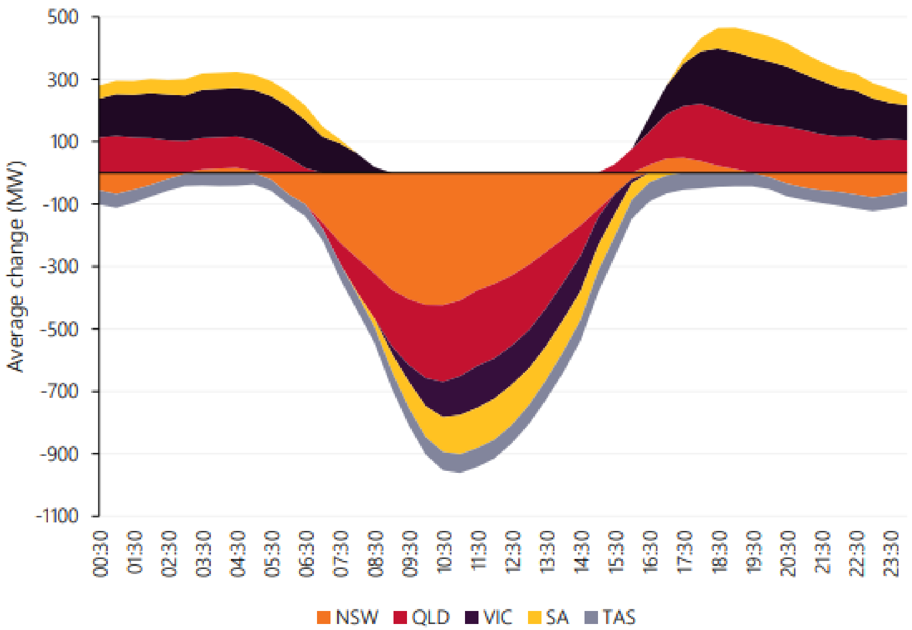


Figure 10.12: Change in NEM-average operational demand by region and time of day (Q4 2019 versus Q4 2018). Source: AEMO Quarterly Energy Dynamics Q4 2019.

The duck curve shows the effect of increases in solar PV capacity on the net load. While peak load grows slowly, the minimum net load decreases, leading to risks of over generation at midday as net load dips below the generation output of must-run facilities and power plants with long start times needed to meet the upcoming evening ramp. This ramp occurs as the sun sets in the evening and output from all solar PV begins to decline.

Coal fired power plants are designed to run mainly at base load. The changes to coal plant operation due to the impact of intermittent renewables occurs in three stages, namely:

i. System changes including:

- increased intermittent generation;
- changes in gas prices to allow increased penetration of gas fired units into the market; and
- lower demand;

ii. Coal asset operational changes such as:

- faster load ramps rates;
- more start ups;
- more frequent load changes;
- more frequent minimal load operation; and
- reserve shutdown;

iii. Impacts on plant O&M such as:

- *Mechanical issues:* Increased wear and tear on components through creep-fatigue interactions, repeated thermal expansion, thermal fatigue in the firebox, and rotor bore cracking of the turbine;
- *Water/steam chemistry:* Increased issues pertaining to the water and steam chemistry, system harder to maintain leading to corrosion through the steam cycle;

- *Loss of efficiency and extra startups:* Fuel usage per kilowatt hour (kWh) of electricity produced will increase as more frequent startups require more fuel to bring units up to full load and as less efficient turndown operations are used more often;
- *Feed System and burn zone issues:* Operating at lower output will affect the solid transport systems used to move coal into the burning zone and will require redesign of the pneumatic system. Operating at the optima mix of air and coal in the burn zone will face similar issues due to changes in gas flow through the feed system; and
- *General/operator error:* Running coal plants outside of normal procedures requires operating the plant more frequently under transient conditions. Variable operations will create increased opportunities for errors.

A thermal plant can be ramped up and down through two cycle types:

i. *On/Off cycles* - this need not actually involve turning the plant off completely. The cycles can be further divided into hot, warm and cold starts, depending on how long the unit is offline and the loss of heat during this period For a hot cycle, the unit is offline for less than 24 hours, for warm the timing is 24–120 hours and a cold cycle occurs over 120 hours after shut down. This, of course, may vary from unit to unit depending on design.

ii. *Load follow cycles* - the increasing and decreasing of generation between maximum and minimum output. Load following can be in either shallow or deep cycles. A shallow load follow reduces generation to the economic minimum level – the lowest level of net production that a generating unit can maintain continuously under normal system conditions. A deep load follow reduces generation to the emergency minimum level or to the lowest theoretical minimum level of operation where the unit is safe, stable and environmentally compliant.

The economic penalties of using these cycles has been summarised by Sloss et.al, (2016) from earlier work by Lefton and Hilleman (2011) as shown in Table 10.8. It is noted that the costs are in 2008 $ and therefore would be considered conservative.

The table indicates quite clearly that costs for cold starts are significantly higher than those for warm and hot starts. The most cost-intensive factors in each type of operation fall within operation and maintenance. These can sometimes be significantly higher than expected.

Curtail or shallow cycling is where coal plants cycle down to their economic minimum generation levels to accommodate for renewables in excess of the levels needed to meet system load. Deep cycles are where coal plants cycle down to their lower emergency minimum levels to accommodate wind and then curtailing in excess of the level needed to meet system load. Curtailing has more certain impacts with costs that are easily quantifiable. Deep cycling, however, creates unpredictable timing of cash expenditure and uncertainty of operating at emergency minimums, increasing risk of damage and outages.

Table 10.8: Typical costs for a 500MW coal-fired plant, in 2008 $ (from Lefton and Hilleman, 2011).

Type of Transient	Cost Category	Cost Estimates ($k)		
		Expected	Low	High
Hot start, 1-23h offline.	Maintenance and capital	53.2	42.6	67.4
	Forced Outage	25.1	20.1	31.7
	Start-up fuel	8.5	5.9	12.7
	Auxiliary power	4.4	3.5	5.5
	Efficiency loss from low and variable load operation	2.1	1.7	3.4
	Water chemistry cost and support	.6	0.5	0.7
	Total cycling cost	93.9	74.3	121.4
Warm start, 24-120h offline.	Maintenance and capital	57.0	45.3	71.0
	Forced Outage	26.9	21.3	33.4
	Start-up fuel	17.8	12.5	23.7
	Auxiliary power	9.4	7.5	11.7
	Efficiency loss from low and variable load operation	2.3	1.9	3.8
	Water chemistry cost and support	2.3	1.8	3.8
	Total cycling cost	115.7	90.3	146.5
Cold start, >120h offline.	Maintenance and capital	85.4	67.7	106.2
	Forced Outage	40.2	31.9	50.0
	Start-up fuel	26.8	18.8	10.2
	Auxiliary power	12.0	9.6	15.0
	Efficiency loss from low and variable load operation	2.6	2.1	4.1
	Water chemistry cost and support	6.9	5.5	8.6
	Total cycling cost	173.9	135.6	194.1
Load follow down to 180MW	Maintenance and capital	8.2	4.8	12.9
	Forced Outage	3.9	2.3	6.1
	Efficiency loss from low and variable load operation	0.5	0.4	0.8
	Mill cycle gas	0.7	8.1	20.9
	Total cycling cost	13.3	8.1	20.9

In order to ramp coal plant output up and down to provide flexible power to balance the grid, changes have to be made in the way the plant operates. In general, this means increasing or decreasing the output by varying fuel input and the number of units/mills in operation at any time. However, ramping unit operation up and down results in rapid changes in temperature and often associated changes in moisture balances through the plant which can cause damage. And so, while the lifetime of some coal plants is being extended, the lifetimes of individual plant components are often reduced, with damage occurring much earlier than predicted for baseload operation. However, even with the increased investment in O&M, increasing plant flexibility can add costs in terms of millions of dollars to the operation of a coal plant, increasing cycling costs by orders of magnitude. The balance of cost and expense must be determined on a plant by plant basis.

Clearly, the increased proportion of VRE in the NEM will result in changing plant operation modes for synchronous generators, requiring greater flexibility to accommodate load following cycles with fast ramping capacities. This is likely to impact plant condition, resulting in increased maintenance costs, forced outages, increased fuel costs and efficiency loss from low and variable load operation. However, these costs from reduced wear and tear are difficult to reliably quantify. For this study, it is assumed that the BESS reduced wear and tear and a causal 5-day unit outage per annum, then based on FY19 forecast earnings before interest, tax, depreciation and amortisation (EBITDA) of ~ $190m; which equates to ~ $0.5m per day for the station (or ~ $0.25m per day per unit) then avoiding one 5-day unit outage per annum would avoid an EBITDA loss of ~$2.5m pa, excluding additional EBITDA loss from direct repair costs and unit restart (eg fuel oil) costs, or excluding recovery of that EBITDA by additional generation at different times of the year.

10.2.5 Ancillary Service Market Development

In response to increasing generation from VRE, the Energy Security Board (ESB) has recently initiated a two-year fit-for-purpose review of the NEM[9]. It is anticipated that the review will incorporate AEMO's assessment of NEM resilience, which is expected to be completed this year. The ESB review is likely to consider international examples of enhanced ancillary service markets developed in response to increasing VRE. Several electricity markets have introduced market arrangements to incentivise the provision of inertia, fast MW and MVAr response, and expanded MW reserve.

Ireland's electricity market is at the forefront of incorporating VRE into the system, with over 20% of annual energy produced by wind farms whose output can exceed 50% of the instantaneous demand. Ireland's original electricity market design had seven ancillary services similar to the NEM's FCAS and voltage control services. In 2016 an additional four services were introduced that included a system inertia service (to limit the rate of change of frequency) and a range of MW ramping services that are used to balance the natural variation in wind generation. In 2018 three additional services were introduced to maintain power system resilience when wind generation exceeded 50% of the instantaneous demand. These services include fast frequency response (2 second response), very fast MW recovery (250ms response) and dynamic reactive response (for large voltage dips).

Conventional thermal generating plant can provide some of the additional services required to maintain system security as VRE increases. These include slow ramping and inertia. Battery technology is ideal for very fast MW and frequency response. It is possible that the ESB review will identify the need to establish new ancillary service arrangements that can best be provided by battery technologies but these new sources of revenue have not been considered for this study.

[9] http://www.coagenergycouncil.gov.au/publications/post-2025-market-design-national-electricity-market-nem

10.3 Business Case Analysis

A business case has been developed, based on the following assumptions:

i. 80MW/40MWh BESS (2 x 40MW/20MWh, ie. one BESS per VPPS unit) with a capital cost of $51.5m, engineering costs $5.15m (total CAPEX $56.7m) and O&M costs of $0.77m pa;

ii. a project life of 10 years to 2030 (ie aligned with current life of VPPS and the nominal 10-year life of the batteries);

iii. RTE degradation of 0.5% pa;

iv. maintaining the VPPS FCAS market size and NSW share of the FCAS market as per calendar year 2018 (ie no growth in the FCAS market);

v. underlying VPPS net FCAS revenues remains unchanged and independent of BESS revenues;

vi. BESS FCAS gross revenues of $7.6m pa corresponding to a FCAS market availability of 30MW diminishing at 0.5% pa for battery degradation;

vii. a $1.2m reduction in coal costs due to decreasing spinning reserve to 5% set point (from current operating policy of 10%;

viii. nil BESS revenues arising from energy arbitrage;

ix. a $2.5m BESS related reduction in operating costs arising from reduced wear and tear;

x. given FCAS expense relates to energy produced and causer pays factors, the associated BESS FCAS expense is expected to be close to zero;

xi. nil contractual mechanism for firming up (ie contracting) FCAS revenues;

xii. a post-tax discount rate of 10% (ie notionally 14.3% pre-tax nominal) on the basis of a merchant revenue business case (with zero gearing).

The high-level cash flows are shown in Table 10.9.

Table 10.9: BESS business case cash flows.

Year		0	1	2	3	4	5	6	7	8	9	10
Revenue ($m, nominal)												
FCAS (BESS Actual)	$m		$7.6	$7.6	$7.5	$7.5	$7.4	$7.4	$7.4	$7.3	$7.3	$7.3
Reduced Coal Costs	$m		$1.2	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2
Reduced Wear	$m		$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5
Total	$m		$11.3	$11.3	$11.2	$11.2	$11.1	$11.1	$11.1	$11.0	$11.0	$11.0
Expenses ($m, nominal)												
FCAS (Causer Pay)	$m		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
O&M	$m		$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8
Total	$m		$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8
Cash Flow	$m	-$56.7	$10.5	$10.5	$10.5	$10.4	$10.4	$10.3	$10.3	$10.3	$10.2	$10.2
Discount Rate (pre-tax)		14.29%										
NPV	$m	-$2.6										

As shown, the business case has a negative NPV at -$2.6m.

A further sensitivity analysis was completed as summarised in Table 10.10.

Table 10.10: Sensitivity Analysis.

	CAPEX ($m)	FCAS Revenue ($m)	Reduced Coal Costs ($m)	Reduced Wear and Tear ($m)	NPV ($m)
CAPEX +30%	74.0	7.6	1.2	2.50	-20.9
CAPEX -30 %	40.0	7.6	1.2	2.50	8.8
Reduced wear/tear (x1.5)	56.7	7.6	1.2	3.75	3.0
FCAS Revenues +10%	56.7	8.4	1.2	2.50	0.9
FCAS Revenues -10%	56.7	6.9	1.2	2.50	-5.7

Capital expenditure has a large impact on project feasibility and the predicted future reduction in battery costs would assist the financial evaluation of the project. FCAS revenues have an effect on the analysis and remain a high risk to the business case due to the uncertain depth of the market, in particular, the cumulative impact on existing participant market share remains speculative as multiple battery installations enter the market. The reduction in revenue could be equated to a change in MLF by +/-0.1 which results in a +/- $3m in NPV which represents the difference in installing the BESS at VPSS compared with a regional area. Additionally, the inclusion of an additional 5-day maintenance outage avoided would benefit the business case but these costs are difficult to confidently or reliably assess as previously detailed.

The business case is sensitive to the cost of equity and selected discount rate. The discount rate is the rate of return used to discount future cash flows back to their present value. The rate represents a company's weighted average cost of capital (WACC), required rate of return or the hurdle rate that investors expect to earn relative to the risk of the investment. A higher discount rate implies greater uncertainty and the lower the present value of future cash flows. The relatively short project life, risks associated with estimating future market share of FCAS revenues and general volatility of the wholesale spot market create sufficient uncertainty in the project to warrant a conservative discount rate of 10% post-tax. The RBA and Deloitte have noted that Australian firms tend to have high 'hurdle rates' of return that are often well above the cost of capital and do not change very often[10]. Hurdle rate is often set above the cost of capital to account for uncertainty about the cash flow projections and to improve the chances that investments add value to the firm on a risk-adjusted basis. A NPV sensitivity analysis with varying discount rates is shown in Figure 10.3 and predicts a NPV break-even point at around 9% post-tax nominal for a 10 year project.

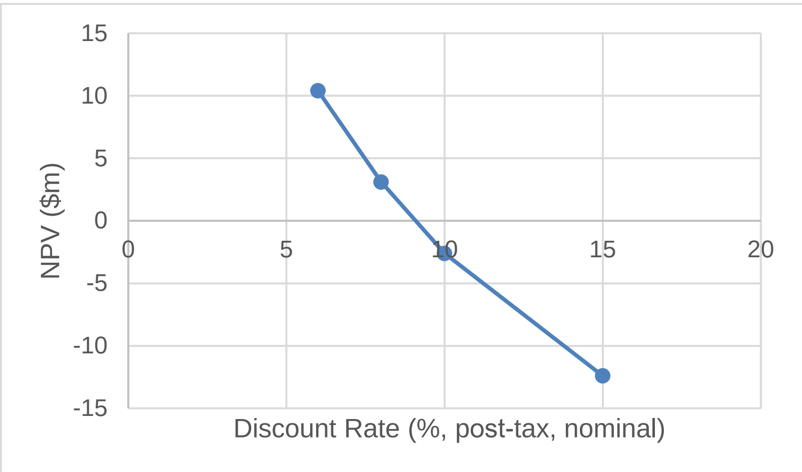


Figure 10.13: NPV sensitivity analysis for changes in discount rate.

[10] RBA, Bulletin - Firms' investment decisions and interest rates, June quarter 2015; Deloitte, CFO Survey: Beyond the clouds, Q3 2014, p. 19, Chart 17: Frequency of hurdle rate updates.

A further sensitivity analysis was completed for the project life. Figure 10.14 shows the effect of project duration on the project NPV for different discount rates.

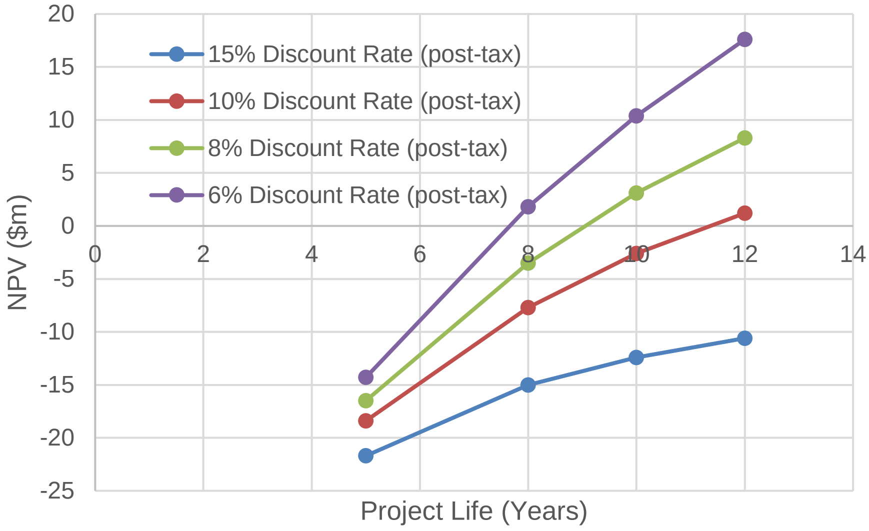


Figure 10.14: Effect of project duration on the project NPV for different discount rates.

The project duration is constrained by the closure of VPPS in 2029-30. This timeframe corresponds well with the expected battery life and commercial warranties offered by suppliers for round trip efficiency and output degradation performance. For a 20-25 year project, the battery pack would be replaced at 10-years whereas the balance of plant equipment would likely last the extended project life if properly maintained. The project duration sensitivity analysis also considered a 12-year project life with the assumption that the round-trip degradation continued to decrease at 0.5% pa beyond the 10-year warranty period. The analysis shows that a project duration of less than 10 years remains NPV negative for the majority of the discount rates investigated. Extending the project duration to 12 years improves the return but relies on the assumption of continued performance outside of normal warranty provisions of the battery pack.

There are several other potential upsides for revenue streams that have not been considered as part of the financial evaluation including:

i. Residual value of assets at the end of 10-year operational period;
ii. Growth in FCAS market depth due to Liddell closure or increased VRE installed; and
iii. Potential for spinning reserve (thermal) to reduce to zero and operate the units with valve wide open.

This analysis has illustrated that the cost for large scale energy storage has generally been shown to outweigh the anticipated revenues from this BESS configuration at this time. Reductions in battery capital costs would assist the business case but the depth of the FCAS market revenues remains a risk. Without additional market mechanisms to value and support the provision of energy capacity or spinning reserve it is unlikely that this configuration of a BESS and synchronous generator will be realized in the NEM.

11.0 Life-Cycle Analysis

A high-level life-cycle analysis (LCA) was completed for the BESS installation proposed in this study. The LCA considers the energy required in the manufacture of the lithium-ion battery as well as the energy balance during the operation of the facility and end-of-life processes. Figure 11.1 shows the proposed LCA framework.

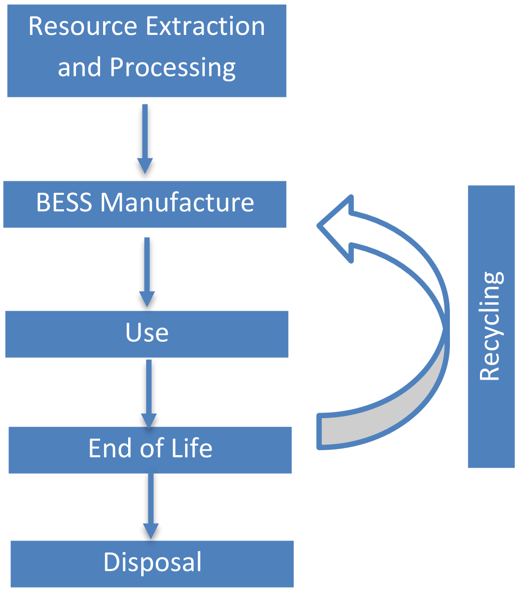


Figure 11.1: Proposed BESS LCA framework.

The energy requirements and associated emissions for the resource extraction, manufacture and recycling of Li-Ion battery have been collated from a range of different sources and summarised in Table 11.1. Previous studies have highlighted the raw material extraction and processing of materials and the manufacturing process as the most energy intensive stages of the process with the level of reuse of materials at the end of life significantly impacting the overall LCA energy balance.

It is noted that there are well documented issues regarding the extraction of materials, minerals processing and component manufacture relating to exploitation of the workforce and poor environmental management standards. Typically, these stages are labour and energy intensive and management of these issues will be key factors in the social acceptance of battery technology for energy storage. The socio-economic costs of the resource extraction and processing of materials for battery manufacturing are not considered in this analysis.

There is great potential to influence the overall energy balance by legislative actions, especially in the area of recycling. Today there is limited economic incentive for recycling of lithium-ion batteries, but by placing the correct requirements on the end of life handling we can create this incentive. Coupling these types of actions with support for technology development both in battery production processes and battery recycling can ensure more a sustainable battery life cycle.

Table 11.1: Key process stages in the LCA for lithium-ion batteries.

Process	Material Input	Energy Use and Waste Emissions	Energy/Emission Estimate MJ/kWh	Energy/Emission Estimate kg CO_2e/kWh
Raw material extraction[1]	Copper, lithium, aluminium, steel and raw materials for anode, cathode, binder (polymer), electrolyte and separator (membrane).	Energy from power plant (fossil fuel/renewable), diesel fueled equipment, Land degradation, water pollution, CO_2 emissions.	670	60
Material Processing[1]	Lithium salts, organic solvent for electrolyte, anode collector.	Energy from power plant (fossil fuel/renewable), CO_2 emissions (depends on energy provider).		
Component manufacturing[2]	Anode, cathode, electrolyte, separator, casing.	Energy from power plant (fossil fuel/renewable), CO_2 emissions (depends on energy provider).	350 - 650	60
Assembly, packaging and distribution[2]	Battery cell and casing.	Energy from power plant (fossil fuel/renewable), CO_2 emissions (depends on energy provider).		
Installation and Use	Battery cells, BOP	Installation is not energy intensive, electricity for charging cycle (fossil fuel/renewable), CO_2 emissions (depends on energy provider).	See following analysis	
End-of-life recycling[3]	Metal recovery.	Energy from power plant for material processing, (fossil fuel/renewable).	148	11
End-of-life disposal[3]	Non-hazardous wastes to landfill, incineration of hazardous materials and remainder of reclaimed materials recycled into manufacture process.	Energy from power plant for material incineration, (fossil fuel/renewable), fossil fuel for transport to disposal (landfill).	-168	-15

1. "Energy analysis of batteries in photovoltaic systems. Part I: Performance and energy requirements" Carl Johan Rydh et. al, 2005.
2. "The Life Cycle energy consumption and greenhouse gas emissions from lithium ion batteries" IVL Swedish Environmental Research Institute 2017.
3. "Prospective LCA of the production and EoL recycling of a novel type of Li-ion battery for electric vehicles" Marco Raugei*, Patricia Winfield.

For this study, it is assumed that the energy and emissions generated for the manufacture and delivery of a 80MW/40MWh battery would be similar regardless of where the BESS was located. That is, the cradle to gate LCA costs for the BESS are the same whether the BESS is installed:

i. co-located with a renewable energy generator;

ii. co-located with a fossil fuel generator; or

iii. grid connected.

If end of life BESS recycling and disposal costs are also considered the same for each location, then the difference in life cycle costs is the energy balance during the charging and discharging cycles of the BESS life assuming the operational costs and RTE are the same for all locations.

A comparison of the operational emissions profile for the following configurations was completed using the following assumptions:

i. 80MW/40MWh BESS that operates 300 annual cycles to 80% DoD for 10 years (ie. 300 cycles x 32MWh x 10 years = 96 GWh);

ii. Balance of plant losses (eg. inverter/transformer and transmission losses, auxillary load) is included in the DoD availability;

iii. Average grid average emissions intensity 0.74 tCO_2-e/MWh (AEMO Quarterly Energy Dynamics, Q4 2019); and

iv. VPPS carbon intensity 0.91 tCO2-e/MWh (Annual Report, 2019).

Table 11.2 shows the carbon dioxide emissions difference for each configuration. It is important to note that similar to pumped hydro energy storage, the charge and discharge cycle of a BESS will be a net negative energy process due to the round-trip efficiency regardless of the charging source. The operation cycle produces zero CO_2 emissions if the BESS is charged with solar or wind energy although the process remains net energy negative.

Table 11.2: LCA Operation CO_2 emissions for lithium-ion batteries installed at different locations.

Configuration	Emissions tCO_2-e/MWh		10-yr operation (net tCO_2)
	Charging Cycle	Discharging Cycle	
Co-located with Solar	0.000	0.000	0
Co-located at VPPS	0.910	1.001	9,600
Grid Connected	0.740	0.810	6,720

As shown in Section 10.2.3, the co-location of a BESS behind the meter at VPPS would result in 65,000t pa reduction in CO_2 emissions as a result of reduced coal usage. This corresponds to an overall emissions reduction of approximately 1% on a station basis.

12.0 Risk Analysis

The high-level risk register for the project is included as Table 12.1 and is based on a 5x5 risk matrix.

		Levels of Consequence				
Consequence Type		**1. Insignificant**	**2. Minor**	**3. Moderate**	**4. Major**	**5. Catastrophic**
Harm to People		First aid case / Exposure to minor health risk	Medical treatment / Exposure to major health risk	Loss time injury / Reversible impact on health	Single fatality or loss of quality of life / Irreversible impact on health	Multiple fatalities / Impact on health ultimately fatal
Operational Secession		Project disruption or shut down for less than 1 week	Project disruption or shut down for between 1 week and 1 month	Project disruption or shut down between 1 month and 6 months	Project disruption or shut down between 6 months and 12 months	Total shut down or divestment of project
Consequential Financial Loss		Loss of less than $100k	Loss of between $100k and $500k	Loss of between $500k and $2m	Loss of between $2m and $6.5 million	Loss of over $6.5million
Environmental Impact		Minimal environmental harm – managed in house	Material environmental harm – controllable in house	Serious environmental harm – some external impact	Major environmental harm – regional impact	Extreme environmental harm – state wide impact
Legal & Regulatory		Low level legal issue	Minor legal issue; non compliance and breaches of the law	Breeches of law; investigation, penalty, reported, prosecution	Major breech of the law; considerable prosecution and penalty	Significant penalties & prosecutions. Multiple law suits & jail terms
Reputation and Community		Slight impact - public awareness may exist but no public concern	Limited impact - local public concern	Considerable impact - regional public concern	National impact - national public concern	International impact - international public attention
Levels of Likelihood	**Descriptive**	**Risk Rating**				
5. Almost Certain	Expected to occur frequently; in order of one or more times per quarter	**11 (M)**	**16 (H)**	**20 (H)**	**23 (Ex)**	**25 (Ex)**
4. Likely	Expected to occur but less frequently; occurs in order of less than twice per year	**7 (M)**	**12 (M)**	**17 (H)**	**21 (Ex)**	**24 (Ex)**
3. Possible	Expected to occur at some point within the next 3 years	**4 (L)**	**8 (M)**	**13 (H)**	**18 (H)**	**22 (Ex)**
2. Unlikely	Could occur within the next 3 years but not deemed likely	**2 (L)**	**5 (L)**	**9 (M)**	**14 (H)**	**19 (H)**
1. Rare	Although still possible it is not expected to occur within the next 3 years	**1 (L)**	**3 (L)**	**6 (M)**	**10 (M)**	**15 (H)**

Interpretation of Risk Level

Risk Rating	**Risk Level**	**Required action**
21 to 25	**(Ex) – Extreme**	Requires an immediate response / action plan with monthly progress reporting to the Project risk committee and quarterly progress reporting to the Project Steering Committee
13 to 20	**(H) – High**	Requires an appropriate response / action plan with monthly progress reporting to the Project Risk Committee.
6 to 12	**(M) – Medium**	Actively monitor / manage where practical
1 to 5	**(L) – Low**	Monitor & manage as appropriate

Table 12.1: Risk Register.

Risk Identification					Inherent Risk Assessment				Residual Risk Assessment			
Reference	Contextual Nature of Risk	Identified Risk Scenario	Most likely causes	Primary Consequence Type	Current Controls in place to mitigate this Risk Scenario	Consequence of Occurrence	Likelihood of Occurrence	Inherent Risk Rating	Mitigational response required to reduce the Inherent Likelihood / Consequence	Consequence of Occurrence	Likelihood of Occurrence	Revised Residual Risk Rating
1	Governance & oversight risk	Project team and/or project contractors are not managing the WHS&E risk appropriately	> Insufficient systems (procurement/contracting and on site) in place to ensure safety of personnel	Harm to people	> Delta's existing procurement and WH&S systems > Ensure project contractors have demonstrated WH&S processes in place that are third-party verified.	4. Major	2. Unlikely		> Project specific WH&S plan interfacing with Delta programs >WH&S plan to include an auditing program	4. Major	1. Rare	
2	Governance & oversight risk	Negative community perception/response to the project	>We don't effectively communicate the ultimate benefits of the projects > Activist groups target development at coal fired station	Reputation and Community	> Delta's existing communication strategy > Project stakeholder engagement plan > Communication protocols are adhered to > Early community engagement	4. Major	4. Likely		> Project specific communication strategy roll-out	3. Moderate	3. Possible	
3	Legal, regulatory or compliance risk	Difficulties associated with achieving planning and regulatory approvals (eg. network connection agreement) leading to delays in project timeframes	> Unclear planning approval process > Project approval delays from NSW Department of Planning and Environment (DPE) or network operators > Scrutiny of application due to the high profile nature and public interest in the project > Environmental impacts cannot be assessed, demonstrated or mitigated	Legal & Regulatory	> Brownfield development site nominated to minimise environmental impact > Modification of existing network connection agreement > Early engagement with key regulators > Develop a legal plan to identify impediments > Develop approval risk assessment > Preliminary environmental investigations planned > Choosing appropriate consultant with track record > Create planning approvals pathway	3. Moderate	3. Possible		> Legal review of development pathway completed > Manage relationship with regulators/stakeholders > Early project specific communication strategy roll-out	3. Moderate	2. Unlikely	
4	Governance & oversight risk	Project capital cost obtained at the end of feasibility stage is unfundable	> Insufficient revenue streams to achieve return on capital investment > FX risks	Operational Cessation	> Maintain watching brief on current equipment capital cost	5.Catastrophic	3. Possible		> Update cost estimate with market changes > Develop a procurement plan to ensure competitive tension during capital raising > Foster supply partnerships (ongoing) > Investigation into revenue stack	4. Major	2. Unlikely	
5	Governance & oversight risk	Feasibility study budget inadequately managed	> Poor procurement management process > Not having proper financial controls in place	Consequential Financial Loss	> Funding agreement with CI NSW > Delta financial and procurement policy > Detailed budget and timetable records > Financial reporting regularly presented to funders > Request for all vendors to regularly report financial position, including stringent variation request processes.	2. Minor	3. Possible		> Track use of project costs to completion and contingency budget > Maintain competative tension between OEMs	2. Minor	2. Unlikely	
6	Legal, regulatory or compliance risk	Non-compliant plant and materials installed	> Correct standards not being used > Overseas components not meeting national standards > Wilful non-compliance by supplier	Consequential Financial Loss	> EPC contract with appropriate specifications and quality processes > Use Tier1 EPC contractors	4. Major	3. Possible		> QA/QC processes for products and manufacturing processes > Routine inspections	4. Major	2. Unlikely	
7	Operational risk	Integration issues with host power station resulting in damage or additional costs	> Host power station compatability issues with BESS technology > Significant modification may be required at host power station	Operational Cessation	> Use experienced EPC contractors > Early engagement with key stakeholders and engineering/asset management teams > Delta procedure POPAM01 - Asset Management Risk Review	4. Major	3. Possible		> Risk review concept design and integration options > Control system and operation strategy review > Protection and control studies > HAZOP detailed design	4. Major	1. Rare	

13.0 Conclusions and Recommendations

13.1 Project Benefits

The key benefits identified for a BESS project at VPPS are listed below, including:

i. *Reduced emissions intensity at Vales Point Power Station*

The BESS will contribute to a reduction in greenhouse gas emissions from VPPS by reducing losses in the turbo-generator by minimising plant ramping and cycling operations. Efficiency gains are also expected from unit heat rate improvement and a reduction of throttling losses. The co-location of a BESS behind the meter at VPPS would result in 65,000t pa reduction in CO_2 emissions as a result of reduced coal usage which corresponds to an overall emissions reduction of approximately 1%.

ii. *Enhanced ability of the network to accommodate increases in variable renewable energy*

The Project, by enhancing stabilisation capability in the NEM, will facilitate the expansion of large and small-scale intermittent generation capacities as NSW and Australia pursues achievement of emission reduction targets.

iii. *Identifying a pathway for improved reliability of the existing coal-fired fleet*

AEMO has flagged negative impacts on the market and system stability from falling availabilities from coal fired power stations. If, as expected, the high level of frequency support being provided by coal-fired units is impacting their availability, then relieving them of this activity would deliver improved availability across the NSW fleet.

iv. *No increase in transmission connection at Vales Point Power Station*

The unique concept of this project is that the AEMO registered VPPS generating unit capacity will not be increased. The battery energy will only be discharged within the overall capability of the existing unit generators as if the battery were not installed. The battery and inverter set will essentially be a control system enhancement rather than an additional generator. Whilst the project represents an alteration to the existing units, there ought to be no need to increase the existing capacities of the connections to the network. This focus on process efficiency improvements confirms that there is no intention to increase the use of coal as a result of this project.

v. *Use of a brownfield location*

The economic advantages of the proposal can be readily observed in the realisation that a larger BESS installed at an existing power station will produce a lower cost impact to the market per MWh than would be the case should many smaller BESS be installed at many different green field sites all over the NEM. The lower deployment cost of the proposed scale of system and the readily available land and existing grid connection makes the project resource efficient. Additionally, it was demonstrated that a difference in MLF by +/-0.1 which results in a +/- $3m in NPV between installation at VPPS compared with a weak area of the network.

vi. *Transferable technology*

Once proven, similar units could be installed at other conventional power stations to complement the remaining synchronous generation fleet and provide added support for additional intermittent capacity. This would be a world-leading and extensive implementation of this technology, which has the potential to result in increased technical capability for NSW and position the State as a showcase for the technology concept.

It is noted that equivalent FCAS market support services could be provided by a free-standing BESS installed elsewhere in the network or a BESS co-located with renewable energy generation. This report highlights the advantages of a behind-the-meter BESS installation at VPPS including the opportunity to reduce the emissions from existing coal-fired generators and identifies an efficiency improvement from reduced equipment wear and tear from a reduction in the load cycling and ramping of the units. These additional benefits would not be achieved by a BESS installed at greenfield locations within the network.

13.2 Recommendations

This feasibility study has demonstrated that the integration of a BESS with an existing synchronous generator is technically feasible and would not compromise the co-located thermal unit or network. Furthermore, the BESS has been shown to support the exiting generator during network fault conditions by providing reactive power for regulating the grid voltage. Unfortunately, the cost for large scale energy storage has been shown to outweigh the anticipated revenues from this BESS configuration during the relatively short 10-year project life. Without additional market mechanisms to value and support the provision of energy capacity or spinning reserve it is unlikely that this configuration of a BESS and synchronous generator will be realized in the NEM.

Alternatively, the installation of a demonstration project at VPPS operationally supported by Delta, with capital funded by Coal Innovation NSW, would promote development of the technology and provide real scale investigation of the proposed business model. If proven successful, this demonstration project would provide sufficient knowledge sharing for a broader roll-out of the technology across all coal-fired units in NSW.

14.0 Attachments

Attachment A – PSCAD Model Test Report

Attachment B – PSSE Model Test Report

Vales Point Battery Energy Storage System

PSCAD Model Test Report

Delta Electricity

January 29, 2020

Level 13, 333 Collins Street

Melbourne VIC

Australia 3000

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Disclaimer

411010-15983-Vales Point Battery Energy Storage System:PSCAD Model Test Report

Rev	Description	Author	Review	Advisian approval	Date
A	First issue	Vishnu M.	Ayaz C.	Bruce M.	January 29, 2020

Contents

Chapter 1

Introduction

1.1 Context

Delta Electricity is exploring the possibility of installing a Battery Energy Storage System (BESS) in their existing Vales point power station. The main drive for installing BESS is to provide spinning reserve, thereby allows the steam turbine to operate with its steam valve fully open. That is, BESS system will provide synthetic inertia, and this will result in a change in the primary frequency response provision from Vales point power station.

Advisian has been engaged by Delta Electricity to conduct a preliminary analysis to identify if there would be any adverse interaction between the BESS and the existing synchronous generator. In this report, Advisian is assessing the total plant response during various faults. As Delta team has not provided the plant model to conduct the analysis, Advisian has developed vales point power station model (in PSSE and PSCAD) and used an inhouse BESS model for performing the analysis.

1.2 Introduction

This section provides a brief introduction to the Vales Point Battery Energy Storage System (VP-BESS). An overview of the connection point, associated connecting equipments, and the assumption made for modelling the system is also provided here.

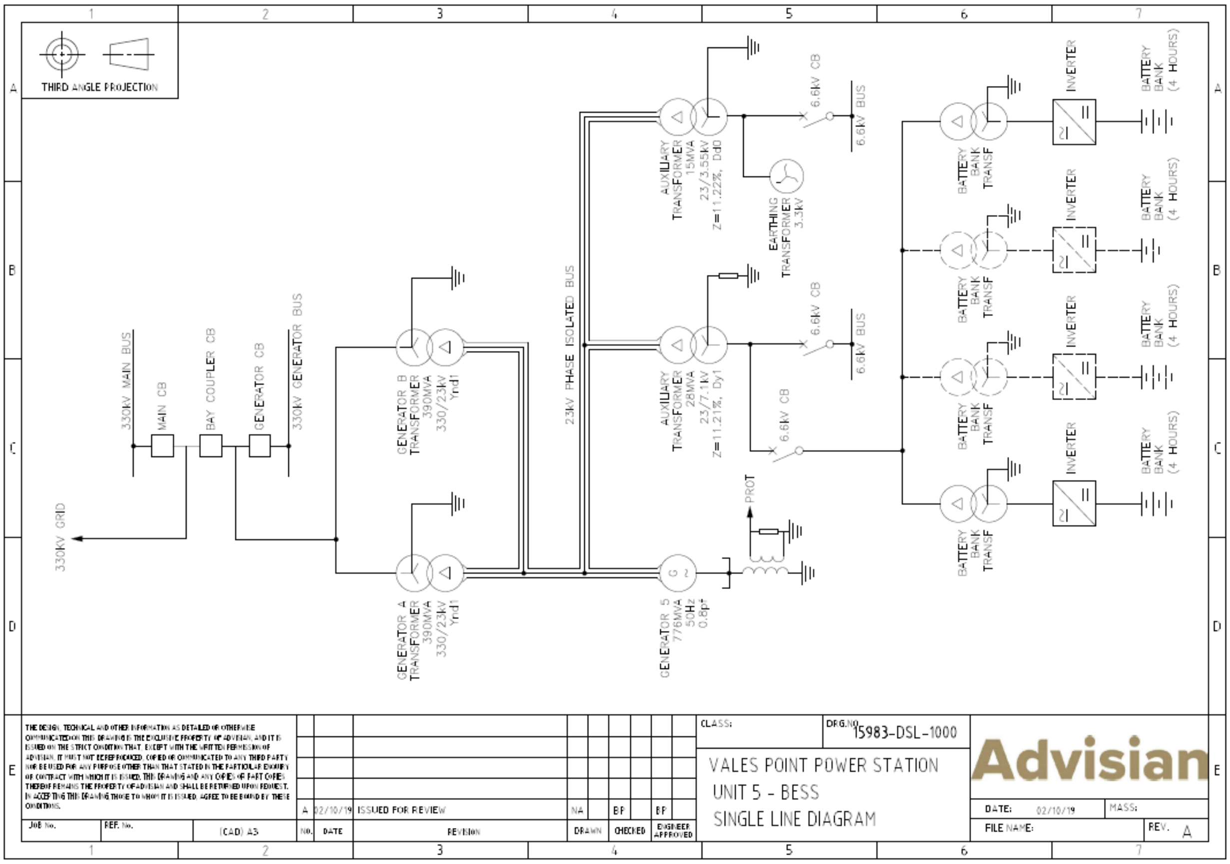

Figure 1.1: Single line diagram of Vales point station with BESS

1.2.1 Broad description of the generating system

The Vales point Battery Energy Storage System (later Vales Point" or VP-BESS") has a total capacity of 40 MW and will be connected to the National Electricity Market via TransGrids 330 kV network. The purpose of the VP-BESS is to provide synthetic inertia support for primary frequency response. The VP-BESS considered in this analysis comprises of 24 battery units with a power rating of 1.872 MVA each. The battery operates at a terminal voltage of 0.48 kV AC. Battery unit transformers connect to each unit, step up the terminal voltage to 6.6 kV. The batteries are then connected to one of the auxiliary transformers in the generating station. which steps up the voltage to 23 kV and connects to the generator bus. Proposed single diagram of the system is shown in Fig. 1.1

Chapter 2

System Model

2.1 Introduction

This section provides an overview on the modelling details and the assumptions that we made for creating the dynamic model in PSSE and PSCAD.

Delta electricity has not provided any model (both PSSE and PSCAD) to Advisian to conduct the study. Advisian developed a PSSE model and used the dynamic files from AEMO to represent the generating station in PSSE. However, the dynamic files from AEMO does not have the turbine governor model and hence Advisian used a standard PSSE library model to represent the turbine governor in PSSE. PSSE model is hence an closer approximation of the actual Vales point power station.

2.1.1 PSCAD Model

Based on the PSSE model, Advisian has developed a PSCAD model from scratch to represent the Vales point generating station in PSCAD. Fig 2.1 shows the PSCAD representation of the Vales point station. It should be pointed out here that Unit-6 is not modelled in this study.

Since the updated control block diagrams for representing AVR, PSS, UEL, OEL are not provided by Delta electricity, Advisian used standards PSCAD library models to represent the AVR and PSS in the model and tuned their performance to match with the PSSE model. Advisian modeled the turbine governor model based on the block diagram received as shown in Fig 2.2. Synchronous

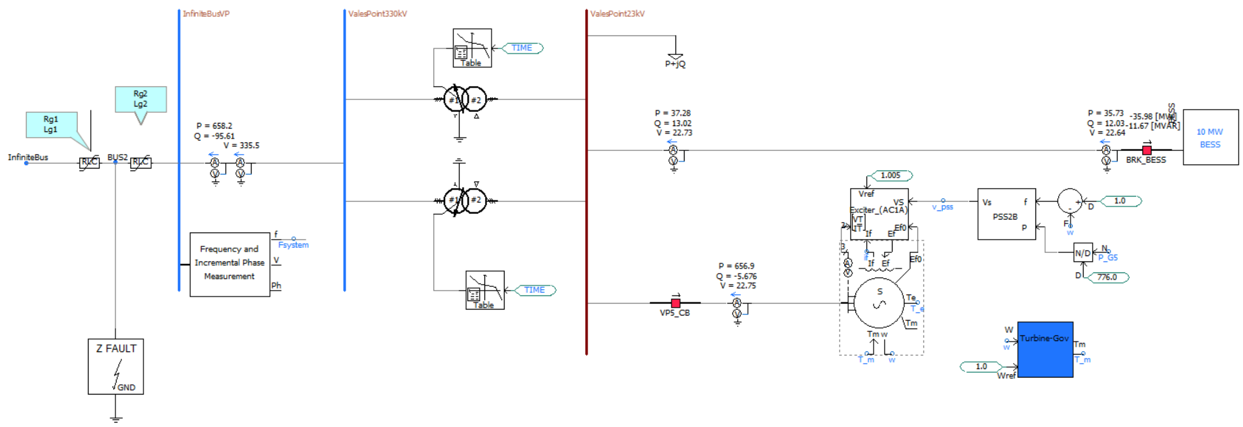

Figure 2.1: PSCAD representation of Vales Point station

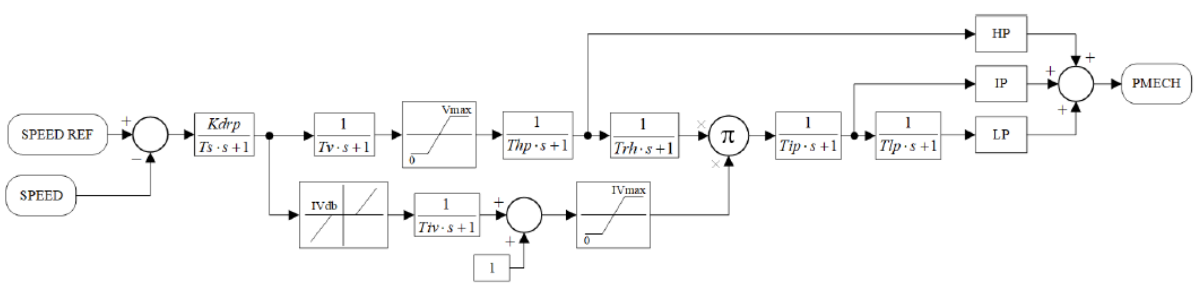

Figure 2.2: Turbine governor model

generator (SG) used is an exact replica of the PSSE model.

Advisian used identical model for representing BESS in both PSSE and PSCAD. Here, the BESS is connected to the 23-kV generator bus. The BESS is comprised of a battery and an inverter. The battery is modeled using algebraic and dynamic equations of battery energy, state of charge. A power plant controller is developed to control active and reactive power references to the battery inverter model. The active power controller is responsible for providing the active power reference to the inverter. Reactive power controller is set to operate in voltage droop control mode. The controller will compare the actual bus voltage with a set point value to provide reactive power command to the inverter controller.

Chapter 3

Scope of the Assessment

3.1 Introduction

The main aim of this report is to conduct a preliminary analysis to identify if there is any unwanted interaction between the BESS system and the existing synchronous generator at the Vales Point substation. For this purpose, the system is subjected to symmetrical and unsymmetrical faults at the POC to assess the BESS and SG responses for different operating points and Short circuit Ratios (SCR). Studies are repeated for 4 different points of the SG capability curve and for SCR ratio 4 and 10. Following initial operating points are considered in this report.

- Point 1 (P=Pmax, Q=Zero)
- Point 2 (P=Pmax, Q=Qmax)
- Point 3 (P=Pmax, Q=Qmin)
- Point 4 (P=Pmin, Q=Zero)

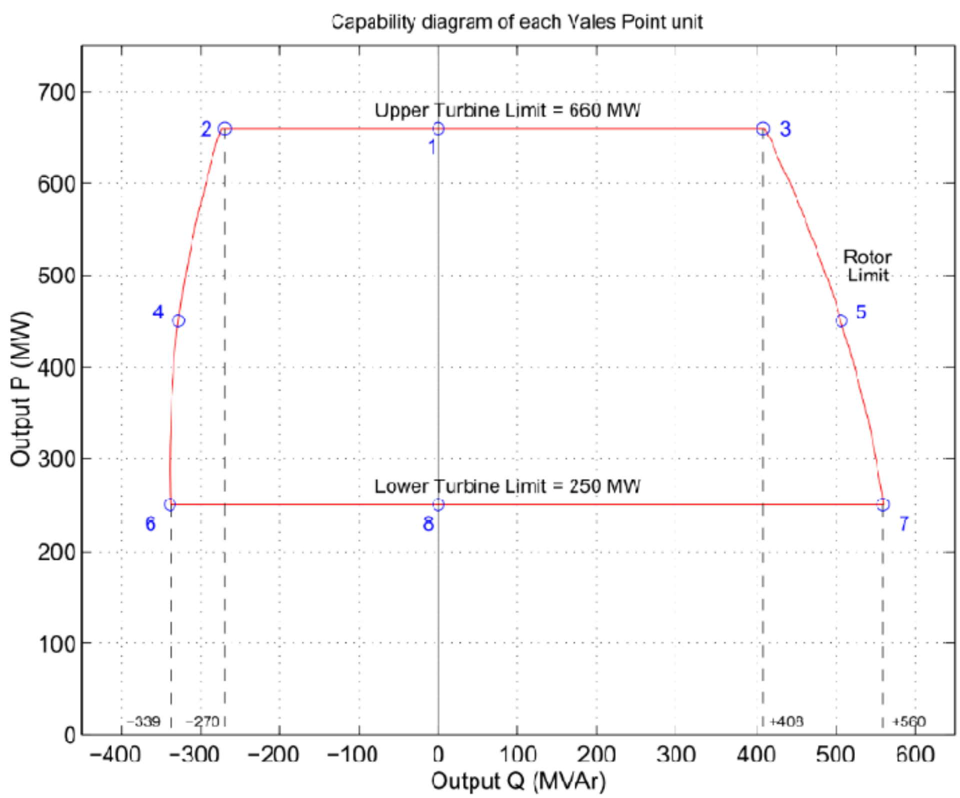

Figure 9: Generator capability diagram of VPPS Unit 5 & 6 [2]

Figure 3.1: Capability diagram of Vales point Unit-5

Chapter 4

Simulation Results

4.1 Benchmarking with PSSE model

Since the PSSE model is a closer representation of the actual station, Advisian used PSSE model to Benchmark the performance of the PSCAD model. Benchmarking is done for 3 different operating point.

4.1.1 Point-1 (P=Pmax, Q=Zero)

The initial operating point of Synchronous generator is fixed at P=660 MW and Q= 0 MVAR. BESS is set to operate at P= 36 MW and Q = 0 MVAR. At t=7 seconds, a 3 Phase to ground fault with fault impedance of 1 ohm and fault duration of 120ms is applied at the point of connection as shown in Fig. 3.1. Corresponding results are shown in Fig. 4.1

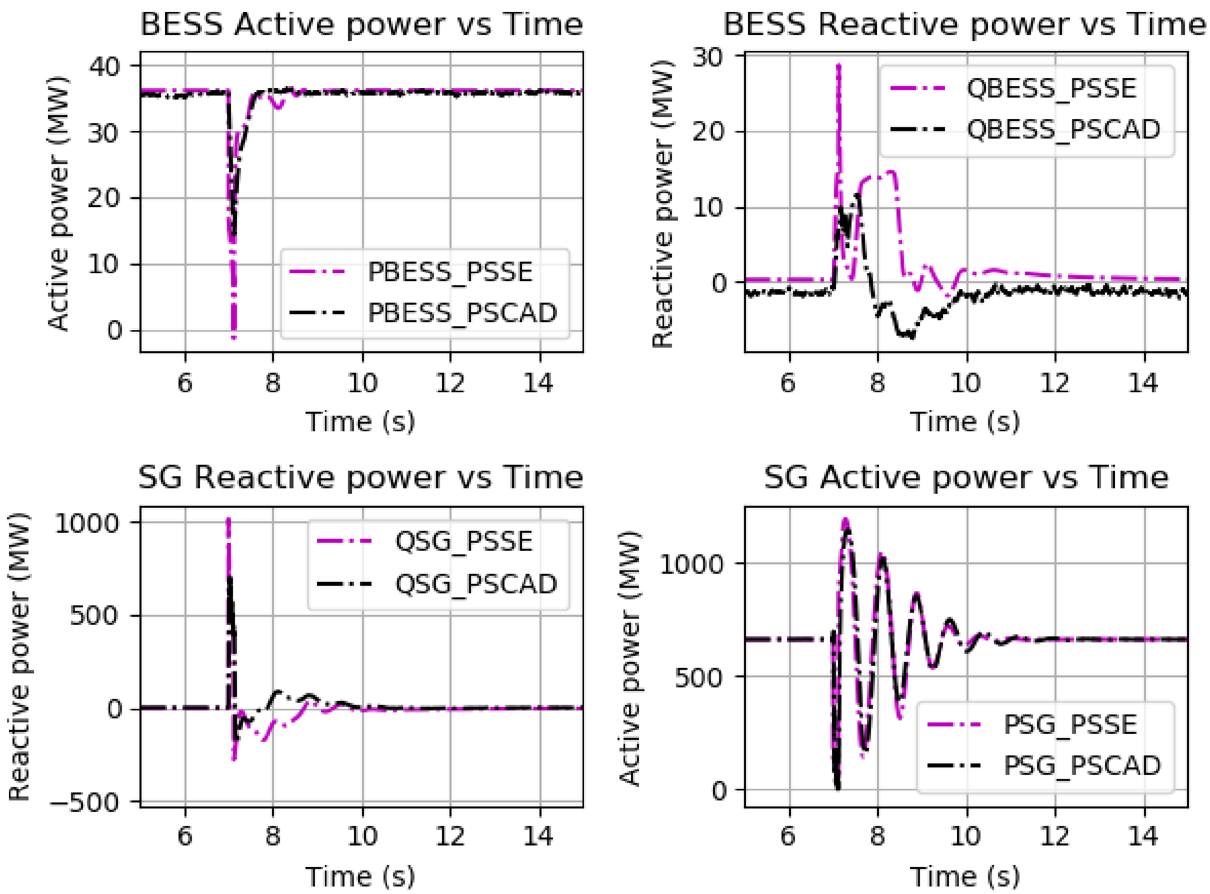

Figure 4.1: PSCAD vs PSSE response for a 3Ph-Gnd fault at POC for point-1

It is observed that the active power response of the Synchronous generator and BESS system is aligning very closely. However, slight deviation in the transient response of SG reactive power is observed in both software. PSCAD response is bit faster and reached pre-fault value slightly faster compared to the PSSE model. The difference is because of the fact that the excitation system model in PSCAD is an approximate representation of that in PSSE. Response can be optimized if Delta team can provide the modelling details of SG excitation system and associated controllers.

4.1.2 Point-2 (P=Pmax, Q=Qmin)

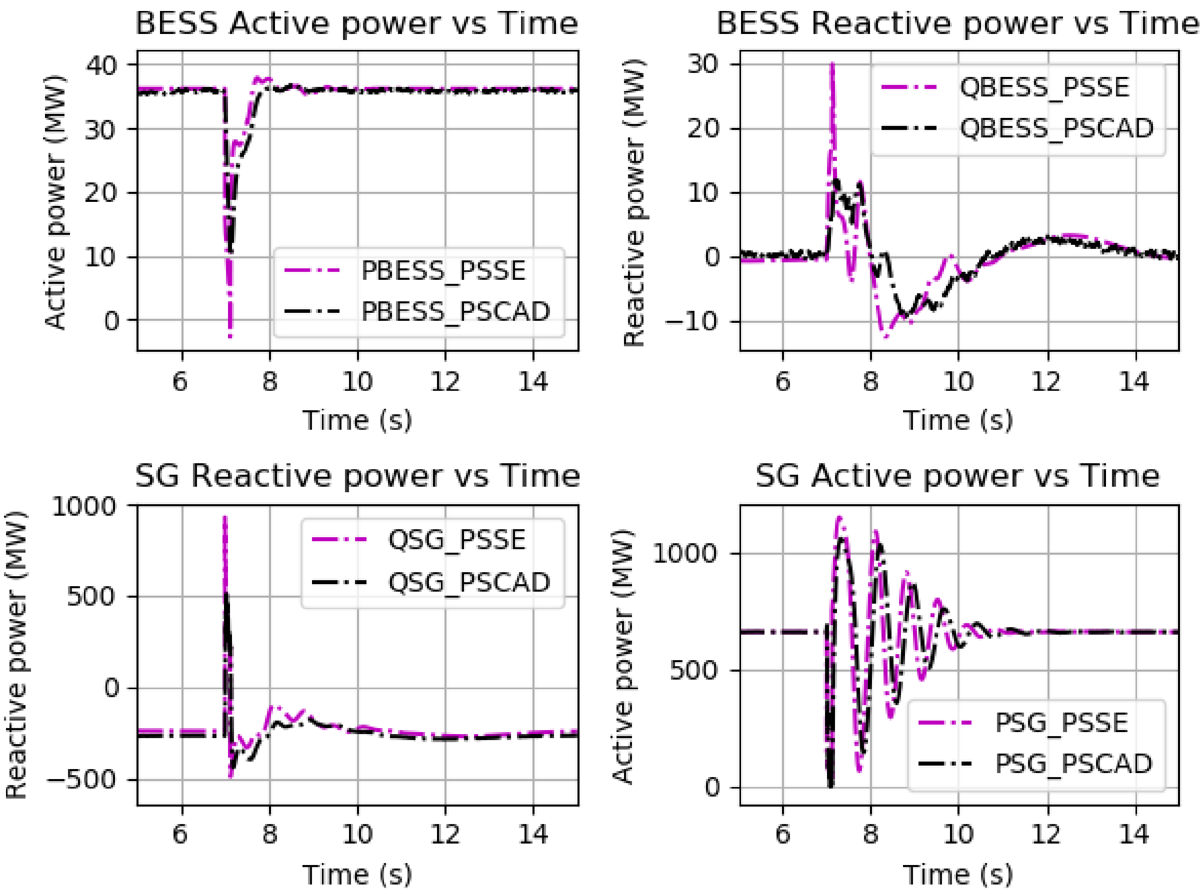

Figure 4.2: PSCAD vs PSSE response for a 3Ph-Gnd fault at POC for point-2

4.1.3 Point-3 (P=Pmin, Q=Zero)

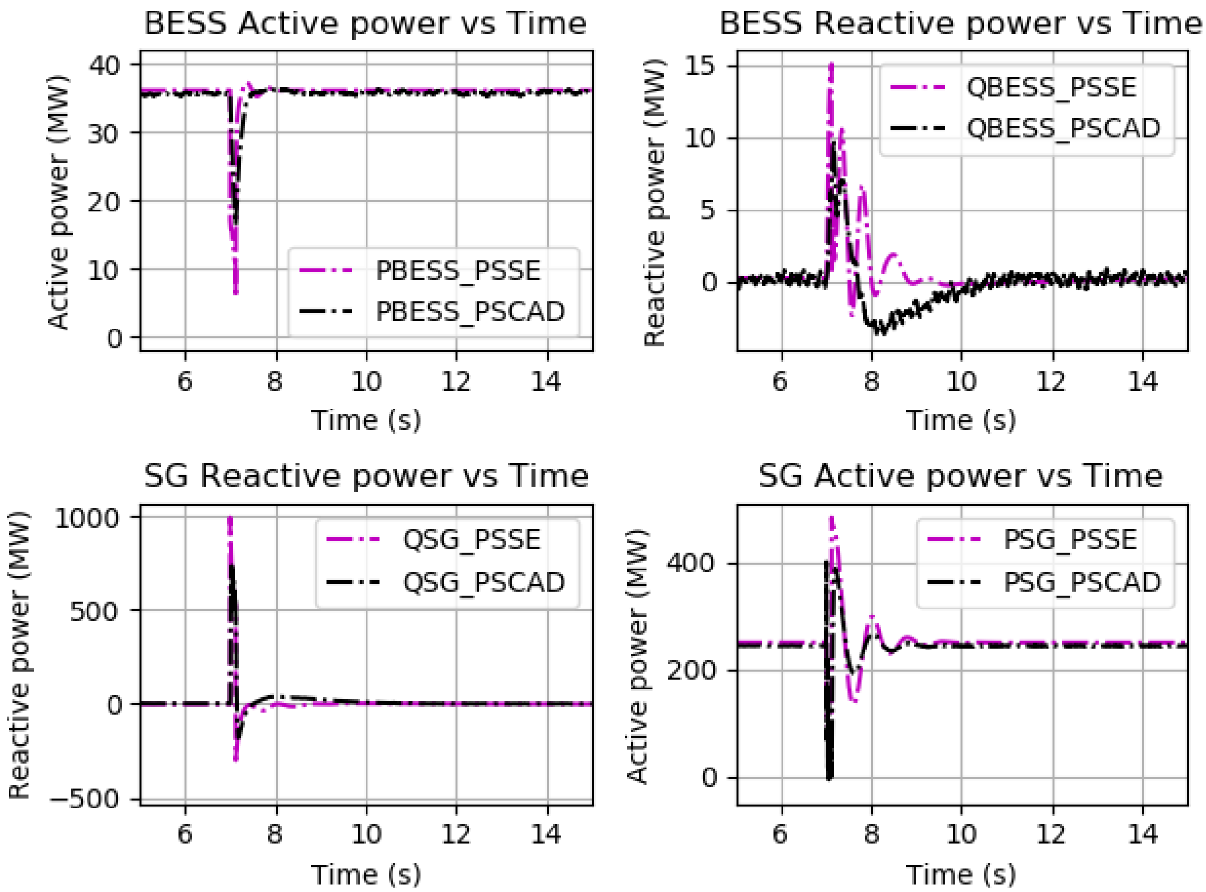

Figure 4.3: PSCAD vs PSSE response for a 3Ph-Gnd fault at POC for point-2

4.2 Fault Analysis

In the previous section, it is shown that the PSCAD model response is aligning closely with the PSSE model. Hence, it would be reasonable to consider PSCAD model to conduct fault studies for analysing the BESS and SG response.

This section provides the simulation result of fault analysis conducted for various generator operating points and short circuit level of the grid. We conduct the fault studies for 4 different operating points with varying SCR ratio for the Grid. Lowest SCR considered for the study is 4 and highest is 10.

4.2.1 3phfault-PmaxQzero-SCR-4

Table 4.1: Test parameters for Case-3phfault-PmaxQzero-SCR-4

Initial Point	SCR	Fault Type	Fault Impedance (Ω)	Fault duration (s)
PmaxQzero	4	3phfault	0.001	0.12

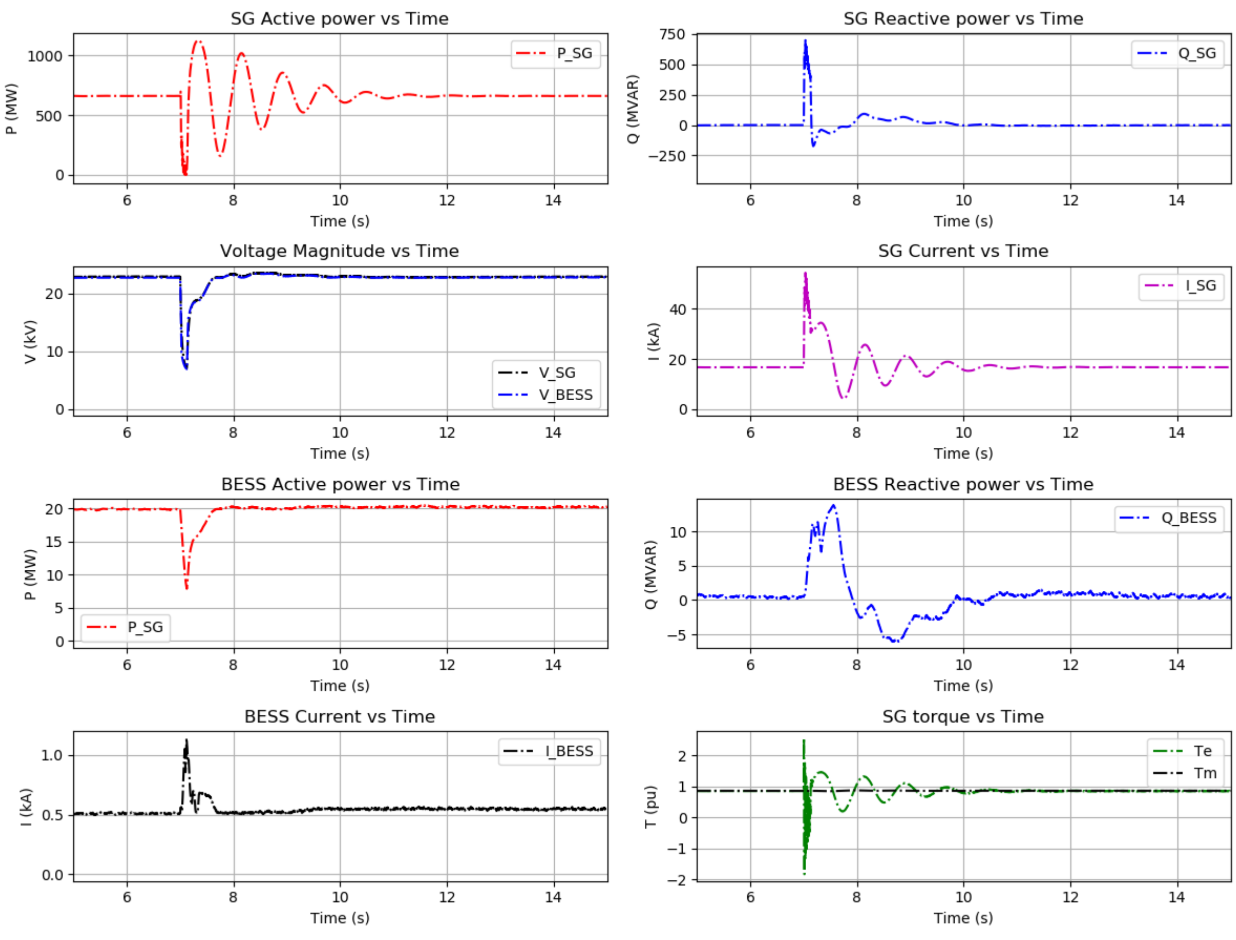

Figure 4.4: Simulation results for case 3phfault-PmaxQzero-SCR-4

4.2.2 3phfault-PmaxQmin-SCR-4

Table 4.2: Test parameters for Case-3phfault-PmaxQmin-SCR-4

Initial Point	SCR	Fault Type	Fault Impedance (Ω)	Fault duration (s)
PmaxQmin	4	3phfault	0.001	0.12

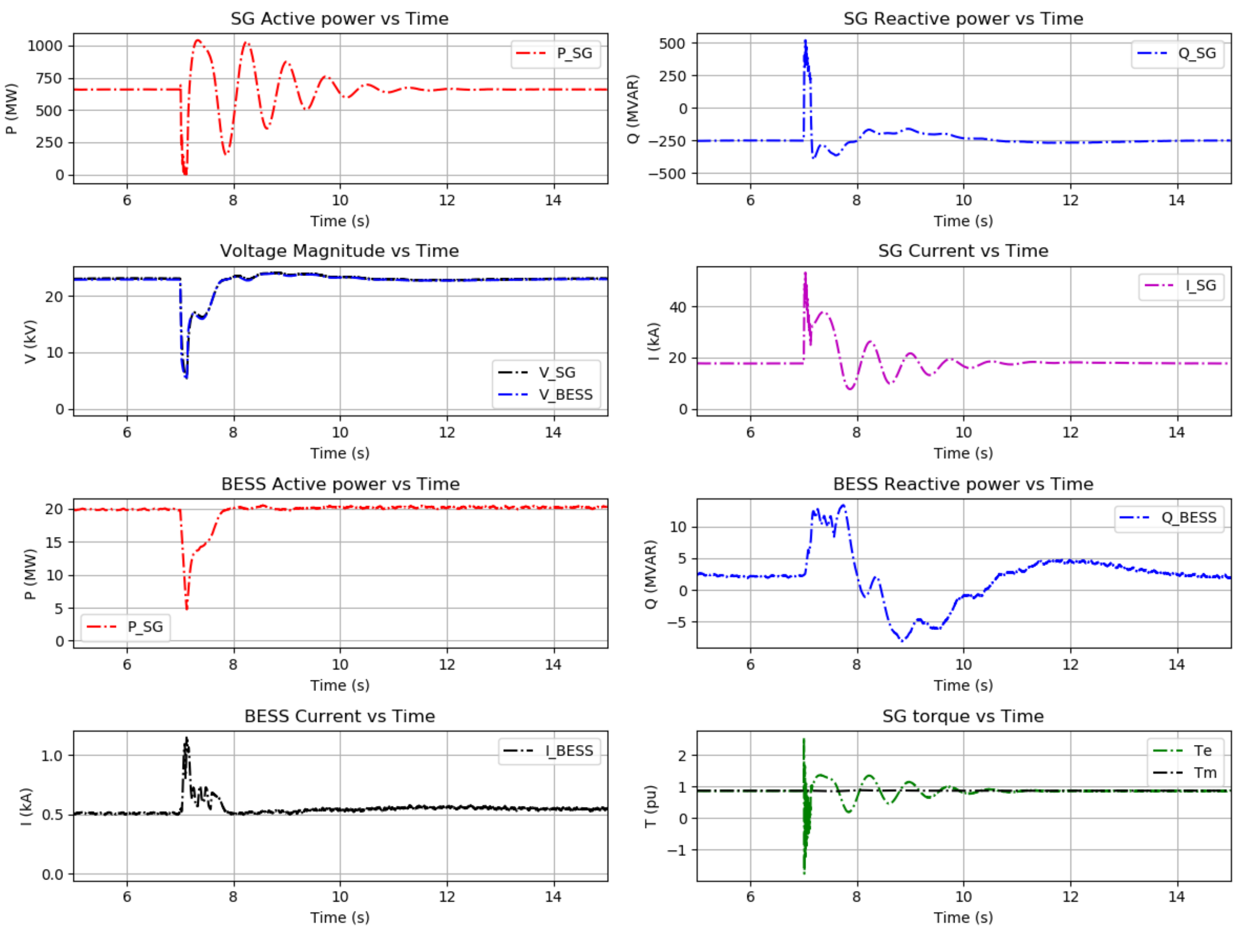

Figure 4.5: Simulation results for case 3phfault-PmaxQmin-SCR-4

4.2.3 3phfault-PmaxQmax-SCR-4

Table 4.3: Test parameters for Case-3phfault-PmaxQmax-SCR-4

Initial Point	SCR	Fault Type	Fault Impedance (Ω)	Fault duration (s)
PmaxQmax	4	3phfault	0.001	0.12

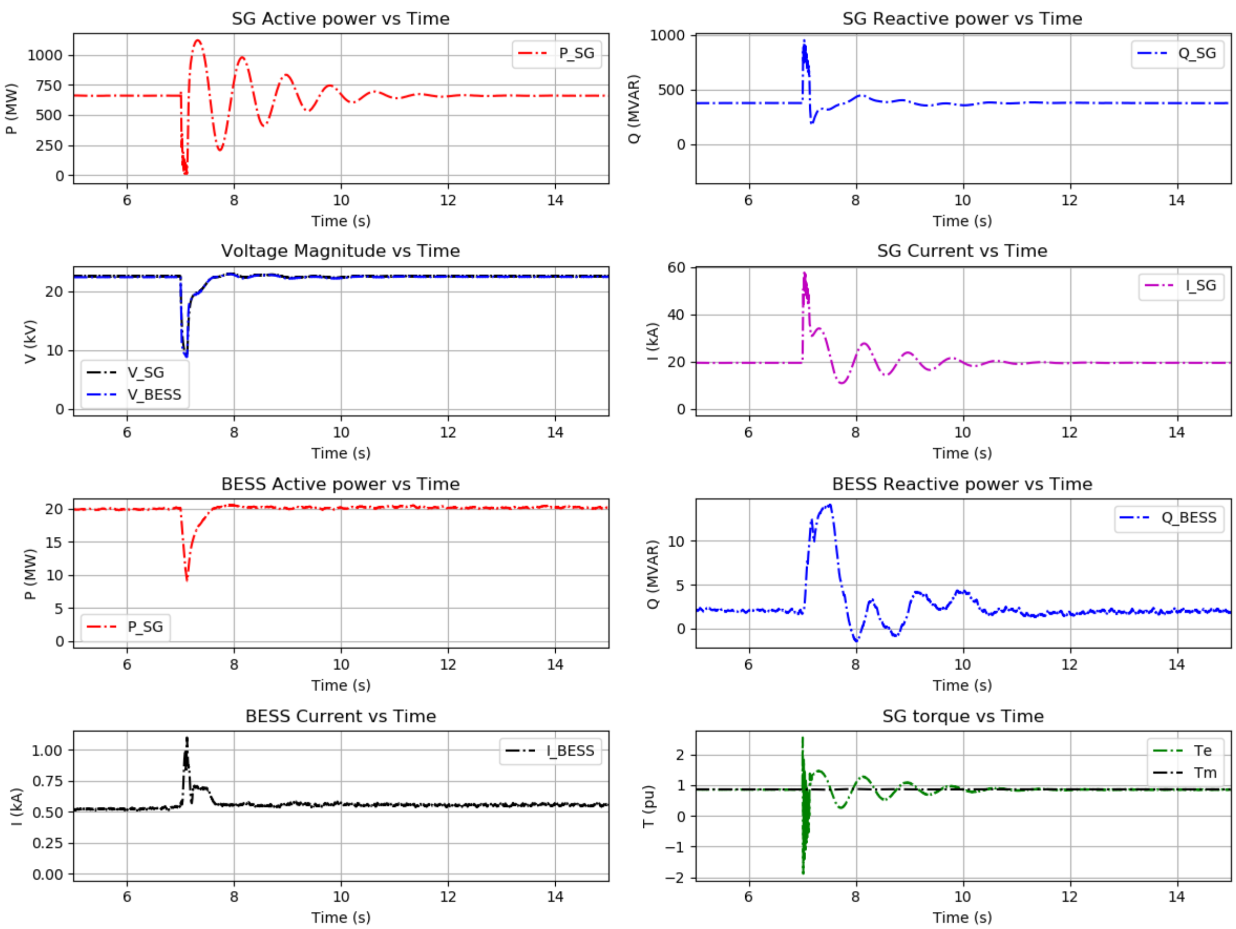

Figure 4.6: Simulation results for case 3phfault-PmaxQmax-SCR-4

4.2.4 3phfault-PminQzero-SCR-4

Table 4.4: Test parameters for Case-3phfault-PminQzero-SCR-4

Initial Point	SCR	Fault Type	Fault Impedance (Ω)	Fault duration (s)
PminQzero	4	3phfault	0.001	0.12

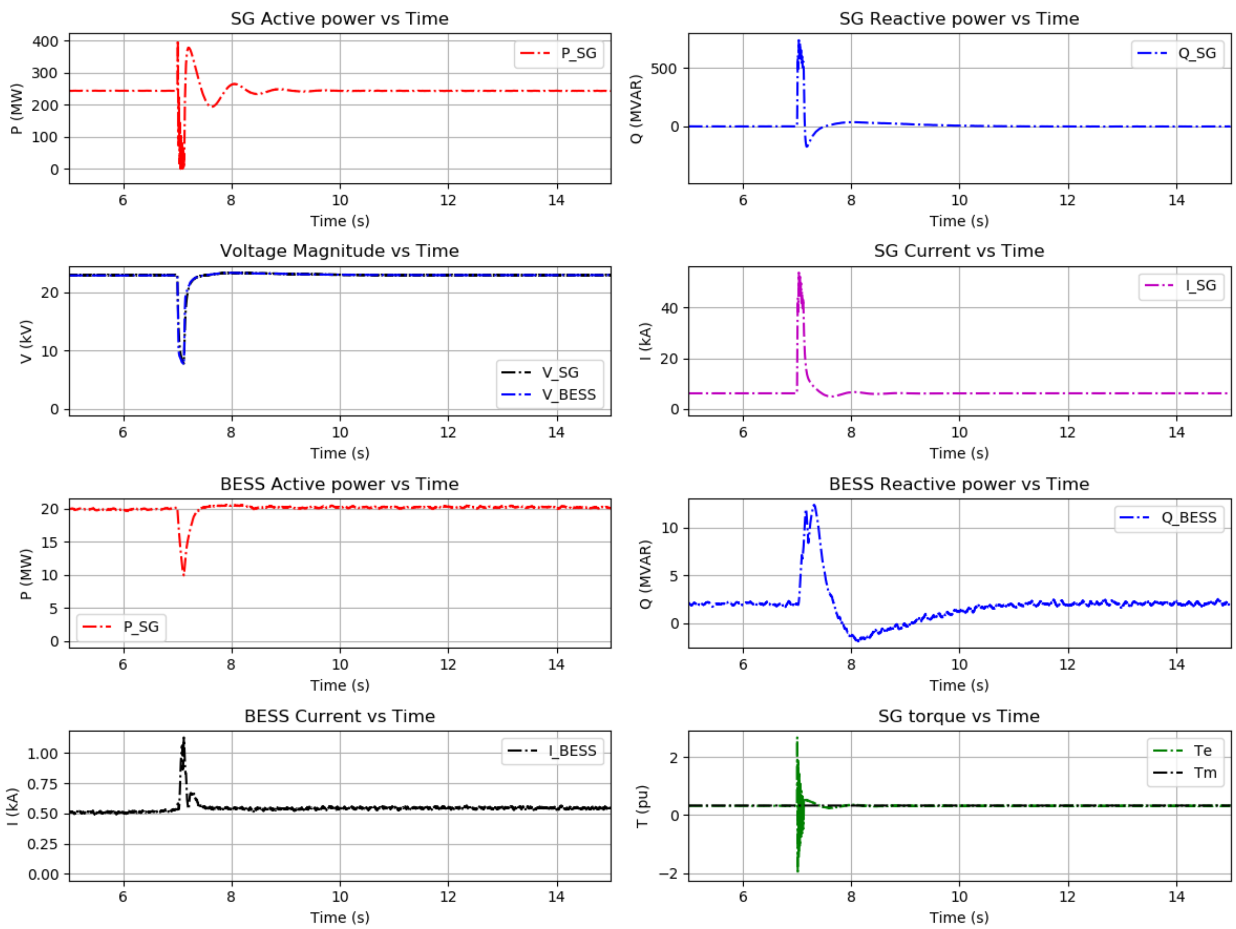

Figure 4.7: Simulation results for case 3phfault-PminQzero-SCR-4

4.2.5 3phfault-PmaxQzero-SCR-10

Table 4.5: Test parameters for Case-3phfault-PmaxQzero-SCR-10

Initial Point	SCR	Fault Type	Fault Impedance (Ω)	Fault duration (s)
PmaxQzero	10	3phfault	0.001	0.12

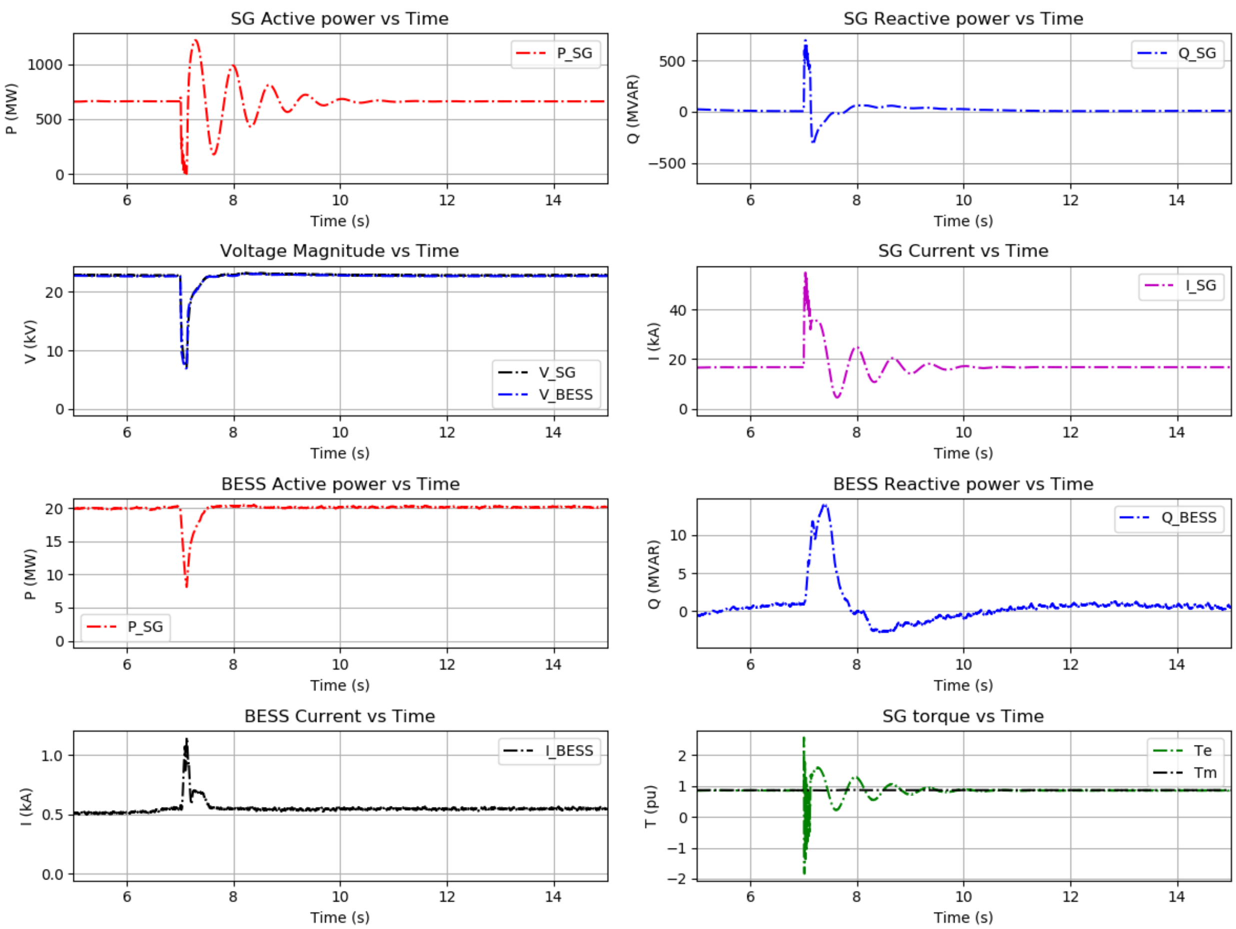

Figure 4.8: Simulation results for case 3phfault-PmaxQzero-SCR-10

4.2.6 3phfault-PmaxQmin-SCR-10

Table 4.6: Test parameters for Case-3phfault-PmaxQmin-SCR-10

Initial Point	SCR	Fault Type	Fault Impedance (Ω)	Fault duration (s)
PmaxQmin	10	3phfault	0.001	0.12

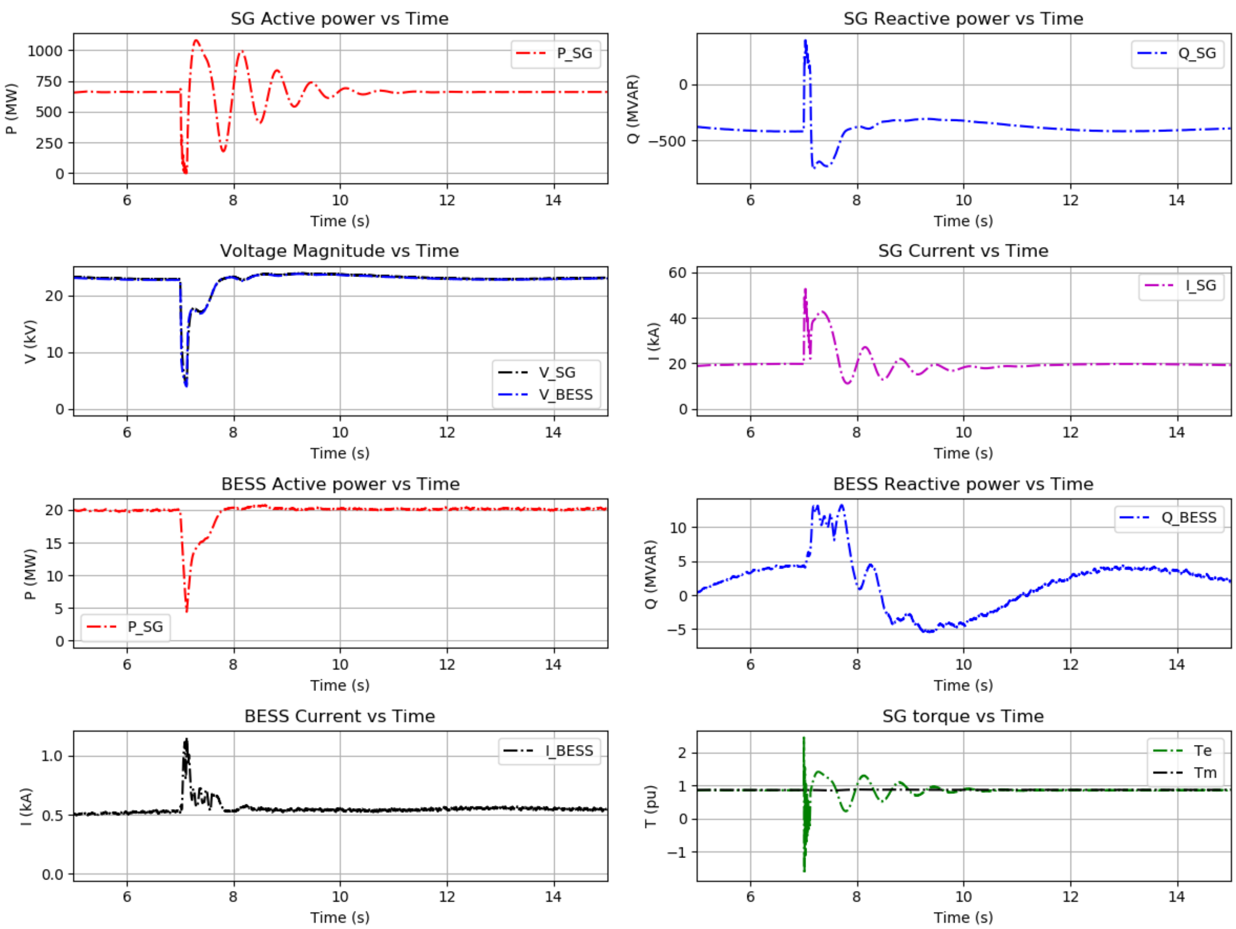

Figure 4.9: Simulation results for case 3phfault-PmaxQmin-SCR-10

4.2.7 3phfault-PmaxQmax-SCR-10

Table 4.7: Test parameters for Case-3phfault-PmaxQmax-SCR-10

Initial Point	SCR	Fault Type	Fault Impedance (Ω)	Fault duration (s)
PmaxQmax	10	3phfault	0.001	0.12

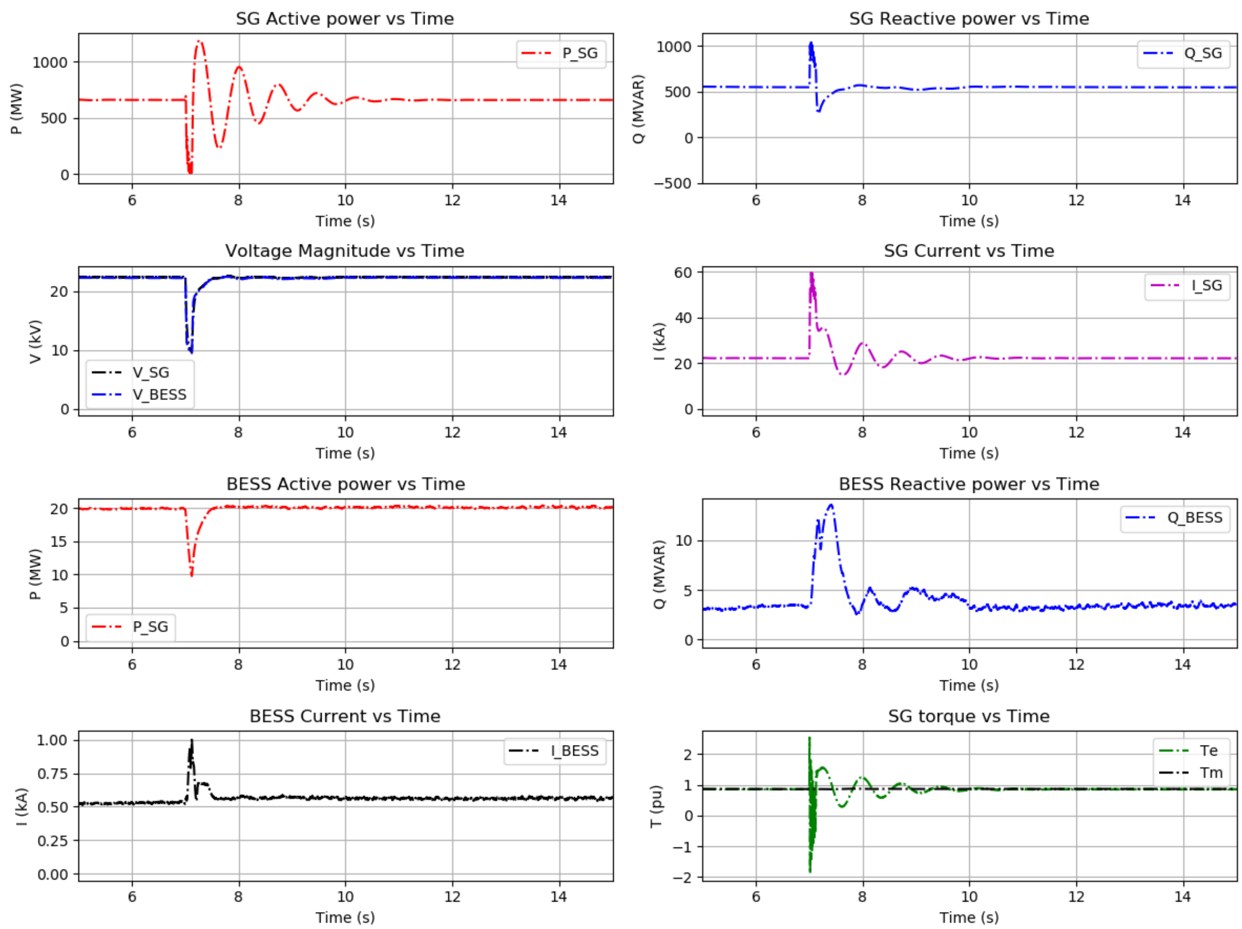

Figure 4.10: Simulation results for case 3phfault-PmaxQmax-SCR-10

4.2.8 3phfault-PminQzero-SCR-10

Table 4.8: Test parameters for Case-3phfault-PminQzero-SCR-10

Initial Point	SCR	Fault Type	Fault Impedance (Ω)	Fault duration (s)
PminQzero	10	3phfault	0.001	0.12

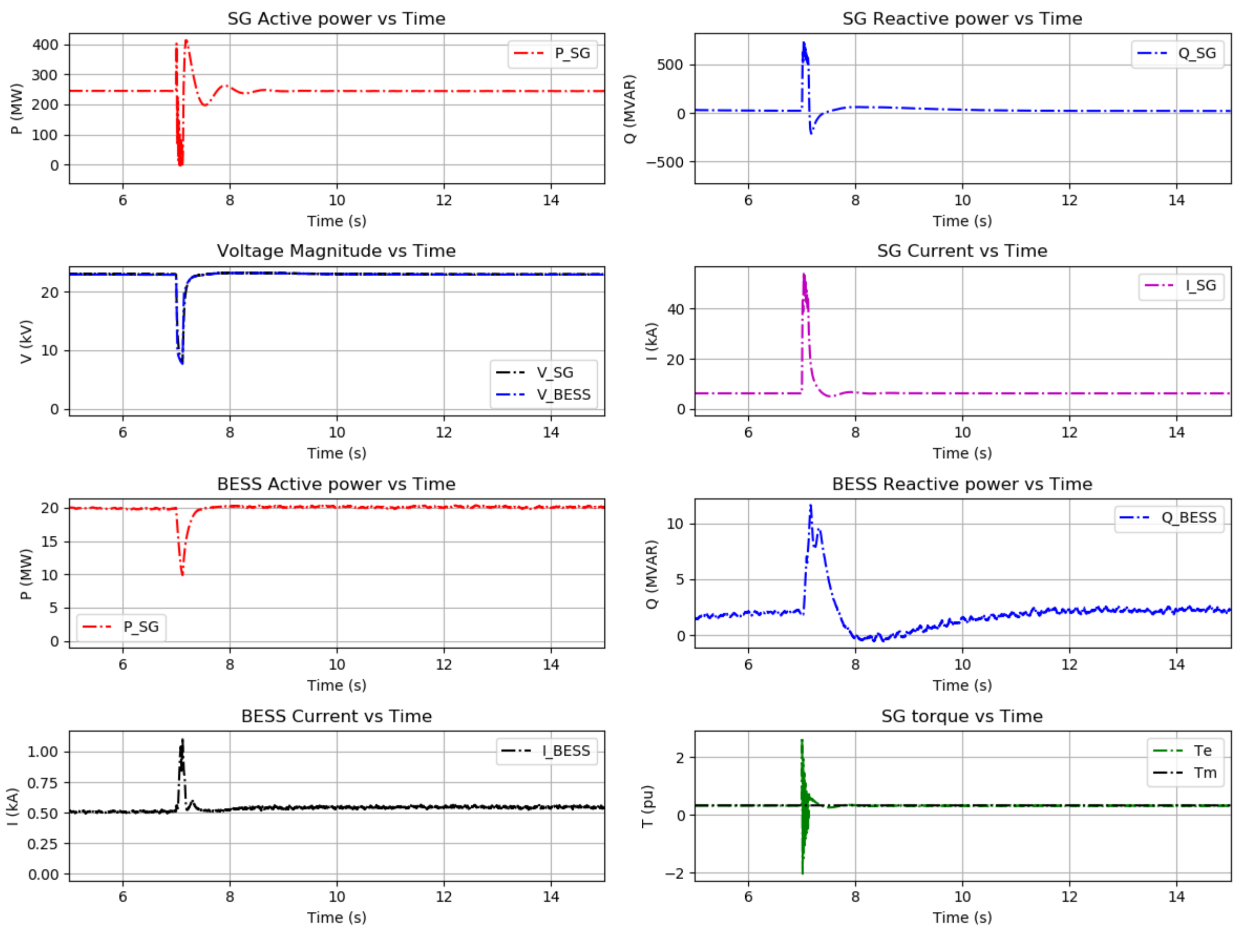

Figure 4.11: Simulation results for case 3phfault-PminQzero-SCR-10

4.2.9 2Phfault-PmaxQzero-SCR-4

Table 4.9: Test parameters for Case-2Phfault-PmaxQzero-SCR-4

Initial Point	SCR	Fault Type	Fault Impedance (Ω)	Fault duration (s)
PmaxQzero	4	2Phfault	0.001	0.24

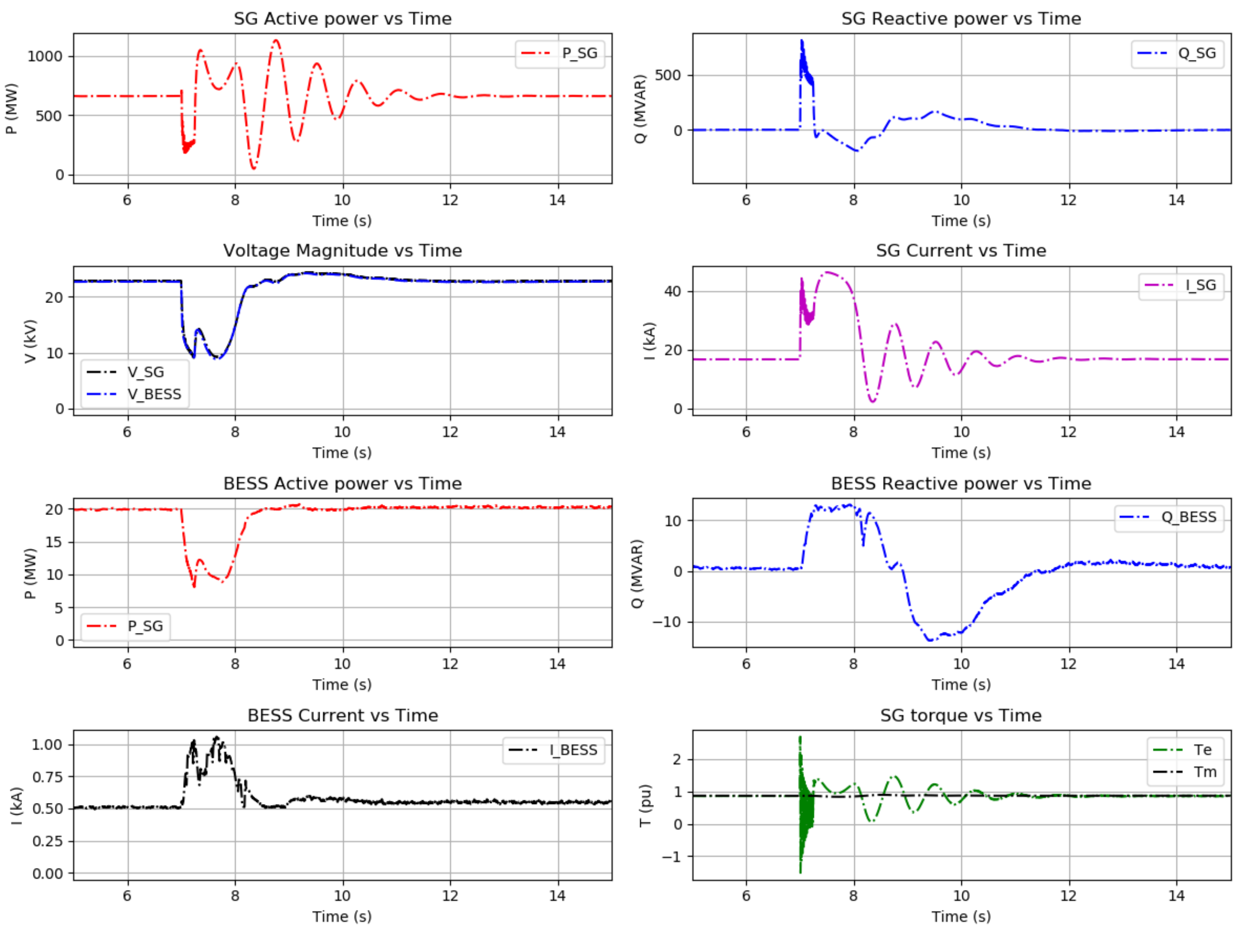

Figure 4.12: Simulation results for case 2Phfault-PmaxQzero-SCR-4

4.2.10 2Phfault-PmaxQmin-SCR-4

Table 4.10: Test parameters for Case-2Phfault-PmaxQmin-SCR-4

Initial Point	SCR	Fault Type	Fault Impedance (Ω)	Fault duration (s)
PmaxQmin	4	2Phfault	0.001	0.24

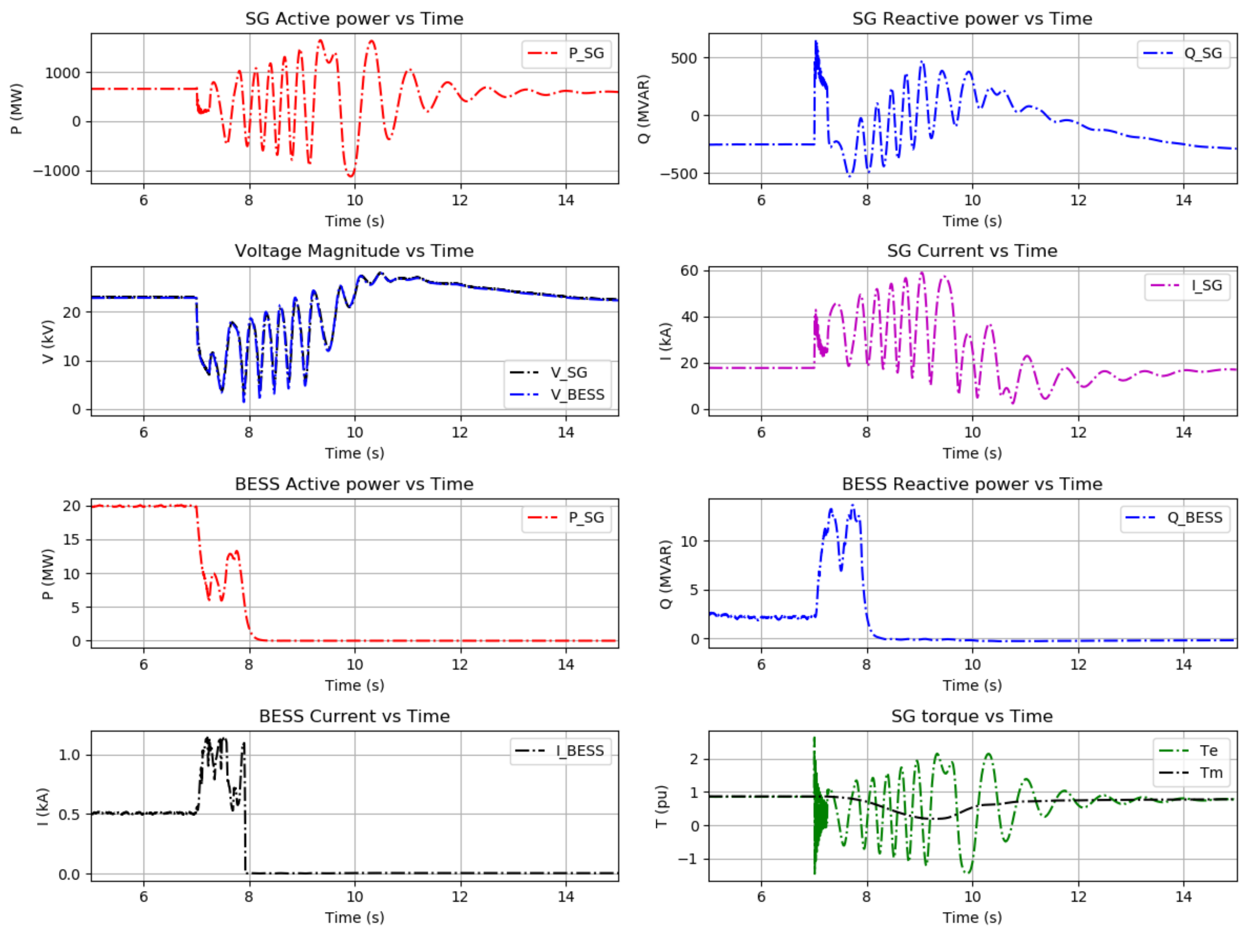

Figure 4.13: Simulation results for case 2Phfault-PmaxQmin-SCR-4

4.2.11 2Phfault-PmaxQmax-SCR-4

Table 4.11: Test parameters for Case-2Phfault-PmaxQmax-SCR-4

Initial Point	SCR	Fault Type	Fault Impedance (Ω)	Fault duration (s)
PmaxQmax	4	2Phfault	0.001	0.24

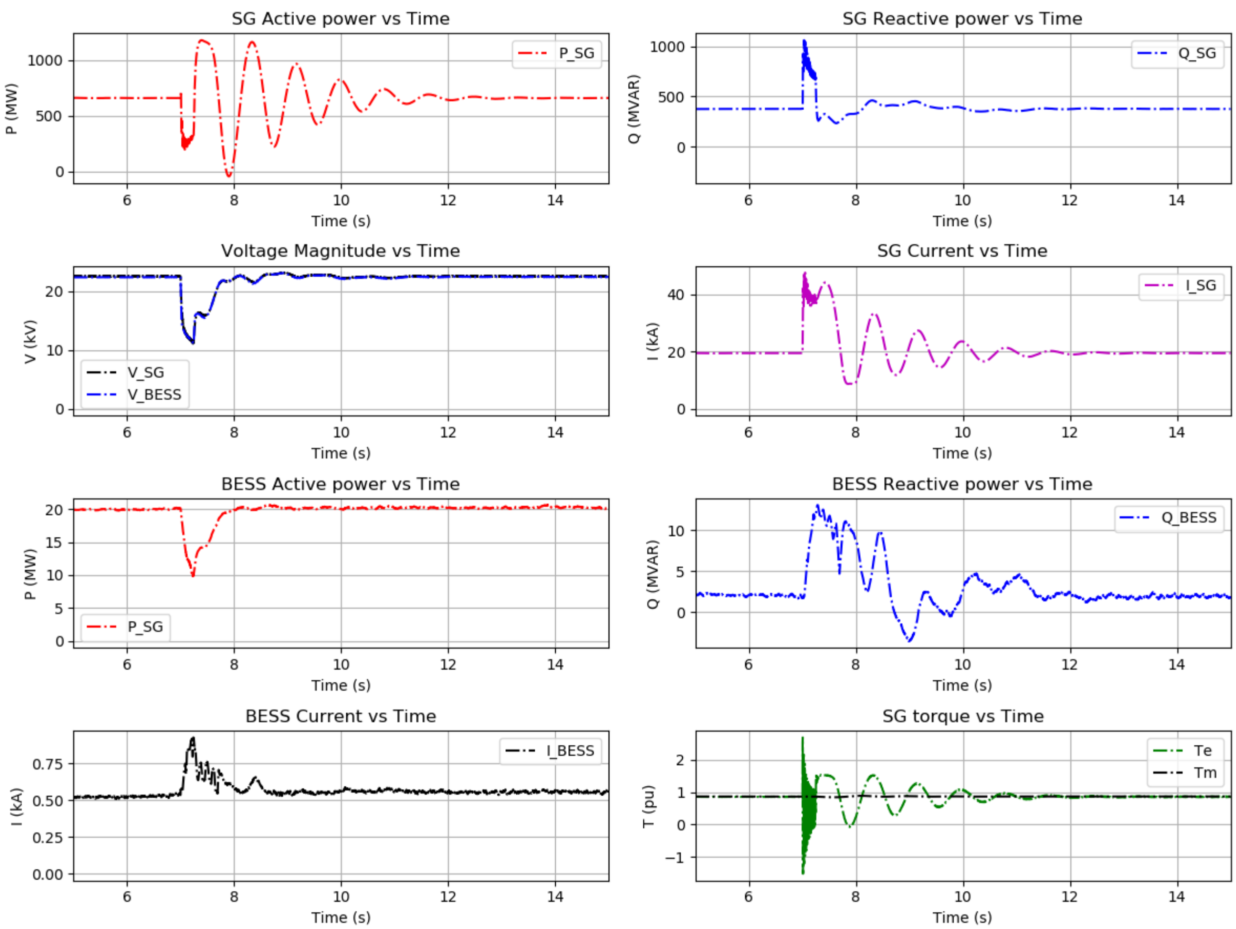

Figure 4.14: Simulation results for case 2Phfault-PmaxQmax-SCR-4

4.2.12 2Phfault-PminQzero-SCR-4

Table 4.12: Test parameters for Case-2Phfault-PminQzero-SCR-4

Initial Point	SCR	Fault Type	Fault Impedance (Ω)	Fault duration (s)
PminQzero	4	2Phfault	0.001	0.24

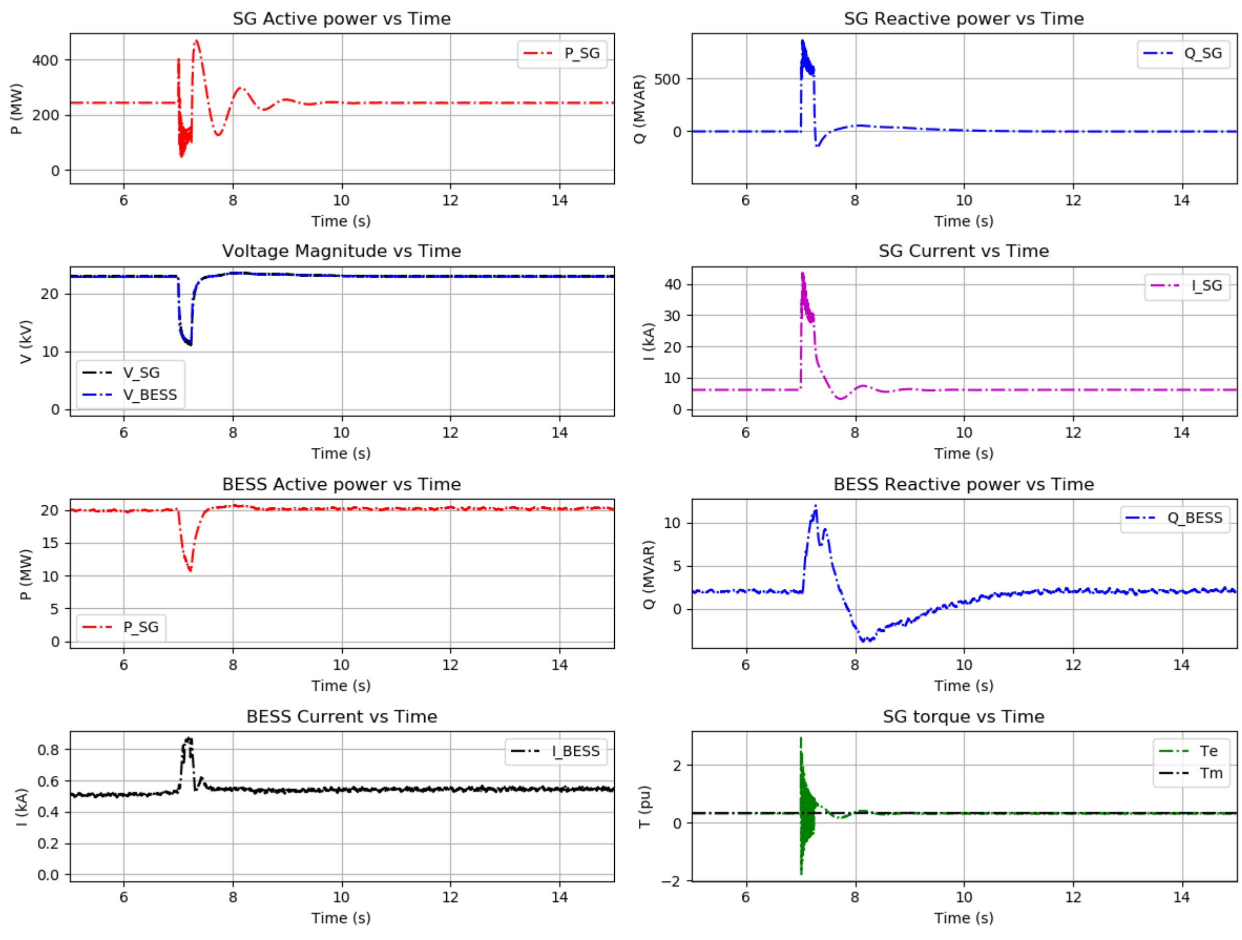

Figure 4.15: Simulation results for case 2Phfault-PminQzero-SCR-4

4.2.13 2Phfault-PmaxQzero-SCR-10

Table 4.13: Test parameters for Case-2Phfault-PmaxQzero-SCR-10

Initial Point	SCR	Fault Type	Fault Impedance (Ω)	Fault duration (s)
PmaxQzero	10	2Phfault	0.001	0.24

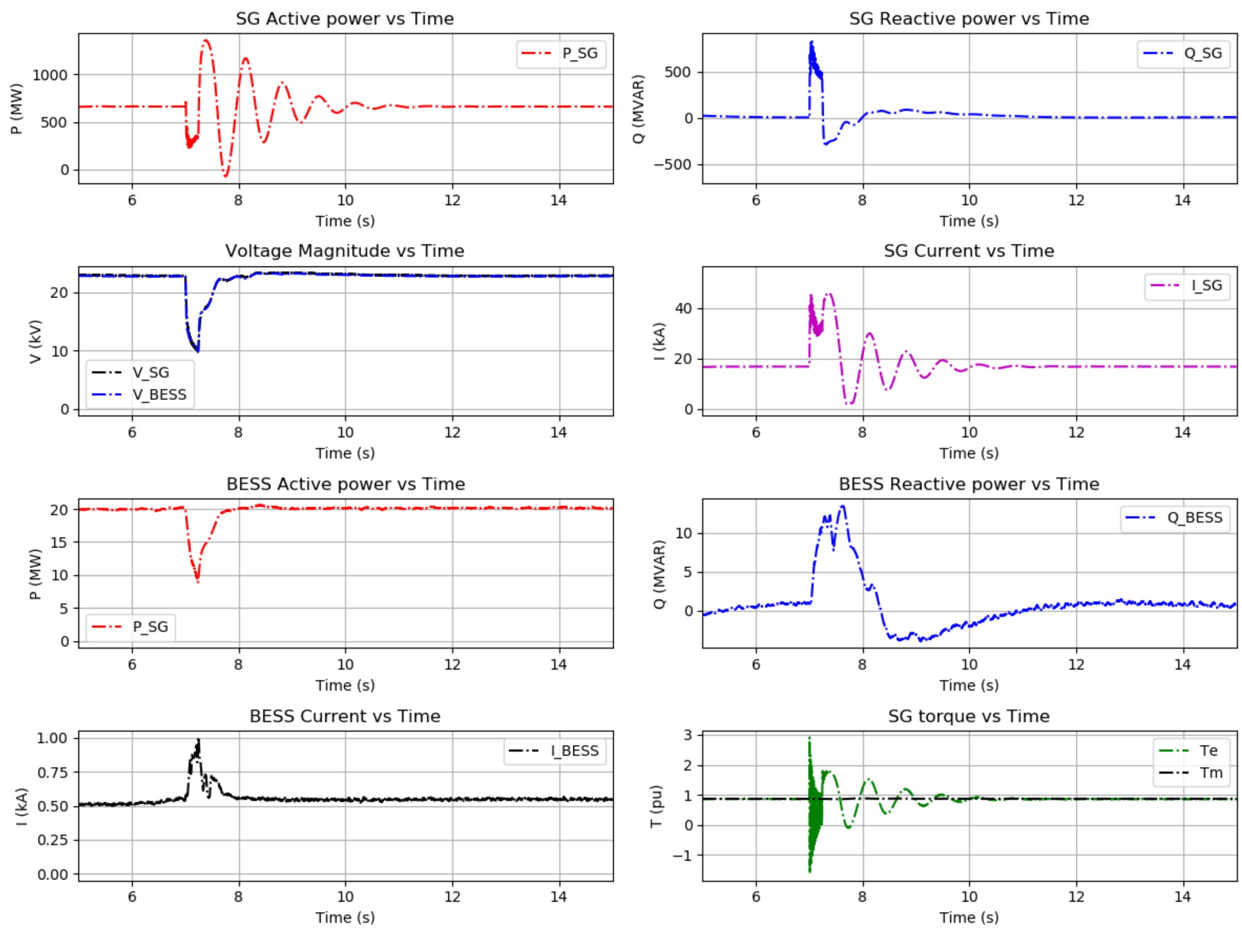

Figure 4.16: Simulation results for case 2Phfault-PmaxQzero-SCR-10

4.2.14 2Phfault-PmaxQmin-SCR-10

Table 4.14: Test parameters for Case-2Phfault-PmaxQmin-SCR-10

Initial Point	SCR	Fault Type	Fault Impedance (Ω)	Fault duration (s)
PmaxQmin	10	2Phfault	0.001	0.24

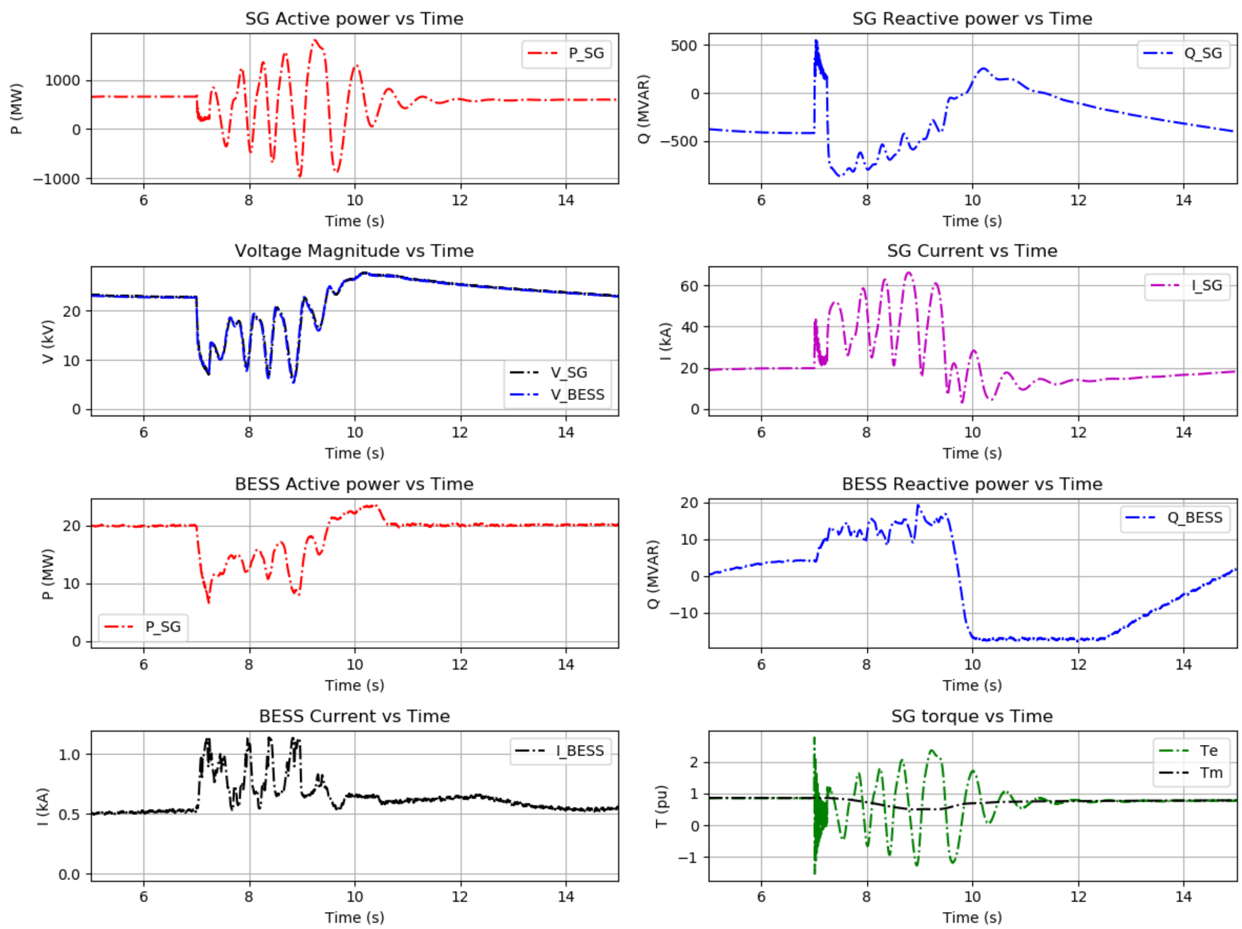

Figure 4.17: Simulation results for case 2Phfault-PmaxQmin-SCR-10

4.2.15 2Phfault-PmaxQmax-SCR-10

Table 4.15: Test parameters for Case-2Phfault-PmaxQmax-SCR-10

Initial Point	SCR	Fault Type	Fault Impedance (Ω)	Fault duration (s)
PmaxQmax	10	2Phfault	0.001	0.24

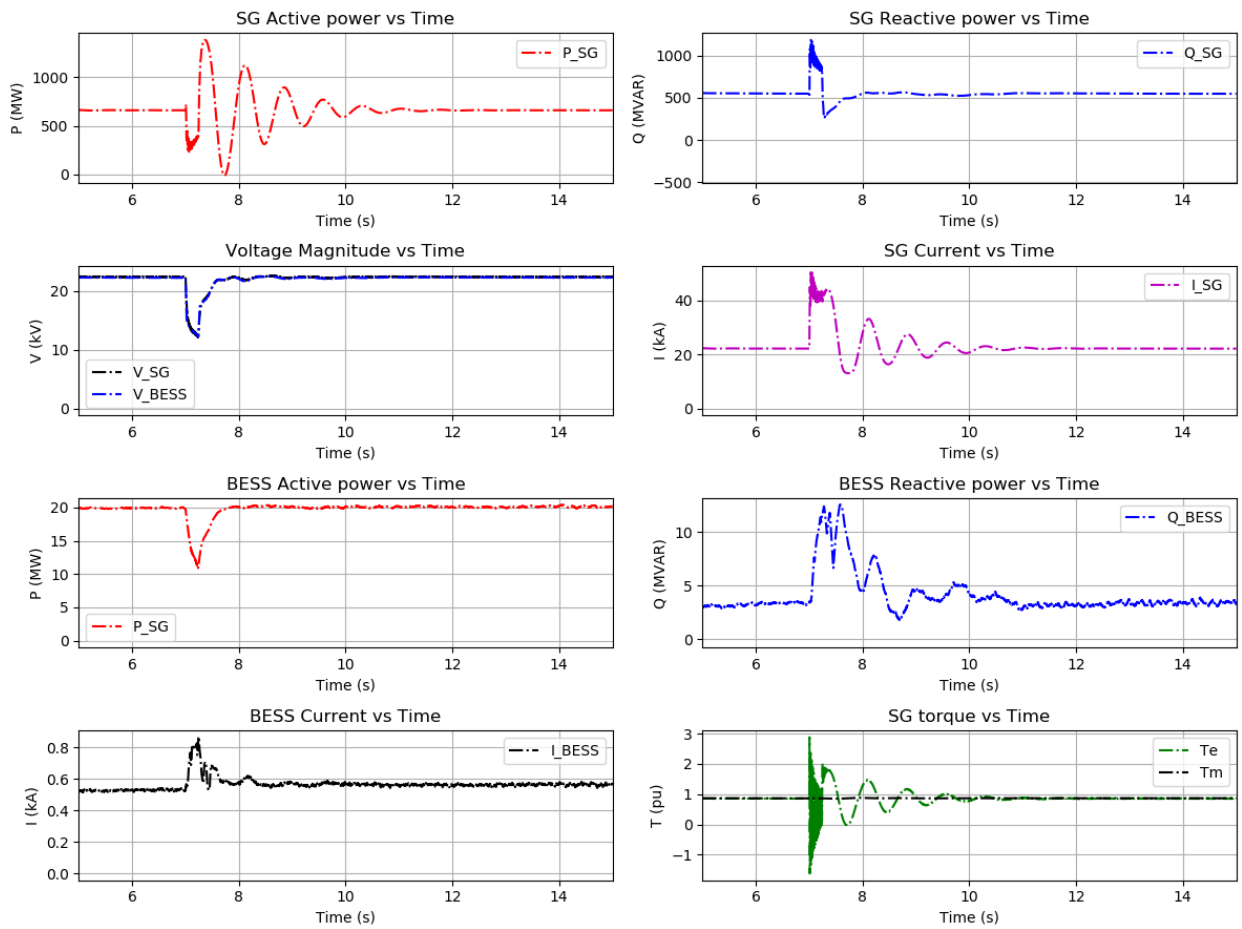

Figure 4.18: Simulation results for case 2Phfault-PmaxQmax-SCR-10

4.2.16 2Phfault-PminQzero-SCR-10

Table 4.16: Test parameters for Case-2Phfault-PminQzero-SCR-10

Initial Point	SCR	Fault Type	Fault Impedance (Ω)	Fault duration (s)
PminQzero	10	2Phfault	0.001	0.24

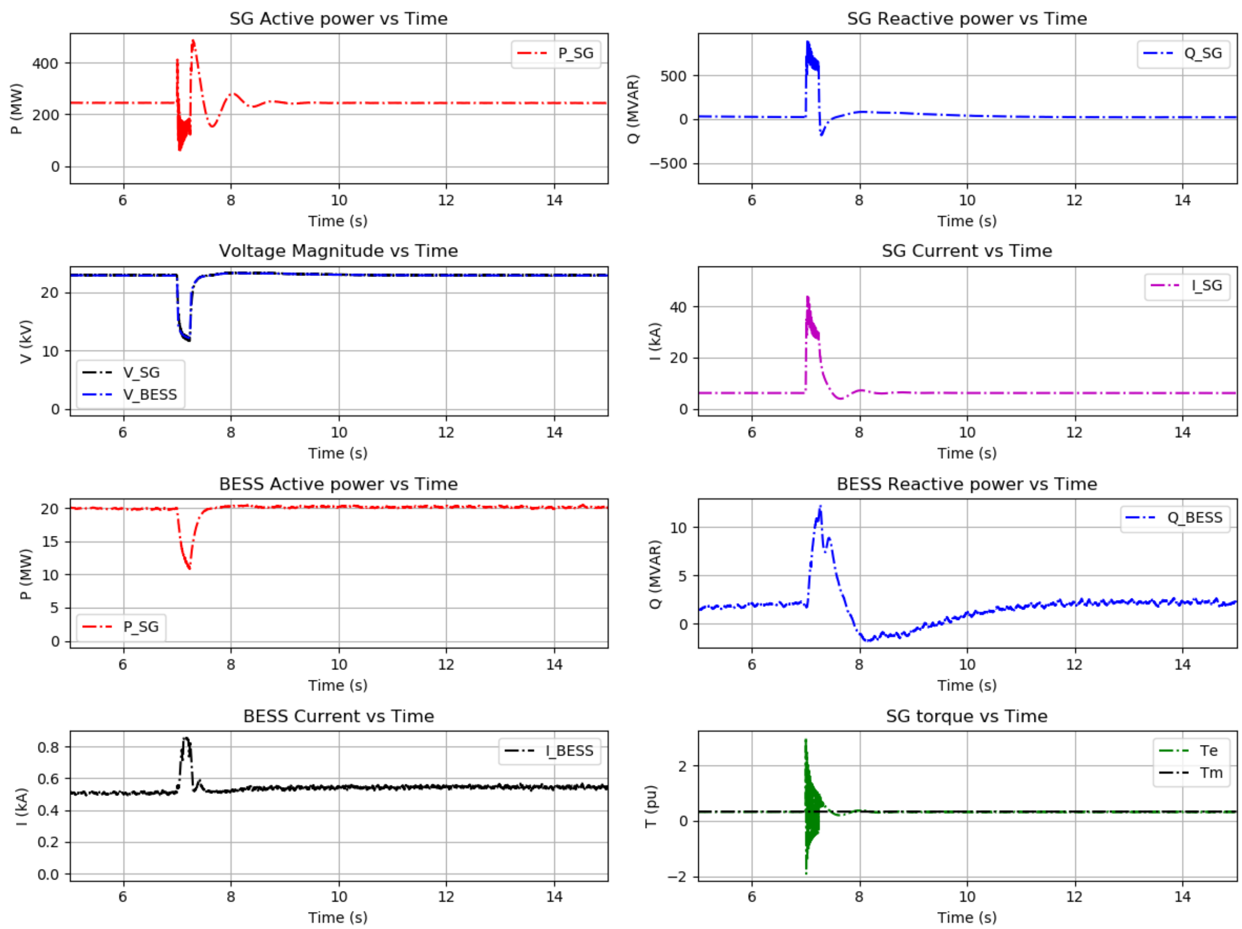

Figure 4.19: Simulation results for case 2Phfault-PminQzero-SCR-10

4.3 Discussion

This report summarize the preliminary assessment that Advisian has carried out for Vales point power station. Report aims to evaluate the performance of a 40 MW BESS system when installed at the existing Vales point power station. Advisian has modelled the VP power station and BESS system in PSCAD from scratch and benchmarked its performance against the PSSE model.

Symmetrical and asymmetrical faults were simulated using the PSCAD model to verify the performance of BESS system. The initial active power output of BESS is kept at 20 MW. Voltage droop control regulates the voltage at BESS terminals by varying the reactive power output. Two SCR ratio is considered in this analysis to assess the BESS performance under weak and strong grid.

Three Phase fault considered in this analysis has a fault impedance of 0.001 Ω and fault duration of 120 ms. For all three phase fault cases considered in the analysis, system remained stable. For the cases where the SCR ratio is 4, settling time is slightly higher than cases with SCR 10 which is expected.

On the other hand, two Phase fault considered in this analysis has a fault duration of 240 ms. Two phase faults created much more oscillations in the system compared to three phase faults when SG operates at P=Pmax and Q= Qmin. With SCR 4, this operating point caused the BESS system to trip with its voltage protection activated. For the rest of operating points, system remain stable.

From this preliminary analysis, it is identified that the BESS system is not creating any unwanted interaction with the existing synchronous generator during various faults. Moreover, BESS is actively participating to support the SG during these events. It is noted that BESS is responding to faults by providing reactive power to bring up the voltage.

It should be noted that the performance of BESS can be optimized by choosing proper control parameters to meet power station performance requirement. In this analysis, Advisian have not considered parameter tuning as the BESS system in not finalized and the controller will most likely change.

Delta electricity

Vales Point Power Station with BESS

PSSE Model Test Report

Delta Electricity

06/02/2020

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411010-15983 – Vales Point Power Station with BESS: PSSE Model Test Report

Rev	Description	Author	Review	Advisian approval	Date
1	Initial issue	M. A. Chowdhur	B. Miller	B. Miller	06/02/2020

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1 Introduction

Delta Electricity is exploring the possibility of installing a Battery Energy Storage System (BESS) in their existing Vales point power station. The main drive for installing BESS is to provide spinning reserve, thereby allows the steam turbine to operate with its steam valve fully open. That is, BESS system will provide synthetic inertia, and this will result in a change in the primary frequency response provision from Vales point power station.

Advisian has been engaged by Delta Electricity to conduct a preliminary analysis to identify if there would be any adverse interaction between the BESS and the existing synchronous generator. In this report, Advisian is assessing the total plant response during various faults. As Delta team has not provided the plant model to conduct the analysis, Advisian has developed Vales Point power station model (in PSSE and PSCAD) and used an inhouse BESS model for performing the analysis.

The Vales point BESS has a total capacity of 40 MW and will be connected to the National Electricity Market via TransGrids 330 kV network. The purpose of the BESS is to provide synthetic inertia support for primary frequency response. The BESS considered in this analysis comprises of 24 battery units with a power rating of 1.872 MVA each. The battery operates at a terminal voltage of 0.48 kV AC. Battery unit transformers connect to each unit, step up the terminal voltage to 6.6 kV. The batteries are then connected to one of the auxiliary transformers in the generating station. which steps up the voltage to 23 kV and connects to the generator bus. Proposed single diagram of the system is shown in Figure 1.

In this report, a number of Generator Performance Standard (GPS) compliance assessments have been performed in PSSE to investigate the dynamic behaviour of the BESS and the interactions between the Vales Point generator and the BESS under any grid disturbances, contingencies or other abnormal grid conditions.

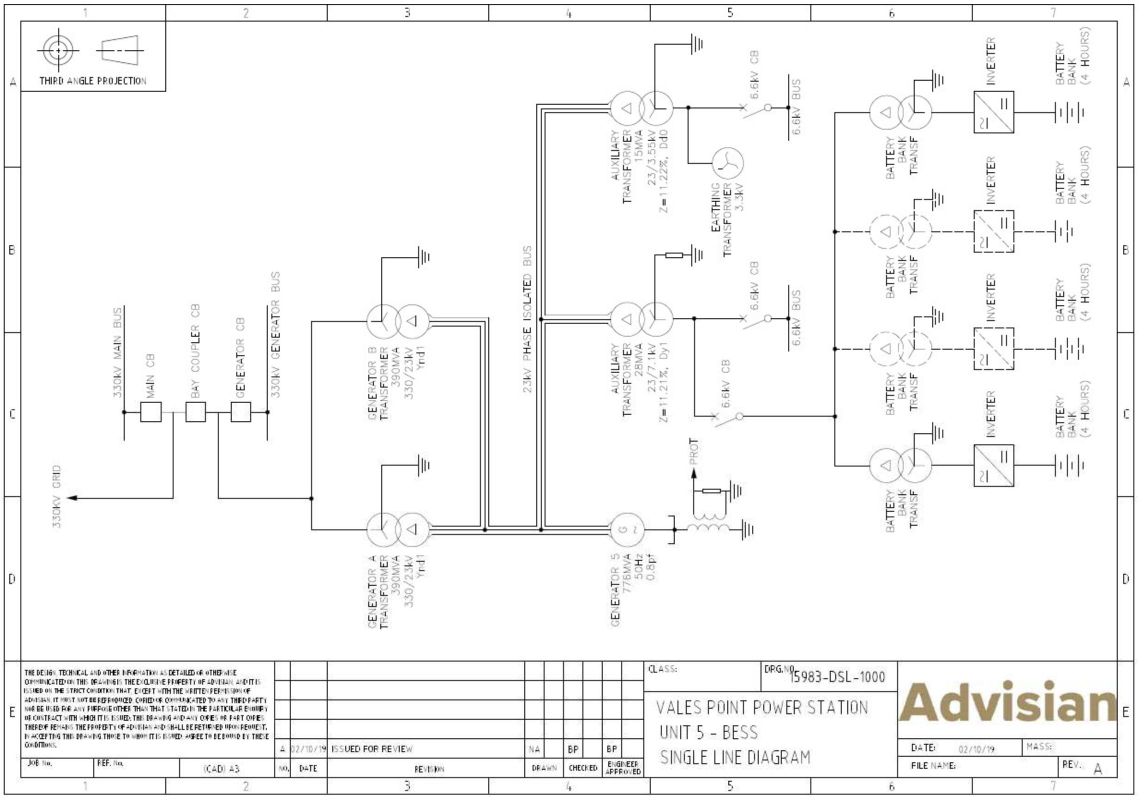

Figure 1: Single line diagram of Vales point station with BESS

2 Model Descriptions

Vales Point power station model has been extracted from the snapshot, namely 'SummerHi-20190125-163118-34-SystemNormal' provided by AEMO. Since a governor model is missing in the snapshot, a standard governor model in PSSE, namely 'IEEEG1' has been incorporated. To conduct the studies, a standard BESS model of the rating of 40 MW has been integrated with detail inverter and PPC specifications to facilitate the intended studies. The Vales Point power station has been connected to a single-machine infinite bus (SMIB) system.

For the assessment of dynamic network capability, a simplified representation of the plant is modelled in PSSE as shown in Figure 2. The model comprises a lumped representation of the collector network, the BESS inverter transformers (23 / 0.48 kV), the BESS (connected at bus 20857), the grid transformers (330 / 23 kV), and the synchronous generator (connected at bus 20855). The generator has a maximum capacity of 660 MW. The grid representation generator (SMIB) at bus 1 is connected to the POC bus number 21854 via a line representing an SCR of 4.5 and X/R of 3.0.

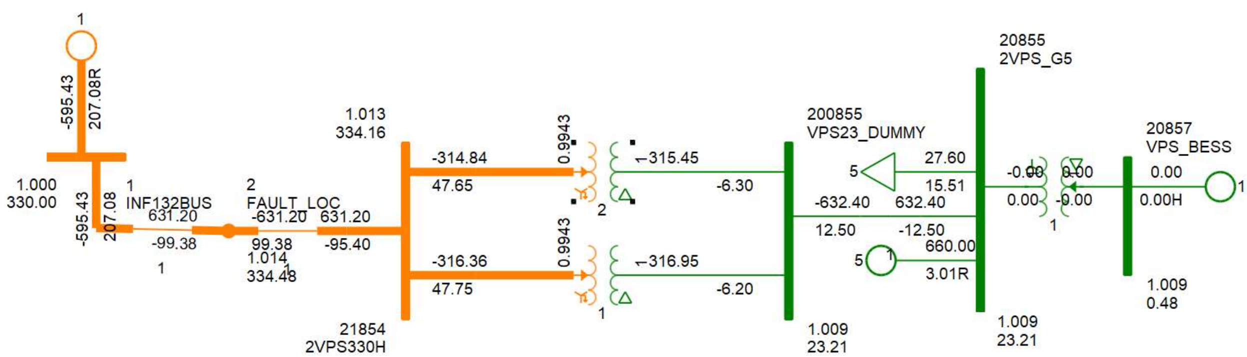

Figure 2: Vales Point Single-machine-infinite-bus (SMIB) PSSE model with integration of the BESS

The PSSE .dyr file setting is given in Appendix A [1].

3 GPS Compliance Assessment in PSSE

In this chapter, a number of GPS compliance assessment has been performed in PSSE under chapter 5 of the NER, revision 132 [2]. The primary objective of the studies is not to demonstrate the compliance of the Vales Point generator with integration of the BESS with the assessed GPS accesses (automatic, negotiated or minimum), rather to investigate the dynamic behaviour of the BESS and interactions between the Vales Point generator and the BESS under any grid disturbances, contingencies or other abnormal grid conditions.

Following GPS compliance assessment has been performed:

- S5.2.5.3 Generating Response to Frequency Disturbances
- S5.2.5.4 Generating Response to Voltage Disturbances
- S5.2.5.5 Generating System Response to Disturbances following Contingency Events
- S5.2.5.13 Voltage and Reactive Power Control
- S5.2.5.14 Active Power Control

3.1 S5.2.5.3 Generating System Response to Frequency Disturbances

The performance of the Vales Point generator is evaluated with the integration of the BESS against the frequency disturbances. For the study, the Vales point Generator has not been equipped with any protection system. Meanwhile, the under-frequency and over-frequency protection system for the BESS has been chosen in compliance with automatic access standard to clause S5.2.5.3 as depicted in Figure 3.

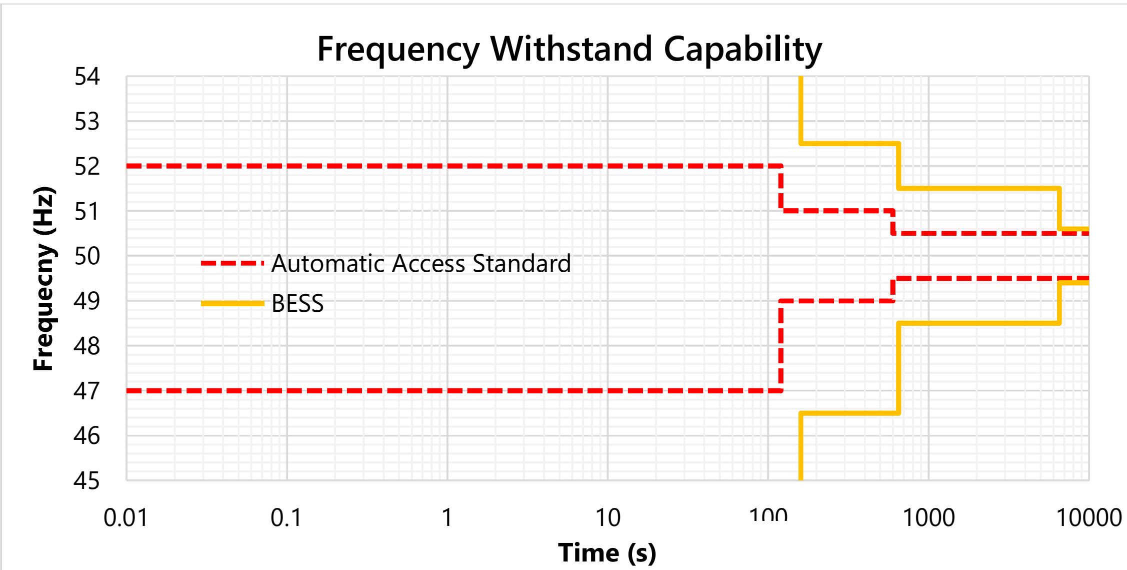

Figure 3: BESS frequency withstand capability

The plant capability is demonstrated by simulation on a controlled voltage and frequency source. The impedance of the grid representation has been for a short-circuit ratio of 4.5 and X/R ratio of 3.0. The voltage at the point of connection is set to 1.01 pu. The active power is set to the maximum output of the vales Point generator.

- The first test follows the over-frequency profile of the automatic access to clause S5.2.5.3 as indicated by the upper dashed red line of Figure 3, and
- the second test follows the under-frequency profile of the automatic access to clause S5.2.5.3 as indicated by the lower dashed red line of Figure 3.

The performance of the Vales Point generator for high frequency event during both charging and discharging states of the BESS is shown in Figure 4 - Figure 7. Low frequency events are demonstrated though Figure 8 - Figure 11. The BESS is able to successfully ride-through the high and low frequencies without having any adverse impact from the Vales Point generator.

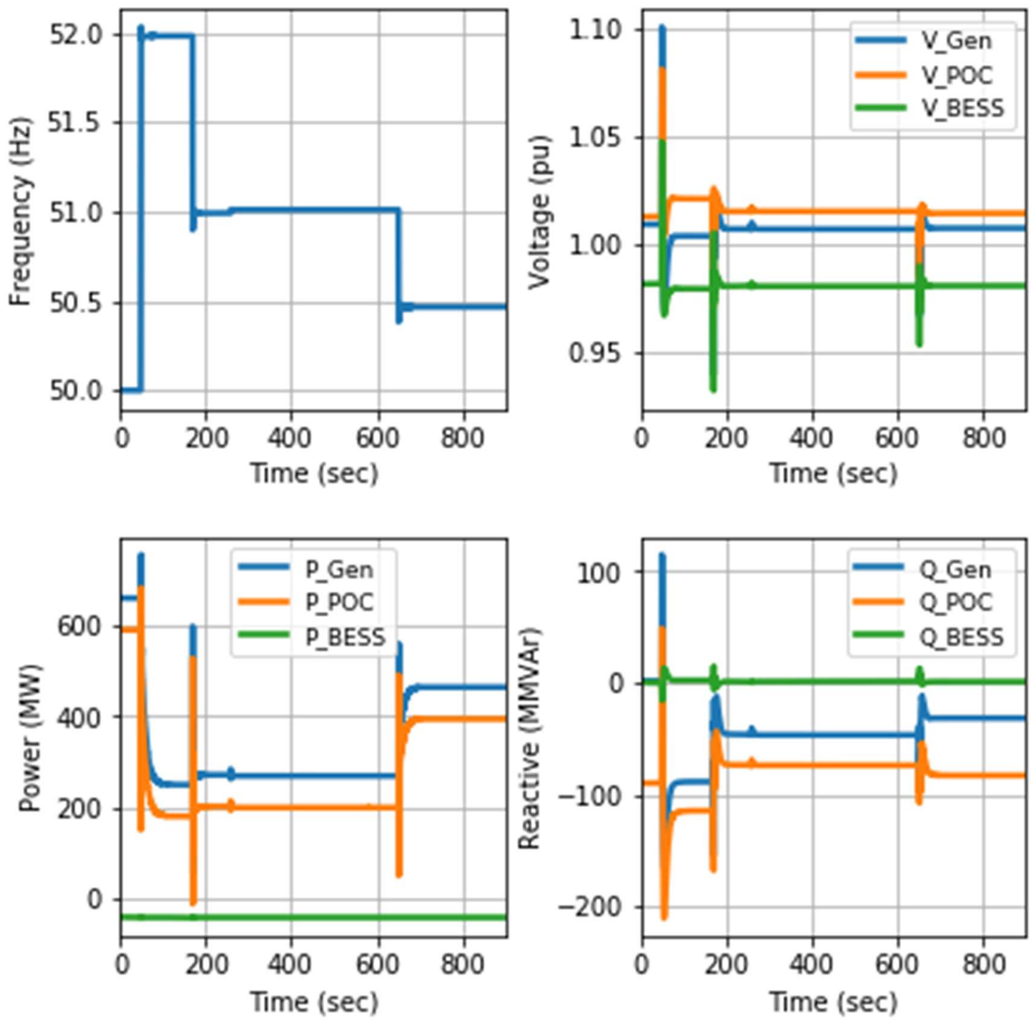

Figure 4: Response to high frequencies during BESS charging

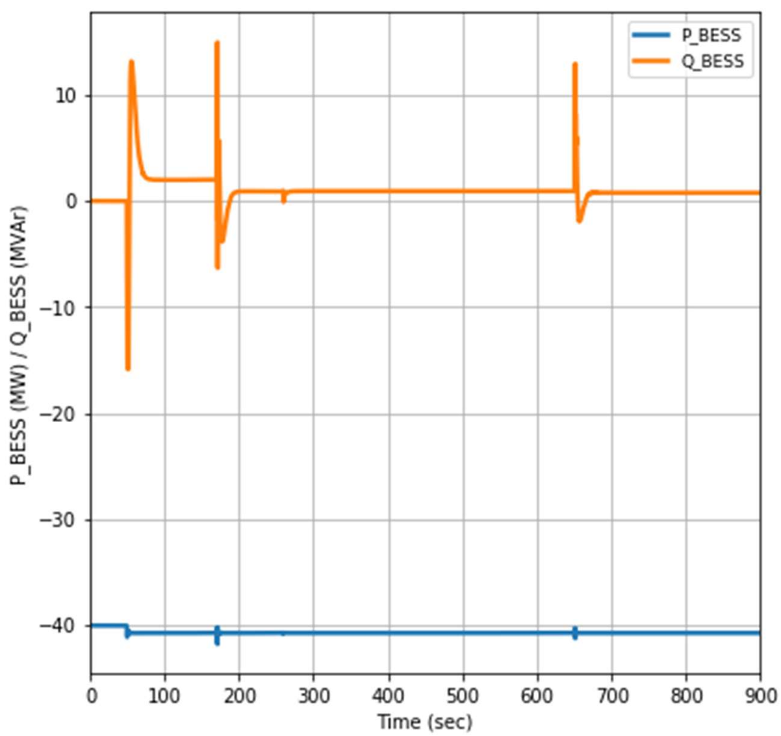

Figure 5: BESS response to high frequencies during charging

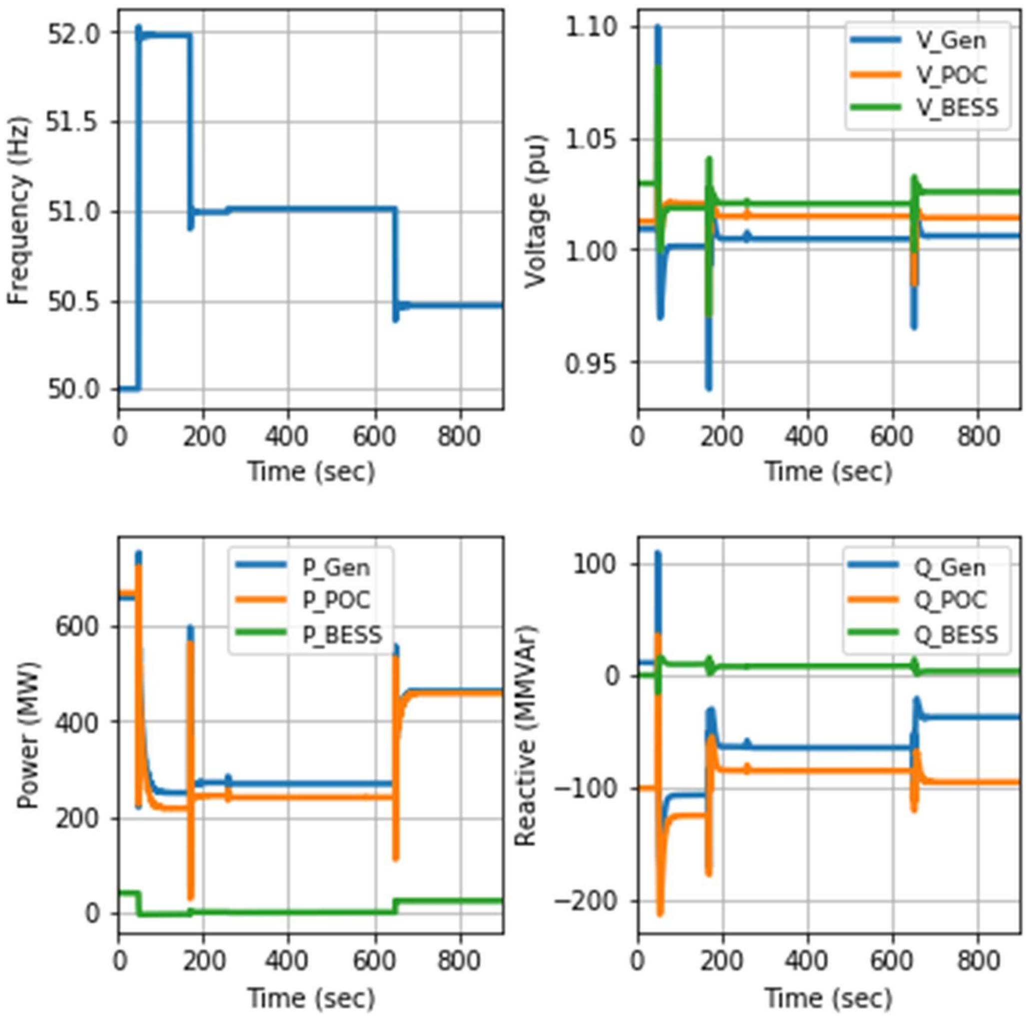

Figure 6: Response to high frequencies during BESS discharging

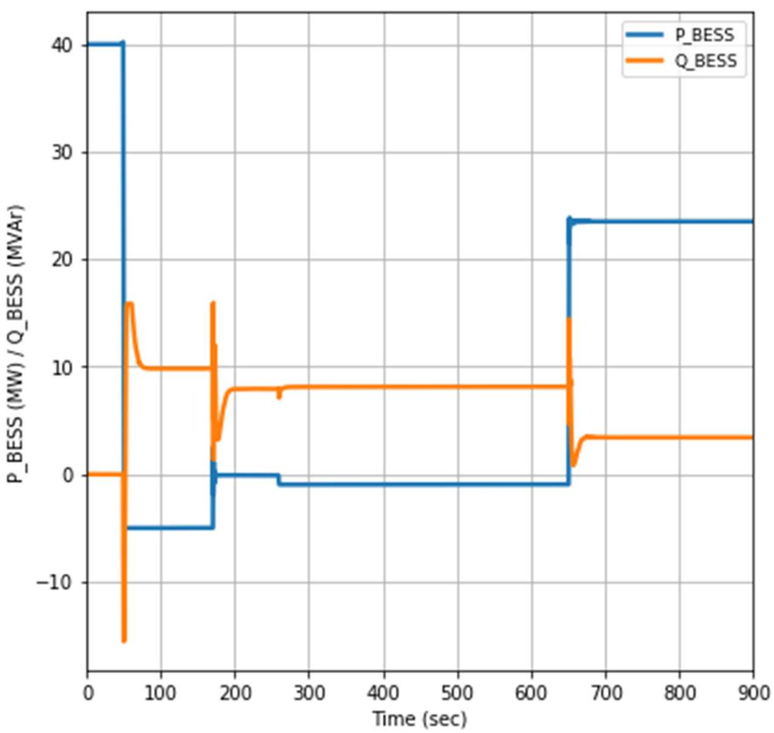

Figure 7: BESS response to high frequencies during discharging

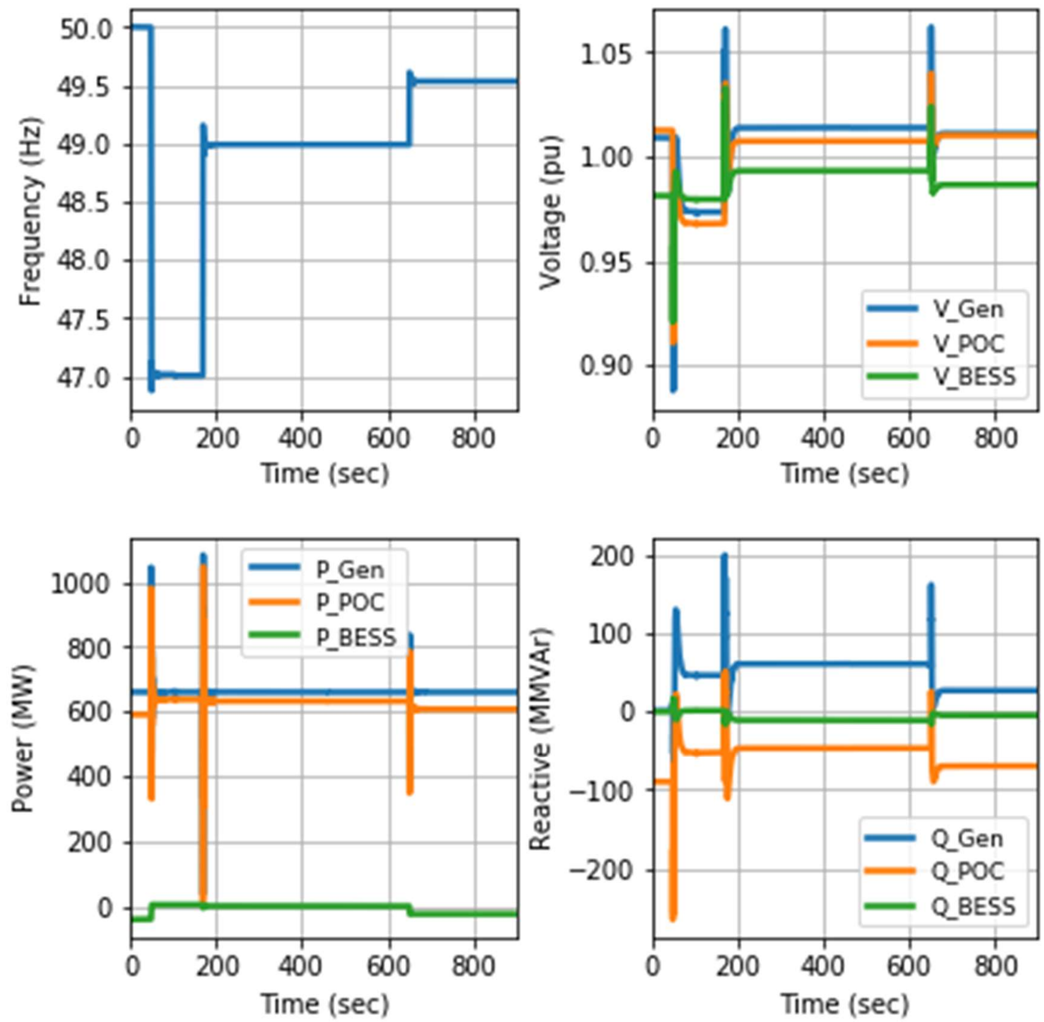

Figure 8: Response to low frequencies during BESS charging

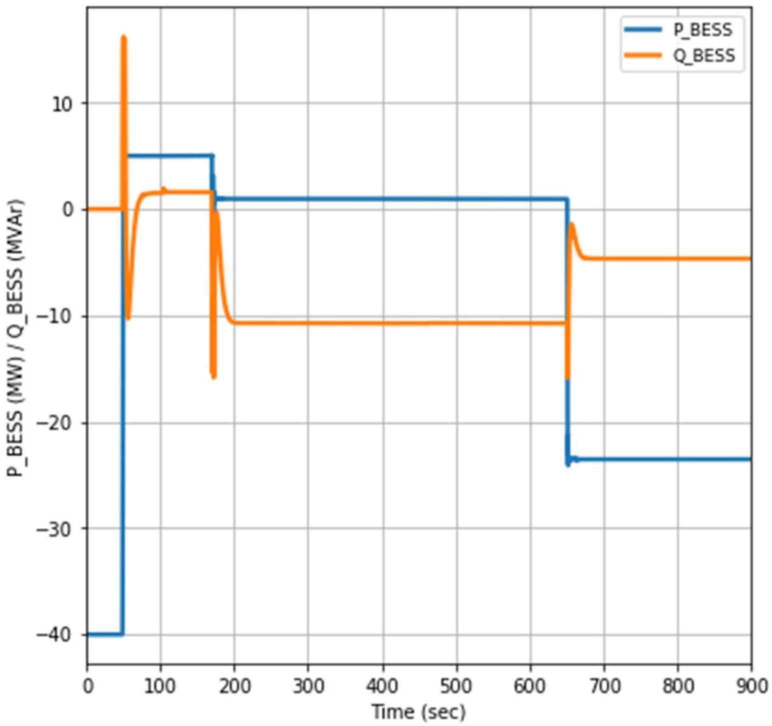

Figure 9: BESS response to low frequencies during charging

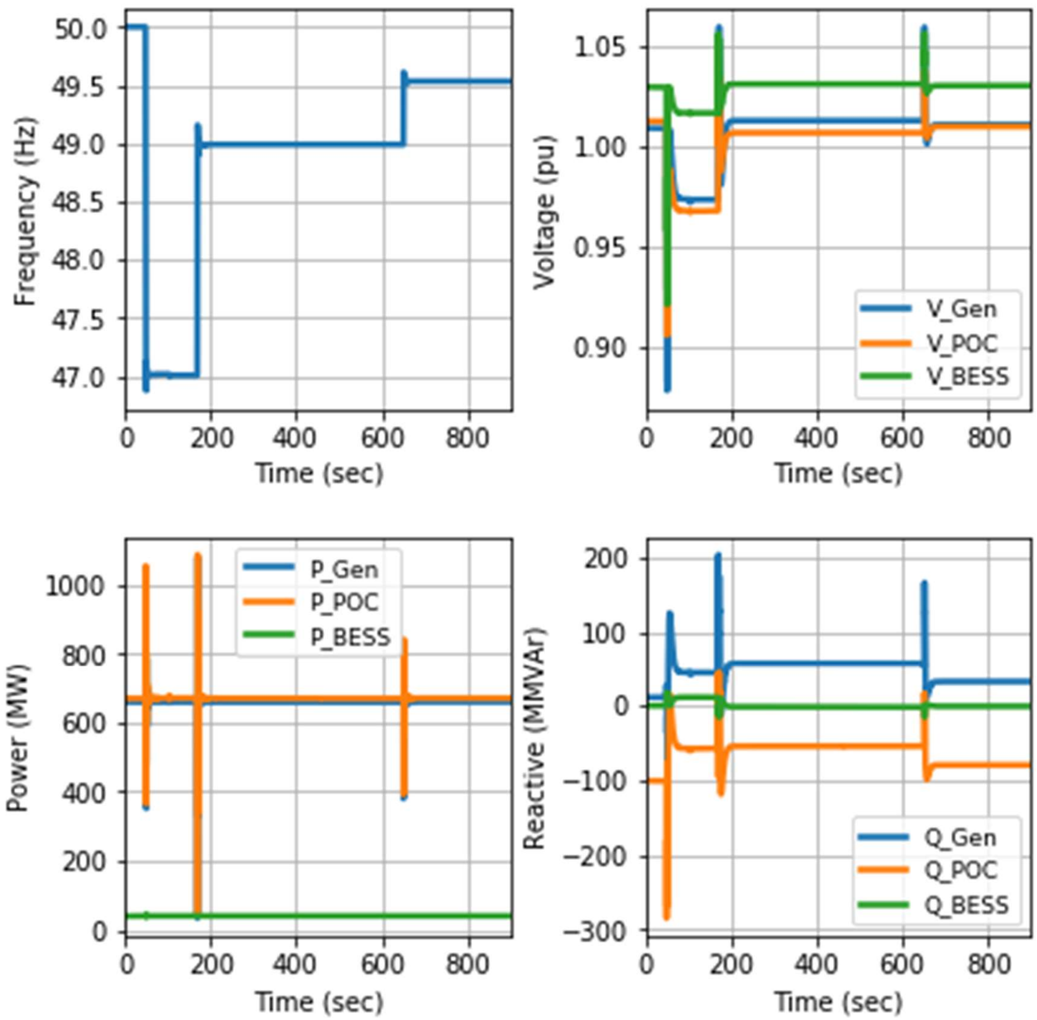

Figure 10: Response to low frequencies during BESS discharging

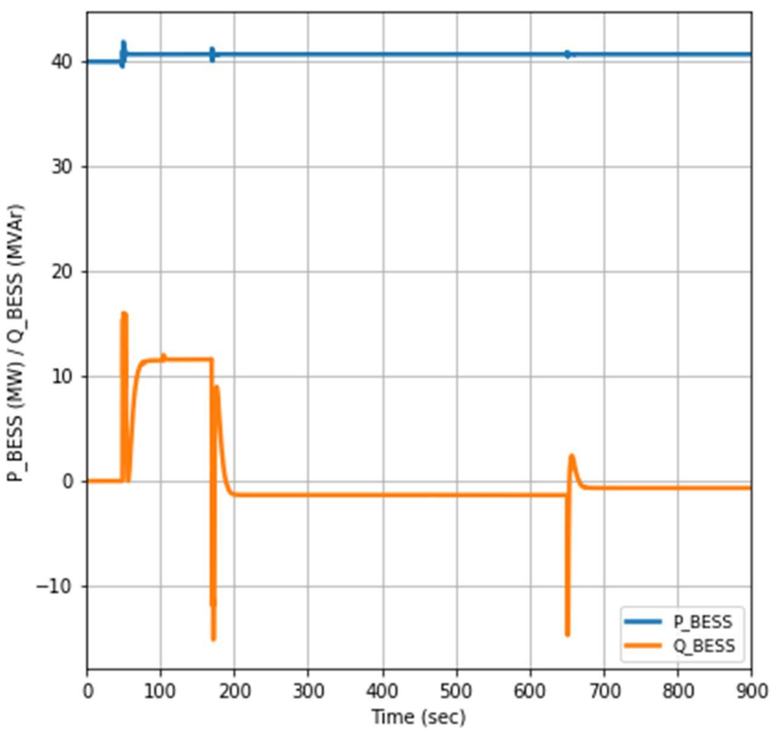

Figure 11: BESS response to low frequencies during discharging

3.2 S5.2.5.4 Generating System Response to Voltage Disturbances

The performance of the Vales Point generator is evaluated with the integration of the BESS against the voltage disturbances. For the study, the Vales point Generator has not been equipped with any protection system. Meanwhile, the under-voltage and over-voltage protection system for the BESS has been chosen in compliance with automatic access standard to clause S5.2.5.4 as depicted in Figure 12.

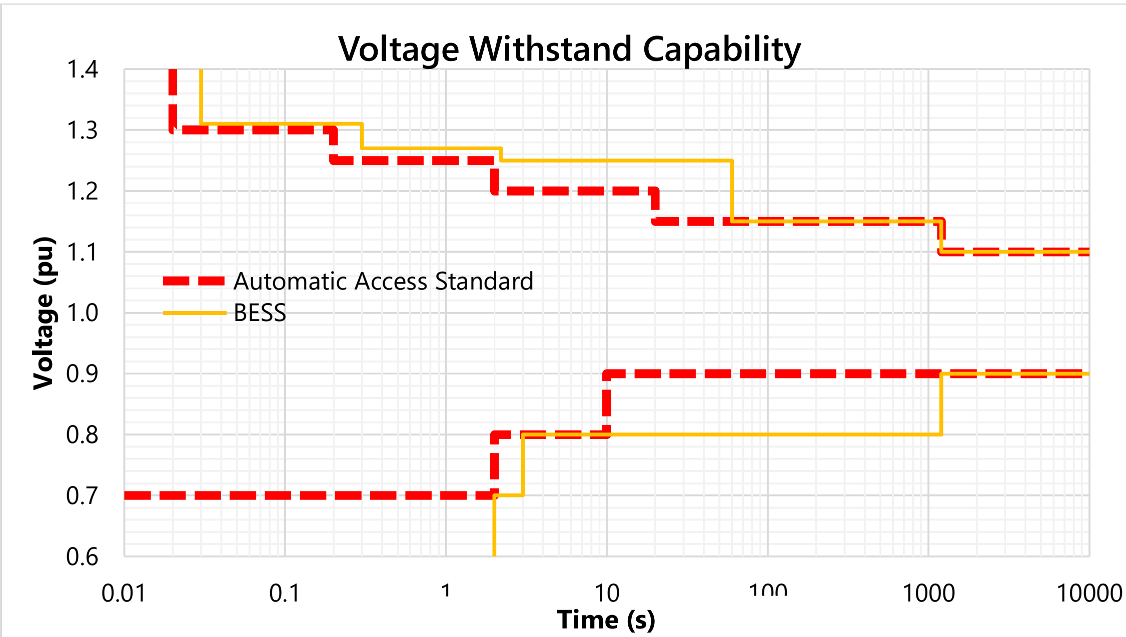

Figure 12: BESS voltage withstand capability

The plant capability is demonstrated by connecting the combined Vales Point Generator model with the BESS to a voltage and frequency controllable source which controls the 330 kV POC bus through a very low impedance line (R=0, X=0.0001). The simulation has been initialized at 660 MW / 400 MVAr at the Vales Point generator terminal.

Simulation results are plotted in Figure 13 - Figure 17. The BESS has been able to ride through the disturbances and can provide a "continuous uninterrupted operation". Active power returns to the pre-disturbance value when the voltage returns to 90%-110% of the normal voltage. The Vales Point generator successfully supports the grid voltage without resulting any adverse impact to the BESS.

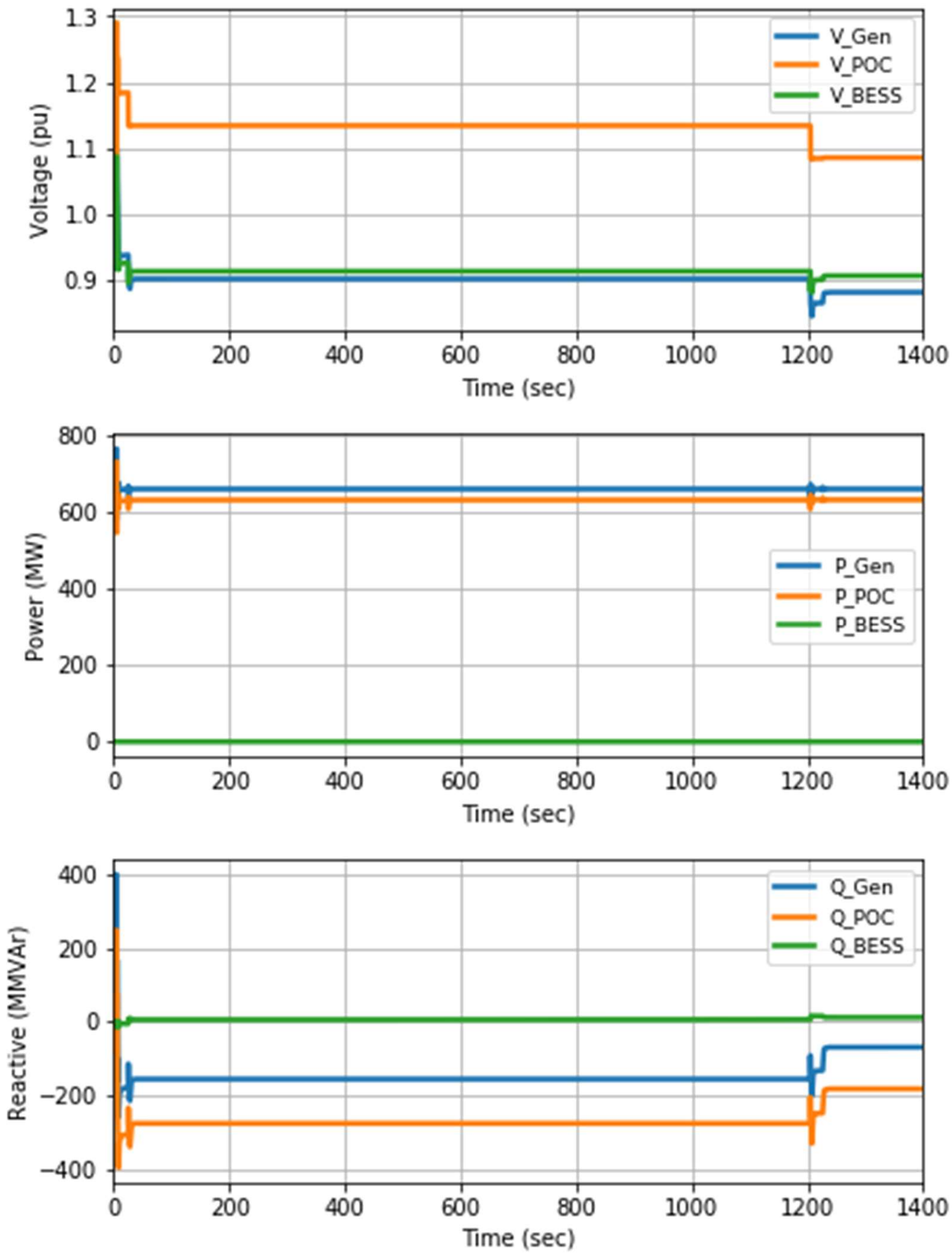

Figure 13: HVRT response

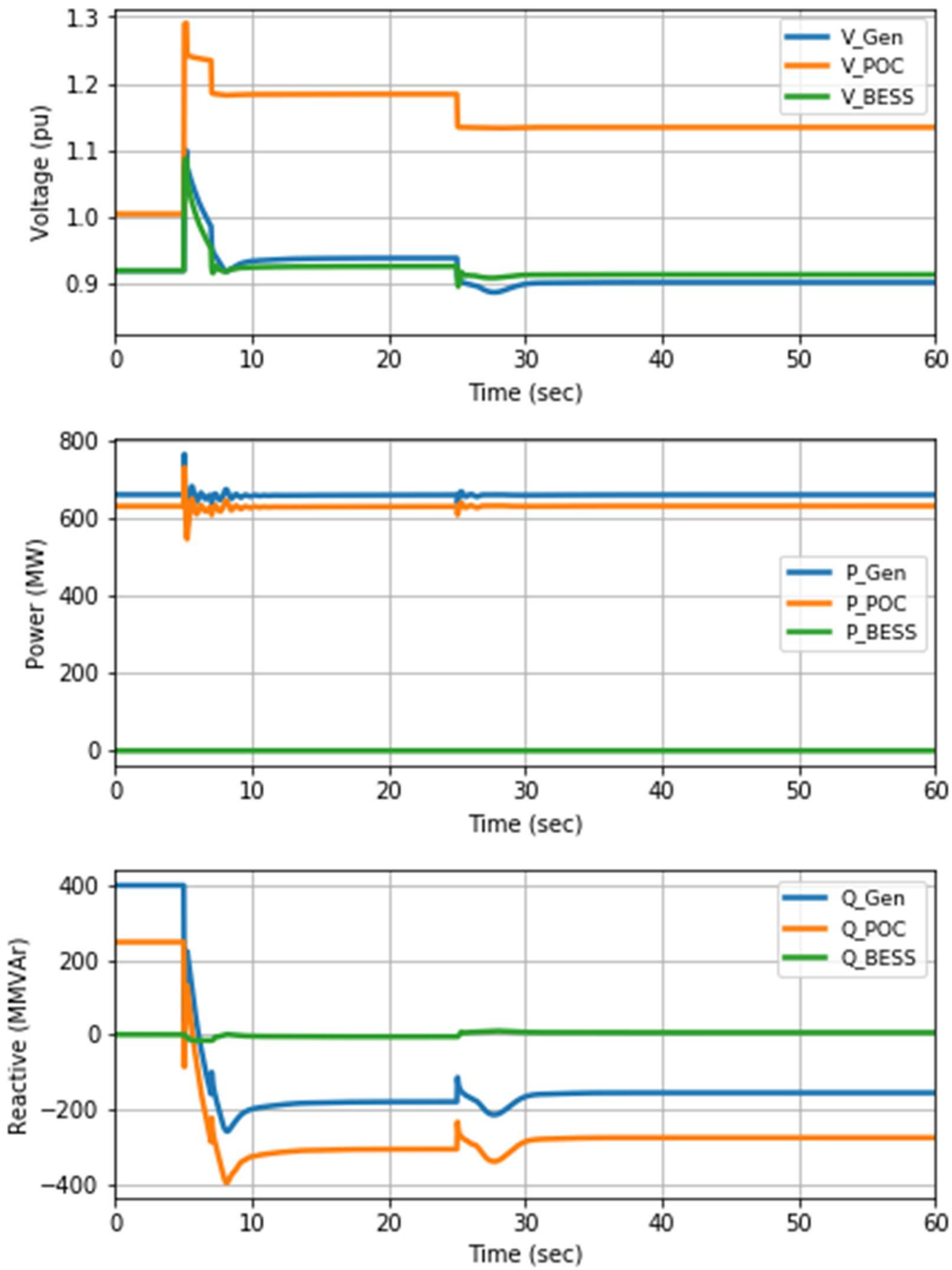

Figure 14: HVRT response (zoomed)

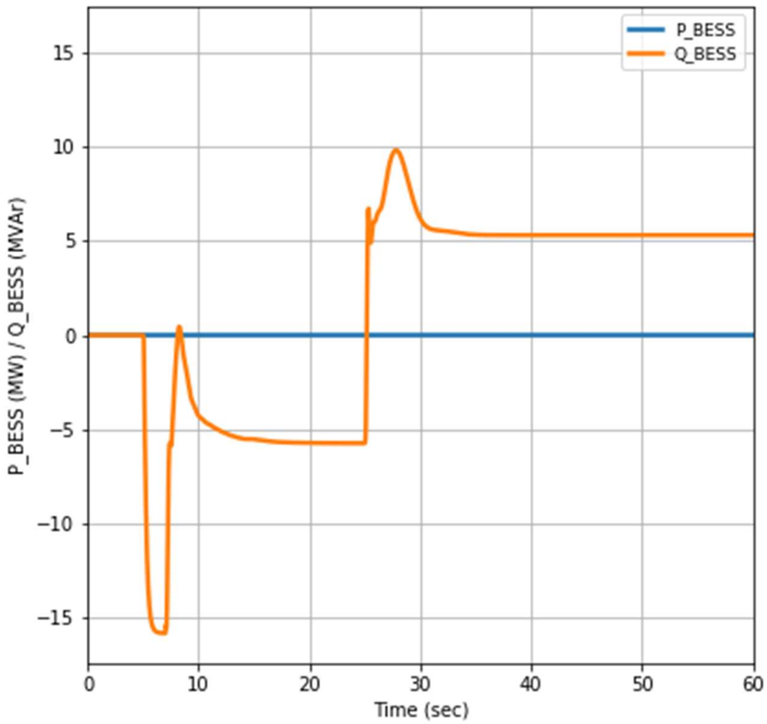

Figure 15: HVRT response (BESS only)

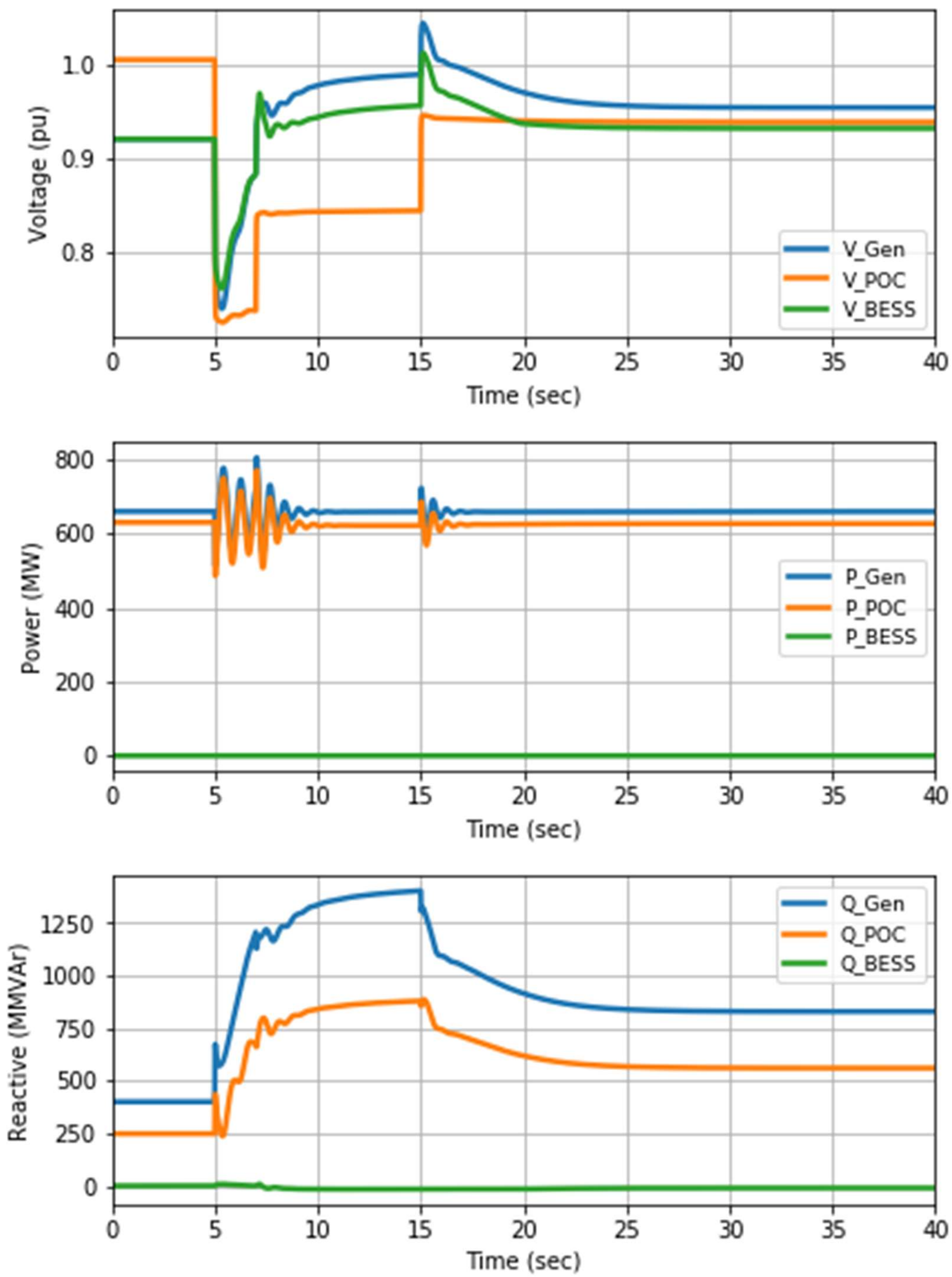

Figure 16: LVRT response

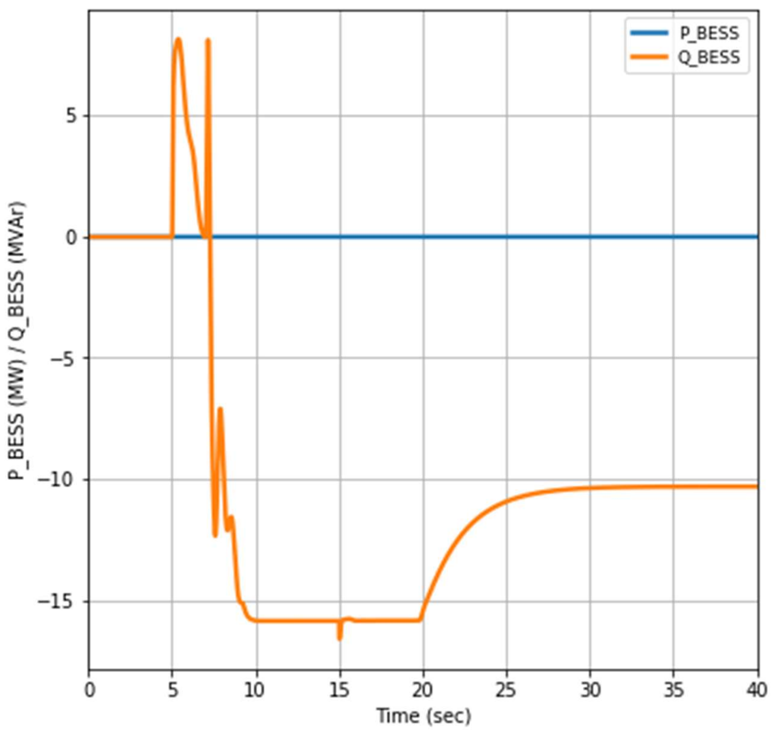

Figure 17: LVRT response (BESS only)

3.3 S5.2.5.5 Generating System Response to Disturbances following Contingency Events

The performance of the Vales Point generator is evaluated with the integration of the BESS against the disturbances following contingency events. The study is conducted by simulation on a controlled voltage and frequency source. The impedance of the grid representation has been for a short-circuit ratio of 4.5 and X/R ratio of 3.0. The active power is set to the maximum output of the vales Point generator. The contingencies listed in Table 1 have been applied at t = 1 s:

Table 1: Contingency specifications

Fault Type	Fault clearance time (ms)	Fault resistance (Ω)
Three-phase short circuit (LLLG) fault	120	1
double circuit (LLG) fault	240	0.001

The simulations have been initialised at six different operating points at the Vales point generator terminal. These are:

Point 1-> 660 MW / 0 MVAr

Point 2-> 660 MW / -250 MVAr

Point 3-> 660 MW / 40 MVAr

Point 4-> 250 MW / -339 MVAr

Point 5-> 250 MW / -560 MVAr

Point 6-> 250 MW / 0 MVAr

As observed from the simulation results plotted in Figure 18 - Figure 41, the system remains stable for all the operating conditions. Moreover, the BESS system does not make any unwanted interaction with the Vales Point generator during various faults, rather it actively participates in supporting the generator to restore the post-fault voltage by providing reactive power.

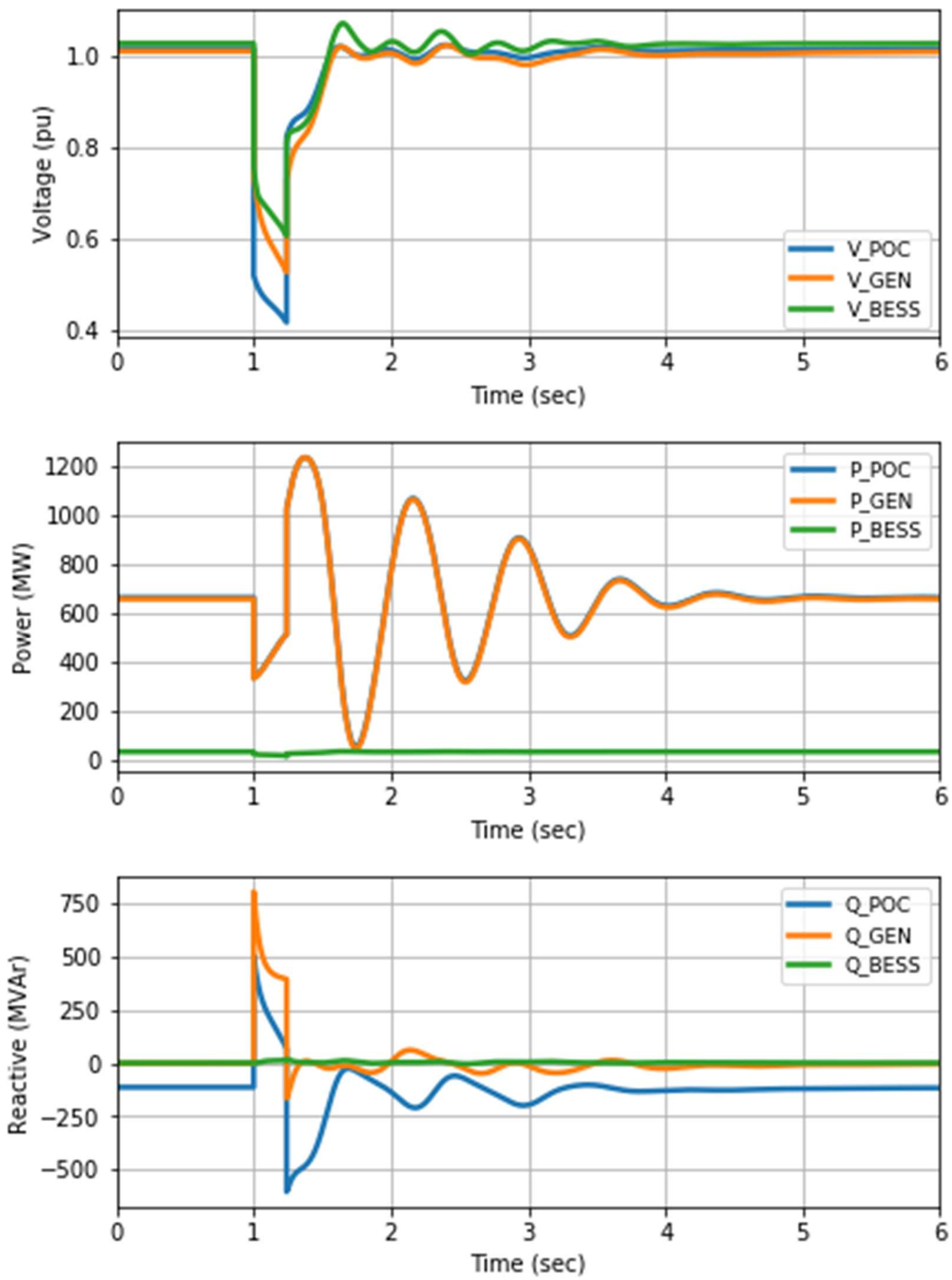

Figure 18: Fault response for an LLG fault - Point 1

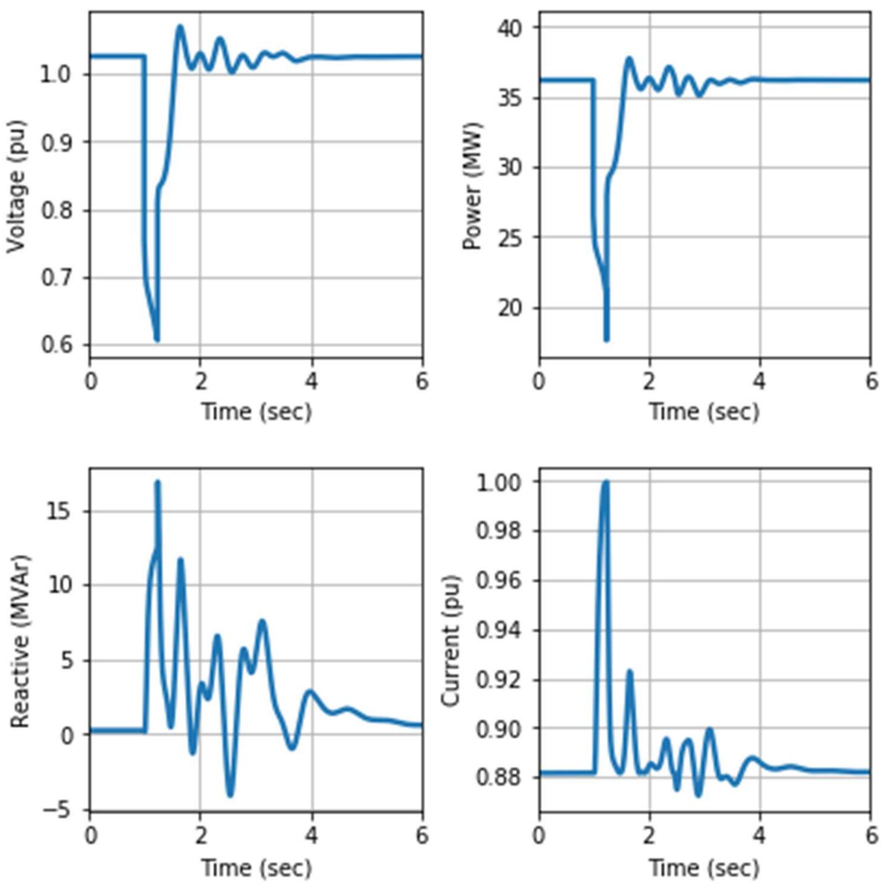

Figure 19: Fault response for an LLG fault (BESS only) - Point 1

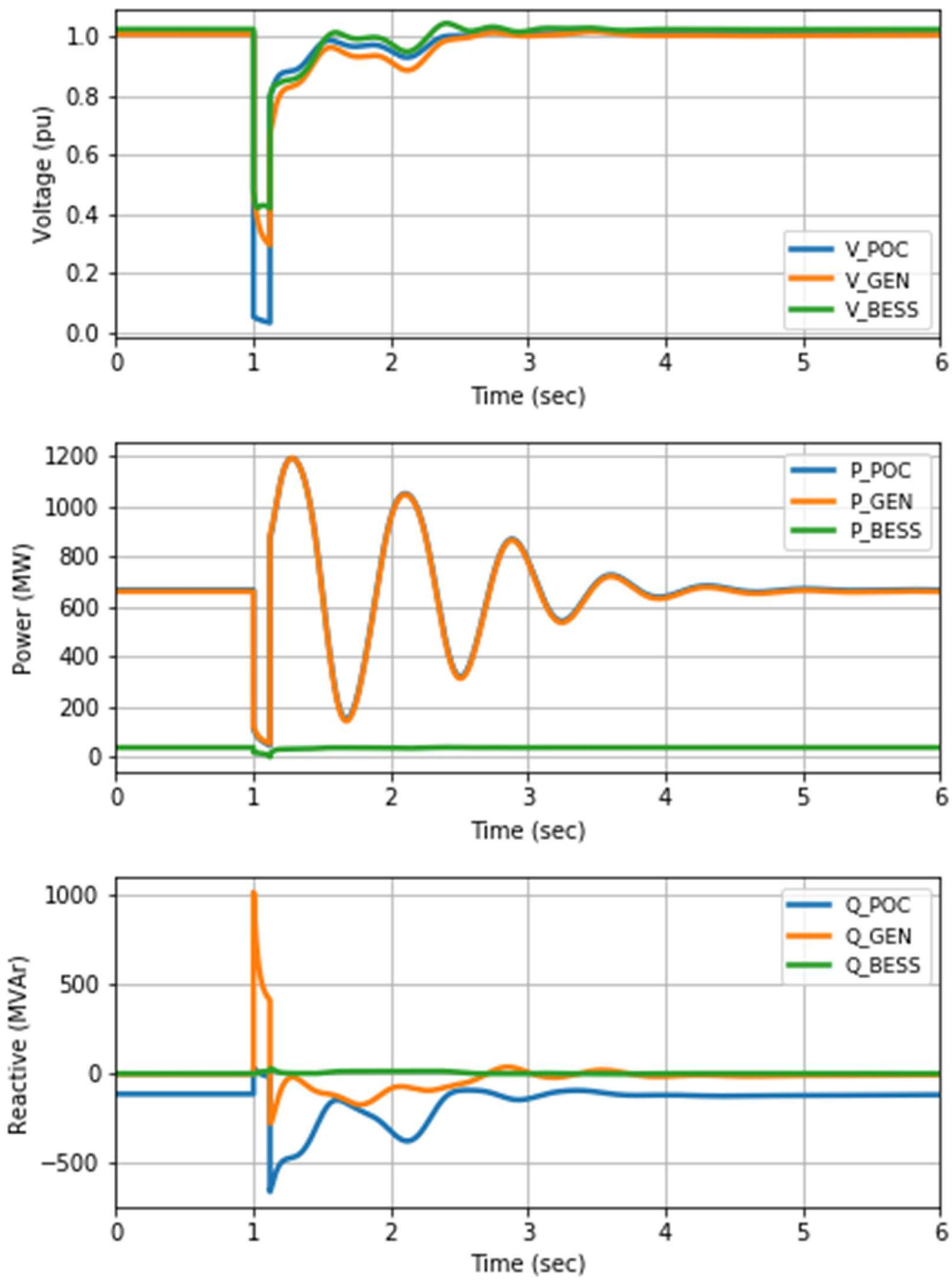

Figure 20: Fault response for an LLLG fault - Point 1

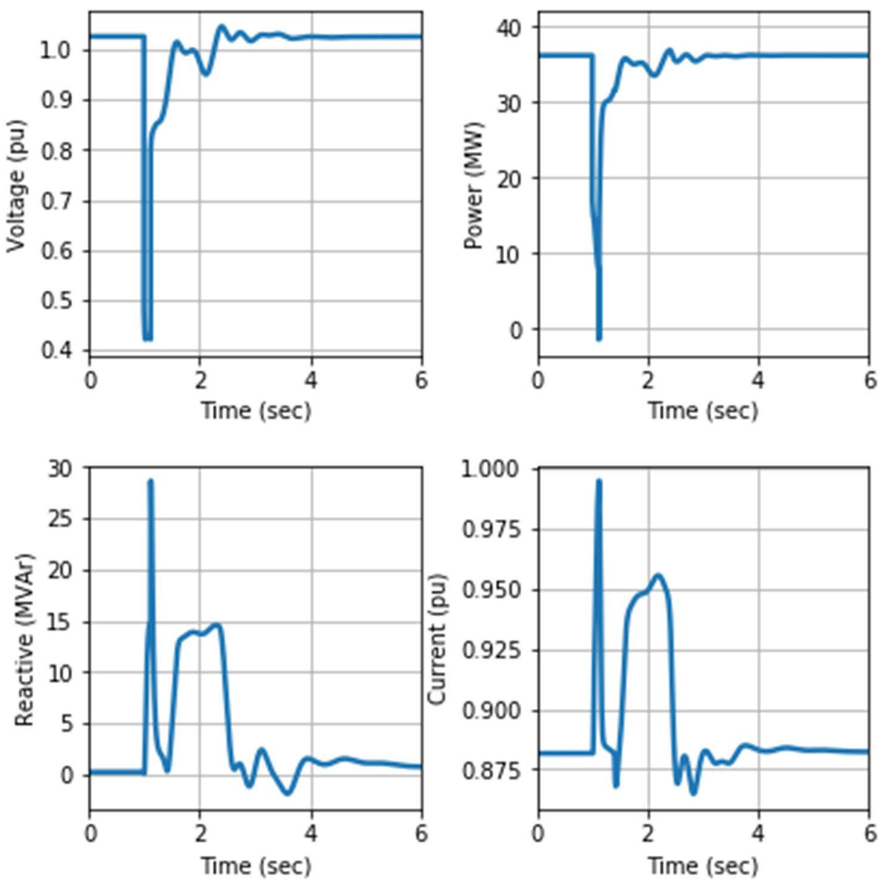

Figure 21: Fault response for an LLLG fault (BESS only) - Point 1

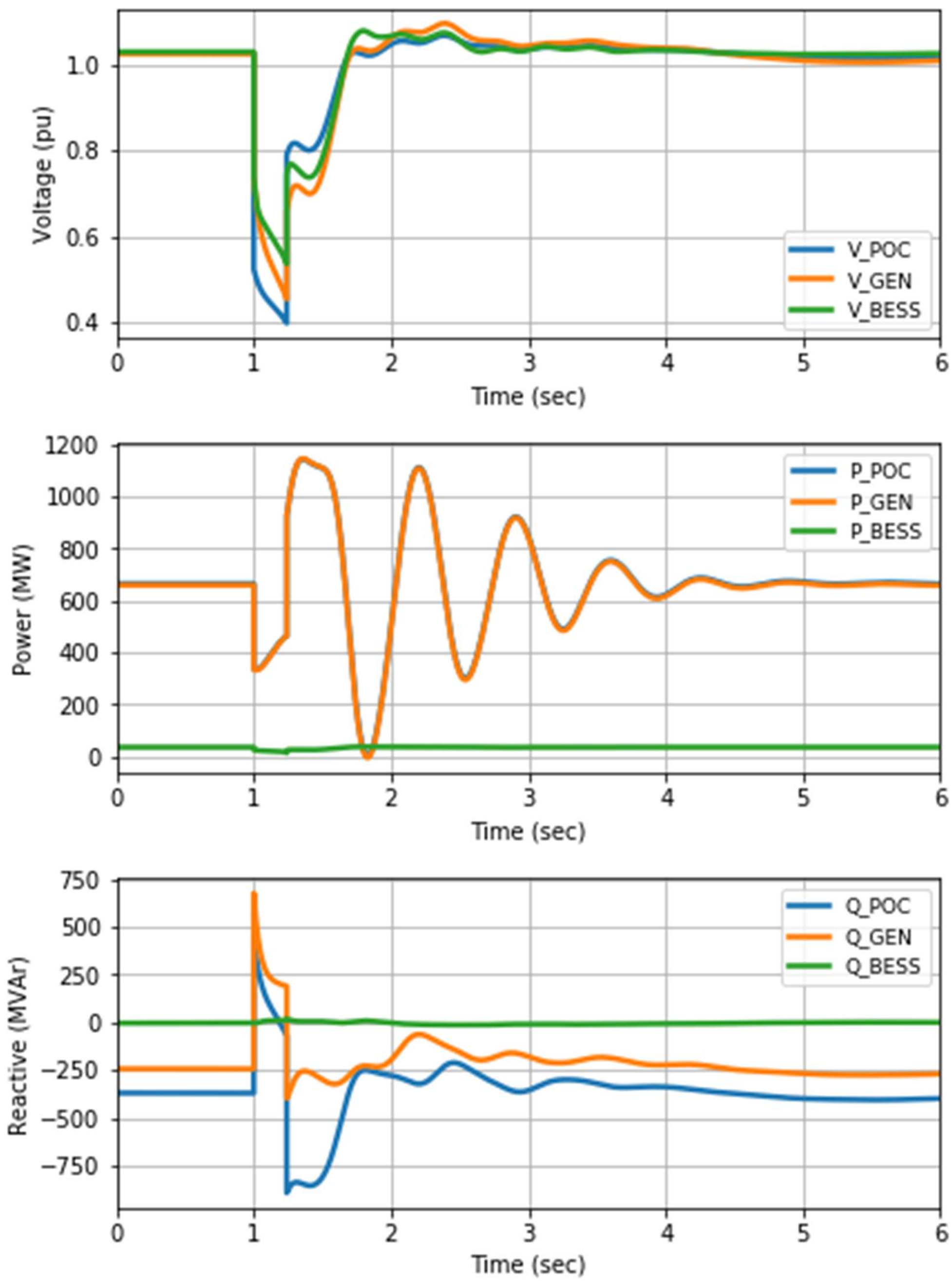

Figure 22: Fault response for an LLG fault - Point 2

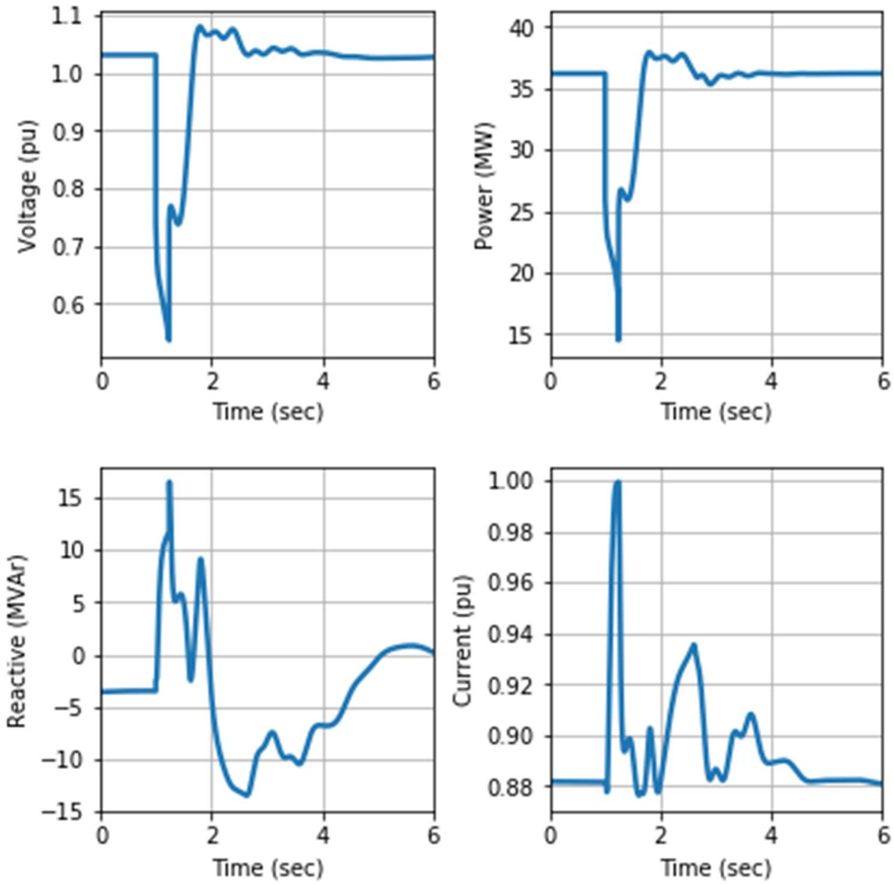

Figure 23: Fault response for an LLG fault (BESS only) - Point 2

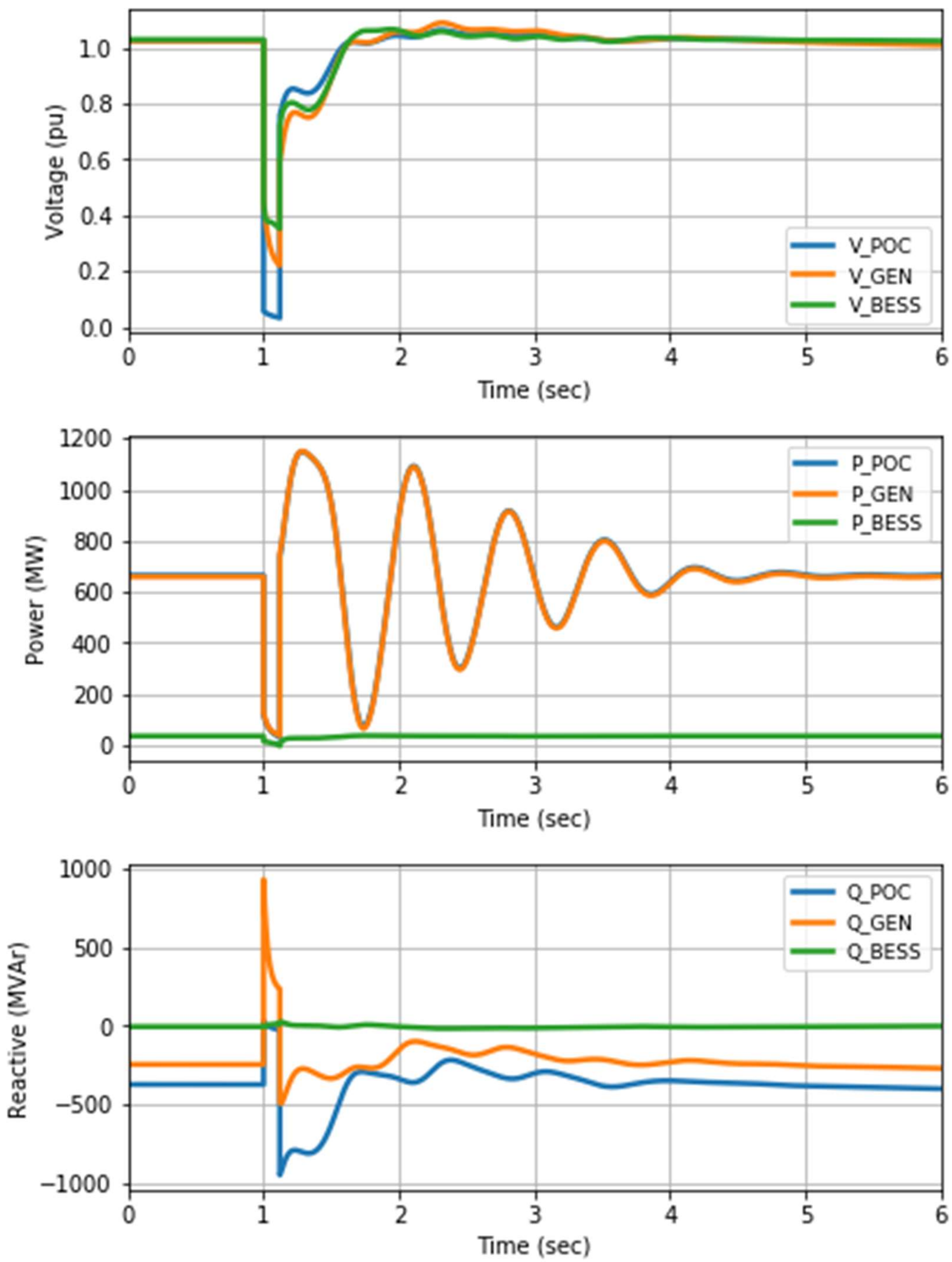

Figure 24: Fault response for an LLLG fault - Point 2

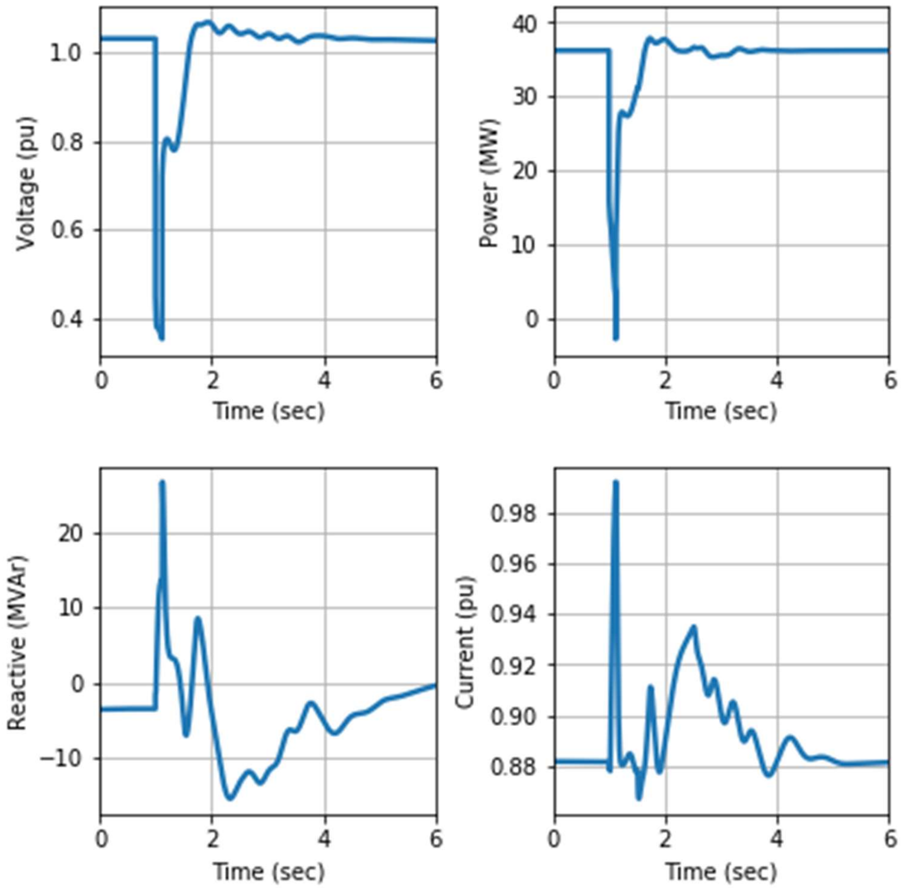

Figure 25: Fault response for an LLLG fault (BESS only) - Point 2

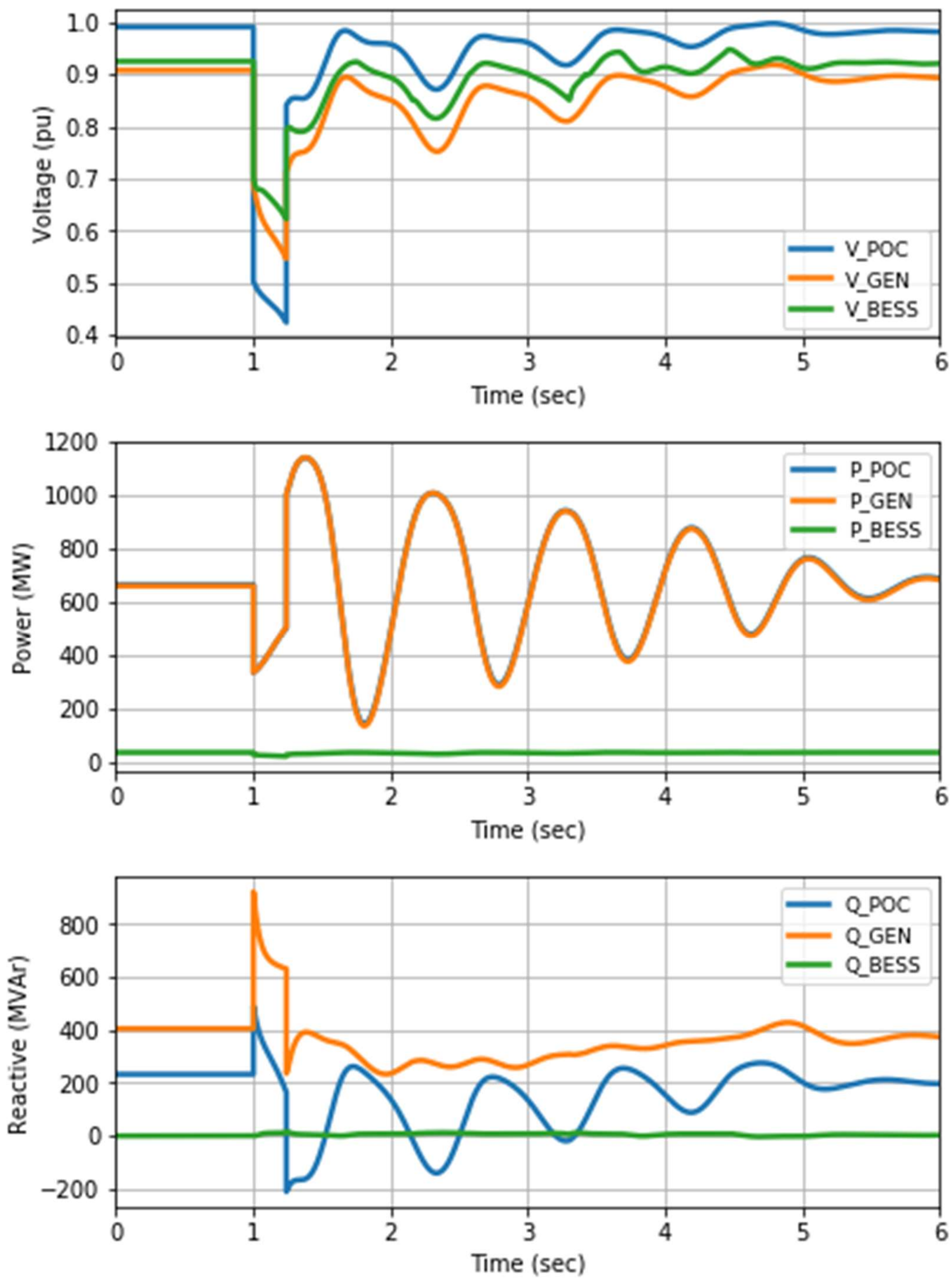

Figure 26: Fault response for an LLG fault - Point 3

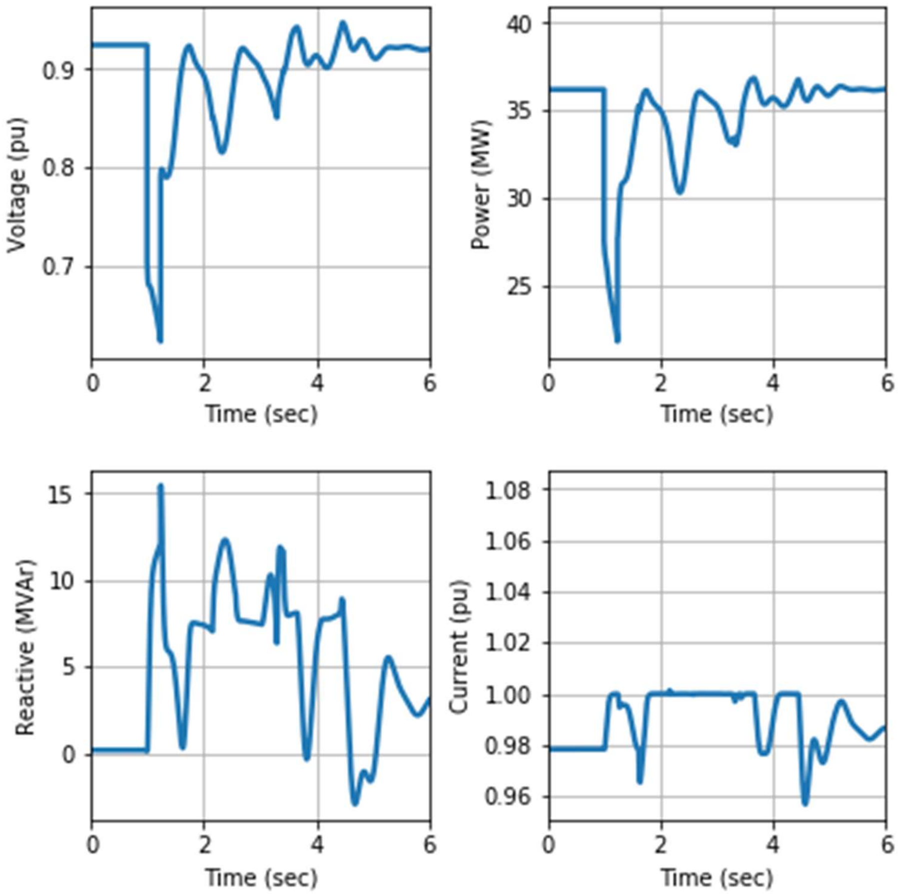

Figure 27: Fault response for an LLG fault (BESS only) - Point 3

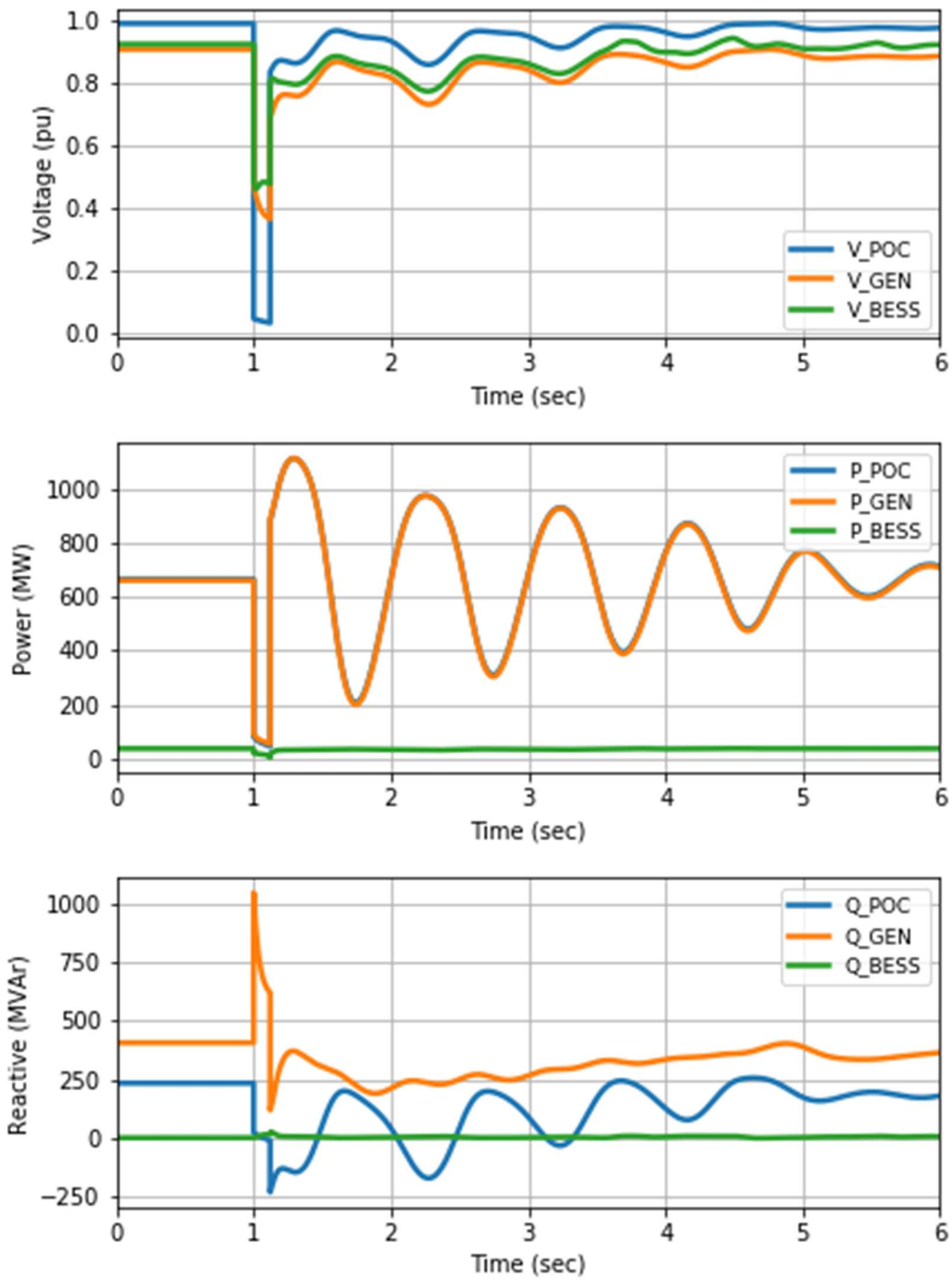

Figure 28: Fault response for an LLLG fault - Point 3

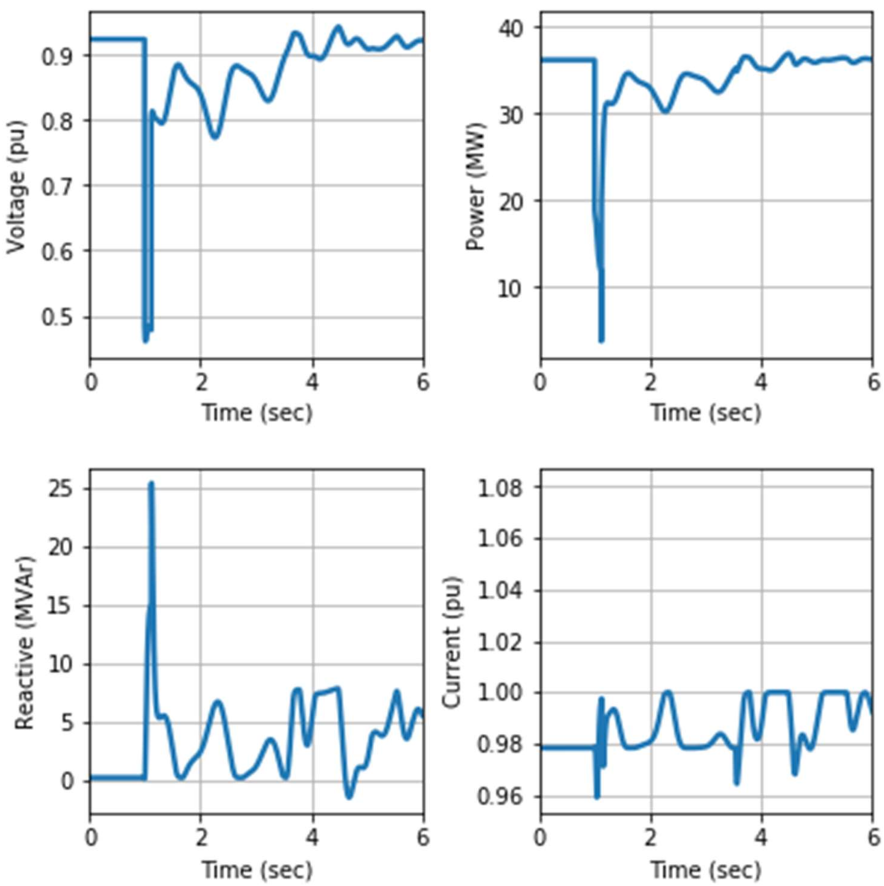

Figure 29: Fault response for an LLLG fault (BESS only) - Point 3

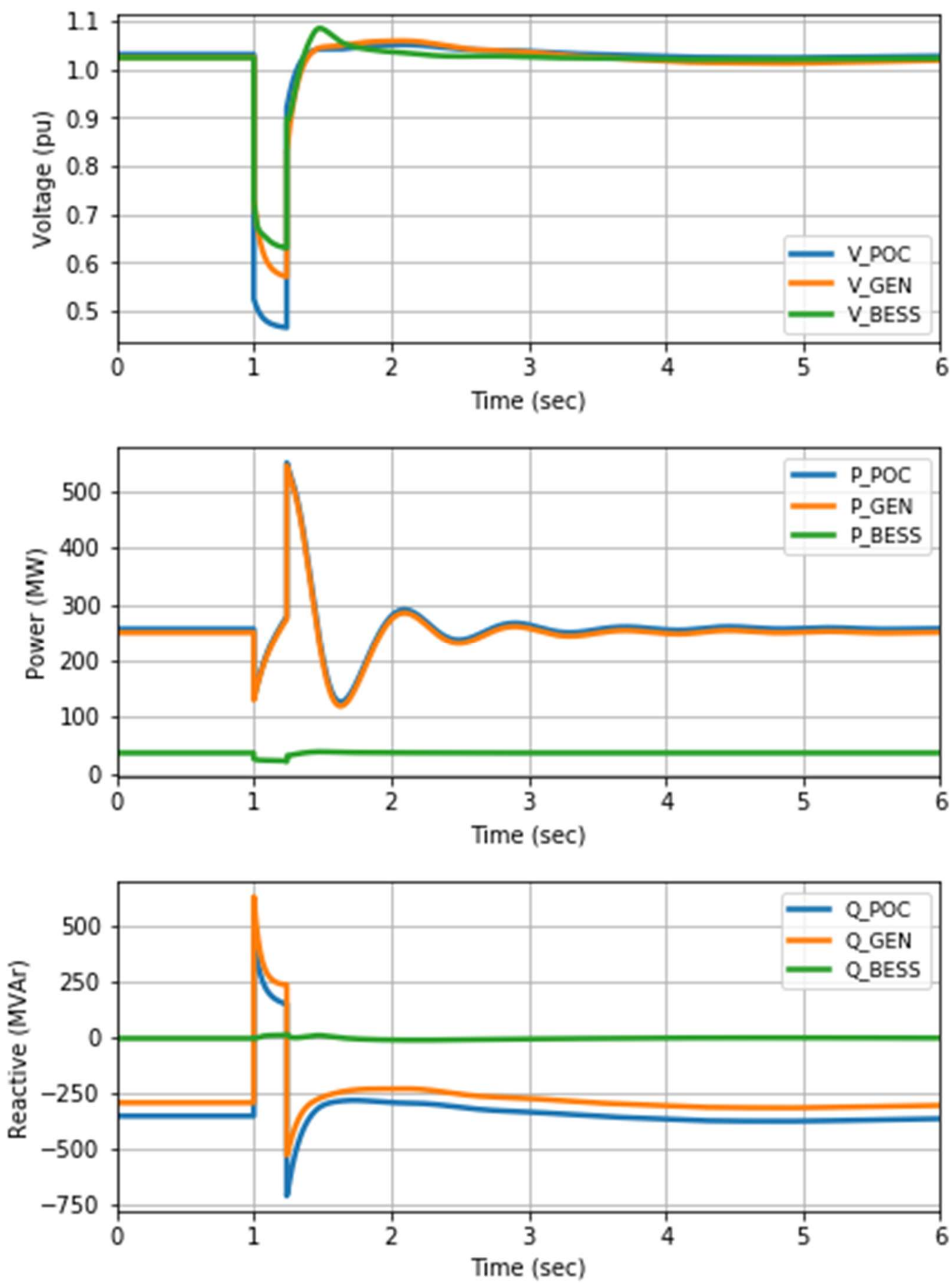

Figure 30: Fault response for an LLG fault - Point 4

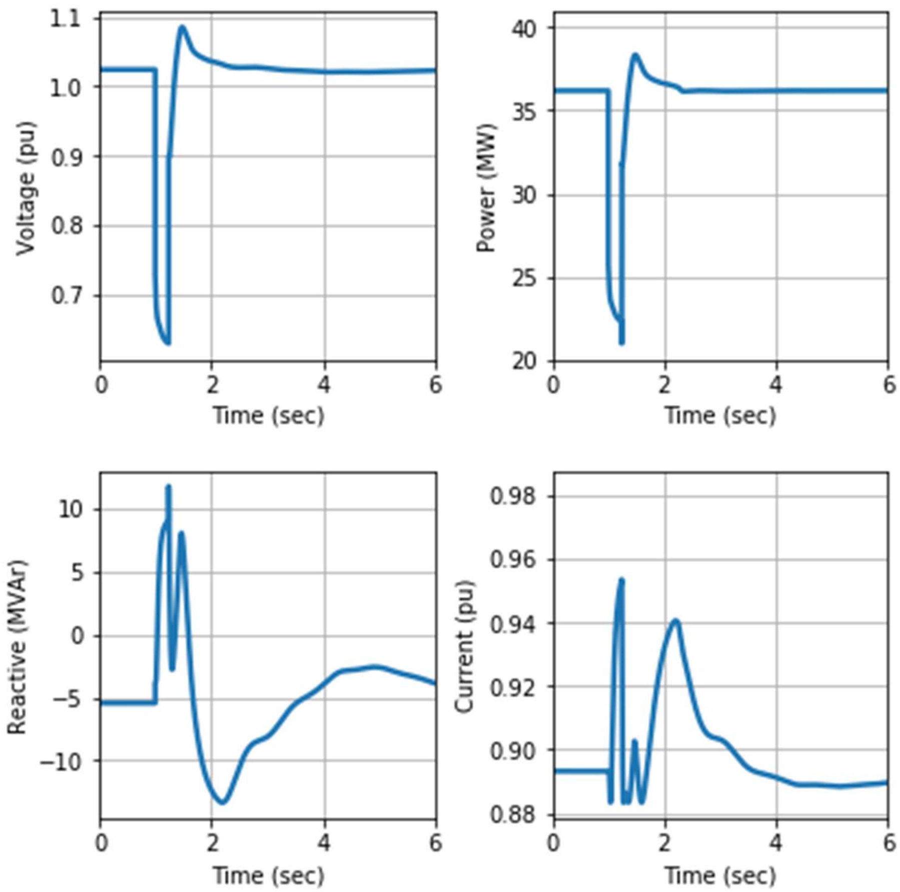

Figure 31: Fault response for an LLG fault (BESS only) - Point 4

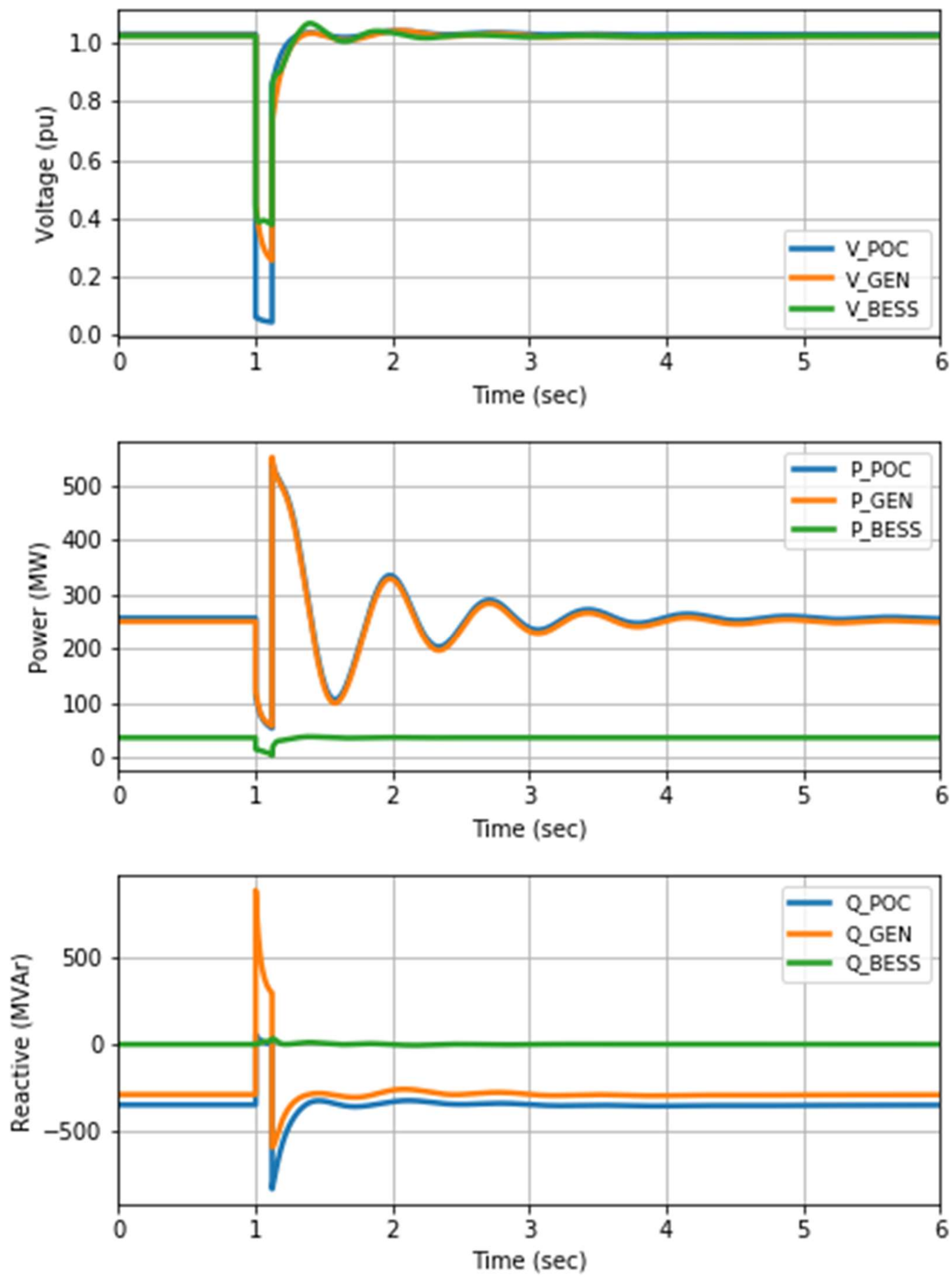

Figure 32: Fault response for an LLLG fault - Point 4

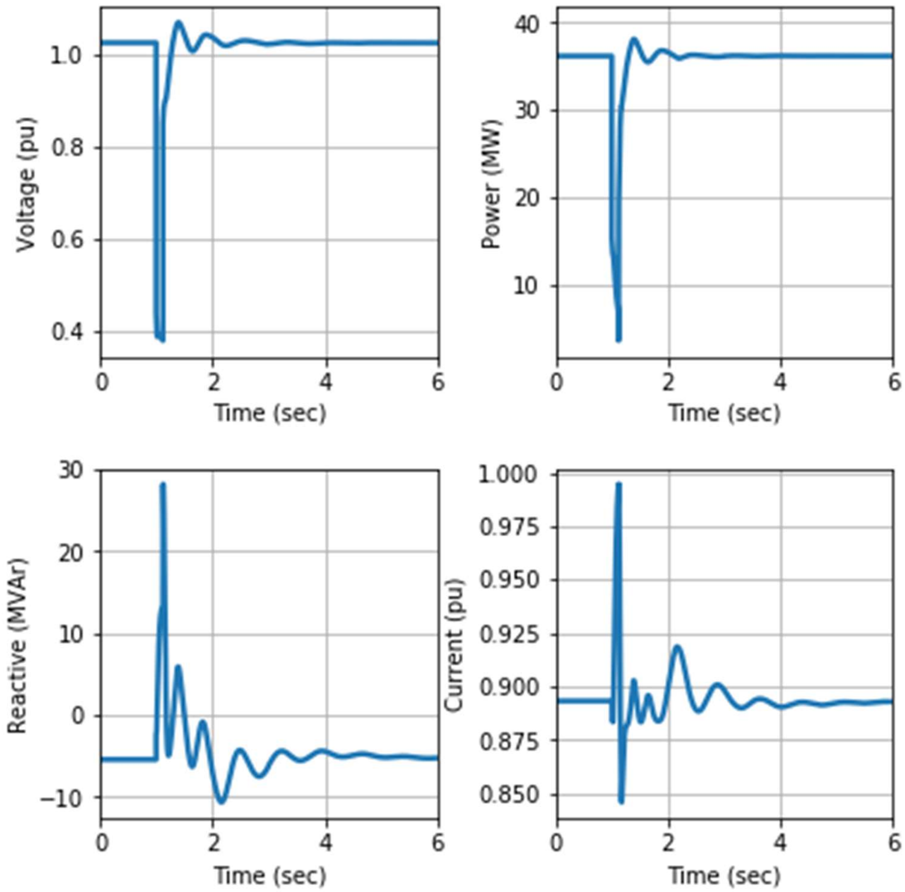

Figure 33: Fault response for an LLLG fault (BESS only) - Point 4

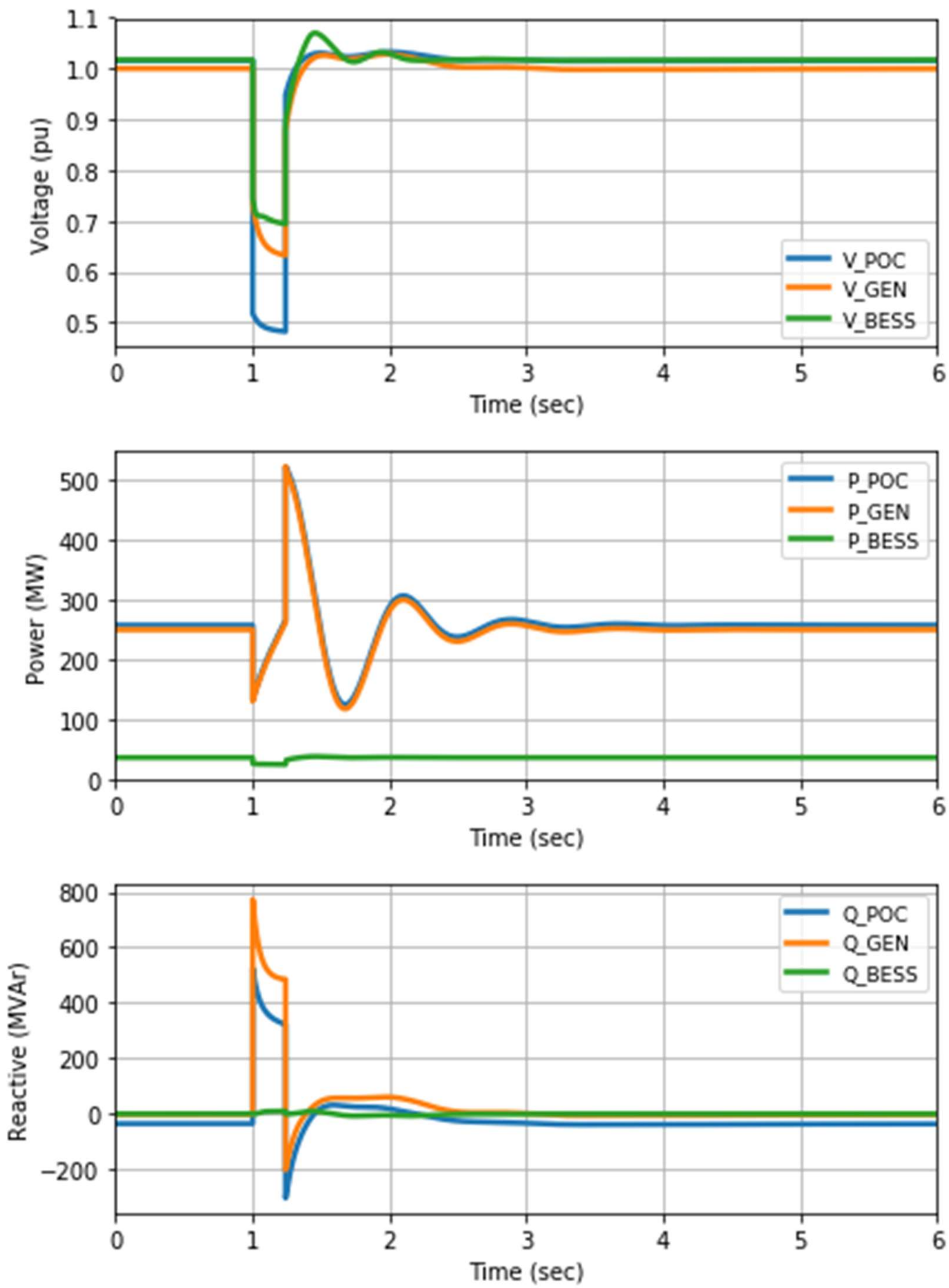

Figure 34: Fault response for an LLG fault - Point 5

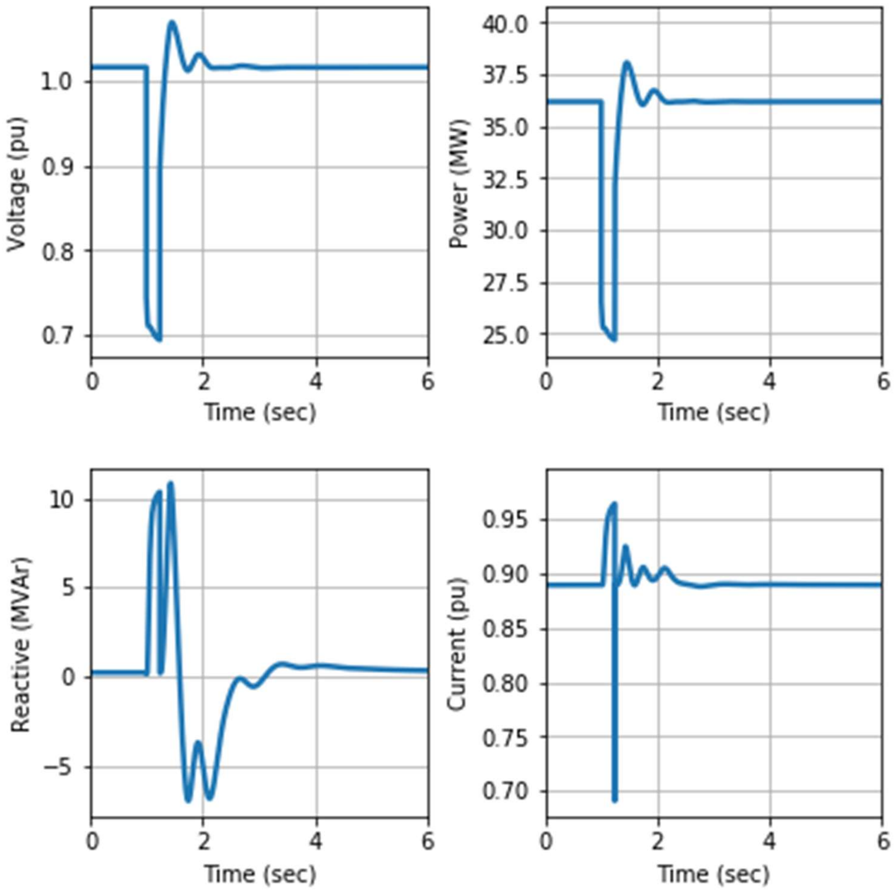

Figure 35: Fault response for an LLG fault (BESS only) - Point 5

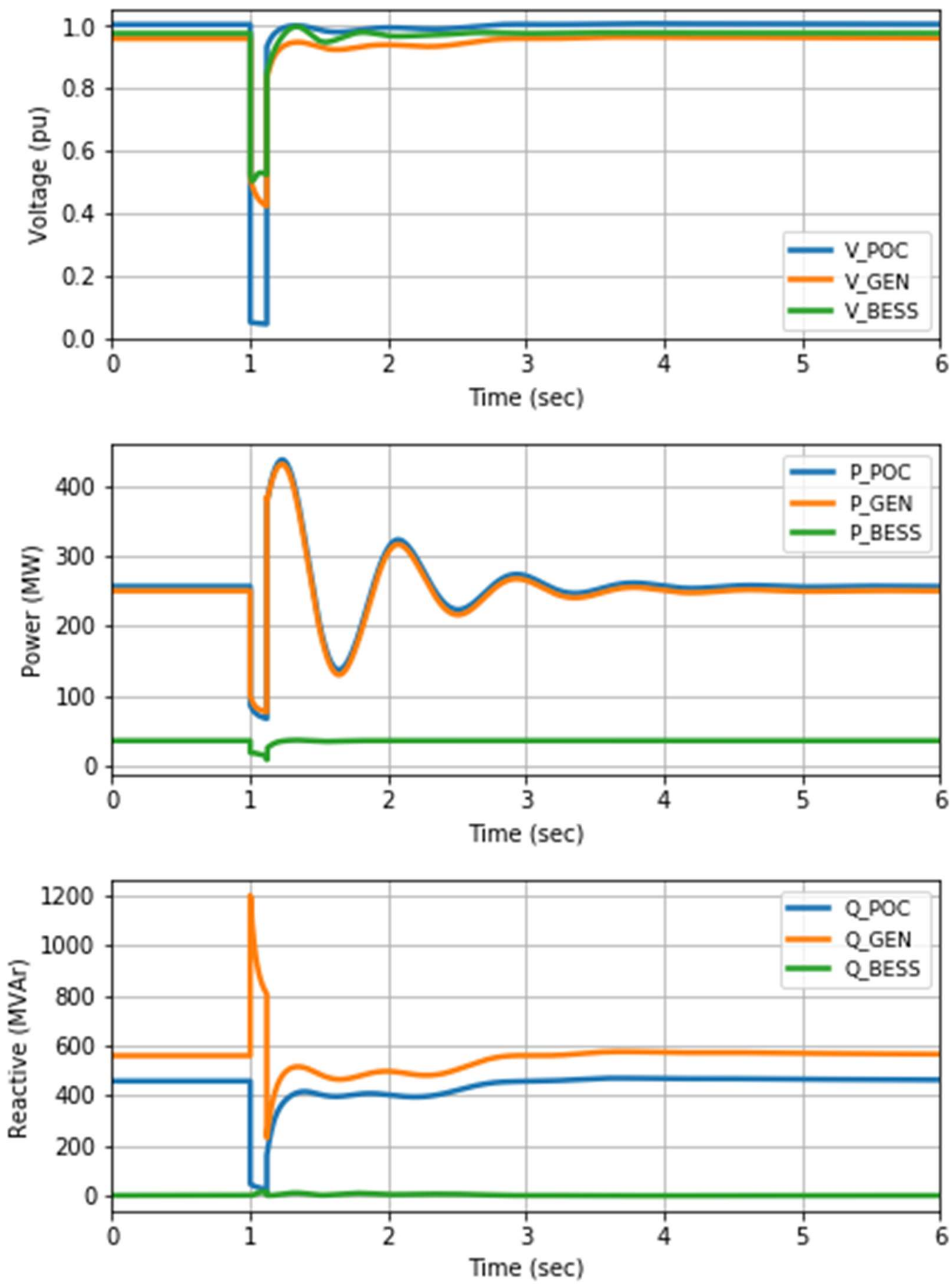

Figure 36: Fault response for an LLLG fault - Point 5

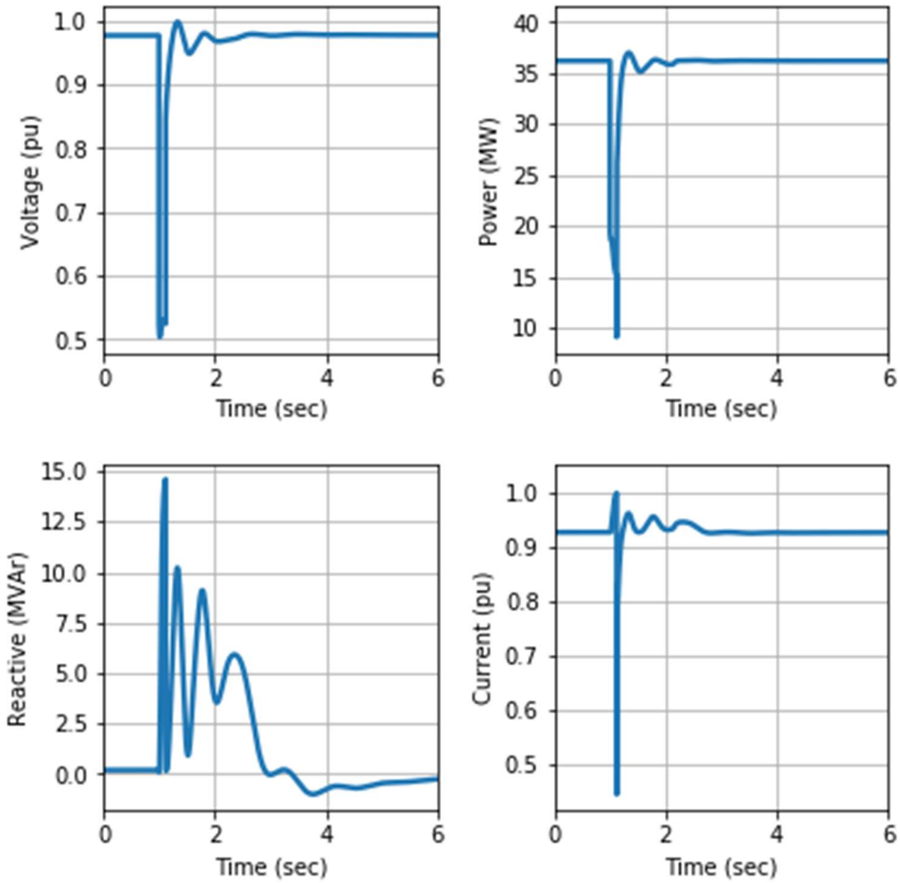

Figure 37: Fault response for an LLLG fault (BESS only) - Point 5

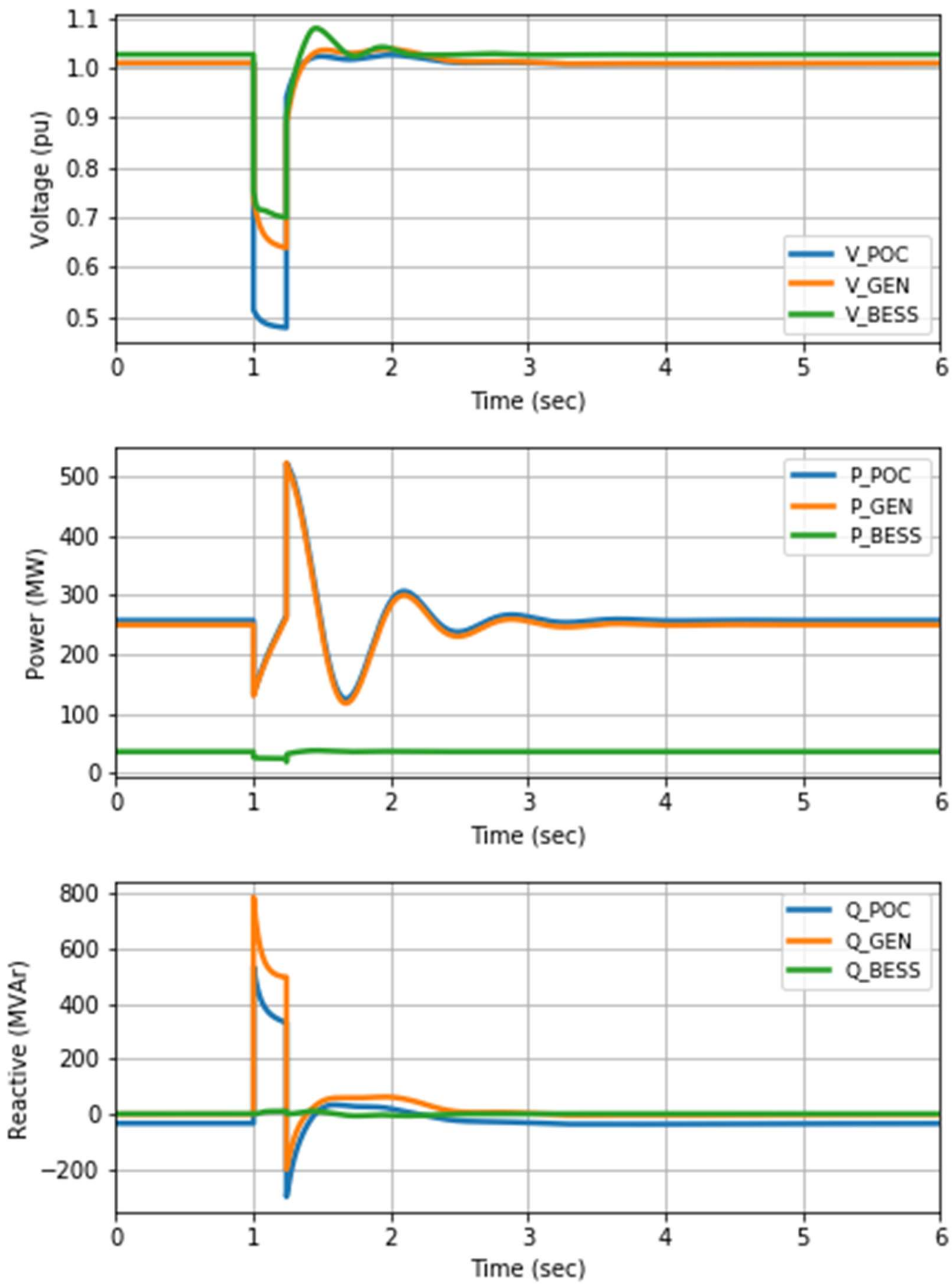

Figure 38: Fault response for an LLG fault - Point 8

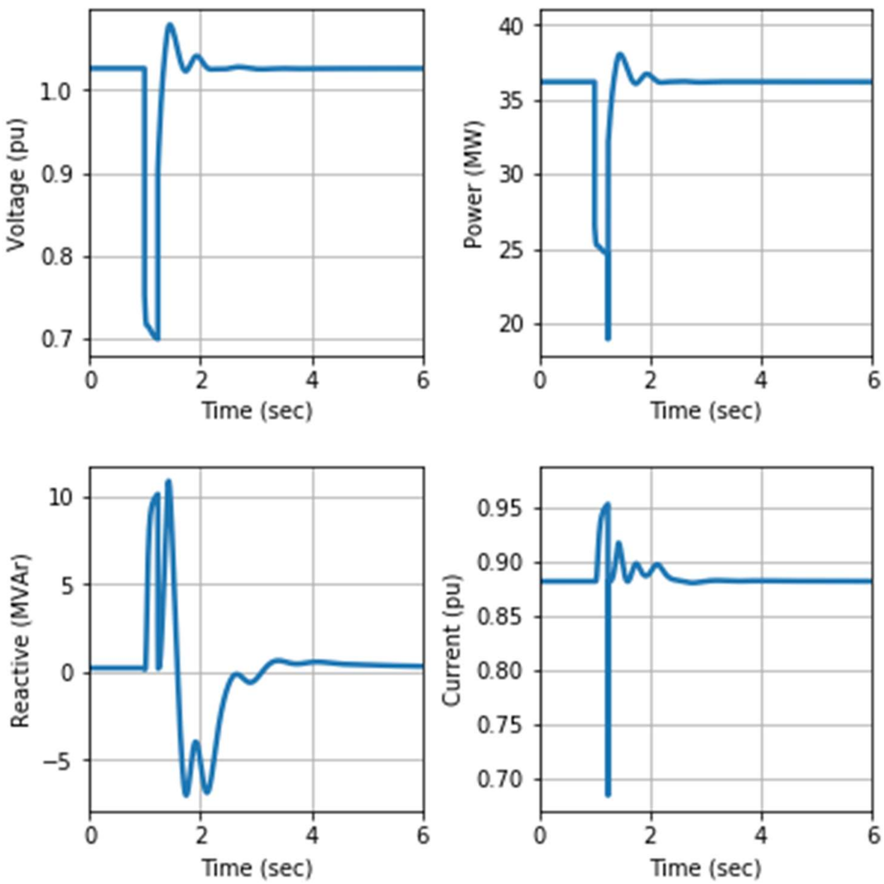

Figure 39: Fault response for an LLG fault (BESS only) - Point 6

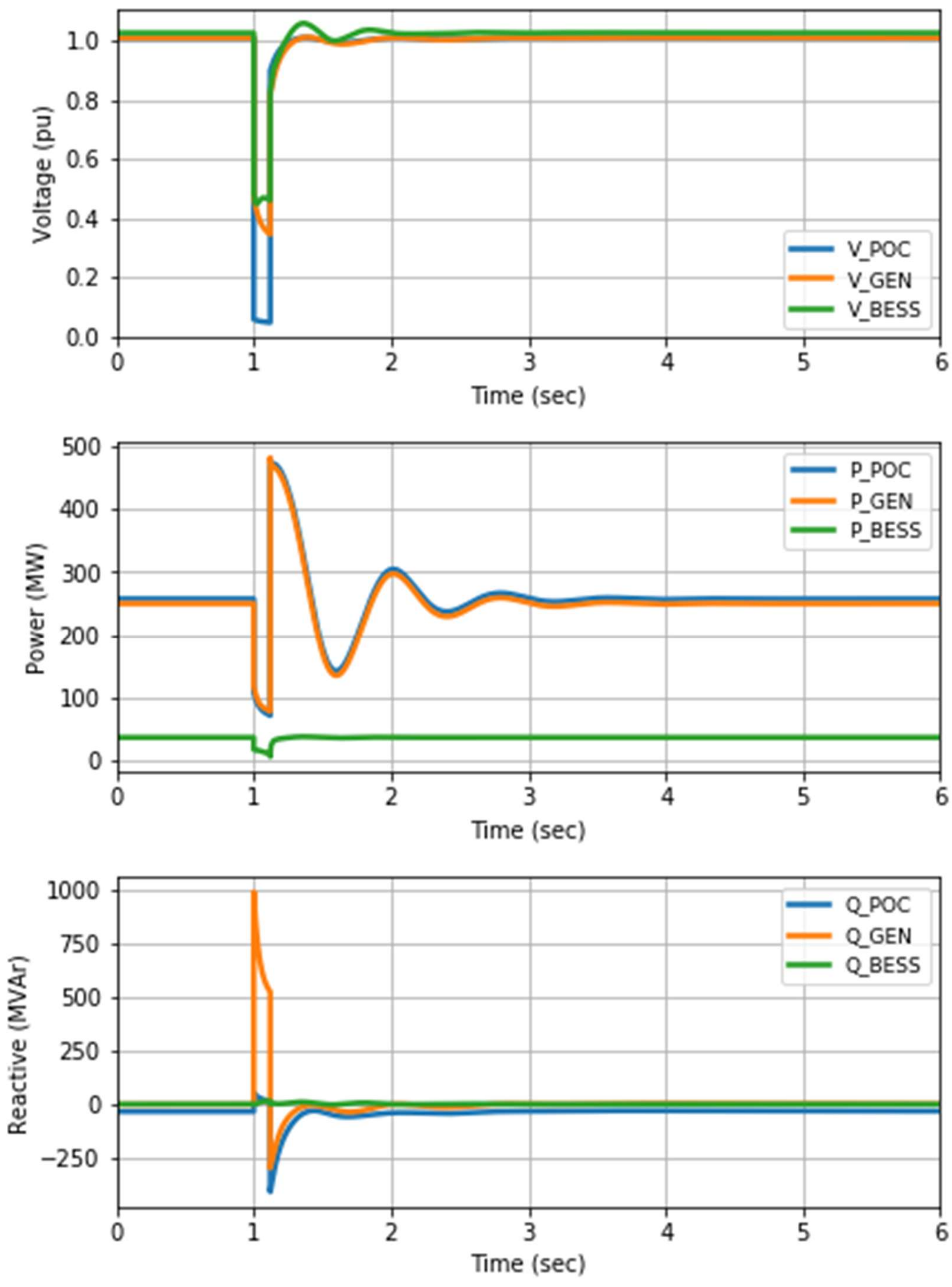

Figure 40: Fault response for an LLLG fault - Point 6

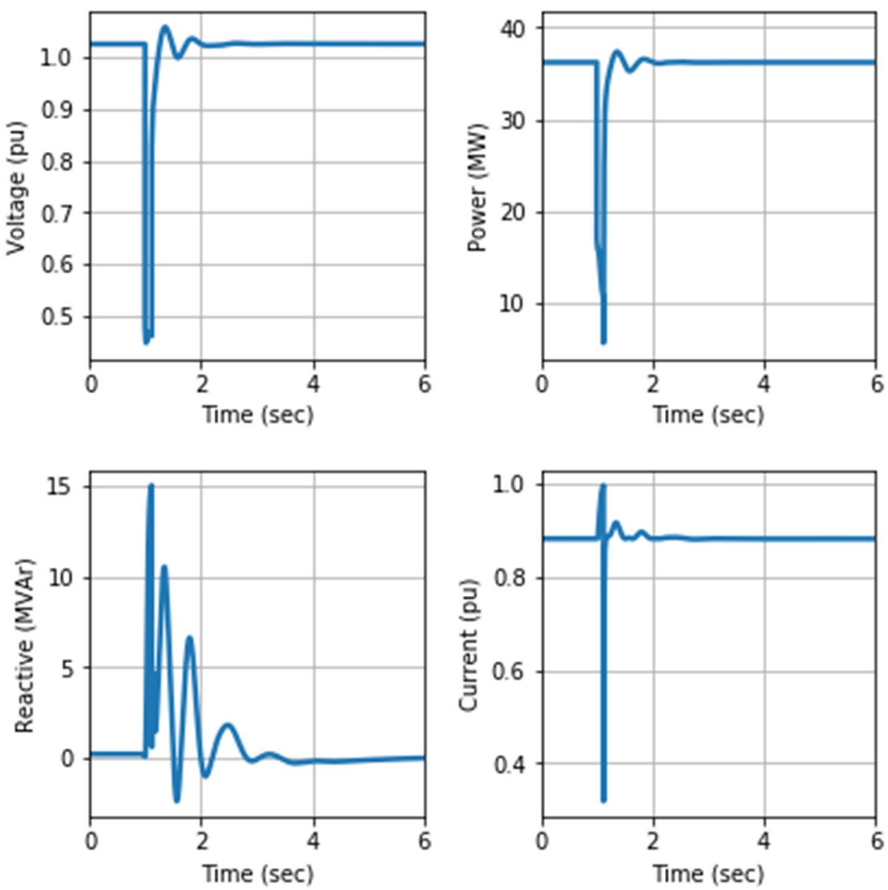

Figure 41: Fault response for an LLLG fault (BESS only) - Point 6

3.4 S5.2.5.13 Voltage and Reactive Power Control

The interaction between the Vales Point generator and the BESS is evaluated with stepping the voltage command up or down. Capability of the voltage control mode has been assessed for both the BESS discharging and charging cases. Voltage command change of ±5% were applied to both the BESS and the Vales Point generator separately to demonstrate the interaction between them. Vales Point generator has been set to operate in its maximum output.

Figure 42 - Figure 57 show the power and voltage profiles at the generator terminal and the BESS for a +5% voltage command steps. When a change in voltage command occurs to either the BESS or the generator, the BESS and the generator respond by supplying/absorbing reactive power and thus maintain the grid voltage.

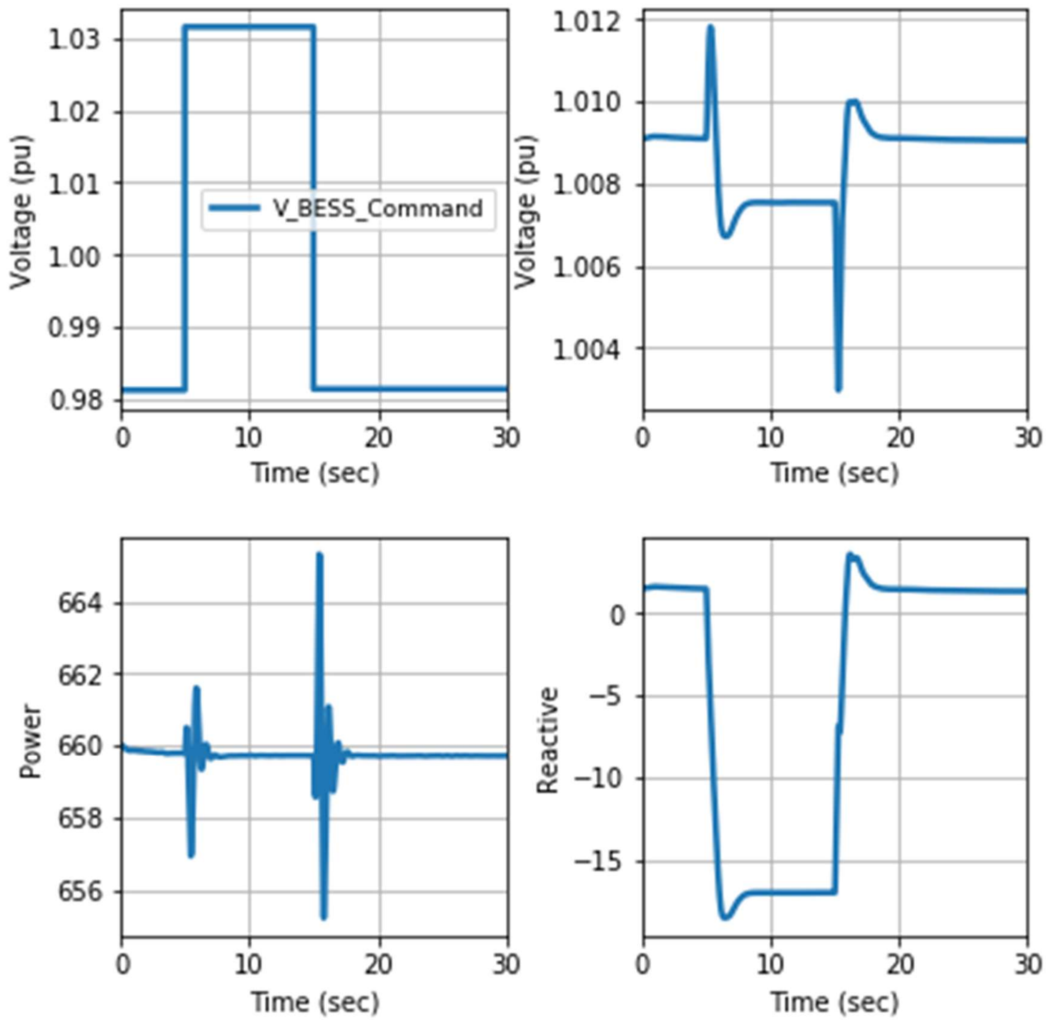

Figure 42: Generator response for BESS voltage command step by +5% when the BESS is charging

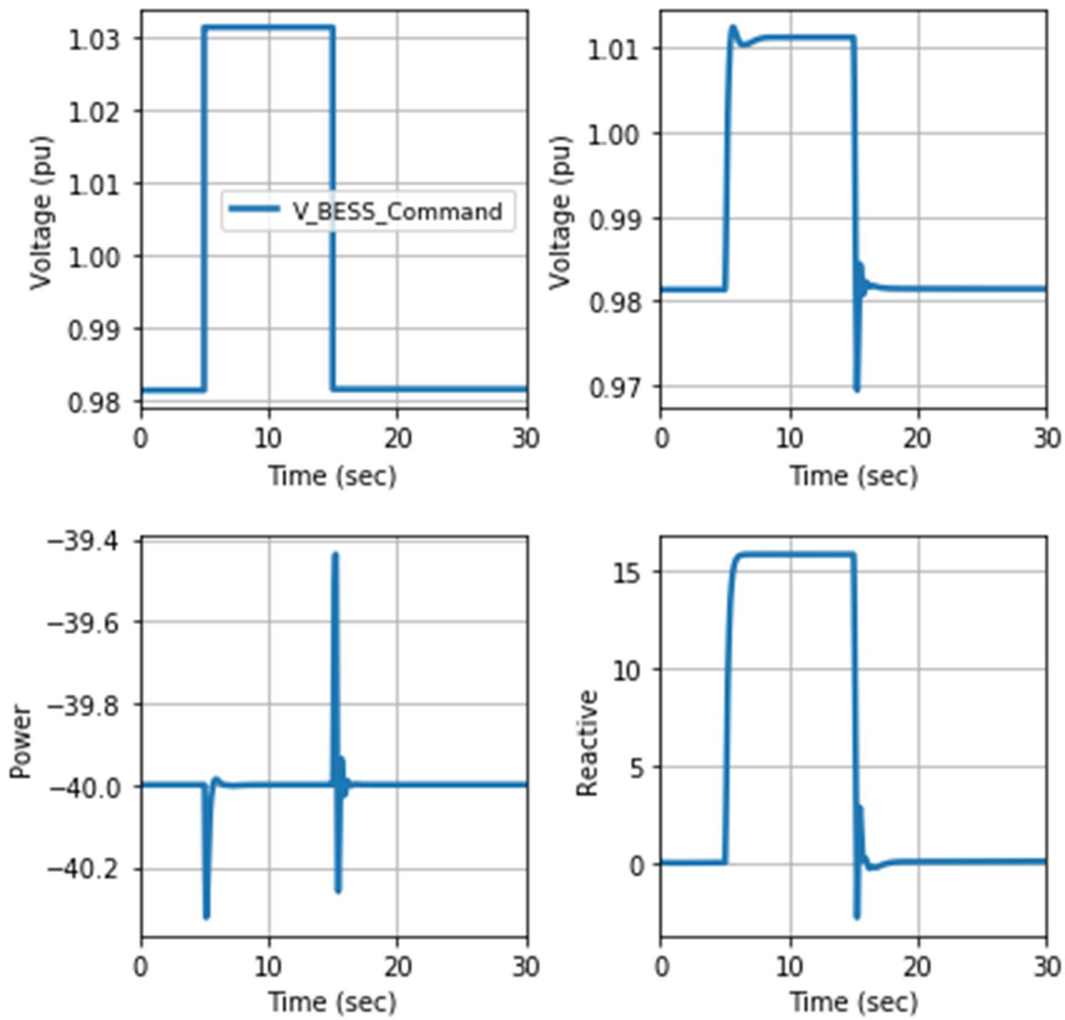

Figure 43: BESS response for BESS voltage command step by +5% when the BESS is charging

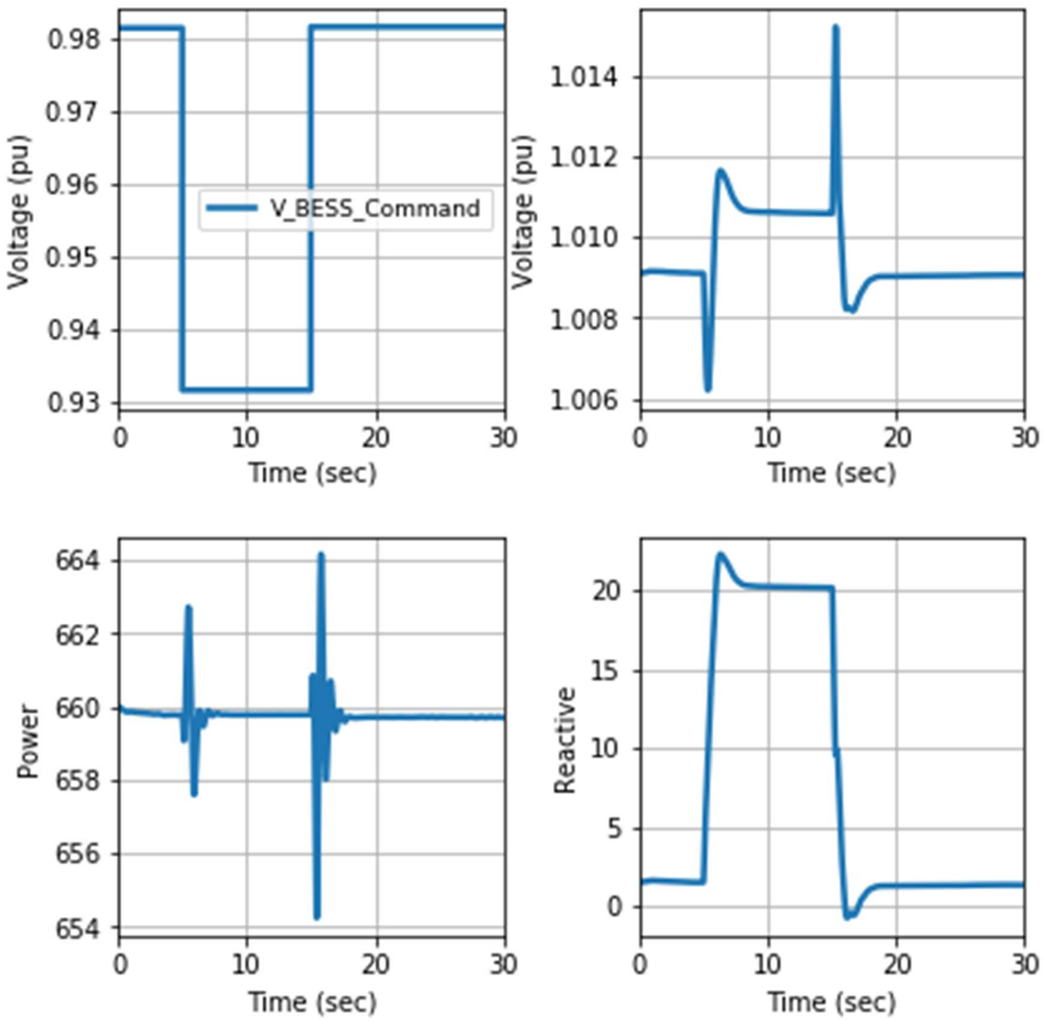

Figure 44: Generator response for BESS voltage command step by -5% when the BESS is charging

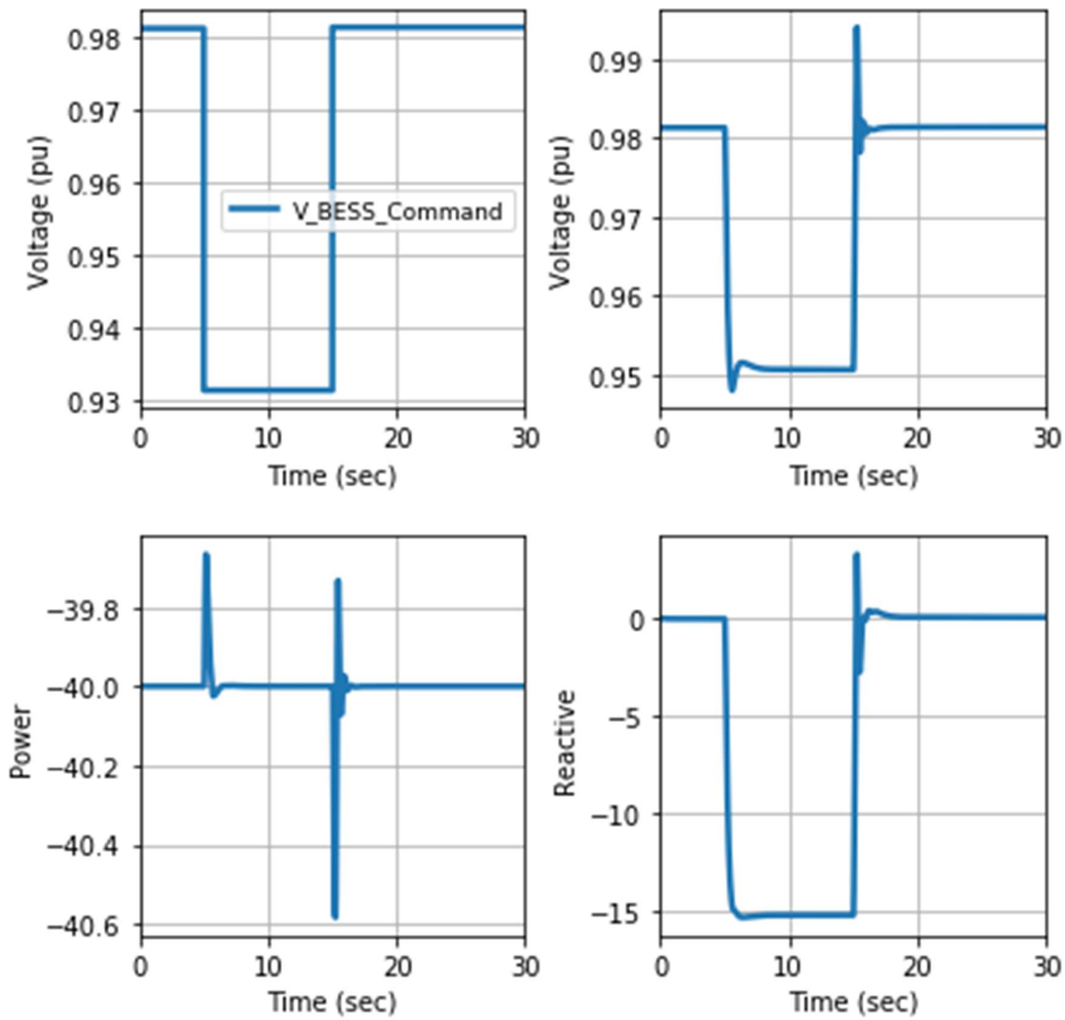

Figure 45: BESS response for BESS voltage command step by -5% when the BESS is charging

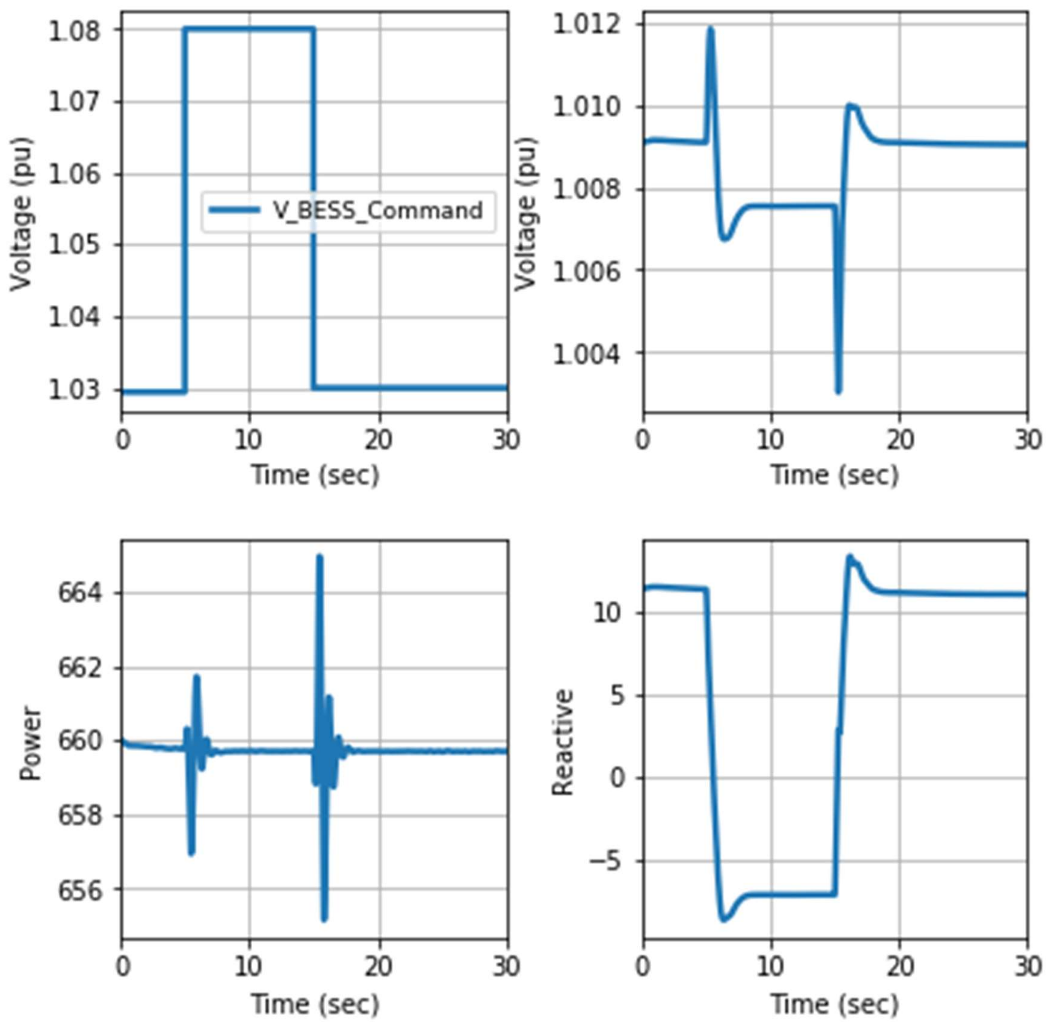

Figure 46: Generator response for BESS voltage command step by +5% when the BESS is discharging

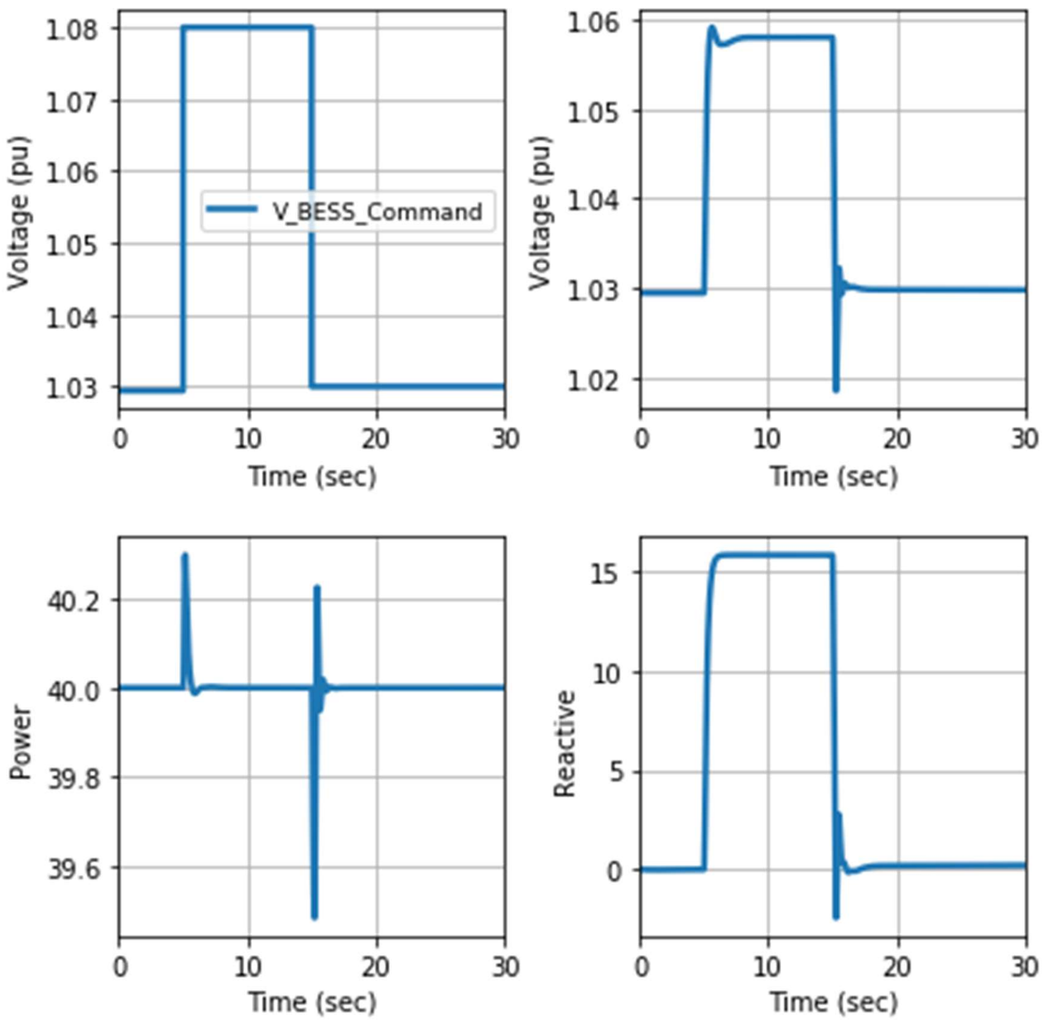

Figure 47: BESS response for BESS voltage command step by +5% when the BESS is discharging

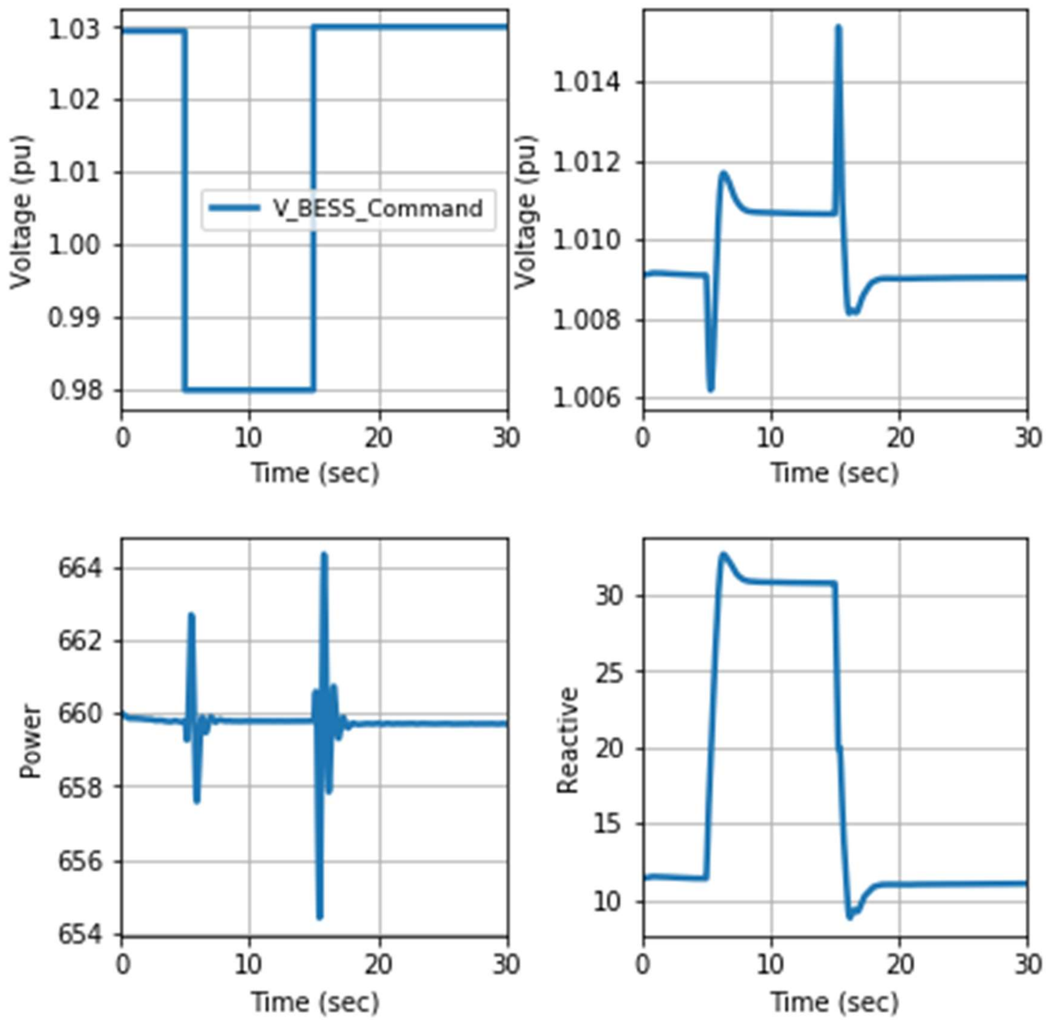

Figure 48: Generator response for BESS voltage command step by -5% when the BESS is discharging

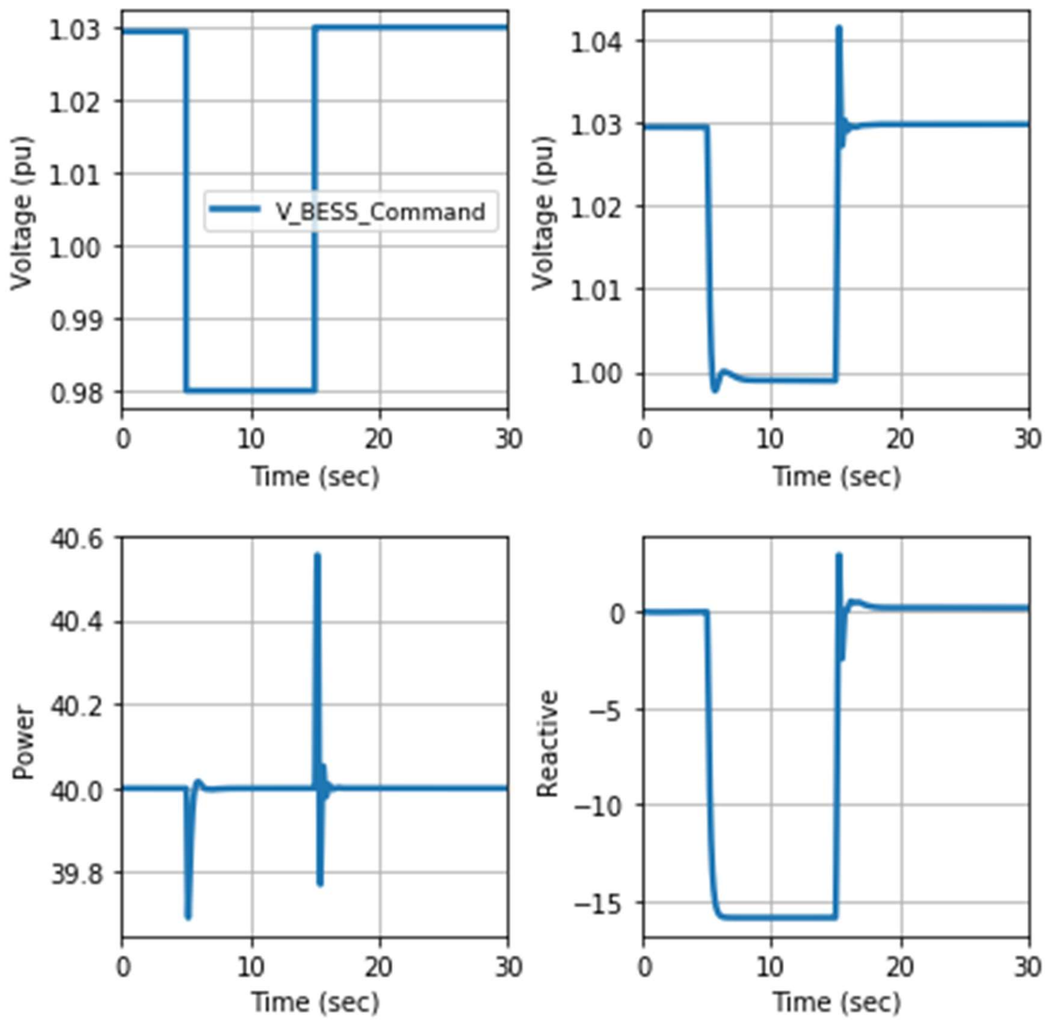

Figure 49: BESS response for BESS voltage command step by -5% when the BESS is discharging

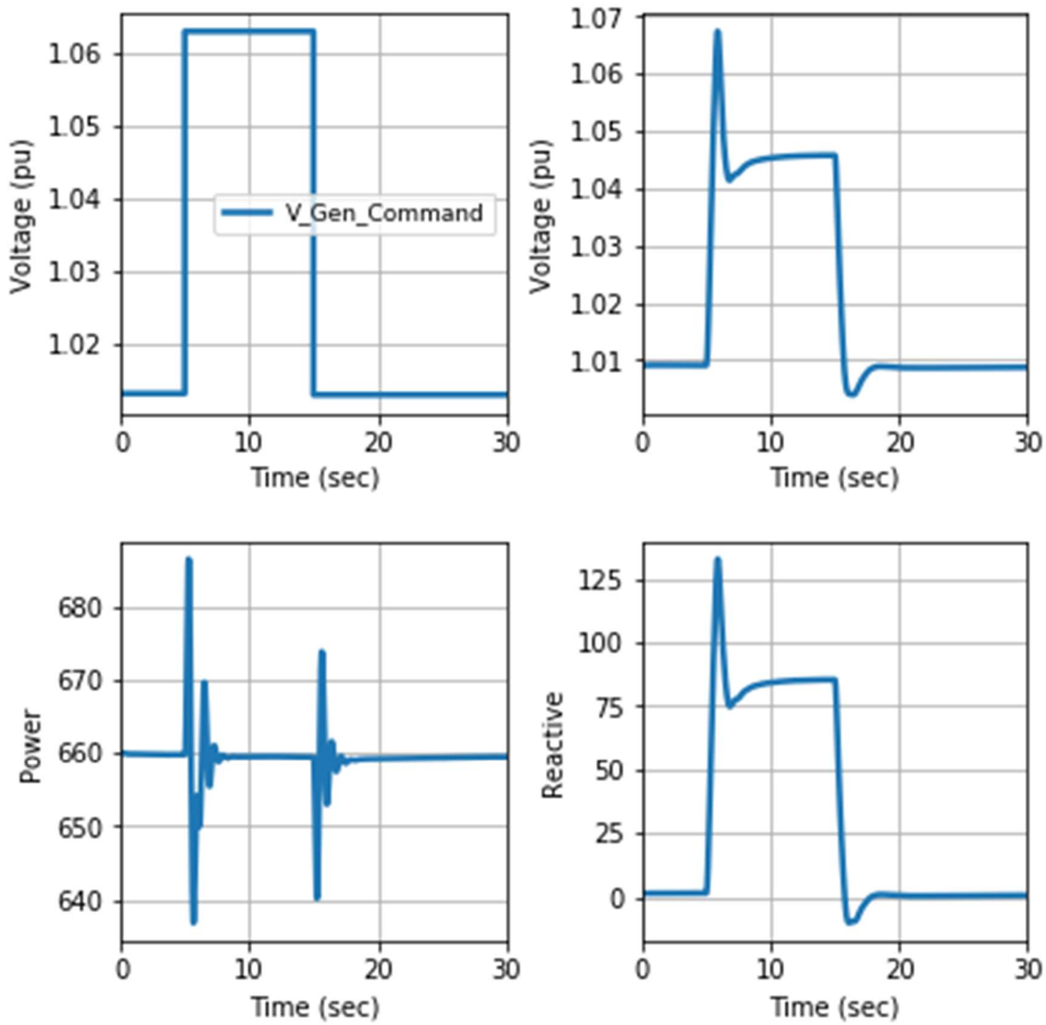

Figure 50: Generator response for generator voltage command step by +5% when the BESS is charging

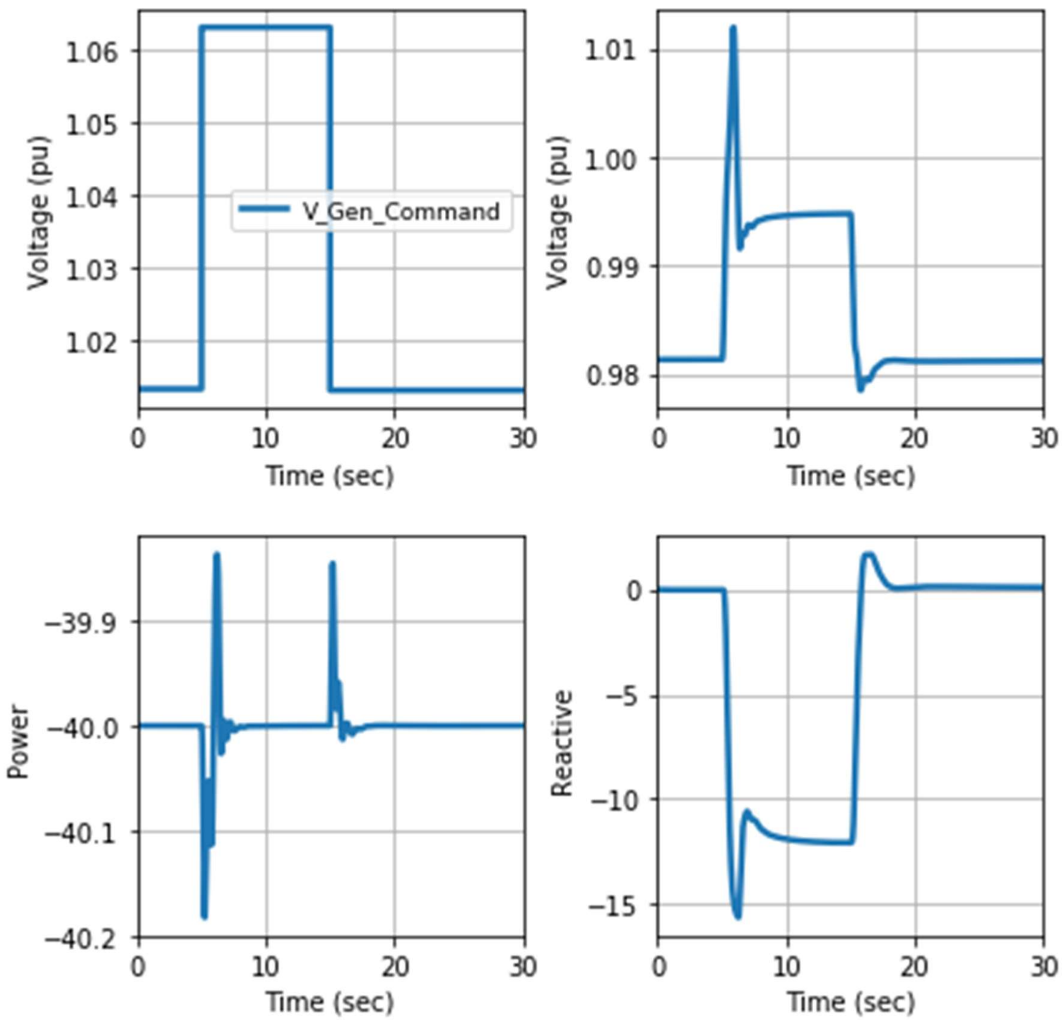

Figure 51: BESS response for generator voltage command step by +5% when the BESS is charging

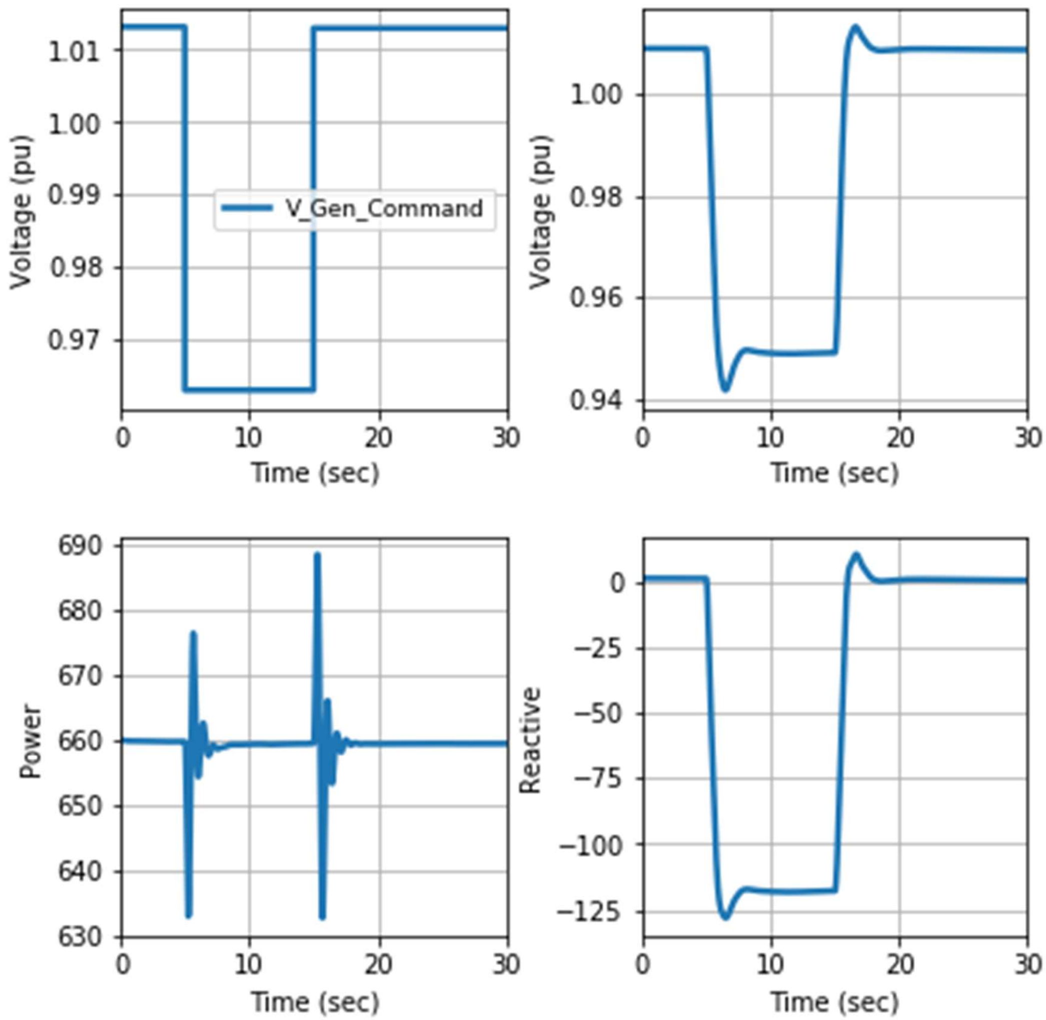

Figure 52: Generator response for generator voltage command step by -5% when the BESS is charging

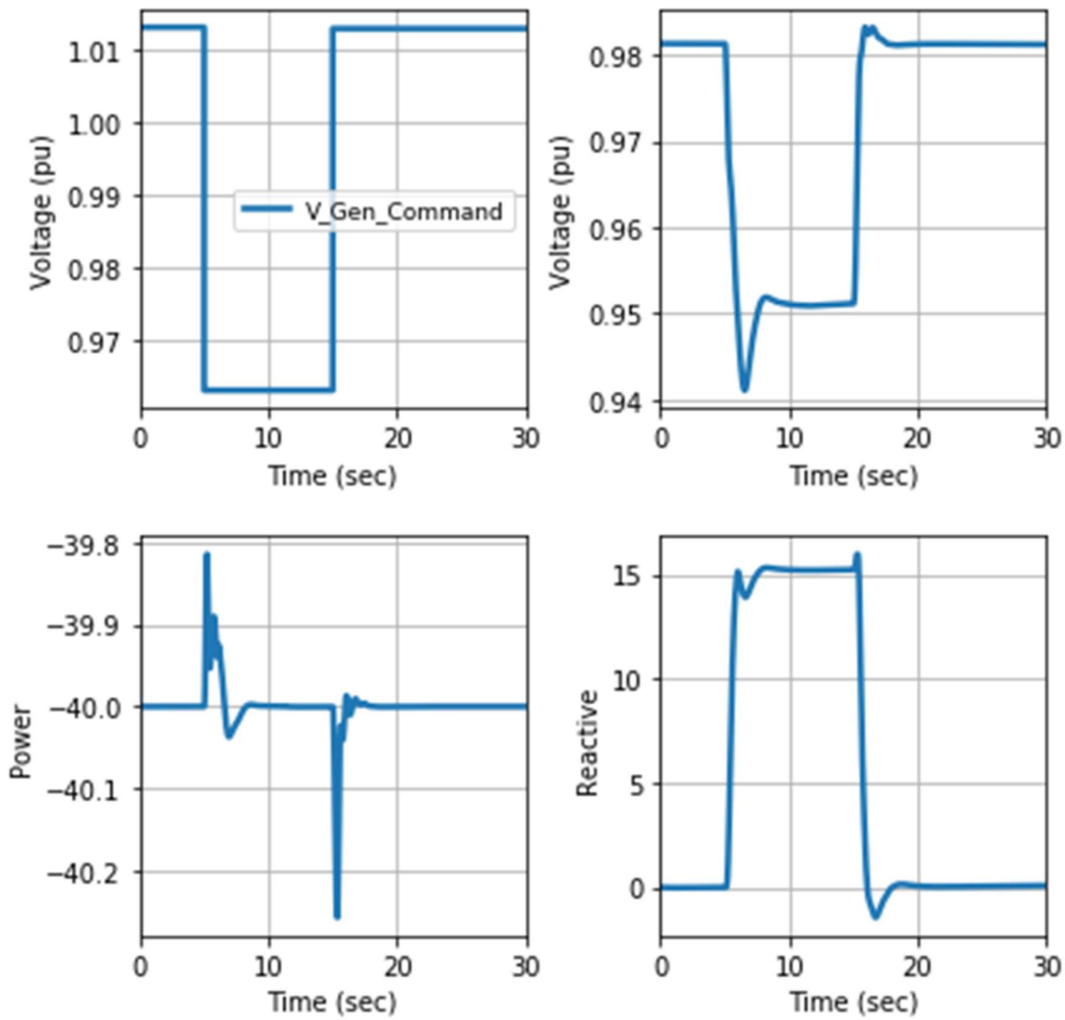

Figure 53: BESS response for generator voltage command step by -5% when the BESS is charging

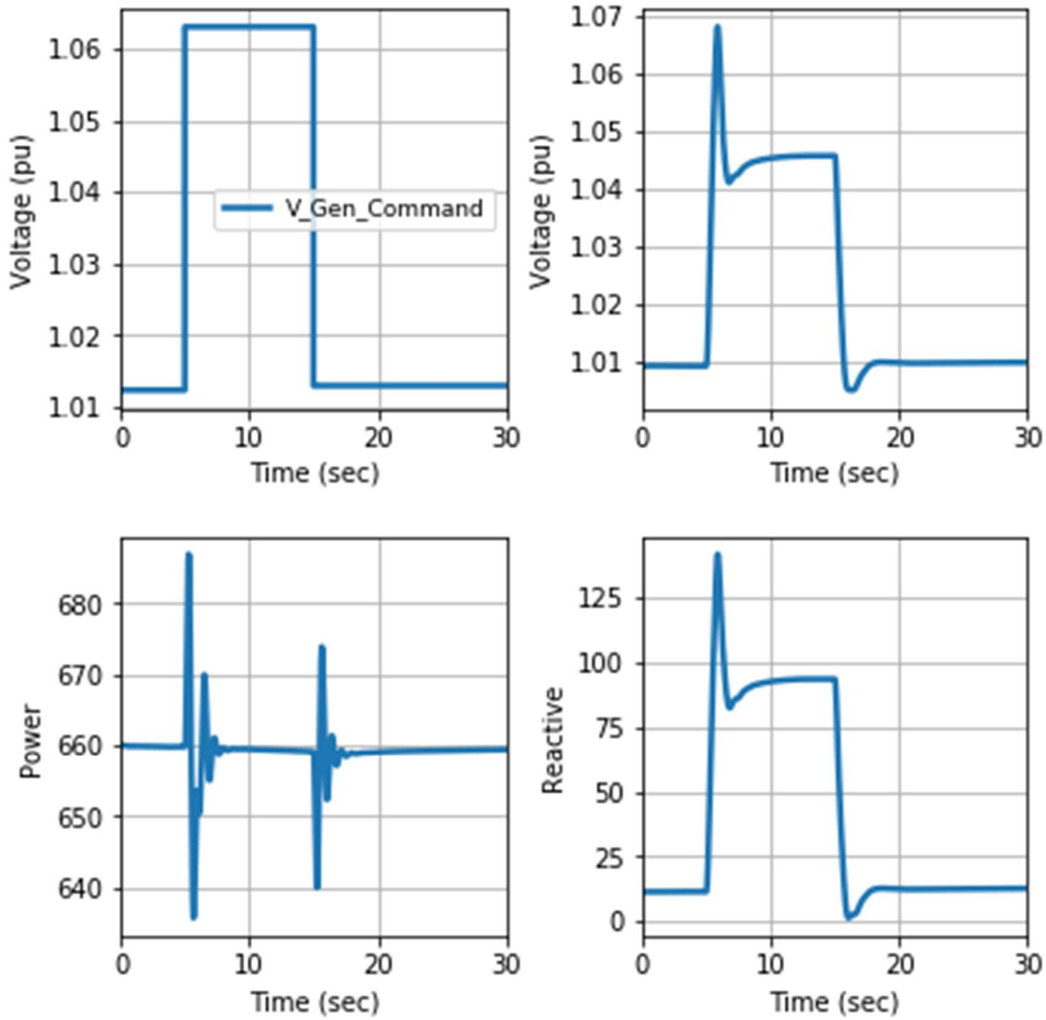

Figure 54: Generator response for generator voltage command step by +5% when the BESS is discharging

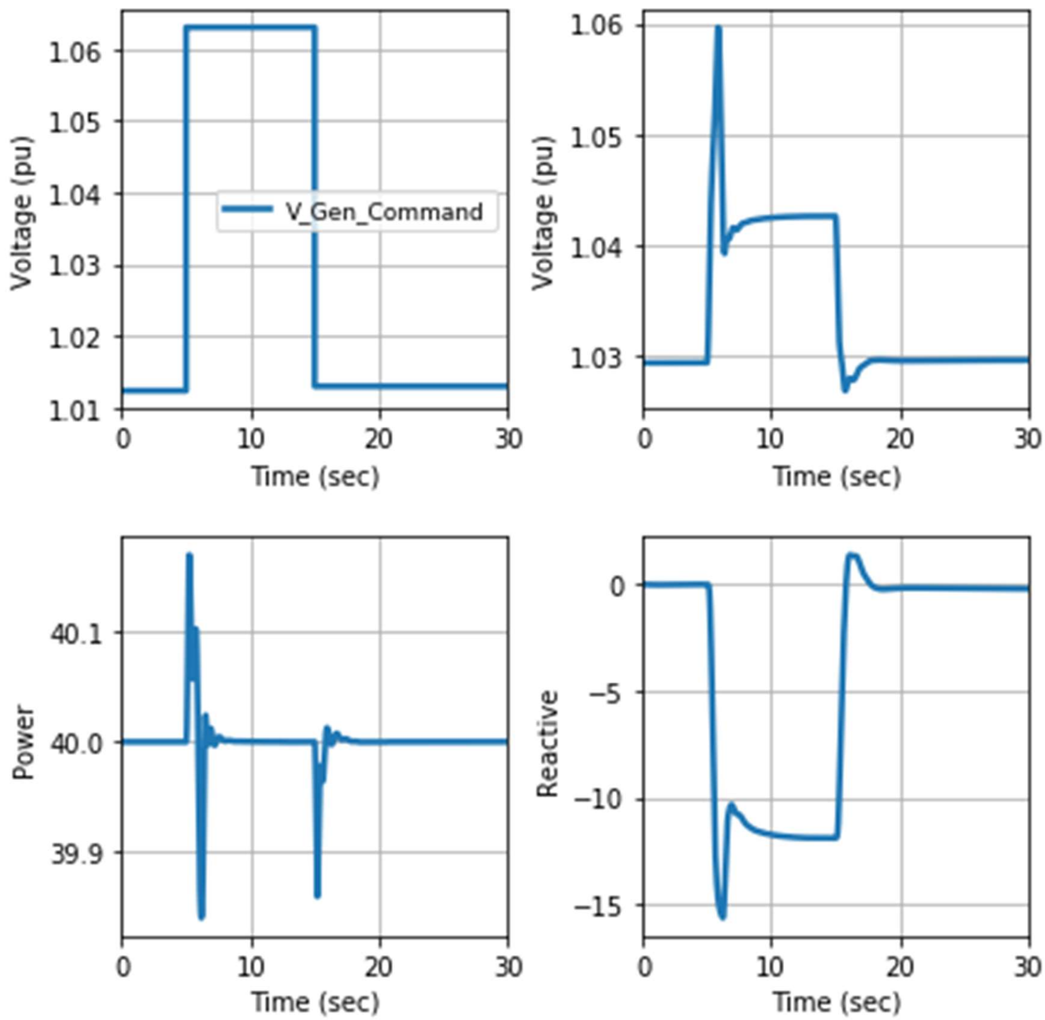

Figure 55: BESS response for generator voltage command step by +5% when the BESS is discharging

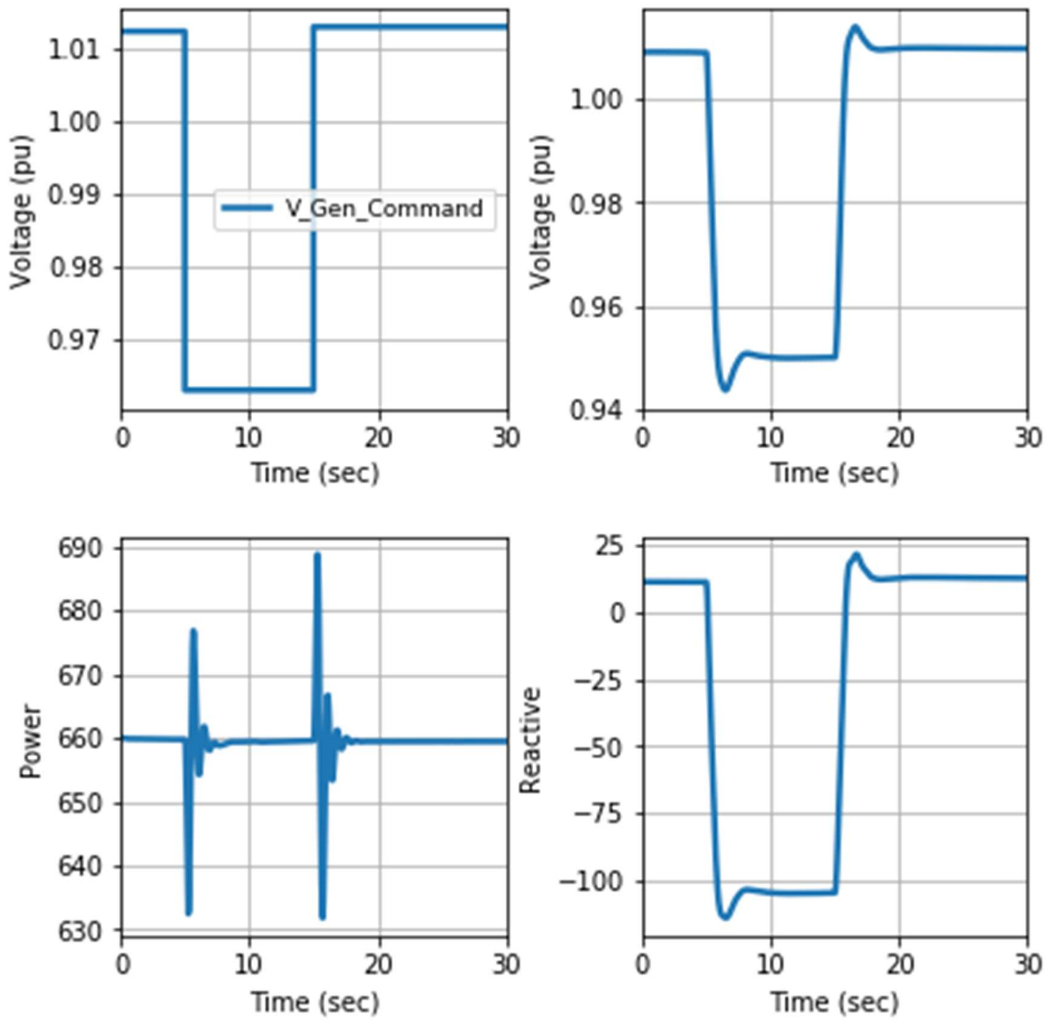

Figure 56: Generator response for generator voltage command step by -5% when the BESS is discharging

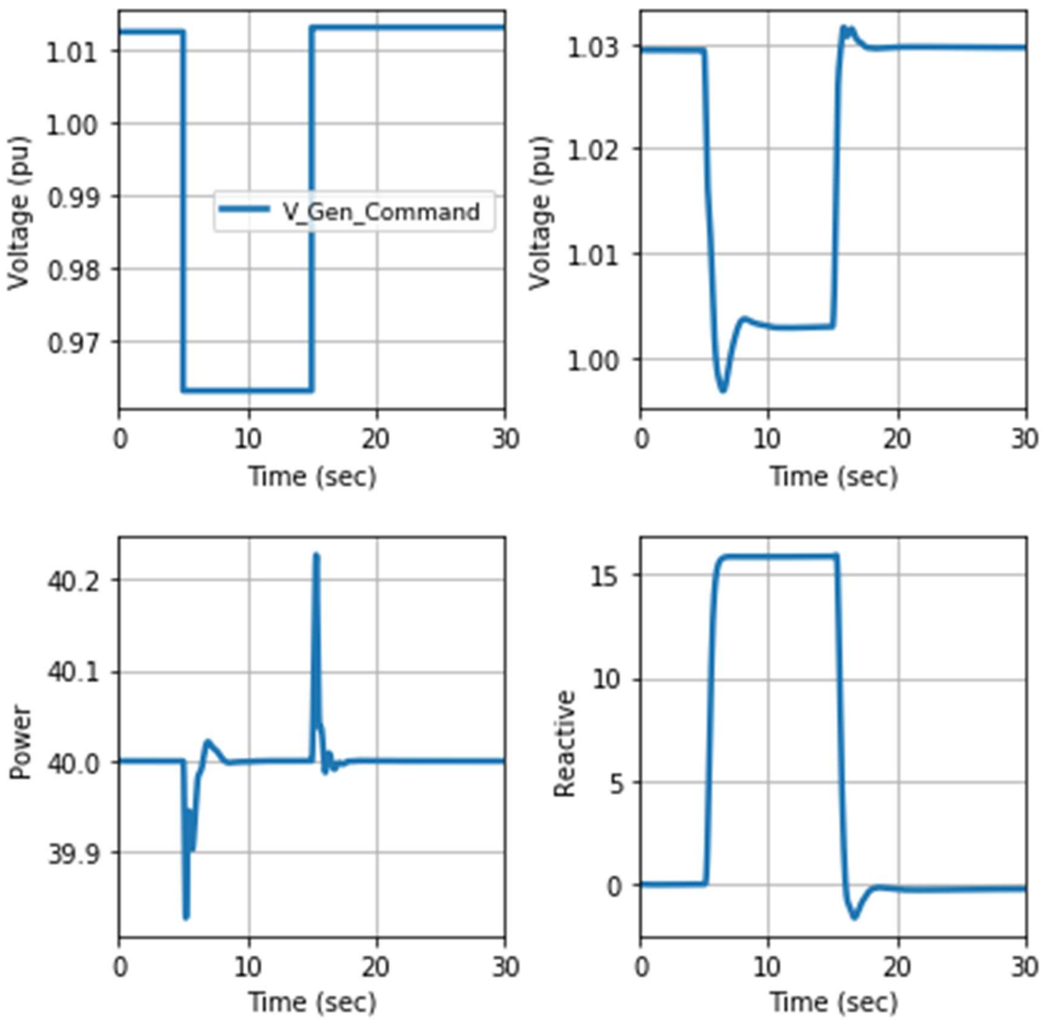

Figure 57: BESS response for generator voltage command step by -5% when the BESS is discharging

3.5 S5.2.5.14 Active power control

The interaction between the Vales Point generator and the BESS is evaluated with changes in the active power command of the BESS. Capability of the active power control has been assessed by changing the active power command of the BESS to demonstrate the interaction between Vales Point generator and the BESS. Vales point generator active power output was set to remain at its maximum throughout the simulation.

Figure 58 shows the power profile of the generator and the BESS when active power command is applied to the BESS PPC. As observed from the figure, active power command of the BESS was changed every several seconds and the BESS successfully responds to active power signals updated with every transition. The generator responds to the command as well without having any adverse impact.

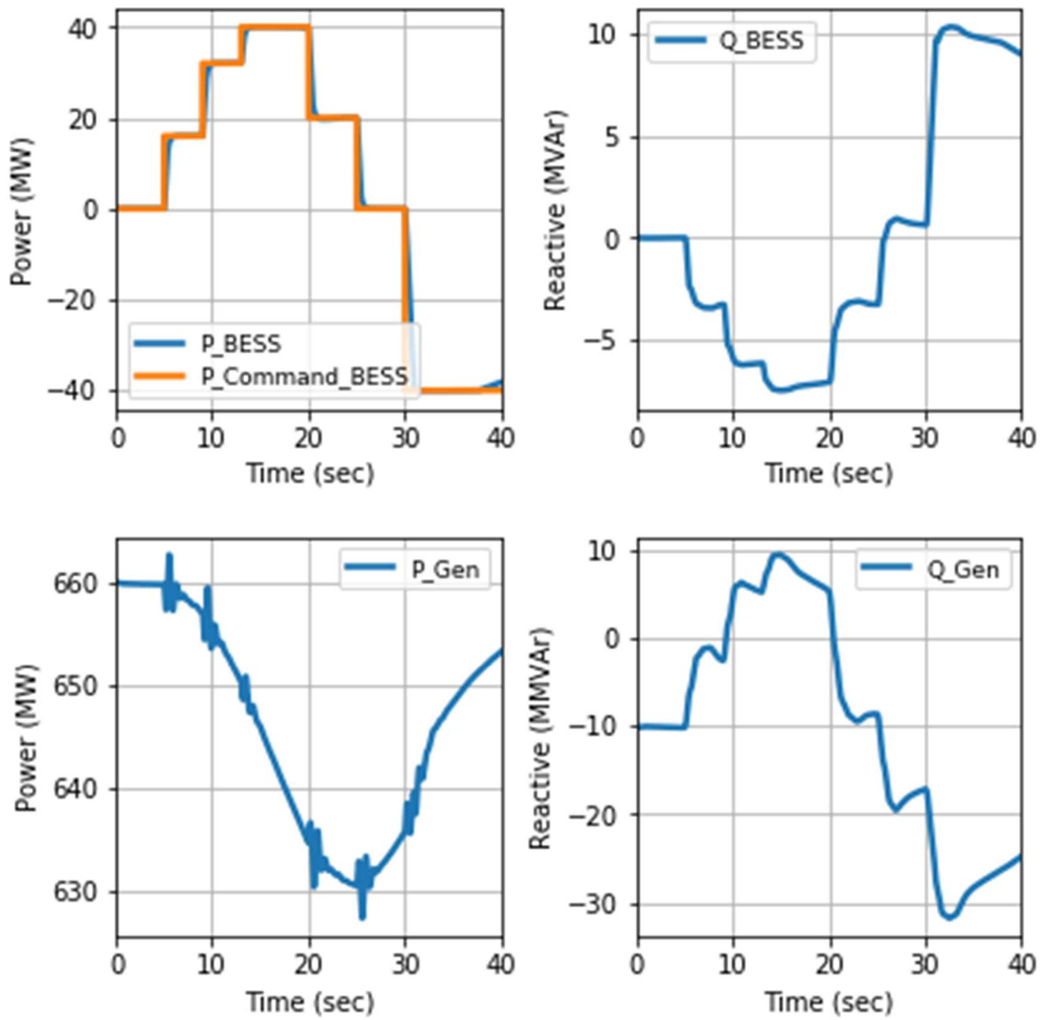

Figure 58: Response for BESS active power command step

4 Conclusions

In this report, a number of Generator Performance Standard (GPS) compliance assessments have been performed in PSSE to investigate the dynamic behaviour of the BESS and the interactions between the Vales Point generator and the BESS under any grid disturbances, contingencies or other abnormal grid conditions. For the assessment, Advisian has extracted the Vales Point power station model in PSSE from the snapshot provided by AEMO and incorporated the standard governor model for the synchronous generator and the 40 MW BESS system.

It should be noted that the performance of BESS can be optimized by choosing proper control parameters to meet power station performance requirement. In this analysis, Advisian have not considered parameter tuning as Advisian is not available with vendor-specific BESS model.

The GPS studies confirm that the integration of the BESS will not result in an adverse impact on the Vales Point power station since no unwanted interactions between the generator and the BESS have been observed due to grid disturbances, contingencies or other grid abnormal conditions. Rather, the BESS provides active support to the generator by providing reactive power for regulating the grid voltage.

5 References

[1] Vales Point AVR Replacement - Releasable User Guide - Rev4

[2] AEMC. (01-January-2020). National Electricity Rules version 132- Chapter 5 Network Connection Access, Planning and Expansion.

Appendix A

PSSE .dyr file settings

```
// Vales Point machine

 20855,'GENROE',5,8.814000,0.060800,1.954000,0.178000,3.200000,0.0000,2.135000,1.603000,
            0.313100,1.081000,0.198000,0.188000,0.094000,0.363000 /Generator
20855,'IEEEG1',5,0,0,25,0.1,0,0.15,0.2,-0.2,0.85,0.322,0.3,0.3,0,10,0.4,0,0.4,0.3,0,0,0,0 /Governor
20855,'USRMDL',5,'ABBEXC',4,0,10,124,44,74,1,1,
            0,0,1,0,0,1,1,1,
            0.01,0.01,0.01,0.01,0.001,1.603,0.0031831,0.02,
            0.0,1.319637,2.066,0.0325,0.168,500.0,2.1,15.0,
            0.065,0.0,1.0,0.7,0.1,-11.65,-11.65,13.25,
            13.25,0.1,0.1,0.1,0.1,0.1,0.1,0.1,
            0.1,0.1,0.100,0.1,0.1,0.1,0.1,0.1,
            0.1,0.1,0.1,0.1,0.1,0.004,0.0,1.0,
            1.0,1.58,0.2,1.0,1.18,5.67,0.02,7.56,
            0.14,2.3,25.0,40.0,10.67,1.0,90.0,-80.0,
            100.0,0.7,15.0,-11.65,13.25,5.36744,0.0,0.2,
            0.4,0.6,0.8,1.0,0.366,0.556,0.973,1.419,
            1.874,2.331,1.05,1.2,1.0,1000.0,1000.0,0.0,
            1.0,0.5,300.0,0.8,6.0,13.25,0.1,0.1,
            -11.65,0.0,300.0,1.0,1.05,110.0,69.2,1.5,
            6.0,13.25,0.1,0.025,0.1,0.025,1.5,6.0,
            -11.65,0.0,1.0,0.1,0.01,0.0,0.16,1.0,
            0.1,0.0,0.0,0.0 /Exciter
```

```
20855,'USRMDL',5,'ABBOEL',10,0,3,17,7,8,1,0,
        1,10.5616,6.9345,350.0,2.1,12.0,13.25,0.7,
        0.1,-11.65,1.0,0.0,0.001,0.1652,1.0,1.0,0.0,0.005 /Over-excitation limiter
20855,'USRMDL',5,'ABBPSS',3,0,3,104,66,32,0,1,
        0,0.01,0.01,0.01,1.603,0.003183,0.02,0.0,
        1.319637,2.066,0.0325,0.168,0.14,0.02,3.5,3.5,
        3.5,0.0,0.546875,3.5,1.0,0.5,0.1,1.0,
        5.0,4.5,0.095,0.013,0.095,0.013,0.017823,0.00012739,
        -0.001759,0.0,0.0,0.0,0.0,0.0,1.0,1.0,
        1.0,1.0,1.0,0.1,0.1,0.1,0.1,0.1,
        0.1,1.0,0.1,0.1,0.1,0.1,0.1,0.1,
        1.0,1.0,0.1,0.1,0.1,0.1,0.1,0.1,
        1.0,0.1,0.1,0.1,0.1,0.1,0.1,1.0,
        2.0,1.0,1.0,1.0,0.1,0.1,0.1,0.1,
        0.1,0.1,1.0,0.1,0.1,0.1,0.1,0.1,
        0.1,1.0,-0.1,-0.1,-0.1,0.1,0.1,0.1,
        0.1,1.0,1.0,1.1,0.9,1.1,1.0,0.05,-0.05 /Stabilizer
20855,'USRMDL',5,'ABBUEL',9,0,1,26,12,10,1,2.135,
        1.603,350.0,1.0,1.0,0.7,0.1,15.0,2.1,
        -0.033285,0.037857,0.0,0.2,0.4,0.6,0.8,1.0,
        -0.375,-0.375,-0.35,-0.325,-0.3,-0.275,0.01,0.01,0.01 /Under-excitation limiter

// Infinite Bus
1,'GENCLS',1,9.99,0
1,'SEXS'   1 0.1 10.0 100.0 0.1 0.0 5.0
```