Hornsdale Power Reserve Expansion Project

ARENA Knowledge Sharing: HPRX Market Report

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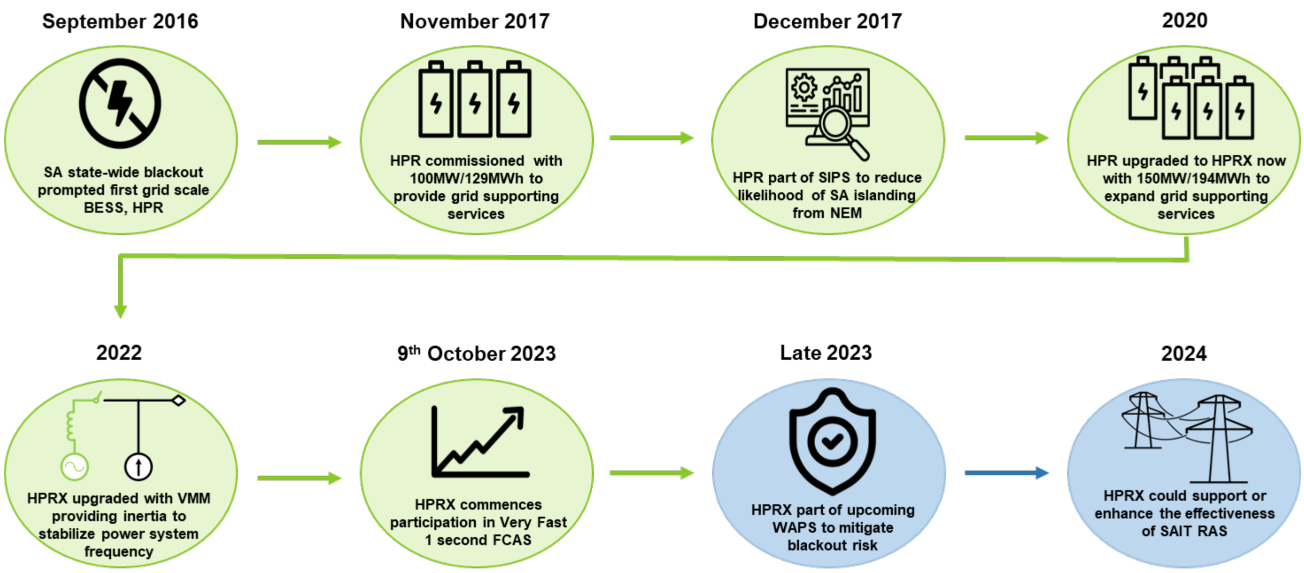
Executive Summary

Following the state-wide blackout across South Australia (SA) in 2016, Neoen and Tesla were selected by the South Australian Government to supply Australia's first grid scale battery named the Hornsdale Power Reserve (HPR). This project was commissioned in 2017 with a nameplate capacity of 100MW/129MWh. In November 2019, Neoen, in collaboration with the South Australian Government, the Australian Renewable Energy Agency (ARENA), and the Clean Energy Finance Corporation (CEFC), unveiled plans for Hornsdale Power Reserve Extension (HPRX) with an additional 50MW/64.5MWh capacity, bringing the combined installed capacity of HPR to 150MW/194MWh. The evolution of HPR is presented the figure below.



Aurecon was engaged by Neoen to complete a market study for submittal to ARENA demonstrating the innovations and objectives of HPRX to address one of the knowledge sharing commitments under the ARENA funding conditions. This knowledge sharing report focuses on the key outcomes from the HPRX innovation objectives shown in the table below.

Objective No.	Innovation Objective	Description
Objective 1	Inertia Services	Demonstrated ability of large-scale Battery Energy Storage Systems (BESS) to provide inertia services by using Tesla's Virtual Machine Mode (VMM) capability.
Objective 2	Enhanced FCAS	Exploration of enhanced Frequency Control Ancillary Services (FCAS) provided by large-scale BESSs and collect information that could be used to feed into a Market Ancillary Services Specification (MASS) review.
Objective 3	Impacts on WAPS and SAIT RAS transfer limits	Impact on transfer limits in relation to the Wide Area Protection Scheme (WAPS) and the related South Australian Interconnector Trip Remedial Action Scheme (SAIT RAS).
Objective 4	Reduced asynchronous generation curtailment	Reduction of asynchronous generation curtailment of solar photovoltaics (PV) and wind generation in SA through synthetic inertia services.

Innovation Objective 1 – Inertia Services

Demonstrated ability of large-scale BESS to provide inertia services by using Tesla's VMM capability.

Key Insights and Lessons Learnt:

1. **Synthetic inertia response:** HPR with VMM functionality has demonstrated technical capability to provide synthetic inertia that is sufficiently fast and large enough to contribute to management of the Rate of Change of Frequency (RoCoF) during grid disturbances. VMM-enabled inverters responded proportionally to the RoCoF in contingency events, which clearly mimics the behaviour and inertial response of synchronous machines. VMM can reduce the overall requirement of FCAS, potentially saving market costs.
2. **Unique benefits of VMM compared to other FFR providers:** The comparison of VMM with other Fast Frequency Response (FFR) providers showcased its unique advantages of being more programmable, flexible, and controllable.
3. **Synthetic inertia needs to be incentivised to unlock potential:** HPR and other large-scale BESS have the potential to become major inertia providers *if* synthetic inertia is eligible for market provision. Transmission Network Service Providers (TNSP) required to procure minimum safe levels of inertia could also choose to procure synthetic inertia from large scale BESS, such as HPR.
4. **VMM supports the provision of a range of services:** HPR with VMM demonstrated its adaptability and ability to contribute to grid stability across different frequency services (FCAS markets) and network support and control ancillary services (non-market services). In addition, as the power system landscape evolves, VMM's role in the emerging Very Fast FCAS market is promising due to its very fast response (within 1 second).
5. **Unique applicability in SA:** Based on the inertia assessment in the SA power network, VMM has the capacity to provide up to 2,000 MWs of inertia, which amounts to roughly one-third of the entire SA state-level inertia requirements, underscoring the significance of VMM in fortifying grid resilience.
6. **VMM capability provides the opportunity to provide various network support services:** System security will continue to be a priority issue in SA, however Australian Energy Market Operator (AEMO) has not identified a Network Support and Control Ancillary Services (NSCAS) gap in SA over the coming five years based on their 2022 assessment.

Innovation Objective 2 – Enhanced FCAS

Exploration of enhanced Frequency Control Ancillary Services (FCAS) provided by large-scale BESS and collect information that could be used to feed into a Market Ancillary Services Specification (MASS) review.

Key Insights and Lessons Learnt:

1. **HPR has provided a significant share of FCAS markets**: HPR and its extension HPRX, have been significant contributors to the FCAS market since 2017 and 2020 respectively. As a combined facility, it provides around 10% of FCAS value each month in the NEM.
2. **HPR successfully demonstrated benefits during the Enhanced FCAS trial:** Updates to the frequency droop response settings were made at HPR in response to the mandatory Primary Frequency Response (PFR) rule change, which increased the active power response to a +/- 0.5Hz frequency deviation from 61MW to 86MW. This response, when standardised against the mainland National Electricity Market (NEM) frequency ramp, was deemed fast enough to warrant a greater registration in the Fast FCAS market than the other contingency markets. This also helped demonstrate the ability of HPR to support future Very Fast FCAS services (now implemented). HPR also successfully demonstrated the ability to enhance large-scale BESS FCAS offerings at no cost through a tighter PFR deadband.
3. **2027-2028 is the earliest expectation for introducing an inertia market:** The increasing deployment of Variable Renewable Energy (VRE) using Inverter Based Resources (IBR) combined with the retirement of fossil fuelled plant will eventually mean that system inertia will become scarcer and that the need for provision of synthetic inertia will grow. There is currently a rule change request

for *"Efficient provision of Inertia"*[1] which includes an Inertial Ancillary Services (IAS) market, for which a formal determination will be made on 29 February 2024. If a determination is made to establish an IAS market, it would likely commence 3 to 4 years after the rule determination circa 2027-2028. Participation by HPR in a future IAS market would require further study into co-optimising the provision of multiple ancillary services (FCAS and IAS) simultaneously.

4. **HPR learnings could contribute to future revisions of the MASS:** Market reforms can take years to progress. Demonstrating capability before the implementation of regulatory reform is necessary step on that journey and HPR has suitably demonstrated its capability to provide synthetic inertia as part of any future IAS market. It would be expected that the learnings from HPR study for synthetic inertia would contribute to a future re-write of Section 4.2 of the MASS if synthetic inertia is eligible for market provision in any future IAS market.

Innovation Objective 3 – Impacts on WAPS and SAIT RAS Transfer Limits

Impact on transfer limits in relation to the Wide Area Protection Scheme (WAPS) and the related South Australian Interconnector Trip Remedial Action Scheme (SAIT RAS).

Key Insights and Lessons Learnt:

1. **HPR will be able to provide a bi-directional response as part of the WAPS upgrade:** ElectraNet's System Integrity Protection Scheme (SIPS) which is currently being upgraded to a WAPS, will harness HPR's ability to both charge and discharge rapidly in case of a WAPS trigger signal received to assist in avoiding the Heywood interconnector tripping.
2. **HPR provides rapid ramping within guaranteed response times for the WAPS:** HPR can ramp active power output from the previous position to up to 150MW within the guaranteed response time.
3. **HPR VMM is capable to enhance the effectiveness of the WAPS by responding to RoCoF:** HPR with VMM capability effectively mitigates high RoCoF and supports alleviation of frequency deviations, which has the potential to significantly enhance the WAPS's effectiveness.
4. **HPR impacts on interconnector transfer limits remain an area of further investigation:** The full SAIT RAS is still under development, and it will be significantly impacted by the stages of the Project EnergyConnect (PEC) interconnector project. Therefore, the full impact of WAPS and HPR on the combined transfer limits for the PEC and Heywood interconnectors will continue to be an area of collaborative engagement and investigation by ElectraNet, AEMO and Neoen.

Innovation Objective 4 – Reduced Asynchronous Generation Curtailment

Reduction of asynchronous generation curtailment of solar PV and wind generation in SA through synthetic inertia services.

Key Insights and Lessons Learnt:

1. **HPR may aid the unlocking of additional headroom on the connection network:** HPR could play a positive role in the future in contributing to increasing generation hosting capacity through the reduction of curtailment risk particularly under N-1 conditions.
2. **HPR has potential to offer benefits against network constraints:** HPR could alleviate network transient stability limits under outage conditions or thermal constraints in SA.
3. **HPR can be beneficial for market participants:** The addition of storage capacity in the network would provide the benefit of additional hosting capacity for generation and potential load which would improve utilisation of the existing network, benefitting new and existing market participants**.**

[1] AEMC, Efficiency provision of inertia (rule change), available at: https://www.aemc.gov.au/rule-changes/efficient-provision-inertia [accessed 14/12/2023]

Abbreviations

AC	Alternating Current
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AGC	Automatic Generation Control
ARENA	Australian Renewable Energy Agency
AUD	Australian Dollars
BESS	Battery Energy Storage System
CEFC	Clean Energy Finance Corporation
DEM	Department of Energy and Mining
FCAS	Frequency Control Ancillary Services
FFR	Fast Frequency Response
FOS	Frequency Operating Standard
GW	Gigawatt
HPR	Hornsdale Power Reserve
HPRX	Hornsdale Power Reserve Extension
HVDC	High Voltage Direct Current
Hz	Hertz
IAS	Inertia Ancillary Service
IBR	Inverter-Based Resource
km	Kilometer
kV	Kilovolt
MASS	Market Ancillary Services Specification
MMS	Market Management System
ms	Millisecond
MVA	Megavolt-amperes
MW	Megawatt
MWh	Megawatt-hour
MWs	Megawatt-second

NEM	National Energy Market
NEMDE	National Energy Market Dispatch Engine
NLCAS	Network Loading Control Ancillary Service
NOFB	Normal Operating Frequency Band
NSCAS	Network Support and Control Ancillary Service
NSW	New South Wales
PEC	Project EnergyConnect
PFC	Primary Frequency Control
PFR	Primary Frequency Response
PMU	Phase Measurement Unit
PoE	Probability of Exceedance
PV	Photovoltaics
RES	Renewable Energy System
REZ	Renewable Energy Zone
RIT-T	Regulatory Investment Test – Transmission
RoCoF	Rate of Change of Frequency
s	Second
SA	South Australia
SAIT RAS	South Australian Interconnector Trip Remedial Action Scheme
SCADA	Supervisory Control and Data Acquisition
SIPS	System Integrity Protection Scheme
SynCon	Synchronous Condenser
TNSP	Transmission Network Service Provider
TOSAS	Transient and Oscillatory Stability Ancillary Service
VCAS	Voltage Control Ancillary Service
VIC	Victoria
VMM	Virtual Machine Mode
VRE	Variable Renewable Energy
WAPS	Wide Area Protection Scheme
YTD	Year To Date

1 Introduction

1.1 Background

Following the September 2016 state-wide blackout which left South Australia (SA) without power, Neoen and Tesla were selected by the South Australian Government to supply Australia's first grid scale battery named the Hornsdale Power Reserve (HPR).

Owned and operated by Neoen, and supplied by Tesla, HPR is a large-scale Battery Energy Storage System (BESS) situated approximately 16 km north of Jamestown in SA. Connected to the National Electricity Market (NEM), HPR shares the same 275kV network connection points as the three Hornsdale wind farms. When it was first established, the original HPR had a nameplate capacity of 100MW/129MWh using Tesla's Powerpack system technology. At the time of its completion in November 2017, the original HPR stood as the world's largest utility-scale battery installation. Subsequently, the HPR expansion, HPRX, was constructed adjacent to the original HPR and has been operational since the first half of 2020 with the support of Tesla. HPRX adds 50MW/64.5MWh of capacity bringing the combined installed capacity of HPR to 150MW/194MWh.

As well as providing frequency support and energy arbitrage in the NEM, HPR is due to be a part of a new Wide Area Protection Scheme (WAPS) in late 2023, currently under development, which reserves power output capacity to rapidly inject power when called upon to mitigate the risk of future state-wide blackouts. HPR will also form part of the related South Australian Interconnector Trip Remedial Action Scheme (SAIT RAS) that is being developed to cater for a non-credible trip of either the Project EnergyConnect (PEC) interconnector or the Heywood interconnector under high power transfer conditions to prevent separation of SA from the NEM. The WAPS and related SAIT RAS are operated by the SA Transmission Network Service Provider (TNSP) ElectraNet.

Further, as the transition to wind and solar power gains momentum, displacing conventional fossil fuel generation, a notable consequence is the reduction of traditional synchronous inertia available on the electrical grid. This reduction eliminates a natural stability buffer, leaving the grid vulnerable to frequency excursions. In response to these evolving challenges, the entire HPR facility was upgraded as part of HPRX project to introduce a new 'virtual inertia' (hereon referred to as synthetic inertia) service in addition to the existing services it provides. This innovation utilises the Tesla's Virtual Machine Mode (VMM) which is specifically engineered to virtually emulate traditional inertia to stabilise power system frequency.

The evolution of HPR is presented in Figure 1-1.

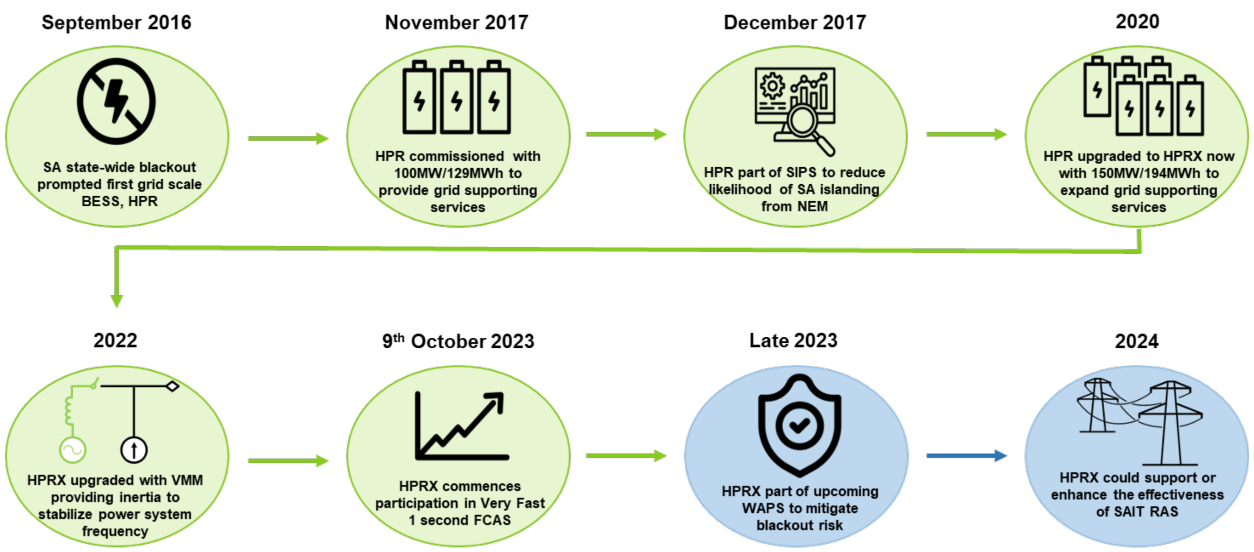


Figure 1-1: Evolution of HPR

1.2 South Australian Government and ARENA Funding

In November 2019, Neoen, in collaboration with the South Australian Government, the Australian Renewable Energy Agency (ARENA), and the Clean Energy Finance Corporation (CEFC), unveiled plans for HPRX. HPRX was expected to serve as a compelling demonstration of the comprehensive advantages that grid-scale batteries bring to the NEM and Australian consumers alike.

Building on the success of the original HPR, Neoen, in collaboration with Tesla, secured funding from ARENA and the South Australian Government's Department of Energy and Mining (DEM). The South Australian Government demonstrated its support for the project by allocating $15 million AUD over a five-year period through its Grid Scale Storage Fund, while ARENA committed $8 million AUD in grant funding through its Advancing Renewables Program.

1.3 This Report

The remainder of this report is structured in the following chapters:

- **Chapter 2 – Context: Inertia and Fast Frequency Response:** provides relevant background on NEM frequency control and recent developments in valuing inertia in the context of declining inertia with particular focus on the SA power network.
- **Chapter 3 – Virtual Machine Mode:** provides an overview of HPR VMM using Tesla's Powerpack energy storage solution and built-in inverters equipped with VMM and their capability in providing synthetic inertia and other ancillary services.
- **Chapter 4 – Enhanced FCAS Capability:** provides an overview of the additional ancillary services available from HPR, and how they might be recognised by future changes to the MASS. Observations about the introduction of Fast Frequency Response (FFR) are also provided.
- **Chapter 5 – Impact on Interconnector Transfer Limits:** illustrates the WAPS and SAIT RAS and their potential influence from HPR with VMM functionality on interconnector transmission limits and the curtailment of generation.
- **Chapter 6 – Impact on Asynchronous Generation Curtailment:** provides a high level of assessment on HPR connection network in terms of the transmission capacity, network constraints and future network development.

2 Context: Inertia and Fast Frequency Response

2.1 Introduction to NEM Frequency Control

The NEM operates at a standard frequency of 50 Hertz (Hz) and the Australian Energy Market Operator (AEMO) is responsible for maintaining system frequency within the Normal Operating Frequency Band (NOFB) which ranges from 49.85Hz to 50.15Hz (50 +/- 0.15Hz). If the frequency deviates too far from 50Hz due to a supply-demand imbalance, it can lead to a loss of grid synchronisation where generators and loads can begin disconnecting, leading to cascading effects and a potential system black scenario. Frequency control of the electricity system involves the provision of several different services including inertia, Primary Frequency Response (PFR), contingency and regulation FCAS, and energy re-dispatch (refer to Appendix A for further details). These frequency control services function by either injecting or absorbing power from the grid at various timescales to restore the frequency back within the NOFB as summarised in Figure 2-1.

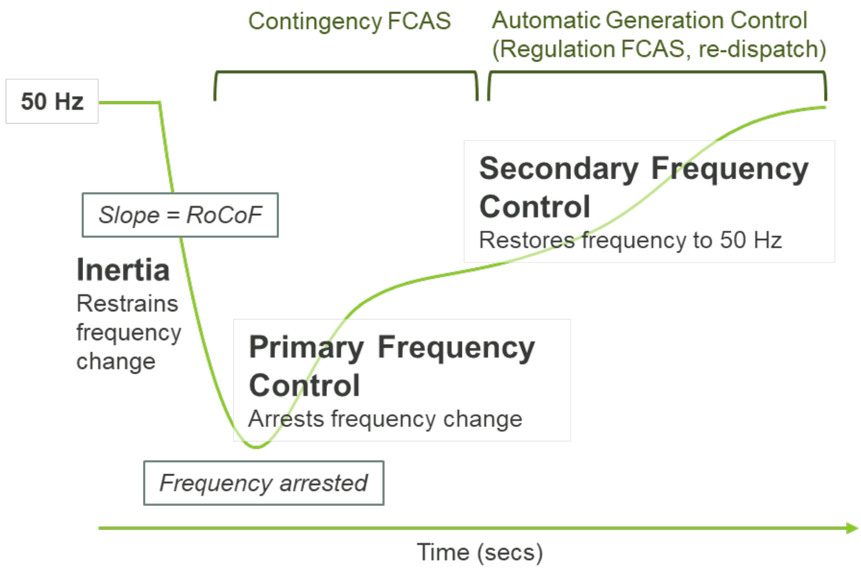


Figure 2-1: Frequency control services used to restore system frequency following a contingency[2]

The rate of change of frequency (RoCoF) is a key metric as specified by the Frequency Operating Standard (FOS)[3] for frequency control, and is predominantly managed using power system inertia. Immediately after a contingency event that leads to a supply-demand mismatch, power system frequency can change rapidly and the RoCoF is highly dependent on the power system conditions and the level of inertia present in the system prior to the contingency event. A power system with higher inertia will exhibit a slower initial RoCoF during a frequency event, effectively minimising the extent of the disturbance, whereas a lower inertia system will experience a faster RoCoF.

Inertia is quantified in megawatt-seconds (MWs) of kinetic energy and is calculated as a product of the generator's size in megavolt-amperes (MVA) and the generator-specific inertia constant in seconds. The inertia constant describes how long a machine could inject/absorb energy at its rated electrical output using the kinetic energy inherent in the rotating mass of the machine.

2.2 Declining Inertia

Historically, traditional inertia services were provided by large synchronous generators and were treated as 'public goods' that were readily available at zero cost. The grid inertia needs began to change with the large-scale deployment of asynchronous Inverter-Based Resources (IBR) such as solar, wind, and large-scale BESS from the mid-2000s onwards. These asynchronous generators provided no system inertia and increased

2 Replicated from Figure 2 in AEMO's Power System Requirements reference paper, July 2020, available at: https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power-system-requirements.pdf [accessed 14/12/2023]

3 AEMC, Review of the Frequency operating standard 2022, available at: https://www.aemc.gov.au/market-reviews-advice/review-frequency-operating-standard-2022 [accessed 14/12/2023]

requirements for regulation FCAS to balance the continuous small fluctuations in output inherent to Variable Renewable Energy (VRE) generation. By around 2020, system frequency stability was also recognised to have deteriorated following the decision by large synchronous plant operators to reduce the stringency of Primary Frequency Control (PFC) governor settings that were not valued or rewarded by market design, thereby reducing the available PFR.

This combination of declining inertia and PFR availability was compensated for by increased reliance on FCAS markets for frequency control, resulting in a less predictable system frequency and greatly increased system costs for FCAS provision. These increased FCAS costs were particularly significant in SA, where limited (and inconsistently dispatched) synchronous gas generation and relatively weak inter-regional links to Victoria resulted in low local inertia and a high demand for local FCAS offered by a small pool of high-priced providers.

2.3 Recent Developments in Valuing Inertia

Major proposals and determinations since the 2016 South Australian System Black with relevance to NEM frequency control are summarised in Appendix B with key points provided below.

2.3.1 Inertia Ancillary Services

The 2016 South Australian System Black was a major event which drew attention to the risks of declining inertia in the NEM, particularly in SA. In response, the Australian Energy Market Commission (AEMC) made a rule determination[4] *Managing the rate of change of power system frequency* which introduced a requirement for TNSPs to ensure a minimum level of inertia within all subregions of the NEM that faced a credible possibility of operating as frequency islands. At this time the AEMC was also considering an AGL proposal for an Inertia Ancillary Services (IAS) market. In 2018, the AEMC made a final determination not to introduce a market for IAS in the NEM.[5] Whilst stakeholders supported the development of competitive markets in principle, it was decided at that time, that the need for inertia services was not sufficiently urgent to justify a market and that inertia requirements could be adequately managed by TNSPs under the new procurement process. At the time, it was flagged that this question of introducing an IAS market should be revisited after the implementation of more pressing reforms (including the Very Fast FCAS market), but before the forecast significant drop in NEM inertia caused by the decommissioning of several synchronous thermal plants.

In 2021, the Australian Energy Council (AEC) submitted a new proposal for market dispatch of an IAS to the AEMC for consideration.[6] In their submission, the AEC argued that circumstances have changed since the 2018 rejection of an IAS market in the NEM for reasons including:

- Expected coal retirement dates being brought forward[7] from the more distant forecast relied upon in 2018, raising the risk of near-term inertia shortfalls.
- Growing appreciation of the high market costs of operating at a minimum safe level of inertia and relying on FCAS for system frequency control, rather than co-optimising inertia and FCAS to find a least-cost solution.
- The successful implementation of reforms to higher-priority Essential System Services such as mandatory PFR and new Fast Frequency Response (FFR) services.

The AEC proposal has attracted joint engagement from AEMO and the AEMC and appears to have support from most market participants. However, AEMO has noted concerns regarding the complexity of integrating a co-optimised IAS market into the NEM Dispatch Engine (NEMDE) and does not appear to support this proposal at present. A draft AEMC determination on the proposal is anticipated in February 2024. If a determination is made to establish an IAS market, it would likely commence 3 to 4 years after the rule determination (in 2027-2028).

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4 AEMC, Managing the Rate of Change of Power System Frequency, 2017, available at: https://www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-frequency [accessed 14/12/2023]

5 AEMC, Inertia Ancillary Service Market Rule Change, available at: https://www.aemc.gov.au/rule-changes/inertia-ancillary-service-market [accessed 14/12/2023]

6 AEMC, Efficient Provision of Inertia consultation, 2023, available at: https://www.aemc.gov.au/rule-changes/efficient-provision-inertia [accessed 14/12/2023]

7 AEMO, 2022 Integrated System Plan, 2022, available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp [accessed 14/12/2023]

2.3.2 Fast Frequency Response

FFR is an ongoing development in the NEM with AEMO's *FFR in the NEM* working paper[8] first released in 2017. FFR provides system benefits at low levels of synchronous inertia. In general, FFR refers to the delivery of a rapid active power increase or decrease by generation or load in a timeframe of two seconds or less to correct a measured supply-demand imbalance and assist in managing power system frequency. Given FFR can respond more quickly than current frequency control services in the NEM, it may also assist in managing challenges related to high RoCoF.

FFR services can be delivered very rapidly (although not instantaneously), and in some cases can reduce the amount of inertia required to maintain a secure power system.[9] However, this service is limited by the resolution, accuracy and reliability of the frequency measurements, thus time delays remain to a small extent and sufficient inertia is still required to be online to respond prior to FFR to maintain system stability.

FFR and inertia are distinct capabilities, each with their unique roles that are not directly interchangeable. FFR, due to its measurement delay, does not inherently have the same impact on mitigating the RoCoF as inertia does. However, FFR is effective in addressing supply-demand imbalances and aiding in the restoration of system frequency. These two power system capabilities are both pertinent to advanced inverters and their contribution to reinforcing the power system, particularly as it adapts to operate with fewer synchronous generators online.

2.3.3 Synthetic Inertia

Synthetic inertia (also referred to as simulated or virtual inertia) is an emerging concept proposed to emulate the inertia response from IBRs or large-scale BESS to a power system disturbance, providing sufficiently fast and large enough capability to help manage RoCoF. By appropriate design of the inverter control system, it is possible for IBRs and large-scale BESS to provide an emulated inertial response to power system disturbances. In this sense, Tesla inverters, when operating under VMM, can simulate an inertial response through microprocessor-based control (see Chapter 3 for details). Its synthetic inertial response is claimed to be instrumental in counterbalancing the diminished synchronous inertia, thereby contributing significantly to the overall stability and reliability of the electrical grid.

As the power system transition progresses, AEMO foresees that the future requirements for the RoCoF control within the NEM can be met by combining synchronous inertia and synthetic inertial responses across the power system.[10] However, AEMO has also stated that they consider synthetic inertia to be distinct from synchronous inertia. Any ability for large-scale BESS such as HPR to contribute towards a future IAS market, and the market benefits delivered through such an increase to inertia supply, will be contingent on regulatory bodies accepting that synthetic inertia can provide equivalent services to synchronous inertia. The results of the VMM trial described in Chapter 3 help make the case that synthetic inertia is indeed capable of providing these services, and that large-scale BESS such as HPR would be able to deliver market and system security benefits through the supply of synthetic inertia to a future IAS market.

2.4 South Australian Inertial Assessment

SA has relatively limited interconnections with the NEM's primary infrastructure and has been identified as a low-inertia sub-region. In essence, this signifies that within this region, the power system encounters limitations in its ability to effectively dampen and counteract frequency variations. Consequently, there is now a pressing demand for additional resources capable of delivering inertial responses for SA.

New VRE capacity in SA is replacing synchronous generators such as gas power plants which is creating operational challenges to provide system strength and inertia. The total registered generation capacity in SA for 2020-21 was 8,239 MW with a high penetration of VRE and storage accounting for 63% of capacity

8 AEMO, Fast Frequency Response in the NEM – Working Paper, 2017, available at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/reports/2017/ffr-working-paper.pdf [accessed 14/12/2023]

9 AEMO, Application of Advanced Grid-Scale Inverters in the NEM (White Paper), August 2021, available at: https://aemo.com.au/-/media/files/initiatives/engineering-framework/2021/application-of-advanced-grid-scale-inverters-in-the-nem.pdf [accessed 14/12/2023]

10 AEMO, Inertia in the NEM explained, 2023, available at: https://aemo.com.au/-/media/files/initiatives/engineering-framework/2023/inertia-in-the-nem-explained.pdf?la=en [accessed 14/12/2023]

including ~2,400 MW wind generation and ~2,600 MW solar generation. AEMO's 2022 assessment reaffirms the existing inertia shortfall, consistent with the 2021 assessment, indicating a requirement of 6,200 MWs of inertia with 360 MW from FFR. Notably, the availability of more FFR can reduce the requirement of synchronous inertia.

AEMO anticipates a further 15.5 GW of new VRE will be built in SA by 2050 indicating an ongoing and growing requirement of inertial response and FFR services. Priority VRE development will go to Renewable Energy Zones (REZ) with high wind quality with Southeast SA expecting an additional 0.76 GW by 2030 and 1.2 GW by 2040, and Mid-North SA installing 1.15 GW by 2030, reaching 2.9 GW by 2040.[11] In anticipation for the increase in VRE and load requirements, several upgrades and new projects across SA’s transmission network are being planned. These projects will help unlock onshore and offshore renewable generation throughout SA and connect REZs to demand centres. Appendix C outlines committed and anticipated transmission network projects that will enable the clean energy transition.

In response to the constraints and performance limitations experienced as VRE increases penetration throughout the network, ElectraNet have installed two high-inertia synchronous condensers each at Davenport and Robertstown to address system strength and synchronous inertia requirements. ElectraNet entered into an agreement for the provision of FFR for 2022-23 with AEMO declaring a new inertia shortfall equivalent to 360MW of FFR from July 2023 until the completion of Stage 2 of the Project EnergyConnect (PEC) interconnector which will significantly enhance the transmission transfer capability between SA and the NEM. ElectraNet has begun procurement of the increased requirement. The PEC project will play a key role in alleviating the inertia shortfall in SA. However, the end date of shortfall could be significantly affected by the provision of sufficient services through maturing of the new Very Fast FCAS markets (refer to Section 4.2.5) or the completion of the WAPS and the related SAIT RAS (refer to Chapter 5).

11 AEMO, 2022 Integrated System Plan, June 2022, available at: **https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en** [accessed 14/12/2023]

3 Virtual Machine Mode

3.1 Key Insights and Lessons Learnt

This chapter provides an assessment on HPR's ability to provide inertia services using Tesla's VMM capability (Innovation Objective 1). Key insights and lessons learnt from the analysis include:

1. **Synthetic inertia response:** HPR with VMM functionality has demonstrated technical capability to provide synthetic inertia that is sufficiently fast and large enough to contribute to management of the RoCoF during grid disturbances. VMM-enabled inverters responded proportionally to the RoCoF in contingency events, which clearly mimics the behaviour and inertial response of synchronous machines. VMM can reduce the overall requirement of FCAS, potentially saving market costs.
2. **Unique benefits of VMM compared to other FFR providers:** The comparison of VMM with other FFR providers showcased its unique advantages of being more programmable, flexible, and controllable.
3. **Synthetic inertia needs to be incentivised to unlock potential:** HPR and other large-scale BESS have the potential to become major inertia providers *if* synthetic inertia is eligible for market provision. TNSPs required to procure minimum safe levels of inertia could also choose to procure synthetic inertia from large scale BESS, such as HPR.
4. **VMM supports the provision of a range of services:** HPR with VMM demonstrated its adaptability and ability to contribute to grid stability across different frequency services (FCAS markets) and network support and control ancillary services (non-market services). In addition, as the power system landscape evolves, VMM's role in the emerging Very Fast FCAS market is promising due to its very fast response (within 1 second).
5. **Unique applicability in SA:** Based on the inertia assessment in the SA power network, VMM has the capacity to provide up to 2,000 MWs of inertia, which amounts to roughly one-third of the entire SA state-level inertia requirements, underscoring the significance of VMM in fortifying grid resilience.
6. **VMM capability provides the opportunity to provide various network support services:** System security will continue to be a priority issue in SA, however AEMO has not identified a Network Support and Control Ancillary Services (NSCAS) gap in SA over the coming five years based on their 2022 assessment.

3.2 Supporting Analysis

3.2.1 Virtual Machine Mode Functionality

One of the notable advantages of the Tesla Powerpacks utilised at HPR is their fast-ramping capability. This unique feature empowers the facility to dispatch substantial amounts of power with speed and reliability. This capacity is particularly valuable as it plays a pivotal role in supporting the SA electricity grid stability. By providing essential frequency control and enhancing short-term network security services, HPR could contribute significantly to substantial cost savings within the region.

Within Tesla's Powerpack for HPR's energy storage solution, the built-in inverters equipped with VMM introduce grid-forming dynamics by providing synthetic system inertia response. These dynamics play a crucial role in bolstering grid stability, as they are designed to respond effectively to fluctuations in both added and rejected loads. Furthermore, they ensure the maintenance of high-quality voltage levels at the point of interconnection.

As illustrated in Figure 3-1, VMM allows the inverter to mimic the behaviour of a synchronous machine through a virtual machine component that runs in parallel with the conventional current source component.

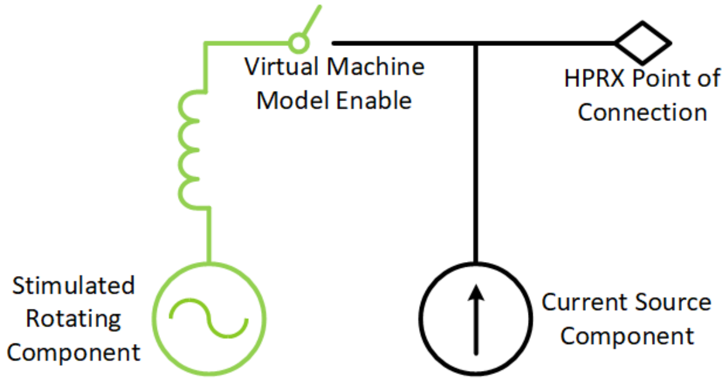

Figure 3-1: Synthetic VMM representation[12,13]

Implementing RoCoF into the control functionality to simulate an inertial response involved conducting a suite of hold-point tests to confirm the intended behaviour. Figure 3-2 shows the comparison between conventional frequency response at the 275kV point of connection and the VMM-enabled (trial) inverters response to a frequency event capture on 21 May 2021. As indicated by the red lines, the conventional inverters responded with active power injection proportional to the magnitude of frequency deviation, while the VMM-enabled (trial) inverters responded proportional to the RoCoF, with peak output being reached prior to the frequency nadir (lowest frequency). This was a clear inertial response performed by HPR.

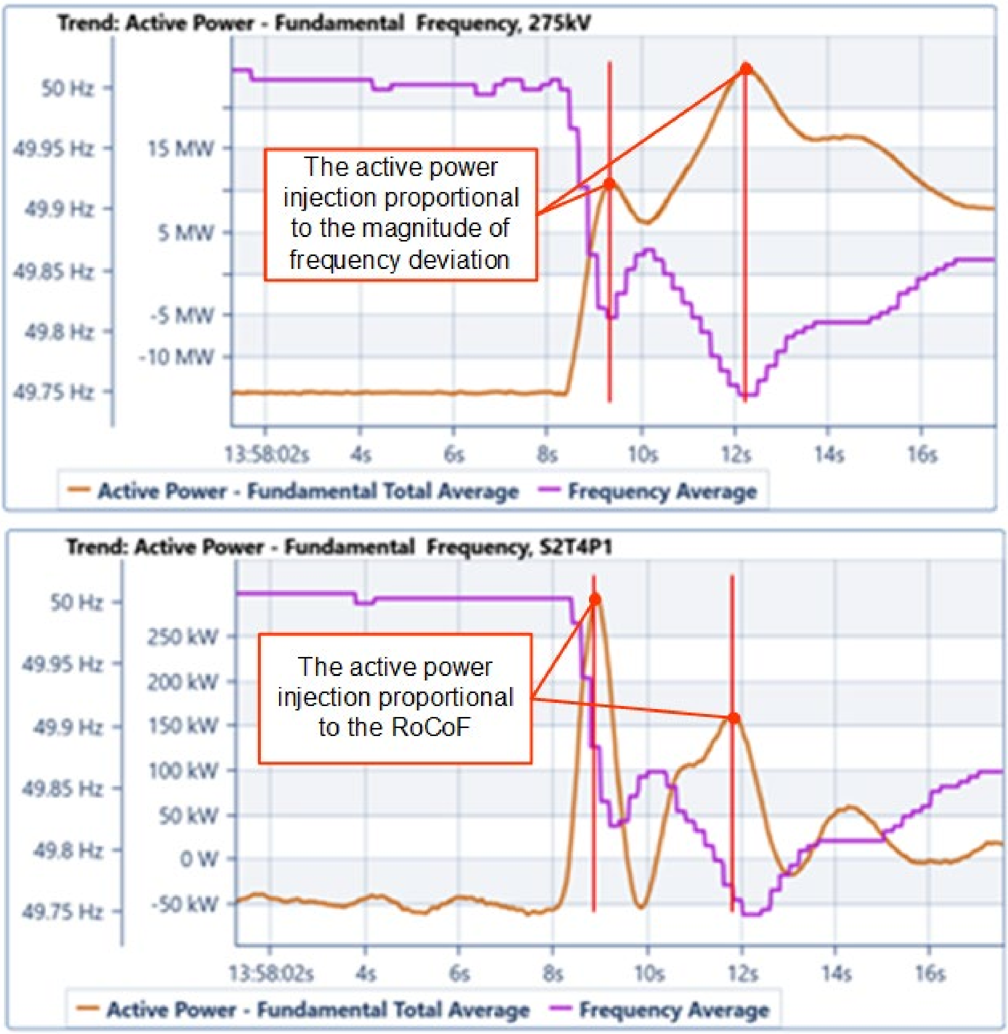

Figure 3-2: HPR response showing conventional inverters (top) and VMM (bottom)[14]

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12 Neoen, Virtual Machine Mode Actual vs Modelled Study, February 2023, available at https://arena.gov.au/assets/2023/09/HPRX-VMM-Modelled-vs-Actual-Report.pdf [accessed 14/12/2023]

13 Note: VMM is always actively monitoring RoCoF.

14 Neoen, Hornsdale Power Reserve Expansion – Virtual Machine Mode Test Summary Report, March 2022, available at: https://arena.gov.au/assets/2022/03/hornsdale-power-reserve-virtual-machine-mode-testing-summary-report.pdf [accessed 14/12/2023]

3.2.2 HPR VMM Case Study

To identify the scenarios for VMM response from HPR to achieve maximum benefits, a case study of frequency control behaviours during a grid contingency event is investigated. On 11 August 2022, a network event saw the grid frequency drop to 49.764Hz, significantly below the lower NOFB of 49.85Hz. The frequency control behaviours of HPR are shown in Figure 3-3.

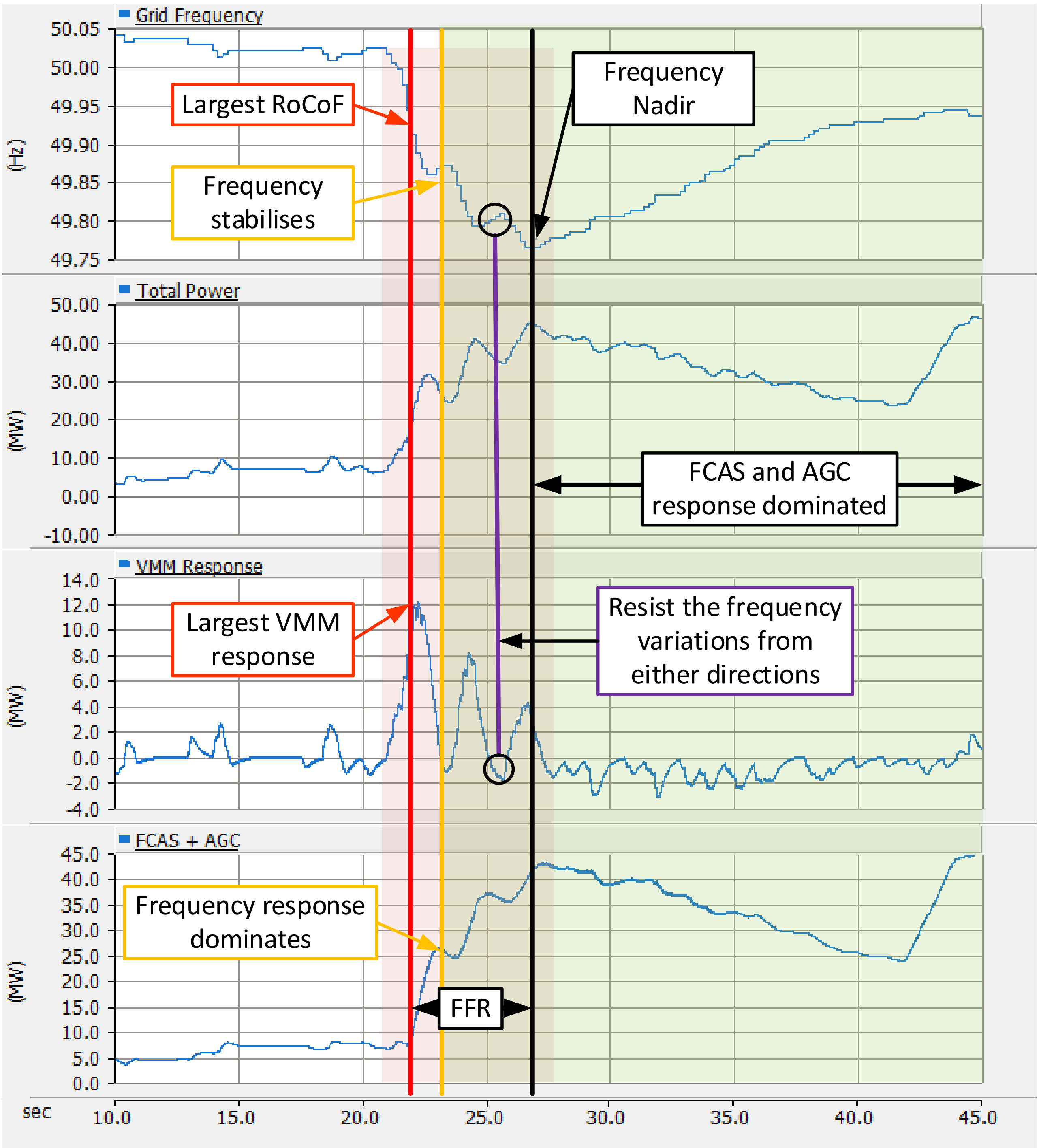

Figure 3-3: Frequency control behaviour of HPR with VMM + FCAS response

The observed results indicate that:

- VMM is responding proportionately to RoCoF, while the FCAS response is responding proportionally to the frequency deviation from a nominal 50Hz.
- The VMM response performed is closely equivalent to synchronous inertia, resisting deviation from either direction of the frequency trend, as shown on the purple line in Figure 3-3.

- VMM responds much faster than conventional FFR, whereby VMM response has reached the maximum injection before the conventional FFR starts to react. This effectively mitigates the significant RoCoF and prevents the frequency from a further frequency drop from the current nadir (lowest frequency at 49.764 Hz). This reduces the overall requirement of FCAS potentially saving market costs.
- HPR allows the inverter to run in parallel with a VMM functionality (red shading) and the conventional current source mode (green shading), but function separately. This enables HPR to operate not only in conventional FCAS markets but also the new Very Fast FCAS market (1 second).

In summary, HPR with VMM capability could effectively provide closely emulated synchronous inertia (or synthetic inertia) to power systems, particularly the SA power network. The VMM resists the high RoCoF during a network contingency event and extends the timeframe to react via existing FCAS. HPR can respond rapidly to correct a frequency deviation prior to the frequency reaching the maximum and minimum points reducing the magnitude of frequency deviations and contingency FCAS requirements.

HPR VMM capabilities become particularly important with the AEMC's final determination on the revised FOS, which includes the additional RoCoF limit of 1Hz per second (measured over any 500 millisecond period) for a credible contingency event and a narrowed operating frequency tolerance band of 49-51Hz (previously was 49-52Hz) during the system restoration.[15]

Although VMM is not currently a service recognised by the available markets in the NEM, synthetic inertia is provided as a blended response along with frequency control, thus presents an enhancement to the response in the existing markets.

3.2.3 VMM Comparison with Alternative Inertia Providers

Inertia providers available in the power system includes conventional synchronous generators, synchronous condensers (SynCon), inverter-based renewable energy systems (RES) and large-scale BESS. As mentioned previously, synchronous inertia is declining in the NEM therefore alternative sources of inertia will need to be sourced.

Large-scale BESS with advanced inverter technology (i.e., VMM) has unique advantages compared to other alternative inertia providers. It has controllable and programmable inertia constants (0.1 to 20 seconds), which can support different levels of inertia response to power network disturbance. In addition, BESS equipped with VMM can be upgraded/augmented by adding additional modular BESS packages, creating unique feasibility for future alteration.

Furthermore, there are specific disadvantages associated with SynCon and inverter-based RES in providing inertia services compared to large-scale BESS with VMM, these include:

- SynCons have high upfront costs, long lead times and high operating costs.
- Inverter-based RES (such as wind and solar) generally cannot offer synchronous inertia. However, it is possible to provide an emulated inertial response to the power system through appropriate inverter controls. Nevertheless, this capacity is highly limited by resource availability and requires some amount of energy storage.

The detailed comparisons of various inertia providers are summarized in Table 6-6 in Appendix D.

3.2.4 Unlocking the Full VMM Potential

HPR alone has the capacity to provide up to 2,000MWs of inertia through its full utilisation of VMM technology. This capability amounts to roughly one third of the entire SA state level inertia requirements,[16] underscoring the significance of VMM in fortifying grid resilience during the ongoing transition to VRE. Therefore, HPR and other large scale BESS have the potential to become major inertia providers if synthetic inertia is eligible for market provision.

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[15] AEMC, Final determination for frequency operating standard, 6 April 2023, available at: https://www.aemc.gov.au/news-centre/media-releases/final-determination-frequency-operating-standard [accessed 14/12/2023]

[16] AEMO, 2022 Inertia Report, December 2022, available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2022/2022-inertia-report.pdf?la=en [accessed 14/12/2023]

Without an IAS market or other cost-minimising approach to inertia provision, there is no financial incentive for large scale BESS to provide synthetic inertia beyond any bilateral TNSP agreements that may exist. This maintenance of inertia at the minimum safe level (corresponding to the highest safe RoCoF following a contingency) maximises requirements for the Very Fast FCAS, even if a higher level of system inertia could reduce FCAS requirements and lower the overall cost of frequency control. Co-optimisation of FCAS and inertia through a market mechanism could lower the overall cost of frequency control from the current minimum-inertia paradigm by reducing requirements for contingency FCAS provision when system inertia exceeds the safe minimum.

3.2.5 VMM Capability for Network Support and Control Ancillary Services

Network Support and Control Ancillary Services (NSCAS) are non-market ancillary services that may be delivered to maintain power system security and reliability of supply of the transmission network, or to maintain or increase the power transfer capability of the transmission network. This ancillary service is provided to the market under long term ancillary service contracts negotiated between AEMO (on behalf of the market) and the participant providing the service.

HPR through its VMM capability provides the opportunity to provide various NSCAS as summarised in Table 3-1. Note AEMO has not identified an NSCAS gap in SA over the coming five years based on their 2022 assessment. However, system security will continue to be a priority issue in SA. The relevant NSCAS for HPR are summarised in Table 3-1.

Table 3-1: HPRX capability in providing Network Support and Control Ancillary Services

NSCAS	Description	HPR VMM Capability
Voltage Control Ancillary Services (VCAS)	In general, Voltage Control Ancillary Services (VCAS) can be provided by Synchronous Condenser and Static Reactive Plant.	HPR with VMM capability has specific benefits on adding voltage smoothing to weak grids (such as the SA region compared to the rest of the NEM) by injecting reactive power to the power system.
Network Loading Control Ancillary Services (NLCAS)	Network Loading Ancillary Services (NLCAS) are used by AEMO to control the flow on inter-connectors within short-term limits.	HPR is already involved in the SA System Integrity Protection Scheme (SIPS) (currently being upgraded to a WAPS) and future SAIT RAS which aims to reduce the likelihood of the SA power system islanding from the rest of the NEM following a sudden increase in flow on the Heywood Interconnector and future PEC. This control scheme was developed and implemented under the NLCAS framework. HPR with VMM functionality can respond to network incidents (loss of either generator or load unit) by rapidly injecting or absorbing up to 150MW of active power to or from the SA power system, thereby alleviating the risk of tripping the Heywood interconnector and PEC due to frequency drop and significant changes in power flow. Refer to Chapter 5 for further details on the WAPS and SAIT RAS.
Transient and Oscillatory Stability Ancillary Services (Powerpack)	Transient and Oscillatory Stability Ancillary Services (TOSAS) control and fast-regulate the network voltage, increase the inertia of rotating mass connected to the power system or rapidly increase/reduce load connected to the power system.	HPR with VMM capability can provide inertia/damping support services to stabilise the network oscillation. Given the VMM operational principle, the amount of response is based on the RoCoF instead of the frequency deviation magnitude. Therefore, VMM presents unique advantages to dampen the frequency and voltage oscillation and enhance the power network stability. In addition, Tesla inverters have a feedback damping loop to improve the control stability. This damping loop also provides an inertial response to system disturbance.

4 Enhanced FCAS Capability

4.1 Key Insights and Lessons Learnt

This chapter explores enhanced FCAS provided by large-scale BESS, providing information that could be used for a future MASS review (Innovation Objective 2). Key insights and lessons learnt from the analysis include:

1. **HPR has provided a significant share of FCAS markets**: HPR and its extension HPRX, have been significant contributors to the FCAS market since 2017 and 2020 respectively. As a combined facility, it provides around 10% of FCAS value each month in the NEM.
2. **HPR successfully demonstrated benefits during the Enhanced FCAS trial:** Updates to the frequency droop response settings were made at HPR in response to the mandatory PFR rule change, which increased the active power response to a +/- 0.5Hz frequency deviation from 61MW to 86MW. This response, when standardised against the mainland NEM frequency ramp, was deemed fast enough to warrant a greater registration in the Fast FCAS market than the other contingency markets. This also helped demonstrate the ability of HPR to support future Very Fast FCAS services (now implemented). HPR also successfully demonstrated the ability to enhance large-scale BESS FCAS offerings at no cost through a tighter PFR deadband.
3. **2027-2028 is the earliest expectation for introducing an inertia market:** The increasing deployment of VRE using IBRs combined with the retirement of fossil fuelled plant will eventually mean that system inertia will become scarcer and that the need for provision of synthetic inertia will grow. There is currently a rule change request for *"Efficient provision of Inertia"*[17] which includes an IAS market, for which a formal determination will be made on 29 February 2024. If a determination is made to establish an IAS market, it would likely commence 3 to 4 years after the rule determination circa 2027-2028. Participation by HPR in a future IAS market would require further study into co-optimising the provision of multiple ancillary services (FCAS and IAS) simultaneously.
4. **HPR learnings could contribute to future revisions of the MASS:** Market reforms can take years to progress. Demonstrating capability before the implementation of regulatory reform is necessary step on that journey and HPR has suitably demonstrated its capability to provide synthetic inertia as part of any future IAS market. It would be expected that the learnings from HPR study for synthetic inertia would contribute to a future re-write of Section 4.2 of the MASS if synthetic inertia is eligible for market provision in any future IAS market.

4.2 Supporting Analysis

4.2.1 Motivations for Enhanced FCAS Trial

The HPR Enhanced FCAS trial was designed to demonstrate several outcomes, including 1) an increase to the permissible level of FCAS registration for HPR, and by extension for other large-scale BESS FCAS providers, and 2) demonstration that amendments to the MASS could improve recognition and valuation of the fast response capability of HPR (and by extension other large-scale BESS FCAS providers), and that this could deliver market benefit to NEM stakeholders. These outcomes involved HPR demonstrating an ability to provide more effective contingency FCAS services because of two core technological capabilities:

- An ability to provide a **greater active power response** to support contingency FCAS enablement by tightening the PFR deadband from ±0.15Hz to ±0.015Hz.
- An ability to provide a **faster active power response** than required for the Fast FCAS (6 second) services.

[17] AEMC, Efficiency provision of inertia (rule change), available at: https://www.aemc.gov.au/rule-changes/efficient-provision-inertia [accessed 14/12/2023]

4.2.2 Recognition of Faster-Responding FCAS

At the time of the HPRX project and the Enhanced FCAS trial, the fastest-responding FCAS services recognised by the MASS v7 were Fast (6 second) Contingency Raise (R6) and Lower (L6). These services require (and recognise) that active power is delivered within 6 seconds of a frequency excursion beyond the NOFB following a contingency event. Large-scale BESS such as HPR can adjust active power within significantly less than 6 seconds, but this faster-than-Fast response was not explicitly recognised. Instead, fast-responding large-scale BESS were permitted to register a higher-than-actual capacity for the R6/L6 services using a 'biased' ramp that delivered peak active power in less than the required 6 seconds.

FCAS registration is granted based on the providers droop response and response time, as compared to the standard frequency ramp in the NEM. This means that assessment of frequency response is performed by normalising the response against the standard frequency ramp. HPRX demonstrated during commissioning a normalised active power response to a frequency deviation of +/-0.5Hz of 61MW in 4 seconds, and could maintain this active power for the 60 seconds required to satisfy Fast and Slow FCAS provision. Under the conditions of MASS v7 then in effect, HPR could thus register 61MW in all frequency markets, plus increase the R6 registered capacity to 95MW as a result of the "multiplier effect" (Figure 4-1).

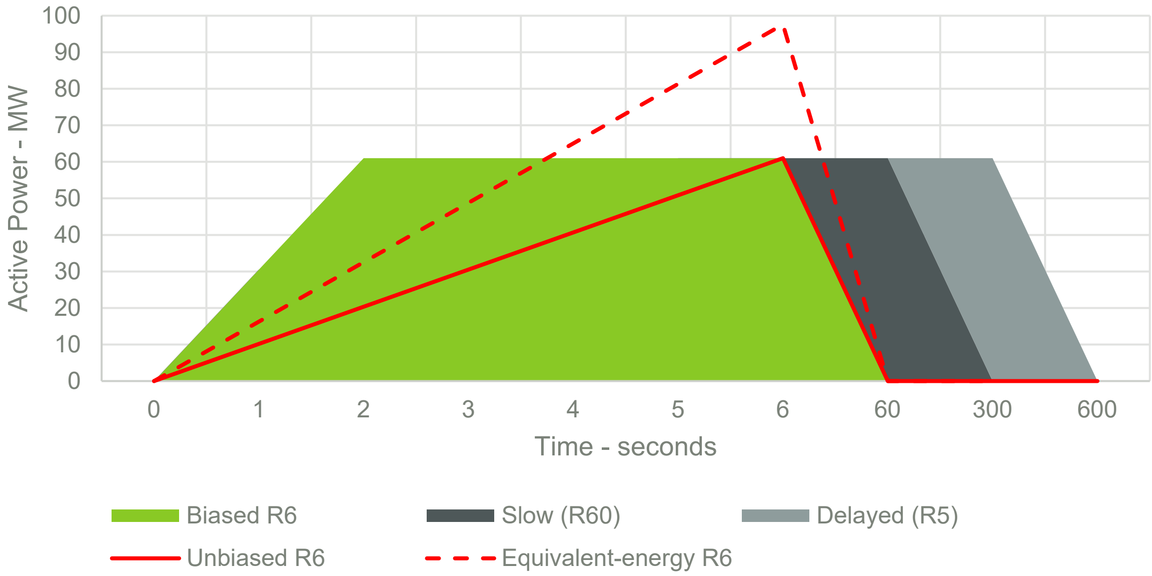

Figure 4-1 Recognition of faster than 6s FCAS provision with biased ramping (MASS v7, prior to Oct 2023)

This multiplier effect existed under the MASS v7, which enabled faster generators to register for an R6/L6 capacity that was more reflective of their actual provision. The multiplier effect was subsequently abolished with the introduction of Very Fast 1 second FCAS Raise and Lower markets with MASS v8 in October 2023 (see Section 4.2.5). These new services explicitly recognise and value the fast response of large-scale BESS to contingency events, as was demonstrated by HPR in the Enhanced FCAS trial.

4.2.3 Enhancing FCAS Registered Capacity with Tighter PFR Deadband

During the Enhanced FCAS trial, HPR progressively tightened the PFR deadband from 50±0.15Hz to 50±0.015Hz. This tighter PFR setting means that HPR will begin adjusting active power in response to smaller frequency deviations and will provide a larger active power response to frequency deviations outside the NOFB. The effects of tightening the PFR deadband are shown in Figure 4-2.

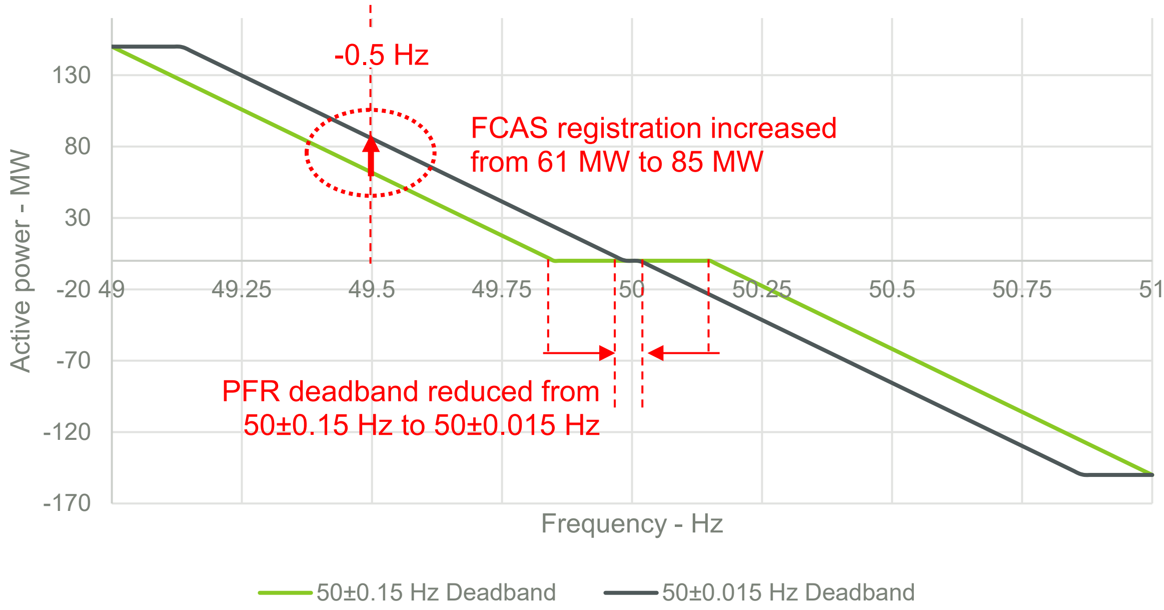

Figure 4-2: HPR active power response to frequency deviations with a tightened PFR deadband

Under the current MASS, FCAS registered capacity is defined by the active power response at a frequency of 50±0.5Hz. This means that the increased active power response to frequency excursions enabled by a tighter PFR deadband allow HPR to register for an increased FCAS capacity of 85MW (delivered at 49.5Hz), up from a previous registered capacity of 61MW, successfully demonstrating the ability to improve large-scale BESS FCAS offerings at no cost through a tighter PFR deadband. Combined with the 'multiplier effect', HPR was able to register a biased Fast FCAS market capacity of 114MW, noting that this registration was updated with the implementation of the MASS v8 and the new Very Fast FCAS market introduction.

Under the current MASS, the additional active power response provided by HPR or other large-scale BESS to frequency deviations beyond 50±0.5Hz does not count towards registered FCAS capacity and is not valued. Recognising this latent FCAS capacity would require changes to the MASS, which might include valuing PFR droop beyond 0.5Hz frequency excursions or allowing FCAS providers to apply higher frequency droop settings than 1.7% to allow the delivery of a larger proportion of available capacity at 50±0.5Hz.

4.2.4 Historical FCAS Market Performance

From its commissioning in 2017, the original HPR quickly emerged as a vital FCAS supplier to meet this demand. Aurecon examined market data for FCAS from AEMO's Market Management Systems (MMS). As shown in Figure 4-3, the current market for FCAS has grown significantly in total market value where the total revenue was less than $50 million each year from 2010 and until 2014. In the years from 2015 to 2021 we have seen the aggregate value increase every year from $63 million to $438 million in 2021, but values fell to $279 million in 2022 and have only been worth $132 million in 2023 (YTD – 6 November 2023). Improved system frequency stability from mandated PFR may have contributed to lower requirements for FCAS and reduced FCAS revenue from 2021 (noting HPR and other large batteries are required to provide mandatory PFR when dispatched above 0MW which can increase wear on battery).

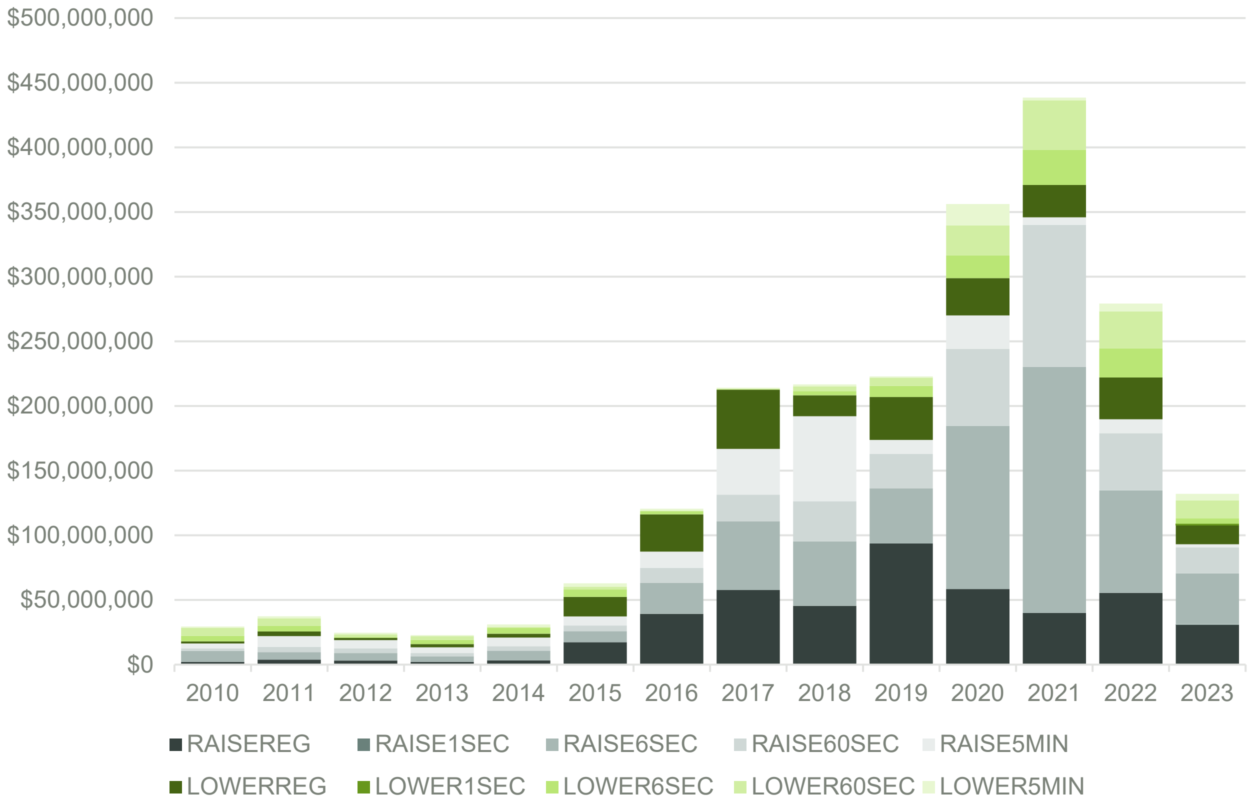

Figure 4-3: Annual FCAS values across the NEM

A more detailed examination of HPR FCAS revenues compared to the total NEM FCAS revenues shows its share against total NEM to be a significant contributor, providing around 10% of market revenues on average. The detail of these results is shown in Figure 4-4.

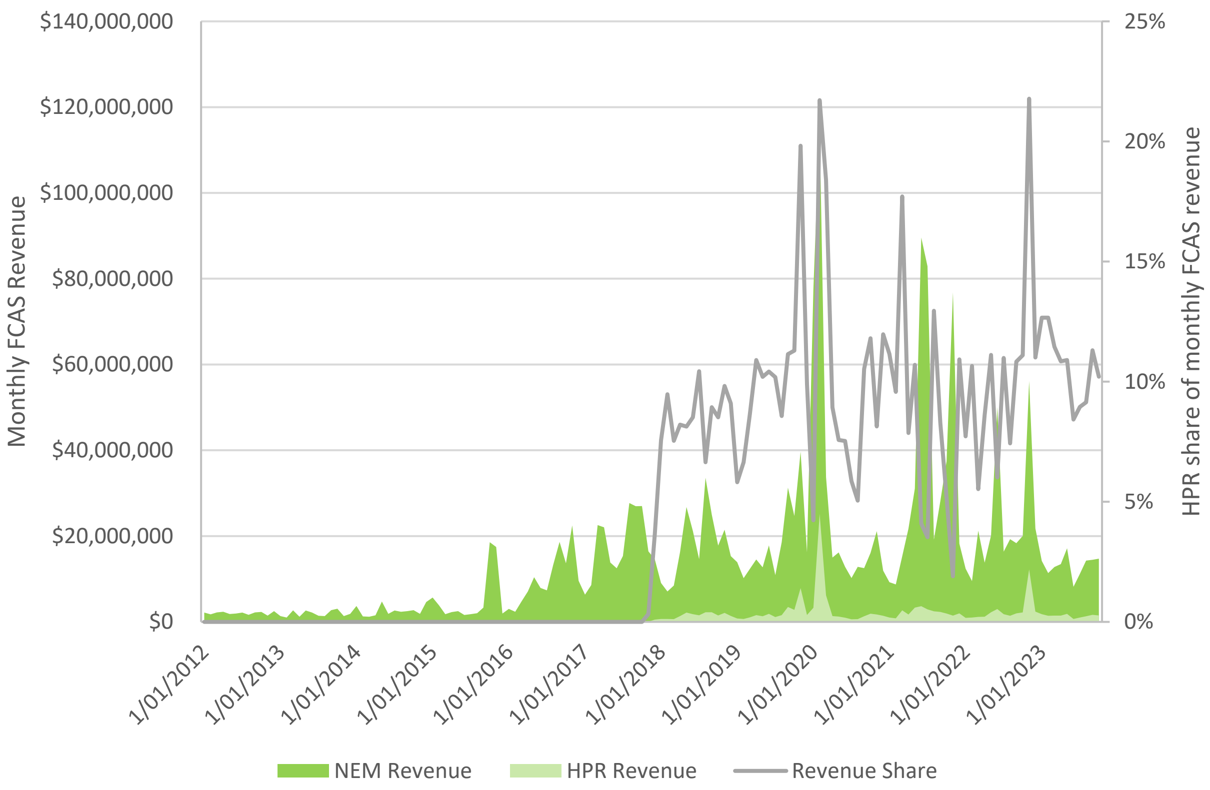

Figure 4-4: HPR and NEM FCAS Revenues, and HPR share (%)

4.2.5 Very Fast FCAS

The Very Fast FCAS market commenced on 9 October 2023. Very Fast FCAS services are efficiently served by the 'premium' fast-ramping capabilities of HPR and other large-scale BESS. While it is no longer possible to 'bias' FCAS capacity towards Fast services (as approved by AEMO during HPR Enhanced FCAS trial, see Figure 4-1),[18] market recognition of Very Fast FCAS services is a significant opportunity to HPR. The introduction of Very Fast FCAS and the MASS v8 brought HPR's registration to the final value of 85MW across all 8 FCAS Contingency markets (Very Fast, Fast, Slow, and Delayed), as shown in Figure 4-5.

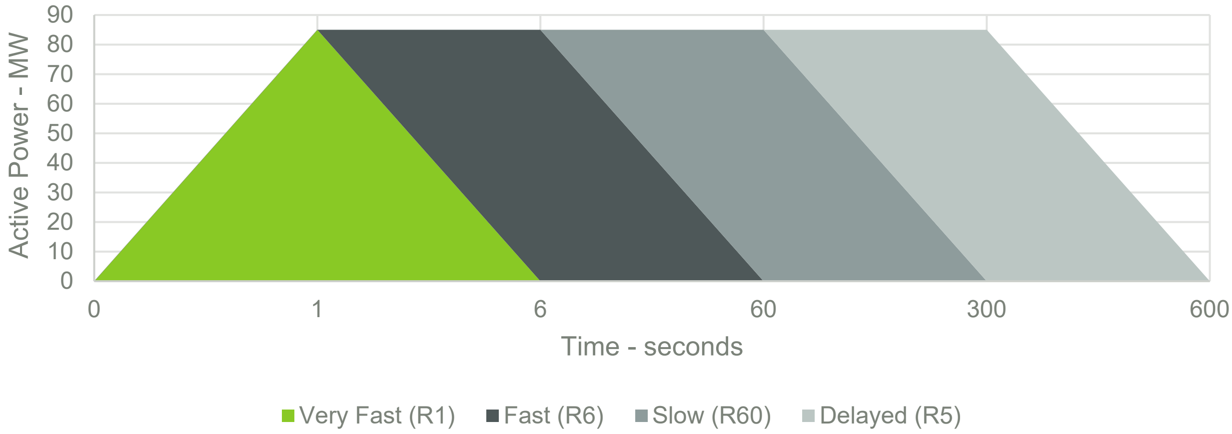

Figure 4-5: Contingency FCAS services following the introduction of Very Fast services (MASS v8, Oct 2023)

As of November 2023, there are only 20 registered providers of Very Fast FCAS in the NEM (Table 4-1), with an aggregate maximum capacity of 338MW in lower and 502MW in raise, with HPR representing 85MW of each total market.

Table 4-1: Very Fast FCAS (1 second) market providers

FCAS 1s - Provider	State	Lower Max MW	Raise Max MW
AS AES NSW	NSW1	1	1
Queanbeyan Battery Energy Storage System	NSW1	5	5
Bouldercombe Battery Project	QLD1	22	22
Bulgana Green Power Hub	VIC1	11	11
ENOC MASP NSW	NSW1		70
ENOC MASP QLD	QLD1		15
ENOC MASP SA	SA1		17
ENOC MASP VIC	VIC1		28
Hornsdale Power Reserve (HPR)	SA1	85	85
Wallgrove BESS 1	NSW1	27	27
Lake Bonney BESS1	SA1	13	13
Victorian Big Battery	VIC1	171	171
DRVIOT01	SA1		2
DRVIOT02	VIC1		2
DRVIOT03	NSW1		2
DRVIOT04	QLD1		23
DRVIOT05	TAS1		5
ASRMGE01	SA1	1	1
ASRMGE02	SA1	1	1
ASRMGE03	SA1	1	1
TOTAL		**338**	**502**

[18] Neoen, HPRX Enhanced FCAS Testing Final Report, Rev2, 4 August 2023

Whilst it is too early to be definitive on the market impacts of the new Very Fast FCAS markets, we can observe that HPR is able to be a significant contributor to these new market services. As of the 6 November 2023, the Very Fast FCAS markets had captured 11% of market revenues in FFR (1 second) ancillary services.

The ancillary services markets are inherently volatile and difficult to predict but it is possible that the Very Fast response (and potentially future IAS markets) will mean that the other FCAS services are less likely to be called upon due to the market's ability to mitigate frequency disturbances in the time domain of up to 6 seconds. Therefore, we can potentially expect that the shorter time frame FCAS markets earn a disproportionate share of ancillary services revenue (relative to the aggregate registered capacity in each market) with the potential to reduce total FCAS costs.

4.2.6 Potential Future Inertial Market

The development of a potential market for inertia has had support from market participants but the challenge has been in establishing the need for inertia and the value of the inertia services at the times when regulatory review has occurred. To date, the requirement for inertia has been managed by TNSPs who must procure these services at the time when there is a forecast shortfall in local inertia. However, the increasing deployment of VRE using IBRs combined with the retirement of fossil fuelled plant will eventually mean that system inertia will become scarcer and that the need for provision of synthetic inertia will grow.

Nonetheless, it can take several years for implementing market reforms. For example, it took more than three years since the initiation of a rule change request by Infigen Energy for FFR in March 2020, to a final determination by the AEMC on 15 July 2021 and then to final implementation on 9 October 2023 for FFR. Other market reforms such as the establishment of FCAS markets, FFR and 5-minute settlement have taken years to progress.

AEMO and the AEMC continue to work together on market reform and their publication *"Essential system services and inertia in the NEM"*[19] details their progress on the efficient provision of inertia in the NEM. There is currently a rule change request for *"Efficient provision of Inertia"*[20] which includes an IAS market, for which a formal determination will be made on 29 February 2024. If a determination is made to establish an IAS market, it would likely commence 3 to 4 years after the rule determination circa 2027-2028.

Demonstrating capability before the implementation of regulatory reform is necessary step on that journey and HPR has suitably demonstrated its capability to provide synthetic inertia as part of any future IAS market.

4.2.7 HPRX Impacts on MASS

The Market Ancillary Service Specification (MASS) was last updated on 9 October 2023 (v8.0), coincident with the commencement of Very Fast FCAS markets in the NEM.[21] V6.0 of the MASS, released on 1 June 2020, was modified to accommodate the PFR draft rule change (ECR00274) for 1 second FCAS markets. Notably, in Section 2.4, the MASS defines that FCAS *does not* include inertia. It would be expected that the learnings from HPR study for synthetic inertia would contribute to a future re-write of the MASS if synthetic inertia is eligible for market provision in any future IAS market.

19 AEMO, Essential System Services and Inertia in the NEM, June 2022, available at: https://www.aemc.gov.au/sites/default/files/2022-06/Essential%20system%20services%20and%20inertia%20in%20the%20NEM.pdf [accessed 14/12/2023]

20 AEMC, Efficiency provision of inertia (rule change), available at: https://www.aemc.gov.au/rule-changes/efficient-provision-inertia [accessed 14/12/2023]

21 AEMO, Market ancillary service specification, v8.0, 9 October 2023, available at: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/amendment-of-the-mass/final-determination/market-ancillary-services-specification---v80-effective-9-oct-2023.pdf?la=en [accessed 14/12/2023]

5 Impact on Interconnector Transfer Limits

5.1 Key Insights and Lessons Learnt

This chapter explores the impacts on the transfer limits in relation to the ElectraNet's WAPS and the related SAIT RAS (Innovation Objective 3). Key insights and lessons learnt include:

1. **HPR will be able to provide a bi-directional response as part of the WAPS upgrade:** ElectraNet's System Integrity Protection Scheme (SIPS) which is currently being upgraded to a WAPS, will harness HPR's ability to both charge and discharge rapidly in case of a WAPS trigger signal received to assist in avoiding the Heywood interconnector tripping.
2. **HPR provides rapid ramping within guaranteed response times for the WAPS:** HPR can ramp active power output from the previous position to up to 150MW within the guaranteed response time.
3. **HPR VMM is capable to enhance the effectiveness of the WAPS by responding to RoCoF:** HPR with VMM capability effectively mitigates high RoCoF and supports alleviation of frequency deviations, which has the potential to significantly enhance the WAPS's effectiveness.
4. **HPR impacts on interconnector transfer limits remain an area of further investigation:** The full SAIT RAS is still under development, and it will be significantly impacted by the stages of the PEC interconnector project. Therefore, the full impact of WAPS and HPR on the combined transfer limits for the PEC and Heywood interconnectors will continue to be an area of collaborative engagement and investigation by ElectraNet, AEMO and Neoen.

5.2 Supporting Analysis

5.2.1 HPR Response and Ramp Times

HPR is capable of rapidly responding to a step change command issued by ElectraNet within the SIPS contract required time. With a ramp rate of more than 600MW per second,[22] HPR will play a pivotal role in responding to commands issued by the WAPS under development and future SAIT RAS and mitigating the risk of cascading failures associated with transfer limitations on the Haywood and PEC interconnectors.

5.2.2 Wide Area Protection System

The SIPS was developed and commissioned in December 2017 by ElectraNet to rapidly detect conditions that are approaching loss of synchronism between SA and Victoria and respond by taking control actions. The SIPS is designed to rapidly inject power from large scale BESS or shedding some load to assist in re-balancing supply and demand in SA to prevent a loss of the Heywood Interconnector. The original HPR was integrated into the SIPS in December 2018 to respond to emergency events via rapid injection up to 100MW of power.

AEMO identified improvements to the SIPS in their Power System Frequency Risk Review published in June 2018.[23] In response, ElectraNet in consultation with AEMO has improved the performance of the scheme using a time synchronised phasor-based scheme. The new scheme called Wide Area Protection Scheme (WAPS) is nearing completion and will provide the following improvements compared to the SIPS:

- More accurate detection and rapid triggering of response elements (i.e. loads and BESS), thus minimising the risk of a Heywood Interconnector trip.
- Real-time measurement of available response (loads and BESS) to provide a proportionate response.
- Introduce charging responses from BESS including HPR.

[22] Tesla, Neoen Hornsdale Power Reserve Extension – SIPS Test Report, 25/09/2020
[23] AEMO, Power System Frequency Risk Review Report, June 2018, available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/psfrr/2018_power_system_frequency_risk_review-final_report.pdf?la=en [accessed 14/12/2023]

Further, ElectraNet will upgrade the WAPS to account for the PEC. Consequently, this will bolster the security and resilience of the SA power system, particularly in mitigating the impact of low probability, high impact non-credible contingencies.

HPR with VMM capability, which effectively mitigates the high RoCoF and alleviates the maximum frequency deviations, brings about significant enhancements to the effectiveness of the WAPS. More specifically, the synthetic inertia provided by VMM enables HPR to inherently (almost instantaneously) respond to a considerable frequency contingency. This creates time, such as delaying frequency reaching the lowest point, for WAPS to detect the network frequency disturbance and implement accurate responses from large scale BESS and controllable load, and eventually minimise the risk of tripping interconnectors.

Another unique contribution of HPR with VMM capability relies on the potential improvement on transmission and tripping constraints in these special protection schemes. For example, the WAPS will be tripped based on the Phase Measurement Unit (PMU) data which measures and compares the local RoCoF and frequency deviation in the SA system. The increased inertia (mixed of synthetic inertia, SynCon or other grid-forming devices) in the power system would reduce the WAPS response requirements, such as minimising the load shedding and surge power transmission via interconnectors.

5.2.3 South Australia Interconnector Trip Remedial Action Scheme

As illustrated in Table 5-1, the operation of the new PEC interconnector will significantly enhance the transmission transfer capability between SA and the NEM. However, the PEC also introduces a new risk that, for a non-credible loss of either of the two double circuit interconnectors under high power transfer conditions, the other interconnector could overload, cause instability and result in separation of SA from the NEM and a potential widespread loss of supply.

Table 5-1: Transmission limits for two interconnectors

Interconnector	Nominal Limit[24]	Nominal Combined Limit	Combined Transfer Limit[25]
Heywood Interconnector	Import: 600 MW Export: 550 MW	Import/export to SA: 1450 MW	Import into SA: 1300 MW Export from SA 1450 MW
PEC Interconnector	Import/export for SA: 800 MW		

Therefore, the SAIT RAS is being developed to cater for a non-credible trip of either the PEC interconnector or the Heywood interconnector under high power transfer conditions to prevent separation of SA from the NEM (scheduled for July 2024). The SAIT RAS will act automatically if either of the double circuit interconnectors is lost. If the event occurs:

- While importing into SA, targeted load shedding to balance supply and demand.
- While exporting from SA, rapid tripping of generation plant to balance supply and demand.
- Rapidly discharging or charging of battery systems also helps.

In general, ElectraNet's WAPS and related SAIT RAS will play a pivotal role in mitigating the risk of generator outage events and preventing cascading failures associated with transfer limitations on the Haywood and PEC interconnectors, thus enhancing the overall system stability for SA.

However, there have several challenges. For example, if an event occurs while operating at maximum transfer conditions, the SAIT RAS will need to shed up to 600MW of load (less response is required at lower transfer levels). In addition, based on the RIT-T market modelling, SAIT RAS operation is expected to be required when the total import/export exceeds approximately 800MW for the period 2025 to 2029. Note that the conventional FFR from a large scale BESS is not fast enough as the primary response. Generally, the lower the system inertia in SA, the bigger and faster SAIT RAS response is required in the related contingency

[24] ElectraNet, Transmission Annual Planning Report, available at https://www.electranet.com.au/wp-content/uploads/231101_2023-TAPR.pdf [accessed 14/12/2023]

[25] Combined transfer limit dependent on transient system stability and sufficient loads and generators in the SAIT RAS

events. This also highlights the VMM's unique advantage of providing system synthetic inertia to support SAIT RAS operation.

In addition, HPR is expected to provide a positive contribution to increasing the transfer limit on the Heywood interconnector by minimising the tripping and alleviating the constraints. It is also noted that the full SAIT RAS is still under development, and it will be significantly impacted by the stages of the PEC project. Therefore, quantitative analysis on the full impact of WAPS and HPR on the combined transfer limits for two interconnectors will continue to be an area of collaborative engagement and investigation by ElectraNet, AEMO and Neoen.

6 Impact on Asynchronous Generation Curtailment

6.1 Key Insights and Lessons Learnt

This chapter explores the reduction of asynchronous generation curtailment of solar PV and wind generation through synthetic inertia services (Innovation Objective 4). Key insights and lessons learnt include:

1. **HPR may aid the unlocking of additional headroom on the connection network:** HPR could play a positive role in the future in contributing to increasing generation hosting capacity through the reduction of curtailment risk particularly under N-1 conditions.
2. **HPR has potential to offer benefits against network constraints:** HPR could alleviate network transient stability limits under outage conditions or thermal constraints in SA.
3. **HPR can be beneficial for market participants:** The addition of storage capacity in the network would provide the benefit of additional hosting capacity for generation and potential load which would improve utilisation of the existing network, benefitting new and existing market participants**.**

6.2 Supporting Analysis

6.2.1 HPR Connection to Current Network Characteristics

HPR is located at the Mid North REZ, approximately 190km north of Adelaide in SA. It is connected to the ElectraNet transmission network via 275kV Mt Lock Substation (owned and operated by ElectraNet) and two 275kV feeders (F1919 and F1968). According to the ElectraNet Transmission Line Data,[26] the utilisation of the adjacent transmission network is shown in Table 6-1.

Table 6-1 Transmission Network Connected to HPR

Feeders:	Historic Line Rating (under normal condition, N-0):	Forecast Loading 2024:	Available capacity at connection Point:[27]
F1919: Mt Lock to Davenport	~ 476MVA	PoE10[28]: ~135MW PoE50: ~108MW	Additional generation: 290MW+ Additional load: 300MW+
F1968: Canowie to Mt Lock	~ 600MVA	PoE10: ~270MW PoE50: ~250MW	

It is noted that the 275kV lines exiting the connection point have sufficient transmission headroom of around 300MW available capacity for additional generation under system intact conditions to be connected to Mount Lock connection point. However, as ElectraNet have not published the N-1 contingency capacity which has less headroom transfer capacity. Aurecon considers HPR project may play a positive role in the future in contributing to increasing generation hosting capacity through the reduction of curtailment risk particularly under N-1 conditions.

[26] ElectraNet, Transmission Line Data 2023, available at https://www.electranet.com.au/what-we-do/network/transmission-annual-planning-reports/ [accessed 14/12/2023]

[27] ElectraNet, Transmission Annual Planning Report, available at https://www.electranet.com.au/wp-content/uploads/231101_2023-TAPR.pdf [accessed 14/12/2023]

[28] Probability of Exceedance (PoE) is a method of measuring any data that can vary. It is generally organised in a distribution curve and uses 90th, 50th, and 10th percentile values to present and measure data.

6.2.2 HPRX Impact on Network Limitations

AEMO utilises constraint equations as a pivotal tool for managing system security during dispatch. When a constraint is enforced during dispatch, it effectively adjusts the power output from either a generator or an interconnector, deviating from the most economical merit order under unconstrained conditions.

Historical constraints are predominantly due to network transient stability limits under outage conditions or substation thermal constraints in SA. ElectraNet has assessed the top 20 binding network constraints for 2022.[29] Aurecon has evaluated the potential positive benefits HPR may have on these binding constraints in Table 6-2.

Table 6-2 Network constraints relevant to HPR

Network constraint:	Constraints description:	Binding duration in 2022 [hours]	Contribution of HPR
SVML_ROC_80:	Transient Stability constraint keeps the rate of change of flow from SA to Victoria across Murraylink HVDC interconnector below 80MW per 5 min.	80.3	HPR with fast ramping capability could potentially alleviate this constraint.
V_S_NIL_ROCOF:	Transient Stability constraint limits the Heywood interconnection flow to prevent RoCoF exceeding 2Hz/second in SA immediately following loss of Heywood interconnector.	22.0	Although PEC (2026) is expected to alleviate this constraint, HPR with VMM could provide additional benefits via an effective amount of synthetic inertia provision to resist the exceeded RoCoF at the interconnector under WAPS.
V::S_NIL_MAXG_1	Victoria to SA Transient Stability constraints for loss of the largest generation block in SA (South East Capacitor Available).	33.9	PEC (2026) is expected to alleviate this constraint. However, the provision of fast response by HPR, such as rapid injection of active power to the grid for loss generation could contribute to reducing the likelihood of this constraint binding, particularly the completion of PEC.

Correspondence with ElectraNet in the development of this report did not identify HPR as being a material coefficient in any existing constraint equations in the SA power network. This means quantification of the impact of HPR of constraints such as those listed above (and others) is not possible without detailed power system studies and modelling.

6.2.3 HPR Impact on Future Network Development

Given the headroom contribution described in Section 6.2.1, Aurecon expects the addition of storage capacity would provide a benefit of additional hosting capacity for generation and potentially load, approximately equivalent to its rated MW capacity. Given the long term plans for REZs in SA, electric vehicle demand, hydrogen export and mining demand, improved utilisation of existing network can only be beneficial for market participants.

[29] ElectraNet, Transmission Annual Planning Repot, available at https://www.electranet.com.au/wp-content/uploads/231101_2023-TAPR.pdf [accessed 14/12/2023]

Appendix A – Frequency Control in the NEM

Table 6-3: Mechanisms of frequency control in the NEM

Mechanism	Response Type	Response Time	Incentive
Inertia	Autonomous reaction against changing frequency. Active power is delivered in proportion to RoCoF.	20ms – 3s	TNSPs are obligated to ensure inertia above minimum levels. Managed indirectly through dispatch constraints (e.g. constrained-on synchronous plant) and procurement.
Primary Frequency Response	Autonomous regulation of system frequency within NOFB which arrest and corrects frequency by providing a proportionate response to the frequency deviation from 50Hz.	Within seconds. Sustained until frequency returns to NOFB.	Frequency performance payments will be made to PFC service providers from 8 June 2025.
Contingency FCAS	Allows the autonomous recovery of system frequency following an excursion outside the NOFB. Active power is varied proportionately to the frequency difference from 50Hz until system frequency recovers to within NOFB.	Speed of ramp varies by service: ▪ Very Fast: 1s (new) ▪ Fast: 6s ▪ Slow: 60s ▪ Delayed: 5 minutes	Payments for enabled providers, settled through a spot market pool.
Regulation FCAS	AEMO-directed regulation of system frequency. Enabled plants adjust active power in response to an Automatic Generation Control (AGC) command received from AEMO every 4 seconds.	AGC setpoint received every 4 seconds and sustained until the next AGC set.	Payments for enabled providers, settled through a spot market pool.
Energy Re-Dispatch	AEMO-directed dispatch of energy to match bulk supply of energy (generation) to demand (load).	5 minutes	Payments for dispatched energy settled through the NEM spot market pool.

Appendix B – NEM Proposals and Determinations

Table 6-4: Proposals and determinations relevant to NEM ancillary services since 2018

Proposal / Determination	Year	Overview
Managing the Rate of Change of Power System Frequency[30]	2017	A rule determination in which: ▪ Minimum required levels of inertia to be determined for NEM sub-networks that may be required to operate as frequency islands. ▪ TNSPs to be required to maintain local inertia at or above these minimum safe levels without those sub-networks.
Inertia Ancillary Services Market proposal rejected by AEMC.[31]	2018	Factors behind this decision include: ▪ New TNSP requirements for minimum levels of inertia in SA meant that inertia shortfalls were no longer anticipated. ▪ With new constraints maintaining minimum safe levels of inertia, the value of procuring additional inertia beyond this minimum was unclear. ▪ Mandatory PFR and FFR services were higher priorities for managing system stability. An inertia market could wait until these reforms were in place.
Mandatory Primary Frequency Response[32]	2020	A rule determination implementing: ▪ PFR to become mandatory for all dispatched scheduled and semi-scheduled generators by responding automatically to deviations in system frequency. ▪ Temporary arrangement: mandatory PFR to sunset in June 2023. This was instigated because of a review between 2014 and 2018, culminating in the AEMC's Frequency Control Frameworks review identifying a deterioration in maintaining system frequency within its normal range. The double-sided frequency performance payments process affecting both loads and generators will be instigated from the 8th of June 2025.
NEM Reform Program / Post-2025 NEM market design[33]	From 2020	An ongoing roadmap of changes and developments in the NEM needed to facilitate the energy transition, including FFR, changes to data sharing, and changes to market design to value essential system services including PFR, system strength provision and inertia.

[30] AEMC, Managing the Rate of Change of Power System Frequency Rule Change, 19/09/2017, available at: https://www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-frequency [accessed 14/12/2023]

[31] AEMC, Inertia Ancillary Services Market Rule Determination, 2018, available at: https://www.aemc.gov.au/sites/default/files/content/0eea371b-f1c0-4071-83c3-3cb3fab91c63/Final-version-for-publication-ERC0208-Final-Determination.pdf [accessed 14/12/2023]

[32] AEMC, Mandatory Primary Frequency Response Rule Determination, 2020, available at: https://www.aemc.gov.au/sites/default/files/2020-03/ERC0274%20-%20Mandatory%20PFR%20-%20Final%20Determination_PUBLISHED%2026MAR2020.pdf [accessed 14/12/2023]

[33] ESB, Post 2025 Electricity Market Design, available at: https://esb-post2025-market-design.aemc.gov.au/ [accessed 14/12/2023]

Proposal / Determination	Year	Overview
Fast Frequency Response Market[34]	2021	A rule determination in which: ■ New *Very Fast* (1 second) contingency FCAS services introduced, which have been active since 9 October 2023. ■ Removal of the 'multiplier rule' from MASS, which had previously rewarded FCAS providers able to provide faster responses than the 6s required for the *Fast* service. ■ Existing *Fast* (6s), *Slow* (60s), and *Delayed* (5m) services maintained. Over time as the Very Fast FCAS market develops, it may provide services which alleviate the need for inertia in each NEM region.
Efficient Provision of Inertia[35]	2022 – 2024	In 2021, AEC submitted a new proposal for an inertia market to the AEMC. AEMO and the AEMC responded with a joint publication[36] suggesting the need for near-term consultation on such a market before operating in the medium term. This new proposal for an IAS market is under AEMC consideration, with a determination expected February 2024. If a determination is made to establish an IAS market, it would likely commence 3–4 years after the rule determination (in 2027-2028).

[34] AEMC, Fast Frequency Response Market Ancillary Service Rule Determination, 2021, available at: https://www.aemc.gov.au/sites/default/files/2021-07/Fast%20frequency%20response%20market%20ancillary%20service%20-%20Final%20Determination.pdf [accessed 14/12/2023]

[35] AEMC, Efficient Provision of Inertia consultation, 2023, available at: https://www.aemc.gov.au/rule-changes/efficient-provision-inertia [accessed 14/12/2023]

[36] AEMC and AEMO, Essential System Services in the NEM, 2022, available at: https://www.aemc.gov.au/sites/default/files/2022-06/Essential%20system%20services%20and%20inertia%20in%20the%20NEM.pdf [accessed 14/12/2023]

Appendix C – SA Transmission Expansion Projects

Table 6-5: SA transmission expansion projects[37]

Project	Description	Benefit	Status	Timing
Eyre Peninsula Link	Upgrade replacing an ageing 132kV single-circuit line from Cultana to Yadnarie and from Yadnarie to Port Lincoln with a higher thermal capacity new double-circuit line.	Upgrade will improve reliability and network capacity on the Eyre Peninsula in SA.	Committed	Jan 2023
Project EnergyConnect (PEC)	A new 330kV double-circuit interconnector running from Robertstown in SA to Wagga Wagga in NSW via the most north section of the transmission network in VIC.	Links the REZs of Riverland, Murray River and South West NSW providing additionally capacity.	Committed	Jul 2026
South East SA REZ expansion	**Stage 1** - String the vacant 275kV circuit between Tailem Bend and Tungkillo. **Stage 2** - New high capacity double-circuit twin conductor lines from the South East SA and South East SA Offshore REZs to Bundey, via a location near Kincraig.	Increase transfer capacity to allow for greater imports and exports of renewables between South East, Tailem Bend and Adelaide.	Anticipated	2025-26 (earliest) 2029-30 (expected)
Mid North SA REZ expansion	**Southern Stage** - A new high-capacity lines from Bundey to Para or a new site between Parafield Gardens West and Torrens Island. **Northern Stage** - Construct new high capacity lines between Bundey and Cultana.	Increase transfer capacity to allow for greater imports and exports of renewables between Mid North and Adelaide.	Anticipated	2029-30 (earliest) 2033-34 (expected)

[37] ElectraNet, Transmission Annual Planning Report Update, May 2023, available at: https://www.electranet.com.au/wp-content/uploads/2023-TAPR-Update.pdf [accessed 14/12/2023]

Appendix D – Comparison FFR Inertia Providers

Table 6-6: Comparisons of technical capability of different FFR providers

Category	Description and Key Characteristics	Evaluation
Synchronous Generator	The spinning turbine of synchronous generators (e.g. fossil-fuelled fired power stations, hydro) provides constant grid synchronous inertia. ▪ **Inertia constant**: fixed, 2 – 8s ▪ **Response timeframe**: instantaneous	▪ Conventional synchronous machine can provide PFR via their physical synchronous inertia. It inherently responds to frequency disturbance in the network. ▪ However, due to the increasing penetration of IBR and retirement of conventional fossil fuel power plant, synchronous generators cannot provide sufficient capacity to meet the FFR requirement.
Synchronous Condenser (SynCon)	Synchronous condensers operate in a similar way to large electric motors and generators, which contains a synchronous motor whose shaft is not directly connected to anything but spins freely. SynCon helps to regulate voltage, provide reactive power support, and enhance the power system strength. ▪ **Inertia constant:** fixed, 2 – 7s ▪ **Response timeframe:** instantaneous	▪ SynCons are specified and designed to provide system strength and system inertia to support a power network disturbance. ▪ The main disadvantages are high upfront costs, long lead time and high operating costs. ▪ Due to its unscalable nature, SynCons are not capable of upgrading or adjusting its size to maximise the FACS capability.
REZ (wind turbines and solar)	In general, IBR do not supply synchronous inertia to the power system. However, it is possible for some IBR to provide an emulated inertia response to the power system through appropriated design with their inverter controls (i.e. grid-forming inverters). ▪ **Inertia constant:** unknown/dynamic ▪ **Response timeframe:** Dynamic depends on the design inverter control scheme.	▪ RESs with advance inverters have the ability to control their power output to respond to grid frequency changes. ▪ However, the reactive power control range is very limited compared to some other grid-support devices.
HPR VMM	▪ VMM is a mode of operation which can be implemented on Tesla's Powerpack system inverters that mimics the behaviour and inertial response of a synchronous machine to grid disturbances. The VMM reacts by injecting active power that is directly proportional to the RoCoF. ▪ **Inertia constant:** 0.1 – 20s ▪ **Response timeframe:** very fast within 150 milliseconds	▪ The implemented VMM at HPR could provide ~2,070 MWs of stimulated inertia, with an overall equivalent H constant of 11.02 MWs/MVA, which is much higher than the conventional synchronous generator. ▪ VMM functionality allows the machine-like characteristics, such as inertia and stator damper, to be created synthetically in Tesla's inverter. More importantly, these parameters are programmable. ▪ Large-scale BESS with VMM can be upgraded/augmented by adding additional modular BESS packages, creating unique feasibility for future alteration.

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