OVEN MOUNTAIN
PUMPED HYDRO STORAGE

Oven Mountain Pumped Hydro Energy Storage

March 2023

FINAL REPORT

Pumped Hydro Energy Storage:

Renewable energy zone and network benefits assessment report

by Dr Jeremy Moon

www.ompshydro.com

ACKNOWLEDGMENT OF COUNTRY

The Oven Mountain Project acknowledges the Thunggutti people, Traditional Custodians of the land on which we operate, and pay our respects to their Elders past and present.

We also extend that respect to Aboriginal and Torres Strait Islander peoples across this nation.

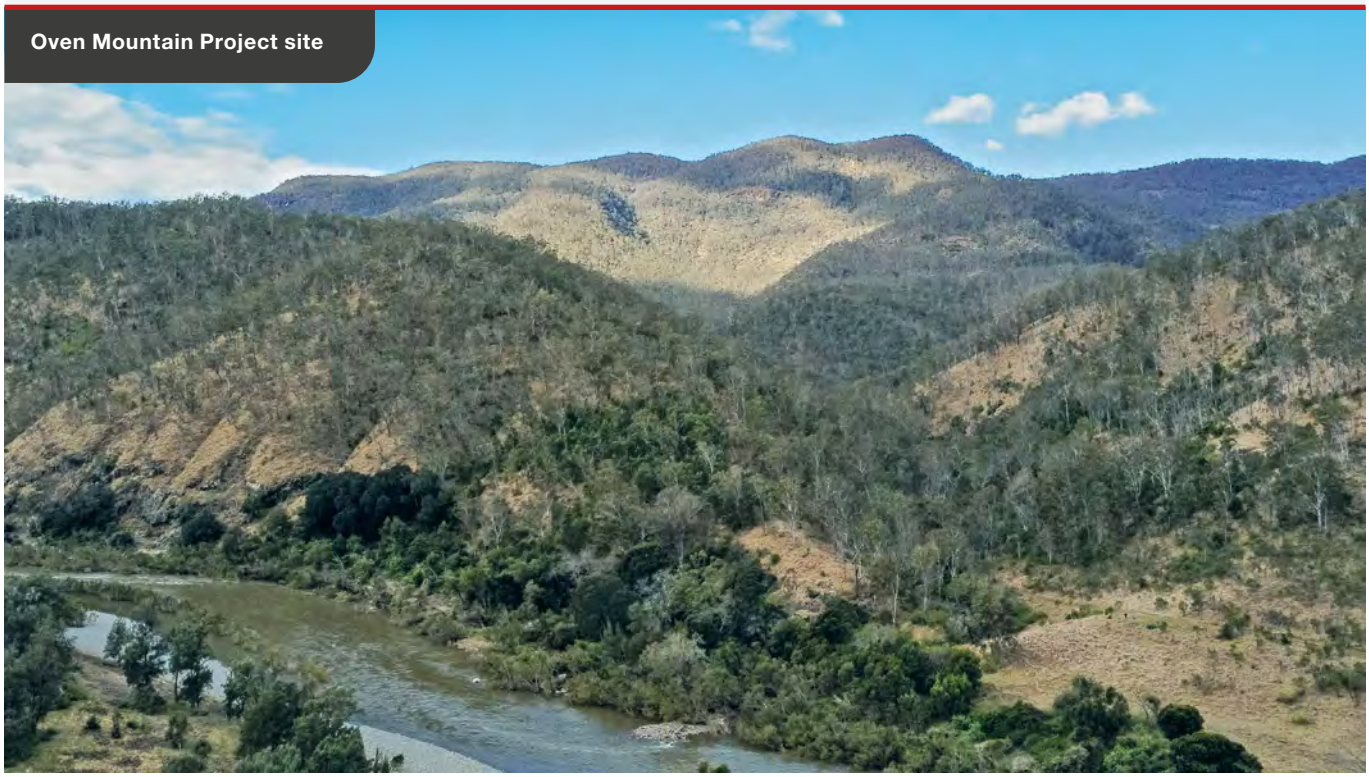
Thunggutti Village, Bellbrook

ACKNOWLEDGMENT AND DISCLAIMER

The Oven Mountain Pumped Hydro Energy Storage project received funding from the Australian Renewable Energy Agency (ARENA) as part of ARENA's Advancing Renewables Program.

The views expressed herein are not necessarily the views of the Australian Government, and the Australian Government does not accept responsibility for any information or advice contained herein.

Oven Mountain Project site



CONTENTS

1 FOREWARD **5**

2 EXECUTIVE SUMMARY **6**

2.1 Outcomes from grid strength and inertia investigations 6

2.2 Outcomes from market benefit investigations 7

3 INTRODUCTION **8**

3.1 The role of pumped hydro energy storage 8

3.2 The New England Renewable Energy Zone 9

3.3 Project overview 11

3.4 Project timeline 13

3.5 Project objectives and stages 13

Stage 1: Inputs baselining and technology finalisation 14

Stage 2: REZ, network and variable renewable energy impacts 14

Stage 3: Final reporting 14

4 KEY CONCEPTS **14**

4.1 Network: Constraints and Limitations 15

4.2 System strength and inertia 15

5 RESULTS SUMMARY **16**

6 CONCLUSION **22**

REFERENCES **22**

APPENDICES **22**

A: Amplitude Report – '*Oven Mountain Pumped Hydro Storage Benefit Assessment – Network Stability Report*' 23

B: Amplitude Report – '*Oven Mountain Pumped Hydro Storage Benefit Assessment – System Strength and Inertia*' 53

C: EY Report – *'Assessment of market benefits of the Oven Mountain Pumped Storage Hydro project'* 89

1 FOREWARD

Energy continues to be at the forefront of government, industry, and kitchen table discussions across Australia. Whether it is the retirement of thermal powered stations, the increasing prevalence of variable renewable energy sources, or the day-to-day cost of electricity – communities and businesses alike are keenly aware of the importance of a modernised energy system that provides reliable, affordable, and clean electricity.

The changing energy landscape – termed a 'once-in-a-generation' transformation – is replete with challenges and opportunities that remain ambitious, complex, and necessary. The '*NSW Electricity Infrastructure Roadmap*' and the '*2022 Integrated System Plan*' emphasise the ongoing importance of coordinated efforts, forward-thinking planning and reform, and continued investment in transmission augmentation, variable renewable energy capacity, and energy storage capabilities.

The '*2022 Integrated System Plan*' notes that by 2050 there will be a need for "over 60 GW of firming capacity to be in place to respond to a dispatch signal…While the system today has approximately 43 GW of firming capacity, 23 GW of this is coal-fired generation. As this coal-fired generation retires, it needs to be replaced with new low-emission firming alternatives. New utility-scale battery and pumped hydro storage, located at appropriate parts of the network, will enable more effective dispatch of clean electricity on demand, increase resilience by shifting energy through time to manage weather variations, and provide critical system security services" (AEMO, 2022, p.51).

The Oven Mountain Pumped Hydro Energy Storage Project is an "off river" development located adjacent to the Macleay River between Armidale and Kempsey. Situated within the New England Renewable Energy Zone (REZ), the Project will provide clean energy generation and storage capabilities, ensuring a reliable, resilient, and renewable future energy supply for NSW and the broader National Electricity Market (NEM).

The Oven Mountain Project is currently undergoing the NSW government's environment and planning approval process. We anticipate that the Project's Environmental Impact Statement will be submitted to the Department of Planning and Environment in early 2023 for formal review and exhibition. Pending approval, construction is anticipated to commence in 2024 and last approximately four years.

Our team is pleased to have received support from the Australian Renewable Energy Agency's (ARENA) Advancing Renewables Program and continue to undertake a study analysing the benefits of a 600 to 900 MW off-river Pumped Hydro Energy Storage (PHES) facility in the New England REZ, with up to 12 hours storage.

We continue to recognise the importance of knowledge sharing activities and this final report aims to share the key findings of the study. It builds on the information and findings highlighted in the '*OMPS New England PHES Benefits Study – Knowledge Sharing Interim Report*' (April 2022). Specifically, this report examines the projected benefits the Project will bring to the New England REZ, broader electricity network, as well as to consumers in the electricity market.

Delivering major infrastructure projects is complex and involves change. We need to meet both the technical and physical requirements, as well as the community obligations associated with garnering social licence. This will mean continuing our conversations with landowners, community groups, industry partners, government stakeholders, and importantly, First Nation people, communities, and businesses.

Pumped hydro energy storage remains an integral and tested part in our journey towards a clean energy future. We look forward to sharing our work and many conversations in the years ahead.

Dr Jeremy Moon

Project Director
OMPS

2 EXECUTIVE SUMMARY

The Oven Mountain Pumped Hydro Energy Storage Project (or the Project) uses mature and tested technology to provide long-duration storage and flexible dispatchable renewable generation.

The Project has received support from the Australian Renewable Energy Agency's (ARENA) Advancing Renewables Program to undertake a study analysing the benefits of a PHES facility on the development of the New England REZ in northern NSW.

Specifically, the Project endeavoured to:

- Investigate the impact of the proposed Project on system strength and inertia
- Quantify the potential market benefit investigations of the Project, such as:
  a) impact on wholesale market and retail electricity prices, dispatch costs and emissions
  b) benefits to wind and solar projects in the New England REZ, including on their Marginal Loss Factors (MLFs) and energy curtailments.

2.1 OUTCOMES FROM GRID STRENGTH AND INERTIA INVESTIGATIONS

A key feature of the thermal generation being retired is their synchronous connection with the grid; that is, the rotation of synchronous generators is directly coupled to the grid. Accordingly, when disruption occurs on the grid - for example a big load trips off the system – the rotating mass of the synchronous generator acts against the grid deviating away from safe levels, essentially providing resilience to the grid. This concept falls under the category of grid system strength.

Modern inverter-based generators like wind energy, solar and even batteries break with that direct relationship by using power electronics. This is understandable as the rotation of wind turbines depends on available wind speed, while solar has no rotating components and neither do batteries. In breaking the synchronous relationship, the resilience levels of the grid are diminished.

Amplitude Consultants have undertaken an assessment of the benefits of PHES' grid strength contribution to both the current network and a future 2030 network using AEMO's projections captured in its '2022 Integrated System Plan'.

Analysing the current network configuration is important as there are several limitations on the grid preventing the deployment of new generation – particularly renewable energy. The limitations due to grid strength are complicated and require sophisticated modelling to be understood. When grids reach their limit on grid strength related issues, the network becomes unstable and uncontrollable – which is clearly a state to avoid from an operator perspective. The limitations in and around the current New England REZ are dominated by these grid stability limits.

In the Intermediate Stage Report, Amplitude showed that the presence of PHES within the current network was able to substantially improve the grid strength of the region and allow significantly more generation to be deployed in the REZ than when the PHES was not present. The amount of generation able to be deployed varied depending on the amount of load on network as well as the levels of wind and solar generation. Under the best conditions, PHES was able to support approximately 1.6GW of additional renewable generation while keeping the network stable. This is attributable to the key feature of PHES having synchronous machines connected to the network.

In the analysis undertaken for the Final Report, Amplitude demonstrated:

- The Project increases the available fault levels (up to 2,350 MVA) which is incredibly important to maintain clear voltage waveform signals, allowing network protection equipment to operate properly, and support voltage during faults to limit tripping of other generation as well as providing stability during the critical period after a fault has been cleared.
- A shortfall of fault current was identified in South Australia, limiting the use of more renewable energy. Four synchronous condensers were developed to resolve the issue, at a cost of $180m in 2019. The Project contributes fault current consistent with over four of these synchronous condensers.
- The Project contributes significant inertia (rotating mass electro-mechanically coupled to the grid) of up to 3,150 MWs (megawatt-second) which is consistent with three of the South Australian synchronous condensers.

These grid strength contributions are provided while the Project is operating as a storage device: in pumping, generating and synchronous condenser modes.

2.2 OUTCOMES FROM MARKET BENEFIT INVESTIGATIONS

AEMO operates the National Electricity Market by matching electricity need with generation. In the physical market, AEMO dispatches generation based on an approach which balances grid security and lowest supplied energy costs. This process is undertaken on a 5-minute basis, 24 hours a day, 7 days a week.

EY have developed software that mirrors AEMO's dispatch approach which allows testing of scenarios from a market perspective. Using this software, a future grid based on AEMO's '*2022 Integrated Services Plan*' and supplemented by the NSW Government's '*Electricity Infrastructure Roadmap*' was developed in the software model. This future grid considered the period of 2030/31, and a model of the NEM was developed to take into account retired generators, where and how much new generation was installed, new installed transmission, future electricity demand, and future fuel costs (referred to as the 'Base Scenario').

The market benefits study conducted by EY on the Base Scenario shows that in 2030-31 the Project:

- Reduces demand-weighted wholesale electricity prices by $7-9/MWh in NSW and $4-5/MWh in the other mainland NEM regions. This amounts to approximately a $1 billion reduction in total mainland customer retail bills.
- Generates $50-70 million savings in fuel costs NEM-wide.
- Results in 400,000 tonnes $CO_{2\text{-}e}$ reduction in generation emissions.

The study also showed that the Project, operating at a capacity of 900 MW, is forecast to have larger benefits compared to the alternatives assessed:

- Compared to the 600 MW Project, the 900 MW Project has a larger benefit to customer retail bills, all market benefits assessed and on reducing the forecast energy curtailment for wind and solar PV projects.

The EY report also examined an option where the New England REZ transmission augmentation was delayed until after 2030-31 (referred to as the 'Insurance case study'). In this instance, the report notes that the market would experience a transmission bottleneck between New England and the rest of NSW.

In the Insurance case study, the 900 MW project:

- Reduces demand-weighted wholesale electricity prices by $6/MWh in NSW and $12/MWh in Queensland. This amounts to approximately a $1.3 billion reduction in total mainland customer retail bills.
- Saves $60 million in fuel costs NEM-wide.
- Saves 540,000 tonnes $CO_{2\text{-}e}$ in generation emissions.
- Reduces curtailment of New England wind generation from 32% to 29% of available energy, and from 33% to 27% for solar PV generation. In total the Project is forecast to allow approximately 680 GWh of additional renewable generation to be dispatched in New England.
- Assuming a conservative PPA price of $45/MWh, this reduction in curtailment results in approximately $30 million of additional revenue for NE REZ wind and solar generators.
- Supports a 0.01 increase to solar MLFs in the NE REZ, with a further direct benefit to the market revenues for these solar projects. Solar projects benefit due to the Project pumping tending to be during the day, which is the same time as solar generation. The dispatchable load added to New England reduces network loading and hence reduces transmission losses between New England and the greater Sydney area load centre.
- Results in a neutral change to wind generator MLFs in the NE REZ. Although the prevailing MLF is higher in the daytime providing a benefit to solar generators, the prevailing MLF is relatively lower when the Project is generating over the evening resulting in a neutral impact to wind generator MLFs.

3 INTRODUCTION

3.1 THE ROLE OF PUMPED HYDRO ENERGY STORAGE

In July 2019, AEMO released an insights paper titled, '*Building power system resilience with pumped hydro energy storage*'. Coming just after the release of the '*2018 Integrated System Plan*', the paper explored key questions (AEMO, 2019, p.3);

- what role does pumped hydro energy storage (PHES) play in delivering reliable, resilient electricity supply in the future?
- What transmission development is needed, by when, to maximise the market benefits of these large PHES projects?
- What additional benefits do these power system developments deliver?
- What are the next steps to drive co-ordinated development in the long-term interests of consumers.

The paper found that the National Electricity Market (NEM) needed a range of projects that provided varying energy storage durations to efficiently distribute renewable energy to ensure network resilience and flexible generation. The paper also highlighted the need to develop new transmission lines to strengthen the NEM backbone and importantly, to access the benefits delivered by PHES projects.

Since then, Australia has continued to see a major transformation in the way it perceives and uses energy. These changes have been marked by prevailing government initiatives (e.g., Net Zero), industry investment in variable renewable energy sources, and the ongoing and planned retirement of coal powered fire stations. The '*2022 Integrated System Plan*' notes the need for investment to "treble the firming capacity provided by new low-emission firming alternatives that can respond to a dispatch signal, with efficient network investment to access it" (AEMO, 2022, p.10).

> "Technical innovation, ageing generation plants, economics, government policies, energy security and consumer choice are all driving this transformation and driving it faster than many anticipated. Some of them form part of the global push for net zero emissions by 2050, while others are independent. All the while, the NEM must continue to meet its objective – to provide reliable, secure, and affordable electricity to consumers."
>
> ***2022 Integrated System Plan (AEMO, 2022, p.7).***

3.2 THE NEW ENGLAND RENEWABLE ENERGY ZONE

In December 2021, the NSW Government formally declared a Renewable Energy Zone (REZ) in the New England region. This REZ will deliver new network capacity to host up to 8 gigawatts of new generation.

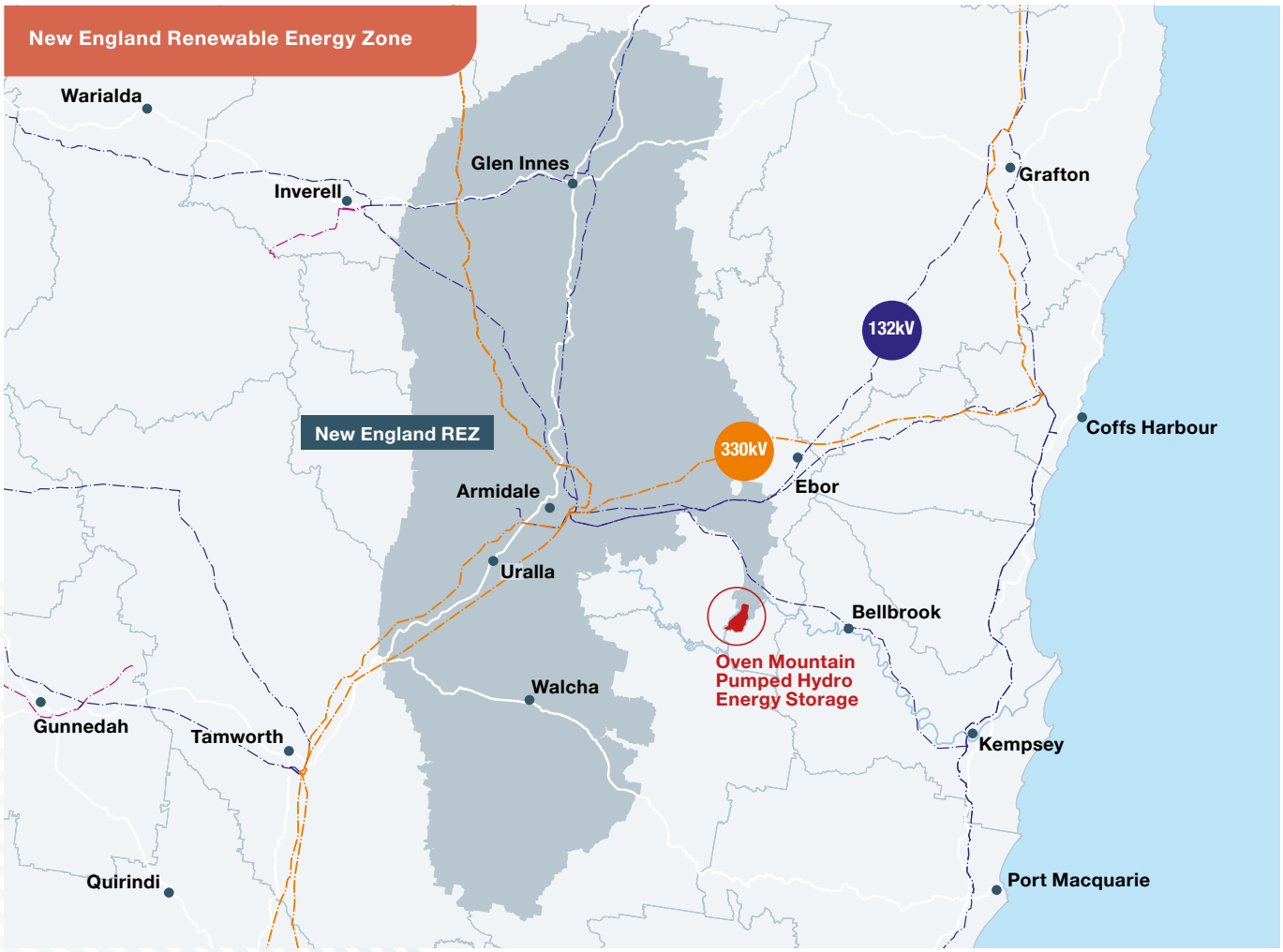
A REZ can be considered as a modern-day power station. They combine renewable energy generation such as wind and solar, storage such as pumped hydro energy storage, and high-voltage poles and wires to deliver energy to the homes, businesses and industries that need it, when they need it.

The NSW Government expects that REZs will deliver multiple benefits to NSW, including more reliable energy from significant amounts of new energy supply; energy bill savings from reduced wholesale electricity costs; emissions reduction from a cleaner energy sector; and community partnership.

The development of the New England REZ is being coordinated by the NSW Energy Corporation (EnergyCo) and includes extensive consultation with the community, government, and industry stakeholders.

Modelling undertaken as part of the '*2022 Integrated System Plan*' suggests that the New England has the potential to become one of the largest REZs in the National Electricity Market. It anticipated that the REZ – along with the delivery of necessary transmission augmentation - will unlock "approximately 6,000 MW of variable renewable energy and storage capacity in the New England REZ, helping meet the objectives of the *New South Wales Electricity Infrastructure Roadmap*" (AEMO, 2022, p.77).

The inclusion of the Oven Mountain Project within the New England REZ recognises the abundance of natural energy sources in the New England region – including the potential for pumped-hydro development – and the need for long-duration storage (of over 8 hours) and network resilience to meet current and future energy requirements.



CASE STUDY – OMPS AND NE REZ – PROVIDING POWER TO THE GRID

The Oven Mountain Project will play an integral part in the NSW Government's New England REZ. In December 2021, the Project team completed initial engagement activities with the broader New England region.

As part of our activities, we visited landowners residing near the existing Armidale-Kempsey 965 transmission Line from Jeogla to the outskirts of Armidale (approximately 50kms). The aim of our engagement was to introduce the Oven Mountain Project, offer residents a ready point of contact, and begin early discussions on renewable energy initiatives in the region.

Good engagement recognises that major infrastructure projects do not exist in isolation. Our early conversations with the New England community served to place our Project scope and energy capacity requirements in the context of broader programs planned by the NSW Government.

The Oven Mountain team met with students from Chandler Public School, situated outside of Armidale, to talk all things renewable energy and pumped hydro energy storage.

3.3 PROJECT OVERVIEW

The Oven Mountain Pumped Hydro Energy Storage Project is an off-river development located adjacent to the Macleay River between Armidale and Kempsey.

Situated within the New England REZ, the Project will provide clean energy generation and storage capabilities, ensuring a reliable, resilient, and renewable future energy supply for NSW.

The Project will be constructed on private land. Being an off-river scheme means that once filled, the Project will have little additional need for water over its operational life. Water from the Macleay River will be used for the initial fill and will be drawn under high river flow conditions.

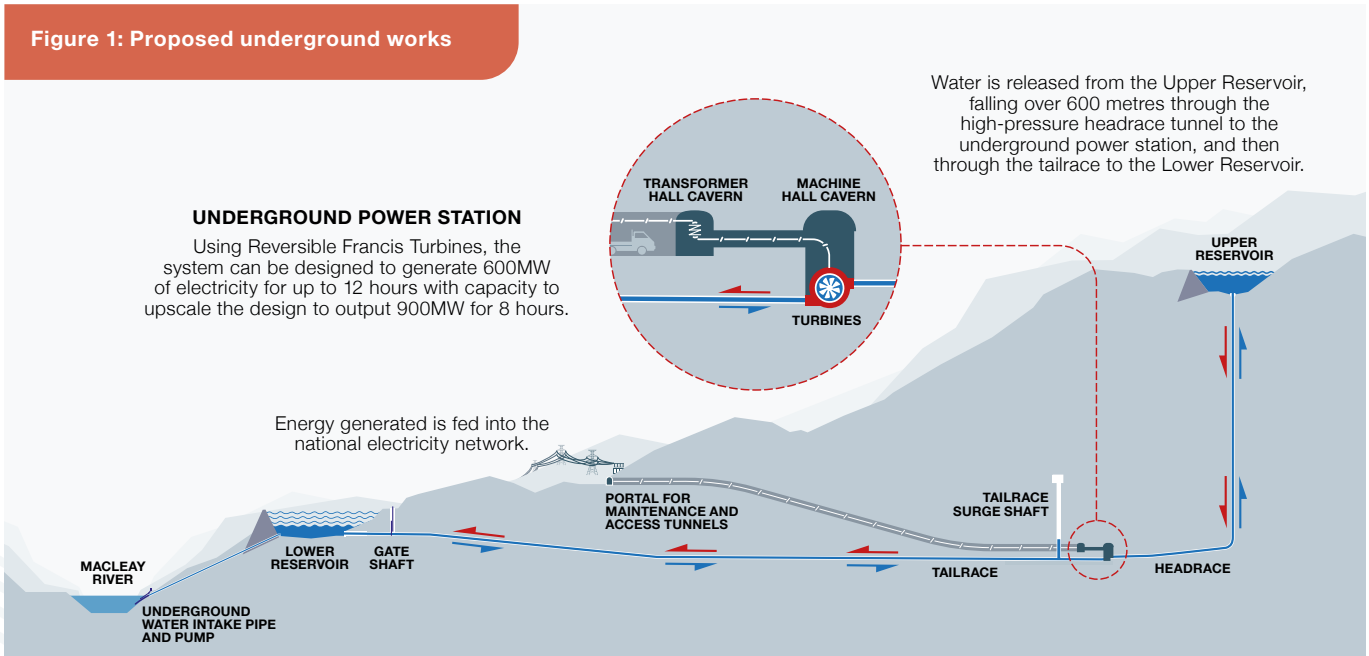
The Project has been declared by the NSW Government to be Critical State Significant Infrastructure (CSSI) under the *NSW Environmental Planning and Assessment Act 1979 (EP&A Act)*. Infrastructure projects are declared to be CSSI if, in the opinion of the NSW Minister for Planning, they are essential to NSW for economic, environmental, or social reasons.

The Project will include the construction of upper and lower water reservoirs; waterways, access tunnels; and a hydro-electric power station; and new electricity transmission network from the generation site to the Lower Creek area. It will also include upgrades to existing local and regional roads, allowing for safe construction and operation access.

The Project will provide much needed long-duration storage and offer greater reliability to the National Electricity Market. The scheme will be designed to provide up to 900 MW of electricity generation.

An indicative design of the proposed scheme is provided in Figure 1. A map of the proposed Project footprint is included in Figure 2.

Figure 1: Proposed underground works



CAPACITY	600MW	900MW
Hours of storage (hours)	12	8
Reservoir storage capacity (MWH)	7,200	

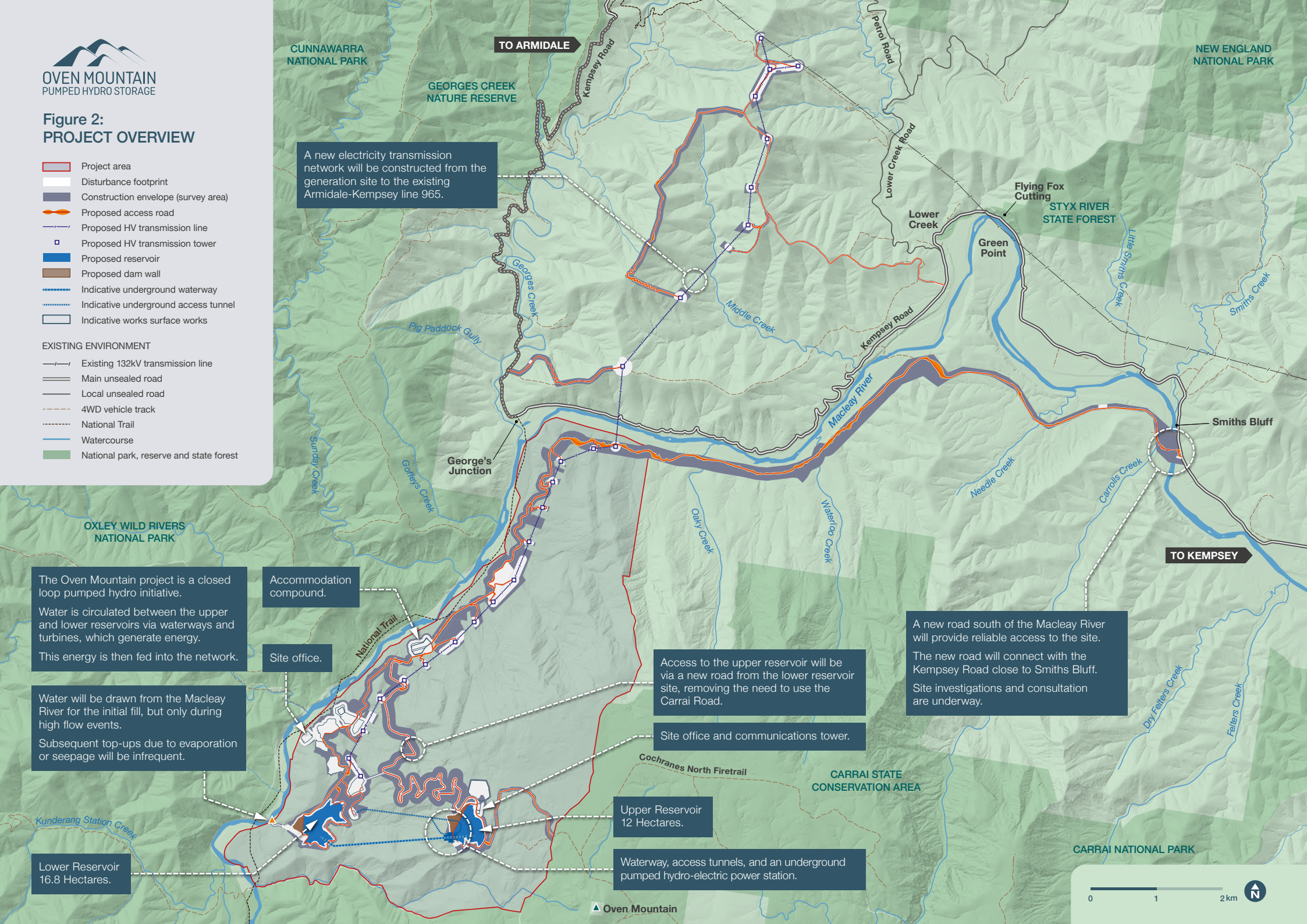
OVEN MOUNTAIN
PUMPED HYDRO STORAGE

Figure 2:
PROJECT OVERVIEW

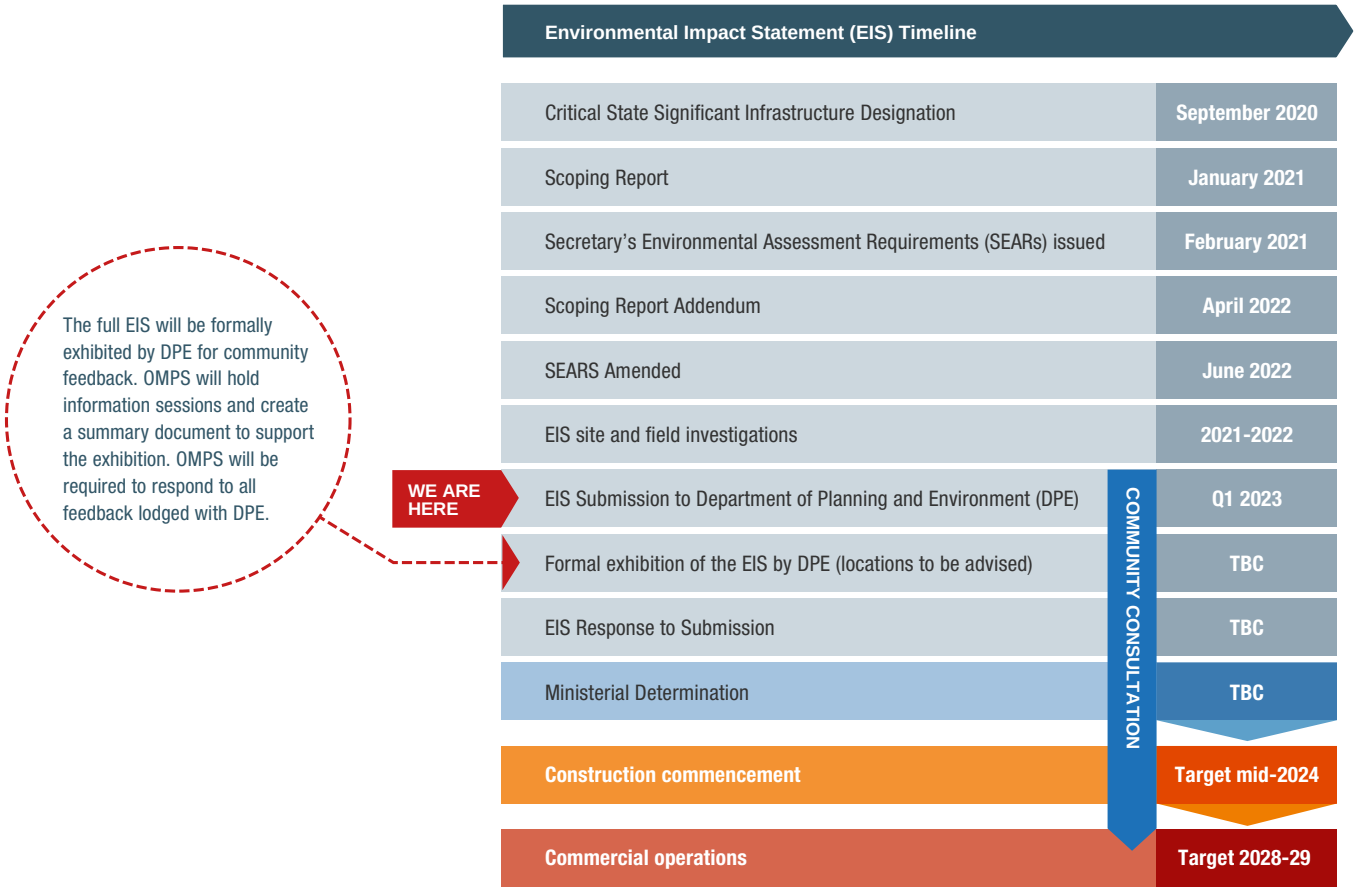
- Project area
- Disturbance footprint
- Construction envelope (survey area)
- Proposed access road
- Proposed HV transmission line
- Proposed HV transmission tower
- Proposed reservoir
- Proposed dam wall
- Indicative underground waterway
- Indicative underground access tunnel
- Indicative works surface works

EXISTING ENVIRONMENT

- Existing 132kV transmission line
- Main unsealed road
- Local unsealed road
- 4WD vehicle track
- National Trail
- Watercourse
- National park, reserve and state forest



3.4 PROJECT TIMELINE



3.5 PROJECT OBJECTIVES AND STAGES

The Oven Mountain Project has received funding from ARENA as part of their Advancing Renewables Program.

The funding supports investigations on the benefits of the Oven Mountain Project and Pumped Hydro Energy Storage (PHES) to the National Electricity Market.

The study has the following objectives:

- Gain an understanding of how and to what extent PHES can support REZs, including quantifying the level of variable renewable energy that could be unlocked with the presence of the Oven Mountain project.
- Gain an understanding of PHES's capacity to provide inter-regional support.
- Examine the relative merits of PHES in providing various system services.
- Gain an understanding of PHES's potential to provide Marginal Loss Factor (MLF) support.

As part of these investigations, the Project has been broken into the following three stages:

STAGE 1: INPUTS BASELINING AND TECHNOLOGY FINALISATION

This section sets about acquiring the data and models required to undertake the modelling work, validating the models and data, consulting with Transgrid and AEMO regarding network constraints and objectives, consulting with original equipment manufacturers regarding their technologies, and settling upon final scenarios for modelling.

STAGE 2: REZ, NETWORK AND VARIABLE RENEWABLE ENERGY IMPACTS

Through the approach of a connecting generator, this section quantified the impacts of the Oven Mountain Project on the New England REZ, addressing topics including the additionality of new renewable generation to the region, impacts on networks, and impacts on constraints.

The resulting report - '*OMPS New England PHES Benefits Study – Knowledge Sharing Interim Report*' – is available from the Oven Mountain Project website. www.ompshydro.com/news

STAGE 3: FINAL REPORTING

Building on the two previous stages, this final report incorporates market modelling of scenarios to review the impact of the Oven Mountain Project within the New England REZ including elements such as curtailments and loss factors.

4 KEY CONCEPTS

Constraints and Limits are often used interchangeably but do have separate but related meanings.

A constraint (e.g. thermal or stability) will include the physics about that constraint. For example, the stability constraint limiting QNI northward transfer is dominated by network stability after a fault at Bulli Ck. In this way, there is enough information to understand what is constraining the network.

A limit is the book-end on network operation to ensure a constraint doesn't occur. For example, it may be an operational MW transfer limit on QNI to ensure that the network remains stable should fault occur at Bulli Ck.

4.1 NETWORK: CONSTRAINTS AND LIMITS

AEMO operates the NEM, coordinating over 500 participants in the market every five minutes. It achieves this by using a platform that optimises the cost of energy offered by the available generators with constraint equations -a mathematical representation of network limitations and frequency control requirements - to match the expected demand for energy.

Understanding network constraints therefore is very important and can impact the overall cost of energy. Constraints can be divided into two broad families: thermal and stability.

Thermal limits capture the bounds on a network element's ability to transfer power due to their design ratings (e.g., power flow in a transmission line may cause the line to heat and sag to an unsafe state).

Stability limits capture the extent of stable operation arising from the dynamic interaction between all NEM elements. This might be for example the behaviour of a single generator on the network after a loss of a transmission line or the complex interaction between numerous generators, loads and network infrastructure after the loss of a large generator.

CURRENT NETWORK

The complex nature of network stability and its interaction with all elements of the national electricity system makes modelling of future networks complicated and limits the applicability of modelled results. The current limitations on the New England REZ are stability based, well studied, and understood. Further, lessons learned from assessing current network stability limitations are transferrable to future stability limits if they arise.

The current network configuration was therefore used to assess the impact of PHES on a constrained network, and to examine PHES as a supporter of network resilience.

In the Interim Report, an examination of known stability limits that relate to the Queensland-New South Wales Interconnector (QNI) was undertaken. QNI was selected as the basis for the study as its limits are well documented, it is electrically very close to the New England Renewable Energy Zone (REZ), and QNI's limits set the limits on the lines passing through the New England REZ. This work was undertaken with consultation of Transgrid, Powerlink and AEMO. The stability constraints events known to impact the Queensland-New South Wales Interconnector (QNI) are provided in Amplitude's accompanying report (see Appendix A).

FUTURE NETWORK

PHES initiatives are complex to deliver. The '*NSW Electricity Infrastructure Roadmap*' notes that "pumped hydro projects can make a substantial contribution to NSW's future electricity storage needs, but they require bespoke design, face long lead times and are capital intensive, which creates a high barrier to their development" (p.30).

To appreciate the impact of PHES on a future network, the '*2022 Integrated System Plan*' was used as the information source for when the '*NSW Electricity Infrastructure Roadmap*' objectives are achieved in 2030/31. This also mirrors when the Oven Mountain Project is anticipated to be operational within the New England REZ.

4.2 SYSTEM STRENGTH AND INERTIA

System strength is best described as the ability of the network to maintain and control the voltage waveform at any location in the system during steady state operation and following a contingency. Higher system strength means that the network is less likely to be adversely impacted by a contingency on the network.

System strength is commonly associated with hosting capacity of inverter connected asynchronous generation; however, it is also important to minimise the voltage disturbance resulting from the switching of network plant as well as the proper operation of certain protection systems.

Amplitude have undertaken assessments of available fault level (AFL) to quantify the benefits the Oven Mountain Project will provide to system strength.

Inertia is best described as the ability of the frequency of the system to withstand disturbances such as sudden changes in the supply demand balance brought about by trips of loads or generators. In a system with higher inertia, the loss of a large load or generator will have a lower rate of change of frequency (RoCoF) and have more time for systems to act to counter the disturbance.

Whereas system strength is a local phenomenon governed by the network topology and distance from synchronous sources, inertia is a system property that is largely independent of the connected network topology.

Historically, system strength and inertia has been sourced from synchronous generation, predominantly baseload coal fired generating units. The operating profile of these units is changing as they are displaced by additional inverter-connected asynchronous generation. This is having the impact of declining system strength and inertia throughout the NEM and progressive changes to the National Electricity Rules are now being implemented to maintain minimum levels of system strength and inertia going forward.

5 RESULTS SUMMARY

In particular, the Project has sought to;

- gain an understanding of how PHES can support the development of REZs
- analyse PHES's capacity to provide inter-regional support
- understand PHES's potential to provide MLF support.

The table below synthesises the areas of investigations and findings to date. Importantly, the table also provides direction to accompanying reports that offer further technical information associated with the investigations. These reports are provided in full in the Appendices of this Final Report.

Area of Investigation	Topics covered	Notes	Source for additional information
Network limitations	• Description of Network. • Limitations identified via consultation.	• The Amplitude Report provides an analysis of the current energy transformation, with a focus on the New England REZ. • The Report introduce two investigation branches: stability and thermal limits. Via analysis, it links 'current' system snapshots with stability limit analysis. • Understanding PHES impact on stability limits is a key differentiator of PHES from other technologies.	Amplitude Report – 'OMPS Benefit Assessment – Network Stability Report' – Amplitude Consultants, April 2022. See Appendix A

ISP and Operations context	• Description of operational treatment of network limits.
	• Outline future Network Planning considerations for scenario testing including ISP and TransGrid's TAPR.
	• Summary of key input parameters including:
	  ◦ Generation Scenarios
	  ◦ Load Scenarios
	  ◦ Dispatch considerations
	• Summary of AEMO and TransGrid consultation input for scenario testing.
		• The future case looked at 2030/31 which is reflective of the Electricity Infrastructure Investment (EII) Act objective dates, and reflective of the planned operational date for Oven Mountain.
		• The ISP has been used as the source of key network augmentations, generator retirements and new generation deployment, load forecast inputs. As an integrated system plan, it takes and consolidates inputs from the Roadmap, Transgrid and other NSP's.
		• The ISP assesses a number (13) of candidate development pathways (CDP) for networks against a range (4) of potential future energy demand and supply scenarios, developing an optimal development path (ODP) blueprint for future network investment.
		• Through AEMO's consultation with key stakeholders, the future energy demand and supply scenario of Step Change is considered the most likely of those considered.
		• EY utilised the information in the Step Change scenario along with the CDP 1, which most aligned with the ODP at 2030/31.
		• Operational treatment of network limits were kept to thermal (c.f. stability based) for this future assessment. Considering the degree of change in network, generation retirement and new generation, the uncertainty in the ratings/technology/performance of these, this approach is reasonable.
		• Further detail on the approach to modelling scenario inputs is provided in EY's report.
			Amplitude Report – 'OMPS Benefit Assessment – System Strength and Inertia' – Amplitude Consultants, July 2022.
			
			See Appendix B
			
			EY Report – 'Assessment of market benefits of the Oven Mountain Pumped Storage Hydro project' – EY Consultants, November 2022.
			
			See Appendix C

Area of Investigation	Topics covered	Notes	Source for additional information
NER requirements	• Outline of key elements of Chapter 5 of NER relevant to modelling • Description of NER elements to be treated in modelling exercise	The key elements of Chapter 5 of the National Electricity Rules relevant to the modelling include a demonstration that the PHES: • provides significant voltage and power system frequency control in accordance with various expectations in Schedule 5.2 of the NER including S5.2.5.11, S5.2.5.13; • is resilient to power system voltage and frequency disturbances in accordance with S5.2.5.3 and S5.2.5.4 and can maintain continuous uninterrupted operation when subjected to large disturbances, as required by S5.2.5.5; • increases the maximum supportable demand in the New South Wales region under all operating conditions, consistent with the requirements in S5.2.5.12; and • does not have an adverse system strength impact in accordance with the system strength impact assessment guidelines.	Amplitude Report – 'OMPS Benefit Assessment – Network Stability Report' – Amplitude Consultants, April 2022. See Appendix A Amplitude Report – 'OMPS Benefit Assessment – System Strength and Inertia') – Amplitude Consultants, July 2022. See Appendix C
Technology and configuration	Description of technologies identified and approach to modelling including: • Network elements • Generator technologies • Pumped Hydro	• For the Current network scenario, the generator, load models exist within AEMO's supplied system snapshots. • Consultation with OEM's allowed for the development of suitable generator, synchronous condenser and load models for PHES which were used to test stability constraints. • For the 2030/31 market assessment work, representative models for wind and solar were sourced from AEMO's snapshots, and network elements were developed to reflect network developments outlined in the ISP's CDP1. Multiple candidate years and generator outages were assessed to derive a central set of results. For further detail, see the EY report.	Amplitude Report – 'OMPS Benefit Assessment – Network Stability Report' – Amplitude Consultants, April 2022. See Appendix A Amplitude Report – 'OMPS Benefit Assessment – System Strength and Inertia' – Amplitude Consultants, July 2022. See Appendix B EY Report – 'Assessment of market benefits of the Oven Mountain Pumped Storage Hydro project' – EY Consultants, November 2022. See Appendix C

Area of Investigation	Topics covered	Notes	Source for additional information
Static and dynamic studies	Key findings of Chapter 5 modelling incorporating centered around OMPS performance particularly	• Amplitude stability studies included detailed dynamic models of the PHES in a full four state mainland NEM model. The models represented the frequency and voltage control performance of the generating system accurately, consistent with the requirements in the AEMO Power System Modelling Guideline (PSMG). • The studies showed the PHES governor and voltage regulation system contributes to power system frequency and voltage stability, and the plant can remain in continuous uninterrupted operation for a broad range of contingencies, as required under Schedule 5.2 of the National Electricity Rules. • Amplitude's 3rd Stage report showed that PHES will not have an adverse system strength impact. In fact, the PHES is shown to have a significant positive contribution to system strength. This potentially defers costly system strength remediation and provides attractive non network options for the management of system strength shortfalls in accordance with Chapter 5, Clause 5.3.4B. • The PHES also provides significant inertia which helps to limit the rate of change of system frequency (ROCOF) and assist with maintaining continuous operation of other generating systems in accordance with Schedule 5.2, S5.2.5.3 requirements. • It also helps avoid maloperation of protection systems due to high rate of change of frequency and provides attractive options for the management of inertia shortfalls in accordance with Chapter 5, Clause 5.20B.3.	Amplitude Report – 'OMPS Benefit Assessment – Network Stability Report' – Amplitude Consultants, April 2022. See Appendix A EY Report – 'Assessment of market benefits of the Oven Mountain Pumped Storage Hydro project' – EY Consultants, November 2022. See Appendix C

Area of Investigation	Topics covered	Notes	Source for additional information
Network impacts	• Quantitative and qualitative description of impacts of selected scenarios • Discussion on the relative merits of different scenarios from technical perspective	• From the Amplitude work, the inclusion of synchronous equipment is shown to significantly relieve known stability limits on QNI and increase the demand that can be addressed by more generation in NSW. These results are discussed in detail in Amplitude's work supporting the Interim Report. • The insurance case undertaken in EY's work shows that PHES can provide benefit to consumers in the scenario of late New England REZ delivery. These are discussed further in EY's report.	Amplitude Report – 'OMPS Benefit Assessment – Network Stability Report' – Amplitude Consultants, April 2022. See Appendix A EY Report – 'Assessment of market benefits of the Oven Mountain Pumped Storage Hydro project' – EY Consultants, November 2022. See Appendix C
Renewable deployment impacts	• Quantitative and qualitative description of level of impact of different scenarios on networks ability to support further Renewable Energy deployment • Particular focus on the New England REZ	• Under the current network scenario where the New England REZ is subject to considerable stability based limits, the work undertaken by Amplitude illustrates that these constraints can be relieved considerably. • In assessing the degree of stability base limit relief alone – that is not considering thermal limits – the PHES could facilitate up to approximately 1,600MW of new renewable generation in the New England REZ under best case scenarios. • In all cases, the amount of demand in NSW that could be addressed by generation in New England based generation increased without adversely impacting the QNI constraints. The Amplitude report supporting the Interim Report provides more detail. • In the 2030/31 scenario, Amplitude showed that PHES can provide significant contribution to the available fault levels and inertia at Armidale. This is seen to be equivalent to approximately 4x of the synchronous condensers being constructed in South Australia for the purpose of addressing system strength and inertia shortfall.	Amplitude Report – 'OMPS Benefit Assessment – Network Stability Report' – Amplitude Consultants, April 2022. See Appendix A Amplitude Report – 'OMPS Benefit Assessment – System Strength and Inertia' – Amplitude Consultants, July 2022. See Appendix B EY Report – 'Assessment of market benefits of the Oven Mountain Pumped Storage Hydro project' – EY Consultants, November 2022. See Appendix C

Area of Investigation	Topics covered	Notes	Source for additional information
MLF impact assessment	• Quantitative analysis of the MLF impacts of PHES on the New England REZ; • Qualitative analysis of the MLF impacts of PHES in the wider network region	• EY's assessment of the 2030/31 forecast year shows modest improvements in MLF for primarily solar at approximately 1%, driven by the use case for PHES. • While the number initially appears modest, when considered in the substantial network development in the New England REZ link, being able to move MLF is more material. • The NE REZ link underpins supporting the 8GW of legislated network transfer capacity, with a generation deployment of approximately 6GW.	EY Report – 'Assessment of market benefits of the Oven Mountain Pumped Storage Hydro project' – EY Consultants, November 2022. See Appendix C
Market benefit assessment	• Quantitative assessment of market benefits of PHES relative to other technologies in resolving identified network limitations • Approach to mirror that of a RIT-T	• EY's assessment showed that PHES shows substantial benefits to the market both in terms of NSW at approximately $600M cost reduction for the one year assessed; and to the NEM generally where the benefit is approximately $1.1bn. • An insurance case where the NE REZ link delivery occurs after the 2030/31 period was undertaken and the benefits of PHES is shown to be approximately $380M cost reduction to NSW and $1.3bn to the NEM generally. • More detail is provided in EY's report.	EY Report – 'Assessment of market benefits of the Oven Mountain Pumped Storage Hydro project' – EY Consultants, November 2022. See Appendix C

6 CONCLUSION

The Oven Mountain Pumped Hydro Energy Storage Project is an “off river” development located adjacent to the Macleay River between Armidale and Kempsey.

Situated within the New England Renewable Energy Zone, the Project will provide clean energy generation and storage capabilities, ensuring a reliable, resilient, and renewable future energy supply for NSW.

As part ARENA’s Advancing Renewables Program (Stage three), the Oven Mountain Project team sought to analyse the benefits that Pumped Hydro Energy Storage (PHES) would have on the development of the New England Renewable Energy Zone (REZ) in northern NSW. This work has been coordinated with the guidance of Amplitude and EY consultants and their detailed analysis can be found in Appendix B and C respectively.

Amplitude assessed the network benefits with respect to the system strength and inertia contribution that the Oven Mountain Project can provide in both the 600 MW and 900 MW configurations. The studies found that the Project can improve the system strength at the Armidale 330 kV bus by up to 2,350 MVA. From an inertia perspective, the 900 MW Oven Mountain configuration can provide up to 3,150 MWs of inertia.

The EY report sought to quantify the potential market benefits of the Project, including on wholesale market and retail electricity prices, dispatch costs and emissions. It also examined the potential benefits of the Project to wind and solar projects in the New England REZ, including on their marginal loss factors (MLFs) and energy curtailments. The report identified reductions in demand-weighted wholesale electricity prices across NSW and other mainland NEM regions; significant savings in fuel costs NEM-wide; reductions in generation emissions; and supports the growth of additional renewable generation to be dispatched in the New England.

The Oven Mountain team look forward to continuing to engage with our diverse range of stakeholders – including government authorities, industry, and community members – as we work to deliver this significant project.

REFERENCES

AEMO. *2022 Integrated System Plan. June 2022*. Australian Energy Market Operator.

AEMO. *Building Power System Resilience with Pumped Hydro Energy Storage. July 2019*. Australian Energy Market Operator.

NSW Department of Planning, Industry and Environment. *NSW Electricity Infrastructure Roadmap. November 2020*. Energy NSW.

APPENDICES

A: Amplitude Report – ‘*Oven Mountain Pumped Hydro Storage Benefit Assessment – Network Stability Report*’ – Amplitude Consultants, April 2022.

B: Amplitude Report – ‘*Oven Mountain Pumped Hydro Storage Benefit Assessment – System Strength and Inertia*’ – Amplitude Consultants, July 2022.

C: EY Report – ‘*Assessment of market benefits of the Oven Mountain Pumped Storage Hydro project*’ – EY Consultants, November 2022.

OVEN MOUNTAIN
PUMPED HYDRO STORAGE

APPENDIX **A**

Amplitude Report

OMPS Benefit Assessment – Network Stability Report

Amplitude Consultants, July 2022

Oven Mountain Pumped Hydro Storage

Benefit Assessment – Network Stability Study

Amplitude Document Number:
PAU0250-REPT-001

Date of Issue:
27 April 2022

Revision:
Rev 2

This document has been carefully prepared for the exclusive use of Amplitude's Client, which is subject to and in accordance with the provisions of the contract between Amplitude and the Client. Amplitude accepts no liability or responsibility whatsoever for, or in respect of, any use of, or reliance upon, this report by any third party.

Revision History

Revision	Description	Prepared By	Approved By	Date
0	Initial Release	Adam Peard, Alastair Pinkard	Adam Peard	31 March 2022
1	Updated to include wind farm sensitivity	Adam Peard, Alastair Pinkard	Adam Peard	19 April 2022
2	Update title and wind farm MSD	Adam Peard	Adam Peard	27 April 2022

Address: Amplitude Consultants PTY LTD
Level 6, 15 Astor Terrace
Spring Hill QLD 4000
Australia

E-mail: info@amplitudepower.com

Phone: (07) 3905 9030

Website: https://amplitudepower.com/

Table of Contents

EXECUTIVE SUMMARY ..... **IV**

1. INTRODUCTION **1**

2. STABILITY STUDIES – APPROACH AND METHODOLOGY **3**

2.1. NEM Power System Model 3
2.2. OMPS Model 3
2.3. Load and generation scenarios 4
2.4. Governor models 6
2.5. Determining stability limits 6
2.5.1. Critical contingencies *6*
2.5.2. Limit search *7*
2.5.3. Monitored variables *8*

3. RESULTS **9**

3.1. Existing limits on QNI 9
3.2. Study Findings 10
3.2.1. Limits without OMPS *10*
3.2.2. Impact of OMPS on Transmission Network Flows *11*
3.2.3. Limits with OMPS Generating *12*
3.2.4. Limits with OMPS Pumping *15*
3.3. Synchronous Condenser Mode 18
3.4. BESS Sensitivity 19
3.5. Increased Hosting Capacity When Pumping 20

4. CONCLUSION **21**

5. REFERENCES **22**

List of Figures

Figure 1 – Indicative Location of OMPS within the New South Wales transmission network [1] 1
Figure 2 – OMPS indicative layout for 600 MW and 900 MW configurations 4
Figure 3 – QNI stability limits without OMPS – Southerly direction 10
Figure 4 – QNI stability limits without OMPS – Northerly direction 11
Figure 5 – Impact of OMPS on flows south of Armidale (shoulder case) 12
Figure 6 – Impact on QNI southerly stability limit (worst case contingency) – OMPS generating 13
Figure 7 – Impact on QNI southerly stability limits by contingency – OMPS generating 13
Figure 8 – Impact on QNI northerly stability limit for Kogan Creek Trip – OMPS generating 15
Figure 9 – Impact on QNI southerly stability limit (worst case contingency) – OMPS pumping 16
Figure 10 – Impact on QNI southerly stability limits by contingency – OMPS pumping 16
Figure 11 – 900 MW pumping increasing hosting capacity 17
Figure 12 – Impact on QNI northerly stability limit for Kogan Creek Trip – OMPS pumping 17
Figure 13 – Impact on QNI Stability Limits – Synchronous Condenser 18
Figure 14 – Voltage response at Armidale 330 kV 19
Figure 15 – Reactive Response of BESS 900 and OMPS 900 20
Figure 16 – Additional Wind Farm Capacity at Armidale 330 kV 21

List of Tables

TABLE 1 – STUDY SCENARIOS 5
TABLE 2 – CONTINGENCIES FOR DYNAMIC STUDIES 7
TABLE 3 – QNI EXISTING LIMITS 9

Executive Summary

Amplitude Consultants Pty Ltd (Amplitude) have been engaged by OMPS Pty Ltd (Client) to investigate the impact of the proposed Oven Mountain Pumped Storage Hydro (OMPS)[1] generating system on power system stability. This work is part of a broader study supported by the Australian Renewable Energy Agency (ARENA) through their Advancing Renewables Program (ARP) to analyse the benefits that Pumped Hydro Energy Storage (PHES) would have on the development of the New England Renewable Energy Zone (REZ) in northern New South Wales.[2]

Specifically, the Client requested Amplitude perform power system analysis studies to assess the impact of OMPS on the existing northerly and southerly power transfer stability limits[3] on the Queensland to New South Wales Interconnector (QNI), under various load and generation scenarios, and for different OMPS capacities and connection arrangements.

The NEM transmission grid can be characterised as a long and skinny power system with geographically dispersed generation and demand centres. Given the nature of the network the power transfer capability across the long interconnections between NEM regions is often set by voltage and transient stability limitations rather than thermal constraints. Amplitude anticipates that with further decline in system strength and inertia stability constraints will become more prevalent, especially across the longer NEM transmission corridors.

Understanding the potential impact of a large new PHES on these stability limitations is important because it could significantly impact the power transfer capability between regions. An increase in the stability limits can provide significant market benefits by reducing generation operating costs and wholesale market prices and can also defer very costly network augmentation. Investigating the potential reductions in power transfer capability is obviously important too, as this could present challenges for the connection of the new plant and potentially severe constraints on its operation, or the operation of other facilities.

Thermal constraints are also important but unlike stability constraints, thermal constraints are affected in the similar manner by any type of generation technology injecting power into a certain location. This study therefore focuses on the impact of PHES on stability limitations only.

OMPS is a proposed PHES planned for connection near Armidale in northern New South Wales. The Client is currently considering two options including a 600 MW generating system connected at 132 kV and a 900 MW generating system connected at 330 kV. Whilst preliminary connection arrangements have been developed for both options, the final connection will likely be influenced by the scope of transmission development for the New England (REZ). For these studies OMPS was connected directly to the 132 kV and 330 kV busses at Armidale for the 600 MW and 900 MW options, respectively.

Amplitude has assessed the impact of OMPS on QNI stability limits across a series of scenarios involving different levels of network demand, renewable generation outputs and QNI flow direction. The impact of OMPS when generating and pumping has been investigated. Several sensitivity studies were also performed. This included an investigation of the benefit of OMPS synchronous condenser

[1] Further information on OMPS can be found at https://www.ompshydro.com/project/
[2] https://www.ompshydro.com/news/pumped-hydro-plant-could-unlock-new-england-rez/4
[3] The study considers voltage and transient stability limits only. An assessment of oscillatory stability has not been included as the models required for this purpose are not readily available to registered participants.

operating mode, a comparison of the performance of OMPS and a notional 900 MW BESS and a study showing how much additional network wind farm hosting capacity might be created when OMPS is pumping.

When OMPS is generating under higher demand conditions, being the most likely operating scenario, it provides a marginal improvement of at least 20 MW in the southerly stability limits and a substantial improvement of greater than 200 MW in the northerly stability limits. There was no assessment of the impact of pumping on high demand scenarios as this was considered an unlikely case.

The contribution of OMPS when generating leads to considerably higher power transfers south of Armidale. Under these circumstances the worst-case credible contingencies setting the QNI stability limit shift from north of Armidale Substation to the south on 330 kV transmission lines between Armidale – Tamworth and between Muswellbrook – Liddell, causing a reduction of up to 180 MW on the southerly QNI limit. The impact of OMPS generation on the northerly stability limit remains very positive with around a 220-400 MW increase.

When operating in pumping mode OMPS draws load from Armidale Substation, reducing the southerly power transfer from Armidale to Tamworth. Under these conditions the worst-case contingencies setting the QNI southerly limit are north of Armidale and the QNI southerly limit increases by around 100-120 MW. This highlights a significant benefit from OMPS. During pumping periods OMPS will enable additional generation to inject at or near Armidale at least up to the level of pumping demand, whilst having little or no net effect on transmission loading and also increasing in the QNI southerly stability limit. The northerly transfer limit is reduced by around 120-140 MW in this scenario, but the benefits OMPS offers to the connection of additional generation near Armidale still stand.

Importantly, although there is a reduction in QNI southerly limits when OMPS is generating under low demand conditions, the reduction is substantively less that the generation output from OMPS. Because of this the effect of OMPS is to increase the New South Wales maximum supportable demand (MSD). These studies indicate an increase in MSD of at least 700 MW across all scenarios when generating, assuming a 900 MW connection.

The most significant improvement in QNI transfer capability is seen when OMPS is operating as a synchronous condenser. In this mode there is almost no real power exchanged with the surrounding transmission lines, but the substantial voltage control capability and inertia provide an increase in the QNI voltage and transient stability limits of more than 200 MW in both directions.

When the OMPS facility is compared against an equivalent sized BESS discharging at the same location (Armidale 330 kV) the results show OMPS can provide more reactive power during a fault causing a less severe voltage depression, likely due to its substantively higher short circuit current contribution. The QNI southerly limit with OMPS in service was also 60 MW higher when compared with the BESS.

The studies show that when OMPS is pumping it enables operation of significant additional generation injection at or near Armidale Substation. Under moderate demand conditions with OMPS pumping at 900 MW, additional wind farm capacity of 1,575 MW was supported at Armidale and the southerly and northerly QNI stability limits were also improved by 120 MW and 440 MW, respectively. Under these circumstances the New South Wales MSD increases by 795 MW, being the difference between the wind farm capacity and OMPS pumping demand, plus the additional 120 MW of southerly import capability into New South Wales on QNI.

Overall, these studies have shown OMPS will provide a very valuable contribution to the network. The plant offers substantial voltage control and inertia benefits, it generally improves the QNI stability limits in the direction of flow most likely for given scenarios, it provides an increase in the New South Wales maximum supportable demand under all circumstances and should significantly increase the hosting capacity in the New England REZ by more than the OMPS pumping demand.[4]

[4] Assuming the additional generation is injected at or near Armidale Substation and operating coincident with OMPS pumping.

1. Introduction

Amplitude Consultants Pty Ltd (Amplitude) have been engaged by OMPS Pty Ltd (Client) to investigate the impact of the proposed Oven Mountain Pumped Storage Hydro (OMPS) generating system on power system stability. This work is part of a broader study commissioned by the Australian Government and the Australian Renewable Energy Agency (ARENA) to analyse the benefits that Pumped Hydro Energy Storage (PHES) would have on the development of the New England Renewable Energy Zone (REZ) in northern NSW. Amplitude have been engaged to assist with two major components of this work involving a:

- Network stability benefits study; and
- Available Fault Level and inertia benefits study.

This report documents the outcomes from the network stability benefits study. A separate report will be prepared to quantify the Available Fault Level and Inertia Benefits.

OMPS is located in the Armidale Regional Local Government Area, approximately 60 km southeast of Armidale and 70 km northwest of Kempsey, via the Kempsey-Armidale Road. The project is bordered by the Macleay River to the west and Carrai Tablelands to the east. Oxley Wild Rivers National Park, Carrai National Parks and Carrai Conservation Area surround the property, with the New England National Park approximately 1 km to the north-west. Figure 1 shows the location of OMPS with respect to the surrounding transmission network and the New England REZ.

Figure 1 – Indicative Location of OMPS within the New South Wales transmission network [1]

The Client is currently considering two options including a 600 MW generating system likely connected at 132 kV and a 900 MW generating system connected at 330 kV. Whilst preliminary connection arrangements have been developed for both options, the final connection will likely be influenced by the scope of transmission development for the New England (REZ). For the purpose of the studies in this report OMPS was connected directly to the 132 kV and 330 kV busses at Armidale for the 600 MW and 900 MW options, respectively.

The power transfer capability on QNI is influenced by numerous factors including the in-service network, the status and size and technology of other generating systems online and the demand on the power system, among others. By the time OMPS is operational circa 2028 the transmission system and generating fleet will be different to that which exists today and it will continue to evolve into the future. Given the uncertainty about future plant, this study has considered the impact of OMPS on the existing power transfer capability across QNI set by stability limitations. However, Amplitude considers the general trends shown in this report in relation to the impact of OMPS (a set of large synchronous machines injecting at Armidale) on QNI stability limits should hold true going forward.

The intent of this study is not to show PHES solves a particular problem and Amplitude is aware of existing committed and proposed augmentations that will lift the stability limitations identified in this report. Rather, this study provides the opportunity to illustrate how a PHES impacts documented NEM constraints knowing that these constraints will influence the development of the New England REZ. The outcomes of this work may also help inform the ideal generation mix of other REZ's as the energy transitions matures.

The stability of the power system is critical to the ongoing management of power security and reliability. It is already well known that the rapid uptake of inverter based generation resources (IBR) is displacing large synchronous machines leading to a progressive decline in system strength and voltage control capability. This can affect the stability of some existing IBR that are reliant on relatively strong grid voltage signals to function correctly and presents challenges to the connection of more traditional IBR plant. Declining power system inertia is also problematic too and leads to a higher rate of change of system frequency during certain contingency events.

Whilst new 'grid forming' IBR technology has been shown to assist with managing system strength and inertia issues, such technology is not commonly installed to provide the long duration (> 8 hours) storage requirements being sought by the New South Wales Government in the NSW Electricity Infrastructure Roadmap [2]. PHES on the other hand is a well proven form of long duration energy storage world wide and can provide excellent system strength and instantaneous inertial support, irrespective of its operating point.

The NEM transmission grid can be characterised as a long and skinny power system with geographically dispersed generation and demand centres. Given the nature of the network, the power transfer capability across the long interconnections between NEM regions is often set by voltage and transient stability limitations rather than thermal constraints. Amplitude anticipates that with further decline in system strength and inertia stability constraints will become more prevalent, especially across the longer NEM transmission corridors.

Understanding the potential impact of a new large PHES on these stability limitations is important because it could significantly impact the power transfer capability between regions. Increases in the

stability limits, ideally up to to thermal ratings of equipment, can provide significant market benefits by reducing generation operating costs and wholesale prices and deferring large network augmentation capital costs. Investigating the potential reductions in power transfer capability is obviously very important too, as this could present challenges for the connection of the new plant and potentially severe constraints on its operation, or operation of other facilities.

Thermal constraints are also important but unlike stability constraints, thermal constraints are affected in the same manner by any type of generation technology injecting power into a certain location. This study therefore focuses on the impact of PHES on stability limitations only.

2. Stability Studies – Approach and Methodology

2.1. NEM Power System Model

This study was performed using PSS®E. The Client provided Amplitude with PSS®E Standard Snapshot models of the NEM power system sourced from AEMO via its OPDMS.

Amplitude removed the Tasmanian network from the models by replacing Basslink with an equivalent load at the Loy Yang converter station. This was done to reduce total simulation time, recognising that the response of Basslink is likely to have an immaterial impact on the study objectives.

The NEM models were modified to integrate OMPS (refer Section 2.2) and prepare a series of load and generation scenarios (refer Section 2.3). Additional governor models were provided by AEMO for this study as many of the governor models in the Standard Snapshot package were missing or did not account for the recent mandatory primary frequency response Rule change[5] (refer Section 2.4).

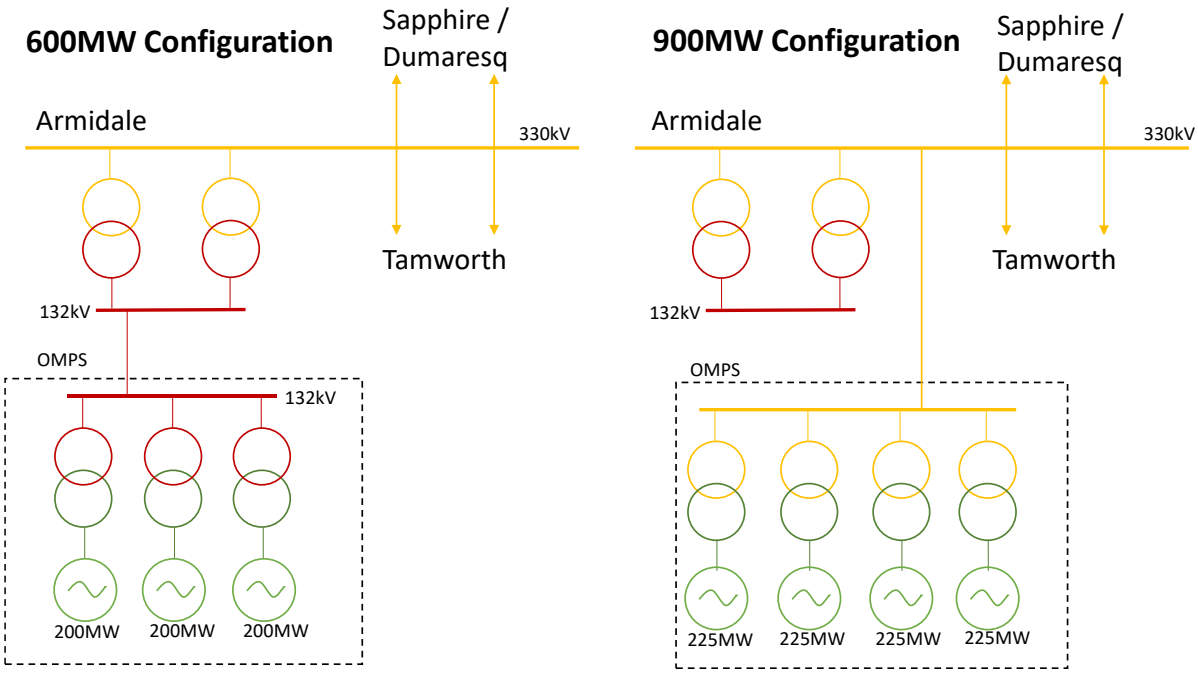
2.2. OMPS Model

Original Engineering Manufacturers (OEM) supplied PSS®E dynamic models to represent OMPS. Amplitude modified the NEM models (refer Section 2.1) to include both the OMPS 600 MW and OMPS 900 MW options.

In scenarios where OPMS is assumed to be a 600 MW facility it is modelled with three 200 MW turbines connected to Armidale 132 kV as shown in Figure 2. Figure 2 also shows the 900 MW configuration with OMPS modelled with four 225 MW turbines connected to Armidale 330 kV. Whilst in practice OMPS will be connected to the national grid via some length of connection assets possibly with other enabling network augmentations, the scope of the connection assets and potential enabling works is not known and a direct connection to Armidale is considered appropriate for the analysis undertaken.

[5] https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response

Figure 2 – OMPS indicative layout for 600 MW and 900 MW configurations



2.3. Load and generation scenarios

Amplitude has assessed the impact of OMPS on the QNI stability limits across a series of scenarios involving different levels of network demand, variable renewable generation outputs and QNI flow direction. The impact of OMPS when generating and pumping has been investigated including 600 MW and 900 MW options. Several sensitivity studies were also performed. This included an investigation of the benefit of OMPS synchronous condenser operating mode, a comparison of the performance of OMPS and a notional 900 MW BESS and a study showing how much additional network hosting capacity might be created for wind farm connections when OMPS is pumping.

Table 1 provides the network configuration for each of the scenarios, noting that each scenario is developed with both northerly and southerly flows on QNI. Cases where OMPS is not included were studied for each network demand condition to establish a baseline for the QNI northerly and southerly stability limits for comparative purposes.

The scenarios have been prepared with consideration of the likely OMPS operating mode and potential output from other renewable sources at certain demand levels, but also with an intent to study broad operating conditions. No pumping cases have been studied under evening peak demand conditions as this is considered an unlikely operating condition. The most likely operating modes for each demand level are shaded in grey.

Table 1 – Study scenarios

Demand	OMPS	Solar Generation	Wind Generation	Scenario ID
Peak (evening) 10.8 GW in NSW	Not included	Low	Moderate	Peak None
	High Generation, 600 MW			Peak G600
	High Generation, 900 MW			Peak G900
Low (midday) 5 GW in NSW	Not included	High	Moderate	Low None
	High Generation, 600 MW			Low G600
	High Generation, 900 MW			Low G900
	High Pumping, 600 MW			Low P600
	High Pumping, 900 MW			Low P900
Shoulder (midmorning/ midafternoon) 6 GW in NSW	Not included	High	High	Shoulder None
	High Generation, 600 MW			Shoulder G600
	High Generation, 900 MW			Shoulder G900
	High Pumping, 600 MW			Shoulder P600
	High Pumping, 900 MW			Shoulder P900
	Synchronous Condenser, 900 MW			Shoulder Syncon
	BESS sensitivity, 900 MW discharging (OMPS not included)			Shoulder BESS
	Wind Farm sensitivity, OMPS High Pumping			Shoulder WIND

The Peak demand scenarios were developed off the summer high Standard Snapshot (SummerHi-20210124-180000) provided by AEMO. The Shoulder and Low demand scenarios were both developed off the autumn low Standard Snapshot (AutumnLo-20210328-110152). For the Shoulder scenarios, demand in New South Wales was increased from ~5 GW to ~6 GW with most of the increase in load supplied by increased wind generation output in New South Wales.

High voltages were observed in the snapshot used to prepare the Low and Shoulder demand scenarios, despite one Hazelwood to South Morang 500 kV circuit already being out of service to help manage these conditions.[6] The 2021 Victorian Annual Planning Report [3] includes information on the Victorian Reactive Power Support RIT-T. This project is a committed project to install an additional 100 MVAr 220 kV reactor at Keilor[7] and two 100 MVAr reactors at Moorabool. These reactors were

[6] AEMO currently switches one South Morang 500 kV line out of service to manage high voltages during low demand – refer Section 2.7, 2021 Victorian Transmission Annual Planning Report.
[7] The reactor installed at Keilor 220 kV bus under the Victorian Reactive Power Support RIT-T is additional to the 100 MVAr 220 kV reactor commissioned at Keilor in 2021 under the approved Network Capacity Incentive Parameter Action Plan (NCIPAP). Amplitude has modelled two additional 100 MVAr reactors at each of Keilor and Moorabool.

not included in the provided snapshot case and were added by Amplitude to assist with managing the high voltage conditions and improve initialisation of the dynamic simulations.

2.4. Governor models

Governor models can be of little significance for power system studies that do not involve frequency disturbances such as tripping of major loads and generating units. This study investigated the response of the power system to a trip of Kogan Creek Power Station from around 750 MW as well as a trip of a Boyne Island Smelter potline from 360 MW, so governor models were considered important.

When preparing the initial study scenarios Amplitude noticed that for a trip of Kogan Creek Power Station from around 750 MW the NEM system frequency would drop rapidly, falling below 49 Hz. This caused protection relays on other generators to disconnect plant leading to cascading failure. This was a surprising outcome as the NEM Standard Snapshots were assumed to reflect a secure operate state. Investigations revealed that many of the synchronous machines did not have governor models, which was identified to be the root cause of the significant frequency deviation.

AEMO subsequently provided generic governor models to use for all plant, noting the models are not verified and hence not supplied as part of the Standard Snapshot Package. Amplitude incorporated the governor models provided by AEMO into the NEM models used in this study and the previous 49 Hz frequency deviation following a trip of Kogan Creek was no longer apparent.

2.5. Determining stability limits

2.5.1. Critical contingencies

When determining the QNI stability limit it is important to account for a range of credible contingencies so that the most critical contingency setting the lowest limit can be identified. The Powerlink Transmission Annual Planning Report 2021 [4] provides a summary of the credible contingencies most likely to set the southerly and northerly transfer limits on QNI.

All the contingencies mentioned by Powerlink which can lead to stability limitations in the southerly direction have been considered. Amplitude also included contingencies on the Armidale – Tamworth 330 kV circuit, recognising that OMPS is a significant new generator injection at Armidale and could result in contingencies on this circuit becoming most onerous.

When assessing the northerly QNI stability limit Amplitude only considered a trip of Kogan Creek Power Station from maximum output. The Powerlink TAPR does indicate that the northerly limit could be set by “transmission line faults in NSW” although it is unclear what line faults should be assessed. In any event a trip of Kogan Creek Power Station was found to be the worst case contingency via information in the public domain (refer Section 3.1).

Table 2 summarises the credible contingencies considered when assessing the northerly and southerly stability limits on QNI. All contingencies were assumed to be 2 phase to ground faults cleared in primary protection clearance times per the National Electricity Rules S5.1a.8.

Table 2 – Contingencies for dynamic studies

QNI Direction	Contingency	Chart Label
Southerly	Trip of 8E Sapphire – Armidale 330 kV	SAPARM_8E
	Trip of 8C Sapphire – Dumaresq 330 kV	SAPDUM_8J
	Trip of 8J Armidale – Dumaresq 330 kV	ARMDUM_8C
	Trip of 83 Liddell – Muswellbrook 330 kV	LIDMUS_83
	Trip of 8L Bulli – Dumaresq 330 kV	QNI_8L_PRM
	Trip of Hazelwood – South Morang 500 kV	HWSM_PRM
	Trip of Boyne Island Smelter Pot Line Load	LD_BOYNE
	Trip of 85 Armidale – Tamworth 330 kV	ARMTAM_85
Northerly	Kogan Creek Power Station Trip	KOGAN TRIP

2.5.2. Limit search

The stability limits on QNI have been determined separately for each of the relevant contingencies in Table 2. For example, the southerly QNI stability limit for a contingency on the Sapphire – Armidale circuit has been determined separately to the southerly QNI stability limit for a contingency on the Sapphire – Dumaresq circuit. The contingency which results in the lowest QNI stability limit is treated as the 'worst case contingency' and may shift depending on the power system operating conditions.

To establish the southerly limit, each of the contingencies relevant to the southerly direction were studied separately in progressively higher increments of 20 MW of power transfer on QNI until instability was observed. The power transfer on QNI was varied by increasing generation in northern and central Queensland while generation in Victoria was reduced. The QNI southerly stability limit for a given contingency was assumed to be 20 MW lower than the QNI power transfer in the marginally unstable case for that contingency.

An unstable power transfer was determined based on a relative angular separation between any two synchronous machines of more than 180 degrees, voltage collapse, very poorly damped response in any monitored variable, or non-convergence.

A similar approach was used to establish the northerly limit considering a trip of Kogan Creek Power Station at progressively higher increments of 20 MW of power transfer on QNI. In this case generation in Victoria was progressively increased while generation in central and northern Queensland was reduced.

In all cases, generation scaling to adjust QNI power transfer relates only to the dispatch of active power from online generating units remote from QNI. No generators were switched on or off, only the machine output is altered to achieve the desired change in flow. This avoided potential step changes in voltage control capability and inertia on the network that might lead to significant distortion in the results. In ensuring that the cases are representative of likely operating scenarios Amplitude discounted cases where pre contingent voltages on the QNI corridor, being the 330 kV network between Bulli Creek and Bayswater, dropped below 0.9 PU (90% of the nominal voltage).

In practise Transmission Network Service Providers can assess thousands of different load and generation scenarios to determine the stability limit and develop operational limit equations for central dispatch purposes. Amplitude acknowledges that there are also alternative approaches involving steady state as well as other dynamic simulation techniques. As the purpose of this study is to compare the relative impact of OMPS on the QNI stability limits found with and without OMPS the approach taken is considered fit for purpose.

2.5.3. Monitored variables

The following variables were monitored throughout each simulation.

- Bu voltage and voltage angle relative to South Pine 275 kV:
  - Braemar 330 kV
  - Bulli Creek 330 kV
  - Dumaresq 330 kV
  - Sapphire 330 kV
  - Armidale 330 kV
  - Tamworth 330 kV
  - Muswellbrook 330 kV
  - Liddell 330 kV
  - OMPS 330 kV
- Voltage, Machine Power (P, Q)
  - Kogan Creek
  - OMPS Unit 1
- Machine Angles relative to Loy Yang Unit 1
  - Eraring Unit 1
  - Tarong Unit 1
  - OMPS Unit 1
- Branch Flow
  - 8E Sapphire – Armidale
  - 8C Sapphire – Dumaresq
  - 8J Armidale – Dumaresq
  - 83 Liddell – Muswellbrook
  - 8L Bulli Creek – Dumaresq
  - 85 Armidale - Tamworth
  - Armidale SVC[8]
- System Frequency
  - Braemar 330 kV

[8] Armidale SVC is modelled as a controlled shunt in the power flow model. The dynamics library does not have an API to extract shunt data, so the line flow was used as a proxy.

3. Results

3.1. Existing limits on QNI

The present range of northerly and southerly stability limits on QNI in the NEM is provided in Table 3. This information is used to compare the operational performance of QNI against the stability limits determined in this study in the 'no OPMS' scenarios and help validate study outcomes.

The information in Table 3 has been extracted from the QNI minor consultation PACR [5][9]. The limits in Table 3 are considered notional in that they are derived using constraint equations based on a set of assumptions that would represent typical operating conditions.

Table 3 shows the southerly limit on QNI ranges from about 950-1225 MW and the northerly limit ranges from 70-670 MW depending on the system demand and generation as well as the output of Sapphire Wind Farm.[10]

Table 3 – QNI existing limits

Operating Condition		Notional QNI Limit (Summer)		Notional QNI Limit (Winter)	
		Northerly Direction	Southerly Direction	Northerly Direction	Southerly Direction
High Sapphire Wind Farm	Day High	365	1070	425	1070
	Day Medium	480	970	570	1070
	Day Low	670	950	670	1030
	Night High	330	1100	365	1000
	Night Medium	475	990	545	990
	Night Low	635	985	635	985
	Average	518	999	557	1015
Low Sapphire Wind Farm	Day High	190	1215	245	1215
	Day Medium	300	1205	375	1205
	Day Low	525	1130	525	1200
	Night High	70	1225	110	1225
	Night Medium	220	1215	285	1215
	Night Low	445	1210	445	1210
	Average	312	1197	348	1211

Amplitude also reviewed the AEMO Annual NEM Constraint Report for 2021 [6] and the monthly reports for January 2022 to February 2022 [7]. This review identified the following constraint equations as the most binding on QNI during 2021 and early 2022. Note only the system intact

[9] Limits in the table are derived from table 5.2 and 5.3 of the QNI Minor Project Assessment Conclusions Report (PACR) [5] by subtracting the limit increase for option 1A from the notional limits in the tables.
[10] Sapphire Wind Farm is connected to the 330 kV network between Armidale and Dumaresq, and as such is considered independent of other generation in assessing the QNI limits.

constraint equations which bound more than 25 hours have been considered. This information is useful to understand the most critical contingencies presently setting the lowest limit on QNI.

In the Northerly direction:

- N^^Q_NIL_B1 - Out= Nil, avoid Voltage Collapse on loss of Kogan Creek.
- N^^Q_NIL_A - Out= Nil, avoid Voltage Collapse on loss of Liddell to Muswellbrook (83) line.

In the Southerly direction:

- Q^^NIL_QNI_SRAR - Out = Nil, limit QLD to NSW on QNI to avoid voltage instability on trip of Sapphire - Armidale (8E) 330 kV line.
- Q:N_NIL_AR_2L-G & Q::N_NIL_AR_2L-G - Out=Nil, limit Qld to NSW on QNI to avoid transient instability for a 2L-G fault at Armidale.

3.2. Study Findings

The following sections of this report provide a summary of the QNI stability limits determined in this study. The results are initially presented without OMPS to form the baseline and then compared with the results for both OMPS 600 MW and 900 MW options.

3.2.1. Limits without OMPS

Figure 3 shows the QNI southerly limits without OMPS. The SAPARM_8E (Sapphire to Armidale) contingency is most limiting setting QNI limits in the range 1040 MW to 1160 MW in the Low None scenario and Peak None scenario, respectively. This finding is consistent with existing dispatch outcomes in Section 3.1 where the constraint equation Q^^NIL_QNI_SRAR (Out = Nil, limit QLD to NSW on QNI to avoid voltage instability on trip of Sapphire - Armidale (8E) 330 kV line) had the highest incidence of binding hours in on QNI. The stability limit is also consistent with with the range of outcomes identified in Table 3. The study results are consistent with historical performance.

Figure 3 – QNI stability limits without OMPS – Southerly direction

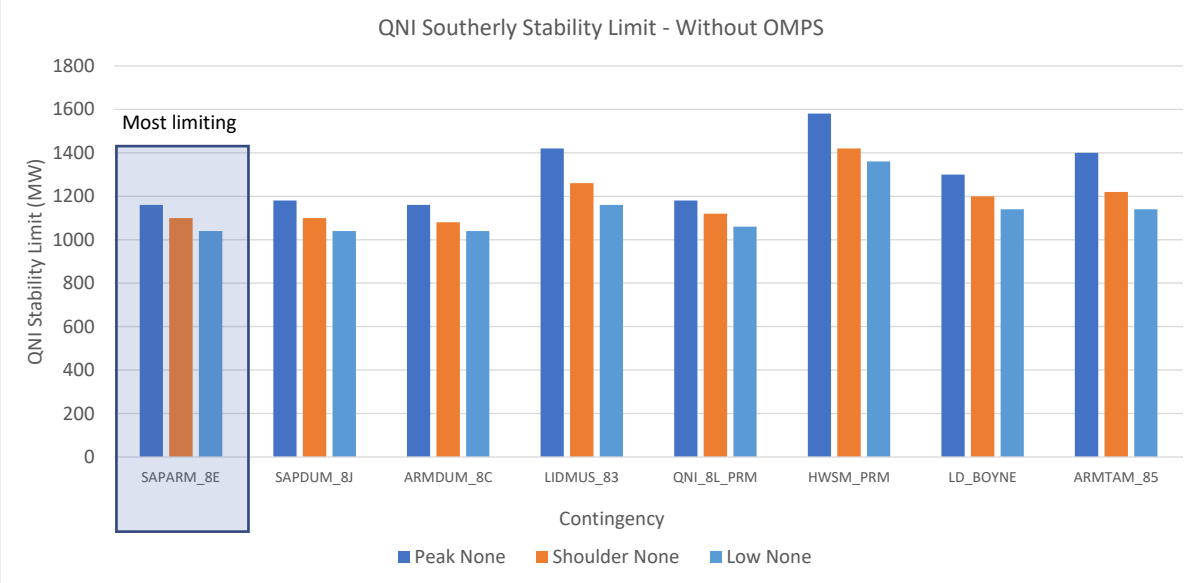
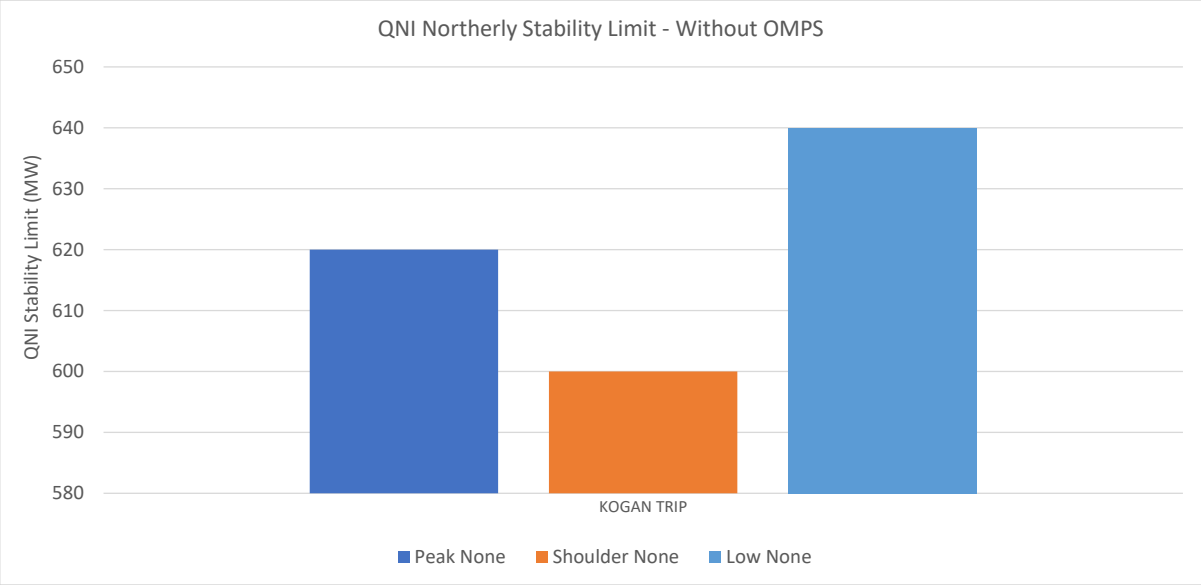


Figure 4 shows the QNI northerly limits without OMPS in service range from 600 MW in the Shoulder None scenario to 640 MW in the Low None scenario. These results fall within the range of existing northerly limits identified in Table 3. The study results are consistent with historical performance.

Figure 4 – QNI stability limits without OMPS – Northerly direction



3.2.2. Impact of OMPS on Transmission Network Flows

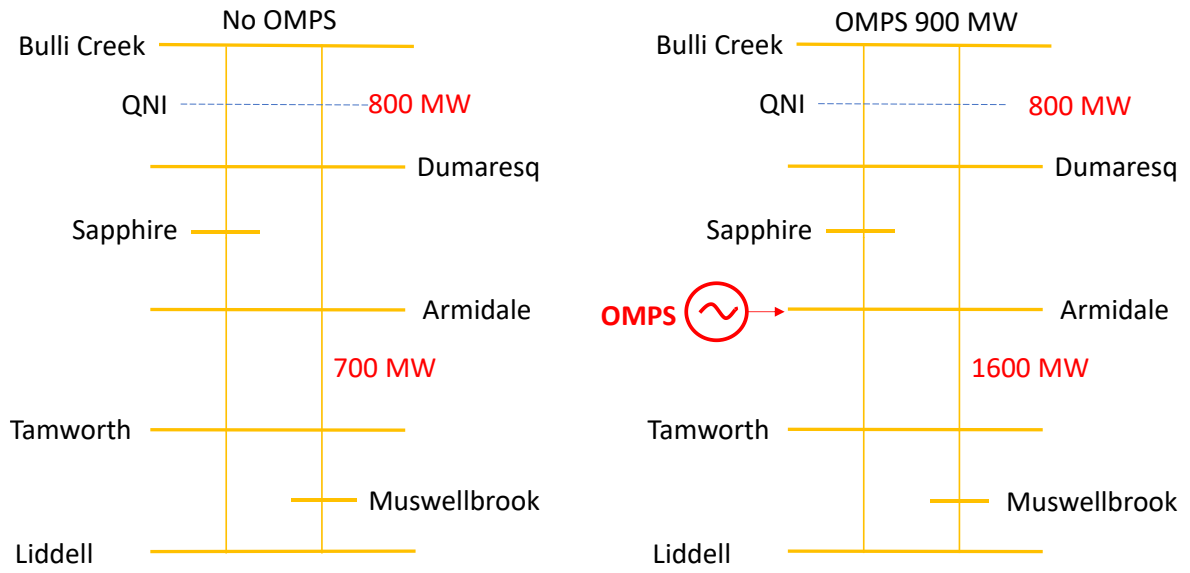
OMPS is assumed in these studies to inject directly into the Armidale Substation. For any given QNI transfer measured across the Bulli Creek to Dumaresq 300 kV lines the impact of OMPS generation at Armidale, all else equal, is to substantially increase the power transfer south of Armidale on the Armidale to Tamworth and Liddell to Muswellbrook 330 kV circuits.

Figure 5 provides an example of this showing the difference in transmission flows south of Armidale between the Shoulder None and Shoulder G900 scenarios for a notional 800 MW southerly power transfer on QNI (measured across the Bulli Creek to Dumaresq 330 kV lines). In the Shoulder None scenario the transfer south of Armidale is 700 MW, being 100 MW less than QNI due to the load offtake at Armidale Substation. In the Shoulder G900 scenario this increases to 1600 MW because of the 900 MW being injected into Armidale.

Conversely, when OMPS is pumping it acts as a substantial load at Armidale Substation and for a given southerly power transfer on QNI it works to significantly reduce the power transfer south of Armidale.

Changes in New South Wales demand also have a similar effect, although less pronounced. As demand increases there is more demand supplied from Armidale Substation, leaving less southerly 'spill' towards Tamworth on the 330 kV network.

Figure 5 – Impact of OMPS on flows south of Armidale (shoulder case)



3.2.3. Limits with OMPS Generating

3.2.3.1. Southerly Limits with OMPS Generating

Figure 6 shows, for each scenario, the relative impact OMPS has on the southerly QNI stability limit set by the worst case contingency.

When OMPS is generating under higher (Peak) demand conditions, being the most likely operating scenario, it provides a marginal improvement of 20 MW in the southerly stability limits. As the demand for electricity on the New South Wales network decreases there is less load offtake from Armidale Substation.

This leads to higher power transfers south of Armidale which is exacerbated with increasing OMPS generation output from the 600 MW to the 900 MW scenarios. Under these circumstances the worst-case credible contingencies setting the QNI stability limit shift from north of Armidale Substation to the south on 330 kV transmission lines, including Armidale - Tamworth and Liddell – Muswellbrook, causing a reduction of up to 180 MW on the southerly QNI limit.

Figure 7 shows the relative impact of OMPS on the southerly QNI stability limits set by the individual contingencies. OMPS generation is generally seen to have a positive impact on the QNI limits set by contingencies to the north of Armidale Substation (the first four contingencies to the left) but a reduces the QNI limit set by contingencies to the south. The biggest impact is seen for the Liddell to Muswellbrook contingency (LIDMUS_83) followed closely by the Armidale to Tamworth contingency (ARMTAM_85).

Figure 6 – Impact on QNI southerly stability limit (worst case contingency) – OMPS generating

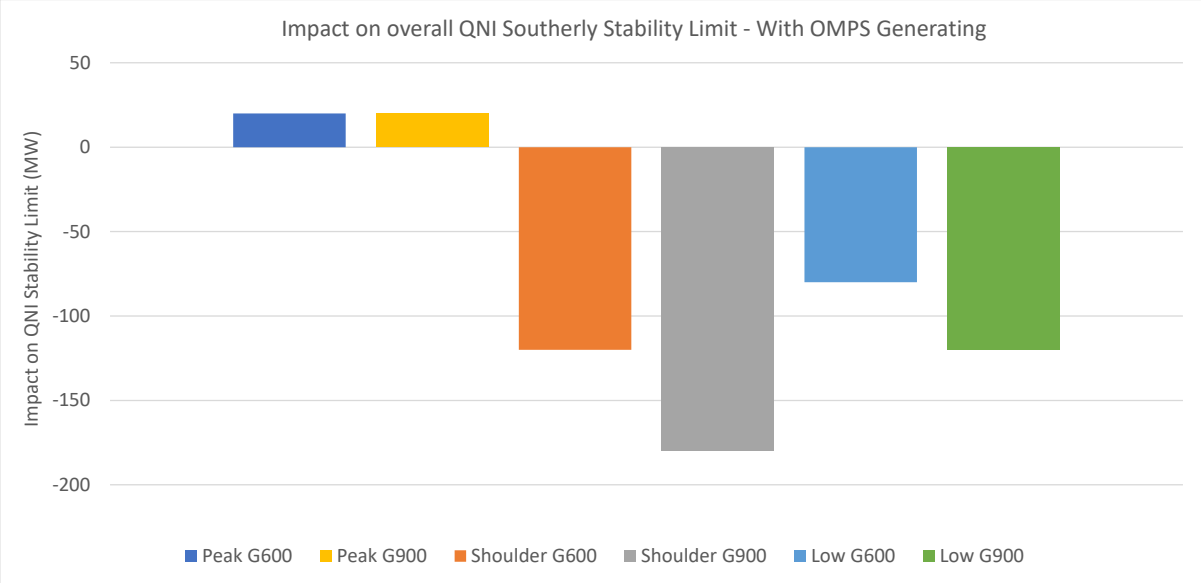
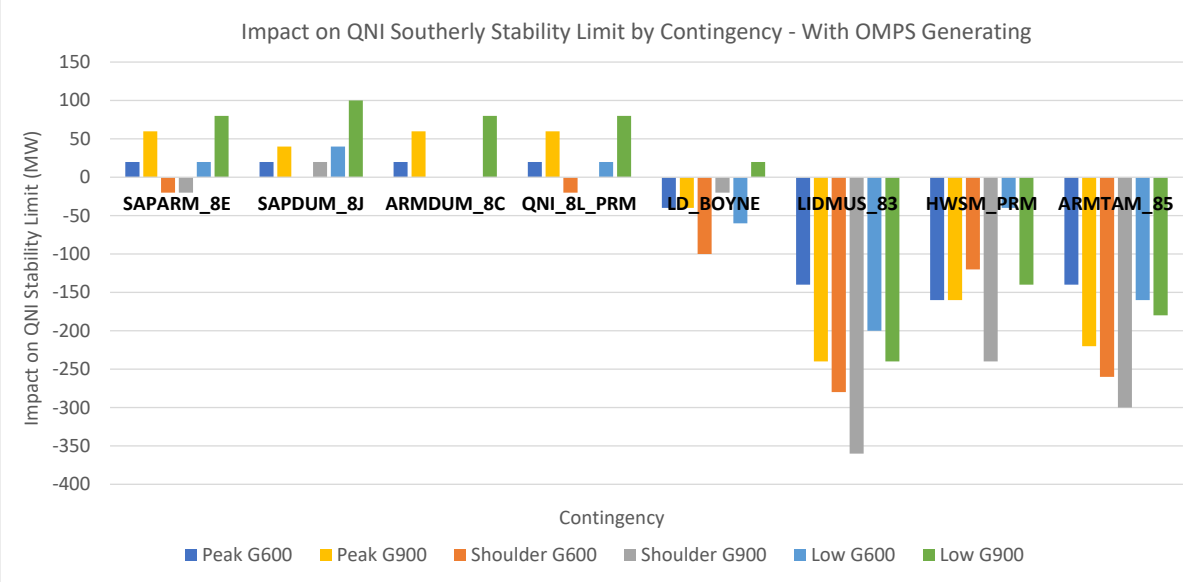


Figure 7 – Impact on QNI southerly stability limits by contingency – OMPS generating



The QNI Minor project is currently under construction and is intended to relieve the limitations south of Armidale Substation. The scope targets increases in both northerly and southerly QNI stability limits by installing dynamic reactive support (SVC) at both the Tamworth and Dumaresq 330 kV substations and installing additional 330 kV shunt connected capacitor banks at Tamworth, Armidale and Dumaresq 330 kV substations [5]. The scope also includes uprating the Liddell to Tamworth 330 kV lines to improve thermal capacity although this will not have a material impact on the stability limits.

The studies in this report do not account for the impact of the QNI Minor augmentations as these are not yet complete and are not included in the AEMO Standard Snapshots of the existing network. Powerlink indicates these augmentations will improve QNI capability by up to 240 MW in the Southerly direction depending on operating conditions [5].

If these committed augmentations were accounted for in the studies OMPS would have a less onerous impact on the QNI limits set by contingencies south of Armidale.

In addition to QNI Minor, the New England REZ Transmission Link is now an actionable ISP project [8] to extend the 500 kV network from Bayswater to south of Armidale, including new 500/330 kV substations south of Armidale and east of Tamworth, dynamic and static reactive plant and reconfiguration of the 330 kV network between Armidale and Tamworth. When completed in 2027, this project is expected to increase the transfer capacity across this corridor by over 3,000 MW in both directions.

Figure 7 also shows OMPS causes a reduction in the QNI southerly limit set by a Hazelwood to South Morang 500 kV contingency. In this scenario the QNI southerly limit being reported is not caused by instability following the contingency. Rather, the pre-contingent southerly transfer on QNI exceeded 1400 MW causing low voltage conditions on QNI below 0.9 PU. In this case the transfer south of Armidale becomes so high before the fault that 330 kV voltages are depressed.

Although there is a reduction in QNI southerly limits when OMPS is generating under lower demand conditions, the reduction in the limit is substantively less that the generation output from OMPS. Because of this the effect of OMPS is to increase the New South Wales maximum supportable demand (MSD).

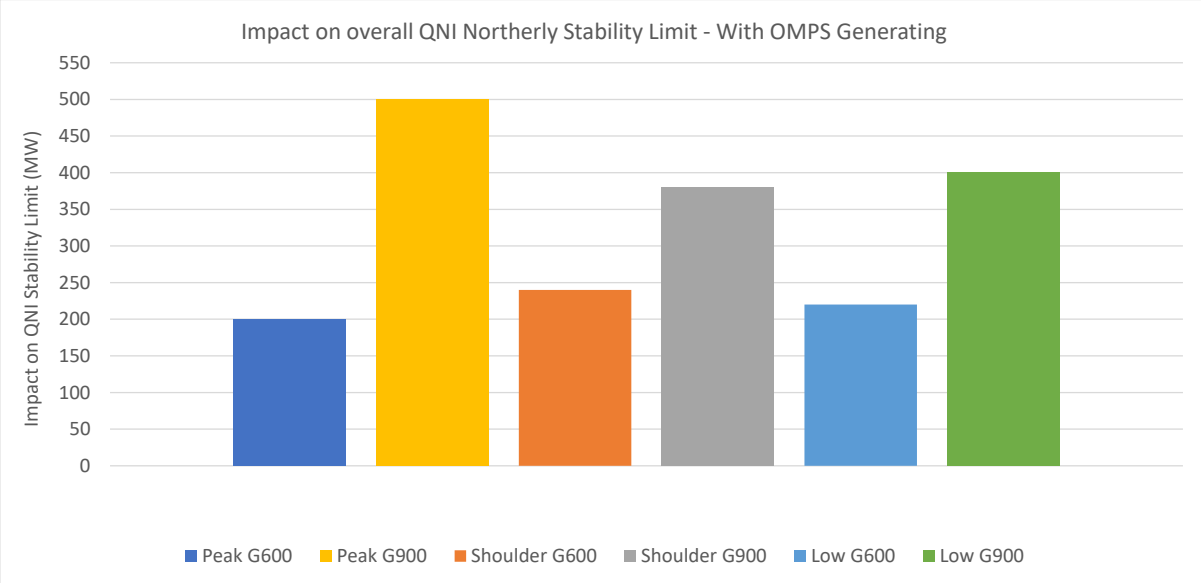
These studies show, from a stability perspective, if OMPS injects 900 MW at Armidale there may be a corresponding reduction in the southerly QNI capability of around 200 MW (ignoring the impact of QNI Minor). This suggests that OMPS provides an increase in MSD of at least 700 MW under these circumstances.

3.2.3.2. Northerly Limits with OMPS Generating

Figure 8 shows, for each scenario, the relative impact OMPS has on the northerly QNI stability limits set by the trip of Kogan Creek.

When OMPS is generating there is a considerable increase in the QNI northerly stability limit in all scenarios ranging from 200 MW to 500 MW.

Figure 8 – Impact on QNI northerly stability limit for Kogan Creek Trip – OMPS generating



3.2.4. Limits with OMPS Pumping

3.2.4.1. Southerly Limits with OMPS Pumping

Figure 9 shows, for each scenario, the relative impact OMPS has on the southerly QNI stability limits set by the worst case contingency. There was no pumping scenario under for Peak demand conditions as this was considered an unlikely outcome. When pumping the worst case QNI southerly limit increases by around 100-220 MW.

When operating in pumping mode OMPS draws load from Armidale Substation, reducing the southerly power transfer from Armidale towards Tamworth. This results in contingencies north of Armidale setting the QNI southerly limit, with contingencies south of Armidale having the largest increase in capability as shown in Figure 10.

Figure 9 – Impact on QNI southerly stability limit (worst case contingency) – OMPS pumping

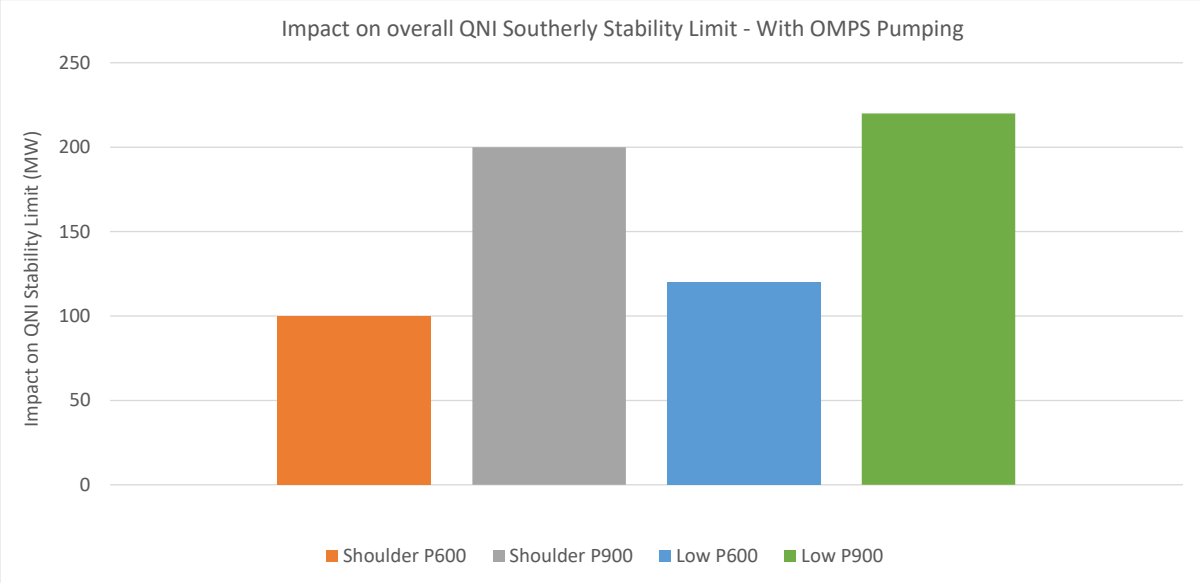
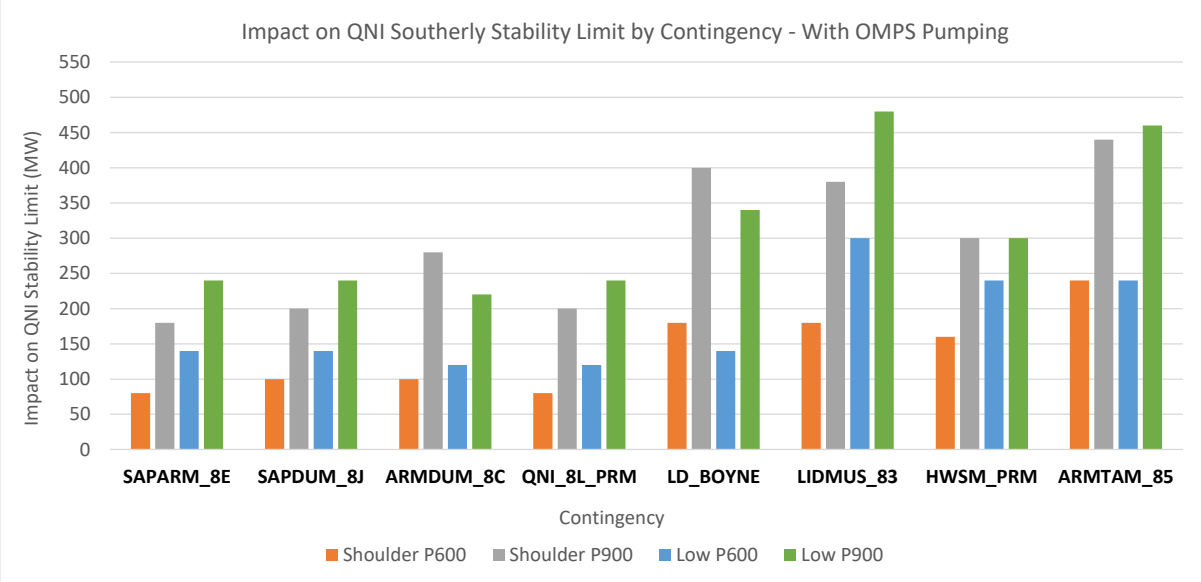


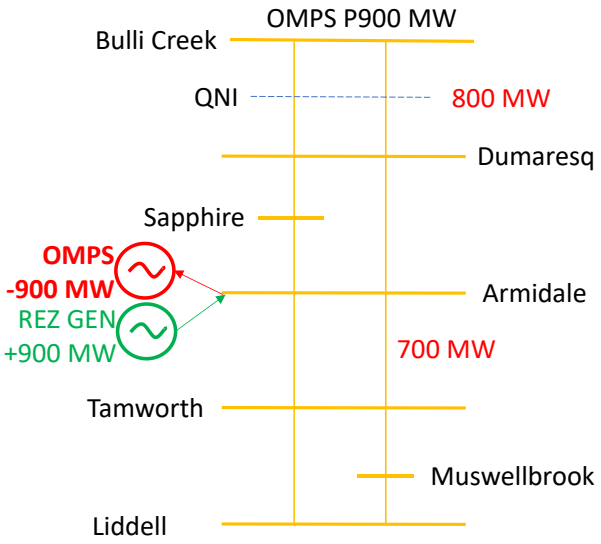
Figure 10 – Impact on QNI southerly stability limits by contingency – OMPS pumping



During pumping periods OMPS will enable additional generation to inject at or near Armidale at least up to the level of pumping demand. The pumping load and additional generation cancel one another leading to negligible net effect on transmission loading as shown in Figure 11, but the benefits of voltage control, inertia and system strength is retained. The ability for OMPS to increase network hosting capacity for other renewable generation is explored further in Section 3.5.

This is analogous to the results in Section 3.3 showing the impact of OMPS in synchronous condenser mode. In this case the net impact of transmission loading is also immaterial and QNI stability limits are increased by around 200 MW in both directions. This highlights a significant benefit of OMPS in supporting increased renewable generation connections at or near Armidale.

Figure 11 – 900 MW pumping increasing hosting capacity

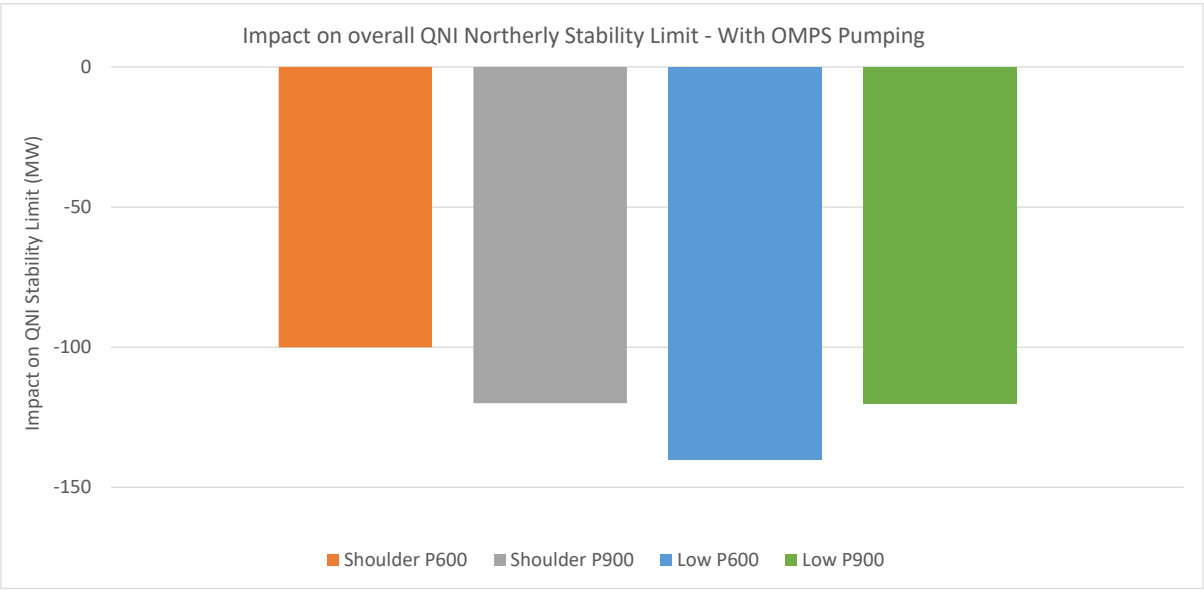


Net zero contribution of OMPS pumping (-900 MW) and new renewable generation (+900 MW) on transmission network flows

3.2.4.2. Northerly Limits with OMPS Pumping

Figure 12 shows, for each scenario, the impact OMPS has on the northerly QNI stability limit when pumping. The northerly transfer limit is reduced by around 120-140 MW in this scenario, but OMPS continues to provide a significant benefit overall by increasing the capacity for additional generation to operate near Armidale.

Figure 12 – Impact on QNI northerly stability limit for Kogan Creek Trip – OMPS pumping



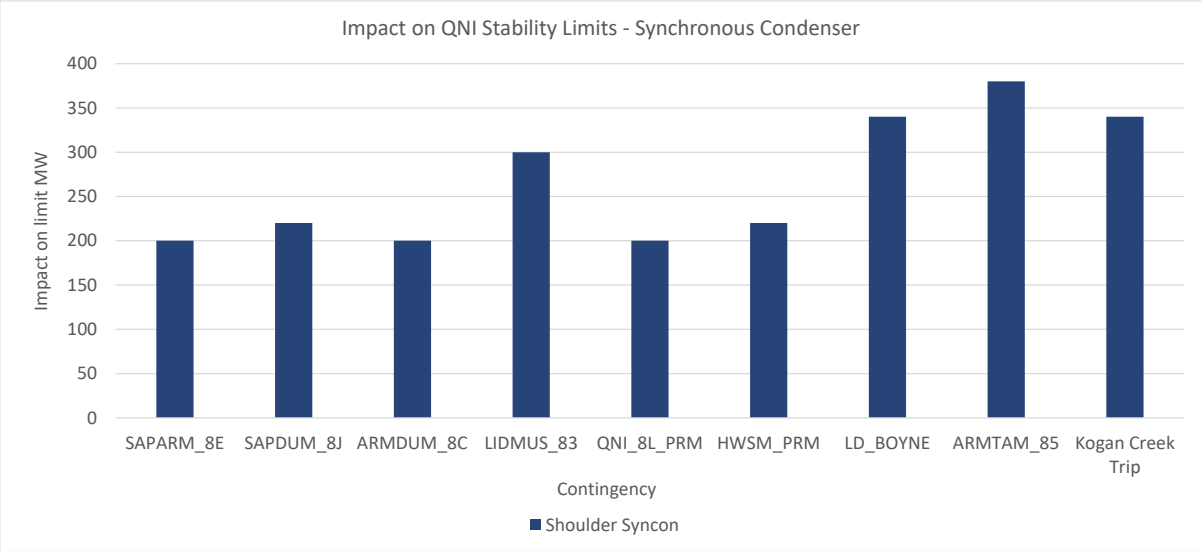
3.3. Synchronous Condenser Mode

OMPS is capable of operating in synchronous condenser mode; a mode of operation where the generating system can continue to provide system strength, voltage support and inertia but does not generate active power.[11]

A sensitivity study was performed to demonstrate the impact of OMPS operating in synchronous condenser mode on the QNI northerly and southerly limits under shoulder demand conditions. The results are provided in Figure 13 showing that in this mode of operation OMPS provides a significant improvement across all contingencies with a bidirectional increase in the QNI stability limit of more than 200 MW.

The synchronous condenser mode of operation is a particular benefit of OMPS. The units can provide substantial system strength, voltage control and inertial support in this mode in a similar manner to generation and pumping modes, but without being reliant on economic security constrained dispatch outcomes. This makes the synchronous condensers a very flexible option to support increased renewable generator connections as they can provide a power system "pillar of strength" for the surrounding network irrespective or wholesale market pricing signals.

Figure 13 – Impact on QNI Stability Limits – Synchronous Condenser



When operating as a synchronous condenser there is negligible contribution to transmission network flows as the units only draw a small amount of active power from the grid. Amplitude considers the results shown in Figure 13 would be also representative of a case where OMPS was pumping at 900 MW at the same time as an additional 900 MW of renewable generation was injecting into Armidale. In this case there would also be minimal impact on surrounding transmission network flows but the OMPS pumps would still provide the same system strength, voltage control and inertia as they do when in synchronous condenser mode.

[11] When in synchronous condenser mode each OMPS unit uses a small amount of electricity from the network sufficient to spin the machine rotor and supply rotational energy (approximately 1 MW).

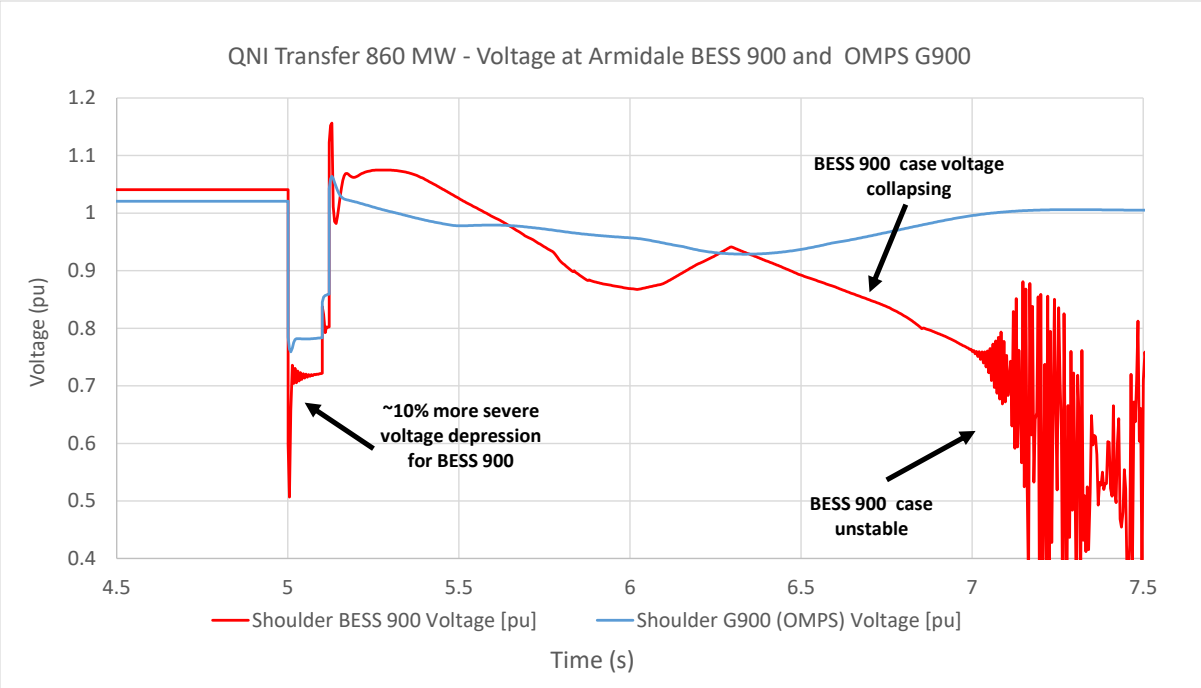
3.4. BESS Sensitivity

An additional sensitivity study has also been carried to compare the performance of a 900 MW OMPS facility with a notional 900 MW BESS model when discharging. This study was performed to investigate the impact on the QNI southerly limit for a single contingency only, the Liddell – Muswellbrook contingency, under shoulder demand conditions. The study found that the 900 MW BESS also reduced the QNI southerly transfer limit for a Liddell – Muswellbrook contingency but by 60 MW more than OMPS.

Figure 14 shows a comparison of the voltage at Armidale 330 kV in the BESS 900 and OMPS G900 scenarios for a QNI transfer of 860 MW, being the marginally unstable case for BESS 900.[12] Note the Liddell – Muswellbrook contingency occurs at five seconds and is cleared 120 ms later.

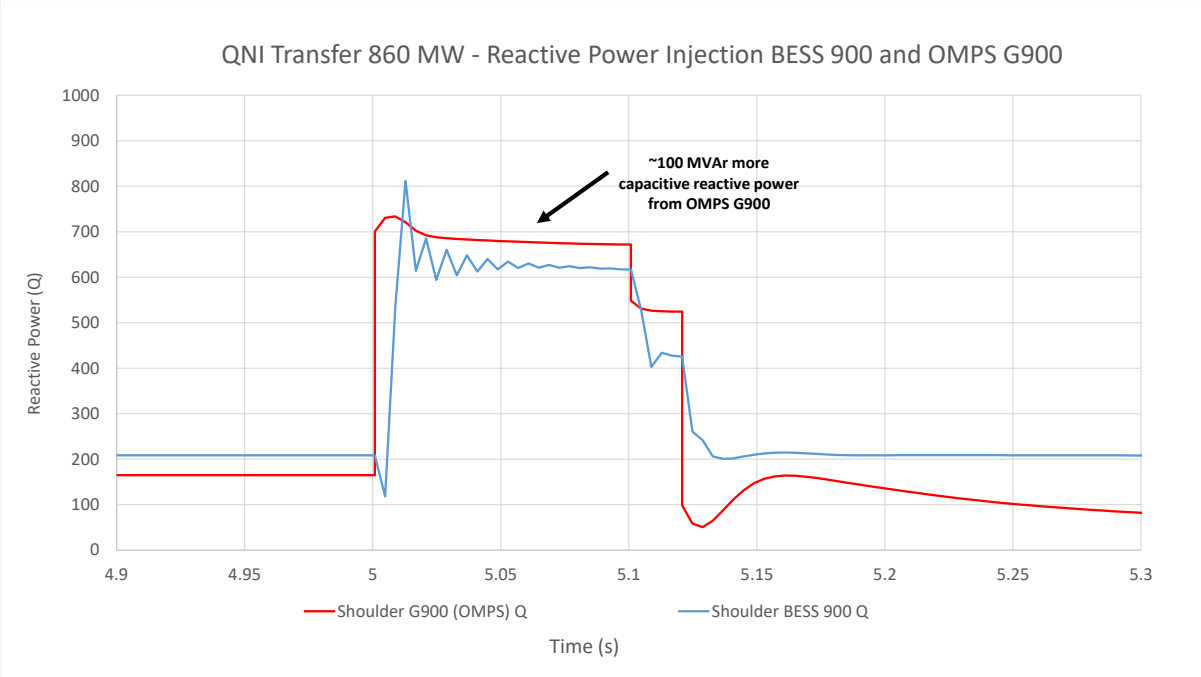
Figure 14 shows that for an 860 MW QNI transfer, unlike the BESS, OMPS G900 can maintain continuous uninterrupted operation. Furthermore, the response from OMPS G900 is favourable as it causes around a 10% less severe voltage depression at Armidale 330 kV when compared with the predisturbance voltages. This is attributed to higher amount of capacitive reactive current injected by OMPS G900 during the fault as shown in Figure 15.

Figure 14 – Voltage response at Armidale 330 kV



[12] The marginally unstable case for OMPS G900 occurred at a southerly transfer of 920 MW on QNI.

Figure 15 – Reactive Response of BESS 900 and OMPS 900



Amplitude acknowledges that both the OMPS and the the BESS models could be further tuned to maximise performance. For example, the BESS model could be configured to provide a more aggressive capacitive current injection during the fault potentially resulting in a voltage depression more comparable with OMPS. Amplitude has not attempted this but considers it unlikely that this would prevent the post fault voltage collapse seen in this case.

Ultimately, for a given nameplate rating, the short circuit current contribution from PHES machines like OMPS is far higher than that of a typical inverter-based facility (circa 3-6 times higher) and this additional short circuit current can assist with maintaining system voltages and preventing voltage collapse following disturbances.

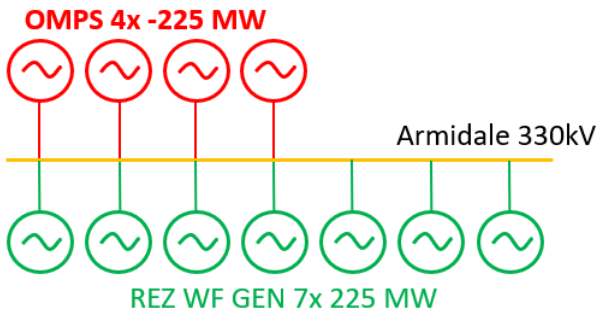
3.5. Increased Hosting Capacity When Pumping

Section 3.2.4.1 explains how operation of OMPS in pumping mode is expected to increase network hosting capacity for other renewable generation at or near Armidale Substation by at least the amount of pumping demand.

Amplitude investigated this further through sensitivity studies with additional wind farm generation capacity injecting into Armidale Substation at 330 kV while OMPS pumping at 900 MW. The wind farm capacity was modelled as several different generators each of which was based on a notional 225 MW wind farm site as shown in Figure 16.

The studies assessed the impact of increasing amounts of wind generation on the QNI southerly stability limit set by the Sapphire to Armidale (SAPARM_8E) contingency and the Liddell to Muswellbrook contingency (LIDMUS_83). These two contingencies were selected as they typically represent the worst case contingencies north and south of Armidale. The QNI northerly stability limit was also assessed for a trip of Kogan Creek Power Station.

Figure 16 – Additional Wind Farm Capacity at Armidale 330 kV



The results showed that with lower amounts of wind farm generation the QNI southerly stability limit was set by the Sapphire to Armidale (SAPARM_8E) contingency. This was expected based on previous studies given the effect of pumping demand on reducing power transfers south of Armidale. As the wind farm capacity is increased so too is the power transfer south of Armidale. Eventually a point is reached where increasing generation further causes the QNI southerly limit to be set by the Liddell to Muswellbrook contingency (LIDMUS_83).

Amplitude found that with 1,575 MW of additional wind farm capacity the QNI southerly limit was 1,220 MW for both the SAPARM_8E and LIDMUS_83 contingencies (the crossover point), which is 120 MW higher than the scenario with no OMPS or wind farm generation at all. The QNI northerly stability limit also improved by 440 MW. As wind farm capacity increases above 1,575 MW the QNI southerly stability limit reduces.

These outcomes show OMPS can provide a significant improvement in renewable generation hosting capacity at or near Armidale during pumping periods. The maximum supportable demand (MSD) in New South Wales also increases by 795 MW, being the difference between the wind farm capacity and OMPS pumping demand, plus the additional 120 MW of southerly import capability into New South Wales on QNI.

4. Conclusion

The studies presented in this work demonstrate that OMPS should provide a valuable contribution to the stability of the power system. The plant offers substantial system strength, voltage control and inertia benefits and can do so irrespective of its mode of operation. This flexibility allows OMPS to support power system stability and improve generation hosting capacity independent of central dispatch processes.[13]

OMPS generally increases the QNI stability limits in the direction of flow most likely for given operating scenarios. It also provides an increase in the New South Wales maximum supportable demand of at least 700 MW[14] and should also increase the hosting capacity for other generation in the New England REZ by at least the maximum operating pumping demand.

[13] A synchronous condenser is not subject to security constrained economic dispatch limitations.
[14] For a 900 MW option.

5. References

[1] NSW Government, "Energy - New England REZ Geographic Area," December 2021. [Online]. Available: https://www.energy.nsw.gov.au/sites/default/files/2021-12/final-web-accessible-new-england-rez-boundary.pdf . [Accessed March 2022].

[2] NSW Government, "NSW Electricity Infrastructure Detailed Report," December 2020. [Online]. Available: https://www.energy.nsw.gov.au/sites/default/files/2020-12/NSW%20Electricity%20Infrastructure%20Roadmap%20-%20Detailed%20Report.pdf. [Accessed March 2022].

[3] AEMO, "2021 Victorian Annual Planning Report," October 2021. [Online]. Available: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2021/2021-victorian-annual-planning-report.pdf?la=en. [Accessed March 2022].

[4] Powerlink, "Powerlink Transmission Annual Planning Report 2021," November 2021. [Online]. Available: https://www.powerlink.com.au/sites/default/files/2021-11/Transmission%20Annual%20Planning%20Report%202021%20-%20Full%20report.pdf. [Accessed 14 December 2021].

[5] Powerlink, "Expanding NSW-QLD Transmission Transfer Capacity - Project Assessment Conclusion Report," 20 December 2019. [Online]. Available: https://www.powerlink.com.au/sites/default/files/2021-11/Expanding%20NSW-QLD%20Transmission%20Transfer%20Capacity%20Project%20Assessment%20Conclusions%20Report%20%28PACR%29%20-%20Full%20Report_0.pdf. [Accessed March 2022].

[6] AEMO, " Congestion Information Resource - Statistical Reporting Streams - Annual NEM Constraint Report 2021," 17 March 2022. [Online]. Available: https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2021/nem-constraint-report-2021-summary-data.xlsx?la=en. [Accessed March 2022].

[7] AEMO, "Congestion Information Resource - Statistical Reporting Streams," 2022. [Online]. Available: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams. [Accessed March 2022].

[8] AEMO, "2022 Integrated System Plan - Appendix 5 Network Investments.," 10 December 2021. [Online]. Available: https://aemo.com.au/-/media/files/major-publications/isp/2022/appendix-5-network-investments.pdf?la=en. [Accessed 14 December 2021].

OVEN MOUNTAIN
PUMPED HYDRO STORAGE

APPENDIX **B**

Amplitude Report

OMPS Benefit Assessment – System Strength and Inertia

Amplitude Consultants, July 2022

Oven Mountain Pumped Hydro Storage

Benefit Assessment – System Strength and Inertia

Amplitude Document Number:
PAU0250-REPT-002

Date of Issue:
28 July 2022

Revision:
Rev 0

This document has been carefully prepared for the exclusive use of Amplitude's Client, which is subject to and in accordance with the provisions of the contract between Amplitude and the Client. Amplitude accepts no liability or responsibility whatsoever for, or in respect of, any use of, or reliance upon, this report by any third party.

Revision History

Revision	Description	Prepared By	Approved By	Date
0	Initial Release	Alastair Pinkard	Adam Peard	28/07/2022

Address: Amplitude Consultants PTY LTD
Level 6, 15 Astor Terrace
Spring Hill QLD 4000
Australia

E-mail: info@amplitudepower.com

Phone: (07) 3905 9030

Website: https://amplitudepower.com/

Table of Contents

EXECUTIVE SUMMARY ..... **IV**

1. INTRODUCTION **1**

1.1. OVEN MOUNTAIN PUMPED HYDRO SCHEME 1
1.2. SYSTEM STRENGTH 2
1.3. INERTIA 4

2. SYSTEM STRENGTH STUDIES – APPROACH AND METHODOLOGY **4**

2.1. NEM POWER SYSTEM MODELS 4
2.2. OMPS 5
2.3. DETERMINING SYSTEM STRENGTH 6
2.3.1. AFL Calculation Methodology *6*
2.3.2. System Strength Nodes *7*
2.4. GENERATION 7
2.4.1. Synchronous Generation Profiles *8*
2.4.2. Asynchronous Generation *9*
2.4.3. Treatment of Battery Energy Storage Systems *9*
2.4.4. Contingencies *10*
2.5. SENSITIVITY TO SHORT CIRCUIT RATIO 10

3. INERTIA STUDIES – APPROACH AND METHODOLOGY **10**

4. STUDY FINDINGS **11**

4.1. SYSTEM STRENGTH 11
4.1.1. BESS Sensitivity *12*
4.1.2. SCR Sensitivity *13*
4.2. INERTIA 14

5. CONCLUSION **15**

6. REFERENCES **16**

APPENDIX A – MODELLED AUGMENTATIONS **18**

APPENDIX B – GENERATION ASSUMPTIONS **21**

APPENDIX C – AVAILABLE FAULT LEVEL RESULTS **24**

List of Figures

FIGURE 1 – INDICATIVE LOCATION OF OMPS WITHIN THE NEW SOUTH WALES TRANSMISSION NETWORK [2] 2
FIGURE 2 – OMPS INDICATIVE LAYOUT FOR 600 MW AND 900 MW CONFIGURATIONS 6

List of Tables

TABLE 1 – MINIMUM SYNCHRONOUS GENERATION PROFILES 8
TABLE 2 – IMPROVEMENT IN AVAILABLE FAULT LEVEL (MVA) AT ARMIDALE 330KV 11
TABLE 3 – IMPROVEMENT IN AVAILABLE FAULT LEVEL (MVA) AT ARMIDALE 330KV – BESS SENSITIVITY 13
TABLE 4 – IMPROVEMENT IN AVAILABLE FAULT LEVEL AT ARMIDALE 330KV – SCR SENSITIVITY 13
TABLE 5 – SYSTEM STRENGTH AND INERTIA BENEFITS OF OMPS. 15
TABLE 6 – MODELLED AUGMENTATIONS 18
TABLE 7 – ASYNCHRONOUS GENERATION ASSUMPTIONS 21
TABLE 8 – AVAILABLE FAULT LEVEL RESULTS 24
TABLE 9 – AVAILABLE FAULT LEVEL RESULTS – BESS SENSITIVITY 26
TABLE 10 – AVAILABLE FAULT LEVEL RESULTS – SCR SENSITIVITY 28

Executive Summary

Amplitude Consultants Pty Ltd (Amplitude) have been engaged by OMPS Pty Ltd (Client) to investigate the impact of the proposed Oven Mountain Pumped Storage Hydro (OMPS)[1] generating system on system strength and inertia. This work is part of a broader study supported by the Australian Renewable Energy Agency (ARENA) through their Advancing Renewables Program (ARP) to analyse the benefits that pumped hydro energy storage (PHES) would have on the development of the New England Renewable Energy Zone (REZ) in northern NSW.[2]

Understanding the potential impact of a large new PHES on system strength is important because it can significantly alter the outlook for inverter-connected generation in the area. Similarly, the potential impact of a large new PHES on inertia is important from the viewpoint of improvement frequency stability for the wider NEM.

The intent of this study is not to show OMPS, or pumped hydro energy storage (PHES) in general, solves a particular problem and Amplitude is aware of existing committed and proposed augmentations that will alter the outcomes of this study. Rather, this study provides the opportunity to illustrate how a PHES impacts system strength which will influence the development of the New England REZ. The outcomes of this work may also help inform the ideal generation mix of other REZ's as the energy transitions matures.

System strength is best described as the ability of the network to maintain and control the voltage waveform at any location in the system during steady state operation and following a contingency. Higher system strength means that the network is less likely to be adversely impacted by a contingency on the network. System strength is commonly associated with hosting capacity of inverter connected asynchronous generation; however, it is also important to minimise the voltage disturbance resulting from the switching of network plant as well as the proper operation of certain protection systems. Amplitude have undertaken assessments of available fault level (AFL), as described in the System Strength Impact Assessment Guidelines[3], to quantify the benefits OMPS provides to system strength.

Inertia is best described as the ability of the frequency of the system to withstand disturbances such as sudden changes in the supply demand balance brought about by trips of loads or generators. In a system with higher inertia, the loss of a large load or generator will have a lower rate of change of frequency (RoCoF) and have more time for systems to act to counter the disturbance. Whereas system strength is a local phenomenon governed by the network topology and distance from synchronous sources, inertia is a system property that is largely independent of the connected network topology.

Historically system strength and inertia has been sourced from synchronous generation, predominantly baseload coal fired generating units. The operating profile of these units is changing as they are displaced by additional inverter-connected asynchronous generation. This is having the impact of declining system strength and inertia throughout the NEM and progressive changes to the

[1] Further information on OMPS can be found at https://www.ompshydro.com/project/
[2] https://www.ompshydro.com/news/pumped-hydro-plant-could-unlock-new-england-rez/4
[3] https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2018/final_determination_ssiag_published.pdf

National Electricity Rules are now being implemented to maintain minimum levels of system strength and inertia going forward.

OMPS is a proposed PHES planned for connection near Armidale in northern New South Wales. The Client is currently considering two options including a 600 MW generating system connected at 132 kV and a 900 MW generating system connected at 330 kV. Whilst preliminary connection arrangements have been developed for both options, the final connection will likely be influenced by the scope of transmission development for the New England REZ. For these studies OMPS was connected through appropriate transformation to the 132 kV and 330 kV busses at Armidale for the 600 MW and 900 MW options, respectively.

The contribution of OMPS leads to significant increases in the system strength at the Armidale 330 kV bus. Under system normal, and under contingency conditions, the available fault level (AFL) is increased by up to 2,350 MVA for the 900 MW configuration. The increase of the 600 MW configuration is approximately 1,300 MVA, reduced not only due to the lower capacity but also due to the additional impedance of the 330/132 kV transformers. This translates to an increase in hosting capacity for new asynchronous generation of around 450 MW for the 600 MW configuration and around 800 MW for the 900 MW configuration.

From an inertia perspective, OMPS can provide a contribution of 2,100 MWs for the 600 MW configuration and 3,150 MWs for the 900 MW configuration. These contributions remain unchanged by the network topology.

To address system strength and inertia shortfalls in South Australia, ElectraNet installed four synchronous condensers under the Main Grid System Strength (MGSS) project, with an approved expenditure over $180 million.[4] Each of these synchronous condensers has a nameplate rating of 129 MVA and a fault level contribution of 575 MVA at 275 kV, and an inertia contribution, thanks to the addition of flywheels, of 1,100 MWs.

Comparing OMPS with the MGSS synchronous condensers, OMPS is able to provide the equivalent benefit to system strength of (just over) two synchronous condensers for the 600 MW configuration and the equivalent of four synchronous condensers for the 900 MW configuration. With respect to the inertia contribution, OMPS can provide the equivalent benefit to system strength of approximately two synchronous condensers for the 600 MW configuration and approximately three synchronous condensers for the 900 MW configuration.

As well as providing these benefits whilst generating or pumping, OMPS will be able to operate in synchronous condenser mode and continue to provide the same contribution to system strength and inertia whilst not dispatched in the market. This has the potential to avoid costly capital expenditure to construct additional synchronous condensers or other remediation measures that might otherwise be required by providing future options for non-network services.

[4] https://www.aer.gov.au/system/files/AER%20-%20Final%20Decision%20-%20ElectraNet%20-%20SA%20system%20strength%20contingent%20project%20-%2016%20August%202019.pdf

1. Introduction

Amplitude Consultants Pty Ltd (Amplitude) have been engaged by OMPS Pty Ltd (Client) to investigate the impact on system strength, inertia and network stability of the proposed Oven Mountain Pumped Storage Hydro (OMPS) generating system. This work is part of a broader study supported by the Australian Renewable Energy Agency (ARENA) through their Advancing Renewables Program (ARP) to analyse the benefits that Pumped Hydro Energy Storage (PHES) would have on the development of the New England Renewable Energy Zone (REZ) in northern NSW. Amplitude have been engaged to assist with two major components of this work involving a:

- Network stability benefits study; and
- System strength and inertia benefits study.

This report documents the outcomes from the system strength and inertia study. A separate report has also been prepared to quantify the Network Stability benefits [1].

1.1. Oven Mountain Pumped Hydro Scheme

OMPS is located in the Armidale Regional Local Government Area, approximately 60 km southeast of Armidale and 70 km northwest of Kempsey, via the Kempsey-Armidale Road. The project is bordered by the Macleay River to the west and Carrai Tablelands to the east. Oxley Wild Rivers National Park, Carrai National Parks and Carrai Conservation Area surround the property, with the New England National Park approximately 1 km to the north-west. Figure 1 shows the location of OMPS with respect to the surrounding transmission network and the New England REZ.

Figure 1 – Indicative Location of OMPS within the New South Wales transmission network [2]

The Client is currently considering two options including a 600 MW generating system likely connected at 132 kV and a 900 MW generating system connected at 330 kV. Whilst preliminary connection arrangements have been developed for both options, the final connection will likely be influenced by the scope of transmission development for the New England (REZ). For the purpose of the studies in this report OMPS was connected directly to the 132 kV and 330 kV bus at Armidale for the 600 MW and 900 MW options, respectively.

By the time OMPS is operational circa 2028 the transmission system and generating fleet will be different to that which exists today, and it will continue to evolve into the future. However, Amplitude considers the general trends shown in this report in relation to the impact of OMPS (a set of large synchronous machines injecting at Armidale) on available fault level and inertia should hold true going forward.

1.2. System Strength

System strength is best described as the ability of the system to maintain and control the voltage waveform at any location in the system during steady state operation and following a contingency [3]. System strength is dependent on the network topology and is assessed for both system normal and credible contingencies.

Historically, system strength has been provided by synchronous machines, initially by smaller localised generation and subsequently by larger, centralised generation connected by high capacity

transmission. As system strength is proportional to the three phase fault level at a network location, the synchronous fault level is often used as the metric for system strength. This is the minimum three phase fault levels, as specified in the National Electricity Rules (NER) Clause 5.20C [4].

As well as the minimum fault level, it is also necessary to consider the ability of inverter-connected asynchronous generation to operate stably and not impact on other nearby generation. Whilst electromagnetic transient (EMT) analysis is required to confirm the requirements for stable operation and interactions with nearby plant, this is resource intensive and presently requires the use of agreed generator models to accurately model the generator in the power system.

For longer term projections, it is considered appropriate to use a high level methodology such as the Weighted Short Circuit Ratio (WSCR) or Available Fault Level (AFL) to quantify the minimum requirements. Amplitude consider that the AFL calculation is more suitable as it uses the network models, rather than judgement, to assess the impact of one plant on a nearby, or even remote, network location.

The intent of this study is not to show OMPS, or pumped hydro energy storage (PHES) in general, solves a particular problem and Amplitude is aware of existing committed and proposed augmentations that will alter the AFL identified in this report. Rather, this study provides the opportunity to illustrate how a PHES impacts AFL which will influence the development of the New England REZ. The outcomes of this work may also help inform the ideal generation mix of other REZ's as the energy transitions matures.

It is already well known that the rapid uptake of inverter based generation resources (IBR) is displacing large synchronous machines leading to a progressive decline in system strength and voltage control capability. This can affect the stability of some existing IBR that are reliant on relatively strong grid voltage signals to function correctly and presents challenges to the connection of more IBR plant. Declining power system inertia is also problematic too and leads to a higher rate of change of system frequency during certain contingency events.

Whilst new 'grid forming' IBR technology has been shown to assist with managing system strength and inertia issues, such technology is not commonly installed to provide the long duration (> 8 hours) storage requirements being sought by the New South Wales Government in the NSW Electricity Infrastructure Roadmap [5]. PHES on the other hand is a well proven form of long duration energy storage and can provide excellent system strength and instantaneous inertial support, irrespective of its operating point.

Understanding the potential impact of a large new PHES on system strength and inertia is important because it could significantly impact the development of not only the New England REZ, but the wider NEM.

To quantify the benefits that OMPS can provide to system strength, Amplitude has assessed the improvement to AFL that OMPS can provide in both the 600 MW, 132 kV connected and 900 MW, 330 kV connected configurations. This has then been compared with the number of synchronous condensers with flywheels required to deliver the same benefit.

1.3. Inertia

Inertia is best described as the ability of the frequency of the system to withstand disturbances such as sudden changes in the supply demand balance brought about by trips of loads or generators. In a system with higher inertia, the loss of a large load or generator will have a lower rate of change of frequency (RoCoF) and have more time for systems to act to counter the disturbance [6]. As with system strength, inertia is currently sourced from synchronous machines.

Whereas system strength is a local phenomenon, inertia is a regional proposition. With the NEM in an intact operating state, there are two 'islands' where the minimum inertia online is considered, the mainland region (QLD, NSW, VIC and SA) and Tasmania. However, when there is an outage or other conditions that mean that there is a risk of islanding of a region, or when a region is operating as an island, minimum inertia requirements are put in place to ensure that the frequency in that region can be controlled following a disturbance on that network.

The 2021 System Strength, Inertia and NSCAS report [7] identifies that no shortfall is declared in New South Wales as it is unlikely to island. The report also notes that there is a projected decline in the inertia in the region with the projections for Inertia in the NSW region dropping below the secure operating level by 2026-27 following the withdrawal of Eraring Power Station.

From an inertia perspective, the intent of this study is not to show OMPS, or pumped hydro energy storage (PHES) in general, solves a particular problem and Amplitude is aware that the introduction of a very fast ancillary service market by 2023 will change the requirements as these markets develop. Rather, this study provides the opportunity to illustrate how a PHES impacts inertia which will influence the development of the New England REZ and the wider NEM. The outcomes of this work may also help inform the ideal generation mix of other REZ's as the energy transitions matures.

To quantify the benefits that OMPS can provide to inertia, Amplitude assessed the inertia that OMPS can provide in both the 600 MW, 132 kV connected and 900 MW, 330 kV connected configurations. This has then been compared with the number of synchronous condensers with flywheels required to deliver the same benefit.

2. System Strength Studies – Approach and Methodology

2.1. NEM Power System Models

Amplitude uses the NEM power system models for fault studies to quantify the impact OMPS can provide on system strength. NEM PSSE models of the existing network were provided by the Client and initially used by Amplitude to benchmark the minimum generation profiles against the existing system strength requirements for the Armidale node to confirm the methodology was sound [7].

As part of the wider benefits study of OMPS, the Client has engaged Ernst and Young (EY) to perform long term market modelling to investigate the impact OMPS has on transmission network power transfers and network constraints as well as marginal loss factors in the vicinity of the plant [8]. As an outcome of the market modelling, the Client, through EY, has provided NEM PSSE steady state power system models representing the transmission network in 2030-31, including the OMPS machines.

A summary of the transmission network projects included in the 2030-31 model follows:

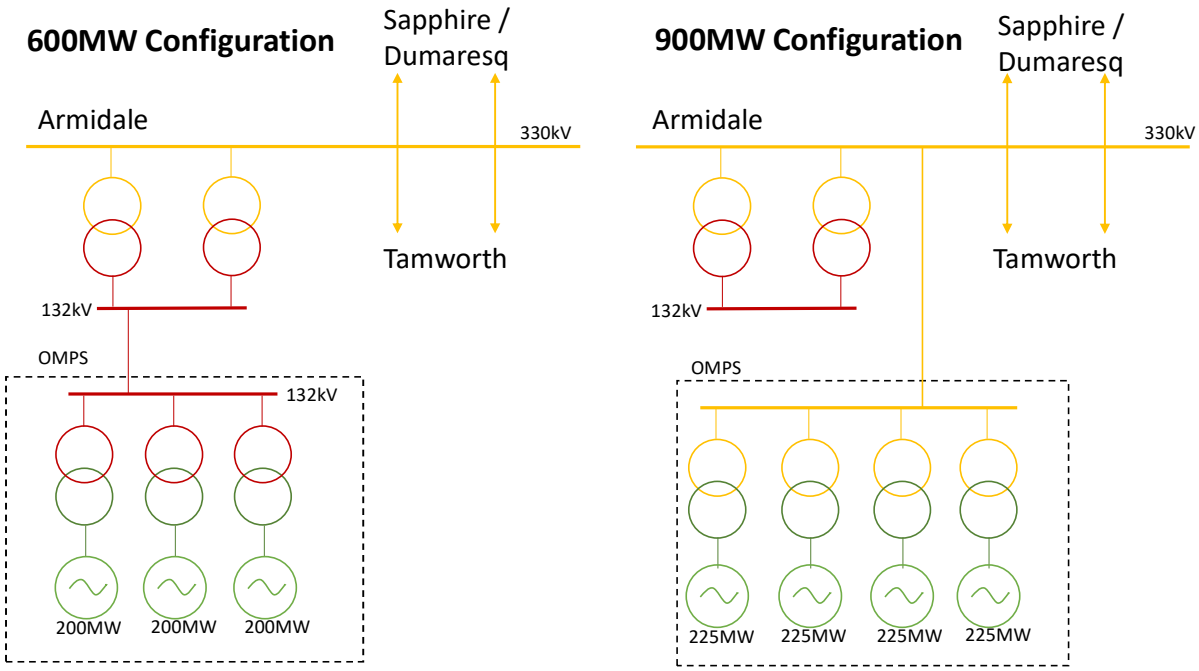
- QNI Minor.
- Western Victoria Stage 1.
- VNI SIPS.
- VNI Minor.
- Northern Queensland REZ Stage 1.
- Central-West Orana REZ Transmission Link.
- Project EnergyConnect.
- South West NSW voltage stability improvement.
- Western Victoria stage 2.
- HumeLink.
- New England REZ.
- MarinusLink Stage 1.
- Reinforcing Sydney, Newcastle and Wollongong Supply (Sydney Loop).
- Gladstone grid reinforcement.

These augmentations are based upon the 2022 Draft ISP [9], with a summary of each of the augmentations provided in Appendix A – Modelled Augmentations.

2.2. OMPS

OMPS is modelled as both a 600 MW and 900 MW configuration. In scenarios where OPMS is assumed to be a 600 MW facility it is modelled with three 200 MW turbines connected via 132 kV transformers to the Armidale 132 kV bus as shown in Figure 2. Figure 2 also shows the 900 MW configuration with OMPS modelled with four 225 MW turbines connected to the Armidale 330 kV bus. Whilst in practice OMPS will be connected to the national grid via some length of connection assets possibly with other enabling network augmentations, the scope of the connection assets and potential enabling works is not known and a direct connection to Armidale is considered appropriate for the analysis undertaken.

Figure 2 – OMPS indicative layout for 600 MW and 900 MW configurations



2.3. Determining System Strength

Amplitude applied the methodology for Preliminary Assessment defined in the System Strength Impact Assessment Guidelines [10], assessing the system strength by calculating the Available Fault Level (AFL) at a number of key network locations ('nodes') under both intact and contingency conditions. The AFL calculations carried out to determine system strength consider the minimum number of synchronous machines online [10], the assumptions for which are discussed in Section 2.4.1.

Amplitude have used a short circuit ratio (SCR) of three in the methodology detailed in 2.3.1. An SCR of three is considered appropriate for the when the minimum SCR withstand capability of the asynchronous generating system is not known, however Amplitude have undertaken a sensitivity to the SCR, discussed further in Section 2.5.

2.3.1. AFL Calculation Methodology

To calculate the AFL, two sets of fault studies are required for each result.

The first fault study is to calculate the synchronous fault level ('s_sg') at the nodes. This is done by applying the minimum synchronous generation profile for the regions. All other synchronous plant out of service, excluding contracted or network synchronous condensers, are switched out of service. Asynchronous plant, DC systems and system voltage control devices such as SVC's, are converted to negative loads so as not to influence the calculation.

The second fault study is to calculate the total fault level ('s_total') at the nodes. For this study, the synchronous generation is treated the same as the synchronous fault level calculation, with the minimum generation profile applied. DC systems and system voltage control devices are also treated the same and converted to negative loads. The difference for the total fault level calculation is how asynchronous plant is modelled, which is modelled as an in service machine with a sub-transient reactance (Xd'') that results in an effective fault level contribution of the plant equal to the short circuit ratio multiplied by the plant rating at the point of connection. The equation to calculate the sub-transient reactance is shown in Equation 1.

Equation 1 – Sub-Transient Reactance

$$X_d'' = {}^{S_{base}}/_{SCR \times P}$$

Where S_{base} is the power system fault level base, *SCR* is the short circuit ratio, and *P* is the plant rating at the point of connection.

For each node and system condition, the AFL is calculated as the difference between the total fault level and the synchronous fault level, subtracted from the synchronous fault level, as shown in Equation 2**Error! Reference source not found.**.

Equation 2 – Available Fault Level Calculation

$$\Delta\,(MVA) = S_{total} - S_{sg}$$
$$AFL(MVA) = S_{sg} - \Delta$$
$$\therefore AFL\,(MVA) = S_{sg} - (S_{total} - S_{sg})$$
$$\therefore AFL\,(MVA) = 2 \times S_{sg} - S_{total}$$

2.3.2. System Strength Nodes

Amplitude has selected Armidale 330 kV node as this is an existing system strength node defined by AEMO [7]. The existing minimum fault level requirements for Armidale, as specified by AEMO, were used to benchmark the generation profiles and power system models used for the AFL calculations to ensure the methodology applied was sound.

The AFL at Armidale and several nodes in the area around OMPS were determined. The nodes were selected to provide a reasonable indication of the benefits OPMS offers to the wider area around Armidale.

2.4. Generation

To undertake the system strength assessments, it is necessary to model the generation as it would be in 2030-31. EY have undertaken market modelling considering the augmentations in Section 2.1 and generation retirements as identified in the 2022 ISP [11] and determined an optimised new entrant

generation plant schedule. Amplitude used the 3030-31 power system models including the modelled augmentations and generation planting from EY in calculating the AFL.

2.4.1. Synchronous Generation Profiles

The AFL calculation is undertaken with the number of synchronous generating units reduced to the minimum levels, defined in the 2020 System Strength and Inertia (SSI) Report as a minimum of seven large units in the New South Wales region [12]. All other synchronous units in the area are switched off on the basis that the asynchronous generation provides the energy required to meet the load.

Whilst no minimum combinations are developed in the SSI Report, Amplitude has developed ten profiles in Table 1 for the purpose of this assessment. It is important to note that whilst the generation profiles are reasonably representative of the minimum as it is currently defined, the synchronous fault level at Armidale is significantly higher due to the augmentations described in Section 2.1. The seven generating unit minimum requirement remains in place despite this increase at Armidale, noting this is the minimum for the entire NSW system.

Table 1 – Minimum Synchronous Generation Profiles

Profile	Vales Point	Mt Piper	Bayswater	Eraring
1	2	2	3	0
2	1	2	4	0
3	2	1	4	0
4	2	2	3	0
5	2	1	2	2
6	1	2	2	2
7	1	1	3	2
8	1	1	3	2
9	1	1	2	3
10	1	1	2	3

Eraring is an announced retirement by 2025 [11] and Vales Point is expected to retire by 2029. When that happens, it is not possible to maintain the minimum of seven large units in the New South Wales region. Whilst it is possible to restore the minimum seven unit requirement through installation of additional fictitious synchronous condensers, Amplitude have instead assumed the generation does not retire as means of maintaining the minimum of seven large units. This is considered appropriate as the purpose of this study is to undertake a comparison of the network with and without OMPS.

Amplitude tested the contribution of generation in Queensland and found that it was able to influence the synchronous fault level at Armidale. As such, a profile was generated for Queensland as well which included four Gladstone machines, two Stanwell machines, one Callide (B or C) machine, one Millmerran machine and three Tarong machines, consistent with the 2020 System Strength and Inertia Report [12]. Additional new entrant gas generation in Central Queensland and Victoria that was

identified in the market modelling (refer Section 2.4) has not been considered in the AFL calculations as it does not form part of the minimum synchronous generation profiles.

The contribution of synchronous generation in the remainder of the NEM (Tasmania, Victoria and South Australia regions) was found in significant for AFL calcs at Armidale so synchronous generation remained unchanged in these regions.

2.4.2. Asynchronous Generation

Amplitude used the power system models provided by the Client, including the asynchronous generation planting and augmentations expected at 2030-31 developed by EY for this study. The Client provided three cases, each providing 2 GW of storage to meet the NSW Electricity Infrastructure Roadmap [5]. Case 1 is the base case, with no OMPS, and the balance of storage modelled as long duration BESS in New South Wales. Case 2 is modelled with OMPS at 600 MW connected to the 132 kV network, and 600 MW less battery energy storage than case 1 in the remainder of New South Wales. Case 3 is modelled with OMPS at 900 MW connected to the 330 kV network, and 900 MW less battery energy storage than case 1 in the remainder of New South Wales.

As the generation in Queensland was able to influence the fault levels at Armidale it was included in the assessment. Appendix B – Generation Assumptions provides a summary of all generation considered in service for the AFL calculations.

Asynchronous generation contribution in the remainder of the NEM (Tasmania, Victoria and South Australia regions) was found insignificant for AFL calcs at Armidale so asynchronous generation remained unchanged in these regions.

2.4.3. Treatment of Battery Energy Storage Systems

Presently, many inverter connected systems use grid-following inverters, which require a reasonably stable voltage profile to function correctly. Battery energy storage systems (BESS) are progressively moving towards use of grid-forming technologies that do not require a stable voltage waveform to operate, and as such do not require a minimum level of system strength.

Amplitude has accounted for this by undertaking two sensitivities, one of which assumes all BESS use grid forming technology and the other grid following technology. This is expected to provide the boundary conditions, with the likely outcome being somewhere in the middle of these two studies.

For the grid-forming sensitivity the BESS are assumed to not require remediation and are converted to negative loads for the total fault level component of the AFL calculation. For the grid following BESS sensitivity the BESS are modelled as a machine with a reactance the same as the wind and solar PV generation.

Whilst the installation of grid-forming inverters for variable renewable energy such as wind and solar PV may form part of the consideration of system strength requirements and remediation in future, Amplitude consider that the scenarios developed present reasonable outcomes for the likely impact of BESS on the network.

2.4.4. Contingencies

When undertaking the system strength assessment, it is important to consider a range credible contingencies, with the contingency that results in the lowest system strength being the most critical contingency. Each contingency is applied by removing an element from service in turn and assessing the impact on the system strength at all monitored nodes. As the system strength is a function of the network topology, there may be different critical contingencies for each monitored node.

The contingencies applied are as follows:

- System normal (no contingency);
- Armidale – Dumaresq 330 kV feeder;
- Armidale 330/132 kV transformer;
- Armidale 500/330 kV transformer;
- Armidale – Sapphire 330 kV feeder;
- Armidale – Tamworth 330 KV feeder;
- Bayswater - East of Tamworth 500 kV feeder;
- Bayswater – Eraring 500 kV feeder;
- Bayswater – Wollar 500 kV feeder;
- Armidale - East of Tamworth 500 kV feeder;
- Tamworth – East of Tamworth 330 kV feeder;
- Liddell – Muswellbrook 330 kV feeder;
- Liddell – Tamworth 330 kV feeder;
- Muswellbrook – Tamworth 330 kV feeder; and
- OMPS Unit 1.

2.5. Sensitivity to Short Circuit Ratio

Amplitude has undertaken the primary assessment assuming a short circuit ratio (SCR) of three for all asynchronous plant, consistent with the System Strength Impact Assessment Guidelines when the minimum SCR withstand capability of the asynchronous generating system is not known [10].

A SCR of three is considered a conservative assessment based on the level at which control system interactions may be observed, necessitating Full Impact Assessment under the Guidelines [10]. Amplitude is aware that many generating systems can operate at lower SCRs with effective control system tuning.

To account for this, Amplitude has considered the benefits of OMPS with a lower SCR by undertaking a sensitivity with an SCR of two for asynchronous generation and compared the requirements with and without OMPS.

3. Inertia Studies – Approach and Methodology

OMPS consists of large hydro machines which will have a significant contribution to system inertia. To quantify the inertia benefits, Amplitude has compared the inertia contribution from OMPS, calculated

as the product of the inertia coefficient and rating, with the equivalent number of synchronous condensers that would be required to provide the same inertial benefit.

4. Study findings

4.1. System Strength

Using the available fault level calculation, Amplitude has assessed the benefits of OMPS to the system strength at a number of nodes across the network, with the full set of results shown in Appendix C – Available Fault Level Results.

A summary of the results in Appendix D are shown in Table 2, based on an SCR of three, and BESS grid-forming and not contributing to AFL. These results demonstrate that OMPS at 900 MW can improve the AFL at the Armidale 330 kV bus by approximately 2,350 MVA for all contingencies aside from those involving OMPS.

Table 2 – Improvement in Available Fault Level (MVA) at Armidale 330kV

Contingency	OMPS 600	OMPS 900
System Normal	1,250	2,350
Armidale – Dumaresq	1,250	2,350
Armidale 132 Tx	1,100	2,350
Armidale 500 Tx	1,225	2,350
Armidale – Sapphire	1,250	2,350
Armidale – Tamworth	1,225	2,350
Bayswater – E Tamworth	1,225	2,350
Bayswater - Eraring	1,250	2,375
Bayswater - Wollar	1,250	2,350
E-Tamworth - Armidale	1,225	2,350
E Tamworth - Tamworth	1,250	2,350
Liddell - Muswellbrook	1,225	2,350
Liddell – Tamworth	1,225	2,350
Muswellbrook – Tamworth	1,225	2,350
OMPS G1	900	1,725

Amplitude was surprised to find that the benefit that OMPS provides is less than expected. Further investigation revealed the main factors influencing this is a higher than expected impedance of the OMPS generator transformers in the power system model.

The improvement in AFL can be compared to the number of synchronous condensers (SynCon) required to achieve the same level of benefit that OMPS is shown to contribute. For example, each of the SynCon's installed as part of the ElectraNet Main Grid System Strength project [13] provide a

nominal fault level of 575 MVA at 275 kV. To achieve the same contribution to fault level as OMPS at 900 MW, four of these SynCon's would be required.

The improvement in AFL at Armidale 330 kV bus for the 600 MW configuration is approximately 1,300 MVA and would require two SynCon's to provide the same fault level benefit. This is reduced compared to the contribution of the 900 MW configuration due to the impedance of the 330/132 kV transformer and one less OMPS generating unit assumed in the 600 MW configuration.

An alternative way to assess the benefits that OMPS can provide is to look at the increase in hosting capacity brought about by the project. For example, if the synchronous fault level is 3,000 MVA and there is 3,000 MVA of asynchronous fault contribution, the resultant AFL with an SCR of three is zero, as can be seen in Equation 3.

Equation 3 – Example AFL Calculation 1

$$AFL = 2 \times 3000 - (3000 + 3000) = 0$$

Increasing the synchronous fault level by 2,350 MVA, and recalculating the AFL, increases the AFL from zero to 2,350 MVA, as shown in Equation 4.

Equation 4 – Example AFL Calculation 2

$$AFL = 2 \times 5350 - (5350 + 3000) = 2350$$

Based on a SCR of three consistent with the guidelines [10], the hosting capacity for asynchronous generation is increased by circa 800 MVA for the 900 MW configuration. Reducing the SCR to two, the hosting capacity for asynchronous generation can be increased by circa 1,200 MVA.

4.1.1. BESS Sensitivity

For the results in Section 4.1, Amplitude has assumed that BESS are connected by grid-forming inverters, and no additional remediation is required for the BESS. For this sensitivity, the BESS is assumed to be grid-following and there is an additional system strength impact.

The results in Table 3 show that there is no impact to the AFL at the Armidale 330 kV bus with the BESS modelled as grid forming or grid following. In both cases OMPS is still able to provide a benefit of circa 2,350 MVA to the system strength at Armidale 330 kV in the 900 MW option.

The full set of results are available in Table 9 in Appendix D. Notably, there is a significant impact to the AFL at Bayswater, Eraring and Wollar as a result of the BESS planted near these locations.

Table 3 – Improvement in Available Fault Level (MVA) at Armidale 330kV – BESS Sensitivity

Contingency	Grid Forming BESS		Grid Following BESS	
	OMPS 600	OMPS 900	OMPS 600	OMPS 900
System Normal	1,250	2,350	1,250	2,350
Armidale – Dumaresq	1,250	2,375	1,250	2,350
Armidale 132 Tx	1,100	2,350	1,100	2,350
Armidale 500 Tx	1,225	2,350	1,225	2,325
Armidale – Sapphire	1,250	2,375	1,250	2,350
Armidale – Tamworth	1,225	2,350	1,225	2,325
Bayswater – E Tamworth	1,225	2,350	1,225	2,350
Bayswater - Eraring	1,250	2,375	1,250	2,375
Bayswater - Wollar	1,250	2,350	1,250	2,350
E-Tamworth - Armidale	1,225	2,350	1,225	2,350
E Tamworth - Tamworth	1,250	2,350	1,250	2,350
Liddell - Muswellbrook	1,225	2,350	1,225	2,350
Liddell – Tamworth	1,225	2,350	1,225	2,325
Muswellbrook - Tamworth	1,225	2,350	1,225	2,350
OMPS G1	900	1,725	900	1,725

4.1.2. SCR Sensitivity

Amplitude has tested the benefits of OMPS assuming that the asynchronous generation is able to operate reliably at a with a short circuit ratio (SCR) of two, reduced from the value of three specified in the guidelines [10]. The results in Table 4 show that reducing the SCR does not impact the benefits of OMPS at the Armidale 330 kV bus. The benefit of OMPS remains largely unchanged at around 2,350 MVA, however in this context the SCR of two means that the 900 MW configuration increases the hosting capacity by around 1,200 MVA.

There is also a significant increase in the AFL at Wollar and Bayswater due to decreasing the SCR, with the full set of results shown in Table 10 of Appendix D. This is to be expected as these nodes are close to the Central-West ORANA REZ, where there is a significant amount of renewable generation.

Table 4 – Improvement in Available Fault Level at Armidale 330kV – SCR Sensitivity

Contingency	Grid Forming BESS		Grid Following BESS	
	OMPS 600	OMPS 900	OMPS 600	OMPS 900
System Normal	1,250	2,350	1,200	2,375
Armidale – Dumaresq	1,250	2,375	1,200	2,375
Armidale 132 Tx	1,100	2,350	1,050	2,375
Armidale 500 Tx	1,225	2,350	1,175	2,350
Armidale – Sapphire	1,250	2,375	1,200	2,375

Contingency	Grid Forming BESS		Grid Following BESS	
	OMPS 600	OMPS 900	OMPS 600	OMPS 900
Armidale – Tamworth	1,225	2,350	1,175	2,350
Bayswater – E Tamworth	1,225	2,350	1,175	2,375
Bayswater - Eraring	1,250	2,375	1,200	2,375
Bayswater - Wollar	1,250	2,350	1,200	2,375
E-Tamworth - Armidale	1,225	2,350	1,175	2,350
E Tamworth - Tamworth	1,250	2,350	1,200	2,375
Liddell - Muswellbrook	1,225	2,350	1,175	2,350
Liddell – Tamworth	1,225	2,350	1,175	2,350
Muswellbrook - Tamworth	1,225	2,350	1,175	2,350
OMPS G1	900	1,725	850	1,750

4.2. Inertia

Amplitude has quantified the benefits OMPS offers to system inertia by way of comparison with an equivalent number of synchronous condenser units.

Amplitude has been informed that the inertia constant of each OMPS machine is 3.5. Calculating the contribution, the 600 MW configuration can provide approximately 2,100 MWs for the whilst the 900 MW configuration provides around 3,150 MWs.

By comparison, each of the four SynCon's installed as part of the ElectraNet Main Grid System Strength project [13] provide a nominal inertia of 1,100 MWs, or a total of 4,400 MWs. The 600 MW OMPS configuration therefore provides the equivalent inertia contribution of two of these SynCon's, whilst the 900 MW configuration provides the equivalent inertia contribution of three.

5. Conclusion

Amplitude has assessed the network benefits with respect to the system strength and inertia contribution that OMPS can provide in both the 600 MW and 900 MW configurations. These studies have found that the OMPS is able to improve the system strength at the Armidale 330 kV bus by 2,350 MVA. This would require four synchronous condensers similar to those installed by ElectraNet as part of the Main Grid System Strength Project (MGSS). That project, which included four synchronous condensers as well as land and substation works, cost over $180 million in August 2019 [13].

From an inertia perspective, the 900 MW OMPS configuration can provide up to 3,150 MWs of inertia, which is the equivalent of around three of the synchronous condensers installed by ElectraNet.

A summary of the benefits of OMPS for both system strength and inertia, as well as the number of equivalent MGSS synchronous condensers (SynCons) that would be required to provide the same benefit is provided in Table 5.

Table 5 – System Strength and Inertia Benefits of OMPS.

Configuration	System Strength	Equivalent SynCon	Inertia	Equivalent SynCon
OMPS 600 MW	1,300 MVA	2.2	2,100 MWs	2
OMPS 900 MW	2,350 MVA	4	3,150 MWs	3

As well as providing these benefits whilst generating or pumping, OMPS will be able to operate in synchronous condenser mode and continue to provide the same contribution to system strength and inertia whilst not dispatched in the market. This has the potential to avoid costly capital expenditure to construct additional synchronous condensers or other remediation measures that might otherwise be required by providing future options for non-network services.

The results show that OMPS is able to significantly increase the system strength around Armidale and the New England REZ, as well as increase the inertia in New South Wales and the wider NEM. The increase in system strength of up to 2,350 MVA translates to an increase in hosting capacity for new asynchronous generation of over 800 MVA.

6. References

[1] Amplitude Consultants, “Oven Mountain Pumped Hydro Storage - Benefit Assessment - Network Stability Study (PAU250-REPT-001 - Rev 2),” 2022.

[2] NSW Government, “Energy - New England REZ Geographic Area,” December 2021. [Online]. Available: https://www.energy.nsw.gov.au/sites/default/files/2021-12/final-web-accessible-new-england-rez-boundary.pdf . [Accessed March 2022].

[3] AEMO, “Energy Explained: System Strength,” 15 July 2020. [Online]. Available: https://aemo.com.au/en/learn/energy-explained/energy-101/energy-explained-system-strength. [Accessed 9 November 2021].

[4] AEMC, “National Electricity Rules,” January 2022. [Online]. Available: https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules.

[5] NSW Department of Planning, Industry and Environment, “NSW Electricity Infrastrucure Roadmap,” November 2020. [Online]. Available: https://www.energy.nsw.gov.au/sites/default/files/2020-11/NSW%20Electricity%20Infrastructure%20Roadmap%20-%20Overview_1.pdf. [Accessed 2022 July].

[6] AEMO, “Energy Explained - Energy 101 - Frequency Control,” July 2020. [Online]. Available: https://aemo.com.au/en/learn/energy-explained/energy-101/energy-explained-frequency-control. [Accessed July 2022].

[7] AEMO, “2021 System Security Reports: System Strength, Inertia and NSCAS,” December 2021. [Online]. Available: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2021/system-security-reports.pdf?la=en. [Accessed March 2022].

[8] Oven Mountain Pumped Hydro Storage, “OMPS New England PHES Benefits Study - Knowledge Sharing Interim Report,” April 2022. [Online]. Available: https://arena.gov.au/assets/2022/04/omps-ne-england-phes-benefits-study.pdf. [Accessed July 2022].

[9] AEMO, “2022 Integrated System Plan Draft - Appendix 5 Network Investments.,” 10 December 2021. [Online]. Available: https://aemo.com.au/-/media/files/major-publications/isp/2022/appendix-5-network-investments.pdf?la=en. [Accessed 14 December 2021].

[10] AEMO, “System Strength Impact Assessment Guidelines,” 1 July 2018. [Online]. Available: https://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-

Market-Frameworks-Review/2018/System_Strength_Impact_Assessment_Guidelines_PUBLISHED.pdf. [Accessed June 2022].

[11] AEMO, "2022 Integrated System Plan," 30 June 2022. [Online]. Available: https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en. [Accessed July 2022].

[12] AEMO, "2020 System Strength and Inertia Report," December 2020. [Online]. Available: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2020/2020-system-strength-and-inertia-report.pdf. [Accessed June 2022].

[13] AER, "Final Decision - ElectraNet Contingent Project - Main Grid System Strength," August 2019. [Online]. Available: https://www.aer.gov.au/system/files/AER%20-%20Final%20Decision%20-%20ElectraNet%20-%20SA%20system%20strength%20contingent%20project%20-%2016%20August%202019.pdf. [Accessed July 2022].

[14] AEMO, "2021 Inputs and assumptions workbook," 10 December 2021. [Online]. Available: https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-and-assumptions-workbook.xlsx?la=en. [Accessed 14 December 2021].

[15] AEMO, "Draft 2022 Integrated System Plan," December 2021. [Online]. Available: https://aemo.com.au/-/media/files/major-publications/isp/2022/draft-2022-integrated-system-plan.pdf?la=en.

[16] AEMC, "Efficient Management of System Strength on the Power System," October 2021. [Online]. Available: https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system. [Accessed March 2022].

[17] AEMO, "System Strength Requirements Methodology and System Strength Impact Assessment Guidelines amendments consultation," 30 May 2022. [Online]. Available: https://aemo.com.au/consultations/current-and-closed-consultations/ssrmiag. [Accessed July 2022].

Appendix A – Modelled Augmentations

The network augmentations modelled by EY are provided in Table 6. These network augmentations were applied to the NEM power system model in the cases provided by EY used for the AFL calculations.

Table 6 – Modelled Augmentations

Augmentation Planning Status	**Details**
QNI Minor Committed / Anticipated	• Uprating of Liddell-Muswellbrook, Muswellbrook-Tamworth and Liddell-Tamworth 330 kV lines. • Install -100/+350 MVAr static var compensators at each of the Dumaresq and Tamworth substations. • Install 240 MVAr, 330 kV shunt capacitor banks at each of the Dumaresq and Tamworth substations. • Install 220 MVAr, 330 kV shunt capacitor banks at Armidale substation.
Western Victoria Stage 1 Committed / Anticipated	Installation of wind monitoring equipment and minor upgrades to transmission equipment on 220 kV network between Bendigo and Red Cliffs and the Moorabool-Terang-Ballarat 220 kV lines.
VNI SIPS Committed / Anticipated	Operate South Morang–Dederang–Murray 330 kV lines to their 5-minute thermal rating following a credible contingency.
VNI Minor Committed / Anticipated	• Uprate South Morang–Dederang 330 kV line. • An additional new 500/330 kV transformer at South Morang. • Power flow controllers on Upper Tumut-Yass and Upper Tumut-Canberra 330 kV lines.
Northern Queensland REZ Stage 1 Committed / Anticipated	• Conversion of one side of the coastal 132 kV double-circuit transmission line (Woree – Tully - Yabulu South - Ross) to permanently operate at 275 kV, as the third transmission line between Ross and Woree substations. • Associated line reactor at the Woree Substation end. • Establishment of a 275 kV bus at Woree Substation. • Construction of a 275 kV bay at Ross Substation. • Installation of a 275/132 kV transformer at Tully Substation
Central-West Orana REZ Transmission Link Actionable	New transmission lines connecting to a 500 kV and 330 kV loop in the vicinity of the Central-West Orana REZ indicative location. EY's explicit implementation: • New substation at Orana with one 500/330 kV transformer • New 500 kV line from Wollar-Orana • New 330 kV line from Orana-Wellington • Cut in Wollar Substation to line 5A3 between Bayswater and Mt Piper.

Augmentation Planning Status	**Details**
Project EnergyConnect Committed / Anticipated	Both stage 1 and stage 2 combined: • A new 275 kV double circuit line between Robertstown to Bundey • A new 330 kV double circuit line between Bundey to Buronga • A new 220 kV double circuit line between Buronga to Red Cliffs • A new 330/275 kV substation and two 330/275 kV transformers at Bundey • A new 330/220 kV substation, two 330/220 kV transformers and two 330 kV phase shifting transformers at Buronga • A new 330 kV switching station at Dinawan • A new 330 kV double circuit line between Buronga to Dinawan • A new 500 kV double circuit line between Dinawan to Wagga Wagga, operating at 330kV initially • Turning the existing 275 kV line between Para and Robertstown into Tungkilo • Static and dynamic reactive plant at Bundey, Robertstown, Buronga, and Dinawan • special protection scheme to detect and manage the loss of either of the AC interconnectors connection to South Australia
South West NSW voltage stability improvement RIT-T PACR Completed	• Construction of a single circuit 330kV transmission line from Darlington Point to Dinawan. • Installation of new 330kV switchbays at Darlington Point and Dinawan substation.
Western Victoria stage 2 Committed / Anticipated	• A new 500/220 kV terminal station north of Ballarat with two new 1000 MVA 500/220 kV transformers. • A new 220 kV double-circuit transmission line from Bulgana Terminal Station to the new terminal station north of Ballarat (one circuit via Waubra Terminal Station). • A new 500 kV double-circuit transmission lines from Sydenham to a new terminal station north of Ballarat.
HumeLink Actionable	• New Wagga Wagga 500/330 kV substation and 330kV double-circuit connection to the existing Wagga Wagga 330kV substation. • New 500 kV transmission line between Maragle and Bannaby 500 kV substations, • New 500 kV transmission line between Maragle and new Wagga Wagga 500 kV substations • New 500 kV transmission line between new Wagga Wagga and Bannaby 500 kV substations. • Three 500/330 kV 1,500 MVA transformers at Maragle. • Two 500/330 kV 1,500 MVA transformers at new Wagga Wagga. • 500 kV Line shunt reactors at the ends of Maragle – Bannaby, Maragle – new Wagga Wagga and new Wagga Wagga – Bannaby 500 kV line.

Augmentation Planning Status	**Details**
New England REZ Actionable	• A new 500/330 kV substation with two 1,500 MVA transformers in locality of Armidale South. • A new 500/330 kV substation in locality of east of Tamworth. • A new 500 kV double-circuit line from locality of Armidale South to Bayswater via east of Tamworth. • A new 330 kV circuit from the locality of east of Tamworth to Tamworth. • A new 330 kV double-circuit line from a new substation in locality of Armidale South to Armidale. • Reconnect both Tamworth–Armidale 330 kV lines from Armidale to a new substation in locality of Armidale South. • 500 kV line shunt reactors at both ends of locality of Armidale South–locality of east of Tamworth and locality of east of Tamworth–Bayswater. • Power flow controllers on each of the Armidale-Tamworth 330 kV circuits. • A +/- 400 MVAr SVC at locality of east of Tamworth.
MarinusLink Stage 1 Actionable	Option 1: • A 750 MW monopole high voltage direct current (HVDC) link between Heybridge (near Burnie) in Tasmania and Hazelwood area in Victoria. • Construction of a new 220 kV switching station at Heybridge adjacent to the converter station. • Establishment of a new 220 kV switching station at Staverton. • Construction of a new double-circuit 220 kV alternative current (ac) transmission line from Staverton to Heybridge via Hampshire and Burnie. • Construction of a new double-circuit 220 kV AC transmission line from Palmerston to Sheffield. • A new 500 kV ac connection between HVDC converter station and Victorian transmission network in Hazelwood area. Brought forward from Option 2: • Construction of a new double-circuit 220 kV transmission Heybridge to Sheffield and the decommissioning single-circuit transmission line in this corridor.
Reinforcing Sydney, Newcastle, and Wollongong Supply (Sydney Loop) Actionable	Option 1 and option 2 combined: • A new 500 kV double-circuit line between Eraring substation and Bayswater substation. • A new 500 kV substation near Eraring. • Two 500/330 kV 1,500 MVA transformers at Eraring substation. • Establish 500/330 kV substation in the locality of South Creek. • A new 500 kV double-circuit line from the Bannaby substation to a new substation in the locality of South Creek. • Cut-in both Eraring – Kemps Creek 500 kV circuits at the new substation in the locality of South Creek.
Gladstone grid reinforcement Future	• New 275 kV double-circuit line between Calvale and Calliope River. • Rebuild Calliope River to Larcom Creek 275 kV as a double-circuit line. • Rebuild Larcom Creek to Bouldercombe 275 kV as a double-circuit line • with one line tapped at Raglan. • A new (third) 275/132 kV transformer at Calliope River.

Appendix B – Generation Assumptions

The new entrant generation planting schedule developed by EY and applied to the power system model for the purposes of the AFL calculations is provided in Table 7.

Table 7 – Asynchronous Generation Assumptions

Unit	Technology	Case 1	Case 2	Case 3
Avonlie Solar	Solar PV	200	200	200
Battery_8hr_CAN_Capital_2CAP330A	Battery 8hr	250	150	150
Battery_8hr_NCEN_Eraring_2EPS500A	Battery 8hr	400.1	500.1	500.1
Battery_8hr_NCEN_Wallerawang_2WWP330A	Battery 8hr	500	300	200
Battery_8hr_NCEN_Wollar_2WOL500A	Battery 8hr	500	300	100
Battery_8hr_SWNSW_Darlington Point_2DLP330A	Battery 8hr	350	150	150
GNNDHSF1	Solar PV	110	110	110
Hillston	Solar PV	85	85	85
Metz	Solar PV	115	115	115
New england_S1	Solar PV	400	400	400
OCGT_NSW_Bayswater_GT09_2BAY500A	OCGT	250	250	250
OCGT_NSW_Eraring_GT03_2EPS330A	OCGT	250	250	250
OCGT_NSW_Eraring_GT04_2EPS330A	OCGT	250	250	250
Riverina Solar Farm	Solar PV	32	32	32
Rye Park	Wind	400	400	400
Sebastapol	Solar PV	90	90	90
Snowy 2.0 gen	Pumped hydro	2000	2000	2000
Solar_FFP_NCEN_Central West Orana_2CRZ500A	Solar PV	500	500	500
Solar_FFP_NCEN_Wellington_2WEL330A	Solar PV	250	250	250
Solar_FFP_NCEN_Wollar_2WOL500A	Solar PV	250	250	250
Solar_FFP_NNS_Armidale_2ARM300A	Solar PV	100	100	100
Solar_FFP_NNS_Armidale_2ARM500A	Solar PV	250	250	250
Solar_SAT_NCEN_Central West Orana_2CRZ500A	Solar PV	600	600	600
Solar_SAT_NCEN_Wallerawang_2WWP330A	Solar PV	100	100	100
Solar_SAT_NCEN_Wellington_2WEL330A	Solar PV	250	250	250
Solar_SAT_NCEN_Wollar_2WOL500A	Solar PV	250	250	250
Solar_SAT_NNS_Armidale_2ARM300A	Solar PV	100	100	100
Solar_SAT_NNS_Dumeresq_2DMQ330A	Solar PV	200	200	200
Solar_SAT_NNS_Dungowan_2DUN500A	Solar PV	200	200	200
Solar_SAT_NNS_Tamworth_2TAM330A	Solar PV	450	450	450
Solar_SAT_SWNSW_Broken Hill_2BKH220A	Solar PV	150	150	150
SUNTPSF1	Solar PV	150	150	150
Tallawarra B	OCGT	316	316	316
Wagga Wagga Solar Farm	Solar PV	30	30	30

WAGGNSF1	Solar PV	55	55	55
Wallgrove battery gen	Battery	50	50	50
West Wyalong Solar Farm	Solar PV	90	90	90
Wind_CAN_Capital_2CAP330A	Wind	250	250	250
Wind_NCEN_Bayswater_2BAY500A	Wind	900	900	900
Wind_NCEN_Central West Orana_2CRZ500A	Wind	1200	1200	1200
Wind_NCEN_Wallerawang_2WWP330A	Wind	500	500	500
Wind_NCEN_Wellington_2WEL330A	Wind	950	950	950
Wind_NCEN_Wollar_2WOL500A	Wind	900	900	900
Wind_NNS_Armidale_2ARM300A	Wind	800	800	800
Wind_NNS_Armidale_2ARM500A	Wind	400	400	400
Wind_NNS_Dumeresq_2DMQ330A	Wind	500	500	500
Wind_NNS_Dungowan_2DUN500A	Wind	1000	1000	1000
Wind_NNS_Tamworth_2TAM330A	Wind	1000	1000	1000
Wyalong Solar Farm	Solar PV	53	53	53
Blue Grass Solar Farm	Solar PV	148	148	148
Clarke Creek Wind Farm_S1	Wind	450	450	450
Columboola Solar Farm	Solar PV	162	162	162
Dulacca Wind Farm	Wind	180	180	180
Edenvale Solar Park	Solar PV	146	146	146
Kaban Wind Farm	Wind	150	150	150
Kidston gen	Pumped hydro	250	250	250
MacIntyre_S1	Wind	500	500	500
Moura	Solar PV	85	85	85
Solar_FFP_SWQ_Bulli Creek_4BUL330A	Solar PV	200	200	200
Solar_SAT_CQ_Bouldercombe_4BOU275A	Solar PV	400	400	400
Solar_SAT_CQ_Calvale_4CVL275A	Solar PV	300	300	300
Solar_SAT_CQ_Gladstone_4GLD275A	Solar PV	400	400	400
Solar_SAT_CQ_Larcom Creek_4LAR275A	Solar PV	400	400	400
Solar_SAT_NQ_Strathmore_4STR_S1	Solar PV	300	300	300
Solar_SAT_SWQ_Braemar_4BRA330A	Solar PV	200	200	200
Western Downs Solar Farm	Solar PV	400	400	400
Wind_CQ_Broadsound_4BRD275A	Wind	1150	1150	1150
Wind_CQ_Calvale_4CVL275A	Wind	900	900	900
Wind_CQ_Raglan_4RAG275A	Wind	400	400	400
Wind_NQ_Chalumbin_4CHA275A	Wind	1100	1100	1100
Wind_NQ_Nebo_4NEB_SV1	Wind	100	100	100
Wind_NQ_Ross_4ROS_SV1	Wind	200	200	200
Wind_SEQ_Woolooga_4WOL275A	Wind	100	100	100
Wind_SWQ_Columboola_4COU275A	Wind	1800	1800	1800
Wind_SWQ_Middle Ridge_4MID330E	Wind	200	200	200

Wind_SWQ_Tarong_4TNG275A	Wind	100	100	100
Wind_SWQ_Western Downs_4WEE275B	Wind	1300	1300	1300
Woolooga Solar Farm	Solar PV	176	176	176

Appendix C – Available Fault Level Results

The available fault level results are shown in Table 8, with all monitored nodes in the rows, and the contingencies in the columns.

Table 8 – Available Fault Level Results

Nodes	OMPS Configuration	System Normal	Armidale – Dumaresq	Armidale 132 Tx	Armidale 500 Tx	Armidale – Sapphire	Armidale – Tamworth	Bayswater – E Tamworth	Bayswater - Eraring	Bayswater - Wollar	E-Tamworth - Armidale	E Tamworth - Tamworth	Liddell - Muswellbrook	Liddell – Tamworth	Muswellbrook - Tamworth	OMPS G1
Armidale 132	-	1527	1466	1149	1407	1471	1456	1233	1474	1461	1359	1507	1421	1414	1421	1527
	600	2868	2813	2509	2749	2818	2799	2574	2832	2804	2704	2847	2756	2755	2762	2393
	900	2227	2196	1502	2149	2201	2182	2034	2191	2174	2112	2210	2154	2149	2154	2105
Armidale 330	-	-3001	-2924	-2958	-2478	-2872	-2588	-4024	-3166	-3073	-3071	-3050	-3399	-3443	-3425	-3001
	600	-1763	-1685	-1855	-1253	-1633	-1362	-2795	-1921	-1834	-1841	-1811	-2164	-2209	-2190	-2105
	900	-645	-563	-603	-139	-510	-245	-1675	-794	-715	-722	-695	-1050	-1095	-1076	-1267
Bayswater 500	-	-1614	-1925	-1612	-1538	-1918	-1606	-85	-1807	390	-1368	-1455	-1454	-1442	-1449	-1614
	600	-224	-458	-413	-226	-452	-233	1178	-439	1773	-50	-94	-29	-16	-24	-579
	900	1208	1035	1208	1105	1042	1161	2449	977	3199	1289	1313	1421	1434	1425	651
Bayswater 330	-	5275	5054	5274	5288	5058	5263	5475	5099	5542	5301	5219	5908	5962	5938	5275
	600	6273	6110	6142	6261	6114	6209	6481	6107	6543	6274	6221	6821	6868	6848	6020
	900	7301	7187	7298	7242	7192	7172	7481	7146	7572	7258	7251	7757	7797	7781	6920
Dumaresq 330	-	1185	824	1184	1048	708	1100	885	1136	1118	1006	1167	1078	1075	1082	1185
	600	1490	950	1452	1380	833	1421	1251	1448	1431	1344	1475	1405	1401	1407	1414
	900	1885	1135	1883	1802	1018	1833	1705	1850	1831	1770	1871	1819	1816	1821	1773
	-	6218	6038	6216	6217	6042	6208	6486	7220	6520	6226	6226	6312	6328	6326	6218

Nodes	OMPS Configuration	System Normal	Armidale – Dumaresq	Armidale 132 Tx	Armidale 500 Tx	Armidale – Sapphire	Armidale – Tamworth	Bayswater – E Tamworth	Bayswater - Eraring	Bayswater - Wollar	E-Tamworth - Armidale	E Tamworth - Tamworth	Liddell - Muswellbrook	Liddell – Tamworth	Muswellbrook - Tamworth	OMPS G1
Eraring 500	**600**	7055	6926	6948	7018	6930	7030	7263	7800	7360	7027	7056	7155	7167	7166	6843
	900	7940	7854	7937	7847	7859	7886	8058	8434	8245	7858	7935	8032	8042	8040	7629
Liddell 330	**-**	5325	5117	5324	5337	5121	5307	5451	5182	5520	5340	5240	5992	6049	6024	5325
	600	6268	6115	6146	6260	6119	6195	6416	6134	6468	6264	6186	6837	6885	6865	6029
	900	7242	7135	7239	7193	7140	7100	7377	7117	7443	7200	7160	7705	7746	7731	6883
Muswell-brook 330	**-**	4974	4870	4972	4979	4873	4929	4919	4874	4946	4949	4828	1364	5140	5322	4974
	600	5491	5417	5427	5494	5421	5410	5469	5396	5469	5464	5345	1448	5640	5683	5361
	900	6050	6003	6047	6037	6007	5921	6040	5961	6030	6009	5901	1576	6175	6075	5864
Sapphire 330	**-**	1827	1674	1826	1689	1057	1741	1523	1775	1760	1646	1810	1720	1715	1722	1827
	600	2132	1896	2093	2019	1107	2061	1886	2089	2073	1982	2117	2045	2040	2046	2055
	900	2538	2200	2536	2450	1199	2483	2348	2502	2484	2418	2524	2469	2465	2470	2419
Tamworth 330	**-**	-1525	-1690	-1522	-1565	-1680	-1021	-2352	-1668	-1583	-1620	-1208	-1921	-1967	-1953	-1525
	600	-660	-790	-766	-671	-781	-344	-1387	-792	-714	-719	-595	-1109	-1160	-1143	-884
	900	263	162	263	262	171	375	-368	142	210	224	80	-232	-288	-268	-99
Wollar 500	**-**	-6795	-6926	-6797	-6788	-6922	-6805	-6501	-6977	-7082	-6780	-6777	-6754	-6744	-6743	-6795
	600	-6201	-6286	-6279	-6220	-6282	-6219	-5956	-6341	-6696	-6211	-6190	-6148	-6141	-6141	-6353
	900	-5575	-5629	-5578	-5635	-5625	-5611	-5401	-5709	-6277	-5625	-5570	-5520	-5516	-5516	-5795

The results for the BESS sensitivity are shown in Table 9, with all monitored nodes down the rows along with the different configurations of OMPS, and the contingencies in the columns.

Table 9 – Available Fault Level Results – BESS Sensitivity

Nodes	OMPS Configuration	System Normal	Armidale – Dumaresq	Armidale 132 Tx	Armidale 500 Tx	Armidale – Sapphire	Armidale – Tamworth	Bayswater – E Tamworth	Bayswater - Eraring	Bayswater - Wollar	E-Tamworth - Armidale	E Tamworth - Tamworth	Liddell - Muswellbrook	Liddell – Tamworth	Muswellbrook - Tamworth	OMPS G1
Armidale 132	**-**	1552	1490	1180	1436	1496	1482	1260	1501	1480	1386	1534	1446	1439	1445	
	600	2880	2825	2527	2764	2831	2810	2594	2845	2814	2719	2862	2764	2763	2771	2408
	900	2249	2217	1527	2173	2222	2204	2056	2216	2190	2135	2233	2175	2170	2175	2128
Armidale 330	**-**	-3058	-2982	-3015	-2507	-2930	-2640	-4034	-3229	-3136	-3104	-3097	-3482	-3525	-3506	
	600	-1819	-1741	-1911	-1280	-1689	-1414	-2802	-1983	-1896	-1872	-1856	-2247	-2291	-2272	-2161
	900	-710	-628	-667	-173	-575	-305	-1686	-864	-785	-760	-749	-1143	-1188	-1167	-1332
Bayswater 500	**-**	-2875	-3186	-2872	-2798	-3180	-2867	-1339	-2849	-601	-2628	-2711	-2723	-2711	-2717	
	600	-1486	-1721	-1674	-1487	-1714	-1496	-78	-1481	781	-1311	-1351	-1299	-1286	-1294	-1840
	900	-69	-242	-69	-172	-235	-117	1178	-82	2192	12	41	135	148	140	-626
Bayswater 330	**-**	5341	5101	5340	5351	5104	5336	5559	5137	5665	5369	5307	6007	6065	6039	
	600	6433	6257	6289	6412	6261	6377	6646	6244	6762	6431	6403	7021	7072	7050	6156
	900	7533	7410	7530	7456	7414	7410	7704	7358	7865	7478	7503	8031	8076	8058	7114
Dumaresq 330	**-**	1213	856	1212	1079	741	1128	915	1167	1139	1036	1197	1105	1101	1109	
	600	1519	980	1481	1412	863	1450	1281	1480	1454	1373	1505	1433	1429	1435	1443
	900	1913	1164	1912	1831	1046	1861	1733	1882	1854	1799	1900	1847	1843	1848	1801
Eraring 500	**-**	4679	4498	4677	4676	4502	4668	4937	5866	5031	4684	4686	4770	4786	4784	
	600	5514	5385	5407	5475	5389	5489	5711	6507	5869	5484	5514	5611	5623	5622	5302

Nodes	OMPS Configuration	System Normal	Armidale – Dumaresq	Armidale 132 Tx	Armidale 500 Tx	Armidale – Sapphire	Armidale – Tamworth	Bayswater – E Tamworth	Bayswater - Eraring	Bayswater - Wollar	E-Tamworth - Armidale	E Tamworth - Tamworth	Liddell - Muswellbrook	Liddell – Tamworth	Muswellbrook - Tamworth	OMPS G1
	900	6395	6308	6392	6301	6313	6341	6502	7195	6751	6311	6389	6484	6494	6492	6083
Liddell 330	**-**	5425	5203	5424	5435	5207	5414	5560	5259	5655	5441	5366	6129	6191	6165	
	600	6443	6280	6310	6429	6284	6377	6590	6290	6678	6436	6386	7053	7106	7084	6185
	900	7470	7356	7467	7409	7361	7334	7593	7329	7708	7418	7412	7975	8021	8005	7081
Muswell-brook 330	**-**	5149	5045	5147	5155	5048	5108	5094	5044	5117	5124	5021	1394	5296	5514	
	600	5686	5612	5620	5688	5616	5609	5659	5587	5659	5657	5556	1475	5822	5891	5551
	900	6249	6202	6246	6233	6206	6123	6231	6157	6226	6203	6116	1602	6365	6283	6056
Sapphire 330	**-**	1855	1707	1854	1720	1082	1769	1553	1806	1781	1676	1839	1746	1742	1749	
	600	2160	1927	2121	2050	1130	2089	1914	2119	2094	2011	2146	2072	2067	2073	2083
	900	2564	2230	2563	2478	1220	2509	2374	2532	2505	2445	2551	2494	2490	2495	2446
Tamworth 330	**-**	-1568	-1735	-1565	-1604	-1726	-1049	-2370	-1717	-1633	-1661	-1192	-1979	-2024	-2009	
	600	-691	-824	-800	-700	-814	-360	-1394	-829	-752	-750	-568	-1159	-1209	-1190	-918
	900	233	131	234	234	140	361	-374	109	175	194	110	-282	-336	-315	-133
Wollar 500	**-**	-8991	-9127	-8993	-8986	-9123	-9001	-8685	-9150	-8904	-8975	-8975	-8956	-8945	-8944	
	600	-8338	-8434	-8423	-8362	-8430	-8356	-8087	-8487	-8462	-8351	-8329	-8288	-8281	-8281	-8504
	900	-7653	-7715	-7655	-7723	-7710	-7691	-7482	-7792	-7989	-7710	-7651	-7601	-7596	-7596	-7895

The results for the SCR sensitivity are shown in Table 10Table 9, with all monitored nodes down the rows along with the different configurations of OMPS, and the contingencies in the columns.

Table 10 – Available Fault Level Results – SCR Sensitivity

	OMPS Configuration	System Normal	Armidale – Dumaresq	Armidale 132 Tx	Armidale 500 Tx	Armidale – Sapphire	Armidale – Tamworth	Bayswater – E Tamworth	Bayswater - Eraring	Bayswater - Wollar	E-Tamworth - Armidale	E Tamworth - Tamworth	Liddell - Muswellbrook	Liddell – Tamworth	Muswellbrook - Tamworth	OMPS G1
Armidale 132	**-**	1877	1819	1394	1766	1825	1811	1603	1829	1812	1722	1860	1776	1770	1776	
	600	3212	3161	2746	3100	3167	3146	2943	3179	3153	3061	3195	3102	3101	3109	2738
	900	2538	2508	1727	2463	2513	2494	2357	2507	2485	2431	2523	2468	2463	2468	2425
Armidale 330	**-**	-182	-211	-158	57	-165	19	-1106	-346	-250	-340	-218	-577	-616	-598	
	600	1008	981	887	1235	1027	1196	77	850	941	843	973	609	568	587	678
	900	2187	2163	2211	2409	2210	2373	1259	2037	2121	2022	2150	1782	1740	1760	1562
Bayswater 500	**-**	1988	1704	1990	2045	1713	1995	3050	1703	3350	2170	2106	2066	2073	2070	
	600	3300	3087	3125	3287	3096	3291	4257	2995	4656	3419	3391	3416	3424	3419	2966
	900	4650	4492	4649	4545	4501	4606	5468	4329	6001	4685	4718	4786	4794	4788	4127
Bayswater 330	**-**	7173	6950	7172	7184	6956	7168	7341	6969	7385	7199	7140	7647	7695	7677	
	600	8219	8057	8084	8202	8063	8167	8390	8030	8435	8219	8190	8624	8666	8651	7955
	900	9287	9175	9285	9220	9181	9173	9424	9112	9503	9239	9258	9612	9648	9637	8889
Dumaresq 330	**-**	2070	1612	2069	1943	1512	1991	1790	2027	2003	1904	2055	1967	1964	1971	
	600	2359	1731	2324	2257	1629	2295	2136	2323	2300	2223	2346	2278	2274	2280	2287
	900	2740	1911	2738	2661	1808	2691	2571	2711	2686	2632	2727	2677	2674	2678	2635
Eraring 500	**-**	7409	7240	7408	7410	7245	7401	7618	8108	7634	7415	7417	7474	7488	7487	
	600	8217	8097	8115	8184	8102	8194	8372	8731	8443	8190	8218	8290	8300	8299	8013

	900	9072	8992	9069	8987	8998	9022	9145	9405	9296	8995	9067	9139	9147	9146	8774
Liddell 330	**-**	7030	6824	7029	7041	6829	7019	7128	6867	7178	7045	6972	7525	7576	7558	
	600	8006	7856	7881	7995	7861	7945	8121	7855	8157	8000	7950	8416	8460	8446	7759
	900	9004	8900	9002	8950	8906	8878	9102	8866	9156	8959	8947	9321	9358	9348	8635
Muswell-brook 330	**-**	5734	5636	5732	5740	5640	5697	5675	5635	5695	5711	5612	1459	5840	5906	
	600	6252	6183	6189	6254	6188	6181	6222	6159	6217	6226	6129	1537	6350	6273	6122
	900	6807	6765	6804	6793	6769	6691	6788	6721	6775	6766	6681	1662	6889	6667	6623
Sapphire 330	**-**	2235	2097	2234	2108	1302	2156	1952	2189	2168	2068	2220	2132	2128	2135	
	600	2522	2306	2486	2417	1348	2455	2291	2483	2462	2382	2508	2438	2433	2439	2449
	900	2910	2599	2909	2827	1438	2858	2732	2880	2856	2798	2897	2844	2840	2845	2800
Tamworth 330	**-**	772	617	773	736	629	1054	21	629	712	683	748	259	212	232	
	600	1585	1462	1485	1576	1473	1698	926	1453	1528	1529	1330	1019	967	990	1375
	900	2461	2366	2461	2460	2376	2388	1889	2342	2405	2423	1977	1849	1793	1818	2121
Wollar 500	**-**	-1682	-1808	-1684	-1675	-1803	-1690	-1440	-1860	-2022	-1668	-1666	-1661	-1652	-1650	
	600	-1056	-1144	-1136	-1076	-1139	-1072	-862	-1225	-1597	-1068	-1048	-1019	-1014	-1013	-1215
	900	-403	-459	-406	-465	-454	-438	-280	-562	-1144	-455	-402	-362	-359	-359	-632

OVEN MOUNTAIN
PUMPED HYDRO STORAGE

APPENDIX C

EY Report

Assessment of market benefits of the Oven Mountain Pumped Storage Hydro project

EY Consultants, November 2022

Assessment of market benefits of the Oven Mountain Pumped Storage Hydro project

OMPS Pty Ltd

18 November 2022

Building a better working world

Building a better working world

RELEASE NOTICE

Ernst & Young was engaged by OMPS Pty Ltd ("the Client") to conduct electricity market modelling to assess potential benefits of a pumped hydro energy storage scheme to a REZ and the National Electricity Market (NEM) with the Oven Mountain Pumped Hydro Energy Storage Project (Project) as a representative scheme and the New England Renewable Energy Zone (REZ) as a REZ of interest. This is part of a broader knowledge sharing project being supported by the Australian Renewable Energy Agency (ARENA) through their Advancing Renewables Program (ARP). However, for the avoidance of doubt, we are solely engaged by the Client and we do not have any contractual arrangement with ARENA.

The key inputs, assumptions, methodology, scenarios and qualifications made in preparing the modelling are set out in EY's report dated 5 November 2022 ("Report"). You should read the Report in its entirety including any disclaimers and attachments. A reference to the Report includes any part of the Report. No further work has been undertaken by EY since the date of the Report to update it.

Ernst & Young has prepared the Report for the benefit of the Client and has considered only the interests of the Client. Ernst & Young has not been engaged to act, and has not acted, as advisor to any other party. Accordingly, Ernst & Young makes no representations as to the appropriateness, accuracy or completeness of the Report for any other party's purposes. Our work for this Report commenced in November 2021 and was completed on 5 November 2022. Therefore, our Report does not take account of events or circumstances arising after 5 November 2022 and we have no responsibility to update the Report for such events or circumstances.

No reliance may be placed upon the Report or any of its contents by any party other than the Client ("Third Parties"). Any Third Parties receiving a copy of the Report must make and rely on their own enquiries in relation to the issues to which the Report relates, the contents of the Report and all matters arising from or relating to or in any way connected with the Report or its contents. Ernst & Young disclaims all responsibility to any Third Parties for any loss or liability that the Third Parties may suffer or incur arising from or relating to or in any way connected with the contents of the Report, the provision of the Report to the Third Parties or the reliance upon the Report by the Third Parties.

No claim or demand or any actions or proceedings may be brought against Ernst & Young arising from or connected with the contents of the Report or the provision of the Report to the Third Parties. Ernst & Young will be released and forever discharged from any such claims, demands, actions or proceedings. Our Report is based, in part, on the information provided to us by the Client and other stakeholders engaged in this process. We have relied on the accuracy of the information gathered through these sources. We do not imply, and it should not be construed that we have performed an audit, verification or due diligence procedures on any of the information provided to us. We have not independently verified, nor accept any responsibility or liability for independently verifying, any such information nor do we make any representation as to the accuracy or completeness of the information. We accept no liability for any loss or damage, which may result from your reliance on any research, analyses or information so supplied.

Modelling work performed as part of our scope inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual outcomes, because events and circumstances frequently do not occur as expected, and those differences may be material. We take no responsibility that the projected outcomes will be achieved. We highlight that our analysis and Report do not constitute investment advice or a recommendation to you on a future course of action. We provide no assurance that the scenarios we have modelled will be accepted by any relevant authority or third party.

Ernst & Young have consented to the Report being published electronically on ARENA's website for informational purposes only. Further the client may want to print and share copies, after public release, with certain stakeholders. Ernst & Young have not consented to distribution or disclosure beyond this.

The material contained in the Report, including the Ernst & Young logo, is copyright. The copyright in the material contained in the Report itself, excluding Ernst & Young logo, vests in the Department. The Report, including the Ernst & Young logo, cannot be altered without prior written permission from Ernst & Young.

Readers are advised that the information provided is based on many detailed assumptions. These assumptions were selected by the Client. The modelled scenario and sensitivity represent a number of possible future outcomes for the development and operation of the National Electricity Market by 2030-31, and it must be acknowledged that many alternative futures exist. Alternative futures beyond those presented have not been evaluated as part of this Report.

Table of contents

1. Executive summary 1
2. Introduction 4
3. Scenario and Project assumptions 5
   3.1 Based on the 2022 ISP Step Change scenario for 2030-31 5
   3.2 Base Scenario and sensitivity assumptions 5
   3.3 Project assumptions 7
   3.4 Scenarios and cases modelled 8
   3.5 Capacity mix in New England 9
4. Modelling approach 11
   4.1 Network constraints application 11
   4.2 Market trading strategy 12
5. Base Scenario results 13
   5.1 Wholesale market outcomes 13
   5.2 Project dispatch outcomes 14
6. Market benefits study outcomes 17
   6.1 Wholesale market and retail prices 17
   6.2 NEM-wide market benefits 17
   6.3 Benefits to the New England REZ 19
7. Project capacity comparison 22
   7.1 Modelling outcomes: comparing Cases 2 and 3 22
8. Insurance case study outcomes 23
   8.1 Overview of outcomes for the Sensitivity scenario 23
   8.2 Retail prices 27
   8.3 NEM-wide market benefits 28
   8.4 Benefits to the New England REZ 28

Appendix A Market modelling assumptions and methodology 30

Appendix B Marginal loss factors 33

Appendix C Constraint formulation 36

1. Executive summary

OMPS Pty Ltd (OMPS) has commissioned EY to undertake market modelling to provide an assessment of potential benefits of a pumped hydro energy storage scheme to a REZ and the National Electricity Market (NEM) with the Oven Mountain Pumped Hydro Energy Storage Project (Project) as a representative scheme and the New England Renewable Energy Zone (REZ) as a REZ of interest. This is part of a broader knowledge sharing project being supported by the Australian Renewable Energy Agency (ARENA) through their Advancing Renewables Program (ARP).

When built, the Project will have a capacity of 600 MW to 900 MW and will be located adjacent to the Macleay River between Armidale and Kempsey. The Project is expected to commence full operation from 2028. For this Report, EY conducted electricity market modelling of the financial year 2030-31 to quantify the following:

- Potential market benefits of the Project, including on wholesale market and retail electricity prices, dispatch costs and emissions.
- Potential benefits of the Project to wind and solar projects in the New England REZ, including on their marginal loss factors (MLFs) and energy curtailment expectations.
- A comparison of the 600 MW and 900 MW capacity options for the Project.

All the modelling conducted is based on the Australian Energy Market Operator's (AEMO) 2022 Integrated System Plan (ISP) Step Change scenario assumptions and outcomes for 2030-31, including the demand outlook, capacity mix (including the wind and solar capacity by REZ) and network augmentations. Notably, the 2022 ISP outcomes meet the NSW Electricity Infrastructure Roadmap targets, which includes 6 GW of wind and solar capacity in the New England REZ and 2 GW of storage with 8 hours storage capacity in addition to the 2 GW Snowy 2.0 pumped hydro project. A key network augmentation to support the 6 GW of renewable capacity in New England REZ is the New England REZ transmission link (NE REZ link), which is expected in the ISP outcomes to be commissioned before 2030-31 and significantly expands the transfer capacity between the majority of NSW load in Newcastle/Sydney/Wollongong and the New England REZ.

Table 1 summarises the scenarios and cases presented in this Report, highlighting the key assumption differences between each.

Table 1: The Base Scenario, Sensitivity and associated cases modelled

Scenario/sensitivity	NE REZ link assumption	Project capacity		
		0 MW	600 MW	900 MW
Base Scenario	In service in 2030-31	Case 1	Case 2	Case 3
Sensitivity – Insurance case study	Delayed until after 2030-31	Case 1a	-	Case 3a

Using the cases in the table, this report presents the modelling outcomes for three assessments in relation to the Project:

1. **Market benefits study** with Cases 1-3 on the Base Scenario comparing the projected market outcomes in 2030-31 with and without the Project in operation.
2. **Project capacity comparison:** Comparison of the 600 MW and 900 MW Project size options, by comparing the market benefits outcomes.
3. **Insurance case study:** exploring the potential benefits of the Project in the Sensitivity scenario as a potential form of insurance in the case that the NE REZ link is delayed until after 2030-31. Cases 1a and 3a compare the projected market outcomes in 2030-31 with and without the 900 MW Project in operation.

All cases assume the Snowy 2.0 pumped hydro project is in service (commissioned before 1 July 2030) and the NSW Roadmap 2 GW storage target policy results in and additional 1,100 MW of 8-hour storage being commissioned by 2030-31. Thus, the cases are quantifying the potential benefits of the 600 MW or 900 MW Project relative to it not being present in the market. Furthermore, whilst the full 2 GW NSW Roadmap target is only met in the cases with the 900 MW Project (Cases 3 and 3a), we note that we are not implying that the 2 GW would not be met in Cases 1, 1a and 2; rather, these cases are used to evaluate the market benefits of the Project located in the New England REZ.

EY conducted half-hourly market dispatch modelling with 48 iterations of 2030-31 in each case, representing three years of weather patterns, eight Monte Carlo forced outage profiles for thermal generators and two peak demand profiles. EY constructed a comprehensive set of N-1 thermal network constraint equations to present how the transmission limitations would be represented in market dispatch. A key potential limitation is an assumption that there are no voltage/transient stability limits that require application of stability constraint equations[1]. Since the Project is expected to contribute to increasing stability limits with its fault level and inertia contribution, the outcomes presented in this Report are considered to be conservative. That is, in the absence of the Project there may be restrictive stability limits which, if captured in this modelling, would present additional market benefits ascribed to the presence of the Project.

The modelling outcomes for the three assessments is summarised as follows:

- The **market benefits study** on the Base Scenario shows that in 2030-31 the Project:
  - Reduces demand-weighted wholesale electricity prices by $7-9/MWh in NSW and $4-5/MWh in the other mainland NEM regions. This amounts to approximately a $1 billion reduction in total mainland customer retail bills.
  - $50-70 million savings in fuel costs NEM-wide.
  - 400,000 tonnes CO_2-e (or 1%) reduction in generation emissions.
- The **Project capacity comparison** outcomes show that the 900 MW Project is forecast to have larger benefits compared to the alternatives assessed:
  - Compared to the 600 MW Project, the 900 MW Project has a larger benefit to customer retail bills, all market benefits assessed and on reducing the forecast energy curtailment for wind and solar PV projects.
- In the **Insurance case study** with a delayed NE REZ link, the market experiences a transmission bottleneck between New England and the rest of NSW. With its location in New England, in Case 3a the Project is able to reduce curtailment for New England renewable generators, significantly reducing wholesale electricity prices in Queensland. In the insurance case study the 900 MW Project:
  - Reduces demand-weighted wholesale electricity prices by $6/MWh in NSW and $12/MWh in Queensland. This amounts to approximately a $1.3 billion reduction in total mainland customer retail bills.
  - Saves $60 million in fuel costs NEM-wide.
  - Saves 540,000 tonnes CO_2-e in generation emissions (a 1.3% reduction).
  - Reduces curtailment of New England wind generation from 32% to 29% of available energy, and from 33% to 27% for solar PV generation. In total the Project is forecast to allow approximately 680 GWh of additional renewable generation to be dispatched in New England.

[1] The impact of the Project on network stability has been considered in a separate study conducted by Amplitude Consultants: Oven Mountain Pumped Hydro Storage. Benefit Assessment – System Strength and Inertia, 28 July 2022.

- Assuming a conservative PPA price of $45/MWh this reduction in curtailment results in approximately $30 million of additional revenue for NE REZ wind and solar generators.
- Supports a 0.01 increase to solar MLFs in the NE REZ, with a further direct benefit to the market revenues for these solar projects. Solar projects benefit due to the Project pumping tending to be during the day, which is the same time as solar generation. The dispatchable load added to New England reduces network loading and hence reduces transmission losses between New England and the greater Sydney area load centre.
- Results in a neutral change to wind generator MLFs in the NE REZ. Although the prevailing MLF is higher in the daytime providing a benefit to solar generators, the prevailing MLF is relatively lower when the Project is generating over the evening resulting in a neutral impact to wind generator MLFs.

Furthermore, comparing the Base Scenario to the Insurance case study shows that the NE REZ link itself results in a reduction in the average NSW price of approximately $21-23/MWh by alleviating network congestion. As per all the outcomes in this Report, this result is in the context of the 6 GW of New England wind and solar capacity development going ahead in all the cases modelled.

Table 2 below summarises the 2030-31 market benefits (compared to the equivalent case without the Project installed) of the Project at 600 MW and 900 MW capacity in the Base Scenario and 900 MW capacity in the Sensitivity.

Table 2: Summary of the 2030-31 market and REZ project benefits

Market benefit / New England REZ project benefit	Base Scenario		Sensitivity – Insurance case study
	600 MW	900 MW	900 MW
Savings to NSW customers ($m)	481	583	378
Savings to QLD customers ($m)	246	274	796
Savings to VIC customers ($m)	178	217	114
Savings to SA customers ($m)	47	60	32
Mainland total customer savings ($b)	**0.95**	**1.13**	**1.32**
Fuel costs & VOM[2] savings ($m)	53	76	67
Generation emissions reductions (%)	-0.9%	-1.1%	-1.3%
New England wind project MLFs	0	0	0
New England solar project MLFs	+0.006	+0.008	+0.01
New England wind project curtailment	-1.0%	-1.1%	-3.1%
New England solar project curtailment	-2.2%	-2.5%	-5.9%

EY advises that the outcomes provided are based on many detailed assumptions underpinning the scenario, and the key assumptions are described in the Report. The modelled scenarios represent two possible futures for the development and operation of the NEM, and it must be acknowledged that many alternative futures exist. We encourage the Client to ensure that they develop a thorough understanding of the sensitivity of the outcomes to key assumptions and consider these assumptions with due care before potentially making any decisions based on the outcomes presented in this Report.

[2] VOM = Variable Operation and Maintenance. Since it is assumed the installed capacity is the same between the cases (apart from the Project), there is no capital cost or Fixed Operation and Maintenance (FOM) cost savings to consider.

2. Introduction

OMPS Pty Ltd (OMPS) commissioned EY to assess potential benefits of a pumped hydro energy storage scheme to a REZ and the National Electricity Market (NEM) with the Oven Mountain Pumped Hydro Energy Storage Project (Project) as a representative scheme and the New England Renewable Energy Zone (REZ) as a REZ of interest. This is part of a broader knowledge sharing project being supported by the Australian Renewable Energy Agency (ARENA) through their Advancing Renewables Program (ARP).

For this Report, EY conducted electricity market modelling of the financial year 2030-31 to quantify the following:

- Potential market benefits of the Project, including on wholesale market and retail electricity prices, dispatch costs and generation emissions.
- Potential benefits of the Project to wind and solar projects in the New England REZ, including on their marginal loss factors (MLFs) and energy curtailment expectations.
- A comparison of the 600 MW and 900 MW capacity options for the Project.

This Report describes the key assumptions and data sources used in a Base Scenario and the sensitivity analysis undertaken, as well as the main outcomes of the analysis.

All prices in this Report refer to real June 2022 dollars unless otherwise labelled. All annual values refer to the fiscal year (1 July – 30 June) unless otherwise stated. We note that the assumptions have been selected by the Client in consultation with EY. We acknowledge that there is a significant range of alternative assumptions that, in isolation or in aggregate, could transpire to produce outcomes that will differ to those that have been modelled. These possible alternative futures have not been considered in this engagement.

3. Scenario and Project assumptions

3.1 Based on the 2022 ISP Step Change scenario for 2030-31

The analysis presented in this Report uses the Step Change scenario candidate development path 1 (CDP1) from the 2022 Integrated System Plan[3] (ISP) as the basis for the modelling. The ISP reflects an accepted roadmap developed by AEMO in close consultation with a wide range of stakeholders across the industry.

The Step Change scenario has been selected primarily due to it being considered by AEMO as the most likely of the four scenarios in the 2022 ISP, with a 50% weighting[4]. The Step Change scenario features an emissions budget that drives rapid coal retirements.

The modelling presented in this Report is for the 2030-31 financial year. The scope was limited to a single future year to allow more value to be obtained through comparing two different sizes for the Project along with detailed analysis of the Project's operational profile, its impact on other generators in the New England REZ and to explore a sensitivity.

2030-31 was selected due to it being a year soon after the Project is planned to be commissioned and it is the year that the NSW Roadmap renewable energy and storage minimum targets are intended to be met, along with key network infrastructure including the New England REZ transmission link (NE REZ link). Whilst there are many uncertainties on whether the Step Change assumptions and outcomes will play out by 2030-31, EY considers this year to be representative of what a future year might look like after the Project is commissioned in terms of the network state and the installed capacity mix. For example, if the coal power stations retire at a slower rate than in the Step Change outcomes, the year modelled may more closely represent a few years later than 2030-31.

One of the key assumed developments in the Base Scenario that supports renewable generation in New England is the NE REZ link. The modelled sensitivity explores the potential benefits of the Project in the event the NE REZ link is delayed post 2030-31.

AEMO modelled thirteen different candidate development paths in the Step Change scenario with generation mix outcomes for each. In consultation with the client, EY selected CDP1[3] due to its transmission developments aligning most closely with the 2022 ISP Optimal Development Path (ODP)[5] by 2030-31.

3.2 Base Scenario and sensitivity assumptions

As described in the previous section, the Base Scenario and sensitivity are aligned with the assumptions and outcomes of the 2022 ISP Step Change scenario[6]. This includes:

- Electricity demand outlook, broken into components including seasonal peak and energy consumption, rooftop PV, distributed storage and electric vehicle uptake.
- Installed capacity mix, including the breakdown of new wind and solar capacity by REZ, storage by region and demand-side participation.

[3] Details available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp

[4] Based on a Delphi Panel approach. See the AEMO ISP report for more details.

[5] The ODP is the primary outcome of the 2022 ISP, presenting a transmission development plan which optimises the net market benefit of transmission projects for all market participants through a scenario-weighted cost benefit analysis.

[6] IASR workbook v3.4, published on 30/6/2022. Available here: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios

Table 3 presents an overview of the transmission network augmentations included in the modelling, selected due its close alignment with the 2022 ISP ODP[7]. The excluded transmission augmentations are considered to be commissioned after the modelled year, 2030-31.

Table 3: Network augmentation assumptions based on CDP1

Transmission augmentation	Base Scenario	Sensitivity
New England REZ Transmission Link	Included	Not included
Project EnergyConnect	Included	
Central West Orana link	Included	
Sydney, Newcastle and Wollongong Reinforcement	Included	
HumeLink	Included	
Marinus Link (cable 1)	Included	
Gladstone Grid Reinforcement	Included	
Marinus Link (cable 2)	Not included	
VNI West	Not included	
QNI Connect	Not included	

Figure 1 below shows the NSW capacity mix comparison of the Step Change CDP1 between 2023-24 and 2030-31. The aggressive coal retirements before 2030 are driven by the emissions budget and being replaced by incoming new storage and renewable generation in wind and solar to meet the NSW roadmap targets.

Figure 1: NSW capacity mix comparison from 2023-24 and 2030-31

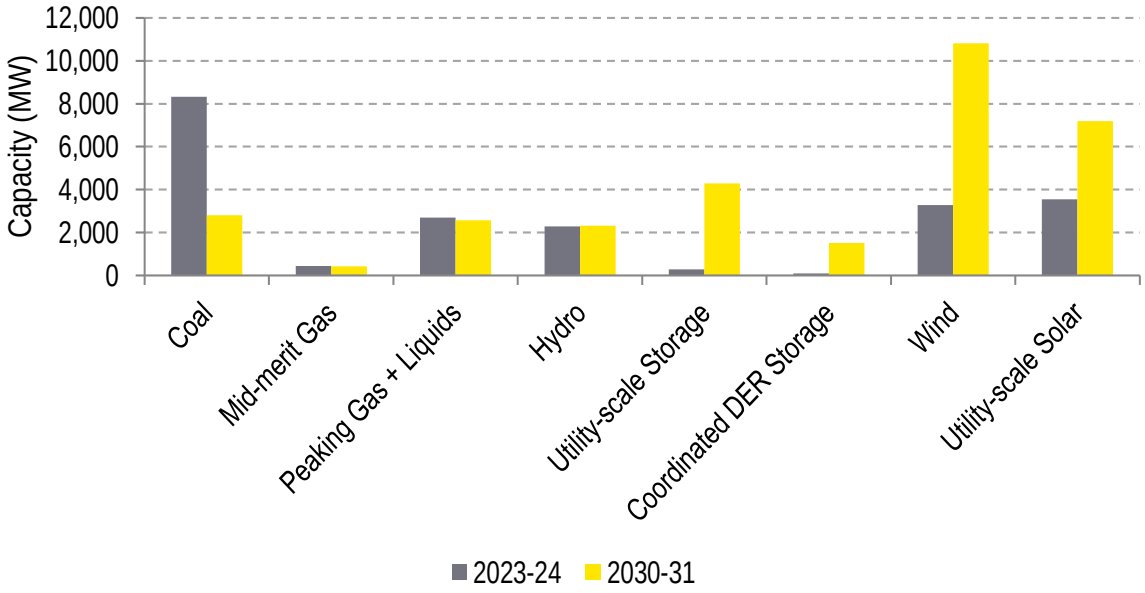
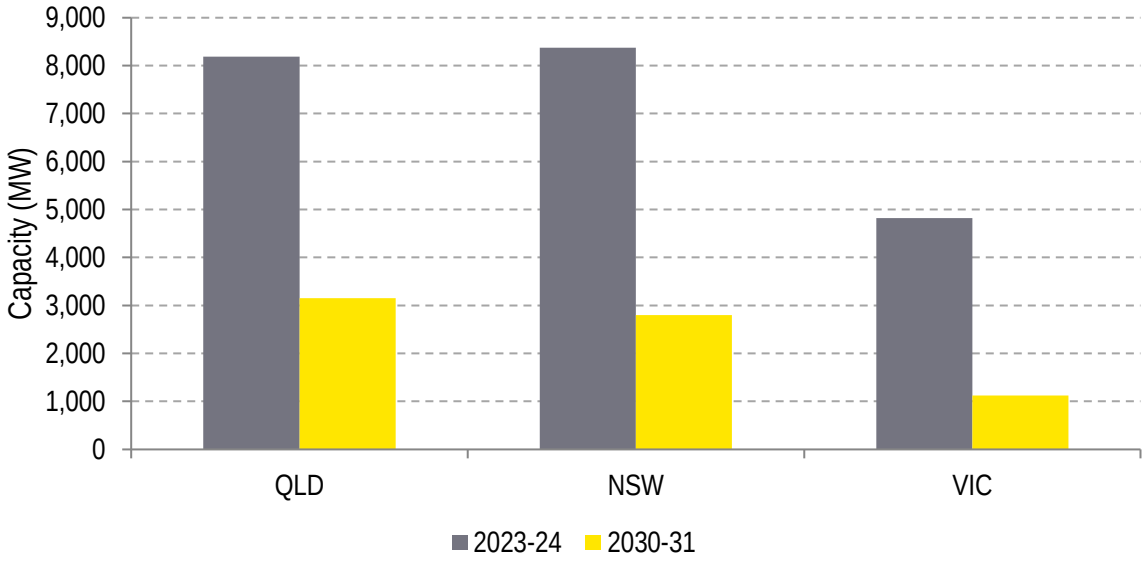


Figure 2 below shows a comparison of coal capacity online in 2023-24 and 2030-31 across QLD, NSW, and VIC in the Step Change CDP1 scenario outcome. To match the ISP 2030-31 NSW coal capacity outcome, two of the four Bayswater units are assumed to be retired, as well as all Eraring, Liddell and Vales Point units. The remaining 2,800 MW of coal generation is assumed to be provided by the remaining two Bayswater units and Mount Piper.

[7] The final 2022 ISP included the Eyre Peninsula Link in the optimal development path as a committed ISP project. However that network augmentation will not have a material impact on the Project due to the augmentation being in South Australia.

Figure 2: Coal capacity online in 2023-24 and 2030-31 in the Step Change CDP1 scenario



3.3 Project assumptions

Table 4 presents a summary of the specifications for the two configurations considered for the Project.

Table 4: Project specification assumptions

Capacity	600 MW	900 MW
Hours of storage (hours)	12	8
Reservoir storage capacity (MWh)	7,200	
Transmission connection point	Armidale 132 kV bus	Armidale 330 kV bus
Number of generator/pump units	3	4
Round trip efficiency (%)	78.2	
Full forced outage rate	1% with 27 hours mean time to repair (AEMO IASR assumptions)	
Maintenance	1 day per year (AEMO IASR assumptions)	

Figure 3 shows the location of the Project along with the transmission network in the New England REZ. The figure shows the 900 MW option for the Project, indicating the new 330 kV network path to approximately follow along the existing 132 kV network between Armidale and the Project.

Figure 3: Map showing the Project location and surrounding transmission network[8]

3.4 Scenarios and cases modelled

Table 1 summarises the scenarios and cases presented in this Report, highlighting the key assumption differences between each.

Table 5: The Base Scenario, Sensitivity and associated cases modelled

Scenario/sensitivity	NE REZ link assumption	Project capacity		
		0 MW	600 MW	900 MW
Base Scenario	In service in 2030-31	Case 1	Case 2	Case 3
Sensitivity – Insurance case study	Delayed until after 2030-31	Case 1a	-	Case 3a

Using the cases in the table, this report presents the modelling outcomes for three assessments in relation to the Project:

1. **Market benefits study** with Cases 1-3 on the Base Scenario comparing the projected market outcomes in 2030-31 with and without the Project in operation.
2. **Project capacity comparison:** Comparison of the 600 MW and 900 MW Project size options, by comparing the market benefits outcomes as well as the relative Project costs.
3. **Insurance case study:** exploring the potential benefits of the Project in the Sensitivity scenario as a potential form of insurance in the case that the NE REZ link is delayed until after 2030-31. Cases 1a and 3a compare the projected market outcomes in 2030-31 with and without the 900 MW Project in operation.

All cases assume the Snowy 2.0 pumped hydro project is in service prior to 2030-31 and the NSW Roadmap 2 GW storage target policy results in 1,100 MW of 8-hour storage separate to the Project being installed by 2030-31. EY determined potential locations and distribution of the long duration

[8] Underlying map is copyright OpenStreetMap contributors (openstreetmap.org/copyright). OpenStreetMap data is licensed under the Open Data Commons Open Database License (ODbL).

storage based on public information of potential projects. Table 6 below presents the long duration storage capacity by location for each case.

Table 6: Long duration storage capacity (MW) in NSW by case in addition to the Snowy 2.0 pumped hydro project (PHES = pumped hydro energy storage, BESS = battery energy storage system)

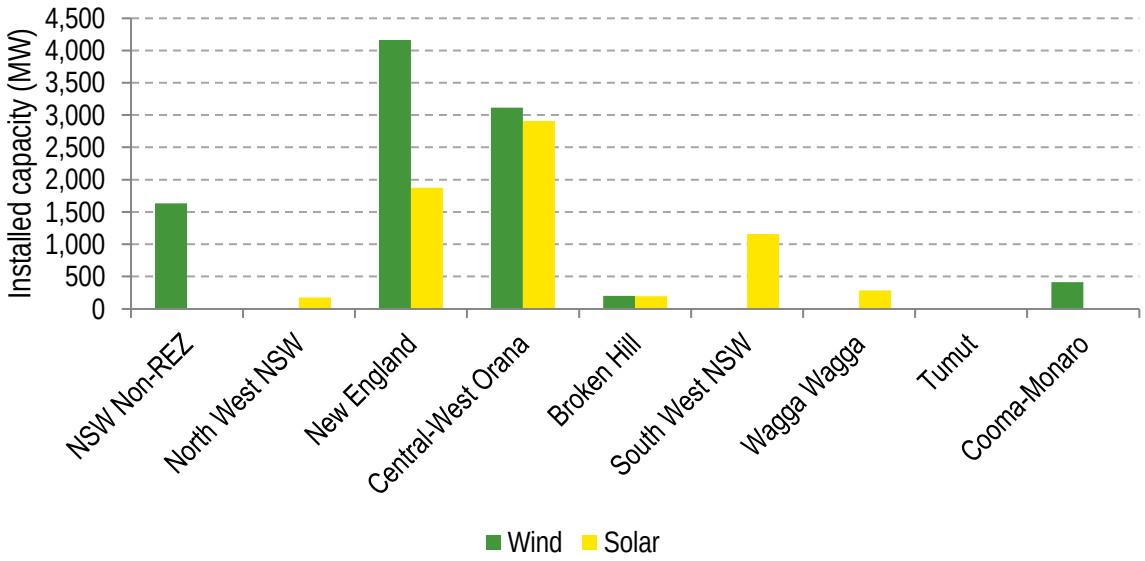
Capacity (MW)	Case 1/1a	Case 2	Case 3/3a
New England REZ (Project)	0	600 (12-hr PHES)	900 (8-hr PHES)
Central-West Orana REZ battery	300 (8-hr BESS)		
South West NSW REZ	150 (8-hr BESS)		
Capital	150 (8-hr BESS)		
Eraring	500 (8-hr BESS)		
Total	**1,100**	**1,700**	**2,000**

The table illustrates that the case comparisons are evaluating the potential benefits of the Project under the assumption that 1,100 MW of other long duration storage in operational (in addition to the 2 GW Snowy 2.0 project). EY notes we are not implying that the 2 GW would not be met in Cases 1, 1a and 2; rather, these cases are selected for the purposes of evaluating the market benefits of the Project to the REZ and the NEM.

3.5 Capacity mix in New England

Figure 4 shows the wind and solar capacity by NSW REZ in 2030-31 from the selected ISP development path outcomes as used in the modelling. It also shows that New England has approximately 6 GW of wind and solar PV capacity, with two-thirds of that being wind.

Figure 4: Wind and solar capacity installed in the NSW REZs in 2030-31



The connection locations of this capacity within each REZ are based on the timing of when new connection points are assumed to be available and economic modelling outcomes, which includes network curtailment and marginal loss factor considerations. The network upgrades in the New England area, particularly the installation of a double circuit 500 kV line from Armidale to Bayswater, provide additional connection options.

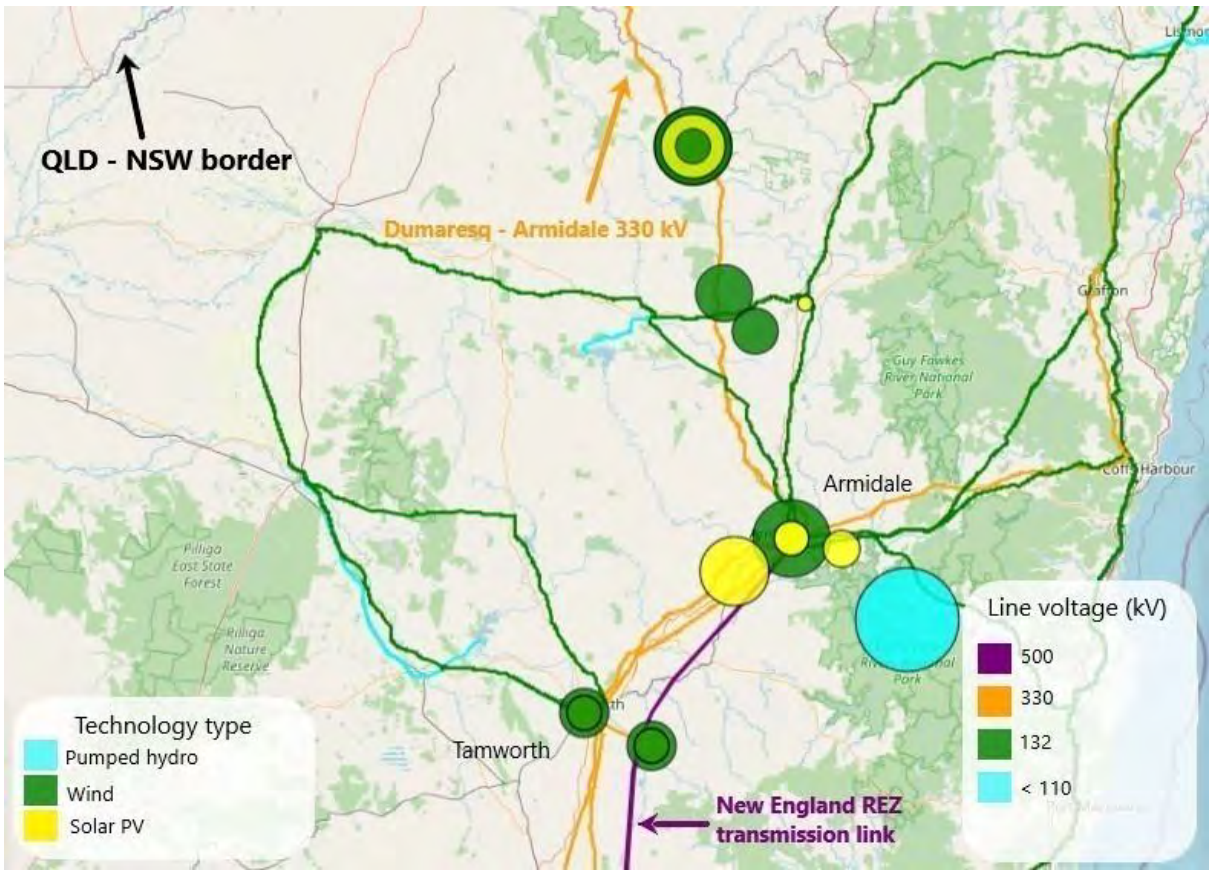
Table 7 below presents EY's assumed capacity of wind and solar in the New England REZ based on connection points to the network for all three cases.

Table 7: Assumed connection points of new wind and solar capacity in New England (Base Scenario)

Capacity (MW)	Wind	Solar	Existing or new network
Armidale 132 kV	175	135	Existing
Armidale 330 kV	1,370	600	Existing
Armidale 500 kV	1,300	650	Part of the NE REZ link[9]
Tamworth 330 kV	100	0	Existing
Dungowan 500 kV	100	0	Part of the NE REZ link
Dumaresq 330 kV	1,100	450	Existing
Total	**4,145**	**1,835**	

Figure 5 presents these capacities along with the existing wind and solar projects on a map for Case 3.

Figure 5: Map of New England wind and solar capacity, the transmission network and the Project for Case 3[10]



[9] This is adjusted in the Insurance case to the existing Armidale 330 kV node.

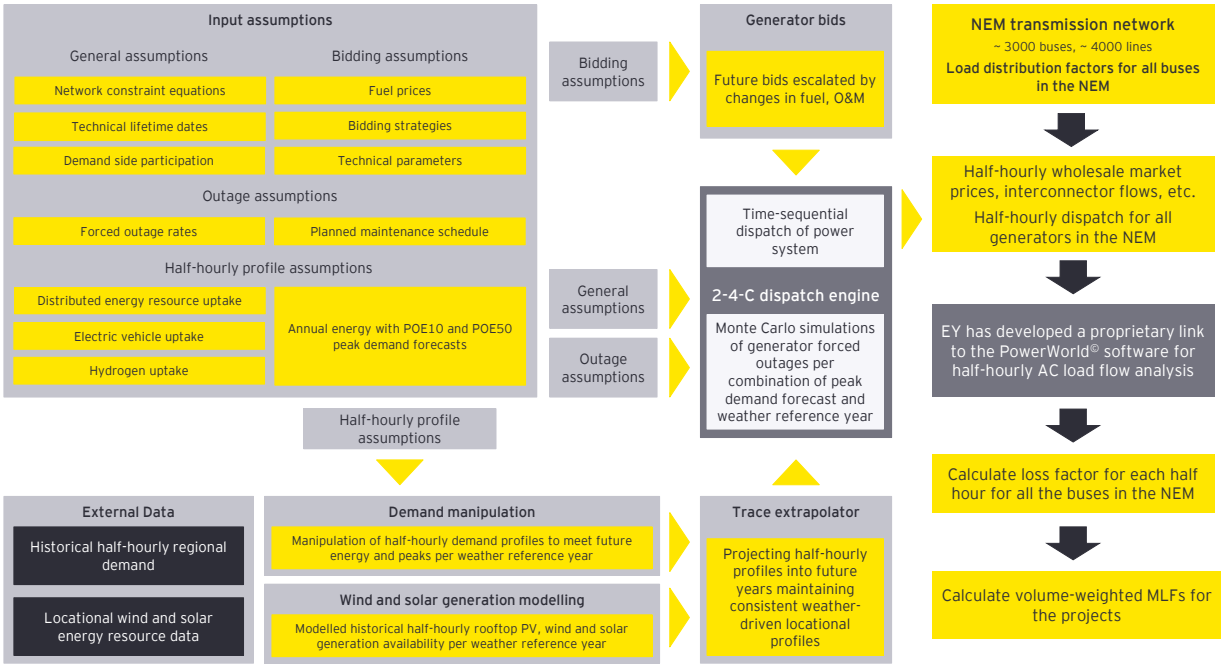
[10] Underlying map is copyright OpenStreetMap contributors (openstreetmap.org/copyright). OpenStreetMap data is licensed under the Open Data Commons Open Database License (ODbL).

4. Modelling approach

For this Report, EY has used our 2-4-C® software suite, which consists of an energy market dispatch engine and several software tools that develop input data and analyse output data. The 2-4-C dispatch engine is equivalent to the NEM Dispatch Engine (NEMDE) used by the Australian Energy Market Operator (AEMO) in operating the market in real time. We conducted half-hourly time-sequential modelling for 2030-31, with explicit modelling of each generating unit using three historical weather reference years and eight Monte Carlo iterations of generator forced outages per year.

Figure 6 provides an overview of the key array of inputs used in a market modelling scenario with 2-4-C, along with the link to PowerWorld where we conduct the power flow modelling for each half-hour to compute marginal loss factors.

Figure 6: Key input data flows in EY's 2-4-C electricity market model



4.1 Network constraints application

Customised N-1 network constraint equations were created to represent the transmission thermal network limitations on dispatch for 2030-31 (see Appendix C for more details). Since the network and generation mix in the 2030-31 scenario is materially different compared to today, the currently available stability network constraint equations will be no longer representative of the future 2030-31 year.

It was outside the scope of this study to formulate new stability constraint equations for 2030-31, including consideration of the impact of the Project on their formulation. As such a simplifying assumption was applied to exclude the current relevant stability constraints from the modelling. It is noted that this may under-value the potential market benefits of the Project across the modelled cases. The impact of the Project on network stability has been considered in a separate study conducted by Amplitude Consultants[11].

[11] Amplitude Consultants. Oven Mountain Pumped Hydro Storage. Benefit Assessment – System Strength and Inertia. 28 July 2022.

4.2 Market trading strategy

For the purposes of this study, the Project was assumed to operate solely within the energy market on an arbitrage basis. Co-optimising energy and frequency services market was not considered here, nor were other approaches such as hedging or portfolio management.

Box 1 summarises EY's modelling approach to storage discharge and charging operational planning. This is applied for all large-scale batteries, battery VPPs and pumped hydro generators in the modelling, except Snowy 2.0. Snowy 2.0 is modelled with a different approach due to its significant storage capacity volume, which takes into account monthly variations in the NSW prices as well as day-to-day price variations.

Box 1: Residual demand - storage operating strategy (for storage capacity 12 hours or less)

EY's residual demand strategy for storage operation in time-sequential market modelling with 2-4-C® aims to simulate a realistic strategy that could be applied in the market. The strategy is based on developing an imperfect forecast of the wholesale market prices for the next four days and planning an optimal charging and discharging profile over those four days to maximise wholesale market price arbitrage. The strategies developed take into account the parameters of each specific battery or pumped hydro project including the present state of charge, available storage capacity and the round-trip efficiency.

The imperfect price forecast is based on residual demand, which is equal to operational demand minus the available large-scale wind and solar generation, minus other low-bidding generation, which includes the plan for Snowy 2.0's generation and pumping. The strategy develops a relationship between residual demand and prices over the previously simulated eight days, and then uses this relationship to forecast the price for the next four days to feed into the storage load and generation plan. The price forecast uses a perfect forecast of residual demand for those next four days (which is known by the model as half-hourly demand, available wind and solar generation and the plan for Snowy 2.0 are inputs into the model). However, the price forecast is imperfect since it does not take into account any curtailment of wind and solar generation and does not foresee any generator forced outages. The storage load and generation profiles determined by the strategy take into account the impact the storage load and generation may have on the price, effectively considering that the storage load and generation would change the residual demand.

Once the storage load and generation profiles are determined, they are fixed for 24 hours of time-sequential modelling and bid in two tranches to allow the generation or load to go beyond the profile if market prices are very favourable. This reflects the dynamic bidding behaviour expected in the actual market. Generation can only be dispatched if there is available reservoir capacity, and vice versa for load. The residual demand strategy for the next four days is then reset taking in the previously simulated eight days (a moving window).

The residual demand algorithm is applied to all modelled large-scale batteries and pumped hydro units with a storage capacity of eight hours or less. The modelled dispatch of the storage units in 2-4-C (and their impact on the modelling outcomes for the market) can deviate from the residual demand strategy's planned profiles due to the modelled price, curtailment due to network constraint equations or hitting the limits of its storage capacity. 2-4-C ensures that these energy limits of the storage units are obeyed; for example, if a storage unit is not able to fully charge as planned due to price, this flows on to the planned discharge profile where it will not be able to completely follow the plan as it will run out of stored energy.

5. Base Scenario results

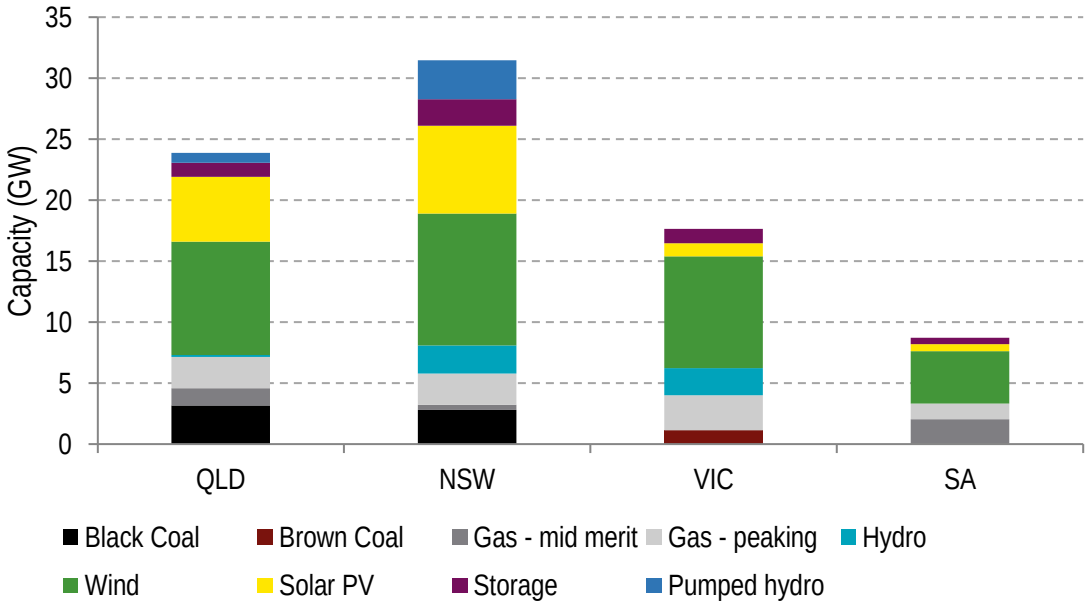
This section presents an overview of the outcomes in the Base Scenario, including the Project dispatch profiles in Cases 2 and 3. These provide useful context for the analysis that follows in the subsequent sections.

5.1 Wholesale market outcomes

5.1.1 Capacity mix

Figure 7 presents forecast capacity by technology in the NEM for the Base Scenario, as taken from the 2022 ISP Step Change outcome for 2030-31 (see Section 3.1) for more details.

Figure 7: Forecast large-scale capacity by technology in the NEM for Case 3



In the Base Scenario and Sensitivity, a total of 10.6 GW of black coal, 3.7 GW of brown coal and 0.8 GW of gas generation is assumed to retire by 2030-31 compared to 2022-23. This primary electrical energy resource is replaced predominantly by 24 GW of wind and 6 GW of utility scale solar PV as per the ISP Step Change outcomes.

These renewable energy technologies are supported by 3.9 GW of large-scale energy storage and 9.5 GW of gas capacity across the NEM. The market modelling includes an assumed additional 1.75 GW of gas capacity in Queensland and Victoria over and above the 7.75 GW of gas in the ISP outcomes in order to maintain unserved energy below the reliability standard[12].

[12] This is likely due to a few fundamental differences in the modelling approach, including that the ISP does not incorporate full detailed N-1 network constraint equations and it dispatches storage with perfect foresight. Whilst additional storage capacity may be able to be installed instead of some of the firming gas capacity, EY adopted this approach for simplicity and consider it to not be material as the OCGT capacity is the same in each case and the NSW capacity (where the Project is located) did not need adjustment.

5.1.2 Price

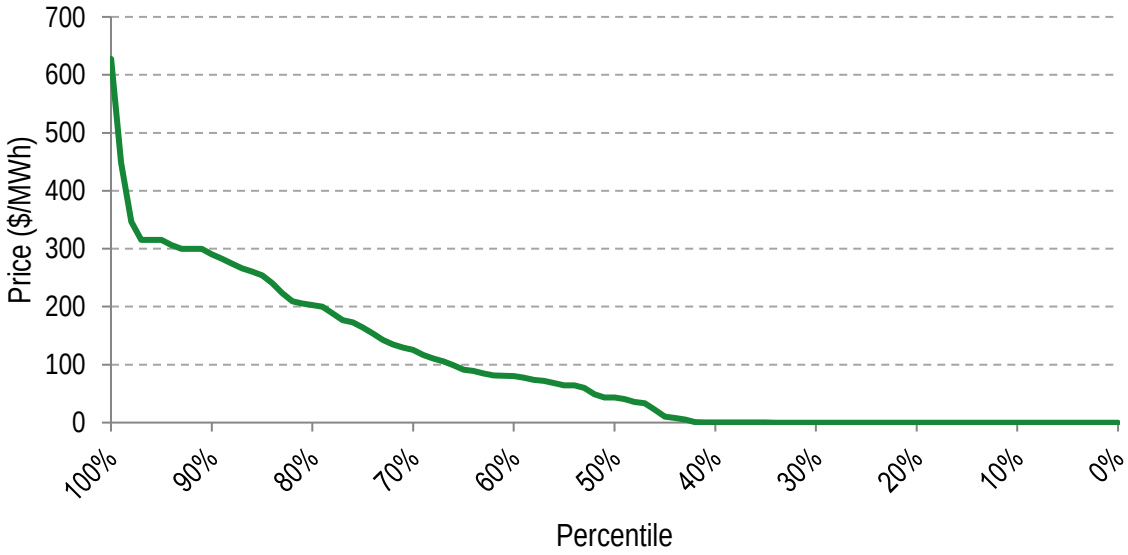
Table 8 shows the annual time-weighted average price forecast for each case in 2030-31 for the NEM mainland regions across three reference years and all iterations. The NSW price is lower in Cases 2 and 3 relative to Case 1, which is a result of the Project helping to reduce peak prices with its generation in the evening.

Table 8: Annual NSW time-weighted average price ($/MWh) in 2030-31 (Base Scenario)

Case 1	Case 2	Case 3
108.29	102.11	100.81

Price duration curves show the distribution of prices across a year. This presentation of market prices is produced by sorting the prices from highest to lowest and presenting the x-axis as a percentile. Figure 8 shows the forecast 2030-31 NSW price duration curve for Case 3.

Figure 8: NSW price duration curve for Case 3 (2030-31)



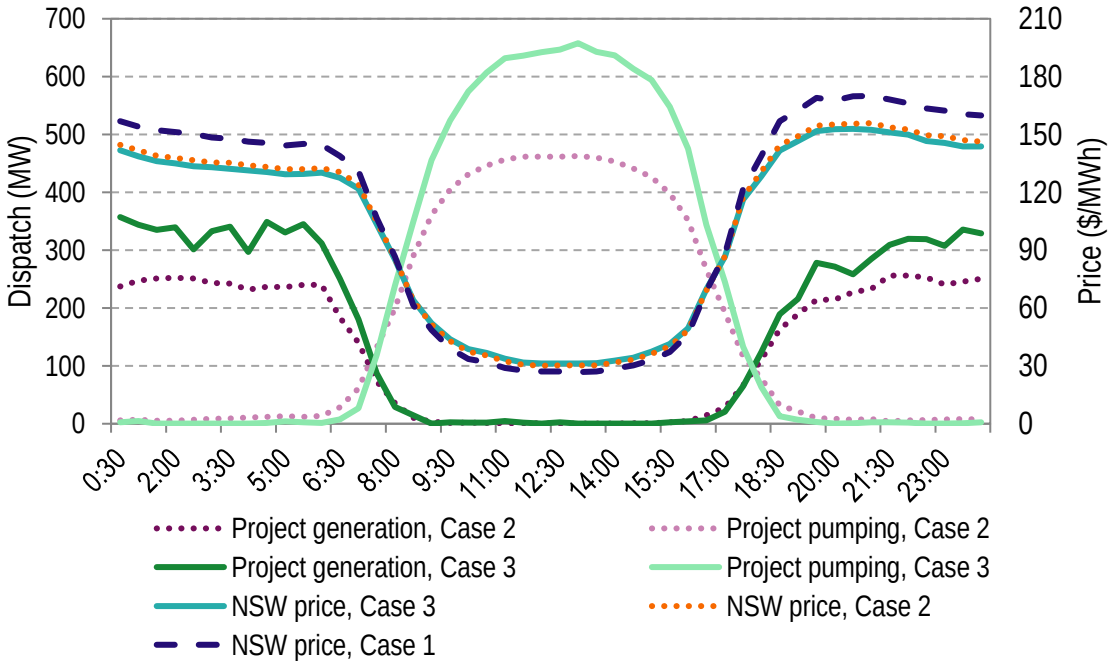
As indicated in Figure 8, over 40% of periods in NSW in 2030-31 have prices at or near zero, while approximately 8% of periods have prices over $300/MWh. This is an outcome of the modelled capacity mix and bidding assumptions, with a significant amount of coal capacity being replaced by zero-bidding renewable generation. Accompanying firming capacity from gas generation for high demand periods set higher wholesale market prices for a small percentage of the year.

These price outcomes are significantly lower than have occurred in the NEM in the recent 12 months at the time of writing this Report. This is partly due to much higher coal and gas prices in the recent year compared to the 2022 ISP assumptions for 2030-31. If similarly high fuel prices were to be assumed for modelling 2030-31, it would be expected that the results for the Project would be at least as large as the ones presented.

5.2 Project dispatch outcomes

Figure 9 presents the modelled outcomes for the Project's generator and pump dispatch alongside the NSW wholesale market price on a time-of-day average basis. It is evident that the storage operation planning algorithm allocates generation during higher priced periods overnight and morning and evening peaks, while pumping is allocated during middle-of-day periods with lower prices largely driven by high solar resource availability.

Figure 9: Time-of-day average dispatch profile for the Project and the NSW wholesale market price



The area under the generation and pumping curves represents the total average volume of energy dispatched or pumped per day. Comparing the energy dispatched between Case 2 and Case 3, there is less energy dispatched in Case 2. This is due to the Project's generation and pumping capacity being smaller (600 MW instead of 900 MW), resulting in a longer pumping time being required to fill the Project's reservoir. This restricts the ability for the Project to fill its reservoir from empty in a single day, especially when it is only economical to do this during low price periods during the day. With the reservoir not full at the end of the daytime, lower generation is available to be dispatched overnight, compared to the 900 MW Project.

Figure 10 shows the duration curves for the modelled generation and pumping profiles for the Project in Case 2 and Case 3. The curves provide some context for the time-of-day averages presented in Figure 9. In particular, the charts show that when the Project is pumping, it tends to be at full capacity in most cases. This means that where the pumping average is lower than full capacity in Figure 9, this is largely comprised of some periods with pumping at full capacity and others with no pumping.

Figure 10: Duration curve of the modelled Project dispatch generation and pumping for Case 2 and Case 3

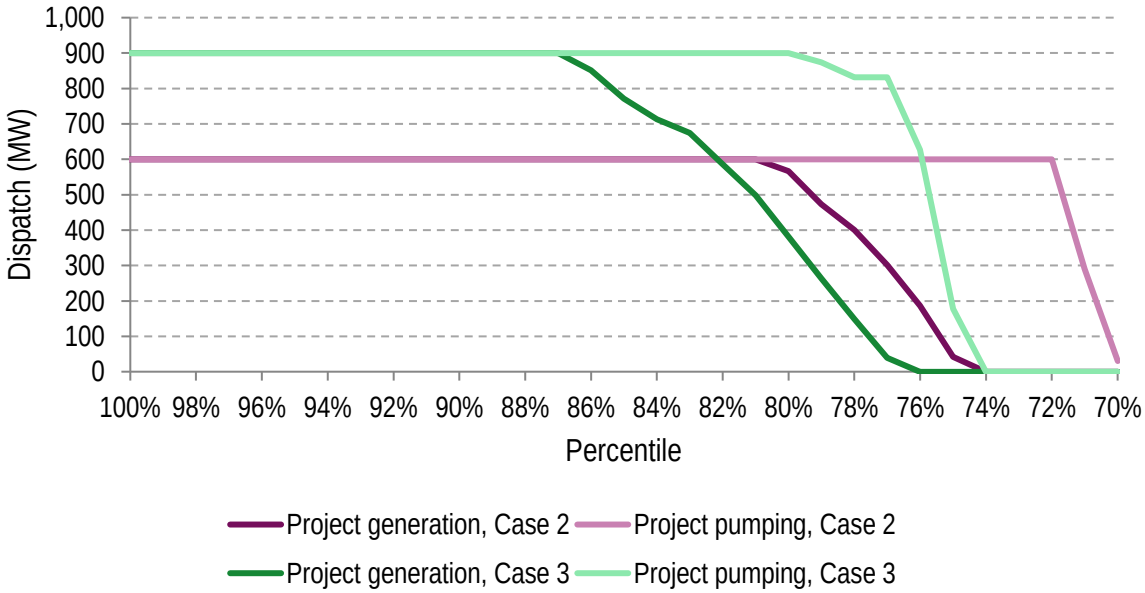


Table 9 below shows the generation and pumping volume, capacity factor and average number of cycles per day from the modelling outcomes.

Table 9: Project dispatch and pumping volume, capacity factor and average number of cycles per day

Project gen/pump	Case 2 gen	Case 2 pump	Case 3 gen	Case 3 pump
Generation/pumping (GWh)	1,156	1,473	1,440	1,836
Capacity factor (%)	22.0	28.0	18.3	23.3
Average number of cycles per day	0.44		0.55	

With 0.55 cycles per day on average, the Project is modelled to use a bit over half of its reservoir capacity through dispatched generation on average each day. This is an outcome of EY's storage operating strategy as presented in Section 4 and takes into account the price arbitrage opportunity for the Project alongside the other competing storage projects, including Snowy 2.0. It is shown that while Case 3 has a lower generation and pumping capacity factor compared to Case 2, this equates to a higher average number of cycles per day due the Project having fewer hours of storage in Case 3 (8 hours versus 12).

6. Market benefits study outcomes

6.1 Wholesale market and retail prices

As shown in Table 8 in Section 5.1.2, the annual time-weighted average wholesale market price in NSW is reduced with the Project in Cases 2 and 3 compared to Case 1. However, the demand-weighted average price is more representative of the wholesale price paid by customers. The demand-weighted average price represents the average price for each MWh of demand, rather than the time-weighted average, which weights each half-hourly price outcome equally across a year. The demand-weighted price is typically higher than the time-weighted average because higher demand periods tend to have higher prices than lower demand periods. Assuming a direct pass through to customer retail bills of modelled changes in the demand-weighted wholesale price, the impact on retail bills can be estimated by multiplying the demand-weighted price by the projected total regional energy market demand.

Table 10 presents the demand-weighted price outcomes for Cases 1-3 in each of the mainland regions, along with the estimate of the total impact across all customer retail bills comparing Cases 2 and 3 with Case 1.

Table 10: Demand-weighted price outcomes for the mainland regions for Cases 1-3 along with an estimate of reductions in total customer retail bills comparing Cases 2 and 3 to Case 1

	Demand-weighted wholesale price ($/MWh)			Total impact on customer retail bills ($m)	
Region	Case 1	Case 2	Case 3	Case 2 – Case 1	Case 3 – Case 1
NSW	125	118	116	-481	-583
Queensland	185	181	180	-246	-274
Victoria	138	134	133	-178	-217
South Australia	114	110	109	-47	-60
			Mainland total:	**-953**	**-1,134**

The table shows that the 900 MW Project is estimated to reduce total NSW customer retail bills by $583m and total retail bills across all mainland regions by $1,134m compared to Case 1 without the Project. The 600 MW Project is estimated to reduce the wholesale component of retail bills by approximately 16% less.

6.2 NEM-wide market benefits

NEM-wide market benefits are typically evaluated in regulatory investment tests for transmission projects (RIT-Ts). These studies often compare proposed transmission infrastructure to non-network options such as storage projects and evaluate the impact on market costs comparing each option to a counterfactual case over a 20-30 year modelling horizon. The RIT-T guidelines[13] organise the key market benefits for a RIT-T into three broad categories: capital costs, operating costs and environmental benefits.

[13] Application guidelines – Regulatory investment test for transmission. Australian Energy Regulator. https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20application%20guidelines%20-%2025%20August%202020.pdf

For this report, we have evaluated the Project for a selected set of market benefits on a single year (2030-31). The market benefits considered directly from the modelling are:

- Operating cost benefit: generation fuel cost savings.
- Operating cost benefit: generation variable operation and maintenance (VOM) cost savings.
- Environmental benefit: electricity sector emissions reductions.

Capital cost deferral benefits and fixed operation and maintenance (FOM) cost savings have no direct outcome from the modelling as the scope only considers a single year and the capacity mix is specifically aligned with the ISP Step Change outcomes. Table 11 summarises the NEM-wide market benefits of the Project comparing Cases 1, 2 and 3.

Table 11: NEM-wide market benefits outcomes in the Base Scenario cases

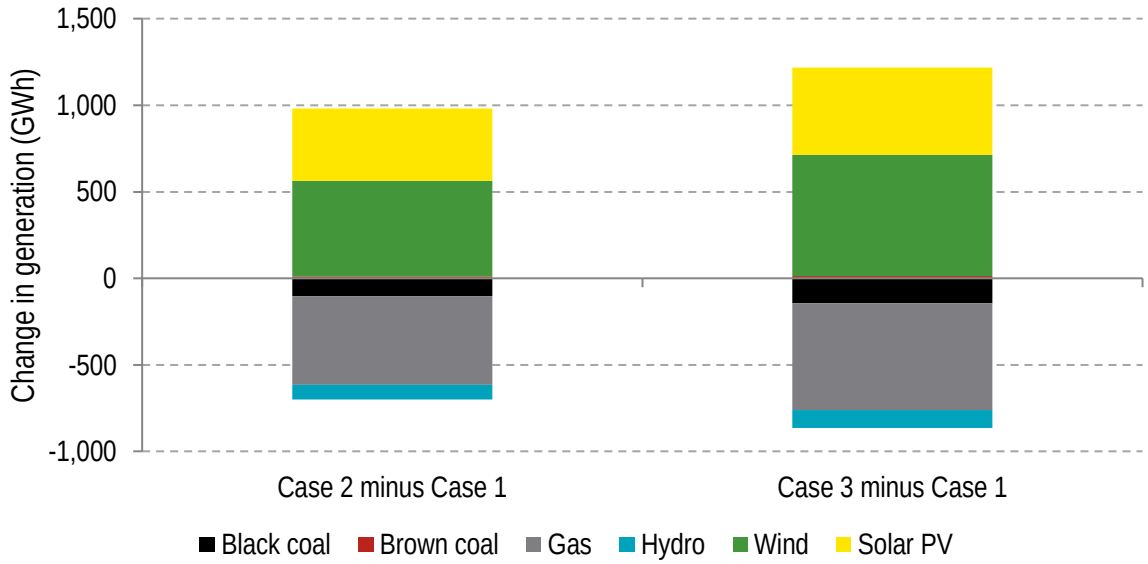
Market benefit type	Case 1	Case 2	Case 3	Market benefit Case 2 – Case 1	Market benefit Case 3 – Case 1
Fuel costs ($m)	2,549	2,501	2,478	-48	-70
VOM ($m)	417	412	411	-5	-6
Generation emissions* (MT CO2-e)	40.5	40.1	40.0	-0.35	-0.43
Generation emissions (% reduction)				-0.9%	-1.1%

* Includes combustion and fugitive emissions.

In Section 5.2, it was shown that the Project is dispatched more in Case 3 compared to Case 2. Consistent with this, the market benefits outcomes in Table 11 show that the 900 MW Project in Case 3 has higher market benefits than the 600 MW Project in Case 2.

Figure 11 below shows the generation dispatch differences comparing Case 2 and Case 3 to the Case 1 counterfactual. The chart indicates which generation technologies the emissions reductions are coming from, as well as the operating cost savings.

Figure 11: NEM change in generation dispatch comparing Case 2 and Case 3 to Case 1



6.3 Benefits to the New England REZ

This section presents the impacts of the Project on the MLFs and curtailment for wind and solar projects in the New England REZ, comparing Cases 1, 2 and 3.

6.3.1 Wind and solar MLFs

Table 12 presents the volume-weighted[14] MLF outcomes for wind and solar projects in New England for each case. This is calculated with a capacity weighting of generic and named projects with connection points at Dumaresq, Armidale, Tamworth and Dungowan.

Table 12: Capacity-weighted MLF outcomes for New England wind and solar PV capacity

MLF	Case 1	Case 2	Case 3	Case 2 minus Case 1	Case 3 minus Case 1
Wind	0.934	0.934	0.934	0.000	0.000
Solar	0.940	0.946	0.948	+0.006	+0.008

Drivers of the differences in MLF

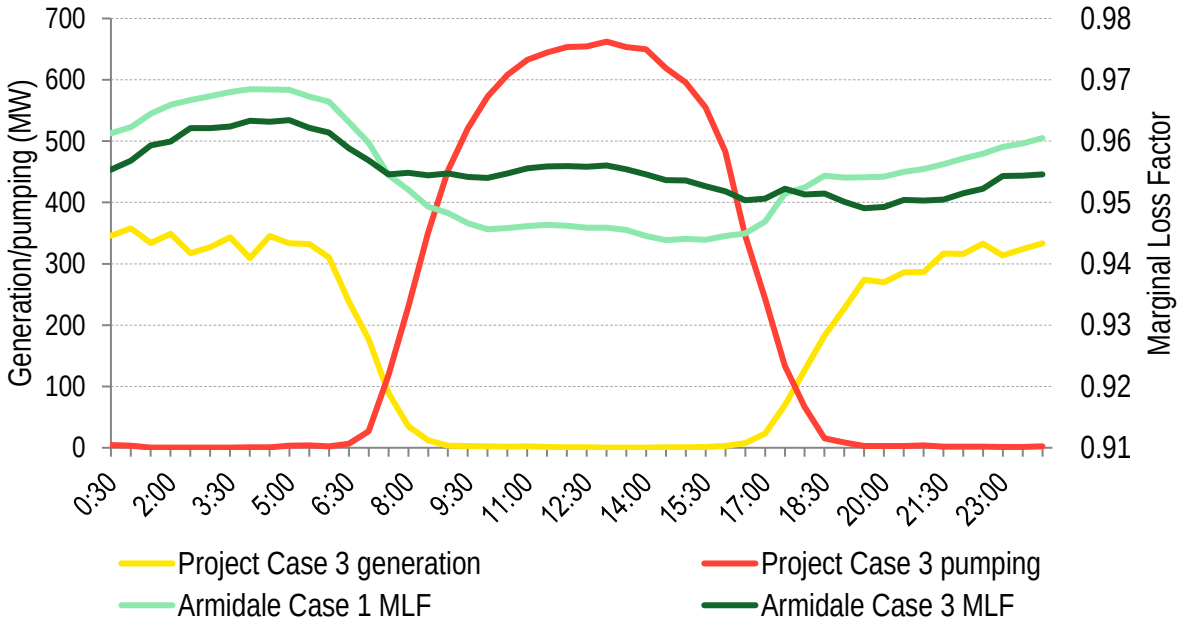
MLFs will tend to be increased when the Project is pumping as that adds load to the New England REZ and reduces flow (and losses) between New England and the NSW regional reference node in Sydney. Conversely, when the Project generates, it adds generation to the New England REZ, and this will tend to increase the flow from New England to Sydney. Since the Project pumping is modelled to occur almost entirely during the day, this benefits solar project MLFs, and the difference between the MLF results in Case 3 and Case 1 is greater for solar than for wind. Since wind generation can occur at all times it is impacted by some increases and some decreases in MLF when the Project pumps or generates, respectively.

The modelled 0.008 MLF increase across the 2 GW of solar capacity in New England is not insignificant as this represents a 0.8% increase in market revenue received by these generators.

Figure 12 presents the relationship on a time-of-day basis between the Project's dispatch and MLF outcomes at Armidale between Case 1 and 3. The figures compare the average half-hourly MLF and dispatch by time-of-day and show that Case 3 MLF tends to be higher during the day when the Project is pumping, although drops by a smaller proportion when the Project generates due to the Project's generation being lower on average compared to pumping periods.

[14] Volume-weighting refers to the average MLF being weighted by the dispatched generation (volume) from each generator, from a set of half-hourly MLFs and generation dispatch values. This is the official calculation method for generator and load MLFs.

Figure 12: Time-of-day average Project generation and Armidale MLF



6.3.2 Wind and solar curtailment

Table 13 and Table 14 present the curtailment of wind and solar in New England in 2030-31 as a percentage of total availability and in absolute in GWh terms respectively. Network curtailment is defined as generation that is constrained due to network limitations. As mentioned earlier only thermal constraint equations have been modelled to capture network limitations. Voltage/transient stability constraint equations have not been considered in this study which may impact the results presented here. Figure 13 presents the numbers included in Table 13 graphically.

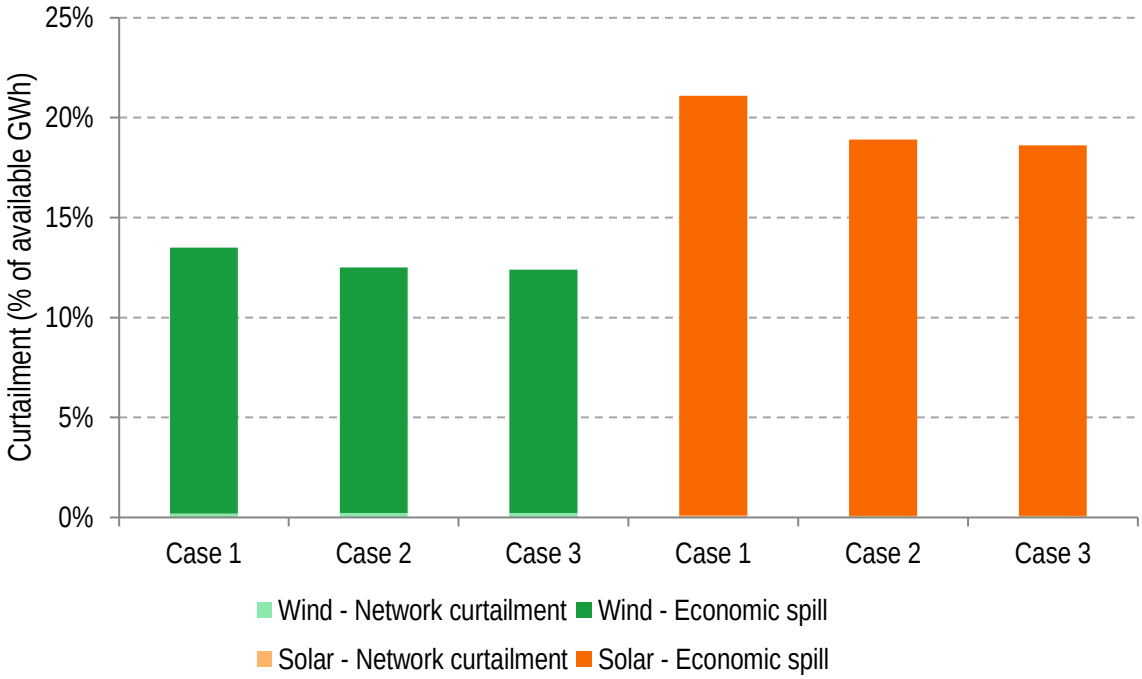
Table 13: Total wind and solar curtailment as a percentage of total availability in New England, 2030-31

	Curtailment (%)	Case 1	Case 2	Case 3	Case 2 minus Case 1	Case 3 minus Case 1
Wind	Network curtailment	0.2	0.2	0.2	0.0	0.0
	Economic spill	13.3	12.3	12.2	-1.0	-1.1
	Total curtailment	13.5	12.5	12.4	-1.0	-1.1
Solar	Network curtailment	0.1	0.1	0.1	0.0	0.0
	Economic spill	21.0	18.8	18.5	-2.2	-2.5
	Total curtailment	21.1	18.9	18.6	-2.2	-2.5

Table 14: Total wind and solar curtailment in absolute GWh terms for New England, 2030-31

	Curtailment (GWh)	Case 1	Case 2	Case 3	Case 2 minus Case 1	Case 3 minus Case 1
Wind	Network curtailment	28	30	30	2	2
	Economic spill	1,842	1,695	1,682	-147	-160
	Total curtailment	1,870	1,725	1,712	-146	-158
Solar	Network curtailment	3	3	3	0	0
	Economic spill	914	818	806	-96	-108
	Total curtailment	917	821	809	-96	-108

Figure 13: Total wind and solar curtailment as a percentage of total availability in New England, 2030-31



It is evident across all three cases that generators in New England are exposed to low levels of thermal network curtailment. This is due to the assumed network augmentations, particularly the NE REZ link alleviating thermal network limits between New England and Sydney. Economic spill is present across all three cases, driven by the significant volume of wind and solar generation installed across NSW resulting in frequent periods of near-zero prices as shown earlier in Figure 8.

In both Cases 2 and 3, the Project is forecast to reduce economic spill for all wind and solar projects across NSW compared to Case 1 (note the results only show the outcomes for generators in the New England REZ). This is because the majority of economic spill is forecast to occur during the day, when both solar PV and wind generation can be available, and this is when the Project is modelled to be pumping and adding load to the market, allowing more solar PV and wind generation to be dispatched.

7. Project capacity comparison

7.1 Modelling outcomes: comparing Cases 2 and 3

Table 15 summarises the modelling outcomes comparing the 600 MW (Case 2) and 900 MW (Case 3) Project configurations, as presented in Section 6.

Table 15: Summary of modelling outcomes comparing the 600 MW and 900 MW Project configurations

Outcome type	Modelling outcome	600 MW Case 2 – Case 1	900 MW Case 3 – Case 1
Electricity customer costs	Mainland customer retail bills ($m)	-953	-1,134
NEM market benefit	Generation emissions* (MT CO2-e)	-0.35	-0.43
NEM market benefit	Fuel costs ($m)	-48	-70
NEM market benefit	VOM ($m)	-5	-6
New England REZ generators	Solar PV capacity-weighted MLFs	+0.006	+0.008
Generation curtailment	Wind total curtailment (% of available energy)	-1.0	-1.1
Generation curtailment	Solar PV total curtailment (% of available energy)	-2.2	-2.5

* Includes both combustion and fugitive emissions

For all outcomes shown the 900 MW Project has a greater benefit than the 600 MW Project. As described in Section 5.2, this is primarily due to the 900 MW project being dispatched more, which is a result of it having more flexibility to pump and generate with the same size storage reservoir as the 600 MW project (7,200 MWh in both cases). However, with an extra turbine unit and associated tunnel, the 900 MW project has a higher capital cost which must be considered in any type of cost/benefit assessment.

8. Insurance case study outcomes

As identified in Sections 5 and 6, the NE REZ link is expected to play a key role in supporting the development of renewable generation in NSW, particularly the New England REZ. The NE REZ link consists of a new 500 kV transmission line between Armidale and Bayswater, via Dungowan. Several new substations integrate the new line into the existing transmission network. The link is expected to provide support to the NE REZ in several ways, including through MLF uplift and reduced curtailment.

Given the outcomes in Section 6 are inclusive of benefits provided by the NE REZ link, the Client was interested in understanding a Sensitivity for 2030-31 assuming that the NE REZ link is delayed beyond that year. This Sensitivity has two cases: with the 900 MW Project (Case 3a) and without the Project (Case 1a). Comparing these two cases explores the potential for the Project to provide:

- Market benefits to the NEM in this NE REZ link delay situation where the market experiences a transmission bottleneck between New England the rest of NSW.
- Generators in the New England REZ reduced levels of curtailment in the absence of this key transmission augmentation project.

All assumptions for the Case 3a/1a are identical to Case 3/1, with two exceptions:

- New thermal network constraints were developed to account for the assumed omission of the NE REZ link.
- Any new entrant renewable generation assumed to connect to a new substation as part of the NE REZ link is moved to the geographically closest existing substation.

Note that total REZ generation capacity as per Table 7 remains unchanged relative to the Base Scenario.

8.1 Overview of outcomes for the Sensitivity scenario

8.1.1 Negative settlement residue and clamping of QNI

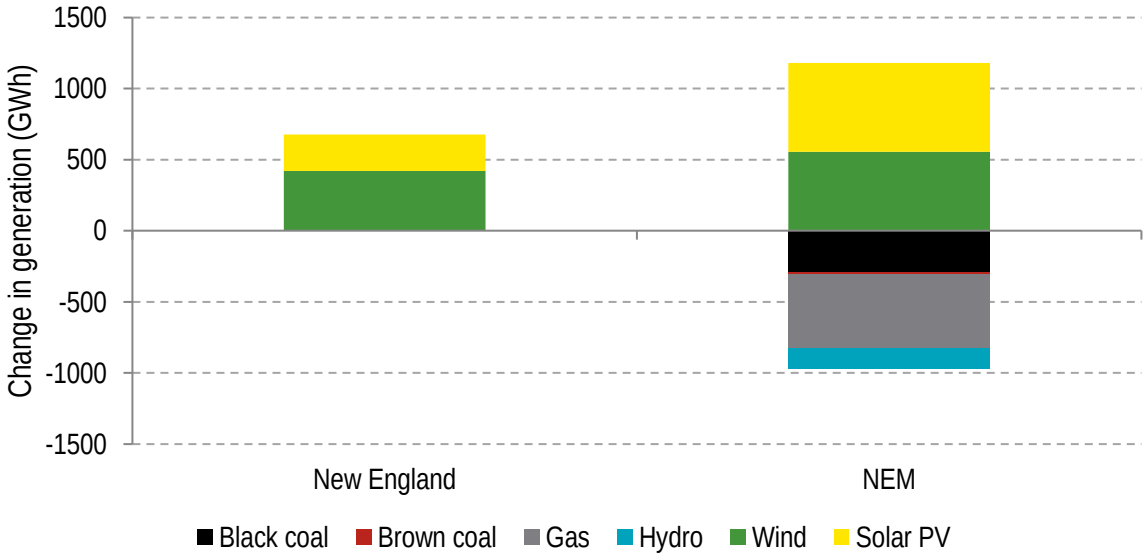
In the NEM, transmission network constraints can sometimes result in the least cost dispatch outcomes having electricity flows from a region with higher wholesale market prices to a region with lower electricity market prices; an outcome referred to as counter-price flows. This creates what is called negative settlement residues that can accumulate if the outcome persists. Under the market rules, AEMO can limit the interconnector to zero (clamping) to prevent this from happening.

In the Base Scenario, counter-price flows did not occur in the modelling with any material regularity. However, in the Sensitivity cases, the modelled outcomes indicated the need for regular application of interconnector clamping on the Queensland – New South Wales interconnector. This occurred with a similar frequency in Cases 1a and 3a due to the Project adding load in some periods and generation in others.

8.1.2 Generation mix

Figure 14 shows the differences in generation dispatched in New England and across the NEM between Case 1a and Case 3a.

Figure 14: Difference in dispatched generation in New England and across the NEM by type between Case 1a and Case 3a



The figure shows that in the event of a delay to the NE REZ link, the inclusion of the Project (Case 3a) results in approximately 700 GWh more wind and solar generation dispatched in New England compared Case 1a. The difference in New England generation between Case 1a and Case 3a is primarily driven by the pumping load from the Project allowing more wind and solar generation to be dispatched in New England that would otherwise be curtailed by network constraints.

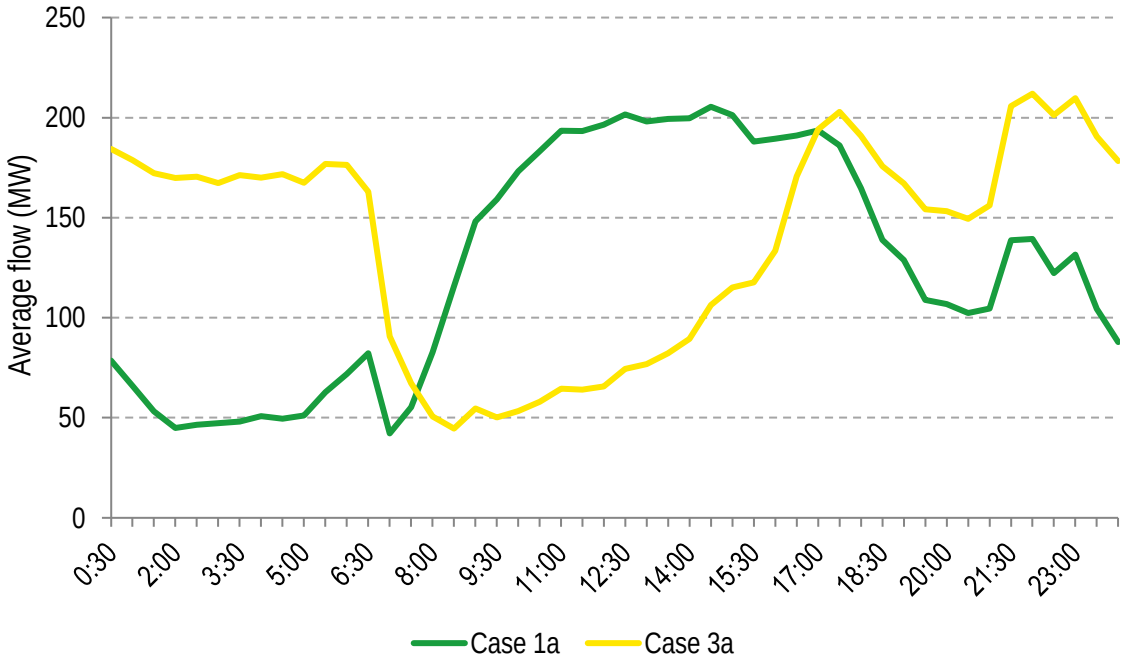
Across the whole NEM, the Project enables approximately 1,200 GWh increased renewable generation dispatch which drives a reduction in the volume of coal and gas fired generation. This is a similar outcome to the comparison between Cases 1 and 3 as presented in Figure 11.

8.1.3 Flow on the Queensland – New South Wales interconnector

Figure 15 shows the forecast average total flow on a time-of-day basis on the interconnectors between NSW and QLD[15] comparing Cases 1a and 3a. In the chart a positive value indicates that NSW is forecast to export more energy to QLD on average, but at all times of the day there are some periods with the flow is southward from QLD to NSW.

[15] The two interconnectors are the Queensland-New South Wales Interconnector (QNI) and the Terranora interconnector. The majority of the flow is on QNI.

Figure 15: Forecast average total flow by time-of-day on the interconnectors between QLD and NSW comparing Cases 1a and 3a (positive represents flow from NSW to QLD on average)



The chart shows that with the Case 3a Project generation overnight, NSW is forecast to export more energy to QLD on average. It is the opposite during the day, with the Project pumping. With the existing transmission between New England and Sydney flowing at its maximum for a high proportion of time in the Sensitivity, the Project in Case 3a has more scope to export the additional New England wind and solar generation to Queensland.

8.1.4 Price

Table 16 below shows the time-weighted average prices in NSW and QLD for Case 1a and 3a and compares this to Case 1 and 3.

Table 16: Annual NSW and QLD time-weighted average prices ($/MWh) outcomes in the Base Scenario Cases 1 and 3 and Sensitivity Cases 1a and 3a

Scenario/Case	Case 1/1a	Case 3/3a
Base (NSW)	108	101
Sensitivity (NSW)	129	124
Base (QLD)	160	156
Sensitivity (QLD)	161	149

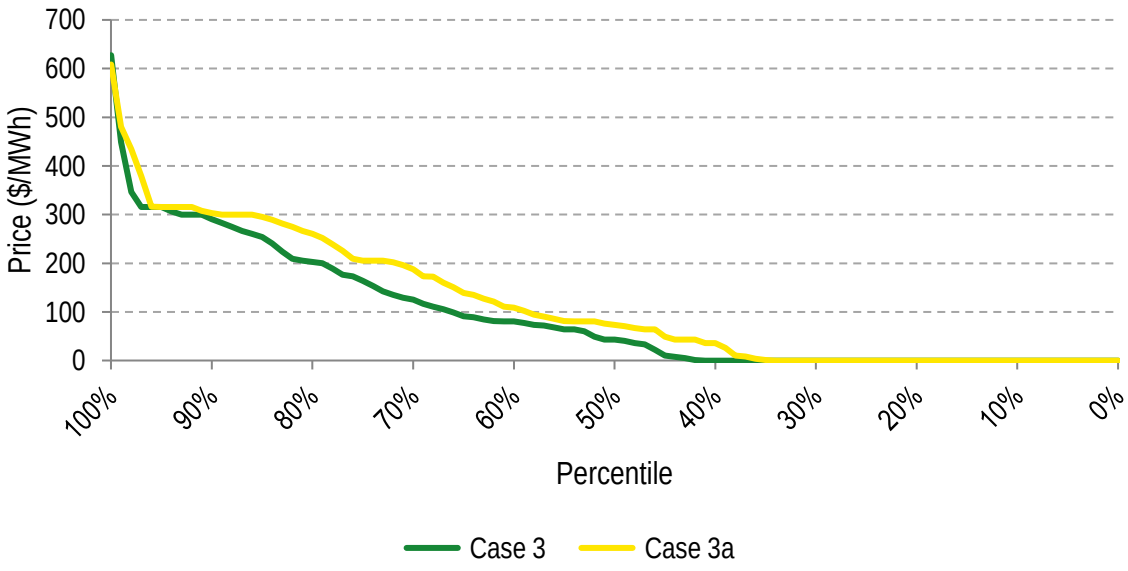
The forecast reduction in the time-weighted average wholesale market price for NSW is on a similar order of magnitude in the Sensitivity compared to the Base Scenario. However, the forecast average prices in Queensland are forecast to be $12/MWh lower in Case 3a compared to Case 1a, compared to a $4/MWh reduction in the Base Scenario. This is a result of the transmission capability between New England and Sydney being at its limit for a significant proportion of the year in the Sensitivity, while there is some headroom on the Queensland-New South Wales Interconnector (QNI), as shown earlier in Figure 15. In Case 3a the Project pumping utilises QNI more, allowing additional wind and solar generation to be dispatched during the day, both in New England and imported over QNI from Queensland, while in the evening the Project generation exports this generation to Queensland, lowering wholesale market prices in Queensland.

The results for the Sensitivity (irrespective of the presence of the Project) represent approximately a 20% increase ($21-23/MWh) in the average NSW wholesale market prices compared to the Base

Scenario. The uplift relative to the Base Scenario is a consequence of increased curtailment of renewable generation in New England in the absence of the NE REZ link. The consequence of this is that higher cost generators located south of New England are frequently required to be dispatched to meet demand in NSW, and therefore setting NSW prices higher, instead of the lower cost generation in New England and Queensland.

Figure 16 demonstrates the impact by comparing the NSW price distributions between Case 3 and Case 3a. In Case 3a there are fewer periods where NSW prices are close to zero which implies that renewables are setting prices less frequently. Furthermore the price is generally higher for a greater proportion of time.

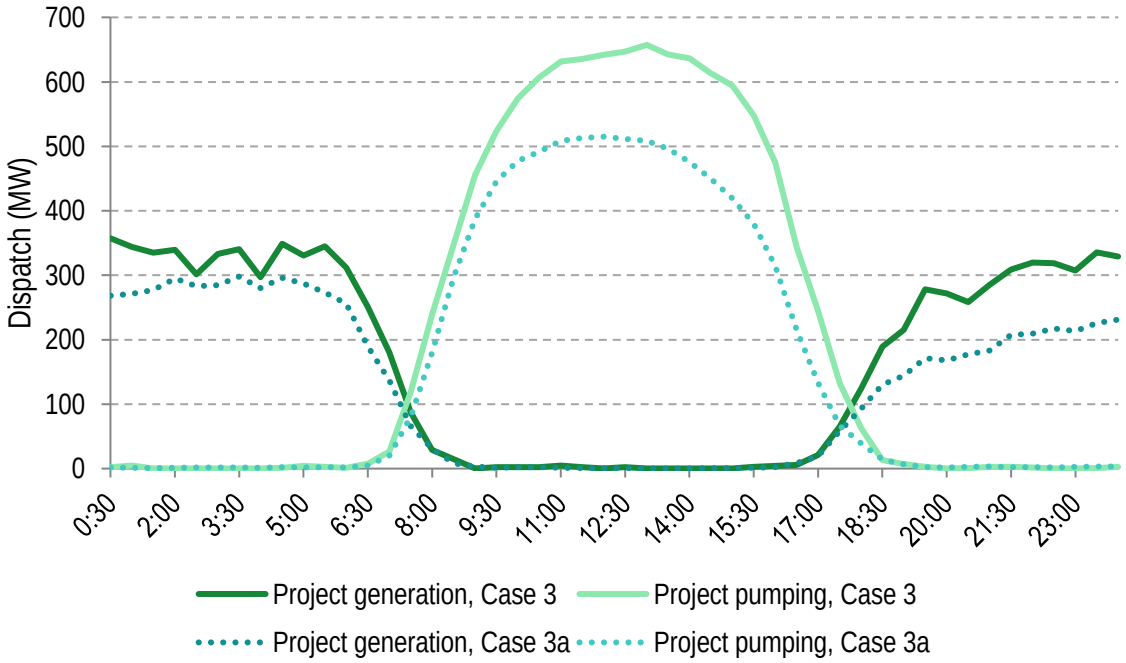
Figure 16: Comparison of NSW price distributions for the Base Scenario (Case 3) and Sensitivity (Case 3a)



8.1.5 Project dispatch profile

Figure 17 shows the modelled time-of-day average generation and pumping dispatch for the Project in the Sensitivity Case 3a, compared to Case 3.

Figure 17: Typical time-of-day average generation and pumping profile for the Project



In Case 3a dispatch of the Project generation is affected more by thermal network constraints in the absence of the NE REZ link, which explains the difference relative to Case 3. Because the Project is unable to generate as much, there is also a reduction in the pumping volume as the reduced generation means the reservoir is full more often preventing the Project from pumping. Table 17 quantifies the total generation and pumping volumes for Case 3a as well as the capacity factor and average cycles per day and compares this to Case 3.

Table 17: Project generation and pumping dispatched in terms of annual energy, capacity factor and average number of cycles per day, Case 3 versus Case 3a

Project gen/pump	Case 3 gen	Case 3 pump	Case 3a gen	Case 3a pump
Generation/pumping (GWh)	1,440	1,836	1,145	1,459
Capacity factor (%)	18.3	23.3	14.5	18.5
Average number of cycles per day	0.55		0.44	

8.2 Retail prices

Table 18 presents the demand-weighted average price outcomes and total impact on retail electricity bills across the four mainland regions comparing Cases 1a and 3a.

Table 18: Demand-weighted price outcomes for the mainland regions for Cases 1a and 3a along with an estimate of reductions in total customer retail bills comparing the two cases

	Demand-weighted wholesale price ($/MWh)		Total impact on customer retail bills ($m)
Region	Case 1	Case 3	Case 3a – Case 1a
NSW	148	142	-378
Queensland	187	173	-796
Victoria	155	152	-114
South Australia	128	126	-32
		Mainland total:	**-1,319**

In comparison to the outcomes in the Base Scenario, the forecast total retail bill impact of the 900 MW Project is higher in the Sensitivity at $1.3b (compared to $1.1b in the Base Scenario as presented in Section 6.1). This increased benefit is due to a large improvement in the wholesale price reductions forecast in Queensland.

8.3 NEM-wide market benefits

Table 19 presents the NEM-wide market benefits for the Sensitivity cases. These outcomes are of a similar order of magnitude to the Base Scenario cases presented in Section 6.2.

Table 19: NEM-wide market benefits outcomes in Cases 1a and 3a

Market benefit type	Case 1a	Case 3a	Market benefit (Case 3a – Case 1a)
Fuel costs ($m)	2,698	2,638	-60
VOM ($m)	433	426	-7
Generation emissions* (MT CO2-e)	41.6	41.0	-0.6
Generation emissions (% reduction)			-1.3%

* Includes combustion and fugitive emissions.

8.4 Benefits to the New England REZ

8.4.1 Wind and solar MLFs

Table 20 shows the capacity-weighted MLF outcomes for New England renewable generators in the Sensitivity.

Table 20: Capacity-weighted MLF outcomes for renewable projects in New England

MLF	Case 1a	Case 3a	Case 3a minus Case 1a
Wind	0.883	0.881	-0.002
Solar	0.882	0.892	0.010

Similar to the Base Scenario, there are only minor differences between the MLF outcomes for wind generation with a larger improvement for solar. The wind MLF outcomes are slightly reduced in this case, and the uplift to the solar PV MLFs is higher than in the Base Scenario. The main driver for this limited impact is the substitutive nature of the line flows in the New England area. Without the NE REZ link and considering the significant build out of renewables in the New England REZ as part of the NSW electricity infrastructure roadmap, the transmission paths to Sydney are heavily loaded for extended periods of time. This heavy loading is present regardless of whether the Project is installed, which results in relatively consistent loss outcomes between the two cases.

8.4.2 Wind and solar curtailment

Table 21 and Table 22 present the curtailment outcomes for new entrant wind and solar in New England as a percentage of total availability and in absolute GWh terms for the Sensitivity. Figure 18 presents the numbers in Table 21 graphically.

Table 21: Total wind and solar curtailment as a percentage of total availability in New England, 2030-31

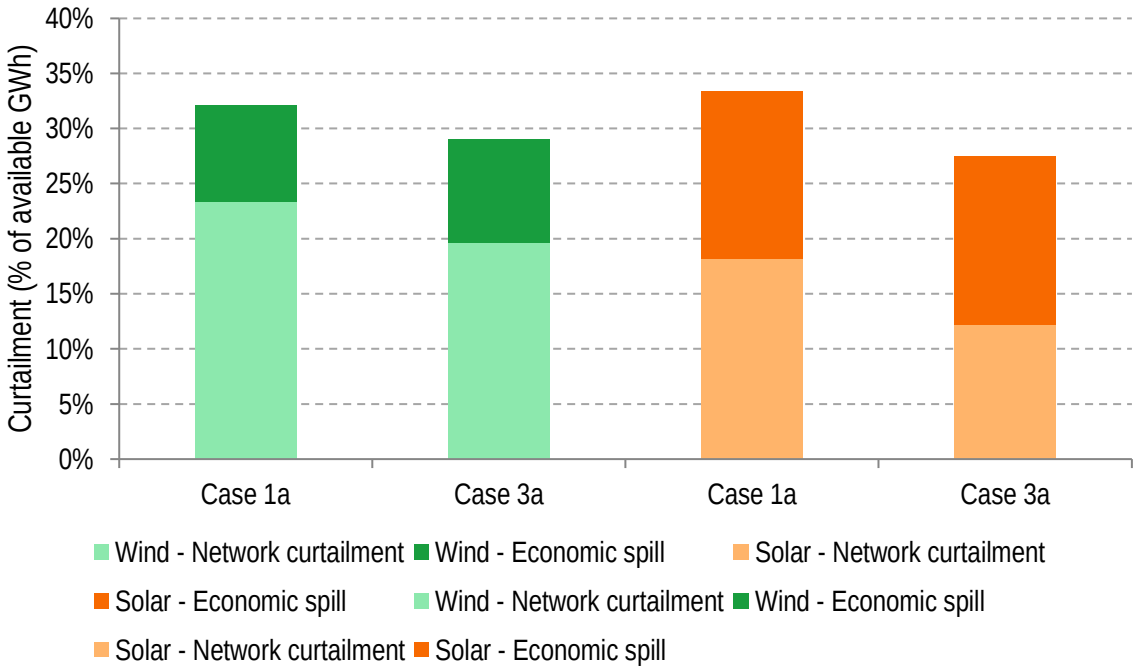
	Curtailment (%)	Case 1a	Case 3a	Case 3a minus Case 1a
Wind	Network curtailment	23.3	19.6	-3.7
	Economic spill	8.8	9.4	0.6
	Total curtailment	32.1	29.0	-3.1

	Curtailment (%)	Case 1a	Case 3a	Case 3a minus Case 1a
Solar	Network curtailment	18.2	12.2	-6.0
	Economic spill	15.2	15.3	0.1
	Total curtailment	33.4	27.5	-5.9

Table 22: Total wind and solar curtailment in absolute GWh terms for New England, 2030-31

	Curtailment (GWh)	Case 1a	Case 3a	Case 3a minus Case 1a
Wind	Network curtailment	3,214	2,704	-510
	Economic spill	1,212	1,300	88
	Total curtailment	4,426	4,004	-422
Solar	Network curtailment	790	532	-258
	Economic spill	662	664	2
	Total curtailment	1452	1196	-256

Figure 18: Total wind and solar curtailment as a percentage of total availability in New England, 2030-31



Unlike the Base Scenario, the forecast level of network curtailment on renewable projects in New England is relatively high in the Sensitivity. As a result, the Project provides a larger reduction to those curtailment outcomes. The Project dispatch reduces thermal network curtailment of wind generation by 3.7% of total availability and 6.0% for solar PV. Some of the benefit of reduced network curtailment is offset by an increase in economic spill driven by increased competition amongst renewables. However, the net impact of the Project is to increase the dispatch of wind generation in New England by 422 GWh and solar PV by 256 GWh, or 678 GWh in total.

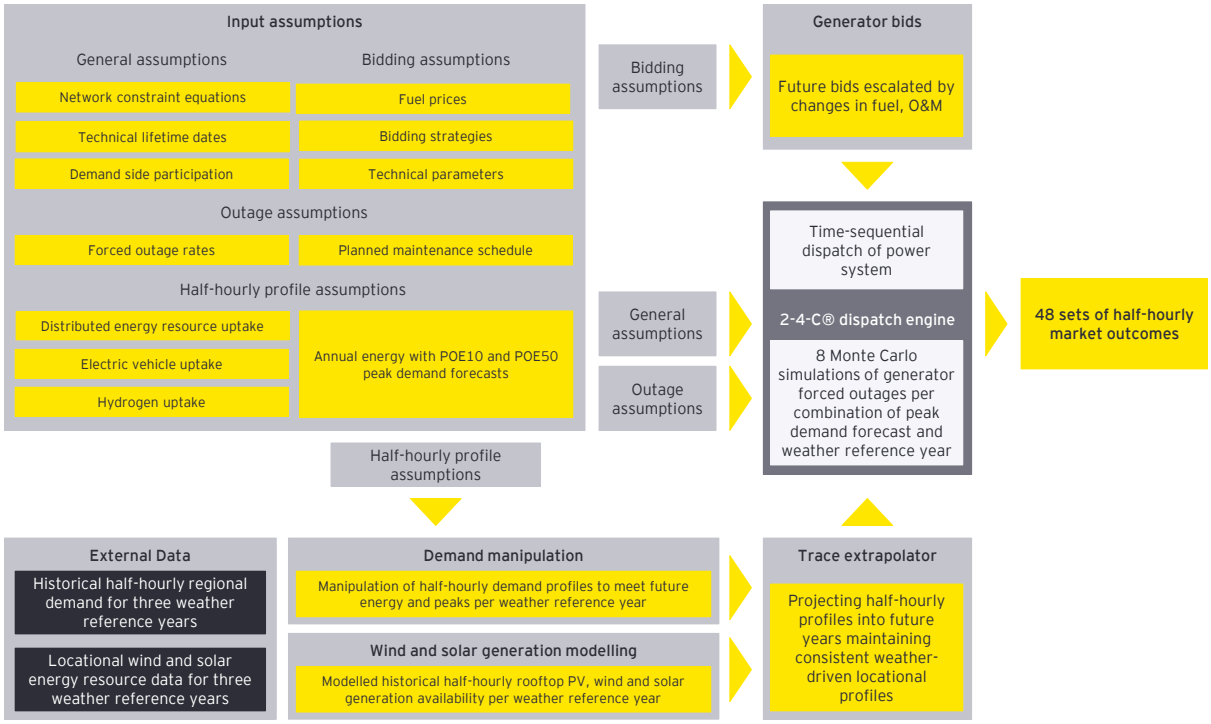
The reduction in spill of NE REZ wind and solar results in increased revenue for these projects. If a conservative PPA price of $45/MWh is assumed, this reduction in spill results in approximately $30 million per annum of additional revenue for NE REZ wind and solar generators.

Appendix A Market modelling assumptions and methodology

A.1 Electricity market simulations

The market simulations are conducted using EY's market modelling suite of software 2-4-C, which consists of an energy market dispatch engine and several software tools that develop input data and analyse output data. The 2-4-C dispatch engine is equivalent to NEMDE used by the AEMO in operating the market in real time. The 2-4-C dispatch engine has been applied in this engagement with half-hourly time-sequential modelling for 2030-31, with explicit modelling of each generating unit and the capabilities of the electricity transmission network. Figure 19 provides an overview of the array of inputs used in a market simulation with 2-4-C.

Figure 19: Key input data flows in EY's 2-4-C electricity market model



As with NEMDE, 2-4-C bases dispatch decisions on the market rules, considering generator strategic bidding patterns and availabilities to meet regional demand. The model considers full and partial forced outages and planned outages for each generator, half-hourly renewable energy generation availability by individual power station as well as inter- and intra-regional transmission capabilities and constraints. This results in typical levels of price volatility at 30-minute time intervals captured in the modelling outcomes.

A.2 Forward-looking half-hourly modelling

EY's approach to forward-looking half-hourly modelling is to base all the inter-temporal and inter-spatial patterns in electricity demand, wind and solar energy on the weather resources and consumption behaviour in one or more historical years (reference years).

For this assessment, each future year is modelled with 48 individual iterations that make up one simulation. The 48 iterations are comprised of:

- Six different half-hourly demand profiles, comprising:
  - Three reference years of half-hourly underlying consumption patterns plus solar rooftop PV and small non-scheduled solar PV (PVNSG) profiles.
  - Two seasonal peak demand projections, representing 50% POE and 10% POE years.
- Eight Monte Carlo simulations, or iterations, of different generator forced outage profiles, based on the forced outage probabilities for each generator, as sourced from AEMO's 2021 IASR[16].
- Each reference year also uses different wind and large-scale solar generation availability profiles based on the historical weather data. Three reference years are used to capture a wide range of weather patterns and their impacts on electricity demand and locational wind and solar generation. In general, the more reference years modelled, the more different types of weather patterns can be captured.

The 48 iterations used in the modelling are summarised in Table 23 below.

Table 23: Summary of individual half-hourly iterations made on each future year

Variable	Description	Number
Peak demand outlooks	50% POE 10% POE	2
Reference year	2016-17 2017-18 2018-19	3
Monte Carlo iterations	Different generator forced outage profiles	8
Total iterations per simulation		48

Annual average outcomes for each simulated year of half-hourly results are a weighted average of 0.7 on the 50% POE iterations and 0.3 on the 10% POE iterations, based on assumptions about the distribution of demand conditions, random of unplanned outages and reference years.

A.3 Generator planned maintenance and reliability

Planned maintenance is allocated such that the availability adjusted peak demand is minimised throughout the year. By allocating the largest units first, they are going to be on maintenance during the lowest demand periods. The ultimate date chosen is the date which has the lowest demand period throughout the maintenance duration, not necessarily the lowest demand day.

As described in Section A.1, EY conducts several Monte Carlo iterations in a market simulation to capture the impact of forced (unplanned) generator outages. Each Monte Carlo iteration assigns random outages to each generating unit, based on assumed outage statistics.

2-4-C applies forced outage rate statistics for different generator types, or each individual generation facility depending on the data sets available. These parameters are applied to randomly schedule forced outages for the relevant units in each Monte Carlo iteration. The relevant units are typically thermal units such as coal, gas and hydro. Outages for wind and solar PV units are built into the half-hourly availability profiles for these units.

[16] AEMO, 10 December 2021, *2021 Inputs and Assumptions workbook*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

A.4 Bidding

For this project, EY has constructed bidding profiles for each individual generator based upon recent historical data published by AEMO. This strategy yields results that accurately model a generator's market behaviour for most of the time, implicitly capturing their bidding behaviour with respect to portfolio and contracting positions. Some of the units have different bidding profiles applied to different time slices, such as evenings, daytimes and early mornings if their historical bidding behaviour was determined to be better captured in that way.

In any single trading interval, each generating unit is modelled with a bid offering their capacity at up to 10 price-quantity pairs, as in the actual market. For example, a coal unit will bid a certain proportion of its load at or near the market floor price (-$1,000/MWh) to reflect its self-commitment intention, and incremental proportions of its capacity at positive prices to reflect their running costs and higher priced bids potentially up to the market price cap to recover fixed costs and be exposed to opportunistic pricing events in the market.

All new wind and solar projects installed in the model bid at their operating costs, which are assumed to be zero as per the 2021 IASR[17].

Whilst this approach produces a useful benchmark and provides probable volatility in pricing outcomes, its limitations are that it does not consider potential changes in portfolios over time and how the portfolios would respond with different bidding strategies to major changes in the competitive dynamics of the market by 2030-31.

A.5 Storage modelling

Battery and pumped hydro storage operation require forward planning to ensure charging/pumping and generation captures the day-to-day opportunities for arbitrage revenue. In 2-4-C, EY adopts a different forward-planning methodology for short-duration (12 hours or shorter) and long-duration storage (greater than 12 hours). This is because long-duration storage requires forward planning over a week or longer to take advantage of its full flexibility. For example, it can charge/pump during periods of high wind and solar generation and save this to generate continuously for half a day or longer when there is low renewable generation available for an extended period and associated high prices. Long-duration storage is a key part of a low-emissions future market to manage high volumes of wind and solar generation. On the other hand, due to having less than half of day or storage, short-duration storage will tend to perform a full charge and full discharge every day, so it generally does not need longer than two days ahead of forward planning.

The methodology for storage operation with 12 hours storage capacity or less is presented in Box 1 in Section 4. The methodology for larger storages, which for this Report applies to Snowy 2.0 only, is described below.

Snowy 2.0 storage operation methodology

EY's long-duration storage planning methodology is applied to individual long-duration storage projects with storage capacities of greater than 12 hours, which for this Report applies only to the Snowy 2.0 pumped hydro project. The methodology creates a generation and load plan ahead of simulating each year. This plan is primarily created using a linear program, which takes into an estimate of the half-hourly prices that would occur in each half-hour if the long-duration storage project's full capacity of generation or pumping was applied and these price estimates are used for the generation and pumping plan outcomes, respectively. The linear program also takes into account the capacity, reservoir size and round-trip efficiency of each long-duration storage project.

[17] AEMO, 10 December 2021, *2021 Inputs and Assumptions workbook*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

Appendix B Marginal loss factors

B.1 The role of marginal loss factors

Every year there is approximately $7-15 billion of electrical energy traded through the NEM. Transmission losses occur when this electrical energy is transported from generators to the demand centres. The associated cost for these transmission losses is approximately $200-320 million per annum.

MLFs apportion the cost of these losses across all participants in the market. They are a scaling factor, normally in the range of 0.9 to 1.1, which is applied to the participant's revenue or costs when generating or consuming energy, respectively.

MLFs provide the marginal increase (or rate of change) in losses for an incremental change in power injection from a load or generator with respect to a reference node (or bus). For example, if generation at one bus increases by 1.0 MW the hypothetical change at the reference node may be 0.9 MW. The reduction of 0.1 MW is losses and is proportional to the square of the power injection. For example if the power injection doubles, losses will quadruple. Figure 20 depicts this two node system example.

Figure 20: Two node generation and reference bus system

The relationship between transmission losses and power injection can be expressed as follows:

$$Losses = kP^2 \quad \text{where } k \text{ is a constant and} \tag{1}$$

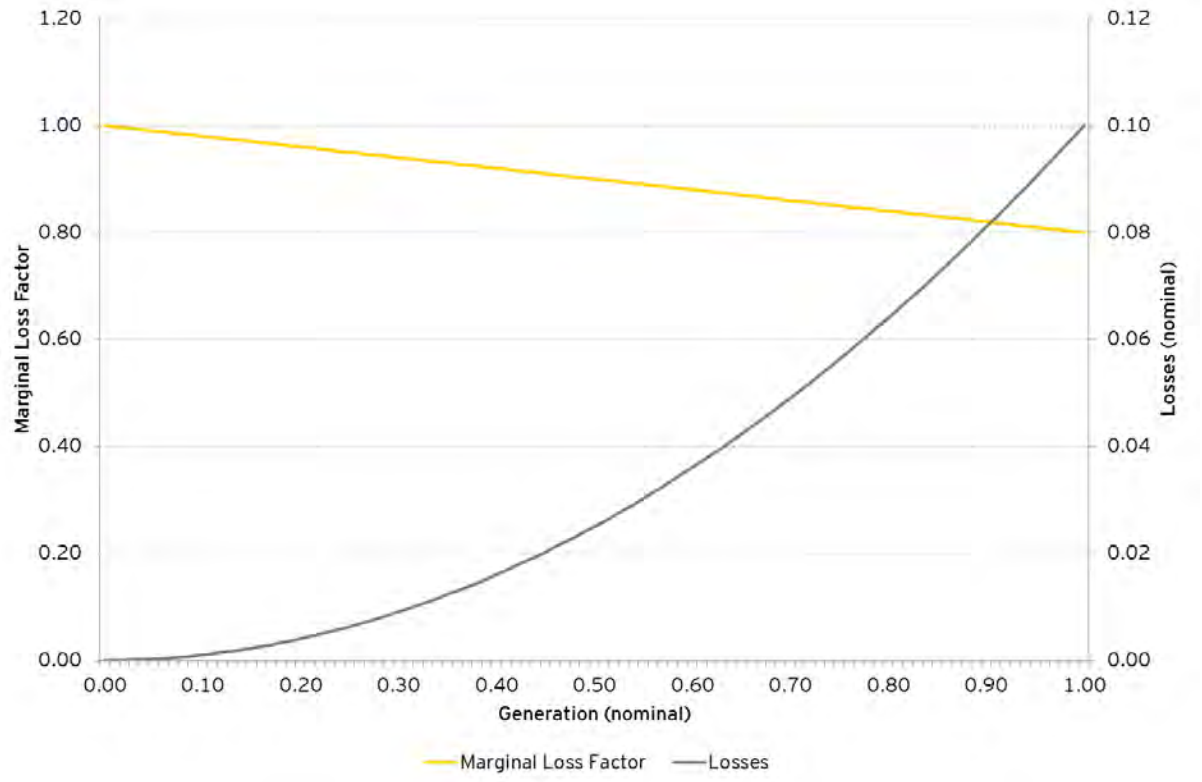
P *is power injection* (a negative value for *generation or positive value for load*)

As MLFs describe the rate of change in losses with respect to a change in power injection we can show that:

$$\frac{\partial}{\partial P}(Losses) = \frac{\partial}{\partial P}(kP^2) = 2kP \tag{2}$$

Therefore the marginal losses from a change in power injection are directly proportional to the level of power injection. This can be helpful when extrapolating (or interpolating) MLF outcomes for a given generator size. Figure 21 shows this relationship for the system described in Figure 20. As generation increases, losses increase in proportion to the square of generation, whereas the resulting MLF decreases linearly with respect to increasing generation.

Figure 21: Relationship between MLFs and losses with respect to generation



The MLF is given by the formula:

$$MLF = 1 + 2kP \quad (3)$$

In this example, losses are 0.1 MW when generation equals 1 MW. Therefore, from equation (1), k = 0.1. From equation (2), when generation equals 1 MW, marginal losses are 0.2, and therefore the MLF[18] equals 0.8.

B.2 AEMO Forward Looking Loss Factor process

The purpose of undertaking MLF forecasts is to understand the loss factor values that AEMO may determine for the Project via their Forward Looking Loss Factor (FLLFs) process, which is undertaken annually for the upcoming financial year. Loss factors are applied to every generation and load point in the NEM. Therefore some appreciation of the FLLF process is useful for understanding the significance and meaning of these loss factors.

To calculate MLFs AEMO is required to conduct the FLLF process each year, publishing the results in April for application in the forthcoming financial year. Approximately 500 connection points are represented in this process comprising both generators and loads.

The FLLF methodology is a well-defined process that specifies how the simulation data should be collated, refined and applied to the Minimal Extrapolation procedure. The Minimal Extrapolation procedure is a form of dispatch engine that is based on historical operation of plant and demand profiles. As AEMO must be independent of any market participant, the methodology is not based around an economic dispatch or forecast since that can be subjective, and instead relies on historical behaviour.

[18] MLF is defined as $(1 + \partial_{loss} / \partial_{load\ increment})$

AEMO collects the historical profiles of generation and demand for the most recent full financial year. This data set is then extrapolated to meet the most up-to-date peak demand and energy projections of the forthcoming financial year. There are clauses in the procedure that outline how new entrant plant, retirements, interconnectors, semi/non-scheduled generation and embedded generation should be treated in this extrapolation.

At the conclusion of the process a volume-weighted MLF for each generator and load is published. Volume weighting differs from time weighting (the latter is more commonly referred to as the average), as the final weighted MLF is based on all observed MLFs across the year weighted against the generation or load profile. Generally, volume weighting by generation will cause the volume-weighted MLF to be lower than the average MLF. Conversely, weighting by demand will commonly result in a higher MLF compared to the average.

EY has used its MLF forecast methodology using its dispatch model and power flow modelling for each half-hour of the future simulated years. This methodology is consistent with AEMO's FLLF process, except the future generation dispatch patterns are derived from market dispatch modelling, rather than the year-on-year Minimal Extrapolation data preparation method that AEMO applies.

Appendix C Constraint formulation

EY applied its 2-4-C® dispatch engine for the modelled years to identify potential material curtailment events experienced by the Project. EY's model was configured such that the constraint equation data set includes mapping of all existing and new generator connection points to constraint equation terms as appropriate. There are two broad categories of constraint equations considered by EY's dispatch engine; stability and thermal.

For thermal limitations, AEMO's existing constraints form a subset of all possible connection points and contingencies. This subset adequately captures the existing network topology and market conditions. To model network congestion for the assumed network upgrades as well as the connection of new entrant generation, EY has constructed custom thermal constraint equations. These custom equations are constructed using an approach which is consistent with AEMO's constraint creation processes and are used to assess the potential curtailment risk to the Project. Approximately 30,000 thermal transmission constraint equations were developed for each network topology considered in the study, comprehensively capturing N-1 and N-0 limits.

The model was also configured with AEMO's 2018 Electricity Statement of Opportunities (ESOO) stability constraint equation data set including mapping of all existing and new generator connection points to terms as appropriate. These ESOO stability constraints remain active in the model while the network configuration for which they were created remains intact and are disabled thereafter. For the avoidance of doubt, EY does not generally construct custom stability constraint equations.

C.1 Constraints and equation formulation

The objective of a thermal constraint equation is to prevent overloading of any transmission network element. N-0 constraints are formulated to prevent the overloading of transmission network elements during system normal operation, while N-1 constraints are formulated to prevent the overloading of transmission network elements should any single credible contingency occur (i.e., the outage/failure of a transmission network element). N-1 constraints are enforced pre-contingently, that is, at all times. In the case of the NEM, constraint equations are formulated such that the sum of terms on the left hand side (LHS) must be less than or equal to the sum of terms on the righthand side (RHS). Generation and interconnector terms are typically assigned to the LHS, while constant and demand terms are typically assigned to the RHS.

The elements within a thermal constraint equation can be categorised as follows:

- Generator terms and coefficients
- Interconnector terms and coefficients
- Demand coefficient
- Constant term

C.2 Example of a binding constraint and resulting curtailment

If, before dispatch, the desirable combination of generator bidding and demand would theoretically lead to a constraint equation violating (i.e. the LHS is exceeding the RHS indicating a potential network element overload) then generator output, interconnector flow or load must be curtailed below the desirable dispatch level to reduce the LHS. Curtailment is based on the cost of that curtailment, with the least cost solution being implemented. The cost of curtailment is an outcome of both the magnitude of the factor (i.e. the unit's impact on the constraint) and the generator/load/interconnector effective bid price.

If two generators have the same bid, the generator with the higher LHS factor is curtailed first. If two generators have the same LHS factor, the generator with the higher bid price is curtailed first. In instances where generators have both the same bid and LHS factor, tie-breaking is employed

which curtails generation proportionally to respective quantities offered at the tied price. This means that in absolute terms, larger units will tend to be curtailed more than smaller units in a tie-breaking situation.

In the example in Table 24 below the LHS of a hypothetical violating constraint can be reduced by 1 MW either by turning down Generator A by 1 MW or Generator B by 2 MW. However, because Generator A has a bid price of -$1000/MWh and Generator B has a bid price of -$100/MWh, it turns out to be more economic to turn down Generator B, even though the level of dispatch impact is double.

Table 24: Example describing how units are curtailed

Generator	LHS Factor	Bid Price ($/MWh)	Outcome if constrained (MW)	Total cost to market for one hour ($)	Least cost outcome
A	1	-1,000	1	1000	Generator not curtailed
B	0.5	-100	2	200	Generator curtailed

C.3 N-0 generator coefficients

For an N-0 constraint, generator coefficients in a constraint equation are determined using Power Transfer Distribution Factors (PTDFs). The PTDF is a sensitivity measure of the power flow on a transmission element connecting bus j to bus k with respect to a generator injection at bus m. The coefficient for a generator connected at bus m can be calculated by differentiating the power flow across a monitored element connecting bus j to bus k with respect to the power injection at bus m, that is:

$$PTDF_{G_m,j\to k} = \frac{dF_{j\to k}}{dP_{G_m}}$$

Where P_{G_m} is the power injected by a generator at bus m and $F_{j\to k}$ is the power flow across the monitored element from bus j to bus k.

An underlying assumption that is inherently applied is that the RRN (location of the slack bus) will absorb any incremental injection at bus m. Therefore, the PTDFs can be viewed as the contribution of a small amount of power injection at bus m on the power flow across element connecting bus j to bus k to supply a small increase in demand at the RRN.

Generator coefficients defined this way will depend purely on the system network topology and the location of the RRN. They will not be influenced by the regional demand or generation dispatch across the system.

C.4 N-0 interconnector coefficients

Similar to the calculation outlined in the previous section, interconnector coefficients are determined using PTDFs associated with power injection at the regional boundary buses. That is, the coefficient for an interconnector at the regional boundary bus n for a monitored element connecting bus j to bus k is defined as:

$$PTDF_{IC_n,j\to k} = \frac{dF_{j\to k}}{dP_{IC_n}}$$

Where P_{IC_n} is the interconnector power injection (positive for importing power and negative for exporting power) from neighbouring regions into bus n.

C.5 N-1 redistribution factor

N-1 constraints are designed to pre-contingently curtail generation to ensure that following a single credible contingency, the resulting power flows do not exceed thermal limits. When a transmission

element is de-energised, the power flowing through the de-energised element redistributes across the remaining transmission elements. The proportion of power flow from a contingent element that flows through a monitored element is known as the redistribution factor. Redistribution factors can be approximated using Line Outage Distribution Factors (LODF). For a monitored network element connecting bus $\boldsymbol{j}$ to bus $\boldsymbol{k}$ and a contingent network element connecting bus $\boldsymbol{h}$ to bus $\boldsymbol{i}$, the LODF can be defined as:

$$LODF_{j\to k,h\to i} = \frac{\Delta F_{j\to k}}{F_{h\to i}} \; when \; F_{h\to i} \to 0$$

Where $F_{j\to k}$ is flow on the monitored element and $F_{h\to i}$ is flow on the contingent element.

C.6 N-1 generator and interconnector coefficients

With the definitions provided in Sections C.3, C.4 and C.5 above, we can define the coefficient for a generator at bus m in an N-1 constraint equation with a monitored network element connecting bus j to bus k following outage of a contingent network element connecting bus h to bus i as;

$$PTDF_{G_m,j\to k} + LODF_{j\to k,h\to i} \cdot PTDF_{G_m,h\to i}$$

Similarly, for interconnectors;

$$PTDF_{IC_n,j\to k} + LODF_{j\to k,h\to i} \cdot PTDF_{IC_n,h\to i}$$

C.7 Demand coefficients

Demand coefficients correspond to the contribution of regional demand towards the power flow on a monitored network element. To calculate the demand coefficient for a monitored network element connecting bus j to bus k, EY calculate the derivative of the power flow from bus j to bus k with respect to the regional *as generated* demand (as delivered demand plus system losses and auxiliary loads), denoted by D_r that is:

$$Coeff_{D_r,j\to k} = \frac{dF_{j\to k}}{dD_r}$$

This value can be approximated accurately by scaling the regional demand up by a small amount (less than 1 %) and dividing the difference in power flow by the difference in regional demand, that is:

$$Coeff_{D_r,j\to k} = \frac{F'_{j\to k} - F_{j\to k}}{D'_r - D_r} = \frac{\Delta F_{j\to k}}{\Delta D_r}$$

Where $F'_{j\to k}$ is the observed flow associated with the scaled demand, and D'_r is the scaled up demand.

It is worth mentioning that the methodology described above assumes that the change in the regional demand is balanced by power injection at the RRN. Furthermore, since the demand is scaled up in proportion to the existing demand distribution, different demand distributions from different system operating states will result in different demand coefficients. Therefore, some consideration is required to decide upon the most adequate demand coefficient for a particular constraint equation.

C.8 Constant term

The constant term corresponds predominantly to the thermal line rating (in MW) of the monitored element, with an additional offset referred to as the $ConstantEx\ Rating$, that is:

$$Constant\ Term = Thermal\ Rating_{j\to k,MW} + ConstantEx\ Rating_{j-k}$$

Thermal line ratings are typically given in MVA. To convert MVA ratings to MW ratings, EY generally assumes a power factor (PF) of 0.95 (unless otherwise specified) and equates the MW ratings as:

$$Thermal\ Rating_{j\to k,MW} = PF \cdot Thermal\ Rating_{j\to k,MVA}$$

The $ConstantEx\ Rating$ value is required in addition to the thermal rating to take into account the difference in power flow between AC and DC solutions (since generator coefficients are calculated based on a DC load flow solution) and the contribution (equivalent PTDF) of all other generators with small coefficients which are not explicitly included in the constraint equation. This value is computed as the difference between the calculated flow across the monitored element based on generator and demand coefficients obtained and the actual AC power flow solution. For a system with *M* generator connection points and *N* interconnector boundaries, the $ConstantEx\ Rating$ value for the monitored element connecting bus j to bus k is calculated as:

$$\begin{aligned} ConstantEx\ Rating_{j-k} \quad = \quad & \sum_{m=1}^{M} P_{G_m} \cdot PTDF_{G_m,j\to k} \\ & + \sum_{n=1}^{N} P_{IC_n} \cdot PTDF_{IC_n,j\to k} \\ & + \sum_{r=1}^{R} D_r \cdot Coeff_{D_r,j\to k} \\ & - F_{j-k} \end{aligned}$$

C.9 Formulating a constraint equation

Having defined the key elements, a constraint equation is formulated with generation and interconnector terms on the LHS and constant and demand terms on the RHS as:

$$\begin{aligned} & \sum_{m=1}^{M} P_{G_m} \cdot \left(PTDF_{G_m,j\to k} + LODF_{j\to k,h\to i} \cdot PTDF_{G_m,h\to k}\right) && Thermal\ Rating_{MW} \\ + & \sum_{n=1}^{N} P_{IC_n} \cdot \left(PTDF_{IC_n,j\to k} + LODF_{j\to k,h\to i} \cdot PTDF_{IC_n,h\to k}\right) \quad \leq \quad + & \sum_{r=1}^{R} Coeff_{D_r,j\to k} \cdot D_r \\ & && + ConstantEx\ Rating \end{aligned}$$

Further to this, AEMO has specified that in cases where the coefficient of a term on the LHS is relatively small then the risk of NEMDE choosing sub-optimal dispatch decisions may exist. To avoid such situations the following rule has been adopted:

LHS terms shall not have coefficients less than |0.07|. This can be achieved by:

Scaling the constraint equation such that all coefficients for LHS terms are not less than 0.07 provided that the absolute value of largest coefficient of any LHS term does not then exceed 1. This is to ensure that the effective violation penalties of network constraint equations grade adequately with other constraints in the dispatch algorithm.

If after scaling, terms with such small coefficients remain, transfer these terms to the RHS.

EY has adopted the above methodology as a final step in the formulation of constraint equations.

EY | Building a better working world

EY exists to build a better working world, helping to create long-term value for clients, people and society and build trust in the capital markets.

Enabled by data and technology, diverse EY teams in over 150 countries provide trust through assurance and help clients grow, transform and operate.

Working across assurance, consulting, law, strategy, tax and transactions, EY teams ask better questions to find new answers for the complex issues facing our world today.

Our report may be relied upon by OMPS Pty Ltd for the purpose of undertaking market modelling to provide an assessment of potential benefits of a pumped hydro energy storage scheme to a REZ and the National Electricity Market with the Oven Mountain Pumped Hydro Energy Storage Project as a representative scheme and the New England Renewable Energy Zone as a REZ of interest, pursuant to the terms of our engagement agreement. We disclaim all responsibility to any other party for any loss or liability that the other party may suffer or incur arising from or relating to or in any way connected with the contents of our report, the provision of our report to the other party or the reliance upon our report by the other party.

EY refers to the global organization, and may refer to one or more, of the member firms of Ernst & Young Global Limited, each of which is a separate legal entity. Ernst & Young Global Limited, a UK company limited by guarantee, does not provide services to clients. Information about how EY collects and uses personal data and a description of the rights individuals have under data protection legislation are available via ey.com/privacy. EY member firms do not practice law where prohibited by local laws. For more information about our organization, please visit ey.com.

About EY Strategy and Transactions

EY Strategy and Transactions teams work with clients to navigate complexity by helping them to reimagine their ecosystems, reshape their portfolios and reinvent themselves for a better future. With global connectivity and scale, EY Strategy and Transactions teams help clients drive corporate, capital, transaction and turnaround strategies through to execution, supporting fast-track value creation in all types of market environments. EY Strategy and Transactions teams help support the flow of capital across borders and help bring new products and innovation to market. In doing so, EY Strategy and Transactions teams help clients to build a better working world by fostering long-term value. For more information, please visit ey.com/strategyandtransactions.

© 2022 Ernst & Young, Australia
All Rights Reserved.

Liability limited by a scheme approved under Professional Standards Legislation.

In line with EY's commitment to minimize its impact on the environment, this document has been delivered electronically.

Ernst & Young is a registered trademark.

OVEN MOUNTAIN
PUMPED HYDRO STORAGE

alintaenergy

Anthony Melov
OMPS Pty Ltd
a.melov@ompshydro.com
0426 235 089

Jeremy Moon
OMPS Pty Ltd
j.moon@ompshydro.com
0414 493 321

www.ompshydro.com