Maintaining reliable supply to Broken Hill PACR market modelling report

TransGrid

13 May 2022

Building a better working world

Release Notice

Ernst & Young was engaged on the instructions of NSW Electricity Networks Operations Pty Limited as trustee for NSW Electricity Networks Operations Trust (Transgrid) to undertake market modelling of system costs and benefits for the "maintaining reliable supply to Broken Hill" Regulatory Investment Test for Transmission (RIT-T) relating to various options.

The results of Ernst & Young's work are set out in this report (Report), including the assumptions and qualifications made in preparing the Report. The Report should be read in its entirety including this release notice, the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report. No further work has been undertaken by Ernst & Young since the date of the Report to update it.

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Readers are advised that the outcomes provided are based on many detailed assumptions underpinning the scenarios, and the key assumptions are described in the Report. These assumptions were selected by Transgrid after public consultation. The modelled scenarios represent several possible future options for the development and operation of the National Electricity Market, and it must be acknowledged that many alternative futures exist. Alternative futures beyond those presented have not been evaluated as part of this Report.

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1. Executive Summary

Transgrid has engaged EY to undertake market modelling of system costs and benefits to support the "maintaining reliable supply to Broken Hill" Regulatory Investment Test for Transmission (RIT-T) relating to various network and non-network options.

This Report forms a supplementary report to the Project Assessment Conclusion Report (PACR) prepared and published by Transgrid[1]. It describes the key modelling outcomes and insights as well as the assumptions and input data sources selected by Transgrid and the modelling methods used. The Report should be read in conjunction with the Transgird PACR.

EY calculated the least-cost generation dispatch and capacity development plan for the National Electricity Market (NEM) associated with six options for the Step Change, Progressive Change and Hydrogen Superpower scenarios from the 2022 Australian Energy Market Operator (AEMO) Draft Integrated System Plan (ISP)[2].

Transgrid has requested to incorporate the most recent input and assumptions since the publication of the draft 2022 ISP, as follows:

- Latest committed and anticipated generators from the AEMO Generation Information, published in February 2022[3].
- Recent announced closure dates for Eraring, Bayswater and Loy Yang coal fired generators[3].

To determine the least-cost solution, EY's Time Sequential Integrated Resource Planner (TSIRP) model was used. It makes decisions for each hourly trading interval in relation to the dispatch of generators and commissioning of new entrant capacity, while taking into account several operational and technical constraints. From the hourly time-sequential modelling we computed the following costs, as defined in the RIT-T:

- capital costs of new generation capacity installed (capex),
- total Fixed Operation and Maintenance (FOM) costs of all generation capacity,
- total Variable Operation and Maintenance (VOM) costs of all generation capacity,
- total fuel costs of all generation capacity,
- total cost of voluntary (demand-side participation, DSP) and involuntary load curtailment (unserved energy, USE),
- transmission expansion costs associated with renewable energy zone (REZ) development.

For each simulation with an option and in the Base Case (without an option), we computed the sum of these cost components and compared the difference between each option and the Base Case. This process was completed for three scenarios: Step Change, Progressive Change and Hydrogen Superpower, as defined in the 2022 draft ISP[2]. The difference in present values of costs is the forecast gross market benefits[4] due to the presence of the corresponding option, as defined in the RIT-T.

[1] TransGrid, *Broken Hill Supply*. Available at: https://www.transgrid.com.au/projects-innovation/broken-hill-supply. Accessed on 4 April 2022.

[2] Note that while most of the assumptions are from the 2021 Inputs and Assumptions workbook published 10 December 2021, some assumptions like the timing of major upgrades are based on the draft 2022 ISP outcomes. AEMO, *2022 Draft ISP Consultation*, available at https://aemo.com.au/consultations/current-and-closed-consultations/2022-draft-isp-consultation, and AEMO, *Current inputs, assumptions and scenarios*, available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios. Accessed on 4 April 2022.

[3] AEMO generation information and expected closure years, available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2022/nem-generation-information-feb-2022.xlsx?la=en

[4] In this Report we use the term *gross market benefit* to mean "market benefit" as defined in the RIT-T guidelines and "net economic benefit" as defined in the RIT-T guidelines.

The forecast gross market benefits capture the impact on transmission losses to the extent that losses across interconnectors and intra-connectors affect the generation that is needed to be dispatched in each trading interval. The forecast gross market benefits also capture the impact of differences in cyclic efficiency losses in storages, including Pumped Storage Hydro (PSH) and large-scale battery storage between each option and the counterfactual Base Case.

Table 1 shows the details of the modelled options. Transgrid has advised EY to maintain the confidentiality of the modelled options. As such, no dollar value results are provided in this report. In addition, the y-axis in all the comparison charts throughout the Report has been removed. For more details on each option, refer to the PACR[1].

Table 1: Summary of the Options[1]

Option	Commissioning date	Description
Option 1A(2)	1 July 2025	Compressed air energy storage (CAES) at Broken Hill Market availability: 50MW/250MWh
Option 1A(4)	1 July 2025	CAES at Broken Hill Market availability: 200MW/1,250MWh
Option 1F	1 July 2024	Liquid air energy storage (LAES) at Broken Hill
Option 3	1 July 2026	New gas turbine at Broken Hill
Option 4	1 July 2027	New 220 kV transmission line from Buronga to Broken Hill
Option 5G	1 July 2024	Thermal energy storage at Broken Hill

The relative size of the forecast gross market benefits for all modelled options and scenarios is shown in Figure 1. Additionally, the composition of market benefit categories in the forecast gross market benefits for all modelled options and scenarios is shown in Figure 2 to Figure 4. In general, across the storage options, higher benefits accrue from larger options. The forecast gross market benefits of each option in each scenario need to be compared to the relevant option cost to determine the forecast net economic benefit for that option. The determination of the preferred option is also dependent on option costs and was conducted outside of this Report by Transgrid, by incorporating the forecast gross market benefits into the calculation of net economic benefits.

Figure 1: Comparison of gross market benefits between scenarios for all options

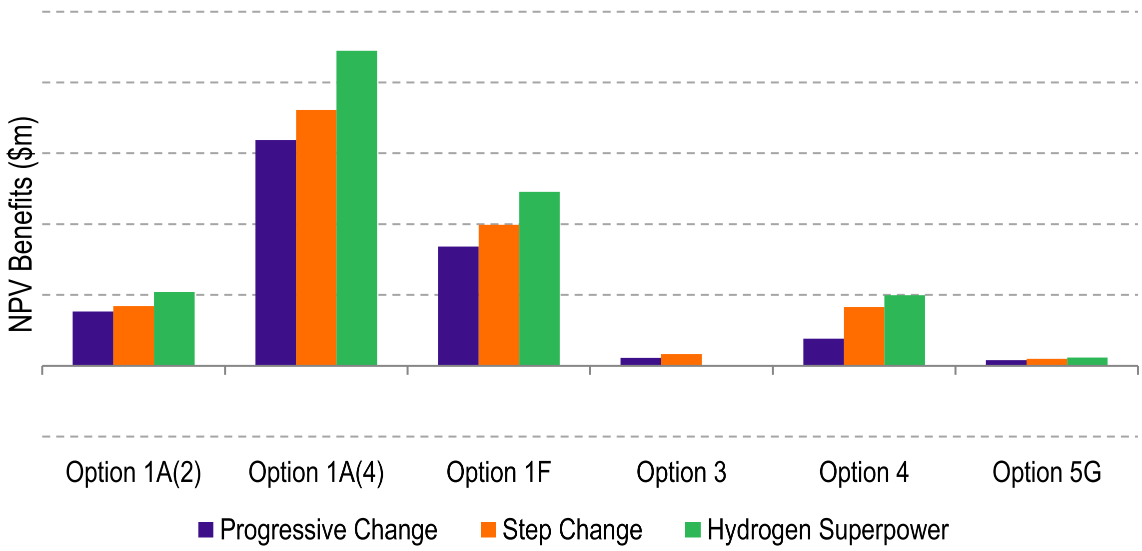


Figure 2: Composition of forecast total gross market benefits for all options in the Progressive Change scenario

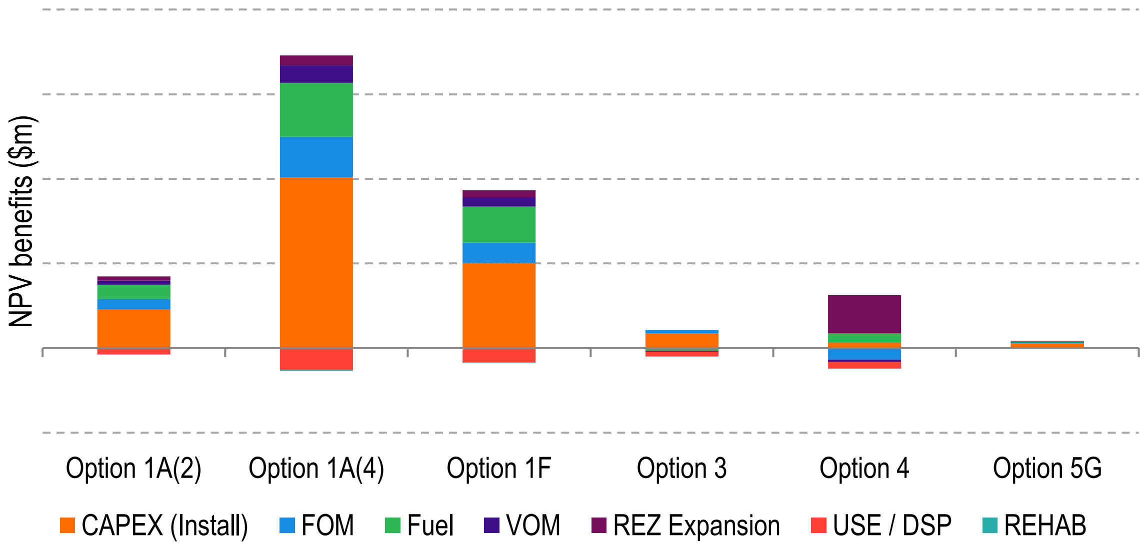


Figure 3: Composition of forecast total gross market benefits for all options in the Step Change scenario

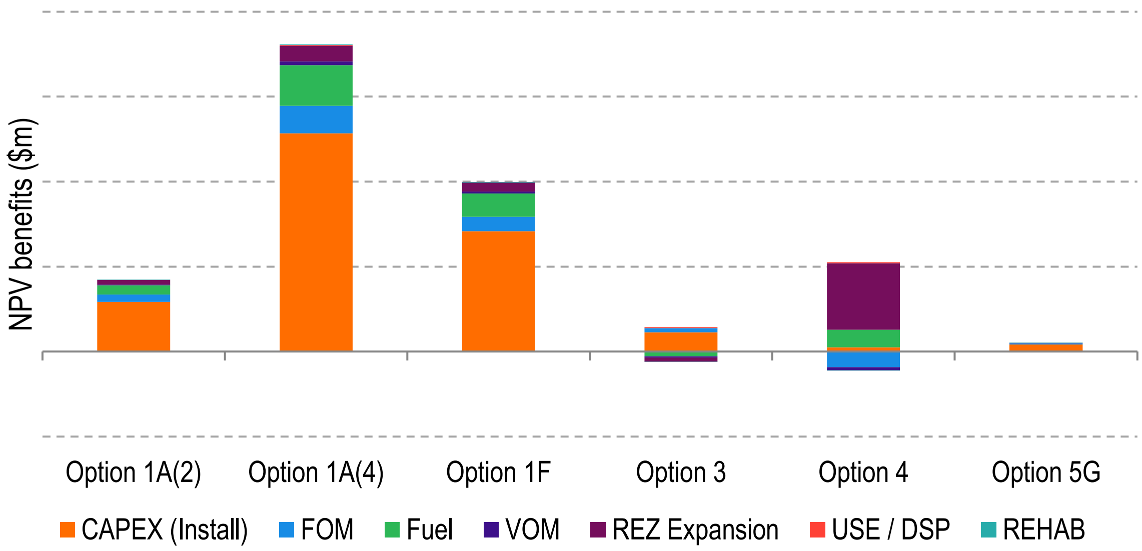
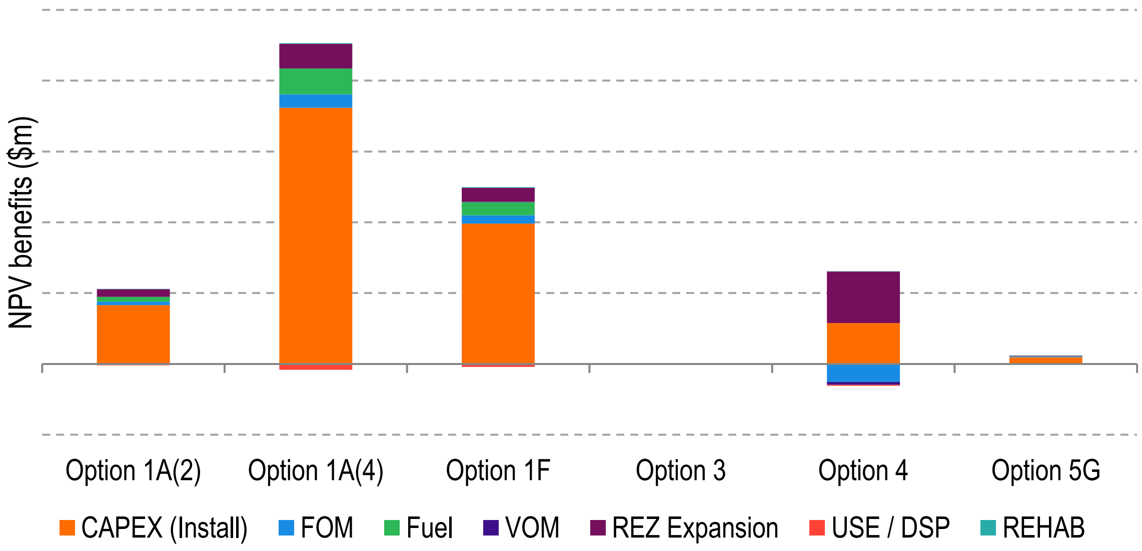


Figure 4: Composition of forecast total gross market benefits for all options in the Hydrogen Superpower scenario



Sources of benefits and the key drivers are discussed below.

- Across the CAES and LAES options, the relative size of the gross market benefits is forecast to vary with the capacity and storage volume of the option. The majority of the forecast gross market benefits in these options is attributed to capex. The proportion of benefits attributed to capex increases from the Progressive Change scenario to the Step Change scenario, and again to the Hydrogen Superpower scenario. In the CAES and LAES options the capex savings are a result of deferred wind build due to increased solar capacity, and avoided battery build due to the storage option being installed.

- Fuel and FOM cost savings are forecast in all scenarios for the CAES and LAES options. The fuel cost savings are attributable to increased solar generation offsetting black coal and gas generation. The proportion of fuel cost savings is highest in the Progressive Change scenario and lowest in the Hydrogen Superpower scenario. This is the result of a restrictive carbon budget in the Hydrogen Superpower scenario which reduces thermal generation earlier compared with the Progressive Change scenario.

- REZ transmission expansion cost savings are forecast in the majority of options. REZ expansion cost savings arise from the storage options enabling increased solar capacity in the Broken Hill REZ and therefore reducing the need for increased REZ transmission in other locations throughout the NEM. Option 4 directly delivers increased network capacity from the Broken Hill REZ, reducing the requirement for network investment in other REZs across the NEM.

- In the Hydrogen Superpower scenario, gross market benefits in Option 3 are forecast to be approximately zero. This is due to the restrictive carbon budget which is forecast to leave the Option 3 gas turbine with little incentive or ability to generate.

- The gross market benefits are forecast to accumulate across the whole modelling period depending on the timing and scale of the option considered.

2. Introduction

Transgrid has engaged EY to undertake market modelling of system costs and benefits to support the "maintaining reliable supply to Broken Hill" Regulatory Investment Test for Transmission (RIT-T) relating to various options[1]. The RIT-T is a cost-benefit analysis used to assess the viability of investment options in regulated electricity transmission assets.

This Report forms a supplementary report to the broader Project Assessment Conclusion Report (PACR) published by Transgrid[1]. It describes the key modelling outcomes and insights as well as the assumptions and input data sources selected by Transgrid and the modelling methods used.

EY computed the least-cost generation dispatch and capacity development plan for the National Electricity Market (NEM) associated with options using input assumptions generally derived from the 2022 Draft Integrated System Plan's (ISP)[2]. Transgrid has requested to incorporate the most recent input and assumptions since the publication of the draft 2022 ISP, as follows:

- ► Latest committed and anticipated generators from the Generation Information Page, published in February 2022[5].

- ► Recently announced closure dates for Eraring, Bayswater and Loy Yang coal fired power stations[6].

The options were defined by Transgrid and are described in detail in the PACR. This is an independent study and the modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator[7]. The Report should be read in conjunction with the Transgird PACR.

The descriptions of outcomes in this Report are focussed on identifying and explaining the key sources of forecast gross market benefits. The categories of gross market benefits modelled are changes in:

- ► capital costs of new generation capacity installed,
- ► total fixed operation and maintenance (FOM) costs of all generation capacity,
- ► total variable operation and maintenance (VOM) costs of all generation capacity,
- ► total fuel costs of all generation capacity,
- ► total cost of voluntary and involuntary load curtailment,
- ► transmission expansion costs associated with renewable energy zone (REZ) development.
- ► transmission and storage losses which form part of the demand to be supplied, which are calculated dynamically within the model.

Each category of gross market benefits is computed annually across a 25-year modelling period from 2023-24 to 2047-48. Benefits presented are discounted to June 2021 using a 5.5 % real, pre-tax discount rate as selected by Transgrid. This value is consistent with the value applied by the Australian Energy Market Operator (AEMO) in the draft 2022 ISP[2].

This modelling considers six options as listed in the table below. For more details on each option, refer to the PACR[1].

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[5] AEMO, *NEM Generation Information February 2022.* Available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Accessed on 5 April 2022

[6] AEMO, *Generating unit expected closure year February 2022.* Available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Accessed on 5 April 2022

[7] AER, August 2020, *Application guidelines - Regulatory investment test for transmission.* Available at: Final decision | Australian Energy Regulator (aer.gov.au). Accessed on 4 April 2022.

Table 2: Overview of the network and non-network options[1]

Option	Commissioning date	Description
Option 1A(2)	1 July 2025	Compressed air energy storage (CAES) at Broken Hill Market availability: 50MW/250MWh
Option 1A(4)	1 July 2025	CAES at Broken Hill Market availability: 200MW/1,250MWh
Option 1F	1 July 2024	Liquid air energy storage (LAES) at Broken Hill
Option 3	1 July 2026	New gas turbine at Broken Hill
Option 4	1 July 2027	New transmission line from Buronga to Broken Hill
Option 5G	1 July 2024	Thermal energy storage at Broken Hill

The forecast gross market benefits of each option need to be compared to the relevant option cost to determine the forecast net economic benefit for that option. The determination of the preferred option is also dependent on option costs and was conducted outside of this Report by Transgrid, by incorporating the forecast gross market benefits into the calculation of net economic benefits. All references to the preferred option in this Report are in the sense defined in the RIT-T as "the credible option that maximises the net economic benefit across the market, compared to all other credible options"[7].

The Report is structured as follows:

- Section 3 describes the assumptions and scenario inputs modelled in this study.
- Section 4 provides an overview of the methodology applied in the modelling and computation of forecast gross market benefits.
- Section 5 outlines model design and input data related to representation of the transmission network, transmission losses and demand.
- Section 6 provides an overview of model inputs and methodologies related to supply of energy.
- Section 7 presents the NEM capacity and generation outlook without the options.
- Section 8 presents the forecast gross market benefits for each option. It is focussed on identifying and explaining the key sources of forecast gross market benefits of all options.

3. Scenario Assumptions

3.1 Scenarios

The options proposed by Transgrid have been assessed under the Step Change, Progressive Change and Hydrogen Superpower scenarios from AEMO's Draft 2022 ISP[2], as selected by Transgrid. These scenarios are summarised in Table 3. Transgrid has also requested to incorporate the most recent input and assumptions since the publication of the draft 2022 ISP, as follows:

► Latest committed and anticipated generators from the Generation Information Page, published in February 2022[8].

► Recently announced closure dates for Eraring, Bayswater and Loy Yang coal fired power stations[9].

Table 3: Overview of key input parameters in the Progressive Change, Step Change and Hydrogen Superpower scenarios

Key drivers input parameter	Scenario		
	Progressive Change	Step Change	Hydrogen Superpower
Underlying consumption	ESOO 2021 (draft ISP 2022)[10] - Progressive Change	ESOO 2021 (draft ISP 2022)[10] - Step Change	ESOO 2021 (draft ISP 2022)[10] - Hydrogen Superpower
New entrant capital cost for wind, solar SAT, OCGT, CCGT, PSH, and large-scale batteries[11]	2021 Inputs and Assumptions Workbook[12] - Progressive Change	2021 Inputs and Assumptions Workbook[12] - Step Change	2021 Inputs and Assumptions Workbook[12] - Hydrogen Superpower
Retirements of coal-fired power stations	2021 Inputs and Assumptions Workbook[12] - Progressive Change: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives beyond 2030	2021 Inputs and Assumptions Workbook[12] - Step Change: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives	2021 Inputs and Assumptions Workbook[12] - Hydrogen Superpower: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives
Gas fuel cost	2021 Inputs and Assumptions Workbook[12] - Progressive Change: Lewis Grey Advisory 2020, Central	2021 Inputs and Assumptions Workbook[12]: Lewis Grey Advisory 2020, Step Change	
Coal fuel cost	2021 Inputs and Assumptions Workbook[12] - Progressive Change: Wood Mackenzie, Central	2021 Inputs and Assumptions Workbook[12]: Wood Mackenzie, Step Change	

[8] AEMO, *NEM Generation Information February 2022*. Available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Accessed on 5 April 2022

[9] AEMO, *Generating unit expected closure year February 2022*. Available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Accessed on 5 April 2022

[10] AEMO, *National Electricity and Gas Forecasting*. Available at: http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational. Accessed on 5 April 2022.

[11] PV = photovoltaics, SAT = Single Axis Tracking, CCGT = Combined Cycle Gas Turbine, OCGT = Open Cycle gas Turbine

[12] AEMO, *2021 Inputs and Assumptions Workbook v3.3*, https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios, Accessed on 5 April 2022.

Key drivers input parameter	Scenario		
	Progressive Change	Step Change	Hydrogen Superpower
NEM carbon budget	2021 Inputs and Assumptions Workbook[12] - Progressive Change: 932 Mt CO_2-e 2030-31 to 2050-51	2021 Inputs and Assumptions Workbook[12] - Step Change: 891 Mt CO_2-e 2023-24 to 2050-51	2021 Inputs and Assumptions Workbook[12] - Hydrogen Superpower: 453 Mt CO_2-e 2023-24 to 2050-51
Victoria Renewable Energy Target (VRET)	40 % renewable energy by 2025 and 50 % renewable energy by 2030 VRET 2 including 600 MW of renewable capacity by 2025		
Queensland Renewable Energy Target (QRET)	50 % by 2030		
Tasmanian Renewable Energy Target (TRET)	2021 Inputs and Assumptions Workbook[12]: 200 % Renewable generation by 2040		
New South Wales (NSW) Electricity Infrastructure Roadmap	2021 Inputs and Assumptions Workbook[12]: 12 GW NSW Roadmap, with 3 GW in the Central West Orana REZ, modelled as generation constraint per the draft 2022 ISP, 2 GW of long duration storage (8hrs or more) by 2029-30		
EnergyConnect	Draft 2022 Integrated System Plan[13] - EnergyConnect commissioned by July 2025		
Western Victoria Transmission Network Project	Draft 2022 Integrated System Plan[13] - Western Victoria upgrade commissioned by November 2025		
HumeLink	Draft 2022 Integrated System Plan[13] - Progressive Change: HumeLink commissioned by July 2035	Draft 2022 Integrated System Plan[13] - Step Change: HumeLink commissioned by July 2028	Draft 2022 Integrated System Plan[13] - Hydrogen Superpower: HumeLink commissioned by July 2027
Marinus Link	Draft 2022 Integrated System Plan[13] -1st cable commissioned by July 2029 and 2nd cable by July 2031		
Victoria to NSW Interconnector (VNI) Upgrade (VNI Minor)	Draft 2022 Integrated System Plan[13] -: VNI Minor commissioned by December 2022		
NSW to QLD Interconnector (QNI) Upgrade (QNI Minor)	Draft 2022 Integrated System Plan[13] -: QNI minor commissioned by July 2022		
QNI Connect	Draft 2022 Integrated System Plan[13] - Progressive Change: QNI Connect commissioned by July 2036	Draft 2022 Integrated System Plan[13] - Step Change: QNI Connect commissioned by July 2032	Draft 2022 Integrated System Plan[13] - Hydrogen Superpower: QNI Connect commissioned by July 2029
QNI Connect 2	Draft 2022 Integrated System Plan[13] - Not commissioned		Draft 2022 Integrated System Plan[13] - QNI Connect stage 2 commissioned by July 2030
VNI West	Draft 2022 Integrated System Plan[13] - Progressive Change: VNI West commissioned by July 2038	Draft 2022 Integrated System Plan[13] - Step Change: VNI West commissioned by July 2031	Draft 2022 Integrated System Plan[13] - Hydrogen Superpower: VNI West commissioned by July 2030
Victorian SIPS	Draft 2022 Integrated System Plan[13] - 300 MW/450 MWh, 250 MW for SIPS service and the remaining 50 MW can be deployed in the market by the operator on a commercial basis, November 2021. After SIPS contract ends (March 2032) 300 MW can be deployed in the market by the operator on a commercial basis.		

[13] AEMO, *Draft 2022 Integrated System Plan*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/2022-draft-isp-consultation. Accessed 21 January 2022.

Key drivers input parameter	Scenario		
	Progressive Change	Step Change	Hydrogen Superpower
New-England REZ Transmission	Draft 2022 Integrated System Plan[13] - Progressive Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2038	Draft 2022 Integrated System Plan[13] - Step Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2035	Draft 2022 Integrated System Plan[13] - Hydrogen Superpower: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 203, New England REZ Expansion commissioned by July 2042
Snowy 2.0	Snowy 2.0 is commissioned by December 2026[12]		

4. Methodology

4.1 Long-term investment planning

EY has used linear programming techniques to perform hourly time-sequential, least-cost, long-term NEM development optimisation modelling spanning 25 years from 2023-24 to 2047-48. The modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator[7].

Based on the full set of input assumptions, the Time-Sequential Integrated Resource Planner (TSIRP) model makes decisions that minimise the overall cost to supply the electricity demand for the NEM over the entire modelling period, with respect to:

- capital expenditure for generation and storage (capex),
- FOM,
- VOM,
- fuel usage,
- demand-side participation (DSP) and unserved energy (USE),
- transmission expansion costs associated with REZ development,
- transmission and storage losses which form part of the demand to be supplied and are calculated dynamically within the model.

To determine the least-cost solution, the model makes decisions for each hourly[14] trading interval in relation to:

- the generation dispatch level for each power plant along with the charging and discharging of storage. Units are assumed to bid at their short-run marginal cost (SRMC), which is derived from their VOM and fuel costs. The generation for each trading interval is subject to the modelled availability of power stations in each hour (those that are not on planned or unplanned outages), network limitations and energy limits (e.g., storage levels).

- commissioning new entrant capacity for wind, offshore wind, solar PV SAT[11], CCGT, OCGT, large-scale storage, PSH and Hydrogen turbine technology (only modelled in the Hydrogen Superpower scenario). We screened nuclear and any other technology options "possible" and found that they would not be a part of the least cost plan.

These hourly decisions take into account constraints that include:

- supply must equal demand in each region for all trading intervals, while maintaining a reserve margin, with USE costed at the value of customer reliability (VCR)[15],

- minimum loads for coal generators,

- transmission interconnector flow limits (between regions),

- intra-regional flow limits (between zones in New South Wales),

- maximum and minimum storage reservoir limits (for conventional storage hydro, PSH and large-scale battery storage),

[14] Whilst the NEM is dispatched on five-minute intervals, the model resolution is hourly as a compromise between managing computation time while still capturing the renewable and storage resources in sufficient detail for the purpose of the modelling

[15] AER, December 2019, *Values of Customer Reliability Final report on VCR values.* Available at https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf. Accessed on 5 April 2022

- new entrant capacity build limits and costs associated with increasing these limits beyond the resource limit for wind and solar in each REZ where applicable, and PSH in each region,

- emission and carbon budget constraints, as defined for each scenario,

- renewable energy targets where applicable by region or NEM-wide.

The model includes key intra-regional constraints in NSW through modelling of zones with intra-regional limits and loss equations. Within these zones and within regions, no further detail of the transmission network is considered.

The model factors in the annual costs, including annualised capital costs, for all new generation capacity and the model determines how much new capacity to build in each region to deliver the least-cost market outcome.

The model meets the specified emissions trajectory at least cost, which may be by either building new lower emissions plant or reducing operation of higher emissions plant, or both.

There are three main types of generation that are scheduled by the model:

- Dispatchable thermal generators, typically coal, gas and liquid fuel which are assumed to have unlimited energy resource in general. An assumed energy limit is placed on coal-fired power stations where specified in AEMO's 2021 Input and Assumptions Workbook[12]. The running cost for these generators is the sum of the VOM and fuel costs. FOM costs are also modelled, which are another factor in the running cost of generators determining their economic retirements. Coal generators and some CCGTs have minimum loads to reflect operational stability limits and high start-up costs and this ensures they are always online when available. This is consistent with the self-commitment nature of the design of the NEM. On the other hand, peaking generators have no minimum operating level and start whenever their variable costs will be recovered and will operate for a minimum of one hour.

- Wind and solar generators are fully dispatched according to their available variable resource in each hour, unless constrained by oversupply or network limitations.

- Storage plant of all types (conventional hydro generators with storages, PSH, large-scale battery storages and virtual power plants (VPP)) are operated to minimise the overall system costs. This means they tend to generate at times of high cost of supply, e.g. when the demand for power is high, and so dispatching energy-limited generation will avoid utilisation of high-cost plant such as gas-fired, liquid fuel generators. Conversely, at times of low energy cost, e.g. when there is a surplus of capacity, storage hydro preserves energy and PSH and large-scale battery storage operate in pumping or charging mode.

4.2 Reserve constraint in long-term investment planning

The TSIRP model ensures there is sufficient dispatchable capacity in each region to meet peak demand by enforcing regional minimum reserve levels to allow for generation contingencies, which can occur at any time.

All dispatchable generators in each region are eligible to contribute to reserve (except PSH, VPPs and large-scale battery storages[16]) and headroom that is available from interconnectors. The hourly modelling accounts for load diversity and sharing of reserves across the NEM and so minimises the amount of reserve carried, and provides reserve from the lowest cost providers,

[16] PSH and large-scale battery storages are usually fully dispatched during the peak demand periods and thus will be unable to contribute to reserve. In the event that they are not dispatched fully, it is likely that they will have insufficient energy in storage.

including allowing for each region to contribute to its neighbours' reserve requirements through interconnectors.

In the modelling presented in this Report, a consecutive contingency reserve requirement was applied with a high penalty cost. This amount of reserve ensures there is sufficient capacity for operational reliability in the event that conditions vary from the perfect-foresight optimisation model (e.g. variability in production from variable renewable energy sources, different forced outage patterns). This constraint is applied to only a subset of simulation hours when demand is high to reduce the optimisation problem size.

There are three geographical levels of reserve constraints applied:

- Reserve constraints are applied to each region.

- The model ensures that interconnector headroom is backed by spare capacity in the neighbouring regions through an additional reserve constraint.

- In New South Wales, where the major proportion of load and dispatchable generation is concentrated in the Central New South Wales (NCEN) zone, the same rules are applied as for the New South Wales region except headroom on intra-connectors between adjacent zones does not contribute to reserve. This is because even if there is headroom on the NCEN intra-connectors, it is likely that the flows from the north and south into NCEN reflect the upstream network limits. However, intra-connectors still implicitly contribute to reserve because increased flow can displace dispatchable generators within NCEN allowing them to contribute to reserve.

4.3 Losses in long-term investment planning

Intra and inter-regional losses are captured in the TSIRP model through explicit modelling of dynamic loss equations. More detail on these equations is given in Section 5.

4.4 Cost-benefit analysis

From the hourly time-sequential modelling the following categories of costs defined in the RIT-T are computed:

- capital costs of new generation capacity installed,
- total FOM costs of all generation capacity,
- total VOM costs of all generation capacity,
- total fuel costs of all generation capacity,
- total cost of voluntary and involuntary load curtailment, called DSP and USE,
- transmission expansion costs associated with REZ development.

For each option a matched no option counterfactual (referred to as the Base Case) long term investment plan is simulated. The changes in each of the cost categories are computed as the forecast gross market benefits due to the option, as defined in the RIT-T.

Each component of gross market benefits is computed annually over the 25-year modelling period. In this Report, we summarise the benefit and cost streams using a single value computed as the Net Present Value (NPV)[17], discounted to June 2021 at a 5.5 % real, pre-tax discount rate as selected by Transgrid.

The forecast gross market benefits of each option need to be compared to the relevant option cost to determine whether there is a positive forecast net economic benefit. The determination of the preferred option is also dependent on option costs and was conducted outside of this Report by

[17] We use the term net present value rather than present value as there are positive and negative components of market benefits captured; however, we do not consider augmentation costs.

Transgrid[1]. All references to the preferred option in this Report are in the sense defined in the RIT-T as "the credible option that maximises the net economic benefit across the market, compared to all other credible options"[7], as identified in the PACR[1].

4.5 Broken Hill REZ with Storage Options

In line with AEMO's 2021 Input and Assumptions Workbook[12], all REZs within the NEM are modelled with a transmission limit to represent the physical limitations of the transmission network that connects the REZ to the relevant major load centre. The transmission limit is modelled as a dispatch constraint where in all time periods, the generation dispatched from the REZ must be less than or equal to the transmission limit. If economic to do so the model can choose to increase this limit at a cost representative of the augmentation required for the specific REZ.

$$REZ\ Dispatched\ Generation \leq REZ\ Transmission\ Limit$$

Storage capacity within a REZ will enable increased VRE generation within that REZ through time shifting of generation. To represent this within the model there were two options:

- ► A static increase to the Broken Hill REZ transmission limit, which makes a simplifying assumption that energy storage options within the REZ are always available to be charged.
- ► Explicitly include the storage options dispatch in the Broken Hill REZ transmission constraint. This allows the operation of the storage option to increase VRE generation in the REZ only if economic to do so.

The second option reduces the risk of overstating benefits and was the chosen approach by Transgrid in this modelling exercise. In this approach the Broken Hill REZ transmission constraint becomes:

$$Wind_{Gen} + Solar_{Gen} + Storage_{Gen/Load} \leq Broken\ Hill\ REZ\ Tx\ Limit$$

This implementation is only possible in a time-sequential model. As the storage dispatch value becomes less than zero when charging, in periods of battery charging the wind and/or solar generation can increase. In the other case where the storage is discharging this may require wind and/or solar generation to be reduced. The state of charge (or reservoir level) at each dispatch interval is important as it determines whether the storage option is able to charge (not already full) or discharge (not already empty). In order to achieve the lowest cost of dispatch over the modelling horizon, the time series nature of storage operation may require preparation of the storage state of charge hours or days ahead.

5. Transmission and demand

5.1 Regional and zonal definitions

Transgrid elected to split New South Wales into sub-regions or zones in the modelling presented in this Report, with a high resolution of the Canberra (CAN) zone which is used in the HumeLink PACR[18], as listed in Table 4. In Transgrid's view, this enables better representation of intra-regional network limitations and transmission losses.

Table 4: Regions, zones and reference nodes

Region	Zone	Zonal Reference Node
Queensland	Queensland (QLD)	South Pine 275 kV
New South Wales	Northern New South Wales (NNS)	Armidale 330 kV
	Central New South Wales (NCEN)	Sydney West 330 kV
	South-West New South Wales (SWNSW)	Darlington Point 330 kV
	Canberra	Canberra 330 kV
	Bannaby	Bannaby 330 kV
	Yass	Yass 330 kV
	Wagga	Wagga 330 kV
	Lower Tumut	Lower Tumut 330 kV
	Snowy (Maragle)	Snowy (Maragle) 330 kV
	Upper Tumut	Upper Tumut 330 kV
Victoria	Murray	Murray 330 kV
	Dederang	Dederang 330 kV
	Victoria (VIC)	Thomastown 66 kV
South Australia	South Australia (SA)	Torrens Island 66 kV
Tasmania	Tasmania (TAS)	Georgetown 220 kV

Dynamic loss equations are defined between reference nodes across these cut-sets. The borders of each zone or region are defined by the cut-sets listed in Table 5, as defined by Transgrid.

Table 5: Key cut-set definitions

Border	Lines
NNS-NCEN	Line 88 Muswellbrook – Tamworth Line 84 Liddell – Tamworth Line 96T Hawks Nest – Taree Line 9C8 Stroud – Brandy Hill

[18] TransGrid, *HumeLink PACR market modelling*, Available at: https://www.transgrid.com.au/media/vqzdxwl3/humelink-pacr-ey-market-modelling-report.pdf, accessed on 8 April 2022.

Border	Lines
NCEN-CAN	Line 61 Gullen Range – Bannaby Line 3W Kangaroo Valley – Capital Line 4/5 Yass – Marulan Line 973 Yass – Cowra Line 999 Yass – Cowra Line 98J Shoalhaven – Evans Lane Line 28P West Tomerong – Evans Lane and new HumeLink lines for each option
CAN/YASS-Bannaby	Line 61 Gullen Range – Bannaby Line 3W Kangaroo Valley – Capital Lines 4 &5 Yass – Marulan and new HumeLink lines from Maragle/Wagga to Bannaby for each option
Snowy cut-set	Line 01 Upper Tumut to Canberra Line 2 Upper Tumut to Yass Line 07 Lower Tumut to Canberra Line 3 Lower Tumut to Yass
CAN (WAG)-SWNSW	Line 63 Wagga - Darlington Pt Line 994 Yanco - Wagga Line 99F Yanco - Uranquinty Line 99A Finley - Uranquinty Line 997/1 Corowa – Albury New 330 kV double circuit from Wagga – Dinawan (after assumed commissioning of EnergyConnect) New 500 kV double circuit from Wagga – Dinawan (after assumed commissioning of VNI West)
VIC-SWNSW	Line 0X1 Red Cliffs – Buronga New Red Cliffs – Buronga (after assumed commissioning of EnergyConnect) New 500 kV double circuit from Kerang - Dinawan (after assumed commissioning of VNI West)
VNI cut-set	Line 060 Jindera – Wodonga Line 65 Upper Tumut – Murray Line 66 Lower Tumut – Murray VIC-SWNSW cut-set (listed above)
SWNSW-SA	New 330 kV double circuit from Buronga – Robertstown (after assumed commissioning of EnergyConnect)

Table 6 summarises the key cut-set limits in the Canberra zone and from Canberra to NCEN, as defined by Transgrid.

Table 6: Key cut-set limits (MW)

Cut-set	Bidirectional limit (MW)
Snowy cut-set	3,080
Snowy cut-set + HumeLink lines	5,372
CAN/YASS – Bannaby cut-set	4,900
CAN-NCEN cut-set	4,500
Bannaby-NCEN	4,500

Table 7 summarises the VNI cut-set limits across the modelling period and are consistent with AEMO's 2021 Input and Assumptions Workbook[12]. The VNI cut-set limits change with the Victorian SIPS contract ending in March 2032, and the commissioning of VNI West. The VNI West timing differs between scenarios[13] and hence the timing in VNI cut-set limit changes will also differ between scenarios.

Table 7: VNI cut-set limits

Description	Import limit (MW)	Export limit (MW)
Original limits	400 all periods	870 peak demand 1,000 summer 1,000 winter
Post Victorian SIPS contract	-150 peak demand[19]	Unchanged
Post VNI West commissioning	+1,800 all periods[19]	+1,930 all periods[19]

5.2 Interconnector and intra-connector loss models

Dynamic loss equations are computed for a number of conditions, including:

- when a new link is defined e.g. NNS-NCEN, SA-SWNSW (EnergyConnect), Bannaby-NCEN, Wagga-SWNSW,
- when interconnector definitions change with the addition of new reference nodes e.g. the VNI now spans VIC-SWNSW and VIC-CAN instead of VIC-NSW,
- when future upgrades involving conductor changes are modelled e.g. VNI West, QNI and Marinus Link.
- for Canberra equivalent lines, using their resistance.

The network snapshots to compute the loss equations were provided by Transgrid.

5.3 Interconnector and intra-connector capabilities

The notional limits imposed on interconnectors are shown in Table 8. The following interconnectors are included in the left-hand side of constraints which may restrict them below the notional limits specified in this table:

- Heywood + Project EnergyConnect has combined transfer export and import limits of 1,300 MW and 1,450 MW respectively. The model will dispatch the two links to minimise costs.

[19] The overall limit is the original limit plus the change

Table 8: Notional interconnector capabilities used in the modelling (sourced from Transgrid and AEMO draft 2022 ISP[13])

Interconnector (From node – To node)	Import[20] notional limit	Export[21] notional limit
QNI[22]	1,205 MW peak demand 1,165 MW summer 1,170 MW winter	685 MW peak demand 745 MW summer/winter
QNI Connect 1	2,285 MW peak demand 2,245 MW summer 2,250 MW winter	1,595 MW peak demand 1,655 MW summer/winter
QNI Connect 2	3,085 MW peak demand 3,045 MW summer 3,050 MW winter	2,145 MW peak demand 2,205 MW summer/winter
Terranora (NNS-SQ)	130 MW peak demand 150 MW summer 200 MW winter	0 MW peak demand 50 MW summer/winter
EnergyConnect (SWNSW-SA)	800 MW	800 MW
Heywood (VIC-SA)	650 MW (before EnergyConnect) 750 MW (after EnergyConnect)	650 MW (before EnergyConnect) 750 MW (after EnergyConnect)
Murraylink (VIC-SA)	200 MW	220 MW
Basslink (TAS-VIC)	478 MW	478 MW
Marinus Link (TAS-VIC)	750 MW for the first leg and 1,500 MW after the second leg	750 MW for the first leg and 1,500 MW after the second leg

New South Wales has been split into zones with the following limits imposed between the zones defined in Table 9.

Table 9: Intra-connector notional limits imposed in modelling for New South Wales (sourced from Transgrid)

Intra-connector (From node – To node)	Import notional limit	Export notional limit
NCEN-NNS	1,177 MW (after QNI Minor) Limit will increase after NEW England REZ augmentations as mentioned in the 2022 draft ISP[13]	1,377 MW (after QNI Minor) Limit will increase after NEW England REZ augmentations as mentioned in the 2022 draft ISP[13]
WAG-SWNSW	300 MW (before EnergyConnect) 1,100 MW (after EnergyConnect) 1,900 MW (after HumeLink) 3,000 MW (after VNI West)	500 MW (before EnergyConnect) 1,300 MW (after EnergyConnect) 2,100 MW (after HumeLink) 2,700 MW (after VNI West)

[20] Import refers to power being transferred from the 'To node' to the 'From node' and follows NEM convention where the 'From node' is the most southerly or easterly node, and the 'To node' is the most northerly or westerly node. e.g. import along QNI implies southward flow and import along Heywood implies eastward flow.
[21] Export refers to power being transferred from the 'From node' to the 'To node' and follows NEM convention where the 'From node' is the most southerly or easterly node, and the 'To node' is the most northerly or westerly node. e.g. export along QNI implies northward flow and export along Heywood implies westward flow.
[22] Flow on QNI may be limited due to additional constraints.

5.4 Demand

The TSIRP model captures operational demand (energy consumption which is net of rooftop PV and other non-scheduled generation) diversity across regions by basing the overall shape of hourly demand on nine historical financial years ranging from 2010-11 to 2018-19.

Specifically, the key steps in creating the hourly demand forecast are as follows:

- the historical underlying demand has been calculated as the sum of historical operational demand and the estimated rooftop PV generation based on historical monthly rooftop PV capacity and solar insolation,
- the nine-year hourly pattern has been projected forward to meet future forecast annual peak demand and energy in each region (scenario-dependent),
- the nine reference years are repeated sequentially throughout the modelling horizon as shown in Figure 5
- the future hourly rooftop PV generation has been estimated based on insolation in the corresponding reference year and the projection of future rooftop PV capacity, which is subtracted from the forecast underlying demand along with other behind-the-meter components (e.g., electric vehicles and domestic storage) to get a projection of hourly operational demand.

Figure 5: Sequence of demand reference years applied to forecast

Modelled year	Reference year
2023-24	2014-15
2024-25	2015-16
2025-26	2016-17
2026-27	2017-18
2027-28	2018-19
2028-29	2010-11
2029-30	2011-12
2030-31	2012-13
2031-32	2013-14
2032-33	2014-15
2033-34	2015-16
2034-35	2016-17
2035-36	2017-18
2036-37	2018-19
...	...
2041-42	2014-15
2042-43	2015-16
2043-44	2016-17

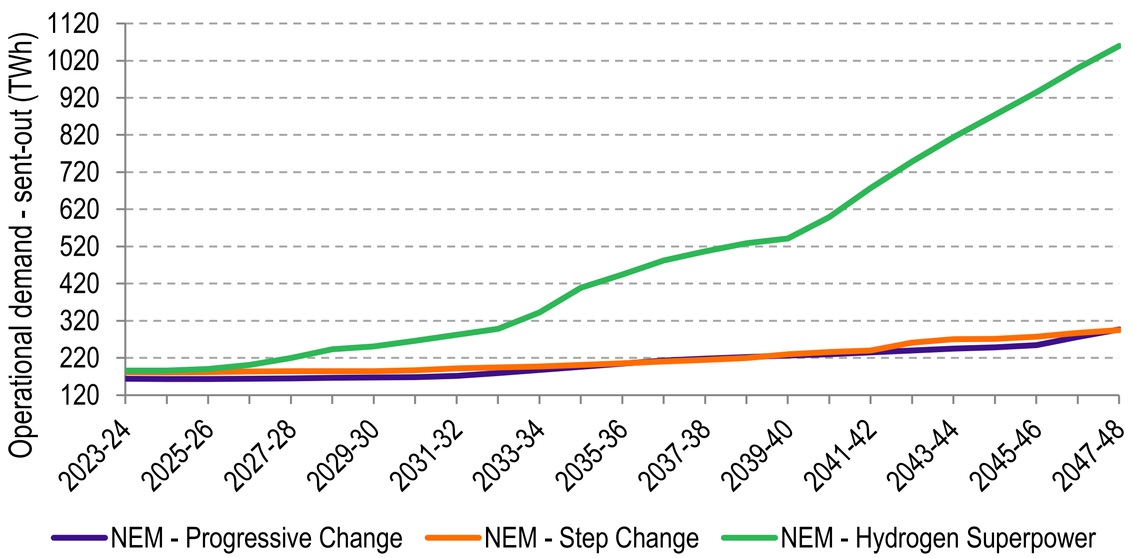
Modelled year	Reference year
2044-45	2017-18
2045-46	2018-19
2046-47	2010-11
2047-48	2011-12

This method ensures the timing of high and low demands across regions reflects historical patterns, while accounting for projected changes in rooftop PV generation and other behind-the-meter loads and generators that may alter the size of peaks and their timing across regions. Overall, due to rooftop PV uptake, we generally see the peak operational demand intervals shifting later in the day throughout the forecast.

The reference year pattern is also consistent with site-specific hourly large-scale wind and solar availability (see Section 6.1) and hydro inflows. This maintains correlations between weather patterns, demand, wind, large-scale solar and rooftop PV availability.

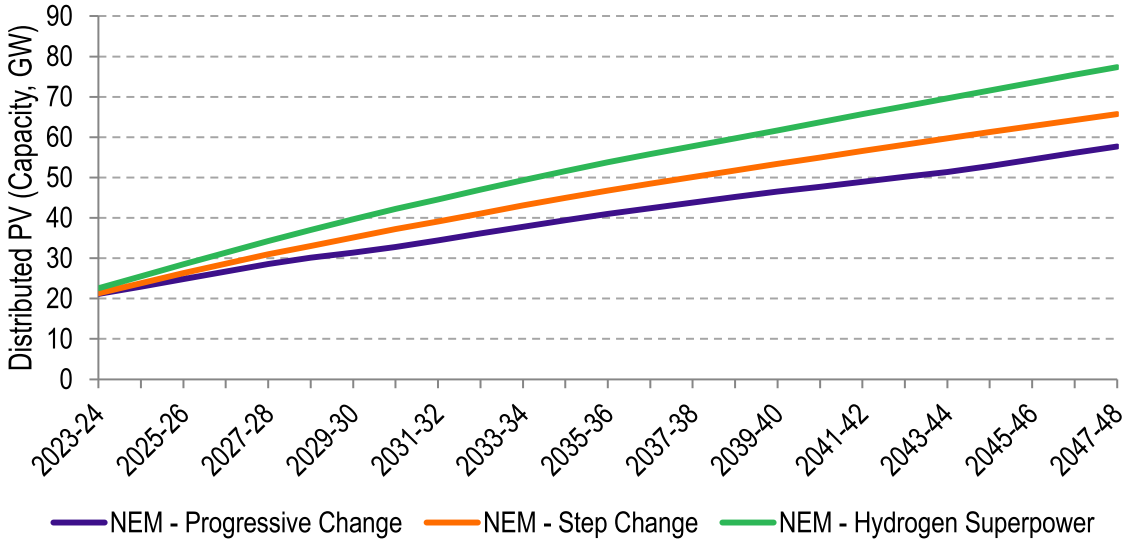
Transgrid selected demand forecasts from the ESOO 2021[23], which are used as inputs to the modelling. Figure 6 and Figure 7 shows the NEM operational energy and distributed PV for the modelled scenarios.

Figure 6: Annual operational demand in the modelled scenarios for the NEM[23]



[23] AEMO, August 2021, *NEM Electricity Statement of Opportunities (ESOO),* Available at: http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational. Accessed on 12 April 2022.

Figure 7: Annual distributed PV (rooftop PV and small non-scheduled PV) uptake in the NEM[23]



For NSW the ESOO 2021 demand forecasts are split into the various NSW zones that have been defined, as described in Section 5.1. Transgrid obtained from AEMO half-hourly scaling factors to convert regional load to connection point loads which are used to split the regional demand into the zones. Doing so captures the diversity of demand profiles between the different zones in NSW.

6. Supply

6.1 Wind and solar energy projects and REZ representation

Several generators not yet built are committed in all simulations, including the Base Case and each option. The source of this list is based on the AEMO 2021 ISP Inputs and Assumptions workbook[12] and the AEMO NEM Generation Information February 2022 workbook[24]; existing, committed, and anticipated projects including batteries are included.

Existing and new wind and solar projects are modelled based on nine years of historical weather data[25]. The methodology for each category of wind and solar project is summarised in Table 10 and explained further in this section of the Report.

Table 10: Summary of wind and solar availability methodology

Technology	Category	Capacity factor methodology	Reference year treatment
Wind	Existing	Specify long-term target based on nine-year average in AEMO ESOO 2019 traces[26] where available, otherwise past meteorological performance.	Capacity factor varies with reference year based on site-specific, historical, near-term wind speed forecasts.
	Committed new entrant	Reference year specific targets based on capacity factor of nearest REZ, medium quality tranche in AEMO's 2021 Input and Assumptions workbook[12]	
	Generic REZ new entrants	Reference year specific targets based on AEMO 2021 ISP Inputs and Assumptions workbook[12]. One high quality option and one medium quality trace per REZ.	

[24] AEMO, *NEM Generation Information February 2022*. Available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Accessed on 5 April 2022

[25] As described by Australian Government Bureau of Meteorology, *ACCESS NWP Data* Information. Available at: http://www.bom.gov.au/nwp/doc/access/NWPData.shtml. Accessed on 5 April 2022.

[26] AEMO, *2019 Electricity Statement of Opportunities: 2019 Wind Traces* and *2019 Solar Traces*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities. Accessed on 5 April 2022.

Technology	Category	Capacity factor methodology	Reference year treatment
Solar PV FFP[27]	Existing	Annual capacity factor based on technology and site-specific solar insolation measurements.	Capacity factor varies with reference year based on historical, site-specific insolation measurements.
Solar PV SAT	Existing		
	Committed new entrant	Reference year specific targets based on capacity factor of nearest REZ, in AEMO's 2021 ISP Inputs and Assumptions workbook[12]	
	Generic REZ new entrant	Reference year specific targets based on AEMO 2021 ISP Inputs and Assumptions workbook[12]	
Rooftop PV and small non-scheduled solar PV	Existing and new entrant	Long-term average capacity factor based on AEMO 2021 ISP Inputs and Assumptions workbook[12].	Capacity factor varies with reference year based on historical insolation measurements.

All existing and committed large-scale wind and solar farms in the NEM are modelled on an individual basis. Each project has a location-specific availability profile based on historical resource availability. The availability profiles are derived using nine years of historical weather data covering financial years between 2010-11 and 2018-19 (inclusive), and synchronised with the hourly shape of demand. Wind and solar availability profiles used in the modelling reflect generation patterns occurring in the nine historical years, and these generation patterns are repeated throughout the modelling period as shown in Figure 5.

The availability profiles for wind generation are derived from simulated wind speeds from the Australian Bureau of Meteorology's Numerical Weather Prediction systems[26] at a representative hub height. Wind speeds are converted into power using a generic wind farm power curve. The wind speed profiles are scaled to achieve the average target capacity factor across the nine historical years. The profiles reflect inter-annual variations, but at the same time achieve long-term capacity factors in line with historical performance (existing wind farms) or the values used in the AEMO 2021 ESOO[23] and draft 2022 ISP assumptions[2], for each REZ (new entrant wind farms, as listed in Table 11).

The availability profiles for solar are derived using solar irradiation data downloaded from satellite imagery processed by the Australian Bureau of Meteorology. As for wind profiles, the solar profiles reflect inter-annual variations over nine historical years, but at the same time achieve long-term capacity factors in line with historical performance (existing solar farms) or close to AEMO's approximation for each REZ (generic new entrant solar farms as listed in Table 11).

Table 11: 2021 IASR REZ wind and solar approximate average capacity factors over nine reference years[2]

Region	REZ	Wind		Solar SAT
		High quality	Medium quality	
Queensland	Far North Queensland	54 %	48 %	27 %
	North Queensland Clean Energy Hub	43 %	36 %	30 %
	Northern Queensland	Tech not available	Tech not available	28 %
	Isaac	37 %	31 %	29 %

[27] FFP = Fixed Flat Plate

Region	REZ	Wind		Solar SAT
		High quality	Medium quality	
	Barcaldine	33 %	31 %	32 %
	Fitzroy	38 %	33 %	28 %
	Wide Bay	32 %	30 %	27 %
	Darling Downs	39 %	34 %	28 %
	Banana	31 %	28 %	29 %
New South Wales	North West New South Wales	Tech not available	Tech not available	29 %
	New England	39 %	38 %	26 %
	Central West New South Wales	37 %	34 %	27 %
	Broken Hill	33 %	31 %	30 %
	South West New South Wales	30 %	30 %	27 %
	Wagga Wagga	28 %	27 %	26 %
	Cooma-Monaro	43 %	41 %	Tech not available
Victoria	Ovens Murray	Tech not available	Tech not available	24 %
	Murray River	Tech not available	Tech not available	27 %
	Western Victoria	42 %	37 %	23 %
	South West Victoria	41 %	39 %	Tech not available
	Gippsland[28]	40 %	35 %	20 %
	Central North Victoria	33 %	31 %	26 %
South Australia	South East SA	40 %	37 %	23 %
	Riverland	29 %	28 %	27 %
	Mid-North SA	39 %	37 %	26 %
	Yorke Peninsula	37 %	36 %	Tech not available
	Northern SA	37 %	35 %	28 %
	Leigh Creek	41 %	40 %	31 %
	Roxby Downs	Tech not available	Tech not available	30 %
	Eastern Eyre Peninsula	40 %	38 %	25 %
	Western Eyre Peninsula	40 %	38 %	27 %
Tasmania	North East Tasmania	46 %	44 %	22 %
	North West Tasmania[29]	51 %	46 %	19 %
	Tasmania Midlands	56 %	54 %	21 %

[28] Gippsland has an option for Offshore wind with an average capacity factor of 46 %.

[29] North West Tasmania has an option for Offshore wind with an average capacity factor of 50 %.

Wind and solar capacity expansion in each REZ is limited by four parameters based on AEMO's 2021 Inputs and Assumptions workbook[12].

► Transmission-limited total build limit (MW) representing the amount of dispatch supported by current intra-regional transmission infrastructure.

► A transmission expansion cost ($/MW) representing an indicative linear network expansion cost to develop a REZ beyond current capabilities and connect the REZ to the nearest major load centre.

► Resource limits (MW) representing the maximum amount of capacity expected to be feasibly developed in a REZ based on topography, land use etc at the given capex.

► A resource limit violation penalty factor ($/MW) to build additional capacity beyond the resource limit. This represents additional capex to build on sites with higher land costs.

The TSIRP model incurs the additional transmission expansion cost to build more capacity up to the resource limit if it is part of the least-cost development plan.

6.2 Forced outage rates and maintenance

Full and partial forced outage rates for all generators as well as mean time to repair used in the modelling are based on the AEMO 2021 Inputs and Assumptions workbook[12].

All unplanned forced outage patterns are set by a random number generator for each existing generator. The seed for the random number generator is set such that the same forced outage pattern exists between the Base Case and the various upgrade options. New entrant generators are de-rated by their equivalent forced outage rate.

Planned maintenance events for existing generators are scheduled during low demand periods and the number of days required for maintenance is set based on the AEMO 2021 Inputs and Assumptions workbook[12].

6.3 Generator technical parameters

All technical parameters are as detailed in the AEMO 2021 Inputs and Assumptions workbook[12], except where noted in the Report.

6.4 Coal-fired generators

Coal-fired generators are treated as dispatchable between minimum load and maximum load. Must run generation is dispatched whenever available at least at its minimum load. In line with the AEMO 2021 Inputs and Assumptions workbook[12]. Maximum loads vary seasonally. This materially reduces the amount of available capacity in the summer periods.

A maximum capacity factor of 75 % is assumed for NSW coal, as per the AEMO 2021 Inputs and Assumptions workbook[12].

6.5 Gas-fired generators

Gas-fired CCGT plant also typically have a must-run component and so are dispatched at or above their minimum load to deliver efficient fuel consumption.

In line with the AEMO 2021 Inputs and Assumptions workbook[12], a minimum load of 46 % of capacity for all new CCGTs has been applied to reflect minimum load conditions for assumed efficient use of gas and steam turbines in CCGT operating mode.

OCGTs are assumed to operate with no minimum load. As a result, they start and are dispatched for a minimum of one hour when the cost of supply is at or above their SRMC.

6.6 Wind, solar and run-of-river hydro generators

Intermittent renewables, in particular solar PV, wind and run-of-river hydro are dispatched according to their resource availability as they cannot store energy. Intermittent renewable production levels are based on nine years of hourly measurements and weather observations across the NEM including all REZ zones. Using historical reference years preserves correlations in weather patterns, resource availability and demand. Modelling of wind and solar PV is covered in more detail in Section 6.1.

Solar PV and wind generation are dispatched at their available resource limit unless curtailed economically, when the marginal cost of supply falls to less than their VOM, or by other constraints such as transmission limits.

6.7 Storage-limited generators

Conventional hydro with storages, PSH and batteries are dispatched in each trading interval such that they are most effective in reducing the costs of generation up to the limits of their storage capacity.

Hourly hydro inflows to the reservoirs and ponds are computed from monthly values sourced from the AEMO 2021 Inputs and Assumptions workbook and the median hydro climate factor trajectory for the respective scenario applied. The Tasmanian hydro schemes were modelled using a ten-pond model, with additional information sourced from the TasNetworks Input assumptions and scenario workbook for Project Marinus PACR[30].

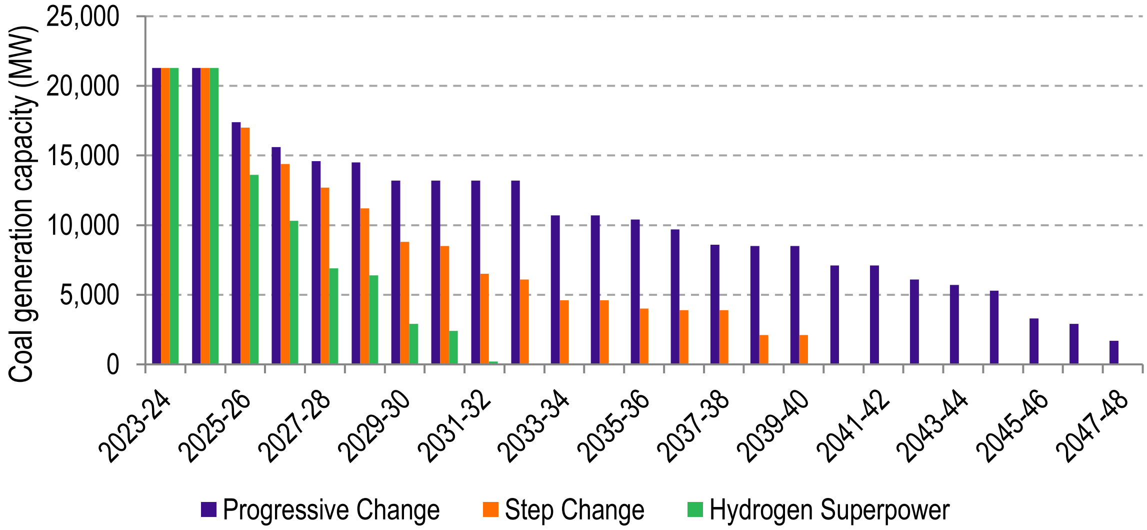
[30] TasNetworks, *Input assumptions and scenario workbook for Project Marinus PACR*. Available at https://www.marinuslink.com.au/rit-t-process/. Accessed on 26 April 2022

7. NEM outlook without options

To understand the forecast benefits of the options, it is useful to examine the differences in the expected capacity and generation outlooks in the modelled scenarios, and the underlying input assumptions driving those differences in the Base Case.

According to the scenario settings selected by Transgrid and in line with AEMO's draft 2022 ISP[2], thermal retirements in the model determined are on an economic basis. Coal retirement dates are at or earlier than their end-of-technical life or announced retirement year. Forecast coal capacity in the Base Case as an output of the modelling is illustrated in Figure 8.

Figure 8: Coal capacity in the NEM by year in the Base Case



The pace of the transition is determined by a combination of market forces, federal and state government policies[2] and timing for end of life of existing assets in a system developed and dispatched at least cost. This includes the corresponding demand outlook and capital cost projections, carbon budget constraint, and state-based policy initiatives such as TRET, VRET, QRET and the NSW Electricity Infrastructure Roadmap. The model forecasts the entire coal capacity to retire by the early 2030s in the Hydrogen Superpower, while this is the late 2030s for the Step Change scenario and in the Progressive Change scenario, coal is forecast to remain until the end of the modelling period.

The NEM-wide capacity mix forecast in the Base Case for the Step Change scenario is shown in Figure 9 and the corresponding generation mix in Figure 10. In the Base Case, the forecast generation capacity of the NEM gradually shifts towards increasing capacity of wind and solar, complemented by large scale battery, PSH, and gas.

Figure 9: NEM capacity mix forecast for the Step Change scenario in the Base Case

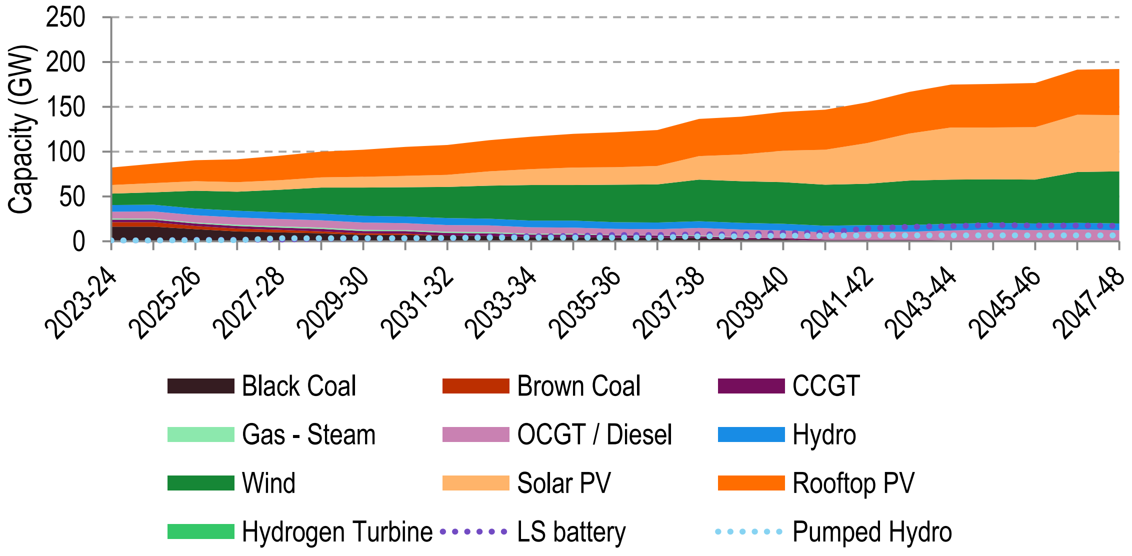
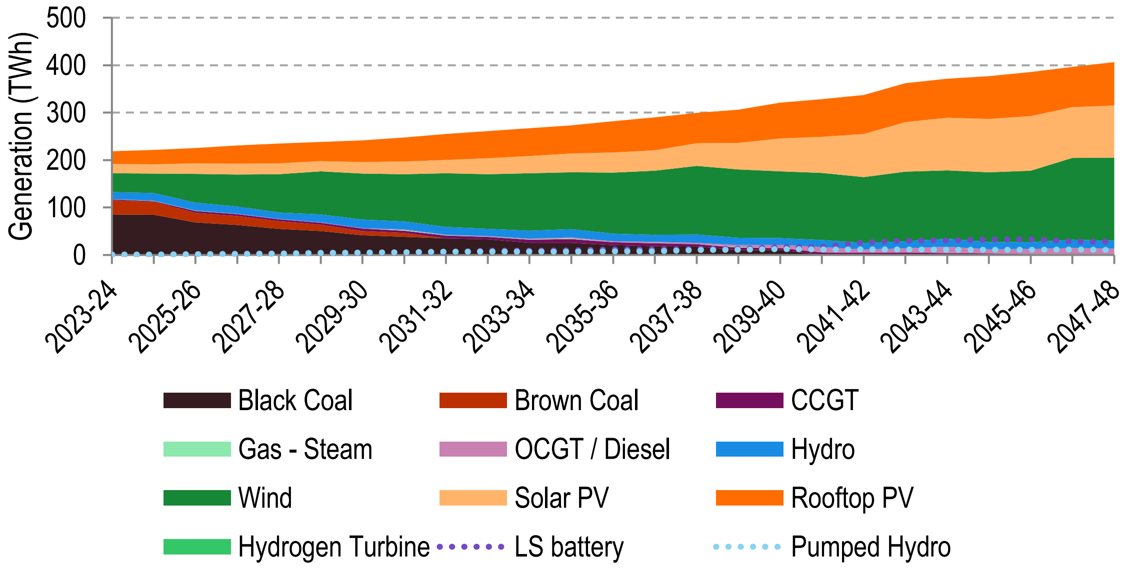


Figure 10: NEM generation mix forecast for the Step Change scenario in the Base Case



Up to 2030, new wind and solar build is largely driven by the assumed state-based renewable energy targets. The forecast increase in renewable capacity leads to some economically driven coal generation retirements in QLD and NSW. To replace the retiring capacity, LS battery capacity is forecast to start to increase from the late 2020s, then PSH and wind capacity increases from the mid-2030s. Solar PV and OCGT capacity is also forecast to increase from the late 2030s complementing other technologies. The forecast gas-fired capacity also supports reserve requirements during peak demand times. Overall, the NEM is forecast to have around 230GW total capacity by 2047-48 (note that total capacity includes PSH and large-scale battery capacities, which are not in the stacked chart), and the forecast timing of the majority of new installed capacity coincides with coal-fired generation retirements.

The other selected scenarios vary in the pace of the energy transition from the Step Change scenario. Figure 11 and Figure 13 show the differences in the NEM capacity development of other scenarios relative to the Step Change scenario, while Figure 12 and Figure 14 show generation differences. The differences are presented as the alternative scenario minus the Step Change scenario, and both capacity and generation differences for each scenario show similar trends. As the figures show, the Progressive Change scenario retains higher coal generation and less wind and solar generation compared to the Step Change scenario due to different assumptions such as the carbon budget, demand forecast and underlying input data. The Hydrogen Superpower scenario has higher wind and solar capacity and generation compared to the Step Change scenario, mainly due to the significant hydrogen demand uptake in this scenario, along with a more restrictive carbon budget.

Figure 11: Difference in NEM capacity forecast between the Progressive Change and Step Change scenarios in the Base case (excluding distributed PV)

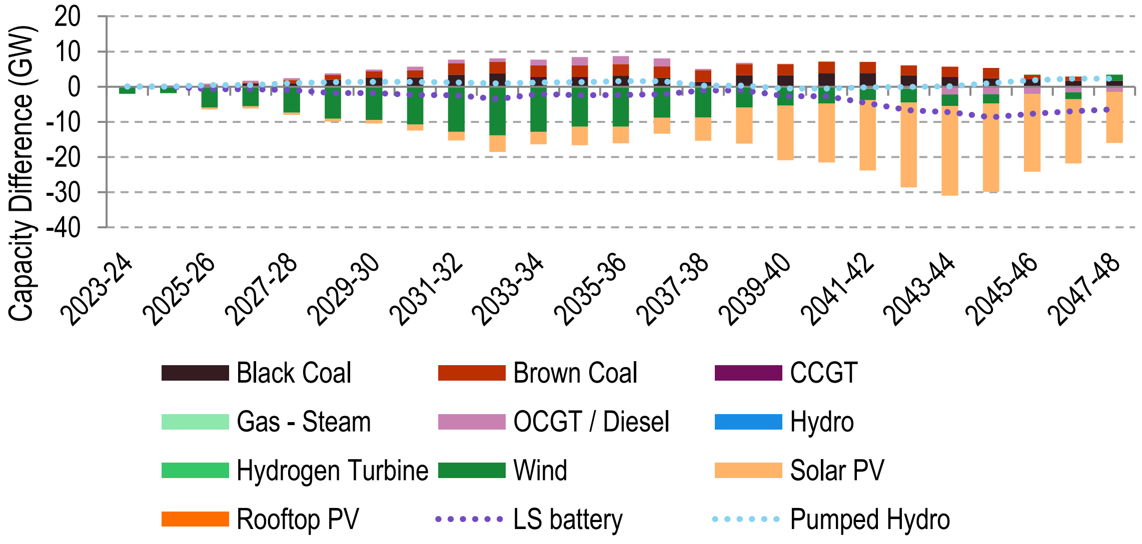


Figure 12: Difference in NEM generation forecast between the Progressive Change and Step Change scenarios in the Base case (excluding distributed PV)

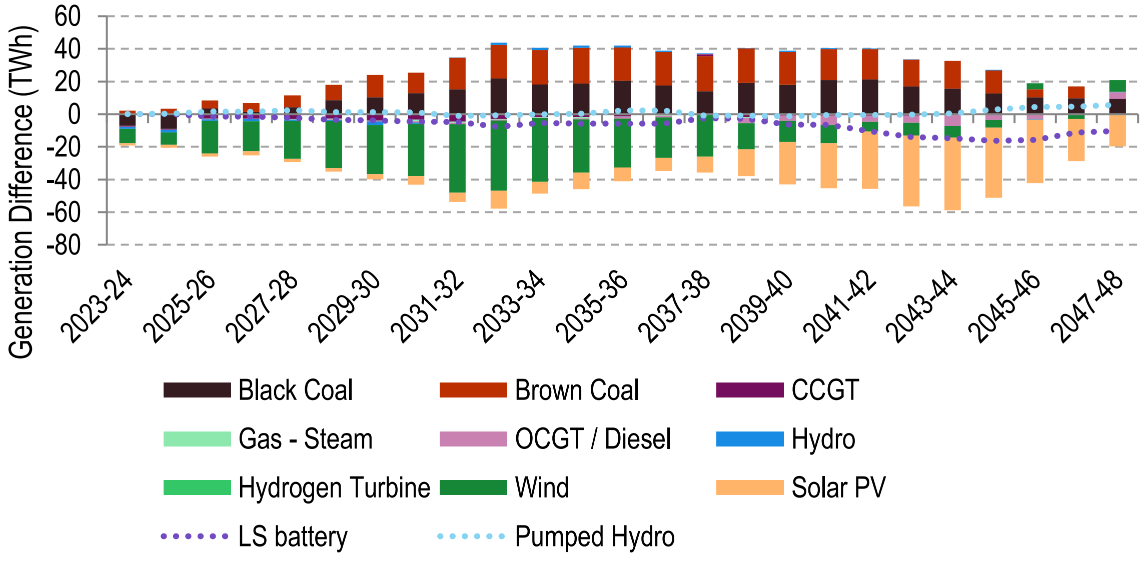


Figure 13: Difference in NEM capacity forecast between the Hydrogen Superpower and Step Change scenarios in the Base case (excluding rooftop PV)

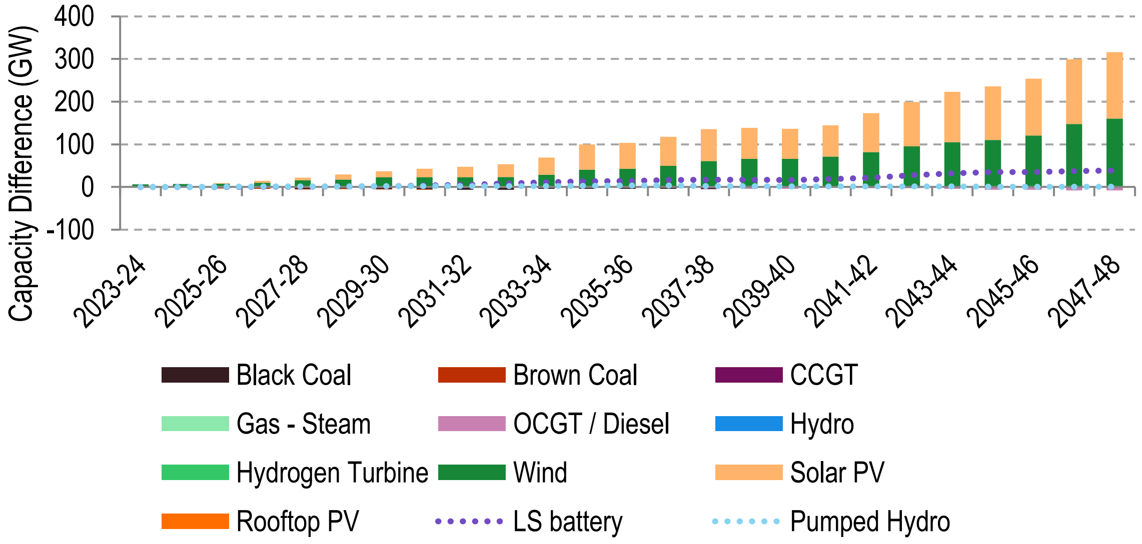
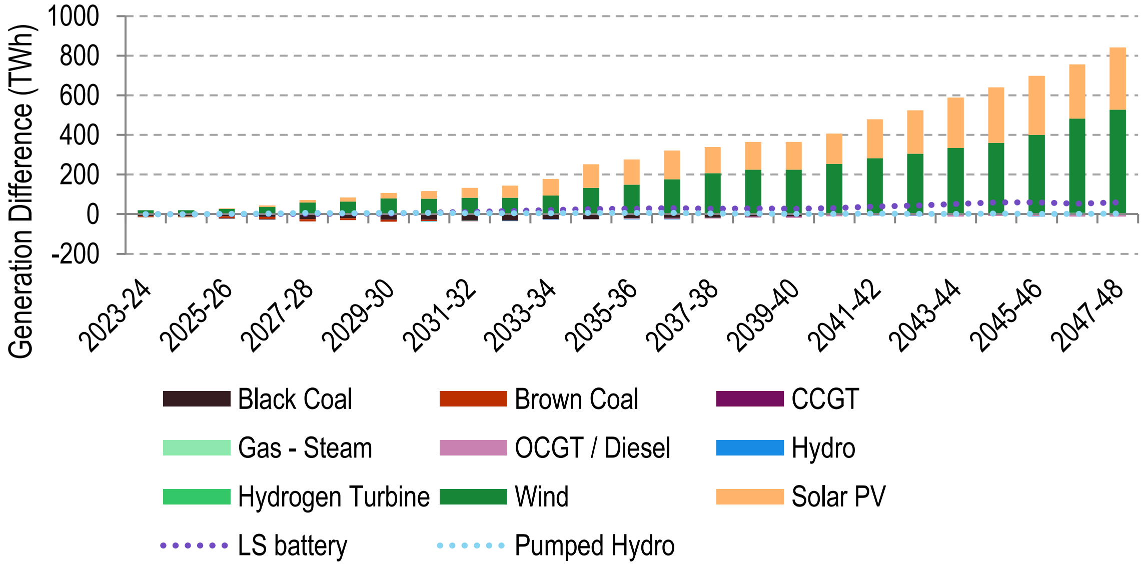


Figure 14: Difference in NEM generation forecast between the Hydrogen Superpower and Step Change scenarios in the Base case (excluding rooftop PV)



8. Forecast gross market benefit outcomes

8.1 Market modelling results

Transgrid has concluded that Option 1A(4) is the preferred option delivering the highest NPV of benefits relative to the costs[1]. All references to the preferred option in this Report are in the sense defined in the RIT-T as "the credible option that maximises the net economic benefit across the market, compared to all other credible options"[7].

Results for the preferred option are presented for all three modelled scenarios, while for all other options the results for only the Step Change scenario are presented. Throughout this section the y-axis in all the comparison charts is removed to maintain the confidentiality of the modelled options as requested by Transgrid.

8.1.1 Option 1A(4)

8.1.1.1 Step Change Scenario

The forecast cumulative gross market benefits for Option 1A(4) in the Step Change scenario are shown in Figure 15. Furthermore, the differences in capacity and generation across the NEM between Option 1A(4) and the Base case in this scenario are shown in Figure 16 and Figure 17 respectively.

Figure 15: Forecast cumulative gross market benefit for Option 1A(4) under the Step Change scenario

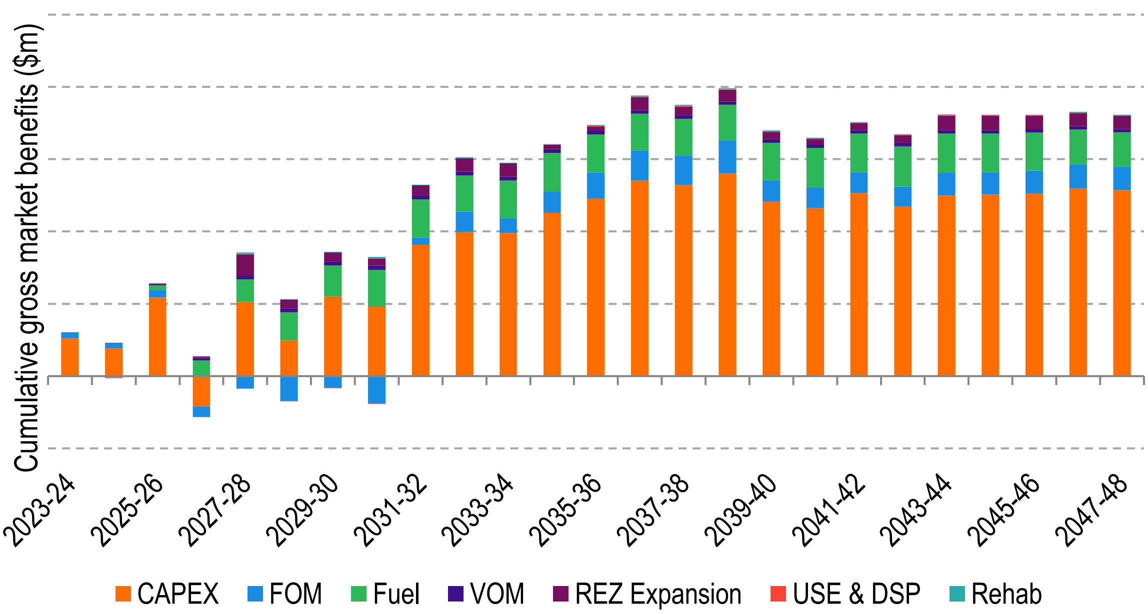


Figure 16: Difference in NEM capacity forecast between Option 1A(4) and Base Case in the Step Change scenario (including assumed capacity of Option 1A(4))

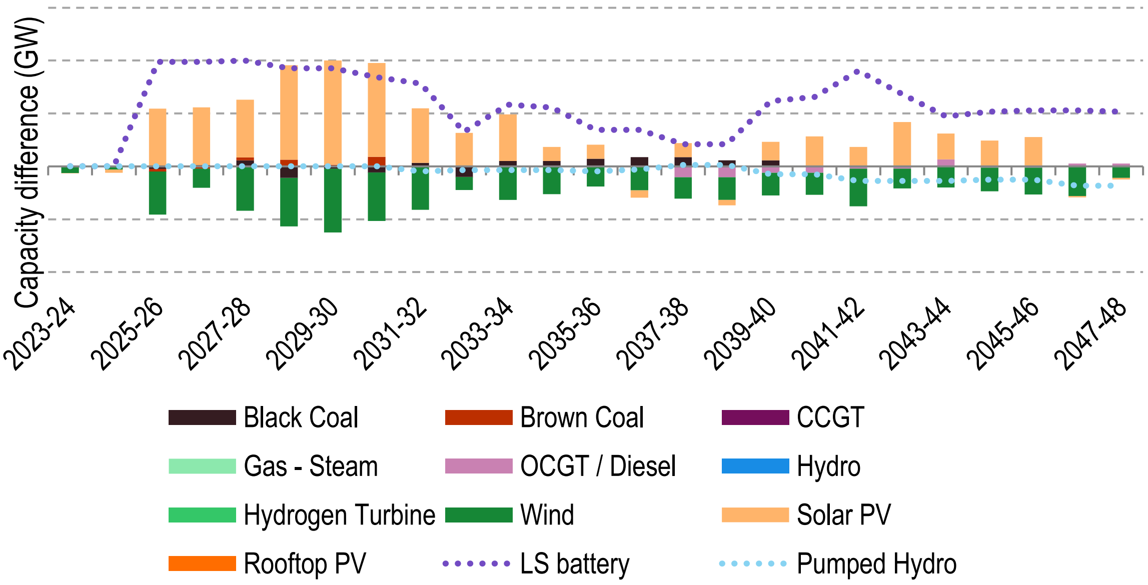
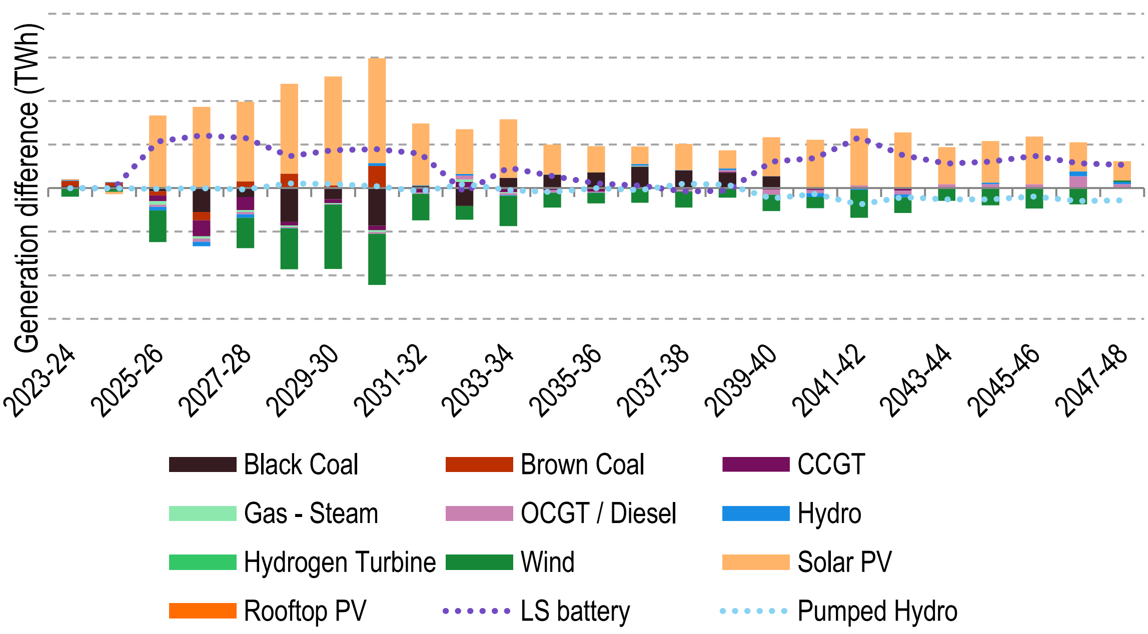


Figure 17: Difference in NEM generation forecast between Option 1A(4) and Base Case in the Step Change scenario (including forecast generation of Option 1A(4))



The primary sources of forecast gross market benefits are from avoided and deferred capex for new generation capacity as well as fuel cost savings from reduced black coal and gas generation followed by REZ expansion benefits and FOM savings. The timing and source of these benefits are attributable to the following:

- Capex benefits are forecast to accrue from the first year through to the late 2030s. These benefits are largely due to deferred wind build through the 2020s, as well as avoided battery storage build due to the option being in place. The option enables increased solar capacity which defers the need for new wind generation. Deferred wind build is also forecast throughout the 2030s due to increased black coal generation.

- ► Fuel cost savings are forecast to accrue from 2025-26 as black coal and gas generation is offset by increased solar and storage generation due to the option being in place.
- ► REZ expansion benefits are forecast to accrue from 2026-27 and fluctuate throughout the whole modelling period. REZ expansion benefits are a result of the increased generation from the storage option offsetting the need to expand VRE capacity in REZs throughout the NEM. The storage option is also forecast to allow for increased solar capacity and generation within the Broken Hill REZ without incurring additional costs.

8.1.1.2 Progressive Change Scenario

The forecast cumulative gross market benefits for Option 1A(4) in the Progressive Change scenario are shown in Figure 18. Furthermore, the differences in capacity and generation across the NEM between Option 1A(4) and the Base case in this scenario are shown in Figure 19 and Figure 20 respectively.

Figure 18: Forecast cumulative gross market benefit for Option 1A(4) under the Progressive Change scenario

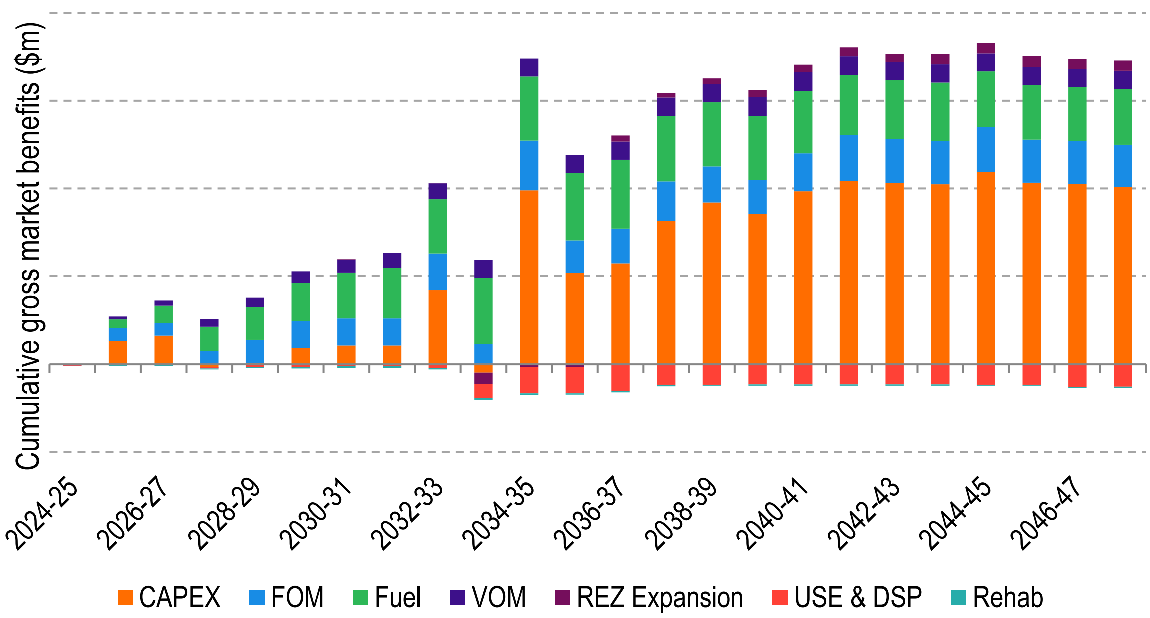


Figure 19: Difference in NEM capacity forecast between Option 1A(4) and Base Case in the Progressive Change scenario (including assumed capacity of Option 1A(4))

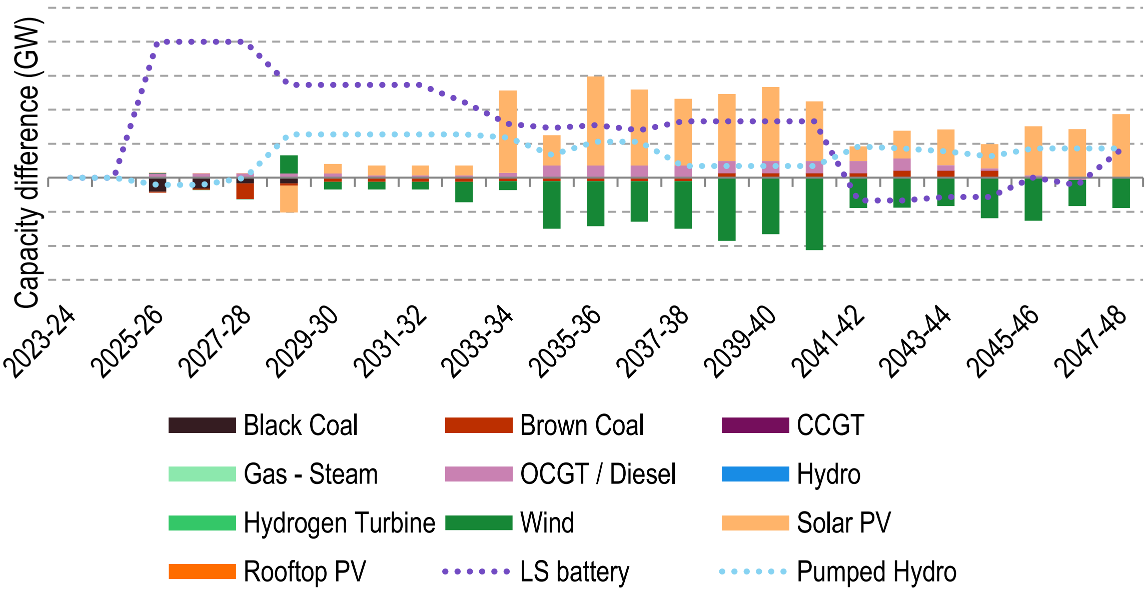
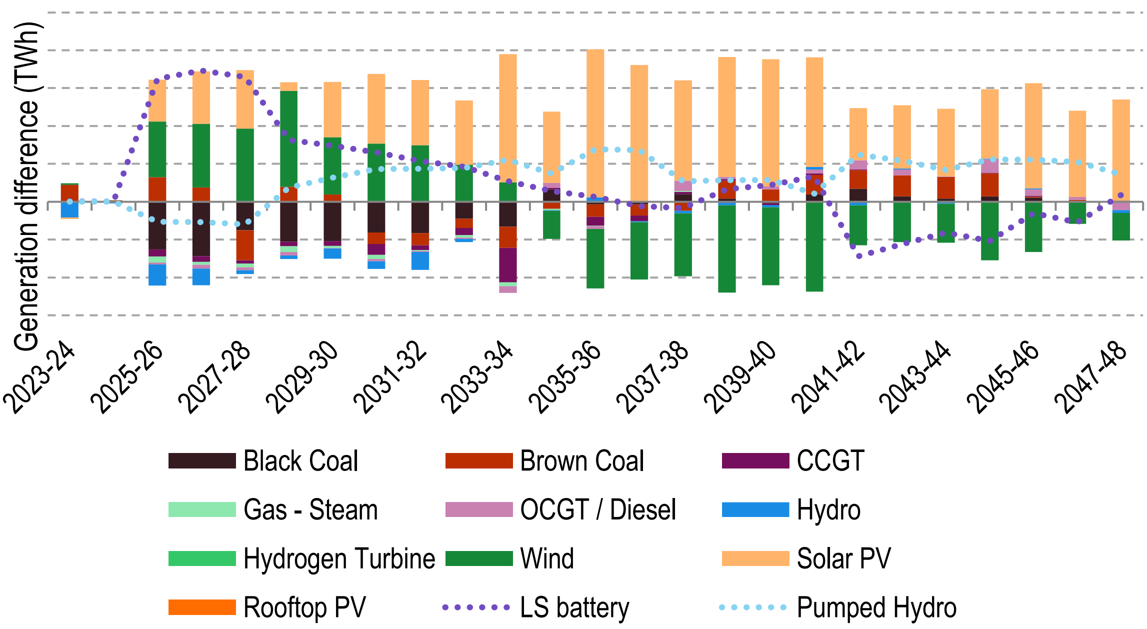


Figure 20: Difference in NEM generation forecast between Option 1A(4) and Base Case in the Progressive Change scenario (including forecast generation of Option 1A(4))



The primary sources of forecast gross market benefits are from avoided and deferred capex for new generation capacity as well as fuel cost savings from reduced black coal and gas generation followed by REZ expansion benefits and FOM savings. The timing and source of these benefits are attributable to the following:

- In the Progressive Change scenario new capacity up to 2030 is forecast to be driven mostly by state-based policy targets and therefore capacity difference are minimal between the option and Base Case in the early years. This results in a forecast slower accumulation of capex benefits from 2032-33 through to 2040-41 when compared to the Step Change scenario. When the cumulative carbon budget begins and demand increases, this results in the need for new zero emissions generation. The presence of the storage option allows for increased solar capacity, while deferring wind and storage build.

- Fuel cost savings are forecast to accumulate from 2025-26 through to the mid 2030s. These savings are a result of the storage option increasing the generation of existing wind and solar farms. The increased VRE and storage generation results in less black coal, brown coal and gas generation from 2025-26 through to 2033-34. The reduced thermal generation in the early 2030s allows for increased brown coal generation in the late 2030s and 2040s, offsetting the need for new capacity.

- REZ expansion benefits are forecast to accrue from 2026-27. Similar to the Step Change scenario, REZ expansion benefits are a result of the increased generation from the storage option offsetting the need to expand capacity in REZs throughout the NEM. The storage option is also forecast to allow for increased solar capacity and generation within the Broken Hill REZ without incurring additional costs.

8.1.1.3 Hydrogen Superpower Scenario

The forecast cumulative gross market benefits for Option 1A(4) in the Hydrogen Superpower scenario are shown in Figure 21. Furthermore, the differences in capacity and generation across the NEM between Option 1A(4) and the Base case in this scenario are shown in Figure 22 and Figure 23 respectively.

Figure 21: Forecast cumulative gross market benefit for Option 1A(4) under the Hydrogen Superpower scenario

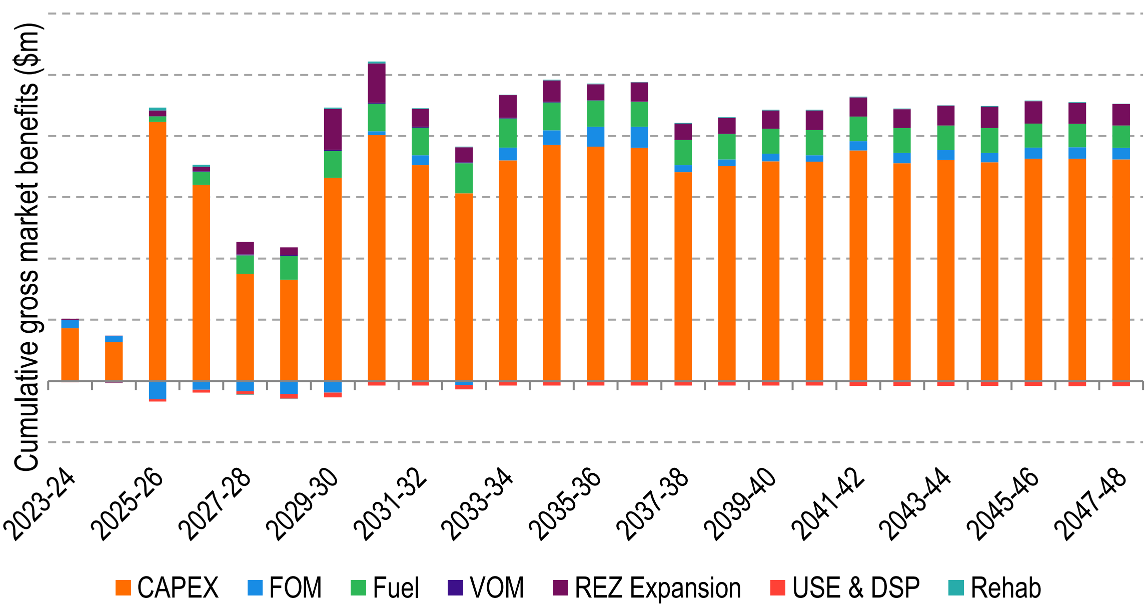


Figure 22: Difference in NEM capacity forecast between Option 1A(4) and Base Case in the Hydrogen Superpower scenario (including assumed capacity of Option 1A(4))

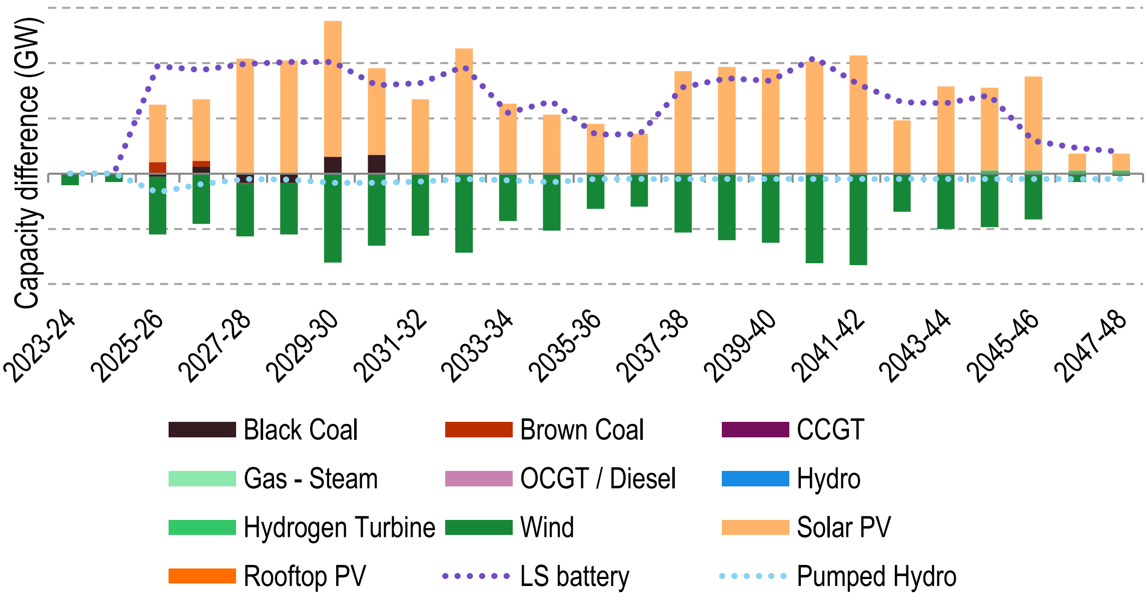
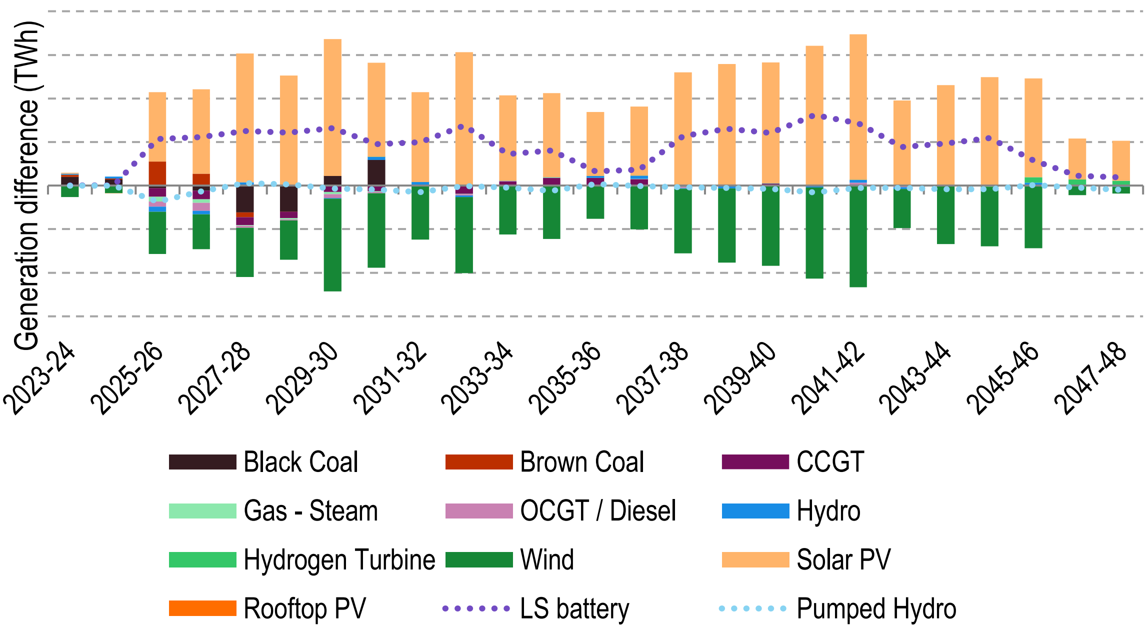


Figure 23: Difference in NEM generation forecast between Option 1A(4) and Base Case in the Hydrogen Superpower scenario (including forecast generation of Option 1A(4))



The primary sources of forecast gross market benefits are from avoided and deferred capex for new generation capacity as well as fuel cost savings from reduced black coal and gas generation followed by REZ expansion benefits and FOM savings. The timing and source of these benefits are attributable to the following:

- In the Hydrogen Superpower scenario capex benefits are forecasted to accumulate from the first year through to the early 2030s. When compared with the step change scenario this is a faster accumulation of benefits. The forecast capex benefits are a result of the storage option allowing for increased solar capacity which defers wind build and avoids the build of some storage capacity.

► Fuel cost savings are forecast to accumulate from 2025-26 through to 2028-29. These savings are a result of the storage option and increased solar generation offsetting black coal and gas generation. Due to the strict cumulative emissions constraint in this scenario, there is forecasted to be limited thermal generation in the Base Case. This results in proportionally smaller fuel cost savings when compared with the Step Change scenario.

► REZ expansion benefits are forecast to accrue from 2026-27. Similar to the Step Change scenario, REZ expansion benefits are a result of the increased generation from the storage option offsetting the need to expand capacity in REZs across the NEM. The storage option is also forecast to allow for increased solar capacity and generation within the Broken Hill REZ without incurring additional costs.

8.1.2 Option 1A(2)

The forecast cumulative gross market benefits for Option 1A(2) in the Step Change scenario are shown in Figure 24. Furthermore, the differences in capacity and generation across the NEM between Option 1F and the Base case in this scenario are shown in Figure 25and Figure 26respectively.

Figure 24: Forecast cumulative gross market benefit for Option 1A(2) under the Step Change Scenario

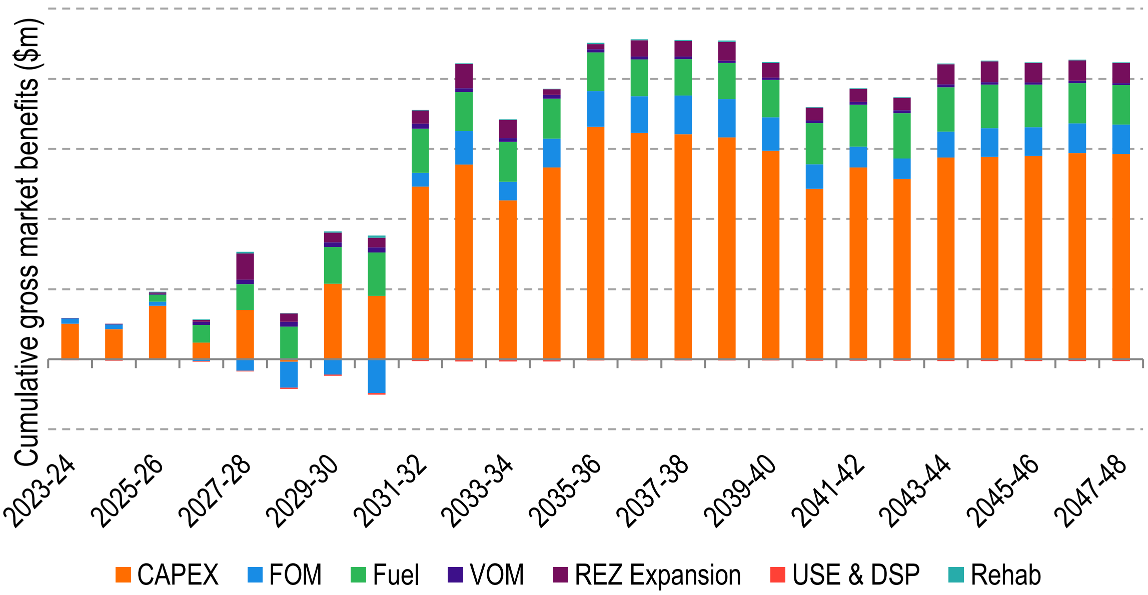


Figure 25: Difference in NEM capacity forecast between Option 1A(2) and Base Case in the Step Change scenario (including assumed capacity of Option 1A(2)

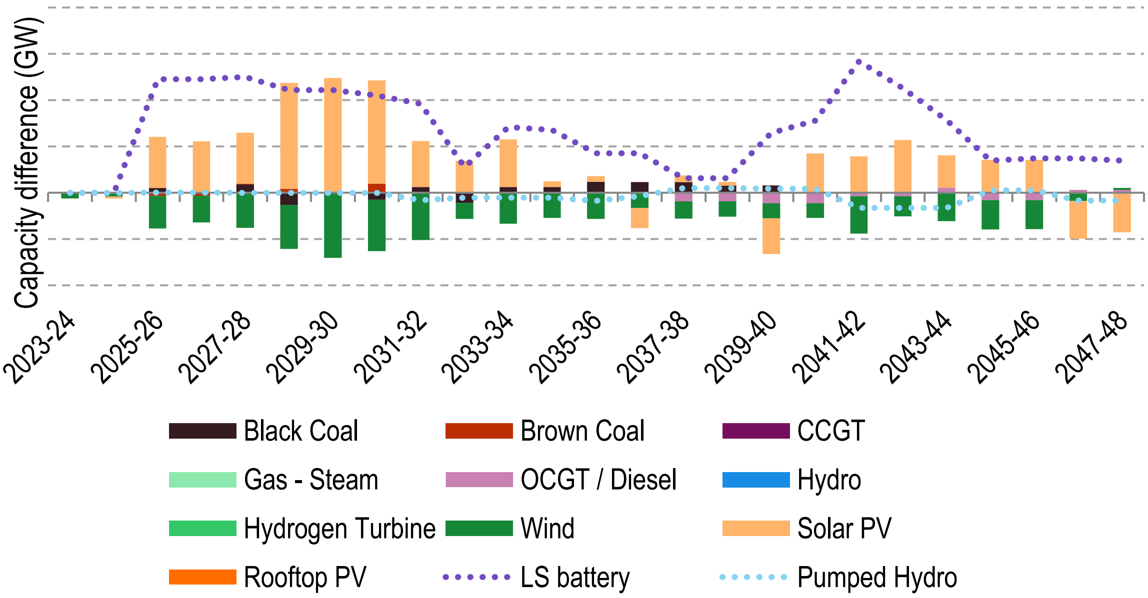
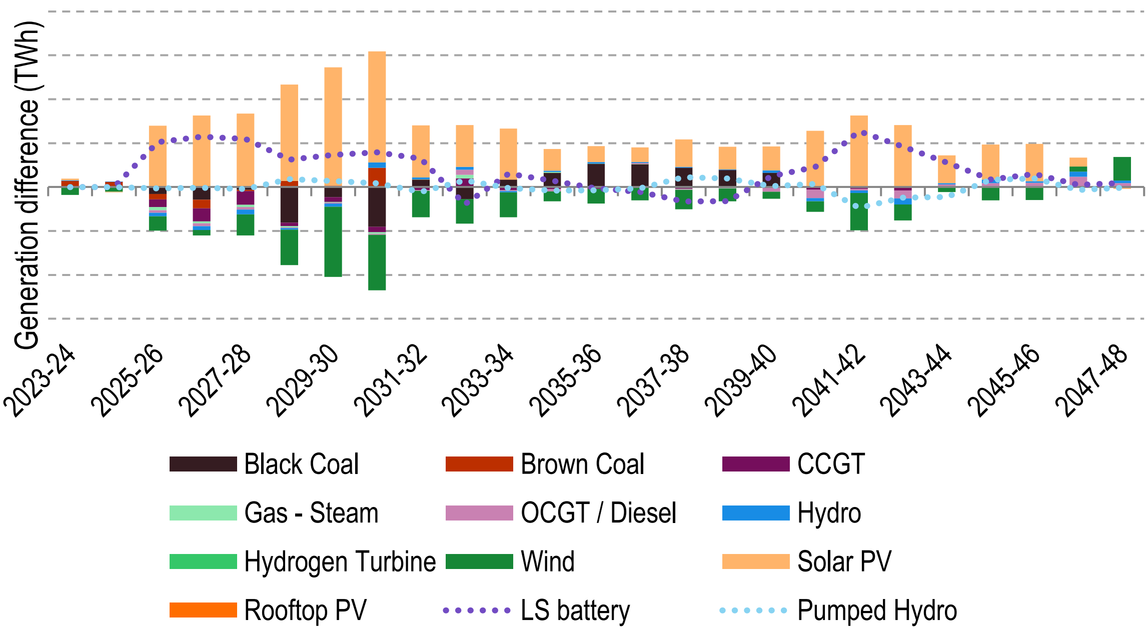


Figure 26: Difference in NEM generation forecast between Option 1A(2) and Base Case in the Step Change scenario (including forecast generation of Option 1A(2))



The primary sources of forecast gross market benefits are from avoided and deferred capex for new generation capacity as well as fuel cost savings from reduced black coal and gas generation followed by REZ expansion benefits and FOM savings. The timing and source of these benefits are attributable to the following:

- Capex benefits are forecast to accrue from the first year through to the late 2030s. These benefits are largely due to deferred wind build through the 2020s, as well as avoided battery storage build due to the option being in place. The option enables increased solar capacity which defers the need for new wind generation. Deferred wind build is also forecast throughout the 2030s due to increased black coal generation.

- Fuel cost savings are forecast to accrue from 2025-26 as black coal and gas generation is offset by increased solar and storage generation due to the option being in place.
- REZ expansion benefits are forecast to accrue from 2026-27 and fluctuate throughout the whole modelling period. REZ expansion benefits are a result of the increased generation from the storage option offsetting the need to expand VRE capacity in REZs throughout the NEM. The storage option is also forecast to allow for increased solar capacity and generation within the Broken Hill REZ without incurring additional costs.

8.1.3 Option 1F

The forecast cumulative gross market benefits for Option 1F in the Step Change scenario are shown in Figure 27. Furthermore, the differences in capacity and generation across the NEM between Option 1F and the Base case in this scenario are shown in Figure 28 and Figure 29 respectively.

Figure 27: Forecast cumulative gross market benefit for Option 1F under the Step Change Scenario

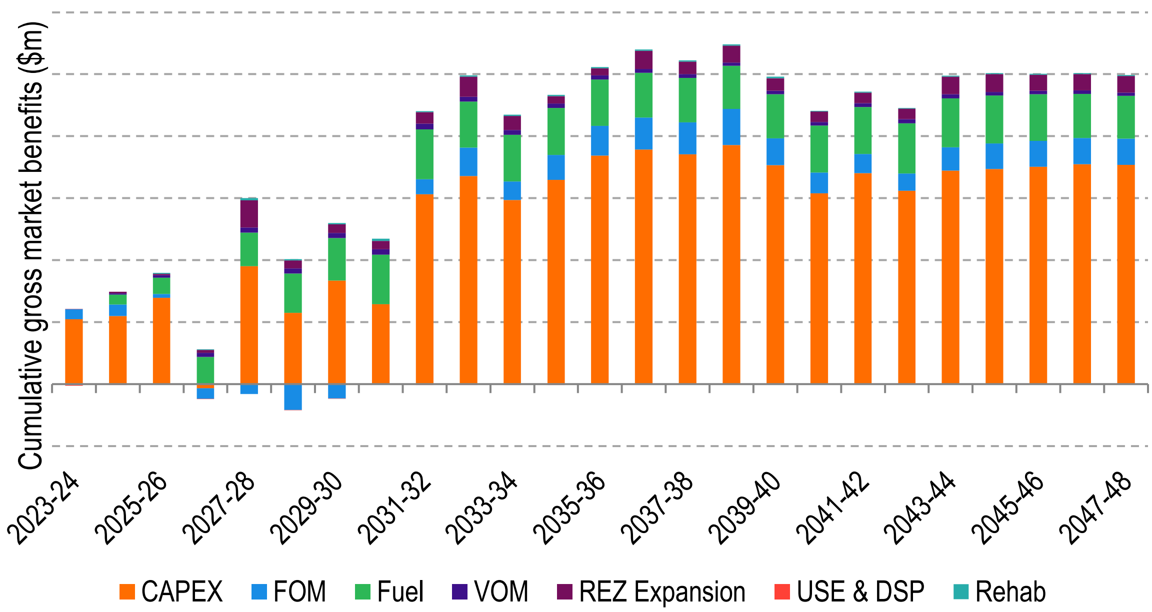


Figure 28: Difference in NEM capacity forecast between Option 1F and Base Case in the Step Change scenario (including assumed capacity of Option 1F)

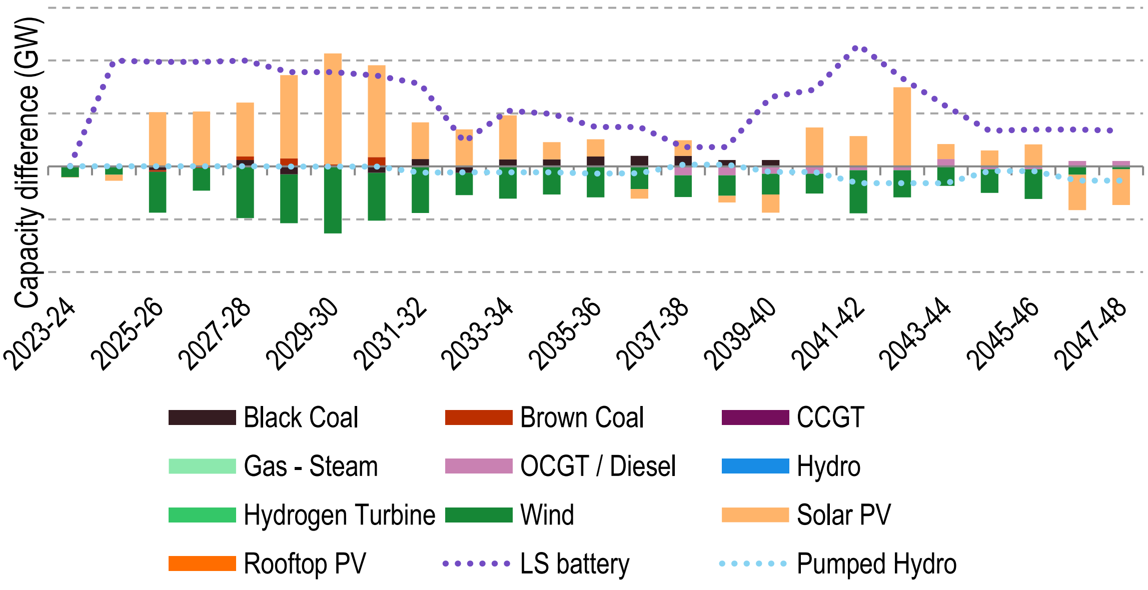
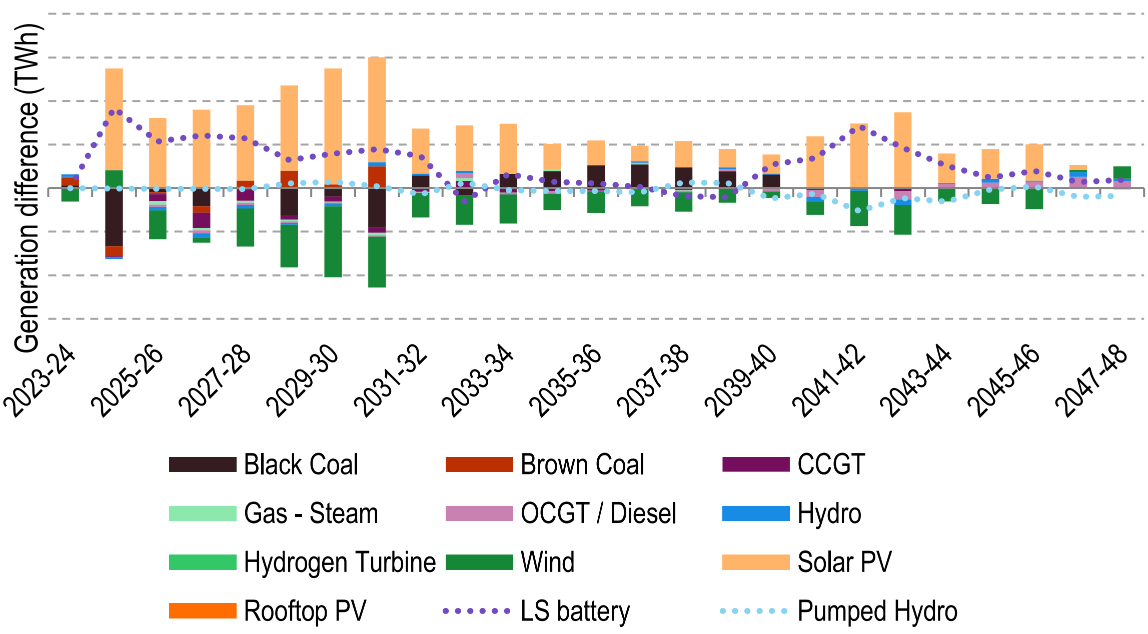


Figure 29: Difference in NEM generation forecast between Option 1F and Base Case in the Step Change scenario (including forecast generation of Option 1F)



The primary sources of forecast gross market benefits are from avoided and deferred capex for new generation capacity as well as fuel cost savings from reduced black coal and gas generation followed by REZ expansion benefits and FOM savings. The timing and source of these benefits are attributable to the following:

- Capex benefits are forecast to accrue from the first year through to the late 2030s. These benefits are largely due to deferred wind build through the 2020s, as well as avoided battery storage build due to the option being in place. The option enables increased solar generation which defers the need for new wind capacity. Deferred wind build is also forecast throughout the 2030s due to increased black coal generation.

- Fuel cost savings are forecast to accrue from 2025-26 as black coal and gas generation is offset by increased solar and storage generation due to the Option being in place.
- REZ expansion benefits are forecast to accrue from 2026-27 and fluctuate throughout the modelled period. REZ expansion benefits are a result of the increased generation from the storage option offsetting the need to expand capacity in REZs across the NEM. The storage option is also forecast to allow for increased solar capacity and generation within the Broken Hill REZ without incurring additional costs.

8.1.4 Option 3

Across all three scenarios Option 3 exhibited minimal benefits relative to the other options. The forecast cumulative gross market benefits for Option 3 in the Step Change scenario are shown in Figure 30. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 3 and the Base Case in this scenario are shown in Figure 31 and Figure 32 respectively.

Figure 30: Forecast cumulative gross market benefit for Option 3 under the Step Change scenario

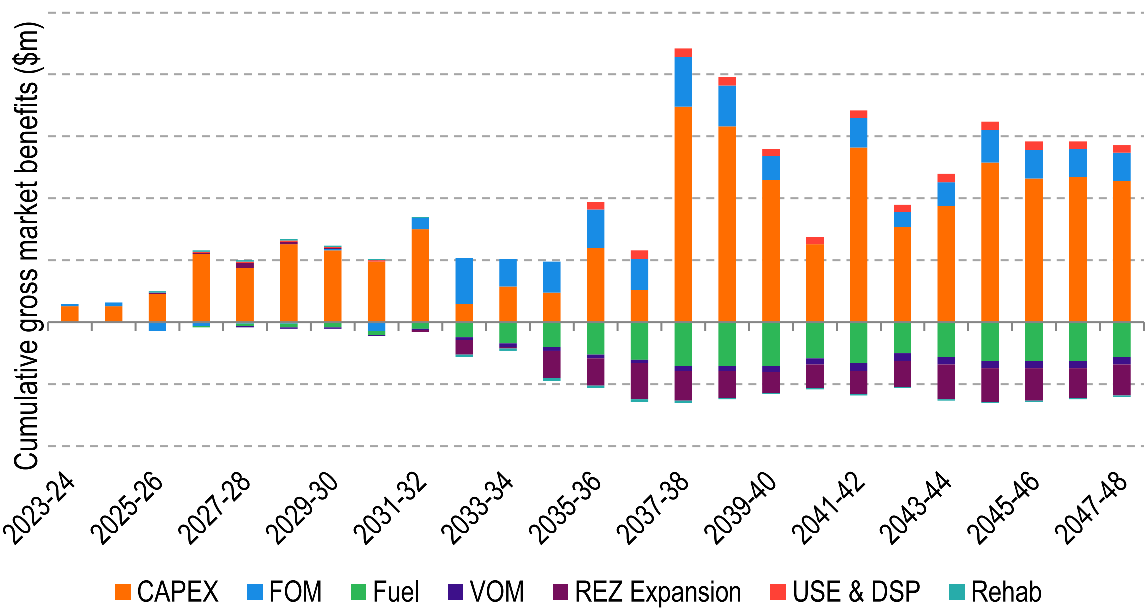


Figure 31: Difference in NEM capacity forecast between Option 3 and Base Case in the Step Change scenario (including assumed capacity of Option 3)

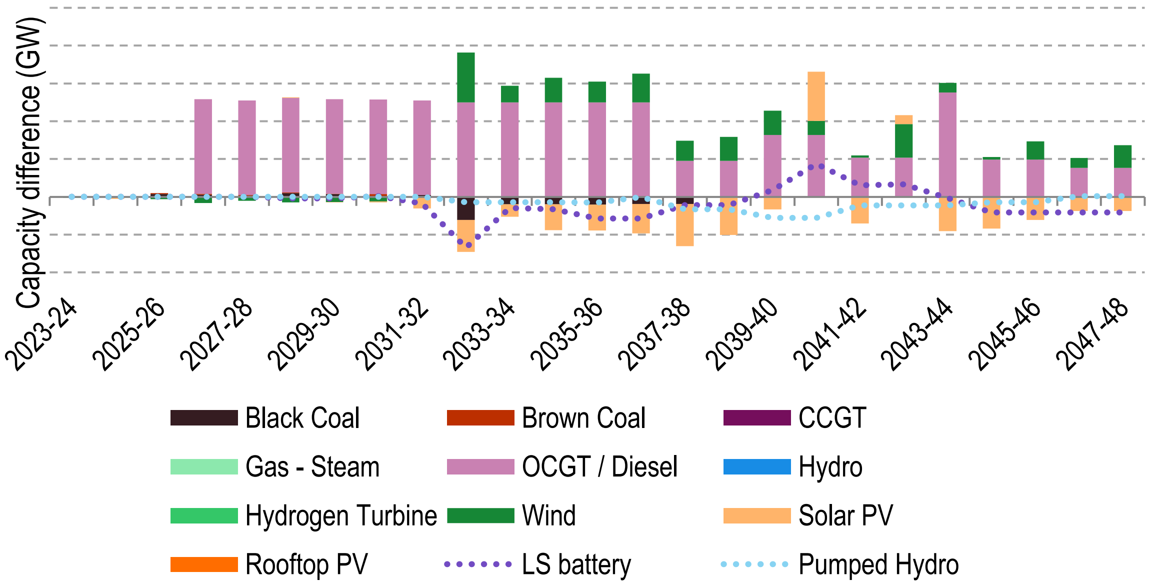
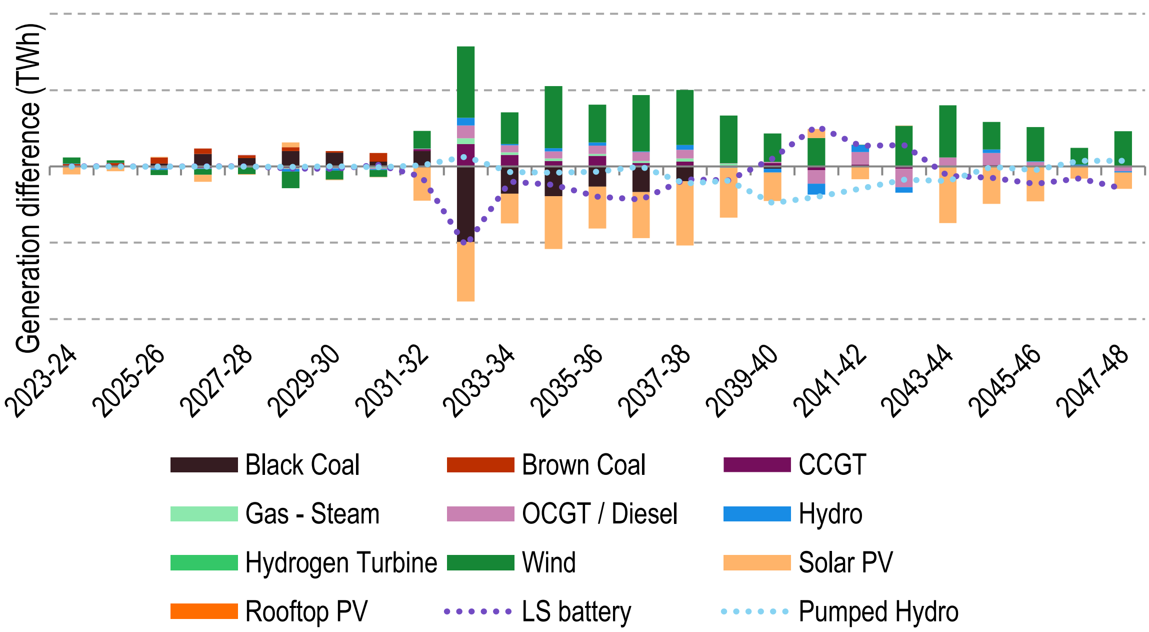


Figure 32: Difference in NEM generation forecast between Option 3 and Base Case in the Step Change scenario (including forecast generation of Option 3)



The primary sources of forecast gross market benefits are from avoided and deferred capex for new generation capacity as well as FOM savings. The timing and source of these benefits are:

- The majority of capex benefits are due to avoided build of gas capacity through the late 2030s. This is a result of the option being in place.
- FOM benefits are due to some earlier black coal retirements from 2032-33 to 2037-38. The black coal capacity is replaced by the gas capacity provided by the option.

There is a forecast increase in fuel costs with the option in place. This is due to the option replacing the high FOM costs of black coal with more expensive short run costs of the option.

8.1.5 Option 4

The forecast cumulative gross market benefits for Option 4 in the Step Change scenario are shown in Figure 33. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 4 and the Base Case in this scenario are shown in Figure 34 and Figure 35 respectively.

Figure 33: Forecast cumulative gross market benefit for Option 4 under the Step Change scenario

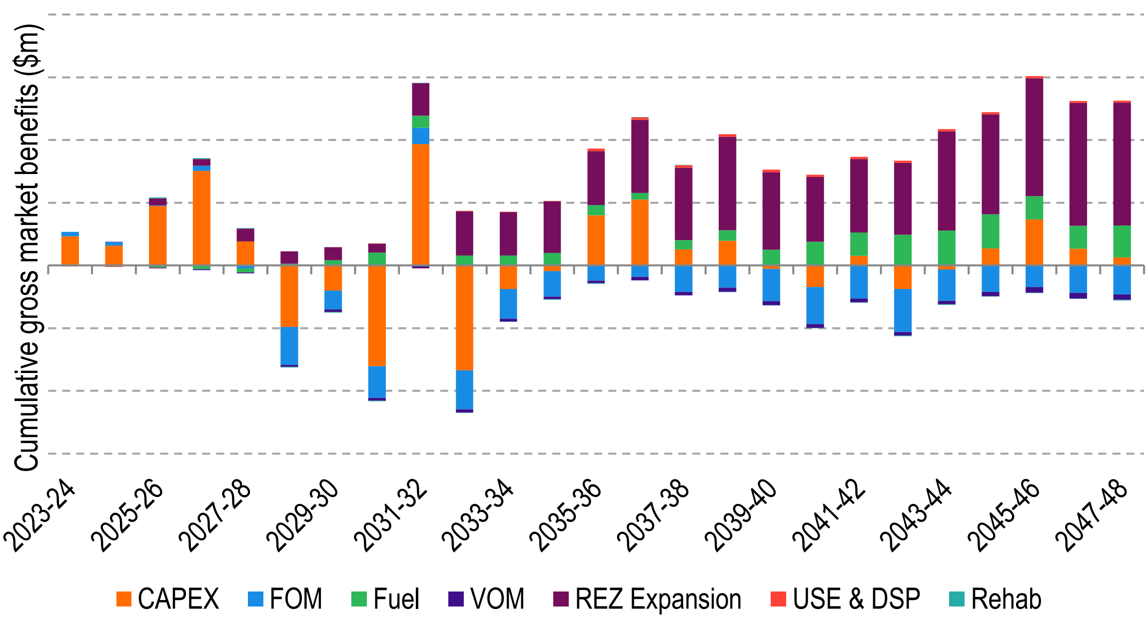


Figure 34: Difference in the NEM capacity forecast between Option 4 and Base Case in the Step Change scenario

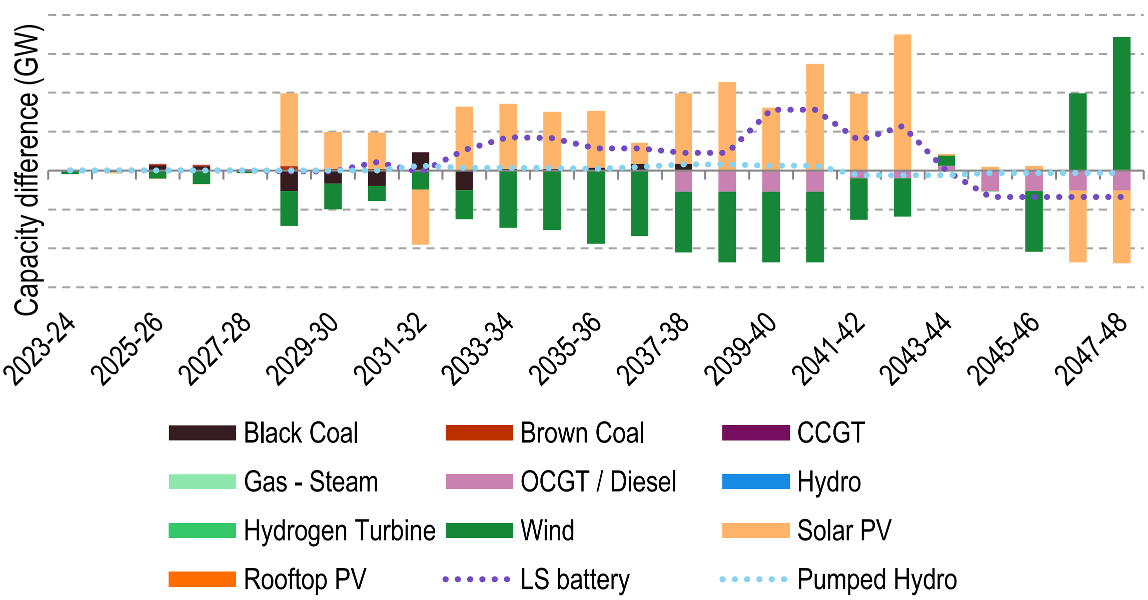
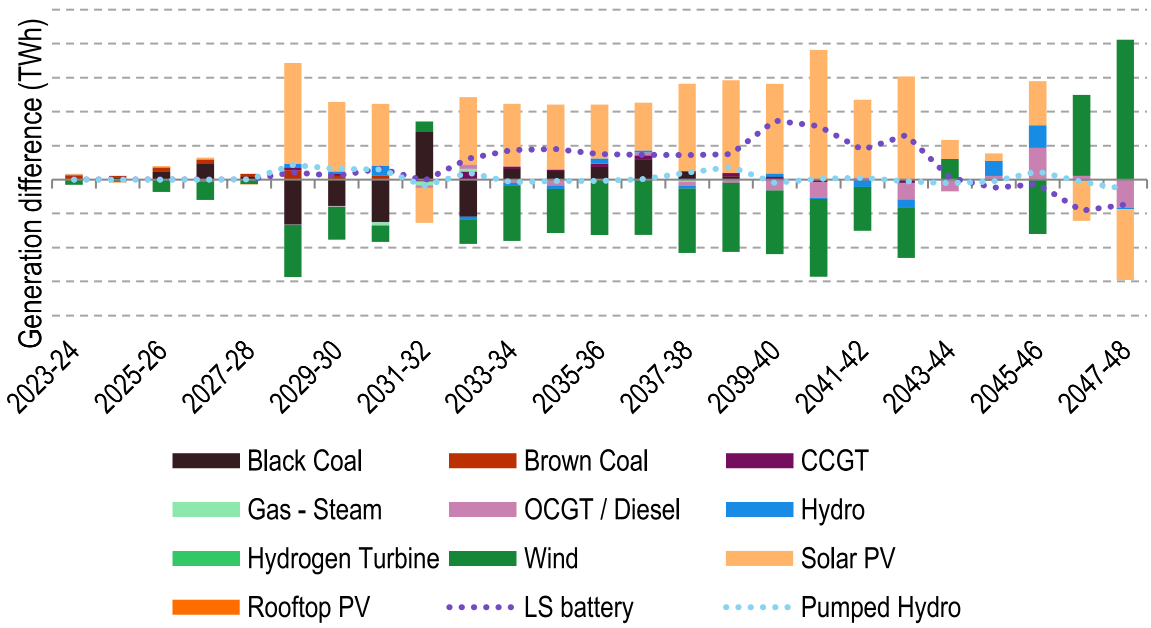


Figure 35: Difference in NEM generation forecast between Option 4 and Base Case in the Step Change scenario



In the Step Change scenario, the primary sources of forecast gross market benefits are due to REZ expansion benefits as well as fuel cost savings from reduced black coal and gas generation. The timing and source of these benefits are attributable to the following:

- The additional level of network capacity that Option 4 enables in the Broken Hill REZ is forecast to reduce the need for additional investment in REZ transmission expansion elsewhere across the NEM. This results in REZ expansion savings accruing strongly through the mid-2030s as significant investment in new capacity is required to meet growing demand and carbon budget constraints.
- The forecasted increase in solar investment within the Broken Hill REZ brings forward battery storage build and in doing so defers investment in wind and gas capacity. This results in neutral capex benefits, but the deferred investment in gas capacity reduces gas generation which results in fuel cost savings throughout the late 2030s to 2040s.

8.1.6 Option 5G

Across all three scenarios Option 5G exhibited minimal benefits relative to the other options. The forecast cumulative gross market benefits for Option 5G in the Step Change scenario are shown in Figure 36. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 5G and the Base Case in this scenario are shown in Figure 37 and Figure 38 respectively.

Figure 36: Forecast cumulative gross market benefit for Option 5G under the Step Change scenario

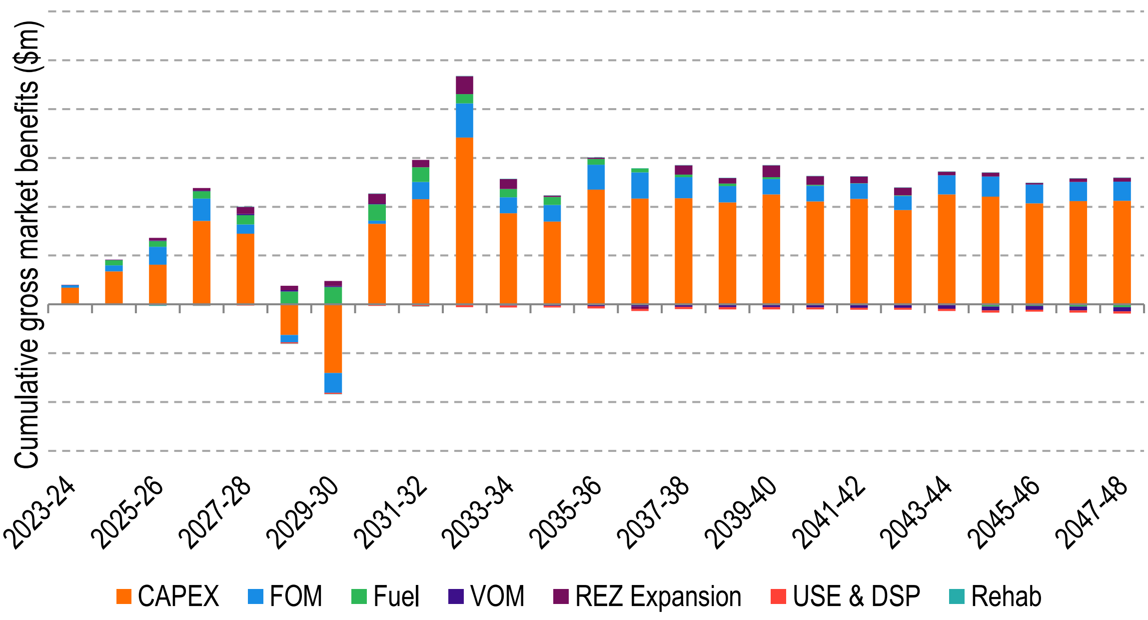


Figure 37: Difference in NEM capacity forecast between Option 5G and Base Case in the Step Change scenario (including assumed capacity of Option 5G)

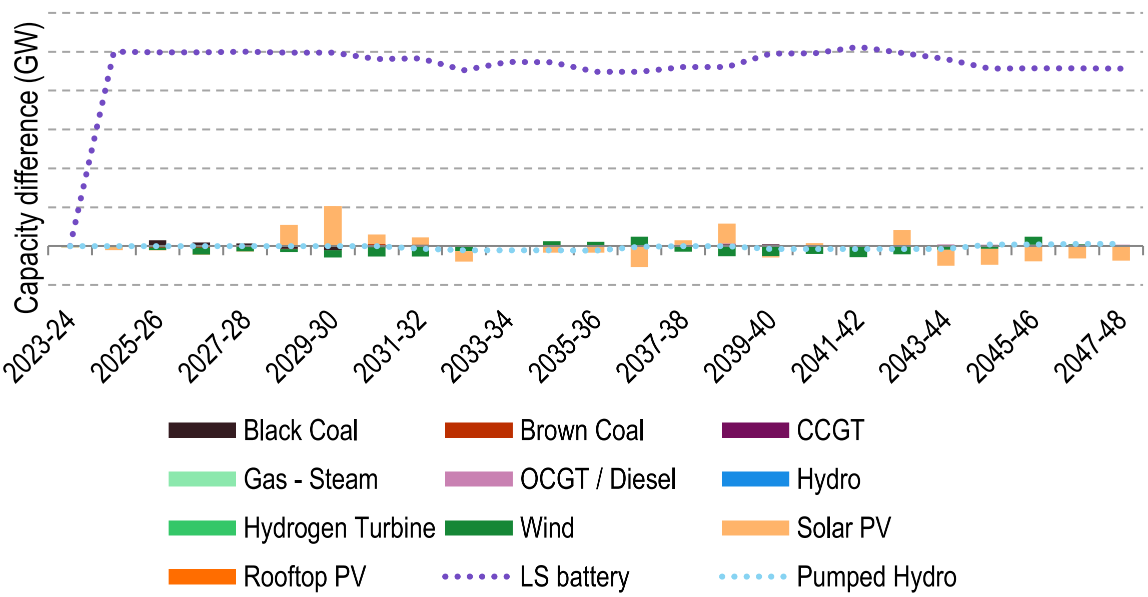
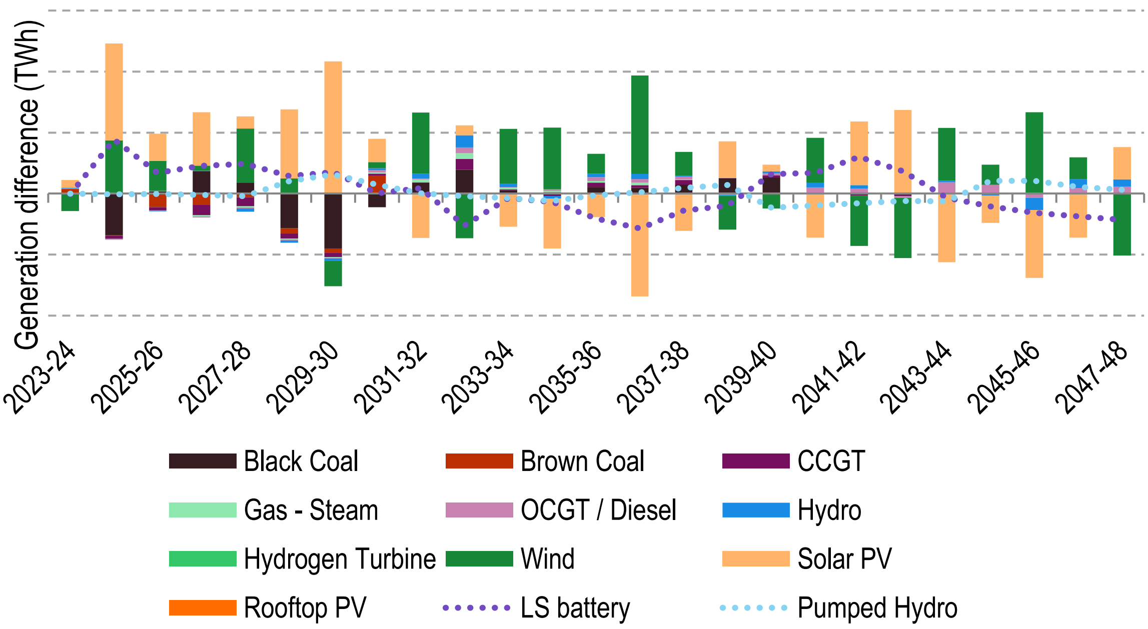


Figure 38:Difference in NEM generation forecast between Option 5G and Base Case in the Step Change scenario (including forecast generation of Option 5G)



The forecast gross market benefits in comparison to other options is small. The primary source of the forecasted market benefits are:

- Capex and FOM benefits due to deferred wind build through the late 2020s, and deferred battery storage build in the early 2030s.

The reduced benefits when compared with other storage options can be attributed to:

- Lower cyclic efficiency
- Significantly shorter storage duration/smaller storage size.

Appendix A Glossary of terms

Abbreviation	Meaning
AEMO	Australian Energy Market Operator
CAES	Compressed air energy storage
CAN	Canberra (NEM zone)
CAPEX	Capital Expenditure
CCGT	Combined-Cycle Gas Turbine
DSP	Demand side participation
FFP	Fixed Flat Plate
FOM	Fixed Operation and Maintenance
GW	Gigawatt
GWh	Gigawatt-hour
ISP	Integrated System Plan
LAES	Liquid air energy storage
LS Battery	Large-Scale battery storage (as distinct from behind-the-meter battery storage)
MW	Megawatt
MWh	Megawatt-hour
NCEN	Central New South Wales (NEM zone)
NEM	National Electricity Market
NNS	Northern New South Wales (NEM zone)
NPV	Net Present Value
NSW	New South Wales
OCGT	Open-Cycle Gas Turbine
PACR	Project Assessment Conclusion Report
PSH	Pumped Storage Hydro
PV	Photovoltaic
QLD	Queensland
QNI	Queensland-New South Wales interconnector
QRET	Queensland Renewable Energy Target
REZ	Renewable Energy Zone
RIT-T	Regulatory Investment Test for Transmission
SA	South Australia
SAT	Single Axis Tracking

Abbreviation	Meaning
SRMC	Short-Run Marginal Cost
SWNSW	South West New South Wales (NEM zone)
TAS	Tasmania
TSIRP	Time-sequential integrated resource planner
TW	Terawatt
TWh	Terawatt-hour
USE	Unserved Energy
VCR	Value of Customer Reliability
VIC	Victoria
VNI	Victoria-New South Wales Interconnector
VOM	Variable Operation and Maintenance
VRET	Victoria Renewable Energy Target
VPP	Virtual Power Plant

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