Maintaining Reliable Supply to Broken Hill PADR Market Modelling Report

TransGrid

11 August 2020

Building a better working world

Release Notice

Ernst & Young ("EY") 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 to assess various network and non-network options for the Maintaining Reliable Supply to Broken Hill Regulatory Investment Test for Transmission in the long term.

The results of EY'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 EY since the date of the Report to update it.

This Report, which should be read in conjunction with the Project Assessment Draft Report (PADR) published by TransGrid[1], describes the key assumptions, input data sources and methodologies that have been applied in our modelling as well as outcomes and key insights developed through our analysis.

EY has prepared the Report for the benefit of TransGrid and has considered only the interests of TransGrid. EY has not been engaged to act, and has not acted, as advisor to any other party. Accordingly, EY makes no representations as to the appropriateness, accuracy or completeness of the Report for any other party's purposes. Our work commenced on 30 April 2020 and was completed on 30 June 2020. Therefore, our Report does not take account of events or circumstances arising after 30 June 2020 and we have no responsibility to update the Report for such events or circumstances.

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Readers are advised that the outcomes provided are based on many detailed assumptions underpinning the scenario, and the key assumptions are described in the Report. These assumptions were selected by TransGrid after public consultation. The modelled scenario represents one possible future option 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.

EY's liability is limited by a scheme approved under Professional Standards Legislation.

[1] TransGrid, *Maintaining reliable supply to Broken Hill PADR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Broken%20Hill%20Supply. Accessed 11 August 2020.

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1. Executive summary

TransGrid has engaged EY to undertake market modelling of system costs and benefits to assess various network and non-network options for the Maintaining Reliable Supply to Broken Hill Regulatory Investment Test for Transmission (Broken Hill RIT-T)[2]. The RIT-T is a cost-benefit analysis used to assess the viability of investment options in electricity transmission assets.

This Report, which should be read in conjunction with the Project Assessment Draft Report (PADR) published by TransGrid[2], describes the key assumptions, input data sources and methodologies that have been applied in our modelling as well as outcomes and key insights developed through our analysis.

EY applied a cost-benefit analysis based on the change in least-cost generation dispatch and capacity development plan with each option for the Broken Hill RIT-T.

EY computed the least-cost generation dispatch and capacity development plan for the National Electricity Market (NEM) associated with four different options provided by TransGrid for the reliable supply to Broken Hill for a Central scenario outlook[3]. This is an independent study and the modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator[4].

TransGrid considered a number of network and non-network options for Broken Hill RIT-T, as detailed in the PADR[2]. Some options will only be capable of maintaining the reliability criterion in Broken Hill, whereas a few options will also be capable of providing benefits to the broader NEM. Furthermore, TransGrid considered variants of some options based on the ownership structure, whether owned by third parties, TransGrid, or on a shared ownership basis. Amongst all of the options that TransGrid considered in the PADR, EY assessed those which may have market benefits regardless of the ownership structure. The options assessed are:

- a compressed air energy storage facility (CAES, Option 1A/5A) with 150 MW/1,300 MWh available for arbitrage, assumed to commission from 1 July 2025
- a battery with 73 MW/42 MWh available for arbitrage (Battery, Option 1C/5C), assumed to commission from 1 July 2022
- a new 50 MW dispatchable gas turbine (New Gas Turbine, Option 3), assumed to commission from 1 July 2022, and
- a transmission network upgrade with an additional 220 kV line from Broken Hill to Buronga (Transmission augmentation, Option 4), assumed to commission from 1 July 2023.

TransGrid has assumed that Option 1A/5A allows 150 MW of free Broken Hill REZ transmission expansion for solar PV build[5] in this REZ as a result of increased demand due to the charging of the storage during the daytime. In addition, 400 MW of free Broken Hill REZ transmission expansion for wind and/or solar PV build[6] is assumed by TransGrid for Option 4. Furthermore, TransGrid elected to adjust the transmission losses incurred on the Broken Hill to Buronga route as a result of the second circuit in Option 4.

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[2] TransGrid, *Maintaining reliable supply to Broken Hill PADR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Broken%20Hill%20Supply. Accessed 11 August 2020.

[3] Note that TransGrid has requested that this report does not present the outcomes of gross market benefits in order to protect the confidentiality of the cost of proponents' options.

[4] 14 December 2018, *RIT-T and RIT-D application guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 30 June 2020.

[5] Wind would also be eligible for consideration for the Broken Hill REZ, but initial modelling showed that the storage facility would be more compatible with the solar profile for this Option.

[6] Both solar and wind build are equally suited to filling the free REZ capacity so the TSIRP model was allowed to choose the technology in accordance with the least cost plan and chose wind.

To assess the potential least-cost solution, a Time Sequential Integrated Resource Planning (TSIRP) model is used that makes decisions for each hourly trading interval in relation to:

- the generation dispatch level for each power plant along with the charging and discharging of storage. Stations and units are assumed to bid at their short-run marginal cost (SRMC), which is derived from their Variable Operation and Maintenance (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 un-planned outages), network limitations and energy limits (e.g., storage levels).
- commissioning new entrant capacity for wind, solar PV SAT, CCGT, OCGT[7], large-scale battery storage (LS Battery) and pumped hydro.

These hourly decisions take into account operational constraints that include:

- supply must equal demand in each region for all trading intervals plus a reserve margin, with unserved energy (USE) costed at the value of customer reliability (VCR)[8],
- minimum loads for generators,
- interconnector flow limits (between regions),
- intra-regional flow limits (between zones in NSW),
- N-0 and N-1 thermal constraint equations in South West NSW (SWNSW),
- maximum and minimum storage (conventional storage hydro, pumped hydro and large-scale battery storage) reservoir limits and cyclic efficiency,
- new entrant capacity build limits for wind and solar for each Renewable Energy Zone (REZ) where applicable, and pumped hydro in each region,
- emission constraints, as defined for the modelled scenario,
- renewable energy targets where applicable by region or NEM-wide.

From the hourly time-sequential modelling we computed the following costs, as defined in the RIT-T:

- capital costs of new generation capacity installed,
- total Fixed Operation and Maintenance (FOM) costs of all generation capacity,
- total 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 (USE),
- transmission expansion costs associated with REZ development.

For each simulation with a Broken Hill RIT-T option and in a matched no option implementation counterfactual (referred to as the Base Case) we computed the sum of these cost components and compared the difference. The difference in costs is the forecast gross market benefits due to the Broken Hill RIT-T option, as defined in the RIT-T.

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

[7] PV = photovoltaics, SAT = Single Axis Tracking, CCGT = Combined-Cycle Gas Turbine, OCGT = Open-Cycle Gas Turbine.

[8] Based on AER, December 2019, *Values of Customer Reliability Final report on VCR values*. CPI Available at: https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf. Accessed 30 June 2020.

differences in losses in storages, including pumped hydro and large-scale battery storage between each option and the counterfactual Base Case.

Potential gross market benefits were forecast for four Broken Hill RIT-T options for a Central scenario outlook for the NEM.

Potential gross market benefits were forecast for four options supporting the reliable supply to Broken Hill for a Central scenario outlook for the NEM. All options assessed were defined by TransGrid and are described in detail in the PADR[9]. To better capture the intra-regional flows in NSW and changes due to options, EY modelled NSW in four zones including the Northern NSW (NNS), Central NSW (NCEN), Canberra (CAN) and South West NSW (SWNSW) zones. In addition, N-0 and N-1 thermal constraints are modelled to capture the network limitations in SWNSW pre and post EnergyConnect commissioning.

The Central scenario modelled is in line with the Australian Energy Market Operator's (AEMO) 2020 Integrated System Plan (ISP) Central scenario[10]:

The Base Case forecasts gradual shifts of the NEM generation and capacity towards increasing wind, solar, pumped hydro, large scale battery storage and gas.

The resulting capacity and generation mix forecasts for the Base case in the Central scenario are shown in Figure 1 and Figure 2.

In the Base Case, the forecast generation capacity of the NEM gradually shifts towards increasing capacity of wind, solar, pumped hydro and gas. The NEM is forecast to have around 114 GW total capacity by 2044-45 (total capacity includes pumped hydro and LS Battery capacities, which are not in the stacked chart). The majority of new capacity installed is coincident with coal generation retirements, which is particularly obvious from the mid-2030s when a number of large coal generators in the NEM are anticipated to retire.

The energy supplied to the grid (see Figure 1) for the Central scenario gradually increases throughout the modelling period due to the modest demand growth of the AEMO ISP 2020 Central demand assumed in this scenario. By the end of study, wind, solar and rooftop PV are expected to be the major suppliers of the NEM energy.

[9] TransGrid, *Maintaining reliable supply to Broken Hill PADR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Broken%20Hill%20Supply. Accessed 11 August 2020.

[10] AEMO, *2020 Integrated System Plan*. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp Accessed 30 June 2020.

Figure 1: NEM capacity mix forecast for the Base Case in the Central scenario

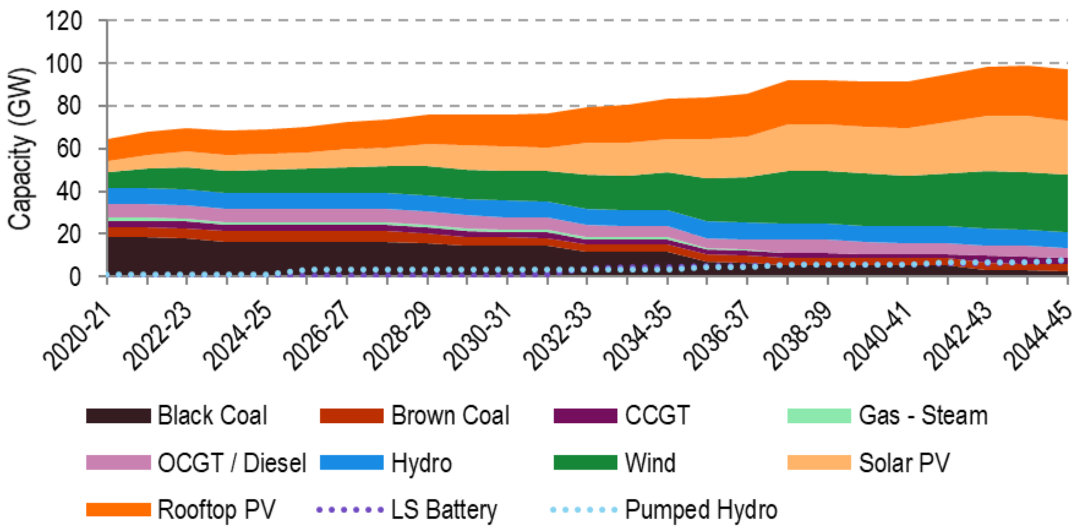
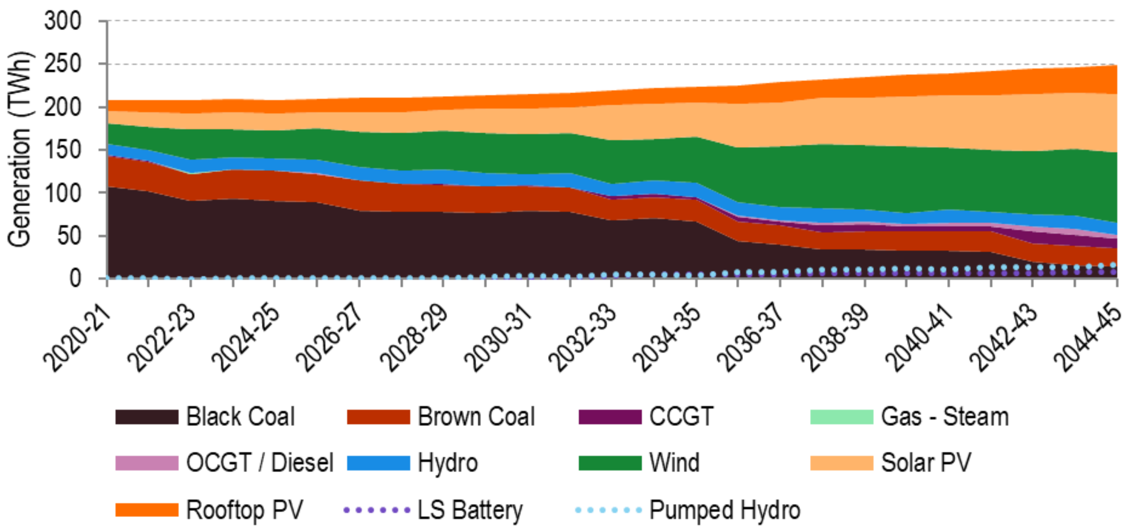


Figure 2: NEM generation mix forecast for the Base Case in the Central scenario[11]



Option 1A/5A, the energy storage facility with 150 MW/1,300 MWh available for arbitrage, has been identified by TransGrid as the preferred option based on the forecast net benefits after incorporating forecast gross market benefits and assumed development costs of the option.

The forecast gross market benefits of each option for Broken Hill computed need to be compared to the relevant development cost to determine whether there is a positive net market benefit. TransGrid has concluded that Option 1A/5A, the energy storage facility with 150 MW/1,300 MWh available for arbitrage, is the preferred option based on option costs[12]. The preferred option is defined in line with the RIT-T application guidelines as "the credible option that maximises the net economic benefit across the market, compared to all other credible options[13]".

[11] All the generation charts in the Report are on an "as-generated" generation basis.

[12] TransGrid, *Maintaining reliable supply to Broken Hill PADR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Broken%20Hill%20Supply. Accessed 11 August 2020.

[13] 14 December 2018, *RIT-T and RIT-D application guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 30 June 2020.

2. Introduction

TransGrid has engaged EY to undertake market modelling of system costs and benefits to assess various network and non-network options for the Maintaining Reliable Supply to Broken Hill Regulatory Investment Test for Transmission (Broken Hill RIT-T)[14].

This Report, which should be read in conjunction with the broader Project Assessment Draft Report (PADR) published by TransGrid[14], describes the key assumptions, input data sources and methodologies that have been applied in this modelling as well as outcomes and key insights developed through our analysis.

EY computed the least-cost generation dispatch and capacity development plan for the National Electricity Market (NEM) associated with four supply options to Broken Hill defined by TransGrid in the PADR[14] for a Central scenario outlook[15].

This work is an independent study and the modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator[16]. The RIT-T is a cost-benefit analysis used to assess the viability of investment options in electricity transmission assets.

The descriptions of outcomes in this Report are focussed on identifying and explaining the key sources of forecast gross market benefits for the modelled scenario. 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, and
- 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 2020-21 to 2044-45. Benefits presented are discounted to June 2020 using a 5.9 % real, pre-tax discount rate as selected by TransGrid. This value is sourced from the commercial discount rate calculated in the *RIT-T Economic Assessment Handbook* published by Energy Networks Australia[17] and is consistent with the value to be applied by the Australian Energy Market Operator (AEMO) in the 2020 Integrated System Plan (ISP)[18].

This modelling considers four different options to maintain reliable supply of Broken Hill, as shown in Table 1. Note that some options presented in the PADR will only be capable of maintaining the reliability criterion in Broken Hill, whereas a few options will also be capable of providing benefits to the broader National Electricity Market (NEM). Furthermore, TransGrid considered variants of some

[14] TransGrid, *Maintaining reliable supply to Broken Hill PADR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Broken%20Hill%20Supply. Accessed 11 August 2020.

[15] Note that TransGrid has requested that this report does not present the outcomes of gross market benefits in order to protect the confidentiality of the cost of proponents' options.

[16] 14 December 2018, *RIT-T and RIT-D application guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 30 June 2020.

[17] Energy Networks Australia, 15 March 2019, *RIT-T Economic Assessment Handbook*. Available at: https://www.energynetworks.com.au/rit-t-economic-assessment-handbook. Accessed 30 June 2020.

[18] AEMO, *2020 Integrated System Plan*. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp Accessed 30 June 2020.

options based on the ownership structure, whether owned by third parties, TransGrid, or on a shared ownership basis. Amongst all options considered in the PADR, EY only assessed those which may have market benefits regardless of the ownership. TransGrid has assumed that Option 1A/5A allows 150 MW of free Broken Hill REZ transmission expansion for solar PV build in this REZ as a result of increased demand due to the charging load of the storage facility during the daytime. In addition, 400 MW free Broken Hill REZ transmission expansion for wind and/or solar PV build is assumed by TransGrid for Option 4. Furthermore, TransGrid elected to adjust the losses incurred on the Broken Hill to Buronga route as a result of the second circuit in Option 4.

Table 1: Broken Hill RIT-T Options[19]

Option	Description	Timing
Option 1A/5A	Compressed Air Energy Storage (CAES) facility: 150 MW/1,300 MWh available for arbitrage. It is assumed that this option allows 150 MW of free Broken Hill REZ transmission expansion for solar PV build in Broken Hill REZ	1/07/2025
Option 1C/5C	Battery Energy Storage facility: 73 MW/42 MWh available for arbitrage	1/07/2022
Option 3	New 50 MW OCGT: 45 MW rating in summer and 50 MW in other seasons	1/07/2022
Option 4	Transmission option: establishing a second single circuit 220 kV transmission line from Buronga to Broken Hill. It is assumed that this option allows 400 MW of free Broken Hill REZ transmission expansion for solar PV and wind build in Broken Hill REZ	1/07/2023

For more information on the different options refer to the broader PADR[19] published by TransGrid.

The resulting forecast gross market benefits of each Broken Hill option need to be compared to the relevant option's cost to determine the forecast net market benefit for that option. The preferred option analysis is dependent on option costs and was conducted by TransGrid separately and independent of the analysis included in this Report[19], by incorporating the forecast gross modelled market benefits into the calculation of net market 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"[20].

The Report is structured as follows:

- Section 3 provides an overview of the methodology applied in the modelling and computation of forecast gross market benefits.
- Section 4 provides an overview of scenario settings.
- Section 5 outlines model design and input data related to the transmission network and demand.
- Section 6 provides an overview of model inputs and methodologies related to the supply of energy.
- Section 7 describes the forecast generation and capacity outlooks in the Base Case.
- Section 8 presents the forecast gross market benefits for each option.

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[19] TransGrid, *Maintaining reliable supply to Broken Hill PADR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Broken%20Hill%20Supply. Accessed 11 August 2020.

[20] 14 December 2018, *RIT-T and RIT-D application guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 30 June 2020.

3. Methodology

3.1 Long-term investment planning

EY used linear programming techniques to perform hourly time-sequential, least-cost, long-term NEM development optimisation modelling spanning 25 years from 2020-21 to 2044-45. The modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator[21].

Based on the full set of input assumptions, the Time-Sequential Integrated Resource Planning (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[22] trading interval in relation to:

- the generation dispatch level for each power plant along with the charging and discharging of storage. Units and stations 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 un-planned outages), network limitations and energy limits (e.g., storage levels).
- commissioning new entrant capacity for wind, solar PV SAT[23], CCGT, OCGT, large-scale battery storage and pumped hydro. We screened nuclear and any other technology options 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)[24],
- minimum loads for some generators,
- transmission interconnector flow limits (between regions),
- intra-regional flow limits (between zones in New South Wales),

[21] 14 December 2018, *RIT-T and RIT-D application guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 30 June 2020.

[22] 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 purposes of the modelling.

[23] PV = photovoltaics, SAT = Single Axis Tracking, CCGT = Closed-Cycle Gas Turbine, OCGT = Open-Cycle Gas Turbine.

[24] Based on AER, December 2019, *Values of Customer Reliability Final report on VCR values.* CPI Available at: https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf. Accessed 30 June 2020.

- N-0 and N-1 thermal constraints[25] in SWNSW,
- maximum and minimum storage reservoir limits (for conventional storage hydro, pumped hydro and large-scale battery storage),
- new entrant capacity build limits for wind and solar for each REZ where applicable, and pumped hydro in each region,
- emission constraints,
- 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 also includes key thermal constraints for SWNSW, as detailed in Section 5.2.

The model incorporates as inputs fixed age based/announced retirement dates for existing generation. It also factors in the annual costs, including annualised capital costs, for all new generator capacity and the model decides 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 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 approximately equal to the maximum annual energy generated in last five years, reflecting coal rail and contractual supply limitations. The running costs for these generators are the sum of the VOM and fuel costs. Coal generators 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, pumped hydro and large-scale battery storages) are operated to minimise the overall system costs. This means they tend to generate at times of high prices, e.g. when the demand for power is high, and so dispatching energy-limited generation will lower system costs. Conversely, at times of low prices, e.g. when there is a surplus of capacity, storage hydro preserves energy and pumped hydro and large-scale battery storage operate in pumping or charging mode.

3.1.1 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, allowing for generation contingencies, which can occur at any time.

25 N-1 constraint equations are implemented avoid the overload of a monitored line or transformer due to a single credible contingency in any other power system component (mainly a transmission line here), as stipulated in the NEM market rules. N-0 constraint equations are designed to avoid overloading any line or transformer (or other power system limitation) while the network is in a system normal state (no prior outages). Both of these power system security limitations have to be met by the market operator at all times, since both the 'system intact' and 'single contingency' power system limitations must be met without the need for redispatch of generation.

All dispatchable generators in each region are eligible to contribute to reserve (except pumped hydro and large-scale battery storages[26]) 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, 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 (highest percentage of demand) to reduce the optimisation problem size. Testing confirmed that this assumption does not affect outcomes as a reserve constraint is unlikely to bind in lower demand intervals.

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 to NCEN are at their limits. However, intra-connectors still implicitly contribute to reserve because increased flow can displace dispatchable generators within NCEN allowing them to contribute to reserve.

3.1.2 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 5.3. Additional losses within New South Wales zones and within the remaining NEM regions are captured through an estimate of loss factors for existing and new entrant generators. To estimate these loss factors, the TSIRP model is interfaced with an AC load flow program. Hourly generation dispatch outcomes from the model are transferred to nodes in a network snapshot. These estimated loss factors are then returned to the TSIRP model and used in a further refining pass to ensure new entrant developments are least-cost when accounting for changing load and generation patterns. Loss factors are estimated based on hourly outcomes for one year at each five-year interval[27]. This method of estimating and incorporating loss factors is sufficient to give a geographic investment signal related to transmission network utilisation. The reduced energy delivered from generators to serve load as a result of the loss factors is incorporated in the modelling.

3.1.3 Cost-benefit analysis

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

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[26] Pumped hydro 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.

[27] The final computation of loss factors is in 2030-31 since at around this time significant REZ transmission upgrade costs have been incurred as part of the least-cost generation development plan. There is insufficient detail to reflect these transmission upgrades in the network snapshot to sensibly compute loss factors after this time, and it is therefore assumed that developments occur that are sufficient to maintain loss factors constant from that time.

- 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 Broken Hill option a matched no augmentation 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 each option, as defined in the RIT-T.

The forecast gross market benefits capture the impact of 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 losses in storages, including pumped hydro and large-scale battery storage between each Broken Hill option and counterfactual Base Case.

Each component of potential 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)[28], discounted to June 2020 at a 5.9 % real, pre-tax discount rate as selected by TransGrid. This value is sourced from the commercial discount rate calculated in the *RIT-T Economic Assessment Handbook* published by Energy Networks Australia[29] and is consistent with the value applied by AEMO in the 2020 ISP[30].

The forecast gross market benefits of each Broken Hill option need to be compared to the relevant option's cost to determine whether there is a positive forecast net market benefit. The preferred option analysis is dependent on option costs and was conducted by TransGrid separately and independent of the analysis included in this Report[31]. 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"[32].

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[28] 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.

[29] Energy Networks Australia, 15 March 2019, *RIT-T Economic Assessment Handbook*. Available at: https://www.energynetworks.com.au/rit-t-economic-assessment-handbook. Accessed 30 June 2020.

[30] AEMO, 17 April 2020, *2019 Input and Assumptions workbook, v1.4*. Available AEMO upon request.

[31] TransGrid, *Maintaining reliable supply to Broken Hill PADR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Broken%20Hill%20Supply. Accessed 11 August 2020.

[32] 14 December 2018, *RIT-T and RIT-D application guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 30 June 2020.

4. Scenario assumptions

4.1 Central scenario

The credible options have been assessed for market benefits under one Central scenario selected by TransGrid following publication of the Project Specification Consultation Report (PSCR)[33]. The underlying scenario assumptions are summarised in Table 2 and are broadly in line with the Central scenario described in AEMO's 2020 ISP[34]. As noted in Table 2, most input data are sourced from the accompanying 2019 Input and Assumptions workbook which formed the initial consultation for the 2020 ISP[35]. The version from April 2020 was the most up-to-date data source available at the time of modelling for this assessment.

Table 2: Overview of key input parameters[36]

Key drivers input parameter	Scenario
	Central
Underlying consumption	AEMO 2020 ISP Central scenario
New entrant capital cost for wind, solar SAT, OCGT, CCGT, pumped hydro, and large-scale batteries	AEMO 2020 ISP Central scenario
Retirements of coal-fired power stations	AEMO Generation Information[37] announced retirement date or end-of-technical-lives
Gas fuel cost	AEMO 2020 ISP Central scenario
Coal fuel cost	AEMO 2020 ISP Central scenario
Federal Large-scale Renewable Energy Target (LRET)	33 TWh per annum by 2020 to 2030 (including GreenPower and ACT scheme), accounting for contribution to LRET by Western Australia (WA), Northern Territory (NT) and off grid locations
COP21 commitment (Paris agreement)	28 % reduction from 2005 by 2030, then a linear extrapolation beyond 2030 to 70 % reduction of 2016 emissions by 2050
Victoria Renewable Energy Target (VRET)	40 % renewable energy by 2025 and 50 % renewable energy by 2030
Queensland Renewable Energy Target (QRET)	50 % renewable energy by 2030
Tasmanian Renewable Energy Target (TRET)	100% Tasmanian renewable energy generation by 2021-22 and 200% by 2039-40

[33] TransGrid, *Maintaining reliable supply to Broken Hill PADR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Broken%20Hill%20Supply. Accessed 11 August 2020.

[34] AEMO, *2020 Integrated System Plan*. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp Accessed 30 June 2020.

[35] AEMO, 17 April 2020, *2019 Input and Assumptions workbook v1.4*. Available from AEMO upon request.

[36] Ibid, unless otherwise stated in table.

[37] AEMO, 30 April 2020, *Generating Unit Expected Closure Year - April 2020*. 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: 15 May 2020.

Key drivers input parameter	Scenario: Central
South Australia Energy Transformation RIT-T	NSW to SA interconnector (Project EnergyConnect) is assumed commissioned from July 2023[38] with the scope in the 2020 Transmission Annual Planning Report[39] and 2020 ISP.
Western Victoria Renewable Integration RIT-T	The preferred option in the Western Victoria Renewable Integration PACR[40] from July 2025 (220 kV upgrade in 2024 and 500 kV to Sydenham in 2025).
Marinus Link and Battery of the Nation	Excluded
Victoria to NSW, and NSW to QLD Interconnectors Upgrades	The Victoria to NSW Interconnector upgrade PADR[41] preferred option and NSW to QLD Interconnector upgrade approved option by AER[42] are assumed commissioned by July 2022
Snowy 2.0	Snowy 2.0 is included from July 2025
HumeLink	The HumeLink PADR preferred option (Option 3C) is assumed commissioned from July 2024[43]
VNI West	The VNI West ISP 2018 preferred option is assumed commissioned from July 2026

[38] ElectraNet, 13 February 2019. *SA Energy Transformation RIT-T: Project Assessment Conclusions Report*. Available at: https://www.electranet.com.au/wp-content/uploads/projects/2016/11/SA-Energy-Transformation-PACR.pdf. There are options for commissioning between 2022 and 2024. Limits also from this document.
[39] TransGrid, 2020 TAPR, https://www.transgrid.com.au/what-we-do/Business-Planning/transmission-annual-planning/Documents/2020%20Transmission%20Annual%20Planning%20Report.pdf, Accessed 11 August 2020.
[40] AEMO, July 2019, *Western Victoria Renewable Integration PACR*. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2019/PACR/Western-Victoria-RIT-T-PACR.pdf. Accessed 30 June 2020.
[41] AEMO and TransGrid, August 2019, *Victoria to New South Wales Interconnector Upgrade – PADR*. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2019/VNI-RIT-T/Victoria-to-New-South-Wales-Interconnector-Upgrade-RIT-T-PADR.pdf. Accessed 30 June 2020.
[42] TransGrid, *Expanding NSW-QLD transmission transfer capacity*. Available at: https://www.transgrid.com.au/qni. Accessed 30 June 2020.
[43] TransGrid, *Reinforcing the NSW Southern Shared Network to increase transfer capacity to demand centres (HumeLink)*. Available at: https://www.transgrid.com.au/humelink. Accessed 30 June 2020.

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, as listed in Table 3. In TransGrid's view, this enables better representation of intra-regional network limitations and transmission losses.

Table 3: 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 (CAN)	Canberra 330 kV
Victoria	Victoria (VIC)	Thomastown 66 kV
South Australia	South Australia (SA)	Torrens Island 66 kV
Tasmania	Tasmania (TAS)	Georgetown 220 kV

The loss factors for generators (as discussed in Section 3.1.2) are computed with respect to the zonal reference nodes they are mapped to, which for New South Wales are the reference nodes defined in Table 3 rather than the regional reference node as currently defined in the NEM. Dynamic loss equations are defined between reference nodes across these cut-sets. The borders of each zone or cut-set are defined in Table 4, as defined by TransGrid.

Table 4: 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
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 Maragle and Wagga to Bannaby after commissioning of HumeLink Option 3C
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

Border	Lines
CAN (WAGGA)-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 - Darlington Point (Dinawan) [44] from 1 July 2023 New 500 kV double circuit from Wagga - Darlington Pt (after commissioning of VNI West)
VIC-CAN	Line 060 Jindera - Wodonga Line 65 Upper Tumut - Murray Line 66 Lower Tumut - Murray
VIC-SWNSW	Line 0X1 Red Cliffs - Buronga New Red Cliffs - Buronga (after assumed commissioning of Project EnergyConnect) New 500 kV double circuit from Kerang - Darlington Pt (after commissioning of VNI West)
SWNSW-SA	New 330 kV double circuit from Buronga - Robertstown (after commissioning of Project EnergyConnect)

5.2 SWNSW constraints

To capture the network limitations in SWNSW, key N-0 and N-1 thermal constraints are modelled. The N-0 constraint is modelled to avoid overload of Balranald to Darlington Point 220 kV line from the start of the study, while additional N-1 constraints, i.e. "to avoid overload of Balranald to Darlington Point 220 kV line due to outage of Buronga to Darlington Point (Dinawan)[44] 330 kV circuit 1" and "to avoid overload of Buronga to Darlington Point (Dinawan) 330 kV circuit 2 due to outage of Buronga to Darlington Point (Dinawan) 330 kV circuit 1" are modelled after the EnergyConnect commissioning date.

5.3 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 (Project EnergyConnect), CAN-NCEN, CAN (Wagga)-SWNSW,
- when interconnector definitions change with the addition of new reference nodes, e.g. the Victoria to New South Wales interconnector (VNI) now spans VIC-SWNSW and VIC-CAN instead of VIC-NSW,
- when future upgrades involving conductor changes are modelled, e.g. VNI West.

The network snapshots to compute the loss equations were provided by TransGrid, being also used for the estimation of generator loss factors.

5.4 Interconnector and intra-connector capabilities

The notional limits imposed on interconnectors are shown in Table 5. 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. The model will dispatch them to minimise costs.

[44] The updated Project EnergyConenct route considers a double circuit 330 kV line from Buronga to Dinawan (see: https://www.transgrid.com.au/what-we-do/Business-Planning/transmission-annual-planning/Documents/2020%20Transmission%20Annual%20Planning%20Report.pdf), rather than the PACR (https://www.electranet.com.au/wp-content/uploads/projects/2016/11/SA-Energy-Transformation-PACR.pdf) route which was a double circuit 330 kV line from Buronga to Darlington Point 330 kV substation.

- QNI bi-directional limits due to stability and thermal constraints provided by TransGrid.

Table 5: Notional interconnector capabilities used in the modelling (sourced from TransGrid and AEMO 2020 ISP[45])

Interconnector (From node – To node)	Import[46] notional limit	Export[47] notional limit
QNI	depending on Sapphire generation and demand, as per Expanding NSW-QLD transmission transfer capacity PADR[48]	depending on Sapphire generation and demand, as per Expanding NSW-QLD transmission transfer capacity PADR
Terranora (NNS-SQ)	-150 MW	50 MW
VIC-NSW[49] (VIC-CAN)	-250 MW	550 MW (Base) 720 MW (after VNI minor upgrade from 1 July 2022)
VIC-NSW (VIC-SWNSW)	-150 MW (Base) -500 MW (after EnergyConnect) and -1,950 MW (after VNI West from 1 July 2026)	150 MW (Base) 500 MW (after EnergyConnect) and 2,250 MW (after VNI West from 1 July 2026)
Project EnergyConnect (SWNSW-SA)	-800 MW	800 MW
Heywood (VIC-SA)	-650 MW (before Project EnergyConnect) -750 MW (after Project EnergyConnect)	650 MW (before Project EnergyConnect) 750 MW (after Project EnergyConnect)
Murraylink (VIC-SA)	-200 MW	220 MW
Basslink (TAS-VIC)	-478 MW	478 MW

New South Wales has been split into zones as outlined in Section 5.1 with the following limits imposed between the zones defined in Table 6.

Table 6: 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	-1,000 MW (Base) -1,177 MW (after QNI Option 1A[48])	1,200 MW (Base) 1,377 MW (after QNI Option 1A[48])
CAN-SWNSW	-700 MW (before Project EnergyConnect) -2,400 MW (after Project EnergyConnect,	700 MW (before Project EnergyConnect) 2,400 MW (after Project EnergyConnect,

[45] AEMO, *2020 Integrated System Plan*. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp Accessed 30 June 2020.

[46] 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 southerly flow and import along Heywood implies easterly flow.

[47] 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 northerly flow and export along Heywood implies westerly flow.

[48]TransGrid and Powerlink, 30 September 2019, *Expanding NSW-QLD transmission transfer capacity PADR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/ExpandingNSWQLDTransmissionTransferCapacity/Documents/Expanding%20NSW-QLD%20Transmission%20Transfer%20Capacity%20PADR%20-%20Full%20Report.pdf. Accessed30 June 2020.

[49] The modelling of zones within New South Wales necessitated that VIC-NSW is split across two zones on the New South Wales side of the border. The VIC-NSW transfer path is a combination of VIC-SWNSW and VIC-CAN and have their limits proportioned based on input from TransGrid.

Intra-connector (From node – To node)	Import notional limit	Export notional limit
	before VNI West) -4,000 MW (after VNI West)[50]	before VNI West) 4,000 MW (after VNI West)

A number of cut-set constraints within NSW are modelled as shown in Table 7.

Table 7: cut-sets limits

Cut-set definition	Limit (MW)
Snowy cut-set pre VNI minor upgrade	2,700
Snowy cut-set post VNI minor upgrade, pre HumeLink Option 3C upgrade	2,870
Snowy cut-set post HumeLink Option 3C upgrade	3,080
Snowy cut-set + HumeLink Option 3C lines (Maragle to Bannaby and to Wagga)	5,372
CAN-NCEN cut-set pre HumeLink Option 3C upgrade	2,700
CAN-NCEN cut-set post HumeLink Option 3C upgrade	4,500

5.5 Demand

The TSIRP model captures operational demand (energy consumption which is net of rooftop PV) 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,
- the nine reference years are repeated sequentially throughout the modelling horizon as shown in Figure 3.
- 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 prepare a projection of hourly operational demand.

Figure 3: Sequence of demand reference years applied to forecast

Modelled year	Reference year
2020-21	2011-12

[50] An additional 330 kV circuit from Darlington Point (Dinawan) to Wagga is assumed on top of Project EnergyConnect, which increases the transfer limit between the zones by 1,000 MW, as per TransGrid advice. The updated Project EnergyConenct route considers a double circuit 330 kV line from Buronga to Dinawan (see: https://www.transgrid.com.au/what-we-do/Business-Planning/transmission-annual-planning/Documents/2020%20Transmission%20Annual%20Planning%20Report.pdf), rather than the PACR (https://www.electranet.com.au/wp-content/uploads/projects/2016/11/SA-Energy-Transformation-PACR.pdf) route which was a double circuit 330 kV line from Buronga to Darlington Point 330 kV substation.

Modelled year	Reference year
2021-22	2012-13
2022-23	2013-14
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
2034-35	2017-18
2035-36	2018-19
...	...
2041-42	2015-16
2042-43	2016-17
2043-44	2017-18
2044-45	2018-19

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). This maintains correlations between weather patterns, demand, wind, large-scale solar and rooftop PV availability.

The aggregated embedded energy storage (VPP) share has been modelled explicitly to be available for arbitrage and the domestic behind-the-meter storage reduced accordingly.

TransGrid selected Central demand forecasts from the AEMO 2020 ISP[51] (see Section 4.1), which are used as inputs to the modelling. Figure 4 to Figure 6 shows the NEM operational energy and rooftop PV.

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[51] AEMO, *2020 Integrated System Plan*. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp Accessed 30 June 2020.

Figure 4: Annual operational demand in the Central scenario for all states from AEMO's 2019 Input and Assumptions workbook[52]

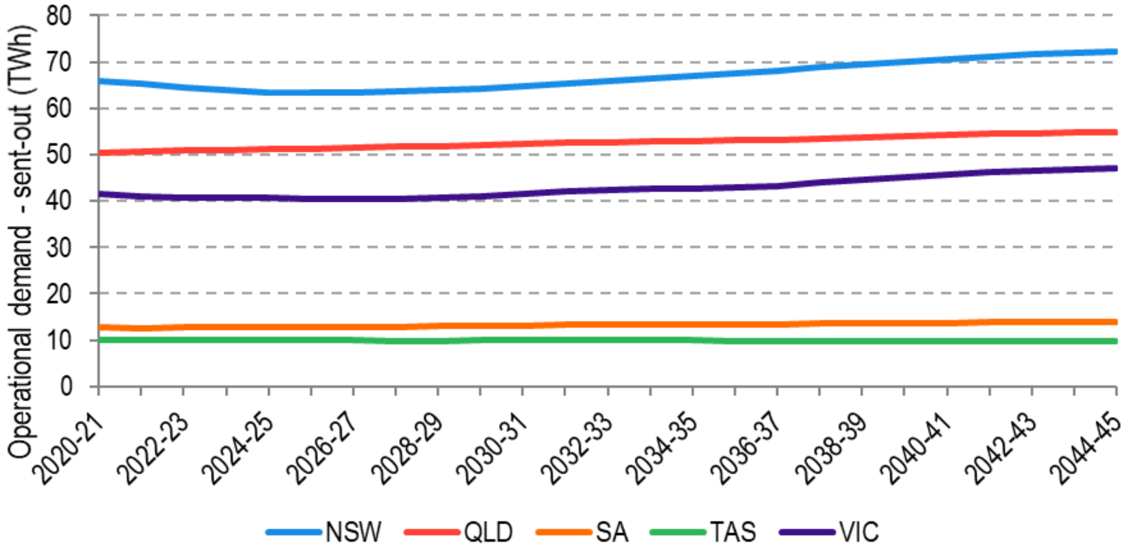
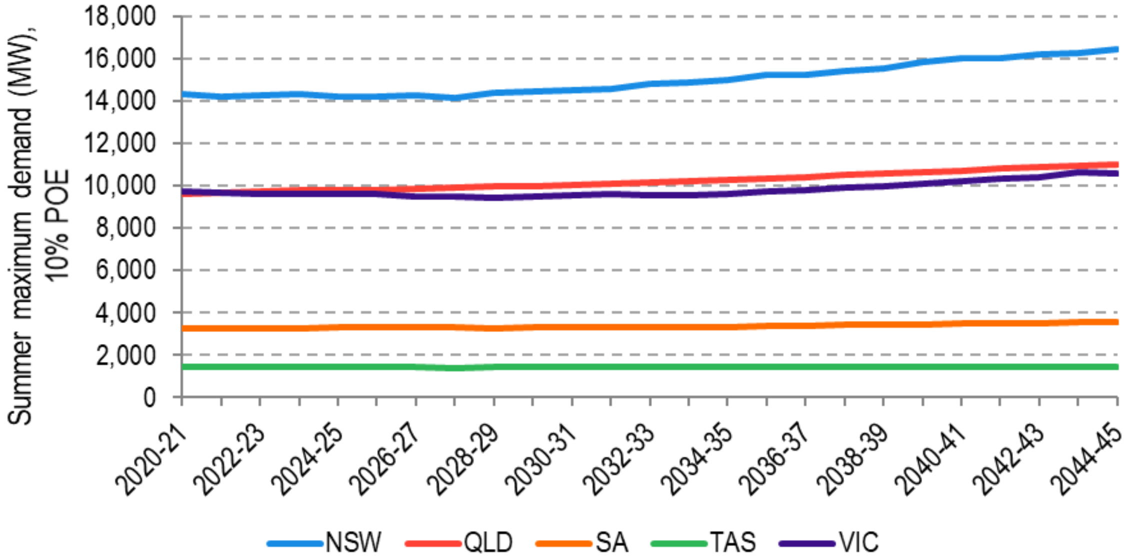
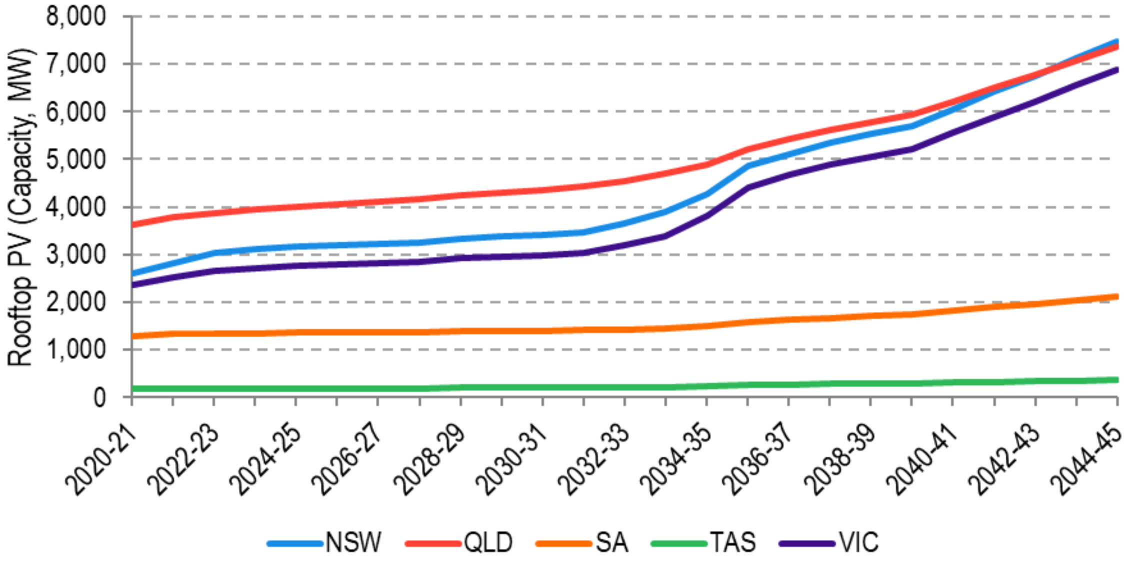


Figure 5: Annual summer maximum demand in the Central scenario in all states for 10% POE from AEMO's 2019 Input and Assumptions workbook[52]



[52] AEMO, 17 April 2020, *2019 Input and Assumptions workbook v1.4*. Available from AEMO upon request.

Figure 6: Annual rooftop PV uptake in the Central scenario in all states from AEMO's 2019 Input and Assumptions workbook[53]



The AEMO 2020 ISP demand forecasts shown above for NSW 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.

53 AEMO, 17 April 2020, *2019 Input and Assumptions workbook v1.4*. Available from AEMO upon request.

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 credible option. The source of this list varies with region:

- AEMO 2019 ISP Input and Assumptions workbook[54], committed projects, anticipated projects and existing, committed and anticipated batteries are used.
- In New South Wales, several additional generators anticipated by TransGrid based on the maturity of the connection applications are modelled, as listed in Table 8. These projects are anonymised in our modelling.

Table 8: Capacity anticipated by TransGrid

Region	Zone	Solar capacity (MW)	Wind capacity (MW)
NSW	NNS	80	0
	NCEN	550	160
	CAN (Yass)	0	106
	CAN (Wagga)	80	0
	SWNSW	147	0

Existing and new wind and solar projects are modelled based on nine years of historical weather data. The methodology for each category of wind and solar project is summarised in Table 9 and explained further in this section of the Report.

Table 9: 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[55] 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	Specify long-term target based on average of AEMO ESOO 2019 traces of nearest REZ, medium quality tranche.	
	Generic REZ new entrants	Specify long-term target based on AEMO 2020 ISP assumptions. One high quality option and one medium quality trace per REZ.	

[54] AEMO, 17 April 2020, *2019 Input and Assumptions workbook v1.4*. Available from AEMO upon request.

[55] 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 30 June 2020.

Technology	Category	Capacity factor methodology	Reference year treatment
Solar PV FFP	Existing	Annual capacity factor based on technology and site-specific solar insolation measurements or traces of nearest REZ.	Capacity factor varies with reference year based on historical, site-specific insolation measurements or nearest REZ.
Solar PV SAT	Existing		
	Committed new entrant		
	Generic REZ new entrant		
Rooftop PV and small non-scheduled solar PV	Existing and new entrant	Long-term average capacity factor based on AEMO's 2020 ISP assumptions.	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 3.

The availability profiles for wind generation are derived from simulated wind speeds from the Australian Bureau of Meteorology's Numerical Weather Prediction systems[56] 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 2019 ESOO and ISP assumptions[57] for each REZ (new entrant wind farms, as listed in Table 10).

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 10).

Table 10: REZ wind and solar approximate average capacity factors over nine reference years[58]

Region	REZ	Wind		Solar SAT
		High quality	Medium quality	
Queensland	Far North Queensland	56%	52%	28%
	North Queensland Clean Energy Hub	45%	37%	32%
	Northern Queensland	Tech not available	Tech not available	31%
	Isaac	41%	35%	30%
	Barcaldine	38%	34%	32%
	Fitzroy	42%	36%	29%

[56] 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 30 June 2020.
[57] AEMO, *2018 Electricity Statement of Opportunities: 2018 REZ Wind Traces* and *2018 REZ Solar Traces*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2018-NEM-ESOO. Accessed 30 June 2020.
[58] AEMO, 17 April 2020, *2019 Input and Assumptions workbook v1.4*. Available from AEMO upon request.

Region	REZ	Wind		Solar SAT
		High quality	Medium quality	
Queensland (cont.)	Wide Bay	34%	29%	28%
	Darling Downs	42%	37%	30%
New South Wales	North West New South Wales	Tech not available	Tech not available	30%
	New England	37%	35%	28%
	Central West New South Wales	38%	34%	28%
	Broken Hill	36%	32%	31%
	South West New South Wales	31%	31%	29%
	Wagga	28%	26%	28%
	Cooma-Monaro	38%	36%	Tech not available
Victoria	Murray River	Tech not available	Tech not available	28%
	Western Victoria	41%	36%	25%
	South West Victoria	37%	36%	Tech not available
	Gippsland[59]	32%	31%	Tech not available
	Central North Victoria	34%	31%	28%
South Australia	South East SA	39%	34%	25%
	Riverland	29%	29%	29%
	Mid-North SA	39%	37%	27%
	Yorke Peninsula	37%	36%	Tech not available
	Northern SA	37%	33%	29%
	Leigh Creek	42%	39%	31%
	Roxby Downs	Tech not available	Tech not available	32%
	Eastern Eyre Peninsula	38%	36%	27%
	Western Eyre Peninsula	36%	34%	29%
Tasmania	North East Tasmania	43%	40%	Tech not available
	North West Tasmania	46%	43%	23%
	Tasmania Midlands	53%	49%	Tech not available

Wind and solar capacity expansion in each REZ is limited by three parameters based on AEMO's 2019 Input and Assumptions workbook[60].

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

[59] Gippsland has an option for Offshore wind with average capacity factors of 42% and 41% for high and medium quality, respectively.
[60] AEMO, 17 April 2020, *2019 Input and Assumptions workbook v1.4*. Available from AEMO upon request.

- 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.

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, maintenance and refurbishment

Forced outage rates for coal generators are based on EY analysis of historical performance. The AEMO 2019 Input and Assumptions workbook[60] provides the forced outage rates for the coal generators as a regional aggregate. EY's analysis applies generator-specific full forced outage rates. TransGrid elected to deviate from the ISP full forced outage rates for coal generators to capture more granular observations of the apparent availability of the existing coal fleet. Table 11 below summarises the full forced outage rates outlined in the ISP along with the rate applied in modelling presented in this Report. Partial outage rates and mean time to repair used in the modelling are the same as in the 2019 Input and Assumptions workbook[60].

Table 11: Coal-fired power station full forced outage rates

Generator	AEMO September ISP 2020 Assumptions full forced outage rate[60]	Full forced outage rate applied in modelling in this Report
Bayswater	6.22 % (until 2022) 4.30 % (after 2022)	5.11 %
Callide B	2.30 %	8.58 %
Callide C	2.30 %	5.23 %
Eraring	6.22 % (until 2022) 4.30 % (after 2022)	8.83 %
Gladstone	2.30%	16.49 %
Kogan Creek	2.30 %	5.02 %
Liddell	6.22 %	24.93 %
Loy Yang A	5.43%	3.78 %
Loy Yang B	5.43 %	0.86 %
Mount Piper	6.22 % (until 2022) 4.30 % (after 2022)	10.78 %
Millmerran	2.30 %	3.40 %
Stanwell	2.30 %	0.59 %
Tarong	2.30%	4.38 %
Tarong North	2.30 %	7.60 %
Vales Point	6.22% (until 2022) 4.30 % (after 2022)	7.52 %
Yallourn	5.43 %	11.24 %

To calculate coal generator-specific forced outage rates, we count zeros in historical dispatch from 2013-14 to 2018-19 based on AEMO's market data database[61]. This records dispatch level at the start of each half-hourly trading interval for each DUID[62]. This is divided by the number of half-hours of historical records to give a total full unavailability rate reflecting historical planned and unplanned outages[63]. Station average outage rates are computed as the average across units in each station. The planned maintenance rate of 20 days per unit[64] is then subtracted to estimate full forced outage rates for each station[65].

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 credible options modelled. New entrant generators are de-rated by their equivalent forced outage rate as defined in the AEMO 2019 Input and Assumptions workbook.

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 2019 Input and Assumptions workbook.

Refurbishment timings are considered for coal generators in a schedule aligned with the AEMO 2019 Input and Assumptions workbook and replace maintenance of the respective units during this period. Schedules are identical for the Base Case and supply options and assumed to take 11 weeks per unit[66].

6.3 Generator technical parameters

All technical parameters are as detailed in the AEMO 2019 Input and Assumptions workbook, except where noted in this section.

6.3.1 Coal-fired generators

Coal-fired generation is 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 2019 Input and Assumptions workbook[64], maximum loads vary seasonally. This materially reduces the amount of available capacity in the summer periods.

An assumed energy limit was placed on coal-fired power stations approximately equal to the maximum annual energy generated between 2013-14 and 2017-18, reflecting coal rail and contractual supply limitations.

[61] Market Data NEMWEB, Daily trading interval data, INITIALMW. Available at: http://nemweb.com.au/Reports/CURRENT/Daily_Reports/. Accessed 12 July 2019.

[62] Dispatchable Unit Identifier. For coal generators each DUID corresponds to a single genset.

[63] Two stations had prolonged outages on units which caused data anomalies and were excluded from the analysis. One unit of Callide B, CALL_B_1, experienced a prolonged outage in 2014 due to fuel supply issues; data for this this unit before 27 November 2014 has been excluded. The Tarong outage rate was based on only units 1 and 3 since units 2 and 4 (TARONG#2, TARONG#4) were mothballed during the analysis period.

[64] AEMO, 17 April 2020, *2019 Input and Assumptions workbook v1.4*. Available from AEMO upon request.

[65] Loy Yang A and Stanwell had lower annual unavailability than what is assigned to maintenance giving a negative forced outage rate after maintenance was subtracted from unavailability. For these stations, we assumed maintenance wouldn't be scheduled over the summer period and hence computed the outage rates using only data from December, January and February.

[66] GHD, September 2018, *AEMO costs and technical parameter review*. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/9110715-REP-A-Cost-and-Technical-Parameter-Review---Rev-4-Final.pdf. Accessed 30 June 2020.

6.3.2 Gas-fired generators

In line with the AEMO 2019 Input and Assumptions workbook[67] there have been no minimum loads applied to existing gas fired CCGT plant.

TransGrid has assumed a minimum load of 40 % of capacity for all new CCGTs 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 level and so start and are dispatched for a minimum of one hour when the cost of supply is at or above their SRMC.

6.3.3 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.

6.3.4 Storage-limited generators

Conventional hydro with storages, pumped hydro, VPPs 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 2019 Input and Assumptions workbook and the median hydro climate factor trajectory for the Central scenario applied[67]. The Tasmanian hydro schemes were modelled using a simplified six pond model.

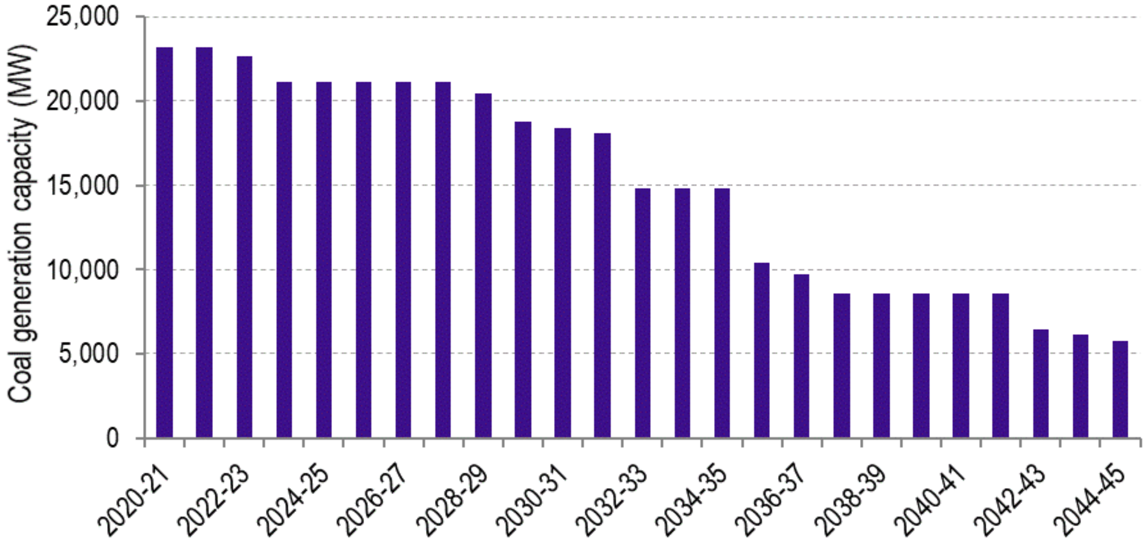
6.4 Retirements

According to the scenario settings selected by TransGrid, thermal retirements in the model are fixed. Retirement dates for the Central scenario are sourced from the latest Generation Information expected closure year document at the time of modelling[68]. Coal retirements in the scenario modelled are illustrated in Figure 7.

[67] AEMO, 17 April 2020, *2019 Input and Assumptions workbook v1.4*. Available from AEMO upon request.

[68] AEMO, 30 April 2020, *Generating Unit Expected Closure Year - April 2020*. 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: 15 May 2020.

Figure 7: Coal capacity in the NEM by year in the Central scenario

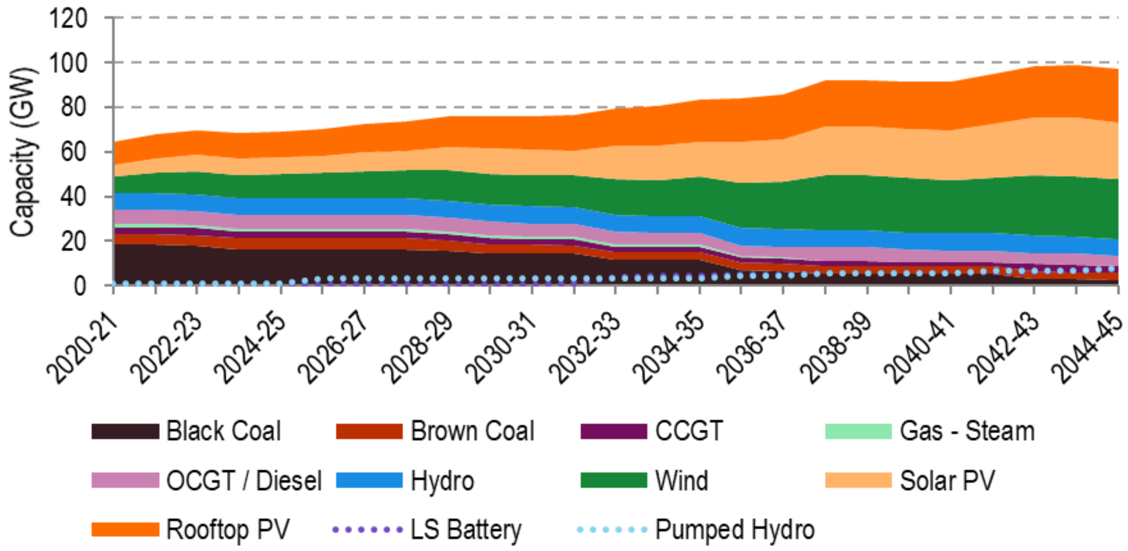


7. NEM outlook in Base Case

Before considering the potential benefits of each of the credible options, it is useful to analyse the capacity and generation forecast outlook for the counterfactual Base Case.

The NEM-wide capacity mix forecast in the Base Case is shown in Figure 8. The forecast generation capacity of the NEM gradually shifts towards increasing capacity of wind, solar, pumped hydro and LS Battery.

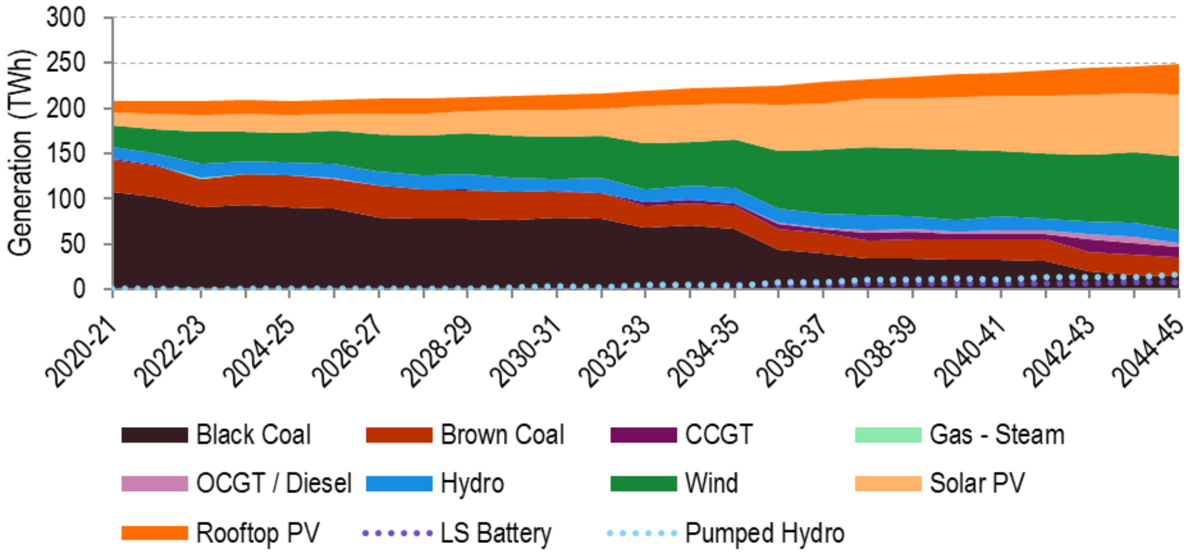
Figure 8: NEM capacity mix forecast for the Base Case



The first new capacity forecasts to be installed by the model as part of the least-cost development plan is approximately 300 MW of new solar capacity in Central West NSW in 2021-22 and then around 100 MW solar in VIC. From 2022-23 onwards it is forecast that wind capacity begins to enter the market first in TAS, and then in QLD and VIC. In the early 2030s approximately 4 GW of LS Battery is forecast to be installed in NSW, QLD and SA, whereas pumped hydro capacity is forecast to be installed from the mid-2030s in NSW, QLD and VIC. Furthermore, approximately 3.6 GW gas capacity is forecast to be installed in NSW, QLD and SA in the last 10 years of the study. Overall, the NEM is forecast to have around 114 GW total capacity by 2044-45 (note that total capacity includes pumped hydro and LS Battery capacities, which are not in the stacked chart). The majority of new capacity forecast to be installed is coincident with the expected coal generation retirements, which is particularly obvious from the mid-2030s when a number of large coal generators in the NEM are assumed to retire.

Figure 9 shows the energy supplied to the grid in the Base Case. Note that all the generation charts in the Report are on an "as-generated" basis. The energy generated gradually increases throughout the modelling period due to the modest growth of the AEMO 2020 ISP Central demand assumed in this scenario. The forecast cost of operating solar and wind trends below that of gas plant, so the forecast mix of generation favours solar and wind over other technologies such as gas-fired plant, except as needed to meet peak demand periods when wind and solar are not always available and furthermore to maintain minimum reserve requirements. OCGT and CCGT capacity and generation production levels are influenced by the assumed 40 % minimum load on new CGGTs and no minimum load requirement on new OCGTs, in accordance with specifications for new generation of both types.

Figure 9: NEM generation mix forecast for the Base Case



The modelling forecasts a significant solar generation increase in 2029-30, 2032-33 and 2035-36, all being coincident with assumed major coal retirements. A noticeable increase in wind generation is forecast in 2035-36, consistent with the need for more renewable energy to replace retiring fossil fuelled generation. The pumped hydro and LS Battery generation trend is forecast to align with solar and wind generation uptake. The model also forecasts a significant increase in CCGT generation from 2041-42 to 2042-43, which is coincident with around 2 GW of assumed coal retirement.

8. Forecast gross market benefit outcomes

8.1 Summary of forecast gross market benefits

Table 12 shows the forecast gross market benefits over the modelled 25-year horizon for all options across the modelled Central scenario. TransGrid has concluded that Option 1A/5A is the preferred option based on the forecast net benefits after incorporating forecast gross market benefits and assumed development costs of the option [69]. 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"[70].

Table 12: Summary of forecast gross market benefits, millions real June 2019 dollars discounted to June 2020 dollars[71]

Option	Description	Timing	Potential gross market benefit ($m)
Option 1A/5A (preferred option)	Compressed Air Energy Storage (CAES) facility: 150 MW/1,300 MWh available for arbitrage with 60 % cyclic efficiency. It is assumed that this option allows 150 MW of free Broken Hill REZ transmission expansion for solar PV build in Broken Hill REZ	1/07/2025	Confidential - removed from public report
Option 1C/5C	Large scale battery: 73 MW/42 MWh available for arbitrage with 85 % cyclic efficiency	1/07/2022	Confidential - removed from public report
Option 3	New 50 MW OCGT: 45 MW rating in summer and 50 MW in other seasons	1/07/2022	Confidential - removed from public report
Option 4	Transmission option: establishing a second single circuit 220 kV transmission line from Buronga to Broken Hill. It is assumed that this option allows 400 MW of free Broken Hill REZ transmission expansion for solar PV and wind build in Broken Hill REZ	1/07/2023	Confidential - removed from public report

The rest of Section 8 explores the timing and sources of these forecast benefits, with a focus on the preferred option, i.e. Option 1A/5A.

8.2 Market modelling results for Option 1A/5A (CAES)

This section summarises market modelling results for Option 1A/5A, the compressed air energy storage facility with 150 MW/1,300 MWh available for arbitrage, which also assumes 150 MW of free Broken Hill REZ transmission expansion for new solar PV build[72] in this REZ.

The forecast cumulative gross market benefits for Option 1A/5A are shown in Figure 10. Furthermore, the differences in capacity and generation outlook across the NEM between Option 1A/5A and the Base Case are shown in Figure 11 and Figure 12 respectively. Note that the compressed air facility capacity and generation is included in these charts under the Pumped Hydro technology type.

[69] TransGrid, *Maintaining reliable supply to Broken Hill PADR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Broken%20Hill%20Supply. Accessed 11 August 2020.

[70] 14 December 2018, *RIT-T and RIT-D application guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 30 June 2020.

[71] Note that TransGrid has requested that this report does not present the outcomes of gross market benefits in order to protect the confidentiality of the cost of proponents' options.

[72] Wind would also be eligible for consideration for the REZ zone, but initial modelling showed that the CAES facility would be more compatible with the solar profile for this Option.

Figure 10: Forecast cumulative gross market benefit[73,74] for Option 1A/5A, millions real June 2019 dollars discounted to June 2020 dollars[75]

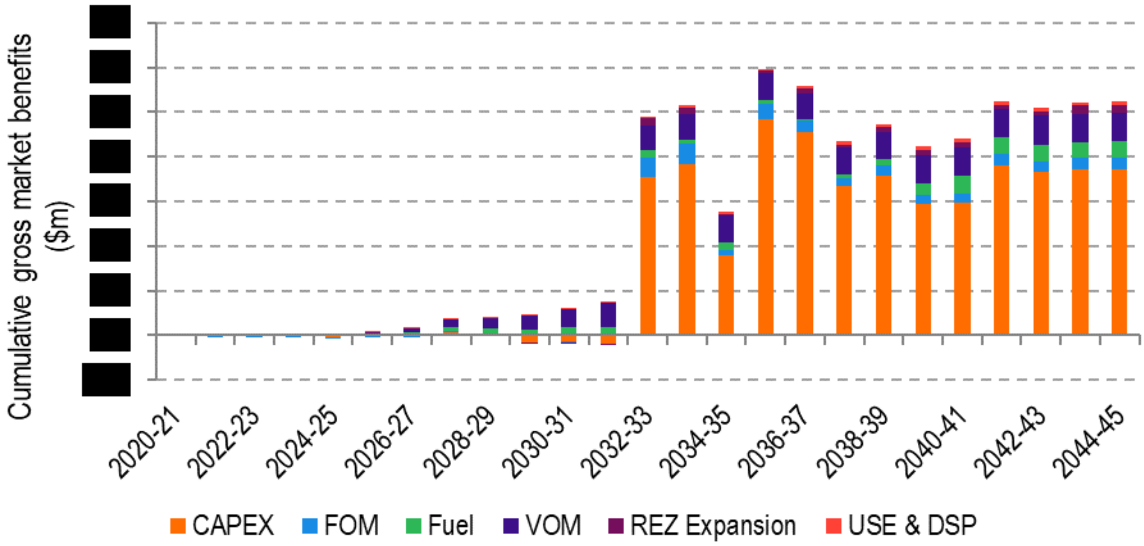
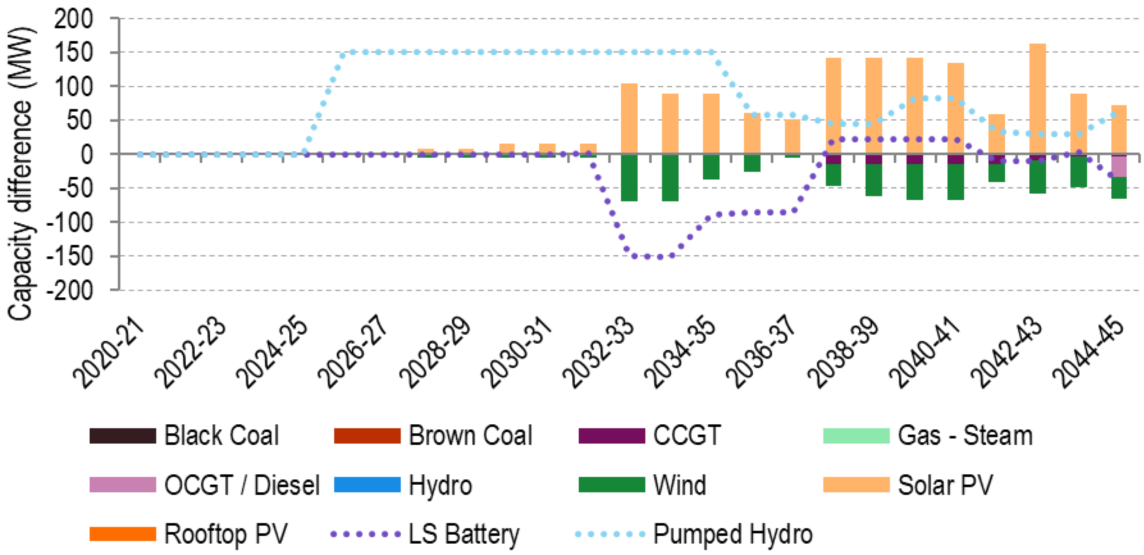


Figure 11: Difference in NEM capacity forecast between Option 1A/5A and Base Case

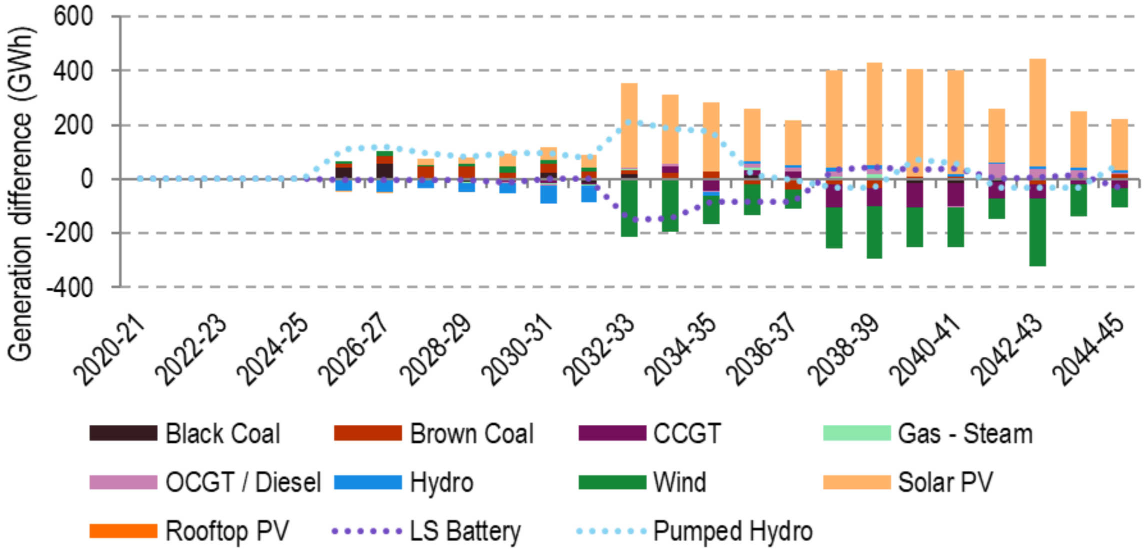


[73] Note that all generator and storage capital costs have been included in the market modelling on an annualised basis. However, this chart and all charts of this nature in the Report present the entire capital costs of these plants in the year avoided to highlight the timing of capacity changes that drive expected capex benefits. This is purely a presentational choice that TransGrid has made to assist with relaying the timing of expected benefits (i.e., when thermal plant retires) and does not affect the overall gross benefits of the options.

[74] Since this figure shows the cumulative forecast gross market benefits in present value terms, the height of the bar in 2044-45 equates to the gross benefits for Option 1A shown in Table 12 above.

[75] Note that TransGrid has requested that this report does not present the outcomes of gross market benefits in order to protect the confidentiality of the cost of proponents' options.

Figure 12: Difference in NEM generation forecast between Option 1A/5A and Base Case



The primary sources of forecast gross market benefits in the CAES option are from avoided and deferred capex for new generators as well as fuel cost and VOM savings. The timing and source of these benefits are attributable to the following:

- The first large potential benefit is expected to occur in 2032-33 where a large amount of wind and LS Battery capacity is deferred (i.e. more wind and LS Battery is installed in this year in the Base Case compared to Option 1A/5A), though around 100 MW solar is built in this year (150 MW more solar in Broken Hill but around 50 MW less solar in Riverland REZ).
- This potential capex benefit is then expected to reduce in 2034-35 when some of the deferred wind and LS Battery capacity is forecast to be built.
- Again in 2035-36 there is an expected large increase in potential capex benefit with avoided pumped hydro build (noting that the compressed air facility capacity is included in the pumped hydro capacity in the charts). The potential capex saving reduces in the next few years before increasing to the level in 2042-43, which then remains unchanged.
- The model also forecasts that Option 1A/5A is estimated to require around 80 MW less pumped hydro in VIC and 40 MW less LS Battery in SA, due to the modelled capacity of CAES.
- 150 MW of solar capacity is built in Broken Hill in 2032-33 in this option while there is no capacity forecast to be built in Broken Hill in the Base Case. This is due to the assumed high cost of REZ transmission expansion for Broken Hill in ISP, which makes it not least cost to build any new wind and solar in this REZ.
- Option 1A/5A leads to a small capacity of solar replacing wind in the SWNSW REZ, and also around the same capacity of solar replacing wind in the Western Victoria REZ compared to the Base Case. Furthermore, around 100 MW solar in the Roxby Downs REZ are forecast to be avoided.
- As a result of more solar but less wind build in the CAES option, noticeably higher solar but lower wind generation is seen in the study period, particularly from 2032.
- Generation from pumped hydro (noting that compressed air facility generation is included in pumped hydro in Option 1A/5A) and LS Battery are expected to be similar for both Option 1A/5A and Base Case, though a ramp up for pumped hydro and a ramp down for the LS Battery generation are forecast from the early 2030s until the late 2030s.

- Fuel cost saving is also forecast which is mainly due to CCGT fuel cost saving and associated higher levels of solar generation.

Other smaller sources of forecast benefits are:

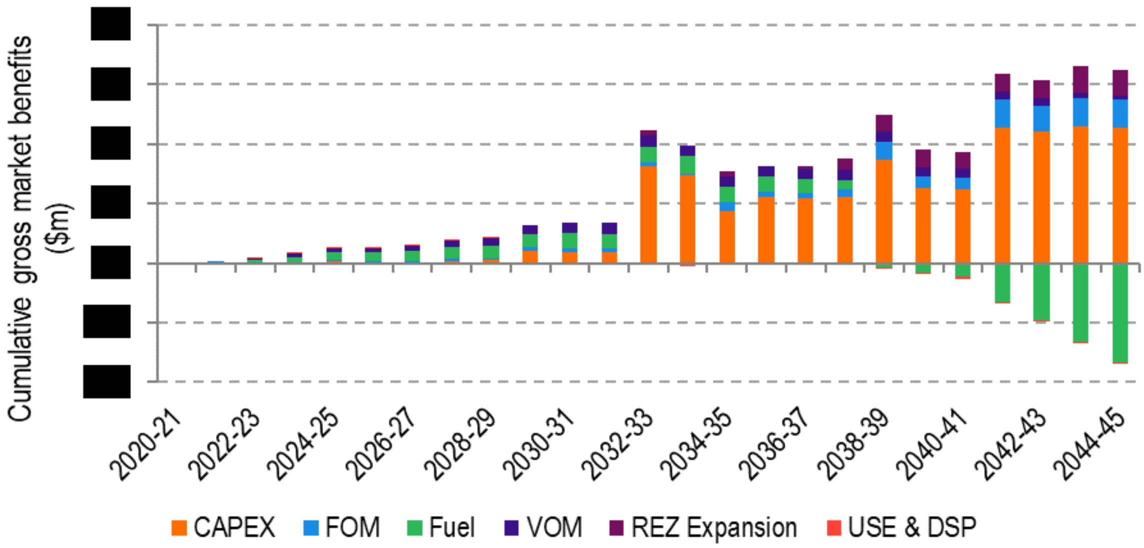
- forecast USE & DSP benefits,
- a forecast reduction in REZ transmission expansion build costs, and
- reduced FOM expenditure.

8.3 Market modelling results for Option 1C/5C (Battery)

This section summarises market modelling results for Option 1C/5C, the battery with 73 MW/42 MWh available for arbitrage, having 85% cyclic efficiency.

The forecast cumulative gross market benefits for Option 1C/5C are shown in Figure 13. Furthermore, the differences in capacity and generation outlook across the NEM between Option 1C/5C and the Base Case are shown in Figure 14 and Figure 15 respectively. Note that the battery option capacity and generation is included in these charts under the LS Battery technology type.

Figure 13: Forecast cumulative gross market benefit[76,77] for Option 1C/5C, millions real June 2019 dollars discounted to June 2020 dollars[78]



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[76] Note that all generator and storage capital costs have been included in the market modelling on an annualised basis. However, this chart and all charts of this nature in the Report present the entire capital costs of these plants in the year avoided to highlight the timing of capacity changes that drive expected capex benefits. This is purely a presentational choice that TransGrid has made to assist with relaying the timing of expected benefits (i.e., when thermal plant retires) and does not affect the overall gross benefits of the options.

[77] Since this figure shows the cumulative forecast gross market benefits in present value terms, the height of the bar (net of above and below the bar) in 2044-45 equates to the gross benefits for Option 1C/5C shown in Table 12 above.

[78] Note that TransGrid has requested that this report does not present the outcomes of gross market benefits in order to protect the confidentiality of the cost of proponents' options.

Figure 14: Difference in NEM capacity forecast between Option 1C/5C and Base Case

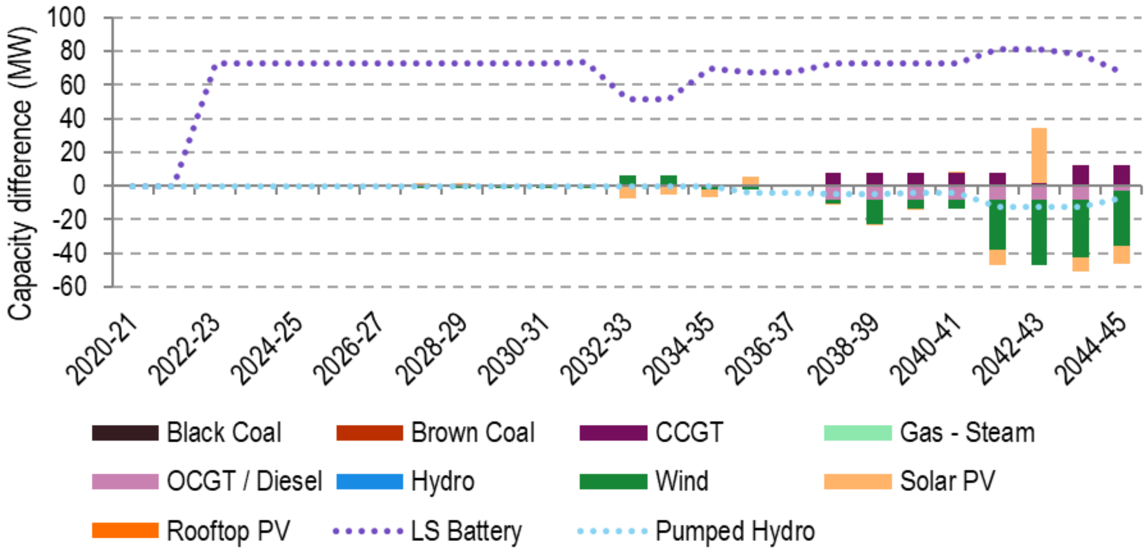
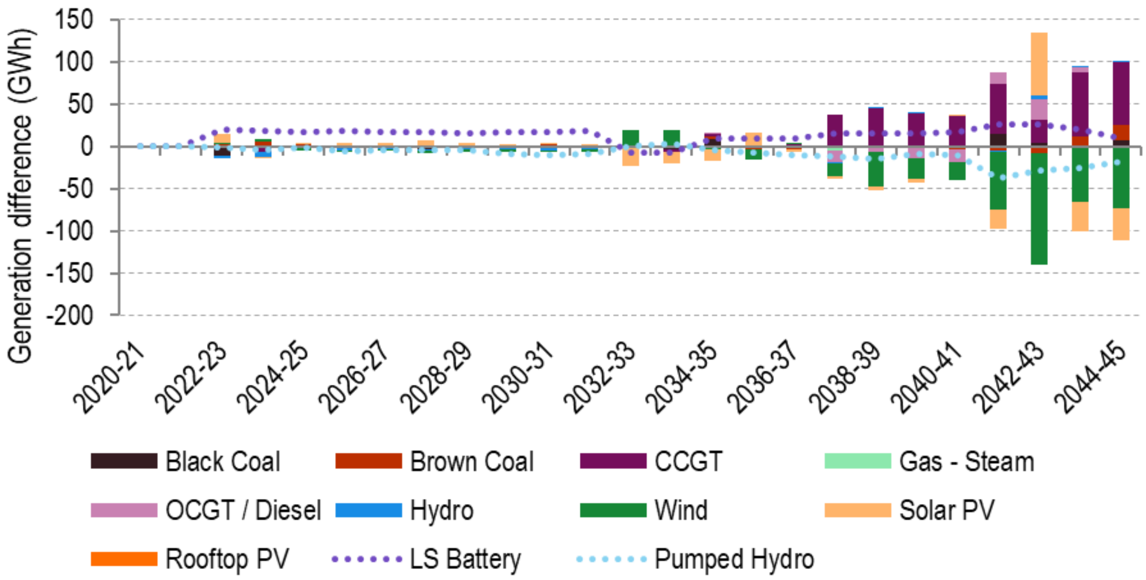


Figure 15: Difference in NEM generation forecast between Option 1C/5C and Base Case



Overall, Option 1C/5C is forecast to have significantly smaller benefits, capacity and generation mix changes relative to the Base Case compared to the benefits in Option 1A/5A, which is mainly due to the smaller capacity and energy available from the modelled battery.

The primary sources of forecast gross market benefits are from avoided and deferred capex (and associated FOM) for new generators as well as avoided REZ transmission expansion build costs. However, the fuel cost in this option is potentially higher than the Base Case. The timing and source of these benefits are attributable to the following:

- Early in the study there are small forecast fuel cost benefits due to reduced black coal generation, however, this benefit is eroded by increased gas and coal generation in the back end of the study resulting in overall increased potential fuel costs from mainly CCGT in this option.
- The first notable capex benefit occurs in 2032-33 where some capacity of LS Battery and solar is deferred (i.e. more LS Battery and solar is installed in this year in the Base Case compared to Option 1C/5C).

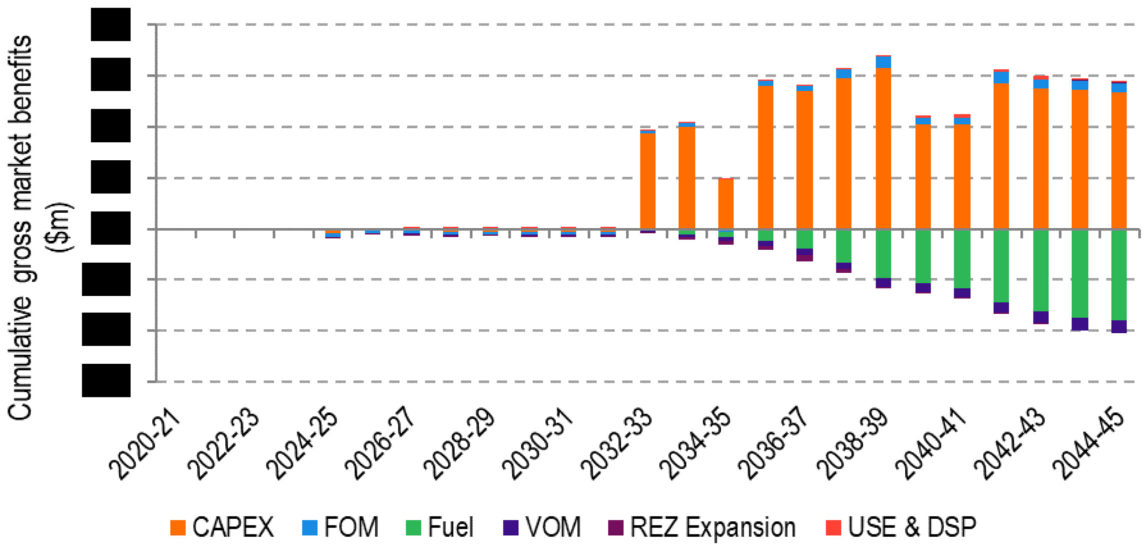
- Further capex benefit is attributable to avoided OCGT, wind, LS Battery and pumped hydro capacity in the back end of the study.
- There is also a forecast reduction in REZ transmission expansion costs.
- The battery is forecast to often charge and increase demand during the day, resulting in 33 MW of solar replacing the same capacity of wind in the SWNSW REZ in this option. No additional free REZ transmission expansion has been assumed for this option, and due to the high cost, there is no change in new capacity in the Broken Hill REZ compared to the Base Case. Furthermore, this option avoids 38 MW solar build in the Roxby Downs REZ in SA.

8.4 Market modelling results for Option 3 (New Gas Turbine)

This section summarises market modelling results for Option 3, a new 50 MW gas turbine in Broken Hill. This option is assumed to be commissioned in July 2022; however, benefits don't start to accumulate until post 2032-33, the year Eraring is assumed to retire.

The forecast cumulative gross market benefits for Option 3 are shown in Figure 16. Furthermore, the differences in capacity and generation outlook across the NEM between Option 3 and the Base Case are shown in Figure 17 and Figure 18 respectively. Note that the Broken Hill gas turbine option capacity and generation is included in these charts under the OCGT/Diesel technology type.

Figure 16: Forecast cumulative gross market benefit[79,80] for Option 3, millions real June 2019 dollars discounted to June 2020 dollars[81]



[79] Note that all generator and storage capital costs have been included in the market modelling on an annualised basis. However, this chart and all charts of this nature in the Report present the entire capital costs of these plants in the year avoided to highlight the timing of capacity changes that drive expected capex benefits. This is purely a presentational choice that TransGrid has made to assist with relaying the timing of expected benefits (i.e., when thermal plant retires) and does not affect the overall gross benefits of the options.

[80] Since this figure shows the cumulative forecast gross market benefits in present value terms, the height of the bar (net of above and below the bar) in 2044-45 equates to the gross benefits for Option 3 shown in Table 12 above.

[81] Note that TransGrid has requested that this report does not present the outcomes of gross market benefits in order to protect the confidentiality of the cost of proponents' options.

Figure 17: Difference in NEM capacity forecast between Option 3 and Base Case

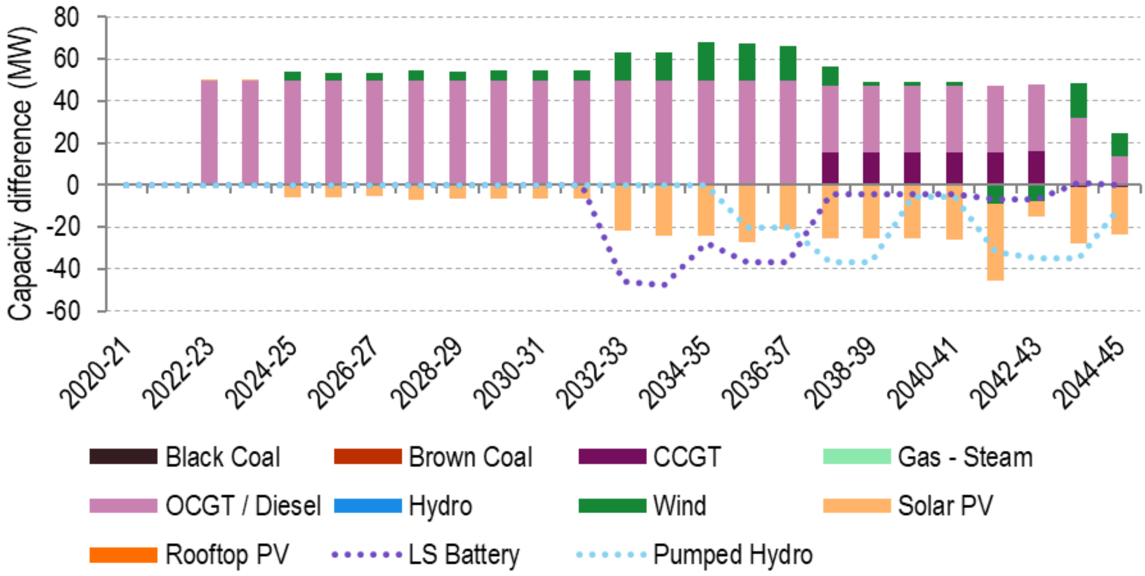
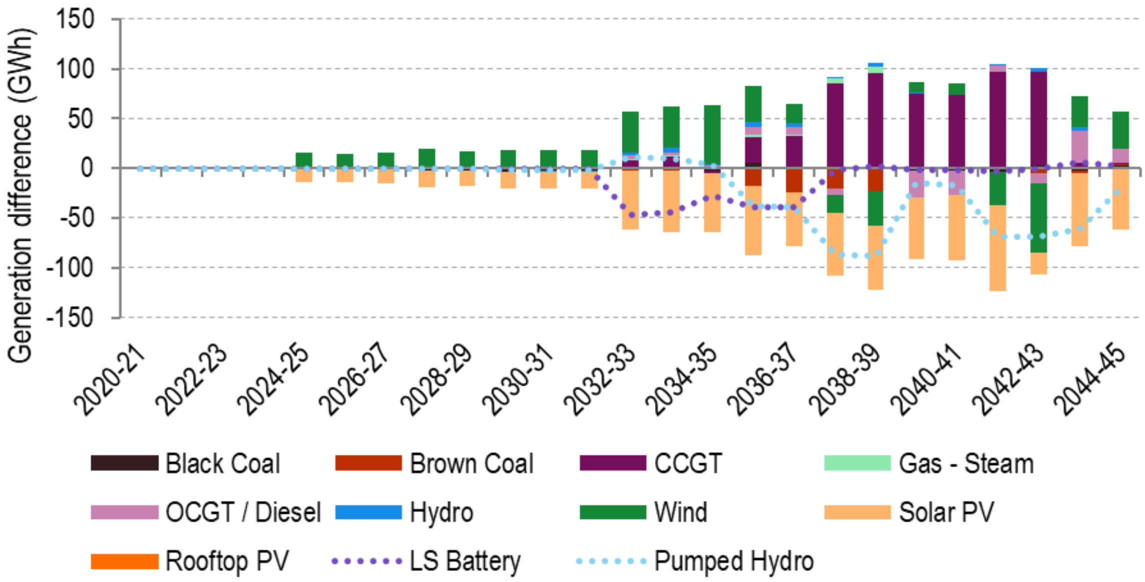


Figure 18: Difference in NEM generation forecast between Option 3 and Base Case



As for Option 1C/5C, Option 3 is forecast to have significantly smaller benefits, capacity and generation mix changes relative to the Base Case compared to that of Option 1A/5A.

The primary sources of forecast gross market benefits are from avoided and deferred capex for new generators, offset by a large amount of fuel cost and VOM. The timing and source of these benefits are attributable to the following:

- The first large benefit is expected to occur in 2032-33 where some capacity of solar and LS Battery capacity is deferred/avoided despite more wind being installed compared to the Base Case.
- This potential capex benefit is then reduced in 2034-35 when some of the deferred LS Battery capacity is built, as well as some additional wind.
- In 2035-36 there is an increase in potential capex benefit with deferment of pumped hydro and LS Battery build.

- By the end of the study the potential capex benefit is due to the avoided build of 36 MW OCGT elsewhere in the NEM (noting that new GT capacity in Option 3 is included in the capacity mix chart), 23 MW solar and 18 MW pumped hydro, though some more wind is built.
- Throughout the study there is less pumped hydro, solar and LS Battery generation. This generation is offset by generation from wind, CCGT and OCGT, resulting in higher fuel costs accumulating from 2032-33, offsetting the benefits due to avoided capex
- No change in the renewable build in the Broken Hill REZ occurs, in line with no free REZ transmission upgrade with this option. Overall this option only results in minor differences in REZ build.

Other smaller sources of forecast benefits are:

- reduced FOM expenditure,
- forecast USE & DSP benefits, and
- a forecast reduction in REZ transmission expansion build costs.

8.5 Market modelling results for Option 4 (Transmission augmentation)

This section summarises market modelling results for Option 4, the transmission augmentation option which establishes a second 220 kV single circuit transmission line from Buronga to Broken Hill. This option is assumed from July 2023, and small benefits start to accumulate from the same year, but with a larger continuous change from 2035-36, the year Bayswater and Gladstone power stations are assumed to retire. The major contributors to the benefits of this option are fuel benefits as well as benefits due to avoided REZ transmission expansion, as this option enables 400 MW of free Broken Hill REZ transmission expansion.

The forecast cumulative gross market benefits for Option 4 are shown in Figure 19. Furthermore, the differences in capacity and generation outlook across the NEM between Option 4 and the Base Case are shown in Figure 20 and Figure 21, respectively.

Figure 19: Forecast cumulative gross market benefit[82,83] for Option 4, millions real June 2019 dollars discounted to June 2020 dollars[84]

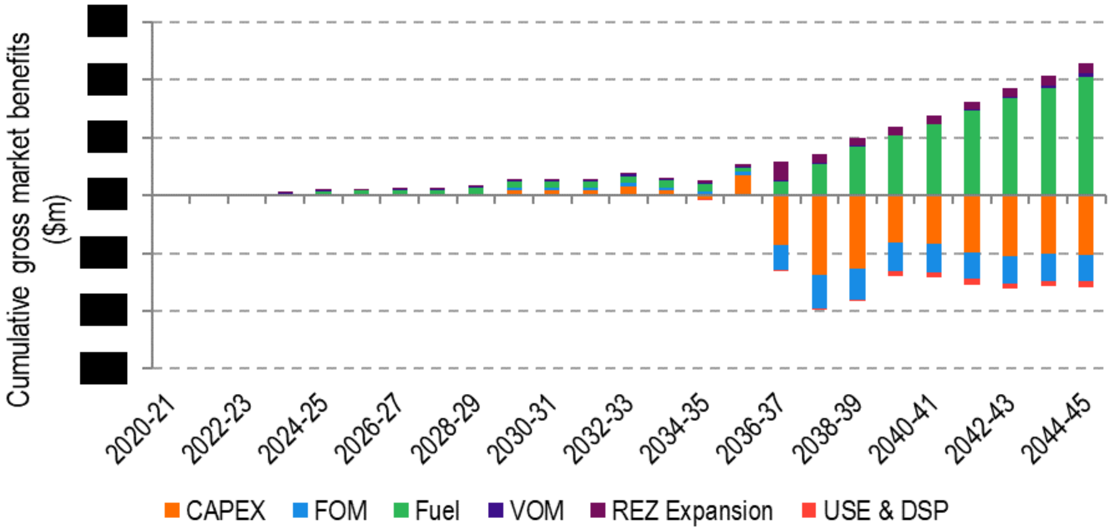
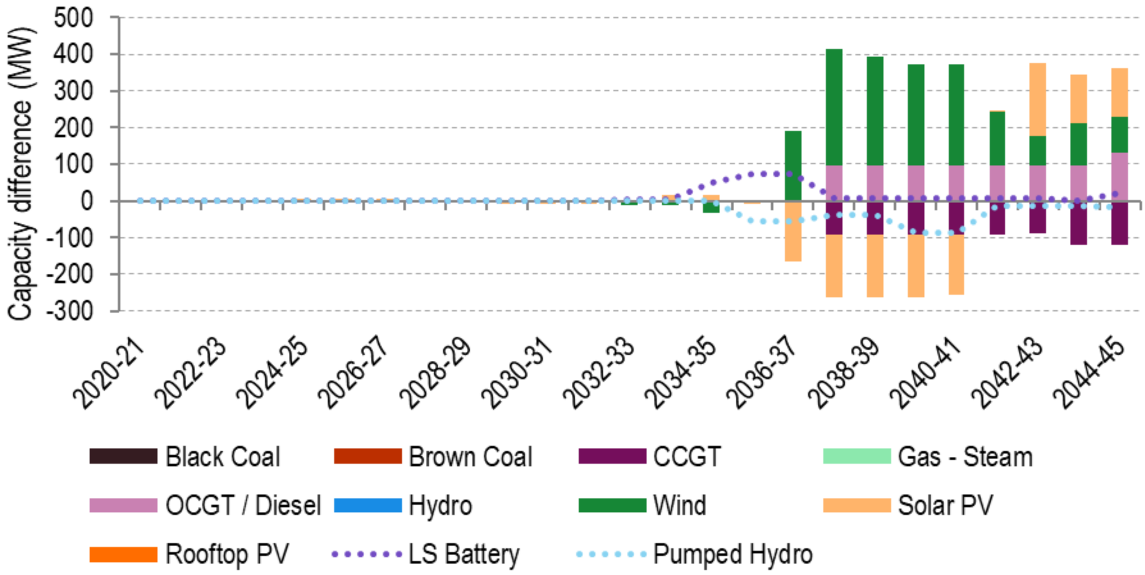


Figure 20: Difference in NEM capacity forecast between Option 4 and Base Case



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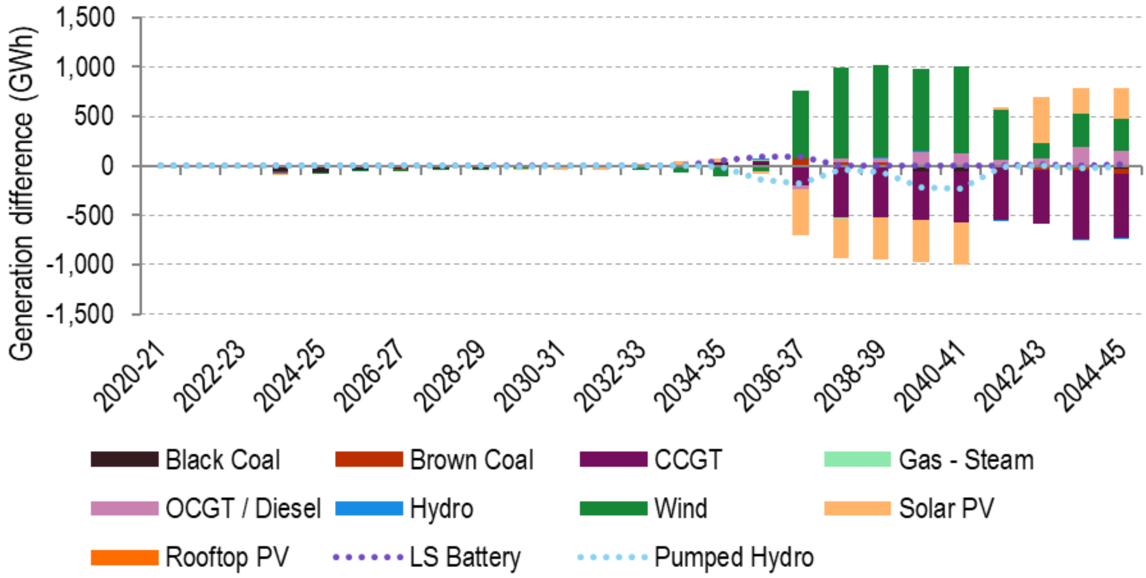
[82] Note that all generator and storage capital costs have been included in the market modelling on an annualised basis. However, this chart and all charts of this nature in the Report present the entire capital costs of these plants in the year avoided to highlight the timing of capacity changes that drive expected capex benefits. This is purely a presentational choice that TransGrid has made to assist with relaying the timing of expected benefits (i.e., when thermal plant retires) and does not affect the overall gross benefits of the options.

[83] Since this figure shows the cumulative forecast gross market benefits in present value terms, the height of the bar (net of above and below the bar) in 2044-45 equates to the gross benefits for Option 4 shown in Table 12 above.

[84] Note that TransGrid has requested that this report does not present the outcomes of gross market benefits in order to protect the confidentiality of the cost of proponents' options.

Figure 21: Difference in NEM generation forecast between Option 4 and Base Case



Contrary to other options, the primary sources of forecast gross market benefits are from avoided fuel cost and REZ transmission expansion. Benefits start to accumulate from 2035-36. These benefits are offset by additional potential capex expenditure and associated FOM cost. The timing and source of these benefits are attributable to the following:

- Small fuel and VOM potential benefits start to accumulate from 2023-24, the year the transmission upgrade is assumed to commission, due to some avoided black coal generation in NSW and QLD compared to the Base Case.
- In 2036-37, the assumed 400 MW free Broken Hill REZ transmission expansion results in 400 MW wind being forecast to be installed in this REZ, incurring capex and FOM cost, but with no REZ transmission expansion cost. The same year, fuel cost benefits start to progressively increase until the end of the study period as the wind generation offsets a considerable amount of CCGT generation
- 190 MW of solar build is delayed from 2036-37 to 2041-42, mainly as this capacity is replaced by the additional wind capacity built in Broken Hill.
- In the southern states, new renewable build is reduced, with 50 MW less wind in Gippsland, and some smaller capacities avoided in Yorke Peninsula and Leigh Creek. It is forecast that around 70 MW less solar in Roxby Downs is built in this option. Slightly more wind is built in South West Victoria and a small capacity of solar is forecast to replace the same capacity of wind in Western Victoria in comparison to the Base Case.
- Overall, this option is forecast to allow more wind, solar and OCGT build, replacing CCGT build. There are no forecast changes in LS Battery and pumped hydro build compared to the Base Case.

Other smaller sources of forecast cost and benefits are:

- forecast USE & DSP potential cost,
- a forecast reduction in REZ transmission expansion build costs, and
- reduced VOM expenditure.

Appendix A Glossary of terms

Abbreviation	Meaning
AEMO	Australian Energy Market Operator
AC	Alternating Current
CAES	Compressed Air Energy Storage
CAN	Canberra (NEM zone)
CAPEX	Capital Expenditure
CCGT	Combined-Cycle Gas Turbine
DCLF	DC Load Flow
DER	Distributed Energy Resources
DSP	Demand side participation
DUID	Dispatchable Unit Identifier
FFP	Fixed Flat Plate
FOM	Fixed Operation and Maintenance
GW	Gigawatt
GWh	Gigawatt-hour
ISP	Integrated System Plan
LRET	Large-scale Renewable Energy Target
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
PADR	Project Assessment Draft Report
POE	Probability of Exceedence
PSCR	Project Specification Consultation Report
PSH	Pumped Storage Hydro
PV	Photovoltaic
QLD	Queensland

Abbreviation	Meaning
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
SRMC	Short-Run Marginal Cost
SWNSW	South West New South Wales (NEM zone)
SWVIC	South West Victoria (REZ)
TAS	Tasmania
TRET	Tasmanian Renewable Energy Target
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

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