Improving stability in south-western NSW PADR

market modelling report

22 September 2021

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 options for improving stability in south-western New South Wales (SWNSW) Regulatory Investment Test for Transmission ("SWNSW RIT-T").

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 23 September 2020 and was completed on 4 May 2021. Therefore, our Report does not take account of events or circumstances arising after 4 May 2021 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, *Improving stability in south-western NSW PADR*. Available at: https://transgrid.com.au/what-we-do/projects/current-projects/Improving%20stability%20in%20south-western%20NSW. Accessed 22 September 2021.

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1. Executive summary

TransGrid has engaged EY to undertake market modelling of system costs and benefits to assess potential options for improving stability in south-western New South Wales (SWNSW) Regulatory Investment Test for Transmission (SWNSW 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 methodology based on the change in least-cost generation dispatch and capacity development with each investment option for the SWNSW RIT-T.

EY computed the least-cost generation dispatch and capacity development plan for the National Electricity Market (NEM) associated with five different options provided by TransGrid for improving stability in south-western New South Wales for four scenarios: Central, Step Change, Fast Change and Slow Change. Note that Option 1A and Option 1B were included in the Project Specification Consultation Report (PSCR)[3], however, TransGrid requested EY to only model Option 1A (which is called Option 1 hereafter in this Report), given their similarities. The modelled options are:

- Option 1: a 330 kV line between Darlington Point and Dinawan (being a new substation as part of EnergyConnect) to be commissioned from 1 December 2024. TransGrid assumed Option 1 unlocks 600 MW transmission capacity for renewable energy in the South West New South West (SWNSW) Renewable Energy Zone (REZ).
- Option 2: a 330 kV line between Darlington Point and Wagga to be commissioned from 1 December 2024. TransGrid assumed Option 2 unlocks 600 MW transmission capacity for renewable energy in the SWNSW REZ.
- Option 3: a static synchronous compensator (STATCOM) at Darlington Point to be commissioned from 1 December 2023.
- Option 4: Option 1 to be commissioned from 1 December 2024 with a battery at Darlington Point which provides network support from 1 January 2022 to 1 December 2024. TransGrid assumed that the battery has market arbitrage capability from its commissioning date.
- Option 5: a standalone battery to be commissioned from 2022 (confidential proponent submission).

The modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator[4]. 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

[2] TransGrid, *Improving stability in south-western NSW PADR*. Available at: https://transgrid.com.au/what-we-do/projects/current-projects/Improving%20stability%20in%20south-western%20NSW. Accessed 22 September 2021.

[3] TransGrid, *Improving stability in south-western NSW PSCR*. Available at: https://www.transgrid.com.au/what-we-do/projects/regulatory-investment-tests/Documents/TransGrid%20PSCR_Stabilising%20SW%20NSW.pdf. Accessed 13 August 2021.

[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 12 May 2021.

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[5], 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)[6],
- minimum loads for generators,
- interconnector flow limits (between regions),
- intra-regional flow limits (between zones in NSW),
- line 63 stability constraint equation in SWNSW, called N^^N_NIL_2[7],
- 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 REZ where applicable, and pumped hydro in each region,
- emission and carbon budget constraints, as defined in the Integrated System Plan (ISP) for the modelled scenarios,
- renewable energy targets where applicable by region or NEM-wide, and
- other constraints such as network thermal and stability constraints, as defined in the Report.

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 SWNSW RIT-T option and in a matched no network augmentation counterfactual (referred to as the Base Case) we computed the sum of these cost components and compared the differences. The sum of the differences in costs is the forecast gross market benefits due to the SWNSW 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 volume of generation that is needed to be dispatched in each trading interval. The forecast gross market benefits also capture the

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

[6] Based on AER, December 2019, *Values of Customer Reliability Final report on VCR values.* Available at: https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf. Accessed 12 May 2021.

[7] AEMO, *New system normal constraint equation in NSW for voltage collapse at Darlington Point*. Available at: https://aemo.com.au/Market-Notices?marketNoticeQuery=darlington+point&marketNoticeFacets=CONSTRAINTS%2CINTER-REGIONAL+TRANSFER%2CLOR2+FORECAST%2CPRICE+ADJUSTMENT%2CFORCED+MAJEURE%2CLOAD+SHED. Accessed 12 May 2021.

impact of differences in losses (cyclic efficiency) 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 five SWNSW RIT-T options for four scenarios for the NEM.

Potential gross market benefits were forecast for five options modelled in the SWNSW RIT-T for the Central, Step Change, Fast Change and Slow Change scenarios. All options assessed were defined by TransGrid and are described in detail in the PADR[2]. 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, the stability constraint equation for line 63 (N^^N_NIL_2) as well as the transfer limit from SWNSW to Wagga were modelled to capture the network limitations in this zone.

The modelled scenarios are in line with the Australian Energy Market Operator's (AEMO) 2020 ISP[8]. TransGrid elected to model age-based and announced coal retirements for the Central scenario, with the Step Change and Fast Change scenarios assuming half of the coal power stations to retire five years and two years earlier, respectively, and the Slow Change scenario assuming half of the coal power stations to retire five years later than the Central scenario. In addition, TransGrid assumed that EnergyConnect and VNI West upgrades will unlock SWNSW REZ transmission capacity of 800 MW and 1,900 MW, respectively. TransGrid also selected a more recent gas price publication than the ISP as well as coal generator outage rates based on EY analysis. For all scenarios, benefits presented are discounted to June 2020 using a 5.9% real, pre-tax discount rate as selected by TransGrid.

Option 1 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 the SWNSW RIT-T need to be compared to the relevant development cost to determine whether there is a positive net market benefit. TransGrid has concluded that Option 1 is the preferred option based on option costs and benefits[9]. 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[10]".

Table 1 shows the forecast gross market benefits over the modelled 25-year horizon from 2021-22 to 2045-46 for all options. From Table 1, it is seen that all options are expected to achieve their highest gross market benefits in the Step Change scenario, whereas their lowest gross market benefits are forecast to be in the modelled Central scenario. The forecast gross market benefits for Option 4 are the highest amongst all options (note that TransGrid instructed EY to remove the forecast gross market benefits for Option 4 as well as Option 5 from this public report due to confidentiality). On the contrary, Option 3 is forecast to have the lowest forecast gross market benefits with as low as approximately $26m in the Central scenario. TransGrid's preferred option, i.e. Option 1, has forecast gross market benefits of approximately $102m, $326m, $181m and $191m in the Central, Step Change, Fast Change and Slow Change scenarios, respectively. The forecast gross market benefits difference between Option 2 and Option 1 is due to the reduced losses for the SWNSW to Wagga link in Option 2, as it includes another 330 kV line between Darlington Point and Wagga.

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[8] 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 12 May 2021.

[9] TransGrid, *Improving stability in south-western NSW PADR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Improving%20stability%20in%20south-western%20NSW. Accessed 12 May 2021.

[10] 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 12 May 2021.

Table 1: Summary of forecast gross market benefits, millions real June 2019 dollars discounted to June 2020 dollars

Option	Description	Timing	Potential gross market benefit ($m)			
			Central	Step Change	Fast Change	Slow Change
Option 1	A new 330 kV line between Darlington Point and Dinawan	1/12/2024	101.73	325.73	180.94	190.69
Option 2	A new 330 kV line between Darlington Point and Wagga	1/12/2024	110.16	348.72	195.62	201.22
Option 3	STATCOM	1/12/2023	25.68	51.16	38.64	28.14
Option 4	Option 1 with a battery from January 2022 which provides network support until Option 1 is commissioned	1/01/2022	Confidential - removed from public report	Confidential - removed from public report	Confidential - removed from public report	Confidential - removed from public report
Option 5	A standalone battery	2022	Confidential - removed from public report	Confidential - removed from public report	Confidential - removed from public report	Confidential - removed from public report

2. Introduction

TransGrid has engaged EY to undertake market modelling of system costs and benefits to assess potential options for improving stability in south-western New South Wales Regulatory Investment Test for Transmission (SWNSW RIT-T)[11].

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 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 five options defined by TransGrid in the PADR[2] for the Central, Step Change, Fast Change and Slow Change scenarios. Option 1A and Option 1B were included in the PSCR[12]. However, TransGrid requested EY to only model Option 1A (which is called Option 1 hereafter in the Report), given their similarities. The modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator[13]. The RIT-T is a cost-benefit analysis used to assess the viability of investment options in electricity transmission assets.

The description 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 forecast 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 2021-22 to 2045-46. Potential benefits presented are discounted to June 2020 using a 5.9% real, pre-tax discount rate in all scenarios as selected by TransGrid.

This modelling considers five different options to improve stability in SWNSW, as shown in Table 2. The modelled options are:

- Option 1: a 330 kV line between Darlington Point and Dinawan (the new substation as part of Energy Connect) to be commissioned from 1 December 2024. TransGrid assumed Option 1 unlocks 600 MW of transmission capacity for renewable energy in SWNSW REZ.

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[11] TransGrid, *Improving stability in south-western NSW PADR*. Available at: https://transgrid.com.au/what-we-do/projects/current-projects/Improving%20stability%20in%20south-western%20NSW. Accessed 22 September 2021.

[12] TransGrid, *Improving stability in south-western NSW PSCR*. Available at: https://www.transgrid.com.au/what-we-do/projects/regulatory-investment-tests/Documents/TransGrid%20PSCR_Stabilising%20SW%20NSW.pdf. Accessed 22 September 2021.

[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 12 May 2021.

- Option 2: a 330 kV line between Darlington Point and Wagga to be commissioned from 1 December 2024. TransGrid assumed Option 2 unlocks 600 MW of transmission capacity for renewable energy in SWNSW REZ.
- Option 3: a STATCOM at Darlington Point to be commissioned from 1 December 2023.
- Option 4: Option 1 to be commissioned from 1 December 2024 with a battery at Darlington Point which provides network support from 1 January 2022 to 1 December 2024. TransGrid assumed that the battery has market arbitrage capability when it is commissioned.
- Option 5: a standalone battery to be commissioned from 2022.

Table 2: SWNSW RIT-T Options[2]

Option	Description	Timing
Option 1	A new 330 kV line between Darlington Point and Dinawan	1/12/2024
Option 2	A new 330 kV line between Darlington Point and Wagga	1/12/2024
Option 3	STATCOM	1/12/2023
Option 4	Option 1 with a battery from January 2022 which provides network support until Option 1 is commissioned	1/01/2022
Option 5	A standalone battery	2022

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

The resulting forecast gross market benefits of each SWNSW RIT-T 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 from the analysis included in this Report[2], by incorporating the forecast gross modelled market benefits into the calculation of potential net market benefits.

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 describes 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 for each scenario.
- Section 8 presents the forecast gross market benefits for the preferred option in detail as well as the outcomes for the other options more broadly.

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 2021-22 to 2045-46. The modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator[14].

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[15] 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[16], CCGT, OCGT, large-scale battery storage and pumped hydro. We screened nuclear and 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)[17],
- minimum loads or capacity factors for some generators,
- transmission interconnector flow limits (between regions),
- intra-regional flow limits (between zones in New South Wales),

[14] 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 12 May 2021.

[15] 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.

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

[17] Based on AER, December 2019, *Values of Customer Reliability Final report on VCR values.* Available at: https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf. Accessed 12 May 2021.

- line 63 stability constraint equation in SWNSW, called N^^N_NIL_2[18],
- 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 and carbon budget constraints for the relevant scenarios,
- renewable energy targets where applicable by region or NEM-wide,
- other constraints such as network thermal and stability constraints, as defined in the Report.

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 the stability constraint for SWNSW, as detailed in Section 5.2.

The model incorporates as inputs fixed age based/announced retirement dates for existing generation in the Central scenario, with the Step Change and Fast Change scenarios assuming half of the coal power stations to retire five years and two years earlier, respectively, and the Slow Change scenario assuming half of the coal power stations to retire five years later than the Central scenario. 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 and carbon budget trajectory, at least cost, which may be by either building new lower emissions plant or reducing the operation of higher emissions plant, or both.

There are three main types of generators 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 in NSW only, as specified by the ISP 2020 assumptions book. 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.

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[18] AEMO, *New system normal constraint equation in NSW for voltage collapse at Darlington Point*. Available at: https://aemo.com.au/Market-Notices?marketNoticeQuery=darlington+point&marketNoticeFacets=CONSTRAINTS%2CINTER-REGIONAL+TRANSFER%2CLOR2+FORECAST%2CPRICE+ADJUSTMENT%2CFORCED+MAJEURE%2CLOAD+SHED. Accessed 12 May 2021.

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.

All dispatchable generators in each region are eligible to contribute to reserve (except pumped hydro and large-scale battery storages[19]) 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 reserve requirement is applied to ensure 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[20]. This method of estimating and incorporating loss factors is sufficient to give a geographic investment

[19] 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.

[20] 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.

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:

- 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 SWNSW RIT-T 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 SWNSW RIT-T option and counterfactual Base Case.

Each component of forecast 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)[21], discounted to June 2020 at a 5.9% real, pre-tax discount rate as selected by TransGrid.

The forecast gross market benefits of each option need to be compared to the relevant option'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 from the analysis included in this Report[22].

[21] 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.

[22] TransGrid, *Improving stability in south-western NSW PADR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Improving%20stability%20in%20south-western%20NSW. Accessed 22 September 2021.

4. Scenario assumptions

The credible options have been assessed for forecast market benefits under the Central, Step Change, Fast Change and Slow Change scenarios as selected by TransGrid following publication of the PSCR[23]. The underlying scenario assumptions are summarised in Table 3 and are in line with the scenarios described in AEMO's 2020 ISP[24]. As noted in Table 3, except where noted, input data are sourced from the accompanying 2019 ISP Input and Assumptions workbook which formed the initial consultation for the 2020 ISP[25]. The version from July 2020 (v1.5) was the most up-to-date data source available and used for this modelling.

Table 3: Overview of key input parameters[26]

Key drivers input parameter	Scenario			
	Central	Step Change	Fast Change	Slow Change
Underlying consumption	AEMO 2020 ISP Central	AEMO 2020 ISP Step Change	AEMO 2020 ISP Fast Change	AEMO 2020 ISP Slow Change
New entrant capital cost for wind, solar SAT, OCGT, CCGT, pumped hydro, and large-scale batteries	AEMO 2020 ISP Central	AEMO 2020 ISP Step Change	AEMO 2020 ISP Fast Change	AEMO 2020 ISP Slow Change
Retirements of coal-fired power stations	AEMO Generation Information[27] announced retirement date or end-of-technical-lives	Half of coal-fired power stations retire five years earlier than Central	Half of coal-fired power stations retire two years earlier than Central	Half of coal-fired power stations retire five years later than Central
Gas fuel cost	TransGrid trajectory based on Core Energy[28] Central Upper case but NSW adjusted for lower price Narrabri gas	TransGrid trajectory based on Core Energy Step Change case, NSW low priced LNG to 2029, increases thereafter	TransGrid trajectory based on Core Energy Central Upper case but NSW adjusted for lower price Narrabri gas	TransGrid trajectory based on Core Energy Slow Change case, NSW adjusted for lower priced LNG gas to 2029, increases thereafter
Coal fuel cost	AEMO 2020 ISP Neutral	AEMO 2020 ISP Fast	AEMO 2020 ISP Neutral	AEMO 2020 ISP Slow
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			

[23] TransGrid, *Improving stability in south-western NSW PSCR*. Available at: https://www.transgrid.com.au/what-we-do/projects/regulatory-investment-tests/Documents/TransGrid%20PSCR_Stabilising%20SW%20NSW.pdf. Accessed 13 August 2021.

[24] 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 12 May 2021.

[25] AEMO, 30 July 2020, *2019 Input and Assumptions workbook v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 18 December 2020.

[26] Ibid, unless otherwise stated in table.

[27] AEMO, 30 July 2020, *Generating Unit Expected Closure Year - July 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 18 December 2020.

[28] Core energy, December 2019, Delivered Wholesale Gas Price Outlook 2020-2050. Available at: https://aemo.com.au/en/consultations/current-and-closed-consultations/2020-planning-and-forecasting-consultation-on-scenarios-inputs-and-assumptions. Accessed 18 December 2020.

Key drivers input parameter	Scenario			
	Central	Step Change	Fast Change	Slow Change
COP21 commitment (Paris agreement)	26% emissions reduction from 2005 levels by 2030			
NEM carbon budget to achieve 2050 emissions levels	N/A	AEMO 2020 ISP Step Change budget of 1,465 Mt CO_2-e to 2050	AEMO 2020 ISP Fast Change budget of 2,208 Mt CO_2-e to 2050	N/A
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		N/A	
Tasmanian Renewable Energy Target (TRET)	100% Tasmanian renewable energy generation by 2021-22	100% Tasmanian renewable energy generation by 2021-22 and 200% by 2039-40	100% Tasmanian renewable energy generation by 2021-22	
South Australia Energy Transformation RIT-T	NSW to SA interconnector is assumed commissioned from July 2024[29] with the scope in the 2020 Transmission Annual Planning Report[30] and the 2020 ISP			
Western Victoria Renewable Integration RIT-T	The preferred option in the Western Victoria Renewable Integration PACR[31] from July 2025 (220 kV upgrade in 2024 and 500 kV to Sydenham in 2025)			
Marinus Link	1st cable: 2036	1st cable: 2028 2nd cable: 2031	1st cable: 2031	Excluded
Victoria to NSW, Interconnector Upgrades	The Victoria to NSW Interconnector upgrade PADR[32] is assumed commissioned from July 2022. VNI West ISP 2018 preferred option is assumed commissioned from July 2028.	The Victoria to NSW Interconnector upgrade PADR is assumed commissioned from July 2022. VNI West ISP 2018 preferred option is assumed commissioned from July 2035.		The Victoria to NSW Interconnector upgrade PADR is assumed commissioned from July 2022. VNI West is excluded.

[29] 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.

[30] TransGrid, 2020 TAPR, https://www.transgrid.com.au/what-we-do/Business-Planning/transmission-annual-planning/Documents/2020%20Transmission%20Annual%20Planning%20Report.pdf, Accessed 18 December 2020.

[31] 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 18 December 2020.

[32] 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 12 May 2021.

Key drivers input parameter	Scenario			
	Central	Step Change	Fast Change	Slow Change
NSW to QLD Interconnector Upgrades	The NSW to QLD Interconnector upgrade approved option by the AER[33] is assumed commissioned from July 2022. QNI medium is assumed from 2032 and QNI large from 2035.			The NSW to QLD Interconnector upgrade approved option by the AER is assumed commissioned from July 2022. QNI medium and large are excluded.
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[34]			

[33] TransGrid, *Expanding NSW-QLD transmission transfer capacity*. Available at: https://www.transgrid.com.au/qni. Accessed 18 December 2020.

[34] TransGrid, *Reinforcing the NSW Southern Shared Network to increase transfer capacity to demand centres (HumeLink)*. Available at: https://www.transgrid.com.au/humelink. Accessed 18 December 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 4. In TransGrid's view, this enables better representation of intra-regional network limitations and transmission losses.

Table 4: Regions, zones and reference nodes

Region	Zone	Zonal Reference Node
Queensland	Queensland (QLD)	South Pine 275 kV
New South Wales	Northern New South Wales (NNS)	Armidale 330 kV
	Central New South Wales (NCEN)	Sydney West 330 kV
	South-West New South Wales (SWNSW)	Darlington Point 330 kV
	Canberra (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 4 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 5, as defined by TransGrid.

Table 5: Key cut-set definitions

Border	Lines
NNS-NCEN	Line 88 Muswellbrook – Tamworth Line 84 Liddell – Tamworth Line 96T Hawks Nest – Taree Line 9C8 Stroud – Brandy Hill
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 – Dinawan [35] (after commissioning of EnergyConnect) New 500 kV double circuit from Wagga – Dinawan (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 EnergyConnect) New 500 kV double circuit from Kerang - Dinawan (after commissioning of VNI West)
SWNSW-SA	New 330 kV double circuit from Buronga – Robertstown (after commissioning of EnergyConnect)

5.2 SWNSW constraints

The system normal constraint equation in NSW for voltage collapse at Darlington Point is modelled for the Base Case and SWNSW RIT-T options. TransGrid advised that Option 1 and Option 2 will fully resolve this constraint, while Option 3 will alleviate this constraint by 30 MW. Option 4 will also alleviate this constraint after the commissioning of the proposed battery on 1 January 2022 by 120 MW.

In addition, TransGrid has defined the transfer limits from SWNSW to Wagga for the Base Case and augmentation options, as shown in Table 6.

Table 6: Transfer limits of SWNSW to Wagga

Case	Limit (MW)	
	from SWNSW to Wagga	from Wagga to SWNSW
Base Case	300 MW pre commissioning of EnergyConnect 1,100 MW after commissioning of EnergyConnect 3,000 MW after commissioning of VNI West	500 MW pre commissioning of EnergyConnect 1,300 MW after commissioning of EnergyConnect 3,000 MW after commissioning of VNI West
Option 1	300 MW pre commissioning of EnergyConnect 1,100 MW after commissioning of EnergyConnect 1,700 MW after commissioning of Option 1 on 1/12/2024 3,000 MW after commissioning of VNI West	500 MW pre commissioning of EnergyConnect 1,300 MW after commissioning of EnergyConnect 1,700 MW after commissioning of Option 1 on 1/12/2024 3,000 MW after commissioning of VNI West
Option 2	300 MW pre commissioning of EnergyConnect 1,100 MW after commissioning of EnergyConnect 1,700 MW after commissioning of Option 2 on 1/12/2024 3,000 MW after commissioning of VNI West	500 MW pre commissioning of EnergyConnect 1,300 MW after commissioning of EnergyConnect 1,700 MW after commissioning of Option 2 on 1/12/2024 3,000 MW after commissioning of VNI West
Option 3	300 MW pre commissioning of EnergyConnect 330 MW after commissioning of Option 3 on 1/12/2023 1,130 MW after commissioning of EnergyConnect 3,000 MW after commissioning of VNI West	500 MW pre commissioning of EnergyConnect 500 MW after commissioning of Option 3 on 1/12/2023 1,300 MW after commissioning of EnergyConnect 3,000 MW after commissioning of VNI West

[35] The updated EnergyConnect 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.

Case	Limit (MW)	
	from SWNSW to Wagga	from Wagga to SWNSW
Option 4	300 MW pre commissioning of Battery 420 MW after commissioning of Battery 1,220 MW after commissioning of EnergyConnect 1,700 MW after commissioning of Option 2 on 1/12/2024 3,000 MW after commissioning of VNI West	500 MW pre commissioning of Battery 500 MW after commissioning of Battery 1,300 MW after commissioning of EnergyConnect 1,700 MW after commissioning of Option 2 on 1/12/2024 3,000 MW after commissioning of VNI West

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. NCEN-NNS, SA-SWNSW, 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 and were 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 7. 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 + SA-SWNSW has combined transfer export and import limits of 1,300 MW and 1,450 MW[36]. The model will dispatch them to minimise costs.
- QNI bi-directional limits due to stability and thermal constraints provided by TransGrid.

Table 7: Notional interconnector capabilities used in the modelling (sourced from TransGrid and AEMO 2020 ISP)

Interconnector (From node – To node)	Import[37] notional limit	Export[38] notional limit
QNI	Depending on Sapphire generation and demand, as per Expanding NSW-QLD transmission transfer capacity PADR[39]. TransGrid advised that QNI medium will increase the QNI notional limit by 760 MW and QNI large will further increase the QNI notional limit by 1,370 MW.	Depending on Sapphire generation and demand, as per Expanding NSW-QLD transmission transfer capacity PADR. TransGrid advised that QNI medium will increase the QNI notional limit by 832 MW and QNI large will further increase the QNI notional limit by 1,540 MW.

36 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 18 December 2020.

37 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.

38 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.

39 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. Accessed 18 December 2020.

Interconnector (From node – To node)	Import[37] notional limit	Export[38] notional limit
Terranora (NNS-SQ)	-150 MW	50 MW
VIC-NSW[40] (VIC-CAN)	-250 MW	550 MW (Base) 720 MW (after VNI minor)
VIC-NSW (VIC-SWNSW)	-150 MW (Base) -500 MW (after EnergyConnect) and -1,950 MW (after VNI West)	150 MW (Base) 500 MW (after EnergyConnect) and 2,250 MW (after VNI West)
EnergyConnect (SWNSW-SA)	-800 MW	800 MW
Heywood (VIC-SA)	-650 MW (before EnergyConnect) -750 MW (after EnergyConnect)	650 MW (before EnergyConnect) 750 MW (after EnergyConnect)
Murraylink (VIC-SA)	-200 MW	220 MW
Basslink (TAS-VIC)	-478 MW	478 MW

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 8.

Table 8: 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[39])	1,200 MW (Base) 1,377 MW (after QNI Option 1A[39])
NCEN-NNS	QNI medium will increase the NCEN-NNS import notional limit by 760 MW and QNI large will further increase this limit by 1,370 MW.	QNI medium will increase the NCEN-NNS import notional limit by 832 MW and QNI large will further increase this limit by 1,540 MW.

A number of cut-set constraints within NSW are modelled as shown in Table 9.

Table 9: Cut-set limits as provided by TransGrid

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

[40] 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.

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 1.
- 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 1: Sequence of demand reference years applied to forecast

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
2035-36	2017-18
2036-37	2018-19
2037-38	2010-11
...	...
2042-43	2016-17
2043-44	2017-18
2044-45	2018-19
2045-46	2010-11

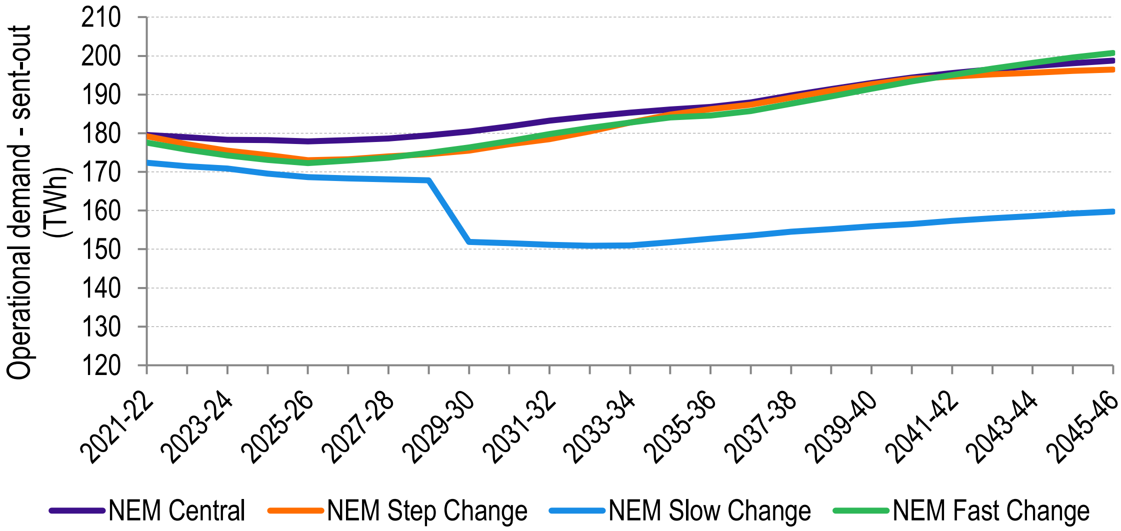
This method ensures the timing of high and low demands across regions reflects historical patterns, while accounting for projected changes in rooftop PV generation and other behind-the-meter loads and generators that may alter the size of peaks and their timing across regions. Overall, due to rooftop 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 demand forecasts from the AEMO 2020 ISP[41], which are used as inputs to the modelling. Figure 2 and Figure 3 show the NEM operational energy and rooftop PV in all scenarios.

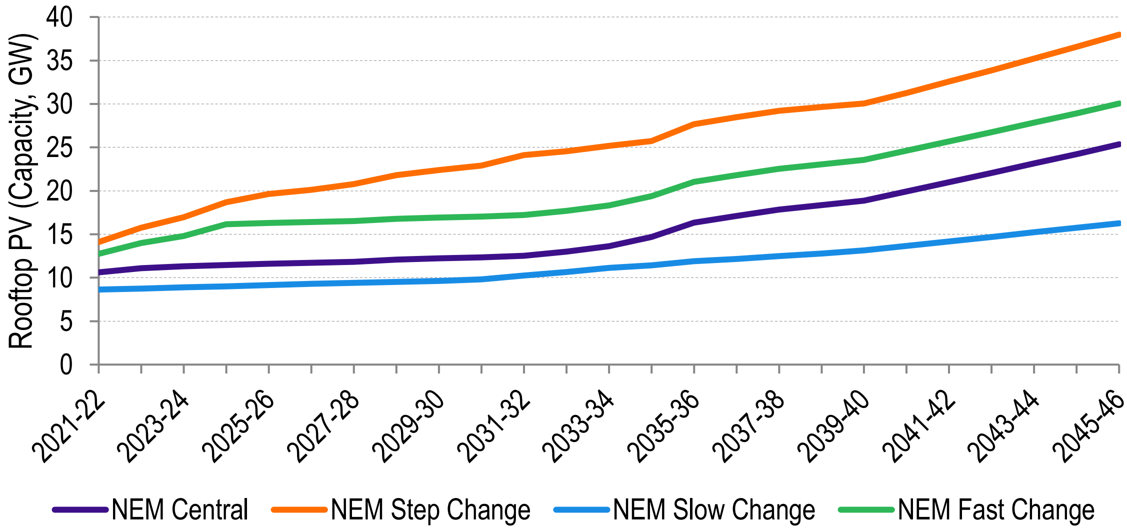
Figure 2: Annual operational demand for all scenarios from AEMO's 2019 Input and Assumptions workbook[42]



[41] 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 12 May 2021.

[42] AEMO, 30 July 2020, *2019 Input and Assumptions workbook v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 18 December 2020.

Figure 3: Annual rooftop PV uptake in all scenario from AEMO's 2019 Input and Assumptions workbook[42]



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.

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[43], 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 10. These projects are anonymised in our modelling.

Table 10: Additional capacity anticipated by TransGrid by 2022

Region	Zone	Solar capacity (MW)	Wind capacity (MW)
NSW	NNS	310	0
	NCEN	700	160
	CAN (Yass)	0	333
	SWNSW	22	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 11 and explained further in this section of the Report.

Table 11: 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[44] 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.	

[43] AEMO, 30 July 2020, *2019 Input and Assumptions workbook v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 18 December 2020.

[44] 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 18 December 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 concurrent 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 1.

The availability profiles for wind generation are derived from simulated wind speeds from the Australian Bureau of Meteorology's Numerical Weather Prediction systems[45] 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[46] for each REZ (new entrant wind farms, as listed in Table 12).

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 12).

Table 12: REZ wind and solar approximate average capacity factors over nine reference years[47]

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%

[45] 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 12 May 2021.

[46] 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 18 December 2020.

[47] AEMO, 30 July 2020, *2019 Input and Assumptions workbook v1.5.* Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 18 December 2020.

Region	REZ	Wind		Solar SAT
		High quality	Medium quality	
Queensland (cont.)	Fitzroy	42%	36%	29%
	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[48]	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

[48] Gippsland has an option for offshore wind with average capacity factors of 42% and 41% for high and medium quality, respectively.

Wind and solar capacity expansion in each REZ is limited by three parameters based on AEMO's 2019 Input and Assumptions workbook[49].

- Transmission-limited total build limit (MW) representing the amount of capacity supported by current intra-regional transmission infrastructure.
- A transmission expansion cost ($/MW) representing an indicative linear network expansion cost to develop a REZ beyond current capabilities and connect the REZ to the nearest major load centre.
- Resource limits (MW) representing the maximum amount of capacity expected to be feasibly developed in a REZ based on topography, land use etc.

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[49] 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 13 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[49].

Table 13: Coal-fired power station full forced outage rates

Generator	AEMO September ISP 2020 Assumptions full forced outage rate[49]	EY 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%

[49] AEMO, 30 July 2020, *2019 Input and Assumptions workbook v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 18 December 2020.

Generator	AEMO September ISP 2020 Assumptions full forced outage rate[49]	EY full forced outage rate applied in modelling in this Report
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[50]. This records dispatch level at the start of each half-hourly trading interval for each DUID[51]. 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[52]. Station average outage rates are computed as the average across units in each station. The planned maintenance rate of 20 days per unit[53] is then subtracted to estimate full forced outage rates for each station[54].

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[55].

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.

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[50] Market Data NEMWEB, *Daily trading interval data, INITIALMW*. Available at: http://nemweb.com.au/Reports/CURRENT/Daily_Reports/. Accessed 18 December 2020.

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

[52] 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.

[53] AEMO, 30 July 2020, *2019 Input and Assumptions workbook v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 18 December 2020.

[54] 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.

[55] 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 18 December 2020.

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[53], maximum loads vary seasonally. This materially reduces the amount of available capacity in the summer periods.

6.3.2 Gas-fired generators

Existing OCGTs and CCGTs are modelled in line with the AEMO 2019 Input and Assumptions workbook[56]. 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 are able to be 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[56]. The Tasmanian hydro schemes were modelled using a simplified six pond model.

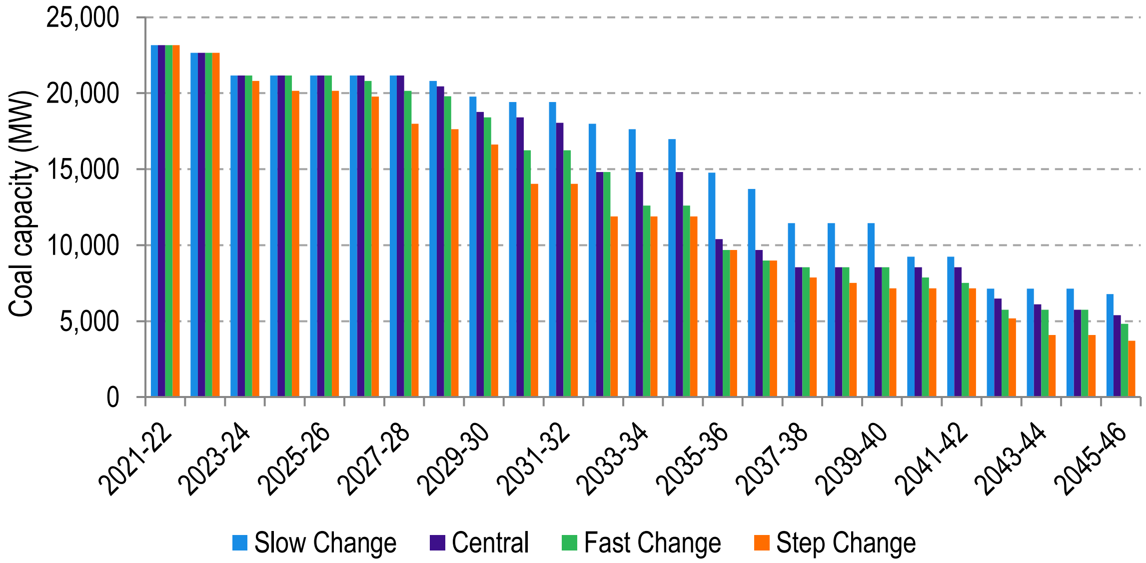
6.4 Retirements

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[57]. Coal retirements in all scenarios modelled are illustrated in Figure 4. For the Step Change, Fast Change and Slow Change scenarios, TransGrid elected to assume the retirement of half of coal generation five years earlier, two years earlier and five years later than the Central scenario, respectively.

[56] AEMO, 30 July 2020, *2019 Input and Assumptions workbook v1.5.* Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 18 December 2020.

[57] AEMO, 30 July 2020, *Generating Unit Expected Closure Year - July 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 18 December 2020.

Figure 4: Coal capacity in the NEM by year in the all scenarios

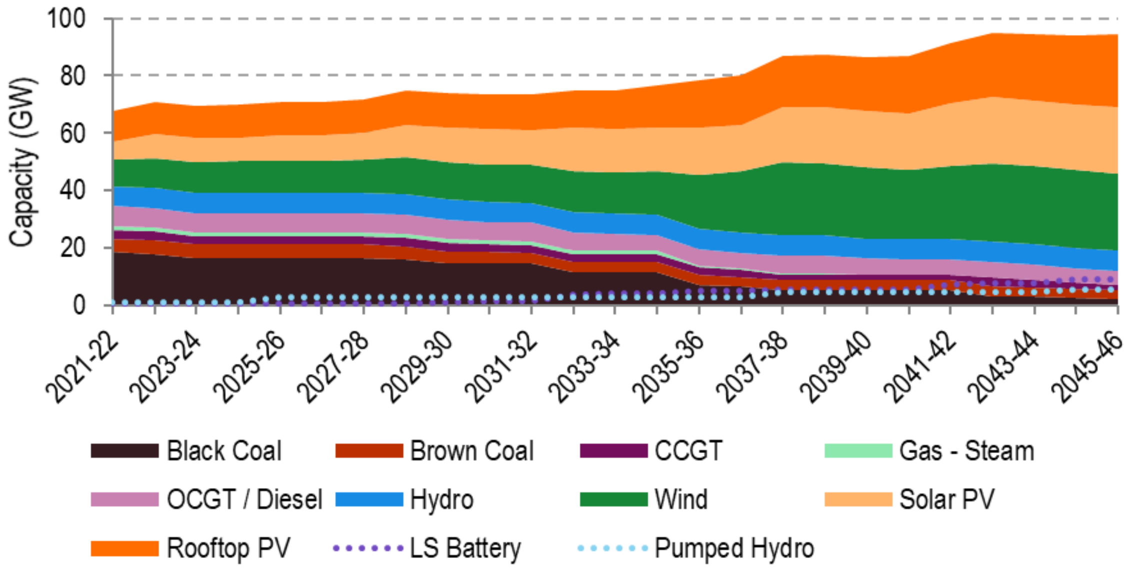


7. NEM outlooks in the Base Case

Before considering the forecast 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 in the Central scenario is shown in Figure 5. The forecast generation capacity of the NEM gradually shifts towards increasing capacity of wind, solar, pumped hydro and LS Battery.

Figure 5: NEM capacity mix forecast for the Base Case in the Central scenario



The first new capacity forecast to be installed by the model as part of the least-cost development plan is approximately 900 MW of new solar capacity in Central West NSW in 2022-23, followed by wind and solar build in Victoria and Queensland in the mid to late 2020s to meet the states' renewable energy targets and also to replace Callide B, which is assumed to retire in 2028. Thereafter, major new solar and wind builds occur when coal fired power stations are assumed to retire in the 2030s and 2040s. Overall, the NEM capacity including pumped hydro and LS Battery capacities is forecast to be around 109 GW by 2045-46, where the highest share belongs to wind and solar, followed by LS Battery, pumped hydro, hydro, gas and coal.

Figure 6, Figure 7 and Figure 8 present the capacity difference of the Step Change, Fast Change and Slow Change scenarios relative to the Central scenario, respectively. It is seen that by the final year of the study, the Step Change scenario requires significantly higher wind and solar as well as additional pumped hydro build compared to the Central scenario. The higher build starts as soon as 2021-22, while it reaches around 20 GW by 2030. In addition, it is seen that LS Battery build is brought forward to the late 2020s in the Step Change scenario. Note that the coal generation capacity difference is due to the assumption of retiring half of the coal fired power stations five years earlier in the Step Change scenario.

The capacity mix in the Fast Change scenario has only small differences to the Central scenario up to 2030. Post 2030, up to 10 GW more wind and solar, plus additional PSH capacity is required. Differences in coal generation capacity are a result of the assumption of retiring half of the coal fired power stations two years earlier in the Fast Change scenario.

The Slow Change capacity mix is similar to the Central scenario in the 2020s, while it requires significantly less wind and solar than the Central scenario from the 2030s onwards. Again, the coal generation capacity difference is due to the assumption of retiring half of the coal fired generators five years later in the Slow Change scenario.

Figure 6: NEM capacity mix forecast for the Base Case – difference between the Step Change and Central scenarios (excluding rooftop PV)

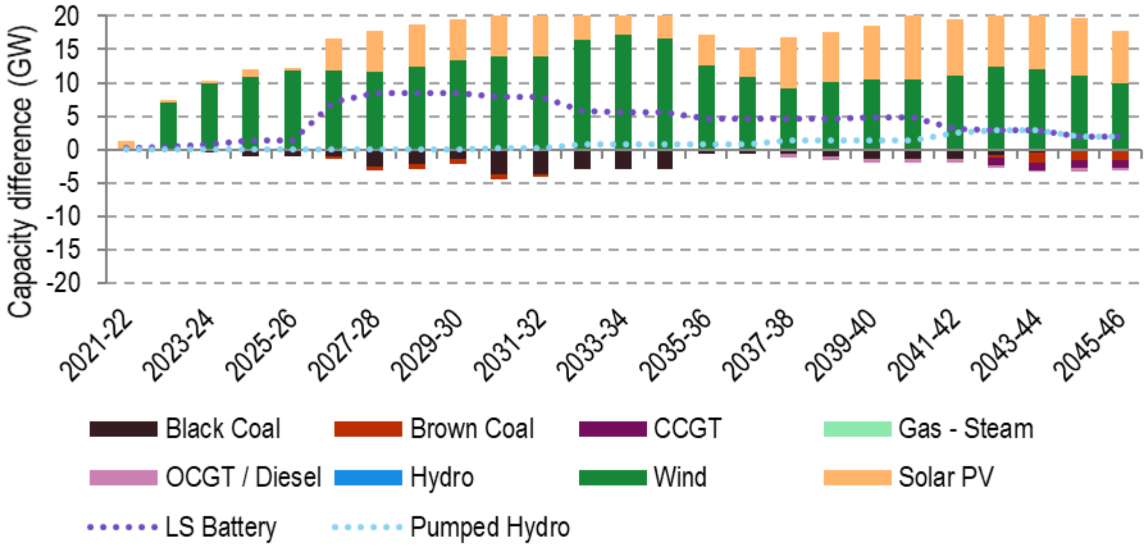


Figure 7: NEM capacity mix forecast for the Base Case – difference between the Fast Change and Central scenarios (excluding rooftop PV)

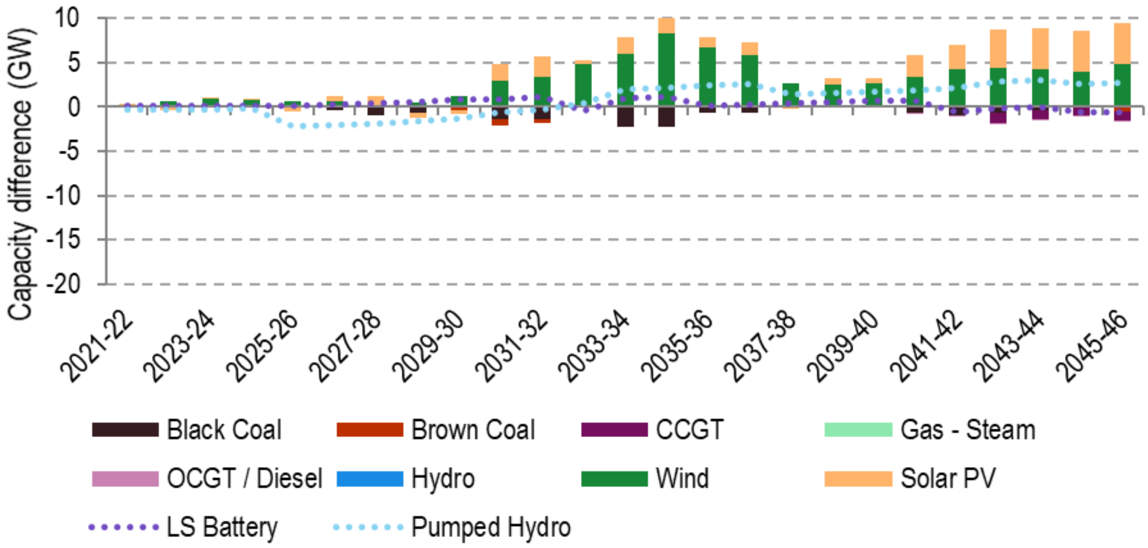


Figure 8: NEM capacity mix forecast for the Base Case – difference between the Slow Change and Central scenarios (excluding rooftop PV)

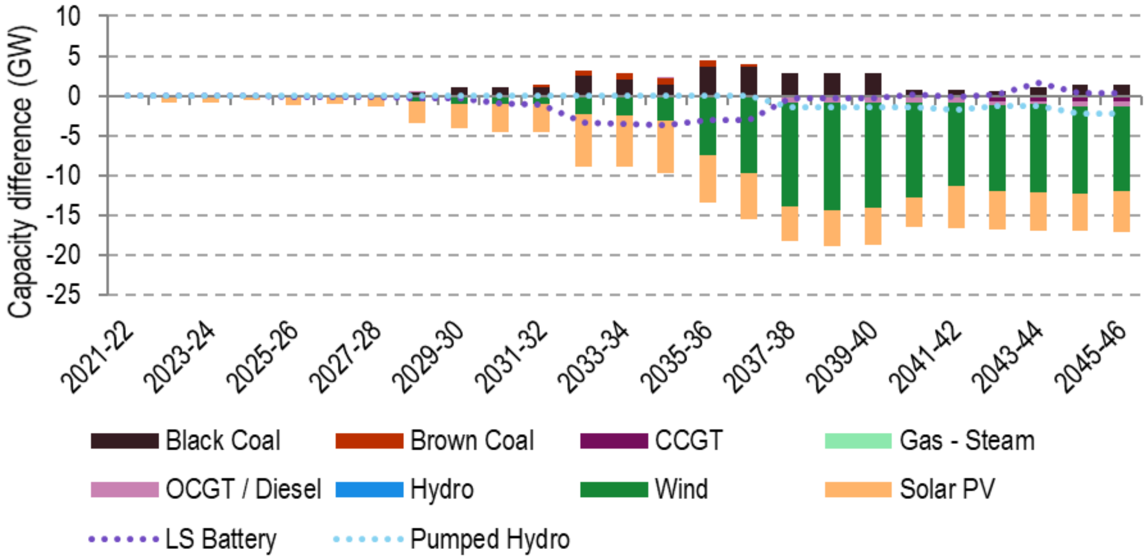
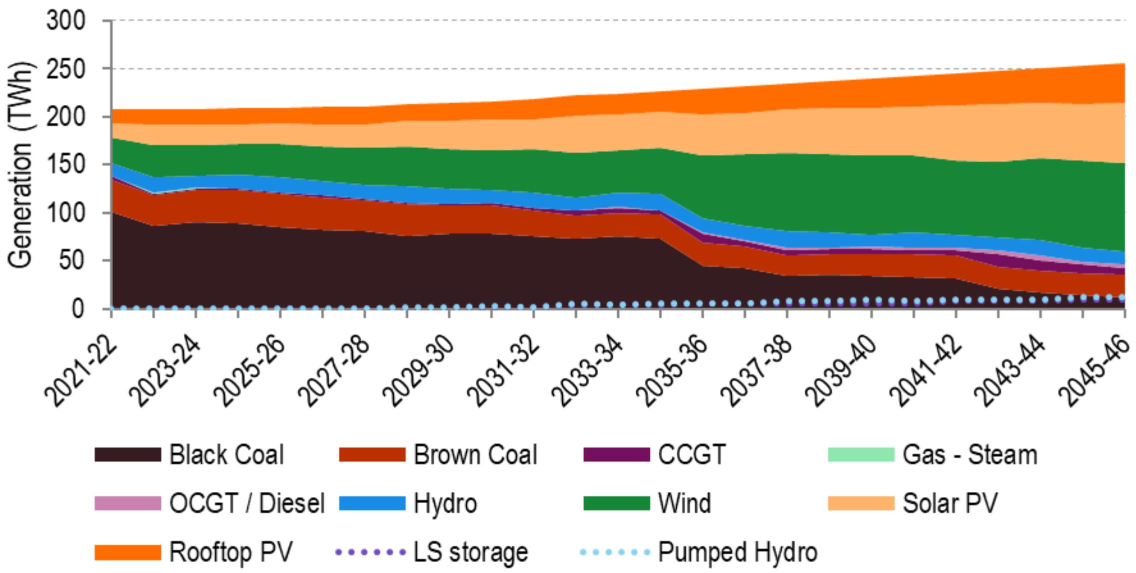


Figure 9 shows the energy generated in the Base Case in the Central scenario. Note that all the generation charts in the Report are on an "as-generated" basis. The energy generated gradually increases throughout the modelling period due to the modest growth of the AEMO 2020 ISP Central demand assumed in this scenario. The forecast cost of operating solar and wind generation 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 the minimum reserve requirements. OCGT and CCGT capacity and generation production levels are influenced by the assumed minimum load of new CCGTs and no minimum load requirement of new OCGTs, in accordance with specifications for new generation of both types.

Figure 9: NEM generation mix forecast for the Base Case in the Central scenario



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 coal capacity assumed to retire.

Figure 10 shows the generation difference between the Step Change and Central scenarios. Significantly lower coal generation is expected, replaced with wind and solar from the first year of study. A key reason behind this trend is the ISP assumption of a carbon budget in the Step Change scenario.

Figure 10: NEM generation mix forecast for the Base Case – difference between the Step Change and Central scenarios

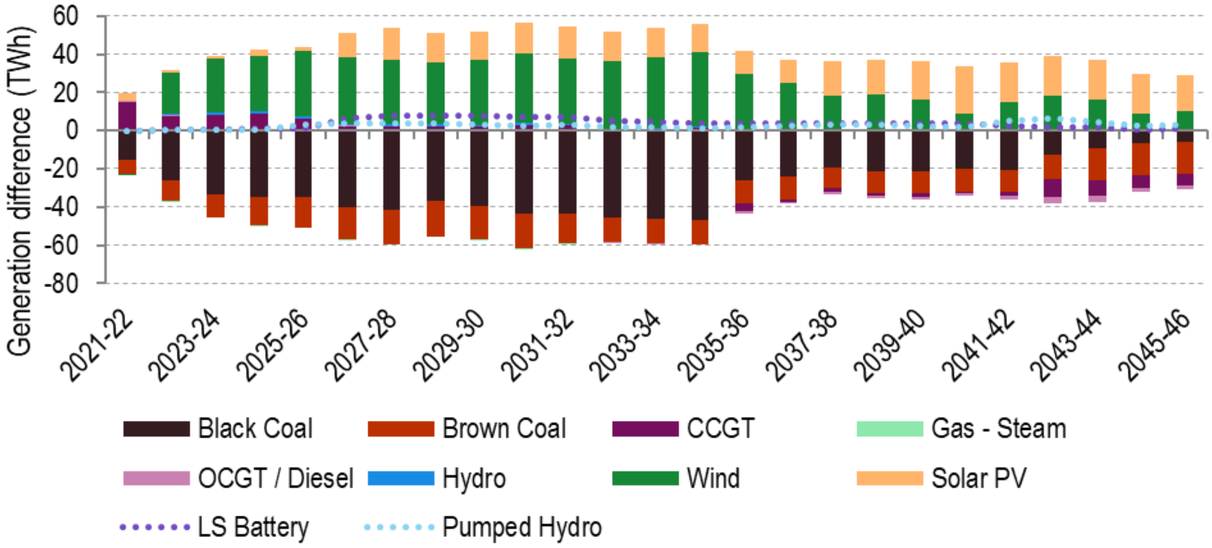


Figure 11 shows the generation difference between the Fast Change and Central scenarios. Similar to the Step Change scenario, black and brown coal generation is offset by generation from wind and solar, however due to a larger carbon budget allowance compared to Step Change, this offset is to a lesser extent.

Figure 11: NEM generation mix forecast for the Base Case – difference between the Fast Change and Central scenarios

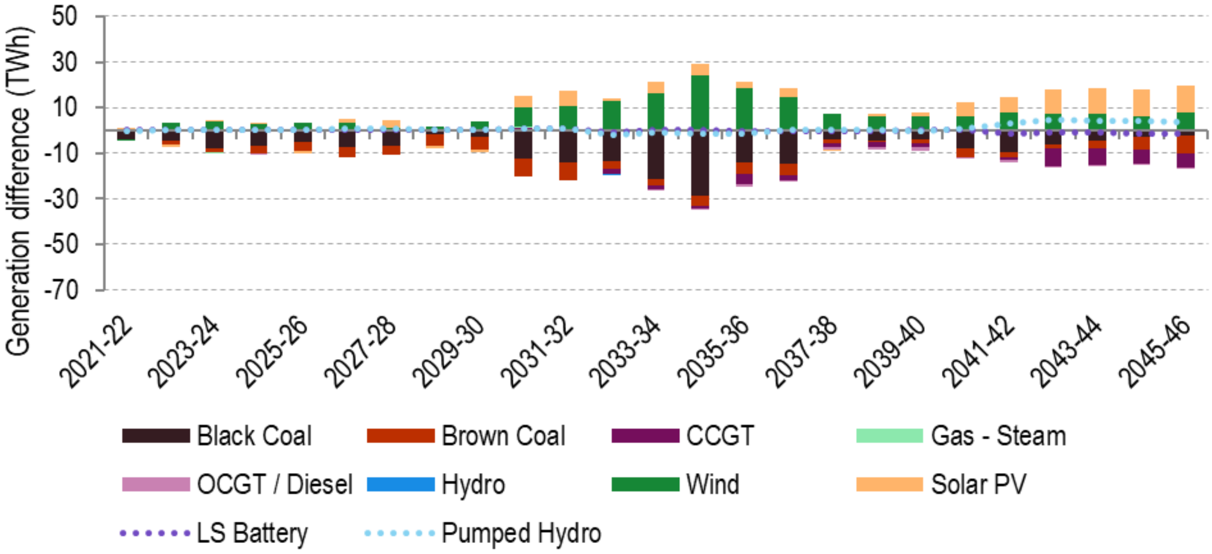
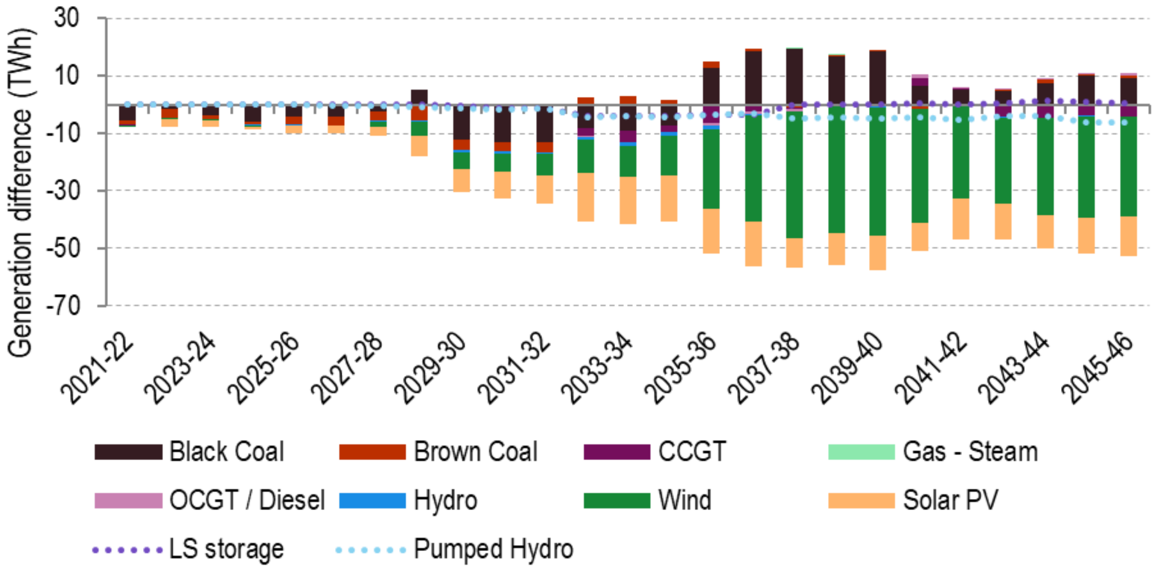


Figure 12 shows the generation difference between the Slow Change and Central scenarios. Lower energy consumption in the Slow Change scenario is the key driver for lower generation from coal as well as wind and solar in 2020s and early 2030s. From the mid-2030s, deferred coal retirement is forecast to result in higher coal generation in the Slow Change scenario and significantly lower solar and wind generation in this scenario compared to the Central scenario.

Figure 12: NEM generation mix forecast for the Base Case – difference between the Slow Change and Central scenarios



8. Forecast gross market benefit outcomes

8.1 Summary of forecast gross market benefits

Table 14 shows the forecast gross market benefits over the modelled 25-year horizon for all options across all scenarios. TransGrid has concluded that Option 1 (Option 1A) is the preferred option based on the forecast net benefits after incorporating forecast gross market benefits and assumed development costs of the option[2]. Option 4 is expected to have the highest forecast gross market benefit (note that TransGrid instructed EY to remove the forecast gross market benefits for Option 4 as well as Option 5 from the public report due to confidentiality), whereas the gross market benefits of Option 3 are forecast to be the lowest, being around $26m, $51m, $39m and $28m for those scenarios. Option 1, TransGrid's preferred option, is forecast to achieve gross market benefits of approximately $102m, $326m, $181m and $191m in the Central, Step Change, Fast Change and Slow Change scenarios, respectively.

Table 14: Summary of forecast gross market benefits, millions real June 2019 dollars discounted to June 2020 dollars

Option	Description	Timing	Potential gross market benefits ($m)			
			Central	Step Change	Fast Change	Slow Change
Option 1	A new 330 kV line between Darlington Point and Dinawan	1/12/2024	101.73	325.73	180.94	190.69
Option 2	A new 330 kV line between Darlington Point and Wagga	1/12/2024	110.16	348.72	195.62	201.22
Option 3	STATCOM	1/12/2023	25.68	51.16	38.64	28.14
Option 4	Option 1 with interim battery from January 2022 which provides network support until Option 1 is commissioned	1/01/2022	Confidential - removed from public report	Confidential - removed from public report	Confidential - removed from public report	Confidential - removed from public report
Option 5	A standalone battery	2022	Confidential - removed from public report	Confidential - removed from public report	Confidential - removed from public report	Confidential - removed from public report

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

8.2 Market modelling results for Option 1

8.2.1 Central scenario

This section summarises market modelling results for Option 1 for the Central scenario.

The forecast cumulative gross market benefits for Option 1 are shown in Figure 13, indicating that the total forecast gross market benefit reaches just under $102m by the end of the study period. Furthermore, the differences in capacity and generation outlook across the NEM between Option 1 and the Base Case are shown in Figure 14 and Figure 15, respectively.

Figure 13: Forecast cumulative gross market benefit[58,59] for Option 1 in the Central scenario, millions real June 2019 dollars discounted to June 2020 dollars

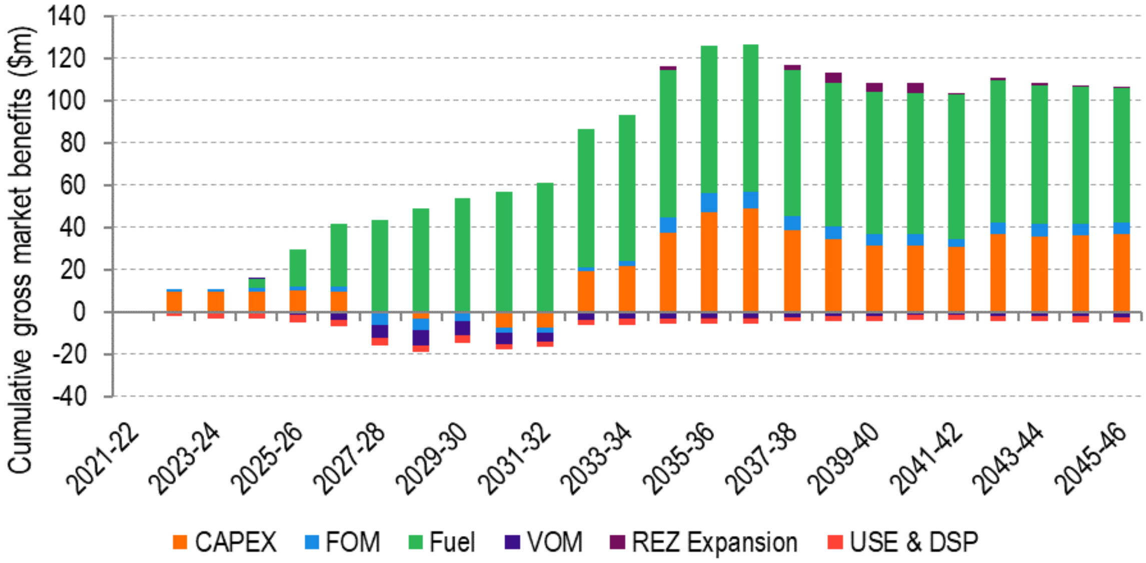
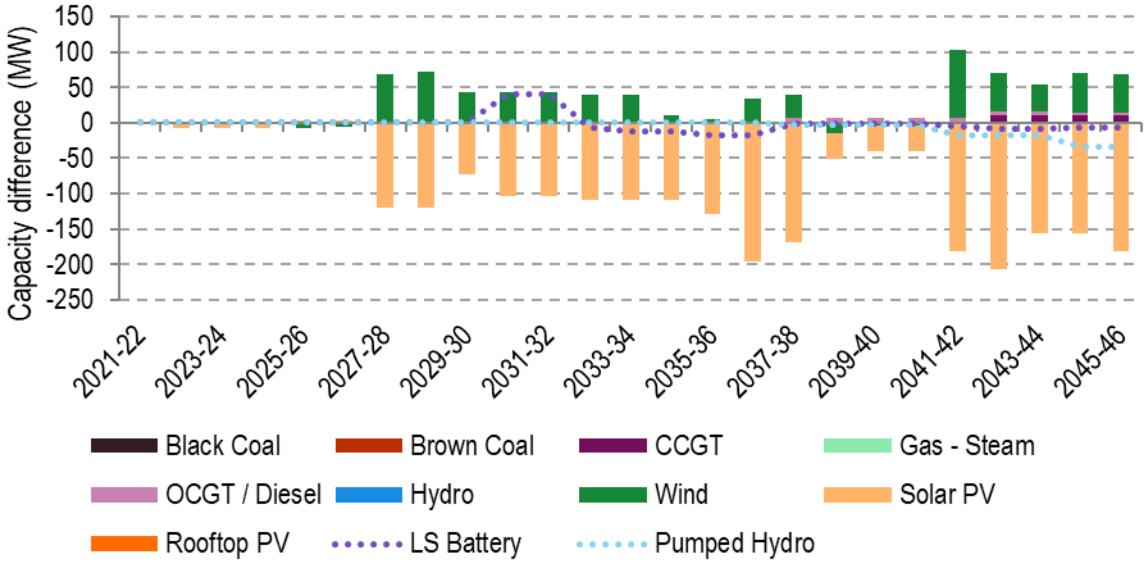


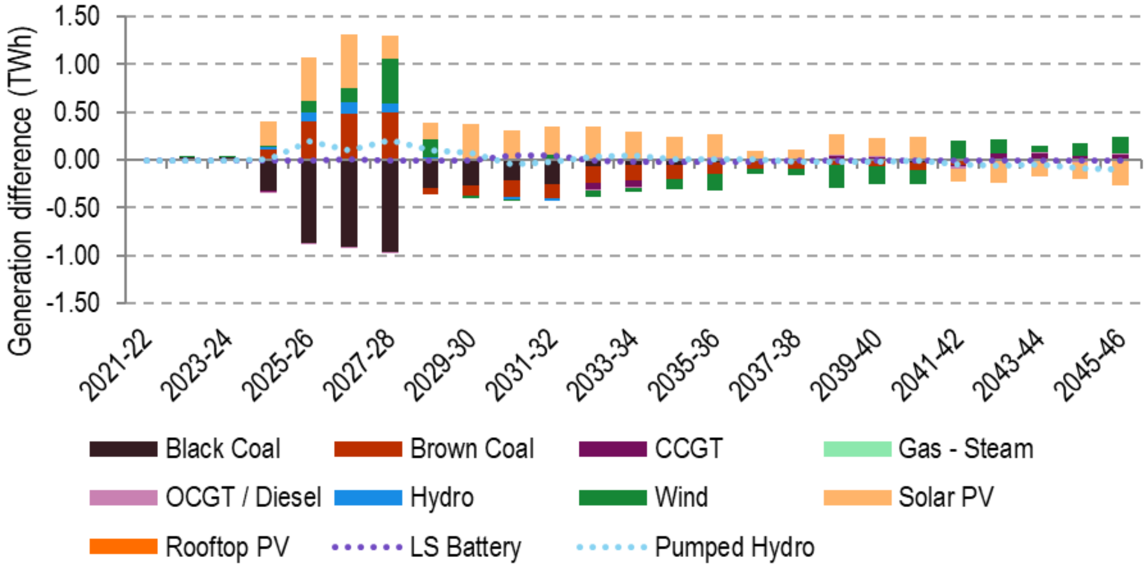
Figure 14: Difference in NEM capacity forecast between Option 1 and Base Case in the Central scenario



[58] 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.

[59] Since this figure shows the cumulative forecast gross market benefits in present value terms, the height of the bar in 2045-46 equates to the gross benefits for Option 1 shown in Table 14.

Figure 15: Difference in NEM generation forecast between Option 1 and Base Case in the Central scenario



The primary sources of forecast gross market benefits in Option 1 are from fuel cost savings and avoided and deferred capex for new generators. The timing and source of these benefits are attributable to the following:

- A small capex saving is forecast from 2022-23 due to deferred capacity for a few years. However, the major capex saving occurs around the mid-2030s and remains stable at just under $37m until the last year of the study.
- The reduced capex in Option 1 is mainly due to solar deferral and avoidance, where at the end of the study around 180 MW solar build is avoided, although approximately 55 MW more wind is forecast to be built in this option. Approximately 120 MW of solar build is forecast to be avoided in the SWNSW REZ and approximately 15 MW in Darling Downs as well as 40 MW wind in South West Victoria, while around 50 MW of solar are forecast to be replaced with wind in Central North Victoria in this option. It is also forecast that approximately 130 MW solar and REZ transmission build in Central West Orana is deferred from the late 2030s to the early 2040s, while a forecast deferral of around 130 MW solar build in Wagga Wagga REZ from 2032-33 to the late 2030s is expected. On the other hand, up to around 160 MW solar build in Riverland REZ is brought forward from the early 2040s to the early-mid 2030s.
- Fuel cost savings are expected to accumulate as soon as Option 1 is in place and increase until the mid-2030s. Thereafter, no more fuel cost saving is expected which results in approximately $64m overall fuel cost saving.
- The reduced fuel cost is mainly due to reduced black coal generation in the early years, although more brown coal generation is expected in Option 1 due to opening of the transfer limit from VIC and SWNSW to NSW load centres. Fuel cost savings are expected to diminish in the mid-2030s when major black coal power plants in NSW and QLD are assumed to retire.
- There is a forecast for a small FOM saving but a small VOM and DSP & USE cost in Option 1, as compared to the Base Case.

8.2.2 Step Change scenario

This section summarises market modelling results for Option 1 for the Step Change scenario.

The forecast cumulative gross market benefits for Option 1 are shown in Figure 16, indicating that the total forecast gross market benefit reaches approximately $326m by the end of the study period. Furthermore, the differences in capacity and generation outlook across the NEM between Option 1 and the Base Case are shown in Figure 17 and Figure 18, respectively.

Figure 16: Forecast cumulative gross market benefit[60,61] for Option 1 in the Step Change scenario, millions real June 2019 dollars discounted to June 2020 dollars

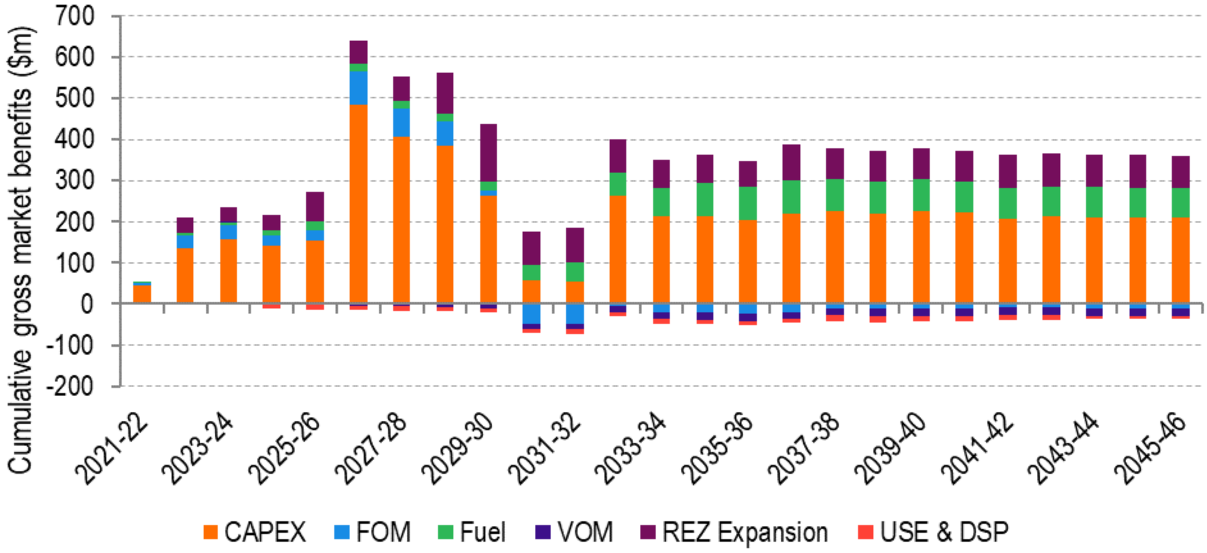
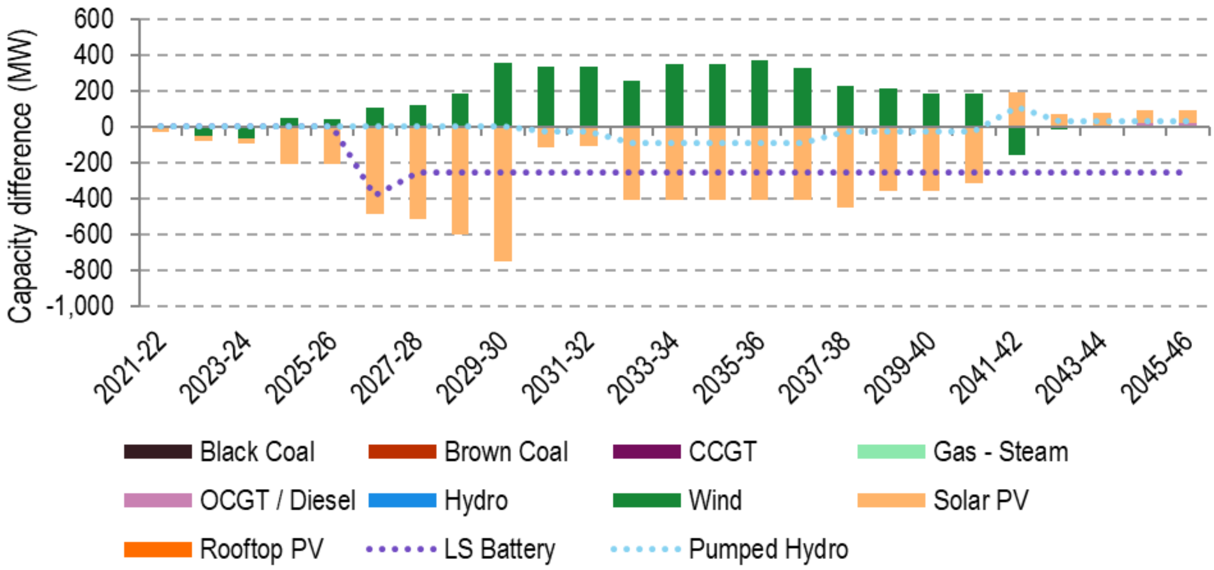


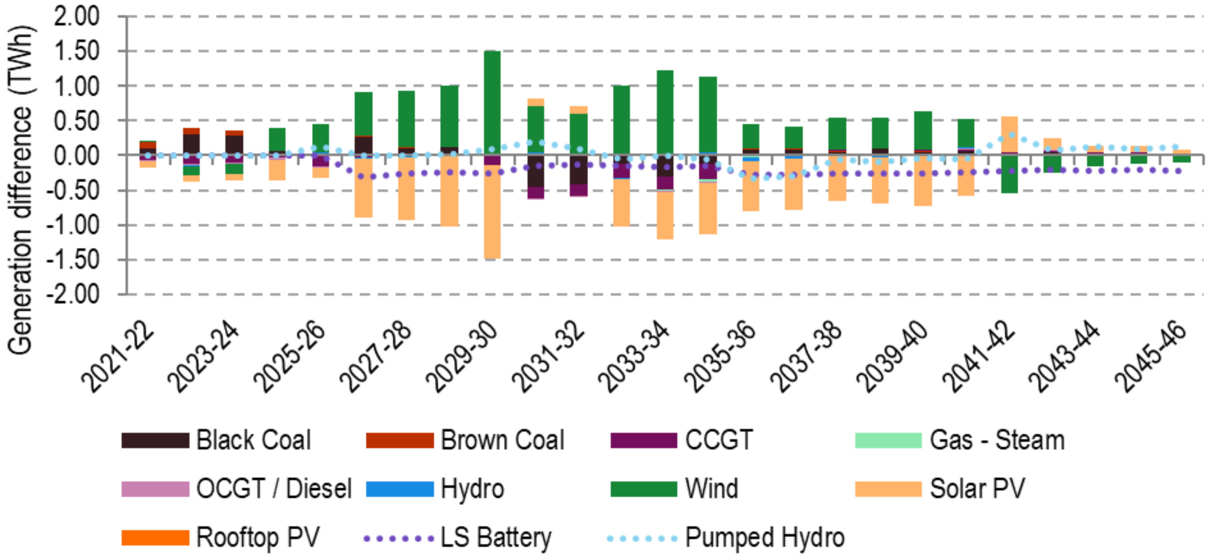
Figure 17: Difference in NEM capacity forecast between Option 1 and Base Case in the Step Change scenario



60 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.

61 Since this figure shows the cumulative forecast gross market benefits in present value terms, the height of the bar in 2045-46 equates to the gross benefits for Option 1 shown in Table 14.

Figure 18: Difference in NEM generation forecast between Option 1 and Base Case in the Step Change scenario



The primary sources of forecast gross market benefits in Option 1 are from avoided and deferred capex for new generators as well as REZ transmission expansion and fuel cost savings. The timing and source of these benefits are attributable to the following:

- The capex saving is expected to start from 2021-22 and increases up to around $485m in 2026-27. The capex saving is then expected to reduce to its lowest point in the early 2030s, followed by a small increase and then levelling off to approximately $210m until the end of the study period.
- It is forecast that up to 350 MW of additional wind will be built earlier in Option 1 in the mid-2030s. On the other hand, solar build is expected to be deferred from 2024-25 until the early 2040s, when slightly more solar is expected to be built. By the end of the study, it is expected that around 35 MW more solar will be built in Option 1. The model forecasts approximately 255 MW battery build avoidance from the mid-2020s, but around 35 MW more pumped hydro build from 2041-42.
- The REZ expansion saving is expected to begin at approximately $36m in 2022-23, mainly due to the deferral of REZ transmission build in Central West Orana, reaching its peak in 2029-30. In the early to mid-2030s, REZ expansion saving is forecast to be due to the deferral of REZ transmission build in Leigh Creek, New England, Darling Downs and Far North Queensland. By the end of the study period this option avoids 20 MW of REZ transmission expansion in Wagga Wagga, 45 MW in Broken Hill and 185 MW in Far North Queensland due to avoided wind and solar build in those REZs. In addition, without any change of transmission upgrade cost, 145 MW of solar is forecast to be avoided in Roxby Downs, as well as 175 MW of Wind in Gippsland while 400 MW additional solar and 200 MW of additional wind build are forecast in SWNSW.
- The fuel cost saving is forecast to accrue from the beginning of the study and continue to increase to the mid-2030s which then levels off to $73m by the end of the study period.
- The reduced fuel cost is mainly due to reduced CCGT and black coal generation in the 2030s, although Option 1 is forecast to generate more black coal in the early years of the study.

Other smaller sources of forecast benefits in the Step Change scenario are as follows.

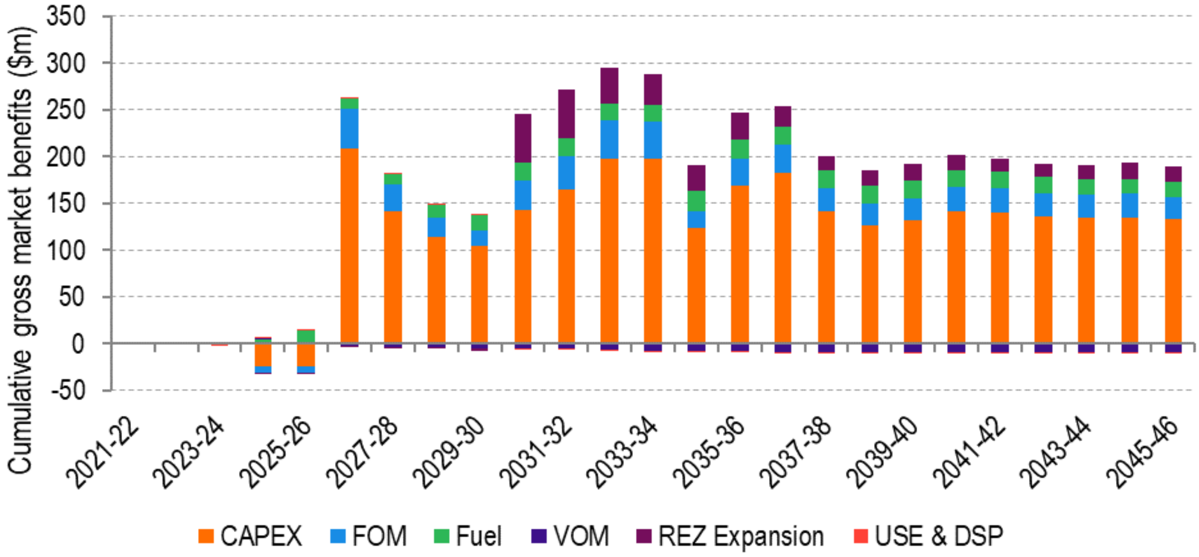
- Approximately $7m USE and DSP costs are forecast in Option 1.
- The VOM is expected to be higher by around $19m in Option 1.
- A small cost of $9.6m is forecast to be obtained from FOM.

8.2.3 Fast Change scenario

This section summarises market modelling results for Option 1 for the Fast Change scenario.

The forecast cumulative market benefits for Option 1 in the Fast Change scenario are shown in Figure 19, indicating that the total forecast gross market benefit reaches $181m by 2045-46. Furthermore, the differences in capacity and generation outlook across the NEM between Option 1 and the Base Case are shown in Figure 20 and Figure 21, respectively.

Figure 19: Forecast cumulative gross market benefit[62,63] for Option 1 in the Fast Change scenario, millions real June 2019 dollars discounted to June 2020 dollars



[62] 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.

[63] Since this figure shows the cumulative forecast gross market benefits in present value terms, the height of the bar in 2045-46 equates to the gross benefits for Option 1 shown in Table 14.

Figure 20: Difference in NEM capacity forecast between Option 1 and Base Case in the Fast Change scenario

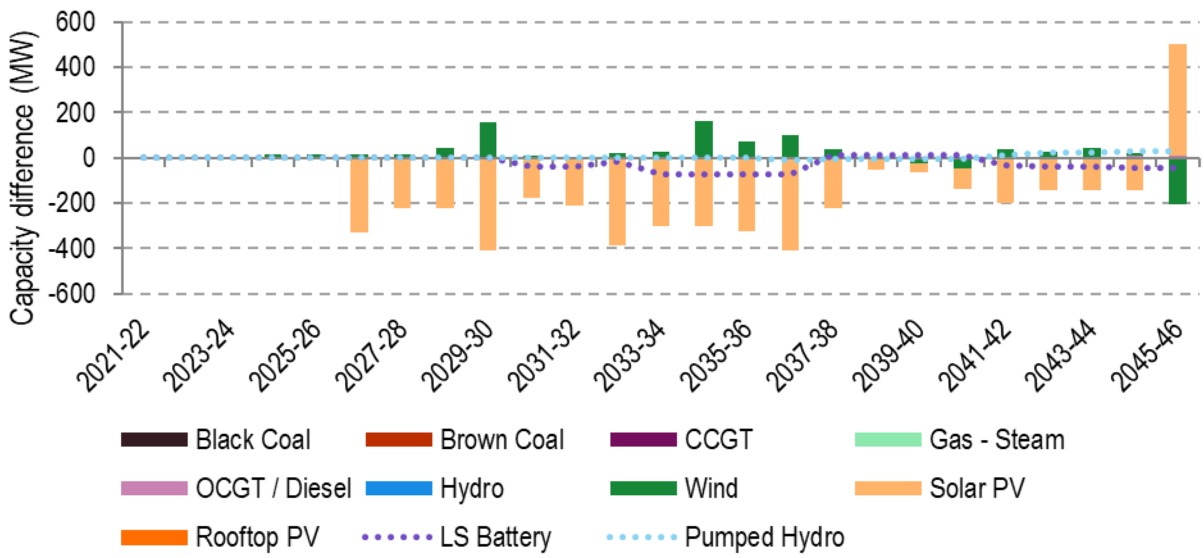
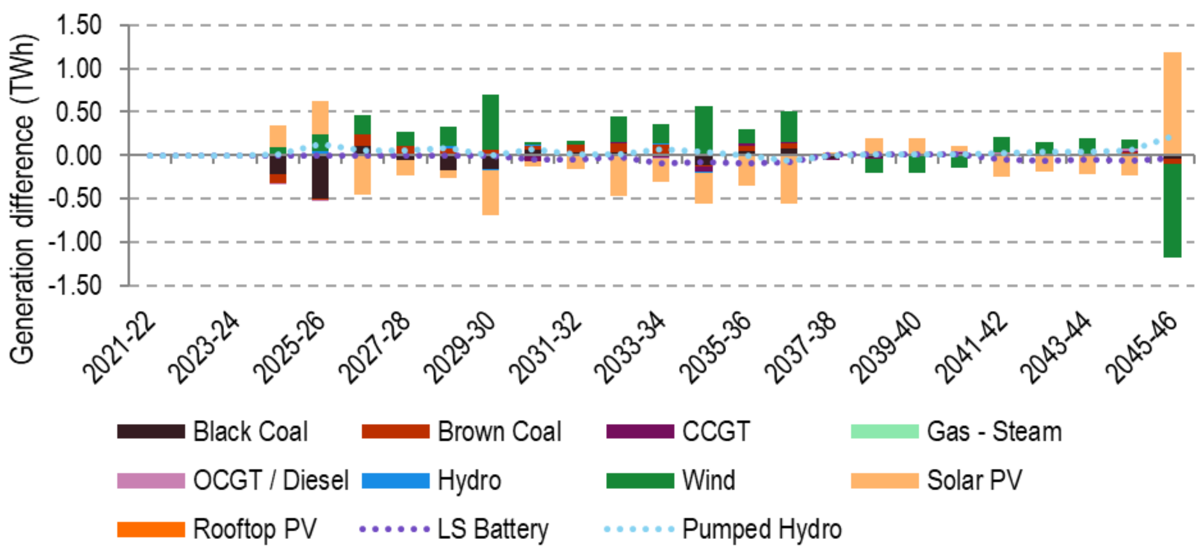


Figure 21: Difference in NEM generation forecast between Option 1 and Base Case in the Fast Change scenario



The primary sources of forecast gross market benefits in Option 1 are from avoided and deferred capex for new generators followed by REZ transmission expansion, fuel and FOM savings in equal shares. The timing and source of these benefits are attributable to the following:

- In 2024-25 and 2025-26 capex cost is forecast to accrue due to the earlier build of small wind capacity. However, the additional cost is offset in the following year by capex savings when the build of 330 MW of solar capacity is deferred. Capex benefits decrease over the next two years as some of the deferred solar capacity is forecast to be built. In 2029-30 capex benefits is forecast to reach their minimum at $105m, when 155 MW wind build is brought forward by one year. A similar decline in benefits is seen in 2034-35 to $125m, but in the long term it is relatively stable at $135m.
- REZ expansion benefits are forecast to accrue from 2030-31, mainly due to the deferral of REZ transmission build in Central West Orana. Over time, these benefits reduce to around $17m as the deferred capacity is expected to be built.
- Fuel cost savings are forecast from 2024-25 and continue to increase to the mid-2030s to $16m and continuing at that level to the end of the study period.

- The reduced fuel cost is mainly due to a decrease in black and brown coal generation in the earlier years, and CCGT generation in the early to the mid-2030s, but then reducing in the long term due to increased CCGT and OCGT generation compared to the Base Case.

Other smaller sources of forecast benefits in the Fast Change scenario are as follows.

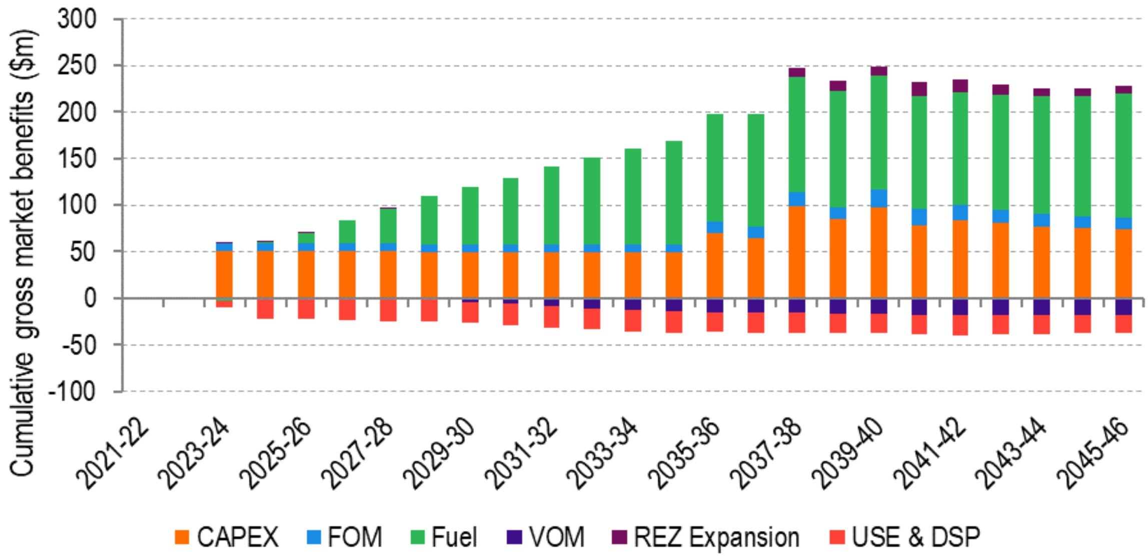
- Approximately $1m USE and DSP costs are forecast in Option 1.
- The VOM is expected to be higher by around $9m in Option 1.

8.2.4 Slow Change scenario

This section summarises market modelling results for Option 1 for the Slow Change scenario.

The forecast cumulative gross market benefits for Option 1 are shown in Figure 22, indicating that the total forecast gross market benefit reaches $190.7m by the end of the study period. Furthermore, the differences in capacity and generation outlook across the NEM between Option 1 and the Base Case are shown in Figure 23 and Figure 24, respectively.

Figure 22: Forecast cumulative gross market benefit[64,65] for Option 1 in the Slow Change scenario, millions real June 2019 dollars discounted to June 2020 dollars



[64] 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.

[65] Since this figure shows the cumulative forecast gross market benefits in present value terms, the height of the bar in 2045-46 equates to the gross benefits for Option 1 shown in Table 14.

Figure 23: Difference in NEM capacity forecast between Option 1 and Base Case in the Slow Change scenario

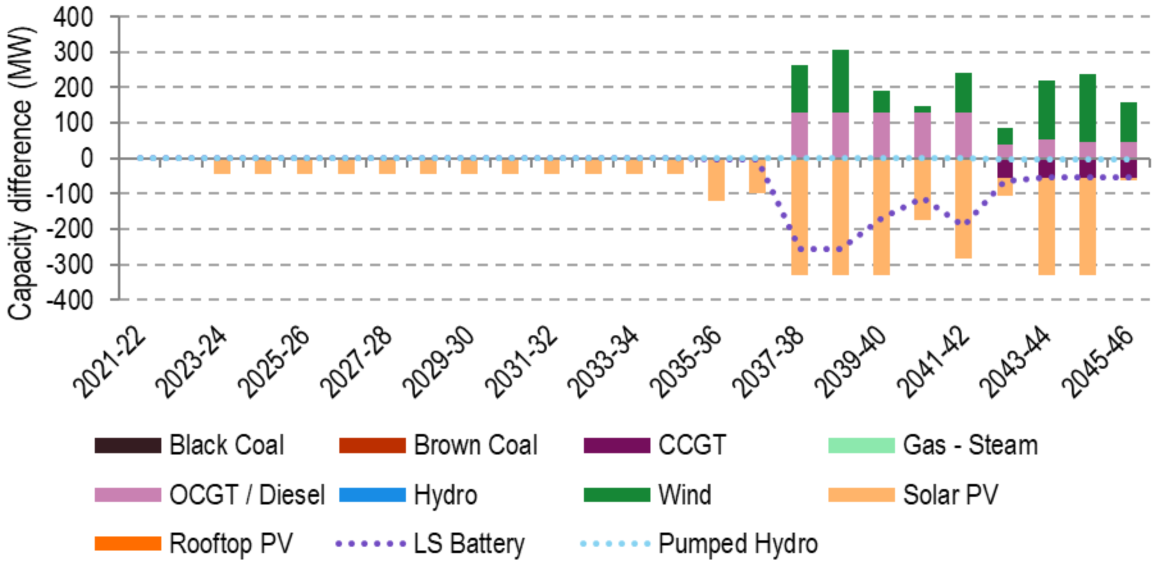
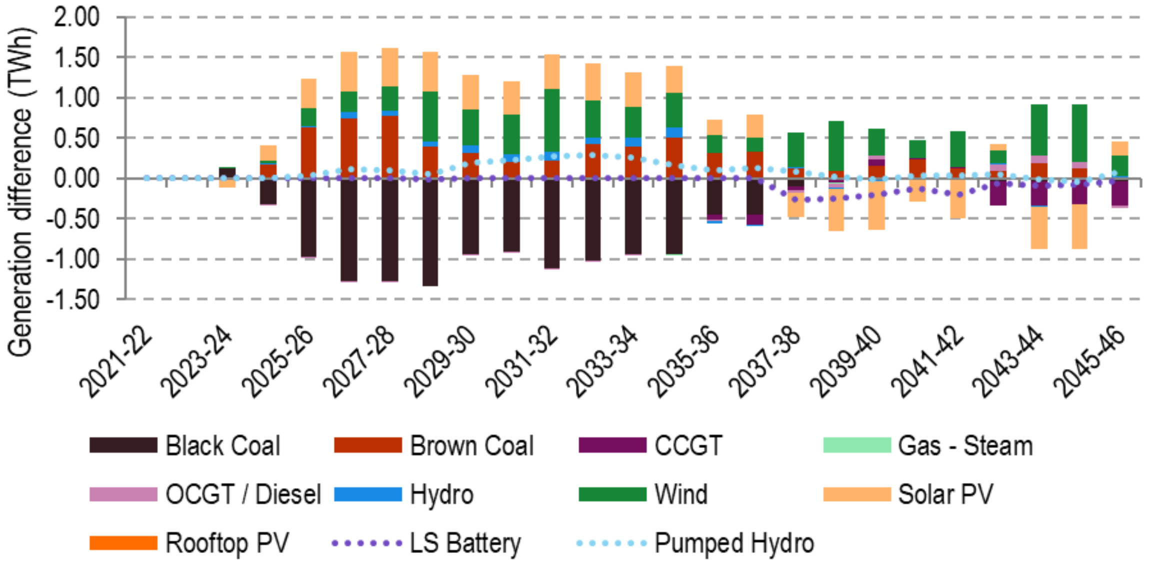


Figure 24: Difference in NEM generation forecast between Option 1 and Base Case in the Slow Change scenario



The primary sources of forecast gross market benefits in Option 1 are from fuel cost savings and avoided and deferred capex for new generators. The timing and source of these benefits are attributable to the following:

- A capex saving of approximately $50m is expected from 2023-24 due to approximately 40 MW of deferred solar capacity. The capex saving is then forecast to reach its highest point of approximately $99m in 2037-38, followed by a reduction to $74.5m in the last year of the study.
- The reduced capex in Option 1 is mainly due to solar deferral. From 2037-38, solar build deferral increases, in addition to around 260 MW battery capacity being forecast to be deferred in the same year. However, it is expected that more wind and OCGT capacity is built in Option 1 in this year. By the last year of the study, it is forecast that Option 1 will require around 110 MW more wind and 47 MW more OCGT, but with the avoidance of around 50 MW CCGT and 50 MW battery development. In this scenario, 145 MW of additional wind is forecast to be built in Yorke Peninsula, incurring REZ transmission expansion cost. The option also defers solar and REZ transmission build in

Central West Orana. It is forecast that around 400 MW solar build in Wagga Wagga is deferred from 2037-38 to 2040-41. However, wind and solar builds are brought forward in Mid-North SA, Riverland, South East South Australia and Roxby Downs from the late 2030s and early 2040s to the early-mid 2030s.

- Fuel cost savings are expected to accumulate from 2025-26 and increase throughout the study period, reaching just above $134m in 2045-46.
- The reduced fuel cost is mainly due to reduced black coal generation in the early years until the late 2030s, although more brown coal generation is expected in Option 1 due to the opening of the transfer limit from VIC and SWNSW to NSW load centres. A small fuel cost saving from CCGT generation is also expected in the later years of the modelling.

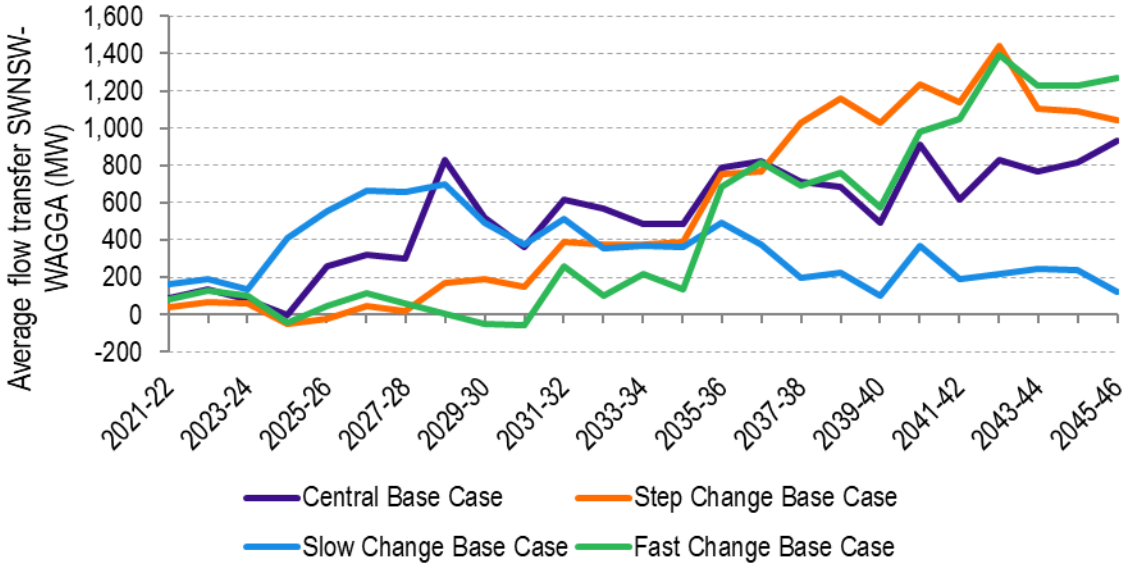
Other smaller sources of forecast benefits are as follows.

- Approximately $19.4m USE and DSP costs are forecast in Option 1.
- The VOM is expected to be higher in Option 1 by around $18.4m.
- A small benefit of $11.8m is forecast to be obtained from the FOM saving.
- A small benefit of $8m is forecast to be obtained from the REZ expansion saving.

8.2.5 SWNSW to WAGGA flow

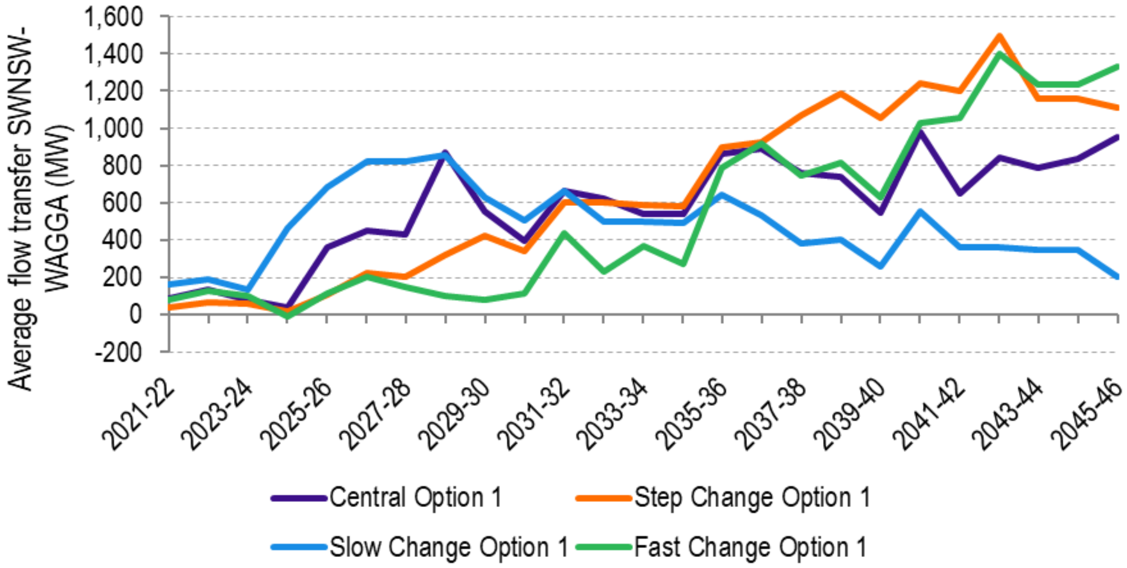
This section summarises the outcomes for the flows from SWNSW to Wagga. Figure 25 shows this flow on an annual average basis for the Base Case in all scenarios. It is seen that except in the Slow Change scenario, the flow has an increasing trend over the study period. The Slow Change scenario has high flows in the early years as soon as EnergyConnect is commissioned, which is mainly due to higher wind and solar export to NSW as well as higher brown coal generation. The annual average flow then decreases from 2030 onwards due to significantly lower demand, retirement of Yallourn Power Station and no VNI West in this scenario. While the Central scenario is expected to have a significant increase in the flow in 2028-29, the Step Change and Fast Change scenarios are expected to have this increase in 2035-36 in line with the assumed VNI West timing in these scenarios. In addition, lower flow in the early years in the Step Change and Fast Change scenarios are mainly due to lower brown coal generation in these scenarios, which is partly a result of the carbon budget assumption.

Figure 25: Average flow transfer of SWNSW-WAGGA in the Base Case



Annual average flow transfer in the preferred option for all scenarios is shown in Figure 26. In comparison to the Base Case, generally higher flow transfers from SWNSW to Wagga are expected in the preferred option. This is more evident in the Step Change, Fast Change and Slow Change scenarios, given that these scenarios are assumed to have 2035-36 VNI West timing for the first two of these and no VNI West for the last. Note that the flow limit of SWNSW to Wagga is 3,000 MW after VNI West, regardless of the modelled options.

Figure 26: Average flow transfer of SWNSW-WAGGA in the preferred option



Flow duration curves of SWNSW-WAGGA for the modelled scenarios in the Base Case are provided in Figure 27, Figure 28 and Figure 30.

It is seen that the flow transfer towards Wagga is expected to be significantly capped in all years and all scenarios, particularly in the Step Change, Fast Change and Slow Change scenarios due to the assumptions of 2035-36 as the VNI West timing in the Step and Fast Change scenarios and no VNI West in the Slow Change scenario.

In comparison, the flow duration curves of SWNSW-WAGGA in the preferred option are shown in Figure 31, Figure 32, Figure 33 and Figure 34. It is seen that the preferred option is expected to have higher flow towards Wagga after its commissioning until VNI West commissioning. This is evident in 2024-25 for all scenarios, and also for later years in the Slow Change scenario as it does not assume VNI West.

Figure 27: Duration curve of flow transfer for SWNSW-WAGGA in the Base Case – Central scenario

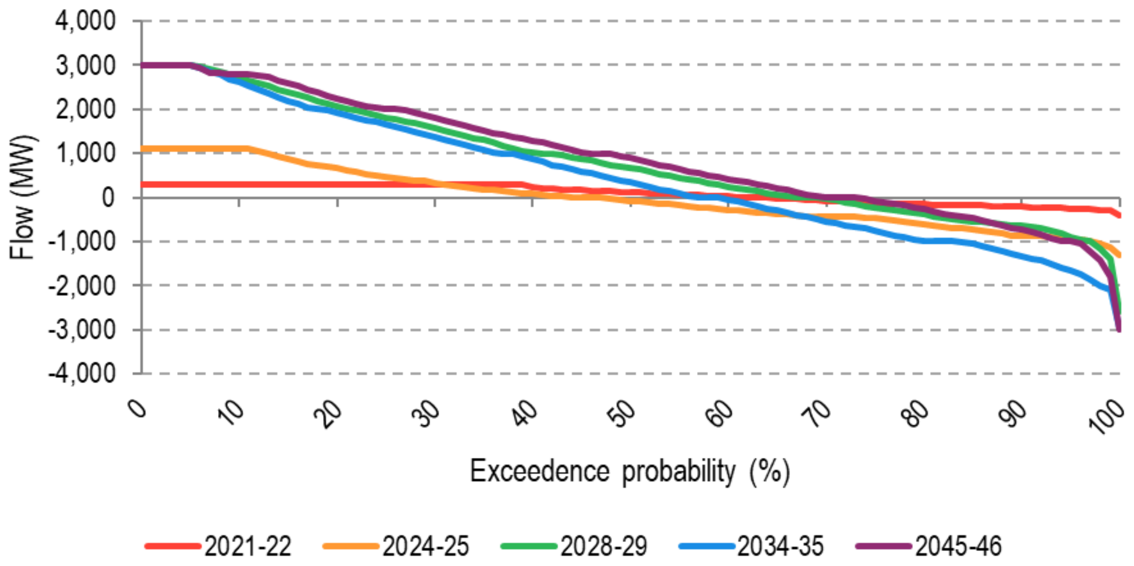


Figure 28: Duration curve of flow transfer for SWNSW-WAGGA in the Base Case – Step Change scenario

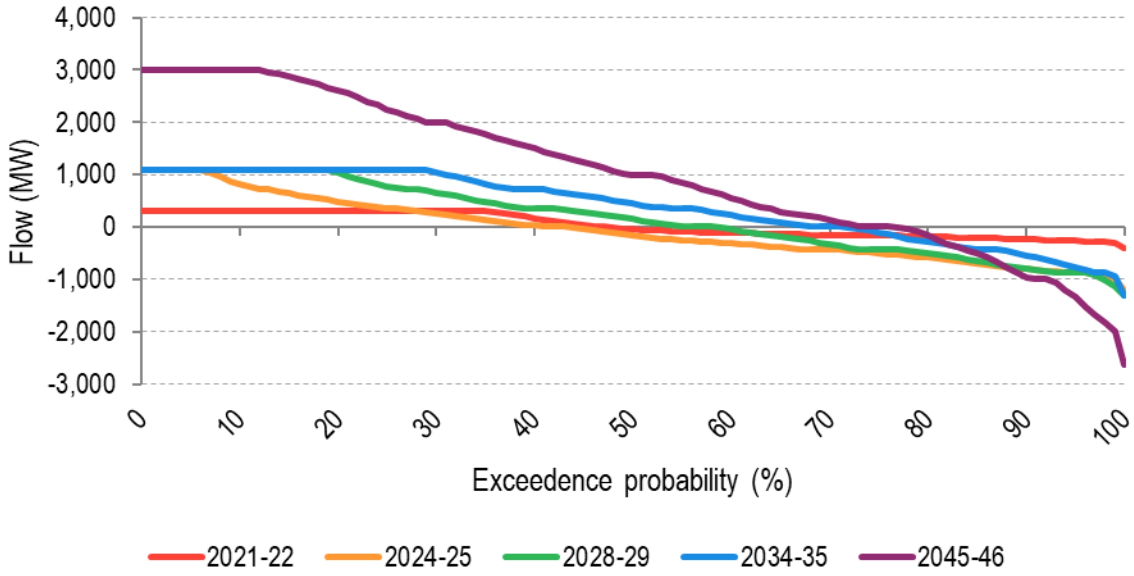


Figure 29: Duration curve of flow transfer for SWNSW-WAGGA in the Base Case – Fast Change scenario

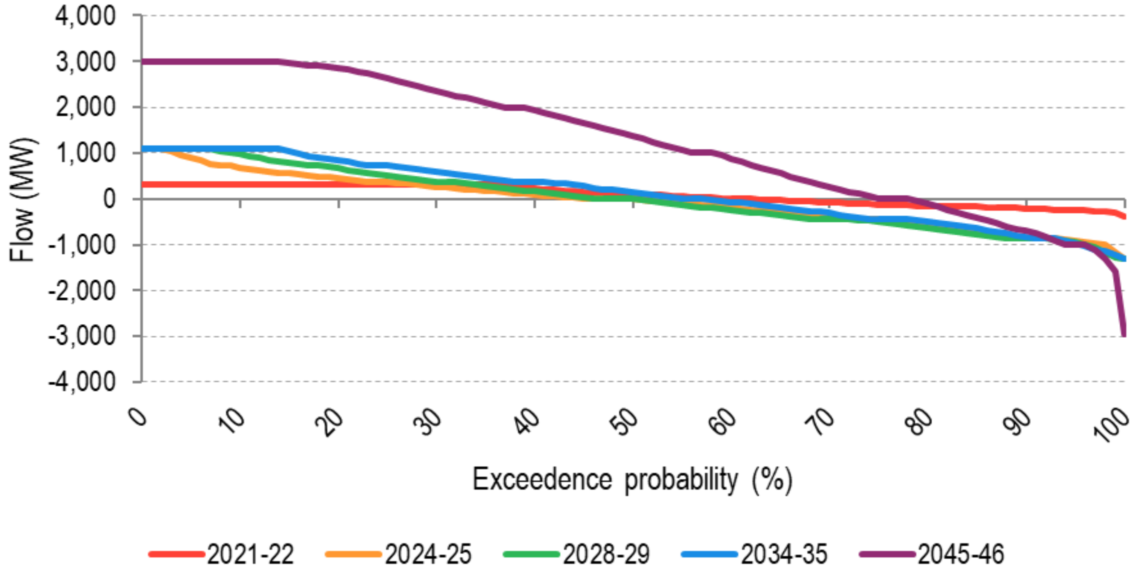


Figure 30: Duration curve of flow transfer for SWNSW-WAGGA in the Base Case – Slow Change scenario

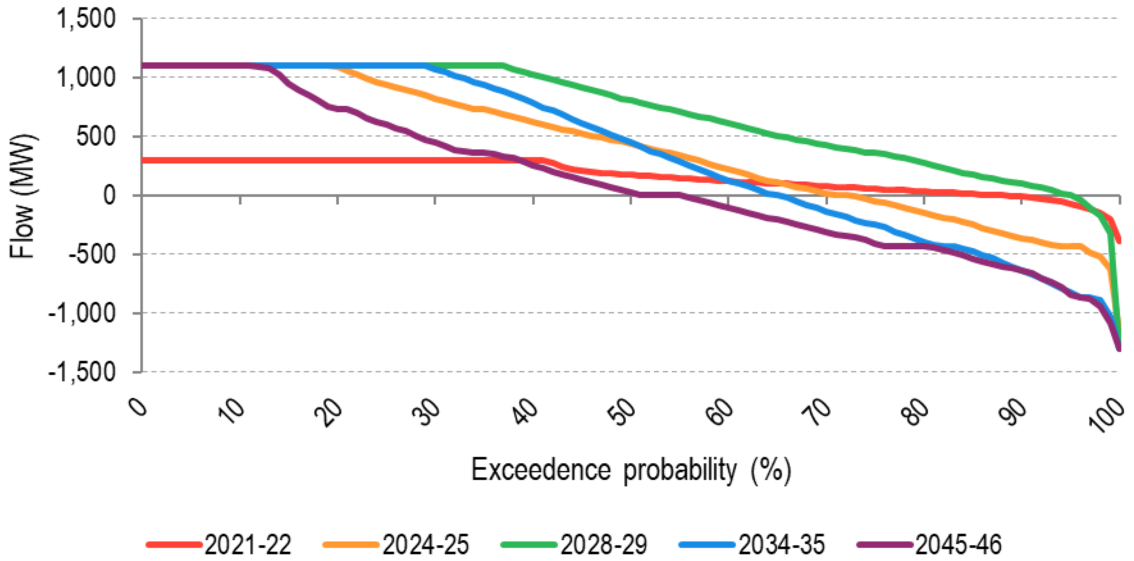


Figure 31: Duration curve of flow transfer for SWNSW-WAGGA in the preferred option – Central scenario

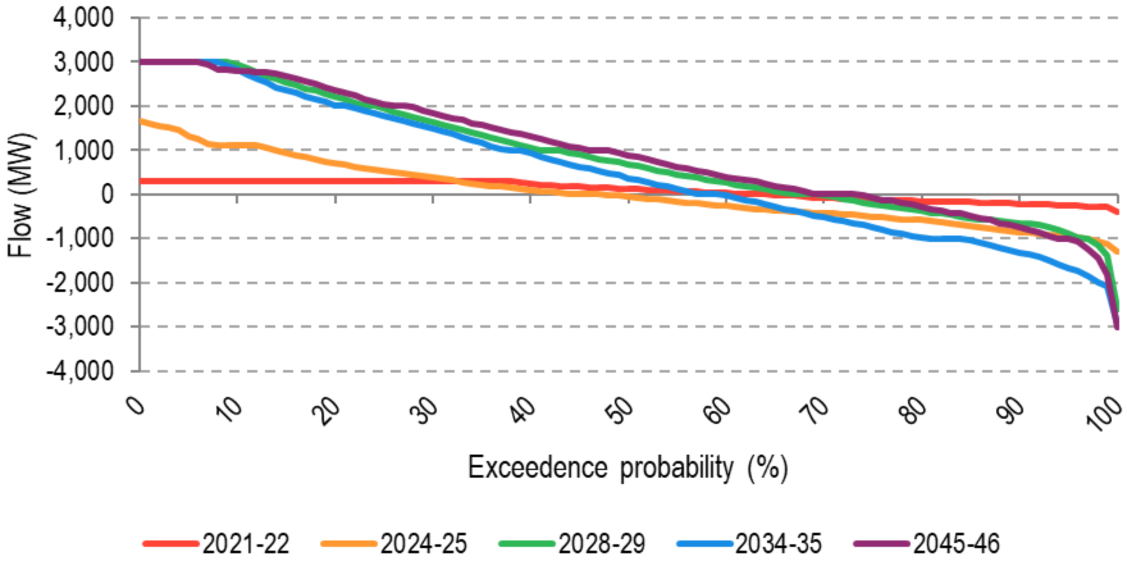


Figure 32: Duration curve of flow transfer for SWNSW-WAGGA in the preferred option – Step Change scenario

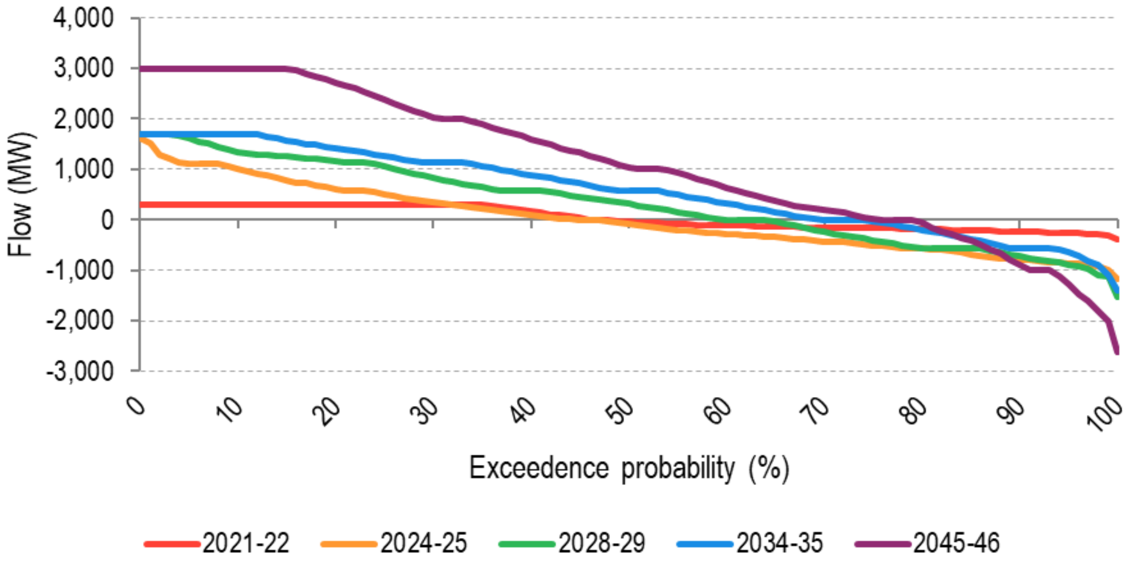


Figure 33: Duration curve of flow transfer for SWNSW-WAGGA in the preferred option – Fast Change scenario

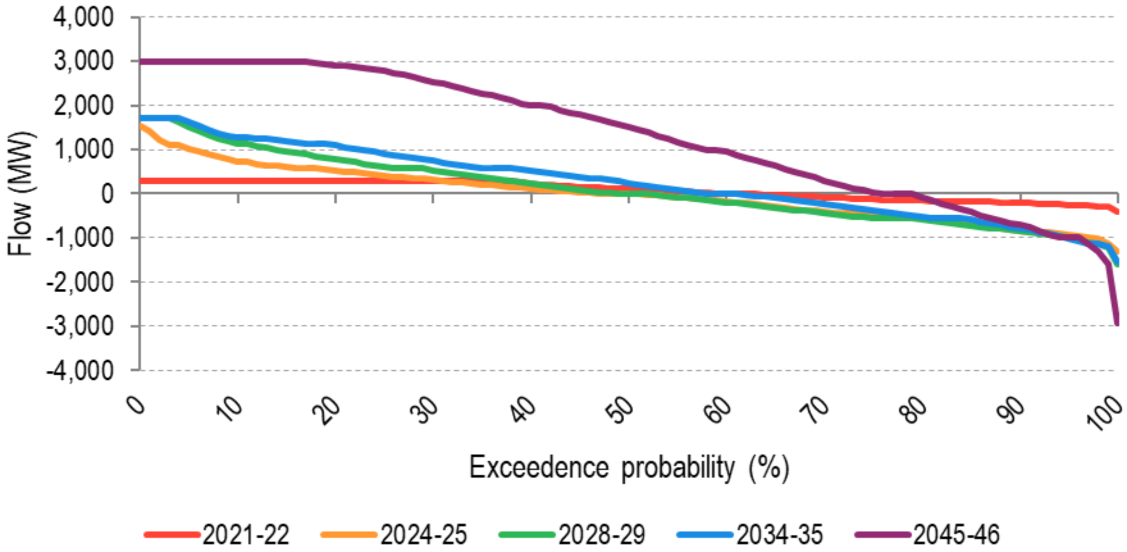
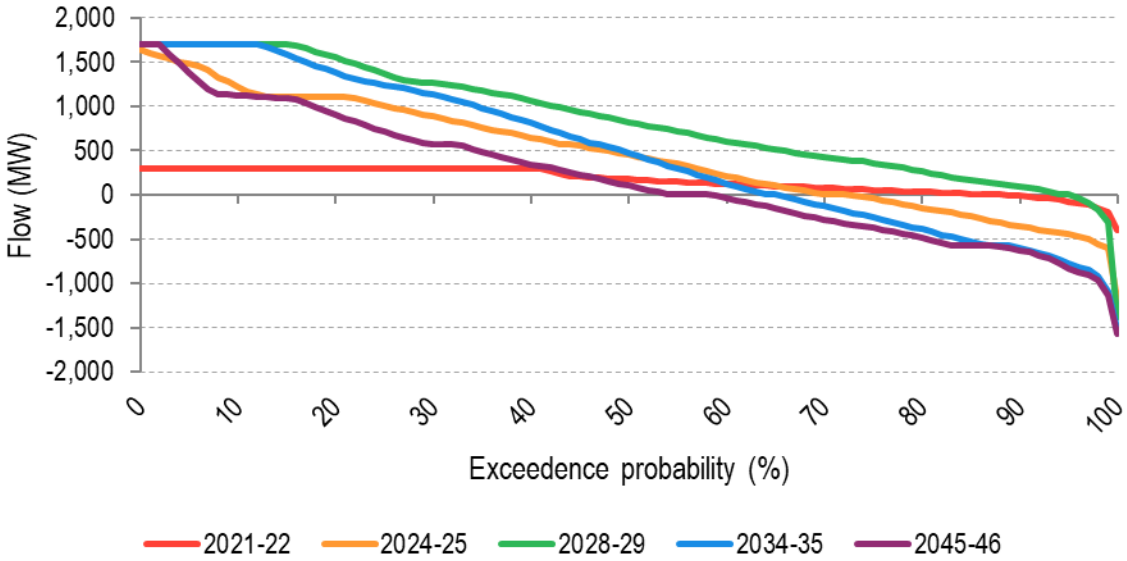


Figure 34: Duration curve of flow transfer for SWNSW-WAGGA in the preferred option – Slow Change scenario



8.3 Other options outcomes

This section provides market modelling results for other options for the Central scenario.

8.3.1 Option 2

The forecast cumulative gross market benefits for Option 2 are shown in Figure 35, indicating that the total forecast gross market benefit reaches around $110m by the end of the study period. Furthermore, the differences in capacity and generation outlook across the NEM between Option 2 and the Base Case are shown in Figure 36 and Figure 37, respectively.

Figure 35: Forecast cumulative gross market benefits[66,67] for Option 2, millions real June 2019 dollars discounted to June 2020 dollars

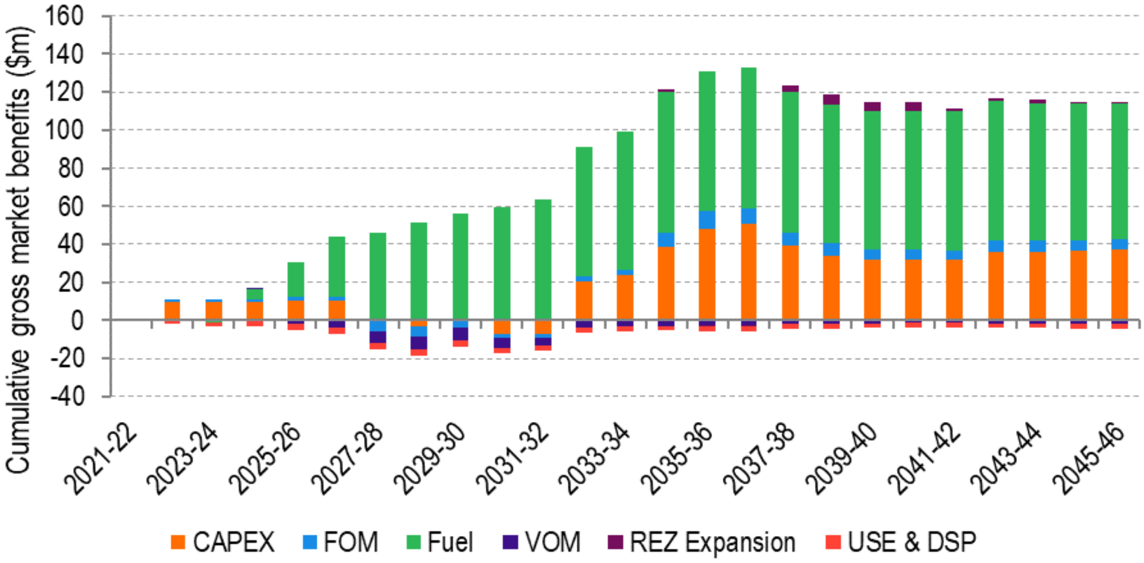
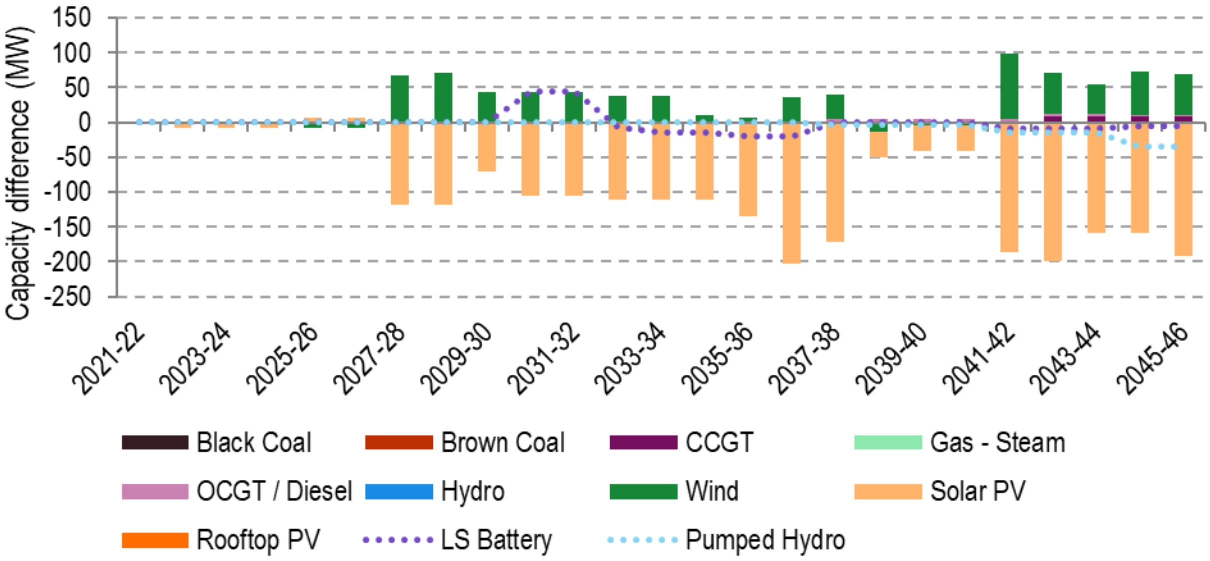


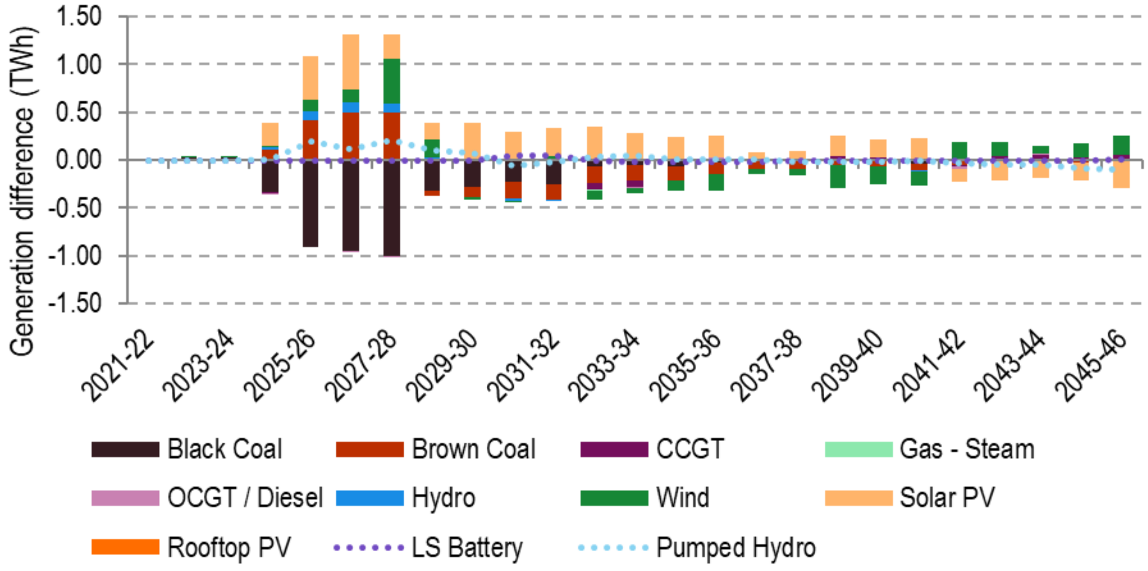
Figure 36: Difference in NEM capacity forecast between Option 2 and the Base Case



[66] 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.

[67] Since this figure shows the cumulative forecast gross market benefits in present value terms, the height of the bar in 2045-46 equates to the gross benefits for Option 2 shown in Table 14.

Figure 37: Difference in NEM generation forecast between Option 2 and the Base Case



The modelling outcomes for Option 2 are similar to Option 1, with around $8m higher benefits. The increase in the forecast benefits is due to the reduced losses from SWNSW to Wagga as a result of a new 330 kV line for this option. The primary sources of forecast gross market benefits in Option 2 are from fuel cost savings and avoided and deferred capex for new generators. The timing and source of these benefits are attributable to the following:

- A small capex saving is expected from 2022-23 due to deferred capacity for a few years. However, the major capex saving occurs around the mid-2030s and remains stable at around $37m until the last year of the study.
- The reduced capex in Option 2 is mainly due to solar deferral and avoidance, where at the end of the study around 190 MW solar build is avoided, although approximately 60 MW more wind is built in this option.
- Fuel cost savings are expected to accumulate as soon as Option 2 is in place, and increase until the mid-2030s. Thereafter, no more fuel cost saving is expected which results in approximately $71m overall fuel cost saving.
- The reduced fuel cost is mainly due to reduced black coal generation in the early years, although more brown coal generation is expected in Option 2 in those years due to opening of the transfer limit from VIC and SWNSW to NSW load centres. Fuel cost savings are expected to diminish in the mid-2030s when major black coal power plants in NSW and QLD are assumed to retire.

8.3.2 Option 3

The forecast cumulative gross market benefits for Option 3 are shown in Figure 38, indicating that the total forecast gross market benefit reaches $25.7m by the end of the study period. Furthermore, the differences in capacity and generation outlook across the NEM between Option 3 and the Base Case are shown in Figure 39 and Figure 40 respectively.

Figure 38: Forecast cumulative gross market benefit[68,69] for Option 3, millions real June 2019 dollars discounted to June 2020 dollars

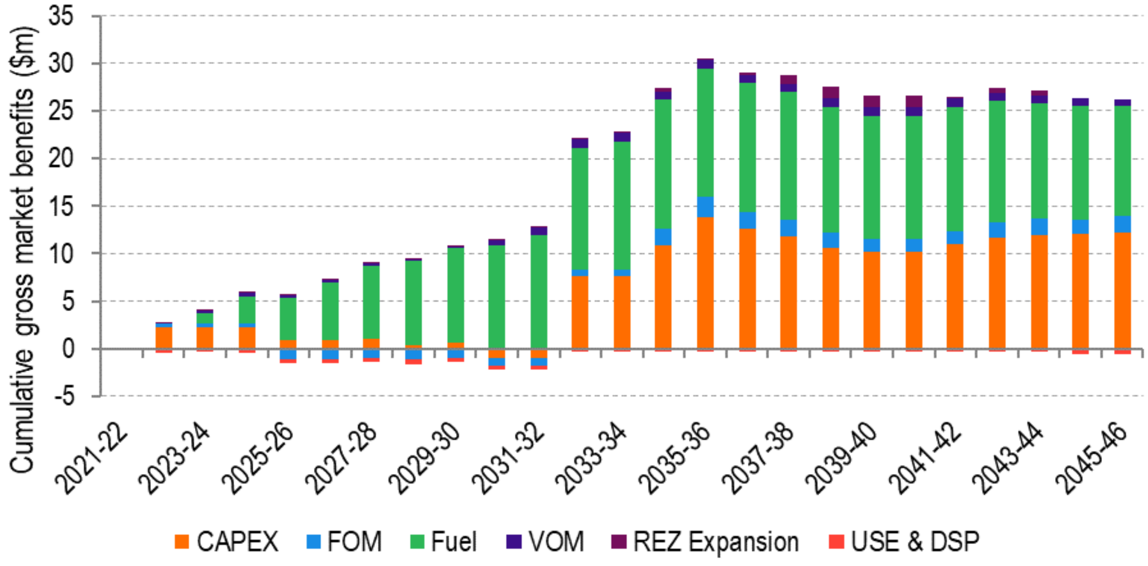
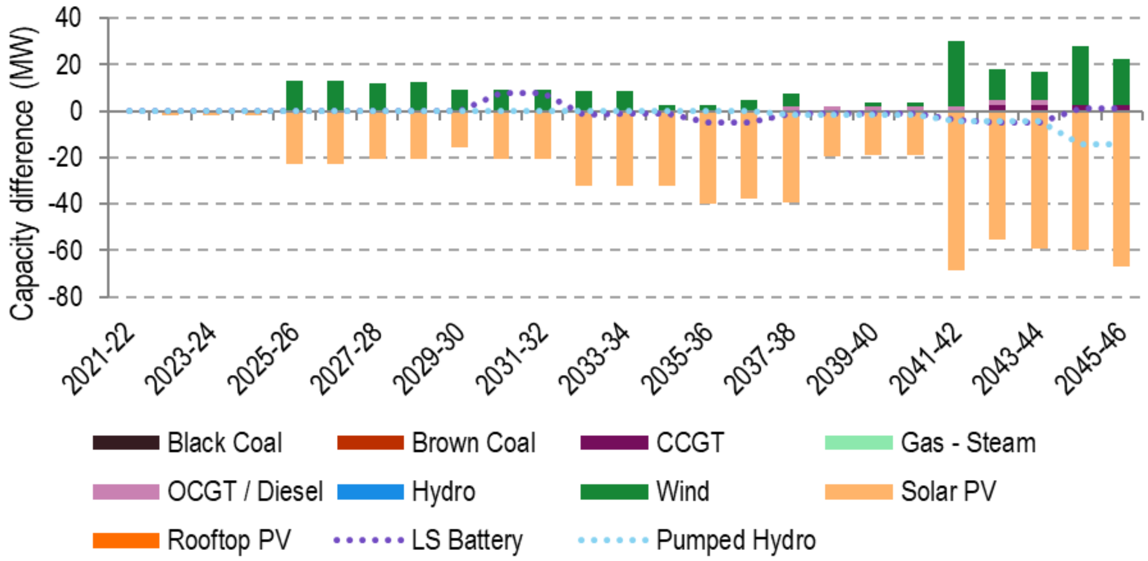


Figure 39: Difference in NEM capacity forecast between Option 3 and the Base Case



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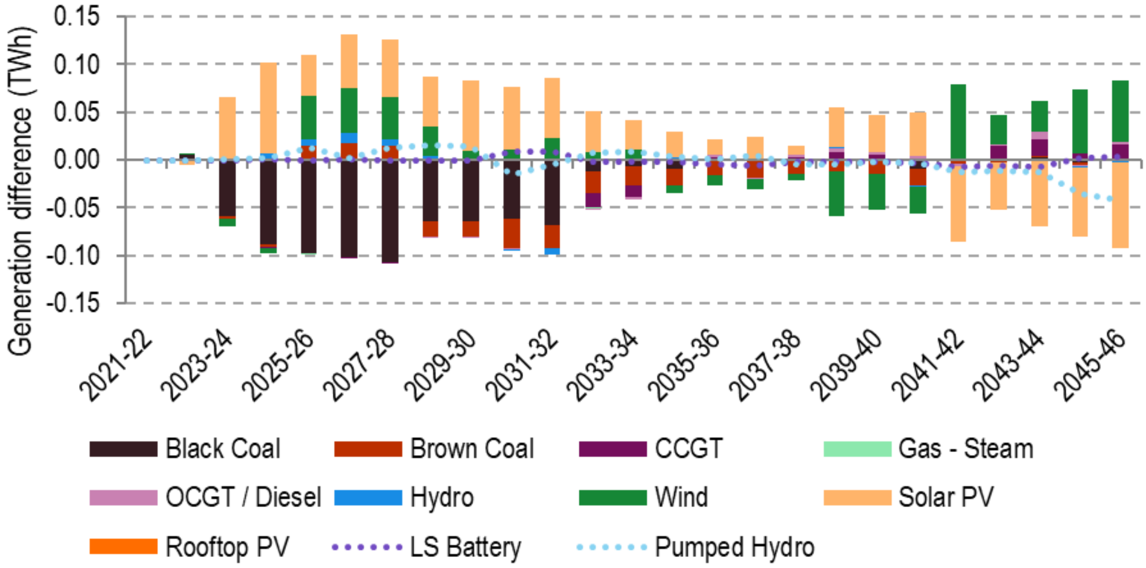
68 Note that all generator and storage capital costs have been included in the market modelling on an annualised basis. However, this chart and all charts of this nature in the Report present the entire capital costs of these plants in the year avoided to highlight the timing of capacity changes that 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.

69 Since this figure shows the cumulative forecast gross market benefits in present value terms, the height of the bar in 2045-46 equates to the gross benefits for Option 3 shown in Table 14.

Figure 40: Difference in NEM generation forecast between Option 3 and the Base Case



The primary sources of forecast gross market benefits in Option 3 are from avoided and deferred capex for new generators and fuel cost savings, having an approximately equal share. The timing and source of these benefits are attributable to the following:

- A small capex saving is expected from 2022-23 due to deferred capacity for a few years. However, the major capex saving occurs around the mid-2030s and remains stable at just under $12m until the last year of the study.
- The reduced capex in Option 3 is mainly due to solar deferral and avoidance, where at the end of the study around 65 MW solar build is avoided, although approximately 20 MW more wind is built in this option.
- Fuel cost savings are expected to accumulate from 2024-25, and increase until the mid-2030s. Thereafter, no more fuel cost savings are expected which results in approximately $12m overall fuel cost saving.
- Similar to Option 2, the reduced fuel cost is mainly due to reduced black coal generation in the early years, although more brown coal generation is expected in Option 3 due to opening of the transfer limit from VIC and SWNSW to NSW load centres. Fuel cost savings are expected to diminish in the mid-2030s when major black coal power plants in NSW and QLD are assumed to retire.

8.3.3 Option 4

TransGrid has instructed EY to only present the result of Option 4 on a qualitative basis, to keep the confidentiality of the battery option. As for Option 1, Option 4's primary source of forecast gross market benefits is from fuel cost savings, followed by capex savings due avoided and deferred build of new generators. Compared to Option 1, Option 4:

- is forecast to have higher capex saving in early years of the study due to more solar build avoidance. The capex saving gradually decreases to zero by the late 2020s. However, from the early 2030s it is expected to increase and then remain relatively stable by the end of the study period. The reduced capex in Option 4 is mainly due to solar deferral and avoidance. Note that the modelled battery is assumed to retire in 2037-38, after 15 years of service.
- brings forward fuel cost savings due to the reduced coal generation. Fuel cost savings are forecast to increase until the mid-2030s. Thereafter, no more fuel cost saving is expected.

8.3.4 Option 5

TransGrid has instructed EY to only present the result of Option 5 on a qualitative basis, to keep the confidentiality of the battery option. Option 5's primary source of forecast gross market benefits is from fuel cost savings, followed by capex savings due avoided and deferred build of new generators.

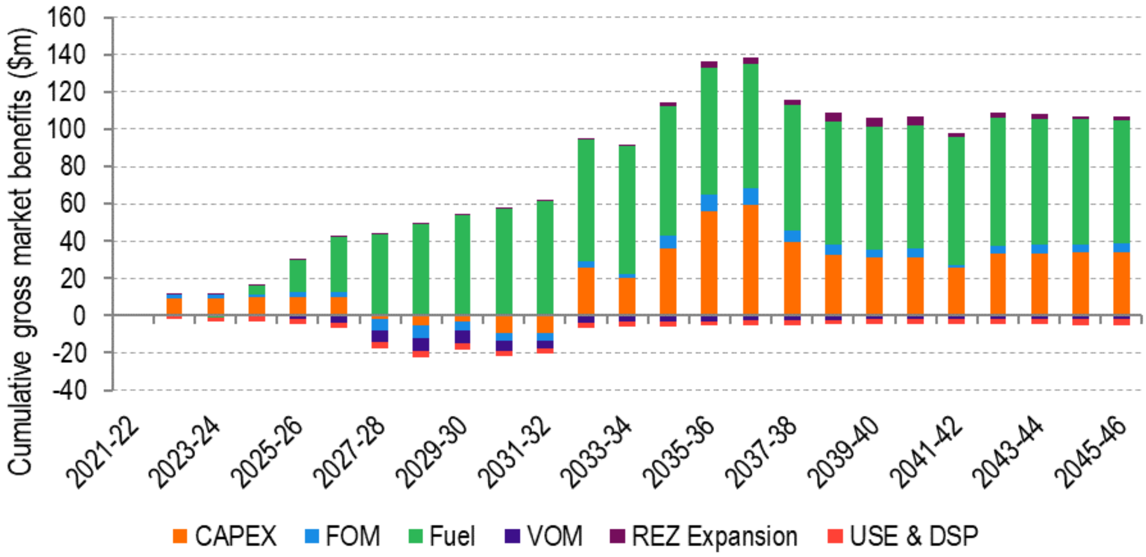
- Fuel cost savings are expected to start as soon as the battery is commissioned, and then gradually increase until the early 2030s when these savings start to stabilise.
- Similarly, capex benefits are forecast to start from 2022, but decrease in the following years. Capex benefits then start to increase until the mid-2030s and stabilise after that.

8.4 Sensitivity - Central scenario with ISP neutral gas prices

At TransGrid's request, a sensitivity is modelled to assess the impact of gas prices on Option 1 in the Central scenario. This section summarises market modelling results for Option 1 using ISP neutral gas prices[70] instead of the TransGrid custom trajectory outlined in Table 3. In general, these gas prices are lower in all regions but NSW for existing and new entrant generators.

The forecast cumulative gross market benefits for Option 1 using ISP gas prices are shown in Figure 41, indicating that the total forecast gross market benefit decrease by $0.1m to $101.6m by the end of the study period. Furthermore, the differences in capacity and generation outlook across the NEM between Option 1 and the Base Case are shown in Figure 42 and Figure 43, respectively.

Figure 41: Forecast cumulative gross market benefit[71,72] for Option 1 in the Central scenario using ISP gas prices, millions real June 2019 dollars discounted to June 2020 dollars



[70] AEMO, 30 November 2020, *2020 Input and assumptions workbook v2.1*. Available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/2020-inputs-and-assumptions-workbook.xlsx?la=en. Accessed 4 December 2020.

[71] 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.

[72] Since this figure shows the cumulative forecast gross market benefits in present value terms, the height of the bar in 2045-46 equates to the gross benefits for Option 1 shown in Table 14.

Figure 42: Difference in NEM capacity forecast between Option 1 and Base Case in the Central scenario using ISP gas prices

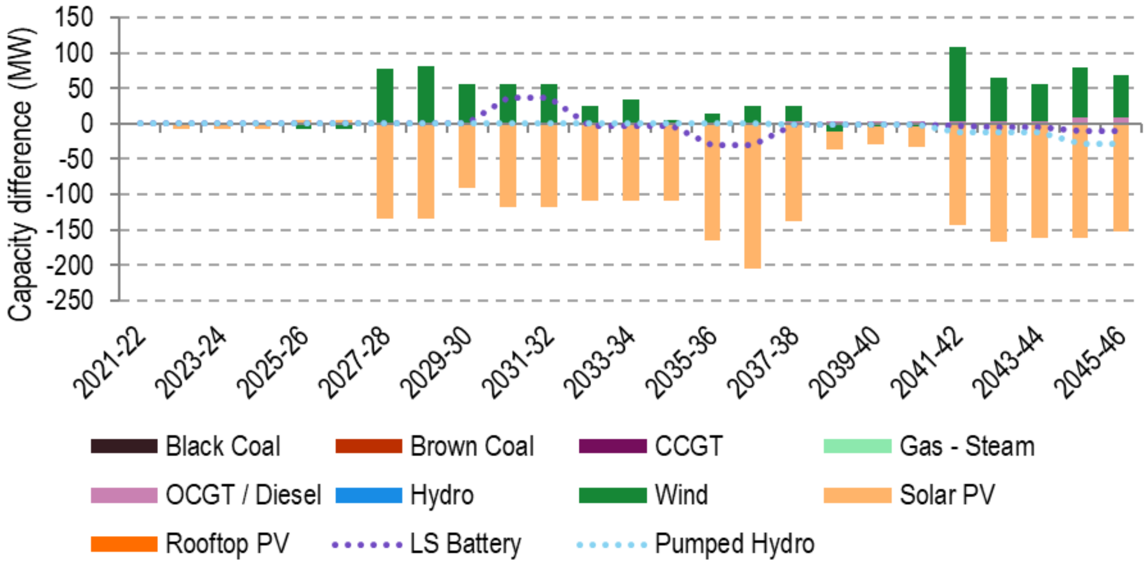
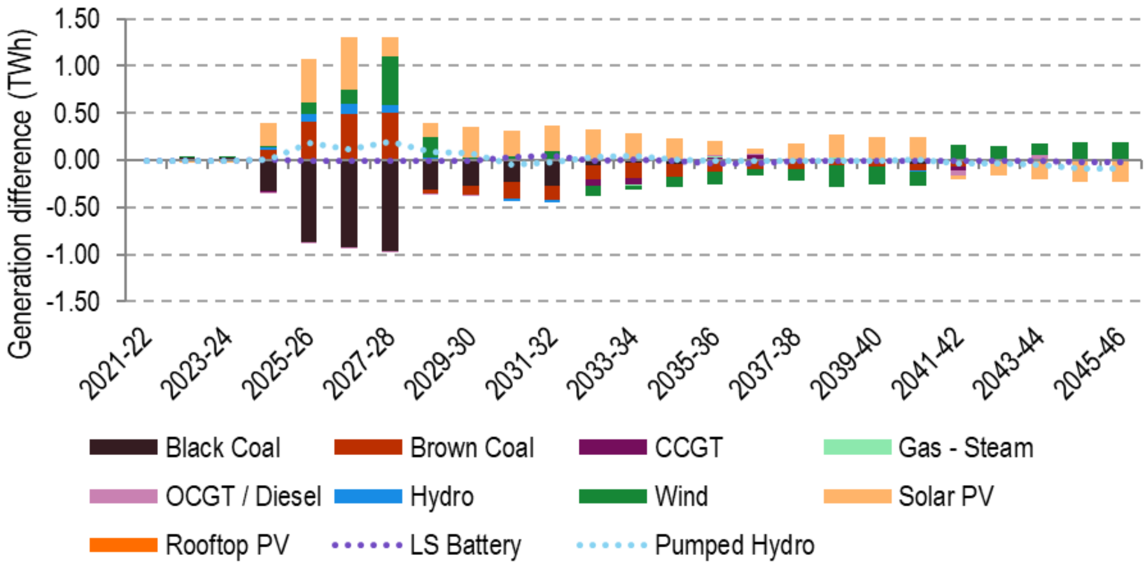


Figure 43: Difference in NEM generation forecast between Option 1 and Base Case in the Central scenario using ISP gas prices



The primary sources and overall forecast gross market benefits in Option 1 in this sensitivity are very similar to the core Option 1 run, being primarily from fuel cost savings and avoided and deferred capex for new generators. Differences between the core Option 1 run and the alternative gas price runs are:

- a small increase in fuel cost benefits by $2.7m as a large proportion of fuel cost benefits is derived from NSW, where prices increase, resulting in larger savings.
- capex benefits in combination with FOM as well as USE are slightly reduced by $2.6m, $1.2m and $0.4m, respectively.
- REZ expansion savings are expected to increase by $1.1m due to small locational changes of new capacity build with the main additional avoided transmission in South West Victoria.

Appendix A Glossary of terms

Abbreviation	Meaning
AEMO	Australian Energy Market Operator
AC	Alternating Current
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 Exceedance
PSCR	Project Specification Consultation Report
PSH	Pumped Storage Hydro
PV	Photovoltaic
QLD	Queensland
QNI	Queensland-New South Wales interconnector

Abbreviation	Meaning
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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