Reinforcing the New South Wales Southern Shared Network PADR Market Modelling Report

TransGrid

10 January 2020

Building a better working world

Release Notice

Ernst & Young was engaged on the instructions of NSW Electricity Networks Operations Pty Limited as trustee for NSW Electricity Networks Operations Trust (TransGrid) to undertake market modelling of system costs and benefits to support the Reinforcing the New South Wales Southern Shared Network (HumeLink) Regulatory Investment Test for Transmission (RIT-T) relating to various network upgrade options to provide additional transfer capacity to the state's demand centres.

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

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1. Executive summary

TransGrid has engaged EY to undertake market modelling of system costs and benefits to support the Reinforcing the New South Wales Southern Shared Network (HumeLink) Regulatory Investment Test for Transmission (RIT-T) relating to various network upgrade options to provide additional transfer capacity to the state's demand centres[1]. The RIT-T is a cost-benefit analysis used to assess the viability of investment options in electricity transmission assets.

This Report forms a supplementary report to the Project Assessment Draft Report (PADR) published by TransGrid[2]. It 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. This Report is accompanied by market modelling workbooks which contain summaries of key outcomes.

EY applied a cost-benefit analysis based on the change in least-cost generation dispatch and capacity development plan with each transmission augmentation option.

EY computed the least-cost generation dispatch and capacity development plan for the National Electricity Market (NEM) associated with four groups of HumeLink augmentation options across a range of voltage variants, scenarios and sensitivities. This is an independent study and the modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator[3].

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

- the generation dispatch level for each power plant along with the charging and discharging of storage. Stations and units are assumed to bid at their short-run marginal cost (SRMC), which is derived from their Variable Operation and Maintenance (VOM) and fuel costs. The generation for each trading interval is subject to the modelled availability of power stations in each hour (those that are not on planned or un-planned outages), network limitations and energy limits (e.g., storage levels).
- commissioning new entrant capacity for wind, solar PV SAT, CCGT, OCGT[4], large-scale battery storage and pumped storage hydro (PSH).

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)[5],
- minimum loads for generators,
- interconnector flow limits (between regions),
- intra-regional flow limits (between zones in NSW),

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[1] TransGrid RIT-T website available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network. Accessed 09 January 2020.

[2] TransGrid, *Reinforcing the NSW Southern Shared Network to increase transfer capacity to the state's demand centres (HumeLink) PADR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network. Accessed 10 January 2020.

[3] 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 09 January 2020.

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

[5] Based on AEMO, September 2014, *Value of customer reliability review: final report*. CPI adjusted to March 2019. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review. Accessed 09 January 2020.

- Canberra (CAN) zone lines and cut-set[6] limits,
- maximum and minimum storage (conventional storage hydro, PSH and large-scale battery storage) reservoir limits and cyclic efficiency,
- new entrant capacity build limits for wind and solar for each Renewable Energy Zone (REZ) where applicable, and PSH in each region,
- emission constraints, as defined for each scenario,
- renewable energy targets where applicable by region or NEM-wide in applicable scenarios.

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 HumeLink augmentation option and in a matched no augmentation counterfactual (referred to as the Base case) we computed the sum of these cost components and compared the difference. The difference in costs is the forecast gross market benefits due to the HumeLink transmission upgrade, as defined in the RIT-T.

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

Gross market benefits were forecast for four HumeLink augmentation options with three voltage variants across four scenarios covering a broad range of reasonable possible futures for the NEM.

Gross market benefits were forecast for four HumeLink augmentation options, each with three voltage variants, across four scenarios covering a broad range of reasonable possible futures for the NEM. The augmentation options were defined by TransGrid and are described in detail in the PADR[7]. To better capture the intra-regional flows in NSW and changes due to the augmentation options, EY applied a DC load flow (DCLF)[8] and split the CAN zone into nine nodes, in addition to the Northern NSW (NNS), Central NSW (NCEN), South West NSW (SWNSW) zones. This also allows for a more detailed investigation of the line flows in NSW, and in particular in the CAN zone. An equivalent network of CAN is derived which captures the nine key high voltage buses in the zone

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[6] A cut-set is a geographical cross-section with several transmission lines which collectively provide the only path between two separate locations on the grid.

[7] TransGrid, *Reinforcing the NSW Southern Shared Network to increase transfer capacity to the state's demand centres (HumeLink) PADR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network. Accessed 10 January 2020.

[8] Also referred to as DC power flow. DC Load Flow is a recognised approximation to AC Load Flow. See, for example, Brian Stott, Jorge Jardim, Ongun Alsac, 'DC Power Flow Revisited', IEEE Transactions on Power Systems, Vol 24, Issue 3, pp1290-1300.

linked by existing and potential new lines. In addition, a number of cut-set limits are used to capture the key network constraints in the zone.

The Snowy Hydro scheme, Snowy 2.0 and all other existing and potential new storages are modelled to operate so as to maximise the value of storages by reducing the cost of fossil generation. This method computes a water value for each storage which represents the cost at or above which the generation should be used to replace fossil generation. At costs below this level it is more economic to save the water, or to replenish PSH and battery storages.

The scenarios modelled are in line with the Australian Energy Market Operator's (AEMO) 2019-20 Integrated System Plan (ISP) scenarios[9]: Central, Step Change, Slow Change and Fast Change. The modelled scenarios differ in various assumptions such as demand, technology and fuel costs, emissions policies, coal fired generator retirement dates, renewable energy targets, and inclusion/exclusion of VNI West[10] and Marinus Link.

The Base case without HumeLink augmentation forecasts gradual shifts of the NEM generation and capacity towards increasing wind, solar, PSH and gas.

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

Without any HumeLink upgrade, the forecast generation capacity of the NEM gradually shifts towards increasing capacity of wind, solar, PSH and gas. The NEM is forecast to have around 109 GW total capacity by 2044-45 (total capacity includes PSH and Large-scale (LS) storage capacities, which are not in the stacked chart). The majority of new capacity installed is coincident with coal generation retirements, which is particularly obvious from the mid-2030s when a number of large coal generators in the NEM are assumed to retire.

The energy supplied to the grid for the Central scenario gradually increases throughout the modelling period due to the modest demand growth of the AEMO ISP 2019-20 Central demand assumed in this scenario. The projected cost of operating solar and wind trends below that of gas plant, so the forecast mix of generation favours solar and wind over gas-fired plant, except as needed to meet peak demand periods when wind and solar are not available and furthermore to maintain reserve requirements within each region.

[9] AEMO, *2019-20 Integrated System Plan*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 09 January 2020.

[10] Previously referred to as KerangLink.

Figure 1: NEM capacity mix forecast for the Central scenario without HumeLink upgrade

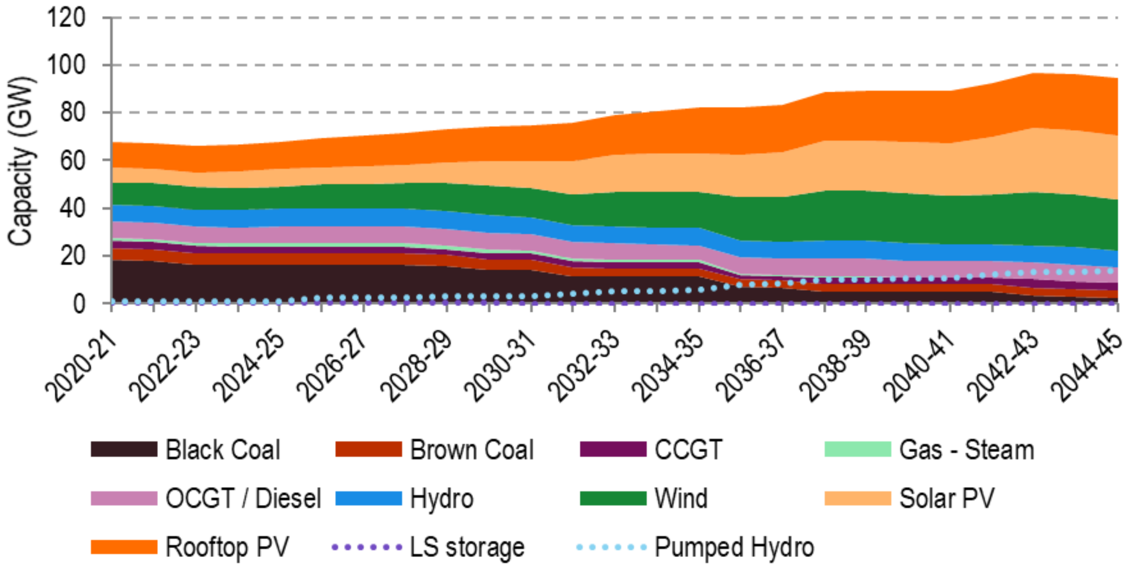
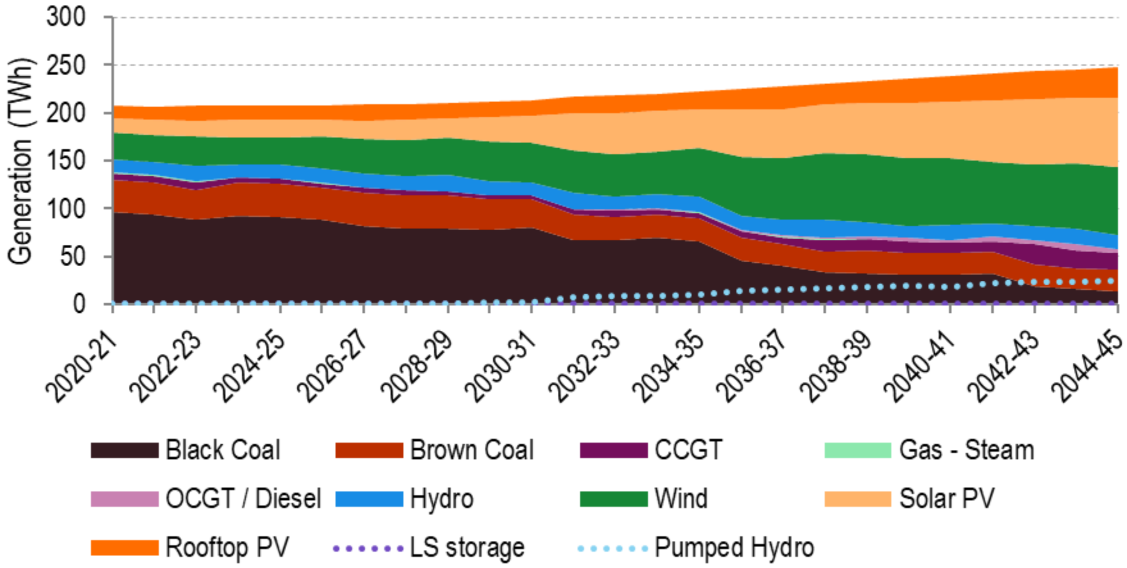


Figure 2: NEM generation mix forecast for the Central scenario without HumeLink upgrade[11]



Compared to the Central scenario, the modelling forecasts an increase in installed wind, OCGT, and PSH capacity in the Step Change scenario by 2044-45 whereas CCGT and solar PV build are forecast to decrease. For the Fast Change scenario, the forecast includes higher wind, solar PV, OCGT, large-scale battery storage and PSH capacity, but lower CCGT build. Overall the forecast trend in capacity is similar in the Step Change and Fast Change scenarios. By 2044-45, black coal capacity in the Step Change scenario is the same as the Central scenario whereas brown coal is around 1.6 GW less. Black and brown coal capacity in the Fast Change scenario is the same as for the Central scenario. The differences in coal capacity are due to assumptions of five and two years earlier retirements of half of coal capacity in the Step Change and Fast Change scenarios, respectively.

The Slow Change scenario has a significantly different NEM capacity outlook than the Central scenario, with the overall forecast showing around 18 GW less wind, solar, PSH and gas capacity by the end of the study. On the other hand, it is forecast that the Slow Change scenario builds more

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

wind and solar in early years relative to the Central scenario, starting with around 370 MW solar in 2020-21. The Slow Change scenario is forecast to have around 660 MW more black coal capacity by 2044-45, but the same brown coal capacity relative to the Central scenario.

Relative to the Central scenario, wind generation offsets brown coal and CCGT in the Step Change scenario, whereas the Fast Change scenario is forecast to have higher wind and solar to offset brown and black coal as well as gas generation.

The Slow Change scenario forecasts considerably less generation from wind, solar, PSH and CCGTs compared to the Central scenario, with more generation from black and brown coal. Furthermore, black and brown coal generation in the early years is less than in the Central scenario.

The forecast gross market benefits of each HumeLink option computed in each scenario need to be compared to the relevant HumeLink development cost to determine whether there is a positive net market benefit. Considering costs and benefits across all scenarios, Option 3C has been identified by TransGrid as the preferred option.

Table 1 shows the forecast gross market benefits over the modelled 25-year horizon for all options across the four scenarios and three voltage variants. The forecast gross market benefits of each HumeLink option computed in each scenario need to be compared to the relevant HumeLink development cost to determine whether there is a positive net market benefit. The modelling shows a similar trend in forecast gross market benefits and generation development for Options 2, 3 and 4 whereas the outcome for Option 1 is significantly different. The key difference in these options is that all options except Option 1 connect Wagga Wagga to Bannaby and Maragle which unlocks renewables in SWNSW and southern regions.

Option 3C has been identified as the preferred option, based on option costs conducted by TransGrid of the forecast net benefits after incorporating development costs of the options. 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[12]".

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

Option	Scenario			
	Slow Change	Central	Step Change	Fast Change
1A	897	992	1,113	1,045
1B	1,167	1,394	1,583	1,517
1C	1,108	1,331	1,516	1,467
2A	1,154	1,798	1,942	1,988
2B	1,412	2,245	2,511	2,533
2C	1,517	2,306	2,550	2,573
3A	1,005	1,621	1,757	1,806
3B	1,321	2,198	2,496	2,508
3C	1,504	2,291	2,545	2,562
4A	1,070	1,738	1,912	1,961

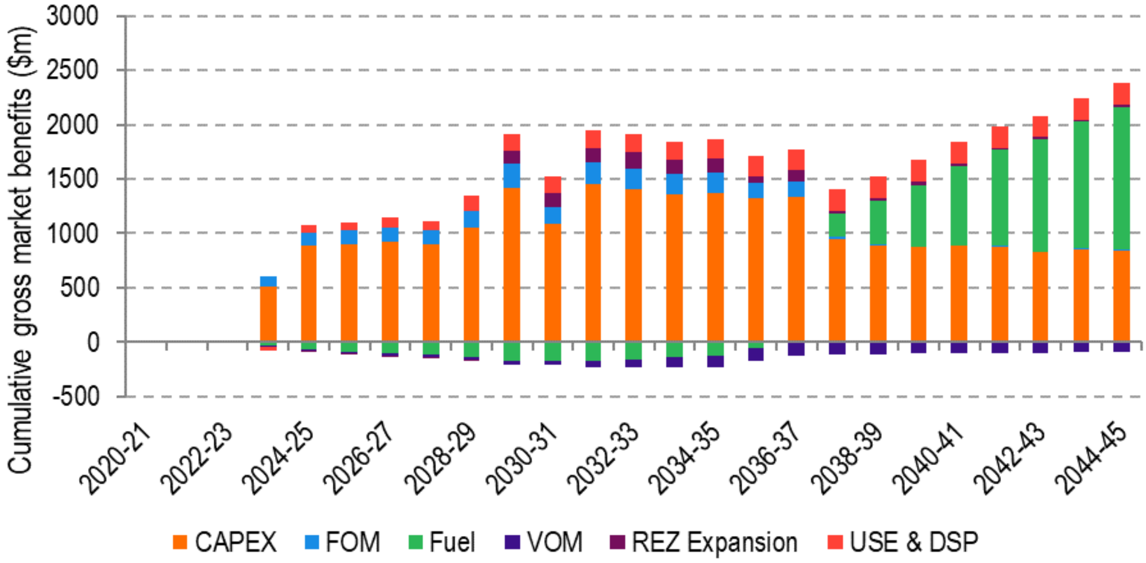
[12] 14 December 2018, *RIT-T and RIT-D application guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 09 January 2020.

Option	Scenario			
	Slow Change	Central	Step Change	Fast Change
4B	1,506	2,438	2,742	2,777
4C	1,628	2,505	2,778	2,816

The forecast cumulative gross market benefits for Option 3C in the Central scenario are shown in Figure 3. Furthermore, the differences in capacity and generation across the NEM between Option 3C and the Base case in the Central scenario are shown in Figure 4 and Figure 5 respectively.

The primary sources of forecast gross market benefits are from avoided and deferred capex for new generators as well as fuel cost saving from reduced CCGT generation.

Figure 3: Forecast cumulative gross market benefits[13,14] for Option 3C under the Central scenario, millions real June 2019 dollars discounted to June 2020 dollars



[13] 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 forecast gross benefits of the options.

[14] Since this figure shows the cumulative forecast gross market benefits in present value terms, the height of the bar in 2044-45 equates to the gross benefits for Option 3C shown in Table 1 above.

Figure 4: Difference in NEM capacity forecast between Option 3C and Base case in the Central scenario

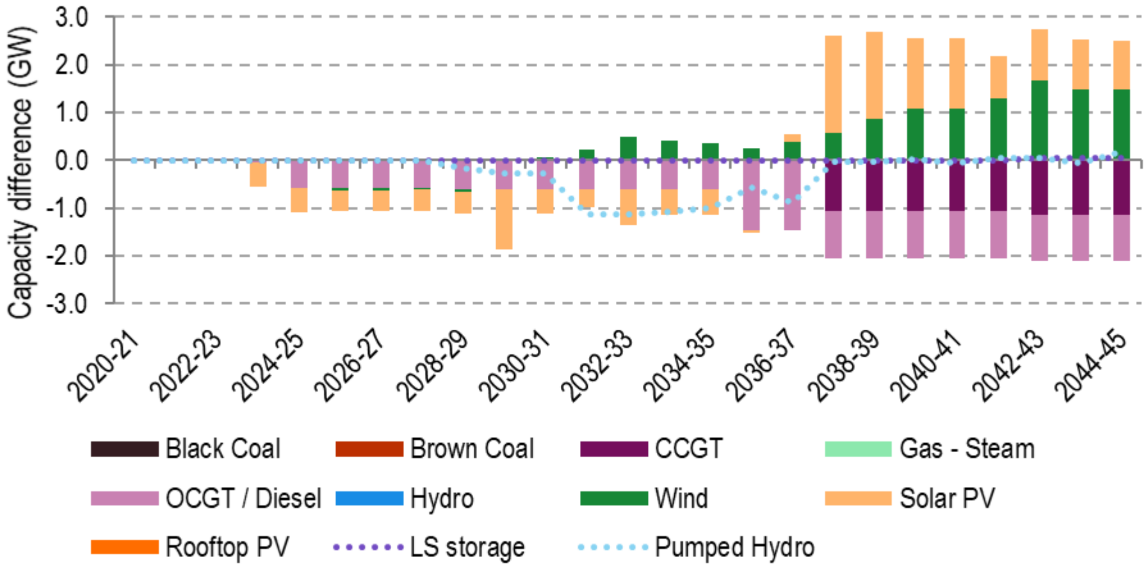
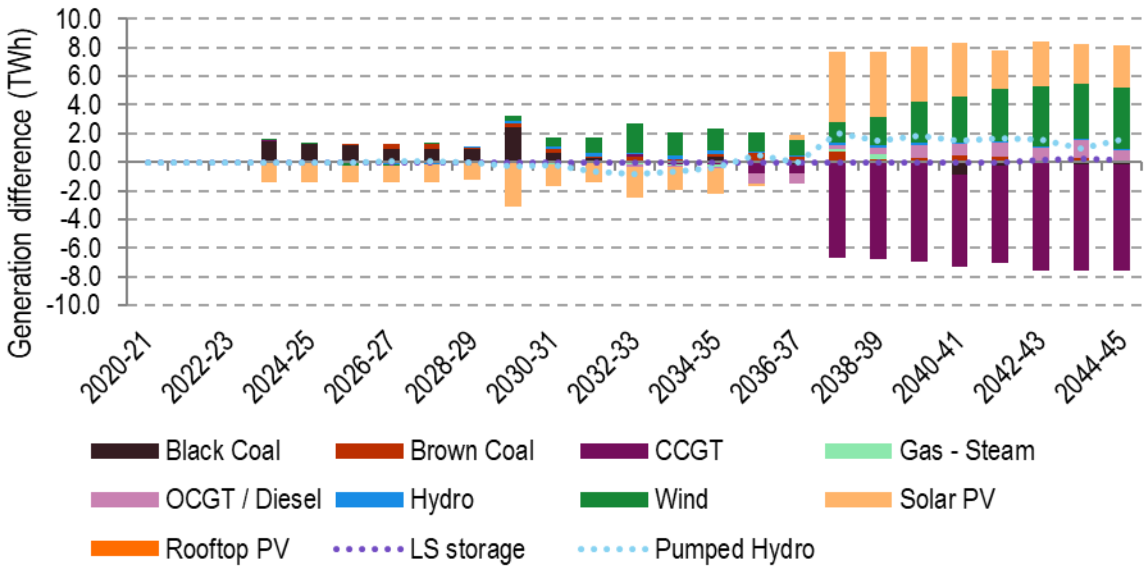


Figure 5: Difference in NEM generation forecast between Option 3C and Base case in the Central scenario



The primary sources of forecast gross market benefits are from avoided and deferred capex for new generators as well as fuel cost saving from reduced CCGT generation. The timing and source of these benefits are attributable to the following:

- The large capex benefit of $506m in 2023-24 comes from a forecast deferral of 500 MW solar build in NCEN just after Liddell is assumed to retire.
- The capex benefit is forecast to increase to around $890m in 2024-25 due to avoidance of approximately 560 MW OCGT build in NCEN. This is the year that the HumeLink network upgrades are assumed to be commissioned.
- Black coal and to a lesser extent brown coal generation offsets the avoided solar generation during the 2020s.
- In 2029-30, when Vales Point is expected to retire, the capex benefit is forecast to increase to $1,411m due to deferral of approximately 800 MW of solar by one year and deferral of PSH build. The following year, the benefit is forecast to reduce to $1,090m when the deferred solar is built.

- In 2031-32, the same year as Eraring is expected to retire, the forecast capex benefit increases to $1,450m due to deferral of approximately 800 MW of PSH in NSW. The majority of this build is deferred until 2035-36.
- During the early to mid-2030s, 100 MW – 500 MW more wind is forecast to be built with Option 3C, but OCGT, solar and PSH is deferred compared to the Base case.
- In 2037-38 the capex benefit is forecast to reduce to $942m due to a large amount of solar PV build of approximately 1.8 GW. This same year there is a large avoidance of CCGT build forecast in NSW of approximately 1.1 GW.
- The fuel cost benefit is forecast to start from 2037-38 with $209m in benefit resulting from VIC wind, NSW and SA solar and PSH generation offsetting NSW CCGT generation (which is due to CCGT build avoidance). From 2037-38 onwards a combination of solar, wind, PSH, OCGT and large-scale battery generation is forecast to offset around 7.4 TWh of CCGT generation. The fuel cost benefit is forecast to progressively increase to $1,313m by 2044-45.

The augmentation expands transfer capacity from southern NSW and southern states to supply major load centres in New South Wales. This may allow for improved utilisation of existing generation before new capacity is required and development of more diverse resources when new capacity is required.

The augmentation expands transfer capacity from southern NSW and southern states to supply major load centres in New South Wales. This may allow for improved utilisation of existing generation before new capacity is required and development of more diverse resources when new capacity is required. Compared to the Base case, Option 3C builds an additional 600 MW of solar in the Wagga Wagga REZ (NSW), 730 MW of solar in the Riverland REZ (SA) and 1,480 MW wind in the South West Victoria REZ (VIC).

Compared to the Central scenario, the magnitude of fuel cost and capex savings are almost the same in the Step Change scenario. The forecast gross market benefits in the Step Change scenario start from 2024-25 at around $500m, followed by a significant growth in 2026-27 (when half of Eraring capacity is assumed to retire) to around $1,700m, and then remain stable until the late 2030s when it gradually increases to just above $2,500m in 2044-45.

As in the Step Change scenario, fuel cost saving due to reduced CCGT generation and avoided and deferred capex for new gas generators and PSH almost equally provide the primary sources of gross market benefits in the Fast Change scenario.

Avoided solar build from 2020-21 and OCGT build from 2023-24 are forecast to be the dominant sources of forecast gross market benefits by the mid-2030s in the Slow Change scenario. Gross market benefits are forecast to increase in 2035-36 due to avoided and deferred PSH build, followed by a relatively stable trend by the end of the modelling period. The magnitude of the savings is expected to be smaller overall throughout the forecast as the need for additional capacity in the long term is lower than in the Central and other scenarios due to lower assumed demand growth and delayed coal-fired generator retirements. Compared to other scenarios, forecast fuel savings are a minor contribution to the overall benefits in the Slow Change scenario. In this scenario, VNI West is not assumed to be commissioned, reducing the opportunity for lower cost generation from the South, in particular Victoria, to displace higher cost New South Wales generation for load centres in NCEN.

2. Introduction

TransGrid has engaged EY to undertake market modelling of system costs and benefits to support the Reinforcing the New South Wales Southern Shared Network (HumeLink) Regulatory Investment Test for Transmission (RIT-T) relating to various network upgrade options to provide additional transfer capacity to the state's demand centres[15]. The RIT-T is a cost-benefit analysis used to assess the viability of investment options in electricity transmission assets.

This Report forms a supplementary report to the broader Project Assessment Draft Report (PADR) published by TransGrid[16]. It 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. This Report is accompanied by market modelling workbooks which contain summaries of key outcomes.

EY computed the least-cost generation dispatch and capacity development plan for the National Electricity Market (NEM) associated with four HumeLink augmentation options across a range of voltage variants, scenarios and sensitivities. The augmentation options were defined by TransGrid and are described in detail in the PADR[16]. This is an independent study and the modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator[17].

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

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

Each category of gross market benefits is computed annually across a 25-year modelling period from 2020-21 to 2044-45. Benefits presented are discounted to June 2020 using a 5.9 % real, pre-tax discount rate as selected by TransGrid. This value is sourced from the commercial discount rate calculated in the *RIT-T Economic Assessment Handbook* published by Energy Networks Australia[18] and is consistent with the value to be applied by the Australian Energy Market Operator (AEMO) in most scenarios in the 2019-20 Integrated System Plan (ISP)[19].

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[15] TransGrid RIT-T website available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network. Accessed 09 January 2020.

[16] TransGrid, *Reinforcing the NSW Southern Shared Network to increase transfer capacity to the state's demand centres (HumeLink) PADR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network. Accessed 10 January 2020.

[17] 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 09 January 2020.

[18] Energy Networks Australia, 15 March 2019, *RIT-T Economic Assessment Handbook*. Available at: https://www.energynetworks.com.au/rit-t-economic-assessment-handbook. Accessed 09 January 2020.

[19] AEMO, 24 September 2019, *2019 Input and Assumptions workbook, v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 09 January 2019.

This modelling considers twelve different HumeLink augmentation options. Figure 6 shows the four different HumeLink transmission augmentation options, which were modelled for three voltage variations: Operation at 330 kV (A), construction to 500 kV but initial operation at 330 kV (B), and construction and operation at 500 kV (C).

Figure 6: Overview of the HumeLink transmission augmentation options considered in this modelling[20]

For more information on the different options refer to the broader PADR published by TransGrid[20].

The gross market benefits of each HumeLink transmission augmentation option forecast in each scenario need to be compared to the relevant HumeLink augmentation cost to determine the forecast net market benefit for that option. The determination of the preferred option is dependent on option costs and was conducted outside of this Report by TransGrid, by incorporating the forecast gross modelled market benefits into the calculation of net market benefits. All references to the preferred option in this Report are in the sense defined in the RIT-T as "the credible option that maximises the net economic benefit across the market, compared to all other credible options"[21].

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.

[20] TransGrid, *Reinforcing the NSW Southern Shared Network to increase transfer capacity to the state's demand centres (HumeLink) PADR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network. Accessed 10 January 2020.

[21] 14 December 2018, *RIT-T and RIT-D application guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 09 January 2020.

- Section 4 provides an overview of scenario settings and sensitivities.
- Section 5 outlines model design and input data related to representation of the transmission network, transmission losses and demand.
- Section 6 provides an overview of model inputs and methodologies related to supply of energy.
- Section 7 describes the forecast generation and capacity outlooks in each of the scenarios without any network augmentation.
- Section 8 presents the forecast gross market benefits for each option across scenarios, and sensitivities. It is focussed on identifying and explaining the key sources of forecast gross market benefits with Option 3C, the preferred HumeLink augmentation option based on TransGrid's analysis of net market benefits. Key intra-connector flows as well as Snowy 2.0 capacity factors for Option 3C are provided next. Furthermore, key modelling outcomes of other scenarios are presented in this section. Lastly, the sensitivities and their market modelling outcomes are given.

3. Methodology

3.1 Long-term investment planning

EY has used linear programming techniques to perform hourly time-sequential, least-cost, long-term NEM development optimisation modelling spanning 25 years from 2020-21 to 2044-45. The modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator[22].

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[23] trading interval in relation to:

- the generation dispatch level for each power plant along with the charging and discharging of storage. Units are assumed to bid at their short-run marginal cost (SRMC), which is derived from their VOM and fuel costs. The generation for each trading interval is subject to the modelled availability of power stations in each hour (those that are not on planned or un-planned outages), network limitations and energy limits (e.g., storage levels).
- commissioning new entrant capacity for wind, solar PV SAT[24], CCGT, OCGT, large-scale storage and pumped storage hydro (PSH). We screened nuclear and any other technology options "possible" and found that they would not be a part of the least cost plan.

These hourly decisions take into account constraints that include:

- supply must equal demand in each region for all trading intervals, while maintaining a reserve margin, with USE costed at the value of customer reliability (VCR)[25],
- minimum loads for some generators,
- transmission interconnector flow limits (between regions),
- intra-regional flow limits (between zones in New South Wales),
- Canberra zone lines and defined cut-set flow limits,

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[22] 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 09 January 2020.

[23] 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.

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

[25] AEMO, September 2014, *Value of customer reliability review: final report* CPI adjusted to March 2019. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review. Accessed 09 January 2020.

- maximum and minimum storage reservoir limits (for conventional storage hydro, PSH and large-scale battery storage),
- new entrant capacity build limits for wind and solar for each REZ where applicable, and PSH in each region,
- emission constraints, as defined for each scenario,
- renewable energy targets where applicable by region or NEM-wide in applicable scenarios.

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 detailed network representations of the Canberra zone by applying a DC load flow model described in Section 5.2.

The model incorporates as inputs the assumed fixed age based/announced retirement dates for existing generation, with the exception of the Economic Retirement Sensitivity. It also factors in the annual costs, including annualised capital costs, for all new generator capacity and the model decides how much new capacity to build in each region to deliver the least-cost market outcome.

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

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

- Dispatchable generators, typically coal, gas and liquid fuel which are assumed to have unlimited energy resource in general. An assumed energy limit is placed on coal-fired power stations approximately equal to the maximum annual energy generated in last five years, reflecting coal rail and contractual supply limitations. The running costs for these generators is the sum of the VOM and fuel costs. Coal generators and some CCGTs have minimum loads to reflect operational stability limits and high start-up costs and this ensures they are always online when available. This is consistent with the self-commitment nature of the design of the NEM. On the other hand, peaking generators have no minimum operating level and start whenever their variable costs will be recovered and will operate for a minimum of one hour.
- Wind and solar generators are fully dispatched according to their available variable resource in each hour, unless constrained by oversupply or network limitations.
- Storage plant of all types (conventional hydro generators with storages, PSH 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 PSH and large-scale battery storage operate in pumping or charging mode.

3.1.1 Reserve constraint in long-term investment planning

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

All dispatchable generators in each region are eligible to contribute to reserve (except PSH and large-scale battery storages[26]) and headroom that is available from interconnectors. The hourly modelling accounts for load diversity and sharing of reserves across the NEM and so minimises the

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

amount of reserve carried, and provides reserve from the lowest cost providers, including allowing for each region to contribute to its neighbours' reserve requirements through interconnectors.

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

This constraint is applied to only a subset of simulation hours (highest 1% 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 5.2 and Section 5.3.

The Canberra zone transmission network is explicitly modelled through a DC load flow technique incorporating losses in the TSIRP, whose details are given in section 5.2. Additional losses within New South Wales zones and within the remaining NEM regions are captured through an estimate of loss factors for existing and new entrant generators. To estimate these loss factors, the TSIRP model is interfaced with an AC load flow program. Hourly generation dispatch outcomes from the model are transferred to nodes in a network snapshot. These estimated loss factors are then returned to the TSIRP model and used in a further refining pass to ensure new entrant developments are least-cost when accounting for changing load and generation patterns. Loss factors are estimated based on hourly outcomes for one year at each five-year interval[27]. This method of estimating and incorporating loss factors is sufficient to give a geographic investment signal related to transmission network utilisation. The reduced energy delivered from generators to serve load as a result of the loss factors is incorporated in the modelling.

3.1.3 Cost-benefit analysis

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

- capital costs of new generation capacity installed,
- total FOM costs of all generation capacity,

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

- 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 HumeLink augmentation 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 the HumeLink augmentation, 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 PSH and large-scale battery storage between each HumeLink augmentation option and counterfactual Base case.

Each component of gross market benefits is computed annually over the 25-year modelling period. In this Report, we summarise the benefit and cost streams using a single value computed as the Net Present Value (NPV)[28], discounted to June 2020 at a 5.9 % real, pre-tax discount rate as selected by TransGrid. This value is sourced from the commercial discount rate calculated in the *RIT-T Economic Assessment Handbook* published by Energy Networks Australia[29] and is consistent with the value to be applied by AEMO in most scenarios in the 2019-20 ISP[30].

The gross market benefits of each HumeLink augmentation option forecast in each scenario and with each voltage variant need to be compared to the relevant HumeLink augmentation cost to determine whether there is a positive forecast net market benefit. The determination of the preferred option is dependent on option costs and was conducted outside of this Report by TransGrid[31]. All references to the preferred option in this Report are in the sense defined in the RIT-T as "the credible option that maximises the net economic benefit across the market, compared to all other credible options"[32].

3.2 Short-term market dispatch simulation

The TSIRP model computes the least-cost generation development plan with perfect foresight based on a single pre-determined forced outage pattern. This creates the possibility that there would be insufficient capacity in the optimal plan to meet the reliability standard when assessed against multiple different forced outage patterns.

We validated the generation development plan using a short-term market dispatch simulation. The short-term model takes the generation development plan computed by the long-term TSIRP model and dispatches it at SRMC with multiple Monte Carlo samples of forced outage patterns. The expected annual USE is then calculated and compared against the reliability standard. This check was done for the Central scenario Option 3C for sample years which coincided with assumed thermal generator retirements. No adjustments needed to be made to the generation development plan based on these simulations given the USE was within the reliability standard range.

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

29 Energy Networks Australia, 15 March 2019, *RIT-T Economic Assessment Handbook*. Available at: https://www.energynetworks.com.au/rit-t-economic-assessment-handbook. Accessed 09 January 2020.

30 AEMO, 24 September 2019, *2019 Input and Assumptions workbook, v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 09 January 2020.

31 Transgrid, *Reinforcing the NSW Southern Shared Network to increase transfer capacity to the state's demand centres (HumeLink) PADR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network. Accessed 10 January 2020.

32 14 December 2018, *RIT-T and RIT-D application guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 09 January 2020.

4. Scenarios and sensitivity assumptions

4.1 Scenarios

The credible options have been assessed under four scenarios selected by TransGrid after public consultation following publication of the Project Specification Consultation Report (PSCR)[33]. These are summarised in Table 2 and are broadly in line with the scenarios described in AEMO's 2019-20 ISP (draft)[34]. As noted in Table 2, most input data are sourced from the accompanying 2019 Input and Assumptions workbook which formed the initial consultation for the 2019-20 ISP[35]. The version from September 2019 was the most up-to-date data source available at the time of modelling for this assessment.

Table 2: Overview of key input parameters across four scenarios[36]

Key drivers input parameter	Scenario			
	Fast Change	Central	Step Change	Slow Change
Underlying consumption	AEMO ISP 2019-20 Fast Change	AEMO ISP 2019-20 Central	AEMO ISP 2019-20 Step Change	AEMO ISP 2019-20 Slow Change
New entrant capital cost for wind, solar SAT, OCGT, CCGT, PSH, and large-scale batteries	AEMO 2019 ISP '2 degree' scenario.	AEMO 2019 ISP '4 degree' scenario.	AEMO 2019 ISP '2 degree' scenario with stronger reductions for wind, PSH and batteries.	AEMO 2019 ISP '4 degree' scenario with weaker reductions for wind, PSH and batteries.
Retirements of coal-fired power stations	Half of stations' capacity retired 2 years earlier than Central. Liddell 2022-2023 fixed.	AEMO Generation Information[37] announced retirement date or end-of-technical-lives.	Half of stations' capacity retired 5 years earlier than Central. Liddell 2022-2023 fixed.	Half of stations' capacity retired 5 years later than Central. Liddell 2022-2023 fixed.
Gas fuel cost	AEMO 2019 ISP: Core Energy 2019, Neutral		AEMO 2019 ISP: Core Energy 2019, Fast	AEMO 2019 ISP: Core Energy 2019, Slow
Coal fuel cost	AEMO 2019 ISP: WoodMackenzie 2019, Neutral		AEMO 2019 ISP: WoodMackenzie 2019, Fast	AEMO 2019 ISP: WoodMackenzie 2019, Slow
Federal Large-scale Renewable Energy Target (LRET)	33 TWh by 2020 to 2030 (including GreenPower and ACT scheme)			

[33]TransGrid, *Reinforcing the New South Wales Southern Shared Network to increase transfer capacity to the state's demand centres PSCR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network/Documents/TransGrid%20PSCR_Reinforcing%20NSW%20Southern%20Shared%20Network.pdf. Accessed 09 January 2020.

[34] AEMO, *2019-20 Integrated System Plan*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 09 January 2020.

[35] AEMO, 24 September 2019, *2019 Input and Assumptions workbook v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 09 January 2020.

[36] Ibid, unless otherwise stated in table.

[37] AEMO, 2 September 2019, *Generating Unit Expected Closure Year – 02 September 2019*. No *longer available online. Available from TransGrid upon request.*

Key drivers input parameter	Scenario			
	Fast Change	Central	Step Change	Slow Change
COP21 commitment (Paris agreement)	52 % reduction from 2005 by 2030, then a linear extrapolation beyond 2030 to 90 % reduction of 2005 emissions by 2050	28 % reduction from 2005 by 2030, then a linear extrapolation beyond 2030 to 70 % reduction of 2016 emissions by 2050	52 % reduction from 2005 by 2030, then a linear extrapolation beyond 2030 to 90 % reduction of 2005 emissions by 2050	28 % reduction from 2005 by 2030, then a linear extrapolation beyond 2030 to 70 % reduction of 2016 emissions by 2050
Victoria Renewable Energy Target (VRET)	40 % renewable energy by 2025 and 50 % renewable energy by 2030			40 % renewable energy by 2025
Queensland Renewable Energy Target (QRET)	50 % by 2030			Q400 only
South Australia Energy Transformation RIT-T	NSW to SA interconnector (Project EnergyConnect) is assumed commissioned by July 2023[38]			
Western Victoria Renewable Integration RIT-T	The preferred option in the Western Victoria Renewable Integration PACR[39] by July 2025 (220 kV upgrade in 2024 and 500 kV to Sydenham in 2025).			
Marinus Link and Battery of the Nation	Assumed commissioned by July 2033 600 MW bi-directional[40]	Excluded	Assumed commissioned by July 2033 1200 MW bi-directional[41]	Excluded
Victoria to NSW Interconnector Upgrade	The Victoria to New South Wales Interconnector Upgrade PADR[42] preferred option is assumed commissioned by July 2022.			
Snowy 2.0	Snowy 2.0 is included from July 2025			
VNI West	The VNI West ISP 2019 preferred option is assumed commissioned by July 2026			Excluded

4.2 Sensitivities

A number of sensitivities to the market modelling have been selected by TransGrid to test the robustness of the forecast gross market benefits in light of uncertainties in input parameters and alternative behaviours. Specifically, the eight sensitivities undertaken in the market modelling are:

- Snowy 2.0 does not proceed, Central and Slow Change scenarios,
- QNI upgrade Option 3C from 2028-29 in the Fast Change scenario,

[38] ElectraNet, 13 February 2019. *SA Energy Transformation RIT-T: Project Assessment Conclusions Report*. Available at: https://www.electranet.com.au/wp-content/uploads/projects/2016/11/SA-Energy-Transformation-PACR.pdf. Accessed 09 January 2020. There are options for commissioning between 2022 and 2024. Limits also from this document.

[39] 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 09 January 2020.

[40] AEMO, 24 September 2019, *2019 Input and Assumptions workbook v1.2*, VIC-TAS Second IC - Option 1. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 09 January 2020.

[41] AEMO, 24 September 2019, *2019 Input and Assumptions workbook v1.2*, VIC-TAS Second IC - Option 2. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 09 January 2020.

[42] 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 09 January 2020.

- economic retirements allowing for earlier than technical life retirements only, as well as economic retirements allowing for earlier and deferred retirements, both under the Central scenario.
- 50% POE demand under the Central scenario,
- High DER scenario,
- staged development of Option 3C, i.e. Maragle-Wagga Wagga-Bannaby lines first and Maragle-Bannaby later, in all scenarios,
- commissioning of VNI West delayed to 2034-35 under the Central scenario,
- demand management prior to the augmentation under the Central scenario.

5. Transmission and demand

5.1 Regional and zonal definitions

TransGrid elected to split New South Wales into sub-regions or zones in the modelling presented in this Report, with a high resolution of the Canberra zone, as listed in Table 3. In TransGrid's view, this enables better representation of intra-regional network limitations and transmission losses.

Table 3: Regions, zones and reference nodes

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

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

The borders of each zone or region are defined by the cut-sets listed in Table 4, as defined by TransGrid.

Table 4: Key cut-set definitions

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

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

Table 5 summarises the key cut-set limits in the Canberra zone and from Canberra to NCEN, as defined by TransGrid.

Table 5: Key cut-set limits

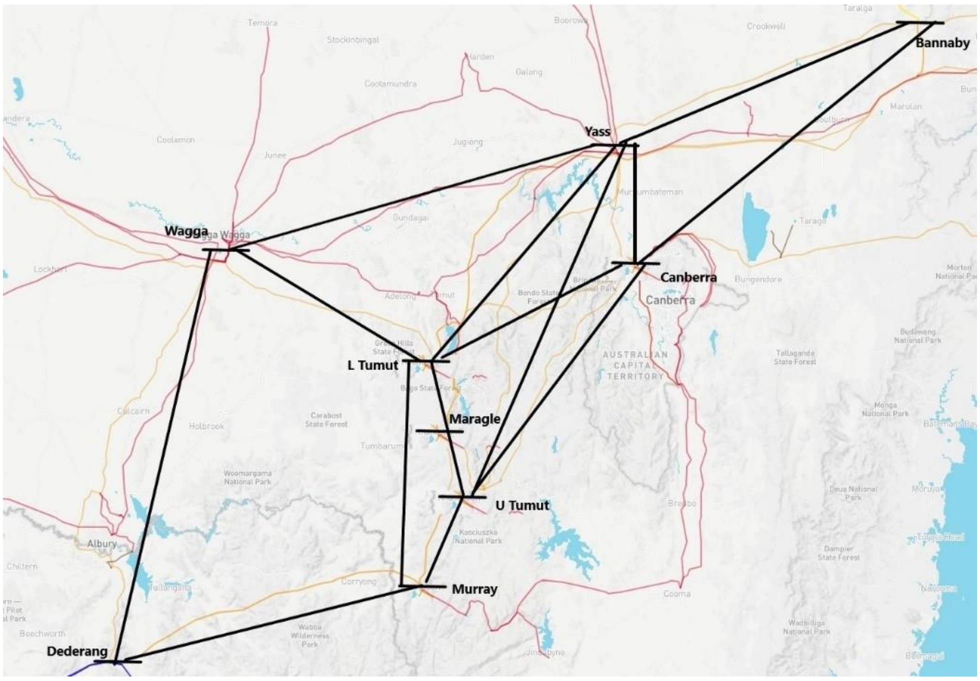
Options	Snowy cut-set	Snowy cut-set + HumeLink lines	CAN/YASS – NCEN cut-set	CAN-NCEN cut-set
Do Nothing	2700 Post VNI 2870	2700 Post VNI 2870	2700	2700
Option 1A	2970	4515	3970	3970
Option 1B	2970	4660	4110	4080
Option 1C	2980	5920	5330	4500
Option 2A	2900	4560	4230	3930

Options	Snowy cut-set	Snowy cut-set + HumeLink lines	CAN/YASS – NCEN cut-set	CAN-NCEN cut-set
Option 2B	2960	4660	4180	4140
Option 2C	3080	5230	5230	4500
Option 3A	2990	4320	3830	3830
Option 3B	2980	4460	3880	3880
Option 3C	3080	5372	4900	4500
Option 4A	3010	4370	3800	3800
Option 4B	3020	4580	4010	4010
Option 4C	3080	5372	5000	5000

5.2 Canberra equivalent network

To achieve a more detailed forecast of southern NSW network flows, the Canberra subregion is further subdivided into nine nodes including Lower Tumut, Upper Tumut, Maragle, Yass, Canberra, Wagga, Dederang, Murray, and Bannaby as shown below in Figure 7. The lines are derived by equivalencing the network connecting the given nodes in the subregion. Demand components are split across the nodes based on their half-hourly proportion of the overall NSW load in 2017-18. Furthermore, generators within this subregion are mapped into the nearest node.

Figure 7: Canberra equivalent network



The TSIRP models the Canberra zone's flows and losses using DC load flow (DCLF) equations. DCLF is a simplified AC load flow which neglects reactive power flows. The model also captures the losses for the given lines through piecewise linear functions using the equivalent resistance of those lines.

5.3 Interconnector and intra-connector loss models

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

- when a new link is defined e.g. NNS-NCEN, SA-SWNSW (Project EnergyConnect), Bannaby-NCEN, 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-DED instead of VIC-NSW,
- when future upgrades involving conductor changes are modelled e.g. VNI West and Marinus Link.
- for Canberra equivalent lines, using their resistance.

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

5.4 Interconnector and intra-connector capabilities

The notional limits imposed on interconnectors are shown in Table 6. The following interconnectors are included in the left-hand side of constraints which may restrict them below the notional limits specified in this table:

- Heywood + Project EnergyConnect has combined transfer export and import limits of 1,300 MW and 1,450 MW. The model will dispatch them to minimise costs.
- QNI bi-directional limits due to stability and thermal constraints provided by TransGrid.

Table 6: Notional interconnector capabilities used in the modelling (sourced from TransGrid and AEMO 2019-20 ISP[43])

Interconnector (From node – To node)	Import[44] notional limit	Export[45] notional limit
QNI	depending on Sapphire generation and demand, as per Expanding NSW-QLD transmission transfer capacity PADR (Base case from 1 July 2020 and upgrade to Option 1A from 1 July 2022)[46]	depending on Sapphire generation and demand, as per Expanding NSW-QLD transmission transfer capacity PADR (Base case from 1 July 2020 and upgrade to Option 1A from 1 July 2022)
Terranora (NNS-SQ)	-150 MW	50 MW
VIC-NSW[47] (VIC-CAN)	-250 MW	550 MW (Base) 720 MW (after VNI minor upgrade from 1 July 2022)
VIC-NSW (VIC-SWNSW)	-150 MW (Base) -500 MW (after EnergyConnect) and -1,950 MW (after VNI West from 1 July 2026)	150 MW (Base) 500 MW (after EnergyConnect) and 2,250 MW (after VNI West from 1 July 2026)
Project EnergyConnect (SWNSW-SA)	-800 MW	800 MW

[43] AEMO, *2019-20 Integrated System Plan*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 09 January 2020.

[44] 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.

[45] 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.

[46] 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 09 January 2020.

[47] 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.

Interconnector (From node – To node)	Import[44] notional limit	Export[45] notional limit
Heywood (VIC-SA)	-650 MW (before Project EnergyConnect) -750 MW (after Project EnergyConnect)	650 MW (before Project EnergyConnect) 750 MW (after Project EnergyConnect)
Murraylink (VIC-SA)	-200 MW	220 MW
Basslink (TAS-VIC)	-478 MW	478 MW
Marinus Link[48] (TAS-VIC)	-600 MW for the Fast Change scenario and -1200 MW for the Step Change scenario	600 MW for the Fast Change scenario and 1200 MW for the Step Change scenario

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 7.

Table 7: 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[46])	1,200 MW (Base) 1,377 MW (after QNI Option 1A[46])
CAN-SWNSW	-700 MW (before Project EnergyConnect) -1,400 MW (after Project EnergyConnect, before VNI West) -3,000 MW (after VNI West)	700 MW (before Project EnergyConnect) 1,400 MW (after Project EnergyConnect, before VNI West) 3,000 MW (after VNI West)

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 (scenario-dependent),
- the nine reference years are repeated sequentially throughout the modelling horizon as shown in Figure 8.
- the future hourly rooftop PV generation has been estimated based on insolation in the corresponding reference year and the projection of future rooftop PV capacity, which is subtracted from the forecast underlying demand along with other behind-the-meter components (e.g., electric vehicles and domestic storage) to get a projection of hourly operational demand.

[48] Proposed interconnector for a second DC interconnector between Tasmania and Victoria. With Marinus Link still undergoing the RIT-T process, TransGrid has assumed Option 1 from the AEMO September 2019 Input and Assumptions workbook as the preferred option for the Fast Change scenario and Option 2 for the Step Change scenario.

Figure 8: Sequence of demand reference years applied to forecast

Modelled year	Reference year
2020-21	2011-12
2021-22	2012-13
2022-23	2013-14
2023-24	2014-15
2024-25	2015-16
2025-26	2016-17
2026-27	2017-18
2027-28	2018-19
2028-29	2010-11
2029-30	2011-12
2030-31	2012-13
2031-32	2013-14
2032-33	2014-15
2033-34	2015-16
2034-35	2016-17
2034-35	2017-18
2035-36	2018-19
...	...
2041-42	2015-16
2042-43	2016-17
2043-44	2017-18
2044-45	2018-19

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

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

TransGrid selected demand forecasts from the AEMO 2019-20 ISP[49] in all scenarios (see Section 4.1), which are used as inputs to the modelling. Figure 9 to Figure 13 shows the NEM

[49] AEMO, *2019-20 Integrated System Plan*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 09 January 2020.

operational energy and rooftop PV as well as NSW operational energy, operational peak and rooftop PV for all scenarios modelled.

Figure 9: Annual operational demand in all scenarios for the NEM from AEMO's 2019 Input and Assumptions workbook[50]

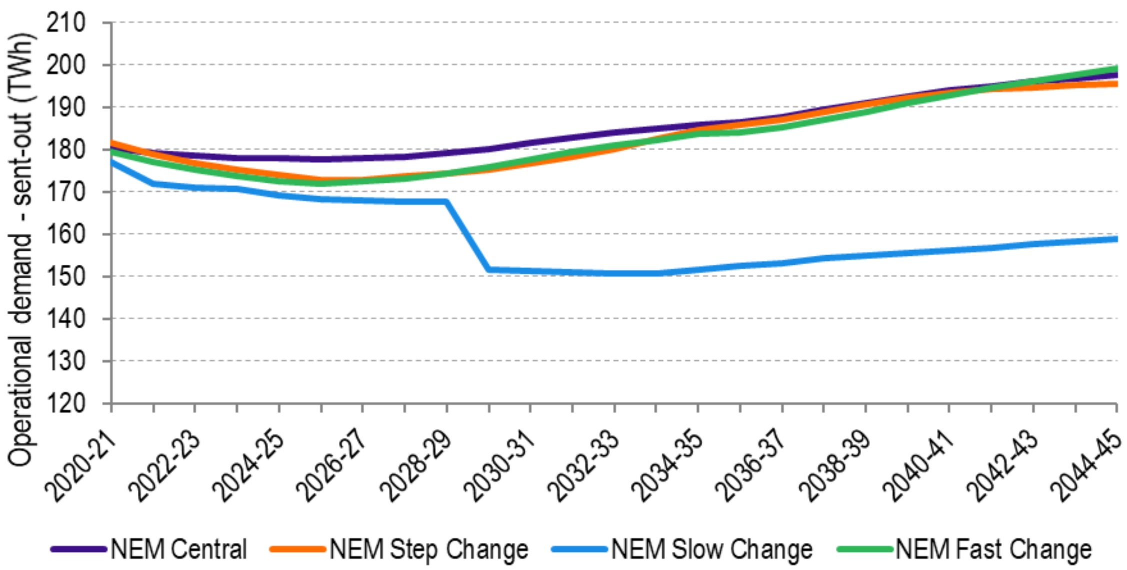
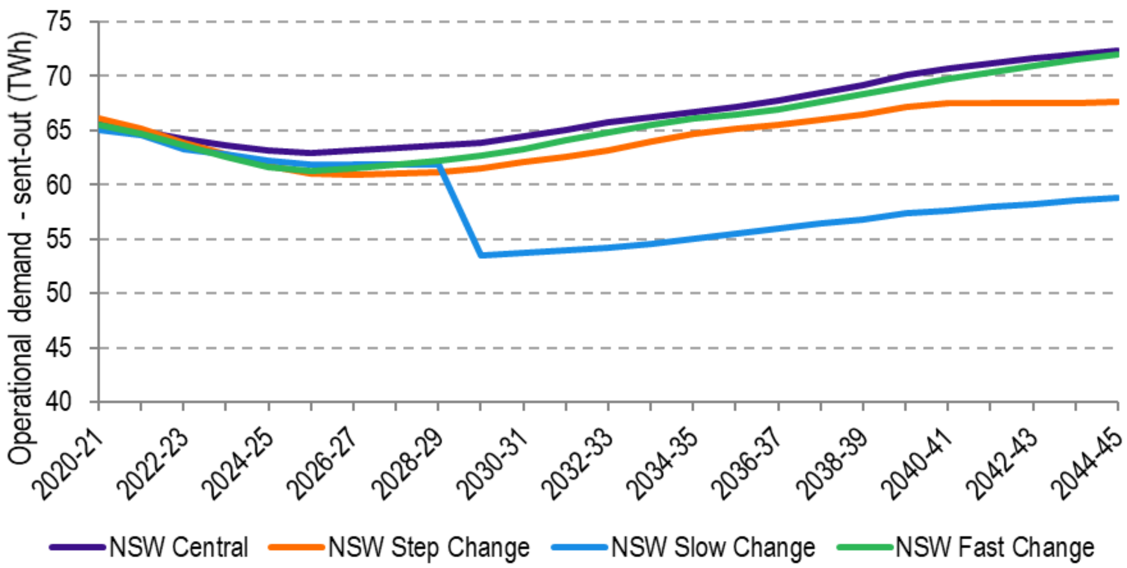


Figure 10: Annual operational demand in all scenarios for NSW from AEMO's 2019 Input and Assumptions workbook[50]



[50] AEMO, 24 September 2019, *2019 Input and Assumptions workbook v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 09 January 2020.

Figure 11: Annual summer maximum demand in NSW for 10% POE from AEMO's 2019 Input and Assumptions workbook[51]

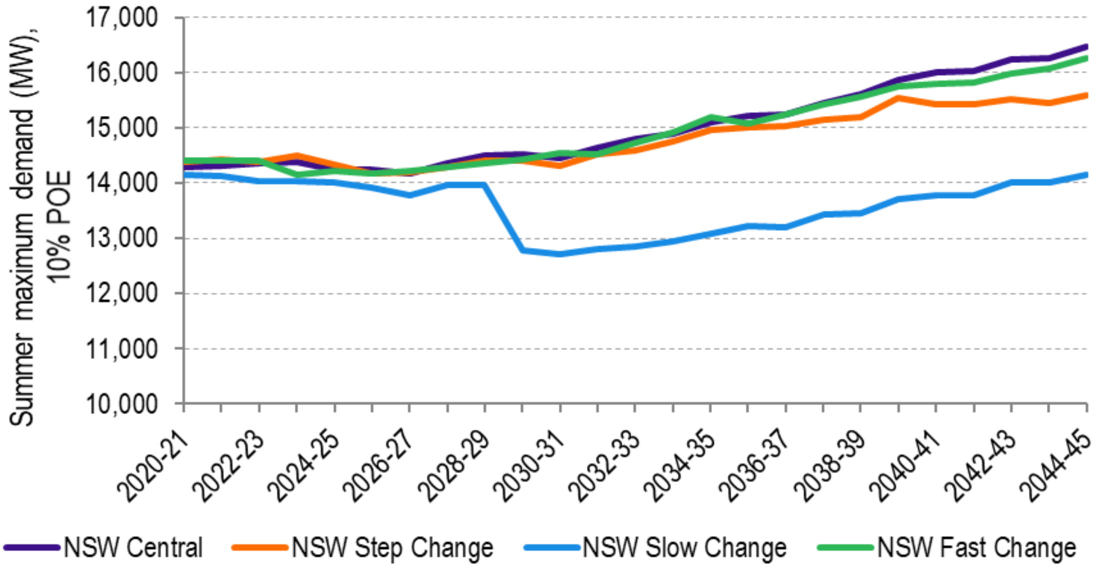
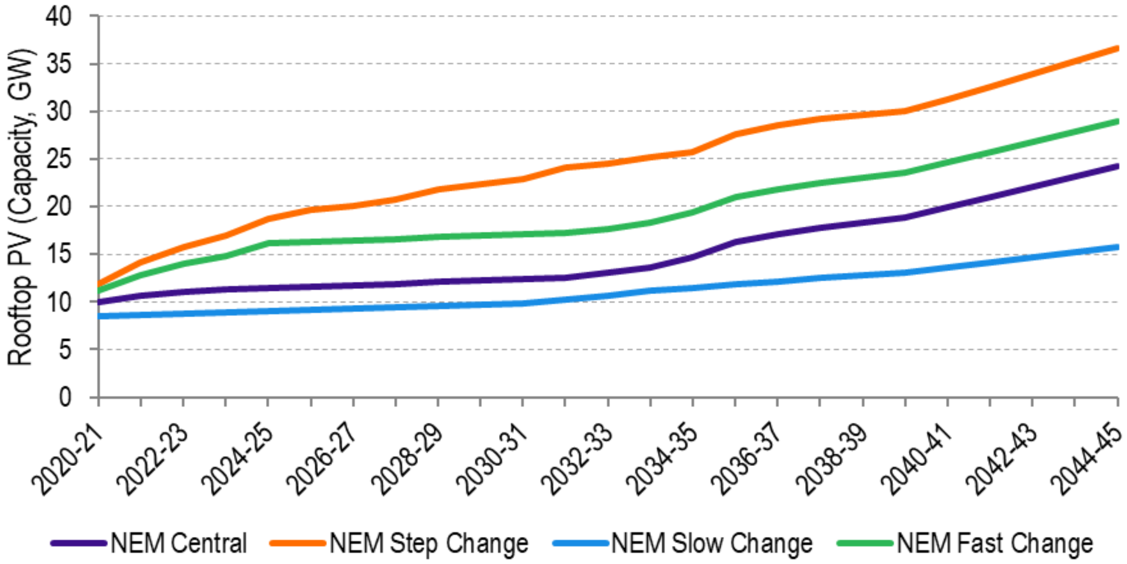
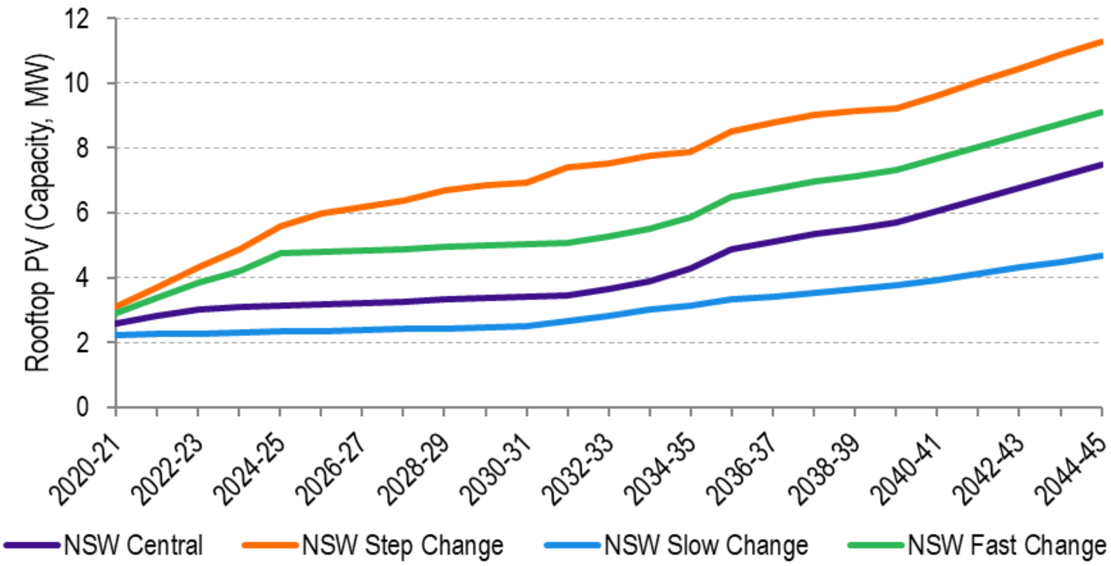


Figure 12: Annual rooftop PV uptake in the NEM from AEMO's 2019 Input and Assumptions workbook[51]



[51] AEMO, 24 September 2019, *2019 Input and Assumptions workbook v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 09 January 2020.

Figure 13: Annual rooftop PV uptake in NSW from AEMO's 2019 Input and Assumptions workbook[52]



The AEMO 2019-20 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.

[52] AEMO, 24 September 2019, *2019 Input and Assumptions workbook v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 09 January 2020.

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 HumeLink augmentation option. The source of this list varies with region:

- AEMO 2019 ISP Input and Assumptions workbook[53], committed projects, advanced VRET projects and committed battery storage projects are used.
- In New South Wales, several additional generators anticipated by TransGrid based on the maturity of the connection applications are modelled, as listed in Table 8. These projects are anonymised in our modelling.

Table 8: Capacity anticipated by TransGrid

Region	Zone	Solar capacity (MW)	Wind capacity (MW)
NSW	NNS	910	0
	NCEN	450	160
	Yass	0	331
	Wagga	80	0
	SWNSW	147	0

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

Table 9: Summary of wind and solar availability methodology

Technology	Category	Capacity factor methodology	Reference year treatment
Wind	Existing	Specify long-term target based on nine-year average in AEMO ESOO 2019 traces[54] 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 2019-20 ISP assumptions. One high quality option and one medium quality trace per REZ.	

[53] AEMO, 24 September 2019, *2019 Input and Assumptions workbook v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 09 January 2020.

[54] 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 09 January 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.	Capacity factor varies with reference year based on historical, site-specific insolation measurements.
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 2019-20 ISP assumptions.	Capacity factor varies with reference year based on historical insolation measurements.

All existing and committed large-scale wind and solar farms in the NEM are modelled on an individual basis. Each project has a location-specific availability profile based on historical resource availability. The availability profiles are derived using nine years of historical weather data covering financial years between 2010-11 and 2018-19 (inclusive), and synchronised with the hourly shape of demand. Wind and solar availability profiles used in the modelling reflect generation patterns occurring in the nine historical years, and these generation patterns are repeated throughout the modelling period as shown in Figure 8.

The availability profiles for wind generation are derived from simulated wind speeds from the Australian Bureau of Meteorology's Numerical Weather Prediction systems[55] 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[56] for each REZ (new entrant wind farms, as listed in Table 10).

The availability profiles for solar are derived using solar irradiation data downloaded from satellite imagery processed by the Australian Bureau of Meteorology. As for wind profiles, the solar profiles reflect inter-annual variations over nine historical years, but at the same time achieve long-term capacity factors in line with historical performance (existing solar farms) or close to AEMO's approximation for each REZ (generic new entrant solar farms as listed in Table 10).

Table 10: REZ wind and solar approximate average capacity factors over nine reference years[57]

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%

[55] 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 09 January 2020.
[56] 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 09 January 2020.
[57] AEMO, 24 September 2019, *2019 Input and Assumptions workbook v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 09 January 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 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[58]	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

[58] 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[59].

- 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 and maintenance

Forced outage rates for coal generators are based on EY analysis of historical performance. The AEMO 2019 Input and Assumptions workbook[59] provides the forced outage rates for the coal generators as a regional aggregate. EY's analysis applies generator-specific full forced outage rates. TransGrid elected to deviate from the ISP full forced outage rates for coal generators to capture more granular observations of the apparent availability of the existing coal fleet. Table 11 below summarises the full forced outage rates outlined in the ISP along with the rate applied in modelling presented in this Report. Partial outage rates and mean time to repair used in the modelling are the same as in the 2019 Input and Assumptions workbook[60].

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

Generator	AEMO September ISP 2019-20 Assumptions full forced outage rate[59]	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 %

[59] AEMO, 24 September 2019, *2019 Input and Assumptions workbook v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 09 January 2020.

[60] AEMO, 24 September 2019, *2019 Input and Assumptions workbook v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 09 January 2020.

Generator	AEMO September ISP 2019-20 Assumptions full forced outage rate[59]	Full forced outage rate applied in modelling in this Report
Stanwell	2.30 %	0.59 %
Tarong	2.30%	4.38 %
Tarong North	2.30 %	7.60 %
Vales Point	6.22% (until 2022) 4.30 % (after 2022)	7.52 %
Yallourn	5.43 %	11.24 %

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

All unplanned forced outage patterns are set by a random number generator for each existing generator. The seed for the random number generator is set such that the same forced outage pattern exists between the Base case and the various upgrade options. New entrant generators are de-rated by their equivalent forced outage rate as defined in the AEMO 2019 Input and Assumptions workbook[64].

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[64].

6.3 Generator technical parameters

All technical parameters are as detailed in the AEMO 2019 Input and Assumptions workbook[64], except where noted in this section.

6.3.1 Coal-fired generators

Coal-fired generation is treated as dispatchable between minimum load and maximum load. Must run generation is dispatched whenever available at least at its minimum load. In line with the AEMO 2019 Input and Assumptions workbook[64], maximum loads vary seasonally. This materially reduces the amount of available capacity in the summer periods.

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

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

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

[64] AEMO, 24 September 2019, *2019 Input and Assumptions workbook v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 09 January 2020.

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

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

6.3.2 Gas-fired generators

Gas-fired CCGT plant also typically have a must-run component and so are dispatched at or above their minimum load to deliver efficient fuel consumption. Minimum loads are applied to several gas generators as listed in Table 12. These assumptions are in line with the AEMO 2019 Input and Assumptions workbook[66].

Table 12: Minimum loads applied to gas-fired power stations

Generator	Value in AEMO September 2019 assumptions (MW)
Condamine	20
Darling Downs	58
Yarwun	54
Osborne	110
Pelican Point	110
Smithfield	30
Tallawarra	190
Swanbank E	120
Barcaldine	14
Tamar Valley CCGT	112
Yabulu	15

TransGrid has assumed a minimum load of 50 % of capacity for all new CCGTs to reflect minimum load conditions for assumed efficient use of gas and steam turbines in CCGT operating mode.

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

A minimum capacity factor is assumed for SA gas generators including Osborne (50%), Pelican Point (50%) and Torrens Island B (20%) as described in the 2019 Input and Assumptions workbook[66].

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.

[66] AEMO, 24 September 2019, *2019 Input and Assumptions workbook v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 09 January 2020.

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

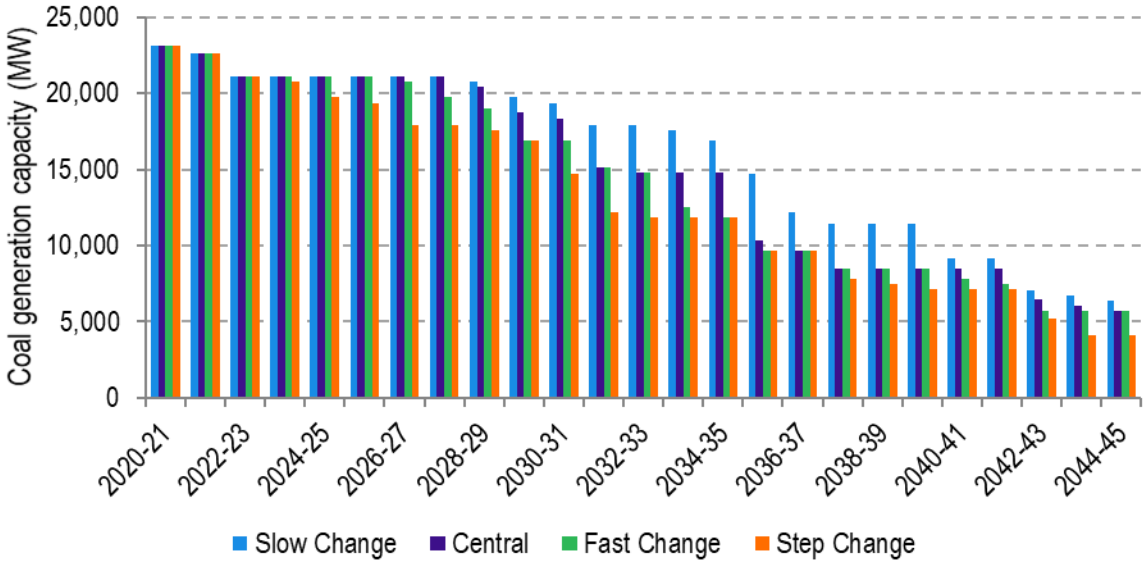
Conventional hydro with storages, PSH and batteries are dispatched in each trading interval such that they are most effective in reducing the costs of generation up to the limits of their storage capacity.

Hourly hydro inflows to the reservoirs and ponds are computed from monthly values sourced from the AEMO 2019 Input and Assumptions workbook and the median hydro climate factor trajectory for the respective scenario applied [67]. The Tasmanian hydro schemes were modelled using a simplified six pond model.

6.4 Retirements

According to the scenario settings selected by TransGrid after public consultation following publication of the PSCR, thermal retirements in the model are fixed. Retirement dates for the Central scenario are sourced from the latest Generation Information expected closure year document at the time of modelling[68]. Other scenarios vary from these dates as noted in Table 2. Coal retirements across scenarios are illustrated in Figure 14.

Figure 14: Coal capacity in the NEM by year across all scenarios



6.5 Snowy 2.0 operation assumptions

In all scenarios Snowy 2.0 is assumed to be commissioned in 2025-26, the first full financial year after the assumed commissioning date of March 2025 in the ISP Input and Assumptions workbook.

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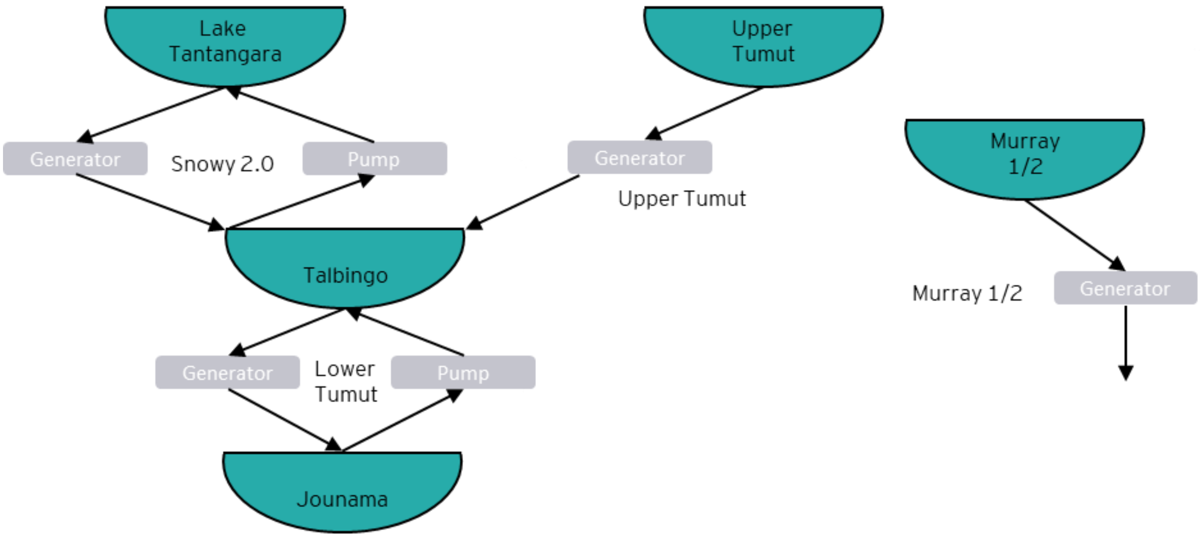
[67] AEMO, 24 September 2019, *2019 Input and Assumptions workbook v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 09 January 2020.

[68] AEMO, 2 September 2019, *Generating Unit Expected Closure Year – 2 September 2019*. No longer available online. Available on request from TransGrid.

Figure 15 shows the modelled Snowy Hydro scheme[69] in the TSIRP. In our modelling, the storage level of Talbingo reservoir factors in and tracks all the following[70]:

- inflows from Snowy Hydro T1/T2 (Upper Tumut) hydro scheme,
- inflows from Tantangara reservoir due to Snowy 2.0 generation,
- inflows from Jounama reservoir due to Tumut 3 pumping,
- outflows to Tantangara reservoir for Snowy 2.0 pumping,
- outflows from Tumut 3 generation to Jounama reservoir.

Figure 15: Snowy Hydro scheme topology[71]



The methodology used to simulate operation of all water storages in the NEM is the same, and the operation of Snowy 2.0 is an example of how the storages are used to most effectively deliver the least cost solution. The storage capacity of Snowy 2.0 is approximately equivalent to seven days of continuous operation. The model assumes that the storages for the upper and lower pond are set at the start of the modelling period to a value between maximum and minimum. Since the TSIRP optimisation provides Snowy 2.0 with perfect foresight, it finds the most beneficial time to generate, typically during high fuel cost periods, which tend to coincide with lower intermittent renewable generation levels, and the most beneficial time to pump, typically in low fuel cost periods, which tend to coincide with higher intermittent renewable generation levels. The methodology then offsets each MWh of generation by an equivalent amount of pumping, taking into account the cyclic efficiency of Snowy 2.0, which is assumed as 76%[72]. The methodology allocates matching amounts of generation and pumping to Snowy 2.0, until the benefit of another MWh of Snowy 2.0 generation matches the cost of fuel to pump to balance that generation. Any additional cycling operation for which the costs exceed the benefits is prevented. The model also accounts for

[69] AEMO, August 2019, *Market Modelling Methodologies.* Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Market-Modelling-Methodology-Paper.pdf. Accessed 09 January 2020.

[70] Snowy Hydro, https://www.snowyhydro.com.au/our-scheme/snowy20/faqs20-2/. Accessed 09 January 2020.

[71] AEMO, August 2019, *Market Modelling Methodologies.* Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Market-Modelling-Methodology-Paper.pdf. Accessed 09 January 2020.

[72] AEMO, 24 September 2019, *2019 Input and Assumptions workbook v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 09 January 2020.

the upper and lower pond minimum and maximum levels and prevents these being breached, even if the market signal favours more cycling if possible.

Since the model can look ahead in time, equivalent to factoring in weather forecasts up to seven days, the breakeven point for the marginal cost of generating and pumping may rise or fall over time, by day, week or season. In times of relative scarcity in cheap resources, typically when wind, solar or thermal resources are not plentiful, the marginal cost at which Snowy 2.0 generates will increase to conserve water. Conversely, if there is low marginal cost generation available to pump, the marginal cost of generation from Snowy 2.0 will also reduce.

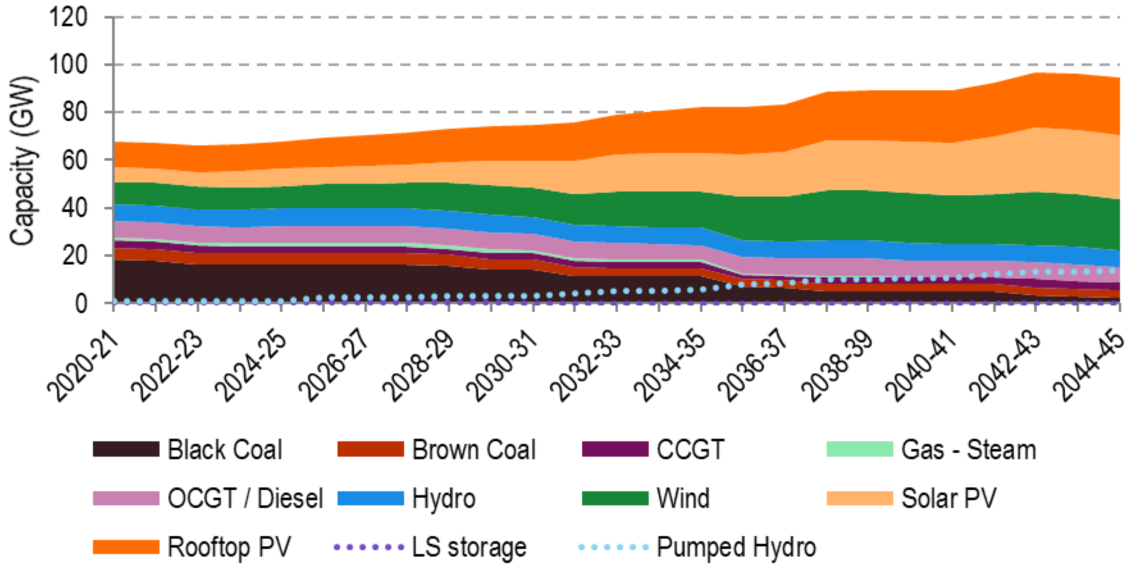
A number of sensitivities have been conducted around the operation, development and capacity of Snowy 2.0 to verify the robustness of the modelling outcomes and their dependence on Snowy 2.0. A sensitivity reducing the active capacity of the pondage from seven days to three and a half days showed only a small reduction in benefit, confirming that Snowy 2.0 would be operable under all forecast conditions without restrictions due to lack of storage volume.

7. NEM outlook across scenarios without HumeLink transmission upgrade

Before considering the benefits of HumeLink augmentation options, it is useful to examine the differences between the generation and capacity forecast outlooks in each of the modelled scenarios. For the sake of comparison, we provide the NEM capacity and generation outlook for the Central scenario and then the difference between each other scenario and the Central scenario.

The NEM-wide capacity mix forecast in the Central scenario without the HumeLink transmission upgrade is shown in Figure 16. Without any HumeLink upgrades, the forecast generation capacity of the NEM gradually shifts towards increasing capacity of wind, solar, PSH and gas.

Figure 16: NEM capacity mix forecast for the Central scenario without HumeLink upgrade



The first new capacity installed by the model as part of the least-cost development plan to meet demand is approximately 600 MW of new solar capacity in Central West NSW in 2023-24, the year after Liddell is assumed to retire. In 2024-25 approximately 570 MW of OCGT capacity in NCEN, 100 MW of wind capacity in Far North QLD and an additional 400 MW of solar capacity in Darling Downs are installed by the model. Overall, the NEM is forecast to have around 109 GW total capacity by 2044-45 (note that total capacity includes PSH and LS storage capacities, which are not in the stacked chart). The majority of new capacity installed is coincident with coal generation retirements, which is particularly obvious from the mid-2030s when a number of large coal generators in the NEM retire.

The following charts (Figure 17, Figure 18 and Figure 19) show the differences in the NEM capacity development of other scenarios relative to the Central scenario. The capacity difference is presented as alternative scenario minus the Central scenario. Accordingly, if a technology is above zero there is more capacity installed in that year in the alternative scenario. As discussed in the assumptions section earlier, the key scenario variables resulting in different forecast long term expansion plans are as follows:

- operational energy consumption (as per Figure 9) and peak demand;
- emission trajectories: the Central and Slow Change scenarios have the same emissions reduction trajectories, which were achieved at no additional cost since the emissions were always below the trajectory, while the Fast Change and Step Change scenarios assume a more aggressive emission reduction target.

- ► generator retirements: compared to the Central scenario, the Slow Change scenario assumes five years delay in retirements (for half of coal power station capacity), while the Fast Change and Step Change scenarios assume two and five years earlier retirements (for half of coal power stations capacity), respectively.
- ► other drivers such as technology costs, fuel costs, renewable energy targets, as well as assumed inclusions/exclusions such as VNI West and Marinus Link.

Figure 17: Difference in NEM capacity forecast between Step Change and Central scenarios without HumeLink upgrade (excluding rooftop PV)

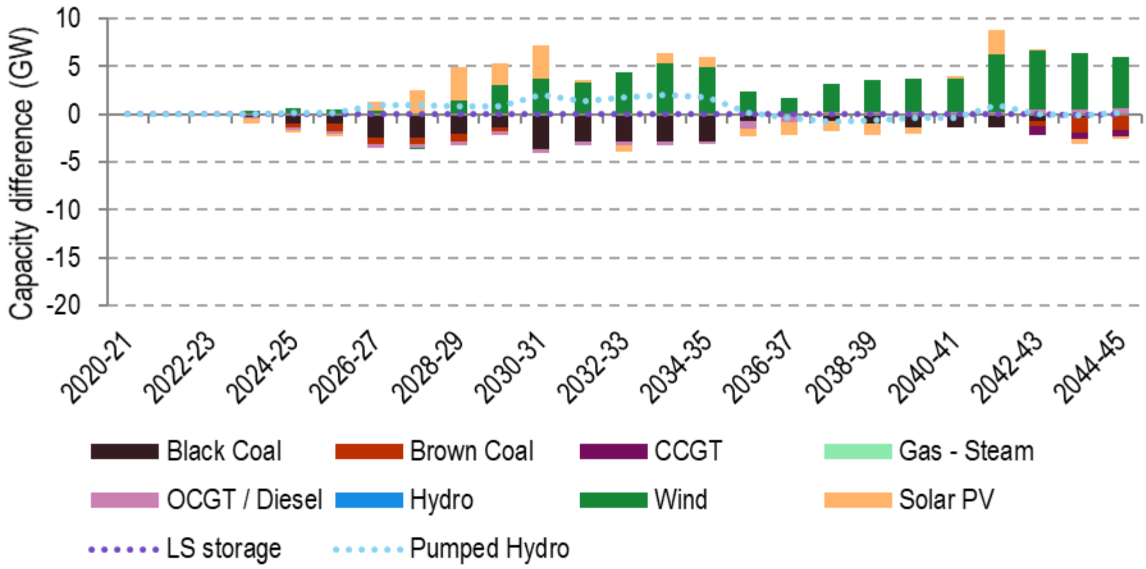


Figure 18: Difference in NEM capacity forecast between Fast Change and Central scenarios without HumeLink upgrade (excluding rooftop PV)

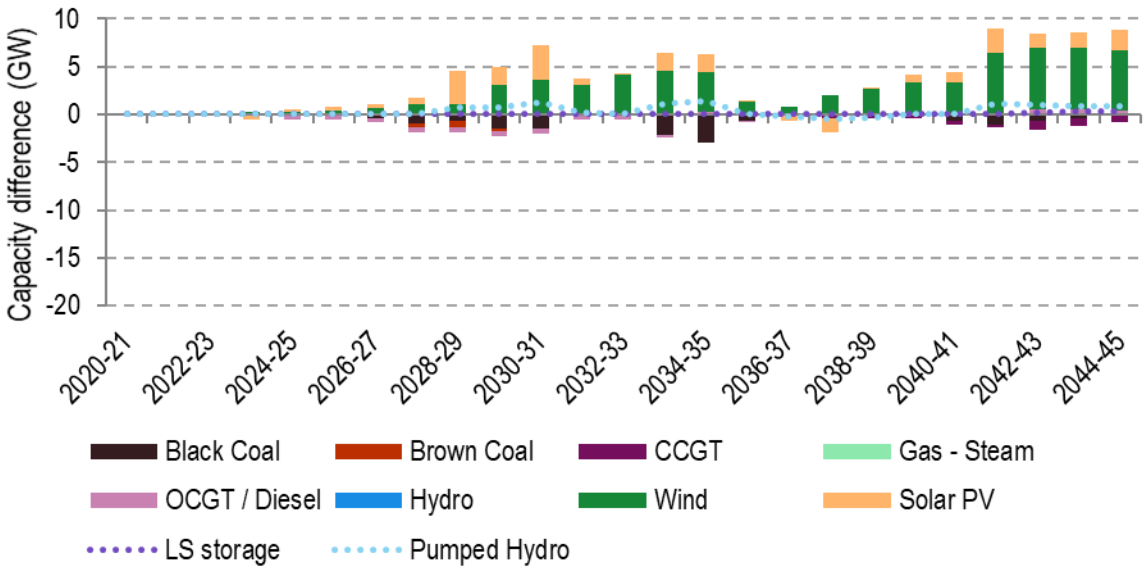
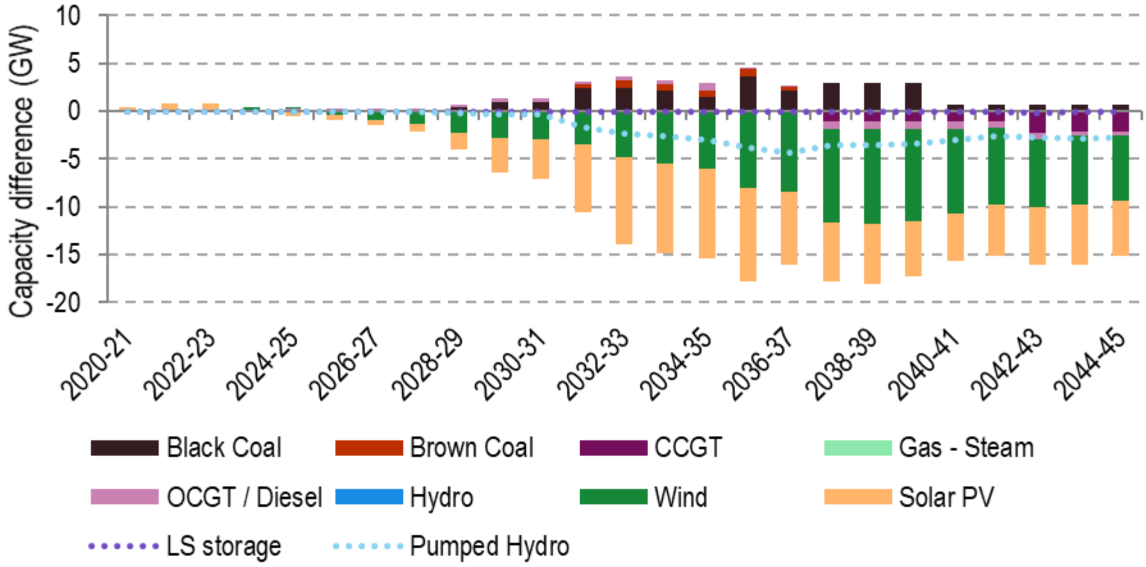


Figure 19: Difference in NEM capacity forecast between Slow Change and Central scenarios without HumeLink upgrade (excluding rooftop PV)

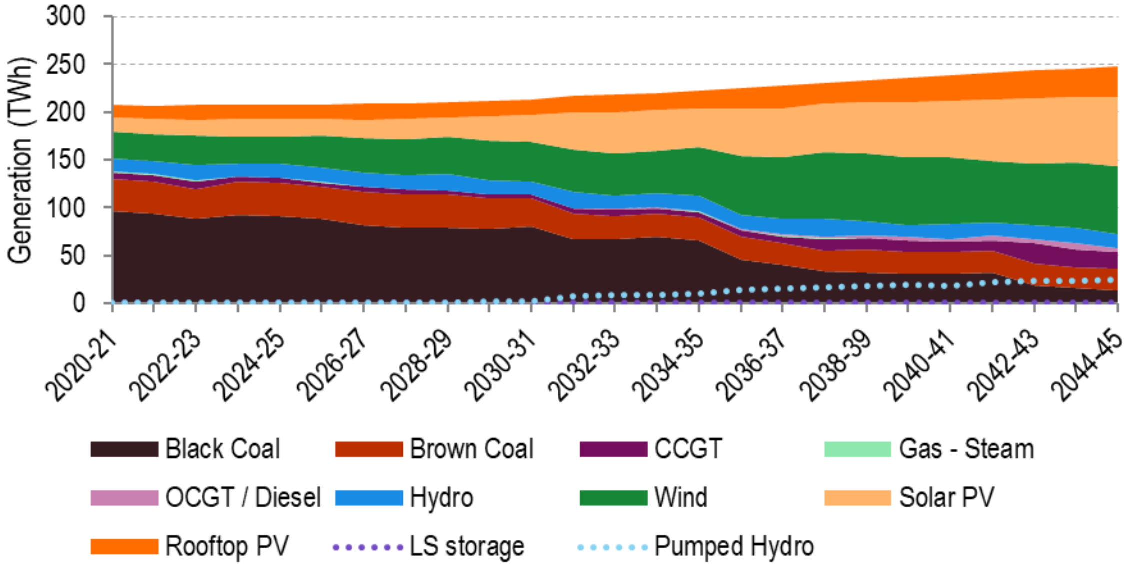


The modelling forecasts an increase in installed wind, solar PV and PSH capacity in the Step Change and Fast Change scenarios relative to the Central scenario (Figure 17 and Figure 18). Overall the forecast trend in capacity difference (relative to the Central scenario) is similar in the Step and Fast Change scenarios with some minor noticeable differences. The Step Change scenario forecasts more wind but less solar and OCGT build in the first few years. Conversely, the Fast Change scenario forecasts more solar build in the first few years. Both the Step and Fast Change scenarios forecast significantly more wind and solar uptake in the late 2020s compared to the Central scenario. Both scenarios (the Step Change scenario to a greater extent) also forecast more PSH capacity earlier compared to the Central scenario. By the end of the modelling period both scenarios have around 6 GW more wind and up to around 700 MW more OCGT capacity, but up to around 800 MW less CCGT capacity. The Fast Change scenario also has more solar and PSH build. The differences in black and brown coal capacity are attributed to the differences in retirement schedules. By 2044-45, black coal capacity in the Step Change scenario is the same as the Central scenario whereas brown coal is around 1.6 GW less. The black and brown coal capacity in the Fast Change scenario is the same as the Central scenario. The differences in coal capacity are due to assumptions of five and two years earlier retirements of half of coal capacity in the Step and Fast Change scenarios, respectively.

The Slow Change scenario (Figure 19) has a significantly different NEM capacity than the Central scenario, with the overall forecast showing around 18 GW less wind, solar, PSH and gas capacity by the end of the modelling period. On the other hand, it is forecast that the Slow Change scenario builds more wind and solar in the early years relative to the Central scenario, starting with around 370 MW solar in 2020-21. The Slow Change scenario will have around 660 MW more black coal capacity by 2044-45, but the same brown coal capacity relative to the Central scenario.

Figure 20 shows the energy supplied to the grid in the Central scenario. 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 demand growth of the AEMO ISP 2019-20 Central demand assumed in this scenario. The forecast cost of operating solar and wind trends below that of gas plant, so the forecast mix of generation favours solar and wind over gas-fired plant, except as needed to meet peak demand periods when wind and solar are not always available and furthermore to maintain minimum reserve requirements. OCGT and CCGT capacity and generation production levels are influenced by the imposition of a 50% minimum load on new CGGTs and no minimum load requirement on new OCGTs, in accordance with specifications for new generation of both types.

Figure 20: NEM generation mix forecast for the Central scenario without HumeLink upgrade



The modelling forecasts a significant solar generation increase in 2029-30, 2031-32 and 2035-36, all being coincident with assumed major coal retirements. However, noticeable increase in wind generation is forecast to be in 2035-36, which is around a 23% increase compared to the previous year, consistent with the need for higher renewable energy to replace retiring fossil generation. The PSH generation trend is forecast to align with solar and wind generation uptake. The model also forecasts a significant increase in CCGT generation from 2042-43, which is coincident with around 2 GW of assumed coal retirement.

Figure 21, Figure 22 and Figure 23 show the changes in generation in the Step Change, Fast Change and Slow Change scenarios relative to the Central scenario. As for the NEM capacity outcomes, the input assumption drivers such as demand, retirements, technology costs, fuel costs and policies have led to different generation trends across scenarios.

Figure 21: Difference in generation forecast between Step Change and Central scenarios without HumeLink upgrade (excluding rooftop PV)

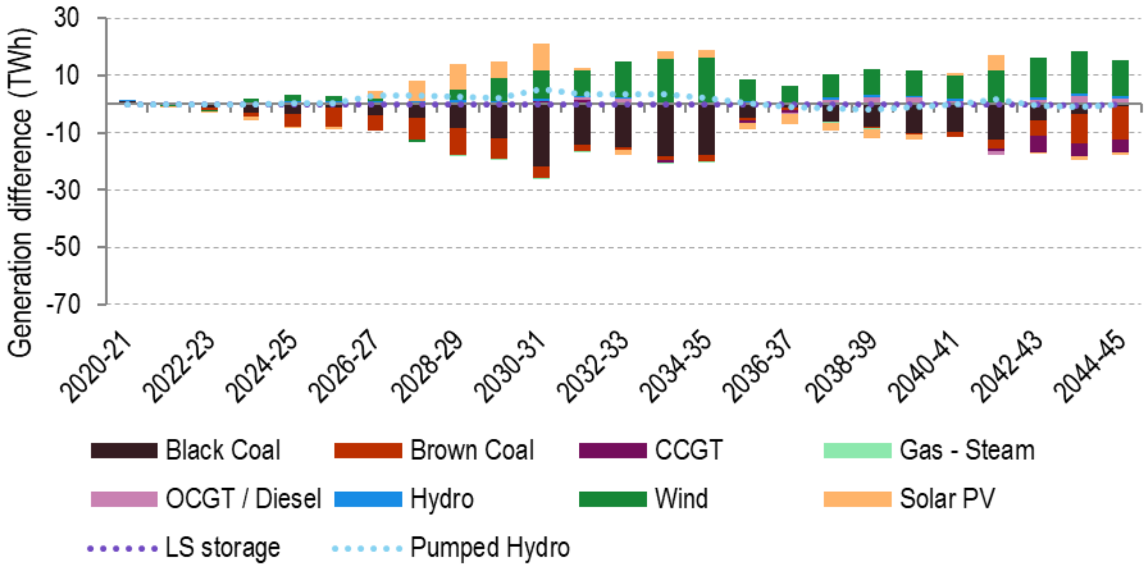


Figure 22: Difference in generation forecast between Fast Change and Central scenarios without HumeLink upgrade (excluding rooftop PV)

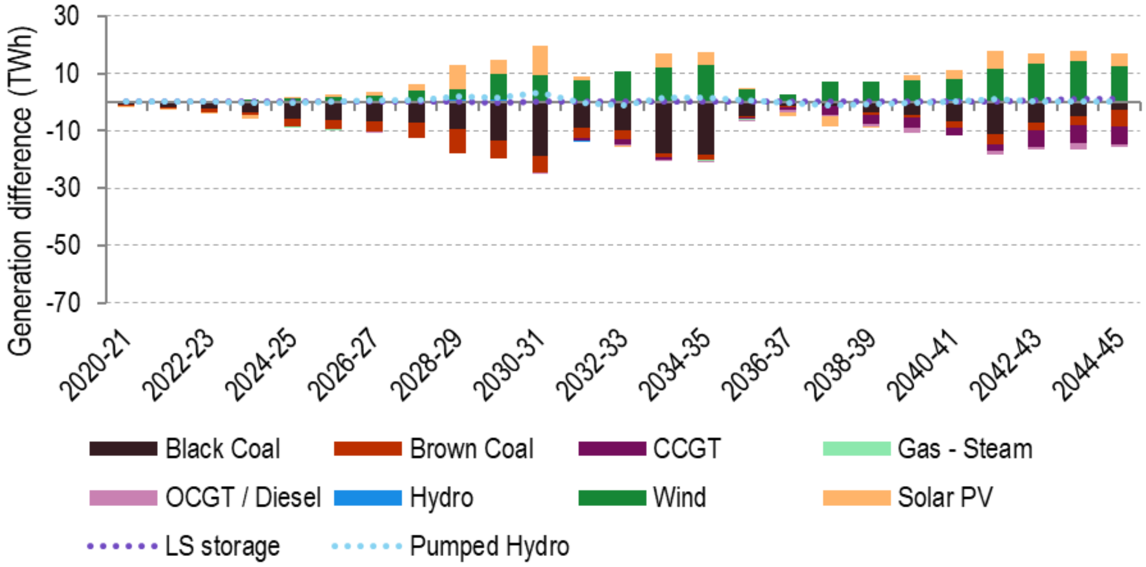
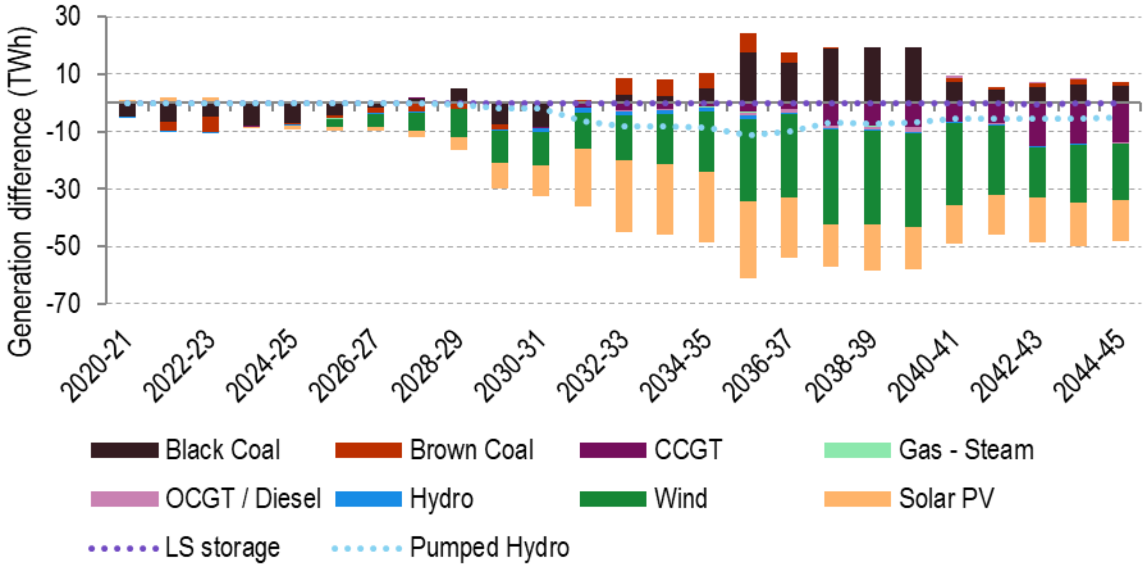


Figure 23: Difference in generation forecast between Slow Change and Central scenarios without HumeLink upgrade (excluding rooftop PV)



The modelling forecasts an increase in wind, solar PV and PSH generation in the Step and Fast Change scenarios relative to the Central scenario Base case (Figure 21 and Figure 22). The overall trend in generation difference is similar to the trend seen in the capacity charts for the Step and Fast Change scenarios. Both scenarios show a gradual increase in wind and solar generation from the mid-2020s until 2030-31. The Step Change scenario shows increased PSH generation from 2025-26 until 2035-36, whereas the Fast Change scenario shows increased PSH generation to a lesser extent over only a few years from 2027-28 until 2030-31. In the final year of the modelling period both scenarios forecast more wind generation (and solar in the Fast Change scenario) and less from gas.

The Slow Change scenario (Figure 23) forecast shows significantly lower generation from wind, solar, PSH and CCGTs but more generation from black and brown coal. It is also evident that black coal and brown coal generation in the early years is lower than the Central scenario, consistent with the reduced energy associated with this scenario.

8. Forecast gross market benefit outcomes

8.1 Summary of forecast gross market benefits

Table 13 shows the forecast gross market benefits over the modelled 25-year horizon for all options across the modelled scenarios. The forecast gross market benefits of each HumeLink option computed in each scenario need to be compared to the relevant HumeLink cost to determine whether there is a positive forecast net market benefit. TransGrid has concluded that Option 3C is the preferred option given the option costs and other criteria[73]. All references to the preferred option in this Report are in the sense defined in the RIT-T as "the credible option that maximises the net economic benefit across the market, compared to all other credible options"[74].

Table 13: Summary of forecast gross market benefits, millions real June 2019 dollars discounted to June 2020 dollars

Option	Scenario			
	Slow Change	Central	Step Change	Fast Change
1A	897	992	1,113	1,045
1B	1,167	1,394	1,583	1,517
1C	1,108	1,331	1,516	1,467
2A	1,154	1,798	1,942	1,988
2B	1,412	2,245	2,511	2,533
2C	1,517	2,306	2,550	2,573
3A	1,005	1,621	1,757	1,806
3B	1,321	2,198	2,496	2,508
3C	1,504	2,291	2,545	2,562
4A	1,070	1,738	1,912	1,961
4B	1,506	2,438	2,742	2,777
4C	1,628	2,505	2,778	2,816

The rest of Section 8 explores the timing and sources of these forecast benefits, with a focus on TransGrid's preferred option, Option 3C.

8.2 Market modelling results for Option 3C

8.2.1 Central scenario

This section summarises market modelling results for Option 3C in the Central scenario.

The forecast cumulative gross market benefits for Option 3C in the Central scenario are shown in Figure 24. Furthermore, the differences in capacity and generation outlook across the NEM between Option 3C and the Base case in this scenario are shown in Figure 25 and Figure 26 respectively.

[73] TransGrid, *Reinforcing the NSW Southern Shared Network to increase transfer capacity to the state's demand centres (HumeLink) PADR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network. Accessed 10 January 2020.

[74] 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 09 January 2020.

Figure 24: Forecast cumulative gross market benefit[75,76] for Option 3C under the Central scenario, millions real June 2019 dollars discounted to June 2020 dollars

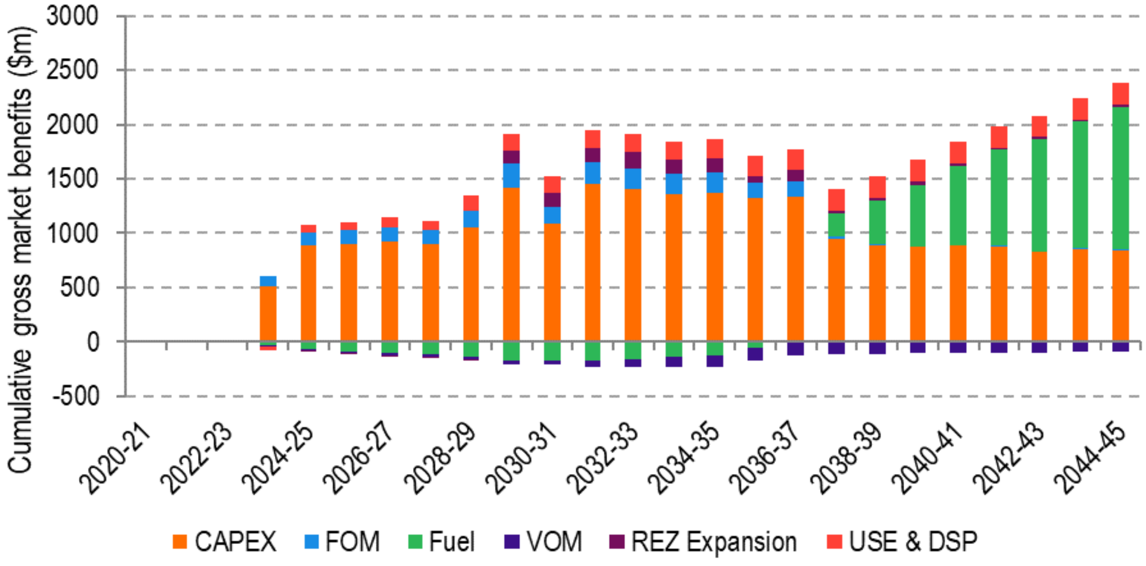
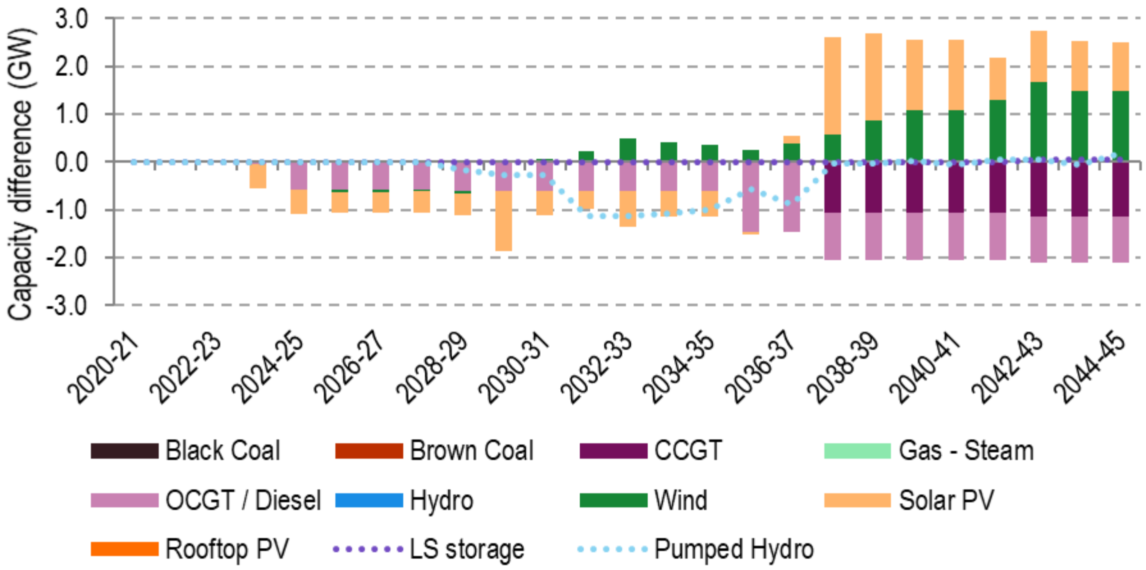


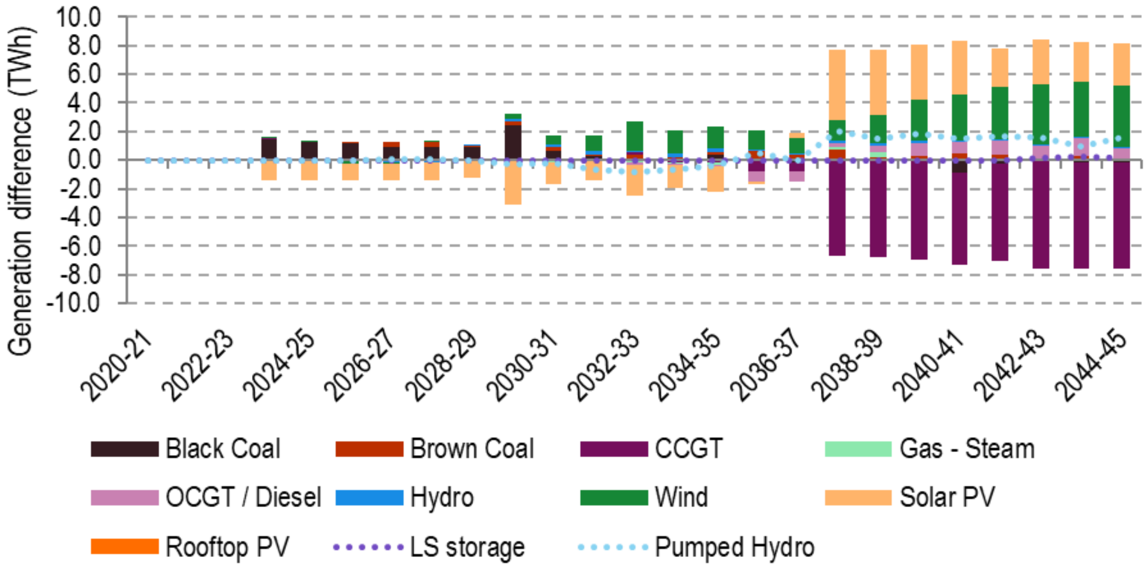
Figure 25: Difference in NEM capacity forecast between Option 3C and Base case in the Central scenario



[75] 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.

[76] Since this figure shows the cumulative forecast gross market benefits in present value terms, the height of the bar in 2044-45 equates to the gross benefits for Option 3C shown in Table 13 above.

Figure 26: Difference in NEM generation forecast between Option 3C and Base case in the Central scenario



The primary sources of forecast gross market benefits are from avoided and deferred capex for new generators as well as fuel cost saving from reduced CCGT generation. The timing and source of these benefits are attributable to the following:

- The large capex benefit of $506m in 2023-24 comes from a forecast deferral of 500 MW of solar build in NCEN just after Liddell is assumed to retire.
- The capex benefit is forecast to increase to around $890m in 2024-25 due to avoidance of approximately 560 MW of OCGT build in NCEN. This is the year that the HumeLink network upgrades are planned to be commissioned.
- Black coal and to a lesser extent brown coal generation offsets the avoided solar generation during the 2020s.
- In 2029-30, when Vales Point is expected to retire, the capex benefit is forecast to increase to $1,411m due to deferral of approximately 800 MW of solar by one year and deferral of PSH build. The following year, the benefit is forecast to reduce to $1,090m when the deferred solar is built.
- In 2031-32, the same year as Eraring is expected to retire, the forecast capex benefit increases to $1,450m due to deferral of approximately 800 MW of PSH in NSW. The majority of this build is deferred until 2035-36.
- During the early to mid-2030s, 100 MW – 500 MW more wind is forecast to be built with Option 3C, but OCGT, solar and PSH is deferred compared to the Base case.
- In 2037-38 the capex benefit is forecast to reduce to $942m due to a large amount of solar PV build of approximately 1.8 GW. This same year there is a large avoidance of CCGT build forecast in NSW of approximately 1.1 GW.
- The fuel cost benefit is forecast from 2037-38 with $209m in benefit resulting from VIC wind, NSW and SA solar and PSH generation offsetting NSW CCGT generation (which is due to CCGT build avoidance). From 2037-38 onwards a combination of solar, wind, PSH, OCGT and large-scale battery generation is forecast to offset around 7.4 TWh of CCGT generation. The fuel cost benefit is forecast to progressively increase to $1,313m by 2044-45.

Other smaller sources of forecast benefits are:

- forecast USE & DSP benefits of $198m by 2044-45,

- a forecast reduction in REZ transmission expansion build costs amounting to $18m by 2044-45,
- a small reduction in benefit from increased VOM costs.

The augmentation expands transfer capacity from southern NSW and southern states to supply major load centres in New South Wales. This may allow for improved utilisation of existing generation before new capacity is required and development of more diverse resources when new capacity is required. Compared to the Base case, Option 3C builds an additional 600 MW of solar in the Wagga Wagga REZ (NSW), 732 MW of solar in the Riverland REZ (SA) and 1,481 MW wind in the SWVIC REZ (VIC).

Figure 27 and Figure 28 show the capacity and generation differences between Option 3C and the Base case for NSW. As seen in Figure 27, most of the avoided and deferred build in the NEM is in NSW. Figure 28 shows that the avoidance of the need for CCGT generation is also largely within NSW.

Figure 27: Difference in NSW capacity forecast between Option 3C and Base case in the Central scenario

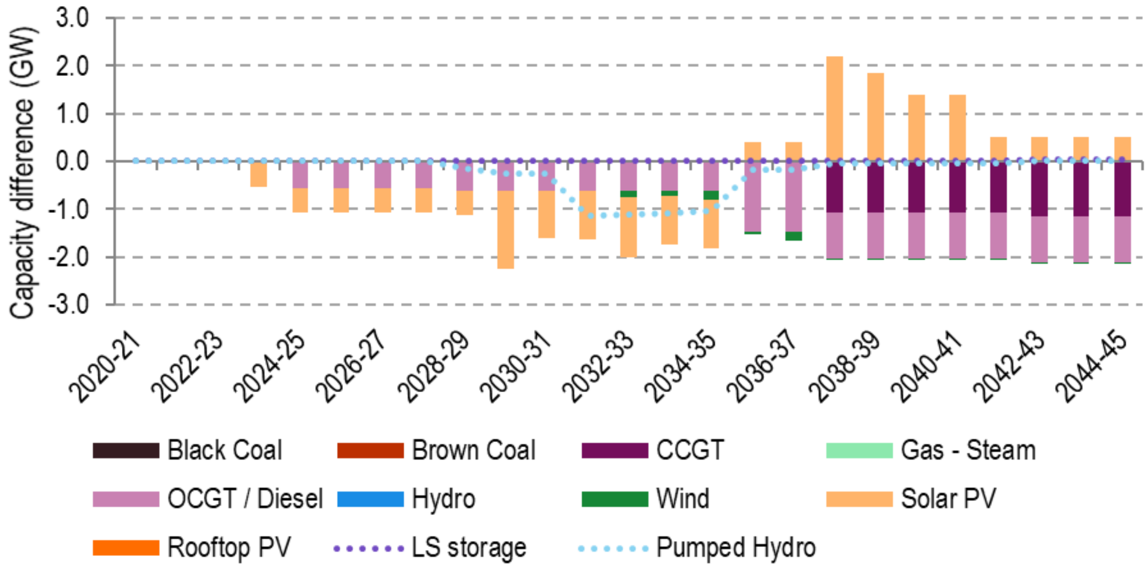
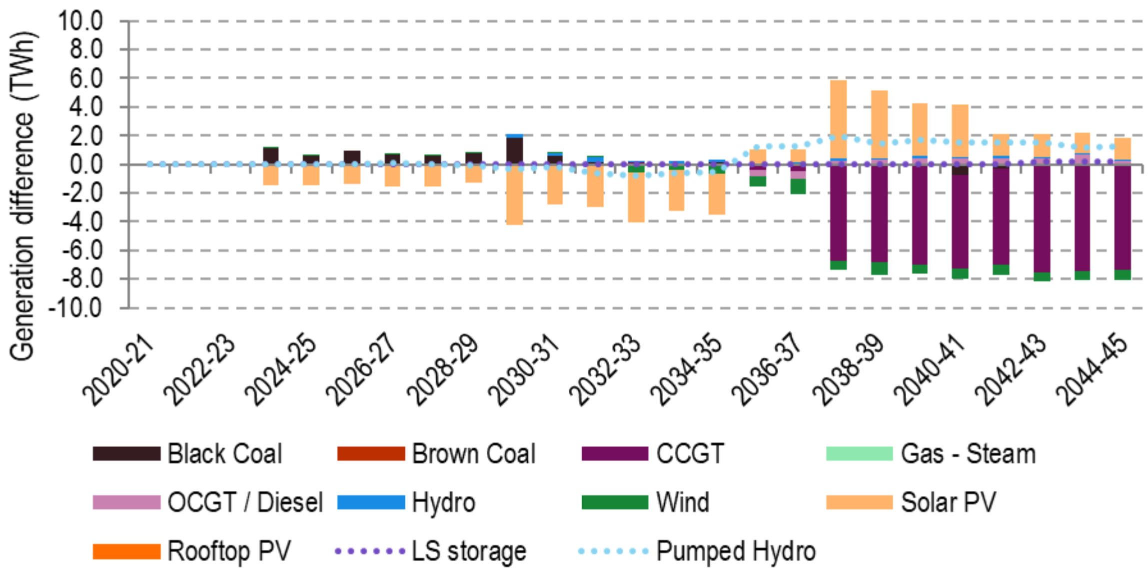


Figure 28: Difference in NSW generation forecast between Option 3C and Base case in the Central scenario



8.2.2 Step Change scenario

The forecast cumulative forecast gross market benefits for Option 3C in the Step Change scenario are shown in Figure 29. Furthermore, the differences in capacity and generation across the NEM between Option 3C and the Base case in the Step Change scenario are shown in Figure 30 and Figure 31.

Figure 29: Forecast cumulative gross market benefit for Option 3C in the Step Change scenario, millions real June 2019 dollars discounted to June 2020 dollars

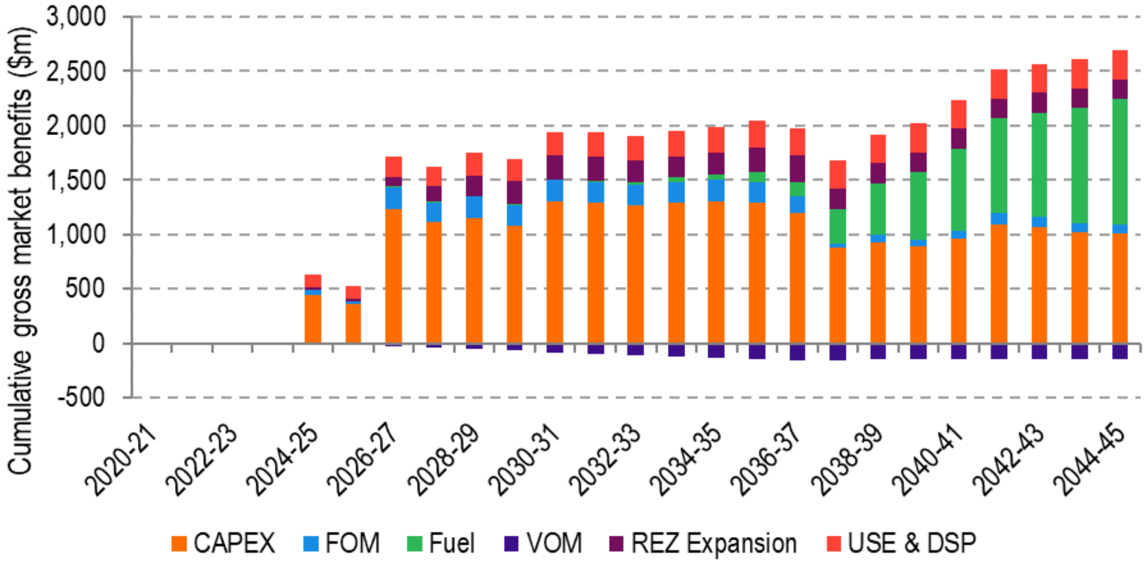


Figure 30: Forecast NEM capacity difference between Option 3C and Base case in the Step Change scenario

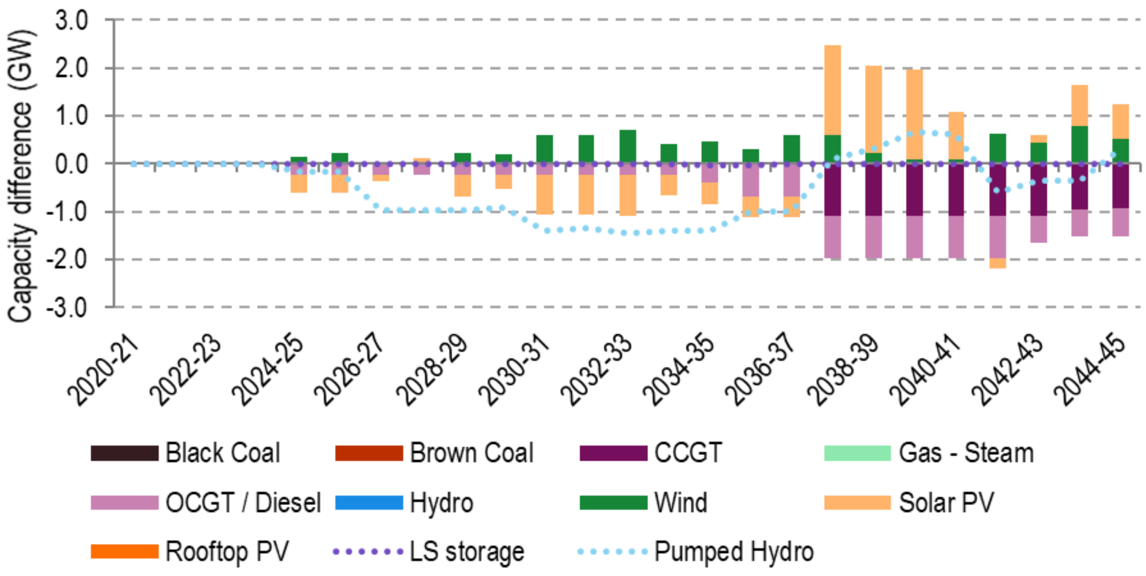
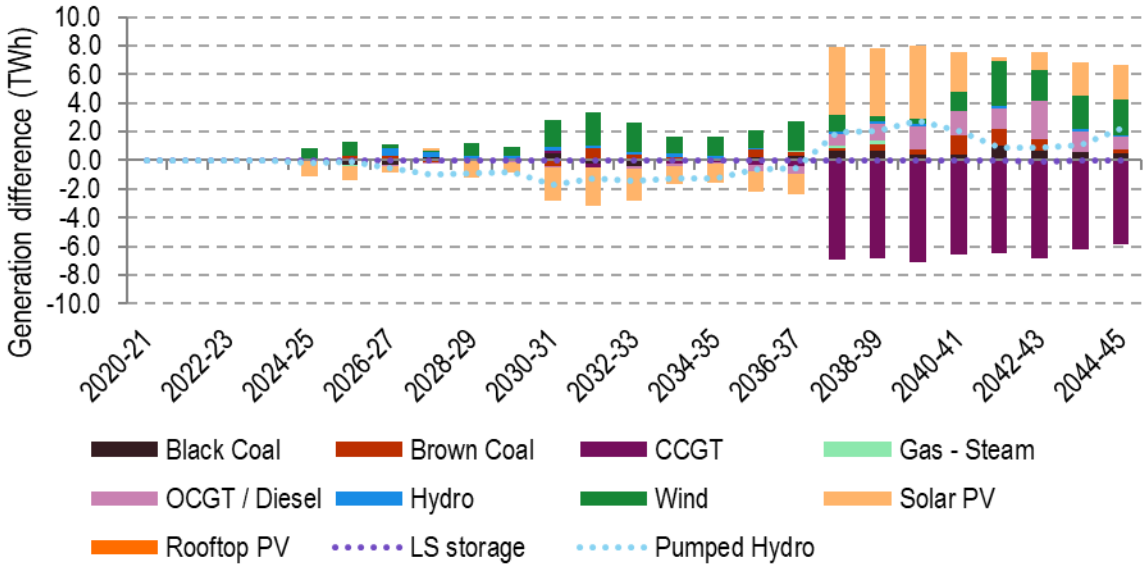


Figure 31: Difference in NEM generation forecast between Option 3C and Base case in the Step Change scenario



The primary sources of forecast gross market benefits are from fuel cost savings and avoided and deferred capex. Compared to the Central scenario, the amount of fuel cost and capex savings is almost the same in the Step Change scenario. The timing and source of these benefits are attributable to the following:

- The large capex benefit of $438m in 2024-25 comes from the forecast avoidance of 230 MW OCGT and deferral of 380 MW of solar build in NCEN when the augmentation is assumed to be commissioned.
- Capex benefit is forecast to increase to around $1,200m in 2026-27 due to the deferral of approximately 800 MW of PSH build in NCEN when half the capacity of Eraring is assumed to retire in this scenario.
- In 2030-31, the capex benefit is forecast to increase to $1,302m due to deferral of approximately 540 MW of solar in NSW by three years and deferral of another 480 MW of PSH build until 2037-38. That year the capex benefit is forecast to decrease to $879m as a result.
- In 2037-38 the capex benefit is forecast to reduce further due to a large amount of solar PV build of approximately 2.3 GW. This same year there is a large avoidance of CCGT build in NSW of approximately 1.1 GW.
- The fuel cost benefit is forecast to increase significantly from 2037-38 onwards as a result of VIC and SA wind, NSW solar and PSH generation offsetting NSW CCGT generation (which is due to avoiding CCGT development).
- The fuel cost benefit is forecast to progressively increase to $1,156m by 2044-45.

Compared to its counterfactual Base case, Option 3C in the Step Change scenario forecasts less solar development in QLD and less wind development in NNS, but approximately 600 MW more solar development in the Wagga Wagga REZ, 1.4 GW more wind development in VIC (South West Victoria and Gippsland REZs) and 650 MW more wind development in SA (Riverland REZ) as the augmentation increases transfer capacity from southern NSW and other Southern states.

As for the Central scenario, the NSW capacity and generation difference in Option 3C relative to the Base case in the Step Change scenario has a similar trend to the NEM overall. There are, however, several key differences in the forecast capacity and generation outlook relative to the Central scenario (Figure 29 versus Figure 24, Figure 30 versus Figure 25 and Figure 31 versus Figure 26).

- Forecast gross market benefits in the Step Change scenario are overall $254m higher, with additional savings from FOM ($85m), and REZ expansion ($180m).
- Option 3C in the Step Change scenario is forecast defer PSH capacity earlier than in the Central scenario, both relative to their corresponding Base cases.
- In the long term, Option 3C in the Step Change scenario results in avoiding less gas build but also building less wind and solar than in the in the Central scenario, both relative to their corresponding Base cases.

8.2.3 Fast Change scenario

The forecast cumulative gross market benefits for Option 3C in the Fast Change scenario are shown in Figure 32. Furthermore, the differences in capacity and generation across the NEM between Option 3C and the Base case in this scenario are shown in Figure 33 and Figure 34.

Figure 32: Forecast cumulative gross market benefit for Option 3C in the Fast Change scenario, millions real June 2019 dollars discounted to June 2020 dollars

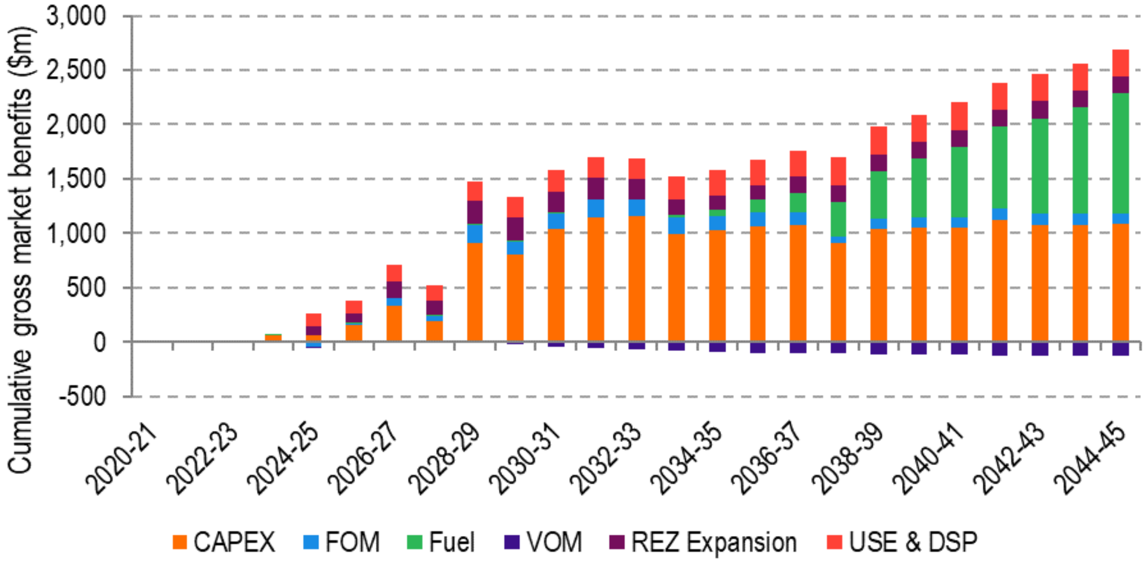


Figure 33: Forecast NEM capacity difference between Option 3C and Base case in the Fast Change scenario

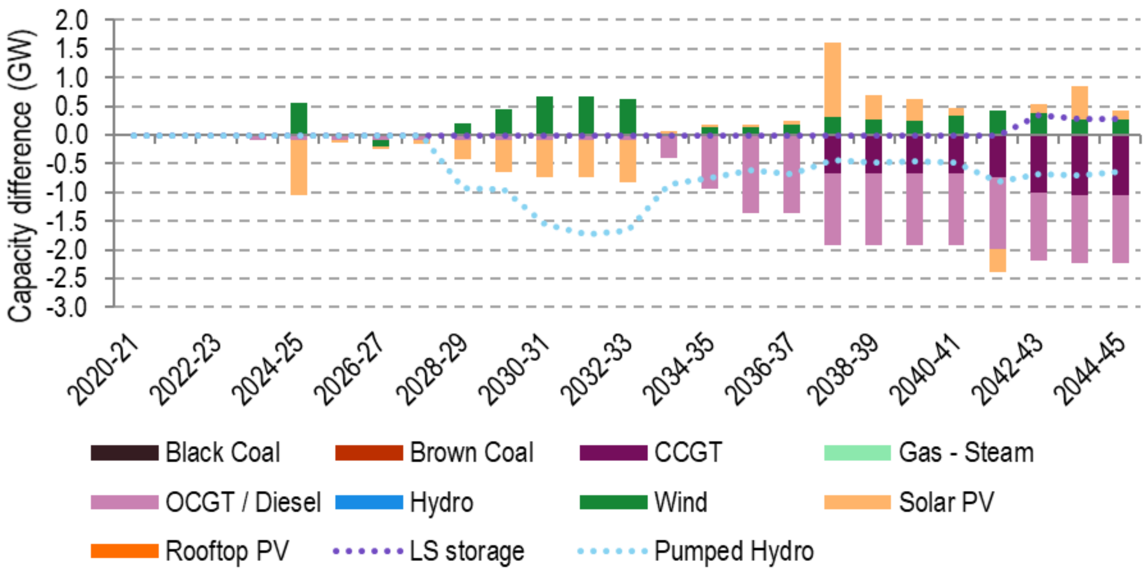
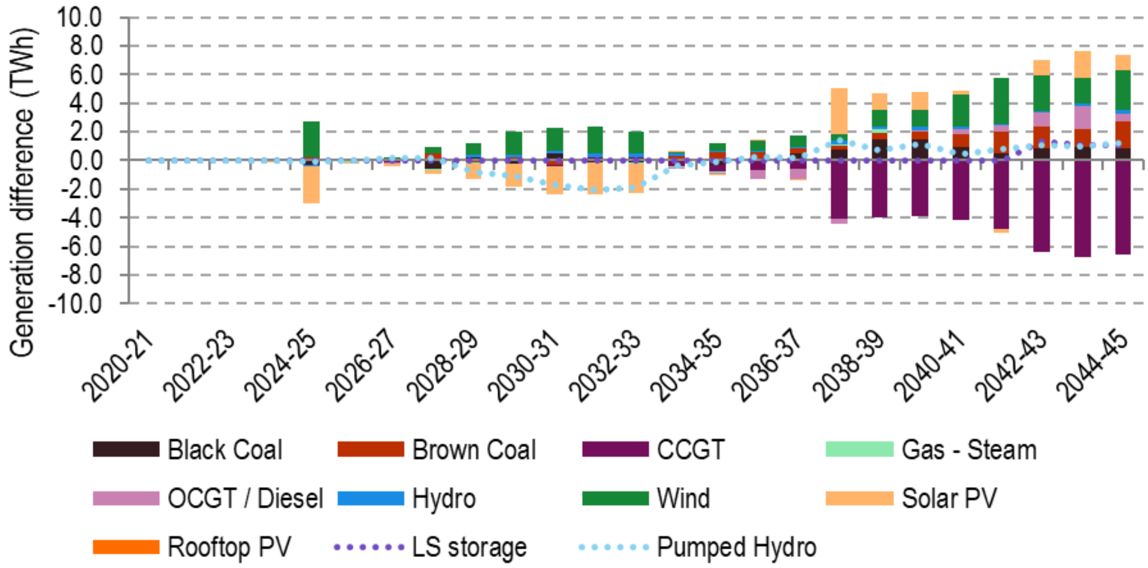


Figure 34: Difference in NEM generation forecast between Option 3C and Base case in the Fast Change scenario



As for the Step Change scenario, fuel cost and avoided/deferred capex savings equally share the major sources of forecast gross market benefits. The timing and sources of these benefits are attributable to the following:

- Aggregated capex and other benefits are around $500m by 2027-28. Decreased operational energy and NSW peak demand compared to the Central scenario and Step Change scenarios (Figure 9 to Figure 11), as well as half capacity coal retirements only two years earlier than end of life, reduce the opportunity for benefits in the mid-2020s compared to those scenarios.
- The major capacity difference in the early 2020's is the deferral of around 960 MW solar in 2024-25 by one year, while the build of 560 MW wind is one year earlier.
- The capex benefit is forecast to increase to $915m in 2028-29 due to avoidance of approximately 935 MW of PSH build in NCEN when the first unit of Yallourn and half of Callide B retires.
- In the late 2020s/early 2030s the model forecasts deferral of around 1.7 GW of PSH and 700 MW of solar, but advancing the timing of wind build.
- The fuel cost benefit is forecast from 2034-35 with $209m in benefit resulting from VIC wind and brown coal offsetting solar and CCGT generation.
- The fuel cost benefit increases in 2037-38 with the offset of approximately 4 TWh of CCGT generation in NCEN and further increasing until 2044-45 mainly due to wind and brown coal in Victoria and solar in NSW and SA offsetting 6.8 TWh of NSW gas generation.
- Over the modelled period, the Option 3C augmentation avoids building 2.2 GW of gas and 630 MW of PSH and builds 265 MW more wind and 170 MW more solar.

Since more new capacity is forecast to be built in the Fast Change scenario than the Central scenario in the long term (due to higher assumed load growth, earlier assumed coal retirement and a more stringent emission reduction trajectory) Option 3C gives more opportunity to generate savings in the forecast by avoiding or deferring capacity and using lower fuel-cost generation.

With the augmentation, more wind (500 MW) and solar (600 MW) are built in the Wagga Wagga REZ, while build in NNS (New England REZ) is reduced. 480 MW additional wind is built in Victoria (Western Vic REZ and Gippsland REZ) as well as 120 MW solar in SA (Riverland REZ) as the augmentation allows better use of existing and future high resource locations.

8.2.4 Slow Change scenario

The forecast cumulative gross market benefits for Option 3C in the Slow Change scenario are shown in Figure 35. Furthermore, the differences in capacity and generation across the NEM between Option 3C and the Base case in this scenario are shown in Figure 36 and Figure 37 respectively.

Figure 35: Forecast cumulative gross market benefit for Option 3C in the Slow Change scenario, millions real June 2019 dollars discounted to June 2020 dollars

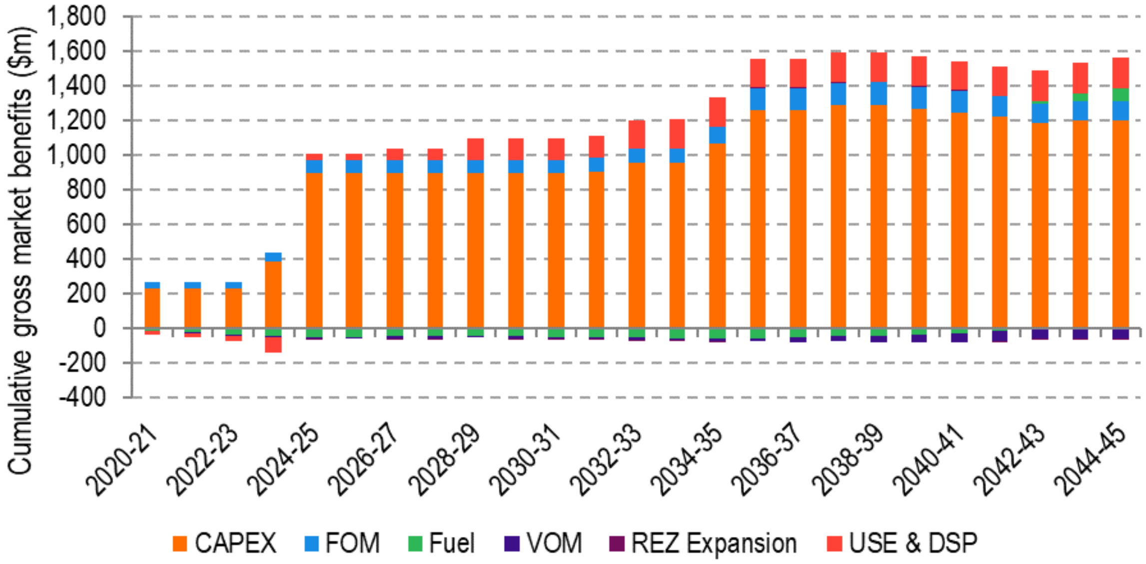


Figure 36: Forecast NEM capacity difference between Option 3C and Base case in the Slow Change scenario

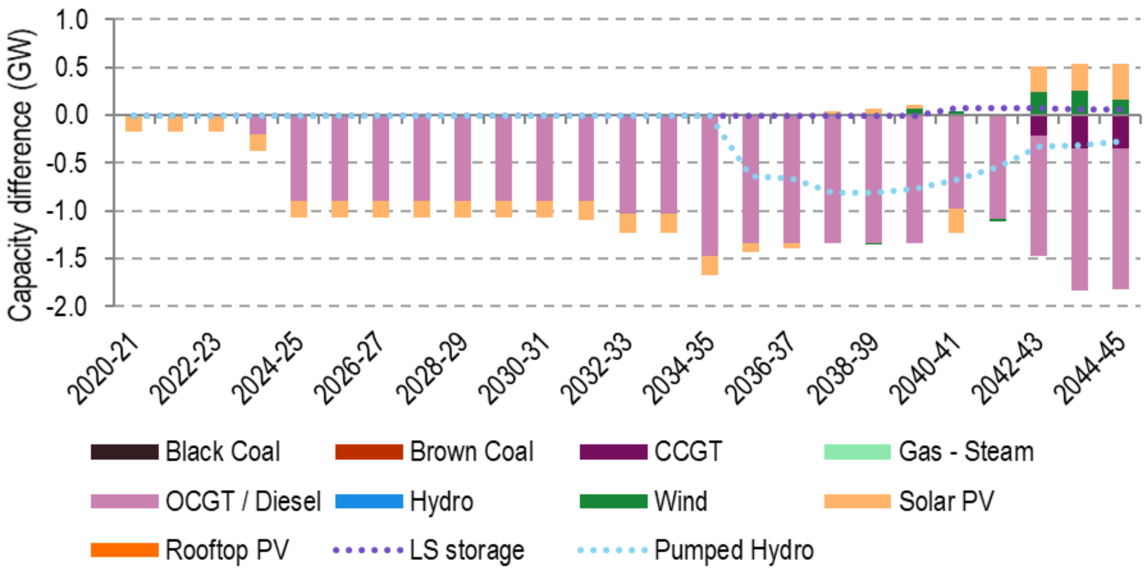
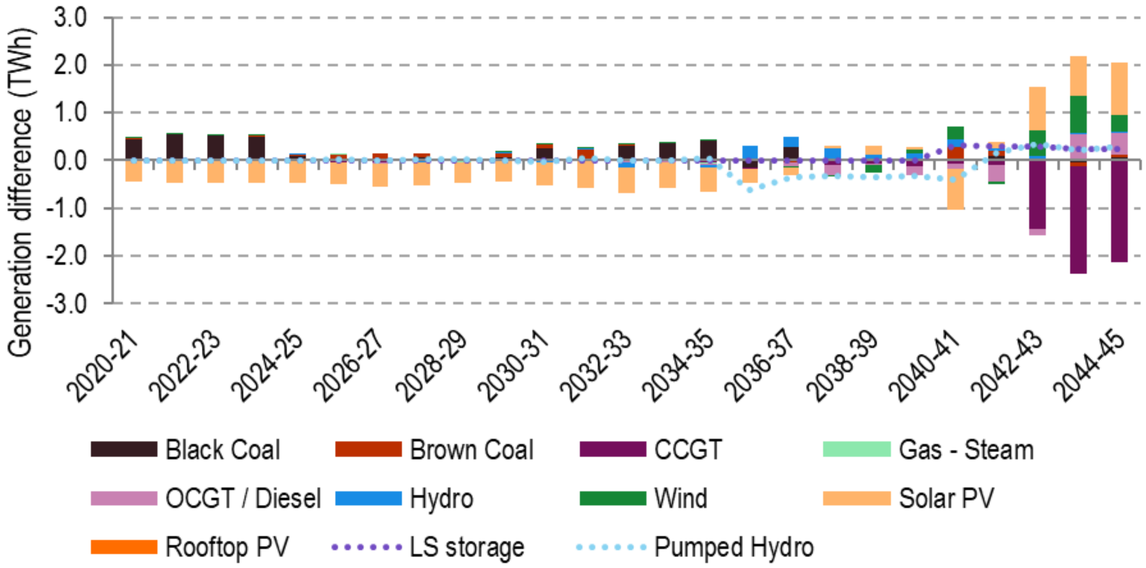


Figure 37: Difference in NEM generation forecast between Option 3C and Base case in the Slow Change scenario



The avoided gas build, deferred solar build, and avoided and deferred PSH installations are forecast to result in capex saving to be the dominant source of forecast gross market benefits in the Slow Change scenario. These benefits are forecast to start occurring from the beginning of the modelling period in 2020-21 and increase when the HumeLink augmentation is assumed to be commissioned in 2024-25. The magnitude of the savings is expected to be smaller overall throughout the forecast as the need for additional capacity in the long term is lower than in the Central and other scenarios due to lower assumed demand growth and delayed coal-fired generator retirements.

Overall, the reduce need for new capacity in this scenario means less opportunity for Option 3C to generate savings and total expected gross market benefits are consequently reduced relative to the Central scenario. Compared to other scenarios, the forecast fuel saving is a minor contribution to the overall benefits in the Slow Change scenario.

In the near term, the key observations for the forecast are as follows:

- Deferral of 170 MW of solar build in NCEN in 2020-21.
- Avoidance of approximately 200 MW and 700 MW of OCGT build in 2023-24 and 2024- 25, respectively, after Liddell is assumed to retire and when the HumeLink augmentation occurs.
- Black coal generation in NSW and QLD replaces the avoided solar build generation in the short term.

Over the longer outlook, the key observations are as follows:

- Deferral of PSH build in the mid-2030s and avoidance of about 280 MW build compared to the Base case.
- In the last three years, approximately 170 MW more wind, and 370 MW more solar is forecast to be built under the augmentation.
- During the same time, built of 345 MW of CCGT is avoided.
- The combination of generation from wind, storage, solar and OCGT offset generation from CCGTs, in line with the forecast avoided fuel cost benefit in Figure 35.

Compared to the Base case, 300 MW more solar is developed in the South West New South Wales REZ. Only around 130 MW more solar is developed in SA (Riverland REZ) and approximately

120 MW more wind in SA and VIC (Western Victoria REZ and Mid-North South Australia REZ, but a significant reduction in Northern South Australia).

8.3 Key South NSW Intra-connector flows for Option 3C

Figure 38 and Figure 39 below show the difference (between Option 3C and the Base case) in forecast average annual flow from Canberra to NCEN zones and from SWNSW to Wagga respectively. The overall trend across all scenarios is that the difference in flows towards NCEN and towards Wagga between Option 3C and the Base case generally increases throughout the modelling period in line with the assumed thermal generation retirements in NSW and QLD and assumed energy consumption increase.

Notably flows towards NCEN and towards Wagga increase earlier and more significantly in the Central, Step Change and Fast Change scenarios compared to the Slow Change scenario. This is largely because VNI West is built in all scenarios except the Slow Change scenario and consequently lower cost generation in the south (in particular VIC) is forecast to displace higher cost generation in NSW in the Central, Step Change and Fast Change scenarios but not in the Slow Change scenario. Different assumptions in thermal generation retirements and energy consumption between scenarios also explain the difference in flow outcomes. The Step and Fast Change scenarios assume earlier retirements whereas the Slow Change assumes later retirements.

Figure 38: Difference in forecast average annual flow transfer from Canberra to NCEN between Option 3C and Base case in all scenarios

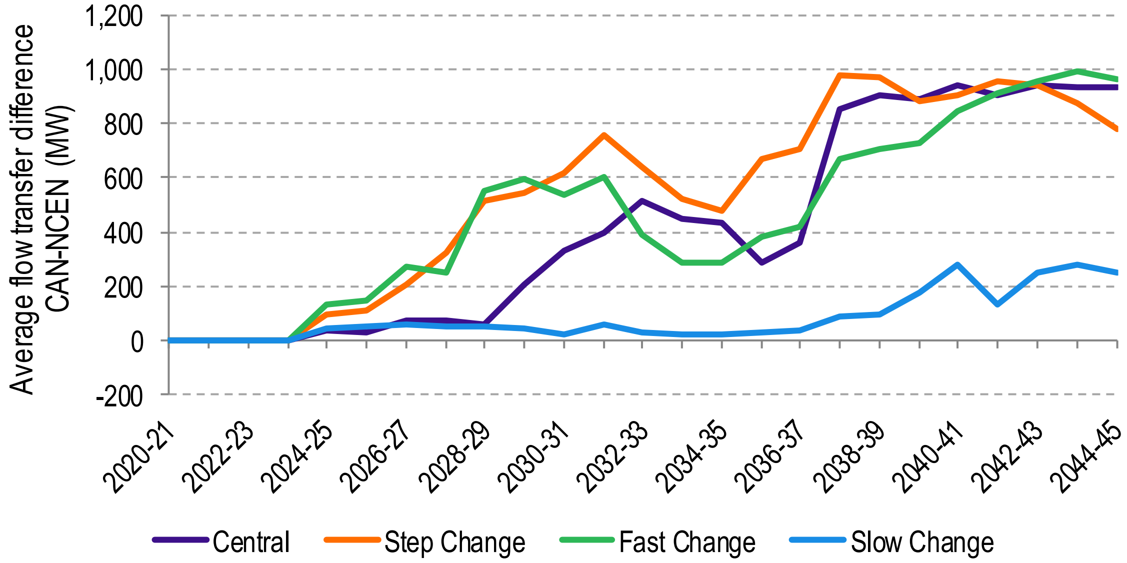


Figure 39: Difference in forecast average annual flow transfer between SWNSW and Wagga in Option 3C and Base case in all scenarios

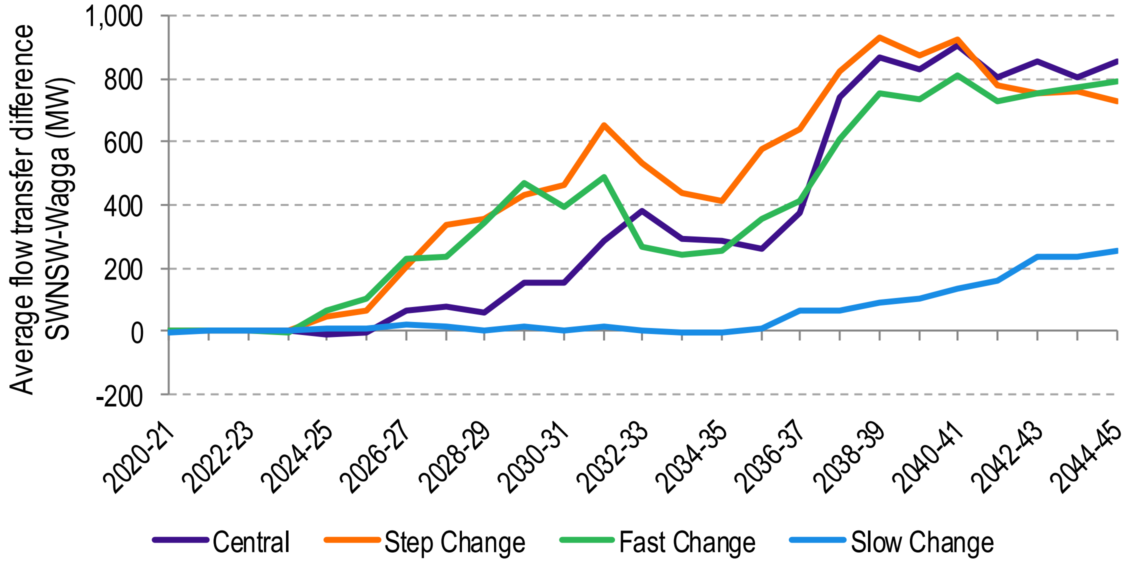


Figure 40 below shows the average time-of-day flow between Canberra and NCEN in the Base case and in Option 3C for the Central scenario. Flows are generally towards NCEN in both cases. In the early years flows towards NCEN are higher during the day and lower during the night. In later years flows are lower during the day and higher during the night. This coincides with Snowy 2.0 pumping during the day (reducing the net flows towards NCEN). In later years flows towards NCEN are greater in Option 3C compared to the Base case. This is due to the Option 3C network upgrades allowing cheaper generation in SWNSW and VIC as well as SA to offset more expensive generation in NCEN as well as increased Snowy 2.0 generation.

Figure 40: Average annual time-of-day energy transfer between Canberra and NCEN in the Base case and Option 3C for the Central scenario for selected years.

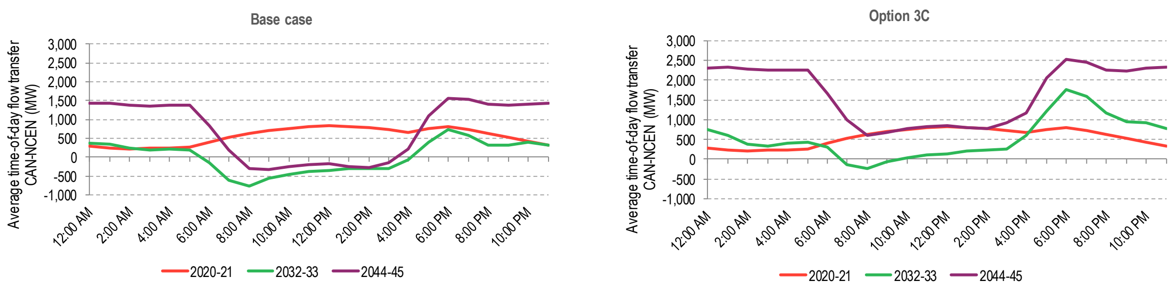
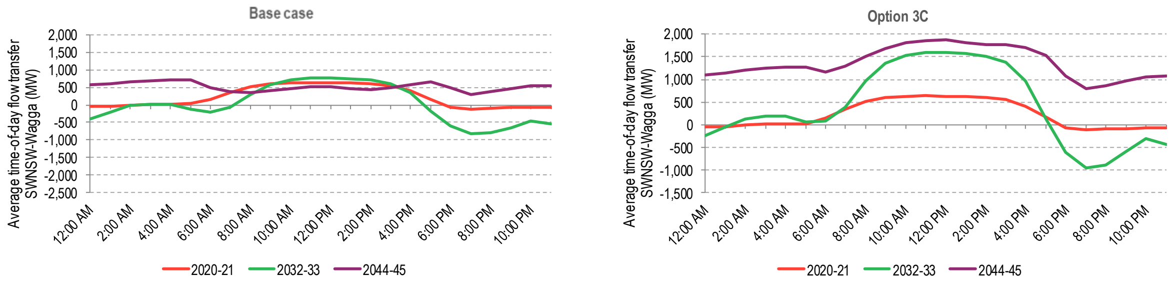


Figure 41 shows the average time-of-day flow between SWNSW and Wagga in the Base case and in Option 3C for the Central scenario. Flows are generally towards Wagga in the Base case and Option 3C. However, the volume in Option 3C is significantly higher. This is again due to the upgrades in Option 3C allowing access to cheaper generation in SWNSW and southern regions which offsets more expensive generation in NCEN. In both cases flows are more towards Wagga during the day in later years due to increased Snowy 2.0 pumping, too.

Figure 41: Average annual time-of-day energy transfer between SWNSW and Wagga in the Base case and Option 3C for the Central scenario for selected years.



8.4 Snowy 2.0 operation

Figure 42 and Figure 43 show the annual capacity factor for Snowy 2.0 generator and pump. Across all scenarios Snowy 2.0 operates more in Option 3C compared to the Base case due to improved network access. In both the Base case and Option 3C the trend in Snowy 2.0 operation over time is similar.

Snowy 2.0 operation increases earlier in the Step and Fast Change scenarios and later in the Slow Change scenario, corresponding with earlier and later assumed coal retirements. In the Central and Step Change scenarios Snowy 2.0 operation peaks in 2031-32 whereas in the Fast Change scenario it peaks in 2035-36 and in the Slow Change scenario in 2039-40. In general, Snowy 2.0 operation is lower in the Slow Change scenario due to lower assumed energy consumption and delayed retirements.

Figure 42: Annual capacity factor for Snowy 2.0 generator and pump for the Base case in all scenarios

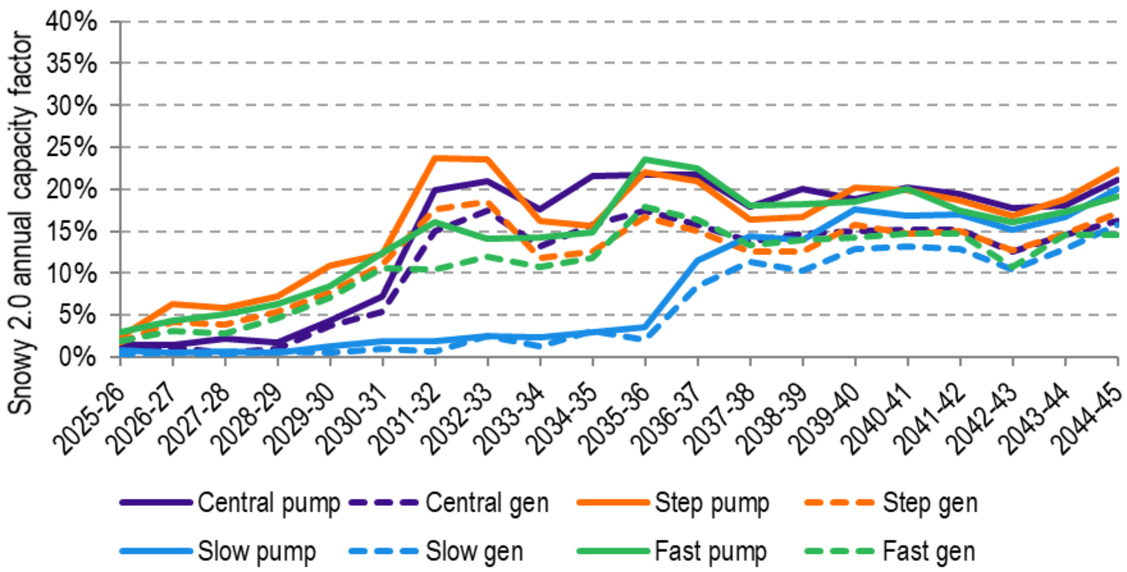
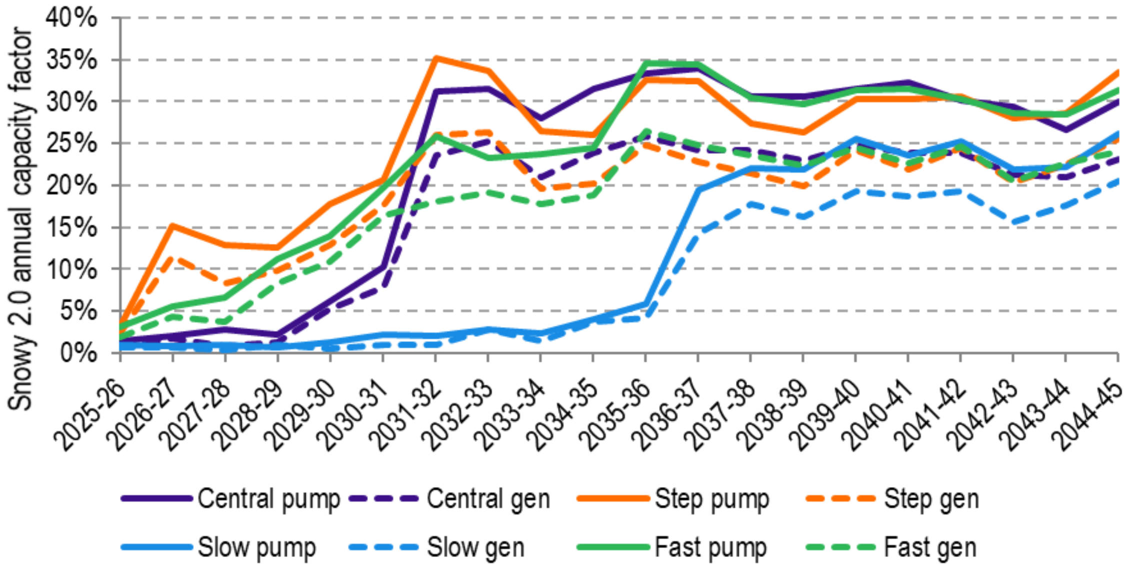


Figure 43: Annual capacity factor for Snowy 2.0 generator and pump for Option 3C in all scenarios



8.5 Other HumeLink options

The modelling results show a similar trend in forecast gross market benefits and generation development for Options 2, 3 and 4 whereas the outcome for Option 1 is significantly different. The key difference in these Options is that Options 2, 3 and 4 connect Wagga Wagga to Bannaby and Maragle which unlocks renewables in SWNSW and southern regions whereas Option 1 does not.

Accordingly, in this section in order to explain the market modelling outcomes, we have grouped Options 2 – 4 together and discussed Option 1 separately. In addition, in the subsequent sections we only provide the market modelling outcome charts for the Central scenario for "C" options.

8.5.1 Options 1A, 1B and 1C - Central scenario

The modelling forecasts that the gross market benefits of all Option 1 cases are primarily due to capex saving, which are more than twice as much as the fuel cost saving (Figure 44). The reason is that these upgrades avoid substantial OCGT build but only save marginally on CCGT generation (Figure 45 and Figure 46).

Figure 44: Forecast cumulative gross market benefit for Option 1C in the Central scenario, millions real June 2019 dollars discounted to June 2020

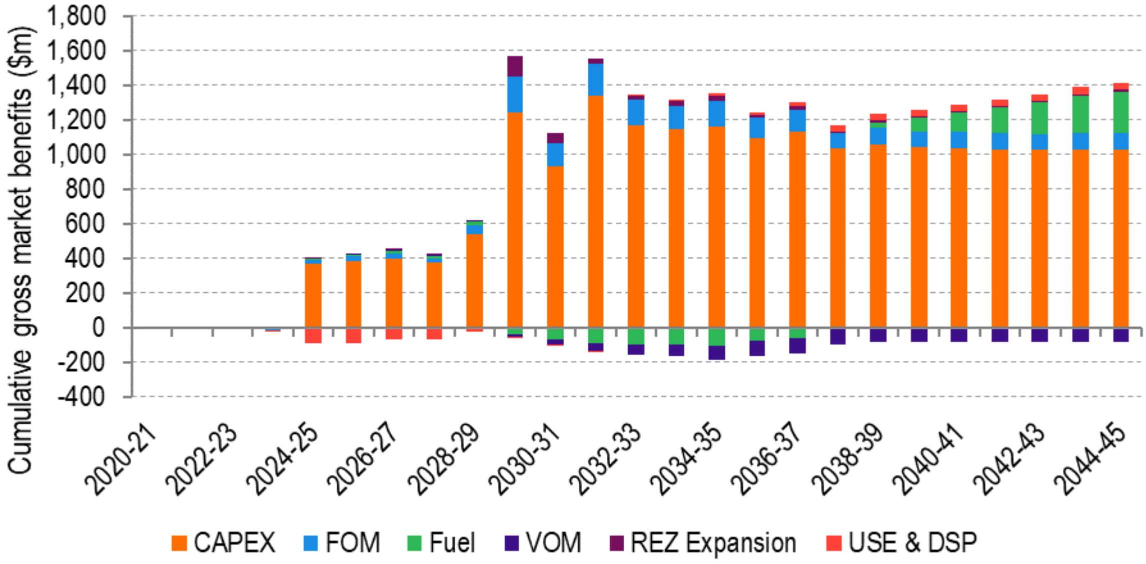


Figure 45: NEM capacity difference between Option 1C and Base case in the Central scenario

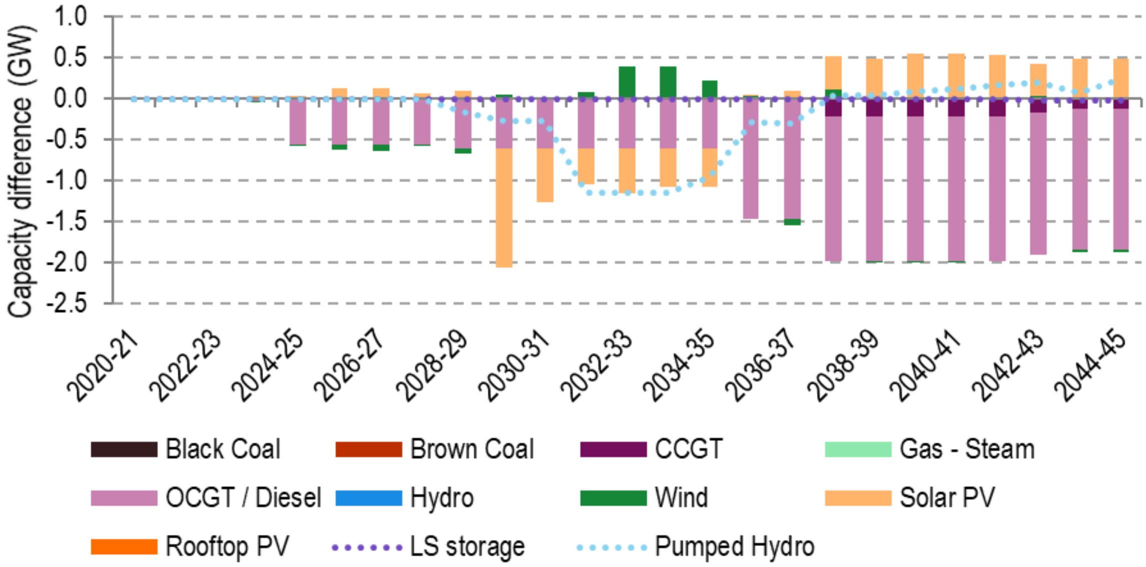
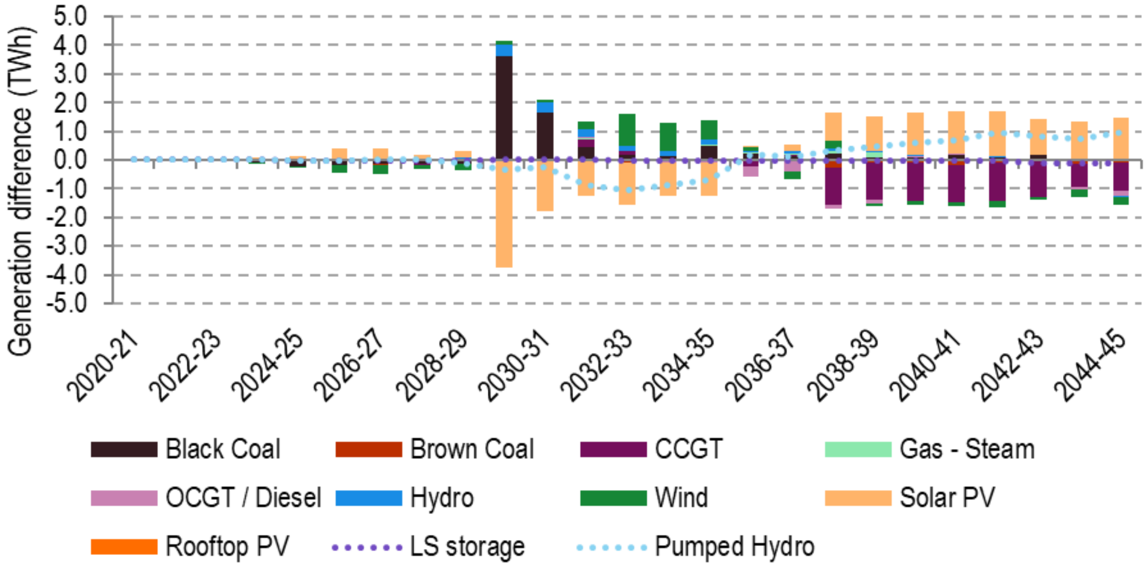


Figure 46: Difference in NEM generation forecast between Option 1C and Base case in the Central scenario



The key findings for the Option 1 cases are as follows.

- The forecast gross market benefit is significantly lower than the preferred Option 3C.
- Gross market benefits begin the same year as the preferred option but remain stable until 2029-30. This is mainly because this upgrade only avoids OCGT build in the first few years.
- The capex saving in 2029-30 and during the early 2030s is mostly due to deferral of solar and PSH. The HumeLink upgrade enables more coal generation which reduces the need for solar build and hence generation. This is primarily because the upgrade allows higher utilisation of Snowy 2.0 to supply demand in NCEN.
- As for the preferred Option 3C, Option 1 cases are forecast to provide fuel cost saving from the late 2030s, although to a much lesser extent. This is due to solar and PSH generation equating to around 2.5 TWh offsetting CCGT generation.
- By the end of the modelling period, OCGT is the primary build avoidance compared to the Base case.

Option 1C is forecast to build small amounts of additional solar in QLD (Darling Downs REZ) and NNS (New England REZ), and 330 MW in SA (Riverland REZ). However, as stated above, renewable energy transfer limitations from the southern states through Wagga result in minor generation differences compared to the Base case.

8.5.2 Options 2 to 4 - Central scenario

The second group represents Options 2-4. We have discussed Option 3C earlier, and in this section market modelling results of Option 2C and Option 4C are provided (Figure 47, Figure 48 and Figure 49).

Figure 47: Forecast cumulative gross market benefit for Option 2C (left) and Option 4C (right) in the Central scenario, millions real June 2019 dollars discounted to June 2020

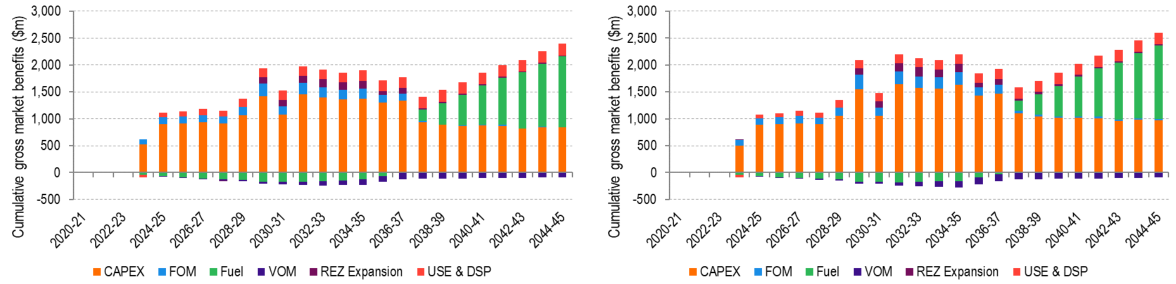


Figure 48: Difference in NEM capacity forecast of Option 2C and Option 4C relative to Base case in the Central scenario

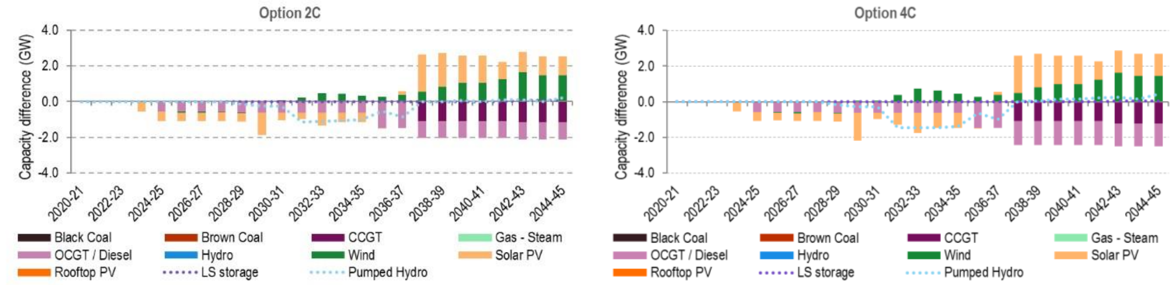
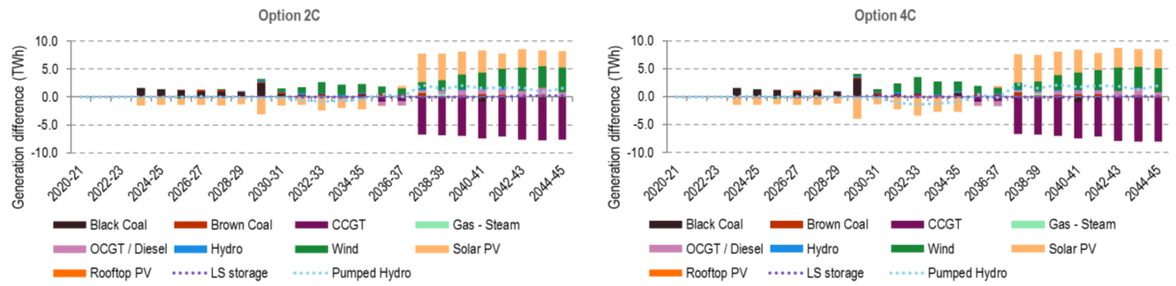


Figure 49: Difference in NEM generation forecast of Option 2C and Option 4C relative to Base case in the Central scenario



The key findings of the market modelling for this group are as follows.

- The forecast gross market benefits, capacity and generation differences of these options follow a similar trend to Option 3C.
- It is evident that Option 4C has higher forecast gross market benefits than Option 2C and Option 3C, although the first few years' benefits are almost the same across these options.
- All options avoid OCGT and CCGT build by installing more wind and solar.
- All options offset CCGT generation with wind, solar and PSH generation.

Unlike Option 1 these options do not experience renewable energy transfer limitations from the SWNSW and southern states through Wagga to the load centres in NSW. Under these options, the model is forecast to build in SWNSW (500 MW additional solar), Victoria (approximately 1.5 GW additional wind in South West Victoria REZ) and South Australia (approximately 730 - 850 MW solar in the Riverland REZ) compared to the Base case which builds more in QLD and earlier in NNS.

8.6 Sensitivities

EY modelled a number of sensitivities around the preferred option and selected scenarios. All sensitivities were selected by TransGrid to test the robustness of the findings for Option 3C. A summary of forecast benefits is shown in Table 14 below (for the sake of comparison, Option 3C forecast gross market benefits are also provided in Table 14). All sensitivities still result in overall positive forecast gross market benefits. Conclusions regarding the impact of sensitivities on net market benefits are presented in the PADR published by TransGrid[77].

Table 14: Summary of sensitivity forecast gross market benefits for Option 3C compared to the Base case, millions real June 2019 dollars discounted to June 2020 dollars

Sensitivity	Scenario				
	Slow Change	Central	Step Change	Fast Change	High DER
Option 3C	*1,504*	*2,291*	*2,545*	*2,562*	*N/A*
Snowy 2.0 does not proceed	1,123	1,559	N/A	N/A	N/A
Economic retirements (a) earlier retirements (b) earlier and deferred retirements	N/A	(a) 2,327 (b) 1,536	N/A	N/A	N/A
High DER scenario	N/A	N/A	N/A	N/A	2,148
QNI Stage 2	N/A	N/A	N/A	1,810	N/A
50% POE	N/A	1,981	N/A	N/A	N/A
Staged development of Option 3C	979	2,010	2,412	2,412	N/A
Commissioning of VNI West delayed	N/A	2,200	N/A	N/A	N/A
Demand management	N/A	2,294	N/A	N/A	N/A

8.6.1 Snowy 2.0 development does not proceed

To respond to the submissions received from the HumeLink PSCR, TransGrid requested modelling for a sensitivity for which Snowy 2.0 does not proceed in the Central and Slow Change scenarios (No Snowy 2.0).

In this sensitivity there is a reduction in the forecast gross market benefits of $381m and $732m in the Slow Change and Central scenarios, respectively.

Compared to the Base case in the Central scenario, the Base case without Snowy 2.0 forecasts more wind and less solar build in the late 2020s to early 2030s. From the same time onwards, the model forecasts to build approximately 500 MW additional PSH compared to the Base case with Snowy 2.0, along with large-scale storage.

In comparison to its counterfactual Base case, no Snowy 2.0 with the augmentation option forecasts more gas build, along with more PSH[78] by the end of the modelling period. In the short term, black coal generation offsets solar generation, resulting in negative fuel cost benefits during this period as seen in Figure 50. In the long term, gas generation is offset by wind, solar, and PSH generation, resulting in a larger proportion of fuel cost benefits, but only a minor contribution from capex saving (Figure 50).

[77] TransGrid, *Reinforcing the NSW Southern Shared Network to increase transfer capacity to the state's demand centres (HumeLink) PADR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network, Accessed 10 January 2020.

[78] Excluding Snowy 2.0.

In the Slow Change scenario, the main source of forecast benefits remains capex saving. Due to low demand growth, the opportunity for savings from the augmentation is reduced and the impact of no generation from Snowy 2.0 is of lower magnitude (Figure 51).

Figure 50: Forecast cumulative gross market benefit for Option 3C in the Central scenario without Snowy 2.0, millions real June 2019 dollars discounted to June 2020

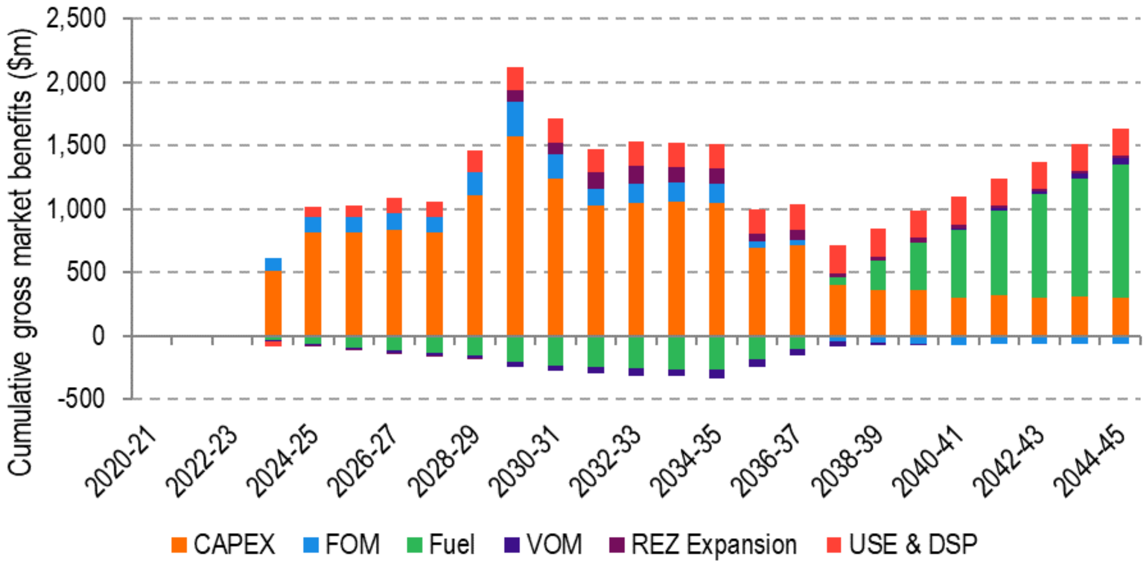
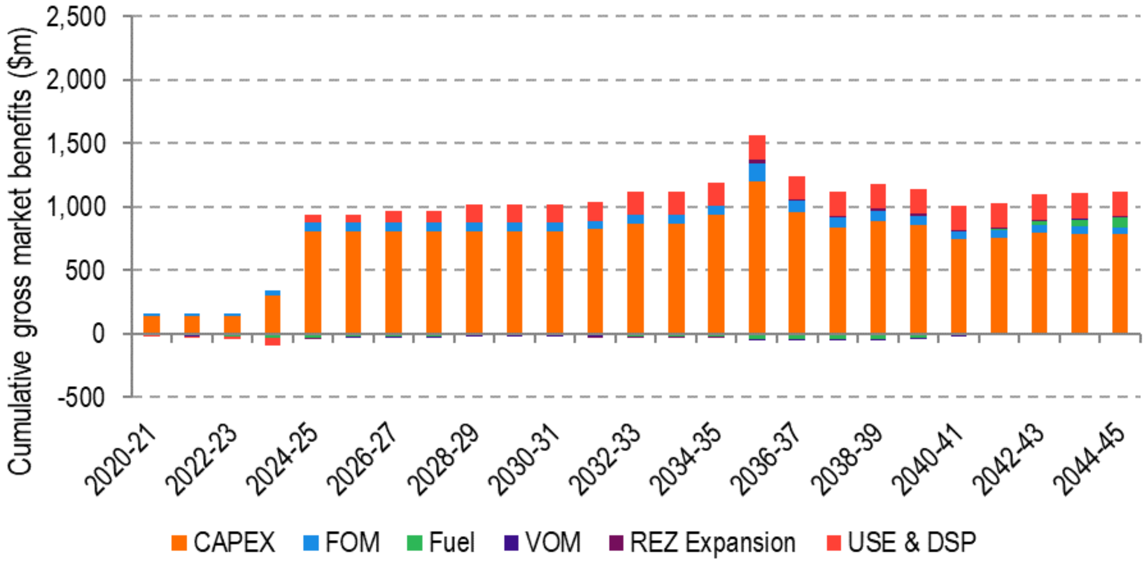


Figure 51: Forecast cumulative gross market benefit for Option 3C in the Slow Change scenario without Snowy 2.0, millions real June 2019 dollars discounted to June 2020



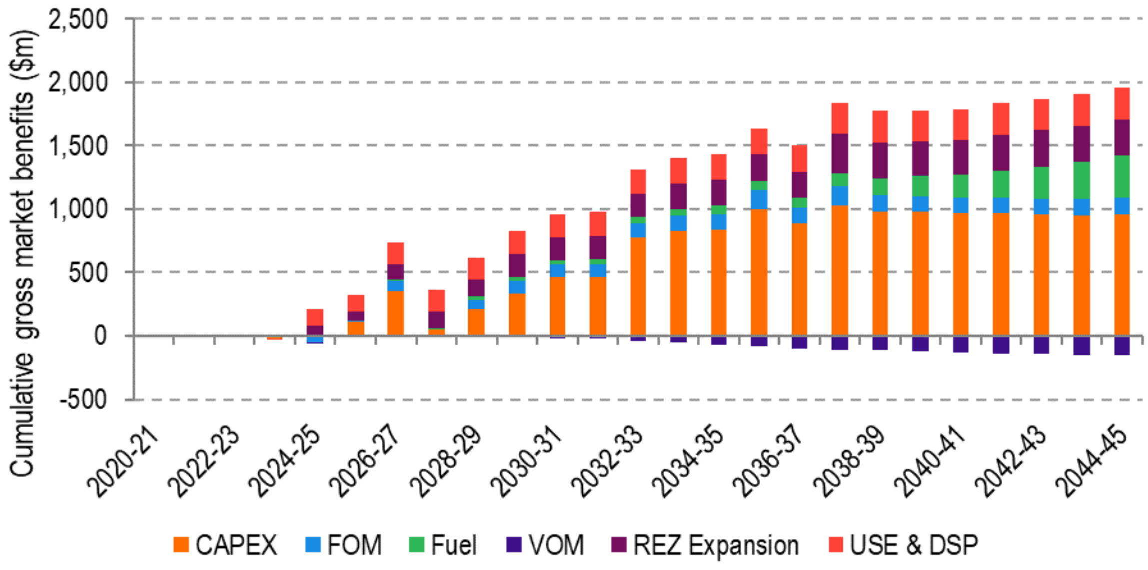
8.6.2 QNI Stage 2

This sensitivity considers the possible development of a QNI Stage 2 upgrade (QNI PSCR Option 3C[79]) in 2028-29 for both the Base case and HumeLink Option 3C in the Fast Change scenario.

[79] TransGrid and Powerlink, 20 November 2018, *Expanding NSW-QLD transmission transfer capacity PSCR*. Available at: https://www.transgrid.com.au/what-we-do/projects/regulatory-investment-tests/Documents/QNI%20PSCR%20November%202018.pdf. Accessed 09 January 2020.

The QNI transmission upgrade sensitivity reduces the forecast benefits of HumeLink Option 3C by $752m, resulting in a gross benefit of $1,810m. Forecast gross market benefit components are shown in Figure 52 below.

Figure 52: Forecast cumulative gross market benefit for Option 3C in the Fast Change scenario with QNI Stage 2 upgrade, millions real June 2019 dollars discounted to June 2020



The QNI augmentation reduces the need for new generation, in particular dispatchable capacity, and as a result the potential for the HumeLink augmentation to deliver capex and fuel savings is reduced. In general, the model forecasts more wind, but less solar capacity in Queensland, as well as additional wind and solar in NNS. In return, the amount of renewable capacity forecast to be built in Wagga Wagga and SWNSW REZs in the QNI sensitivity is reduced.

8.6.3 Economic retirements

TransGrid has considered two different sensitivities for economic retirements of coal-fired power stations in the Central scenario.

- Sensitivity (a) allows only earlier retirements,
- Sensitivity (b) allows earlier retirements as well as life extensions of Vales Point, Eraring and Bayswater.

Compared to Option 3C, Sensitivity (a) forecasts an increase of gross market benefits by $36m, and Sensitivity (b) results in reduced forecast gross market benefits by $755m. For each of these sensitivities both the Base case and Option 3C were rerun, allowing for the calculation of the increase in forecast gross market benefits from HumeLink to be assessed against the corresponding Base case.

In the Base case, Sensitivity (a) results in the early retirement of 1150 MW black coal in QLD. In Sensitivity (b), 1780 MW black coal in QLD and around 230 MW coal in NSW are forecast to retire early, however the remaining NSW coal generators' retirement was forecast to be deferred by 10 years.

With the augmentation, under Sensitivity (a), 1150 MW QLD and 570 MW NSW black coal are forecast to retire before their end-of-technical life.In Sensitivity (b), 1690 MW QLD and 800 MW NSW black coal are forecast to retire early, but other NSW black coal generators' retirements are forecast to be deferred by 10 years. Figure 53 and Figure 54 show the forecast gross market benefits for Sensitivities (a) and (b), respectively. These charts include refurbishment costs as FOM.

Figure 53: Forecast cumulative gross market benefit for Option 3C in the Central scenario for economic retirement sensitivity (a), millions real June 2019 dollars discounted to June 2020

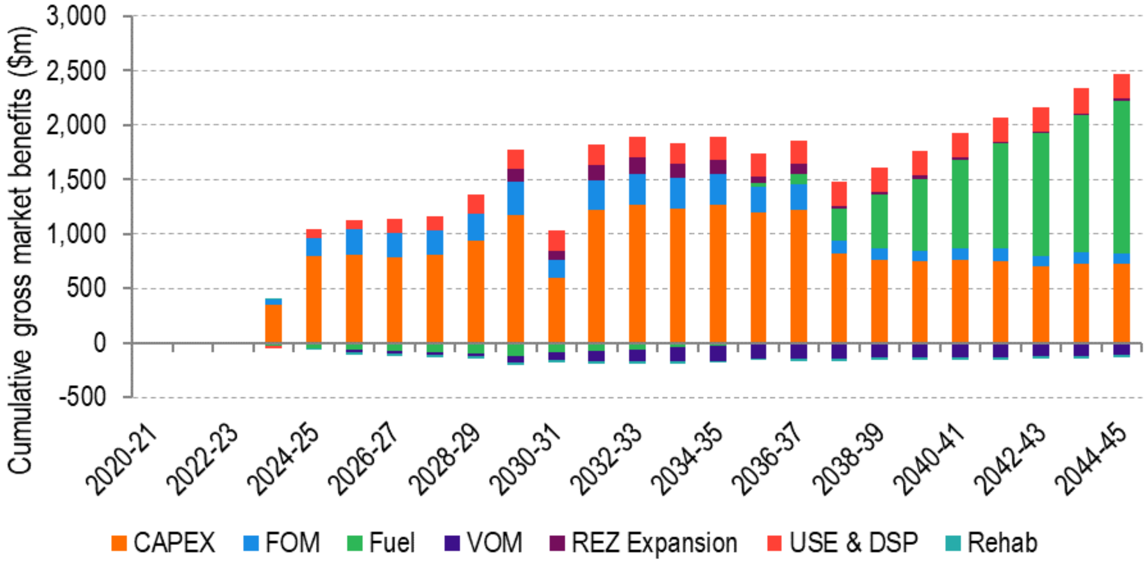
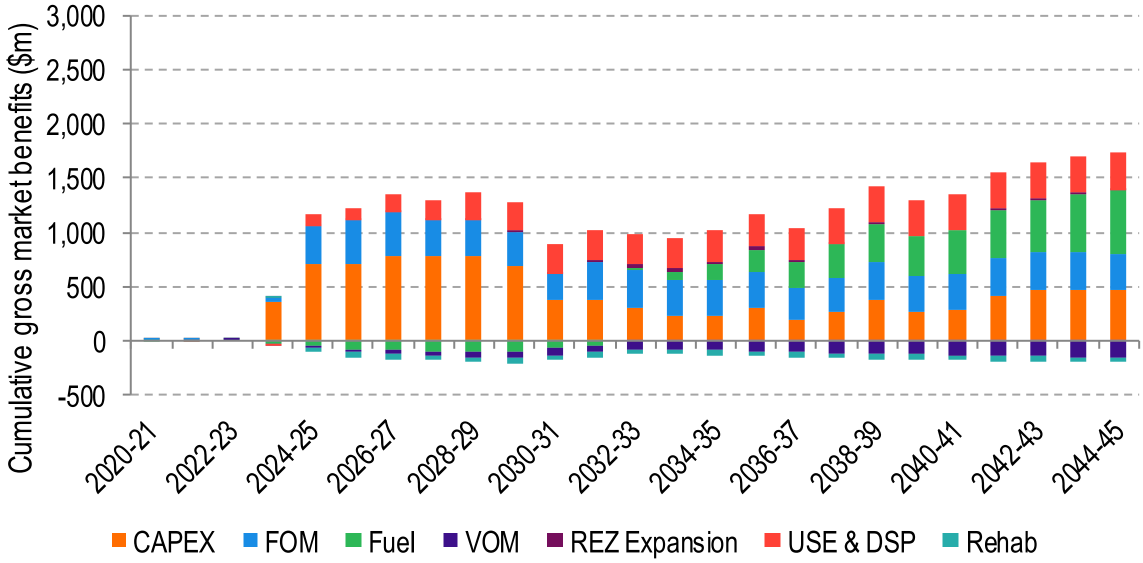


Figure 54: Forecast cumulative gross market benefit for Option 3C in the Central scenario for economic retirement sensitivity (b), millions real June 2019 dollars discounted to June 2020



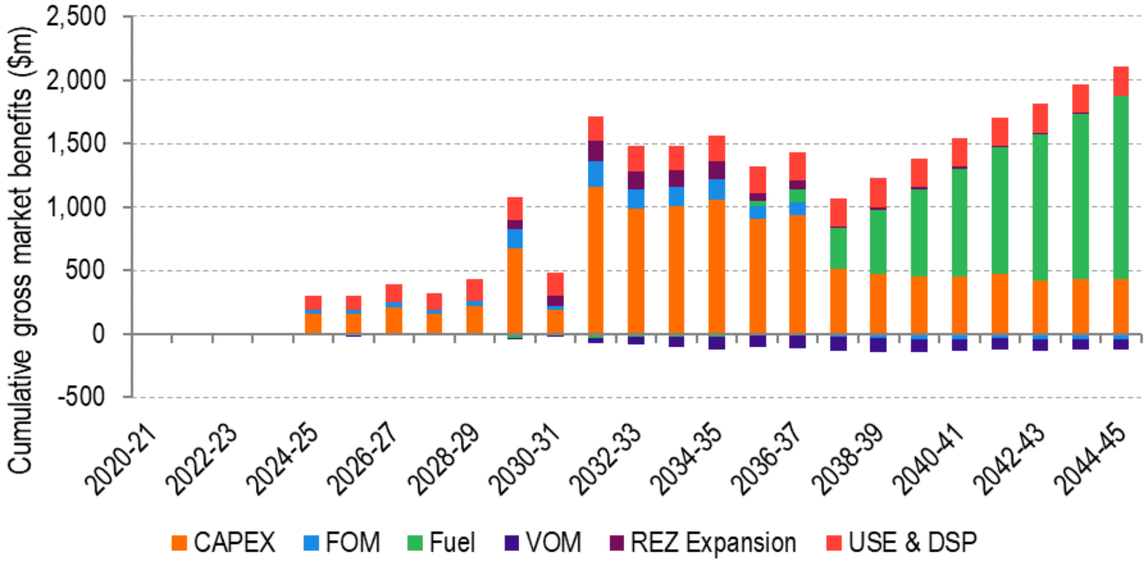
For the Sensitivity (a), there is no difference in retirements post 2035-36 and composition of benefits is very similar to the Central scenario without economic retirements. The significant reduction in forecast gross market benefits in the Sensitivity (b) is due to the reduction in build for gas-fired plants in this sensitivity, as the retirement of black coal generators in NSW is deferred by 10 years.

8.6.4 50% POE demand

The probability of exceedance (POE) demand forecast refers to the likelihood of the forecast peak annual demand being exceeded in a given year. The modelling used AEMO's 2019-20 ISP 10% POE peak demands, which correspond to the expectation of 1 in 10 years exceedance of the forecast peak demand. This has been selected as generally acceptable to plan transmission (e.g. the NSW Government Energy Strategy released in November states 10% POE as an appropriate standard to plan transmission networks).

However, a sensitivity has been modelled to analyse the outcome for the preferred option under a 50% POE peak demand scenario for which the forecast peak demand is expected to be exceeded 5 years in 10. This corresponds to lower peak demands, reducing the need for peaking gas-fired plants, and thus reducing the potential for capex and fuel savings through the augmentation. Accordingly, the forecast gross market benefits in the Central scenario are reduced by $310m to $1,981m. The corresponding composition of forecast gross market benefits is similar to the 10% POE scenario (Figure 55 vs Figure 24).

Figure 55: Forecast cumulative gross market benefit for Option 3C in the Central scenario for 50% POE peak demand, millions real June 2019 dollars discounted to June 2020



8.6.5 High DER scenario

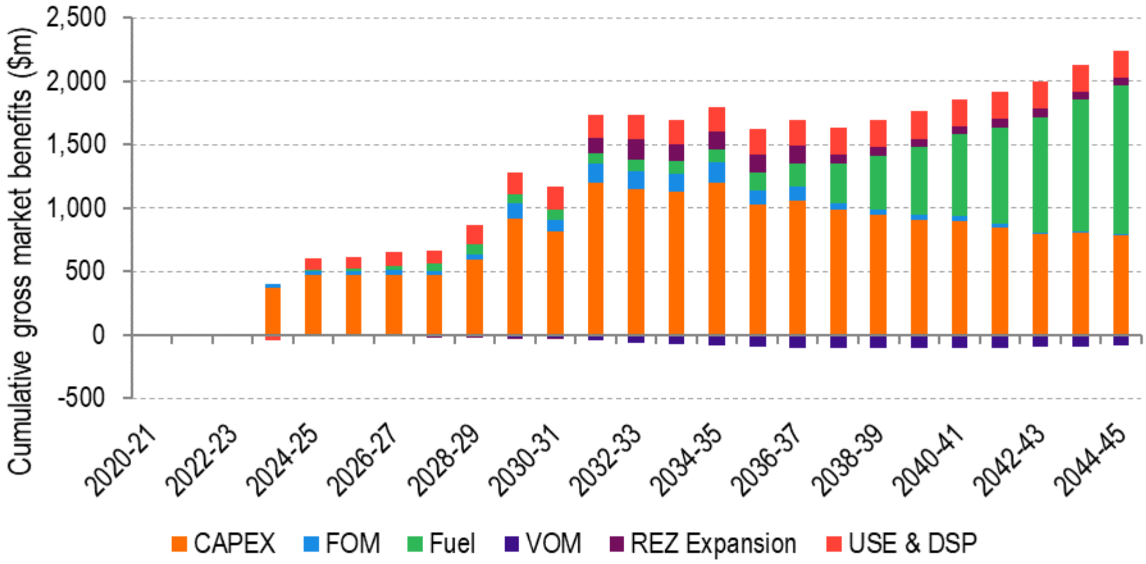
The fifth scenario modelled in AEMO's 2019-20 ISP is the High DER scenario, which reflects a Central scenario with a more rapid consumer-led transformation of the energy sector with reduced technology costs and increased distributed energy resources (DER)[80].

High DER has been modelled as a sensitivity for Option 3C. In this sensitivity, the forecast gross market benefits (Figure 56) are reduced to $2,148m which is $143m lower than the Central scenario. The High DER has a lower annual operational consumption forecast compared to the Central scenario, but higher expected peak demands. The modelling forecasts more CCGTs and OCGTs, as well as PSH build, compared to the Central scenario, but less wind.

With the augmentation, less of the CCGT generation in the High DER scenario compared to the Central scenario, is replaced by generation from wind, solar and PSH, resulting in a reduction of $145m in forecast fuel cost benefits. Capex saving is also reduced by $60m, and almost $50m additional saving from REZ expansion is seen.

[80] AEMO, *2019 Forecasting and Planning Scenarios, Inputs, and Assumptions*. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2019/2019-to-2020-Forecasting-and-Planning-Scenarios-Inputs-and-Assumptions-Report.pdf. Accessed 09 January 2020.

Figure 56: Forecast cumulative gross market benefit for Option 3C in the Central scenario for the High DER scenario, millions real June 2019 dollars discounted to June 2020



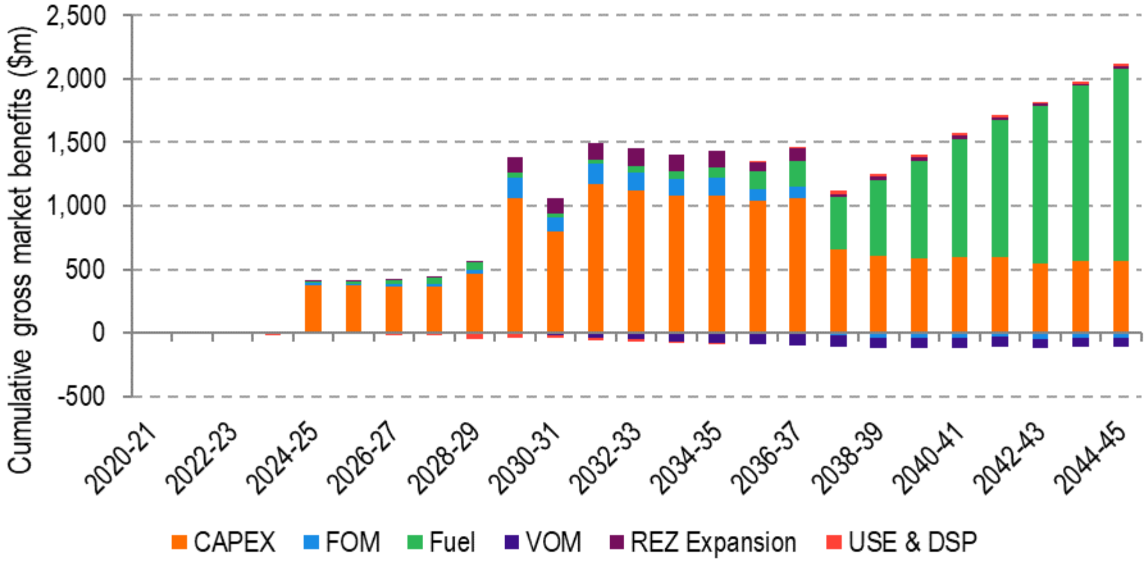
8.6.6 Staged development of the preferred option

A new option was tested in all scenarios with a staged development of Option 3C, in which the circuits Maragle-Wagga-Bannaby are built in July 2024, followed by the Maragle-Bannaby circuit. The optimised timing of the second stage was determined by scenario as July 2029 in the Central, July 2026 in the Step Change, July 2028 in the Fast Change, and July 2035 in the Slow Change scenarios.

The staged development results in a reduction of benefits of $281m in the Central scenario, $525m in the Slow Change scenario, $150m in the Fast Change scenario, and $133m in the Step Change scenario.

The forecast gross market benefits for the Central scenario with a staged development of Option 3C are shown in Figure 57. In this sensitivity the second stage is assumed to be developed in July 2029. The main differences in this sensitivity are in the first few years of the modelling period, in which less solar build is avoided with only stage 1 of the upgrade. This solar generation offsets black coal generation in Option 3C. As a result, capex savings are forecast to reduce compared to Option 3C, while fuel savings are increased.

Figure 57: Forecast cumulative gross market benefit in the Central scenario for the staged development of Option 3C, millions real June 2019 dollars discounted to June 2020



The results for the staged development in the Fast and Step Change scenarios are very similar. In both scenarios the full potential of the upgrade is opened up later (2028-29 and 2026-27, respectively) and benefits reduce compared to Option 3C by $150m in the Fast Change scenario and $133m in the Step Change scenario.

In the Slow Change scenario, until the second stage of the upgrade in July 2035, the additional solar generation offsets black coal generation forecast for Option 3C, resulting in forecast fuel cost benefits. From the year of the second stage, capex benefits in the sensitivity approximately double, but are still significantly lower compared to Option 3C.

8.6.7 Commissioning of VNI West delayed to 2034

To test the impact of the timing of VNI West on the preferred option, this sensitivity assumes a delay in the commissioning of VNI West from 2026-27 to 2034-35.

The sensitivity results in forecast gross market benefits reducing by $91m to $2,200m, with only minor impacts on composition of benefits, generation and capacity mix. In this sensitivity, the model forecasts a very similar build in the later years post the assumed commissioning of VNI West in 2034-35, resulting in only minor reductions of benefits with a similar long-term build.

8.6.8 Demand management

As the implementation of the augmentation is technically not feasible to be commissioned earlier than modelled in 2024-25, TransGrid tested a non-network solution for the years prior.

This sensitivity assumed increased Snowy cut-set limits during times of peak demand (210 MW additional transfer capacity in 2021-22, and 110 MW in 2022-23 and 2023-24) to model consumer demand management before the network augmentation (only for Option 3C).

An increase in forecast gross market benefits by $2.4m to $2,294m can be observed through this scheme, primarily due to higher savings from USE&DSP.

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 Exceedence
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
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