Reinforcing the NSW Southern Shared Network PACR

Market Modelling Report

TransGrid

29 July 2021

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.

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

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

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1. Executive summary

TransGrid has engaged EY to undertake market modelling of system costs and benefits to support the 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]. This is an independent study and the modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator[2].

This Report forms a supplementary report to the Project Assessment Conclusions Report (PACR) prepared and published by TransGrid[3]. It describes the key modelling outcomes and insights developed through our analysis for the assumptions, input data sources and methodologies that have been provided by TransGrid. This Report is accompanied by market modelling workbooks which contain summaries of key outcomes.

EY calculated the least-cost generation dispatch and capacity development plan for the National Electricity Market (NEM) associated with three groups of HumeLink augmentation options across a range of voltage variants, scenarios and sensitivities[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 dispatch of generators and commissioning of new entrant capacity, while taking into account several operational and technical constraints. From the hourly time-sequential modelling we computed the following costs, as defined in the RIT-T:

- capital costs of new generation capacity installed (Capex),
- total Fixed Operation and Maintenance (FOM) costs of all generation capacity,
- total VOM costs of all generation capacity,
- total fuel costs of all generation capacity,
- total cost of voluntary (demand-side participation, DSP) and involuntary load curtailment (Unserved energy, USE),
- transmission expansion costs associated with 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 between each option and the Base case. The difference in present values of costs is the forecast gross market benefits due to the HumeLink transmission augmentation, 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 Pumped Storage Hydro (PSH) and large-scale battery storage between each HumeLink augmentation option and the counterfactual Base case.

[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 29 July 2021.

[2] AER, August 2020, *Application guidelines - Regulatory investment test for transmission*. Available at: https://www.aer.gov.au/system/files/AER%20-]%20Regulatory%20investment%20test%20for%20transmission%20application%20guidelines%20-%2025%20August%202020.pdf. Accessed 28 June 2021.

[3] TransGrid, *Reinforcing the NSW Southern Shared Network to increase transfer capacity to the state's demand centres (HumeLink) PACR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network. Accessed 29 July 2021.

In addition, EY evaluated competition benefits for selected options in line with the Frontier Economics approach[4]. Clause 5.15A.2(b)(4)(viii) of the NER requires a RIT–T proponent to consider competition benefits as a class of potential market benefits that could be provided by a credible option[5]. Competition benefits are likely to occur if a credible option could impact the bidding behaviour of generators (and other market participants) who may have a degree of market power relative to the Base case. The Frontier approach for defining competition benefits is to measure the additional benefits that an augmentation might accrue if the assumption of competitive bidding were relaxed. These benefits are over and above conventionally-measured market benefits, which are expected to flow from taking into account likely bidding behaviour[4]. The importance of competition benefits has been highlighted by Frontier Economics, where it is stated that: *"as the power system evolves with the connection of new generators and loads in response to the price signals given by the market, the contribution of the other (non-competition related) benefits to the overall benefits of interconnection will diminish. This will mean that competition benefits will become an increasingly important source of the benefits of interconnection. Therefore, more time and effort will need to be spent in understanding the nature of these benefits and how they can be measured"*[4].

Gross market benefits were forecast for three HumeLink augmentation topologies, each with different 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 PACR[6].

The scenarios modelled are in line with the Australian Energy Market Operator's (AEMO) 2020 Integrated System Plan (ISP) scenarios[7]: Central, Step Change, Slow Change and Fast Change. The modelled scenarios differ in various assumptions such as demand, technology and fuel costs, emissions constraints, coal fired generator retirement dates, renewable energy targets, and inclusion/exclusion of VNI West, QNI Medium and Large, and Marinus Link.

Table 1 shows the forecast gross market benefits over the modelled 25-year horizon for all options across the four scenarios and various voltage variants. The modelling shows a similar trend in forecast gross market benefits and generation development for Options 2 and 3, 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 Wagga Wagga, SWNSW and southern regions. Furthermore, while the forecast gross market benefits of the Fast Change scenario are close to the Central scenario, as this scenario has a relatively similar underlying assumptions to the Central scenario, the gross market benefits of the Step Change and Slow Change scenarios are significantly higher and lower than the Central, given major differences in assumptions such as demand, emissions, renewable policies and coal retirements.

TransGrid has concluded, after incorporating development costs of the options, that Option 3C is the preferred option, as it results in the highest NPV of benefits compared with costs. We note that TransGrid has decided that a number of other options modelled in the Project Assessment Draft Report (PADR) (Options 2A and 3A, Option 4) to be excluded in the PACR. This decision was based on either the assessment conducted in the PADR or the significant cost of Option 4.

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[4] Frontier Economics, September 2004, *Evaluating interconnection competition benefits.* Available at: https://www.aer.gov.au/system/files/Frontier%20Economics%20report%20-%20evaluating%20interconnection%20competition%20benefits%20-%20September%202004.pdf. Accessed 28 June 2021.

[5] AER, August 2020, *Application guidelines - Regulatory investment test for transmission*. Available at: https://www.aer.gov.au/system/files/AER%20-]%20Regulatory%20investment%20test%20for%20transmission%20application%20guidelines%20-%2025%20August%202020.pdf. Accessed 28 June 2021.

[6] TransGrid, *Reinforcing the NSW Southern Shared Network to increase transfer capacity to the state's demand centres (HumeLink) PACR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network. Accessed 29 July 2021.

[7] AEMO, *2020 Integrated System Plan (ISP)*. Available at: https://www.aemo.com.au/energy-systems/major-publications/integratd-system-plan-isp/2020-integrated-system-plan-isp. Accessed 26 May 2021.

Table 1: Summary of forecast gross market benefits, millions real June 2019 dollars discounted to June 2021 dollars

Option	Scenario			
	Central	Step Change	Fast Change	Slow Change
1A	1,242	1,392	1,268	585
1B	1,687	1,877	1,726	703
1C	1,710	1,892	1,754	718
2B	2,073	2,631	2,112	741
2C	2,093	2,645	2,134	758
3B	2,075	2,651	2,112	746
3C	2,114	2,680	2,154	770

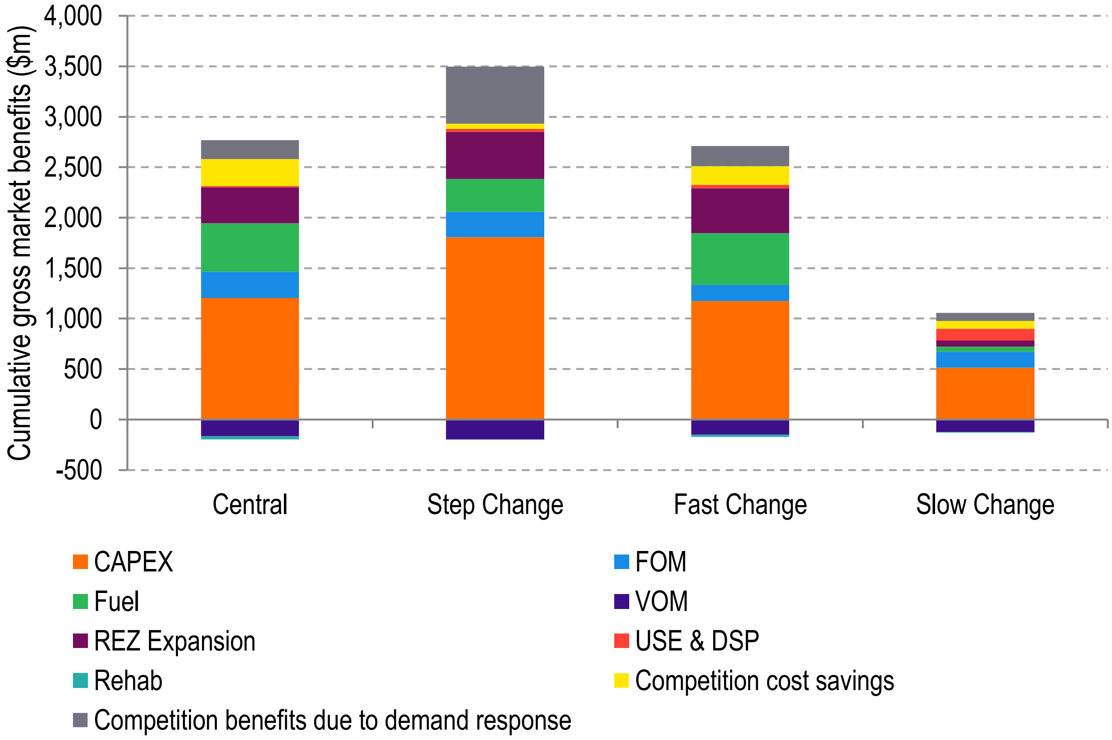
For the two highest ranked options, i.e. Options 2C and 3C, EY also calculated the potential competition benefits, including competition cost savings and competition benefits due to demand response, and the resulting total benefits are summarised in Table 2. It is forecast that Option 3C will result in a slightly higher competition benefits across all scenarios. In addition, the modelling forecasts that similar to the conventional benefits, competition benefits are close in the Fast Change and Central scenarios, while they are significantly higher and lower in the Step Change and Slow Change scenarios, respectively.

Table 2: Summary of forecast gross market benefits and competition benefits, millions real June 2019 dollars discounted to June 2021 dollars

Scenario		Benefits			
		Market benefits	Competition cost savings	Competition benefits due to demand response	Total
Option 2C	Central	2,093	263	186	2,542
	Step Change	2,645	45	566	3,256
	Fast Change	2,134	174	198	2,506
	Slow Change	758	75	80	913
Option 3C	Central	2,114	270	186	2,570
	Step Change	2,680	51	565	3,296
	Fast Change	2,154	184	199	2,538
	Slow Change	770	78	80	928

The composition of forecast total gross market benefits for Option 3C, the preferred option, in all scenarios is shown in Figure 1.

Figure 1: Forecast total gross market benefits for Option 3C for all scenarios, millions real June 2019 dollars discounted to June 2021 dollars



Sources of benefits and the key drivers are discussed below.

- The Central scenario is forecast to have the highest benefits from capex savings, followed by fuel and REZ expansion savings. For the competition-related benefits, competition cost savings are expected to have a higher share than the benefits due to demand response.
- Similar to the Central scenario, capex savings are expected to account for the majority of benefits in the Step Change scenario. Fuel cost savings are forecast to be smaller due to the significantly higher coal retirements in this scenario. On the other hand, more renewable build requirement in Step Change is expected to result in more REZ expansion savings with Option 3C. For the competition-related benefits, competition cost savings are expected to have a small share (mainly due to lower fuel cost savings with more coal retirements), while the benefits due to demand response are considerable given Option 3C is expected to result in a larger price difference to the Base case and as such higher surplus due to increased demand from elastic demand.
- The Fast Change scenario is forecast to have close benefits to the Central scenario. While carbon budget constraints and other drivers result in higher opportunities for renewable diversity through Option 3C, assumptions such as VNI West commissioning in 2035-36 are expected to constrain this diversity from southern states.
- The Slow Change scenario is forecast to have significantly smaller benefits as compared to other scenarios, which is due to drivers such as a significantly lower demand expectation, NSW roadmap, and the allowance of coal life extensions by 10 years.
- All scenarios are expected to incur VOM cost, mainly due to increased pumped hydro generation and also to some extend wind generation.

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[8]. The RIT-T is a cost-benefit analysis used to assess the viability of investment options in regulated electricity transmission assets.

This Report forms a supplementary report to the broader Project Assessment Conclusions Report (PACR) published by TransGrid[9]. It describes the key modelling outcomes and insights developed through our analysis for the assumptions, input data sources and methodologies that have been provided by TransGrid. 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 three 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 PACR[9]. This is an independent study and the modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator[10].

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.

In addition, EY computed competition benefits for selected options in line with the Frontier Economics approach[11]. Clause 5.15A.2(b)(4)(viii) of the NER requires a RIT–T proponent to consider competition benefits as a class of potential market benefits that could be provided by a credible option[10]. Competition benefits are likely to occur if a credible option could impact the bidding behaviour of generators (and other market participants) who may have a degree of market power relative to the Base case. The Frontier approach for defining competition benefits is to measure the additional benefits that an augmentation might accrue if the assumption of competitive bidding were relaxed. These benefits are over and above conventionally-measured market benefits, which are expected to flow from taking into account likely bidding behaviour[4]. The

[8] TransGrid RIT-T website available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network. Accessed 29 July 2021.

[9] TransGrid, *Reinforcing the NSW Southern Shared Network to increase transfer capacity to the state's demand centres (HumeLink) PACR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network. Accessed 29 July 2021.

[10] AER, August 2020, *Application guidelines - Regulatory investment test for transmission.* Available at: https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20application%20guidelines%20-%2025%20August%202020.pdf. Accessed 28 June 2021.

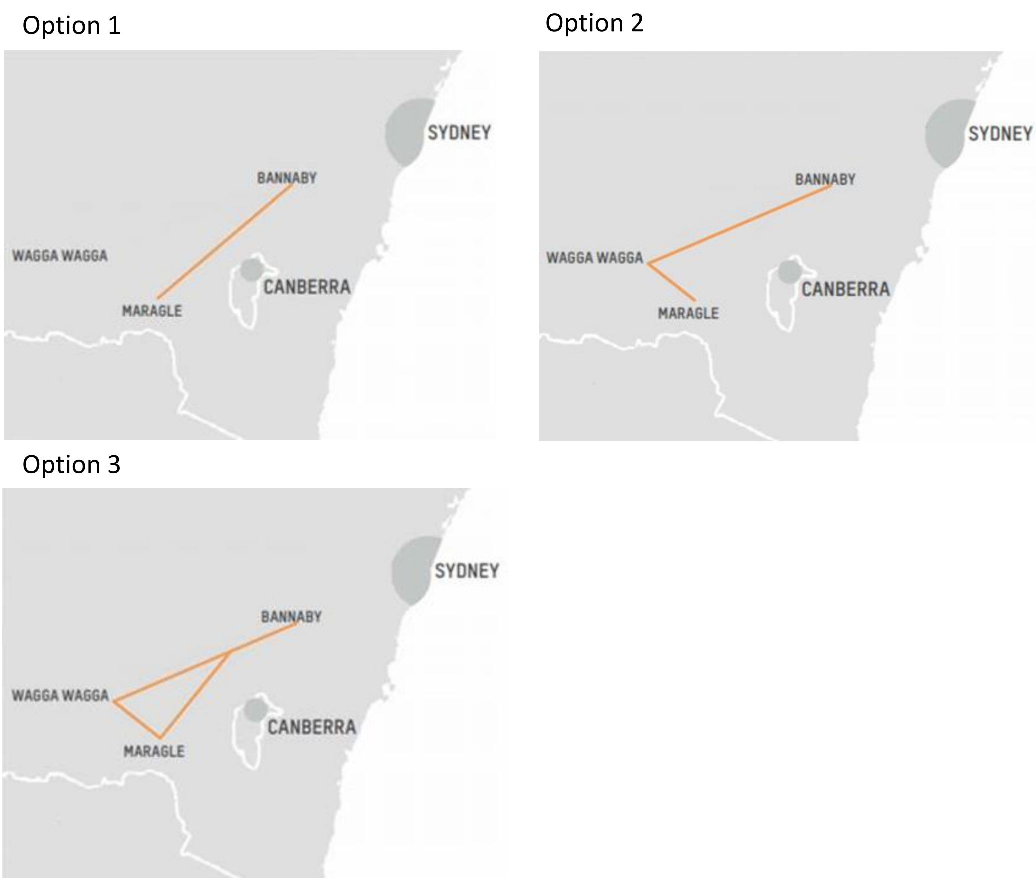
[11] Frontier Economics, September 2004, *Evaluating interconnection competition benefits.* Available at: https://www.aer.gov.au/system/files/Frontier%20Economics%20report%20-%20evaluating%20interconnection%20competition%20benefits%20-%20September%202004.pdf. Accessed 29 July 2021.

importance of competition benefits has been highlighted by Frontier Economics, where it is stated that: *"as the power system evolves with the connection of new generators and loads in response to the price signals given by the market, the contribution of the other (non-competition related) benefits to the overall benefits of interconnection will diminish. This will mean that competition benefits will become an increasingly important source of the benefits of interconnection. Therefore, more time and effort will need to be spent in understanding the nature of these benefits and how they can be measured"*[4].

Each category of gross market benefits is computed annually across a 25-year modelling period from 2021-22 to 2045-46. Benefits presented are discounted to June 2021 using a 5.9% real, pre-tax discount rate as selected by TransGrid. This value is consistent with the value applied by the Australian Energy Market Operator (AEMO) in most scenarios in the 2020 Integrated System Plan (ISP)[12].

This modelling considers seven different HumeLink augmentation topologies as detailed in the PACR[13]. All options are assumed to be commissioned by 1 September 2026. Figure 2 shows the three different HumeLink transmission augmentation topologies, which were modelled for up to 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 2: Overview of the HumeLink transmission augmentation topologies considered in this modelling[13]



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

[12] AEMO, 30 July 2020, *2019 Input and Assumptions workbook, v1.5*. Available at: https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 26 May 2021.

[13] TransGrid, *Reinforcing the NSW Southern Shared Network to increase transfer capacity to the state's demand centres (HumeLink) PACR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network. Accessed 29 July 2021.

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"[14].

The Report is structured as follows:

- Section 3 describes assumptions on scenarios as well as sensitivities modelled in this study.
- Section 4 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 of Option 3C, the preferred HumeLink augmentation.
- Appendix A provides an overview of the methodology applied in the modelling and computation of forecast gross market benefits.
- Appendix B outlines model design and input data related to representation of the transmission network, transmission losses and demand.
- Appendix C provides an overview of model inputs and methodologies related to supply of energy.
- Appendix D presents the NEM capacity and generation outlook across all scenarios without the HumeLink augmentation option.

[14] AER, August 2020, *Application guidelines - Regulatory investment test for transmission.* Available at: https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20application%20guidelines%20-%2025%20August%202020.pdf. Accessed 28 June 2021.

3. Scenarios and sensitivity assumptions

3.1 Scenarios

The options proposed by TransGrid have been assessed under four scenarios selected by TransGrid in line with AER guidelines to make the ISP actionable[15]. These are summarised in Table 3 and are aligned with the scenarios described in AEMO's 2020 final ISP[16]. As noted in Table 3, most input data are sourced from the accompanying final 2019 Input and Assumptions workbook[17].

Table 3: Overview of key input parameters across the four scenarios[18]

Key drivers input parameter	Scenario			
	Central	Step Change	Fast Change	Slow Change
Underlying consumption	ESOO 2020 Central	ESOO 2020 Step Change	ESOO 2020 Fast Change	ESOO 2020 Slow Change
New entrant capital cost for wind, solar SAT, OCGT, CCGT, PSH, and large-scale batteries	2020 ISP Central	2020 ISP Step Change	2020 ISP Fast Change	2020 ISP Slow Change
Retirements of coal-fired power stations	Economic retirement. Earlier than or at the end of technical life as per AEMO Generation Information[19]. Yallourn 2028[20]. Liddell 2022-2023.	Economic retirement. Earlier than or at the end of technical life as per AEMO Generation Information. Yallourn 2028. Liddell 2022-2023.	Economic retirement. Earlier than or at the end of technical life as per AEMO Generation Information. Yallourn 2028. Liddell 2022-2023.	At the end of technical life or ten-year life extension if economic to do so. Yallourn 2028. Liddell 2022-2023.
Gas fuel cost	AEMO 2020 ISP: Core Energy 2019, Neutral	AEMO 2020 ISP: Core Energy 2019, Fast	AEMO 2020 ISP: Core Energy 2019, Neutral	AEMO 2020 ISP: Core Energy 2019, Slow
Coal fuel cost	AEMO 2020 ISP: WoodMackenzie 2019, Neutral	AEMO 2020 ISP: WoodMackenzie 2019, Fast	AEMO 2020 ISP: WoodMackenzie 2019, Neutral	AEMO 2020 ISP: WoodMackenzie 2019, Slow
Federal Large-scale Renewable Energy Target (LRET)	33 TWh per annum by 2020 to 2030 (including GreenPower and ACT scheme), accounting for contribution to LRET by Western Australia (WA), Northern Territory (NT) and off grid locations			
COP21 commitment (Paris agreement)	26% emissions reduction from 2005 levels by 2030			

[15] AER, 25 August 2020, *Guidelines to make the integrated system plan actionable*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable. Accessed 27 May 2021.

[16] AEMO, *2020 Integrated System Plan*. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp. Accessed 27 May 2021.

[17] AEMO, 30 July 2020, *2019 Input and Assumptions workbook v1.5*. Available at: https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 27 May 2021.

[18] Ibid, unless otherwise stated in table.

[19] AEMO, July 2020, *Generating Unit Expected Closure Year – July 2020*. No *longer available online. Available from TransGrid upon request*.

[20] In March 2021, EnergyAustralia announced that the Yallourn power station in Victoria's Latrobe Valley will retire in mid-2028: https://www.energyaustralia.com.au/about-us/media/news/energyaustralia-powers-ahead-energy-transition.

<table>
<tr><th rowspan="2">Key drivers input parameter</th><th colspan="4">Scenario</th></tr>
<tr><th>Central</th><th>Step Change</th><th>Fast Change</th><th>Slow Change</th></tr>
<tr><td>NEM carbon budget to achieve 2050 emissions levels</td><td>NA</td><td>Cumulative NEM electricity sector emissions budget to 2050 of 1,465 Mt CO2-e</td><td>Cumulative NEM electricity sector emissions budget to 2050 of 2,208 Mt CO2-e</td><td>NA</td></tr>
<tr><td>Victoria Renewable Energy Target (VRET)</td><td colspan="4">40% renewable energy by 2025 and 50% renewable energy by 2030</td></tr>
<tr><td>Queensland Renewable Energy Target (QRET)</td><td colspan="2">50% by 2030</td><td colspan="2">NA</td></tr>
<tr><td>Tasmanian Renewable Energy Target (TRET)</td><td>100% by 2022</td><td>100% by 2022 and 200% by 2040</td><td colspan="2">100% by 2022</td></tr>
<tr><td>NSW Electricity Infrastructure Roadmap</td><td colspan="3">12 GW NSW Roadmap, with 3 GW in the Central West Orana (CWO) REZ, 8 GW free transmission in the New England (NE) REZ but build can be anywhere in NSW, 2 GW Pumped Storage Hydro (PSH) in 2029-30.</td><td>10 GW NSW Roadmap, but 3 GW in the CWO REZ, 8 GW free transmission in the NE REZ but build can be anywhere in NSW by 2032, 2 GW PSH in 2029-30.</td></tr>
<tr><td>South Australia Energy Transformation RIT-T</td><td colspan="4">NSW to SA interconnector (EnergyConnect) is assumed commissioned by July 2024[21].</td></tr>
<tr><td>Western Victoria Renewable Integration RIT-T</td><td colspan="4">The preferred option in the Western Victoria Renewable Integration PACR[22] by July 2025 (220 kV upgrade in 2024 and 500 kV to Sydenham in 2025).</td></tr>
<tr><td>Marinus Link</td><td>1st cable: July 2036, 2nd cable excluded[23]</td><td>1st cable: July 2028, 2nd cable: July 2031</td><td>1st cable: July 2031, 2nd cable excluded</td><td>Excluded</td></tr>
<tr><td>Victoria to NSW Interconnector Upgrade</td><td colspan="4">The Victoria to New South Wales Interconnector Upgrade PADR[24] preferred option is assumed commissioned by July 2022.</td></tr>
<tr><td>NSW to QLD Interconnector Upgrade</td><td colspan="3">QNI minor July 2022,
QNI Medium 2032-33, QNI Large 2035-36.</td><td>QNI minor July 2022,
QNI Medium and Large: excluded.</td></tr>
<tr><td>VNI West</td><td>VNI West is assumed</td><td colspan="2">VNI West is assumed commissioned by July 2035.</td><td>Excluded</td></tr>
</table>

[21] 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 28 June 2021. There are options for commissioning between 2022 and 2024. Limits also from this document.

[22] 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 28 June 2021.

[23] AEMO, 24 September 2019, *2019 Input and Assumptions workbook v1.5*, 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 28 June 2021.

[24] 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 28 June 2021.

Key drivers input parameter	Scenario			
	Central	Step Change	Fast Change	Slow Change
	commissioned by July 2028[25,26].			
Victorian SIPS[27]	300 MW/450 MWh, 250 MW for SIPS service and the remaining 50 MW can be deployed in the market by the operator on a commercial basis, November 2021.			
Snowy 2.0	Snowy 2.0 is included from July 2025.			

3.2 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 four sensitivities undertaken in the market modelling are:

- Central scenario with Kurri Kurri and Tallawarra B as committed in 2023,
- commissioning of VNI West delayed to 2035-36 under the Central scenario,
- adding a Modular Power Flow Control (MPFC) to increase transfer limit from Bannaby to Sydney under the Central scenario, and
- the Central scenario using the draft IASR assumptions[28] for the ISP 2022.

[25] AEMO and TransGrid, December 2019, *Victoria to New South Wales Interconnector West (VNI West) PSCR*. Available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/vni-west-rit-t/vni-west_rit-t_pscr.pdf?la=en. Accessed 29 June 2021.

[26] AEMO, 11 December 2020, *Draft 2021-22 Inputs and Assumptions workbook v.3.0*. Available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/draft-2021-22-inputs-and-assumptions-workbook.xlsx?la=en. Accessed 2 July 2021.

[27] Victoria Government, Victorian Big Battery, Available at: https://www.energy.vic.gov.au/renewable-energy/the-victorian-big-battery/the-victorian-big-battery-q-and-a, Accessed 1 July 2021.

[28] AEMO, 11 December 2020, *Draft 2021-22 Inputs and Assumptions workbook v.3.0*. Available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/draft-2021-22-inputs-and-assumptions-workbook.xlsx?la=en. Accessed 29 June 2021.

4. Forecast gross market benefit outcomes

4.1 Summary of forecast gross market benefits

Table 4 shows the forecast gross market benefits (non-competition related benefits) over the modelled 25-year horizon for all options across the modelled scenarios. It is forecast that the Option 2 and Option 3 variants have the highest gross market benefits, while Option 1 variants result in lower benefits mainly due to lack of connection to Wagga Wagga, which reduces the benefits from utilising better quality resources in southern regions as well as Wagga Wagga and SWNSW REZs.

Table 4: Summary of forecast gross market benefits, millions real June 2019 dollars discounted to June 2021 dollars

Option	Scenario			
	Central	Step Change	Fast Change	Slow Change
1A	1,242	1,392	1,268	585
1B	1,687	1,877	1,726	703
1C	1,710	1,892	1,754	718
2B	2,073	2,631	2,112	741
2C	2,093	2,645	2,134	758
3B	2,075	2,651	2,112	746
3C	2,114	2,680	2,154	770

As advised by TransGrid, for the two highest ranked options, i.e. Options 2C and 3C, EY also computed the expected competition benefits, including competition cost savings and competition benefits due to demand response, and the resulting total benefits are summarised in Table 5.

Table 5: Summary of forecast gross market benefits and competition benefits, millions real June 2019 dollars discounted to June 2021 dollars

Scenario		Scenario			
		Market benefits	Competition cost savings	Competition benefits due to demand response	Total
Option 2C	Central	2,093	263	186	2,542
	Step Change	2,645	45	566	3,256
	Fast Change	2,134	174	198	2,506
	Slow Change	758	75	80	913
Option 3C	Central	2,114	270	186	2,570
	Step Change	2,680	51	565	3,296
	Fast Change	2,154	184	199	2,539

Scenario		Scenario			
		Market benefits	Competition cost savings	Competition benefits due to demand response	Total
	Slow Change	770	78	80	928

TransGrid has concluded that Option 3C is confirmed as the preferred option given the option costs, thus delivering the highest NPV of benefits relative to costs[29]. 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"[30].

The rest of Section 4 explores the timing and sources of these forecast benefits for TransGrid's preferred option, Option 3C. For each scenario, we first present non-competition related benefits with detailed analysis on outcomes and drivers, and then present competition benefits.

4.2 Market modelling results for Option 3C

4.2.1 Central scenario

The forecast cumulative gross non-competition related market benefits for Option 3C in the Central scenario are shown in Figure 3. 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 4 and Figure 5, respectively. The key assumptions of the Central scenario are a moderate demand outlook and fuel prices, matching current policies, with VNI West in July 2028, and coal retirements if economic, as outlined in detail in Table 3.

[29] TransGrid, *Reinforcing the NSW Southern Shared Network to increase transfer capacity to the state's demand centres (HumeLink) PACR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network. Accessed 29 July 2021.

[30] AER, August 2020, *Application guidelines - Regulatory investment test for transmission*. Available at: https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20application%20guidelines%20-%2025%20August%202020.pdf. Accessed 28 June 2021.

Figure 3: Forecast cumulative gross market benefit[31,32] for Option 3C under the Central scenario (excluding competition benefits), millions real June 2019 dollars discounted to June 2021 dollars

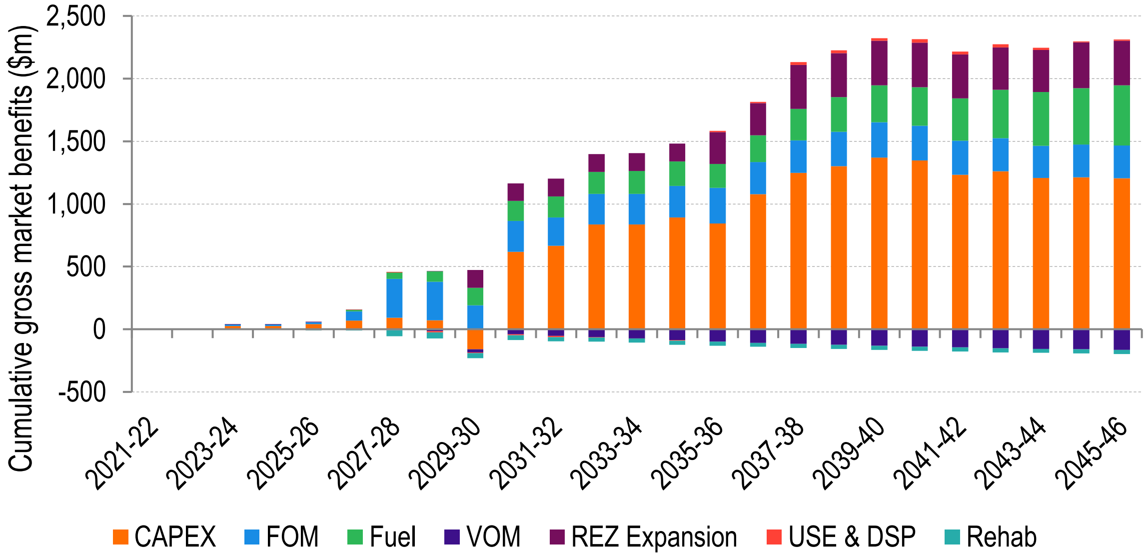
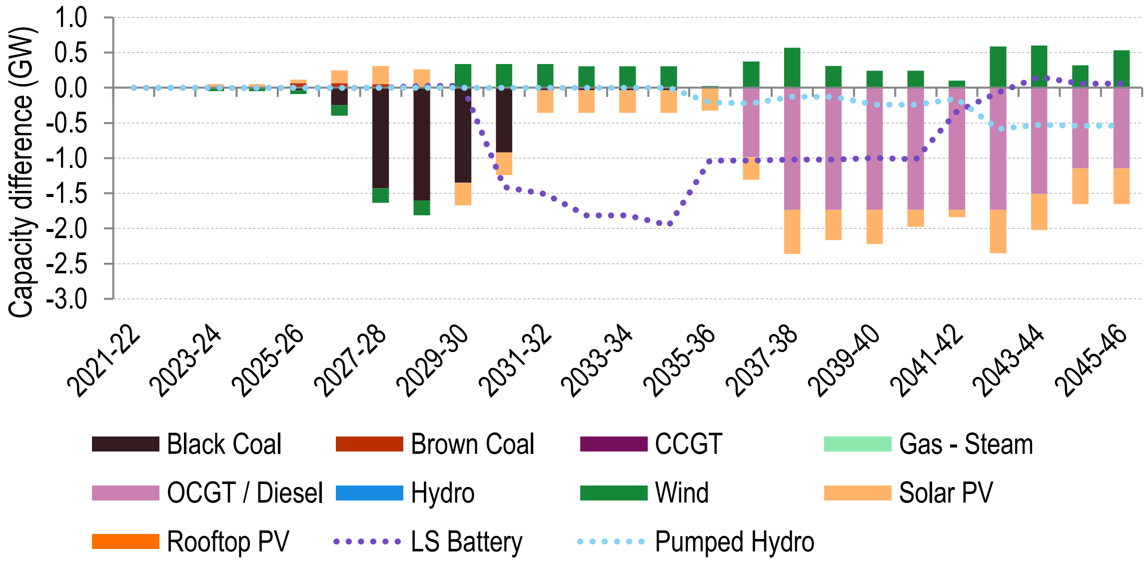


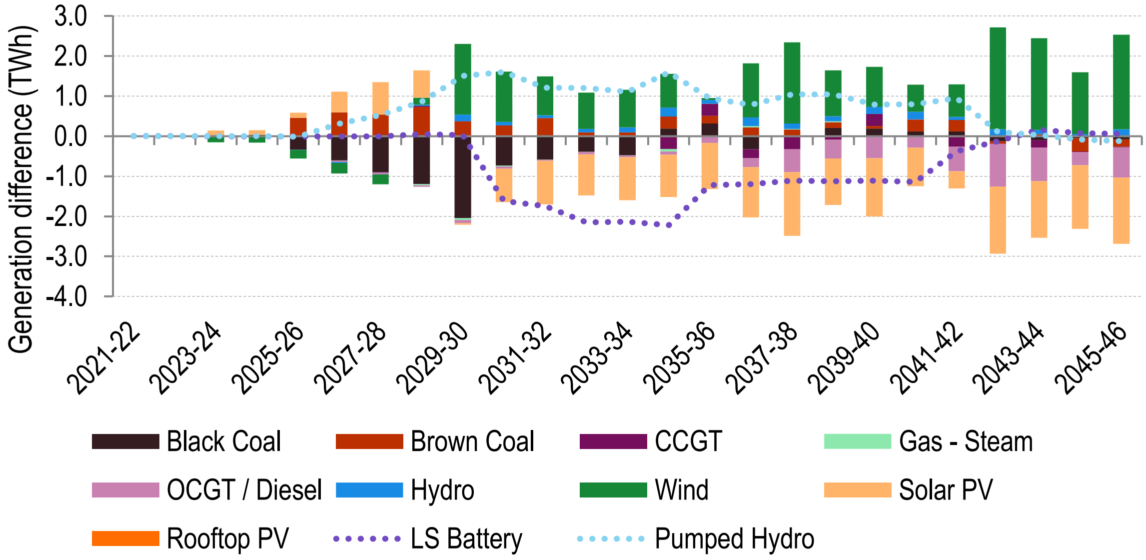
Figure 4: Difference in NEM capacity forecast between Option 3C and Base case in the Central scenario



31 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.

32 Since this figure shows the cumulative forecast gross market benefits in present value terms, the height of the bar in 2045-46 equates to the gross benefits for Option 3C shown in Table 4 above.

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 savings from reduced black coal and OCGT generation, followed by REZ expansion benefits and FOM savings. The timing and source of these benefits are attributable to the following:

- Benefits are forecast to start from 2027-28, largely due to FOM and fuel savings as some NSW black coal capacity is forecast to retire earlier in Option 3C than the Base case. Forecast fuel benefits in early years are due to replacing higher cost black coal generation with lower cost brown coal as well as solar and Snowy 2.0 in NSW. Expected benefits due to avoided or deferred capex are forecast to be small during this period, due to the large amount of new capacity entering the market as part of the NSW Roadmap in both the Base case and Option 3C.
- REZ expansion benefits are forecast to start from 2029-30. In that year, Option 3C is expected to build 1 GW solar in the Wagga Wagga REZ which has 1 GW free REZ transmission capacity, instead of the Central West Orana (CWO) REZ where additional transmission capacity needs to be paid for.
- From 2029-30 to the end of the study, solar capacity in the CWO REZ is forecast to be avoided. On the other hand, wind in New England is forecast to be brought forward from the 2040s, resulting in an overall capex cost, but REZ expansion cost savings in 2029-30.
- Capex benefits are forecast to increase to around $620m in 2030-31 due to avoidance/deferral of approximately 1.4 GW of LS battery build in NCEN. That year, some NSW coal capacity is forecast to retire economically, and with Option 3C, better utilisation of Snowy 2.0 as well as a different capacity and generation mix are forecast to result in deferring new build of LS battery until the 2040s.
- This capex benefit is forecast to increase with further assumed coal retirements to approximately $890m by 2034-35, with more LS battery (QLD) is deferred.
- From 2035-36, increased REZ expansion benefits are forecast. In the Base case, with the QNI Large upgrade in this year, the model is forecast to build wind in North Queensland, incurring transmission expansion cost. With the HumeLink augmentation though, this wind is forecast to be built in South Australia and Western Victoria instead, avoiding transmission costs. In addition, wind is forecast to be deferred in the CWO, Far North and North QLD REZs in that year, resulting in REZ expansion benefits. The REZ expansion benefits are forecast to further increase in 2037-38 due to savings in some South Australia REZs.

- After a decline in capex benefits in 2035-36 which is mainly due to building some of the deferred NCEN LS battery capacity in Option 3C, capex is forecast to further increase in 2036-37. This year, 1 GW of OCGT build is avoided in NCEN, and this further increases to 1.7 GW in the following year and settles at 1.1 GW by the end of the study.
- In the 2040s and by the end of the study period, it is forecast that the deferred LS Battery in NSW is built. On the other hand, more LS Battery is built in QLD while some solar and wind are avoided in that state. It is also forecast that more wind is built in VIC and SA, while up to around 500 MW LS Battery is avoided in SA.
- Fuel cost savings are forecast to accrue from 2027-28, gradually increasing due to less black coal generation until around the late 2030s and beyond where further fuel cost savings are expected due to lower OCGT generation in Option 3C.

Other smaller sources of forecast costs and benefits are:

- forecast USE & DSP benefits of $9.6m by 2045-46,
- rehabilitation (rehab) cost of $33m due to earlier coal retirements,
- an increase in VOM costs of $165m, partly as a result of the additional pumped hydro and wind generation.

Competition benefits are another category of the RIT-T benefits as stated by the AER. As discussed in the methodology, the Frontier approach for calculating competition benefits has been applied.

The first step to calculate competition benefits is to model strategic bidding by portfolios and generators to determine the Nash Equilibria. In order to determine the Nash Equilibria, all the combinations of bidding strategies by the portfolios presented in Appendix A.2, Table 8 are examined, while for other generators their SRMC bids are modelled as they are generally price takers.

Preferred bid options in establishing the Nash Equilibria are listed in Table 6. The modelling indicates that the Nash Equilibria are forecast to be achieved when both Bayswater (AGL NSW) and Mt Piper (EA NSW) bid 40% at SRMC and withdraw the remaining 60% of their capacities during peak times to higher bid bands ($500/MWh in this study), while Loy Yang A (AGL Vic) is forecast to have 80% of its capacity at SRMC, and Stanwell and Tarong (Stanwell QLD) are expected to bid 70% of their capacities at SRMC. The results of the model are consistent with the recent modelling and historical analysis by Frontier Economics[33].

While price bids of $300-$500/MWh are generally considered as cap contracts, price bids of $500/MWh and above are considered merchant bids[33]. These bids can be considered as the possible bids that generators and players might use as their strategy to influence the wholesale prices and as such increase their payoffs. We have used $500/MWh as a bid corresponding to the strategy options of the modelled portfolios. Note that this assumption is more conservative as opposed to other strategies such as bids at market price cap (MPC) or capacity withdrawal (reducing available capacity entirely), which would be expected to result in higher estimated competition benefits.

Table 6: Preferred bidding strategies

Portfolio	Generators	Preferred strategy options (SRMC capacity)
AGL NSW	Bayswater	40%
AGL Vic	Loy Yang A	80%

[33] Frontier Economics, *Modelling of Liddell power station closure*. Available at: https://www.energy.gov.au/sites/default/files/Frontier%20Economics%20Modelling%20of%20Liddell%20Power%20Station%20Closure.pdf. Accessed 5 July 2021.

Portfolio	Generators	Preferred strategy options (SRMC capacity)
EA NSW	Mt Piper	40%
Stanwell QLD	Stanwell, Tarong	70%

Figure 6 shows the forecast cumulative competition benefits for Option 3C for the Central scenario. Note that competition benefits are calculated from 2027-28, the first full year HumeLink is assumed commissioned.

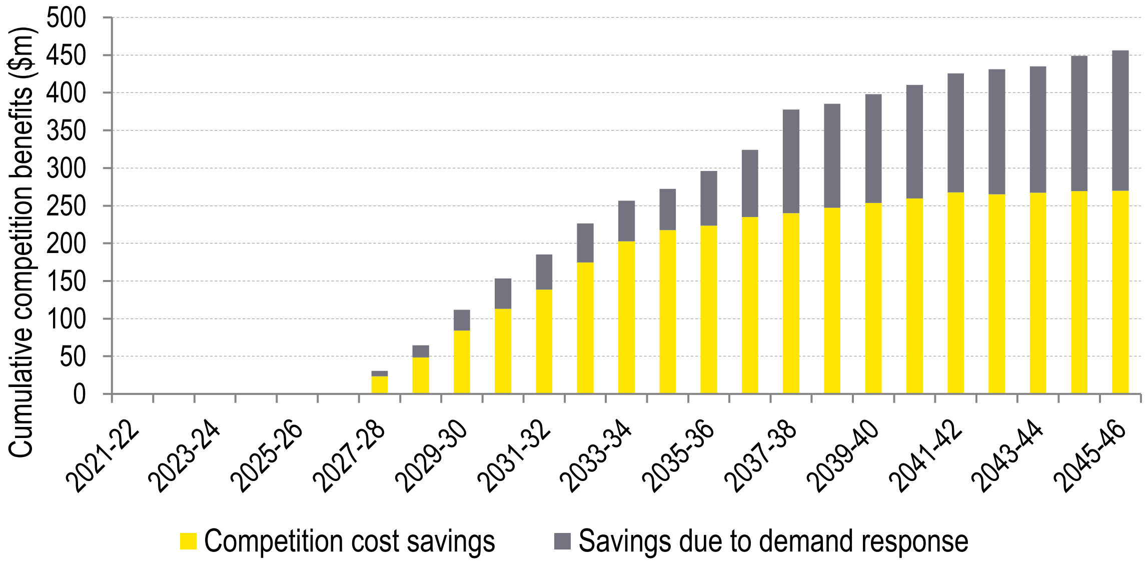
Competition benefits are forecast to reach around $450m by the end of the study period. Forecast benefits begin to accrue as soon as Option 3C is commissioned, with both competition cost savings and competition benefits due to demand response contributing to that.

While the share of competition cost savings is higher in early years, competition benefits due to demand response are forecast to be achieved mainly in the mid-2030s. As discussed in the methodology, competition cost savings represent the net dispatch cost saving of strategic bidding compared with competitive (SRMC) bidding for Option 3C relative to the Base case.

The modelling forecasts that more gas generation, mainly CCGT, is replaced by unlocked renewables and Snowy 2.0 generation in Option 3C with strategic bidding as opposed to black coal being replaced in competitive bidding. As such, with gas fuel costs being higher than black coal, competition cost savings are expected to be achieved in Option 3C. This, however, is expected to reduce from the mid-2030s as significant coal is expected to retire which results in gas generation being the main generation avoided in both strategic and competitive bidding.

On the other hand, competition savings due to demand response are expected to increase from the mid-2030s as unlocking cheaper renewables in Option 3C is forecast to result in a larger price gap between the Base case and Option 3C resulting in higher expectations of economic surplus due to increased consumption from elasticity of demand.

Figure 6: Forecast cumulative competition benefits for Option 3C under the Central scenario, millions real June 2019 dollars discounted to June 2021 dollars



4.2.2 Step Change scenario

The cumulative forecast gross non-competition related market benefits for Option 3C in the Step Change scenario are shown in Figure 7. Furthermore, the differences in capacity and generation across the NEM between Option 3C and the Base case in this scenario are shown in Figure 8 and Figure 9.

The capacity development plan in the Step Change scenario is shaped by moderate demand with a high uptake of DER, a strict carbon budget resulting in early coal retirements, high fuel prices, strong commitment to renewable policies including the full TRET, both stages of Marinus Link, and VNI West from 2035-36 as outlined in detail in Table 3.

Figure 7: Forecast cumulative gross market benefit for Option 3C in the Step Change scenario (excluding competition benefits), millions real June 2019 dollars discounted to June 2021 dollars

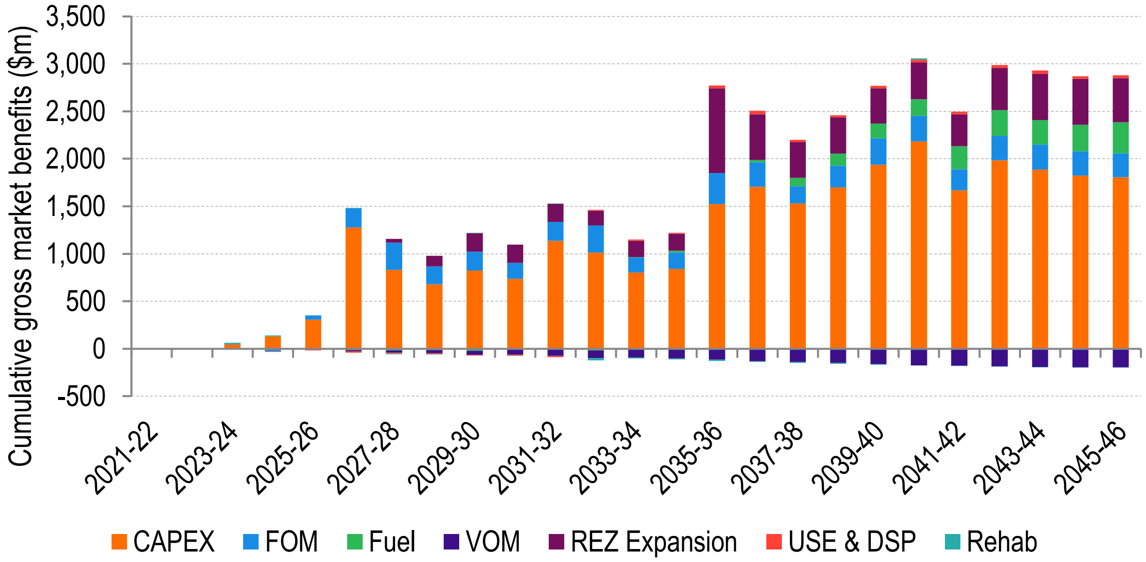


Figure 8: Forecast NEM capacity difference between Option 3C and Base case in the Step Change scenario

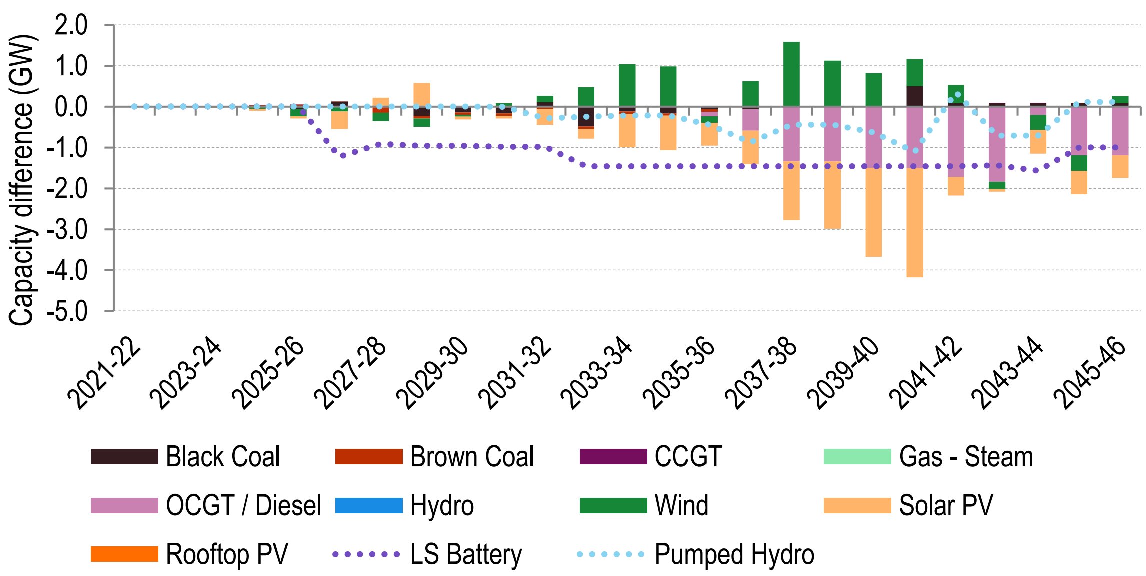
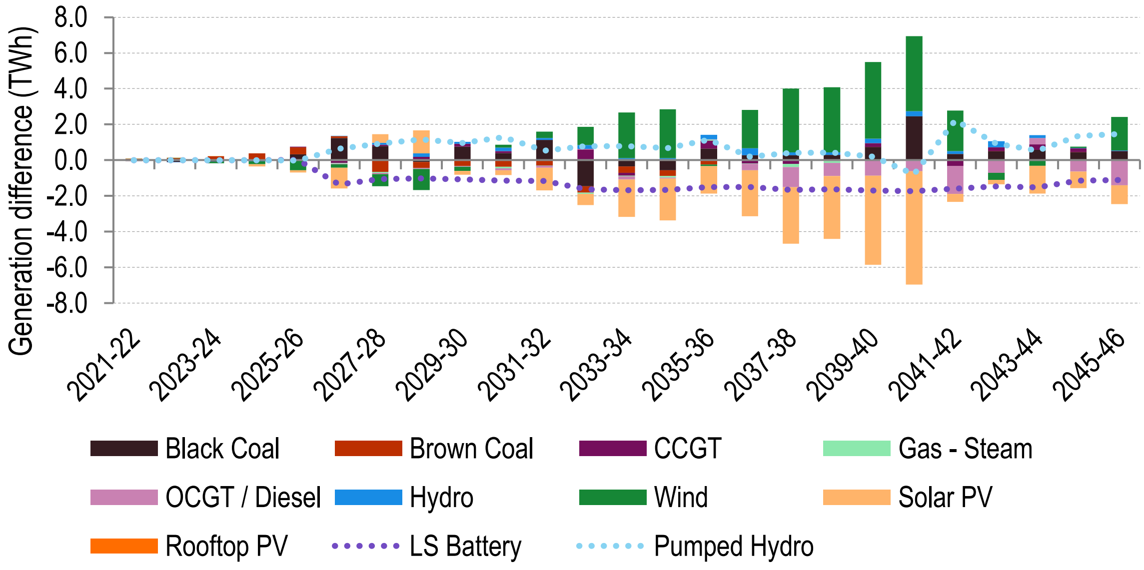


Figure 9: Difference in NEM generation forecast between Option 3C and Base case in the Step Change scenario



The primary and largest source of forecast gross market benefits is from avoided and deferred capex, followed by REZ expansion benefits, fuel cost savings and FOM. Compared to the Central scenario, capex and REZ expansion savings are forecast to be higher in the Step Change scenario, while fuel cost savings are lower. The timing and source of the benefits in the Step Change scenario are attributable to the following:

- The large capex benefit of $1.3b in 2026-27 comes from the forecast avoidance of 1.2 GW of LS Battery in NCEN and deferral of around 300 MW of solar and 190 MW of wind build in the New England REZ in the year the augmentation is assumed to be commissioned. As coal is driven to retire earlier due to the assumed carbon budget, the impact on capacity deferral/avoidance can be seen earlier in this scenario than the Central scenario. Capex benefits decrease in the following year as some of the deferred New England solar and LS Battery capacity is forecast to be built in that year.
- REZ expansion benefits start from 2027-28 as solar is forecast to be built in Wagga Wagga instead of the CWO REZ and Darling Downs in QLD, avoiding REZ transmission cost.
- A large increase in REZ expansion benefits can be seen in 2035-36, the assumed commissioning year of VNI West and QNI Large in the Step Change scenario, as well as the retirement of Bayswater. That year, significant amounts of new transmission capacity is forecast to be deferred in North Queensland due to wind deferral, while more wind is built in REZs in SA with free transmission capacity.
- The capex benefits are also forecast to increase in 2035-36, as a result of 110 MW OCGT build being avoided and 200 MW of PSH being deferred by two years. Capex benefits gradually increase after 2035-36, with the key drivers being increasing avoidance of NCEN OCGT build over the next two years, as well as increasing deferral of solar capacity up to 2041-42, even though some of this capacity is offset by wind.
- In 2041-42, the solar capacity and transmission expansion deferred in Darling Downs is forecast to be built, in line with the assumed partial economic retirement of some QLD coal capacity. This decreases the forecast capex benefits in that year, as well as REZ expansion benefits.
- By 2045-46 and NEM wide, Option 3C is forecast to avoid ~1.2 GW of OCGT, 550 MW of solar and 1 GW of LS Battery, but build 170 MW additional wind and 115 MW additional PSH.

- While it is forecast that Option 3C will result in effectively near zero fuel cost savings until the mid-2030s, the fuel cost benefits start to increase from 2036-37 onwards as a result of pumped hydro and wind generation offsetting NSW OCGT generation (which is due to avoiding OCGT development). The fuel cost benefit is forecast to progressively increase from the mid-2030s onwards to $327m by 2045-46.

As for the Central scenario VOM cost increases in Option 3C compared to the Base case due to the additional PSH and wind generation. There are, however, several key differences in the forecast capacity and generation outlook and thus benefits, relative to the Central scenario (Figure 7 versus Figure 3, Figure 8 versus Figure 4 and Figure 9 versus Figure 5).

- Forecast gross market benefits in the Step Change scenario are overall $566m higher, with additional savings from capex ($603m) and REZ transmission expansion ($109m) as a result of the overall higher penetration of renewables.
- Option 3C in the Step Change scenario is forecast to defer LS Battery capacity earlier than in the Central scenario, both relative to their corresponding Base cases as a result of earlier coal retirements in response to the carbon budget.
- In the long term, Option 3C in the Step Change scenario is forecast to avoid slightly more gas generation than in the Central scenario, relative to the corresponding Base cases. However, less coal capacity in this scenario giving less opportunity to replace higher cost black coal with brown coal results in overall lower fuel benefits ($153m).

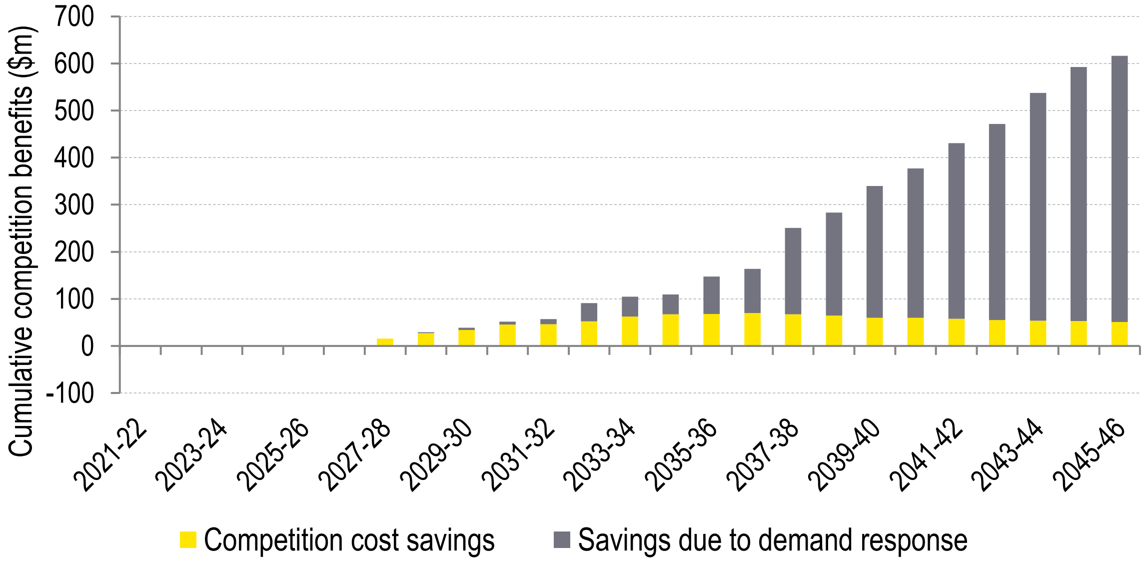
Figure 10 shows the forecast cumulative competition benefits for Option 3C in the Step Change scenario, considering the same bidding strategy as the Central scenario. Note that competition benefits are calculated from 2027-28, the year HumeLink is assumed to be fully commissioned.

Competition benefits are forecast to reach around $616m by the end of the study period. Forecast benefits begin to accrue as soon as Option 3C is commissioned, with both competition cost savings and competition benefits due to demand response contributing to that.

As for the Central scenario, the share of competition cost savings is higher in early years, while competition benefits due to demand response are forecast to be achieved mainly from the mid-2030s onwards.

It is obvious from Figure 10 that the majority of benefits are due to competition benefits due to demand response, which is resulting from a higher consumer and generator surplus from higher energy consumption as Option 3C is expected to have significantly lower prices relative to the Base case. This is particularly evident from 2035-36, the year VNI West is assumed to be commissioned, which is forecast to allow better utilisation of renewables in the southern states in Option 3C and as such results in a larger difference in prices between the Base case and Option 3C, and consequently higher benefits from elasticity of demand.

Figure 10: Forecast cumulative competition benefits for Option 3C under the Step Change scenario, millions real June 2019 dollars discounted to June 2021 dollars



4.2.3 Fast Change scenario

The forecast cumulative non-competition related gross market benefits for Option 3C in the Fast Change scenario are shown in Figure 11. Furthermore, the differences in capacity and generation across the NEM between Option 3C and the Base case in this scenario are shown in Figure 12 and Figure 13.

The Fast Change scenario is overall similar to the Central scenario, with moderate demand outlook and fuel prices, but a carbon budget to restrict emissions, with QRET excluded and the VNI West timing is assumed to be 2035-36.

Figure 11: Forecast cumulative gross market benefit for Option 3C in the Fast Change scenario (excluding competition benefits), millions real June 2019 dollars discounted to June 2021 dollars

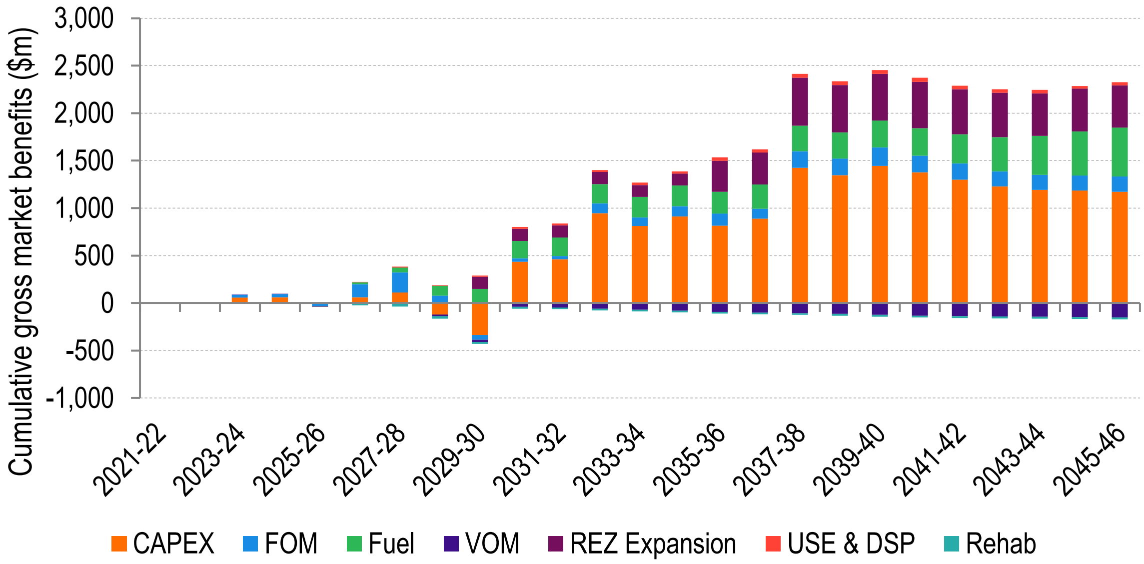


Figure 12: Forecast NEM capacity difference between Option 3C and Base case in the Fast Change scenario

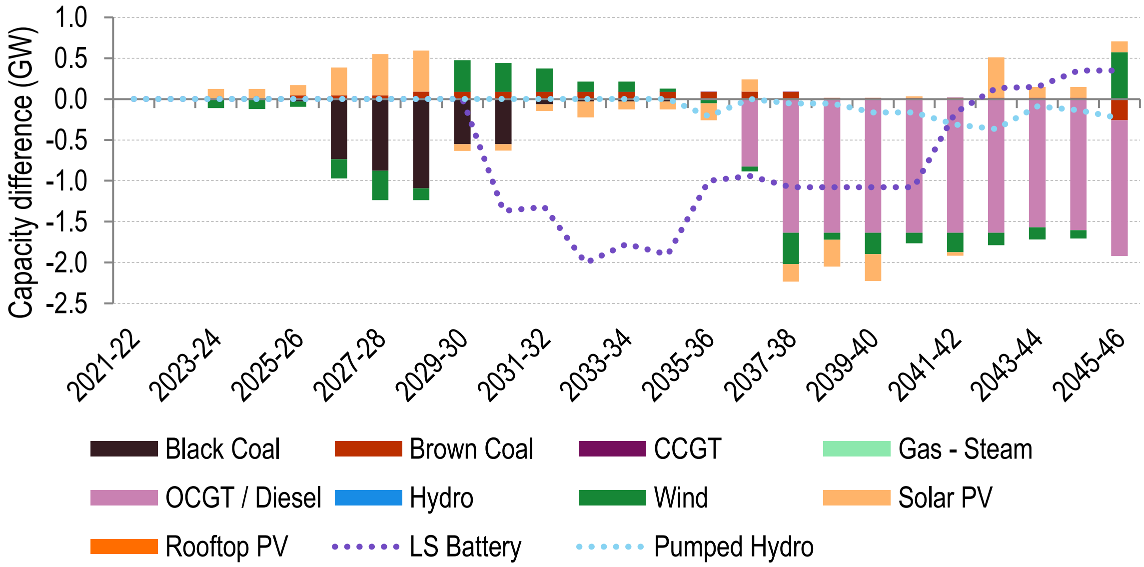
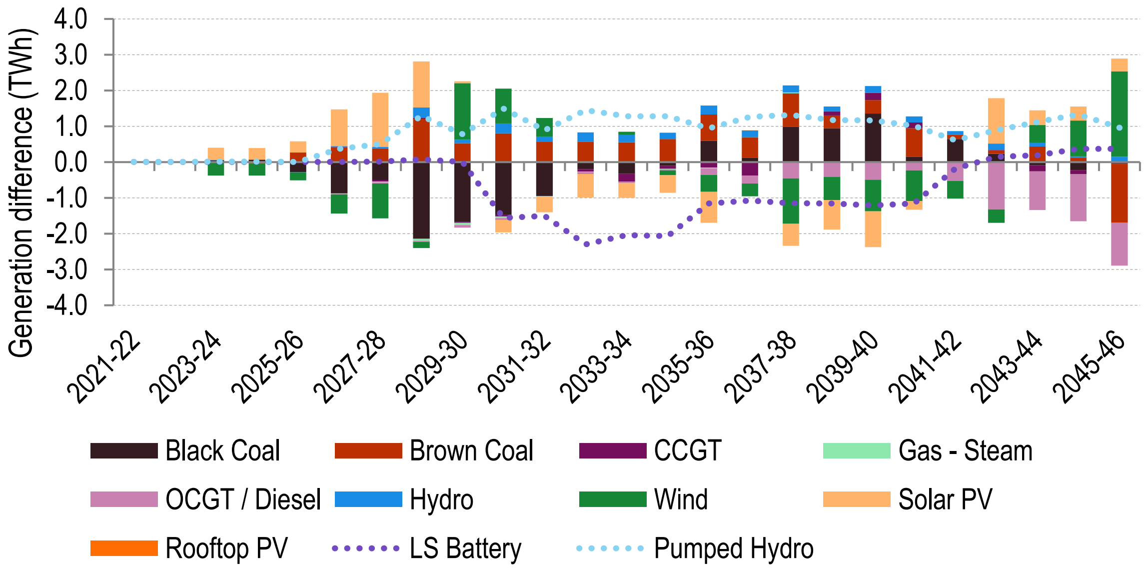


Figure 13: Difference in NEM generation forecast between Option 3C and Base case in the Fast Change scenario



As for the other scenarios, avoided/deferred capex savings are the major source of forecast gross market benefits, followed by fuel cost savings and REZ expansion benefits. The timing and sources of these benefits are attributable to the following:

- As in the Central scenario, opportunity for benefits in the early years is forecast decrease as a result of the NSW Roadmap. From 2026-27 to 2028-29 benefits accumulate from $200m to $347m to $22m as a combination of capex, FOM and fuel cost savings. Fuel and FOM cost savings are expected to accrue due to the earlier retirement of some NSW black coal capacity in Option 3C and replacing it with solar, PSH and brown coal generation. However, this is offset by extra capex cost due to wind build in Darling Downs being brought forward, particularly in 2028-29.
- As in the Central scenario, REZ expansion benefits are forecast to start from 2029-30 with avoiding new capacity and transmission build in the CWO REZ and building solar in Wagga Wagga instead. At the same time, 345 MW of wind in the New England REZ is forecast to be brought forward from 2041-42, incurring capex cost.

- Capex benefits are forecast to increase in 2030-31 due to the deferral of 1.4 GW of LS Battery to 2042-43. The same year, more effective utilisation of Snowy 2.0, bringing forward wind build, and more brown coal generation are also seen in Option 3C. Capex benefits are expected to increase in 2032-33, with more LS Battery, solar and wind deferral. Capex benefits are then expected to remain around $800-$900m in the following years until 2037-38, when another major increase in capex benefits is observed mainly due to the avoidance of an additional 800 MW NCEN OCGT. That year, some solar is deferred in NSW and QLD, wind is avoided in QLD, while more solar is brought forward in VIC and more wind is built in VIC and SA. Option 3C is also forecast to have around 100 MW less brown coal retirement in that year.
- REZ expansion benefits are forecast to increase post 2035-36, where with the assumed commissioning of VNI West and other drivers such as major coal retirements an additional wind capacity of 700 MW is avoided/deferred in each North Queensland, and CWO REZ.
- By the end of the study year, it is forecast that Option 3C will have more wind, LS Battery and solar build, while more brown coal is expected to retire, and around 1.7 GW OCGT is avoided.
- Continuously throughout the study, the augmentation facilitates brown coal generation offsetting black coal generation up to the mid-2030s, followed by offsetting OCGT generation in later years, accumulating fuel benefits. This is possible in the Fast Change scenario as opposed to the Step Change scenario due to the less restrictive carbon budget compared with less aggressive coal retirements as a result. In addition, the augmentation replaces some emissions-intensive generation with renewables, allowing for increased high-emissions brown coal to be used in the augmentation case throughout the study period without violating the carbon budget.

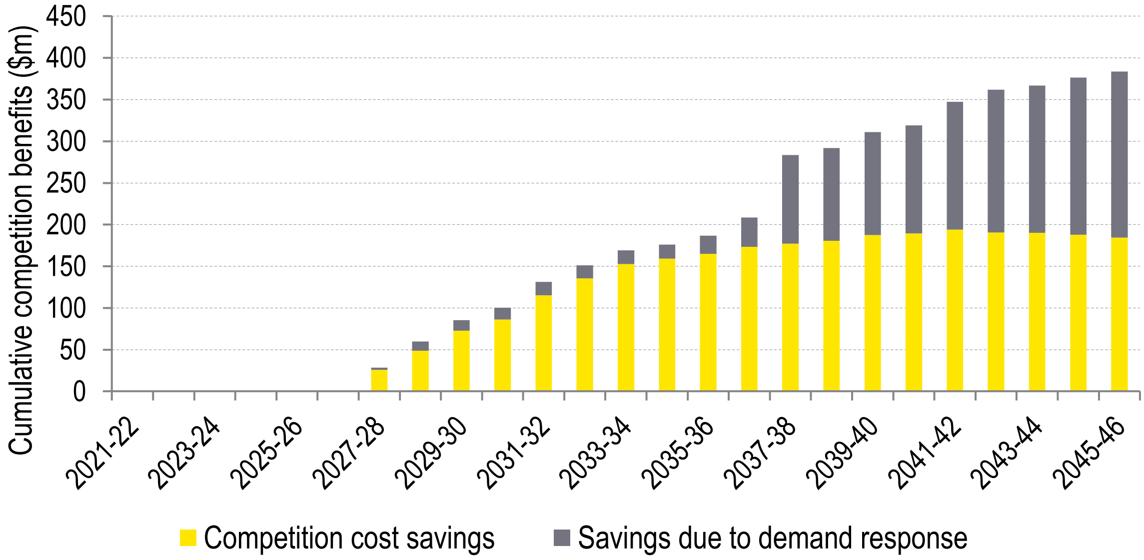
Overall, the Fast Change scenario has slightly higher benefits than the Central scenario ($40m). As a result of the carbon budget and therefore earlier assumed coal retirements in the Fast Change scenario, more new capacity is forecast to be built in this scenario than in the Central scenario in the long term. However, as VNI West is not assumed to be commissioned until 2035-36, allowing a more efficient use of the resources in southern states in combination with HumeLink, Option 3C generates similar savings in the forecast by avoiding or deferring capacity. On the other hand, REZ expansion benefits and benefits from using lower fuel-cost generation, which is more limited in the Fast Change Base case, are also increased.

Figure 14 shows the forecast cumulative competition benefits for Option 3C in the Fast Change scenario, considering the same bidding strategy as the Central scenario. Note that competition benefits are calculated from 2027-28, the year HumeLink is assumed to be fully commissioned.

Competition benefits are forecast to reach around $383m by the end of the study period. The Fast Change scenario is forecast to have lower benefits than the Central and Step Change scenarios.

In comparison to the Central scenario, the Fast Change scenario has lower competition cost savings, mainly due to the carbon budget, which limits the thermal generation, as well as the delay in VNI West in the Fast Change scenario. The competition cost savings are however higher than the Step Change scenario, as a less restrictive carbon budget is assumed. On the other hand, competition benefits due to demand response are higher in the Fast Change scenario than the Central, while being significantly lower than the Step Change scenario. As discussed previously, competition benefits due to demand response are dependent on the amount of surplus from higher energy consumption in Option 3C as a result of lower prices in that option relative to the Base case.

Figure 14: Forecast cumulative competition benefits for Option 3C under the Fast Change scenario, millions real June 2019 dollars discounted to June 2021 dollars



4.2.4 Slow Change scenario

The forecast cumulative non-competition related gross market benefits for Option 3C in the Slow Change scenario are shown in Figure 15.

Furthermore, the differences in capacity and generation across the NEM between Option 3C and the Base case in this scenario are shown in Figure 16 and Figure 17, respectively.

As outlined in Table 3, the outcomes of the Slow Change scenario are influenced by assumptions of low demand growth expectation and fuel costs, no QRET, the NSW Roadmap, the possibility of coal life extensions and no VNI West or QNI medium or large.

Figure 15: Forecast cumulative gross market benefit for Option 3C in the Slow Change scenario (excluding competition benefits), millions real June 2019 dollars discounted to June 2021 dollars

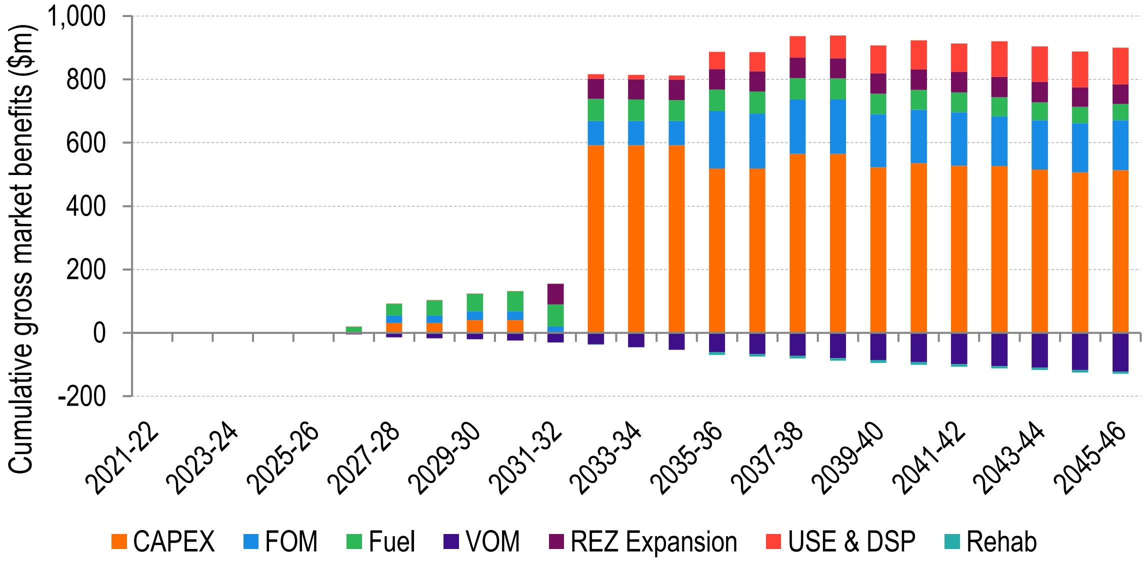


Figure 16: Forecast NEM capacity difference between Option 3C and Base case in the Slow Change scenario

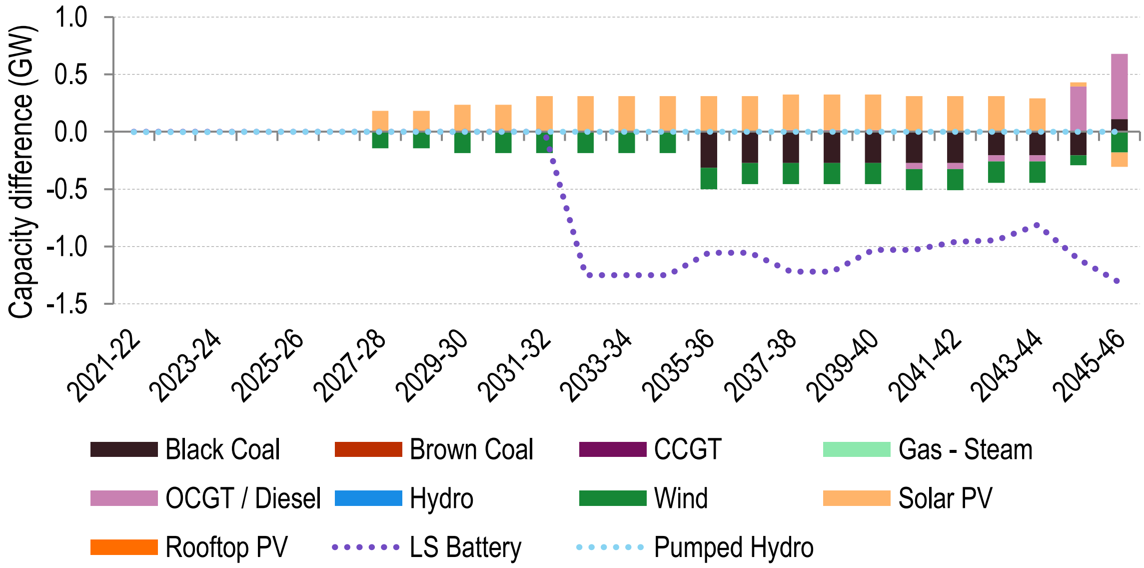
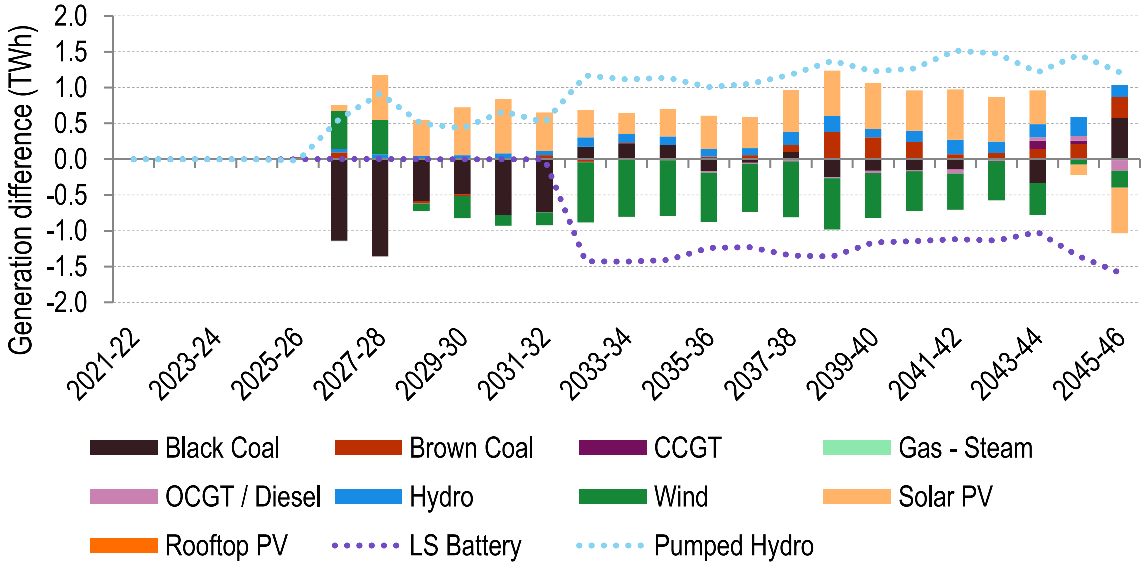


Figure 17: Difference in NEM generation forecast between Option 3C and Base case in the Slow Change scenario



Capex savings due to avoided LS Battery build are forecast to be the dominant source of forecast gross market benefits in the Slow Change scenario, followed by savings in FOM and USE & DSP. The magnitude of the savings is expected to be significantly smaller overall throughout the forecast as the need for additional capacity in the long term is lower than in the Central and other scenarios. This is due to lower assumed demand growth and the forecast deferred coal-fired generator retirements, as well as the capacity oversupply created by the NSW Roadmap assumption.

Overall, the reduced need for new capacity in this scenario is forecast to provide less opportunity for Option 3C to generate savings, and total expected gross market benefits are consequently significantly reduced relative to the Central scenario and other scenarios. In addition, without VNI West, access to resources in the southern states is more limited compared to the other scenarios.

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

- Replacement of 145 MW of wind with 185 MW of solar in 2027-28 within the New England REZ is forecast to result in capex and FOM benefits.

- Wind and solar generation in combination with increased PSH generation from Snowy 2.0 enabled through HumeLink, offsetting black coal generation are forecast to result in fuel cost benefits from 2026-27 onwards.
- Additional solar build increases to around 310 MW in 2031-32 by using up the free REZ transmission capacity in Wagga incurring REZ expansion benefits by avoiding build in the CWO REZ.

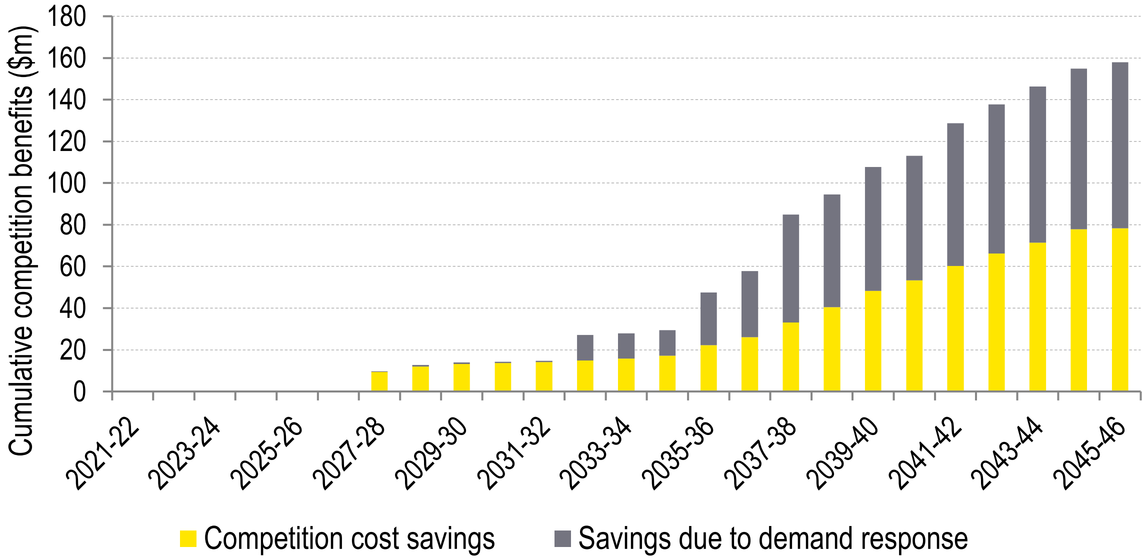
Over the longer outlook, the key observations are as follows:

- Avoidance of LS Battery build from the mid-2030s is forecast to lead to a large increase in capex benefits, and avoidance of life extension of black coal in 2035-36.
- While the build of around 50 MW OCGT in 2040 is forecast to be deferred, approximately 570 MW more OCGT capacity is required with Option 3C by the last two years of the study period.
- In the Slow Change scenario, starting from 2032-33 USE & DSP benefits continuously increase throughout the study period and add up to around $115m by the end.

Figure 18 shows the forecast cumulative competition benefits for Option 3C in the Slow Change scenario, considering the same bidding strategy as the Central scenario. Note that competition benefits are calculated from 2027-28, the year HumeLink is assumed to be fully commissioned.

Competition benefits are forecast to reach just below $160m by the end of the study period. Both competition cost savings and competition benefits due to demand response are forecast to be small until the mid-2030s, mainly due to the replacement of generation from strategic coal portfolios with available excess renewable generation in both the Base case and Option 3C. These benefits are forecast to increase in the later years of the modelling period, as with increasing coal retirements a lower excess of renewable generation is expected in the Base case which results in replacing generation from strategic coal portfolios with gas generation. However, Option 3C is expected to unlock constrained renewable generation, resulting in lower gas generation than the Base case and thus creates competition benefits.

Figure 18: Forecast cumulative competition benefits for Option 3C under the Slow Change scenario, millions real June 2019 dollars discounted to June 2021 dollars



4.3 CAN to NCEN cutset flow

Figure 19 and Figure 20 present the flow duration curves for the Canberra (CAN) to NCEN cutset for the Base case and Option 3C in the Central scenario. A few observations are as follows:

- The flow to NCEN and also the reverse flow to Canberra are capped to the limit of 2,700 MW in the Base case. This is especially seen in the years from 2031-32 onwards.
- For all years, it is seen that the flow to NCEN in Option 3C exceeds the cutset limit of the Base case, i.e. 2,700 MW. For 2027-28, this is expected to be around 5% of time, and increases until 2045-46 which shows around 20% of time the flow is above the cutset limit without HumeLink.
- The reverse flow also increases in Option 3C, although it is forecast not to reach the 4,500 MW limit until the last year.
- While the flow is in both directions, and approximately evenly towards both in the Base case, the flow in Option 3C is more towards NCEN reflecting the increased ability to supply NCEN with HumeLink.

Figure 19: Flow duration curve for CAN - NCEN for the Base case in the Central scenario

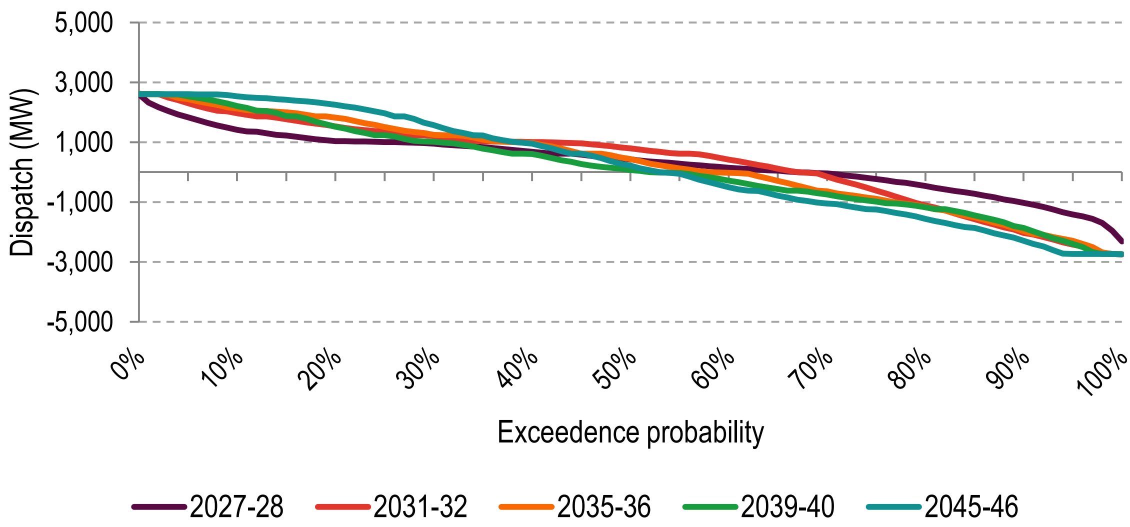
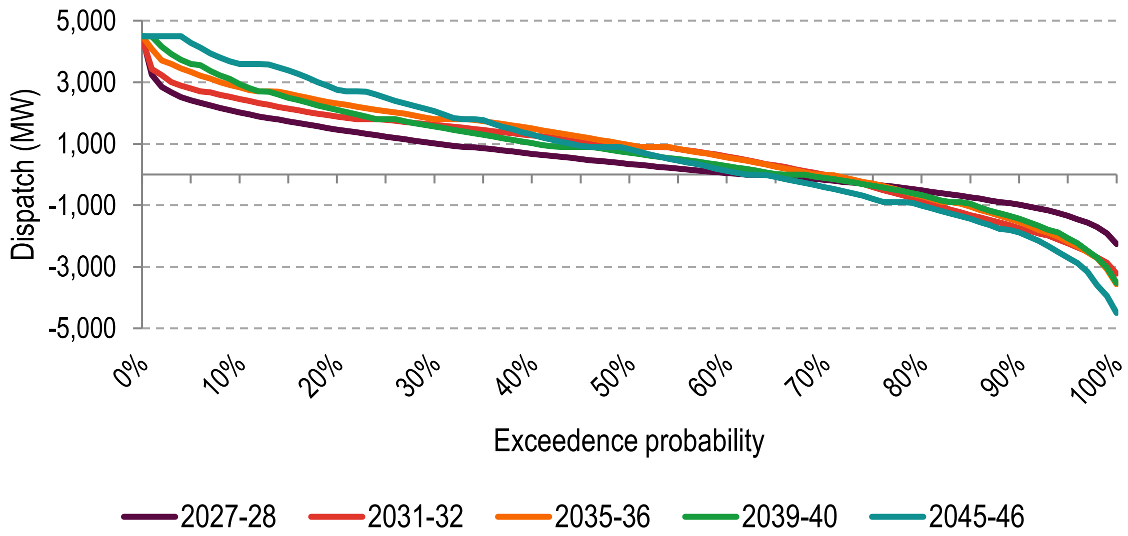


Figure 20: Flow duration curve for CAN - NCEN for Option 3C in the Central scenario



4.4 Snowy 2.0 operation

Figure 21 and Figure 22 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 on average around 6.5% in the Central, Step and Fast Change scenarios, and 5.3% in Slow Change. This increase is 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 scenario Snowy 2.0 operation peaks in 2035-36, whereas in the Fast Change scenario it peaks in 2044-45 and in the Slow and Step Change scenarios in 2032-33 and 2037-38, respectively. In general, Snowy 2.0 operation is lower in the Slow Change scenario in the long term due to lower assumed energy consumption and delayed retirements.

Figure 21: Annual capacity factor for Snowy 2.0 generator and pump for the Base case in all scenarios

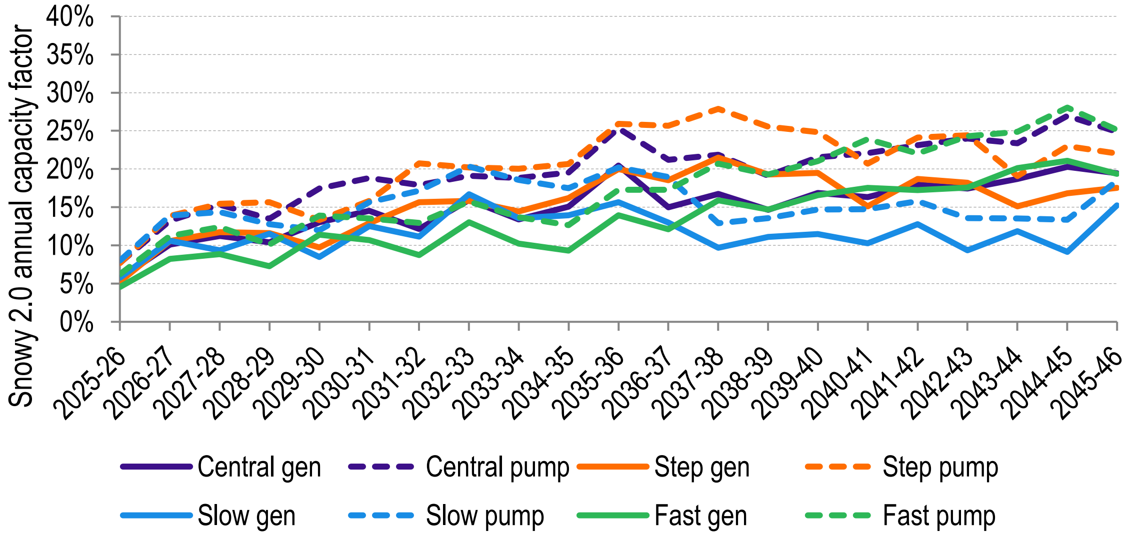
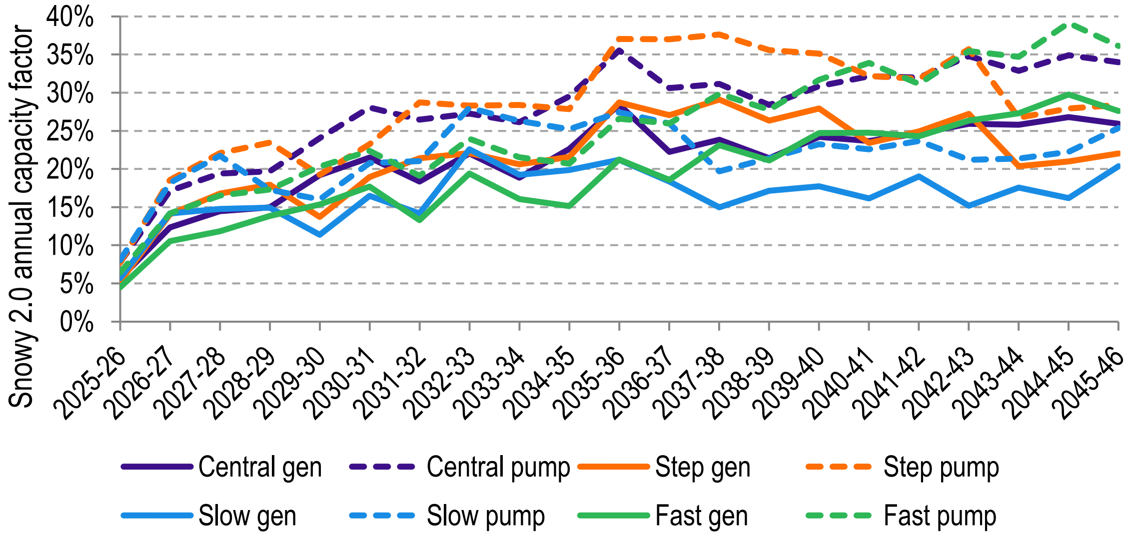


Figure 22: Annual capacity factor for Snowy 2.0 generator and pump for Option 3C in all scenarios



4.5 Sensitivities

At TransGrid's request, EY modelled a number of sensitivities for the TransGrid's two highest ranked options, i.e. Options 2C and 3C for the Central scenario. For selected sensitivities, competition benefits were also computed.

All sensitivities were selected by TransGrid to test the robustness of the findings for the options. A summary of forecast benefits is shown in Table 7 below (for the sake of comparison, Option 2C and Option 3C forecast gross market benefits for the Central scenario in core runs are also provided). All sensitivities are forecast to result in overall positive forecast gross market benefits. Conclusions regarding the impact of sensitivities on net market benefits are presented in the PACR published by TransGrid[34].

Table 7: Summary of forecast gross market benefits and competition benefits for sensitivity runs on the Central scenario, millions real June 2019 dollars discounted to June 2021 dollars (except the IASR[35])

Sensitivity		Benefits			
		Market benefits	Competition cost saving	Competition benefits due to demand response	Total
Option 2C	*Core*	*2,093*	*263*	*186*	*2,542*
	Kurri Kurri and Tallawarra B	1,918	307	139	2,364
	VNI West delayed	2,032	216	164	2,412
	IASR	2,482	NA	NA	NA
Option 3C	*Core*	*2,114*	*270*	*186*	*2,570*
	Kurri Kurri and Tallawarra B	1,936	316	138	2,390
	VNI West delayed	2,059	225	165	2,449
	IASR	2,500	NA	NA	NA
	Modular Power Flow Control (MPFC)	2,135	NA	NA	NA

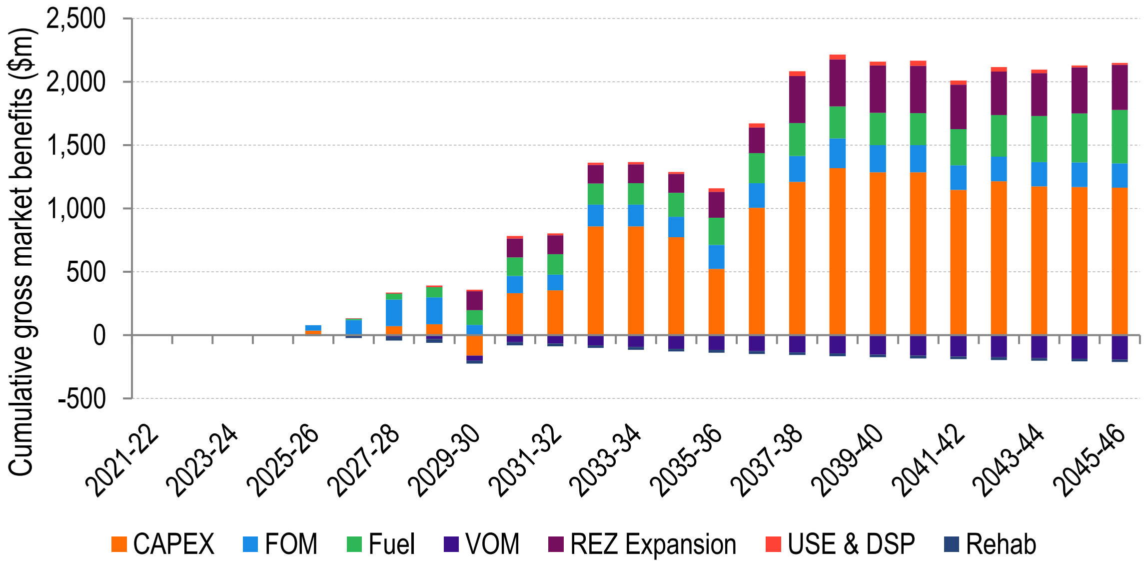
4.5.1 Central scenario including Kurri Kurri and Tallawarra B

Kurri Kurri (modelled as 750 MW OCGT) and Tallawarra B (modelled as 300 MW CCGT) are two recently announced gas generators in NCEN, which are not part of the committed or anticipated generators outlined in the 2019 Inputs and Assumptions workbook.

Due to their potential impact on the project, TransGrid selected to assess a sensitivity on the Central scenario which included both these generators, and the resulting gross market benefits are shown in Figure 23. As advised by TransGrid, both are assumed commissioned in 2023-24.

[34] TransGrid, *Reinforcing the NSW Southern Shared Network to increase transfer capacity to the state's demand centres (HumeLink) PACR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network,.
[35] millions real June 2020 dollars discounted to June 2021 dollars, using a discount rate of 4.8%.

Figure 23: Forecast cumulative gross market benefit for Option 3C in the Central scenario including Kurri Kurri and Tallawarra B (excluding competition benefits), millions real June 2019 dollars discounted to June 2021 dollars

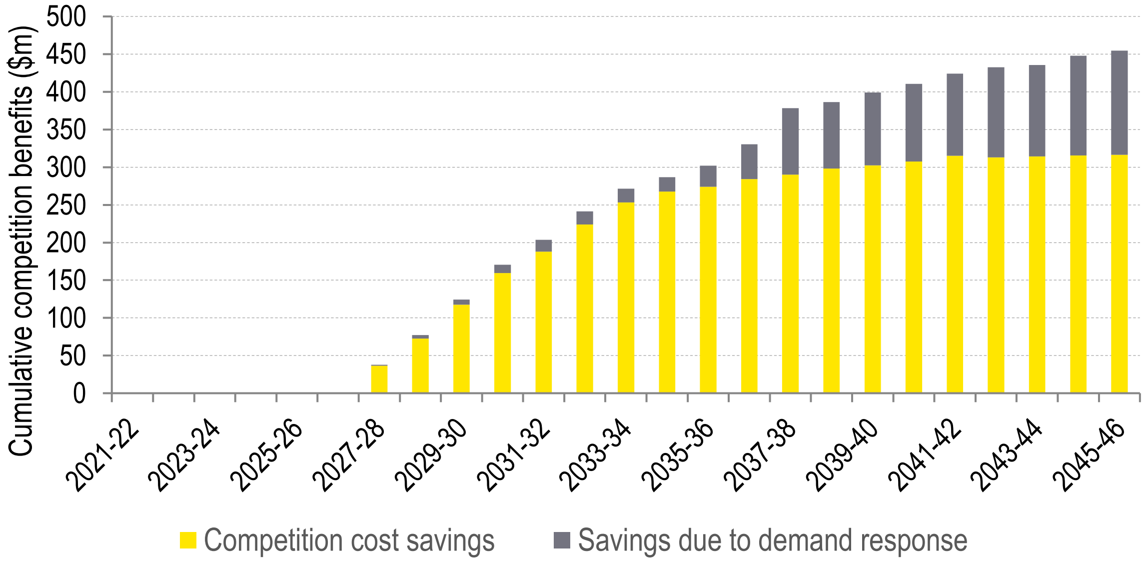


Including those gas generators is expected to result in benefits of $1,936m for Option 3C, a reduction of ~$180m with lower benefits due to avoided/deferred capex in the early and mid-2030s as well as FOM. In the sensitivity, the additional gas capacity is forecast to allow for earlier coal retirements, and with decreased coal capacity, FOM benefits due to more efficient use of resources instigating earlier coal retirements in Option 3C decrease.

Further, with the additional gas generators, there is less LS Battery in the early 2030s as well as less gas build in the late 2030s forecast to be required in the Base case, reducing the benefits expected for avoided or deferred capex, as well as fuel savings in the later years.

The overall competition benefits are forecast to be similar to the core run, being approximately $450m (see Figure 24). The key difference to the core run is a higher competition cost savings but lower competition benefits due to demand response. The reason for higher competition cost savings is that in the sensitivity, coal is retired earlier and the reduced generation from the strategic portfolios in the Base case is replaced with the gas generation, particularly with the new gas generators. This will result in higher fuel cost savings in Option 3C as the more expensive gas is replaced with unlocked renewable generation as opposed to the core run that has black coal being replaced by renewable generation. On the other hand, the competition benefits due to demand response is forecast to be lower than the core run mainly due to early years' reduced benefits.

Figure 24: Forecast cumulative competition benefits for Option 3C under the Central scenario including Kurri Kurri and Tallawarra B, millions real June 2019 dollars discounted to June 2021 dollars

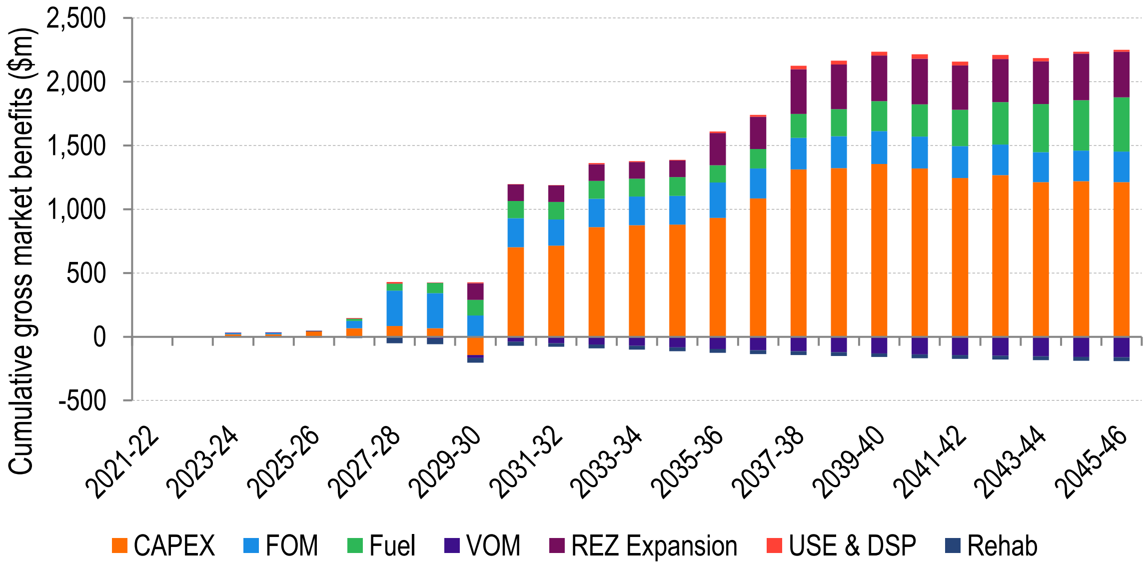


4.5.2 Commissioning of VNI West delayed to 2035

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 2028-29 to 2034-35.

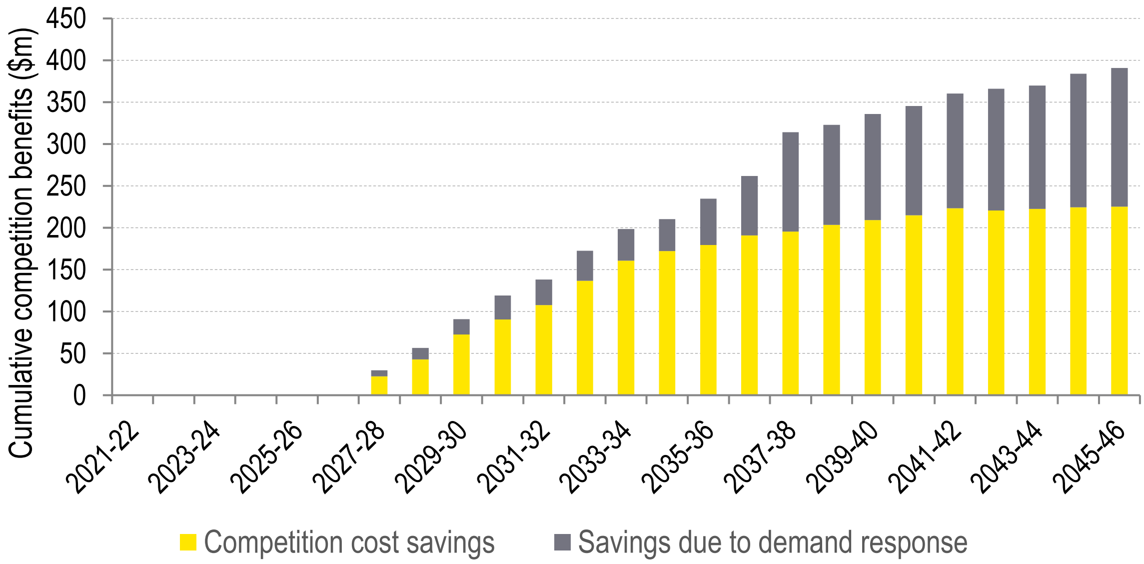
The sensitivity results in forecast gross market benefits reducing by $55m to $2,059m for Option 3C, with only minor impacts on composition of benefits, generation and capacity mix. In this sensitivity, the model forecasts a very similar build in the later years post the assumed commissioning of VNI West in 2035-36, resulting in only minor reductions of benefits with a similar long-term build.

Figure 25: Forecast cumulative gross market benefit for Option 3C in the Central scenario with VNI West delayed to 2035 (excluding competition benefits), millions real June 2019 dollars discounted to June 2021 dollars



The competition benefits, shown in Figure 26, indicate that delaying VNI West is expected to reduce the benefits by around $65m. The reduced benefits are forecast to be due to less interconnection between the southern states and NSW (particularly NCEN), which reduces the opportunity for diversifying and better utilising cheaper renewable resources in Option 3C.

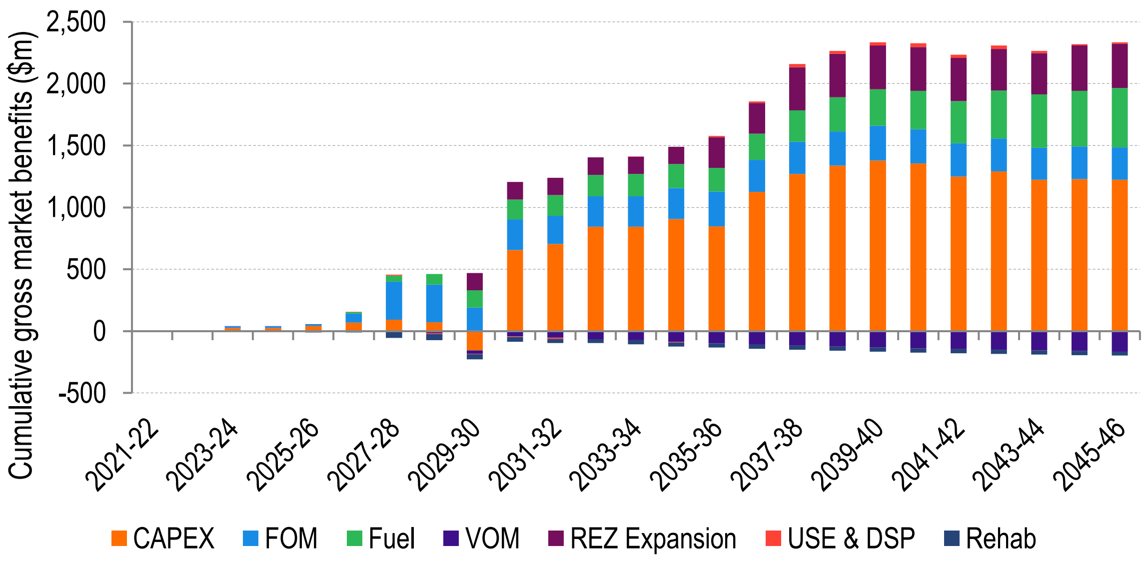
Figure 26: Forecast cumulative competition benefits for Option 3C with VNI West delayed to 2035, millions real June 2019 dollars discounted to June 2021 dollars



4.5.3 Modular Power Flow Control (MPFC)

TransGrid selected to model a sensitivity for using MPFC to increase transfer limit from Bannaby to Sydney in Option 3C for the Central scenario. The MPFC is expected to increase the transfer limit by 75 MW, resulting in a slight increase in the gross market benefits of $21m relative to Option 3C in the core run.

Figure 27: Forecast cumulative gross market benefit for Option 3C in the Central scenario with MPFC (excluding competition benefits), millions real June 2019 dollars discounted to June 2021 dollars



4.5.4 Central IASR

The 2020 Forecasting and Planning Inputs, Assumptions and Scenarios Report (IASR)[36], which outlines the proposed assumptions for use in AEMO's 2022 ISP, is expected to be published in its final version at the end of July 2021. This sensitivity tests the impact of the updated assumptions,

[36] AEMO, December 2020, *Draft 2021 Inputs, Assumptions and Scenarios Report*. Available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/draft-2021-inputs-assumptions-and-scenarios-report.pdf?la=en. Accessed 2 July 2021.

as published in the corresponding Draft 2021-22 Inputs and Assumptions workbook[37], on the preferred option in the Central scenario.

Using the new assumptions, Option 3C benefits are forecast to increase to $2,500m. This increase of ~$385m consists of approximately equal increase in benefits from avoided or deferred capex, FOM and fuel savings, however REZ expansion benefits are forecast to decrease.

Figure 28: Forecast cumulative gross market benefit for Option 3C in the IASR Central scenario (excluding competition benefits), millions real June 2020 dollars discounted to June 2021 dollars[38]

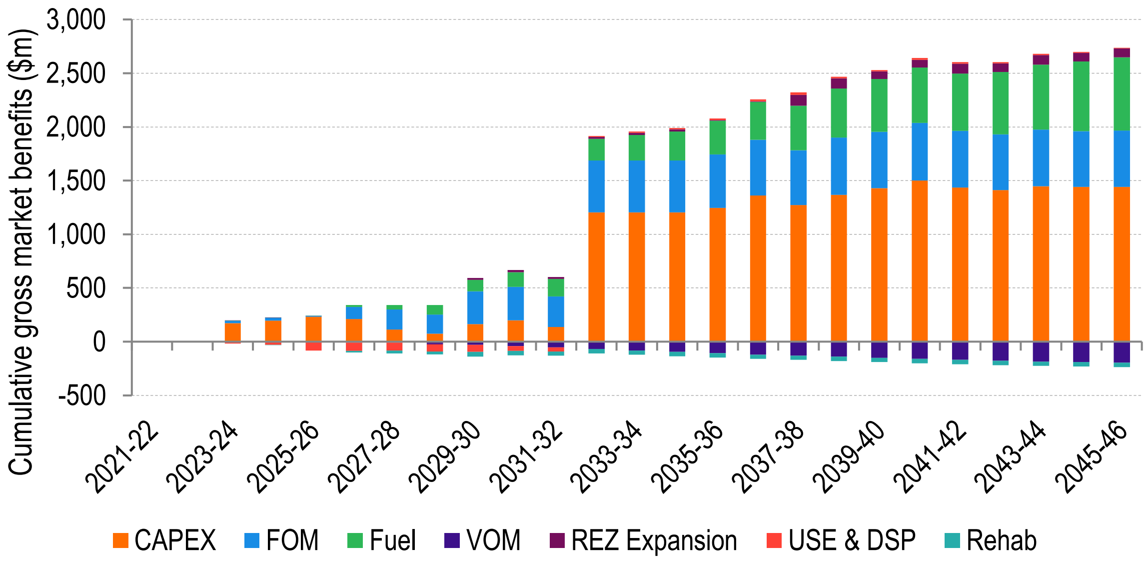
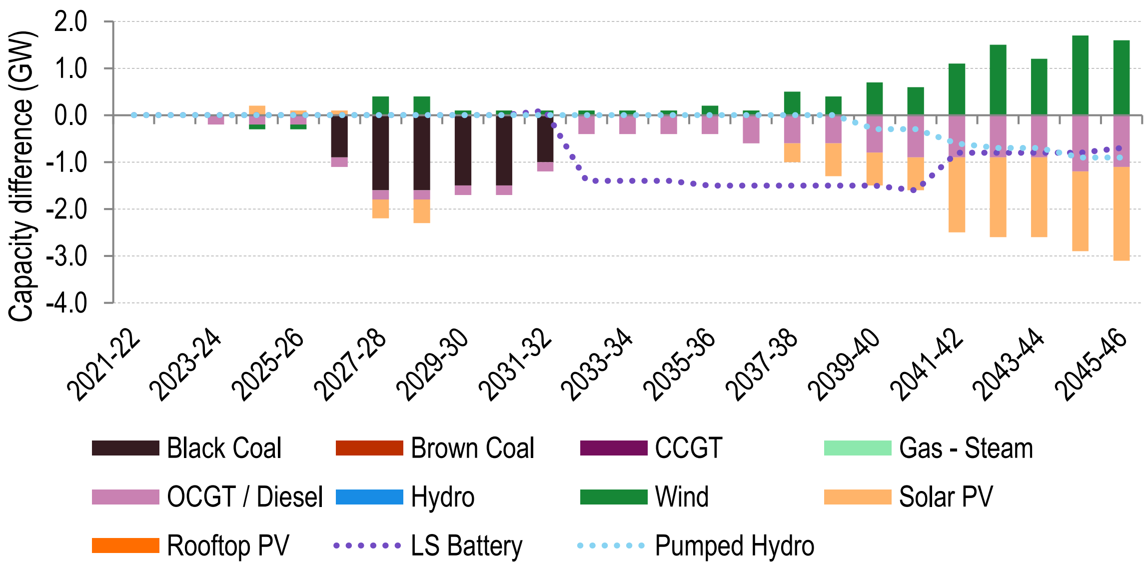


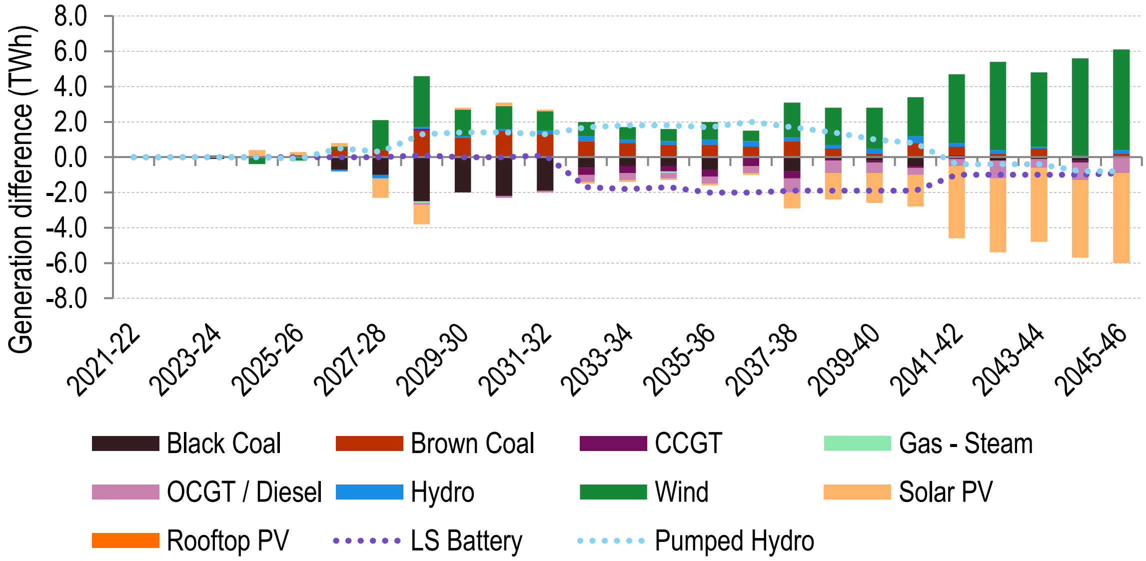
Figure 29: Difference in NEM capacity forecast between Option 3C and Base case in the IASR Central scenario



[37] AEMO, 11 December 2020, *Draft 2021-22 Inputs and Assumptions workbook v.3.0.* Available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/draft-2021-22-inputs-and-assumptions-workbook.xlsx?la=en. Accessed 2 July 2021.

[38] Using a discount rate of 4.8% as per the Draft 2021-22 Inputs and Assumptions Workbook.

Figure 30: Difference in NEM generation forecast between Option 3C and Base case in the IASR Central scenario



With the IASR assumptions, the model forecasts OCGT build in the early 2020s due to several factors such as the lower assumed OCGT capex, different forced outage rates, different coal prices, lower assumed discount rate, and other drivers which led to building OCGT being the cheapest option in early years while retiring more coal compared to the core run. Option 3C is forecast to result in some OCGT savings resulting in capex savings in the early 2020s.

Option 3C is forecast to retire up to 1.5 GW of coal earlier than the Base case, which results in FOM and fuel benefits between 2026-27 and 2031-32, even though some of the black coal generation is forecast to be offset with brown coal generation.

Forecast benefits due to deferred or avoided capex increase in 2032-33 with the deferral of 1.4 GW of LS Battery and 225 MW of OCGT (900 MW of both technologies avoided by the end of the study). Even though by the end of the study similar OCGT capacity is avoided compared to the core run, capacity is forecast to be avoided earlier and hence fuel and capex benefits are higher.

In this sensitivity, the model forecasts the build of more wind instead of solar and LS Battery compared to the core run. This is partly due to the new assumption of zero VOM for wind, as well as solar capex slightly increasing. It contributes to the decreased REZ expansion benefits, as only 490 MW of the free 1,000 MW transmission capacity in the Wagga Wagga REZ is forecast to be used as the wind resource in Wagga Wagga has lower quality compared to other locations. In later years, more solar in the CWO REZ is forecast to be replaced with wind in southern states and REZs, e.g. Yorke Peninsula (SA), where the better resource and transfer capacity is enabled with the augmentation.

Appendix A Methodology

A.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 2021-22 to 2045-46. The modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator[39].

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[40] 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[41], CCGT, OCGT, large-scale storage and 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)[42],
- minimum loads for some generators,
- transmission interconnector flow limits (between regions),
- intra-regional flow limits (between zones in New South Wales),

[39] AER, 25 August 2020, *Guidelines to make the integrated system plan actionable*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable. Accessed 2 July 2021.

[40] 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.

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

[42] AER, December 2019, *Values of Customer Reliability Final report on VCR values.* Available at: https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf. Accessed 29 June 2021.

- Canberra zone lines and defined cut-set flow limits,
- 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 and carbon budget 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 B.2.

The model incorporates economic retirements for all scenarios except the Slow Change scenario which allows life extension of coal if it is economic to do so. 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 where specified in the ISP dataset. 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.

A.2 Competition benefits

Clause 5.15A.2(b)(4)(viii) of the NER requires a RIT–T proponent to consider competition benefits as a class of potential market benefits that could be provided by a credible option[43]. Competition benefits are likely to occur if a credible option could impact the bidding behaviour of generators (and other market participants) who may have a degree of market power relative to the Base case.

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[43] AER, *Application guidelines - Regulatory investment test for transmission (August 2020)*. Available at: https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20application%20guidelines%20-%2025%20August%202020.pdf. Accessed 28 June 2021.

The importance of competition benefits has been highlighted by Frontier Economics, where it is stated that with more new generators and loads connecting to the power system, which will have a diminishing impact on non-competition related benefits, competition benefits will become an increasingly important source of the benefits of interconnection[44].

Competition benefits calculate market benefits as the difference between the following present values of the overall economic surplus[43]:

- arising with the credible option, with bidding behaviour reflecting any market power prevailing with that option in place; and
- in the Base case, with bidding behaviour reflecting any market power in the Base case.

The AER suggest two possible approaches, known as the "Biggar approach" and the "Frontier approach", where their difference relates to how to divide the overall market benefits of a credible option between competition benefits and other benefits (also referred to as "efficiency benefits").

EY modelling follows the Frontier approach[44], which is explained below. The modelling considers the static benefits, as described in the Frontier approach. The static benefits are concerned with making more efficient use of existing inputs. These benefits are as opposed to the dynamic benefits which capture the increased competition in the market due to avoiding generators (or proponents) with a degree of market power investing in new capacity earlier than an independent investor, in order to entrench its market position. The reason for modelling the static benefits is to remove the need for the complexity of calculating the dynamic benefits, as outlined by Frontier Economics, unless there is a sufficient justification for undertaking further complex analysis beyond that of the static competitive analysis.

The Frontier approach for defining competition benefits is to measure the additional benefits that an augmentation might accrue if the assumption of competitive bidding was relaxed[44]. These benefits are over and above conventionally-measured market benefits, which are expected to flow from taking into account likely bidding behaviour. A Nash Equilibrium bidding strategy for generators under realistic bidding is applied, where an equilibrium outcome is found when no generator (or portfolio) could unilaterally increase their payoff by changing its bidding behaviour.

In order to define generators and portfolios with some degree of market power, EY has used the latest analysis conducted by Frontier Economics[45] and confirmed their findings. However, a shorter list of generators is considered given that with the assumption of economic retirement in the modelling, some generators in the Frontier Economics list either retire earlier than HumeLink commissioning date or within a short time after that. Those generators are therefore modelled to continue bidding at SRMC levels consistent with a fully competitive market. Table 8 provides the list of generators adopting strategic bidding. The strategy options for each generator represent the percentage of capacity which is assumed to bid at SRMC. For example, Bayswater is allowed to withdraw 20%, 30% and 60% of its capacity to a higher bid band while bidding the remaining capacity at SRMC. The full combinations of the following bidding strategies are then modelled to determine the Nash Equilibrium. Note that the bidding strategies are applied only during the typical peak demand periods between 6am-10am and 6pm-10pm, in which portfolios with market power are expected to exert their market power. Note also that Either capacity bids (Cournot modelling, withdrawing capacity) or price bids (Bertrand modelling, increasing prices) can be used for the game theory approach[44].

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[44] Frontier Economics, September 2004, *Evaluating interconnection competition benefits.* Available at: https://www.aer.gov.au/system/files/Frontier%20Economics%20report%20-%20evaluating%20interconnection%20competition%20benefits%20-%20September%202004.pdf. Accessed 28 June 2021.

[45] Frontier Economics, *Modelling of Liddell power station closure.* Available at: https://www.energy.gov.au/sites/default/files/Frontier%20Economics%20Modelling%20of%20Liddell%20Power%20Station%20Closure.pdf. Accessed 28 June 2021.

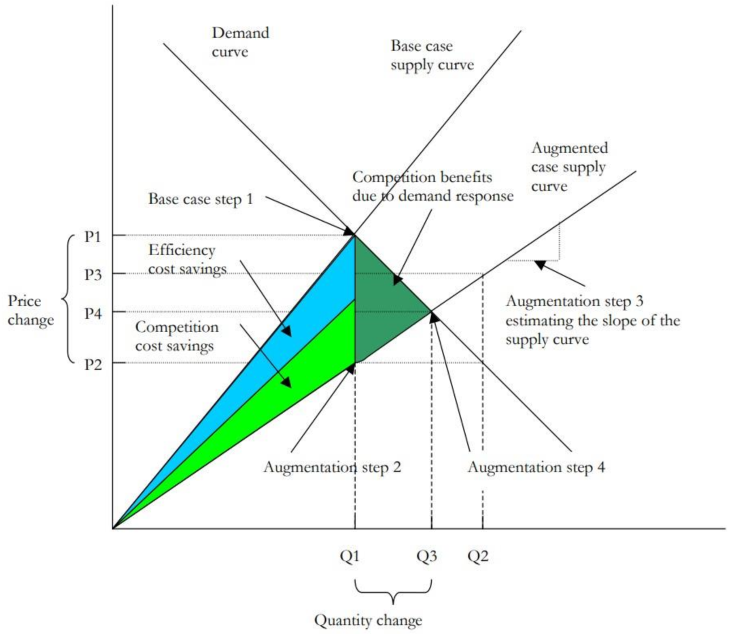
Table 8: Bidding strategies

Portfolio	Generators	Strategy options
AGL NSW	Bayswater	40%, 70%, 80%
AGL Vic	Loy Yang A	80%, 95%
EA NSW	Mt Piper	40%, 75%, 80%
Stanwell QLD	Stanwell, Tarong	40%, 70%, 90%

Competition benefits account for competition cost savings and competition benefits due to demand response, as shown in Figure 31. As seen in Figure 31, there are three areas of benefits associated with a new or upgraded interconnection, called:

- efficiency cost savings, which are due to more efficient dispatch in the SRMC bidding paradigm
- competition cost savings, which are enhanced efficiency benefits due to creating an increased level of competition, i.e. less withholding capacity to higher priced bid offers than without the interconnection
- competition benefits due to a demand increase response to lower electricity market prices, resulting in an increase in the level of aggregate supply and demand, which is due to elasticity of demand. To compute this benefit, TransGrid provided EY with elasticity of demand for each region, ranging between -0.1 and -0.21 percent demand response per percent change in price. Considering this range, TransGrid advised using -0.1 for all regions as the most conservative, that is, lowest, value for the elasticity of demand. EY halved this value to -0.05 to represent the reduced impact of wholesale electricity price changes to the retail market.

Figure 31: Calculation of competition benefits[44]



Since the efficiency savings were calculated as part of the RIT-T SRMC market modelling these benefits were subtracted from the competition benefits calculation.

As per the Frontier approach[44], the following steps have been undertaken to calculate competition benefits:

- Step 1: Equilibrium market outcomes are derived for the counterfactual Base case. This determines the optimal bidding strategy of the generators, which results in equilibria with the annual average demand weighted price in the Base case ($P1$ in Figure 31) for the annual demand $Q1$.
- Step 2: Step 1 is repeated for the HumeLink augmentation case with an assumption that the demand is inelastic. This allows calculation of $P2$.
- Step 3: This step estimates the slope of the augmented case supply curve in each region. For this purpose, a small change in each region's demand is applied and the resulting prices ($P_{3,r,c}$) in that region and other regions are calculated. This allows construction of an inverse cross-elasticity of supply matrix using the relationships between relative demand changes to relative price changes in each region. The elements of the inverse cross-elasticity of supply matrix, S, are constructed as follows:

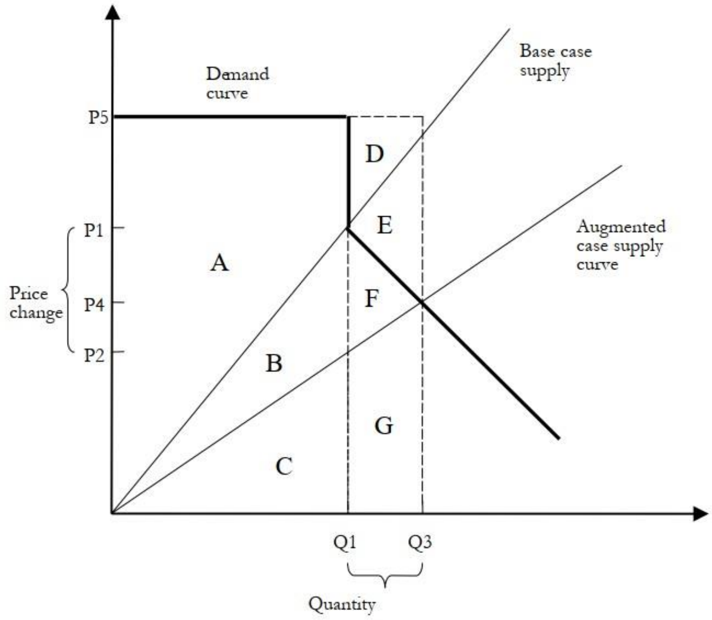
$$element\ (r,c) = \frac{\frac{P_{3,r,c} - P_{2,r}}{P_{1,r}}}{\Delta Q_{3,c}}$$

  where, $element\ (r,c)$ is the matrix element in row/region r, column/region c, and $P_{1,r}$ and $P_{2,r}$ are the demand weighted price in region r from Step 1 and Step 2, respectively. $P_{3,r,c}$ is the demand weighted price in region r for a small change in demand in region c. $\Delta Q_{3,c}$ is the relative demand change in region c.
- Step 4: Having the inverse cross-elasticity of supply and also inverse cross elasticity of demand matrices, a linear approximation of supply and demand curves can be derived and accordingly, the intersection of the two curves in Figure 31 can be calculated. The intersection is at Q_3 and P_4, the augmentation equilibrium point. This also enables estimation of the production cost at the equilibrium point, which is calculated as the average incremental cost of each region by constructing the production cost matrix as follows:

$$element\ (1,c) = \frac{PC_{3,c} - PC_2}{\Delta Q_{3,c}}$$

  where, $element\ (1,c)$ is the matrix element for column/region c, and PC_2 is the total production cost in Step 2. $P_{3,c}$ is the total production cost in Step 3 for a small change in demand in region c. $\Delta Q_{3,c}$ is the relative demand change in region c. As such, the relative increase in production costs from Step 2 to the post-augmentation equilibrium can be calculated as Cq, where q is the quantity change of the post-augmentation equilibrium for each region relative to the pre-augmentation equilibrium.
- Step 5: Having the intersection of supply and demand curves, as well as the production costs, the gross benefits can be calculated by subtracting the total surplus of Base case equilibrium from augmentation equilibrium, resulting in areas B and F in Figure 32. While area F represents competition benefits due to demand response, area B represents the aggregated productive efficiency of HumeLink due to efficiency and competition cost savings. However, as discussed, to avoid double counting this benefit, the modelling only considers the productive efficiency due to increased competition by subtracting the benefits from SRMC modelling from the total benefits.

Figure 32: calculation of surplus[44]



The TSIRP model is adjusted to use the capacity build and retirements schedule which resulted from the long-term investment planning from the Base case on which the economic dispatch is run. Hydro and energy-limited storages are optimised in the model in such a way that they maximise their water values. The model is run on both the Base case and Option 3C for two sets of bidding, i.e. competitive and strategic bidding. As mentioned previously, the modelling of competitive bidding allows subtracting the benefits of fuel and VOM from the total benefits in the strategic bidding in order to avoid double counting these benefits in non-competition benefits modelling and competition benefits simulation.

A.3 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[46]) and headroom that is available from interconnectors. The hourly modelling accounts for load diversity and sharing of reserves across the NEM and so minimises the amount of reserve carried, and provides reserve from the lowest cost providers, including allowing for each region to contribute to its neighbours' reserve requirements through interconnectors.

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

This constraint is applied to only a subset of simulation hours 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:

[46] 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.

- 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.

A.4 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 Appendix B.

The Canberra zone transmission network is explicitly modelled through a DC load flow technique incorporating losses in the TSIRP, whose details are given in Appendix B. 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[47]. 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.

A.5 Cost-benefit analysis

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

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

For each 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

[47] 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.

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)[48], discounted to June 2020 at a 5.9 % real, pre-tax discount rate as selected by TransGrid. This value is consistent with the value applied by AEMO in most scenarios in the 2019-20 ISP[49].

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[50]. 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"[51].

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[48] 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.

[49] AEMO, 30 July 2020, *2019 Input and Assumptions workbook, v1.5*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 29 June 2021.

[50] Transgrid, *Reinforcing the NSW Southern Shared Network to increase transfer capacity to the state's demand centres (HumeLink) PACR*. Available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network. Accessed 28 June 2021.

[51] AER, August 2020, *Application guidelines - Regulatory investment test for transmission*. Available at: https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20application%20guidelines%20-%2025%20August%202020.pdf. Accessed 28 June 2021.

Appendix B Transmission and demand

B.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 9. In TransGrid's view, this enables better representation of intra-regional network limitations and transmission losses.

Table 9: 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 A.4) 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 9 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 10, as defined by TransGrid.

Table 10: 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-Bannaby	Line 61 Gullen Range – Bannaby Line 3W Kangaroo Valley – Capital Lines 4 &5 Yass – Marulan and new HumeLink lines from Maragle/Wagga to Bannaby for each option
Snowy cut-set	Line 01 Upper Tumut to Canberra Line 2 Upper Tumut to Yass Line 07 Lower Tumut to Canberra Line 3 Lower Tumut to Yass
CAN (WAG)-SWNSW	Line 63 Wagga - Darlington Pt Line 994 Yanco - Wagga Line 99F Yanco - Uranquinty Line 99A Finley - Uranquinty Line 997/1 Corowa – Albury New 330 kV double circuit from Wagga – Dinawan (after assumed commissioning of EnergyConnect) New 500 kV double circuit from Wagga – Dinawan (after assumed commissioning of VNI West)
VIC-CAN	Line 060 Jindera – Wodonga Line 65 Upper Tumut – Murray Line 66 Lower Tumut - Murray
VIC-SWNSW	Line 0X1 Red Cliffs – Buronga New Red Cliffs – Buronga (after assumed commissioning of EnergyConnect) New 500 kV double circuit from Kerang - Dinawan (after assumed commissioning of VNI West)
SWNSW-SA	New 330 kV double circuit from Buronga – Robertstown (after assumed commissioning of EnergyConnect)

Table 11 summarises the key cut-set limits in the Canberra zone and from Canberra to NCEN, as defined by TransGrid.

Table 11: Key cut-set limits

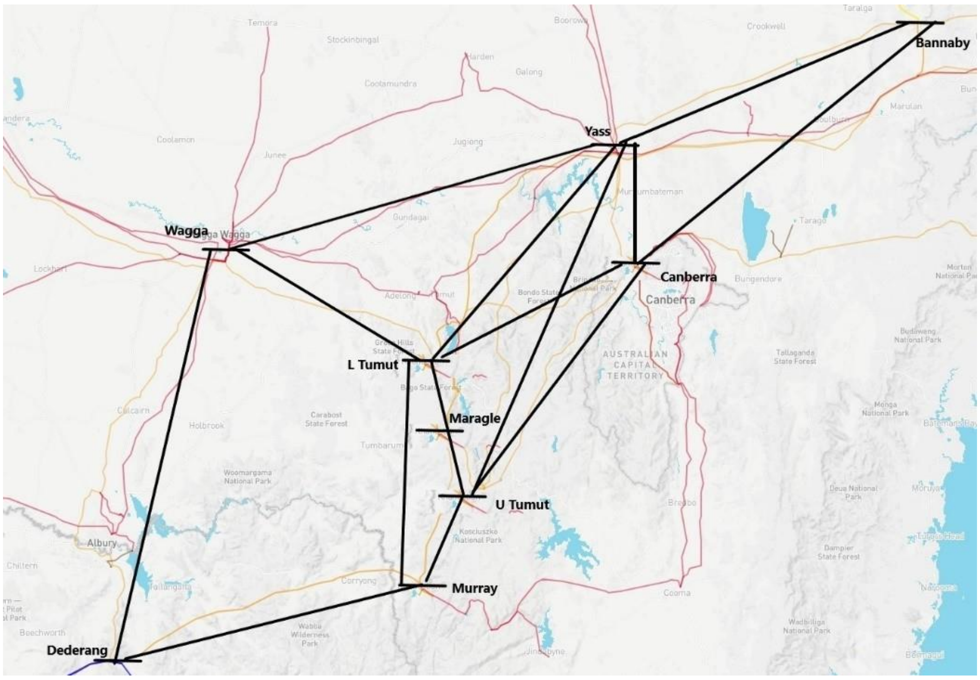
Options	Snowy cut-set	Snowy cut-set + HumeLink lines	CAN/YASS – Bannaby cut-set	CAN-NCEN cut-set	Bannaby-NCEN
Do Nothing	2700 Post VNI 2,870	2,700 Post VNI 2,870	2,700	2,700	3,100
Option 1A	2,970	4,515	3,970	3,970	4,030
Option 1B	2,970	4,660	4,110	4,080	4,080
Option 1C	2,980	5,920	5,330	4,500	4,500
Option 2B	2,960	4,660	4,180	4,140	4,140

Options	Snowy cut-set	Snowy cut-set + HumeLink lines	CAN/YASS – Bannaby cut-set	CAN-NCEN cut-set	Bannaby-NCEN
Option 2C	3,080	5,230	5,230	4,500	4,500
Option 3B	2,980	4,460	3,880	3,880	4,030
Option 3C	3,080	5,372	4,900	4,500	4,500

B.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 33. 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 33: 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.

B.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 (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, QNI 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.

B.4 Interconnector and intra-connector capabilities

The notional limits imposed on interconnectors are shown in Table 12. 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 12: Notional interconnector capabilities used in the modelling (sourced from TransGrid and AEMO 2019-20 ISP[52])

Interconnector (From node – To node)	Import[53] notional limit	Export[54] notional limit
QNI	-915 MW -1060 MW after QNI minor upgrade -2070 MW after QNI medium upgrade -3440 MW after QNI large upgrade	565 MW 715 MW after QNI minor upgrade 1230 MW after QNI medium upgrade 2770 MW after QNI large upgrade
Terranora (NNS-SQ)	-150 MW	50 MW
VIC-NSW[55] (VIC-CAN)	-250 MW -500 MW after VIC SIPS commissioning	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)	150 MW (Base) 500 MW (after EnergyConnect) and 2,250 MW (after VNI West)
EnergyConnect (SWNSW-SA)	-800 MW	800 MW
Heywood (VIC-SA)	-650 MW (before EnergyConnect) -750 MW (after EnergyConnect)	650 MW (before EnergyConnect) 750 MW (after EnergyConnect)
Murraylink (VIC-SA)	-200 MW	220 MW
Basslink (TAS-VIC)	-478 MW	478 MW

52 AEMO, *2020 Integrated System Plan*. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp. Accessed 27 May 2021.

53 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.

54 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.

55 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[53] notional limit	Export[54] notional limit
Marinus Link[56] (TAS-VIC)	-750 MW for the first leg and -1,400 MW for the second leg	750 MW for the first leg and 1,400 MW for the second leg

New South Wales has been split into zones as outlined in Section B.1 with the following limits imposed between the zones defined in Table 13.

Table 13: 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) -4,177 MW in 2026 with 3,000 MW New England REZ upgrade due to NSW roadmap -9,177 MW in 2028 with an additional 5,000 MW New England REZ upgrade due to the NSW roadmap -10,187 MW after QNI Medium -11,557 MW after QNI Large	1,200 MW (Base) 1,377 MW (after QNI Option 1A) 4,377 MW in 2026 with 3,000 MW New England REZ upgrade due to NSW roadmap 9,377 MW in 2028 with an additional 5,000 MW New England REZ upgrade due to the NSW roadmap 9,890 MW after QNI Medium 10,932 MW after QNI Large
CAN-SWNSW	-300 MW (before EnergyConnect) -1,100 MW (after EnergyConnect, before VNI West) -3,000 MW (after VNI West)	500 MW (before EnergyConnect) 1,300 MW (after EnergyConnect, before VNI West) 3,000 MW (after VNI West)

B.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 34.
- the future hourly rooftop PV generation has been estimated based on insolation in the corresponding reference year and the projection of future rooftop PV capacity, which is subtracted from the forecast underlying demand along with other behind-the-meter components (e.g., electric vehicles and domestic storage) to get a projection of hourly operational demand.

Figure 34: Sequence of demand reference years applied to forecast

Modelled year	Reference year
2021-22	2012-13

[56] Proposed second DC interconnector between Tasmania and Victoria. With Marinus Link still undergoing the RIT-T process, TransGrid has assumed Option 1 from the AEMO July 2020 Input and Assumptions workbook as the preferred option for the Fast Change scenario and Option 2 for the Step Change scenario.

Modelled year	Reference year
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
2045-46	2010-11

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

The reference year pattern is also consistent with site-specific hourly large-scale wind and solar availability (see Section C.1). This maintains correlations between weather patterns, demand, wind, large-scale solar and rooftop PV availability.

TransGrid selected demand forecasts from the ESOO 2020[57] in all scenarios (see Section 3.1), which are used as inputs to the modelling. Figure 35 to Figure 39 shows the NEM operational energy and rooftop PV as well as NSW operational energy, operational peak and rooftop PV for all scenarios modelled.

[57] AEMO, August 2020, *NEM Electricity Statement of Opportunities (ESOO),* Available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo. Accessed 29 June 2021.

Figure 35: Annual operational demand in all scenarios for the NEM from AEMO's Draft 2021 Inputs and Assumptions workbook[58]

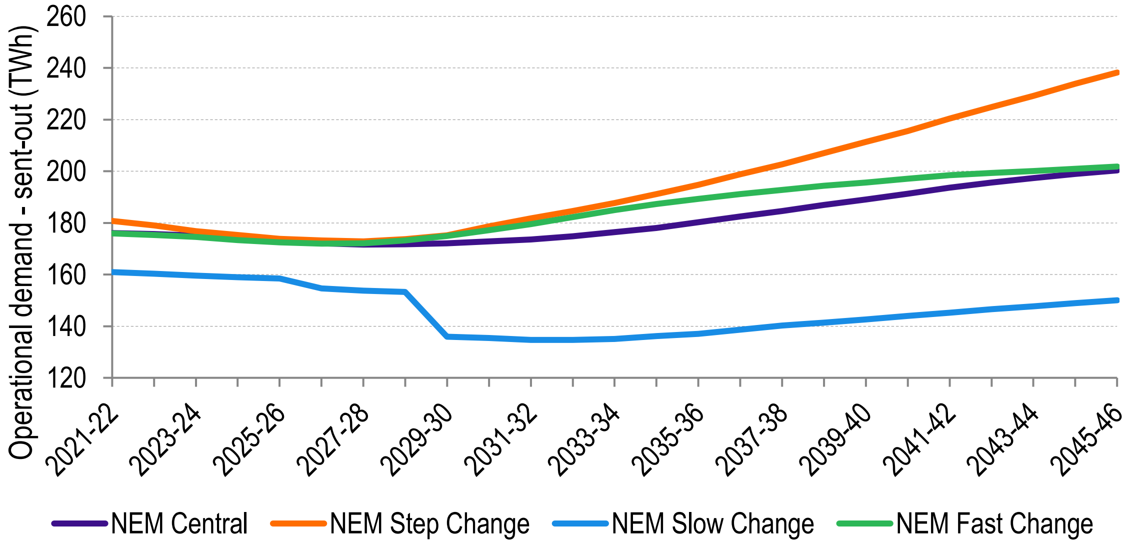
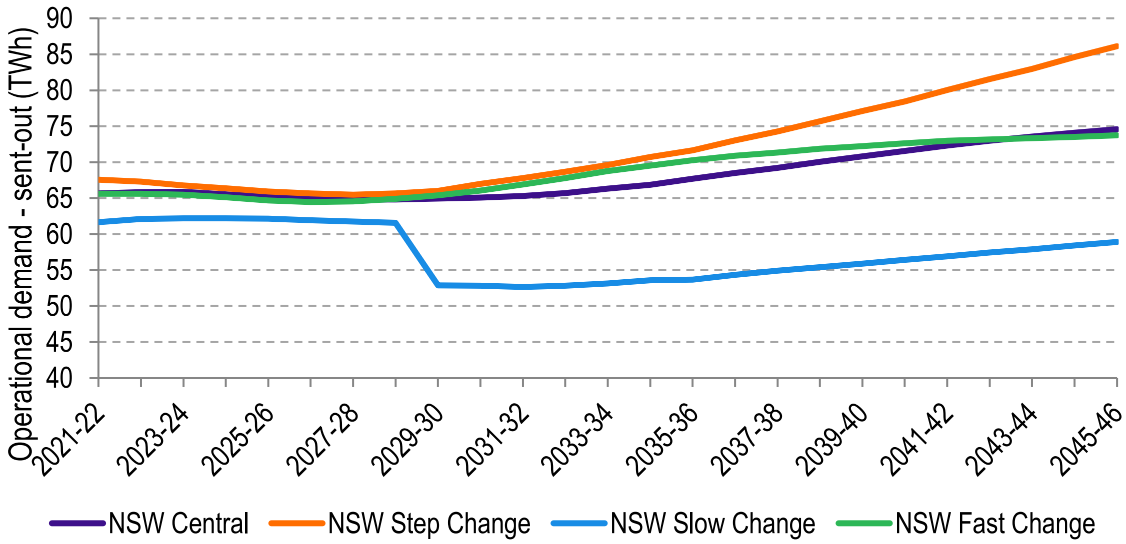


Figure 36: Annual operational demand in all scenarios for NSW from AEMO's Draft 2021 Inputs and Assumptions workbook



[58] AEMO, 11 December 2020, *Draft 2021-22 Input and Assumptions workbook v3.0*. Available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/draft-2021-22-inputs-and-assumptions-workbook.xlsx?la=en. Accessed 29 June 2021.

Figure 37: Annual summer maximum demand in NSW for 10% POE from AEMO's Draft 2021 Inputs and Assumptions workbook

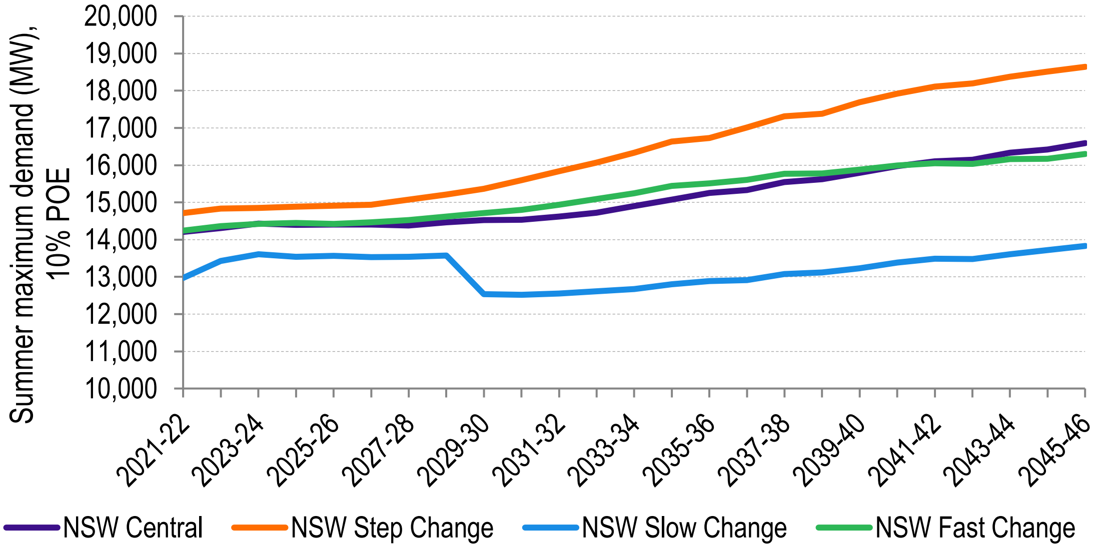


Figure 38: Annual rooftop PV uptake in the NEM from AEMO's Draft 2021 Inputs and Assumptions workbook

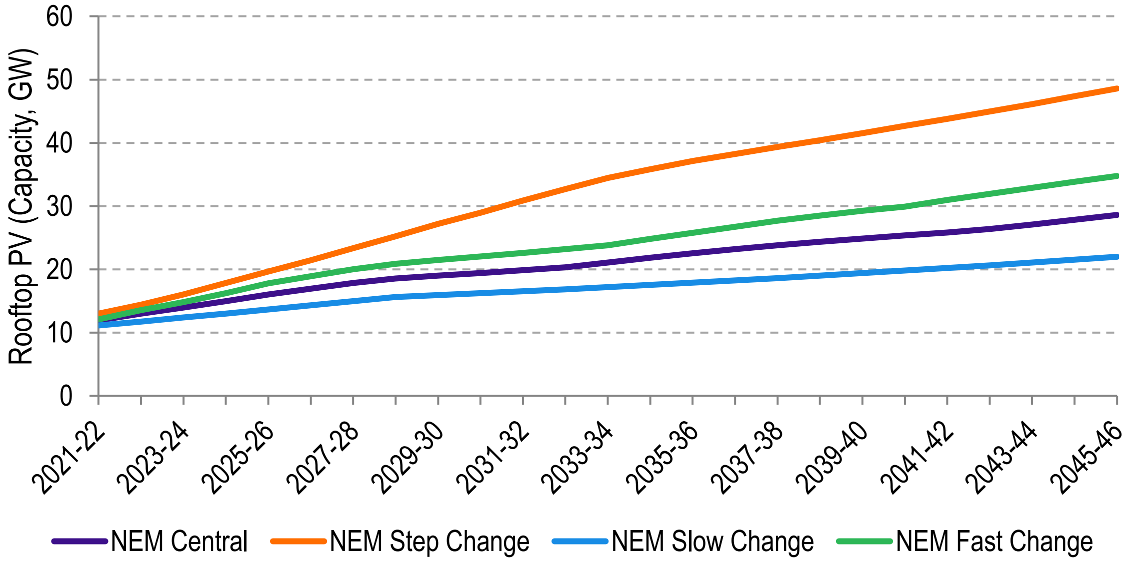
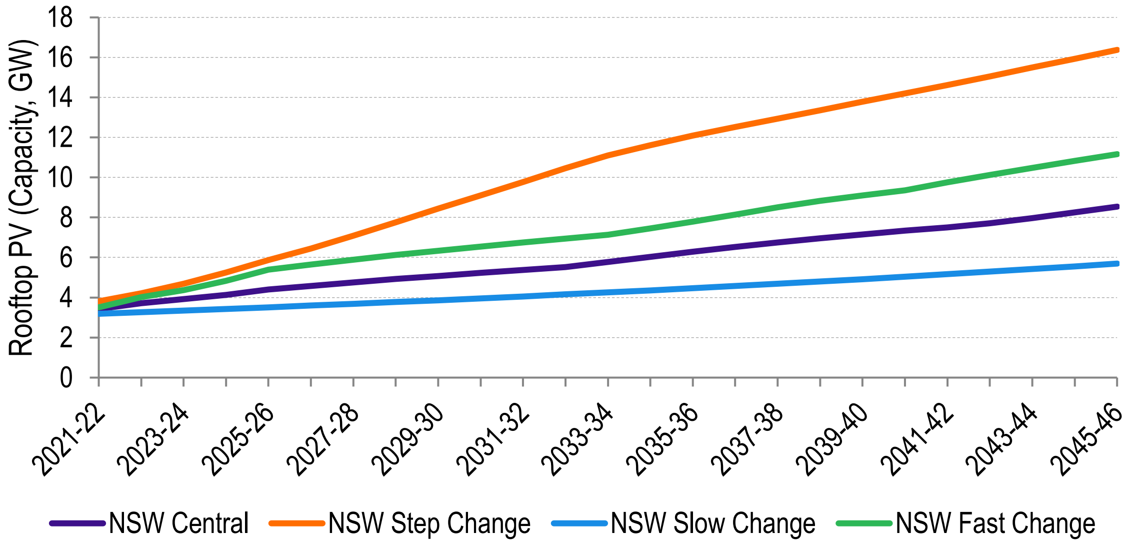


Figure 39: Annual rooftop PV uptake in NSW from AEMO's 2019 Input and Assumptions workbook



The ESOO 2020 demand forecasts shown above for NSW are split into the various NSW zones that have been defined, as described in B.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.

Appendix C Supply

C.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[59], existing, committed and anticipated projects as well as batteries are used.
- In New South Wales, several additional generators anticipated by TransGrid based on the maturity of the connection applications are modelled, as listed in Table 14. These projects are anonymised in our modelling.

Table 14: Capacity anticipated by TransGrid

Region	Zone	Solar capacity (MW)	Wind capacity (MW)
	NCEN	220	0
	Yass	0	106
	Wagga	330	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 15 and explained further in this section of the Report.

Table 15: 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[60] 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.	

[59] AEMO, 30 July 2020, *2019 Input and Assumptions workbook v1.5*. Available at: https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 29 June 2021.

[60] 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 29 June 2021.

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 34.

The availability profiles for wind generation are derived from simulated wind speeds from the Australian Bureau of Meteorology's Numerical Weather Prediction systems[61] 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[62] for each REZ (new entrant wind farms, as listed in Table 16).

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 16).

Table 16: REZ wind and solar approximate average capacity factors over nine reference years[63]

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%

[61] 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 29 June 2021.
[62] 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 29 June 2021.
[63] AEMO, 30 July 2020, *2019 Input and Assumptions workbook v1.5*. Available at: https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 29 June 2021.

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[64]	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

[64] 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[65].

- 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.

C.2 Forced outage rates and maintenance

Full and partial forced outage rates for all generators as well as mean time to repair used in the modelling are based the AEMO 2019 Input and Assumptions workbook[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.

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[65].

C.3 Generator technical parameters

All technical parameters are as detailed in the AEMO 2019 Input and Assumptions workbook[65], except where noted in the Report.

C.4 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[65], maximum loads vary seasonally. This materially reduces the amount of available capacity in the summer periods.

A maximum capacity factor of 75% is assumed for NSW coal, as per the AEMO 2019 Input and Assumptions workbook.

C.5 Gas-fired generators

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

TransGrid has assumed a minimum load of 40% of capacity for all new CCGTs to reflect minimum load conditions for assumed efficient use of gas and steam turbines in CCGT operating mode.

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

[65] AEMO, 30 July 2020, *2019 Input and Assumptions workbook v1.5.* Available at: https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 29 June 2021.

A minimum capacity factor is assumed for gas generators including Condamine, Darling Downs, Osborne, Pelican Point, Swanbank E, Tallawarra, Torrens Island A and B, Yabulu and Yarwun as described in the 2019 Input and Assumptions workbook[66].

C.6 Wind, solar and run-of-river hydro generators

Intermittent renewables, in particular solar PV, wind and run-of-river hydro are dispatched according to their resource availability as they cannot store energy. Intermittent renewable production levels are based on nine years of hourly measurements and weather observations across the NEM including all REZ zones. Using historical reference years preserves correlations in weather patterns, resource availability and demand. Modelling of wind and solar PV is covered in more detail in Section C.1.

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

C.7 Storage-limited generators

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

Hourly hydro inflows to the reservoirs and ponds are computed from monthly values sourced from the AEMO 2019 Input and Assumptions workbook and the median hydro climate factor trajectory for the respective scenario applied[66]. The Tasmanian hydro schemes were modelled using a simplified six pond model.

C.8 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. Figure 40 shows the modelled Snowy Hydro scheme[67] in the TSIRP. In our modelling, the storage level of Talbingo reservoir factors in and tracks all the following[68]:

- 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.

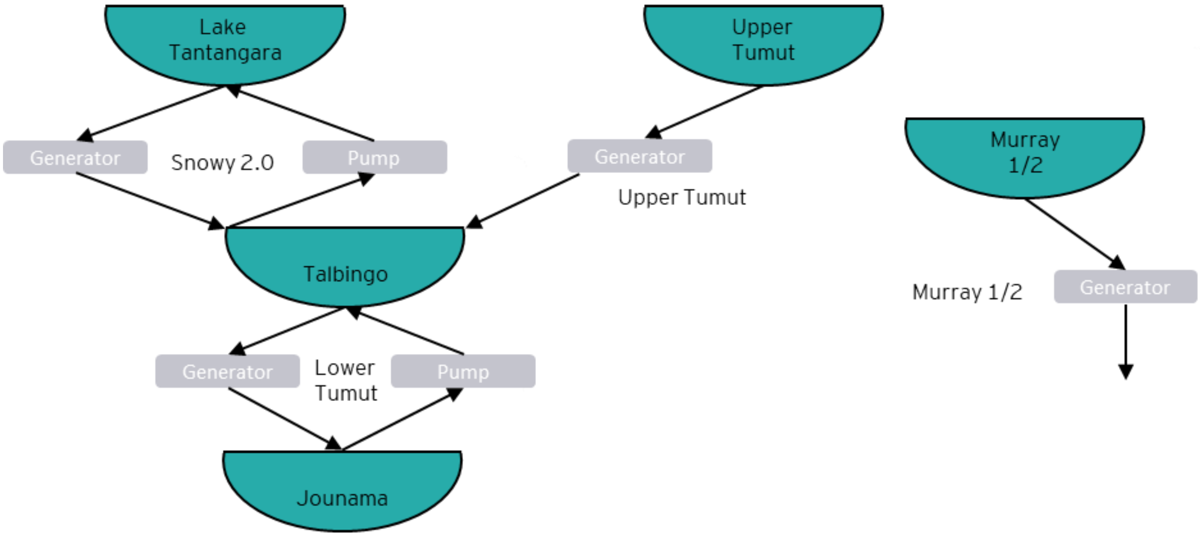
The methodology used to simulate operation of all water storages in the NEM is the same, and the operation of Snowy 2.0 is an example of how the storages are used to most effectively deliver the least cost solution.

[66] AEMO, 30 July 2020, *2019 Input and Assumptions workbook v1.5*. Available at: https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 29 June 2021.

[67] 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 29 June 2021.

[68] Snowy Hydro, https://www.snowyhydro.com.au/our-scheme/snowy20/faqs20-2/. Accessed 29 June 2021.

Figure 40: Snowy Hydro scheme topology[69]



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 ponds 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%[70]. 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 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.

In the PADR modelling, 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.

[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 29 June 2021.

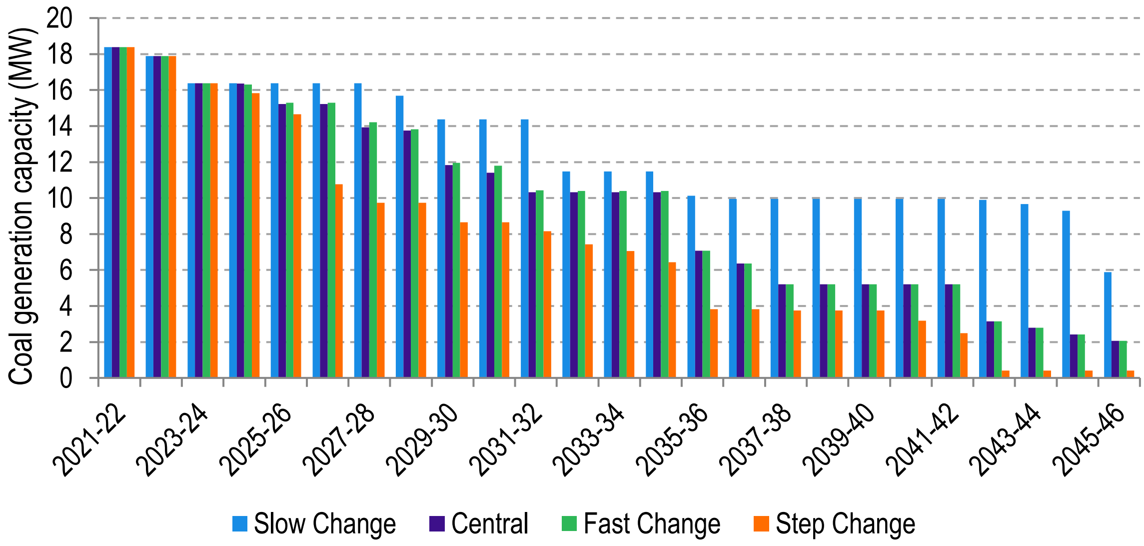
[70] AEMO, 30 July 2020, *2019 Input and Assumptions workbook v1.5.* Available at: https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 29 June 2021.

Appendix D NEM outlook across scenarios without HumeLink transmission upgrade

To understand the benefits of the HumeLink augmentation options, it is useful to examine the differences in the capacity and generation forecast outlooks in each of the modelled scenarios, and the underlying assumptions driving those differences in the Base case without a HumeLink augmentation.

According to the scenario settings selected by TransGrid and in line with the 2020 ISP, thermal retirements in the model are on an economic basis. Coal retirement dates are at or earlier than their end-of-technical life or announced retirement year which were sourced from the latest Generation Information expected closure year document at the time of modelling[71]. In the Slow Change scenario, no early retirements were allowed, but 10-year life extensions were possible if economic to do so. Coal retirements for the Base case across all scenarios as an output of the modelling are illustrated in Figure 41.

Figure 41: Coal capacity in the NEM by year across all scenarios in the Base case



In the Central Scenario, the pace of transition is determined by market forces under current federal and state government policies[72]. This includes a central demand outlook and capital cost projections, neutral fuel cost prices, no federal commitment to emissions reduction, but state-based initiatives such as VRET, QRET and the NSW Roadmap. Considered transmission augmentations include Marinus Link 1st cable in 2036-37, VNI West from 2028-29, QNI Medium in 2032-33 and QNI Large in 2035-36.

The NEM-wide capacity mix forecast in the Central scenario without the HumeLink transmission upgrade is shown in Figure 42 and the corresponding generation mix in Figure 43. Without any HumeLink upgrades, the forecast generation capacity of the NEM gradually shifts towards increasing capacity of wind and solar, complemented by LS Battery, PSH, and gas.

[71] AEMO, July 2020, *Generating Unit Expected Closure Year – July 2020*. No longer available online. Available on request from TransGrid.

[72] AEMO, July 2020. *2020 Integrated System Plan.* Available at: https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en. Accessed 5 July 2021.

Figure 42: NEM capacity mix forecast for the Central scenario in the Base case

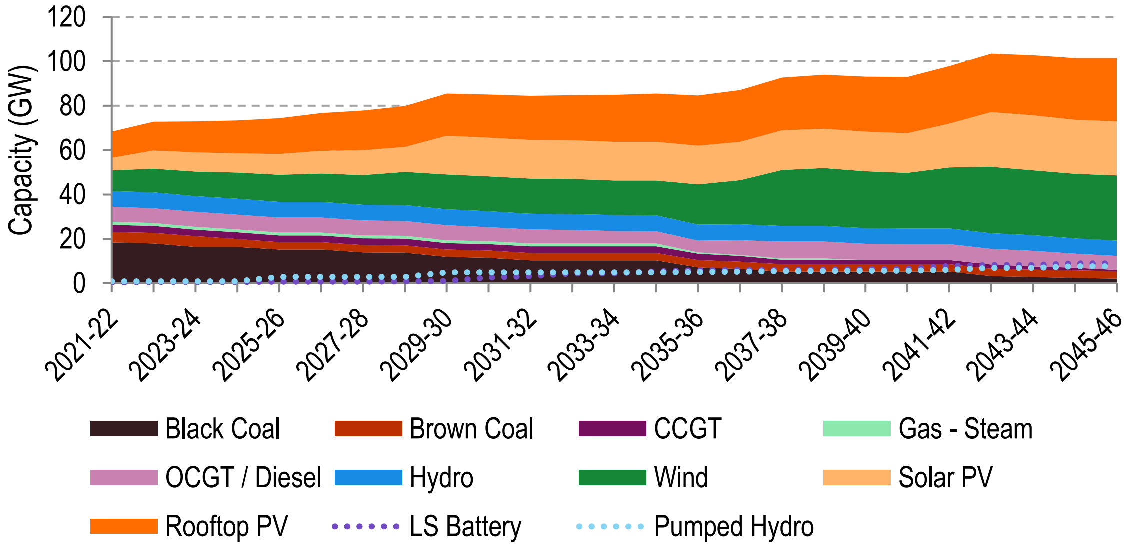
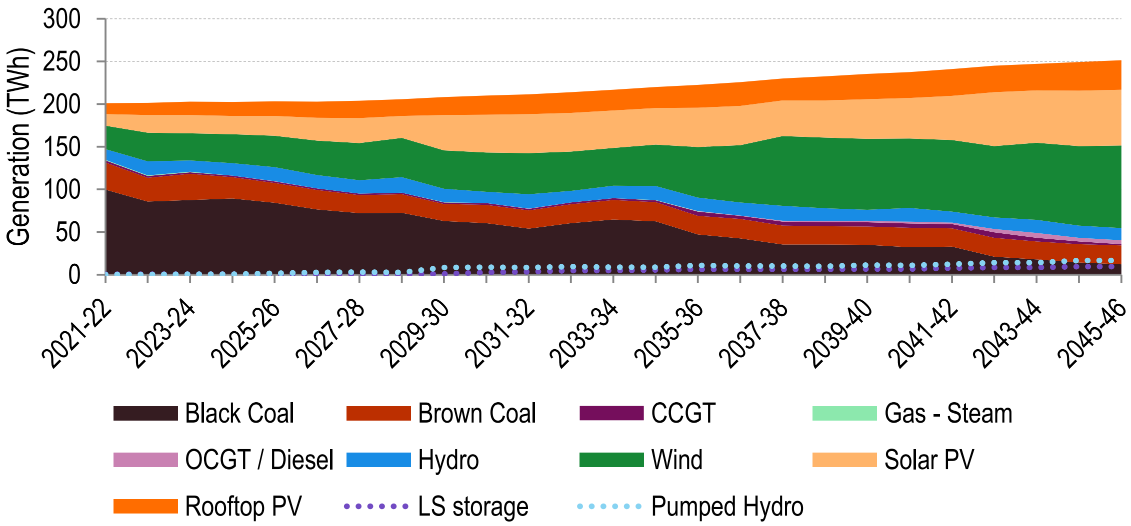


Figure 43: NEM generation mix forecast for the Central scenario in the Base case



Up to 2030, new wind and solar build is driven by the state-based renewable energy targets. The increase in in renewable capacity leads to some economically driven, earlier black coal retirements in QLD and NSW. From 2030-31, with further assumed coal retirements, LS Battery capacity starts to increase, and from 2035-36 PSH and wind, to replace the retiring capacity. Solar and OCGT capacity is also forecast to start to increase from the late 2030s, complementing other technologies and the gas also supporting reserve requirements during peak demand times. Overall, the NEM is forecast to have around 118 GW total capacity by 2045-46 (note that total capacity includes PSH and LS Battery capacities, which are not in the stacked chart), and the timing of the majority of new capacity installed is coincident with coal generation retirements.

The other ISP scenarios vary in the pace of the energy transition from the Central scenario. Figure 44, Figure 46 and Figure 48 show the differences in the NEM capacity development of other scenarios relative to the Central scenario, while Figure 45, Figure 47 and Figure 49 show generation differences. The differences are presented as alternative scenario minus the Central scenario, and both capacity and generation differences for each scenario show similar trends.

The ISP Step Change scenario represents a rapid energy transition with both consumer-led and technology-led transitions occurring in the midst of aggressive global decarbonisation[73]. The main underlying assumptions driving differences in the Step Change scenario are

- Higher demand (see Figure 35 and Figure 37), but also higher uptake of DER,
- restrictive carbon budget,
- higher fuel prices,
- state-based renewable targets, including TRET 200% by 2040,
- transmission upgrades including Marinus Link 1st cable in 2028, 2nd cable in 2031, VNI West in 2035, QNI Medium in 2032 and QNI Large in 2035.

These assumptions, in particular the carbon budget, are forecast to result in additional black and brown coal economic retirements forecast from the mid-2020s onwards (Figure 41). This coal capacity is offset by mainly more wind and LS Battery capacity in those early years, and with increasing capacity of solar and OCGT capacity from the late 2030s onwards. The OCGT capacity is needed particularly for peak demand periods, as well as for reserve requirements.

The Fast Change scenario is assumed to have greater investment in grid-scale technology, and is in many aspects similar to the Central scenario, e.g. fuel prices and operational- and peak demand, but with higher DER uptake and a carbon budget for emissions reduction. Overall, as for the Step Change scenario, these assumptions lead to an increase in wind and solar capacity in the long-term, but with a smaller magnitude. In the medium-term, less solar capacity is forecast compared to the Central scenario due to higher uptake of rooftop PV (Figure 38), the exclusion of the QRET and delay of VNI West to 2035, but higher capacity of wind and LS Battery. In the long-term, driven by the carbon budget, wind and solar capacity complemented by a small capacity of OCGTs, are offsetting brown coal and LS Battery.

The Slow Change scenario is characterised by slower economic growth and emissions reductions. Demand expectation is low compared to the Central scenario, fuel prices are low, and many augmentations are assumed to not go ahead, this includes VNI West, Marinus Link and QNI Medium and Large. In addition, this scenario allows 10-year life extensions of coal-fired generators. As a result, the capacity outlook in this scenario shows increased coal capacity due to the forecast (partially) deferred retirement of several black and brown coal plants (Figure 41), as well as significantly reduced wind and solar capacity due to the reduced need for new generation. This scenario shows little change in its overall capacity mix until late in the study period, unless driven by state policies such as the NSW Roadmap.

[73] AEMO, July 2020. *2020 Integrated System Plan.* Available at: https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en. Accessed 5 July 2021.

Figure 44: Difference in NEM capacity forecast between the Step Change and Central scenarios in the Base case (excluding rooftop PV)

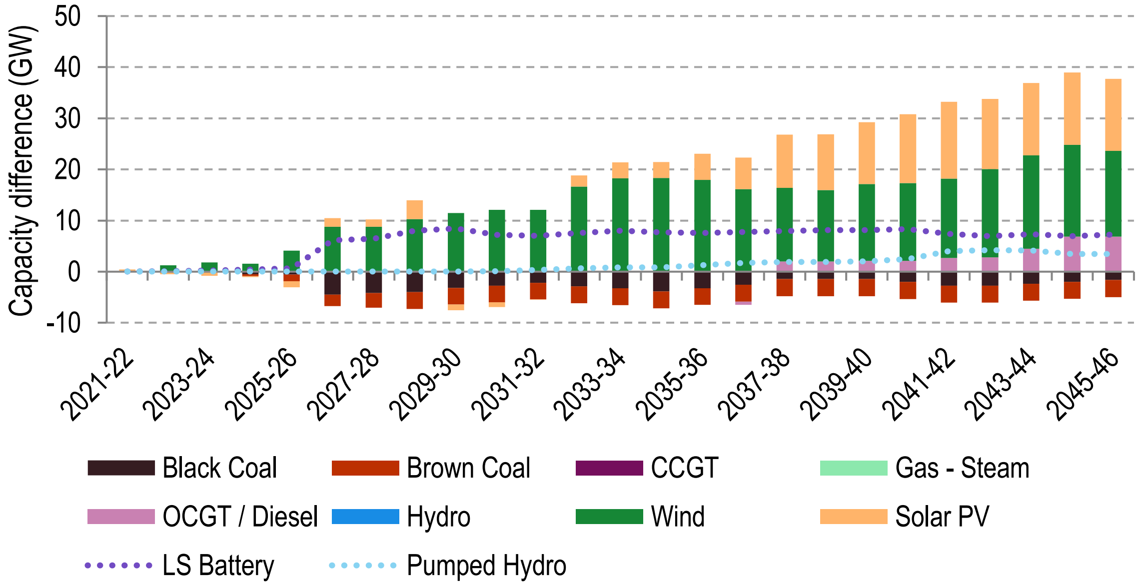


Figure 45: Difference in NEM generation forecast between the Step Change and Central scenarios in the Base case (excluding rooftop PV)

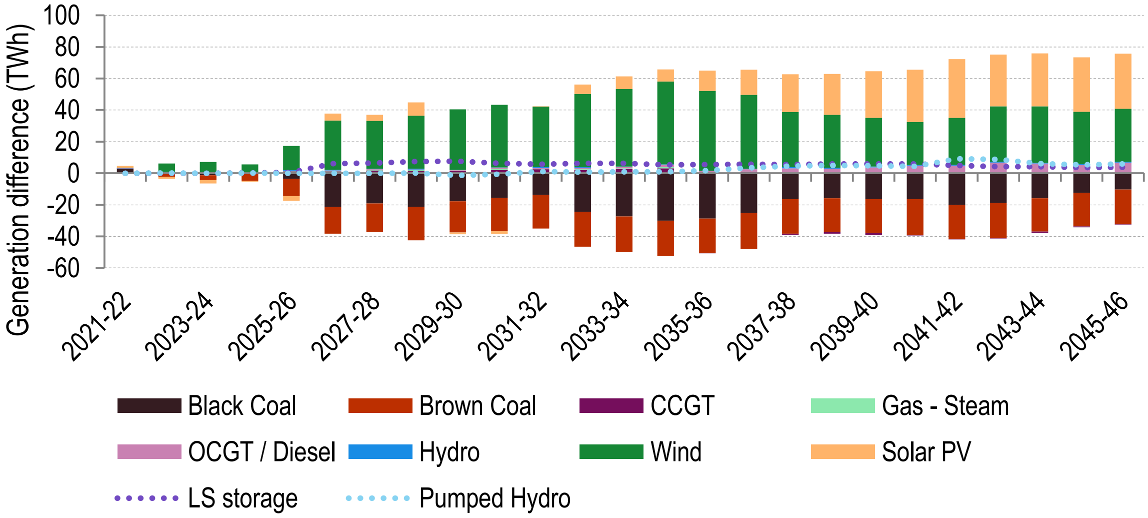


Figure 46: Difference in NEM capacity forecast between the Fast Change and Central scenarios in the Base case (excluding rooftop PV)

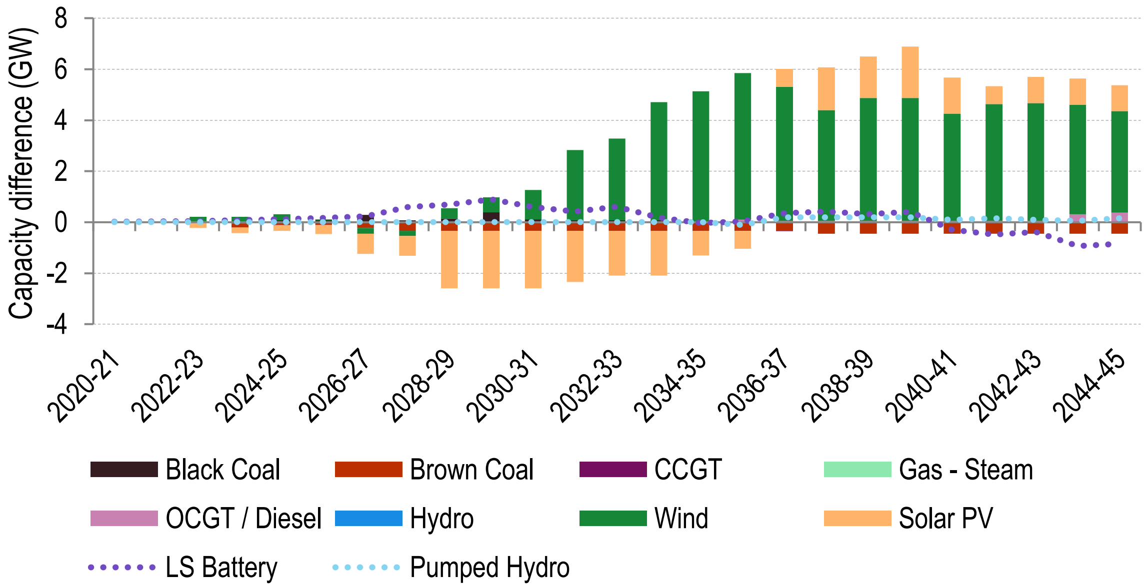


Figure 47: Difference in NEM generation forecast between the Fast Change and Central scenarios in the Base case (excluding rooftop PV)

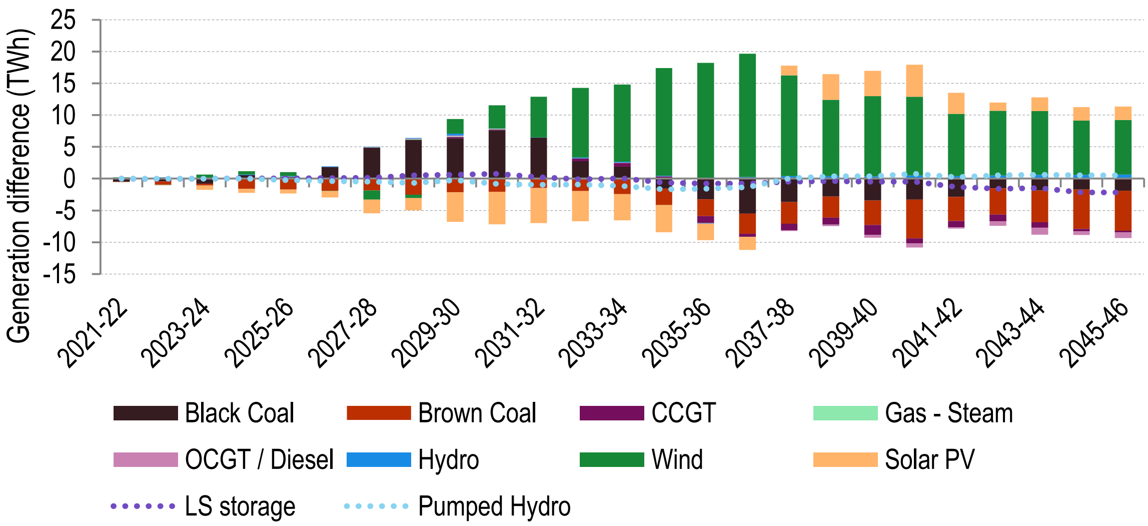


Figure 48: Difference in NEM capacity forecast between the Slow Change and Central scenarios in the Base case (excluding rooftop PV)

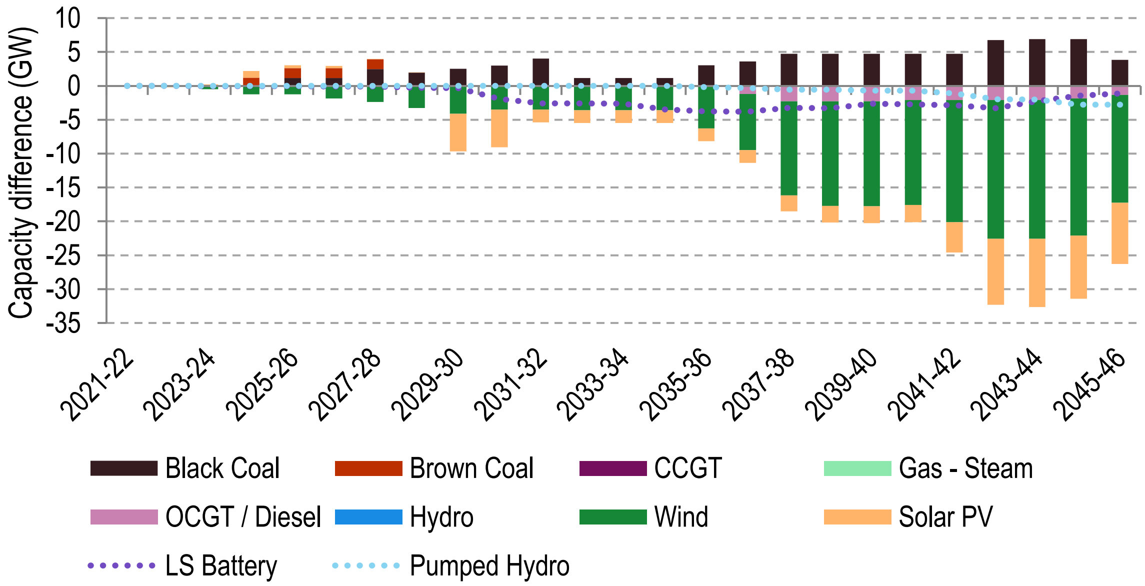
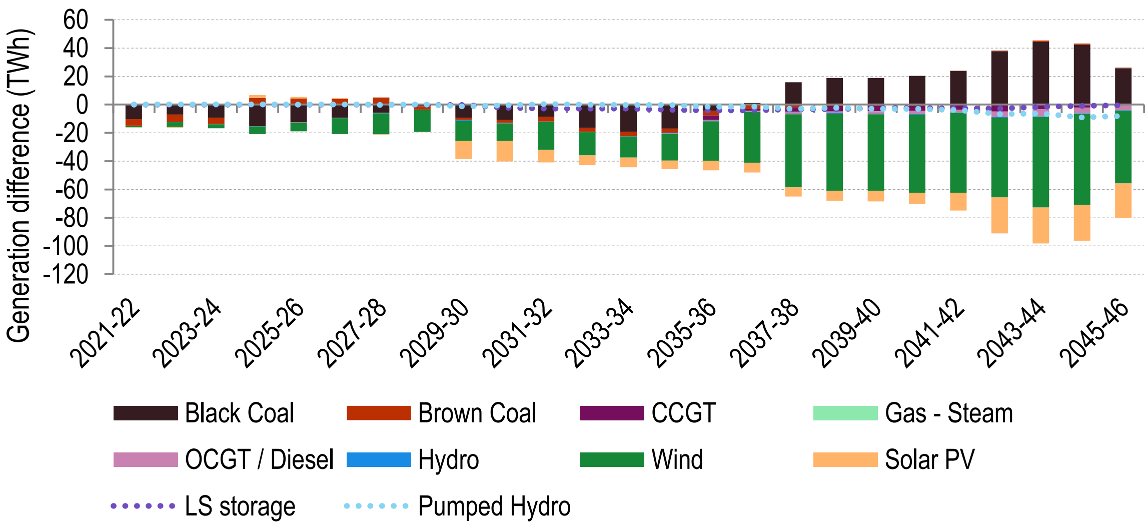


Figure 49: Difference in NEM generation forecast between the Slow Change and Central scenarios in the Base case (excluding rooftop PV)



Appendix E 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