Sonya Petreski

From:	Burkitt, Blair
Sent:	Thursday, 29 July 2021 4:12 PM
To:	Kaur, Kami
Cc:	Hassan, Ali
Subject:	FW: Embargoed - HumeLink PACR and EY market modelling report [SEC=OFFICIAL]
Attachments:	Reinforcing the New South Wales Southern Shared Network PACR - EY Market Modelling Report.pdf; HumeLink_PACR_Embargoed_EMBARGOED_sent to AER 28 July 2021.pdf

OFFICIAL

Hi Kami

fyi, TransGrid have sent us a copy of the final RIT-T for Humelink, this will be relevant to our discussion with the Markets Committee on 11 August.

[redacted]

B

From: Roberts, Sebastian <sebastian.roberts@accc.gov.au>
Sent: Thursday, 29 July 2021 9:31 AM
To: Burkitt, Blair <blair.burkitt@aer.gov.au>; Hassan, Ali <Ali.Hassan@accc.gov.au>
Cc: Jovanoski, Slavko <slavko.jovanoski@aer.gov.au>; Funston, Kris <Kris.Funston@aer.gov.au>; Petersen, Adam <adam.petersen@aer.gov.au>
Subject: FW: Embargoed - HumeLink PACR and EY market modelling report [SEC=OFFICIAL]

OFFICIAL

Embargoed copy of the PACR ….

From: [redacted]@transgrid.com.au>
Sent: Wednesday, 28 July 2021 2:07 PM
To: Roberts, Sebastian <sebastian.roberts@accc.gov.au>
Cc: [redacted]@transgrid.com.au>
Subject: [UNSCANNED CONTENT]Embargoed - HumeLink PACR and EY market modelling report

CONFIDENTIAL / EMBARGOED until 12pm 12 July 2021

Dear Sebastian

We are pleased to provide an early draft of our HumeLink PACR and accompanying EY Market Modelling report.

These documents are confidential and embargoed until they are published on our website. We expect this to occur at 12pm tomorrow.

Thank you for our ongoing discussions on the regulatory process for HumeLink.

Please do not hesitate to give me a call if you would like to discuss.

Kind regards
[redacted]

[redacted] | Finance and Regulation
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T: [redacted] M: [redacted]
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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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Modelling work performed as part of our scope inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual outcomes, because events and circumstances frequently do not occur as expected, and those differences may be material. We take no responsibility that the projected outcomes will be achieved. We highlight that our analysis and Report do not constitute investment advice or a recommendation to you on a future course of action. We provide no assurance that the scenarios we have modelled will be accepted by any relevant authority or third party.

Ernst & Young have consented to the Report being published electronically on TransGrid's website for informational purposes only. Ernst & Young have not consented to distribution or disclosure beyond this. The material contained in the Report, including the Ernst & Young logo, is copyright. The copyright in the material contained in the Report itself, excluding Ernst & Young logo, vests in TransGrid. The Report, including the Ernst & Young logo, cannot be altered without prior written permission from Ernst & Young.

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.

Ernst & Young's liability is limited by a scheme approved under Professional Standards Legislation.

Table of contents

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.

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

[2] AER, August 2020, *Application guidelines - Regulatory investment test for transmission*. Available at: https://www.aer.gov.au/system/files/AER%20-1%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.

[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%20-1%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

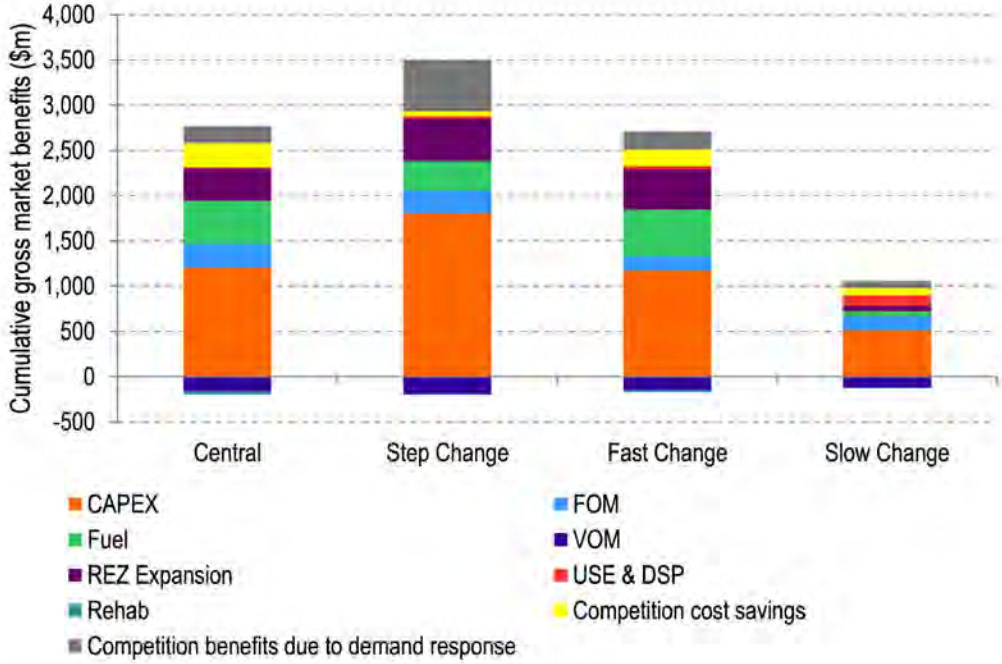
For the two highest ranked options, i.e. Options 2C and 3C, EY also calculated the potential competition benefits, including competition cost savings and competition benefits due to demand response, and the resulting total benefits are summarised in Table 2. It is forecast that Option 3C will result 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.

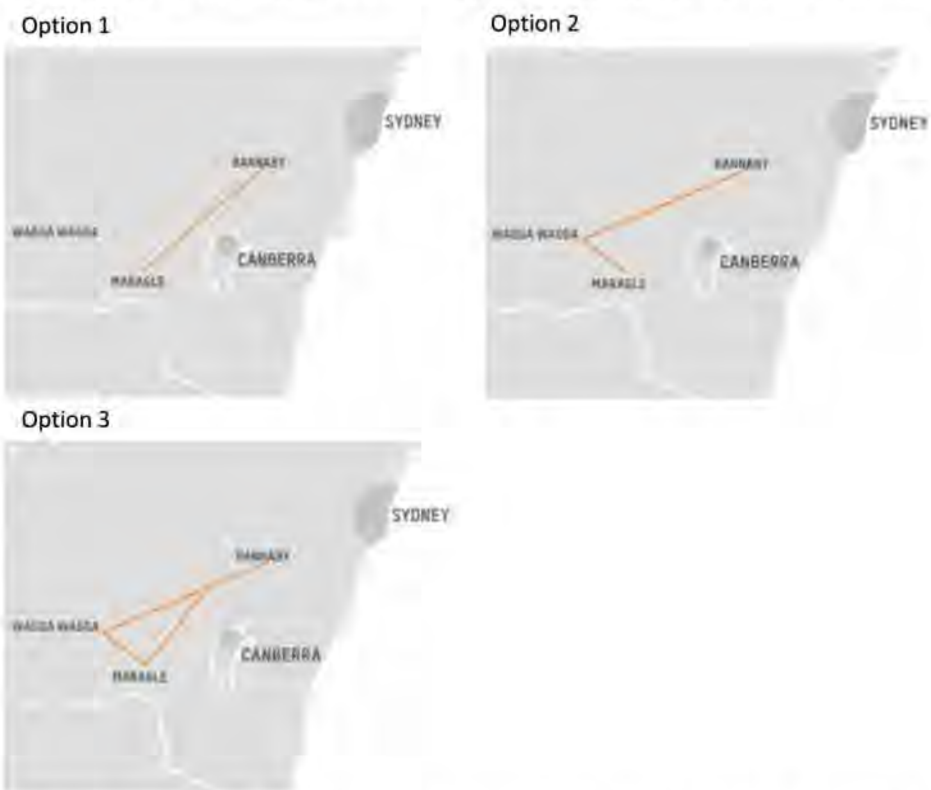
[11] Frontier Economics, September 2004, *Evaluating interconnection competition benefits*. Available at: https://www.aer.gov.au/system/files/Frontier%20Economics%20report%20-%20evaluating%20interconnection%20competition%20benefits%20-%20September%202004.pdf. Accessed 29 July 2021.

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

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[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.

Key drivers input parameter	Scenario			
	Central	Step Change	Fast Change	Slow Change
NEM carbon budget to achieve 2050 emissions levels	NA	Cumulative NEM electricity sector emissions budget to 2050 of 1,465 Mt CO2-e	Cumulative NEM electricity sector emissions budget to 2050 of 2,208 Mt CO2-e	NA
Victoria Renewable Energy Target (VRET)	40% renewable energy by 2025 and 50% renewable energy by 2030			
Queensland Renewable Energy Target (QRET)	50% by 2030		NA	
Tasmanian Renewable Energy Target (TRET)	100% by 2022	100% by 2022 and 200% by 2040	100% by 2022	
NSW Electricity Infrastructure Roadmap	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.			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.
South Australia Energy Transformation RIT-T	NSW to SA interconnector (EnergyConnect) is assumed commissioned by July 2024[21].			
Western Victoria Renewable Integration RIT-T	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).			
Marinus Link	1st cable: July 2036, 2nd cable excluded[23]	1st cable: July 2028, 2nd cable: July 2031	1st cable: July 2031, 2nd cable excluded	Excluded
Victoria to NSW Interconnector Upgrade	The Victoria to New South Wales Interconnector Upgrade PADR[24] preferred option is assumed commissioned by July 2022.			
NSW to QLD Interconnector Upgrade	QNI minor July 2022, QNI Medium 2032-33, QNI Large 2035-36.			QNI minor July 2022, QNI Medium and Large: excluded.
VNI West	VNI West is assumed	VNI West is assumed commissioned by July 2035.		Excluded

[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.

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[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

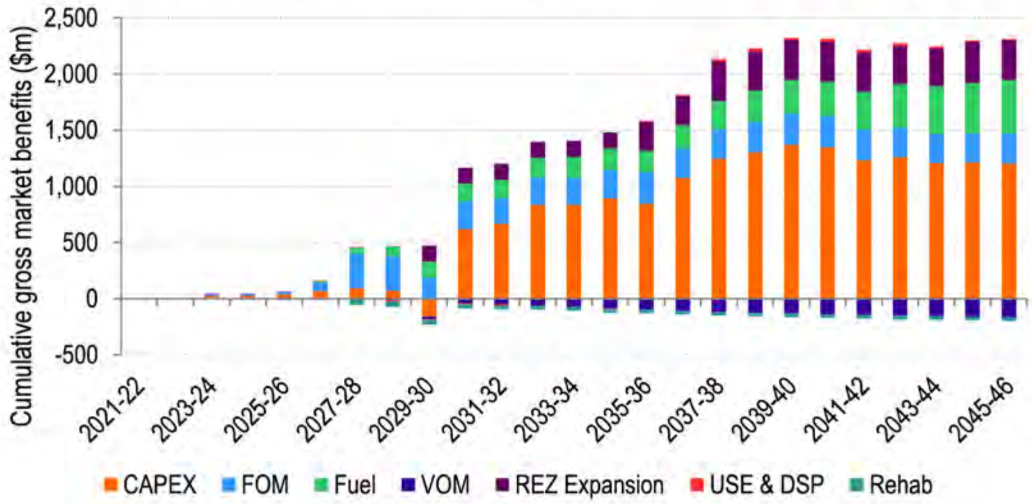
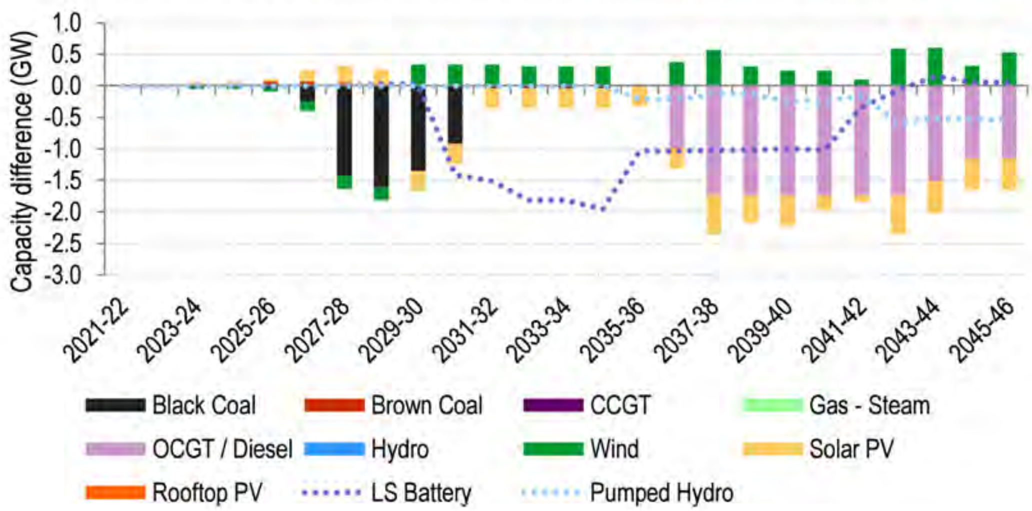


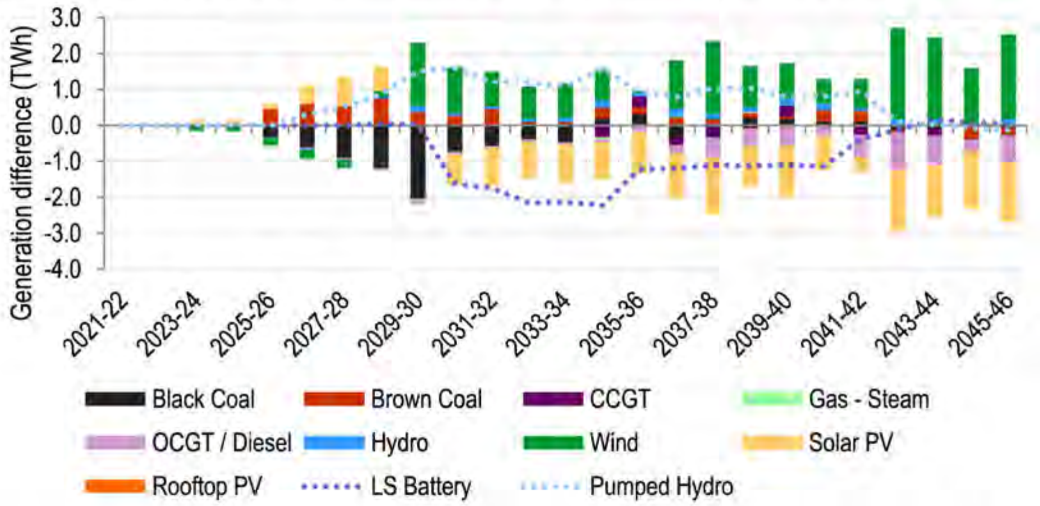
Figure 4: Difference in NEM capacity forecast between Option 3C and Base case in the Central scenario



[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.

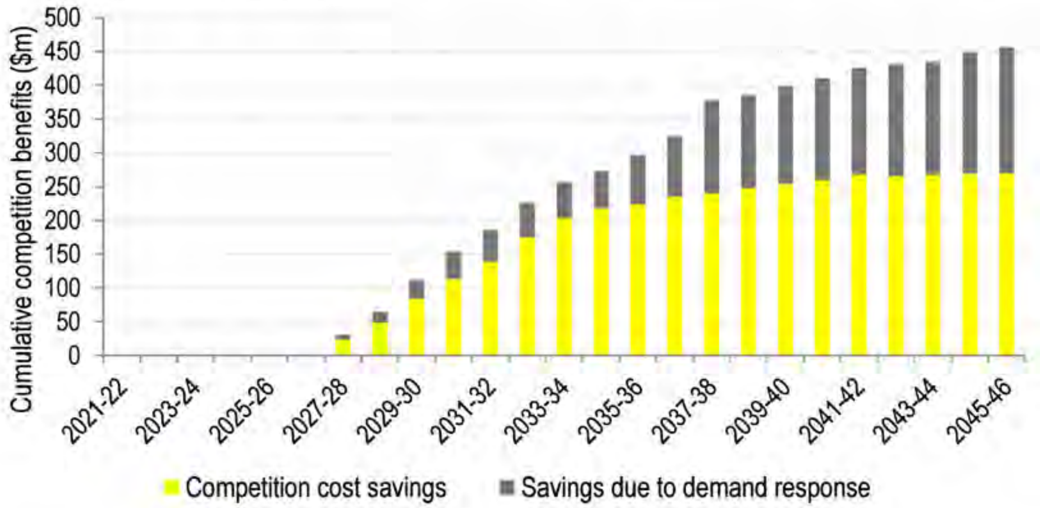
Competition benefits are forecast to reach around $450m by the end of the study period. Forecast benefits begin to accrue as soon as Option 3C is commissioned, with both competition cost savings and competition benefits due to demand response contributing to that.

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

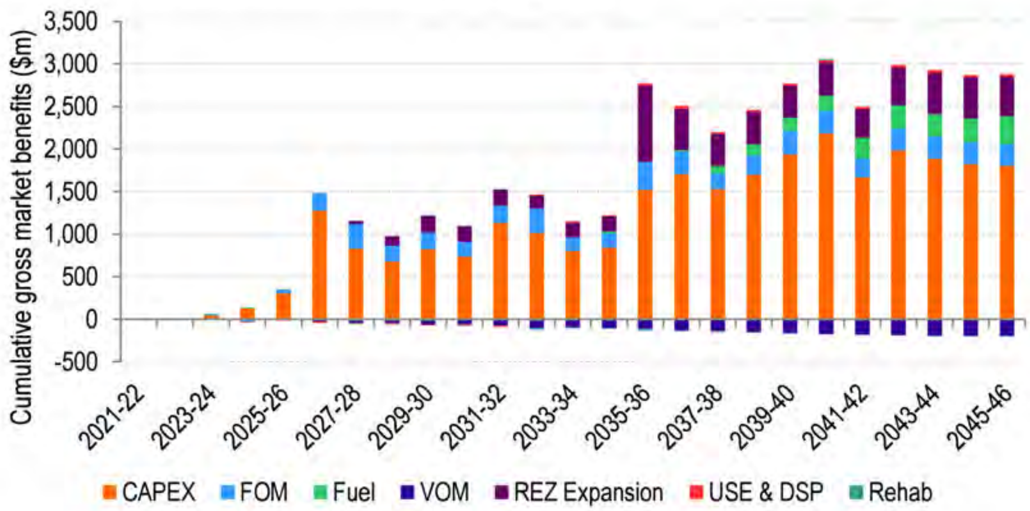


Figure 8: Forecast NEM capacity difference between Option 3C and Base case in the Step Change scenario

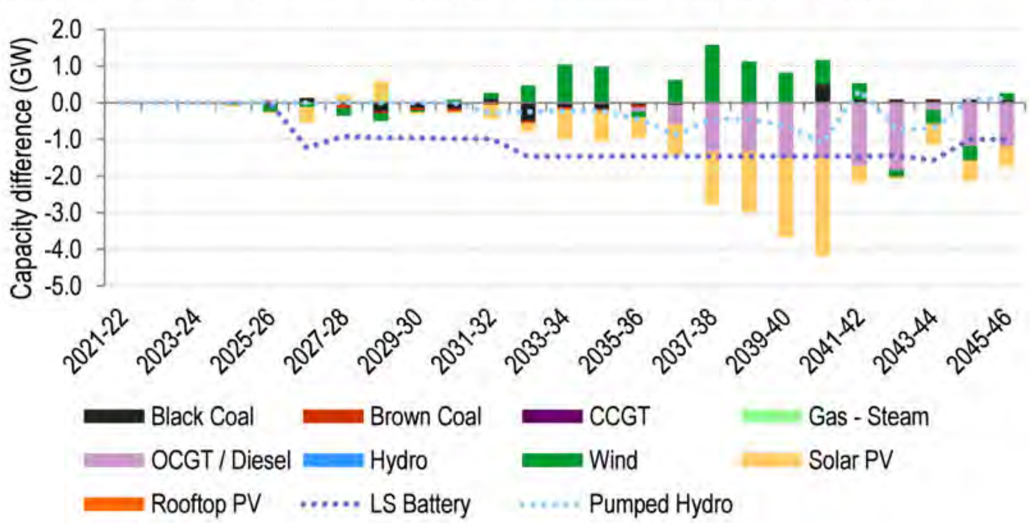
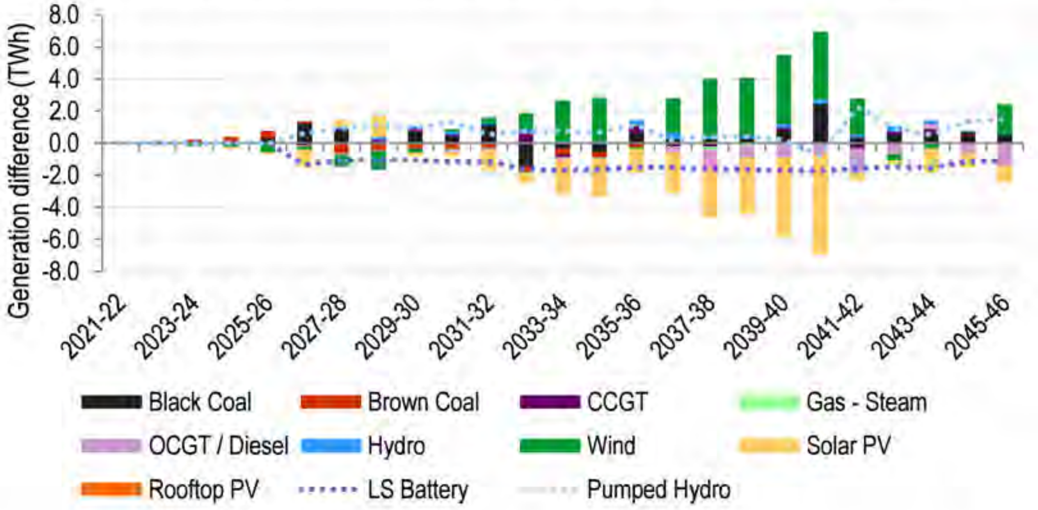


Figure 9: Difference in NEM generation forecast between Option 3C and Base case in the Step Change scenario



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).

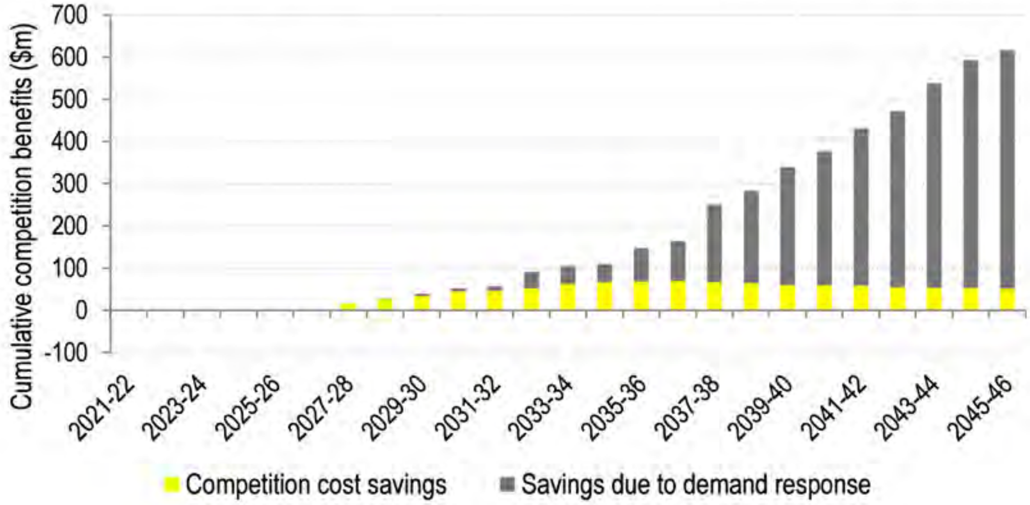
Figure 10 shows the forecast cumulative competition benefits for Option 3C in the Step Change scenario, considering the same bidding strategy as the Central scenario. Note that competition benefits are calculated from 2027-28, the year HumeLink is assumed to be fully commissioned.

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

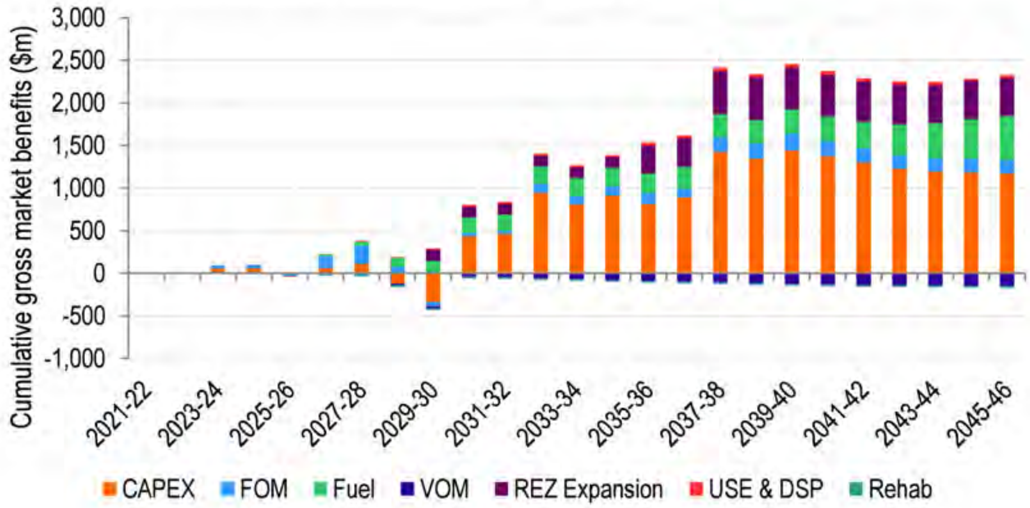


Figure 12: Forecast NEM capacity difference between Option 3C and Base case in the Fast Change scenario

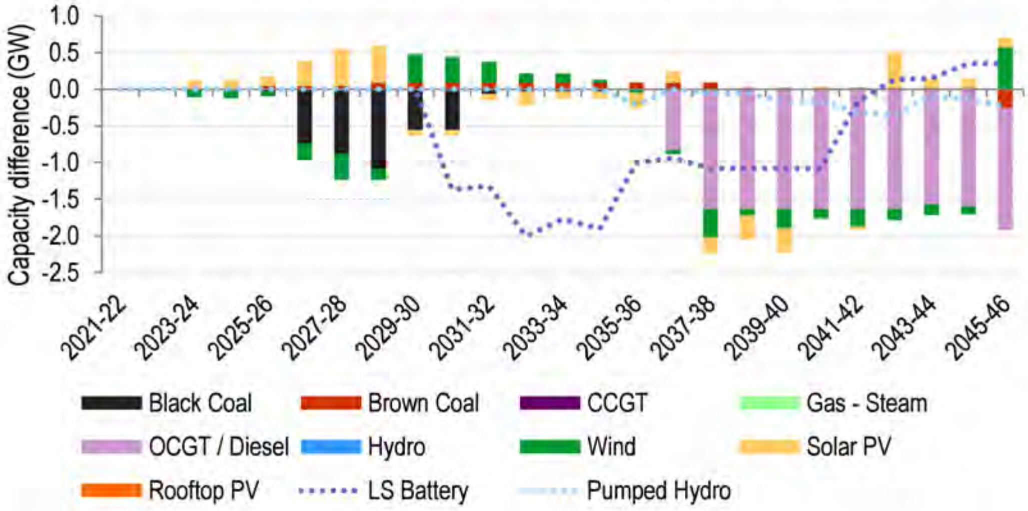
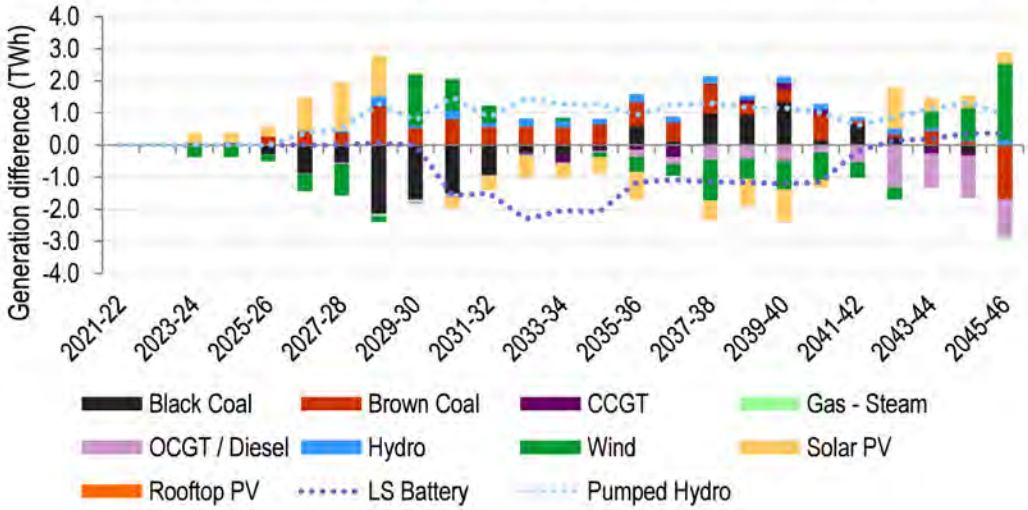


Figure 13: Difference in NEM generation forecast between Option 3C and Base case in the Fast Change scenario



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.

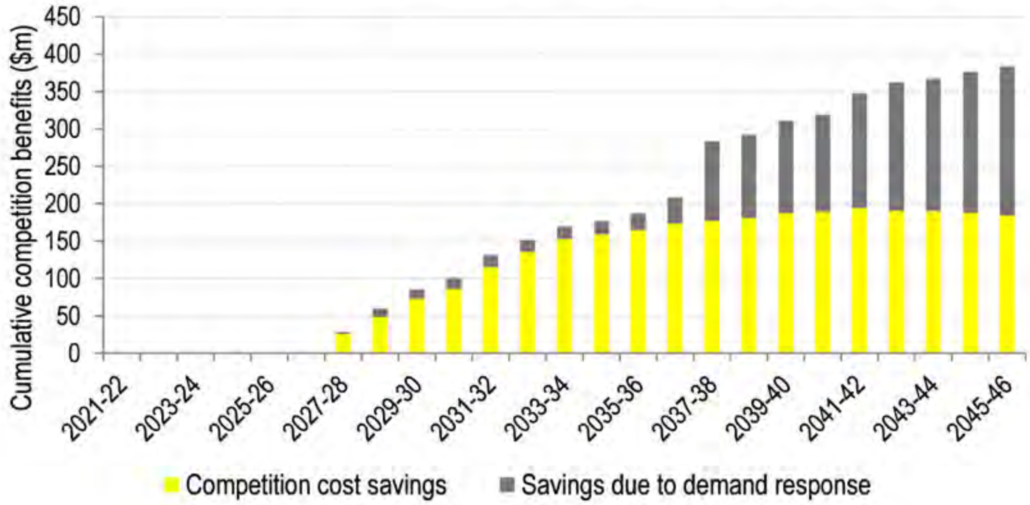
Overall, the Fast Change scenario has slightly higher benefits than the Central scenario ($40m). As a result of the carbon budget and therefore earlier assumed coal retirements in the Fast Change scenario, more new capacity is forecast to be built in this scenario than in the Central scenario in the 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

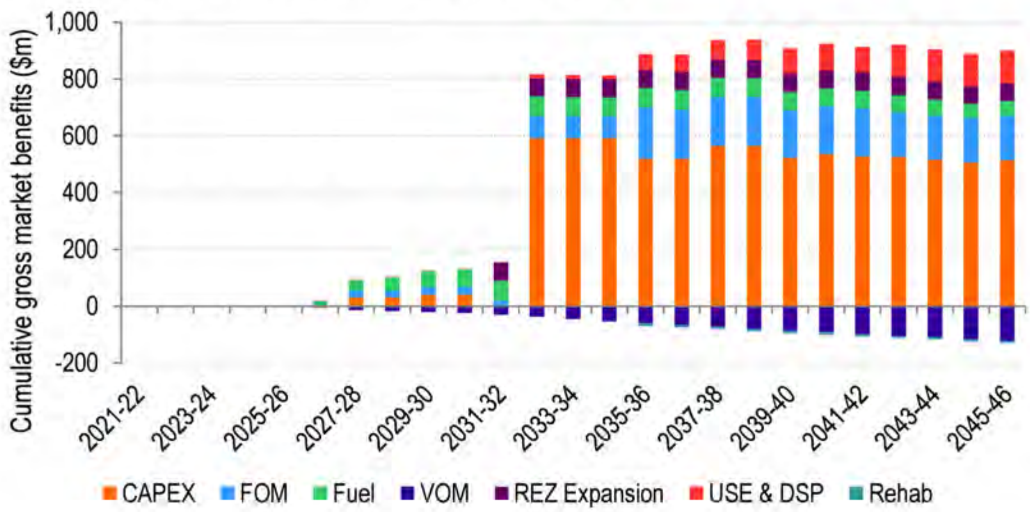


Figure 16: Forecast NEM capacity difference between Option 3C and Base case in the Slow Change scenario

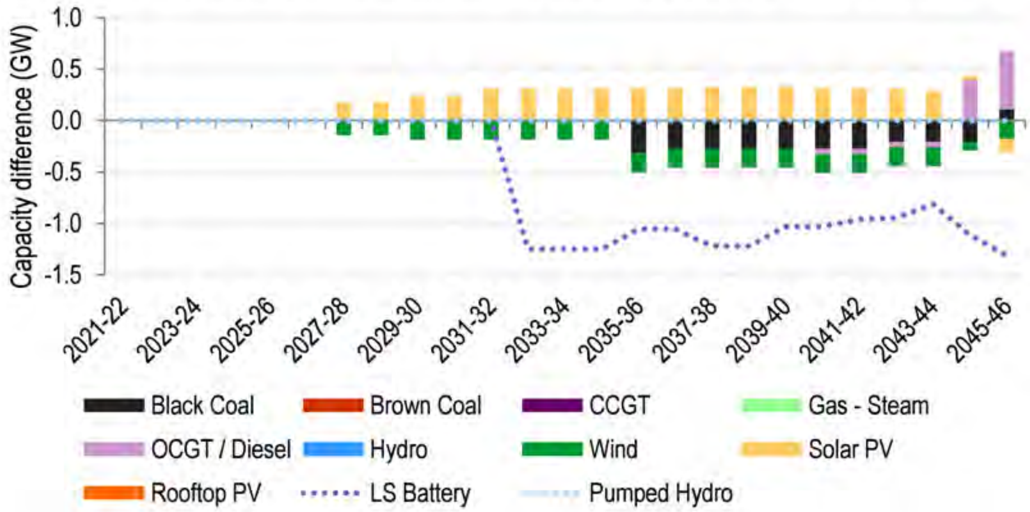
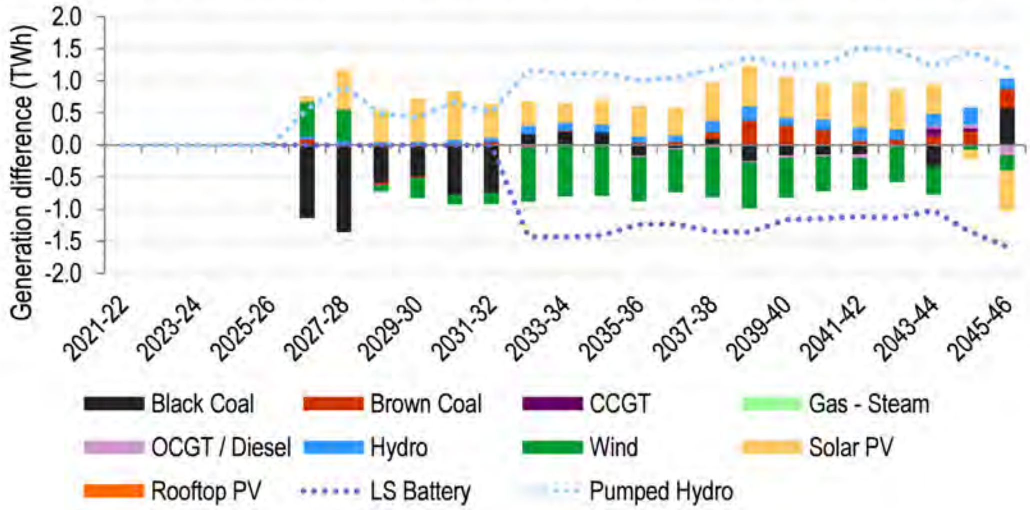


Figure 17: Difference in NEM generation forecast between Option 3C and Base case in the Slow Change scenario



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.

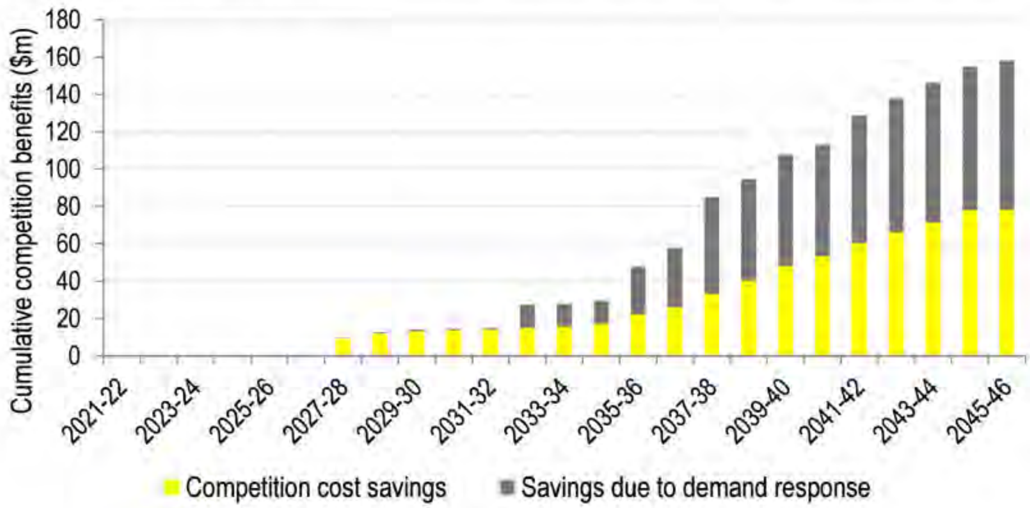
Over the longer outlook, the key observations are as follows:

- 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

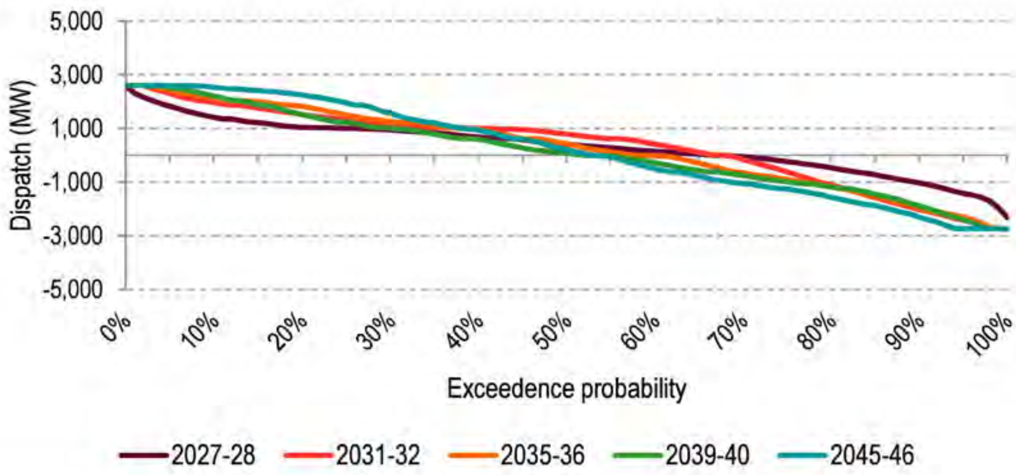
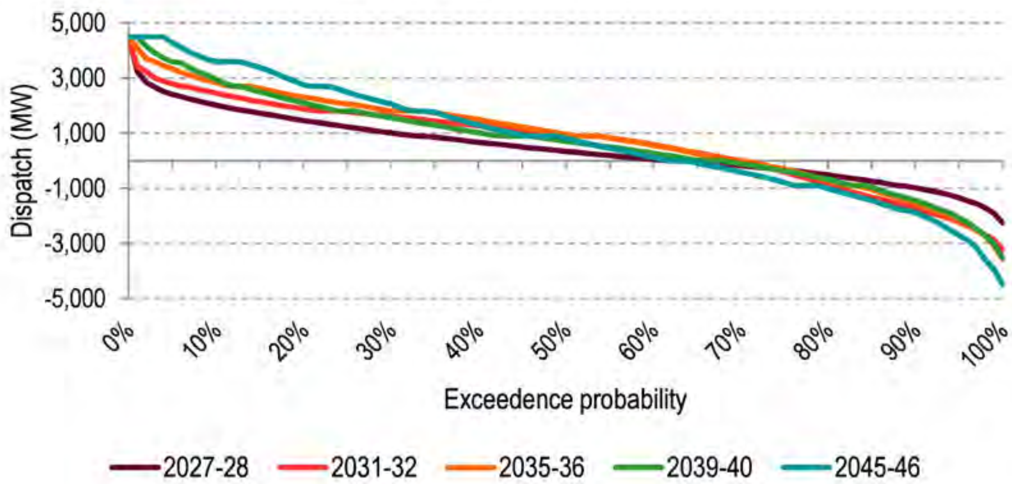


Figure 20: Flow duration curve for CAN - NCEN for Option 3C in the Central scenario



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

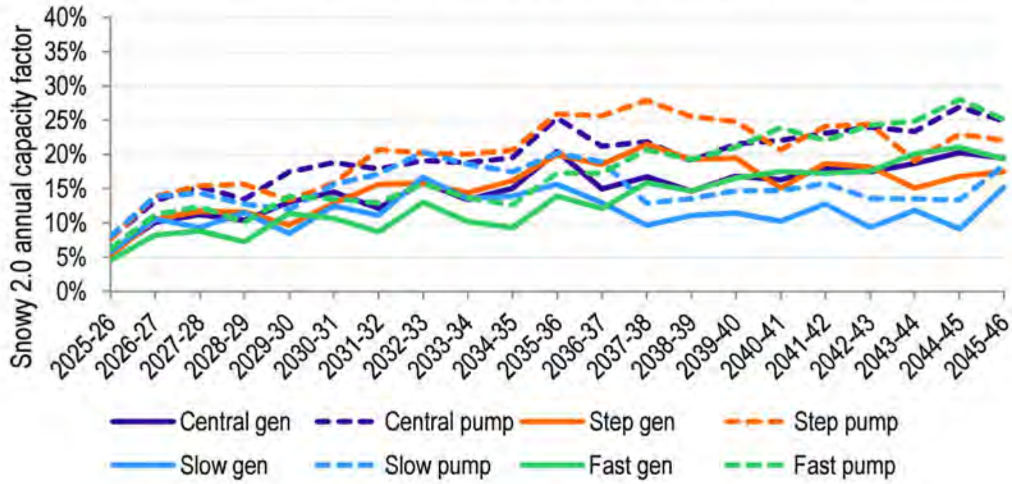
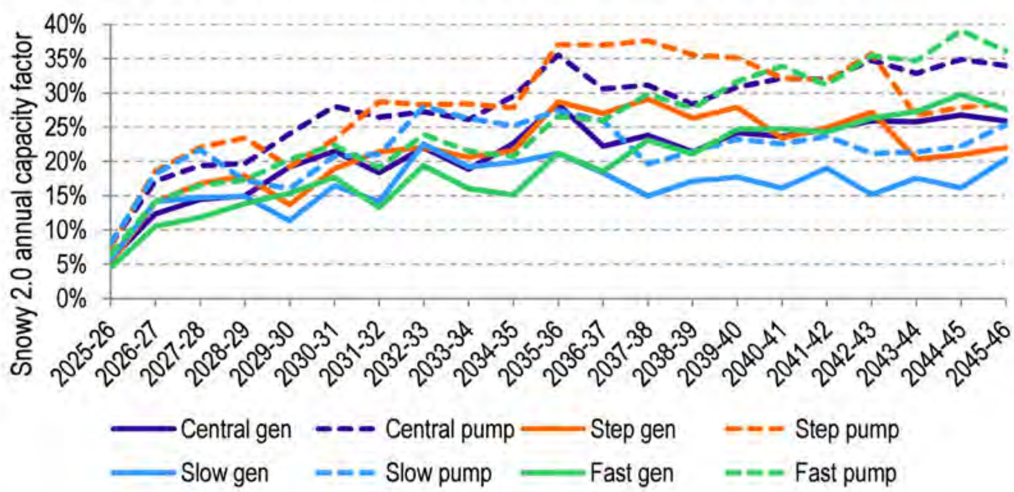


Figure 22: Annual capacity factor for Snowy 2.0 generator and pump for Option 3C in all scenarios



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*
Option 2C	Kurri Kurri and Tallawarra B	1,918	307	139	2,364
Option 2C	VNI West delayed	2,032	216	164	2,412
Option 2C	IASR	2,482	NA	NA	NA
Option 3C	*Core*	*2,114*	*270*	*186*	*2,570*
Option 3C	Kurri Kurri and Tallawarra B	1,936	316	138	2,390
Option 3C	VNI West delayed	2,059	225	165	2,449
Option 3C	IASR	2,500	NA	NA	NA
Option 3C	Modular Power Flow Control (MPFC)	2,135	NA	NA	NA

4.5.1 Central scenario including Kurri Kurri and Tallawarra B

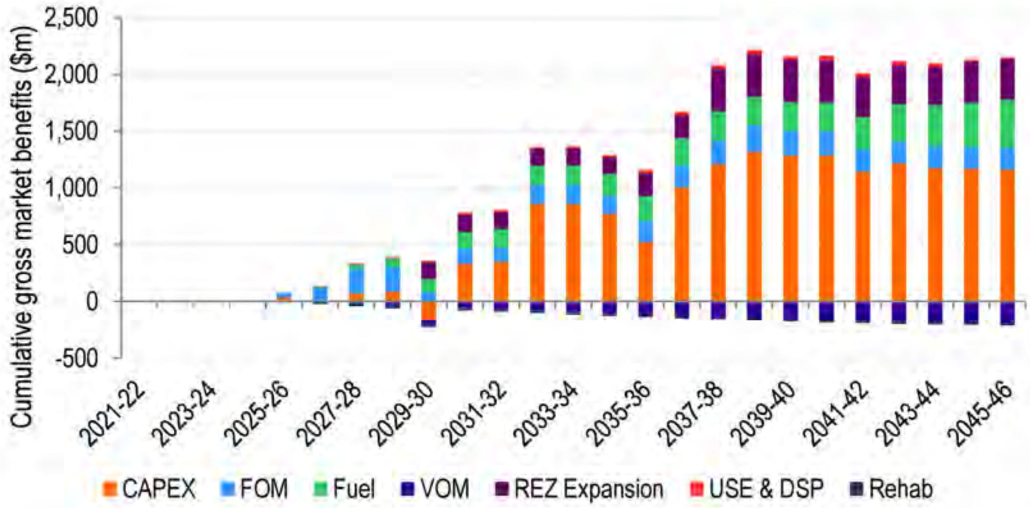
Kurri Kurri (modelled as 750 MW OCGT) and Tallawarra B (modelled as 300 MW CCGT) are two recently announced gas generators in NCEN, which are not part of the committed or anticipated generators outlined in the 2019 Inputs and Assumptions workbook.

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

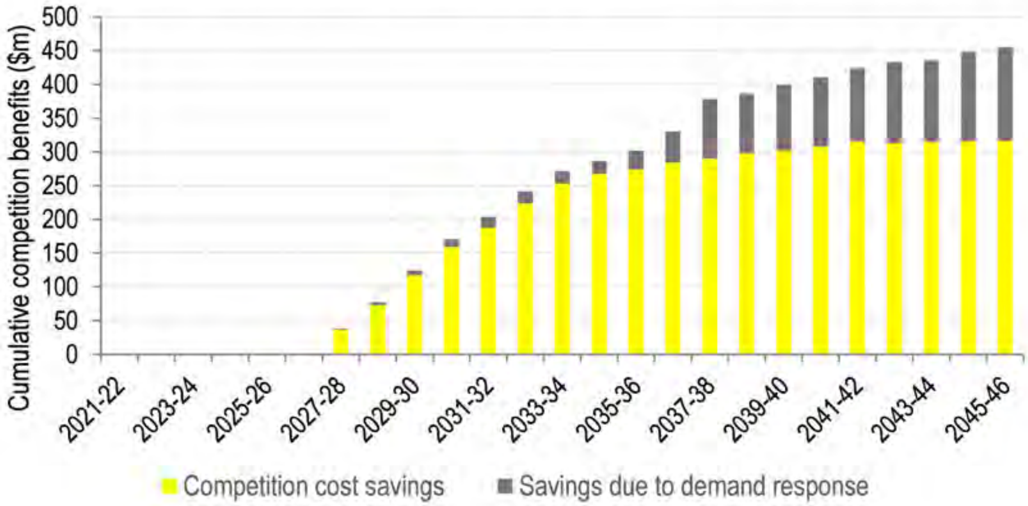


Including those gas generators is expected to result in benefits of $1,936m for Option 3C, a reduction of ~$180m with lower benefits due to avoided/deferred capex in the early and mid-2030s as well as FOM. In the sensitivity, the additional gas capacity is forecast to allow for earlier coal retirements,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

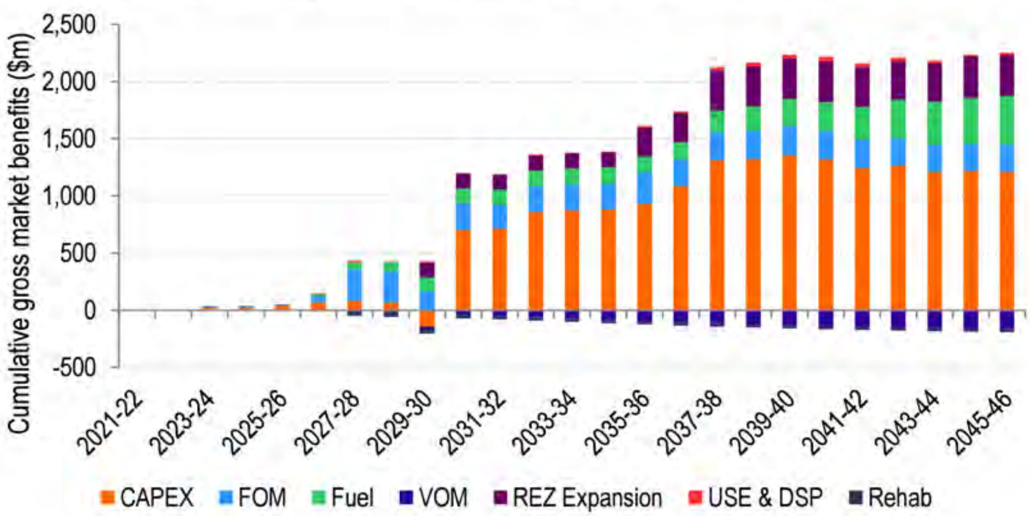


4.5.2 Commissioning of VNI West delayed to 2035

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.

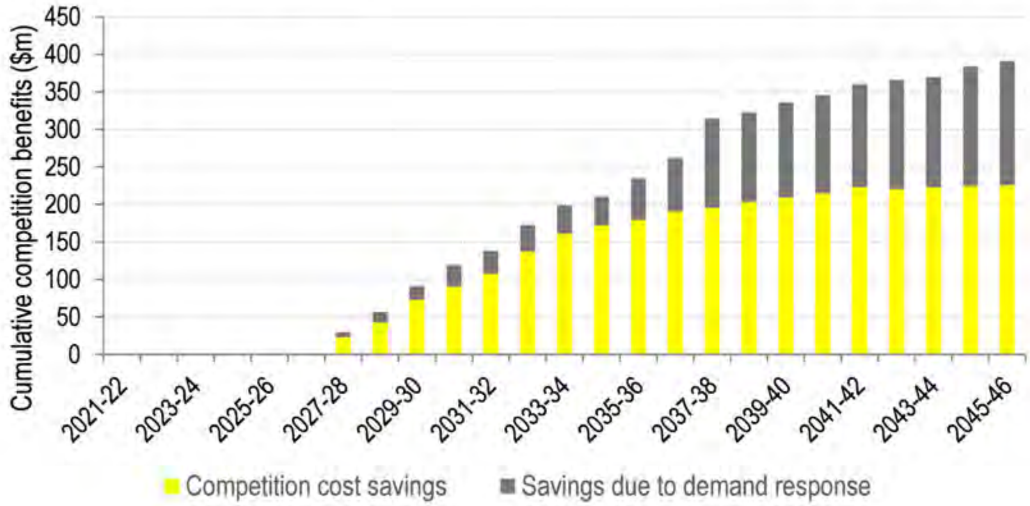
The sensitivity results in forecast gross market benefits reducing by $55m to $2,059m for Option 3C, with only minor impacts on composition of benefits, generation and capacity mix. In this sensitivity, the model forecasts a very similar build in the later years post the assumed commissioning of VNI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

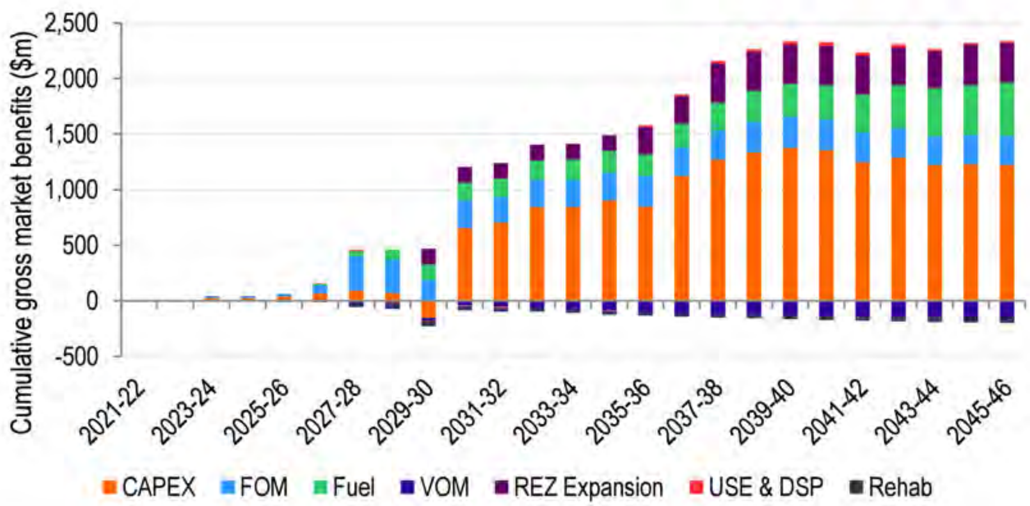
Figure 26: Forecast cumulative competition benefits for Option 3C with VNI West delayed to 2035, millions real June 2019 dollars discounted to June 2021 dollars



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]

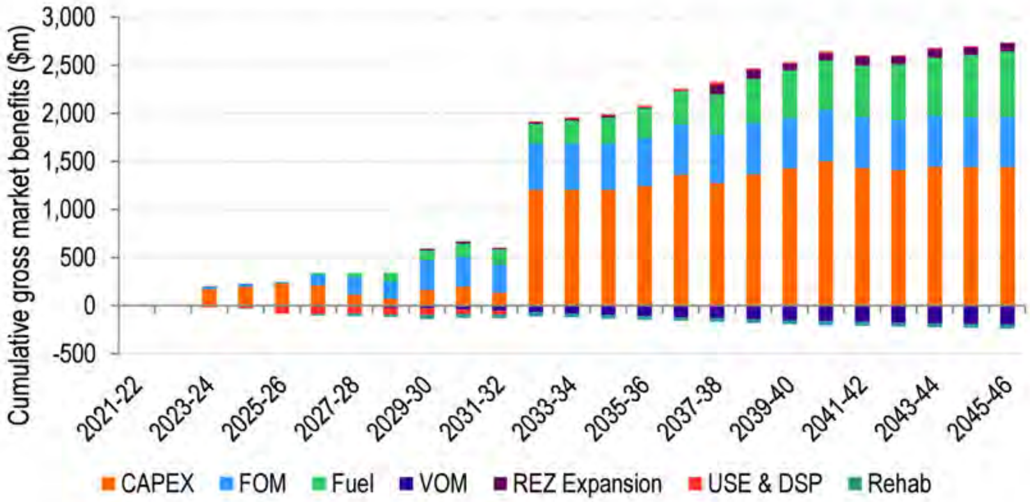
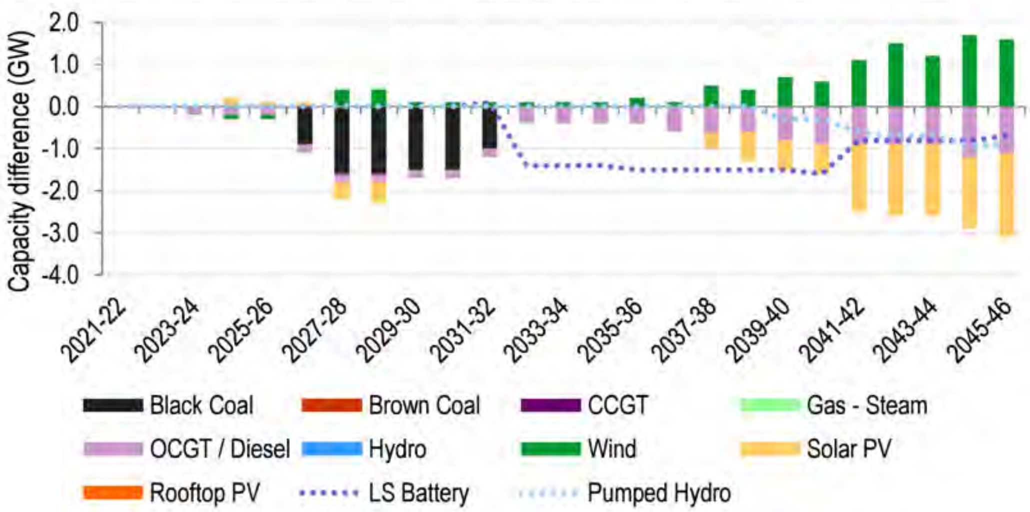


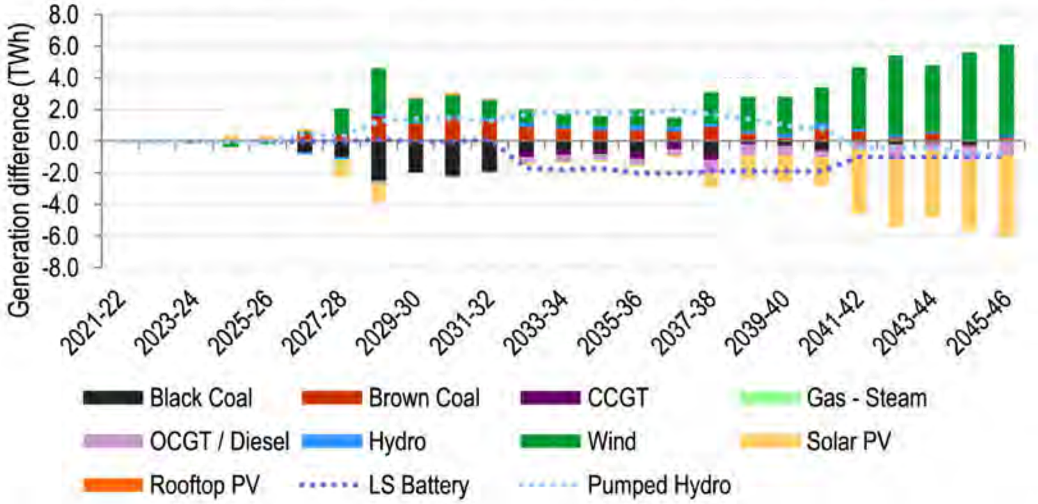
Figure 29: Difference in NEM capacity forecast between Option 3C and Base case in the IASR Central scenario



[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 SAT41, 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.

[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.

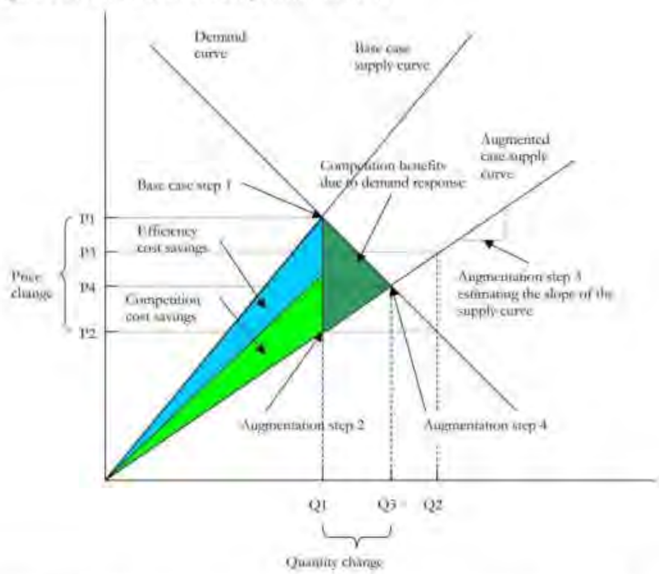
Table 8: Bidding strategies

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:

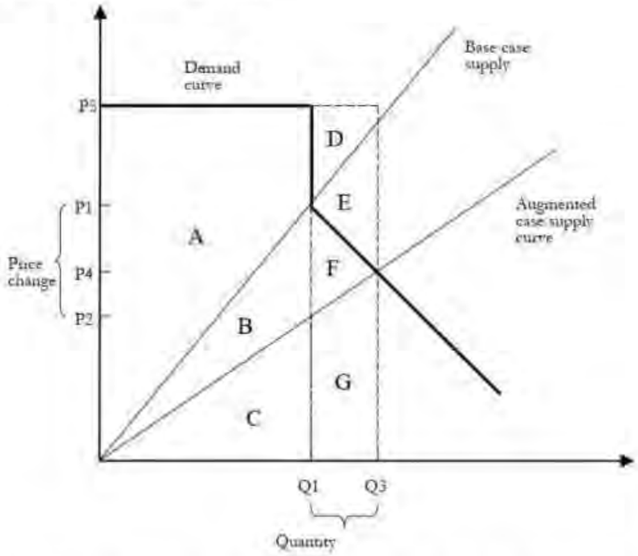
$$element\ (r,c) = \frac{\frac{P_{3,r,c} - P_{2,r}}{P_{1,r}}}{\Delta Q_{3,c}}$$

  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:

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[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].

[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

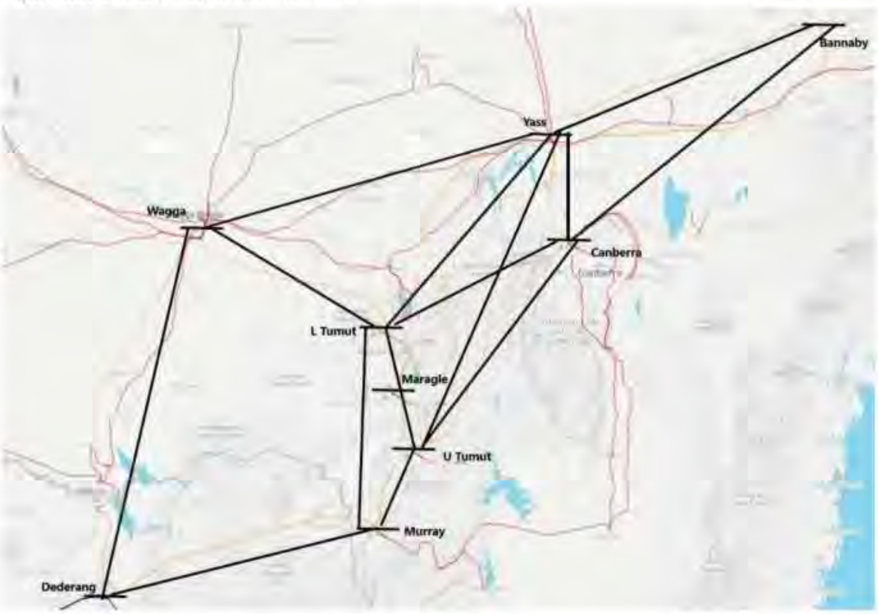
Options	Snowy cut-set	Snowy cut-set + HumeLink lines	CAN/YASS – Bannaby cut-set	CAN-NCEN cut-set	Bannaby-NCEN
Do Nothing	2700 Post VNI 2,870	2,700 Post VNI 2,870	2,700	2,700	3,100
Option 1A	2,970	4,515	3,970	3,970	4,030
Option 1B	2,970	4,660	4,110	4,080	4,080
Option 1C	2,980	5,920	5,330	4,500	4,500
Option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

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[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]

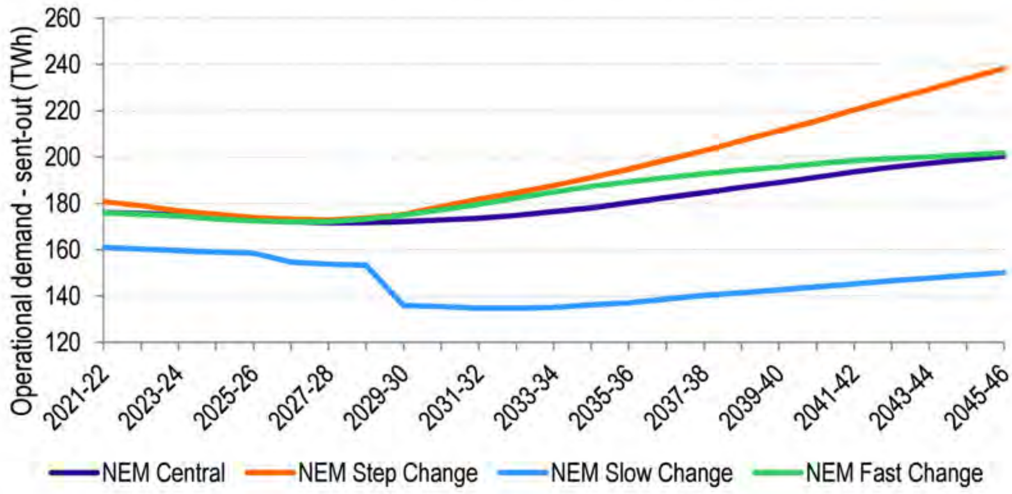
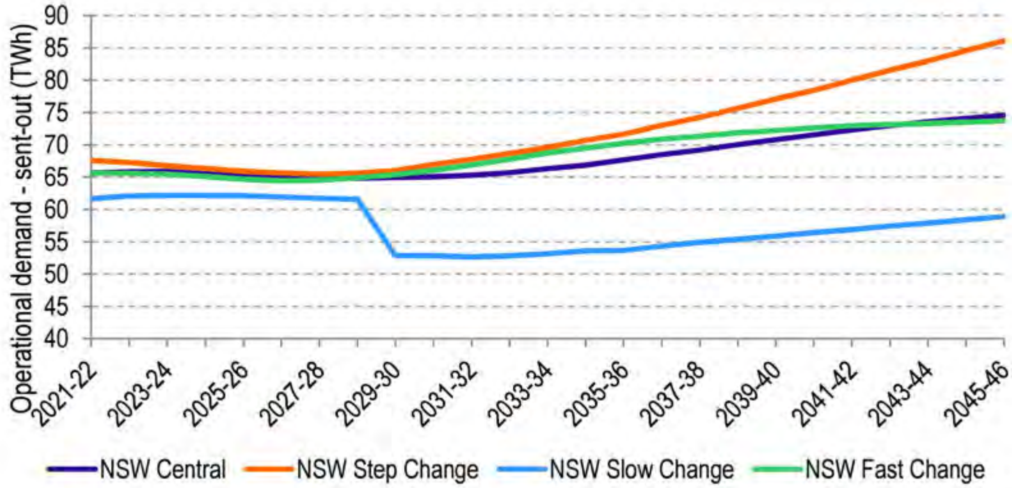


Figure 36: Annual operational demand in all scenarios for NSW from AEMO's Draft 2021 Inputs and Assumptions workbook



[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

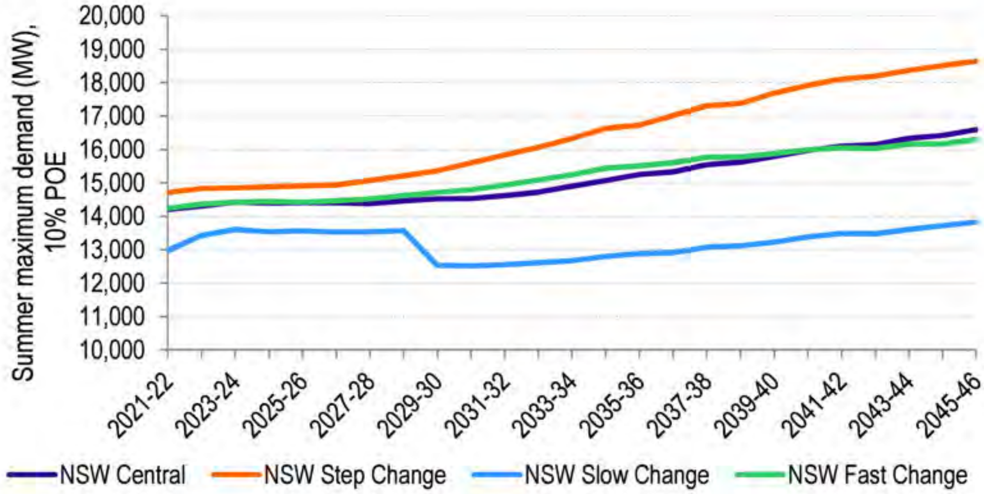


Figure 38: Annual rooftop PV uptake in the NEM from AEMO's Draft 2021 Inputs and Assumptions workbook

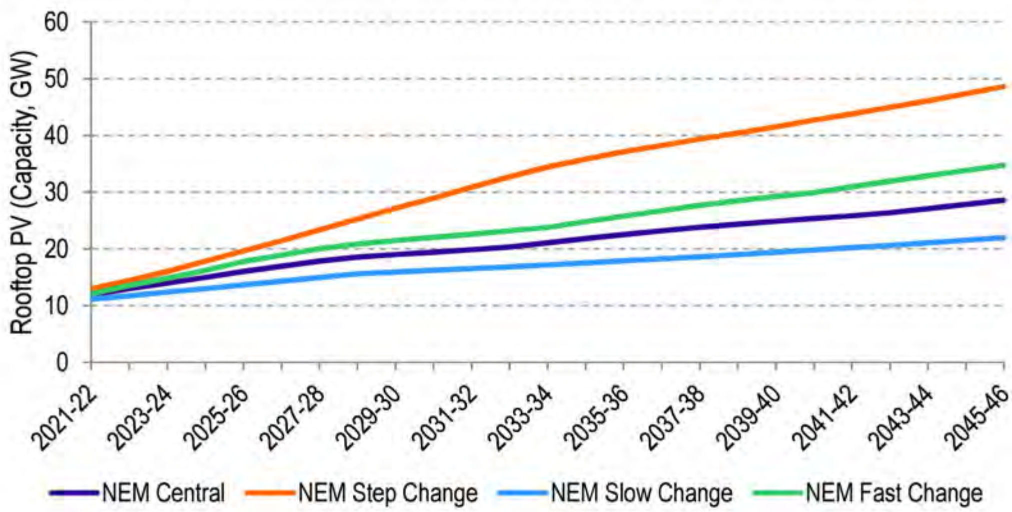
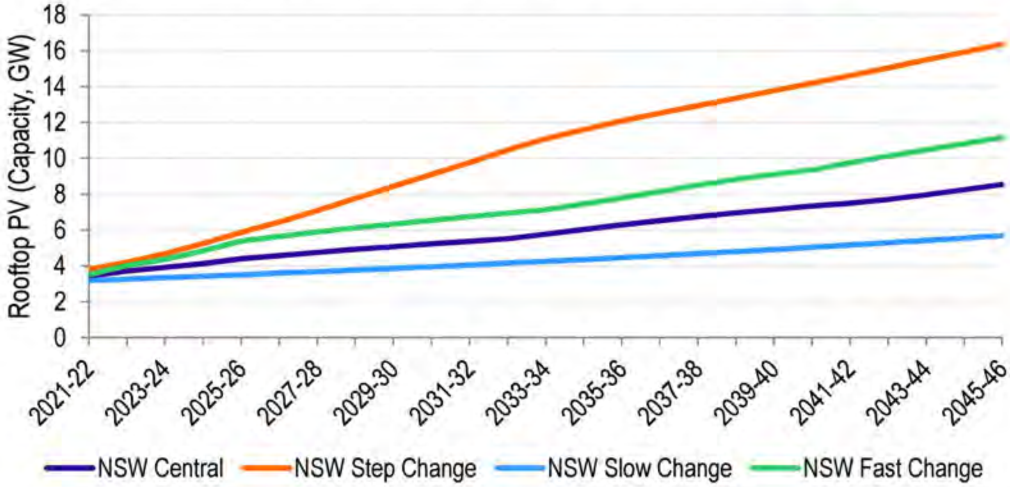


Figure 39: Annual rooftop PV uptake in NSW from AEMO's 2019 Input and Assumptions workbook



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.

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[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.

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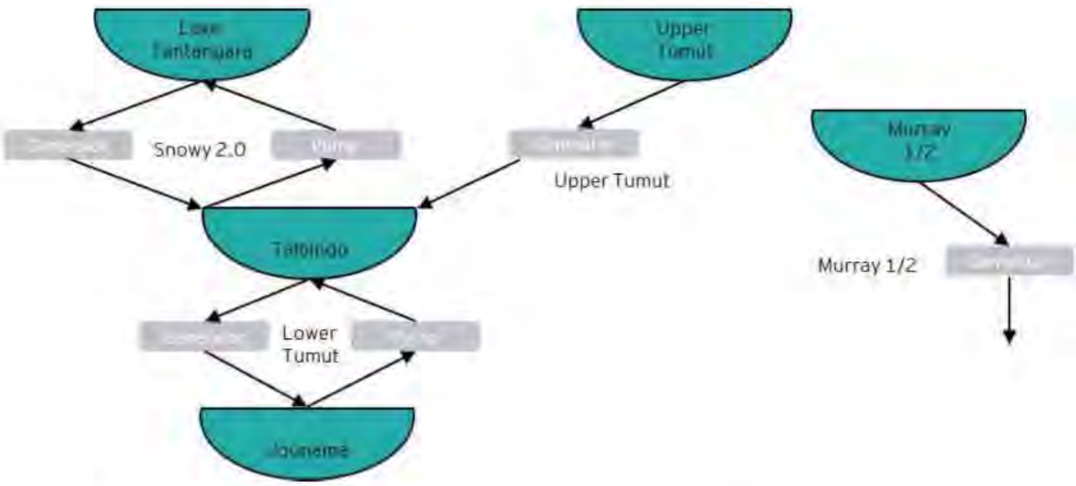
[66] AEMO, 30 July 2020, *2019 Input and Assumptions workbook v1.5*. Available at: https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 29 June 2021.

[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.

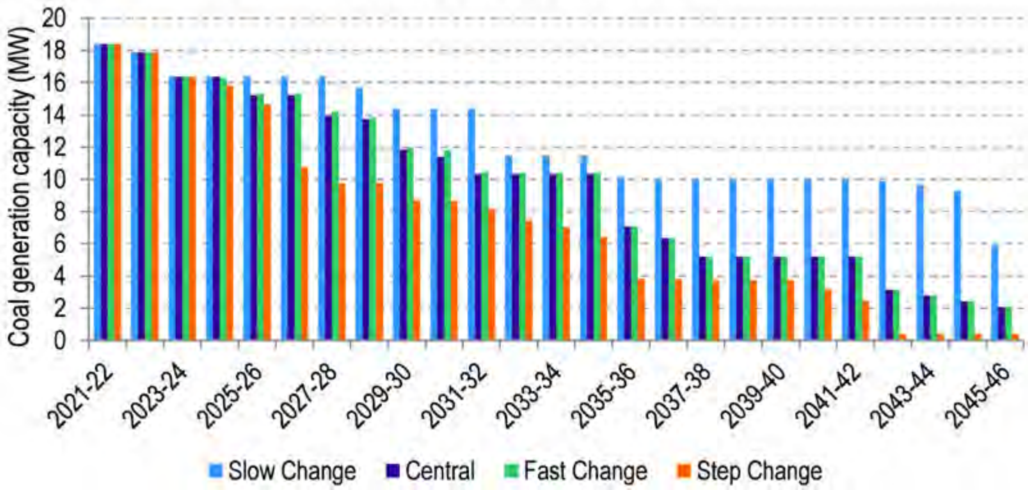
[70] AEMO, 30 July 2020, *2019 Input and Assumptions workbook v1.5*. Available at: https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 29 June 2021.

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

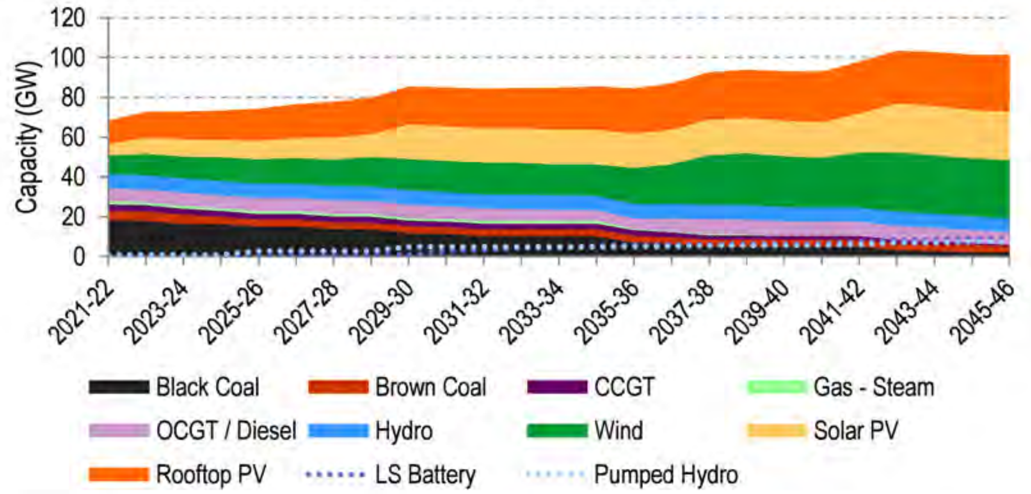
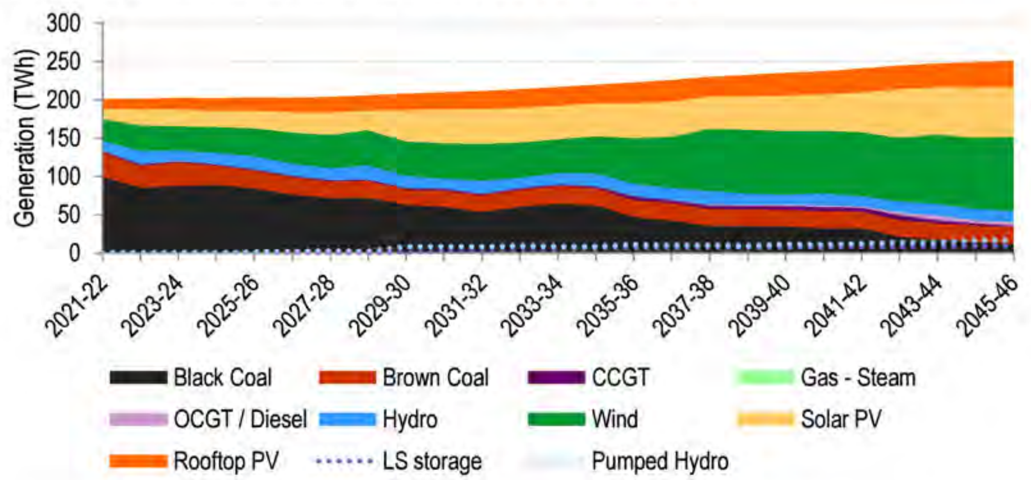


Figure 43: NEM generation mix forecast for the Central scenario in the Base case



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)

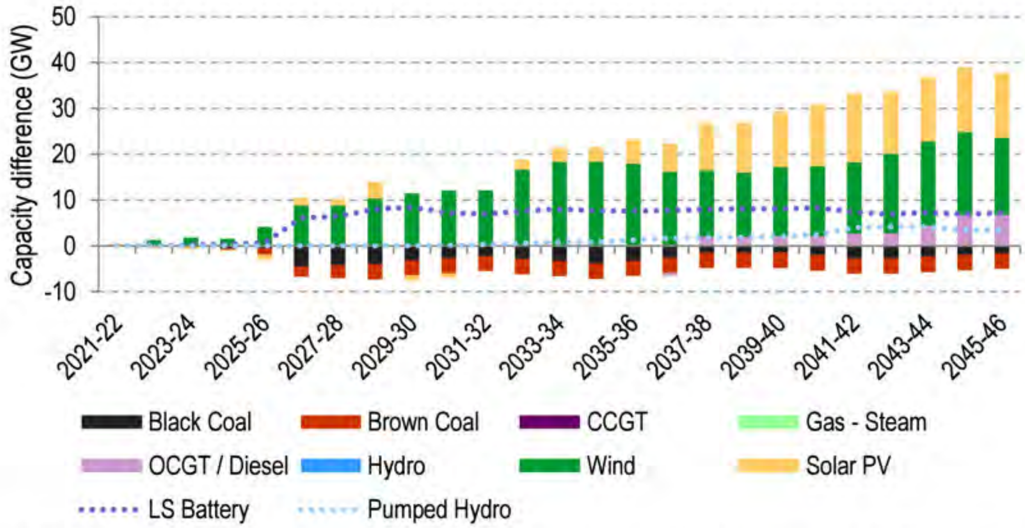


Figure 45: Difference in NEM generation forecast between the Step Change and Central scenarios in the Base case (excluding rooftop PV)

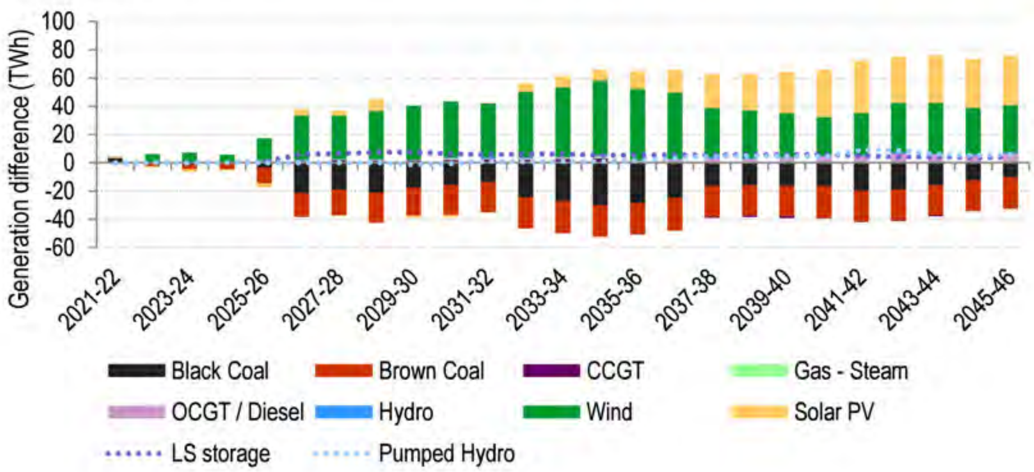


Figure 46: Difference in NEM capacity forecast between the Fast Change and Central scenarios in the Base case (excluding rooftop PV)

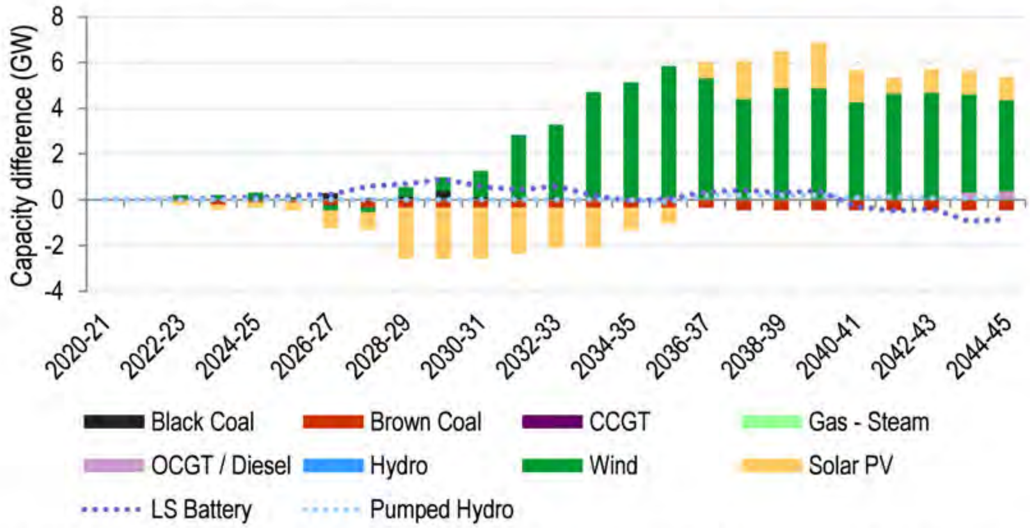


Figure 47: Difference in NEM generation forecast between the Fast Change and Central scenarios in the Base case (excluding rooftop PV)

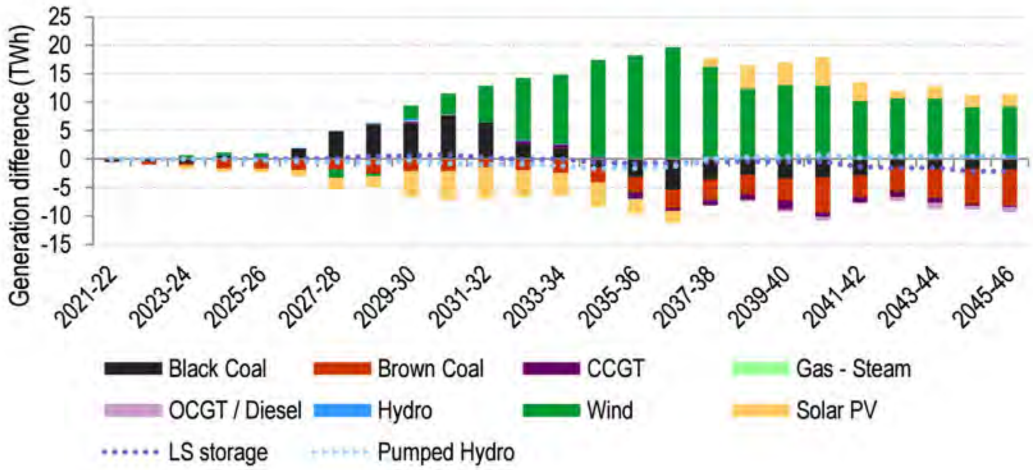


Figure 48: Difference in NEM capacity forecast between the Slow Change and Central scenarios in the Base case (excluding rooftop PV)

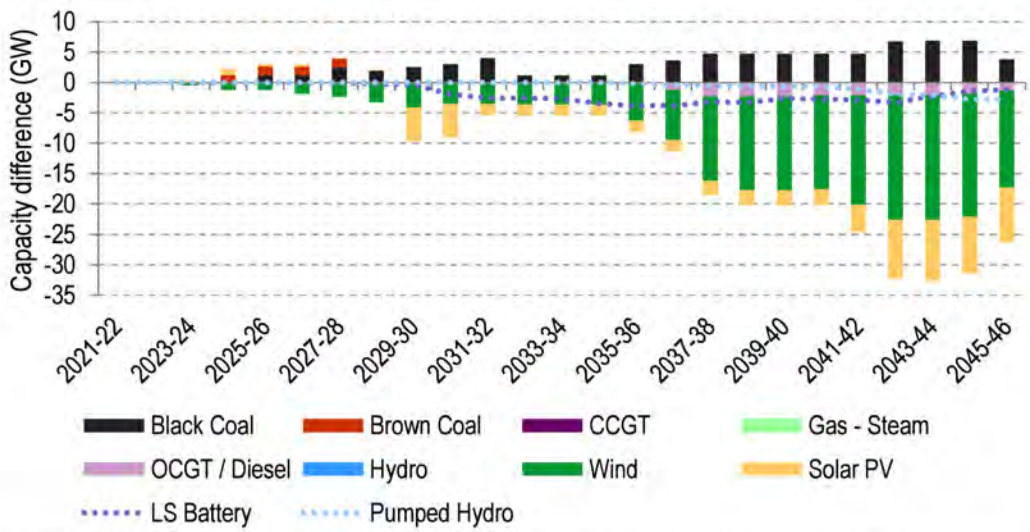
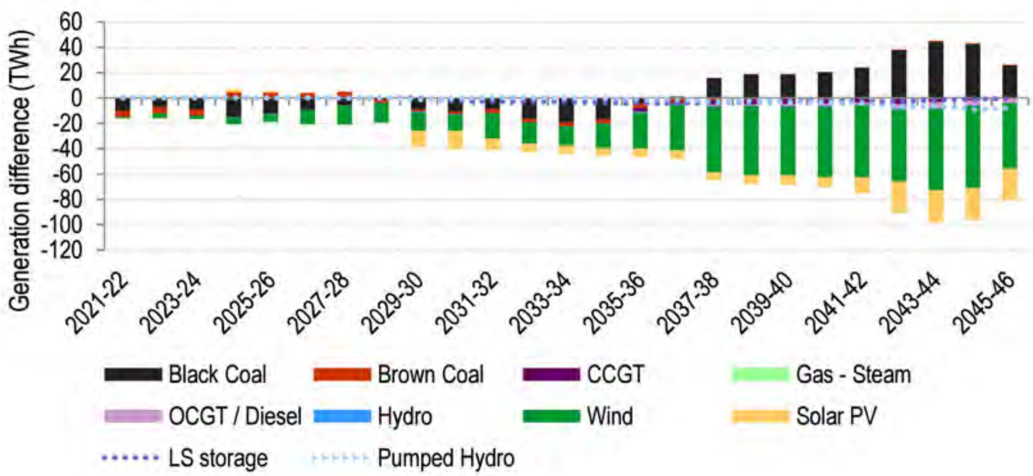


Figure 49: Difference in NEM generation forecast between the Slow Change and Central scenarios in the Base case (excluding rooftop PV)



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

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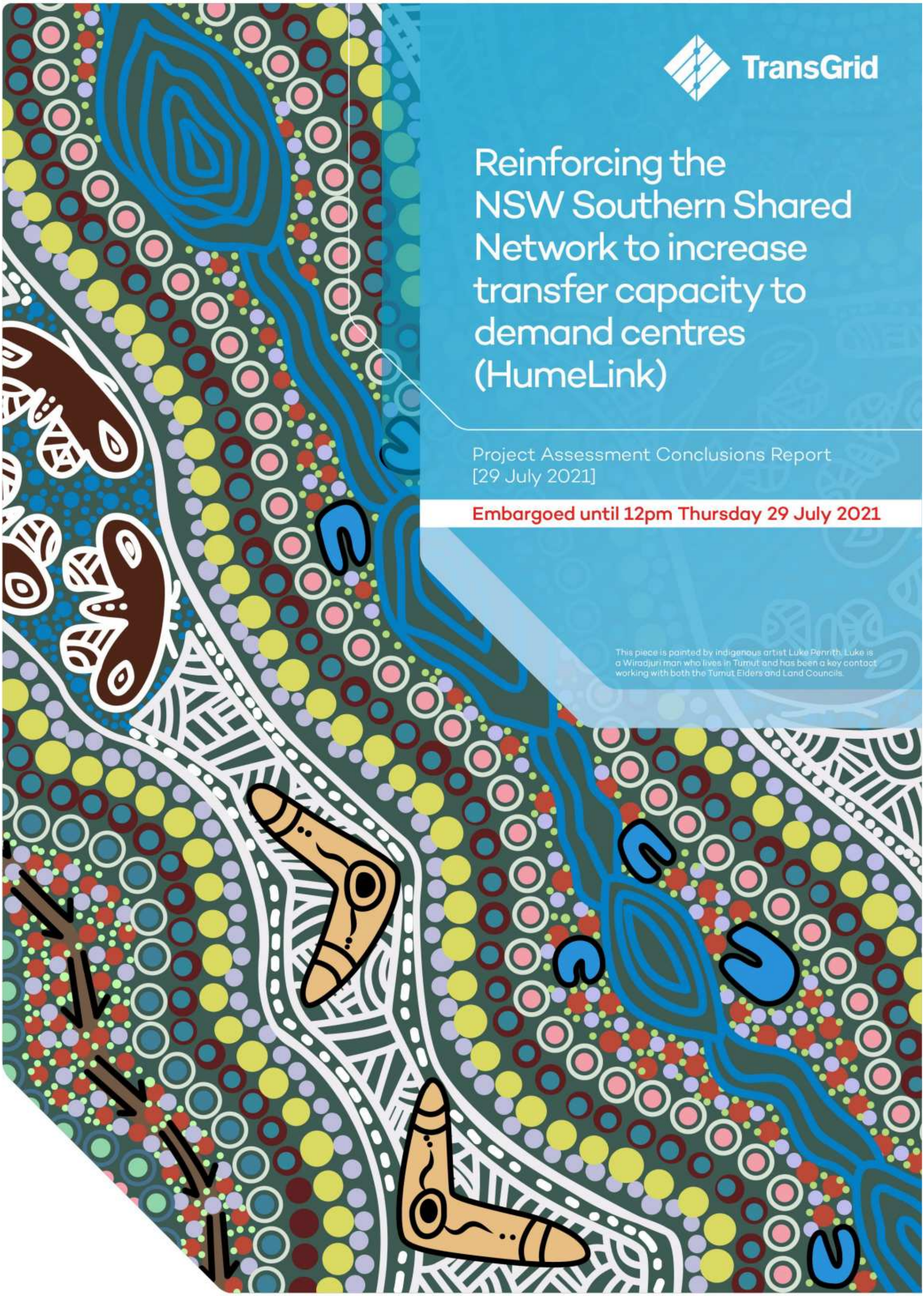


TransGrid

Reinforcing the NSW Southern Shared Network to increase transfer capacity to demand centres (HumeLink)

Project Assessment Conclusions Report
[29 July 2021]

Embargoed until 12pm Thursday 29 July 2021

This piece is painted by indigenous artist Luke Penrith. Luke is a Wiradjuri man who lives in Tumut and has been a key contact working with both the Tumut Elders and Land Councils.

Executive summary

Gugaa – the Wiradjuri totem is the Gugaa (goanna). Totems are animals that are significant to a family, region, community or individual person as a spirit guide that looks after them.

TransGrid has investigated options for reinforcing the New South Wales (NSW) Southern Shared Network to increase transfer capacity to the state's major load centres of Sydney, Newcastle and Wollongong.

The driver for reinforcing the Southern Shared Network is to deliver a net economic benefit to consumers and producers of electricity and support energy market transition through:

- increasing the transfer capacity between southern NSW and major load centres of Sydney, Newcastle and Wollongong;
- enabling greater access to lower cost generation to meet demand in these major load centres;
- facilitating the development of renewable generation in high quality renewable resource areas in southern NSW as well as the southern states, which will further lower the overall investment and dispatch costs in meeting NSW demand whilst also ensuring that emissions targets are met at the lowest overall cost to consumers; and
- increasing the competitiveness of bidding in the wholesale electricity market.

In January 2020, we released a Project Assessment Draft Report (PADR) as part of the Regulatory Investment Test for Transmission (RIT-T) to progress the assessment of investments that increase transfer capacity of the shared transmission network between southern New South Wales and the major load centres within the state. The PADR followed the Project Specification Consultation Report (PSCR) released in June 2019. This Project Assessment Conclusions Report (PACR) represents the final stage in the RIT-T consultative process.

OVERVIEW

This PACR finds that Option 3C, comprised of new 500 kV lines in an electrical 'loop' between Maragle, Wagga Wagga and Bannaby, provides the greatest net benefit of all options considered, across all four scenarios investigated.

Option 3C is therefore the preferred option identified under this RIT-T and is found to have approximately 23 per cent greater estimated net benefits than the second ranked option (Option 2C), on a weighted basis across the four scenarios investigated.

The analysis shows that the preferred option is expected to:

- deliver net benefits of approximately $491 million over the assessment period, in present value terms, which increases further if alternate scenario weightings are assumed, in-line with recent commentary by the Australian Energy Market Operator (AEMO) and the Energy Security Board (ESB);
- reduce the need for new dispatchable generation investment to meet demand going forward;
- avoid capital costs that would otherwise be required associated with enabling greater integration of renewables in the National Electricity Market (NEM);
- lower the aggregate generator fuel costs required to meet demand in the NEM going forward; and
- provide significant 'competition benefits' by increasing the efficiency of bidding in the wholesale market.

The preferred option identified over the course of this RIT-T is consistent with the network topology and operating capacity of HumeLink in the final AEMO 2020 Integrated System Plan (ISP).

All lines are to be constructed in a double-circuit configuration to minimise the overall costs to consumers. This reflects a change since the PADR and represents a refinement of the ISP candidate option, which reduces the investment cost. This has been enabled through undertaking a detailed assessment of the risks involved with adopting double-circuit lines for the specific options considered, compared to single-circuit, and how these can be mitigated to an acceptable level.

Executive summary (continued)

THIS RIT-T HAS EXAMINED REINFORCING THE SOUTHERN SHARED NETWORK TO INCREASE TRANSFER CAPACITY TO KEY DEMAND CENTRES IN NEW SOUTH WALES

TransGrid operates and maintains the transmission network in NSW. The shared transmission network between the Snowy Mountains and Bannaby carries power from all generation across southern NSW to the major load centres of Sydney, Newcastle and Wollongong. It also carries all electricity that is imported from Victoria to the major load centres in NSW. The main transmission lines in this area are heavily congested at times of high demand and will become more congested as new generation connects in southern NSW.

In NSW, where the existing coal-fired generators are retiring progressively from 2022, there is a pressing need for new sources of supply to meet the community's growing energy demand.

There are currently substantial new renewable generation developments anticipated in southern NSW, with projects in construction or under development currently totalling 1,900 MW. In addition, Snowy 2.0 will provide a new source of generation to meet future demand in the major load centres of NSW and to 'firm' supply from the new renewable generation.

However, reinforcement of the Southern Shared Network will be required to allow the transfer of energy to demand centres. Existing congestion at times of high demand limits access to the existing generation capacity of the Snowy Mountains Scheme at times of peak demand. Access to the additional 1,900 MW of new renewable generation and 2,000 MW capacity of Snowy 2.0 in southern NSW would be severely limited, without reinforcement to the Southern Shared Network.[1]

BENEFITS FROM REINFORCING THE SOUTHERN SHARED NETWORK COMPARED TO THE STATUS QUO

The RIT-T must demonstrate that there is an overall net market benefit to the NEM from increasing the transfer capacity of the transmission network – the Southern Shared Network between southern NSW and the major demand centres of Sydney, Newcastle and Wollongong.

The analysis in this PACR shows that the investments considered in this RIT-T are expected to:

- open up additional capacity for new generation (primarily renewable generation) in areas of southern NSW, which have recognised high-quality wind and solar resources;
- increase the transfer capacity between Victoria and NSW, which would provide NSW with access to additional generation from Victoria;
- allow the additional transfer capacity between South Australia and NSW provided by EnergyConnect and the additional transfer capacity between Victoria and NSW provided by the VNI Minor upgrade to flow to major demand centres; and
- increase the competitiveness of bidding in the wholesale market by relieving existing transmission constraints.

In the absence of investment under this RIT-T, alternative investment by market participants in peaking plant and other generation technologies in NSW would be required to continue to meet the State's demand, system stability and security requirements, as existing dispatchable generation in NSW retires.

Increasing access to generation capacity in southern NSW therefore has the potential to benefit the market and consumers through lowering the overall dispatch and investment costs required to meet demand from households and businesses in NSW, as well as to provide significant 'competition benefits' by increasing the competitiveness of bidding in the wholesale market.

KEY DEVELOPMENTS SINCE THE PADR WAS RELEASED HAVE BEEN REFLECTED IN THIS PACR

The PADR for this RIT-T was published in January 2020, along with an accompanying market modelling report. On 12 February 2020, we held a public forum on the PADR that was attended by representatives from 17 organisations.

Formal submissions from eight parties were received in response to the PADR, seven of which have been published on our website (one submitter requested confidentiality).[2] While submissions covered a range of topics, there were six broad topics that were most commented upon, namely:

- timing and scope of the options included in the assessment;
- assumptions used in the market modelling;
- modelling outcomes;
- cost of the options;
- the incidence of market benefits;
- diversity benefits from an electrical 'loop'; and
- use of double-circuit versus single-circuit.

In addition, prior to, as well as after, receiving submissions, we held bilateral meetings with interested parties in order to further discuss the RIT-T assessment. These have played a pivotal role in being able to define and undertake the assessment in this PACR.

We have taken all feedback raised in submissions and stakeholder feedback sessions into account in undertaking our PACR analysis and have reflected two key points raised by submitters directly in the wholesale market modelling undertaken (i.e., applying 'realistic bidding' and whether modular power flow control (MPFC) can be expected to increase the net market benefits expected from the preferred option).

There have been a number of other key developments since the release of the PADR in January 2020, including:

- Snowy 2.0 receiving environmental approval and construction approval from the Federal government in mid-2020;
- the final 2020 ISP being released by AEMO in July 2020, which concluded that HumeLink is a 'low regret' investment and represents an 'actionable ISP project';
- the NSW Government publishing its Electricity Infrastructure Roadmap in November 2020, which was legislated in December 2020, setting out a commitment to a number of minimum objectives in terms of developing Renewable Energy Zones (REZs) in NSW;
- the new actionable ISP framework being finalised under the National Electricity Rules (NER) and the Australian Energy Regulator (AER) finalising the new cost benefit analysis guideline to make the ISP actionable;
- the announcement of new gas plants in NSW, the early retirement of Yallourn power station in Victoria and the Victorian 'Big Battery';
- clarification from the AER over September and October 2020 regarding applying a multi-stage contingent project application (CPA) to HumeLink (in order to provide certainty regarding funding for deriving more accurate costings);
- the AER approving the EnergyConnect contingent project at the end of May 2021; and
- progression of ecological surveys and community and stakeholder engagement activities in parallel to the RIT-T process to inform the subsequent Environmental Impact Statement (EIS) for HumeLink.

1 New generators will connect to the transmission network at various locations. The connection works are funded by the respective generator and are outside the scope of this RIT-T, which examines reinforcing the shared network.

2 https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network

Executive summary (continued)

The assessment in this PACR reflects these developments. It also builds on the analysis in the PADR through:

- expanding the analysis in response to submissions on the PADR;
- focussing the RIT-T analysis on the seven options with the greatest expected net market benefits;
- refining the option cost estimates, including the estimation of the environmental offset costs required for each network topology;
- undertaking the studies required to inform a view on lightning and bushfire risks, and how they can be mitigated, for options involving double-circuit portions;
- updating the assessment to fully align with the assumptions and outcomes in the 2020 ISP and Inputs, Assumptions and Scenarios Report (IASR), as well as the 2020 Electricity Statement of Opportunities; and
- further investigating competition benefits and finding that they are material to the assessment.

SEVEN OPTIONS HAVE BEEN ASSESSED IN THIS PACR

Based on the net present value (NPV) assessment in the PADR, and further detailed screening of the options considered, the list of credible options has been refined since the PADR to ensure that the top-ranked options are able to be assessed at a greater level of detail as part of the PACR.

The analysis in the PACR focuses on seven options that are expected to have the greatest net market benefits overall. Specifically, this PACR assesses options across the following three different topologies:

1. Topology 1 – a 'direct' path between Maragle and Bannaby:
   - Option 1A, Option 1B and Option 1C from the PADR
2. Topology 2 – a path between Maragle and Bannaby via Wagga Wagga that would open up additional capacity for new renewable generation in southern NSW:
   - Option 2B and Option 2C from the PADR
3. Topology 3 – a wider footprint via Wagga Wagga, that would open up both direct and additional capacity for new renewable generation in southern NSW:
   - Option 3B and Option 3C from the PADR

The PACR does not assess the 'Topology 4' options from the PADR (involving new transmission lines in an electrical 'loop' between Maragle, Wagga Wagga and Bannaby and direct between Bannaby and Sydney). These options have significantly greater revised costs than the other options (in the order of $4.7 billion to $5 billion) and are not expected to provide commensurately greater market benefits than the other options.

The PACR also does not assess Option 2A or Option 3A from the PADR (the two 330 kV build and operate options of these network topologies) since they were found to have significantly lower benefits than the other options.

We have investigated different circuit configurations of the top performing network topologies and operating capacities in the PADR and PACR analysis (i.e., 'Option 2C' and 'Option 3C'). The outcome of this process is that Option 2C and Option 3C from the PADR are presented in the PACR as complete double-circuit options, which allows significant cost reductions relative to where they are constructed as either a single-circuit, or a combination of single- and double-circuit, configuration. Additional work undertaken since the PADR assessing the risks involved with double-circuit configuration, compared to single-circuit, and how these risks can be mitigated, has enabled these two options to be refined as part of this PACR.

WE HAVE UNDERTAKEN A POSITIONING ASSESSMENT TO INFORM THE ULTIMATE RIT-T ANALYSIS

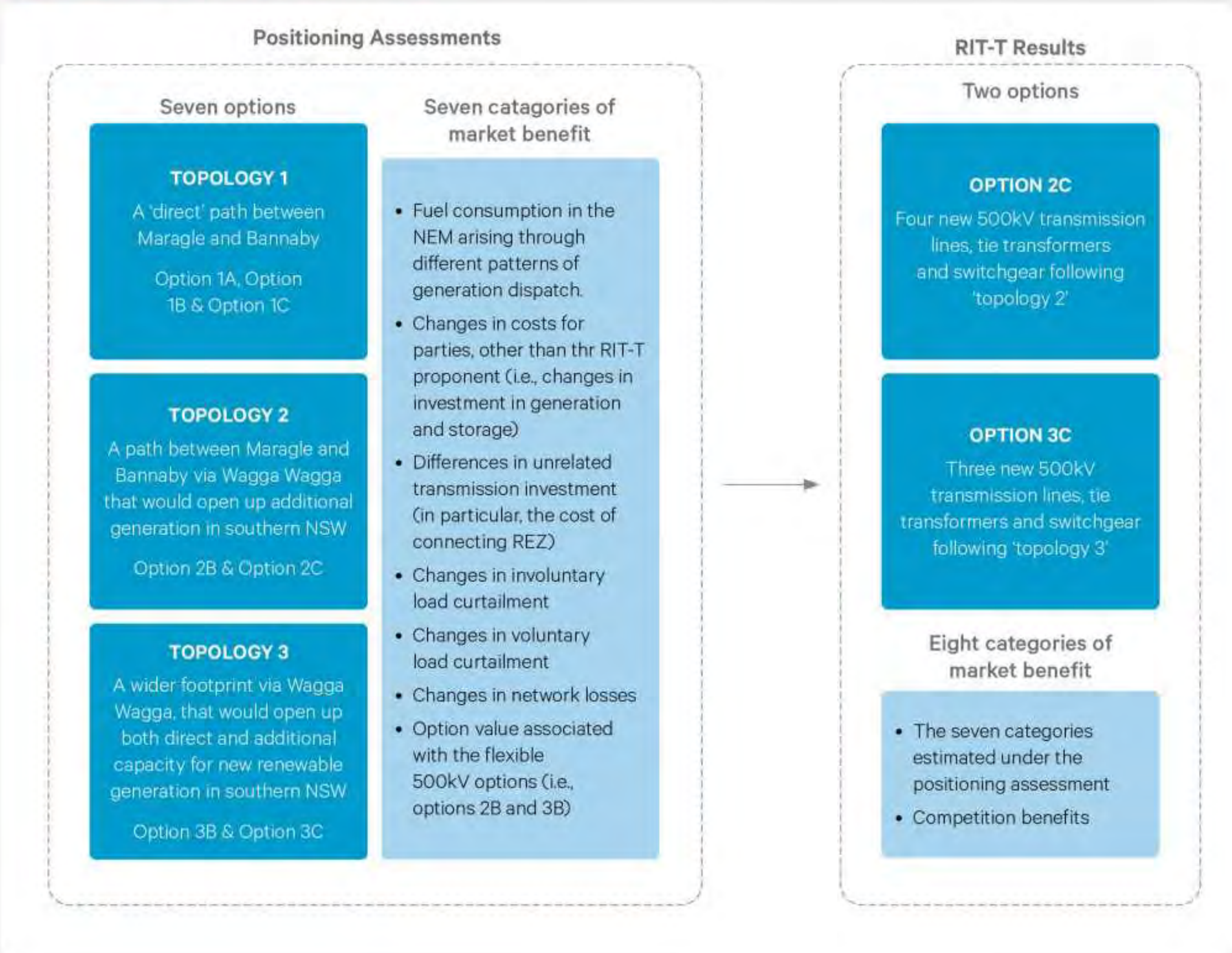
We have undertaken a positioning assessment in this PACR that assesses all seven credible options across each of the four scenarios included by AEMO in its 2020 ISP. This positioning analysis covers all market benefits with the exception of competition benefits, since the modelling required to estimate competition benefits is considerable for each option, whilst the outcome is not expected to be materially different across options. Competition benefits have then been estimated for the two top-ranked options coming out of the positioning assessment. We consider this to be a proportionate approach for this RIT-T.

Executive summary (continued)

Uncertainty is captured under the RIT-T framework through the use of scenarios, which reflect different assumptions about future market development, and other factors that are expected to affect the relative market benefits of the options being considered.

Four core scenarios have been considered as part of this PACR, which are intended to cover a wide range of possible futures and are aligned with the AEMO 2020 ISP 'central', 'slow-change', 'fast-change' and 'step-change' scenarios. The four scenarios differ in relation to key variables expected to affect the market benefits of the options considered, including demand outlook, Distributed Energy Resources (DER) uptake, assumed generator fuel prices, assumed emissions targets, retirement profiles for coal-fired power stations, timing of major transmission augmentations and generator and storage capital costs.

Figure E.1 – Structure to the PACR assessment

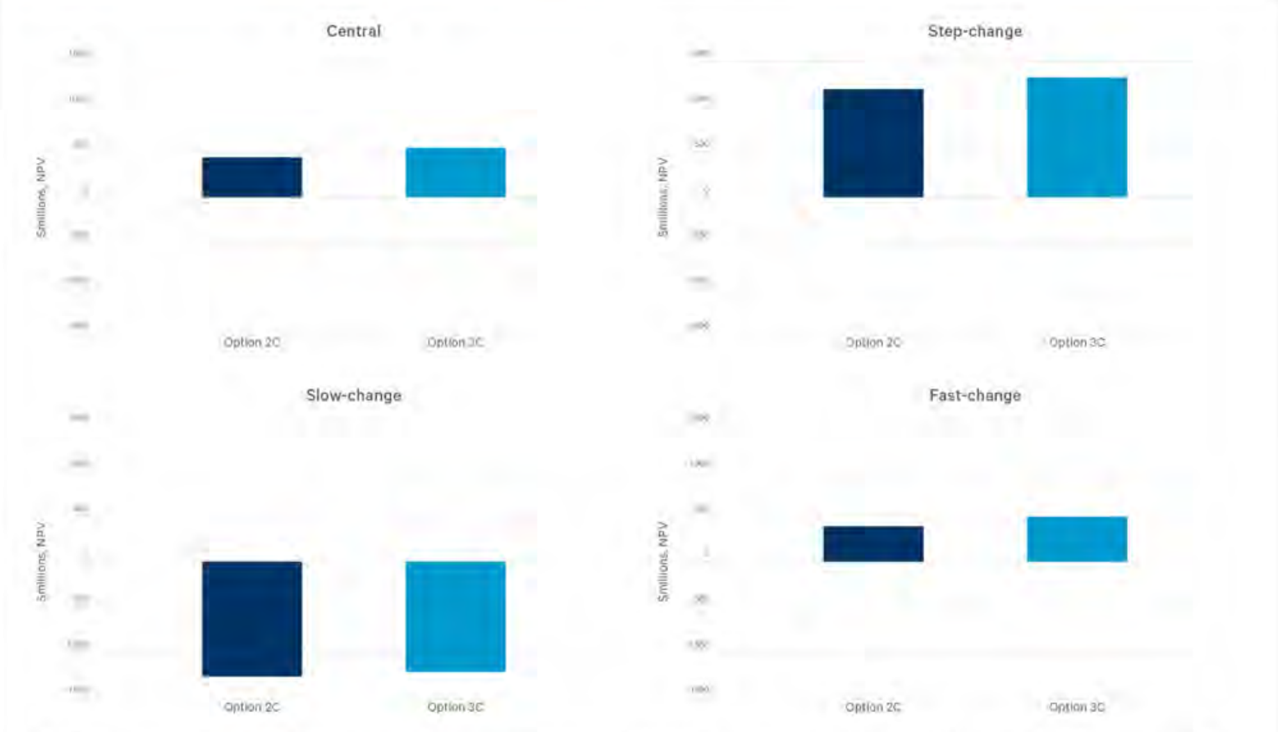


Executive summary (continued)

THE PREFERRED OPTION IS NEW 500 KV DOUBLE-CIRCUIT LINES IN AN ELECTRICAL 'LOOP' BETWEEN MARAGLE, WAGGA WAGGA AND BANNABY

The results of the PACR assessment find that Option 3C, comprised of new 500 kV double-circuit lines in an electrical 'loop' between Maragle, Wagga Wagga and Bannaby, provides the greatest net benefits across all scenarios. Option 3C is found to have positive net benefits under all scenarios investigated, except for the slow-change scenario.

Figure E.2 – Estimated net benefits for each scenario, $2020/21[3]



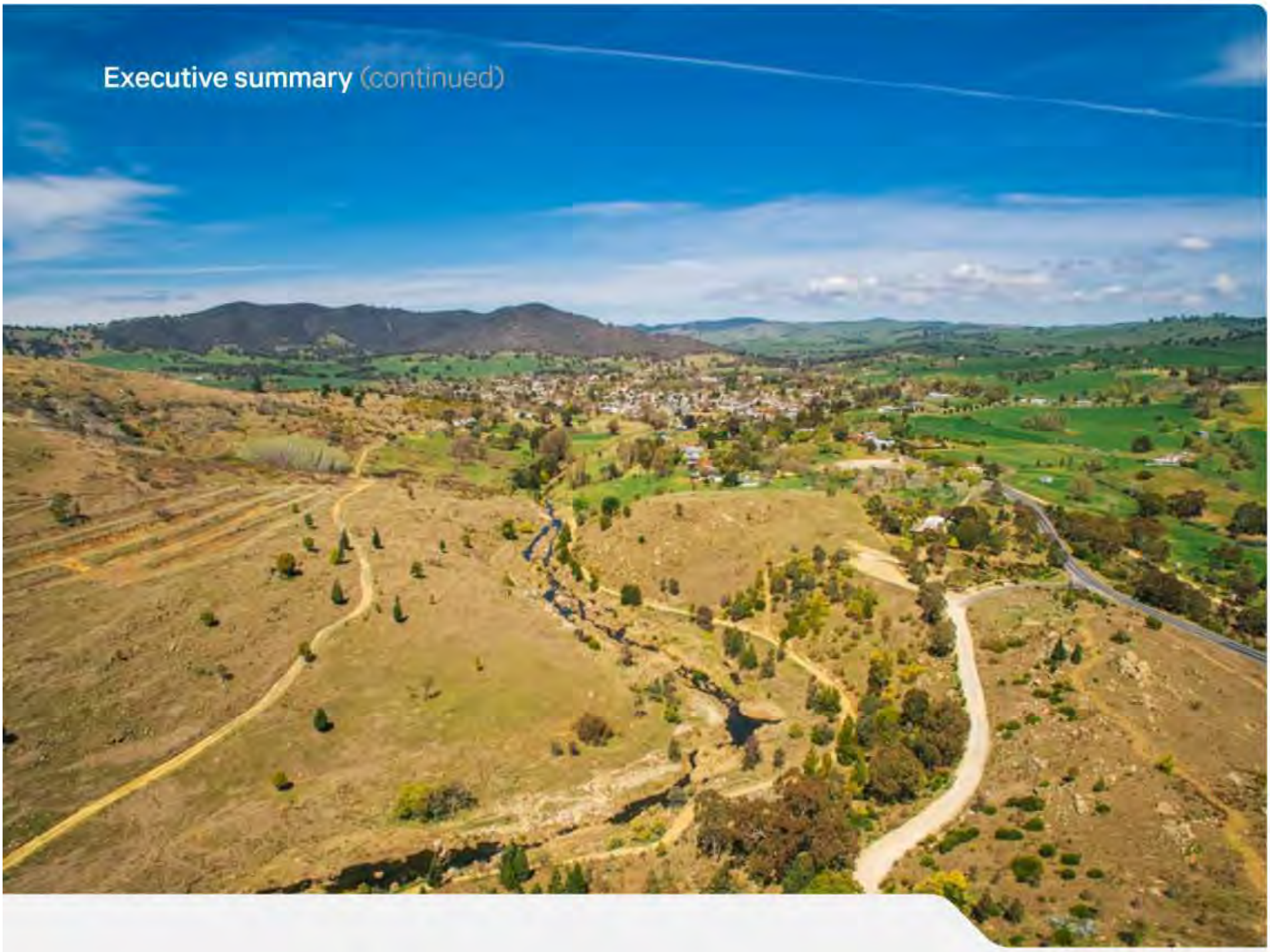
Note: The two options shown above reflect those with the greatest expected net benefits based on a positioning assessment undertaken across the full seven credible options. The net market benefits estimated for each of the other five options are presented in the body of this PACR.

While the slow-change scenario finds negative net benefits for both options, we note that this scenario is considered the least likely of the four scenarios and is given a 10 per cent weighting in the analysis, consistent with the recommended weighting in the 2020 ISP.[4] In addition, we note that recent commentary from the ESB suggests that the NEM is in fact tracking closest to the step-change currently.[5]

Under all scenarios, the benefits for Option 3C are primarily driven by avoided, or deferred, costs associated with generation and storage build. Avoided generator fuel costs, competition benefits and avoided transmission capital costs to connect new REZs make up the vast majority of other market benefits estimated, with their relativities varying across the scenarios.

On a weighted-basis, Option 3C is expected to deliver approximately $491 million of net benefits and is ranked first out of the options assessed (with estimated net benefits that are 23 per cent greater than the second-ranked option, Option 2C). Option 3C is therefore the preferred option overall under the RIT-T.

3. All dollars presented in this report are $2020/21, unless otherwise stated.
4. AEMO, *2020 Integrated System Plan*, July 2020, p. 86
5. See Renew Economy, "We are headed for step change:" ESB's Kerry Schott on new market design, Parkinson, G., 30 September 2020 (accessed via https://reneweconomy.com.au/we-are-headed-for-step-change-esbs-kerry-schott-on-new-market-design-89487/ on 7 July 2021), Argus Media, Australia tops step-change energy transition scenario, Morrison, K., 7 May 2021 (accessed via https://www.argusmedia.com/en/news/2212777-australia-tops-stepchange-energy-transition-scenario on 7 July 2021) & ESB, The Health of the National Electricity Market 2020, Volume 1: The ESB Health of the NEM Report, 5 January 2020, p. 8



Executive summary (continued)

FURTHER INFORMATION AND NEXT STEPS

This PACR represents the final stage in the RIT-T process.

Activities not related to the RIT-T but necessary to progress assessment of the project in order to achieve approval, are also being undertaken, including preparation of an Environmental Impact Statement (EIS) under the NSW planning approval pathway, managed by the Department of Planning, Industry and Environment (DPIE).

Following clarification from the AER over September and October 2020,[6] we are intending to submit two CPAs to the AER in relation to the regulatory cost recovery for the project, namely:

- 'Initial CPA' – will seek cost recovery for works to-date and the cost of the works necessary to develop a robust cost estimate for the project, based on the preferred option; and
- 'Final CPA' – will seek cost recovery for the implementation costs, including construction cost of the project, once a final estimate is available (this CPA will cover the bulk of the project cost).

In each case, AEMO's 'feedback loop' will be applied to the estimated costs of the entire project, in line with the new actionable ISP Rules. This will provide stakeholders with additional confirmation that the project remains consistent with AEMO's ISP 'optimal development path', at the costs included in the CPA. For the initial CPA we envisage that the cost estimate used for the feedback loop will reflect the cost of the option included in the RIT-T PACR. The feedback loop may then need to be applied again for the final CPA, based on the final cost estimate for the project.[7]

We note that the RIT-T does not address line route specifics for the preferred option[8] and, instead, these are scoped by the TNSP and assessed within the EIS. Planning approval would only be granted by the NSW Minister for Planning and Public Spaces following extensive, genuine community and stakeholder consultation and demonstration that environmental impacts can be effectively managed or mitigated. This process is currently underway and will continue following the conclusion of this RIT-T.

Further details in relation to this project can be obtained from regulatory.consultation@transgrid.com.au

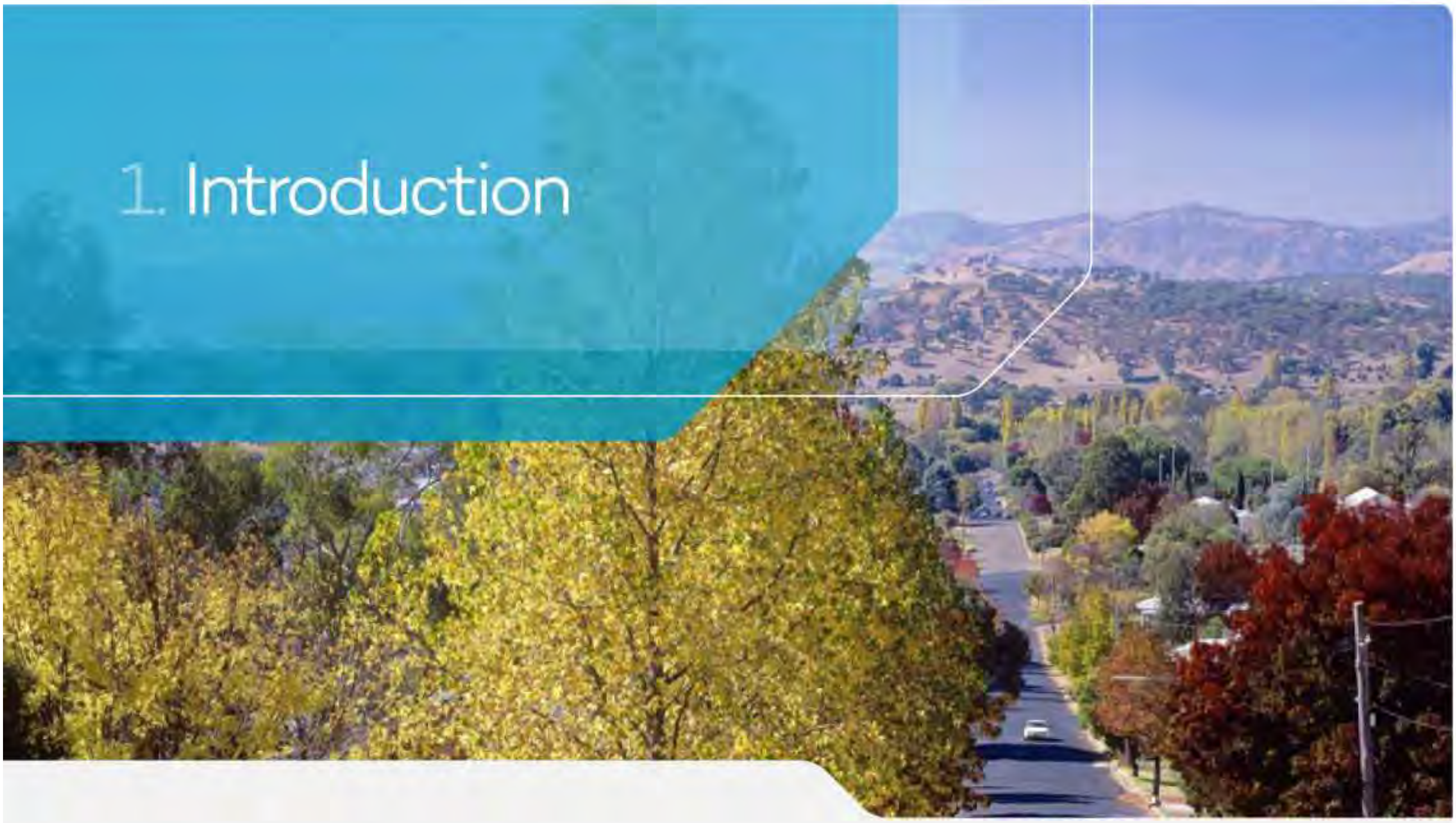
6. https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/transgrid-humelink-contingent-project/aer-position
7. TransGrid letter to AER - Humelink - Staging of the regulatory process, 14 September 2020, p. 2. AEMO would not apply the feedback loop at the final CPA stage if the total cost of the project remains at or below that used for the feedback loop for the initial CPA.
8. Instead, the RIT-T approval process reviews, and publicly consults on, a TNSP's application for new investment to meet an identified need. Overall, it identifies the technical solution to the need that provides the greatest net benefit to the NEM overall. This RIT-T process is undertaken in consultation with consumers, AEMO, Registered Participants and other interested parties regarding the investment options under consideration.

Contents

Contents (continued)

LIST OF TABLES

LIST OF FIGURES



1. Introduction

The National Electricity Market (NEM) is currently undergoing rapid change as the sector transitions to lower carbon emissions and greater uptake of new technologies. In NSW, coal-fired generators are expected to begin to close from 2022, with this capacity being replaced with new generation, including substantial new investment in renewable generation.

There are currently substantial new renewable generation developments anticipated in southern NSW, with projects in construction or under development currently totalling 1,900 MW. In addition, Snowy 2.0 will provide a new source of generation to meet future demand in the major load centres of NSW and to 'firm' supply from the new renewable generation.

In January 2020, we released a Project Assessment Draft Report (PADR) as part of the Regulatory Investment Test for Transmission (RIT-T) to progress the assessment of investments that increase transfer capacity of the shared transmission network between southern New South Wales and the major load centres within the state. The PADR followed the Project Specification Consultation Report (PSCR) released in June 2019.

The PADR drew on submissions to the PSCR and assessed twelve investment options, differing in topologies and operating capacity. The 500 kV options connected between Maragle, Wagga Wagga and Bannaby (i.e., Option 2C and Option 3C) were found to provide the greatest net benefits across all scenarios. Overall, the 500 kV electrical 'loop' reinforcement (Option 3C) was the preferred option due to the additional risk reduction benefits it provides through its more diverse path than for Option 2C.

There have been a number of key developments since the release of the PADR, including:

- Snowy 2.0 receiving environmental approval and construction approval from the Federal government in mid-2020;
- the final 2020 ISP being released by AEMO in July 2020, which concluded that HumeLink is a 'low regret' investment and represents an 'actionable ISP project';
- the NSW Government publishing its Electricity Infrastructure Roadmap in November 2020, which was legislated in December 2020, setting out a commitment to a number of minimum objectives in terms of developing Renewable Energy Zones (REZs) in NSW;
- the new actionable ISP framework being finalised under the NER and the AER finalising new cost benefit analysis guidelines to make the ISP actionable;
- the announcement of new gas plants in NSW, the early retirement of Yallourn power station in Victoria and the Victorian 'Big Battery';
- clarification from the AER over September and October 2020 regarding applying a multi-stage contingent project application (CPA) to HumeLink (in order to provide certainty regarding funding for deriving more accurate costings);
- the AER approving the EnergyConnect contingent project at the end of May 2021; and
- progression of ecological surveys and community and stakeholder engagement activities in parallel to the RIT-T process to inform the subsequent Environmental Impact Statement (EIS) for HumeLink.

The assessment in this PACR reflects these developments. It also builds on the analysis in the PADR through:

- expanding the analysis in response to submissions on the PADR;
- focussing the RIT-T analysis on the seven options with the greatest expected net market benefits;
- refining the option cost estimates, including the environmental offset costs required for each topology;
- undertaking the studies required to inform a view on lightning and bushfire risks, and how they can be mitigated, for options involving double-circuit portions;
- updating the assessment to fully align with the assumptions and outcomes in the 2020 ISP and IASR, as well as the 2020 ESOO; and
- further investigating competition benefits and finding that they are material to the assessment (consistent with previous commentary by Frontier Economics for these types of investments).

1. Introduction (continued)

This report presents the final findings of the RIT-T assessment, including confirming that new 500 kV lines in an electrical 'loop' between Maragle, Wagga Wagga and Bannaby is the preferred network topology and operating capacity. Specifically, the PACR analysis finds that Option 3C, where it is now assumed that all new lines are built as a double-circuit configuration, is expected to maximise overall net benefits. Our finding is consistent with the network topology and operating capacity of HumeLink in the final 2020 ISP.

All transmission lines for the preferred option are to be constructed in a double-circuit configuration to minimise the overall costs to consumers. This reflects a change since the PADR and represents a refinement of the ISP candidate option, which reduces the investment cost. This has been enabled through undertaking a detailed assessment of the risks involved with adopting double-circuit lines for the specific options considered, compared to single-circuit, and how these can be mitigated to an acceptable level.

The RIT-T approval process reviews, and publicly consults on, a TNSP's application for new investment to meet an identified need. Overall, it identifies the technical solution to the need that provides the greatest net benefit to the NEM overall. This RIT-T process has been undertaken in consultation with consumers, AEMO, Registered Participants and other interested parties regarding the investment options under consideration.

In the case of new transmission line investments, the RIT-T does not address line route specifics for the preferred option[9] and, instead, these are scoped by the TNSP and assessed within the EIS. Planning approval would only be granted by the NSW Minister for Planning and Public Spaces following extensive, genuine community and stakeholder consultation and demonstration that environmental impacts can be effectively managed or mitigated. This process is currently underway and will continue following the conclusion of this RIT-T.

1.1 ROLE OF THIS REPORT

This PACR is the final consultation document in the RIT-T process assessing options for reinforcing the Southern Shared Network of New South Wales to best serve load centres in New South Wales.

This report:

1. identifies and confirms the market benefits expected from reinforcing the Southern Shared Network of New South Wales, based on the most recent final assumptions and forecasts developed and consulted on by AEMO at the time of this assessment;
2. summarises points raised in submissions to the PADR and the accompanying consultation material, and highlights how these have been addressed in the RIT-T analysis;
3. describes the options that have been assessed under this RIT-T;
4. presents the results of the updated NPV analysis for each of the credible options assessed;
5. describes the key drivers of these results, and the assessment that has been undertaken to ensure the robustness of the conclusion; and
6. identifies the overall preferred option of the RIT-T, i.e., the option that is expected to maximise net benefits.

Overall, a key purpose of this PACR is to provide interested stakeholders the opportunity to review the analysis and assumptions and have certainty and confidence that the preferred option has been robustly identified as optimal.

We are also releasing supplementary reports on our website to complement this PACR. Detailed cost benefit results are included as a spreadsheet appendix accompanying this report.

1.2 FURTHER INFORMATION AND NEXT STEPS

This PACR represents the final stage in the RIT-T process.

Activities not related to the RIT-T but necessary to progress assessment of the project in order to achieve approval are also being undertaken, including the Environmental Impact Statement process. Following clarification from the AER over September and October 2020,[10] we are intending to submit two contingent project applications (CPAs) to the AER in relation to the regulatory cost recovery for the project, namely:

- 'Initial CPA' – will seek cost recovery for works to-date and the cost of the works necessary to develop a robust cost estimate for the project, based on the preferred option; and
- 'Final CPA' – will seek cost recovery for the implementation costs, including construction cost of the project, once a final estimate is available (this CPA will cover the bulk of the project cost).

In each case, AEMO's 'feedback loop' will be applied to the estimated costs of the entire project, in line with the new actionable ISP Rules. This will provide stakeholders with additional confirmation that the project remains consistent with AEMO's ISP 'optimal development path', at the costs included in the CPA. For the initial CPA we envisage that the cost estimate used for the feedback loop will reflect the cost of the option included in the RIT-T PACR. The feedback loop may then need to be applied again for the final CPA, based on the final cost estimate for the project.[11]

Going forward, we note that development of the project may be subject to delays including any objection processes. The cost of such delays is at this point indeterminate.

Further details in relation to this project can be obtained from regulatory.consultation@transgrid.com.au

9. Instead, the RIT-T approval process reviews, and publicly consults on, a TNSP's application for new investment to meet an identified need. Overall, it identifies the technical solution to the need that provides the greatest net benefit to the NEM overall. This RIT-T process is undertaken in consultation with consumers, AEMO, Registered Participants and other interested parties regarding the investment options under consideration.
10. https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/transgrid-humelink-contingent-project/aer-position
11. TransGrid letter to AER - Humelink - Staging of the regulatory process, 14 September 2020, p. 2. AEMO would not apply the feedback loop at the final CPA stage if the total cost of the project remains at or below that used for the feedback loop for the initial CPA.

2. Key developments since the PADR

SUMMARY OF KEY POINTS:

There have been a number of key developments external to the RIT-T since the release of the PADR, including:

- Snowy 2.0 receiving environmental approval and construction approval from the Federal government;
- the final 2020 ISP being released by AEMO in July 2020, which concluded that HumeLink is a 'low regret' investment and represents an 'actionable ISP project';
- the NSW Government publishing its Electricity Infrastructure Roadmap in November 2020, which was legislated in December 2020, setting out a commitment to a number of minimum objectives in terms of developing REZs in NSW;
- the new actionable ISP framework being finalised under the NER and the AER finalising the new cost benefit analysis guidelines to make the ISP actionable;
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- progression of ecological surveys and community and stakeholder engagement activities in parallel to the RIT-T process to inform the subsequent Environmental Impact Statement (EIS) for HumeLink.

The assessment in this PACR reflects these developments. It also builds on the analysis in the PADR through:

- expanding the analysis in response to submissions on the PADR;
- focussing the RIT-T analysis on seven options with the greatest expected net market benefits;
- refining the option cost estimates, including the environmental offset costs required for each topology;
- undertaking the studies required to inform a view on lightning and bushfire risks, and how they can be mitigated, for options involving double-circuit portions;
- updating the assessment to fully align with the assumptions and outcomes in the 2020 ISP and IASR, as well as the 2020 ESOO; and
- further investigating competition benefits and finding that they are material to the assessment (consistent with previous commentary by Frontier Economics for these types of investments).

There have also been a range of other processes and developments that have necessitated the approximate 18 months between the PADR and PACR, including the NSW bushfires and COVID-19 during 2020.

2.1 KEY DEVELOPMENTS EXTERNAL TO THE RIT-T SINCE THE RELEASE OF THE PADR

There have been a number of key developments outside of this specific RIT-T process since the PADR was released in January 2020.

HumeLink is a significant transmission investment, being undertaken at a time in which there is a major energy transition with many moving parts. It is appropriate for the final RIT-T cost benefit assessment to have waited for key elements of these changes to have been confirmed, in order for the conclusion to incorporate as many of these important factors as possible.

Each of the key developments external to the RIT-T process since the PADR was released is outlined below.

2.1.1 Snowy 2.0 receiving final environmental approval and construction approval

In June 2020, the Federal Government gave final environmental approval for Snowy 2.0's main works.[12]

In August 2020, the Federal Government approved Snowy 2.0's main works construction, allowing construction to commence on the underground power station, waterways and access tunnels, and other supporting infrastructure.[13]

This confirms Snowy 2.0 as a 'committed project' under the RIT-T. This is consistent with AEMO's final 2020 ISP, which refers to Snowy 2.0 as committed and includes it in all scenarios.[14]

12. https://www.snowyhydro.com.au/news/australian-govt-green-lights-snowy-2-0-main-works-3/
13. https://www.snowyhydro.com.au/news/australian-govt-green-lights-snowy-2-0-main-works-3-2/
14. AEMO, *Integrated System Plan*, July 2020, pp. 33 & 51.

2. Key developments since the PADR (continued)

2.1.2 The final 2020 ISP reconfirmed the conclusion of the PADR

The final 2020 ISP, released by AEMO in July 2020, built on the 2018 ISP analysis and concluded that new 500 kV lines between Maragle, Wagga Wagga and Bannaby are a 'low regret' investment and represent an 'actionable ISP project'. This transmission upgrade is consistent with Option 3C under the RIT-T.

AEMO assumed the upgrade would be completed by 2025-26 as part of the optimal development path for the central scenario, the fast-change scenario and the step-change scenario.[15] AEMO stated that, while HumeLink is not part of the least-cost development path under the slow-change scenario, it represents a 'low-regret' investment given the relatively low likelihood of this scenario (assigning this scenario 10 per cent weighting) and so included it in all candidate development paths.[16]

2.1.3 Legislation of the NSW Government's Electricity Infrastructure Roadmap

The NSW government published its Electricity Infrastructure Roadmap (the Roadmap) in November 2020.[17] The Roadmap outlines a vision that transitions the NSW electricity sector towards a low emission generation fleet underpinned by increased transmission investment.

In December 2020, the Electricity Infrastructure Investment Bill 2020 passed the NSW parliament and gave legal effect to the key features of the Roadmap. In particular, section 44 of the legislation formalises the infrastructure objectives of the Roadmap that generation infrastructure from renewable energy sources of at least 30 MW generates at least the same amount of electricity in a year as:

- 8 GW of generation capacity from the New England REZ;
- 3 GW of generation capacity from the Central-West Orana REZ; and
- 1 GW of additional generation capacity in NSW.

The generation capacities set out above are referred to as 'minimum objectives' in the legislation, meaning they are objectives that relate to the period ending 31 December 2029.

While the Roadmap was not included in the final 2020 ISP, we have reflected it in the market modelling for the PACR since it is now legislated (and note this approach is consistent with the draft 2021 IASR assumptions). Specifically, we have applied the following assumptions regarding the Roadmap:

- 8 GW of transmission capacity from the New England REZ;
- 3 GW of generation and transmission capacity from the Central-West Orana REZ;
- 1 GW additional generation capacity from other NSW REZs; and
- for all scenarios, except the slow change, the target is assumed to be met by 2030 (for the slow-change, the target is assumed to be met by 2032).

In addition, all scenarios assume 2 GW long duration storage in 2029-30 and that the NNS, NCEN and Canberra zones have an approximately equal share of storage capacity. More detail on how the Roadmap has been incorporated can be found in the accompanying market modelling report.

AEMO is proposing to model the Roadmap as a minimum constraint of 12 GW on the development of new variable renewable energy in NSW in addition to generation that is committed. AEMO are not proposing to model specific REZ targets under the Roadmap and only the Central-West Orana REZ is considered anticipated.[18]

2.1.4 Finalisation of the new actionable ISP framework and AER guidelines

In March 2020 the ESB put forward its final recommendations in relation to Rule changes to introduce the 'actionable ISP' framework. These Rule changes came into effect from 1 July 2020. In August 2020, the AER finalised its new guidelines under this framework, including its new Cost Benefit Analysis guidelines. These guidelines set out how the cost benefit assessment should be undertaken for actionable ISP projects like HumeLink, including as part of the RIT-T.

As part of the transitional provisions in the Cost Benefit Analysis guidelines, the AER has stated that the RIT-T assessment for HumeLink is to apply the 2018 AER RIT-T guidelines, as opposed to the new guidelines, since the PADR was published ahead of the new guidelines.[19] However, going forward, actionable ISP projects are required to apply the new guidelines.

While the 2018 AER RIT-T guidelines provide some flexibility in the assumptions and scenarios that can be used in the RIT-T assessment,[20] the new actionable ISP guidelines are more prescriptive in the assumptions and scenarios that should be used, stating that the default assumptions should be drawn from AEMO's most recent Input and Assumptions Report (IASR) since they have been identified and developed through a robust consultation process with stakeholders.[21]

The assessment in this PACR applies the final 2020 IASR assumptions and scenarios, as well as updated demand assumptions from the final 2020 ESOO. We consider this consistent with the 2018 guidelines and also how the RIT-T will be applied to other actionable ISP projects under the new framework going forward. We have also confirmed in discussions with AEMO that it considers that we should apply the 2020 ISP and IASR assumptions.

We recognise that AEMO is close to completing its process of updating the assumptions in the IASR, which is expected to result in an updated set of assumptions (the 2021 IASR) to be used in the 2022 ISP. Consultation on these updated assumptions is currently on-going, with the final 2021 IASR expected to be published later in July this year. Notwithstanding that the 2020 ISP and IASR assumptions remain the latest final assumptions at the time of this RIT-T assessment, we have also undertaken a sensitivity using the draft 2021 IASR assumptions, to investigate the impact of changes in assumptions on the outcome of this RIT-T. This sensitivity finds that the draft 2021 IASR assumptions significantly increase the expected net benefits of the preferred option under the central scenario (see section 8.4.7).

15. AEMO, *Integrated System Plan*, July 2020, pp. 14 & 61-62.
16. AEMO, *Integrated System Plan*, July 2020, pp. 64 & 86.
17. Energy New South Wales, Electricity Infrastructure Roadmap, at https://energy.nsw.gov.au/government-and-regulation/electricity-infrastructure-roadmap.
18. AEMO, *Draft 2021 Inputs, Assumptions and Scenarios Report*, December 2020, pp. 44-45.
19. AER, *Guidelines to make the Integrated System Plan actionable*, Final Decision, August 2020, p. 19.
20. Specifically, the 2018 guidelines state that "RIT-T proponents should consider external documents, such as the most up-to-date material published by AEMO in developing the NTNDP, ISP, or similar documents when developing assumptions and inputs to use in a RIT-T analysis. It may be more appropriate to use alternative sources of information where there is evidence and good reason to demonstrate that this information is more up-to-date or is more appropriate to the particular circumstances under consideration. For clarity, it would be reasonable to only depart from default assumptions in limited cases, such as if there has been a material change in circumstances such that data in the most up-to-date ISP has been superseded or changed." [Emphasis added]. See: AER, Regulatory investment test for transmission, Application Guidelines, December 2018, p. 25.
21. AER, *Guidelines to make the Integrated System Plan actionable*, August 2020, p. 58 & AER, *Guidelines to make the Integrated System Plan actionable*, Final Decision, August 2020, p. 56.

2. Key developments since the PADR (continued)

2.1.5 The announcement of new gas plants in NSW, the early retirement of Yallourn power station and the Victorian 'Big Battery'

In early May 2021, there were two announcements regarding Federal Government funding for new gas-fired generators in NSW. Namely:

- on 3 May 2021, EnergyAustralia announced it would build the 316 MW Tallawarra B gas-hydrogen plant with $83 million in Government support;[22] and
- on 18 May 2021, the Federal Government announced it will spend up to $600 million to build a new 660 MW gas plant at Kurri Kurri in NSW.[23]

We have considered the impact that these two developments have on the expected net benefits of the credible options in section 8.4.1, as one of the sensitivity tests conducted on the RIT-T outcome.

In November 2020, the Victorian Government announced its commitment to a 300 MW/450 MWh battery in Victoria (the Victorian 'Big Battery').[24]

In March 2021, EnergyAustralia announced that the Yallourn power station in Victoria's Latrobe Valley will retire in mid-2028.[25] The wholesale market modelling undertaken for this PACR applies economic retirement to all coal-fired generators (as outlined in section 6.1) and assumes that the retirement of Yallourn power station will occur no later than 1 July 2028.

2.1.6 Clarification from the AER regarding the CPA process for Humelink

We engaged with the AER over September and October 2020 following the ISP rule change introducing automatic CPA provisions in order to clarify the CPA process for Humelink. This concluded with the AER confirming that we can apply a multi-stage CPA to HumeLink in order to provide certainty regarding funding for deriving more accurate costings.[26]

2.1.7 The AER approving EnergyConnect

At the end of May 2021, the AER approved the costs for EnergyConnect. This represented the AER's final regulatory approval for the new South Australia to New South Wales interconnector to be built by ElectraNet and TransGrid. The AER's decision approved the final and efficient costs for EnergyConnect following contingent project applications from ElectraNet and TransGrid.[27]

2.1.8 Progression of the Environmental Impact Statement for HumeLink

We have been progressing studies for the EIS in parallel with the RIT-T process in order to meet the overall optimal project timeframes set-out in the ISP. Ecological surveys, desktop environmental investigations and community and stakeholder engagement activities undertaken since the PADR will inform the development of the EIS.

The NSW planning approval process, under the *Environmental Planning and Assessment Act 1979*, will formally commence with the lodgement of the Scoping Report to the NSW Department of Planning, Industry and Environment (DPIE). The Scoping Report will be published on the DPIE website and will be publicly accessible.

A parallel process with the Federal government will be undertaken to determine whether the project is a Controlled Action under the *Environment Protection and Biodiversity Conservation Act 1999*.

22. https://www.nsw.gov.au/media-releases/australias-first-green-hydrogen-and-gas-power-plant
23. https://www.minister.industry.gov.au/ministers/taylor/media-releases/protecting-families-and-businesses-higher-energy-prices
24. https://www.energy.vic.gov.au/renewable-energy/the-victorian-big-battery/the-victorian-big-battery-q-and-a
25. https://www.energyaustralia.com.au/about-us/media/news/energyaustralia-powers-ahead-energy-transition
26. https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/transgrid-humelink-contingent-project
27. https://www.aer.gov.au/news-release/aer-approves-costs-for-project-energyconnect

2. Key developments since the PADR (continued)

2.2 HOW THE PACR ANALYSIS HAS BEEN UPDATED SINCE THE PADR

In addition to the key developments outlined above, we have also updated the analysis in response to points raised in submissions to the PADR and made a number of general refinements in line with this stage of the RIT-T process. Each of these updates are outlined below.

2.2.1 The analysis has been expanded in response to submissions on the PADR

The market modelling undertaken for this PACR explicitly covers points raised in submissions. In particular, and as summarised in more detail in section 4 below, submitters raised the following points in response to the PADR:

- that realistic bidding should be assumed in the modelling (as opposed to SRMC bidding); and
- whether a modular power flow control (MPFC) can add to the expected net benefits of the preferred option.

We have adopted realistic bidding as part of estimating the competition benefits for the top-ranked options (as outlined in section 7.3). We have also explicitly investigated a sensitivity in response to the second point (see section 8.4.3).

2.2.2 The analysis in this PACR focuses on the top-ranked options

The PADR assessed twelve different network options to provide additional transfer capacity on the NSW Southern Shared Network between the Snowy Mountains and the major load centres.

Based on the NPV assessment in the PADR and further detailed screening of the options considered, the list of credible options has been refined to ensure that the top-ranked options are able to be assessed at a greater level of detail as part of the PACR.

The analysis now focuses on seven options that are expected to have the greatest net market benefits overall. Specifically, this PACR assesses the options across the following three different topologies:

1. Topology 1 – a 'direct' path between Maragle and Bannaby:
   Option 1A, Option 1B and Option 1C from the PADR
2. Topology 2 – a path between Maragle and Bannaby via Wagga Wagga that would open up additional capacity for new renewable generation in southern NSW:
   Option 2B and Option 2C from the PADR
3. Topology 3 – a wider footprint via Wagga Wagga, that would open up both direct and additional capacity for new renewable generation in southern NSW:
   Option 3B and Option 3C from the PADR

The PACR does not assess the 'Topology 4' options from the PADR (involving new transmission lines in an electrical 'loop' between Maragle, Wagga Wagga and Bannaby and direct between Bannaby and Sydney). These options have significantly greater revised costs than the other options (in the order of $4.7 billion to $5 billion) and are not expected to provide commensurately greater market benefits than their counterparts following the three topologies outlined above at this point in time. Any assessment of increasing the transmission capacity between Bannaby and Sydney may form part of a future RIT-T.

The PACR also does not assess Option 2A or Option 3A from the PADR (the two 330 kV build and operate options of these network topologies) since they were found to have significantly lower benefits than the other options and, in particular, Option 3C in the PADR assessment. Specifically, these options were found to have net benefits that were 38 and 36 per cent lower than Option 3C respectively on a weighted basis in the PADR.

Overall, the options considered in this PACR differ in terms of their topology, circuitry and whether they are built at 330 kV or 500 kV (including whether they are built to 500 kV from the outset or provide optionality through being able to initially be operated at 330 kV and then upgraded to operate at 500 kV once conditions require the additional capacity).

2.2.3 Option costs have been refined

The capital cost of all credible options has been estimated to a greater degree of accuracy than presented in the PADR. Specifically, all credible options have been through a detailed cost estimation based on:

- concept designs for both transmission lines and substations;
- desktop geotechnical assessments;
- biodiversity offset assessments;
- updating market construction rates based on recent transmission projects;
- site testing and inspections requirements; and
- property desktop evaluation reports.

In addition, we have refined the assumption regarding annual operating costs based on more detailed cost assessment. We now assume this to be 0.5 per cent of each option's capital costs each year (excluding capital costs relating to biodiversity costs, since these are one-off and do not require ongoing operating costs).

2. Key developments since the PADR (continued)

2.2.4 Investigation of double-circuit options

We have investigated different circuit configurations of the top performing network topologies and operating capacities in the PADR and PACR analysis (i.e., 'Option 2C' and 'Option 3C'). The outworking of this process is that Option 2C and Option 3C from the PADR are presented in the PACR as complete double-circuit options, which allows significant cost reductions relative to where they are constructed as either a single-circuit, or a combination of single- and double-circuit, configuration.

In addition, while the other options are primarily single-circuit, they all now involve a 132 km double-circuit component west of Bannaby, an area where we consider bushfire risk is a more manageable risk, in order to reduce costs. We have not investigated complete double-circuit versions of these options, as we have for Option 2C and Option 3C, as any cost reductions are not expected to result in these options becoming top ranked options given their significantly lower net benefits than for Option 2C and Option 3C.

Additional work undertaken since the PADR assessing the lightning and bushfire risks involved with double-circuit, compared to single-circuit, and how these risks can be mitigated has enabled Option 2C and Option 3C to be refined as part of this PACR (which is outlined in section 4.7 and Appendix B.1.2).

2.2.5 Modelling assumptions have been updated to align with the final 2020 IASR, the 2020 ISP optimal development path and the ESOO published by AEMO

The modelling undertaken in this PACR aligns with the final assumptions and scenarios used by AEMO in the 2020 ISP (i.e., those in the final 2020 IASR) and updates demand for the final 2020 ESOO, both of which were published by AEMO in August 2020. This ensures the latest final set of consulted on assumptions and scenarios from AEMO at the time of preparing this PACR are taken into account and is consistent with the new actionable ISP framework (as discussed above).

The assessment also now models the retirement dates of coal-fired generators based on when it is economic for these plants to retire, as opposed to the broad range of dates applied in the PADR. The approach taken is consistent with what AEMO applied in the 2020 ISP and is covered in more detail as part of the accompanying market modelling report.

While the PADR reflected the majority of the final 2020 ISP assumptions, some were not available from AEMO when the PADR market modelling was undertaken and so were not able to be captured in the analysis at the time.

The assessment in this PACR now reflects all of the final 2020 IASR assumptions. The base case for the assessment also incorporates all of the other transmission investments included in the 2020 ISP's optimal development path.

The two key exceptions relate to key developments that have occurred since the 2020 ISP and are considered committed for the analysis, i.e.:

- the NSW Government publishing its Electricity Infrastructure Roadmap in November 2020, which was legislated in December 2020, setting out a commitment to a number of minimum objectives in terms of developing REZs in NSW (see section and the accompanying market modelling report for how the Roadmap has been reflected in the PACR analysis); and
- the Victorian 'Big Battery' announced by the Victorian Government in November 2020:
  - the 300 MW/450 MWh battery has been assumed in all base cases and option cases in the market modelling for this PACR. We note that, during the summer months, 250 MW of the battery will be reserved to provide the System Integrity Protection Scheme (SIPS) service and the remaining 50 MW can be deployed in the market by the operator on a commercial basis.[28]

In addition, we have assumed an earlier commissioning date for VNI West under the central scenario than in the core 2020 ISP assumptions, consistent with AEMO's accelerated delivery date in the 2020 ISP (and the draft 2021 IASR timing). Specifically, we have assumed a timing of 2028/29 for VNI West under the central scenario.[29] We have also investigated a sensitivity assuming the core ISP timing of 2035/36 (see section 8.4.2).

The analysis in this PACR also applies an assumed timing for the preferred option of 2026/27. The assumed timing has been updated since the 2020 ISP (and PADR) to reflect our current best estimate of how long we expect the project will take to commission.

2.2.6 Further investigation of competition benefits

While the PADR concluded that we did not expect competition benefits to be material in terms of identifying the preferred option for this RIT-T, additional testing of expected competition benefits undertaken following the PADR has shown that they are in fact expected to constitute a substantial benefit category for this RIT-T. Failure to adequately consider competition benefits would therefore substantially underestimate the potential market benefits associated with HumeLink, and therefore the net market benefit.

As a consequence, we have now estimated competition benefits in this RIT-T. This is consistent with the AER's latest cost benefit analysis guidelines and is outlined in more detail in section 7.1.8 below.

28. https://www.energy.vic.gov.au/renewable-energy/the-victorian-big-battery/the-victorian-big-battery-q-and-a
29. While AEMO has an accelerated delivery date of 2027/28 for VNI West in the 2020 ISP (and draft 2021 IASR), we have assumed a commissioning of 1 July 2028 as this is our current view of the earliest practical delivery date.

3. Benefits from HumeLink

***Scar tree survey** – Scarred trees tell us where Aboriginal people used to live, what they may have used the tree for and also provide Aboriginal people today with a link to their culture and past*

SUMMARY OF KEY POINTS:

- The investment considered under this RIT-T will allow future New South Wales demand and NEM emissions targets to be met at the lowest cost.
- The driver for the credible options considered in this PACR is to deliver a net economic benefit to consumers and producers of electricity and support energy market transition through:
  - increasing the transfer capacity between the Snowy Mountains and major load centres of Sydney, Newcastle and Wollongong;
  - enabling greater access to lower cost generation to meet demand in these major load centres; and
  - facilitating the development of renewable generation in high quality renewable resource areas in southern NSW as well as southern states, which will further lower the overall investment and dispatch costs in meeting NSW demand whilst also ensuring that emissions targets are met at the lowest overall cost to consumers.
- These sources of market benefit were included as the identified need for Humelink in the 2020 ISP.
- This PACR also finds that there are significant benefits expected from the preferred option through increasing the competitiveness of bidding in the wholesale market (referred to as 'competition benefits' under the RIT-T).
- This is a 'market benefit' RIT-T (as opposed to a 'reliability corrective action' RIT-T).
- While this section provides a high-level overview of the key benefits expected from Humelink, section 7.1 covers each of the eight specific categories of market benefit under the RIT-T that have been estimated.

The planned expansion of generation in southern New South Wales provides sources of generation that can be used to meet demand in the major load centres as existing New South Wales coal-fired generation retires. However, access to existing capacity from southern New South Wales is currently limited by constraints on the transmission network between the Snowy Mountains and Sydney, Newcastle and Wollongong at times of peak demand. Access to additional generation capacity would be similarly limited under the existing network configuration.

Investment to increase the transfer capacity between southern New South Wales and these major load centres will both relieve constraints that currently limit the use of existing generation capacity to supply these load centres and enable greater access to new generation as it develops.

In addition, the dispatchable generation that can be provided via the expanded storage capacity at Snowy Hydro can be used to 'firm' renewable generation and is expected to support the development of additional

3. Benefits from HumeLink (continued)

renewable generation in NSW, SA and VIC, as the NEM transitions to low-emission generation technologies.

Depending on the topology adopted, the investments being considered in this RIT-T also have the potential to:

- open up additional capacity for new generation (primarily renewable generation) in areas of southern NSW, which has recognised high-quality wind and solar resources;
- increase the transfer capacity between Victoria and NSW, which would provide NSW with access to additional generation in Victoria; and
- support additional transfer capacity between South Australia and NSW which will be provided by EnergyConnect (which is planned to terminate at Wagga Wagga), to also flow to Sydney.

Opening up additional capacity in areas of the NEM for renewable generation investment will also facilitate geographical diversity in renewable generation and lead to less variability in output as a result of local weather effects.

Within the context of the RIT-T assessment, greater output from renewable generation can be expected to primarily deliver the following classes of market benefit:

- further reductions in total dispatch costs, by enabling lower cost renewable generation to displace higher cost conventional generation;
- reduced generation investment costs, resulting from more efficient investment and retirement decisions, due to wind, solar and pumped hydro generation being able to locate at optimal high-quality locations rather than inferior locations; and
- avoided/lower intra-regional transmission investment associated with the development of Renewable Energy Zones (REZ).

The modelling in this PACR shows that, in the absence of investment under this RIT-T, alternative additional investment by market participants in technologies such as solar, gas-fired generation and other technologies such as large-scale batteries and pumped hydro investment in NSW in addition to that anticipated under the NSW government's Electricity Infrastructure Roadmap would be needed in the next twenty five years, in order to continue to meet New South Wales demand and system stability and security requirements, as existing dispatchable generation in New South Wales retires. Overall, the net cost to the market (and therefore ultimately to consumers) is expected to be higher under the 'do nothing' path, than if investment under this RIT-T proceeds.

The above sources of market benefit were included as the identified need for Humelink in the 2020 ISP.[30]

In addition, this PACR finds that the preferred option is expected to provide significant benefits to the NEM through facilitating more competitive bidding in the wholesale market (termed 'competition benefits' under the RIT-T). These benefits accrue through the option removing transmission constraints and allowing for an overall lower cost pattern of generation and storage being able to meet demand across the NEM (which ultimately reduces prices to end-consumers).

Section 7.1 discusses each of the eight specific categories of market benefit under the RIT-T that have been estimated as part of the PACR assessment.

30. AEMO, *Integrated System Plan*, July 2020, p. 86.

Document 2

4. Consultation on the PADR has been incorporated in this analysis

SUMMARY OF KEY POINTS:

- We have undertaken extensive stakeholder consultation to investigate the potential credible options for reinforcing the Southern Shared Network of New South Wales to enable the southern NSW generation to best serve load centres in New South Wales and ensure the robustness of the RIT-T findings.
- This consultation has included publication of a separate detailed market modelling and assumptions report, a consultation session at the public forum on the PADR on 12 February 2020, briefing our Customer Panel, bilateral discussions with interested stakeholders, and the release of detailed analysis in response to stakeholder requests.
- The analysis presented in this PACR has been informed by this consultation, which has helped test the conclusions reached and ensure the robustness of the analysis.
- We thank all parties for their valuable input to the consultation process.

The PADR for this RIT-T was published in January 2020, along with an accompanying market modelling report. On 12 February 2020, we held a public forum on the PADR that was attended by representatives from 17 organisations (excluding TransGrid and the consultants that worked directly on the PADR preparation).

Formal submissions from eight parties were ultimately received in response to the PADR, seven of which have been published on our website (one submitter requested confidentiality).[31]

While submissions covered a range of topics, there were six broad topics that were most commented upon, namely:

- timing and scope of the options included in the assessment;
- assumptions used in the market modelling;
- modelling outcomes;
- cost of the options;
- the incidence of market benefits;
- diversity benefits from an electrical 'loop'; and
- use of double-circuit versus single-circuit.

In addition, prior to, as well as after, receiving submissions, we held bilateral meetings with interested parties in order to further discuss the RIT-T assessment. These have played a pivotal role in being able to define and undertake the assessment in this PACR.

The key matters raised in non-confidential submissions and stakeholder feedback sessions relevant to the RIT-T assessment are summarised in the following subsections, as well as our responses and how the matters raised have been reflected in the PACR assessment. Appendix D provides a full summary of all points raised as part of consultation on the PADR, most of which remain relevant notwithstanding the time passed since submissions were received.

4.1 TIMING AND SCOPE OF THE OPTIONS

A number of submitters commented on the timing and scope of the credible options. Specifically, the following topics were raised:

- the optimal timing of the preferred option and whether it can be delayed;
- whether the options should be extended to all include reinforcing the southern and western Sydney transmission network;
- whether the options can be staged to provide greater net benefits;
- why Option 3C does not require a phase shifting transformer (while Option 3B does); and
- whether the preferred option can be coupled with modular power flow control equipment to provide greater net benefits.

The points raised and our responses to each are set out below.

4.1.1 The optimal timing of the preferred option and whether it can be delayed

EnergyAustralia requested that the optimal timing under each scenario and sensitivity be demonstrated and enquired as to whether the investment decision can be delayed.[32]

The optimal timing of the HumeLink development has been investigated thoroughly by AEMO as part of the ISP optimal development path based on the outcomes under the four core scenarios. While the 2020 ISP assumes a Humelink project completion date of 2025/26, the analysis in this PACR applies an assumed timing for the preferred option of 2026/27. The assumed timing has been updated since the 2020 ISP (and PADR) to reflect our current best estimate of how long we expect the project will take to construct and commission.

4.1.2 Whether the options should be extended to include reinforcing the southern and western Sydney transmission network

Snowy Hydro suggested we should continue to investigate the possible future reinforcement of the southern and western Sydney transmission network to ensure the southern supply route meets future demand requirements.[33] Similarly, ERM Power considered it unclear whether the preferred option will require completion of the proposed additional 330 kV circuit between Bannaby

31. https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network
32. EnergyAustralia, p. 2
33. Snowy Hydro, p. 2.

4. Consultation on the PADR has been incorporated in this analysis (continued)

and Sydney West as set out in Option 4A to accommodate the required higher flows from southern NSW towards the Sydney West switchyard, following the planned retirement of generation in the Hunter Valley and central coast sub-regions of NSW to deliver the calculated market benefits set out in the RIT-T.[34]

While an additional 330 kV circuit between Bannaby and Sydney West will help accommodate additional flow from southern NSW to the Sydney load centre, the NPV assessment finds that the costs of providing this additional capacity are not outweighed by the additional expected market benefits at this point in time. Specifically, the assessment in the PACR continues to find that the options including delivery of the Bannaby-Sydney West component in the same timeframe as the other transmission lines (i.e., options 4A, 4B and 4C) result in lower expected net market benefits than the equivalent options that do not include the Bannaby-Sydney West component (i.e., options 3A, 3B and 3C). This demonstrates that the Bannaby-Sydney West component is not expected to be incrementally net beneficial in the same timeframe as the other transmission lines. The 'topology 4' options have not been considered further in this PACR (as outlined in section 2.2.2).

We will continue to investigate strategic land acquisition between Bannaby to Sydney West to secure the property and easements for future development, due to the significant infrastructure development in the western Sydney area. However, this sits outside of the current RIT-T process.

EnergyAustralia queried whether the Bannaby to Sydney West transmission line (Line 39) would constrain optimal dispatch over the outlook period once the preferred option has been installed.[35]

We find that the binding percentage of time on the Bannaby to Sydney West constraint is forecast to be less than 1 per cent/year until the late 2030s and up to 4 per cent in later years of the study, once the preferred option has been implemented. While the binding hours do increase in the 2040s, any options to address this would be considered as part of a future RIT-T process.

4.1.3 Whether the options can be staged to provide greater net benefits

ERM Power suggested that consideration should be given to staging the preferred option and proposed that, while an initial segment between Wagga Wagga and Bannaby is warranted, the other elements of the project could be staged.[36]

The PADR investigated sensitivities under all scenarios that involve completing the Bannaby to Wagga Wagga and Wagga Wagga to Maragle transmission lines first, with the Bannaby to Maragle transmission line built at a later stage. These sensitivities found that, compared to when both stages are constructed at the same time, the expected gross market benefits of Option 3C fall under all scenarios (and were negative under the slow-change scenario). The PADR therefore concluded that staging the preferred option in this manner was not expected to provide net benefits over the non-staged version of Option 3C.

In addition, we do not consider it practical to build the Wagga Wagga to Bannaby segment ahead of the other lines due to the interaction with contractors and the cost synergies associated with building Wagga Wagga to Maragle segment (i.e., the sensitivity investigated as part of the PADR).

4.1.4 Why Option 3C does not require a phase shifting transformer (when Option 3B does)

ERM Power consider it unclear why Option 3B requires installation of a phase shifting transformer on Bannaby to Sydney West 330 kV line to control flows across this network flow path, while Option 3C will result in the delivery of higher flows to the 500 kV and 330 kV buses at Bannaby and does not have this same requirement.[37]

Power system assessment undertaken by TransGrid confirms that a phase shifting transformer is required for the 330 kV options but is not required for the 500 kV options due to the power sharing between 330 kV and 500 kV network beyond Bannaby. Specifically:

- for 500 kV options (e.g. options 1C, 2C and 3C), the power will flow into Bannaby 500 kV directly via HumeLink – a portion of the power will flow via the Bannaby to Mt Piper 500 kV lines and the rest will flow via the Bannaby 500/330/33 kV transformers and the Bannaby to Sydney West 330 kV line; while
- for 330 kV options, the power will flow into Bannaby 330 kV directly via HumeLink – the majority of the power will flow via the Bannaby to Sydney West line, while the rest will flow via the Bannaby 500/330/33 kV transformer and the Bannaby to Mt Piper 500 kV lines.

The thermal constraint on the Bannaby to Sydney West line is the most critical limit between Bannaby and Sydney load centres. The assessment confirms that the 500 kV options will have less power

34. ERM Power, p. 4.
35. EnergyAustralia, p. 5.
36. ERM Power, pp. 2 & 3.
37. ERM Power, p. 3.

4. Consultation on the PADR has been incorporated in this analysis (continued)

sharing on the Bannaby to Sydney West line due to transformer impedance than the 330 kV options.

4.1.5 Whether the preferred option can be coupled with modular power flow control equipment to provide greater net benefits

Smart Wires propose the use of MPFC equipment as part of the project in order to extract the maximum capability from the existing transmission system. Smart Wires suggest that MPFC should be assessed based on an evaluation of the net economic benefits it would provide in the context of the preferred solution.[38]

We have investigated a sensitivity where the proposed MPFC is added to the preferred option and find that, while it will help accommodate additional power flow from Southern NSW to Sydney load centre by changing the impedance of Bannaby to Sydney West line, the costs of providing this additional capacity are not outweighed by the additional expected market benefits at this point in time. Section 8.4.3 presents the results of this analysis.

4.2 ASSUMPTIONS USED IN THE MARKET MODELLING

As outlined in section 2.2.5, the market modelling assumptions used in the PACR assessment have been updated since the PADR to align with the final 2020 ISP assumptions and final 2020 ESOO. This ensures the latest final set of consulted on assumptions and scenarios from AEMO at the time of preparing this PACR are taken into account and is consistent with the new actionable ISP framework.

Notwithstanding, several submissions to the PADR commented on the assumptions used in the market modelling and remain relevant. We address each of these points below.

ERM Power considered that the modelling should calculate the net market benefit using the total calculated estimated cost for EnergyConnect and VNI West as well as HumeLink. ERM Power also stated that the market benefit modelling should be conducted on the HumeLink project in isolation with both the EnergyConnect and VNI West projects excluded.[39]

We have sought to apply the actionable ISP framework to this RIT-T and align its key assumptions with those used in the final 2020 ISP. Excluding EnergyConnect and VNI West (or including their costs) does not fit with this framework, since they are included in all 2020 ISP scenarios (with the exception of VNI West being excluded from the slow-change scenario).

Further, the AER guidelines make clear that all actionable ISP projects besides the one being assessed should be included in the base case.[40] In the case of EnergyConnect, its costs have now been approved by the AER and therefore it will proceed as planned in the base case.[41] In the case of VNI West, we have adopted the final 2020 ISP timing for all scenarios with the exception of the central scenario (for the reasons outlined in section 2.2.5) but have also investigated a sensitivity analysis that adopts the final 2020 ISP timing under the central scenario and find that, while this reduces the estimated net benefits of the options, it does not change the outcome of the RIT-T (as outlined in section 8.4.2).

ERM Power consider that low demand sensitivities should be run on all modelled scenarios to assess the impact of events like smelters shutting down.[42]

We have not investigated the effects of a demand shock as part of the PACR and consider that a demand shock of the severity (large), timing (early in the assessment period) and location (NSW) to affect the conclusion of this RIT-T is highly unlikely. For example, while the Tomago aluminium smelter shutting down is considered one example of such a shock, the Tomago Aluminium Company has signed an eleven year base-load power supply contract with Macquarie Generation that expires in 2028 and therefore is unlikely to shut down prior to the expiry of that contract.[43]

EnergyAustralia requested clarification as to whether the central real, pre-tax discount rate of 5.9 per cent, as well as the sensitivities (which were 2.85 per cent and 8.95 per cent at the time of the PADR), have been applied to the discounted cash flow analysis and generator hurdle rates as well as when determining the annualised costs of the transmission investment and therefore in determining the optimal timing.[44]

We have adopted the same approach as AEMO for the ISP in terms of the discount rates and WACC. We have applied the different discount rate sensitivities to the NPV assessment, as is required under the RIT-T, with the market modelling based on a single discount rate (ie, consistent the approach adopted in the 2020 ISP, which was consulted on by AEMO).

EnergyAustralia also requested clarification on how the departures from the 2020 ISP assumptions, including advanced closing of half of the coal power station capacity in the NEM by 2 to 5 years in three of the four scenarios, affects the net benefits and timing of the preferred option.[45]

The modelling undertaken in this PACR aligns with the final assumptions and scenarios used by AEMO in the 2020 ISP and 2020 ESOO, consistent with the now finalised actionable ISP framework.

EnergyAustralia expressed concern that the modelling of hydro generation assumes perfect foresight, is targeted to reduce total system costs and that these assumptions are inconsistent with reality. EnergyAustralia requested consideration of whether the benefits are overstated because of this.[46]

The core market modelling assumes short run marginal cost (SRMC) bidding, which is a feature of least-cost market development modelling and is standard practice in projecting generation and investment requirements in wholesale electricity markets as well as a requirement under the RIT-T.[47] Similar approaches have been utilised by AEMO in the 2018 and 2020 ISP, previous

38. Smart Wires, pp. 2-3.
39. ERM Power, p. 2.
40. AER, *Guidelines to make the Integrated System Plan actionable*, August 2020, pp. 58-59.
41. https://www.aer.gov.au/news-release/aer-approves-costs-for-project-energyconnect
42. ERM Power, p. 3.
43. https://www.csr.com.au/investor-relations-and-news/csr-news-releases/2010/tomago-aluminium-secures-long-term-power-supply-contract
44. EnergyAustralia, p. 2.
45. EnergyAustralia, p. 3.
46. EnergyAustralia, p. 4.
47. AER, *Regulatory Investment Test for Transmission*, June 2010, pp. 8-9.

4. Consultation on the PADR has been incorporated in this analysis (continued)

NTNDPs and RIT-Ts that have all assessed the relative expected benefits of alternative network investments.

We do not consider that SRMC bidding in least-cost modelling would necessarily overstate the estimated benefits, on account of the bidding type assumed feeding into both the base case for the RIT-T assessment and the option cases. This means that the effect of assuming least-cost modelling, over market-driven modelling, is ambiguous and may actually understate the estimated benefits since, by definition, least-cost modelling assumes lower cost generators are dispatched than under market-driven modelling.

EnergyAustralia also questioned whether Snowy Hydro's portfolio after the construction of Snowy 2.0 could influence dispatch outcomes away from the perfect outcomes represented in SRMC bidding and requested confirmation as to whether historical peak demand coincident factors are maintained in the demand traces.[48]

The competition benefits exercise undertaken in the PACR applies realistic bidding (as outlined in section 7.3). Even though the market model assumes perfect foresight, it considers constraints for the energy limited hydros and pumped hydros including the constraints on upper and lower ponds. The modelling outcomes are consistent with the real market where larger scale pumped hydro tends to generate during renewable scarcity and pump during excess renewable generation time. The competition benefits modelling has shown that the operation of pumped storages under realistic bidding is similar to that with fully competitive bidding.

We can confirm that all historical correlations from the last nine years of measurements of demand at the half hourly or hourly level are carried forward into the future, including coincidence factors.

EnergyAustralia requested EY explain how its market modelling is calibrated to actual outcomes, and how it extrapolates this over the outlook period.[49]

The market modelling is undertaken on an hourly resolution level from July 2021 and this data can be compared with historical data to verify the realism of the model. All the significant factors affecting market dispatch are incorporated, including generation, transmission, bidding. The market rules[50] are carried forward over time, including all the projected ISP data relating to input costs and decisions to build or retire plant on economic grounds.

We consider that the market modelling undertaken adequately mimics what can be expected to occur in the wholesale market, due to the calibration of the market modelling to actual outcomes undertaken by EY. The accompanying market modelling report details how the market model has been calibrated to ensure the results are realistic and in-line with how entities in the wholesale market can be expected to operate.

EnergyAustralia requested we outline the use of EY generation forced outage rates and mean time to repair assumptions and explain how they differ from those used by AEMO in its ISP.[51] EY adopted outage rates for the PADR modelling that differ from those in the ISP on the basis that they represent a more recent and comprehensive data set. The PACR analysis now adopts the AEMO rates.

EnergyAustralia requested that we explain and publish the dynamic loss equations and changes, including discussion on whether there are any material benefits in terms of loss savings.[52]

Loss savings associated with HumeLink are calculated using quadratic loss equations as are used by AEMO to dispatch generation in all regions. Where new lines are added, these loss equations are recalculated and, where additional detail is called for, lines and losses are modelled explicitly, rather than bundled across the transmission corridor.

The benefit of changes to network losses is captured within the wholesale market modelling of dispatch cost benefits of avoided fuel costs and changes to voluntary and involuntary load shedding. The reduction in network losses between the base case and the options is material for the options considered and reduces both the energy to be produced by fossil fuel generators to account for the losses, and a reduction in new capacity that has to be built to supply demand, particularly during peak periods.

EnergyAustralia queried whether transient and voltage stability limits are included in the modelling and whether they impact on the transfer capacity modelled in the system technical assessment studies.[53] Similarly, Malcolm Park queried whether there is confidence that the modelling of additional pumping capacity adequately represents the characteristics necessary to fully understand the power system transient stability performance when pumps operate.[54]

We can confirm that both transient and voltage stability limits are included in the modelling. They have been assessed in accordance with industry standards and are taken into account in the transfer capacities of the options.

48. EnergyAustralia, p. 4.
49. EnergyAustralia, p. 4.
50. 'Market rules' refers to all the rules associated with the gross pool market, including generators being dispatched in merit order, free entry and exit of generators from the market (if retirements are permitted), FCAS provided through minimum reserve criteria, unserved energy met by economic trade-off between cost of new entry generation and the cost of unsupplied energy, five region modelling of NEM with bi-directional constraints between regions, all generators meeting costs including capital costs for new generation, energy and storage limits met for energy limited plant etc.
51. EnergyAustralia, p. 4.
52. EnergyAustralia, p. 5.
53. EnergyAustralia, p.
54. Malcolm Park, p. 2.

4. Consultation on the PADR has been incorporated in this analysis (continued)

4.3 MODELLING OUTCOMES

EnergyAustralia requested additional information and analysis on the assumed changes in the supply side, notably in pumped hydro energy storage, and coal-fired installed capacity in order to understand the level of reliance the conclusions have on these assumptions and whether the system will be operationally manageable.[55]

The EY model includes assessment of dispatch of all generation types, including allocation of reserve in each time interval to ensure that there is sufficient dispatchable capacity and that the system will be operationally manageable. All storages have their overall efficiency accounted for and all generation earns at least its marginal cost of supply. All new generation earns at least its variable, fixed and capital costs, by uplifting marginal costs when it is dispatched.

Changes in the supply side, consisting of retirement of coal fired generation at end of life, are compensated by the installation of several other types of generation, including pumped storage and new gas fired generation, which fully replace the energy and capacity of the coal plant, assisted by intermittent renewables which provide capacity to fill pump storages and/or replace the need to operate gas plant, with consequent cost savings.

The model also trades off the cost of a supply shortfall in a given hour against the cost of building additional capacity of any type to cover the shortfall and incorporates a look ahead for the lifetime of the generation to be built to assess whether it is economically justified.

The generation and transmission model is therefore considered to reflect an operationally sound outcome for the NEM, at the lowest cost.

EnergyAustralia stated concern that the central case finds that an additional 11,300 GW of long duration pumped hydro storage, in addition to the capacity provided by Snowy 2.0, is required by 2044/45, and that the lack of utility scale batteries appears to be disconnected from what is happening in the market today and gas-fired generation appears to be missing from the supply mix. EnergyAustralia considered a sensitivity that challenges the presumption of pumped hydro playing a critical role in the transition of the electricity system should be undertaken.[56]

The modelling outcomes reflect the ISP projections for costs of all generation technologies. There are several interchangeable technologies for providing peaking capacity that are operationally identical including pumped hydro, large scale batteries and OCGT, as well as diesel. Should those other technologies be more economic they will be built and replace the equivalent pumped hydro capacity.

The model does not account for batteries to be built to meet fast frequency response or for virtual transmission lines. Such developments are not compatible with the usage of batteries for peak lopping and valley filling duty, which is the main opportunity for arbitrage which leads to investment of battery capacity in the gross pool market.

There is also gas fired generation being developed in the modelled outcomes, since peaking gas capacity and pumped storage and battery capacity are competing technologies for meeting peak demands in the NEM.

A sensitivity that challenges the presumption of pumped hydro playing a critical role in the transition of the electricity system has not been run as it is not expected to be material to the RIT-T assessment. Specifically, if the building of pumped hydro is restricted in the model, it will simply result in alternate, more expensive, technologies being built under both the base case and the option cases. While this is expected to increase the estimated market benefits of the options (since more expensive capacity will be avoided with the options), it is not expected to change their overall ranking.

55. EnergyAustralia, pp. 2-3.
56. EnergyAustralia, p. 3.

4. Consultation on the PADR has been incorporated in this analysis (continued)

EnergyAustralia requested that we publish details of the sensitivity studies around closure of coal plant based on economic viability to be summarised and published, including the details on the closure criteria applied.[57] This material has been published with this PACR and the accompanying market modelling report.

EnergyAustralia raised three specific questions in relation to system security and strength going forward:[58]

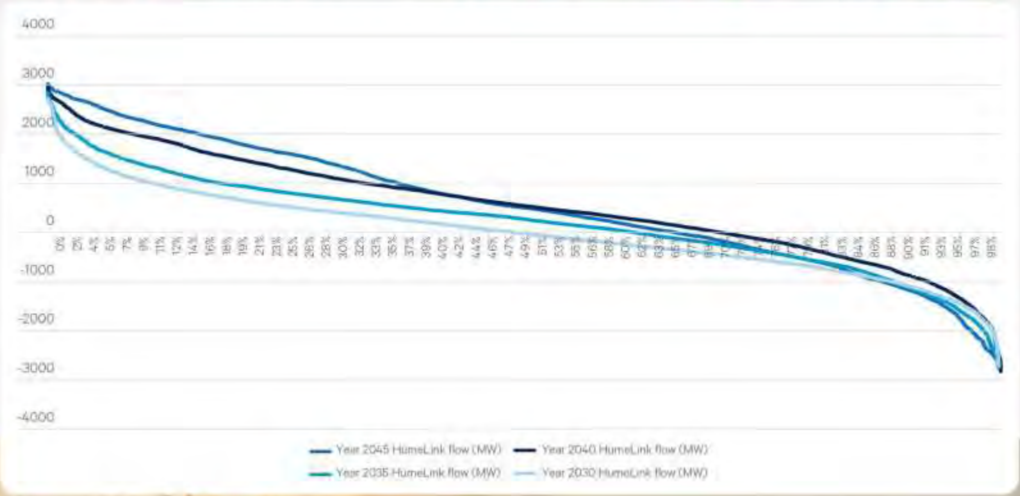
1. How dependent is power system operation, or maintaining the reliability standard, on the levels of pumped hydro from the long-term planning and, if the forecast capacity of pumped hydro does not arrive, does the system face significant security and reliability challenges?
2. Will system strength, low inertia or frequency/voltage control issues prevail that have not been considered in the study?
3. Will the remaining dispatchable coal plants be able to ramp up and down to efficiently support the swings in intermittent generation from new capacity built as a result of the new interconnector?

With respect to each of the three questions:

1. The forecast is a market development forecast and ensures an allocation of reserve in each time interval to ensure that there is sufficient dispatchable capacity and that the system will be operationally manageable. If pumped storage is not built in sufficient capacity, or not operated at the level that has been predicted by the model, then it is anticipated that the market will provide additional peaking capacity of a different type, particularly peaking gas or batteries.
2. These factors have not been explicitly modelled as constraint equations in the model. Instead reserve against a single contingency with full restoration of security following the contingency is incorporated as a constraint to reflect market rules relating to LOR1, LOR2 and LOR3 conditions. The reserve carried is expected to contribute significantly to meeting the requirements listed.
3. Remaining coal plants are able to ramp to efficiently meet the swings in intermittent generation as evidenced by review of hourly dispatch. Specific testing of existing ramp rate settings by generators in the market has been undertaken and does not change the NPV of the market benefits, as the preferred option and the 'do nothing' case are slightly impacted by binding ramp rates for a small proportion of the time. The generators will be incentivised by the market to expand ramp rates to alleviate any constraints that could emerge.

EnergyAustralia requested that the utilisation of HumeLink (per cent of transfer capacity) is published, including intraday flows and duration curves.[59] The figure below presents the duration curves for forecast Humelink flow for 2030, 2035, 2040 and 2045.

Figure 3 – Load duration curve for HumeLink flow to supply load centres (Maragle – Bannaby and Wagga Wagga – Bannaby)



57. EnergyAustralia, p. 3.
58. EnergyAustralia, pp. 3-4.
59. EnergyAustralia, p. 6.

4. Consultation on the PADR has been incorporated in this analysis (continued)

4.4 COST OF THE OPTIONS

EnergyAustralia queried whether the network project costs include easements and land acquisition allowances and what needs to be done to refine 'midpoint' costs for the purposes of the PACR.[60] ERM Power recommended that in finalising this RIT-T process the costings be subject to potential variation not greater than +/- 15 per cent.[61]

Significant effort has gone into refining the cost estimates for the credible options as part of this PACR (as outlined in section 2.2.3). A key component of the updated costs is updated easement/land acquisition costs as well as biodiversity offset costs.

We consider our cost estimates to be 'class 4' estimates, which is in-line with the level of accuracy expected at this stage of the investment process. For example, AEMO commented during the consultation process on its transmission cost database that the cost certainty at the PACR stage is typically between -30 per cent and +50 per cent ('class 4' estimates) or -20 per cent and +30 per cent ('class 3' estimates).[62] We do not consider that it is either necessary or feasible for the cost estimates to be +/- 15 per cent as suggested by ERM Power. Substantive further work will be necessary to further refine the current cost estimate.

We consider that the capital costs used in the PACR analysis are 'P50' estimates, i.e., they have a 50 per cent expected probability of cost underrun. For completeness, we have also considered alternate 'P90' capex estimates as a sensitivity (see section 8.4.5), which are higher than the P50 estimates and allow for additional contingencies (the P90 capex estimates have an expected 90 per cent probability of cost underrun).

Activities not related to the RIT-T but necessary to progress assessment of the project in order to achieve approval are being progressed, including the Environmental Impact Statement process. Following clarification from the AER over September and October 2020,[63] we are intending to submit two contingent project applications (CPAs) to the AER in relation to the regulatory cost recovery for the project, namely:

- 'Initial CPA' – will seek cost recovery for works to-date and the cost of the works necessary to develop a robust cost estimate for the project, based on the preferred option; and
- 'Final CPA' – will seek cost recovery for the implementation costs, including construction cost of the project, once a final estimate is available (this CPA will cover the bulk of the project cost).

As part of the contingent project processes, we will seek a 'feedback loop' confirmation from AEMO in-line with the new actionable ISP framework if the costs of the preferred option exceed those currently estimated in the RIT-T assessment. This will ensure that the investment is confirmed as being consistent with the optimal development path in the ISP, where costs have increased.

EnergyAustralia requested confirmation that the transmission asset economic lives used and the one per cent of capex per annum opex assumption are consistent with AER views when approving expenditure allowances.[64]

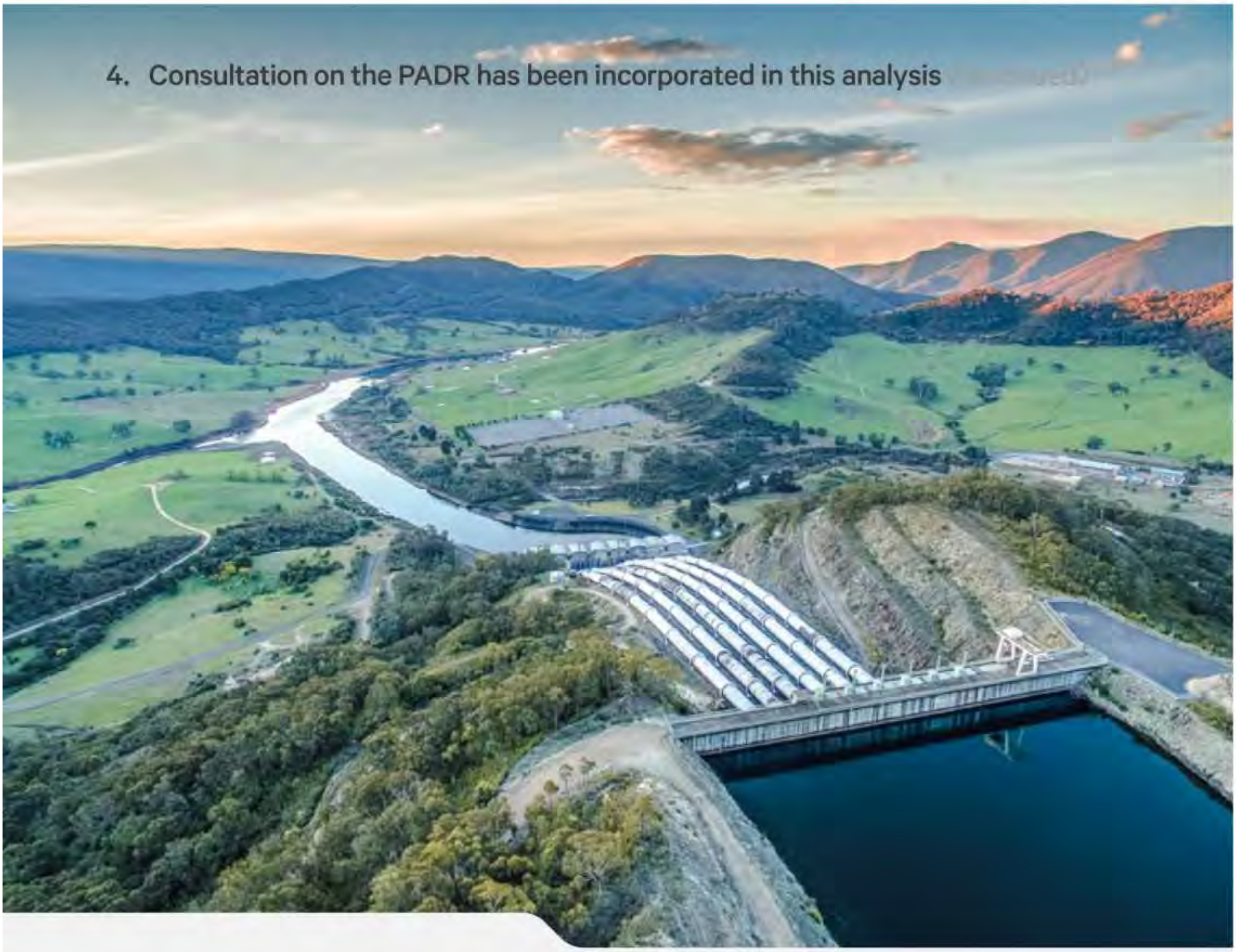
The economic NPV model released with the PADR states the asset lives used in the RIT-T assessment, which are 40 years for substation equipment and 50 years for transmission lines. These are consistent with our current revenue determination made by the AER (please refer to the 'PTRM input' tab of our current Post Tax Revenue Model[65]).

We have also refined the assumption regarding annual operating costs based on more detail cost assessment. We now assume this to be 0.5 per cent of each option's capital costs each year (excluding capital costs relating to biodiversity costs since these are one-off and do not require ongoing operating costs).

EnergyAustralia requested that the cumulative transmission capex/opex on annual profile charts be published (Figures 5, 10, 15 and 20 in the PADR).[66] This material has been published with this PACR.

60. EnergyAustralia, p. 5.
61. ERM Power, p. 3.
62. AEMO & GHD Advisory, AEMO ISP Transmission Cost Database Stakeholder Webinar, 20 January 2021, slide 5.
63. https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/transgrid-humelink-contingent-project/aer-position
64. EnergyAustralia, p. 5.
65. Available from https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/transgrid-determination-2018-23
66. EnergyAustralia, p. 5.

4. Consultation on the PADR has been incorporated in this analysis



4.5 THE INCIDENCE OF MARKET BENEFITS

PIAC recommended that TransGrid determine the share of benefits from the investment that accrue to Snowy 2.0 and those that accrue to consumers. Specifically, PIAC suggests we should identify any imbalance of costs and benefits for NSW consumers and examine options to address this, including Snowy 2.0 being required to directly fund a commensurate portion of the investment, as part of the HumeLink RIT-T.[67]

Similarly, ERM Power recommend that we also consult on and conduct modelling with regards to the changes in consumers and supplier benefits as part of this RIT-T process.[68]

EnergyAustralia requested that the regional benefits, relative to regional costs, are published, particularly for NSW, South Australia and Victoria.[69] EnergyAustralia also requested that the modelled price outcomes are published, including duration curves and intraday price shape.[70]

We note that the RIT-T identifies where transmission investment is expected to provide an overall net benefit to the market as a whole. That is, investments as a result of which customers across the NEM will benefit in the long-run by more than the cost of the investment incurred. Cost allocation, and the sharing of risk as between different stakeholders in the energy market and the extent to which a market benefit serves to the greater advantage of one party than the other is a public benefits assessment that is separate to the market benefit analysis of the RIT-T processes. Accordingly, PIAC's concerns, echoed by ERM Power and EnergyAustralia are considerations that are not within the purview of a RIT-T process and instead is the subject matter for consultation and engagement by governments and regulators in broader market reform and regulatory processes.

The purpose of the RIT-T and this PACR is to identify through cost benefit analysis classes of market benefits that are identified in clause 5.15A.2(b)(4) of the NER and accordingly the accompanying market modelling report to this PACR provides detail on where the relative costs and benefits are expected to accrue in the NEM. Specifically, this report outlines the regions and technologies expected to be affected with each of the options in-place under each scenario, compared to the base case.

The market benefits are expected to be passed through to customers in the long run. The modelling of specific customer impacts has been considered by policymakers in the past to be too reliant on assumptions made about pricing to be workable.

67. PIAC, p. 3.
68. ERM Power, p. 2.
69. EnergyAustralia, p. 5.
70. EnergyAustralia, p. 5.

4. Consultation on the PADR has been incorporated in this analysis (continued)

4.6 DIVERSITY BENEFITS FROM AN ELECTRICAL 'LOOP'

EnergyAustralia requested clarification of the expected costs (and cost inputs) associated with our estimate in the PADR of a simultaneous failure of both circuits of an interconnector.[71]

The costs associated with such 'high impact low probability' events are subject to a number of variables, including line loading at the time of the event, power system conditions, availability of alternative generation, duration of the outage, etc. Depending on the severity of the event, the cost impact can range from a few million dollars to hundreds of millions.

By way of comparison, an example of such an event was the double-circuit trip of the QNI in August 2018 due to a lightning strike with no prior warning of storm activity in the area. In this event, Queensland and South Australia both separated from the other states in the NEM and 1,078 MW of load was shed. Load was restored between 20 minutes and 2½ hours after the event. Using the AER VCR estimates for NSW and Queensland, this lost load is valued at approximately $25 million.

The calculation EnergyAustralia refer to was undertaken in the PADR to provide a high-level estimate of the consequence if a 'high impact low probability' event affects two lines simultaneously to provide context for why Option 3C is expected to be inherently less risky, since its lines are further apart and so less likely to both go down at the same time, than Option 2C. It was intended only to be indicative and was labelled as such in the PADR.

We note that the PACR now finds that Option 3C is more strongly preferred over Option 2C than it was at the PADR stage for numerous reasons, including it now having significantly lower costs than Option 2C and greater estimated competition benefits. We therefore do not consider this calculation to be material to identifying the top-ranked option. We have therefore not updated, or repeated, it in the PACR.

4.7 USE OF DOUBLE-CIRCUIT VERSUS SINGLE-CIRCUIT

Malcolm Park suggested that the need for two new single-circuit lines in sections where one double-circuit line could be enough is reviewed.[72]

As part of this PACR, we have investigated different circuit configurations of the top performing network topologies and operating capacities in the PADR and PACR analysis (i.e., 'Option 2C' and 'Option 3C'). Specifically, we have investigated:

- three variants of the preferred network topology and operating capacity in the PADR and PACR analysis, i.e., Option 3C:
  - Option 3C, constructed as 100 per cent double-circuit configuration;
  - Option 3C-0, constructed as a 100 per cent single-circuit configuration; and
  - Option 3C-1, constructed primarily as a single-circuit configuration but with a 132 km double-circuit portion west of Bannaby;
- two variants of the second-ranked network topology and operating capacity in the PADR and PACR analysis, i.e., Option 2C:
  - Option 2C, constructed as 100 per cent double-circuit configuration;
  - Option 2C-1, constructed primarily as a single-circuit configuration but with a 132 km double-circuit portion west of Bannaby.

Each variant for the two network topologies is electrically the same and so delivers the same expected gross benefits.

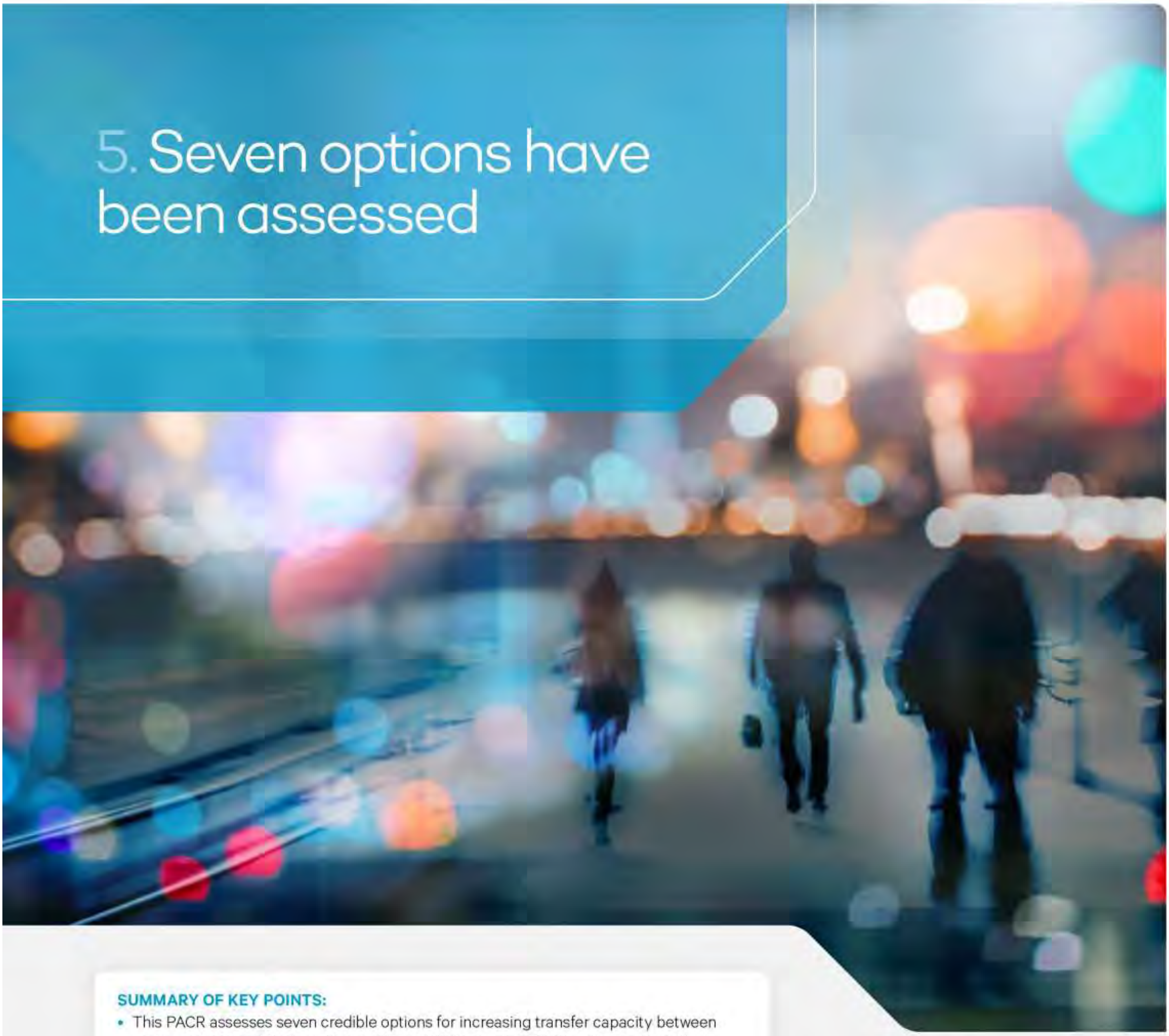
All variants involving double-circuit portions of transmission line (i.e., 2C, 2C-1, 3C and 3C-1) have been assessed to investigate lower cost variants of the top performing network topologies and operating capacity. Specifically, the use of double-circuits for portions of these lines reduces the associated land and environmental offset costs compared to two separate single-circuit portions.

The outworking of these studies is that Option 2C and Option 3C from the PADR are presented in the PACR as complete double-circuit options, which allows significant cost reductions relative to where they are constructed as either a single-circuit, or a combination of single- and double-circuit, configuration.[73] The additional work undertaken since the PADR assessing the risks involved with double-circuit configuration, compared to single-circuit, and how these risks can be mitigated, has enabled these two options to be put forward as double-circuit configurations as part of this PACR.

Appendix B.1.2 provides additional detail on the consideration of these alternate line configurations and the risk assessment undertaken.

71. EnergyAustralia, p. 5.
72. Malcolm Park, p. 1.
73. In addition, while the other options are primarily single-circuit, they all now involve a 132 km double-circuit component west of Bannaby, an area we where we consider bushfire risk is a more manageable risk, in order to reduce costs. We have not investigated complete double-circuit versions of these options, as we have for Option 2C and Option 3C, as any cost reductions are not expected to result in these options becoming top ranked options given their significantly lower net benefits than for Option 2C and Option 3C.

5. Seven options have been assessed



SUMMARY OF KEY POINTS:

- This PACR assesses seven credible options for increasing transfer capacity between southern NSW and Sydney, Newcastle and Wollongong, reflecting three alternative network topologies and two different operating capacities.
- Seven of the twelve options from the PADR continue to be assessed, reflecting the same three operating capacities.
- The three options from the PADR that follow 'topology 4' (involving new transmission lines in an electrical 'loop' between Maragle, Wagga Wagga and Bannaby and direct between Bannaby and Sydney) have not been assessed further. These options have significantly greater revised costs than the other options and are not expected to provide commensurately greater market benefits at this point in time.
- The PACR does not assess Option 2A or Option 3A from the PADR (the two fixed 330 kV versions of these network topologies) since they were found to have significantly lower benefits than the others and, in particular, Option 3C in the PADR assessment.
- The costs of the options have been refined since the PADR. These costs reflect our current best estimates of the costs involved with each of the options at this point in time.
- Once the RIT-T process is complete, we intend to submit an initial CPA for HumeLink to seek cost recovery for works necessary to develop a robust final cost estimate for the project. If this final cost estimate is materially higher, then AEMO will need to confirm that the project remains consistent with the ISP optimal development path at the higher cost (as part of the 'feedback loop') before the project can proceed further.

This PACR assesses seven different network options to provide additional transfer capacity on the NSW Southern Shared Network between the Snowy Mountains and the major load centres of Sydney, Newcastle and Wollongong.

Based on the NPV assessment in the PADR and further detailed screening of the options considered, the list of credible options has been refined to ensure that the top-ranked options are able to be assessed at a greater level of detail as part of the PACR.

The analysis now focuses on seven options that are expected to have the greatest net market benefits overall. Specifically, this PACR assesses the options across the following three different topologies:

1. Topology 1 – a 'direct' path between Maragle and Bannaby:
   - Option 1A, Option 1B and Option 1C from the PADR

5. Seven options have been assessed (continued)

2. Topology 2 – a path between Maragle and Bannaby via Wagga Wagga that would open up additional capacity for new renewable generation in southern NSW:
   - Option 2B and Option 2C from the PADR
3. Topology 3 – a wider footprint via Wagga Wagga, that would open up both direct and additional capacity for new renewable generation in southern NSW:
   - Option 3B and Option 3C from the PADR

The PACR does not assess the 'Topology 4' options from the PADR (involving new transmission lines in an electrical 'loop' between Maragle, Wagga Wagga and Bannaby and direct between Bannaby and Sydney). These options have significantly greater revised costs than the other options (in the order of $4.7 billion to $5 billion) and are not expected to provide commensurately greater market benefits than their counterparts following the three topologies outlined above. Any assessment of increasing the transmission capacity between Bannaby and Sydney may form part of a future RIT-T.

The PACR also does not assess Option 2A or Option 3A from the PADR (the two 330 kV build and operate options of these network topologies) since they were found to have significantly lower benefits than the other options and, in particular, Option 3C in the PADR assessment. Specifically, these options were found to have net benefits that were 38 and 36 per cent lower than Option 3C on a weighted basis in the PADR.

We have investigated different circuit configurations of the top performing network topologies and operating capacities in the PADR and PACR analysis (i.e., 'Option 2C' and 'Option 3C'). The outworking of this process is that Option 2C and Option 3C from the PADR are presented in the PACR as complete double-circuit options, which allows significant cost reductions relative to where they are constructed as either a single-circuit, or a combination of single- and double-circuit, configuration.[74] Additional work undertaken since the PADR assessing the risks involved with double-circuit configurations, compared to single-circuit, and how these risks can be mitigated has enabled these two options to be refined as part of this PACR.

Each of the network options for topologies 1, 2 and 3 are summarised in Table 5-1, Table 5-2 and Table 5-3 below, respectively.[75] Each of these tables shows the additional network capacity that each provides between southern NSW and the major load centres of Sydney, Newcastle and Wollongong.[76,77] All costs are presented in 2020/21 dollars.

All diagrams are high-level schematic illustrations only and specific line routes are not defined within the PACR. Moreover, all quoted line lengths in this section are only indicative and, for the preferred option, are subject to change once the more detailed route selection and line alignment is undertaken.

74. In addition, while the other options are primarily single-circuit, they all now involve a 132 km double-circuit component west of Bannaby, an area we where we consider bushfire risk is a more manageable risk, in order to reduce costs. We have not investigated complete double-circuit versions of these options, as we have for Option 2C and Option 3C, as any cost reductions are not expected to result in these options becoming top ranked options given their significantly lower net benefits than for Option 2C and Option 3C.
75. Please note that the biodiversity offset costs shown in the tables below for Option 2C and Option 3C are lower than for Option 1C due to their full double circuit arrangement, while Option 1C involves two single circuit lines to be constructed in parallel (with a 132 km of double circuit lines) that translates to a larger easement width footprint. Similarly, Option 2C and Option 3C have lower biodiversity costs than Option 2B and Option 3B, respectively, since these 'B' options assume two single circuit lines (with the exception of the 132 km double circuit section).
76. While the indicative additional firm capacities in this table assume an average level of import from VIC to NSW of 200 MW and average wind generation in southern NSW of 265 MW and zero SA-NSW imports, the market modelling dynamically models both of these key sources of supply for NSW.
77. Note that all costs in these tables have been rounded to the nearest $5 million for presentational purposes. The accompanying NPV results spreadsheets have the full cost estimates in them.

Released under FOI

Document 2

5. Seven options have been assessed (continued)

Table 5-1 Summary of the 'topology 1' credible options assessed in this PACR

TOPOLOGY/OPERATING CAPACITY	A. FIXED 330 KV	B. FLEXIBLE 500 KV	C. FIXED 500 KV
1 Two new transmission lines between Maragle and Bannaby	**OPTION 1A** Two new 330 kV high capacity transmission lines, switchgear and phase shifting transformer	**OPTION 1B** Two new 500 kV transmission lines operated at 330 kV, switchgear and phase shifting transformer	**OPTION 1C** Two new 500 kV transmission lines, tie transformers and switchgear
	Additional firm capacity 2,050 MW	**Additional firm capacity** 2,170 MW initially 2,570 MW if upgraded to 500 kV	**Additional firm capacity** 2,510 MW
	Indicative capex Lines and substations: $1,470m Biodiversity offset cost: $1,060m Total capex: $2,530m	**Indicative capex** Lines and substations: $1,990m Biodiversity offset cost: $1,320m Total capex: $3,310m	**Indicative capex** Lines and substations: $1,725m Biodiversity offset cost: $1,340m Total capex: $3,065m

Note: Lines represent circuits only and are not intended to represent transmission line routes.

Table 5-2 Summary of the 'topology 2' credible options assessed in this PACR

TOPOLOGY/OPERATING CAPACITY	B. FLEXIBLE 500 KV	C. FIXED 500 KV
2 New transmission lines between Maragle, Wagga Wagga and Bannaby	**OPTION 2B** Four new 500 kV transmission lines operated at 330 kV, switchgear and phase shifting transformers	**OPTION 2C** Four new 500 kV transmission lines, tie transformers and switchgear
	Additional firm capacity 2,000 MW initially 2,500 MW if upgraded to 500 kV	**Additional firm capacity** 2,510 MW
	Indicative capex Lines and substations: $3,150m Biodiversity offset cost: $1,150m Total capex: $4,300m	**Indicative capex** Lines and substations: $2,585m Biodiversity offset cost: $815m Total capex: $3,400m

Note: Lines represent circuits only and are not intended to represent transmission line routes.

Table 5-3 Summary of the 'topology 3' credible options assessed in this PACR

TOPOLOGY/OPERATING CAPACITY	B. FLEXIBLE 500 KV	C. FIXED 500 KV
3 New transmission lines in an electrical 'loop' between Maragle, Wagga Wagga and Bannaby	**OPTION 3B** Three new 500 kV transmission lines operated at 330 kV, switchgear and phase shifting transformer	**OPTION 3C** Three new 500 kV transmission lines, tie transformers and switchgear
	Additional firm capacity 2,030 MW initially 2,570 MW if upgraded to 500 kV	**Additional firm capacity** 2,570 MW
	Indicative capex Lines and substations: $2,560m Biodiversity offset cost: $1,220m Total capex: $3,780m	**Indicative capex** Lines and substations: $2,380m Biodiversity offset cost: $935m Total capex: $3,317m

Note: Lines represent circuits only and are not intended to represent transmission line routes.

5. Seven options have been assessed (continued)

All options are assumed to have annual operating costs equal to approximately 0.5 per cent of their capital costs. This assumption has been refined since the PADR as part of the wider cost refinement (as outlined in section 2.2.3).

Construction for all options is expected to take 2-3 years, with commissioning in 2026/27, subject to obtaining necessary environmental and development approvals. The future upgrades associated with the flexible 500 kV options are expected to take two years and the timing differs by scenario (as summarised in section 7.1.7).

The remainder of this section provides further detail on each of these options. Appendix B outlines the network options that have been considered but not progressed over the course of this RIT-T (together with the reasons why).

Final decisions regarding route diversity for the preferred option will be based on an assessment of network risks and mitigation strategies, having regard to the relative cost of diversity options, that sits outside of the RIT-T process (specifically, the EIS process summarised in the introduction).

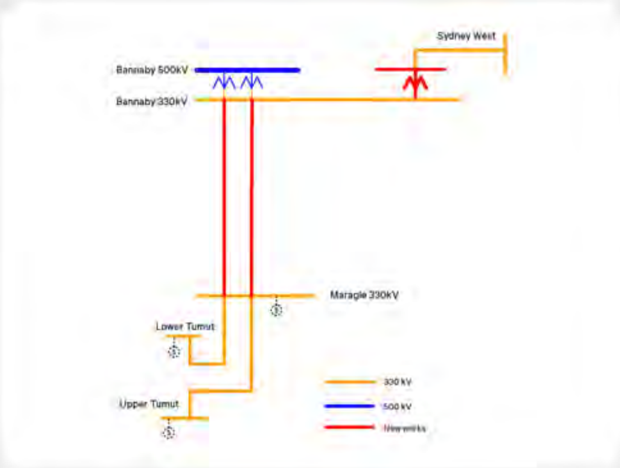
5.1 TWO NEW LINES BETWEEN MARAGLE AND BANNABY

5.1.1 Option 1A – Two new 330 kV lines from Maragle to Bannaby using high capacity conductor

This option involves constructing two new 330 kV lines from Maragle to Bannaby using a high capacity conductor and a phase shifting transformer on Bannaby – Sydney West 330 kV line to control power flows on existing transmission lines between Bannaby and Sydney.

The high level scope includes:

- Constructing two 330 kV transmission lines using high capacity conductor:
  - Between Maragle 330 kV switching station and Bannaby 330 kV substation
- Phase shifting transformers on Bannaby-Sydney West 330 kV line
- Augment the Maragle switching station to accommodate the additional transmission lines
- Augment the existing Bannaby substation to accommodate the additional transmission lines and phase shifting transformers



Preliminary modelling indicates that an additional 2,050 MW generation could be accommodated at times of average import from VIC and average renewable generation in southern NSW.

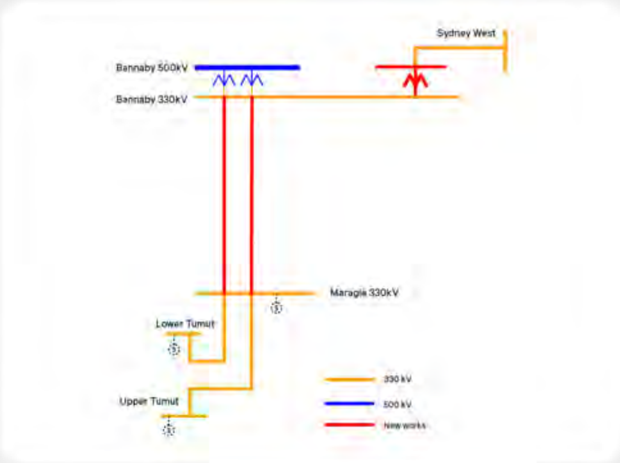
The estimated capital cost of this option is approximately $2,529 million.

5.1.2 Option 1B – Two new 500 kV lines initially operated at 330 kV between Maragle and Bannaby

This option involves constructing two new 500 kV lines initially operated at 330 kV between Maragle and Bannaby and a phase shifting transformer on Bannaby – Sydney West 330 kV line.

The high level scope includes:

- Construct two 500 kV transmission lines to be initially operated at 330 kV:
  - Between Maragle 330kV switching station and Bannaby 330 kV substation
- Phase shifting transformers on Bannaby-Sydney West 330 kV line
- Augment the Maragle switching station to accommodate the additional transmission lines
- Augment the existing Bannaby substation to accommodate the additional transmission lines and phase shifting transformers



Preliminary modelling indicates that additional 2,170 MW generation could be accommodated at times of average import from VIC and average renewable generation in southern NSW.

The estimated initial capital cost of this option is approximately $3,311 million. There would be additional costs associated with upgrading from 330 kV to 500 kV as well but these have not been estimated as part of this PACR.[78]

78. The 330 kV to 500 kV upgrade costs were not estimated as part of the PACR assessment as an initial assumption to investigate how these options fared relative to the other options before resources were dedicated to estimating the upgrade costs. Since the flexible options are found to always be inferior to the fixed 500 kV options, we have not estimated the upgrade costs as part of this PACR. We consider this a proportionate approach to considering these options.

5. Seven options have been assessed (continued)

5.1.3 Option 1C – Two new 500 kV lines between Maragle and Bannaby

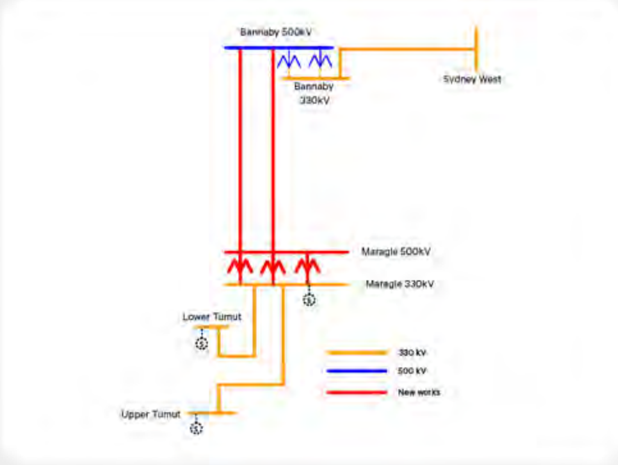
This option involves constructing two new 500 kV lines between Maragle and Bannaby.

The high level scope includes

- Construct two 500 kV transmission lines:
  - Between Maragle substation and Bannaby 500 kV substation
- Three new 500/330/33 kV 1,500 MVA transformers at Maragle substation
- Augment the Maragle substation to accommodate the additional transmission lines
- Augment the existing Bannaby substation to accommodate the additional transmission lines

Preliminary modelling indicates that additional 2,510 MW generation could be accommodated at times of average import from VIC and average renewable generation in southern NSW.

The estimated capital cost of this option is approximately $3,066 million.



5.2 NEW LINES BETWEEN MARAGLE, WAGGA WAGGA AND BANNABY

5.2.1 Option 2B – New 500 kV lines initially operated at 330 kV between Maragle, Wagga Wagga and Bannaby

This option involves constructing new 500 kV lines initially operated at 330 kV between Maragle and Bannaby via Wagga Wagga and a phase shifting transformer on Bannaby – Sydney West 330 kV line.

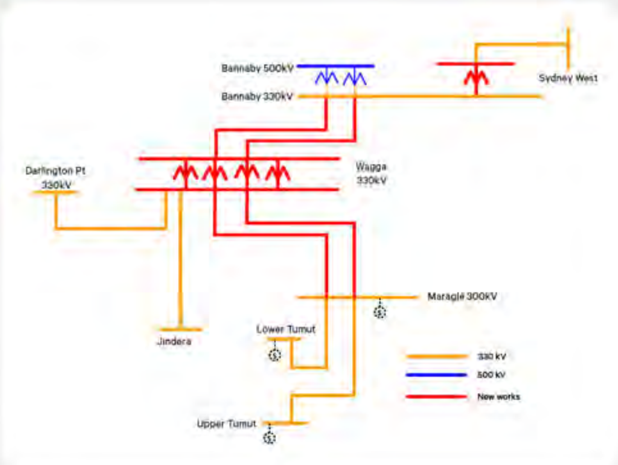
The high level scope includes:

- Construct four 500 kV transmission lines to be initially operated at 330 kV:
  - Two lines between Maragle 330 kV switching station and Wagga Wagga 330 kV switching station; and
  - Two lines between Wagga Wagga 330 kV switching station and Bannaby 330 kV substation
- Phase shifting transformers on Bannaby-Sydney West 330 kV line
- Phase shifting transformers on Wagga Wagga–Bannaby 330 kV lines
- New Wagga Wagga 330 kV switching station
- Augment the Maragle switching station to accommodate the additional transmission lines
- Augment the existing substations at Wagga Wagga and Bannaby to accommodate the additional transmission lines

Preliminary modelling indicates that an additional 2,000 MW generation could be accommodated at times of average import from VIC and average renewable generation in southern NSW.

The initial estimated capital cost of this option is approximately $4,302 million. There would be additional costs associated with upgrading from 330 kV to 500 kV as well but these have not been estimated as part of this PACR.[79]

Option 2B is more expensive than its 500 kV counterpart (Option 2C) on account of the phase shifting transformers required to accommodate 2,000 MW of new generation at 330 kV (which are redundant at 500 kV).

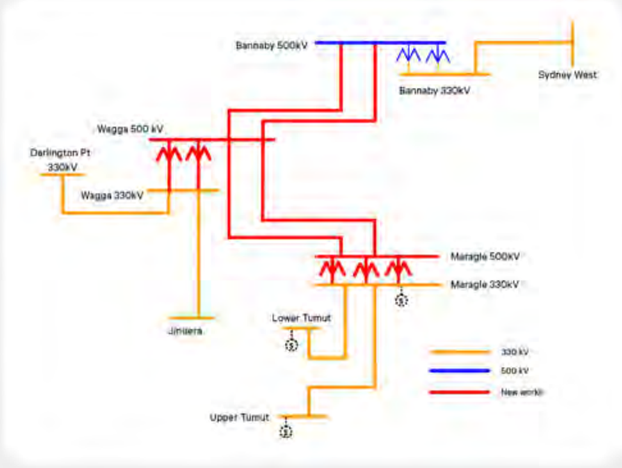


79. The 330 kV to 500 kV upgrade costs were not estimated as part of the PACR assessment as an initial assumption to investigate how these options fared relative to the other options before resources were dedicated to estimating the upgrade costs. Since the flexible options are found to always be inferior to the fixed 500 kV options, we have not estimated the upgrade costs as part of this PACR. We consider this a proportionate approach to considering these options.

5. Seven options have been assessed (continued)

5.2.2 Option 2C – New 500 kV double-circuit lines between Maragle, Wagga Wagga and Bannaby

This option involves constructing new 500 kV lines between Maragle, Wagga Wagga and Bannaby.



The high level scope includes:

- New Wagga Wagga 500/330 kV substation and double circuit 330 kV connection to the existing Wagga Wagga substation
- Construct four 500 kV transmission lines:
  - Two lines between Maragle substation and Wagga Wagga 500 kV substation; and
  - Two lines between Wagga Wagga substation and Bannaby 500 kV substation
- Three new 500/330/33 kV 1,500 MVA transformers at Maragle substation and two new 500/330/33 kV 1,500 MVA transformers at Wagga Wagga substation
- Augment the Maragle substation to accommodate the additional transmission lines
- Augment the existing substations at Wagga Wagga and Bannaby to accommodate the additional transmission lines

Preliminary modelling indicates that an additional 2,500 MW generation could be accommodated at times of average import from VIC and average renewable generation in southern NSW.

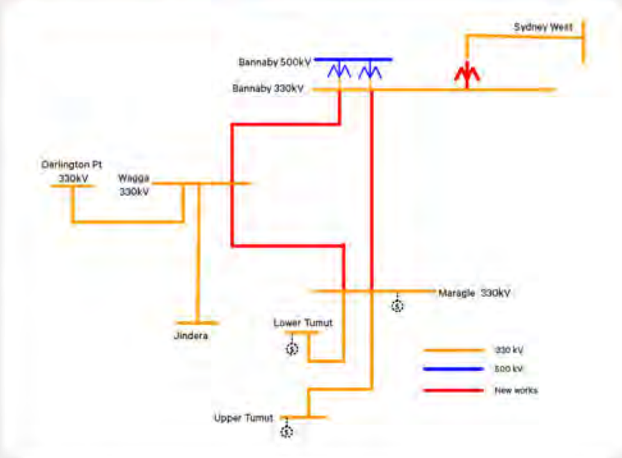
The estimated capital cost of this option is approximately $3,399 million.

As part of the PACR analysis, we have investigated another variant of Option 2C's network topology and operating capacity, which is constructed primarily as a single-circuit configuration but with a 132 km double-circuit portion west of Bannaby. While this variant is electrically identical to Option 2C, and so provides the same expected market benefits, it is found to have significantly greater costs and so has not been progressed as credible options in the body of this PACR. A discussion of this variant can be found in Appendix B.1.2.

5.3 NEW LINES IN AN ELECTRICAL 'LOOP' BETWEEN MARAGLE, WAGGA WAGGA AND BANNABY

5.3.1 Option 3B – New 500 kV lines in an electrical 'loop' initially operated at 330 kV between Maragle, Wagga Wagga and Bannaby

This option involves constructing new 500 kV lines initially operated at 330 kV between Maragle, Wagga Wagga and Bannaby, and a phase shifting transformer on Bannaby – Sydney West 330 kV line.



The high level scope includes:

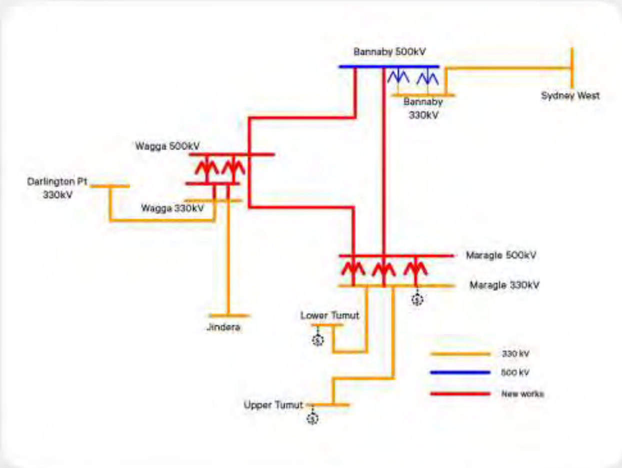
- Construct three 500 kV transmission lines:
  - Between Maragle switching station and Bannaby 330 kV substation;
  - Between Maragle and Wagga Wagga 330 kV switching stations; and
  - Between Wagga Wagga 330 kV switching station and Bannaby 330 kV substation
- Phase shifting transformers on Bannaby-Sydney West 330 kV line
- New Wagga Wagga 330 kV switching station
- Augment the Maragle switching station to accommodate the additional transmission lines
- Augment the existing substations at Wagga Wagga and Bannaby to accommodate the additional transmission lines.

Preliminary modelling indicates that additional 2,030 MW generation could be accommodated at times of average import from VIC and average renewable generation in southern NSW.

80. The 330 kV to 500 kV upgrade costs were not estimated as part of the PACR assessment as an initial assumption to investigate how these options fared relative to the other options before resources were dedicated to estimating the upgrade costs. Since the flexible options are found to always be inferior to the fixed 500 kV options, we have not estimated the upgrade costs as part of this PACR. We consider this a proportionate approach to considering these options.

5. Seven options have been assessed (continued)

The initial estimated capital cost of this option is approximately $3,782 million. There would be additional costs associated with upgrading from 330 kV to 500 kV as well but these have not been estimated as part of this PACR.[80]



5.3.2 Option 3C – New 500 kV double-circuit lines in an electrical 'loop' between Maragle, Wagga Wagga and Bannaby

This option involves constructing new 500 kV double-circuit lines between Maragle, Wagga Wagga and Bannaby.

The high level scope includes:

- New Wagga Wagga 500/330 kV substation and 330kV double circuit connection to the existing Wagga Wagga 330kV substation
- Construct three 500 kV transmission lines:
  - Between Maragle and Bannaby 500 kV substations;
  - Between Maragle and Wagga Wagga 500 kV substations; and
  - Between Wagga Wagga and Bannaby 500 kV substations
- Three new 500/330/33 kV 1,500 MVA transformers at Maragle substation and two new 500/330/33 kV 1,500 MVA transformers at new Wagga Wagga 500kV substation
- Augment the Maragle substation to accommodate the additional transmission lines
- Augment the existing Wagga Wagga 330kV and Bannaby 500kV substations to accommodate the additional transmission lines

Preliminary modelling indicates that additional 2,570 MW generation could be accommodated at times of average import from VIC and average renewable generation in southern NSW.

The estimated capital cost of this option is approximately $3,317 million.

As part of the PACR analysis, we have investigated two other variants of Option 3C's network topology and operating capacity, i.e:

- Option 3C-0 – constructed as a 100 per cent single-circuit configuration;[81] and
- Option 3C-1 – constructed primarily as a single-circuit configuration but with a 132 km double-circuit portion west of Bannaby.

While these variants are electrically identical to Option 3C, and so provide the same expected market benefits, they are found to have significantly greater costs and so have not been included in the body of this PACR. A discussion of these variants can be found in Appendix B.1.2.

81. Option 3C-0 represents the ISP candidate option, as identified by AEMO in its 2020 ISP. See AEMO, *2020 ISP*, July 2020, Appendix 3, p. 30.

6. Ensuring the robustness of the analysis

SUMMARY OF KEY POINTS:

- The RIT-T assessment considers four ISP scenarios, which differ in relation to demand outlook, DER uptake, assumed generator fuel prices, assumed emissions targets, retirement of coal-fired power stations, timing of major transmission augmentations and generator and storage capital costs.
- The scenarios cover a broad range of potential outcomes across the key uncertainties that are expected to affect the future market benefits of the investment options being considered and reflect the scenarios used by AEMO in the final 2020 ISP.
- The weighting of the scenarios has been updated since the PADR to align with the final 2020 ISP.
- A range of sensitivity tests have also been investigated, to further test the robustness of the outcome to key uncertainties and to test the likely impact of changes to assumptions in the 2022 ISP.

The transmission investments considered as part of this RIT-T involve long-lived assets, and it is important that the recommended preferred option does not depend on a narrow view of future outcomes, given that the future is inherently uncertain.

Uncertainty is captured under the RIT-T framework through the use of plausible scenarios, which reflect different assumptions about future market development, and other factors that are expected to affect the relative market benefits of the options being considered. The adoption of different plausible scenarios tests the robustness of the RIT-T assessment to different assumptions about how the energy sector may develop in the future.

The robustness of the outcome is also investigated through the use of sensitivity analysis in relation to key input assumptions. The sensitivity tests investigated in this PACR have been informed by submissions to the PADR. We have also undertaken a sensitivity to assess the impact of adopting the draft 2021 IASR assumptions.

6.1 THE ASSESSMENT CONSIDERS FOUR 'REASONABLE SCENARIOS'

The RIT-T is focused on identifying the top ranked credible option in terms of expected net benefits. However, uncertainty exists in terms of estimating future inputs and variables (termed future 'states of the world').

To deal with this uncertainty, the NER requires that costs and market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each scenario to determine a weighted ('expected') net benefit. It is this 'expected' net benefit that is used to rank credible options and identify the preferred option.

The credible options have been assessed under four scenarios as part of this PACR assessment, which reflect the scenarios adopted by AEMO in the 2020 ISP.[82]

While the scenarios are the same as applied in the PADR assessment, some of the specific assumptions feeding into them have been updated to align with the final 2020 IASR and final 2020 ISP and the ESOO published in August 2020. In particular:

- the QNI Medium and Large ISP projects are now reflected in the base case; and
- the PADR assumptions regarding the implications of the COP21 commitment and VRET/QRET have been updated.

In addition, the assessment now models the retirement dates of coal-fired generators based on when it is economic for these plants to retire, as opposed to the broad range of dates applied in the PADR. The approach taken is consistent with what AEMO applied in the 2020 ISP and is covered in more detail as part of the accompanying market modelling report.

The table below summarises the specific key variables that influence the net benefits of the options under each of the four scenarios considered.

Additional detail and discussion of each scenario is provided in the accompanying market modelling report released alongside this PACR.

82. AEMO, *Integrated System Plan*, July 2020, p. 86.

6. Ensuring the robustness of the analysis (continued)

Table 6-1 PACR modelled scenario's key drivers input parameters

KEY DRIVERS INPUT PARAMETER	CENTRAL	STEP-CHANGE	SLOW-CHANGE	FAST-CHANGE
Underlying consumption	ESOO 2020 Central	ESOO 2020 Step Change	ESOO 2020 Slow Change	ESOO 2020 Fast Change
Economic growth and population outlook	Moderate	High	Low	Moderate
Energy efficiency improvement	Moderate	High	Low	Moderate
DSP	Moderate	High	Low	Moderate
Rooftop PV	Moderate	High	Low	Moderate-High
Battery storage	Moderate	High	Low	Moderate-High
EV uptake	Moderate	High	Low	Moderate-High
New entrant capital cost for wind, solar SAT, OCGT, CCGT, and large-scale batteries	AEMO 2020 ISP Central	AEMO 2020 ISP Step Change	AEMO 2020 ISP Slow Change	AEMO 2020 ISP Fast Change
Gas fuel cost	Core Energy 2019, Neutral	Core Energy 2019, Fast	Core Energy 2019, Slow	Core Energy 2019, Neutral
Coal fuel cost	WoodMackenzie 2019, Neutral	WoodMackenzie 2019, Fast	WoodMackenzie 2019, Slow	WoodMackenzie 2019, Neutral
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.			
NEM carbon budget to achieve 2050 emissions levels	NA	Cumulative NEM electricity sector emissions budget to 2050 of 1,465 Mt CO2-e	NA	Cumulative NEM electricity sector emissions budget to 2050 of 2,208 Mt CO2-e
Victoria Renewable Energy Target (VRET)	40% renewable energy by 2025 and 50% renewable energy by 2030			
Queensland Renewable Energy Target (QRET)	50% renewable energy by 2030		NA	
Tasmanian Renewable Energy Target (TRET)	100% by 2022	100% by 2022 and 200% by 2040	100% by 2022	
NSW Electricity Infrastructure Roadmap	See section 2.1.3.			
EnergyConnect	1 July 2024			
Western Victoria Renewable Integration RIT T	All scenarios: 2025-26 (1 July 2025)			
Marinus Link and Battery of the Nation	1st cable 2036-37, 2nd cable not needed	1st cable 2028-29, 2nd cable 2031-32	NA	1st cable 2031-32, 2nd cable not needed
Victoria to NSW, Interconnector Upgrades	VNI Minor 2022-23; VNI West 2028-29[83]	VNI Minor 2022-23; VNI West 2035-36	VNI Minor 2022-23; VNI West: NA	VNI Minor 2022-23; VNI West: 2035-36
NSW to QLD Interconnector Upgrades	QNI minor, 1/07/2022; QNI Medium 2032-33, QNI Large 2035-36		QNI minor, 1/07/2022; QNI medium and large: NA	QNI minor, 1/07/2022; QNI Medium 2032-33, QNI Large 2035-36
Snowy 2.0	Snowy 2.0 is included from 1 July 2025			

It is not expected that these variables reflect all future uncertainties that may affect future market benefits of the options being considered, but are expected to provide a broad enough 'envelope' of where these variables may reasonably be expected to fall.

83. As outlined in section 2.2.5, we have assumed an earlier commissioning date for VNI West under the central scenario than in the core 2020 ISP assumptions, consistent with AEMO's accelerated delivery date in the 2020 ISP (and the draft 2021 IASR timing). Specifically, we have assumed a timing of 2028/29 for VNI West under the central scenario. We have also investigated a sensitivity assuming the core ISP timing of 2035/36 (see section 8.4.2).

6. Ensuring the robustness of the analysis (continued)

6.2 WEIGHTING THE SCENARIOS

We have weighted each of the above scenarios using the probabilities proposed by AEMO in the final 2020 ISP for HumeLink, i.e.:[84]

- 40 per cent to the central scenario;
- 30 per cent to the fast-change scenario;
- 20 per cent to the step-change scenario; and
- 10 per cent to the slow-change scenario.

While the above probabilities have been applied to weight the estimated market benefits and identify the preferred option across scenarios (illustrated in section 8), we have carefully considered the results in each scenario in section 8. We have also investigated a sensitivity that amends the scenario weightings applied based on recent commentary from the Energy Security Board (ESB) (presented in section 8.4.4).

6.3 SENSITIVITY ANALYSIS

In addition to the scenario analysis, we have also considered the robustness of the outcome of the cost benefit analysis through undertaking a range of sensitivity testing.

The range of factors tested as part of the sensitivity analysis in this PACR are:

- the impact of the recently announced new Kurri Kurri and Tallawarra B gas generators;
- delaying VNI West until 2035/36 (in-line with the core 2020 ISP assumption for the central scenario);
- whether adding MPFC as proposed by Smart Wires would increase the expected net benefits of the preferred option;
- increasing the weighting of the step-change scenario, in-line with recent commentary from the ESB;
- adopting higher and lower network capital costs of the credible options (including P90 estimates);
- alternate commercial discount rate assumptions; and
- adopting the draft 2021 IASR assumptions.

The results of the sensitivity tests are discussed in section 8.4.

The above list of sensitivities focuses on the key variables that could impact the identified preferred option.

84. AEMO, *2020 Integrated System Plan*, July 2020, p. 86.

7. Estimating the market benefits

SUMMARY OF KEY POINTS:

- Eight categories of market benefit under the RIT-T are considered material for this RIT-T and have been estimated as part of the economic assessment for the credible options within this PACR.
- 'Option value' has been estimated for both the flexible 500 kV options as well as going via Wagga Wagga.
- Competition benefits have been included in the PACR analysis and modelled using the 'Frontier approach'.
- Wholesale market modelling has been used to estimate these categories of market benefits.
- The market modelling assumptions and inputs have been updated since the PADR to align with those used in the final 2020 ISP and the 2020 ESOO.
- A separate modelling report has been released alongside this PACR that provides greater detail on the modelling approaches and assumptions, including details on the technical constraints adopted.

As outlined in section 3, the key benefits expected from increasing transmission capacity are driven by anticipated changes in wholesale market outcomes going forward.

The RIT-T requires categories of market benefits to be calculated by comparing the 'state of the world' in the base case where no action is undertaken, with the 'state of the world' with each of the credible options in place, separately. The 'state of the world' is essentially a description of the NEM outcomes expected in each case, and includes the type, quantity and timing of future generation investment as well as unrelated future transmission investment (e.g., that is required to connect REZ).

A wholesale market modelling approach has been applied to estimate the market benefits associated with each credible option included in this RIT-T assessment. The wholesale market modelling has also been applied to the base case for each scenario, i.e., the state of the world without a Humelink option in it.[85]

This section first outlines the specific categories of market benefit that are expected from reinforcing the Southern Shared Network of New South Wales, before providing an overview of the wholesale market modelling undertaken.

We are publishing a separate modelling report alongside this PACR that provides greater detail on the modelling approach and assumptions, to provide transparency to market participants.

7.1 EXPECTED MARKET BENEFITS FROM EXPANDING TRANSFER CAPACITY

The specific categories of market benefit under the RIT-T that have been modelled as part of this PACR are:

- changes in fuel consumption in the NEM arising through different patterns of generation dispatch;
- changes in costs for parties, other than the RIT-T proponent (i.e., changes in investment in generation and storage);
- differences in unrelated transmission investment (in particular, the cost of connecting REZ assumed in the 2020 ISP);
- changes in involuntary load curtailment;
- changes in voluntary load curtailment;
- changes in network losses;
- competition benefits; and
- option value associated with the flexible 500 kV options (i.e., options 2B and 3B).

We have estimated all of the market benefits categories, with the exception of competition benefits, across all of the options considered in this PACR (the 'positioning analysis'). We have then considered the top two ranked options, and estimated competition benefits for those options, as part of the formal RIT-T assessment.

All market benefits for the credible options are presented in this PACR as being relative to the base case for each scenario, i.e., the state of the world without the Humelink option in it.

The approach taken to estimating each of these market benefits is outlined below and discussed in greater detail in the accompanying market modelling report.

85. The RIT-T requires that in estimating the magnitude of market benefits, a market dispatch modelling methodology must be used, unless the TNSP(s) can provide reasons why this methodology is not relevant. See: AER, *Final Regulatory Investment Test for Transmission*, June 2010, version 1, paragraph 11, p. 6.

7. Estimating the market benefits (continued)

7.1.1 Changes in fuel consumption in the NEM

This category of market benefit is expected where credible options result in different patterns of generation and storage dispatch across the NEM, compared to the base case.

In particular, the primary effects of reinforcing the NSW Southern Shared Network come from enabling demand centres to be supplied by lower cost generation than can be expected if no upgrade is undertaken. The market modelling finds that new renewable generation avoids the need for gas-fired generation to operate. As outlined in section 8, this is a key category of benefit estimated for all scenarios (except under the slow-change scenario).[86]

7.1.2 Changes in costs for other parties in the NEM

This category of market benefit is expected where credible options result in different investment patterns of generators and large-scale storage across the NEM, compared to the base case.

In particular, the market modelling finds that there are large amounts of avoided new dispatchable generation in NSW compared to the base case. As shown in section 8, these avoided or deferred, costs associated with generation and storage are the largest category of market benefit estimated across all options and scenarios.

7.1.3 Differences in unrelated transmission costs

This benefit category relates to the costs of intra-regional transmission investment associated with the development of REZs that could be avoided if a credible option is pursued.

AEMO has identified a number of REZs in various NEM jurisdictions as part of the ISP and has included allowances for transmission augmentations that it considers would be required to develop those REZs. In addition, as outlined in section 2.2.3, while the NSW Government Roadmap REZs were not included in the final 2020 ISP, we have reflected it in the market modelling for the PACR since it is now legislated (and note this approach is consistent with the draft 2021 IASR assumptions). The credible options being considered in this RIT-T can allow development of some of these REZs without the need for additional intra-regional transmission investment (or less of it).

7.1.4 Changes in involuntary load curtailment

Increasing the transmission transfer capacity in southern New South Wales increases the generation supply availability from existing generation to meet New South Wales demand. This will provide greater reliability for each state by reducing the potential for supply shortages and the consequent risk of involuntary load shedding.

This market benefit involves quantifying the impact of changes in involuntary load shedding associated with the implementation of each credible option via the time sequential modelling component of the market modelling. Specifically, the modelling estimates the MWh of unserved energy (USE) in each trading interval over the modelling period, and then applies a Value of Customer Reliability (VCR, expressed in $/MWh) to quantify the estimated value of avoided USE for each option.

While the PADR adopted AEMO's standard assumptions for VCR, this PACR now applies the recently estimated AER VCR values.

This category of market benefit has been found to be relatively small within the market modelling. This is due to there not being a material difference in the quantity of involuntary load shedding between each option and the base case, under each of the scenarios. The reason is that, for both the options and the base cases, it is economic to build sufficient dispatchable capacity to maintain high levels of reliability.

7.1.5 Changes in voluntary load curtailment

Voluntary load curtailment is when customers agree to reduce their load once wholesale prices in the NEM reach a certain threshold. Customers usually receive a payment for agreeing to reduce load in these circumstances. Where the implementation of a credible option affects wholesale price outcomes, and in particular results in wholesale prices reaching higher levels in some trading intervals than in the base case, this may have an impact on the extent of voluntary load curtailment.

This class of market benefit has also been found to be relatively low within the market modelling, reflecting that the level of voluntary load curtailment currently present in the NEM is not significant. As for changes in involuntary curtailment outlined above, the model will build additional capacity if that is more economic than the market costs of voluntary load curtailment.

7.1.6 Changes in network losses

The time sequential market modelling has taken into account the change in network losses that may be expected to occur as a result of the implementation of each of the credible options, compared with the level of network losses which would occur in the base case, for each scenario.

The benefit of changes to network losses is captured within the wholesale market modelling of dispatch cost benefits of avoided fuel costs and changes to voluntary and involuntary load shedding.

The reduction in network losses between the base case and the options is material for the options considered in this PACR (particularly for the 500 kV options) and reduces both the energy to be produced by fossil fuel generators to account for the losses, and a reduction in new capacity that has to be built to supply demand, particularly during peak periods.

7.1.7 Option value

This PACR investigates whether there is significant option value associated with flexible options, which would readily and cost-effectively increase the transfer capacity between the Snowy Mountains and Sydney in the future. This is investigated through inclusion of option variants that would be built at 500 kV but initially operated at 330 kV (options 2B, 3B). These options provide flexibility to 'scale up' transfer capacity at a later date, in response to changes in demand and/or the expansion of generation capacity along the transmission corridor, whilst avoiding upfront investment associated with higher capacity.

The modelling in this PACR estimates the option value associated with these flexible options as part of the scenario analysis, which is in line with the AER's cost benefit assessment guidelines.[87] Specifically, the flexible options are assumed to operate at 330 kV until the benefits from upgrading to 500 kV exceed the annualised upgrade cost. Since the benefits from each of these flexible options differ across the scenarios, the PACR modelling finds it is optimal to upgrade these options to 500 kV at different times for each scenario. Specifically, the PACR modelling

86. AER, *Guidelines to make the Integrated System Plan actionable*, August 2020, pp, p. 37-42.
87. AER, *Guidelines to make the Integrated System Plan actionable*, August 2020, pp, p. 37-42.

7. Estimating the market benefits (continued)

finds that it is optimal to upgrade these flexible options from 330 kV to 500 kV in the following years:[88]

- 2030-31 in the central scenario;
- 2032-33 in the fast-change scenario;
- 2029-30 in the step-change scenario; and
- 2035-36 in the slow-change scenario.

As outlined in section 8, the flexible 500 kV options are found to provide lower net benefits than the fixed 500 kV options under all scenarios.[89]

7.1.8 Competition benefits

The PADR concluded that we did not expect competition benefits to be material in terms of identifying the preferred option for this RIT-T, due to the modelling finding that the largest capacity options were preferred (which can be expected to have the greatest impact on any competition benefits). We note that AEMO did not consider competition benefits in its 2020 ISP.

However, additional testing of expected competition benefits undertaken following the PADR, showed that they are in fact expected to constitute a substantial benefit category for this RIT-T. This is consistent with previous commentary by Frontier Economics, who have noted the importance of competition benefits for investments like Humelink.[90]

Failure to adequately consider competition benefits would therefore substantially underestimate the potential market benefits associated with HumeLink, and therefore the net market benefit (which may be material to the RIT-T outcome if the assessment excluding competition benefits were to find that no option has a positive net market benefit).

As a consequence, we have now estimated competition benefits in this RIT-T. This is consistent with the AER's latest cost benefit analysis guidelines, under which a RIT-T proponent has discretion when considering whether to quantify a market benefit class that AEMO did not include in the ISP. In applying its discretion, the AER states that the RIT-T proponent should consider whether doing so is likely to materially affect the outcome of the CBA, and that the associated computational burden of including it is not expected to be disproportionate to the potential benefits.[91] We have taken this as guidance on how to apply the RIT-T for Humelink on the basis that it is an actionable ISP project and the cost benefit analysis guidelines are critical to actionable ISP project, despite it not being strictly applicable to Humelink. Including competition benefits in the assessment is also consistent with the NER requirements for the PACR (i.e., those under clauses 5.16A.4(d)(5) and 5.16A.4(j)(1)).

We have focused on the two highest ranked options (from the 'positioning analysis', which excludes competition benefits – see section 8.2). This is due to the time required and complexity of estimating competition benefits. We consider this a proportionate approach, as the extent of competition benefits is unlikely to differ materially between options of the same capacity, and so is not expected to change the ranking of options.

Competition benefits arise when there is a change in the dispatch of generators and/or storage in the market in light of a credible option being commissioned. Specifically, they occur when there is a change in the way these entities dispatch so that there is overall more efficient dispatch in the market than under the base case, and a price impact that allows consumers to benefit through a change in their consumption decisions.

The AER suggest two possible methodologies for identifying that component of market benefits attributable to competition benefits – the 'Biggar approach' and the 'Frontier approach'. Both of these approaches involve the same methodology for calculating the overall market benefits of a credible option. The difference between the two approaches is in how to divide the overall market benefits of a credible option between competition benefits and other benefits (also referred to as 'efficiency benefits').[92]

We have adopted the Frontier approach as part of this PACR, which involves finding the difference between the change in overall economic surplus resulting from the credible option:

- assuming bidding reflected the prevailing degree of market power both before and after the augmentation; and
- assuming competitive bidding both before and after the augmentation.

Section 7.3 provides more detail on how the Frontier approach has been applied in the context of this PACR.

88. The 330 kV to 500 kV upgrade costs have not been estimated as part of the PACR and so this analysis has been undertaken assuming the upgrade costs from the PADR, which are lower than what is expected now due to the general increase in costs between the PADR and PACR. The flexible options (i.e., the 'B' options) therefore assume that they are upgraded from 330 kV to 500 kV at the dates listed above, and so attract greater market benefits from this upgrade, but do not include the cost of the upgrade (which means that their net benefits are over-estimated compared to if the upgrade costs were included). This approach was taken as an initial assumption to investigate how these options fared relative to the other options before resources were dedicated to estimating the upgrade costs and, since the flexible options are found to always be inferior to the fixed 500 kV options, we have not estimated the upgrade costs as part of this PACR (which we consider a proportionate approach to considering these options).

89. Option 1B, Option 2B, and Option 3B, being the flexible 500 kV options, are ranked 6th, 7th and 4th respectively in the positioning assessment. These flexible options consistently exhibit lower net benefits than their corresponding fixed 500 kV options due to their higher initial costs.

90. Frontier Economics have previously 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. See: Frontier Economics, 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

91. AER, *Guidelines to make the Integrated System Plan actionable*, August 2020, p. 61.

92. AER, *Application guidelines Regulatory Investment Test for Transmission*, August 2020, p. 88.

7. Estimating the market benefits (continued)

7.2 WHOLESALE MARKET MODELLING HAS BEEN USED TO ESTIMATE MARKET BENEFITS

We engaged EY to undertake the wholesale market modelling to assess the market benefits expected to arise under each of the credible options and scenarios.

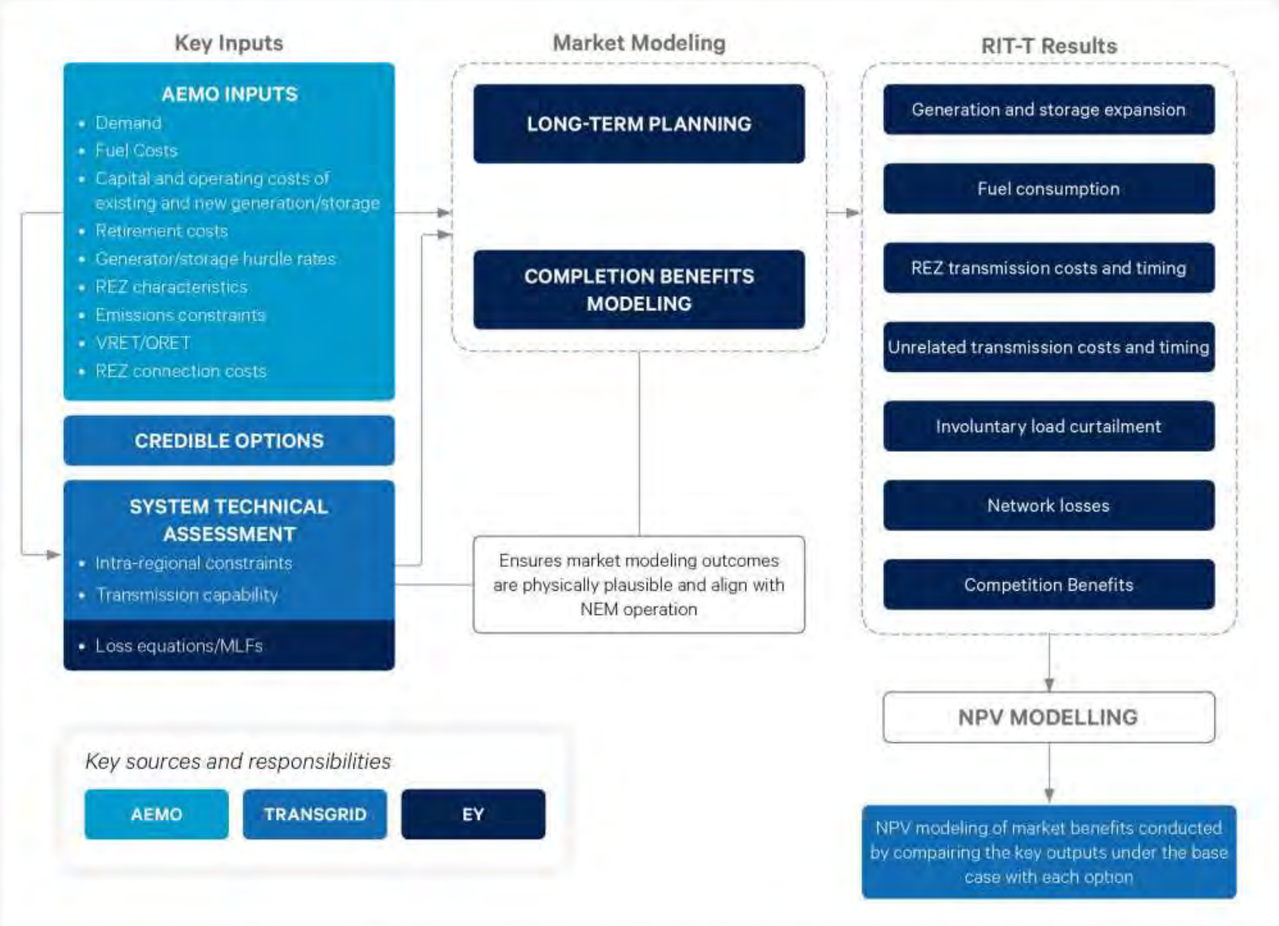
EY has applied a linear optimisation model and performed hourly, time-sequential, long-term modelling for the NEM to estimate categories of wholesale market benefits expected under each of the options. Specifically, EY has undertaken long-term Investment Planning which identifies the optimum generation (including storage) and unrelated transmission infrastructure development schedule, while meeting reliability requirements, policy objectives, and technical generator and network performance limitations for both the base case and each of the different options.

We have undertaken a detailed System Technical Assessment, which evaluates the power system behaviour and performance under each credible option and ensures market modelling outcomes are physically plausible, follow the operation of the NEM, and that the benefits of credible options align with the changes to the power system under each credible option. This assessment serves as an input to the wholesale market modelling exercises EY has undertaken (as outlined above).

These exercises are consistent with an industry-accepted methodology, including within AEMO's ISP.

Figure 4 illustrates the interactions between the key modelling exercises, as well as the primary party responsible for each exercise and/or where the key assumptions have been sourced.

Figure 4 – Overview of the market modelling process and methodologies



As these modelling exercises investigate different aspects of the market simulation process, they necessarily interact and are executed iteratively using inputs and outputs.

The accompanying market modelling report provides additional detail on these modelling exercises, as well as the key modelling assumptions and approach adopted more generally.

7. Estimating the market benefits (continued)

7.3 COMPETITION BENEFITS HAVE BEEN ESTIMATED

Clause 5.15A.3(b)(4) 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. 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 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.[93]

At a high-level, competition benefits are calculated as the difference between the following present values of the overall economic surplus:[94]

- arising with the credible option assumed, 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 for estimating competition benefits, known as the 'Biggar approach' and the 'Frontier approach', where their difference is in how to divide the overall market benefits of a credible option between competition benefits and other benefits (also referred to as 'efficiency benefits').

In order to define generators and portfolios with some degree of market power, EY has used the latest analysis conducted by Frontier Economics[95] and confirmed their findings. However, a shorter list of generators has been considered since, with the assumption of economic retirement in the modelling, some generators in the Frontier Economics list either retire earlier than when HumeLink is commissioned or within a short time after that and thus make a minimal contribution to competition benefit estimation.

The EY model is adjusted to use the capacity build and retirements that result from long-term investment planning under the base case on which the economic dispatch is run. Hydro and energy-limited storages are optimised in the model in such a way they maximise their water values while not exceeding their storage and inflow characteristics. The model is run on both the base case and option cases for two sets of bidding, i.e. competitive and strategic bidding. 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 modelling.

For further details on the modelling of competition benefits, please refer to the accompanying market modelling report.

7.4 GENERAL MODELLING PARAMETERS ADOPTED

The RIT-T analysis spans a 25-year assessment period from 2021/22 to 2045/46.

Where the capital components of the credible options have asset lives extending beyond the end of the assessment period, the NPV modelling includes a terminal value to capture the remaining asset life. This ensures that the capital cost of long-lived options over the assessment period is appropriately captured, and that all options have their costs and benefits assessed over a consistent period, irrespective of option type, technology or asset life. The terminal values are calculated as the undepreciated value of capital costs at the end of the analysis period and can be interpreted as a conservative estimate for benefits (net of operating costs) arising after the analysis period. We note that for this RIT-T, the terminal value assumption is not material in terms of the outcome, with the benefits generated by the preferred option exceeding the total estimated project costs before the end of the assessment period.

A real, pre-tax discount rate of 5.90 per cent has been adopted as the central assumption for the NPV analysis presented in this PACR, consistent with the assumptions adopted in the ISP. The RIT-T requires that sensitivity testing be conducted on the discount rate and that the regulated weighted average cost of capital (WACC) be used as the lower bound. We have therefore tested the sensitivity of the results to a lower bound discount rate of 2.23 per cent,[96] and an upper bound discount rate of 7.90 per cent (i.e., consistent with the 2020 IASR).

93. Frontier Economics, 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.
94. 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.
95. Frontier Economics, *Modelling of Liddell* power station closure, 6 December 2019 – available at: https://www.energy.gov.au/sites/default/files/Frontier%20Economics%20Modelling%20of%20Liddell%20Power%20Station%20Closure.pdf (accessed 28 June 2021).
96. This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM, see: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/directlink-determination-2020-25

8. Net present value results

SUMMARY OF KEY POINTS:

- We have undertaken a positioning assessment covering all seven credible options across each of the four ISP scenarios and find that Option 3C is consistently the top-ranked option, delivering positive net benefits in all scenarios, with the exception of the slow-change scenario, as well as on a weighted basis (in order of $39 million in present value terms).
- The formal RIT-T assessment builds on the positioning assessment and includes estimates of the additional competition benefits expected from the top two ranked options (Option 2C and Option 3C). We find that Option 3C continues to be strongly preferred (with expected net benefits increasing to $491 million in present value terms).
- Under all scenarios, the benefits for Option 3C are primarily driven by avoided, or deferred, costs associated with generation and storage build.
- Avoided generator fuel costs, competition benefits and avoided transmission capital costs to connect new REZ make up the vast majority of other market benefits estimated for Option 3C, with their relativities varying across the scenarios.
- This conclusion is found to be robust to a range of sensitivity tests.
- All market benefits for the credible options are presented as being relative to the base case for each scenario, i.e., the state of the world without a Humelink option in it.

8.1 STRUCTURE OF THE PACR NPV ASSESSMENT

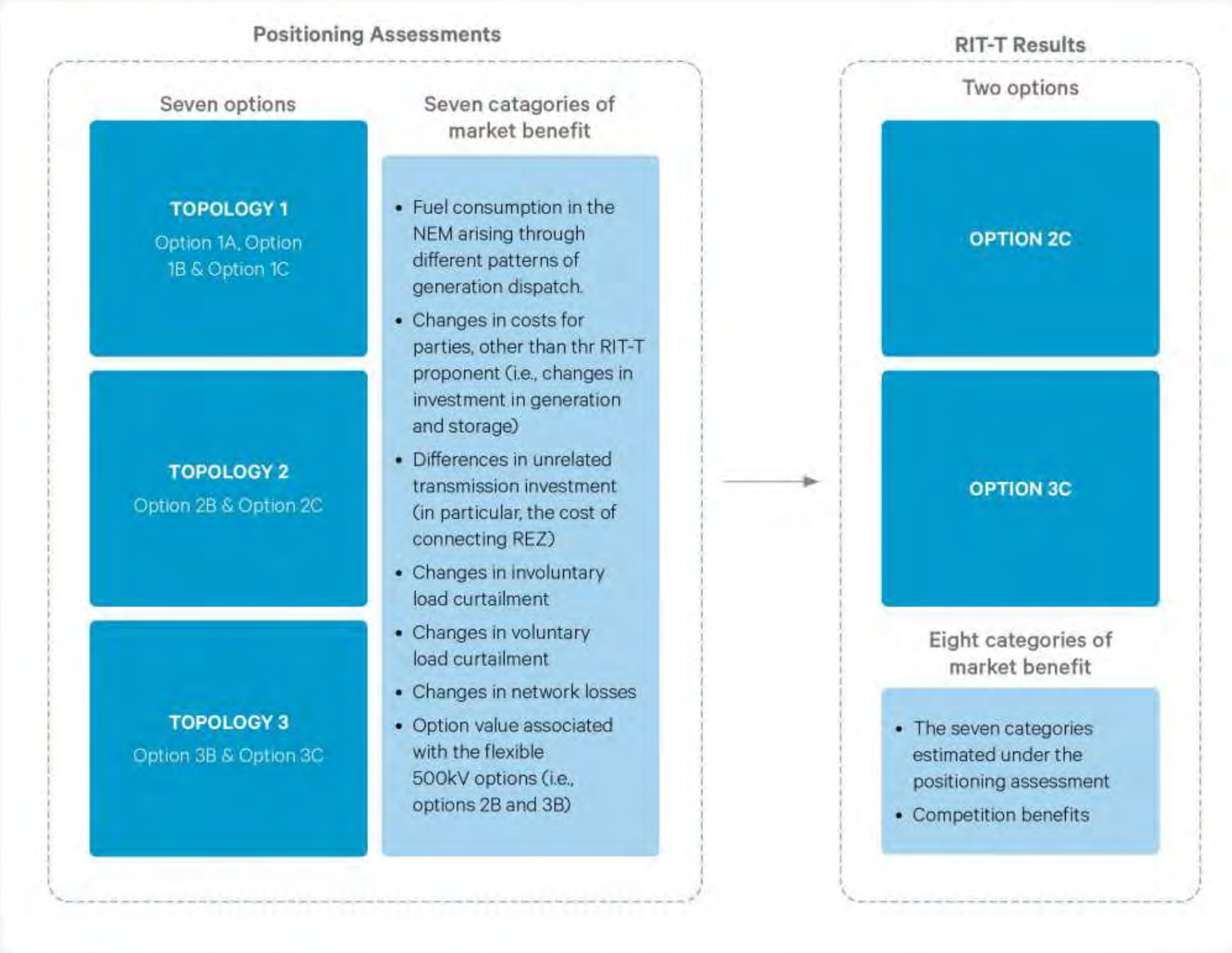
We have applied a two-stage approach to the NPV assessment for the PACR. Specifically, we have:

- undertaken a positioning assessment, which covers all seven credible options across each of the four ISP scenarios; then
- focused the formal RIT-T assessment on the top two ranked options from the positioning assessment (Option 2C and Option 3C).

The key difference between these two stages is that the formal RIT-T assessment includes estimates of the additional competition benefits expected from the top two ranked options. This is considered a proportionate approach to assessing all seven credible options given the complexities and modelling resources required to estimate competition benefits.

8. Net present value results (continued)

Figure 5 – Structure of the NPV assessment



8.2 POSITIONING ASSESSMENT (EXCLUDING COMPETITION BENEFITS)

The positioning assessment assesses all seven credible options across each of the four ISP scenarios. It does not include competition benefits since the modelling required is considerable for each option and is not considered a proportionate exercise for most of the options based on the positioning assessment set-out below. Competition benefits have been estimated for the top-ranked options coming out of the positioning assessment and are presented in section 8.3 below.

8.2.1 Central scenario

The central scenario reflects AEMO's moderate demand forecasts (including Demand-Side Participation (DSP)), neutral gas and coal price forecasts, coal plants retiring on an economic basis (or at the end of their announced/technical lives), as well as a national emissions reduction of around 28 per cent below 2005 levels by 2030.

Released under FOI

Document 2

8. Net present value results (continued)

AEMO describes the central scenario as reflecting 'the current transition of the energy industry under current policy settings and technology trajectories, where the transition from fossil fuels to renewable generation is generally led by market forces and supported by current federal and state government policies'.[97]

The PACR assessment finds that Option 3C has the highest expected net benefit under these assumptions and is the only option with a positive expected net benefit (at $49 million). Option 2C is the second-ranked option with estimated negative net benefits (i.e., a net cost) of $33 million.[98]

Figure 6 shows the overall estimated net benefit for each option under the central scenario.

Figure 6 – Summary of the estimated net benefits under the central scenario – excluding competition benefits

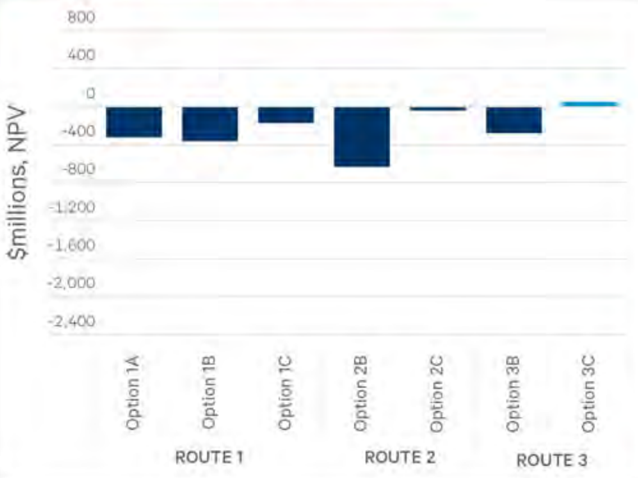
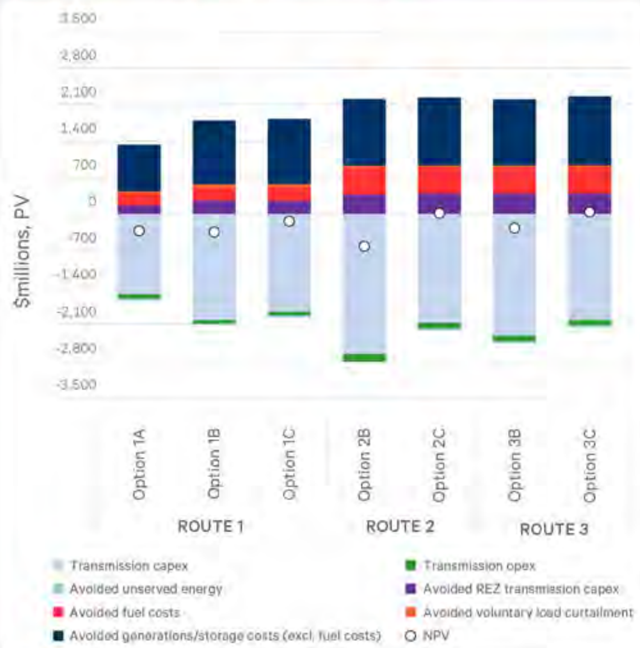


Figure 7 shows the composition of estimated net benefits for each option under the central scenario.

Figure 7 – Breakdown of estimated net benefits under the central scenario – excluding competition benefits



The key findings from the assessment of each option under the central scenario (excluding competition benefits) are that:[99]

- All credible options beside Option 3C are found to deliver negative net market benefits, ranging from approximately -$33 million (Option 2C) to -$639 million (Option 2B).
- The fixed 500 kV options (i.e., the 'C' options) provide the greatest net benefit of the options considered on account of these options providing the greatest (and earliest) increase in transfer capacity.
- Market benefits of all options are primarily derived from avoided/deferred generation and storage capital costs (shown by the dark blue sections of each bar in Figure 7 respectively).
  - These benefits are primarily driven by avoided/deferred large-scale storage (LS battery) developments and avoided solar developments from 2030. While the deferred LS battery capacity starts to be built in the late 2030s, avoided OCGT build from the late 2030s and pumped hydro from the early 2040s results in further market benefits.
  - The market modelling indicates that the majority of capacity deferral/avoidance occurs in New South Wales and, to a lesser extent, in Queensland. Southern states are forecast to have additional installations of renewables as HumeLink allows for a more diverse and higher quality of capacity mix.

97. AEMO, *2019 forecasting and planning scenarios, inputs, and assumptions*, August 2019, p. 3.
98. Calculation of benefits and costs have involved escalation of capital cost inputs and wholesale market benefit inputs. Capital cost inputs are estimated in real 2019/20 dollars and inflated to real 2020/21 dollars. Similarly, wholesale market benefit inputs are modelled in real 2018/19 dollars and inflated to real 2020/21 dollars (except for IASR sensitivity inputs, where market benefit inputs are modelled in 2019/20 dollars). We have used Australia CPI (ABS Series ID A2325846C) to inflate inputs to real 2020/21 dollars. Adjustments to June 2020 and September 2020 quarter CPI were made to smooth out the effects of deflation during these quarters due to the effect of the COVID-19 pandemic. These adjustments were made as the pandemic significantly reduced price levels for furnishings, household equipment and services, transport and education components of CPI that, while relevant for CPI as a whole, is less relevant for transmission project costs or the long term value consumers receive from transmission projects. We also have estimated June 2021 quarter CPI based on an annual inflation rate of 2.5 per cent, being the mid-range of RBA's long term inflation target.
99. The detailed descriptions of the drivers of the key market benefit categories below are based on the market modelling results for Option 3C. Please refer to the accompanying market modelling results, and report, released alongside this PADR for more detail on the market modelling results for all options.

8. Net present value results (continued)

- Avoided fuel costs are the second most material category of market benefit estimated across the options (shown by the red sections of each bar in Figure 7).
  - These arise primarily from lower black coal generation in New South Wales in the early years of the assessment period.
  - In the later years of the modelling period, lower gas generation in New South Wales is forecast to also contribute to fuel cost savings.
- REZ transmission cost savings (shown by the purple sections of each bar in Figure 7) are mainly driven by Humelink allowing builds in REZs with free transmission capacity such as Wagga Wagga and West Victoria to replace/defer REZ transmission expansion in REZs such as Central West Orana.

Figure 8 below presents the estimated cumulative expected gross benefits for Option 3C for each year of the assessment period under the central scenario.[100] It shows the cumulative market benefits, in present value terms (and so the final year's stacked bars align with the overall breakdown of estimated market benefits shown in Figure 7 above).

Figure 8 – Breakdown of cumulative gross benefits for Option 3C under the central scenario[101] - excluding competition benefits

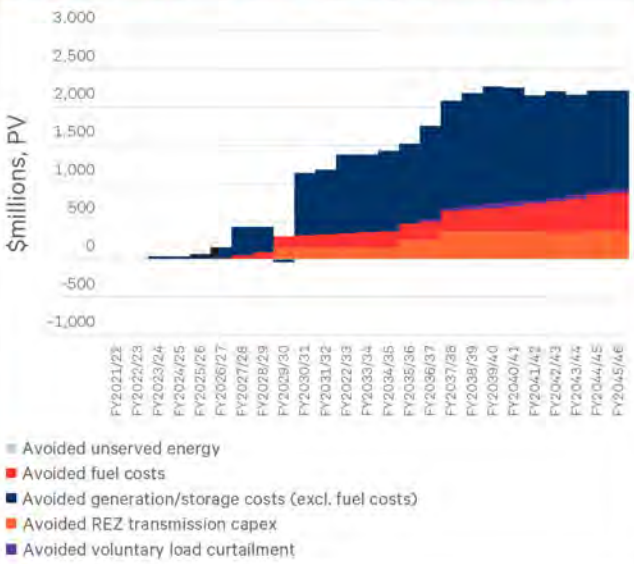


Figure 9 summarises the difference in generation and storage output modelled for Option 3C (in TWh), compared to the base case, i.e. what is found to be driving the avoided fuel cost benefit. The accompanying market modelling results workbook provides the data underpinning this chart, as well as the same data for all other options and scenarios (at both the technology and regional levels).

Figure 9 – Difference in output with Option 3C, compared to the base case, under the central scenario

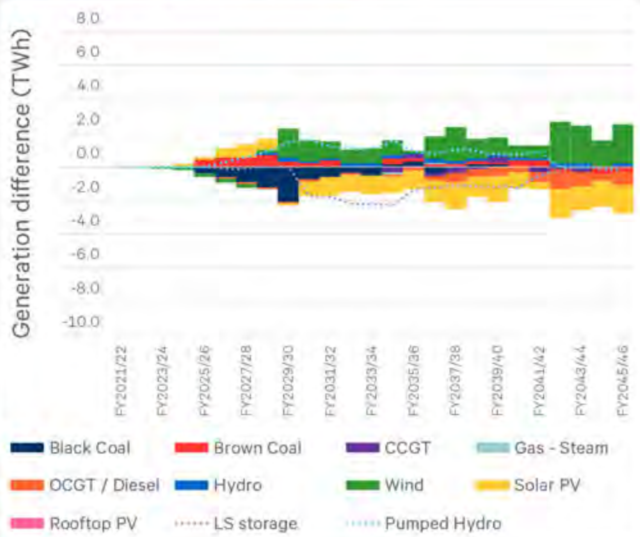
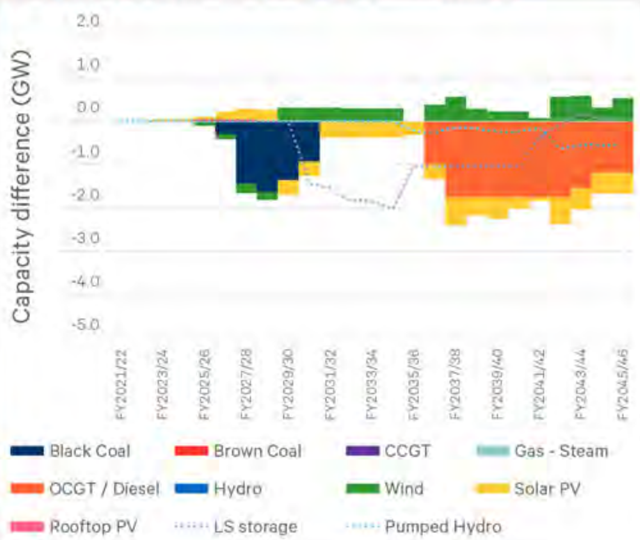


Figure 10 summarises the difference in generation and storage capacity modelled for Option 3C (in GW), compared to the base case, i.e. what is found to be driving the avoided or deferred costs associated with generation and storage benefit.

Figure 10 – Difference in cumulative capacity built with Option 3C, compared to the base case, under the central scenario



While this section (as well as sections 8.2.2, 8.2.3 and 8.2.4) focusses on the drivers of market benefits for Option 3C, we note that the drivers are effectively the same for the second ranked option (Option 2C) under this scenario.

100. This figure only presents the annual breakdown of estimated gross benefits for the preferred option. The separately released spreadsheet presents an annual breakdown of costs and benefits for all options. Since this figure shows the cumulative gross benefits in present value terms, the height of the bar in 2045-46 equates to the gross benefits for Option 3C shown in Figure 7 above.

101. While all generator and storage capital costs have been included in the market modelling on an annualised basis, this chart, and all charts of this nature in the PADR, present the entire capital costs of these plant in the year avoided in order to highlight the timing of the expected market benefits. This is purely a presentational choice that we have made to assist with relaying the timing of expected benefits (i.e. when thermal plant retire) and does not affect the overall estimated net benefit of the options.

8. Net present value results (continued)

8.2.2 Fast-change scenario

The fast-change scenario reflects a state of the world where there is a rapid technology-led transition of the power system and a 'fast-change' in emissions. Assumptions made in the fast-change scenario include AEMO's moderate demand forecasts (including DSP), neutral gas and coal price forecasts, carbon budget, and economic retirements of coal plants.

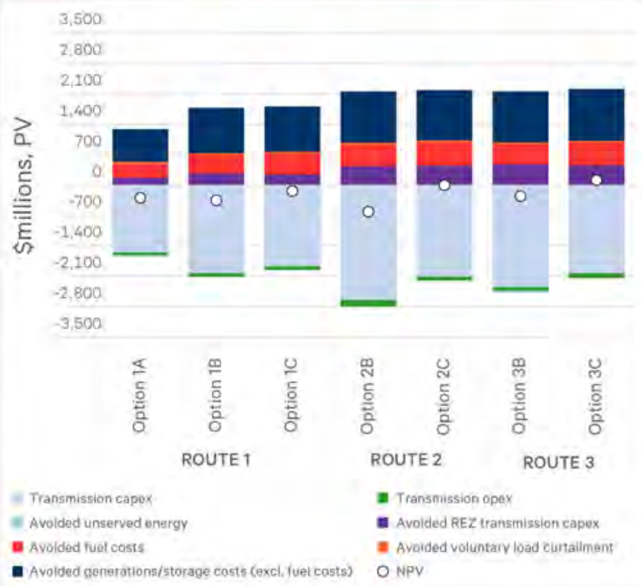
AEMO describes the fast-change scenario as reflecting a 'rapid technology-led transformation, particularly at grid scale, where advancements in large scale technology improvements and targeted policy support reduce the economic barriers of the energy transmission. In this scenario, coordinated national and international action towards achieving emissions reductions, leading to manufacturing advancements, automation, accelerated retirement of existing generators, and integration of transport into the energy sector'.[102]

The PACR assessment finds that Option 3C has the highest expected net benefit under these assumptions and, besides Option 2C, is the only option with positive net benefits. Option 3C is estimated to deliver approximately $91 million in net benefits under this scenario, while the second-ranked option (Option 2C) has marginally positive estimated net benefits of $9 million.

Figure 11 – Summary of the estimated net benefits under the fast-change scenario – excluding competition benefits

Figure 12 shows the composition of estimated net benefits for each option under the fast-change scenario.

Figure 12 – Breakdown of estimated net benefits under the fast-change scenario – excluding competition benefits



The key findings from the assessment of each option under the fast-change scenario (excluding competition benefits) are that:[103]

- The fast-change scenario results in a slightly higher estimated net benefits for all options compared to the central scenario.
  - The fast-change scenario increases the estimated net benefits compared to the central scenario by between approximately $27 million (Option 1A) and $46 million (Option 1C).
- The fixed 500 kV options (i.e. the 'C' options) continue to provide the greatest net benefit of all options considered on account of these options providing the greatest (and earliest) increase in transfer capacity.
- Market benefits of all options (besides the topology 1 options) are mostly derived from avoided generation and storage costs in the wholesale market (shown by the dark blue section of bars in Figure 12). Avoided fuel costs (red section of bars in Figure 12) and avoided REZ transmission capex (purple section of bars in Figure 12) also contribute significantly to gross wholesale market benefits.
  - As for the central scenario, this scenario finds that avoided/deferred capex is primarily from LS batteries and OCGTs in NSW. By the end of the study period, the model forecasts avoidance of OCGT and pumped hydro as well as more brown coal retirement with Option 3C, while more LS battery, wind and solar capacities are expected to be built.
  - Fuel cost savings are also expected to be mainly due to lower black coal generation in NSW in the early years of the assessment period, followed by lower gas generation later on.
  - REZ transmission capex are also avoided, mainly in 2029 and the mid-2030s, as Option 3C allows builds in REZs with free transmission capacity such as Wagga Wagga and other REZs in South Australia and Victoria to replace installations in REZs that incur transmission build in the base case.

102. AEMO, *2019 forecasting and planning scenarios, inputs, and assumptions*, August 2019, p. 4.

103. The detailed descriptions of the drivers of the key market benefit categories below are based on the market modelling results for Option 3C. Please refer to the accompanying market modelling results, and report, released alongside this PADR for more detail on the market modelling results for all options.

8. Net present value results (continued)

Figure 13 below presents the estimated cumulative expected gross benefits for Option 3C for each year of the assessment period under the fast-change scenario.

Figure 13 – Breakdown of cumulative gross benefits for Option 3C under the fast-change scenario– excluding competition benefits

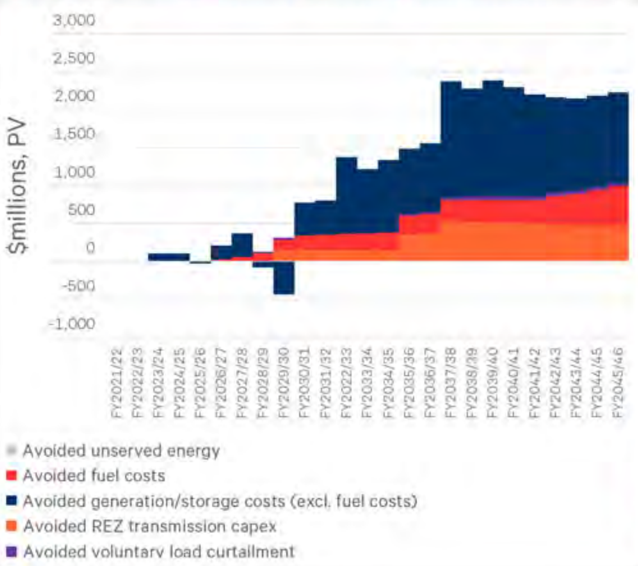


Figure 14 summarises the difference in generation and storage output modelled for Option 3C (in TWh), compared to the base case.

Figure 14 – Difference in output with Option 3C, compared to the base case, under the fast-change scenario

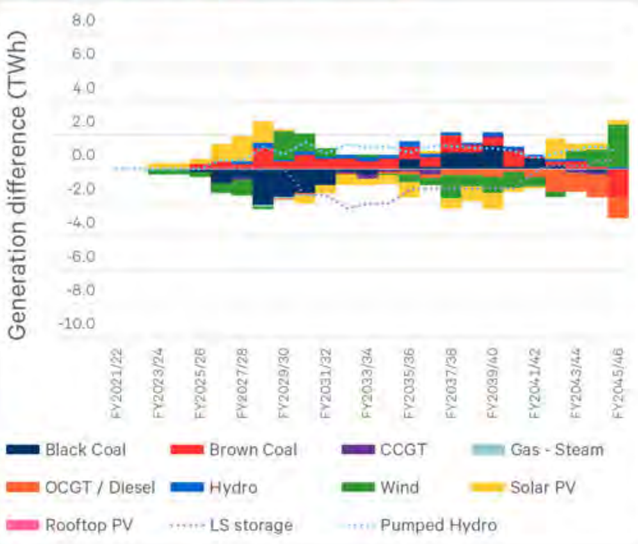
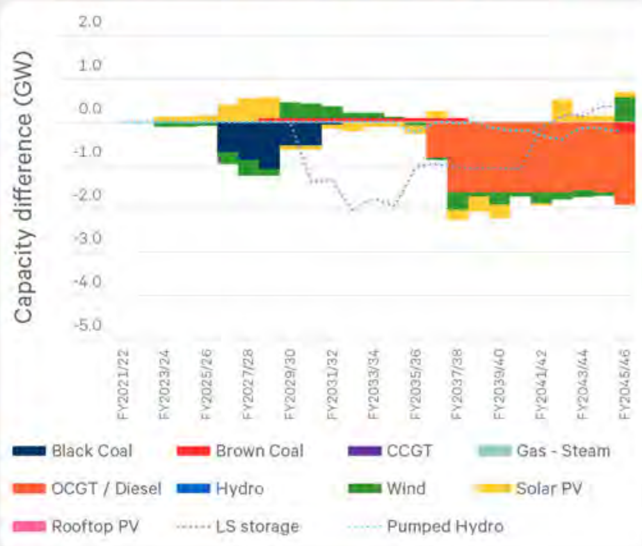


Figure 15 summarises the difference in generation and storage capacity modelled for Option 3C (in GW), compared to the base case.

Figure 15 – Difference in cumulative capacity built with Option 3C, compared to the base case, under the fast-change scenario



8.2.3 Step-change scenario

The step-change scenario reflects a state of the world where there is strong action on climate change and a 'step-change' in emissions, including AEMO's high demand forecasts (including DSP), fast gas and coal price forecasts, coal plants retiring earlier than the central scenario, as well as a restrictive carbon budget.

AEMO describe the step-change scenario as reflecting 'strong action on climate change that leads to a step-change reduction of greenhouse gas emissions. In this scenario, aggressive global decarbonisation leads to faster technological improvements, accelerated exit of existing coal generators, greater electrification of the transport sector with increased infrastructure developments, energy digitalisation, and consumer-led innovation'.[104]

The PACR assessment finds that Option 3C continues to be the top-ranked option under this scenario and is estimated to deliver $634 million in net benefits, while the second-ranked option (Option 2C) has estimated net benefits of $537 million. Under the step-change scenario, the net benefits of all options are found to increase significantly yielding positive expected net benefits, besides Option 1A, Option 1B and Option 2B.

104. AEMO, *2019 forecasting and planning scenarios, inputs, and assumptions*, August 2019, p. 4.

8. Net present value results (continued)

Figure 16 shows the overall estimated net benefit for each option under the step-change scenario.

Figure 16 – Summary of the estimated net benefits under the step-change scenario – excluding competition benefits

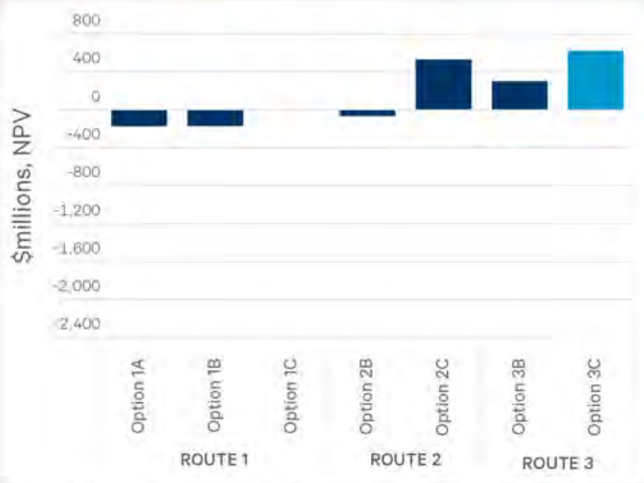
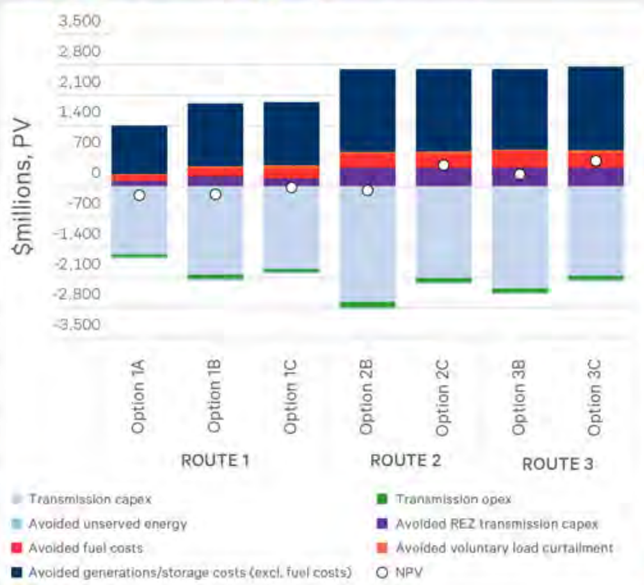


Figure 17 shows the composition of estimated net benefits for each option under the step-change scenario.

Figure 17 – Breakdown of estimated net benefits under the step-change scenario – excluding competition benefits

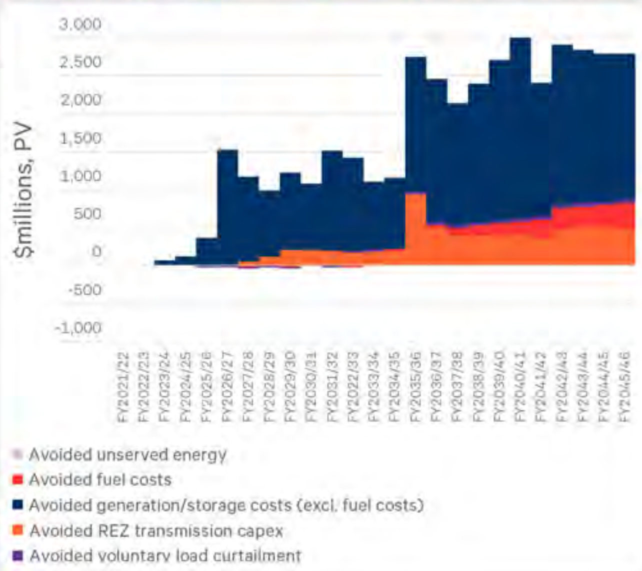


The key findings from the assessment of each option under the step-change scenario (excluding competition benefits) are that:[105]

- The step-change results in greater estimated net benefits for all options than under the central scenario, ranging from approximately $155 million (Option 1A) to $596 million (Option 3B).
- The fixed 500 kV options (i.e., the 'C' options) continue to provide the greatest net benefit within each route considered on account of these options providing the greatest (and earliest) increase in transfer capacity.
- Market benefits of all options are primarily derived from avoided generation and storage costs (shown by the dark blue section of bars in Figure 17) and are expected to accrue as soon as HumeLink is commissioned and then significantly increase from around 2035/36.
  - These benefits are found to be most significant around the time large black coal generators are expected to retire and are initially driven by an increased utilisation of Snowy 2.0 and changes in capacity mix that result in the avoidance of LS battery build in New South Wales from 2026/27.
  - The forecast capex savings from the mid-2030s are mostly driven by the deferral/avoidance of solar investment followed by the avoidance of OCGT installations, with some wind build forecast to be brought forward (however, the reduced wind build in Queensland in the 2040s is offset by the additional wind installation in southern states, particularly Victoria, in those years).
- Avoided or deferred REZ transmission capex is the second most material category of market benefit estimated across the options (shown by the purple section of bars in Figure 17).
  - These benefits start from 2027/28 as wind and solar installations are forecast to be built in Wagga Wagga and South Australia instead of the Central West Orana REZ and Queensland, avoiding transmission costs.
- Fuel cost savings are expected to be lower than for the central scenario, mainly due to higher coal retirements in the step-change scenario.
  - The modelled fuel cost savings start from the late 2030s, where gas generation is avoided.

Figure 18 below presents the estimated cumulative expected gross benefits for Option 3C for each year of the assessment period under the step-change scenario.

Figure 18 – Breakdown of cumulative gross benefits for Option 3C under the step-change scenario – excluding competition benefits



105. The detailed descriptions of the drivers of the key market benefit categories below are based on the market modelling results for Option 3C. Please refer to the accompanying market modelling results, and report, released alongside this PADR for more detail on the market modelling results for all options.

8. Net present value results (continued)

Figure 19 summarises the difference in generation and storage output modelled for Option 3C (in TWh), compared to the base case.

Figure 19 – Difference in output with Option 3C, compared to the base case, under the step-change scenario

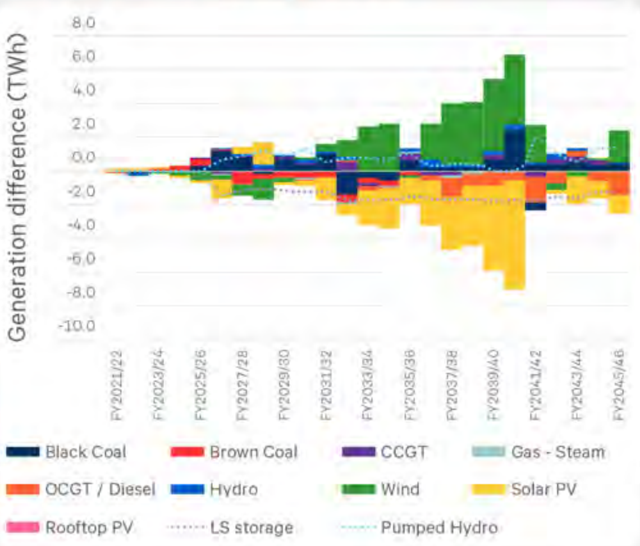
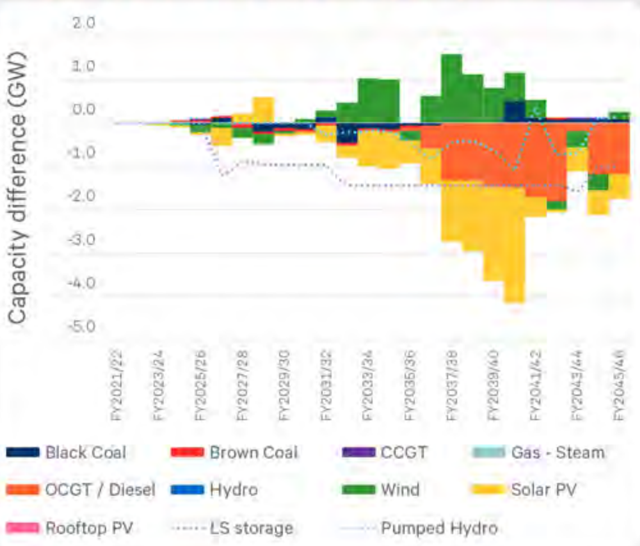


Figure 20 summarises the difference in generation and storage capacity modelled for Option 3C (in GW), compared to the base case.

Figure 20 – Difference in cumulative capacity built with Option 3C, compared to the base case, under the step-change scenario



8.2.4 Slow-change scenario

The slow-change scenario is made up of a set of conservative assumptions reflecting a future world of lower demand forecasts (including DSP), slow gas and coal price forecasts and coal plants allowed a ten-year life extension (if economic to do so). While the slow-change scenario assumes the same national emissions reduction as the central scenario by 2030, it assumes lower state-based renewables commitments. The slow-change scenario also excludes VNI West going ahead.

AEMO describe the slow-change scenario as reflecting 'a general slow-down of the energy transition. It is characterised by slower advancements in technology and reductions in technology costs, low population growth, and low political, commercial, and consumer motivation to make the upfront investments required for significant emissions reduction'.[106]

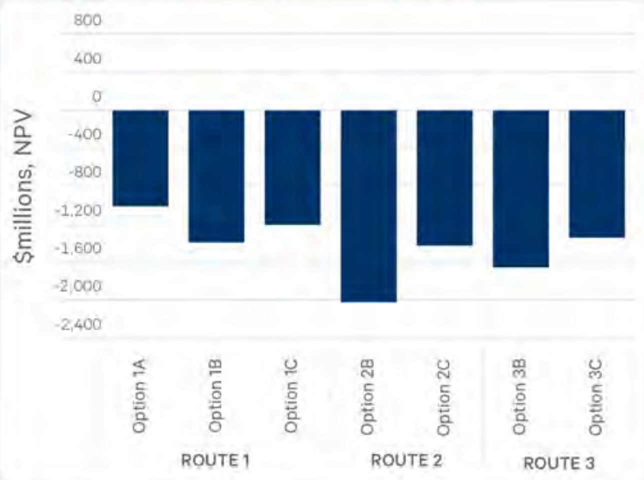
The slow-change scenario is therefore intended to represent the lower end of the potential range of realistic net benefits associated with the various options.

We note that the slow-change scenario is considered the least likely of the four scenarios and is given a 10 per cent weighting in the analysis, consistent with the recommended weighting in the 2020 ISP.[107] In addition, we note that recent commentary from the ESB[108] suggests that the NEM is in fact tracking closest to the step-change currently.[109]

All options are found to have significantly negative net benefits under the slow-change scenario. Option 1A is found to have the least negative net benefits at around -$1,011 million. Option 3C is the third ranked option with an estimated negative net market cost that is approximately 32 per cent greater than Option 1A.

Figure 21 shows the overall estimated net benefit for each option under the slow-change scenario.

Figure 21 – Summary of the estimated net benefits under the slow-change scenario – excluding competition benefits



106. AEMO, *2019 forecasting and planning scenarios, inputs, and assumptions*, August 2019, p. 3.

107. AEMO, *2020 Integrated System Plan*, July 2020, p. 86

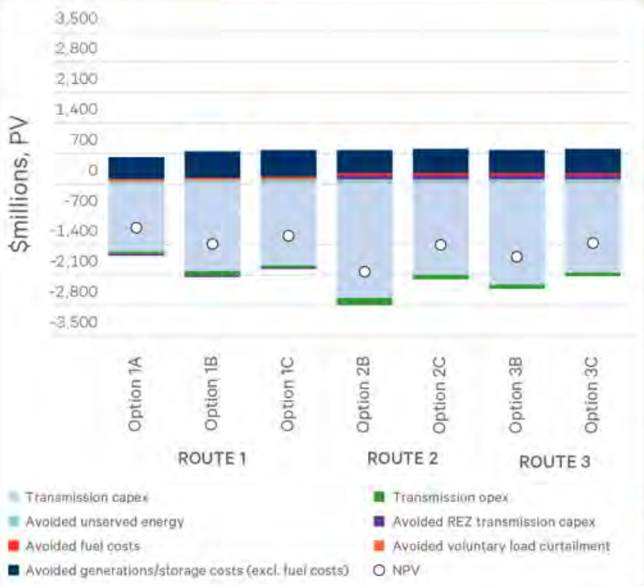
108. See Renew Economy, "We are headed for step change:" ESB's Kerry Schott on new market design, Parkinson, G., 30 September 2020 (accessed via https://reneweconomy.com.au/we-are-headed-for-step-change-esbs-kerry-schott-on-new-market-design-89487/ on 7 July 2021), Argus Media, Australia tops step-change energy transition scenario, Morrison, K., 7 May 2021 (accessed via https://www.argusmedia.com/en/news/2212777-australia-tops-stepchange-energy-transition-scenario on 7 July 2021) & ESB, The Health of the National Electricity Market 2020, Volume 1: The ESB Health of the NEM Report, 5 January 2020, p. 8.

109. We have investigated the impact of this via a sensitivity, in section 8.4.4, that applies a higher weight to the step-change scenario in-line with this recent commentary.

8. Net present value results (continued)

Figure 22 shows the composition of estimated net benefits for each option under the slow-change scenario.

Figure 22 – Breakdown of estimated net benefits under the slow-change scenario – excluding competition benefits



The key findings from the assessment of each option under the slow-change scenario (excluding competition benefits) are that:[110]

- The estimated net market benefits for all options fall significantly relative to the central scenario (and are all negative).
- The fixed 500 kV options (i.e., the 'C' options) continue to provide the greatest net benefit (least net cost) of all options considered that are able to operate at 500 kV on account of these options providing the greatest (and earliest) increase in transfer capacity.
  - A key exception to this is the one 330 kV option assessed (Option 1A), which has the greatest estimated net benefit (least net cost) of all options considered on account of its low costs.
- The flexible 500 kV options are found to be upgraded from 330 kV to 500 kV in 2035-36, being the time at which the benefits from upgrading to 500 kV exceed the annualised upgrade cost under this scenario.
- The market benefits for all options are almost completely driven by avoided or deferred costs associated with generation and storage (shown by the dark blue bars in Figure 22).
  - The market modelling finds that this is driven primarily by avoided LS battery investment in New South Wales from around 2032/33.
  - Other wholesale market benefit categories are found to be of a smaller scale under the slow scenario than the other scenarios.
  - Overall, due to the low demand and assumptions regarding the NSW Roadmap in this scenario as well as life extension of coal plants, HumeLink is forecast to have significantly lower market benefits as compared to the other scenarios.

Figure 23 below presents the estimated cumulative expected gross benefits for Option 3C for each year of the assessment period under the slow-change scenario. It shows that the majority of the overall benefits have accrued by 2032-33 under this scenario.

Figure 23 – Breakdown of cumulative gross benefits for Option 3C under the slow-change scenario – excluding competition benefits

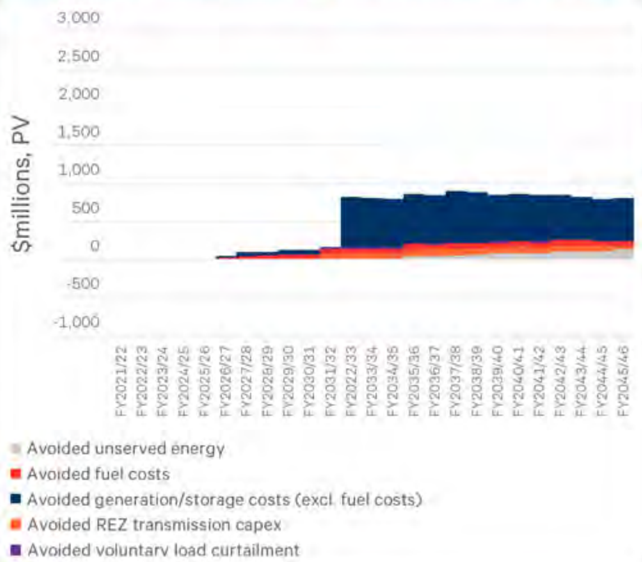
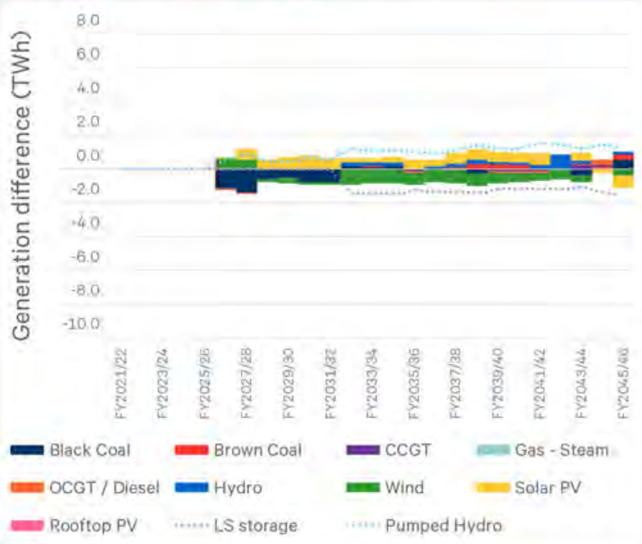


Figure 24 summarises the difference in generation and storage output modelled for Option 3C (in TWh), compared to the base case.

Figure 24 – Difference in output with Option 3C, compared to the base case, under the slow-change scenario



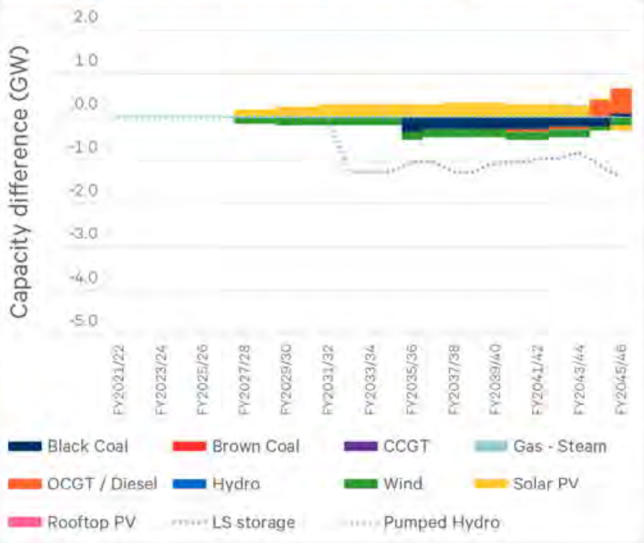
110. The detailed descriptions of the drivers of the key market benefit categories below are based on the market modelling results for Option 3C. Please refer to the accompanying market modelling results, and report, released alongside this PADR for more detail on the market modelling results for all options.

Document 2

8. Net present value results (continued)

Figure 25 summarises the difference in generation and storage capacity modelled for Option 3C (in GW), compared to the base case.

Figure 25 – Difference in cumulative capacity built with Option 3C, compared to the base case, under the slow-change scenario

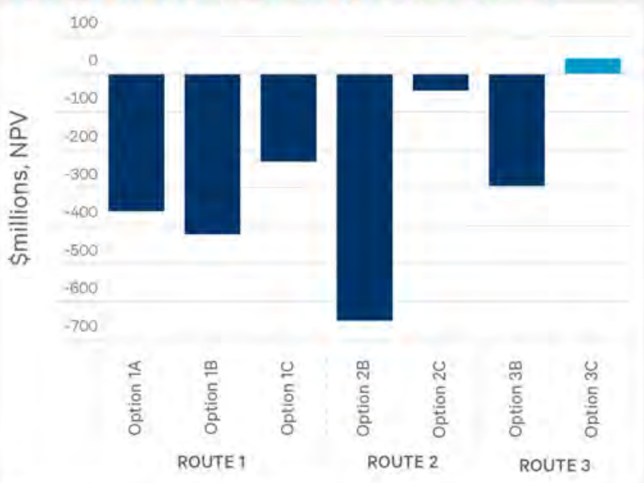


8.2.5 Weighted net benefits

Figure 26 shows the estimated net benefits for each of the credible options weighted equally across the four scenarios investigated (and discussed above).

On a weighted-basis, Option 3C is the top-ranked option and is expected to deliver approximately $39 million in net benefits (excluding competition benefits), which is around $83 million more net benefits than the second-ranked option (Option 2C) in present value terms.

Figure 26 – Summary of the estimated net benefits, weighted across the four scenarios – excluding competition benefits



The top two ranked options (i.e., Option 2C and Option 3C) are assessed further in section 8.3 below.

8.3 RIT-T RESULTS

This section presents the RIT-T assessment for the PACR. Specifically, it builds upon the positioning assessment discussed above by presenting the net market benefits for the two top-ranked options coming out of that analysis (i.e., Option 2C and Option 3C), across each of the four ISP scenarios investigated, as well as capturing the eighth category of market benefits estimated for these options, i.e. competition benefits.

The seven market benefits estimated for each option in section 8.1 above remain unchanged in this section. We therefore do not repeat the discussion of these for each scenario but, instead, focus the discussion of the new category of market benefit captured in this assessment, i.e., competition benefits.

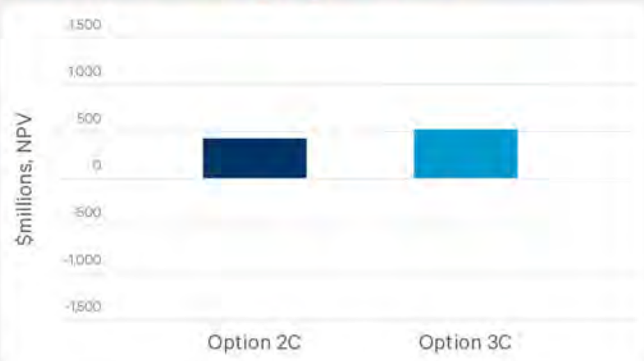
8.3.1 Central scenario

Both of the options are found to deliver strongly positive net benefits, under the central scenario, ranging from $431 million to $520 million in present value terms. Overall, Option 3C continues to be the top-ranked option with estimated net benefits that are approximately 21 per cent greater than the second-ranked option (Option 2C).

Competition benefits add significantly to each option's estimated net benefits (between $464 million and $471 million across the options), which is approximately 18 per cent of their estimated gross wholesale market benefits for both options.

Figure 27 shows the overall estimated net benefit for each option under the central scenario. The 'core net benefits' shown in this chart (and all charts of this nature in this section), are the net benefits estimated in section 8.1 above, i.e., the net benefits factoring in the seven categories of market benefit estimated as part of the positioning assessment and the option costs.

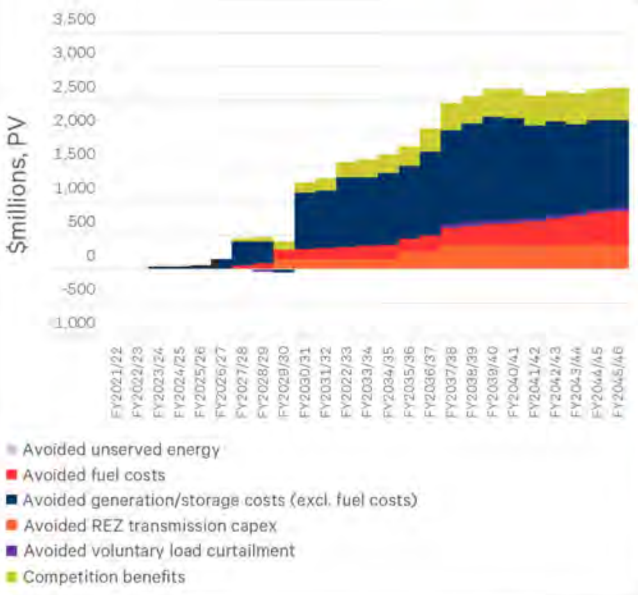
Figure 27 – Summary of the estimated net benefits under the central scenario – including competition benefits



8. Net present value results (continued)

Figure 28 below presents the estimated cumulative expected gross benefits for Option 3C for each year of the assessment period under the central scenario. It shows the cumulative market benefits, in present value terms (and so the final year's stacked bars align with the overall breakdown of estimated market benefits shown in Figure 27 above). This figure, and all figures of this nature in section 8.3, update the corresponding figures in section 8.2 to include the estimated competition benefits.

Figure 28 – Breakdown of cumulative gross benefits for Option 3C under the central scenario – including competition benefits



Competition benefits are expected to accrue from shortly after Option 3C is commissioned and are material across the assessment period, ultimately contributing 18 per cent of the total expected gross benefits. Under this scenario, around 59 per cent of the competition benefits are comprised of wholesale market cost savings with the remainder made up of demand response benefits.

8.3.2 Fast-change scenario

Each of the options is found to deliver strongly positive net benefits under the fast-change scenario, ranging from $394 million to $487 million in present value terms. Overall, Option 3C is the top-ranked option with estimated net benefits that are approximately 24 per cent greater than the second-ranked option (Option 2C).

Competition benefits add significantly to each option's estimated net benefits (between $384 million and $396 million across the options), which is approximately 15 per cent of their estimated gross benefits for both options.

Figure 29 shows the overall estimated net benefit for each option under the fast-change scenario.

Figure 29 – Summary of the estimated net benefits under the fast-change scenario – including competition benefits

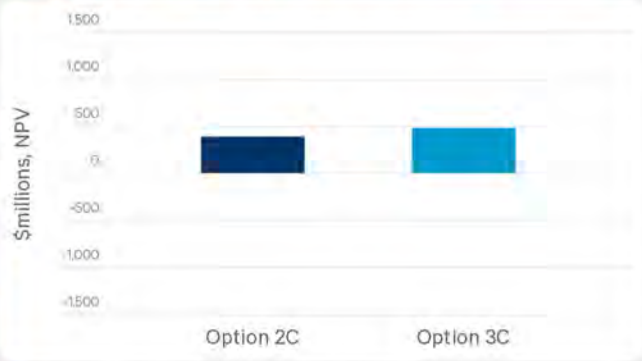
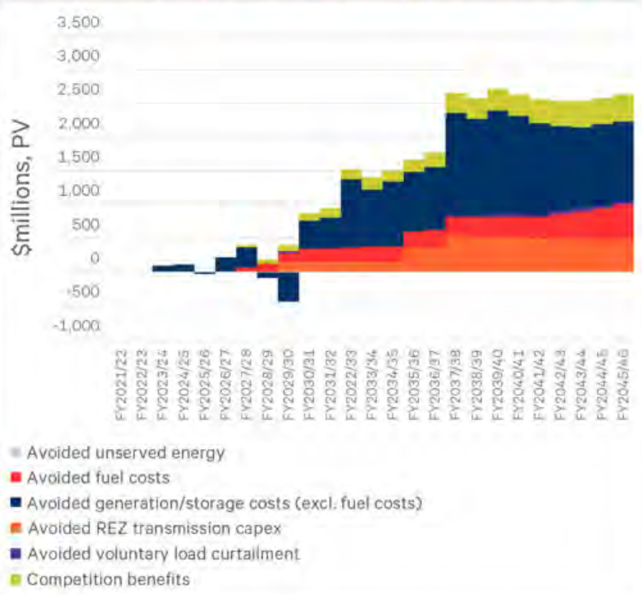


Figure 30 below presents the estimated cumulative expected gross benefits for Option 3C for each year of the assessment period under the fast-change scenario. It shows the cumulative market benefits, in present value terms (and so the final year's stacked bars align with the overall breakdown of estimated market benefits shown in Figure 29 above).

Figure 30 – Breakdown of cumulative gross benefits for Option 3C under the fast-change scenario – including competition benefits



Competition benefits are expected from shortly after Option 3C is commissioned and are material across the assessment period, ultimately contributing 15 per cent of the total expected gross benefits. Under this scenario, around 48 per cent of the competition benefits are comprised of wholesale market cost savings with the remainder made up of demand response benefits.

8. Net present value results (continued)

8.3.3 Step-change scenario

Each of the options is found to deliver strongly positive net benefits under the step-change scenario, ranging from $1,168 million to $1,271 million in present value terms. Overall, Option 3C is the top-ranked option with estimated net benefits that are approximately 9 per cent greater than the second-ranked option (Option 2C).

Competition benefits add significantly to each option's estimated net benefits (between $631 million and $637 million across the options), which is approximately 19 per cent of their estimated gross benefits for both options.

Figure 31 shows the overall estimated net benefit for each option under the step-change scenario.

Figure 31 – Summary of the estimated net benefits under the step-change scenario – including competition benefits

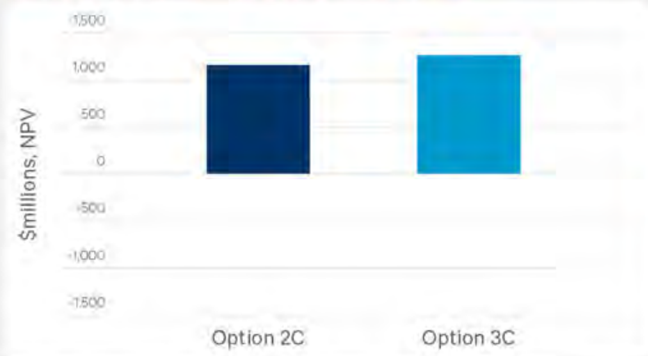
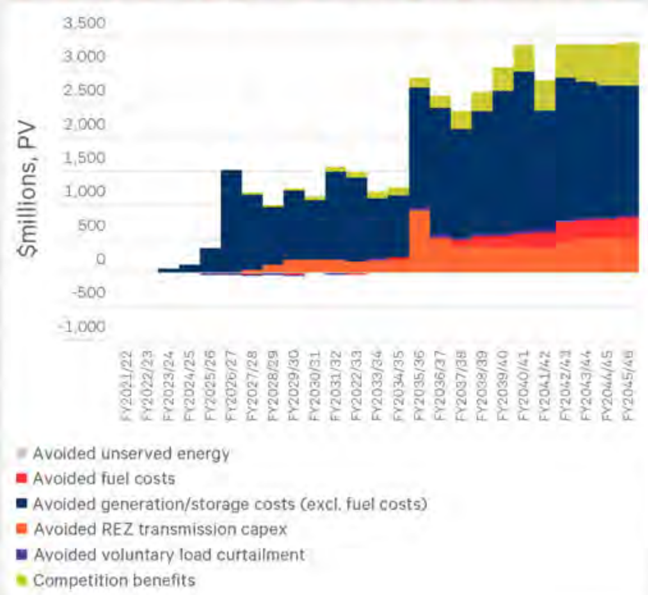


Figure 32 below presents the estimated cumulative expected gross benefits for Option 3C for each year of the assessment period under the step-change scenario. It shows the cumulative market benefits, in present value terms (and so the final year's stacked bars align with the overall breakdown of estimated market benefits shown in Figure 31 above).

Figure 32 – Breakdown of cumulative gross benefits for Option 3C under the step-change scenario – including competition benefits



Competition benefits do not appear until later in the period under the step-change scenario, compared to the central and fast-change scenarios, but are material by the end of the assessment period, ultimately contributing 19 per cent of the total expected gross benefits. Under this scenario, almost all of the competition benefits are made up of demand response benefits (92 per cent), with wholesale market cost savings making up the remainder.

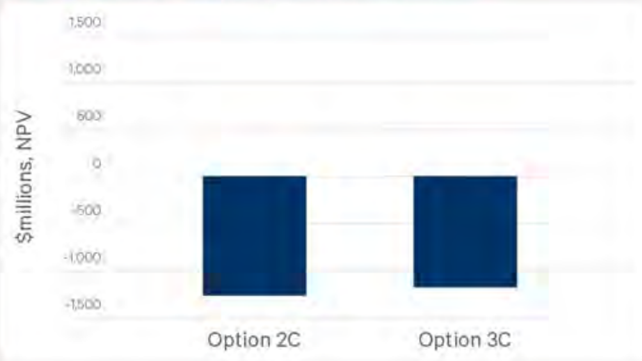
8.3.4 Slow-change scenario

None of the options is found to deliver a positive net benefit under the slow-change scenario, even once competition benefits are included, with negative net benefits (net costs) ranging from -$1,253 million to -$1,177 million in present value terms. Overall, Option 3C is the top-ranked option with estimated net costs that are approximately 6 per cent lower than the second-ranked option (Option 2C).

Competition benefits add to each option's estimated net benefits (between $160 million and $163 million for Option 2C and Option 3C respectively), which is approximately 17 per cent of estimated gross benefits for both options.

Figure 33 shows the overall estimated net benefit for each option under the slow-change scenario.

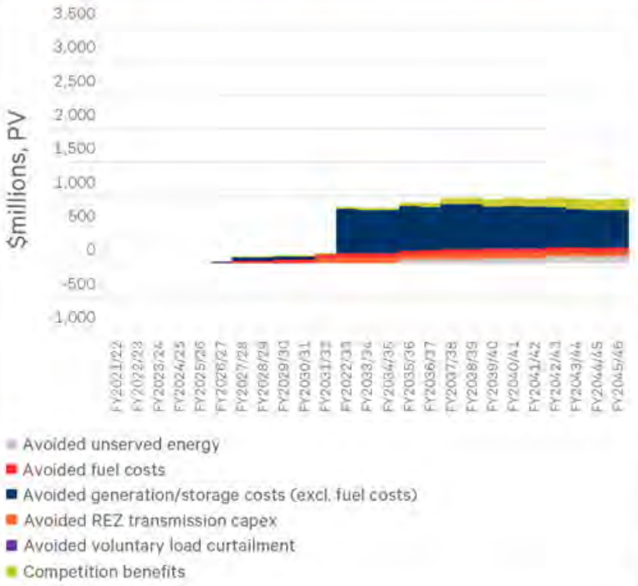
Figure 33 – Summary of the estimated net benefits under the slow-change scenario – including competition benefits



8. Net present value results (continued)

Figure 34 below presents the estimated cumulative expected gross benefits for Option 3C for each year of the assessment period under the slow-change scenario. It shows the cumulative market benefits, in present value terms (and so the final year's stacked bars align with the overall breakdown of estimated market benefits shown in Figure 33 above).

Figure 34 – Breakdown of cumulative gross benefits for Option 3C under the slow-change scenario – including competition benefits



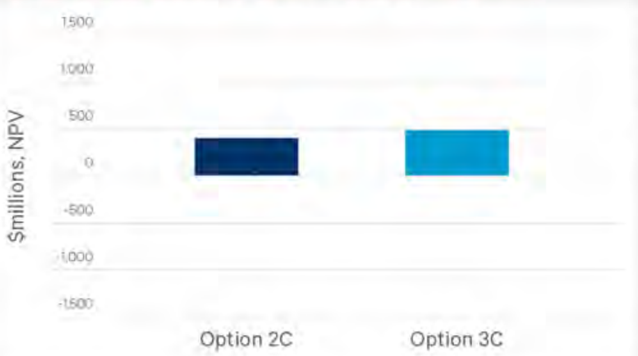
Competition benefits, along with all benefits, are much lower under the slow-change scenario compared to the other three scenarios. They appear from around midway through the period and remain constant from then, ultimately contributing 17 per cent of the total expected gross benefits. Under this scenario, around 49 per cent of the competition benefits are comprised of wholesale market cost savings with the remainder made up of demand response benefits.

8.3.5 Weighted net benefits

Figure 35 shows the estimated net benefits for each of the credible options weighted across the four scenarios according to weights set out in section 6.2.

On a weighted-basis, Option 3C is the top-ranked option and is expected to deliver approximately $491 million in net benefits, which is around 23 per cent greater net benefits than the second-ranked option (Option 2C).

Figure 35 – Summary of the estimated net benefits, weighted across the four scenarios – including competition benefits



8.4 SENSITIVITY ANALYSIS

A range of sensitivity analyses have been undertaken to test the robustness of the PACR modelling outcomes.

Specifically, we have assessed a number of sensitivities that involve additional market modelling, namely:

- the impact of the recently announced new Kurri Kurri and Tallawarra B gas generators;
- delaying VNI West until 2035/36 (in-line with the core 2020 ISP assumption for the central scenario);
- whether adding the MPFC solution proposed by Smart Wires would increase the expected net benefits of the preferred option; and
- the impact on the positioning analysis of adopting the draft 2021 IASR assumptions.

Each of these sensitivity tests has been designed to test the robustness of the net benefit outcomes for Option 3C. The market modelling for each of the above sensitivities has not been undertaken for all credible options and scenarios. This is due to the computational time required to complete such an exercise and the fact that the four core scenarios outlined in the sections above already include significant variability in the underlying assumptions and find that Option 3C is the top-ranked option.

Three other sensitivity tests that do not require wholesale market modelling have also been investigated, namely adopting:

- higher weighting of the step-change scenario, in-line with recent commentary from the ESB;
- higher and lower network capital costs of the credible options (including the adoption of P90 costs); and
- alternate commercial discount rate assumptions.

Each of the sensitivity tests are discussed below.

8.4.1 Impact of the recently announced new Kurri Kurri and Tallawarra B gas generators

In early May 2021, there were two announcements regarding Federal Government funding for new gas-fired generators in NSW. Namely:

- on 3 May 2021, EnergyAustralia announced it would build the 316 MW Tallawarra B gas-hydrogen plant with $83 million in Government support;[111] and
- on 18 May 2021, the Federal Government announced it will spend up to $600 million to build a new 660 MW gas plant at Kurri Kurri in NSW.[112]

These developments are not reflected in our wholesale market modelling assumptions, which are based on the 2020 ISP. However we have considered the impact that these two developments would have on the expected net benefits of Options 3C and 2C.

Under the central scenario, we find that the estimated net benefits of Option 3C decrease by around 36 per cent assuming the new Kurri Kurri and Tallawarra B gas generators are commissioned. However, overall Option 3C continues to provide substantial positive net market benefits. We find that Option 3C still delivers approximately $334 million in net benefits. Option 3C is around 36 per cent higher in net benefits than the second-ranked option (Option 2C).

111. https://www.nsw.gov.au/media-releases/australias-first-green-hydrogen-and-gas-power-plant
112 https://www.minister.industry.gov.au/ministers/taylor/media-releases/protecting-families-and-businesses-higher-energy-prices

8. Net present value results (continued)

Figure 36 shows the overall estimated net benefit for each option under this sensitivity, as well as under the RIT-T outcome (i.e., the net benefits estimated in section 8.3 above).

Figure 36 – Net benefits assuming the new Kurri Kurri and Tallawarra B gas generators – including competition benefits

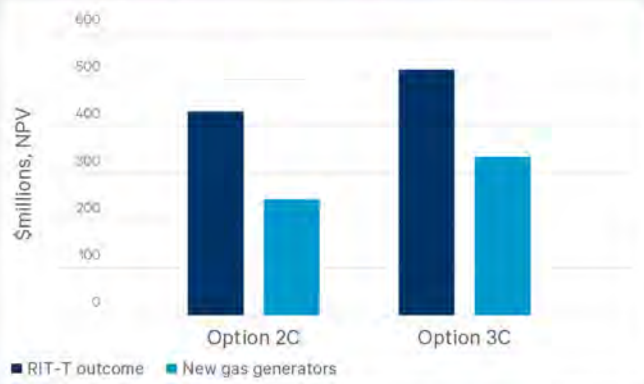
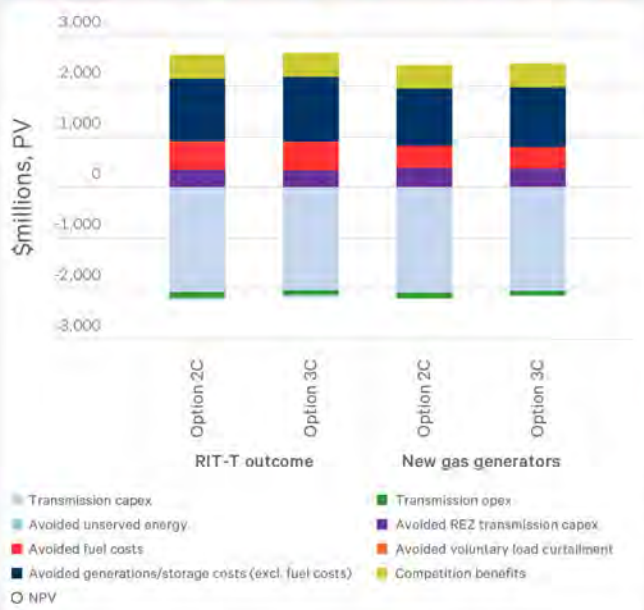


Figure 37 breaks down the estimated net benefits under core RIT-T outcome (i.e., the net benefits estimated in section 8.3 above) on the left-hand side and assuming the new gas generators on the right-hand side. The largest reduction in estimated benefits for the preferred option is found to come from avoided generation/storage costs (shown in dark blue below).

Figure 37 – Breakdown of estimated net benefits assuming with and without the new Kurri Kurri and Tallawarra B gas generators



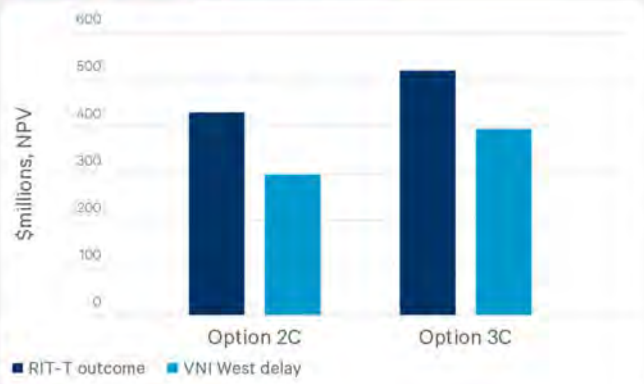
8.4.2 Impact of the assumed timing for VNI West

Our wholesale market modelling is based on an assumed commissioning date for VNI West of 2028/29. This is based on AEMO's 2020 ISP accelerated delivery date for VNI West and our current view of the earliest commissioning date for this investment. However, we have investigated the impact of delaying the commissioning date of VNI West to until 2035/36, in-line with the 2020 ISP core assumption for the central scenario.

Under the central scenario, we find that the estimated net benefits of Option 3C decreases by around 24 per cent if it is assumed that VNI West is delayed until 2035/36 (from the core assumption of 2028/29). Option 3C is around 33 per cent higher in net benefits than the second-ranked option (Option 2C).

Figure 38 shows the overall estimated net benefit for each option under this sensitivity, as well as under the RIT-T assessment.

Figure 38 – Net benefits assuming VNI West is delayed until 2035/36 – including competition benefits



8.4.3 Expected impact of MPFC

We have considered whether MPFC can add to the expected net benefits of the preferred option, in response to the submission from Smart Wires.

Under the central scenario, we find that the estimated net benefits of Option 3C decrease by $7 million assuming it is coupled with the MPFC solution proposed by Smart Wires (under these assumptions, Option 3C is found to deliver approximately $513 million in net benefits). Consequently, we find that the cost of providing additional capacity through MPFC are not outweighed by the additional expected market benefits at this point in time.

8.4.4 Alternate weighting of the scenarios in-line with recent commentary

We have investigated the effects of assuming alternate scenario weightings based on more recent information than the 2020 ISP. Specifically, and informed by ESB commentary that the NEM is on step-change scenario, we have applied the following scenario weightings as part of this sensitivity:

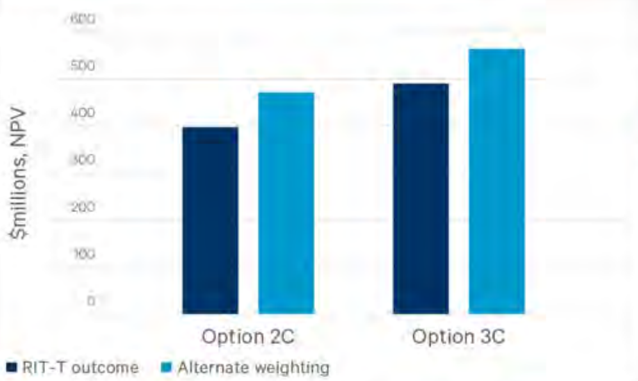
- 30 per cent to the central scenario (i.e., a decrease of 10 per cent);
- 30 per cent to the fast-change scenario;
- 30 per cent to the step-change scenario (i.e., an increase of 10 per cent); and
- 10 per cent to the slow-change scenario.

We find that the estimated net benefits of Option 3C increase by around 15 per cent under these assumed weightings compared to the weightings for HumeLink set out in the 2020 ISP. Under these weightings, Option 3C is found to deliver $566 million in net benefits on a weighted basis, which is approximately $93 million greater than the second-ranked option (Option 2C).

8. Net present value results (continued)

Figure 39 shows the overall estimated net benefit for each option under this sensitivity, as well as under the ISP weightings.

Figure 39 – Net benefits assuming alternate scenario weightings – including competition benefits

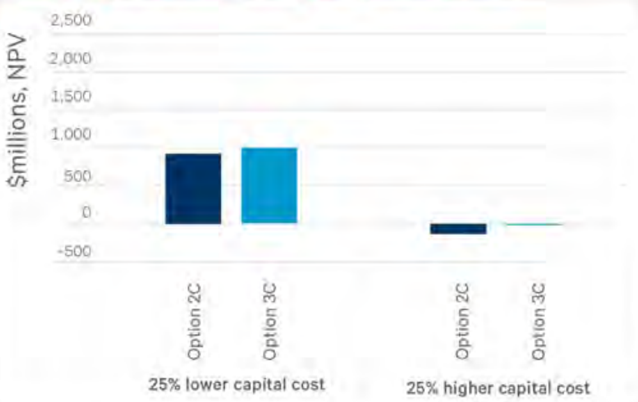


8.4.5 Higher and lower network capital costs of the credible options

We have tested the sensitivity of the results to the underlying network capital costs of the credible options.

Figure 40 shows that Option 3C remains the top-ranked credible option if the capital cost assumptions are varied by 25 per cent (higher or lower) across both options. Under the assumption of 25% lower capital costs, the net benefits of Option 3C increase to $999 million. However, under the 25 per cent higher assumed capital costs, Option 3C is found to have negative net benefits of -$17 million for Option 3C.

Figure 40 – Impact of 25 per cent higher and lower network capital costs, weighted NPVs – including competition benefits



We find that if Option 3C's capital costs are more than 24 per cent higher than the central estimates, it would no longer have positive estimated net benefits (on a weighted-basis). We also find that if Option 2Cs costs were to remain constant, Option 3C's costs would need to increase by more than 4 per cent for Option 2C to become preferred.

There is currently a high degree of uncertainty in relation to the accuracy of the capital cost estimates (which are 'class 4' estimates), consistent with the stage that the project is currently at. We also note that a substantial proportion of the costs of HumeLink will relate to biodiversity offset costs, which are determined by external processes.

For completeness, we have also considered alternate 'P90' capex estimates, which are higher than the P50 estimates used in the main RIT-T analysis, and allow for additional contingencies. Specifically, the P90 capex estimates have an expected 90 per cent probability of cost underrun, while the P50 capex estimates have a 50 per cent expected probability of cost underrun. Figure 41 shows that both options have significantly negative weighted net benefits under P90 capex estimates (with the preferred option expected to result in a net cost of approximately $193 million).

Figure 41 – P50 capex estimates compared to P90 capex estimates, weighted NPVs – including competition benefits

We will be undertaking further detailed analysis in relation to the costs of the preferred option as part of progressing this project, following the initial CPA. Any increase in the estimated costs of the project resulting from this analysis would result in AEMO needing to issue a 'feedback loop' confirmation that the project remains consistent with the ISP optimal development path, before we could lodge a further CPA. Consumers can therefore have confidence that any increase in the cost estimate for the preferred option will only result in the project proceeding if AEMO confirms that it remains part of the ISP at the higher cost.

8.4.6 Alternate commercial discount rate assumptions

Figure 42 illustrates the sensitivity of the results to adopting different discount rate assumptions in the NPV assessment. In particular, it illustrates the impact of adopting:

- a high discount rate of 7.90 per cent; and
- a low discount rate of 2.23 per cent.

Option 3C is the top-ranked option under both alternate assumptions and continues to deliver positive net benefits, albeit only marginally under the high discount rate assumption. We consider that a discount rate of 7.90 per cent is at the extreme end for commercial discount rates today, and note that the draft 2021 IASR assumptions propose a 4.80 per cent discount rate as part of the central scenario (which is lower than our assumed central rate of 5.90 per cent).

8. Net present value results (continued)

Figure 42 – Impact of different assumed discount rates, weighted NPVs – including competition benefits

We have extended this sensitivity and find a discount rate that is higher than 7.98 per cent would result in Option 3C having a negative estimated net benefit.

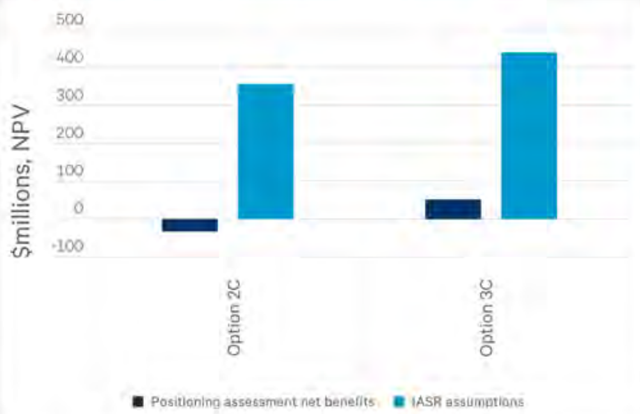
8.4.7 Adopting AEMO's draft 2021 IASR assumptions

This sensitivity reapplies the positioning assessment to the two top-ranked options, adopting the draft 2021 IASR assumptions published by AEMO in December 2020.[113] It provides insight into the possible outcomes of the forthcoming 'feedback loop' assessment if AEMO adopts the final 2021 IASR assumptions (due to be published by the end of July 2021) for this analysis. We consider that adopting the most recently consulted upon final IASR assumptions, which will underpin the 2022 ISP, in applying the feedback loop would be consistent with the objectives of the overall actionable ISP framework.

Under the central scenario, we find that the estimated net benefits under the positioning assessment for Option 3C increase significantly using the draft 2021 IASR assumptions, and becomes substantially positive. Under the draft 2021 IASR assumptions, Option 3C is found to deliver approximately $436 million in net benefits. Option 3C has around 22 per cent greater net benefits than the second-ranked option (Option 2C) under draft 2021 IASR assumptions.

Figure 43 shows the overall estimated net benefit for each option under this sensitivity, as well as under the 'positioning assessment net benefits' (i.e., the net benefits estimated in section 8.3 above, which excludes competition benefits).

Figure 43 – Net benefits under the central scenario adopting AEMO's draft 2021 IASR assumptions – excluding competition benefits



It is important to note that the net benefits shown above do not include competition benefits. The analysis in this PACR demonstrates that competition benefits are material for this RIT-T (as illustrated in section 8.3). Including competition benefits alongside the 2021 IASR assumptions can therefore be expected to further increase the net benefits of both Option 2C and Option 3C. We anticipate that AEMO will need to consider competition benefits in applying the feedback loop to HumeLink.

113. AEMO, Draft 2021 Inputs Assumptions and Scenarios Report (IASR), 17 December 2020.

Conclusion

This PACR finds that Option 3C, involving new 500 kV double-circuit lines in an electrical 'loop' between Maragle, Wagga Wagga and Bannaby is expected to deliver approximately $491 million in net benefits over the assessment period (on a weighted-basis) and is the preferred option identified under this RIT-T. Option 3C is found to have approximately 23 per cent greater estimated net benefits than the second ranked option (Option 2C).

The high level scope of Option 3C includes:

- a new Wagga Wagga 500/330 kV substation and a 330 kV connection to the existing Wagga Wagga substation;
- construction of three 500 kV transmission lines:
  - between Maragle and Bannaby 500 kV substation;
  - between Maragle and Wagga Wagga 500 kV substation;
  - between Wagga Wagga and Bannaby 500 kV substation;
- three new 500/330/33 kV 1,500 MVA transformers at the Maragle substation and two new 500/330/33 kV 1,500 MVA transformers at the Wagga Wagga substation;
- augmenting the Maragle substation to accommodate the additional transmission lines;
- augmenting the existing substations at Wagga Wagga and Bannaby to accommodate the additional transmission lines/transformers.

Option 3C is expected to provide net benefits to consumers and producers of electricity and to support energy market transition through:

- increasing the transfer capacity between the Snowy Mountains and major load centres of Sydney, Newcastle and Wollongong;
- enabling greater access to lower cost generation to meet demand in these major load centres;
- facilitating the development of renewable generation in high quality renewable resource areas in southern NSW as well as southern states, which will further lower the overall investment and dispatch costs in meeting NSW demand whilst also ensuring that emissions targets are met at the lowest overall cost to consumers; and
- increasing the competitiveness of bidding in the wholesale market.

The estimated capital cost of Option 3C is approximately $3,317 million ($2020/21) and is comprised of:

- 55 per cent transmission lines costs (5 per cent of which is land costs);
- 17 per cent substation costs (1 per cent of which is land costs); and
- 28 per cent biodiversity offset costs.

Annual operating and maintenance costs are estimated to be 0.5 per cent of capital costs (excluding capital costs relating to biodiversity costs, since these are one-off and do not require ongoing operating costs).

Construction is expected to start in 2023/24 with delivery and completion of inter-network testing expected by 2026/27. The timing has been updated since the 2020 ISP (and PADR) to reflect our current best estimate of how long we expect the project will take to commission.

Once the RIT-T process is complete, we intend to submit an initial CPA to the AER for HumeLink to seek cost recovery for works necessary to develop a robust final cost estimate for the project.

We also note that activities not related to the RIT-T but necessary to progress assessment of the project in order to achieve approval, are also being undertaken, including the Environmental Impact Statement process. This includes community and stakeholder consultation on line route specifics for the preferred option.

Appendix A
Checklist of compliance clauses

This section sets out a compliance checklist which demonstrates the compliance of this PACR with the requirements of clause 5.16A.4(j) of the National Electricity Rules version 167.

RULES CLAUSE	SUMMARY OF REQUIREMENTS	RELEVANT SECTION(S) IN PACR
5.16A.4(j)	The project assessment conclusions report must include:	-
	(1) the matters detailed in the project assessment draft report as required under paragraph (d)	See below.
	(2) a summary of, and the RIT-T proponent's response to, submissions received, if any, from interested parties sought under paragraph (f).	4
5.16A.4(d)	The project assessment draft report must include:	-
	(1) include the matters required by the Cost Benefit Assessment Guidelines;	While the AER Cost Benefit Assessment Guidelines do not apply to HumeLink,[114] we have covered these matters below.
	(2) adopt the identified need set out in the *Integrated System Plan* (including, in the case of proposed reliability corrective action, why the RIT-T proponent considers reliability corrective action is necessary);	3
	(3) describe each credible option assessed	5 and Appendix B
	(4) include a quantification of the costs, including a breakdown of operating and capital expenditure for each credible option	5 and Appendix B
	(5) assess market benefits with and without each credible option and provide accompanying explanatory statements regarding the results	Section 8 presents the market benefits for each option relative to the base case for each of the four scenarios (i.e., without the option in-place).
	(6) if the RIT-T proponent has varied the ISP parameters, provide demonstrable reasons in accordance with 5.15A.3(b)(7)(iv)	2.2.4
	(7) identify the proposed preferred option that the RIT-T proponent proposes to adopt	9
	(8) for the proposed preferred option identified under subparagraph (7), the RIT-T proponent must provide: (i) details of the technical characteristics; and (ii) the estimated construction timetable and commissioning date.	9
Binding elements for the PACR from the Cost Benefit Assessment Guidelines	When publishing the Conclusions Report, RIT–T proponents are required to:	-
	Publish, in addition to a summary of submissions, any submissions received in response to the Draft Report, unless marked confidential.	See https://www.transgrid.com.au/humelink
	Date the Conclusions Report to inform potential disputing parties of the timeframes for lodging a dispute notice with the AER.	See cover page.
	If a RIT-T proponent receives any confidential submissions on its Draft Report, it must consider working with submitting parties to make a redacted or non-confidential version public.	This has been undertaken for the one confidential submission received.

114. AER, *Guidelines to make the Integrated System Plan actionable*, Final Decision, August 2020, p. 19.

Appendix B
Further detail on options considered but not progressed

This appendix outlines the various options that have been considered but not progressed over the course of this RIT-T.

B.1 OPTIONS RULED OUT AT THE PACR STAGE

B.1.1 Options ruled out on the basis of the PADR analysis

The PACR does not assess Option 2A or Option 3A from the PADR (the two 330 kV build and operate options of these network topologies) since they were found to have significantly lower benefits than the other options and, in particular, Option 3C. Specifically, the PADR found these options to have net benefits that were 38 and 36 per cent lower than Option 3C, on a weighted basis.

The PACR also does not assess the three 'topology 4' options from the PADR (involving new transmission lines in an electrical 'loop' between Maragle, Wagga Wagga and Bannaby and direct between Bannaby and Sydney). These options have significantly greater costs than the other options (with the updated 'class 4' cost estimates in the order of $4.7 billion to $5 billion) and the PADR analysis showed that they are not expected to provide commensurately greater market benefits than their counterparts following the three topologies outlined above.

B.1.2 Use of single-circuit versus double-circuit

As part of this PACR, we have investigated different circuit configurations of the top performing network topologies and operating capacities in the PADR analysis (i.e., 'Option 2C' and 'Option 3C'). Specifically, we investigated:

- three variants of the preferred network topology and operating capacity in the PADR and PACR analysis, i.e., Option 3C:
  - Option 3C is constructed as 100 per cent double-circuit configuration – estimated capital cost of $3,317 million;
  - Option 3C-0 is constructed as a 100 per cent single-circuit configuration (which is the 'ISP candidate option' identified in the 2020 ISP) – estimated capital cost of $4,253 million; and
  - Option 3C-1 is constructed primarily as a single-circuit configuration but with a 132 km double-circuit portion west of Bannaby – estimated capital cost of $3,509 million;
- two variants of the second-ranked network topology and operating capacity in the PADR analysis, i.e., Option 2C:
  - Option 2C is constructed as 100 per cent double-circuit configuration – estimated capital cost of $3,399 million.
  - Option 2C-1 is constructed primarily as a single-circuit configuration but with a 132 km double-circuit portion west of Bannaby – estimated capital cost of $3,770 million;
  - we did not investigate a fully single-circuit version of Option 2C (i.e., an Option 2C-0) since, based on the assessment of 3C-0, the costs of this configuration are expected to be significantly greater than the other two variants (without providing any additional benefit).

Each variant for the two network topologies is electrically the same and so delivers the same expected gross market benefits. All options involving double-circuit portions of transmission line (i.e., 2C, 2C-1, 3C and 3C-1) were assessed to investigate lower cost variants of the top performing network topologies and operating capacity. Specifically, the use of double-circuitry for portions of these lines reduces the associated land and environmental offset costs compared to two separate single-circuit portions.

Appendix B Further detail on options considered but not progressed (continued)

Further assessment following the PADR of the network risks associated with double circuit topology has enabled double-circuit options to be included. The key findings from this risk/mitigation assessment were that:

- inclusion of surge arrestors on towers and improving their earthing design have been assessed as effective in mitigating risk of double-circuit outages from lightning strikes;
- the impact of tripping two circuits due to bushfires can be managed by pre-emptively reducing the HumeLink transfer capacity when there is a bushfire in the vicinity; and
- line configurations including double circuit in areas where bushfires are considered a more manageable risk have been assessed (and included as the 132km section west of Bannaby for Option 2C-1 and Option 3C-1 above).

The benefits arising from separated single circuit lines has been reviewed and assessed against the incremental environmental and community impact relative to double circuit topology. The incremental cost and impact of single circuit configurations, weighed against risks of effectively designed double circuits, has been assessed as favouring consideration of double circuit configuration on an equivalent footing with single circuit options.

Overall, the outworking of this process is that Option 2C and Option 3C from the PADR are presented in the PACR as complete double-circuit options, which allows significant cost reductions relative to where they are constructed as either a single-circuit, or a combination of single- and double-circuit, configuration. The additional work undertaken since the PADR assessing the risks involved with double-circuit configuration, compared to single-circuit, and how these risks can be mitigated, has enabled these two options to be refined as part of this PACR.

The variants of these options involving single circuit line (i.e., Option 3C-0, Option 3C-1 and Option 2C-1) have not been included as options in the body of this PACR due to their significantly greater costs compared with the double-circuit variants, but with the same market benefits (ie, they are not economically feasible).

B.1.3 Consideration of the 2020 ISP candidate option

While AER has stated that the new ISP Rules require that the ISP candidate option is considered as a credible option in the RIT-T analysis,[115] we have not presented the results for Option 3C-0 in the body of the PACR since it is always inferior to Option 3C (as outlined in the section above) and thus is considered superfluous to the outcome of the RIT-T.

Instead, we have presented the assessment of this credible option in the table below, alongside Option 3C (which is the preferred option under the RIT-T). For all four scenarios, Option 3C-0 has significantly lower net benefits than Option 3C due to its greater costs.

Table B-1 Net market benefits of Option 3C-0 compared to Option 3C, $m NPV

OPTION	CENTRAL	FAST-CHANGE	STEP-CHANGE	SLOW-CHANGE
3C	520	487	1,271	-1,177
3C-0	-55	-88	696	-1,752

B.1.4 Option 3D – New 500 kV lines between Blowering and Bannaby, and between Blowering and Wagga Wagga, and constructing new 330 kV lines between Blowering and Maragle

We investigated a new option as part of the PACR that we initially considered may be able to be a lower scope and cost version of the 'topology 3' options, i.e., those casting a wider footprint than the other options and going via Wagga Wagga, that would open up both direct and additional capacity for new renewable generation in southern NSW. Option 3D is electrically different to the Option 3C variants and involves four 500 kV transmission lines.

This option involves constructing new 500 kV lines between Blowering and Bannaby, and between Blowering and Wagga Wagga, and constructing new 330 kV lines between Blowering and Maragle. All lines are double-circuit.

The high level scope includes:

- New Wagga Wagga 500/330 kV substation and 330 kV connection to the existing Wagga Wagga substation
- New Blowering 500/330 kV substation
- Construct four 500 kV transmission lines:
  - Between Blowering and Bannaby 500/330 kV substation; and
  - Between Blowering and Wagga Wagga 500/330 kV substation;
- Construct two 330 kV transmission lines:
  - Between Blowering and Maragle 500/330 kV substation

115. AER, Explanatory statement, Draft *guidelines to make the Integrated System Plan actionable*, p. 43.

Appendix B Further detail on options considered but not progressed (continued)

- Three new 500/330/33 kV 1,500 MVA transformers at Blowering substation and two new 500/330/33 kV 1,500 MVA transformer at Wagga Wagga substation
- Augment the existing substations at Wagga Wagga and Bannaby to accommodate the additional transmission lines/transformers.

An initial assessment of running a 330 kV double circuit lines from Blowering to Maragle was undertaken as 330 kV is cheaper than 500 kV to construct. However, late in the assessment, it came to light that the 330 kV double circuit lines would be required to use high temperature conductors, which added significantly to cost. The overall capital cost of this option is expected to be in the order of $3,453 million and, since this option was not found to deliver significantly greater market benefits than the other options, we concluded that it is not a credible option (and it is not economically feasible) and have not included it in the body of this PACR.

B.2 OPTIONS RULED OUT AT THE PADR STAGE

As outlined in section 4.2.2 of the PADR, Snowy Hydro[116] and participants at the TAPR forum raised the possibility of a staged development, bringing forward of one of the circuits from Maragle to Bannaby prior to the completion of Snowy 2.0 to support load in New South Wales with improved access to existing generation at the Snowy scheme and Victorian generation.

We have not included this as a credible option in the assessment as it is not technically feasible to move forward parts of HumeLink, given that there is insufficient time to obtain the necessary environmental approvals to do so.

B.3 OPTIONS RULED OUT AT THE PSCR STAGE

We have considered a range of other potential options as part of this RIT-T but ceased to progress these as part of the PSCR on the grounds that they are not considered technically and/or economically feasible, and therefore are not credible options.

A summary of each is provided in Table B-2.

Table B-2 Options considered but not progressed at the PSCR stage

OPTION	OVERVIEW	REASON(S) IT HAS NOT BEEN PROGRESSED
Brownfield options	We have considered options that re-use existing transmission line routes ("brownfield" options). These options may be, for example: • replacement of existing single-circuit transmission lines with double-circuit transmission lines; and • replacement of existing standard conductor transmission lines with high capacity conductor transmission lines. The scope of "brownfield" options includes demolition of existing transmission lines and construction of new single-circuit high capacity or double-circuit transmission lines on multiple existing transmission line routes.	The removal of several existing transmission lines for their demolition and construction periods would remove capacity from the transmission system and significantly increase constraints on generation and inter-regional transfers within the NEM. We will consider re-use of existing corridors where practical and cost-effective, where the impact of outages on the market is within our reliability and network performance obligations.
HVDC options	We have also considered HVDC options following the topologies set out in options 1, 2, 3 and 4.[117] These would require the installation of two or three new HVDC transmission lines, tie transformers and switchgear	Preliminary estimation has found that HVDC options would be substantially more expensive than other potential greenfield options and would not provide materially higher capacities. These options have costs that are between 50 and 100 per cent higher than other options with comparable capacity. These options are therefore not considered economically feasible, as the higher costs are not expected to be outweighed by materially higher market benefits, and have not been considered further as part of this RIT-T.

This appendix represents additional detail provided in the PADR on the two key wholesale market modelling exercises EY have undertaken as part of this PACR assessment, as well as how intra-regional constraints have been modelled.

The accompanying market modelling report provides additional detail on these modelling exercises, as well as the key modelling assumptions and approach adopted more generally.

116. Snowy Hydro, p 2.

117. The topology of option 3D differs from the other options, with transmission lines from Snowy 2.0 to Wagga and Wagga to Sydney, to minimise the number of HVDC converter stations required.

Appendix C Additional detail on the market modelling undertaken

C.1 LONG-TERM INVESTMENT PLANNING

The Long-term Investment Planning function is to develop generation (including storage) and unrelated transmission infrastructure forecasts over the assessment period for each of the credible options and base cases.

This exercise determines the least-cost development schedule for each credible option and scenario drawing on assumptions regarding demand, reservoir inflows, generator outages, wind and solar generation profiles, and maintenance over the assessment period.

The generation and transmission infrastructure development schedule resulting from the Long-term Investment Planning is determined such that:

- it economically meets hourly regional and system-wide demand while accounting for network losses;
- it builds sufficient generation capacity to meet demand when economic while considering potential generator forced outages;
- the cost of unserved energy is balanced with the cost of new generation investment to supply any potential shortfall;
- generator's technical specifications such as minimum stable loading, and maximum capacity are observed;
- notional interconnector flows do not breach technical limits and interconnector losses are accounted for;
- hydro storage levels and battery storage state of charge do not breach maximum and minimum values and cyclic losses are accounted for;
- new generation capacity is connected to locations in the network where it is most economical from a whole of system cost;
- NEM-wide emissions constraints are adhered to;
- NEM-wide and state-wide renewable energy targets are met, or else penalties are applied;
- refurbishment costs are captured;
- generator maintenance outages are scheduled to represent planned generator outages;
- regional and mainland reserve requirements are met;
- energy-limited generators such as Tasmanian hydro-electric generators and Snowy Hydro-scheme are scheduled to minimise system costs; and
- the overall system cost spanning the whole outlook period is optimised whilst adhering to constraints.

The Long-term Investment Planning adopts the same commercial discount rates as used in the NPV discounting calculation in the cost benefit analysis. This is consistent with the approach taken in the 2020 ISP.[118]

Coal-fired and gas-fired generation is treated as dispatchable between its minimum load and its maximum load in the modelling. Coal-fired 'must run' generation is dispatched whenever available at least at its minimum load, while gas-fired CCGT 'must run' plant is dispatched at or above its minimum load. Open cycle gas turbines are typically bid at their short run marginal cost with a zero minimum load level, and started and operated whenever the price is above that level. The accompanying market modelling report provides additional detail on how cycling constraints have been reflected in the analysis.

The Long-term Investment Planning model ensures there is sufficient dispatchable capacity in each region to meet peak demand in the region, plus a reserve level sufficient to allow for generation or transmission contingences which can occur at any time, regardless of the present dispatch conditions.

Due to load diversity and sharing of reserve across the NEM, the reserve to be carried is minimised at times of peak, and provided from the lowest cost providers of reserve including allowing for each region to contribute to its neighbours reserve requirements through interconnectors.

The market modelling report accompanying this PACR provides additional detail on the assumptions and methodological approaches adopted in the Long-term Investment Planning, including necessary model simplifications, sub-regional modelling and how new capacity has been modelled.

118. AEMO, *Planning and Forecasting 2019 Consultation Process Briefing Webinar*, Wednesday 3 April 2019, slide 21.

Appendix C Additional detail on the market modelling undertaken (continued)

C.2 MODELLING OF DIVERSITY IN PEAK DEMAND

The market modelling accounts for peak period diversification across regions by basing the overall shape of hourly demand on nine historical years ranging from 2010/11 to 2018/19.

Specifically, the key steps to accounting for this diversification are as follows:

- the historical underlying demand has been calculated as the sum of historical metered demand and the estimated rooftop PV generation based on historical rooftop PV capacity and solar insolation;
- the nine-year hourly pattern has been projected forward to meet future forecast annual peak demand and energy in each region;
- the nine reference years are repeated sequentially throughout the modelling horizon; and
- 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.

This method ensures the timing of peak demand 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 diversity of timing.

Additional detail on how peak period diversification has been modelled is provided in the market modelling report accompanying this PACR.

C.3 MODELLING OF INTRA-REGIONAL CONSTRAINTS

The wholesale market simulations include models for intra-regional constraints in addition to the inter-regional transfer limits.

Key intra-regional transmission constraints in New South Wales have been captured by splitting NSW into zones (NNS, NCEN, CAN and SWNSW), and explicitly modelling intra-regional connectors across boundaries or cut-sets between these zones. Bi-directional flow limits and dynamic loss equations were formulated for each intra-regional connector. To more accurately capture the benefit of the options being considered, the Canberra zone is split into further nodes and an equivalent network has been developed for this zone to accommodate the DC power flow with all transmission lines, both existing and defined in the options, explicitly modelled by its impedance and thermal limits.

In addition, loss factors for each generator were applied. These were computed from an AC power flow programme interfaced with the Long-term Investment Planning model. The loss factors for each generation investment plan were computed on a five-year basis up to 2030-31 and fed back into the Long-term Investment Planning model to capture both the impact on bids and intra-zonal losses.

Beyond 2030/31, the loss factors have been maintained at the same values as 2030-31, since network changes beyond that stage and additional renewable generation are becoming much less certain. However, this does not preclude generation investment if economic at any location.

Appendix D Summary of consultation on the PADR

Formal submissions from eight parties were received in response to the PADR, seven of which have been published on our website (one submitter requested confidentiality).[119] This appendix provides a summary of non-confidential points raised by stakeholders during the PADR consultation process.

The points raised are grouped by topic and a response is provided to every point raised. All section references are to this PACR, unless otherwise stated.

A similar table was included in the PADR for submissions received on the PSCR (see Appendix B of the PADR). We note that some of the points summarised in that appendix have been superseded by analysis in the current PACR.

Table A-3 – Summary of points raised in consultation on the PADR

SUMMARY OF COMMENT(S)	SUBMITTER(S)	OUR RESPONSE
TIMING AND SCOPE OF THE OPTIONS		
The optimal timing of the preferred option and whether it can be delayed		
Request that specific validation of the optimal timing in each scenario and sensitivity is shown.	EnergyAustralia, p. 2.	See section 4.1.1.
Explain the inconsistency in timing for the preferred option between AEMO's draft 2020 ISP (which describes this project as a 'no regrets' option in 2025-26) and the PADR (which assumes a 2024-25 timing).	EnergyAustralia, p. 2.	While the 2020 ISP stated that HumeLink should be delivered in 2024/25 in the majority of places (i.e., the same timing as the PADR), it did refer to 2025-26 in three places. EnergyAustralia would need to check with AEMO the reasons for these two different dates.
Queried whether the investment decision can be delayed.	EnergyAustralia, p. 5.	
Queries whether there are regret costs in some cases, or under some sensitivities, if the project proceeds in 2024-25.	EnergyAustralia, p. 2.	We do not consider it possible to commission the project in 2024/25.

119. https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network

Appendix D Summary of consultation on the PADR (continued)

SUMMARY OF COMMENT(S)	SUBMITTER(S)	OUR RESPONSE
Whether the options should be extended to all include reinforcing the southern and western Sydney transmission network		
Suggest we should continue to investigate the possible future reinforcement of the southern and western Sydney transmission network to ensure the critical southern supply route meets future demand requirements through diversified lateral feeders into the greater Sydney metro load centre.	Snowy Hydro, p. 2.	See section 4.1.2.
Priority should be given to bring HumeLink to the Sydney West load centre, which could be undertaken through a further stage of 'Powering Sydney's Future' with parallel pathing of the approvals and route selection process.	Snowy Hydro, p. 6.	
It is unclear whether the preferred option will require completion of the proposed additional 330 kV circuit between Bannaby and Sydney West as set out in Option 4A to accommodate the required higher flows from southern NSW towards the Sydney West switchyard, following the planned retirement of generation in the Hunter Valley and Central Coast electrical sub-regions of NSW to deliver the calculated market benefits set out in the RIT-T.	ERM Power, p. 4.	
The topology 4 easement is valuable and should be used for a double-circuit 500kV line to ensure the very long-term needs of supply to Sydney from the south is secured.	Email submission from Malcolm Park.	
Does the Bannaby to Sydney West (Line 39) transmission line constrain optimal dispatch over the outlook period, once the preferred option has been installed.	EnergyAustralia, p. 5.	
While Option 4C is the most likely to reduce network congestion, it is understandable that the additional expense over Option 3C may not be justified by these benefits. In any case deeper connection to the load can be done at a later date if deemed valuable.	Neoen, p. 1.	
Whether the options can be staged to provide greater net benefits		
Consideration should be given to staging the preferred option from a consumer benefit perspective. ERM Power suggests that, while an initial segment between Wagga Wagga and Bannaby is warranted, the other elements of the project could be staged.	ERM Power, pp. 2 & 3.	See section 4.1.3.
Why Option 3C does not require a phase shifting transformer		
It is unclear why Option 3B requires installation of a phase shifting transformer on Bannaby to Sydney West 330 kV line to control flows across this network flow path, yet the preferred option which will result in the delivery of higher flows to the 500 and 330 kV Buses at Bannaby does not have this same requirement.	ERM Power, p. 3.	See section 4.1.4.
Whether the preferred option can be coupled with modular power flow control equipment to provide greater net benefits		
Propose the use of modular power flow control (MPFC) equipment as part of the project in order to extract the maximum capability from the existing transmission system. MPFC should be assessed based on an evaluation of the net economic benefits it would provide in the context of the preferred solution.	Smart Wires, pp. 2-3.	See section 4.1.5.

Appendix D Summary of consultation on the PADR (continued)

SUMMARY OF COMMENT(S)	SUBMITTER(S)	OUR RESPONSE
ASSUMPTIONS USED IN MARKET MODELLING		
Please clarify if the central real, pre-tax discount rate of 5.9 per cent, as well as the sensitivities at 2.85 per cent and 8.95 per cent, have been applied to the discounted cash flow analysis and generator hurdles rates as well as when determining the annualised costs of the transmission investment and therefore in determining the optimal timing.	EnergyAustralia, p. 2.	See section 4.2.
Seek clarification on how the departures from the 2020 ISP assumptions (including advanced closing of half of the coal power station capacity in the NEM by 2 to 5 years in three of the four scenarios) affects the net benefits and timing of the preferred option.	EnergyAustralia, p. 3.	
Confirm whether the cost of Snowy 2.0 is treated as a sunk cost.	EnergyAustralia, p. 4.	Snowy 2.0 received environmental approval and construction approval from the Federal government in mid-2020. We consider Snowy 2.0 as a 'committed project' under the RIT-T and so the costs are treated as sunk in the analysis. This is consistent with the final 2020 ISP, which refers to Snowy 2.0 as committed and includes it in all scenarios.[120]
Confirm that, if a hypothetical market driven announcement to install a 500 MW OCGT/CCGT in NSW (upstream of Bannaby) occurred in the next few months, this would be treated as a sunk cost, and whether this would have any bearing on the cost benefits analysis and the preferred timing.	EnergyAustralia, p. 4.	An announcement of a market-driven entry of a new 500 MW OCGT/CCGT in NSW (upstream of Bannaby) would enter the RIT-T assessment as part of the counterfactual base case. The costs of this generator would not form part of the costs of the base case. However, to the extent that the generator was not fully committed and was expected not to proceed if the HumeLink development went ahead, the avoided cost would enter the assessment of the HumeLink options. We have investigated a sensitivity assuming that the recently announced Kurri Kurri and Tallawarra B gas plants are in-place (see section). This finds that the preferred option would continue to deliver substantial positive net market benefits to the market.
Concern that the modelling of hydro assumes perfect foresight and is targeted to reduce total system costs. EnergyAustralia suggests this is unreasonable and that basing the development path and investment decisions on operational assumptions that are inconsistent with reality is a concern. Request considerations of whether the benefits outlined in the PADR are overstated because hydro modelling assumes perfect foresight and is targeted to reduce total system costs. EnergyAustralia questions whether Snowy Hydro's portfolio after the construction of Snowy 2.0 could influence dispatch outcomes away from the perfect outcomes represented in SRMC bidding.	EnergyAustralia, p. 4.	See section 4.2.
Confirm whether historical peak demand coincident factors are maintained in the demand traces.	EnergyAustralia, p. 4.	See section 4.2.
Explain how EY has calibrated its market modelling to actual outcomes, and how it extrapolates this over the outlook period.	EnergyAustralia, p. 4.	See section 4.2.
Outline the use of EY generation forced outage rates and mean time to Repair assumptions and explain how they differ from those used by AEMO in its ISP.	EnergyAustralia, p. 4.	See section 4.2.

120 AEMO, *Integrated System Plan*, July 2020, pp. 33 & 51.

Appendix D Summary of consultation on the PADR (continued)

SUMMARY OF COMMENT(S)	SUBMITTER(S)	OUR RESPONSE
Explain and publish the dynamic loss equations and changes, including discussion on whether there are any material benefits in terms of loss savings.	EnergyAustralia, p. 5.	See section 4.2.
Outline whether transient and voltage stability limits are included in modelling, and whether they impact on the transfer capacity modelled in the system technical assessment studies.	EnergyAustralia, p. 5.	Both transient and voltage stability limits are included in the modelling. They have been assessed in accordance with industry standards and are taken into account in the transfer capacities of the options.
Queries whether there is confidence that the modelling of additional pumping capacity adequately represents the characteristics necessary to fully understand the power system transient stability performance when pumps operate.	Email submission from Malcolm Park.	
The market benefit is dependent on a large number of modelling input assumptions occurring in what is an uncertain future.	ERM Power, p. 2.	The RIT-T assessment continues to consider four reasonable scenarios, which differ in relation to demand outlook, DER uptake, assumed generator fuel prices, assumed emissions targets, retirement of coalfired power stations, and generator and storage capital costs. The scenarios reflect a broad range of potential outcomes across the key uncertainties that are expected to affect the future market benefits of the investment options being considered and are aligned with the scenarios used by AEMO in the final 2020 ISP. A range of sensitivity tests have also been investigated in order to further test the robustness of the outcome to key uncertainties.
The modelling should calculate the net market benefit using the total calculated estimated cost for EnergyConnect and VNI West as well as HumeLink.	ERM Power, p. 2.	See section 4.2.
The market benefit modelling should be conducted on the HumeLink project in isolation with both the EnergyConnect and VNI West projects excluded.	ERM Power, p. 2.	
Consider that low demand sensitivities should be run on all modelled scenarios (reflecting in particular the outlook for future smelter load) to assess the impact of events like smelters shutting down.	ERM Power, p. 3.	See section 4.2.
MODELLING OUTCOMES		
Explain the apparent significant avoided generation or storage capital costs (excl. fuel costs) in the years before the transmission is commissioned.	EnergyAustralia, p. 2.	This reflects plants changing their behaviour in anticipation of HumeLink being commissioned.
Requests additional information and analysis on the assumed changes in the supply side, notably in Pumped Hydro Energy Storage, and coal-fired installed capacity in order to understand the level of reliance the conclusions have on these assumptions and whether the system will be operationally manageable.	EnergyAustralia, pp. 2-3.	See section 4.3.

Appendix D Summary of consultation on the PADR (continued)

SUMMARY OF COMMENT(S)	SUBMITTER(S)	OUR RESPONSE
EnergyAustralia is concerned that the central case finds that an additional 11,300 GW of long duration pumped hydro storage, in addition to the capacity provided by Snowy 2.0, is required by 2044/45. Further, the lack of utility scale batteries appears to be disconnected from what is happening in the market today and gas-fired generation appears to be missing from the supply mix. We consider TransGrid should produce a sensitivity that challenges the presumption of pumped hydro playing a critical role in the transition of the electricity system.	EnergyAustralia, p. 3.	See section 4.3.
Encourage details of the sensitivity studies around closure of coal plant based on economic viability to be summarised and published, including the details on the closure criteria applied.	EnergyAustralia, p. 3.	See section 4.3.
Request that we publish EYs findings of the sensitivities around Snowy 2.0 not proceeding, halving the planned storage, having reduced capacity, and reduced round trip efficiency, on the timing of the preferred option.	EnergyAustralia, p. 3.	See section 4.3.
Provide more detail on how much dispatchable capacity is available in NSW and more broadly across the NEM in the scenario outlooks.	EnergyAustralia, p. 3.	Dispatchable capacity exceeds demand at all times by the reserve level, unless load shedding or demand side participation is occurring. The workbooks released alongside the PADR include this dispatchable capacity – see in particular the market modelling output workbooks, capacity worksheets, published on the HumeLink RIT-T website.
EnergyAustralia raised three questions for the forecast scenarios: How dependent is power system operation, or maintaining the reliability standard, on the implausible levels of pumped hydro from the long-term planning? If the forecast capacity of pumped hydro does not arrive, does the system face significant security and reliability challenges? Will system strength, low inertia or frequency/voltage control issues prevail that have not been considered in the study? Will the remaining dispatchable coal plants be able to ramp up and down to efficiently support the swings in intermittent generation from new capacity built as a result of the new interconnector?	EnergyAustralia, pp. 3-4.	See section 4.3.
Request that the utilisation of HumeLink (% of transfer capacity) is published, including intraday flows and duration curves.	EnergyAustralia, p. 6.	See section 4.3.
COSTS OF THE OPTIONS		
Confirm if the network project costs include easements and land acquisition allowances. Confirm what needs to be done to refine 'midpoint' costs for the purposes of the PACR.	EnergyAustralia, p. 5.	See section 4.4.
Recommend that in finalising this RIT-T process that costings be subject to potential variation not greater than +/- 15 per cent.	ERM Power, p. 3.	
Confirm the transmission asset economic lives used, and the 1 per cent O&M capex per annum assumption are consistent with AER views when approving expenditure allowances.	EnergyAustralia, p. 5.	See section 4.4.
Request that the cumulative transmission capex/opex on annual profile charts be published (Figures 5, 10, 15 and 20 in the PADR).	EnergyAustralia, p. 5.	See section 4.4.

Appendix D Summary of consultation on the PADR (continued)

SUMMARY OF COMMENT(S)	SUBMITTER(S)	OUR RESPONSE
THE INCIDENCE OF MARKET BENEFITS		
Request that the modelled price outcomes are published, including duration curves and intraday price shape.	EnergyAustralia, p. 5.	See section 4.5.
Request that the regional benefits, relative to regional costs, are published (particularly for NSW, SA and VIC).	EnergyAustralia, p. 5.	See section 4.5.
Recommends that TransGrid determine the share of benefits from the investment that accrue to Snowy 2.0 and those that accrue to consumers. TransGrid should identify any imbalance of costs and benefits for NSW consumers and examine options to address this, including Snowy 2.0 being required to directly fund a commensurate portion of the investment, as part of the HumeLink RIT-T.	PIAC, p. 3.	
Recommend that the proponents also consult on and conduct modelling with regards to the changes in consumers and supplier benefits as part of this RIT-T process.	ERM Power, p. 2.	
DIVERSITY BENEFITS FROM AN ELECTRICAL 'LOOP' AND THE USE OF DOUBLE-CIRCUIT VERSUS SINGLE-CIRCUIT		
Suggests that the need for two new single-circuit lines in sections where one double-circuit line could be enough is reviewed.	Email submission from Malcolm Park.	See section 4.7.
Summarise the preconditions and insights into the methodology used to determine the cost estimate if two lines of an interconnector were to fail simultaneously ($450 million). EnergyAustralia, requests to see views on the probability of this event, the forced outage rate and the mean time to repair.	EnergyAustralia, p. 5.	See section 4.6.
OTHER POINTS RAISED		
Submit that the Maragle 330 kV substation and the cut in line to Line 64 should be captured in the RIT-T process. Maragle 330kV substation would allow access to existing Snowy and Victorian generation which is currently constrained out of the NSW market. This would be in addition to the connection of Snowy 2.0 which would also connect into the existing Maragle substation by extending the 330 kV bus and installing dedicated 330 kV connection bays for the Snowy 2.0 connecting lines.	Snowy Hydro, p. 6.	The shared network component covered by the RIT-T relates to all transmission assets up to but not including the connection point for a generator. The extent of works for the shared network are set out in the option descriptions in this PACR.
We believe that a review of this RIT-T process by the AER, similar to the review undertaken by the AER of the proposed EnergyConnect project RIT-T process, would provide additional certainty to consumers that the proposed project will deliver a net market benefit.	ERM Power, p. 4	We will be seeking AER approval of a contingent project allowance for this investment, which is expected to proceed in two stages. As part of the staged contingent project process, we will seek a 'feedback loop' confirmation from AEMO if the future estimated costs of the preferred option exceed those currently estimated in the RIT-T assessment. The feedback loop is designed to confirm whether the project remains part of AEMO's optimal development path.


TransGrid