Increasing the capacity for generation in the Molong and Parkes area (Line 94T) PADR

Market modelling report forecasting gross market benefits

7 June 2023

Building a better working world

Release Notice

Ernst & Young ("EY") was engaged on the instructions of NSW Electricity Networks Operations Pty Limited, as trustee for NSW Electricity Networks Operations Trust ("Transgrid"), to undertake market modelling of system costs and benefits to assess the options for increasing the capacity for generation in the Molong and Parkes area (Line 94T) Regulatory Investment Test for Transmission ("Line 94T RIT-T").

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

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

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1. Executive summary

Transgrid engaged EY to undertake market modelling to forecast the system costs and gross market benefits of the options related to increasing the capacity for generation in the Molong and Parkes area (Line 94T) of the Regulatory Investment Test for Transmission (RIT-T).

The Line 94T RIT-T was initiated by Transgrid as the transmission network service provider in New South Wales (NSW) and the assumptions and input data sources were selected by Transgrid. The selection of input assumptions and modelling methodology follows the *RIT-T guidelines* published by the Australian Energy Regulator (AER)[1].

This Report forms a supplementary report to the Project Assessment Draft Report (PADR) prepared and published by Transgrid[2], and describes the key modelling outcomes and insights as well as the assumptions and input data sources selected by Transgrid. The Report should be read in conjunction with the PADR published by Transgrid[2].

EY was engaged to compute the least-cost generation dispatch and capacity development plan for the National Electricity Market (NEM) associated with the Line 94T options (and the counterfactual Base Case without Line 94T options) for the Step Change, Progressive Change and Hydrogen Superpower scenarios issued in the AEMO 2022 Integrated System Plan (ISP)[3,4]. In addition, Transgrid advised us to incorporate more recent inputs and assumptions updates based on new information related to committed and anticipated generators and storage, as well as generator retirements announced since the publication of 2022 ISP[5].

Transgrid requested that we model six augmentation options related to Line 94T as core simulations across the three scenarios, as well as counterfactual Base Cases without augmentation. Options provided by Transgrid include network and non-network solutions for increasing the capacity for generation in the Molong and Parkes area, as outlined in Table 1. The options are: uprating the existing conductors, restringing Line 94T using different conductors, implementing a powerflow controller, rebuilding Line 94T to double-circuit transmission line using existing easement, and a non-network battery energy storage system (BESS) solution. Transgrid assumed that the BESS option operates in the wholesale electricity market and would alleviate the congestion on the Line 94T by its expected charging during the day. Transgrid advised us to include the preferred option of Maintaining Reliable Supply to the Bathurst, Orange and Parkes Areas RIT-T PACR[6] (BOP BESS) in the Base Case and Line 94T options.

1 AER, 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 on 26 May 2023

2 Transgrid, *Increasing transmission capacity for generation in the Molong and Parkes area: RIT-T Project Assessment Draft Report*. Available at: https://www.transgrid.com.au/about-us/regulatory-framework/regulatory-investment-test-for-transmission-rit-t. Accessed on 26 May 2023

3 AEMO, July 2022, *2022 Integrated System Plan*. Available at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp. Accessed on 26 May 2023

4 AEMO, July 2022, *Inputs assumptions and scenarios workbook v3.3*, available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios. Accessed 26 May 2023.

5 AEMO, January 2023, *Generation Information*. Available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Accessed on 26 May 2023

6 Transgrid, June 2022, *Maintaining Reliable Supply to the Bathurst, Orange and Parkes areas PACR*. Available at: https://www.transgrid.com.au/media/fkupsd1t/transgrid-pacr_supply-to-bathurst-orange-and-parkes.pdf. Accessed on 26 May 2023

Table 1: Summary of the modelled Base Case and Line 94T options[2]

Option	Description	Timing
Option 1	Increase transmission line design temperature of Line 94T	1/04/2025
Option 2	Restring Line 94T with a higher rated conductor on existing structure (Flicker/ACSS)	1/11/2025
Option 2A	Restring Line 94T with a higher rated low sag conductor on existing structure (Partridge/ACSS/HS285)	1/11/2025
Option 2B	Implementing Option 2 together with power flow controllers	1/11/2025
Option 3	Replacing Line 94T with double circuit transmission lines	1/11/2026
Option 4	Installation of 50MW/300MWh BESS at Molong substation[7]	1/07/2025

In addition to the core simulations, Transgrid requested an assessment of four sensitivities on gross market benefits as listed below.

- Sensitivity 1: including three additional generators (in addition to the core simulation assumptions) in the Central West NSW area for the Base Case and all options (3 Gen sensitivity),
- Sensitivity 2: using increased demand forecast in the Orange area in the Base Case and all options (High load sensitivity),
- Sensitivity 3: including BOP stage 2 (Wellington to Parkes double circuit 132 kV line) upgrade in the Base Case and all options (BOP Stage 2 sensitivity),
- Sensitivity 4: excluding BOP RIT-T's BESS from the Base Cases and all options in the model (No BOP BESS sensitivity).

Based on Transgrid advice, sensitivities 1 to 3 were only modelled for the Step Change scenario, while sensitivity 4 was modelled for all three scenarios.

To assess the least-cost solution, EY's Time Sequential Integrated Resource Planner (TSIRP) model was used. It makes decisions for each hourly trading interval in relation to:

- the generation dispatch level for each power plant along with the charging and discharging of storage. Generators are assumed to dispatch at their short run marginal cost (SRMC), which is derived from their variable operation and maintenance (VOM) and fuel costs. The generation for each trading interval is subject to the modelled availability of power stations in each hour (those that are not on planned or un-planned outages), network limitations and energy limits (e.g., storage levels).
- commissioning new entrant capacity for wind, solar PV SAT, OCGT[8], large-scale battery, pumped hydro energy storage (PHES) and hydrogen turbine technology (only applied in the Hydrogen Superpower scenario).
- the withdrawal of existing generation on a least-cost basis, often to meet the emissions budgets assumed in the modelled scenarios. Coal generation withdrawal is applied on a unit basis, following AEMO ISP methodology, considering the announced retirement priority, based on Generating Unit Expected Closure Year of January 2023[9].

[7] The BESS in Option 4 is assumed by Transgrid to operate by its full capacity in the market, alleviating network congestion on Line 94T by its expected charging during the day.

[8] PV = photovoltaics, SAT = Single Axis Tracking, OCGT = Open-Cycle Gas Turbine

[9] AEMO, January 2023, *Expected closure years (estimated generator retirement dates)*. Available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Accessed on 26 May 2023.

- Expansion of transmission network upgrades for Renewable Energy Zones (REZs).

The hourly decisions consider operational constraints[10] that include:

- supply must equal demand in each region for all trading intervals plus a reserve margin, with unserved energy (USE) costed at the value of customer reliability (VCR)[11],
- minimum loads for coal generators,
- interconnector flow limits (between regions),
- intra-regional flow limits (between zones in Northern NSW),
- dynamically modelled intra-regional flow limits for the detailed network modelled in Southern NSW as well as thermal N-0 and N-1 constraint equations in the Central West NSW area,
- maximum and minimum storage (conventional storage hydro, PHES and large-scale battery) reservoir limits and cyclic efficiency,
- new entrant capacity build limits for wind and solar for each REZ where applicable, and PHES in each region,
- carbon budget constraints, as defined in the ISP for the modelled scenarios,
- renewable energy policies where applicable by region or NEM-wide, and
- other constraints such as network thermal and stability constraints, as defined in the Report.

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

- capital costs of new generation capacity installed (capex),
- 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 (demand-side participation, DSP) and involuntary load curtailment (unserved energy, USE),
- transmission expansion costs associated with REZ development, defined in the ISP methodology as the amount of power that can be transferred from the REZ through the shared transmission network. REZ transmission limits can be increased by augmenting the shared transmission network (modelled as a network expansion cost)[12]. Note that the REZ transmission cost is different to the connection cost of new generators within the REZ.

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 needs to be dispatched in each trading interval. The forecast gross market benefits also capture the impact of differences in cyclic efficiency losses in storages, including PHES and large-scale batteries between each option and the counterfactual Base Case.

For each simulation with a Line 94T option and in a matched no augmentation 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 value terms of costs is the forecast gross market

[10] The constraints are generally aligned with the 2022 ISP, while additional network constraints are modelled to present a higher network resolution in Wellington, Parkes and Orange areas of Central West NSW.

[11] Based on AER, December 2021, *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 on 26 May 2023. These are the same values applied in AEMO's 2022 ISP.

[12] AEMO, August 202, *ISP methodology*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-isp-methodology.pdf?la=en. Accessed on 26 May 2023

benefits[13] due to the presence of the corresponding option. This aligns with the classes of market benefits, as required by the RIT-T guidelines. For all scenarios, benefits are presented in real June 2021 dollars discounted to June 2021 using a 5.5% real, pre-tax discount rate, consistent with the value applied by AEMO in the 2022 ISP[3].

Forecast gross market benefits in core simulations

Table 2 summarises the forecast gross market benefits over the modelled horizon (2023-24 to 2047-48) for all options across all scenarios.

Table 2: Summary of forecast gross market benefits of all Line 94T options for core simulation relative to each scenario's Base Case, millions real June 2021 dollars discounted to June 2021 dollars

Option	Description	Timing	Forecast gross market benefits ($m) – core simulations		
			Step Change	Progressive Change	Hydrogen Superpower
Option 1	Increase transmission line design temperature	1/04/2025	15.8	12.3	33.6
Option 2	Restring Line 94T with a higher rated conductor on existing structure (Flicker/ACSS)	1/11/2025	21.5	18.1	50.6
Option 2A	Restring Line 94T with a higher rated low sag conductor on existing structure (Partridge/ACSS/HS285)	1/11/2025	21.4	18.2	50.6
Option 2B	Option 2 with power flow controllers	1/11/2025	19.6	17.2	52.6
Option 3	Replacing Line 94T with double circuit transmission lines	1/11/2026	18.7	14.3	14.5
Option **4**	Non-network option (BESS)	1/07/2025	91.2	96.7	106.9

All options, except Option 3, are expected to achieve relatively higher forecast gross market benefits in the Hydrogen Superpower scenario, while their forecast benefits in other scenarios are relatively similar. This is mainly due to the significantly higher demand forecast in the Hydrogen Superpower scenario which increases network congestion in the Base Case and therefore benefits of the options.

Option 2, Option 2A, and Option 2B (Option 2 variants) are forecast to have similar gross market benefits due to the same impact on Line 94T constraint binding frequency. The Option 2 variants show that while increasing line ratings increases expected gross market benefits, this effect saturates. Beyond a certain level, further increases to thermal line ratings are not beneficial due to other limitations in the network.

Option 1 is forecast to have a relatively lower benefit compared to Option 2 variants due to the lower line thermal rating for this option and more frequent constraint binding compared to Option 2 variants.

Option 3 is forecast to have the lowest market benefits in the Hydrogen Superpower scenario, mainly due to the limitation that this option introduces in other parts of the network. In particular,

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[13] In this Report we use the term *gross market benefit* to mean "market benefit" as defined in the AER's *RIT-T guidelines*, and "net economic benefit" in the same manner defined in the guidelines.

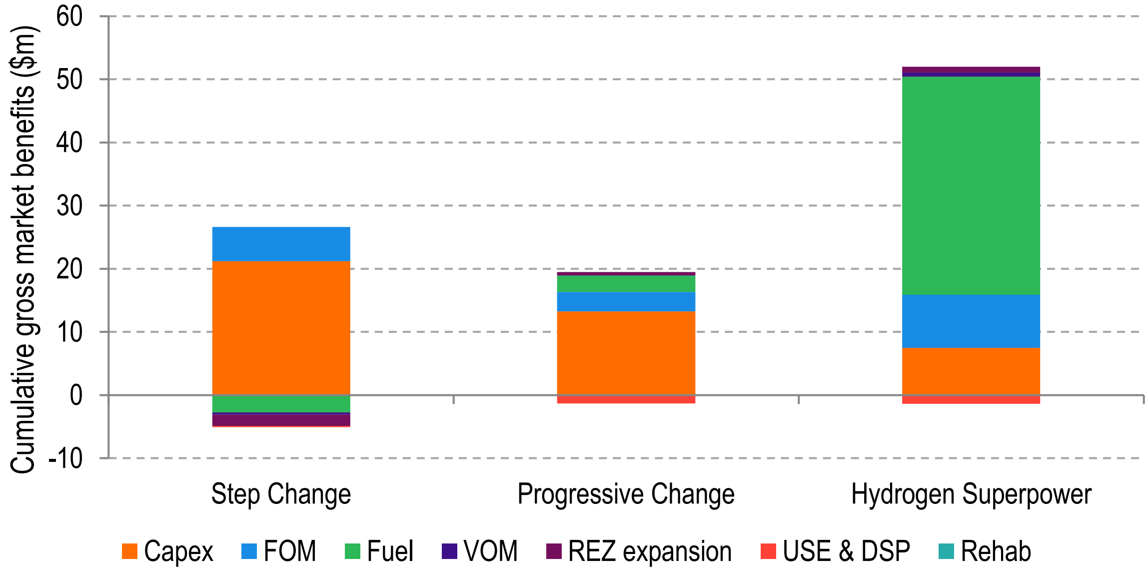
since this option reduces the impedance on the flow paths towards Orange, it is forecast that N-0 constraints on Wellington to Molong lines bind more frequently, limiting generation, particularly wind generation, in Central West Orana, which is forecast to result in lower benefits for this option.

Option 4 has the highest forecast gross market benefits among all the options, mainly as the BESS is allowed to be dispatched in the market modelling than be reserved for network support. As the BESS is assumed to be committed in the Option 4 model it results in reduced capacity build and consequently capex cost savings with this option. This benefit is generic to a battery committed at almost any location and is unrelated to the impact of Option 4 on Line 94T ratings.

Option 2 and Option 2A have been determined by Transgrid to be the preferred options on the basis of net economic benefits. The cost assessment, calculation of net economic benefits (gross market benefits minus option costs) and determination of the preferred options were conducted outside of this Report by Transgrid.

Figure 1 shows the breakdown of gross market benefits by category for the Transgrid preferred option (Option 2) for the three scenarios. Option 2 has the highest forecast net economic benefits as calculated by Transgrid in the PADR [2]. The numbers in the chart represent the net present value of gross market benefits for each option relative to the scenario-specific Base Case. The forecast gross market benefits of each option in each scenario need to be compared to the relevant option cost (estimated by Transgrid) to determine the forecast net economic benefit for that option.

Figure 1: Composition of forecast total gross market benefits for the Preferred Option 2, millions real June 2021 dollars discounted to June 2021 dollars



Capex and FOM cost savings are forecast to make up the largest proportion of benefits across Step Change and Progressive Change scenarios for Line 94T options, while it is forecast that fuel and FOM cost savings make up the largest proportion of the benefits in the Hydrogen Superpower scenario. The primary drivers of the forecast cost savings due to Line 94T options, particularly Option 2 and Option 2A as preferred options, are:

- Line 94T options forecast to reduce curtailment of renewable generation in the Central West NSW area, particularly solar generation in the Wellington, Parkes and Orange areas. In turn, this is forecast to avoid additional solar capacity investment.
- Fuel cost savings in the Step Change and Progressive Change scenarios are mainly due to reduced coal generation with the augmentation, while relatively higher fuel cost savings forecast in the Hydrogen Superpower scenarios are mostly as a result of avoided hydrogen turbine generation with Line 94T options in place.

- With each of the options implemented in isolation and considering the rest of the network functioning under current constraints, while Line 94T constraint is relieved to a great degree, other constraints in the vicinity are forecast to bind more frequently which may limit further benefits.

Forecast gross market benefits in sensitivities

Table 3 summarises the forecast gross market benefits for four sensitivities for all options for the Step Change scenario. Forecast gross market benefits provided are assessed by implementing the changes in input assumptions for that sensitivity to the Base Case and all options.

Table 3: Summary of forecast gross market benefits for the three sensitivities of all Line 94T options relative to sensitivity Base Case, millions real June 2021 dollars discounted to June 2021 dollars

Option	Description	Timing	Forecast gross market benefits ($m) – Step Change Scenario			
			Core simulation	3 Generator Sensitivity	High load Sensitivity	BOP Stage 2 Sensitivity
Option 1	Increase transmission line design temperature	1/04/2025	15.8	23.1	25.2	13.34
Option 2	Restring Line 94T with a higher rated conductor on existing structure (Flicker/ACSS)	1/11/2025	21.5	37.7	38.5	16.67
Option 2A	Restring Line 94T with a higher rated low sag conductor on existing structure (Partridge/ACSS/HS285)	1/11/2025	21.4	37.5	38.6	16.44
Option 2B	Option 2 with power flow controllers	1/11/2025	19.6	35. 8	37.6	14.42
Option 3	Replacing Line 94T with double circuit transmission lines	1/11/2026	18.7	27.5	28.1	24.61
Option **4**	Non-network option (BESS)	1/07/2025	91.2	101.1	96.2	88.31

The sensitivities show that three additional generators in the area and high load growth in the Orange area are forecast to deliver generally higher benefits for all options. The higher expected benefits of these sensitivities are due to increasing network congestion in the area in the Base Case, where Line 94T options are forecast to be more beneficial in alleviating the congestion.

On the other hand, BOP Stage 2 sensitivity is forecast to reduce the gross market benefits for all options except Option 3. The reason for lower benefits of options in this sensitivity is that additional Wellington-Parkes transmission line in the Base Case reduces the network congestion in the area. Therefore, the options are forecast to be less beneficial as compared with core simulations. Higher forecast benefits of Option 3 in the BOP Stage 2 sensitivity are mainly due to reduced impedance on the flow path of Wellington to Parkes reducing diverting the flow from Wellington to Wellington Town which is forecast to be a bottleneck in the core simulations for this option. As a result, Option 3 is expected to enable further generation in the area, resulting in higher benefits than what is forecast in the core simulations.

Table 4 shows, the gross market benefits for the BOP BESS exclusion sensitivity which are forecast to be higher for all options compared to the core simulations. This is mainly due to the increased network congestion forecast in the Base Case as a result of excluding Parkes BESS (being one of the BOP BESSs). This is forecast to provide more opportunity for the Line 94T options to reduce network congestion and renewable generation spill in the area, improving gross benefits.

Table 4: Summary of forecast gross market benefits for BOP BESS exclusion sensitivity of all Line 94T options relative to sensitivity Base Case, millions real June 2021 dollars discounted to June 2021 dollars

Option	Description	Timing	Forecast gross market benefits ($m)		
			Step Change	Progressive Change	Hydrogen Superpower
Option 1 - Core Simulation	Increase transmission line design temperature	1/04/2025	15.8	12.3	33.6
Option 1 - Sensitivity			16.5	12.8	35.9
Option 2 - Core Simulation	Restring Line 94T with a higher rated conductor on existing structure (Flicker/ACSS)	1/11/2025	21.5	18.1	50.6
Option 2 - Sensitivity			23	19.2	54.8
Option 2A - Core Simulation	Restring Line 94T with a higher rated low sag conductor on existing structure (Partridge/ACSS/HS285)	1/11/2025	21.4	18.2	50.6
Option 2A - Sensitivity			22.9	19.3	54.5
Option 2B - Core Simulation	Option 2 with power flow controllers	1/11/2025	19.6	17.2	52.6
Option 2B - Sensitivity			21	18.4	57.2
Option 3 - Core Simulation	Replacing Line 94T with double circuit transmission lines	1/11/2026	18.7	14.3	14.5
Option 3 - Sensitivity			19.9	15	16
Option 4 - Core Simulation	Non-network option (BESS)	1/07/2025	91.2	96.7	106.9
Option 4 - Sensitivity			91.7	97	107.5

2. Introduction

Transgrid engaged EY to undertake market modelling of system costs and benefits of the options related to the increasing the capacity for generation in the Molong and Parkes area (Line 94T) RIT-T.

The Line 94T RIT-T was initiated by Transgrid as the transmission network service provider in NSW and the assumptions and input data sources were selected by Transgrid. The selection of input assumptions and modelling methodology follows the *RIT-T guidelines* published by the AER[1].

This Report forms a supplementary report to the PADR prepared and published by Transgrid[2]. It describes the key modelling outcomes and insights as well as the assumptions and input data sources selected by Transgrid. The Report should be read in conjunction with the consultation report published by Transgrid[2].

EY computed the least-cost generation dispatch and capacity development plan for the NEM, generally adopting the 2022 ISP assumptions for three scenarios[3,4] with updates to reflect new market information in the AEMO Generation Information data as of January 2023[5].

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

- capital costs of new generation capacity installed (capex),
- 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,
- transmission expansion costs associated with REZ development,
- transmission and storage losses which form part of the demand to be supplied, which are calculated dynamically within the model, impacting the calculated classes of benefits mentioned above.

Each category of gross market benefits is computed hourly across a modelling period from 2023-24 to 2047-48. Benefits are presented in real June 2021 dollars discounted to June 2021 using a 5.5% real, pre-tax discount rate as agreed jointly by Transgrid. This value is consistent with the value applied by AEMO in 2022 ISP[3].

This modelling considers the options outlined in Table 5[2]. Transgrid requested to model six augmentation options related to Line 94T, as well as counterfactual Base Cases without augmentation. The differences between the options relate to the type of network upgrades as well as one non-network battery option provided by Transgrid. The options are uprating the existing conductors, restringing Line 94T, using different conductor, implementing powerflow controller, rebuilding Line 94T to double-circuit transmission lines using existing line easement as well as a non-network battery option. Transgrid advised us to include the preferred option of Maintaining Reliable Supply to the Bathurst, Orange and Parkes Areas RIT-T PACR[6] (BOP BESS) in the model.

Table 5: Summary of the modelled Base Cases and Line 94T options[2]

Option	Line 94T parameters								
	Impedance (per unit)			Rating (MVA)					
Options modelled for Line 94T	R	X	B	Summer-Day	Summer-night	Winter-day	Winter-night	Autumn/Spring-day	Autumn/Spring-night

Option	Line 94T parameters								
	Impedance (per unit)			Rating (MVA)					
Base Case	0.03257	0.06729	0.01472	112	119	120	127	112	123
Option 1	0.03257	0.06729	0.01472	125	121	135	135	125	126
Option 2	0.02139	0.06942	0.01443	177	202	195	215	180	206
Option 2A	0.03868	0.07119	0.01398	152.3	159.3	159.5	165.2	153.8	161.1
Option 2B	0.02139	0.1224	0.01443	177	202	195	215	180	206
Option 3[14]	0.02131	0.06276	0.01609	144	141	163	162	145	148
Option 4[7]	0.03257	0.06729	0.01472	112	119	120	127	112	123

In addition to the core simulations, Transgrid requested to assess the impact of a few sensitivities on gross market benefits as listed below:

- Sensitivity 1: including three additional generators (in addition to the core simulation assumptions) in the Central West NSW area to the model for the Base Case and all options (3 Gen sensitivity),
- Sensitivity 2: using increased demand forecast in the Orange area in the Base Case and all options (High load sensitivity),
- Sensitivity 3: including BOP stage 2 (Wellington to Parkes double circuit 132 kV line) upgrade in the Base Case and all options (BOP Stage 2 sensitivity),
- Sensitivity 4: excluding BOP RIT-T's BESS from the Base Cases and all options in the model (No BOP BESS sensitivity).

The forecast gross market benefits of each option need to be compared to the cost of the relevant option to determine the forecast net economic benefit for that option. The assessment of costs and calculation of net economic benefits and preferred option was conducted outside of this Report by Transgrid using the forecast gross market benefits from this Report and other inputs[2].

The Report is structured as follows:

- Section 3 provides an overview of the specific Line 94T network modelling assumptions.
- Section 4 provides an overview of forecast market modelling.
  - Section 4.1describes the outlook of the Base Case for all three scenarios without augmentation options.
  - Section 4.2 provides a summary of forecast gross market benefits for all options.
  - Section 4.3 describes the market modelling outcomes for the top-ranked options.
  - Section 4.4 describes market modelling outcomes for other options (excluding top-ranked options) in the core simulations.
  - Section 4.5 describes market modelling outcomes for sensitivities.
- Appendix A describes key assumptions for modelling scenarios.
- Appendix B details the modelling methodology.
- Appendix C discusses the constraint formulation methodology in detail.
- Appendix D describes transmission and demand related assumptions and inputs.

[14] The ratings for Option 3 in this table are for each circuit.

- Appendix E provides supply related inputs and assumptions

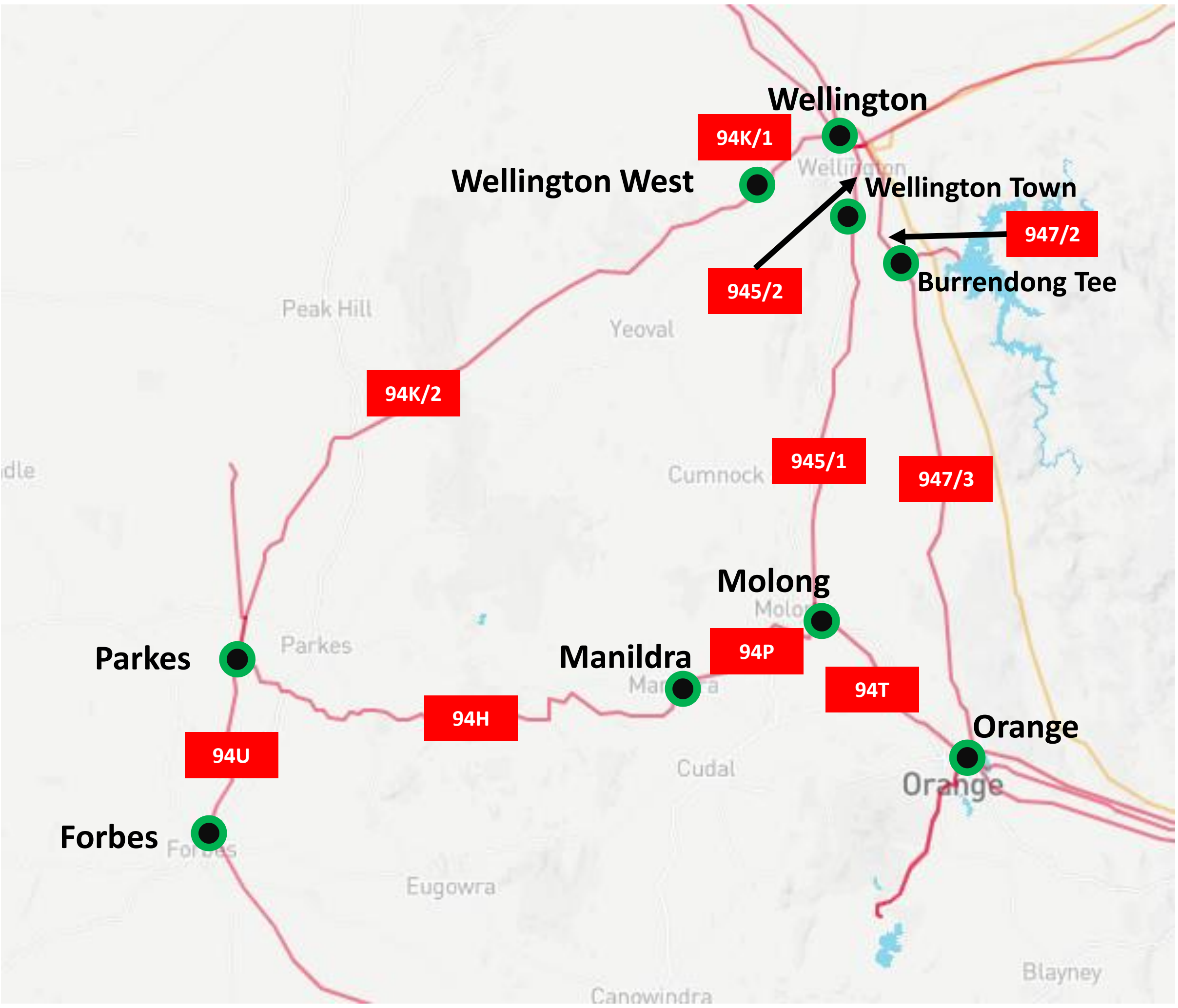
3. Specific Line 94T network assumptions

This section provides the key Line 94T specific assumptions which are considered in order to more accurately capture the benefits of the proposed options.

3.1 Network modelling assumptions

In order to increase the network resolution in the Central West NSW area for the purpose of modelling the proposed options for Line 94T, multiple thermal constraint equations are considered. These represent network limitations of the area. Figure 2 shows transmission lines in the area which are selected by Transgrid and considered by EY to create N-0 and N-1 thermal constraint equations. Note that Appendix D presents details of modelling assumptions for the transmission networks in the NEM, including the breakdown of regions, network modelling and cut-sets definition and limits. Note that all the relevant run-back and protection schemes for the generators in the area are modelled, as advised (and provided) by Transgrid.

Figure 2: Central West NSW network considered for thermal constraints in the model[15]



[15] AEMO map overlayed with an indicative visualisation of Transgrid's assumed transmission lines for additional network resolution in the area for this modelling, https://www.aemo.com.au/aemo/apps/visualisations/map.html

The methodology employed by EY to create thermal transmission constraint equations is described in detail in Appendix C, and follows the method that AEMO employs for developing pre-contingent constraint equations.

The thermal constraint equations developed consider seasonal, time of day thermal ratings of the transmission lines sourced from AEMO transmission equipment rating documents[16].

Two constraint types are considered: N-1 and N-0. N-1 constraints avoid the overload of the monitored line due to the outage of a single credible contingency in power system component (predominantly transmission lines), as stipulated in the NEM market rules. On the other hand, N-0 constraints avoid overloading of a line while no contingency occurs. Network constraint equations are created for the current network and updated each time network upgrades are assumed in the future. Table 6 shows the list of N-0 and N-1 constraint equations considered in this modelling.

Table 6: List of thermal constraint equations considered in the model in the Base Case

Thermal constraint description
To avoid overload of Molong to Orange 132 kV line
To avoid overload of Molong to Orange on outage of Wellington to Burrendong Tee 132 kV line
To avoid overload of Manildra to Molong 132 kV line (both directions)
To avoid overload of Parkes to Manildra 132 kV line (both directions)
To avoid overload of Forbes to Parkes 132 kV line (both directions)
To avoid overload of Parkes to Wellington West 132 kV line (both directions)
To avoid overload of Wellington West to Wellington 132 kV line (both directions)
To avoid overload of Wellington to Wellington Town 132 kV line (both directions)
To avoid overload of Wellington Town to Molong 132 kV line (both directions)
To avoid overload of Wellington to Burrendong Tee 132 kV line (both directions)
To avoid overload of Burrendong Tee to Orange 132 kV line (both directions)

The listed thermal constraint equations were created for the network as of today and for future network states considering the network augmentation assumptions in the model. After each set of future network augmentations, thermal constraint equations are re-created to reflect the future of the network. In addition, for all options and sensitivities with different network topology or transmission line parameters, thermal constraint equations are re-created and updated accordingly, and also additional thermal constraints are created as required. Specifically for Option 3, N-0 and N-1 constraint equations for Line 94T double circuits are created and for the BOP Stage 2 sensitivity, N-0 and N-1 constraint equations for double circuit Parkes to Wellington lines are created in addition to other updated constraint equations.

3.2 Central West Orana REZ transmission and constraints

AEMO 2022 ISP models multiple REZs in the NEM. One of the key assumptions used for each REZ is the existing transmission capacity and, for the REZs that are forecast to have network upgrades, future transmission limits. This is defined in the ISP methodology[12] as the amount of power that can be transferred from the REZ through the shared transmission network. REZ transmission limits can be increased by augmenting the shared transmission network (modelled as a network expansion

[16] AEMO, Transmission Equipment Ratings: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/data-nem/network-data/transmission-equipment-ratings. Accessed on 26 May 2023

cost, also assumed by AEMO). For the Central West Orana REZ, for example, the transmission build limit is 3,900 MW based on AEMO 2022 ISP inputs and assumptions[4].

As discussed in the previous section, network constraint equations are created for the current network and updated each time a network upgrades are assumed in the future. Specifically for the network configuration in the Central West Orana, we have updated the constraint equations once the Central West Orana REZ transmission upgrade is assumed, using details of the Central West Orana REZ network provided by Transgrid.

However, as advised by Transgrid, the Line 94T modelling does not allow further transmission upgrades in the Central West Orana REZ, which could otherwise be built linearly based on the 2022 ISP REZ transmission expansion cost in the least cost optimisation modelling. The reason is that the constraint equations need to be reformulated with any network changes, and since the REZ transmission expansion is built linearly in the model, it is impractical to recreate the constraint equations for each MW linear transmission expansion in this REZ. In addition, without knowing the exact configuration of the network upgrades, it is impossible to update constraint formulations. Multiple simulations were conducted, and it was concluded by Transgrid that if transmission in this REZ was allowed to be expanded based on the least cost solution, the gross market benefits of the modelled options would unrealistically increase if constraint equations are not adjusted.

4. Forecast market modelling outcomes

The following sections discuss the forecast market modelling results for the Base Case and modelled options.

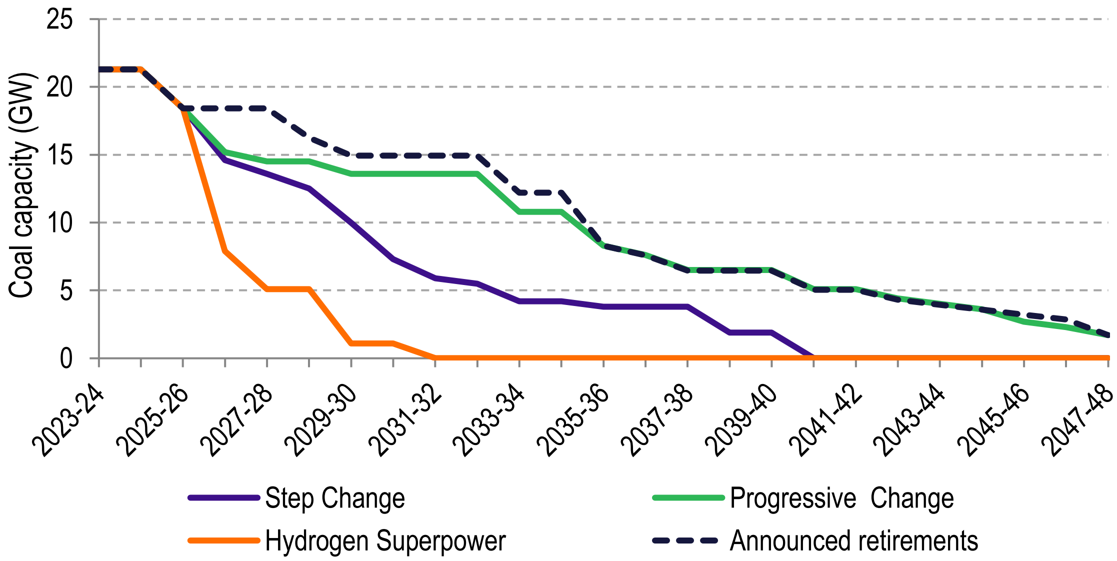
4.1 NEM outlook in the Base Case without Line94T Options

Before presenting the forecast benefits of the options, it is useful to understand the expected capacity and generation outlooks in the modelled scenarios, and the underlying input assumptions driving those outlooks in the Base Case. This gives a sense of the range of possible futures captured in the three scenarios modelled.

4.1.1 Coal power plants withdrawal

Coal power plants withdrawal is determined on a least-cost basis in the market modelling for different scenarios. Coal withdrawal dates are at or earlier than their end-of-technical-life or announced withdrawal year. The announced retirement schedules for coal units are based on the January 2023 Generating unit expected closure[9]. Forecast coal capacity in the Base Case across all scenarios as an output of the modelling is illustrated in Figure 3. Note that the modelling forecasts a similar coal retirement trend for the options modelled as indicated in the figure.

Figure 3: Forecast coal capacity in the NEM by year across all scenarios in the Base Case[17]



The forecast pace of the transition away from coal is determined by a combination of assumed carbon budgets, legislated renewable energy targets (NSW Electricity Infrastructure Roadmap, VRET, VRET2, QRET and TRET), demand outlook and end-of-life for existing assets in a system developed and dispatched at least cost. The model forecasts the entire coal capacity withdraws by the early 2030s in the Hydrogen Superpower scenario, while this is around 2040 for the Step Change scenario. In the Progressive Change scenario, coal-fired generation is forecast to remain until the end of the modelling period, although earlier withdrawal than AEMO's announced withdrawal is expected until around the mid-2030s.

4.1.2 NEM capacity and generation outlook

The NEM-wide capacity mix forecast in the Base Case for the Step Change scenario is shown in Figure 4 and the corresponding generation mix in Figure 5. In the Base Case, the forecast

[17] In the model 2,880 MW from the four units of Eraring retires in August 2025 based on the AEMO January 2023 generation

generation capacity of the NEM shifts towards increasing capacity of wind and solar, complemented by large-scale battery, PHES, and gas.

Figure 4: NEM capacity mix forecast for the Step Change scenario in the Base Case

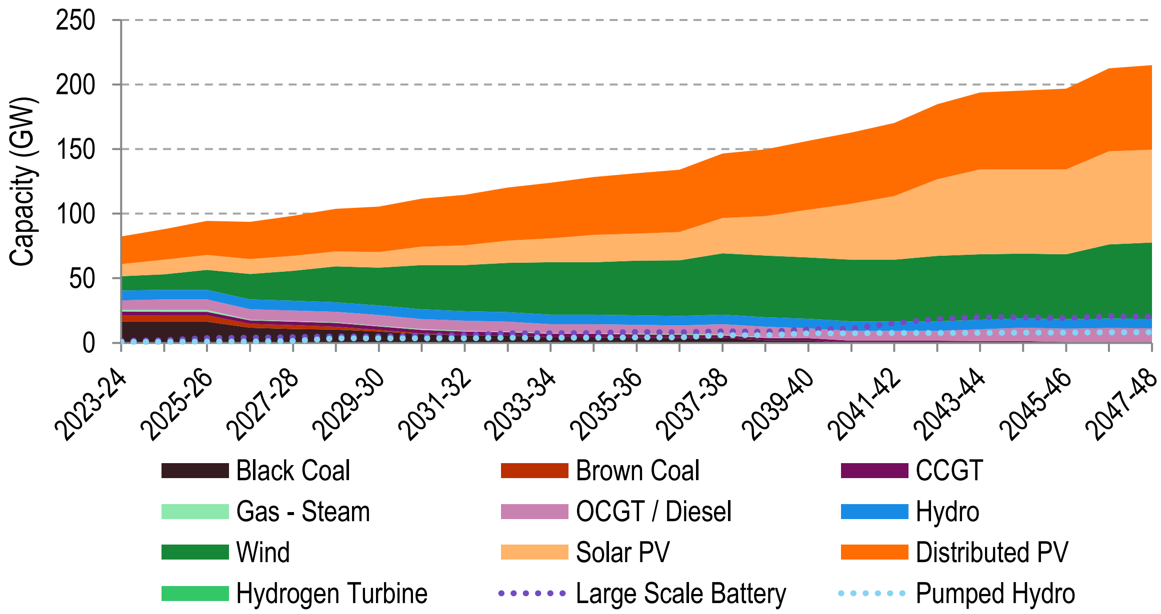
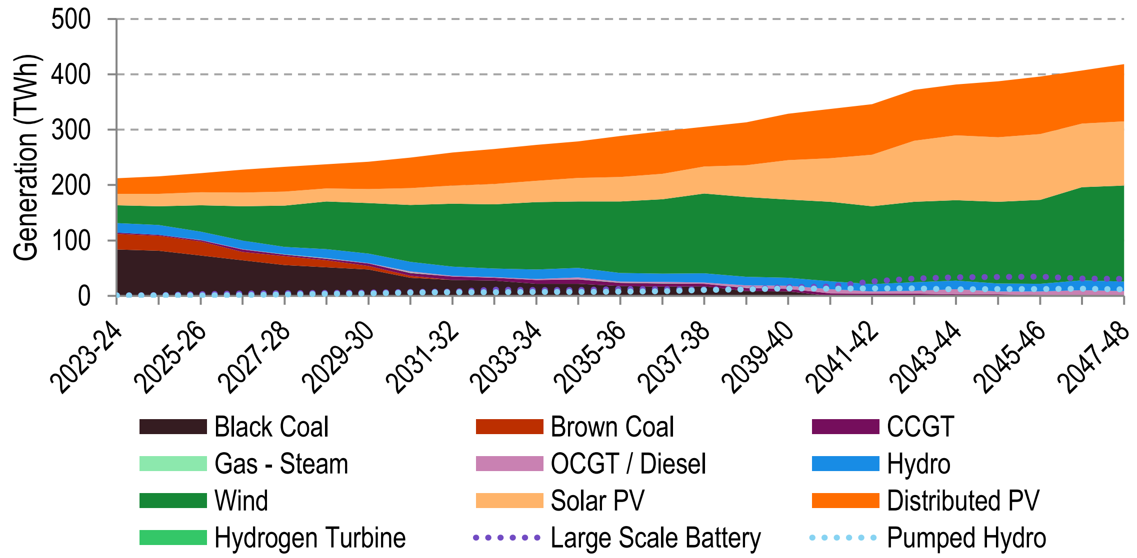


Figure 5: NEM generation mix forecast for the Step Change scenario in the Base Case



The new wind and solar build up to 2030 is largely driven by the assumed state-based renewable energy targets as well as carbon budget constraint implemented in this decade. The forecast increase in renewable capacity together with the carbon budget constraints, leads to some earlier-than-announced coal capacity withdrawals[18] in NSW, Victoria, and Queensland. To replace the retiring capacity, large-scale battery capacity is forecast to be built starting in the late 2020s, then PHES and wind capacity increases from the mid-2030s. Solar PV and OCGT capacity is also forecast to further increase from the late 2030s complementing other technologies. The forecast gas-fired capacity also supports reserve requirements during peak demand. Overall, the NEM is forecast to have around 243 GW total capacity by 2047-48 (note that this total capacity includes PHES and

[18] Note that the earlier coal withdrawal in TSIRP is based on the least cost optimisation, rather than revenue assessment.

large-scale battery capacities, which are not stacked in Figure 4). The forecast timing of entry of the majority of new installed capacity coincides with coal-fired generation withdrawal.

The other selected scenarios vary in the pace of the energy transition from the Step Change scenario. Figure 6 and Figure 8 show the differences in the NEM capacity development of other two scenarios relative to the Step Change scenario, while Figure 7and Figure 9 show generation differences. The differences are presented as alternative scenario minus the Step Change scenario, and both capacity and generation differences for each scenario show similar trends. As the figures show, the Progressive Change scenario is forecast to retain coal generation and install less wind and solar generation compared to the Step Change scenario due to different assumptions such as the less restrictive carbon budget, lower demand forecast and other underlying input data.

Figure 6: Difference in NEM capacity forecast between the Progressive Change and Step Change scenarios in the Base case

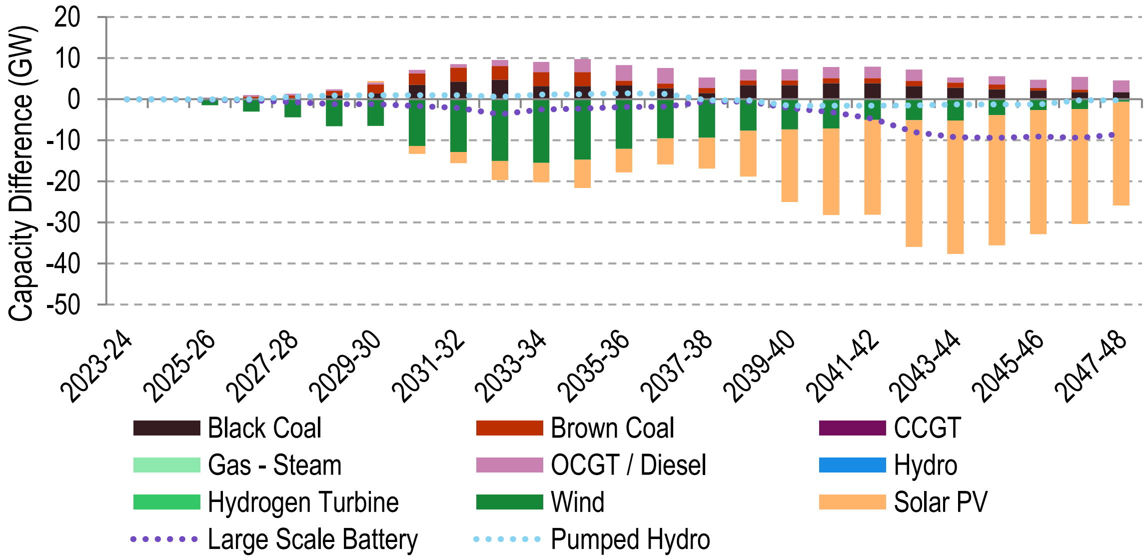
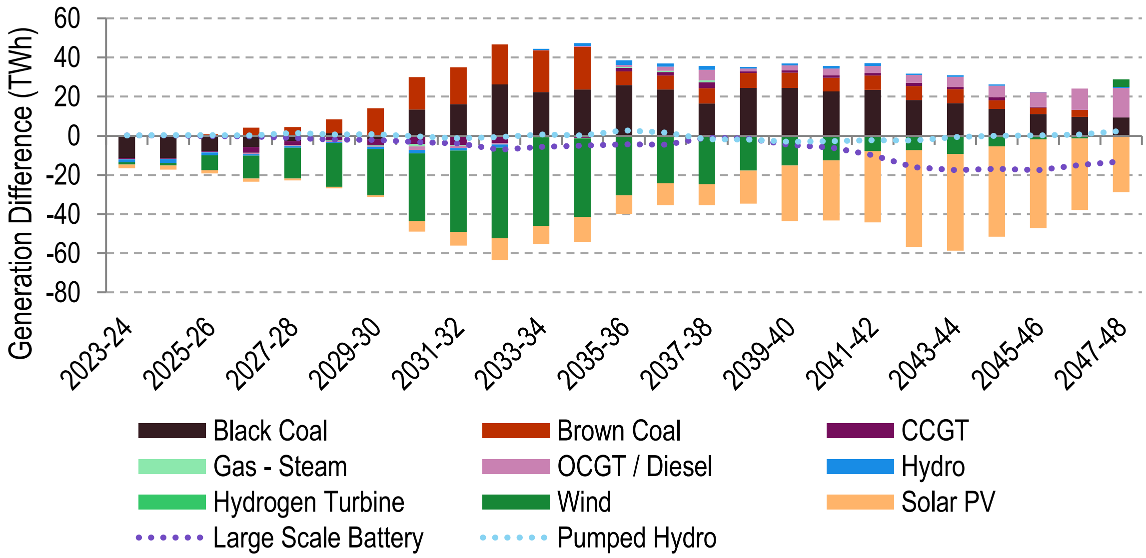


Figure 7: Difference in NEM generation forecast between the Progressive Change and Step Changes scenarios in the Base case



The Hydrogen Superpower scenario is forecast to have higher wind, solar and large-scale battery installed and less coal and OCGT capacity and generation compared to the Step Change scenario, mainly due to the significant hydrogen demand uptake in this scenario, along with a more restrictive carbon budget.

Figure 8: Difference in NEM capacity forecast between the Hydrogen Superpower and Step Change scenarios in the Base case

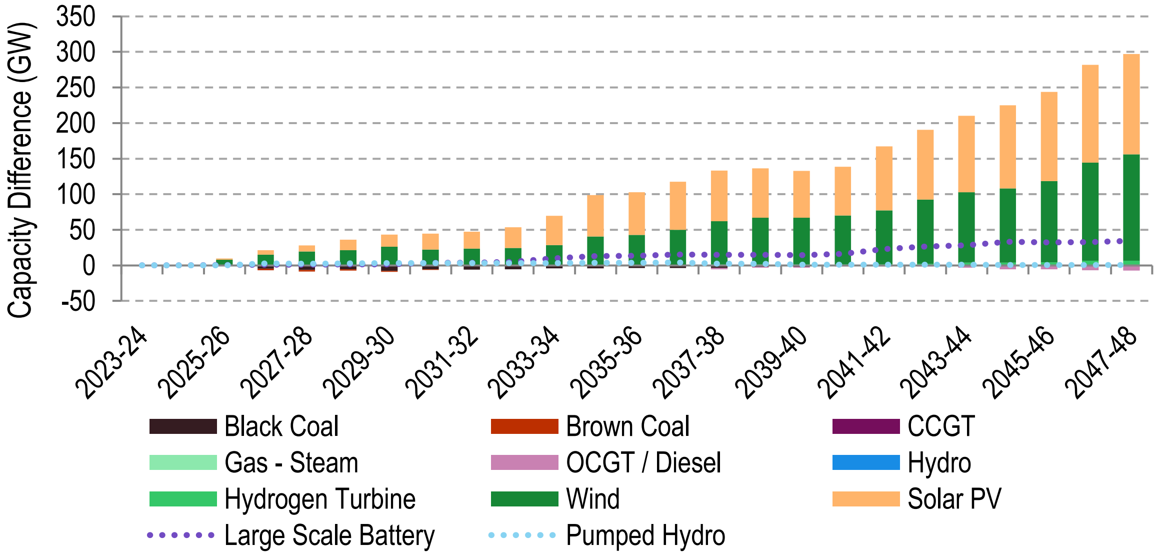
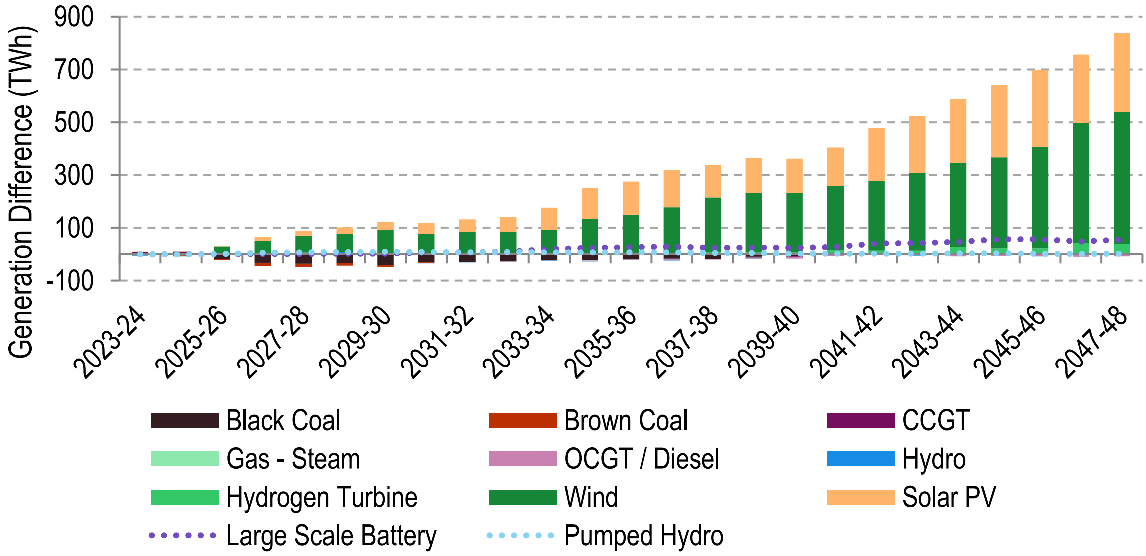


Figure 9: Difference in NEM generation forecast between the Hydrogen Superpower and Step Change scenarios in the Base case



4.2 Summary of forecast gross market benefits

Table 7 summarises the forecast gross market benefits over the modelled horizon (2023-24 to 2047-48) for all options across all scenarios.

Table 7: Summary of forecast gross market benefits of all Line 94T options relative to each scenario's Core Base Case, millions real June 2021 dollars discounted to June 2021 dollars

Option	Description	Timing	Forecast gross market benefits ($m)		
			Step Change	Progressive Change	Hydrogen Superpower
Option 1	Increase transmission line design temperature	1/04/2025	15.8	12.3	33.6
Option 2	Restring Line 94T with a higher rated conductor on existing structure (Flicker/ACSS)	1/11/2025	21.5	18.1	50.6
Option 2A	Restring Line 94T with a higher rated low sag conductor on existing structure (Partridge/ACSS/HS285)	1/11/2025	21.4	18.2	50.6
Option 2B	Option 2 with power flow controllers	1/11/2025	19.6	17.2	52.6
Option 3	Replacing Line 94T with double circuit transmission lines	1/11/2026	18.7	14.3	14.5
Option 4	Non-network option (BESS)	1/07/2025	91.2	96.7	106.9

All options, except Option 3, are expected to achieve relatively higher forecast gross market benefits in the Hydrogen Superpower scenario, while their forecast benefits in other scenarios are relatively similar. This is mainly due to the significantly higher demand forecast in Hydrogen Superpower scenario which increases network congestion and benefits of the options. Option 2, Option 2A, and option 2B (Option 2 variants) are forecast to have similar gross market benefits due to the same impact on the constraint bindings. It is worth mentioning that modelling online ratings for Option 2 variants forecasts that gross market benefits increase by increasing thermal line ratings to a certain level and any additional thermal line rating more than that is forecast to not been utilised.

Option 1 is forecast to have a relatively lower benefit compared to Option 2 variants due to the lower line thermal rating for this option and more constraint binding compared to Option 2 variants.

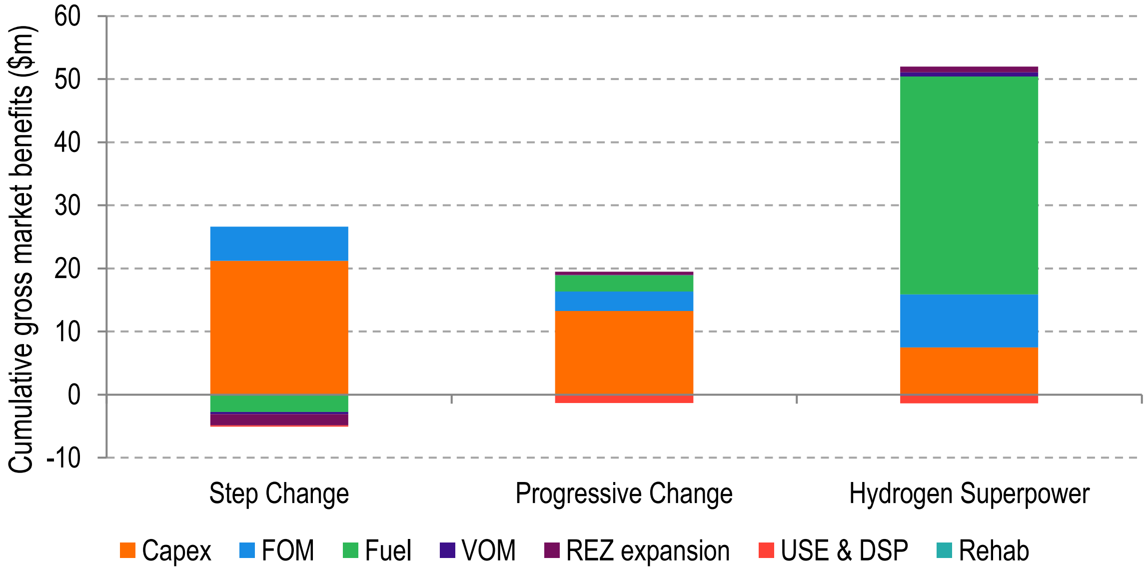
Option 3 is forecast to have the lowest market benefits in the Hydrogen Superpower scenario, mainly due to the limitation that this option is forecast to introduce in other parts of the network. In particular, since this option is forecast to reduce the impedance on the flow paths towards Orange, it is forecast that N-0 constrains on Wellington to Molong lines bind more frequently, limiting generation, particularly wind generation, in the Central West Orana, which is forecast to result in lower benefits for this option.

Option 4 has the highest forecast gross market benefits among all the options, mainly as it is allowed to be dispatched in the market modelling than be reserved for network support. The battery is assumed committed in the model which is forecast to result in avoided capacity build and consequently capex cost saving in this option.

The forecast gross market benefits for Option 2 and Option 2A, as the preferred options determined by Transgrid, range between just over $18m in the Progressive Change scenario, $21m in the Step Change scenario and around $50m in the Hydrogen Superpower scenario.

Figure 10 shows the breakdown of gross market benefits by category for the preferred Option (Option 2) for the three scenarios. Option 2 has the highest expected net market benefits as calculated by Transgrid in the PADR [2]. The numbers in the chart represent the net present value of gross market benefits for each option relative to the scenario-specific Base Case. The forecast gross market benefits of each option in each scenario need to be compared to the relevant option cost to determine the forecast net economic benefit for that option. The cost assessment, calculation of net economic benefits (gross market benefits minus option costs) and determination of the preferred option were conducted outside of this Report by Transgrid.

Figure 10: Composition of forecast gross market benefits for the preferred Option 2, millions real June 2021 dollars discounted to June 2021 dollars



Capex and FOM cost savings are forecast to make up the largest proportion of benefits across Step Change and Progressive Change scenarios for Line 94T options, while it is forecast that fuel and FOM cost savings make up the largest proportion of the benefits in the Hydrogen Superpower scenario. The primary drivers of the forecast cost savings due to Line 94T options, particularly Option 2 and Option 2A as preferred options, are:

- Line 94T options forecast to reduce curtailment of renewable generation in the Central West NSW area, particularly solar generation in the Wellington, Parkes and Orange areas. In turn, this is forecast to avoid mostly solar capacity, being mainly in the Central West Orana REZ. With each of the options implemented in isolation and considering the rest of the network functioning under current constraints, while Line 94T constraint is relieved to a great degree, other constraints in the vicinity are forecast to bind more frequently which may limit further benefits.

- Fuel cost savings in the Step Change and Progressive Change scenarios are mainly due to reduced coal generation with the augmentation, while relatively higher fuel cost savings forecast in the Hydrogen Superpower scenarios are mostly as a result of avoided hydrogen turbine generation with Line 94T options in place.

Table 8 summarises the forecast gross market benefits for all options for the three sensitivities to the Step Change scenario, i.e., three additional generator sensitivity, high load in Orange area sensitivity and BOP RIT-T Stage 2 (double circuit 132 kV line from Wellington to Parkes).

Table 8: Summary of forecast gross market benefits for the three sensitivities of all Line 94T options relative to sensitivity Base Case, millions real June 2021 dollars discounted to June 2021 dollars

Option	Timing	Forecast gross market benefits ($m) – Step Change Scenario			
		Core simulation	3 Generator Sensitivity	High load Sensitivity	BOP Stage 2 Sensitivity
Option 1	1/04/2025	15.8	23.1	25.2	13.34
Option 2	1/11/2025	21.5	37.7	38.5	16.67
Option 2A	1/11/2025	21.4	37.5	38.6	16.44
Option 2B	1/11/2025	19.6	35. 8	37.6	14.42
Option 3	1/11/2026	18.7	27.5	28.1	24.61
Option **4**	1/07/2025	91.2	101.1	96.2	88.31

The sensitivities that assume three additional generators in the area and high load growth in the Orange area are forecast to have generally higher benefits for all options. The higher expected benefits of these sensitivities are due an increasing network congestion in the area in the Base Case, where Line 94T options are forecast to be more beneficial in alleviating the congestion.

On the other hand, BOP Stage 2 sensitivity is forecast to reduce the gross market benefits for all options except Option 3. The reason for lower benefits of options in this sensitivity is that additional Wellington-Parkes transmission line in the Base Case reduces the network congestion in the area. Therefore, the options are forecast to be less beneficial as compared with core simulations. Higher forecast benefits of Option 3 in the BOP stage 2 sensitivity are mainly due to reduced impedance on the flow path of Wellington to Parkes reducing the need for the flow from Wellington to Wellington Town which is forecast to be a bottleneck in the core simulations for this option. As a result, Option 3 is expected to enable further generation in the area, resulting in higher benefits than what is forecast in the core simulations.

Table 9 shows the forecast gross market benefits for the sensitivity with BOP BESS exclusion in the model. The gross market benefits for this sensitivity are forecast to be higher for all options compared to the core simulations. This is mainly due to the increased network congestion forecast in the Base Case as a result of excluding Parkes BESS (being one of the BOP BESSs). This is forecast to provide more opportunity for the Line 94T options to reduce network congestion and renewable generation spill in the area, improving gross benefits.

Table 9: Summary of forecast gross market benefits for the BOP BESS exclusion sensitivity of all Line 94T options, millions real June 2021 dollars discounted to June 2021 dollars

Option	Description	Timing	Forecast gross market benefits ($m)		
			Step Change	Progressive Change	Hydrogen Superpower
Option 1	Increase transmission line design temperature	1/04/2025	16.5	12.8	35.9
Option 2	Restring Line 94T with a higher rated conductor on existing structure (Flicker/ACSS)	1/11/2025	23	19.2	54.8
Option 2A	Restring Line 94T with a higher rated low sag conductor on existing structure (Partridge/ACSS/HS285)	1/11/2025	22.9	19.3	54.5

Option	Description	Timing	Forecast gross market benefits ($m)		
			Step Change	Progressive Change	Hydrogen Superpower
Option 2B	Option 2 with power flow controllers	1/11/2025	21	18.4	57.2
Option 3	Replacing Line 94T with double circuit transmission lines	1/11/2026	19.9	15	16
Option 4	Non-network option (BESS)	1/07/2025	91.7	97	107.5

4.3 Market modelling outcomes for Option 2 and Option 2A

In this section, the modelling outcomes for Option 2 and Option 2A, as the Transgrid's highest ranked options, are presented in greater detail. Note that while the charts and majority of the discussion focuses on Option 2, Option 2A is also forecast to have similar outcomes.

4.3.1 Step Change scenario

The forecast cumulative gross market benefits for Option 2 in the Step Change scenario are shown in Figure 11 using an annualised presentation of capex and FOM benefits. Furthermore, the corresponding differences in the forecast capacity and generation outlooks across the NEM between Option 2 and the Base Case in the same scenario are presented in Figure 12 and Figure 13, respectively.

Figure 11: Forecast cumulative gross market benefit for Option 2 under the Step Change scenario, millions real June 2021 dollars discounted to June 2021 dollars

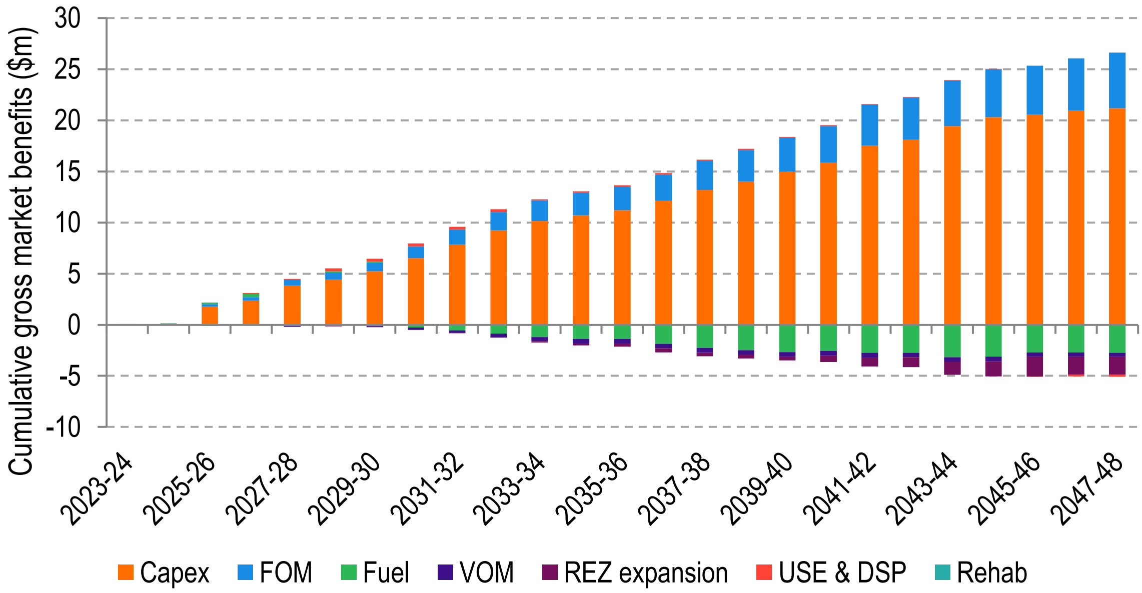


Figure 12: Difference in NEM capacity forecast between Option 2 and Base Case in the Step Change scenario

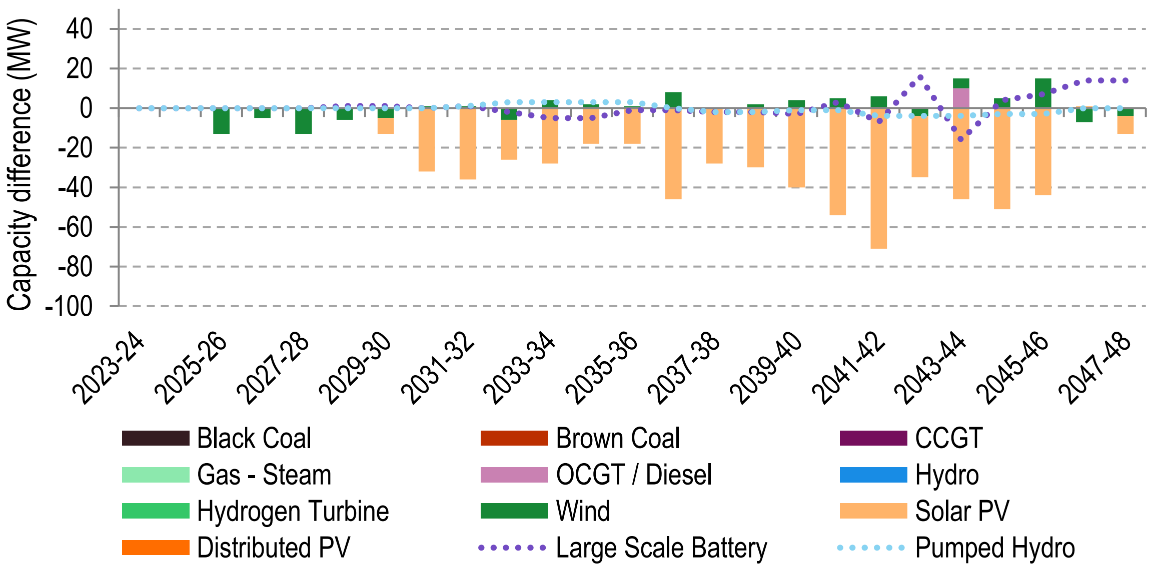
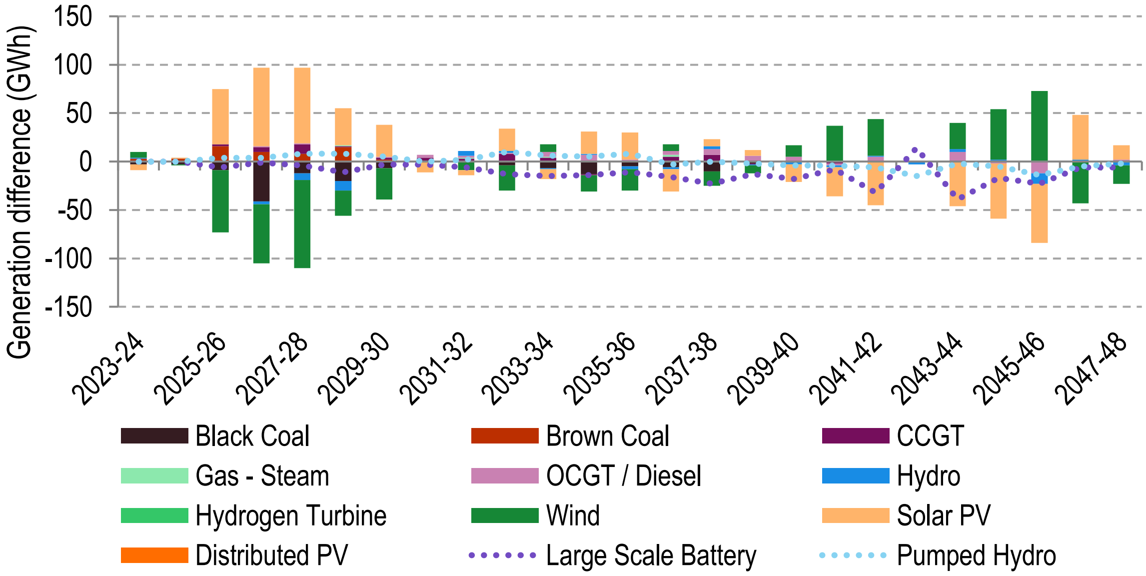


Figure 13: Difference in NEM generation forecast between Option 2 and Base Case in the Step Change scenario



The largest share of forecast gross market benefits in this scenario are from capex and FOM savings from deferred and avoided capacity build. At the same time there is an increase in fuel costs and REZ transmission expansion costs forecast with this option in place.

- Line 94T Option 2 is forecast to largely avoid solar capacity investment in the NEM which generates the majority of the capex and FOM cost savings.
    - Avoided solar capacity is expected primarily due to increased expected solar generation in the Parkes, Wellington and Molong area throughout the study period as a result of Option 2. A high share of avoided solar capacity forecast is in Central West Orana REZ, being the main REZ impacted by the congestion on Line 94T. Option 2 is forecast to allow more solar generation for less investment in new solar capacity by reducing solar spill.
- Line 94T Option 2 is forecast to incur some increased fuel costs, mainly due to increased generation of gas generation units.
- There is a small increase in forecast REZ transmission costs with Option 2 in place, as minor additional transmission expansion is forecast in some REZs in Victoria relative to the Base Case.

As shown in Figure 14 and Figure 15 the constraints in the area (mainly Molong to Orange constraints) are forecast to bind frequently in the Base Case, with the binding percentage reducing over the modelling horizon. The reason for reduction in expected frequency of binding is additional capacity built in the area and specifically in Central West Orana and NCEN which supplies demand using other transmission paths. Option 2 is forecast to alleviate these constraint bindings once commissioned.

Figure 14: Line 94T N-0 constraint binding percentage for Step Change

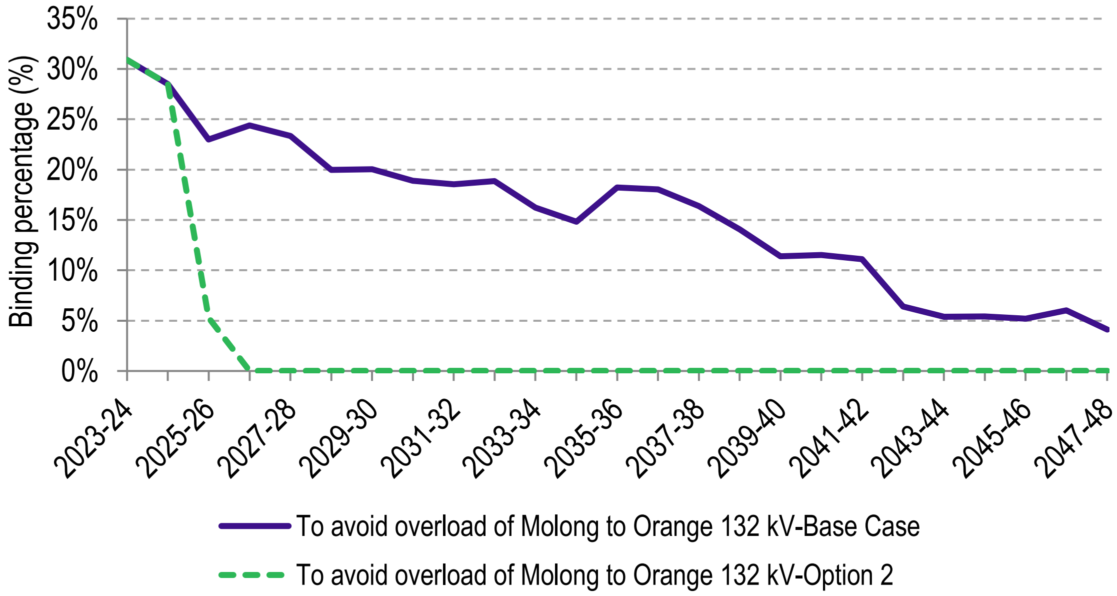
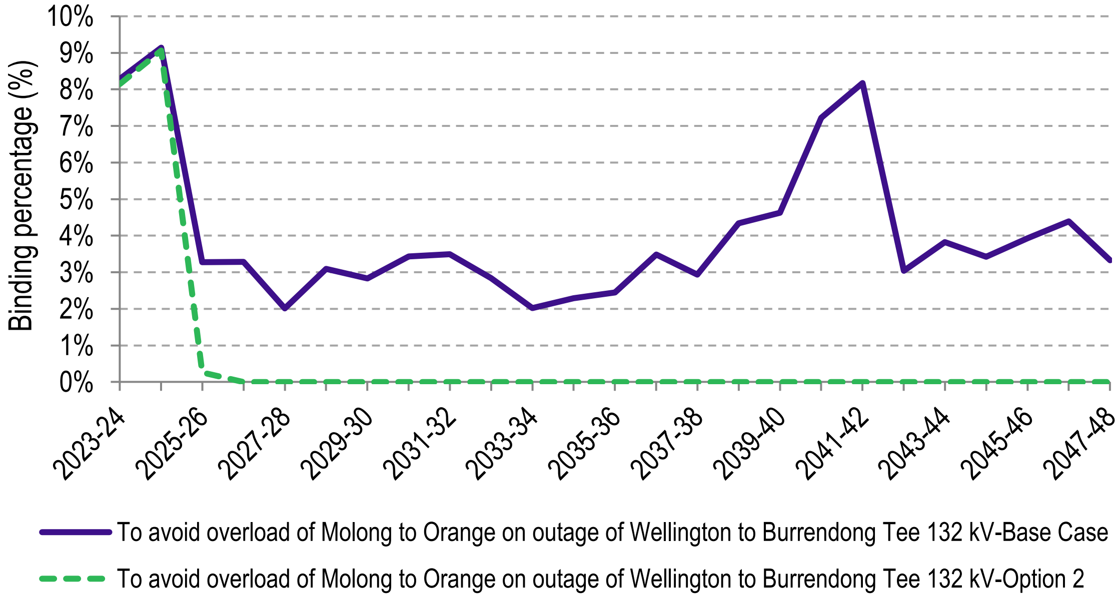
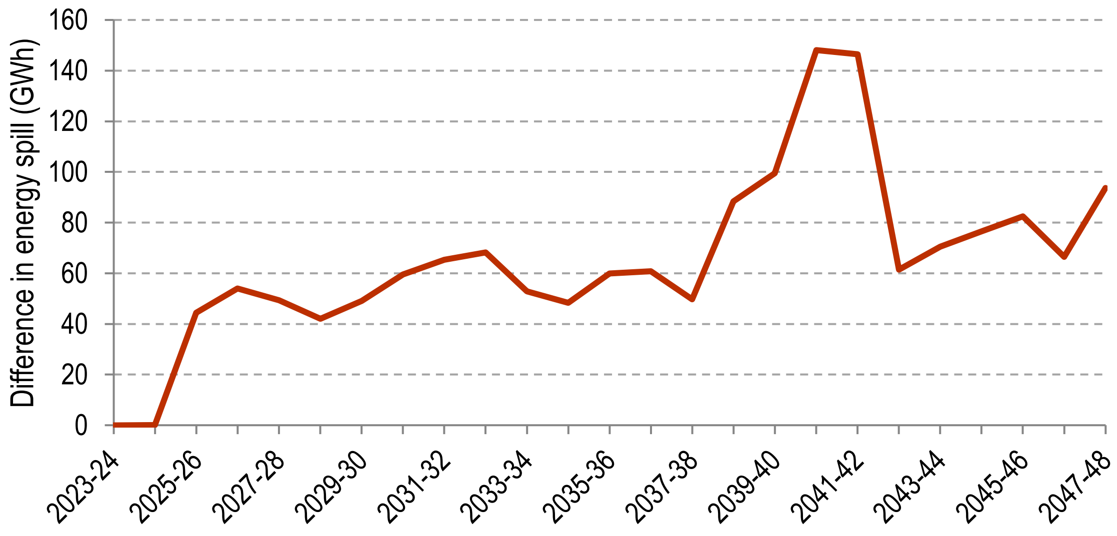


Figure 15: Line 94T N-1 constraint binding percentage for Step Change



Both Option 2 and Option 2A are forecast to reduce the renewable spill in the Central West NSW area, as shown for Option 2 in Figure 16. On average both options reduce the forecast renewable spill in the area by around 60 GWh, though this is considerably higher in the early 2040s. The forecast increase in renewable energy spill from the late 2030s is due to the extra capacity in the Central West Orana REZ expected as a result of demand growth and some retirements in NSW. The forecast spill reduces again as soon as Nyngan solar farm retires, as assumed in the 2022 ISP.

Figure 16: Central West NSW Wind and solar energy spill - Base Case minus Option 2 – Step Change



Although Option 2 is assumed to have higher line thermal ratings than Option 2A, both options have almost the same forecast gross market benefits. This is mainly due to the nearby network limitations which are forecast to cap the benefits that Line 94T upgrade could achieve beyond a certain point.

4.3.2 Progressive Change scenario

The forecast cumulative gross market benefits for Option 2 in the Progressive Change scenario are shown in Figure 17. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 2 and the Base Case are shown in Figure 18 and Figure 19.

Figure 17: Forecast cumulative gross market benefit for Option 2 under the Progressive Change scenario, millions real June 2021 dollars discounted to June 2021 dollars

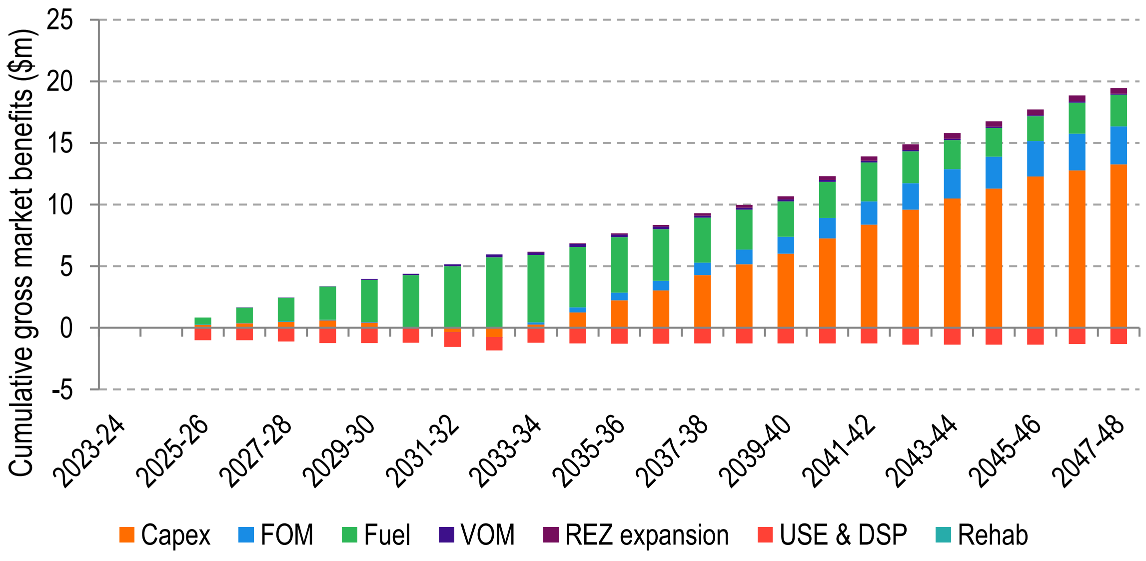


Figure 18: Difference in NEM capacity forecast between Option 2 and Base Case in the Progressive Change scenario

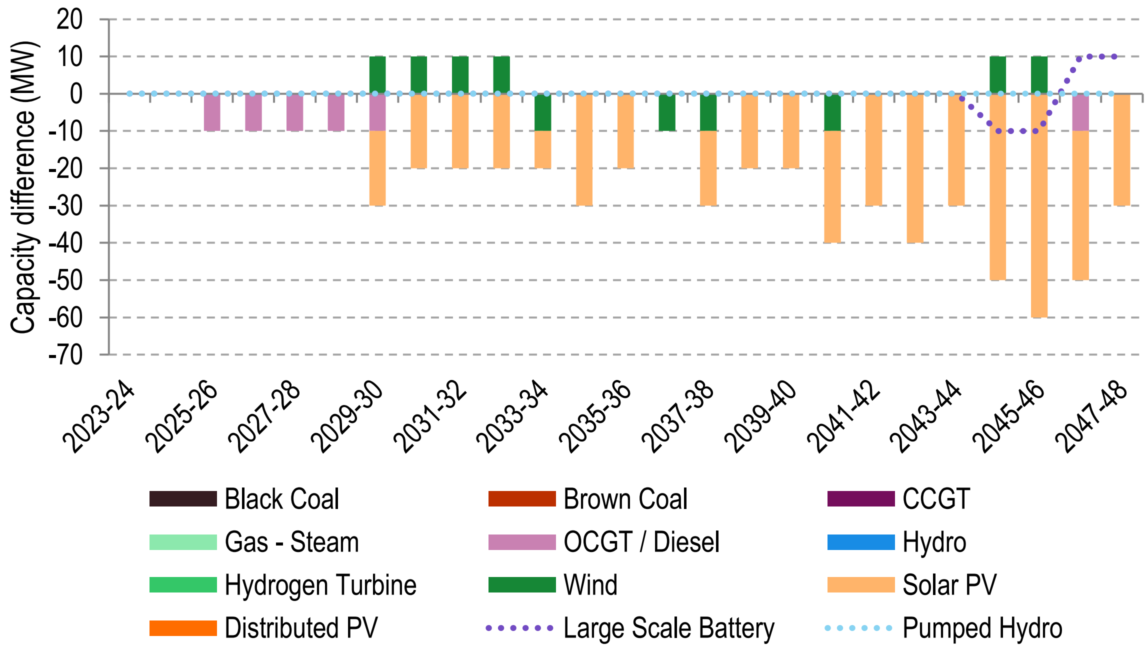
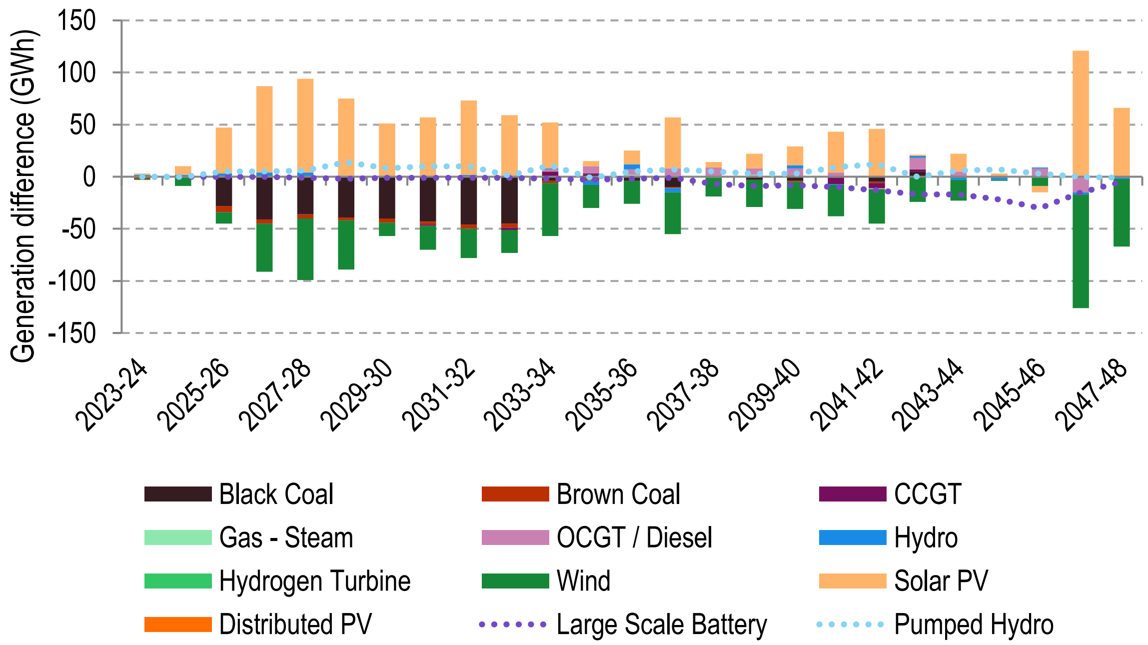


Figure 19: Difference in NEM generation forecast between Option 2 and Base Case in the Progressive Change scenario



The largest sources of forecast gross market benefits in this scenario are capex and FOM savings from deferred and avoided capacity build, followed by fuel costs savings though a small USE & DSP cost increase is forecast with this option in place. Option 2A is also forecast to have similar trends in gross market benefits.

- The Progressive Change scenario forecasts proportionately lower benefits than the Step Change scenario due to its underlying assumptions such as the assumed lower pace of demand growth and less restrictive carbon budget.
- Similar to the Step Change scenario, in the Progressive Change scenario Option 2 is forecast to result in avoiding mainly solar capacity build throughout the study period, being the major driver of the forecast capex and FOM cost savings.

- With Option 2 in place, fuel cost savings are forecast, being mainly due to avoided black coal generation since this option is forecast to reduce spill of solar generation in the Central West NSW area.
- With a less restrictive carbon budget in the Progressive Change scenario, the modelling forecasts more coal generation in the Base Case for this scenario than in the Step Change scenario. This provides greater opportunity for avoiding generation from this resource technology with Option 2 in place. Note that Option 2A is also forecast to result in similar level of reduced coal generation and as a result fuel cost savings.
- Both modelled N-0 and N-1 constraints for Molong to Orange are forecast to be alleviated with Option 2 in this scenario (see Figure 20 and Figure 21), similar to the Step Change scenario outcomes. As a result, this option is forecast to unlock some solar generation in the Wellington, Parkes and Molong area, resulting in mainly solar capacity avoided, mostly in the Central West Orana REZ.

Figure 20: Line 94T N-0 constraint binding percentage for Progressive Change

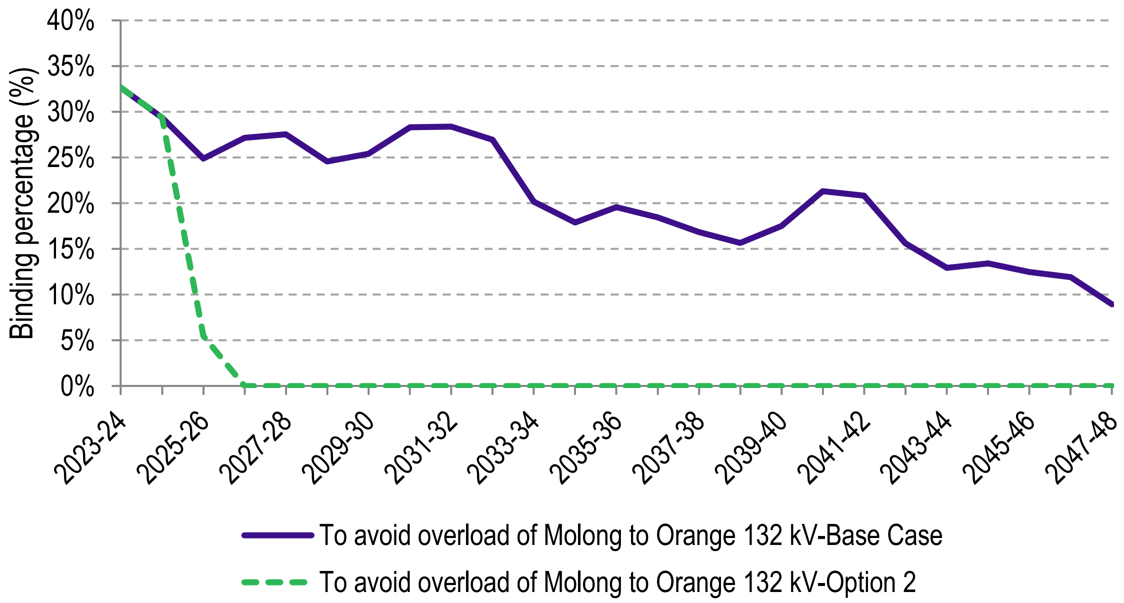
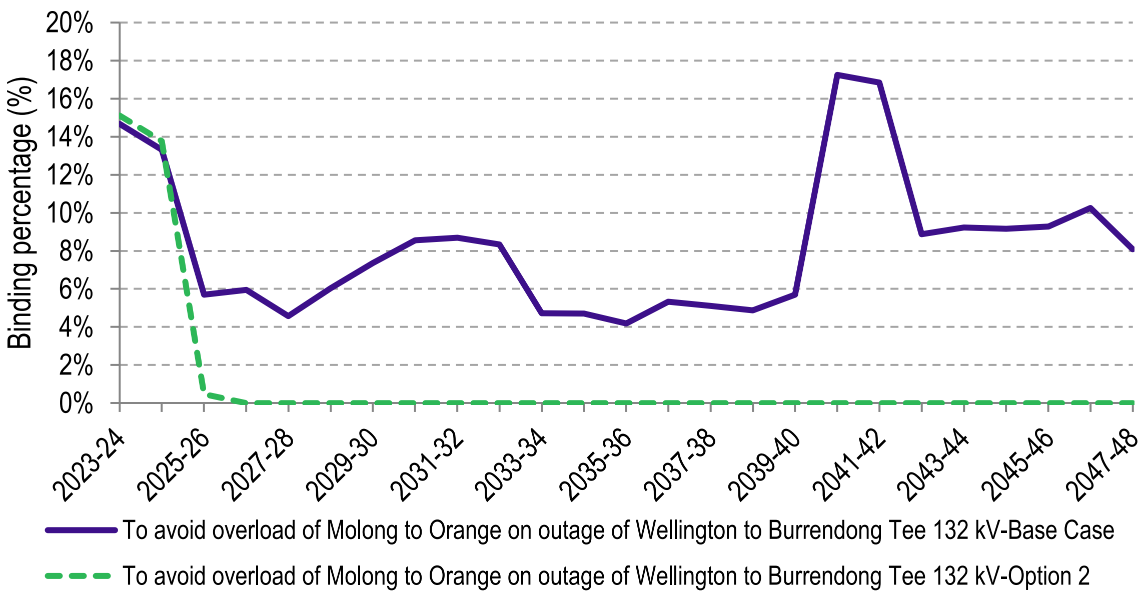
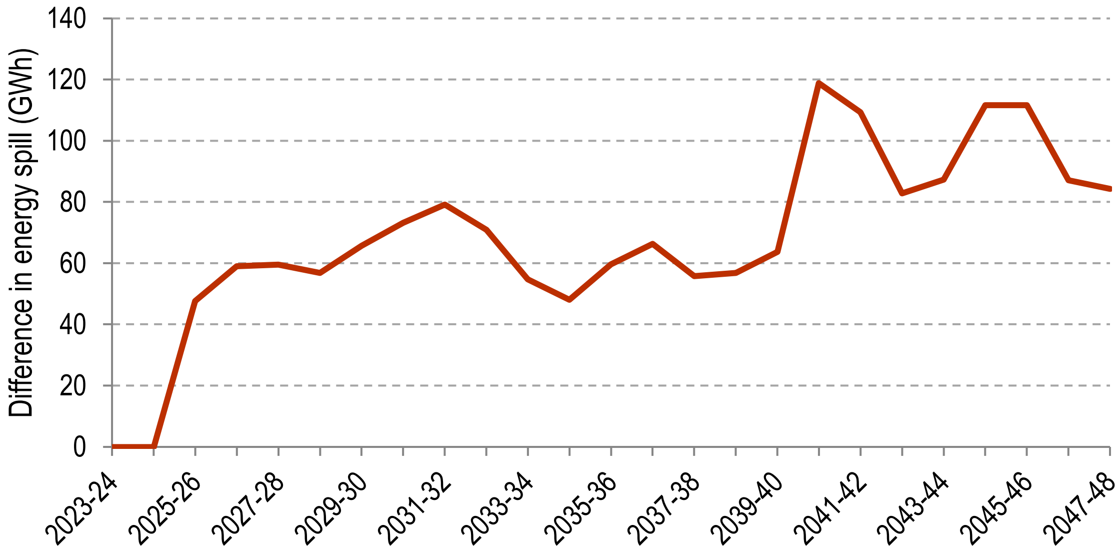


Figure 21: Line 94T N-1 constraint binding percentage for Progressive Change



Both Option 2 and Option 2A are forecast to reduce the renewable spill in the Central West NSW area, as shown for Option 2 in Figure 22. On average both options reduce forecast renewable spill within a range of 60 GWh to 80 GWh in 2020's and 2030's, then increasing in the 2040s.

Figure 22: Central West NSW area Wind and solar energy spill - Base Case minus options – Progressive Change



4.3.3 Hydrogen Superpower scenario

The forecast cumulative gross market benefits for Option 2 in the Hydrogen Superpower scenario are shown in Figure 23. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 3A and the Base Case in this scenario are shown in Figure 24 and Figure 25.

Figure 23: Forecast cumulative gross market benefit for Option 2 under the Hydrogen Superpower scenario, millions real June 2021 dollars discounted to June 2021 dollars

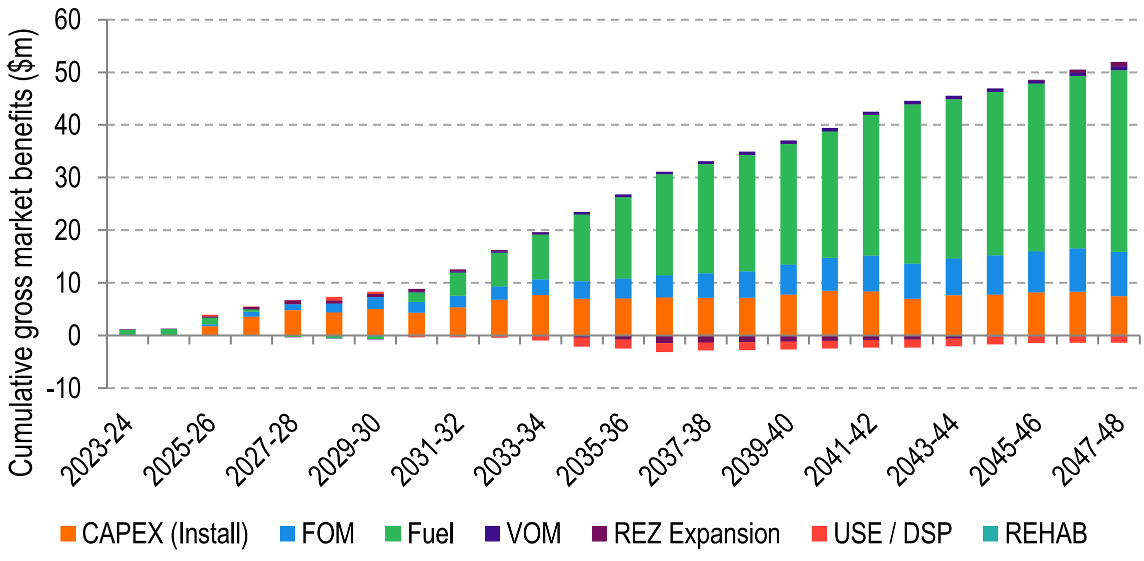


Figure 24: Difference in the NEM capacity forecast between Option 2 and Base Case in the Hydrogen Superpower scenario

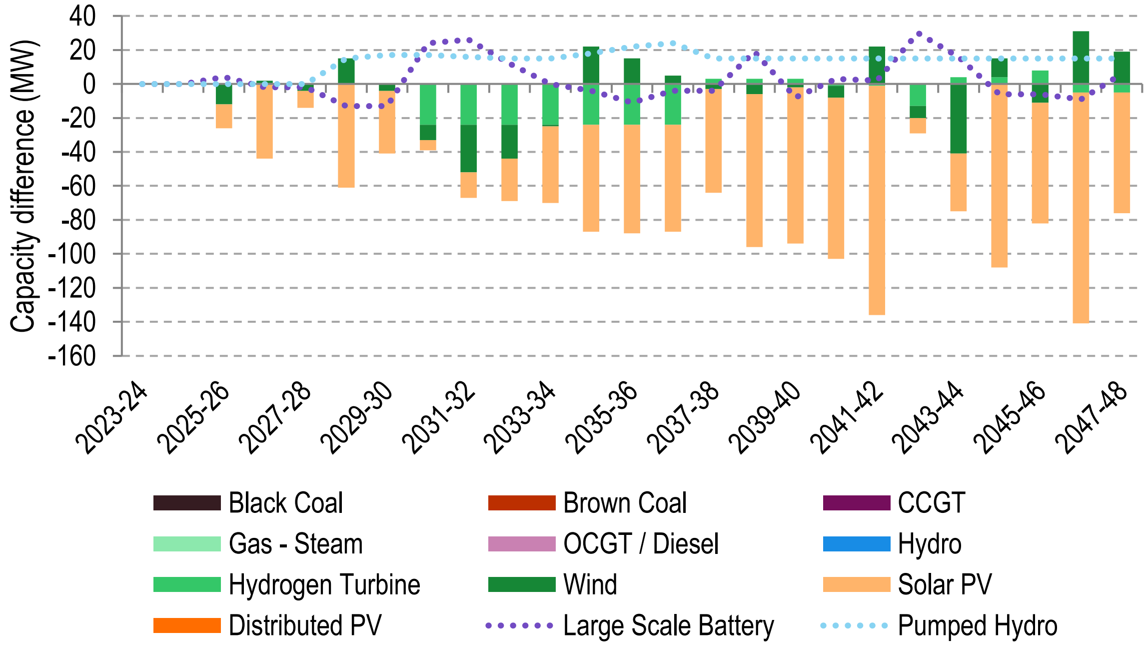
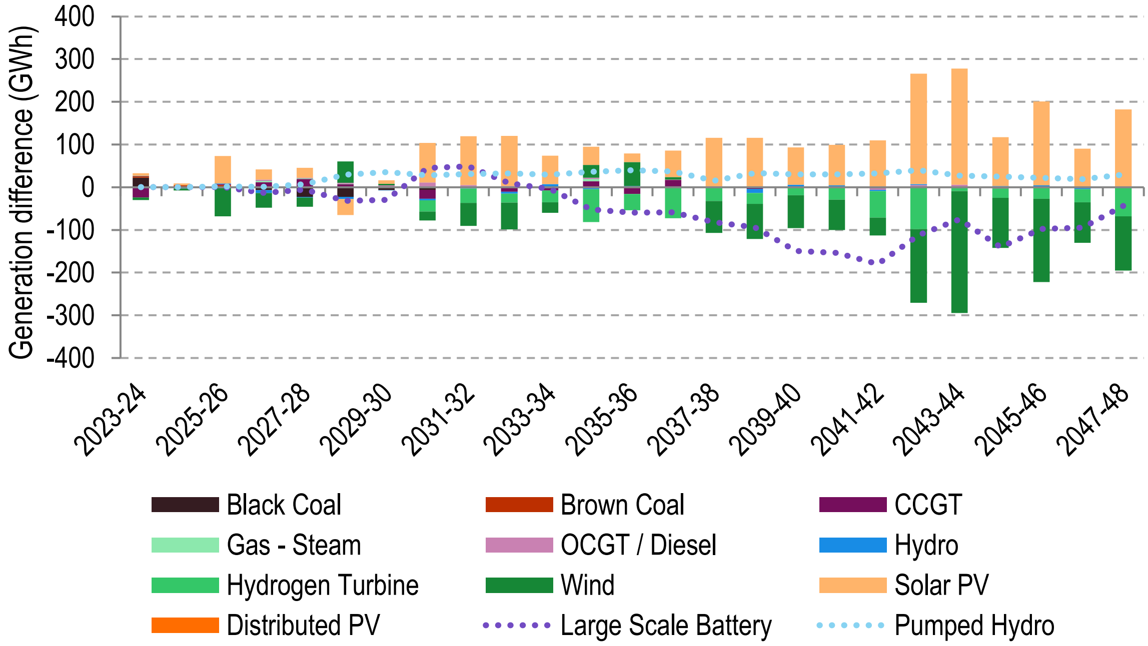


Figure 25: Difference in NEM generation forecast between Option 2 and Base Case in the Hydrogen Superpower scenario



The largest sources of forecast gross market benefits in this scenario are fuel cost savings due to avoided hydrogen turbine generation from 2030-31 followed by capex and FOM costs savings from early years.

- The Hydrogen Superpower scenario is forecast to have the highest benefits among all scenarios, due to the more aggressive assumptions, particularly demand growth, combined with a more restrictive carbon budget. This results in more renewable energy and hydrogen turbine capacity forecast to be built.
- Similar to other scenarios, solar capacity is forecast to be the main technology which is avoided with Option 2. However, in this scenario, this option is forecast to defer some

hydrogen turbine capacity, though generally more PHES is forecast. Overall, some capex cost savings are expected in this scenario.

- Similar to other scenarios, majority of the avoided solar capacity is forecast to be in the Central West Orana REZ.
- Both N-0 and N-1 constraints for Molong to Orange are forecast to be alleviated with Option 2 in place (see Figure 26 and Figure 27).
- Hydrogen turbines are forecast to become a major firming technology after the rapid coal retirement forecast in this scenario. As a result, with larger reductions in spill in the Central West NSW in the presence of Option 2 (see Figure 28), this option is forecast to reduce expected hydrogen turbine generation particularly in NSW. This derives high fuel cost savings relative to the other scenarios.

Figure 26: Line 94T N-0 constraint binding percentage for Hydrogen Superpower

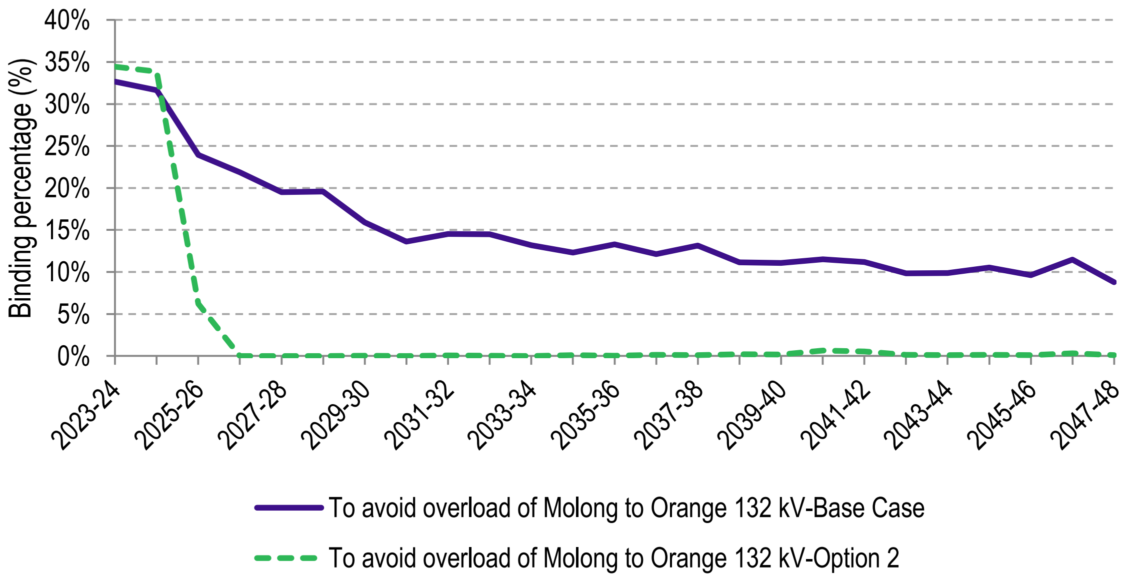
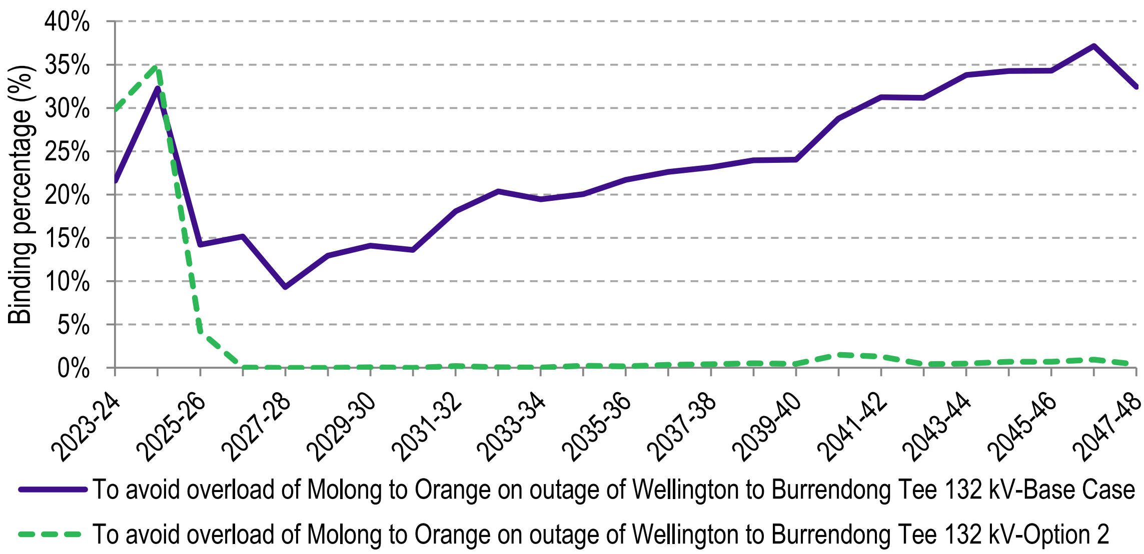
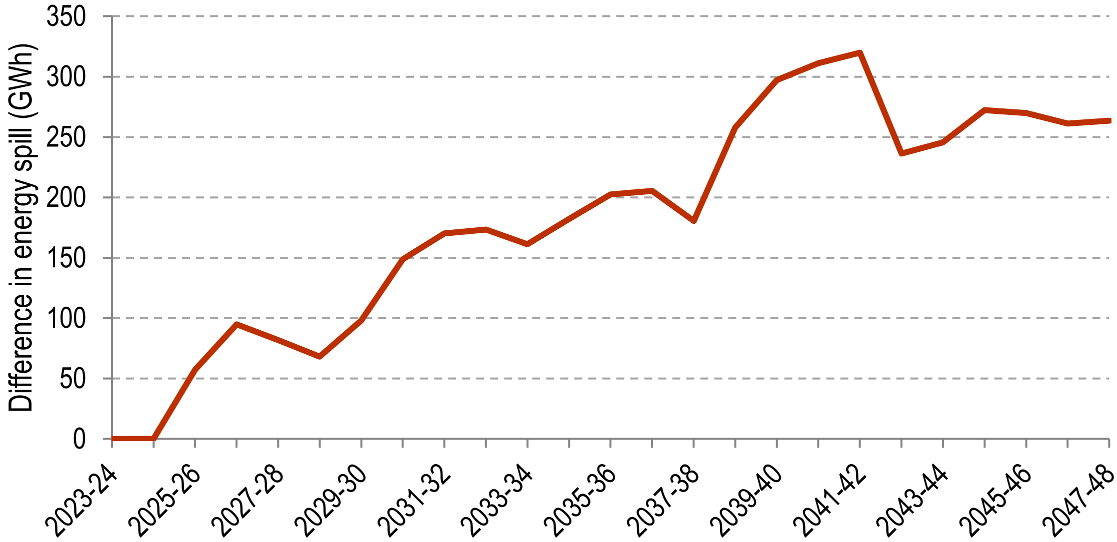


Figure 27: Line 94T N-1 constraint binding percentage for Hydrogen Superpower



With the assumptions in this scenario such as significant demand growth and a considerably more restrictive carbon budget, significant renewable capacity is forecast in both Base Case and Line 94T options including Option 2. As a result, with congestion on Line 94T expected to be alleviated in the presence of Option 2, significantly greater reductions in renewable spill are expected than in the other two scenarios.

Figure 28: Central West NSW Wind and solar energy spill - Base Case minus Option 2 – Hydrogen Superpower



4.4 Market modelling outcomes for other options

The proposed network and non-network options for alleviating Line 94T constraint bindings are forecast to have different impacts on the power flow and generation dispatch in the area. This section summarises market modelling outcomes for options other than the preferred option and outlines the key drivers of gross market benefits for each option.

Option 1 benefits and drivers

Option 1 is forecast to have the lowest gross market benefits in the Step Change and Progressive Change scenarios and the second lowest benefits in the Hydrogen Superpower scenario. This option is assumed to increase the Line 94T thermal rating by only 10% approximately, as compared to 65% increase in Option 2. With this assumption, this option is not expected to alleviate the constraint as much as Option 2, resulting in smaller forecast benefits.

Figure 29 and Figure 30 show forecast Line 94T constraint binding for the Base Case, Option 1, and Option 2 in the core Step Change scenario. Option 1 is forecast to alleviate the key N-1 constraint (To avoid overload of Molong to Orange on outage of Wellington to Burrendong Tee 132 kV line) significantly (Figure 30). However, the N-0 constraint (To avoid overload of Molong to Orange 132 kV line) is forecast to bind much more frequently with Option 1 than Option 2, though at a reduced frequency than the Base Case.

Figure 29: Line 94T N-0 constraint binding percentage for the Base Case, Option 1, and Option 2 - Step Change

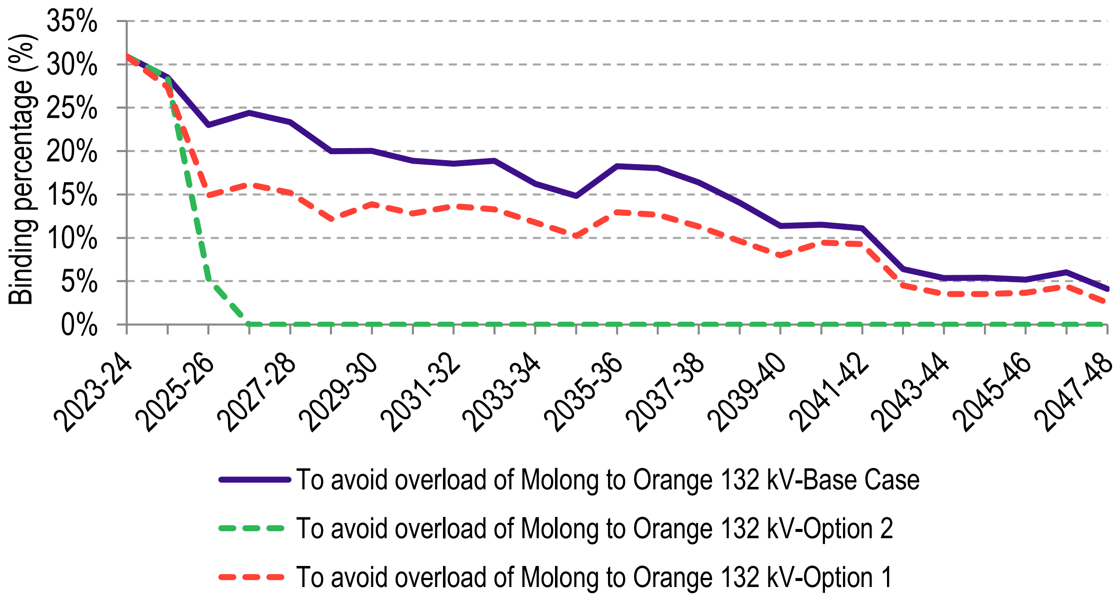


Figure 30: Line 94T N-1 constraint binding percentage for the Base Case, Option 1, and Option 2 - Step Change

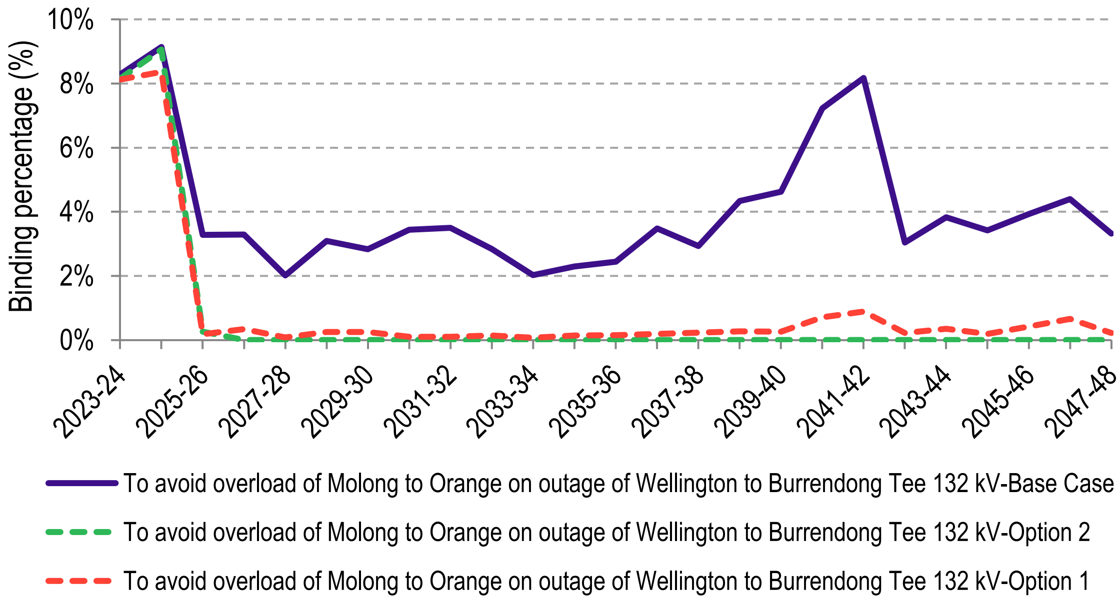
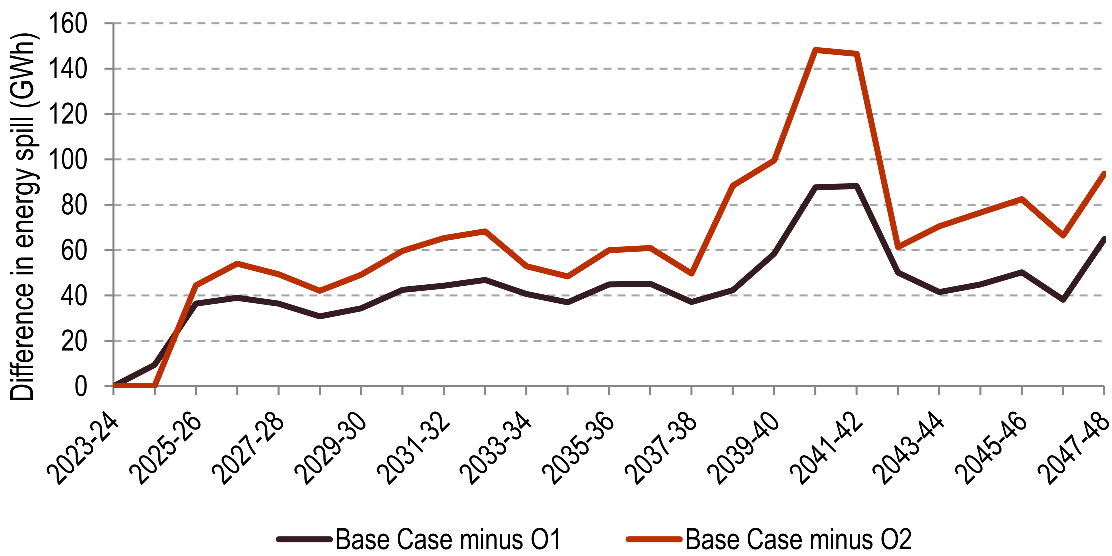


Figure 31 shows the wind and solar generation spill forecast in the Central West NSW area with Option 1 and Option 2 compared to the Base Case. Option 1 is forecast to result in a smaller decrease in spill compared to Option 2, further illustrating the reasons for the reduced forecast benefits of this option relative to Option 2.

Figure 31: Central West NSW Wind and solar energy spill - Base Case minus options – Step Change



Option 2B benefits and drivers

Option 2B is forecast to have similar gross market benefits to Option 2 and Option 2A. Option 2B is assumed to have a power flow controller in order to reduce the flow on Line 94T, and thus congestion on that line.

Figure 32 and Figure 33 show that the forecast N-0 and N-1 constraints for Line 94T are alleviated with any of Option 2 variants in place, which forecasts no advantage out of the power flow controller in Option 2B over Options 2 and 2A for reducing Line 94T congestion.

Figure 32: Line 94T N-0 constraint binding percentage for the Base Case and Option 2 variants – Step Change

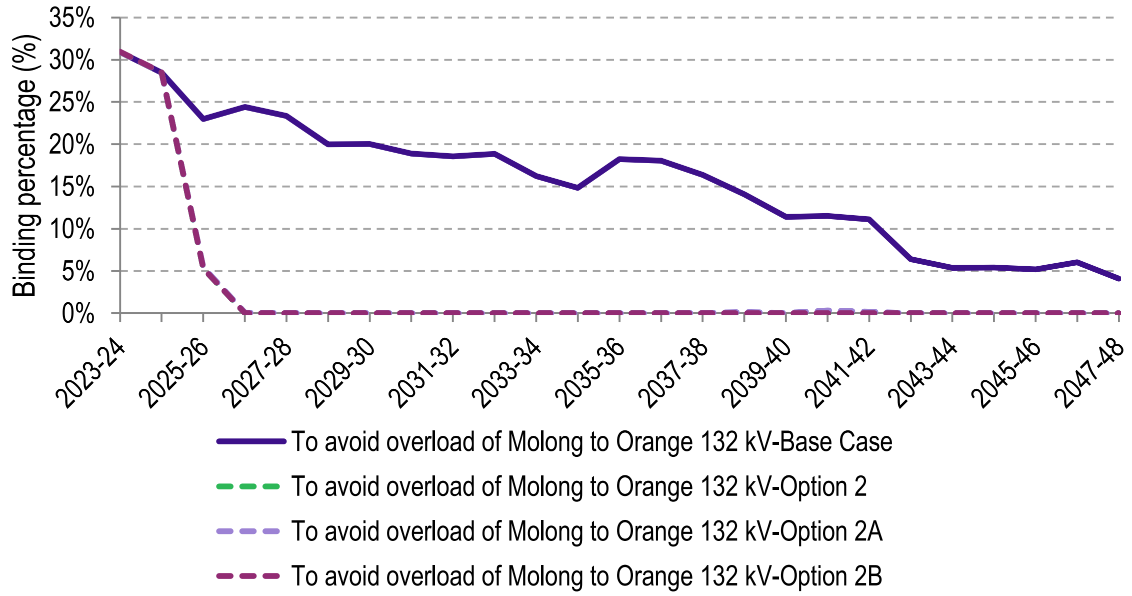
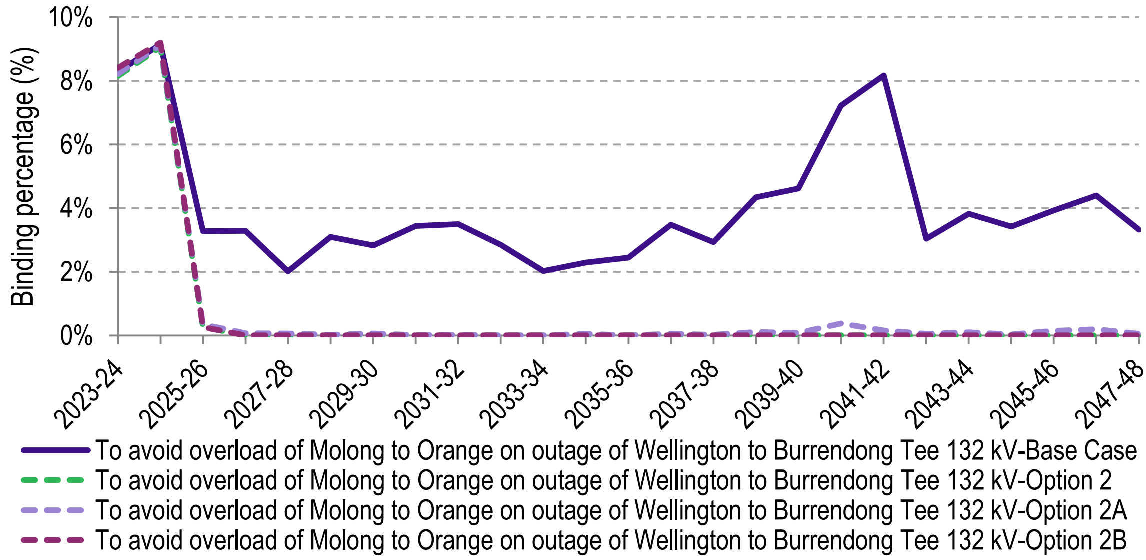


Figure 33: Line 94T N-1 constraint binding percentage for the Base Case and Option 2 variants – Step Change



For Option 2B, it is forecast that with the power flow controller in place, power flow in the direction towards Molong reduces and is diverted to other nearby lines causing congestion in other parts of the nearby network. This is forecast to result in a slightly more renewable spill in Option 2B than Option 2 in the Step Change and Progressive Change scenarios, resulting in lower forecast benefits in this option than Option 2. A different trend is forecast in the Hydrogen Superpower scenario, where Option 2B has marginally higher forecast benefits than Option 2. This is due to a lower level of congestion on the Wellington to Wellington Town expected with Option 2B in place. In the Hydrogen Superpower scenario, a large quantity of wind is forecast to be required, particularly in the Central West Orana REZ, to supply the peak load in NSW load centres. However, Wellington to Wellington Town transmission limits are forecast to be a limiting factor. Binding of constraints on this line peaks during the evening when wind generation is highest (see Figure 34). Since Option 2B is forecast to reduce the level of congestion in this line (see Figure 34 and Figure 35), it is forecast to result in slightly higher benefits.

Figure 34: Line 945/2 time of day average constraint binding percentage for the Base Case, Option 2 and Option 2B - Hydrogen Superpower scenario

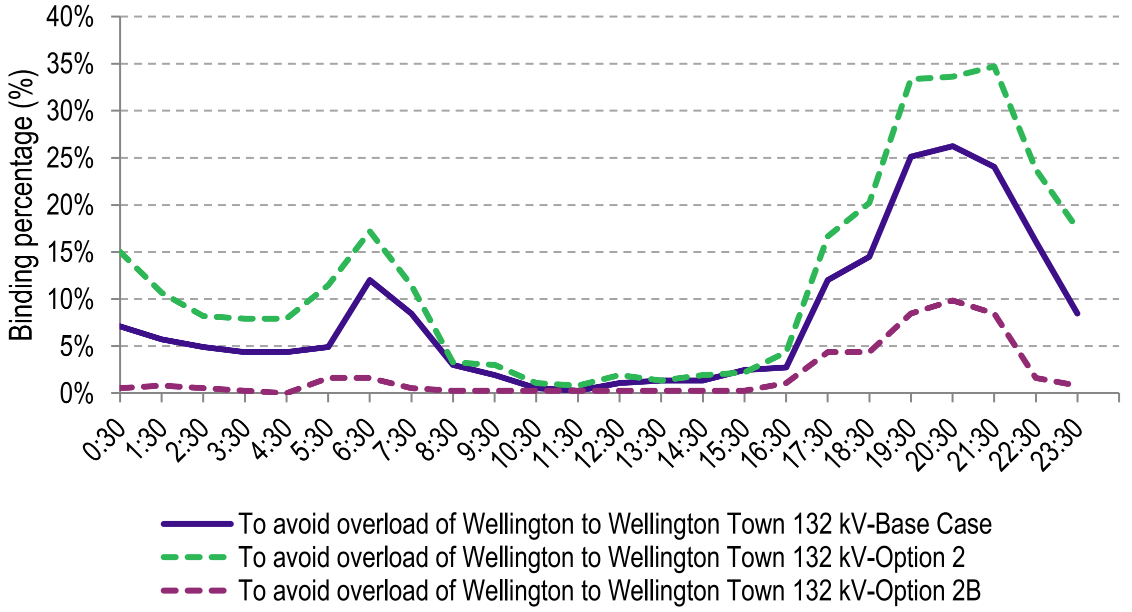
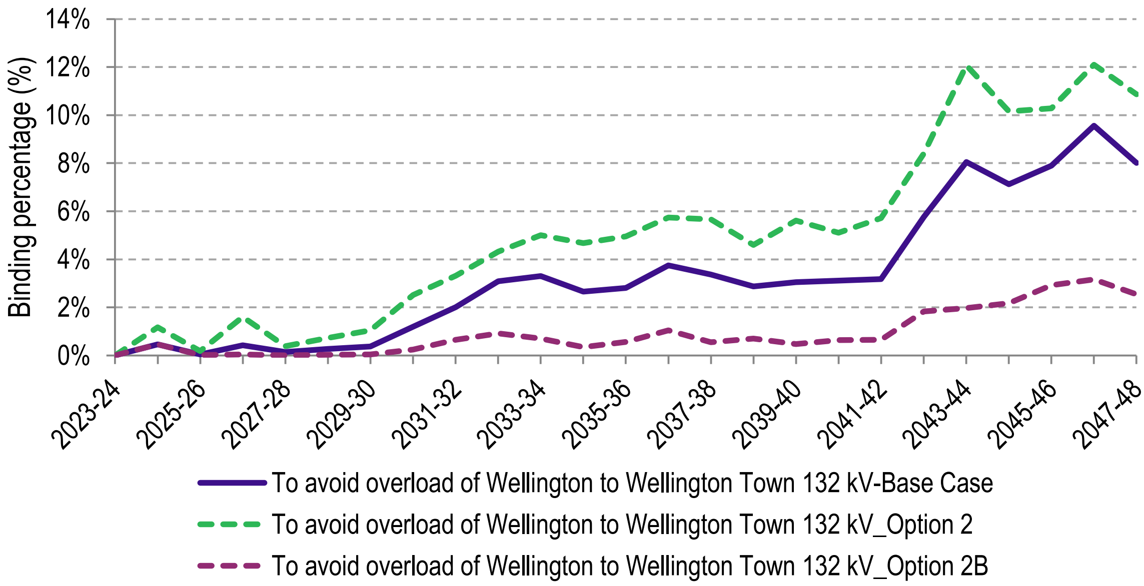


Figure 35: Line 945/2 constraint binding percentage for the Base Case, Option 2, and Option 2B – Hydrogen Superpower scenario

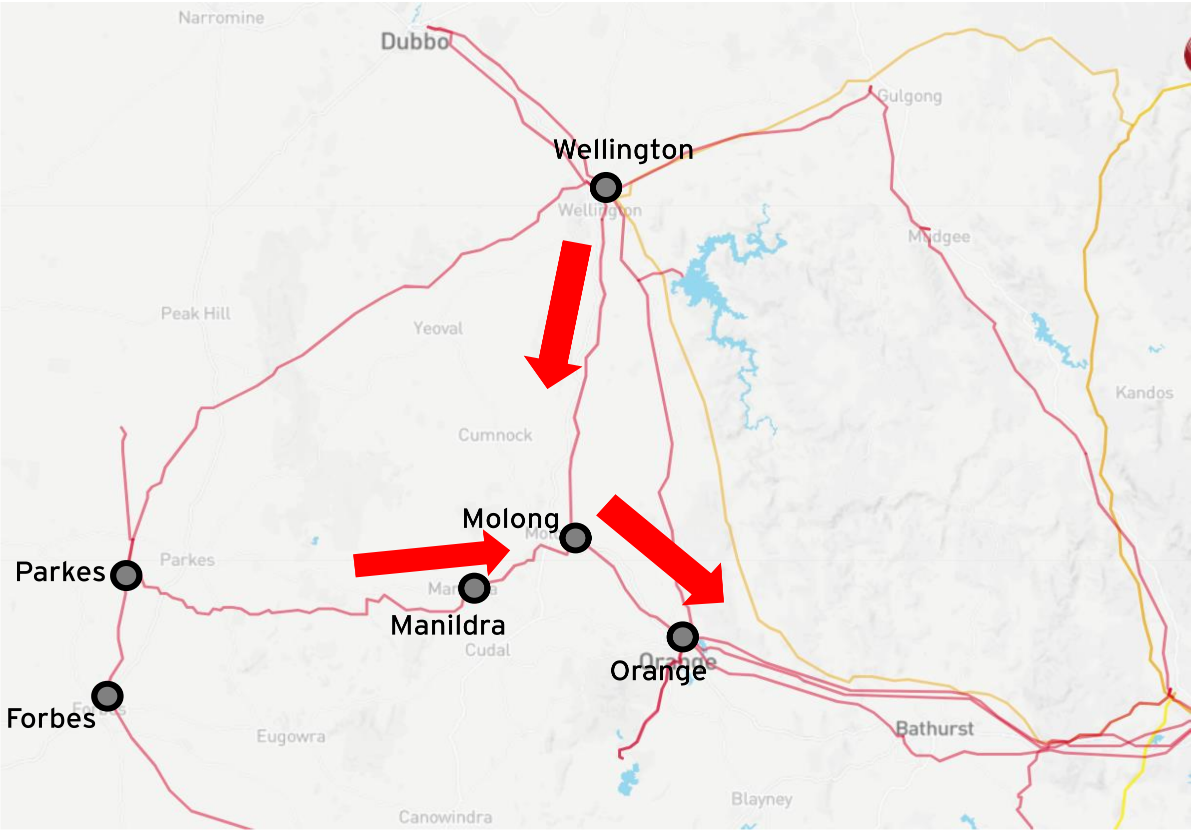


Option 3 – benefits and drivers

Option 3 is forecast to have smaller gross market benefit on average compared to other options in all scenarios. This difference is particularly high in the Hydrogen Superpower scenario so that the gross benefits in the Hydrogen Superpower scenario for Option 3 are similar to the Step Change scenario, which is a marked contrast to outcomes for the other options. Consequently, this section focusses on describing the modelling outcomes for Hydrogen Superpower scenario for this option.

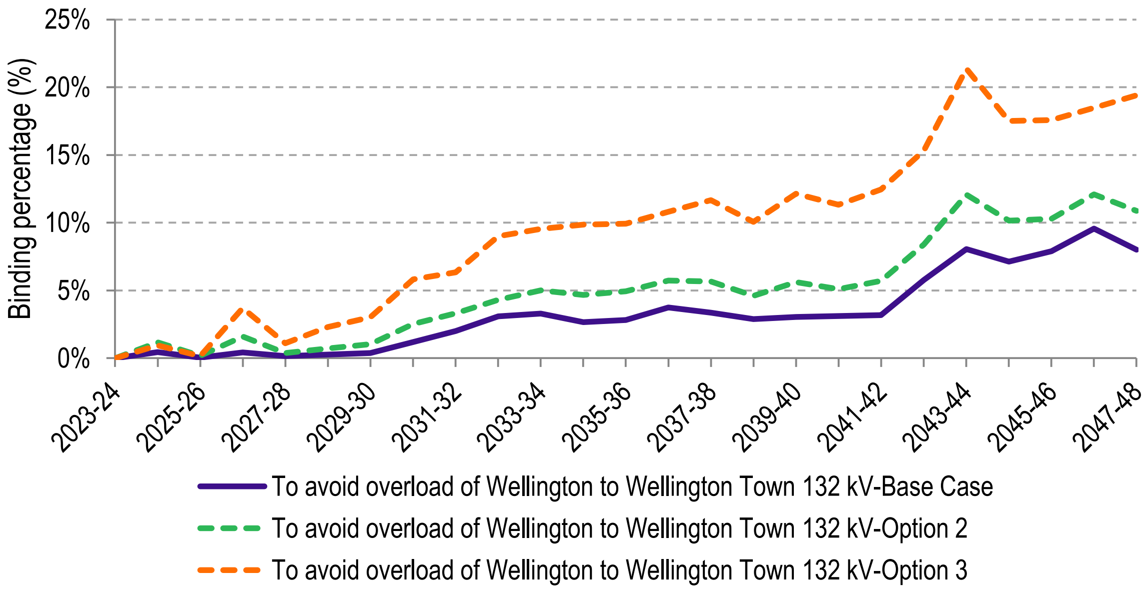
Option 3 is an assumed double circuit Molong to Orange 132 kV line. This is forecast to result in a lower equivalent impedance in the Molong and Orange transmission lines, and in transmission corridors through this flow path towards the Sydney West (see Figure 36). As a result the flow on the lines in this direction is forecast to increase relative to other options (although a significantly higher flow is still forecast on the higher voltage network).

Figure 36: Transmission network of the area[15]



One major impact of the lower impedance of the flow path is that the modelling forecasts more frequent binding of the N-0 constraint on the Wellington to Wellington Town line. Figure 37 shows that this constraint binds more frequently with Option 3 than Option 2, particularly in the later years of the study.

Figure 37: Line 945/2 constraint binding percentage for the Base Case, Option 2, and Option 3 - Hydrogen Superpower scenario



Considering that the N-0 Wellington to Wellington Town constraint is forecast to bind more during the evening (as time of day binding percentage in Figure 38 shows), it is expected that it becomes a limiting factor for wind capacity investment and generation in the Central West NSW, particularly in the later years of the study, as shown in Figure 39. As a result, in order to supply the evening load in major NSW load centres (Sydney, Wollongong and Newcastle) the model forecasts a need for more hydrogen turbine capacity and particularly generation in the area, which results in more fuel cost with Option 3 in place, eroding the benefits of this option (see Figure 40).

Figure 38: Line 945/2 time of day average constraint binding percentage for the Base Case, Option 2, and Option 3 - Hydrogen Superpower scenario

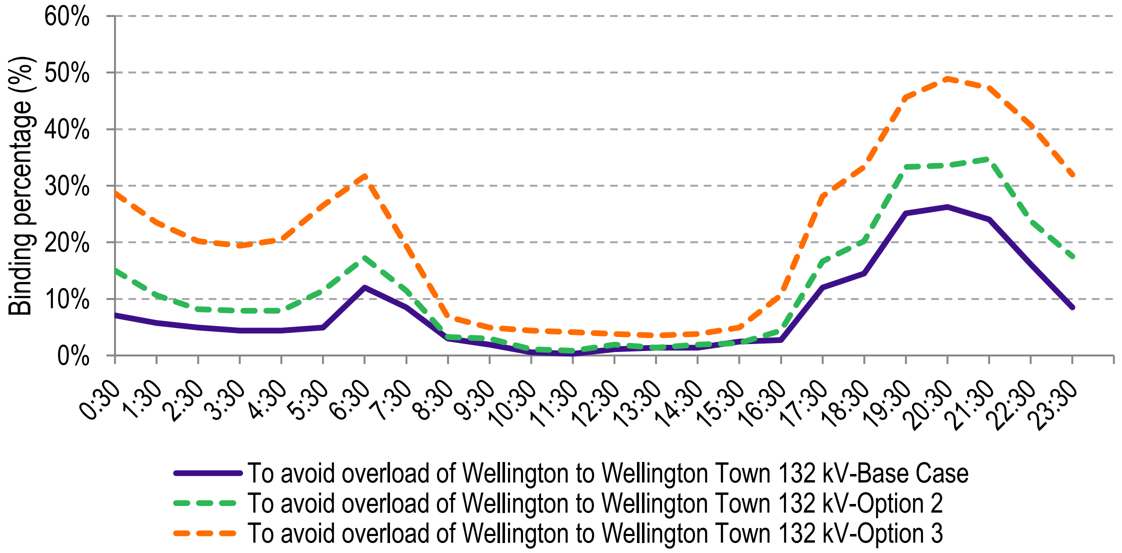


Figure 39: Difference in NEM capacity forecast between Option 3 and Base Case in the Hydrogen Superpower scenario

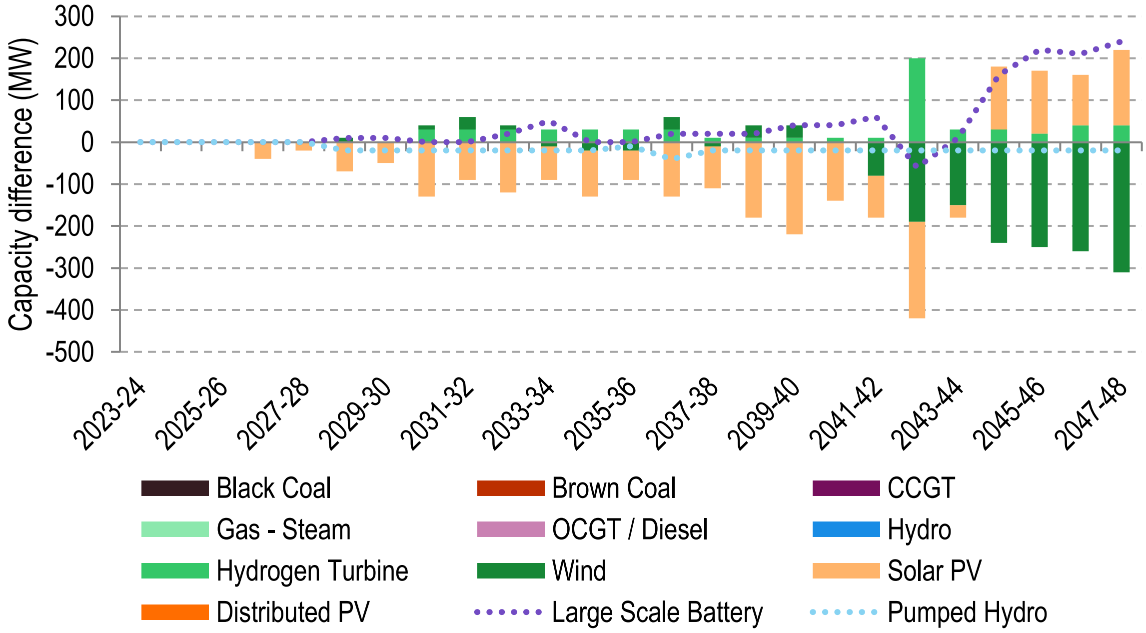
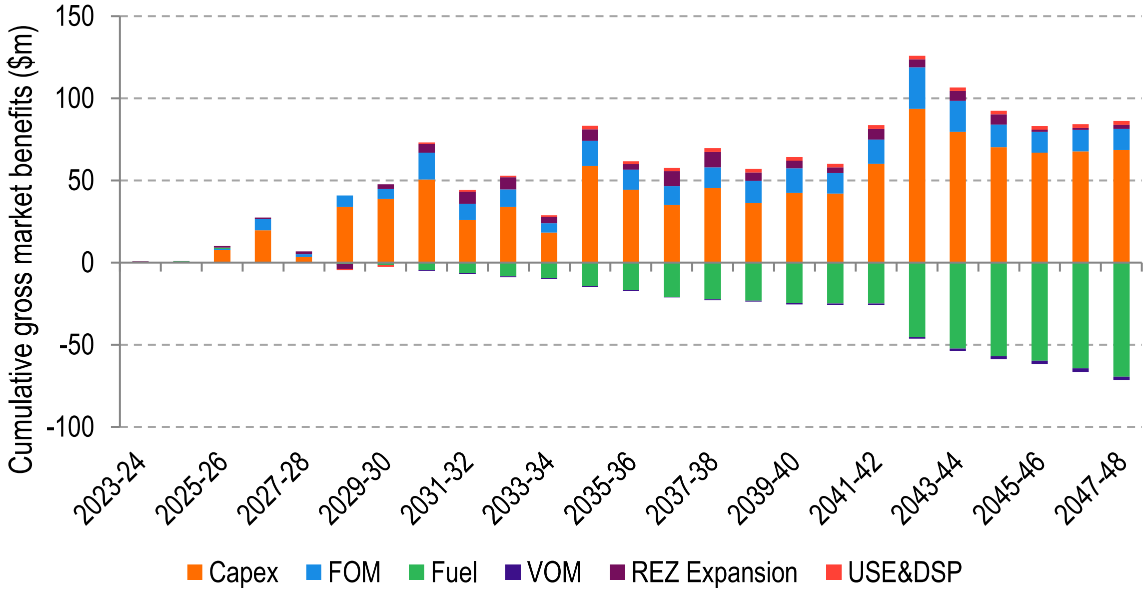
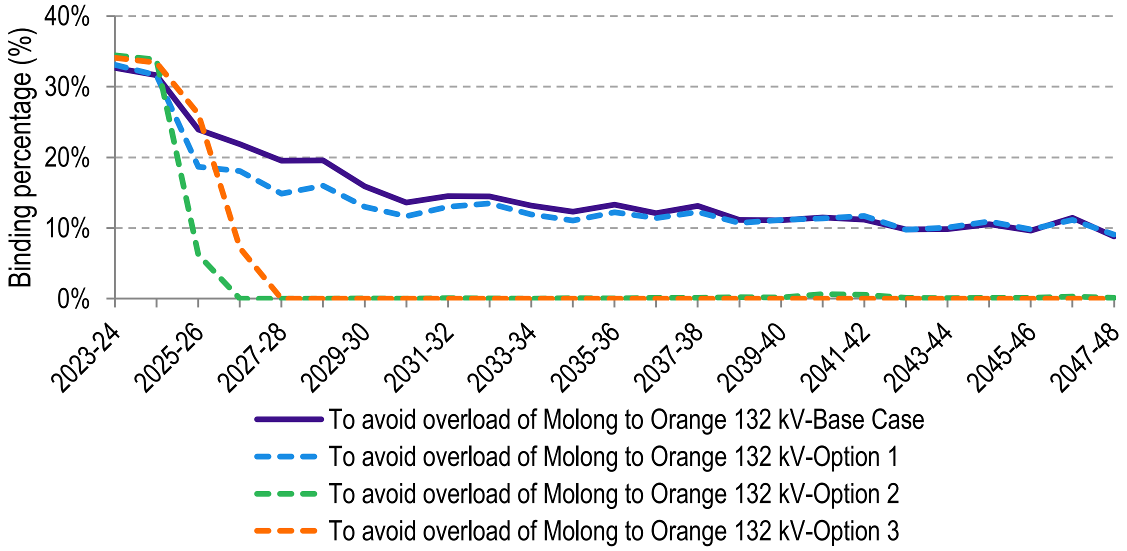


Figure 40: Forecast cumulative gross market benefit for Option 3 under the Hydrogen Superpower scenario, millions real June 2021 dollars discounted to June 2021 dollars



It is worth noting that the expected impact of Options 3 and Option 2 on alleviating constraint binding of Line 94T is fairly similar, as shown in Figure 41.

Figure 41: Line 94T constraint binding for the Base Case and options 1, 2, and 3 - Hydrogen Superpower scenario



Option 4 - benefits and drivers

Option 4 is forecast to have the largest gross market benefits among all options, mainly as it is allowed to be dispatched in the market modelling than be reserved for network support. The battery operation is forecast to result in avoided large-scale battery and solar capacity build and thus, forecast capex savings in this option (see Figure 42). Transgrid assumes that Option 4 does not impact Line 94T thermal rating. Instead, it is assumed to be dispatched in the wholesale electricity market modelling which is expected to reduce congestion on Line 94T by its forecast charging load during the day.

Figure 42: Difference in NEM capacity forecast between Option 4 and Base Case in the Step Change scenario

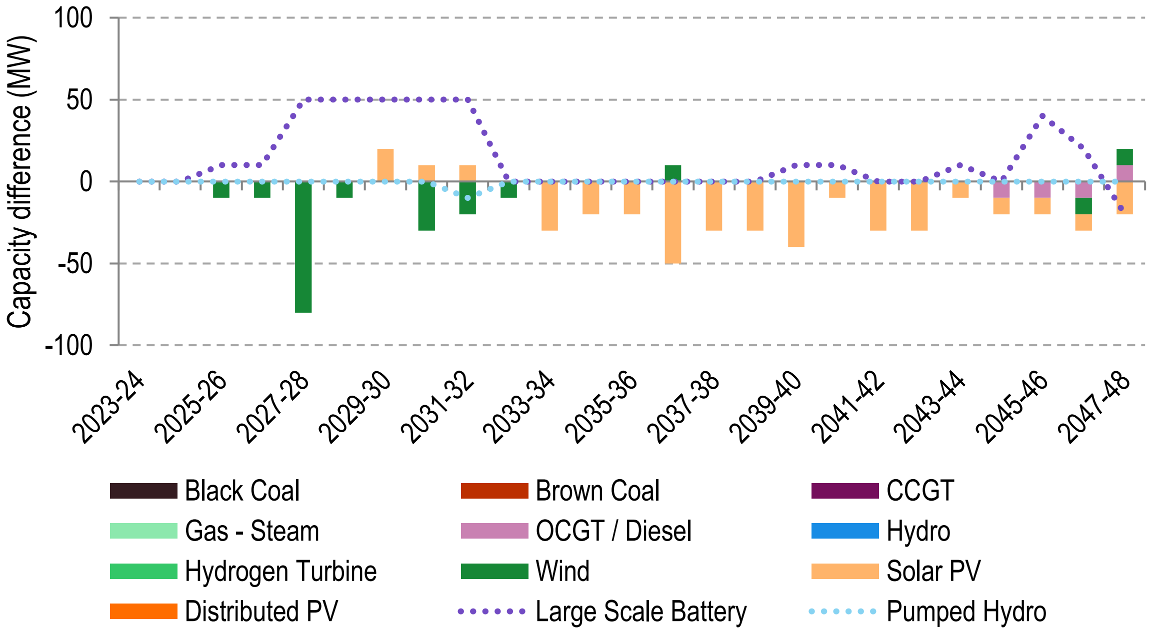
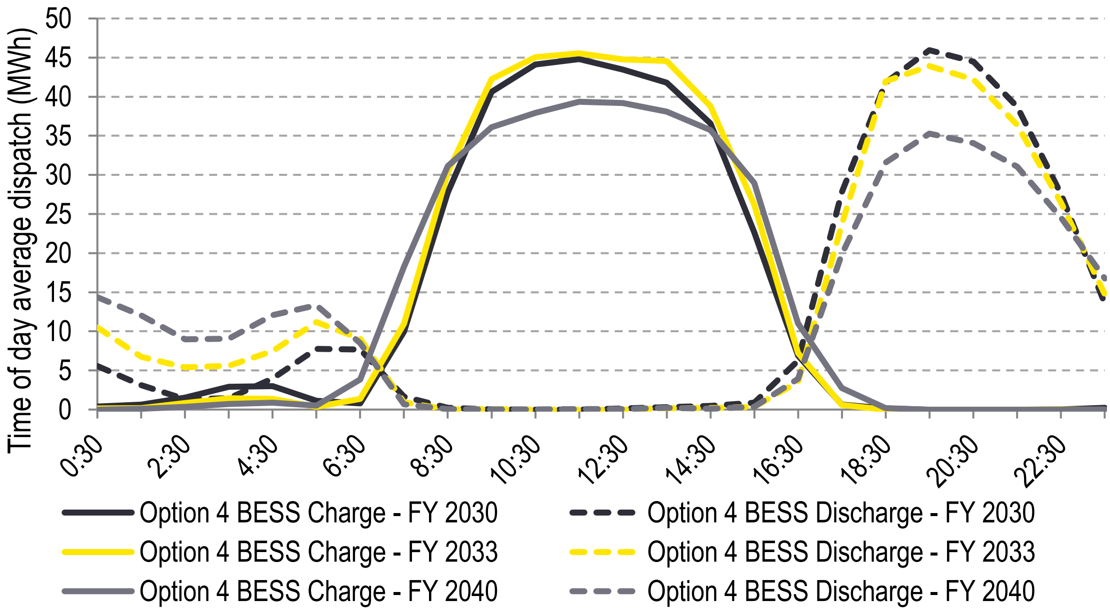


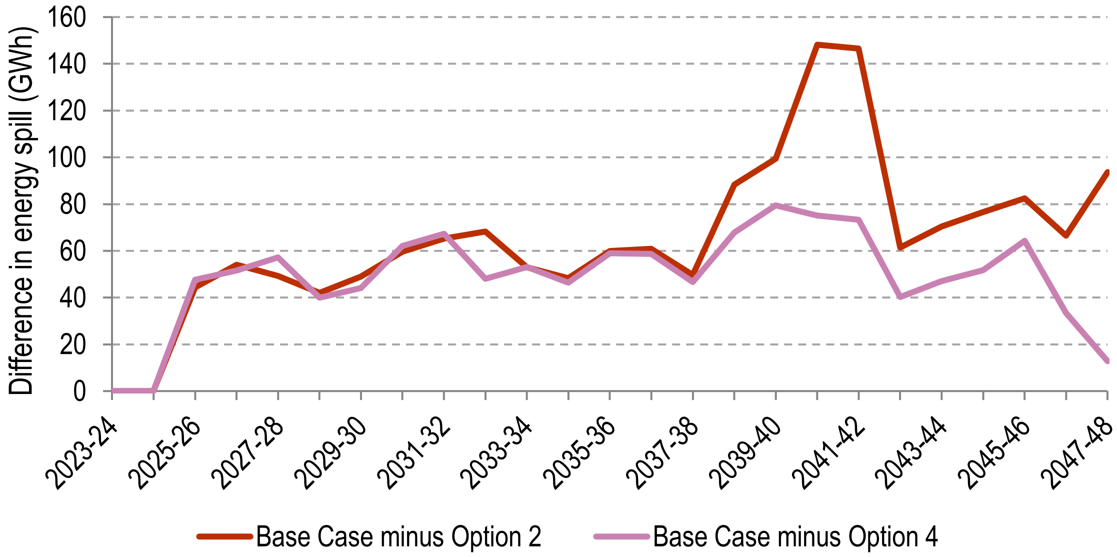
Figure 43 shows the forecast BESS time of day dispatch in Option 4 for a few sample years which is mainly charging in the day and discharging during the evening.

Figure 43: Forecast time of day average dispatch of Option 4 BESS in three sample years



Option 4 does have some local impacts on Central West Orana. The model forecasts less reduction in congestion and spill of the nearby renewable generation with Option 4 compared to Option 2 in the later years of the study, as shown in Figure 44. The forecast increase in renewable energy spill from the late 2030s is due to the extra capacity in the Central West Orana REZ as a result of demand growth and some retirements in NSW. It is forecast that the spill reduces as soon as Nyngan solar farm retires, as assumed in the 2022 ISP. It is forecast that the reduction in spill with Option 4 is even lower than with Option 2 in the later years of the modelling period, showing the higher benefits expected in this option are not a result of avoiding congestion, but rather the generic BESS, mainly as it is allowed to be dispatched in the market modelling than be reserved for network support.

Figure 44: Central West NSW Wind and solar energy spill - Base Case minus options – Step Change



4.5 Market modelling outcomes for sensitivity cases

Transgrid requested EY to model four sensitivity cases to assess the impact of possible changes to the modelling assumptions on the gross market benefits of the modelled options. All sensitivities were variants of the Step Change scenario only, except sensitivity 4 which was modelled across all three scenarios. The four sensitivity cases can be summarised as follows:

- Sensitivity 1: additional assumed generators in the model (3 Gens sensitivity);
- Sensitivity 2: increased demand forecast in the Orange area (high load sensitivity);
- Sensitivity 3: BOP Stage 2 addition in the model (BOP Stage 2 sensitivity);
- Sensitivity 4: excluding BOP BESS preferred option from the model (No BOP BESS sensitivity).

The sensitivity outcomes are presented in the following sections.

4.5.1 Sensitivity 1: assumed three committed generators in the model

In this sensitivity Transgrid advised to assume three additional generators as committed. Table 10 shows the assumed timing of entry of the generators and other details as provided by Transgrid.

Table 10: Assumed three generators in the model for sensitivity 1

Project	Nameplate capacity (MW)	Timing in the model	Connection point
Wellington North solar farm	330	01-Jan-2025	Wellington 330 kV bus
Stubbo solar farm	400	1-May-2024	Stubbo 330 kV Switching Station (Line 79)[19]
Uungula wind farm	400	1-Oct-2025	Uungula 330 kV Switching Station

Table 11 shows forecast gross market benefit of all proposed options in this sensitivity and the core simulations. Forecast gross benefits increase for all options relative to core Step Change simulations.

Table 11: Summary of forecast gross market benefits of all Line 94T options relative to Base Case, millions real June 2021 dollars discounted to June 2021 dollars, Step Change

Option	Description	Timing	Forecast gross market benefits ($m)	
			Sensitivity - Step Change	Core - Step Change
Option 1	Restring Line 94T with a higher rated conductor on Option 1	1/04/2025	23.1	15.8
Option 2	Restring Line 94T with a higher rated conductor on existing structure (Flicker/ACSS)	1/11/2025	37.7	21.5
Option 2A	Restring Line 94T with a higher rated low sag conductor on existing structure (Partridge/ACSS/HS285)	1/11/2025	37.5	21.4
Option 2B	Option 2 with power flow controllers	1/11/2025	35. 8	19.6

[19] For simplicity in the modelling, Transgrid assumes Stubbo solar farm to connect at Uungula switching station. As advised by Transgrid, commissioning date of this project is also assumed to be 1 July 2025. It is expected that this assumption has a minor impact on the modelling outcomes.

Option	Description	Timing	Forecast gross market benefits ($m)	
			Sensitivity - Step Change	Core - Step Change
Option 3	Replacing Line 94T with double circuit transmission lines	1/11/2026	27.5	18.7
Option **4**	Non-network option (BESS)	1/07/2025	101.1	91.2

The main source of additional gross market benefits in this sensitivity is additional expected spill for the nearby generators in the Base Case in this sensitivity as compared with the core simulations. This is forecast to result in more opportunity for all options to avoid spill, resulting in higher expected gross benefits for all options.

It is forecast that Option 2 and its variants result in a relatively higher increase in the benefits in this sensitivity compared to other options. This is mainly due to their higher assumed thermal rating for Line 94T, which is forecast to alleviate congestion to a greater extend, resulting in more gross benefits.

The forecast limitations in Option 3, discussed earlier, are expected to be a limiting factor in the increase in the gross market benefits in this sensitivity too. As discussed earlier, Option 4 benefits are mainly due to the operation of the BESS, and its benefits in this sensitivity are not forecast to increase significantly as it is not expected to result in significant reduction in congestion.

Figure 45 compares the forecast annual frequency of constraint binding in the core simulations and the modelled sensitivity for the Base Case and Option 2. As can be seen, Line 94T constraint is forecast to bind more frequently in the Base Case in this sensitivity compared to corresponding Base Case in the core Step Change simulation.

Figure 45: Line 94T constraint binding percentage for the core and sensitivity scenarios

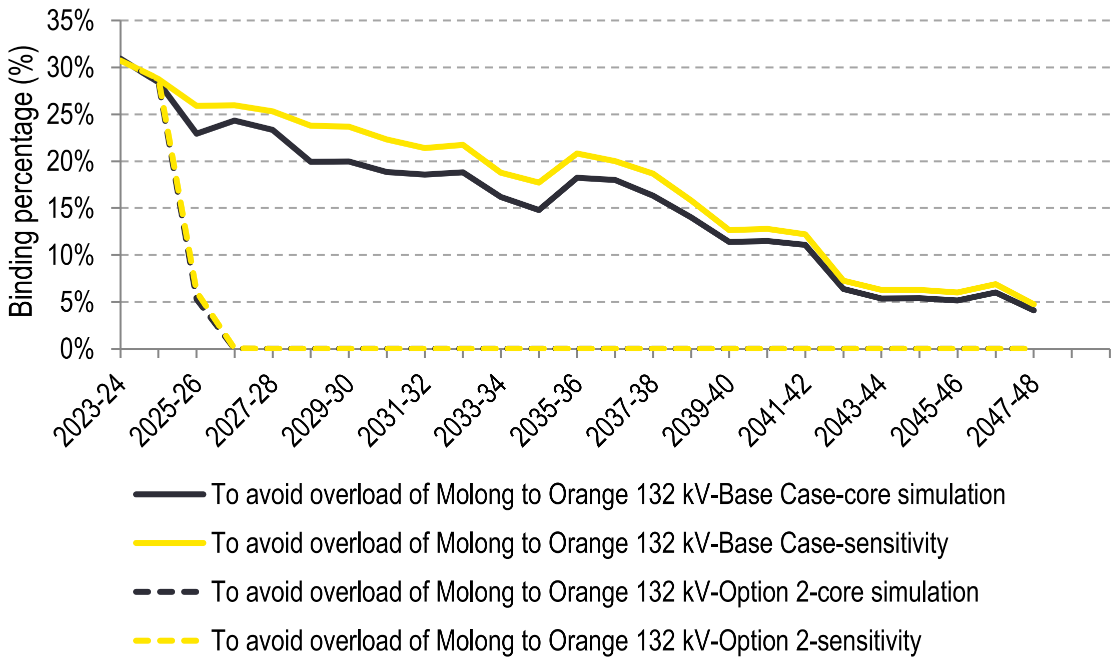


Figure 46 compares wind and solar energy spill in the Central West NSW area for the core and sensitivity cases for Option 2 compared to the Base Case, indicating that more generation is forecast to be unlocked with this option in place in the sensitivity compared with the core simulation.

Figure 46: NCEN wind and solar energy spill - Base Case minus Option 2, core and 3 Gens sensitivity - Step Change

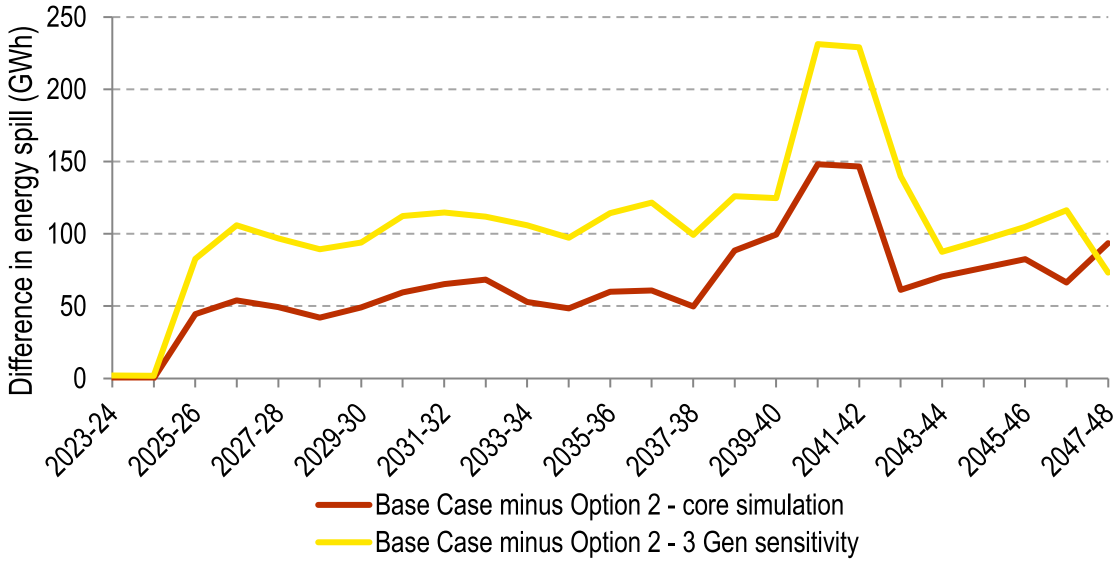
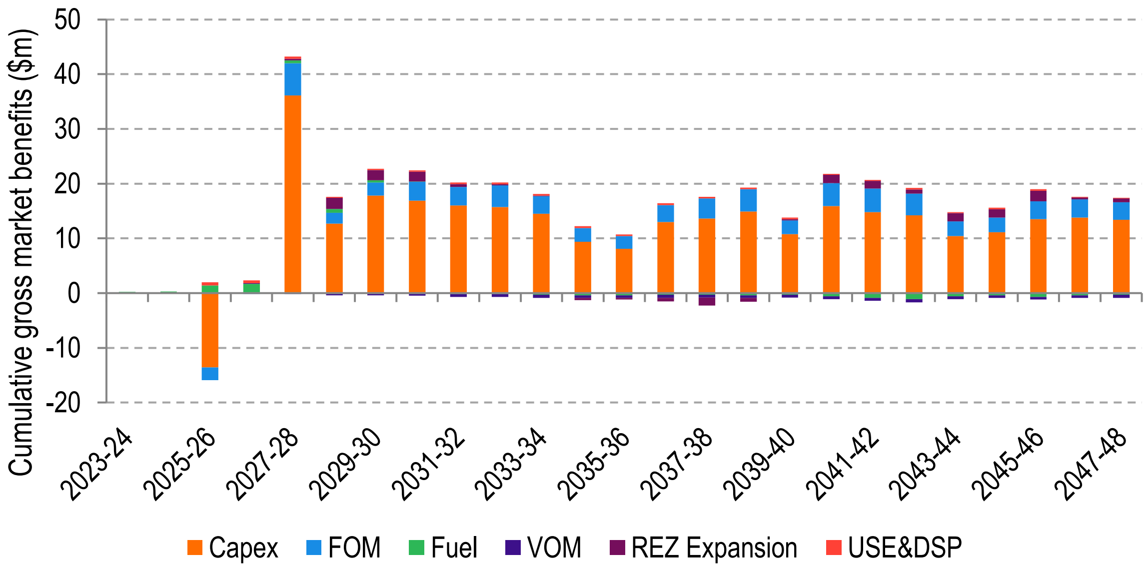


Figure 47 shows the forecast gross market benefits of Option 2 in the sensitivity minus gross market benefits of Option 2 in the core scenario, demonstrating forecast more capex and FOM cost savings in the sensitivity.

Figure 47: Forecast cumulative gross market benefit difference of Option 2 in 3 Gens sensitivity and Option 2 in core case under Step Change scenario, millions real June 2021 dollars discounted to June 2021 dollars



4.5.2 Sensitivity 2: increased demand forecast in the Orange area

For this sensitivity Transgrid requested EY increase the assumed demand in the Orange area to assess its impact on the gross market benefit of options. For this sensitivity Transgrid provided an increased demand forecast in the Orange area, which is approximately 16% higher than the assumed demand in the area in the core simulations. Table 12 shows the forecast gross market benefits of the options for this sensitivity.

Table 12: Summary of forecast gross market benefits of all Line 94T options relative to Base Case, millions real June 2021 dollars discounted to June 2021 dollars, Step Change

Option	Description	Timing	Forecast gross market benefits ($m)	
			Sensitivity - Step Change	Core - Step Change
Option 1	Increase transmission line design temperature	1/04/2025	25.2	15.8
Option 2	Restring Line 94T with a higher rated conductor on existing structure (Flicker/ACSS)	1/11/2025	38.5	21.5
Option 2A	Restring Line 94T with a higher rated low sag conductor on existing structure (Partridge/ACSS/HS285)	1/11/2025	38.6	21.4
Option 2B	Option 2 with power flow controllers	1/11/2025	37.6	19.6
Option 3	Replacing Line 94T with double circuit transmission lines	1/11/2026	28.1	18.7
Option **4**	Non-network option (BESS)	1/07/2025	96.2	91.2

Gross market benefits of all options are forecast to increase with the additional load assumed in the area in this sensitivity. Gross market benefits for Options 2, 2A, and 2B are forecast to almost double in this sensitivity, while other options are forecast to have relatively smaller increase in the gross market benefits.

With additional load assumed in this sensitivity, both N-0 and N-1 constraints for Molong to Orange are expected to bind significantly more frequently in the Base Case than the corresponding Base Case in the core simulations. Similar to the previous sensitivity, the options are then forecast to result in more benefits by alleviating the congestion and lowering expected spill (see Figure 48, Figure 49, and Figure 50). Overall, more capex and FOM cost savings are forecast for all options in this sensitivity compared to the core simulations.

A similar trend in the benefits increase relative to the core simulations is forecast as in the case of Sensitivity 1.

Figure 48: Line 94T constraint binding percentage for the core and sensitivity scenarios

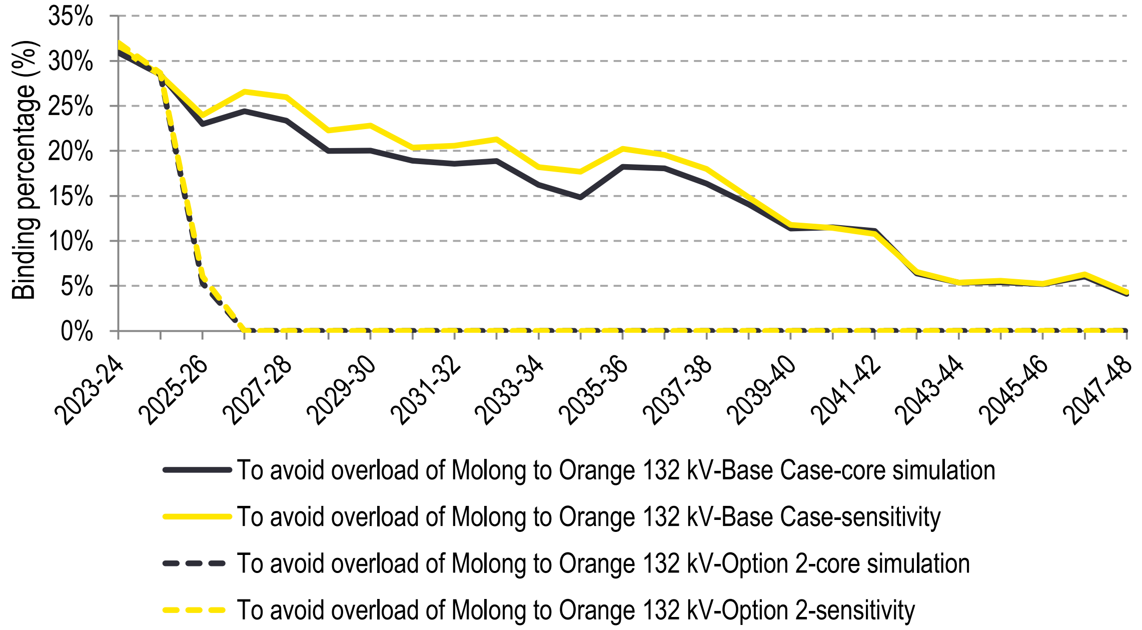


Figure 49: Line 94T N-1 constraint binding percentage for the core and sensitivity scenarios

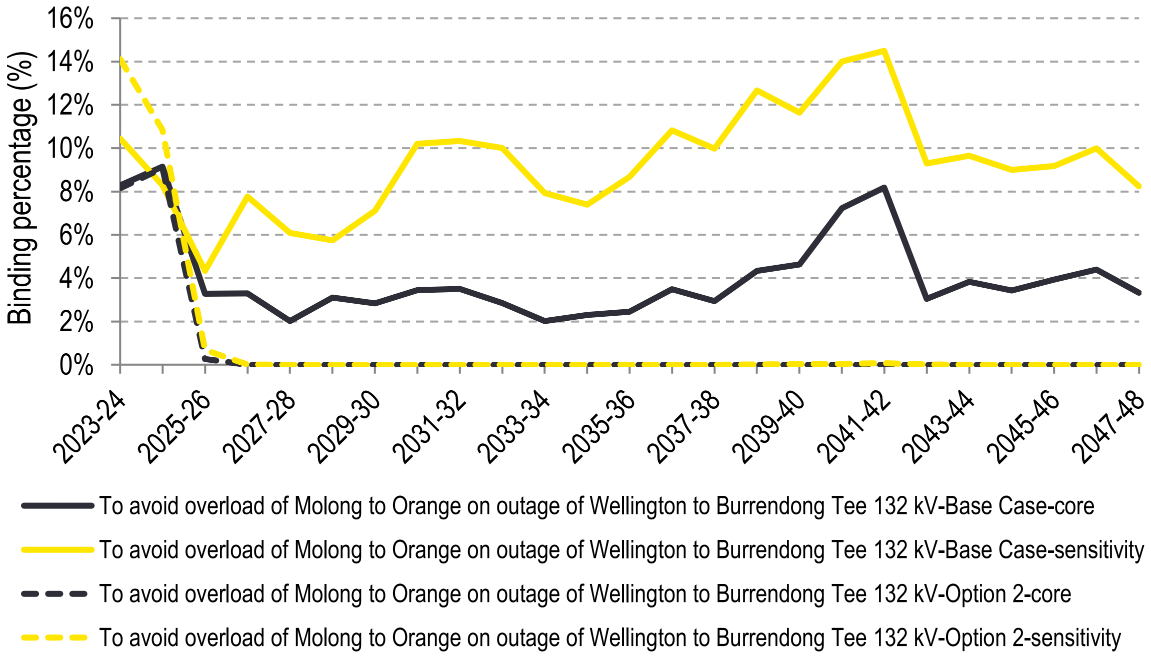
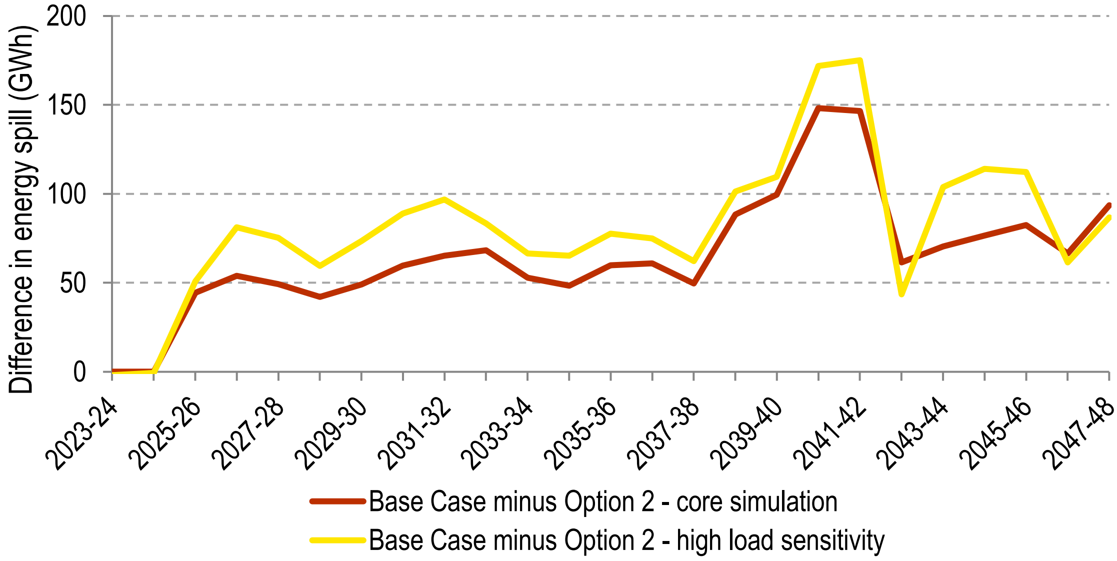


Figure 50: Central West NSW wind and solar energy spill - Base Case minus Option 2, core and high load sensitivity - Step Change



4.5.3 Sensitivity 3: BOP Stage 2 addition in the model

For this sensitivity Transgrid requested EY assess impact of the second stage of BOP preferred option from the BOP PACR report[6] on the market modelling outcome and gross market benefits. The BOP Stage 2 preferred option is the second 132 kV circuit for the transmission line between Wellington and Parkes, assumed to be commissioned from 1 July 2031 as per Transgrid advice. Table 13 shows gross market benefits for this sensitivity.

Table 13: Summary of forecast gross market benefits of all Line 94T options relative to Base Case, millions real June 2021 dollars discounted to June 2021 dollars, Step Change

Option	Description	Timing	Forecast gross market benefits ($m)	
			Sensitivity - Step Change	Core - Step Change
Option 1	Increase transmission line design temperature	1/04/2025	13.34	15.8
Option 2	Restring Line 94T with a higher rated conductor on existing structure (Flicker/ACSS)	1/11/2025	16.67	21.5
Option 2A	Restring Line 94T with a higher rated low sag conductor on existing structure (Partridge/ACSS/HS285)	1/11/2025	16.44	21.4
Option 2B	Option 2 with power flow controllers	1/11/2025	14.42	19.6
Option 3	Replacing Line 94T with double circuit transmission lines	1/11/2026	24.61	18.7
Option **4**	Non-network option (BESS)	1/07/2025	88.31	91.2

It is forecast that this sensitivity results in lower benefits for all options, except Option 3. The forecast reduced benefits of the relevant options are mainly due to reduced congestion (and as a result renewable spill) on the flow path towards Wellington, which is due to the reduced equivalent impedance in this flow path with the parallel Wellington to Parkes transmission line. This lower congestion in the Base Case is forecast to reduce the opportunity for options to avoid renewable spill compared to the observed forecast in the core simulations, resulting in lower benefits for those options.

Figure 51 and Figure 52 compares the forecast constraint binding of the Line 94T N-0 and N-1 constraints for the core simulation and the sensitivity.

Figure 51: Line 94T N-0 constraint binding percentage for the core and sensitivity scenarios

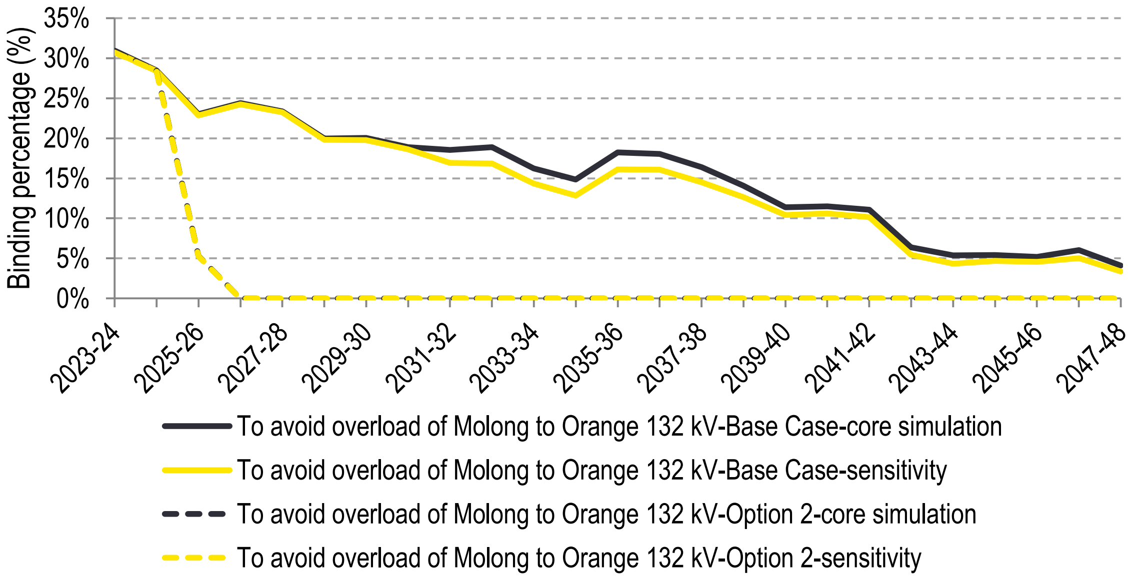
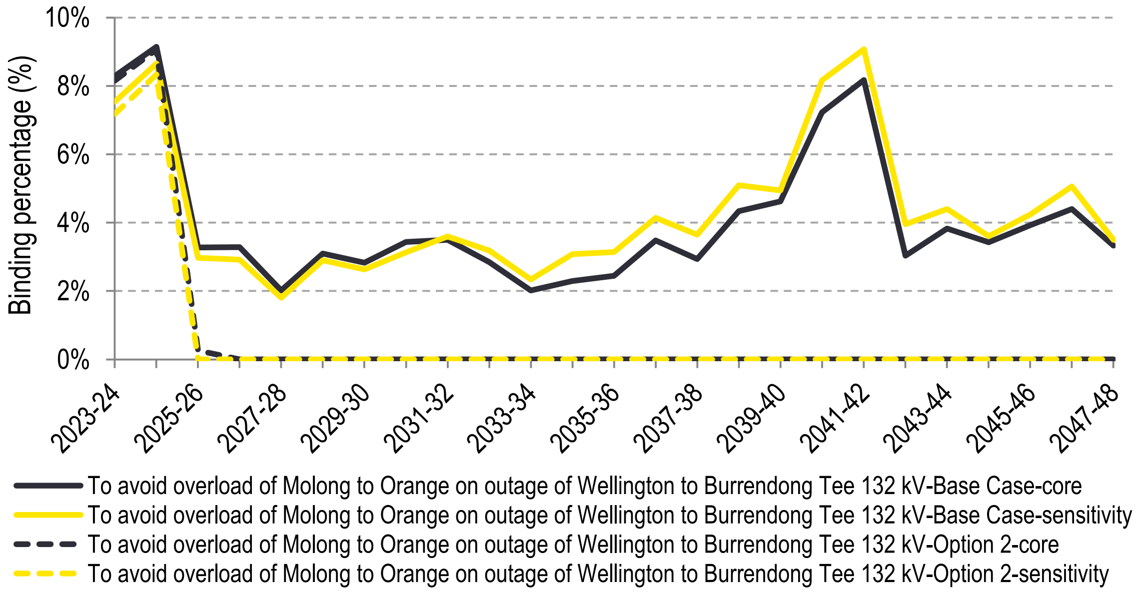


Figure 52: Line 94T N-1 constraint binding percentage for the core and sensitivity scenarios



Option 3 is forecast to behave differently in this sensitivity as the forecast gross market benefit of this option increases compared to the core simulation unlike the rest of the options. This is mainly because Option 3 can further benefit from the reduced impedance of Wellington to Parkes, which avoids/reduces the congestion in Wellington to Wellington Town which is seen in the core simulations.

4.5.4 Sensitivity 4: BOP BESS preferred option exclusion from the model

As a sensitivity, Transgrid requested to exclude the BOP preferred option (Option 7D of BOP PACR[6]) from the modelled core simulations to assess its impact on the gross market benefits of Line 94T options. Table 14 shows the forecast gross market benefits of Line 94T options for all scenarios without BOP BESS Option 7D and core simulations.

Table 14: Summary of forecast gross market benefits of all Line 94T options relative to Base Case, millions real June 2021 dollars discounted to June 2021 dollars, Step Change, Progressive Change, and Hydrogen Superpower

Option	Description	Timing	Forecast gross market benefits ($m)		
			Step Change	Progressive Change	Hydrogen Superpower
Option 1 - Core Simulation	Increase transmission line design temperature	1/04/2025	15.8	12.3	33.6
Option 1 - Sensitivity			16.5	12.8	35.9
Option 2 - Core Simulation	Restring Line 94T with a higher rated conductor on existing structure (Flicker/ACSS)	1/11/2025	21.5	18.1	50.6
Option 2 - Sensitivity			23	19.2	54.8
Option 2A - Core Simulation	Restring Line 94T with a higher rated low sag conductor on existing structure (Partridge/ACSS/HS285)	1/11/2025	21.4	18.2	50.6
Option 2A - Sensitivity			22.9	19.3	54.5
Option 2B - Core Simulation	Option 2 with power flow controllers	1/11/2025	19.6	17.2	52.6
Option 2B - Sensitivity			21	18.4	57.2
Option 3 - Core Simulation	Replacing Line 94T with double circuit transmission lines	1/11/2026	18.7	14.3	14.5
Option 3 - Sensitivity			19.9	15	16
Option 4 - Core Simulation	Non-network option (BESS)	1/07/2025	91.2	96.7	106.9
Option 4 - Sensitivity			91.7	97	107.5

As compared with the core simulations, gross market benefits are forecast to increase in this sensitivity, assuming BOP BESS does not go ahead. The key reason for the increased benefits is that excluding the modelled BOP BESS batteries from the model is forecast to increase the constraint binding in the Base Case resulting in more added value when congestion in the area is alleviated with Line 94T options in place. That is, particularly with the BOP battery in Parkes in the core simulation, it is forecast that its charging load reduces congestion (and spill of nearby solar farms) in the Base Case, which is forecast to provide less opportunity for the options to avoid it and gain market benefits.

Appendix A Scenario assumptions

Key assumptions for modelled Scenarios

The options proposed by Transgrid have been assessed under the Step Change, Progressive Change and Hydrogen Superpower scenarios from 2022 ISP[3,20], using the corresponding inputs and assumptions as summarised in Table 15. We were also requested to incorporate modifications to AEMO's input and assumptions based on updated information since the publication of 2022 ISP.

Table 15: Overview of key input parameters in the Step Change, Progressive Change and Hydrogen Superpower scenarios

Key drivers input parameter	Scenario		
	Step Change	Progressive Change	Hydrogen Superpower
Underlying consumption	ISP 2022 - Step Change	ISP 2022 - Progressive Change	ISP 2022 - Hydrogen Superpower
Committed and anticipated generation	AEMO Generation Information data as of January 2023[5]		
New entrant capital cost for wind, solar PV, SAT, OCGT, PHES large-scale batteries and hydrogen turbine	2021 Inputs and Assumptions Workbook[21] - Step Change	2021 Inputs and Assumptions Workbook[21] - Progressive Change	2021 Inputs and Assumptions Workbook[21] - Hydrogen Superpower
Retirements of coal-fired power stations	Coal retirement is based on EY market modelling outcomes	Coal retirement is based on EY market modelling outcomes	Coal retirement is based on EY market modelling outcomes
Gas fuel cost	2021 Inputs and Assumptions Workbook[21] - Step Change	2021 Inputs and Assumptions Workbook[21] - Progressive Change	2021 Inputs and Assumptions Workbook[21] - Hydrogen Superpower,
Coal fuel cost	2021 Inputs and Assumptions Workbook[21] - Step Change	2021 Inputs and Assumptions Workbook[21] - Progressive Change	2021 Inputs and Assumptions Workbook[21] - Hydrogen Superpower
NEM carbon budget	2021 Inputs and Assumptions Workbook[21] - Step Change: 891 Mt CO_2-e 2023-24 to 2050-51	2021 Inputs and Assumptions Workbook[21] - Progressive Change: 932 Mt CO_2-e 2030-31 to 2050-51	2021 Inputs and Assumptions Workbook[21] - Hydrogen Superpower: 453 Mt CO_2-e 2023-24 to 2050-51
Victorian Renewable Energy Target (VRET)	40% renewable energy by 2025 and 50% renewable energy by 2030[21] VRET2 including 600 MW of renewable capacity by 2025[21]		
Queensland Renewable Energy Target (QRET)	50% by 2030[21]		
Tasmanian Renewable Energy Target (TRET)	100% by 2022, 150% by 2030 and 200% Renewable generation by 2040, excluding hydro[21]		
NSW Electricity Infrastructure Roadmap	12 GW NSW Roadmap, with 3 GW in the Central West Orana REZ, modelled as generation constraint per 2022 ISP and 2 GW of long duration storage (8 hrs or more) by 2029-30[21]		

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[20] The AER's *Cost benefit analysis guidelines* requires that the RIT-T proponent of an actionable ISP project adopts the scenarios specified in the AEMO ISP as relevant.

[21] *2022 Inputs and Assumptions Workbook, version 3.4*, https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios. Accessed on 26 May 2022.

Key drivers input parameter	Scenario		
	Step Change	Progressive Change	Hydrogen Superpower
Victorian SIPS	300 MW/450 MWh, 250 MW for SIPS service during summer. In the summer months the remaining 50 MW can be deployed in the market on a commercial basis, in the winter months the full capacity is available. From April 2032 the full capacity is available to the market.[21]		
EnergyConnect	2022 ISP: EnergyConnect commissioned by July 2026		
Western Renewable Link	Western Renewables Link commissioned by July 2026		
HumeLink	2022 ISP[3] outcome - Step Change: HumeLink commissioned by July 2028	2022 ISP[3]. outcome - Progressive Change: HumeLink commissioned by July 2035	2022 ISP[3]. outcome - Hydrogen Superpower: HumeLink commissioned by July 2027
New-England REZ Transmission	2022 ISP outcome[3] - Step Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2035	2022 ISP outcome[3] - Progressive Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2038	2022 ISP outcome[3] - Hydrogen Superpower: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2031, and stage 2 by July 2042
Marinus Link	2022 ISP[3] outcome:1st cable commissioned by July 2029 and 2nd cable by July 2031		
QNI Connect	2022 ISP[3] outcome - Step Change: QNI Connect commissioned by July 2032	2022 ISP[3] outcome - Progressive Change: QNI Connect commissioned by July 2036	2022 ISP[3] outcome - Hydrogen Superpower: QNI Connect commissioned by July 2029 and stage 2 to be commissioned by July 2030
VNI West	2022 ISP[3] outcome - Step Change: VNI West commissioned by July 2031	2022 ISP[3] outcome - Progressive Change: VNI West commissioned by July 2038	2022 ISP[3] outcome - Hydrogen Superpower: VNI West commissioned by July 2030
Snowy 2.0	Snowy 2.0 is commissioned by December 2027[21]		

Appendix B Methodology

Long-term investment planning

EY has used linear programming techniques to perform hourly time-sequential, least-cost, long-term NEM development optimisation modelling spanning from 2023-24 to 2047-48. The modelling methodology follows the RIT-T guidelines for actionable ISP projects published by the AER[1].

Based on the full set of input assumptions, the 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:

- capex,
- FOM,
- VOM,
- fuel usage,
- DSP and USE,
- transmission expansion costs associated with REZ development,
- transmission and storage losses which form part of the demand to be supplied and are calculated dynamically within the model.

To determine the least-cost solution, the model makes decisions for each hourly[22] trading interval in relation to:

- the generation dispatch level for each power plant along with the charging and discharging of storage. Generators are assumed to run at their 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 unplanned outages), network limitations and energy limits (e.g., storage levels).
- commissioning new entrant capacity for wind, offshore wind, solar PV SAT, OCGT, large-scale battery and PHES[8]. Hydrogen turbine technology is only modelled as available in the Hydrogen Superpower scenario. Nuclear and other technically feasible technology options were screened 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 VCR[11],
- minimum loads for some generators,
- transmission interconnector flow limits (between regions),
- intra-regional flow limits (between zones in NSW),
- intra-regional flow limits for a detailed network modelled in Victoria and Southern NSW through DCLF,
- maximum and minimum storage reservoir limits (for conventional storage hydro, PHES and large-scale battery),
- new entrant capacity build limits and costs associated with increasing these limits beyond the resource limit for wind and solar in each REZ where applicable, and PHES in each region,

[22] Whilst the NEM is dispatched on five-minute intervals, the model resolution is hourly as a compromise between managing computation time while still capturing the renewable and storage resources in sufficient detail for the purposes of the modelling.

- emission and carbon budget constraints, as defined for each scenario,
- renewable energy targets where applicable by region or NEM-wide.

The model includes key intra-regional constraints in NSW and Victoria through modelling of zones with intra-regional limits and losses. Within these zones and within regions, no further detail of the transmission network is considered. More detail on the transmission network representation is given in Appendix D.

The model 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 carbon budget assumed in each scenario 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 2022 ISP dataset[21]. The running cost for these generators is the sum of the VOM and fuel costs. FOM costs are another component of the running cost of generators contributing to potential earlier economic withdrawal [23]. Coal generators and some CCGTs[24] 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 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, PHES, large-scale battery and virtual power plants (VPPs)) are operated to minimise the overall system costs. This means they tend to generate at times of high cost of supply, e.g., when the demand for power is high, and so dispatching energy-limited generation will avoid utilisation of high-cost plant such as gas-fired or liquid fuel generators. Conversely, at times of low supply cost, e.g., when there is a prevailing surplus of renewable generation capacity, storage hydro preserves energy and PHES and large-scale battery operate in pumping or charging mode.

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 to allow for generation contingencies, which can occur at any time.

All dispatchable generators in each region are eligible to contribute to reserve (except PHES, VPPs and large-scale battery[25]) 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.

[23] Note that earlier coal withdrawal in TSIRP is an outcome of the least cost optimisation rather than revenue assessment.

[24] Close cycle gas turbines

[25] PHES 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.

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, sub-optimal operation of storage). This constraint is applied to only a subset of simulation hours when demand is high to reduce the optimisation problem size.

There are three geographical levels of reserve constraints applied:

- Reserve constraints are applied to each region.
- The model ensures that interconnector headroom is backed by spare capacity in the neighbouring regions through an additional reserve constraint.
- In NSW, where the major proportion of load and dispatchable generation is concentrated in the Central NSW (NCEN) zone, the same rules are applied as for the NSW 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 into NCEN reflect the upstream network limits. However, intra-connectors still implicitly contribute to reserve because increased flow can displace dispatchable generators within NCEN allowing them to contribute to reserve.

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 scenario a matched no option 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 option, as defined in the RIT-T. The RIT-T instrument requires RIT-T for actionable ISP projects to calculate all classes of benefits identified in the ISP.

Each component of forecast gross market benefits is computed hourly 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[26], discounted to June 2021 at a 5.5% real, pre-tax discount rate as agreed jointly by Transgrid. This value is consistent with the value applied by AEMO in 2022 ISP[3], as required by the CBA guidelines[1].

The forecast gross market benefits of each option need to be compared to the relevant option cost to determine whether there is a positive forecast net economic benefit. The determination of the forecast net economic benefit and preferred option was conducted outside of this Report by Transgrid [2] using the forecast gross market benefits from this Report and other inputs.

[26] 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.

Appendix C Constraint formulation

EY's model was configured such that the constraint equation data set includes mapping of all existing and new generator connection points to constraint equation terms as appropriate for the thermal limits of the 132 kV lines in the Orange area for the network topography agreed by Transgrid.

To model network congestion for the assumed network upgrades provided by Transgrid as well as the connection of new entrant generation, EY has constructed custom thermal constraint equations. These custom equations are constructed using an approach which is consistent with AEMO's constraint creation processes and are used to assess the potential N-1 and N limits near Line 94T.

Constraints and equation formulation

The objective of a thermal constraint equation is to prevent overloading of any transmission network element. N-0 constraints are formulated to prevent the overloading of transmission network elements during system normal operation, while N-1 constraints are formulated to prevent the overloading of transmission network elements should any single credible contingency occur (i.e., the outage/failure of a transmission network element). N-1 constraints are enforced pre-contingently, that is, at all times. In the case of the NEM, constraint equations are formulated such that the sum of terms on the left-hand side (LHS) must be less than or equal to the sum of terms on the right-hand side (RHS). Generation and interconnector terms are typically assigned to the LHS, while constant and demand terms are typically assigned to the RHS.

The elements within a thermal constraint equation can be categorised as follows:

- Generator terms and coefficients
- Interconnector terms and coefficients
- Demand coefficient
- Constant term

Description of binding constraint

If, before dispatch, the desirable combination of generator bidding and demand would theoretically lead to a constraint equation violating (i.e., the LHS is exceeding the RHS indicating a potential network element overload) then generator output, interconnector flow or load must be curtailed below the desirable dispatch level to reduce the LHS. Curtailment is based on the cost of that curtailment, with the least cost solution being applied. The cost of curtailment is an outcome of both the magnitude of the coefficient (a multiplier which determines the unit's impact on the constraint) and the generator/load/interconnector's cost.

If two generators have the same SRMC, the generator with the higher LHS coefficient is curtailed first. If two generators have the same LHS coefficient, the generator with the higher SRMC is curtailed first.

N-0 generator coefficients

For an N-0 constraint, generator coefficients in a constraint equation are determined using Power Transfer Distribution Factors (PTDFs). The PTDF is a sensitivity measure of the power flow on a transmission element connecting bus j to bus k with respect to a generator injection at bus m. The coefficient for a generator connected at bus m can be calculated by differentiating the power flow across a monitored element connecting bus j to bus k with respect to the power injection at bus m, that is:

$$PTDF_{G_m,j\to k} = \frac{dF_{j\to k}}{dP_{G_m}}$$

Where P_{G_m} is the power injected by a generator at bus m and $F_{j\to k}$ is the power flow across the monitored element from bus j to bus k.

An underlying assumption that is inherently applied is that the RRN (location of the slack bus) will absorb any incremental injection at bus m. Therefore, the PTDFs can be viewed as the contribution of a small amount of power injection at bus m on the power flow across element connecting bus j to bus k to supply a small increase in demand at the RRN.

Generator coefficients defined this way will depend purely on the location of the RRN and the assumed system network topology provided by Transgrid. They will not be influenced by the regional demand or generation dispatch across the system.

N-0 interconnector coefficients

Similar to the calculation outlined in the previous section, interconnector coefficients are determined using PTDFs associated with power injection at the regional boundary buses. That is, the coefficient for an interconnector at the regional boundary bus n for a monitored element connecting bus j to bus k is defined as:

$$PTDF_{IC_n,j\to k} = \frac{dF_{j\to k}}{dP_{IC_n}}$$

Where P_{IC_n} is the interconnector power injection (positive for importing power and negative for exporting power) from neighbouring regions into bus n.

N-1 redistribution factor

N-1 constraints are designed to pre-contingently curtail generation to ensure that following a single credible contingency, the resulting power flows do not exceed thermal limits. When a transmission element is de-energised, the power flowing through the de-energised element redistributes across the remaining transmission elements. The proportion of power flow from a contingent element that flows through a monitored element is known as the redistribution factor. Redistribution factors can be approximated using Line Outage Distribution Factors (LODF). For a monitored network element connecting bus $\boldsymbol{j}$ to bus $\boldsymbol{k}$ and a contingent network element connecting bus $\boldsymbol{h}$ to bus $\boldsymbol{i}$, the LODF can be defined as:

$$LODF_{j\to k,h\to i} = \frac{\Delta F_{j\to k}}{F_{h\to i}} \; when \; F_{h\to i} \to 0$$

Where $F_{j\to k}$ is flow on the monitored element and $F_{h\to i}$ is flow on the contingent element.

N-1 generator and interconnector coefficients

With the definitions provided in above sections, we can define the coefficient for a generator at bus m in an N-1 constraint equation with a monitored network element connecting bus j to bus k following outage of a contingent network element connecting bus h to bus i as;

$$PTDF_{G_m,j\to k} + LODF_{j\to k,h\to i} \cdot PTDF_{G_m,h\to i}$$

Similarly, for interconnectors;

$$PTDF_{IC_n,j\to k} + LODF_{j\to k,h\to i} \cdot PTDF_{IC_n,h\to i}$$

Demand coefficients

Demand coefficients correspond to the contribution of regional demand towards the power flow on a monitored network element. To calculate the demand coefficient for a monitored network element connecting bus j to bus k, EY calculate the derivative of the power flow from bus j to bus k with respect to the regional *as generated* demand (as delivered demand plus system losses and auxiliary loads), denoted by D_r that is:

$$Coeff_{D_r,j\to k} = \frac{dF_{j\to k}}{dD_r}$$

This value can be approximated accurately by scaling the regional demand up by a small amount (less than 1 %) and dividing the difference in power flow by the difference in regional demand, that is:

$$Coeff_{D_r,j\to k} = \frac{F'_{j\to k} - F_{j\to k}}{D'_r - D_r} = \frac{\Delta F_{j\to k}}{\Delta D_r}$$

Where $F'_{j\to k}$ is the observed flow associated with the scaled demand, and D'_r is the scaled up demand.

The methodology described above assumes that the change in the regional demand is balanced by power injection at the RRN. Furthermore, since the demand is predominantly scaled up in proportion to the historical regional demand distribution, different demand distributions from different system operating states will still result in different demand coefficients.

Constant term

The constant term corresponds predominantly to the thermal line rating (in MW) of the monitored element, with an additional offset referred to as the $ConstantEx\ Rating$, that is:

$$Constant\ Term = Thermal\ Rating_{j\to k,MW} + ConstantEx\ Rating_{j-k}$$

Thermal line ratings are typically given in MVA. To convert MVA ratings to MW ratings, EY generally assumes a power factor (PF) of 0.95 (unless otherwise specified) and equates the MW ratings as:

$$Thermal\ Rating_{j\to k,MW} = PF \cdot Thermal\ Rating_{j\to k,MVA}$$

The $ConstantEx\ Rating$ value is required in addition to the thermal rating to take into account the difference in power flow between AC and DC solutions (since generator coefficients are calculated based on a DC load flow solution) and the contribution (equivalent PTDF) of all other generators with small coefficients which are not explicitly included in the constraint equation. This value is computed as the difference between the calculated flow across the monitored element based on generator and demand coefficients obtained and the actual AC power flow solution. For a system with *M* generator connection points and *N* interconnector boundaries, the $ConstantEx\ Rating$ value for the monitored element connecting bus j to bus k is calculated as:

$$
\begin{aligned}
ConstantEx\ Rating_{j-k} \quad = \quad & \sum_{m=1}^{M} P_{G_m} \cdot PTDF_{G_m,j\to k} \\
& + \sum_{n=1}^{N} P_{IC_n} \cdot PTDF_{IC_n,j\to k} \\
& + \sum_{r=1}^{R} D_r \cdot Coeff_{D_r,j\to k} \\
& - F_{j-k}
\end{aligned}
$$

Formulating a constraint equation

Having defined the key elements, a constraint equation is formulated with generation and interconnector terms on the LHS and constant and demand terms on the RHS as:

$$
\begin{aligned}
& \sum_{m=1}^{M} P_{G_m} \cdot \left(PTDF_{G_m,j\to k} + LODF_{j\to k,h\to i} \cdot PTDF_{G_m,h\to k}\right) & & Thermal\ Rating_{MW} \\
& + \sum_{n=1}^{N} P_{IC_n} \cdot \left(PTDF_{IC_n,j\to k} + LODF_{j\to k,h\to i} \cdot PTDF_{IC_n,h\to k}\right) \quad \le & & + \sum_{r=1}^{R} Coeff_{D_r,j\to k} \cdot D_r \\
& & & + ConstantEx\ Rating
\end{aligned}
$$

Further to this, AEMO has specified that in cases where the coefficient of a term on the LHS is relatively small then the risk of NEMDE choosing sub-optimal dispatch decisions may exist. To avoid such situations the following rule has been adopted:

LHS terms shall not have coefficients less than |0.07|. This can be achieved by:

- Scaling the constraint equation such that all coefficients for LHS terms are not less than 0.07 provided that the absolute value of largest coefficient of any LHS term does not then exceed 1. This is to ensure that the effective violation penalties of network constraint equations grade adequately with other constraints in the dispatch algorithm.

- If after scaling, terms with such small coefficients remain they are typically moved to the RHS. However, as the TSIRP is a time sequential model, generators and interconnectors terms cannot be modelled on the RHS of the constraint which uses the previous period dispatch. To overcome this, the modelling keeps them on the LHS. To avoid sub optimality, all lower than 0.001 coefficients are removed. If the previous dispatch interval was independent of the current dispatch interval, these terms could be moved to the RHS.

EY has adopted the above methodology as a final step in the formulation of constraint equations.

Appendix D Transmission and demand

Regional and zonal definitions

Transgrid requested to split NSW into sub-regions or zones in the modelling presented in this Report[27], as listed in Table 16. In addition, southern NSW and Victorian networks are modelled with higher resolution through several nodes and an overlayed DC power flow model in TSIRP. This network representation varies from that applied in 2022 ISP but in Transgrid's views, enables better representation of intra-regional network limitations and transmission losses in the relevant parts of the network.

Table 16: Regions, zones and reference nodes

Region	Zone	Zonal Reference Node
Queensland	Queensland (QLD)	South Pine 275 kV
NSW	Northern NSW (NNS)	Armidale 330 kV
	Central NSW (NCEN)	Sydney West 330 kV
	South-West NSW (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 borders of each zone or region are defined by the cut-sets listed in Table 17, as defined by Transgrid. Dynamic loss equations are defined between reference nodes across these cut-sets.

Table 17: 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

[27] TransGrid, July 2021, *HumeLink PACR market modelling*, Available at: https://www.transgrid.com.au/media/vqzdxwl3/humelink-pacr-ey-market-modelling-report.pdf. Accessed on 26 May 2023.

Border	Lines
NCEN- Canberra	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
Canberra/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
SWNSW-SA	New 330 kV double circuit from Buronga - Robertstown (after assumed commissioning of EnergyConnect)

Table 18 summarises the key cut-set limits in the Canberra zone and from Canberra to NCEN, as defined by Transgrid.

Table 18: Key cut-set limits (MW)

Options	Bidirectional limit (MW)
Snowy cut-set	3,080
Snowy cut-set + HumeLink lines	5,372
Canberra/Yass - Bannaby cut-set	4,900
Canberra-NCEN cut-set	4,500
Bannaby-NCEN	4,500

Interconnector and intra-connector loss models

Dynamic loss equations for the existing network are generally sourced from AEMO's *Regions and Marginal Loss Factors*[28]. New dynamic loss equations are computed for several conditions, including:

- when a new link is defined e.g., NNS-NCEN, SA-Buronga (EnergyConnect), Bannaby-NCEN,
- all the Victorian and southern NSW equivalenced lines between the modelled nodes, through their equivalent resistance, and
- when future upgrades involving conductor changes are modelled e.g., VNI West, QNI and Marinus Link.

The network snapshots to compute the loss equations were provided by Transgrid.

[28] AEMO, July 2018, *Marginal Loss Factors for the 2018-19 Financial Year*. Available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries. Accessed on 26 May 2022.

Interconnector and intra-connector capabilities

The notional limits imposed on interconnectors are shown in Table 19. The following interconnectors are included in the left-hand side of constraint equations 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 across the two links to minimise costs.

Table 19: Notional interconnector capabilities used in the modelling (sourced from AEMO 2022 ISP[21])

Interconnector (From node – To node)	Import[29] notional limit	Export[30] notional limit
QNI[31]	1,205 MW peak demand 1,165 MW summer 1,170 MW winter	685 MW peak demand 745 MW summer/winter
QNI Connect 1[32]	2,285 MW peak demand 2,245 MW summer 2,250 MW winter	1,595 MW peak demand 1,655 MW summer/winter
QNI Connect 2[32]	3,085 MW peak demand 3,045 MW summer 3,050 MW winter	2,145 MW peak demand 2,205 MW summer/winter
Terranora (NNS-SQ)	130 MW peak demand 150 MW summer 200 MW winter	0 MW peak demand 50 MW summer/winter
EnergyConnect (Buronga-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
Marinus Link (TAS-VIC)	750 MW for the first stage and 1,500 MW after the second stage	750 MW for the first leg and 1,500 MW after the second leg
VNI West	Original limits: 400 MW all periods After VNI West: SIPS Contract Implemented: 2,200 MW all periods SIPS Contract ended: 2,050 MW peak demand 2,200 MW summer peak 2,200 MW winter peak	Original limits: 870 MW peak demand 1,000 MW summer peak 1,000 MW winter peak After VNI West: 2,800 MW peak demand 2,930 MW summer peak 2,930 MW winter peak

[29] 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 southward flow and import along Heywood and EnergyConnect implies eastward flow.

[30] 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 northward flow and export along Heywood and EnergyConnect implies westward flow.

[31] Flow on QNI may be limited due to additional constraints.

[32] AEMO, December 2021. *Appendix 5: Network Investments (Appendix to Draft 2022 ISP for the National Electricity market)*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/2022-draft-isp-consultation. Accessed on 26 May 2022.

NSW has been split into zones with the following limits imposed between the zones defined in Table 20.

Table 20: Intra-connector notional limits imposed in modelling for NSW

Intra-connector (From node – To node)	Import notional limit	Export notional limit
NCEN-NNS	1,177 MW (after QNI Minor) Limit will increase after NEW England REZ augmentations as mentioned in the Draft 2022 ISP[3].	1,377 MW (after QNI Minor) Limit will increase after NEW England REZ augmentations as mentioned in the Draft 2022 ISP[3].
WAG-SWNSW (provided by Transgrid)	300 MW (before EnergyConnect) 1,100 MW (after EnergyConnect) 1,900 MW (after HumeLink with PEC Enhanced) 3,000 MW (after VNI West)	500 MW (before EnergyConnect) 1,300 MW (after EnergyConnect) 2,100 MW (after HumeLink, with PEC Enhanced) 2,700 MW (after VNI West)

Demand

The TSIRP model captures operational demand (energy consumption which is net of rooftop PV and other non-scheduled generation) 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 and historical data for other non-scheduled generation,
- 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 Table 21.
- 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, domestic battery and other small non-scheduled generation) to get a projection of hourly operational demand.

Table 21: Sequence of demand reference years applied to forecast

Modelled year	Reference year
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

Modelled year	Reference year
2032-33	2014-15
2033-34	2015-16
2034-35	2016-17
2035-36	2017-18
2036-37	2018-19
…	…
2043-44	2016-17
2044-45	2017-18
2045-46	2018-19
2046-47	2010-11
2047-48	2011-12
2048-49	2012-13
2049-50	2013-14

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 distributed 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 and hydro inflows. This maintains correlations between weather patterns, demand, wind, large-scale solar and distributed PV availability.

Transgrid selected demand forecasts from the ESOO 2021[33]consistent with the relevant scenarios in the ISP 2022[21] which are used as inputs to the modelling. Figure 53 and Figure 54 show the NEM operational energy and distributed PV (rooftop PV and small-scale non-scheduled PV) for the modelled scenarios.

[33] AEMO, National Electricity and Gas Forecast, http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational. Accessed on 26 May 2023.

Figure 53: Annual operational demand in the modelled scenarios for the NEM[33]

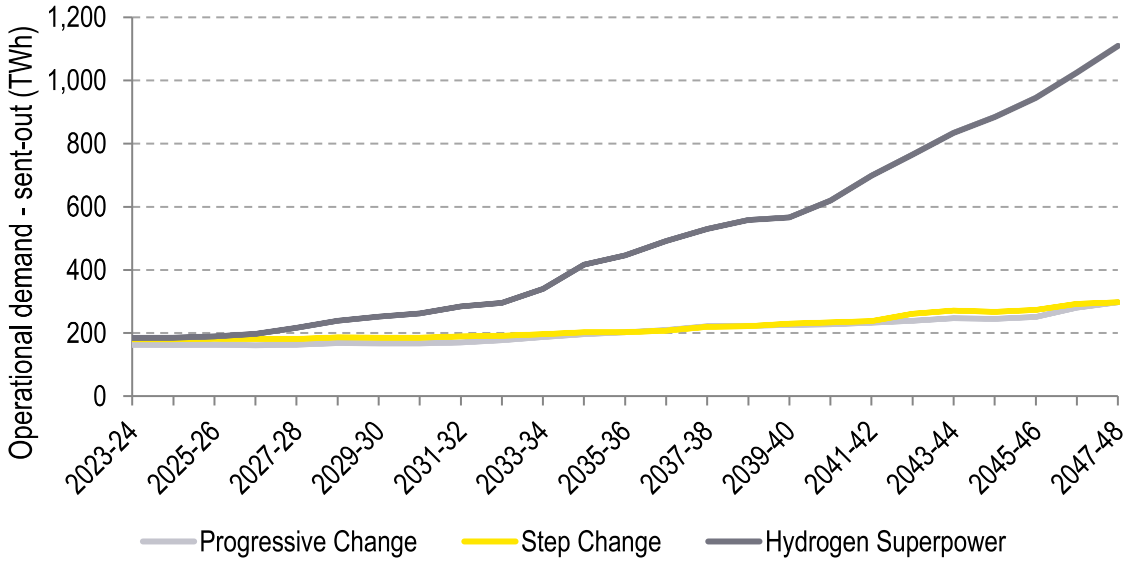
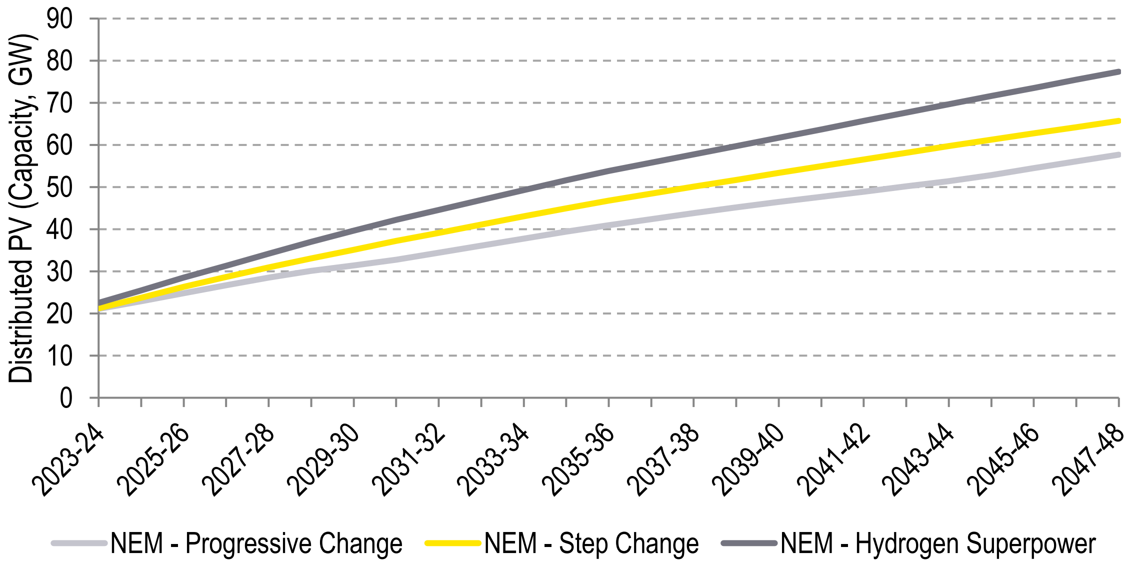


Figure 54: Annual distributed PV (rooftop PV and small non-scheduled PV) uptake in the NEM[33]



The ESOO 2021 demand forecasts for NSW and Victoria are split into the corresponding zones/nodes that have been defined. 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 these regions.

Appendix E Supply

Wind and solar energy projects and REZ representation

Several generators not yet built are committed in all simulations, including the Base Case and each option. The source of this list is the AEMO 2021 ISP Inputs and Assumptions workbook[21], existing, committed and anticipated projects with updates based on new information since the publication of 2022 ISP[3].

Existing and new wind and solar projects are modelled based on nine years of historical weather data[34]. The methodology for each category of wind and solar project is summarised in Table 22 and explained further in this section of the Report.

Table 22: 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[35] 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	Reference year specific targets based on capacity factor of nearest REZ, medium quality tranche in AEMO's 2021 ISP Inputs and Assumptions workbook[21].	
	Generic REZ new entrants	Reference year specific targets based on AEMO 2021 ISP Inputs and Assumptions workbook[21]. One high quality option and one medium quality trace per REZ.	
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	Reference year specific targets based on capacity factor of nearest REZ, in AEMO's 2021 ISP Inputs and Assumptions workbook[21].	
	Generic REZ new entrant	Reference year specific targets based on AEMO 2021 ISP Inputs and Assumptions workbook[21].	
Rooftop PV and small non-scheduled solar PV	Existing and new entrant	Long-term average capacity factor based on AEMO 2021 ISP Inputs and Assumptions workbook[21].	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

[34] 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 on 26 May 2023.

[35] AEMO, *2019 Electricity Statement of Opportunities: 2019 Wind Traces* and *2019 Solar Traces*. Available at: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo Accessed on 26 May 2023.

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 Table 21.

The availability profiles for wind generation are derived from simulated wind speeds from the Australian Bureau of Meteorology's Numerical Weather Prediction systems[36] 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 draft 2021 ISP inputs and assumptions[21] for each REZ (new entrant wind farms, as listed in Table 23).

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 target AEMO's capacity factor for each REZ (generic new entrant solar farms as listed in Table 23).

Table 23: Assumed REZ wind and solar average capacity factors over the nine modelled reference years[21]

Region	REZ	Wind		Solar SAT
		High quality	Medium quality	
Queensland	Far North Queensland	55%	48%	27%
	North Queensland Clean Energy Hub	44%	37%	30%
	Northern Queensland	Tech not available	Tech not available	28%
	Isaac	37%	32%	28%
	Barcaldine	34%	31%	32%
	Fitzroy	38%	33%	28%
	Wide Bay	32%	31%	26%
	Darling Downs	39%	34%	27%
	Banana	31%	28%	29%
NSW	North West NSW	Tech not available	Tech not available	29%
	New England	39%	38%	26%
	Central West Orana	37%	34%	27%
	Broken Hill	33%	31%	30%
	South West NSW	30%	30%	27%
	Wagga Wagga	28%	27%	26%
	Cooma-Monaro	43%	40%	Tech not available
Victoria	Ovens Murray	Tech not available	Tech not available	24%
	Murray River	Tech not available	Tech not available	27%

[36] 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 on 26 May 2023.

Region	REZ	Wind		Solar SAT
		High quality	Medium quality	
	Western Victoria	41%	37%	23%
	South West Victoria	41%	39%	Tech not available
	Gippsland[37]	39%	34%	20%
	Central North Victoria	33%	31%	26%
South Australia	South East SA	39%	37%	23%
	Riverland	29%	28%	27%
	Mid-North SA	39%	37%	26%
	Yorke Peninsula	37%	36%	Tech not available
	Northern SA	37%	35%	28%
	Leigh Creek	41%	39%	30%
	Roxby Downs	Tech not available	Tech not available	30%
	Eastern Eyre Peninsula	40%	38%	24%
	Western Eyre Peninsula	39%	38%	27%
Tasmania	North East Tasmania	45%	43%	22%
	North West Tasmania[38]	50%	46%	19%
	Central Highlands	56%	54%	20%

Wind and solar capacity expansion in each REZ is limited by four parameters based on AEMO's 2021 Inputs and Assumptions workbook[21].

- Transmission-limited total build limit (MW) representing the amount of dispatch supported by current intra-regional transmission infrastructure.
- A transmission expansion cost ($/MW) representing an indicative linear network expansion cost to develop a REZ beyond current capabilities and connect the REZ to the nearest major load centre.
- Resource limits (MW) representing the maximum amount of capacity expected to be feasibly developed in a REZ based on topography, land use etc at the given capex.
- A resource limit violation penalty factor ($/MW) to build additional capacity beyond the resource limit. This represents additional capex to build on sites with higher land costs.

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.

Generator 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 on the AEMO 2021 Inputs and Assumptions workbook[21].

[37] Gippsland has an option for Offshore wind with an average capacity factor of 46%.
[38] North West Tasmania has an option for Offshore wind with an average capacity factor of 50%.

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 2021 Inputs and Assumptions workbook[10].

Generator technical parameters

Technical generator parameters applied are as detailed in the AEMO 2021 Inputs and Assumptions workbook[10] for AEMO's long-term planning model, except as noted in the Report.

Coal-fired generators

Coal-fired generators are 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 2021 Inputs and Assumptions workbook[10]. 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 2021 Inputs and Assumptions workbook[10].

Gas-fired generators

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

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.

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.

Storage-limited generators

Conventional hydro with storages, PHES 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 2021 Inputs and Assumptions workbook and the median hydro climate factor trajectory for the respective scenario applied[10]. The Tasmanian hydro schemes were modelled using a ten-pond model, with additional information sourced from the TasNetworks Input assumptions and scenario workbook for Project Marinus Project Assessment Conclusions Report (PACR)[39].

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[39] TasNetworks, June 2021, *Input assumptions and scenario workbook for Project Marinus PACR*. Available at https://www.marinuslink.com.au/rit-t-process/. Accessed on 26 May 2022

Appendix F Glossary of terms

Abbreviation	Meaning
AC	Alternating Current
AEMO	Australian Energy Market Operator
AER	Australia Energy Regulator
$b	Billion dollars
BOP	Bathurst, Orange and Parkes
BESS	Battery Energy Storage System
Capex	Capital Expenditure
CDP	Candidate Development Path
CO_2	Carbon Dioxide
CCGT	Combined-Cycle Gas Turbine
DC	Direct Current
DCLF	Direct Current Load Flow
DSP	Demand Side Participation
ESOO	Electricity Statement of Opportunities
FFP	Fixed Flat Plate
FOM	Fixed Operation and Maintenance
GW	Gigawatt
GWh	Gigawatt-hour
ISP	Integrated System Plan
$m	Million dollars
Mt	Mega Ton
MW	Megawatt
MWh	Megawatt-hour
NCEN	Central New South Wales (NEM zone)
NEM	National Electricity Market
NNS	Northern New South Wales (NEM zone)
NSW	New South Wales
OCGT	Open-Cycle Gas Turbine
PACR	Project Assessment Conclusion Report
PADR	Project Assessment Draft Report
PFC	Power Flow Controller

Abbreviation	Meaning
PHES	Pumped Hydro Energy Storage
PV	Photovoltaic
QLD	Queensland
QNI	Queensland-New South Wales interconnector
QRET	Queensland Renewable Energy Target
REZ	Renewable Energy Zone
RIT-T	Regulatory Investment Test for Transmission
SA	South Australia
SAT	Single Axis Tracking
SRMC	Short-Run Marginal Cost
SWNSW	South West New South Wales (NEM zone)
TAS	Tasmania
TRET	Tasmanian Renewable Energy Target
TSIRP	Time-sequential integrated resource planner
TW	Terawatt
TWh	Terawatt-hour
USE	Unserved Energy
VCR	Value of Customer Reliability
VIC	Victoria
VNI	Victoria-New South Wales Interconnector
VOM	Variable Operation and Maintenance
VRET	Victorian Renewable Energy Target
VPP	Virtual Power Plant
VTL	Virtual Transmission Line

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