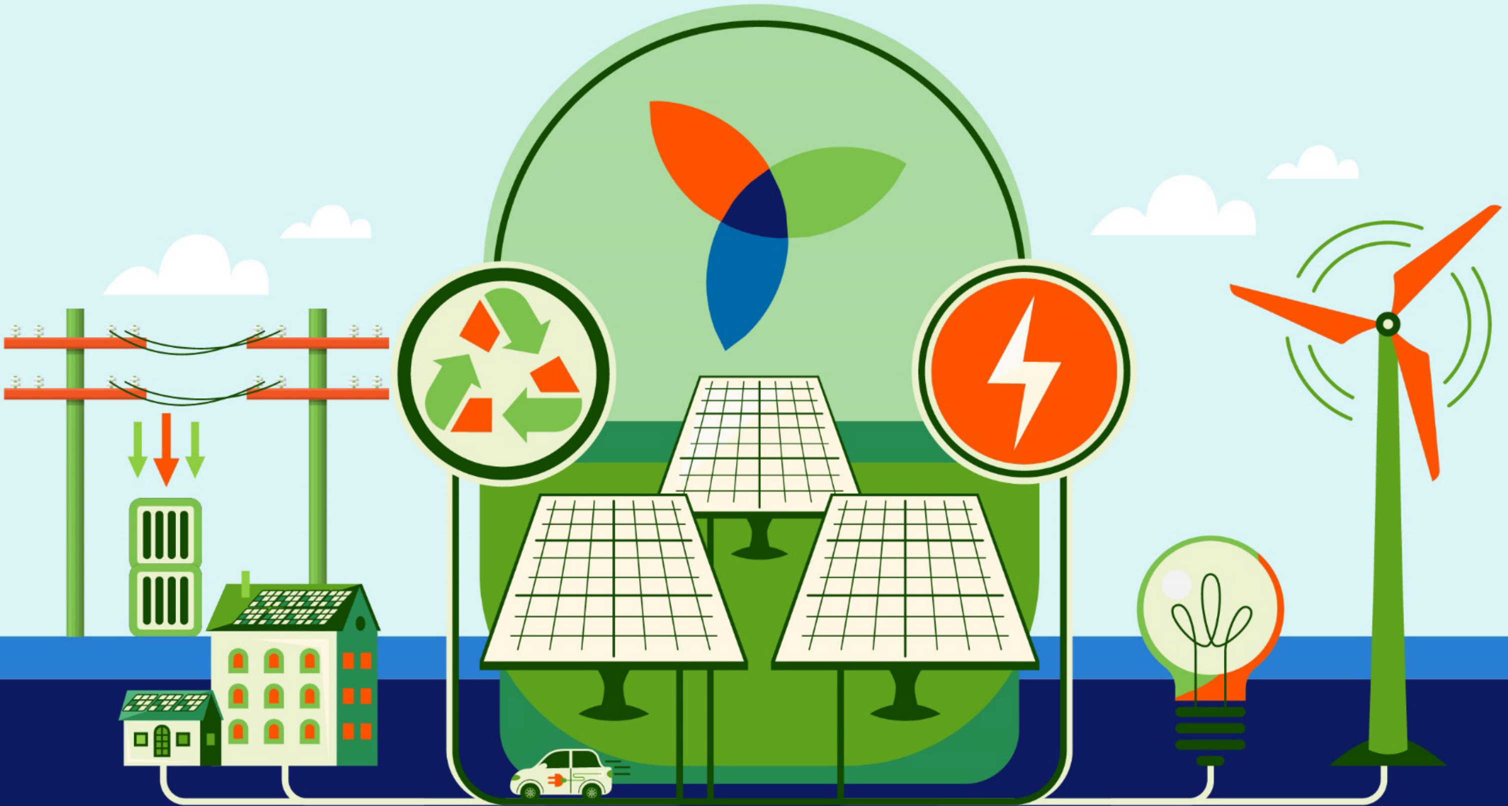
Ausgrid

Endeavour Energy

Essential Energy

Distribution System Plan

Appendices



November 2025

Contents

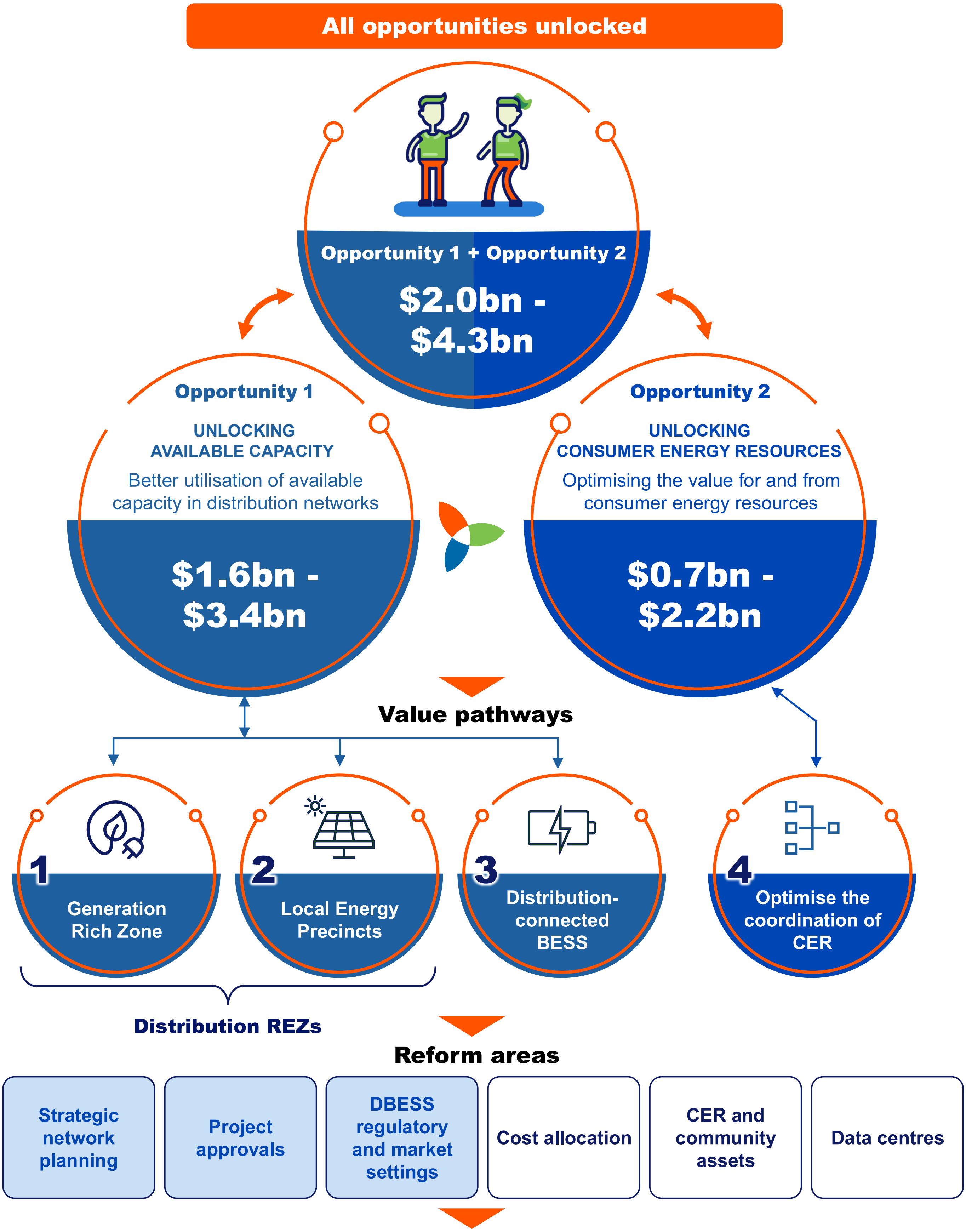
Version control

Version	Release date	Changes
1.0	17/11/2025	Initial release
1.1	21/11/2025	Updated description of results in Section G.6.2.

Appendix A: Integrated methodology

The integrated methodology considered within this project is outlined in Figure A1.

Figure A1: Integrated methodology for DSP Opportunities Report



Calls to action

Reform Area 1: Strategic system planning

- Enable bottom-up Distribution Network System Provider (DNSP) led strategic planning
- NSW system planner to co-optimise across distribution and transmission, informed by individual DNSP plans

Reform Area 2: Project approvals

- Align approval pathway to New South Wales (NSW) integrated system plan
- Improve the ability to invest in anticipatory projects by extending the time horizon over which demand is considered under the National Electricity Rules (NER)
- Develop fit-for-purpose appraisal framework suited to capturing and assessing the complexities of the distribution network under the *Electricity Infrastructure Investment Act*
- Introduce changes to NER uncertainty mechanisms to allow for more flexible application, as well as the potential introduction of new mechanisms to allow for new load connections within period

Reform Area 3: DBESS regulatory and market settings

- Address inequities in Transmission Use of System charges for large distribution-connected Battery Energy Storage Systems (DBESS)
- Align treatment of NSW Roadmap charges for DBESS connections with transmission-connected counterparts

The DSP Opportunities Report models two distribution network opportunities across three future scenarios (**Appendix B**).

Distribution network impacts are modelled via the techno-economic model (**Appendix C** and **Appendix D**), and wholesale market impacts are modelled in PLEXOS (**Appendix E**).

The modelling outcomes inform the economic analysis of distribution network opportunities and quantification of the 'size of the prize' (**Appendix F**)

The modelling demonstrates the value of utility-scale generation and storage connected to the distribution network, co-location of generation and load, DBESS and coordination of Consumer Energy Resources (CER). To unlock this value, the Distribution System Plan (DSP) Opportunities Report focuses on four headline value pathways (**Section 5**). The case for greater CER coordination is supported by Energy Behavioural Demand Modelling (**Appendix G**).

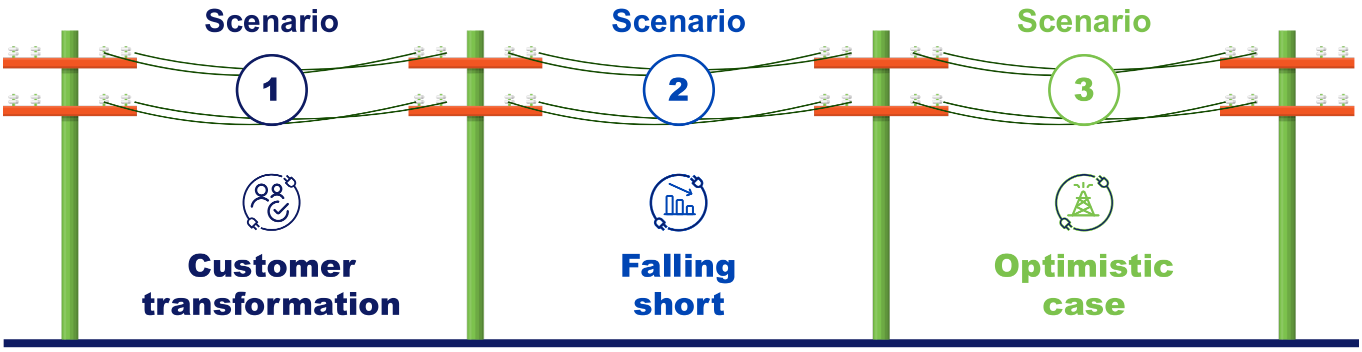
However, to unlock these value pathways, there are barriers that need to be addressed. These barriers are assessed under six reform areas (**Section 6**). Targeted calls to action are proposed for the first three reform areas, while the remaining areas are identified as requiring further consideration to fully realise the value of distribution network opportunities.

Appendix B: Scenarios and opportunities

B.1 Scenario development

To explore how the benefits of each opportunity might vary under different uncertain future conditions, three scenarios have been developed reflecting varying levels of decarbonisation ambition, customer behaviour, and infrastructure delivery. Figure B1 outlines the three scenarios considered in the modelling.

Figure B1: Summary of modelled scenarios



This scenario represents a future where decarbonisation progresses rapidly, driven by high levels of customer and societal behavioural change. Customers adopt new technologies including EVs, rooftop PV and electrified appliances quicker and more extensively. Despite this, there are delays to transmission projects and constraints on the annual generation build limits for utility-scale projects, reflecting ongoing challenges in infrastructure delivery at the transmission-level.	This scenario reflects a future where decarbonisation progresses slowly and there is lower societal and customer appetite for behavioural change. Technology adoption is slower, leading to more gradual electrification. At the same time, further challenges are encountered at the transmission-level, with increased delays to transmission projects and tighter constraints on annual generation build limits.	This scenario broadly mirrors Customer transformation, but supply-side assumptions align with AEMO's Step Change scenario with ideal infrastructure delivery, e.g., no delays to transmission build out or annual generation build limits. It assumes stronger policy support, effective coordination and smooth delivery of the optimal development path

A high-level summary of the demand and supply assumptions in NSW and rest of National Electricity Market (NEM) are provided in Table B1. Further detail is provided in the following sections.

Table B1: Demand and supply assumptions in each scenario

Data item	Component	*Customer transformation*	*Falling short*	*Optimistic case*
Demand – NSW	Mass market		DNSP forecast	
	Data centres	DNSP forecast	Electricity Statement of Opportunities (ESOO) 2025 Step Change	DNSP forecast
	Electric vehicles and non-transport electrification	DNSP forecast	ESOO 2024 Progressive Change	DNSP forecast
	Behind-the-meter (BTM) batteries		DNSP forecast	
	Rooftop & mid-scale solar		DNSP forecast	
	Hydrogen		Not included due to recent industry movement	
Demand – Rest of NEM	Mass market		ESOO 2024 Central	
	Data centres		ESOO 2024 Central	
	Electric vehicles and non-transport electrification	ESOO 2024 Central	ESOO 2024 Progressive Change	ESOO 2024 Central
	BTM batteries		ESOO 2024 Central	
	Rooftop & mid-scale solar		ESOO 2024 Central	
	Hydrogen		Not included due to recent industry movement	
Supply – NSW	Utility-scale wind build limits	1.5 GW/year, alleviating by 500 MW from FY 2030	0.5 GW/year, alleviating by 250 MW from FY 2030	No limit
	Utility-scale solar build limits	No limit	1 GW/year, alleviating by 500 MW from FY 2030	No limit
	Transmission development		Refer to Appendix B.1.2	
Supply – Rest of NEM	Utility-scale wind build limits	2.5 GW/year, alleviating by 500 MW from FY 2030	1.5 GW/year, alleviating by 250 MW from FY 2030	No limit
	Utility-scale solar build limits	No limit	3 GW/year, alleviating by 500 MW from FY 2030	No limit
	Transmission development		2024 Integrated System Plan (ISP) Optimal Development Path (ODP)	

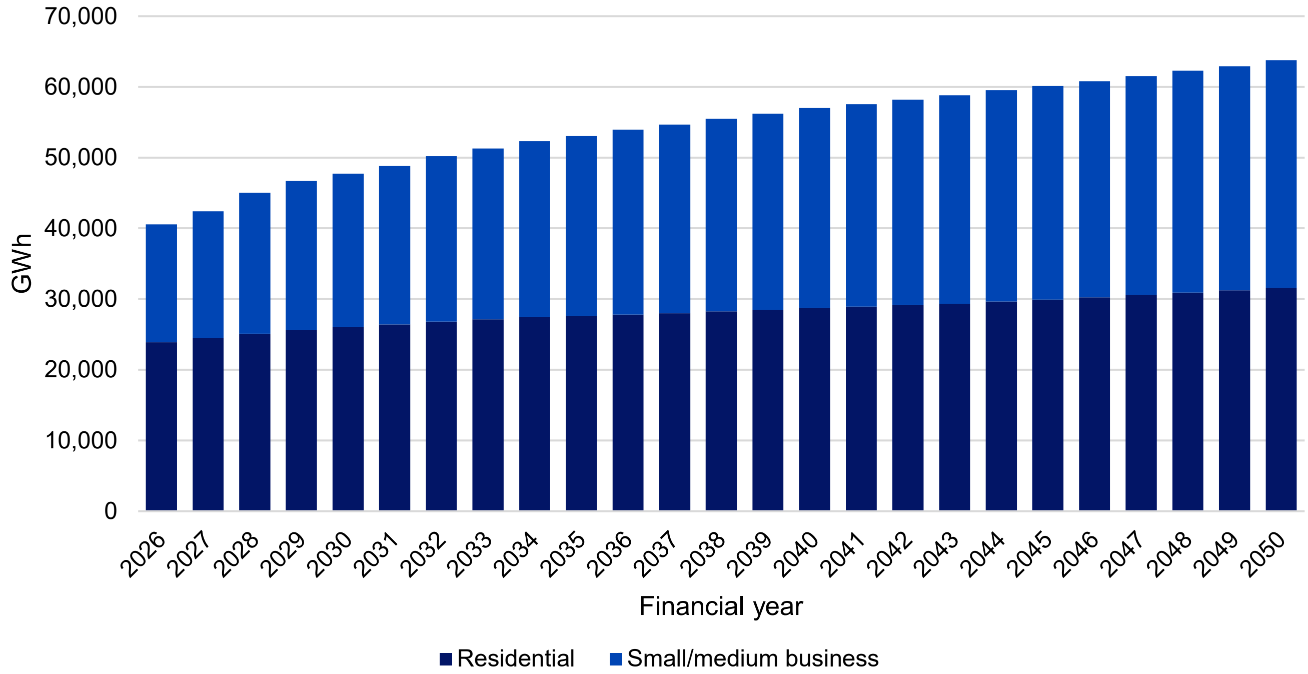
B.1.1 Demand forecasts in NSW

Demand forecast inputs for NSW are provided by the each of the DNSPs. This section outlines the breakdown of each DNSP's consumption forecast by demand component.

B.1.1.1 Mass market and non-transport electrification

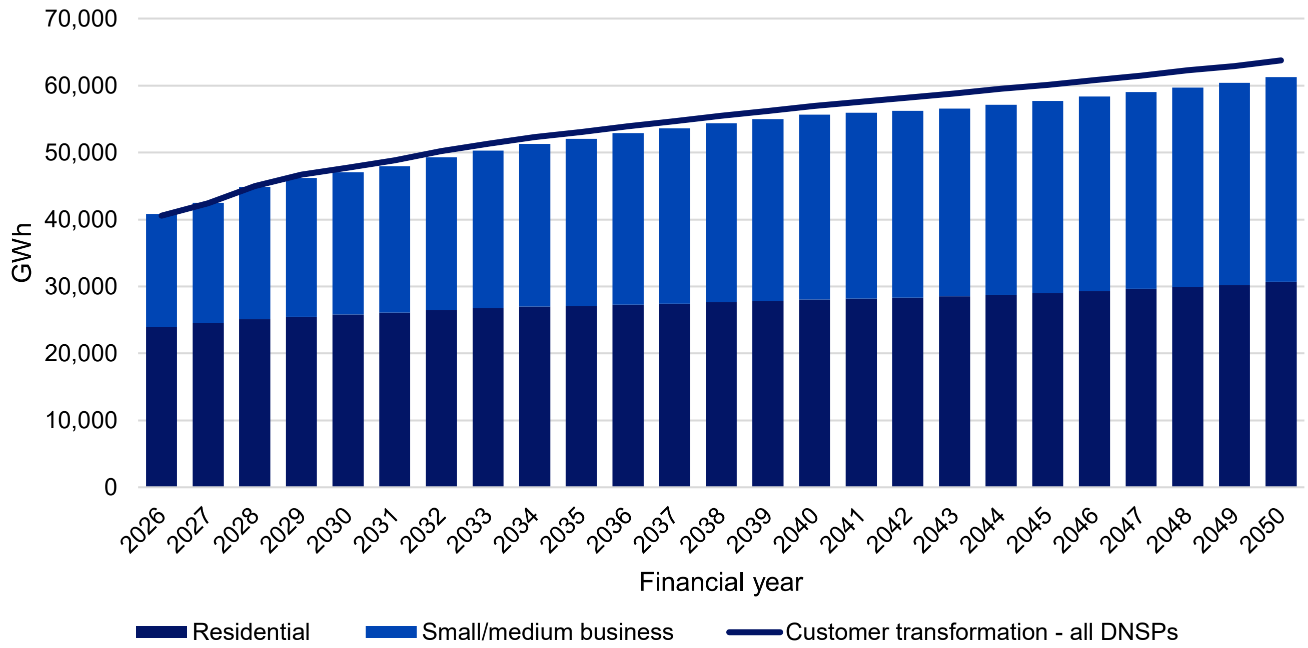
Mass-market consumption, broken down by residential and business load, including the impact of non-transport electrification through electrification of heating, cooking and large industrial enterprises was provided by each DNSP. The resulting load, including that met by self-consumed solar generation in the distribution network, increases from approximately 40 TWh in FY2026 to approximately 65 TWh in FY2050, before considering the impact of electric vehicle (EV) uptake in the *Customer transformation* and *Optimistic case* scenarios as shown in Figure B2.

Figure B2: Distribution connected residential and small/medium enterprise underlying consumption (excluding EVs) - Customer transformation and Optimistic case



In the *Falling short* scenario, the non-transport electrification load is moderated to the levels projected by the Australian Energy Market Operator's (AEMO's) ESOO 2024 Progressive Change scenario, resulting in a reduction in NSW load by approximately 2 TWh. This is shown in Figure B3.

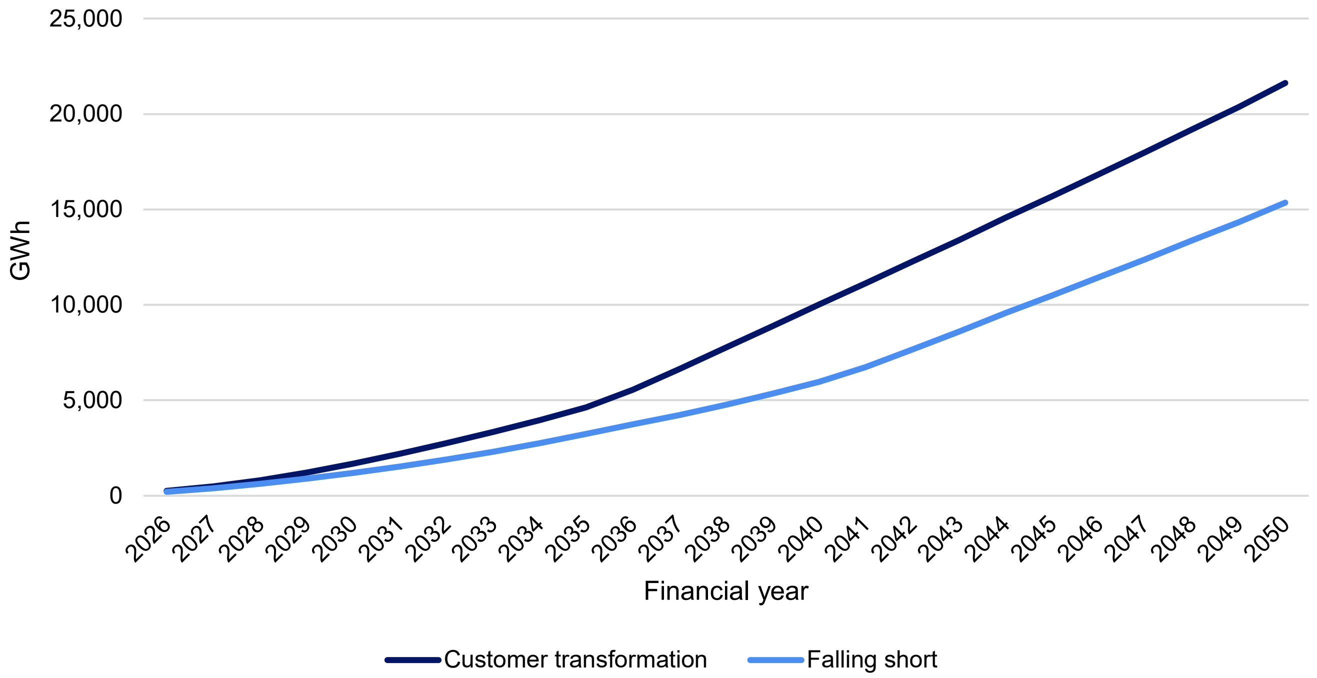
Figure B3: Distribution connected residential and small/medium enterprise underlying consumption (excluding EVs) - Falling short



B.1.1.2 Electric vehicles

EV uptake is expected to continue growing in the future. Across the DNSPs consumption steadily trends upwards, moving from 1.7 TWh in FY2030 to 21 TWh in FY2050 in the *Customer transformation* and *Optimistic case* scenarios. In the *Falling short* scenario, EV uptake is subdued to the levels projected by AEMO's ESOO 2024 Progressive Change forecast, resulting in 6.3 TWh less demand relative to *Customer transformation* and *Optimistic case* scenarios by FY2050, as shown in Figure B4.

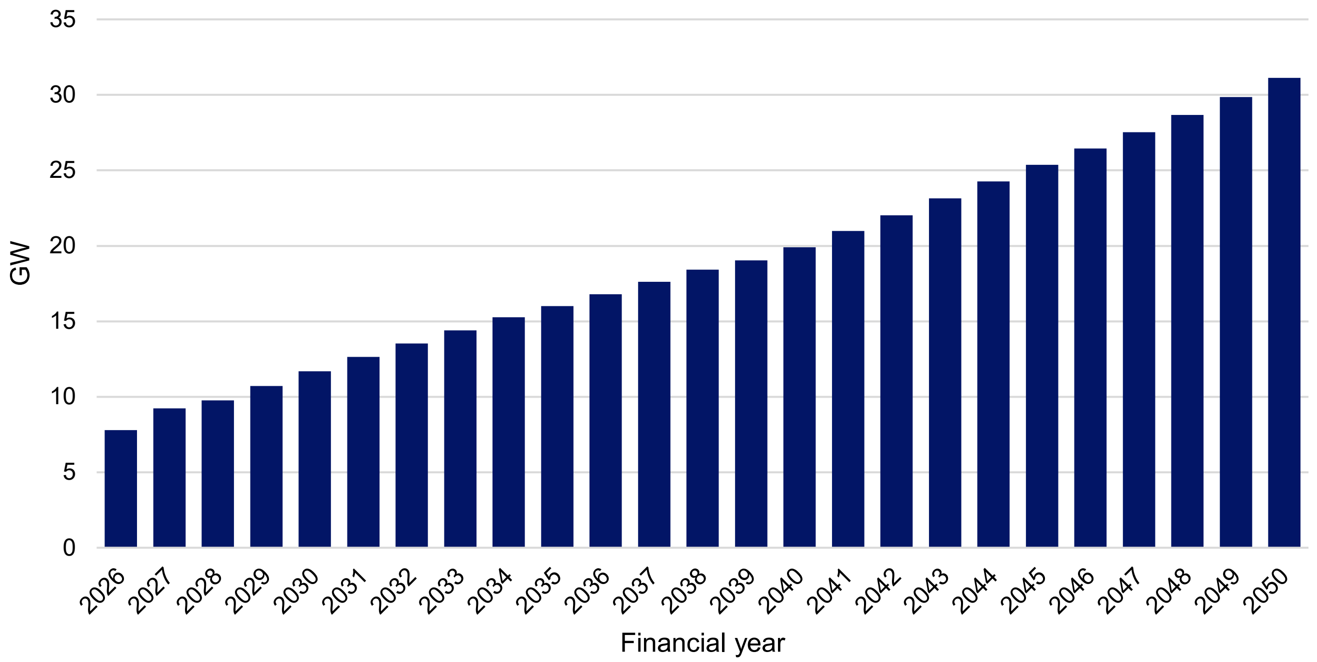
Figure B4: Comparison of EV load consumption in Customer transformation and Falling short scenarios



B.1.1.3 Rooftop and mid-scale solar

Rooftop and mid-scale PV systems are expected to see continued strong growth across NSW, supported by government incentives and increasing customer recognition of their potential to reduce energy costs. This forecast growth across all DNSPs, from around 8 GW in FY2026 to over 30 GW in FY2050, is shown in Figure B5.

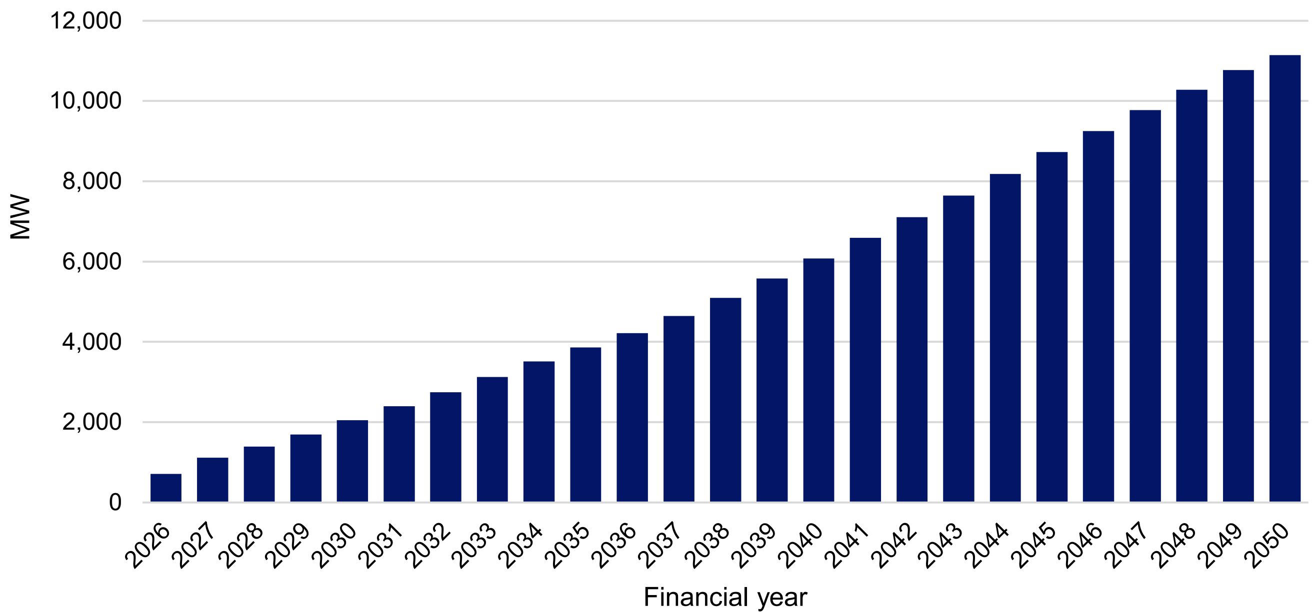
Figure B5: Rooftop PV and mid-scale solar capacity in all scenarios



B.1.1.4 BTM batteries

Supportive government policies and the widespread adoption of rooftop PV is also expected to rapidly increase the uptake of BTM Battery Energy Storage Systems (BESS), growing from approximately 700 MW in FY2026 to approximately 11,000 MW by FY2050, as shown in Figure B6.

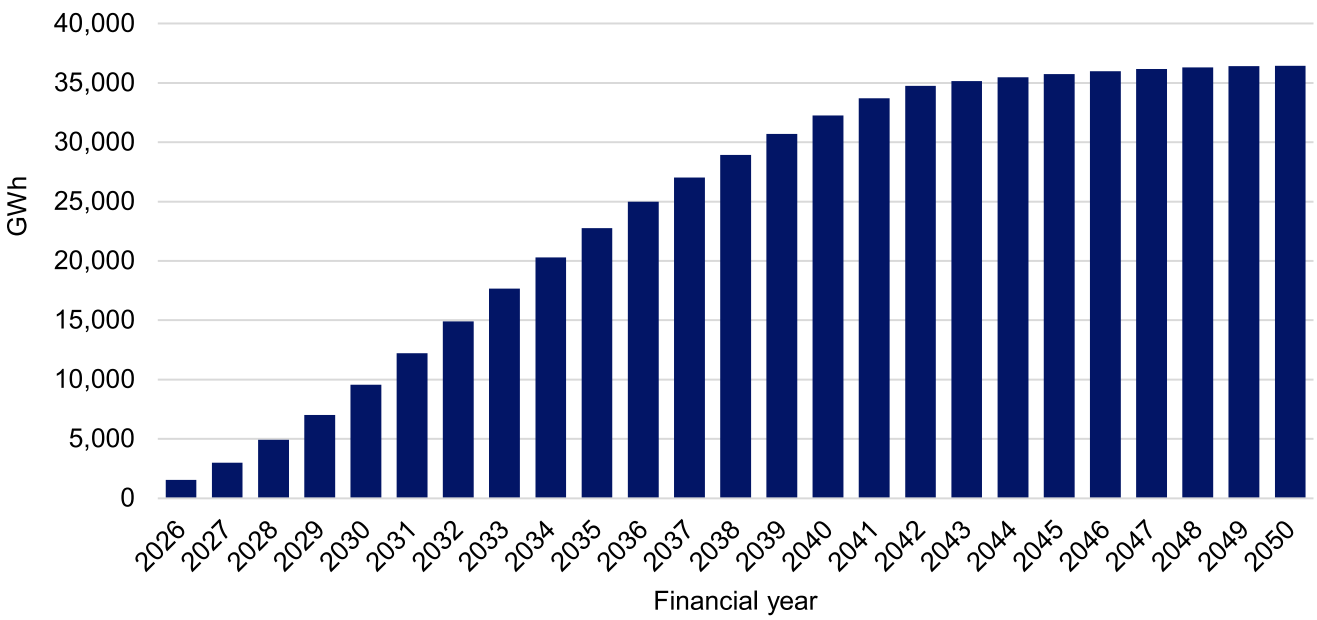
Figure B6: BTM battery uptake in all scenarios



B.1.1.5 Data centres

NSW data centre load in the *Customer transformation* and *Optimistic case* scenarios is based on DNSP forecasts, derived using a probability weighted estimate of expected growth using current connection enquiries. To ensure that only highly likely projects are included, the data centre load forecast only includes connection requests before and up to 2030 that are likely to proceed. A 'ramping profile' that linearly increases data centre load after entry is also included such that the data centre load reaches its full capacity well into the late 2030s. While data centres often have BTM resources that can provide flexibility, their operational models place a premium on energy reliability. As such, the modelling assumes a flat data centre load in the absence of a more consistent and considerate approach across the NEM, noting that further work is required to establish the operating profile of data centres to enhance forecasting. The DNSP's data centre load forecast is significantly higher than the Australian Energy Market Operator (AEMO) ESOO 2024 Central forecast (which has only a small amount of data centre load uptake). The data centre load for *Customer transformation* and *Optimistic case* scenarios is shown in Figure B7.

Figure B7: Data centre load in Customer transformation and Optimistic case



In the *Falling short* scenario, the data centre load is halved, which is comparable to AEMO's ESOO 2025 Central forecast in the long term.

B.1.1.6 NSW operational demand

This section shows the impact of the above individual demand components on NSW operational demand, which is the demand met by the transmission-connected generation fleet, and is critical to the operation and cost of the wholesale market.

The DNSP's forecasts for the *Customer transformation* and *Optimistic case* scenarios result in a higher level of consumption than AEMO's ESOO Central (i.e. Step Change) scenario, reflecting the networks' internal views on load growth, including data centres. NSW demand in the *Falling short* scenario is comparable to the 2025 ESOO Central forecast due to lower electrification and data centre growth. The modelling for this project also excludes any hydrogen load.

Figure B8 and Figure B9 show the breakdown of total modelled across the scenarios, compared to AEMO's ESOO 2024 and 2025 Central forecasts.

Figure B8: NSW operational demand (excluding hydrogen) – Customer transformation and Optimistic case

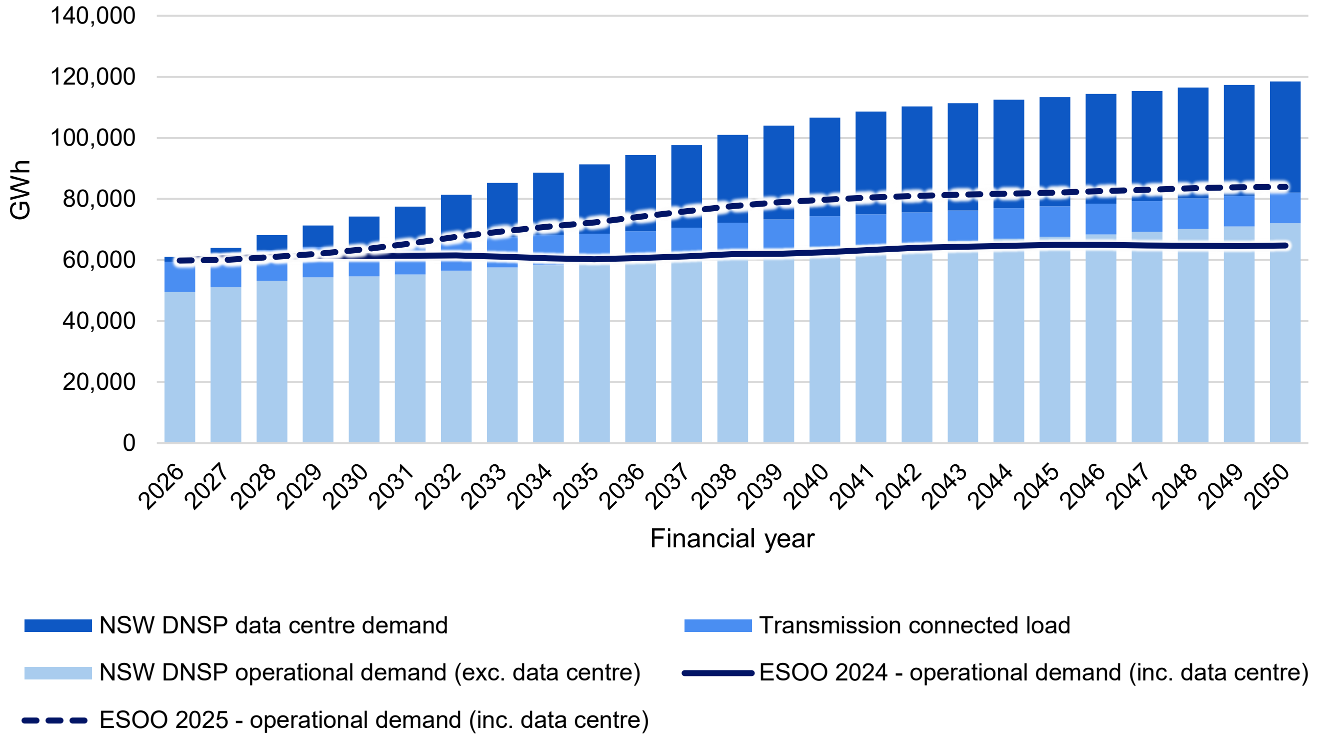
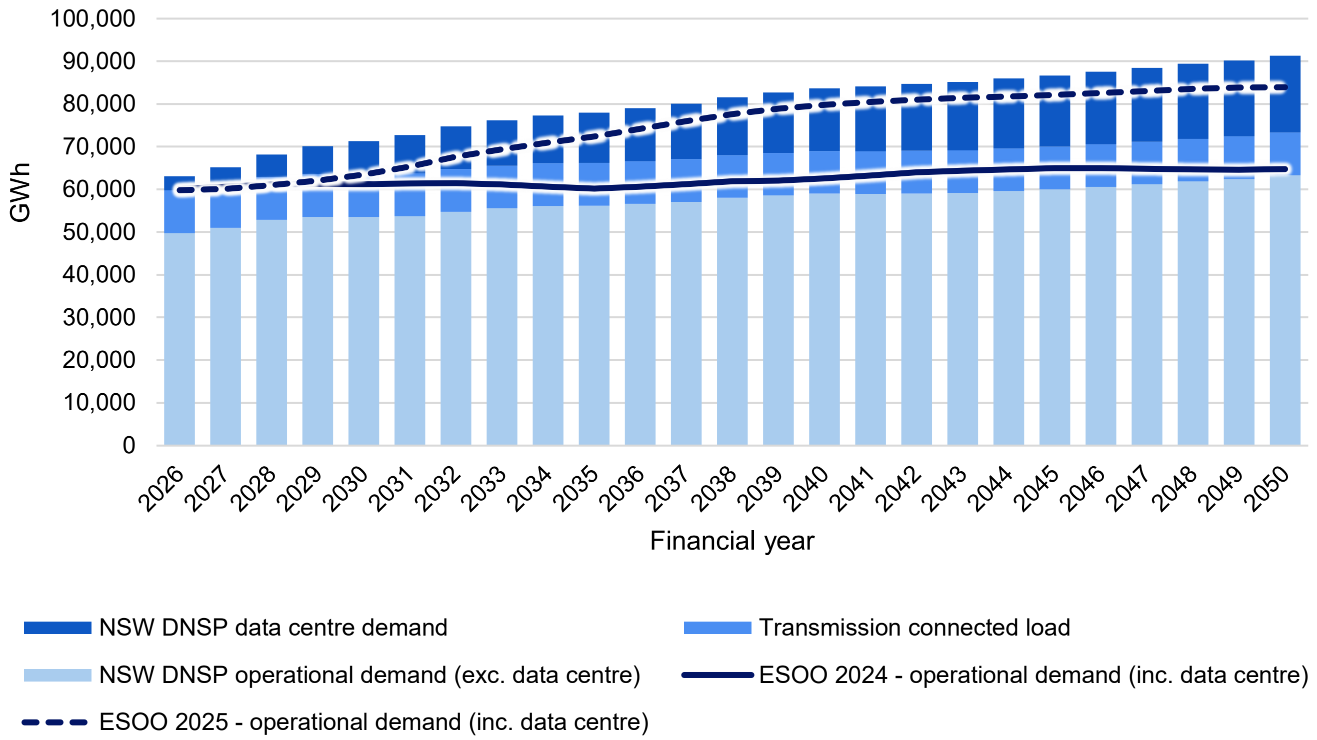


Figure B9: NSW operational demand (excluding hydrogen) – Falling short



B.1.2 Committed and anticipated transmission timing

The NSW transmission projects outlined in Table B2 are assumed to be commissioned as a fixed input in the wholesale market modelling. The *Optimistic case* scenario assumes they proceed according to the timing outlined in the 2024 ISP ODP. The *Customer transformation* and *Falling short* scenarios assume some projects will be delayed to reflect the current challenges for transmission investment. These timing assumptions are summarised in Table B2.

Table B2: Timing of committed and anticipated transmission projects

Project	2024 ISP	Customer transformation	Falling short	Optimistic case
Central West Orana (CWO) Renewable Energy Zone (REZ) – Stage 1	2028	2028	2028	2028
Project Energy Connect	2027 full commissioning	2027 full commissioning	2027 full commissioning	2027 full commissioning
Sydney Ring North	2029	2031	2032	2029
Sydney Ring South	2030	2032	2033	2030
Hunter Central Cost REZ	2031	2031	2031	2031
Queensland-NSW Interconnector	2035	2035	2035	2035

The New England REZ and the second stage of CWO REZ are not assumed as a fixed input for this modelling to test the impact of using distribution hosting capacity on transmission REZ investment. As a result, the model re-optimises the timing and size of these transmission projects in each modelled scenario and opportunity.

B.1.3 Utility-scale annual generation entry limits

To reflect the growing supply chain pressures and social licence issues impacting renewable energy projects, the modelling applies annual entry limits on wind and solar generation. For wind, the entry limit applies to both transmission and distribution-connected projects. Note that solar uptake in distribution REZs are not constrained due to the relatively low social licence impact. These limits are summarised Table B3.

Table B3: Utility-scale wind and solar annual generation entry limits by scenario

Project	*Customer transformation*	*Falling short*	*Optimistic case*
Wind	**NEM**: 2.5 GW/year to FY2030 **NSW**: 1.5 GW/year to FY2030 Limit relaxed 500 MW/year beyond FY2030	**NEM**: 2.5 GW/year to FY2030. **NSW**: 0.5 GW/year to FY2030. Limit relaxed 250 MW/year beyond FY2030	No limit
Solar	No limit	**NEM**: 3 GW/year to FY2030. **NSW**: 1 GW/year to FY2030. Limit relaxed 500 MW/year beyond FY2030	No limit

B.2 Opportunities

The distribution network opportunities assessed within each scenario are summarised in Figure B10.

Figure B10: Opportunities to unlock value within the distribution network

Opportunity 1: Unlocking available capacity

Better utilisation of available capacity in distribution networks

This opportunity considers the potential for connecting **utility-scale generation and storage into the distribution network** where it provides least-cost system outcomes, as well as **targeted investment in DBESS** and **mid-scale solar** to defer network augmentation.

Opportunity 2: Unlocking CER

Optimising the value for and from consumer energy resources

This opportunity considers how **improved coordination and integration of CER**, including rooftop and mid-scale solar, batteries and EVs can reshape load profiles and contribute to whole-of-system cost savings.

All opportunities unlocked

Pulling on all levers to understand the total ‘**size of the prize**’ for distribution network opportunities.

These opportunities are assessed against a *Status quo*.

B.2.1 *Status quo*

The *Status quo* represents a future in which a smaller proportion of BTM BESS and EVs are operated in a coordinated way. In this project, coordination means that these assets adjust their operations to respond to distribution and network price signals, leading to lower total system costs, including opting into aggregator arrangements such as virtual power plants. The same CER coordination assumptions are used in the distribution techno-economic modelling and in the wholesale market modelling.

In the *Status quo*, DNSPs can only undertake traditional investments in network assets to alleviate import and export constraints. That is, investment in distribution-connected batteries, or investment in BTM CER and mid-scale PV beyond the baseline DNSP forecast (see Section B.1.1.3 and B.1.1.4) are not available. In the wholesale market model, transmission-connected generation and storage, accompanied by network augmentation, are the only options for meeting future load growth. Distribution REZs are not available in the *Status quo*.

B.2.2 *Unlocking available capacity*

Unlocking available capacity considers the potential to invest in distribution-connected storage and generation, both at or below the zone substation level and the sub-transmission level.

In the techno-economic model (TEM), the modelling enables investment in DBESS of 1, 2, 4 or 8 hours storage duration, as well as mid-scale solar assets in the distribution network, providing an alternative option to relieve distribution network constraints.

In the wholesale market model, existing hosting capacity predominantly in the sub-transmission network can be leveraged to connect utility-scale generation (wind and solar) and storage, potentially deferring or reducing the need for transmission-connected generation and/or REZ augmentation.

The level of CER uptake and coordination remains the same as the *Status quo* for this opportunity.

B.2.3 *Unlocking CER*

Unlocking CER assesses the impact of increasing the proportion of customers who operate their energy resources in a "coordinated" manner relative to the *Status quo*. In both the TEM and wholesale market model, additional CER investment and mid-scale solar is now allowed, above what is assumed in the *Status quo*. In addition, a larger proportion of BTM BESS and EVs are assumed to be coordinated.

Figure B11 and Figure B12 shows the resulting coordination percentages for BTM batteries and EV charging profiles in *Unlocking CER* against the *Status quo*.

Figure B11: Assumed coordination proportion for household batteries, by opportunity

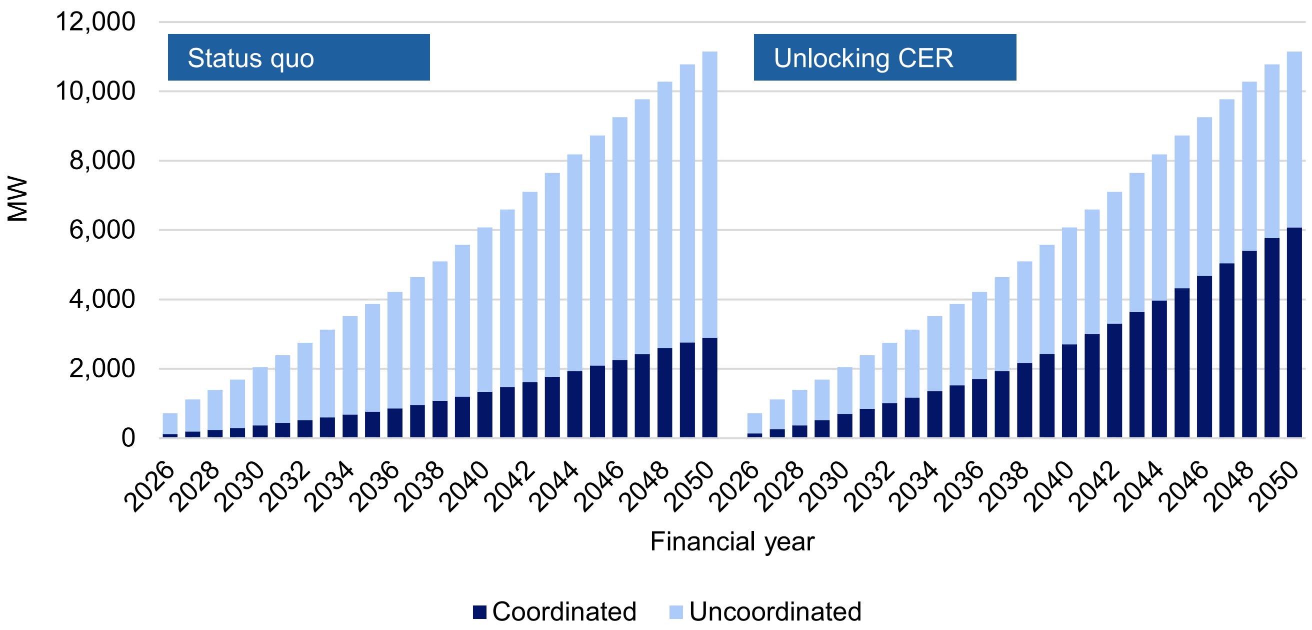
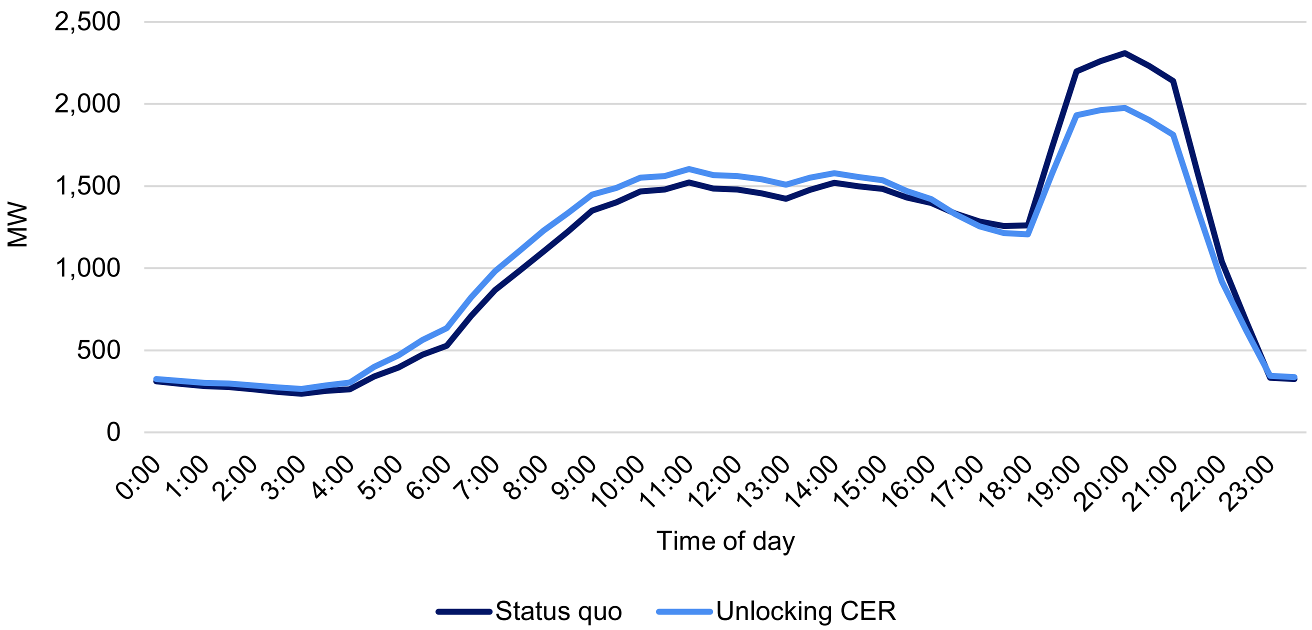


Figure B12: Average NSW time-of-day EV charging shape in FY2040, by opportunity



B.3 Quantifying the benefit

Both the TEM and the market modelling adopt a consistent least-cost approach, similar to AEMO's ISP.

The TEM minimises the cost of serving the load behind a zone substation, This includes both capital costs of building new infrastructure, as well as the operational costs of importing from the wholesale market to meet load. The levers available for optimisation, in addition to traditional distribution network augmentation, vary by opportunity:

- ***Unlocking available capacity***: DBESS and mid-scale solar investment
- ***Unlocking CER***: Mid-scale solar, rooftop PV and BTM BESS investment

The market model determines the least-cost investment mix and dispatch to minimise the cost of the wholesale system. These costs include the capital and operational costs of building generation and transmission infrastructure, as well as the costs associated with emissions and reliability. Like the TEM, the levers available for optimisation vary by opportunity, in addition to traditional investment in transmission-connected generation and storage:

- ***Unlocking available capacity***: Same as the TEM, with additional option to invest in utility-scale distribution-connected generation and storage
- ***Unlocking CER***: Mid-scale solar investment

The net present value of the total resource cost from the TEM and the market model is calculated for each opportunity and under each scenario to determine the economic benefit. This is detailed in Appendix F.

Appendix C: Techno-economic model and wholesale model data and input assumptions

C.1 Overview

The distribution techno-economic modelling and wholesale market modelling incorporates a wide range of data related to both the distribution network and wholesale markets. This includes, but is not limited to:

- DNSP-specific demand-side data, such as customer interval load profiles, customer population demographics and asset uptake (such as CER).
- DNSP-specific supply-side data, such as zone substation thermal import and export limits, voltage constraints and network augmentation costs.
- Distribution REZ hosting capacity, which outlines the quantum of utility-scale wind and solar that can be installed in the distribution network areas.
- Wholesale electricity demand-side data, such as rest-of-NEM forecast grid electricity consumption and associated load shape.
- Wholesale electricity supply-side data, such as generation and transmission expansion costs, network topology, and build constraints.

C.2 TEM data and input assumptions

Inputs to the TEM fall into two broad categories: customer population and demand data, and distribution network limitations and cost data.

The **customer population data** includes:

- Distribution network customer population data
- Sample half-hourly individual customer consumption data
- Future network energy and maximum demand forecast.

The **network limitation and cost data** includes:

- Distribution network zone substation import and export limitations (including thermal and voltage limitations).
- Augmentation costs for alleviating the above constraints.

Table C1 provides a detailed description of the data inputs used in the TEM.

Table C1: TEM inputs and assumptions

Data item	Details	Source
Interval customer load profiles	Half-hourly customer import and export profiles (kW) for FY2024. Each DNSP provided a subset of their customer base.	DNSPs
Population customer information, including, but not limited to, billed imports/exports and asset status	Billing information for all customers served by the DNSP. This included the billed consumption in each billing period, split by tariff and imports or exports streams, where relevant, rooftop PV installation status and asset size, and connected zone substation.	DNSPs
Zone substation import and export limits	Maximum thermal import and export capacity in (in MVA) at each zone substation	DNSPs
Bulk supply point import and export limits	Maximum thermal import and export capacity (in MVA) at each bulk supply point	DNSPs
Zone substation consumption and peak demand forecasts	Used to project the FY2024 constructed synthetic customer population into future forecast years. Split into relevant demand components, such as EV charging load and rooftop PV uptake.	DNSPs
Network augmentation costs	Cost to expand import and export thermal limits at each zone substation, either through transformer upgrades or building new zone substations.	DNSPs
Rooftop PV capital costs	Capital cost to install rooftop PV, excluding any subsidies.	Commonwealth Scientific and Industrial Research Organisation (CSIRO) small-scale solar PV and battery projections 2024[1]
Mid-scale solar capital	Capital cost of mid-scale solar	AEMO 2025 Inputs, Assumptions and Scenarios Report (IASR)[2]
Customer-installed battery system capital costs	Capital cost to install a battery by a customer, including any subsidies.	CSIRO's small-scale solar PV and battery projections 2024
Distribution battery costs	Capital cost to install a battery within the sub-transmission network, including any subsidies.	AEMO 2025 IASR

[1] Commonwealth Scientific and Industrial Research Organisation (2024). *Small-scale solar PV and battery projections*

[2] Australian Energy Market Operator (2025). *2025 Inputs, Assumptions and Scenarios Report*

C.2.1 Zone substation limits and augmentation costs

Each zone substation was modelled with a collection of network constraints belonging to two major classes:

- **Zone substation limits** that limit import and export at the zone substation.
- **CER export limits** that limit CER exports due to voltage constraints.

Zone substation import limits reflect the thermal limitations of each asset in transferring energy to or from the sub-transmission network. This constraint can be alleviated by augmenting zone substations or by investing in distribution and BTM BESS and discharging them at the time of the constraint. The DNSPs provided the zone substation thermal limit on an N-1 basis as well as the cost of the associated network investment to alleviate the constraint. The costs account for various factors, including feeder type, location, and scale of upgrade required.

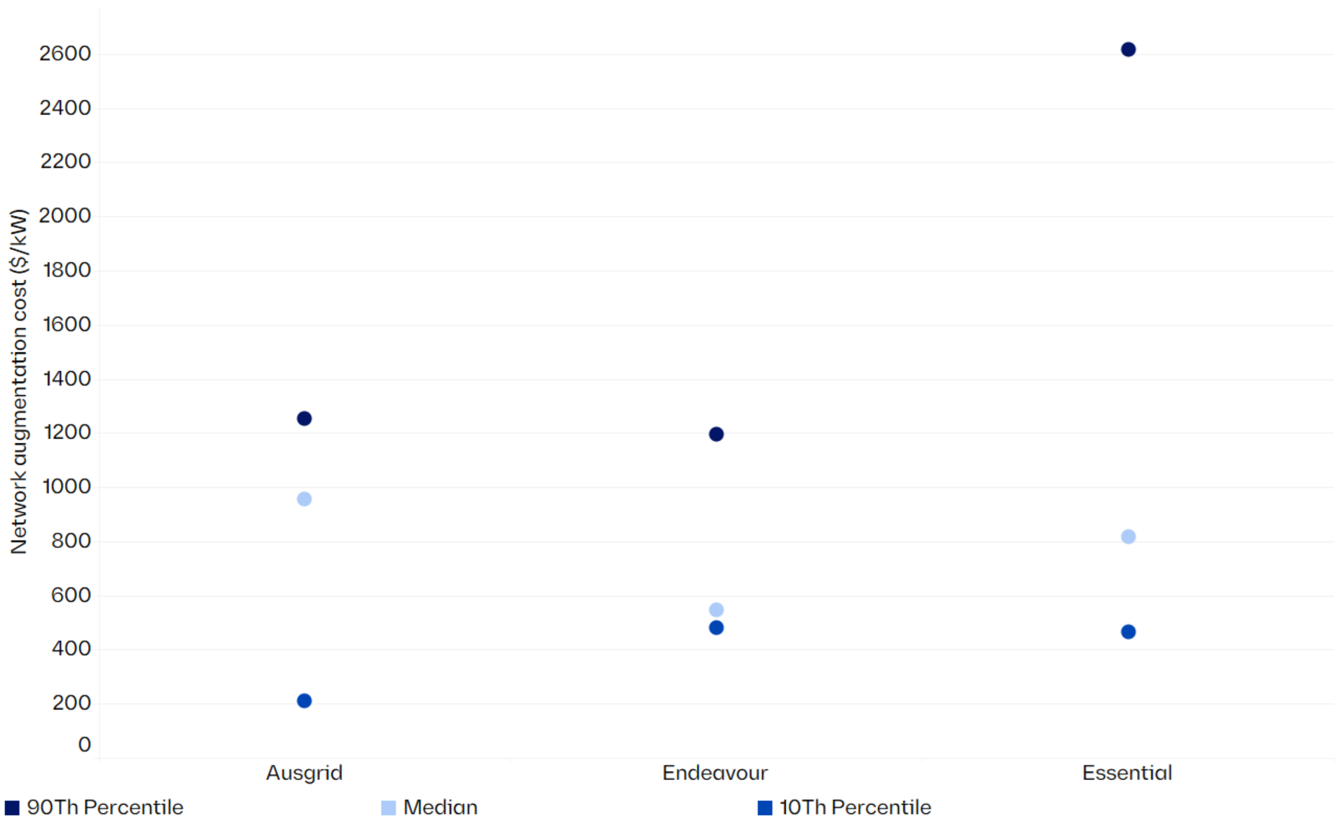
The CER export limits reflect voltage limitations that constrain the export of net generation – defined as total generation minus household consumption – from the low voltage network. In the TEM, solar generation within a zone substation (whether it is from rooftop or mid-scale solar) is assumed to contribute to the export constraint. The charging of household and distribution batteries alleviates this constraint. Due to the availability of data, this constraint was applied after all “low-cost remediation” options have been exhausted. This simplifies the export constraint to a single, static proportion of the thermal limit at each zone substation advised by each DNSP. This constraint can be alleviated by either investing in zone substation network augmentation or investing in distribution-connected and BTM BESS, and charging them at the time of the constraint.

The modelling for the first iteration of the DSP Opportunities Report makes simplifying assumptions regarding distribution network constraints and the remediation cost due to limited data availability:

- The TEM models every zone substation in isolation and does not capture the potential for load sharing across zone substations in meshed networks. This could lead to an upward bias in modelled investment need. To mitigate this, a buffer has been applied to increase import capacity by 30 per cent for partially meshed zone substations and by 50 per cent for heavily meshed zone substations.
- Distribution network constraints and remediation costs are represented at the zone substation level. In practice, network constraints can arise at both the downstream low voltage network and the upstream sub-transmission network, which may have different implications for remediation actions and costs. As a result of not capturing these constraints, the current modelling potentially underestimates the network augmentation needs and hence the benefit of the modelled opportunities.

The augmentation costs are shown in Figure C1.

Figure C1: Network cost for expanding zone substation limits



C.2.2 PV and BESS cost in the TEM

The costs for rooftop PV, mid-scale solar and DBESS generally align with trends in the utility sector. However, due to their smaller scale, these technologies typically incur higher unit costs compared to their utility-scale counterparts. The unit costs for solar and battery storage are shown in Figure C2 and Figure C3 respectively.

Figure C2: Solar unit costs

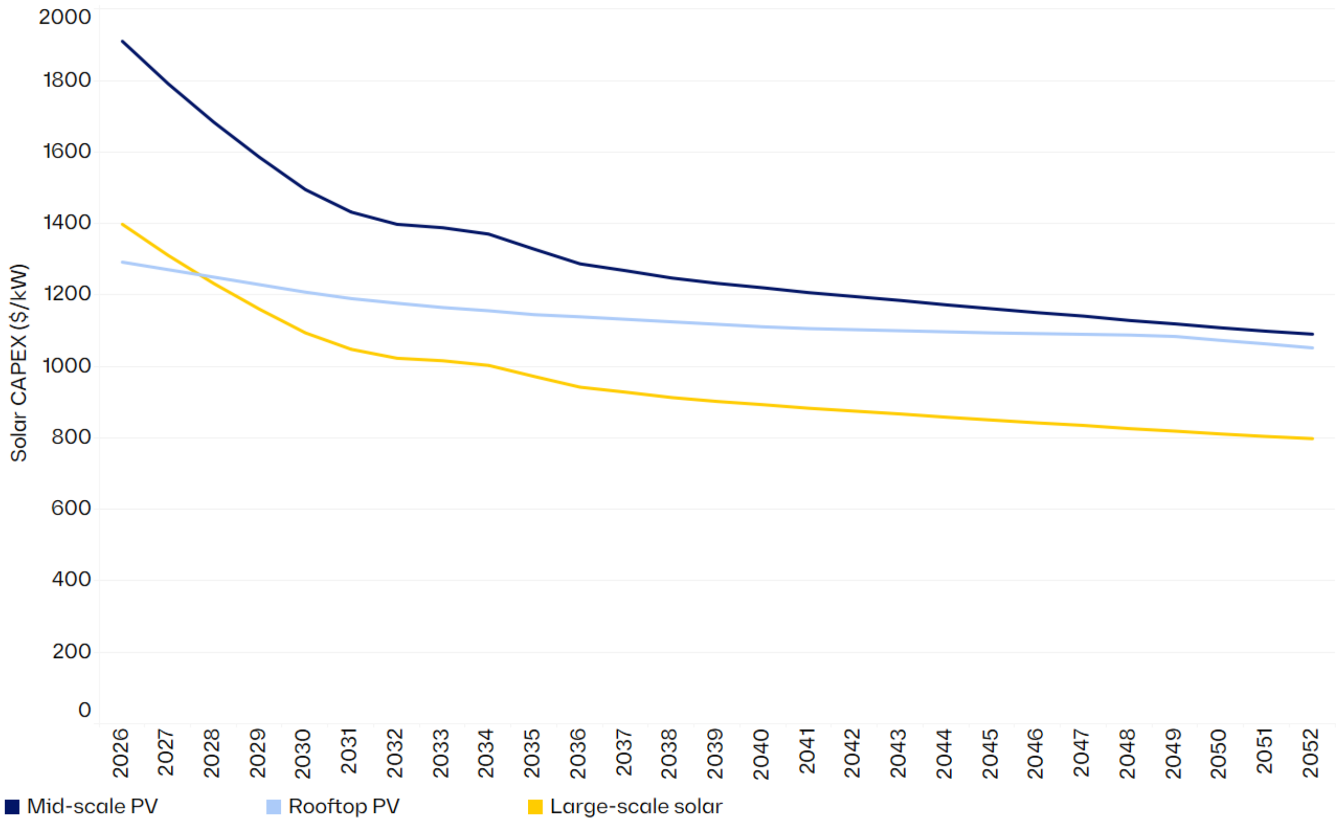
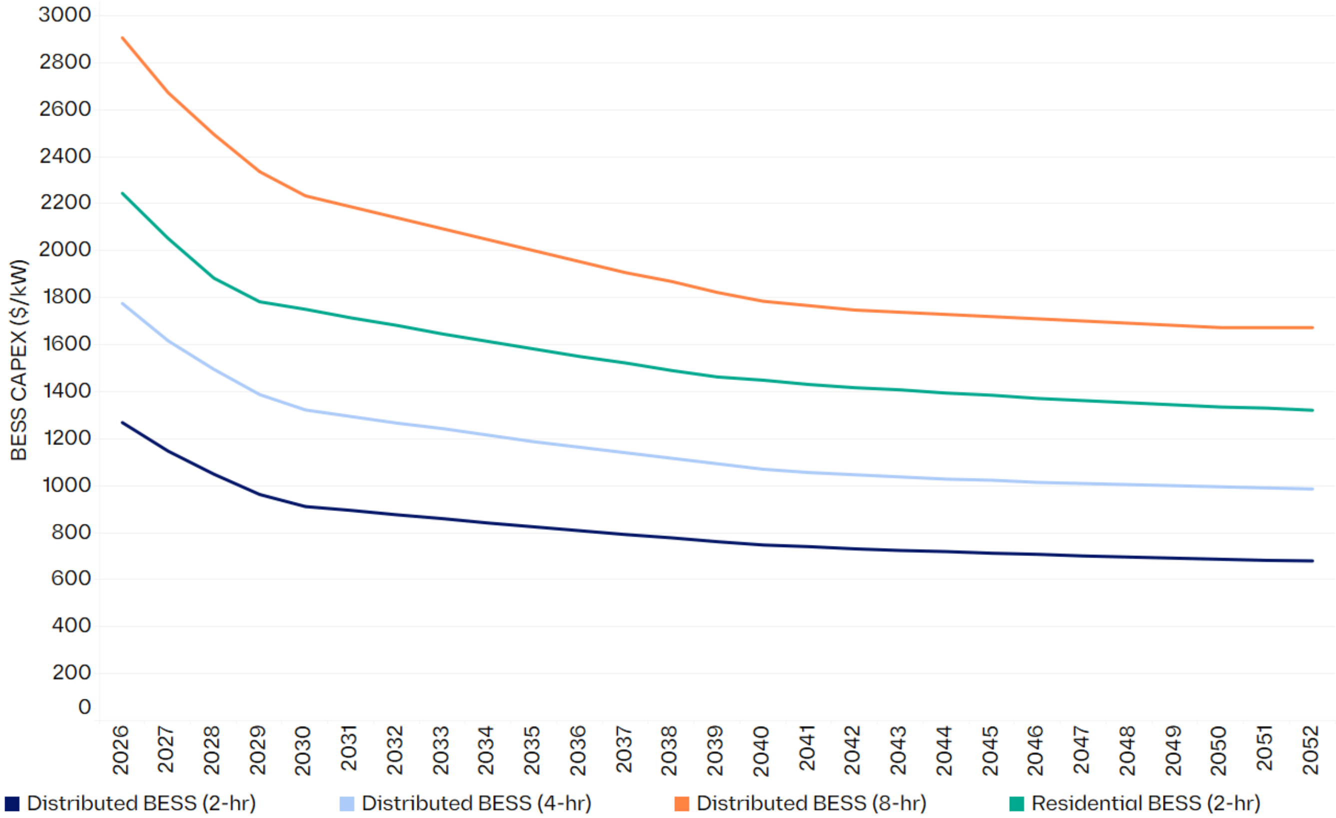


Figure C3: Battery storage unit costs

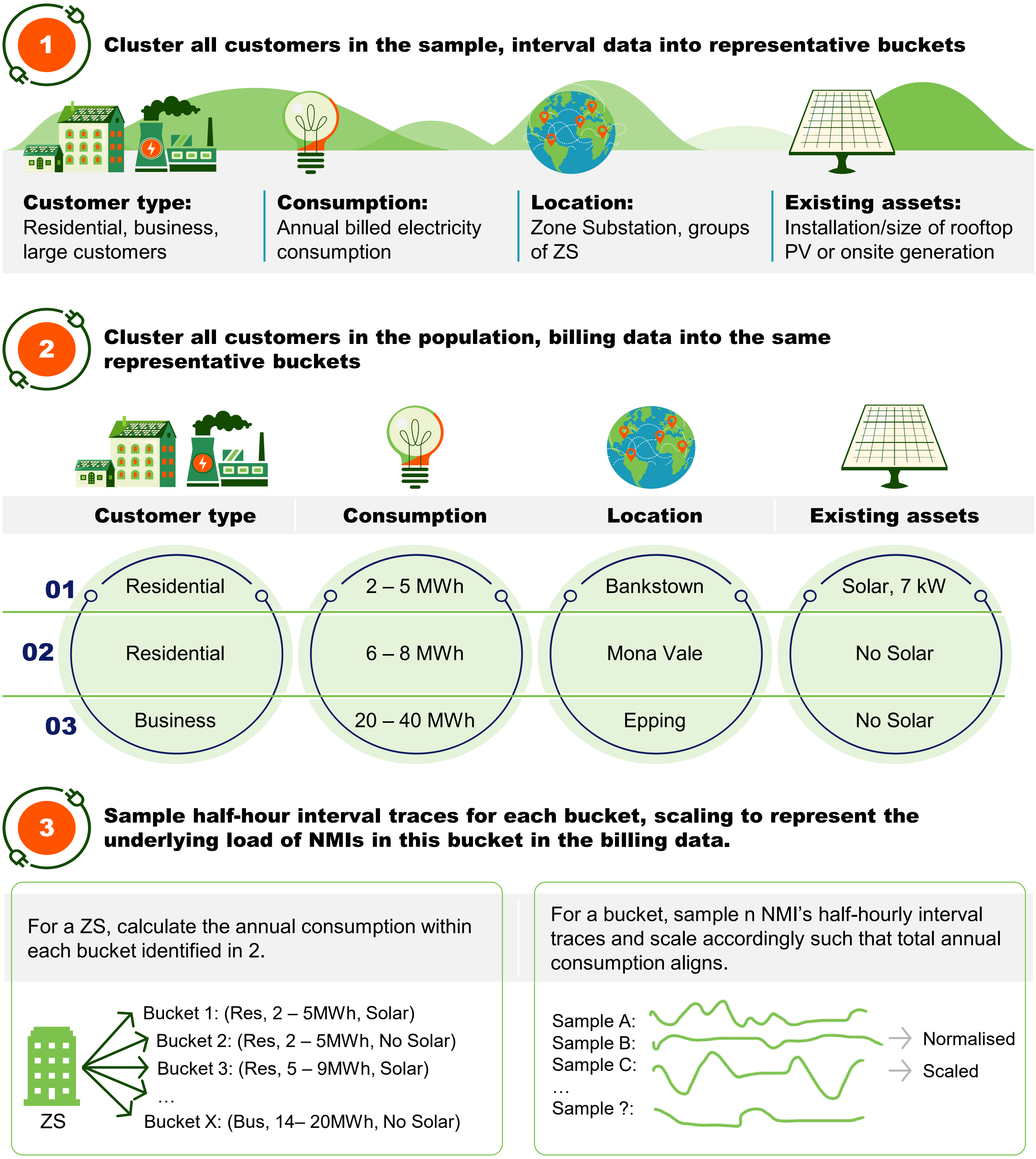


C.2.3 Synthetic population

In reality, each zone substation can serve up to thousands of customers, and there are significant variations in the customer composition and behaviour across the approximately 700 distribution zone substations modelled in NSW.

Modelling distribution network investment, including the impact of DBESS and CER, requires the model to have visibility of the effect of detailed customer behaviour on network constraints. On the other hand, not all customers are on half-hourly interval data, and even if the data were available, it would be a computationally prohibitive exercise to model all NSW customers in the TEM. As a result, a synthetic population behind each zone substation is required for the TEM. To achieve this, a statistical approach was used to develop half-hourly profiles of residential and business customers based on “similar” customer load shapes from the sample interval data, along with appropriate scaling factors. A summary of this approach is shown in Figure C4 below.

Figure C4: Creating a synthetic load profile



First, customers were stratified based on key features that were known for all customers. These features included annual imported energy in kilowatt-hours, customer type, whether the customer had rooftop solar installed and where applicable, the installed rooftop solar size. From here, the customer population from a cluster was represented by sampling customer load profiles from the same cluster. For each cluster, multiple customer load profiles were randomly sampled to capture the inherent and unavoidable variability of customer load shape. Due to the total sample size, the number of sampled customers in many zone substations was too small to represent the variability of customer profiles. In this case, sample profiles were drawn from other zone substations that belonged to the same cluster. This was considered appropriate, especially for residential customers, as the distribution of consumption patterns is likely to be similar across zone substations for customers belonging to the same cluster. To manage computational complexity, a cap was applied on the number of load profiles sampled to represent a single cluster (in the order of at most 50 customers per cluster and zone substation).

Once the sample customer load profiles were selected, each profile was proportionally scaled such that the annual underlying consumption of all sampled load profiles equalled the annual underlying consumption of all customers in the population that belonged to the cluster for the relevant zone substation.

At this point, in most cases the synthetic population (i.e. reconstructed load from the sample customers) closely reflected the underlying consumption behind each zone substation for the financial year 2024 (the year for which the initial synthetic customer population was created). However, in some instances, a “residual” existed between the load as determined by the synthetic population and the aggregate, publicly available zone substation load profile, either due to statistical error, losses, or very large customers that were not explicitly modelled in the TEM. Modelling CER uptake and operation on these very large customers required detailed inputs and calibration that were beyond the current strategic view of the TEM, which assessed all 700 zone substations in NSW. As such, the residual was derived by taking the difference between the synthetic customer population and the interval zone substation load profile. This “residual” was held constant in the TEM, CER uptake and operation modelled on the synthetic customer population only.

Once the residual was derived, the synthetic population for the financial year 2024 was complete. The next step involved adapting the synthetic population to meet the energy consumption and peak demand forecast behind the zone substation for each modelled year into the future. Prior to this, a down-casting step was applied if the DNSP only had an energy forecast at the network level instead of each zone substation. In this case, the network forecast load was broken down by component and customer class, such as underlying consumption, EVs and CER uptake. The synthetic population derived for the financial year 2024 was then scaled to meet the forecast annual underlying consumption in each modelled financial year.

Subsequently, CER, such as EVs, rooftop PV and BTM BESS, were allocated to modelled customers. This allocation was performed on a discrete basis, so that a modelled or sampled customer was either given one or none of the CER assets. After uptake was determined, coordination and vehicle-to-grid (V2G) participation were assigned based on the relevant level of coordination in the modelled opportunities.

C.3 Wholesale market modelling data inputs and assumptions

The wholesale market modelling generally follows the methodology in AEMO’s ISP.

The demand-side data is discussed in detail in Section B.1.1. The supply-side data, including:

- generation capital and fuel costs are sourced from the Step Change scenario in AEMO’s 2025 IASR[3]
- transmission network costs are sourced from AEMO’s 2025 Electricity Network Options Report[4]
- transmission timing assumptions are detailed in Section B.1.2.

The DNSPs also provided information regarding the total renewable energy hosting capacity in their respective networks (predominantly at sub-transmission levels). This capacity, as summarised below, is made available in the wholesale market model in *Unlocking available capacity*:

- 4.7 GW for Ausgrid
- 3.3 GW for Endeavour
- 8.1 GW for Essential Energy

[3] Australian Energy Market Operator (2025). 2025 Inputs, Assumptions and Scenarios Report
[4] Australian Energy Market Operator (2025). 2025 Electricity Network Options Report

Appendix D: Techno-economic model methodology and outputs

The TEM assesses the physical and operational capabilities of the distribution network under each scenario. It identifies constraints, required network upgrades, Distributed Energy Resources (DER) hosting limits, and potential investment pathways. These outputs define the technical feasibility and timing of distribution-level options. The purpose of the TEM is to determine the optimal investment and operation of assets to meet forecast customer load at each zone substation within the distribution network across a range of opportunities.

D.1 Methodology

D.1.1 Zone substation least cost modelling

The TEM identifies the least-cost asset mix to meet customer demand for each modelled zone substation between FY2026 and 2050. The cost consists of the following:

- Capital cost incurred in a zone substation. This could come from:
  - Traditional distribution network investment to increase the import and export capacities of the zone substation, which is available in all modelled opportunities
  - Investment in DBESS, which is available in *Unlocking available capacity* and *All opportunities unlocked*
  - Investment in distribution-connected mid-scale solar (i.e. between 100 kW and 5 MW), which is available in *Unlocking available capacity*, *Unlocking CER*, and *All opportunities unlocked*
  - BTM storage and rooftop solar, which is available in *Unlocking CER* and *All opportunities unlocked*.
- Operating cost incurred to meet load, which is the cost of running the utility-scale fleet connected in the transmission sector. For the TEM, this is proxied by the half-hourly pool prices from an initial market modelling run, where the inputs are consistent with those used in this project.
- Cost of import exceeding zone substation import capacity, which is valued at the NSW Value of Customer Reliability (VCR) as published by the Australian Energy Regulator (AER).

D.1.2 Modelling import and export constraints

To meet future demand growth, the model has the option to:

- expand the distribution network capacity directly
- invest in DER or CER.

Expanding distribution network capacity alleviates network import constraints to allow more imports from the wholesale market. However, it does not reduce the cost of imports.

DER and CER investments, on the other hand, reduce the need for imports and hence offset the operating cost of meeting the zone substation load. In particular, BESS can charge using cheaper midday solar generation and time-shift the energy to meet demand during the evening peak and overnight, when pool prices are typically higher. As a result, CER and DER investment can, in some cases, replace traditional network investment as part of the least-cost capacity mix.

The model also considers the value of alleviating solar export curtailment. In some zone substations, solar exports can exceed the network's export limit and lead to curtailment. The opportunity cost of solar curtailment is meeting the demand at the time by running more wholesale generation. Therefore, it is represented by the wholesale pool prices at the time of curtailment. Export curtailment can be mitigated by expanding the zone substation capacity, which increases its import and export capacity simultaneously, or by investing in DBESS and BTM BESS which can soak up excess solar during the day.

D.1.2.1 Modelling battery operation in the TEM

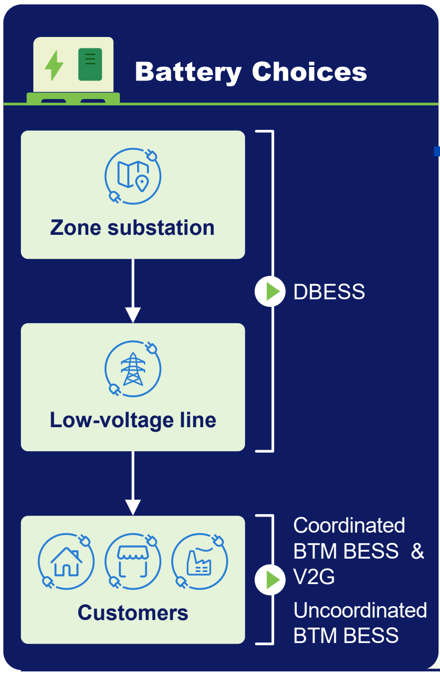
Different types of battery storage can be developed within the distribution network. The TEM classifies these into three categories:

- **DBESS**: These are assumed to be placed at an optimal location within the distribution network and can alleviate export constraints where needed. They have no restrictions on charging and discharging, and can respond to wholesale and network price signals.
- **Uncoordinated BTM BESS**: These are located at the customer end and primarily serve on-premises consumption needs. They generally operate according to wholesale and network price signals, but have flatter charging and discharging profiles. The modelling assumes that 15 per cent of their stored energy is reserved for household consumption.
- **Coordinated BTM BESS and V2G:** These are also located at the customer end but are more coordinated than uncoordinated BTM BESS. They are allowed to break from their normal flat operation profile when there is a strong wholesale or network need (proxied by a $300/MWh penalty cost).

The modelling assumes that 15 per cent of BTM BESS stored energy and 50 per cent of V2G stored energy is reserved for household consumption.

The battery storage options available in TEM are summarised in Figure D1 below.

Figure D1: Characteristics of different battery choices



Battery Characteristics

	DBESS (2, 4, and 8 hours)	Uncoordinated BTM BESS (2 hours)	Coordinated BTM BESS and V2G
Flexibility	**No restriction** on charging and discharging volume and time	• 8 am to 4 pm charge, discharge otherwise • Flat discharge profile over 16 hours • Flat charge profile over 4 hours	• 8 am to 4 pm charge, discharge otherwise • Flat discharge profile over 16 hours – **break if price signal >$300/MWh** • Flat charge profile over 4 hours
State of Charge limit assumptions	0% min	15% min	Coordinated BTM BESS: 15% min V2G: 50% min
Ability to relieve voltage constraint	Yes	Yes	Yes

D.1.2.2 Representing customer load profiles behind zone substations

To capture the potential change in customer load profile due to load growth, underlying consumption behaviour (such as EV charging), and the impact of rooftop solar and BTM, the TEM utilised a half-hourly synthetic population for each zone substation between FY2026 and FY2050. This is discussed in more detail in Section C.2.3.

To balance the computational complexity, the synthetic population profile in the TEM is modelled by “representative day clusters” for each month, where the clusters are defined by:

- Weekday and weekend
- Low, medium and high solar days based on daily solar availability (0^{th} - 25^{th} percentile, 25^{th} - 75^{th} percentile, and 75^{th} – 100^{th} percentiles, respectively).

The load profiles in each day-cluster are averaged, and a total of six clusters represent each month. Additionally, the model included a winter peak day and a summer peak day. The load profile for that day is scaled to meet DNSP’s zone substation demand forecast at probability of exceedance (POE) 50 plus a 10 per cent margin.[5]

[5] POE is the likelihood a maximum or minimum demand forecast will be met or exceeded. POE50 therefore means there is a 50 per cent likelihood of exceeding peak demand.

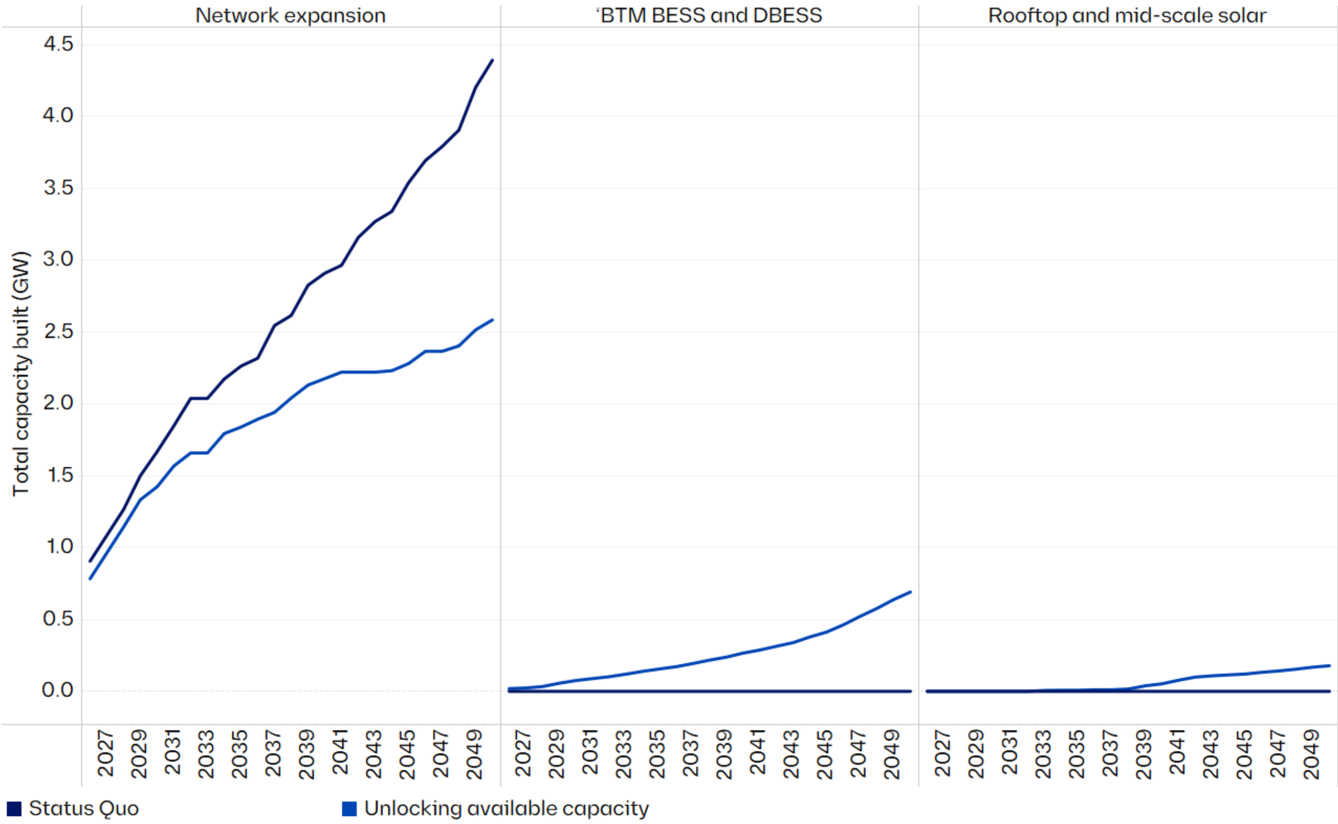
D.2 Outputs

D.2.1 Modelling results in *Customer transformation* and *Optimistic case*

D.2.1.1 Impact of *Unlocking available capacity*

The modelling indicates that the NSW distribution network will require continued augmentation over the next 25 years to accommodate projected load growth. However, investing in DBESS can significantly reduce the need for traditional network investment, as shown in Figure D2 below.

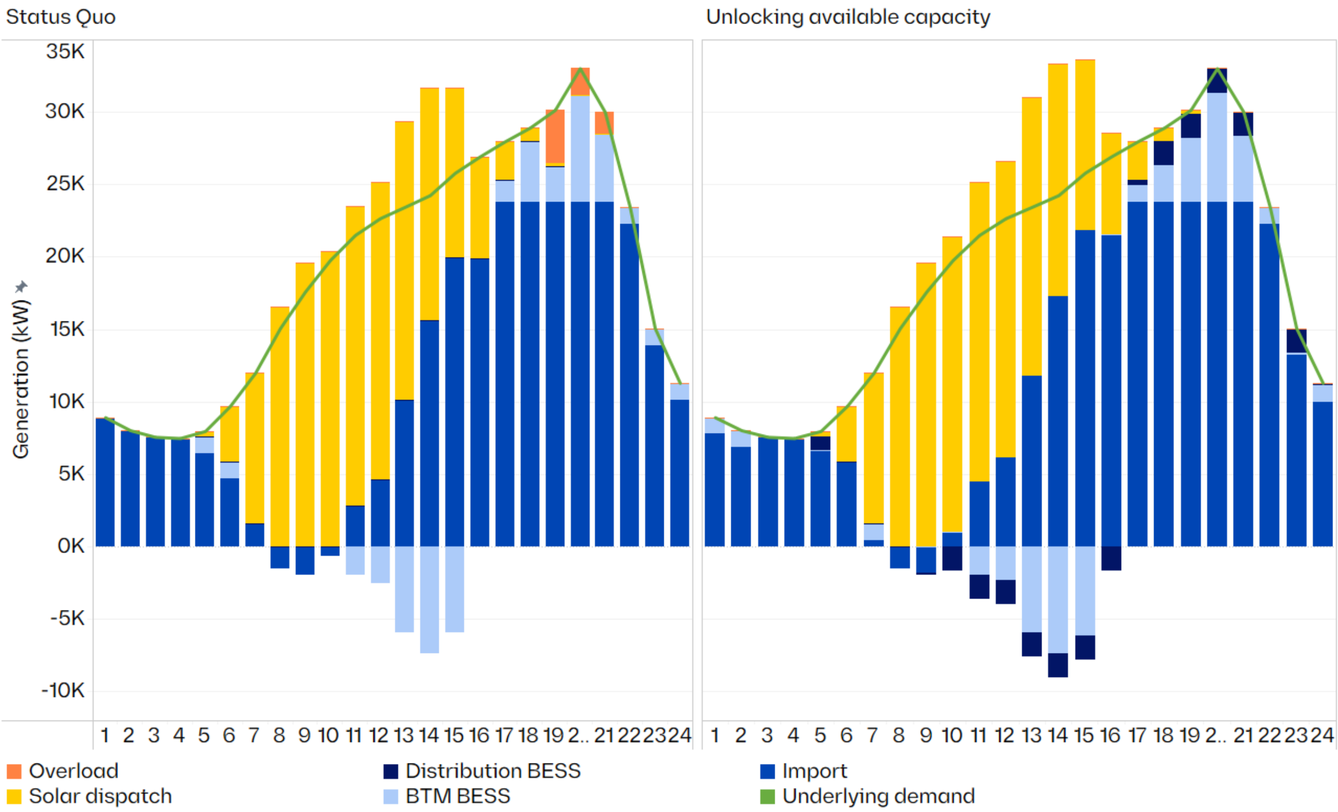
Figure D2: NSW-wide investment outcome in Status quo and Unlocking available capacity – Customer transformation and Optimistic case



The vast majority of DBESS investment is 4 or 8-hour storage, as the longer duration enables them to capture network and wholesale benefits over more sustained periods. DBESS can be a cost-effective substitute for traditional distribution network investment due to its flexibility in scale. Unlike traditional distribution investments, which tend to be "lumpier" in nature, batteries can be built in smaller increments over time, which can significantly reduce capital expenditure. In addition, DBESS can also participate in wholesale market arbitrage, which reduces the high generation costs of meeting evening and overnight demand. As a result, DBESS can be part of the least cost capacity mix in some zone substations.

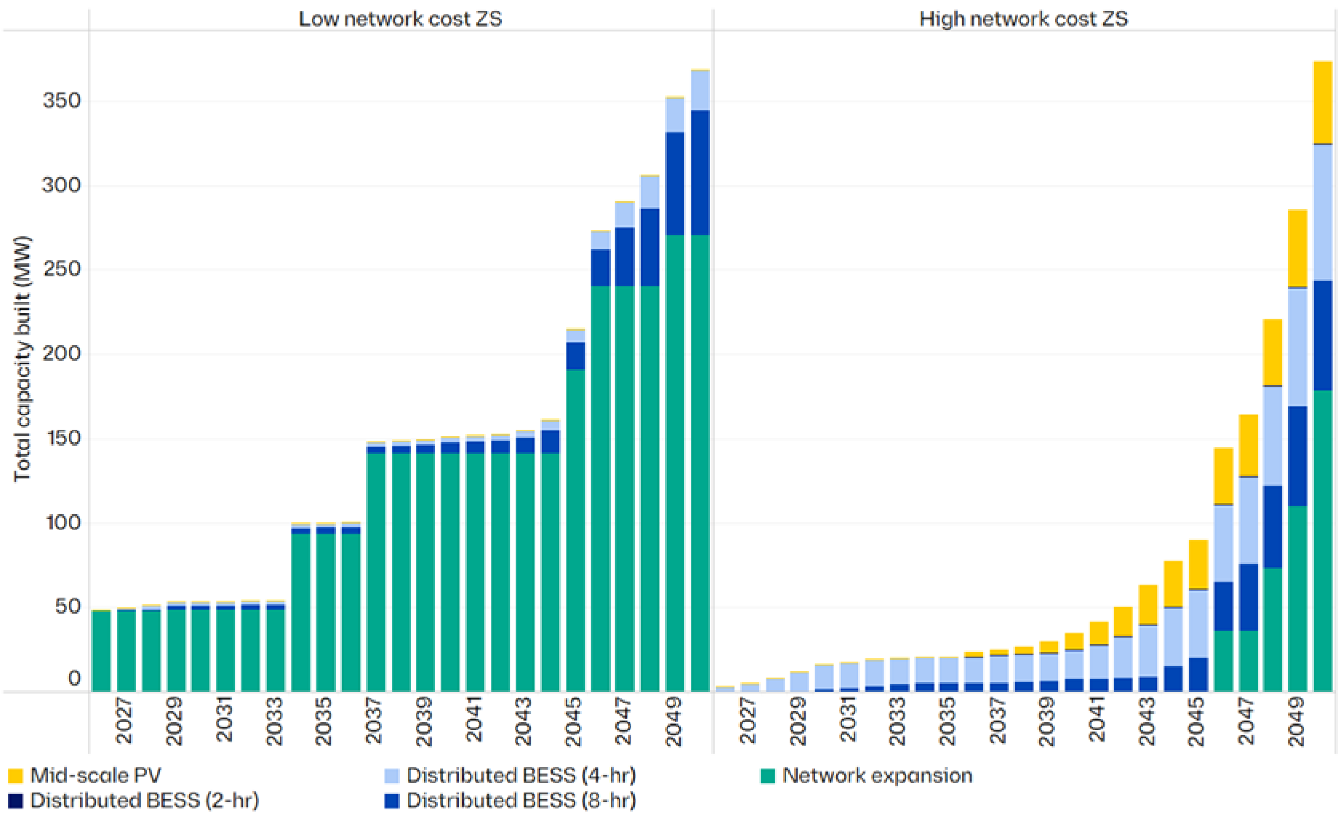
Figure D3 below shows an example of DBESS reducing the need for zone substation augmentation. In the *Status quo*, evening demand is greater than the sum of the zone substation import capacity and the generation from rooftop solar and BTM BESS. This results in overload at the zone substation, which can trigger the need for zone substation augmentations. In *Unlocking available capacity*, DBESS can provide additional generation during this constrained period, helping to buy time for network augmentation need.

Figure D3: Example zone substation with DBESS impact



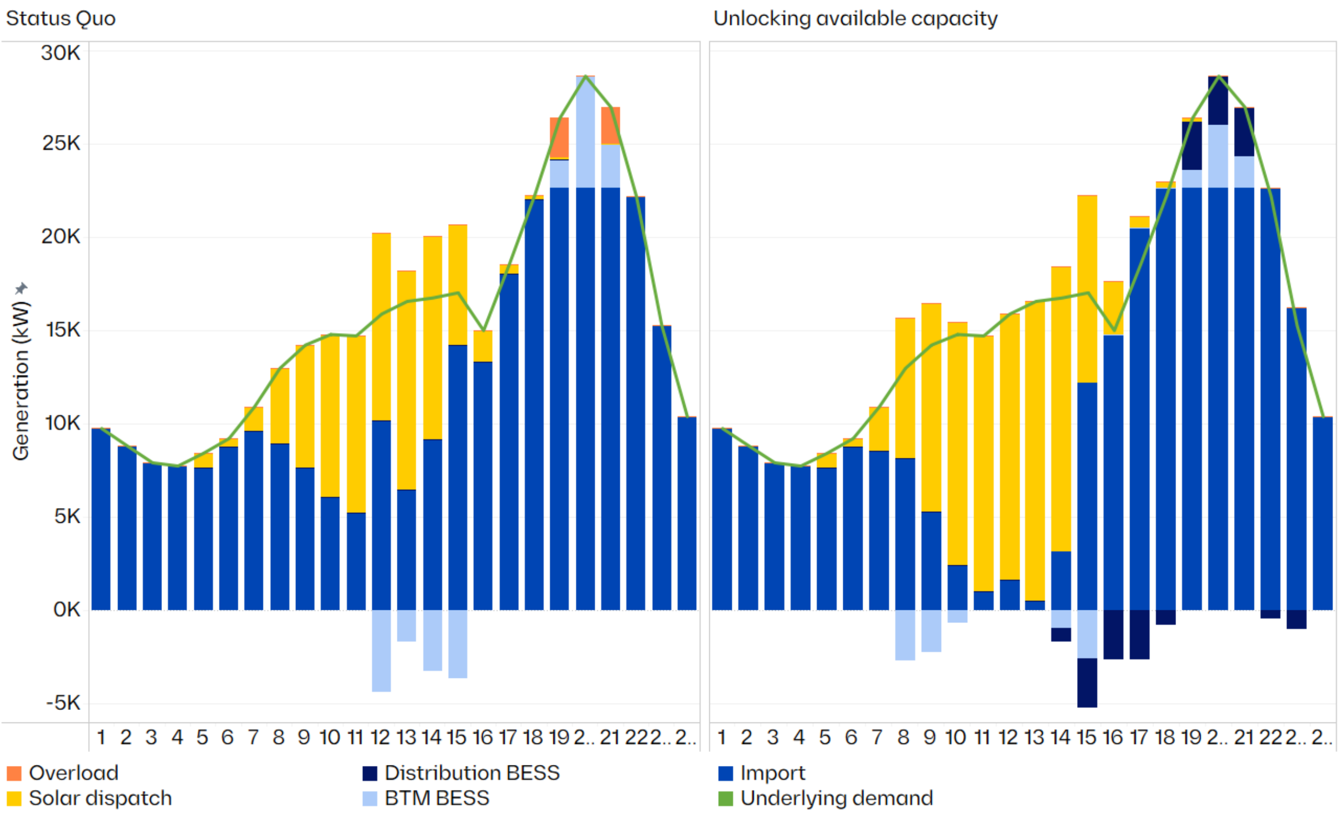
The suitability of DBESS in replacing traditional network investment is a function of the relative cost between DBESS and the cost of network augmentation. Figure D4 below shows the long-term mix of DBESS and network augmentation for a selected DNSP. DBESS are used extensively for zone substations that fall into the high-cost category, which accounts for over 50 per cent of zone substations for this DNSP.

Figure D4: DBESS investment based on zone substation augmentation costs – Customer transformation and Optimistic case



The modelling also identified additional opportunities for mid-scale solar uptake in the distribution network. Note this is additional investment beyond the baseline forecast, which is approximately 30 GW in NSW distribution networks (see Section B.1.1.3). This is driven by the assumed strong EV uptake, a significant proportion of which will be charged at midday. This leads to a lack of network import capacity post-2040, when midday EV charging has become a significant driver of distribution load profiles. *In Status quo*, the constrained midday import capacity prevents batteries in the distribution network from being fully charged to meet evening demand. In *Unlocking available capacity*, the extra mid-scale solar investment provides an additional generation source to charge batteries in the distribution network. This is coupled with additional DBESS investment to remove the need for distribution network augmentation, as shown in Figure D5 below.

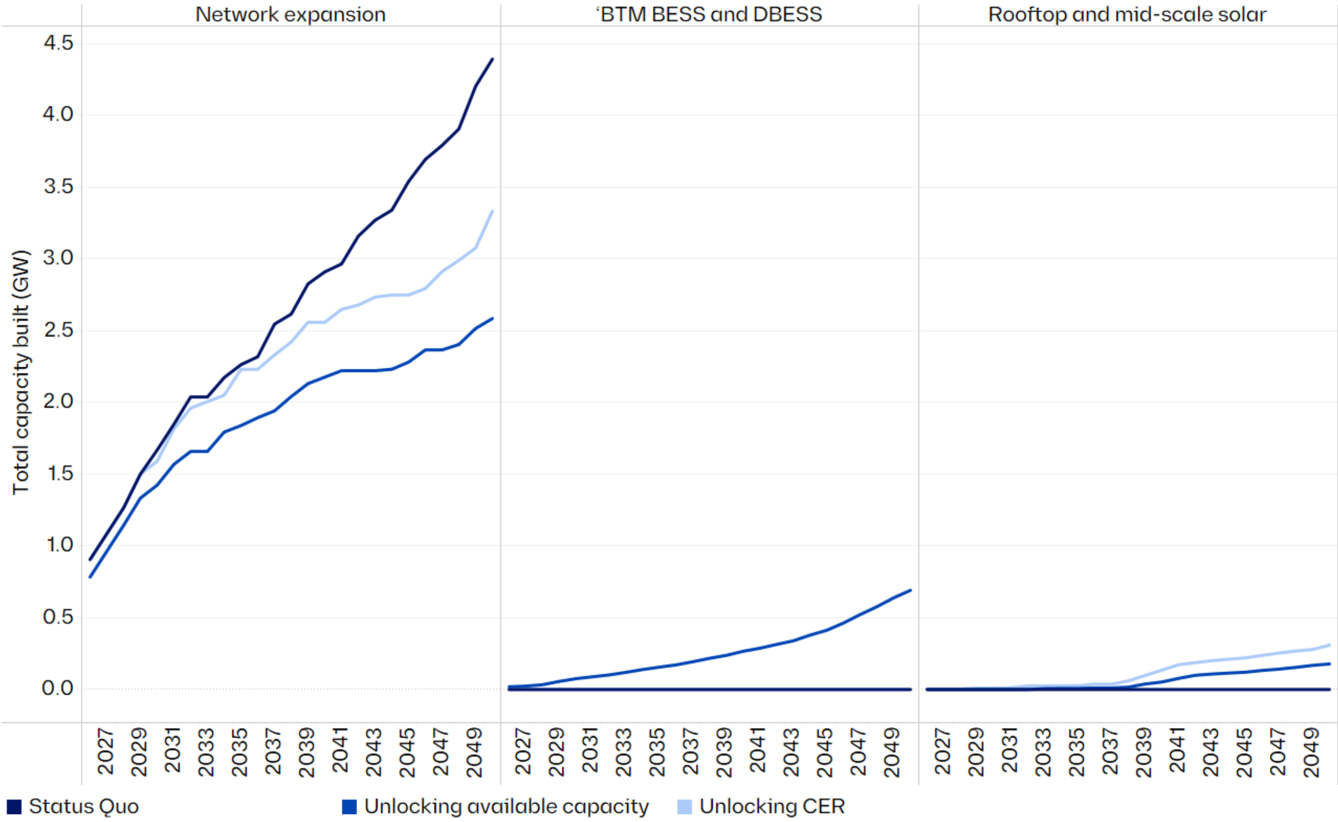
Figure D5: Example zone substation with mid-scale solar



D.2.1.2 Impact of *Unlocking CER*

In *Unlocking CER*, CER assets are assumed to be more coordinated, and the model can choose to build additional CER beyond the baseline level in the *Status quo*. CER also reduces network investment but is less effective than DBESS. There are several factors driving this. Firstly, the impact of increased CER coordination grows in lockstep with CER uptake, which grows over time but has a smaller impact before the 2030s. Secondly, BTM BESS and V2G are used primarily for meeting customer consumption needs, including those for transportation. This means these assets are more limited in their ability to respond to wholesale and network needs and hence are less effective in replacing traditional network investment. The investment outcome for *Unlocking CER* is shown in Figure D6 below, alongside the result for *Unlocking available capacity*.

Figure D6: NSW-wide investment outcome in Status quo, Unlocking available capacity and Unlocking CER – Customer transformation and Optimistic case

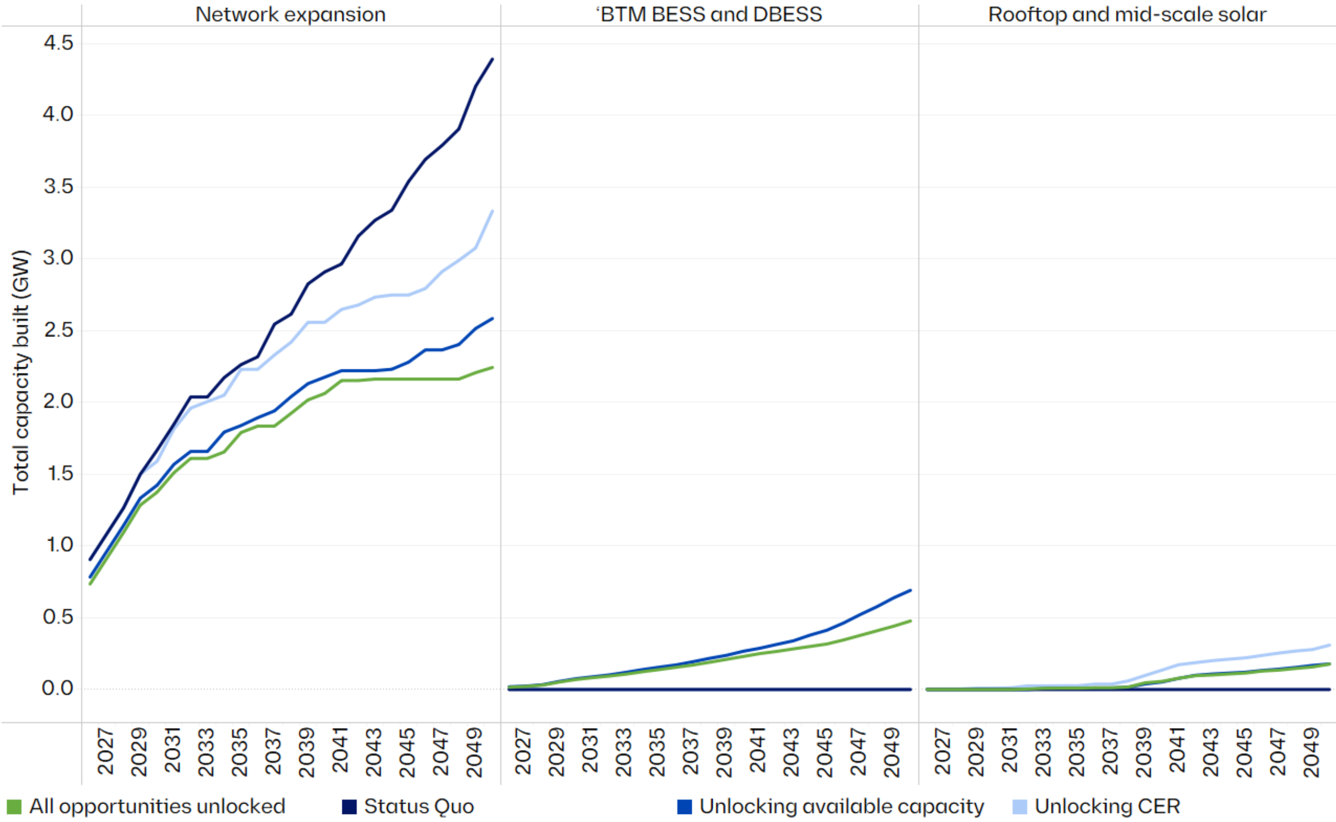


D.2.1.3 Impact of *All opportunities unlocked*

In All opportunities unlocked, across NSW as a whole, the benefits of DER and CER assets are additive. For example, unlocking both CER and DER further reduces the need for traditional network augmentation and also decreases the need for DBESS investment.

Before 2030, investment in DBESS provides the primary benefits due to lower CER uptake in the early years. From 2030 onwards, the impact of CER uptake and coordination becomes more material, and by the 2040s, with total coordinated CER growing with continued uptake, the value stacking between the two opportunities becomes material. The results of All opportunities unlocked is shown alongside Unlocking available capacity and Unlocking CER in Figure D7.

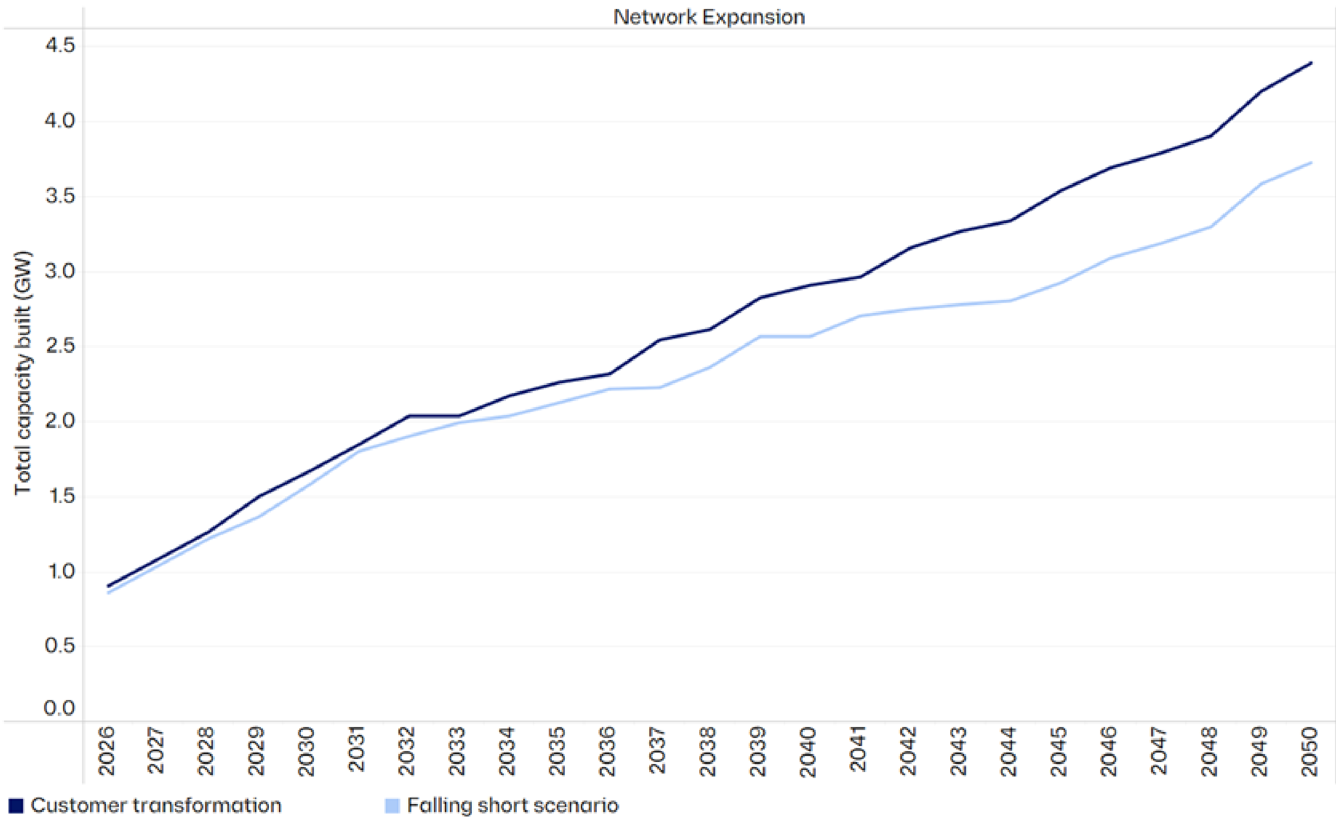
Figure D7: NSW-wide investment outcome in Status quo, Unlocking available capacity, Unlocking CER and All opportunities unlocked



D.2.2 Modelling results from the *Falling short* scenario

The *Falling short* scenario assumes lower EV and non-transport electrification uptake than the Customer transformation and Optimistic case scenarios. This results in less need for network expansion in the *Status quo* for the *Falling short* scenario compared to the *Customer transformation* scenario, as shown in Figure D8.

Figure D8: Network expansion outcome in status Quo - Customer transformation vs Falling short

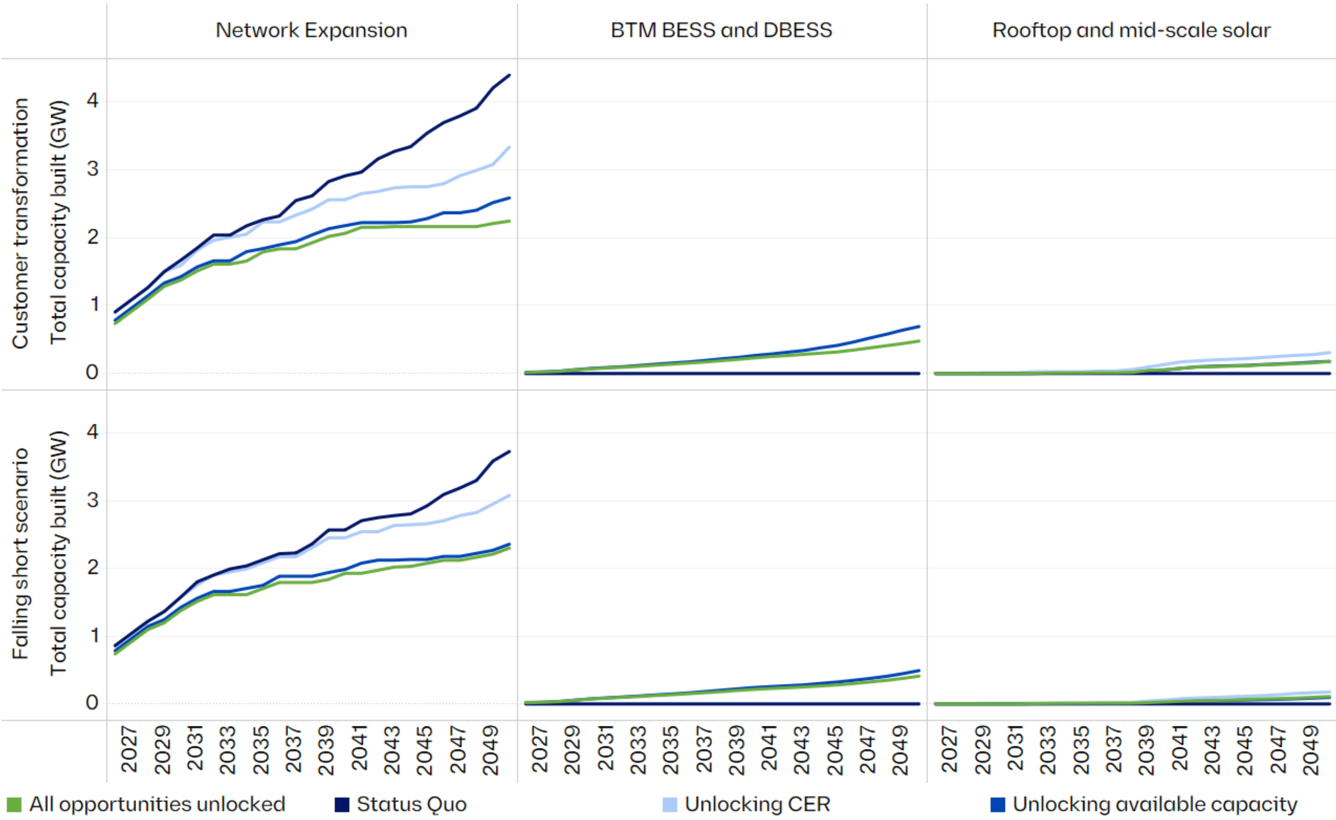


With the reduced need for network expansion in the *Falling short* scenario, investment in assets associated with each modelled opportunity case also decreases. However, the broad directionality and narrative for Unlocking available capacity and *Unlocking CER* aligns with the *Customer transformation* scenario:

- Investing in DBESS can significantly reduce the need for traditional network investment
- Unlocking CER also reduces network investment but is less effective than DBESS
- The impact of increased CER coordination increases with CER uptake, which grows over time but has a lesser impact before the 2030s.

However, in *All opportunities unlocked*, CER investment only marginally reduces network investment in the long term if DER opportunities are already in place. There is a slight coupling effect between the CER and DER opportunities in the mid-2030s to mid-2040s, driven by increased CER uptake and coordination in this period. However, given that DBESS is more effective than BTM assets in responding to network needs, investing in these assets will already capture the majority of “avoidable” network investment. This is shown in Figure D9 below.

Figure D9: NSW-wide investment outcome in Status quo, Unlocking available capacity, Unlocking CER and All opportunities unlocked



D.3 Capabilities

Recent technological advances have led to significant reductions in storage costs and the widespread adoption of CER. This has significantly changed the role and complexity of distribution planning beyond building poles and wires to meet peak demand.

The TEM equips distribution planners with the right tool to handle problems of this complexity and provides quantitative, modelling-based insights into long-term distribution investment strategies. It leverages the well-established modelling framework in the wholesale market and transmission planning framework and uses an optimisation-based approach to assess the least-cost based investment pathway for the distribution network at the zone substation level. The model employs a synthetic customer population approach to represent detailed underlying customer information for each zone substation. It accounts for the long-term impact on individual customer consumption patterns and aggregate zone substation load profiles due to long-term demand growth and CER uptake and orchestration. This is the first time such a bottom-up approach has been used in distribution system planning in Australia.

D.4 Limitations

The modelling approach for this iteration of the DSP is subject to some limitations. One key limitation is that, due to data and time constraints, distribution network constraints and augmentation costs are modelled at the zone substation level, excluding downstream feeder constraints and upstream sub-transmission constraints. These constraints can be material for some zone substations, as zone substation level augmentation costs only account for 45 per cent of the total forecast augmentation costs for the NSW DNSPs over the next five years. As a result, the benefit of opportunities may be understated. On the other hand, the TEM currently treats each zone substation in isolation and does not explicitly model the potential load sharing across zone substations in meshed networks. To mitigate the risk of overestimating augmentation needs, the model applied a buffer to uplift the import capacity of meshed zone substations. The accuracy of the TEM could be further improved by modelling “pockets” of zone substations together to account for the potential for load sharing.

On the demand side, the absence of forecasts at the zone substation level means that future zone substation consumption profiles might not reflect expected local characteristics (e.g. future demographic shift that turns an existing industrial site into a residential area). While the absence of detailed zone substation-level calibration introduces some limitations, this is partially mitigated by the strategic-level modelling approach. The directionality of the insights – particularly regarding the drivers of distribution investment patterns such as load shape, technology costs, and CER uptake and behaviour – remains robust.

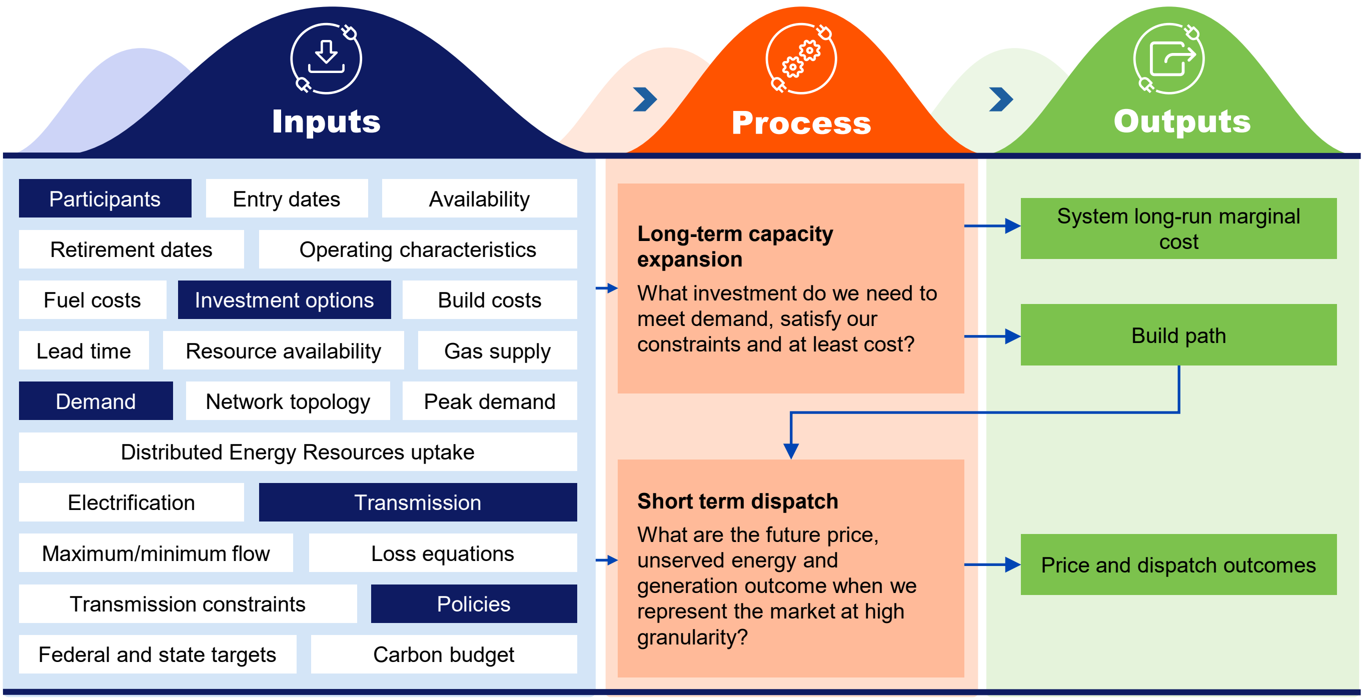
Appendix E: Wholesale model methodology and outputs

Wholesale market modelling has been used to evaluate the impact of distribution network opportunities on the electricity system in NSW and the NEM.

E.1 Methodology

Wholesale market modelling, in its most general form, simulates the optimisation that determines least-cost electricity dispatch and associated pool prices in the NEM. This overarching goal is broken down into multiple optimisations, usually a long-term capacity expansion module, where future generation and network investment is determined, followed by a short-term dispatch module, where capacity is fixed and the system is represented with a higher fidelity to determine half-hourly dispatch and pool prices. See Figure E1 below.

Figure E1: Inputs, process and outputs into wholesale market modelling



One key use case for market modelling is in system planning, whereby the "optimal" generation mix, broken down by technology and location, can be determined, given the provided constraints.

The general methodology for the wholesale market modelling used in this project is similar to that used by AEMO in its ISP. In the ISP, transmission and generation investment across the NEM are co-optimised to meet future electricity demand at least system cost, subject to meeting policy objectives and emissions targets. Electricity demand is represented in each of the five NEM regions, comprising 15 sub-regional nodes with intra- and interconnectors that allow for energy sharing. Beyond sub-regional flow limits, additional transmission constraints are included to reflect transmission-connected REZs or particularly consequential network limitations, such as flows around the Sydney Ring. In the upcoming 2026 ISP, AEMO proposed incorporating distribution-level network limitations and available augmentation through high-level, DNSP-wide constraints (i.e. one constraint for each distribution network).

However, the wholesale market modelling in this project has a few important departures. The impact of distribution investment – including the option to build DBESS – on the ability of CER to export to the sub-transmission network has been directly modelled at each zone substation through a bottom-up approach within the TEM. This allows for a more granular representation of distribution constraints by explicitly capturing the diversity of load profiles and hosting capacities at different zone substations. The outcome of the TEM, including the impact on NSW system load profile and additional distribution BESS capacity, has been fed into the market model as an input. In addition, DNSPs' inputs on their major demand (such as data centres) and supply (distribution REZ hosting capacity) opportunities are directly included.

Since coordinated action and investment by NSW DNSPs has the potential to buy time for transmission investment, transmission projects in NSW beyond those committed in the near term will be re-optimised in both their quantum and timing. This includes the New England REZ and Stage 2 of the CWO REZ. This means the model determines whether it is optimal to reduce the size (MW) or defer the entry date of these future transmission REZs given the opportunities unlocked within the DNSPs. Transmission projects in other NEM regions, including interconnector upgrades, remain fixed.

E.2 Outputs

Across all scenarios, the wholesale market modelling highlights that distribution-connected generation provides whole-of-system benefits by enabling well-located, low-cost investments – derisking the timing of transmission projects in NSW, putting downward pressure on customer costs and reducing the emission footprint of the electricity sector.

E.2.1 Outcomes from *Customer transformation* and *Optimistic case*

E.2.1.1 Status quo

The NEM is expected to undergo a fundamental evolution on both the supply and demand sides. On the supply side, baseload coal plants are aging and are expected to steadily exit before FY2040. Demand is expected to grow due to the continued uptake of EVs and non-transport electrification. Data centres are also expected to drive significant load growth. Changing supply and demand landscapes act together to drive sustained investment in wind and solar assets, firmed with storage and long-duration firming assets such as pumped hydro energy storage and peaking gas plants, as seen in Figure E2.

Figure E2: Installed NSW capacity in Status quo – Customer transformation

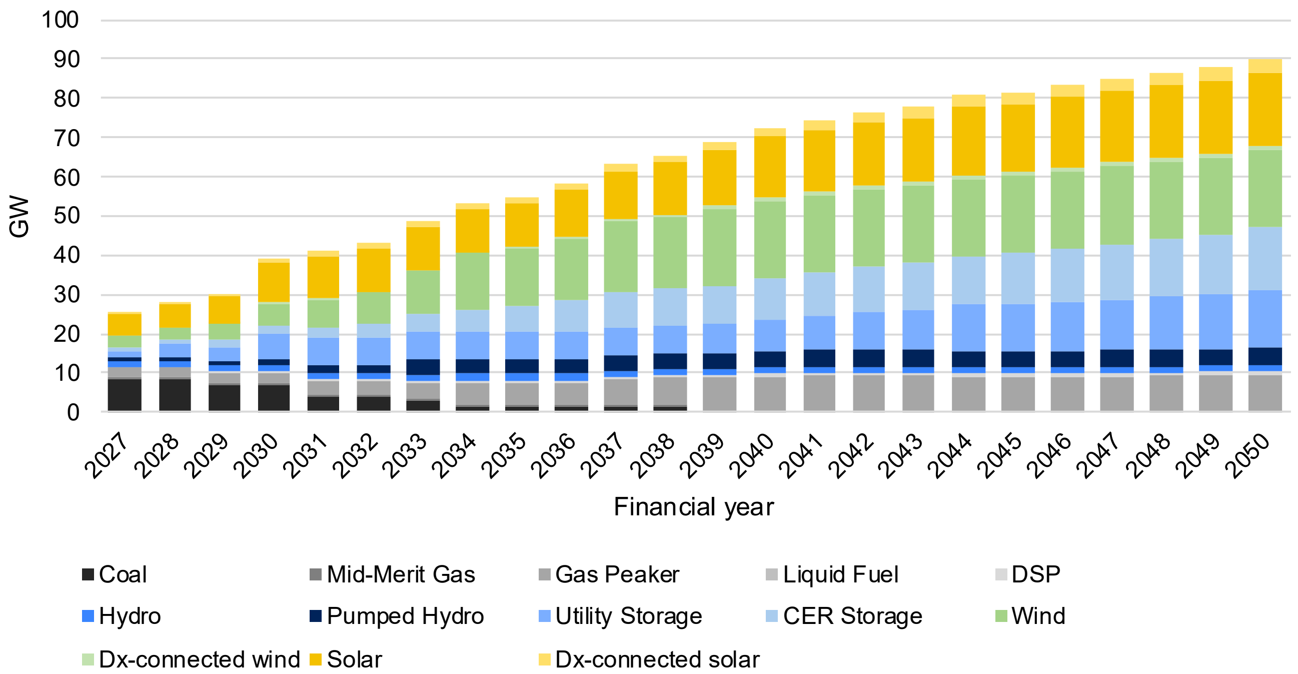
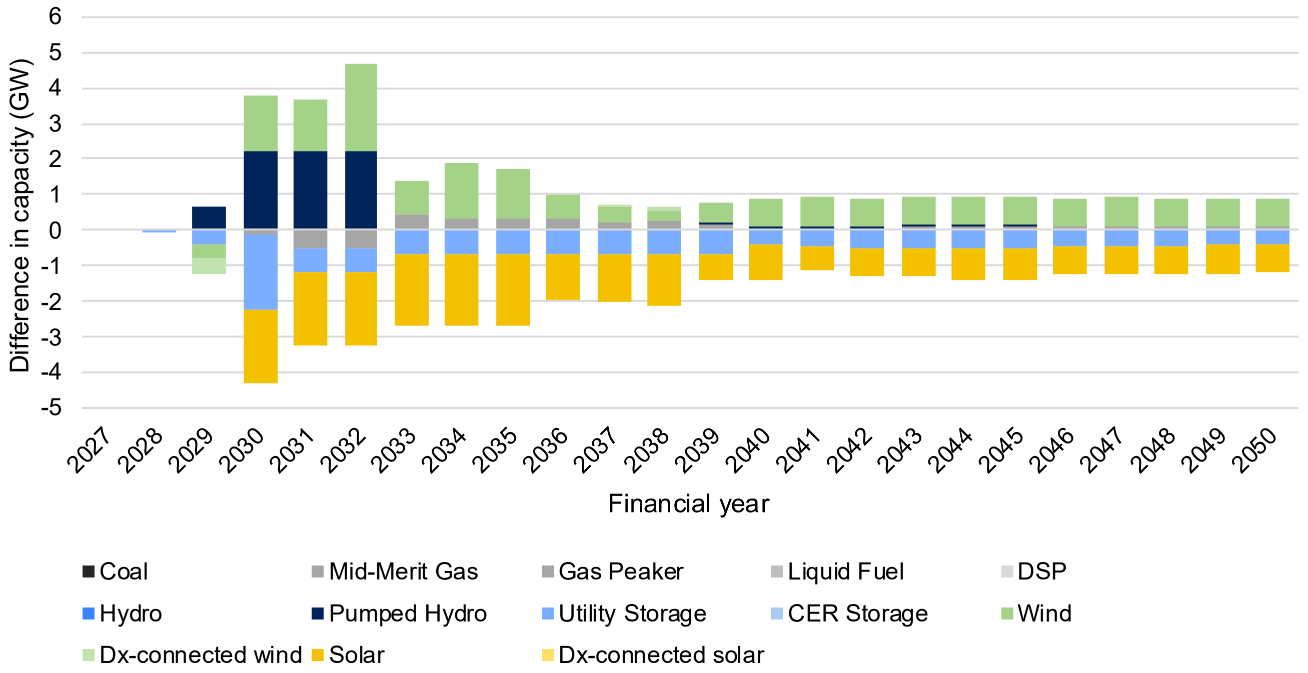


Figure E3 illustrates the difference in installed capacity between the *Optimistic case* and the *Customer transformation* scenarios, with a positive bar indicating more capacity in the *Optimistic case*. The *Customer transformation* scenario captures the current trend that wind build is constrained by the supply-chain limit. As a result, additional solar investment is required to meet load growth and the NSW Long-Term Energy Service Agreements generation target. In addition, the *Customer transformation* scenario also assumes delays in other key infrastructure, such as Snowy 2.0. In the long term, as supply-chain constraints slowly alleviate, the difference in installed capacity generally diminishes.

Figure E3: Change in NSW capacity in Status quo between Optimistic Case and Customer transformation

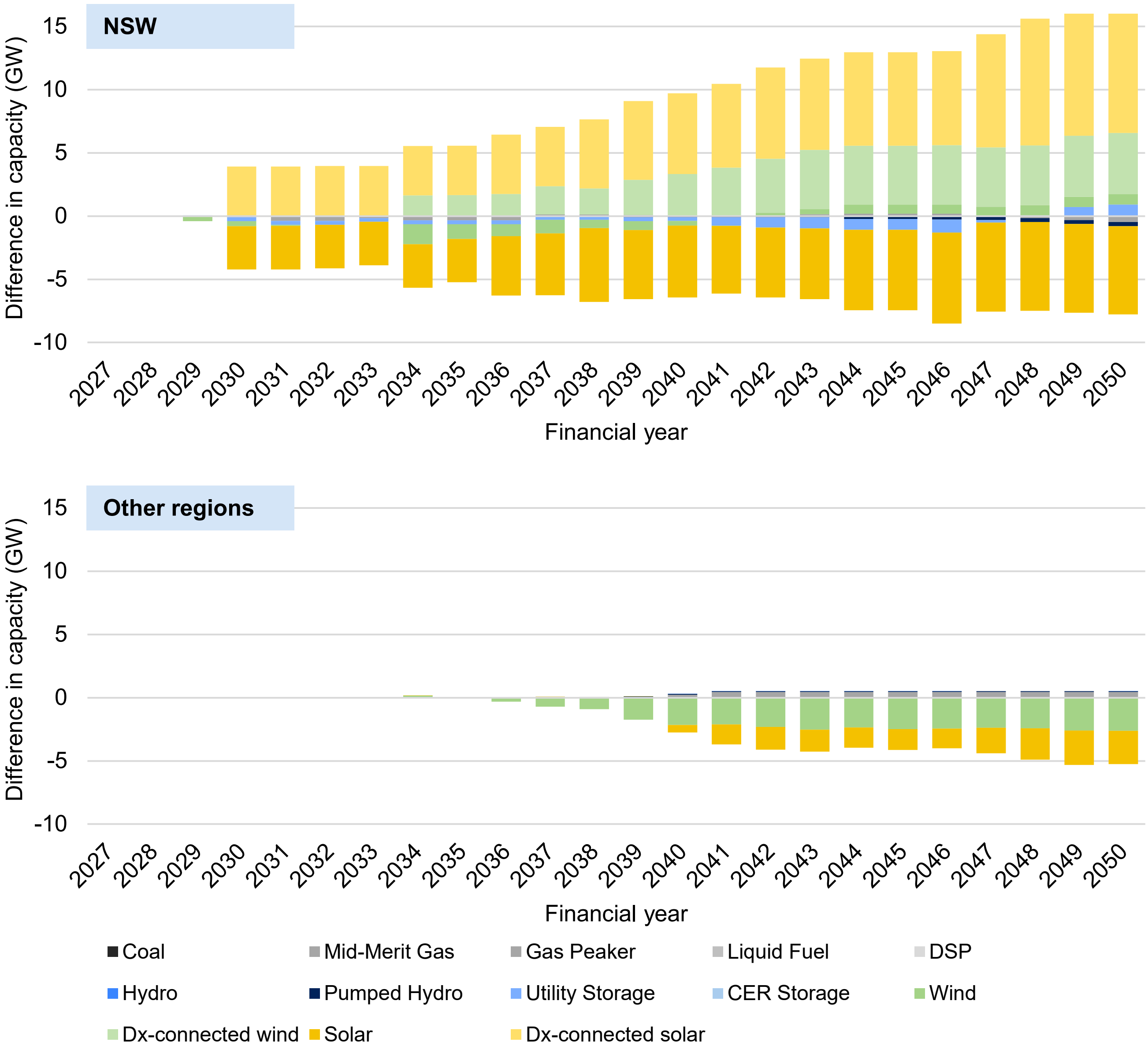


Given the broad convergence of long-term market outcomes between *Customer transformation* and *Optimistic case*, the impact of each opportunity for the *Customer transformation* scenario will be shown.

E.2.1.2 Impact of Unlocking available capacity

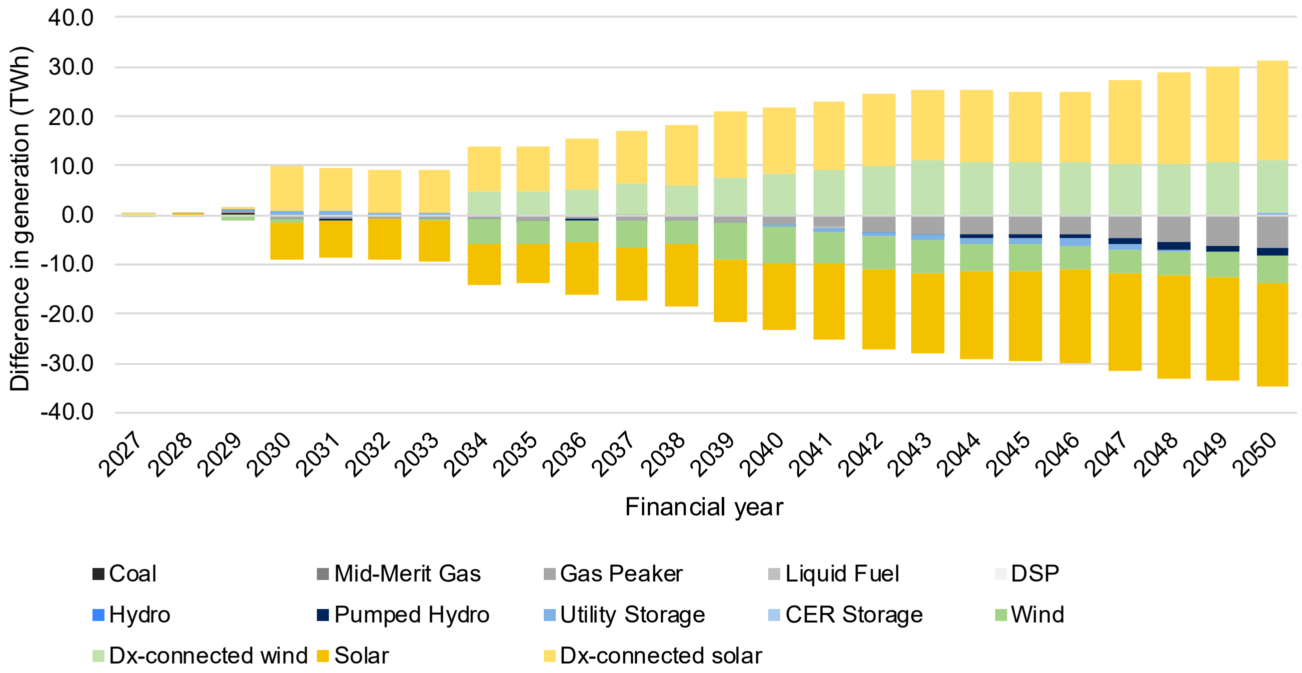
Figure E5 shows how allowing distribution-connected generation, in the form of mid-scale solar, utility-scale solar and wind, and storage, significantly changes the capacity mix in the system. In the short-term, solar plant moves to connect within the distribution network and closer to load-centres. This reduces network constraint that prevents power flow into the major load centres. In the long-term, additional windfarms can connect to the NSW system through distribution-connected REZs to serve continued load growth, displacing renewable investment in the rest of NEM and reliance on interconnector imports into NSW.

Figure E4: Difference in installed capacity between Unlocking available capacity and Status quo by region – Customer transformation



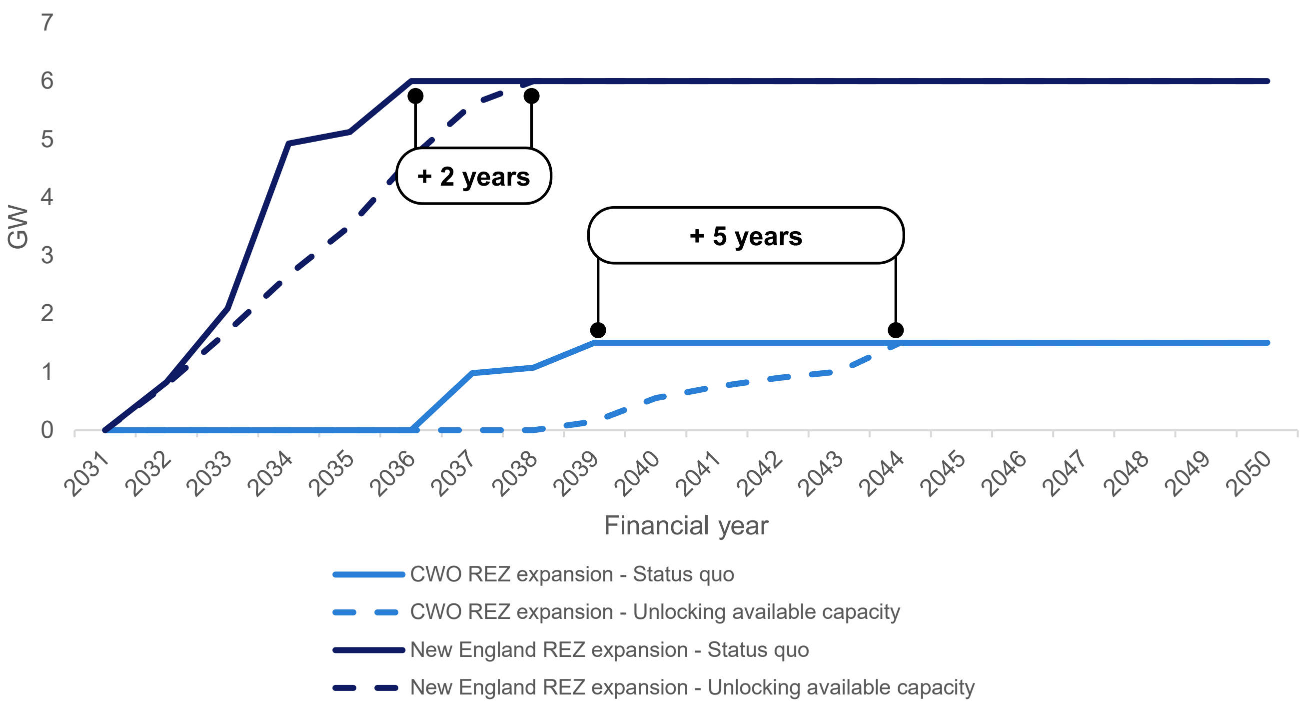
As seen in Figure E6, a key value driver for investment distribution-connected generation stems from reduced gas-powered generation (GPG) dispatch, resulting in approximately 6.5 TWh less utilisation in the long term across the NEM.

Figure E5: Difference in NEM generation between Unlocking available capacity and Status quo – Customer transformation



Additionally, Figure E7 demonstrates the utilisation of distribution network capacity de-risks the energy transition in NSW by buying time for further transmission network augmentation, such as CWO REZ Stage 2 and New England REZ. In addition to the cost savings associated with deferral of capital expenditure, this also mitigates the risk of potential delays in transmission investment and commissioning.

Figure E6: Endogenous NSW REZ expansion – Customer transformation



E.2.1.3 Impact of *Unlocking CER*

Unlocking CER sees better coordination of CER through increased participation in virtual power plants, further orchestration of EVs to charge during the middle of the day, and enabling additional investment in mid-scale solar (i.e. on commercial and industrial premises) above the *Status quo* level. The resulting impact on the system is smaller than that in *Unlocking available capacity* and tends to be backloaded. This follows naturally from the changing dynamics in the wholesale sector, whereby future supply scarcity is driven primarily by prolonged energy shortages rather than capacity shortfalls. Given the expected influx of long-duration storage assets in the NEM, their impact on the system will dominate that of increased coordination of short-duration household batteries. However, in the long term, distribution-connected solar, complemented with additional utility storage, is built to support growing load within the load-centre, and can displace some solar plants in remote regions that are built under *Status quo*. This is shown in Figure E9.

Figure E7: Difference in installed capacity between Unlocking CER and Status quo by region – Customer transformation

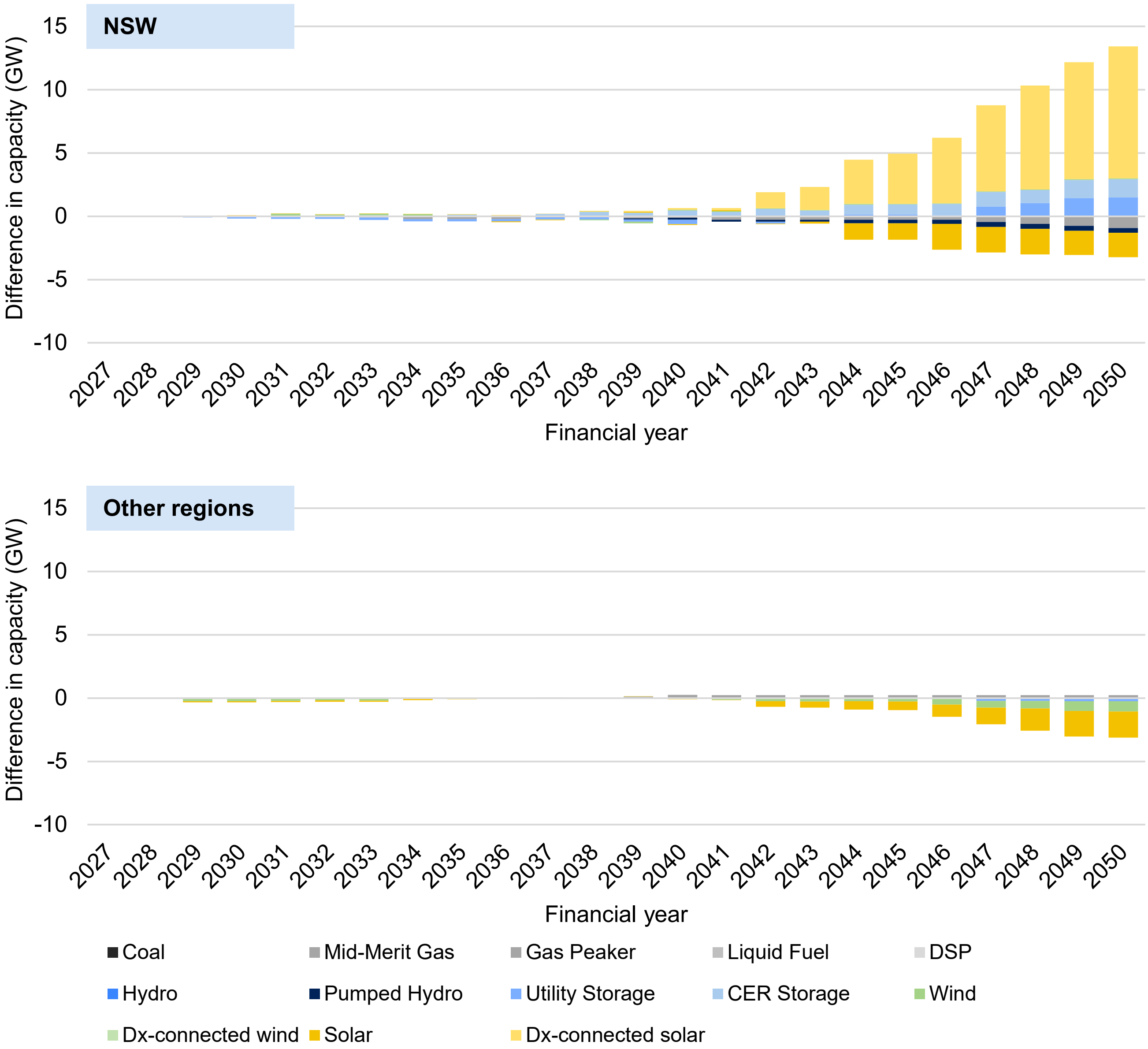
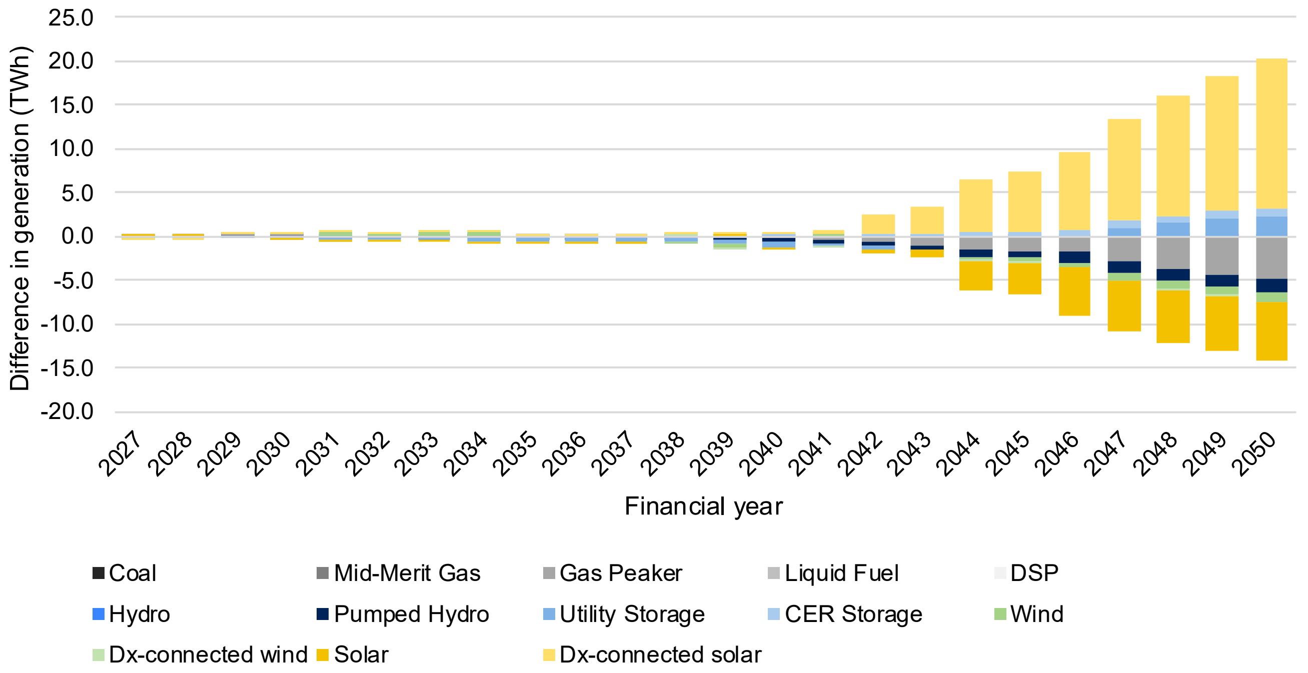


Figure E10 shows how this new investment reduces both transmission-connected solar generation and dispatch of peaking gas (reaching approximately 5 TWh per annum in the second half of the 2040s).

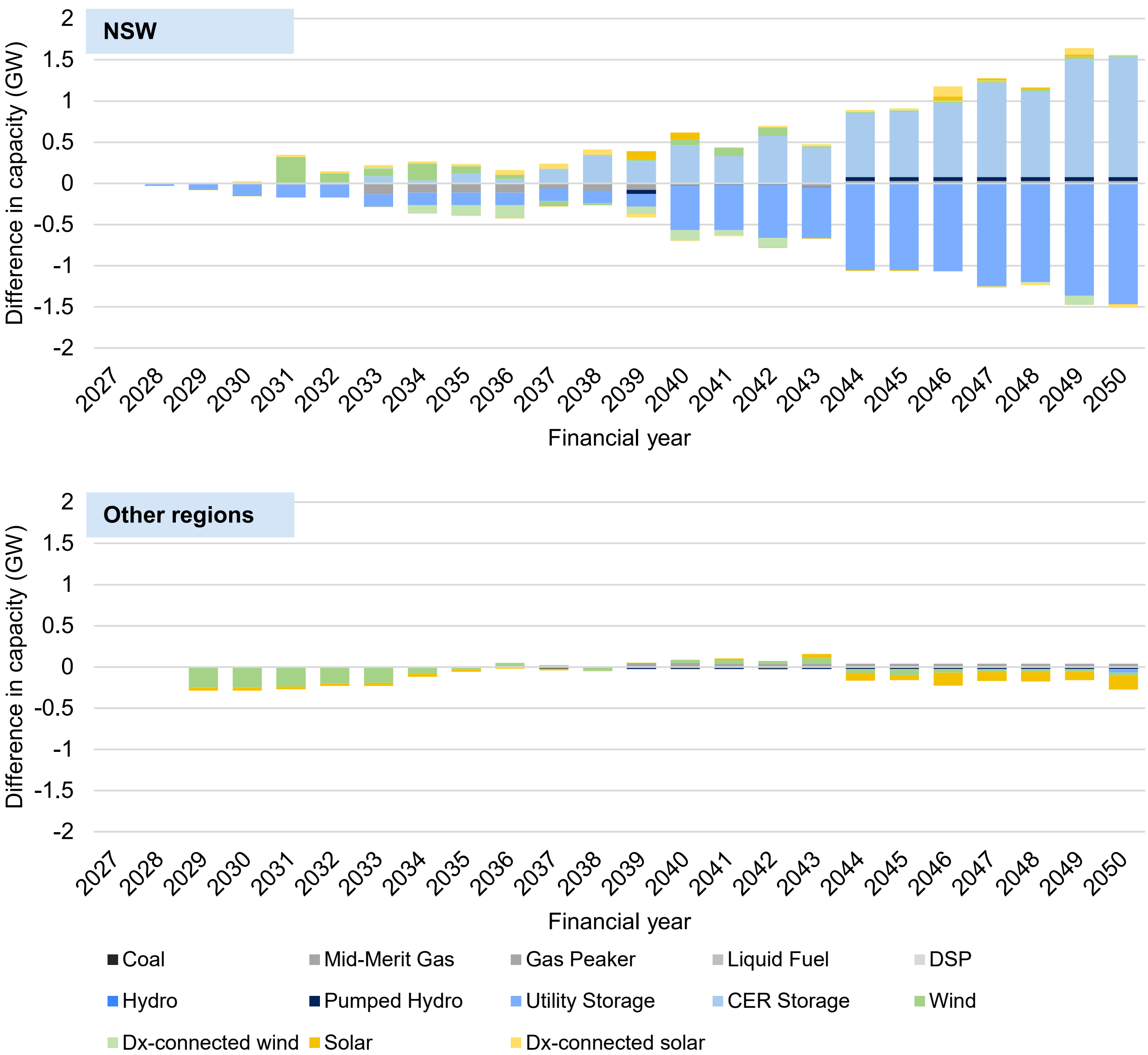
Figure E8: Difference in NEM generation between Unlocking CER and Status quo – Customer transformation



E.2.1.4 Impact of All opportunities unlocked

Figure E12 shows that when all levers are pulled in *All opportunities unlocked*, build and generation outcomes most closely mirror *Unlocking available capacity* with additional benefits derived from reduced long-term storage need through increased CER storage coordination.

Figure E9: Difference in installed capacity between All opportunities unlocked and Unlocking available capacity by region– Customer transformation



E.2.2 Outcomes from *Falling short*

E.2.2.1 *Status quo*

The *Falling short* scenario sees lower demand compared to the *Customer transformation* and *Optimistic case* scenarios due to lower electrification, EV and data centre loads. The reduced demand leads to a lower level of investment and generation in the NEM relative to the *Customer transformation* scenario as shown in Figure E14 and Figure E15. Before the mid-2030s, tighter wind and solar entry limits lead to reduced investment in renewable generation, which temporarily increase reliance on thermal plants relative to the *Customer transformation* scenario.

Figure E10: Difference in NEM capacity in Status Quo between Falling short and Customer transformation

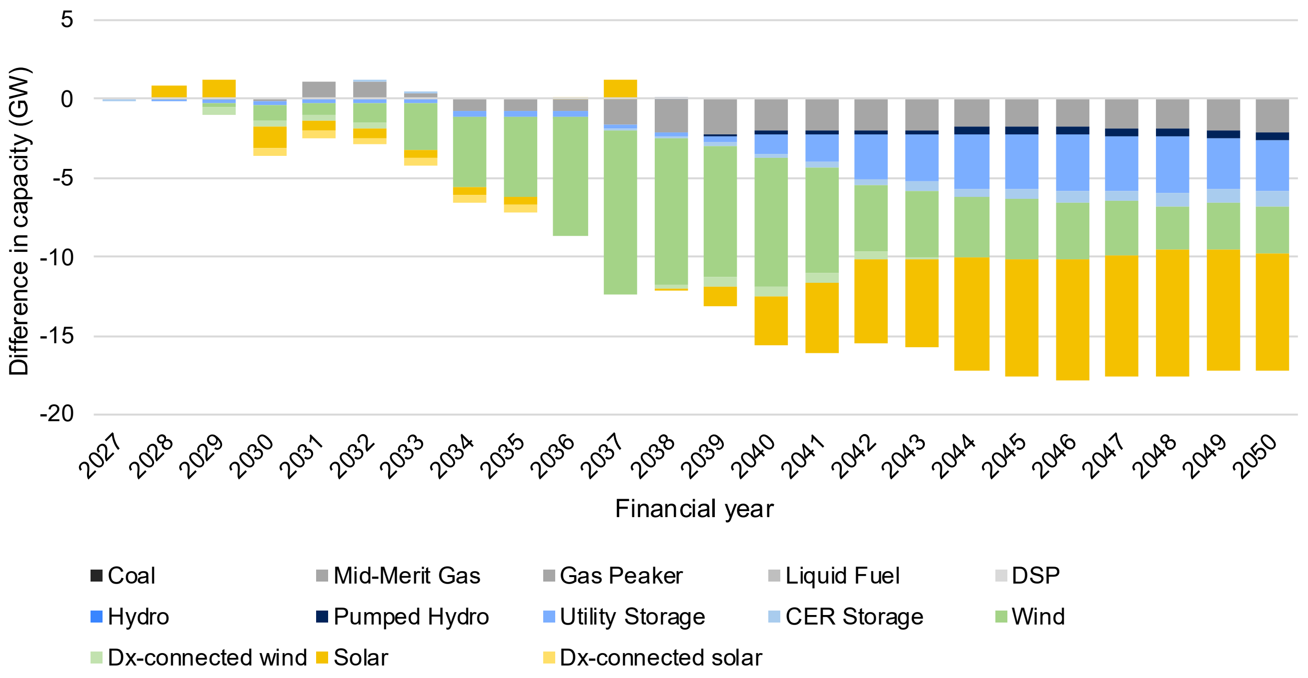
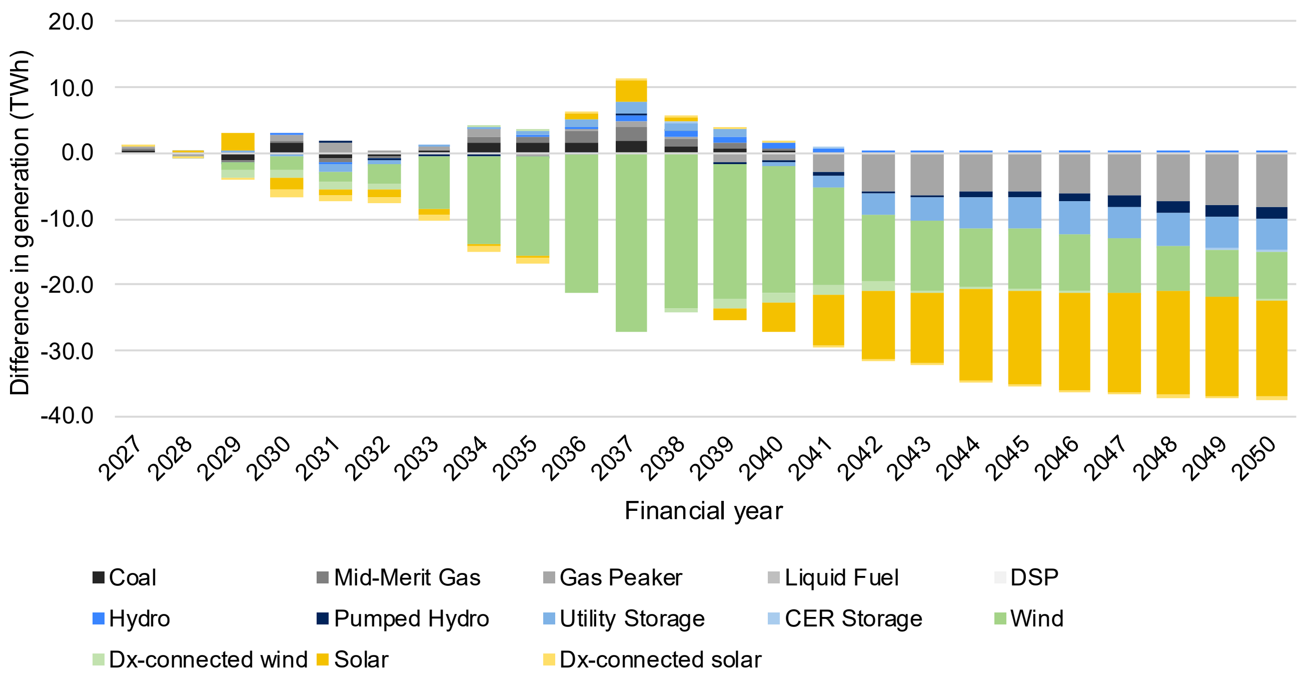


Figure E11: Difference in NEM generation in Status quo between Falling short and Customer transformation



E.2.2.2 Impact of opportunities

As shown in Figure E16, similar dynamics to *Customer transformation* are seen in *Falling short*, whereby distribution-connected generation allows solar investment to be closer to load centres and brings on further wind investment into the NSW energy mix, reducing reliance on GPG dispatch and imports from other states. However, the quantum of investment is moderated due to lower long-term demand assumptions (see Figure E17).

Figure E12: Difference in NEM installed capacity relative to Status quo in FY2050

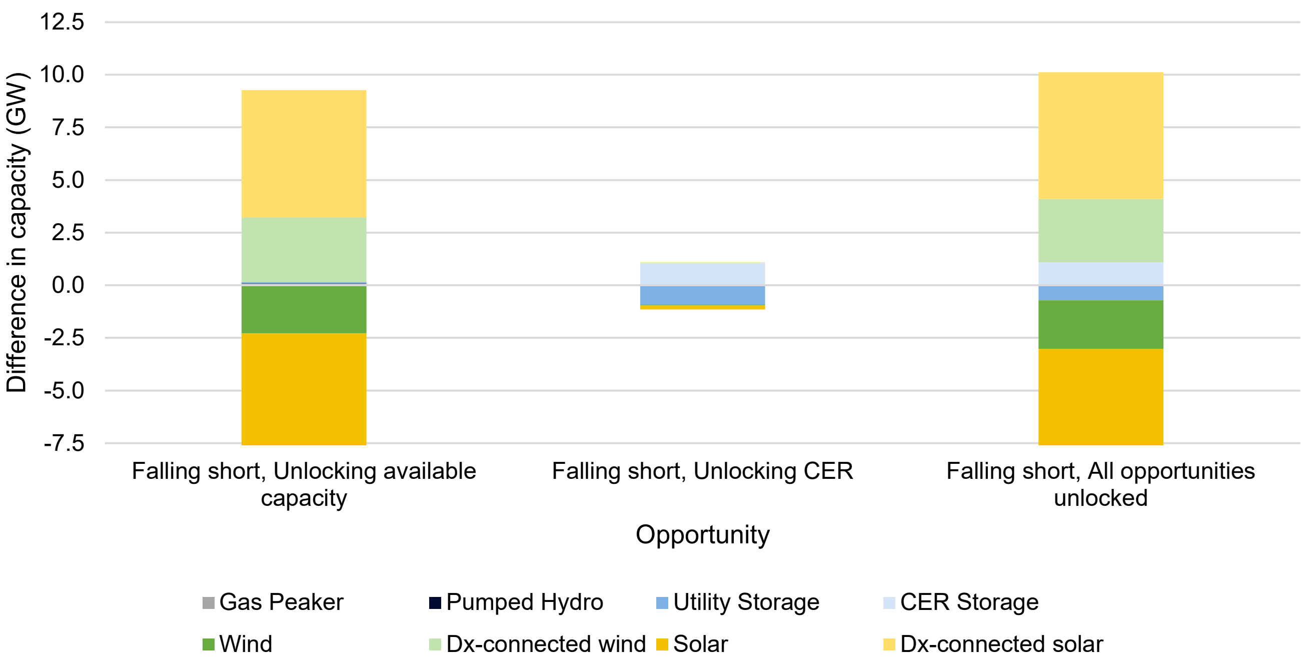
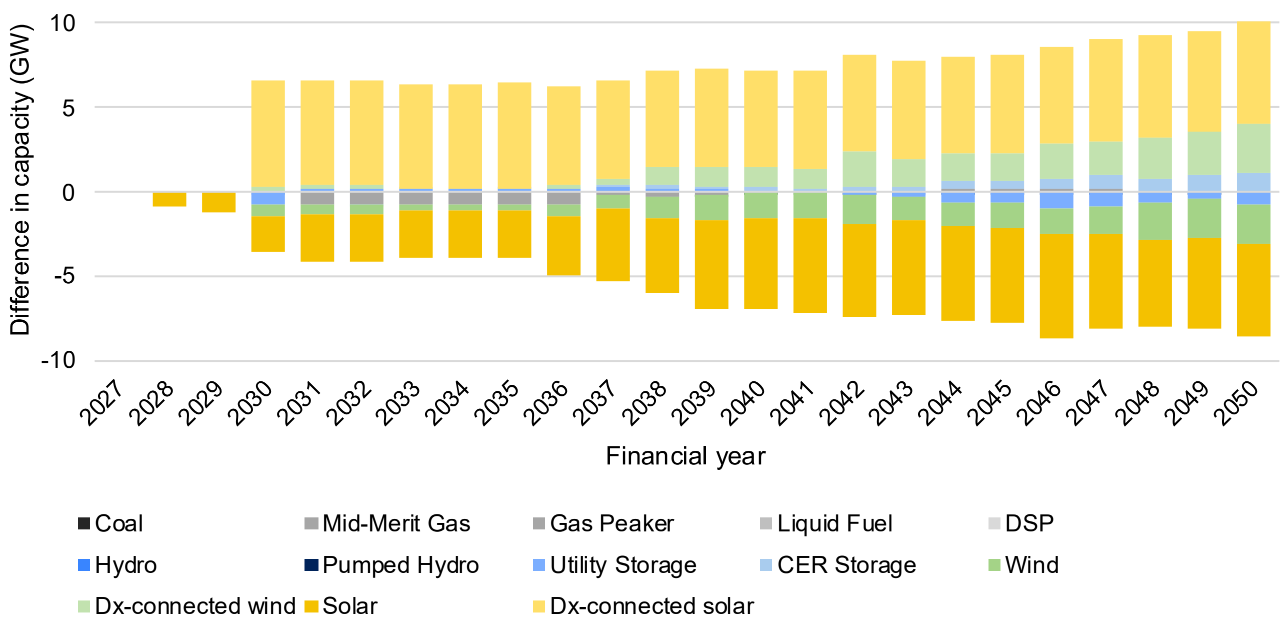
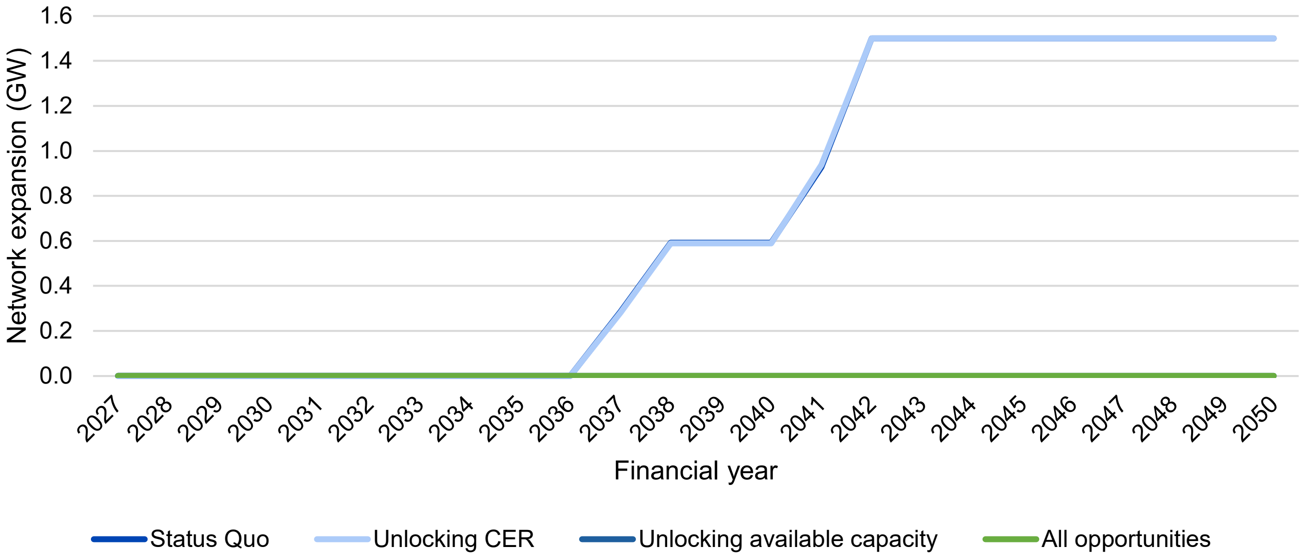


Figure E13: Difference in NEM capacity between Unlocking available capacity and Status quo – Falling short



Additionally, Figure E19 shows how utilisation of distribution network capacity in *Unlocking available capacity* and *All opportunities unlocked* de-risks the transition and buys time for investment in CWO REZ Stage 2 to beyond the appraisal period. Note that New England REZ still sees complete subscription in *Falling short*.

Figure E14: Network augmentation for CWO REZ Stage 2 – Falling short



E.3 Capabilities

The market modelling used in the DSP adopts a similar methodology to that in AEMO's 2024 ISP and examines the impact of various distribution network opportunities on the NSW electricity system. The market model also incorporates hosting capacity, provided by DNSPs, to potentially connect utility-scale wind and solar capacity. This includes the impact on generation investment and dispatch, as well as the implications for future transmission investment.

E.4 Limitations

Modelling for this iteration of the DSP was subject to some limitations. Limited data availability meant that detailed sub-transmission constraints could not be incorporated to accurately capture the curtailment of distribution-connected assets within the market model. However, conservative estimates were employed to avoid overestimating the benefit of distribution-connected generation. Similarly, acknowledging this as a first-of-its-kind exercise, the modelling did not split the Sydney-Newcastle-Wollongong load centre to reflect the topology of Ausgrid and Endeavour's networks within the subregion, with the load aggregated.

Appendix F: Economic appraisal

F.1 Overview

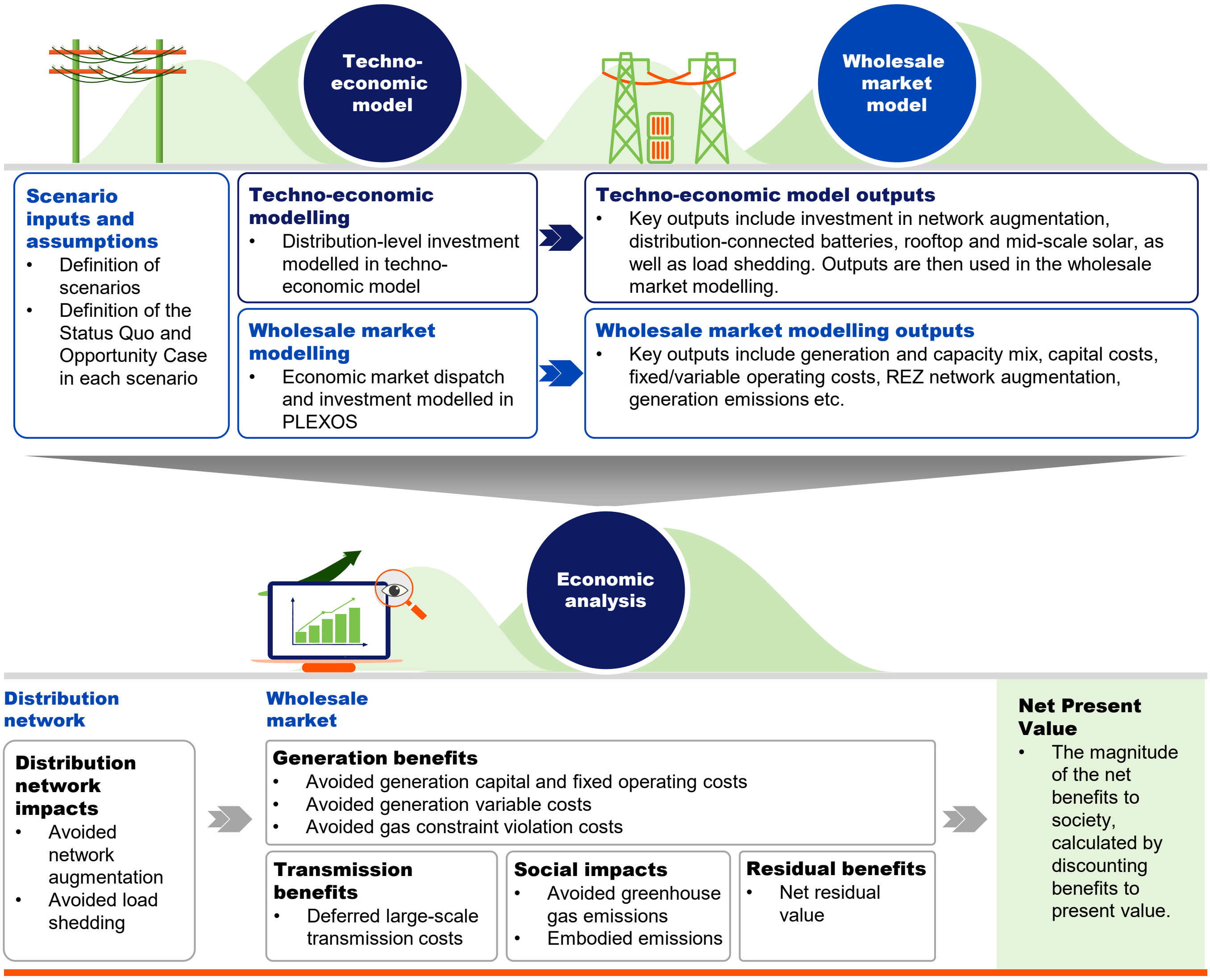
The economic appraisal compares the NEM-wide incremental impacts of the modelled Opportunity Cases relative to a *Status quo*:

- **Status quo**: represents a future with limited coordination of CER, no investment in distribution batteries and no opportunity to leverage hosting capacity in the distribution network.
- **Opportunity Case**: represents a future with the modelled distribution network opportunities: better utilisation of available capacity in the distribution network and optimising the value for and from CER.

The *Status quo* and Opportunity Cases are further detailed in Appendix B.

The approach and parameters used in this appraisal are derived from relevant guidelines and agreed assumptions and inputs from a range of stakeholders including the three DNSPs, NSW Treasury and Infrastructure Australia (IA). The economic appraisal framework is summarised in Figure F1.

Figure F1: DSP economic appraisal framework



The economic appraisal framework includes three components:

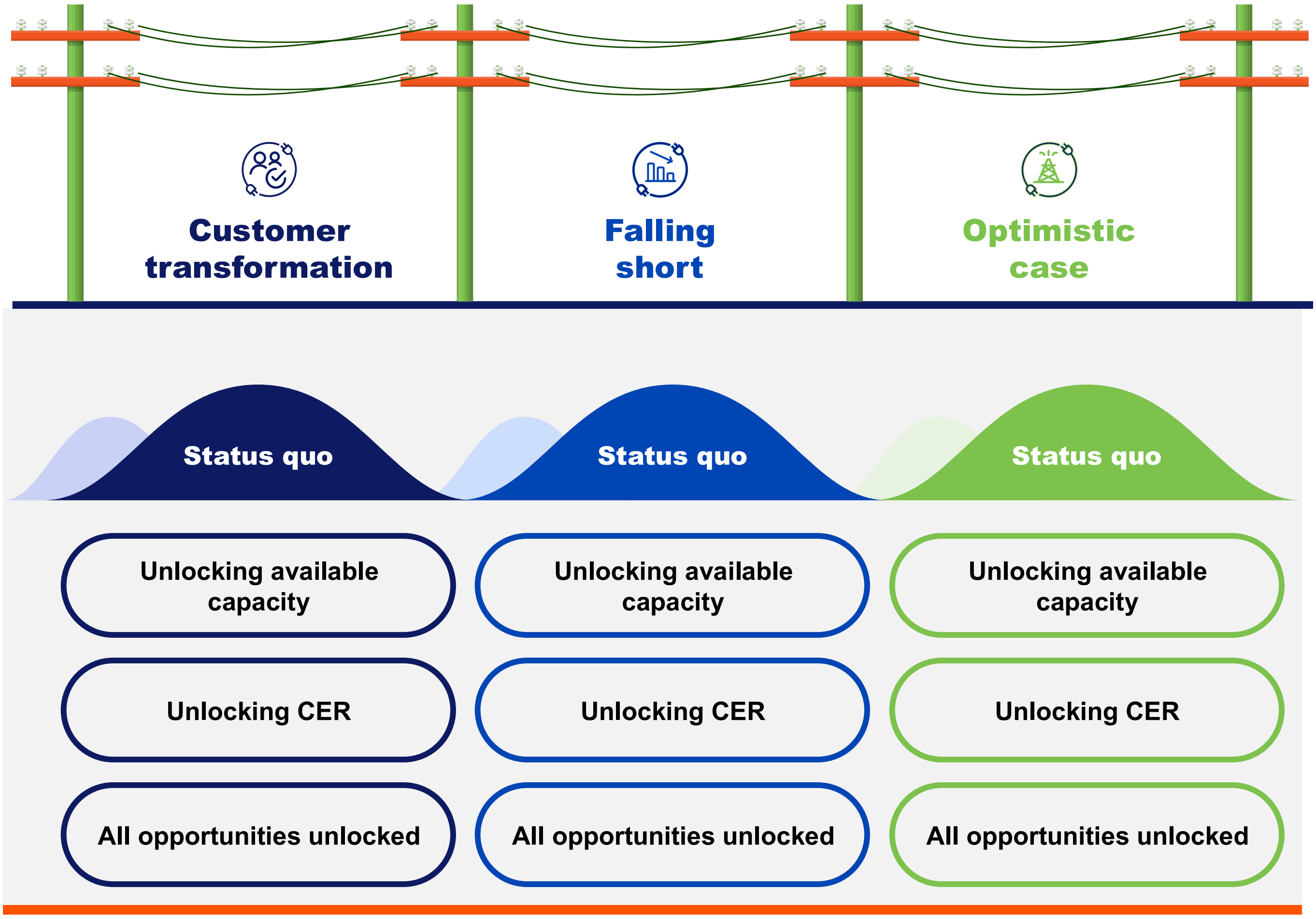
- TEM
- Wholesale market modelling
- Economic analysis

The economic analysis is discussed further below, and the TEM and wholesale market modelling are discussed in Appendix D and Appendix E respectively.

F.2 Modelling opportunities and scenarios

Three future scenarios (outlined in Appendix B) have been considered, within which three Opportunity Cases and a *Status quo* have been modelled. The economic appraisal evaluates each Opportunity Case against its respective *Status quo* for each scenario. This results in a total of nine combinations, as illustrated in Figure F2.

Figure F2: Overview of opportunities and scenarios assessed in the economic appraisal



F.3 Key inputs and assumptions

The key inputs and assumptions used in the economic appraisal include:

- Scenarios of future energy requirement – refer to Appendix B for a description of the three scenarios used in the economic appraisal for more detail.
- Energy market forecasts – outputs from the PLEXOS modelling for NEM-wide for 2027 through to 2050, including the following variables:
  - unserved energy
  - generation by fuel source
  - capacity by fuel source
  - short run marginal costs
  - generation greenhouse gas emissions
  - generation capital expenditure and operating expenditure
  - consumption
  - gas consumption constraint violation costs
  - demand side participation costs
  - REZ transmission augmentation costs

- Distribution network forecasts – outputs from the TEM for 2027 through to 2050, including the following variables:
  - capacity and cost of network augmentation
  - capacity and cost of distribution-connected BESS (2-hour, 4-hour, 8-hour and BTM)
  - capacity and cost of rooftop solar and mid-scale solar
  - load shedding
- Unit rates – primarily based on AEMO, AER documentation and inputs from the DNSPs.
- Applicable evaluation parameters – key input parameters are summarised in Table F1

Table F1: Key input parameters

Parameter	Value	Description
Discount rate, real	7% (central) 5%, 10% (sensitivity analysis)	Consistent with IA guidelines. [6,7,8] Economic appraisal uses a discount rate to convert future costs and benefits into present values, that is the value of those benefits in the present day.
Capital costs	Informed by the DNSPs	The cost of distribution network augmentations required to unlock the modelled hosting capacity across the networks
Capital cost escalation rate (real)	0.4% per year	Equal to the 2018-2025 real compound annual growth rate of the Heavy and civil engineering construction Australia cost index published by the Australian Bureau of Statistics (ABS).[9]
Operational commencement	Financial year 2027	The first year that the distribution network opportunities are implemented
Appraisal period	Financial year 2027 to financial year 2050.	To align with the model years for the energy market forecasts. The residual value of assets (transmission and generation) is included in the last year of evaluation to incorporate the benefits that will continue to be delivered by assets with economic lives that extend beyond the end of the evaluation period. A sensitivity is also included which shows the appraisal results for a 30-year evaluation period which aligns with IA[10] and NSW Treasury[11] guidance.
Price year	Financial year 2025	Most recent completed financial year.
Base year for discounting	Financial year 2025	To align with the price year.
Carbon price (central)	\$87/tCO2-e (2027)-\$446/tCO2 (2050). Held constant thereafter (\$FY25).	Based on the AER Value of Emissions Reduction. Values escalated to \$FY27 at Consumer Price Index (CPI) in the cost-benefit analysis. Financial year values are calculated by averaging the values of the corresponding calendar years (e.g. the financial year 2027 value is the average of the calendar year 2026 and 2027 values).

[6] Infrastructure Australia (2021). *Guide to economic appraisal - Technical guide of the Assessment Framework* (pg. 23).
[7] Oxford Economics (2024). *Discount rates for Energy Infrastructure*, (pg. 47) – guidelines for the 2026 ISP
[8] Note, NSW Treasury guidelines advise a 5% discount rate for use in economic appraisal – this rate was used as a sensitivity for the economic appraisal.
[9] Projecting future escalation of costs based on historical growth is consistent with AER precedence. For example, the AER's preferred method to project wages escalation is to use the ABS wage price index. AER (2024) *Expenditure Forecast Assessment Guideline for Electricity Transmission*. Accessed online at AER - Final decision - Expenditure Forecast Assessment Guidelines - Electricity Transmission - October 2024 (clean version).pdf
[10] Infrastructure Australia (2021). *Guide to economic appraisal - Technical guide of the Assessment Framework* (pg. 24) – road initiatives are used as a proxy for the evaluation period.
[11] NSW Treasury (2023). *NSW Government Guide to Cost-Benefit Analysis* (pg. 30) – NSW Treasury advises 30 to 60 year appraisal period post-construction. The lower end of this period was used to align with IA Guidelines.

F.4 Economic costs

IA guidelines note that only economic costs are to be included in an economic analysis. Economic costs include incremental costs relative to the Base Case necessary to implement each of the opportunities, such as capital and recurrent costs but exclude all sunk costs and transfer payments.

Economic costs are expressed as real values (using a 2025 price base). A real value is a value that has been adjusted to remove the effects of general price level changes over time (i.e. CPI).

F.4.1 Capital costs

The capital costs reflect high-level assumptions from the three DNSPs on the capital works required to unlock the modelled hosting capacity across the networks for *Unlocking available capacity* and *All opportunities unlocked* across all scenarios. The capital costs are escalated using real escalation, which reflects real increases in costs over and above CPI. The cumulative real, escalated, undiscounted net capital expenditure is $2,550m.[12]

The costs associated with coordinating CER are not considered in the economic appraisal. As a result, no capital costs are included in *Unlocking CER*.

F.4.2 Fixed operating and maintenance costs

Fixed operating and maintenance costs includes all the necessary costs relating to operating, maintenance and periodical renewal of the distribution network augmentations.

Operating and maintenance costs are estimated at 1 per cent per annum of the total capital cost. This is considered an appropriate figure for operating costs for distribution and transmission line works and is consistent with the approach taken in the AEMO ISP.[13] The 1 per cent is applied to the escalated capital costs. No further escalation is considered for the operating and maintenance costs.

F.5 Economic benefits

This section discusses the benefits delivered by unlocking opportunities in the distribution network. The economic benefits are summarised into four broad categories:

- **Distribution network benefits** - Avoided load shedding as well as changes in the avoided investment in network augmentation.
- **Transmission benefits** – Investments in large-scale transmission projects can be deferred due to the ability to delay transmission capacity enhancements to the REZs.
- **Generation benefits** – Benefits to society that result from avoided generation capital and operating costs, changes in the variable operating costs incurred to generate electricity and avoided gas constraint violation costs.
- **Social benefits** – Benefits to society that result from decreased greenhouse gas emissions and changes to embodied emissions.

F.5.1 Distribution network benefits

The TEM considers the least-cost investment combination to meet load at the zone substation. As demand approaches the zone substation import limit, the TEM evaluates whether to shed load – at the VCR – or invest in network augmentation, distribution-connected batteries or increased uptake of rooftop and mid-scale solar, depending on the Opportunity Case considered.

Note that the buildout of DBESS and CER coordination also contribute to the other benefits discussed below as the TEM outputs were used in the wholesale market modelling.

Avoided cost of load shedding

Table F2 shows the present value of avoided load shedding. The interventions reduce load shedding across the network. This results in a range of benefits between $50m to $100m across the evaluation period.

[12] The undiscounted costs remain consistent across each opportunity and scenario; however, they differ after discounting due to variations in the timing of capital works

[13] Australian Energy Market Commission (2019). *Draft 2023 Transmission Expansion Options Report*

Table F2: Value of avoided load shedding, all opportunities, (real, discounted, $FY25. Rounded to nearest $50m)

Scenario	Unlocking available capacity	Unlocking CER	All opportunities unlocked
Customer transformation	$100m	$50m	$100m
Falling short	$100m	$50m	$100m
Optimistic case	$100m	$50m	$100m

Avoided network augmentation

Table F3 shows the present value of avoided network augmentation. The deployment of DBESS and CER reduces the need for network augmentation investments as demand grows over the evaluation period. This reduction generates savings ranging from $50m to $200m across the evaluation period. Among the opportunities, *Unlocking CER* delivers the smallest benefits, as the orchestration of CER alone does not significantly defer network augmentation compared to other opportunities.

On the other hand, *Unlocking available capacity* and *All opportunities unlocked* yield between $150m $200m in benefits due to improved utilisation of DER across the network, which defers or avoids more network augmentation than the orchestration of CER.

Table F3: Value of avoided network augmentation, all opportunities, (real, discounted, $FY25. Rounded to nearest $50m)

Scenario	Unlocking available capacity	Unlocking CER	All opportunities unlocked
Customer transformation	$200m	$50m	$200m
Falling short	$150m	$50m	$150m
Optimistic case	$200m	$50m	$200m

F.5.2 Transmission benefits

Deferred large-scale transmission costs

The wholesale market model re-optimises the timing and size of New England REZ and Central-West Orana Stage 2 using linearised augmentation costs. These reflect the cost of augmenting the transmission network to increase the transfer capacity of the REZs and accommodate additional generation.

Table F4 shows the present value for the deferral of large-scale transmission costs. The distribution network opportunities reduce the need for REZ network investment, resulting in $150m in benefits for *Unlocking available capacity* and *All opportunities unlocked* across all scenarios.

There are no transmission augmentation benefits for the *Unlocking CER* opportunity.

Table F4: Deferred large-scale transmission costs, all opportunities, (real, discounted, $FY25. Rounded to nearest $50m)

Scenario	Unlocking available capacity	Unlocking CER	All opportunities unlocked
Customer transformation	$150m	-	$150m
Falling short	$150m	-	$150m
Optimistic case	$150m	-	$150m

F.5.3 Generation benefits

Avoided generation capital expenditure

Avoided capital expenditure is calculated by multiplying the annual change in installed generation capacity by the generation capital expenditure (for each fuel type) using capital cost projections (per kW of generation capacity avoided) for the different generation sources (informed by AEMO ISP assumptions).[14]

By capitalising on capacity in the sub-transmission network, the distribution network opportunities result in the build-out of more renewable generation, especially at the distribution level, compared to the *Status quo*.

[14] Australian Energy Market Operator (2025). *2025 Inputs Assumptions and Scenarios Report.*

Figure F3 and Figure F4 show the change in capacity between the *Status quo* and *All opportunities unlocked* for the *Customer transformation* and *Falling short* scenarios. In addition, Figure F5 shows the change in capacity for *Unlocking CER* for the *Falling short* scenario as it deviates considerable from every other opportunity. For brevity, only these capacity charts are shown.[15]

Although distribution-connected wind and solar do substitute for transmission-connected wind and solar, overall, there is a net increase in renewable generation capacity in the Opportunity Cases compared to the *Status quo* cases (Figure F3 and Figure F4). This additional capacity acts as a substitute for existing gas generation (discussed further in the avoided generation variable cost benefit).

In *Unlocking CER* in the *Falling short* scenario, the coordination of CER substitutes for utility storage, leading to a less utility storage and solar build (which usually pairs with utility storage). Alongside the lower demand profile, this means that less generation capacity is required in this scenario compared to the *Status quo* (Figure F5).

Figure F3: Change in total capacity from Status quo to All opportunities unlocked for Customer transformation scenario

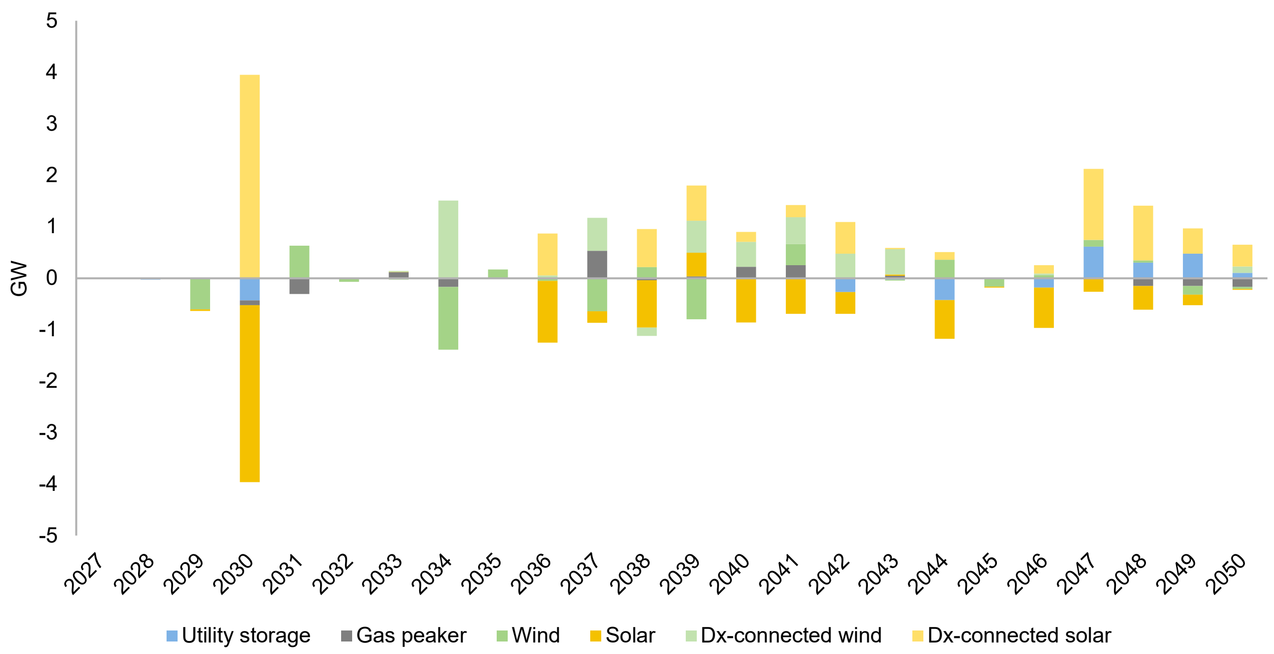
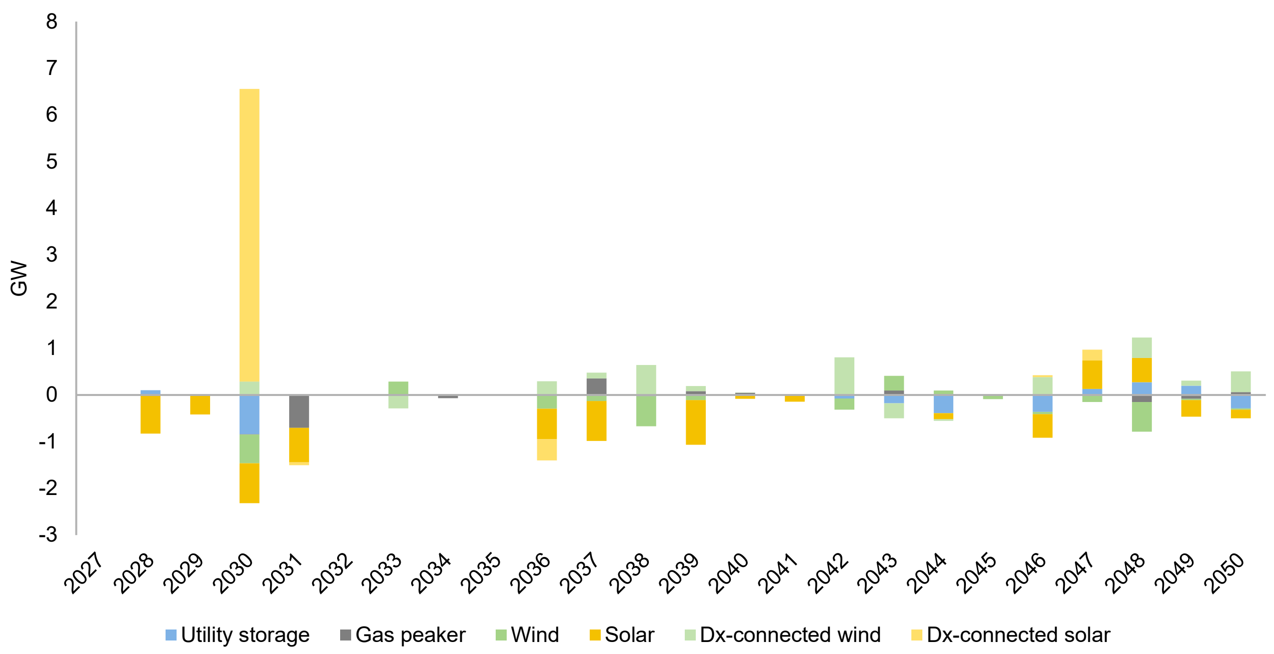


Figure F4: Change in total capacity from Status quo to All opportunities unlocked for Falling short scenario



[15] As discussed in Appendix E.2.2.1, there is a long-term convergence of market outcomes between *Customer transformation* and *Optimistic case*. As such, the *Optimistic case* is not shown. *All opportunities unlocked* is a combination of the outcome of both *Unlocking available capacity* and *Unlocking CER* and is presented in place of separately showing each individual opportunity. For *Falling short*, this opportunity deviates considerably from the other scenarios and is shown to support the analysis.

Figure F5: Change in total capacity from Status quo to Unlocking CER for Falling short scenario

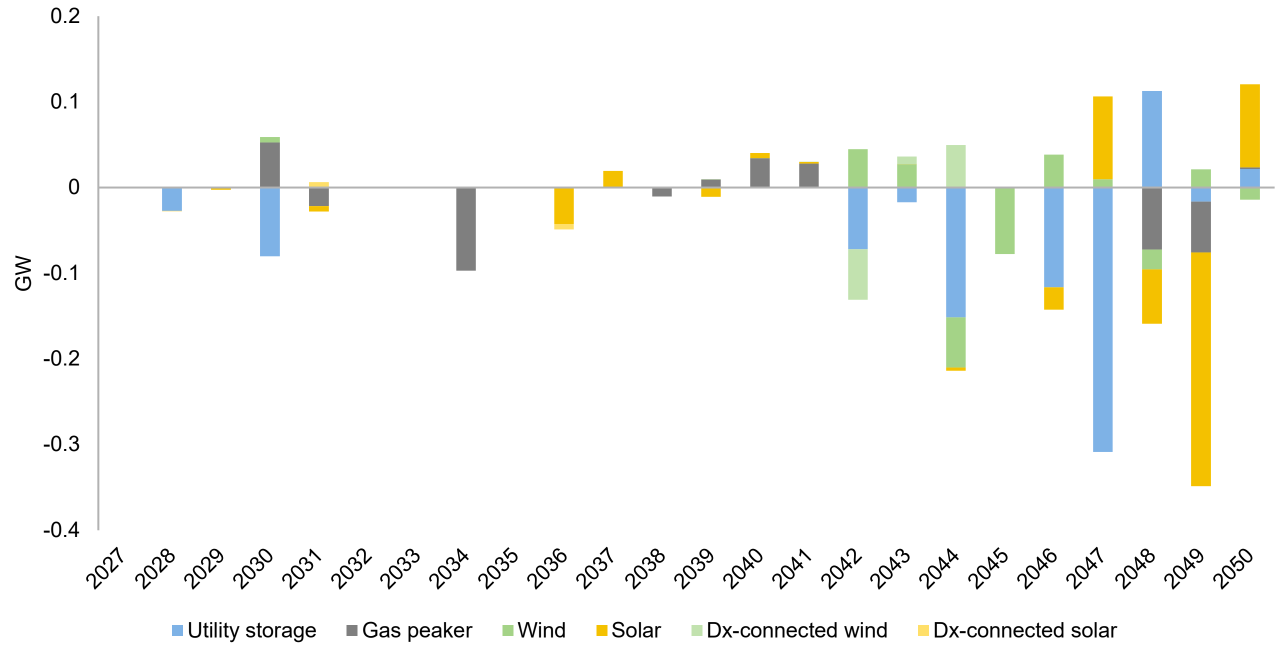


Table F5 shows the present value of avoided generation capital costs, for each opportunity. For each scenario except for *Unlocking CER, Falling short*, more generation is built in the opportunity case compared to its respective *Status quo*, resulting in negative benefits. In *Unlocking CER*, *Falling short*, the reduction in utility storage and solar paired with low demand means less generation is built overall, resulting in positive benefits for this opportunity.

Table F5: Avoided generation capital costs, all opportunities, (real, discounted, $FY25. Rounded to nearest $50m)

Scenario	Unlocking available capacity	Unlocking CER	All opportunities unlocked
Customer transformation	-$1,900m	-$250m	-$1,050m
Falling short	-$1,450m	$650m	-$950m
Optimistic case	-$1,850m	-$350m	-$800m

Avoided generation fixed operating and maintenance costs

Fixed operating and maintenance expenditure is calculated based on the unit costs (informed by AEMO ISP assumptions)[16] and the capacity mix of each opportunity. Only fixed operating and maintenance costs are considered in this benefit category, with the results for changes in variable operating costs shown below.

The change in the generation mix from the *Status quo* to the Opportunity Cases also leads to a resulting change in the fixed operating and maintenance expenditure.

Table F6 shows the present value of avoided generation fixed operating and maintenance expenditure. For the most part, *Unlocking available capacity* and *All opportunities unlocked* across all scenarios see an increase in generation fixed operating and maintenance expenditure, reflecting the uplift in the build-out of additional renewable generation capacity seen in these opportunities. *Unlocking CER* across all scenarios does avoid generation fixed operating and maintenance expenditure due to the lower build-out in generation capacity, especially utility storage and solar.

Table F6: Avoided generation fixed operating and maintenance costs, all opportunities, (real, discounted, $FY25. Rounded to nearest $50m)

Scenario	Unlocking available capacity	Unlocking CER	All opportunities unlocked
Customer transformation	-$150m	$50m	-
Falling short	-$250m	$100m	-$100m
Optimistic case	-$200m	$50m	-$50m

[16] Australian Energy Market Operator (2025). 2025 Inputs Assumptions and Scenarios Report.

Avoided generation variable costs

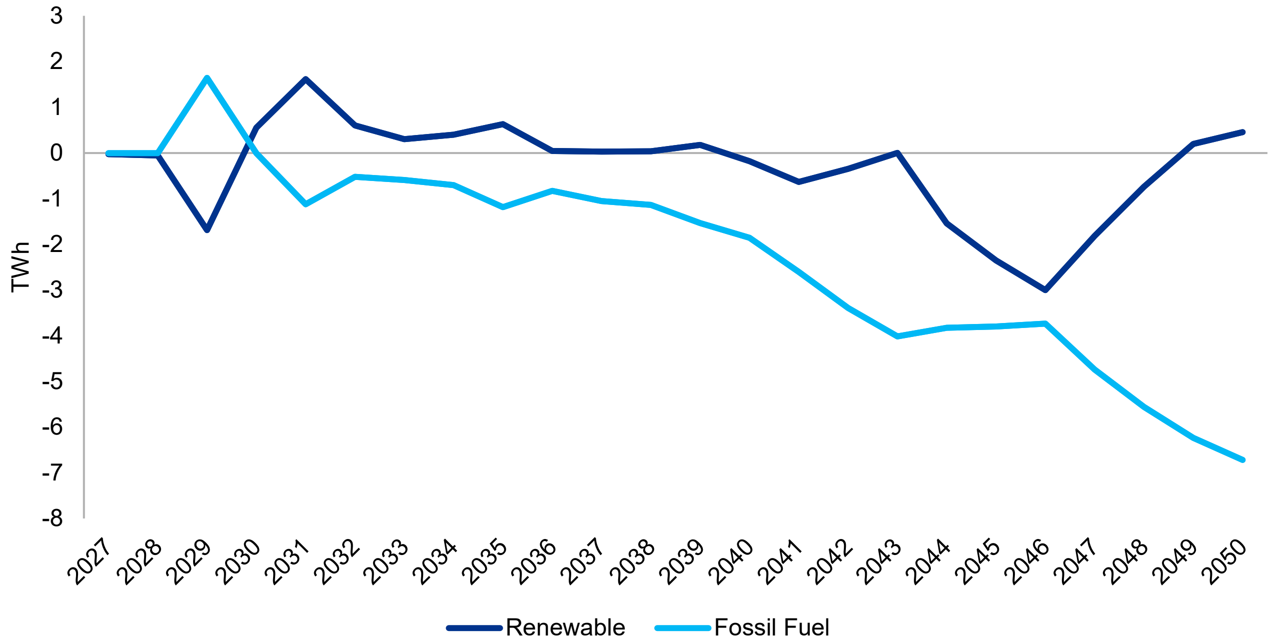
The variable costs of electricity generation are calculated by multiplying annual generation by the short run marginal cost for each fuel type (informed by AEMO ISP assumptions)[17] - a function of the variable operating and maintenance cost, the heat rate and the fuel cost. The short run marginal cost of renewable energy sources, including solar, battery storage, offshore wind and onshore wind is zero. Coal and gas-powered generation have higher short run marginal costs.

Figure F6 and Figure F7 show the change in renewable and fossil fuel generation between the *Status quo* and *All opportunities unlocked* for the *Customer transformation* and *Falling short* scenarios respectively. Figure F8 shows the change for *Unlocking CER* for the *Falling short* scenario. For *All opportunities unlocked* in the *Customer transformation*, the increase in renewable generation capacity leads to the displacement of significant fossil fuel generation.

For *All opportunities unlocked* (Figure F7) in the *Falling short* scenario, the lower demand profile results in more fossil fuel generation being offset by renewable generation during the 2030s, leading to greater reductions in fossil fuel generation compared to the *Customer transformation* scenario. The gap in generation between the two sources reduces over time as transmission delays and supply chain constraints are alleviated.

In *Unlocking CER* in the *Falling short* scenario, the lower demand profile means that the orchestration of CER effectively acts as a substitute for some renewable generation (utility storage for the most part) and therefore displaces renewable generation and not fossil fuel generation. This means that there no net reduction in generation variable costs for this opportunity.

Figure F6: Change in renewable and fossil fuel generation from Status quo to All opportunities unlocked for Customer transformation Scenario



[17] Ibid.

Figure F7: Change in renewable and fossil fuel generation from Status quo to All opportunities unlocked for Falling short Scenario

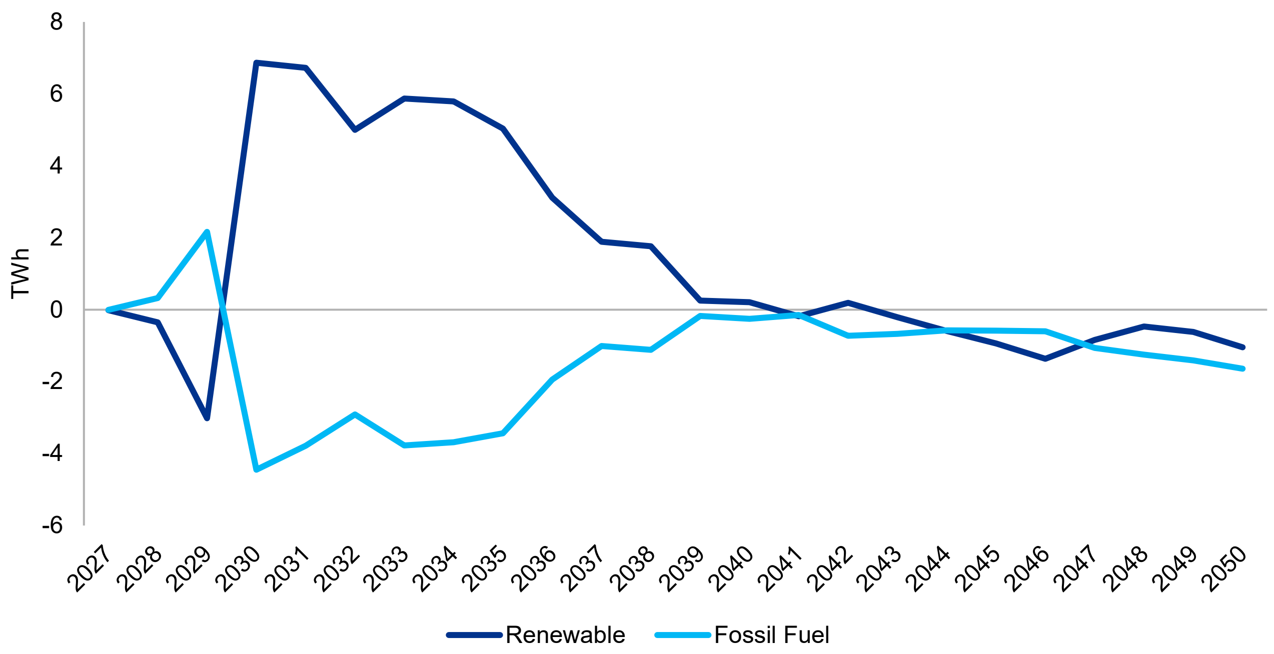


Figure F8: Change in renewable and fossil fuel generation from Status quo to Unlocking CER for Falling short Scenario

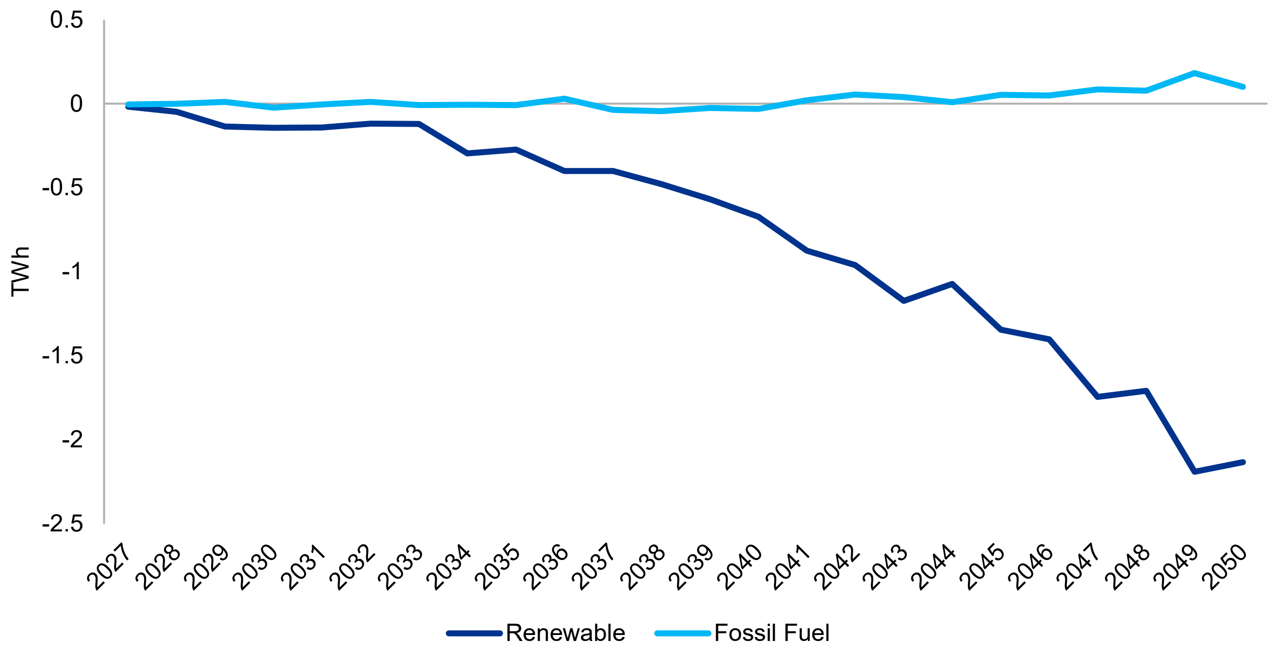


Table F7 shows the present value of the avoided generation variable costs. Across all scenarios, *Unlocking available capacity* and *All opportunities unlocked* have substantial benefits, ranging from $2,250m to $2,400m. *Unlocking CER* for the *Customer transformation* and *Optimistic case* has lower benefits as only orchestrating CER does not displace significant fossil fuel generation. As discussed above, *Unlocking CER* of *Falling short* as no benefits as fossil fuel generation is not abated.

Table F7: Avoided generation variable costs, all opportunities, (real, discounted, $FY25. Rounded to nearest $50m)

Scenario	Unlocking available capacity	Unlocking CER	All opportunities unlocked
Customer transformation	$2,400m	$700m	$2,400m
Falling short	$1,900m	-	$1,900m
Optimistic case	$2,300m	$750m	$2,250m

Avoided gas constraint violation costs

If demand for gas-powered generation exceeds the available supply of gas each year, additional costs are assumed to be incurred to switch from gas to more expensive liquid fuels such as diesel. This benefit category reflects the reduction in these costs in the Opportunity Case compared to the *Status quo*. The assumed gas constraint is 800 capacity TJ/day across all three scenarios.

Table F8 shows the present value of the avoided gas violation cost. Reducing fossil fuel use (which is mostly gas) across most opportunities leads to a resulting reduction in the degree that gas use exceeds the daily capacity, resulting in positive benefits. As *Unlocking CER* in the *Falling short* scenario does not have any benefit as in this opportunity, no gas use is offset.

Table F8: Avoided gas constraint violation costs, all opportunities, (real, discounted, $FY25. Rounded to nearest $50m)

Scenario	Unlocking available capacity	Unlocking CER	All opportunities unlocked
Customer transformation	$450m	$200m	$500m
Falling short	$250m	-	$250m
Optimistic case	$500m	$250m	$500m

F.5.4 Social impacts

Avoided greenhouse gas emissions

As demonstrated for the avoided generation variable cost benefit, most opportunities result in the reduction of fossil fuel generation. Figure F9 shows the cumulative emissions avoided for the *All opportunities unlocked* for *Customer transformation* scenario, *All opportunities unlocked* for *Falling short* scenario and *Unlocking CER* for *Falling short* scenario. The cumulative greenhouse gas emissions that are abated reflect the reduction in fossil fuel generation discussed in the avoided generation variable cost benefit.

The economic appraisal applies AER values of emissions reduction to the total emissions abated, illustrated in Figure F10. The value per tonne of greenhouse gases emitted increases over time until 2050 and is held constant thereafter. The AER publishes values on a calendar year basis. For the purposes of the economic appraisal, financial year values are calculated by averaging the values of the corresponding calendar years (e.g. the financial year 2027 value is the average of the calendar year 2026 and 2027 values). These have been escalated from $FY23 values to $FY25 using the Consumer Price Index.

Figure F9: Cumulative greenhouse gas emissions avoided, All opportunities unlocked for Customer transformation scenario, All opportunities unlocked for Falling short scenario, Unlocking CER for Falling short scenario

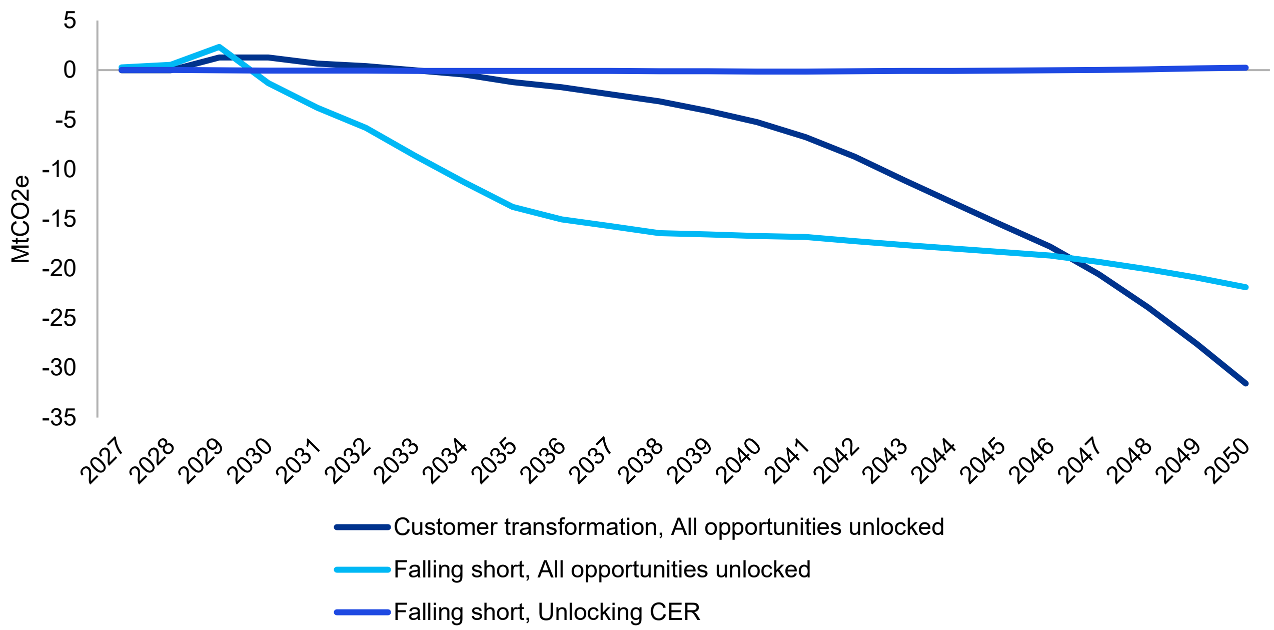
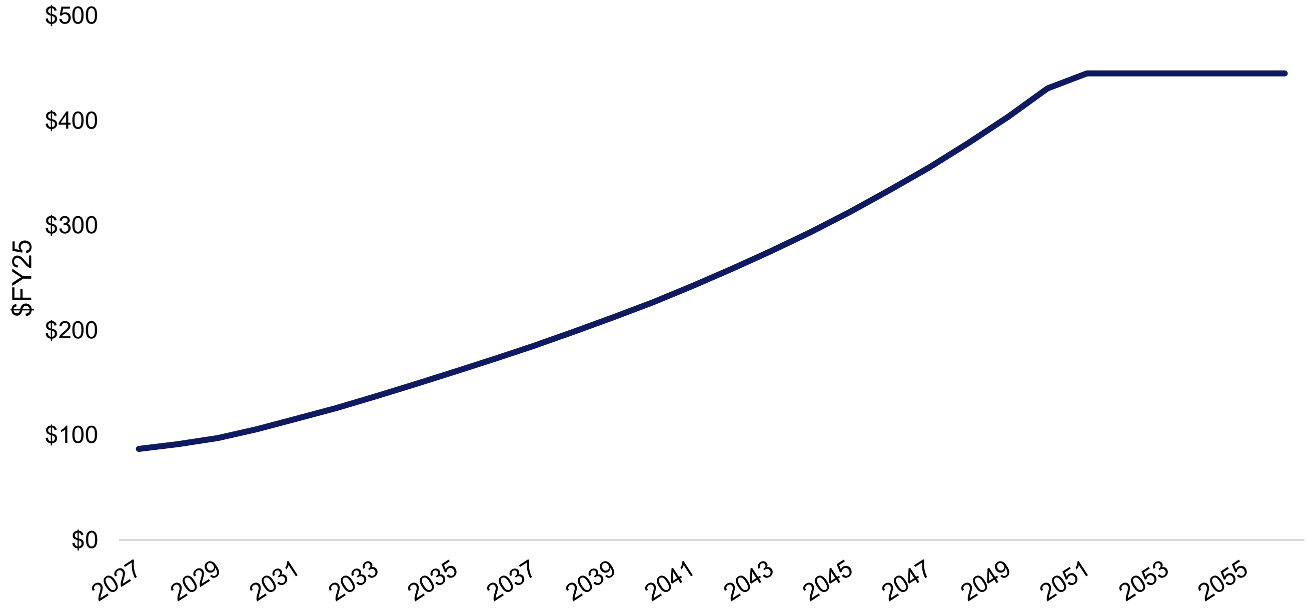


Figure F10: Value of greenhouse gas emissions, \$/tCO2-e (\$FY25)



Source: AER (2024), Valuing emissions reduction, Table 1, ABS CPI

Table F9 shows the present value of avoided greenhouse gas emissions for all opportunities.

Table F9: Avoided greenhouse gas emissions, all opportunities, (real, discounted, \$FY25. Rounded to nearest \$50m)

Scenario	Unlocking available capacity	Unlocking CER	All opportunities unlocked
Customer transformation	\$2,600m	\$900m	\$2,550m
Falling short	\$1,800m	-	\$1,750m
Optimistic case	\$2,600m	\$900m	\$2,550m

Embodied emissions

Greenhouse gases are emitted during the construction of transmission and generation infrastructure. These are referred to as embodied emissions and are estimated by applying the Australian Government calculation methodologies and parameter values. [18]

Construction emissions are estimated by multiplying the Australian Government benchmarks for materials share of capital expenditure and carbon emissions per dollar of expenditure. The materials share used in this analysis is 23 per cent.[19] Embodied emissions are monetised using the same values of emissions as illustrated in Figure F10.

The present value of the embodied emissions for each opportunity is shown in Table F10. The net increase in the construction of additional generation and distribution augmentation, offset by a small degree by the deferral of large-scale transmission costs, leads to a net increase in embodied emissions (and therefore negative benefits) for all opportunities except for *Unlocking CER* of the *Falling short* opportunity. This opportunity sees a net reduction in embodied emissions due to there being a net reduction in generation capital expenditure and there being no distribution augmentation capital expenditure.

Table F10: Embodied emissions, all opportunities, (real, discounted, \$FY25. Rounded to nearest \$50m)

Scenario	Unlocking available capacity	Unlocking CER	All opportunities unlocked
Customer transformation	-\$450m	-\$150m	-\$400m
Falling short	-\$250m	\$100m	-\$200m
Optimistic case	-\$500m	-\$200m	-\$350m

[18] Infrastructure and transport ministers (2024). Embodied Carbon Measurement for Infrastructure. Accessed online at *Embodied Carbon Measurement for Infrastructure Technical Guidance*

[19] Infrastructure and transport ministers (2024). Embodied Carbon Measurement for Infrastructure. Accessed online at *Embodied Carbon Measurement for Infrastructure Technical Guidance*. As there was not a materials share available for Distribution/Transmission Line, a figure of 23 per cent was used, which represents the average across all infrastructure types.

F.5.5 Residual benefits

Net residual asset value

The appraisal period includes 24 years of operations to align with the energy market modelling. Notwithstanding this, the investment in other generation and distribution infrastructure required in both the *Status quo* and the opportunities may have an economic life beyond the end of the appraisal period. The residual value is an estimate of the economic benefit of the generation and distribution infrastructure from the end of the appraisal period to the end of the economic life of the asset. Table F11 shows the asset lives for the different infrastructure assets.

Table F11: Assumed asset useful life (years)[20]

Benefit	Asset life
Transmission	50
Distribution infrastructure	58
OCGT	40
Large scale Solar PV	30
Battery storage (1-8 hrs storage)	20
Wind – onshore	30
Wind – offshore	30
Pumped hydro	50

Table F12 shows the present value of net residual asset value for all the opportunities. The residual assert value is positive for all scenarios, reflecting that there is a net increase in generation and distribution infrastructure, except for *Unlocking CER* of the *Falling short* opportunity which has a net reduction in the asset build-out.

Table F12: Net residual asset value, all opportunities, (real, discounted, $FY25. Rounded to nearest $50m)

Scenario	Unlocking available capacity	Unlocking CER	All opportunities unlocked
Customer transformation	$1,400m	$600m	$1,150m
Falling short	$600m	-$200m	$450m
Optimistic case	$1,350m	$650m	$1,100m

F.6 Economic results

The economic appraisal presents the economic results using the net present value (NPV), which gives an indication of the magnitude of the net benefit to society, calculated by taking the difference between the present value of the total incremental benefits and the present value of the total incremental costs. A positive NPV indicates that an investment is desirable to society as a whole.

F.6.1 Core results

The economic evaluation results (applying a 7 per cent discount rate) for all scenarios are presented in Table F13. The NPVs range from $700m for *Unlocking CER* in the *Falling short* scenario to $4,300m for *All opportunities unlocked* for the *Optimistic case* scenario.

The positive NPVs are mostly driven by a significant reduction in gas generation across all opportunities except for *Unlocking CER* in the *Falling short* scenario, which does not reduce gas generation. The reduction in gas generation decreases generation variable costs, reduces emissions and avoids gas constraint violation costs. Offsetting these benefits is the build-out more renewable generation that result from the unlocking of capacity in the distribution network. This also leads to higher generation fixed operating costs.

The residual value of assets is another large contributor to benefits. This is driven by the 24-year evaluation period, meaning there is a large asset base still available at the end of the evaluation period in 2050.

The distribution network benefits that are derived from the reduction in load shedding and deferred network augmentations contribute are a relatively small overall contributor to the total benefits.

[20] AEMO 2025 ISP inputs and assumptions workbook, Lead time and project life worksheet; AER Regulatory Depreciation

Table F13: Economic evaluation results, all opportunities (real, discounted, $FY25. Rounded to nearest $50m $FY25. Rounded to nearest $50m)[21]

	Customer transformation			Falling short			Optimistic case		
Category	**Unlocking available capacity**	**Unlocking CER**	**All opportunities unlocked**	**Unlocking available capacity**	**Unlocking CER**	**All opportunities unlocked**	**Unlocking available capacity**	**Unlocking CER**	**All opportunities unlocked**
Benefits									
Distribution network benefits									
Avoided cost of load shedding	$100m	$50m	$100m	$100m	$50m	$100m	$100m	$50m	$100m
Deferred network augmentations	$200m	$50m	$200m	$150m	$50m	$150m	$200m	$50m	$200m
Transmission network benefits									
Deferred large-scale transmission costs	$150m	-	$150m	$150m	-	$150m	$150m	-	$150m
Generation benefits									
Avoided generation capital costs	-$1,900m	-$250m	-$1,050m	-$1,450m	$650m	-$950m	-$1,850m	-$350m	-$800m
Avoided generation fixed operating costs	-$150m	$50m	-	-$250m	$100m	-$100m	-$200m	$50m	-$50m
Avoided generation variable costs	$2,400m	$700m	$2,400m	$1,900m	-	$1,900m	$2,300m	$750m	$2,250m
Avoided gas constraint violation costs	$450m	$200m	$500m	$250m	-	$250m	$500m	$250m	$500m
Social benefits									
Avoided GHG emissions	$2,600m	$900m	$2,550m	$1,800m	-	$1,750m	$2,600m	$900m	$2,550m
Net embodied emissions	-$450m	-$150m	-$400m	-$250m	$100m	-$200m	-$500m	-$200m	-$350m
Residual value									
Net residual value	$1,400m	$600m	$1,150m	$600m	-$200m	$450m	$1,350m	$650m	$1,100m
Total benefits	**$4,750m**	**$2,150m**	**$5,600m**	**$3,000m**	**$700m**	**$3,500m**	**$4,700m**	**$2,150m**	**$5,650m**

[21] Figures may not sum precisely due to rounding.

	Customer transformation			Falling short			Optimistic case		
Category	**Unlocking available capacity**	**Unlocking CER**	**All opportunities unlocked**	**Unlocking available capacity**	**Unlocking CER**	**All opportunities unlocked**	**Unlocking available capacity**	**Unlocking CER**	**All opportunities unlocked**
Costs									
Distribution REZ network augmentation capital expenditure	$1,300m	-	$1,300m	$1,350m	-	$1,350m	$1,250m	-	$1,250m
Distribution REZ network augmentation operating expenditure	$100m	-	$100m	$100m	-	$100m	$100m	-	$100m
Total costs	**$1,400m**	**-**	**$1,400m**	**$1,450m**	**-**	**$1,450m**	**$1,350m**	**-**	**$1,350m**
Net Present Value	**$3,400m**	**$2,150m**	**$4,200m**	**$1,550m**	**$700m**	**$2,050m**	**$3,350m**	**$2,150m**	**$4,300m**

F.6.2 Sensitivity analysis

Sensitivity analysis acknowledges and accounts for a degree of uncertainty surrounding opportunities and scenarios. It tests the impact on overall economic appraisal results of changes to key variables, including:

- Discount rates of 5 per cent and 10 per cent
- Excluding distribution REZ network augmentation capital expenditure
- 30-year evaluation period until 2056, aligning with IA and NSW Treasury guidance. Annual values are held constant from 2050 until 2056.

The NPV and incremental change from the core results are shown for each sensitivity test are presented in Table F14.

The results of the sensitivity analysis align with the results of the core analysis – the opportunities are robust to changes in all of the key assumptions and parameter values. The results of all sensitivity analyses are as expected:

- The economic rationale for the opportunities increases with a lower discount rate (as the present value of future benefits is discounted less) and decreases with a higher discount rate (as the present value of future benefits is discounted more). Given that the benefits of most infrastructure-related projects are realised after the costs are incurred, they are generally more sensitive to the discount rate applied.
- Removing distribution REZ network augmentation leads to higher NPVs in *Unlocking available capacity* and *All opportunities unlocked* across all scenarios, as the elimination of associated costs increases the overall NPV.
- A later evaluation period leads to significantly higher NPVs. This is due to much lower gas generation in 2050 in the Opportunity Cases compared to the *Status quo*, which results in avoided generation variable costs and emission benefits beyond 2050, as the values from 2050 are held constant.

Table F14: Economic sensitivity evaluation results (NPV, real, discounted, $FY25. Rounded to nearest $50m)[22]

	Customer transformation			Falling short			Optimistic case		
Category	**Unlocking available capacity**	**Unlocking CER**	**All opportunities unlocked**	**Unlocking available capacity**	**Unlocking CER**	**All opportunities unlocked**	**Unlocking available capacity**	**Unlocking CER**	**All opportunities unlocked**
Core results	**$3,400m**	**$2,150m**	**$4,200m**	**$1,550m**	**$700m**	**$2,050m**	**$3,350m**	**$2,150m**	**$4,300m**
5% discount rate	$5,300m **(+$1,950m)**	$3,050m **(+$900m)**	$6,350m **(+$2,150m)**	$2,400m **(+$850m)**	$850m **(+$150m)**	$2,950m **(+$950m)**	$5,200m **(+$1,900m)**	$3,000m **(+$850m)**	$6,350m **(+$2,100m)**
10% discount rate	$1,750m **(-$1,650m)**	$1,400m **(-$800m)**	$2,350m **(-$1,850m)**	$800m **(-$800m)**	$550m **(-$200m)**	$1,150m **(-$900m)**	$1,750m **(-$1,600m)**	$1,350m **(-$800m)**	$2,450m **(-$1,800m)**
No distribution REZ network augmentation capital expenditure	$4,600m **(+$1,200m)**	$2,150m **(-)**	$5,400m **(+$1,200m)**	$2,800m **(+$1,250m)**	$700m **(-)**	$3,300m **(+$1,250m)**	$4,500m **(+$1,150m)**	$2,150m **(-)**	$5,450m **(+$1,150m)**
Evaluation period ended in 2056	$5,400m **(+$2,050m)**	$3,850m **(+$1,700m)**	$6,450m **(+$2,250m)**	$2,000m **(+$450m)**	$850m **(+$150m)**	$2,600m **(+$550m)**	$5,350m **(+$2,050m)**	$3,800m **(+$1,700m)**	$6,550m **(+$2,250m)**

[22] The changes from the core results are shown in brackets. Figures may not sum precisely due to rounding.

Appendix G: Energy Behavioural Demand Model

G.1 Overview of key findings

G.1.1 What is EBDM?

The Energy Behavioural Demand Model (EBDM) simulates household decision-making regarding electricity consumption and investment in CER technologies. It is best used to evaluate the impact of policy and pricing interventions on the behaviour of households. EBDM represents detailed household-level demand profiles and uptake of various CER technologies and focuses on BTM impacts.

EBDM is a novel approach for estimating how customers might respond to changes in supply, prices, policies or energy market conditions. While EBDM is still in development and further work is needed to enhance its behavioural sophistication, it represents a meaningful step forward in addressing the limitations of traditional energy modelling approaches that assume perfectly inelastic demand. By incorporating behavioural dynamics and customer agency, EBDM highlights the value of more responsive and realistic demand modelling in a rapidly changing energy landscape.

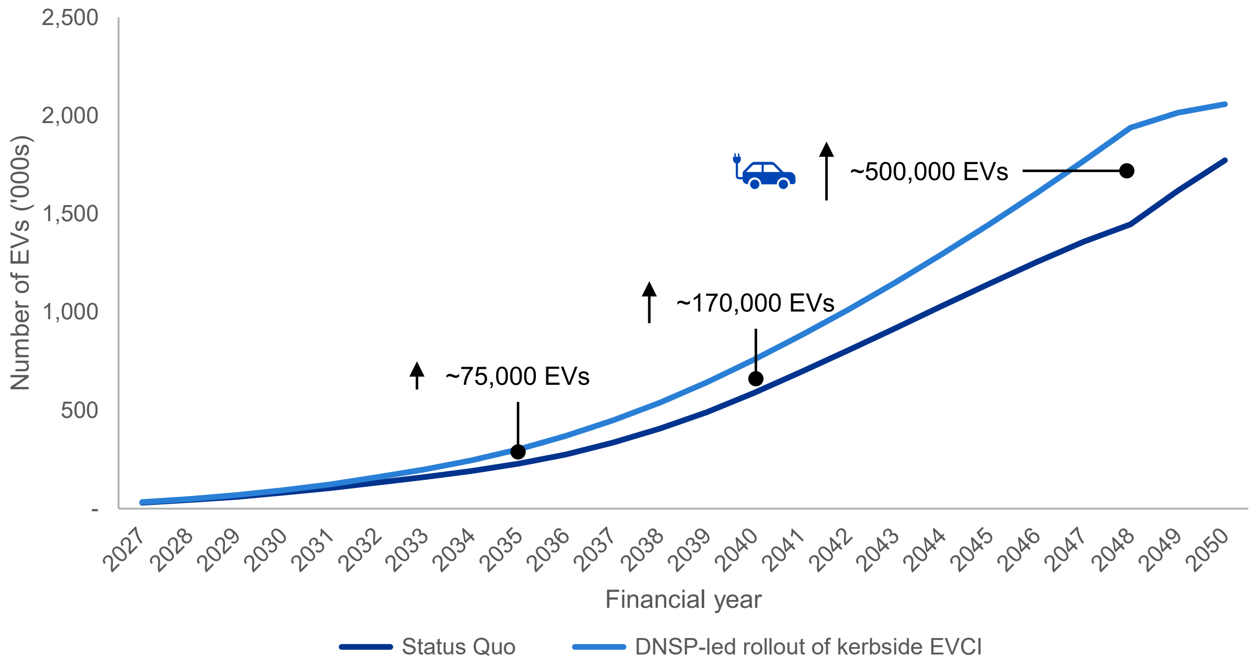
G.1.2 Scenario modelled

EBDM is well suited to testing a range of scenarios relating to BTM behaviour of consumers, including the amount and timing of energy consumption and CER uptake decisions. In this instance, EBDM was used to test a *Kerbside EV charging infrastructure* (EVCI) scenario, representing the impact of a proactive, targeted rollout of kerbside EV chargers. This provides convenient charging for households without off-street parking to accelerate EV uptake.

G.1.3 *Kerbside EVCI* adds almost half a million EVs in NSW by the late 2040s – abating over 1.5 million tonnes of CO_2e in that year

Kerbside EVCI represents a proactive, DNSP-led rollout of kerbside EVCI, making charging more convenient and cheaper for households without access to off-street parking. Under *Kerbside EVCI*, the number of kerbside chargers would increase to 157,200 by 2051 compared to 18,000 under *Status quo*. This provides convenient EV charging for over a million households without off-street parking by the 2040s. *Kerbside EVCI* results in 493,000 additional EVs relative to *Status quo* by the late 2040s, equivalent to 1.5 million tonnes of CO_2e abatement in that year. Figure G1 shows EV uptake for NSW between 2025 and 2050 under each scenario for households without dedicated off street parking.

Figure G1: EV uptake for NSW for households without dedicated off street parking, Status quo vs Kerbside EVCI, 2025 to 2050



Source: EBDM

G.2 Limitations

EBDM represents a novel approach to simulating customer responses to changing energy market conditions. Its primary innovation lies in moving beyond the traditional assumption of perfectly inelastic demand — a simplification that, while historically reasonable, is increasingly misaligned with the evolving landscape of CER. As customers gain more agency and access to flexible technologies, modelling approaches must adapt accordingly to represent their choices as they adapt to changing energy market conditions.

While the EBDM offers a more dynamic representation of customer behaviour, it is still in the early stages of development. In this context, some limitations should be noted. First, the model is calibrated against AEMO forecasts rather than historical behavioural data. As a result, behavioural parameters are inferred rather than directly estimated. This approach is appropriate for the current stage of EBDM development and the early stages of the energy transition, but could be improved in future iterations through the use of high-quality revealed or stated preference data.

The current version of EBDM includes a limited set of endogenous choices — such as demand reduction, load shifting, residential battery investment, participation in virtual power plants (VPPs), EVs and V2G. Other relevant customer decisions, including solar adoption, hot water system upgrades, energy efficiency improvements and gas connection choices, are externally imposed. Future development will aim to endogenise these decisions to provide a more comprehensive and integrated behavioural framework.

Despite these limitations, the EBDM provides a solid, forward-looking framework for understanding customer behaviour in a rapidly changing energy system. Its structure and calibration are grounded in sound analytical principles, and its flexibility allows for ongoing refinement as better data and behavioural insights become available.

G.3 Approach

This appendix outlines the EBDM approach, assumptions and results. EBDM is used to estimate changes in electricity demand and CER decisions resulting from shifts in energy policy and pricing. EBDM is based on random utility theory and can be used to test how demand-side interventions can address system constraints. An overview of how TEM and EBDM are complementary is illustrated in Figure G2.

Figure G2: Techno-economic model and EBDM

The **techno-economic modelling** estimates the benefits available if we can achieve a certain outcome in relating to demand

The **Energy Behavioural Demand Model** estimates to what extent a given intervention will realise the 'system benefits' by incentivizing behaviour change from residential customers. It helps to assess the **relative efficacy of different types of interventions.**

Demand Scenario

e.g., increased level of orchestration

Demand Impacts

e.g., reduction in peak demand

Intervention 1

Intervention 2

e.g., policy that leads to consumers perceiving more cost reflective pricing

Demand Impacts

Demand Impacts

e.g., reduction in peak demand, increase in minimum demand

Modelled scenario:

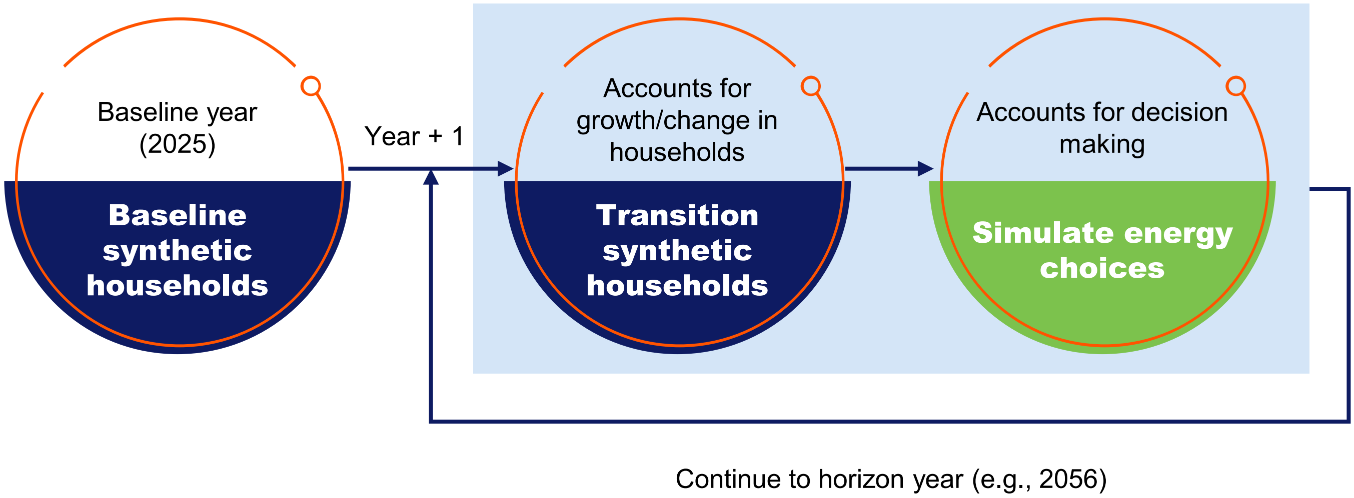
Kerbside EVCI: *Kerbside EVCI* adjusts the rollout rate of kerbside EV chargers. This aims to make charging more convenient and cheaper for people who do not have ready access to off-street parking, encouraging higher EV uptake.

G.4 Methodology

G.4.1 Overview of EBDM

EBDM is a dynamic, agent-based behavioural demand model designed to simulate household decisions about electricity consumption and investment in CER technologies. The model simulates the decisions of households which are influenced by a broad range of factors including tariffs, incentives, mandates and other factors. The model represents the choices of the current population and the projected future population over the forecast horizon. This dynamic is illustrated in Figure G3.

Figure G3: Illustration of EBDM methodology



Source: EBDM

1 **Baseline synthetic households:** The Baseline synthetic households (occupied private dwellings) are built with ABS Census data from the 2016 and 2021 Census'. The synthetic households capture location, dwelling type and a range of baseline technology and energy tariff assumptions.

2 **Transition synthetic households:** In each year, a 'transition' is applied where the existing households are updated to reflect the assumed increase in households aligned with official NSW Government population and demographic projections from the Transport for NSW Travel Zone Projections 2024 (TZP24)[23]. The composition of new households' dwelling types are aligned to development trends observed in the recent past.

3 **Simulate energy choices:** EBDM simulates a set of 'choices' for each household relating to underlying energy consumption and CER investment decisions each year using price-demand elasticity and discrete choice models. CER investment choices are driven by a combination of financial NPV, barriers to adoption and calibrated behavioural parameters. This approach represents interdependence between choices, as past choices made by a given household directly modify the attractiveness of future choices. For example, if a household has rooftop solar this will increase the NPV of installing a battery.

G.4.2 Synthetic households: Baseline and future

As an agent-based model, EBDM incorporates a representation of all households in occupied private dwellings (agents) at its core. This set of households is explicitly modelled to represent the known characteristics of the observable households in NSW (Baseline synthetic households) and the future households, introduced to the model by way of a transition model (Transition synthetic households).

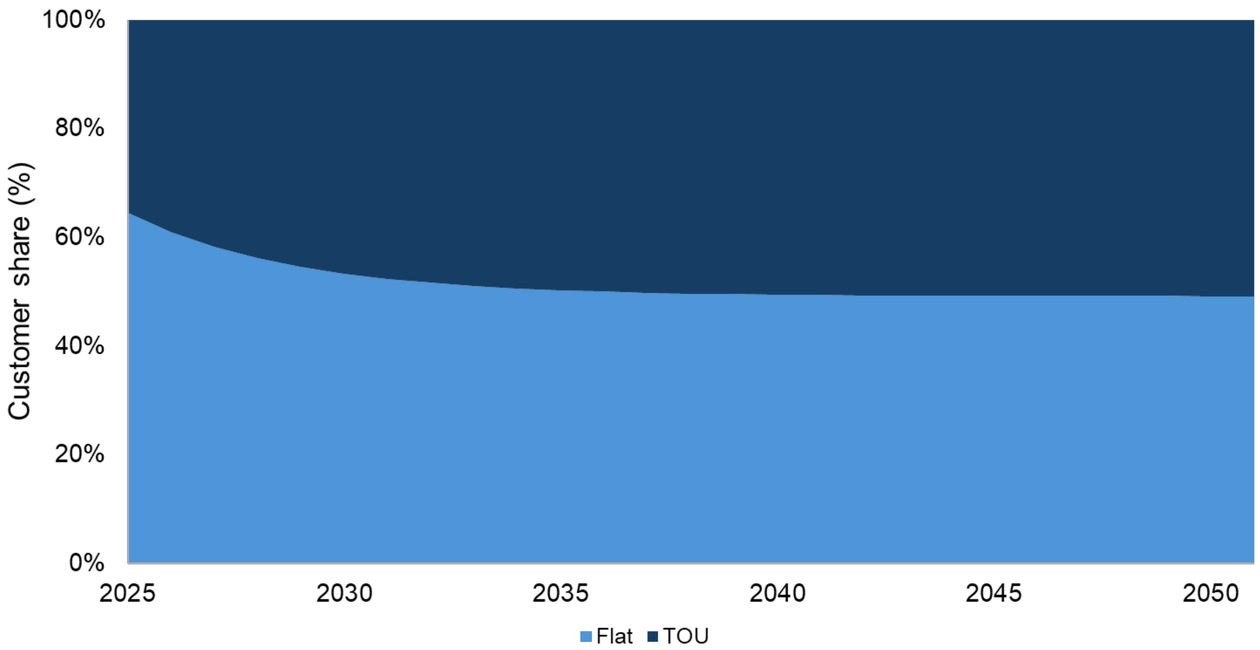
The foundation of the synthetic households is the ABS Census. For the baseline synthetic households, the model uses the number of households by dwelling type (detached, semi-detached, and apartment) and tenure (owned or rented) at the postcode level. The future households, post-2021 census, are based on Transport for NSW TZP24 household projections and cover the period from 2021 to 2051. In future years, the composition of households' dwelling type and tenure are modelled on the observed development and tenure change between 2016 and 2021. This approach addresses the long-term shift in new dwelling types with a trend in favour of semi-detached and apartment dwellings; a key consideration regarding household decisions to adopt CER.

[23] Transport for NSW (2024). Travel Zone Projections 2024 (TZP24)

Beyond dwelling type and tenure, the synthetic population is supplemented with a range of complementary attributes. Some key attributes and how they vary by scenario are described below.

- **Tariffs**: Under Status quo, a share of modelled households is assigned to flat or time of use (TOU) tariffs. The assignment of each household to a specific tariff assumption changes throughout the forecast period. In EBDM, Status quo reflects a gradual decline in the proportion of households on flat tariffs, consistent with the trends reported in the Independent Pricing and Regulatory Tribunal's (IPART) 2024 Annual Report[24]. This decline is assumed to stabilise over the medium term (5–10 years), resulting in a slower, more incremental shift in the residential tariff mix. The share of tariffs across all households by tariff type for Status quo are illustrated in Figure G4.

Figure G4: Share of customers on flat and TOU tariffs, Status quo scenario, NSW



Source: EBDM Assumption

- **Ability to charge an EV:** The ability of households to charge an EV at their place of residence is a function of the type of dwelling and by effect, the suitability of the location for charging. Consistent with the NSW Electric Vehicle Strategy, 30 per cent of households are unable to access private off-street parking where they can charge their EV in the synthetic population baseline year[25]. In future years, whilst the number of households increases, the share of those households that have access to off-street parking where they can charge their EV decreases. This reflects the increased likelihood of new dwellings being semi-detached or apartments. The share of NSW dwellings that are unable to access private off-street parking to charge their EV's is shown in Table G1.

Table G1: Share of households that are unable to access private off-street parking where they can charge their EV

Year	Share of households unable to access off-street parking
2021	30.0%
2031	31.6%
2041	32.4%
2051	32.9%

Source: NSW Electric Vehicle Strategy, EBDM

24 Independent Pricing and Regulatory Tribunal (2024).*Annual-Report-Monitoring-the-NSW-retail-electricity-market-2023-24-November-2024.PDF*
25 NSW Government (2021). *NSW Electric Vehicle Strategy*

G.4.3 Simulate energy choices: Choice models and chooser behaviour

EBDM uses discrete choice models to estimate how households make CER technology investments. These models apply statistical techniques to predict individual household's decision-making by representing the characteristics of the decision maker and the available alternatives. The models represent the probability of a customer making a given choice depending on the 'utility' of that choice to them. In EBDM, the characteristics stem from each household, such as dwelling type, tenure, and existing CER technologies. Each household is presented a range of choices relating to:

- Uptake of residential batteries.
- Participation in battery coordination programs (coordinated batteries).
- Uptake of EVs
- Uptake of V2G (vehicles with coordinated charging and discharging).

These choices are driven by a range of factors captured in the 'utility' of each choice to each household. The drivers included in this model include:

- **Financial returns:** the 'purely rational' factors relating to household financial costs and benefits.
- **Individual constraints:** individual constraints that present barriers to adoption (or mandate adoption).
- **Individual preferences:** the distribution of individual circumstances, priorities, preferences and risk appetites.
- **Social factors:** the dynamics of how people adopt new technologies and how their social environment influences their decisions. Technology-specific adoption curves reflect households' awareness and their willingness to embrace new technologies. In line with the theory of technology adoption, households are slow to adopt the technology as the population gradually builds familiarity with it. Later, as awareness and comfort levels rise, adoption increases rapidly. Eventually, the adoption rate flattens, indicating saturation among households likely to adopt these technologies[26].

G.4.4 EBDM CER Choice models

EBDM implements specific choice models for each CER technology. The nature of each model is dictated by the range of factors outlined in Section G.2.3 and captured within each model specification. The choice model utility calculation for the purchase of a home battery and purchase of an EV are described below.

Decision to purchase a home battery

Households consider home batteries based on their knowledge of the technology and practical factors such as dwelling type and ownership. Apartments and rentals face barriers from shared infrastructure, limited space, and lack of ownership, whereas detached or semi-detached owner-occupied homes face fewer barriers. The decision is also strongly influenced by whether the household already has rooftop PV.

The number of households who would consider investing in a home battery increases through time. This is implemented in the form of an 'awareness curve'.

The battery choice model presents each household with two choices each year: whether to invest in a residential battery or not. The utility of choosing a battery is calculated using Equation 1 as:

$$U_{ij} = \beta_0 Awareness_i + \beta_1 DwellingType_i + \beta_2 Tenure_i + \beta_3 \mathrm{NPV}_{ij} + \epsilon_{ij}$$

Equation 1

Where:

- $\mathrm{U_{ij}}$ is the utility that household (i) derives from choosing alternative (j).
- $\mathrm{Awareness}_i$ represents the binary awareness of Batteries for household (i).
- $\mathrm{DwellingType_i}$ represents the type of dwelling for household (i).
- Tenure_i represents the tenure status for household (i).
- NPV_{ij} represents the net present value for household (i) and alternative (j).
- ϵ_{ij} is the random component of the utility, capturing unobserved factors that influence the choice.

[26] This is consistent with consumer adoption theory as popularised by Everett Rogers in his book *Diffusion of Innovations* (1962).

Decision to purchase an EV

Households consider the purchase of new EVs based on their readiness to purchase a new vehicle, their awareness of the technology and key considerations such as the ability to charge the vehicle at the customer's place of residence. Over time, as the benefits of EVs become better known and the number of available products increase, the number of households willing to consider an EV increase, represented by an awareness curve, which reflects technology adoption trends. The decision to invest in an EV is also influenced by home charger availability. Charging infrastructure depends on both dwelling type and parking arrangement.

The EV choice model offers each household two options when they are purchasing a new vehicle: Do not adopt an EV (household chooses an internal combustion engine vehicle instead) or adopt an EV. The utility of each option is calculated using Equation 4 as:

$$U_{ij} = \beta_0 Awareness_i + \beta_1 Charging_i + \beta_2 \mathrm{NPV}_{ij} + \epsilon_{ij}$$

Equation 2

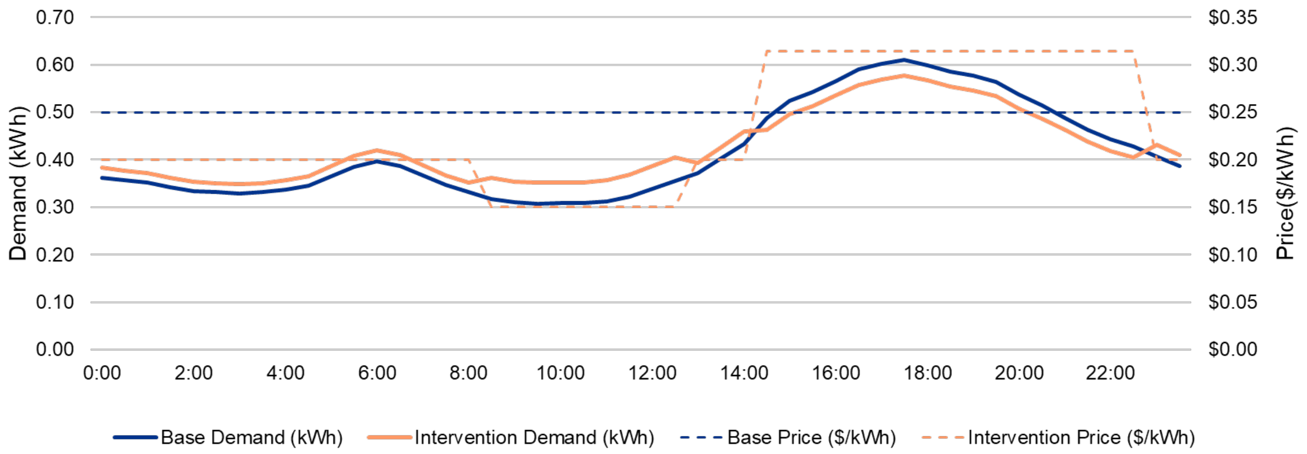
where:

- U_{ij} is the utility that household (i) derives from choosing alternative (j).
- $\mathrm{Awareness}_i$ represents the binary awareness of EVs for household (i).
- $\mathrm{Charging}_i$ represents the ability to charge at home for household (i).
- NPV_{ij} represents the net present value for household (i).
- ϵ_{ij} is the random component of the utility, capturing unobserved factors that influence the choice.

G.4.5 Price elasticity of demand

EBDM captures customers' behavioural responses to changes in electricity prices or options by adjusting the amount and timing of electricity usage. In the short term, residential electricity demand in Australia shows low responsiveness to price changes. Over the long run, price elasticity of demand increases as households have more opportunities to adapt through improved energy efficiency, behavioural shifts, or the adoption of technologies. For any given modelling year, the EBDM represents a relationship between demand and prices based on price elasticity of demand assumptions which are applied at half hourly intervals. Over the forecasting horizon, the model assumes that price elasticity of demand ranges from -0.3 in the short term, gradually increasing to -0.5 by 2040, and remaining at that level beyond 2040[27]. Demand responsiveness to price signals affects the net financial returns of household-scaled investments, which is represented in the demand load profiles varying by tariff structure and the net present value of technology options, as discussed in next sub-section. Figure G5 shows an illustrative example of the price-demand elasticity logic for a single day applying an elasticity of -0.5

Figure G5: Illustration of the EBDM price elasticity of demand logic



Source: EBDM

[27] Infrastructure Victoria (2019). How much do households respond to electricity prices? Evidence from Australia and abroad

G.4.6 NPV Model

NPV is a key factor influencing investment decisions in CER technologies, as it helps households assess the financial viability of their investments. The NPV calculation accounts for upfront costs (including capital cost and/or subscription costs), estimated energy bill savings from CER technologies, any available incentives or rebates from Federal or State Governments over the lifespan of assets or the effective term of orchestration measures, and discount rate. The NPV of a technology option for a given type of household is calculated using Equation 3 Equation 3 as:

$$NPV = Function\ (Costs, savings, incentives, discount\ rate, effective\ life)$$

Equation 3

where:

- $Costs$: Costs incurred over asset's lifecycle, including capital expenditure and/or subscription costs.
- $Savings$: This includes reduction in electricity bills due to household energy generation and storage, realised annually.
- $Incentives$: Incentives or rebates by Federal and/or NSW government, and/or sign-up bonus and premium feed-in-tariffs for coordinated CER that offsets the net investments.
- $Discount\ rate$: Represents the time value of money and investment risk, used to discount future savings and incentives to present values.
- $Effective\ life$: This is based on the assumed operational lifespan of assets.

The unit capital costs of CER technology generally follow a downward trend in the medium term, driven by technology improvement and economies of scale, and then remain relatively constant over the long term. The Australian Federal Government's Cheaper Home Battery Scheme provides households with upfront discounts on eligible solar battery installations through the creation of small-scale technology certificates, starting from July 1, 2025. This discount will gradually decrease over time until 2030. It is assumed that the cost of purchasing and installing residential batteries declines gradually over time, in line with industry expectations.

Financial returns are primarily derived from energy bill savings through the installation of CER technologies or participation in CER coordination programs. Households benefit from reduced grid imports by using solar production and/or stored battery energy. The extent of energy bill savings depends on several factors, including household energy demand profile throughout the year, import and export tariff structures, the type and specifications of CER technology, solar irradiation by geographical location, and network export limits. These savings are underpinned by individual customers' behaviours at half-hour intervals and are responsive to changes in electricity prices as well as policy interventions, making it an important component of NPV. Energy bill savings are estimated by EBDM using Equation 4 as:

$$Bill\ Savings = f\ (Load\ Profile, Location, Tariffs, Technology, Network\ Constraint, VPP, Dwelling\ Type)$$

Equation 4

where:

- $Load\ Profile$: The pattern of a typical household's electricity consumption, home energy generation and storage at half-hour intervals.
- $Location$: The physical location of the household, affecting solar irradiation, local energy policies, and renewable energy availability.
- $Tariffs$: The pricing schemes for importing and exporting electricity, impacting overall costs and potential savings from installing CER technologies.
- $Technology$: The specifications of energy technologies used, such as solar panels and battery storage systems.
- $Network\ Constraint$: The network export limit imposed by the local electricity distribution network.
- VPP: Whether the household is part of a battery coordination programs, which can provide additional savings.
- $Dwelling\ Type$: The type of residential building, such as apartments, detached houses, or townhouses, influencing energy consumption patterns and efficiencies.

G.4.7 Representation of tariffs

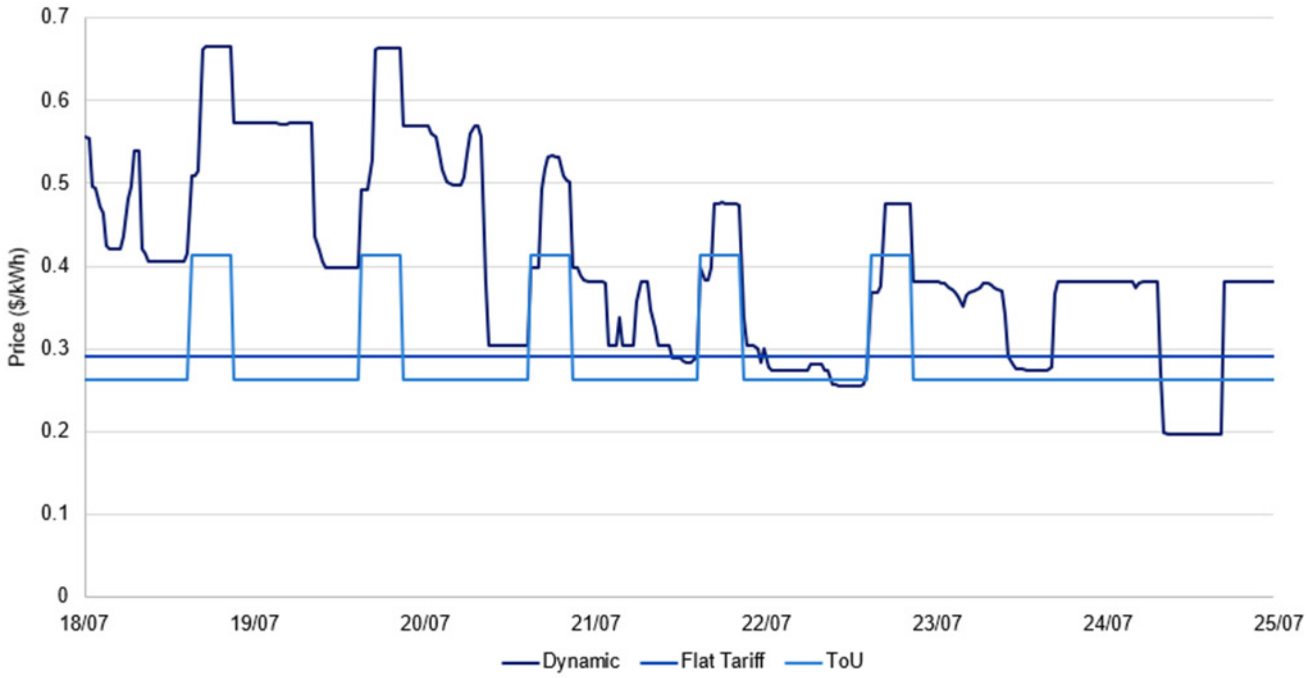
Electricity tariffs are important inputs to the NPV model as household demand loads are price-elastic and import and export tariffs influence the bill savings by reduced grid imports. Three import tariff assumptions, flat, TOU and dynamic tariff are modelled. Electricity prices are assumed to increase modestly over time, in line with industry expectations.

For modelling purposes, each household is assumed to be on either flat, TOU or dynamic tariff. Figure G6 illustrates the three import tariffs over an illustrative week in July 2039. Figure G6 illustrates the three import tariffs over an illustrative week in July 2039. The three structures all represent the same overall revenue for a household with an average load profile, but TOU and dynamic tariffs provide a price signal for customers to load shift and reduce demand during peak periods.

The TOU tariff sets different prices for peak and off-peak. During peak periods, the TOU tariff is higher than the flat rate; during off-peak periods, it is lower. For modelling purposes, the peak is represented as between 3 pm to 9 pm on weekdays. The two prices are calculated by applying a factor to the flat tariff, i.e. TOU tariff during peak periods is 1.3 times the flat tariff, and during off-peak is 0.9 times the flat tariff.

Dynamic tariffs expose households to fluctuations in wholesale prices. It is modelled as wholesale prices with an additional network component.[28]

Figure G6: Flat import tariff, TOU import tariff and dynamic import tariff ($/kWh) at each half-hour over winter peak week Monday 18th July 2039 to Sunday 24th July 2039



Source: EBDM

EV Total cost of ownership

Total cost of ownership (TCO) is represented by EBDM in vehicle purchase decisions and underpins the vehicle choice module. TCOs can be influenced by various policy interventions including FBT exemption and state government rebate. TCO comprises purchase cost, operating costs, maintenance costs, depreciation, and any applicable subsidies or rebates for new sales of passenger vehicles. Operating cost refers to the required fuel consumption for internal combustion engine vehicles and electricity consumption for EVs based on the customer's travel behaviour. Fuel efficiency and electricity usage per 100 kilometres in urban and regional areas, combined with the retail prices of fuel/energy and annual household travel distances, are used to estimate the total annual running costs. Most cost components are subject to changes driven by economic outlook, technology advancement and policy interventions, with each of these assumed to change over the forecasting period. For a passenger vehicle with a given fuel type f in a given model year t, the TCO is calculated using Equation 5.

$$TCO_{f,t} = Purchase_{f,t} + Operating_{f,t} + Maint._{f,t} + Depreciation_{f,t} + Subsidies\ or\ charges_{f,t}$$

Equation 5

[28] Network component is based on the Australian Energy Market Commission's *Residential electricity price trends 2024 report.* For NSW, the network cost is higher during peak periods (3 pm to 9 pm on weekdays) and lower during off-peak periods.

The household travel distance determines the operating cost and varies by location, which is derived from the Method of Travel to Work by ABS. For a given suburb in NSW, the operating cost is calculated using Equation 6.

$$Operating_{f,t} = Fuel\ or\ energy\ efficiency_{f,t} \cdot Retail\ price_{f,t} \cdot Annual\ mileage_{suburb,t}$$

Equation 6

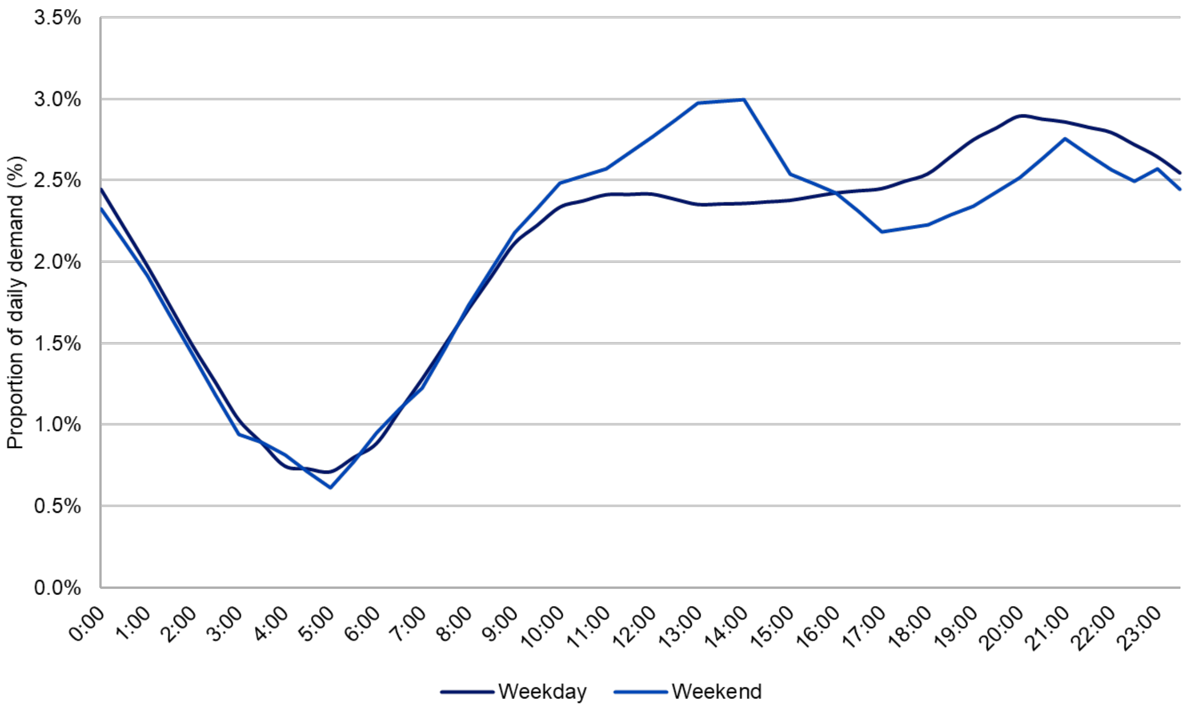
Demand profile model

The simulation of household demand load profiles accounts for seasonal variations in electricity consumption, household-scale solar production, and battery charge and discharge patterns at half-hour intervals. The electricity consumption and solar production profiles for NSW are based on the Step Change Reference Year 2015 from AEMO's 2024 ISP Operational Demand Traces. Reference Year 2015 is typical in terms of weather and holiday schedules for the forecasting horizon (accounting for climate change expectations). The battery charge and discharge profile are simulated by EBDM, considering seasonal usage patterns by dwelling type, the availability and size of household solar systems, import tariff plans, and participation in battery coordination.

EV charging

The tariff that a household is on is assumed to influence uncoordinated EV charging profiles. The uncoordinated EV charging profiles are modelled by first assuming a default charging profile, based on AEMO ISP, which is then adjusted based on the weighted average import tariff for the relevant scenario, in line with the EBDM price elasticity of demand model described in Section G.4.5. Figure G7 shows the uncoordinated charging profiles for EVs on weekdays and weekends.

Figure G7: Weekday and weekend EV uncoordinated charging profile at each half-hour



Source: AEMO 2024 ISP

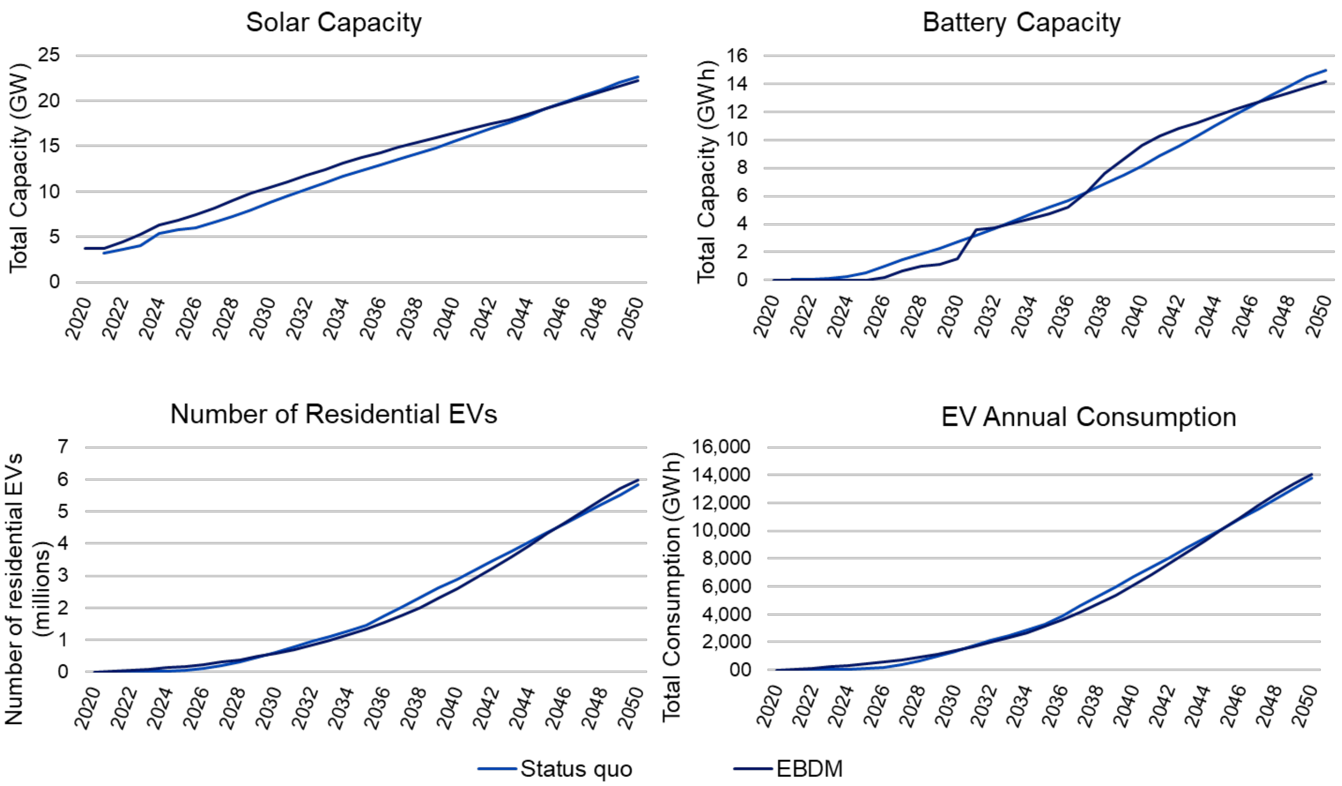
Solar curtailment

Solar curtailment refers to the reduction of solar energy output from PV systems by limiting the amount of electricity generated. This is typically done to maintain grid stability and prevent overloading the network during periods of low demand and high solar generation. EBDM provides a mechanism to assess the level of solar curtailment as a function of residential demand, alternative residential CER technology uptake and the degree of coordination occurring as a function of network and retailer policy options.

Model calibration

A NSW specific calibration was performed for EBDM to ensure alignment with *Status quo* modelling assumptions across the three distributors, Ausgrid, Endeavor Energy and Essential Energy. Calibration is the process of adjusting the model parameters to ensure that the model accurately reflects the relevant *Status quo* assumptions. The EBDM synthetic households were prepared in alignment with the Transport for NSW TZP24 household projections.

Figure G8: EBDM Status quo forecast versus Status quo scenario assumptions - Solar, Battery and EV



Source: EBDM

Figure G8 illustrates the strong alignment between the calibrated EBDM and *Status quo* modelling assumptions for NSW. This alignment demonstrates that EBDM forecasts broadly align with *Status quo* scenario.

G.5 Scenario definitions

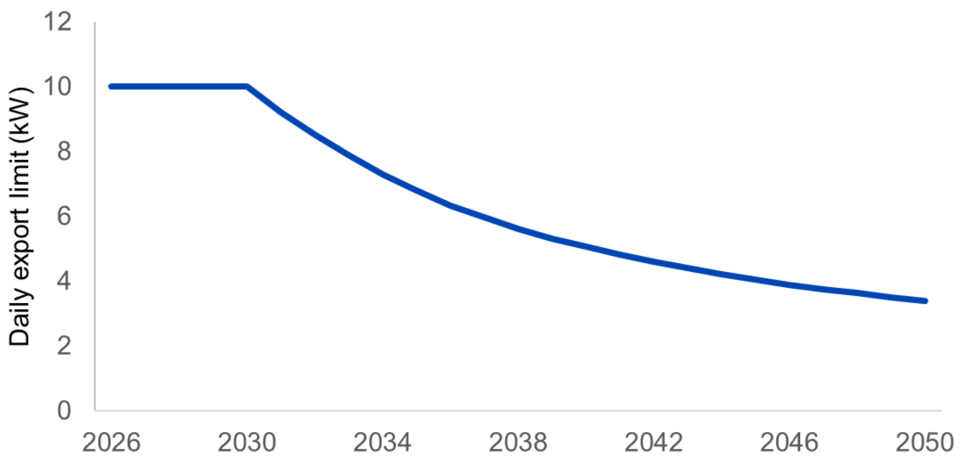
This section presents the key assumptions and modelling approaches that underpins the assessment of flexibility options for NSW. *Status quo* assumptions establish a common set of demand, price, technology, and coordination parameters drawn from AEMO, ABS, Australian Energy Market Commission and EBDM modelling assumptions.

Base Case: Status quo

- **Operational demand forecast**: The demand profile was developed based on AEMO's 2024 ISP demand traces with 2015 as the reference year. This reference year was selected because it had weather and holiday schedules that are expected to be consistent with the forecast horizon (accounting for expected climate change).
- **Household projections**: Household projections were developed using ABS Census data from 2016 and 2021 and Transport for NSW TZP24 household projects out to 2051, with synthetic profiles constructed across apartments, semi-detached and detached households at a postcode scale.
- **Price assumptions**: The time of use and flat tariff inputs are based on EBDM assumptions. The baseline share of customer on each on the tariff type is based on IPART retail market report.[29] For Status quo, EBDM assumes 21 per cent of customers on TOU tariffs in 2024 increasing to 77 per cent on TOU by 2050 and 65 per cent of customers on flat tariffs in FY24 decreasing to 49 per cent by FY50.
- **Coordination**: Coordination rates for batteries and EVs are based on Status quo scenario assumptions.
- **Technology uptake**: Forecast of solar PV, battery storage, and EV consumption are calibrated to Status quo modelling assumptions.
- **Export limits**: Solar export limits are fixed until 2030 and reduced gradually through to 2050. For Ausgrid, the export limit is set at 10 kW until 2030 and reduced gradually to 3.4 kW. The export limit for Essential Energy and Endeavor Energy begins at 5 kW through to 2030 and decreased to 1.7 kW by 2050. The daytime export limit is assumed to decline to maintain the level of rooftop solar exports from 2030. This trend is illustrated for the Ausgrid area in Figure G9.

[29] Independent Pricing and Regulatory Tribunal (2024). *Monitoring the NSW retail electricity market*

Figure G9: Illustration of Ausgrid daytime export limit by forecast year

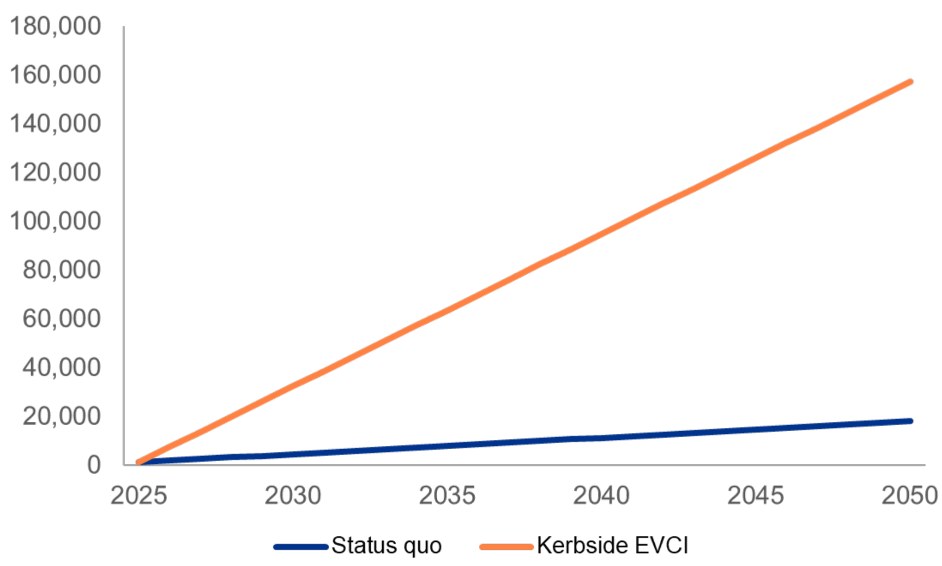


Source: EBDM

Intervention: Kerbside EVCI

- **Description:** *Kerbside EVCI* adjusts the rollout rate of kerbside EV chargers. This aims to make charging more convenient and cheaper for people without off-street parking, encouraging higher EV uptake.
- **Modelling approach:** The scenario assumes an accelerated rollout of kerbside EV chargers relative to *Status quo*. The number of EV chargers in *Status quo* is based on the continuation of the current pace of rollout.[30] In *Kerbside EVCI*, the installation pace is based Energy Networks Australia assessment of what could be achievable in NSW under stronger policy direction and targeted investment support.[31] This would increase the number of kerbside chargers to around 157,200 in 2051, improving accessibility for households without off-street parking. Greater charger availability reduces search and waiting times, makes charging more convenient, and lowers non-monetary barriers to EV ownership. Figure G10 illustrates the roll out of kerbside chargers in *Status quo* and *Kerbside EVCI*.

Figure G10: Number of kerbside EV chargers in Status quo and Kerbside EVCI



Source: EBDM

[30] NSW Government (2024). NSW turbocharges kerbside EV charging with 600+ new ports | Media release | Environment and Heritage

[31] Energy Networks Australia (2025). *Street-Smart-EV-charging-paper_-ENA_10-Jan-2025-F.pdf*.

G.6 Results

This section provides the outcomes of the EBDM modelling based on the approach, scenarios and assumptions detailed in the preceding sub-sections of this appendix. The results of the modelling are structured as follows:

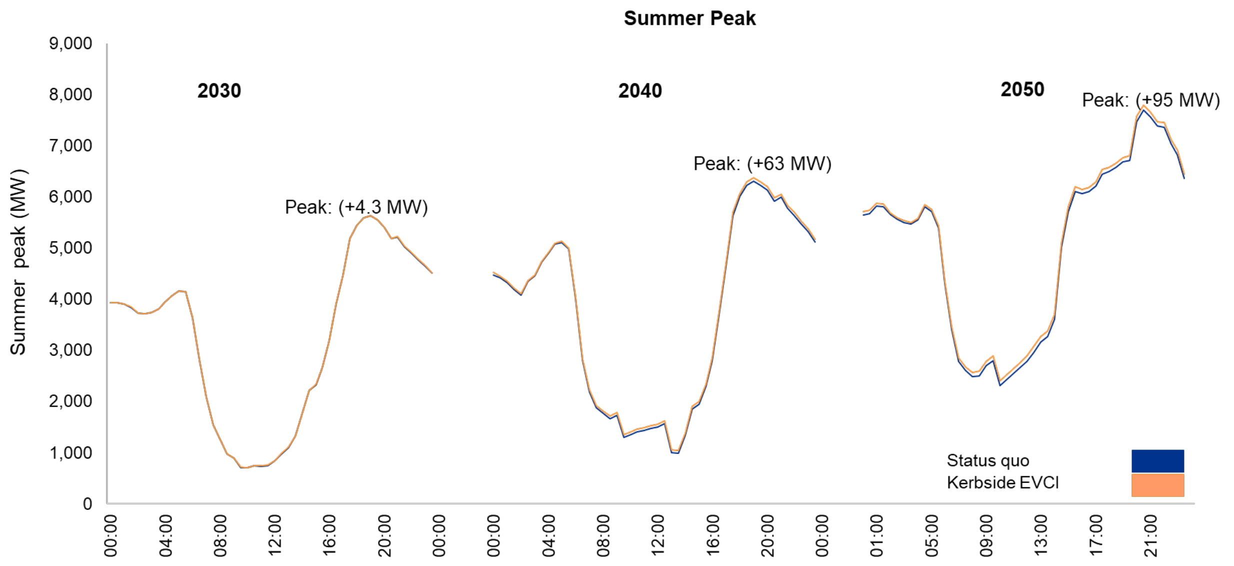
- Peak demand outcomes
- Uptake of EVs

G.6.1 Peak demand outcomes

Electricity demand outcomes were assessed based on the highest seasonal peaks observed across the NSW network during typical high-demand periods in summer and winter.

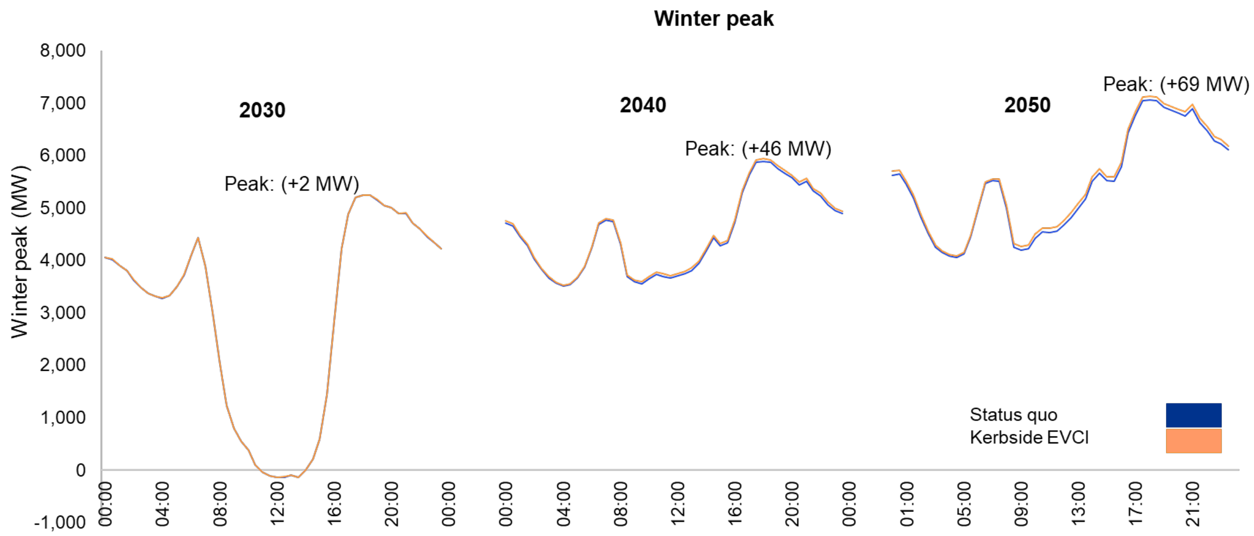
Kerbside EVCI : Figure G11, Figure G12 and Table G2 illustrate the peak summer and winter demand profiles for 2030, 2040 and 2050. The outputs show an increase in EV uptake. This leads to modestly increased electricity demand, including in peak periods.

Figure G11: Peak demand in summer peak by year for Kerbside EVCI versus Status quo (MW)



Source: EBDM

Figure G12: Peak demand in winter peak by year for Kerbside EVCI versus Status quo (MW)



Source: EBDM

Table G2: Peak demand in summer and winter peak periods by year for Kerbside EVCI versus Status quo (MW)

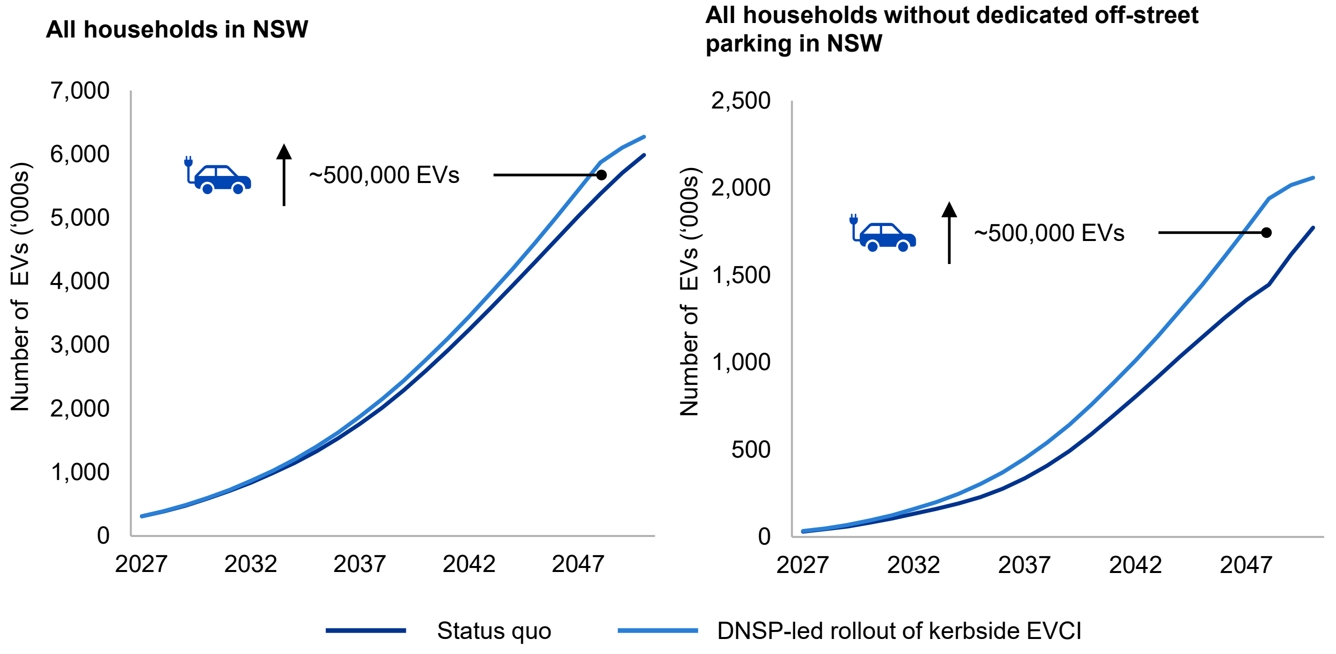
Intervention	2030	2040	2050
Summer Peak (Status quo)	**5,546**	**6,231**	**7,469**
Kerbside EVCI	+4.3	+63	+95
Winter Peak (Status quo)	**5,242**	**5,890**	**7,060**
Kerbside EVCI	+2	+46	+69

Source: EBDM

G.6.2 Uptake of electric vehicles

EV uptake in NSW was assessed based on the impact of increased kerbside charging availability. In the modelled intervention case, greater availability of kerbside EVCI increased EV uptake for customers without off-street parking by almost half a million by 2048, before reaching a level of saturation where the uptake trajectory begins to converge with the *Status quo*, as shown in Figure G13.

Figure G13: EV uptake for NSW for all households (left) and only those without dedicated off-street parking (right), Status quo vs Kerbside EVCI, 2025 to 2050



Source: EBDM

Table G3: Electric vehicle uptake against each scenario for Kerbside EVCI versus Status quo

Option	2030	2040	2050
Status quo	**583,700**	**2,592,800**	**5,988,000**
Kerbside EVCI	+12,800	+168,400	+285,900

Note: Values rounded to the nearest 100
Source: EBDM

Glossary

Term	Definition
ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AI	Artificial intelligence
ARENA	Australian Renewable Energy Agency
ASL	AusEnergy Services Limited
BESS	Battery Energy Storage System
BTM	Behind-the-meter
CER	Consumer Energy Resources
CESS	Capital Expenditure Sharing Scheme
C&I	Commercial and industrial
CO2	Carbon dioxide
CO2-e	Carbon dioxide equivalent
CPI	Consumer Price Index
CPN	Community Power Networks
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CWO	Central West Orana
DAPR	Distribution Annual Planning Report
DBESS	Distribution-connected Battery Energy Storage System
DCCEEW	Department of Climate Change, Energy, the Environment and Water
DDP	Dubbo Distribution Project
DER	Distributed Energy Resources
DNSP	Distribution Network Service Provider
DSP	Distribution System Plan
DSO	Distribution System Operator
EBDM	Energy Behavioural Demand Model
EII Act	*Electricity Infrastructure Investment Act*
ESOO	Electricity Statement of Opportunities
ESTM	Energy Security Target Monitor
EV	Electric vehicles
EVCI	Electric vehicle charging infrastructure
GPG	Gas-powered generation
GW	Gigawatt
GWh	Gigawatt-hour
GRZ	Generation Rich Zone
IA	Infrastructure Australia
IASR	Input Assumptions and Scenarios Report
IIO Report	Infrastructure Investment Objectives Report

Term	Definition
IPART	Independent Pricing and Regulatory Tribunal
ISP	Integrated System Plan
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LEP	Local Energy Precinct
LLM	Large language model
MtCO2-e	Million tonnes of carbon dioxide equivalent
MVA	Megavolt-ampere
MW	Megawatt
MWh	Megawatt-hour
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net present value
NSW	New South Wales
NSW Roadmap	NSW Electricity Infrastructure Roadmap
NTNDP	National Transmission Network Development Plan
ODP	Optimal Development Path
PJ	Petajoule
PNIP	Priority network infrastructure project
POE	Probability of exceedance
PV	Photovoltaic
RAB	Regulatory asset base
REZ	Renewable Energy Zone
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
RNIP	REZ network infrastructure project
TAPR	Transmission Annual Planning Report
TCO	Total cost of ownership
tCO2-e	Tonnes of carbon dioxide equivalent
TEM	Techno-economic model
TNSP	Transmission Network Service Provider
TOU	Time of Use
TUoS	Transmission Use of System
TWAP	Time-Weighted Average Price
TWh	Terawatt-hour
TZP24	Travel Zone Projections 2024
V2G	Vehicle-to-grid
VCR	Value of Customer Reliability
VPP	Virtual power plant
V	Volt

Ausgrid

Endeavour Energy

Essential Energy