Appendix A9. Demand Side Factors Statement

June 2026

Appendix to the 2026 Integrated System Plan for the National Electricity Market

We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO is proud to have launched its Innovate Reconciliation Action Plan (RAP) in June 2026. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation – a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

This is Appendix A9 to the 2026 Integrated System Plan (ISP) which is available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp. AEMO publishes the 2026 ISP pursuant to its functions under section 49(2) of the National Electricity Law (which defines AEMO's functions as National Transmission Planner) and its supporting functions under the National Electricity Rules. This publication is generally based on information available to AEMO as at 20 April 2026 unless otherwise indicated.

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Version control

Version	Release date	Changes
1	25/06/2026	First release

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AEMO's *Integrated System Plan* (ISP) is a roadmap for the National Electricity Market's (NEM's) transition, and outlines an 'optimal development path' (ODP) for generation, storage and network investments to meet both consumer needs and government policies, at least cost, to 2050. The 2026 ISP reaffirms that renewable energy, connected by transmission and distribution, firmed with storage and backed up by gas, presents the least-cost way to supply secure and reliable electricity to consumers through to 2050, as coal plants retire and while meeting government policies.

For the first time, the 2026 ISP includes this Demand Side Factors statement (DSF statement). This DSF statement analyses the potential for demand side factors to affect the efficient development of the power system, and associated opportunities for the development of distribution networks to access latent capacity from resources such as rooftop solar and increase the value of these resources for *all* consumers. It demonstrates the impact of, and opportunities for, demand side factors such as consumer energy resources (CER) and energy efficiency to influence the development needs of the power system.

The statement provides information about:

- the potential for demand side factors to affect the efficient development of the power system, and
- opportunities for the efficient development of distribution networks that support consumers' needs.

What are demand side factors?

Demand-side factors are factors affecting consumers' demand for electricity and the resulting use of distribution system services. They include consumers' investments in CER and choices to allow their CER to be coordinated by virtual power plants (VPPs), energy efficiency investments that reduce electricity consumption, electrification of other energy forms, and demand management devices.

Demand side factors reduce overall investment needs in transmission infrastructure and utility-scale generation and storage developments.

Demand side factors impact the efficient development of the power system

Currently, demand side factors provided by consumers are already shaping how electricity is produced, stored and consumed in the NEM. Over the summer (Q1) of 2026[1], rooftop solar contributed 16% of the NEM's total electricity production, more than grid-scale solar (11%), wind power (15%), hydro (5%) or gas (3%), and this contribution is forecast to rise. Over 36% of rooftop solar-suitable dwellings[2] in NEM regions currently have rooftop solar, and are forecast in the *Step Change* scenario to rise to 47% by 2035 and 56% by 2050. By 2050, rooftop and small-scale solar capacity is forecast to reach 87 gigawatts (GW), and home batteries are forecast to be installed in around 65% of dwellings with solar. Small-scale batteries are forecast in the *Step Change* scenario to provide 35 GW/78 gigawatt hours (GWh) of storage capacity, with 53% of those batteries coordinated as part of a VPP in that scenario. Energy efficiency improvements from consumers' investing in more efficient appliances and buildings continue to reduce electricity use, with energy efficiency measures increasing to deliver 75 terawatt hours (TWh) of end-use electricity savings by 2050.

[1] AEMO. *Quarterly Energy Dynamics* Q1, April 2026, https://www.aemo.com.au/-/media/files/major-publications/qed/2026/qed-q1-2026.pdf?rev=f6c1205d357742108ff08563cc0da0e8&sc_lang=en&hash=8A56BC5D49D9C4CFB6233DD3C6E7901D.

[2] Rooftop solar-suitable dwellings include detached houses and semi-detached dwellings (duplexes and townhouses), and excludes apartments. A slightly higher 43% of fully detached houses in the NEM have rooftop solar.

Together, these demand side factors reduce the electricity that needs to be supplied by the grid, lower the need for additional grid-scale infrastructure investment, and create benefits for all consumers, not only households and businesses that own these assets. The sensitivities presented in this DSF statement show that, across the sensitivities assessed, lower uptake or coordination of demand side factors than forecast in the *Step Change* scenario could increase total system costs.

Impact of uptake and coordination of demand side factors on system costs

Coordination of CER is expected to deliver cost savings by reducing the investment need in utility-scale assets:

- Coordination of stationary batteries and electric vehicles (EVs) contributed to $5.2 billion total system cost savings in *Step Change* in real, present value terms (that is, in today's dollars).
- Coordination of stationary batteries only, through VPPs, contributed to $3.8 billion total system cost savings in *Step Change* in real, present value terms.

Energy efficiency improvements and initiatives reduce the amount of electricity that needs to be supplied by the power system, lowering the need for additional generation, storage and network investment.

- If efficiency savings presently forecast in *Step Change* (representing the contribution from existing policy, new potential policies, and market-driven savings) are not achieved additional investment in grid-scale infrastructure would be needed, increasing the total system cost by $9.5 billion in real, present value terms.
- Even greater investment in reducing consumers' electricity consumption would avoid a further $7.2 billion.

Opportunities for efficient investment in distribution networks to support CER export

To prepare this DSF statement*,* AEMO has identified opportunities for efficient investment in distribution networks across the NEM to support operation of CER. AEMO involved distribution network service providers (DNSPs) in developing an ISP modelling approach to reflect the existing capability of distribution networks to facilitate export of CER generation from consumers' homes and businesses into the grid. This work recognises that DNSPs will continue to invest to support demand growth in their networks which will naturally provide more export opportunities for much of the future growth in CER. Beyond that, the modelling reveals modest investment opportunities in the distribution network to support a further 3.8 GW of CER generation export by 2049-50, under the *Step Change* scenario.

In addition, the 2026 ISP has explored opportunities for distribution networks to support mid-scale generation and storage (discussed in Appendix A2 Generation and Storage Development Opportunities) and utility-scale generation and storage (discussed in Appendix A5 Network Investments).

AEMO thanks DNSPs for their involvement and voluntary data provision, and acknowledges that the approach adopted for the 2026 ISP is necessarily a high-level representation of distribution networks and cannot capture all inherent distribution network complexities. AEMO expects that this approach will improve over time, as DNSPs conduct more analysis of how their networks support CER export, and as DNSPs and AEMO evolve their modelling capability and data availability.

AEMO has published the *Demand Side Factors Information Guidelines*[3], which will apply for the 2028 ISP (for the first time), and will set out the categories of information that DNSPs are required to provide to enable AEMO's assessment of distribution network development opportunities to support CER export in future ISPs.

[3] At https://www.aemo.com.au/consultations/current-and-closed-consultations/2025-demand-side-factors-information-guidelines-consultation.

A9.1 Introduction

In 2022, the Energy and Climate Change Ministerial Council (ECMC) commenced a review of the scope and functions of the ISP to ensure it remains fit for purpose, and to identify opportunities for the ISP to consider additional factors which influence Australia's energy transition[4,5]. The ISP review identified the need for improved consideration of demand side factors. Subsequently, the Australian Energy Market Commission (AEMC) consulted on and made changes to the National Electricity Rules (NER) to require the ISP to include a demand side factors statement (DSF statement) that considers the potential for demand side factors to affect the efficient development of the power system and opportunities for the development of distribution networks[6].

Demand side factors that impact the development needs of the shared power system (including the transmission and distribution networks) include the key investments and choices that consumers can make, such as consumer investments in rooftop solar batteries and EVs, investments in building products and appliances that improve energy efficiency, and behavioural choices of consumers to improve demand flexibility. AEMO has considered the expected development of these demand side factors in the NEM and assessed the impact and benefits of demand side investments and distribution network development opportunities that can support CER generation export.

This DSF statement has been prepared in accordance with clauses 5.22.6(a)(9) and 5.22.6A of the NER and provides information about:

- the potential for demand side factors to affect the efficient development of the power system, and
- opportunities for the development of distribution networks that are consistent with the efficient development of the power system.

The DSF statement does not seek to co-optimise consumer investments alongside utility-scale and supply-side infrastructure. Rather, it explores how consumer decisions, such as investment in CER, energy efficiency and distribution investments, can influence the scale of utility-scale investments. In doing so, it recognises that consumer investment decisions are driven by a wide range of factors, not solely economic considerations that affect the total energy system's costs.

What is a virtual power plant (VPP)?

Households and businesses that choose to take part in VPPs allow their devices to be aggregated into larger systems for coordinated imports and exports of energy between them and the grid. Participants usually enter into agreements that allow their batteries to be charged and discharged at times when the power system requires that flexibility, which in turn helps with supporting reliability, moderating prices in peak periods, reducing the need for power system investment, and managing power system risks, thereby benefitting all consumers. In return, participants in VPPs may receive financial incentives or other rewards, and the benefit of knowing they are helping to support energy reliability.

[4] See https://www.energy.gov.au/energy-and-climate-change-ministerial-council/energy-ministers-publications/review-integrated-system-plan.

[5] See https://www.aemc.gov.au/sites/default/files/2024-06/erc00395_enhancing_the_isp_to_support_the_energy_transition_info_sheet_20_june_2024_1.pdf.

[6] See https://www.aemc.gov.au/rule-changes/improving-consideration-demand-side-factors-isp.

Additional information is available alongside this appendix, including in Appendix A2 Generation and Storage Development Opportunities (for mid-scale generation and storage, within broader generation and storage development opportunities), Appendices A3 Renewable Energy Zones and A5 Network Investments (for distribution projects for utility-scale solar and wind developments) and Appendix A6 Cost Benefit Analysis (for sensitivity analysis that tests the resilience of the optimal development path).

Key changes from the Draft 2026 ISP[7]

The following updates are intended to improve the modelling approach, incorporating more recent data and reflecting stakeholder feedback on the Draft 2026 ISP.

- Stationary consumer battery uptake has been updated to reflect the latest settings of the federal Cheaper Home Batteries Program (CHBP) and observed trends in consumer battery uptake. These updated forecasts are based on those published in the Draft 2026 *Forecasting Assumptions Update*[8], updated to reflect stakeholder submissions to the consultation process and more recent installation data. VPP participation rates remain the same as the 2025 *Inputs, Assumptions and Scenarios Report* (IASR), however the capacity of coordinated batteries increased due to the increase in total battery capacity.
- Vehicle-to-grid (V2G) capacity has been reduced from the Draft 2026 ISP to reflect vehicle usage patterns. This results in a lower contribution from V2G to coordinated CER capacity in the *Step Change* scenario. In effect, while total coordinated CER capacity is broadly unchanged from the Draft 2026 ISP, its composition has shifted with more VPP and less V2G. More details can be found in the Draft 2026 *Forecasting Assumptions Update*.
- A higher energy efficiency sensitivity has been added to complement the lower energy efficiency sensitivity included in the Draft 2026 ISP. Together, these sensitivities test how higher and lower electricity consumption, driven by energy efficiency savings, affect generation and storage requirements, opportunities for distribution networks to support CER export and system costs. The sensitivity analyses presented in this DSF statement do not examine how the need for transmission network investment might change. However, AEMO has conducted separate analysis in which transmission network investment requirements are also examined (Appendix A6).
- Updated generation and storage technology costs between the draft and final 2026 ISP, now reflecting CSIRO's draft 2025-26 GenCost[9], have contributed to the differences in estimated system cost impacts observed for the DSF statement's sensitivities.

[7] AEMO has published all inputs and assumptions within the 2026 ISP Inputs and Assumptions Workbook, including a change log of changes.

[8] See https://www.aemo.com.au/consultations/current-and-closed-consultations/draft-2026-forecasting-assumptions-update. The final 2026 *Forecasting Assumptions Update* will be published in August 2026.

[9] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/csiro-gencost-2025-26-consultation-draft-report.pdf?rev=0d9be21b4a364929bb875d486665cc87&sc_lang=en.

A9.2 Demand side factors considered

The terms below have the following meaning when used in this DSF statement:

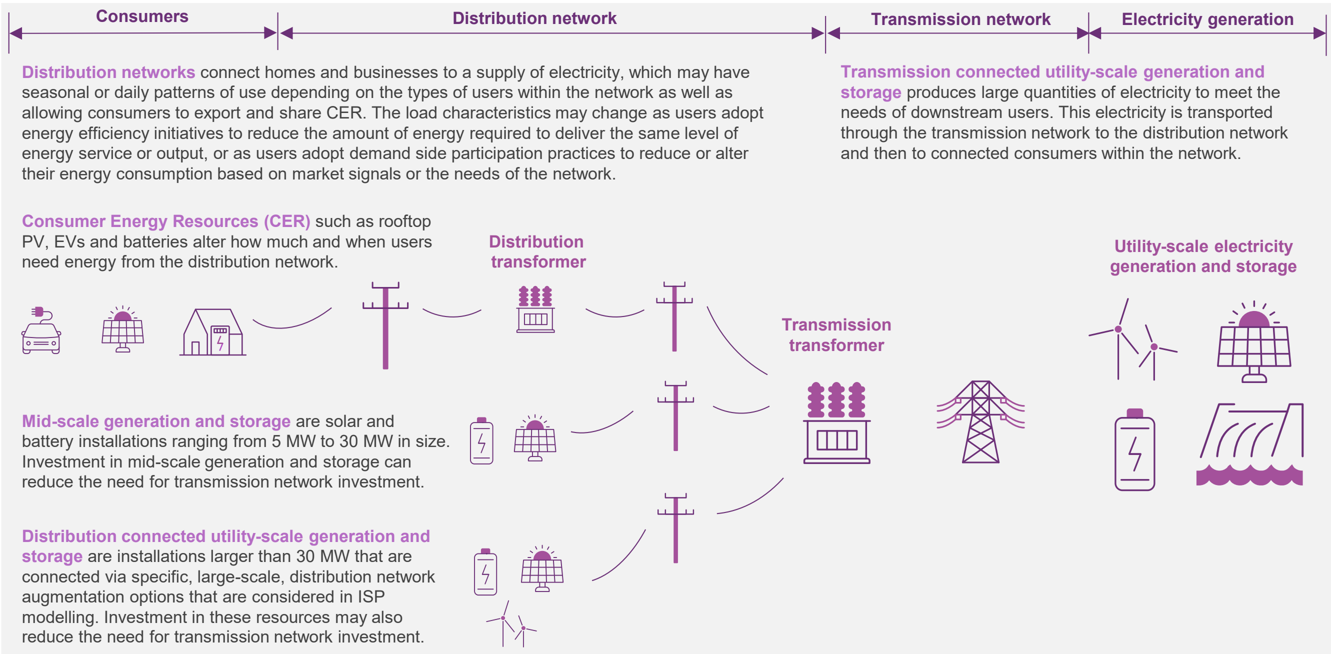
- **Efficient development of the power system** – the overarching purpose of the ISP is to deliver a plan for the efficient development of the power system that achieves power system needs such as reliability and security, and has regard to achieving the three limbs of the National Electricity Objective.
- **Distribution network development opportunities to support CER export** – distribution network investments that AEMO identifies could be effective in supporting the integration of more CER and other demand side factors in a manner consistent with the efficient development of the power system. These investment opportunities enable greater export of CER generation from consumers' homes and businesses into the distribution network through voltage management optimisation or distribution network augmentation.

Demand side factors and the needs of the energy network

This DSF statement examines the current and potential developments in demand side factors such as CER and energy efficiency, and the associated opportunities for distribution networks to facilitate these developments in line with the efficient development and future needs of the power system. Specifically, this DSF statement examines the impact that demand side factors may have on utility-scale generation and storage investment needs, and on distribution network opportunities to support CER export.

To identify the broader impact that demand side factors may have on the efficient development of the power system, AEMO has conducted complementary analysis which additionally assesses their impact on transmission network investment (discussed in Appendix A6). The interaction between demand-side and supply-side investments is shown in **Figure 1**.

Figure 1 Simplified electricity network topology and description of terms



Demand side factors assessed in this DSF statement

The scope and analysis presented in this inaugural DSF statement reflect a balance between completeness and what could feasibly be incorporated into the 2026 ISP, given its introduction as a new element of the analysis and reporting framework. The DSF statement is likely to evolve in successive ISPs, given the engagement opportunities for stakeholders to identify areas of greatest contribution to support decision making, and as more information is provided by DNSPs under the *Demand Side Factors Information Guidelines*.

In response to stakeholder feedback to the Draft 2026 ISP, AEMO has improved the scope and assessment of demand-side factors. These improvements include updating stationary consumer battery uptake to reflect expected investment under the CHBP and recent installation trends and incorporating a V2G availability factor to better reflect real-world vehicle usage patterns. AEMO has also introduced a higher energy efficiency sensitivity, alongside the lower sensitivity included in the Draft 2026 ISP, to test the impact of both higher and lower electricity consumption on power system outcomes, and improve the representation of these demand-side factors in the core scenarios.

This DSF statement focuses on CER and energy efficiency, reflecting two significant components affecting consumer demand and therefore the future needs, and efficient development, of the power system (including the efficient distribution network development opportunities to support CER export). As outlined in subsequent sections, AEMO's analysis deployed sensitivities to assess the impact of selected demand side factors on the efficient development of the power system, by considering the impacts on utility-scale generation and storage development and distribution network development to support CER export. This assessment is consistent with AEMO's capacity outlook modelling methodology. Assumption differences for each sensitivity and the *Step Change* scenario are described for each factor in Section A9.3.

'Demand side factor' is defined in the NER as a factor that affects demand for, or patterns of use of, the distribution services of a DNSP, which may include:

- a development in technology or services available to end users,
- the effect of distribution connected units,
- a policy promoting electrification, or
- demand management or energy efficiency schemes.

The uptake, integration, use and potential coordination of CER and mid-scale generation and storage are forecast to increase with time, as detailed in the 2025 IASR. As consumers continue to invest in these technologies, their effects on demand for, and the patterns of use of, distribution networks will become more pronounced. Given these technologies may lead to significant changes in the investments in, and management of, the distribution networks, this first DSF statement focuses on assessing CER. These are assets connected to distribution networks across the NEM that can generate or store electricity, including[10]:

- rooftop photovoltaic (PV) generation systems with a capacity of less than 100 kilowatts (kW),
- PV non-scheduled generation (PVNSG) with capacity between 100 kW and 5 megawatts (MW),

[10] CER does not include devices which manage the operation of CER or electricity consumption such as smart meters, or aggregation of CER in a VPP, or demand side flexibility and demand side participation (DSP).

- batteries with generation capacity of less than 50 kW, and
- EVs, including storage and generation using EV batteries, which is referred to as V2G.

Forecasting approach

AEMO's forecasting approach[11] describes several forecasting components that are included in the NER definition of demand side factors noted above. The definition of AEMO's forecasting components reflects its hierarchy of forecasting models which are consulted on via various publications within its forecasting approach.

Table 1 defines these components and describes how the forecast components were developed.

Table 1 DSF elements included in this DSF statement

DSF category	Forecast component	Definition	Development for and application in the ISP
CER technology	Rooftop and other small-scale solar	PV (solar panels in a residential home or business with a capacity of less than 100 kW), or PVNSG (non-scheduled generation) with a capacity between 100 kW and 5 MW.	Exogenous unconstrained forecast[A] developed and consulted on within the 2025 IASR. Modelled with regard to distribution network capabilities that support the operation of CER, potentially constraining CER exports. Export to distribution networks constrained by existing network limitations unless economic to augment the distribution network to harness latent CER capacity.
	Batteries	NEM connected battery in a residential home or business with a capacity not exceeding 50 kW.	
	EV	A battery EV or plug-in hybrid EV (PHEV) registered in the NEM.	
CER coordination	VPP	Coordination of batteries[B] in the NEM through a third party aggregator or retailer.	Exogenous unconstrained forecast developed and consulted on within the 2025 IASR, reflecting the dynamic management of the CER assets to maximise their benefit. Modelled explicitly as a component of the ISP capacity outlook modelling that can be operated to minimise system costs and maintain power system reliability, with regard to distribution network capabilities that support the operation of CER, potentially constraining CER exports. Export to distribution network constrained by existing network limitations unless economic to augment the distribution network to harness latent CER capacity.
	V2G	Coordination of EV batteries.	
Energy efficiency	EE	The cumulative reduction in energy use (energy savings) due to factors such as technical improvements in consumer appliances and the thermal efficiency improvements of buildings due to building energy efficiency standards.	Energy efficiency is developed as an exogenous forecast in the IASR, reflecting technology developments, policies and underlying consumer appetite for bill savings and environmental benefits.

A. Unconstrained CER forecasts represent the expected uptake and operation of CER driven by underlying consumer demand, economics, technology trends before considering any operational and network constraints.
B. Batteries as defined under 'CER technology' in the DSF category.

Scope of DSF statement

This DSF statement addresses the requirements of clause 5.22.6A of the NER by:

- providing information about, and analysis of, AEMO's inputs and assumptions for the projected impacts of the relevant demand-side factors (see Section A9.3),

[11] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach.

- identifying demand-side factors that can reasonably be expected to affect the efficient development of the power system, projecting the impact of these factors on the efficient development of the power system, and conducting a sensitivity analysis to understand the implications if impacts are higher and lower than forecast (see Section A9.3),
- providing insight into AEMO's assumptions about distribution network development opportunities to support CER export and how these assumptions have shaped its identification of the ODP (see Section A9.4), and
- identifying distribution network development opportunities to support CER export that are consistent with the efficient development of the power system (see Section A9.4).

A9.3 Demand side factors

Demand side factors are factors affecting consumers' demand for electricity and the resulting use of distribution network services, including CER, participation in VPPs, energy efficiency, electrification and demand management. For this inaugural DSF statement, AEMO has focused on the factors most relevant to the efficient development of the power system; see Section A9.2 for the full definition and scope.

These are described in the sections that follow, and at a summary level include:

- Integrating CER so it can respond to market signals, and coordinating these devices effectively, can reduce operational demand and the investment needed to maintain reliability, particularly during evening peaks. Two sensitivities demonstrate the value for all consumers of enabling and adopting forecast levels of coordination in *Step Change*, including only stationary batteries that are operated under a VPP, and another which includes coordination of vehicle charging under V2G arrangements. Enabling market signals to influence CER operation, and then operating these devices to minimise the costs incurred by the entire system, would save approximately $3.8 billion (for VPP only) or up to $5.2 billion (if inclusive of V2G) when compared to the *Step Change* scenario in real, present value terms.
- Improving energy efficiency reduces the amount of electricity consumers use, which lowers the requirements for new generation, storage and network investment. AEMO's sensitivity analysis of lower energy efficiency shows if no further energy efficiency investments are made beyond those supported by current policy, energy savings are projected to be 34% lower than forecast in *Step Change*, with 27 TWh higher operational consumption in 2049-50 and approximately $9.5 billion of additional system investment (roughly $35/MWh on average for the incremental demand). In contrast, AEMO's higher energy efficiency sensitivity increases energy efficiency savings by around 27%, reducing consumption by approximately 21 TWh in 2049-50, lowering total system costs by approximately $7.2 billion relative to *Step Change*, equivalent to an average saving of about $31/MWh on average.

The 2026 ISP includes both higher and lower energy efficiency sensitivities, extending the analysis provided on a lower energy efficiency sensitivity included in the Draft 2026 ISP.

What investment decisions are re-examined under the sensitivities?

Sensitivity analysis in this DSF statement considers the effect on the efficient development of the power system, when the impact of a demand side factor is *less* than or *greater* than that projected in ISP scenario analysis. Utility scale generation and storage capacity development and distribution network developments (to support CER export) were re-optimised in these sensitivity analyses, and with the transmission developments assessed for relevant transmission development paths[12] (DPs).

Sensitivity testing of CER coordination focuses on lower impacts than those identified in scenario analysis by exploring two sensitivities: *No Further CER Coordination* and *No Further VPP Uptake.* While the impact of greater CER coordination than that in scenario analysis is not tested via sensitivities, an uplift in the CER battery forecast for the 2026 ISP to better reflect investment driven by the CHBP and recent uptake trends is reflected in the scenarios and carried across to the two CER coordination sensitivities. In addition, AEMO acknowledges stakeholder feedback that forecasts for CER coordination,

[12] DPs represent a combination of transmission developments delivered at specific timeframes, depending on if each project was delivered in its actionable window, or after that window if it is a future ISP project. See Appendix A6 Cost Benefit Analysis for more details.

including VPP and V2G participation rates, may be optimistic. While coordination of CER at scale has the potential to deliver system benefits and reduce utility-scale investment requirements, consumer adoption of coordination programs remains uncertain and current uptake is low. Accordingly, AEMO has chosen to explore the impacts of lower CER coordination.

The selection of sensitivities for the DSF statement balances the number of sensitivities that can be practicably included as part of the 2026 ISP sensitivity suite and the materiality of sensitivities on system outcomes. For the 2026 ISP, AEMO has focused sensitivity testing on the variations considered most material and practicable within the broader ISP program. AEMO seeks to improve future DSF statements by improving underlying data through information gathering under the *Demand Side Factors Information Guidelines* and continuing to engage with stakeholders on the appropriate scope of demand side factors and prioritisation of sensitivities to be tested.

A9.3.1 Consumer energy resources coordination

Consumers play a pivotal role in the energy transition. Households and businesses are increasingly investing in CER and other investments to reduce their costs. Many households are moving towards electricity and away from gas for heating, cooking, and cooling, installing rooftop solar, batteries, adopting EVs and participating in VPPs to share stored energy.

Communities are also working together to establish locally led and owned energy projects, such as community solar and wind farms, while businesses are making sizable investments to reduce energy use and to switch to renewables.

About 60 GW of renewables and batteries were operating in the NEM at the start of 2026. Rooftop solar, along with grid-scale solar, wind and hydro, met around 45% of all NEM demand for electricity through the 2026 financial year, including over 50% during the December 2025 quarter. They set a record for a half-hour on 11 October 2025, reaching almost an 80% share. On 5 October 2025, renewables had the potential to deliver almost 115% of demand, around half from rooftop solar (though not all of that capacity could be used due to market and technical limits). These record levels vary seasonally, but are consistently rising.

The *Step Change* scenario in the 2026 ISP forecasts that:

- By 2035, 47% of rooftop solar-suitable dwellings[13] in the NEM would have rooftop solar (up from 36% today), rising to 56% in 2050, driven by declining costs. At that time, forecast rooftop solar and other small scale solar capacity would be 87 GW.
- EV ownership is projected to surge from the late 2020s, driven by falling costs, greater model choice and availability (assisted by new vehicle efficiency standards), and more charging infrastructure. By 2050, up to 80% of all vehicles are projected to be battery EVs, compared to 2% today.
- By 2050, about 65% of rooftop solar-suitable dwellings with solar would have supporting batteries, equating to 4.5 million residential batteries. Residential and commercial batteries are being adopted more quickly than previously forecast, supported by government policies and lower costs. From 5 GW/12 GWh in April 2026[14] installed across 600,000 premises, residential and commercial battery capacity in the NEM is expected to grow to 12.5 GW/33 GWh in 2030, then 35 GW/78 GWh by 2050.

[13] Rooftop solar-suitable dwellings include detached houses and semi-detached dwellings (duplexes and townhouses), and excludes apartments. A slightly higher 43% of fully detached houses in the NEM have rooftop solar.

[14] Based on data from the Clean Energy Regulator from July 2025 to April 2026 combined with an estimate to June 2025 based on Sunwiz's *Australian Battery Market Report 2025* and extrapolated to end of June 2025; see https://www.sunwiz.com.au/battery-market-report-australia-2025/.

- 53% of batteries would be coordinated as part of a VPP, providing 18.6 GW/42 GWh of storage capacity by 2050.
- 11% of residential EVs would be capable of providing flexible capacity to charge and discharge (via V2G), providing approximately 4.3 GW/48.8 GWh of additional energy storage capacity by 2050.

CER influence the efficient development of the power system by providing a direct source of electricity for homes and businesses, reducing the need for broader system investments, if integrated effectively within distribution networks. Specifically:

- generation from rooftop and other small-scale solar reduces the level of consumption from the grid, therefore reducing the utility-scale investment needed,
- batteries and EVs can help increase the minimum system load by charging during periods of high surplus generation, and
- batteries and EVs can be coordinated (via VPPs and, increasingly in the future via V2G arrangements) to reduce the magnitude of peak demand, or increase the peak demand if charging occurs without regard to energy system impacts.

To effectively integrate and support CER operation, explicit distribution investment to reduce inefficient CER curtailment may be warranted; see Section A9.4.

Effective integration of CER to enable them to respond to market signals, and subsequent bundling through a retailer or independent aggregator to provide VPP or V2G services, are key demand side factors in this energy transition. **CER coordination provides an opportunity for consumers to influence the needs of the power system by maximising the benefit of their investments not only for them, but for all consumers.** CER coordination is the dynamic management of VPP and V2G services to maximise their benefit to the power system, for example by coordinating when and how many of these assets discharge into, or charge from, the grid to deliver the greatest value. CER coordination reduces the need for utility-scale generation and storage investments through more efficient utilisation and management of existing CER.

The complete description of the CER coordination trajectories is provided in Section 3.3.7 of the 2025 IASR. The forecasts for consumer batteries are based on the Draft 2026 *Forecasting Assumptions Update* to reflect the change in the federal CHBP.

CER coordination impacts broader investment needs

To understand the impact of CER coordination on the efficient development of the power system, AEMO examined reduced CER coordination through sensitivity analysis to provide a contrast to the *Step Change* scenario. In this sensitivity, AEMO assumed that the level of VPP and V2G capacity was held at current levels. This assumption effectively removes any appreciable volumes of coordinated CER capacity from the NEM, as both VPP and V2G participation are currently at the nascent stages of uptake among consumers. In this *No Further CER Coordination* sensitivity, total CER uptake continues at the level forecast in the *Step Change* scenario but was assumed to operate passively to solely benefit the consumer's own load, rather than in a coordinated manner.

CER coordination in response to market signals will support the power system during periods of peak demand when the balance between supply capacity and consumer demand is typically most tight. The 2026 ISP estimates the impact of coordination on both peak and minimum system demand. For example, in New South Wales, if battery coordination did not expand above current levels, then the capacity of batteries operating on passive or default modes of operation would increase from 3.8 GW to 11.5 GW by 2049-50. However, these batteries are not forecast to materially lower the maximum demand, with only 274 MW (1.5%) reduction in peak demand relative to *Step Change*. These passive batteries are assumed to discharge mostly overnight and in the early morning to meet behind-the-meter consumption when rooftop solar is not generating and not necessarily coincide with system maximum demand periods. In contrast, the impact on minimum demand is more pronounced. Passive batteries will predominantly charge during solar hours to store excess behind-the-meter PV generation. For the same example, minimum system demand increases by 580 MW (9%) compared to the *Step Change* scenario.

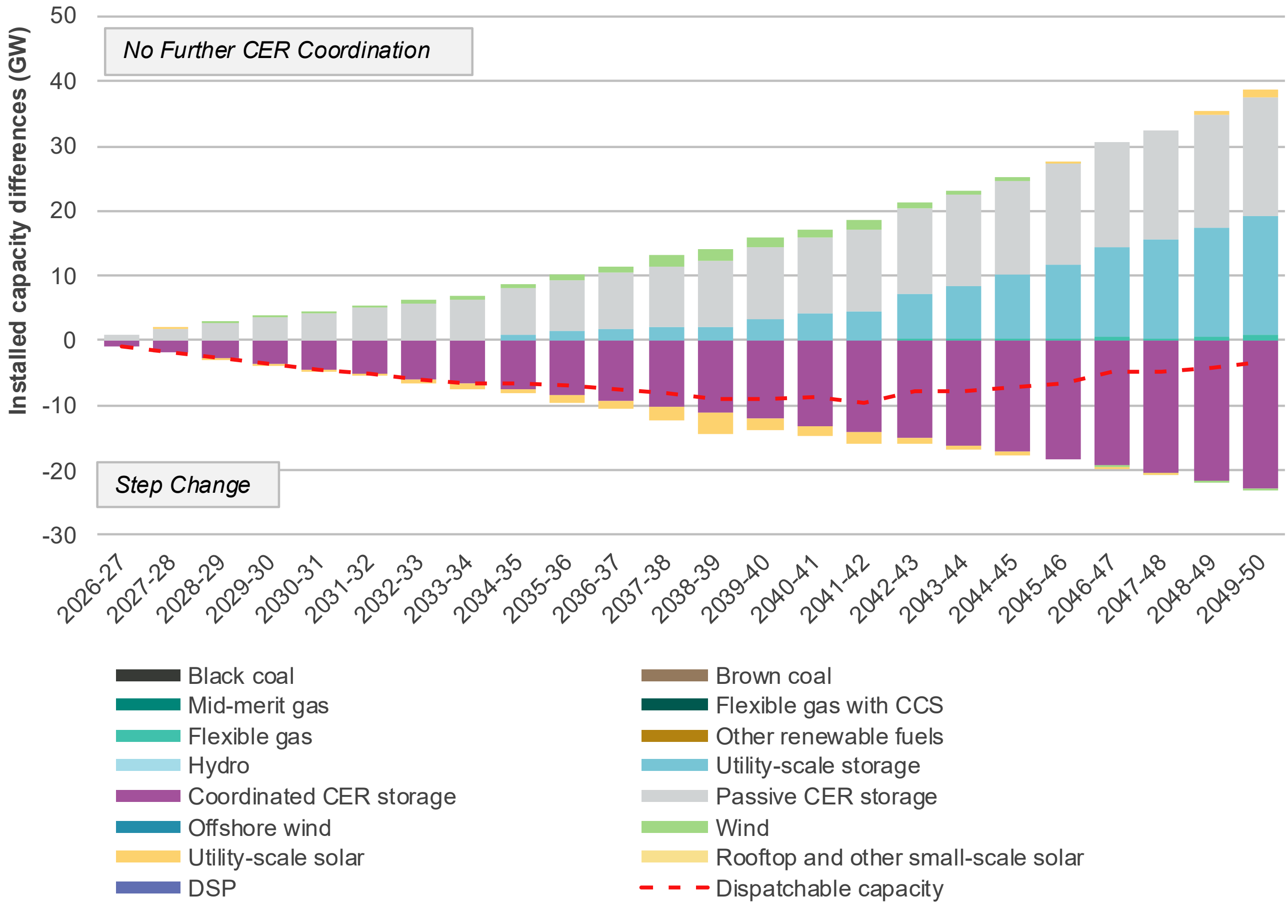
Passive operation of CER is expected to provide less support to periods of tight supply availability, and operational minimum demands are also lower as battery charging does not consistently charge during minimum load conditions.

Figure 2 compares the difference in installed capacity by technology between the *Step Change* scenario and the *No Further CER Coordination* sensitivity.

In this figure, values below the x-axis indicate more of that technology is needed in *Step Change*, whereas values above the x-axis indicate more of that technology being deployed in the sensitivity. The figure therefore demonstrates that the impact of the consumers' decisions to coordinate their batteries or EVs to respond to market signals is to avoid the need to develop a comparable capacity (in GW) of utility-scale storage.

With less coordination than what is forecast in *Step Change*, additional utility-scale storages, primarily of medium depth (four to 12 hours duration) is needed, along with some additional wind and solar generators to provide additional energy generation. The generation and storage development differences observed in **Figure 2** impact the total system cost; developing the forecast level of CER coordination avoids utility-scale storage alternatives and the capital cost of utility-scale generation assets and their associated maintenance, which reduces the net present value of system costs by $5.2 billion to 2049-50. This reduction in total system costs would be in the long-term interest of all consumers. The contribution by category to the system cost can be seen in **Table 2**.

Figure 2 Forecast capacity developments to 2049-50 under the *No Further CER Coordination* sensitivity compared with *Step Change* (GW)



Note: Coordinated CER storage includes VPP and V2G capacity. Passive CER storage includes passive stationary battery capacity only; it does not include passive EV capacity (which is assumed to only draw power from the grid).

Table 2 Difference in total system costs under the *No Further CER Coordination* sensitivity by 2049-50, in $ million (NPV)

Cost category	*Step Change* scenario	*No Further CER Coordination* sensitivity	Difference in costs
Generator, storage, and electrolyser capital deferral	$96,882	$101,104	$4,222
Fixed operating and maintenance cost savings	$52,438	$53,214	$776
Fuel cost savings	$17,697	$17,760	$63
Variable operating and maintenance cost savings	$4,825	$4,837	$12
Retirement cost	$3,980	$3,980	$0
Voluntary and involuntary load shedding reductions	$123	$150	$28
Emissions reduction benefits	$45,345	$45,345	$0
Renewable energy zone (REZ) investment (REZ augmentations)	$97	$118	$21
Distribution expenditure (capital and operating costs)	$214	$193	-$21
System security costs	$2,755	$2,883	$127
Transmission Network (Actionable and Future ISP Projects)	$8,407	$8,407	$0
Total (NPV)	**$232,763**	**$237,990**	**$5,227**

The system cost differences between the scenario and sensitivity outlined in this section have accounted for differences in distribution investment required, but have not accounted for the potential integration costs of making VPP and V2G operation widely available.

While VPP and V2G service levels are currently minor, manufacturers and service providers can play a significant role by:

- providing products which are VPP or V2G ready to offer consumers the flexibility to enrol in these services,
- providing meaningful incentives for consumers to both invest in batteries and EVs and enrol in VPP and V2G programs, and
- in the case of EVs, investing in charging infrastructure and associated distribution network infrastructure to provide flexibility to EV drivers and mitigate range anxiety concerns.

Consumers' stationary home batteries and vehicular batteries offer two routes to coordination, both providing value by lowering broader system needs

Coordination of CER includes the opportunity to operate home batteries under VPP arrangements, and coordinating the charge and discharge of connected EVs. These resources offer different impacts, particularly as vehicular availability will depend on driving behaviours, and that vehicles typically offer a deeper energy store per kW of capacity than home batteries. The average depth of home batteries in 2050 is projected to be 2.3 hours (at full discharge), whereas an EV would provide 11.3 hours (at full discharge) if connected (and if pre-charged). This deeper volume can increase the opportunity for EV coordination to reduce investment needs, however the overall capacity of VPP resources is forecast to be significantly greater than V2G in *Step Change*, with 4.3 GW/48.8 GWh of V2G capacity compared to 18.6 GW/42 GWh of VPP by 2049-50.

The *No Further CER Coordination* sensitivity considered both VPP and V2G as sources of coordinated consumer response. AEMO also performed a further *No Further VPP Uptake* sensitivity to gain insights on the relative value of VPP and V2G, by isolating only VPP uptake in this sensitivity while retaining *Step Change* V2G levels.

The results of this additional sensitivity analysis, including comparison to the 2024 ISP, are that the 2026 ISP shows the value of VPP-only coordination to be $3.8 billion (in real June 2025 dollars) when compared to the *Step Change* scenario. AEMO's *No Further CER Coordination* sensitivity shows VPP and V2G together yield a benefit of $5.2 billion (in real June 2025 dollars). The lower incremental value of V2G is consistent with assumptions that V2G capacity is a lower proportion of the coordination capacity of VPPs.

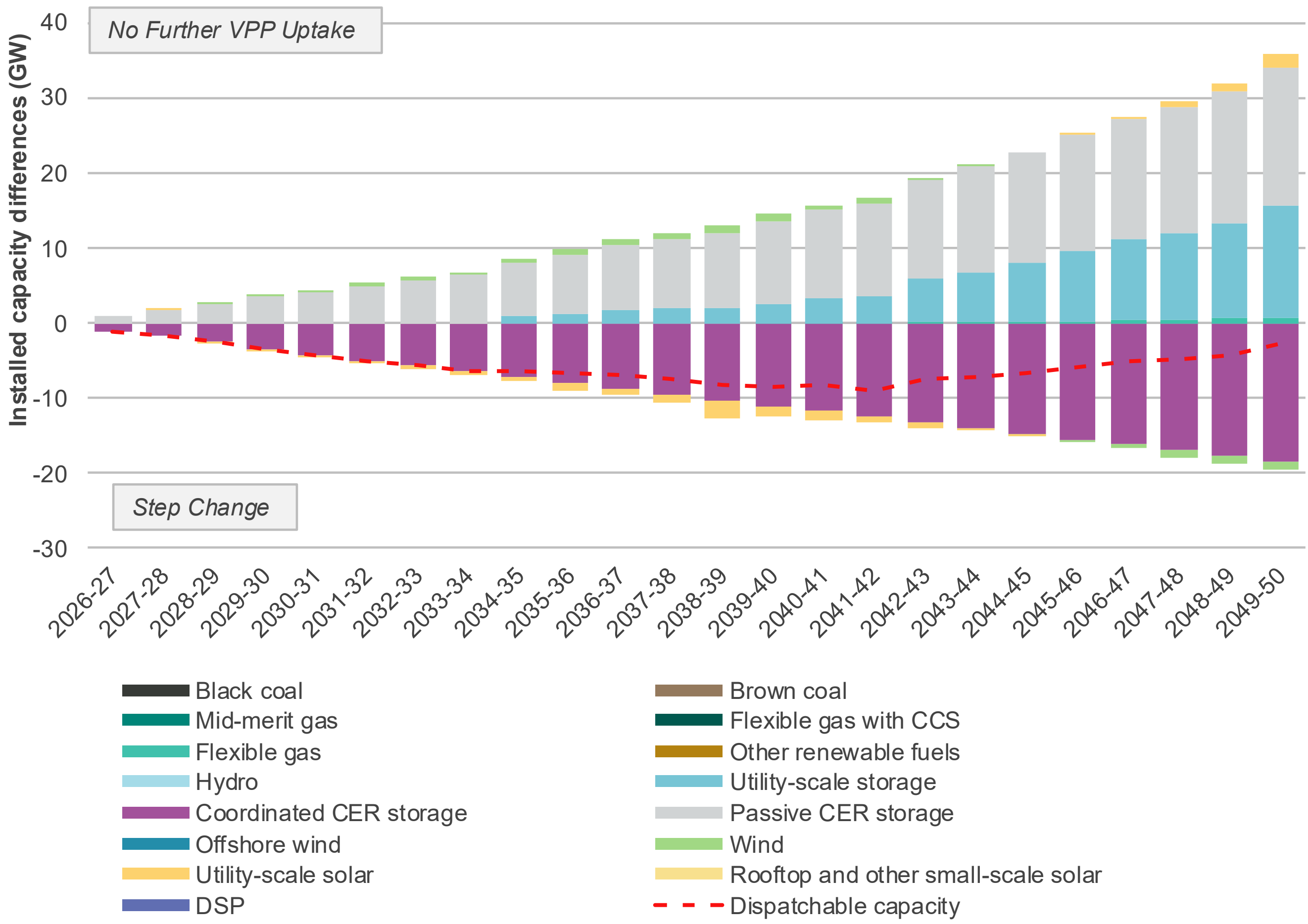
This figure is slightly lower than the equivalent 2024 ISP figure because the 2026 ISP forecasts have less anticipated VPP capacity than the 2024 ISP [15]. More information on the forecasts is in the 2025 IASR and 2026 Draft *Forecasting Assumptions Update*.

Figure 3 compares the difference in installed capacity by technology between the *Step Change* scenario and the *No Further VPP Uptake* sensitivity. If there is no further coordination of forecast stationary CER storage, additional utility-scale investments would be needed. However, less investment in utility-scale storage is needed compared to the *No Further CER Coordination* sensitivity, as coordinated V2G capacity assumed in *Step Change* has not been removed from *No Further VPP*

[15] The 2024 ISP showed the value of *No further VPP Uptake* sensitivity to be $4.1 billion (in real June 2023 dollars, or equivalent to approximately $4.3 billion in real June 2025 dollars). These values are not appropriate to compare, given the broad range of changes to system dynamics (such as the higher forecast of home batteries from the CHBP) in the 2026 ISP.

Uptake. The value of this coordinated V2G capacity can be determined by comparing outcomes of the two sensitivities. The additional coordination provided by V2G in addition to VPPs avoids the need for up to 4 GW of utility scale storage builds and 1 GW of additional wind capacity by 2049-50, avoiding $1.4 billion in total system cost driven by generator capital costs ($1.1 billion).

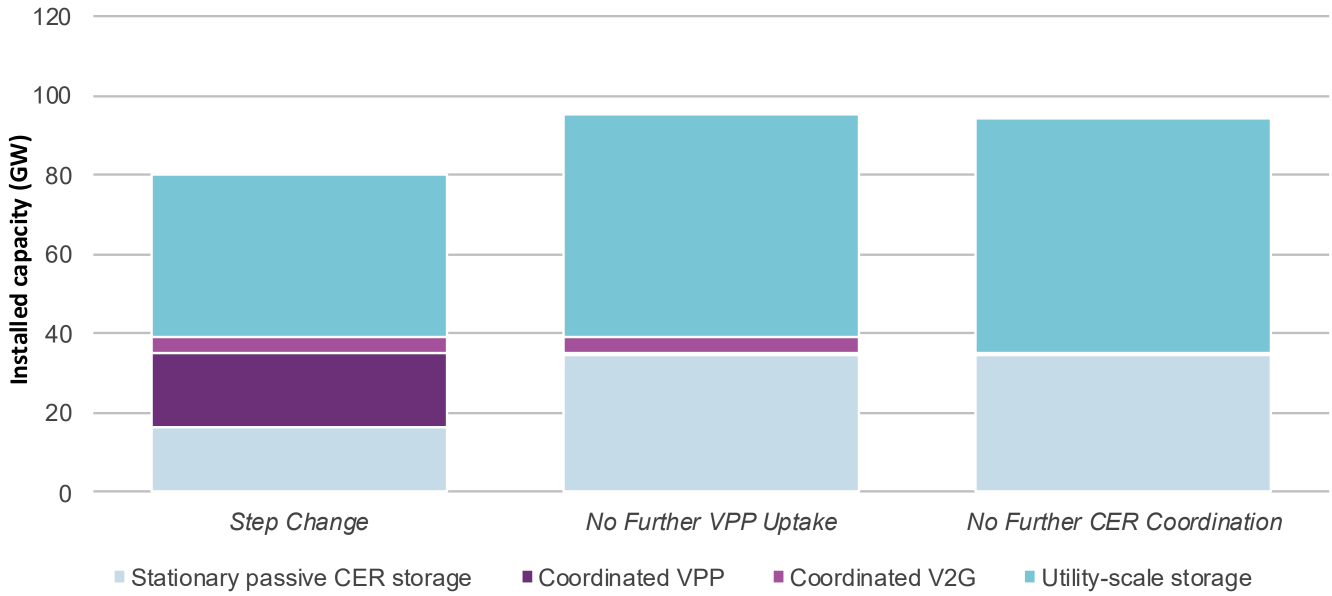
Figure 3 Forecast capacity developments to 2049-50 under the No Further VPP Uptake sensitivity compared with *Step Change* (GW)



Note: Coordinated CER storage includes VPP and V2G capacity. Passive CER storage includes passive stationary battery capacity only; it does not include passive EV capacity (which is assumed to only draw power from the grid).

Figure 4 summarises the variation of VPP and V2G capacity assumption in each sensitivity and the resulting utility-scale storage development, highlighting the additional utility-scale storage required with reduction in coordinated CER. By 2049-50, an additional 15 GW/60 GWh of medium duration utility-scale storage would be required in the *No Further VPP Uptake* sensitivity to make up for the shortfall in coordinated consumer devices and passive device behaviour. Similarly, an additional 3.2 GW/13.8 GWh of medium duration utility-scale storage would be required in the *No Further CER Coordination* sensitivity, on top of what is already additionally built in the *No Further VPP Uptake* sensitivity.

Figure 4 Summary of utility-scale storage required in the CER coordination sensitivities in 2049-50 (GW)



Unlocking CER potential via the National CER Roadmap

Realisation of the value described above requires the right policy, market and system settings, consumer technologies and the voluntary participation of consumers. Governments, consumers and industry will need new and collaborative approaches to ensure the growth and integration of CER can continue to play a pivotal role in advancing the energy transition. Such work must support transparency over data requirements, equitable rewards for participation, and confidence in the market settings.

The Federal Government's National CER Roadmap was published in July 2024. It sets out an overarching vision and plan to unlock the benefits of CER for all Australians and the electricity system. The Roadmap aims for a consistent approach across industry while ensuring fair access to CER and stronger protections for consumers. This includes:

- developing CER device interoperability requirements and a National Technical Regulatory Framework for CER, to set clear national direction and conformance on minimum CER capabilities,
- modernising frameworks to support consumers to engage with the energy market with a focus on consumer protection and opportunities,
- defining clear roles, responsibilities and resources across the electricity sector to ensure effective, consistent and accountable delivery of CER integration outcomes, and
- establishing a National CER data management framework and coordination function and developing interfaces and infrastructures to enable data and operational coordination.

The National CER Roadmap recognises effective CER integration requires the intersection of consumers, technology, markets, and power system operation. AEMO will continue working with governments, market bodies, industry and consumers to implement the Roadmap's four workstreams, which are urgently required to realise the benefits of CER while ensuring the efficient development, security and resilience of the power system.

A9.3.2 Energy efficiency investments reduce electricity consumption and lower system costs

Energy efficiency is the reduction in energy required to deliver the same service or outcome by reducing energy waste through means such as technology improvements and policy mechanisms such as building and energy standards. These drivers reduce the amount of electricity that needs to be provided, reducing strain on existing assets, reducing investment needs, and lowering emissions.

The complete description of the energy efficiency trajectories is provided in Section 3.3.12 of the 2025 IASR.

Two types of energy efficiency improvements are identified – those that improve the technical efficiency of consumer and commercial appliances (including industrial processes), and those that improve the thermal efficiency of buildings such that the energy needs of heating and cooling devices are reduced.

Government policies can be an effective means of encouraging consumers to choose an efficient option over a less efficient alternative at a faster pace than would otherwise occur. While increasingly efficient appliances and building products tend to become available through technological improvements over time, consumers will likely only make a replacement decision at the end of an appliance's useful life, and building renovations to improve building materials tend to be costly and infrequent investments.

Policies may influence consumers directly (through financial incentives such as the Household Energy Upgrades Fund[16]) or indirectly (by requiring increased transparency of information or compliance to standards, such as the *Greenhouse and Energy Minimum Standards Act 2012*[17]). This applies to both residential and commercial energy efficiency opportunities. Relevant energy efficiency policies are outlined in Table 4 of the 2025 IASR.

Energy efficiency investments that lower electricity consumption and demand reduce investment needs

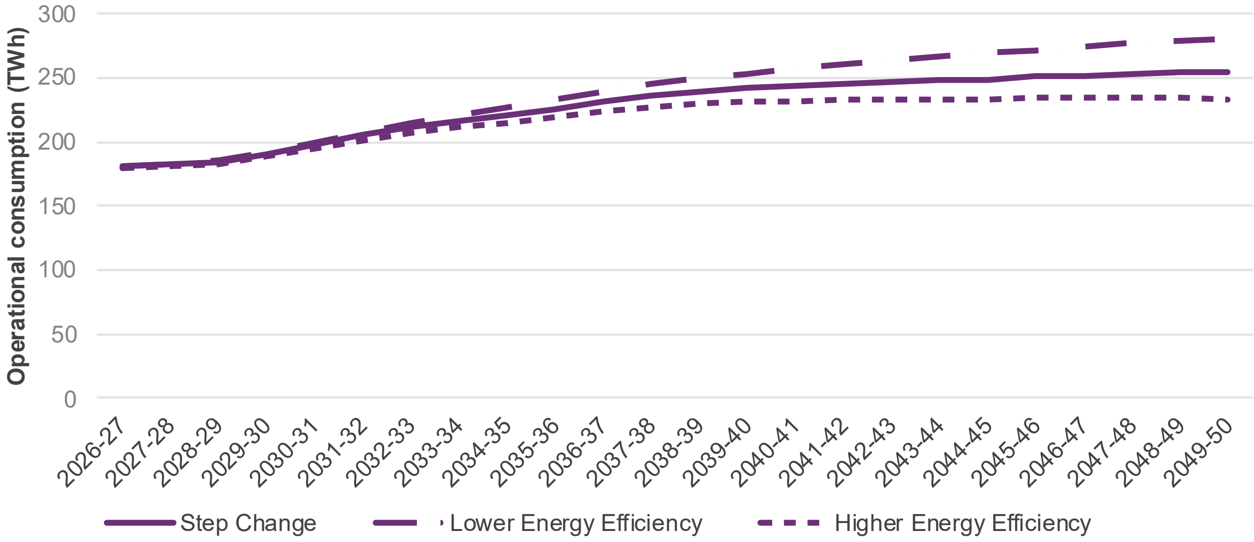
To understand the impact of growing energy efficiency investments on the efficient development of the power system, AEMO examined lower and higher energy efficiency outcomes through sensitivity analyses to provide a contrast to the *Step Change* scenario.

Figure 5 compares NEM-wide electricity consumption over time in the *Lower and Higher Energy Efficiency* sensitivity against *Step Change*, demonstrating an increasing variation between the two forecasts of operational electricity consumption over time. By 2049-50, there is 27 TWh higher consumption (compared to *Step Change)* required NEM-wide in the *Lower Energy Efficiency* sensitivity and 21 TWh lower consumption than *Step Change* required in the *Higher Energy Efficiency* sensitivity.

[16] See https://www.energy.gov.au/rebates/household-energy-upgrades-fund.

[17] See https://www.energyrating.gov.au/industry-information/legislative-framework.

Figure 5 Operational consumption for the NEM by energy efficiency trajectory, 2026-27 to 2049-50 (TWh)

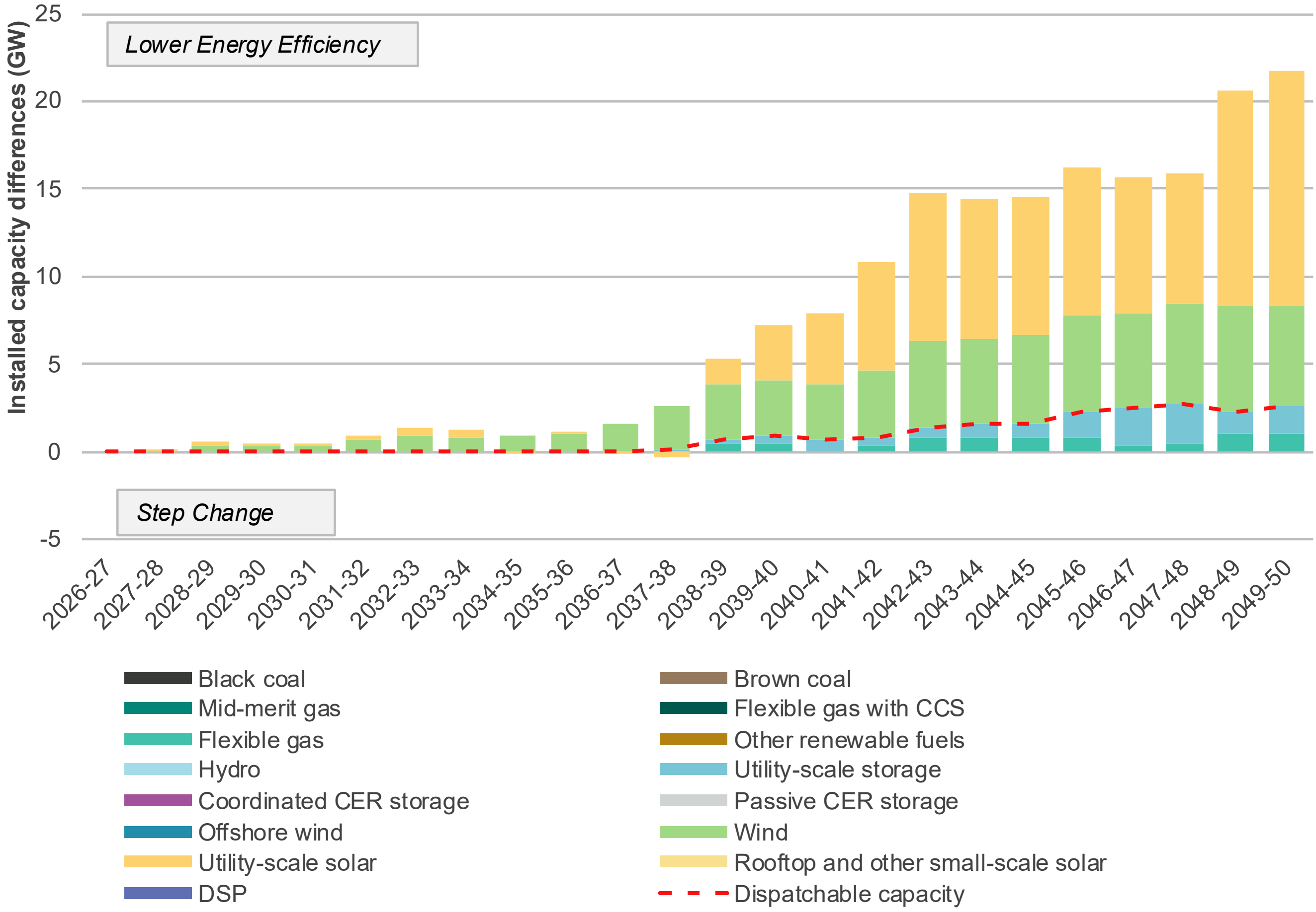


In the *Lower Energy Efficiency* sensitivity, only energy efficiency improvements that are market-led were assumed to occur after current policy support is scheduled to end, and these mechanisms are not extended or increased over time. The key observations from this sensitivity analysis are:

- The additional generation and storage deployments observed in *Lower Energy Efficiency,* along with associated additional REZ network augmentation and system security requirements, contribute to an additional $9.5 billion in system costs by 2049-50 compared to the *Step Change* scenario. The contribution by category to the system cost can be seen in **Table 3**.
- Over the period to 2050, cumulative electricity consumption is 273 TWh higher (compared to *Step Change*), incurring an additional system cost of $35/MWh for that additional demand.
- In aggregate, approximately 13.4 GW of utility-scale solar, 5.8 GW of wind, 1.5 GW of large scale storage and an additional 1.1 GW of flexible gas generation is required by 2049-50 to service the higher load compared to *Step Change*, as shown in **Figure 6.**

Figure 6 compares the difference in installed capacity by technology between the *Step Change* scenario and the *Lower Energy Efficiency* sensitivity. In this figure, the values indicate more of that technology is forecast in the sensitivity. The figure demonstrates the impact of energy efficiency investments on the efficient development of the power system is to reduce utility-scale developments.

Figure 6 Forecast capacity developments to 2049-50 under the *Lower Energy Efficiency* sensitivity compared with *Step Change* (GW)



Note: Coordinated CER storage includes VPP and V2G capacity. Passive CER storage includes passive stationary battery capacity only; it does not include passive EV capacity (which is assumed to only draw power from the grid).

Table 3 Difference in total system costs under the *Lower Energy Efficiency* sensitivity by 2049-50, in $ million (NPV)

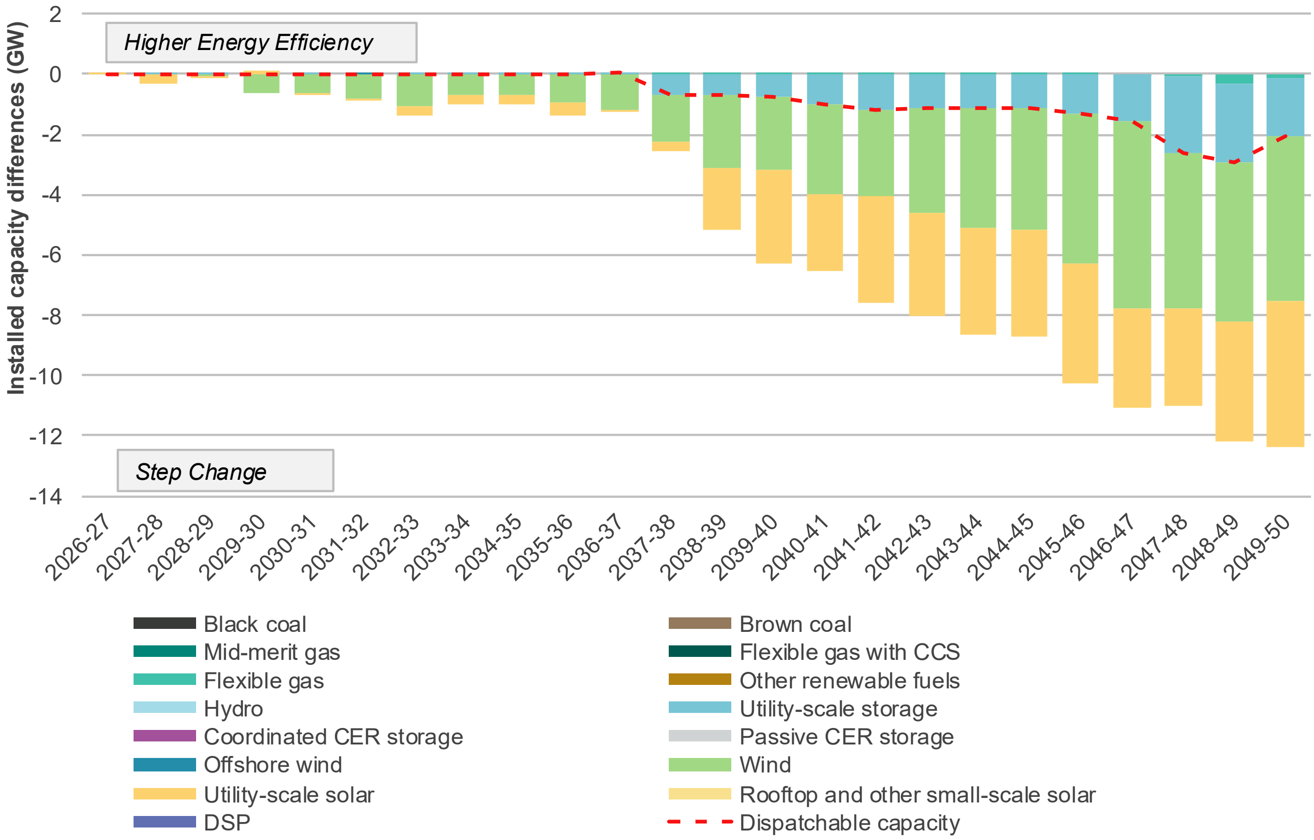
Cost category	*Step Change* scenario	*Lower Energy Efficiency* sensitivity	Difference in costs
Generator, storage, and electrolyser capital deferral	$96,882	$104,486	$7,604
Fixed operating and maintenance cost savings	$52,438	$53,507	$1,069
Fuel cost savings	$17,697	$18,072	$375
Variable operating and maintenance cost savings	$4,825	$4,862	$38
Retirement cost	$3,980	$3,983	$3
Voluntary and involuntary load shedding reductions	$123	$177	$54
Emissions reduction benefits	$45,345	$45,348	$3
REZ investment (REZ augmentations)	$97	$204	$108
Distribution expenditure (capital and operating costs)	$214	$233	$19
System security costs	$2,755	$2,970	$215
Transmission Network (Actionable and Future ISP Projects)	$8,407	$8,407	$0
Total (NPV)	**$232,763**	**$242,250**	**$9,487**

The *Higher Energy Efficiency* sensitivity demonstrates the power system impacts resulting from greater savings in electricity consumed, by applying the higher *Accelerated Transition* energy efficiency savings for the business mass market[18] and residential sectors. The key observations from this sensitivity analysis are:

- The reduction in utility-scale generation needed to meet the combination of reduced consumption and demand, contributes to a reduction of $7.2 billion in total system costs in the *Higher Energy Efficiency* sensitivity. The contribution by category to the system cost is presented in **Table 4**.
- Over the period to 2050, cumulative electricity consumption is 232 TWh lower (compared to the *Step Change)*, reducing the need for generation and storage capacity development and delivering system cost savings of $31/MWh for that avoided demand.
- In aggregate, approximately 5.4 GW less wind, 4.9 GW of less utility-scale solar and 2 GW less utility-scale storage is needed in this sensitivity as presented in **Figure 7**.

Figure 7 compares the difference in installed capacity by technology between the *Step Change* scenario and the *Higher Energy Efficiency* sensitivity, showing that higher energy efficiency leads to significantly lower generator capital investments.

Figure 7 Forecast capacity developments to 2049-50 under the *Higher Energy Efficiency* sensitivity compared with *Step Change* (GW)



Note: Coordinated CER storage includes VPP and V2G capacity. Passive CER storage includes passive stationary battery capacity only; it does not include passive EV capacity (which is assumed to only draw power from the grid).

[18] Business mass market is a subset of the business sector that covers a broad range of consumers which are not covered by the large industrial load, hydrogen, EV, data centre or liquefied natural gas (LNG) sector forecasts.

Table 4 Difference in total system costs under the *Higher Energy Efficiency* sensitivity by 2049-50, in $ million (NPV)

Cost category	*Step Change* scenario	*Higher Energy Efficiency* sensitivity	Difference in costs
Generator, storage, and electrolyser capital deferral	$96,882	$91,144	-$5,738
Fixed operating and maintenance cost savings	$52,438	$51,627	-$812
Fuel cost savings	$17,697	$17,360	-$336
Variable operating and maintenance cost savings	$4,825	$4,782	-$43
Retirement cost	$3,980	$3,983	$3
Voluntary and involuntary load shedding reductions	$123	$107	-$15
Emissions reduction benefits	$45,345	$45,345	-$0
REZ investment (REZ augmentations)	$97	$57	-$40
Distribution expenditure (capital and operating costs)	$214	$207	-$7
System security costs	$2,755	$2,588	-$167
Transmission Network (Actionable and Future ISP Projects)	$8,407	$8,407	$0
Total (NPV)	**$232,763**	**$225,608**	**-$7,155**

AEMO recognises that consumer responses to changes in energy costs may influence the outcomes observed in the sensitivity analysis. For example, higher consumption needs may prompt consumers to invest in rooftop solar rather than replace inefficient appliances with more efficient alternatives. These behavioural responses have not been explicitly modelled in this sensitivity and may affect the scale of the impacts identified.

A9.4 Opportunities for the development of the distribution network

AEMO has developed an approach to model the existing capability of distribution networks to accommodate CER export, and to estimate the scale of distribution investments to efficiently support CER export. This approach has been developed through close involvement with DNSPs across the NEM.

This section:

- identifies what a distribution network development opportunity to support CER export is in the context of the ISP (Section A9.4.1),
- explains how distribution network development opportunities have been modelled and considered in the ISP (Section A9.4.2),
- presents the distribution network development opportunities identified to facilitate operation of forecast CER by sub-region (Section A9.4.3),
- discusses enhancements to the approach for identifying distribution network development opportunities in future ISPs (Section A9.4.4), and
- outlines the information that AEMO has published alongside this DSF statement (Section A9.4.5).

AEMO has published the 2026 ISP model alongside the ISP report and input files, and has included average annual CER generation limit time of day profiles for each distribution network area in the ISP model in the 2026 ISP Inputs and Assumptions Workbook[19]. AEMO has not published the underlying data that was voluntarily provided by DNSPs, which AEMO has synthesised and used in analysis to inform the CER generation limits that are used in ISP modelling.

A9.4.1 Distribution network development opportunities to support CER export

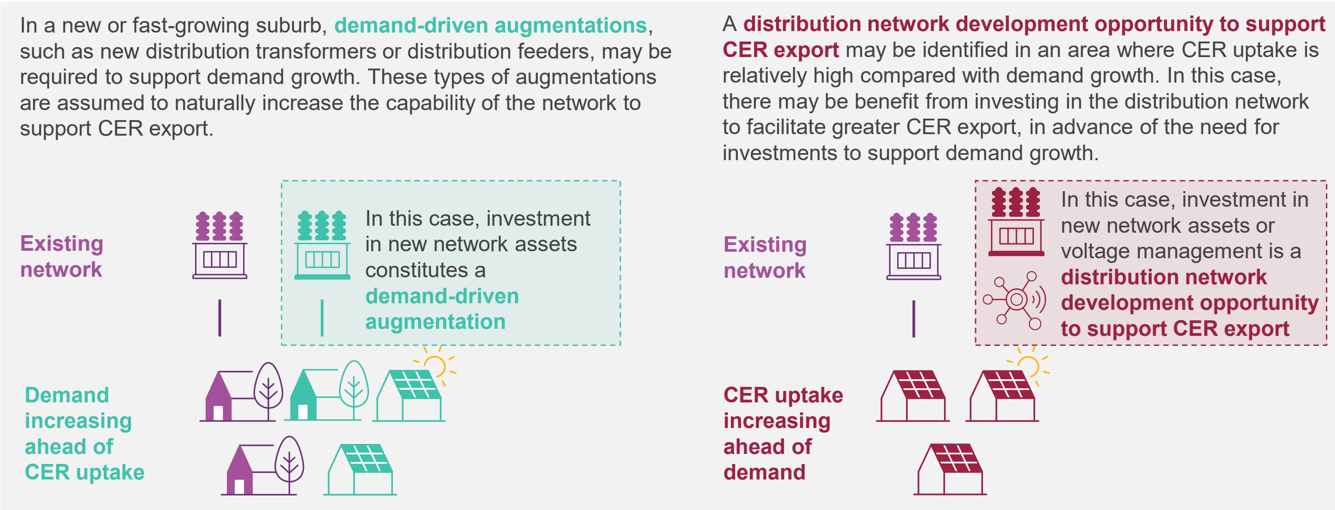
In this DSF statement, 'distribution network development opportunities to support CER export' refer to economically efficient distribution network investments that specifically enable greater export of CER from consumers' homes and businesses into the distribution network, unlocking latent CER capacity to benefit all consumers. The 2026 ISP has also considered opportunities for mid-scale generation and storage connected via distribution networks (discussed in Appendix A2) and distribution network development opportunities that facilitate utility-scale generation and storage (discussed in Appendix A5).

Separate to these opportunities, AEMO understands that DNSPs already invest in network augmentations to support the growing demand for electricity within their networks. DNSPs are expected to need to continue to invest in these types of augmentations into the future as new customers connect and existing customers increase their electricity loads. AEMO refers to these augmentations that are required to meet demand growth as 'demand-driven' augmentations. AEMO understands that demand-driven augmentations are likely to also be able to support greater export of CER generation. These types of distribution network investment are mutually exclusive within ISP modelling.

Figure 8 distinguishes between demand-driven augmentations and distribution network development opportunities to support CER export and demonstrates what might drive each type of distribution network investment.

[19] At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp.

Figure 8 Distribution network development opportunities to support CER export and demand-driven augmentations



Of the two types of investment shown in **Figure 8,** the ISP modelling approach only identifies, and optimises, distribution network development opportunities to support CER export[20]. While demand-driven augmentations are not considered directly in the ISP model, Section A9.4.2 describes a key assumption regarding the proportion of new CER uptake and demand growth that are estimated to be supported via demand-driven augmentations, and explains how this assumption impacts AEMO's assessment of distribution network development opportunities.

Distribution network development opportunities that enable greater export of CER are identified in this DSF statement at a sub-region level in Section A9.4.3. They reflect the scale of efficient investment in distribution networks at an aggregate level based on macro-level cost rates for two types of investment: voltage management optimisation and network augmentations. AEMO does not identify the specific projects, such as the upgrade of a specific distribution feeder within a DNSP's network, that would enable greater CER export.

A9.4.2 Identifying distribution network development opportunities to support CER export that are consistent with the efficient development of the power system

In this DSF statement, AEMO identifies distribution network development opportunities to support CER export that it considers to be consistent with the efficient development of the power system. This is achieved by representing the existing capacity of distribution networks across the NEM to support CER export in the ISP model, and then co-optimising distribution network development opportunities (which increase the capacity of distribution networks to support CER export) with transmission network options, utility-scale generation and storage, and mid-scale generation and storage . In other words, it trades off the cost of distribution network investment against benefit to all consumers of accessing latent CER capacity. AEMO's approach to identifying distribution network development opportunities that enable greater CER export is outlined in the following sub-sections.

[20] 2026 ISP modelling has also considered opportunities for efficient investments in mid-scale generation and storage, distribution network development opportunities to facilitate operation of mid-scale generation and storage, and distribution network development opportunities to facilitate utility-scale generation and storage within ISP modelling.

A pragmatic approach is required to model distribution networks in the ISP

Most CER across the NEM is connected to low voltage (less than 1 kilovolt [kV]) parts of distribution networks. The network constraints that may limit CER export, and associated opportunities to enable higher CER exports, are also primarily at the low voltage level, meaning the opportunity assessment needs to include consideration of distribution networks at this level. Across the NEM, this would require consideration of over 500,000 distribution transformer sites and the CER potentially connected to over nine million customers.

Following close involvement with DNSPs, AEMO notes differing DNSP modelling and assessment capabilities regarding the capacity of their existing network to support aggregate CER export. DNSPs also have different data and information available to them on their own networks.

Given these considerations, AEMO has worked with DNSPs to develop a pragmatic approach to representing distribution network capabilities in the 2026 ISP. This approach accommodates DNSPs' differing capabilities to conduct CER curtailment modelling, and the data they each have available, and also helps keep the ISP modelling tractable. AEMO acknowledges that the approach adopted for the 2026 ISP is necessarily a high-level representation of distribution networks and cannot capture all inherent distribution network complexities.

For the 2026 ISP, AEMO has estimated distribution network capabilities based on information provided voluntarily by DNSPs, due to the need to collect inputs from DNSPs for the 2026 ISP ahead of AEMO's publication of the *Demand Side Factors Information Guidelines* (the Guidelines) on 19 December 2025. AEMO thanks the DNSPs for their significant voluntary efforts, involvement and data provision to date.

In future ISPs, DNSPs will be required to provide information to AEMO in accordance with the Guidelines. The considerations noted above, which have informed the approach to identifying distribution network development opportunities that support CER export in the 2026 ISP, have also informed the Guidelines. However, AEMO expects that the approach taken in future ISPs, and the information required by the Guidelines, will be enhanced over time as DNSPs improve the information they have available on their own networks, and improve their ability to conduct detailed power system modelling of CER. Potential enhancements are discussed in more detail in Section A9.4.4.

Demand-driven augmentations are assumed to support up to 80% of new CER uptake

DNSPs are expected to need to invest in demand-driven augmentations to support demand growth within their networks. Through workshops with DNSPs, AEMO understands that these demand-driven augmentations are likely to also be able to support the operation of CER. Therefore, in the 2026 ISP, AEMO has assumed the following:

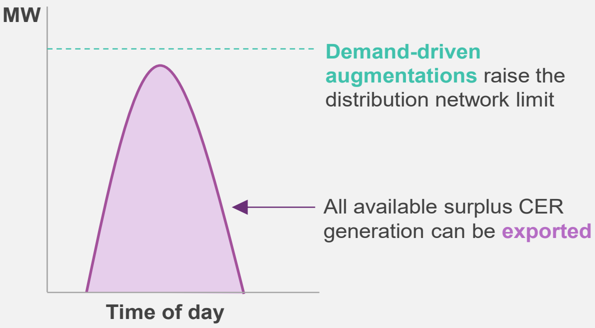
- **Demand-driven augmentations will naturally support operation of a specified proportion of new CER uptake** – for each DNSP, AEMO has assumed that a certain proportion of new CER uptake in their network will be supported by demand-driven augmentations. The proportions assumed for each DNSP are in **Table 5**, and were agreed on with each DNSP based on their expectation on the future need for demand-driven augmentations to 2050 across their network.
- **Distribution network development opportunities may be identified as efficient to support operation of the remaining proportion of new CER uptake** – the remaining proportion of new CER uptake will only be supported up to the capacity of the existing distribution network, unless distribution network development opportunities are identified as being efficient.

Figure 9 illustrates the first assumption, while **Table 5** shows the proportion of new CER uptake that was assumed to be supported by demand-driven augmentations. For most DNSPs, AEMO assumed that demand-driven augmentations will naturally support CER export from 80% of new CER uptake; see **Table 5**. This means it has been assumed that 80% of new rooftop and small-scale solar generation, and 80% of new passive and coordinated CER storage discharge, does not face potential curtailment in ISP modelling, in any time interval, because demand-driven augmentations provide sufficient CER export capability. The remaining 20% of new rooftop and small-scale solar generation, and passive and coordinated CER discharge, faces potential curtailment in ISP modelling, possibly driving opportunities for investment to support CER export.

Figure 9 Impact of demand-driven augmentations on identification of distribution network development opportunities to support CER export

Consider a group of consumers connected via the same distribution network. Each consumer's CER generation (and storage) can supply their own demand or can supply other consumers connected to this distribution network. When these consumers are considered in aggregate, if their CER generation is above their demand at a given time, there is surplus available CER generation. This surplus available CER generation can be exported to the distribution network, and into the transmission network, up to the limit of the distribution network between those consumers and the transmission network connection point.

A specified proportion of new CER uptake is assumed to be naturally supported by **demand-driven augmentations** that will be delivered. These demand driven augmentations raise the capacity of the existing network to support demand growth, but in doing so, also allow greater export of surplus available CER generation.



AEMO assumes the remaining proportion of new CER uptake will only be supported by the existing distribution network. **Distribution network development opportunities to support CER export** that are identified will raise the capability of the network to allow export of surplus available CER generation.

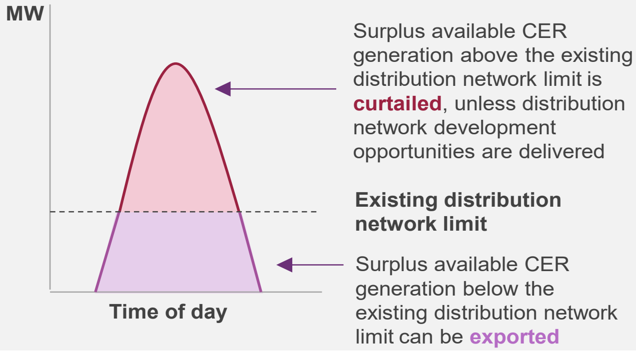


Table 5 Proportion of new CER uptake and demand that will be supported by demand-driven augmentations

DNSP	Proportion of new CER uptake assumed to be supported by demand-driven augmentations
Ausgrid	50%
AusNet	80%
CitiPower	35%
Endeavour Energy	80%
Energex	80%
Ergon Energy	80%
Essential Energy	80%
Evoenergy	80%
Jemena	80%
Powercor	65%
SA Power Networks	80%
TasNetworks	80%
United Energy	45%

This assumption was influential in identifying distribution network development opportunities. In isolation, assuming that a higher proportion of new CER uptake will be supported through demand-driven augmentations reduces the potential need for investments that specifically support CER export and thereby reduces the scale of distribution network development opportunities that may be identified through ISP modelling. AEMO will continue to seek DNSP input on the proportion of new CER uptake that should be expected to be supported by demand-driven augmentations for future ISPs.

Two types of investment were considered as candidate distribution network development opportunities

Two different physical equipment limitations can result in curtailment of CER generation that is available for export into the distribution network – voltage limits and thermal limits. Many DNSPs identified voltage management as the primary driver for CER generation curtailment, with voltage rise challenges being caused by high rooftop solar generation export.

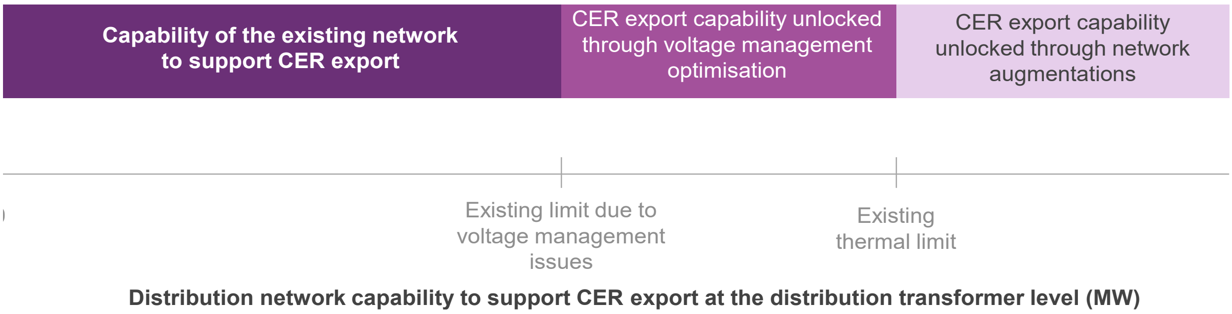
AEMO received thermal limit data from DNSPs at the distribution transformer level, but received limited information on voltage limits. The majority of DNSPs were able to provide voltage limit information but in cases where this was not possible, AEMO assumed that voltage management issues arise when CER generation export exceeds two-thirds of the existing distribution transformer level thermal limit[21]. This assumption was determined through consultation with DNSPs.

In the 2025 *Electricity Network Options Report*, AEMO identified two types, or tranches, of distribution network investment that can alleviate each type of physical network limit, and thereby increase CER generation export capability[22]:

- **Voltage management optimisation** – typically, investments by DNSPs in software, control systems, or minor operational changes that can deliver additional CER generation export capability with relatively low capital investment. These may include a combination of dynamic operating envelopes (DOEs), dynamic voltage management systems, distribution transformer tap changer optimisation, load-shifting tariffs, or phase rebalancing.
- **Network augmentation** – once the scope for lower-cost voltage management optimisation investments has been exhausted, DNSPs may consider more capital-intensive investments in network infrastructure through network augmentations. These may include a combination of new voltage control plant, transformer upgrades, local battery storage, network reconfiguration and augmentations.

Figure 10 illustrates the causes of CER generation curtailment that are described above, and the types of investment that can alleviate CER generation curtailment.

Figure 10 Causes of CER generation export curtailment, and types of investment that can reduce curtailment



21 AEMO received voltage limit information from Ausgrid, AusNet, CitiPower, Energex, Ergon Energy, Powercor and United Energy. The 'two thirds assumption' was applied for Endeavour Energy, Essential Energy, Evoenergy, Jemena and TasNetworks.

22 At https://www.aemo.com.au/consultations/current-and-closed-consultations/2025-electricity-network-options-report-consultation.

AEMO acknowledges that using assumed voltage limits in cases where actual voltage limit information was unavailable raises the risk of over- or under-estimating the existing capability of distribution networks to support CER export[23]. As noted above, the assumption used was consulted upon with the affected DNSPs and was informed by the data available. Seeking more complete voltage limit data from DNSPs will be an important improvement for future ISPs and would avoid the need for AEMO to assume that voltage limits bind at a given proportion of the distribution network's thermal limits. AEMO anticipates that, over time, DNSPs will be able to provide additional voltage limit information as they conduct more analysis of CER operation within their networks.

In ISP modelling, voltage management optimisation and network augmentations can be 'built' at a specific cost rate, in dollars per megawatt of additional CER generation export capability. The cost rates for voltage management optimisation and network augmentations and the total possible scope (the tranche range) for investment in each DNSP's network are presented in **Table 6**. There is considerable variability in costs among DNSPs, which could arise from regional factors, network characteristics or the condition of existing infrastructure. This variability in cost is likely to be a significant driver for where efficient distribution network development opportunities are identified, with modelling favouring investment in distribution networks with lower associated costs. For a detailed explanation of how these costs and the tranche ranges were derived, please see Section 5.2 of the 2025 *Electricity Network Options Report*[24].

Table 6 Distribution network development opportunity cost rates and tranche ranges for each DNSP, as assessed by AEMO

DNSP	Use existing capacity		Voltage management optimisation		Network augmentations	
	Cost ($/MW)A	Tranche range (MW)	Cost ($/MW)A	Tranche range (MW)	Cost ($/MW)A	Tranche range (MW)
Ausgrid	-	0 to 4,760	251,000	4,760 to 7,890	730,000	7,890 to 20,000
AusNet	-	0 to 4,520	275,000	4,520 to 6,720	2,400,000	6,720 to 11,950
CitiPower	-	0 to 1,240	400,000	1,240 to 2,880	2,400,000	2,880 to 8,900
Endeavour Energy	-	0 to 8,170	400,000	8,170 to 12,190	2,400,000	12,190 to 21,860
Energex	-	0 to 12,570	400,000	12,570 to 16,880	2,400,000	16,880 to 30,570
Ergon Energy	-	0 to 6,650	400,000	6,650 to 10,100	2,400,000	10,100 to 18,740
Essential Energy	-	0 to 7,030	400,000	7,030 to 10,790	2,400,000	10,790 to 20,390
Evoenergy	-	0 to 1,520	400,000	1,520 to 2,340	2,400,000	2,340 to 4,500
Jemena	-	0 to 1,980	400,000	1,980 to 3,050	2,400,000	3,050 to 5,820
Powercor	-	0 to 2,310	400,000	2,310 to 5,260	2,400,000	5,260 to 16,040
SA Power Networks	-	0 to 3,000	90,000	3,000 to 9,000	1,600,000	9,000 to 18,040
TasNetworks	-	0 to 2,520	400,000	2,520 to 3,920	2,400,000	3,920 to 7,600
United Energy	-	0 to 1,340	400,000	1,340 to 3,300	2,400,000	3,300 to 10,650

A. Costs presented in this table are in June 2024 dollars, as presented in the 2025 *Electricity Network Options Report*. Costs applied in ISP modelling were escalated to June 2025 dollars.

[23] AEMO received voltage limit information from Ausgrid, AusNet, CitiPower, Energex, Ergon Energy, Powercor and United Energy. The 'two thirds assumption' was applied for Endeavour Energy, Essential Energy, Evoenergy, Jemena and TasNetworks.

[24] At https://www.aemo.com.au/consultations/current-and-closed-consultations/2025-electricity-network-options-report-consultation.

Distribution network development opportunities to support CER export are estimated in ISP modelling through constraints on CER generation

Distribution network development opportunities are estimated where benefits are associated with increasing the capacity of the distribution network to support CER export. In ISP modelling, the capacity of the existing distribution network to support CER export is represented through constraint equations, which reflect real-world infrastructure limitations at an aggregated level. Distribution network development opportunities can alleviate these constraints, allowing a greater amount of available CER generation to be exported to meet grid demand. It is important that CER storage uptake is considered in these constraints because CER storage can store excess rooftop and small-scale solar generation during the day, and discharge in the evening. This reduces net available CER generation that could potentially be exported during the day and introduces the possibility of CER export in the evening when CER storage discharges.

Constraint equations in ISP modelling

In ISP modelling, constraints are used to reflect real-world infrastructure limitations at an aggregated level. In the case of CER generation export, this can be represented in a simplified way as:

$$\textit{CER Generation Export } (MW) \leq \textit{Existing distribution network CER generation export capability } (MW)$$

The breakout box above illustrates the CER export constraint at the highest possible level. A more complete conceptual illustration of the constraint equation used to represent the existing capacity of distribution networks to support CER export, and identify distribution network development opportunities, is shown below:

$$\begin{matrix}\textit{CER} \\ \textit{Generation}\end{matrix} - \begin{matrix}\textit{Passive CER} \\ \textit{Storage} \\ \textit{Charging}\end{matrix} - \begin{matrix}\textit{Coordinated} \\ \textit{CER Storage} \\ \textit{Charging}\end{matrix} - \begin{matrix}\textit{Distribution-connected} \\ \textit{underlying demand}\end{matrix} \leq \begin{matrix}\textit{Existing network} \\ \textit{limit on CER} \\ \textit{generation export}\end{matrix} + \begin{matrix}\textit{Distribution} \\ \textit{network} \\ \textit{development} \\ \textit{opportunities}\end{matrix}$$

The ISP model can choose to 'build' distribution network development opportunities to increase the right-hand side of the constraint and therefore allow more CER generation (and therefore more CER generation export) at a given time. The more CER storage assumed, the lower the left-hand side of the constraint, creating additional headroom in the existing network for further CER generation.

The previous sub-section identified two types of distribution network development opportunity to enable greater CER export: voltage management optimisation and network augmentation. Each type of distribution network development opportunity can be built in the ISP model at a specified cost rate. These cost rates vary between DNSPs, based on their specific network characteristics.

In the ISP model, the constraint is actually formulated as[25]:

$$\begin{matrix}\textit{Rooftop and other small} \\ \textit{scale solar generation}\end{matrix} + c_1 \times \begin{matrix}\textit{Coordinated CER} \\ \textit{storage discharge}\end{matrix} - \begin{matrix}\textit{Distribution network} \\ \textit{development opportunities}\end{matrix} \leq \textit{CER Generation Limit}$$

[25] CER storage charging is not included in the formulation as it is accounted for when calculating the CER generation limit via CER curtailment modelling.

The constraint formulation in the ISP model does not explicitly include demand, or CER storage charging (passive or coordinated) because these terms are already considered in deriving the CER Generation Limit term. The approach for deriving the CER Generation Limit is described in the next section.

CER generation limits for each constraint are derived through CER curtailment studies

Determining the CER generation limit for each distribution area in every half-hour across the ISP horizon is achieved by calculating how much CER generation curtailment would occur if only demand-driven augmentations were delivered in the period to 2050. For each CER generation constraint in the ISP model, the CER generation limit in half-hourly time interval t is calculated as:

$$CER\ Generation\ Limit_t = Available\ PV_t + c_1\ (Coordinated\ CER\ Storage\ Discharge_t) - Curtailment_t$$

$Available\ PV_t$	The total possible amount of consumer-owned PV generation that can operate before consideration of any distribution network limits, based on the assumed installed capacity and solar irradiance.
$Coordinated\ CER\ Storage\ Discharge_t$	The total possible amount of discharge from coordinated CER storage before consideration of any distribution network limits.
c_1	Set to 1 when coordinated CER storage discharges and set to 0 when it charges. The variable is set to 0 when coordinated CER storage charges so that it does not incorrectly reduce the $CER\ Generation\ Limit$.
$Curtailment_t$	The amount of CER generation that cannot be exported from households and businesses due to existing distribution network limitations.

That is, CER generation in any interval is limited to the total amount of possible CER generation in the interval, less any curtailment occurring due to distribution network limitations, as identified in CER curtailment modelling.

AEMO has worked with DNSPs to develop two pathways for collecting data for, and performing, CER curtailment modelling. These pathways accommodate DNSPs' differing capabilities in modelling CER curtailment within their networks and differences in data availability:

- **Low Voltage (LV) Asset Data Template Pathway** – under this pathway, DNSPs provide limits at the distribution transformer level, and a mapping between each distribution transformer, and a transmission node identifier. AEMO separately maps transmission-node identifiers to each ISP sub-region. AEMO's demand and CER uptake forecasts (as half-hourly interval time series) are translated to the distribution transformer level. By considering demand and CER uptake at the distribution transformer level, against network limits at the distribution transformer level, a time series of CER generation curtailment in the unaugmented distribution network can be derived. Using the distribution transformer to transmission node identifier mapping, and AEMO's transmission node identifier to ISP sub-region mapping, curtailment results for the unaugmented distribution network can be aggregated to the sub-region-DNSP area level.
- **Detailed Modelling Pathway** – under this pathway, DNSPs conduct curtailment studies through power system modelling. AEMO's ISP sub-region level demand and CER uptake forecasts are disaggregated to the distribution transformer level and are taken as power system modelling inputs. CER generation curtailment results (as a time series) are aggregated by the DNSP to the sub-region-DNSP area level.

While the process for modelling CER curtailment under each pathway is different, the objective is the same. **Table 7** shows the pathway taken by each DNSP, and **Figure 11** illustrates how CER curtailment is modelled under the LV Asset Data Template Pathway.

Two aspects of the curtailment modelling approach under the LV Asset Data Template Pathway, which are not present under the Detailed Modelling Pathway, limit the quality of CER curtailment results:

- **Lack of analysis of zone substation and sub-transmission substation level limitations on CER export** – few DNSPs have conducted analysis of limitations on CER export that may arise at the zone substation or sub-transmission substation level across their entire network. This analysis is made challenging by the meshed-nature of distribution networks. This means that, for the most part, CER curtailment is only assessed at the distribution transformer level, and additional curtailment that may occur at the zone substation or sub-transmission substation levels is omitted: see steps 2 and 3 in **Figure 11**.
- **Distribution transformer level curtailment results are mapped simplistically to the transmission node level** – the approach assumes that curtailment at a given distribution transformer can be mapped directly to a single transmission-node: see step 4 in **Figure 11**. In reality, distribution networks are meshed, and CER generation exported through a given distribution transformer may have multiple parallel paths up to transmission nodes.

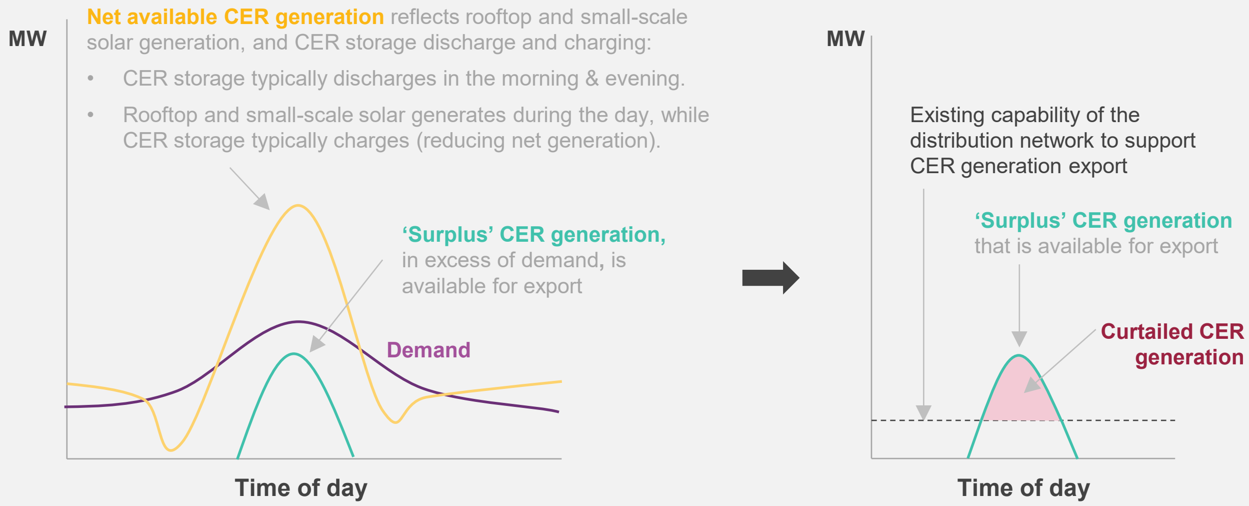
For future ISPs, AEMO anticipates the extent to which these limitations will impact the identification of distribution network development opportunities will reduce as DNSPs increase their ability to provide information at the zone substation and sub-transmission substation levels, or through DNSPs adopting the Detailed Modelling Pathway.

Table 7 DNSPs providing data via the LV Asset Data Template Pathway and Detailed Modelling Pathway

Pathway	DNSPs
LV Asset Data Template Pathway	Ausgrid, Ausnet, CitiPower, Endeavour Energy, Energex, Ergon Energy, Essential Energy, Evoenergy, Jemena, Powercor, TasNetworks, United Energy
Detailed Modelling Pathway	SA Power Networks

Figure 11 Illustration of the CER curtailment modelling under the LV Asset Data Template Pathway

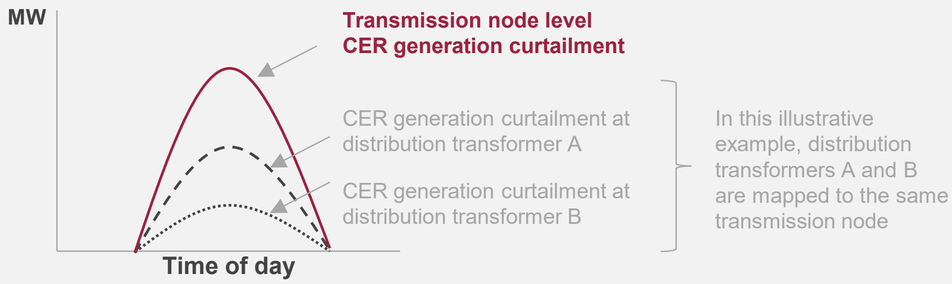
1. **Derive CER generation curtailment at the distribution transformer level:**



2. **Where data is available, determine additional CER curtailment that may occur at the zone-substation level:**
   - Additional CER generation curtailment may occur in medium voltage parts of the distribution network.
   - Where DNSPs have provided a distribution transformer to zone substation mapping, and have provided zone substation limits, any additional curtailment at the medium voltage level can be calculated.

3. **Where data is available, determine additional CER curtailment that may occur at the sub-transmission substation level:**
   - Additional CER generation curtailment may occur in high voltage parts of the distribution network.
   - Where DNSPs have provided a zone substation to sub-transmission substation mapping, and have provided sub-transmission substation limits, any additional curtailment at the medium voltage level can be calculated.

4. **Aggregate CER curtailment to the transmission level:**



5. **Aggregate CER curtailment to the relevant distribution network area in ISP modelling.**

As explained earlier, AEMO only considers a proportion of new CER uptake in its approach to identifying distribution network development opportunities (see **Figure 9** earlier). For most DNSPs, this proportion is 20%[26]. This means the net available CER generation considered in step 1 of **Figure 11** is based on existing CER uptake, and 20% of new CER uptake in AEMO's CER uptake forecast, for each distribution transformer.

[26] For most DNSPs, demand-driven augmentations are assumed to support operation of 80% of new CER uptake; see **Table 5**.Table 5.Distribution network development opportunities are assessed for the remaining portion of CER uptake (20%).

Aggregation across DNSPs is required to represent distribution networks within ISP sub-regions

The power system is modelled in different ways depending on the analysis being performed. In market and economic modelling, the electricity network is represented as either a regional or sub-regional topology:

- In the regional topology, each of the five NEM regions is represented by a single reference node. In this topology, all loads are placed at the respective regional reference nodes.
- The sub-regional topology breaks down some of the NEM regions into smaller sub-regions. In this topology, the regional load and generation resources are appropriately split between the different sub-regions.

The ISP uses a sub-regional topology, and sub-regions are defined through consideration of transmission network topology. This means that sub-regional boundaries are not necessarily aligned with distribution network boundaries:

- The distribution network operated by a given DNSP may cross the geographic boundary of a sub-region. For example, Ausgrid's network sits within the Sydney, Newcastle and Wollongong sub-region, and in Central New South Wales.
- Some sub-regions contain distribution networks that are operated by several DNSPs. For example, five DNSPs operate distribution networks in the Greater Melbourne and Geelong sub-region.

Ideally, AEMO would estimate distinct distribution network development opportunities to support CER export for each DNSP as a direct output of ISP modelling. This would require adding spatial granularity to the ISP capacity outlook models to represent 29 unique distribution network areas which would have an extremely high computational impact. To balance the importance of modelling distribution network development opportunities against computational considerations, AEMO aggregated existing distribution network capabilities in sub-regions with multiple DNSPs, where those DNSPs are assumed to have the same distribution network development opportunity cost rates to support CER export (one exception is outlined below). This results in 19 unique distribution network areas within the ISP model; see **Table 8**.

Table 8 Aggregation of existing distribution network capabilities for ISP modelling

Sub-region	DNSPs with assets in the sub-region's geographic area	Distribution network areas (One CER constraint per area)	Explanation of aggregation
Northern Queensland (NQ)	• Ergon Energy	• NQ-Ergon Energy	No aggregation required.
Central Queensland (CQ)	• Ergon Energy	• CQ-Ergon Energy	No aggregation required.
Gladstone Grid (GG)	• Ergon Energy	• GG-Ergon Energy	No aggregation required.
Southern Queensland (SQ)	• Ergon Energy • Energex	• SQ-Ergon-Energex	A single constraint was created to represent Ergon Energy's and Energex's networks within Southern Queensland.
Northern New South Wales (NNSW)	• Essential Energy	• NNSW-Essential Energy	No aggregation required.
Central New South Wales (CNSW)	• Ausgrid • Endeavour Energy • Essential Energy	• CNSW-Essential-Ausgrid	A single constraint for Ausgrid and Essential Energy was created. A very small portion of distribution networks across Central New South Wales are operated by Endeavour Energy.
Sydney, Newcastle and Wollongong (SNW)	• Ausgrid • Endeavour Energy • Essential Energy	• SNW-Ausgrid • SNW-Endeavour Energy	Separate constraints for Ausgrid and Endeavour Energy were created as their estimated distribution network development opportunity cost rates are different. A very small portion of distribution networks across Sydney, Newcastle and Wollongong are operated by Essential Energy.

Sub-region	DNSPs with assets in the sub-region's geographic area	Distribution network areas (One CER constraint per area)	Explanation of aggregation
Southern New South Wales (SNSW)	• Essential Energy • Evoenergy • Ausnet	• SNSW-Essential Energy • SNSW-Evoenergy	Constraints for Essential Energy and Evoenergy were created. A very small portion of the distribution networks across Southern New South Wales are operated by Ausnet
West and North Victoria (WNV)	• AusNet • Essential Energy • Powercor	• WNV-AusNet • WNV-Powercor	Constraints for Ausnet and Powercor were created. A very small portion of the distribution networks across West and North Victoria are operated by Essential Energy.
Greater Melbourne and Geelong (MEL)	• AusNet • CitiPower • Jemena • Powercor • United Energy	• MEL-AusNet • MEL-CitiPower-Jemena-Powercor-United Energy	One constraint was created for Ausnet and another which combines CitiPower, Jemena, Powercor and United Energy. Ausnet is split because it has different distribution network development opportunity cost rates to the other four DNSPs.
South East Victoria (SEV)	• AusNet	• SEV-AusNet	No aggregation required.
Northern South Australia (NSA)	• SA Power Networks	• NSA-SA Power Networks	No aggregation required.
Central South Australia (CSA)	• SA Power Networks	• CSA-SA Power Networks	No aggregation required.
South East South Australia (SESA)	• SA Power Networks	• SESA-SA Power Networks	No aggregation required.
Tasmania (TAS)	• TasNetworks	• TAS-TasNetworks	No aggregation required.

Done in this way, the aggregation does not impact distribution network development opportunities that are identified at the distribution network area level, or at the sub-region level, for the following reasons:

- **CER generation limits are based on CER curtailment studies that are conducted at the appropriate distribution network granularity** – the previous sub-section explained that CER curtailment is assessed at the distribution transformer level and is then aggregated to the transmission-node level. This means CER curtailment in each DNSP's network is aggregated to transmission nodes that interface with its network. Subsequent aggregation to the distribution network area, or even to the sub-region, including summing curtailment results across transmission nodes that interface with different DNSP networks, does not impact the validity of those CER curtailment modelling results. Therefore, the CER generation limit can be calculated for each distribution network area using CER curtailment aggregated to this level.
- **The ISP model will identify the same opportunities, in aggregate, if cost rates are the same** – the distribution network areas created by AEMO only include DNSPs where the distribution network development opportunity cost rates are the same (with one exception for Central New South Wales – discussed below). If the cost rates for each DNSP within a distribution network area are the same, then the same distribution network development opportunities would be identified through ISP modelling regardless of whether separate constraints are created for each DNSP or a single constraint for the distribution network area.

As seen above in **Table 8**, the Central New South Wales sub-region contains distribution networks operated by Ausgrid, Endeavour Energy and Essential Energy. Distribution network assets operated by Endeavour Energy within Central New South Wales comprise a small portion of distribution networks within the sub-region. As a result, AEMO omitted Endeavour Energy from the Central New South Wales distribution network area. By contrast, approximately 30% of CER uptake within

Central New South Wales is expected to connect within Ausgrid's network, while the remaining 70% is expected to connect to Essential Energy's network.

Ausgrid and Essential Energy were assumed to have different distribution network development opportunity cost rates for supporting CER export; see **Table 6** earlier. As noted in this sub-section, AEMO has generally only aggregated across DNSPs where the cost rates for each DNSP are assumed to the same. Due to computational limitations, and the importance of creating distribution network areas in other sub-regions, AEMO elected to create a combined constraint for Ausgrid and Essential Energy. To reflect that the cost rates for Ausgrid and Essential Energy are different, AEMO applied a weighted average cost rate, where weightings are the installed CER capacity in each DNSP's network within Central New South Wales as a proportion of installed CER capacity for the entire sub-region. The cost rates applied for voltage management optimisation and network augmentations in Central New South Wales were $355,000 per MW and $1,899,000 per MW in June 2024 dollars[27].

Distribution network development opportunities are estimated alongside transmission and utility-scale generation investments in ISP modelling

The ISP model co-optimises several types of electricity system infrastructure, such as transmission network augmentations and utility-scale generation and storage. Distribution network development opportunities (that support CER export, mid-scale generation and storage, or utility-scale generation and storage) have been considered alongside these other types of infrastructure for the first time for this DSF statement, as shown in **Figure 12**.

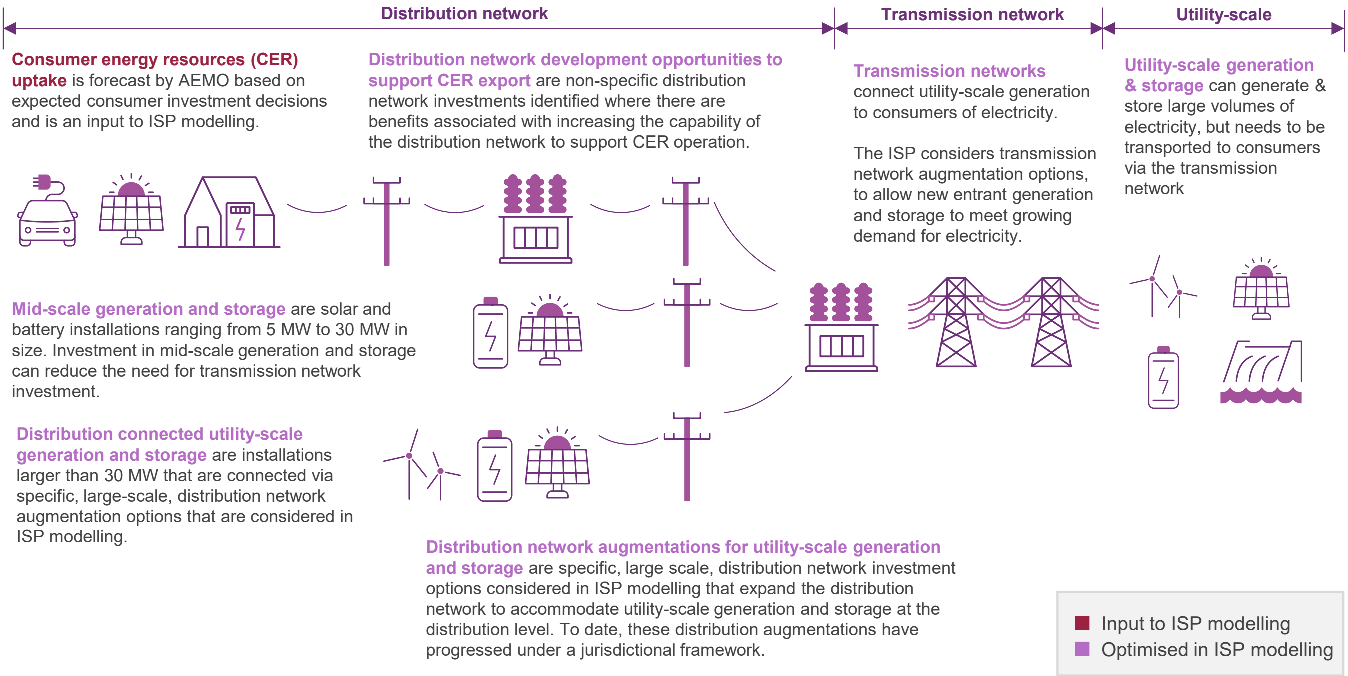
Distribution network development opportunities can reduce CER generation curtailment and can therefore reduce the need for other types of infrastructure. Conversely, investments in other types of infrastructure can reduce the need for distribution network development opportunities. Opportunities for efficient investment in distribution networks are identified by considering the relative cost of each infrastructure type, and the contribution each makes to ensuring a reliable energy system.

In practice, rooftop and small-scale solar generation exported to the distribution network – at the zone substation or sub-transmission level – can be absorbed by mid-scale storage. This has the potential to reduce curtailment of CER that might otherwise occur due to network limitations at these points. As a result, investing in distributed storage could be considered as an alternative to traditional distribution network upgrades.

However, in ISP modelling, this specific interaction is not captured because representing the detailed operation of distributed storage across the network is highly complex, and there is limited data available at the zone substation and sub-transmission levels. While this is a limitation of AEMO's current modelling, it is broadly internally consistent, as CER curtailment in the ISP has primarily been estimated based on limits at the distribution transformer level, with only limited consideration of curtailment at the zone substation or sub-transmission station level.

[27] Costs applied in ISP modelling are escalated to June 2025 dollars.

Figure 12 Infrastructure types co-optimised in ISP modelling



A9.4.3 Distribution network development opportunities to support CER export exist in certain parts of the NEM

AEMO has identified distribution network development opportunities to support CER export that are consistent with the efficient development of the power system through ISP modelling, using the approach described in Section A9.4.2. These opportunities are presented and explained in the following sub-sections.

There are opportunities to invest in voltage management optimisation alongside demand-driven augmentations

Across the NEM, AEMO's modelling reveals opportunities to deliver benefits in the long-term interest of consumers by investing in $214 million of voltage management optimisation to facilitate more CER generation export. This reflects the present value of efficient distribution investment identified in the ODP under the *Step Change* scenario. As the ODP represents the least-cost pathway, this investment is selected only where it is more efficient than alternative options, such as additional mid- or utility-scale generation or storage. While the benefits have not been separately quantified, the modelled outcome indicates that the value unlocked through increased CER utilisation is expected to outweigh the cost of the distribution investment.

In other words, distribution network development opportunities contribute to the efficient development of the power system, enabling efficient operation of CER by reducing CER generation curtailment and deferring need to investment in grid-scale alternatives.

AEMO recognises that DNSPs may be required to invest in demand-driven augmentations across the period to 2049-50 as consumers' demand for electricity grows. AEMO assumed that these types of augmentations will naturally support operation of a given proportion of new CER uptake (Section A9.4.2). The potential need for any demand-driven augmentations will be identified by DNSPs through their own planning activities.

The distribution network development opportunities identified in this DSF statement are presented at a sub-regional level in **Table 9**, and in **Figure 13**, highlighting that under *Step Change,* distribution network development opportunities are largely identified in New South Wales, South Australia and Victoria, with a small volume identified in Queensland. This is discussed in the next sub-section. The scale of the investment is relatively modest and focuses solely on voltage management optimisation, due to relatively small volumes of CER generation curtailment projected, even without the distribution network development opportunities.

Table 9 Distribution network development opportunities consistent with the efficient development of the power system, *Step Change*

Region	Sub-region	Existing capability of the distribution network to support CER export (MW)	Full scope of opportunities to raise CER export capability of the distribution network (MW)		Distribution network development opportunities developed in ISP modelling (MW)	
			Voltage management optimisation	Network augmentation	Voltage management optimisation	Network augmentation
New South Wales	Northern New South Wales	0 to 2,985	2,985 to 4,582	4,582 to 8,660	0	0
	Central New South Wales	0 to 1,821	1,821 to 2,794	2,794 to 5,280	526	0
	Sydney, Newcastle & Wollongong	0 to 12,930	12,930 to 20,080	20,080 to 41,860	101	0
	Southern New South Wales	0 to 3,744	3,744 to 5,753	5,753 to 10,950	291	0
Queensland	Northern Queensland	0 to 3,243	3,243 to 4,925	4,925 to 9,138	46	0
	Central Queensland	0 to 1,758	1,758 to 2,670	2,670 to 4,954	0	0
	Gladstone Grid	0 to 219	219 to 333	333 to 618	4	0
	Southern Queensland	0 to 14,000	14,000 to 19,052	19,052 to 34,600	146	0
South Australia	Northern South Australia	0 to 125	125 to 376	376 to 754	79	0
	Central South Australia	0 to 2,690	2,690 to 8,070	8,070 to 16,176	851	0
	South East South Australia	0 to 185	185 to 554	554 to 1,110	41	0
Tasmania	Tasmania	0 to 2,520	2,520 to 3,920	3,920 to 7,600	0	0
Victoria	West and North Victoria	0 to 1,858	1,858 to 3,767	3,767 to 10,376	500	0
	Greater Melbourne & Geelong	0 to 8,312	8,312 to 15,629	15,629 to 39,758	1,168	0
	South East Victoria	0 to 1,220	1,220 to 1,814	1,814 to 3,227	22	0

Distribution network development opportunities differ by sub-region based on four factors

Distribution network development opportunities are identified where it is efficient to reduce CER generation curtailment and therefore enable greater CER export. The occurrence of CER generation curtailment, and whether it is efficient to reduce the volume of curtailed generation, depends on four factors:

- **Capacity of existing networks to support CER export** – distribution networks across the NEM currently have differing capacities to support CER generation export. Distribution network augmentations are less likely to be needed in distribution networks that already have a lot of headroom to support CER exports.
- **The proportion of new CER uptake that is assumed to connect via demand-driven augmentations** – if a higher proportion of new CER uptake is assumed to be supported by demand-driven augmentations within a given distribution network, then less of the new CER uptake will be subject to existing low voltage network limitations, and therefore less curtailment will be observed. This will reduce the scale of distribution network development opportunities identified through ISP modelling, noting that relatively more demand-driven distribution network investment would instead be anticipated in that sub-region.
- **The relative cost of distribution network development opportunity investments** – for most DNSPs, AEMO has estimated that voltage management optimisation can unlock additional CER generation export capacity at an investment rate of $400,000 per megawatt of additional export capacity. This value was derived by considering network marginal cost (long-run marginal cost) models that support DNSPs' publicly available Tariff Structure Statements[28]. For three DNSPs, unique investment rates have been applied, which were prepared by the DNSP based on the unique characteristics of their networks. These DNSPs are Ausgrid ($251,000 per MW), AusNet ($275,000 per MW) and SA Power Networks ($90,000 per MW)[29].
- **The level of CER storage that is developed** – the operation of CER storage (both passive and coordinated) will reduce the potential need for investment, as storage can store surplus generation for later use, thereby reducing CER exports.

Consideration of these factors and consumer-owned solar curtailment observed in ISP modelling before and after investments in the distribution network to support CER export could be made (see **Figure 14**) offers insight into the results presented in **Figure 13**. AEMO assumed that investments in voltage management optimisation have a four-year lead time, meaning that that distribution network development opportunities could be developed from 2030-31 in 2026 ISP modelling:

- **Absence of distribution network development opportunities identified in certain sub-regions** – few or no distribution network development opportunities have been identified for Northern New South Wales, Gladstone Grid, Central Queensland and Tasmania (see **Figure 13**). It is possible that after accounting for expected demand-driven augmentations, the distribution networks in these sub-regions have sufficient headroom to support growth in CER exports across the ISP horizon without needing further investment in distribution network development opportunities, although this would need to be confirmed through further assessment by DNSPs.

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[28] For further explanation, please see Section 5.2 of the 2025 *Electricity Network Options Report*, at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/2025-electricity-network-options-report/final/2025-electricity-network-options-report.pdf?la=en.

[29] Cost presented here are in June 2024 dollars. The costs applied in ISP modelling were escalated to June 2025 dollars.

- **Distribution network development opportunities identified in South Australia** – sub-regions across South Australia see higher levels of curtailment in the period to 2029-30, before efficient investments in voltage management optimisation begin to be identified from 2030-31 onward. This suggests that, even after accounting for demand-driven augmentations, distribution networks across South Australia, in particular Northern and Central South Australia, do not have sufficient headroom to support growth in CER exports. While curtailment in Northern South Australia is much higher than in Central South Australia in percentage terms, the volume of rooftop and small-scale solar uptake is 14 times higher in Central South Australia. This explains why a greater volume of distribution network development opportunities are identified in Central South Australia than in Northern South Australia. Finally, the cost of voltage management optimisation for SA Power Networks is $90,000 per MW, which is notably lower than the cost rate estimated for most other DNSPs (see **Table 6** earlier), making investment in voltage management optimisation relatively more attractive in South Australia than in other regions.
- **High initial consumer-owned solar curtailment in Victorian sub-regions drives the need for distribution network investment** – **Figure 14** shows modest levels of curtailment in Greater Melbourne and Geelong and in West and North Victoria, and distribution network development opportunities are identified in both sub-regions across the 2026 ISP horizon starting from 2030-31. Curtailment in South East Victoria is shown to be lower, suggesting sufficient headroom within the distribution network (after accounting for demand-driven augmentations) to efficiently support growth in CER exports without needing further investment in distribution network development opportunities.
- **Modest distribution network development opportunities are identified across New South Wales, Southern Queensland and Northern Queensland** – on average, curtailment in Central and Southern New South Wales after 2029-30 is shown to be 1% to 3%, with investments in voltage management optimisation identified across the 2026 ISP horizon from 2030-31 onwards. Distribution network development opportunities are identified in Sydney, Newcastle and Wollongong, Northern Queensland and Southern Queensland to almost completely avoid curtailment.

Figure 13 Distribution network development opportunities by sub-region, 2049-50, *Step Change* (MW)

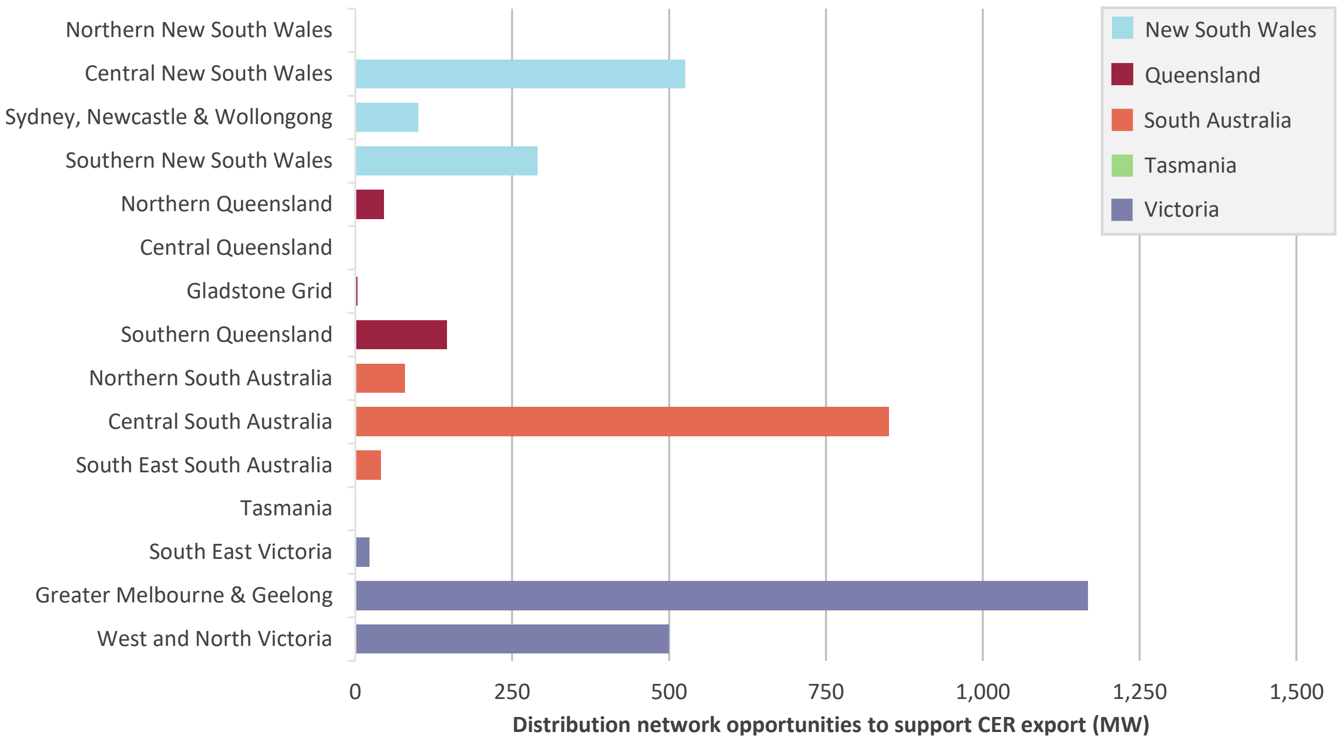
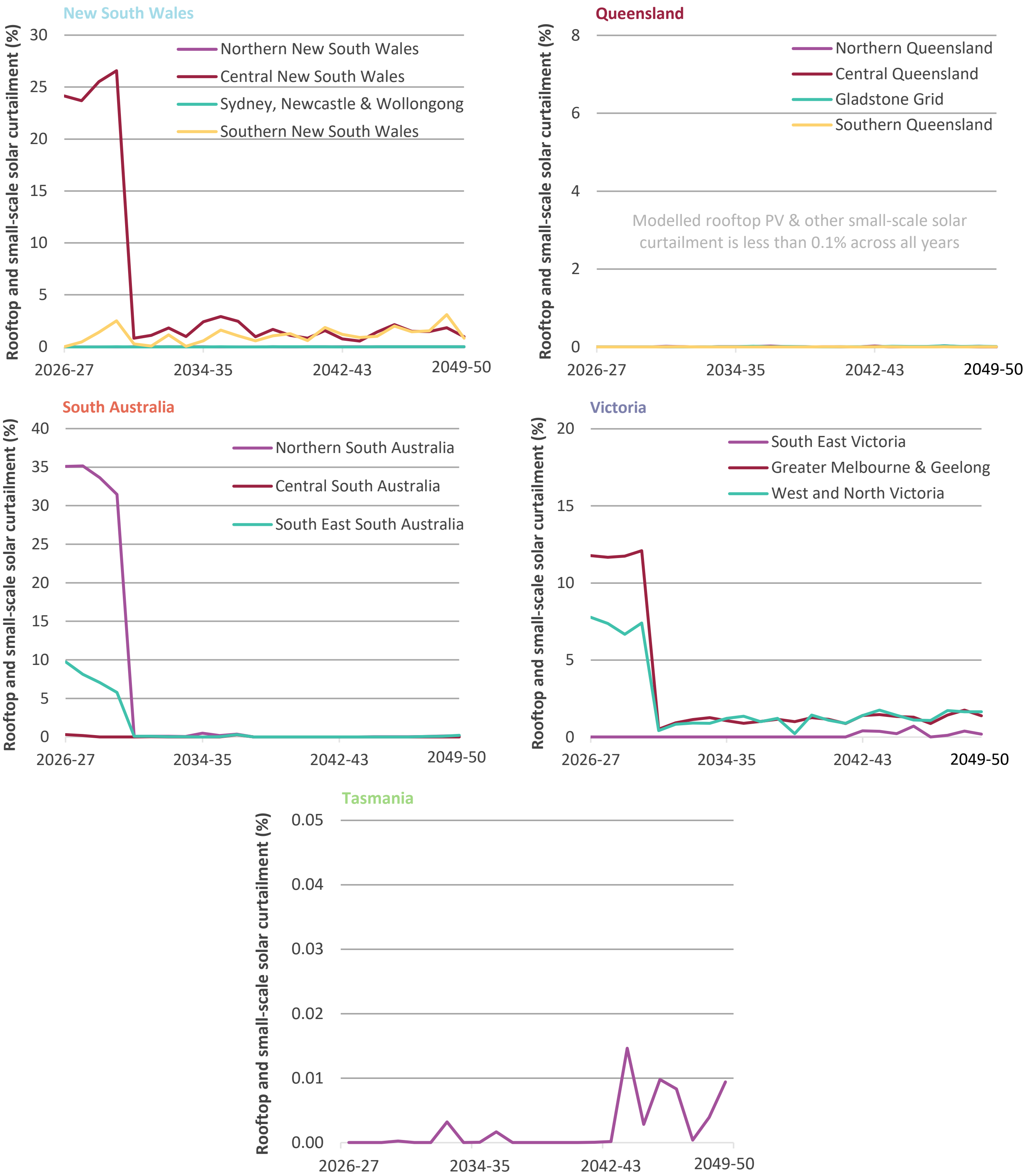


Figure 14 below shows rooftop and small-scale solar generation curtailment after consideration of the distribution network development opportunities identified in **Table 9** (and presented in **Figure 13**).

Figure 14 Curtailment of rooftop and small-scale solar generation, *Step Change* (%)



Limitation in AEMO's identification of distribution network development opportunities

As noted in the introduction, AEMO updated (increased) its stationary consumer battery uptake forecasts between the draft and final 2026 ISP. Ideally, to maintain internal consistency and precision, this update should be accompanied by a corresponding update to the CER generation limits derived via the process described in Section A9.4.2. In practice, AEMO has had to balance the need to maintain internal consistency within ISP modelling against the need to deliver the ISP within the required timeframe; this requires consideration of the materiality of any internal inconsistency that may be introduced through incomplete data updates. For the 2026 ISP, AEMO has not updated the CER generation limits between the draft and final 2026 ISP. AEMO considers that updating the CER generation limits to reflect the increased consumer battery uptake forecasts would have had a relatively small impact on the distribution network development opportunities identified in **Table 9**, for reasons outlined below.

Consumer batteries, which are used by consumers to manage their own energy needs, as opposed to being coordinated via a VPP arrangement, are reflected in ISP modelling in two distinct places: demand traces and CER generation limits. AEMO has updated the demand traces to reflect the increased consumer battery uptake forecast, while keeping the CER generation limits the same between draft and final 2026 ISP:

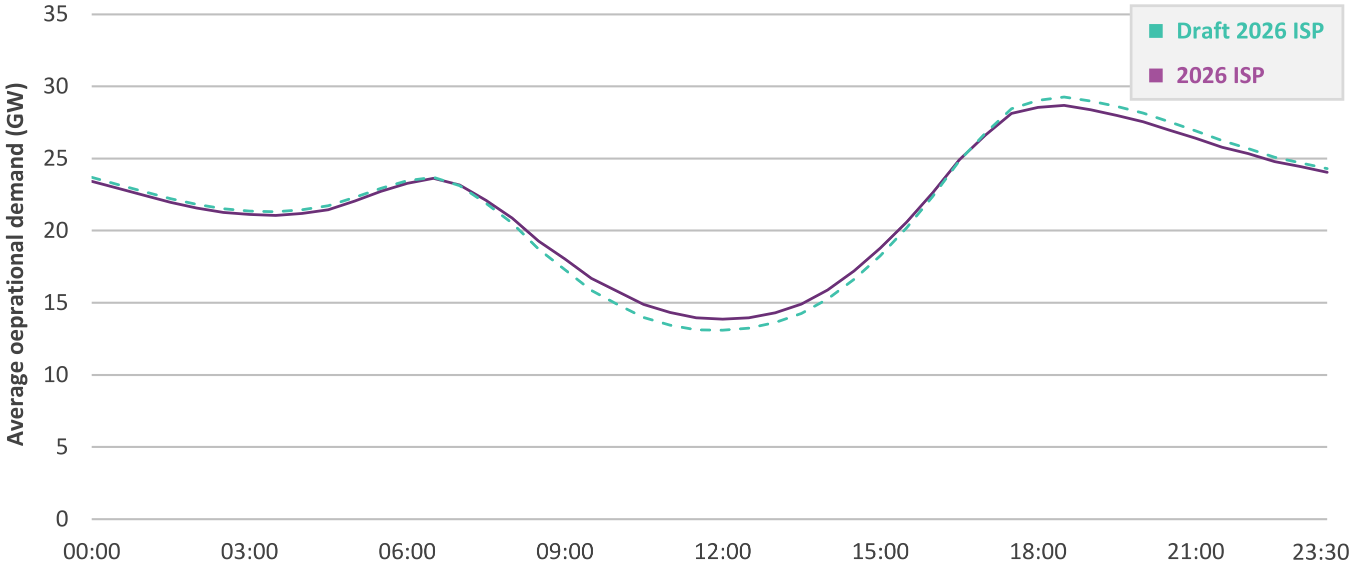
- **Demand traces:** although the consumer battery uptake forecast has changed materially, this is reflected as a modest change in the demand traces applied for ISP modelling. Consumers' batteries were assumed to charge during midday periods, adding to operational demand, and discharge in the evening or early morning periods, reducing operational demand. Therefore, increasing the consumer battery uptake forecast results in demand traces which are lower in the morning and evening when these batteries discharge, and higher in the middle of the day when they charge.

  The NEM-wide consumer battery uptake forecast for 2029-30, for example, was increased from an installed capacity of 5.2 GW to 12.5 GW. While this represents a significant increase in uptake (in terms of installed capacity), it translates to a smaller change in overall operation on a half-hourly basis. **Figure 15** illustrates this by comparing the average time-of-day operational demand profile for the NEM under *Step Change* in 2029-30 between the draft 2026 ISP (with its lower CER uptake forecast) and the final 2026 ISP (which has elevated CER uptake from CHBP). When uncoordinated, aggregate battery charging and discharging behaviour impacts are observed throughout the day, rather than concentrating at times of peak or minimum demand.

- **CER generation limits**: Section A9.4.2 explained that AEMO derives CER generation limits through CER curtailment modelling, which considers forecast demand, CER uptake and existing distribution network constraints across half-hourly intervals over the ISP horizon. Higher consumer battery uptake reduces midday CER export by absorbing rooftop PV generation locally, resulting in lower curtailment and slightly higher CER generation limits.

  However, AEMO's expectation is that the CER generation limits would have changed by a relatively small amount if they had been updated for the final 2026 ISP. This is because CER curtailment modelling conducted for the Draft 2026 ISP revealed relatively low CER curtailment across most sub-regions, limiting the extent to which increased battery uptake would further reduce curtailment or increase CER generation limits.

Figure 15 Comparison of draft and final 2026 ISP NEM average daily operational demand profiles, 2029-30, Step Change



This figure shows the operational demand profile, being net of behind-the-meter CER operation that is not coordinated by VPP or V2G arrangements. As such, for batteries, additional peak demand impacts may be provided by coordinated CER, which is projected to operate in a more coordinated manner to minimise system costs.

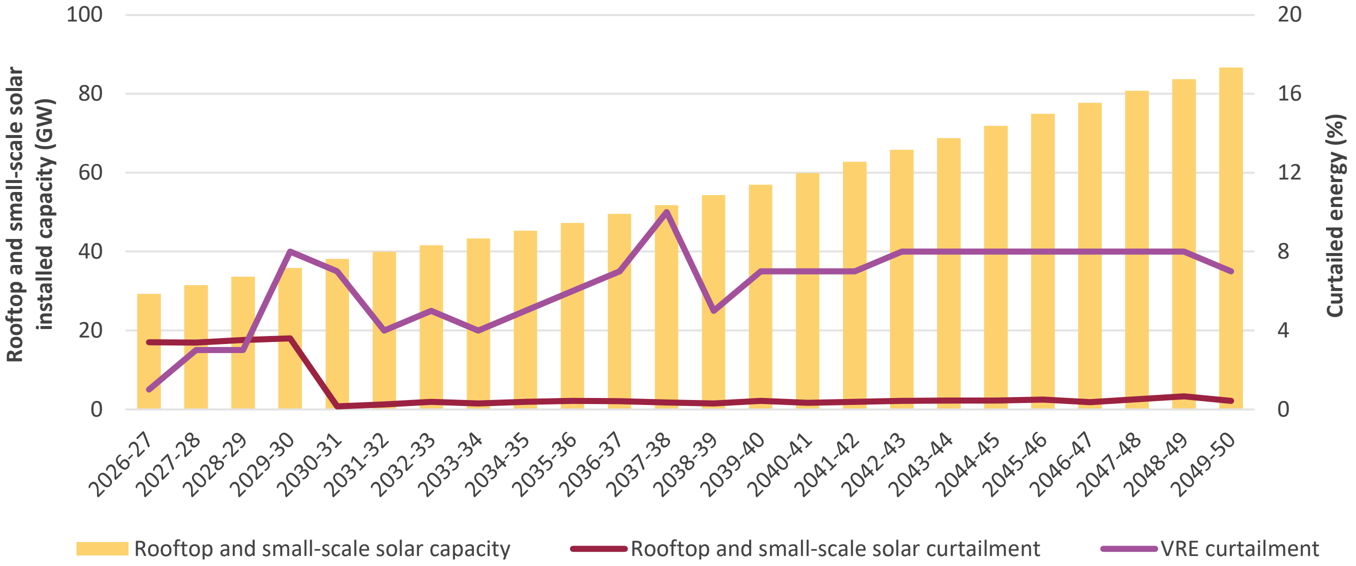
In summary, the application of higher consumer battery uptake has increased midday demand and reduced evening peaks in the 2026 ISP. As CER generation limits were not updated for the final modelling and are therefore likely to be slightly under-estimated, meeting higher midday demand through rooftop solar generation requires additional distribution network investment to support CER export. Consistent with this, the 2026 ISP identifies a modestly higher level of distribution network development than the Draft ISP, including an additional 300 MW (9%) across the NEM.

CER curtailment is lower than variable renewable energy curtailment

The final sub-section of A9.4.2 explains how distribution network development opportunities are co-optimised against various types of electricity system infrastructure, including transmission network augmentations for REZs. At $400 per kilowatt or less (see **Table 6** earlier), investments in distribution network voltage management optimisation are similar to costs at the lower end of the typical cost range for renewable energy zone (REZ) transmission network augmentations. Distribution network development opportunities are identified to bring NEM-wide curtailment of consumer-owned solar generation to almost 0%, while variable renewable energy (VRE) generation curtailment typically ranges from 4 to 8% across the ISP horizon; see **Figure 16**.

This highlights that market benefits in the long-term interest of all consumers are optimised by utilising CER as efficiently as possible (without compromising the value of the resource to the home-owner), including through augmentation of the distribution network, if needed.

Figure 16 NEM-wide curtailment of rooftop and small-scale solar and variable renewable energy curtailment, *Step Change*



A9.4.4 Enhancing the approach for identifying distribution network development opportunities for future ISPs

Most CER across the NEM are connected to low voltage parts of each distribution network. The network constraints that may limit CER export, and associated opportunities to enable higher CER export, are also primarily at the low voltage level. Therefore, assessing opportunities for distribution network investment to support CER export would require consideration of over 500,000 distribution transformer sites and the CER connected to over nine million customers. This makes modelling distribution networks extremely complex.

The approach adopted by AEMO to identify distribution network development opportunities for this DSF statement, outlined in Section A9.4.2, is the first iteration of an approach that will be refined for future ISPs. The approach relies on necessary simplifications of distribution network topology and on key assumptions that were agreed upon with DNSPs. In future, improved data availability and improved DNSP capabilities to conduct detailed power system modelling will limit the need for assumptions to be applied, or will allow for assumptions to be more robustly supported in cases where they are still needed. Limitations and enhancements were discussed briefly in Section A9.4.2 and are discussed in more depth below:

- **Assumed proportion of new CER uptake that is expected to be supported by demand-driven augmentations** – AEMO assumed, based on workshops involving DNSPs, that up to 80% of new CER uptake would be naturally supported by demand-driven augmentations[30]. This assumption was influential in identifying distribution network development opportunities. Assuming that a higher proportion of new CER uptake will be supported through demand-driven augmentations reduces the potential need for investments that specifically support CER export, and therefore reduces the scale of distribution network development opportunities that may be identified through ISP modelling. AEMO will continue to seek DNSP input on the proportion of new CER uptake that should be expected to be supported by demand-driven augmentations for future ISPs.

[30] **Table 5** shows the proportion of new CER uptake assumed to be supported by demand-driven augmentations for each DNSP.

- **Assumed network limits arising from voltage management issues** – while DNSPs were able to voluntarily provide comprehensive thermal limitations on CER generation export at the distribution transformer level, AEMO received limited information regarding export limits arising from voltage management. As a result, AEMO assumed (following DNSP involvement) that voltage issues arise when CER generation export reaches two thirds of the thermal limit (see **Figure 10**).
- **The identified distribution network development opportunities primarily reflect opportunities at the distribution transformer level** – AEMO received limited data regarding the spare capacity of existing distribution networks to support CER export at the zone-substation and sub-transmission substation level from DNSPs who adopted the LV Asset Data Template Pathway. This means that additional limitations on CER generation arising from constraints at these levels of the distribution network are not fully considered for this DSF statement (see **Figure 11**).
- **Constraints on CER generation and mid-scale generation and storage are separated in ISP modelling** – mid-scale generation and storage are distribution-connected resources between 5 MW and 30 MW in size. In addition to constraints on CER generation, AEMO has included constraints on mid-scale generation (discussed in detail in Appendix A2). New entrant 'mid-scale generation and storage' are expected to connect at sub-transmission level of the distribution network. Ideally, an assessment of the spare capacity of distribution networks to support CER and mid-scale generation would consider both forms of generation simultaneously. Unfortunately, two factors prevented AEMO from creating a single constraint for each distribution network area within the ISP model that could appropriately consider CER and mid-scale generation and storage together:
  - Creating a single constraint which can constrain both CER export and generation from mid-scale generation and storage would require consideration of complex distribution networks characteristics such as the meshed nature of the medium and higher voltage levels of the distribution network, and the ability to switch loads between different transformers and substations. This was beyond capability of the model at this stage.
  - AEMO received limited data from DNSPs regarding network capability at the zone-substation and sub-transmission substation levels.

  Should data availability improve for future ISPs, AEMO would consider the benefits of creating constraints which can limit generation from CER and mid-scale generation and storage simultaneously against the increased computational burden.

For the 2028 ISP and beyond, DNSPs will provide the information required by AEMO to prepare the DSF statement in accordance with the Guidelines. AEMO anticipates that, over time, the extent to which these limitations will impact the identification of distribution network development opportunities will be mitigated. This is based on the expectation that DNSPs will perform more analysis of how their networks support CER export, and that DNSPs and AEMO will be able to evolve their modelling capability and data availability over time.

AEMO also anticipates that the breadth of the demand side factors assessed in future Demand Side Factors statements will evolve over time, which may enhance the analysis available to consider distribution network opportunities, or other potential network impacts. The Demand Side Factors statement will also likely interact with the first Demand-side Statement of Opportunities (DSOO) that will help identify and quantify demand-side opportunities in the NEM that enable decarbonisation, support energy system reliability and security, and lower the cost of the energy transition.

A9.4.5 Publication of data used in ISP modelling to identify distribution network development opportunities

AEMO publishes the final 2026 ISP model alongside the report and input files and has included average annual CER generation limit time of day profiles for each distribution network area in the ISP model in the final 2026 ISP Inputs and Assumptions Workbook[31]. The CER generation limit reflects the spare capacity of distribution networks to support CER exports within the ISP model. The final 2026 ISP Inputs and Assumptions workbook also includes AEMO's rooftop solar and consumer battery uptake (as 'embedded energy storages') forecasts.

The underlying data and information used by AEMO to develop the CER generation limit was provided by DNSPs on a voluntary basis on the condition that the data would not be published. Reporting arrangements for future ISPs have been consulted on through AEMO's preparation of the *Demand Side Factors Information Guidelines*[32]. The *Demand Side Factors Information Guidelines* were published in December 2025.

[31] At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp.

[32] At https://www.aemo.com.au/consultations/current-and-closed-consultations/2025-demand-side-factors-information-guidelines-consultation.

Glossary

This glossary has been prepared as a quick guide to help readers understand some of the terms used in the ISP. Words and phrases defined in the National Electricity Rules (NER) have the meaning given to them in the NER. This glossary is not a substitute for consulting the NER, the AER's *Cost Benefit Analysis Guidelines*, or AEMO's *ISP Methodology*.

Term	Acronym	Explanation
Actionable ISP project	-	Actionable ISP projects optimise benefits for consumers if progressed before the next ISP. A transmission project (or non-network option) identified as part of the ODP and having a delivery date within an actionable window. For newly actionable ISP projects, the actionable window is two years, meaning it is within the window if the project is needed within two years of its earliest in-service date. The window is longer for projects that have previously been actionable. Project proponents are required to begin newly actionable ISP projects with the release of a final ISP, including commencing a RIT-T.
Actionable project progressing under a jurisdictional framework	-	A transmission project (or non-network option), other than an actionable ISP project, which optimises benefits for consumers if progressed before the next ISP, is identified as part of the ODP, and which will progress under a jurisdictional policy that AEMO considers under NER 5.22.3 (b) and includes in the ISP.
Anticipated project	-	A generation, storage or transmission project that is in the process of meeting at least three of the five commitment criteria (planning, construction, land, contracts, finance), in accordance with the AER's Cost Benefit Analysis Guidelines. Anticipated projects are included in all ISP scenarios.
Candidate development path	CDP	A collection of development paths which share a set of potential actionable projects. Within the collection, potential future ISP projects are allowed to vary across scenarios between the development paths. Candidate development paths have been shortlisted for selection as the ODP and are evaluated in detail to determine the ODP, in accordance with the ISP Methodology.
Capacity	-	The maximum rating of a generating or storage unit (or set of generating units), or transmission line, typically expressed in megawatts (MW). For example, a solar farm may have a nominal capacity of 400 MW.
Committed project	-	A generation, storage or transmission project that has fully met all five commitment criteria (planning, construction, land, contracts, finance), in accordance with the AER's Cost Benefit Analysis Guidelines. Committed projects are included in all ISP scenarios.
Consumer energy resources	CER	Generation or storage assets owned by consumers and installed behind-the-meter. These can include rooftop solar, batteries and electric vehicles (EVs). CER may include demand flexibility.
Consumption	-	The electrical energy used over a period of time (for example a day or year). This quantity is typically expressed in megawatt hours (MWh) or its multiples. Various definitions for consumption apply, depending on where it is measured. For example, underlying consumption means consumption being supplied by both CER and the electricity grid.
Cost-benefit analysis	CBA	A comparison of the quantified costs and benefits of a particular project (or suite of projects) in monetary terms. For the ISP, a cost-benefit analysis is conducted in accordance with the AER's Cost Benefit Analysis Guidelines.

Term	Acronym	Explanation
Counterfactual development path	-	The counterfactual development path represents a future without major transmission augmentation. AEMO compares candidate development paths against the counterfactual to calculate the economic benefits of transmission.
Demand	-	The amount of electrical power consumed at a point in time. This quantity is typically expressed in megawatts (MW) or its multiples. Various definitions for demand, depending on where it is measured. For example, underlying demand means demand supplied by both CER and the electricity grid.
Demand-side participation	DSP	The capability of consumers to reduce their demand during periods of high wholesale electricity prices or when reliability issues emerge. This can occur through voluntarily reducing demand, or generating electricity, and is a form of 'demand flexibility'.
Development path	DP	A set of projects (actionable projects, future projects and ISP development opportunities) in an ISP that together address power system needs.
Dispatchable capacity	-	The total amount of generation that can be turned on or off, without being dependent on the weather. Dispatchable capacity is required to provide firming during periods of low variable renewable energy output in the NEM.
Distribution network service provider	DNSP	A business which owns, controls or operates a distribution system (including a distribution network).
Distribution project	-	A distribution project that is part of the ODP and forecast to be needed in the future. The project is an ISP development opportunity and does not address an identified need specified in the ISP. The ISP cannot make a distribution project 'actionable' or require commencement of the Regulatory Investment Test for Distribution (RIT-D).
Economic offloading	-	Refers to a VRE generator being dispatched below its maximum availability as its output is offered at a higher price bands greater than the regional reference price. This may also be referred to as economic 'spill' or 'spilled energy'.
Firming	-	Grid-connected assets that can provide dispatchable capacity when variable renewable energy generation is limited by weather, for example storage (pumped-hydro and batteries) and gas-powered generation.
Future ISP project	-	A transmission project (or non-network option) that addresses an identified need in the ISP, that is part of the ODP, and is forecast to be actionable in the future.
Identified need	-	The objective a TNSP seeks to achieve by investing in the network in accordance with the NER or an ISP. In the context of the ISP, the identified need is the reason an investment in the network is required, and may be met by either a network or a non-network option.
ISP development opportunity	-	A development identified in the ISP that does not relate to a transmission project (or non-network option) and may include generation, storage, demand-side participation, or other developments such as distribution network projects.

Term	Acronym	Explanation
Mid-scale	-	Generation and storage typically connected to the distribution network rather than to either the transmission network or behind the meter at a business or residence. For the 2026 ISP, these resources are assumed to have a generation or charge/discharge capacity of between 5 MW and 30 MW. For ease of reporting in this document, mid-scale generation and storage are sometimes included within the totals for utility-scale generation and storage. In other AEMO documents, such as the *Demand Side Factors Information Guidelines* and the *ISP Methodology*, these resources are sometimes referred to as 'other distributed resources'.
National Electricity Rules	NER	The Rules are legally binding rules made under the National Electricity Law, which govern the operation of the National Electricity Market and the ways in which AEMO manages power system security. The Rules also provide the regulatory framework for network connections and access, national transmission planning and pricing for network services. The Rules are mainly made by the AEMC having regard to the National Electricity Objective.
Net market benefits	-	The present value of total market benefits associated with a project (or a group of projects), less its total cost, calculated in accordance with the AER's Cost Benefit Analysis Guidelines. The net market benefits of the ODP through to 2050 is the difference between the cost of the ODP and the cost of a 'counterfactual' development path which has no new transmission build.
Non-network option	-	A means by which an identified need can be fully or partly addressed, that is not a network option. A network option means a solution such as transmission lines or substations which are undertaken by a Network Service Provider using regulated expenditure.
Optimal development path	ODP	The development path identified in the ISP as optimal and robust to future states of the world. The ODP contains actionable projects, future ISP projects and ISP development opportunities, and optimises costs and benefits of various options across a range of future ISP scenarios.
Regulatory Investment Test for Transmission	RIT-T	The RIT-T is a cost benefit analysis test that TNSPs must apply to prescribed regulated investments in their network. The purpose of the RIT-T is to identify the credible network or non-network options to address the identified network need that maximise net market benefits to the NEM. RIT-Ts are required for some but not all transmission investments.
Reliable (power system)	-	The ability of the power system to supply adequate energy to satisfy consumer demand, allowing for credible generation and transmission network contingencies.
Renewable energy	-	For the purposes of the ISP, the following technologies are referred to under the grouping of renewable energy: "solar, wind, biomass, hydro, and hydrogen turbines". Variable renewable energy is a subset of this group, explained below.
Renewable energy zone	REZ	An area identified in the ISP as a high-quality resource area where a cluster of large renewable energy projects can be developed using economies of scale.
Renewable lull	-	A prolonged period of very low levels of variable renewable output, typically associated with dark and still conditions that limit production from both solar and wind generators.

Term	Acronym	Explanation
Rooftop solar and other small-scale solar	-	Solar photovoltaic (PV) generation assets that are not centrally controlled by AEMO dispatch. Examples include residential and business rooftop PV as well as larger commercial or industrial "non-scheduled" PV systems.
Scenario	-	A possible future of how the NEM may develop to meet a set of conditions that influence consumer demand, economic activity, decarbonisation, and other parameters. For this ISP, AEMO has considered three scenarios: *Slower Growth*, *Step Change* and *Accelerated Transition*.
Secure (power system)	-	The system is secure if it is operating within defined technical limits and is able to be returned to within those limits after a major power system element is disconnected (such as a generator or a major transmission network element).
Sensitivity analysis	-	Analysis undertaken to determine how sensitive modelling outcomes are to a change in input or assumption (or a collection of related inputs and assumptions).
Spill	-	Refers to a VRE generator being dispatched below its maximum availability as its output is offered at a higher price, typically during periods of negative prices due to an oversupply of generation. Also referred to as 'economic offloading' or 'spilled energy'.
Transmission network service provider	TNSP	A business that owns, controls or operates a transmission network.
Utility-scale or utility	-	For the purposes of the ISP, 'utility-scale' and 'utility' refers to technologies connected to the high-voltage power system rather than behind the meter at a business or residence.
Value of greenhouse gas emissions reduction	VER	The VER estimates the value (dollar per tonne) of avoided greenhouse gas emissions. The VER is calculated consistent with the method agreed to by Australia's Energy Ministers in February 2024.
Variable renewable energy	VRE	Renewable resources whose generation output can vary greatly in short time periods due to changing weather conditions, such as solar and wind.
Virtual power plant	VPP	An aggregation of resources coordinated to deliver services for power system operations and electricity markets. For the ISP, VPPs enable coordinated control of consumer-scale batteries.