2024 Forecasting Assumptions Update

August 2024

For the 2024 National Electricity Market Electricity Statement of Opportunities and its Reliability Forecast

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 Group is proud to have launched its first Reconciliation Action Plan in May 2024. '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

AEMO publishes this 2024 Forecasting Assumptions Update pursuant to National Electricity Rules (NER) 4A.B.1(e) and the Australian Energy Regulator's (AER's) Forecasting Best Practice Guidelines (FBPG). This report includes information on updated assumptions to apply in the Reliability Forecast (and other publications, as named in this report, for the National Electricity Market (NEM)). This publication is generally based on information available to AEMO as at 12 June 2024 unless otherwise indicated.

Disclaimer

AEMO has made reasonable efforts to ensure the quality of the information in this publication but cannot guarantee that information, forecasts and assumptions are accurate, complete or appropriate for your circumstances.

Modelling work performed as part of preparing this publication inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material.

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Version control

Version	Release date	Changes
1.0	29/8/2024	Initial release

Executive summary

AEMO delivers a range of forecasting and planning publications for the National Electricity Market (NEM), including the *Electricity Statement of Opportunities* (ESOO) and the *Integrated System Plan* (ISP). Key inputs and assumptions for the ISP are published at least biennially as part of the *Inputs, Assumptions and Scenarios Report* (IASR). The most recent IASR, used to prepare the 2024 ISP, is the 2023 IASR[1].

Many of the same inputs and assumptions are applied in preparing the NEM ESOO and the East Coast Gas System *Gas Statement of Opportunities* (GSOO), which are produced annually.

This report therefore complements the 2023 IASR and provides updated assumptions for inputs for the 2024 ESOO.

Summary of updated assumptions

This *Forecasting Assumptions Update* and associated 2024 *Forecasting Assumptions Update Workbook* (the Updated Assumptions Book) outline updates to various forecasting components. The updates reflect both:

- Updated component forecasts that have been prepared in accordance with the Australian Energy Regulator's (AER's) Forecasting Best Practice Guidelines (FBPG)[2], and
- Re-baselined elements to reflect the latest actual market observations.

Forecasting components that reflect updated drivers and forecasts (rather than changes based on more recent actual observations) include:

- Updated generation developments based on the most recent issue of the Generation Information dataset[3].
- Updated gas prices (based on forecasts used in the 2024 GSOO).
- Updated technology costs, including for hydrogen electrolysers (developed for the annual CSIRO GenCost publication, the latest version of which was finalised in May 2024).
- Updated technical parameters associated with new and existing generation technology and hydrogen electrolysers, based on Aurecon's 2023-2024 AEMO costs and technical parameters review.
- Updated transmission network representations to reflect the 2024 ISP, 2024 marginal loss factors (MLFs) and other advice provided by relevant transmission network service providers (TNSPs).

[1] At https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[2] At https://www.aer.gov.au/system/files/AER%20-%20Forecasting%20best%20practice%20guidelines%20-%2025%20August%202020.pdf.

[3] See the July 2024 issue, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

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1 Introduction

AEMO produces several publications that use inputs, assumptions and scenarios that are detailed in the *Inputs, Assumptions and Scenarios Report* (IASR). These publications include the *Electricity Statement of Opportunities* (ESOO) and *Integrated System Plan* (ISP) for the National Electricity Market (NEM), and the *Gas Statement of Opportunities* (GSOO) for the East Coast Gas System. These publications complement each other, providing adequacy assessments of the electricity and gas systems, as well as optimal developments needed within the power system to provide energy consumers a path to a transformed reliable, low cost, net zero emissions future NEM.

AEMO uses a scenario analysis approach to:

- Investigate the various uncertainties facing the energy sector.
- Assess supply adequacy.
- Identify the economically efficient level of infrastructure investment necessary to support the future energy needs of consumers in the presence of uncertainty and risks of over- or under-investment.

This 2024 *Forecasting Assumptions Update* outlines several updated inputs that apply to the 2024 ESOO. In many instances, assumptions applied in the ESOO are unchanged since the 2023 IASR. This 2024 *Forecasting Assumptions Update* complements the biennial IASR, which provides the broader assumptions deployed across AEMO's forecasting and planning activities, including the ISP. Inputs that have not been updated since the 2023 IASR are not repeated in this publication.

The information in this report is supported by the 2024 *Forecasting Assumptions Update Workbook* (the Updated Assumptions Book)[4], which provides more granular detail for these updated inputs and assumptions.

All dollar values provided in this report are in real July 2023 Australian dollars unless stated otherwise.

1.1 Consultation process

In accordance with the Australian Energy Regulator's (AER's) Forecasting Best Practice Guidelines (FBPG)[5], AEMO has consulted with stakeholders transparently and openly regarding the updated assumptions in this *Forecasting Assumptions Update*. Table 1 summarises the consultation activities undertaken for this purpose.

[4] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-Forecasting-Assumptions-Update-Workbook

[5] At https://www.aer.gov.au/system/files/AER%20-%20Forecasting%20best%20practice%20guidelines%20-%2025%20August%202020.pdf.

Table 1 Stakeholder engagement on the Forecasting Assumptions Update

Consultation steps	Engagement opportunity	When
Publication of the Draft Forecasting Assumptions Update and Gencost, and call for stakeholder submissions	Submissions	21 December 2023
Economics and population forecasts	Forecasting Reference Group (FRG) consultation	28 February 2024
Updated demand side component forecasts: • **Large industrial loads** • **Electrification (non EV)** • **Electricity price indices** • **Demand side participation** • **Energy efficiency** • **Appliance uptake** • **Households and connections**	FRG consultation	29 May 2024
Unplanned outages affecting inter-regional power transfers	FRG consultation	12 June 2024
Scheduled generator unplanned outage rates	FRG consultation	12 June 2024
Publication of the: • **2024 Forecasting Assumption Update** • **2024 Forecast Assumptions Update Consultation Summary Report**	Published with the ESOO	29 August 2024

AEMO received formal submissions from seven stakeholders to the Draft Forecasting Assumptions Update consultation. Key themes in the feedback are summarised in Table 2.

Table 2 Stakeholder feedback summary to the *Draft 2024 Forecasting Assumptions Update consultation*

Issue	Description
Photovoltaics (PV)	Distributed PV forecasts did not appropriately consider the distribution network hosting capacity.
Embedded energy storage	A greater diversity of battery technologies should be considered, and cost projection trends reflecting utility-scale future estimates are inappropriate for residential scale installations.
Virtual power plants (VPPs)	Forecasts for adoption of VPPs need to recognise that consumers are unlikely to embrace an arrangement that relinquishes asset control to third parties.
Electric vehicles (EVs)	Forecast EV uptake was considered too fast, while forecast plug-in hybrid electric vehicle (PHEV) uptake was considered too low. Stakeholders demonstrated the uncertainty regarding vehicle-to-grid (V2G) uptake with mixed views submitted.

AEMO documented the material stakeholder feedback arising during its consultation and its consideration of the stakeholder feedback in its 2024 *Forecasting Assumptions Update Consultation Summary Report*[6].

1.2 Approach taken to update key forecasting inputs

AEMO has applied two forms of updates in the updated assumptions since the 2023 IASR:

- **Updated assumptions**, reflecting holistic updates since the 2023 IASR, applying the same, or similar, methodologies to derive new component forecast(s).

[6] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-Forecasting-Assumptions-update-Consultation-Summary-Report

- **Rebased assumptions**, reflecting an updated starting point for the 2023 IASR scenario-based trajectories or trends, rebased to apply more recent actual data.

This *Forecasting Assumptions Update* outlines the method for each assumption update in each subsection. All other component forecasts remain unchanged since the 2023 IASR.

1.3 Supporting material

Table 3 documents additional information on AEMO's inputs and assumptions.

Table 3 Additional information and data sources

Organisation	Document/source	Link
AEMO	2023 *Inputs, Assumptions and Scenarios Report*	https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf
Aurecon	2023-24 Cost and Technical Parameter Review	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/Aurecon-2024-Cost-and-Technical-Parameters-Review-Report
CSIRO	2023-24 Gencost report	https://www.csiro.au/en/research/technology-space/energy/GenCost
ACIL Allen	ACIL Allen gas price forecast for GSOO 2024	https://aemo.com.au/-/media/files/major-publications/isp/2023/iasr-supporting-material/acil-allen-natural-gas-price-forecasts.pdf
Green Energy Markets	Rooftop PV, PVNSG and battery forecast	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/Green-Energy-Markets-2023-Consumer-Energy-Resources-Forecast-Report
CSIRO	Electrical Vehicle forecast	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/CSIRO-2023-Electric-Vehicle-Forecast-Report
Deloitte Access Economics	Economic forecasts 2023/24	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/Deloitte-Access-Economics-2023-24-Economic-forecast-report.pdf

2 Updated assumptions

2.1 Historical data affecting forecasting components

Input vintage	**Updated** since the 2023 IASR • March 2024 for inputs affecting consumption and demand • May 2024 for transmission loss data • April 2024 for Generation Information • April 2024 for unplanned outage data
Source	• Supervisory control and data acquisition (SCADA)/electricity market management system (EMMS)/National Metering Identifier (NMI) data • Generation Information page • AER and network operators
Updates since 2023 IASR	Updated as mentioned above.

AEMO uses a range of historical data to train and develop its forecasting models, and consultant forecasts of various demand and energy consumption components, to deliver the overall Forecasting Approach[7]. Historical data is updated at varying frequency, from live metered data to monthly, quarterly, or annual updates depending on the forecasting component. Key historical datasets include:

- Metered electricity and gas consumption.
- Distributed photovoltaics (PV) uptake, and other consumer energy resources (CER) information.
- Other non-scheduled generators.
- Estimated network loss factors.
- Outage information regarding scheduled and significant non-scheduled generators.
- Weather data (such as temperature and humidity levels, solar irradiance and wind speed data) influencing demand, distributed PV generation and other renewable energy sources.

Information on datasets updated or rebased is outlined in the following sub-sections.

Historical weather data

AEMO uses historical weather data for training the annual consumption and demand models as well as to produce traces of historical consumption across AEMO's reference year collection. The historical weather data comes from the Bureau of Meteorology (BoM)[8], using a subset of the weather stations available in each region, as shown in Table 4.

AEMO selected these weather stations based on data availability and correlation with regional consumption or demand. AEMO uses one weather station per region, except where weather stations have been discontinued.

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

[8] Bureau of Meteorology Climate Data, at http://www.bom.gov.au/climate/data/.

Table 4 Weather stations used in consumption, minimum and maximum demand

Region	Station name	Data range	BoM site number
New South Wales	Bankstown Airport AWS	January 1989 ~ Now	066137
Queensland	Archerfield Airport	July 1994 ~ Now	040211
South Australia	Adelaide (Kent Town)	October 1993 ~ July 2020	023090
	Adelaide (West Terrace)	July 2020 ~ Now	023000
Tasmania	Hobart (Ellerslie Road)	January 1882 ~ Now	094029
Victoria	Melbourne Regional Office	January 1955 ~ January 2015	086071
	Melbourne (Olympic Park)	May 2013 ~ Now	086338

Operational demand

Operational demand as-generated is collected through the electricity market management system (EMMS) by AEMO in its role as the market operator. It includes generation from scheduled generating units, semi-scheduled generating units, and some non-scheduled generating units[9].

Generator auxiliary load

Estimates of historical auxiliary load are determined by using the auxiliary rates provided by participants in the Generation Information page. This is used to convert between operational demand as-generated (which includes generator auxiliary load) and operational demand sent-out (which excludes this component).

Network losses

The AER and network operators provide AEMO with annual historical transmission loss factors. The AER also provides AEMO with annual historical distribution losses which are reported to the AER by distribution companies. AEMO uses the transmission and distribution loss factors to estimate half-hourly historical losses across the transmission network for each region in megawatts (MW) or megawatt hours (MWh).

Large industrial loads

AEMO's *Electricity Demand Forecasting Methodology* defines a methodology for identifying large loads for inclusion in the large industrial load (LIL) sector. AEMO collects the historical demand of these LILs from National Metering Identifier (NMI) metering data.

Residential and business demand

AEMO splits historical consumption data (excluding industrial loads identified above) into business and residential segments using a hybrid bottom-up and top-down approach, as detailed in Appendix A6 (Residential-business segmentation) of the *Electricity Demand Forecasting Methodology*. The bottom-up approach is based on sampling of AEMO residential meter data. The top-down approach considers annual ratios between the two segments provided by electricity distribution businesses to the AER as part of their processes in submitting a Regulatory Information Notice.

[9] A small number of exceptions are listed in Section 1.2 of https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf.

Distributed PV uptake and generation

AEMO sources historical PV installation data from the Clean Energy Regulator and applies a solar generation model to estimate the amount of power generation at any given time.

Other non-scheduled generators

AEMO reviews its list of other non-scheduled generators (ONSG) – non-scheduled generation that excludes distributed PV[10] – using information from AEMO's Generator Information dataset, the Distributed Energy Resources (DER) Register, and the Demand Side Participation (DSP) Information Portal. These datasets are complemented with information provided from network operators and publicly available information. This *Forecasting Assumptions Update* includes updates to April 2024.

Through these sources of information, AEMO collects withdrawn, committed, and proposed ONSG connections and site information. AEMO uses the generator's Dispatchable Unit Identifier (DUID) or NMI to collect generation output at half-hourly frequency.

AEMO forecasts connections or withdrawal of ONSG generators based on firm commitment statuses of these generators in the short term and applying historical trends of ONSG by fuel type (for example, gas- or biomass-based cogeneration, or generation from landfill gas or wastewater treatment plants) in the long term.

AEMO's current view of ONSG is contained in the Generation Information page. As at the April 2024 release, which was used in the development of the demand and energy forecasts, aggregated ONSG by NEM region is shown in Table 5 (noting that changes to aggregated non-scheduled generation capacity since this release are minimal).

Table 5 Aggregate other non-scheduled generation capacity, by NEM region

	New South Wales	Queensland	South Australia	Tasmania	Victoria
Installed capacity (MW)	472	613	61	131	320

2.2 Energy consumption and demand updates

AEMO updates its projections of energy consumption and demand at least annually[11], and undertakes significant stakeholder engagement through the Forecasting Reference Group[12] (FRG), industry engagement via surveys, and consultant forecasts, in accordance with the AER's FBPG. This engagement focuses on key influences and outcomes from AEMO's forecasting models within the Forecasting Approach of each sector and sub-sector affecting energy consumption and peak demands.

[10] Distributed PV is discussed in Section 2.2.2.

[11] Updated forecasts within a year can be issued in case of material change to input assumptions.

[12] See https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/forecasting-reference-group-frg.

Table 6 Status and update for key inputs and assumptions

Input	Status
Historical data	• Updated
Consumer energy resources (including distributed PV, distributed battery storage and EVs)	• Updated and rebased for distributed PV • Updated for battery storage • Updated for EVs
Electrification of other sectors	• Rebased
Economic and population, including connections	• Updated
Large industrial loads, including liquified natural gas	• Updated
Energy efficiency	• Rebased
Appliance uptake	• Updated
Electricity prices	• Updated
Demand side participation	• Updated
Hydrogen electrolysers	• Updated
Gas prices	• Updated

2.2.1 Electrification

Input vintage	**Rebased** since the 2023 IASR
Source	CSIRO and Climateworks Centre (multi-sector modelling)
Updates since 2023 IASR	The multi-sector modelling electrification forecasts were updated following a comparison with the 2024 ESOO LIL survey information. Initial trajectories were rebased to adjust for magnitude of electrification occurring in the base year of the forecasts. The electrification forecasts do not include electricity consumption forecasts by EVs. EV forecasts are provided as a separate category.

Energy usage presently met from non-electric alternatives can be met with alternative energy sources, including electricity, through fuel-switching. AEMO considers the potential electrification of Australia's economy, across the residential, business (comprised of commercial and industrial and other sectors), and non-road transport sectors.

In the residential and commercial (building) sectors, appliances that service space heating, cooking, and hot water are all able to be electrified, shifting from gas or liquefied petroleum gas (LPG) demand into electricity demand. The cost-efficiency of electrification is uncertain and will depend on many factors including appliance replacement costs, electricity infrastructure capabilities and costs, and the availability of alternative fuels, such as hydrogen or blended hydrogen-natural gas. AEMO has therefore considered a range of electrification outcomes for these sectors, with the *Green Energy Exports* scenario applying greater hydrogen fuel substitution as an alternative to electrification.

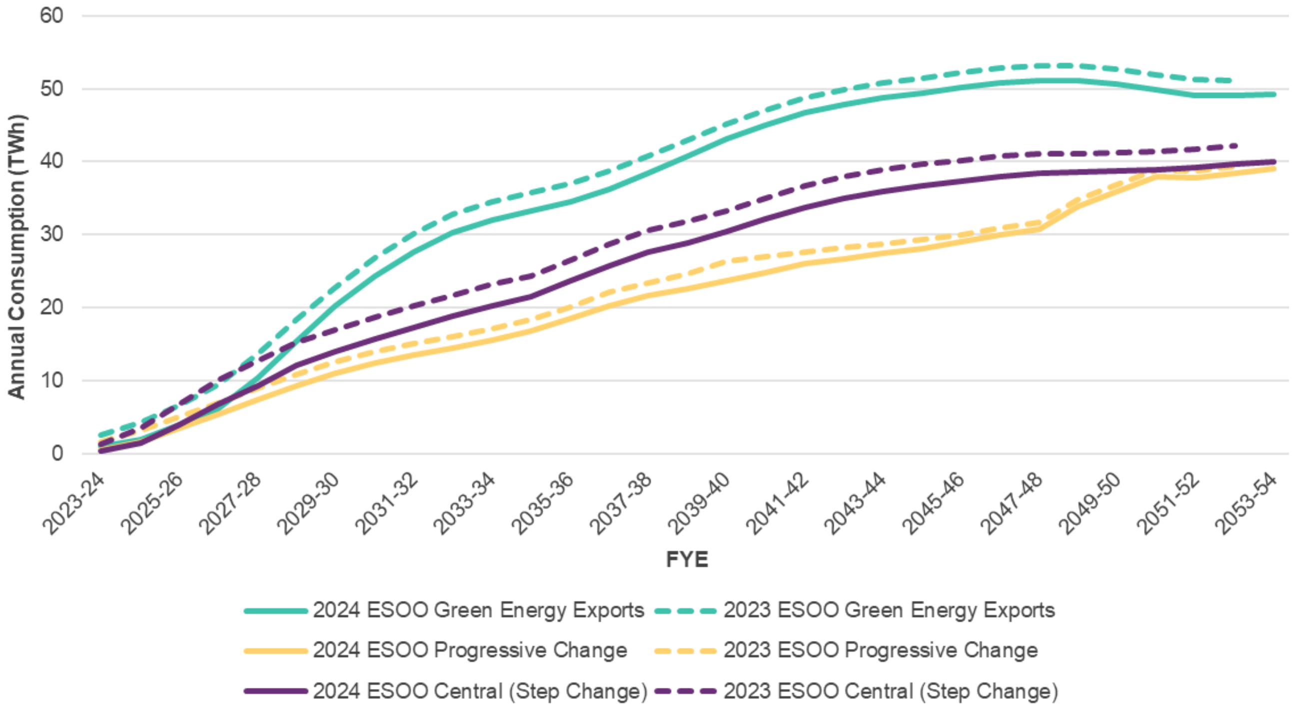
In the industrial sector there is a wide range of subsectors considered, each of which have their own fuel consumption profiles. Broadly speaking, while most oil and gas demands can be electrified (or switched to biofuels), many loads also exist that will be challenging to electrify for various reasons. The electrification of high-heat processes, including electric arc furnaces for iron and steel production, and high-temperature mineral processing such as alumina calcination, may necessitate technological advancements. For these processes it may be possible to convert from high temperature blast furnaces to lower temperature electric arc furnaces. Investment in these technological advances is assumed in scenarios with more ambitious emissions reductions, to help decarbonise more challenging industrial processes and lower broader economy costs associated with alternative investments or offsets.

Electrification of the transport sector is expected in all scenarios. Electricity consumption forecasts by road transport are provided separately under the EV forecasts.

Figure 1 shows the total electrification across the modelled scenarios. As forecast for the 2024 ESOO, around 40 terawatt hours (TWh) of new electricity consumption is forecast in scenarios which assume coordination of activities to achieve net zero emissions economy-wide in 2050. The key difference between these scenarios is the timing of investment, with earlier investment leading to increased electrification and faster achievement of emissions reduction targets.

In this *Forecasting Assumptions Update*, the scale of electrification has been rebased in the short term, by applying a modest reduction in the base year of the forecast, to adjust for the magnitude of electrification estimated to have occurred in that year. This adjustment removes potential double-counting of electrification, the impact of which would already be embedded in the base year historical data used for forecasting consumption.

Figure 1 Forecast of electrification for residential, commercial, industrial and non-road transport, 2023-24 to 2053-54



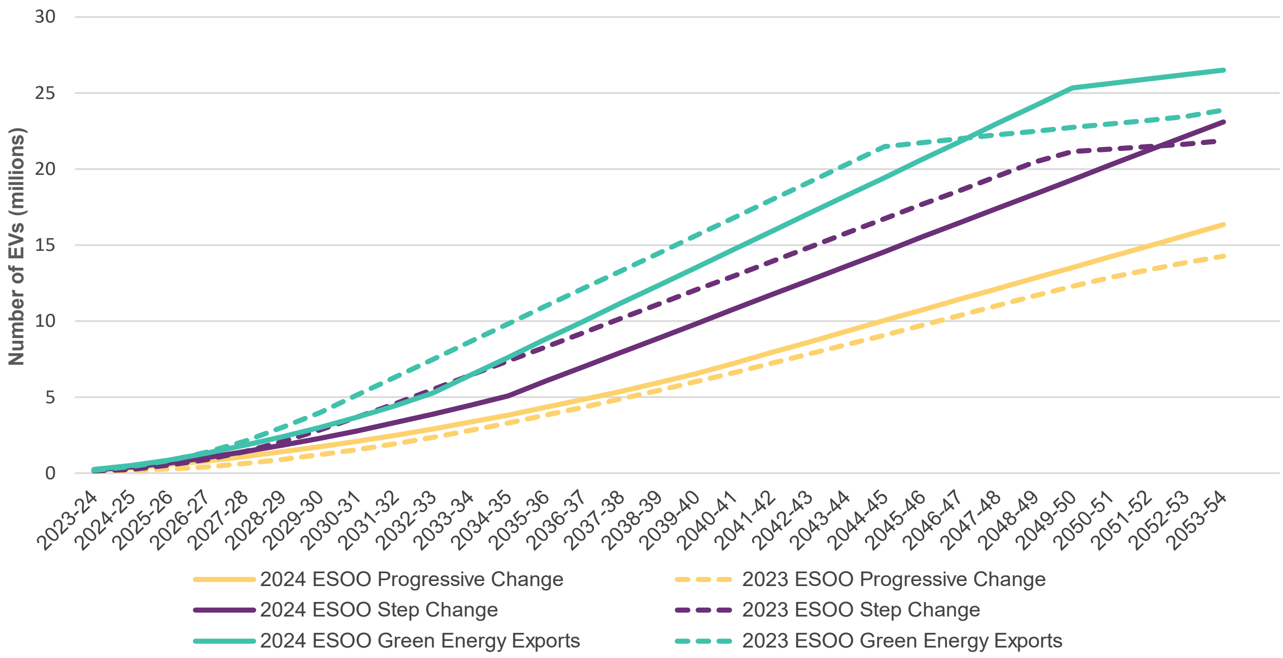
Electric vehicle uptake

Input vintage	**Updated** since the Draft 2024 Forecasting Assumptions Update
Source	CSIRO, EV Council[13] , Federal Chamber of Automotive Industries *VFACTS*
Updates since 2023 IASR	Revised to account for the now-legislated New Vehicle Emission Standard (NVES), considering longer vehicle lifetime from BITRE

[13] Known to be approximate only but considered by the EV Council to be a reasonable estimate.

Electrification of the transport sector will increase electricity consumption in future. This document uses electric vehicles (EVs) as the collective term for battery electric vehicles (BEVs) and plug-in hybrid vehicles (PHEVs). Figure 2 shows the total EV fleet size forecast by scenario, considering new clarity on the expected impact of the NVES.

Figure 2 Projected BEV and PHEV fleet size by scenario, 2023-24 to 2053-54



Compared to the 2023 IASR, this *Forecasting Assumptions Update* shows changes to EV uptakes reflecting:

- The latest actual sales figures of BEVs and PHEVs.
- Policy changes since the 2023 IASR, including the New Vehicle Emission Standard (NVES) which is set to apply to new light vehicles (new cars, sport utility vehicles [SUVs], four-wheel drive vehicles [4WDs] and utility vehicles) rather than all vehicle types.
- Feedback received in response to the *Draft 2024 Forecasting Assumptions Update* consultation process suggesting AEMO's earlier EV uptake outlook appeared too ambitious.
- An updated approach to PHEV forecasts in response to stakeholder feedback which has resulted in an uplift for that vehicle category.
- Updated road transport data from Bureau of Infrastructure and Transport Research Economics (BITRE) showing longer vehicle lifetimes leading to lower new vehicle sales.

The following sub-sections elaborate on these points, then describe overall EV uptake, energy use and charging profiles.

Short-term updates reflecting vehicle sales

Updated vehicle sales figures are available quarterly until December 2023, and based on more recent data from Federal Chamber of Automotive Industries *VFACTS* until end of December 2023, the actual number of vehicles in NEM is estimated to be approximately 221,000 by end June 2024. Recent EV sales figures have exceeded the previous 2023 IASR *Step Change* forecast. As a result, AEMO's forecasts include increases in the short term.

Medium term uptake impact from government policy

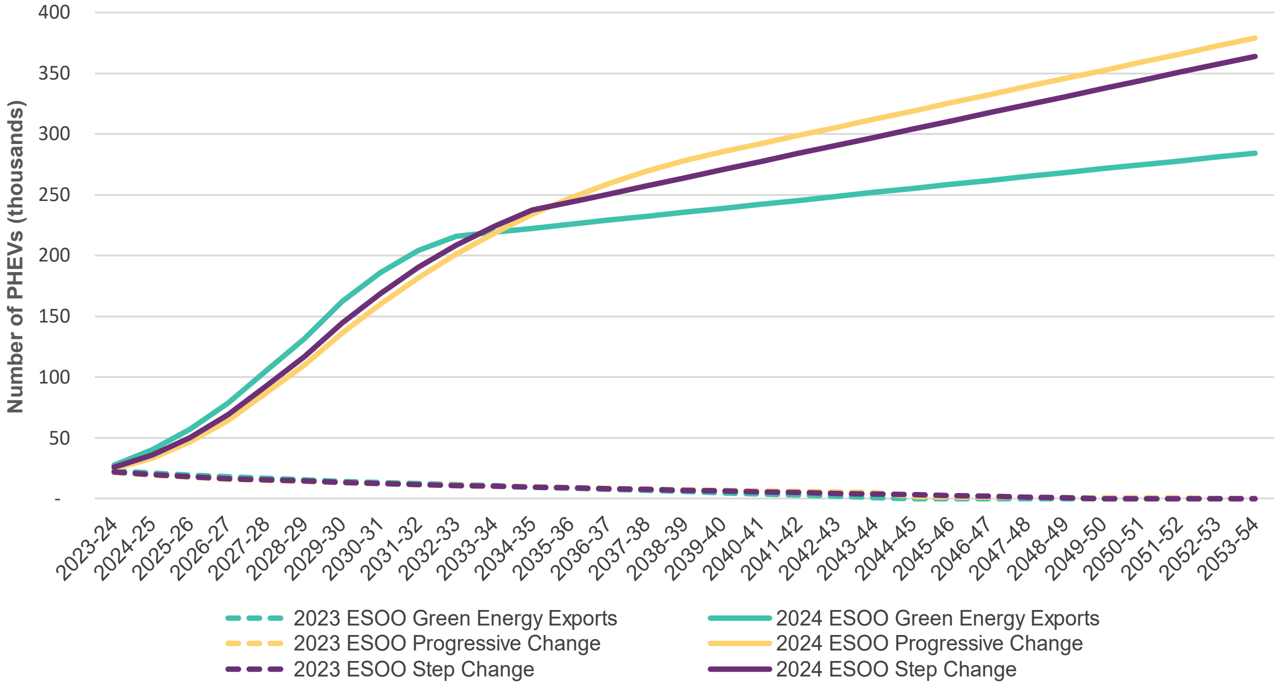
The *New Vehicle Efficiency Standard Act 2024* (Cth)[14] (NVES) will regulate carbon dioxide emissions from the transport sector. The NVES applies to new, light vehicles (new cars, SUVs, 4WDs and utility vehicles). When developing the EV forecasts for the 2023 IASR, AEMO applied assumptions on the expected design, coverage and implementation of the efficiency standard.

In response to stakeholder feedback and considering the legislated efficiency standard, AEMO revised the EV light vehicle sales share in recognition of flexibility within the design of the NVES. The updated forecast continues to reflect the uncertainty for transport electrification, covered by the scenarios, although the trajectory to 2030 is narrower than the 2023 IASR given less uncertainty regarding the design and breadth of vehicle types that would be covered by the NVES.

Influence of plug-in hybrid vehicles

AEMO's EV forecasts consider the relative share of sales for BEVs and PHEVs, given the difference in impact of the two vehicle types to EV consumption and charging behaviours. The PHEV forecast has been updated considering stakeholder feedback received. The change in forecast values reflect revised buying preference assumptions for some consumers, considering battery range anxiety, limited public charging infrastructure, and limited model availability for some purposes such as towing heavy loads. Previous PHEV forecasts projected PHEVs as a declining share of EV sales. However, the greater clarity of NVES application, and updated sales data, support an increased share and longevity of PHEVs, as shown in Figure 3.

Figure 3 Projected PHEV fleet size by scenario, 2023-24 to 2053-54



Driving distances and vehicle saturation impacts

BITRE has released its Australian Infrastructure and Transport Statistics Yearbook 2023, providing updated data on road transport demand, vehicle sales and the contribution of road travel to total passenger and freight travel. The updated data

[14] See Federal Register of Legislation, *New Vehicle Efficiency Standard Act 2024*, at https://www.legislation.gov.au/C2024A00034/asmade/text.

on vehicle kilometres travelled (from BITRE) and updated new vehicle sales (from *VFACTS*) allowed for updated estimates of vehicle lifetimes, which have returned to pre-pandemic levels, and resulted in lower projected vehicle sales and a reduced future demand for vehicles. Consequently, the revised projections indicate that the previously forecast dates for EV saturation will be pushed back, with the new vehicle sales rates leading to a longer timeline for achieving 99% EV fleet share as shown in Table 7.

The updated data from BITRE also indicated that road's share of passenger transport has fallen significantly, with aviation recovering almost all the share it lost during the pandemic. This change reduces the projected demand for road transport kilometres which, along with the changes in vehicle lifetime, reduces future demand for vehicles.

Table 7 Changes to market saturation (99% EV fleet share) dates

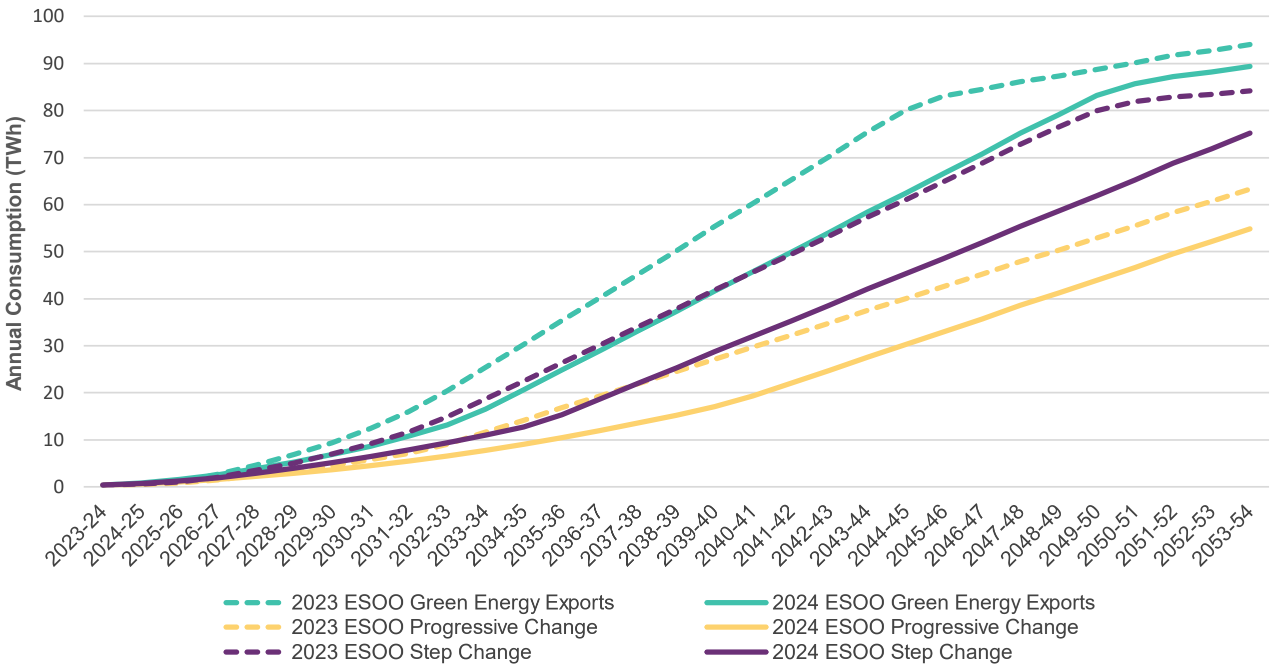
	Progressive Change	Step Change	Green Energy Exports
Previous	2060	2050	2045
Revised	2060	2055	2050

Electricity consumption associated with electric vehicles

The changes to EV uptake impact the energy use associated with EVs over the forecast horizon. While the actual number of EVs in the NEM is forecast to be lower by 13% (in 2030) and 20% (in 2050), the consumption is forecast to be lower by 40% (in 2030) and 25% (in 2050) compared to the Draft *2024 Forecasting Assumptions Update* for the *Step Change* scenario. The difference in impact on the EV fleet size and consumption reflects that greater emphasis has been placed on light and medium-sized road vehicles to meet the NVES target. This incorporates feedback from several stakeholders who observed that the availability of EV utility vehicles and 4WDs will lag that of other vehicle types.

Figure 4 shows projected BEV and PHEV electricity consumption by scenario over the forecast horizon. More detail on the projected uptakes, consumption and charging profiles for each scenario is in the accompanying Updated Assumptions Book.

Figure 4 BEV and PHEV electricity consumption, 2023-24 to 2053-54



EV charging profiles

For the 2023 IASR, a range of half-hourly charging profiles were developed to reflect the link between various EV driver charging behaviours and the time-specific load on the power system. The profiles varied over vehicle type, time (months, years), geography (NEM regions) and day ‘types’ (weekdays/weekends).

The latest charging profiles have revised names and descriptions (see Table 8), with the change providing greater transparency on how tariffs relate to charging behaviour. Average after-diversity charging profiles are explicitly presented, with the three scenarios showing different utilisation of abundant solar energy, and different demand outcomes.

Table 8 EV charging profiles

Charging profile name	Previous name	Description
Unscheduled	Convenience	Driven by user’s lifestyle choices other than cost reduction, and occurs at a residence on a flat tariff
TOU Grid solar	Day	Where a TOU tariff includes day charging incentives, and even customers without solar are incentivised to use abundant low cost solar via the grid
Off-peak and solar	Night	Traditional time of use (TOU) tariff without day incentives, other than use of home solar, with a focus on charging during off-peak hours (primarily overnight)
TOU Dynamic	Coordinated	TOU tariff, but dynamically priced to reflect solar energy availability. Used for charging only – does not include vehicle-to-home (V2H) and vehicle-to-grid (V2G) power flows
Public	Fast/Highway (FHWY)	Available only at public locations with dedicated infrastructure and enabled by DC fast public charging (Level 2, Level 3, Level 4)
V2G/V2H	V2G/V2H	Vehicle to home/grid (dynamic system-controlled charging)

Relative to the 2023 IASR forecast, the new forecast better recognises the important role of public charging, both for managing vehicle range and travel needs, and for those drivers who cannot charge their EV at home or work. The ‘public’ EV charging profile (previously called Fast/Highway) has been updated with new projections for the share of use of public and private chargers.

Figure 5 below shows the result of CSIRO and AEMO modelling of charging types over time. It considers various trial data referred to in CSIRO’s report, stakeholder feedback, and the anticipated evolution of Time of Use (TOU) tariffs.

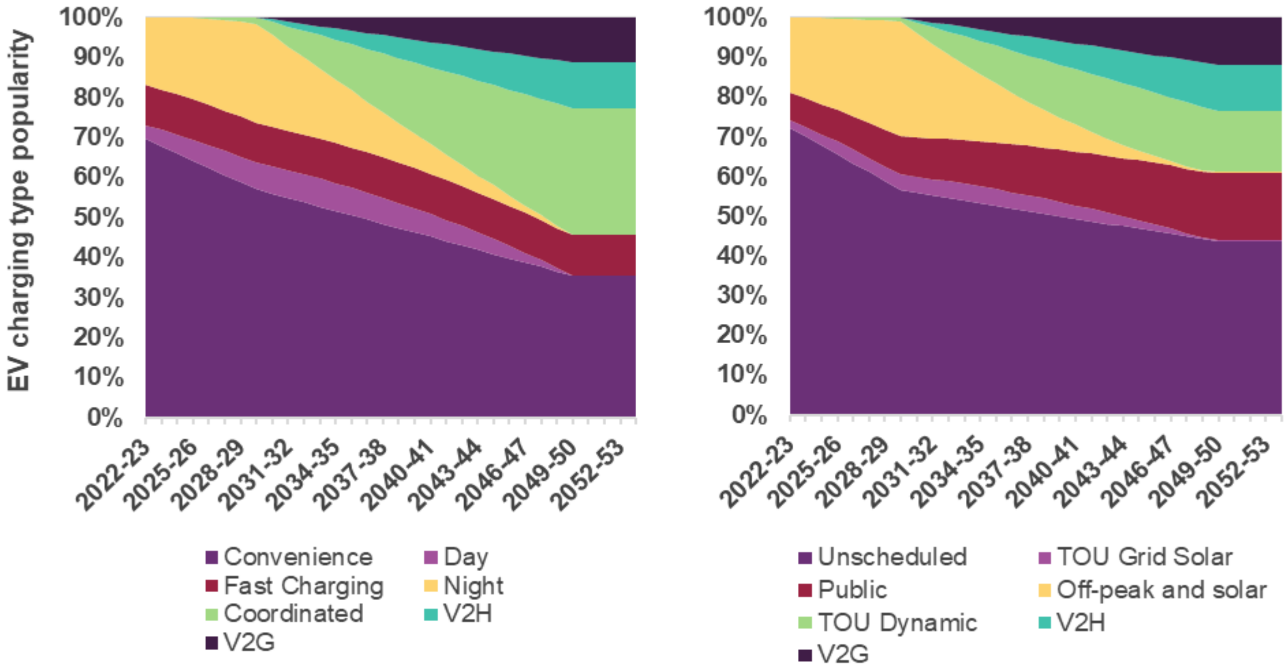
This figure shows:

- Initially, EV drivers are assumed to primarily use 'unscheduled' charging when returning home, given limited access to workplace or carpark charging. Over time, public charging is assumed to increase, driven by increased workplace and public charging infrastructure. Such infrastructure addresses the needs of those in housing with limited off-street parking, and caters to the increasing number of electric passenger vehicles embarking on longer trips, helping reducing range anxiety.
- EV drivers are assumed to use Off-peak and solar, which is based on traditional TOU with peak/shoulder/off-peak periods. The peak price is late afternoon and evening, the shoulder price is morning to mid- afternoon (and possibly late evening), and the off-peak price occurs around midnight to early morning. The tariff incentivises charging during overnight off-peak, or from their rooftop PV systems if applicable. This traditional TOU tariff does not support EV drivers without access to rooftop PV to make use of the abundant low cost solar available on the grid.
- TOU Grid Solar assumes pricing that better reflects daytime solar abundance. The lower daytime price is available to everyone, including those without rooftop PV. While solar is generally available in the daytime, the tariff does not cater

for daily weather variations. Thus, EV drivers would still be incentivised to charge, even on a day when cloud-coverage limits solar availability.

- TOU Dynamic assumes a dynamic weather sensitive element to best contribute to managing the power system needs. For example, daytime cloud cover would lead to higher prices that would discourage charging at that time. Smart charging facilities would be required to automate the charging behaviours dynamically. The TOU Dynamic charging type is assumed to become the most popular as it would offer the greatest incentives to charge at times when solar power is abundant.

Figure 5 Split of charging types for medium residential vehicles: 2023 IASR (left), 2024 *Forecasting Assumptions Update* (right)



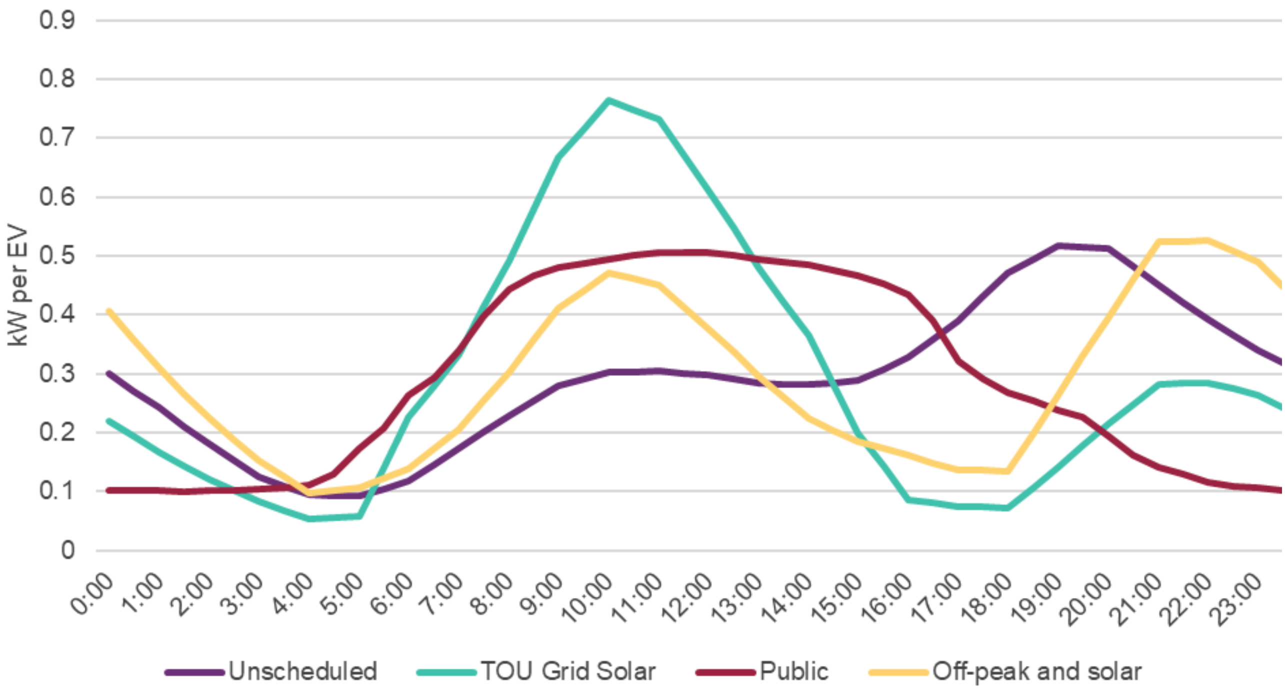
Note: The figure shows AEMO analysis values for New South Wales under the *Step Change* scenario, based on CSIRO projections.

Figure 6 below represents the updated half-hourly charging profiles of all the static charging types. The profiles below are shown for a typical January weekday in New South Wales, under the *Step Change* scenario.

Further information regarding the drivers for vehicle uptake, and charging behaviours and consumption, is provided in the CSIRO report[15].

[15] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/CSIRO-2023-Electric-Vehicle-Forecast-Report

Figure 6 Static charging profiles of different EV charging types for medium residential vehicles in New South Wales normalised to 7kWh/day



2.2.2 Consumer energy resources

Input vintage	**Rebased** since the Draft 2024 *Forecasting Assumptions Update*
Source	• CSIRO • Green Energy Markets, informed by updated market data from: – Clean Energy Regulator – Victorian Energy Saving Scheme – AEMO's DER Register
Updates since 2023 IASR	Distributed Photovoltaic model rebased from end of March 2024 using latest data on installations. Revised forecasts based on GEM's latest update (December 2023), as per Draft 2024 *Forecasting Assumptions Update*

Consumer energy resources (CER) predominantly describes consumer-owned devices that can generate or store electricity as individual units and which may have the 'smarts' to actively manage energy import and export. CER can also refer to consumer-shared devices, such as community batteries and other resources that enable greater demand flexibility.

The CER forecasting component generally refers to components including distributed PV systems (which includes PV non-scheduled generation, known as PVNSG), battery storage (including virtual power plants [VPPs]), and EVs (covered in section above).

As for the 2023 IASR, AEMO used the work of two consultants to inform the 2024 *Forecasting Assumptions Update* CER forecasts. Expert advice for distributed PV and battery forecasts was provided by CSIRO and Green Energy Markets (GEM). AEMO considers that CER forecasts benefit from input from multiple independent models aligned to the same assumptions and scenario narratives. For the 2024 *Forecasting Assumptions Update*, AEMO has used CSIRO's analysis for the 2023 IASR, and GEM's 2024 analysis. CSIRO's outlooks were translated to 2024 figures by applying GEM's year-on-year forecast changes to the 2023 CSIRO forecasts. This technique maintains the relationship between each of CSIRO's scenario forecasts, while ensuring these updated forecasts reflect new insights and information.

Table 9 summarises AEMO's treatment of the consultant inputs to arrive at the CER forecast components. In the table, average means the average of the current GEM forecast and the previous CSIRO forecast escalated by the GEM forecast.

Table 9 Forecast blending of consultant forecasts for key CER components, by scenario

Forecast	*Green Energy Exports*	*Step Change*	*Progressive Change*
Rooftop PV	GEM	Average	CSIRO, escalated per *Step Change*
PVNSG	GEM	GEM	CSIRO, escalated per *Step Change*
Battery storage	Average	Average	Escalated CSIRO by GEM forecast

The following sections provide descriptions of changes that reflect the updated forecast by GEM for each component. These updated trends have been applied to CSIRO's 2023 forecasts, as outlined in Table 9 above. The following sections describe the revised observations from the GEM updated forecast.

Distributed PV

This section comprises rooftop PV and PVNSG (larger PV systems between 100 kilowatts [kW] and 30 megawatts [MW]) forecasts, which together make up total distributed PV at the end of the section.

Rooftop PV and PVNSG current installed capacity estimates are from the Clean Energy Regulator, with AEMO's DER Register available as a comparison. The forecasts were rebased to reflect the latest actual installation data before the 2024 ESOO was finalised.

The forecasting approaches by the consultants may differ, but fundamentally use the same scenario definitions, and the same primary inputs such as technology cost and population trends. The consultant reports provide details on individual PV forecasting components within their reports, as well as their methodologies. For this updated forecast, relevant component updates include updated installation data, the consultant's views on forward retail prices and tariff options, and the consumers' investment appetite and capabilities. Key components including technology costs and economic outcomes and population trends remain unchanged from the 2023 IASR components.

Distribution network service provider (DNSP) hosting of CER is considered in the rooftop PV section below, which provides an update on the relevance of dynamic operating envelopes (DOEs) to PV forecasts.

Rooftop PV

The rooftop PV forecasts include inputs from the 2022-23 GenCost[16] and retail price trends, and the forecasts also use PV installation size data from the Clean Energy Regulator[17]. The May 2024 GenCost report[18] was not available in time for 2024 *Forecasting Assumptions Update* CER forecast development.

[16] See https://doi.org/10.25919/zmvj-tj87.

[17] See Figure 1-16 of GEM's report 'Share of residential solar capacity installed by system size band'.

[18] See https://www.csiro.au/-/media/Energy/GenCost/GenCost2023-24Final_20240522.pdf.

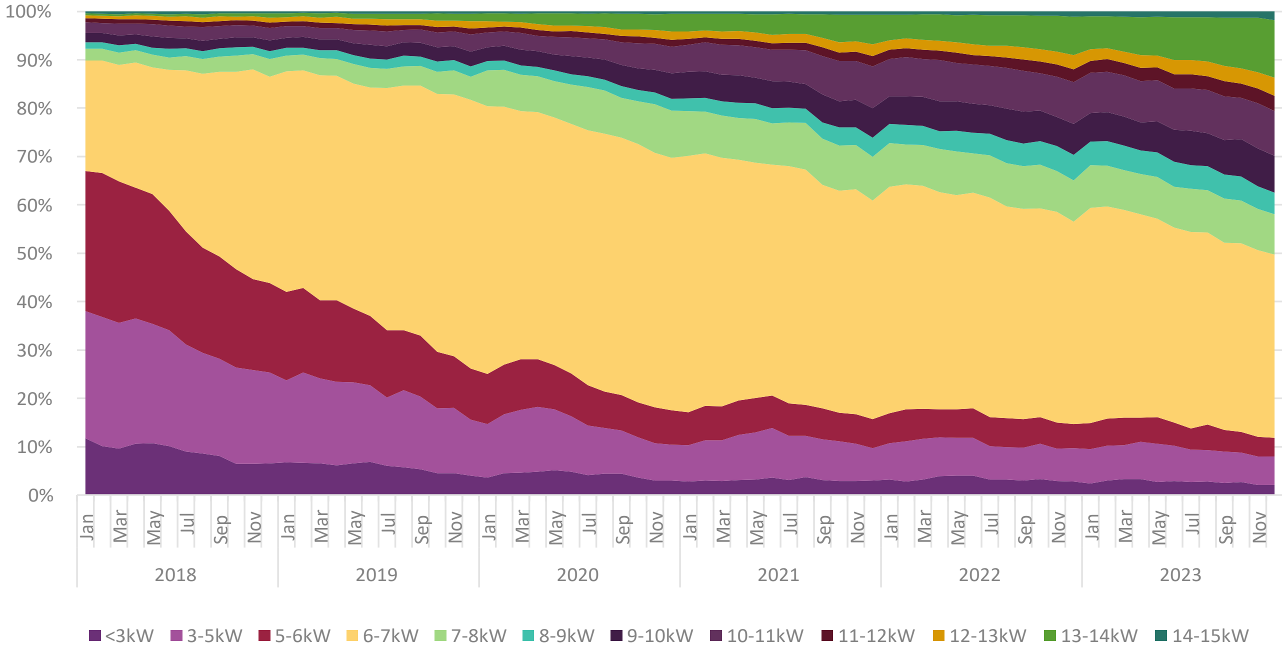
Details on GEM's forecasting approach and outlook can be found in its report[19]. Key insights include:

- The Clean Energy Regulator data reveals ongoing increases in average installation size.
- *Green Energy Exports* and *Step Change* forecasts have lowered uptake due to increased overall costs relative to the 2023 IASR forecast. Note that GEM considers 'fully installed costs' which include various overhead costs associated with retail sales and marketing, installation costs, and retail margin.
- The above points are now expanded on in the sub-headings below.

Average PV system size

The Clean Energy Regulator data in Figure 7 below shows ongoing increases in average system size, and this has previously been used to support projections in average system size. It is observed that systems in the 10 kW and above range are growing at the expense of systems in the 6-7 kW range.

Figure 7 Share of new residential PV installations by system size band

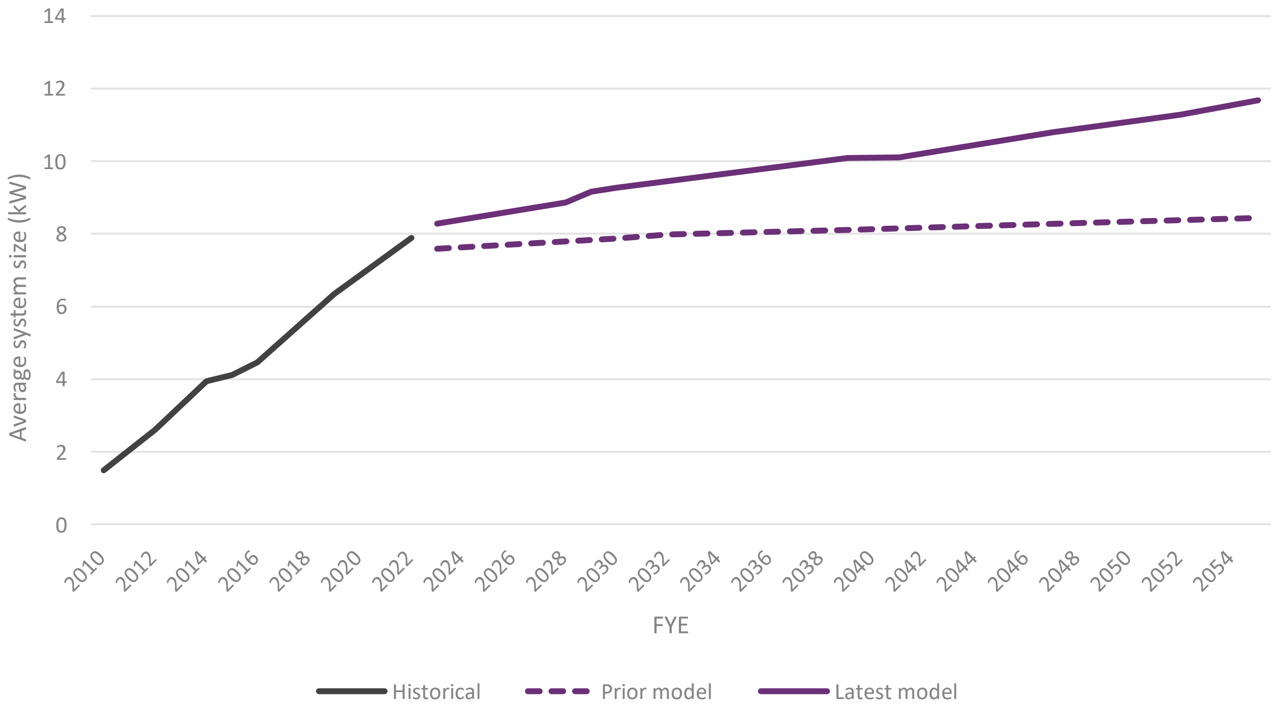


Source: Clean Energy Regulator, via GEM.

As the latest data continues to show increases in system sizes, it has prompted an updated system size projection, as shown in Figure 8 below. Note that the latest system size forecast includes limits to average system size growth (such as network's export limits, reductions in the years of certificate deeming under the Small-scale Renewable Energy Scheme [SRES] and suitable household roof space), however, AEMO considers this upper (average) limit to lie at or beyond the current projection due to several factors (expanding export limits, increases in consumer load, future improvements in panel efficiency, and decreasing costs of solar panels which allow use of suboptimal roof space).

[19] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/Green-Energy-Markets-2023-Consumer-Energy-Resources-Forecast-Report

Figure 8 Actual and forecast average system size of new PV installations



In considering the above projection of PV system size, AEMO notes:

- The declining outlook for solar feed-in tariffs is accounted for in the payback calculations and associated uptake, rather than the system size.
- As consumers increase their consumption needs with EVs and/or electric heating, it is expected that more value may be obtained, or perceived when making a purchase decision, with a larger PV system.

GEM's report[20] (Section 1.3.2) provides more commentary on PV system size.

PV system costs

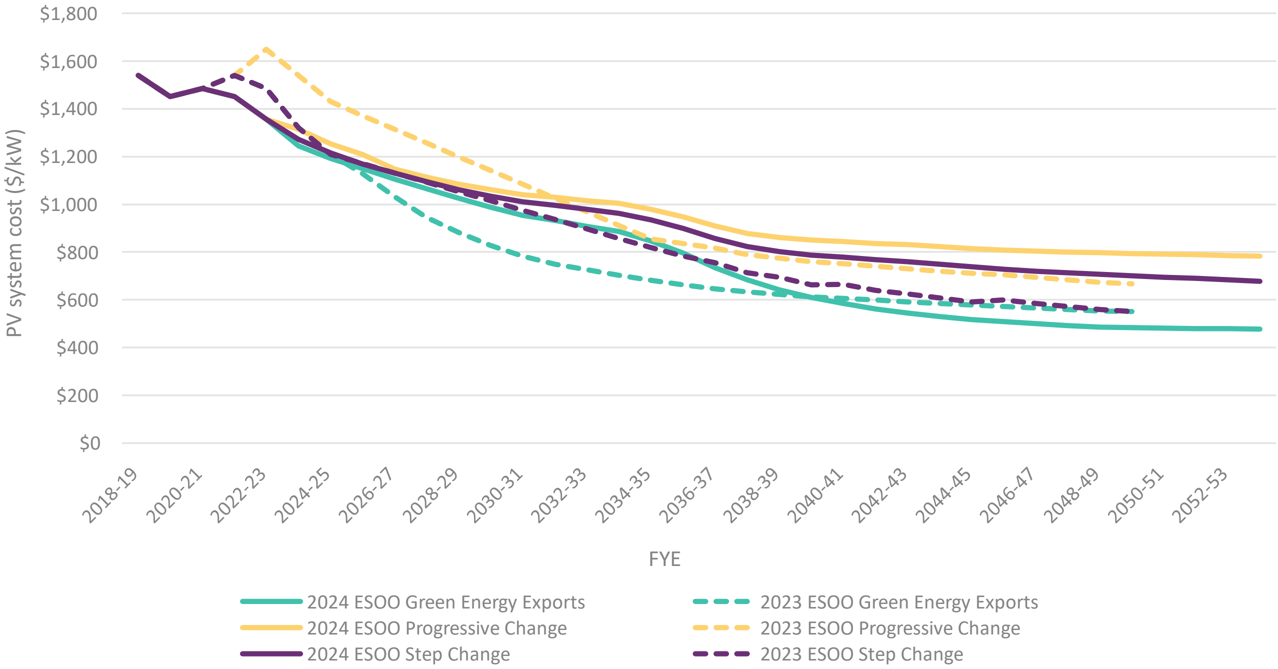
PV system costs are forecast by GEM, based on the 2022-23 GenCost publication and its own market research. These costs include installation costs and various forms of retail overheads.

Figure 9 below shows changes in such overhead costs (excluding government support such as Small Technology Certificates (STCs)).

GEM's report (Section 1.3.1) provides more detail, including re-evaluation of the impact of labour costs in the medium-term and long-term trajectory.

[20] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/Green-Energy-Markets-2023-Consumer-Energy-Resources-Forecast-Report.

Figure 9 GEM view on fully installed residential PV system costs



Rooftop PV system count and capacity forecasts

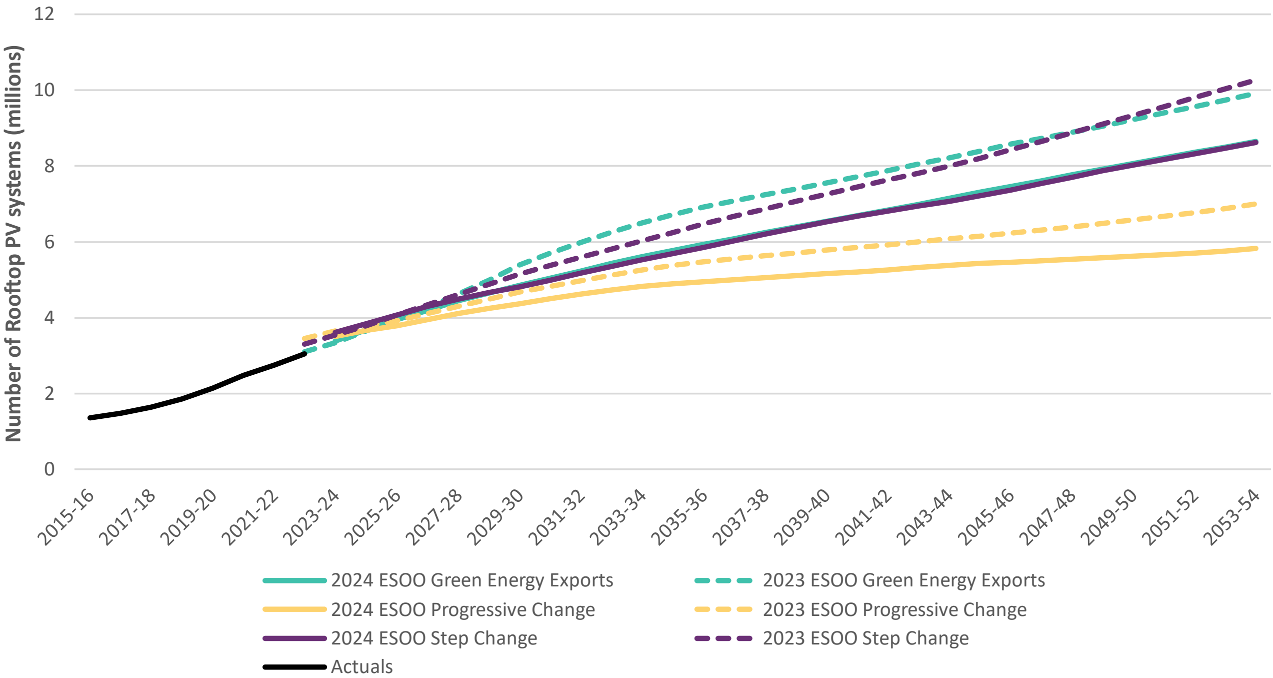
The PV system forecasts decline relative to the 2023 ESOO, reflecting the increased outlook on costs shown above and the impact of reduced SRES certificate values. Additionally, the updated forecast has greater regard of the price feedback effect, whereby as PV volumes rise, the value of daytime energy falls, which diminishes PV payback and limits further uptake.

Green Energy Exports and *Step Change* attain similar system count forecast values, but due to different dynamics. *Step Change* has higher relative forecast wholesale prices but also higher PV system costs. *Green Energy Exports* forecasts lower relative wholesale prices but also lower PV system costs. While the wholesale price outlook remains unchanged from the last forecast, the levels, and relativities of fully installed costs for the two scenarios have changed to produce this result.

AEMO notes stakeholder interest in how distribution network hosting capacity limitations might limit further growth of PV. DNSP strategies to accommodate further PV growth, and how this influences forecasts, are described in the *Network curtailment risks and impacts on distributed PV forecast* box at the end of Section 2.2.2.

Figure 10 below shows the resulting system counts.

Figure 10 Actual and forecast number of NEM rooftop PV systems, 2015-16 to 2053-54

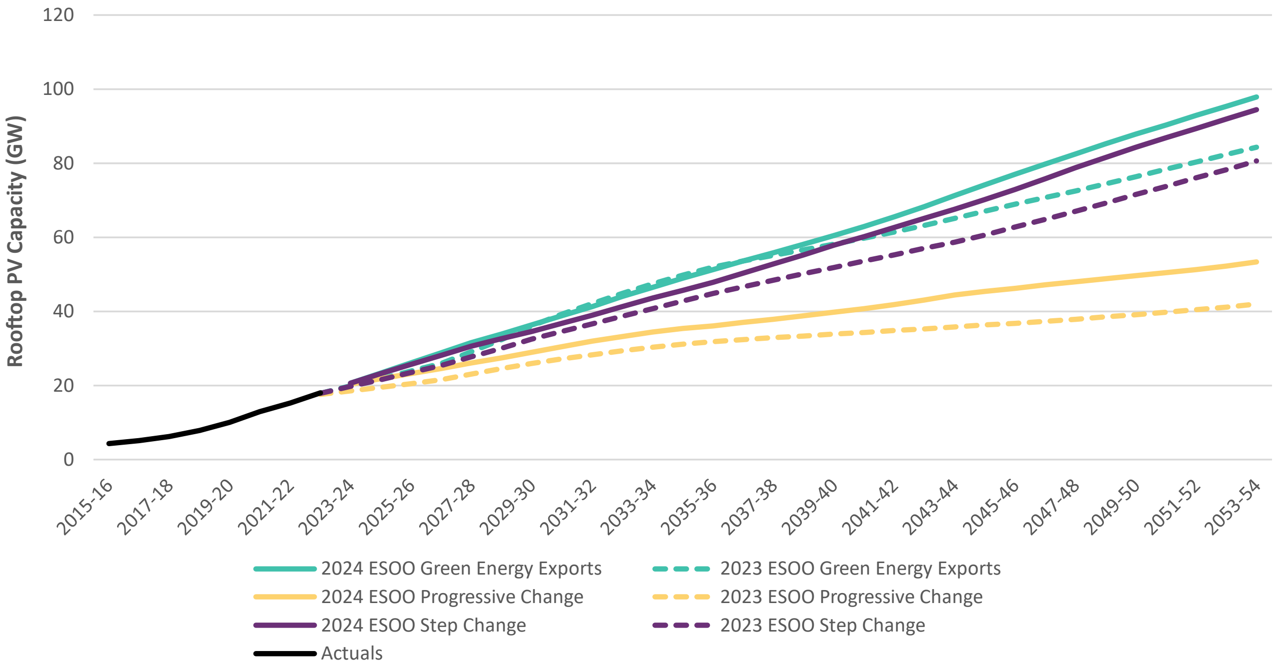


In considering all of the above, AEMO has used:

- GEM's forecast as the foundation for the *Green Energy Exports* scenario. This results in a modest rooftop PV capacity increase compared to the 2023 IASR. While PV numbers decrease, ongoing system size growth outweighs the reduced number of PV systems.
- An average of GEM's forecast, and an escalated CSIRO forecast, for the *Step Change* scenario. This results in a modest increase to rooftop PV capacity forecast for *Step Change* compared to the 2023 IASR, due to the expectation of ongoing system size growth outweighing the reduced number of PV systems.
- The 2023 IASR CSIRO *Progressive Change* forecast, escalated by GEM's view of changes to its *Step Change* forecast. AEMO retained CSIRO's *Progressive Change* forecast after considering GEM's, but considered that the large increases narrowed the forecasting range too much, and that there remains reasonable uncertainty regarding the expected rate of PV system size growth that validates the retention of the milder CSIRO forecast in this regard.

Figure 11 shows the resulting forecast PV capacity.

Figure 11 Actual and forecast NEM rooftop PV installed capacity, 2015-16 to 2053-54



PVNSG

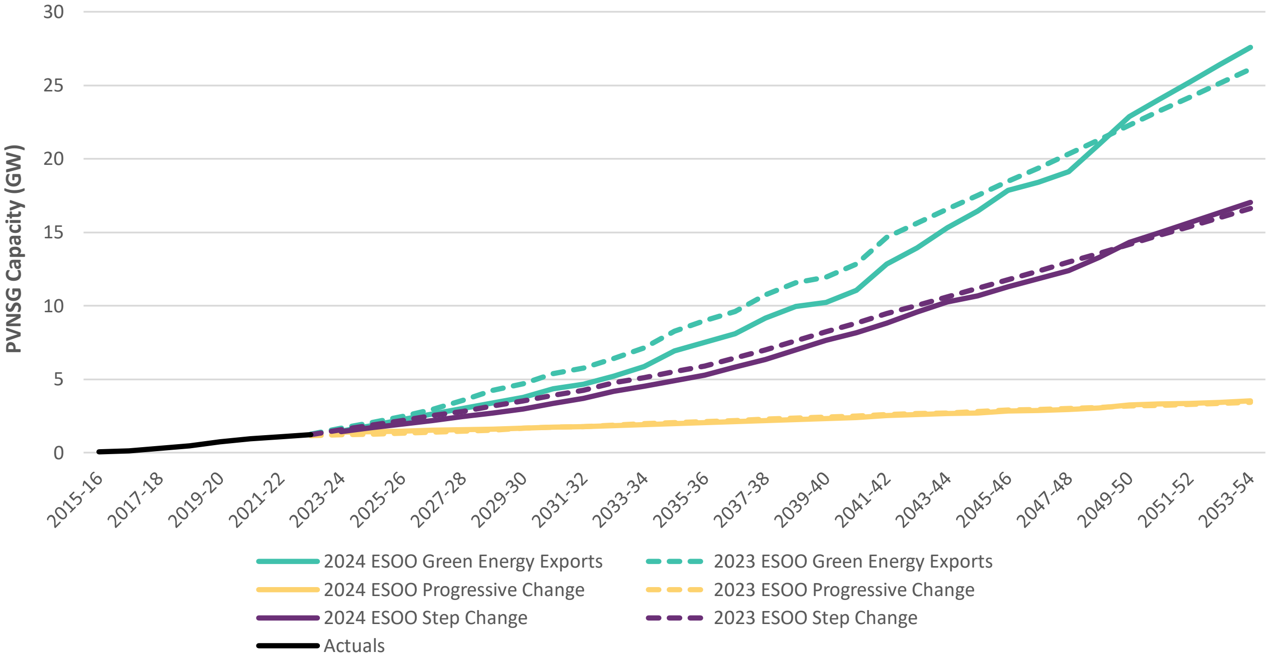
The uptake of PVNSG systems (between 100 kW and 30 MW, that are either rooftop or ground-mounted, installed by larger energy consumers or by market developers), reflects scenario-specific revenue and capital cost dynamics over the forecast horizon:

- Across all scenarios, revenue from PVNSG systems is expected to decline over the 2020s before stabilising around the mid-2030s. This reflects the completion of the Large-scale Generation Certificate (LGC) scheme in 2030.
- Under the *Green Energy Exports* scenario, capital costs decline faster, and a supportive environment for solar encourages faster emission reductions. This outpaces the fall in revenues, and results in continued growth in PVNSG installations over the remainder of the 2020s. Growth continues through the 2030s due to ongoing capital cost reductions, while revenue remains stable.
- The *Step Change* scenario shows almost no change in uptake as system cost changes and revenue outlook changes are at a comparable scale, in effect balancing each other out.
- Across all scenarios, the 2040s rate of annual additions stabilises due to slowing capital cost reductions and an expected degree of maturation/saturation in the PVNSG market.

AEMO has retained the same consultant forecast allocation approach to each of the scenarios as developed for the 2023 IASR (see Table 9 earlier).

Figure 12 provides the forecast capacity of PVNSG for each scenario. For *Progressive Change*, AEMO notes that GEM forecast slower growth in the 2020s and then higher growth in the 2030s due to its scenario-specific system cost outlook. As outlined and consulted on in the Draft 2024 Forecasting Assumptions Update, applying this approach, even when averaged with the escalated CSIRO forecast as described previously, would uplift this scenario's forecast materially, and AEMO considered that the breadth of the scenario collection did not warrant narrowing at this time, therefore the same relative adjustment to *Step Change* has been applied.

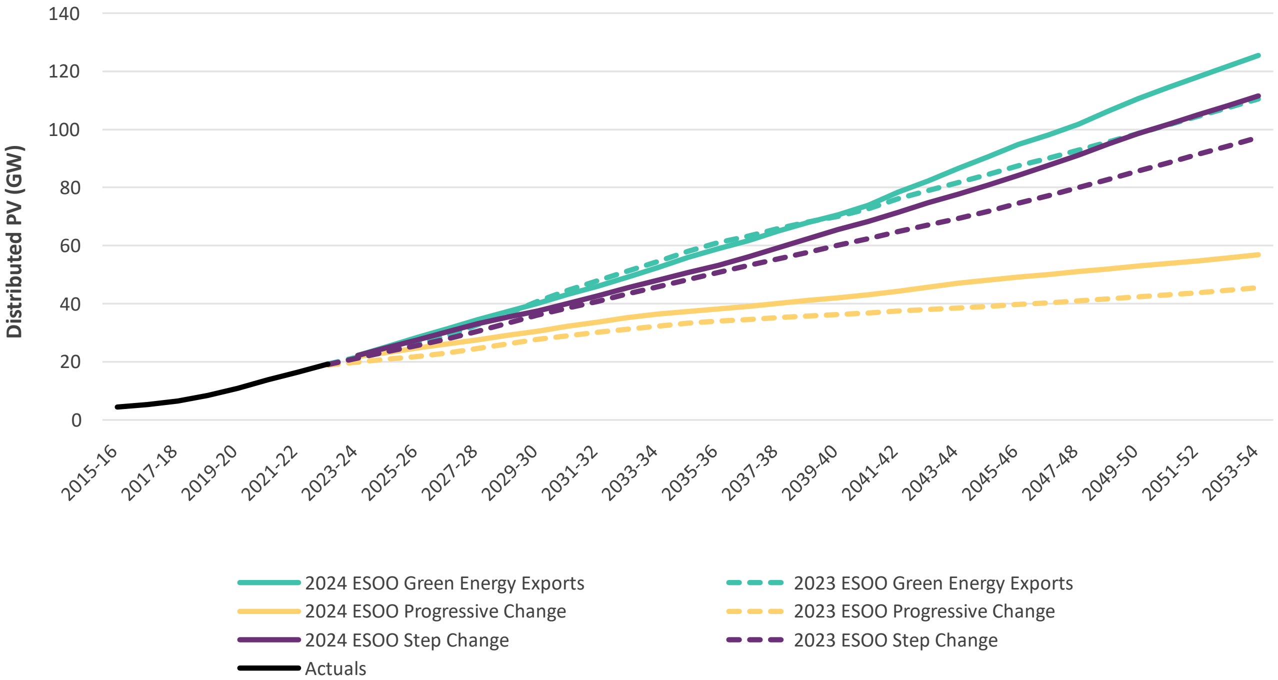
Figure 12 Actual and forecast NEM PVNSG capacity, 2015-16 to 2053-54



Aggregate distributed PV

Figure 13 below aggregates the rooftop PV component and the PVNSG component, to construct the total aggregate distributed PV forecast. The total installed capacity of distributed PV systems in the NEM from the most recent Clean Energy Regulator release is 22.8 gigawatts (GW) as of end of March 2024, and forecasts were rebased from this point.

Figure 13 Actual and forecast NEM distributed PV installed capacity, 2015-16 to 2053-54



Network curtailment risks and impacts on distributed PV forecast

Regarding DNSPs' PV hosting capability, page 72 of the 2023 IASR summarises AEMO and DNSP positions as at the IASR publication date of July 2023. At that time, AEMO noted the DNSPs' commitment and action plans were documented in their Distribution Annual Planning Reports. The plans included reference to Dynamic Operating Envelopes (DOE). This technology avoids the curtailing imposed by historical static export limits, such as 5 kW export limits per phase.

Since then, AEMO notes DNSPs are continuing to develop DOE capabilities. In South Australia, SA Power Networks (SAPN) has mandated that from July 2023 all new solar installations must have DOE functionality and that all consumers will have the option to enter a dynamic connection agreement with SAPN from the same date, with the aim to have DOE rolled out state-wide by mid-2024[21]. In Queensland, Energex and Ergon Energy have recently released a standard for dynamic connection of small inverter energy systems which sets DOE implementation requirements for new connections[22]. In Victoria, DNSPs will be using CSIP-Aus technology[23] to implement emergency backstop capabilities[24] for systems equal to and less than 200 kW from 1 July 2024 and this technology has the potential to enable DOE[25]. All DNSPs are planning for DOE implementations, with most in the trial stage. Nine out of 13 NEM DNSPs have plans to offer a DOE option to all customers within the next three years[26]. Recent DNSP revenue proposals to the AER have also proposed network expenditure to increase low voltage visibility for system upgrades to manage their networks more dynamically[27].

AEMO considers that DOE technology retains the vast majority of opportunities to export energy for the consumer, while minimising grid impact in extreme circumstances. With appropriate availability and use of DOE technology, and relevant investment over time in distribution systems, AEMO considers the revised distributed PV projections included in the forecasts above to be appropriate for AEMO's 2024 planning and forecasting functions.

In July 2024, Australia's Energy Ministers agreed to a National CER Roadmap[28], which sets out an overarching vision and plan to unlock CER at scale across Australia, and reflects the need to implement critical technical capabilities to support the continued security of the power system. AEMO remains committed to the National CER Roadmap, which sets out an implementation plan to put in place foundational reforms for better integrating CER across the industry. AEMO is also considering its forecasting and modelling approach for future ISP use in response to the recommendations by Energy and Climate Ministers in the 2024 ISP review[29]. AEMO will update its electricity and demand forecasting, and ISP methodologies regarding CER as appropriate for consultation with stakeholders as required by the AER's Forecasting Best Practice Guidelines.

[21] See https://www.sapowernetworks.com.au/data/315274/attention-update-issued-on-sa-s-dynamic-export-requirements/.

[22] See https://www.ergon.com.au/__data/assets/pdf_file/0008/1072592/STNW3510-Dynamic-Standard-for-Small-IES-Connections.pdf.

[23] Common Smart Inverter Profile Australia (Australian implementation of the IEEE 2030.5 standard that has been mandated for inverter-based resources (IBR) in California (USA), to support the deployment, monitoring and active management of CER. For more details, see https://arena.gov.au/knowledge-bank/common-smart-inverter-profile-australia/.

[24] Capacity of network service providers (NSPs) to remotely turn down or switch off rooftop PV systems during an energy supply emergency to support system security and avoid blackouts, as directed by AEMO.

[25] For details of Victoria's Emergency Backstop Mechanism, see https://engage.vic.gov.au/victorias-emergency-backstop-mechanism-for-rooftop-solar.

[26] See https://arena.gov.au/assets/2022/07/review-of-dynamic-operating-envelopes-from-dnsps.pdf.

[27] See https://www.aer.gov.au/system/files/2023-11/Draft%20export%20limit%20interim%20guidance%20note%20-%20November%202023.pdf.

[28] At https://www.energy.gov.au/sites/default/files/2024-07/national-consumer-energy-resources-roadmap.pdf.

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

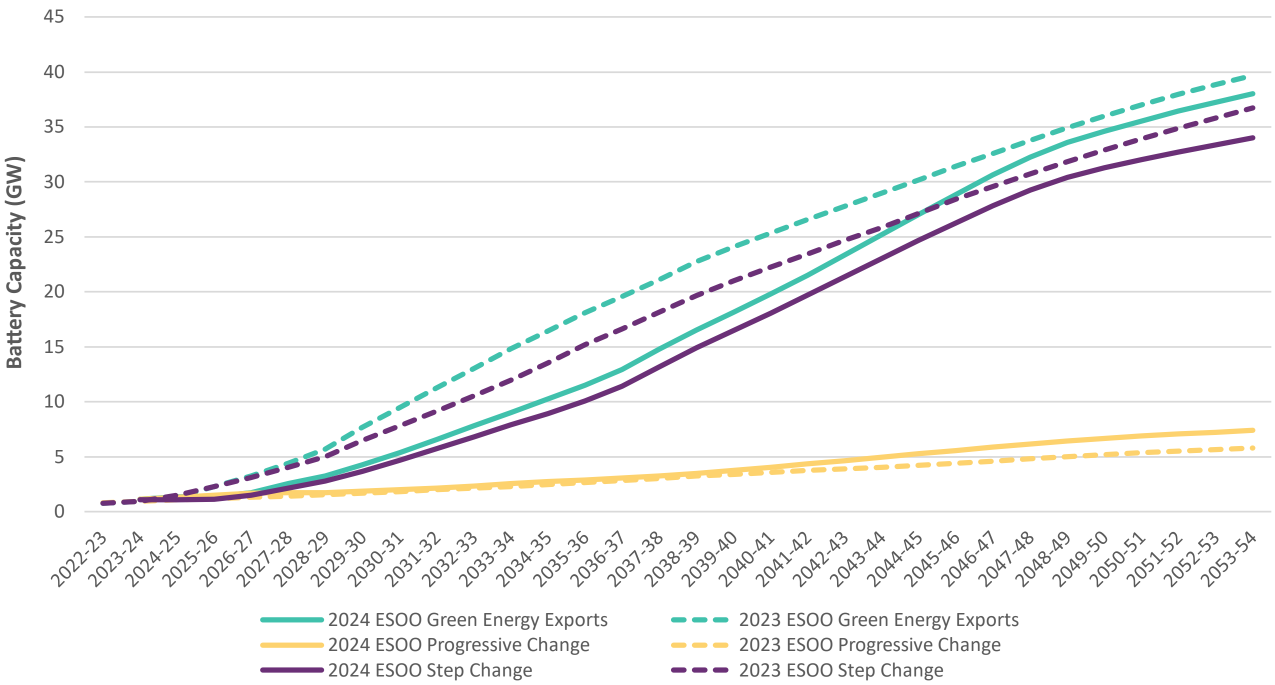
Embedded energy storage

The outlook for distributed batteries takes into account:

- Recent slower than anticipated battery sales.
- The forecast reduction in the number of PV installations.
- An anticipated reduction in battery capital costs, consistent with the trends of 2022-23 GenCost publication (see comment above), adjusted by GEM to consider small-scale battery influences and expected retail costs. The forecast reflects near-term battery cost reductions that are faster than those expected in the longer term[30].

As shown in Figure 14 below, the above points lead to a slightly lower battery uptake in the *Step Change* and *Green Energy Exports* forecast. In contrast, recent battery sales, although slow, uplift the lower *Progressive Change* forecast in the short term. In the longer term, the scenario specific energy price outlook drives the energy saving (and thus uptake) for the *Progressive Change* forecast.

Figure 14 Distributed battery forecast for the NEM, 2022-23 to 2053-54



Virtual power plants (VPPs)

A VPP broadly refers to the involvement of an aggregator to coordinate (or 'orchestrate') CER via software and communications technology, to deliver energy services similar to large-scale inverter-based generation and storage developments. This is in contrast to typical household battery installations which are configured to offset household energy costs by reducing the volume of grid supplied energy and increase self-consumption of complementary PV generation.

[30] Note that this contrasts with NREL's battery costs projections (https://www.nrel.gov/docs/fy22osti/83586.pdf), which reflect a striking difference in battery installation costs between the Australian and US markets, as analysed in this RMI report: https://rmi.org/insight/lessons-from-australia-reducing-solar-pv-costs-through-installation-labor-efficiency/.

The role of coordinating CER to provide energy for the power system at large will be a significant influence on the scale of network and utility-scale investments needed to maintain reliability, security and affordability through the energy transition. Consumer resources that increase load flexibility and provide reliable capacity to meet system peaks will offset other investments.

AEMO incorporates VPPs with a slightly different approach to other CER, as the concept of a VPP effectively converts them to a pseudo-dispatchable supply resource. For other CER technologies, AEMO adapts the demand forecast to increase or decrease the effect on electricity consumption and/or the demand profile across the day. For VPPs, consumption and demand are forecast gross of the effect of the use of these devices, and the capacity is then captured as an alternative and controllable supply source in AEMO's forecasting and planning models. Depending on the objective of the modelling, the methodology and treatment of VPPs therefore can change. For reliability assessments, AEMO's 2023 ESOO and associated Reliability Forecasting Guidelines excluded VPPs that were not committed or anticipated, bringing it into line with other transmission, generation, and storage projects. For the ISP, VPP growth is adopted, but the contribution of the technology to regional reserves is reduced. See the relevant methodology documents of each publication for more information.

New evidence reinforces the view of the technical practicality and economic advantages of VPP programs.

- Project Symphony[31] successfully coordinated approximately 900 CER (including rooftop PV, batteries and large appliances) across 500 homes and businesses in Western Australia.
- The cost benefit analysis from the three-year-long Project EDGE demonstrated feasible end-to-end technical capabilities, projecting an estimated $6 billion in future cost savings for NEM electricity consumers, plus $3 billion further societal benefits through emissions reduction[32]. The project involved substantial collaboration between a range of agencies, including a DNSP (Ausnet Services), Mondo acting as an aggregator, retailers AGL and Discover Energy, and Rheem as a technology provider.
- South Australia has at least seven market participants offering VPP. The Australian Energy Market Commission (AEMC) lists a wide range of VPP programs and their details[33]. AEMO considers that the long-term potential of VPPs remains of keen interest to retailers, particularly gentailers with legacy coal generators, who are particularly motivated to harness consumer investments to transition their business to renewable sources.

Despite that long-term potential, the marketing of VPP products to date has been modest, as retailers evolve their VPP offerings and communications to increase VPP popularity.

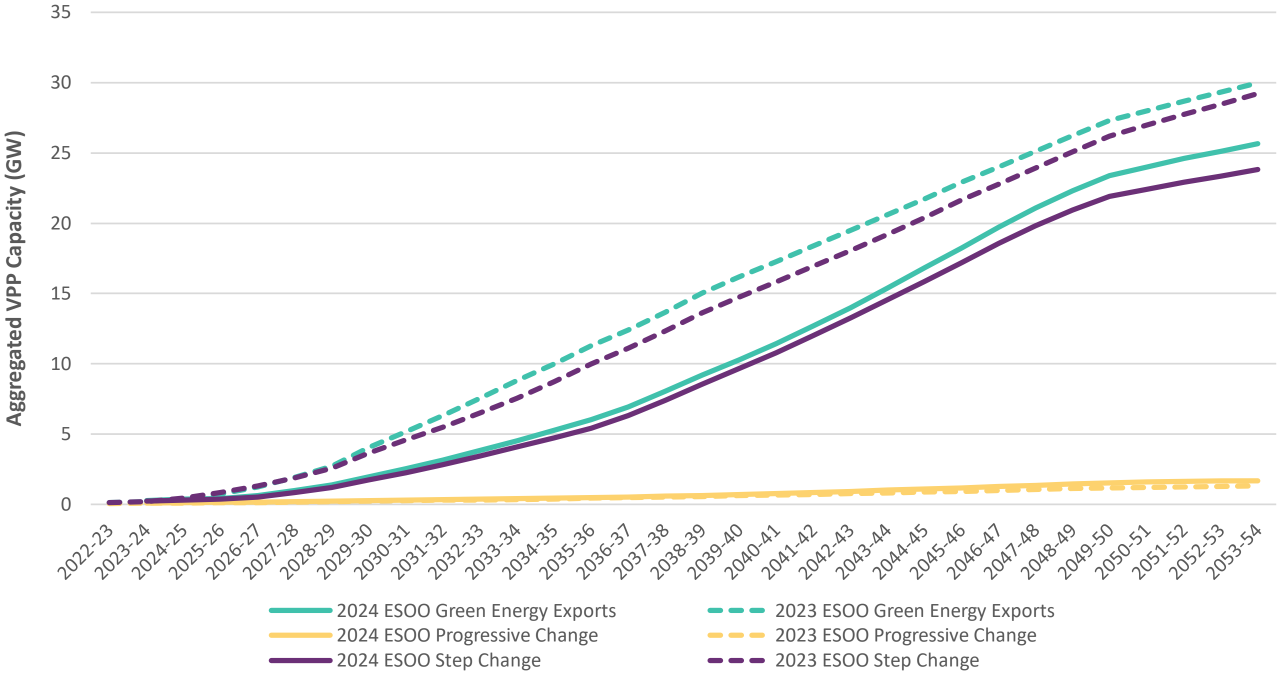
Overall, AEMO has retained the participation rate for VPPs (the proportion of battery owners signed up to VPPs) of the 2023 IASR. The downtick in distributed battery numbers passes through to a downtick in VPP capacity, as seen in Figure 15 below.

[31] See https://aemo.com.au/en/initiatives/major-programs/wa-der-program/project-symphony.

[32] See https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge.

[33] See https://www.aemc.gov.au/news-centre/data-portal/retail-energy-competition-review-2020/vpp-offers-available.

Figure 15 Aggregation trajectories for VPP forecasts, 2022-23 to 2053-54



2.2.3 Economic and population forecasts

Input vintage	**Updated** in June 2024
Source	Deloitte Access Economics (DAE)
Updates since 2023 IASR	Updated forecasts developed in 2024

AEMO engaged Deloitte Access Economics (**DAE**) to develop long-term economic forecasts for each Australian state and territory as a key input to AEMO's demand forecasts. DAE projects three scenarios in alignment with the 2023 IASR[34] and the 2024 ISP[35]. The scenarios capture a range of assumptions and economic outcomes including the pace of population and economic growth, pace of decarbonisation, and climate change.

Economic growth

In the near term, economic growth in NEM regions slows across all scenarios due to the lagged effect of tight monetary policy, cost of living challenges, and weakness in dwelling construction activity. As demand and supply in the economy move towards a better balance, monetary policy is projected to ease, and economic growth is expected to accelerate. Long-term economic growth is driven by a combination of factors including population growth, labour force participation, labour productivity, and capital intensity.

Population growth was strong following the pandemic, led by high net overseas migration. Population growth is forecast to decline from post-pandemic highs but will remain elevated in the medium term. Stronger population growth is expected in

[34] See https://aemo.com.au/en/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

[35] At https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp.

New South Wales, Victoria, and Queensland, with more moderate population growth expected South Australia and Tasmania. In the long run, population growth across the NEM is expected to decline, largely due to a declining fertility rate.

Labour productivity growth is expected to remain relatively stable in the long run. Climate change risks will potentially drag the labour productivity growth rate lower over the longer term.

Labour force participation is expected to gradually decline as the population ages, especially in Tasmania and South Australia.

Industry

Mining activity is expected to remain weak in the near term as subdued global economic activity weighs on exports. However, the near-term outlook for Australian coal exports is bolstered by strong demand from India, which predominantly benefits Queensland in which mining is the largest single industry.

The manufacturing industry has continued its downward trend of the past several decades in 2023 and is expected to remain weak as long running structural challenges, such as international competition and high labour costs, constrain growth. In the short term, growth in the construction industry is expected to be modest due to capacity constraints. Strong underlying drivers, including population growth and an eventual unwinding of capacity pressures, will see growth rebound in the medium to long term.

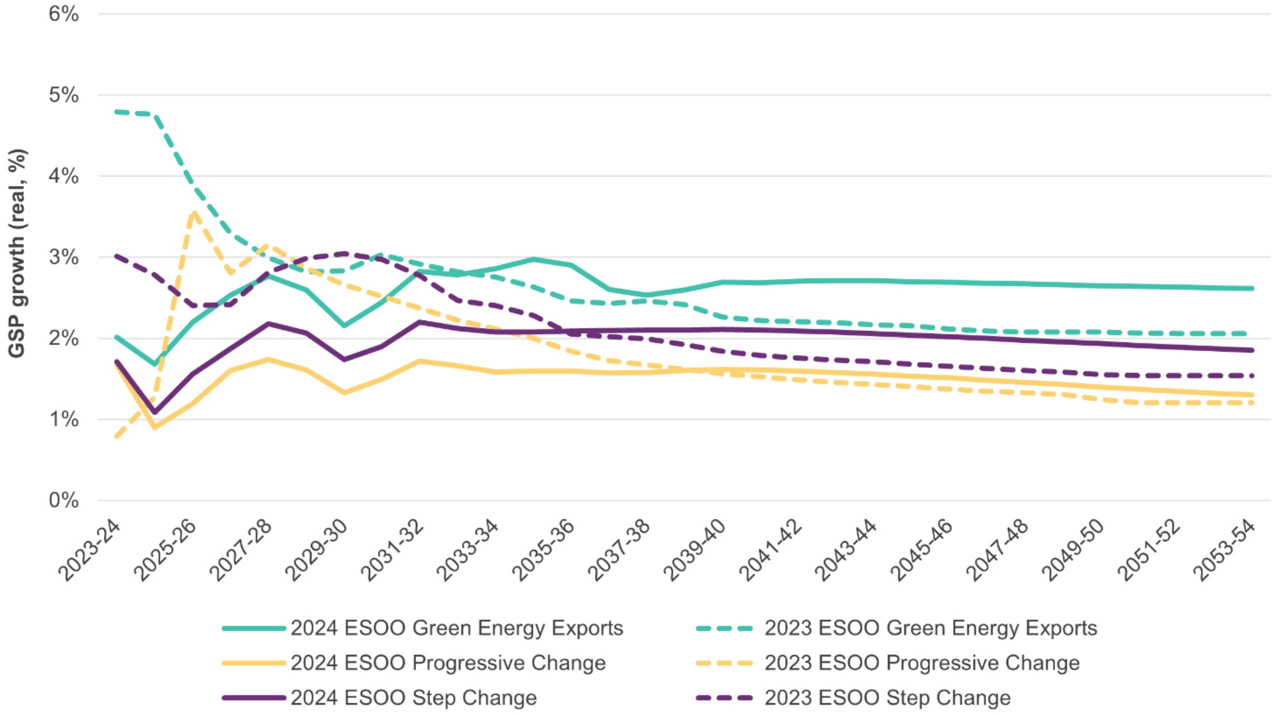
Service industries activity has softened in line with a slowdown in consumer spending. In the near term, growth is expected to remain weak due to weak consumer spending. In the long term, service industries are largely expected to outperform growth in the broader economy and benefit service-intensive states such as Victoria and New South Wales.

Figure 16 shows the 2024 forecasts of economic growth for gross state product (GSP) of the aggregated NEM regions in comparison to forecasts in 2023 ESOO[36]. It shows more modest forecast in short to mid run compared to the 2023 forecasts, reflecting the recent slowing national economy with elevated inflation and higher interest rates and the pressure on household spending. The economic growth is expected to gradually recover from mid 2020s when the tight monetary policy is expected to ease. The drop in GSP growth towards the end of 2030s is driven by a projected peak in the housing cycle around 2028-29, with a slight weakening afterwards, as dwelling investment is expected to increase over the next few years to catch up with the high migration and as supply chain pressures in the construction sector unwind. In the long run, growth in GSP will stabilise with a slight declining trend in line with moderating population growth and labour force participation. The 2024 forecasts predict higher long-term GSP growth compared to the 2023 forecasts. High GSP growth is driven by higher projected population growth, reflecting the post-COVID population surge led by high net overseas migration[37].

[36] AEMO engaged Oxford Economics Australia to provide forecasts for GSP, population and other economic indicators for the 2023 ESOO. For detail see Oxford Economics Australia, Macroeconomic Projections Report, 2022, at https://www.oxfordeconomics.com/resource/australian-macroeconomic-energy-transition-scenarios/.

[37] Net overseas migration was a record high in 2022-2023, especially in some NEM states including New South Wales and Victoria, see Australian Bureau of Statistics (2023), National, state and territory population, June 2023, at https://www.abs.gov.au/statistics/people/population/national-state-and-territory-population/jun-2023.

Figure 16 NEM aggregated gross state product growth forecasts, 2023-24 to 2053-54



2.2.4 Households and connections forecasts

Input vintage	**Updated** in June 2024
Source	• ABS • Deloitte Access Economics (DAE) • AEMO meter database
Updates since 2023 IASR	Connections forecasts developed with latest connection numbers and updated population forecasts

AEMO's forecast of residential electricity consumption is driven by electricity connections growth.

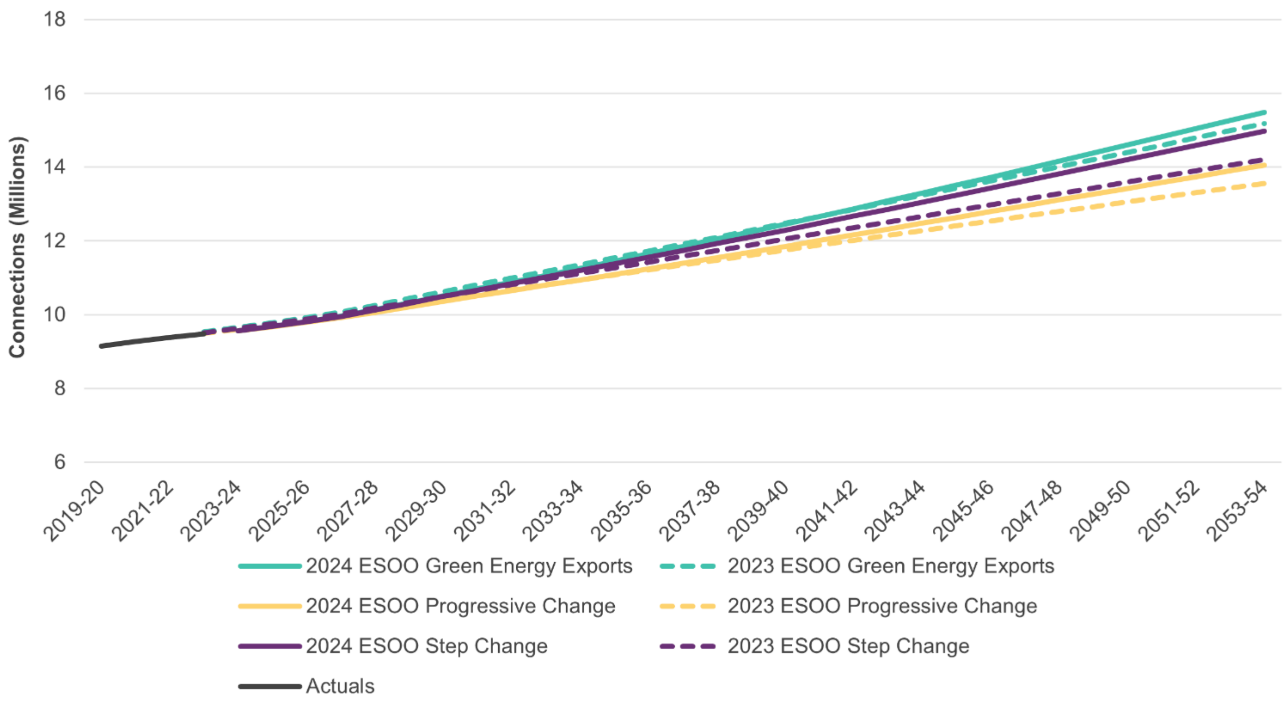
AEMO's 2024 connections forecast estimates the number of new residential electricity connections by combining existing dwelling stock informed by ABS and AEMO metering data with forecast dwelling completions (newly constructed dwellings) sourced from the DAE economic forecast to estimate the number of new connections expected over the forecast period.

AEMO's 2024 connections forecasts use the current number of connections in the NEM as the starting point. For the 2024 forecast, adjustments were made to the reporting of current connections, reducing the count of existing connections and lowering the starting total of connections to 9.5 million. A lower starting point combined with current low dwelling completions result in the 2024 dwelling forecast that estimates 63,000 fewer connections in 2024 than predicted in the 2023 connections forecast. The dwelling completion forecast provided by DAE also anticipates lower dwelling completion rates in the short term (3 to 5 years) before dwelling completions recover to an annual growth of about 1.5%. The reduction in growth in early years also reduces the spread between scenarios. The 2024 connection forecast under the *Step Change* scenario anticipates that there will be 15 million connections by 2054, approximately 800,000 more than forecast in the 2023 forecast. These additional dwellings are backed by a higher population forecast in the longer term, compared to the 2023 IASR.

The distribution of new connections is different between regions across the NEM, with increased connections in New South Wales, Victoria and Queensland and reduced activity in the Australian Capital Territory, South Australia and Tasmania compared to the 2023 forecasts.

Figure 17 shows the residential connections actual and forecast for all scenarios.

Figure 17 NEM residential connections actuals and forecasts, 2019-20 to 2053-54



2.2.5 Large industrial loads

Input vintage	**Updated** in June 2024
Source	• Interviews/surveys with LILs including self-reported forecasts until 2043- 44. • Historical consumption from the AEMO meter database • Distribution network service providers (DNSPs) • Media search/announcements
Updates since 2023 IASR	Updated based on new survey data provided by large customers.

AEMO segments and forecasts LILs separately to small and medium commercial enterprises, as the broader econometric model used to forecast other business customers may not provide appropriate accuracy for these larger industrials that have more unique circumstances to the remainder of business customers.

AEMO identifies LILs by analysing AEMO's meter data and working with transmission and distribution network operators for each region to cross-reference loads where demand exceeds at least 10 MW for greater than 10% of the latest financial year. This threshold aims to capture the most energy-intensive consumers in each region.

Loads are analysed on a site basis, not on a meter basis. A larger site could use several meters, which AEMO may identify over a period of time. AEMO adjusts the sites considered in the LIL forecasts, as additional meter information for a particular site becomes known.

AEMO currently sources information regarding LILs from:

- Surveys sent out to the LIL customers.
- Interviews conducted with a subset of LIL consumers when clarification of the survey response is needed. Follow up interviews are commonplace for larger industrial facilities that exceed 100 gigawatt hours (GWh) per annum, or where AEMO seeks clarification on the facility's future plans.
- AEMO's standing information requests from distribution and transmission network service providers (DNSPs and TNSPs) regarding prospective and newly connecting loads.
- AEMO's metering data for transmission and distribution connected NMIs associated with the LILs.
- Media searches and company announcements.

AEMO's 2024 LIL forecast is higher than in the 2023 IASR, due to the reallocation of about 60 sites from the Business Mass Market (BMM) sector to the LIL sector. The increased LIL consumption resulting from the reallocation is counterbalanced by a lower BMM forecast.

- About half of the newly reallocated LILs are data centres which have a large growth potential. In the 2024 *Step Change* scenario, data centres are the fastest growing segment within LILs. Committed and existing data centres are forecast to consume almost 5 TWh per year by the early 2040s.
- More prospective[38] data centres loads were included in the 2024 *Accelerated Data Centre Growth* sensitivity that showed an increase of more than 10 TWh of annual consumption in this market segment alone by the 2040s.
- The loads that were classified as LIL in the 2023 ESOO show a slight decrease in the forecast due to lower desalination water orders in the short term and production downgrades in mining and manufacturing in the longer term.

Similar to the 2024 *Step Change* scenario, the alternative scenarios are higher compared to the 2023 ESOO, due to the reallocation of sites from the BMM to the LIL sector, compensated by slight downgrades in mining and manufacturing. The 2024 *Progressive Change* scenario also forecasts a lower risk of closures for some LILs in the short term (2022-26).

The LIL consumption forecast for all scenarios is shown in Figure 18.

[38] The sensitivity was informed by the 2024 Standing Information Request responses received from NSPs and other industry engagement on data centre application enquiries and non-committed loads.

Figure 18 NEM LIL consumption actuals and forecasts, 2015-16 to 2053-54 (TWh)

Note: Actuals data is higher in 2024 data because of the reclassification of around 60 sites from the BMM to the LIL sector.

2.2.6 Liquified natural gas (LNG)

Input vintage	**Updated** in June 2024
Source	2024 GSOO surveys
Updates since 2023 IASR	Revised data from 2024 GSOO surveys

Queensland's LNG industry represents a substantial NEM load, consuming approximately 5% of AEMO's total business consumption category in the NEM in 2024-25. Due to their significance, AEMO forecasts LNG loads separately for improved transparency.

Figure 19 shows the forecast for LNG electricity consumption applied to the 2024 ESOO.

The LNG forecasts estimate the expected electricity consumption drawn from the NEM by operations of coal seam gas (CSG) fields, using data provided by the LNG consortia via the GSOO survey process. This data considers the anticipated operating range of CSG facilities over the short to medium term until 2034-35. Beyond then, the longer-term forecast is developed by extending the surveyed trend based on by scenario-dependent assumptions of global natural gas production and LNG demand, particularly in the Asia Pacific.

AEMO shaped the long-term trajectory of scenarios in LNG forecasts based on trends observed in the 2023 International Energy Agency (IEA) World Energy Outlook (WEO)[39], whereby:

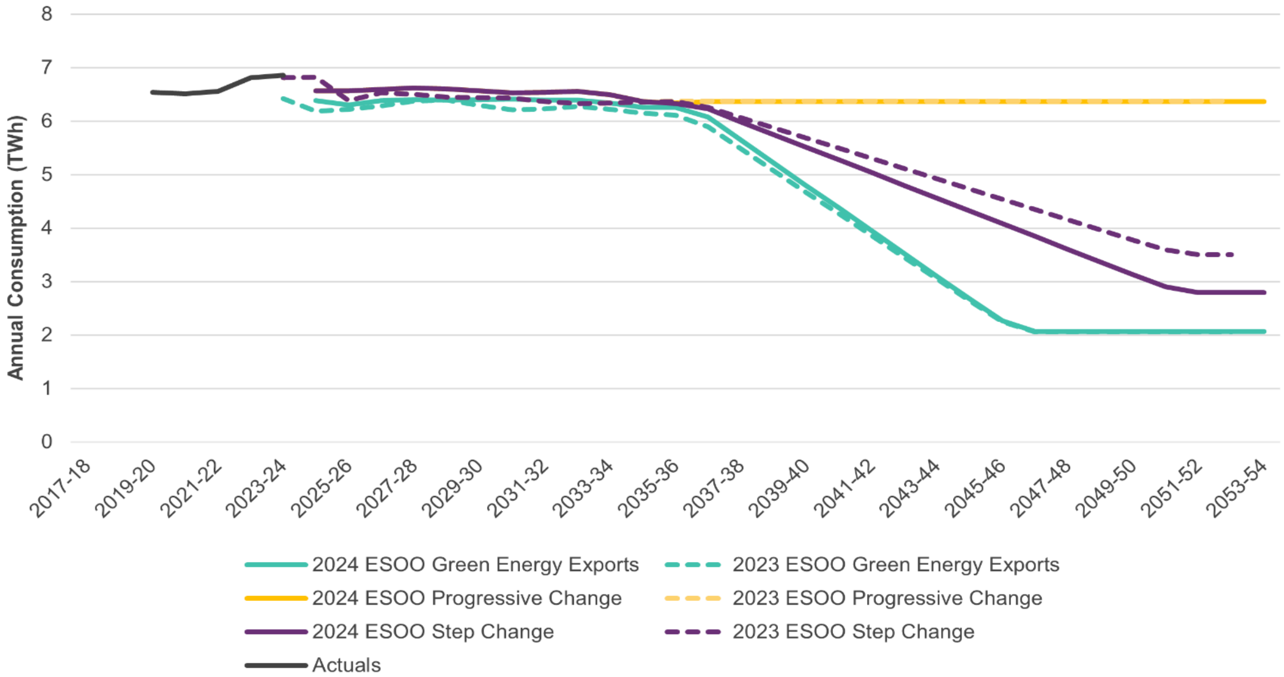
[39] Where possible, AEMO's LNG forecasts have been aligned with IEA forecasts of LNG export from Australia from the 2023 World Energy Outlook (see https://www.iea.org/reports/world-energy-outlook-2023).

- The *Progressive Change* scenario has been aligned to the IEA's Stated Policies Scenario (STEPS). Lower global economic growth and reduced action towards global decarbonisation means LNG continues to be a valued energy form and LNG export consumption stays flat post 2035.
- The *Green Energy Exports* scenario features the greatest level of global decarbonisation action to reduce energy sector emissions and assumes the Queensland LNG industry will consolidate to the equivalent of a single remaining LNG train by 2050.
- The *Step Change* scenario features a moderate level of global decarbonisation ambition. In this scenario, LNG export consumption falls between levels projected in the IEA's Announced Pledges Scenario (APS) and AEMO's *Green Energy Exports* scenario.

The international LNG market faces an uncertain near-term future, affected by geopolitical uncertainties in Europe and the Middle East, while large amounts of new liquefication capacity are forecast to come online from Qatar and United States by 2030, as the transition towards cleaner energy and focus on energy security are influenced by geographical locations. The degree of uncertainty regarding the future scale of LNG export demand is reflected by the spread in forecast LNG electricity consumption across AEMO's modelled scenarios.

The *Step Change* and *Green Energy Exports* scenarios are slightly higher in the short term than those forecast in the 2023 IASR, while the *Progressive Change* scenario remains the same.

Figure 19 LNG actuals and forecast electricity consumption, 2017-18 to 2053-54 (TWh)



2.2.7 Energy efficiency forecast

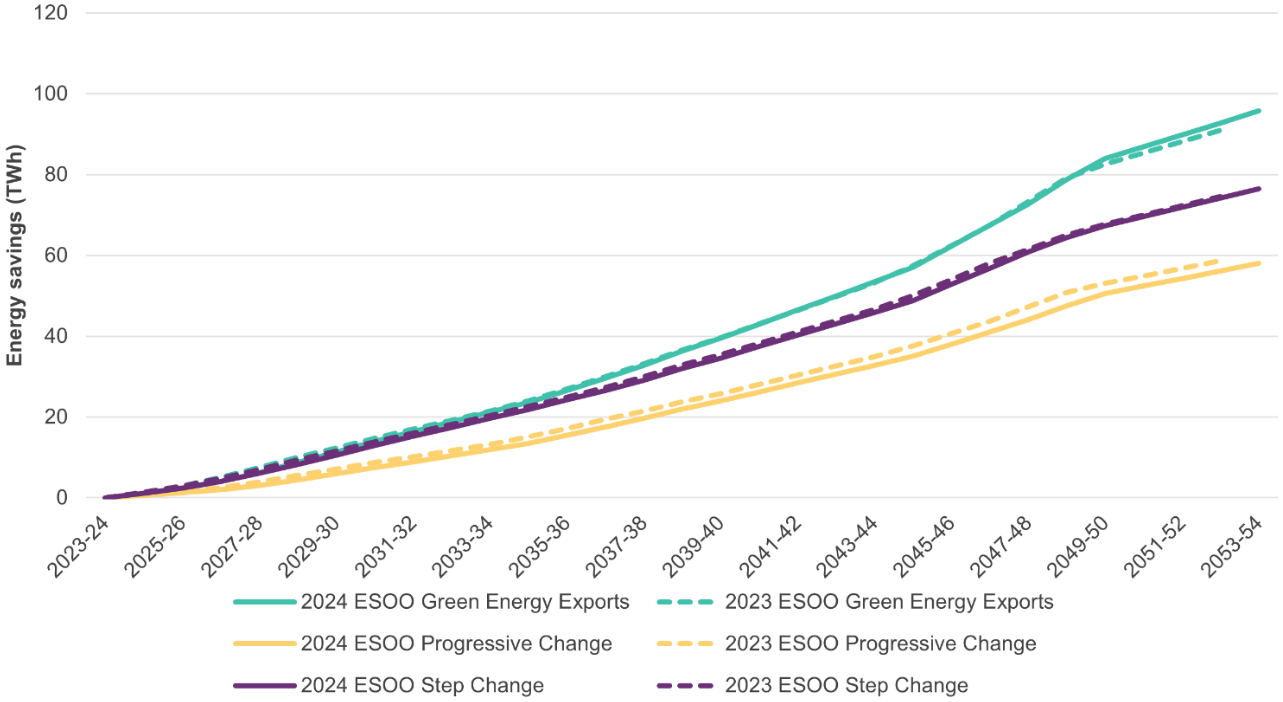
Input vintage	**Rebased** since the 2023 IASR
Source	Strategy Policy Research (SPR)
Updates since 2023 IASR	Energy efficiency forecasts have been rebased (base year of 2023-24).

Australia's governments have developed a range of measures to mandate or promote energy efficiency uptake across the economy. AEMO's energy efficiency forecasts have been developed for the 2023 IASR, with support from *Strategy Policy Research* and are influenced by the outcomes affecting economic, population, housing, and connections growth for each scenario. Policy differences across scenarios also inform energy efficiency forecasts for each scenario[40].

More information is available in Section 3.3.11 of the 2023 IASR.

Figure 20 shows the total energy efficiency applied as reductions to electricity consumption across the modelled scenarios. AEMO rebased these forecasts to reflect more recent estimates of actual consumption. *Step Change* and *Green Energy Exports* scenarios then revert to the 2023 forecast trend, with energy savings becoming effectively equivalent to the 2023 forecasts within approximately five years.

Figure 20 Energy efficiency savings forecasts, 2023-24 to 2053-54



2.2.8 Appliance uptake forecast

Input vintage	**Updated** in June 2024
Source	• Department of Industry, Science, Energy and Resources (DISER), 2021 Residential Baseline Study for Australia and New Zealand for 2000 – 2040, available at www.energyrating.gov.au • Economic forecast - Deloitte Access Economics (see Section 2.2.3)
Updates since 2023 IASR	Appliance uptake forecasts have been rebased to a base year of 2023-24. Economic forecast inputs for Household Disposable Income and population updated.

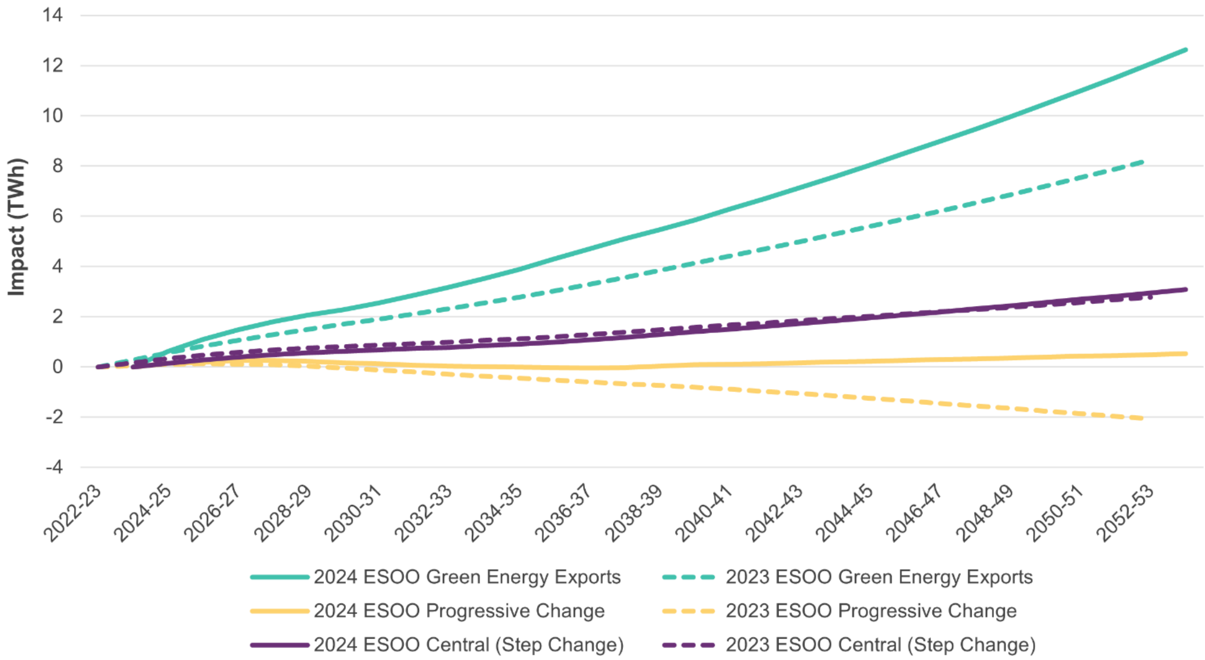
[40] AEMO removes the future savings from activities that took place prior to the base year of the forecasts. For more information, see the *Electricity Demand Forecasting Methodology* information paper, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach/forecasting-and-planning-guidelines

Electricity consumption forecasts consider policies and programs that induce fuel-switching behaviour (between electricity and natural gas) through the energy efficiency forecasts and the residential sector's forecast of appliance growth. The appliance uptake forecasts specifically exclude the impact of fuel-switching from gas to electric devices. See Section 2.2.1 for more information on electrification forecasts.

As part of the 2023 IASR, AEMO used appliance data from the former Federal Government Department of the Environment and Energy (now the Department of Climate Change, Energy, the Environment and Water [DCCEEW]) to forecast the growth in appliances per connection in the residential sector. The data allowed AEMO to estimate changes to the level of energy services supplied by electricity per households across the NEM. Energy services here is a measure based on the number of appliances per appliance category across the NEM, their usage hours, and their capacity and size (see Appendix A5 of AEMO's *Electricity Demand Forecasting Methodology*[41] for details on the methodology used).

The 2024 appliance uptake forecast (see Figure 21) has been rebased since the 2023 IASR and includes updated Household Disposable Income (HDI) and population growth forecasts. For the 2024 *Step Change* scenario, appliance uptake largely resembles the 2023 forecast with minimal variation over the outlook. However, the relativity[42] between scenarios has changed since 2023, informed by economic drivers such as HDI and population growth. For example, compared to 2024 *Step Change*, households are forecast to have markedly higher disposable incomes in the 2024 *Green Energy Exports* scenario, leading to forecast greater spending on appliances, increasing electricity consumption.

Figure 21 Residential appliance uptake forecasts, 2022-23 to 2053-54 (TWh)



Note: Change relative to base year (2023-24)

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

[42] Dispersion across the scenarios is derived by applying a per capita HDI index to the scenarios, relative to a moderate or central scenario (also detailed in Appendix A5 of AEMO's *Electricity Demand Forecasting Methodology*).

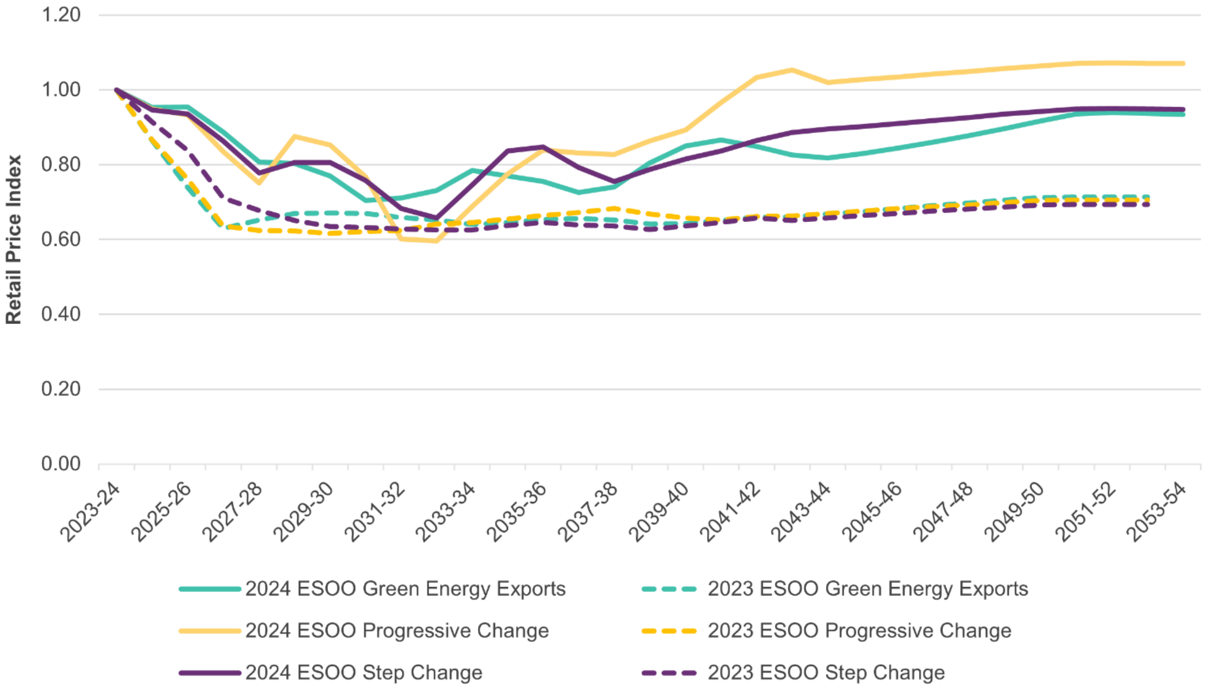
2.2.9 Electricity price indices

Input vintage	**Updated** in June 2024
Source	• AEMO internal wholesale price forecasts. • Transmission costs from the 2024 ISP's optimal development path[43] • ASX Energy Electricity Futures • AER Determinations and Access Arrangements[44]. • Australian Energy Market Commission (AEMC) annual Residential Electricity Price Trends report, 2021 forecasts[45] (not updated in this report). • Australian Competition and Consumer Commission (ACCC) Inquiry into the National Electricity Market report - November 2022[46] (not updated in this report)
Updates since 2023 IASR	Retail price forecasts have been updated with components from the latest available AER pricing proposals and transmission determinations, AEMO 2024 wholesale price forecasts, and transmission costs associated with the 2024 ISP.

Electricity prices are assumed to influence consumption through short-term behavioural changes (such as how electricity devices are used or energy consumption is managed), and longer-term structural changes (such as decisions to invest in CER).

Figure 22 shows the retail price index assumed in 2024 for the *Step Change*, *Progressive Change*, and *Green Energy Exports* scenarios.

Figure 22 NEM Residential retail price index forecasts, 2023-24 to 2053-54



Note: Price weighted by household consumption per region.

[43] See https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp.

[44] At https://www.aer.gov.au/industry/registers/determinations.

[45] At https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2021.

[46] At https://www.accc.gov.au/about-us/publications/serial-publications/inquiry-into-the-national-electricity-market-2018-25-reports/inquiry-into-the-national-electricity-market-report-november-2022.

Prices are projected to fall until the early 2030s as significantly more low-cost renewable energy generation is expected to come online. Some price volatility is expected in the mid-2030s as traditional thermal generation is phased out and replaced by renewables with firming from utility-scale battery storage. Modest increases in wholesale prices in the 2040s are projected due to the increased penetration of flexible gas power generation. Gradual increases in network charges from the 2040s follow transmission investment to support the ISP's optimal development path for each scenario.

The difference in residential retail price trajectories between scenarios represents a differing pace and pathway of decarbonisation, including the shift to renewables and the transformation of the transmission and distribution networks.

The retail price forecasts are formed from bottom-up projections of the various components of retail prices. Table 10 shows the high-level mapping of the various price components used, and their incorporation into the 2024 scenarios.

Table 10 High-level mapping of price input settings by scenario

Scenario	*Progressive Change*	*Step Change*	*Green Energy Exports*
Wholesale component	**Short term** (up to FYE2027): Blend of ASX Futures and 2024 ISP *Progressive Change* **Longer term** (FYE2028 onwards): Solely based on Final ISP wholesale price forecast.	**Short term** (up to FYE2027): Blend of ASX Futures and 2024 ISP *Step Change*. **Longer term** (FYE2028 onwards): Solely based on Final ISP wholesale price forecast.	**Short term** (up to FYE2027): Blend of ASX Futures and 2024 ISP *Green Energy Exports*. **Longer term** (FYE2028 onwards): Solely based on Final ISP wholesale price forecast.
Transmission costs	**Short term** (up to FYE 2029): AER pricing proposals and determinations actuals (latest available). **Longer term** (FYE 2030 onwards): Forecast charges based on forecast transmission network augmentations per the 2024 ISP *Progressive Change* scenario.	**Short term** (up to FYE 2029): AER pricing proposals and determinations actuals (latest available). **Longer term** (FYE 2030 onwards): Forecast charges based on forecast transmission network augmentations per the 2024 ISP *Step Change* scenario.	**Short term** (up to FYE 2029): AER pricing proposals and determinations actuals (latest available). **Longer term** (FYE 2030 onwards): Forecast charges based on forecast transmission network augmentations per the 2024 ISP *Green Energy Exports* scenario.
Distribution costs	**Short term** (up to FYE 2029): AER pricing proposals and determinations actuals (latest available). **Longer term** (FYE 2030 onwards): Same growth trajectory as transmission costs.	**Short term** (up to FYE 2029): AER pricing proposals and determinations actuals (latest available). **Longer term** (FYE 2030 onwards): Same growth trajectory as transmission costs.	**Short term** (up to FYE 2029): AER pricing proposals and determinations actuals (latest available). **Longer term** (FYE 2030 onwards): Same growth trajectory as transmission costs.
Environmental costs	AEMC (2021) to FYE2024 then decline to zero by FYE2030.	AEMC (2021) to FYE2024 then decline to zero by FYE2030.	AEMC (2021) to FYE2024 then decline to zero by FYE2030.
Retail component	ACCC (2022) derived residual.	ACCC (2022) derived residual.	ACCC (2022) derived residual.

Consumption forecasts consider the price elasticity of demand; that is, the percentage change in demand for a given change in price. The underlying price elasticity of demand that is used to give effect to the price indices and influence the consumption forecasts is as per the 2023 IASR.

Table 11 below provides the price elasticities of demand adopted across the modelled scenarios, where negative values indicate a reduction in consumption resulting from a price increase.

Table 11 Price elasticities of demand for various appliances and sectors.

Scenario	*Progressive Change*	*Step Change*	*Green Energy Exports*
Residential: Baseload appliances	0	0	0
Residential: weather-sensitive appliances	-0.10	-0.10	-0.10
Business: all load components	-0.10	-0.10	-0.05

2.2.10 Demand side participation

Input vintage	**Updated** forecast in June 2024
Source	• Historical meter data analysis and information submitted to the demand side participation (DSP) Information Portal in April 2024 • Information about policy-driven programs
Updates since 2023 IASR	New South Wales Peak Demand Reduction Scheme (PDRS) is included in all scenarios as it is considered formally committed[47]
Update process	Forecast DSP will be updated based on information submitted to the DSP Information Portal in April 2024 and historical meter data analysis

AEMO's forecast approach considers DSP explicitly in its market modelling, meaning that demand forecasts reflect what demand would be in the absence of DSP to avoid double-counting. The forecast for DSP in the upcoming year is produced following AEMO's Demand Side Participation Forecast Methodology[48].

The reliability response estimate is a key input to the ESOO, showing the maximum estimated demand reduction possible to avoid USE during lack of reserve (LOR) conditions. For all regions except New South Wales, the static DSP forecasts for the upcoming year have been used for the whole horizon of the ESOO for all scenarios, as no other data source is available to provide a reference for future trends in DSP growth or decline.

The NSW Peak Demand Reduction Scheme (PDRS) is now a committed scheme and will create a financial incentive to reduce electricity consumption during peak times in New South Wales[49]. The scheme is included in all scenarios, starting in 2024-25 with the target growing to nearly 6% of the forecast peak demand by 2031-32, thereafter declining. The scheme will, in its current design, provide additional DSP during summer only. The scheme considers that 25% of the PDRS target will be delivered through energy efficiency and battery storage initiatives, which are accounted for separately in AEMO's forecast components. Accordingly, the growth in DSP is scaled down to match its anticipated effects excluding these additional components.

Figure 23 below shows the PDRS and DSP targets for the *Step Change* scenario (excluding the assumed contribution from energy efficiency and battery storage). The data is consistent with the ESOO 2024.

For longer-term planning studies, such as the ISP, AEMO uses different scenario-specific projections out to a longer-term horizon to account for DSP resources that may be developed consistent with the defined scenario settings.

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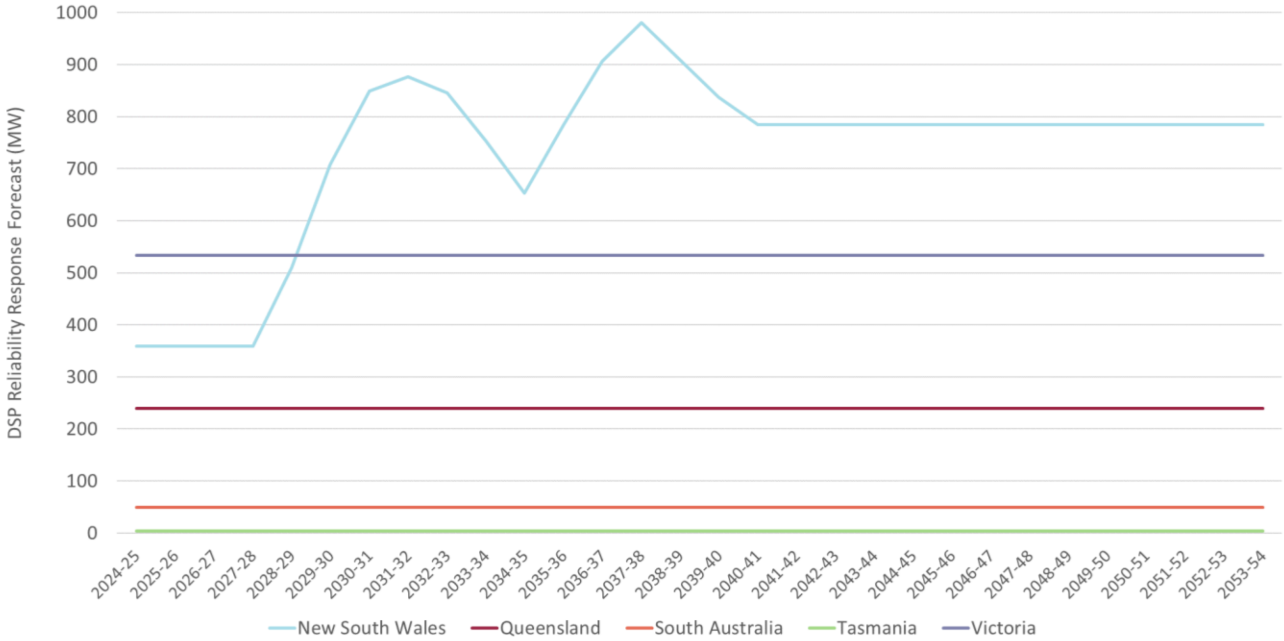
[47] At https://www.energy.nsw.gov.au/government-and-regulation/energy-security-safeguard/peak-demand-reduction-scheme.

[48] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/demand-side-participation/final/demand-side-participation-forecast-methodology.pdf.

[49] This is for the New South Wales state only. The NEM region of New South Wales also includes the Australian Capital Territory, so adjustments have been made to ensure the target reflects the New South Wales state demand only.

Figure 23 Forecast DSP for each NEM region, Summer, 2024-25 to 2053-2054, Step Change scenario only



2.2.11 Hydrogen electrolysers

Input vintage	**Updated** forecast in June 2024
Source	• Latest project listing from HyResource website (CSIRO)[50] • Government policy (New South Wales)
Updates since 2023 IASR	New South Wales Renewable Fuel Scheme and South Australian Hydrogen Jobs Plan assumptions updated

Hydrogen production is an emerging consumer of electricity, with the scale and timing of production a key uncertainty. Compared to the 2023 ESOO, forecast hydrogen consumption in 2033-34 has remained largely unchanged. However, consumption in the shorter term has decreased, due to:

- Slower than expected progress in developing hydrogen projects to Financial Investment Decision (FID) stage.
- Modified assumptions for the New South Wales legislated Renewable Fuels Scheme policy, whose commencement has been adjusted and for which consultation is underway. The consultation considers, among other things, a potential expansion to cover other renewable gases.
- Adjustments to the assumed utilisation factor for the South Australian Hydrogen Jobs Plan electrolyser, to reflect Draft ISP outcomes.

The hydrogen forecasts are summarised in the following plots, and details are provided in the 2024 *Forecasting Assumptions Update Workbook*.

[50] At https://research.csiro.au/hyresource/projects/.

Figure 24 Electricity consumption for domestic hydrogen production, 2023-24 to 2053-54, all scenarios (TWh)

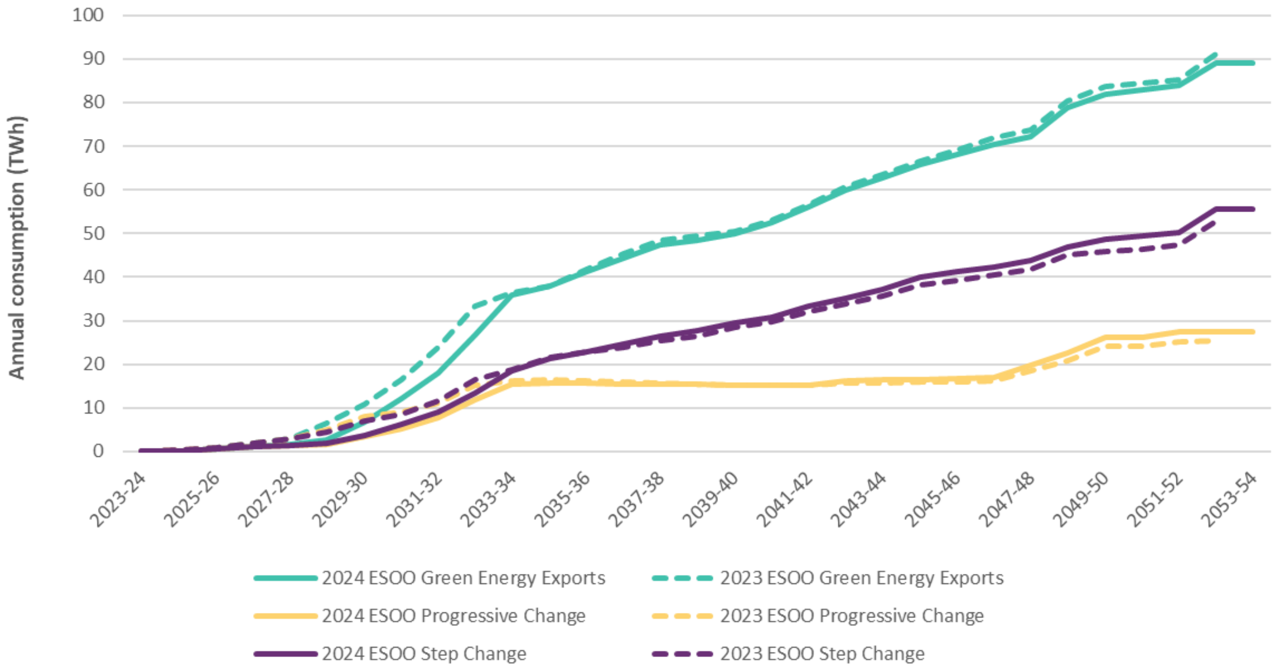
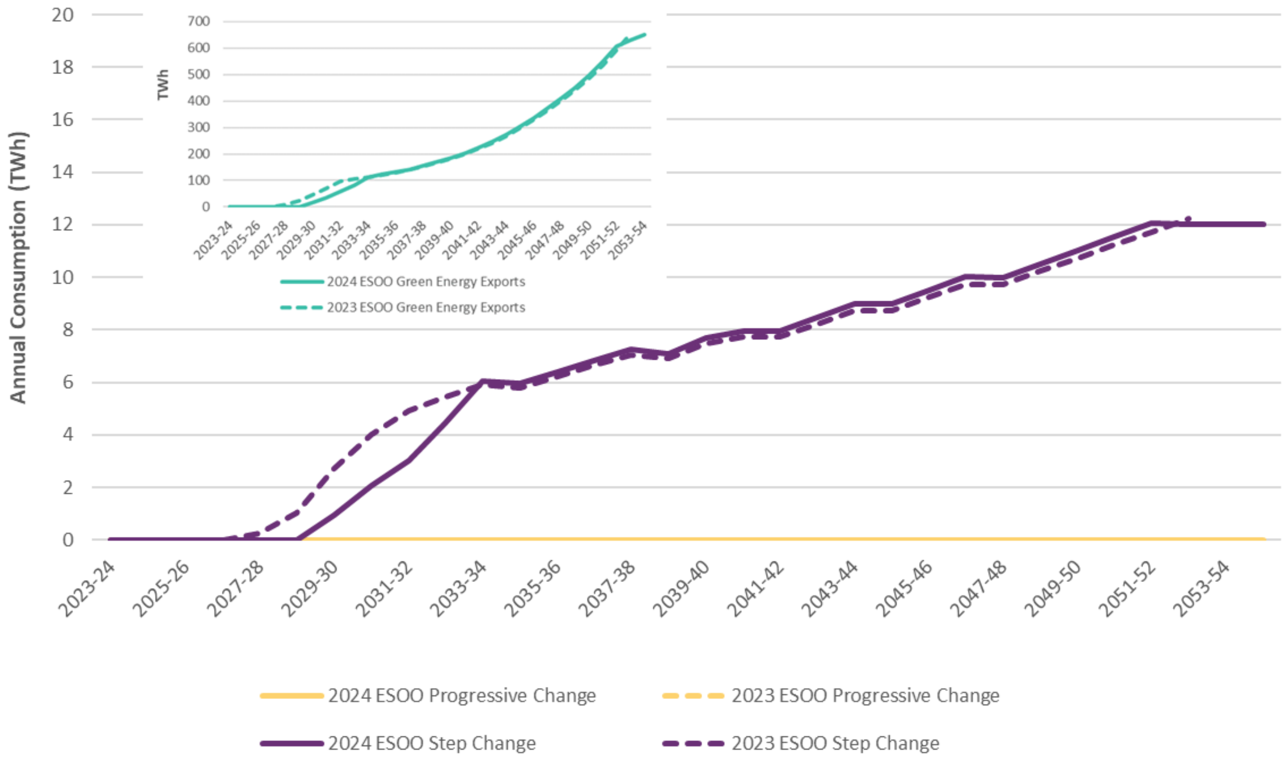


Figure 25 Electricity consumption for green steel and export hydrogen, 2023-24 to 2053-54, all scenarios (TWh) – inset shows *Green Energy Exports* only



2.3 Existing generators and transmission

AEMO uses a range of data to describe the existing generators in its models. Some of this data is updated through established processes and documented methodologies, as outlined in Table 12 below.

Table 12 Status and update process for key inputs and assumptions for existing generation and transmission

Input	Input vintage	Sources and updates since 2023 IASR
Generation Information data	Updated in July 2024	• Updated based on NEM July 2024 Generation Information published on AEMO's Generation Information website[A]. • This data is collected and published in accordance with the Generation Information Guidelines[B].
Marginal loss factors (MLFs), inter-regional loss flow equations, and loss proportion factors	Updated in April 2024	• Initial MLFs, loss equations, and proportioning factors are based on the MLFs for the 2024-25 Financial Year report[C]. • Loss flow equations and proportion factors are varied based on flow path augmentations, as outlined in the ISP Methodology[D].
Scheduled generator unplanned outage rates (UORs)	Updated in April 2024	• The outage data was updated based on historical and forward-looking UORs provided by registered participants in accordance with AEMO's Standing Information Request[E]. The data was collected in April 2024 and thus accounts for generator performance over the 2023-24 summer. • Based on the methodology outlined in the *ESOO and Reliability Forecast Methodology* [F] , AEMO calculated UORs for all scheduled generators. • The UORs were presented to the FRG in June 2024.
Unplanned outages affecting inter-regional power transfers	Updated in May 2024	• AEMO engaged with stakeholders through FRG consultation in June 2024 where the most recent interregional unplanned outage rates were presented.
Transmission network modelling	Updated in June 2024	• Updates to transmission project timing and constraint equations based on latest available information. Project timing updates are reported the NEM Transmission Augmentation Information Page June 2024[G].
Technology costs	Updated in May 2024	• Updated, based on GenCost 2023-24[H], which underpinned the 2024 ISP.

A. See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.
B. See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/final-generation-information-guidelines.pdf.
C. See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries.
D. See https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.
E. See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/standing-information-requests.
F. See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/esoo-and-reliability-forecast-methodology-document.pdf?la=en.
G. See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.
H. See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/2024-forecasting-assumptions-update-consultation-page/final-documents/csiro-gencost-2023-24-report.pdf?la=en.
J. See aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/aurecon-2022-cost-and-technical-parameter-review.pdf.

2.3.1 Generator unplanned outage rates

For the 2024 ESOO, AEMO collected outage information for existing scheduled generators including storage units, via an annual survey process, on the timing, duration, and de-rating of historical unplanned outages. This data is then used to forecast the full and partial unplanned outage rates[51] (UORs) for each financial year, for each generator over the ESOO horizon consistent with the *ESOO and Reliability Forecasting Methodology*. For small peaking plants and hydro generator

[51] Planned outages are not modelled in the ESOO, because these are assumed to be planned in lower demand periods or to shift if low reserve conditions were to occur, and therefore not impact USE outcomes.

technology types, technology aggregates are applied to individual stations. Where AEMO requested participants to provide outage rate projections, these projections were adopted in consultation with the station owners/operators.

Long duration unplanned outages

For the 2024 ESOO, AEMO models long duration unplanned outages (outages with a duration longer than five months) for each region and technology class, using the last 14 years of historical outage data, from 2010-11 to 2023-24, before calculating the forecast UOR.

The long duration outages used in 2024 ESOO modelling, and in other reliability assessments such as Medium Term Projected Assessment of System Adequacy (MT PASA) and Energy Adequacy Assessment Projection (EAAP) , are shown in Table 13.

Table 13 Existing generators – long duration outages

Fuel type/technology	Long duration outage rate (%)	Mean time to repair (hours)
All coal	0.91%	6,331
OCGT	0.73%	4,872
Hydro	0.17%	4,065
Other gas and liquids	0.54%	6,632

OCGT: Open cycle gas turbine.

Unplanned outage rate (equivalent) trajectories (excluding long duration outages)

The forecast equivalent full and partial UORs by technology for 2024-25, the first year of the forecast horizon period in the 2024 ESOO, are based on participant-provided information as shown in Table 14. Relative to the values used in the 2023 ESOO, the rates have generally increased for gas-fired and brown coal-fired generators but have reduced marginally for black coal-fired and hydro generators.

Table 14 Unplanned outage assumptions (excluding long duration outages) for 2024-25 financial year

	Eqvt. Full outage rate – 2024 ESOO (%)	Eqvt. Full outage rate – 2023 ESOO (%)	Change since 2023 ESOO (%)	Partial outage rate (%)	Partial derating (% of capacity)	Mean time to repair – Full (Hours)	Mean time to repair – Partial (Hours)
Brown coal	10.08	9.82	+0.26	15.45	17.39	92	37
Black coal QLD	8.66	9.98	-1.32	13.70	24.03	160	44
Black coal NSW	10.01	11.54	-1.53	27.08	17.67	136	28
OCGT	8.48	7.32	+0.95	2.42	9.86	57	130
Small peaking plant*	8.75	9.69	-0.94	0.35	28.29	201	323
Hydro	4.70	5.37	-0.67	1.06	13.30	51	436
CCGT + gas-fired steam turbines	6.87	5.29	+1.58	1.25	13.25	54	38
Battery	1.84	1.84	0.00	N/A	N/A	141	102

CCGT: Closed cycle gas turbine.
*Small peaking plants are generally classified as those less than 150 MW in capacity, or with a very low and erratic utilisation (such as Colongra and Bell Bay/Tamar peaking plant)

The 10-year projections for the equivalent full UOR[52] of all technology aggregates are shown in Figure 26, Figure 27 and Figure 28 with and without the effect of long duration outages. The annual equivalent UOR is affected by changes to assumed reliability and retirements of generators over the horizon. To protect the confidentiality of the individual station-level information used, UOR projections are provided for the next 10 years for technology aggregates. Due to the small number of coal plant in later years, all regions have been further aggregated to an 'All Coal' value to protection confidentiality.

Figure 26 Equivalent full UOR projections for coal-fired generation technologies

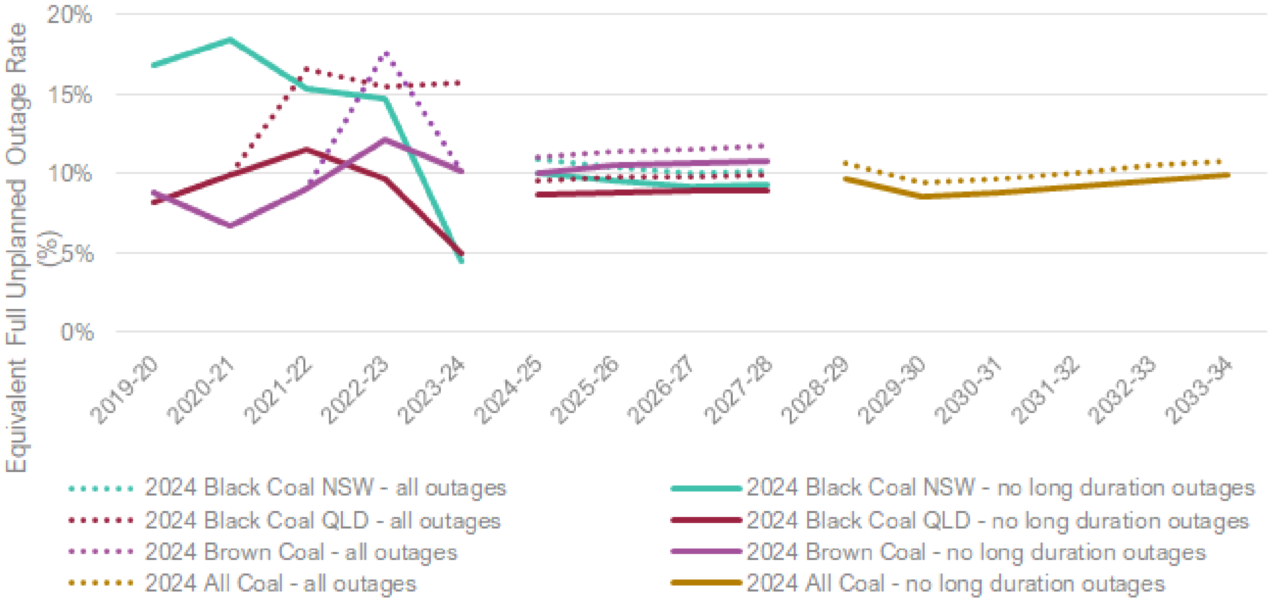
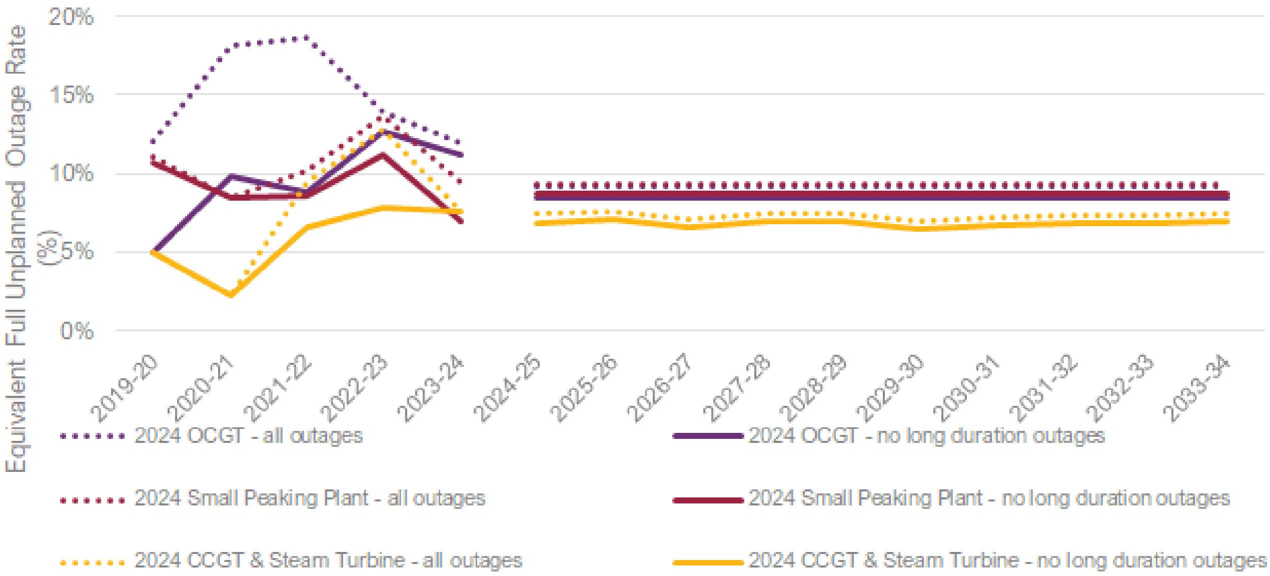
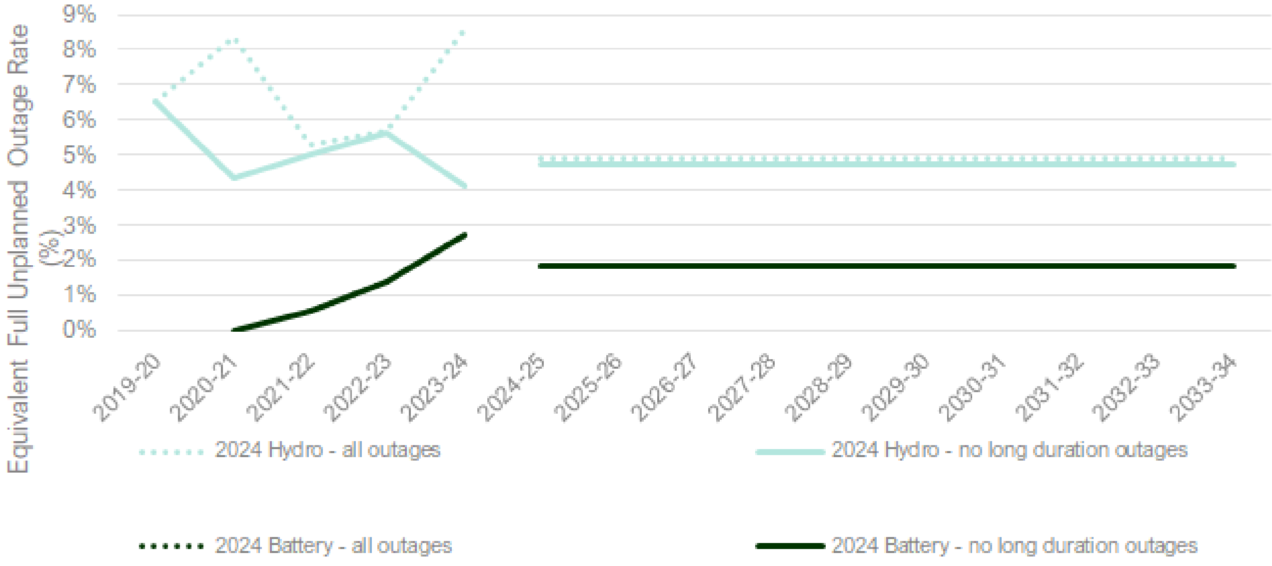


Figure 27 Equivalent full UOR projections for other generation technologies (gas)



[52] Where equivalent full UOR = Full unplanned outage + partial outage rate x average partial derating.

Figure 28 Equivalent full UOR for other generation technologies (battery and hydro)



Inter-regional transmission unplanned outage rates

Similar to generators, unplanned outage rates of inter-regional transmission elements are critical inputs for AEMO's reliability assessments. Information is collected on the timing, duration, and severity of the transmission outages to inform transmission forced outage rate forecasts. Table 15 shows the rates and method used in the 2024 ESOO. The selection of inter-regional flow paths is consistent with the updated ESOO and Reliability Forecast Methodology. The Mortlake to South East flow path unplanned outage rates have been revised to 0% post the commissioning of the second stage of Project Energy connect, this was revised after consultation feedback that was received on draft results in the June 2024 FRG as AEMO consider this flow path too immaterial to model based on current modelling and assumptions once PEC Stage 2 is completed.

Table 15 Inter-regional transmission flow path unplanned outage rates

Flow path	ESOO 2024 transmission UOR (%)	ESOO 2024 Mean time to repair (hours)	Outage rate method
Liddell – Bulli Creek (QNI) Credible Contingency	0.2	16	Annual static
Liddell – Bulli Creek (QNI) Reclassification	1.62	4	Annual static
Murraylink – Credible Contingency	1.37	72	Annual static
Basslink – Credible Contingency	5.27	192	Annual static
Mortlake – South East (VSA) Credible Contingency	0.03	2	Annual, set to 0% post commissioning of PEC stage 2
Mortlake – South East (VSA) Reclassification	0.01	5	Annual, set to 0% post commissioning of PEC stage 2

2.3.2 Technology build costs

Capital cost trajectories

AEMO's generator capital cost trajectories are informed by the GenCost publication series, an annual publication of electricity generation technology cost projections conducted jointly through a partnership between CSIRO and AEMO. To support this forecast, Aurecon provided estimates of the current capital cost of each generation technology (and supporting technical information). The GenCost projections use CSIRO's GALLM model, which produces capital cost forecasts that are a function of global and local technology deployment.

The build cost projections are given for three GenCost scenarios ("Global NZE by 2050", "Global NZE post 2050" and "Current policies"). These scenarios are described in greater detail in CSIRO's GenCost report[53]. AEMO maps the scenarios to the GenCost scenarios, as shown in Table 16. The scenario mapping of GenCost scenarios to the scenario collection reflects what AEMO considers the best fit to the narratives of AEMO's scenario collection.

Table 16 Mapping AEMO scenario themes to the GenCost scenarios

AEMO scenario	GenCost scenario	Explanation
Progressive Change	Current Policies*	Consistent with current commitments to the Paris Agreement, leading to the lowest global emissions reduction ambition and a 2.5°C warming future.
Step Change	GenCost Global NZE post 2050	Consistent with global action to limit temperature rises to less than 2°C, and with industrialised countries targeting net zero emissions by 2050.
Hydrogen Export	GenCost Global NZE by 2050**	The most ambitious global emissions reduction scenario, consistent with limiting temperature rises to less than 1.5°C.

* While *Progressive Change* does increase its emissions reduction ambition, achieving net zero emission domestically by 2050, the scenario also delays significant action to align with a higher warming future at a global scale and is not consistent with a "well below 2°" target.

Figure 29, Figure 30 and Figure 31 present a comparison of *GenCost 2022-23 Global NZE post 2050* compared to GenCost *2023-24 Global NZE Post 2050* build cost projections (excluding connection costs) for selected technologies.

53 At https://www.csiro.au/en/research/technology-space/energy/GenCost .

Figure 29 2023 Global NZE post 2050 vs 2024 Global NZE post 2050: build cost trajectories forecast for wind and solar

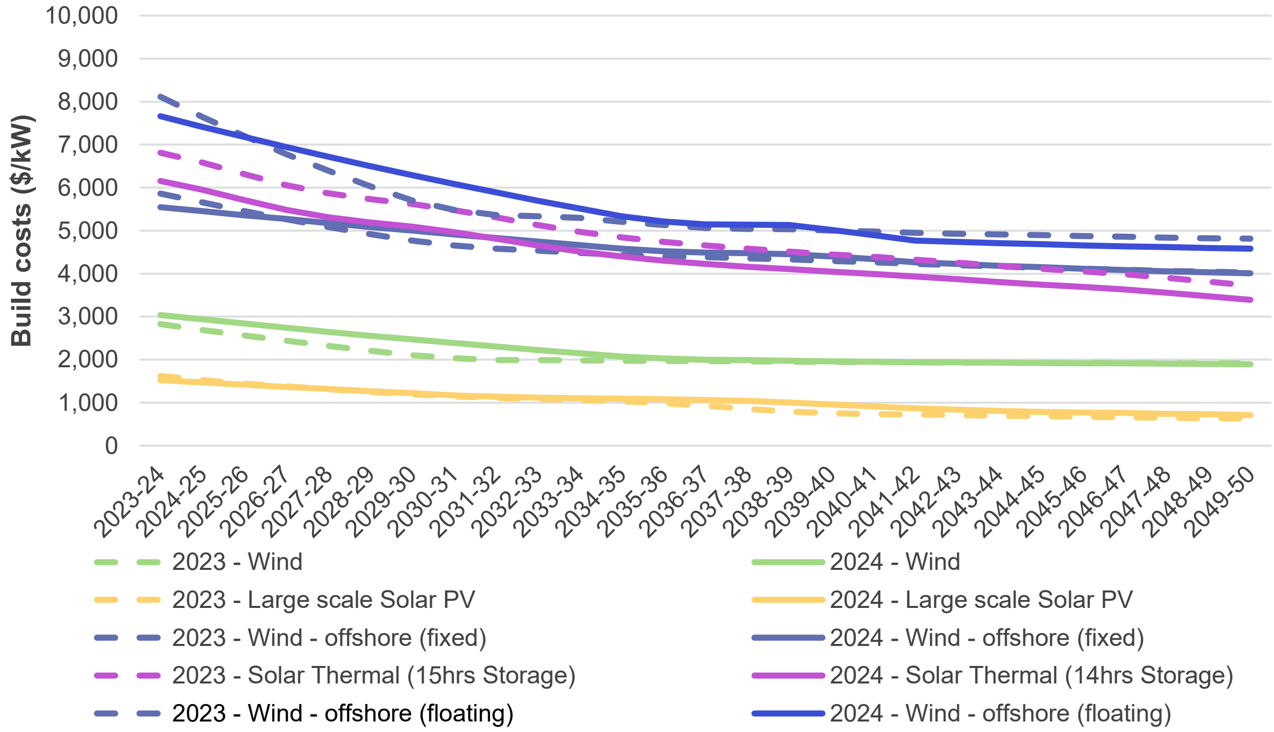


Figure 30 2023 Global NZE post 2050 vs 2024 Global NZE post 2050: build cost trajectories forecast for gas

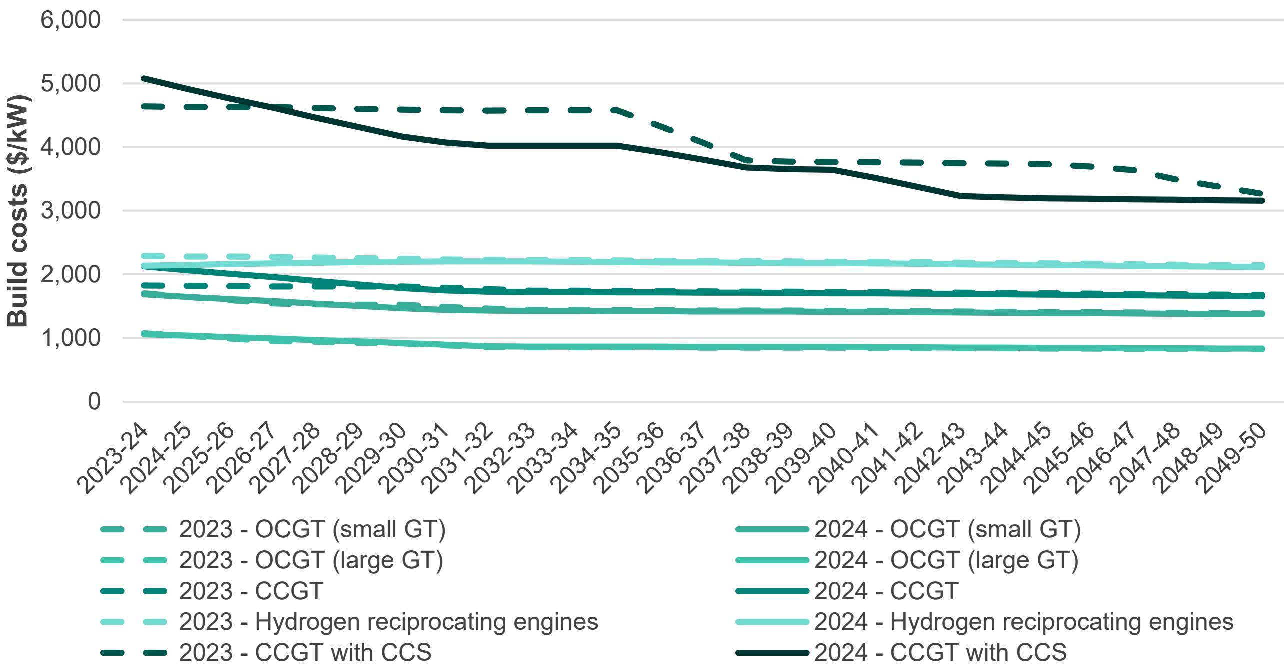
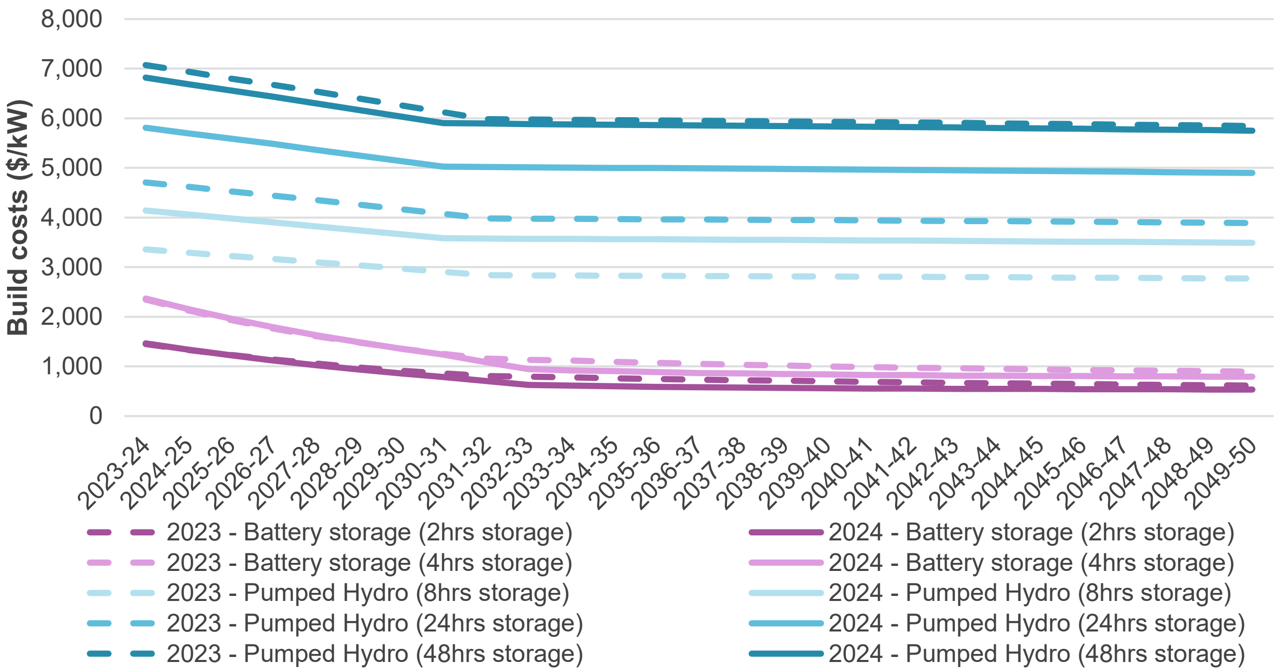


Figure 31 2023 Global NZE post 2050 vs 2024 Global NZE post 2050: build cost trajectories forecast for selected storage



2.4 Fuel price assumptions

Gas prices

Input vintage	**Updated** July 2023
Source	ACIL Allen Consulting
Updates since 2023 IASR	None

AEMO sourced updated natural gas price forecasts from ACIL Allen Consulting in July 2023. These gas prices were used for the 2024 GSOO report.

The gas price forecasts consider fundamental inputs including forecast gas production costs from existing and developing fields, reserves, gas network infrastructure and pipelines, in addition to international gas prices, oil prices and economic indicators. The forecasts also consider the influence of international prices on east coast gas prices through LNG netback pricing, the local level of competition, and the extent of exposure to spot market prices.

The effect of governmental domestic gas policy has also been included in these gas price forecasts. On the east coast gas market, the Australian Domestic Gas Supply Mechanism (ADGSM) reforms commenced 1 April 2023 and are designed to make the ADGSM more responsive to domestic gas shortfalls while protecting established long-term contracts. The existing Heads of Agreement with east coast gas exporters is in place until 1 January 2026. Further, the Federal Government's mandatory Code of Conduct (Code)[54] published in July 2023, enforces a reasonable pricing framework extending the gas price cap of $12/gigajoule (GJ) for wholesale gas contracts and non-urgent transactions (outside three days) at the Gas

[54] At https://www.dcceew.gov.au/energy/markets/gas-markets/gas-market-code.

Supply Hubs. Small producers (less than 100 petajoules [PJ] per year) supplying the domestic market are exempt from the pricing rules, while other producers can apply for conditional exemptions. The Code will be subject to a review commencing 1 July 2025.

Figure 32 compares industrial gas price forecasts at Melbourne across scenarios, and Figure 33 shows the pricing relationship between regions. Complete industrial gas price forecasts for all other regions and scenarios are provided in the accompanying *Forecasting Assumptions Update Workbook*. The industrial gas price forecasts assume that new gas production becomes available when required, and makes no assumptions around access to finance for new gas developments. They reflect the marginal cost for new wholesale gas supply in each region, excluding retail and distribution costs.

Figure 32 Forecast industrial gas prices by scenario – Melbourne, 2024 to 2054 ($AUD/GJ)

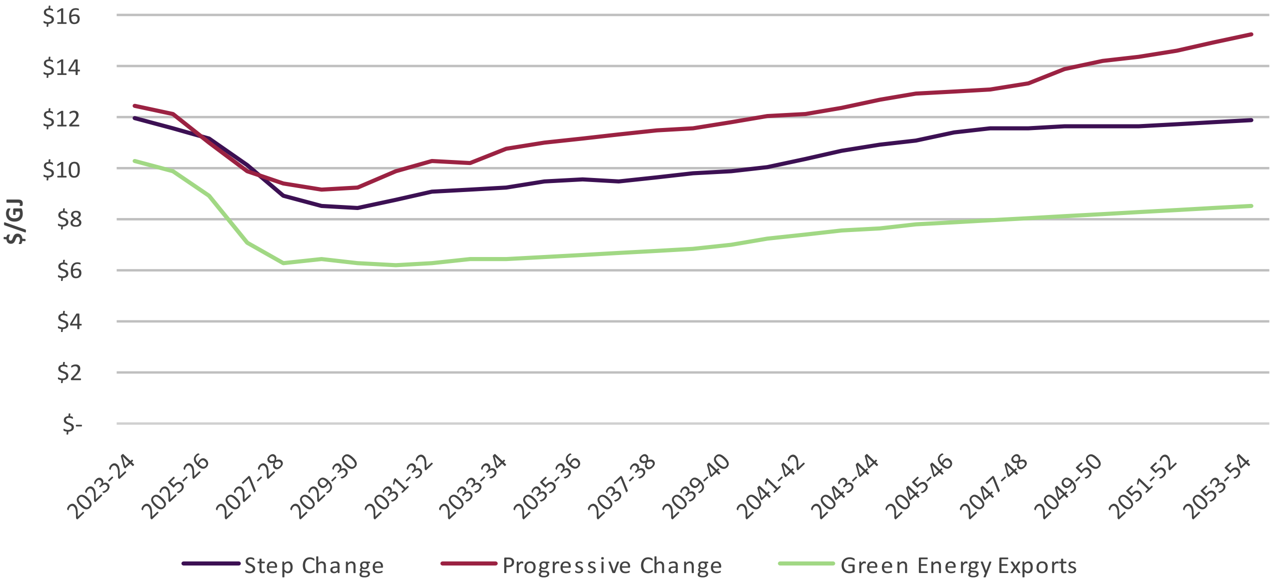
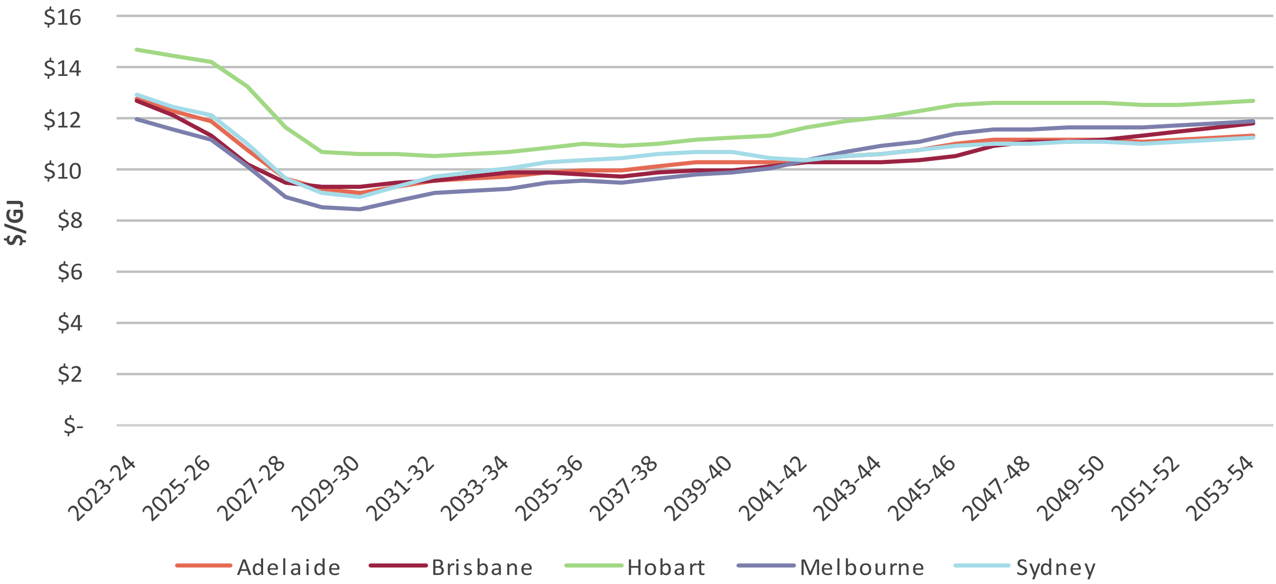


Figure 33 Forecast industrial gas prices by region – *Step Change*, 2024 to 2054 ($AUD/GJ)



The gas price projections all feature a high starting point, reflecting current global economic challenges, but remain close to $12/GJ, reflecting the impact of the Code and gas price cap. Gas prices are forecast to decline to a minimum in the late 2020s, largely driven by a forecast reduction in LNG netback prices[55]. In the long term, gas prices are forecast to increase due to the competing effects of reduced supply and higher production costs.

Overall, southern markets are forecast to experience higher prices compared to Brisbane due to weaker southern supply and increasing reliance on northern supply via the South-West Queensland Pipeline and Moomba to Sydney Pipeline to meet demand. Industrial prices reach a lower minimum in Melbourne in the late 2020s to early 2030s due to a faster rate of industrial demand reduction, and because of the approach taken by ACIL Allen to remove price premiums for supplying to seasonal loads for flatter industrial demand. Prices are highest in Tasmania due to additional transport costs.

Note that the beginning of winter 2024 has seen tight supply and demand conditions across the east coast gas market, driven by reduced production, cold weather, low variable renewable energy (VRE) availability, and high system and gas-fired generation demand. On 19 June 2024, AEMO issued an East Coast Gas System Risk or Threat Notice[56] for the first time. These market conditions have produced elevated gas prices above forecast but have not been reflected within this updated fuel price forecast . AEMO will update gas price forecasts for the 2025 GSOO.

Across scenarios, the spread in gas prices is attributable to scenario-dependent assumptions of gas demand, long-term underlying costs of supply, and international oil prices.

Gas prices associated with each gas-fired generator are also provided in the accompanying *Forecasting Assumptions Update Workbook*. The costs include regional pricing, considering the supply options and the relevant cost of pipeline transmission.

2.5 Transmission network modelling

Input vintage	**Updated** since the 2023 IASR
Source	• 2024 ISP • Transmission Augmentation Information Page[57] • Transmission Network Service Providers
Updates since 2023 IASR	Described below, and in the 2024 ESOO

Most of the transmission network modelling assumptions applied in the 2024 ESOO are consistent with those canvassed through the 2023 IASR and 2024 ISP. The following changes were made to reflect the most up to date information available:

- Updates to the committed and anticipated projects, including updated project scopes, timing and status consistent with the Transmission Augmentation Information Page and the advice from TNSPs or proponents responsible for the delivery and/or development of the project. Details are provided in the 2024 ESOO report.

[55] See https://www.accc.gov.au/inquiries-and-consultations/gas-inquiry-2017-30/lng-netback-price-series.

[56] See https://www.nemweb.com.au/Reports/CURRENT/ECGS/ECGS_Notices/Attachments/20240619180058%20-%20EAST%20COAST%20GAS%20SYSTEM%20RISK%20OR%20THREAT%20NOTICE%2019%20JUNE%202024.PDF.

[57] August updated to the Transmission Augmentation Information Page available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

- The actionable transmission network projects, including updated project scopes, timing and status consistent with the Transmission Augmentation Information Page and the advice from TNSPs or proponents responsible for the delivery of actionable projects. Details are provided in the 2024 ESOO report.
- Updates to proportioning factors for inter-regional losses for existing flow paths, to align with AEMO's marginal loss factor (MLF) publication for 2024-25. Details are provided in the 'Proportioning factors' tab of the Updated Assumptions Book.
- Updates to transmission constraint equations to reflect the latest constraints used in the NEM Dispatch Engine (NEMDE), and subsequent updates to forecast those constraints for the ESOO time horizon. The 2024 ESOO model provides the constraint equations used for the 2024 ESOO.