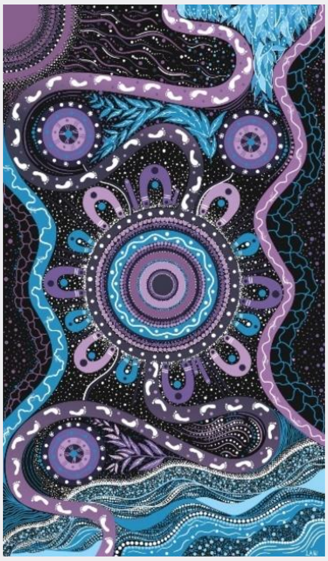
South Australian Electricity Report

December 2024

South Australian Advisory Functions



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

The purpose of this publication is to provide information to the South Australian Minister for Energy and Mining about South Australia's electricity supply and demand. While some historical price information is provided for completeness, this publication does not present any views on the effectiveness of price signals in the National Electricity Market.

AEMO publishes this South Australian Electricity Report in accordance with its additional advisory functions under section 50B of the National Electricity Law. This publication is based on information available to AEMO as at 1 October 2024, although AEMO has endeavoured to incorporate more recent information where practical (generation information specifically is based on AEMO's 31 October 2024 update).

Disclaimer

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Version control

Version	Release date	Changes
1	20/12/2024	Initial release

Executive summary

The *South Australian Electricity Report* (SAER) is an annual report providing key independent insights for the South Australian jurisdiction of the National Electricity Market (NEM) from a range of AEMO publications and studies.

Key historical observations reported in this SAER

- **Generation development dominated by wind and large-scale solar** – in 2023-24, the major grid connected capacity increases in South Australia came from wind (209 megawatts (MW)), with a smaller increase in large-scale solar (32 MW).
  - Wind farms again provided the largest source of electricity generated, contributing 6,330 gigawatt hours (GWh) and 45.2% of the total electricity generated (down from 46.9% last year).
  - While on a declining trend, gas-powered generation was the second highest contributor to electricity generated, with a 23.6% share (down from 25.4%).
  - Rooftop photovoltaics (PV) provided 18.3% of generation (up from 17.6%) with larger solar (including PV non-scheduled generation (PVNSG)) providing another 10.7% combined. If grouped together, solar technologies generated more than gas-powered generation in South Australia.
- After the unprecedented energy market conditions experienced in early 2022-23, **South Australia's average wholesale electricity price reduced by 40%** to average $79.53/megawatt hour (MWh) across 2023-24.
- **Minimum demand continued to decline due to continued growth in rooftop PV installations**, with operational demand (sent-out) reaching a then record low of -30 MW on Sunday 31 December 2023[1], when the combination of low weekend demand, mild weather with minimal cooling or heating needs, and solar insolation caused the lowest demand for grid-supplied electricity during the year.
- **Maximum operational demand[2]** occurred on Monday 23 January 2024, reaching 2,748 MW at 8:00 PM (Adelaide time). Despite seeing El Niño climate conditions, for the time since 2020, summer did not have any strong heatwaves with temperatures in the mid to high forties, which have commonly been observed in previous years.
- **Net imports from Victoria greatly increased** from 499 GWh in 2022-23 to 927 GWh in 2023-24 as energy exports decreased and energy imports increased from 2022-23 to 2023-24.
- Increased penetration of renewables, reduced gas generation and increased imports saw **total emissions and annual emissions intensity from South Australian generation continue to decline** again in 2023-24, both reaching their lowest level yet (1.55 million tonnes carbon dioxide equivalent (CO2-e) and 0.14 tonnes CO2-e per MWh respectively).

[1] After the cut-off date for this report, a new record minimum operational demand of -205 MW (sent-out) was reached on Saturday 19 October 2024.

[2] Measured on a sent-out basis, reflecting the demand met by scheduled, semi-scheduled and significant non-scheduled generators.

Major forecasting insights

- **The timely delivery of expected investments in generation storage and transmission is critical to maintaining reliability.**
  - No reliability gaps are expected if projects that are expected to be delivered under federal and state government schemes are delivered on time and in full.
  - Without these additional projects, and if generation projects that are yet to reach commissioning stages are affected by typically-observed development and commissioning delays, reliability gaps may emerge in South Australia for the coming summer, in 2026-27 and in 2033-34.
- Developments on the demand side include:
  - **Distributed PV and battery storage growth is forecast to continue**, although technology costs and retail energy prices movements uncertainties in the years ahead result in variance across AEMO's scenarios.
  - **Operational consumption (as sent out) is expected to increase at a steady rate,** driven by electrification, domestic hydrogen production, and growth in business consumption, tempered by continued uptake of distributed PV and energy efficiency investments. Growth in distributed PV is projected to outpace underlying consumption in the residential sector, reducing the sector's reliance on energy delivered from the grid.
  - **Minimum operational demand is forecast to experience relatively constant decline** of almost 110 MW per year in the shoulder seasons (September, October, April and May), where the annual minimum most often occurs. Southern Australia reached a negative minimum operational demand (when distributed generation and storage discharge exceeds demand) for the first time in 2023-24 in the absence of operational measures to curtail distributed PV.
  - **Maximum operational demand is forecast to continue to occur in summer** around sunset where distributed PV contributes little. It is projected to grow approximately 35 MW per year due to expansion of large industrial loads, and growth in EV uptake as well as the growth in electricity connections in general.
- On the supply side:
  - **1.4 gigawatts (GW) of new capacity is committed or anticipated, split between wind, solar and storage,** based on AEMO's October 2024 Generation Information update. An additional 17.5 GW of projects are publicly announced but not sufficiently advanced to be considered committed or anticipated, including 8.3 GW of battery projects, 5.3 GW of large-scale solar projects and 2.5 GW of wind projects.
  - **Gas-powered generation volumes are forecast to keep falling in the near to medium term**, as more renewable energy and storage are connected to the NEM, and Project EnergyConnect increases the capacity to import electricity from New South Wales and Victoria. Gas-powered generation also provides a key role in stabilising the grid. In the long term, gas-powered generation volumes are forecast to increase to support electricity demand growth and high renewable penetration as coal completely retires in neighbouring regions.
- **System security remains a key focus in South Australia**, as the rapid energy transition pushes the system to operate more frequently near its technical boundaries. New security gaps and shortfalls declared during 2023 and 2024 have active remediation strategies in place, or underway, while longer-term solutions are being

progressed. In the 2024 security reports, AEMO did not identify any system strength or inertia shortfalls, and confirmed that the magnitude and timing of the previously declared gap for voltage control in South Australia remains unchanged. A number of improvements have also been made to the system security planning frameworks from 1 December 2024, with the introduction of new national inertia requirements allowing for synthetic inertia providers and providing AEMO with the ability to procure both system strength and inertia services, when necessary, as a planner of last resort. AEMO will continue to work closely with the South Australian Government, ElectraNet, SA Power Networks, and industry participants to adapt to any newly identified challenges.

- The **costs associated with direction compensation in South Australia decreased in 2023-24**, driven by a decrease in the compensation prices paid to directed participants, which reduced relative to the compensation prices over the previous year.

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1 Introduction

The *South Australian Electricity Report* (SAER) provides a high-level summary of key insights into electricity supply and demand, as well as the latest developments in energy, in South Australia. The report compiles information and insights from various AEMO studies and publications, including reporting on historical information and forecasts.

1.1 Purpose and scope

The SAER provides key independent insights for the South Australian jurisdiction under AEMO's South Australian Advisory Functions (SAAF) in section 50B of the National Electricity Law.

The 2024 SAER consolidates data and insights relevant to South Australia from a range of AEMO publications, including the 2024 *Electricity Statement of Opportunities* (ESOO) for the National Electricity Market (NEM), the 2024 *Gas Statement of Opportunities* (GSOO) for eastern and south-eastern Australia, and the *Quarterly Energy Dynamics* reports. This SAER is supplemented by additional sources that can provide additional data or detail; these sources are listed in Table 1 and noted throughout the report.

Unless otherwise stated, all times are NEM time (equivalent to AEST) and all dollar amounts are in nominal dollars.

1.2 Information sources

AEMO has sourced insights and data in this report from other AEMO publications and used information provided by existing and potential market participants as at 1 October 2024, unless otherwise specified. Generation information specifically is from AEMO's 31 October 2024 update of its Generation Information web page. Reporting of historical observations on the gas and electricity markets is based on the 2023-24 financial year, unless otherwise specified.

Table 1 provides links to additional AEMO information, and Appendix A1 lists additional external sources.

This report is complemented by the 2024 SAER Data File[2], containing the key data used in tables and figures in this report.

Table 1 Information data sources and reference material

Information source	Website address
Relevant publications and methodologies	
2024 *Electricity Statement of Opportunities* (ESOO) ***ESOO and Reliability Forecast Methodology Document***	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

Information source	Website address
Electricity Demand Forecasting Methodology ***Demand Side Participation (DSP) Forecasting Methodology***	https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach
2023 *Forecast Accuracy Report*	https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/forecasting-accuracy-reporting
2023 *Inputs, Assumptions and Scenarios Report* (IASR)	https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios
2024 *Integrated System Plan* (ISP)	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan
Transmission Augmentation Information Page	https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.
2024 *Gas Statement of Opportunities* (GSOO) for Australia's East Coast Gas Market	http://aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities
Quarterly Energy Dynamics	https://www.aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed
2023 and 2024 *System Strength Report* **2023 and 2024 *Inertia Report*** **2023 and 2024 *Network Support and Control Ancillary Services Report***	https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning
Additional relevant reference material	
AEMO forecasting portal	https://forecasting.aemo.com.au/
Engineering Roadmap for the NEM	https://www.aemo.com.au/initiatives/major-programs/engineering-roadmap.
Distributed Energy Resources (DER) Program	https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program
Guide to Ancillary Services in the NEM	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services
Carbon Dioxide Equivalent Intensity Index	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Settlements-and-payments/Settlements/Carbon-Dioxide-Equivalent-Intensity-Index
Generation Information page	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information
Interconnector capabilities report	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information/Network-status-and-capability
Historical system strength, inertia and network support and control ancillary services (NSCAS) assessments	https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning

1.3 Scenarios

AEMO presents forecasts in this SAER and other reports based on scenarios that reflect a plausible range of futures for the pace of change in the energy industry.

Electricity forecasts in the 2024 SAER are consistent with the three scenarios presented in the 2024 ESOO and shown in **Figure 1** and **Table 2** below. **The three scenarios are *Progressive Change*, *Step Change*, and *Green Energy Exports*.** These scenarios were developed in consultation with interested stakeholders for use in AEMO's forecasting and planning publications, including the 2024 ESOO and 2024 *Integrated System Plan* (ISP). More information on these scenarios is available in the 2023 *Inputs, Assumptions and Scenarios Report* (IASR).

The 10-year reliability forecasts in the 2024 ESOO and this 2024 SAER include a "Central scenario" projection. These Central projections are based on the *Step Change* demand scenario. This is consistent with the 2023 SAER, which also reported on the *Step Change* scenario as the Central outlook.

Figure 1 2023 scenarios for AEMO's forecasting and planning publications

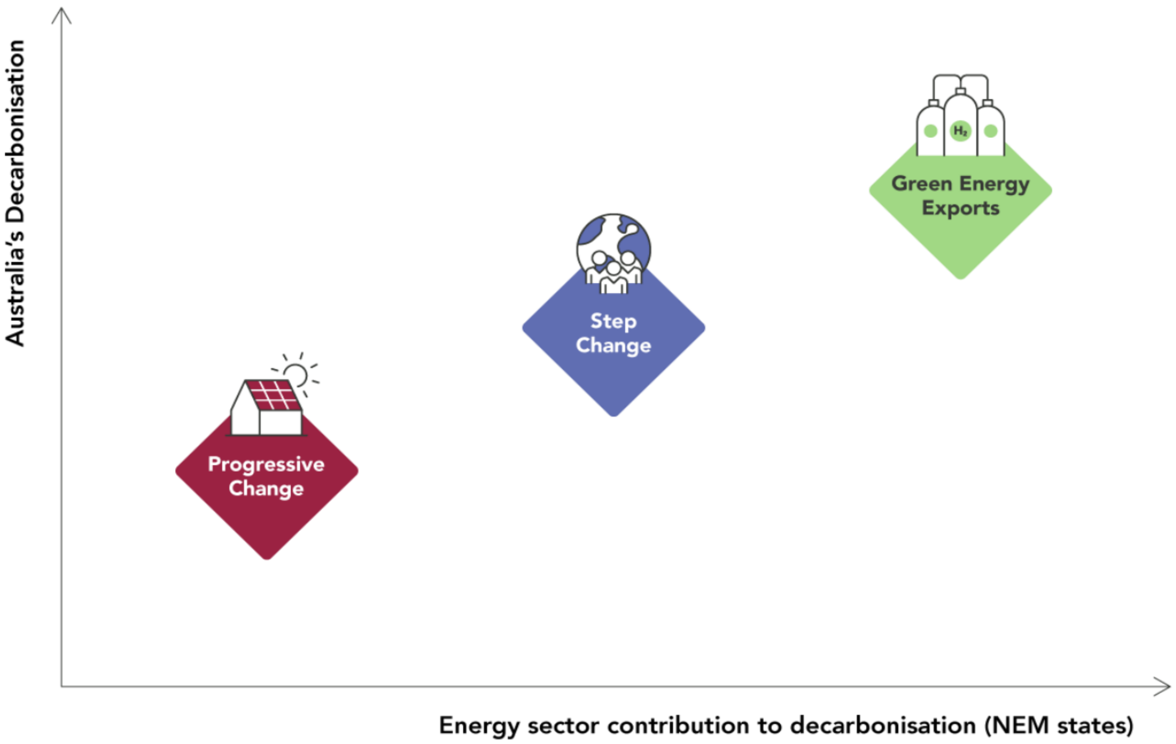


Table 2 Descriptions of AEMO's 2024 forecasting and planning scenarios

Scenario	Scenario description
Progressive Change	Meets Australia's current Paris Agreement commitment of 43% emissions reduction by 2030 and net zero emissions by 2050. This scenario has more challenging economic conditions, higher relative technology costs and more supply chain challenges relative to other scenarios.
***Step Change* (ESOO Central scenario)**	Achieves a scale of energy transformation that supports Australia's contribution to limiting global temperature rise to below 2°C compared to pre-industrial levels. The NEM electricity sector plays a significant role in decarbonisation and the scenario assumes the broader economy takes advantage of this, aligning broader decarbonisation outcomes in other sectors to a pace aligned with beating the 2°C abatement target of the Paris Agreement. The NEM's contribution may be compatible with a 1.5°C abatement level, if stronger actions are taken by other sectors of Australia's economy simultaneous with the NEM's decarbonisation. Consumers provide a strong foundation for the transformation, with rapid and significant continued investments in CER, including electrification of the transportation sector.
Green Energy Exports	Reflects very strong decarbonisation activities domestically and globally aimed at limiting temperature increase to 1.5°C, resulting in rapid transformation of Australia's energy sectors, including a strong use of electrification, green hydrogen and biomethane. The NEM electricity sector plays a very significant role in decarbonisation.

2 Demand and consumption

In 2023-24, South Australia's operational (grid) consumption continued to follow a long-term decline, as a result of the sustained strong uptake of distributed photovoltaics (PV). Forecast consumption is lower compared to the 2023 SAER, particularly from 2028, accounting for a slower rate of adoption of electric vehicles (EVs) and slower forecast development of a hydrogen production industry. This SAER also forecasts stronger uptake of distributed PV, resulting in lower operational consumption over the outlook period. AEMO's forecasts for large industrial loads are dependent on information from ElectraNet, however methodological differences result in different outlooks. AEMO is consulting on changes to its methodology which would bring these outlooks closer.

In 2023-24, South Australia experienced the first negative operational demand.

The effects of high distributed PV generation on operational demand remain consistent with what was observed in previous years. Operational maximum demand continues to occur late in the day, at times when distributed PV contributes little to consumers' energy needs, and minimum operational demand continues to occur during the middle of the day, when distributed PV operates most. Continued growth in distributed PV has resulted in negative operational demand and is forecast to reduce minimum operational demand in future years.

For more information:

- 2023 IASR (used in 2024 ISP), at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.
- 2024 ESOO, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nemforecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.
- AEMO forecasting portal, at https://forecasting.aemo.com.au/.
- AEMO *Forecast Accuracy Report*, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/forecasting-accuracy-reporting.

2.1 Demand and consumption inputs and assumptions

AEMO updates its projections of energy consumption and demand annually. The inputs and assumptions used in these forecasts have been developed and refined through significant stakeholder consultation through the Forecasting Reference Group (FRG), industry engagement via surveys, consultant data and recommendations, including formal consultation processes regarding the IASR and the Forecasting Assumptions Update[3] (in years when the IASR is not published).

[3] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-forecasting-assumptions-update.pdf.

For this publication of the *South Australian Electricity Report*, the Forecasting Assumptions Update contains several updated inputs (relative to the IASR[4]) and should be referenced in combination. Together these reports contain specific detail about how forecast inputs and assumptions support forecasts of electricity consumption and maximum/minimum demand, using methodologies defined in the *Electricity Demand Forecasting Methodology*[5].

AEMO uses a range of historical data to train and develop component models, including:

- Operational demand meter reads.
- Estimated network loss factors.
- Other non-scheduled generators.
- Distributed PV uptake.
- Solar irradiance and resulting estimated distributed PV normalised generation.
- Weather data (such as temperature and humidity levels).

Section 2.1.1 summarises scenario-specific drivers and input forecasts related to:

- Electrification pathways (businesses and households switching from other fuels – such as natural gas – to electricity), and uptake and charging of EVs.
- The potential impacts of a hydrogen industry in Australia.

Section 2.1.2 shows South Australian forecasts for consumer energy resources (CER), specifically rooftop PV, PV non-scheduled generation (PVNSG), and behind-the-meter battery storage. These component forecasts include consideration of CER uptake and generation/charging/discharging patterns, including potential aggregation and coordinated charging/discharging opportunities for CER, such as virtual power plants (VPPs) and vehicle-to-grid (V2G) vehicle charging patterns. Other key components in the consumption and demand forecasts include:

- Economic and population growth drivers, including meter connections.
- Climate.
- Large industrial loads (LILs) across various sectors, as informed by direct surveying of existing facility operators.
- Energy efficiency.

2.1.1 Electrification and hydrogen

Electrification, including electric vehicles

AEMO has forecast a range of electrification outcomes across different scenarios:

- In the residential and commercial (building) sectors, the scale of electrification will depend on factors including appliance replacement costs, electricity infrastructure capabilities and costs, and the cost and availability of

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

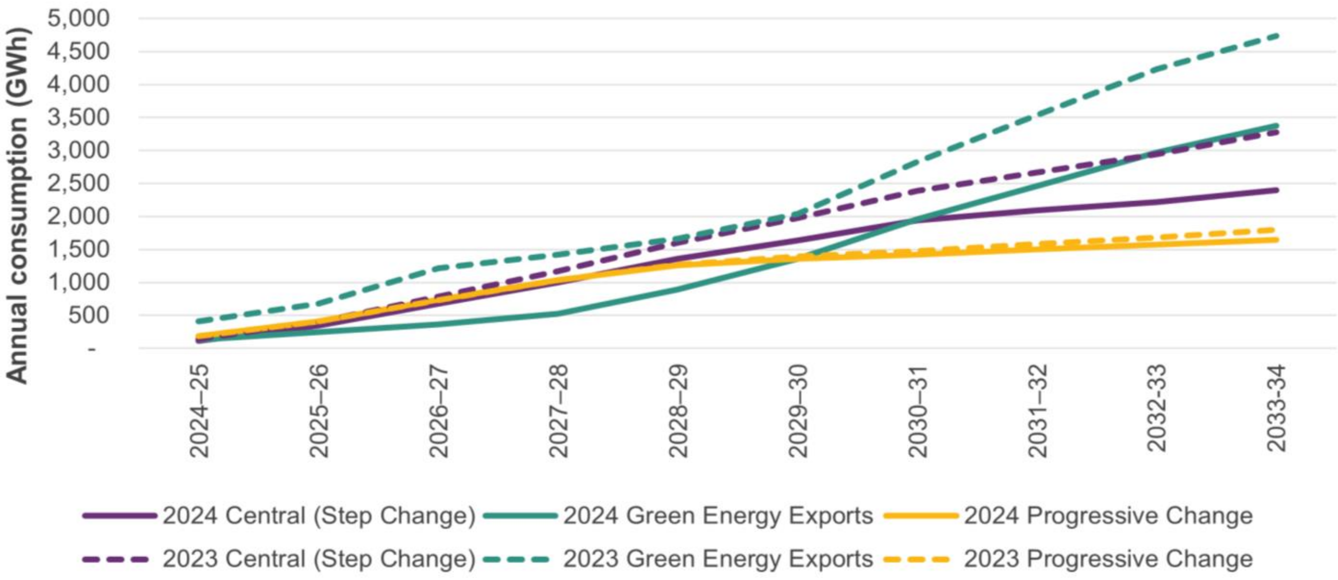
[5] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/electricity-demand-forecasting-methodology.pdf.

alternative fuels such as hydrogen or blended hydrogen-natural gas. The ongoing costs, efficiency and emissions intensity of existing fuels such as natural gas, diesel, and other fuel supplies also influence forecasting electrification outcomes.

- The industrial sector has a broad range of subsectors, each with a different degree of technical potential to switch from traditional fuels such as oil and gas to electricity (for example, steelmaking shifting from traditional blast furnace production to an electric arc furnace). A key motivation to a business for making this switch is the extent to which it intends to reduce its carbon emissions (or is required to under policy initiatives, for example to meet its obligations under the Safeguard Mechanism). AEMO is aware of a number of potential investments in the industrial sector, such as electrification projects, which could substantially increase demand if developed. While not currently in the forecasts due to uncertainty, AEMO will continue to monitor these projects and consider performing sensitivity analysis to better understand the implications of potential demand increases.
- The forecast growth in EVs has been revised downward due to:
  - Updated assumptions regarding the New Vehicle Efficiency Standard (NVES) – the NVES, legislated in May 2024, allows flexibility in meeting emission reduction targets. The updated forecast acknowledges emission reduction opportunities in non-EV sales, leading to lower predicted EV sales.
  - Updated road transport data – December 2023 figures from the Bureau of Infrastructure and Transport Research Economics (BITRE) indicate longer vehicle lifetimes. This results in lower new sales and hence slower EV adoption.

Figure 2 shows the magnitude of the electrification forecast, including transport (EVs), for each scenario, compared to the 2023 forecasts.

Figure 2 Electrification and electric vehicle forecast consumption for South Australia, 2024-25 to 2033-34 (GWh)



Electrification remains an important driver of growth, contributing around 1,650 gigawatt hours (GWh) to 3,375 GWh of additional consumption across the scenarios by 2033-34. This extends to just over 8,400 GWh in the *Step Change* scenario by 2053-54, representing approximately 60% of today's underlying consumption.

Variations between scenarios are influenced by the availability of electrification alternatives, such as renewable gases, and the pace of decarbonisation targeted in the scenarios. For example, while *Green Energy Exports* has the most ambitious carbon reduction trajectory, it also has a relatively slower electrification trajectory in the near term as observed in the figure, as more low-emissions molecular alternatives are assumed to be preferred, particularly with that scenario featuring a much greater growth opportunity for hydrogen developments.

Consumption from EVs makes up 615 GWh (293,500 vehicles) in 2033-34 and 5,013 GWh (1.6 million vehicles) in 2053-54 of the electrification forecast for the Central scenario, from a base of 21 GWh (14,500 vehicles) in 2023-24.

Hydrogen

The South Australian Government is supporting several green hydrogen projects to promote a local hydrogen industry[6]. In September 2023, the Federal and South Australian governments announced funding for the Port Bonython Hydrogen Hub near Whyalla, which is expected to host hydrogen export projects worth up to $13 billion[7].

In addition, the South Australian Hydrogen Jobs Plan[8] will build 250 megawatts (MW) of electrolysers, 200 MW of power generation, and hydrogen storage for the Whyalla project. Development approval was secured during the second half of 2024, with sitework expected to occur in late 2024 and completion expected during 2026[9].

The $240 million H2U Eyre Peninsula Gateway Hydrogen Project is also currently in development. The initial stage will see the installation of a 75 MW electrolysis plant near Whyalla, capable of producing enough hydrogen to create 40,000 tonnes of ammonia each year, currently undergoing Front End Engineering Design (FEED)[10].

Hydrogen facilities are expected to be capable of operating with high degrees of flexibility, minimising exposure to periods of scarce electricity and operating when abundant renewable energy is available.

Hydrogen development remains a key uncertainty affecting the scale of energy consumption in the NEM and its regions. As such, AEMO's planning scenarios apply differing assumptions to hydrogen development, from a relatively modest scale that largely follows current policy drivers only, to the potential for green commodities and hydrogen exports which would develop if renewable energy were abundant, enabling greater domestic fuel substitution as well. The location of hydrogen developments across the NEM is also uncertain, particularly in *the Green Energy Exports* scenario which includes a strong hydrogen development outlook. The overall 2024 hydrogen forecasts for South Australia are lower relative to the scale of South Australian hydrogen development in the previous forecast's *Green Energy Exports* scenario.

2.1.2 Consumer energy resources

In the ESOO, AEMO reports on total distributed PV, which includes both small rooftop systems and other non-scheduled PV capacity. The SAER breaks down total distributed PV into individual forecasts for small rooftop

[6] See https://www.energymining.sa.gov.au/industry/modern-energy/hydrogen-in-south-australia.

[7] See https://minister.dcceew.gov.au/bowen/media-releases/joint-media-release-port-bonython-hydrogen-hub-boost-australias-hydrogen-industry.

[8] See https://www.hydrogen.sa.gov.au/projects/hydrogen-jobs-plan/whyalla-hydrogen-power-facility.

[9] See https://research.csiro.au/hyresource/south-australian-government-hydrogen-facility/.

[10] See https://research.csiro.au/hyresource/eyre-peninsula-hydrogen-and-ammonia-supply-chain-project/.

PV[11] systems and for larger PV non-scheduled generation (PVNSG)[12], and forecasts growth in both installed capacity and the amount of energy generated by these systems.

The following sub-sections discuss the outlook for each category. AEMO forecasts the uptake of each PV type, and those capacity forecasts are transformed to distributed PV generation forecasts using half-hourly profiles of normalised generation. Further information is available in AEMO's consultant reports (CSIRO[13] and GEM[14]) that serve as inputs to AEMO's 2024 forecasts.

The CER forecasts described in this document assume consumer uptake based on economic returns, such as payback achieved by avoiding retail energy charges, and assume that distribution networks continue to be developed to not materially inhibit CER investment or operation.

Rooftop PV capacity

Total installed rooftop PV capacity in South Australia has grown strongly since 2009, and continues to grow, with South Australia now having over 385,000 residential installations[15] and 47% penetration for dwellings[16] in residential rooftop PV, the second highest of all NEM regions (after Queensland at 48%). Current installed capacity estimates for rooftop PV are from the Clean Energy Regulator.

Figure 3 shows estimated actual rooftop PV installed capacity since 2013-14 and the 10-year forecast for installed capacity under all scenarios in the 2024 ESOO, including a comparison to the scenarios in the 2023 ESOO.

Changes relative to the 2023 ESOO forecasts reflect an interplay between updated PV cost and size projections. In view of latest market trends, forecast PV costs were revised upwards in the 2024 ESOO, resulting in reduced uptake (number of systems), which predominantly affects the Central and *Green Energy Exports* scenarios. In addition, average PV system size was also revised upwards reflecting continued preferences for larger system size installations, resulting in higher capacity. The relative strengths of these two factors determine the changing relativities over time (see details in the 2024 *Forecasting Assumptions Update*[17]), with growth in installed capacity expected to continue in the coming years.

[11] Rooftop PV is defined as behind-the-meter systems, installed by households and businesses typically, up to 100 kilowatts (kW) capacity. "Business PV" in this report means business rooftop PV.

[12] PVNSG is defined as PV systems with a capacity between 100 kW and 30 MW. These are typically very large rooftop PV systems and small solar farms below AEMO's registration threshold of 30 MW.

[13] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-2022-solar-pv-and-battery-projections-report.pdf. Note that CSIRO 2022 forecasts were escalated and used as an input to AEMO 2024 forecasts presented here. See details in AEMO's 2024 *Forecasting Assumptions Update*, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-forecasting-assumptions-update.pdf?la=en.

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

[15] See *Small generation unit – solar (deemed)* at https://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations#Postcode-data-files. The data was adjusted by AEMO's known residential/business split.

[16] Dwellings estimated from AEMO's records of residential electricity connections.

[17] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-forecasting-assumptions-update.pdf?la=en.

Figure 3 Actual and forecast South Australian rooftop PV installed capacity, 2012-13 to 2033-34

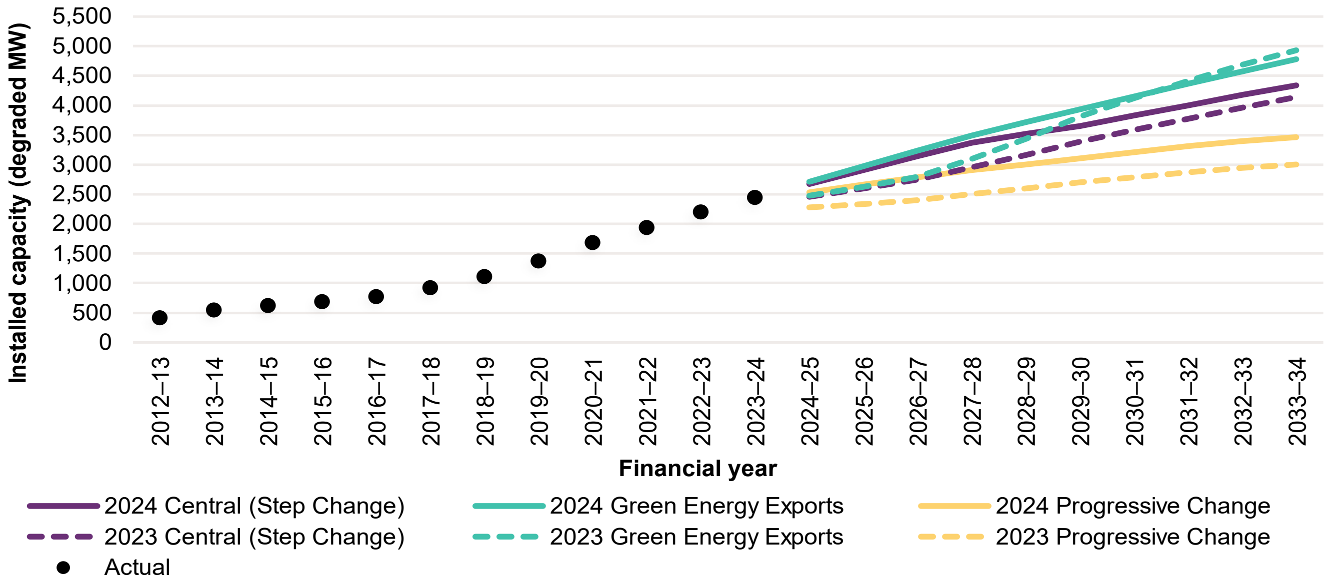
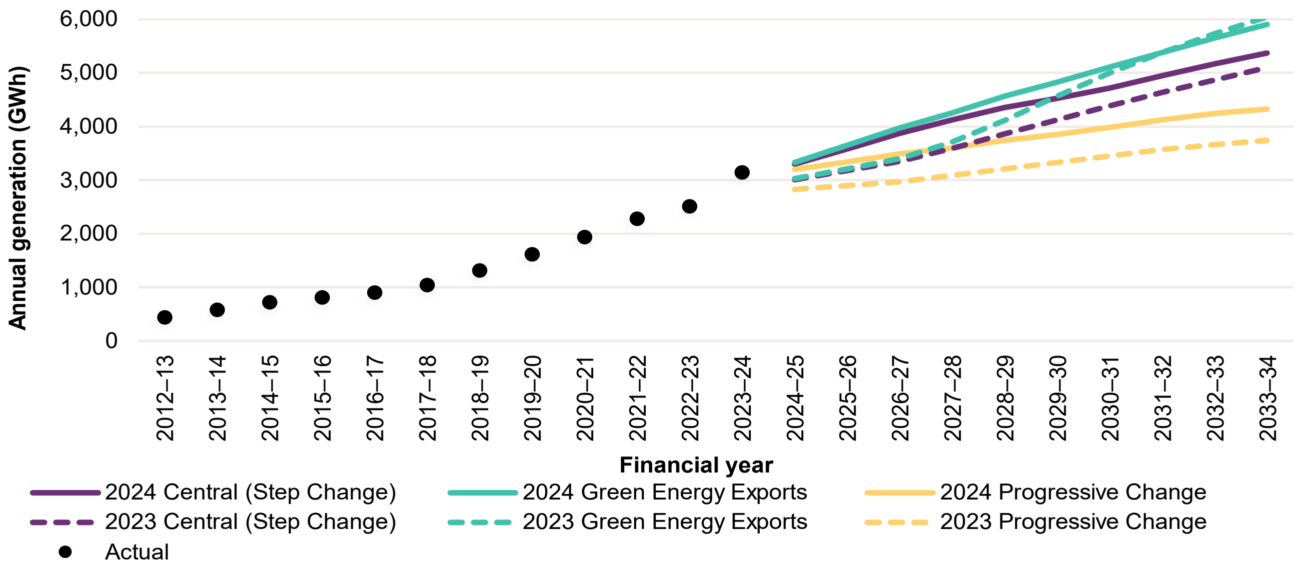


Figure 4 shows estimated actual annual rooftop PV generation since 2012-13 and the 10-year forecast under all scenarios.

Figure 4 Actual and forecast South Australian rooftop PV generation, 2012-13 to 2033-34



It shows:

- In 2023-24, annual rooftop PV generation was estimated at 3,134 GWh[18], or 19% of total annual underlying consumption[19].

[18] Estimates calculated for the financial year 2023-24 for the 2024 IASR.

[19] Underlying consumption means all the electricity used by consumers, which can be sourced from the grid but also, increasingly, from other sources including consumers' distributed PV and battery storage.

- In the Central scenario, PV generation is forecast to increase to 5,372 GWh by 2033-34, which would represent approximately 21% of annual underlying consumption at that time in South Australia.
- Over the next 10 years, South Australia is projected to have the highest ratio of rooftop PV generation to operational consumption[20] of all NEM regions (39%).
- The 2023-24 figure, an apparent slight increase, reflects above-average levels of solar radiation in that year, especially relative to 2022-23. Forecasts going forward assume average levels of solar radiation.

PV non-scheduled generation (PVNSG) forecasts

Figure 5 shows South Australia's PVNSG capacity since 2017-18, and the 10-year forecast for installed capacity under all scenarios:

- PVNSG capacity forecasts have been revised downwards relative to the 2023 ESOO, because revenue from PVNSG systems is expected to decline, thus decreasing uptake. This is due to the completion of the Large-scale Generation Certificate (LGC) scheme in 2030 and a lower decline in capital costs than previously anticipated, particularly impacting the *Green Energy Exports* scenario, affecting all NEM regions (not just South Australia). The forecast for *Progressive Change*, however, has been revised upwards in the short term to align with the latest rate of installations.
- PVNSG installed capacity on 30 June 2024 is estimated at 298 MW, and is forecast to grow in the Central scenario to 651 MW by 2033-34.

Figure 5 Actual and forecast South Australian PVNSG installed capacity, 2016-17 to 2033-34

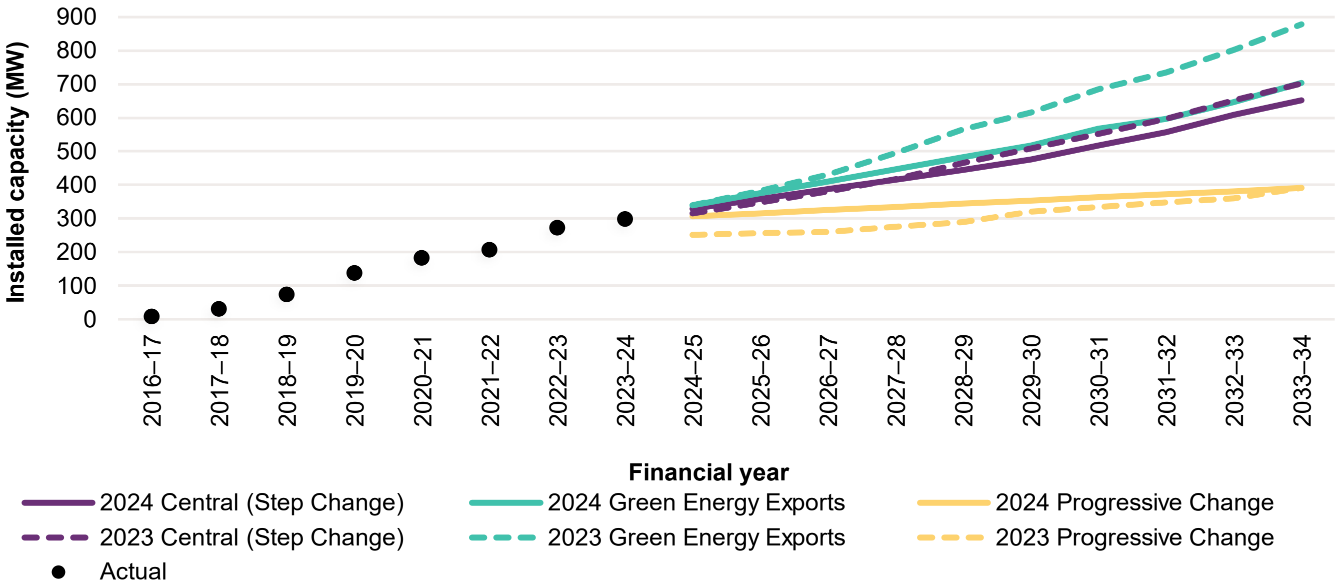
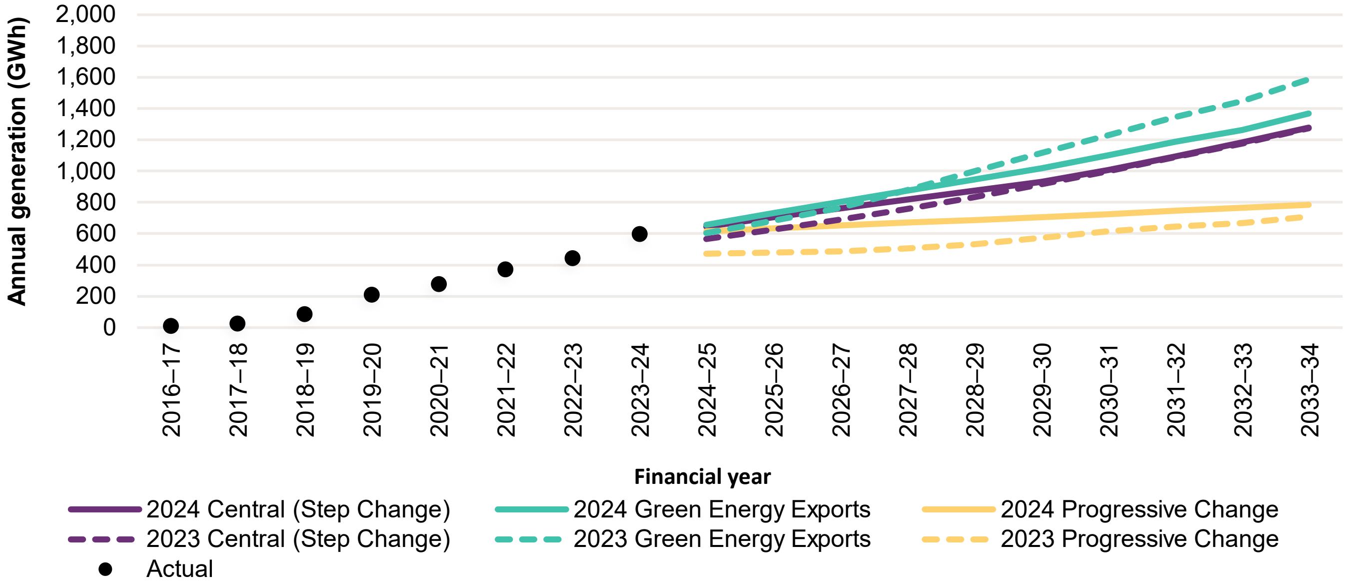


Figure 6 shows PVNSG actual generation since 2016-17 and the 10-year forecast under all scenarios. As shown in the figure, PVNSG generation was estimated at 595 GWh in 2023-24 (noting the above-average solar conditions in that year, mentioned earlier).

[20] Operational consumption and demand are drawn from the grid and supplied by large-scale generation.

Figure 6 Actual and forecast South Australian PVNSG generation, 2016-17 to 2033-34



Distributed battery storage forecast

Behind-the-meter residential and commercial battery systems have the potential to change the future demand profile in South Australia, particularly maximum and minimum operational demand. As at 30 June 2024, South Australia has an estimated 365 MW of embedded battery systems (from over 49,000 units)[21], which represents a 22% share of the NEM's CER battery capacity.

By 2033-34, the scenario outlook for uptake of business and residential behind-the-meter battery systems reaches approximately 1,073 MW (in the Central scenario) and up to 1,187 MW (in the *Green Energy Exports* scenario). Battery uptake forecasts in the 2024 forecasts include a delay in the anticipated uptake, as recent battery uptake lags previous forecasts. In contrast, recent battery sales, although slow, lift the lower *Progressive Change* forecast in the short term. The long-term battery scenario uptake outlook, however, continues to project growth, as battery system prices are expected to fall and drive market growth.

Figure 7 shows the 10-year forecast installed capacity of behind-the-meter battery systems relative to the 2023 forecasts. The forecast assumes battery storage systems will be coupled with PV systems, and store surplus solar production for meeting evening peak demands. The effectiveness of battery systems to support household consumption will be influenced by pricing incentives, and there will be broader system benefits if the battery fleet is actively managed, or coordinated, for example through a VPP arrangement. This coordination will mitigate the need for more utility-scale resources, and the cost savings associated with this are assumed to benefit consumers in the 2024 forecasts, as retailers and coordinators (also called aggregators) encourage this resource type.

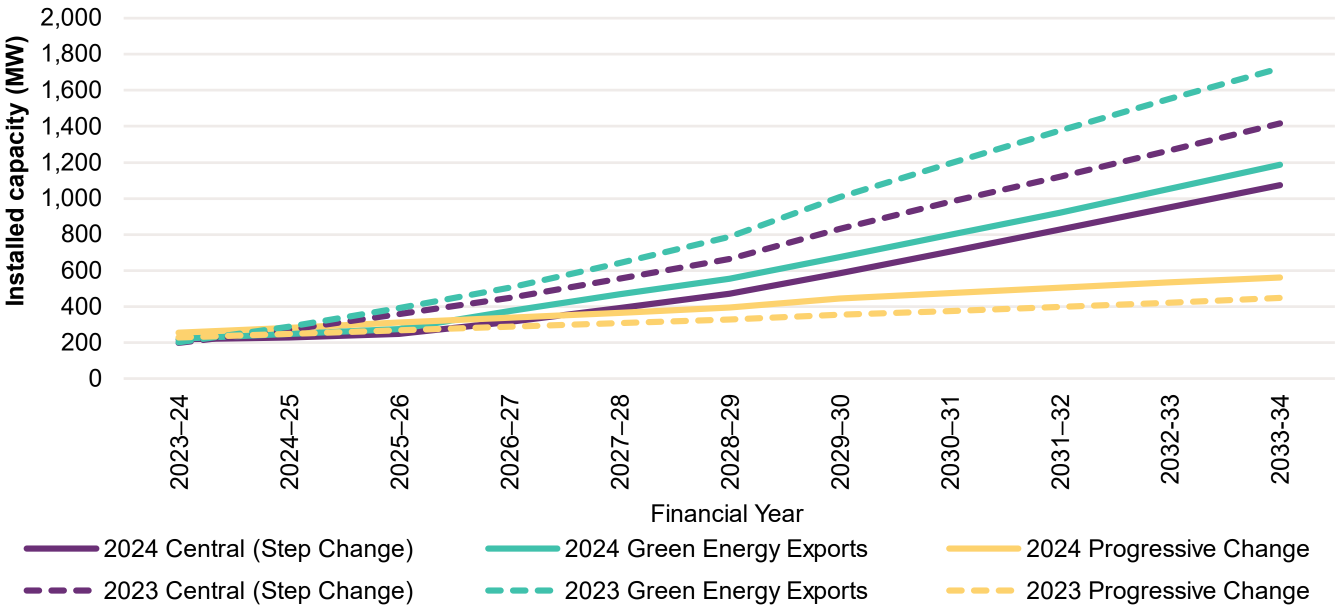
Project Edge[22], a trial designed to demonstrate market participants effectively collaborating to deliver VPP services to consumers, reported a positive cost benefit analysis for VPP, and lends momentum to a variety of

[21] This is based on best available market data to date (SunWiz 2024 battery report for residential sector and AEMO's DER register for commercial sector, which is thought to underestimate total market size). This data was not available at the time of 2024 ESOO forecast production.

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

earlier South Australian trials in indicating the technical feasibility, technical benefits, and overall benefits of VPP operation.

Figure 7 Behind-the-meter battery capacity forecasts for South Australia, 2023-24 to 2033-34



2.1.3 Large industrial loads

AEMO forecasts LIL across various sectors based on:

- Direct surveys of existing facility operators about expected consumption, maximum demand and closure date (if known).
- Information from ElectraNet and SA Power Networks about committed and prospective loads.

AEMO's scenarios presented in the following section explore different combinations of future load growth from LIL based on the information sourced above, and scenario-based growth trajectories from multi-sectoral modelling, to account for structural changes in the medium to longer term, as the economy decarbonises.

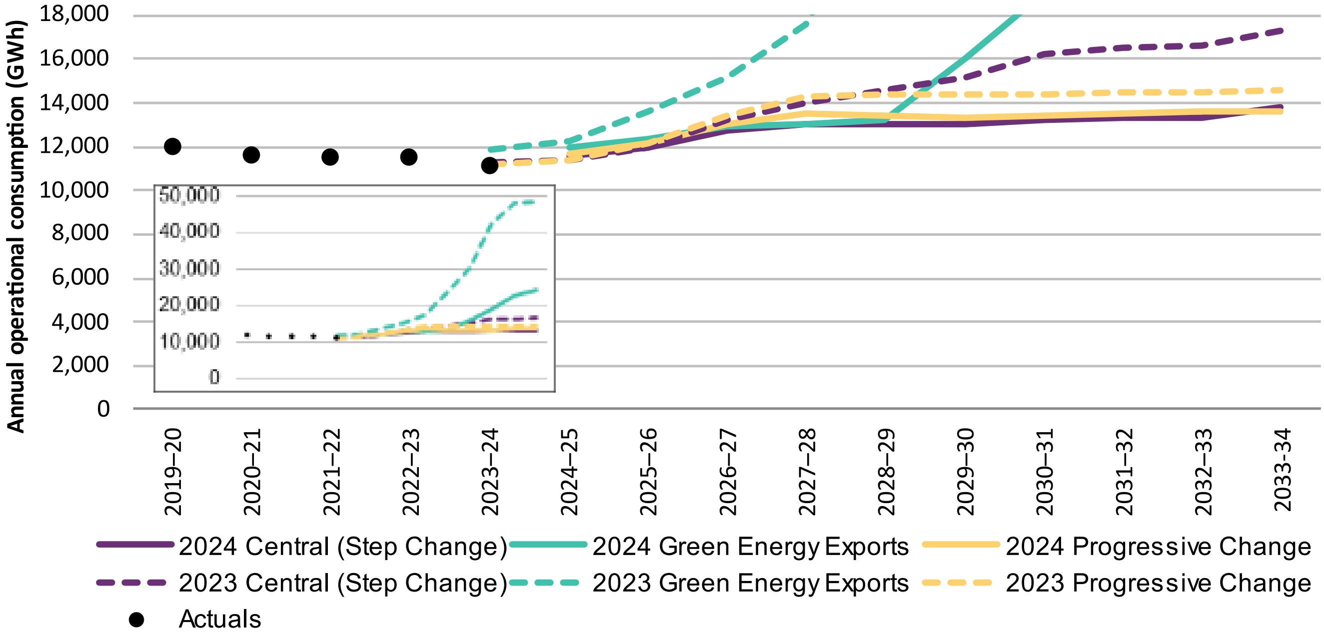
2.2 Historical and forecast consumption

2.2.1 Operational consumption

Figure 8 shows South Australia's actual sent-out operational consumption since 2019-20 and forecast annual sent-out operational consumption to 2033-34[23]. In 2023-24, operational consumption was 11,095 GWh, which is marginally lower (411 GWh) than the 2022-23 total of 11,506 GWh.

[23] Operational consumption is supply to the grid by scheduled, semi-scheduled, and significant non-scheduled generators. "Sent-out" excludes auxiliary loads (energy used by the generator to produce electricity). Published sent-out totals may be revised as more data on auxiliary loads becomes available.

Figure 8 Annual operational consumption (sent-out) actual and forecast for South Australia, 2019-20 to 2033-34 (GWh)



Note: The *Green Energy Exports* scenario forecast continues well beyond the main chart driven by the potential for hydrogen exports (see chart inset).

Over the next decade, AEMO forecasts consumption to grow steadily, although at a slower pace compared to the 2023 SAER. The projected growth is driven by electrification, business mass market (BMM) load, hydrogen for domestic use and LIL consumption growth, and tempered by the continuous uptake of distributed PV and energy efficiency investments. AEMO recognises that ElectraNet's outlook for the development of new LILs exceeds that presented in this SAER. AEMO notes that methodological differences largely explain the different outlooks, and is presently consulting on updates to its methodology.

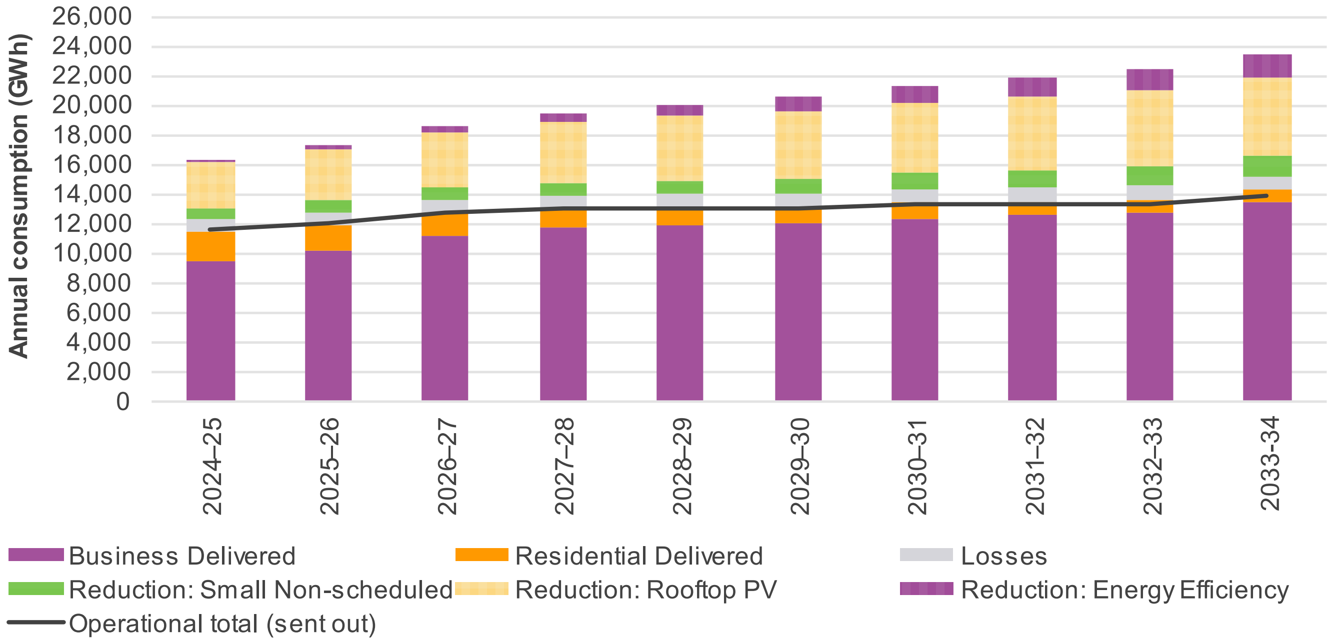
In the Central scenario, AEMO forecasts consumption to increase to 13,861 GWh in 2033-34. From 2028 onwards, this increase occurs at a slower pace compared to the 2023 forecast, primarily due to lower forecast hydrogen production for domestic and export purposes this year. Other contributing factors include slower EV uptake and to a lesser extent, more moderate growth in BMM load reflecting a slower economic growth forecast.

Hydrogen production dominates the growth trajectory of *Green Energy Exports* from around 2028-29, however this growth is lower than forecast in the 2023 SAER due to a reduced forecast of hydrogen production for export. Domestic hydrogen consumption in this scenario is forecast to grow slightly higher than both the Central and *Progressive Change* scenarios.

Figure 9 shows forecast operational consumption by sector to 2033-34 under the Central scenario. Components below the operational total (sent-out) line are items that consume energy. Components above this line offset growth, for example by saving energy through energy efficiency investments, or self-consumption from distributed PV systems.

Overall, forecast consumption growth is steady, driven by electrification (including EV uptake), BMM load, hydrogen for domestic use, and LIL consumption growth, tempered by continued uptake of distributed PV and energy efficiency investments. The growth in residential rooftop PV generation is also expected to outpace consumption drivers, resulting in an overall decline in operational residential consumption.

Figure 9 Forecast annual South Australia electricity consumption, Central scenario, 2024-25 to 2033-34 (GWh)



Data source: AEMO forecasting portal, at https://forecasting.aemo.com.au/.

The forecast rise in operational consumption (sent-out) over the next decade is primarily from the business sector, while the residential sector shows a modest decline over this period due to increasing distributed PV uptake. Further breakdowns of the residential and business sector forecasts are presented in Section 2.2.2 and Section 2.2.3.

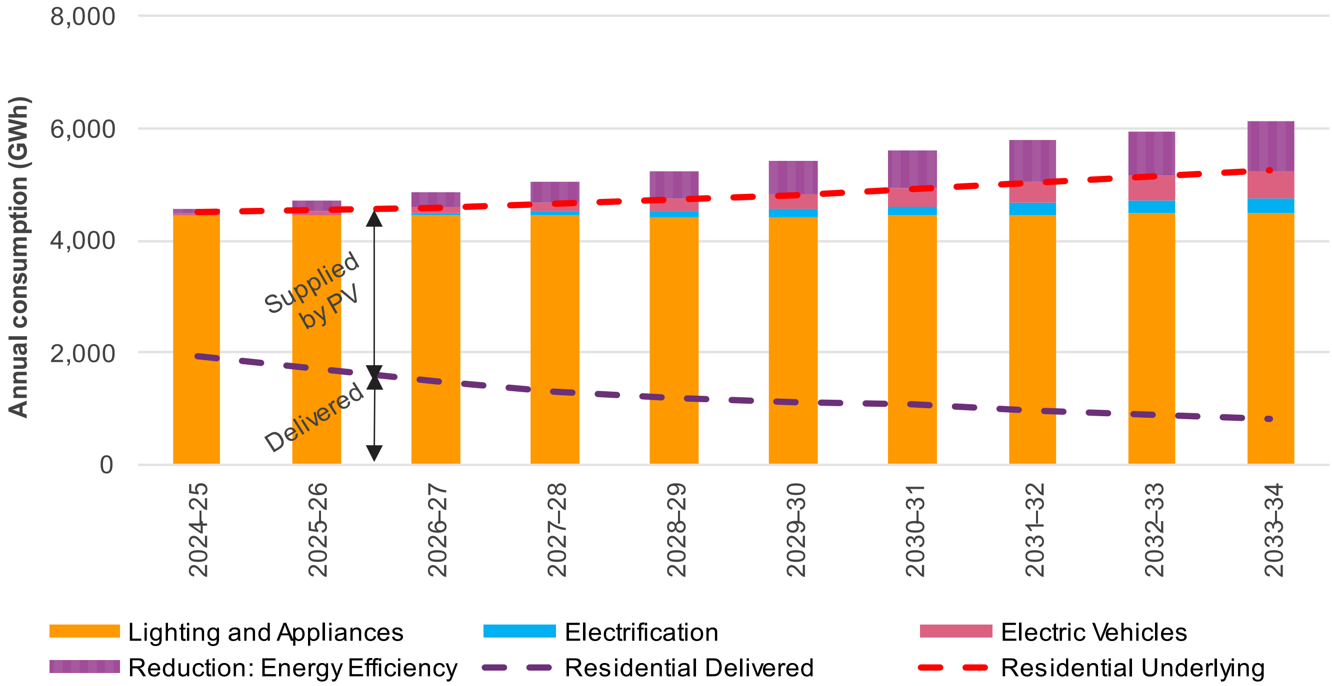
2.2.2 Residential sector – underlying and delivered[24] consumption

Figure 10 presents a breakdown of residential sector electricity forecasts for South Australia. Forecast underlying residential consumption is driven predominately by new connections growth and electrification (conversion from gas appliances) and uptake of electric vehicles.

Over the next decade, growth in underlying residential consumption is expected to be limited, increasing from 4,501 GWh in 2024-25 to 5,250 GWh in 2033-34, in the Central scenario. Energy efficiency improvements play a key role in offsetting the increases from electrification, including EVs. AEMO also forecasts continued strong growth in residential rooftop PV. Currently, residential rooftop PV generation meets more than half of underlying consumption, with that set to increase to 84% by 2033-34. Across all scenarios, strong growth in PV installations in the next decade is forecast to surpass the smaller growth in underlying demand, resulting in a net reduction of energy delivered from the grid.

[24] Delivered consumption is electricity delivered from the transmission system to household and business consumers. Delivered consumption also includes electricity required to charge EVs.

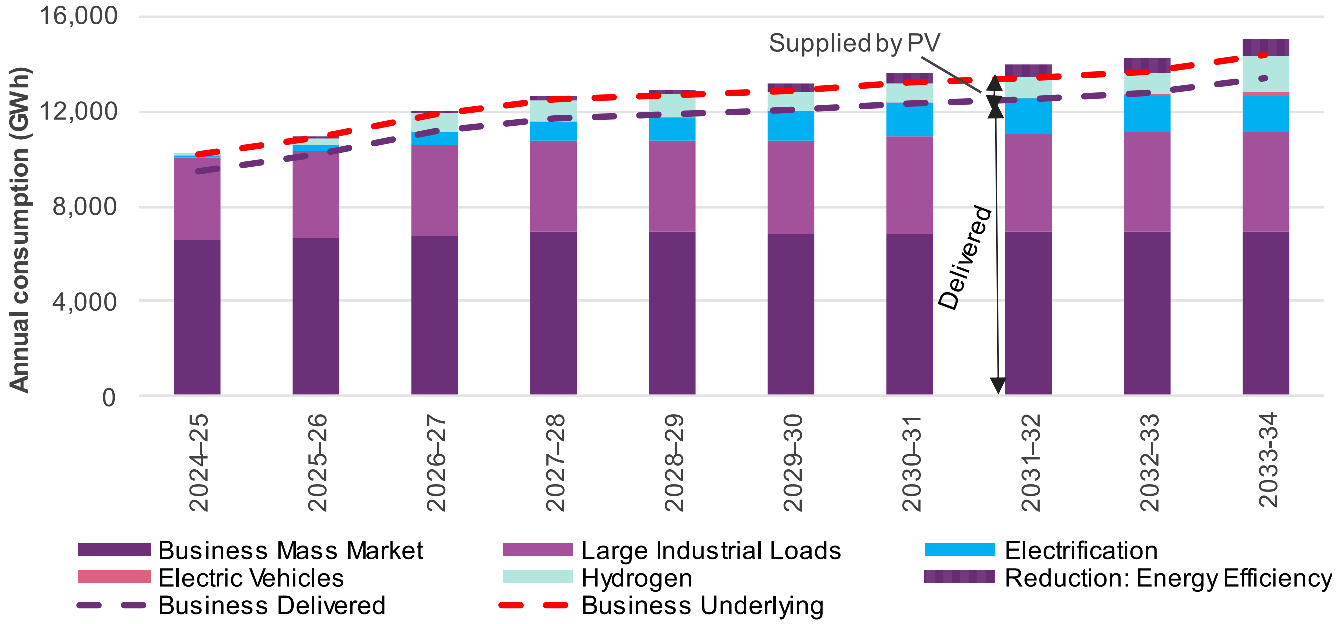
Figure 10 **Breakdown of residential sector electricity forecasts for South Australia, Central scenario, 2024-25 to 2033-34 (GWh)**



2.2.3 Business sector – underlying and delivered consumption

Figure 11 presents a breakdown of business sector electricity forecasts for South Australia. Forecast underlying business consumption is expected to increase from around 10,165 GWh in 2024-25 to around 14,371 GWh in 2033-34 in the Central scenario. This is driven by electrification, emerging hydrogen production to meet the South Australian Hydrogen Jobs Plan, and more modest forecast growth in the BMM and LIL sectors.

Figure 11 **Breakdown of business sector electricity forecasts for South Australia, Central scenario, 2024-25 to 2033-34 (GWh)**



Energy efficiency investments partially offset the growth in consumption, while continued uptake of rooftop PV reduces demand from the grid. AEMO forecasts that delivered demand increases from 9,509 GWh in 2024-25, to just over 13,425 GWh in the Central scenario by 2033-34.

2.2.4 Other potential industrial load growth

Following the publication of the 2024 ESOO, ElectraNet shared with AEMO an extensive pipeline of prospective LILs with the potential for future development. While AEMO incorporated some of these loads in the 2024 ESOO – as they met the commitment requirements of AEMO's *Electricity Demand Forecasting Methodology* – the majority would not currently satisfy the criteria for inclusion within the Central scenario of the forecast.

AEMO is presently consulting on updates to its methodology, which may lead to adjustments to the manner in which industrial load developments are included in future, with greater proposed consideration of anticipated projects that are not currently committed, but are likely to impact electricity consumption in the medium to longer term. A detailed description of AEMO's proposal for consideration of prospective projects is described in the *Electricity Demand Forecasting Methodology* consultation[25].

The prospective projects provided by ElectraNet cover new mine sites, a seawater desalination plant and a number of hydrogen production and green steel developments, with many of these developments located in the northern areas of the state's electricity grid. The inclusion of some of these prospective projects would have a material impact on South Australia's electricity forecasts, with the potential for more than 1,000 MW of additional demand growth by 2033-34.

2.3 Maximum demand and minimum demand

2.3.1 Operational maximum demand

South Australian operational maximum demand has historically occurred during periods of hot weather over summer, largely attributed to air-conditioner load.

The large levels of installed distributed PV capacity in South Australia are a major contributing factor for the timing of maximum operational demand. As **Table 3** (later in this section) shows, since 2017-18, the time of maximum operational demand has occurred in the evening, when there is little to no generation from distributed PV.

On Monday 23 January 2024, operational demand in South Australia reached 2,748 MW (measured on a sent out basis) at 8:00 PM (Adelaide time) with a peak temperature of 41.2°C recorded at Adelaide (West Terrace/Ngayirdapira) earlier that day. At the time of the maximum demand, the Adelaide temperature had cooled to approximately 36°C, but load remained high in response to the higher daytime temperature.

Despite seeing El Niño climate conditions, for the first time since 2020, summer did not reach temperatures in the mid to high forties, which have commonly been observed in previous years.

Rooftop PV generation at the time of the maximum demand was very low (estimated 16 MW), due to low solar irradiance in the evening. With maximum operational demand events tending to occur at times when PV

[25] See https://aemo.com.au/consultations/current-and-closed-consultations/2024%20Electricity%20Demand%20Forecasting%20Methodology%20Consultation.

generation is low, further increases in distributed PV capacity will have minimal impact on maximum operational demands.

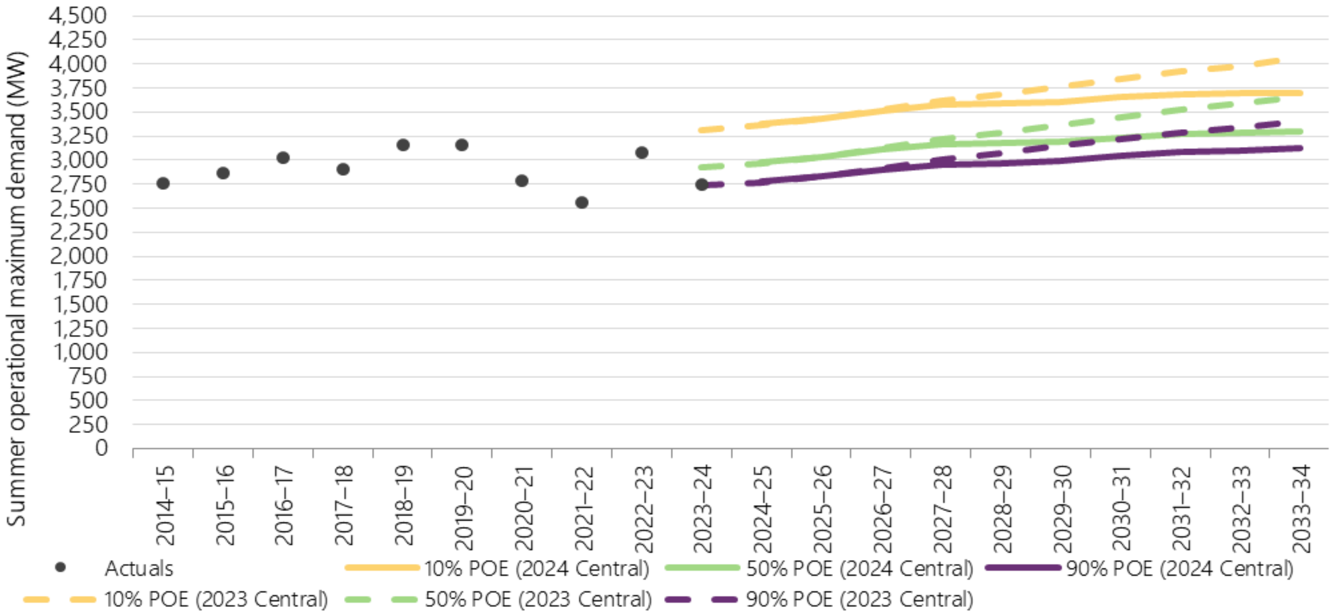
Forecast operational maximum demand

Annual maximum operational demand is forecast to continue to occur in summer, and is expected to grow slightly, due to expansion of large industrial loads, growth in EVs, and increased connections.

Figure 12 shows historical summer maximum demand actuals since 2014-15, and 10%, 50%, and 90% probability of exceedance (POE)[26] forecasts from the 2024 and 2023 NEM ESOOs (Central scenario).

EV growth is projected to have some impact on maximum operational demand, although it will depend on the time of day that vehicle charging occurs. AEMO forecasts several charging profiles, with daytime (to maximise the use of rooftop PV generation) and overnight (taking into account lower tariffs offered for overnight consumption) charging preferable for grid reliability over convenience charging that may amplify evening peak demands. At this stage of EV adoption, high uncertainty remains regarding the impact EV charging will have; the impact will depend on the effectiveness of consumer preferences (and incentives) to operate in a manner that minimises the strain on the grid while still maintaining broad convenience.

Figure 12 Actual and forecast summer operational maximum demand (sent-out) for South Australia (Central scenario), 2014-15 to 2033-34 (MW)



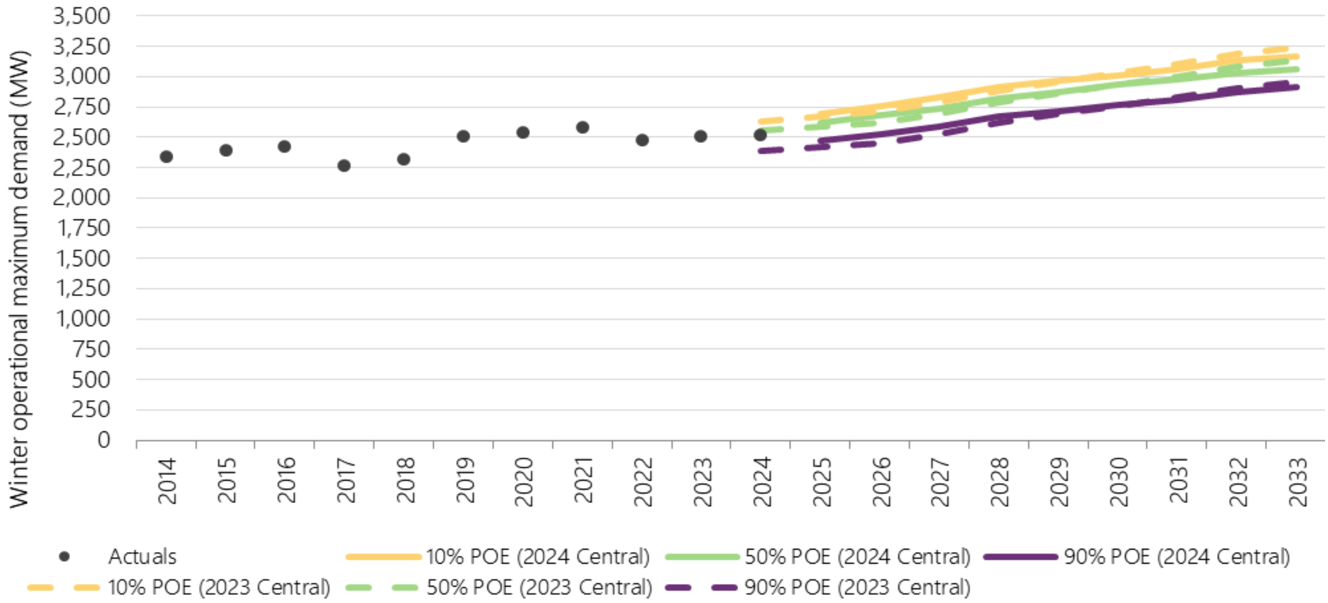
As **Figure 12** shows, the maximum summer operational demand observed in 2023-24 was below the 50% POE forecast. From 2029-30 to 2033-34, forecast growth rates are lower than the 2023 ESOO, primarily due to the lessening growth trends affecting consumption, including lower EV uptake than was previously forecast. BMM

[26] POE is the probability a forecast will be met or exceeded. The 10% POE maximum demand forecast (and 90% minimum demand forecast) is mathematically expected to be met or exceeded once in 10 years and represents demand under more extreme weather conditions than a 50% POE forecast, which is expected to be met or exceeded once every two years.

consumption has also stabilised, with slight increases. Despite some growth in LILs, it has been offset by the lower EV growth rate compared to the 2023 ESOO. As a result, the forecasts tend to be flatter.

Figure 13 below shows the forecast for South Australia's operational maximum demand in winter.

Figure 13 Actual and forecast winter operational maximum demand (sent-out) for South Australia (Central scenario), 2014 to 2033 (MW)



Note: Winter analysis uses calendar years to capture the full winter period from June to August.

In winter 2024, a maximum demand of 2,517 MW was reached on 25 June 2024 at 6:00 PM (Adelaide time). With shorter days in winter, evening peaks tend to have no offset from PV generation, so winter peaks are driven by forecast growth in population, electrification and the economy overall. Winter maximum demand is – like summer demand – projected to grow significantly over the next 10 years.

Impact of distributed PV on underlying maximum demand

Over the last decade, growth in rooftop PV generation in South Australia has gradually shifted the time of maximum operational demand from occurring late afternoon or early evening to happen later into the evening. The typical time of peak is now 7:30 PM to 8.00 PM Adelaide time in summer, when solar irradiance is low. In the last five years, no rooftop PV generation has been observed during winter maximum demand periods, because they occur in the evening.

Table 3 shows estimated distributed PV generation at the time of underlying and operational maximum demand for the last five years, illustrating that the contribution of distributed PV at time of underlying maximum demand has grown over time, while its contribution at time of operational maximum demand more than doubled but still remains low.

Table 4 shows this data for winter maximum demand. Historically, there has been no PV output during either underlying or operational winter maximum demand; in the last couple of years, cold mornings have caused underlying peak to be 9:30 AM local time, but the generation of distributed PV at that time pushed the operational peak to the evening when PV no longer contributes.

Table 3 Distributed PV contribution to underlying and operational summer maximum demand in South Australia

Year	Distributed PV contribution to underlying maximum demand (MW)	Date and time of underlying maximum demand (Adelaide time)	Distributed PV generation at the time of operational maximum demand (MW)	Date and time of operational maximum demand (Adelaide time)
2018-19	413	24/01/2019 5:00 PM	19	24/01/2019 8:00 PM
2019-20	490	19/12/2019 5:00 PM	58	19/12/2019 7:30 PM
2020-21	451	18/02/2021 6:00 PM	82	18/02/2021 7:30 PM
2021-22	1,018	11/01/2022 3:30 PM	121	11/01/2022 7:30 PM
2022-23	849	23/02/2023 5:00 PM	80	23/02/2023 7:30 PM
2023-24	906	11/03/2024 5:00 PM	197	11/03/2024 7:00 PM

Table 4 Distributed PV contribution to underlying and operational winter maximum demand in South Australia

Calendar year*	Distributed PV contribution to underlying maximum demand (MW)	Date and time of underlying maximum demand (Adelaide time)	Distributed PV generation at the time of operational maximum demand (MW)	Date and time of operational maximum demand (Adelaide time)
2019	0	24/06/2019 6:30 PM	0	24/06/2019 6:30 PM
2020	0	7/08/2020 6:30 PM	0	7/08/2020 6:30 PM
2021	0	22/07/2021 6:00 PM	0	22/07/2021 6:00 PM
2022	533	6/07/2022 9:30 AM	0	22/08/2022 6:30 PM
2023	748	19/7/2023 9:30 AM	0	22/06/2023 6:00 PM
2024	871	29/07/2024 10:30 AM	0	25/06/2024 5:00 PM

* Winter analysis uses calendar year to capture the full winter period from June to August.

Demand side participation (DSP)

An alternative to adding grid generation to help meet maximum operational demand is to seek resources on the demand side to reduce consumption (particularly at peak times). DSP reflects the capability of demand side resources (customer load reductions or generation from customers' embedded generators) to reduce operational demand at times of high wholesale prices or emerging reliability issues. DSP captures direct response by industrial users and consumer response through programs run by retailers, DSP aggregators, or network service providers (NSPs).

Consumption may be reduced voluntarily by customers exposed directly to the wholesale price, in cases where prices are high at times of maximum demand. More commonly, the reduction is automatically controlled by retailers or DSP aggregators which have contracted with customers to reduce their consumption at different price levels to provide price hedging in the market.

The estimated level of DSP available in South Australia for summer 2023-24 and winter 2024 is shown in **Table 5**, which contains the estimated DSP by wholesale price levels and reliability response for South Australia. It reflects AEMO's expected (median) DSP response to different wholesale price levels. Reliability response DSP estimates are also included, referring to situations where additional DSP is observed in response to AEMO issuing a market notice declaring Lack of Reserve (LOR) conditions (LOR 2 or LOR 3)[27].

The table shows the estimated cumulative price response is 27 MW for South Australia when prices exceed $300 per megawatt hour (MWh), and 45 MW when prices exceed $500/MWh. If prices exceed $7,500/MWh, or if LOR 2 or LOR 3 conditions are declared, the total DSP response is estimated to be 49 MW in South Australia.

Table 5 Estimated DSP by wholesale price levels and reliability response* for South Australia

Trigger	Summer 2023-24 (MW – cumulative for each price band)	Winter 2024 (MW – cumulative for each price band)
>$300-$500 / MWh	27	27
>$500-$7,500 / MWh	45	45
>$7,500 / MWh	49	49
Reliability response	49	49

* Reliability response refers to situations where a LOR notice (LOR 2 or LOR 3) is issued.

The methodology used is explained in AEMO's DSP forecast methodology[28], which includes a summary of the types of demand flexibility included in, or excluded from, AEMO's DSP forecasts and the reasons why. Notably:

- DSP responses triggered by the Reliability and Emergency Reserve Trader (RERT) process, as discussed in Section 4.2.2, are excluded.
- Operation of battery storage units, including VPPs, is reflected in AEMO's supply-side forecasts and this is therefore excluded from DSP to avoid double-counting.
- Time-of-use tariff impacts and controlled-load arrangements are captured in the demand forecast, and are therefore not included in the DSP forecast to avoid double-counting.
- Wholesale Demand Response (WDR) is included as DSP, and has been since the 2021 DSP forecast.

2.3.2 Operational minimum demand

South Australia has experienced minimum demand in the middle of the day since 2013-14, and this is forecast to continue. Minimum operational demand typically occurs during weekends or public holidays when demand is low and temperatures are mild, and around noon when high distributed PV output reduces the need for grid-delivered electricity.

Table 6 shows the time of underlying and operational maximum demand along with an estimated contribution of distributed PV to underlying and operational minimum demand for the last five years.

[27] The declaration of LOR conditions indicates times the system may not or does not have enough reserves to meet demand. See AEMO's reserve level declaration guidelines, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ power_system_ops/ reserve-level-declaration-guidelines.pdf. Note that the estimated reliability response DSP applies for when an actual LOR 2 or LOR 3 occurs, not for periods where it was forecast, but did not eventuate.

[28] AEMO, *Demand Side Participation Forecast Methodology*, at https://aemo.com.au/-/media/files/stakeholder_consultation/ consultations/nem-consultations/2020/demand-side-participation/final/demand-side-participation-forecast-methodology.pdf.

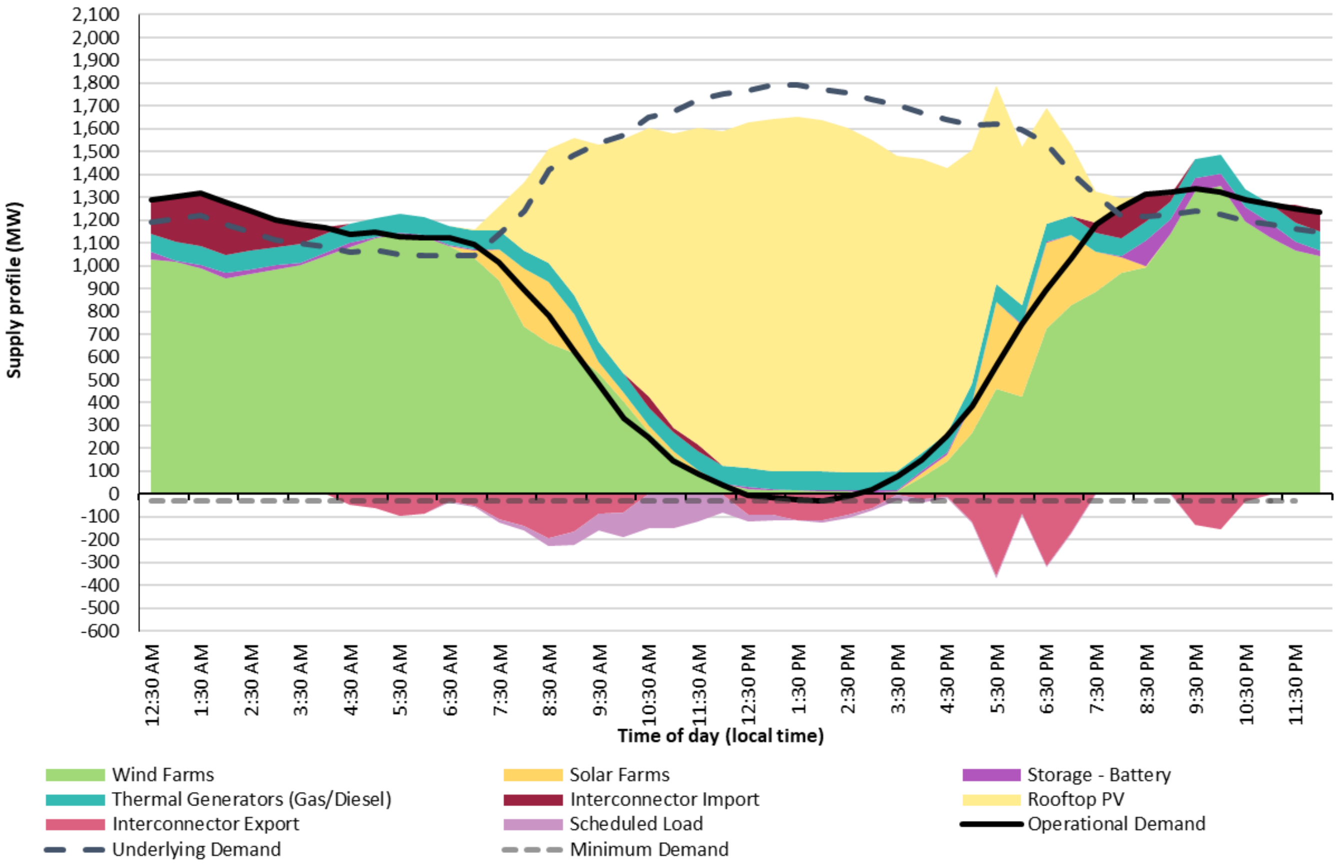
Table 6 Distributed PV contribution to underlying and operational annual minimum demand in South Australia

Year	Distributed PV contribution to underlying minimum demand (MW)	Date and time of underlying minimum demand (Adelaide time)	Distributed PV generation at the time of operational minimum demand (MW)	Date and time of operational minimum demand (Adelaide time)
2018-19	0	22/04/2019 5:00 AM	670	21/10/2018 1:30 PM
2019-20	0	3/11/2019 6:30 AM	834	10/11/2019 2:00 PM
2020-21	0	11/10/2020 5:00 AM	986	11/10/2020 1:00 PM
2021-22	0	3/10/2021 5:00 AM	1221	21/11/2021 1:30 PM
2022-23	0	13/11/2022 4:30 AM	1277	16/10/2022 1:30 PM
2023-24	0	26/11/2023 4:30 AM	1540	31/12/2023 2:00 PM

A new record low minimum operational demand of -30 MW as-generated was set on Sunday, 31 December 2023[29].

The most recent record, as seen in **Figure 14**, occurred at 1:30 PM (Adelaide time). During that half-hour, estimated rooftop PV output was 1,540 MW.

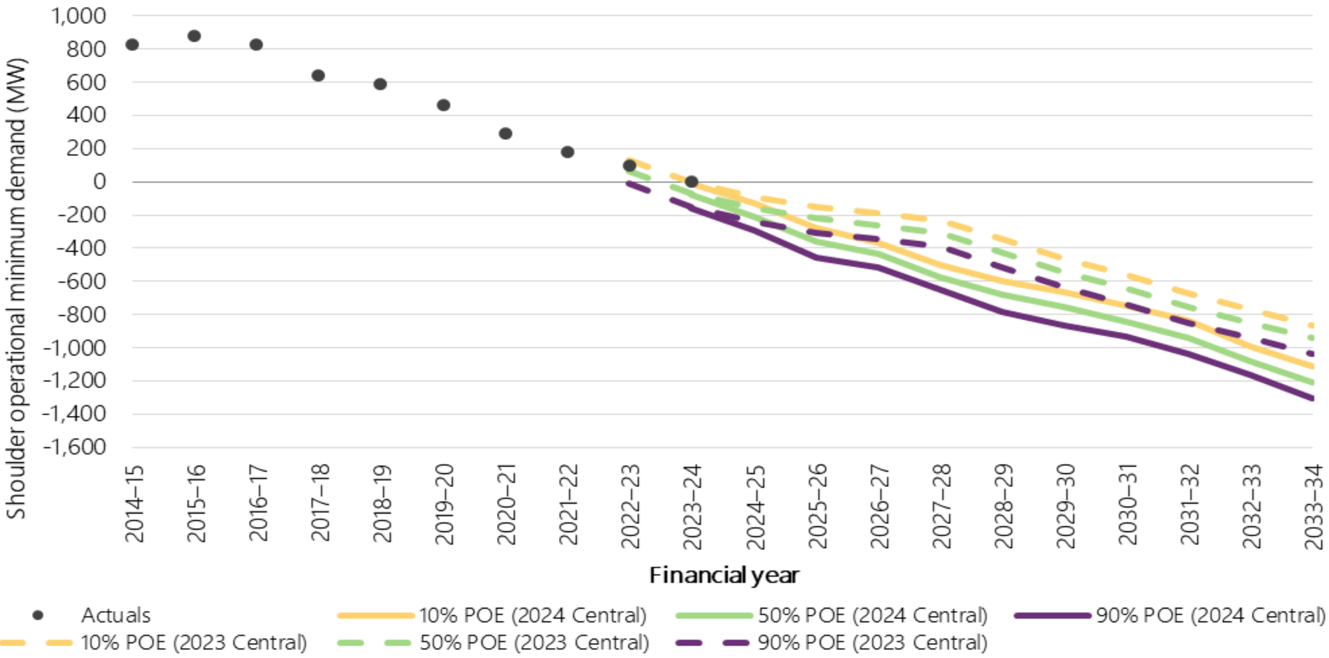
Figure 14 Profile of record minimum operational (as-generated) demand day (31 December 2023)



29 After the cut-off date for this report, a new record minimum operational demand of -205 MW (sent-out) was reached on Saturday 19 October 2024.

Figure 15 shows the Central scenario forecast of shoulder[30] minimum demand from the 2024 ESOO. It illustrates a relatively constant forecast decline of around 110 MW per year in minimum demand in the shoulder season, where the annual minimum most often occurs.

Figure 15 Actual and forecast shoulder operational minimum demand (sent-out) for South Australia (Central scenario), 2014-15 to 2033-34



Note: the 2016-17 minimum excludes the black system event day in South Australia on 28 September 2016.

2.4 Daily demand profiles

The average daily demand profiles presented in this section represent the operational (as-generated) demand, in megawatts, for each 5-minute dispatch interval of a day, averaged over the relevant days of the selected period. Changes to the average daily demand profile over time can provide insights into the impact of increasing distributed PV generation and demand side management. Only South Australian workdays have been included in the analysis; weekends and gazetted public holidays were excluded.

Summer daily demand

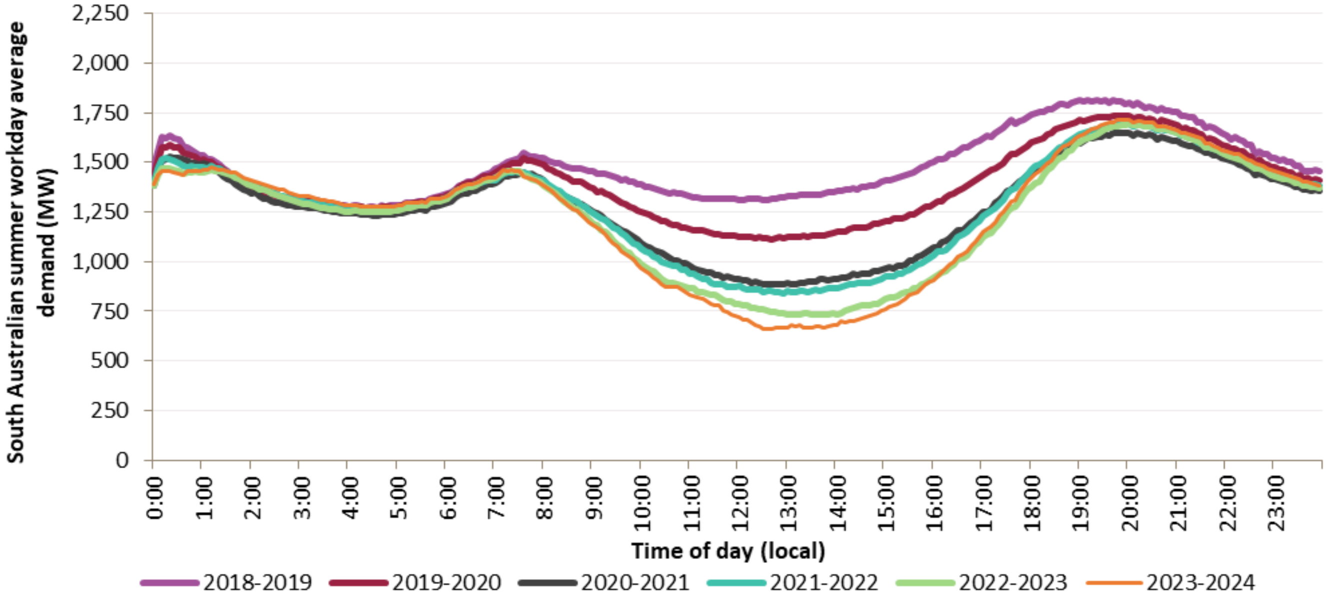
Figure 16 shows the South Australian average workday operational demand profile for summer from 2018-19 to 2023-24. Average summer operational demand year on year has been generally declining during daylight hours, due to increasing distributed PV generation, changing the shape of operational demand and lowering morning and evening peak demands.

Another noticeable feature in the demand profile is the sharp uptick at midnight (local time, or 11:30 PM NEM time), due to the controlled switching of electric hot water storage systems. SA Power Networks has been progressively moving some of its customers' hot water systems away from the night-time timer setting to turn on

[30] The shoulder period refers to September, October, April and May months.

during the middle of the day instead. Additional residential customer hot water loads may have been moved by retailers, or by customers themselves, as smart meters are being installed or to increase the amount of PV self-consumption. This has lowered the observed night-time peak significantly in recent years and may be reducing the decline in minimum demand.

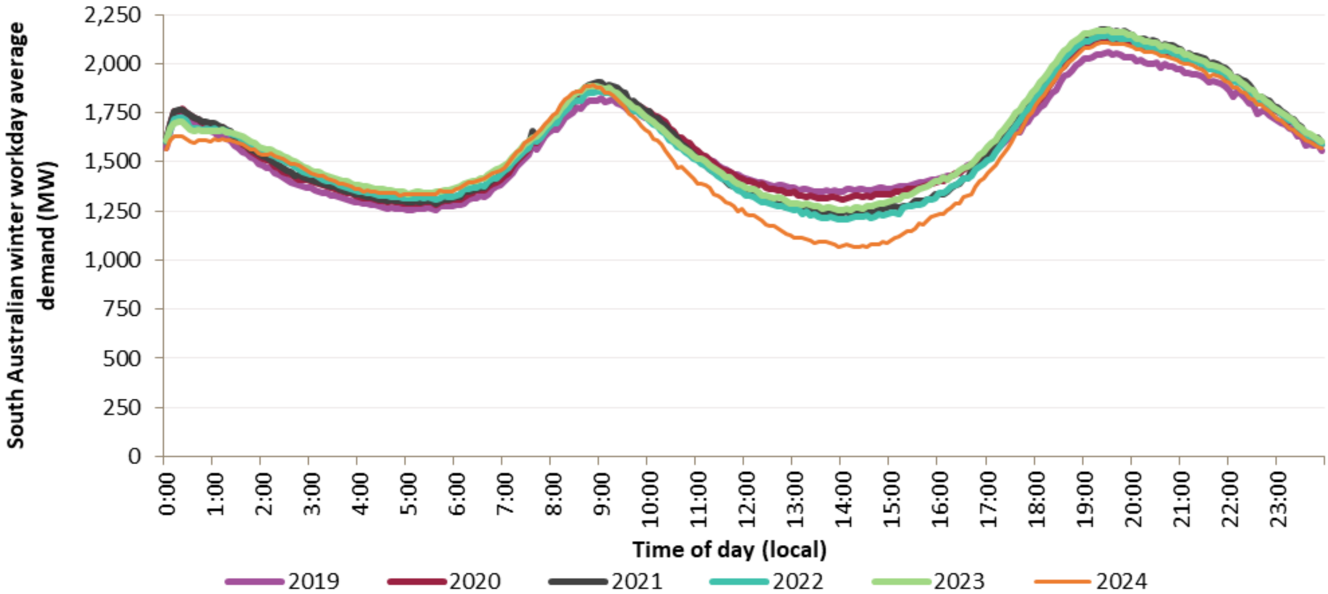
Figure 16 Summer workday average operational demand profiles



Winter daily demand

Figure 17 shows the South Australian average winter workday demand profile for winter 2019 to 2024. Clear morning and evening peaks in electricity consumption continue to be observable. Similar to summer, reduced grid demand is observed in the daylight hours, due to the increased output of distributed PV.

Figure 17 Winter workday average operational demand profiles



3 Existing supply and new developments

The supply mix in South Australia continues to evolve, with new developments particularly of wind generation and firming large-scale batteries in the last year.

For more information:

- **Generation information, October 2024 update, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.**
- **2024 ESOO, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.**
- **Generation forecast for South Australia, published October 2024, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/south-australian-advisory-functions.**
- **NEM generation maps at, https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/nem-generation-maps.**

The SAER applies commitment categories for supply in accordance with AEMO's Generation Information page definitions:

- **In service** generation and storage.
- **In commissioning** projects[31], which have met the commissioning requirements of their first hold point.
- **Committed** projects[32], that meet all five of AEMO's commitment criteria[33] but have not yet met the commissioning requirements of their first hold point.
- **Committed*** projects[34] that satisfy AEMO's Land, Finance and Construction commitment criteria plus either Planning or Components criteria. Progress towards meeting the final criteria is also evidenced and construction or installation has also commenced.
- **Anticipated** projects[35] that have demonstrated progress towards meeting at least three of the commitment criteria, and have updated their submission in the previous six months.

[31] Projects that are in commissioning are included in reliability assessments and integrated system planning. These projects are included in the ESOO Reliability Forecast at the Full Commercial Use Date (FCUD) submitted by the developer.

[32] Committed projects are included in the ESOO Reliability Forecast at six months after the FCUD submitted by the developer. These projects are included in reliability assessments and integrated system planning.

[33] For details about commitment criteria, see the Background Information tab on each spreadsheet at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[34] Committed* projects are included in the ESOO Reliability Forecast at six months after the FCUD submitted by the developer. These projects are included in reliability assessments and integrated system planning.

[35] Anticipated projects are included in the ESOO Reliability Forecast at the furthest date of either 1) the first day after the T-1 year for Retailer Reliability Obligation (RRO) purposes, or 2) one year after the FCUD submitted by the developer. These projects are included in reliability assessments and integrated system planning.

- **Publicly announced** projects that are earlier in their project development cycle and have not yet met sufficient commitment criteria to be included in either reliability assessments or system planning.

3.1 Existing generation and storage

Table 7 shows all generation and storage capacity in South Australia at the end of 2023-24. Wind power has overtaken gas to be the largest source of registered capacity and remains the largest source of generated electricity.

Table 7 South Australian registered capacity and local generation by energy source in 2023-24

Energy source	Registered capacity		Electricity generated	
	MW	% of total	GWh	% of total
Gas	2,569	23.9%	3,303	23.6%
Wind	2,770	25.8%	6,330	45.2%
Diesel + Other Non-Scheduled Generation (ONSG)	497	4.6%	122	0.9%
Rooftop PV	2,469	23.0%	2,566	18.3%
PVNSG	596	5.6%	476	3.4%
Solar	791	7.4%	1,028	7.3%
Storage – battery	1,044	9.7%	193	1.4%
Total	**10,736**	**100.00%**	**14,018**	**100.0%**

Table 8 shows differences in generation between 2022-23 and 2023-24, including interconnector flow metrics. Total generation declined slightly from 2022-23 to 2023-24, with increased imports and decreased exports. Wind remained the largest share of generation but decreased its share. Gas represented the second highest share of generation, though it decreased by 295 GWh. Solar and PVNSG increased their share.

Gas-powered generation and interconnector imports continued to be required to meet South Australian demand in periods with combinations of high demand, low solar irradiance and/or low wind, and for providing power system security.

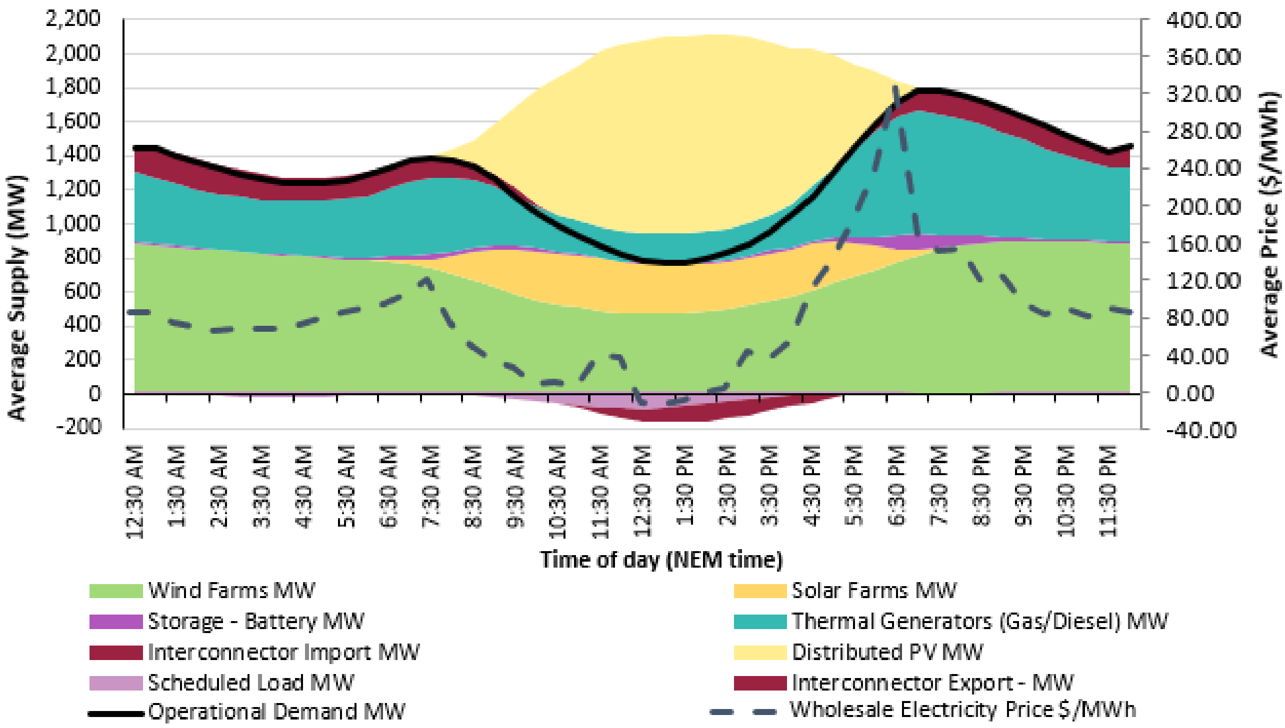
Table 8 South Australian electricity generation by fuel type, comparing 2022-23 to 2023-24

Supply source	2022-23 (GWh)	2023-24 (GWh)	Change (GWh)	Percentage change (%)	2022-23 percentage share (%)	2023-24 percentage share (%)	Change in percentage share (%)
Gas	3,598	3,303	-295	-8.2%	25.4%	23.6%	-2.0%
Wind	6,651	6,330	-322	-4.8%	46.9%	45.2%	-2.1%
Diesel + ONSG	116	122	6	5.5%	0.8%	0.9%	0.0%
Rooftop PV	2,504	2,566	62	2.5%	17.6%	18.3%	0.5%
PVNSG	440	476	36	8.2%	3.1%	3.4%	0.3%
Solar	804	1,028	233	27.7%	5.7%	7.3%	1.6%
Storage – battery	74	193	119	159.3%	0.5%	1.4%	0.8%

Supply source	2022-23 (GWh)	2023-24 (GWh)	Change (GWh)	Percentage change (%)	2022-23 percentage share (%)	2023-24 percentage share (%)	Change in percentage share (%)
Total local generation	**14,188**	**14,018**	**-170**	**190.2%**	**100.0%**	**100.0%**	
Energy imports	1,382	1,677	296	21.4%			
Energy exports	883	750	- 133	-15.0%			
Net energy imports	499	927	428	85.8%			

Figure 18 shows the average daily supply profile observed across 2023-24. While each actual day varied subject to actual consumer demand, wind, and solar output, the profile clearly shows that daytime solar generation enabled excess electricity to be exported to neighbouring regions, while South Australia is, on average, a net importer overnight. Average prices also follow this distinct intra-day trend, with low or negative prices during daylight hours, and higher prices in the evening (see Section 5.2).

Figure 18 Average daily supply profile, 2023-24 (MW)



3.2 Changes in generation and storage over the last five years

Figure 19 shows the mix of electricity generated in South Australia by fuel type[36] from 2017-18 to 2023-24, from:

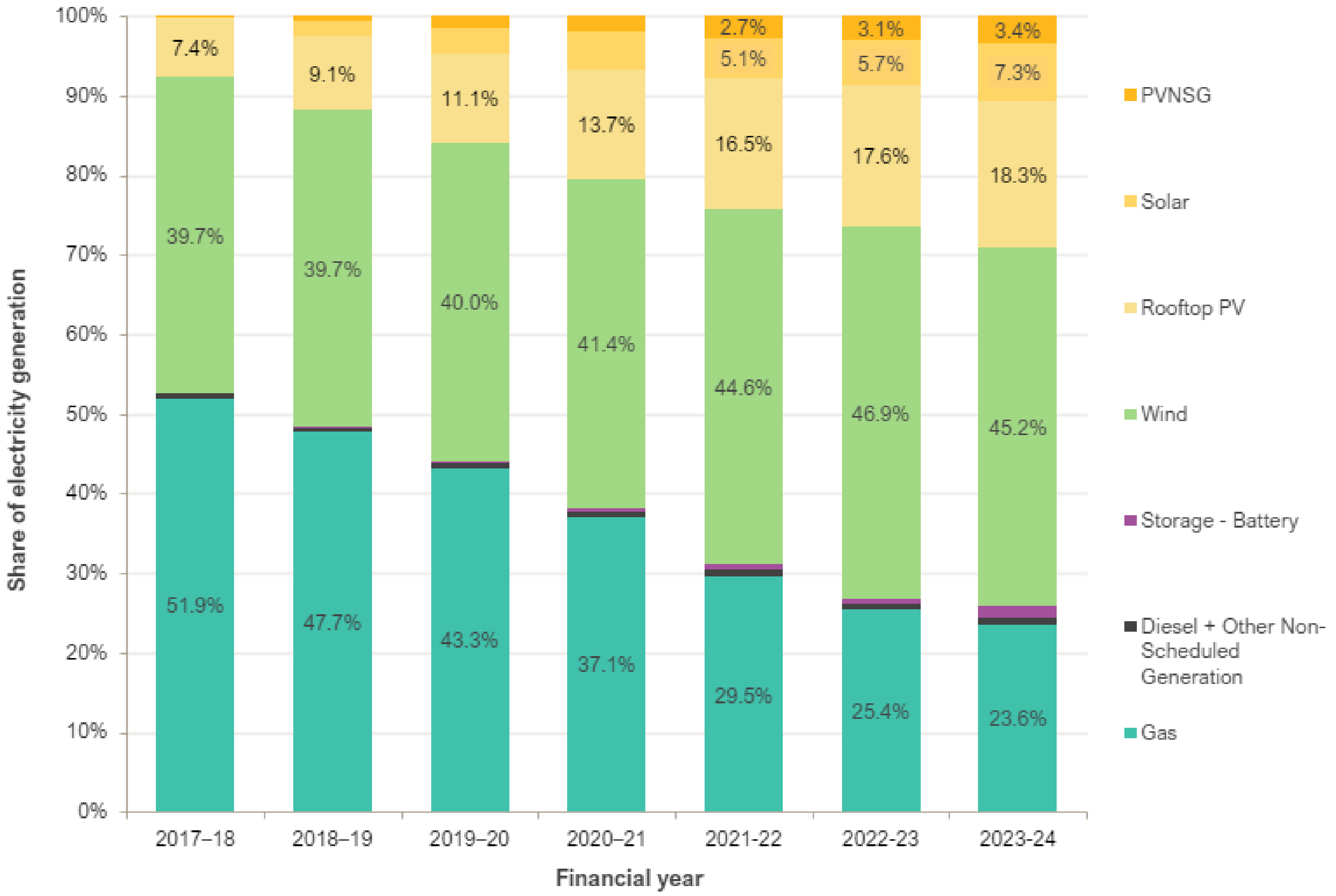
- All scheduled generators, including storage.

[36] Generation has been aggregated based on each power station's primary fuel type, and does not capture generation by secondary fuel type. The figure reflects the local generation market share. No adjustments have been considered for imports or exports across the interconnectors with Victoria, or scheduled load.

- All semi-scheduled and market non-scheduled wind farms.
- All semi-scheduled solar farms.
- Selected smaller market and non-market non-scheduled generators (NSGs).
- Estimated distributed PV.

Throughout the subsequent sections, changes in each technology grouping for 2023-24 are provided, including the average volume-weighted prices achieved for each technology (see Section 5.1 for more detail on pricing trends).

Figure 19 South Australian electricity generation by fuel type, 2017-18 to 2023-24



3.2.1 Wind farm capacity changes

Wind capacity grew by 209 MW in 2023-24, due to the development of Goyder South Wind Farm 1A.

Table 9 Wind generation changes in nameplate capacity, generation and volume-weighted price, 2017-18 to 2023-24

Financial year	Nameplate capacity (MW)*	Reason for increase in capacity	Maximum five-minute generation (MW)*	Volume weighted price ($/MWh)
2017-18	1,810	Hornsdale Stage 3 (112 MW)	1,618	81.15

Financial year	Nameplate capacity (MW)*	Reason for increase in capacity	Maximum five-minute generation (MW)*	Volume weighted price ($/MWh)
2018-19	2,141	Lincoln Gap (212.4MW), Willogoleche (119.36 MW)	1,713	84.18
2019-20	2,141	NA	1,823	45.25
2020-21	2,141	NA	1,826	30.16
2021-22	2,351	Port Augusta Renewable Energy Park (210 MW)	2,050	79.38
2022-23	2,348	NA	2,111	81.54
2023-24	2,557	Goyder South Wind Farm 1A (209 MW)	2,121	54.97

* Nameplate capacity taken from Generation Information publication and may change slightly from year to year. It includes In Commissioning facilities and excludes non-scheduled generation, apart from significant non-scheduled generators.

3.2.2 Large-scale solar capacity changes

In 2023-24, growth in large-scale solar continued as shown in **Table 10**, with nameplate capacity growing by 32 MW, largely due to the establishment of Mannum Solar Farm (30 MW).

Table 10 Large-scale solar generator changes in nameplate capacity, generation and volume-weighted price, 2017-18 to 2023-24

Year	Nameplate capacity (MW) [A]	Reason for increase in capacity	Maximum five-minute generation (MW) [A]	Volume weighted price ($/MWh)
2017-18	135	Bungala One Solar Farm (135 MW)	31	92.91
2018-19	378	Bungala Two Solar Farm (135 MW), Tailem Bend Solar Project 1 (108 MW)	209	126.26
2019-20	378	NA	227 [B]	55.74
2020-21	411	Adelaide Desalination Plant (11 MW), Morgan-Whyalla Pipeline Pumping Station No's 1-4 (22 MW)	326 [B]	21.80
2021-22	488	Adelaide Desalination Plant expansion (13 MW), Bolivar Waste Water Treatment Plant (8 MW), Happy Valley WTP (11 MW), Mannum-Adelaide Pipeline Pumping Station No's 2 and 3 (32 MW), Murray Bridge-Onkaparinga Pipeline Pumping Station No. 2 (13 MW)	342	56.52
2022-23	661	Tailem Bend Stage 2 Solar (105 MW) Port Augusta Renewable Energy Park – Solar (79 MW)	451	52.53
2023-24	693	Mannum Solar Farm 2 (30 MW)	561	33.03

A. Nameplate capacity taken from Generation Information publication and may change slightly from year to year. It includes In Commissioning facilities and excludes non-scheduled generation.
B. This figure increased more than registered capacity because Bungala Two was registered in 2018-19, was in commissioning and generating at lower levels in 2019-20, then generated at higher levels from July 2020.

3.3 Expected changes in generation and storage

Table 11 summarises combined nameplate capacity data, by generation source, for all scheduled, -semi scheduled, and -non-scheduled generation in South Australia[37] that is currently (at 31 October 2024) either:

[37] The total South Australian capacity in **Table 7** in **Section 3.1** is higher than shown here because a) it includes rooftop PV capacity and additional small non-scheduled generation, and b) it reports the originally registered capacity, not the current nameplate capacity as in **Table 7**.

- Operating.
- Expected to connect (definitions of committed and anticipated are discussed above at the start of Section 3.1).
- Expected to withdraw (as advised by participants).
- Proposed.

Table 11 Capacity of existing, announced withdrawal, committed, anticipated and publicly announced projects (MW) at October 2024

Status	CCGT	OCGT	Gas other	Solar [B]	Wind	Water	Biomass	Battery Storage	Other	Total
In service [A]	709	1,272	1,010	547	2,348	-	16	464	114	**6,479**
In service – excluding announced withdrawal	529	1,114	210	547	2,348		16	464	114	**5,342**
In service – announced withdrawal (permanent)	180	158	800							**1,138**
In commissioning				163	209	1		51		**424**
Committed					204			371		**575**
Anticipated		204		357				260		**821**
Publicly announced		465	45	5,272	2,503	780		8,280	200	**17,545**

A. In service includes announced withdrawal.
B. Solar is large-scale solar and excludes rooftop PV installations.

The key generation and storage forecast trends highlighted by this data, and by AEMO's 2024 *South Australian Generation Forecasts*[38], are:

- **Gas generation**, combining combined-cycle gas turbine (CCGT), open-cycle gas turbine (OCGT) and other gas technologies, collectively represents the largest technology of In Service generation with nearly 3,000 MW of capacity. It will have reduced capacity share due to advised retirements of 1,138 MW. Only 669 MW of additional OCGT generation is being considered, including the 204 MW hydrogen-ready dual-fuelled generator as part of the South Australian Hydrogen Jobs Plan which is considered Anticipated.
- **Wind generation** has a significant share of current capacity, with over 2,300 MW of In Service capacity, and is expected to grow with over 400 MW of In Commissioning and Committed projects and 2,503 MW of Publicly Announced projects.
- **Solar generation** represents a much smaller proportion of existing capacity (710 MW of In Service and In Commissioning capacity) but has a very large pipeline of projects (357 MW of Anticipated projects and 5,272 MW of Publicly Announced projects).
- **Battery storage** currently occupies a modest proportion of generation (515 MW of In Service and In Commissioning capacity); there is a very large amount of Publicly Announced projects (8,280 MW), as well as 631 MW of further Committed and Anticipated projects.

[38] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/south-australian-advisory-functions.

3.3.1 Capacity for next summer

Table 12 shows:

- The expected available capacity of scheduled, semi-scheduled, and significant non-scheduled generation in summer 2024-25 – for both peak and typical temperatures – and for winter 2025.
- How this expected capacity compares with the forecast capacity available last summer (2023-24), in peak and typical temperatures, and in winter 2024.

Notable changes since last summer include new wind generation and battery storage capacity.

Table 12 Scheduled, semi-scheduled, and significant non-scheduled generation available capacity, summer (peak and typical) 2023-24 and 2024-25 and winter 2024 and 2025

Energy source	Summer peak available capacity [A] (MW)		Summer typical available capacity [B] (MW)		Winter available capacity [A] (MW)	
	2023-24	2024-25	2023-24	2024-25	2024	2025
Diesel	338	237	361	252	397	283
Gas	2,105	2,123	2,229	2,247	2,387	2,390
Wind [C]	1,553	1,945	2,197	2,589	2,395	2,731
Solar	594	597	605	594	609	586
Storage – battery	470	670	470	671	511	741
Total	**5,060**	**5,571**	**5,862**	**6,353**	**6,300**	**6,730**

Source: AEMO Generation Information published October 2023 and October 2024.
A. Summer peak available capacity incorporates the impact of expected derating in response to high temperatures.
B. Summer typical available capacities represent the capacity available over summer during typical temperatures.
C. Available capacity for wind farms classed as significant non-scheduled is based on nameplate rating, since 10-year availability forecasts are not provided to AEMO for these units.

3.3.2 Generation developments by commitment classification

The following sub-sections outline the key developments affecting generation developments and withdrawals, informed by submissions to AEMO's Generation Information dataset. This section represents the October 2024 release of the Generation Information dataset[39], unless otherwise stated.

Generation withdrawals

Engie has advised its intention to mothball Port Lincoln Gas Turbine (GT) and Snuggery power stations effective July 2024, and has advised revised closure dates of 1 January 2028 for both power stations.

Committed developments

Committed and 'In Commissioning' projects in South Australia include:

- Blyth Battery Energy Storage System (BESS, 200 MW/400 MWh of storage).
- Clements Gap – BESS (60 MW/120 MWh of storage).

[39] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

- Goyder South Wind Farm 1A (209 MW of wind).
- Goyder South Wind Farm 1B (204 MW of wind).
- Mannum Solar Farm 2 (30 MW of solar).
- Tailem Bend Battery Project (42 MW/84 MWh of storage).
- Tailem Bend Stage 2 Solar Project (105 MW of solar).
- Templers BESS (111 MW/291 MWh of storage).

Anticipated developments

The following projects are classified as anticipated developments:

- Bungama Solar (150 MW/300 MWh of storage).
- Cultana Solar Farm (357 MW of solar).
- Hydrogen Jobs Plan (204 MW of OCGT).
- Lincoln Gap BESS Bidirectional Unit (BDU, 10 MW/10 MWh of storage).
- Mannum BESS (100 MW/200 MWh of storage).

Other publicly announced developments

A total of 89 electricity generation and storage developments are classified as publicly announced in South Australia, being neither committed nor anticipated, totalling 17,545 MW. This includes some small non-scheduled projects. **Table 13** lists these developments by generation source (only large sites with capacity ≥200 MW are listed, with the full list being available in the Generation Information publication).

As noted above, publicly announced new generation investment in South Australia continues to focus on renewable developments and energy storage.

Table 13 Publicly announced generation and storage developments with capacity of ≥200 MW, October 2024

Wind farms	Solar farms	Gas or hydrogen projects	Storage developments	Hybrid developments [A]
• Goyder North Stage 1 Wind Farm (300 MW) • Lincoln Gap Wind Farm Stage 3 (277 MW) • Palmer Wind Farm (294 MW) • Twin Creek Wind Farm (302 MW) • Yorke Peninsula Wind Farm (749 MW)	• Australia Plains Solar Farm (200 MW) • Bridie Track Solar Project (300 MW) • Bungama Solar (280 MW) • Port Augusta Solar Farm (300 MW) • Port Pirie Solar Farm (300 MW) • Project Monash – Solar (375 MW) • Riverland Solar Storage – Solar (330 MW)	• Green Hydrogen Power Station (200 MW)	• Augusta BESS (403 MW/403 MWh) • Baroota Pumped Hydro Project (250 MW) • Brinkworth BESS (250 MW/780 MWh) • Bundy Energy Hub A (BESS) (250 MW/Storage not supplied) • Bundy Energy Hub B (250 MW/Storage not supplied) • Bungama BESS (ARENA) (200 MW/400 MWh)	• Bundey BESS and Solar Project (475 MW) • Carmodys Hill Wind Farm (251 MW) • Geranium Plains Solar and BESS (250 MW) • Markaranka Solar and Storage (125 MW) • Robertstown Solar (500 MW) • Solar River Solar And BESS Project (256 MW) • Sturt Solar (300 MW)

Wind farms	Solar farms	Gas or hydrogen projects	Storage developments	Hybrid developments [A]
	• The Solar River Project – Stage 1 (200 MW) • The Solar River Project – Stage 2 (200 MW) • Yoorndoo Ilga Solar (250 MW)		• Davenport BESS (270 MW/540 MWh) • Goat Hill Pumped Hydro (230 MW/1,840 MWh) • Highbury Pumped Hydro Energy Storage (300 MW/Storage not supplied) • Osborne BESS (300 MW/Storage not supplied) • Pacific Green Energy Park – Limestone Coast North (250 MW/500 MWh) • Pacific Green Energy Park – Limestone Coast West (250 MW/500 MWh) • Para Substation/Gould Creek BESS (225 MW/450 MWh) • South East BESS – Storage (200 MW/400 MWh) • Summerfield BESS (240 MW/480 MWh) • Tailem Bend Stage 3 (204 MW/408 MWh) • Templers B BESS (200 MW/400 MWh) • Tungkillo BESS (270 MW/2,715 MWh)	

A. Hybrid developments means generation projects that incorporate multiple technologies within the one project, for example a solar farm with a battery storage solution. The capacity refers to the wind or solar farm. See the Generation Information dataset for more information on the storage capacity.

Table 14 shows that since the October 2023 Generation Information (reported on in the 2023 SAER) there has been an increase of 2,745 MW of aggregate capacity proposed in South Australia, driven by solar and battery storage projects. The capacity of wind projects has decreased, due to some revisions to project sizes.

Table 14 South Australian publicly announced generation projects by energy source, as of October 2024

Energy source	Number of projects	Capacity (MW)	Capacity (% of total projects tracked)	Change in number of projects from October 2023	Change in capacity from October 2023 (MW)
Gas	4	510	4.05%	0	0
Diesel	0	0	0.00%	0	0
Solar	26	5,272	30.05%	5	1,903
Biomass	0	0	0.00%	0	0
Wind	8	2,503	14.27%	0	-1,588
Water	3	780	4.45%	0	0
Storage – battery and VPP	48	8,280	47.19%	8	2,430
Total	**89**	**17,345**	**100.0%**	**13**	**2,745**

3.4 Gas-powered generation

For more information:

- **2024 GSOO, at http://aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.**
- **2024 South Australian Generation Forecasts, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/south-australian-advisory-functions.**
- **AEMO forecasting portal, at https://forecasting.aemo.com.au/.**

South Australia observed a continued decline in electricity production from gas-powered generation in 2023-24, with a drop of 7.5% compared to last year. The decline in gas-powered generation resulted from:

- Additional supply from distributed rooftop PV, grid-scale renewables and storages, including ramping of commissioning at Tailem Bend Solar Farm and Torrens Island battery project.
- Increased imports from Victoria.
- Low electricity spot prices that resulted in less frequent economic operation of gas-powered generation.

From July 2023 to the end of March 2024, gas generators elected to decommit their units during periods of high variable renewable energy (VRE) output, resulting in more directions required by AEMO to maintain minimum synchronous generation levels (albeit still at substantially lower volumes than before operation of all four synchronous condensers) as compared to the same periods in 2022-23. During April to June 2024, low wind and dry conditions[40] in southern NEM regions lead to increased gas generation in South Australia. This highlights the important role of flexible gas-powered generation during periods of reduced renewable generation.

Medium- and long-term gas-powered generation forecasts for South Australia are difficult to predict. The requirement for flexible gas-powered generation will be largely affected by the development pace of new wind, solar and battery storages in South Australia, Victoria and New South Wales to replace retiring thermal units. Increased electrification, adoption of EV and ramping up hydrogen production may increase the overall electricity demands and consequently gas generation in South Australia. Other factors – such as weather volatility, coal outages and seasonal mothballing in neighbouring regions, and project delays for replacements to dispatchable capacity – could also heighten dependence on gas-powered generation.

AEMO's latest projections[41] show a continuation of the downward trend for annual gas-powered generation in South Australia in the near to medium term, driven by:

- Continued forecast installation of distributed PV causing lower operational demand.
- Increasing supply from wind and grid-scale solar as new facilities are connected and commissioned.
- Growing imports of low-cost electricity at times of surplus in neighbouring regions, as new VRE capacity comes online in Victoria.

[40] See https://aemo.com.au/en/newsroom/media-release/wintry-weather-on-the-east-coast-and-warmer-weather-in-the-west

[41] At http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions.

- New grid-scale batteries[42] that will compete with gas-powered generation to provide firming and grid services during low-VRE and peak demand periods.
- Planned completion of the Project EnergyConnect interconnector in 2026 that will enable increased sharing of electricity between New South Wales and South Australia. Full operation of Project EnergyConnect may reduce the minimum number of synchronous generating units online under normal operating conditions.
- Delayed retirement of Eraring Power Station in New South Wales from August 2025 to August 2027.

Despite the declining forecast of gas generation in South Australia, AEMO anticipates that flexible gas generators will continue to play a critical role in both South Australia and the NEM by providing essential power system security services, peaking capacity, and backup generation particularly during periods of low renewable output.

In the long term, South Australia's annual gas generation is anticipated to increase in the late 2030s. This projected rise is driven by the retirement of coal generators in other NEM regions, along with the growing need to support a high-penetration VRE system. Many major gas plants in South Australia are also scheduled to exit the market around the same period. The 2024 ISP[43] projects a need for investment in new flexible gas generators or alternative firming technologies in the 2030s to address the increasing demand for flexible generation to replace aging thermal plants across the NEM.

3.5 Emissions intensity of South Australian generation

Annual South Australia emissions intensity, measured as the Carbon Dioxide Equivalent Intensity Index (CDEII)[44] from local generators in South Australia, continued to decline, with emissions at their lowest level during the 2023-24 financial year, as **Figure 20** shows.

Notably:

- Total emissions from South Australian generation in 2023-24 were 1.55 million tonnes (Mt) carbon dioxide equivalent (CO2-e), a decrease of 0.39 Mt (or 20%) compared to 2022-23.
- Emissions intensity reduced by 14% from 0.17 tonnes/MWh in 2022-23 to 0.14 tonnes/MWh in 2023-24, the lowest levels to date.

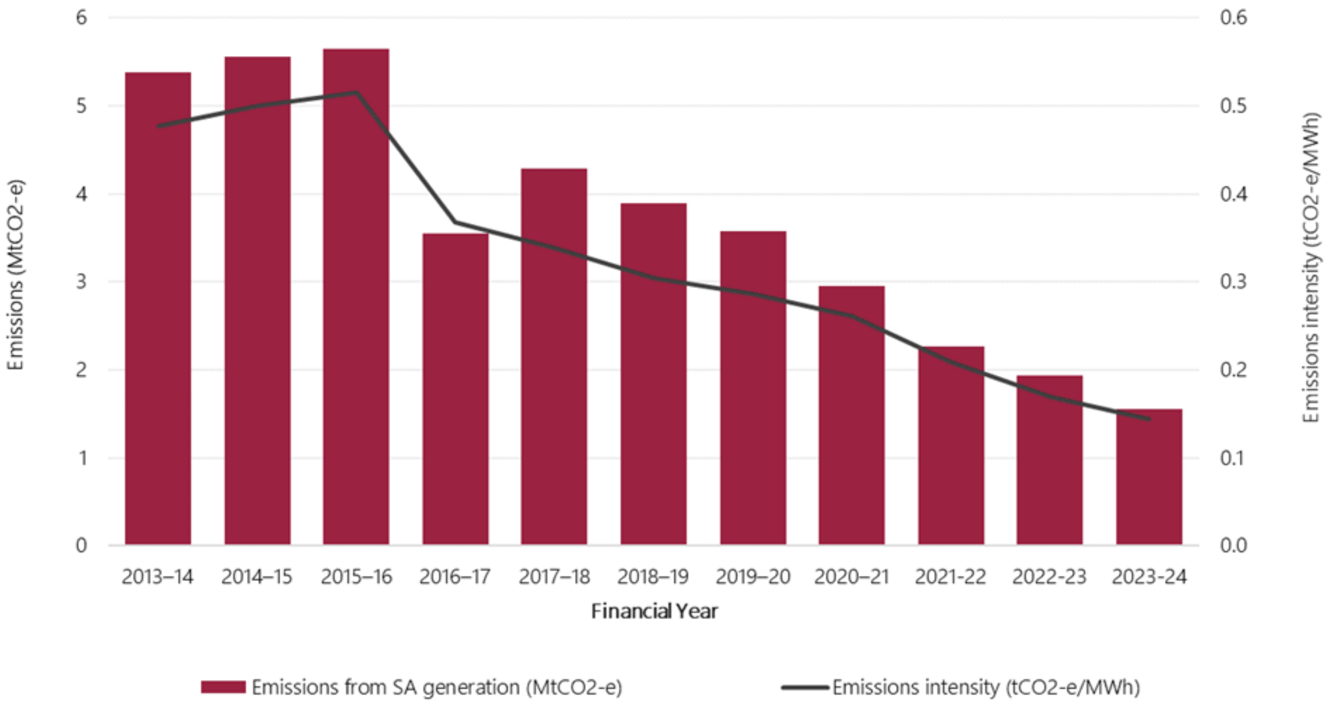
These reductions reflect increased penetration of rooftop PV, large-scale renewables and storages, and reduced gas-powered generation.

[42] The 250 MW/250 MWh Torrens Island BESS was operational from August 2023 and the 200 MW/400 MWh Blyth BESS is expected to be available in 2025.

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

[44] See http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Settlements-and-payments/Settlements/Carbon-Dioxide-Equivalent-Intensity-Index.

Figure 20 South Australian annual emissions and emissions intensity, 2013-14 to 2023-24 (MtCO2-e)



3.6 Curtailment and economic offloading

For historical curtailment data, this report uses the term "curtailment" in the same sense it is used in AEMO's *Quarterly Energy Dynamics* reports[45]. In this context, curtailment refers to any limitation on the output of a generator other than due to "economic offloading".

Economic offloading refers to a generator being dispatched below its maximum availability, because some or all of its output was bid into price bands greater than the regional reference price, that is, it was undercut by competitors offering their output at a lower price.

Curtailment therefore refers to energy from a generator not being dispatched, even though it was bid at or below the regional reference price, because of some other limitation (for example a network constraint).

Figure 21 shows the average quarterly curtailment and economic offloading for South Australia wind generators (as an average value across all dispatch periods in each quarter). The figure also shows the South Australian regional reference price (RRP) averaged across only the dispatch periods where wind curtailment or economic offloading occurred.

In 2023-24, both wind curtailment and economic offloading decreased relative to the prior year, with economic offloading averaging 43 MW, and curtailment averaging 12 MW, across all dispatch periods in the year.

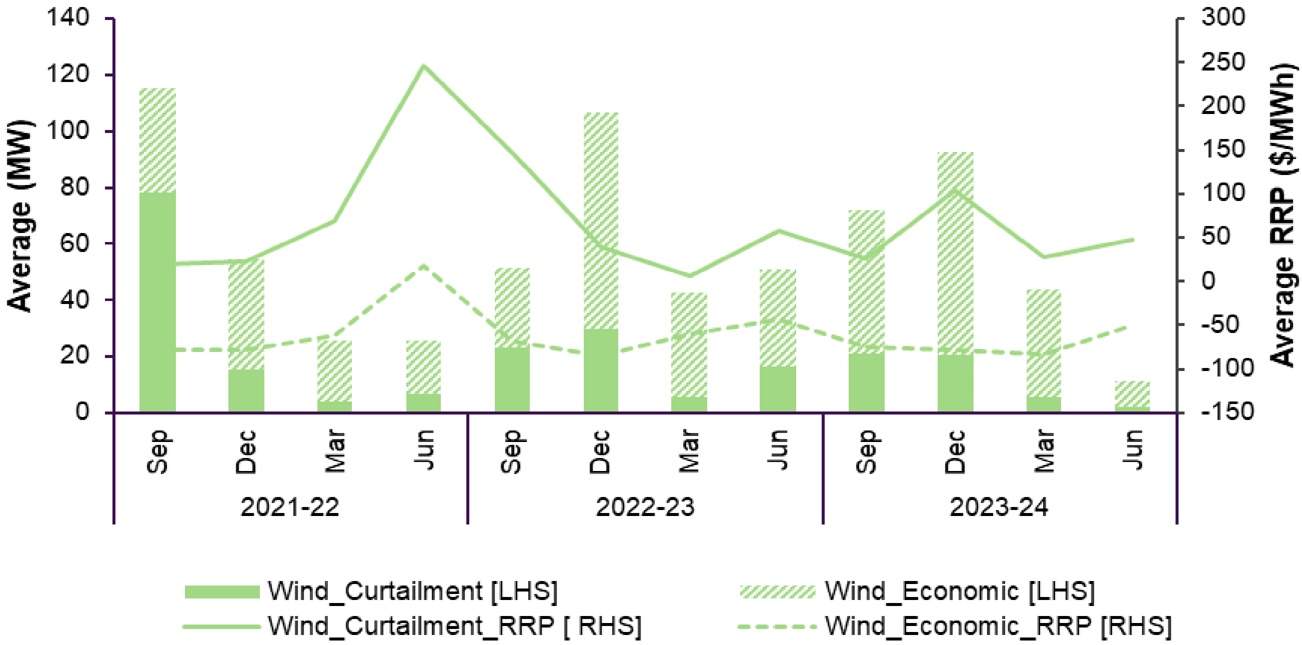
The sum of wind curtailment and economic offloading as a percentage of wind generation availability was 7% in 2023-24, down from 8% in 2022-23. This year-on-year reduction was driven by the June quarter, due to sustained

[45] At https://aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed.

periods of low wind speeds reducing the availability of wind generators to the lowest level experienced since the June 2017 quarter.

As expected, the average South Australian RRP during dispatch periods where economic offloading occurred was negative, at -$72/MWh in 2023-24, and the average South Australian RRP during periods of curtailment over 2023-24 was $51/MWh. The highest quarterly average was $103/MWh in the December quarter, driven by severe weather events on 8 December 2023 which caused the reclassification of non-credible contingency risks as credible, impacting the Heywood interconnector and other South Australian transmission lines and constraining the output of multiple wind generators in the region and causing price volatility.

Figure 21 Average wind curtailment and economic offloading, 2021-22 to 2023-24



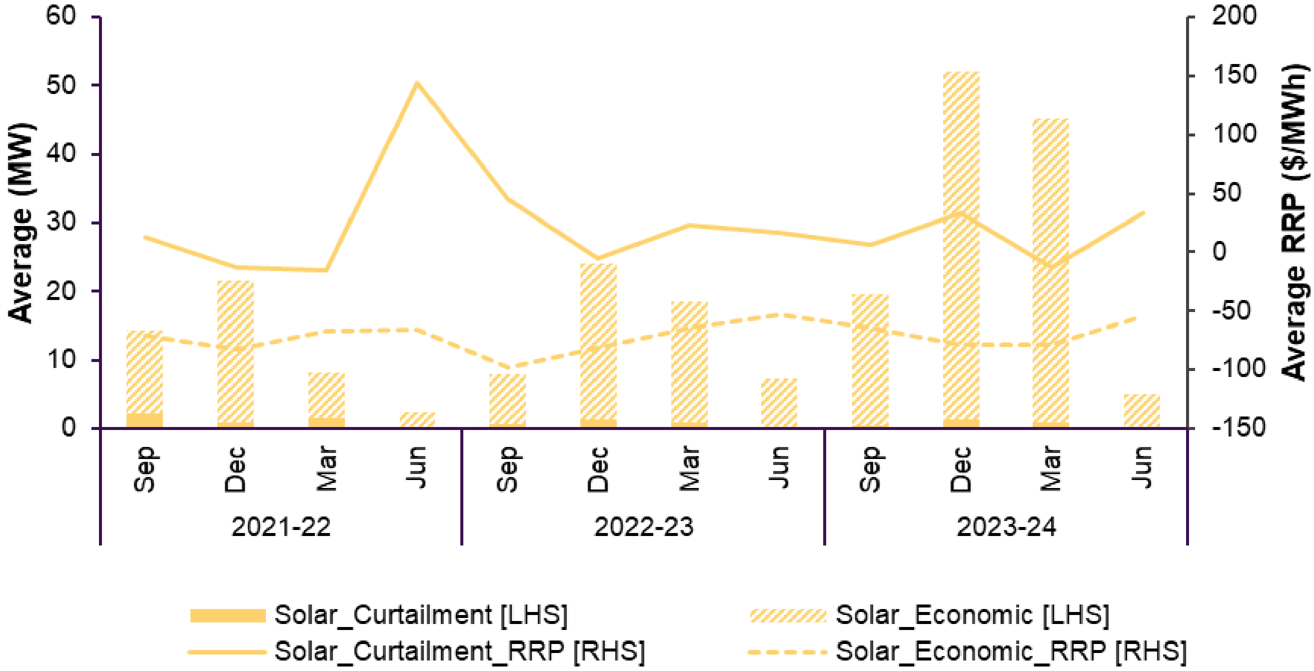
Note: The total height of the bars in the figure shows the total amount of wind generation not dispatched due to both economic offloading and curtailment as a MW average across all dispatch periods in each quarter. The lines show the average South Australian RRP during dispatch periods where economic offloading or curtailment of wind generation occurred, respectively.

Figure 22 shows the average quarterly curtailment and economic offloading for South Australia grid-scale solar generators (as an average value across all dispatch periods in each quarter). The figure also shows the South Australian RRP averaged across only the dispatch periods where grid-scale solar curtailment or economic offloading occurred.

In South Australia, grid-scale solar curtailment has been minor, averaging around 1 MW during the past three years. Economic offloading of grid-scale solar generators however increased in 2023-24 to average 30 MW, more than double the 14 MW average in the previous year. As a percentage of grid-scale solar generator availability this represented an increase from 13% in 2022-23 to 21% in 2023-24. The increase in grid-scale solar economic offloading has been driven by growth in distributed PV output in South Australia, with average distributed PV output increasing by 47 MW (+16%) from 2022-23 levels to reach 343 MW in 2023-24.

In 2023-24, the average South Australian RRP during dispatch periods with economic offloading of grid-scale solar generation was -$69/MWh, and the average RRP during dispatch periods with curtailment was $15/MWh.

Figure 22 Average grid-scale solar curtailment and economic offloading, 2021-22 to 2023-24



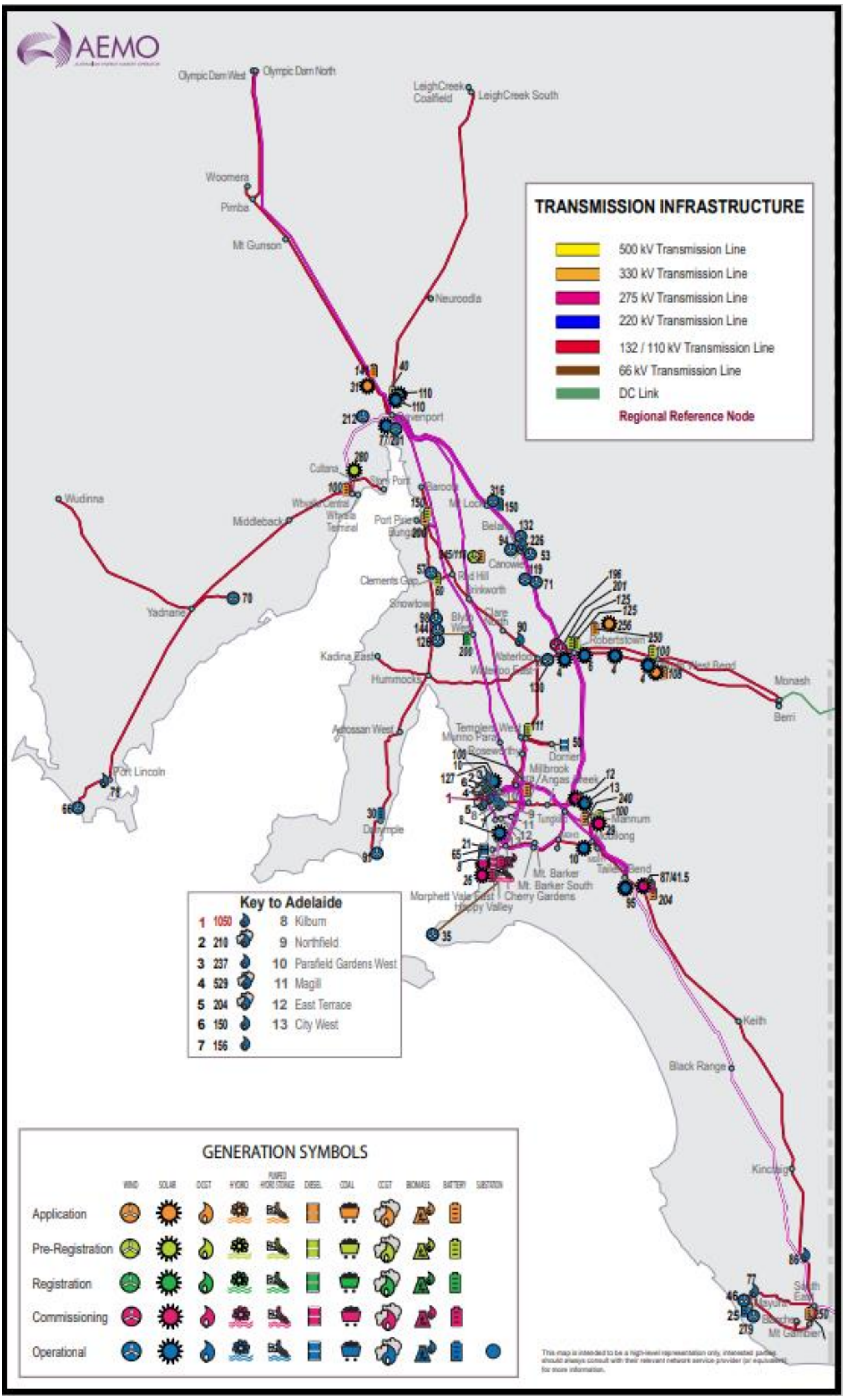
Note: The total height of the bars in the figure shows the total amount of grid-scale solar generation not dispatched due to both economic offloading and curtailment as a MW average across all dispatch periods in each quarter. The lines show the average South Australian RRP during dispatch periods where economic offloading or curtailment of grid-scale solar generation occurred, respectively.

3.7 Location of South Australian generation and storage

Figure 23 shows the locations of existing and proposed generation and storage projects in South Australia, with existing transmission[46].

[46] This map version is dated 12 August 2024. The map is regularly updated on AEMO's website at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/nem-generation-maps.

Figure 23 Locations of generation and storage in South Australia



3.8 Existing and future transmission developments

For more information:

- Transmission Augmentation Information page, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.
- 2023 IASR, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.
- 2024 ISP, at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp.

3.8.1 Status of transmission upgrade projects

A number of critical network infrastructure projects are underway or have recently been completed in South Australia to support its energy transition:

- **Project EnergyConnect** will be a new interconnector between the electricity systems of South Australia and New South Wales, with a connection to Victoria. The Australian Energy Regulator (AER) provided expenditure approval for this project in May 2021. The project will be delivered in two stages and involves:
  - Stage 1 (Energised[47]):
    - A new Robertstown to Bundey 275 kilovolts (kV) double-circuit line.
    - A new Bundey to Buronga 330 kV double-circuit line with one circuit connected initially.
    - A new Buronga to Red Cliffs 220 kV double-circuit line.
    - Turning the existing 275 kV line between Para and Robertstown into Tungkillo.
    - Associated reactive plant, transformers, phase shifting transformers and synchronous condensers.
    - An inter-trip protection scheme to trip the Project EnergyConnect interconnector if South Australia becomes separated from Victoria via the Heywood Interconnector.
  - Stage 2 (expected in service by May 2026, with capacity release expected in July 2027)[48]
    - A second 330 kV circuit on the Bundey–Buronga 330 kV double-circuit line.
    - A new Dinawan to Buronga 330 kV double-circuit line.
    - A new 500 kV double-circuit line from Dinawan to Wagga Wagga operating initially at 330 kV.
    - Associated reactive plant, transformers, phase shifting transformers and synchronous condensers.
    - A special protection scheme to detect and manage the loss of either of the AC interconnectors connecting to South Australia.

[47] The capacity release for Project EnergyConnect stage 1 is conditional on availability of suitable market conditions and acceptable test results.

[48] ElectraNet has updated expected in service timing of Project EnergyConnect stage 2 to June 2026 in its *2024 Transmission Annual Planning Report* (TAPR). The capacity release timing for Project EnergyConnect stage 2 is conditional on availability of suitable market conditions and acceptable test results.

- **SA Transmission Network Voltage control**, expected in service by mid-2026[49]. This project is to install four 60 megavolt amperes reactive (MVAr) 275 kV reactors around the Adelaide metropolitan area and a 50 MVAr 275 kV capacitor back at South East to increase static and dynamic reactive voltage control capability across the South Australian network.
- ElectraNet is completing the **Robertstown 132 kV Uprating project,** by end 2024. This project involved the replacement of low rated plant and updating of the Murraylink runback schemes to improve export capacity through Murraylink.

3.8.2 Renewable energy zones (REZs)

AEMO identifies candidate REZs as part of the ISP. These are high-quality resource areas where clusters of large-scale renewable energy projects can be developed using economies of scale.

In the 2024 ISP, published in June 2024, the VRE outlook for the *Step Change* scenario shows nearly 10 GW of new utility-scale wind and solar is projected to be required by 2050 to assist in replacing retiring gas generation capacity and to support load growth. The Mid-North South Australia REZ sees an immediate increase in VRE, with an additional 1,200 MW of new wind capacity required by 2029-30.

A set of REZ scorecards[50] for South Australia were also published as part of the 2024 ISP. These scorecards include characteristics such as indicative resource availability, indicative geographic area of the REZ, generator capacity factor assessed against a number of reference years, potential climate risks, and transmission expansion outlooks.

As an outcome of the 2022 ISP, AEMO requested preparatory activities from ElectraNet for the South East South Australia REZ and Mid-North South Australia REZ[51,52]. In the 2024 ISP, AEMO identified the Mid North South Australia REZ expansion as an actionable ISP project, and specified that ElectraNet publish a *Project Assessment Draft Report* (PADR) as part of a Regulatory Investment Test (RIT-T) for the project by 1 December 2025[53]. A range of information about the declaration of this actionable ISP project is available in the 2024 ISP, including Appendix 5 Network Investments[53] and Appendix 6 Cost Benefit Analysis[54].

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[49] ElectraNet, *2024 Transmission Annual Planning Report*, at https://www.electranet.com.au/wp-content/uploads/ElectraNet-2024-TAPR.pdf.

[50] AEMO, *2024 ISP Appendix 3 Renewable Energy Zones,* at https://aemo.com.au/-/media/files/major-publications/isp/2024/appendices/a3-renewable-energy-zones.pdf.

[51] ElectraNet. *South East South Australia Renewable Energy Zone Preparatory Activities Final Report*, at https://aemo.com.au/-/media/files/major-publications/isp/2023/teor-reference-materials/electranet---south-east-south-australia-rez-expansion.pdf.

[52] ElectraNet. *Mid-North South Australia Renewable Energy Zone Preparatory Activities Final Report*, at https://aemo.com.au/-/media/files/major-publications/isp/2023/teor-reference-materials/electranet---mid-north-south-australia-rez-expansion.pdf.

[53] AEMO, *2024 ISP Appendix 5 Network Investments*, at https://aemo.com.au/-/media/files/major-publications/isp/2024/appendices/a5-network-investments.pdf.

[54] AEMO, *2024 ISP Appendix 6 Cost Benefit Analysis*, at https://aemo.com.au/-/media/files/major-publications/isp/2024/appendices/a6-cost-benefit-analysis.pdf.

4 Reliability of supply

As reported in the 2024 ESOO, AEMO identified that the timely delivery of expected investments in generation, storage and transmission are critical to maintaining reliability for electricity consumers, and that reliability levels have the potential to be maintained within relevant standards over the next 10 years if programs and initiatives already established are delivered on time and in full. However, under a sensitivity that includes only developments that meet AEMO's commitment criteria, AEMO forecasts reliability gaps in South Australia for the coming summer, in 2026-27 and in 2033-34.

4.1 Forecast power system reliability

AEMO's ESOO assesses the NEM's adequacy of supply in meeting forecast demand over the next 10 years, evaluating supply scarcity risks that may result in expected unserved energy (USE) exceeding the IRM of 0.0006%[55] or, from 30 June 2028, the reliability standard of 0.002%[56].

The assumptions used to develop the 2024 ESOO's reliability forecasts are outlined in AEMO's 2023 IASR Workbook[57] and the 2024 *Forecasting Assumptions Update*[58]. The supply data used in this assessment is from the July 2024 Generation Information publication available at the time of ESOO modelling.

Unserved energy (USE) is the amount of energy demanded, but not supplied due to reliability incidents. This may be caused by factors such as insufficient levels of generation capacity, demand response or inter-regional network capability to meet demand.

The **Interim Reliability Measure (IRM)** is set to ensure that sufficient supply resources and inter-regional transfer capability exist to meet 99.9994% of annual demand for electricity in each NEM region, by helping keep expected USE in each region to no more than 0.0006% in any year.

Any forecast reliability gap is based on expected USE not meeting the IRM (or, from 30 June 2028, not meeting the reliability standard, which is 0.002% of expected USE in a region in a year).

If AEMO reports a forecast reliability gap, this triggers a reliability instrument request under the **Retailer Reliability Obligation (RRO)**.

4.2 South Australian reliability outlook for the next 10 years

The 2024 ESOO includes four sensitivities, all of which consider the *Step Change* demand scenario, which are also included in this report[59]:

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[55] The IRM allows for a maximum expectation of 0.0006% of energy demand to be unmet in a given region per financial year. It was introduced by the National Electricity Amendment (Interim Reliability Measure) Rule 2020 (IRM Rule). The IRM Rule and changes to the Retailer Reliability Obligation (RRO) rules are intended to support reliability in the system while more fundamental reforms are designed and implemented. The use of the measure for contracting reserves and for the RRO is set to expire in June 2028, after which the reporting obligation reverts to the previous position under the National Electricity Rules (NER), that AEMO must report on whether the reliability standard would be exceeded in any financial year.

[56] The NEM reliability standard is set to ensure sufficient supply resources and inter-regional transfer capability exists to meet 99.998% of annual demand for electricity in each region. It allows for a maximum expectation of 0.002% of energy demand to be unmet in a given region per financial year.

[57] At https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-iasr-assumptions-workbook.xlsx.

[58] At https://aemo.com.au/en/consultations/current-and-closed-consultations/2024-forecasting-assumptions-update-consultation.

[59] Further detail about the full set of assumptions in each sensitivity is available in the 2024 ESOO, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

- The *Committed and Anticipated Investments* sensitivity includes existing, in commissioning, committed and anticipated generation, storage and transmission projects, according to AEMO's commitment criteria, as well as committed investments in demand flexibility and consumer batteries that are coordinated to minimise investment needs in utility-scale solutions. This sensitivity adjusts participant supplied timing to reflect average differences in advised and observed commissioning, and is the sensitivity that applies for Retailer Reliability Obligation (RRO) purposes. It does not include actionable transmission investments nor forecast growth in coordinated CER and flexible demand resources.
- The *On-time Delivery* sensitivity uses similar assumptions to the *Committed and Anticipated Investments* sensitivity but assumes projects commence at the FCUD provided by the project proponent. The *Committed and Anticipated Investments* sensitivity applies delays based on the status of the project in AEMO's commitment criteria.
- The *Actionable Transmission and Coordinated CER* sensitivity includes projects defined in the 2024 ISP as 'actionable', meaning that they should progress as soon as possible. Should these projects progress as identified in the ISP, they have the potential to significantly improve the reliability outlook, particularly in the second half of the ESOO horizon.
- *Federal and State Schemes* sensitivity includes the impact of policies such as the first tender as part of the federal Capacity Investment Scheme, the South Australian Hydrogen Jobs Plan, and the Australian Renewable Energy Agency (ARENA) large-scale battery storage funding round[60]. It also includes:
  - Actionable transmission investments and forecast growth in coordinated CER and flexible demand resources.
  - Firming and some renewable energy developments that have specific funding, development or contracting arrangements under federal, state and territory government schemes and programs.

Figure 24 shows results on the forecast USE for South Australia under the relevant modelled scenarios and sensitivities:

- Results from the *Federal and State Schemes* sensitivity indicate that if delivered on time and in full, then federal and state government programs providing additional renewable generation and dispatchable resources, actionable transmission developments, and coordination of forecast CER would provide sufficient generation capacity to meet growing electricity demand within relevant reliability standards over most of the next 10 years. Timely delivery of these expected investments is critical.
- Results from the *Committed and Anticipated Investments* sensitivity indicate that if further investment beyond current committed and anticipated projects is delayed or does not materialise, AEMO forecasts reliability gaps will exist over the coming years in South Australia. In this sensitivity, reliability risks are forecast higher than the relevant reliability standard[61] in South Australia this coming summer, again in 2026-27 and in 2033-34.

[60] Other projects in other jurisdictions included in this sensitivity include the Victorian Renewable Energy Target Auction 2, New South Wales Infrastructure Investment Objectives (IIO) report, and the Queensland Energy and Jobs Plan.

[61] The IRM of 0.0006% expected US) applies until June 2028, after which the reliability standard of 0.002% USE applies.

Figure 24 South Australia expected USE, scenarios and sensitivities, 2024-25 to 2033-34

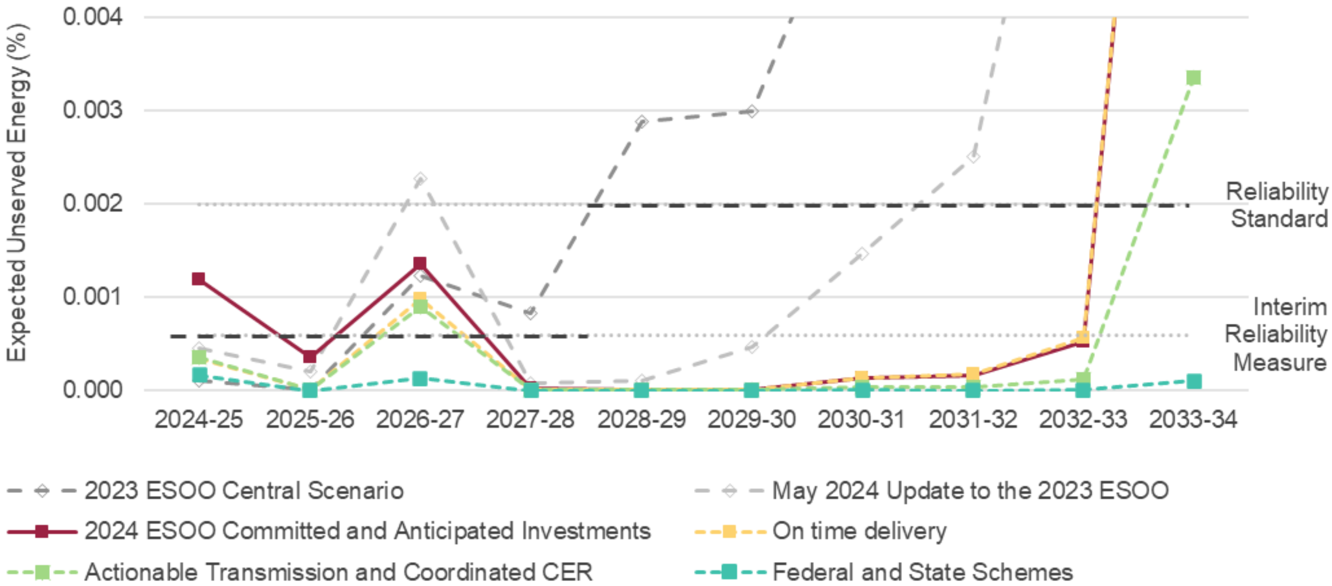


Figure 24 also shows that:

- Under the *Committed and Anticipated Investments* sensitivity:
  - Expected USE is forecast above the IRM in 2024-25, before decreasing in 2025-26 when Blyth BESS and Goyder South Wind Farms 1A and 1B are assumed to commission.
  - From 2026-27, forecast risks increase materially due to the advised retirement of Osborne Power Station and Torrens Island B Power Station, with expected USE forecast above the IRM.
  - From 2027-28, the advised availability of the full transfer capacity of Project EnergyConnect Stage 2 reduces reliability risks significantly, allowing better connection between South Australia, Victoria and New South Wales.
  - In 2033-34, expected USE increases due to announced retirements of gas and liquid fuel generators in South Australia, and the impact of the Bayswater and Vales Point power stations closure in New South Wales.
- Under the *On-time Delivery* sensitivity, should all currently committed and anticipated projects be delivered to their advised schedules, reliability lowers to within the IRM in 2024-25. Risks remain above the relevant standard in 2026-27 and 2033-34.
- Under the *Actionable Transmission and Coordinated CER* sensitivity[62], expected USE is forecast below the relevant standard except for in 2026-27 and 2033-34 where retirement of generation in South Australia and New South Wales increases supply scarcity.

[62] The *Actionable Transmission and Coordinated CER* sensitivity also includes transmission projects that have been categorised as Actionable in the 2024 ISP.

- Additional assumed capacity developments under the *Federal and State Schemes* sensitivity, including the first tender of the Victoria and South Australia Capacity Investment Scheme tender and coordinated CER developments, are shown to largely address the reliability risks in 2026-27 and beyond.
- Compared to the 2023 ESOO and May 2024 Update to the ESOO, the 2024 ESOO found:
  - USE is lower over most of the horizon, due to lower demand forecasts as well as the inclusion of new projects such as the 204 MW Hydrogen Jobs Plan hydrogen generator (which has been included since the May 2024 Update to the 2023 ESOO), Mannum BESS and Bungama Solar (newly included in the 2024 ESOO).
  - In 2024-25, reliability risks in the *Committed and Anticipated Investments* sensitivity, which incorporates a delay to the project timing provided by the project proponent, have increased since comparable forecasts in previous publications due to the advised mothballing of Torrens Island B1, Port Lincoln and Snuggery power stations in South Australia, and a revised network configuration in Victoria that reduces risks across both regions but allocates a greater portion of the risk to South Australia. Reliability risks have further increased in 2026-27 due to revised dates for the full capacity release of Project EnergyConnect Stage 2 (included since the May 2024 Update to the 2023 ESOO).

Figure 25 shows the reliability outcomes for South Australia in 2024-25 under different weather years, demonstrating the significant variance that is expected depending upon the weather conditions at time of maximum demand (affecting consumer load profiles, as well as renewable generator resources). The 'weighted outcome' shown on the graph represents the average of all weather reference years and is the expected value presented in **Figure 24**.

Figure 25 Reliability outcomes for South Australia in 2024-25 under different weather reference years, *Committed and Anticipated Investments* sensitivity, which includes delays to project completion timing

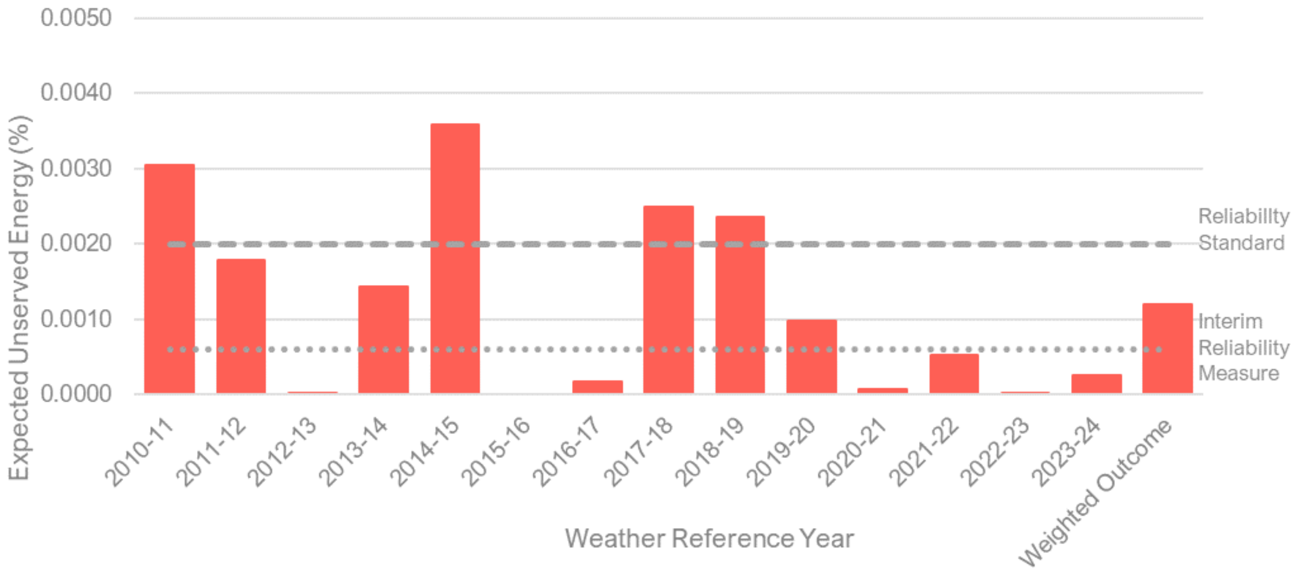
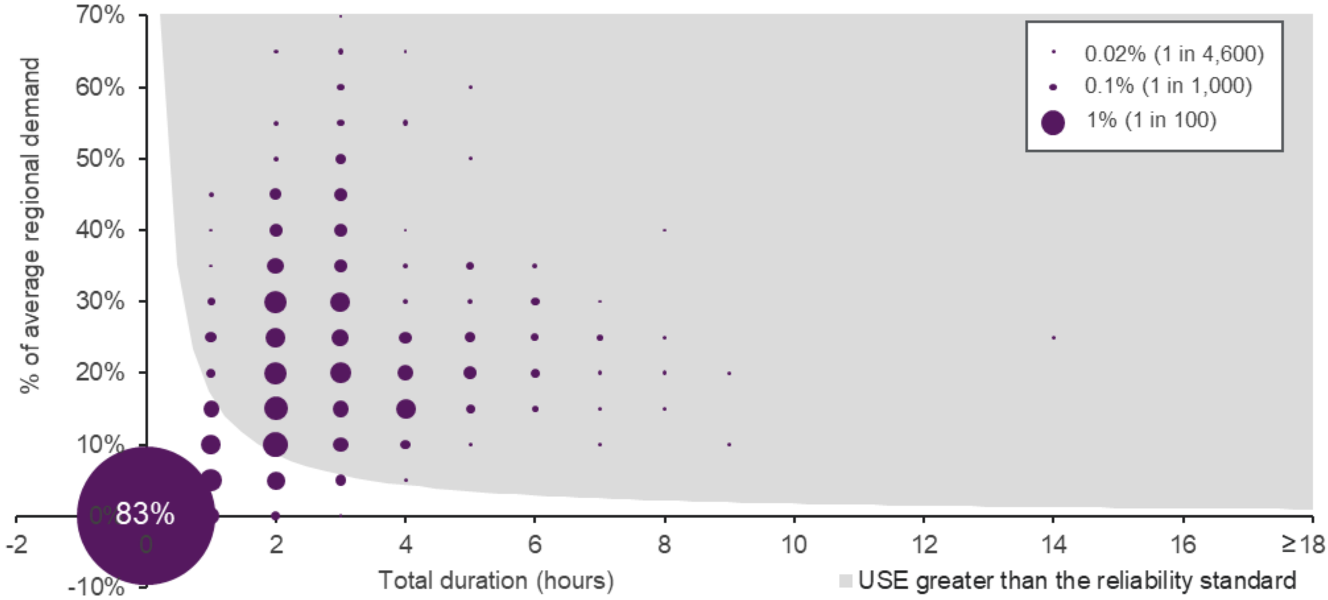


Figure 26 shows a bubble plot of the depth and duration of USE forecast in South Australia for 2024-25 in the *Committed and Anticipated Investments* sensitivity. It shows that the most likely outcome for South Australia is that USE does not occur in the coming year (the large purple dot), but that there is a 17% probability of a USE

outcome. For those simulations that did have USE, the total number of hours unserved was likely to be up to four hours in duration, and of average depth up to 35% of average regional demand. While this assessment shows the results for South Australia only, risks in Victoria also have the potential to impact South Australian consumers due to the tight coupling of both regions for reliability purposes.

Figure 26 Bubble plot of depth and duration of forecast USE in South Australia 2024-25, *Committed and Anticipated Investments* sensitivity



4.2.1 Energy adequacy

The Energy Adequacy Assessment Projection (EAAP) forecasts electricity supply reliability in the NEM over a 24-month outlook period. The EAAP complements the ESOO reliability assessments, providing a focus on the impact of energy constraints on forecast reliability, and is embedded within the ESOO published report.

The EAAP focuses on the reliability impact of limited water and thermal fuel availability by considering the following three energy adequacy scenarios:

- EAAP Central scenario – the most likely fuel and water availability used for generation purposes[63].
- EAAP Low Rainfall scenario – considering water availability during drought conditions, and most likely fuel availability for thermal production units. Severe drought conditions observed during the Millennium Drought[64], are applied in this scenario.
- EAAP Low Thermal Fuel scenario – considering thermal fuel availability limits under 1-in-10-year low fuel availability conditions[65] for each power station in the NEM. Hydro generators apply most likely water availability.

[63] The *Committed and Anticipated Investments* sensitivity is considered the Central scenario for EAAP purposes.

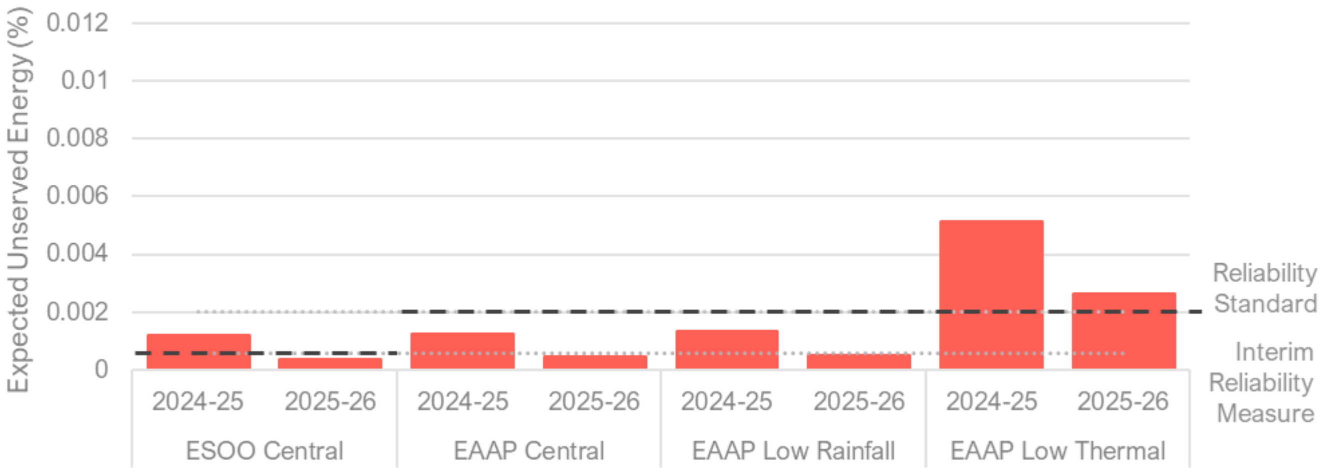
[64] The Millennium Drought is categorised as the period between 1997 to 2009, but inflows in 2006 (and therefore affecting the 2006-07 financial year) were at or near the lowest on record in many parts of the NEM, including the Murray Darling basin. For power stations in South Australia, parameters are provided based on the rainfall experienced between 1 July 2006 and 30 June 2007.

[65] When developing one-in-10-year low fuel availability limits, participants are asked to consider the potential impacts of wet coal, longwall moves, train and truck deliveries, loader outages, likely market limitations, pipeline constraints, gas supply issues, and whether these events could occur over a prolonged period, or for shorter events only.

The EAAP assesses reliability by comparing expected USE against the reliability standard of 0.002% USE; the IRM does not apply for the purposes of the EAAP.

Figure 27 shows expected USE in South Australia under the three EAAP scenarios and the 2024 ESOO Central scenario. The EAAP low fuel scenario shows USE above the reliability standard in both years in South Australia, but as this scenario is based on participant-provided energy limits under a one-in-10-year fuel unavailability scenario, it does not reflect an expected outlook. This scenario, however, demonstrates the importance of maintaining ongoing availability of fuel, and fuel supply chains throughout the energy transition.

Figure 27 EAAP annual expected USE by scenario (%)



4.2.2 Managing reliability risks

The 2024 ESOO projected expected USE to exceed the IRM in South Australia in 2024-25 under the *Committed and Anticipated Investments* sensitivity. Due to expected USE forecast above the IRM in 2024-25, AEMO has published a tender[66] for interim reliability reserves and is currently evaluating these offers. AEMO may contract for interim reserves up to the calculated reliability gap of 200 MW. AEMO has also contracted a Short Notice RERT portfolio of approximately 120 MW.

[66] See https://aemo.com.au/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert/rert-tendering.

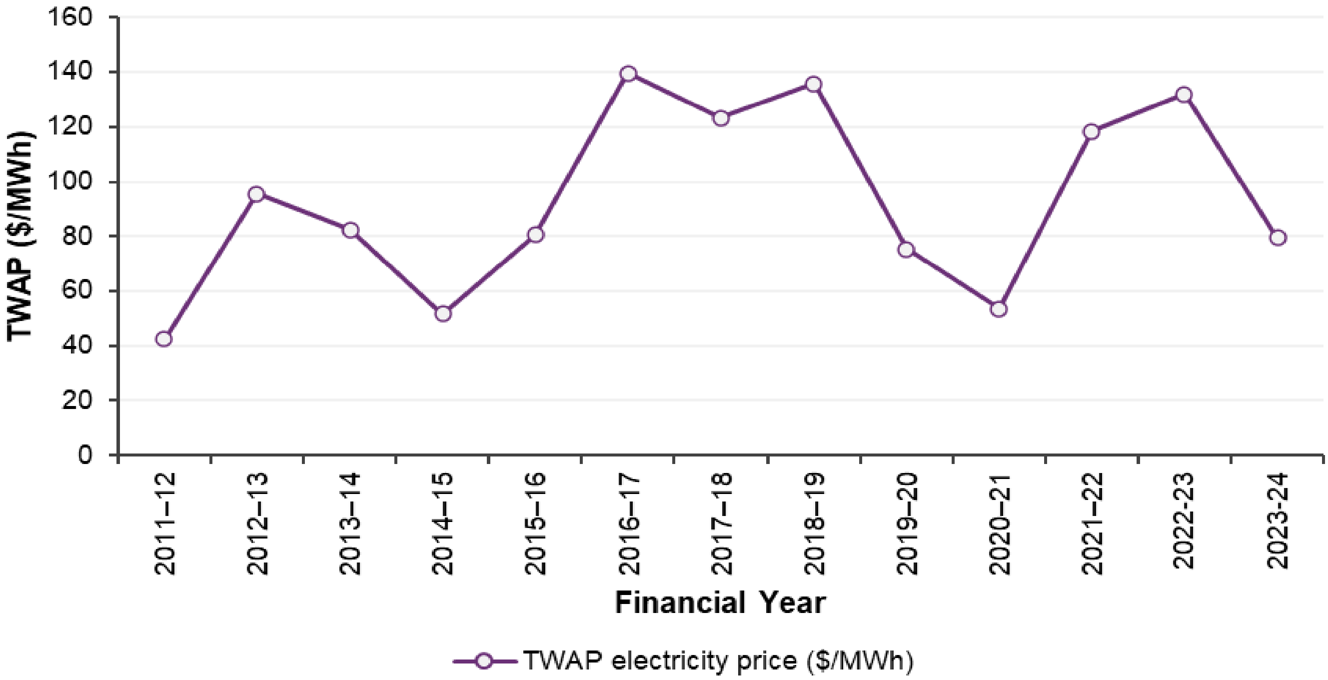
5 Electricity spot prices

In 2023-24, South Australia's average wholesale electricity price dropped significantly compared to the previous year. Monthly prices remained lower year-on-year in most months despite several high volatility events across the year. Frequency control ancillary services (FCAS) prices also declined sharply, with all services except the two new very fast contingency services experiencing lower averages. The one-second contingency raise (R1SE) and lower (L1SE) services, introduced on 9 October 2023, recorded the highest average prices out of all services in their first quarter of operation but gradually decreased in subsequent quarters.

5.1 Historical wholesale electricity prices

In the 2023-24 financial year, South Australia's time-weighted average price (TWAP) decreased to $79.53/MWh[67], a 40% drop from the previous year's average of $131.90/MWh (**Figure 28**). Similar reductions were observed in all other NEM regions, with the NEM-wide TWAP declining by 39% year-on-year.

Figure 28 Average South Australian spot electricity price (real June 2024 $/MWh)



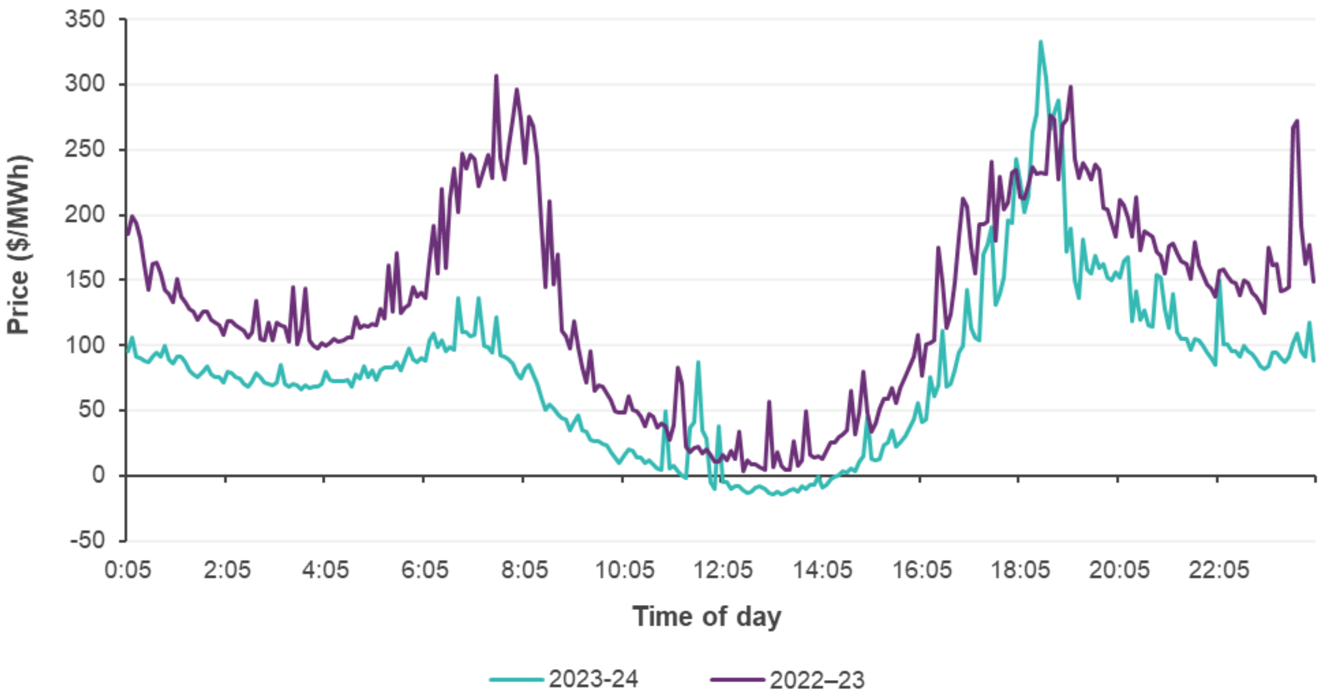
[67] Uses the time-weighted average which is the average of spot prices over the year, consistent with the measure used in AEMO's *Quarterly Energy Dynamics* reporting. The AER reports the volume-weighted average price which is weighted against native demand in its quarterly wholesale reporting.

Table 15 2023-24 time-weighted average prices for the NEM

	Queensland	New South Wales	Victoria	South Australia	Tasmania
Time-weighted average price ($/MWh)	88.89	102.61	63.77	79.53	69.37

Price reductions were evident across most hours[68] of the day (**Figure 29**), except during late-morning and evening periods, where several high price events throughout the year pushed prices higher during these times.

Figure 29 Average South Australian spot electricity price by time of day (real June 2024 $/MWh)



After dropping to a monthly average of $75/MWh in July 2023, South Australian prices surged to $165/MWh in August, driven by a major volatility event on 11 August (**Figure 30**). This event occurred when limits on the Heywood interconnector coincided with low wind conditions, leading to 15 dispatch intervals exceeding $10,000/MWh throughout the day. The volatility contributed $15/MWh to South Australia's quarterly cap return for the December quarter. Following this spike, monthly spot prices steadily declined, reaching $15/MWh in October 2023 – an all-time low for October.

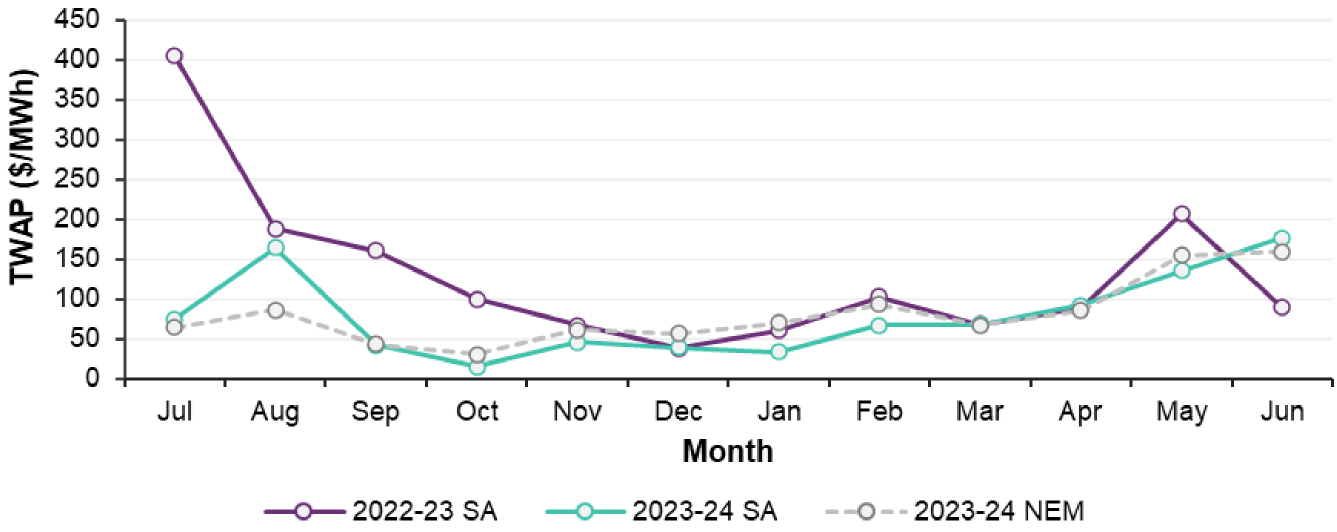
After consistently low prices during the March quarter, prices began to rise again in the June quarter due to very low wind speeds across the southern and eastern regions, which significantly reduced wind availability in South Australia. As a result, June 2024 prices averaged $177/MWh, nearly double the $89/MWh recorded in the same period the previous year.

Drivers of the observed reduction in South Australian wholesale spot prices in 2023-24 include:

[68] Since commencement of Five-Minute Settlement (5MS) from 1 October 2021, electricity spot prices are now shown on 5-minute basis for current and previous years.

- Prices set by gas, black coal, brown coal, and hydro generators (when they were the marginal fuel type) reduced significantly from the previous year, while their price-setting frequency remained relatively unchanged, exerting downward pressure on average spot prices. See Section 5.3 for more information.
- Government policies capping domestic thermal coal prices (introduced in December 2022) and improvements in the fuel supply position of key generators were reflected in increased black coal volumes offered to the market at lower prices. This contributed to lower prices being set by black coal in South Australia, which occurred in 19% of intervals in 2023-24.
- Gas generators generally offered lower priced volumes, resulting in lower prices set by this fuel type when marginal (from $270/MWh in 2022-23 to $186/MWh in 2023-24). With gas setting prices 14% of the time in 2023-24, this contributed to lower prices in South Australia.
- Increased distributed PV output and increases in new and commissioning grid-scale solar capacity in the region also contributed to lower prices in 2023-24.

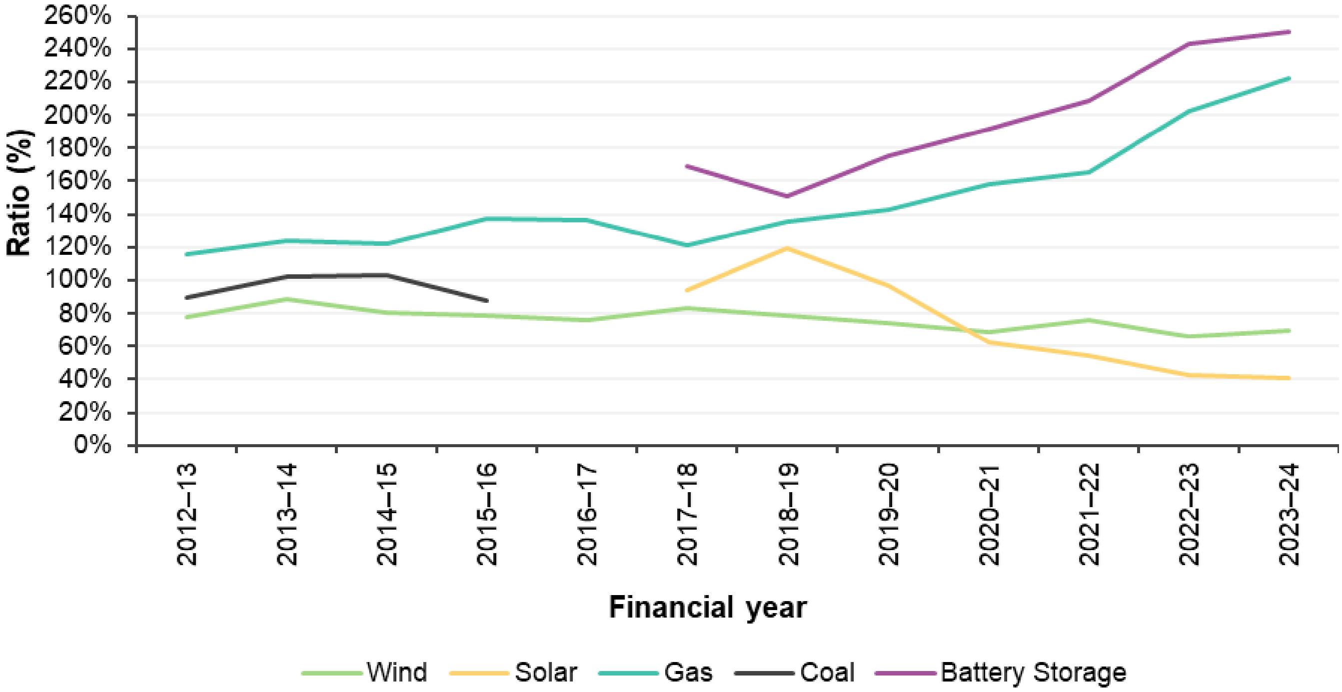
Figure 30 Average South Australian spot electricity price by month, FY23-24 and FY22-23 (real June 2024 $/MWh)



After consistently low prices during the March quarter, prices began to rise again in the June quarter due to very low wind speeds across the southern and eastern regions, which significantly reduced wind availability in South Australia. As a result, June 2024 prices averaged $177/MWh, nearly double the $89/MWh recorded in the same period the previous year.

The volume-weighted average price (VWAP) by fuel type represents the average price received by each fuel technology. Higher output during high-priced periods will result in a higher VWAP. **Figure 31** illustrates the ratio of VWAP as a relative percentage to TWAP.

Figure 31 Ratio of VWAP by fuel to total TWAP for South Australian generators



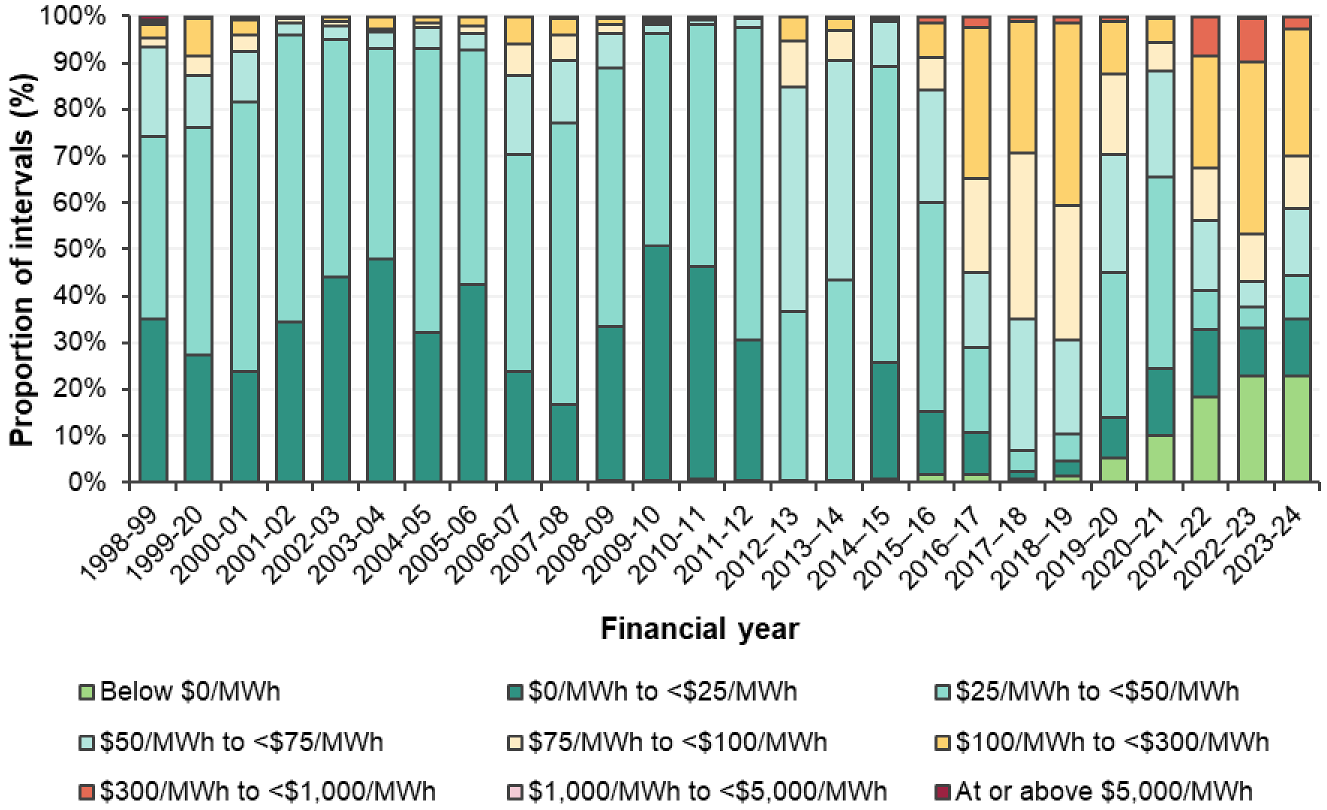
In summary:

- The ratio of VWAP to total TWAP for gas generators increased from 202% in 2022-23 to 222% in 2023-24. This high VWAP to TWAP ratio reflects that gas generators increased output during high priced intervals, including during peak demand periods and volatility events, and reduced their output during periods of low prices. Volatility events driven by network outages and coincident low wind generation in the March and June quarters of 2024 contributed to this increased VWAP to TWAP ratio, relative to the previous year.
- Batteries' output was highest during morning and evening peak hours when wholesale spot prices were at the highest levels for the day. Due to their short duration of output, batteries tended to minimise their exposure to lower prices at other times, so they recorded the highest ratio of VWAP to total TWAP out of all fuel types. In 2023-24, batteries' VWAP to TWAP ratio was 243%, up 7 percentage points (pp) from the previous year.
- After reaching its lowest level since 2012-13 of 66% in 2022-23, and with the reduction in overnight negative prices, the VWAP to TWAP ratio for wind generators increased slightly to 70% in 2023-24.
- The VWAP to TWAP ratio for grid-scale solar generators continued to decrease from 43% in 2022-23 to 41% in 2023-24, driven by the increased frequency of occurrence of negative prices during the middle part of the day (see **Figure 36** in Section 5.2.2).

5.2 Price volatility

In 2023-24, South Australia saw a notable decrease in intervals with high prices compared to the previous year, with 2.7% of intervals recording spot prices above $300/MWh, compared to 9.7% in 2022-23. The frequency of occurrence of spot prices between $100-$300/MWh also decreased significantly, down 9.5 pp. The year-on-year downward shift in prices was reflected in an increase in the frequency of intervals in the $50-$75/MWh price band, up 9.1 pp, and in the $25-$50/MWh band, up 4.7 pp. The occurrence of negative prices stayed almost unchanged relative to 2022-23, down just 0.2 pp (see **Figure 32**).

Figure 32 Frequency of occurrence of spot prices for South Australia, 1998-99 to 2023-24



5.2.1 High prices

Spot price volatility, as measured by cap returns (the contribution of spot prices in excess of $300/MWh to the annual average), reduced to $13/MWh (-58%) from the previous year's $30/MWh (**Figure 33**). This year-on-year reduction in cap return was observed during all four quarters of 2023-24. The September 2023 quarter had the largest drop reducing to $27/MWh, from the $80/MWh recorded in the September 2022 quarter when impacts from the 2022 energy crisis were still evident.

Despite the year-on-year reduction, the September 2023 quarter still accounted for slightly more than half of South Australia's cap return during 2023-24. In this quarter, spot price volatility was mainly evident during August when Heywood interconnector capacity was limited over several periods due to line outage works. A significant proportion of the September quarterly cap return occurred in intervals when low wind generation coincided with periods when the limit on flows from Victoria via Heywood was binding at 50 MW or lower.

Volatility events across the rest of 2023-24 were also generally driven by restrictions on Heywood interconnector flows into South Australia (caused by network outages or severe weather causing re-classification of non-credible contingency risks as credible) coinciding with periods of peak demand and low VRE output.

Figure 34 illustrates the breakdown of the aggregate cap returns in South Australia, differentiating between spot prices higher than $1,000/MWh and those between $300/MWh and $1,000/MWh. Most of the reduction in cap return during September quarter was driven by fewer spot prices between $300/MWh to $1,000/MWh. Notably, the September quarter only saw 12% of its cap return component resulting from prices between $300/MWh to $1,000/MWh while this was almost 50% during the same time last year.

Figure 33 South Australian cap returns

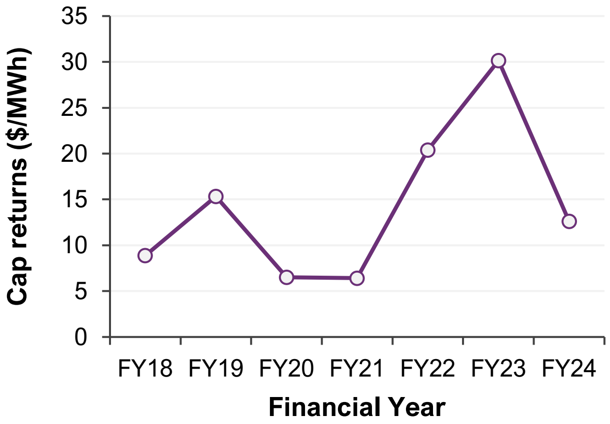
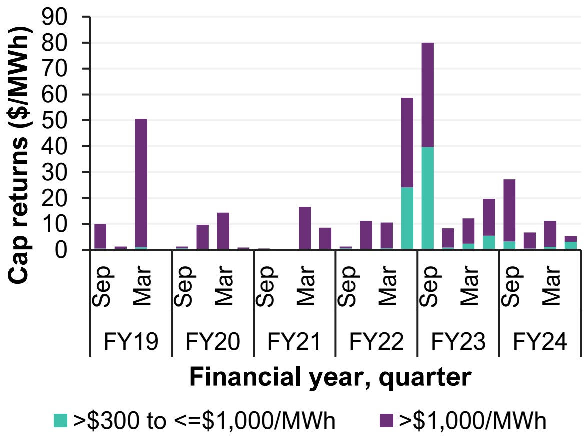


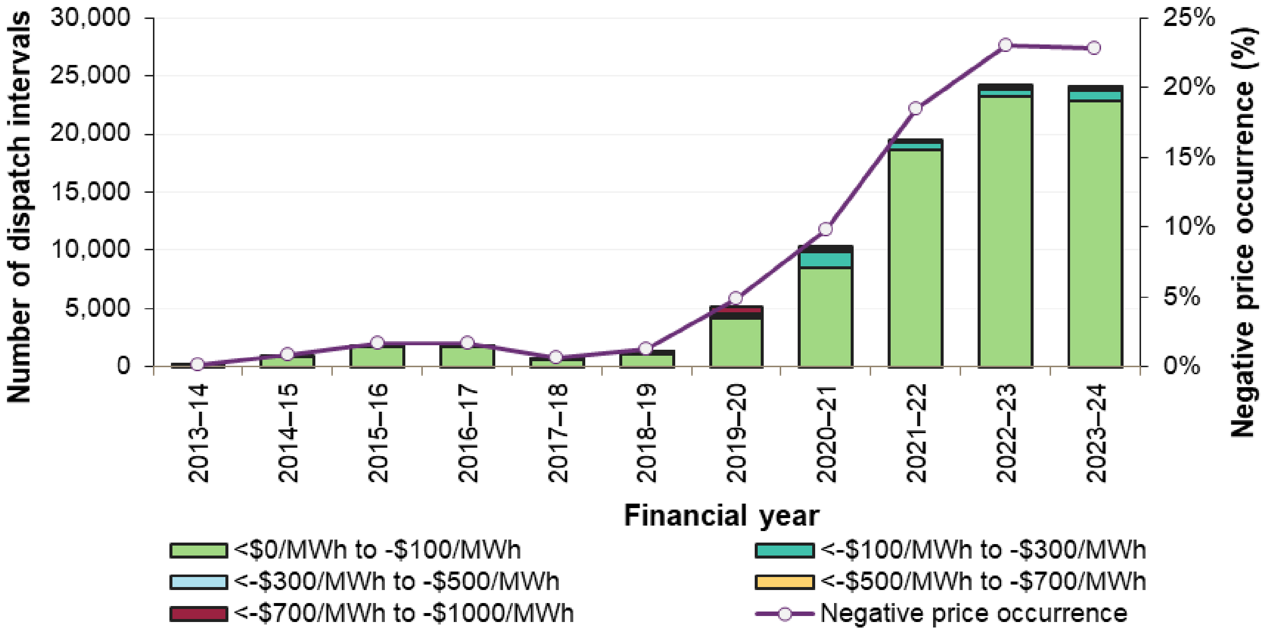
Figure 34 Contribution to total South Australian cap return by price range - quarters



5.2.2 Negative prices

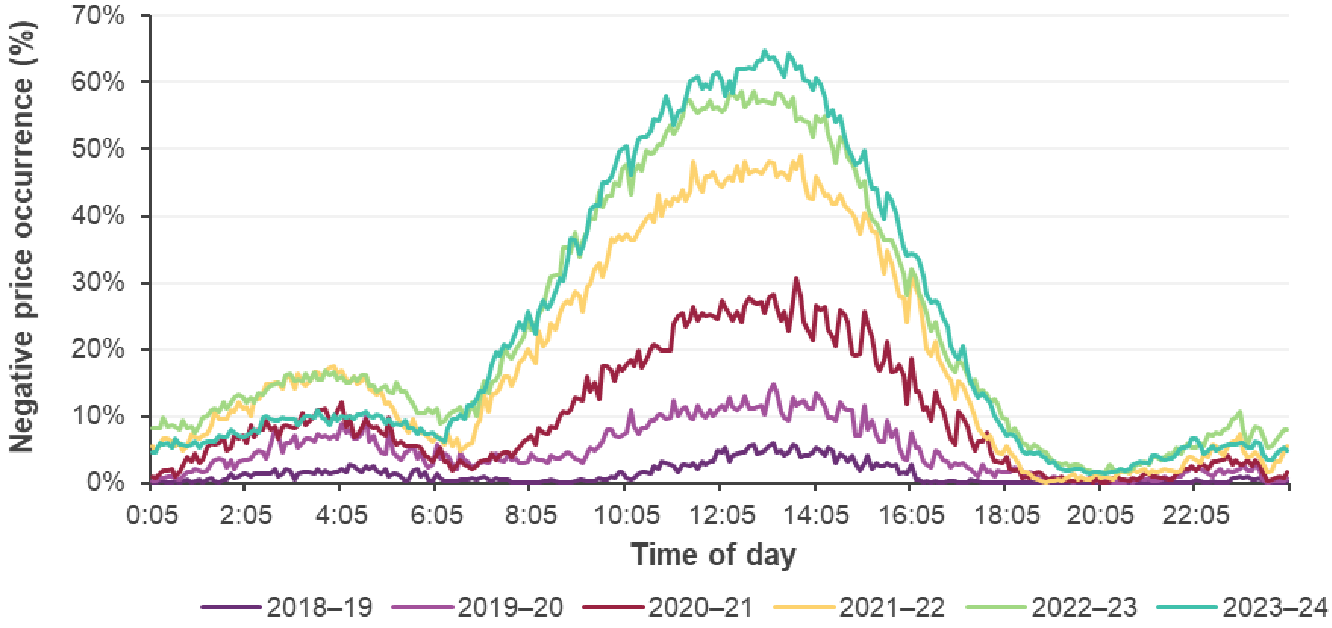
After experiencing rapid increases in the frequency of negative spot prices in recent years, South Australia maintained a similar level of negative price occurrence in 2023-24, compared to the previous year, with 23% of dispatch intervals experiencing negative prices (**Figure 35**). This was driven by a year-on-year reduction in wind generation in South Australia (-20%) offsetting the impacts of increased distributed PV output (+16%) and grid-scale solar generation (+18%).

Figure 35 Count of negative price dispatch intervals per year



Negative spot prices were predominantly observed during daytime hours due to distributed PV output reducing operational demand, alongside increasing grid-scale solar generation. Negative spot prices between 1000 hrs and 1500 hrs occurred 58% of the time on average, a 4 pp increase in frequency from the previous year. These daytime increases were offset by a decline in overnight negative price occurrence, with the frequency of negative prices dropping slightly due to lower overnight wind generation compared to previous year (**Figure 36**).

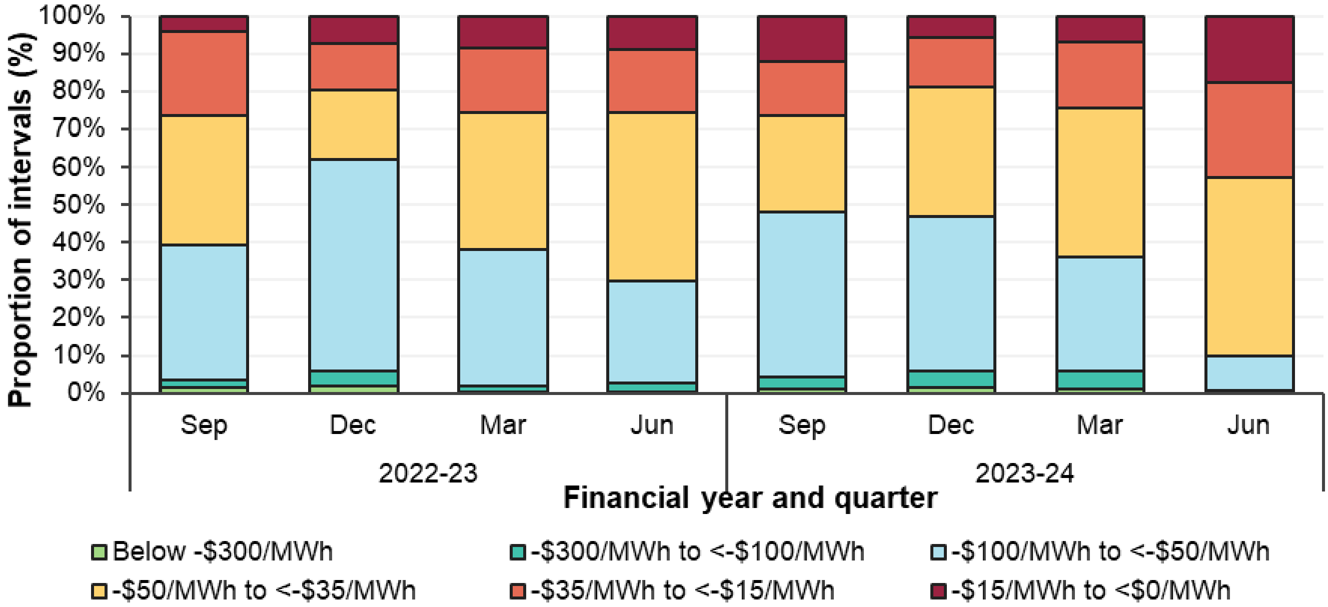
Figure 36 Percentage of time South Australian price was negative by time of day



Along with the reduction in the frequency of negative spot prices, the negative price impact[69] reduced from $13.1/MWh in 2022-23, down to $11.9/MWh in 2023-24. The largest reduction in negative price occurrence was seen in prices in the -$100/MWh to -$50/MWh range, which reduced by 7.9 pp to 31% this year, with a corresponding shift to prices between -$50/MWh and -$0/MWh (**Figure 37**). This coincided with a decrease in spot prices of large-scale renewable certificates (LGCs) created by renewable generators, from an average of $56/certificate in 2022-23 to $49/certificate in 2023-24.

[69] This refers to by how much the average annual spot price was lowered due to negative prices. The higher the negative price impact, the lower the average will be.

Figure 37 South Australian negative spot price band – proportion of intervals when price was negative



5.3 Price setting outcomes

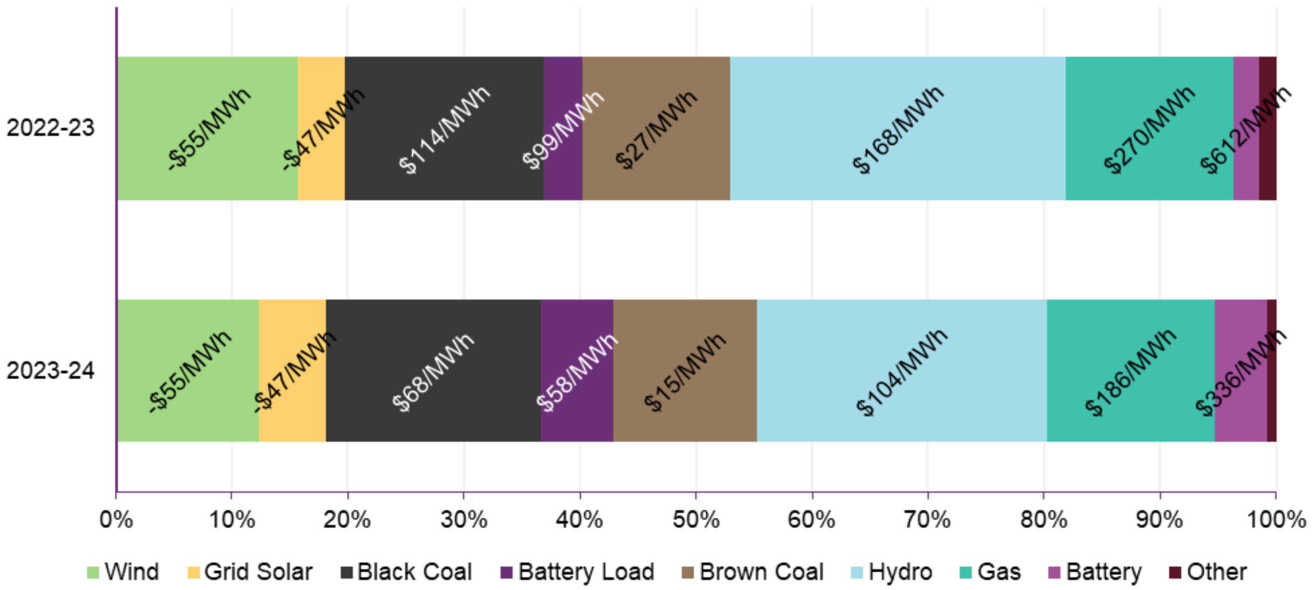
Figure 38 shows South Australia's price setting outcomes by fuel type for 2022-23 and 2023-24. In 2023-24, all fuel types, except wind and solar, saw reductions in the average prices set when being marginal, relative to the previous year. Key price setting outcomes[70] for 2023-24 included:

- Wind and grid-scale solar generators set prices in 18% of intervals in 2023-24, compared to 20% in 2022-23. Wind's price-setting frequency dropped by 3 pp (due to less wind availability relative to last year), while grid-scale solar increased by 2 pp. The average price set by wind and solar maintained similar levels to last year's at -$55/MWh and -$47/MWh, respectively.
- While gas did not see any change in price setting frequency (at 14% of intervals) the average price set by this fuel type notably reduced from $270/MWh in 2022-23 to $186/MWh in 2023-24. Black coal saw only 1 pp increase in price setting frequency reaching 19% of intervals in 2023-24, but the price set by this fuel type significantly reduced from $114/MWh to $68/MWh. Brown coal saw marginal reduction in price setting frequency (at 12% of intervals this year) with an average price of $15/MWh in 2023-24 (down from $27/MWh in the previous year).
- Hydro generation set the price in 25% of intervals relative to 29% in 2022-23, recording the largest reduction in price setting frequency amongst all fuel types. The average price set by hydro also saw a notable reduction from $168/MWh in 2022-23 to $104/MWh in 2023-24.

[70] The NEM's interconnected structure allows prices in one region to be set by market offers in a different region provided that interconnector flows are not constrained, meaning for example that offers from black coal generators in New South Wales or Queensland may at times set price in southern NEM regions as well as in those generators' home regions.

- Batteries saw a significant increase in their price setting frequency reaching 5% (+2 pp) when generating and 6% (+3 pp) when charging as a load. This increase in price setting frequency was driven by the notable increase in battery capacity from last year to this year.

Figure 38 South Australia price setting by fuel type



5.4 Gas spot price impact on electricity spot prices

Historical average electricity and gas prices are shown in **Figure 39**. The strong relationship between the movements of the South Australian electricity price and Adelaide's Short-Term Trading Market (STTM) across time reflects the role of gas-powered generation as a key marginal supply source in the NEM.

Overall, in nominal terms, South Australia's average TWAP decreased by 36%, between 2022-23 and 2023-24, while the average Adelaide STTM price also decreased by 36% to $12/GJ, significantly lower than the record levels experienced during the energy crisis in 2022.

Domestic gas prices continued the trend downwards from the end of 2022-23 across the September quarter, with warmer than average weather leading to some of the lowest domestic gas demands observed on the east coast.

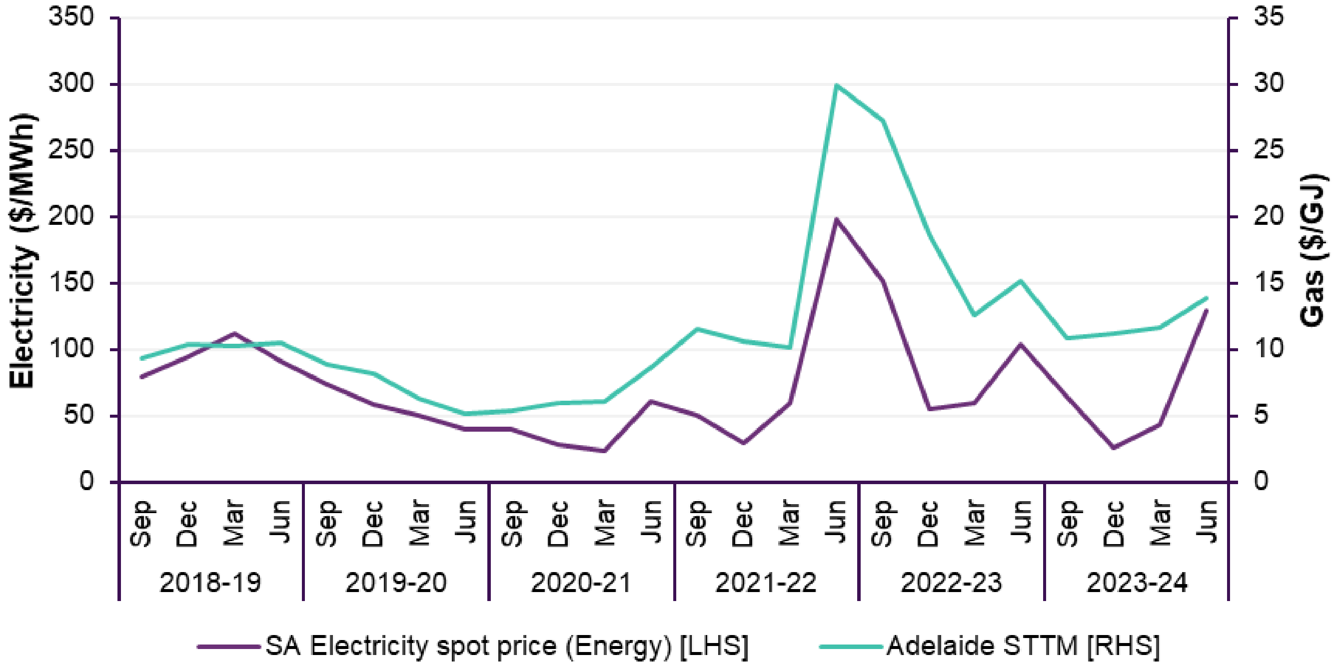
Domestic gas prices increased slightly in the December quarter, diverging from electricity prices, with these decreasing steeply from the September to the December quarter due to downward price pressure from record high grid-scale VRE generation.

In the March quarter, domestic gas prices increased marginally, and electricity prices increased at a greater rate, driven by increasing summer cooling demand. Both domestic gas and electricity quarterly average prices remained below the March 2023 averages.

The June quarter saw both domestic gas prices and electricity prices rise. A wind drought and low rainfall across the NEM drove increased gas-powered generation, with South Australia gas-powered generation in June 2024 at the highest monthly average recorded since July 2022. These factors put upward pressure on domestic gas production, and gas supply dynamics continued to be influenced by declining gas production from Longford.

AEMO issued an East Coast Gas System Threat or risk notice on 19 June 2024 due to the potential for gas supply shortfalls caused by the depletion of southern storage inventories, in particular Iona Underground Storage (UGS)[71].

Figure 39 South Australian electricity and gas price



Note: To remove the impact of electricity price volatility, South Australian electricity spot prices are capped at $300/MWh to prepare this chart.

5.5 Frequency control ancillary services market prices

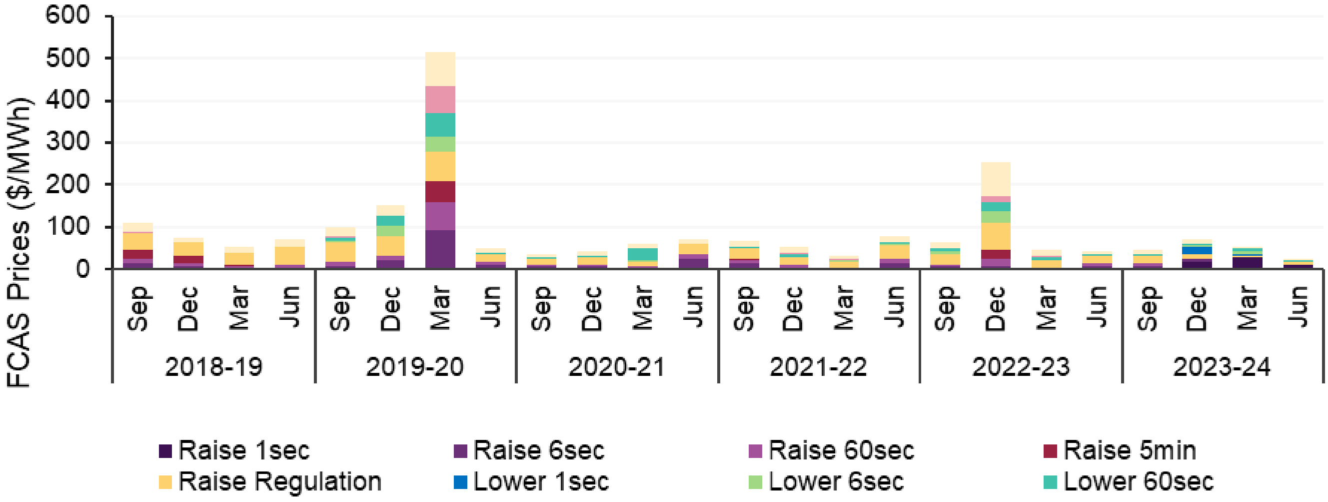
During 2023-24, South Australian FCAS prices averaged $5.1/MWh across all FCAS markets, a significant reduction from $12.9/MWh in 2022-23 (**Figure 40**). In the December 2023 quarter, two new contingency services – the Very Fast Raise Contingency and the Very Fast Lower Contingency – commenced operation on 9 October 2023. In their first quarter of operation, South Australia's one-second contingency raise (R1SE) price averaged $18.42/MWh, the highest among all FCAS services, followed by one-second contingency lower (L1SE) at $18.37/MWh.

R1SE prices further increased in the March 2024 quarter, averaging $27.65/MWh in South Australia, before decreasing to $9.98/MWh in the June quarter, with enablement levels remaining near the cap[72]. Meanwhile, NEM-wide average prices for L1SE stayed below $1/MWh throughout the March and June quarters, as the underlying requirement for L1SE remained well under the cap. All other FCAS services saw considerably lower average prices during the 2023-24 year compared to the previous year.

[71] The East Coast Gas System threat or risk notice was revoked on 23 August 2024 as Iona UGS inventories recovered during August due to warmer weather and reduced gas-fired generation.

[72] Under the new market transition approach, both very fast services commenced with a 50 MW cap on enablement volumes with a fortnightly review to determine if these volumes could be incremented. In the following months, the caps for R1SE and L1SE were raised multiple times, reaching 350 MW and 225 MW respectively, by the end of June 2024.

Figure 40 Quarterly average South Australia FCAS prices by service – stacked



6 System security

This section describes the maintenance of power system security[73] in South Australia, considering the changing generation mix, increased distributed PV uptake, and decreasing minimum operational demand. AEMO continues to work closely with the South Australian Government, ElectraNet, SA Power Networks and industry participants to adapt system planning and operations during the energy transition so consumers can continue to exercise choice and access reliable, low-cost energy.

The energy transition is transforming the way electricity is generated, transported, and consumed across the NEM. While the system was once able to operate well inside its technical envelope, the energy transition is pushing the system to operate more frequently near its boundaries, highlighting security concerns which require a supportive and adaptive regulatory framework that is fit for purpose.

Of note, in March 2024, the Australian Energy Market Commission (AEMC) made a final determination and published a final rule to improve security frameworks (ISF) for the energy transition[74]. This Rule, effective from 1 December 2024, made a number of improvements to the system security planning frameworks, including the addition of a new mainland inertia requirement, the introduction of new transmission network service provider (TNSP) obligations to plan for future inertia needs, and a greater ability to leverage emerging new technologies in the provision of inertia services.

The rule also requires AEMO to publish an annual *Transition Plan for System Security*, the first iteration of which was published on 2 December 2024[75]. This new report outlines a plan to maintain power system security for the NEM through the transition to a low emissions power system, and complements AEMO's ISP[76], system security reports[77], and the Engineering Roadmap program[78], to:

- Provide a structured approach for maintaining power system security by planning for and navigating key transition points.
- Define capabilities and progress understanding of what is needed to achieve system security in a low emissions power system. This includes specifying the range of services that will be required and the range of technologies capable of providing them.

The Transition Plan further reports on the initial steps being taken by AEMO to use the new Transitional Services procurement framework[79], including:

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[73] Power system security means the power system is operating within defined technical limits and is likely to return within those technical limits after a disruptive event occurs, such as the disconnection of a major power system element (such as a power station or major powerline).

[74] AEMC, 'Improving security frameworks for the energy transition', at https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition.

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

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

[77] See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

[78] See https://aemo.com.au/en/initiatives/major-programs/engineering-roadmap.

[79] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/transitional-services-guideline-consultation/transitional-services-guideline.pdf.

- Type 1 transitional services contracts to procure services necessary for the energy transition that cannot otherwise be provided through existing frameworks.
- Type 2 transitional services contracts to trial new sources of security services or new applications of existing technologies to support system security.

6.1 System strength

System strength is a critical requirement for a secure and stable power system. A minimum level of system strength is required for the power system to maintain a stable voltage waveform, both during normal operation, and following a disturbance[80]. System strength is often approximated by the amount of electrical current available during a network fault (fault current), however the concept also includes a range of electrical characteristics and complex power system interactions.

It is increasingly difficult to accommodate new inverter-based resources (IBR) investment while maintaining stable power system operation as the system transitions away from synchronous resources which have historically provided system strength. The system strength framework is currently in a transitionary period as changes are progressively implemented to provide the system strength services required for a more rapid connection of IBR with solutions that achieve economies of scale.

AEMO has not identified any system strength shortfalls in South Australia in the 2023 or 2024 System Strength Reports, covering an outlook period to 1 December 2027. ElectraNet is currently progressing a RIT-T to deliver against its longer-term system strength obligations.

6.1.1 System strength framework

Under the current system strength framework, ElectraNet as the System Strength Service Provider (SSSP) for South Australia is required to undertake ongoing investment in services to meet a set of minimum fault level requirements and projected IBR levels over a 10-year period, as published annually by AEMO. These obligations take effect from 2 December 2025, and associated investments must be justified through a reliability corrective action RIT-T[81].

Until 1 December 2025, AEMO assesses the projected availability of system strength and declares any projected security shortfalls for remediation by ElectraNet. This process continues in parallel with the new SSSP obligations from December 2025, however the ISF Rule also introduces last-resort planning powers for AEMO with respect to system strength under the network support and control ancillary services (NSCAS) framework.

Investments made by the SSSPs to meet their system strength obligations are treated as prescribed transmission services, with costs passed through to consumers. This cost is offset by system strength charges payable by connecting parties, where they elect to do so instead of self-remediating.

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[80] For definitions and descriptions of system strength and power system security, see AEMO's *Power System Requirements*, updated in July 2020, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf.

[81] As a reliability corrective action RIT-T is undertaken to meet externally imposed obligations, the preferred option may have a negative net economic benefit if it is the solution that maximises the net market benefits. That is, the benefits can be negative if demonstrated that they are the *least* negative of all the options considered. This differs from a market benefit RIT-T for which the preferred option must have a positive net market benefit.

6.1.2 System strength assessment for South Australia

AEMO published the 2023 *System Strength Report* in December 2023[82] and its most recent *System Strength Report* in December 2024[83]. These reports specify system strength requirements for South Australia, and form the basis of TNSP investment obligations in such services. The requirements remain largely unchanged in the 2023 and 2024 reports, and AEMO has not currently identified any system strength shortfalls against them in South Australia over a three-year assessment period.

Fault current requirements and shortfalls

AEMO has assessed forecast levels of available system strength against minimum fault level requirements. AEMO did not identify any projected system strength shortfalls in South Australia. The results of this assessment are presented in **Table 16**.

As part of the 2023 and 2024 assessments, AEMO considered if any material system changes had occurred that would warrant reassessment of the current system strength nodes, or a recalculation of their associated minimum fault level requirements. No changes were made to the system strength nodes or minimum fault level requirements as a result. Two possible future system strength nodes at Tailem Bend and Cultana were considered as potential candidates, and may be declared in future system strength reports, subject to the changing needs of the power system as more IBR connects in South Australia.

Table 16 South Australia fault level requirements, expected availability, and identified shortfalls

System strength node	Fault level requirement (megavolt amperes (MVA))	Typical level available (MVA)				Identified shortfall (MVA)			
		2024-25	2025-26	2026-27	2027-28	2024-25	2025-26	2026-27	2027-28
Davenport 275 kV	2,400	2,555	2,567	2,629	2,624	0	0	0	0
Para 275 kV	2,250	2,745	2,574	2,511	2,485	0	0	0	0
Robertstown 275 kV	2,550	2,897	3,084	3,451	3,449	0	0	0	0

IBR projections

AEMO forecasts IBR associated with each node to allow ElectraNet, as the local SSSP, to plan for delivering the efficient level of system strength. The 10-year forecast of the quantity and technology of IBR for South Australia is shown in **Figure 41** with underlying datasets provided in **Table 17.** While these are based on 2024 ISP results, AEMO has applied minor adjustments in allocating these forecasts to specific nodes based on local network knowledge and engineering judgement.

These projections highlight a continued trend of investment in IBR in South Australia for which ElectraNet is required to provide sufficient system strength to allow their stable operation. AEMO expects ElectraNet will engage in joint planning to identify any investment efficiencies when assessing solutions and is supportive of these values being adjusted considering the latest available information and announcements for use in system strength RIT-Ts.

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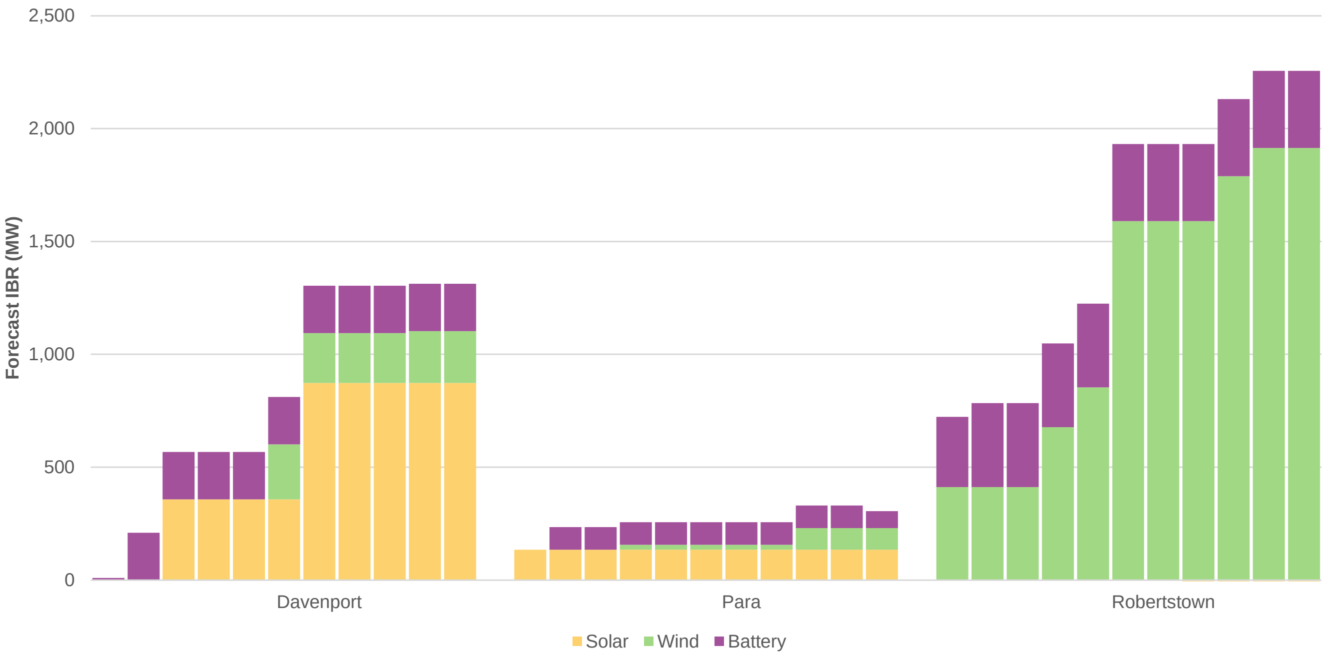
[82] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/2023-system-strength-report.pdf?la=en.

[83] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-system-strength-report.

Figure 41 Forecast level and type of IBR at each system strength node for the next 10 years



Notes: the near-term years of the forecast may require adjustment by the SSSP as more information becomes available about committed plant, such as their technical characteristics or their elections under the system strength framework.

Table 17 Forecast level and type of IBR at each system strength node for the next 10 years

Node	Technology type	Existing (MW)	Projected IBR by financial year ending (MW)										
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Davenport 275 kV	Solar	349	0	0	357	357	357	357	873	873	873	873	873
	Wind	557	0	0	0	0	0	244	221	221	221	230	230
	Battery	0	10	210	210	210	210	210	210	210	210	210	210
	Total IBR	**906**	**10**	**210**	**567**	**567**	**567**	**811**	**1,304**	**1,304**	**1,304**	**1,313**	**1,313**
Para 275 kV	Solar	188	135	135	135	135	135	135	135	135	135	135	135
	Wind	358	0	0	0	22	22	22	22	22	96	96	96
	Battery	323	0	100	100	100	100	100	100	100	100	100	75
	Total IBR	**869**	**135**	**235**	**235**	**257**	**257**	**257**	**257**	**257**	**331**	**331**	**306**
Robertstown 275 kV	Solar	25	0	0	0	0	0	0	0	-6	-6	-6	-6
	Wind	1,434	413	413	413	677	854	1,590	1,590	1,590	1,790	1,915	1,915
	Battery	180	311	371	371	371	371	341	341	341	341	341	341
	Total IBR	**1,639**	**724**	**784**	**784**	**1,048**	**1,225**	**1,931**	**1,931**	**1,925**	**2,125**	**2,250**	**2,250**

Note: forecasts may require adjustment by the SSSP when preparing system strength services, with new information on newly committed IBR.

System Strength RIT-T

ElectraNet is currently undertaking a RIT-T[84] to determine the most efficient means to meet the efficient level of system strength while balancing affordability, reliability and flexibility to respond to rapid deployment of IBR on the

[84] See https://www.electranet.com.au/projects/system-strength-requirements-in-south-australia/.

system. The RIT-T for system strength requirements in South Australia commenced in November 2023, with the publication of the *Project Specification Consultation Report* (PSCR)[85] accompanied by an Expression of Interest (EOI) for non-network service providers.

ElectraNet currently anticipates publishing the PADR in February 2025[86]. The PADR is the second stage of the RIT-T process and will include a full options analysis. Potential system strength solutions may include additional synchronous condensers, hydrogen gas-based synchronous generators, synchronous clutch enabled gas generators, or grid-forming inverter-based plants such as batteries[87].

6.2 Inertia

Inertia is a critical requirement for a secure and stable power system and is used in conjunction with other frequency control services to maintain the power system frequency within appropriate limits[88]. A decrease in the proportion of online synchronous generation has resulted in a reduction of the inertia inherently available to the power system.

To improve and align existing security frameworks and allow AEMO to better manage system security through the current energy transition, the ISF Rule has updated the inertia framework, including the introduction of a new system-wide inertia level, and the removal of restrictions on the procurement of synthetic inertia. AEMO has consulted on amendments to the Inertia Requirements Methodology to reflect these new requirements and changes[89].

In the 2023 *Inertia Report*, AEMO declared an inertia shortfall from July 2024 until Project EnergyConnect stage 2 was operational and appropriate control schemes were in place. Since that declaration, there have been sufficient new registrations in the 1-second FCAS market to offset inertia requirements and remove this shortfall. The 2024 *Inertia Report* did not identify any inertia shortfalls in South Australia.

6.2.1 New inertia framework

The ISF Rule makes several improvements to proactively address system security issues. There are four key updates to the inertia framework:

1. AEMO must now set a system-wide inertia level for the mainland NEM regions, where previously no inertia requirements were specified during the typical interconnected operation of NEM mainland regions.
2. AEMO must allocate portions of this new system-wide inertia level among the regions, that the TNSP must then procure.
3. The procurement timeframes of the system strength and inertia frameworks have been aligned to allow for greater investment coordination.

[85] At https://www.electranet.com.au/wp-content/uploads/ritt/ElectraNet-System-Strength-RIT-T-PSCR-FINAL.pdf.

[86] See https://www.electranet.com.au/wp-content/uploads/ElectraNet-2024-TAPR.pdf.

[87] Ibid.

[88] For definitions and descriptions of inertia in the NEM, see AEMO's *Inertia in the NEM explained* factsheet, published in March 2023, at https://aemo.com.au/-/media/files/initiatives/engineering-framework/2023/inertia-in-the-nem-explained.pdf?la=en.

[89] At https://aemo.com.au/consultations/current-and-closed-consultations/amendments-to-the-inertia-requirements-methodology.

4. The scope of inertia network services has been broadened to include synthetic and other non-synchronous service providers.

Under the previous framework, TNSPs have only a reactionary obligation to address declared inertia gaps. The updates made by the ISF Rule reflects the need for a 'base' amount of inertia during interconnected operation to be proactively met through balanced procurement in all mainland regions of the NEM. The ISF Rule also reintroduced declarable NSCAS gaps for inertia; as such, AEMO can now declare shortfalls against minimum requirements as NSCAS gaps.

6.2.2 Inertia assessment for South Australia

AEMO published the 2023 *Inertia Report* in December 2023[90] and its most recent *Inertia Report* in December 2024[91]. These reports assess inertia requirements in South Australia, and form the basis of TNSP investment obligations.

As part of the 2023 assessment, AEMO reviewed the inertia requirements for South Australia. AEMO increased the minimum operating level and decreased the secure operating level in response. The changes to the inertia requirements reflect the introduction of more onerous requirements in the Frequency Operating Standard (FOS), the commencement of a new 1-second FCAS market, and updates to AEMO's load and distributed PV models.

When assessing shortfalls in South Australia, AEMO recognised that ElectraNet had sufficient Fast Frequency Response (FFR) contracts in place to address existing inertia shortfalls until 1 July 2024, and that South Australia would not be considered sufficiently likely to island following completion of Project EnergyConnect stage 2, assuming necessary control schemes were in place to manage the non-credible loss of either Project EnergyConnect or the Heywood Interconnector. As such, AEMO's 2023 report declared a reduced shortfall of only 500 megawatt seconds (MWs) from 1 July 2024 until Project EnergyConnect stage 2 was operational.

AEMO noted that this could be addressed by dedicated FFR contracts, or reduced by new proponents registering their capacity in the 1-second FCAS market. In June 2024, AEMO determined that there were now sufficient registrations of 1-second FCAS to meet inertia requirements in South Australia. AEMO subsequently revoked the declared gap and ElectraNet has cancelled its inertia shortfall agreements[92].

As part of the 2024 assessment, AEMO has also determined a system-wide inertia level of 36,200 MWs that applies to the mainland NEM when fully interconnected. This amount is apportioned to regions in a way that ensures balanced and efficient procurement of inertia. The apportionment for South Australia is 4,300 MWs, and forms the basis for new TNSP procurement obligations. For South Australia, ElectraNet must ensure that the amount is made continuously available within the region from 1 December 2027.

AEMO has assessed expected levels of available inertia in South Australia against the latest inertia requirements. These results are summarised in **Table 18** and **Table 19**, and indicate that sufficient inertia is expected to available to meet requirements in South Australia over the period to 2027-28.

[90] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/2023-inertia-report.pdf?la=en.

[91] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-inertia-report.

[92] At https://www.electranet.com.au/wp-content/uploads/ElectraNet-2024-TAPR.pdf.

Table 18 Inertia sub-network allocation and projections for South Australia

	2024-25	2025-26	2026-27	2027-28
***Inertia sub-network allocation* (MWs)**	4,300	4,300	4,300	4,300
Available inertia 99.87% of the time (MWs)	6,200	4,400[A]	4,400	4,400
***NSCAS gap* (MWs)**	-	-	-	-

A. The projected level of inertia noted here is the expected availability after the commissioning of Project EnergyConnect stage 2, and associated control schemes.

Table 19 Secure inertia requirements and projections for South Australia

	2024-25	2025-26[A] (Early)	2025-26[A] (Late)	2026-27	2027-28
Assumed level of 1-second FCAS (MW)	315	315	315	315	315
***Secure level of inertia* (MWs)**	5,600	5,600	5,600	5,600	5,600
Available inertia 99.87% of the time (MWs)	6,200	6,200	5,300	4,400	4,400
Inertia sub-network likely to island	Likely	Likely	Unlikely[B]	Unlikely	Unlikely
***NSCAS gap* (MWs)**	-	-	-	-	-

Note: Modelling was conducted on a financial year basis, however the gap declaration period is from 2 December 2024 to 1 December 2027.
A. A significant transition happens within this year, following the expected commissioning of Project EnergyConnect stage 2, and associated control schemes. As such, results for 2025-26 have been split into values that apply before and after Project EnergyConnect commissioning.
B. AEMO does not consider South Australia to be sufficiently likely to island following the expected commissioning of Project EnergyConnect stage 2 and necessary protection schemes are in place to manage the non-credible loss of Project EnergyConnect and the Heywood interconnector.

6.3 Network support and control ancillary services

NSCAS are defined in the National Electricity Rules (NER) as services with the capability to control the active or reactive power flow into or out of a transmission network. There are two categories of NSCAS need:

- Reliability and Security Ancillary Services (RSAS) – RSAS may be procured to maintain security and supply reliability of the transmission network in accordance with the power system security standards and the reliability standard.
- Market Benefits Ancillary Services (MBAS) – MBAS may be procured to maintain or increase capability of the transmission network to maximise net economic benefits to all those who produce, consume or transport electricity in the market.

AEMO assesses the need for these services annually and declares NSCAS gaps where it identifies an unmet need. The NER give TNSPs primary responsibility for acquiring NSCAS (with or without a declared gap). AEMO may be required to procure NSCAS under its last resort planning functions but can only do so to meet the RSAS category of NSCAS needs.

The ISF Rule introduces inertia network services and system strength services into the NSCAS framework effective from 1 December 2024. AEMO has consulted on amendments to the NSCAS Description and Quantity Procedure to reflect these new requirements and changes[93].

[93] At https://aemo.com.au/en/consultations/current-and-closed-consultations/amendments-to-the-nscas-description-and-quantity-procedure.

Voltage control challenges in South Australia

The 2023 NSCAS Report, published in December 2023[94], declared an immediate NSCAS gap for voltage control in South Australia, drawing on revised limits advice provided by ElectraNet in June 2023.

The limits advice confirmed that voltage control is one factors driving the current two generating unit requirement in South Australia, that this may be relaxed to a one-unit requirement under certain conditions where additional voltage control measures are met, and that fast-start resecure options are available in the region. Addressing this need in isolation is unlikely to result in a zero-unit requirement until PEC Stage 2 has been commissioned, and adequate grid reference testing has been conducted.

AEMO's 2023 NSCAS Report modelled the latest limits advice and confirmed that a voltage control need did exist in South Australia when operating with fewer than two synchronous generating units online. As the need is unmet, and it exists within the five-year NSCAS period, AEMO declared an ongoing RSAS gap of 200 MVAr[95] during periods when South Australian demand is below 600 MW, and South Australia is not islanded or at credible risk of islanding[96].

Following declaration of the NSCAS gap, ElectraNet concluded its voltage control RIT-T with a solution expected to be in place progressively across 2025-26. The RIT-T did not identify a means of providing the necessary voltage control services any faster. AEMO subsequently determined that an NSCAS gap would exist during the interim period, and commenced activities to procure services under its last-resort planning mechanism, in accordance with the NER[97].

The 2024 NSCAS report, published in December 2024[98], confirmed the magnitude and timing of the previously declared gap, and AEMO is continuing to progress procurement activities.

6.4 Secure operations with high levels of distributed resources

Australians continue to invest in distributed PV and other CER at world-leading levels. More than one-third of homes across the country now host rooftop solar systems, helping households and businesses reduce their energy bills and directly contributing to the decarbonisation of the energy system. With a growing penetration of distributed resources, challenges are emerging to maintain system security during low operational load conditions.

In July 2024, Australia's Energy Ministers agreed to a National CER Roadmap, building on advice from the Energy Security Board (ESB) around critical technical capabilities for ongoing power system security. The CER Roadmap sets out an overarching vision and plan to unlock CER at scale and identifies measures to "unleash the full potential of CER" by establishing the required mechanisms, tools and systems. This includes both:

[94] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/2023-nscas-report.pdf?la=en.

[95] The reactive power required from a solution that addresses this gap will depend on the network location it is provided from.

[96] Two synchronous generating units are recommended for management of ramping events when South Australia is at credible risk of separation from the NEM or when South Australia is operating as an island.

[97] https://aemo.com.au/consultations/tenders/nscas-procurement.

[98] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-nscas-report.

- Reforms to increase the opportunities for market participation of CER, including through enhanced coordination, allowing customers to respond to market-based incentives which will also help meet the challenges of low operational demand.
- Measures to support ongoing power system security, particularly the requirement for "backstop mechanisms to be in place" by the end of 2025 for "emergency response to ensure operational security when required".

Minimum operational demand in the NEM has been falling on average more than 1.2 GW per year and is projected to continue on this trajectory. During periods, there is limited demand being supplied from the main transmission system. At present, the power system relies on large-scale plant to deliver a range of system security services (system strength, inertia, voltage management and ramping). To deliver these services, these large-scale plant need to operate above minimum safe operating levels (MSOLs). In periods of very low operational demand, it may not be possible to dispatch enough large-scale plant above their MSOLs to deliver these essential security services.

AEMO is working on a range of options to manage the challenges associated with minimum operational demand. AEMO has recently released relevant information in recent publications, including the 2024 *Transition Plan for System Security*[99]*,* the 2024 NEM ESOO[100], and the *Supporting Secure Operation with High Levels of Distributed Resources* report[101]. Further information on these challenges and opportunities may be found in these reports.

6.4.1 Operational demand thresholds

South Australia has experienced a record minimum 30-minute operational demand of -205 MW, occurring at 13:00 on 19 October 2024 due to mild temperatures, clear skies and an ongoing large load outage. In this interval, distributed PV supplied approximately 114% of the underlying demand in the region, with exports into Victoria via interconnectors.

Minimum demand in South Australia has been falling on average more than 100 MW per year, and is projected to continue on this trajectory.

Table 20 summarises operational thresholds in South Australia (based on the present operational toolkit). These will continue to change over time as the power system evolves, as AEMO's ability to model the power system under these novel conditions continues to improve, and as the operational toolkit expands.

Table 20 Regional demand thresholds: South Australia (as of July 2024)

System conditions	Threshold	Level of regional demand required for secure operation, based on present operational toolkit (MW)	Details
Interconnected to rest of NEM	Minimum System	-520 MW to	• Defined by the level of regional demand in South Australia where SA->VIC interconnector export violations start to occur.

[99] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/transition-planning/aemo-2024-transition-plan-for-system-security.pdf

[100] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-electricity-statement-of-opportunities.pdf.

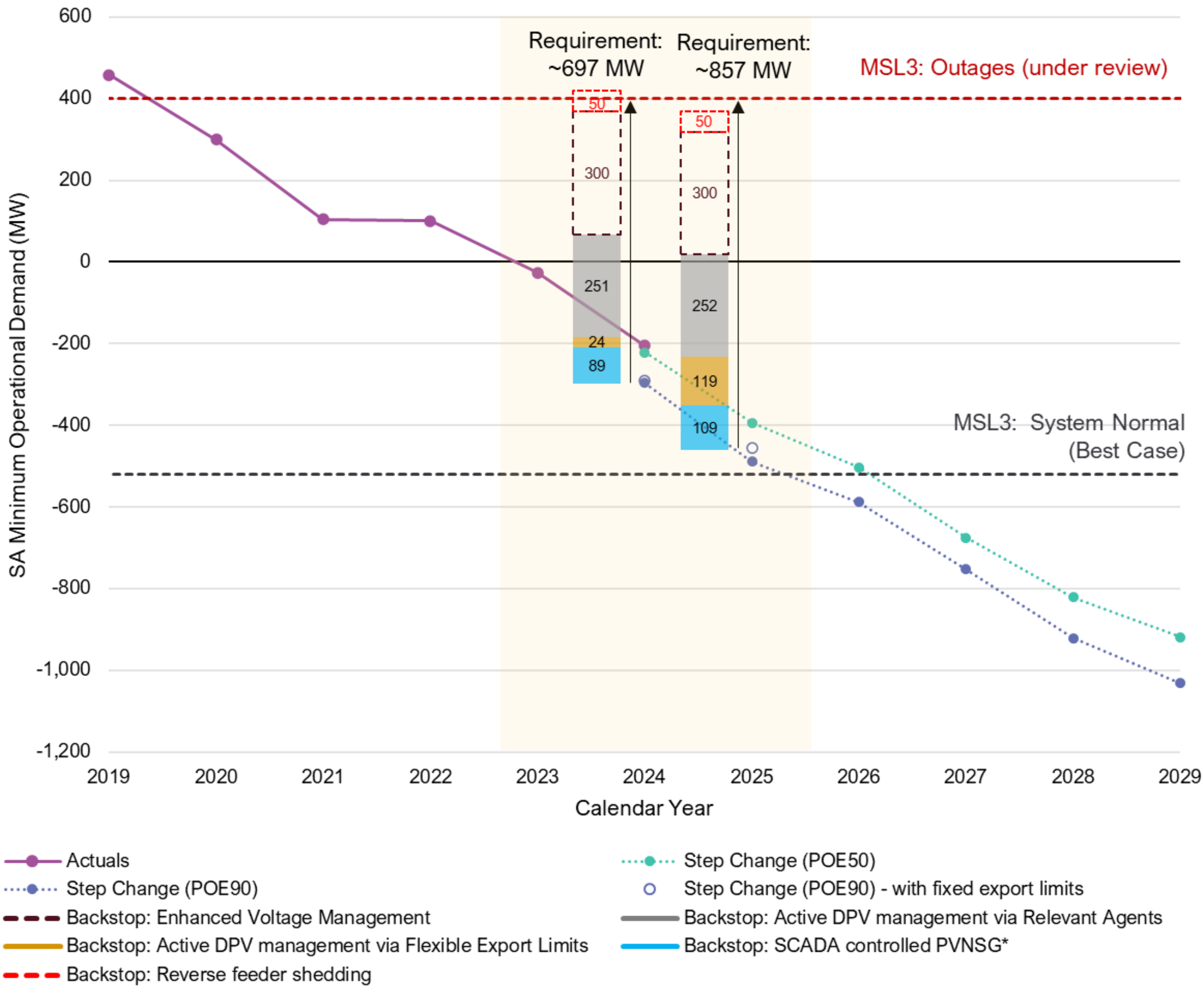
[101] At https://wa.aemo.com.au/-/media/files/initiatives/der/managing-minimum-system-load/2024-minimum-demand-and-emergency-backstop.pdf

System conditions	Threshold	Level of regional demand required for secure operation, based on present operational toolkit (MW)	Details
	Load 3 (MSL3)	400 MW (under review)	• Depends on the minimum safe operating levels of the minimum generating units required for essential system services in South Australia, and any network outages that affect interconnector limits. • The lowest threshold (-520 MW) assumes the smallest possible unit combination online to deliver essential services, no outages affecting interconnector limits, and allows for a small operating margin. • The highest threshold (400 MW) could occur in the case of multiple coincident outages including outages of Murraylink, other network equipment that significantly reduces Heywood interconnector export limits, the four synchronous condensers, and multiple generating units, such that a large unit combination must operate to deliver essential system services. This is an unlikely but plausible operating scenario, for which AEMO must ensure suitable plans and operational tools available.
South Australia at credible risk of separation	PTP (permission to proceed) with planned outages	250 MW (under review)	• AEMO does not provide permission to proceed (PTP) with planned network outages that put South Australia at credible risk if operational demand is forecast to go below 250 MW during the outage window. Demand forecast below this level is within uncertainty margins of requiring use of emergency backstop to maintain interconnectors within secure limits, if the outage were to proceed. • Defined by interconnector limits that apply when at credible risk of separation, which include terms to manage distributed PV shake-off impacts on contingency sizes.
SA island	MSL3	400 MW to 600 MW (under review)	• Defined by the level of operational demand required for secure operation of the South Australia island, avoiding violation of supply-demand balance and FCAS requirements. • Depends on the minimum safe operating levels of minimum generating units required for essential system services, including voltage management capability. • The level of regional demand required for secure operation, based on present operational toolkit is 600 MW, however latest analysis accounting for evolving minimum unit requirements in South Australia shows that this can reduce to 400 MW under some conditions.
	Distributed PV Contingency 3 (DPVC3)	400 MW to 900 MW (under review)	• Defined by need to maintain total maximum credible contingency size to within available frequency reserves. • Depends on the availability of frequency reserves (including conventional FCAS, very fast FCAS and inertia), the limits defined in the FOS, minimum safe operating level of the largest unit operating, and the amount of distributed PV and load shake-off that could occur if there is a severe fault at that location. This is influenced by the compliance of distributed PV with the disturbance ride-through requirements in AS/NZS4777.2:2020. • The level of regional demand required for secure operation, based on present operational toolkit varies depending on system conditions, but can be as high as 900 MW. However, accounting for the introduction of the very fast FCAS market, increasing availability of fast frequency response from BESS, and improving compliance of distributed PV with the disturbance ride-through requirements in AS/NZS4777.2:2020 can reduce this limit to 400 MW under some conditions.

Figure 42 compares the Minimum System Load 3 (MSL3) interconnected system thresholds with the minimum demand actuals and forecasts in South Australia. The maximum amount of backstop capability available in South

Australia in 2024 and 2025 is shown, based on advice from SA Power Networks, indicating whether it is likely to be possible to achieve the necessary operational thresholds if required under various conditions.

Figure 42 South Australia: Minimum demand thresholds, projections and estimated backstop capabilities



Note: a proportion of new distributed PV connections choose a fixed export limit of 1.5 kilowatts (kW) in preference to the SA Power Networks Flexible Exports offering. The minimum demand levels forecast in the ESOO do not consider the impact of these fixed export sites on minimum demand. SA Power Networks estimates this could increase the minimum demand in 2024 by ~7 MW, and increase minimum demand in 2025 by ~33 MW, compared with the ESOO forecast levels. This is shown in the figure above as the alternative "Step Change (POE90) forecast - with fixed export limits". The amount of emergency backstop distributed PV curtailment capability available is indicated in bars originating from this adjusted level.
* Further to PVNSG curtailment, there may be other non-scheduled generation (ONSG) in SA Power Networks' network which can also be curtailed, noting these systems may self-curtail during minimum demand periods due to low prices, and the more binding security threshold in South Australia tends to be distributed PV contingency management.

As shown in **Figure 42**, minimum demand has already been experienced in South Australia below MSL3 interconnected system outage thresholds. This means that use of emergency backstop is already required in South Australia under certain circumstances, especially if South Australia is operating as an island or at credible risk of separation, or if there are outages materially affecting interconnector export limits.

Emergency backstop capabilities have already been needed and used operationally on several occasions in South Australia, including:

- 13-19 November 2022[102] – South Australia operated as an island for a week following storm damage to the Heywood interconnector. During this week, with high levels of distributed PV generation, AEMO instructed SA Power Networks to maintain regional demand above 715-855 MW to maintain contingency sizes within the required ranges. This required curtailment of 400-600 MW of distributed PV. On several days, the amount of capability required represented the full extent of SA Power Networks' abilities.
- 15 February 2024 – following storm damage and failure of six 500 kV towers between Heywood and Moorabool on 13 February 2024[103], South Australia operated at credible risk of separation for several days, and distributed PV curtailment was necessary on 15 February to prevent violation of interconnector limits affected by the credible contingency size.

The minimum demand thresholds in South Australia for managing island and credible risk of separation conditions account for the following developments, all of which help to support the secure operation of the power system under low demand conditions:

- Commissioning of the ElectraNet synchronous condensers.
- Reduction in the minimum unit requirements in South Australia for maintaining essential system services.
- Increasing understanding of transmission voltage management requirements in South Australia under low demand conditions.
- New BESS in South Australia, delivering additional fast frequency response capability.
- Introduction of the new Very Fast FCAS market.
- Recent improvements in compliance of new distributed PV installations with AS/NZS4777.2:2020[104], reducing Distributed PV Contingency (DPVC) risk.

From 2026, the 90% POE regional demand in South Australia is projected to fall below thresholds where backstop will be required in system normal conditions with no outages. Project EnergyConnect will increase the export capability from South Australia, and will therefore affect these regional thresholds. However, by the time this interconnector is fully commissioned, all NEM regions may simultaneously be experiencing low demand, which limits the ability to export excess generation from South Australia.

Table 21 presents estimates of the amount of emergency backstop needed in South Australia to provide reasonable confidence of an ability to operate a secure system under most foreseeable conditions, based on the information available at the present time. This is based on needing to restore South Australian regional demand to at least 400 MW to maintain system security under some circumstances such as unplanned outages. Minimum demand records typically occur on weekends and public holidays in the October to December period, so requirements are presented as the maximum amount that may be required by this period each year (but this capability could also be required and has been called on during other periods).

[102] AEMO (May 2023), *Trip of South East – Tailem Bend 275kV lines on 12 November 2022*, https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/trip-of-south-east-tailem-bend-275-kv-lines-november-2022.pdf?la=en&hash=A89F330CF6C979E52EF15EB86E5CF058.

[103] AEMO (February 2024), *Preliminary Report – Trip of Moorabool – Sydenham 500 kV No. 1 and No. 2 lines on 13 February 2024*, https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/preliminary-report---loss-of-moorabool---sydenham-500-kv-lines-on-13-feb-2024.pdf?la=en.

[104] AEMO (December 2023), *Compliance of Distributed Energy Resources with Technical Settings: Update*, https://aemo.com.au/-/media/files/initiatives/der/2023/oem_compliance_report_2023.pdf?la=en&hash=E6BEA93263DE58C64FCC957405808CA6.

Table 21 Emergency backstop capability required in South Australia (based on information available as at July 2024)

	Oct 2023	Oct 2024	Oct 2025
Emergency backstop required	~426 MW	~697 MW	~857 MW

6.4.2 Emergency backstop implementation and compliance

SA Power Networks has been working to implement an emergency backstop mechanism in South Australia since 2020. Use of the mechanism during a power system incident in 2022 revealed that compliance rates were very low, with less than 30-40% of distributed PV systems responding correctly. Non-compliance was primarily associated with devices never being connected to their relevant control platform. Proper commissioning could not be automatically verified with the simple "no frills" technology used in this initial phase.

Since July 2023, SA Power Networks has introduced a Flexible Export Limits (FELs) capability. Customers installing a new distributed PV system in an area eligible for FELs are offered the choice of FELs or a fixed export limit of 1.5 kW. The FELs mechanism involves the following aspects which support improved compliance:

- Use of Common Smart Inverter Profile – Australia (CSIP-Aus) to enable communications loss failsafe behaviour (devices default to a 1.5 kW export limit if communications are lost for an extended period of time) and automated compliance checking through device telemetry.
- A compliance program which automatically prevents new applications from solar retailers who do not meet a threshold level of compliance.
- Extensive support and engagement with installers and solar retailers to help them correctly implement the new requirements.
- Extensive engagement with original equipment manufacturers (OEMs) and technology providers to help them understand and implement the new requirements.

This has led to a greater proportion of FELs systems being correctly commissioned, and this is steadily continuing to increase over time as the industry gains familiarity. As such, where emergency backstop capability used by SA Power Networks leverages the same technology, response and compliance is also improved. During the use of this newer system on 15 February 2024:

- SA Power Networks records show that of the installed sites that chose FELs, 75% were correctly commissioned by the installer.
- Independent analysis found that of those correctly commissioned FELs sites:
  - 75% responded fully to the curtailment signal and reduced export to close to 0 kW at each site. This represents a substantial improvement since November 2022, when much of the measured response was likely related to use of enhanced voltage management.
  - 10% correctly delivered the "loss of communications" 1.5 kW fallback export limit, which minimised the impact of these systems having lost communications on system security outcomes.

These steps represent important improvements, but considerable further work is required to improve compliance to the levels required for operational effectiveness. Of the ~16 MW of installed capacity of distributed PV that was eligible for FELs from 1 July 2023 to 14 Feb 2024, ~5 MW of demand increase was successfully delivered following the curtailment signal. SA Power Networks is targeting full rollout of the FELs mechanism by January 2025, and compliance continuing to improve throughout 2025.

6.4.3 Backstop capability available

South Australia has the following mechanisms available to deliver emergency backstop capabilities:

- **Curtailment of SCADA-controlled PV non-scheduled generation (PVNSG) sites** – since 2017, distributed PV sites with export capacity larger than 200 kilowatts (kW) must have Supervisory Control and Data Acquisition (SCADA) control installed on SA Power Networks' network, providing the ability to be curtailed to 0 MW if necessary. As of February 2024, there was a total installed capacity of 204 MW of SCADA-controlled PVNSG generation in South Australia[105]. In low demand periods, these units typically generate less in response to low market prices.
- **Relevant Agents** – the Smarter Homes regulations[106] have been applicable to all distributed PV systems installed in South Australia since 28 September 2020. These regulations require that all new electricity generating plants connecting to the distribution network in South Australia must be capable of being remotely disconnected (and later reconnected) by a "relevant agent".
- **Flexible Export Limits (FELs)** – SA Power Networks has also introduced the Flexible Exports mechanism[107]. This new connection option is offered to new or upgrading solar customers as an alternative to fixed export limits, and on agreement by the customer, allows the customer to export at higher levels most of the time unless network or security limits require a lower export limit in that interval. SA Power Networks is then able to utilise the technology put in place for the Flexible Export mechanism to deliver backstop capability on direction in MSL or DPVC conditions. The increased sophistication of the mechanism allows improved tracking and monitoring of commissioning and compliance. Flexible Exports has been offered to a growing base of SA Power Networks' customers from July 2023, targeting offering to 100% of customers from January 2025.
- **Enhanced voltage management (EVM)** – SA Power Networks uses EVM to regulate voltage levels throughout the year and, under normal circumstances, maximise the amount of energy that distributed PV systems can generate. When using EVM, SA Power Networks increases or decreases the voltage levels at key distribution zone substations (within safe limits). A side-benefit of EVM is that at certain higher voltage levels, a subset of distributed PV systems trip, disconnecting from the system. This method of disconnecting distributed PV can be used as a last resort when required to maintain system security. This is only suitable for use in rare emergency conditions; it is not recommended for regular use since if used regularly it may risk damage to customer equipment.

Table 22 outlines estimated levels of the total capability available to SA Power Networks via these various methods to deliver emergency backstop capabilities, as a last resort if required to maintain power system security.

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[105] Further to PVNSG curtailment, there may be other non-scheduled generation (ONSG) in SA Power Networks' network which can also be curtailed, noting these systems may self-curtail during minimum demand periods due to low prices, and the more binding security threshold in South Australia tends to be distributed PV contingency management, which is only alleviated by curtailment of distributed PV at risk of shake-off.

[106] Government of South Australia, Energy & Mining, Remote disconnect and reconnection of electricity generating plants, at https://www.energymining.sa.gov.au/industry/hydrogen-and-renewable-energy/solar-batteries-and-smarter-homes/regulatory-changes-for-smarter-homes/remote-disconnect-and-reconnection-of-electricity-generating-plants.

[107] SA Power Networks, Flexible Exports, at https://www.sapowernetworks.com.au/industry/flexible-exports/.

Uplift in compliance to curtailment signals under the Relevant Agent and FELs functions is required for operational effectiveness in restoring demand to levels required for system security.

Table 22 Emergency backstop capability available in South Australia (based on information available as at July 2024)

	Oct 2023	Oct 2024	Oct 2025
SCADA-controllable PVNSG	~ 42 MW	~ 89 MW	~ 109 MW
Flexible Export Limits	~ 0 MW	~ 24 MW	~ 119 MW
Relevant Agents	~ 206 MW	~ 251 MW	~ 252 MW
Enhanced Voltage Management	~ 300 MW	~ 300 MW	~ 300 MW
Total backstop available*	**~ 548 MW**	**~ 665 MW**	**~ 780 MW**
Backstop requirement	~ 426 MW	~ 697 MW	~ 857 MW
Shortfall	**-**	**~ 32 MW**	**~ 77 MW**

* Excludes shedding of reverse flowing loads to increase regional demand.

As shown in **Figure 42** and **Table 22**, South Australia does not have sufficient backstop capability available at present, with a shortfall of ~33 MW anticipated for plausible emergency conditions that could be experienced as early as this spring (October 2024). The shortfall is growing over time. Improvement in compliance with backstop capabilities is an urgent priority.

6.4.4 Actions and recommendations

Table 23 summarises the recommended short-term actions, all of which are underway at present.

Table 23 Short-term actions required: South Australia

SA Power Networks	• Full rollout of Flexible Exports mechanism. • Implement systems for monitoring, maintaining and enforcing high levels of compliance with: – Emergency backstop requirements. – Disturbance ride-through requirements in AS/NZS4777.2:2020. • Implement systems to minimise delay between AEMO instruction and delivery of backstop (ideally achieving confidence in delivery in <10 minutes).
ElectraNet	• Ensure suitable transmission voltage management capabilities for low demand periods, including for management of plausible fringe/outage conditions. The outcome of the Voltage Control RIT-T is the investment in additional reactors in South Australia*. • Planning assessments of alternative approaches for delivery of essential system services in MSL periods, including consideration of operability in fringe/outage conditions. • Commissioning of Project EnergyConnect.
AEMO	• Determine operational MSL thresholds for system normal, and revise AEMO's operational MSL procedures. • Update thresholds and procedures for operation of an SA island and SA at credible risk of separation from the rest of the NEM.

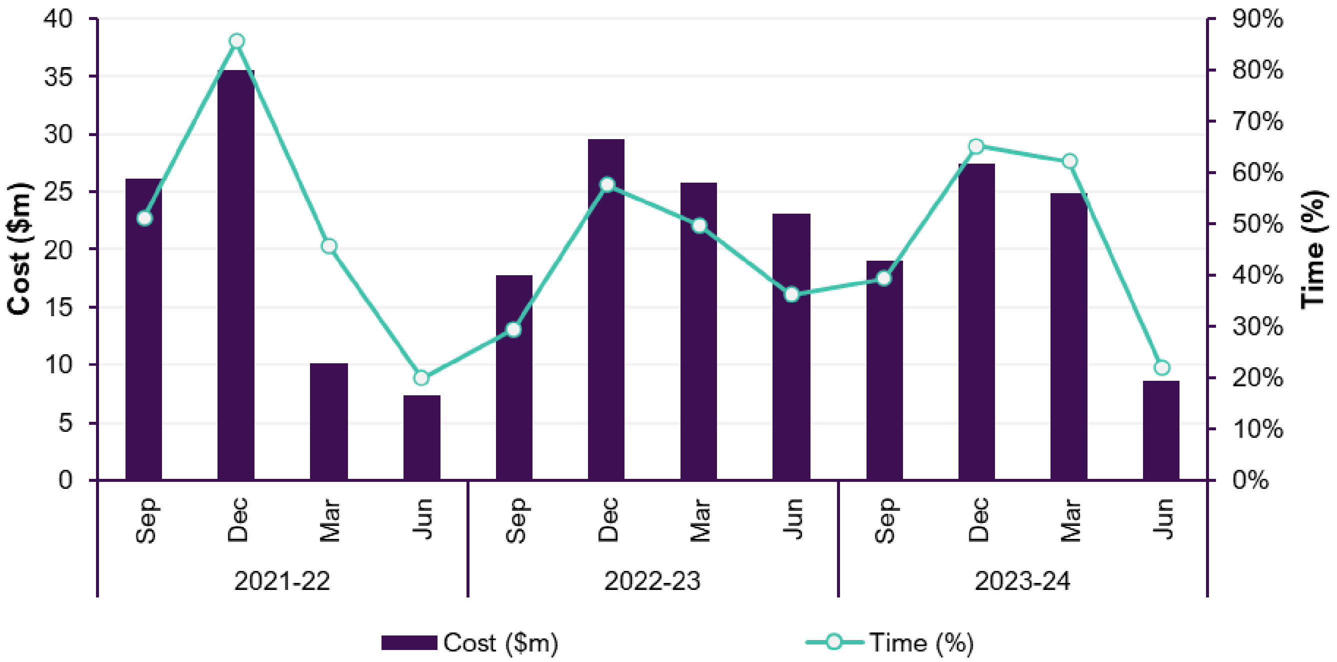
* ElectraNet (May 2024), *SA Transmission Network Voltage Control: RIT-T Project Assessment Conclusions Report*, at https://www.electranet.com.au/wp-content/uploads/ritt/SA_Transmission_Network_Voltage_Control_PACR.pdf.

6.5 Directions to maintain system security

AEMO may, where it considers necessary, direct a registered participant in the NEM to take relevant actions to maintain or restore the security or reliability of the power system. AEMO's *Quarterly Energy Dynamics* reports[108] have noted recent trends in the frequency, volume and total costs of directions issued to gas-fired generation in South Australia to maintain system security in the region.

In 2023-24, overall direction costs for energy amounted to $80 million, 17% less than the $96 million in the previous financial year (2022-23), and marginally higher than the $79 million in 2021-22 (**Figure 43**).

Figure 43 Frequency and cost of system security directions (energy only) in South Australia



Note: direction costs are preliminary costs which are subject to revision.

The year-on-year decrease was predominately driven by the June 2024 quarter, with the earlier three quarters' costs in line with the corresponding quarters in the prior year.

- In the September quarter, with relatively lower wholesale spot prices in South Australia and higher VRE output, gas-fired generators more frequently opted to decommit their units from the system. These factors led to an increase in the frequency of directions required to maintain minimum synchronous generation levels to ensure system security. However, direction costs remained close to the same quarter in the previous year due to a reduction in the average quarterly direction compensation price[109] due to the lower wholesale spot prices recorded over the preceding quarters.
- The trend of increased frequency of directions continued into the December and March quarters. Relatively low wholesale spot prices in South Australia, and high VRE output, saw an increase the number of intervals with directions in place due to gas-fired generators more frequently decommitting for economic reasons.

[108] At https://aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed.

[109] Directed generators receive a compensation price calculated as the 90th percentile level of spot prices over a trailing 12-month window.

However, the overall cost of directions was less than during the same quarters in the prior year, with the increase in direction frequency and volume offset by the lower direction compensation price.

- In the June quarter, there was a notable decline in directions required to maintain minimum synchronous generation levels to ensure system security as South Australian gas-fired generators increased their output in response to the relatively lower VRE output and higher wholesale spot prices over this quarter. The resultant decline in the frequency and volume of directions, along with a decrease in compensation prices paid to directed participants, led to directions costs less than half those in the previous June quarter.

AEMO publishes specific details on market directions issued in South Australia in the Direction reports section of the market event reports page of its website[110].

AEMO has recently released a Transitional Services Guideline[111] which outlines how AEMO must procure transitional services while meeting the Transitional Services Procurement Objective (TSPO) which balances emissions reduction, power system security, and minimising costs to end consumers[112].

The newly created framework[113] enables a capability for AEMO to procure Type 1 Transitional Service Contracts which are for the provision of services that are required for power system security and that cannot otherwise be provided through an existing framework[114], avoiding direct market intervention. AEMO currently envisages that Type 1 contracts will help secure critical system services required to manage minimum system load thresholds falling within the next two years, discussed further in the *Transition Plan for System Security*[115].

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[110] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/market-event-reports.

[111] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/transitional-services-guideline-consultation/transitional-services-guideline.pdf.

[112] NER 3.11.11(c)

[113] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/transitional-services-guideline-consultation/transitional-services-guideline.pdf.

[114] NER 3.11.11(b)(1)

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

A1. Resource availability and technology review

As well as the AEMO publications listed in **Table 1** (in Section 1.2), the following sources provide more detail on resource availability and relevant technologies.

Table 24 Additional data sources

Information source	Website address
Aurecon: 2023-24 Cost and Technical Parameters Review	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/aurecon-2024-cost-and-technical-parameters-review-report.pdf
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
CSIRO: GenCost 2023-24 Report	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
CSIRO: 2023 Electric vehicle Forecasts Report	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/2024-forecasting-assumptions-update-consultation-page/csiro---2023-electric-vehicle-projections-report.pdf
CSIRO and ClimateWorks Centre: 2022 Multi-sector modelling,	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-climateworks-centre-2022-multisector-modelling-report.pdf
Green Energy Markets – 2023 Consumer Energy Resources Forecast Report	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/green-energy-markets-2023-consumer-energy-resources-forecast-report.pdf

A2. Generation and demand breakdown

	SA generation								NEM balancing				SA consumption						
Financial year	**Wind (SS/NS)**	**Solar (SS)**	**Storage - battery (S)**	**ONSG**	**PVNSG**	**Rooftop PV**	**Coal, gas, diesel (S)**	**Total SA generation**	**Imports VIC-SA**	**Net Imports**	**Exports SA-VIC**	**Total electricity requirement**	**Auxiliary energy use**	**Transmission network losses**	**Distribution network losses**	**Scheduled Loads**	**Residential + business consumption**	**Consumption met by SNSG**	**Consumption met by Rooftop PV**
2012-13	3,473	-	-	79	3	434	9,031	**13,020**	1,710	1,377	-333	14,397	397	309	651	-	13,045	82	434
2013-14	4,087	-	-	82	3	582	7,664	**12,418**	1,925	1,637	-288	14,055	353	364	709	-	12,632	86	582
2014-15	4,218	-	-	92	4	716	7,246	**12,277**	1,904	1,528	-376	13,805	387	368	661	-	12,391	96	716
2015-16	4,317	-	-	65	4	812	7,145	**12,344**	2,227	1,941	-286	14,285	414	424	799	-	12,685	69	812
2016-17	4,340	-	-	78	8	904	5,620	**10,951**	2,889	2,725	-164	13,676	194	327	718	-	12,438	87	904
2017-18	5,561	4	22	72	22	1,041	7,282	**14,004**	1,039	-292	-1,331	13,712	224	313	676	27	12,477	94	1,041
2018-19	5,725	303	41	66	83	1,314	6,886	**14,418**	791	-468	-1,259	13,950	204	341	638	51	12,720	149	1,314
2019-20	5,798	483	47	67	209	1,611	6,278	**14,493**	922	-413	-1,335	14,080	180	313	703	59	12,834	276	1,611
2020–21	5,739	673	85	69	275	1,930	5,235	**14,005**	1,147	123	-1,023	14,128	142	384	545	104	12,954	343	1,930
2021-22	6,131	698	88	77	372	2,271	4,118	**13,754**	1,467	625	-842	14,379	111	379	622	111	13,137	448	2,271
2022-23	6,651	804	74	70	440	2,504	3,644	**14,188**	1,377	500	-877	14,688	78	381	618	97	13,594	510	2,504
2023-24	6,330	1,028	193	72	476	2,566	3,354	**14,018**	1,677	927	-750	14,945	42	269	424	260	14,009	547	2,566