South Australian Electricity Report

November 2022

South Australian Advisory Functions

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 30 September 2022, although AEMO has endeavoured to incorporate more recent information where practical (generation information specifically is based on AEMO's 31 October 2022 update).

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Version control

Version	Release date	Changes
1	30/11/2022	Initial release

AEMO acknowledges the Traditional Owners of country throughout Australia and recognises their continuing connection to land, waters and culture. We pay respect to Elders past and present.

2021-22 quick facts

- Distributed PV generated 2,269 GWh (estimated) and met up to 92% of underlying demand at times
- Distributed battery capacity 142 MW (estimated at 30 June 2022)

- Operational consumption (sent out) was 11,447 GWh
- Operational maximum demand was 2,554 MW at 7.30 pm, 11 January 2022, 8% lower than 2020-21 maximum
- Operational minimal demand saw record lows – record during 2020-21 was 104 MW (as generated) 1.30 pm, Sunday 21 November 2021, 45% lower than previous record

- Registered capacity 8,239 MW, total generated 14,004 GWh (more generation from wind, distributed PV and solar, less from gas)

- Net interconnector imports rose 407% to 625 GWh (imports rose to 1,467 GWh, exports fell to 842 GWh)

- Time-weighted average price (TWAP) increased to $105/MWh, after two years of decline, frequency of negative spot prices again increased to record levels, in 18.5% of dispatch intervals compared to 10% last year FCAS prices steady compared to 2020-21

AEMO reported system strength requirements to 2025-26 would be met by new synchronous condensers, an inertia shortfall was extended from July 2023 until the completion of Project EnergyConnect, and a reactive power absorption gap was declared for when the minimum number of synchronous generating units in the region reduces from two to zero.

Forecasts summary*

- Rooftop PV (up to 100 kW capacity) to generate 4,470 GWh in 2031-32 (about 24% of forecast annual underlying consumption), and PV non-scheduled generation (100 kW to 30 MW) to increase to 1,369 GWh by 2031-32
- Distributed battery capacity 1,293 MW (estimated) in 2031-32, 85% more than 10-year forecast capacity in 2021 SAER

- Operational consumption (sent out) increasing to 13,814 GWh in 2031-32 (up to 40,400 GWh in Hydrogen Export scenario)
- Summer operational maximum demand (sent out, 10% POE) increasing to 3894 MW in 2031-32
- Operational minimal demand decreasing constantly by almost 100 MW a year, will be negative at times by 2023-24 (50% POE) and more frequently challenging secure operation of the power system

- Additional supply – currently 437 MW committed, 435 MW anticipated, 12,300 MW proposed – majority wind, solar and firming battery storage/VPP

- Reliability gaps are forecast in 2023-24 and again in 2031-32, following generation retirements

- AEMO is currently preparing for the December 2022 release of the updated system security assessments for system strength, inertia and Network Support and Control Ancillary Services (NSCAS). This will include an assessment of the status of the existing declared inertia shortfall and NSCAS gap. In addition, the new system strength rules framework will be applied for the first time in December 2022, setting a decade-ahead system strength standard for all declared system strength nodes in South Australia.

* Unless otherwise noted: forecasts are based on the 2022 ESOO Central scenario assumptions, and additional supply categories are as at October 2022.

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 shifted back to wind** – in 2021-22, wind capacity grew by 210 megawatts (MW) with completion of Port Augusta Renewable Energy Park, after three years in which no new wind capacity was built in South Australia and new capacity was primarily large-scale solar and distributed photovoltaic (PV) systems.
  - Wind was again the largest source of energy generated in South Australia in 2021-22, contributing 6,151 gigawatt hours (GWh) and 41% of the total electricity generated. Gas still had the highest generation capacity (31% of total capacity when including distributed PV in the total, with wind at 29%).
  - Large-scale solar capacity for dispatch from the grid grew by 77 MW across a range of projects, and 294 MW of new distributed PV generation was installed. This growth meant distributed PV reached an 8% share of total capacity, double the share recorded in 2016-17.
- **South Australia's average wholesale electricity price climbed strongly after two years in decline**, following the NEM-wide trend of rising prices during 2021-22. South Australia's average time-weighted average price (TWAP) for electricity increased to its highest average since 2018-19, driven by unprecedented volatility across the NEM, particularly in the April-June quarter. South Australia experienced both high price volatility and increased incidence of negative spot prices in 2021-22, along with rest of the NEM.
- **Lower daytime operational demand and new minimum operational demand records were observed**, due to mild, sunny conditions and high distributed PV generation. The new record of 98 MW ('sent-out') demand from the grid, set at 1.30 pm on Sunday 21 November 2021, was 45% lower than the previous record. At this time, the estimated 1,221 MW output of rooftop PV was meeting 92% of South Australia's underlying demand, also a record.
- **Maximum operational demand again occurred in the evening, when distributed PV has a limited impact**. The peak demand for 2021-22 was 2,554 MW (sent-out) on Tuesday 11 January 2022 at 7:30 pm (Adelaide time), when rooftop PV was estimated at a very low 121 MW.
- South Australia was again a **net importer of electricity from other regions**. Net interconnector imports increased by 407% across the full year, mainly driven by the withdrawal and mothballing of Torrens Island A gas generation units.
- **The commissioning of the last of four synchronous condensers in November 2021 saw a significant reduction in the number of directions required to maintain power system security** in the second half of the year, but the overall number and cost of directions in 2021-22 was higher than in 2020-21.
- Increased penetration of large-scale solar and distributed PV saw **total emissions and annual emissions intensity from South Australian generation continue to decline** in 2021-22, both reaching their lowest level yet (2.26 million tonnes CO_2-e and 0.21 tonnes CO_2-e per megawatt hour respectively).

Major forecasting insights

- **Generation retirements are projected to create reliability risks:**
  - A reliability gap is forecast against the Interim Reliability Measure (IRM) of 0.0006% unserved energy (USE) in 2023-24, after Osborne Power Station's expected retirement. The AER has accepted AEMO's request to authorise a T-1 Retailer Reliability Obligation (RRO) instrument in 2023-24 in response. This risk has emerged due to forecast growth in industrial load, revised considerations of generation and transmission outages, and a delayed commissioning schedule for Project EnergyConnect since last year's SAER.
  - While the commissioning of Project EnergyConnect is forecast to reduce reliability risks, AEMO projects a reliability gap against the reliability standard in 2031-32, following the expected retirement of gas generators including Dry Creek, Mintaro, Port Lincoln and Snuggery power stations in 2030.
  - As the 2022 ESOO showed, significant investments in the NEM are expected in addition to the committed projects[1] included in the reliability assessment. Anticipated generation and storage developments (which meet some of AEMO's commitment criteria, but not enough to be considered committed) and the actionable transmission projects identified in the 2022 *Integrated System Plan* (ISP) are projected to improve the reliability forecast significantly if developed to their current anticipated schedules, keeping South Australia's unserved energy below the IRM and reliability standard throughout the 10-year forecast.
  - Since the 2022 ESOO was published, Bolivar Power Station – which had been included as anticipated in the ESOO modelling – has met sufficient criteria to be classified as committed. If the ESOO cases were run today to include the Bolivar Power Station, the Central projection would be close to being under the IRM in 2023-24.
- In all scenarios, **distributed PV and battery storage growth is forecast to continue**, although rooftop PV growth is forecast to be slower than projected last year. Increasing consumer generation and storage is forecast to keep **offsetting growth in underlying consumer demand**, reducing demand from the grid from the levels it would otherwise reach.
  - This year's Central scenario consumption forecasts are based on the *Integrated System Plan*'s *Step Change* scenario, which stakeholders now see as the most likely. *Step Change* includes higher projected rates of residential and commercial electrification (switching energy source from other fuels to electricity), and growth in electric vehicles. This forecast growth in electrifying the building, industrial and transport sectors is forecast to increase operational consumption over the next 10 years, rather than the decline in operational consumption forecast in the 2021 SAER (based on *Progressive Change*).
- **Minimum operational demand is forecast to experience relatively constant decline** of almost 100 MW per year in the shoulder season, where the annual minimum most often occurs. Based on AEMO's central scenario, South Australia may reach negative minimum operational demand (when distributed generation and storage discharge exceeds demand) by 2023-24. A negative operational demand means South Australia must export power to neighbouring regions.

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[1] Reliability assessments in the Central case include committed projects that satisfy all five commitment criteria (relating to land, contracts, planning, finance and construction), and projects classed as committed* that meet four criteria (including land, finance and construction) and are highly progressed towards satisfying the fifth criterion. For more, see Background information in AEMO's generation information updates, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

- **Maximum operational demand is forecast to continue to occur in summer, and to grow slightly**, due to expansion of large industrial loads, growth in EVs, and increased connections.
- An **additional 13,390 MW of new capacity has been committed, anticipated or proposed**; 30% of this total is battery or virtual power plant (VPP) storage projects (combined 4,045 MW), while there are 4,148 MW of large-scale solar projects and 3,499 MW wind projects.
- **Gas generation volumes are forecast to keep falling**, as more renewable energy is connected to the NEM, and Project EnergyConnect increases the capacity to import variable renewable energy (VRE) from New South Wales and Victoria. AEMO also expects that a minimum synchronous generator requirement will no longer be needed in South Australia under system normal conditions after Stage 2 of Project EnergyConnect is operational and ElectraNet implement a scheme to manage the non-credible loss of either Project EnergyConnect or the Heywood interconnector. Gas generation will continue to be an important source of peaking capacity at times of low VRE output, and of system security services, although over time, additional storage (both large-scale and distributed) as well as additional utilisation of South Australia's interconnectors, are expected to also contribute to managing the variability of VRE.
- **System security will remain a focus** as the transformation of the power system continues. In late 2021, AEMO declared a reactive power absorption gap in South Australia as well as an extension of the inertia shortfall from July 2023 until the completion of Stage 2 of Project EnergyConnect. AEMO is currently preparing for the release of the 2022 system security assessments, which will include updates on the status of the existing declared shortfalls and gaps.

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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 a number of 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 2022 SAER consolidates data and insights relevant to South Australia from a range of AEMO publications, including the 2022 *Electricity Statement of Opportunities* (ESOO) for the National Electricity Market (NEM), the 2021 *Inputs, Assumptions and Scenarios Report* (IASR), the 2022 *Gas Statement of Opportunities* (GSOO) for eastern and south-eastern Australia, the 2022 *Integrated System Plan* (ISP), the *Quarterly Energy Dynamics* reports, and the 2021 *System Security 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 30 September 2022, unless otherwise specified. Generation information specifically is from AEMO's 31 October 2022 update of its Generation Information web page. Reporting of historical observations on the gas and electricity markets is based on the 2021-22 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 2022 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	
2022 *Electricity Statement of Opportunities* (ESOO)	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

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

Information source	Website address
ESOO and Reliability Forecast Methodology Document	
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
2021 Forecast Accuracy Report	https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/forecasting-accuracy-reporting
2021 Inputs, Assumptions and Scenarios Report **(IASR)**	https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios
2022 ***Integrated System Plan*** **(ISP)**	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan
2022 ***Gas Statement of Opportunities*** **(GSOO) for eastern and south-eastern Australia**	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
2021 ***System Security Reports*** ***Update to 2021 System Security Reports***	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	http://forecasting.aemo.com.au/
Engineering Framework for the NEM	https://www.aemo.com.au/initiatives/major-programs/engineering-framework
Application of Advanced Grid-scale Inverters in the NEM **– White Paper**	https://www.aemo.com.au/initiatives/major-programs/engineering-framework
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 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 2022 SAER are consistent with the four scenarios presented in the 2022 ESOO, and shown in Figure 1 and Table 2 below. **The four scenarios are *Slow Change*, *Progressive Change*, *Step Change*, and *Hydrogen Export*.** These scenarios were developed in consultation with industry and consumer groups for use in AEMO's 2022 forecasting and planning publications, including the 2022 ESOO and 2022 ISP. More information on these scenarios is available in the 2021 IASR.

The 10-year demand and reliability forecasts in the 2022 ESOO and this 2022 SAER include "Central scenario" projections. These Central projections are based on the *Step Change* scenario, which was identified as the most likely scenario for the NEM during extensive stakeholder consultation in preparation for the 2022 ISP. This is different from the 2021 ESOO (and 2021 SAER), which adopted the *Progressive Change* scenario as the Central outlook.

Figure 1 2022 scenarios for AEMO's forecasting and planning publications

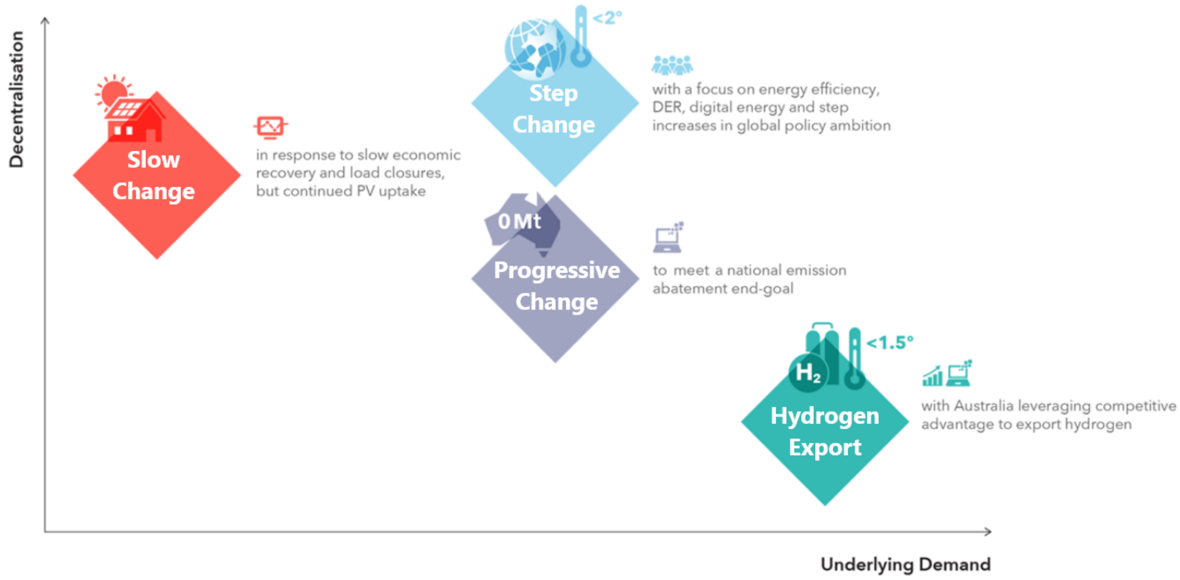


Table 2 Descriptions of AEMO's 2022 forecasting and planning scenarios

Slow Change	• **Challenging economic environment** following the COVID-19 pandemic, with greater risk of industrial load closures, and slower net zero emissions action. • Consumers continue to manage their energy needs through DER, particularly distributed PV.
Progressive Change	• **Pursuing an economy-wide net zero emissions 2050 target progressively**, ratcheting up emissions reduction goals over time to deliver a net zero emission economy, with a progressive build-up of momentum ending with deep cuts in emissions across the economy from the 2040s. • The 2020s would continue the current trends of the NEM's emission reductions, assisted by government policies, consumer DER investment, corporate emission abatement, and technology cost reductions. The 2030s would see commercially viable alternatives to emissions intensive heavy industry emerge after a decade or longer of research and development, paving the way for stronger economy-wide decarbonisation and industrial electrification in the 2040s, and nearly doubling the total capacity of the NEM. • EVs become more prevalent over time and consumers gradually switch to using electricity to heat their homes and businesses. • Some domestic hydrogen production supports the transport sector and as a blended pipeline gas, with some industrial applications.
***Step Change* (ESOO Central scenario)**	• **Rapid consumer-led transformation of the energy sector and co-ordinated economy-wide action.** • *Step Change* moves much faster initially to fulfilling Australia's net zero policy commitments that would further help to limit global temperature rise to below 2°C compared to pre-industrial levels. • Rather than building momentum as *Progressive Change* does, *Step Change* sees a consistently fast-paced transition from fossil fuel to renewable energy in the NEM. International action follows a similar fast-pace of expanded policy commitment and investment, supported by rapidly falling costs of energy production, including consumer devices. • Increased digitalisation helps both demand management and grid flexibility, and energy efficiency is as important as electrification. • By 2050, most consumers rely on electricity for heating and transport, and the global manufacture of internal-combustion vehicles has all but ceased. • Some domestic hydrogen production supports the transport sector and as a blended pipeline gas, with some industrial applications.
Hydrogen Export	• **Strong global action and significant technological breakthroughs.** • While the two previous scenarios assume the same doubling of demand for electricity to support industry decarbonisation, *Hydrogen Export* nearly quadruples energy consumption to support a NEM-connected hydrogen export industry.

	• The technology transforms transport and domestic manufacturing, and renewable energy exports become a significant Australian export, retaining Australia's place as a global energy resource. • While household electrification of heating and cooking appliances still occurs, many households with gas connections will progressively switch to a hydrogen-gas blend before appliance upgrades achieve 100% hydrogen use.

2 Demand and consumption[3]

While operational (grid) consumption has declined in recent years, AEMO's 2022 forecast projects a reversal of this trend from 2022-23, with electrification of stationary energy loads and transport expected to drive up consumption and more than offset the forecast reduction from continued growth in distributed PV and energy efficiency.

South Australia's high penetration of distributed PV, which reduces operational consumption during daylight hours, is impacting both maximum and minimum demand. Operational maximum demand now occurs late in the day, at times when distributed PV contributes little to consumers' energy needs. Minimum operational demand now occurs during the middle of the day, when distributed PV operates most, and it is forecast to keep declining as distributed PV continues to grow.

For more information:

- **2021 IASR (used in 2022 ISP) and the 2022 Forecasting Assumption Update, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.**
- **2022 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 http://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 at least annually[4]. The inputs and assumptions used in these forecasts are developed having regard to stakeholder consultation through its industry technical forum, the Forecasting Reference Group (FRG), as well as industry engagement via surveys, consultant data and recommendations.

The IASR[5] contains detail about the inputs, assumptions, and scenarios. Specific detail about how these inputs support electricity consumption and maximum/minimum demand forecasts is published in the Electricity Demand Forecasting Methodology[6]. For gas demand forecasting, the GSOO's demand forecasting methodology[7] also outlines the usage of these key inputs.

[3] Insights into AEMO's forecasting performance are reported annually in its 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.

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

[5] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[6] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/electricity-demand-forecasting-methodology/finalstage/electricity-demand-forecasting-methodology.pdf.

[7] At https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2022/2022-gas-statement-of-opportunities-methodology-demand-forecasting.pdf.

AEMO uses a range of historical data to train and develop component models. Historical data – ranging from live metered data to monthly, quarterly, or annual batch data – includes:

- Operational demand meter reads.
- Estimated network loss factors.
- Other non-scheduled generators.
- Distributed PV uptake.
- Gridded 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 electric vehicles [EVs]).
- The potential impacts of a hydrogen industry in Australia.

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

- Economic and population growth drivers, including meter connections.
- Climate change factors.
- Stakeholder surveys, including for large industrial loads across various sectors.
- Energy efficiency.

2.1.1 Electrification and hydrogen

Electrification, including electric vehicles

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

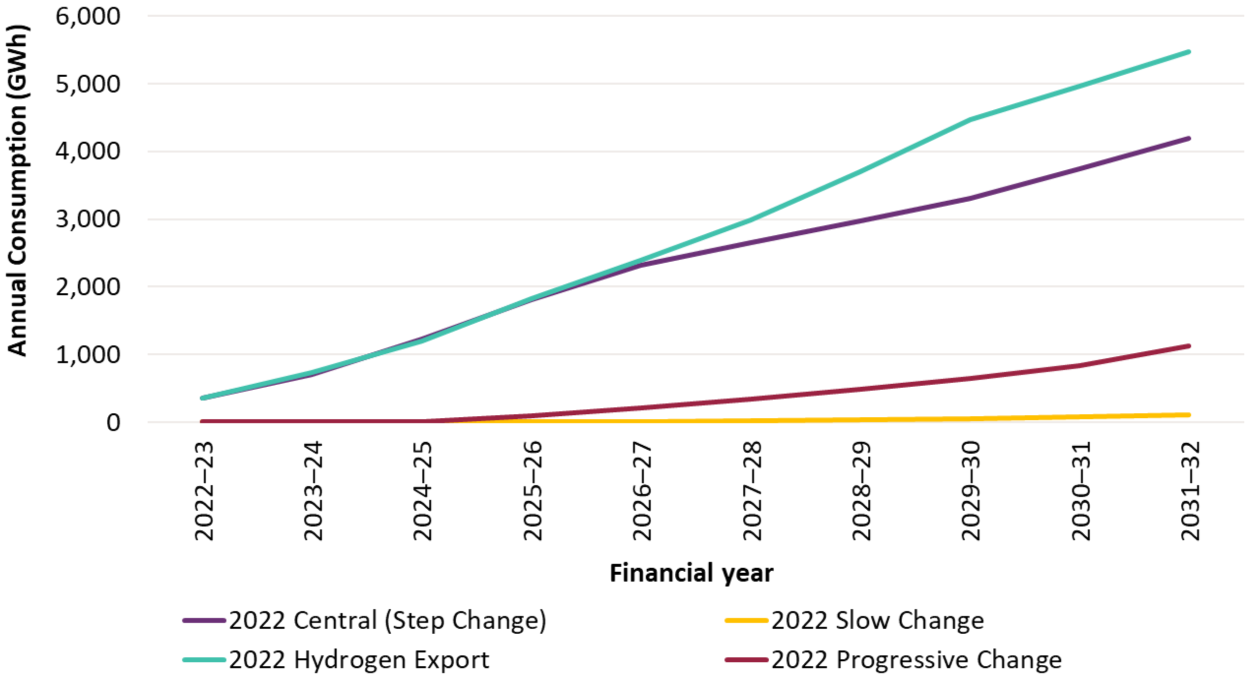
- In the residential and commercial (building) sectors, electrification will depend on factors including appliance replacement costs, electricity infrastructure capabilities and costs, and the cost and availability of alternative fuels, such as hydrogen or blended hydrogen-natural gas, as well as the ongoing costs, efficiency and emissions-intensity of existing fuels such as natural gas, diesel, and other fuel supplies.
- The industrial sector has a broad range of subsectors, with varying degrees of technical potential to switch from oil and gas fuels to electricity. However, in some cases fuel-switching may only be cost-effective for businesses that seek to significantly reduce their carbon emissions.
- Electrification of road and non-road transport is expected in all scenarios to varying degrees.

Figure 2 shows the magnitude of electrification including transport (EVs) forecast for each scenario and reveals a range of possible futures. By 2031-32, electrification is projected to reach 4,200 gigawatt hours (GWh) and 5,500 GWh in the Central (*Step Change*) and *Hydrogen Export* scenarios respectively, and as low as 100 GWh and 1,000 GWh in the *Slow Change* and *Progressive Change* scenarios, respectively.

In the *Progressive Change* and *Slow Change* scenarios, little to no residential or business electrification is forecast over the next decade, with the trend in Figure 2 almost entirely from EV uptake. Conversely, electrification of residential appliances and business loads is the dominant growth driver in the Central (*Step Change*) and *Hydrogen Export* scenarios, representing 3,300 GWh and 4,300 GWh of consumption respectively by 2031-32.

While the SAER focuses on the next 10 years, AEMO has forecast the scenarios to 2051-52[8], and projects an electrification impact of up to 13,600 GWh in the Central (Step Change) scenario over this extended period, of which 7,500 GWh is from fuel-switching of residential and business loads, and the remaining 6,100 GWh is from EVs. In comparison, consumption from EVs is estimated at 5.84 GWh in 2021-22, from around 3,900 road vehicles. By 2051-52, the forecast electrification impacts are approximately 100% of today's underlying consumption.

Figure 2 Electrification and electric vehicle forecast consumption (GWh) for South Australia, 2022-23 to 2031-32



Hydrogen

The hydrogen sector is still in its infancy, with the South Australian Government supporting several projects to promote a local hydrogen industry:

- The first commercial supply of renewable hydrogen from the HyP SA project[9] to BOC's plant in Whyalla, South Australia, took place in August 2022. The South Australian Government has committed $4.7 million to this project, which generates renewable hydrogen via a 1.25 MW Siemens Proton Exchange Membrane (PEM) electrolyser, the biggest of its type in Australia as of September 2022.

[8] The full forecasts are available from AEMO's forecasting portal: http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational.

[9] See https://www.agig.com.au/hydrogen-park-south-australia.

- The $240 million H2U Eyre Peninsula Gateway Hydrogen Project[10] supported by the South Australian Government has finished its feasibility analysis, site selection, and preliminary planning. Aiming for completion by the end of 2023, the first commercial-scale Demonstrator Stage will have a 100 MW electrolysis facility capable of producing up to 15,000 tonnes of green hydrogen and 40,000 tonnes of green ammonia per year. As of April 2021, Worley was awarded the engineering services contract to conduct the front-end engineering design (FEED) studies for the Demonstrator Stage.
- In the 2022-23 State Budget, the South Australian Government announced a 'Hydrogen Jobs Plan'[11], allocating AUD$593 million over four years for the development of a new hydrogen plant in the Whyalla area, with the goal of providing 200 MW of hydrogen-fuelled power generation and hydrogen storage infrastructure by the end of 2025. The hydrogen power station will be owned and operated by Hydrogen Power South Australia[12], a new government entity. The Office of Hydrogen Power South Australia (OHPSA) has been set up as a temporary agency to run the Hydrogen Jobs Plan's early implementation.

These, and other hydrogen projects being considered across South Australia, can have significant implications for the state's electricity sector.

The 2022 ESOO projects that if demand for green hydrogen increases rapidly, the utilisation of a flexible fleet of electrolysers could add flexible energy consumption to South Australia's electricity profile. This load could operate to avoid periods of electricity supply scarcity, instead preferring to operate when energy was readily available from excess renewable energy from wind and solar resources.

AEMO has applied a range of hydrogen assumptions across scenarios to model uptake rates of hydrogen as a fuel source; for example, the *Hydrogen Export* scenario applies greater hydrogen fuel substitution than other scenarios, as an alternative to electrification.

The *Hydrogen Export* scenario also explores the unique opportunities for domestic manufacturing and transport, and the case where renewable energy exports via hydrogen become a significant part of Australia's economy.

2.1.2 Distributed 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 PV systems and for PV non-scheduled generation (PVNSG), and projects changes in both installed capacity and the amount of energy generated by these systems. The breakdown uses the following definitions:

- 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.
- 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.

Energy generated for a particular time interval is calculated by multiplying the installed capacity by an associated normalised generation value, reflecting the solar insolation and the generating efficiency of the solar panels. AEMO uses normalised generation half-hourly profiles provided by Solcast to forecast distributed PV generation.

[10] See https://www.energymining.sa.gov.au/industry/modern-energy/hydrogen-in-south-australia/the-hydrogen-utility-h2u-eyre-peninsula-gateway.

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

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

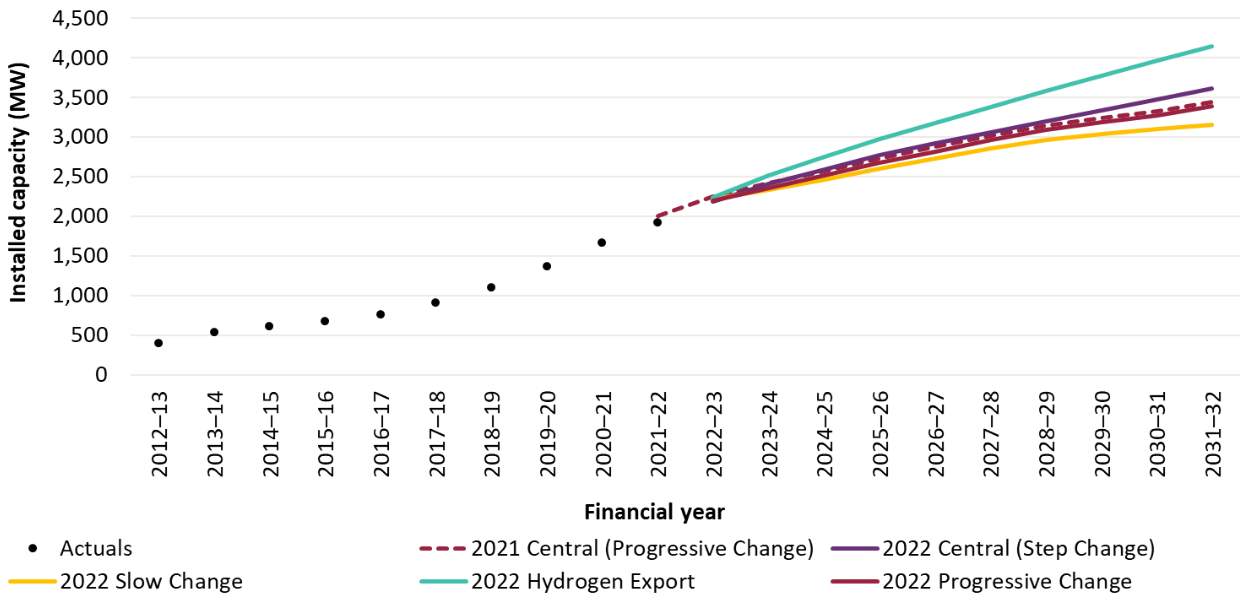
Rooftop PV capacity

Total installed rooftop PV capacity in South Australia has grown strongly since 2009, and continues to grow, with South Australia now having over 350,000 residential installations[13] and 44% penetration for dwellings[14] in residential rooftop PV, the highest of all NEM regions.

Current installed capacity estimates for rooftop PV are from the Clean Energy Regulator (CER), with AEMO's DER Register data providing a useful supplement. Additional information on rooftop PV forecasts is available in the CSIRO[15] and GEM[16] reports provided to AEMO.

Figure 3 shows estimated actual rooftop PV installed capacity since 2012-13 and the 10-year forecast for installed capacity under all scenarios in the 2022 ESOO, including a comparison to the Central scenario in the 2021 ESOO.

Figure 3 Actual and forecast South Australian rooftop PV installed capacity, 2012-13 to 2031-32



This shows that under all scenarios but *Hydrogen Export*, growth in installed capacity is forecast to slow in the coming years, although additional capacity is still forecast to increase by at least 50% from 2021-22 to 2031-32 in these scenarios (it is projected to increase by 100% in *Hydrogen Export*).

From 2012-13, rooftop PV generation in South Australia has impacted the minimum operational demand, shifting it from overnight to the middle of the day (see Section 2.3.2), and the time of maximum operational demand further into the evening, typically 7:30 pm Adelaide time in summer (see Section 2.3.1). Winter maximum demand

[13] 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.

[14] Dwellings using the ABS classification (for example, separate house, semi-detached, row or terrace house, townhouse) at https://www.abs.gov.au/statistics/people/housing/housing-census/latest-release#:~:text=There%20were%2010%2C852%2C208%20private%20dwellings%20counted%20in%20the%202021%20Census.

[15] See https://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2021/CSIRO-DER-Forecast-Report.

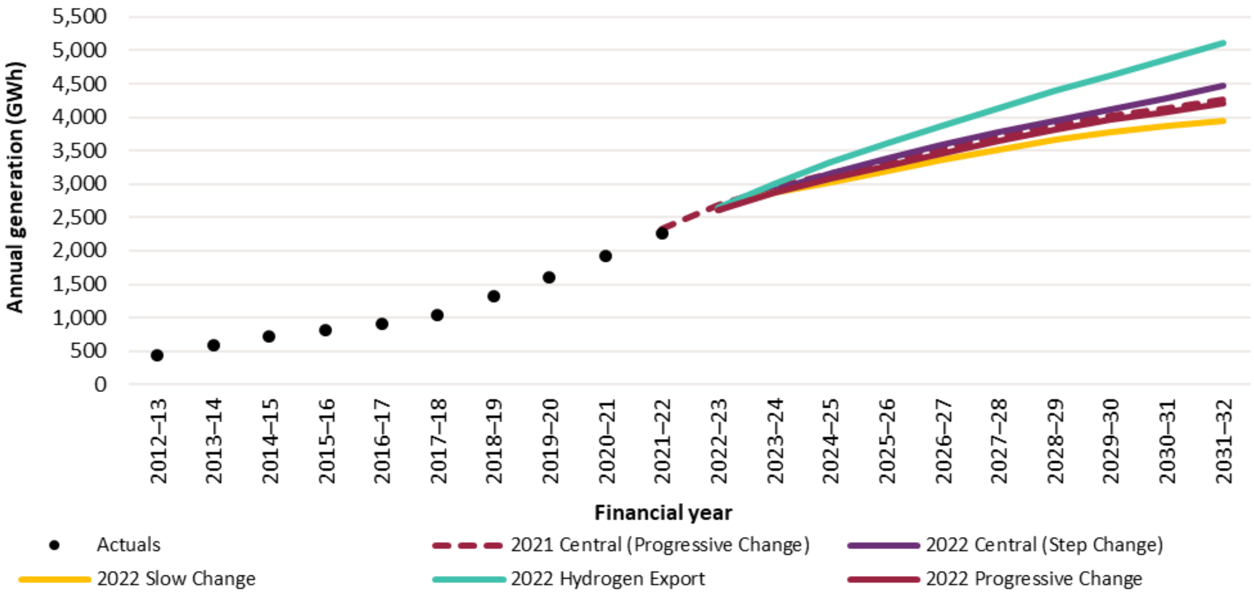
[16] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/green-energy-markets-derforecast-report.pdf.

periods are typically in the evening when rooftop PV generation is not operating, although rooftop PV generation does influence the morning peak, which can be significant.

Figure 4 shows estimated actual annual rooftop PV generation since 2012-13 and the 10-year forecast under all scenarios, including a comparison to the Central scenario in the 2021 ESOO:

- In 2021-22, annual rooftop PV generation was estimated at 2,269 gigawatt hours (GWh)[17], or 17% of total annual underlying consumption[18].
- In the Central scenario, it is forecast to increase to 4,470 GWh by 2031-32, which would represent approximately 24% of annual underlying consumption at that time in South Australia. In comparison, Queensland by 2031-32 is forecast to have approximately 20% of underlying demand met by rooftop PV.
- Over the next 10 years, South Australia is projected to have the highest ratio of rooftop PV generation to operational consumption[19] of all NEM regions.

Figure 4 Actual and forecast South Australian rooftop PV generation, 2012-13 to 2031-32



PV non-scheduled generation (PVNSG) forecasts

Figure 5 shows South Australia's PVNSG capacity since 2016-17, and the 10-year forecast for installed capacity under all scenarios, including a comparison to the Central scenario in the 2021 ESOO:

- PVNSG installations have slowed in the past two years relative to the strong trend otherwise seen since 2016-17. This was also observed in other NEM regions.
- The estimated amount of PVNSG installed capacity on 30 June 2022 was 207 MW[20], and is forecast to grow in the Central scenario to 710 MW in 2031-32, with an assumed return to stronger growth after the slowdown

[17] Estimates calculated as at 6 September 2022, for the financial year 2021-22.

[18] 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.

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

[20] There is a delay between a PVNSG connection and its registration with the CER for Large Generation Certificate (LGCs). Estimates calculated as at 14 September 2022, for the financial year 2021-22.

observed in the past two years. In contrast, the 2021 ESOO Central scenario forecast persisting slower growth (with the difference influenced by the Central scenario changing from *Progressive Change* in 2021 to *Step Change* in 2022).

Figure 5 Actual and forecast South Australian PVNSG installed capacity, 2016-17 to 2031-32

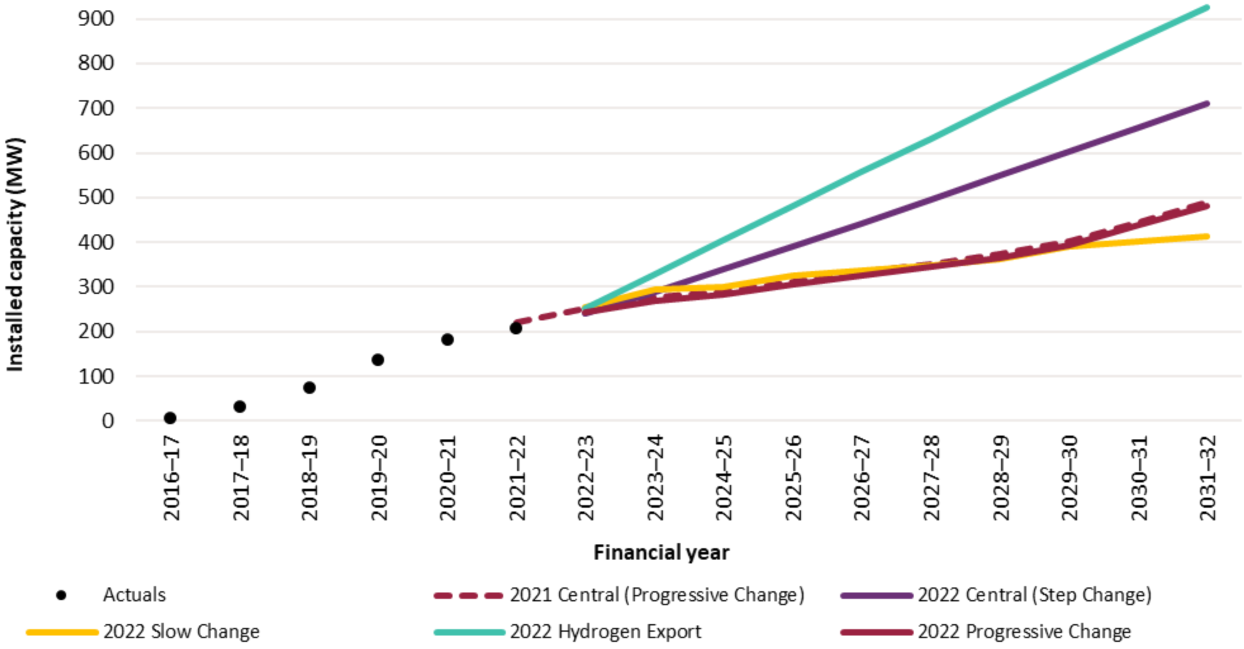
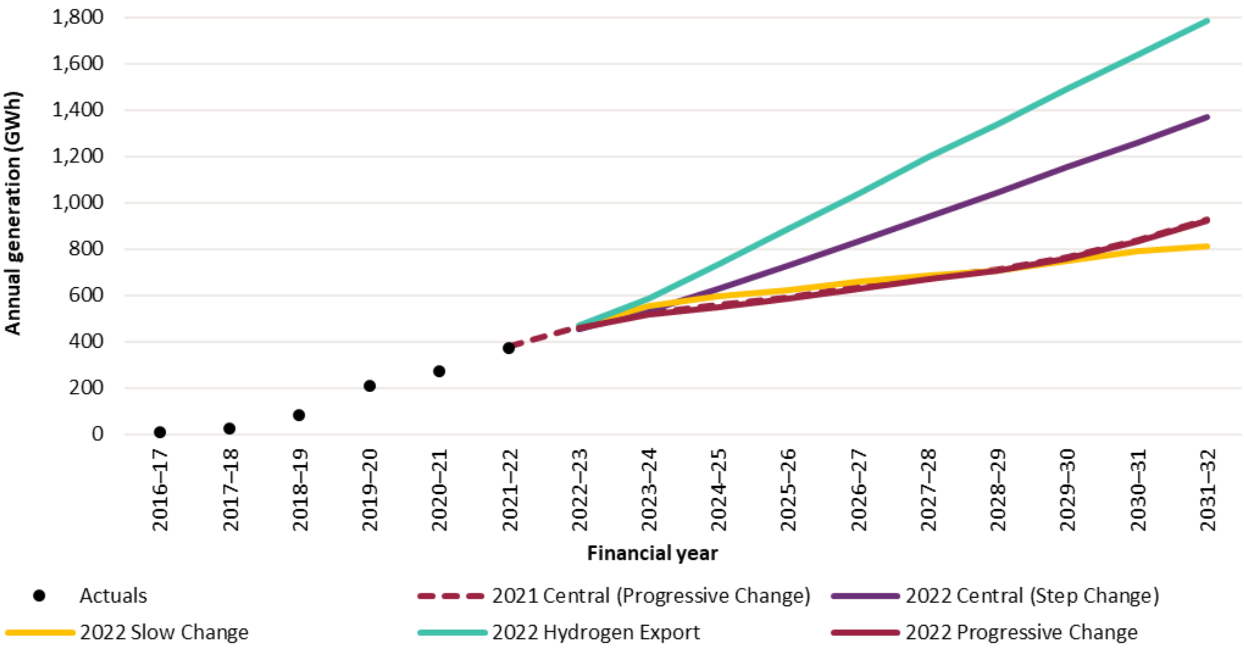


Figure 6 Figure 6shows PVNSG actual generation since 2016-17 and the 10-year forecast under all scenarios, including a comparison to the Central scenario in the 2021 ESOO.

Figure 6 Actual and forecast South Australian PVNSG generation, 2016-17 to 2031-32



It shows that:

- Annual PVNSG generation was estimated at 371 GWh in 2021-22. In the Central scenario, it is forecast to increase to 1,369 GWh by 2031-32.
- As with installed capacity, the forecast for the Central scenario shows stronger growth in PVNSG generation than in the 2021 ESOO Central outlook, driven by the change from *Progressive Change* last year to *Step Change* as the ESOO Central outlook in 2022.

Distributed battery storage forecast

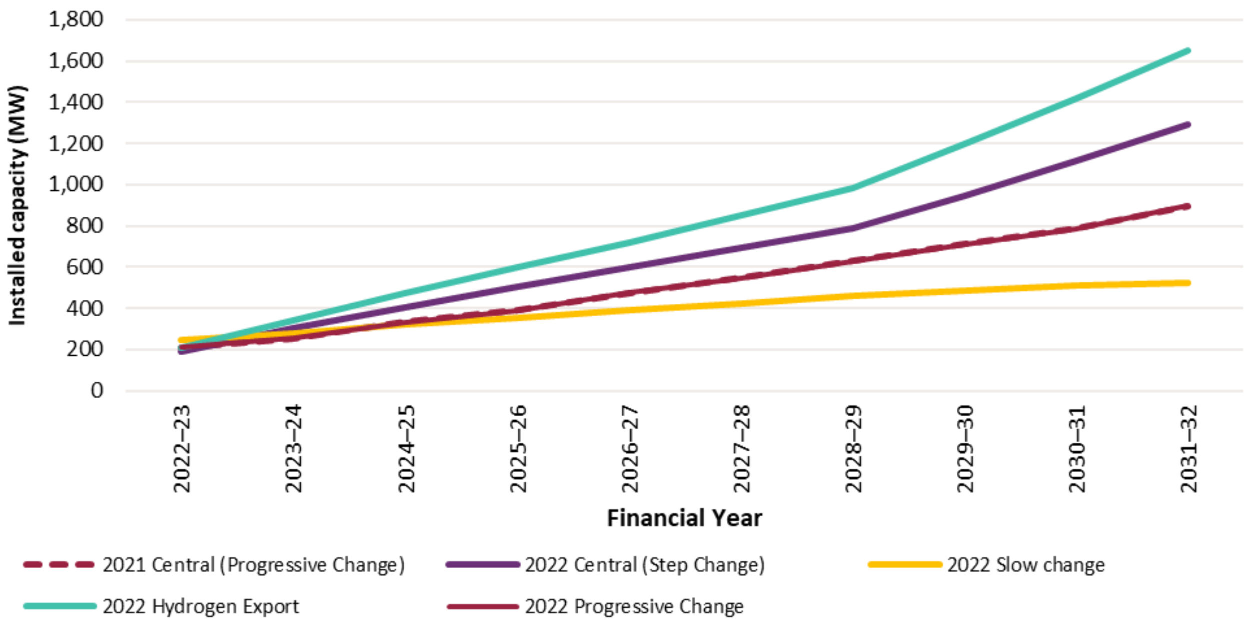
Behind-the-meter residential and commercial battery systems have the potential to change the future demand profile in South Australia, particularly maximum and minimum operational demand.

As at 30 June 2022, South Australia has an estimated 142 MW of embedded battery systems (from more than 23,000 units)[21].

By 2031-32, uptake of business and residential behind-the-meter battery systems is forecast to reach approximately 1,293 MW (in the Central scenario) and up to 1,652 MW (in the *Hydrogen Export* scenario). Battery uptake forecasts are the same as the previous year's projections, apart from the ESOO Central scenario being revised from the *Progressive Change* scenario to the *Step Change* scenario.

Figure 7 shows the 10-year forecast installed capacity of customer battery systems in South Australia for all scenarios, compared to the 2021 ESOO Central scenario.

Figure 7 Behind-the-meter battery capacity forecasts for South Australia, 2022-23 to 2031-32



Battery storage systems will operate to impact the demand profile, enabling households to store and use surplus solar production (if part of an integrated battery and solar system) and shift this energy for use to meet evening peak demands. The effectiveness of battery systems to support household consumption, or broader grid

[21] This estimate is based on AEMO's DER register data, as of end of June 2022.

consumption needs, will be influenced by pricing incentives, and there may be broader system benefits if the battery fleet is orchestrated as part of a VPP to provide a more certain network peak support role.

Retailers and technology providers have participated in trials of VPPs in South Australia, including the VPP demonstrations program[22] co-ordinated by AEMO to test VPPs' capacity to support system security. South Australian VPP demonstrations have included:

- South Australia VPP (SA VPP) (16 MW current registered capacity) operated by Energy Locals and Tesla with support from the South Australian Government[23].
- AGL VPP (6 MW), with support from the Australian Renewable Energy Agency (ARENA)[24].
- Simply Energy VPP (4 MW), with support from ARENA[25].
- Shinehub VPP (1 MW)[26].

The VPP demonstrations program closed in mid-2021.

2.2 Historical and forecast consumption and demand

2.2.1 Operational consumption

Figure 8 shows the historical trend of annual sent-out operational consumption in South Australia from 2017-18, as well as the 10-year forecast to 2031-32[27].

In 2021-22, South Australia's operational consumption (sent-out) was 11,447 GWh. This was 1.5% (169 GWh) lower than the 2020-21 consumption of 11,616 GWh. As detailed in Section 2.1, this decrease in consumption was largely a consequence of continued rooftop PV installation and operation.

Over the next 10 years, the 2022 ESOO Central scenario (*Step Change*) outlook for South Australia shows an increase in operational consumption of 21% to 13,814 GWh. From 2027-28, there is a steeper forecast incline in operational consumption due to expansion of large industrial loads.

[22] See https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/virtual-power-plant-vpp-demonstrations.

[23] At https://virtualpowerplant.sa.gov.au/.

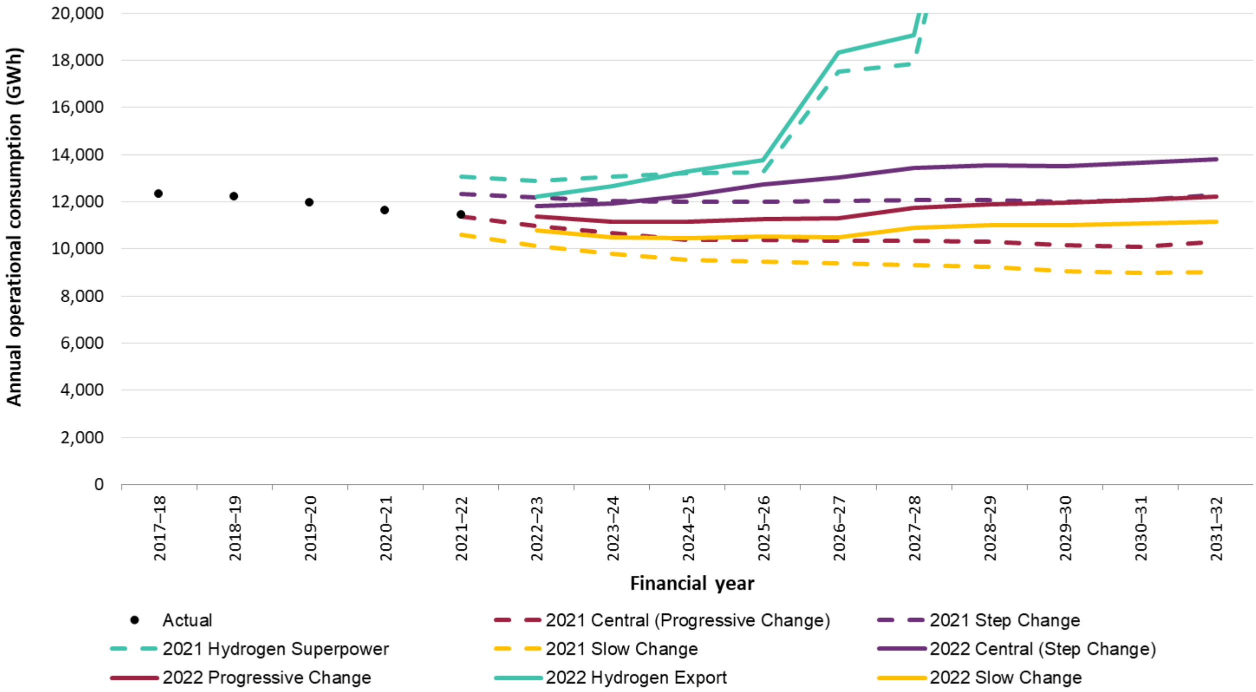
[24] At https://arena.gov.au/projects/agl-virtual-power-plant/.

[25] At https://www.simplyenergy.com.au/residential/energy-efficiency/simply-vpp.

[26] At https://shinehub.com.au/virtual-power-plant/.

[27] 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 Actual and forecast annual operational consumption (sent-out) for South Australia, 2017-18 to 2031-32



Note: *2022 Hydrogen Export* and *2021 Hydrogen Superpower* continues beyond the chart to reach approximately 40 TWh in 2031-32.
Note: Operational Consumption (sent-out) has changed historically due to updated auxiliary loads in line with the 2022 ESOO.
Data source: AEMO forecasting portal, at http://forecasting.aemo.com.au/.

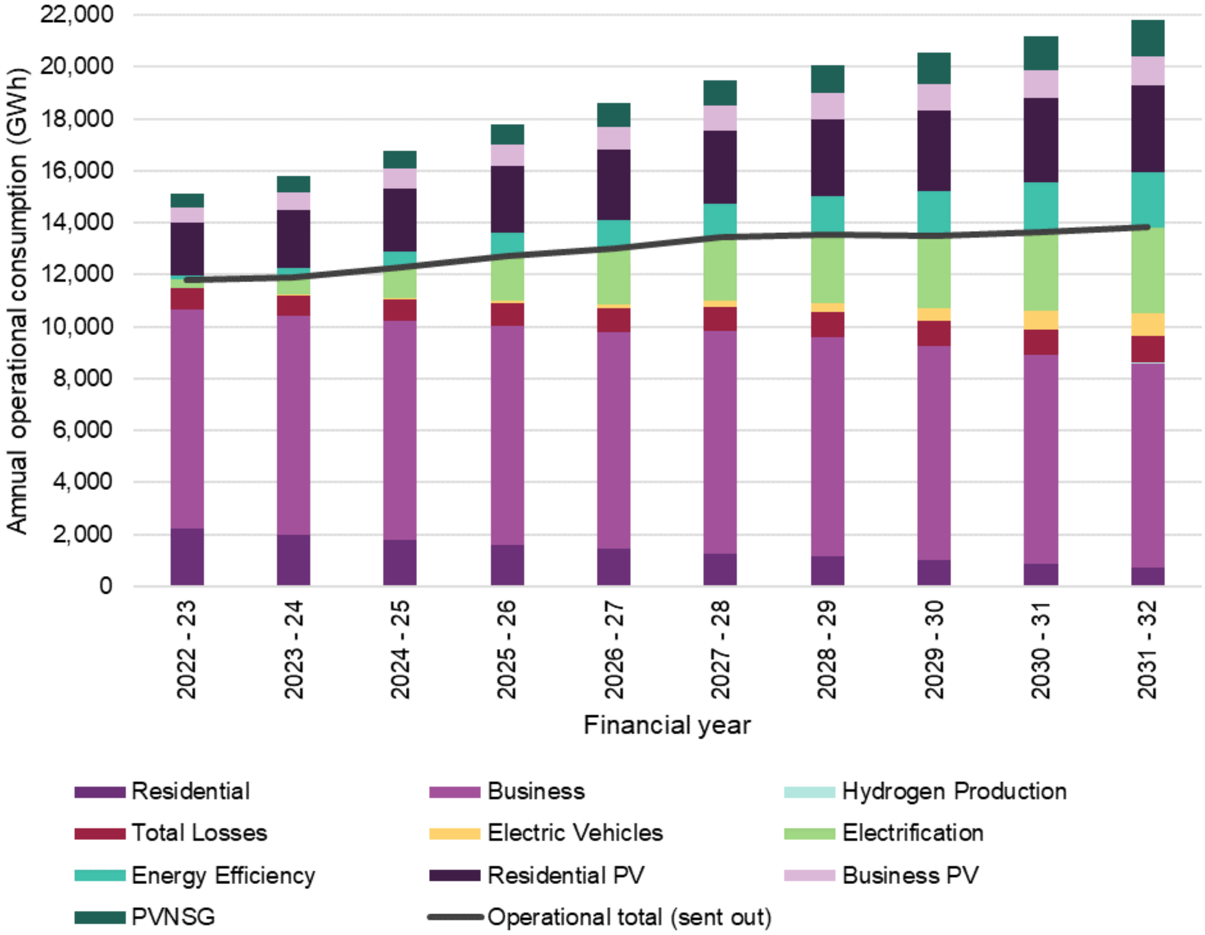
Figure 9 shows forecast operational consumption by sector to 2031-32. Components below the operational total (sent-out) line are items that consume energy. Components above this line offset growth, for example by saving energy through energy efficiency improvements, or self-generation from distributed PV systems.

As Figure 9 shows, the main driver of forecast growth is electrification of residential and business loads (3,300 GWh) and EVs (900 GWh), both of which have more aggressive uptake trends compared to the 2021 Central (*Progressive Change*) forecasts. The combined business and residential consumption, however, is forecast to be offset by new generation from distributed PV (2,200 GWh). Ongoing improvements in energy efficiency of appliances and industrial processes further reduce underlying consumption.

The forecasts vary by scenario from 2021-22 to 2031-32:

- Under the *Progressive Change* scenario, the combination of steady electrification of stationary loads (800 GWh) and EV uptake (400 GWh), moderated by continued growth in distributed PV growth (1,900 GWh), sees a modest increase in net operational consumption of approximately 800 GWh by 2031-2032.
- The *Hydrogen Export* scenario sees the greatest net increase in operational consumption, reaching approximately 40,400 GWh by 2031-32. The growth trajectory is dominated by hydrogen production for domestic and export markets, which represents 25,000 GWh of extra consumption. Additional growth is mainly attributed to electrification of stationary loads and transportation, though this is partially offset by strong penetration of rooftop PV.
- In contrast, the *Slow Change* scenario forecasts operational consumption to decrease by 300 GWh by 2031-32, due to rapid short-term PV growth coupled with limited electrification and EV adoption, large industrial load closure risks, and fewer new residential connections.

Figure 9 Forecast annual operational consumption (sent-out) with components (Central scenario), 2022-23 to 2031-32



Note:

- Electrification and Energy Efficiency cover both forecast residential and business consumption impacts.
- Rooftop PV is split into residential and business forecasts.
- The Residential segment of the bars is offset by growth in Residential PV (separate segment above the Operational total line). This Residential segment excludes residential electrification (part of the Electrification segment), which would contribute to the electrical footprint of households.

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

2.2.2 Residential sector – underlying and delivered consumption[28]

Underlying residential consumption is driven by a combination of new connections growth and electrification (gas appliances and transport), of which the latter is the dominant growth driver.

Over the next decade, growth in underlying residential consumption is expected to be moderate, increasing from 4,400 GWh in 2021-22 to 5,200 GWh in the Central (*Step Change*) outlook, 4,700 GWh in *Progressive Change*, and 5,500 GWh in *Hydrogen Export*. The *Slow Change* scenario forecasts limited residential electrification, so projected consumption by the end of the decade remains at approximately the same level as in 2021-22.

Residential rooftop PV generation currently meets approximately 41% of South Australian underlying energy consumption, providing 1,800 GWh of generation in 2021-22 and leaving approximately 2,600 GWh to be delivered from the grid. 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.

[28] Delivered consumption is underlying consumption less rooftop PV, so the amount of electricity provided from the grid to consumers. Reporting delivered consumption helps in isolating and discussing the impact of rooftop PV.

By 2031-32, residential rooftop PV is forecast to provide approximately 65% to 70% of underlying residential consumption, with grid-delivered electricity ranging from 1,400 GWh to 1,800 GWh across the scenarios.

2.2.3 Business sector – underlying and delivered consumption

Underlying business consumption is forecast to increase from 9,100 GWh in 2021-22 to 13,500 GWh in 2031-32 in the Central (*Step Change*) scenario, and as high as 40,700 GWh in *Hydrogen Export*. This is comprised of load from large industrial loads, business mass market customers (mainly services), electrification including EV uptake, and hydrogen production. In summary:

- Forecast growth in large industrial load consumption is predominantly driven by planned site expansion from 2027-28, resulting in a marked step change in underlying business consumption. Across all scenarios, consumption from large industrial loads is forecast to increase from 3,100 GWh in 2021-22 to 3,800-4,200 GWh by 2031-32.
- Consumption from business mass market customers is also forecast to rise at a steady rate over the next decade, increasing by 800-1,000 GWh in the *Slow Change*, *Progressive Change* and *Hydrogen Export* scenarios. Forecast growth is lower in *Step Change* at 400 GWh, due to greater business electrification.
- Projected electrification of stationary business loads contributes significantly to variations in underlying consumption. In the Central (*Step Change*) and *Hydrogen Export* scenarios, electrification drives 2,800 GWh and 4,000 GWh of consumption growth respectively. However, the pace of business electrification is uncertain, resulting in a wide spread of forecast outcomes across AEMO's scenarios (limited to 700 GWh in *Progressive Change*, and a negligible level in *Slow Change*). Uptake of EVs in the business sector contributes an additional consumption of 40-600 GWh by 2031-32, reaching 400 GWh in the Central (*Step Change*) scenario.
- Hydrogen production is the dominant growth driver in the *Hydrogen Export* scenario, accounting for 25,300 GWh by 2031-32. There is limited hydrogen production of 40 GWh in Step Change and none in the remaining scenarios over the next decade.
- Steady uptake of PV generation is forecast to continue in the business sector, offsetting operational consumption. Across the scenarios, rooftop PV is expected to grow by 500-700 GWh, while PVNSG is also expected to grow by between 400 GWh and 1,400 GWh. See Section 2.1.2 for further discussion on PVNSG.
- The resultant delivered consumption for the sector is forecast to increase from 8,600 GWh in 2021-22 to 9,800-12,400 GWh across the *Slow Change*, *Progressive Change* and Central (*Step Change*) scenarios, and up to 39,500 GWh in *Hydrogen Export*.

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 to date have resulted in maximum operational demand shifting from the middle of the day to the evening, when distributed PV is not generating. As Table 3 below shows, since 2017-18, the time of maximum operational demand has occurred late in the day.

On Tuesday 11 January 2022, operational demand in South Australia reached 2,554 MW (measured on a sent-out basis) at 7:30 pm (Adelaide time) with a temperature of 40.2ºC recorded at Adelaide (Kent Town) earlier that day. At the time of the maximum demand, the Adelaide temperature had cooled to approximately 25ºC, but load remained high in response to the higher daytime temperature. La Niña conditions meant that summer did not have any strong heatwaves with temperatures in the mid to high forties, which has commonly been observed in previous years.

Rooftop PV generation at the time of the maximum demand was very low (estimated 121 MW), because solar irradiance is low at this time of day.

With maximum operational demand events now tending to occur at times when PV generation is low, the 2022 ESOO suggests that further increases in distributed PV capacity are unlikely to impact maximum operational demands.

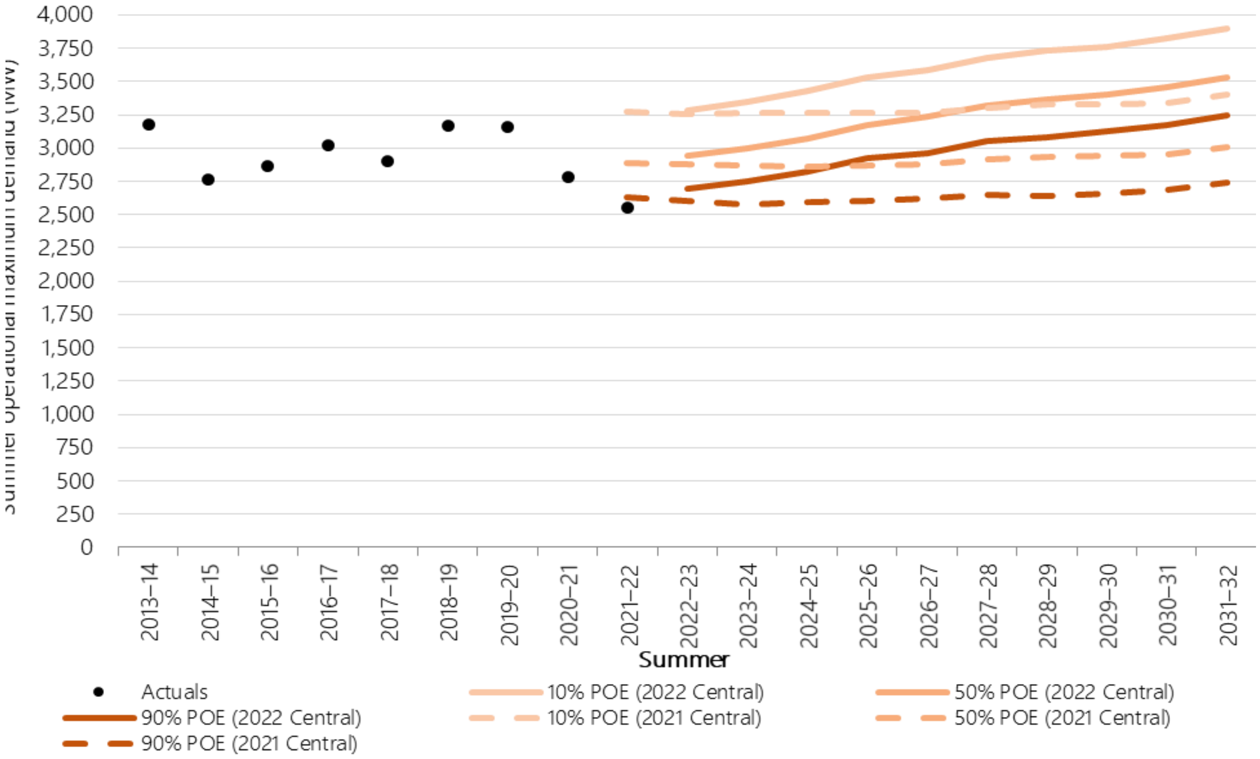
Forecast operational maximum demand

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 10 shows historical summer maximum demand actuals since 2013-14, and 10%, 50%, and 90% probability of exceedance (POE)[29] forecasts from the 2022 and 2021 NEM ESOOs (Central scenario). With limited offset for PV due to the late peaks, maximum operational demand (50% POE, Central scenario) is forecast to grow significantly over the next 10 years driven by forecast growth in population, electrification and the economy overall.

[29] 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.

Figure 10 Actual and forecast summer operational maximum demand (sent-out) for South Australia (Central scenario), 2013-14 to 2031-32

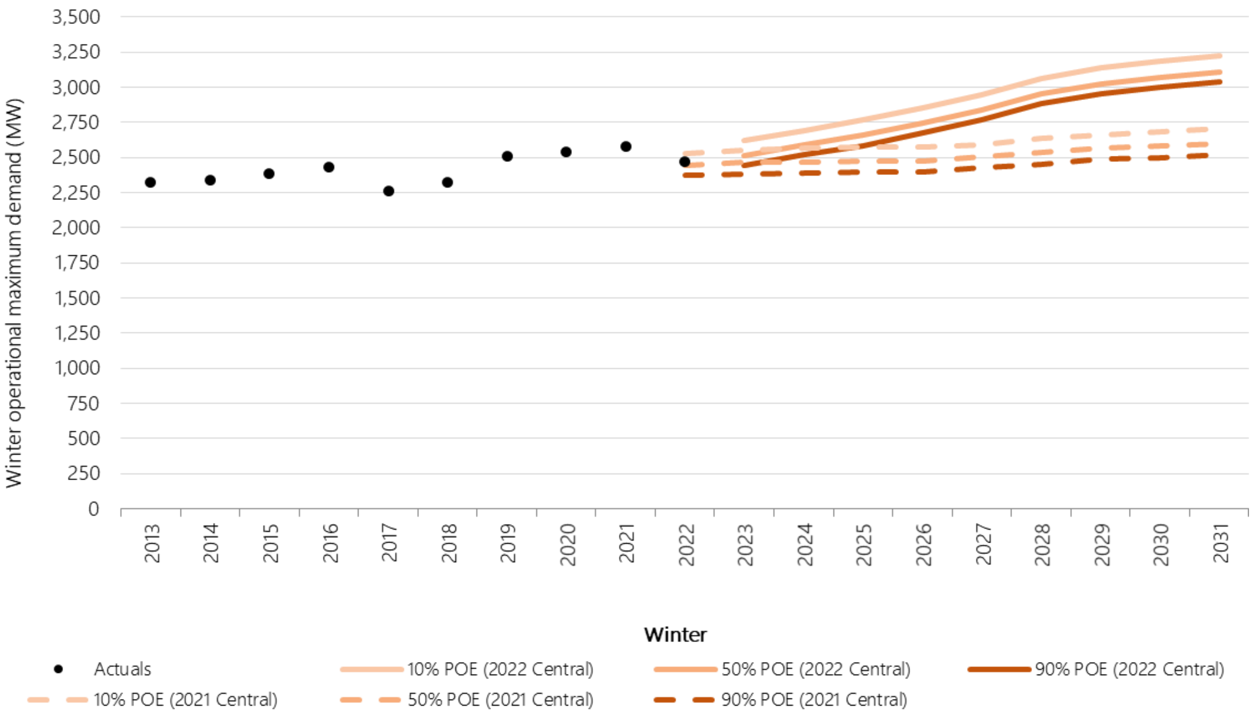


EV growth is projected to have some impact on maximum operational demand, although it will depend on the time of day that vehicle charging occurs. AEMO forecasts several charging profiles, with daytime (to benefit from rooftop PV generation) and overnight (taking into account lower tariffs offered for overnight consumption) charging more preferable than convenience charging that may amplify evening peak demands. As outlined previously, the magnitude of impact will depend on the infrastructure available and consumer preferences (and incentives) to operate in a manner that minimises grid disruption while still maintaining broad convenience.

As Figure 10 shows, the maximum summer operational demand observed in 2021-22 was just under the 90% POE forecast. This was due to the very mild summer driven by the La Niña conditions referred to above.

Figure 11 below shows the forecast for South Australia's operational maximum demand in winter. In winter 2022, a maximum demand of 2,471 MW was reached on 22 August 2022 at 6:30 pm (Adelaide time). With shorter days in winter, evening peaks have no offset from PV generation, and therefore 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.

Figure 11 Actual and forecast winter operational maximum demand (sent-out) for South Australia (Central scenario), 2013 to 2031



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

Impact of distributed PV on underlying maximum demand

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 remains low.

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)
2017-18	360	19/01/2018 5:00 PM	58	18/01/2018 7:30 PM
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	1018	11/01/2022 3:30 PM	121	11/01/2022 7:30 PM

Table 4 shows this data for winter maximum demand; 6 July 2022 was the third consecutive week of below average temperature across South Australia resulting in above average underlying demand across the day. Historically, however, there is no PV output during either underlying or operational winter maximum demand.

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)
2017-18	0	26/06/2018 6:30 PM	0	26/06/2018 6:30 PM
2018-19	0	24/06/2019 6:30 PM	0	24/06/2019 6:30 PM
2019-20	0	7/08/2020 6:30 PM	0	7/08/2020 6:30 PM
2020-21	0	22/07/2021 6:00 PM	0	22/07/2021 6:00 PM
2021-22	531	6/07/2022 9:30 AM	0	22/08/2022 6:30 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. 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.

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 2022-23 and winter 2023 is shown in Table 5. It reflects AEMO's expected (median) DSP resource response to different wholesale price levels. Reliability response DSP estimates are also included, referring to situations where additional DSP is observed in response to a Lack of Reserve (LOR) notice (LOR 2 or LOR 3) being issued[30].

The methodology used is explained in AEMO's DSP forecast methodology[31], which includes a summary of the groups that are included in AEMO's DSP values, the groups excluded, and the reasons why. Notably:

- DSP responses triggered by the Reliability and Emergency Reserve Trader (RERT) process, as discussed in Section 4.2, are excluded.
- Operation of battery storage units, including VPPs, is reflected in other parts of AEMO's forecasting process 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 of these effects.
- Wholesale Demand Response (WDR) is included as DSP, and has been included since the 2021 DSP forecast.

[30] LOR conditions indicate times the system may not have enough reserves to meet demand if there is a large, unexpected event. 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.

[31] 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 5 shows the estimated cumulative price response is 5 MW for South Australia when prices exceed $500 a megawatt hour (MWh), and 12 MW when prices exceed $5,000/MWh. However, if LOR 2 or LOR 3 conditions are declared, the total DSP response is estimated to be 13 MW in South Australia.

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

Trigger	Summer 2022-23 (MW – cumulative for each price band)	Winter 2023 (MW – cumulative for each price band)
>$300 / MWh	2	2
>$500 / MWh	5	5
>$1000 /MWh	7	7
>$2500 /MWh	8	8
>$5,000 / MWh	12	12
>$7,500 / MWh	13	13
Reliability Response	13	13

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

The 2021 DSP forecasts for estimated WDR response were higher than eventuated. As of June 2022, WDR had only been dispatched in New South Wales and Victoria, and in lower than forecast amounts compared to the 2021 DSP forecast. Partly informed by the over-forecast of WDR, AEMO has reduced estimated DSP capacity in South Australia for 2022-23 compared to the 33 MW forecast last year for 2021-22.

2.3.2 Operational minimum demand

South Australia has experienced minimum demand in the middle of the day since 2012-13, 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 distributed PV reduces the need for grid-delivered energy.

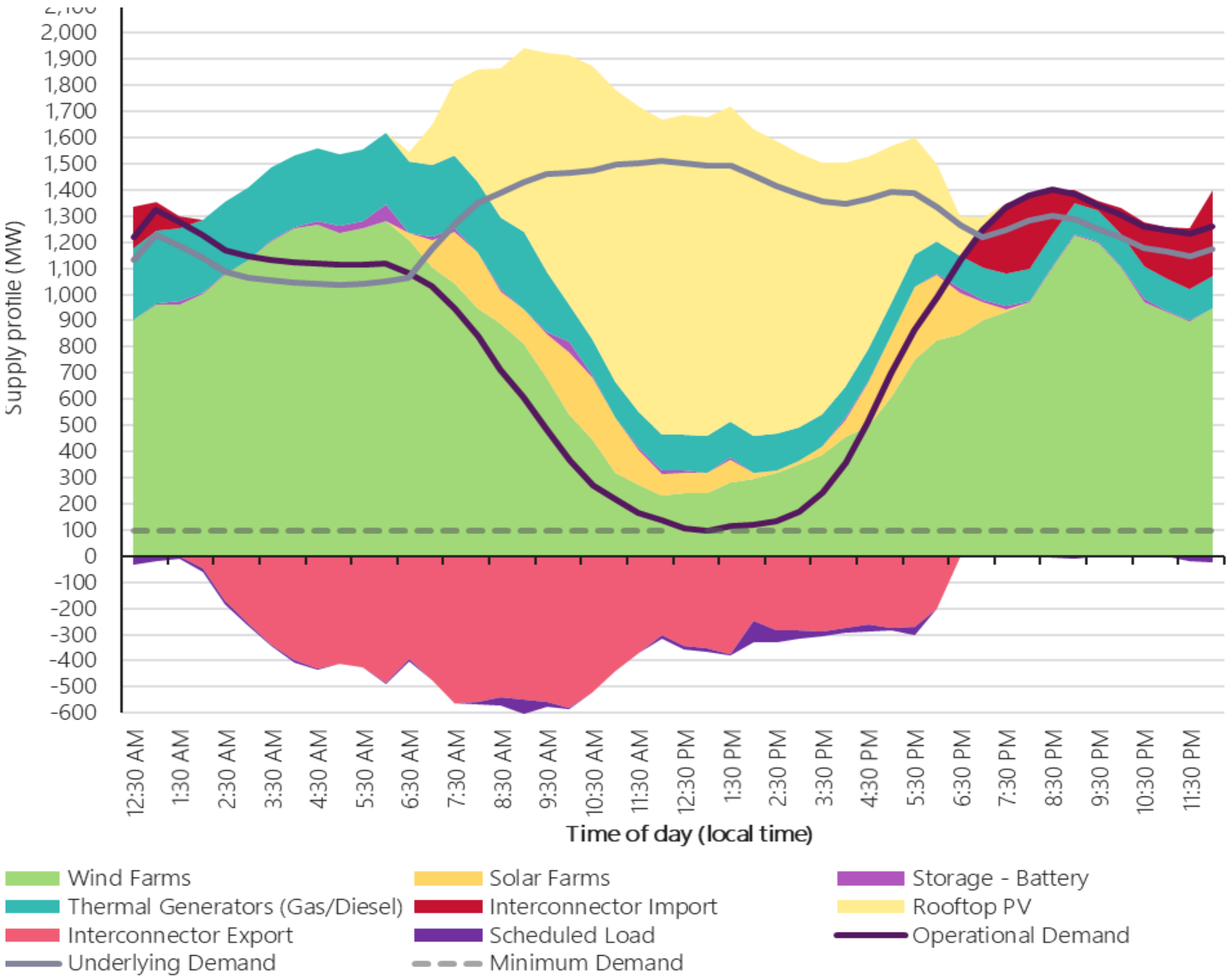
Table 6 shows the time of underlying and operational maximum demand along with an estimated contribution of distributed PV to underlying and operational minimum demand for the last five years.

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)
2017-18	0	22/10/2017 5:00 AM	533	2/10/2017 1:30 PM
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	1,382	11/10/2020 1:00 PM
2021-22	0	3/10/2021 5:00 AM	1,221	21/11/2021 1:30 PM

A new record low minimum operational demand of 104 MW as-generated (and 98 MW sent-out) was set on Sunday, 21 November 2021[32]; this was down 45% from the previous record of 188 MW on 31 October 2021. The most recent record, as seen in Figure 12, occurred at 1:30 pm (Adelaide time). During that half hour, estimated rooftop PV output was 1,221 MW, accounting for 92% of the region's underlying electricity demand, which was also a new record.

Figure 12 Profile of record minimum operational (as-generated) demand day (21 November 2021)



Forecast operational minimum demand

Figure 13 shows the Central scenario forecast of shoulder[33] minimum demand from the 2022 ESOO. It illustrates a relatively constant forecast decline of almost 100 MW per year in minimum demand in the shoulder season, where the annual minimum most often occurs. In the absence of material new flexible loads or distributed storage beyond what was included in the forecast, South Australia may reach negative minimum operational demand (when distributed generation and storage discharge exceeds demand) by 2023-24. A negative operational demand means South Australia must export power to neighbouring regions. The operational challenges of declining minimum demand conditions are discussed in Section 6.1, together with the actions taken, in progress and recommended to manage these challenges. The 2023-24 forecast for operational demand to become

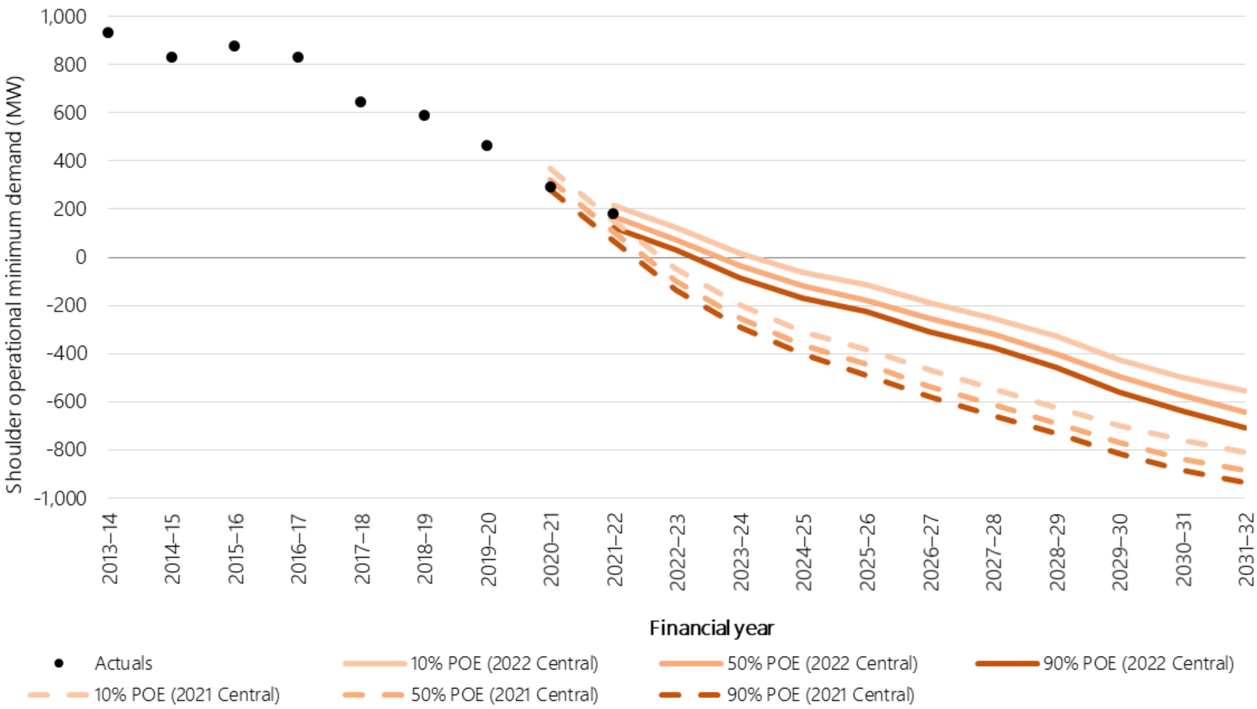
[32] After the cut-off date for this report, a new record minimum operational demand (as-generated) of 100 MW was reached on Sunday 16 October 2022.

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

negative is later than forecast in the 2021 ESOO, as the projected decline is more moderate in the 2022 forecast. This is mainly due to projected stronger growth in battery storage uptake (battery storages may consume excess distributed PV generation by storing for later use, thereby raising operational demand).

The minimum demand observed in November 2021 is consistent with the 50% POE Central scenario forecast in the 2022 ESOO.

Figure 13 Actual and forecast shoulder operational minimum demand (sent-out) for South Australia (Central scenario), 2013-14 to 2031-22



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

2.4 Daily demand profiles

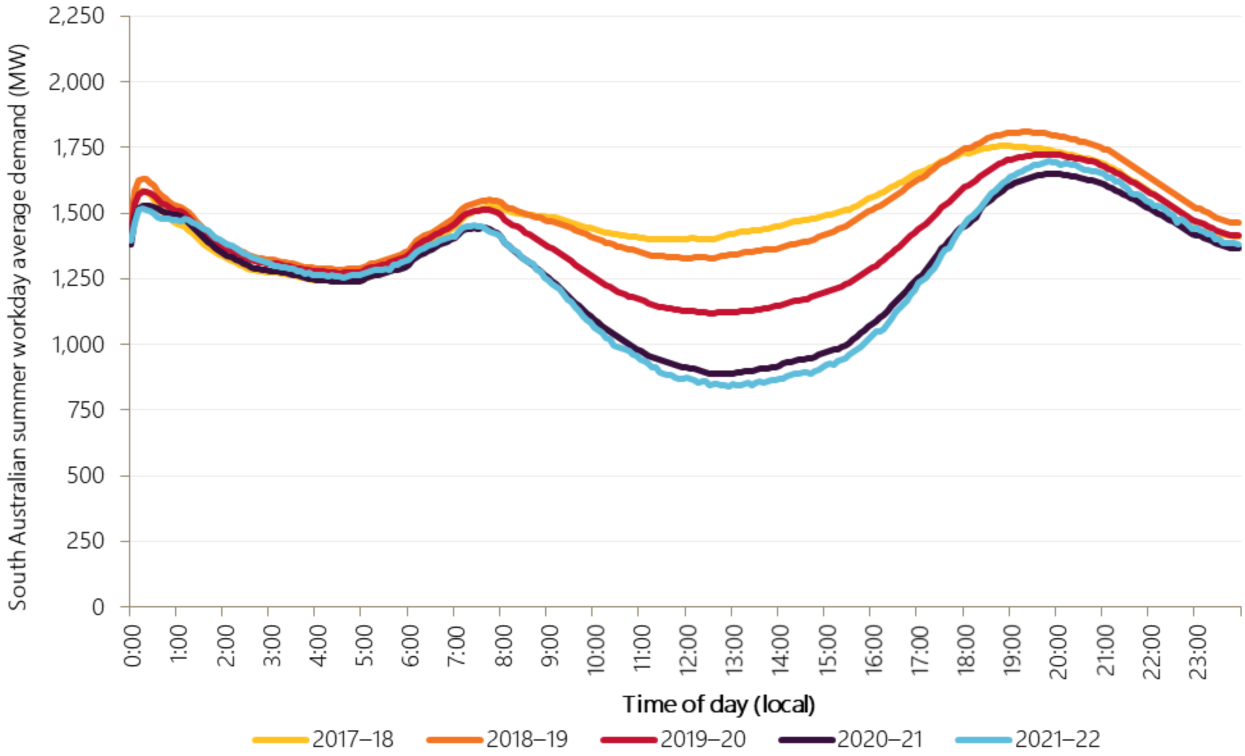
The average daily demand profiles presented in this section represent the operational (as-generated) demand, in megawatts, for each 5-minute dispatch interval of a day, averaged over the relevant days of the selected period. Changes to the average daily demand profile over time can provide insights into 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 14 shows the South Australian average workday operational demand profile for summer from 2017-18 to 2021-22. 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. The average daily peak in operational demand has shifted from 6:30 pm to around 8.00 pm when solar irradiance reduces the generation from distributed PV installations.

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

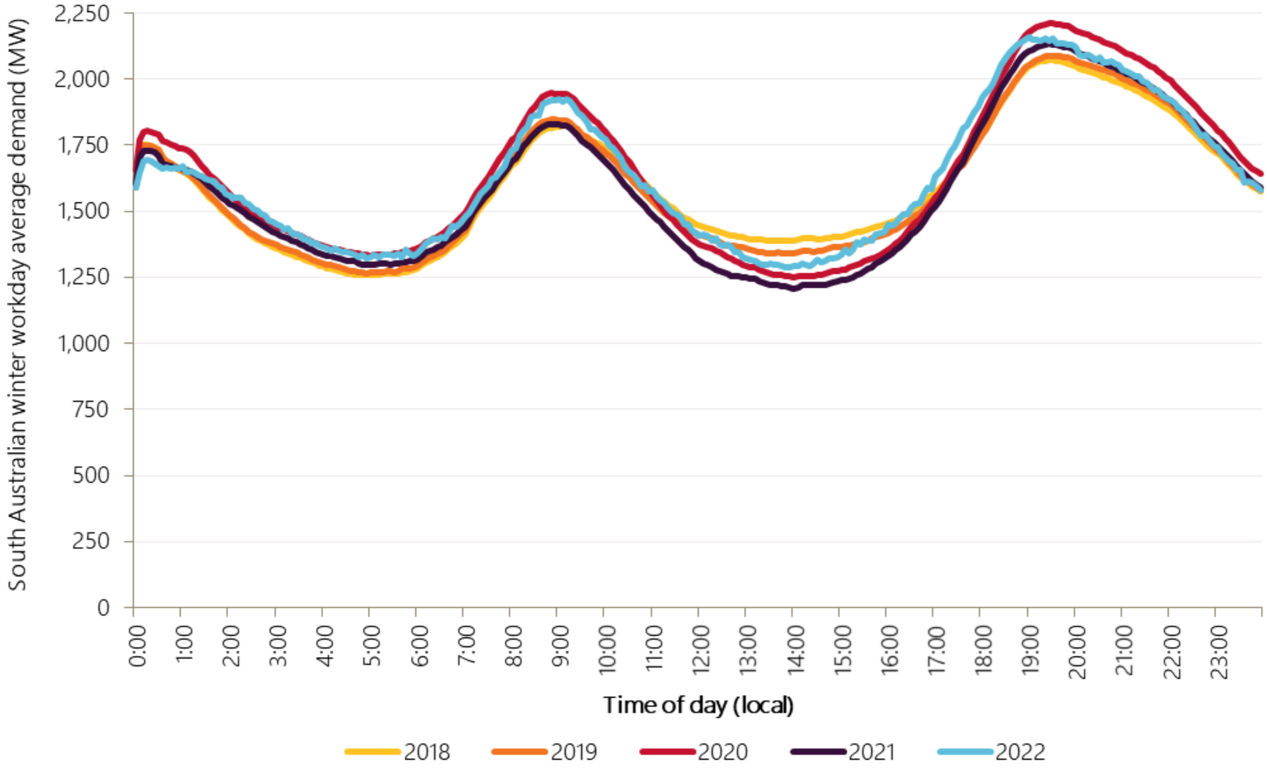
Figure 14 Summer workday average operational demand profiles



Winter daily demand

Figure 15 shows the South Australian average winter workday demand profile for winter 2018 to 2022. 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 15 Winter workday average operational demand profiles



3 Supply

The supply mix in South Australia continues to evolve. Firming large-scale batteries, large-scale solar, and distributed PV showed the most growth in the last year, and wind farms, batteries and solar farms dominate proposed new projects. The total installed registered capacity of 8,239 MW in 2021-22 is higher than the previous year, and an additional 13,390 MW of capacity has been committed, anticipated or proposed, almost a third of which is battery storage.

3.1 Generation and storage

For more information:

- **Generation information, October 2022 update, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.**
- **2022 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 May 2022, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions.**

The SAER applies commitment categories in accordance with AEMO's Generation Information Page definitions:

- **Existing** generation and storage.
- **Committed** projects, that meet all five of AEMO's commitment criteria[34] and are assumed to become available for full commercial operation at dates provided by participants, and **committed*** projects that are under construction and well advanced to becoming committed[35]. These projects are included in reliability assessments and integrated system planning.
- **Anticipated**[36] projects, that are relatively well progressed towards satisfying at least three of the five commitment criteria, and are therefore considered reasonably likely to proceed. These projects are included in integrated system planning.
- **Proposed** projects, which have not yet progressed far enough towards meeting commitment criteria to be included in modelling for either reliability or system planning.

[34] Commitment criteria relate to land, contracts, planning, finance, and construction. For details, see the Background Information tab on each spreadsheet at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[35] Committed* or Com* projects are highly likely to proceed, satisfying the land, finance and construction criteria, plus either the planning or contracts criteria while progress towards the final criterion is evidenced, and construction or installation has also commenced.

[36] Typically, anticipated projects are included in integrated system planning, but not in reliability assessments.

3.1.1 Existing generation and storage

Table 7 shows all generation and storage capacity in South Australia at the end of 2021-22. Gas generators remained the largest source of capacity, although wind farms provided the largest source of generated electricity.

Table 7 South Australian registered capacity and local generation by energy source in 2021-22

Source	Registered capacity		Electricity generated	
	MW	% of total	GWh	% of total
Gas	2,561	31.1%	4,055	29.5%
Wind	2,351	28.5%	6,131	44.6%
Diesel + Other Non-Scheduled Generation (ONSG)	486	5.9%	139	1.0%
Rooftop PV	1,926	23.4%	2,269	16.5%
PVNSG	207	2.5%	371	2.7%
Solar	488	5.9%	698	5.1%
Storage - Battery	220	2.7%	88	0.6%
Total	**8,239**	**100%**	**13,751**	**100%**

Table 8 shows differences in generation between 2020-21 and 2021-22, including interconnector flow metrics. With declining operational consumption in 2021-22, gas also declined from 37% to 30% of total generation. Wind generation remained the largest source of energy and increased its share. Rooftop PV and large-scale solar slightly increased their shares of total generation (from 14% to 17% and 4.8% to 5.1%, respectively).

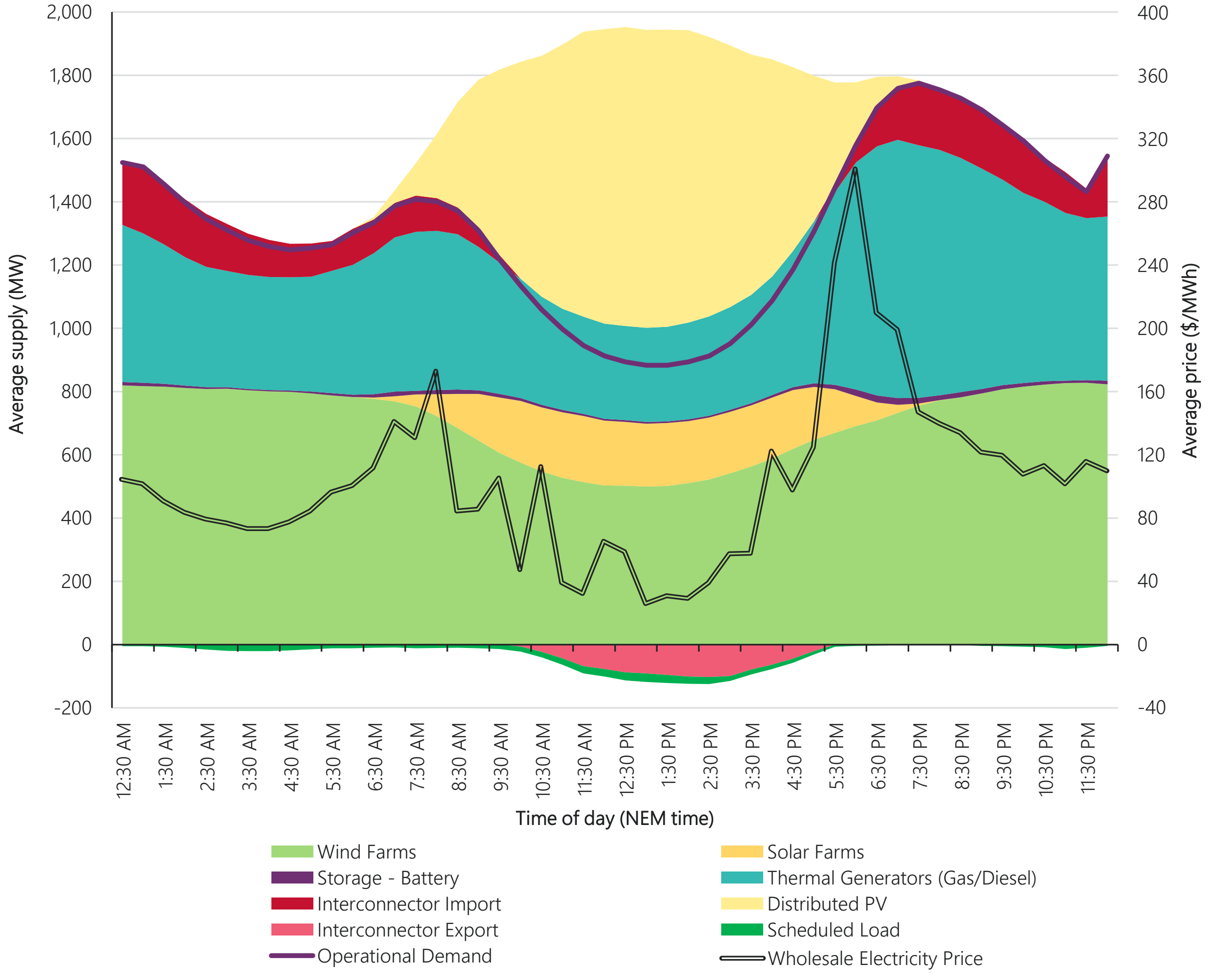
Gas generation and interconnector imports continued to be required to meet South Australian demand in periods with combinations of high demand, low solar irradiance and/or low wind. Following the withdrawal and mothballing of the Torrens Island A gas generation units, imports increased significantly. While requirements for gas generators to operate and maintain system services reduced following the installation of synchronous condensers, gas generation continued to be required to maintain power system stability (see Section 6.2).

Table 8 South Australian electricity generation by fuel type, comparing 2020-21 to 2021-22

Supply source	2020-21 (GWh)	2021-22 (GWh)	Change (GWh)	Percentage change (%)	2020-21 percentage share (%)	2021-22 percentage share (%)	Change in percentage share (%)
Gas	5,226	4,055	-1,170	-22.4%	37.3%	29.5%	-7.8%
Wind	5,739	6,131	392	6.8%	41.0%	44.6%	3.6%
Diesel + ONSG	78	139	61	77.4%	0.6%	1.0%	0.5%
Rooftop PV	1,930	2,269	339	17.6%	13.8%	16.5%	2.7%
PVNSG	274	371	97	35.4%	2.0%	2.7%	0.7%
Solar	673	698	25	3.8%	4.8%	5.1%	0.3%
Storage – battery	85	88	3	4.0%	0.6%	0.6%	0.0%
Total	**14,004**	**13,751**	**-253**	**-1.8%**	**100.0%**	**100.0%**	
Interconnector net imports	123	625	502	406.6%			
Interconnector total imports	1,147	1,467	320	27.9%			
Interconnector total exports	1,023	842	-182	-17.8%			

Figure 16 shows the average daily supply profile observed across 2021-22. 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 outside of daylight hours South Australia is, on average, a net importer. 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 16 Average daily supply profile, 2021-22



3.1.2 Changes in generation and storage over the last five years

Changing composition of generation over the past five years

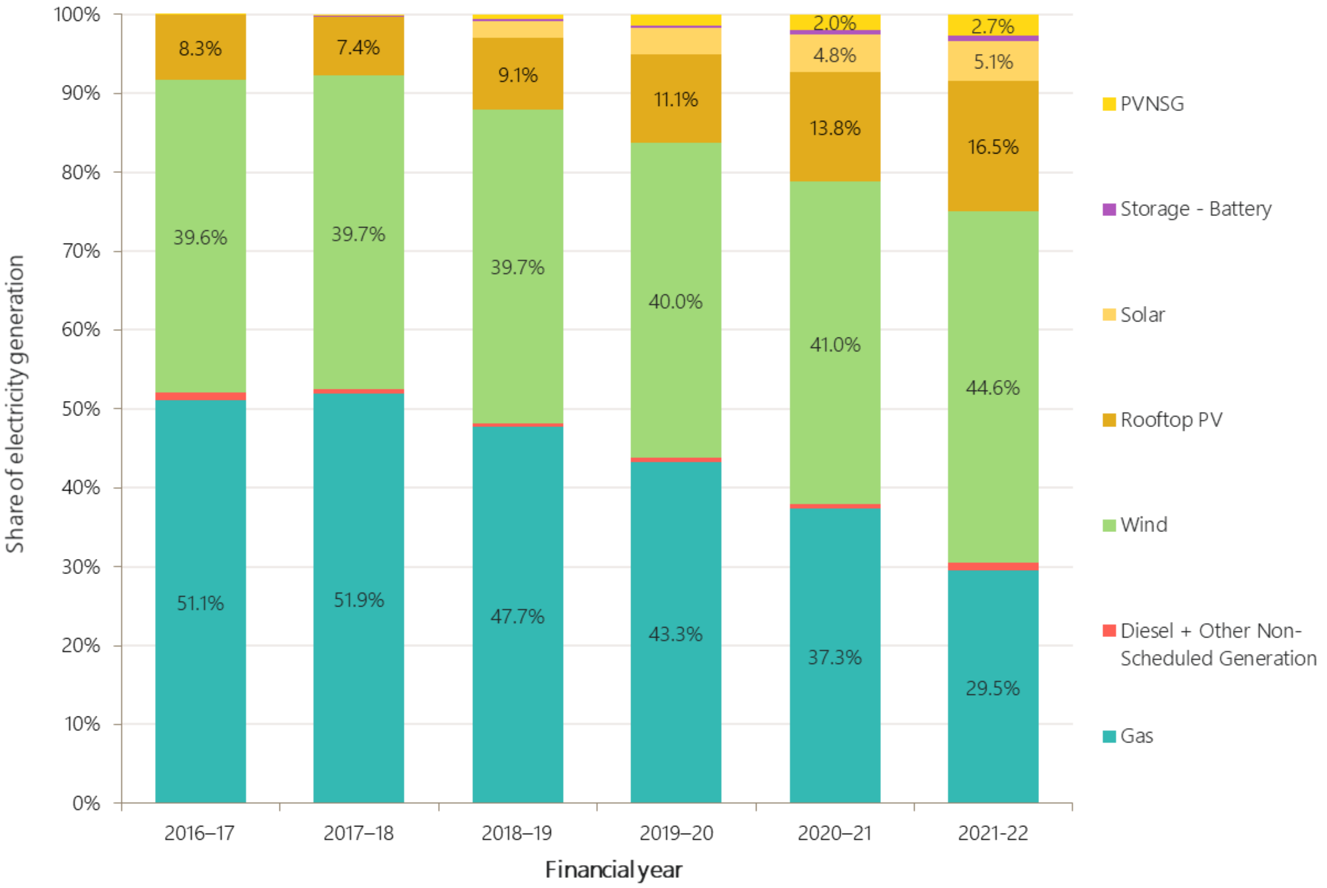
Figure 17 shows the mix of electricity generated in South Australia by fuel type[37] from 2016-17 to 2021-22, from:

- All scheduled generators, including storage.
- All semi-scheduled and market non-scheduled wind farms.
- All semi-scheduled solar farms.

[37] 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.

- Selected smaller market and non-market non-scheduled generators (NSGs).
- Estimated distributed PV.

Figure 17 South Australian electricity generation by fuel type, 2016-17 to 2021-22



Note: Historical percentages may differ from those published in previous years due to updated estimates of distributed PV generation. Battery generation included in this figure ignores the resources that are used to charge the battery.

Wind generation changes

After several years in which wind capacity was unchanged, it increased in 2021-22 with the completion of the Port Augusta Renewable Energy Park, as shown in Table 9. See Section 5.1 for more on volume-weighted prices.

Table 9 Wind generation changes in registered capacity, generation and volume-weighted price, 2016-17 to 2021-22

Financial year	Registered capacity (MW)*	Reason for increase in capacity	Maximum five-minute aggregate wind generation (MW)*	Volume-weighted price ($/MWh)
2016–17	1,698	Hornsdale Stage 2 (102.4MW), Waterloo expansion (19.8MW)	1,541	76.19
2017–18	1,810	Hornsdale Stage 3 (112MW)	1,618	81.15
2018–19	2,141	Lincoln Gap (212.4MW), Willogoleche (119.36MW)	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 (210MW)[38]	2,050	79.38

* Data is captured from when each wind farm was entered into AEMO systems, and includes the commissioning period.

Large-scale solar generation changes

In 2021-22, growth in large-scale solar continued, with numerous new projects leading to an additional 77 MW of registered capacity during the year, as shown in Table 10. See Section 5.1 for more on volume-weighted prices.

Table 10 Large-scale solar generation changes in registered capacity, generation and volume-weighted price, 2017-18 to 2021-22

Financial year	Registered capacity (MW)*	Reason for increase in capacity	Maximum five-minute aggregate large-scale solar generation (MW)*	Volume-weighted price ($/MWh)
2017–18	135	Bungala One Solar Farm (135MW)	31	92.91
2018–19	378	Bungala Two Solar Farm (135MW), Tailem Bend Solar Project 1 (108MW)	209	126.26
2019–20	378	NA	227**	55.74
2020–21	411	Adelaide Desalination Plant (11MW), Morgan-Whyalla Pipeline Pumping Station No's 1-4 (22MW)	326**	21.80
2021-22	488	Adelaide Desalination Plant expansion (13MW), Bolivar Waste Water Treatment Plant (8MW), Happy Valley WTP (11MW), Mannum-Adelaide Pipeline Pumping Station No's 2 and 3 (32MW), Murray Bridge-Onkaparinga Pipeline Pumping Station No. 2 (13MW)	342	56.52

* Data is captured from when each wind farm was entered into AEMO systems, and includes the commissioning period.
** 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.

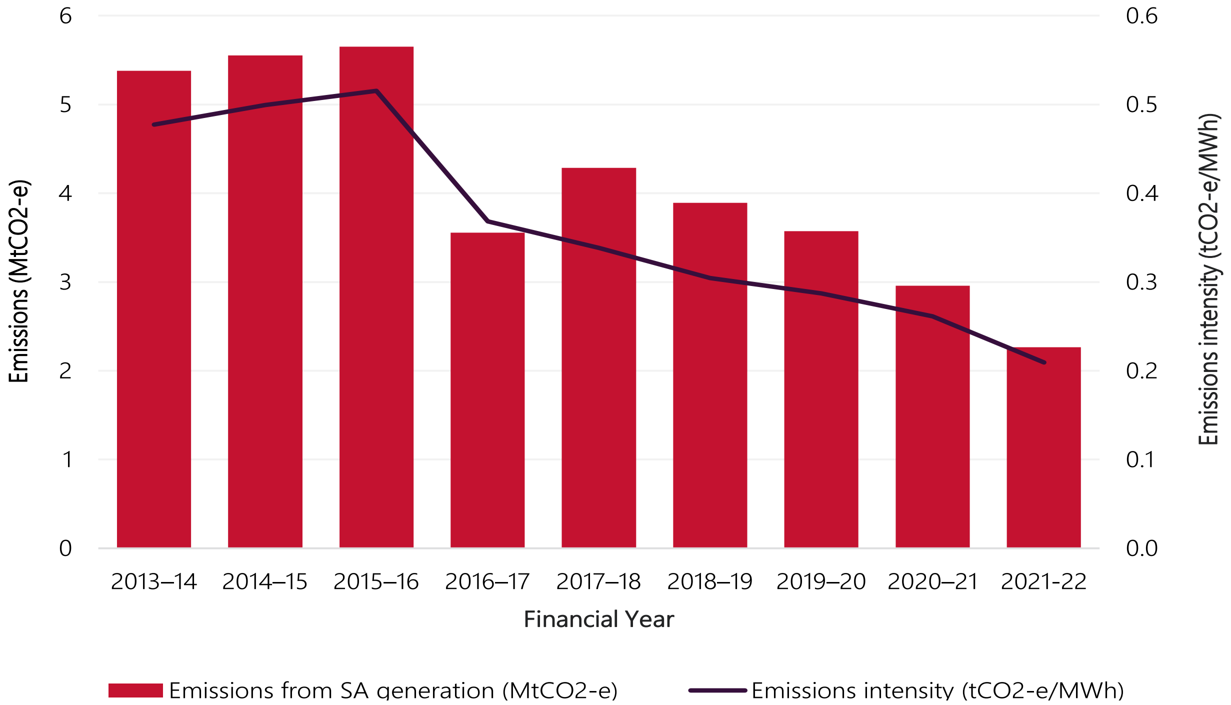
[38] Port Augusta Renewable Energy Park had not fully completed commissioning at the time of data collection for the October 2022 Generation Information and is listed as Committed in this document.

3.1.3 Emissions intensity of South Australian generation

Annual NEM emissions intensity, measured as the Carbon Dioxide Equivalent Intensity Index (CDEII), continued to decline, with emissions at their lowest level during the 2021-22 financial year[39] in South Australia, as Figure 18 shows. Notably:

- Total emissions from South Australian generation in 2021-22 were 2.26 million tonnes (Mt) CO_2-e, a decrease of 0.7 Mt (or 13%) compared to 2020-21. This reduction was due to decreased local gas generation.
- Emissions intensity reduced by 20% from 0.26 t/MWh in 2020-21 to 0.21 t/MWh in 2021-22, the lowest levels to date. This change reflects increased penetration of rooftop PV and large-scale solar, and reduced gas generation.

Figure 18 South Australian annual emissions and emissions intensity, 2012-13 to 2021-22



3.1.4 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[40] that is currently (at October 2022) either:

- 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.

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

[40] The total South Australian capacity in Table 7 in Section 3.1.1 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 11.

The key generation and storage forecast trends highlighted by this data, and by AEMO's 2022 South Australian Generation Forecasts[41], are:

- **Wind generation** is the highest single generation technology with over 2 GW of capacity.
- Almost 10% of the existing generation capacity is committed, offsetting announced retirements. Over 10% of the existing generation capacity – in addition to that committed – is anticipated to be developed.
- **Retirements of gas and diesel generation** will reduce the capacity share from these technologies. Far fewer gas generation proposals exist compared with renewable and storage projects. Reduced operation is further anticipated as Project EnergyConnect increases connectivity with other regions, and in response to the relaxation of system strength requirements following the delivery of four synchronous condensers, which are now in service (see Section 6.2).

Table 11 Capacity of existing or withdrawn generation, and committed, anticipated and proposed projects (MW) at 31 October 2022

Status	CCGT[A]	OCGT[B]	Gas other	Solar[C]	Wind	Water	Biomass	Storage – battery and VPP	Other	Total
Existing[D]	713	1,148	1,010	510	2,142	3	13	221	184	5,944
Announced withdrawal[E]	180									180
Existing less announced withdrawal	533	1,148	1,010	510	2,142	3	13	221	184	5,764
Upgrade/ expansion		165								165
Committed		123		189	210			56	6	584
Anticipated				357				261		618
Proposed		620	45	3,602	3,289	870		3,728	34	12,187
Withdrawn		277	240							517

A. CCGT: Combined-cycle gas turbine.
B. OCGT: Open-cycle gas turbine.
C. Large-scale solar, excludes rooftop and other distributed PV installations.
D. Includes generation that has been announced as withdrawing from the NEM but is still operating at 31 October 2022.
E. Generation that has been announced as withdrawing from the NEM at a scheduled future date.

Capacity for next summer

Table 12 shows:

- The expected available capacity of scheduled, semi-scheduled, and significant non-scheduled generation in summer 2022-23 – for both peak and typical temperatures – and for winter 2023.
- How this expected capacity compares with the capacity available last summer, in peak and typical temperatures, and in winter 2022.

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

Table 12 Scheduled, semi-scheduled, and significant non-scheduled generation available capacity, summer (peak and typical) 2021-22 and 2022-23 and winter 2022 and 2023

Source	Summer peak available capacity[A] (MW)		Summer typical available capacity (MW)[C]		Winter available capacity[A] (MW)	
	2021-22	2022-23	2021-22	2022-23	2022	2023
Diesel	463	369	492	392	418	428
Gas	2,057	2,022	2,136	2,155	2,290	2,106
Wind[B]	1,731	1,867	2,131	2,344	2,131	2,338
Solar	332	486	346	499	347	411
Storage – battery	205	219	205	219	211	219
Total	**4,788**	**4,964**	**5,310**	**5,609**	**5,397**	**5,503**

A. AEMO Generation Information for South Australia, published 31 October 2022.
B. 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.
C. Summer typical available capacities were introduced in the July 2020 Generation Information update and represent the capacity available over summer during typical temperatures.

Notable changes since last summer include the decommissioning of additional Torrens Island units A Unit 1 (see details in 'Generation withdrawals' section below) and connection of new large-scale solar projects (see Section 3.1.2). Summer peak available capacity incorporates the impact of expected derating in response to high temperatures. There is a recent trend among wind generators to report lower summer peak availability following incidents of significant observed temperature derating.

Generation withdrawals

As of 31 October 2022, projects recently withdrawn from service in South Australia include:

- All four units of Torrens Island A (120 MW each) are decommissioned and deregistered.
- Torrens Island B unit 1 (200 MW) was mothballed on 30 September 2021 with advised return to service on 1 October 2024.
- Temporary Generation North (154 MW of diesel) and Temporary Generation South (123.2 MW of diesel) are withdrawn (Temporary Generation South relocation is now committed – see Bolivar Power Station, below).
- Osborne Power Station is expected to close by 31 December 2023.

Committed developments

As of 31 October 2022[42], committed projects in South Australia include:

- Port Augusta Renewables Energy Park (210 MW of wind and 79 MW of solar).[43]
- Bolivar Power Station (123 MW of open-cycle gas turbine [OCGT]).
- Tailem Bend Stage 2 Solar Project (105 MW of solar).
- Tailem Bend Battery Project (51 MW of storage).
- Simply Energy VPP (6 MW of VPP).

[42] Date based on latest (October 2022) AEMO Generation Information Page at time of writing. At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[43] Current status for Port Augusta Wind Farm is "In Service" while Port Augusta Solar farm is now "In Commissioning"

- SA Government VPP – stage 2 (5 MW of VPP).
- Mannum Solar Farm (5 MW).

Anticipated developments

As of 31 October 2022[44], the following projects are classified as anticipated developments:

- Lincoln Gap Wind Farm Battery Energy Storage System (BESS) (10 MW).
- Torrens Island BESS (251 MW of battery storage).
- Cultana Solar Farm (357 MW).

Other proposed developments

As at 31 October 2022, 70 proposed electricity generation and storage developments are classified as proposed in South Australia, being neither committed nor anticipated, totalling 12,187 MW. Table 13 aggregates these developments by generation source.

Given the increasing penetration of renewable generation, there will be growing value in generation technologies that can complement the natural variability of the weather by providing rapid start capabilities and increased operational flexibility, such as battery (including VPP) or pumped hydro storages, flexible thermal generation, or flexible load. The South Australian Government is supporting the development of the world's largest VPP, and is also supporting several green hydrogen projects as part of its efforts in scaling up the South Australian hydrogen industry (see Section 2.1.1).

As of 31 October 2022[45], as noted above, proposed new generation investment in South Australia continues to focus on renewable developments and energy storage/VPP.

The largest proposed projects are:

- Goyder South hub (up to 465 MW of wind, 600 MW of solar, and 900 MW of battery storage)[46].
- Yorke Peninsula Wind Farm (636 MW).
- Pelican Point S2 (320 MW natural gas).
- Lincoln Gap Wind Farm stage 3 (312 MW).
- Woakwine Wind Farm (up to 304 MW).
- Blyth West BESS (300 MW).
- Bridle Track Solar Project (300 MW).
- Highbury Pumped Hydro Energy Storage (300 MW).
- Port Pirie (300 MW of solar).

[44] Date based on latest (October 2022) AEMO Generation Information Page at time of writing. More recent information may be available by time of publication, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[45] Date based on latest AEMO Generation Information Page at 31 October 2022. More recent information may be available by time of publication, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[46] Construction of this project has reportedly commenced, but based on information provided by the developer ahead of the October 2022 AEMO Generation Information Page update, it did not meet the commitment criteria at that point in time.

- Summerfield (300 MW of storage).
- Palmer Wind Farm (294 MW)
- Bungama Solar (280 MW).
- Twin Creek Wind Farm (up to 277 MW).
- Riverland Solar Storage (253 MW).
- Carmody's Hill Wind Farm (up to 251 MW).
- Baroota Pumped Hydro (250 MW).
- Geranium Plains Solar Farm and BESS (250 MW of solar, 150 MW of battery storage).
- SA Government VPP – Stage 3 (245 MW).
- Goat Hill Pumped Hydro (230 MW).
- Para Substation/Gould Creek BESS (225 MW).
- Templers BESS (GreenPower) (200 MW).
- The Solar River Project – Stage 1 (200 MW) and Stage 2 (200 MW).

Table 13 shows that since the October 2021 Generation Information (reported on in the 2021 SAER) there has been a slight decrease of 85 MW of aggregate capacity proposed in South Australia.

Table 13 South Australian proposed generation projects by energy source, as of 31 October 2022

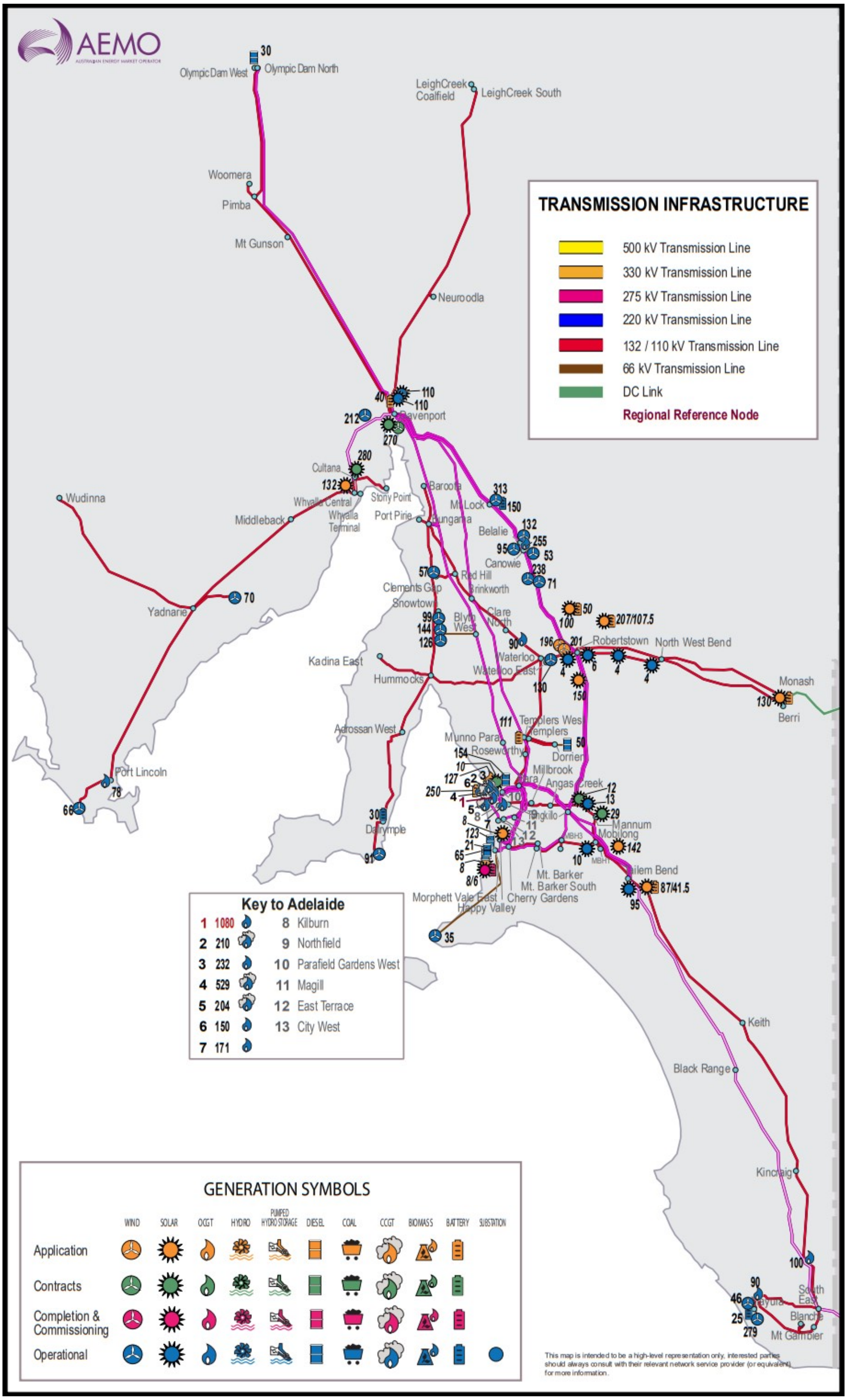
Energy source	Number of projects	Capacity (MW)	Capacity (% of total projects tracked)	Change in number of projects from November 2021	Change in capacity from November 2021 (MW)
Gas	4	665	5.5%	-2	-138
Diesel	0	-	0.0%	0	-
Solar	23	3,602	29.6%	-2	-80
Steam	1	34	0.3%	1	34
Biomass	0	-	0.0%	0	-
Wind	12	3,289	27.0%	0	-587
Water	4	870	7.1%	-1	-250
Storage – battery and VPP	26	3,728	30.6%	7	935
Total	**70**	**12,187**	**100.0%**	**3**	**-85**

3.1.5 Location of South Australian generation and storage

Figure 19 shows the locations of existing and proposed generation and storage projects in the state, with existing transmission[47].

[47] This map version is dated July 2022. 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 19 Locations of generation and storage in South Australia



3.2 Gas generation

For more information:

- 2022 GSOO, at http://aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.
- 2022 South Australian Generation Forecasts, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/south-australian-advisory-functions
- AEMO forecasting portal, at http://forecasting.aemo.com.au/.

South Australia has seen declining electricity production from gas generators since 2018, and last summer again hit near-record low volumes, with wind providing more energy than gas generation in 2021-22. Concurrently, gas prices rose in 2021-22, compounding the reduced need for increasingly higher cost gas generation.

As of November 2021, following the commissioning and testing of all four ElectraNet synchronous condensers at Davenport and Robertstown, AEMO is now able to operate South Australia securely with a reduced number of synchronous generators. Following updated limits advice from ElectraNet[48], the minimum number of gas generation units required to ensure power system security has been reduced from four large units to two under most normal operating conditions, as well as allowing for an increased nominal limit on non-synchronous generation in the state.

This reduces gas generation in two ways:

- By directly requiring fewer gas generation units to continuously operate to provide security services.
- By relaxing constraints on wind and solar which displaces gas generation when weather conditions are favourable.

Torrens Island A was fully withdrawn at the end of September 2022, after not generating at all in the previous 12 months. One unit of Torrens Island B Power Station has been mothballed since October 2021.

AEMO's latest projections show South Australian gas generation continuing to trend downwards, driven by:

- Growing share of local renewable generation, particularly distributed PV, which continues to reduce operational demand.
- Gas prices remaining high following recent international shocks and the gas supply situation in south-eastern Australia forecast to be tight over the next few years.
- Growing electricity imports from Victoria as new variable renewable energy (VRE) generation capacity comes online in that region, driven at least in part by state policy.
- Project EnergyConnect, with commissioning currently scheduled in stages over 2024-26, which will allow sharing of VRE with New South Wales and, when fully operational, is expected to end the requirement to maintain a minimum number of synchronous units online in most conditions.

The medium- and long-term gas generation outlook is more uncertain. Events of winter 2022 have demonstrated how tightly intertwined energy markets in Australia are with world markets, particularly for gas and coal. World events may continue to impact Australian gas prices and its use in the electricity sector for some time to come.

[48] See: https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf

The continued build-out of wind and solar resources in South Australia and neighbouring NEM regions is expected to continue to displace coal and gas-powered generation across the NEM. If sufficient renewable generation is operational in time for, or ahead of, coal closures, gas generation may not need to provide significant volumes of generation to fill the energy gaps left by coal. However, weather volatility and the potential for disrupted retirements or generator mothballing, or delayed commissioning schedules for replacement capacity may lead to an increased need for gas to operate more significantly.

Gas generation is forecast to remain an important source of peaking capacity and system security services within South Australia, even if annual gas generation volumes decline. Weather variability, extreme weather events, coal supply disruptions, and generation and transmission outages will continue to drive volatility.

As the penetration of VRE increases, so too may the variability in gas generation depending on the availability of alternative energy storages, for example to ramp up in the early evening as output from large scale solar and distributed PV drop. When wind generation is low in South Australia, gas generation (in addition to imports from Victoria) is currently a vital generation source particularly when outside daylight hours.

Over time, however, it is expected that additional storage (both large-scale and distributed) as well as additional interconnection, will also contribute to managing variability of VRE.

3.3 Existing and future transmission

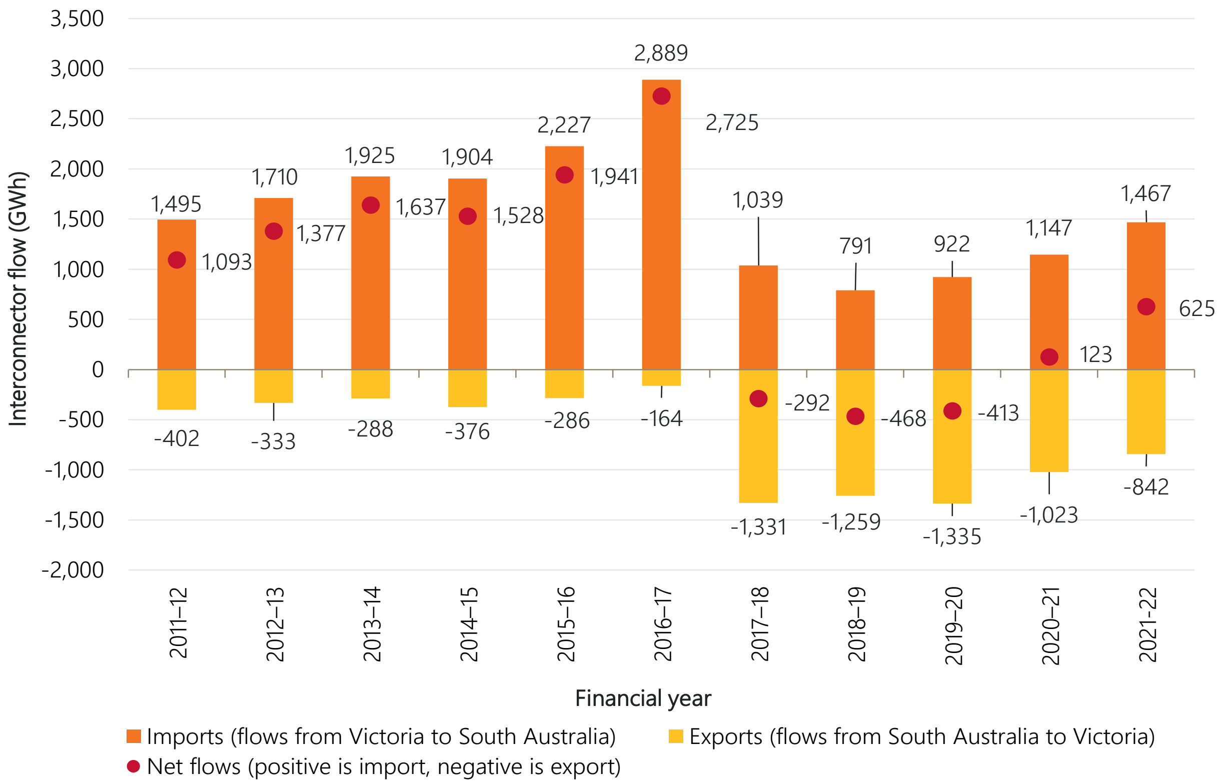
For more information:

- **2021 IASR**, at https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

3.3.1 Historical imports and exports

In 2021-22, South Australia's exports continued to decrease and imports increased. Net imports increased with the full retirement of all units of Torrens A, following several years of net exports following the retirement of Hazelwood Power Station in Victoria.

Figure 20 Combined interconnector total imports and exports, and net flows, 2011-12 to 2021-22



3.3.2 Status of transmission upgrade projects

A number of critical network infrastructure projects are underway 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 an added connection to Victoria. This project involves construction of new double-circuit 330 kilovolts (kV) transmission lines between Robertstown, Buronga, Dinawan and Wagga Wagga[49], and an additional 220 kV transmission line between Red Cliffs and Buronga. The Australian Energy Regulator (AER) provided expenditure approval for this project in May 2021. Stage 1 (Robertstown to Buronga) is forecast for completion in late 2023 with the overall project forecast for completion of construction and first energisation in the second half of 2024. Commissioning activities and inter-network testing is scheduled to follow first energisation. Project EnergyConnect is modelled to progressively release transfer capacity from July 2024 onwards with its full capacity available, including completion of inter-network testing, from July 2026.
- ElectraNet has reported on these projects within South Australia[50]:
  - South Australia Power System Strength Project – involved the installation of two high inertia synchronous condensers at Davenport and two high inertia synchronous condensers at Robertstown (in service)[51].

[49] The section between Dinawan and Wagga Wagga will be built as a new 500 kV double circuit line, initially operated at 330 kV, as per Transgrid, 2022 Transmission Annual Planning Report, at https://www.transgrid.com.au/media/jn4klv4s/tgr12164-tapr-2022-v5-4-final.pdf.

[50] ElectraNet, 2021 Transmission Annual Planning Report, at https://www.electranet.com.au/wp-content/uploads/2021-ElectraNet-Transmission-Annual-Planning-Report.pdf.

[51] Further detail about the project is available at ElectraNet's website via https://www.electranet.com.au/what-we-do/projects/power-system-strength/, and the AER's final regulatory approval is available via https://www.aer.gov.au/news-release/aer-approves-electranet-spending-on-south-australia-system-strength.

- Eyre Peninsula Link – replacement of the existing 132 kV lines between Cultana and Yadnarie with a new double-circuit line that is initially energised at 132 kV, with the option to be energised at 275 kV in the future, and replacement of the existing 132 kV line between Yadnarie and Port Lincoln with a new double-circuit 132 kV line, in early 2023.
- Power flow controller on the Templers – Waterloo 132 kV line (in service).
- Turn-in the Tailem Bend – Cherry Gardens 275 kV line at Tungkillo by June 2023.
- An additional 1 x 100 megavolt-amperes reactive (MVAr) 275 kV capacitor at South East 275 kV by October 2022 (in service)[52].

3.3.3 Renewable energy zones (REZs)

AEMO's ISP identifies REZs, which are high-quality resource areas where clusters of large-scale energy projects can be developed using economies of scale. The 2022 ISP, published in June 2022, included an updated set of REZ scorecards for South Australia[53]. The 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 risk, and transmission expansion outlooks.

In the 2022 ISP, AEMO requested preparatory activities from ElectraNet for the South East South Australia REZ and Mid-North South Australia REZ, as future ISP projects. Preparatory activities may be triggered for future ISP projects to improve the assessment of these projects in future ISPs. The preparatory activities for these two REZs are to be completed by 30 June 2023[54].

[52] In-service date based on advice from ElectraNet.

[53] AEMO, 2022 ISP Appendix 3 Renewable Energy Zones, at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/a3-renewable-energy-zones.pdf.

[54] AEMO, 2022 ISP, at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf.

4 Reliability of supply

As reported in the 2022 ESOO, reliability risks are forecast in South Australia under the Central scenario that considers only existing and committed developments. A reliability gap is forecast against the Interim Reliability Measure (IRM) of 0.0006% USE in 2023-24 when Osborne Power Station is expected to retire. In following years, reliability risks are forecast to subside as Project EnergyConnect is commissioned, however risks emerge again at the end of the horizon due to the expected retirement of numerous gas generators.

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 2025, the reliability standard of 0.002%[56].

The assumptions used to develop the 2022 ESOO's reliability forecasts are outlined in AEMO's 2022 Forecasting Assumptions Update (FAU)[57]. The supply data used in this assessment is from the July 2022 Generation Information update 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 2025, 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)**.

4.1.1 South Australian reliability outlook for the next 10 years

A reliability gap is identified in 2023-24 against the IRM, when Osborne Power Station is expected to retire. While this known retirement did not lead to a reliability gap in the 2021 ESOO, a gap has emerged due to several changes since that time, including increased forecast industrial load, generation and transmission outage considerations and changes to the modelled timing of completion of construction and first energisation of Project EnergyConnect (now expected from 2024-25, instead of 2023-24).

[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 currently set to expire in June 2025, 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. The standard 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/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

The AER has approved AEMO's request to make a T-1 RRO instrument for South Australia in 2023-24 in response to this reliability gap[58].

A reliability gap against the reliability standard is also projected for 2031-32 following the expected retirement of numerous gas generators (total 383 MW) in 2030, including Dry Creek, Mintaro, Port Lincoln and Snuggery power stations.

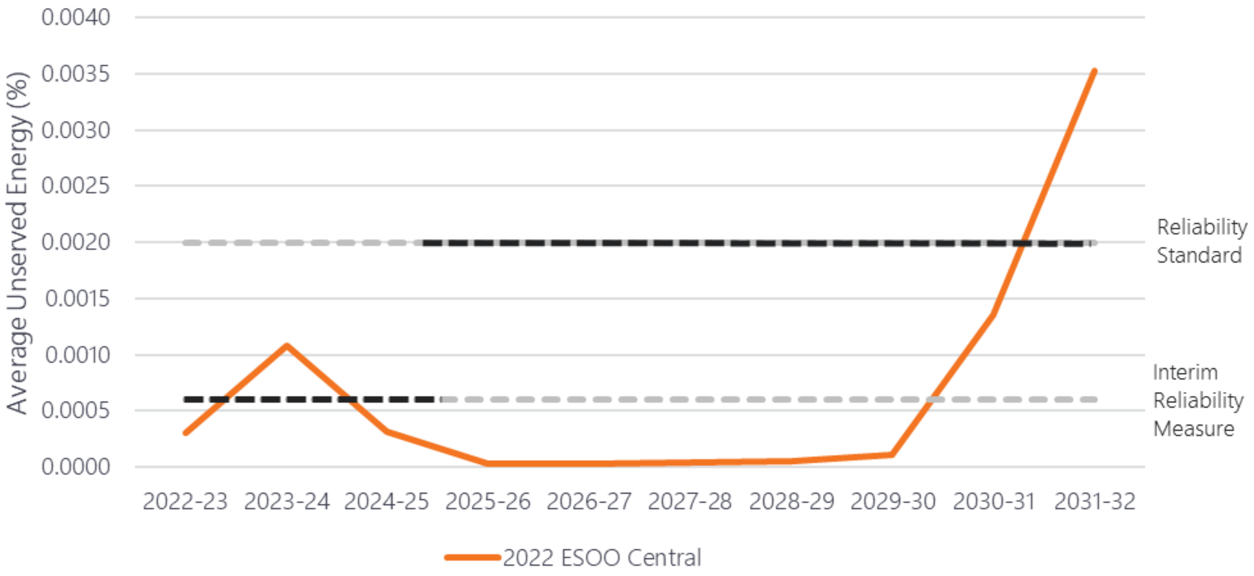
Figure 21 shows the forecast USE outcomes for South Australia under the 2022 ESOO Central scenario.

The main changes to last year's forecast that impact this assessment are:

- The 2022 Central scenario demand forecast, based on the *Step Change* scenario, is higher than the 2021 forecast, when the Central scenario was based on the *Progressive Change* scenario. Large industrial load operators have also advised of expansions which further increased AEMO's demand forecasts.
- An additional 457 MW of VRE generation is expected to become operational by 2022-23, with a further 105 MW by 2023-24 and 12 MW by 2024-25.
- Bolivar Power Station was categorised as anticipated in the 2022 ESOO[59] and was therefore not included (in the 2021 ESOO, the previous site [Temporary Generation South] was included in the 10-year forecast).
- Project EnergyConnect modelled timeframes have been updated. Early stages are now expected from 2024-25, rather than 2023-24.

As Figure 21 shows, reliability gaps are identified in 2023-24 against the IRM and in 2031-32 against the reliability standard.

Figure 21 Forecast USE outcomes for South Australia – existing and committed projects only



[58] At https://www.aer.gov.au/communication/aer-approves-aemo%E2%80%99s-retailer-reliability-obligation-requests-for-south-australia-and-new-south-wales.

[59] The 2022 ESOO was based on the July 2022 Generation Information, where Bolivar Power Station was categorised as anticipated. In the most recent 31 October 2022 Generation Information, Bolivar is now categorised as committed.

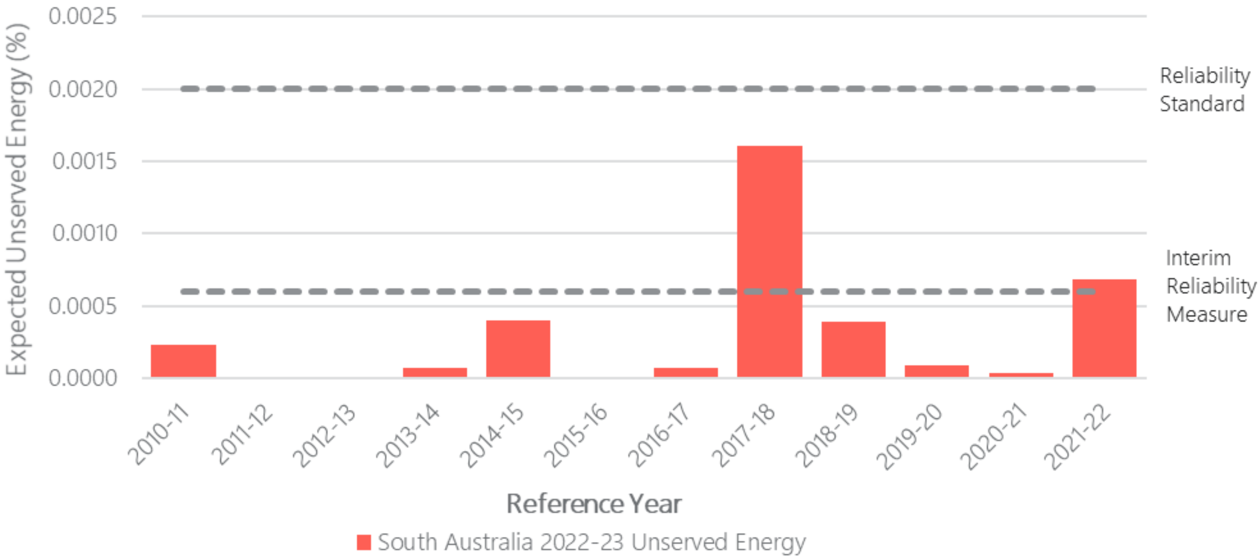
This reliability assessment includes all existing and committed generation and storage, reported in the Generation Information page published in July 2022, as well as committed and relevant anticipated transmission augmentations[60] and generation retirements.

Specifically, this assessment:

- Excludes generator developments that had not yet met AEMO's commitment criteria, including Bolivar Power Station[61] and Torrens Island BESS.
- Includes Snapper Point Power Station, now an operational gas generator.
- Does not include any additional capacity that could be made available through Reliability and Emergency Reserve Trader (RERT)[62].
- Represents USE outcomes before any equitable load shedding principles are applied.

Figure 22 shows the level of expected USE forecast in South Australia for the 2022-23 summer in each of the historical reference years. The chart shows that under the weather conditions associated with the 2017-18 reference year, the forecast level of expected USE next summer would exceed the IRM. The 2017-18 reference year has high electricity demands during low VRE conditions. Importantly, temperatures were still high at 8.00 pm when solar output is low, resulting in high USE due to high demand.

Figure 22 Impact of different reference years on expected USE in South Australia 2022-23, Central scenario



While the 2022 ESOO identifies numerous reliability gaps over the 10-year horizon, significant investments in the NEM are expected in addition to the committed and committed* projects included in the reliability assessment.

[60] This includes major and minor committed augmentations. In AEMO's Generation Information page, Committed projects meet five criteria, while Committed* (or Com*) projects are considered highly likely to proceed, satisfying the land, finance and construction commitment criteria, plus either of the planning or contracts criteria and progress towards meeting the final criterion evidenced, and construction or installation has also commenced. See Section 3 of the 2021 ESOO for more details.

[61] Since the 2022 ESOO was published, the October 2022 Generation Information release identified that Bolivar Power Station has progressed to a committed project. This project was classified as anticipated in the 2022 ESOO.

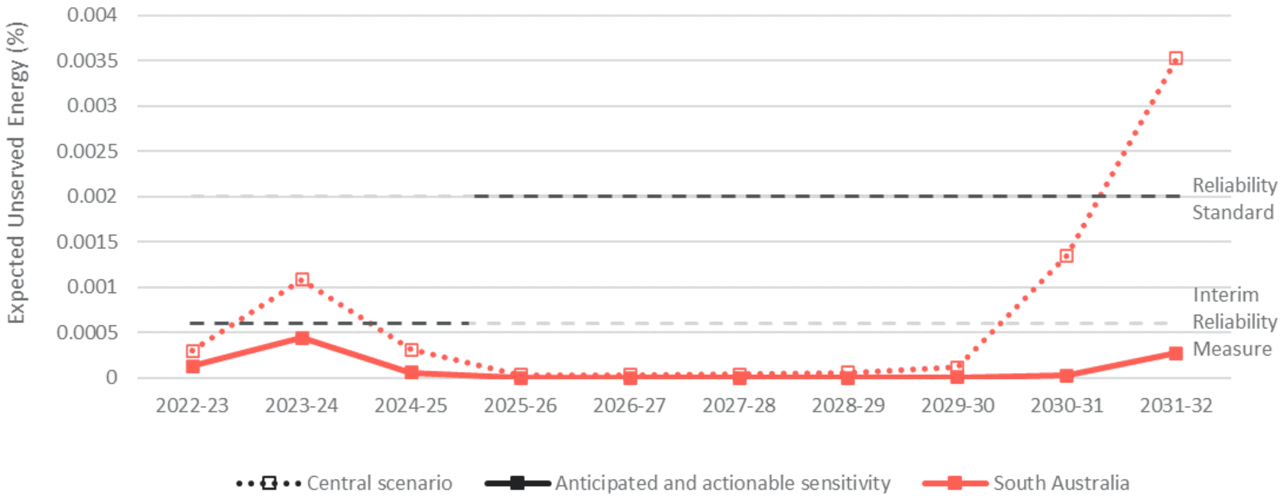
[62] The exception being demand side participation (DSP) responses from RERT panel members delivered outside RERT, which have been included in the DSP forecasts. See DSP methodology for more details, at https://aemo.com.au/consultations/current-and-closed-consultations/demand-side-participation-forecast-methodology-consultation.

Anticipated generation and storage developments are projects which meet some of AEMO's commitment criteria, but not enough to be considered committed. These generation and storage projects, alongside the actionable transmission projects identified in the 2022 ISP, will improve the reliability forecast significantly if they are developed and become committed according to their current schedules.

AEMO assessed the potential impact of these developments by modelling a sensitivity in the 2022 ESOO that forecasts expected USE if all anticipated generation, and anticipated and ISP actionable transmission developments, as well as committed and committed* projects, were developed to schedule.

Figure 23 shows the improved reliability outlook in this sensitivity, compared to the ESOO Central case. It highlights that these investments (if they are delivered in accordance with current schedules) would improve the NEM reliability outlook in every mainland region, compared to the forecast with only existing and committed developments.

Figure 23 Reliability impact of projects well advanced but not yet committed, 2022-23 to 2031-32 (%)



Since the 2022 ESOO was published, Bolivar Power Station – which had been included as anticipated in the ESOO modelling – has met sufficient criteria to be classified as committed. If the ESOO cases were run today, with Bolivar Power Station included, the Central projection would be close to being under the IRM in 2023-24.

4.2 Managing reliability risks

RERT for summer 2021-22

For summer 2021-22, the 2021 ESOO and Update to the 2021 ESOO did not forecast expected USE to exceed the reliability standard or the IRM in any NEM region. As a result, no long notice RERT or interim reliability reserves were contracted in the NEM[63].

During the summer of 2021-22, AEMO had up to 2,300 MW of potential RERT reserves across the NEM, including 80 MW in South Australia, under short notice panel arrangements that could be contracted in the event

[63] AEMO, RERT End of Financial Year Report 2021-22, at https://aemo.com.au/-/media/files/electricity/nem/emergency_management/ rert/ 2022/rert-end-of-financial-year-report-202122.pdf.

of a forecast lack of reserve (LOR) event. No short notice reserves were contracted for South Australia during summer 2021-22, and no costs were incurred.

RERT for summer 2022-23 and beyond

As the 2022 ESOO did not project expected USE to exceed the reliability standard or the IRM this summer in any region, no long notice RERT or interim reliability reserves will be contracted, unless AEMO receives new information that materially changes the reliability outlook.

AEMO is currently considering expressions of interest for short notice RERT panel arrangements in South Australia for the 2022-23 summer[64]. AEMO has seen an increase in interest supplying short notice RERT in South Australia compared to 2021-22 because of growth in available capacity from aggregators.

Due to expected USE forecast above the IRM in 2023-24 (see Section 4.1.1), AEMO may need to contract long notice RERT or interim reliability reserves for that period.

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

5 Electricity spot price

South Australia's average wholesale electricity price climbed strongly after two years in decline, following the NEM-wide trend of rising prices during 2021-22. Average time-weighted prices increased to their highest average since 2018-19, driven by unprecedented volatility during the June quarter across the NEM. In contrast with energy markets, frequency control ancillary services (FCAS) prices remained steady against 2020-21 levels.

5.1 Historical wholesale electricity prices

South Australia's time-weighted average price (TWAP) in 2021-22 increased to $105/MWh, rebounding strongly from the declining trend in the last two years to reach its highest average since 2018-19 (see Figure 24 and Table 14). The pattern of South Australian prices by time of day is shown in Figure 25, illustrating an upward shift across all hours[65].

Figure 24 Average South Australian spot electricity price (real June 2022 $/MWh)

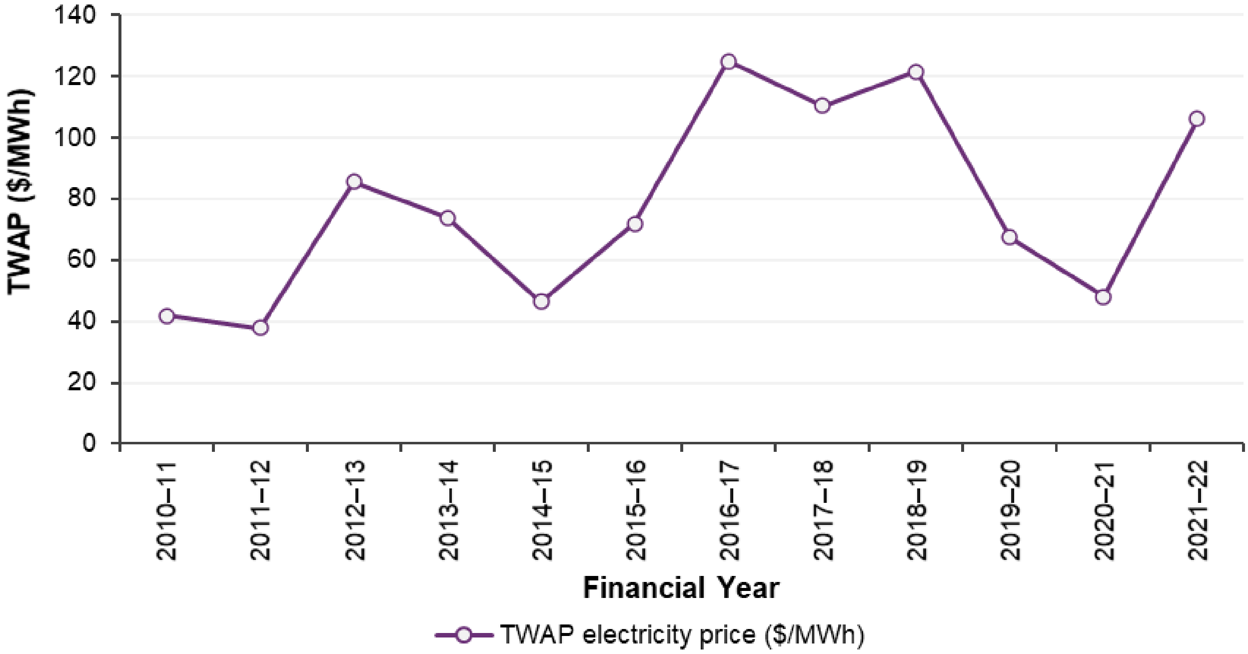
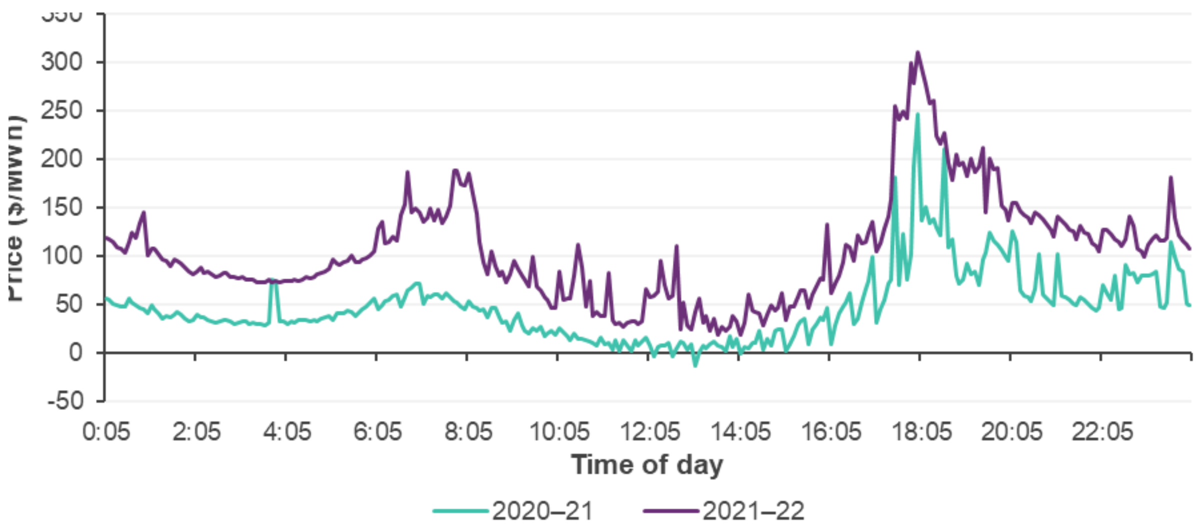


Table 14 2021-22 time-weighted average prices for the NEM

	Queensland	New South Wales	Victoria	South Australia	Tasmania
Time-weighted average ($/MWh)	162.06	132.35	91.06	**104.60**	84.89

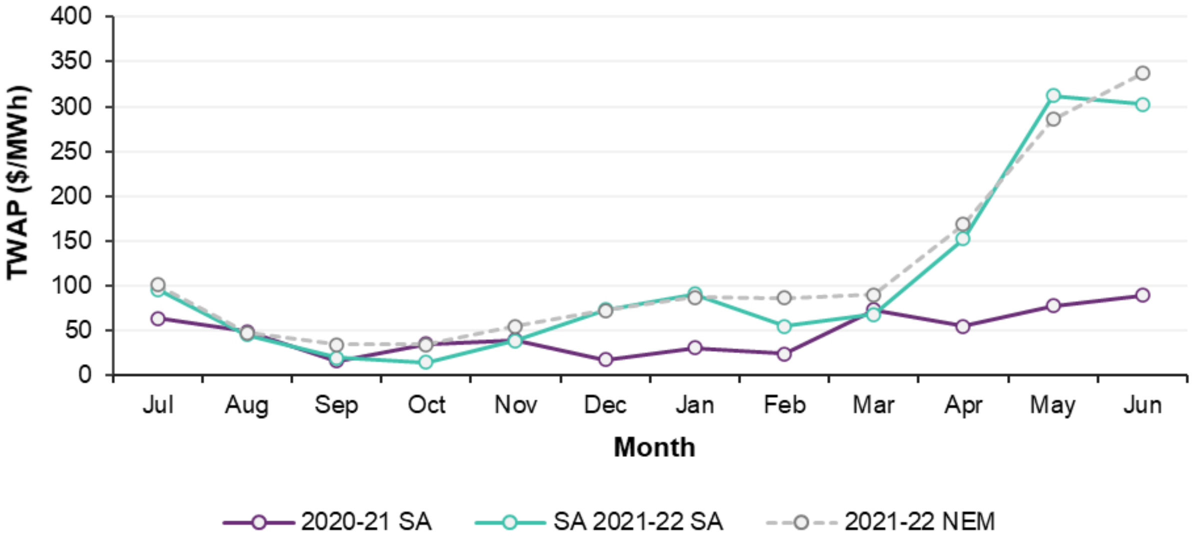
[65] Since commencement of five-minute settlement (5MS) from 1 October, electricity spot prices are now shown on a 5-minute basis for current and previous years. All times in Section 5 refer to NEM time.

Figure 25 Average South Australian spot electricity price by time of day (real June 2022 $/MWh)



During the first half of the financial year, spot prices in South Australia were relatively steady against the same period in the previous year. Prices lifted significantly during the second half of the year, however, due to factors affecting the entire NEM (Figure 26). In particular, spot prices rose significantly in the June quarter (April to June) as the eastern Australian energy markets were significantly impacted by price volatility and unprecedented market events, including a NEM-wide spot market suspension between 15 and 24 June 2022[66]. Further detail on the circumstances and impacts of the event are outlined in the market suspension report.

Figure 26 Average South Australian spot electricity price by month – FY20-21 and FY21-22 (real June 2022 $/MWh)



During 2021-22, South Australia's spot price was set by non-South Australian units 75% of the time[67], with prices set during these dispatch intervals averaging $87/MWh, more than double the levels of 2020-21.

[66] NEM market suspension and operational challenges in June 2022: https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2022/nem-market-suspension-and-operational-challenges-in-june-2022.pdf.

[67] Excludes periods between 12 June 2022 (Administered price period in Queensland commenced) and 23 June 2022 (when market suspension scheduled pricing was lifted).

Key contributors to the overall price increase during 2021-22 included:

- Higher-priced offers from coal and gas generators
  - Relative to 2020-21, there was a significant upward shift in the prices that most coal capacity was offered from black coal-fired generators in the NEM, influenced by a combination of high international coal prices, higher outage levels removing low-cost supply and local coal supply issues[68]. The higher priced offers contributed to black coal-fired generation setting South Australia's price at an average of $87/MWh in 2021-22 (21% of the time) compared to $38/MWh in 2020-21 (32% of the time).
  - A confluence of local drivers as well as record high Asian liquefied natural gas (LNG) prices significantly lifted gas prices particularly from May 2022, with overall wholesale gas prices across the NEM reaching new highs during 2021-22. In South Australia, Adelaide Short-Term Trading Market (STTM) prices averaged $16 per gigajoule (GJ), much of it which was due to the substantial increase in prices during the June quarter ($30/GJ). Higher gas prices were reflected in the higher-priced marginal offers from gas-fired generation, contributing to a $108/MWh increase in average price set by South Australian gas-fired generation units compared to 2020-21 ($81/MWh).
- Hydro price setting frequency and offers increased – reduced black coal generation lifted the incidence of hydro generation as a marginal fuel source, with hydro setting South Australian prices 28% of the time in 2021-22, up from 22% last year (discussed in Section 5.3).
  - A similar upward shift in offers also occurred for hydro generators particularly during the June quarter as hydro generation offers generally follow overall changes in thermal generation offer pricing to manage limited water supplies. Hydrological constraints at several hydro generators during the June quarter further limited their operational flexibility. Increased price offers resulted in hydro generators setting South Australia's spot price at an average of $128/MWh compared to $60/MWh in 2020-21.
- Increased price volatility – see Section 5.2 for more detail.

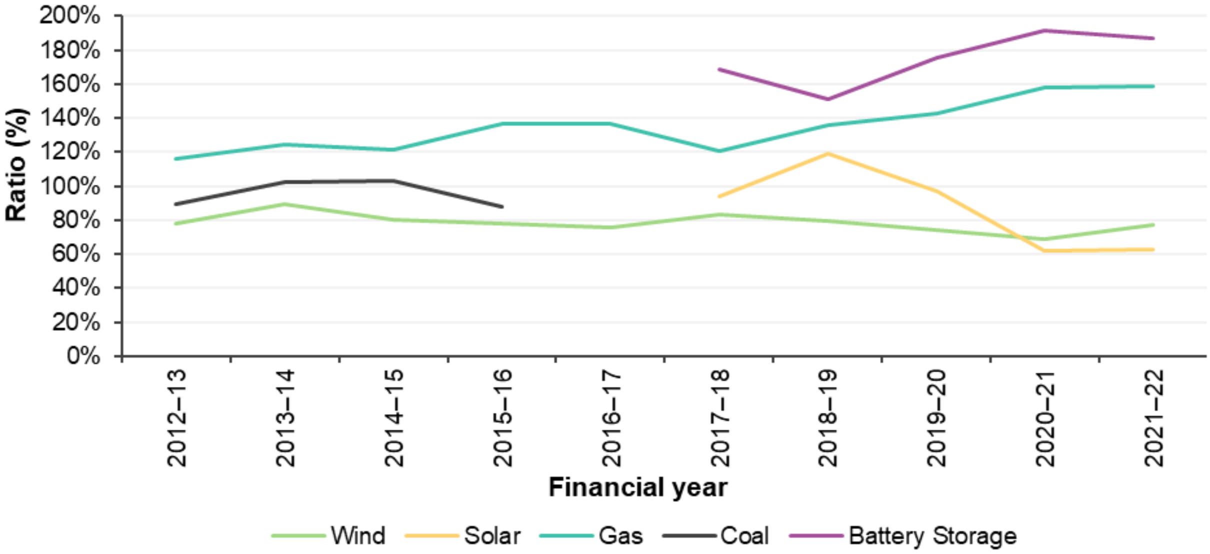
The volume-weighted average price (VWAP) by fuel type represents the average price received by each fuel technology when dispatched. Higher output during high-priced periods will result in a higher VWAP. Figure 27Figure 27 illustrates the ratio of VWAP as a relative percentage to TWAP. In summary:

- **Gas generation** – VWAP remained above TWAP at 159% this year similar to 2020-21 (158%). High VWAP to TWAP ratio reflects the tendency for gas generators to operate at elevated levels during high priced events and operate less during low prices.
- **Battery** – while slightly lower in 2021-22 (187%) compared to 2020-21 (192%), VWAP to TWAP ratio remained the highest among all fuel types. Generally, due to round trip inefficiencies[69], batteries will require a reasonable VWAP to TWAP ratio to ensure that charging costs do not exceed discharging revenues.
- **Wind farms** – the VWAP to TWAP ratio increased from 68% in 2020-21 to 77% in 2021-22, its highest level since 2018-19, driven by high ratios in the June quarter.
- **Grid-scale solar** – similar to 2020-21, VWAP remained below TWAP at 63%, largely driven by increased occurrence of low and negative prices during the middle of the day particularly during the first half of the year.

[68] For further information see AEMO's Quarterly Energy Dynamics report Q2 2022: https://aemo.com.au/-/media/files/major-publications/qed/2022/qed-q2-2022.pdf.

[69] This represents losses when operating the storage through a charging/discharging cycle, which have been estimated to be around 15%.

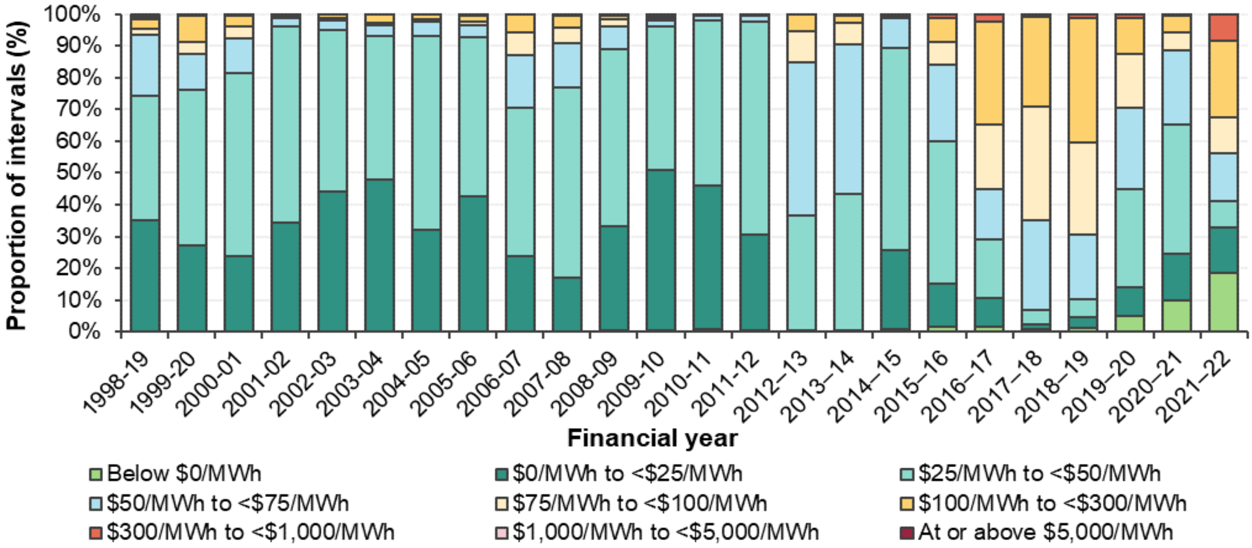
Figure 27 Ratio of VWAP by fuel to total TWAP for South Australian generators



5.2 Price volatility

During 2021-22, South Australia experienced both high price volatility and increased incidence of negative spot prices, similar to the rest of the NEM. Spot prices at $300/MWh and above were at a record 8.4% of the time, a marked increase from only 0.5% in 2020-21[70] while negative price occurrence also increased to new highs of 18.5% (Figure 28).

Figure 28 Frequency of occurrence of spot prices for South Australia, 1998-99 to 2021-22



[70] Since commencement of 5MS from 1 October, proportion of intervals are now calculated on a 5-minute basis for current and previous years.

5.2.1 High prices

Larger customers can insulate themselves from spot price volatility through the purchase of cap contracts; a common cap limits price exposure to $300/MWh. Cap returns, measured as the excess component of spot prices above $300/MWh, increased to $20/MWh (Figure 29) in 2021-22. Historically, cap returns have mostly been driven by relatively infrequent occurrences of extremely high spot prices, often at or near the market price cap (MPC)[71] arising from tight supply-demand balance and/or other constraints.

While there were instances of these extreme price events in South Australia during 2021-22, a significant proportion of the increased cap returns this year were driven from spot prices being above $300/MWh but well below the MPC. This occurred most frequently during the June quarter (especially between May and June 2022).

Figure 30 illustrates the breakdown of the aggregate cap returns in South Australia from spot prices higher than $1,000/MWh and those between $300/MWh and $1,000/MWh. While volatility arising from extreme spot prices (>$1,000/MWh) remained high, it remained within historical precedents. The contribution from spot prices occurring in the lower range (>$300/MWh to $1,000/MWh) however was much greater than recent years.

Figure 29 South Australian cap returns

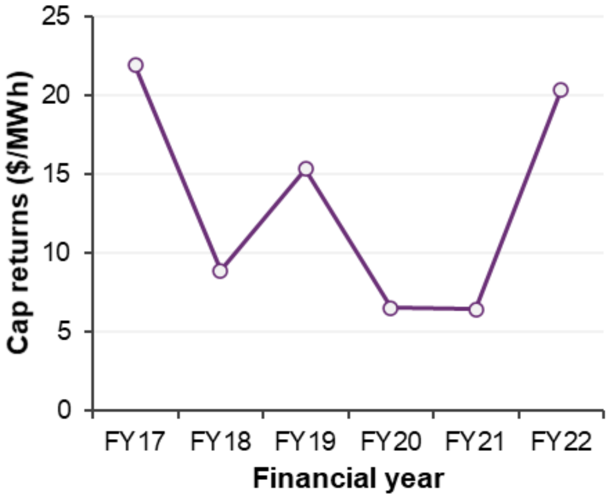
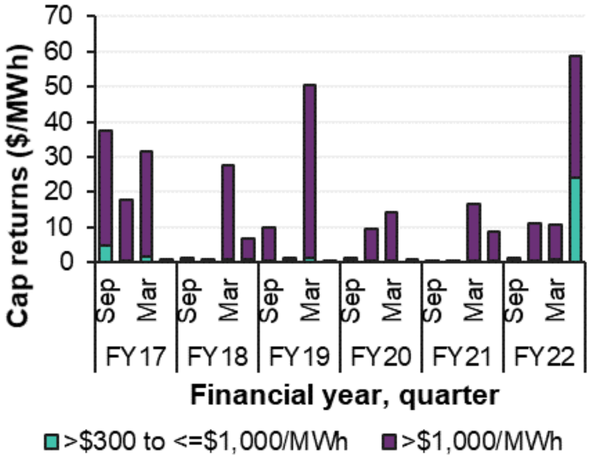


Figure 30 Contribution to total South Australian cap return by price range - quarters



Source: AEMO calculations based on dispatch price outcomes.

5.2.2 Negative prices

During 2021-22, the frequency of negative spot prices in South Australia reached new highs, occurring 18.5% of all dispatch intervals, compared to 10% in 2020-21[72] (Figure 31).

Negative spot prices now most frequently occur during the middle of the day, when excess grid-scale solar and wind generation occur at times of low operational demand (typically due to high distributed PV generation). Spot prices were negative 44% of the time between 10.00 am and 3.00 pm in 2021-22, up from 24% in 2020-21 (Figure 32).

[71] The MPC between 1 October 2021 to 30 June 2022 was $15,100/MWh.

[72] Since the commencement of 5MS from 1 October 2021, negative spot price occurrences are now calculated on a 5-minute basis for current and previous financial years. This may lead to differences in the results from the 2020-21 report as it was calculated on a 30-minute basis previously.

Figure 31 Count of negative price dispatch intervals per year

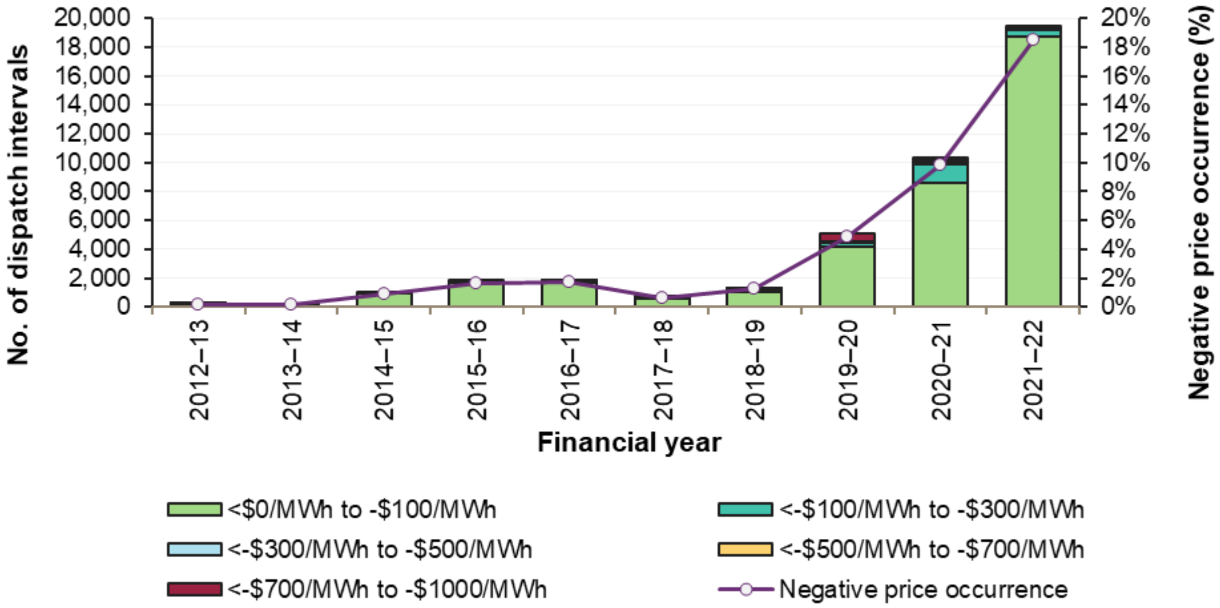
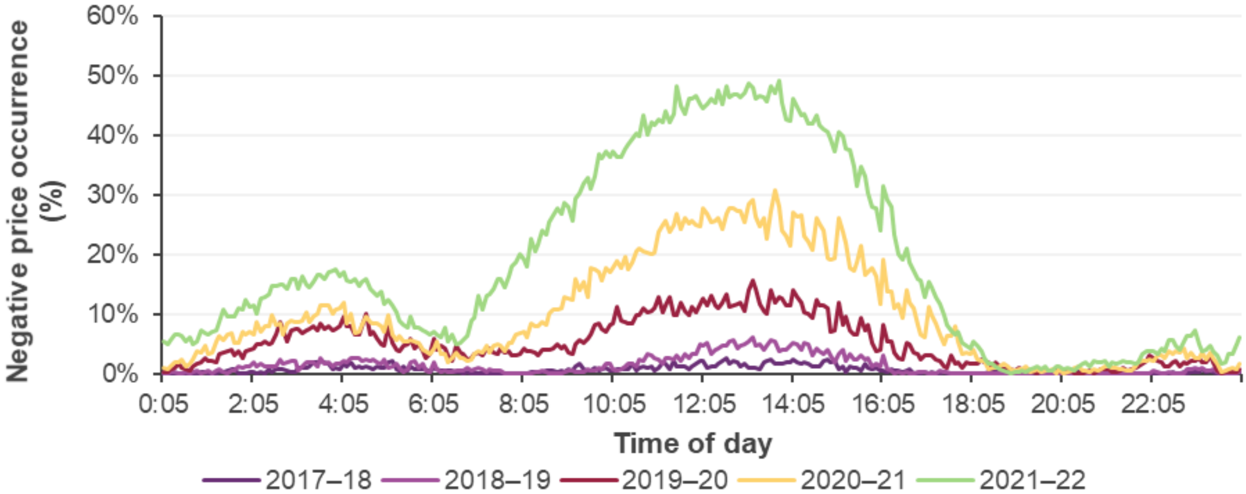


Figure 32 Percentage of time South Australian price was negative by time of day



Key drivers of increased negative price occurrence included:

- Inter-regional pricing dynamics – the occurrence of negative prices in South Australia were even more closely aligned with Victoria during 2021-22, particularly during the first three quarters. During 2021-22, South Australia's prices were negative 77% of the time when Victoria prices were negative, up from 59% in 2020-21.
  - During the year, transfers across the Victoria – New South Wales interconnector (VNI) were often constrained, binding 44% of the time compared to 34% the previous year. These constraints[73], which

[73] An important factor in reducing daytime exports from Victoria despite higher inter-regional differential was the impact of network constraints controlling flows on transmission lines in the south-west of New South Wales. For more information see AEMO's Quarterly Energy Dynamics report Q3 2021: https://aemo.com.au/-/media/files/major-publications/qed/2021/q4-report.pdf.

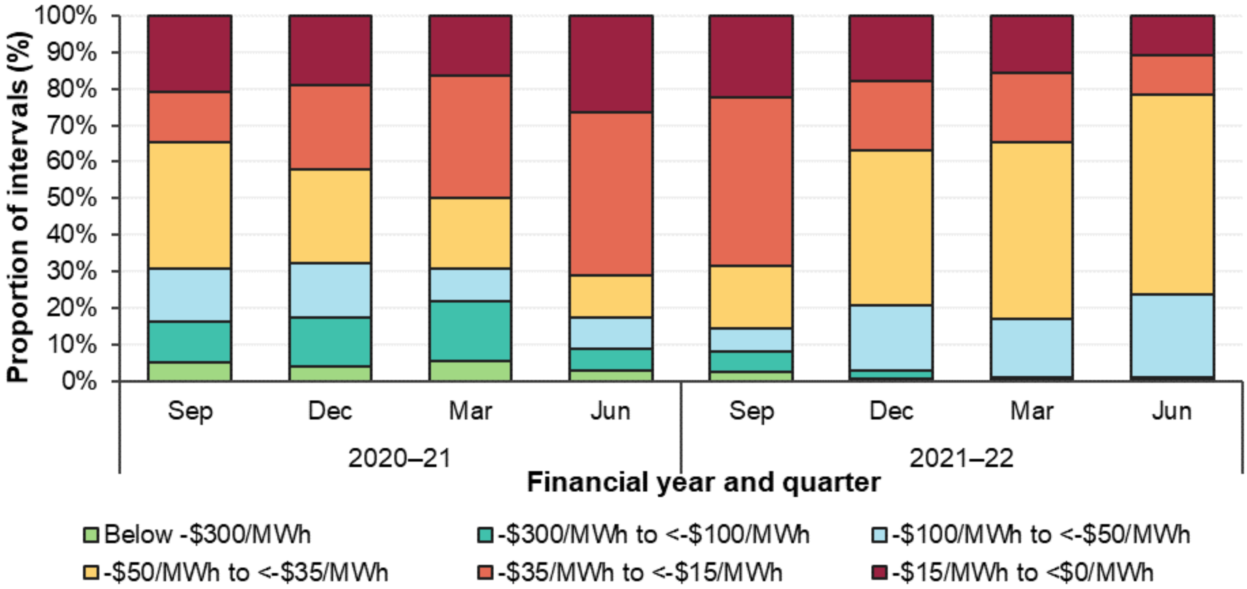
mainly occurred during daytime hours, tended to reduce flows from Victoria to New South Wales, suppressing prices in the southern regions.

- Compared to 2020-21, there were increased periods of very high Victorian and South Australian VRE output, mainly due to ramping up of Dundonnell and Berrybank wind farms in Victoria and new capacity installed during the year such as Stockyard Hill Wind Farm, also in Victoria. This, coupled with low daytime operational demand and constraints on the VNI during the day (discussed above), contributed to periods of oversupply in both regions. In 2021-22, combined Victorian and South Australian VRE output between 1000 hrs and 1500 hrs was above 2,000 MW 48% of the time compared to 38% in 2020-21, while combined operational demand in the same period fell below 4,500 MW 22% of the time compared to 12% of the time in 2020-21.

Despite overall frequency of negative spot prices rising significantly, the negative price impact this year was only marginally higher than 2020-21 (approximately $7.80/MWh), reducing the average South Australian spot price by approximately $8.80/MWh. The limited impact of negative spot prices on average was due to a reduced proportion of very low negative prices (between the market floor price of -$1,000/MWh and -$100/MWh). Instead, spot prices in the -$50 to -$35/MWh range, close to the value of a Large Generation Certificate (LGC) increased substantially.

A key driver to this was the change in VRE bidding behaviour since 1 October 2021 (December quarter), where a large proportion of semi-scheduled generators altered their bidding behaviour by shifting their offers towards their break-even price or short run marginal cost (SRMC) within the -$100 to -$35/MWh range. As an example, in South Australia 56% of all negative price intervals fell within the -$100 to -$35/MWh band during 2021-22, a substantial increase from 34% in 2020-21 (Figure 33).

Figure 33 South Australian negative spot price band – proportion of intervals when price was negative

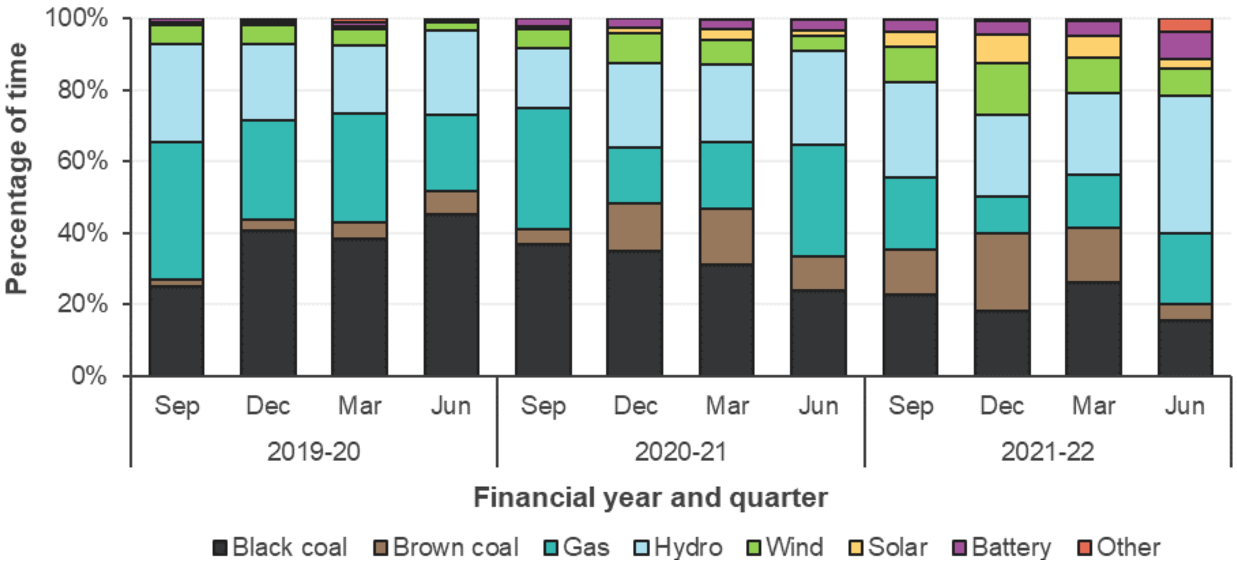


5.3 Price setting outcomes

Figure 34 shows South Australia's quarterly price setting outcomes by fuel type for 2020-21 and 2021-22. Key price setting outcomes[74] in 2021-22 included:

- Brown coal continued to set price more frequently, setting spot prices 14% of the time in 2021-22, up from 11% in 2020-21, while black coal's price setting reduced from 32% to 21%. Price separation between northern and southern NEM, particularly during September and December quarters meant that black coal set prices much less frequently in the south.
- Hydro generators more frequently set price, from 22% in 2020-21 to 28% in 2021-22, with a marked increase in price setting during the June quarter (39%). Lower coal availability during 2021-2022 led to an increase in marginal dispatch of hydro-generation, particularly from Snowy Hydro's Murray and Tumut generators.
- Gas generation set price less frequently, from an average of 25% of the time in 2020-21 to 16% in 2021-22, largely due to lower gas output in the region.
- Grid-scale solar and wind set price twice as frequently this year (16% combined) compared to 2020-21 (8%), while batteries also increased its price setting frequency from 3% in the previous financial year to 5% this year. VRE generation as well as batteries frequently set prices during the middle of the day due to increased occurrence of negative spot prices (Section 5.2.2).
- Murray Hydroelectric Power Station in Victoria continued to remain the most common price setting power station during 2021-22 setting prices 10.4% of the time, followed by Loy Yang B Power Station (7.6%) as the second most common price setter. Torrens Island Power Station continued to set prices less frequently, only setting prices 3.8% of the time this year compared to 9.6% in 2020-21, with the withdrawal of Unit A1 on 30 September 2021 contributing partially.

Figure 34 South Australia price setting by fuel type



Note: June quarter 2022 data only includes periods up to the commencement of the Administered Price Period in Queensland (12 June 2022).

74 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.

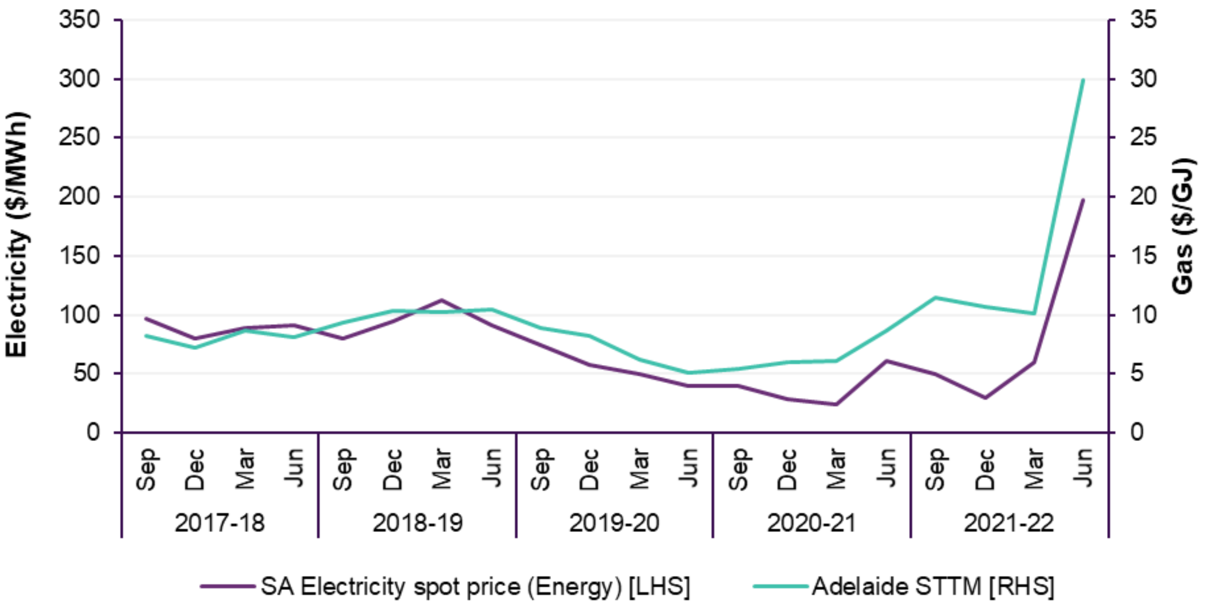
5.4 Gas spot price impact on electricity spot prices

Historical average electricity and gas prices are shown in Figure 35. The strong relationship between the movements of the South Australian electricity price and Adelaide's gas STTM across time reflects the role of gas-fired generation as a key marginal supply source in the NEM.

Overall, between 2020-21 and 2021-22, South Australia's average TWAP increased by 134% while Adelaide STTM increased by 138% to $15.6/GJ. While there was a notable divergence between spot electricity and gas market prices in the first three quarters of 2021-22, which was a continuation from 2020-21, the inter-relationship between the two tightened again in the final June quarter.

Low electricity demand coupled with continued growth in renewables lessened the relationship between gas and electricity prices, as gas generation reduced operation and less frequently set the electricity price (particularly in the first three quarters of the year). However, a confluence of major market events across eastern Australian energy markets during the June quarter saw a tightening of demand-supply balance and a rise in gas generators' price setting frequency, and price volatility in both markets restored the strong relationship between gas and electricity price.

Figure 35 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

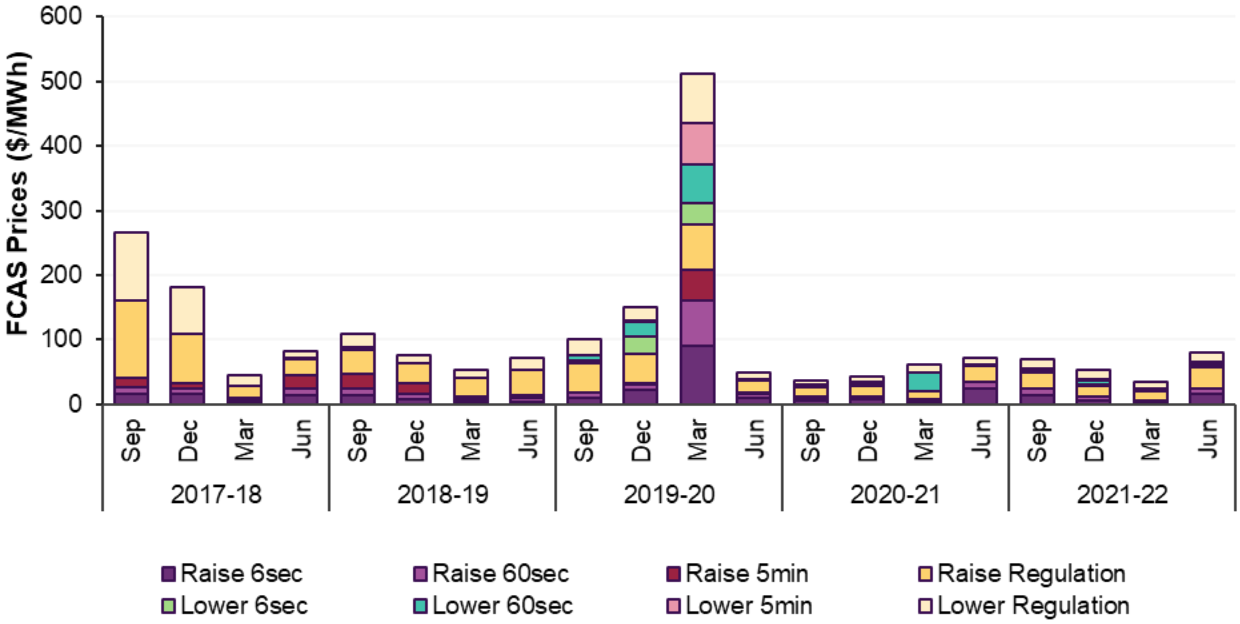
South Australian FCAS prices during 2021-22 were comparable to 2020-21. The average 2021-22 FCAS price in the region across all eight FCAS markets was approximately $7.40/MWh compared to approximately $6.60/MWh in 2020-21 (Figure 36).

Despite an increase in NEM-wide FCAS requirements (+131 MW or 4% across the eight markets) compared to 2020-21, average South Australian FCAS prices in 2021-22 were relatively similar. Across the markets, results were mixed with small increases in prices across the regulation (+$4.30/MWh) and raise contingency (+$0.20/MWh) markets while lower contingency prices declined slightly (-$1.10/MWh).

Regulation FCAS prices during 2021-22 remained steady around typical levels throughout 2021-22, until the June quarter. A primary contributor to the lift in prices during the June quarter was the significant price volatility in the raise regulation market in the lead up to NEM-wide market suspension on 13 and 14 June, where daily prices on those two days averaged $359/MWh and $163/MWh respectively. High raise regulation prices on these two days can be largely attributable to the extremely volatile energy prices, because raise markets often move in line with energy prices due to the opportunity cost of service provision.

Contingency lower prices were down marginally in 2021-22 compared to 2020-21, mainly due to reduced event-based localised FCAS requirements in the lower 60 second market (2% in 2021-22 compared to 4% in 2020-21). Unlike last year[75], no major event occurred during 2021-22 that necessitated high levels of local South Australian contingency lower requirements. High FCAS prices typically occur during local requirements, because FCAS supply can only be provided by local supply in the region, which can lead to a tight supply/demand balance and/or increased market concentration.

Figure 36 Quarterly average South Australia FCAS prices by service – stacked



[75] During 2020-21 between 12 to 17 March 2021, South Australia's lower 60 second FCAS price was above $1,000/MWh 20% of the time due to a confluence of events including (1) a planned outage of the Moorabool-Mortlake 500kV line in Victoria which necessitated local South Australian contingency lower FCAS requirements during the period; (2) Limited 60 Second FCAS supply from Torrens Island Power Station following the 12 March transformer issue; (3) Periods of high local 60 second requirement (greater than 100 MW), largely from 13-17 March to cover for the loss of the Heywood to Tarrone to Haunted Gully to Moorabool 500 kV lines.

6 System security

This section discusses ongoing maintenance of power system security[76] in South Australia, in light of 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 this energy transition so consumers can keep exercising choice and accessing reliable, low-cost energy.

6.1 Declining minimum demand

As households and businesses supply more of their own energy from distributed PV and storage, they draw less electricity from the grid. Operating a power system with unprecedented levels of distributed PV and declining levels of operational demand creates challenges and opportunities that are particularly pertinent to South Australia.

6.1.1 Challenges associated with minimum demand

South Australia has experienced periods where up to 93%[77] of estimated underlying demand was supplied by distributed PV and is, to AEMO's knowledge, the first gigawatt-scale power system in the world to be close to supplying 100% of underlying demand by distributed PV. AEMO forecasts that South Australia could experience periods in the near future where distributed PV supplies all of the underlying demand.

The whole NEM power system is experiencing declining minimum operational demand, but it is particularly noticeable for South Australia as a direct result of its high and growing uptake of distributed PV and higher proportion of load being residential/commercial rather than industrial[78]. The challenges South Australia is managing include:

- Maintaining sufficient operational demand to support the operation of generating units needed to provide essential system security services.
- Managing and minimising unintended disconnection of distributed PV during power system disturbances. The disconnection of distributed PV following disturbances increases contingency sizes, which increases the need for frequency control services, and adversely affects network stability limits.
- Maintaining transmission voltages within the necessary ranges when operational demand is low and the network is lightly loaded.
- Maintaining a sufficient emergency under-frequency response to manage severe non-credible disturbances. Distributed PV is reducing the net load on under-frequency load shedding (UFLS) circuits, reducing its effectiveness in arresting a frequency decline. This capability needs to be restored, as UFLS is an important last line of defence to protect against system collapse.

[76] 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 (for example, a power station or major powerline).

[77] The highest observed penetration as of 16 October 2022.

[78] For more, see 2021 ESOO, Section 6.1.2 and Appendix Sections A3.3 and A3.5, 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.

- Maintaining the ability to perform a system restart under conditions of very low operational demand. At present, system restart requires the start-up of transmission-connected synchronous generators. These generating units require a minimum level of stable load to operate above their minimum loading levels. In high distributed PV periods, there may not be enough stable load available in the vicinity.

AEMO's operating procedures include a minimum operational demand threshold of 600 MW in periods when South Australia is separated from the rest of the NEM, and a dynamic threshold when South Australia is at credible risk of separation from the rest of the NEM. These thresholds can be higher depending on estimated contingency sizes associated with distributed PV shake-off in response to a disturbance.

It is noted that operational demand well below 600 MW has already occurred in South Australia. For example, South Australia reached a minimum operational demand record of 100 MW on 16 October 2022. No action was needed at that time because the interconnector was fully available, but if an unplanned outage had occurred, AEMO would have needed to instruct ElectraNet to instruct SA Power Networks to increase operational demand to the necessary thresholds.

6.1.2 Mechanisms to address declining minimum demand

Increased capabilities for distributed PV

In 2020, AEMO recommended a number of measures to the South Australian Government to address challenges associated with declining minimum demand[79]. Since then, the following actions have been undertaken:

- AEMO has worked extensively with stakeholders to update Australian Standard AS/NZS 4777.2, aiming to minimise unintended self-disconnections of future customer rooftop PV in response to system disturbances. The updated standard came into effect in December 2021. It aims to improve the ability of new installations of customer rooftop PV to stay connected and operational following power system disturbances, and in so doing, reduce the need for South Australia to manage increasing generation contingency sizes that could otherwise arise from unexpected disconnection of a growing level of distributed PV. Investigation to date indicates that the new standard appropriately defines the required behaviours, but compliance with the new standard is poor, with only ~35% of distributed PV systems installed in January to March 2022 correctly set to the new standard[80]. AEMO is working with inverter manufacturers, the Clean Energy Council and distribution network service providers (DNSPs) to improve compliance, and engaging with the AEMC on a review of governance frameworks for inverter compliance[81].
- South Australia introduced a requirement for all new distributed energy generating installations in South Australia to have the ability to be remotely curtailed. Curtailment may be effected when necessary as an emergency last resort to maintain power system security. The requirement does not apply to the legacy fleet of distributed PV installed in South Australia[82]. This last resort capability was effective from 28 September 2020, and has been used in 2021-22[83].

[79] AEMO (May 2020) Minimum operational demand thresholds in South Australia, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/sa_advisory/2020/minimum-operational-demand-thresholds-in-south-australia-review.pdf.

[80] AEMO (July 2022), Power System Frequency Risk Review, Section 3.3.1, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2022-final-report---power-system-frequency-risk-review.pdf.

[81] AEMC (29 September 2022), Review into consumer energy resources technical standards, at https://www.aemc.gov.au/market-reviews-advice/review-consumer-energy-resources-technical-standards.

[82] AEMO (May 2021) *Behaviour of distributed resources during power system disturbances*, at https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf.

[83] AEMO (November 2021) Maintaining operational demand in South Australia on 14 March 2021, at https://aemo.com.au/-/media/files/electricity/ nem/market_notices_and_events/power_system_incident_reports/2021/maintaining-operational-demand-in-south-australia.pdf.

- AEMO introduced operating procedures known as the distributed PV Contingency and/or Minimum System Load (CMSL) market notice framework[84]. The CMSL is similar to the well-established three-tiered Lack of Reserve notices in the NEM, but instead warns of risks relating to minimum operational demand and distributed PV contingencies. Where possible, these notices are issued one day in advance to provide time for the market to prepare and respond. If curtailment of distributed PV has to occur for system security, it is only where the market response has not been sufficient to clear the risk in time, and as an emergency last resort after all other feasible options are taken. A market notice is issued if this becomes necessary.
- SA Power Networks is pursuing the implementation of a "Flexible Exports" mechanism to deliver longer-term technical capabilities for more sophisticated active management of distributed PV[85].
- AEMO is continuing to review its system operational procedures.

Enhancement to South Australia's System Integrity Protection Scheme (SIPS)[86]

ElectraNet, in collaboration with AEMO, continues to work on enhancements to the reliability of South Australia's System Integrity Protection Scheme (SIPS) by implementing a Wide Area Protection Scheme (WAPS). The final scheme is expected to be commissioned by early 2023.

Under-frequency load shedding

AEMO is working with SA Power Networks and ElectraNet to implement a suite of measures to provide suitable emergency under-frequency response, and manage the impacts of distributed PV on the functionality of under-frequency load shedding. The AER recently approved SA Power Networks' proposal to implement dynamic arming of UFLS circuits[87,88].

SA Power Networks, ElectraNet, and AEMO are also collaborating on long-term options for restoring emergency under-frequency response (EUFR), including seeking expressions of interest for new services[89]. Further analysis is also progressing to determine suitable targets for EUFR capability in periods with low operational demand, to manage plausible non-credible contingency events.

Recommending a new protected event for South Australia

In the 2020 Power System Frequency Risk Review, AEMO recommended that the non-credible synchronous separation of South Australia from the rest of the NEM be declared a protected event. This would allow AEMO to take additional measures to maintain the South Australian power system frequency within acceptable ranges for a separation event occurring at any time, including (for example) purchasing frequency control and ancillary services or constraining generator dispatch. However, AEMO is required to undertake extensive quantitative assessments to support and justify a protected event declaration by the AEMC Reliability Panel.

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[84] AEMO, Distributed Photovoltaics (DPV) Contingency and/or Minimum System Load market notice frameworks, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/power-system-operation.

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

[86] See AEMO, *Power System Frequency Risk Review – Stage 2*, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/power-system-frequency-risk-review.

[87] AEMO, South Australian Under Frequency Load Shedding – Dynamic Arming, May 2021, at https://aemo.com.au/-/media/files/initiatives/der/2021/south-australian-ufls-dynamic-arming.pdf.

[88] AER, SA Power Networks – Cost pass through – Emergency standards 2021-22, at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/cost-pass-throughs/sa-power-networks-cost-pass-through-emergency-standards-2021%E2%80%9322.

[89] SA Power Networks, Tenders, at https://www.sapowernetworks.com.au/industry/tenders/.

This analysis is underway and has to date included extensive examination of non-credible separation events at different points in the network (including at the Heywood Interconnector and multiple different points in the Victorian network), along with the ability of the South Australian power system to survive the immediate separation event as well as recover frequency within the subsequent ten minutes. This has required development of new models and novel techniques, especially given the potentially low number of synchronous units that may be online in some periods following the commissioning of the ElectraNet synchronous condensers.

A selection of actions has been identified which aim to minimise risk as much as possible within existing frameworks, and implementation of these measures is underway. AEMO intends to propose to the Reliability Panel a selection of remaining actions that require a protected event for implementation, and is currently targeting submission of a request to the Panel in early 2023.

6.2 System strength and inertia

System strength and inertia are critical requirements for a secure and stable power system. A minimum level of system strength is required for the power system to remain stable, particularly for stability of the voltage waveform. Inertia in conjunction with frequency control services is needed to maintain the power system frequency within limits.

AEMO publishes at least annual assessments of system strength and inertia requirements and shortfalls across the NEM[90]. The need for this regular, detailed assessment was prompted by the changing generation mix and declining minimum demand projections driving the need for additional system strength and inertia services, and a recognition that the electricity sector will need to continue to innovate and adapt to maintain secure and efficient operation of the future power system.

This section summarises the current system strength and inertia situation in South Australia.

6.2.1 System strength

AEMO's 2021 *System Security Reports*[91] noted that the installation of a total of four synchronous condensers at Robertstown and Davenport substations as part of the South Australian System Strength Project would meet the region's system strength requirements for the period up to the end of the study horizon (2026-27). It is important to note that this does not necessarily encompass the need for system strength remediation from newly connecting or modified generators.

AEMO has updated its operational procedures to incorporate the two Robertstown and two Davenport synchronous condensers[92]. With all four synchronous condensers now in operation, system limits advice shows that the South Australian system has sufficient system strength to operate with up to 2,500 MW of non-synchronous generation online while in a system normal mode and connected to the rest of the NEM.

AEMO is preparing to release its 2022 System Strength Report in December. This will include the application of the new system strength framework, including a decade-ahead assessment of a system strength standard for all declared system strength nodes in South Australia.

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

[91] AEMO, *2021 System Security Reports*, December 2021 and *Update to 2021 System Security Reports*, May 2022, at https://aemo.com.au/energy-systems/ electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

[92] See AEMO, *Transfer limit advice – System strength in SA and Victoria,* September 2022, at https://aemo.com.au/-/media/files/electricity/ nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?la=en.

6.2.2 Inertia

AEMO's 2021 *System Security Reports* declared an inertia shortfall from 1 July 2023 until the completion of inter-network testing of Project EnergyConnect, against the secure operating level of inertia in the South Australia region. It was also noted that an existing inertia shortfall would persist until 30 June 2022. ElectraNet has entered into inertia support agreements that close the shortfall in 2022-23 and is working to close the larger shortfall declared from 1 July 2023.

Stage 1 of Project EnergyConnect (Robertstown to Buronga) is forecast for completion in late 2023 with the overall project forecast for completion of construction and first energisation in the second half of 2024. Commissioning activities and inter-network testing is scheduled to follow first energisation. It is assumed in AEMO's projections to progressively release transfer capacity from July 2024 onwards, with its full capacity available from July 2026.

AEMO is preparing to release its 2022 Inertia Report in December. This will include an assessment of the current status of the declared inertia shortfall.

6.3 Network Support and Control Ancillary Services

The Network Support and Control Ancillary Services (NSCAS) framework is one of the mechanisms in the NEM for AEMO to manage power system security and reliability of supply, and is part of the broader joint system planning processes between ElectraNet and AEMO for South Australia[93].

This framework requires that, at least annually, AEMO assesses the system requirements over a five-year period to keep the network operating within minimum acceptable security and reliability requirements, or to relieve network constraints where this maximises net economic benefits to the market. ElectraNet is expected to procure services or other solutions to address any need for South Australia that AEMO has declared as an NSCAS gap. If ElectraNet does not do so, AEMO may itself seek to acquire the necessary NSCAS to meet any gap for security or reliability needs.

In its annual NSCAS assessment released in December 2021 as part of the 2021 *System Security Reports*, AEMO declared an NSCAS gap of 40 megavolt-amperes reactive (MVAr) reactive power absorption in South Australia, which emerges when the requirements for a minimum combination of synchronous generating units to remain online in normal conditions are relaxed. AEMO also noted that ElectraNet and SA Power Networks have identified a need for larger reactive absorption than is identified in AEMO's NSCAS studies, as a result of investigating the interrelated challenges of controlling voltages across the distribution and transmission systems during low demand periods.

AEMO is preparing to release its 2022 NSCAS Report in December. This will include an assessment of the current status of the declared reactive power absorption gap.

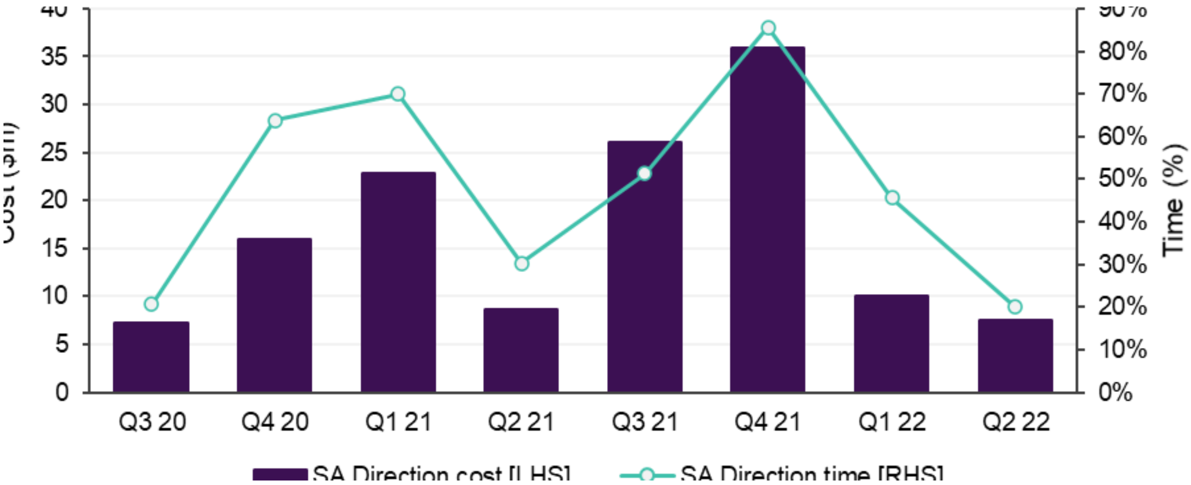
[93] The NER preclude the use of NSCAS to meet an inertia or system strength shortfall. However, solutions to address system strength or inertia shortfalls may also address NSCAS needs. Accordingly, AEMO ensures consistency across the inertia, system strength and NSCAS assessments, and where necessary and appropriate considers shortfalls and needs across all three areas holistically in its public annual reports.

6.4 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 (QED) reports[94] have noted recent trends in time on direction and total costs for directions issued to gas-fired generation in South Australia to maintain system security in the region:

- Overall directions costs for energy in 2021-22 were $79.6 million, up from $54.8 million during 2020-21. Notably, time and cost of system directions were much higher during first half of the year (Q3 and Q4 2021) before declining in Q1 and Q2 2022 (Figure 37).
- Direction costs reached a new quarterly high in Q4 2021, driven by significantly increased time on directions in South Australia (86% of the time in Q4 2021 was a record to date, with a total of 135 directions issued). With South Australian electricity spot prices below $30/MWh for 52% of the time in Q4 2021 and Adelaide average spot gas prices remaining high, gas-fired generation in the region frequently sought to de-commit from the market for economic reasons, therefore directions were required at times to manage system security.
- During the second half of the year (Q1 and Q2 2022), directed volumes for South Australian gas-fired generation units declined significantly. A key driver for the marked decline was the move to full operation of four synchronous condensers in late November 2021, which allowed AEMO to operate the South Australian region securely with a reduced number of large synchronous generating units. On 25 November 2021, the minimum number of large gas generating units required online for power system security was reduced from four to two under most operating conditions, with an increased nominal limit on non-synchronous generation in the state[95]. This – combined with higher South Australian spot prices (especially in Q2 2022) inducing gas generators to stay online for economic reasons – resulted in reduced direction requirements.

Figure 37 Time and cost of system security directions (energy only) in South Australia



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

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[96].

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

[95] See Market Note 92718 and https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/.

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

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 15 Additional data sources

Information source	Website address
Aurecon: 2021-22 Cost and Technical Parameters Review **Aurecon: 2021-22 Cost and Technical Parameters Review – Workbook**	https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios
BIS Oxford Economics: 2021 Macroeconomic Projections Report: Final	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/bis-oxford-economics-macroeconomic-projections.pdf
CSIRO: Small-scale solar and battery projections 2021	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/csiro-der-forecast-report.pdf
CSIRO: Electric vehicle projections 2021	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/csiro-ev-forecast-report.pdf
CSIRO: Multi-sector energy modelling, 2021	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/csiro-multi-sector-modelling.pdf
CSIRO: Gencost 2021-22	https://www.csiro.au/-/media/News-releases/2022/GenCost-2022/GenCost2021-22Final_20220708.pdf
Green Energy Markets (GEM): Final 2021 Projections for distributed energy resources – solar PV and stationary energy battery systems, 2021	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/green-energy-markets-der-forecast-report.pdf
Strategy Policy Research: Energy Efficiency Forecasts 2021	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/strategy-policy-research---energy-efficiency-forecasts-2021.pdf

A2. Generation and demand breakdown

Table 16 Generation and demand detailed breakdown in GWh

Financial year	SA generation							NEM balancing				SA consumption							
	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 NSG	Consumption met by rooftop PV
2011-12	3,562	0	0	80	3	253	9,391	13,290	1,495	1,094	-401	14,384	469	293	665	0	12,976	84	253
2012-13	3,473	0	0	79	3	434	9,031	13,021	1,710	1,377	-333	14,398	395	309	651	0	13,063	82	434
2013-14	4,087	0	0	82	3	582	7,664	12,417	1,925	1,637	-288	14,055	352	364	710	0	12,651	85	582
2014-15	4,218	0	0	92	4	716	7,246	12,276	1,904	1,528	-376	13,805	386	368	661	0	12,413	96	716
2015-16	4,317	0	0	94	4	812	7,145	12,373	2,227	1,941	-286	14,314	413	424	799	0	12,707	99	812
2016-17	4,340	0	0	77	8	904	5,620	10,950	2,889	2,725	-164	13,675	193	327	718	0	12,456	86	904
2017-18	5,561	4	22	71	22	1,041	7,282	14,003	1,039	-292	-1,331	13,713	221	313	676	27	12,494	94	1,041
2018-19	5,725	303	41	65	83	1,314	6,886	14,417	791	-468	-1,259	13,952	202	341	639	51	12,735	149	1,314
2019-20	5,798	483	47	67	209	1,610	6,278	14,492	922	-413	-1,335	14,085	179	334	701	59	12,849	276	1,610
2020-21	5,739	673	85	69	274	1,930	5,235	14,005	1,147	123	-1,023	14,097	144	324	696	104	13,045	343	1,930
2021-22	6,131	698	88	76	371	2,269	4,118	13,751	1,467	625	-842	14,404	112	300	556	111	13,325	447	2,269