South Australian Electricity Report

October 2021

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 2021, although AEMO has endeavoured to incorporate more recent information where practical.

DISCLAIMER

VERSION CONTROL

Version	Release date	Changes
1	29/10/2021	

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Executive summary

The South Australian Electricity Report (SAER) is an annual report providing key independent insights for the South Australian jurisdiction, consolidating data and insights relevant to South Australia from a range of AEMO publications and studies.

The energy landscape in South Australia continues to be shaped by the growing penetration of renewable generation – including distributed photovoltaic (PV) generation installed by households and businesses – in South Australia and in neighbouring regions of the National Electricity Market (NEM).

Key historical observations reported in this SAER

- **A shift in new renewable generation development from wind to solar** – in 2020-21, no new wind capacity was built in South Australia for the third year in a row, while 33 megawatts (MW) of large-scale solar capacity for dispatch from the grid was installed, and 294 MW of new distributed PV generation was installed. However, this shift is expected to be short-lived. More large-scale wind than solar is committed or anticipated in the next few years.
- **Lower-priced renewable generation displacing gas-powered generation of electricity (GPG):**
  - South Australia had the l**owest time-weighted average price (TWAP) for electricity among NEM regions** for the first time last year, and **more frequent negative prices** than previously observed.
  - The state had **near-record low volumes of GPG** last summer, and wind replaced gas as the largest energy source last year. In 2020-21 there were **more events than ever before in which AEMO directed GPGs** that had gone offline back online to maintain system security. The pressure on GPGs of lower spot and forward wholesale prices was also evident in the **mothballing of one of four units at Torrens Island Power Station B** from October 2021.
  - The volume-weighted average spot price received by large-scale solar generation reduced significantly to $21.92/megawatt hour (MWh), nearly $10/MWh lower than the volume-weighted average spot price received by wind generators in South Australia[1].
- **Lower daytime operational demand and new minimum operational demand records**, due to mild, sunny conditions and high distributed PV generation – to maintain secure power system operation with reduced operational demand, **AEMO and SA Power Networks equipped themselves with operational levers that allow distributed PV to be curtailed as a last resort** if required. These foundational measures should also, over time, allow **consumers to maximise the value of their surplus PV generation**.
- Since 2016-17, **the contribution of rooftop PV at the time of maximum underlying demand has almost tripled**. The time of maximum operational demand has settled at 8.00 PM for the past four years. Peak winter demand in 2021-22 reached a record 2,583 MW, due to colder than average temperatures.
- Last year, for the first time since 2016-17, South Australia was a **net importer of electricity**.

Major forecasting insights

- **System security will remain a focus** as the energy mix transformation continues – AEMO may declare **Network Support and Control Ancillary Services (NSCAS) gaps** in the coming year for reactive power, and is currently reviewing the **inertia** situation for the period to when Stage 2 of the Project EnergyConnect (PEC) interconnector is completed.
- **No reliability issues are expected** – South Australia is forecast to have enough supply to meet both the Interim Reliability Measure and the reliability standard for the next 10 years. After Osborne Power Station

[1] These figures are absent any consideration of contractual revenues associated with this generation, such as Power Purchase Agreements.

retires in 2023-24, the commissioning of Snapper Point Power Station and PEC, and the return to service of the mothballed Torrens Island Power Station B unit will help maintain reliability.

- In all scenarios, **distributed PV and battery storage is forecast to keep growing**, with projections higher than last year, and this growth is forecast to keep **offsetting growth in underlying consumer demand**. This trend results in operational demand falling in the Central scenario, and operational demand growth being lower that it would otherwise be in scenarios that assume higher rates of electrification (households and businesses switching from other fuels to electricity to reduce costs and emissions).
- **Maximum operational demand is forecast to start growing**, in the second half of the next decade once it occurs more frequently in the evening when rooftop PV does not supply underlying demand.
- As well as the continued growth of wind farms, and large-scale and distributed solar, the major supply change is **rapid developer interest in firming large-scale batteries** – the capacity of proposed (but not yet anticipated or committed) battery storage has doubled in the past year to now exceed 3,000 MW.
- **GPG volumes are forecast to keep falling**, as more renewable energy is connected in Victoria and New South Wales and PEC makes this energy available to South Australia, but **GPG will continue to play a role** at times of low variable renewable energy (VRE) output, and to help maintain system security.

2020-21 quick facts	Compared to 2019-20
Distributed PV generated 2,173 GWh (estimated) and met up to 83% of underlying demand at times Distributed battery capacity 80-140 MW (estimated)	↑
Operational consumption (sent out) was 11,614 GWh Operational maximum demand was 2,782 MW at 8.00 pm, 18 February 2021, 11% lower than 2019-20 maximum Operational minimal demand saw record lows (latest 236 MW (as generated) 1.00 pm-1.30 pm, Sunday 26 September 2021)	↓
Registered capacity 7,845 MW, total generated 13,973 GWh (more generation from rooftop PV and solar, less from GPG and wind), interconnector imports rose to 1,147 GWh, exports reduced to 1,023 GWh	↓
Time-weighted average price (TWAP) fell to $45/MWh, lowest average since 2014-15, frequency of negative spot prices increased to record levels, FCAS prices lower in all markets	↓
Backstop tool introduced for emergency curtailment of distributed PV if needed (used once on 14 March 2021), and AS/NZS 4777.2 updated to reduce unintended distributed PV disconnections AEMO reported system strength requirements to 2025-26 would be met by new synchronous condensers, and inertia shortfall extended to 2022-23	

Forecasts summary*
Distributed PV to generate 4,974 GWh in 2030-31 Distributed battery capacity 700 MW (estimated) in 2030-31
Operational consumption (sent out) in 2030-31 to range from 10,100 GWh (Central) to 14,814 GWh (Strong Electrification sensitivity) Operational maximum demand (sent out, 10% POE) 3,336 MW in 2030-31 Operational minimal demand decreasing, negative at times as early as 2022-23 (50% POE) and more frequently challenging secure operation of the power system
Additional supply – currently 269 MW committed, 643 MW anticipated, 12,258 MW proposed – majority solar, wind and firming battery storage/VPP
Expected unserved energy is forecast to be within the reliability standard and Interim Reliability Measure every year of the 10-year assessment
AEMO may declare an NSCAS gap this year, and will review declared inertia shortfall as PEC connects in stages

* Unless otherwise noted: forecasts are based on Central scenario assumptions, and supply categories at July 2021

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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 2021 SAER provides key independent insights for the South Australian jurisdiction under Section 50B of the National Electricity Law, known as the South Australian Advisory Functions (SAAF).

It consolidates data and insights relevant to South Australia from a range of AEMO publications, including the 2021 *Electricity Statement of Opportunities* (ESOO) for the National Electricity Market (NEM), the 2021 *Inputs, Assumptions and Scenarios Report* (IASR), the 2021 *Gas Statement of Opportunities* (GSOO) for eastern and south-eastern Australia, the 2020 *Integrated System Plan* (ISP), the *Quarterly Energy Dynamics* reports, the 2020 *System Strength and Inertia Report*, and the 2020 *Network Control and Ancillary Services Report*. This SAER is supplemented by additional sources that can provide additional data or detail; these sources are listed in Table 1 and noted through the report.

Unless otherwise stated, all times are NEM time 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 market participants and potential investors as at 30 September 2020, unless otherwise specified. Reporting of historical observations on the gas and electricity markets is based on the previous financial year (2020-21), unless otherwise specified. Table 1 provides links to additional information referred to above or provided either as part of the accompanying information suite for this report, or related AEMO forecasting and planning information. Appendix A1 lists additional external sources.

Table 1 Information and data sources

Information source	Website address
2021 Electricity Statement of Opportunities* (ESOO)** ***Market modelling methodology report ***Demand Forecasting Methodology Information Paper*** ***Demand Side Participation (DSP) Forecasting Methodology*** ***ESOO and Reliability Forecast Methodology Document***	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
***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
2020 *Integrated System Plan* (ISP)	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

Information source	Website address
2021 *Gas Statement of Opportunities* (GSOO) for eastern and south-eastern Australia	http://aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities
2021 SAER Data File – data used in tables and figures in this report	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions
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
Maps and network diagrams	https://www.aemo.com.au/aemo/apps/visualisations/map.html
Quarterly Energy Dynamics	https://www.aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed
2020 *System Strength and Inertia Report*, 2020 Notice of South Australia Inertia Requirements and Shortfall	https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability
2020 *Network Support and Control Ancillary Services Report*	https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability

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 shown in the 2021 SAER are in line with the five scenarios (and additional sensitivities) presented in the 2021 ESOO for the NEM, and shown in Figure 1 and Table 2 below. These were developed in consultation with industry and consumer groups for use in AEMO's 2021-22 forecasting and planning publications, including the 2021 ESOO, 2022 *Gas Statement of Opportunities* (GSOO) for eastern and south-eastern Australia, and 2022 *Integrated System Plan* (ISP).

The five scenarios are Slow Change, Steady Progress, Net Zero 2050, Step Change, and Hydrogen Superpower. More information is in the 2021 *Inputs, Assumptions and Scenarios Report* (IASR)[2]. The 10-year demand and reliability forecasts in the 2021 ESOO and this SAER report include "Central scenario" projections. These Central projections use the assumptions (shared over the 10-year horizon) of both the Steady Progress and Net Zero 2050 scenarios.

[2] At https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

Figure 1 2021-22 scenarios for AEMO's forecasting and planning publications

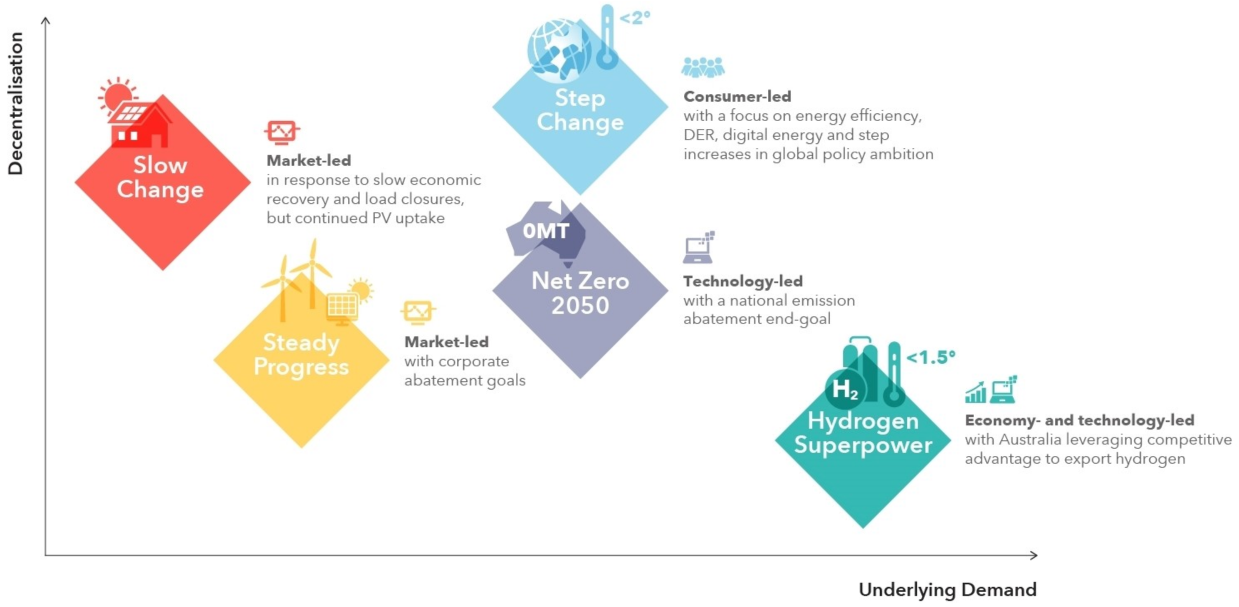


Table 2 Descriptions of AEMO's 2021-22 forecasting and planning scenarios and sensitivity

Slow Change	Challenging economic environment following the COVID-19 pandemic, with greater risk of industrial load closures, slower decarbonisation action, and consumers proactively managing energy costs through continuing investments in DER, particularly distributed PV.
Steady Progress (ESOO Central scenario)	Future driven by existing government policy commitments, continuation of current trends in consumer investments such as DER and corporate emission abatement, and technology cost reductions. By 2050, many consumers are still relying on gas for heating.
Net Zero 2050 (ESOO Central scenario)	Action towards an economy-wide net zero emissions objective by 2050 through technology advancements. Short-term activities in low emission technology research and development enable deployment of commercially viable alternatives to emissions-intensive activities in the 2030s and 2040s, with stronger economy-wide decarbonisation, particularly industrial electrification, as 2050 approaches. Electric vehicles (EVs) become more prevalent over time and consumers gradually switch to using electricity to heat their homes and businesses.
Step Change	A future with rapid consumer-led transformation of the energy sector and a coordinated economy-wide approach that efficiently and effectively tackles the challenge of rapidly lowering emissions. This requires a step change in global policy commitments to achieve the minimum objectives of the Paris Agreement, supported by rapidly falling costs of energy production, including consumer devices. Increased digitalisation enhances the role consumers can play in managing their energy use, along with advancements in energy efficient technologies and buildings. EV adoption is strong, with early decline in manufacturing of internal-combustion vehicles. By 2050, most consumers rely on electricity to heat their homes and businesses. Carbon sequestration in the land use sector helps offset hard-to-abate emissions.
Hydrogen Superpower	Strong global action towards emissions reduction, with significant technological breakthroughs and social change to support low and zero emissions technologies. Emerging industries such as hydrogen production present unique opportunities for domestic developments in manufacturing and transport, and renewable energy exports via hydrogen become a significant part of Australia's economy. New household connections tend to rely on electricity for heating and cooking, but those households with existing gas connections progressively switch to using hydrogen – first through blending, and ultimately through appliance upgrades to use 100% hydrogen.
Strong Electrification sensitivity	A high emissions-reduction future, aligned with the decarbonisation objectives of the Hydrogen Superpower scenario, only in this future, hydrogen uptake is limited and energy efficiency is also more muted. This leaves the majority of the emissions reductions to be achieved through electrification, testing the outer bounds of the existing system. No export hydrogen or associated green steel manufacturing facilities are therefore included in this sensitivity.

2. Demand and consumption

In all scenarios, distributed PV is forecast to keep growing, with projections higher than last year, and the trend of distributed PV offsetting growth in underlying consumer demand is forecast to continue. This results in operational electricity consumption falling in the Central scenario, and operational consumption growth being lower that it would otherwise be in scenarios that assume higher rates of electrification (households and businesses switching from other fuels to electricity to reduce costs and emissions).

Maximum operational demand is forecast to grow, as it now occurs in the evening when rooftop PV does not supply underlying demand.

For more:

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

2021 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.

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

2.1 Demand and consumption inputs and assumptions

AEMO updates its projections of energy consumption and demand at least annually[3]. The inputs and assumptions used in these forecasts are developed and refined in significant stakeholder consultation through the Forecasting Reference Group (FRG), industry engagement via surveys, consultant data and recommendations, and AEMO's internal forecasting of each sector and sub-sector affecting energy consumption and peak demands.

The IASR[4] contains detail about inputs, assumptions and scenarios, and specific detail about how these inputs are applied to develop electricity forecasts (consumption and maximum/minimum demand) is published in the *Electricity Demand Forecasting Methodology*[5]. For gas demand forecasting, the GSOO's demand forecasting methodology[6] also outlines the usage of these key inputs.

AEMO uses a range of historical data to train and develop models, and develops component forecasts to project future outcomes using these 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.

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

[4] At https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

[5] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/electricity-demand-forecasting-methodology/final-stage/electricity-demand-forecasting-methodology.pdf?la=en.

[6] At https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2021/2021-gas-statement-of-opportunities-methodology-demand-forecasting.pdf?la=en.

- 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 to electricity), take-up and charging of electric vehicles (EVs), and the potential impacts of a hydrogen industry in Australia.

Section 2.1.2 shows 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.
- Stakeholder surveys, including for large industrial loads (LILs) across various sectors.
- Energy efficiency.

2.1.1 Electrification and hydrogen

The scenarios developed with industry for the 2021 IASR included – for the first time in AEMO's modelling – the potential for significant impacts on electricity demand from:

- Electrification (users switching from other fuels to electricity to reduce costs and emissions).
- The development of a hydrogen production industry in Australia.

Electrification (including electric vehicles)

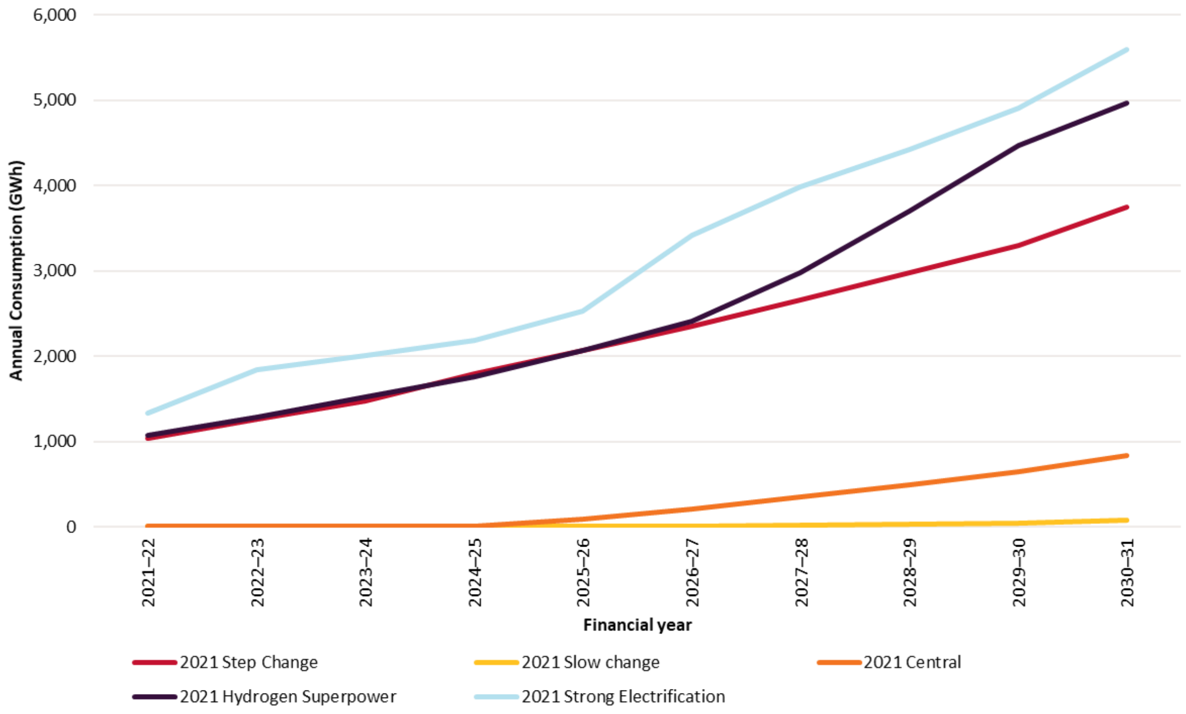
AEMO has considered a range of electrification outcomes across different scenarios:

- In the residential and commercial (building) sectors, electrification will depend on factors including appliance replacement costs, electricity infrastructure capabilities and costs, and the availability of alternative fuels, such as hydrogen or blended hydrogen-natural gas.
- The industrial sector has a wide range of subsectors, each of which have their own fuel consumption profiles. Broadly speaking, most oil and gas demands can be electrified, and some technological advances, may make conversion possible, but investment in these technological advances may be more economically efficient in scenarios with more ambitious emissions reductions.
- Electrification of transport is expected in all scenarios to varying degrees.

Figure 2 shows the magnitude of electrification forecast for each scenario, including transport (EVs). It shows that by 2030-31, scenarios with a carbon budget (Step Change, Hydrogen Superpower, and Strong Electrification) project a range from approximately 3,750 gigawatt hours (GWh) to over 5,500 GWh of new electricity consumption. In the Central scenario, electrification by 2030-31 is much lower (800 GWh), and largely due to EV uptake.

While the SAER focuses on the next 10 years, AEMO has forecast the scenarios to 2050, and projects an electrification impact for South Australian underlying consumption of up to 19,736 GWh (in the Strong Electrification sensitivity). Considering electrification impacts, this is 155% of today's underlying consumption, with 13,056 GWh of the impact coming from household and business demand switched from other fuels, and 6,680 GWh from EVs (including road and non-road vehicles). Currently, the number of EVs in South Australia is estimated at 1,386 (all road vehicles), with 3.29 GWh of consumption.

Figure 2 Electrification and electric vehicle forecast consumption (GWh) for South Australia, 2021-22 to 2030-31



Hydrogen

The South Australian Government is supporting several green hydrogen projects to promote a local hydrogen industry[7]. Most recently, on 5 November 2020, the South Australian Government announced its support of a world-leading $240 million hydrogen project. The initial stage of the $240 million H2U Eyre Peninsula Gateway Hydrogen Project will see the installation of a 75 MW electrolysis plant near Whyalla, capable of producing enough hydrogen to create 40,000 tonnes of ammonia each year, and with a target completion date of late 2022. The South Australian Government has committed a $4.7 million grant and a $7.5 million loan to this project.

The 2021 ESOO projects that if demand for green hydrogen increases rapidly, the NEM could experience significant load growth and greater load flexibility. This demand would be expected to take advantage of the flexibility of proton exchange membrane (PEM) electrolysers, avoiding periods of electricity supply scarcity and operating when energy was readily available in the middle of the day.

A range of hydrogen assumptions have been applied across scenarios to model rates of uptake for hydrogen as a fuel source; for example, the Hydrogen Superpower scenario applies greater hydrogen fuel substitution than other scenarios as an alternative to electrification.

In this Hydrogen Superpower scenario, hydrogen production presents unique opportunities for domestic developments in manufacturing and transport, and renewable energy exports via hydrogen become a significant part of Australia's economy. Export hydrogen will be further explored in the 2022 ISP (draft to be released in December 2021).

2.1.2 Distributed energy resources

Distributed PV means small-scale solar PV systems connected to the distribution network by businesses and households. These systems have a measurable impact on South Australia's operational electricity demand, by

[7] For more information, see http://www.renewablessa.sa.gov.au/topic/hydrogen/hydrogen-projects.

reducing residential and commercial grid consumption during daylight hours, when consumer demand can be met by rooftop PV. Distributed PV normalised generation half-hourly profiles are provided by Solcast.

In the ESOO, AEMO reports on distributed PV in total, including both rooftop systems and other smaller non-scheduled PV capacity. The SAER provides detail individually for forecasts of rooftop PV and PV non-scheduled generation (PVNSG), projecting changes in both installed capacity and the amount of energy generated by these systems:

- Rooftop PV is defined as behind-the-meter systems, installed by households and businesses, up to 100 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.

Rooftop PV forecasts

From 2012-13, rooftop PV generation in South Australia has shifted minimum operational demand from overnight to occur in the middle of the day (see Section 2.3.2), and the time of maximum operational demand further into the evening, typically 8.00 pm Adelaide time in summer, when solar irradiance is low. Rooftop PV generation is rarely observed during winter maximum demand periods as they typically occur in the evening.

Current installed capacity estimates for rooftop PV are from the Clean Energy Regulator (CER), with DER Register data now becoming available as a supplement. Additional information on rooftop PV forecasts is available in the CSIRO[8] and GEM[9] reports provided to AEMO.

Total installed rooftop PV capacity in South Australia has grown strongly since 2009, and continues to grow, with South Australia now having over 300,000 residential installations and 40% penetration for dwellings[10]in residential rooftop PV, the highest (equal with Queensland) of NEM regions.

Figure 3 shows that AEMO's 10-year forecasts for rooftop PV capacity, in all scenarios, are higher this year than in 2020. Last year, the COVID-19-related economic downturn was expected to slow consumer investment in PV systems, but data for 2020 showed uptake continued to be strong through the year, so projections have been revised up. PV sales are forecast to be higher than what is shown in the figure due to an increasing number of existing systems reaching end-of-life and needing to be replaced.

Over the next 10 years, South Australia is projected to have the highest ratio of rooftop PV generation to operational consumption[11] of all NEM regions.

In 2020-21, annual rooftop PV generation was estimated at 1,925 gigawatt hours (GWh)[12], or 15% of total annual underlying consumption[13]. In the Central scenario, it is forecast to increase to 4,138 GWh by 2030-31, which would represent approximately 29% of annual underlying consumption at that time[14]. In comparison, Victoria by 2030-31 is forecast to have approximately 19% of underlying demand met by rooftop PV.

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 lower growth forecast in 2020.

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

[9] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/green-energy-markets-der-forecast-report.pdf?la=en.

[10] Dwellings using the ABS classification (for example, separate house, semi-detached, row or terrace house, townhouse).

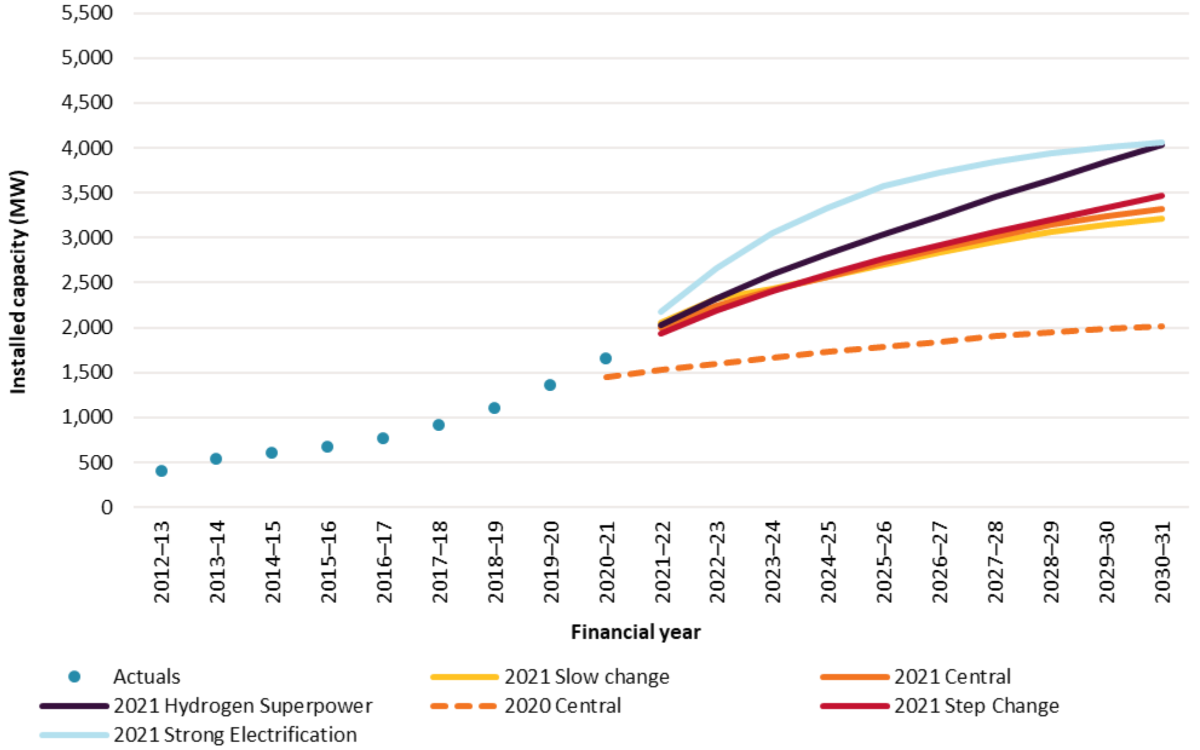
[11] Operational consumption and demand are drawn from the grid and supplied by large-scale generation.

[12] Estimates calculated as at date, for the financial year 2020-21.

[13] 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.

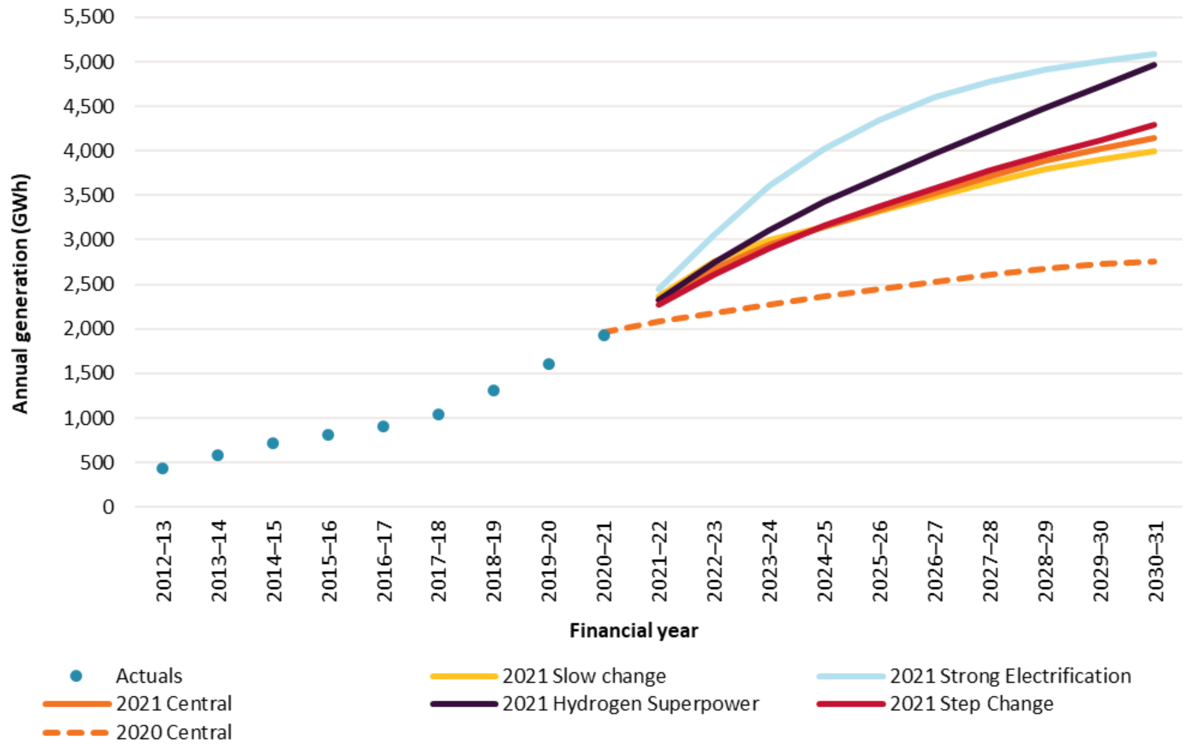
[14] Victoria and Queensland are equal next highest NEM regions for ratio of rooftop PV generation to underlying consumption in 2030-31 (Central scenario), at approximately 19%.

Figure 3 South Australian rooftop PV installed capacity forecasts to 2030-31



Note: 2021 Central is the forecast under assumptions for both Net Zero 2050 and Steady Progress scenarios, as explained in Section 1.3).

Figure 4 South Australian rooftop PV generation forecasts to 2030-31



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

PV non-scheduled generation (PVNSG) forecasts

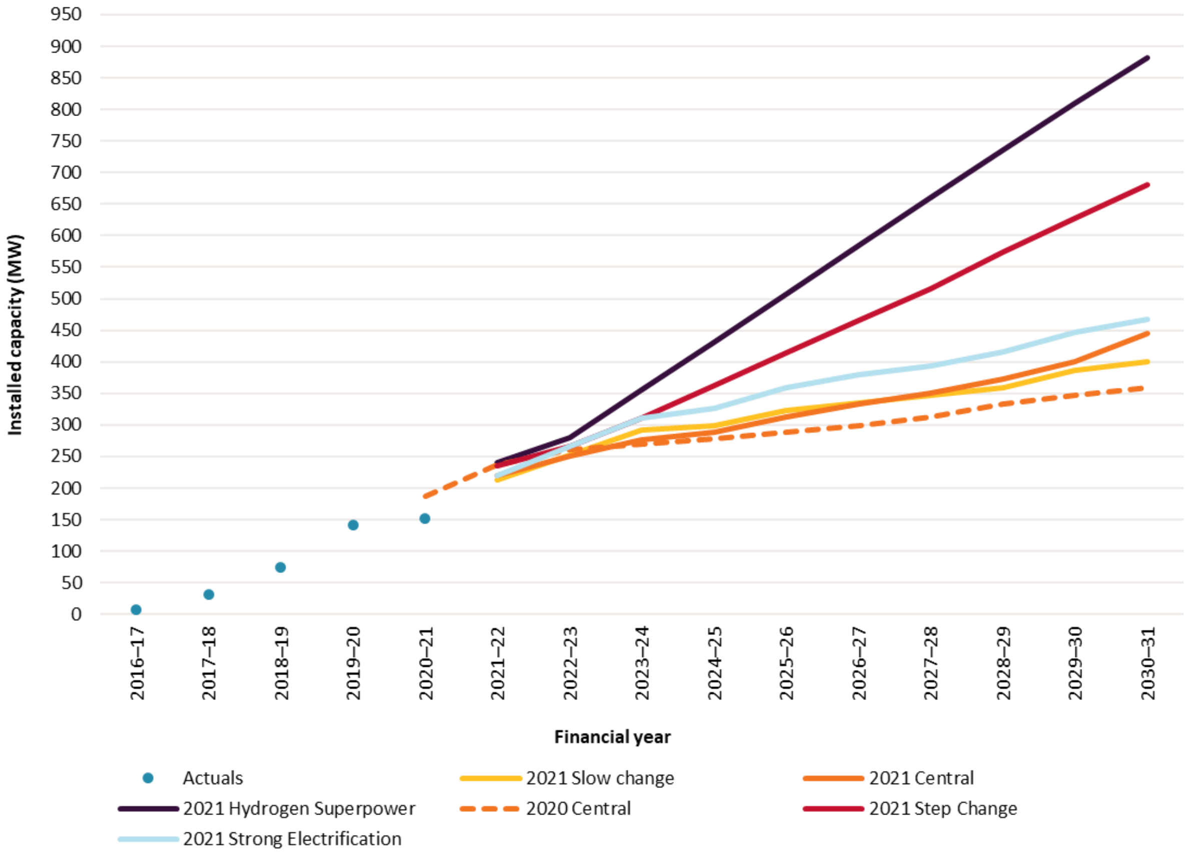
Figure 5 shows South Australia’s PVNSG capacity since 2016-17, and forecast to 2030-31.

Figure 6 shows PVNSG actual annual generation since 2016-17, and forecast annual generation to 2030-31.

These figures highlight that:

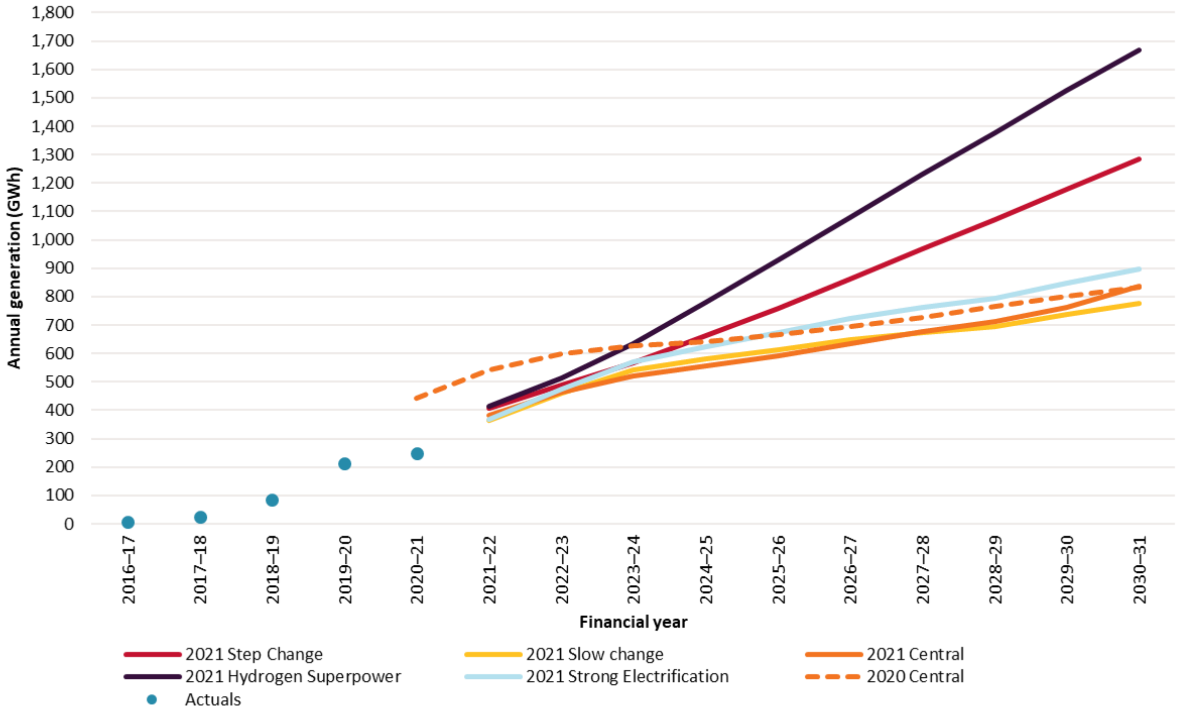
- The rapid growth in PVNSG since 2016-17, from a relatively low base, slowed in 2020-21. This was also observed in other NEM regions, and has been attributed by GEM to a weakening of anticipated financial payback in light of lower spot prices and futures wholesale costs for energy, and potentially to the business impacts of the COVID-19 pandemic.
- Annual PVNSG generation was estimated at 248 GWh in 2020-21. In the Central scenario, it is forecast to increase to 836 GWh by 2030-31. The estimated amount of PVNSG installed capacity at 30 June 2021 was 151 MW[15] and is forecast to grow in the Central scenario, to 446 MW in 2030-31.

Figure 5 South Australian PVNSG capacity forecasts to 2030-31



[15] There is a delay between a PVNSG connection and its registration with the CER for LGCs. Estimates calculated as at 25 May 2021, for the financial year 2020-21.

Figure 6 South Australian PVNSG generation forecasts to 2030-31



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

Distributed battery storage forecasts

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 2021, South Australia has an estimated 80 MW to 140 MW (or 20,000-30,000 units) of embedded battery systems[16]. In the next five years, the number of batteries is forecast to reach nearly 50,000 units supported by the South Australian Government's Home Battery Scheme[17]. This represents approximately 20% of all the batteries forecast to be installed in the NEM by 2025.

By 2030-31, uptake of business and residential behind-the-meter battery systems is forecast to reach approximately 700 MW (in the Central scenario) and 1,200 MW (in the Hydrogen Superpower scenario). Battery uptake is forecast to be higher than previous projections, due to revisions to payback periods, technology costs, and linkages to distributed PV uptake rates. Current modelling assumes most battery systems would be installed as part of integrated solar and battery systems.

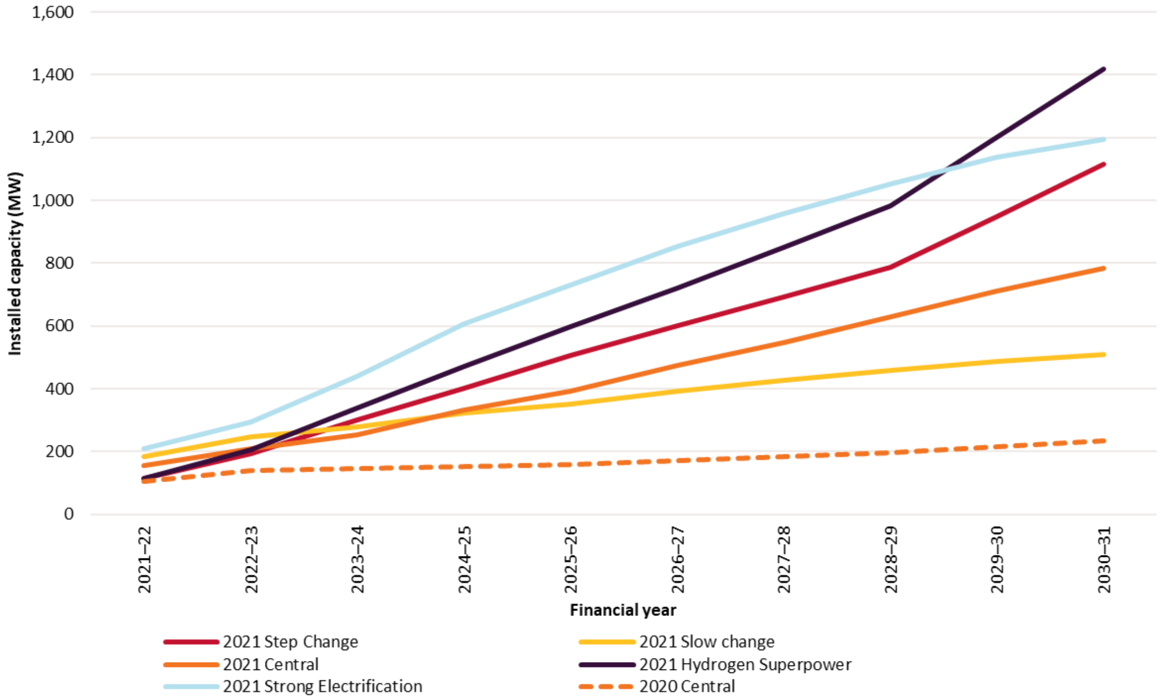
Figure 7 shows the 10-year forecast installed capacity of customer battery systems in South Australia for all scenarios, compared to the 2020 Central scenario forecast. The 2021 forecasts are higher than the 2020 forecasts, largely driven by higher distributed PV forecasts (with greater distributed PV penetration driving higher uptake of battery installations)[18].

[16] For more information, see https://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2020/CSIRO-DER-Forecast-Report and https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/green-energy-markets-der-forecast-report.pdf?la=en.

[17] For more information, see https://homebatteryscheme.sa.gov.au/.

[18] For more information on the forecasts, see the CSIRO and GEM reports at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

Figure 7 Behind-the-meter battery capacity forecasts for South Australia, 2021-22 to 2030-31



Data source: IASR.

Distributed storage systems can operate as part of a VPP. AEMO models a projected level of aggregation among distributed storage systems which would effectively act as a VPP, operating to meet system peaks (rather than household drivers) and optimising charge and discharge to minimise system cost[19].

Retailers and technology providers have participated in trials of VPPs in South Australia, including the VPP Demonstrations program[20] co-ordinated by AEMO to test VPPs' capacity to support system security. South Australian VPP Demonstrations participants have been:

- South Australia VPP (SA VPP) (16 MW current registered capacity) operated by Energy Locals and Tesla with support from the South Australian Government[21].
- AGL VPP (6 MW), with support from the Australian Renewable Energy Agency (ARENA)[22].
- Simply Energy VPP (4 MW), with support from ARENA[23].
- Shinehub VPP (1 MW).[24]

2.2 Historical and forecast consumption and demand

2.2.1 Operational consumption

Figure 8 shows South Australia's actual annual sent-out operational consumption (from the grid) since 2011-12 and forecast annual operational consumption to 2030-31[25].

[19] Details of assumptions and forecasts are in the 2021 IASR, Section 3.3.6, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

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

[21] See https://virtualpowerplant.sa.gov.au/.

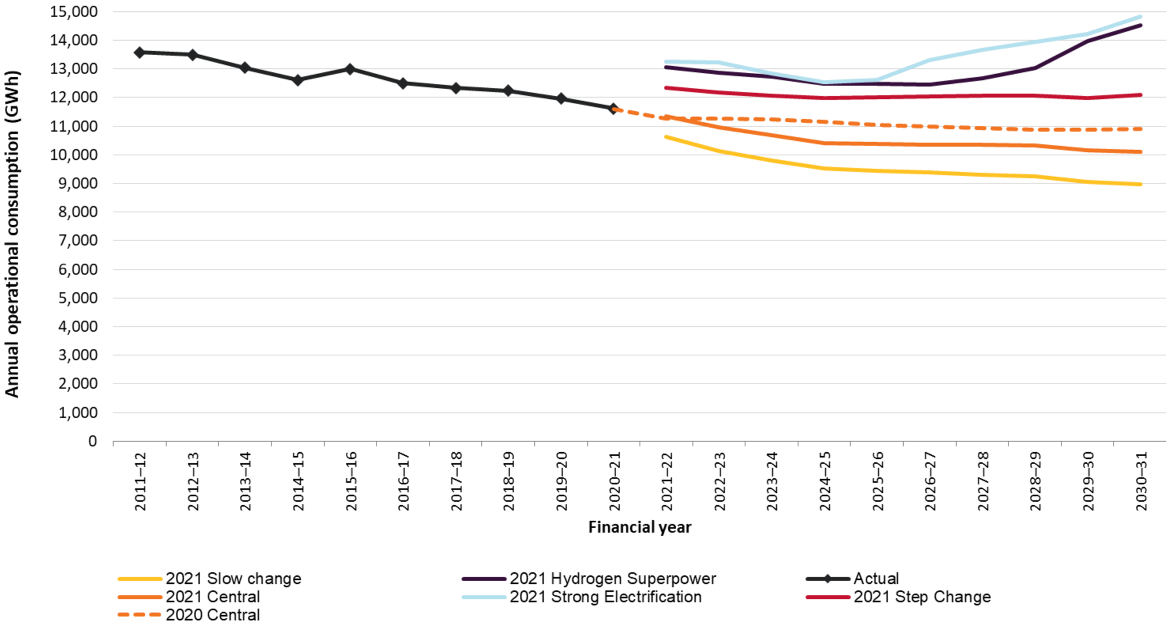
[22] See https://arena.gov.au/projects/agl-virtual-power-plant/.

[23] See https://www.simplyenergy.com.au/energy-solutions/battery-storage/south-australian-virtual-power-plant-vpp.

[24] See https://shinehub.com.au/virtual-power-plant/..

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

Figure 8 Annual operational consumption (sent-out) actual and forecast for South Australia, 2011-12 to 2030-31



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

In 2020-21, operational consumption (sent-out) in South Australia was 11,614 GWh. This is 2.9% lower than the 2019-20 total of 11,964 GWh.

As discussed in Section 2.1.1, rooftop PV continued its strong growth of the past few years, and offset other growth arising from new residential connections and increased activity in the business sector.

Under the 2021 ESOO Central scenario, this trend of rooftop PV growth more than offsetting modest growth in underlying consumption is forecast to continue over the next decade. Total annual operational consumption by 2030-31 is forecast to decline 13% to 10,100 GWh in this scenario, as approximately 1,300 GWh of new growth (approximately 800 GWh due to electrification and 500 GWh from a combination of business and residential growth) is more than offset by over 2,200 GWh of new generation from distributed PV.

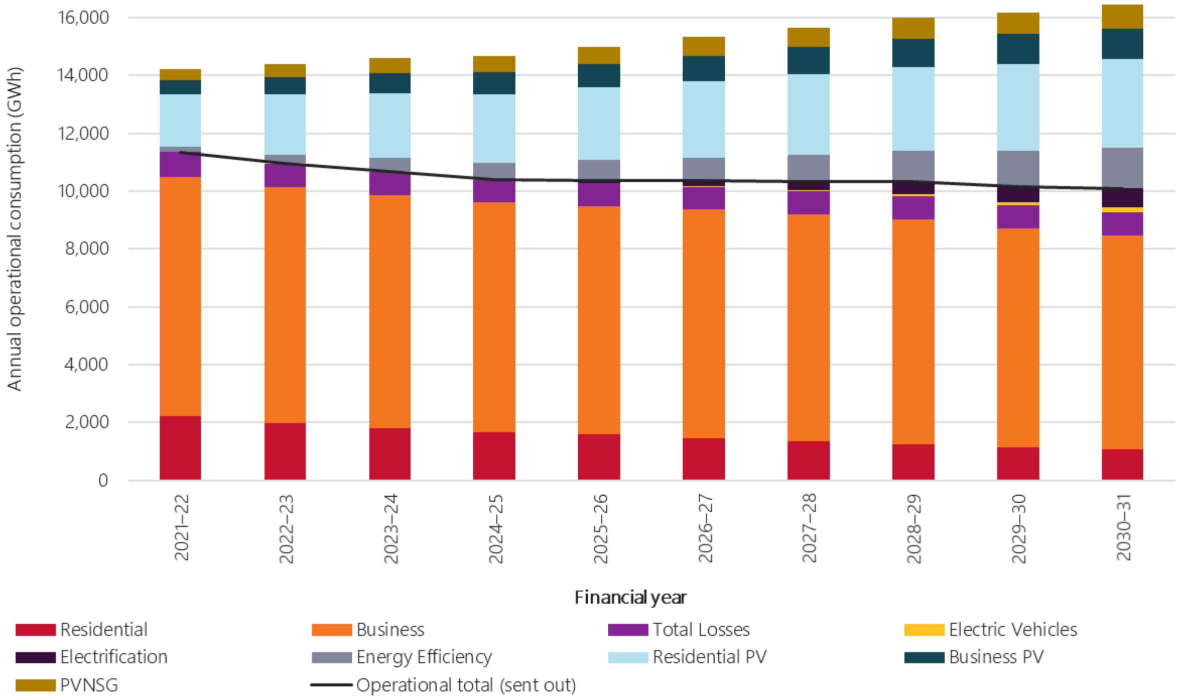
The forecasts vary by scenario from 2020-21 to 2030-31:

- In Slow Change, a combination of strong distributed PV growth, dampened business growth, a lower residential connections forecast, and no electrification sees a decline of approximately 2,600 GWh by 2030-31 compared to 2020-21 operational consumption.
- In Hydrogen Superpower, there is a net increase in operational consumption of approximately 2,900 GWh by 2030-31. Growth in underlying consumption is driven by steady, high electrification (nearly 5,000 GWh of new load), domestic hydrogen production (1,000 GWh of extra consumption), and about 1,400 GWh growth from new residential connections and new business consumption. However, the increase from these drivers is largely offset by growth in distributed PV generation (increase of 4,500 GWh).
- In Step Change, stronger electrification than the Central scenario sees over 3,700 GWh more electrification of load by 2030-31 and 200 GWh from new residential and business consumption, but this growth is moderated by higher distributed PV generation, which is forecast to grow by nearly 3,400 GWh. The net increase in operational consumption by 2030-31 is 500 GWh
- In the Strong Electrification sensitivity, which assumes the highest electrification potential, new electrified load grows steadily, reaching over 5,600 GWh, while new residential connections and business growth also drives increased underlying consumption of approximately 1,400 GWh. Some of the total growth is offset by distributed PV generation growing strongly and contributing approximately 3,800 GWh more in

2030-31 than in 2020-21. The net increase in operational consumption by 2030-31 is approximately 3,200 GWh.

Figure 9 shows forecast operational consumption by sector to 2030-31. Components consuming energy are shown below the operational total line. The elements shown above the line offset growth (by either saving energy or generating behind the meter) and reduce the operational total to the level shown by the line.

Figure 9 Forecast annual operational consumption (sent-out) with components (Central scenario), 2021-22 to 2030-31



Note: Rooftop PV is here split into residential and business forecasts.
Data source: AEMO forecasting portal, at http://forecasting.aemo.com.au/.

Residential sector – underlying and delivered consumption

Underlying residential consumption is driven predominately by new connections growth, though moderated by gains in energy efficiency. Electrification (EVs and conversion from gas appliances) are additional new growth drivers.

Underlying residential consumption is expected to grow moderately over the next decade, from approximately 4,100 GWh in 2020-21 to between 4,300 GWh (Slow Change) and 5,500 GWh (Strong Electrification) in 2030-31, with the Central outlook at 4,500 GWh, Step Change at 4,900 GWh, and Hydrogen Superpower at 5,300 GWh.

The South Australian residential sector currently sources approximately one-third of its energy from rooftop PV. In 2020-21, rooftop PV generation contributed 1,500 GWh to underlying consumption, leaving residential delivered[26] energy at approximately 2,600 GWh.

In all scenarios, forecast continual growth in rooftop PV generation more than offsets any growth in underlying residential consumption, and delivered energy for the sector is projected to decline by 2030-31.

[26] Delivered consumption or demand refers to the electricity supplied to electricity customers from the grid. It therefore excludes the part of their consumption that is met by behind-the-meter (typically rooftop PV) generation. Operational electricity consumption or demand is measured by metering supply to the network rather than what is consumed. For further information refer to the Forecasting Approach – Electricity Demand Forecasting Methodology document: https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/electricity-demand-forecasting-methodology/final-stage/electricity-demand-forecasting-methodology.pdf?la=en.

In both Central and Slow Change scenarios, some 70% of underlying residential demand is forecast to be met by residential rooftop PV, and delivered consumption is forecast to reach 1,200 GWh, by 2030-31. This corresponds to approximately 50% of dwellings in South Australia with a rooftop PV installation.

Rooftop PV has a much bigger impact in the other scenarios, resulting in delivered energy between 600 GWh (in Hydrogen Superpower) and 700 GWh (in Step Change and the Strong Electrification sensitivity). In the Hydrogen Superpower scenario, rooftop PV generation is forecast to meet 80% of residential load by 2030-31.

Business sector – underlying and delivered consumption

By 2030-31, under the Central outlook, underlying business consumption is forecast to increase from approximately 8,800 GWh in 2020-21 to 9,800 GWh in the Central scenario, and to as much as 13,700 GWh in the Strong Electrification sensitivity.

The forecast growth is due to a combination of electrification of business load, EVs, and growth from the services sector (and, as noted below, demand for domestic hydrogen manufacturing in the Hydrogen Superpower scenario).

Key insights across the scenarios include:

- Electrification is one of the key differentiators in business consumption between scenarios by 2030-31. The key sectors that most strongly influence electrification of energy demand are expected to be industry and to a relatively smaller extent transport (EVs), accounting for at least 90% of newly electrified loads in all scenarios. The varying influence of business sector electrification by 2030-31 is up to 4,600 GWh across scenarios.
- The services sector is expected to play an increasingly dominant role in the South Australian business sector, driving underlying consumption growth of approximately 500 GWh by 2030-31 in all scenarios.
- Electricity consumed for domestic production of hydrogen is forecast to ramp up from 2026-27 and reach 1,000 GWh by 2030-31 in the Hydrogen Superpower scenario.
- Business rooftop PV is expected to grow during this period and to offset consumption growth by between 700 GWh and 900 GWh across scenarios.
- PVNSG growth is also expected to grow during this period and further offset delivered energy (and lower operational consumption requirements) by between 500 GWh and 1,400 GWh (see Section 2.1.2 for discussion on PVNSG).

2.3 Maximum demand and minimum demand

2.3.1 Operational maximum demand

South Australian operational maximum demand 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 have shifted maximum operational demand from the middle of the day to increasingly late in the afternoon, and now maximum demand occurs late in the evening, when distributed PV is not generating (8.00 pm on 18 February in 2020-21, peaking at 2,782 MW of operational demand).

South Australia is expected to continue to experience maximum demand events during summer over the next 10 years; however, with increasing electrification of heating load forecast, winter maximum demands are expected to increase from 2025. Operational demand figures in this section are all sent-out.

Forecast operational maximum demand

In summer (see Figure 10), maximum operational demand forecasts initially soften as distributed PV partially meets underlying demand requirements in the late afternoon and early evening, then as both residential and business consumption continue to increase outside of daylight hours, maximum demands are forecast to rise and to be more prevalent in the early evening.

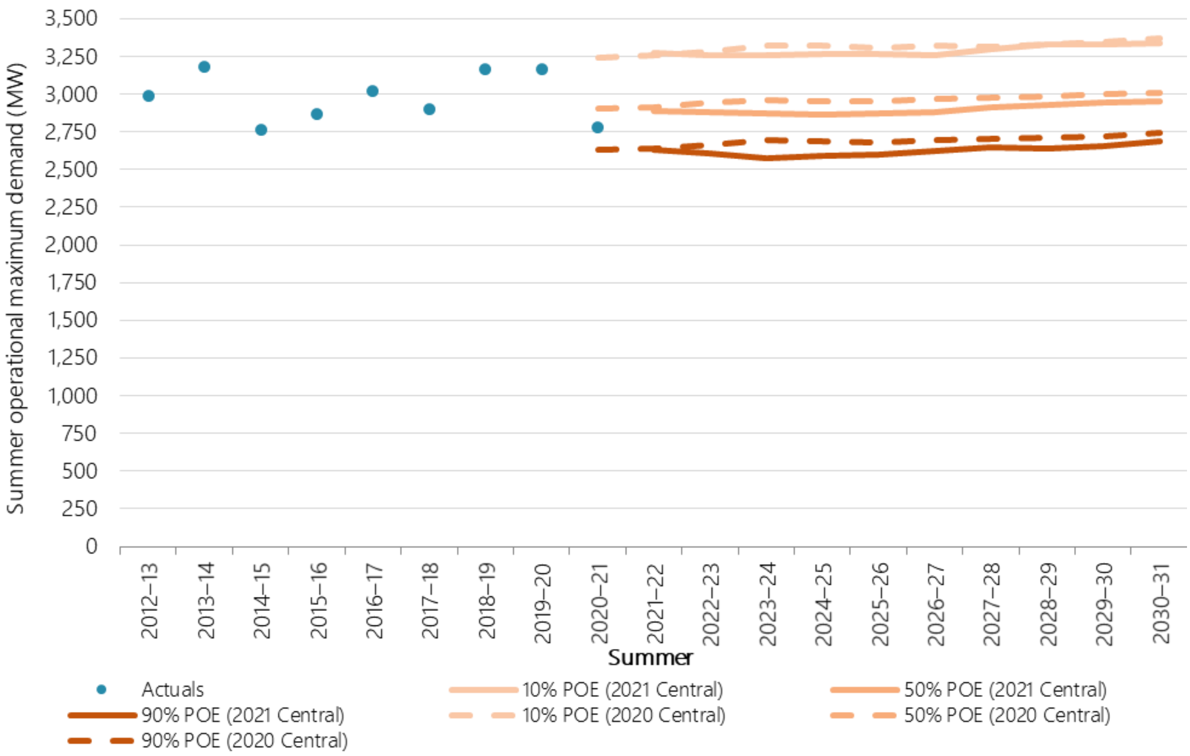
Towards 2030-31, further increases in maximum operational demand are expected, as drivers such as electrification and EV uptake are forecast to start influencing the outlook.

In winter (see Figure 11), maximum operational demand forecasts remain steady initially, then start to grow towards the end of the decade as they follow similar trends to underlying consumption patterns, excluding the influence of distributed PV. Specifically, the outlook for residential, business, and electrification growth primarily determines the outlook for winter demand in South Australia. The primary factor that has acted to increase winter maximum demands in comparison to last year's forecast is a stronger outlook for the business mass market sector. This particular sector during the winter months is less likely to be complemented by generation from distributed PV which assists in moderating high demand events.

In recent years, South Australian actual maximum winter demands have tended to be higher than or similar to the 10% probability of exceedance (POE) forecast for the Central scenario. In its 2020 *Forecast Accuracy Report*[27], AEMO attributed the high winter 2020 outcome to COVID-19, with more people being at home heating their houses, when forecast drivers suggested demand should have been more moderate. The 2021 winter maximum demand was even higher, which can be attributed to extreme weather, with many locations having their coldest day (lowest daily maximum) on record. AEMO is also looking into whether higher winter maximums may continue, driven by:

- A more permanent shift in working habits following COVID-19.
- A behavioural change from customers with rooftop PV, who may be using more power at the time of evening peak during the coldest days, even though their PV system is not generating at the time, because their electricity bills overall are lower following the installation of rooftop PV.

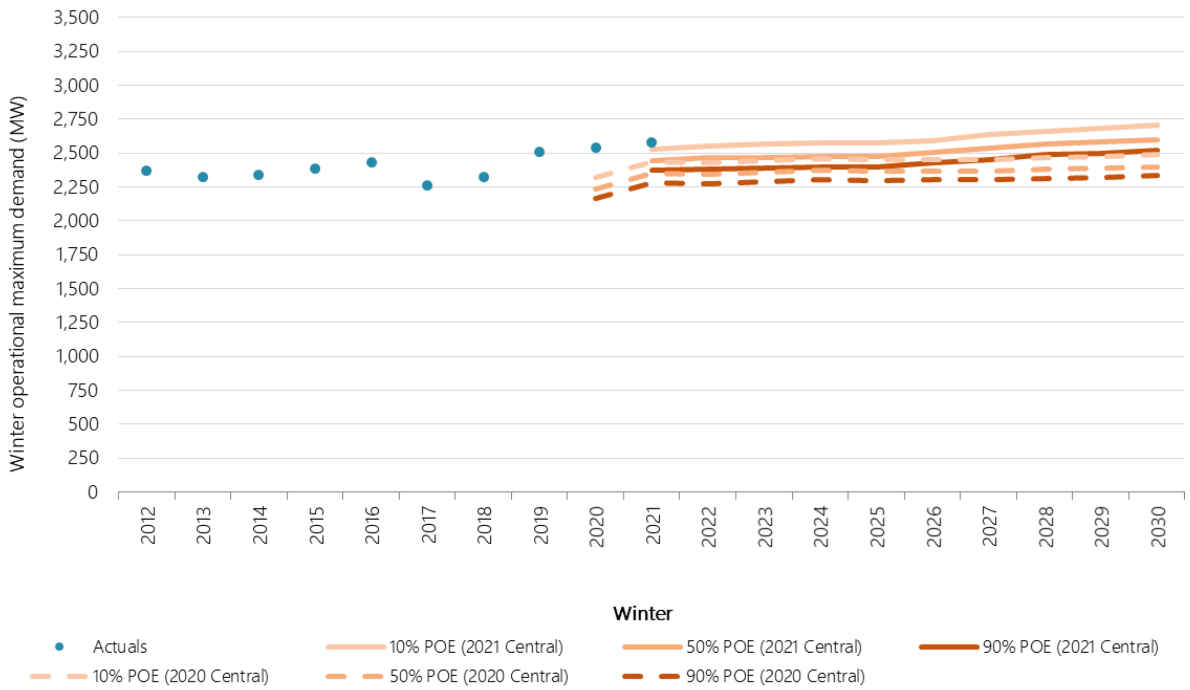
Figure 10 Summer operational maximum demand (sent-out) actual and forecast for South Australia, 10%/50%/90% POE (Central scenario), 2013-13 to 2030-31



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

27 At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/accuracy-report/forecast-accuracy-report-2020.pdf.

Figure 11 **Winter operational maximum demand (sent-out) actual and forecast for South Australia, 10%/50%/90% POE (Central scenario), 2012 to 2030**



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

Impact of distributed PV on underlying maximum demand

Table 3 shows estimated distributed PV generation at 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 substantially year on year in this time, while contribution at time of operational maximum demand is declining .

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

Financial Year	Distributed PV estimated contribution to underlying maximum demand (MW)	Date and time of underlying maximum demand (Adelaide time)	Distributed PV estimated generation at the time of operational maximum demand (MW)	Date and time of operational maximum demand (Adelaide time)
2016-17	261	8/2/2017 5:30 PM	96	8/2/2017 7:00 PM
2017-18	312	19/1/2018 5:30 PM	15	18/1/2018 8:00 PM
2018-19	367	24/1/2019 5:30 PM	21	24/1/2019 8:00 PM
2019-20	599	20/12/2019 1:00 PM	27	19/12/2019 8:00 PM
2020-21	742	11/1/2021 3:00 PM	17	18/2/2021 8:00 PM

Table 4 shows this data for winter maximum demand; 10 June 2020 saw below average temperatures across South Australia with Parafield airport breaking a 74-year-old record with a minimum temperature of -2.4°C. These colder than average temperatures lasted until 12 June 2020, causing higher than average underlying demand during these days. Normally, 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 estimated contribution to underlying maximum demand (MW)	Date and time of underlying maximum demand (Adelaide time)	Distributed PV estimated generation at the time of operational maximum demand (MW)	Date and time of operational maximum demand (Adelaide time)
2017	0	3/7/2017 7:30 PM	0	3/7/2017 7:30 PM
2018	0	26/6/2018 8:00 PM	0	26/6/2018 8:00 PM
2019	0	24/6/2019 7:30 PM	0	24/6/2019 7:30 PM
2020	441	10/6/2020 10:00 AM	0	7/8/2020 8:00 PM
2021	0	22/7/2021 7:30 PM	0	22/7/2021 7:30 PM

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

Demand side participation (DSP)

For 2021 forecasting reports, AEMO updated its estimate of DSP (also called demand response) responding to price and reliability signals[28]. In South Australia, it includes a small (4 MW) contribution from the October 2021 introduction of Wholesale Demand Response (WDR), based on early indications from potential WDR providers to AEMO.

The WDR mechanism is being implemented following a June 2020 Australian Energy Market Commission (AEMC) Rule change. It will allow demand side (or consumer) participation in the wholesale electricity market at any time, most likely at times of high electricity prices and electricity supply scarcity. Demand Response Service Providers (DRSPs) will classify and aggregate the demand response capability of large market loads for dispatch through the NEM's standard bidding and scheduling processes.

There has been a noticeable reduction of estimated DSP capacity in South Australia compared to what was forecast last year (up to 61 MW). This is attributable to improved baseline models created for the region this year, which showed the 2020 DSP forecast for that region was over-forecast.

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

Trigger	Summer 2021-22 (MW – cumulative for each price band)	Winter 2022 (MW – cumulative for each price band)
>$300 / MWh	4	4
>$500 / MWh	12	12
>$1000 /MWh	14	14
>$2500 /MWh	18	18
>$5,000 / MWh	23	23
>$7,500 / MWh	33	33
Reliability response	33	33

* Reliability response refers to situations where an actual Lack of Reserve (LOR 2 or LOR 3) is declared.

[28] DSP has been estimated using AEMO's DSP methodology. See https://aemo.com.au/consultations/current-and-closed-consultations/demand-side-participation-forecast-methodology-consultation.

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, when temperatures are mild, and around the middle of the day when distributed PV reduces the need for grid-delivered energy.

Table 6 shows minimum operational demand in the past five years.

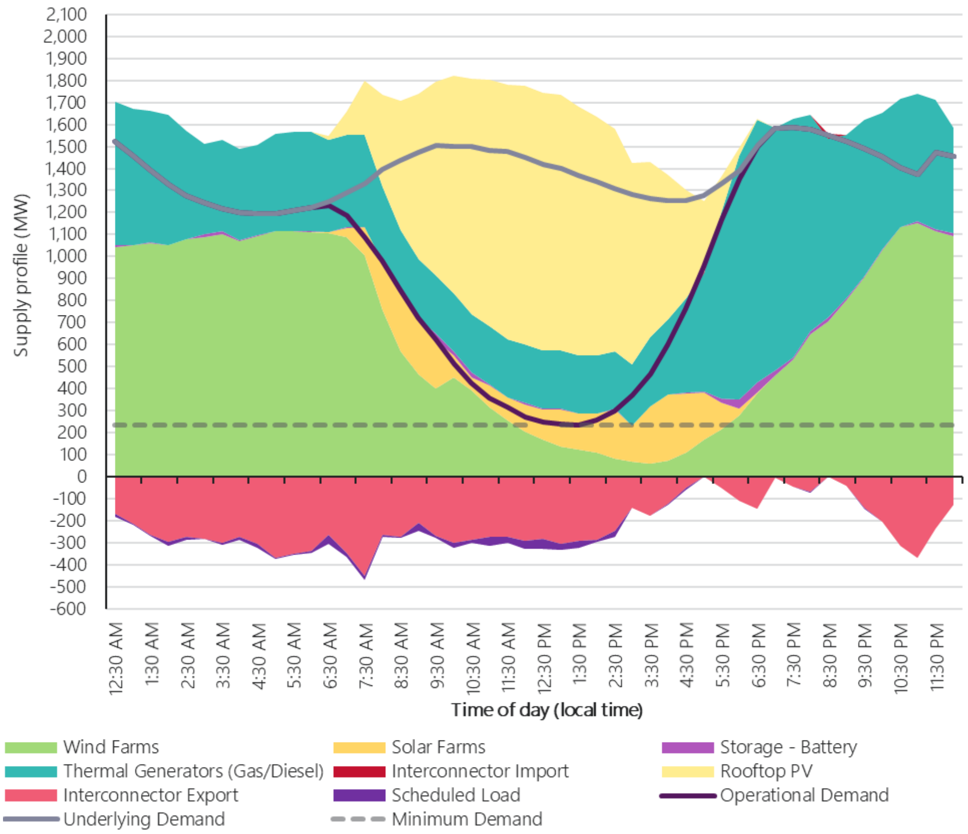
Table 6 Distributed PV contribution to underlying and operational minimum demand in South Australia

Financial year	Date and time of underlying minimum demand	Distributed PV generation at the time of operational minimum demand (MW)	Date and time of operational minimum demand
2016-17	23/4/2017 6:30 AM	471	5/11/2016 2:30 PM
2017-18	22/10/2017 5:30 AM	533	2/10/2017 2:00 PM
2018-19	22/4/2019 6:30 AM	688	21/10/2018 2:00 PM
2019-20	3/11/2019 6:00 AM	890	10/11/2019 2:30 PM
2020-21	11/10/2020 5:30 AM	1,089	11/10/2020 1:30 PM

2.4 Daily demand profiles

A new record low minimum operational demand of 236 MW (as-generated) was set on Sunday, 26 September 2021. This broke the previous year's minimum demand record, set in October 2020. The most recent record, as seen in Figure 12, occurred between 1:00 pm and 1:30 pm (Adelaide time).

Figure 12 Profile of record minimum operational (as-generated) demand day (26 September 2021)



At this time, South Australia was a net exporter, and the peak generation from large-scale solar and rooftop PV was 1,296 MW. This was a clear day, with high solar irradiance for the time of the year and daytime temperatures in the low to mid 20s; being a weekend, commercial and industrial loads were relatively low.

Forecast operational minimum demand

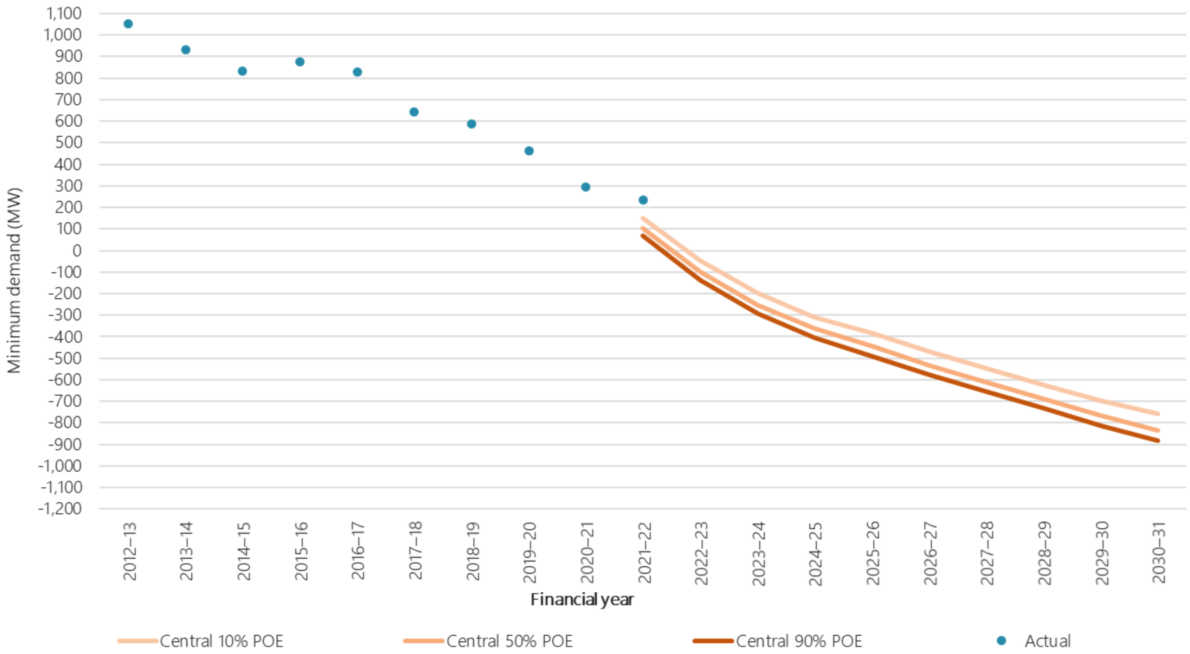
Minimum operational demand is expected to follow the historical reduction and continue to decline rapidly in the short term across all scenarios, primarily driven by the ongoing uptake of distributed PV. The rate of decline is then forecast to be tempered, driven by the increased uptake in EVs, batteries, and electrification, with some of this new load assumed to occur in the middle of the day.

Notably:

- Negative 50% POE minimum operational demand events are expected in South Australia as early as 2022-23 in the Central scenario if distributed PV uptake continues at levels forecast.
- South Australian minimum operational demand levels are forecast to more frequently challenge secure operation of the power system (see Section 6.1).

Figure 13 shows actual and forecast minimum demand in the Central scenario. The 2021-22 actual reflects the most recent record at time of publication (see Figure 12), but may yet be superseded this year (as Table 6 shows, minimum demands have occurred in October and November in the past five years).

Figure 13 Shoulder operational minimum demand (sent-out) actual and forecasts for South Australia, 10%/50%/90% POE (Central scenario), 2012-13 to 2030-31



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

The average daily demand profiles in the SAER 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 changes in consumption patterns. Only South Australian workdays have been included in the analysis. Weekends and gazetted public holidays were excluded.

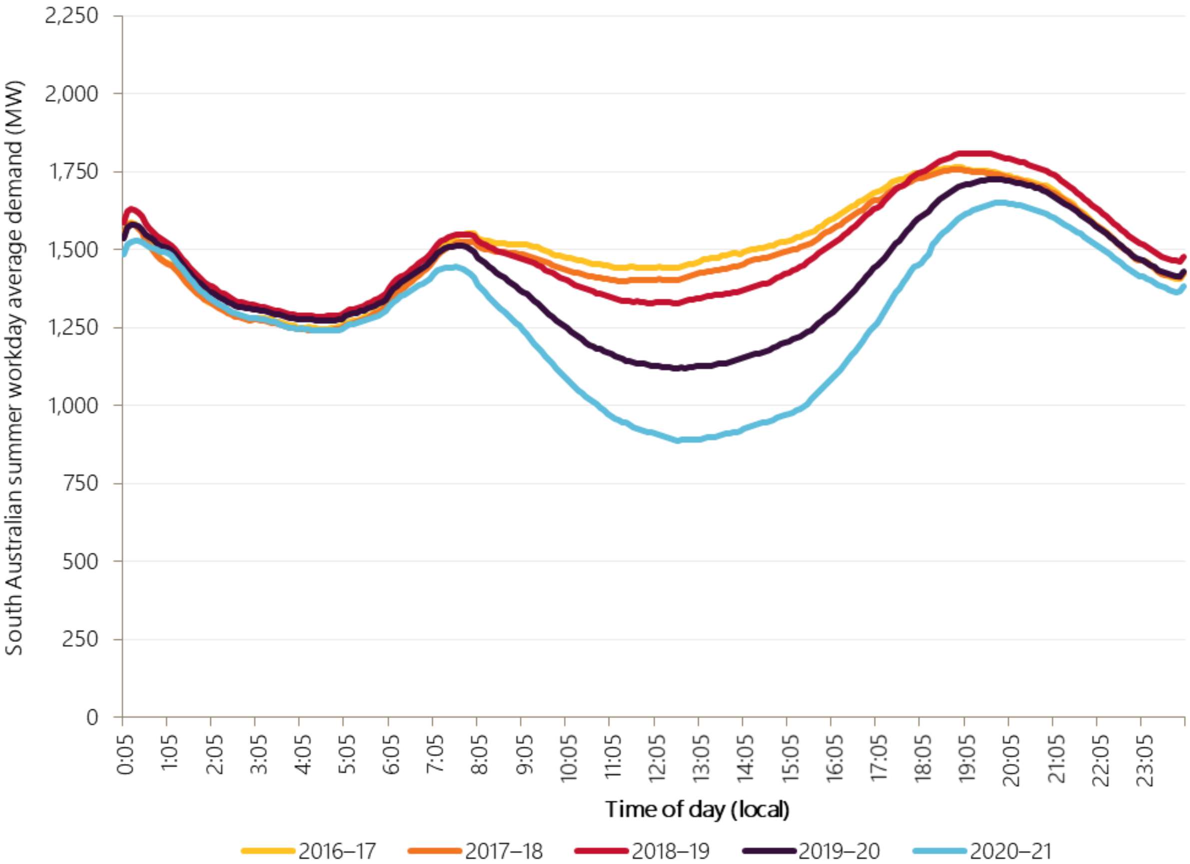
Average daily demand profiles for shoulder and winter periods have not changed markedly since the 2020 SAER, and the observations and insights to be drawn from them remain the same:

- Increasing distributed PV installation plays a large role in shaping operational demand.

- The sharp uptick from 11:30 pm, due to the controlled switching of electric hot water storage systems, remains, although some systems have been moved to turn on in the middle of the day, either by SA Power Networks or by retailers as smart meters are being installed, lowering the night-time peak.

In the summer period (November to March), average demand continued to fall during daylight hours in 2020-21. The 18% decrease in average demand between 10.00 am and 4.00 pm compared to 2019-20 (see Figure 14) can be attributed to the 2020-21 summer being much milder in temperature compared to previous summers, as well as the ongoing trend for increases in rooftop PV to reduce operational demand in the middle of the day.

Figure 14 Summer workday average demand profiles



Data source: Summer, shoulder, and winter daily average demand curves can be found in the 2021 SAER datafiles.

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, batteries and solar dominate proposed new projects. The total installed registered capacity of 7,845 MW in 2020-21 is slightly lower than the previous year, while an additional 13,170 MW of capacity has been committed, anticipated or proposed, 23.4% of which is battery storage and VPPs. South Australia was a net importer from Victoria for the first time since 2016-17.

3.1 Generation and storage

For more:

Generation information, October 2021 update, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

2021 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 April 2021, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions. To be updated as new forecasts become available.

The SAER follows the Generation Information Page categorisation of generation and storage:

- **Existing** generation and storage.
- **Committed** projects, that meet all five of AEMO's commitment criteria[29] 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[30]. These projects are included in reliability assessments and integrated system planning.
- **Anticipated**[31] projects 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 are other projects that have not yet progressed far enough towards meeting commitment criteria to be included in modelling for either reliability or system planning.

3.1.1 Existing generation and storage

Table 7 shows all generation and storage capacity in South Australia at the end of 2020-21. This includes a limited number of new solar and storage projects and no new wind projects.

Table 7 South Australian registered capacity and local generation by energy source in 2020-21

Energy source	Registered capacity		Electricity generated	
	MW	% of total	GWh	% of total
Gas	2,681	34%	5,226	37%
Wind	2,141	27%	5,738	41%
Diesel + other non-scheduled generation (ONSG)	598	8%	78	0.6%
Rooftop PV	1,651	21%	1,925	14%
PVNSG	151	1.9%	248	1.8%
Large-scale solar	411	5%	673	5%
Storage – Battery	212	2.7%	85	0.6%
Total	**7,845**	**100%**	**13,973**	**100%**

[29] 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.

[30] In the Generation Information, 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.

[31] Anticipated projects are those that are sufficiently progressed towards meeting at least three of the five commitment criteria used by AEMO to determine commitment status. Typically, anticipated projects are included in integrated system planning, but not in reliability assessments.

Table 8 shows the differences in generation between 2019-20 and 2020-21, including interconnector flow metrics. With declining operational consumption observed in 2020-21, GPG also declined from 43% to 37% of total generation between 2019-20 and 2020-21. Wind generation remained steady, but now represents the largest source of energy. Rooftop PV and large-scale solar slightly increased their shares of total generation (from 12% to 14% and 3% to 5%, respectively).

GPG 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 many of the Torrens Island GPGs, imports have increased by 25.2%. System security constraints added to the requirement for remaining GPG operation, as this generation continued to provide critical services for the power system. The need to use GPG for these services is likely to decline in future following the installation and testing of synchronous condensers (see Section 6.2).

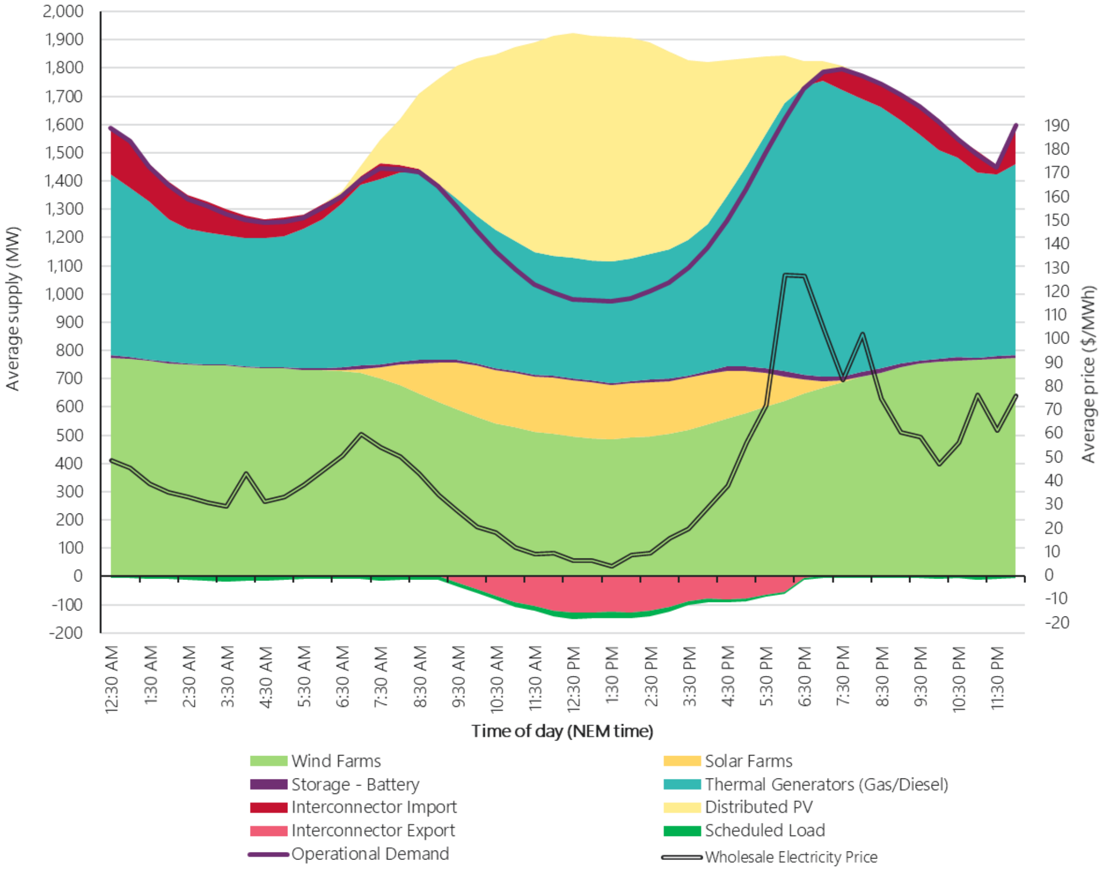
Table 8 South Australian electricity generation by fuel type (GWh), comparing 2019-20 to 2020-21

Supply source	2019-20 (GWh)	2020-21 (GWh)	Change (GWh)	Percentage change (%)	2019-20 percentage share (%)	2020-21 percentage share (%)	Change in percentage share (%)
Gas	6,278	5,226	-1,052	-16.8%	42.9%	37.4%	-5.5%
Wind	5,798	5,738	-60	-1.0%	39.7%	41.1%	1.4%
Diesel + ONSG	62	78	16	25.7%	0.4%	0.6%	0.1%
Rooftop PV	1,692	1,925	233	13.8%	11.6%	13.8%	2.2%
PVNSG	258	248	-10	-3.7%	1.8%	1.8%	0.0%
Solar	485	673	188	38.7%	3.3%	4.8%	1.5%
Storage – Battery	47	85	38	80.3%	0.3%	0.6%	0.3%
Total	**14,620**	**13,973**	**- 647**	**- 4.4%**	**100.0%**	**100.0%**	
Interconnector net imports	- 413	123	536	-129.8%			
Interconnector total imports	916	1,147	231	25.2%			
Interconnector total exports	1,329	1,023	-306	-23.0%			

Figure 15 shows the average daily supply profile observed across 2020-21.

While each actual day varied subject to actual consumer demand, wind, and solar output, the profile clearly shows an averaged intra-day profile defined by daylight hours. During daylight hours, South Australia is, on average, a net exporter, and is otherwise, 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 15 Daily supply profile, 2020-21



3.1.2 Changes in generation and storage over the last five years

Changing composition of generation over past five years

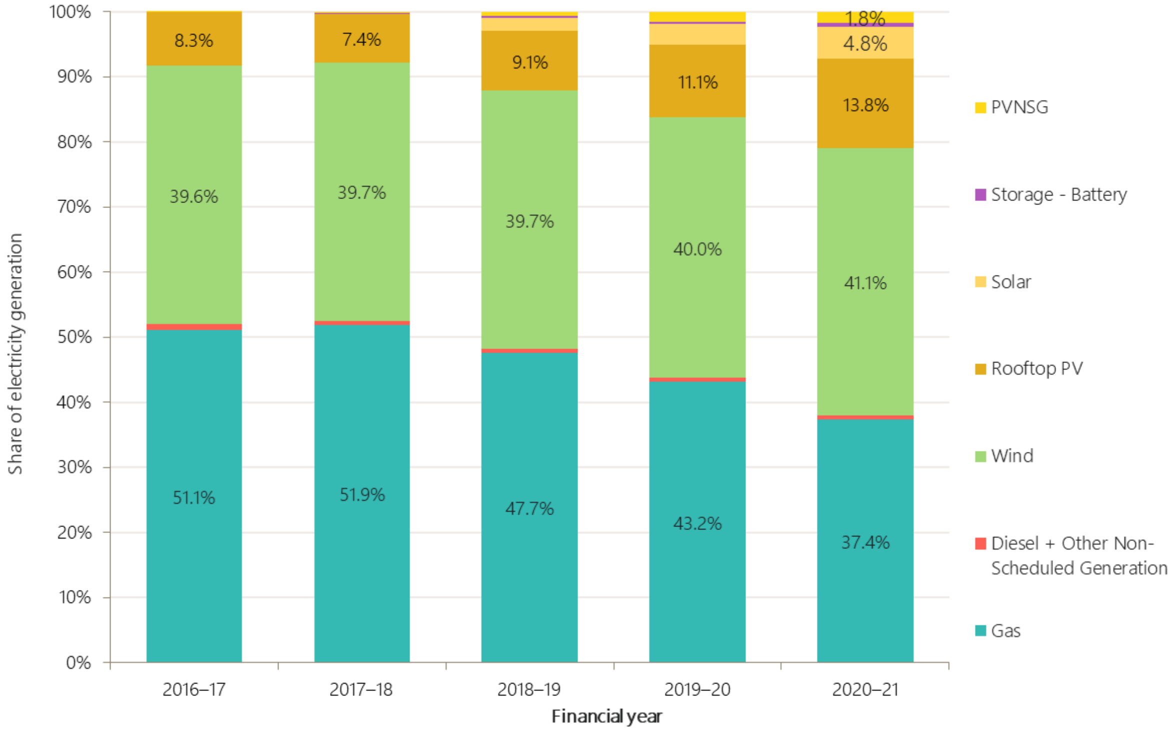
Figure 16 shows the mix of energy generated in South Australia by fuel type[32] from 2016-17 to 2020-21, from:

- All scheduled generators, including storage.
- All semi-scheduled and market non-scheduled wind farms.
- All semi-scheduled solar farms.
- Selected smaller market and non-market non-scheduled generators (SNSGs).
- Estimated distributed PV.

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.

[32] Generation has been aggregated based on each power station's primary fuel type, and does not capture generation by secondary fuel type.

Figure 16 South Australian electricity generation by fuel type, 2016-17 to 2020-21



Note: Historical percentages may differ from those published in previous years due to updated estimates of distributed PV generation. Only battery generation is included in this figure, with no consideration as to what resources are used to charge the battery. Batteries are net system loads over time.

Wind generation changes

After several years of growth, wind generation capacity in South Australia has not changed since 2018-19, as shown in Table 9, although available capacity continued to increase as hold points on Lincoln Gap Wind Farm have been gradually lifted during commissioning. 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 2020-21

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 (102.4 MW), Waterloo expansion (19.8MW)	1,541	82.39
2017-18	1,810	Hornsdale Stage 3 (112 MW)	1,618	86.00
2018-19	2,141	Lincoln Gap** (212.4 MW), Willogoleche (119.36 MW)	1,713	87.81
2019-20	2,141	N/A	1,823	47.39
2020–21	2,141	N/A	1,826	31.19

* Data is captured from when each wind farm was entered into AEMO systems, and includes the commissioning period.
** This table reports registered capacity. Lincoln Gap Wind Farm's registered capacity is 212.4 MW, as reported here. The current (October 2021 Generation Information) nameplate capacity is 126 MW, with the remaining 86.4 MW to be completed by February 2022.

Large-scale solar generation changes

From no large-scale solar generation before 2017-18, South Australia's solar capacity tripled from 2017-18 to 2020-21, 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 2020-21

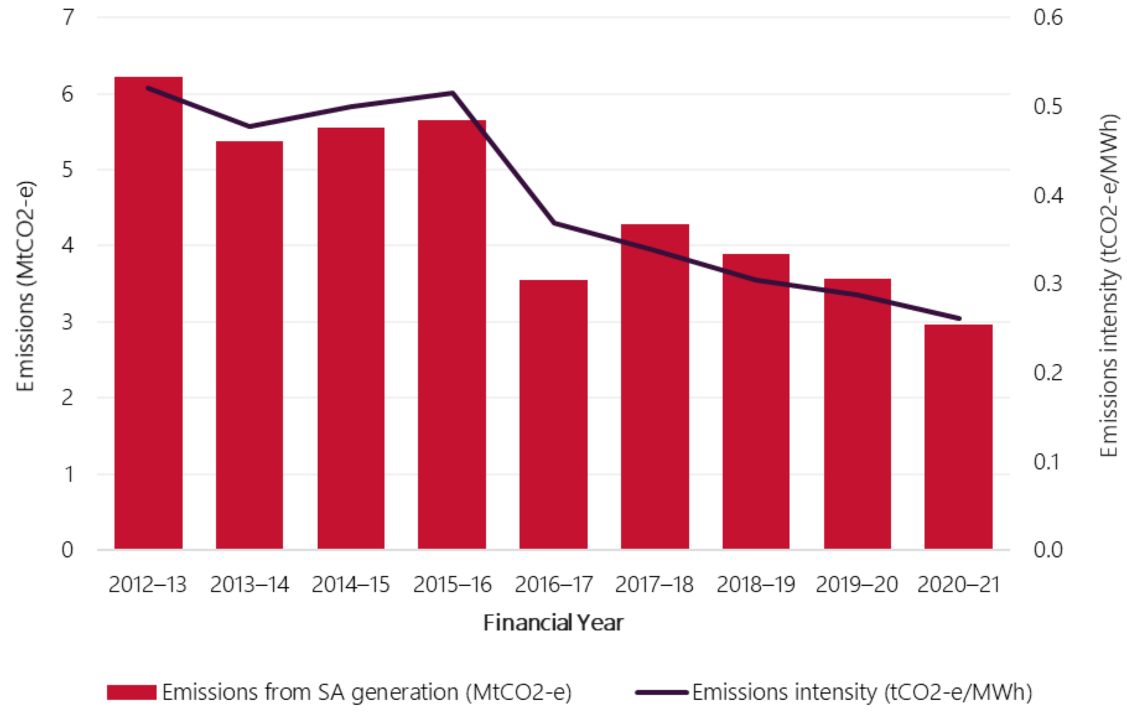
Financial year	Registered capacity (MW)*	Reason for increase in capacity	Maximum five-minute aggregate large-scale solar generation (MW)*	Volume-weighted price ($/MWh)
2017-18	135	Bungala One Solar Farm (135 MW)	31	98.48
2018-19	378	Bungala Two Solar Farm (135 MW), Tailem Bend Solar Project 1 (108 MW)	209	130.36
2019-20	378	N/A	227**	55.64
2020-21	411	Adelaide Desalination Plant (11 MW), Morgan-Whyalla Pipeline Pumping Station No. 1- No. 4 (22 MW)	326**	21.92

* 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.

3.1.3 Recent emissions intensity history

Annual NEM emissions intensity, measured as the Carbon Dioxide Equivalent Intensity Index (CDEII), continued to decline, with emissions at their lowest level during the 2020-21 financial year[33] in South Australia, as Figure 17 shows.

Figure 17 South Australian annual emissions and emissions intensity, 2012-13 to 2020-21



Notably:

- Total emissions from South Australian generation in 2020-21 decreased 0.6 metric tonnes (or 17.2%) compared to 2019-20. This reduction was due to decreased local GPG.

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

- Emissions intensity reduced by 9.8% from 0.29 t/MWh in 2019-20 to 0.26 t/MWh in 2020-21, the lowest levels to date. This change reflects increased penetration of rooftop PV and large-scale solar. The wider NEM has also been seeing reductions in emissions intensity since the peak in 2014-15, with NEM emissions intensity reaching its lowest levels to date in 2020-21 (0.70 t/MWh)[32].

3.1.4 Expected changes in generation and storage

Table 11 summarises combined nameplate capacity data, by energy source, for all scheduled, semi-scheduled, and non-scheduled generation in South Australia[34] that is currently (at October 2021) 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).
- Been proposed.

The key generation and storage forecast trends highlighted by this data, and by AEMO's 2021 South Australian Generation Forecasts[35], are:

- The amount of forecast generation beyond 2022-23 will be influenced by the announced retirement of existing assets, the development of currently proposed projects, and the potential for increased demand (in scenarios with high economic growth, high electrification and/or hydrogen industry growth) driving new generation investment.
- **Wind generation** is forecast to increase in the near term due to the commissioning of Lincoln Gap Wind Farm Stage 2, planned for full commercial use by February 2022. While solar development has been dominant in the last few years, there are more committed and anticipated wind projects than solar in the near term.
- **Large-scale solar** generation is forecast to increase in the near term due to commissioning of new projects. The forecast degree of growth beyond this point varies between scenarios depending on future demand growth.
- The most notable change since last year is the volume of developer interest in **large-scale battery** projects. The capacity of proposed (but not yet anticipated or committed) battery storage has increased in the past year to now exceed 2,700 MW.
- **Gas and diesel generation** is forecast to decrease relative to history. This is driven by a combination of factors: the retirement of Torrens Island A and Osborne power stations, the commissioning of new VRE, the commissioning of Project EnergyConnect (PEC), and the relaxation of system strength requirements as synchronous condensers are delivered (see Section 6.2).
- **Rooftop PV and PVNSG generation** are forecast to continue increasing over the next decade (see Section 2.1.2).

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[34] 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.

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

Table 11 Capacity of existing or withdrawn generation, and committed, anticipated and proposed projects (MW) at 15 October 2021

Status	CCGT[A]	OCGT[B]	Gas other	Solar[C]	Wind	Water	Biomass	Storage – battery and VPP	Other	Total
Existing[D]	713.4	1,266.6	1,130.0	416.0	2,053.3	3.2	18.2	205.5	178.9	**5,985.1**
Announced withdrawal[E]	180.0	-	120.0	-	-	-	-	-	-	**300.0**
Existing less announced withdrawal	533.4	1,266.6	1,010.0	416.0	2,053.3	3.2	18.2	205.5	178.9	**5,685.1**
Upgrade	-	15.0	-	-	-	-	-	-	-	**15.0**
Committed	-	154.0	-	11.0	86.4	-	-	17.3	-	**268.7**
Anticipated	-	-	-	164.5	210.0	-	-	268.3	-	**642.8**
Proposed	-	743.2	45.0	3,681.1	3,875.4	1,120.0	-	2,793.0	-	**12,257.7**
Withdrawn	-	-	120.0	-	-	-	-	-	-	**120.0**

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 15 October 2021.
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 2021-22 – for both peak and typical temperatures – and for winter 2022.
- How this expected capacity compares with the capacity available last summer, in peak and typical temperatures, and in winter 2021.

Notable changes since last summer include the decommissioning of additional Torrens Island units A Unit 1 (see details in 'Generation withdrawals' section below table) 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.

Table 12 **Scheduled, semi-scheduled, and significant non-scheduled generation available capacity, summer (peak and typical) 2020-21 and 2021-22 and winter 2021 and 2022**

Energy source	Summer peak available capacity[A] (MW)		Summer typical available capacity (MW)[D]		Winter available capacity[A] (MW)	
	2020-21	2021-22	2020-21	2021-22	2021	2022
Diesel (scheduled)[B]	331	463	353	492	388	418
Gas (scheduled)	2,369	2,057	2,451	2,136	2,605	2,290
Wind (semi-scheduled)	1,375	1,345	1,659	1,745	1,681	1,745
Wind (significant non-scheduled)[C]	386	386	386	386	386	386
Solar (semi-scheduled)	329	332	337	346	347	347
Storage – battery (scheduled)	205	205	205	205	205	211
Total	**4,995**	**4,788**	**5,391**	**5,310**	**5,612**	**5,397**

A. AEMO Generation Information for South Australia, published 15 October 2021.
B. Excludes SA Temporary Generation North diesel generator (Chapter 4 has details of this generation's status in reliability forecasts).
C. Available capacity for wind farms classed as significant non-scheduled is based on nameplate rating, since 10-year availability forecasts are not provided to AEMO for these units.
D. Summer typical available capacities were introduced in the July 2020 Generation Information update and represent the capacity available over summer during typical temperatures.

Generation withdrawals

- Torrens Island A unit 2 (120 MW) and unit 4 (120 MW) were closed (decommissioned and deregistered) on 30 September 2020.
- Torrens Island A unit 1 (120 MW) was closed (decommissioned and deregistered) on 30 September 2021.
- Torrens Island A unit 3 (120 MW) was mothballed on 30 September 2021[36] with plans to close on 30 September 2022[37,38].
- Torrens Island B unit 1 (200 MW) was mothballed on 30 September 2021 with plans to return to service 1 October 2024.
- Osborne Power Station is expected to close by 31 December 2023.

Committed developments

As of 15 October 2021[39], 11 MW of VPP projects, 154 MW of diesel, and approximately 86 MW of new wind, 6 MW of new battery storage, and 11 MW of new solar generation projects are committed in South Australia:

- Adelaide Desalination Plant – (11 MW of solar and 6.27 MW of battery storage), due to be operational by December 2021.
- SA Government VPP – Stage 2 (5 MW).
- Simply Energy VPP (6 MW/16 MWh).

[36] After being mothballed, this unit will remain registered and available for service on six-month recall until its closure date, when it will be decommissioned and deregistered.

[37] See change log, 15 October 2021, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[38] See the generation expected closure years, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[39] Date based on latest (October 2021) 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.

- Lincoln Gap Wind Farm Stage 2[40] (86.4 MW), due to be operational by February 2022.
- Snapper Point Power Station (previously South Australia Temporary Generation North, 154 MW), which is scheduled to be operational before summer 2021-22. Due to being considered Committed* (as per AEMO's consulted on commitment criteria), it was not modelled in the ESOO as available until July 2023[41].
- Temporary Generation South (123.2 MW) was modelled in the ESOO to remain at its current site for the next 10 years, as the proposed turbine transfer to the Bolivar site was not yet considered Committed or Anticipated in the July 2021 Generation Information publication.

Anticipated developments

As of 15 October 2021[42], approximately 210 MW of new wind, 268 MW of new battery storage, and 164 MW of new solar generation projects are classed as anticipated in South Australia:

- Port Augusta Renewable Energy Park (210 MW of wind, 79.2 MW of solar).
- Adelaide Desalination Plant – Solar – 1 (13.72 MW).
- Bolivar Wastewater Treatment (11.25 MW of solar, 2.46 MW battery storage).
- Christies Beach Wastewater Treatment Plant (4.8 MW of solar, 2.09 MW of battery storage).
- Happy Valley Reservoir (8.34 MW of solar, 3.78 MW of battery storage).
- Lincoln Gap Wind Farm Battery Energy Storage System (BESS) (10 MW).
- Mannum Adelaide Pumping Station No. 2 and No. 3 (33.42 MW of solar).
- Murray Bridge – Onkaparinga Pipeline Pump 2 – Solar (13.74 MW).
- Torrens Island BESS (250 MW of battery storage).

Other proposed developments

As at 15 October 2021, AEMO's Generation Information update reported 66 proposed electricity generation and storage developments that are neither committed or anticipated in South Australia, totalling 12,258 MW.

Table 13 aggregates these developments by energy source, showing the volume of connection interest within South Australia.

Given the increasing penetration of renewable generation, there will be growing value in generation technologies that can complement the natural variability of renewable generation 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, through the Home Battery Scheme, 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 15 October 2021[43], 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 (1,200 MW of wind, 600 MW of solar, and 900 MW of battery storage).
- Yorke Peninsula Wind Farm (up to 636 MW).

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[40] Lincoln Gap Wind Farm (registered capacity 212.4 MW) currently has a nameplate capacity of 126 MW, with an additional 86.4 MW to be completed by February 2022, as reported on AEMO's Generation Information Page, 15 October 2021.

[41] AEMO's ESOO and Reliability Forecast Methodology specifies that Committed* projects will be modelled to start on the later of the first day after the end of the "T-1 financial year" defined under the RRO, or the actual commercial use date submitted by the proponent. See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2021/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

[42] Date based on latest (October 2021) 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.

[43] Date based on latest AEMO Generation Information Page at 15 October 2021. 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.

- Palmer Wind Farm (375 MW).
- Pelican Point S2 (320 MW natural gas).
- Templers BESS (GreenPower) (315 MW).
- Woakwine Wind Farm (up to 304 MW).
- Bridle Track Solar Project (300 MW).
- Highbury Pumped Hydro Energy Storage (300 MW).
- Bungama Solar (280 MW).
- Cultana Solar Farm (280 MW).
- Riverland Solar Storage (253 MW).
- Lincoln Gap Wind Farm stage 3 (252 MW).
- Baroota Pumped Hydro (250 MW).
- Geranium Plains Solar Farm and BESS (250 MW of solar, 150 MW of battery storage).
- Kanmantoo Hydro (250 MW).
- SA Government VPP – stage 3 (245 MW).
- Goat Hill Pumped Hydro (230 MW).
- Para Substation/Gould Creek BESS (200 MW).
- Bungama BESS (200 MW).
- Templers BESS (GreenPower) (200 MW).

Table 13 shows that since the November 2020 Generation Information (in the 2020 SAER) there has been an increase of 2,347 MW of capacity proposed in South Australia. However the total number of proposed projects has fallen by one. A number of projects that were considered proposed last year are now committed developments, but some new larger proposed projects have been added, offsetting this change.

Table 13 South Australian proposed generation projects by energy source, as of 15 October 2021

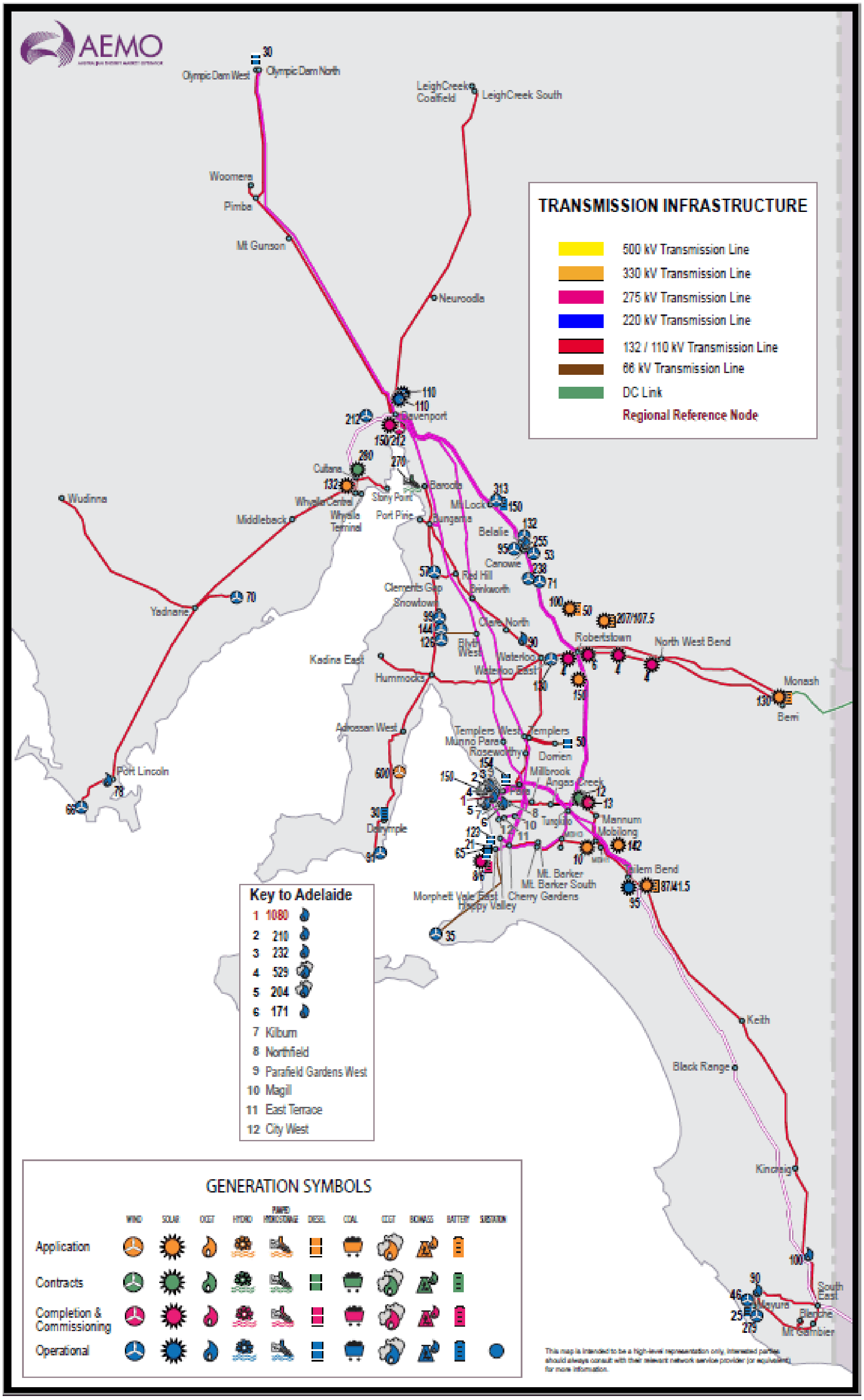
Energy source	Number of projects	Capacity (MW)	Capacity (% of total projects tracked)	Change in number of projects from November 2020	Change in capacity from November 2020 (MW)
Gas	6*	803.2	6.5%	0	0
Diesel	0	0	0.0%	-1	-154.0
Solar	25	3,681.1	30.0%	-4	898.1
Biomass	0	0	0.0%	0	0.0
Wind	12	3875.4	31.6%	1	252.0
Water	5	1,120.0	9.1%	0	125.0
Storage – battery and VPP	19	2,793.0	22.8%	5	1,225.4
Total	**67**	**12,272.7**	**100%**	**1**	**2,346.5**

Since the July 2021 Generation Information, proposed projects that are scheduled or semi-scheduled and are sufficiently progressed towards meeting at least three of the five commitment criteria are assigned a commitment status of anticipated for ISP purposes. This status did not exist for previous SAERs. Anticipated projects, outlined on the previous page, are not included in Table 13.* Gas projects include an upgrade to Quarantine Power Station of 15 MW and Temporary Generation South (Bolivar) of 123.2 MW

3.1.5 Location of South Australian generation and storage

Figure 18 shows the locations of existing and proposed projects in the state, with existing transmission[44].

Figure 18 Locations of generation and storage in South Australia



[44] This map version is dated October 2021, and uses October 2021 Generation Information update data. 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.

3.2 Gas-powered generation

For more:

2021 GSOO, at http://aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

2021 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 GPG declining since 2018, and last summer hit near-record low volumes of GPG. Wind replaced gas as the largest energy source last year. The pressure of lower spot and forward wholesale prices on GPGs (see Section 5.2) was also evident in the July 2021 announcement that one of four units at Torrens Island Power Station B would be mothballed from October 2021[45].

In the short term, consistent with the 2021 GSOO forecast, AEMO's latest projections show South Australian GPG continuing to trend downwards, even more significantly than previously anticipated, driven by:

- Reducing underlying energy consumption and peak demand.
- Growing share of local renewable generation, particularly distributed PV, which continues to reduce operational demand.
- Growing imports from Victoria as new variable renewable energy (VRE) generation capacity comes online in that region, driven by state policy.
- Relaxing of system strength requirements as synchronous condensers are delivered.
- Declining GPG capacity due to the complete withdrawal of Torrens Island A (September 2022) expected retirement of Osborne Power Station in December 2023, and mothballing of one unit of Torrens Island B Power Station from October 2021[46].

In the medium and long term, the GPG outlook is more uncertain. Since the 2021 GSOO there have been several changes in market conditions which have the potential to materially influence GPG, most notably, the introduction of the *New South Wales Electricity Infrastructure Investment Act* (New South Wales Roadmap) which will drive a significant uptake of VRE and storage capacity over the next decade.

PEC, the new interconnector between South Australia and New South Wales, is expected to start operation in 2025-26 and will allow the sharing of more resources across the NEM. With stronger interconnection and increasing VRE penetration, it is anticipated that at times of supply surplus in New South Wales, South Australia will benefit from low-cost imports. This could further erode GPG volumes in South Australia, particularly from mid-merit gas generators. PEC will also end the requirement to maintain a minimum number of synchronous units online at all times. This is forecast to result in lower GPG generation, although the magnitude of this reduction will ultimately depend on strategic behaviour of generators.

On the other hand, state policies such as the New South Wales Roadmap, the Victorian Renewable Energy Target (VRET), and the Tasmanian Renewable Energy Target (TRET) are accelerating the transition of the NEM, which could result in faster withdrawal of coal generation. Earlier than expected coal closures, particularly in Victoria and New South Wales, might temporarily increase reliance on existing South Australian GPG. An even greater contribution from GPG could be required in the event of prolonged coal outages, as well as during seasonal coal mothballing. The timing and scale of transmission developments and availability of alternative dispatchable technologies will impact the GPG outlook.

AEMO's latest projections also anticipate an accelerated interest in hydrogen production and greater electrification, as well as stronger EV uptake, which will have a material impact on demand outlook and therefore potentially GPG. These drivers will be explored in detail as part of the 2022 ISP and 2022 GSOO.

[45] See https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2021/july/agl-to-mothball-one-unit-at-torrens-b-in-south-australia?zcf97o=vlx3ap.

[46] The planned recall time for the mothballing will be six months. Return to service is expected in 2024-25 following Osborne Power Station retirement.

More broadly, GPG is forecast to remain an important source of peaking capacity and system security services within South Australia, even if annual GPG volumes decline. Weather variability, extreme weather events, and generation and transmission outages will continue to drive volatility. As the penetration of VRE increases, so too does the variability in GPG generation, 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, GPG (in addition to imports from Victoria) is a vital source in being able to supply load 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

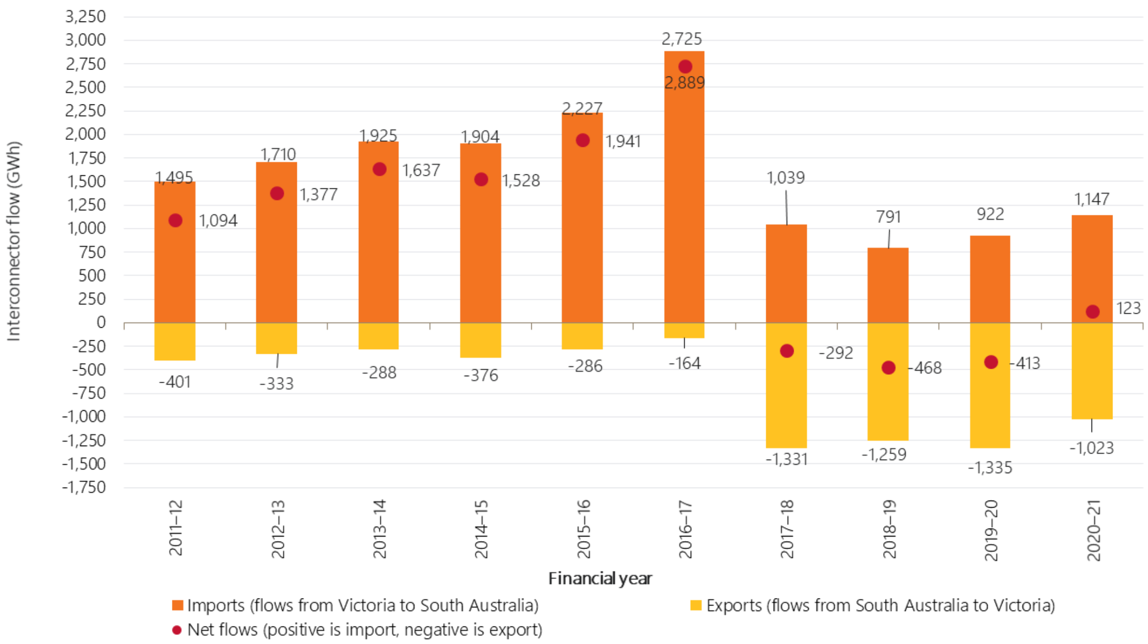
For more:

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 2020-21, South Australia's exports were lower and imports were higher than the previous year, and the state was a net importer for the first time since becoming a net exporter to Victoria in 2017-18, the first full year after Hazelwood Power Station in Victoria retired.

Figure 19 Combined interconnector total imports and exports, and net flows



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 (PEC), a new interconnector linking South Australia and New South Wales (with an added connection to Victoria), involves construction of new double-circuit 330 kV transmission lines between Robertstown, Buronga, Dinawan, and Wagga Wagga, and an additional 220 kV line between Red Cliffs and Buronga. It has completed its regulatory process, and received expenditure approval from the

AER in May 2021. To allow for inter-network testing, AEMO modelled PEC with full capacity available from June 2025[47].

- ElectraNet has reported on these projects within South Australia[48]:
  - South Australia Power System Strength Project (final commissioning and testing underway at time of writing this report), involving the installation of two high inertia synchronous condensers at Davenport and two high inertia synchronous condensers at Robertstown[49].
  - Eyre Peninsula Link, by December 2022. This involves 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, as well as replacement of the existing 132 kV line between Yadnarie and Port Lincoln with a new double circuit 132 kV line[50].

3.3.3 Renewable energy zones (REZs)

The 2021 IASR details the nine candidate REZs in South Australia that will be considered in the upcoming Draft 2022 ISP, due for publication in December 2021[51]. The list of South Australian candidate REZs is unchanged from the 2020 ISP. Appendix 5 of the 2020 ISP provides a set of REZ scorecards, where an assessment of capability and future needs is summarised for each REZ in South Australia. The draft 2022 ISP to be released in December 2021 will include an updated set of REZ scorecards for South Australia.

The 2022 ISP, due to be published in June 2022, will also identify whether any potential REZ transmission development in South Australia may be on the optimal development path within the next 12 years. If so, this would trigger preparation of a REZ design report by ElectraNet, setting out a plan for development of the REZ, including a community impact assessment.

The 2021 Transmission Cost Report[52] supports the IASR and details the transmission network augmentations and associated costs and capacity increases required to support the development of generation within REZs.

4. Reliability of supply

As reported in the 2021 ESOO, South Australia is forecast to meet the reliability standard and the Interim Reliability Measure (IRM) in all of the next 10 years. The commissioning of Snapper Point Power Station, and the commissioning of Project EnergyConnect help maintain reliability well below the IRM once Osborne Power Station retires in 2023-24.

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[47] Further detail about the project is available at https://www.transgrid.com.au/projects-innovation/energyconnect, and the AER's final regulatory approval is available at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/transgrid-and-electranet-%E2%80%93-project-energyconnect-contingent-project. The Australian Government has provided underwriting to enable transmission lines being built from south of Coleambally to Wagga Wagga as part of enabling PEC to be constructed at a larger capacity; see https://www.minister.industry.gov.au/ministers/taylor/media-releases/government-supporting-delivery-critical-transmission-infrastructure-southwest-nsw.

[48] ElectraNet, 2020 Transmission Annual Planning Report, at https://www.electranet.com.au/wp-content/uploads/2020/11/2020-ENet-TAPR.pdf.

[49] 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.

[50] Further information about the project is available at ElectraNet's website, via https://www.electranet.com.au/wp-content/uploads/2020/11/2020-ENet-TAPR.pdf.

[51] See 2021 IASR Section 3.9, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

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

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 Interim Reliability Measure (IRM) of 0.0006%[53] or, from 30 June 2025, the reliability standard of 0.002%[54] .

The assumptions used to develop the 2021 ESOO's reliability forecasts are outlined in AEMO's 2021 IASR[55]. The supply data used in this assessment is from the latest Generation Information update available at the time of ESOO modelling (July 2021 for the 2021 ESOO).

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

Apart from the first year, the 2021 ESOO reliability assessment for South Australia (Central scenario) improved compared to last year's assessment.

The reliability forecast for next summer worsened slightly, primarily due to the announced mothballing of one Torrens Island B unit, but the supply shortfall risk is still forecast to remain below both the reliability standard and the IRM for all years of the Central scenario, as Figure 21 shows.

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

- Between summer 2020-21 and 2021-22, 127 MW of additional VRE generation is expected to become available (measured in summer typical capacity, or the capability of the generating unit during average summer temperatures).
- The 120 MW Torrens Island A Unit 1 has retired, with the 120 MW Torrens Island A Unit 3 mothballed until it is scheduled to retire late 2022.
- One Torrens Island B unit (200 MW) is mothballed from 2021-22 to 2023-24 inclusive.
- The 180 MW Osborne gas generator is expected to retire in December 2023, and is now followed by the modelled connection of 154 MW Snapper Point Power Station (previously Temporary Generation North) in 2023-24.
- Project EnergyConnect, a new interconnector linking South Australia and New South Wales (with an added connection to Victoria) has now passed regulatory approvals and is assumed to commence operations in stages from 2023-24[56]. This is forecast to reduce supply scarcity risks by increasing transfer capacity between New South Wales and South Australia, allowing more resources to be shared across the NEM.
- Several generators are expected to retire in 2030-31, including the 156 MW Dry Creek Power Station, 90 MW Mintaro Power Station, 74 MW Port Lincoln Power Station, 63 MW Snuggery Gas Station, and 30 MW Dalrymple Battery Energy Storage System (BESS).

As Figure 20 shows, the expected USE for South Australia is below both the reliability standard and the IRM during the 10-year modelling horizon for the Central scenario.

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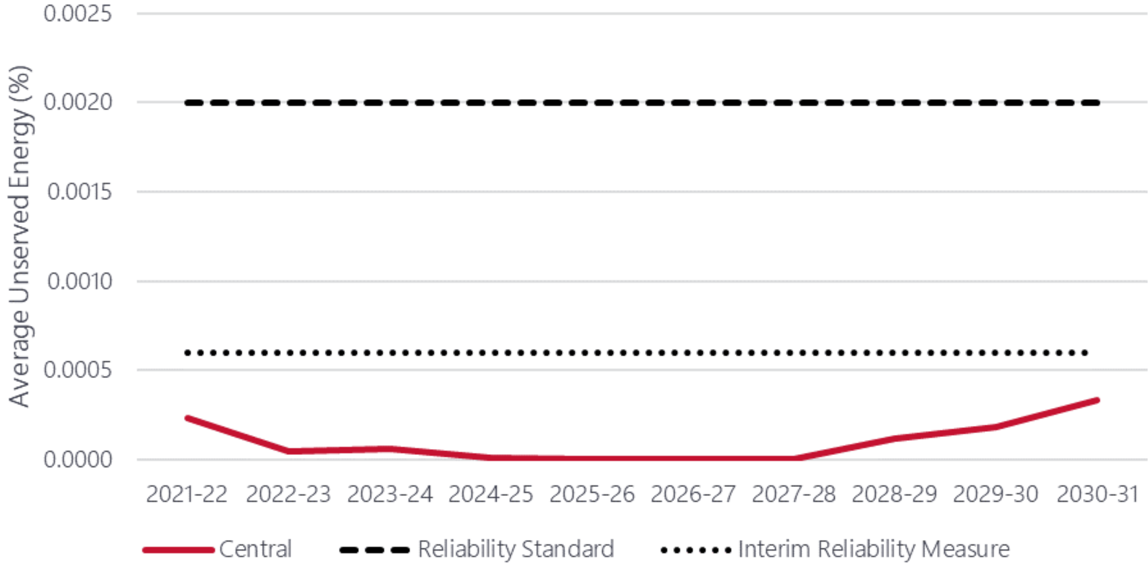
[53] The IRM allows for a maximum expectation of 0.0006% of energy demand to be unmet in a given region per financial year. It was introduced by the National Electricity Amendment (Interim Reliability Measure) Rule 2020 (IRM Rule). The IRM Rule and changes to the Retailer Reliability Obligation (RRO) 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.

[54] 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.

[55] At https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

[56] Based on AER approval of the contingent project application and confirmation of funding by transmission network service providers (TNSPs).

Figure 20 Forecast USE outcomes for South Australia – existing and committed projects only



This reliability assessment includes all existing and committed generation and storage, reported in the Generation Information page published in July 2021, as well as committed and relevant anticipated transmission augmentations[57] and generation retirements. Specifically, this assessment:

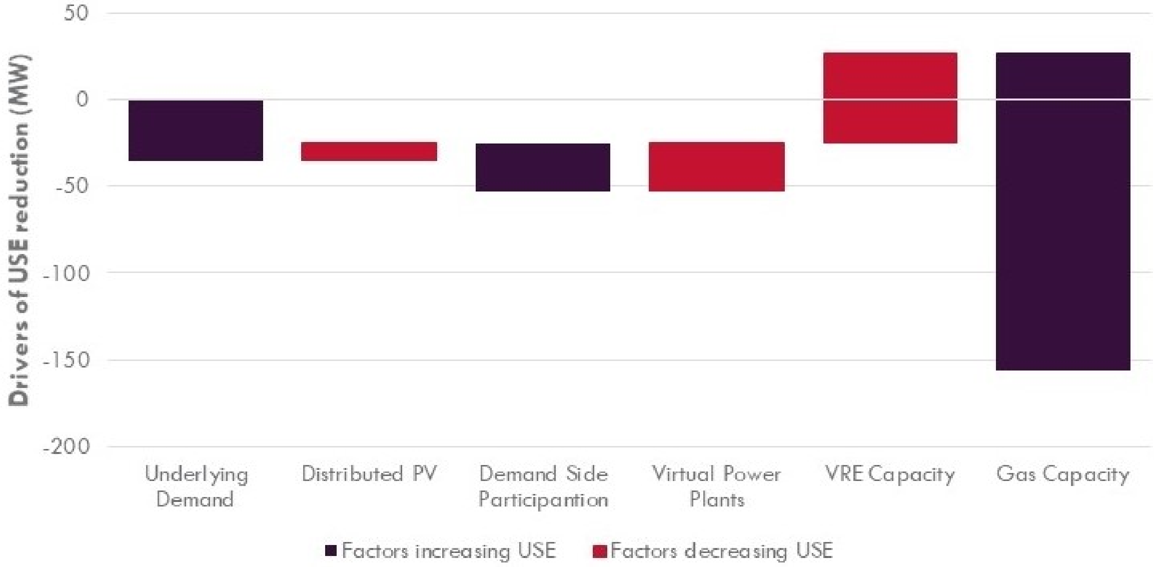
- Does not include major transmission investments that have not yet completed all necessary approvals, including HumeLink (the new transmission development to unlock congestion and enable the full benefits of Snowy 2.0 to be delivered to the NEM).
- Includes the diesel generators in South Australia – Temporary Generation South remaining at the existing site until plans for the new site 'Bolivar' develop further, and includes Snapper Point Power Station from July 2023 onwards (given its status as Committed*).
- Does not include any additional capacity that could be made available through Reliability and Emergency Reserve Trader (RERT)[58].
- Represents USE outcomes before any equitable load shedding principles are applied.

Figure 21 quantifies the main factors that contributed to the slight worsening of the reliability forecast for next summer compared to the forecast last year. In this figure, negative values represent drivers increasing USE, while positive values represent drivers lowering USE. The largest driver of the USE change is the reduction in gas capacity, as expected given the Torrens Island B unit mothballing.

[57] 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.

[58] 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.

Figure 21 Indicative drivers of change in expected unserved energy in South Australia in 2021-22 (2021 ESOO forecast versus 2020 ESOO forecast)

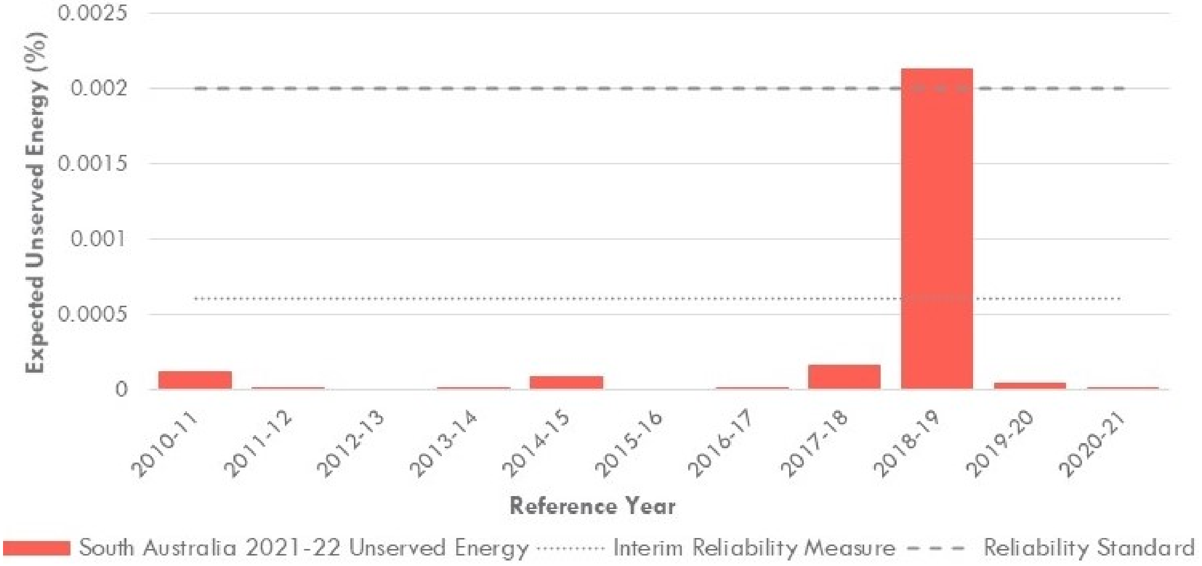


A further investigation into the factors that may lead to USE focuses on the breakdown between historical reference years being modelled. Historical reference years are used to model the impact of weather conditions in time series on wind generation, solar generation, consumer demand patterns, high temperature periods for thermal plant deratings, and some transmission line ratings (those with dynamic line ratings). Variation in expected USE between reference years is due to the relative contribution of VRE during times of high demand, the level of coincidence in demand between regions, or the length of time demands were at near-peak levels, during those years.

Figure 22 shows the level of expected USE forecast in South Australia for the 2021-22 summer in each of the historical reference years. The chart shows that under the weather conditions associated with the 2018-19 reference year, the forecast level of expected USE next summer would exceed both the IRM and the reliability standard. The 2018-19 reference year contains the highest maximum temperature ever recorded for Adelaide Airport (45.8°C on 24 January 2019) coinciding with close to record-level temperatures in Victoria, resulting in high electricity demands across both regions during low VRE conditions. This low VRE output, as observed and modelled, incorporates any potential impact of high temperature deratings.

The newly added 2020-21 reference year, which was a relatively mild summer without frequent high temperature periods that could cause derating, is characterised by below average VRE availability throughout the year but average levels of VRE availability during high demand periods.

Figure 22 Impact of different reference years on expected USE in South Australia 2021-22, Central scenario



4.1.2 Managing reliability risks

RERT for summer 2020-21

During the summer of 2020-21, AEMO had 171 MW of RERT in South Australia available on Short Notice Panel Agreements that could be activated in the event of an actual lack of reserve (LOR) event. No short notice reserves were contracted during summer 2020-21, and no costs were incurred.

RERT for summer 2021-22

As the 2021 ESOO did not project expected USE to exceed the reliability standard or the IRM this summer in any region, no long notice contracts for RERT Reserve will be contracted, unless AEMO receives new information that materially changes the reliability outlook. AEMO is currently considering expressions of interest for Short Notice Panel Agreements in South Australia for the 2021-22 summer.

AEMO expects to enter into agreements for over 80 MW of Short Notice RERT in South Australia this summer. The reduction in Short Notice RERT compared to 2020-21 is because an unscheduled reserve that previously supplied RERT is now being repurposed to participate in the energy market as scheduled and can no longer participate in RERT.

5. Electricity spot price

South Australia's average wholesale electricity price fell to its lowest levels since 2014-15, supplanting Queensland to become the lowest-priced mainland NEM region. The reduction was part of the NEM-wide trend of falling prices, with particularly large reductions in South Australia and Victoria, driven by increased VRE output, improved brown coal availability, and lower-priced hydro offers.

5.1 Historical wholesale electricity prices

South Australia's time-weighted average price (TWAP) in 2020-21 fell to $45/MWh, its lowest average since 2014-15, representing a 28% decrease from 2019-20 (Figure 23). For the first financial year since 2006-07, South Australia was the lowest-priced mainland region, just below Victoria's average of $46/MWh (Table 14).

Figure 23 Average South Australian spot electricity price (real June 2021 $/MWh)

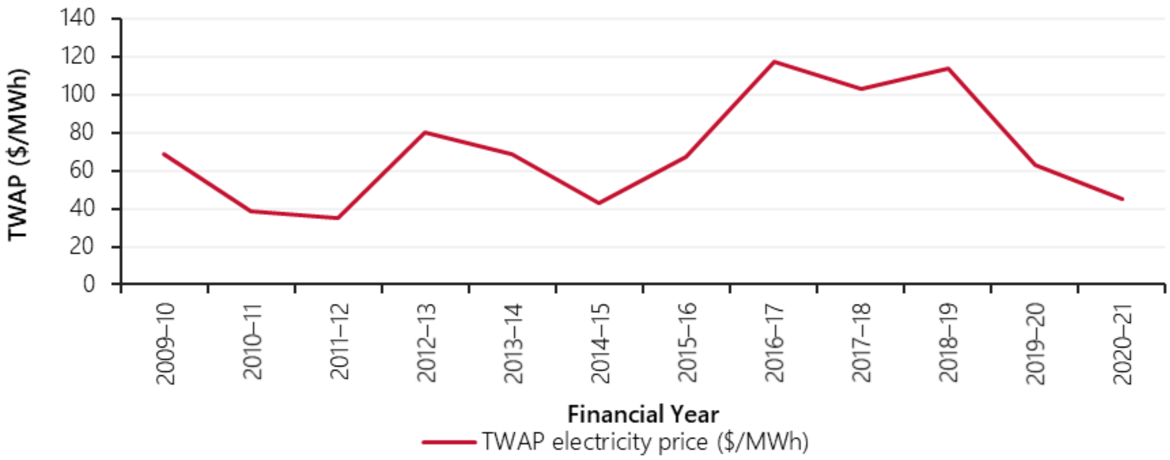


Table 14 2020-21 time-weighted average prices for the NEM

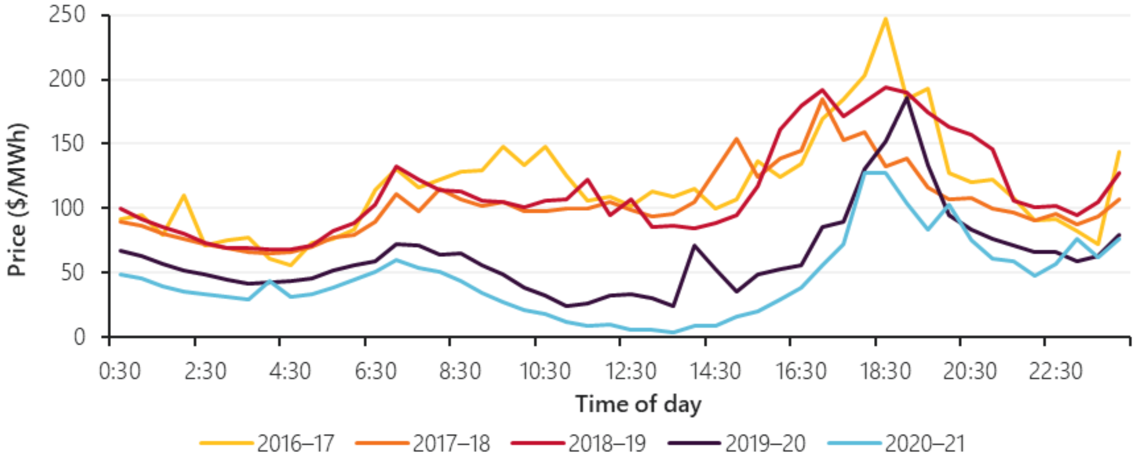
	Queensland	New South Wales	Victoria	South Australia	Tasmania
Time-weighted average ($/MWh)	61.81	64.81	45.93	44.83	43.69

South Australia's spot price was set by non-South Australian units 72% of the time, with prices set during these dispatch intervals averaging $43/MWh, down from $61/MWh in 2019-20.

The decline in South Australian spot prices was in line with the NEM-wide trend of falling prices, driven by factors including increased lower-priced offers from dispatchable generation (black coal, hydro, and brown coal), increased VRE output, and reduced operational demand. Spot price reductions were, however, particularly large in South Australia, and Victoria:

- Combined South Australian and Victorian **VRE output** increased by 255 MW compared to 2019-20, mainly driven by ramping up of recently installed Victorian capacity as well as new capacity additions.
- Average **operational demand** in South Australia and Victoria decreased by 136 MW compared to 2019-20, largely driven by increased distributed PV output (+95 MW) and mild summer conditions. Lower daytime demand contributed to reduced daytime spot prices, with South Australia's spot price between 1000 hrs and 1500 hrs averaging $10/MWh in 2020-21, down from $37/MWh in 2019-20 (Figure 24). This contributed to the low volume-weighted average spot price received by large-scale solar generators, as shown earlier in Table 10.

Figure 24 Average South Australian spot electricity price by time of day (real June 2021 $/MWh)



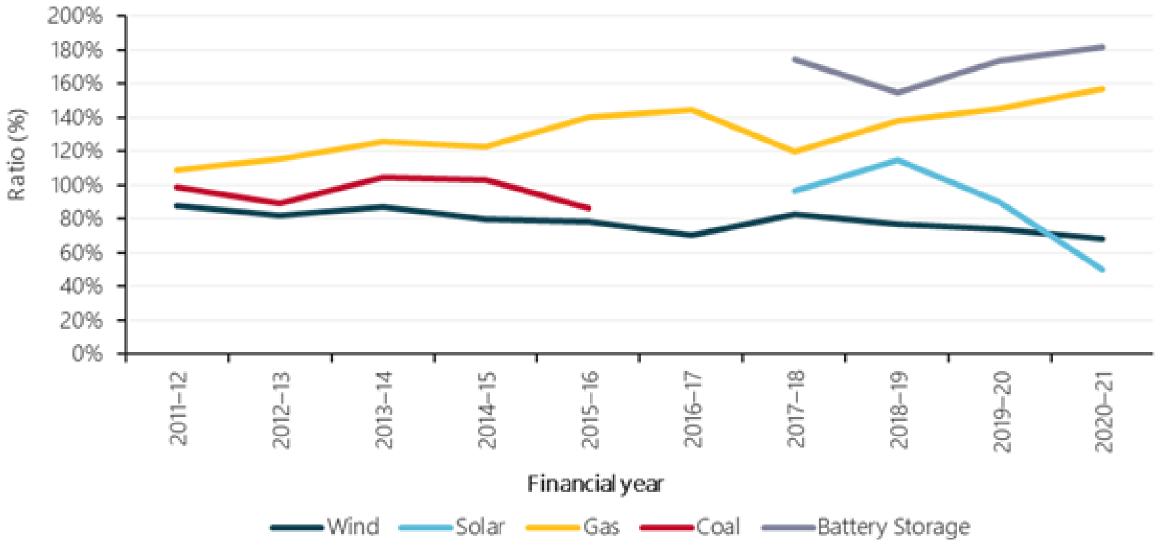
- Compared to 2019-20, an additional 268 MW of combined Victorian and New South Wales **hydro generation** was offered at prices below $35/MWh, influenced by above-average rainfall which enabled hydro generators to bid in at lower prices to increase dispatch.
- There was **higher brown coal availability**, as fewer outages at Loy Yang A in Victoria compared to 2019-20 contributed to a 155 MW increase in low-priced supply (<$35/MWh) on average across the year.
- South Australia's average **gas market price** declined from $7.13 per gigajoule (GJ) in 2019-20 to $6.54/GJ this year. Lower gas prices[59] were reflected in the lower-priced marginal offers from GPGs, contributing to a $12/MWh decline in average price set by South Australian GPGs ($81/MWh) compared to 2019-20.

The volume-weighted average price (VWAP) by fuel type represents the average price received by each fuel technology. Higher output during high-priced periods will result in a higher VWAP. As a relative percentage to TWAP, shown in Figure 25, the following occurred over 2020-21:

- Large-scale solar – the VWAP to TWAP ratio fell sharply from 90% in 2019-20 to 50% in 2020-21, mainly due to reductions in average daytime prices when solar generation is the highest.
  - Notably, record low monthly wholesale prices in September 2020 resulted in South Australian solar farms having to pay $9.7/MWh to generate.
- Gas – despite a lower number of high-priced periods compared to 2019-20, the VWAP to TWAP ratio continued to trend up, from 146% in 2019-20 to 157% last year. This was largely due to gas generators running at substantially lower levels during the lower-priced daytime trading intervals. Compared to 2019-20, output between 0700 hrs and 1700 hrs reduced by 124 MW on average.
- Battery – the VWAP to TWAP ratio remained the highest among all fuel types, as battery storage systems have fast ramping capability that enables them to generate at elevated levels during high priced periods and rapidly reduce output or charge during the increasing number of low or negative priced intervals.

[59] During Q3 2021, gas prices have increased across the NEM, with Adelaide's Short-Term Trading Market (STTM) averaging $11.51/GJ, largely due to high prices in July 2021 ($17.16/GJ). Increased prices were a function of tight supply/demand balance and record high international JKM LNG gas prices.

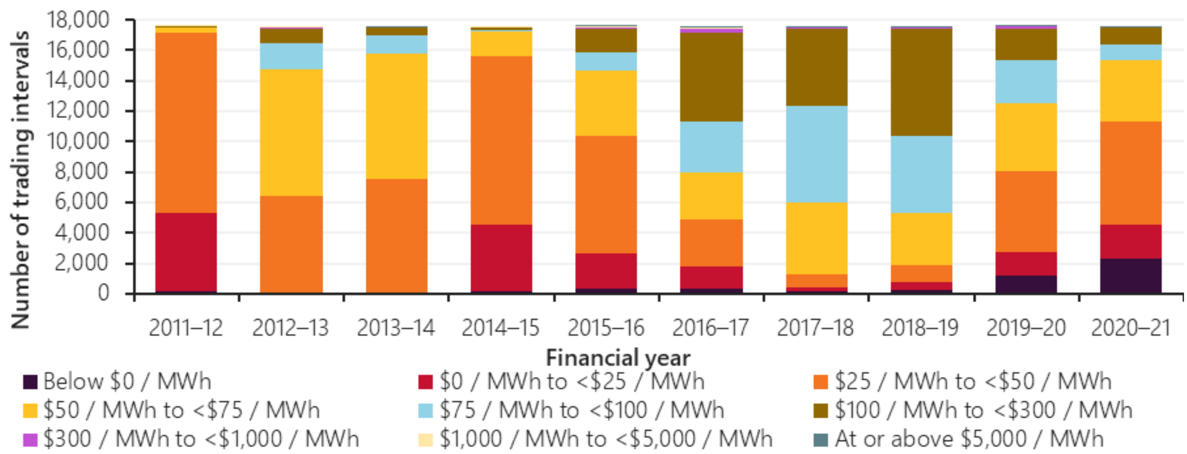
Figure 25 Ratio of VWAP by fuel to total TWAP for South Australian generators



5.2 Price volatility

In 2020-21, South Australian negative price occurrences increased to record levels, while prices above $300/MWh declined to 0.29% of the time (Figure 26).

Figure 26 Frequency of occurrence of spot prices for South Australia

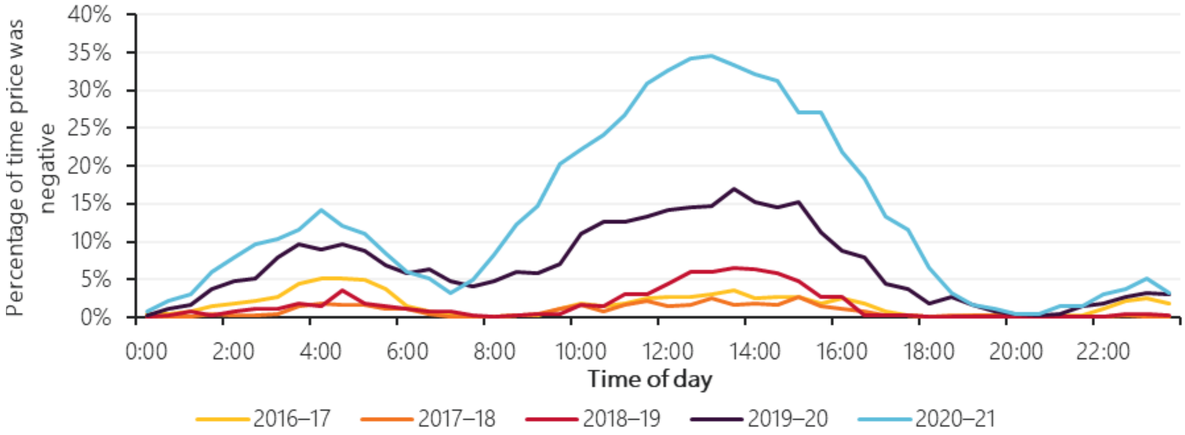


5.2.1 Negative prices

In 2020-21, the frequency of negative spot prices in South Australia reached record levels, occurring 13% of the time, almost doubling the previous year's record (6.8%). Notably, negative spot prices were no longer confined to the shoulder seasons (typically low-demand and windy periods), with a sizeable increase in summer due to very mild and sunny conditions[60]. The largest increase by time of day occurred in the sunny early afternoon period, with spot prices negative 32% of the time between 1200 hrs and 1500 hrs in 2020-21, up from 15% in 2019-20 (Figure 27).

[60] For more information, see AEMO's Quarterly Energy Dynamics Report Q1 2021, at https://aemo.com.au/-/media/files/major-publications/qed/2021/q1-report.pdf?la=en&hash=6EBB0A2B39B0205CEF782695505A87E9.

Figure 27 Percentage of time South Australian price was negative by time of day



Key drivers of increased negative price occurrence included:

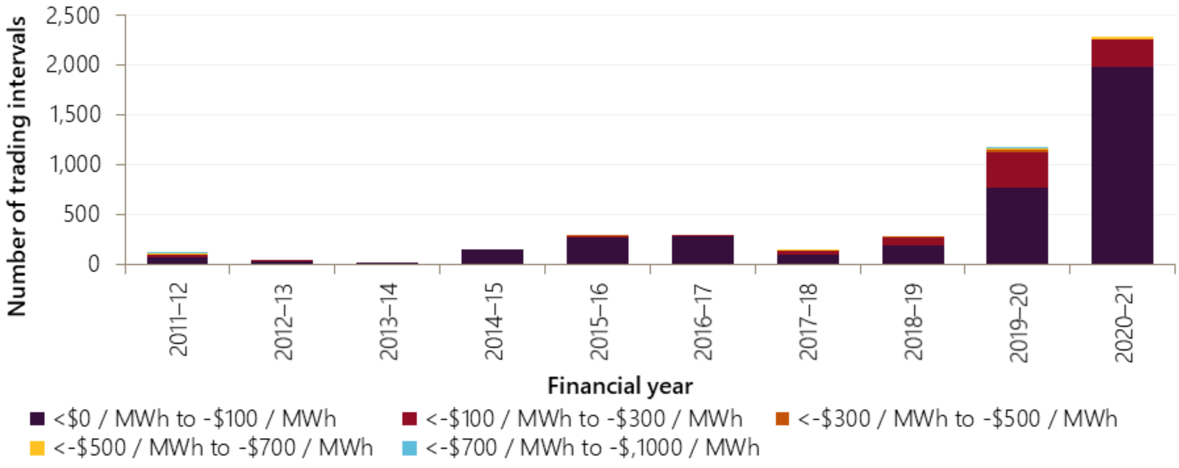
- **Inter-regional pricing dynamics** – this year, the occurrence of negative prices in South Australia was more closely aligned with Victoria; South Australia's prices were negative 55% of the time when Victorian prices were negative, up from 22% in 2019-20.
  - Compared to 2019-20, there were increased periods of very high Victorian and South Australian VRE output, mainly due to ramping up of recently installed Victorian renewable capacity (Dundonnell and Bulgana wind farms), as well as new capacity installed in Victoria over the past year (Berrybank and Moorabool wind farms). This, coupled with low daytime demand, contributed to periods of oversupply in both regions. In 2020-21, combined Victorian and South Australian VRE output was above 2,000 MW 35% of the time, compared to 26% in 2019-20.
- **Intervention pricing changes** – in December 2019, the AEMC introduced a rule change which removed intervention pricing when units are directed for system security purposes, with this change (in most circumstances) leading to lower spot prices during directions[61]. On average, 196 MW of GPG was directed during negative spot prices in the first half of 2020-21, compared to 108 MW of GPG in the first half of 2019-20 (before the rule change was introduced).
- **Interconnector limits** were similar to 2019-20 and not a main driver of the increase in negative prices.

Despite frequency of negative spot prices reaching record highs, the negative price impact[62] was similar to 2019-20 levels ($6.22/MWh), reducing the average South Australian spot price by $6.78/MWh. The limited impact of negative spot prices on average prices was due to reduced occurrence of highly negative prices (that is, prices below minus $100/MWh). On average, when prices were negative, it was below minus $100/MWh only 13% of the time, compared to 35% of the time in 2019-20 (Figure 28).

[61] When an intervention event brings on additional capacity and counteractions are not implemented, the prices produced by the what-if run will generally be higher than those produced by the dispatch run. This is because the what-if run will continue to signal the price associated with the supply demand balance as it was prior to the intervention, while prices in the dispatch run will generally be lower due to the addition of generation capacity.

[62] Calculated as the sum of the half-hourly price in the financial year where the pool price is below $0/MWh divided by the number of half-hours in the year.

Figure 28 Count of negative price trading intervals per year

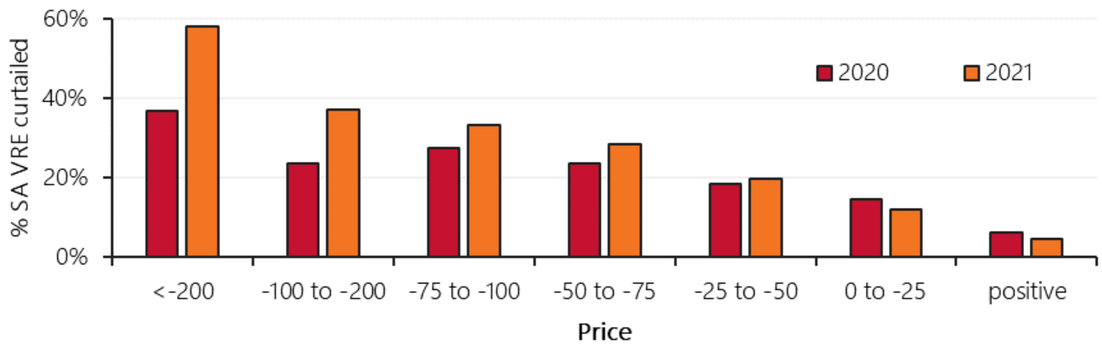


Generators' response to negative prices

The large increase in negative spot prices in South Australia led to a variety of responses from generators:

- **South Australian VRE:**
  - High levels of negative spot prices led to increasing responsiveness from wind and solar farms as they rebid output to higher price bands to avoid being dispatched at negative prices. On average, 27 MW of VRE output self-curtailed in response to negative prices, up from 19 MW in 2019-20[63], with a sizeable increase in response at more negative prices (below -$75/MWh, Figure 29). Notably, 25% of Tailem Bend Solar Farm's generation was curtailed in response to negative prices in 2020-21, up from 14% in 2019-20.
  - In addition to high levels of negative price occurrences, the deployment of participant automated bidding software during 2020 led to a substantial increase in VRE re-bids. In 2020-21, South Australian wind and solar farms re-bid 126,419 times, four times higher than in 2019-20. AEMO estimates that around one-third of South Australian VRE capacity has installed automated bidding software[64].

Figure 29 South Australian VRE curtailed at different price points



- **South Australian GPGs** – as negative spot price occurrences in South Australia continued to trend upwards, GPGs more frequently sought to de-commit from the market for economic reasons, resulting in AEMO needing to direct them to stay on to maintain system strength. This resulted in a record high number of directions in 2020-21 (see Section 6.4), with average GPG under direction increasing from 48 MW in 2019-20 to 76 MW in 2020-21.

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[63] Some minor updates have been made to historical curtailment categorisation due to updated methodology.

[64] For more information, see AEMO's Quarterly Energy Dynamics Report Q1 2021, at https://aemo.com.au/-/media/files/major-publications/qed/2021/q1-report.pdf?la=en&hash=6EBB0A2B39B0205CEF782695505A87E9.

5.2.2 High prices

Spot price volatility remained low in 2020-21, with cap returns declining to their lowest levels since 2015-16 (Figure 30). During 2020-21, spot prices exceeded $300/MWh only 0.3% of the time; this is slightly lower than in 2019-20, which also recorded low price volatility (0.76%).

The lack of price volatility was a function of:

- **Mild summer conditions** – the number of Adelaide days above 38°C reduced from 14 days in 2019-20 to seven days in 2020-21 (Figure 31). This contributed to a 98% reduction in trading intervals in which operational demand exceeded 2,800 MW.
- **Increased wind supply during high demand periods** – South Australian wind availability during high demand periods (top 2% of demand) increased by 85 MW on average compared to 2019-20, as mentioned in Section 4.1.1.

Figure 30 Average SA annual cap returns[65]

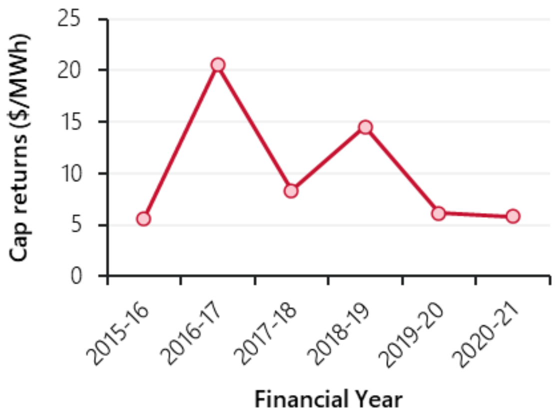
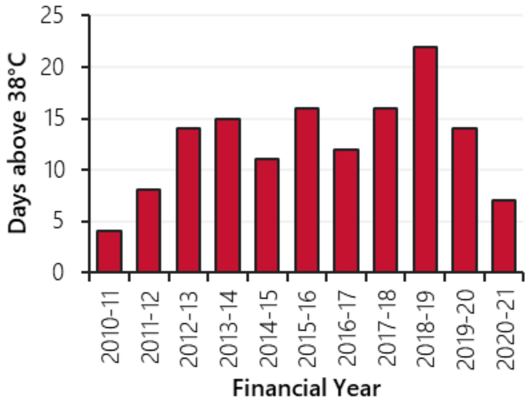


Figure 31 Fewer extreme heat days



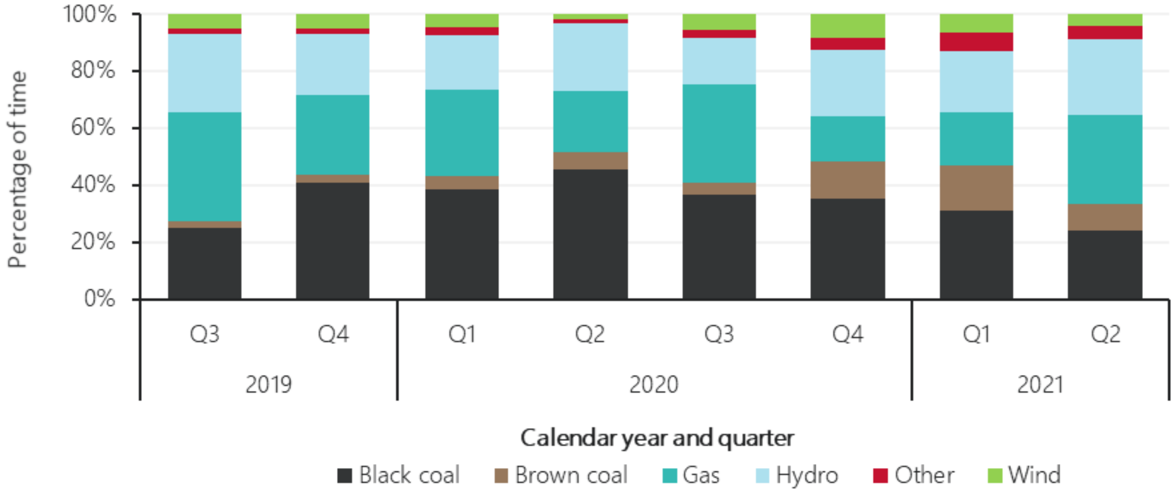
5.3 Price setting outcomes

Figure 32 shows South Australia's quarterly price setting outcomes by fuel type for 2019-20 and 2020-21. Key price setting outcomes in 2020-21 included:

- Brown coal's price- setting role increased from 4% in 2019-20 to 11% in 2020-21. This was largely due to an increase in lower-priced supply in South Australia and Victoria, resulting in the spot prices occurring at levels where brown coal-fired generation was the marginal unit (typically $0-$20/MWh).
- Gas price setting declined from an average of 29% in 2019-20 to 25% in 2020-21, largely due to reduced South Australian and Victorian GPG output.
- Grid-scale wind and solar continued to set the price more frequently at 8% of the time (combined), up from 5% in 2019-20. The increased price setting role was due to a high frequency of negative spot prices, particularly during the middle of the day (see Section 5.2.1).
- The most common price setting power station this year was Murray Hydroelectric Power Station in Victoria (set the price 10.3% of the time), which surpassed Torrens Island Power Station (9.6% of the time), partially due to the withdrawal of Torrens Island A units 2 and 4 in October 2020.

[65] A measure of volatility in electricity prices is the presence of high price events (above $300/MWh), calculated as the sum of the NEM half-hourly price minus the $300 cap price for every half-hour in the financial year where the pool price exceeds $300/MWh, divided by the number of half-hours in the year.

Figure 32 South Australian price setting by fuel type

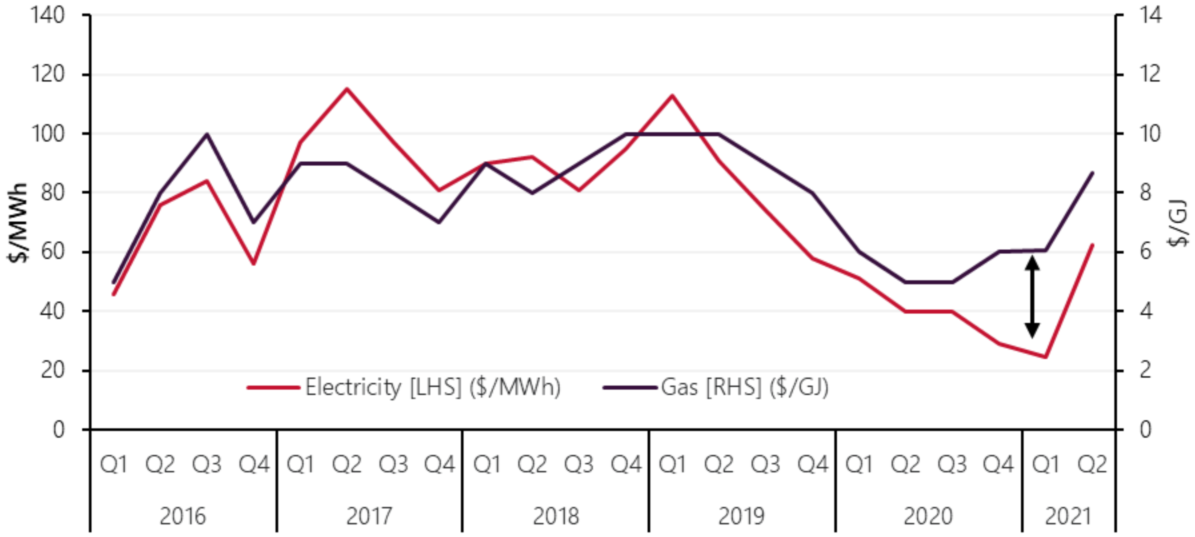


5.4 Gas spot price impact on electricity spot prices

Historical average electricity and gas prices are shown in Figure 33, with the similarity in price trend over the years demonstrating an inter-relationship between the two. Between 2019-20 and 2020-21, South Australia's average electricity TWAP decreased by 28%, while average gas prices in Adelaide's Short-Term Trading Market (STTM) declined by 8% to $6.54/GJ. However, as Figure 33 shows, there was a notable divergence between South Australia's spot electricity and gas market prices throughout much of the year. Drivers of the divergence over this period included:

- Falling electricity demand and renewables growth, coupled with near record low GPG, reducing the prominence of gas prices in electricity price outcomes.
- Gas prices being strongly influenced by international liquified natural gas (LNG) and oil markets.

Figure 33 South Australian electricity and gas price diverge

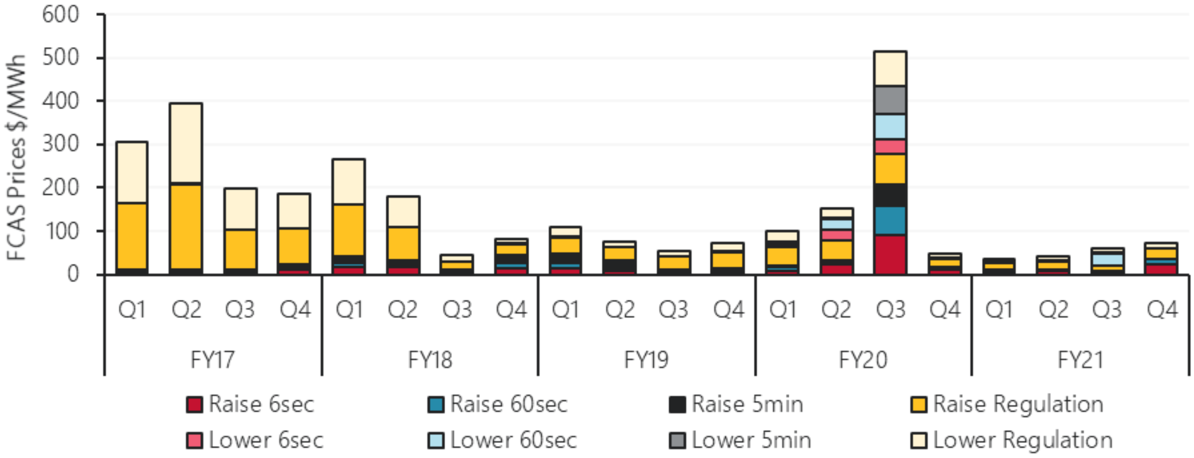


Note: To remove the impact of electricity price volatility, trading interval prices were capped at $300/MWh to prepare this chart. Prices are presented on a nominal basis.

5.5 Frequency control ancillary services market prices

During 2020-21, South Australian FCAS prices decreased substantially from their levels in 2019-20 (Figure 34), a year which was significantly impacted by major power system separations of South Australia from the rest of the NEM.

Figure 34 Quarterly average South Australian FCAS prices by service



Despite increased NEM-wide FCAS requirements (+326 MW across the eight markets[66]) compared to 2019-20, South Australian FCAS prices declined across all eight FCAS markets, driven by:

- **Reduced localised FCAS requirements** – localised requirements declined from 14% in 2019-20 to 4% of the time in 2020-21, largely due to no major power system separation events. 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.
- **Additional new supply** – in 2020-21 there was a large increase in NEM-wide FCAS supply from new providers including batteries, demand response, and VPPs (see Figure 35).
  - The marked increased in battery supply in Contingency Lower (+117 MW), Contingency Raise (+60 MW), and Regulation (+43 MW) FCAS was mainly driven by the expansion of Hornsdale Power Reserve in September 2020. The increase in capacity from 100 MW/129 MWh to 150 MW/193.5 MWh resulted in additional supply across all eight FCAS markets[67], which contributed to the NEM-wide FCAS market share of batteries increasing from 19% in 2019-20 to 24% in 2020-21.
  - An additional 135 MW of Contingency Raise supply from demand response was mainly driven by increased capacity from Enel X's demand response, and increased FCAS availability from the Portland Aluminium Smelter.
  - Compared to 2019-20, the number of VPPs registered to provide FCAS increased from two to eight (four in South Australia), with total registered capacity across the six Contingency FCAS markets increasing to 184 MW[68]. Additional new capacity resulted in a 52 MW increase in average Contingency FCAS enablement, with VPP market share increasing from 0.5% to around 2.6% in 2020-21.

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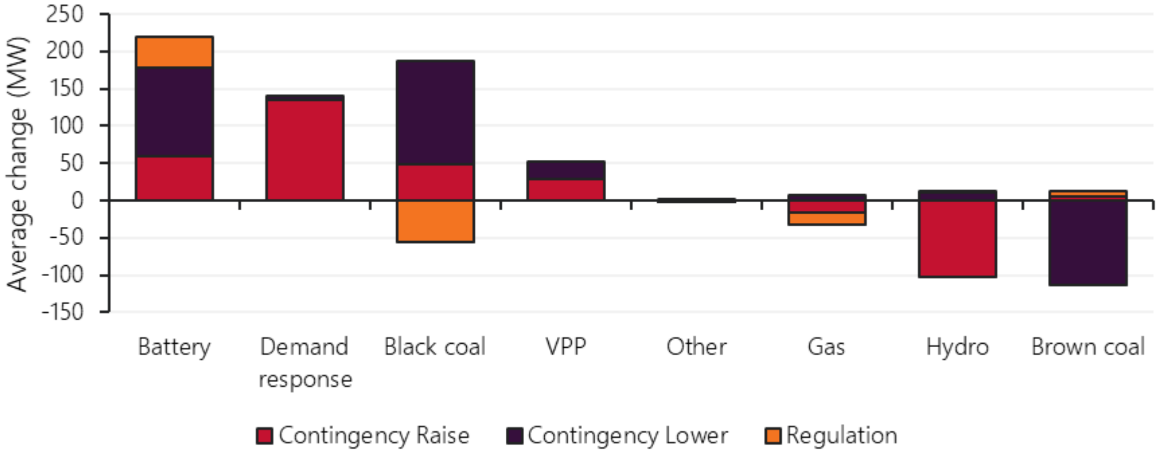
[66] In the NEM, generation and demand are balanced through the central dispatch process for both energy and FCAS. FCAS is a market mechanism that uses generation or load to correct imbalances between supply and demand in real time. AEMO operates eight separate markets for the delivery of FCAS – two Regulation markets (Raise and Lower) and six Contingency markets (6 Second Raise, 60 Second Raise, 5 Minute Raise, 6 Second Lower, 60 Second Lower, 5 Minute Lower).

[67] For more information, see AEMO's Quarterly Energy Dynamics Report Q3 2020, at https://aemo.com.au/-/media/files/major-publications/qed/2020/qed-q3-2020.pdf?la=en&hash=2A20B13F240C567BA0DECF322509235F.

[68] For more information on VPPs, see AEMO's VPP Demonstrations Knowledge Sharing reports, at https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/virtual-power-plant-vpp-demonstrations.

- **Increased lower priced black coal supply** – this was largely driven by increased supply from Mount Piper Power Station, which accounted for 72% of the increase in black coal Contingency FCAS supply; this was 187 MW higher than 2019-20 on average.
- **Lower energy prices** – Raise FCAS markets often move in line with energy prices, due to the opportunity cost of service of provision. As discussed in Section 5.1, South Australian energy spot prices have been declining over the past year.

Figure 35 Change in FCAS supply by fuel type – 2020-21 versus 2019-20



6. System security

This section discusses ongoing maintenance of power system security[69] 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.

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

6.1.1 Challenges associated with minimum demand

South Australia has experienced periods where up to 83.25%[70] of 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. Further, 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[71]. The challenges South Australia is managing include:

- Ensuring there is 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 safety net that is the last line of defence protecting consumers from black system events.
- 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 reported on minimum operational demand levels necessary to support the generation needed for secure operation of South Australia in the 2021 ESOO. These levels were derived considering the behaviour of distributed PV during power system disturbances. AEMO's initial operating procedures included minimum operational demand thresholds of 600 MW for when South Australia is separated from the rest of the NEM, and 400 MW when South Australia is at a credible risk of separating from the rest of the NEM. These thresholds are being reviewed. It is noted that:

- Minimum operational demand below both these 600 MW and 400 MW thresholds has already occurred in South Australia, as discussed in Section 2.3.2. For example, South Australia reached a minimum operational demand record of 236 MW on 26 September 2021. 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.
- South Australian operational demand was below 600 MW for 2% of the time in the 2020 calendar year, and this is forecast to increase to 8% of the time in 2022, and 12% of the time in 2023[72]. The proportion of time that operational demand was below 400 MW was 0.04% in 2020, and is forecast to increase to 4% of the time in 2022, and 7% of the time in 2023. Further, negative 50% POE minimum operational demand events are currently forecast as early as next year.

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70 The highest observed penetration as of 17 October 2021.

71 For more information, 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.

72 Forecast values are provided on a 'season-year' basis. A 'season-year' extends from 1 September to 31 August, where the 2022 season-year is 1 September 2021 to 31 August 2022.

6.1.2 Mechanisms to address declining minimum demand

Increased capabilities for DPV

AEMO published the *Minimum operational demand thresholds in South Australia* report in May 2020, recommending a number of measures to the South Australian Government to address challenges associated with declining minimum demand. Since this report was published, the following related actions have been undertaken to support increased participation by South Australian customers in the energy system:

- 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 comes into effect in December 2021. This new standard 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.
- South Australia introduced a requirement for all new distributed energy generating installations in South Australia to have the ability to be remotely curtailed, effective 28 September 2020, when absolutely necessary as an emergency last resort to maintain power system security. This requirement does not apply to the legacy fleet of distributed PV installed in South Australia[73]. This last resort capability has been used once, on 14 March 2021. AEMO is preparing an incident report on this event and expects to publish this report before the end of 2021.
- AEMO has introduced new operating procedures to alert the market ahead, known as the distributed PV Contingency and/or Minimum System Load (CMSL) market notice framework[74]. The CMSL is similar to the well-established three-tiered Lack of Reserve notices in the NEM, but will instead warn of risks relating to minimum operational demand and distributed PV contingencies. Where possible, these notices will generally be 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 would only be where the market has not been able to take sufficient action to clear the risk, and would only be taken as an emergency last resort after all other feasible options are taken. A market notice will also be issued if this becomes necessary.
- SA Power Networks is pursuing the implementation of a "Flexible Exports" mechanism to deliver longer term technical capabilities[75].
- AEMO is continuing to review its system operational procedures. For example, AEMO has replaced the previous 400 MW minimum operational demand threshold for times of credible risk of separation from the NEM with a dynamic method that determines the threshold based on the number of generating units online and system conditions at the time. Work is also underway to replace the 600 MW threshold for when South Australia is separated from the rest of the NEM with a similarly dynamic threshold representative of actual system conditions at the time.

Enhancement to South Australia's System Integrity Protection Scheme (SIPS)[76]

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 mid-2022.

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

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

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

[76] 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.

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. AEMO has recommended that SA Power Networks implement dynamic arming of UFLS circuits[77]. SA Power Networks, ElectraNet, and AEMO are also collaborating on long-term options for restoring emergency under-frequency response, possibly including procurement of fast frequency response (FFR) when UFLS load is below required thresholds. Further analysis is also progressing to assess the impacts of distributed PV on the effectiveness of UFLS schemes across the mainland NEM, and to review the NEM-wide UFLS frequency trip settings, including in South Australia.

Existing protected event for South Australia

On 20 June 2019, the AEMC declared a protected event catering for the loss of multiple transmission elements causing generation disconnection in the South Australia region during periods where destructive wind conditions are forecast by the Bureau of Meteorology.

Recommending a new protected event for South Australia

In both Stage 1 and Stage 2 of 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. If the AEMC Reliability Panel approves this protected event, it will mean AEMO can use additional measures to maintain the South Australian power system frequency within acceptable ranges, including 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.

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 have been identified (including improvements to control schemes and improvements to the UFLS scheme) which aim to minimise risk as much as possible within the existing framework, and implementation is being explored. AEMO will propose to the Reliability Panel a selection of remaining actions that require a protected event for implementation, targeting a submission in late 2021 or early 2022.

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.

In December 2020, AEMO published the first *System Strength and Inertia Report*[78] to assess the outlook for system strength and inertia in the NEM over a 10-year horizon. 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.

[77] 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?la=en&hash=C82E09BBF2A112ED014F3436A18D836C.

[78] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2020/2020-system-strength-and-inertia-report.pdf?la=en.

System strength

AEMO's 2020 *System Strength and Inertia Report*[79] 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 meets the region's system strength requirements for the period up to 2025-26.

AEMO has updated its operational procedures to incorporate the two Robertstown and two Davenport synchronous condensers[80]. All four synchronous condensers have now completed commissioning and system tests. AEMO and ElectraNet are currently reviewing these system tests and developing necessary system limits advice. Once all four synchronous condensers are in operation, the South Australian system is expected to be able to operate with up to 2,500 MW of non-synchronous generation online in a secure state while in a system normal mode and connected to the rest of the NEM.

Inertia

In its 2020 *System Strength and Inertia Report*[81], AEMO declared an extension of the South Australia inertia shortfall up to 2022-23. This extension assumed that the four high inertia synchronous condensers at Robertstown and Davenport were fully installed and tested, and is an update to the previously declared inertia shortfall from the *Notice of South Australia Inertia Requirements* report[82], published in August 2020. ElectraNet and AEMO are currently collaborating on solutions to address this requirement.

PEC recently attained AER approval[83] and is assumed to commence operations in stages from 2023-24 with full capacity available from June 2025 following inter-network testing. PEC is expected to reduce the need for inertia services in the South Australia region, as this additional synchronous connection to the rest of the NEM reduces the likelihood of the South Australia region islanding from the NEM. The situation for the period up until the expected commissioning and operation of PEC will be reviewed further in the upcoming 2021 *System Strength and Inertia Report* due to be released in December 2021.

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[84].

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 a security or reliability need for South Australia that AEMO has declared as an NSCAS gap. In some situations, AEMO may use reasonable endeavours itself to acquire the necessary NSCAS for security or reliability needs.

In its annual NSCAS assessment released in December 2020[85], AEMO did not identify any NSCAS gaps in South Australia over the five-year period to 2024-25. However, AEMO noted in this assessment that:

- Voltages in South Australia could come very close to allowable limits after a credible contingency.

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[79] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2020/2020-system-strength-and-inertia-report.pdf?la=en.

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

[81] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2020/2020-system-strength-and-inertia-report.pdf?la=en.

[82] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/2020-notice-of-south-australia-inertia-requirements-and-shortfall.pdf?la=en.

[83] AER, "AER approves costs for Project EnergyConnect", at https://www.aer.gov.au/news-release/aer-approves-costs-for-project-energyconnect.

[84] 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 makes sure that shortfalls and needs across all three areas are considered holistically in its public annual reports.

[85] At https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/Operability/2020/2020-NSCAS-Report.

- The South Australian power system is changing rapidly, and operational measures are being relied upon more frequently to help manage voltages during low demand conditions.
- AEMO would review whether network planning assumptions needed to change so that the system was designed to more efficiently maintain reliability and security with manageable operational risks.

At the time of writing, AEMO is undertaking the 2021 NSCAS assessment by applying the updated supply and demand projections discussed in Section 3 and Section 4 as well as the outcomes of its review of traditional network planning assumptions. The updated NSCAS assessment will be released before the end of 2021.

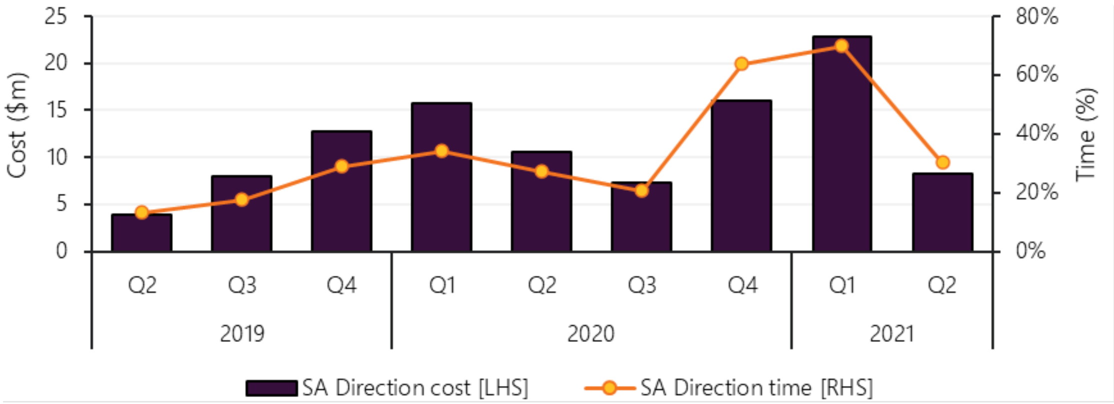
6.4 Directions to maintain system security

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[86] have noted recent trends in time on direction and total costs for directions issued to GPGs in South Australia to maintain system security in the region (see Figure 36 below, from the QED Q2 2021 report):

- A trend of increasing time and costs for directions from Q3 of 2020 to Q1 of 2021. Direction costs reached new highs in this period, driven by significantly increased time on directions in South Australia (70% of the time in Q1 2021 was a record to date). Lower spot prices for electricity saw GPGs frequently decommitting for economic reasons, so directions were needed at times to get them back online for system security.
- A reduction of $14.9 million in total directions costs for energy in Q2 2021 compared to Q1 2021, to total Q2 costs of $8.3 million.
  - The reduction from Q1 record costs was largely due to lower time on direction (30% of the time in Q2 2021, compared to 70% in Q1 2021, resulting in 7% of total South Australian GPG output directed in Q2 2021, compared to 30% in Q1). Although there was slightly higher time on directions than in the equivalent quarter (Q2) in 2020, costs were $2.2 million lower, due to lower compensation prices[87].
  - The key driver of reduced time on direction was higher spot prices at these times, influenced by lower wind output in South Australia and thermal unit outages in other NEM regions.

Figure 36 South Australian direction costs down from record highs in Q1 2021

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[88].

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

[87] Compensation prices for participants responding to directions are based on a benchmark of the average 12-month 90th percentile spot price. Participants can also submit compensation claims; AEMO received 44 compensation claims in Q1 2021, when the compensation price had fallen, compared to 36 claims in all of 2020, and final total costs for Q1 2021 were $4.4 million higher than the preliminary costs published in the Q1 report.

[88] 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, the following sources provide more detail on resource availability and relevant technologies.

Table 15 Additional data sources

Information source	Website address
ACIL Allen: *Fuel And Technology Cost Review*, 2014	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/ntndp/2014/data-sources/fuel_and_technology_cost_review_report_acil_allen.pdf
Aurecon: *Cost and Technical Parameters Review 2020* Aurecon: *Cost and Technical Parameters Review 2020 – 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?la=en
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?la=en
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?la=en
CSIRO: *Multi-sector energy modelling*, 2021	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/csiro-multi-sector-modelling.pdf?la=en
CSIRO: *Gencost 2020-21*	https://www.csiro.au/-/media/EF/Files/GenCost2020-21_FinalReport.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?la=en
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?la=en

A2. Generation and demand breakdown

Table 16 Generation and demand detailed breakdown

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 SNSG	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	12,957	84	253
2012–13	3,473	0	0	79	3	434	9,031	13,020	1,710	1,377	-333	14,398	395	309	651	0	13,043	82	434
2013–14	4,087	0	0	82	3	582	7,664	12,418	1,925	1,637	-288	14,055	352	364	710	0	12,629	85	582
2014–15	4,218	0	0	92	4	716	7,246	12,277	1,904	1,528	-376	13,805	386	368	661	0	12,389	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	12,678	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	12,437	86	904
2017–18	5,561	4	22	71	24	1,041	7,282	14,005	1,039	-292	-1,331	13,713	221	313	676	27	12,476	95	1,041
2018–19	5,725	303	41	65	86	1,314	6,886	14,420	791	-468	-1,259	13,952	202	341	639	51	12,719	152	1,314
2019–20	5,798	483	47	67	215	1,610	6,278	14,497	922	-413	-1,335	14,085	179	334	701	59	12,811	281	1,610
2020–21	5,739	673	85	69	248	1,925	5,235	13,973	1,147	123	-1,023	14,097	144	324	696	104	12,829	317	1,925