South Australian Electricity Report

November 2020

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 12 November 2020, although AEMO has endeavoured to incorporate more recent information where practical.

DISCLAIMER

AEMO has made every reasonable effort to ensure the quality of the information in this publication but cannot guarantee that information, forecasts and assumptions are accurate, complete or appropriate for your circumstances. This publication does not include all of the information that an investor, participant or potential participant in the National Electricity Market might require and does not amount to a recommendation of any investment.

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Executive summary

In 2019-20, South Australia's world-leading energy transformation again saw new records set, variability in demand grow further, and the continued emergence of trends requiring action to maintain secure and reliable supply.

- South Australian consumers continued to invest in distributed energy resources (DER, primarily distributed photovoltaic [PV] systems), and AEMO forecasts this growth to continue over the next decade, with installation rates remaining strong despite COVID-19 impacts in 2020:
  - South Australia now has approximately 33% of dwellings with rooftop PV installed – the highest proportional penetration of all Australian states and territories, and among the highest proportional uptake in the world.
  - On 11 October 2020, for one hour between 12.30 pm and 1:30 pm[1], the amount of solar power generated was sufficient to meet 100% of South Australia's electricity needs – a first in Australia and for any major jurisdiction globally[2]. Mild temperatures and cloudless skies contributed to ideal generation conditions in South Australia, with solar power from the state's 288,000 rooftop systems providing 992 megawatts (MW) and large-scale solar 313 MW to power the region.
- The high penetration of distributed PV systems is lowering minimum operational (grid) demand, as distributed PV generation meets a growing proportion of consumer demand in the daytime.
  - Minimum operational demand continues to set new record lows, most recently on 11 October 2020 at 1:00 pm, when a new record low minimum operational demand of 290 MW sent-out was set. AEMO forecasts that minimum operational demand will continue to decline rapidly, with forecast minimum demand approaching zero by 2024-25 in some scenarios.
  - Declining minimum demand is already creating operational and planning challenges in South Australia, related to the security of the grid, managing voltage, and having enough system strength and inertia. AEMO is working closely with the South Australian Government, ElectraNet, SA Power Networks, the Energy Security Board (ESB), and wider industry on actions necessary to efficiently integrate increasing levels of distributed PV and other DER in the NEM.
- The number of embedded batteries in South Australia is estimated to have increased by 35% to 17,000 units in 2019-20, and is forecast to almost triple in the next five years, representing approximately 20% of all the batteries forecast to be installed in the NEM by 2025.
  - AEMO continues to establish a framework for virtual power plants (VPPs) through the VPP Demonstrations program, supported by the Australian Renewable Energy Agency (ARENA). This program and other VPP trials are demonstrating the potential capability for batteries to provide contingency frequency control ancillary services (FCAS) and energy market services. The VPP Demonstrations will continue through to mid-2021 and inform the effective integration of VPPs into the NEM before they reach scale.
- Despite the relatively strong penetration of renewable energy and battery storages, gas-powered generation (GPG) remains a critical source of firming supply and at times provides almost 100% of the electricity demand in South Australia when renewable generation is not available.

[1] All times written throughout this report are in local time unless stated otherwise.

[2] See media release at https://www.aemo.com.au/newsroom/media-release/solar-power-fuels-south-australias-total-energy-demand. In accordance with system strength requirements, there were three synchronous units online in South Australia at this time.

- The impact of COVID-19 is increasing the uncertainty associated with forecasting consumption and demand patterns. In South Australia the pandemic has reduced commercial demand and increased residential demand since restrictions were introduced. It is also forecast to reduce energy consumption and peak demand for the year ahead, but the medium- and longer-term impacts are harder to assess. These impacts could affect demand, maintenance of assets, and generators returning to service. AEMO is closely monitoring this and working with asset operators on prudent planning.
- In January 2020, the Australian Energy Regulator (AER) published its decision to approve ElectraNet's Regulatory Investment Test for Transmission (RIT-T) application for the South Australia – New South Wales interconnector, Project EnergyConnect, and is currently considering ElectraNet and TransGrid's contingent project applications. Subject to satisfactory regulatory and other approvals, ElectraNet and TransGrid are working towards completing construction by 31 December 2023.

AEMO again worked with industry, government and ARENA so South Australia remains at the forefront of implementing innovative solutions, addressing technical challenges so consumers can realise maximum benefits from the energy transformation. Key operating challenges and actions in 2019-20 included:

- South Australia was islanded from the NEM from 31 January to 17 February 2020[3]. This was the longest separation of the Victoria and South Australia networks and the first time the Alcoa Portland aluminium smelter has been connected to the South Australia network without a connection to Victoria. Findings from this event, as well as increased projections for distributed PV and other factors, led AEMO to declare a new inertia shortfall in August 2020. AEMO's declaration emphasised the important role of fast frequency response (which may be sourced from batteries and other devices) in addressing the shortfall. ElectraNet is currently considering how to address the shortfall.
- AEMO had earlier declared a system strength shortfall for the region in 2017 and a minimum inertia requirement shortfall in 2018. The delivery by ElectraNet of synchronous condensers with flywheels at Davenport and Robertstown will address these shortfalls, with the first two expected to be energised by the end of January 2021 and two more by May 2021[4]. Until then, AEMO is intervening in the market, when necessary, to maintain secure system operations. In 2019-20, these interventions included 253 directions to generators to ensure system strength, an increase of 65% compared to 2018-19.

Consumer investments in distributed resources increase operational challenges

- **Consumers continued to increase their adoption of behind-the-meter rooftop PV and storage**, with 288 MW of rooftop PV installed in 2019-20. By July 2020, rooftop PV capacity was 1,417 MW (26 % increase on the previous year) and battery systems reached 72 MW (33 % increase). Rooftop PV contributed 1,692 gigawatt hours (GWh) in 2019-20, 12% of South Australia's underlying consumption.
- Growing DER and increasing investments in energy efficiency has **kept annual operational consumption in South Australia in slow decline** at 11,890 GWh in 2019-20, despite underlying population growth. It is expected to continue a slow decline for the next 10 years.
- PV systems larger than 100 kilowatts (kW), known as PV Non-Scheduled Generation (PVNSG) and typically installed on commercial premises, as well as small solar farms not large enough to be registered in the market, have also seen steady growth with installed capacity increasing 74% since 2018-19, to 129 MW.
- **Rooftop PV and PVNSG combined – 'distributed PV' – contributed 210 MW more output at the time of underlying[5] peak demand** in 2019-20 than had been forecast the previous year, delivering 682 MW at the time of peak (12:30 pm). Maximum grid demand is not observed until late in the evening, at

[3] AEMO, Final Report – Victoria and South Australia Separation Event, 31 January 2020, published November 2020, at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/final-report-vic-sa-separation-31-jan--2020.pdf?la=en.

[4] See https://www.electranet.com.au/what-we-do/projects/power-system-strength/

[5] Underlying demand is total demand from consumers, whether met from the grid or from their own generation or storage behind the meter.

approximately 7:30 pm, which will mean that future rooftop PV installations are unlikely to further reduce the operational peak grid demand unless combined with energy storage.

- High and growing distributed PV penetration is **reducing minimum operational demand**[6], with minimum demand already falling below the thresholds for secure operation of a South Australian island. **Minimum demand continues to occur in the middle of the day,** typically at the weekend or on public holidays. A **record low operational minimum demand** (sent-out) of 290 MW was recorded on Sunday 11 October 2020 at 1:00 pm. Minimum demand is forecast to approach zero by 2023-24 in some scenarios[7], or earlier if PV penetration continues at a pace faster than that forecast.

Minimum demand is extremely sensitive to forecast growth in distributed PV. Evidence of strong sales and installations in 2019 and 2020 have strengthened the confidence that consumers continue to look for energy savings through PV installations, and distributed PV forecasts have been revised upwards accordingly. COVID-19 had been assumed to temper some installation growth, however, as at the end of June 2020, there was limited evidence to confirm any real slowdown of distributed PV installations. Due to the continued strong uptake of distributed PV projected, forecast minimum operational demand is declining rapidly.

The 2020 ESOO highlighted the minimum demand-related challenges and opportunities arising from increasing penetration of distributed PV, noting that:

- Effective market and regulatory arrangements that incentivise more demand during the middle of the day would help minimise the occurrence of these extreme minimum load conditions.
- Innovative solutions could include providers/aggregators of DER offering services such as increased distributed PV controllability, load flexibility, storage, and load shifting.
- Urgent action is required to ensure all new distributed PV installations have suitable disturbance ride through capabilities and emergency distributed PV curtailment capabilities to be enabled under rare circumstances as a last resort to maintain system security. AEMO is working with stakeholders to introduce these capabilities through updates to the Inverter Requirements Standard, and on an accelerated timeframe in South Australia in partnership with the SA Government[8],[9].

While these challenges and opportunities are emerging across the NEM, they are most prevalent in South Australia, due to its world-leading levels of distributed PV penetration.

Demand and supply changes, including COVID-19 impacts, and reliability forecasts

Under the Central scenario, AEMO is forecasting:

- **Energy consumption to continue to fall** with the growth in DER offsetting the growth drivers.
- **Maximum demand to initially grow slightly** in South Australia, driven mainly by large industrial loads, then remain flat until 2029-30 as growth in underlying residential and business load is offset by increasing energy efficiency.

COVID-19 has added to existing uncertainties for demand forecasting. The impact could be to increase or decrease overall demand; AEMO is monitoring this, given the lack of precedent.

From a supply perspective:

- There is **117 MW of committed new solar generation** expected to commence commercial operations by summer 2020-21.

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[6] Operational demand is electricity supplied to consumers via the grid, by local scheduled generation, semi-scheduled generation, and non-scheduled wind/solar generation of at least 30 MW aggregate capacity, and by imports, excluding the demand of local scheduled loads.

[7] AEMO's forecasts in this year's publications are based on a range of plausible scenarios and sensitivities, explained in the body of this report.

[8] AEMO, Short Duration Undervoltage Disturbance Ride-through Test Procedure, at https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/standards-and-connections/vdrt-test-procedure.

[9] Government of South Australia, Department of Energy and Mining, Consultation on Regulatory Changes for Smarter Homes, at https://energymining.sa.gov.au/energy_and_technical_regulation/energy_resources_and_supply/regulatory_changes_for_smarter_homes/consultation_on_regulatory_changes_for_smarter_homes.

- Beyond this summer, there is a further **376 MW of committed new variable renewable energy (VRE) generation capacity** that is scheduled to connect in the outlook period.
- The current pipeline of proposed projects (not yet committed) is approximately 9,926 MW and includes 6,406 MW of VRE.
- In light of COVID-19, if there are unplanned network or generation outages that require labour or parts from overseas, there may be additional delays in returning those assets to service due to supply chain disruptions. AEMO continues to monitor this delay risk.

For the reliability outlook, AEMO has forecast whether there will be any unserved energy (USE) in South Australia, and compared this to both the reliability standard (no more than 0.002% of USE in any year) and to the new interim reliability measure (IRM, no more than 0.0006% in any year)[10].

The reliability outlook is improved compared to that reported in the 2019 SAER:

- Forecast USE in South Australia remains below both the reliability standard and the IRM across the reliability outlook period (to 2029-30)
- The additional peaking generation and battery storage capacity added over the past year softens the impact of the announced retirement of Osborne Power Station in 2023-24.
- The implementation of Project EnergyConnect would result in a substantial reduction in forecast USE (from 2024-25 onwards) that would more than offset the remaining reliability impact of the retirement of Osborne Power Station.

Supply changes and impacts on exports, emissions, and prices in 2019-20 were:

- Generation in South Australia increased 0.6% in 2019-20 to 14,621 GWh, with generation from renewable sources increasing to 56% of total generation, up from 52% in 2018-19. South Australia again was a net exporter of electricity in 2019-20. Compared to 2018-19, 6% more energy was exported to Victoria from South Australia on average during the daylight hours
- Generation capacity in South Australia increased 7% in 2019-20 (by 539 MW) to 7804 MW (including 1,417 MW of rooftop PV capacity).
- Closure of Torrens Island Power Station A (480 MW) is underway, and Osborne Power Station (172 MW) has been reported to AEMO as closing in 2023-24.
- The continued decline in emissions intensity reflects the decrease of GPG and the increased wind and solar penetration in the region.
- South Australia's average wholesale electricity prices fell 45% from the record high levels of 2018-19 to their lowest levels since 2015-16, following the NEM-wide trend of falling prices. Factors driving the NEM-wide reductions included lower-priced offers from black coal-fired generation, falling gas market prices, and increased VRE output.
- FCAS prices were significantly higher than in 2018-19, primarily due to extreme price volatility in November 2019, January 2020, and February 2020 resulting from power system separation events.

The proposed Project EnergyConnect interconnector to New South Wales has an AER approved RIT-T application and final contingent project applications from TransGrid and ElectraNet submitted for approval.

Actions to maintain system security and increase consumer value

As well as energy resources to meet demand, the power system also needs services to **maintain system strength and keep frequency and voltage within required limits**. These system security services have traditionally been supplied by synchronous generators, but when this generation is not online – such as at times of low operational demand – alternative options are needed.

[10] The IRM came into effect in South Australia in March 2020.

AEMO's Renewable Integration Study Stage 1 Report (May 2020)[11] highlighted specific challenges related to South Australia and identified actions to address these and maximise the value of renewable generation behind the meter and at grid scale.

The key challenges observed, solutions identified, and developments progressed in the past year were:

- AEMO issued 253 directions in South Australia in 2019-20, directing synchronous generators to maintain the system in a secure operating state, compared to 153 issued in 2018-19. This continued the trend of a substantial increase on previous years.
- Synchronous condensers, improved interconnection, and contingency frequency reserves from renewable generation and large-scale battery storage, as well as fast-start and rapid-response technologies, are all being progressed as more sustainable long-term options.
  - ElectraNet, with support from AEMO, the AER, and the South Australian Government, has progressed a project for four synchronous condensers, fitted with flywheels, to be installed to supply both system strength and inertia to the South Australian region. The first two synchronous condensers will be installed at the Davenport substation by January 2021, and the second two will be installed at the Robertstown substation by May 2021.
- Regulatory changes have recently been made or are under consideration to support system security in South Australia and the wider NEM, including:
  - The Australian Energy Market Commission's (AEMC's) Final Determination and Rule to introduce a mandatory requirement for generators to activate an existing capability to provide primary frequency to improve frequency control in the NEM. The mandatory requirement applies to all scheduled and semi-scheduled generators for a period of three years.
  - Revision of the Inverter Requirements Standard for smaller distribution-connected generation to optimise and support a secure power system under high levels of DER penetration, support energy affordability and allow consumers to pursue individualised services.
  - The AEMC making a Final Determination and Rule to facilitate wholesale demand response in the NEM, through implementing a wholesale demand response mechanism, which is expected to contribute to improved reliability and security in the NEM. This mechanism will allow consumers to sell demand response in the wholesale market directly or through aggregators.
  - The identification of a new "protected event" declaration requirement for non-credible separation of South Australia's transmission network with the rest of the interconnected NEM. This would limit energy imports on the Heywood interconnector in periods when the Under Frequency Load Shedding schemes in South Australia are not effective to prevent cascading failures and potential system black. A request for a new protected event declaration to the Reliability Panel is expected by early 2021.

[11] At https://aemo.com.au/energy-systems/major-publications/renewable-integration-study-ris.

Contents

Tables

Figures

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 the 2020 Integrated System Plan (ISP).

1.1 Purpose and scope

The 2020 SAER provides key insights drawn from a collection of independent reports for the South Australian jurisdiction under Section 50B of the National Electricity Law, known as the South Australian Advisory Functions (SAAF). This report is supplemented by several Excel files with comprehensive data and figures summarising historical information and forecasts. These data files contain many more metrics than are presented in this report.

1.2 Information sources

AEMO has sourced information in this report from other AEMO publications and used information provided by market participants and potential investors as at 12 November 2020, unless otherwise specified. Reporting of gas and electricity market observations is generally based on the previous financial year (2019-20), 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 planning information.

Table 1 Information and data sources

Information source	Website address
2020 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** **2020 Inputs, Assumptions and Scenarios Report**	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
2020 Integrated System Plan (ISP)	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan
August 2020 Notice of South Australia inertia requirements and shortfall	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&hash=673E32C8547A8170C9F4FA34323F3A8F#:~:text=AEMO%20subsequently%20declared%20an%20inertia,Development%20Plan%20(NTNDP)6.&text=are%20closely%20related.-,Power%20systems%20with%20high%20inertia%20can%20resist%20larger%20changes%20in,imbalance%20in%20supply%20and%20demand.

Information source	Website address
2020 Gas Statement of Opportunities (GSOO) for eastern and south-eastern Australia	http://aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities
2020 SAER Data File – tables and figures in this report, as well as many additional metrics	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions
AEMO: Specification for Distributed Energy Resources to provide Contingency FCAS	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Market-ancillary-services-specifications-and-FCAS-verification
AEMO: Wind farms and solar farms testing requirements for Contingency FCAS registration	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Market-ancillary-services-specifications-and-FCAS-verification
AEMO's Summer 2019-20 Readiness Plan	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Summer-operations-report
Renewable Integration Study	https://www.aemo.com.au/energy-systems/major-publications/renewable-integration-study-ris
Distributed Energy Resources Program	https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program
AEMO's 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

1.2.1 Relating the Integrated System Plan to South Australia

In July 2020, AEMO published the 2020 ISP[12], a whole-of-system plan to maximise net market benefits and deliver low-cost, secure and reliable energy by utilising investments in the optimal development path consisting of ISP projects and development opportunities, as well as necessary regulatory and market reforms. The ISP focused on the optimal integration of renewable energy zones (REZs) into an overall strategic NEM-wide network development plan. The next ISP will be published in 2022, with a draft publication for consultation in December 2021 – the timetable for the 2022 ISP is now published with further milestones detailed[13].

The ISP continues to reinforce the need for independent, integrated, transparent, NEM-wide planning, rather than project-by project-assessments, to optimise local project requirements. The strategic developments of a

[12] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

[13] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

portfolio of network and non-network developments provide critical diversity and reliability benefits from existing and new diverse renewable resources, maximising the value from available resources and infrastructure and minimising the overall investment needs.

Outcomes from the ISP studies relating to the South Australian network included:

- The South Australia system strength and inertia remediation to maintain the system security – see Chapter 8 for further information.
- The continued need for a new interconnection between South Australia and New South Wales – see Section 5.2 for further information.
- The importance of coordinating DER to realise the potential it could provide to the market and system operations – see Chapter 8.

Appendix A1 contains important clarifying information regarding data sources and reporting methodology used throughout the SAER and its data files.

1.3 Scenarios

Some tables and figures in this report are based on scenarios that reflect the pace of change in the energy industry, in line with scenarios presented in the 2020 Electricity Statement of Opportunities (ESOO) for the National Electricity Market (NEM) and the 2020 ISP for the NEM.

In summary:

- The **Central** scenario reflects the current transition of the energy industry under current policy settings and technology trajectories, where the transition from fossil fuels to renewable generation is generally led by market forces and supported by current federal and state government policies.
- The **Slow Change** scenario reflects a general slow-down of the energy transition. It is characterised by slower advancements in technology and reductions in technology costs, low population growth, and low political, commercial, and consumer motivation to make the upfront investments required for significant emissions reduction.
- The **High DER** scenario reflects a more rapid consumer-led transformation of the energy sector, relative to the Central scenario. It represents a highly digital world where technology companies increase the pace of innovation in easy-to-use, highly interactive, engaging technologies. This scenario includes reduced costs and increased adoption of distributed energy resources (DER), with automation becoming commonplace, enabling consumers to actively control and manage their energy costs while existing generators experience an accelerated exit. It is also characterised by widespread electrification of the transport sector.
- The **Fast Change** scenario reflects a rapid technology-led transition, particularly at grid scale, where advancements in large-scale technology improvements and targeted policy support reduce the economic barriers of the energy transition. This includes coordinated national and international action towards achieving emissions reductions, leading to manufacturing advancements, automation, accelerated exit of existing generators, and integration of transport into the energy sector.
- The **Step Change** scenario reflects strong action on climate change that leads to a step change reduction of greenhouse gas emissions. In this scenario, aggressive global decarbonisation leads to faster technological improvements, accelerated exit of existing generators, greater electrification of the transport sector with increased infrastructure developments, energy digitalisation, and consumer-led innovation.

AEMO developed additional sensitivities in 2020 to specifically explore the reliability impacts of COVID-19. These sensitivities examined the effects on consumer peak demand and energy consumption associated with the social and economic restrictions associated with the pandemic, and included:

- *Central Downside* captures a more sustained economic downturn and lower manufacturing activity before returning to trend by 2023-24.

- *Central Downside, High DER* captures the same economic downturn as the Central Downside sensitivity but examines how higher distributed PV uptake, possibly stimulated by Government recovery efforts, could affect grid consumption.
- *Central Downside, High DER + Industrial closures* captures the same economic downturn and distributed PV uptake as the Central Downside, High DER sensitivity but applies a larger shock to the manufacturing sector, with only a partial return of load by 2023-24.
- *Central Upside* sensitivity that reflects a 'return to office' transition whereby the ramp up of business demand overlaps with a more gradual decrease in residential load.

Further information on the 2019-20 scenarios is available in the 2020 Inputs, Assumptions and Scenarios Report (IASR)[14]. As part of the two-yearly processes associated with the ISP, AEMO is currently reviewing these scenarios for use across 2021 and 2022 including for the 2022 ISP.

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

2. Consumer behaviour – behind the meter

The proportion of South Australian dwellings that now have rooftop photovoltaic (PV) systems installed is around 33%, a higher penetration than any other state or territory in Australia and the world[15]. Distributed PV systems of residential and commercial scale showed the highest yearly increase on record in 2019-20, and South Australia is projected to have the highest ratio of rooftop PV generation to operational consumption of all NEM regions at least until 2029-30.

This section covers uptake of these technologies and the role of DER, as forecast in the 2020 NEM ESOO[16]. Section 3 covers the forecast impact on the timing and magnitude of maximum operational demand.

2.1 Rooftop photovoltaics (PV)

Rooftop PV systems installed on South Australian residential and commercial premises have a measurable impact on the region's operational electricity demand, by reducing residential and commercial grid consumption during daylight hours, when consumer demand can be met by rooftop PV.

From 2012-13, rooftop PV production has shifted minimum operational demand from overnight to occur in the middle of the day, and the time of maximum operational demand further into the evening. In South Australia, maximum demand now typically occurs late in the day (between 6:30 pm and 8.00 pm Adelaide time in summer), when solar irradiance is low.

In this SAER:

Rooftop PV means solar systems up to 100 kilowatts (kW) connected "behind the meter" to the distribution system.

PV non-scheduled generation (PVNSG) means distributed systems greater than 100 kW, up to 30 megawatts (MW).

Distributed PV means rooftop PV and PVNSG combined.

2.1.1 Rooftop PV forecast methodology

Forecast methodology

AEMO's Electricity Demand Forecasting Methodology Information Paper[17] describes the methodology for rooftop PV capacity and generation forecasts, as used across AEMO's forecasting and planning publications, including the 2020 NEM ESOO. A short summary of capacity and generation estimation methods is below.

Capacity estimation

Historical installed capacity for rooftop PV is extracted from a data set provided by the Clean Energy Regulator (CER).

[15] See http://apvi.org.au/wp-content/uploads/2018/12/Solar-Trends-Report-for-Solar-Citizens-FINAL_11-12-18_2_logos.pdf.

[16] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

[17] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

Generation estimation

The historical energy generated by rooftop PV systems is estimated for each half-hour, converting measurements of solar irradiance into generation outputs appropriate for small-scale installations[18]. It models inefficiencies related to shading effects and considers the geographic distribution of rooftop PV installations. This method takes into account the historical reduced panel efficiency associated with ageing.

AEMO's historical rooftop PV generation is thereby a combination of the historical capacity estimates (calculated from CER data) and the modelled normalised generation expected for each kW of rooftop PV capacity installed.

2.1.2 Rooftop PV forecast

Rooftop PV capacity

Since 2009, South Australian total installed rooftop PV[19] capacity has grown strongly. The proportion of South Australian dwellings that now have rooftop PV systems installed is around 33%, which is the highest proportional penetration in a state in Australia[20].

An additional 288 MW is estimated to have been installed in 2019-20 across the business (104 MW) and residential (184 MW) sectors[21], this being the highest yearly increase on record and bringing the total estimated combined residential and business PV capacity in South Australia to 1,417 MW.

Figure 1 shows the estimated actual and forecast installed rooftop PV capacity (residential and business sectors) for South Australia from 2015-16 to 2029-30. In the Central scenario, rooftop PV installed capacity is forecast to grow steadily over the next decade.

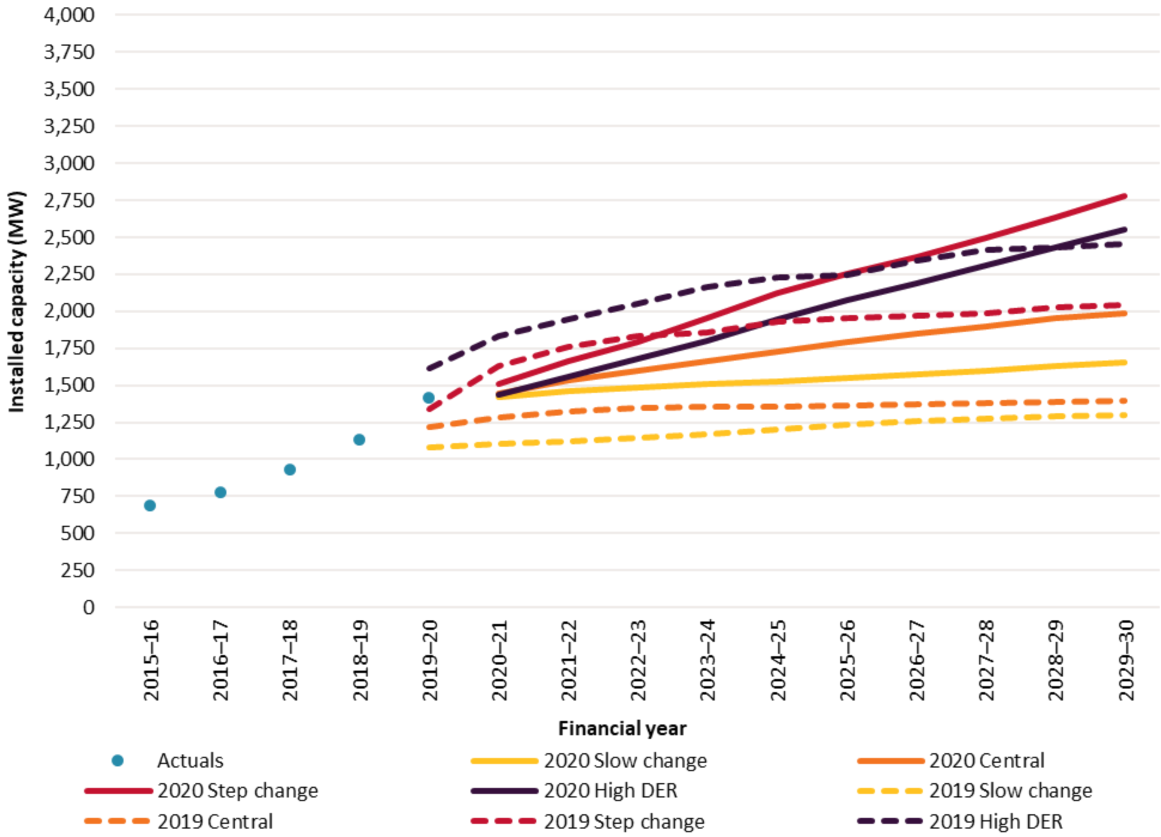
[18] Solar irradiance developed in collaboration with AEMO by the University of Melbourne[18] (2000-07),and procured from *Weatherzone* (2008-20).

[19] Rooftop PV comprises both business and residential installations.

[20] Based on CER data for the number of systems, and AEMO's database on the number of household electricity connections.

[21] Estimates calculated as at September 2020, for the financial year 2019-20.

Figure 1 South Australian rooftop PV installed capacity forecasts to 2029-30



According to recent AEMO internal analysis of current installation rates, an estimated 90 MW of additional rooftop PV is expected to be installed by October 2020, compared with AEMO's forecast for the Central scenario. This indicates that the current DER installation rate sits between the Central and the Step Change scenario forecasts.

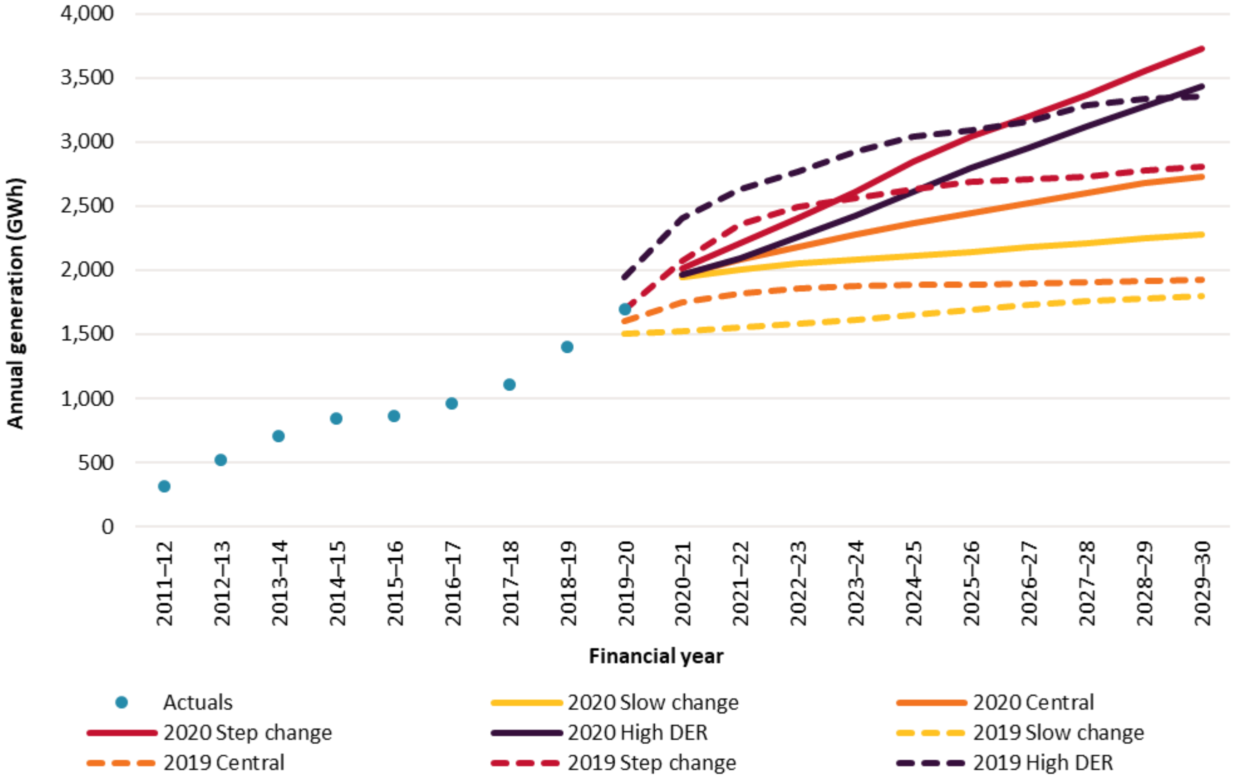
Rooftop PV generation

Over the next 10 years, South Australia is projected to have the highest ratio of rooftop PV generation to operational consumption of all NEM regions. This is attributed to the region's high penetration of rooftop PV installations, good solar resources, and the second-lowest operational consumption of all regions in the NEM.

Figure 2 shows the estimated actuals and forecasts of annual rooftop PV generation for South Australia from 2011-12 to 2029-30. In 2019-20, annual rooftop PV generation was estimated at 1,692 gigawatt hours (GWh)[22]. In the Central scenario, it is forecast to increase to 2,725 GWh by 2029-30, which would represent approximately 25% of annual underlying consumption at that time.

[22] Estimates calculated as at September 2020, for the financial year 2019-20.

Figure 2 South Australian rooftop PV generation forecasts to 2029-30



2.2 PV non-scheduled generation (PVNSG)

PVNSG capacity is defined as capacity between 100 kW and 30 MW and is typically business rooftop PV and small solar farms below AEMO's registration threshold of 30 MW.

South Australia has experienced rapid growth in PVNSG over the last four years, although from a relatively low base. This has been driven by commercial decisions in the small to medium commercial sector to reduce energy costs, as well as incentives driven by large-scale generation certificates (LGCs).

Figure 3 shows the estimated amount of PVNSG installed capacity at 30 June 2020 was 129 MW[23].

In the Central scenario, PVNSG installed capacity is forecast to grow from 190 MW in 2020-21 to 348 MW in 2029-30. Figure 4 shows the estimated actuals and forecasts of annual PVNSG generation for South Australia from 2011-12 to 2029-30. In 2019-20, annual PVNSG generation was estimated at 258 GWh. In the Central scenario, it is forecast to increase to 801 GWh by 2029- 30.

[23] Note there is a delay between a PVNSG connection and its registration with the CER for the LGCs. Estimates calculated as at September 2020, for the financial year 2019-20.

Figure 3 South Australian PVNSG installed capacity forecasts

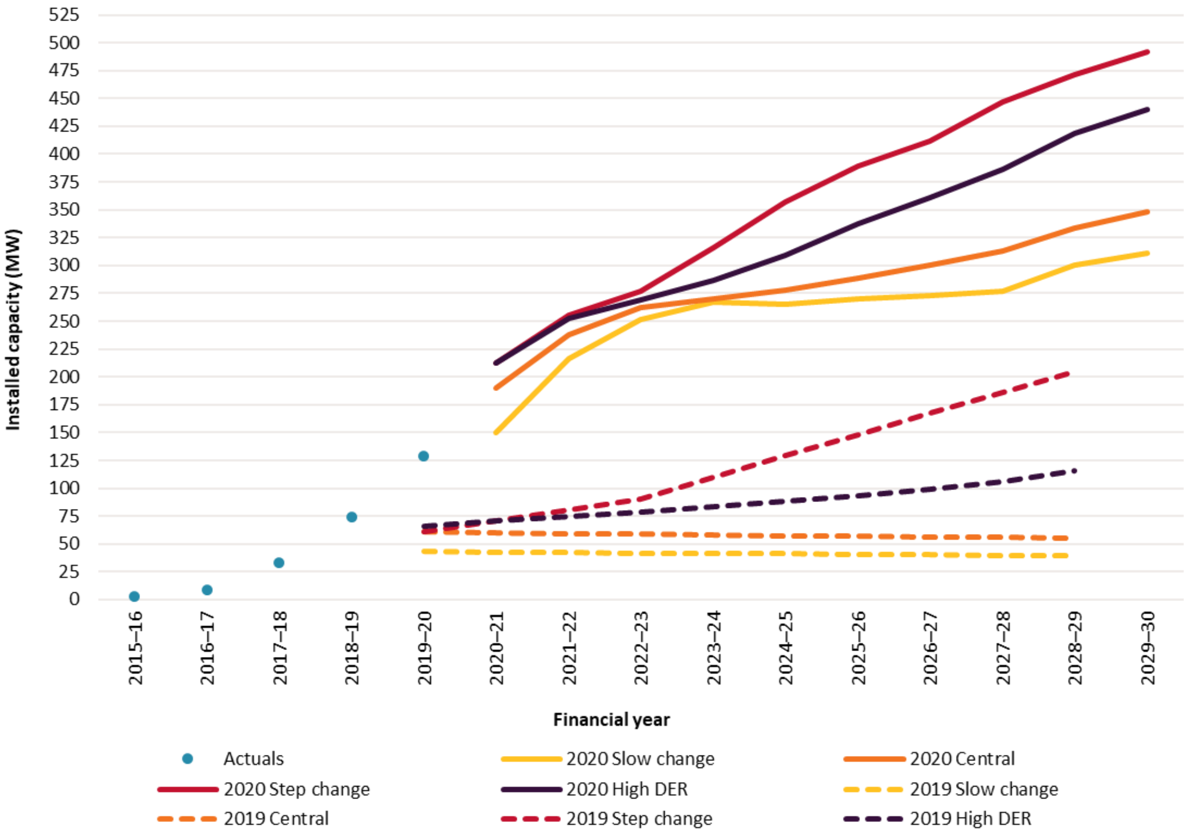


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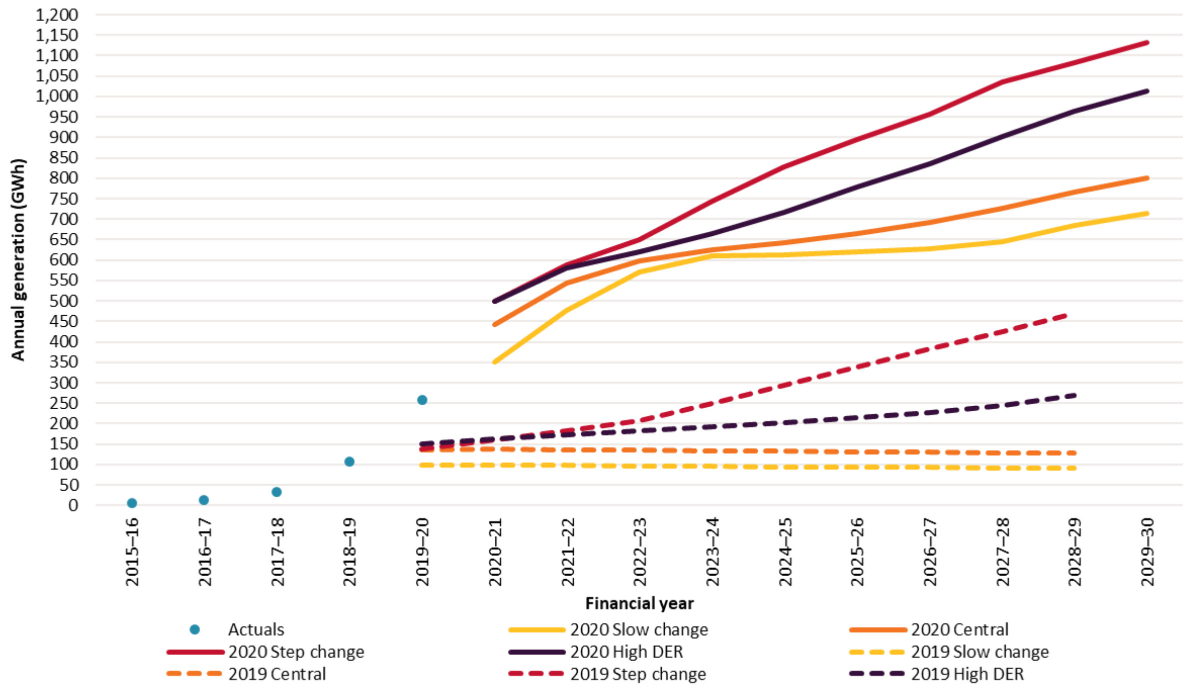
Figure 4 South Australian PVNSG generation forecasts



2.3 Embedded battery storage

As at 30 June 2020, South Australia has an estimated 72 MW (or 17,000 units) of embedded battery systems[24]. In the next five years, the number of batteries is forecast to reach nearly 50,000 units. This represents approximately 20% of all the batteries forecast to be installed in the NEM by 2025, supported by the South Australian Government's Home Battery Scheme[25].

By 2029-30, uptake of business and residential behind-the-meter battery systems is forecast to reach approximately 322 MW (in the Central scenario) and 875 MW (in the Step Change scenario). Battery uptake is forecast to be slower than previous projections, due to revisions to payback periods, technology costs, and linkages to distributed PV uptake rates. Current modelling assumed most battery systems would be installed as part of integrated solar and battery systems.

Depending on pricing incentives, battery storage systems may have differing impact on the demand profile, enabling households to store and use surplus solar production (if part of an integrated battery and solar system) and shift this energy for use to meet evening peak demands. Increased market benefits are expected if the battery fleet is coordinated to provide a more certain peak support role.

It is possible for embedded battery systems to join a virtual power plant (VPP). A VPP broadly refers to an aggregation of resources (such as decentralised generation, storage and controllable loads) coordinated to deliver services for power system operations and electricity markets.

VPP trials are underway by retailers and technology providers, including:

- South Australia VPP (SA VPP) (10 MW) operated by Energy Locals and Tesla with support from the South Australian Government[26].
- AGL VPP (3 MW), with support from the Australian Renewable Energy Agency (ARENA)[27].
- Simply Energy VPP's (3 MW), with support from ARENA[28].
- Shinehub VPP (1 MW).[29]
- SA Power Networks Advanced VPP Grid Integration, with support from ARENA[30].

Further information on VPPs, including the VPP Demonstrations program, is provided in Section 8.7.

2.4 Electric vehicles

In 2019-20, there were an estimated 1,700 electric vehicles (EVs) in South Australia including plug-in hybrid electric vehicles (PHEVs), although confidence in the actual number of EVs at this stage is relatively low[31].

By 2029-30, in the Central scenario, there are forecast to be over 38,000 residential EVs in the state, and over 9,000 non-residential vehicles. The Step Change scenario EV forecast is higher, projecting nearly 200,000 residential vehicles and over 50,000 non-residential vehicles.

Annual electricity consumption from EV charging is forecast to be approximately 158 GWh (or 1.6% of total consumption) in 2029-30 in South Australia (under the Central scenario). The impact of EVs on the daily load profile and maximum demand depends on how and when they are charged. Charging is likely to be

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[24] 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.

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

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

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

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

[29] At https://shinehub.com.au/sa-vpp-launch-offer.

[30] At https://arena.gov.au/projects/advanced-vpp-grid-integration/.

[31] CSIRO, 2019 Projections for small-scale embedded technologies report, at https://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2020/CSIRO-DER-Forecast-Report.

influenced by the availability of public infrastructure, tariff structures, any energy management systems, and drivers' routines.

For the 2020 ESOO, AEMO considered four distinct charging profiles:

- Convenience charging – vehicles assumed to have no incentive to charge at specific times.
- 'Smart' daytime charging – vehicles incentivised to charge during the day by tariff structures, with available associated infrastructure to enable charging at this time.
- 'Smart' night-time charging – vehicles incentivised to charge overnight by tariff structures, with available associated infrastructure to enable charging at this time.
- Highway fast-charging – vehicles require a fast-charging service while in transit.

These profiles reflected different incentives to charge during day-time or overnight off-peak periods, relative to convenience-based behaviours which may impact more significantly on peak loads.

Not incorporated in these forecasts is the potential for EV charging to take place in a coordinated manner, for example as part of a VPP that optimises vehicle charging profiles for demand and/or market conditions. This is one potential innovative solution to increase system load in the daytime that could provide relief to the challenges associated with lower minimum demand (these challenges are explored further in Chapter 8.)

Charge profile preferences are forecast to change over time. The increasing electrification of the transport sector is expected to lead to greater charging infrastructure development and tariff change, providing consumers with greater choice to charge their vehicles in ways that are increasingly convenient and cost-effective, while minimising grid cost and impact. As a result, AEMO anticipates growth over time in charging behaviour aligned to times of low overall demand, such as when distributed PV generation is high.

However, vehicles will remain modes of transportation first and foremost, and a key challenge as the sector transforms will be the enablement of data-driven decision-making that attempts to maintain vehicle availability for travel when required, while avoiding unnecessary costs to consumers associated with charging. Without this, charging load may put more stress on the power system than may be necessary with energy management innovation incorporated into these future vehicles and charging infrastructure.

3. Operational consumption and demand

In recent years, operational (grid) consumption has declined, and this decline is forecast to continue, although at a slower rate, with varying trends for individual customer segments.

Residential operational consumption is forecast to continue to decline with continued high growth in distributed PV, mostly offset by forecast growth in electric vehicle uptake. Growth in the state economy (notably large industrial loads) is forecast to offset the decline from commercial distributed PV installations and business sector energy efficiency programs.

High penetration of distributed PV in South Australia means peak demand now occurs later in the day, limiting the impact on forecast maximum demands, but is forecast to lead to rapid declines in minimum demand.

3.1 Historical and forecast consumption and demand

3.1.1 Operational consumption

This section presents recent historical observations and long-term forecasts of annual operational consumption in South Australia[32].

In 2019-20, South Australia's operational consumption (sent-out) was 11,890 GWh. This was 0.2% (91 GWh) lower than the 2018-19 consumption of 12,166 GWh.

Operational consumption in the region is forecast to decrease under the 2020 NEM ESOO Central scenario, from 11,584 GWh in 2020-21 to 10,874 GWh in 2029-30 (-0.7% average annual growth rate).

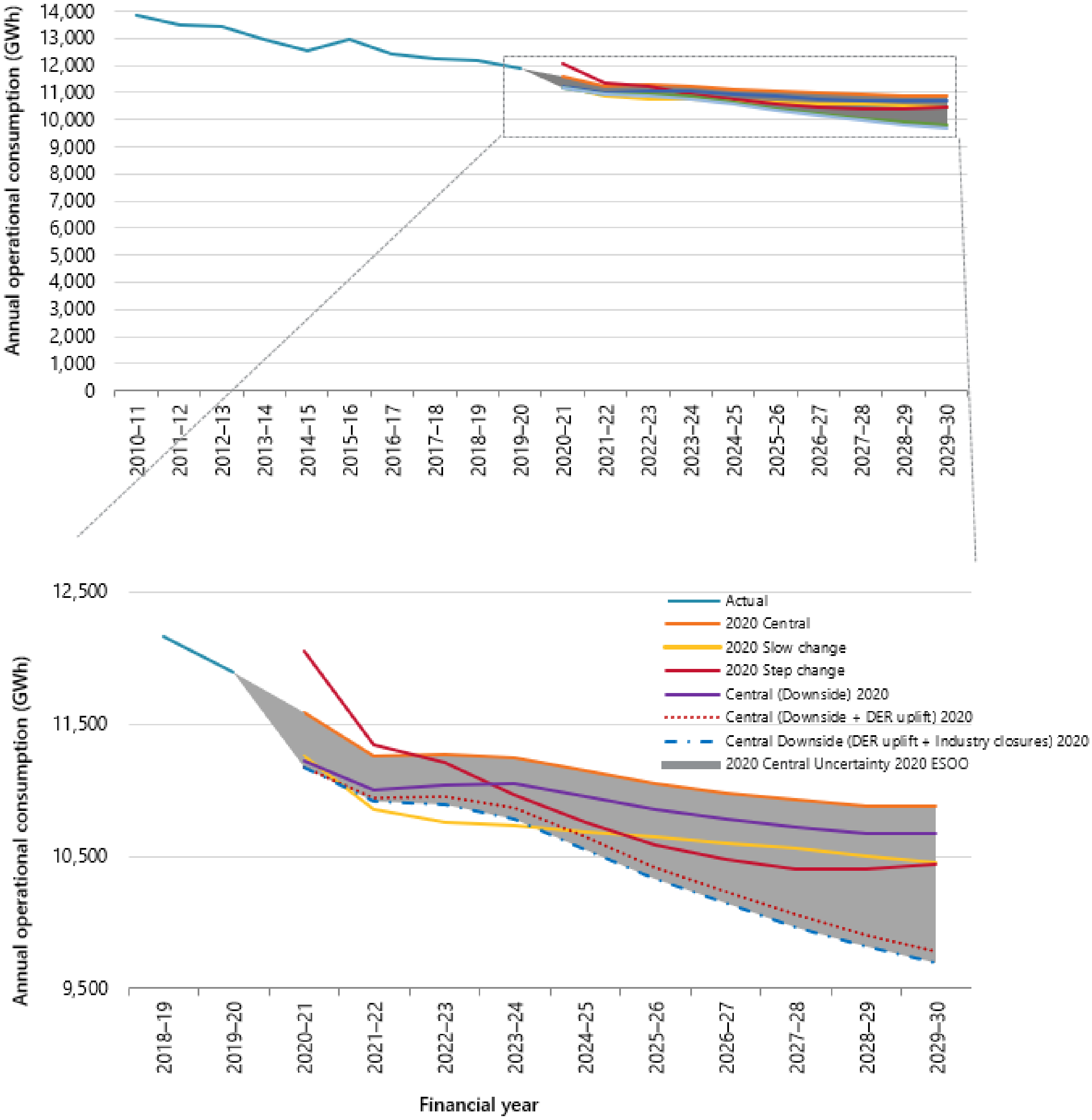
Figure 5 shows the historical trend of operational consumption in South Australia from 2010-11 as well as the 10-year forecast. It shows a noticeable decline from 2011-12 onwards, which has been driven by a fall in residential, commercial, and industrial consumption as consumers have become more actively engaged in their energy use, with strong uptake of distributed PV and investments in devices and activities that increase energy efficiency.

Over the next 10 years, the decline is forecast to continue, although at a lesser rate, and there are varying trends projected for individual customer segments, such as large industrial loads which have a moderate increase.

The uncertainty in the impact of COVID-19, expressed through the scenarios and sensitivities, has resulted in a range of reduced operational energy consumption and maximum demand forecasts in the short to medium term – see Section 3.1.4.

[32] Forecasts are presented on a sent-out basis, meaning the forecasts exclude generator auxiliary loads. See Glossary, measures, and abbreviations for more on definitions.

Figure 5 Annual operational consumption (sent-out) actual and forecast for South Australia

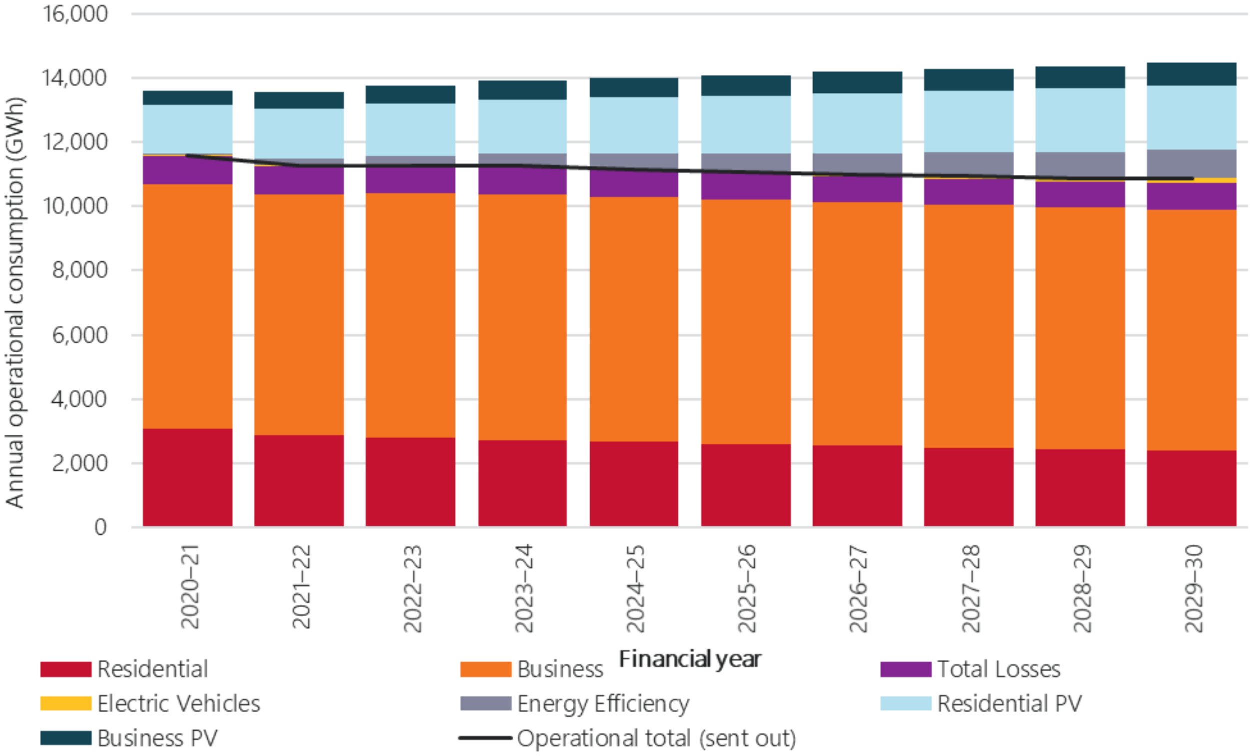


As Figure 6 below shows, residential consumption is forecast to continue to decline post COVID-19 recovery, driven by only minor growth in population, combined with continued high growth in distributed PV installations and ongoing improvements in energy efficiency through new schemes and appliances (including air-conditioning) and better insulation of houses.

Business consumption is forecast to remain relatively flat (-0.1% year-on-year average growth), as growth in large industrial loads is forecast to offset the decline from commercial distributed PV installations and business sector energy efficiency programs.

EV consumption is projected to mostly offset the drop in residential consumption.

Figure 6 Forecast annual operational consumption (sent-out) with components (Central scenario)



3.1.2 Operational maximum demand

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

The large levels of installed distributed PV capacity in South Australia to date have resulted in maximum operational demand shifting from the middle of the day to the evening, when distributed PV is not generating. On Thursday 19 December 2019, operational demand in South Australia reached 3,147 MW (measured on a 'sent-out' basis) at 7:30 pm (Adelaide time) with a temperature of 40.5 degrees Celsius (ºC) recorded at Adelaide (Kent Town). The maximum event occurred when production from rooftop PV was very low as solar irradiance is low at this time. High temperatures could have negatively impacted PV generation across the day, as solar panels' output start to degrade when they are overheated.

With maximum operational demand events now tending to occur at times when PV generation is low, the 2020 ESOO suggests that further increases in rooftop PV capacity will unlikely impact maximum operational demands. Table 2 shows that since 2015-16, the time of maximum operational demand has occurred late in the day.

Insights into AEMO's forecasting performance are reported annually in its *Forecast Accuracy Report*[33].

Impact of distributed PV on underlying maximum demand

Table 2 shows estimated distributed PV generation at time of underlying maximum demand[34] for the last five years, illustrating that the contribution of distributed PV has grown year on year since 2015-16.

[33] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Forecasting-Accuracy-Reporting.

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

Table 2 Distributed PV contribution to underlying and operational maximum demand in South Australia

Year	Distributed PV estimated contribution to underlying maximum demand (MW)	Time of underlying maximum demand (Adelaide time)	Distributed PV estimated generation at the time of operational maximum demand (MW)	Time of operational maximum demand (Adelaide time)
2015-16	229	5:30 PM	88	7:00 PM
2016-17	331	5:00 PM	177	6:30 PM
2017-18	393	5:00 PM	83	7:30 PM
2018-19	472	5:00 PM	97	7:30 PM
2019-20	682	12:30 PM	90	7:30 PM

Note: Underlying demand 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.

Underlying maximum demand for 2019-20 occurred at 12:30 PM on 20 December 2019, following Adelaide's hottest December daily temperature since 1904 of 45.3°C (on Thursday 19 December) and hottest December overnight temperature on record since 1897 of 33.6°C. By 12:00 pm on Friday 20 December, temperatures were close to 42°C before a cool change arrived and temperatures decreased into the evening.

Forecast operational maximum demand

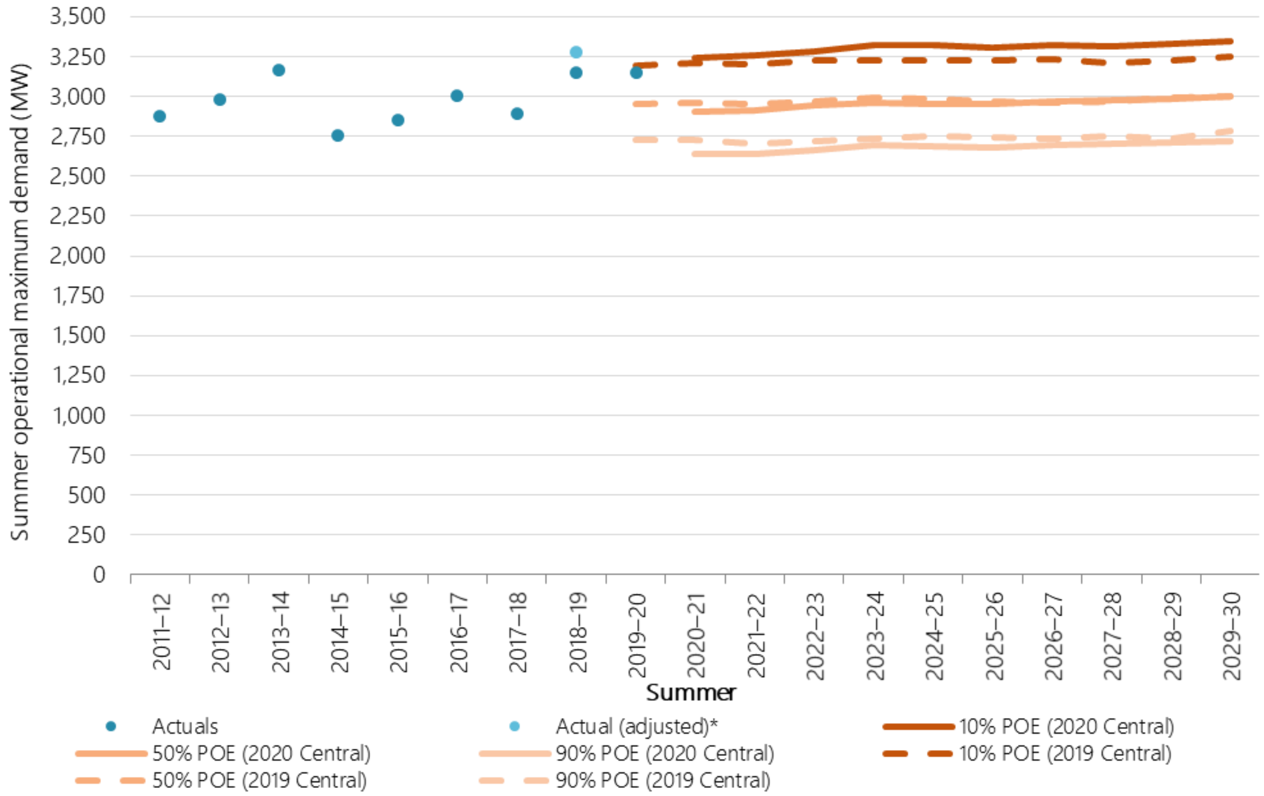
Annual maximum operational demand is forecast to continue to occur in summer, and is expected to grow slightly, due to expansion of large industrial loads, growth in EVs, and increased connections.

Figure 7 shows historical summer maximum demand actuals since 2010-11, and 10%, 50%, and 90% POE forecasts from the 2020 and 2019 NEM ESOOs (Central scenario). Over the next 10 years, maximum operational demand (50% POE, Central scenario) is forecast to have an average annual growth rate of 0.34%.

South Australia's home battery scheme subsidy is expected to have some dampening effect on operational demand in the early evening. EV growth is projected to have a minor impact on maximum operational demand, due to an expectation of more overnight charging, although as outlined previously the magnitude of impact will depend on the infrastructure available and consumer preferences (and incentives) to operate in a manner that minimises grid disruption while maintaining convenience.

As Figure 7 shows, the operational demand that was reached on Thursday 19 December 2019 was in line with the 10% POE forecast peak.

Figure 7 Summer operational maximum demand (sent-out) actual and forecast for South Australia, 2011-12 to 2029-30 (Central scenario)



* Adjusted actual value for 2018-19 is AEMO's estimate of what would have been reached without load shedding or demand side participation (DSP) of any sort. As there was no load shedding or significant DSP during 2019-20, there is no adjustment required for demand in that year.

South Australia's home battery scheme subsidy is expected to have some dampening effect on operational demand in the early evening. EV growth is projected to have a minor impact on maximum operational demand, due to an expectation of more overnight charging, although as outlined previously the magnitude of impact will depend on the infrastructure available and consumer preferences (and incentives) to operate in a manner that minimises grid disruption while maintaining convenience.

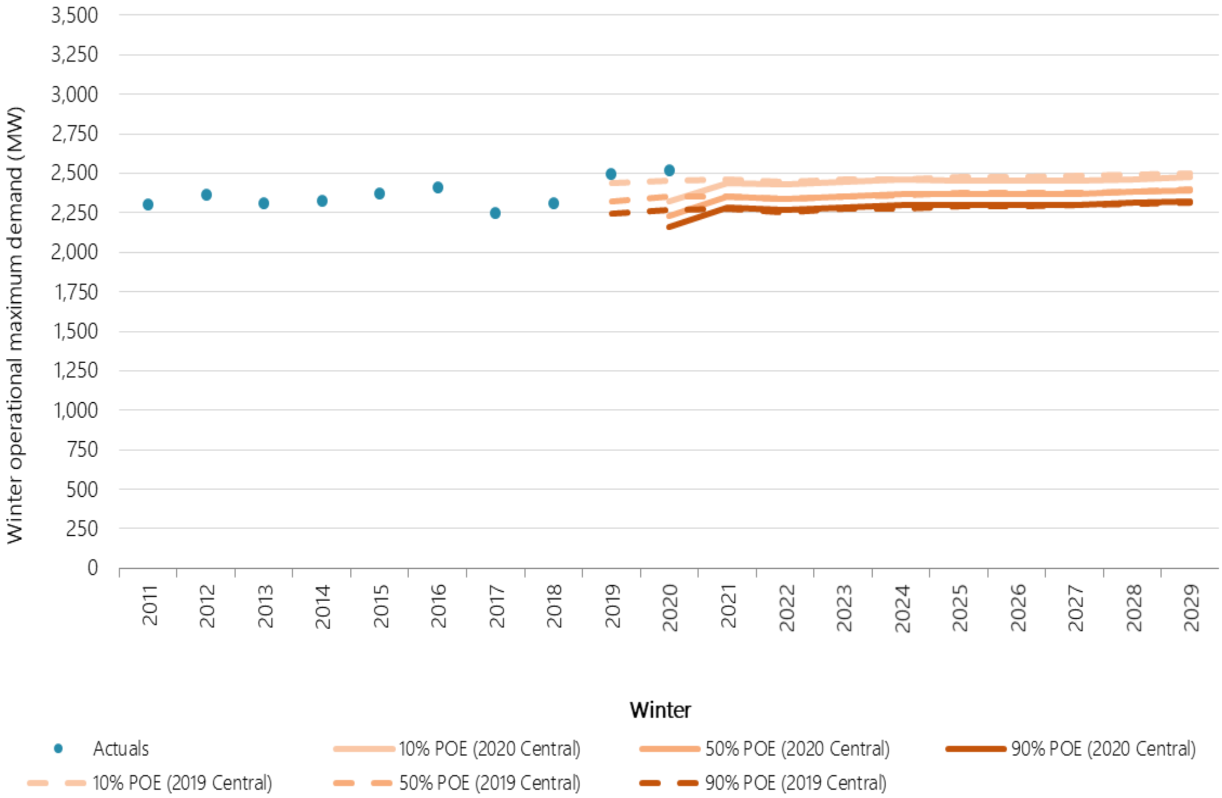
As Figure 7 above shows, the operational demand that was reached on Thursday 19 December 2019 was in line with the 10% POE forecast peak.

Figure 8 below shows the same period for South Australia's operational maximum demand in winter.

The 2020 Central forecasts included a lower maximum winter demand in 2020 due to the estimated impact of COVID-19 at the time (see Section 3.1.4). South Australia's actual operational maximum demand increased through winter due to weather, increases in residential heating and higher industrial load. COVID-19 may have influenced the demand shape leading to higher demand in the evenings[35]. A new record high winter demand of 2,523 MW was set on 7 August 2020, in a significantly cold week, exceeding the previous record set on 24 June 2019. From 2020-21 onwards, winter maximum demand is forecast return to previous levels and remain relatively constant across the time horizon.

[35] See AEMO's Quarterly Energy Dynamics reports for Q2 2020 and Q3 2020, at https://aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed.

Figure 8 Winter operational maximum demand (sent-out) actual and forecast for South Australia, 2011 to 2029 (Central scenario)



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

Demand side participation (DSP)

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

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

The estimated level of DSP available in South Australia for summer 2020-21 and winter 2021 is shown in Table 3. It reflects AEMO's expected (median) DSP resource response to different wholesale price levels. Reliability response DSP estimates are also included, referring to situations where additional DSP is observed in response to a Lack of Reserve (LOR) notice (LOR 2 or LOR 3) being issued[36].

The methodology used is explained in AEMO's DSP forecast methodology[37], which includes a summary of the groups that are included in AEMO's DSP values, the groups excluded, and the reasons why. Notably:

- DSP responses triggered by the Reliability and Emergency Reserve Trader (RERT) process, as discussed in Section 7.2, are excluded.

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[36] LOR conditions indicate times the system may not have enough reserves to meet demand if there is a large, unexpected event. See AEMO's reserve level declaration guidelines, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/ reserve-level-declaration-guidelines.pdf.

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

- Operation of battery storage units, including VPPs, is reflected in other parts of AEMO's forecasting process and this is therefore excluded from DSP to avoid double-counting.
- Time-of-use tariff impacts and controlled-load arrangements are captured in the demand forecast, and are therefore not included in the DSP forecast to avoid double-counting of these effects.

Table 3 shows the estimated cumulative price response is 27 MW for South Australia when prices exceed $500 a megawatt hour (MWh), and 58 MW when prices exceed $5,000/MWh. However, if LOR 2 or LOR 3 conditions are declared, the total DSP response is estimated to be 61 MW in South Australia.

The region had its 2019-20 maximum demand in the evening of 19 December 2019. Prices reached the market price cap ($14,700/MWh), but the state had sufficient supply to avoid declaring an LOR2. A few customers reduced consumption, but mainly in line with what they often do during that time of day, which would be accounted for in AEMO's maximum demand forecast, so, the estimated DSP response is negligible. On the second highest demand day last financial year, on 30 January 2020, the region entered an actual LOR2 state with prices reaching a maximum of $12,217.13. On that day, AEMO estimated 50-60 MW of DSP response from various customers.

Table 3 Estimated DSP by wholesale price levels and reliability response* for South Australia

Trigger	Summer 2020-21 (MW – cumulative for each price band)	Winter 2021 (MW – cumulative for each price band)
>$300 / MWh	12	12
>$500 / MWh	27	27
>$1000 /MWh	33	33
>$2500 /MWh	50	50
>$5,000 / MWh	58	58
>$7,500 / MWh	61	61
Reliability Response	61	61

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

3.1.3 Operational minimum demand

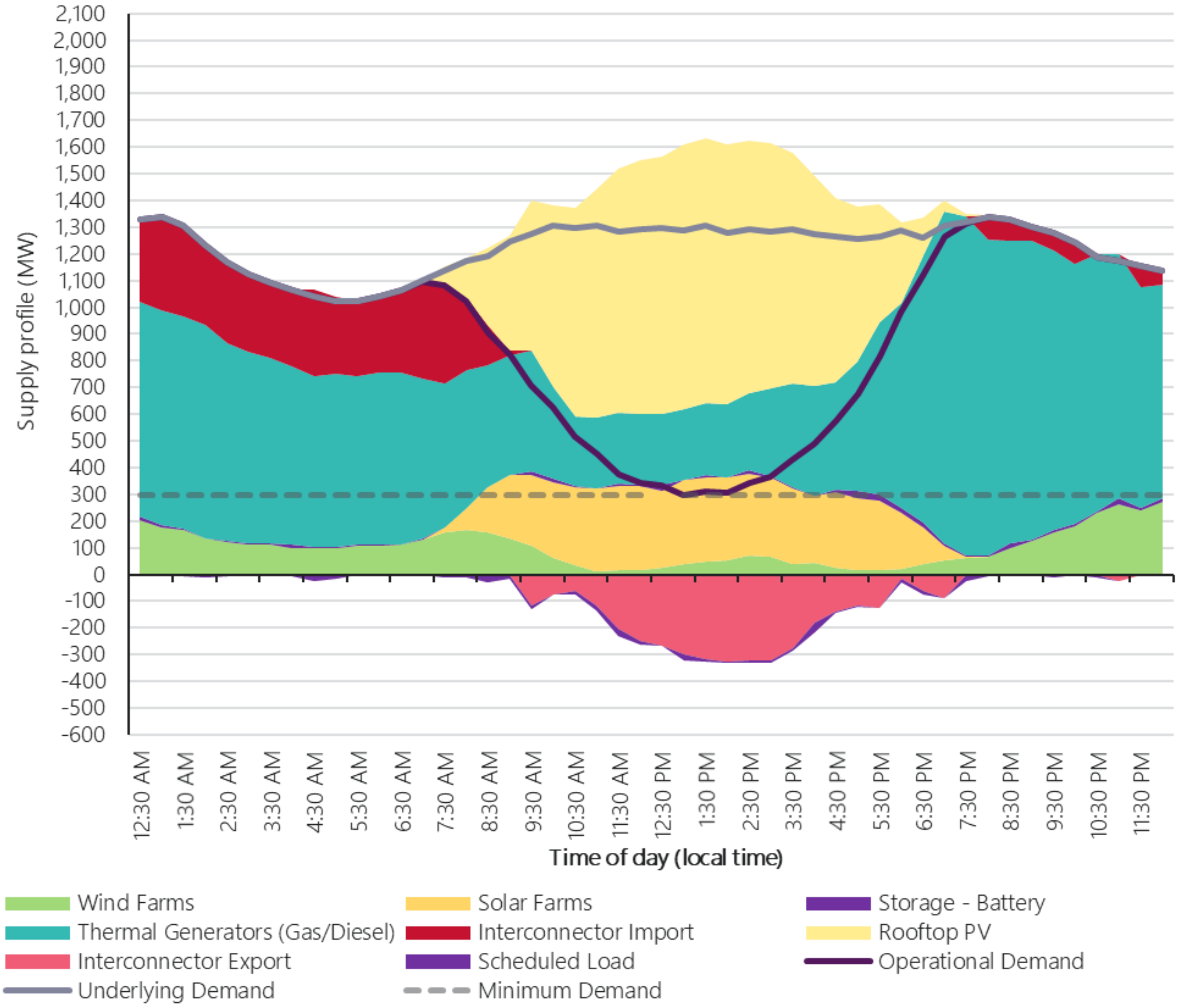
South Australia has experienced minimum demand in the middle of the day since 2012-13, and this is forecast to continue. Minimum operational demand typically occurs during weekends or public holidays when demand is low, when temperatures are mild, and around noon when distributed PV reduces the need for grid-delivered energy.

A new record low minimum operational demand of 290 MW sent-out (300 MW as-generated[38]) was set on Sunday, 11 October 2020. This broke the previous year's minimum demand record, set in November 2019.

The most recent record, as seen in Figure 9, occurred at 1:00 pm (Adelaide time). At this time, South Australia was a net exporter, and the peak generation from large-scale solar and rooftop PV was 1,305 MW, which also was the first time all solar generation reached 100% of the total underlying demand (of 1,289 MW). This day was a clear day, with high solar irradiance for the time of the year and daytime temperatures in the low to mid 20s, but, being a weekend, commercial and industrial loads were relatively low.

[38] As-generated demand, unlike sent-out, includes auxiliary loads. For more definitions, see https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/2020/demand-terms-in-emms-data-model.pdf?la=en&hash=72FA78488ED638F1A00A8C9AF80D303C.

Figure 9 Profile of record minimum operational (as-generated) demand day (11 October 2020)



Forecast operational minimum demand

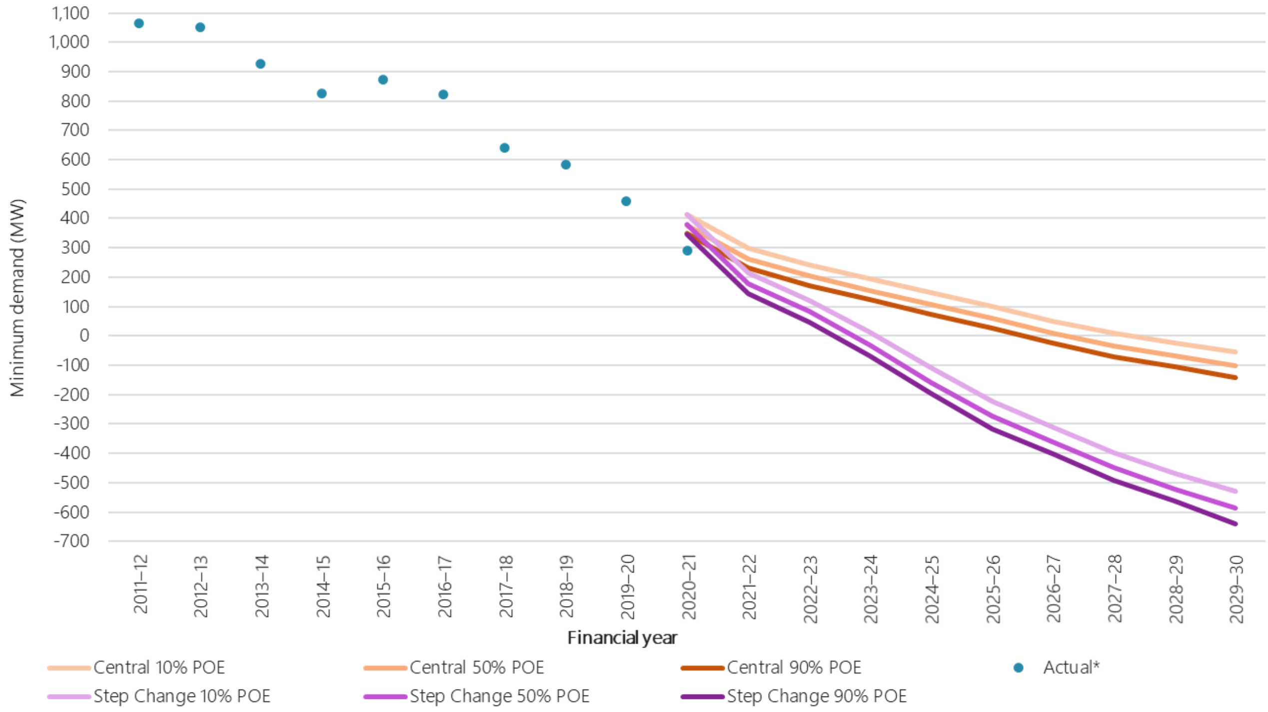
Figure 10 shows that shoulder[39] minimum demand is forecast to decline significantly in the Central scenario from 2020-21 to 2021-22, at a rate of 18% per annum, due to an increase in distributed PV installation, then to decline more gradually in the following years and, in the absence of flexible loads or storage, reach negative minimum operational demand by 2026-27. The slower decline post 2022-23 is due to a forecast lower rate of distributed PV installation. The South Australian Government's Home Battery Scheme is forecast to slightly reduce the impact of high distributed PV installation on minimum operational demand.

The High DER scenario also forecasts a steep decline forecast in the first two years, then a more moderate decline, until reaching negative operational demand by 2023-24.

The minimum demand observed in October 2020 is more consistent with the Step Change 90% POE 2020 ESOO forecast than the Central scenario, primarily due to more distributed PV installations in the year to date than was forecast under the Central scenario.

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

Figure 10 Shoulder operational minimum demand (sent-out) actual and forecasts for South Australia (Central and Step Change scenarios)



* Record minimum demand occurred 11 October 2020 and has been included in the 2020-21 financial year actual; 2020-21 has been included as an actual despite it being an incomplete year as annual minimum demand typically now occurs in Spring. The 2016-17 minimum excludes the black system event day in South Australia on 28 September 2016.

3.1.4 COVID-19 impacts

There has been an increase in near-term forecast demand uncertainty due to COVID-19, as the economic and social impact of drivers such as activity and movement restrictions are without precedent in modern times.

The 2020 ESOO annual consumption, minimum and maximum demand forecasts incorporated estimated COVID-19 impacts on the economy and large industrial loads, and short-term and long-term changes to the daily load profile. The uncertainty affected the input drivers for each scenario, and led to additional sensitivities in the 2020 ESOO.

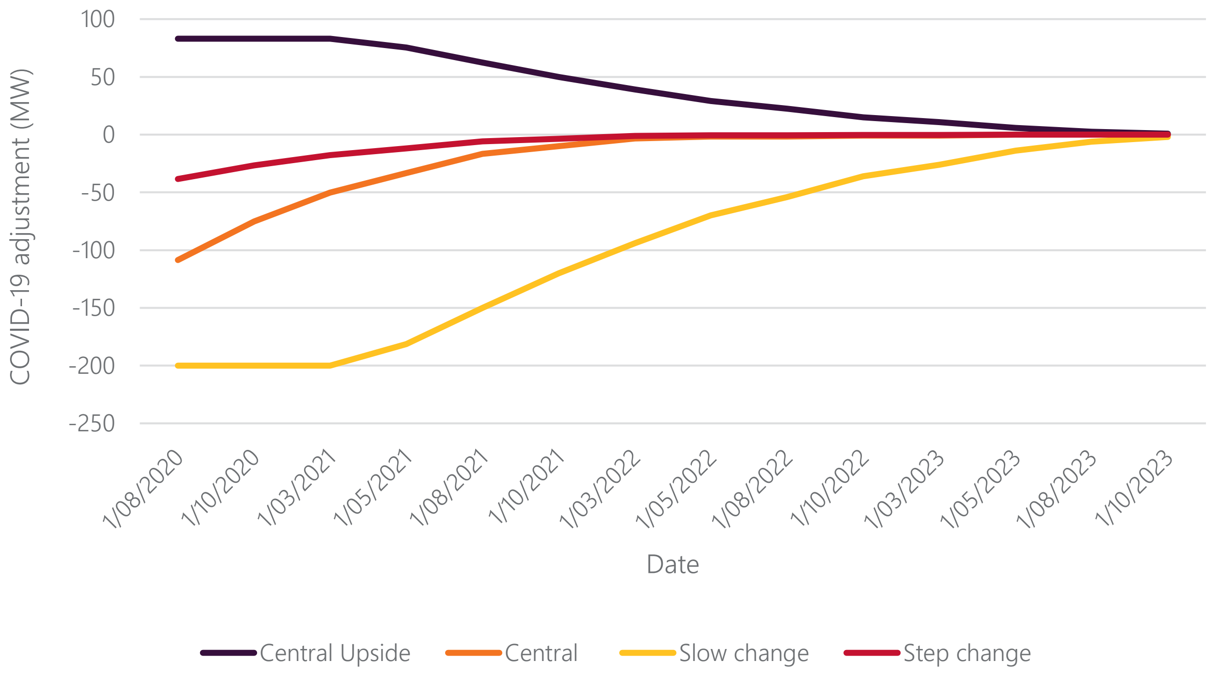
In 2020-21, the effect of COVID-19 on the economy is forecast to lower consumption for the business sector. This is partly offset by a forecast increase in residential consumption, in part due to the modelled impact of COVID-19 leading to greater "work from home" energy consumption. Beyond this point, a forecast return to near pre-COVID-19 mobility levels reduces residential consumption. Consumption in other sectors is expected to recover alongside an economic recovery.

COVID-19 has also impacted the daily load profile, and AEMO's forecasts estimated the impact to minimum and maximum demand. This was captured through two parts:

1. Estimation of base COVID-19 impact to minimum and maximum over autumn and winter 2020.
2. Forecast trend of COVID-19 impact to future years using assumptions and scenarios.

Figure 11 shows the South Australian forecast maximum demand impact of COVID-19. The figure assumes that as lockdown restrictions ease, and people return to work, the economy recovers and the overall impact returns to pre COVID drivers over time. Figure 11 shows the three 2020 ESOO scenarios and a more recent Central Upside sensitivity that reflects a slower 'return to office' transition whereby the ramp up of business demand overlaps with a more gradual decrease in residential load. For more information on the methodology and assumptions please see Appendix A2 of the 2020 ESOO.

Figure 11 Forecast maximum demand offsets due to COVID-19



3.1.5 Trends in maximum and minimum demand

The relatively large range between minimum and maximum demand in South Australia creates challenges for managing the power system (see Chapter 8).

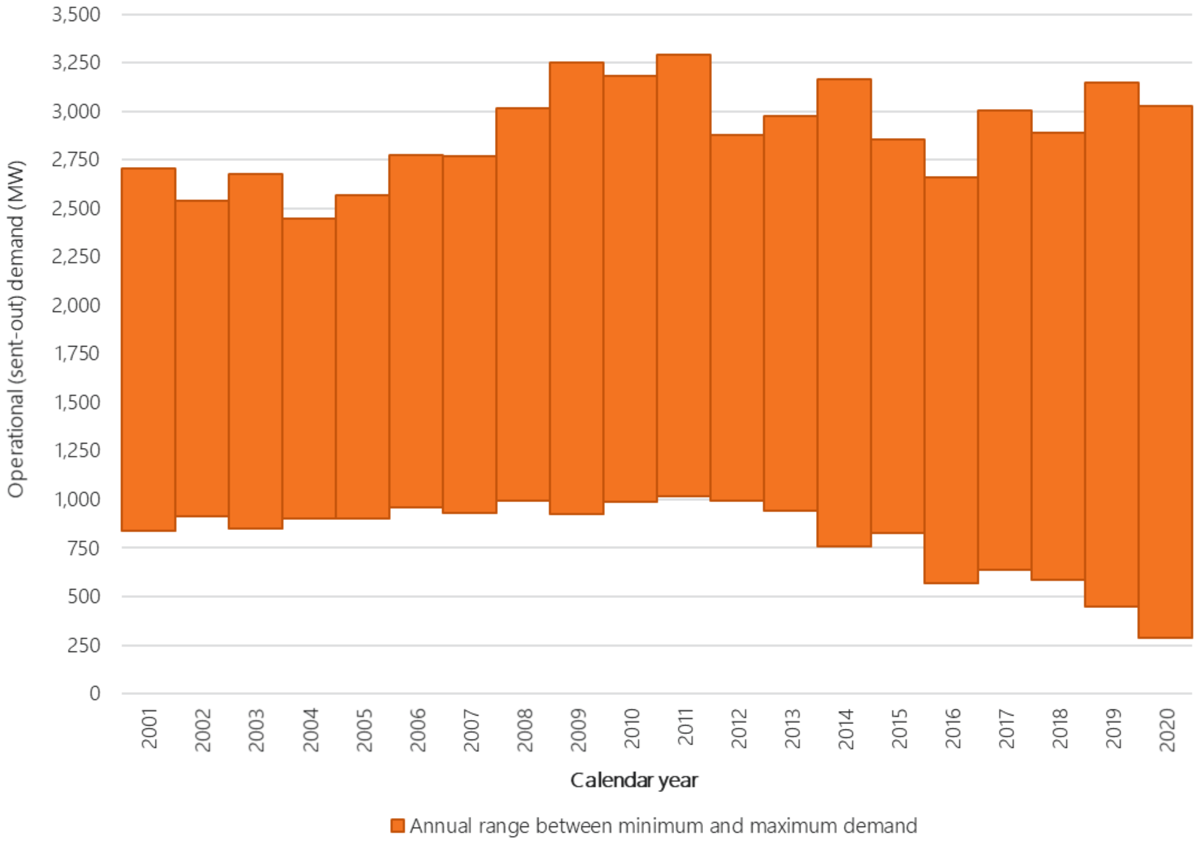
Between 2001 and 2010, demand for energy rose, with higher increases in summer maxima. Since 2012, annual maxima have remained at a similar level.

In December 2012, annual minima switched from overnight to daytime. Since then, minima have continued to occur during the day and to further reduce in line with distributed PV installations.

As a result, the difference between the annual maximum and annual minimum has grown from approximately 1,867 MW in 2001 to approximately 2,738 MW in 2020.

Figure 12 shows the annual operating range of South Australian sent-out demand for the last 18 years, demonstrating the widening trend.

Figure 12 South Australian historical annual range of operational (sent-out) demand



Note: analysis excludes black system event in South Australia on 28 September 2016.

3.1.6 Daily demand profiles

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

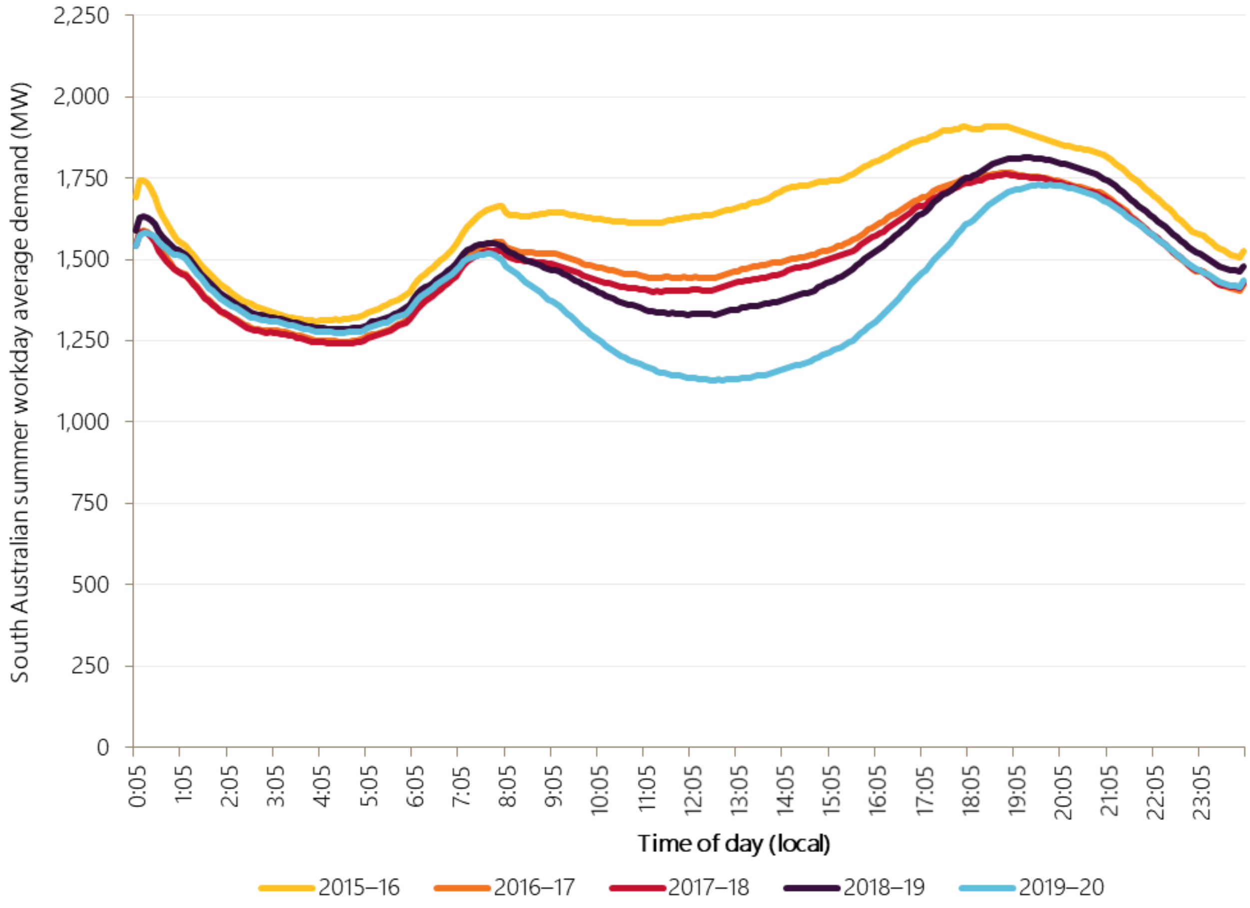
Summer daily demand

Figure 13 shows the South Australian average workday demand profile for summer from 2015-16 to 2019-20. Average summer demand year on year has been generally declining in daylight hours, due to increasing distributed PV generation following continued growth in installations,

Increasing distributed PV installation plays a large role in shaping operational demand. From 2015-16 to 2019-20, operational demand in the middle of the day (when solar irradiance is high) has reduced, while the time of daily peak operational demand has shifted from 5:30 pm to 7.00-7:30 pm when solar irradiance reduces the generation from distributed PV installations.

Another noticeable feature in the demand profile is the sharp uptick from 11:30 pm, due to the controlled switching of electric hot water storage systems. SA Power Networks (SAPN) has started moving some of its customers' hot water systems away from the night-time timer setting to turn on during the middle of the day instead. Additional residential customer hot water loads may have been moved by retailers as smart meters are being installed. This has lowered the observed night-time peak.

Figure 13 Summer workday average demand profiles

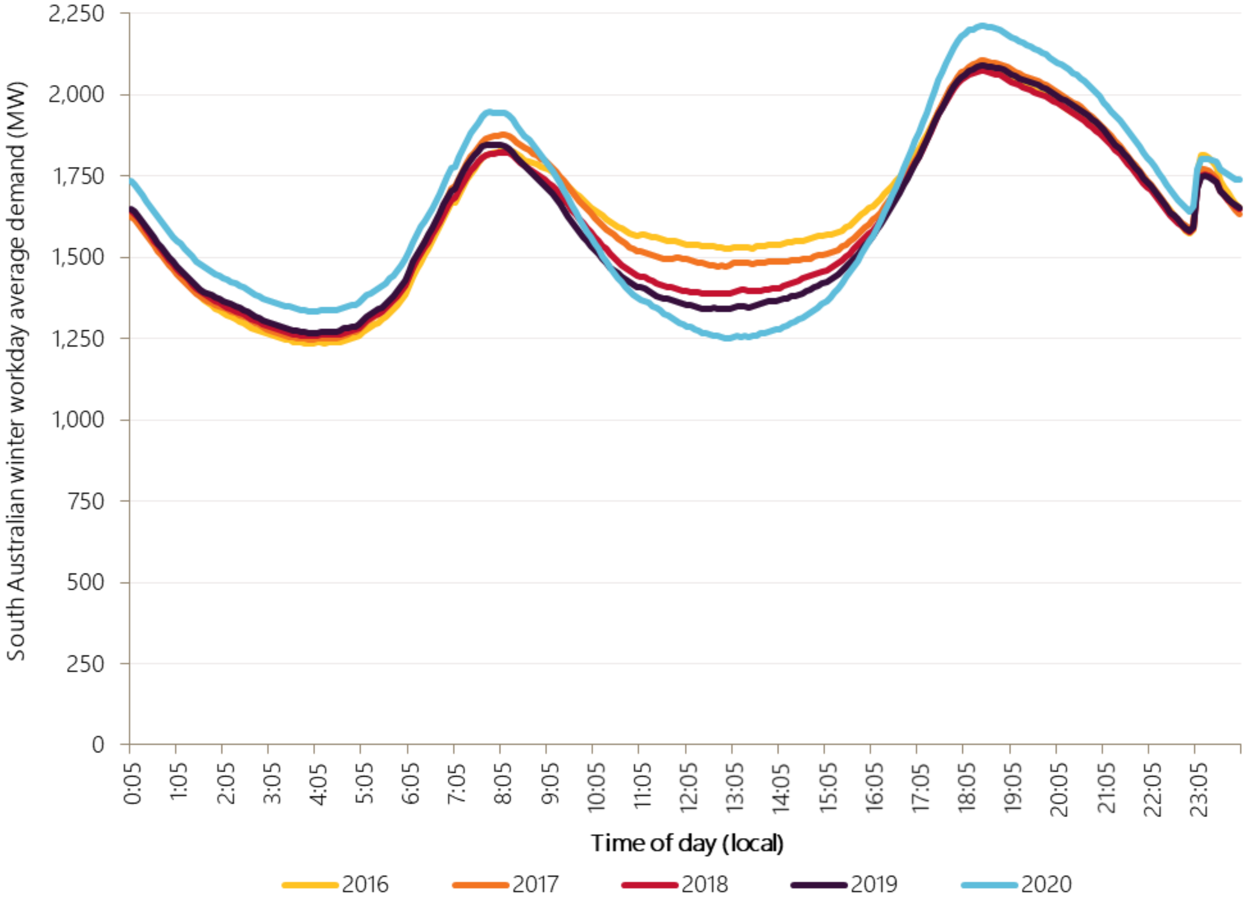


Winter daily demand

Figure 14 shows the South Australian average winter workday demand profile for winter 2016 to 2020. It shows that demand increases at times where the workday is starting or ending. Similar to summer, reduced grid demand is observed in the daylight hours, due to the increased output of distributed PV.

The winter evening peak on 7 August 2020 was the highest winter peak in South Australia on record. This can be attributed to increased diversified heating load due to COVID-19 over this winter, and while the day itself was not that cold (7°C minimum), it was soon after the equal coldest winter day in the last 100 years (5 August 2020, equal coldest at almost 1°C minimum with 24 June 1944), resulting in higher heating load.

Figure 14 Winter workday average demand profiles



4. Existing, committed and proposed supply

The generation capacity mix in South Australia continues to evolve, with an overall increase of 9.3% in total installed capacity[40] to 7,804 MW in 2019-20 compared with the previous year, mainly due to an increase in storage and gas generation capacity. Approximately 394 MW of further new generation and storage capacity is committed[41], comprising wind, solar and battery storage/VPP projects.

Generation slightly increased by 0.6% to 14,621 GWh, and South Australia continued to be a net exporter of electricity in 2019-20. The proportion of generation from wind remained similar to the previous year, while gas decreased from 47.3% to 42.9%, and large-scale solar and distributed PV increased to 3.3% and 13.3% respectively (from 2.1% and 10.4% respectively).

Recent market developments and government initiatives are providing strong signals for increased generation supply in the future.

4.1 Existing capacity

The supply capacity mix in South Australia continues to evolve. Table 4 shows the mix at the end of 2019-20[42].

Table 4 South Australian registered capacity and local generation by energy source in 2019-20

Energy source	Registered capacity		Electricity generated	
	MW	% of total	GWh	% of total
Gas	2,921	37%	6,278	42.9%
Wind	2,141	27%	5,798	40%
Diesel + Other Non-Scheduled Generation (ONSG)	613	8%	63	0.4%
Rooftop PV	1,417	18%	1,692	12%
PVNSG	129	1.7%	258	1.8%
Solar	378	5%	485	3%
Storage – battery	205	2.6%	47	0.3%
Total	**7,804**	**100%**	**14,621**	**100%**

[40] Includes AEMO registered capacity, as well as estimated rooftop PV and PVNSG capacity and estimated other non-scheduled generation (ONSG) capacity.

[41] Date based on 12 November 2020 AEMO Generation Information Page, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[42] See the latest registered capacity in the NEM Registration and Exemption List, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/registration/.

Compared to the end of 2018-19[43], the biggest increases were in gas and storage capacity. Barker Inlet, the first natural gas reciprocating engine power station in South Australia, commenced operation in November 2019[44], and can provide rapid response under some circumstances to changes in demand or supply.

Lake Bonney Battery Energy Storage System, a 25 MW Tesla battery, commenced operation in October 2019 co-located with the existing 278.5 MW Lake Bonney wind farm in South Australia. The battery will provide new dispatchable generation in South Australia to help meet peak demand, as well as critical system balancing services (frequency control ancillary services [FCAS]).

The Hornsdale Power Reserve expansion, supported by Tesla, is an expansion of the existing battery (100 MW capacity) by a further 50 MW, that came into service in 2020. The Hornsdale Power Reserve is co-located with the Hornsdale Wind Farm in South Australia.

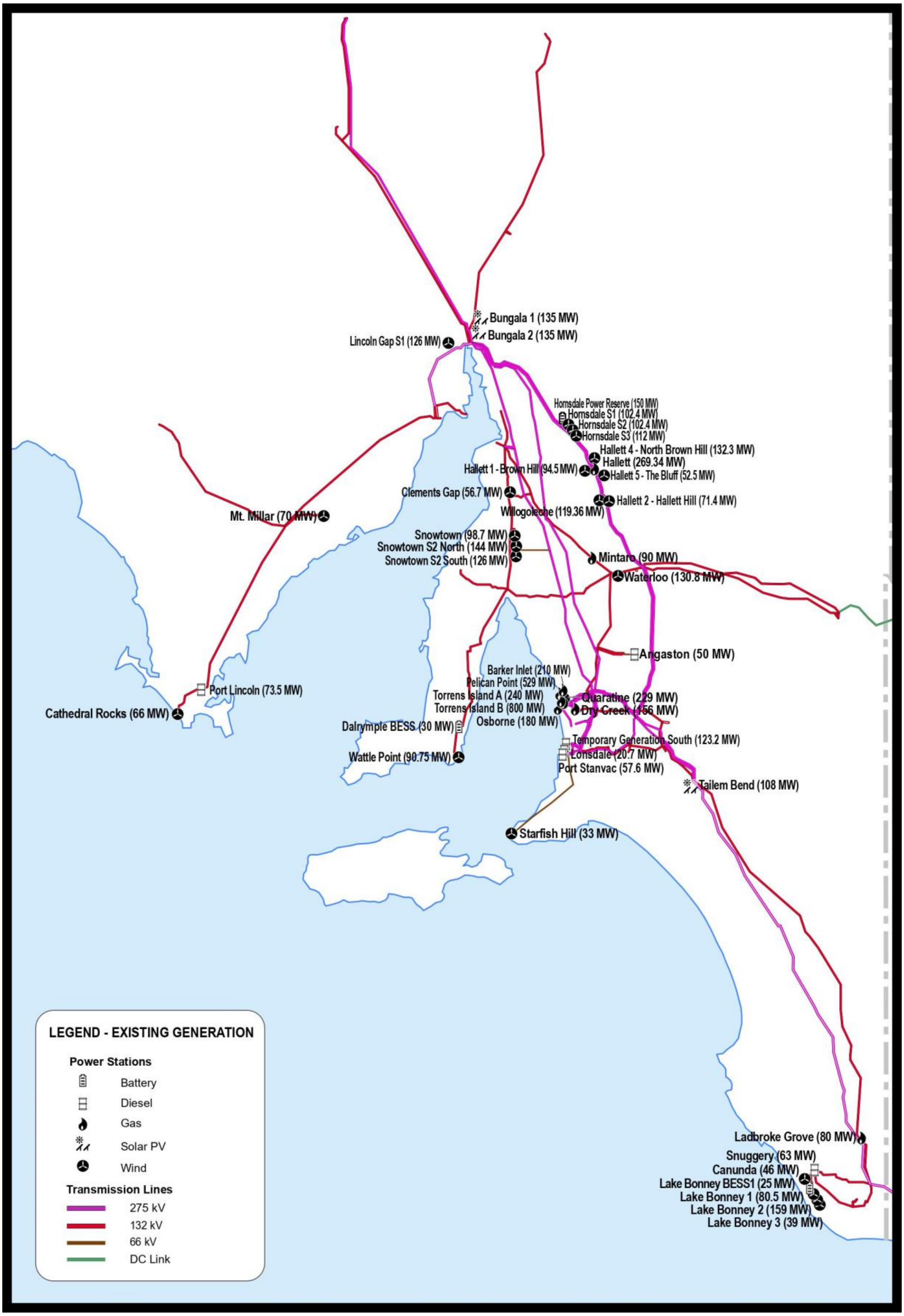
4.2 Historical generation

Figure 15 shows the location, nameplate capacity, and energy source of registered operational generators in South Australia (all scheduled, semi-scheduled, and significant non-scheduled generators used in operational reporting). More details of existing generators can be found in the supporting data pack.

[43] Refer to 2020 SAER data file, Table 4.24.

[44] Date based on latest (12 November 2020) 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.

Figure 15 Location and capacity of South Australian generators



Composition of generation

Figure 16 shows the mix of energy generated in South Australia by fuel type[45] from 2015-16 to 2019-20, from:

- All scheduled generators.
- All semi-scheduled and market non-scheduled wind farms.
- All semi-scheduled solar farms.
- Selected smaller market and non-market non-scheduled generators (SNSG).
- 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.

Figure 16 South Australian electricity generation by fuel type

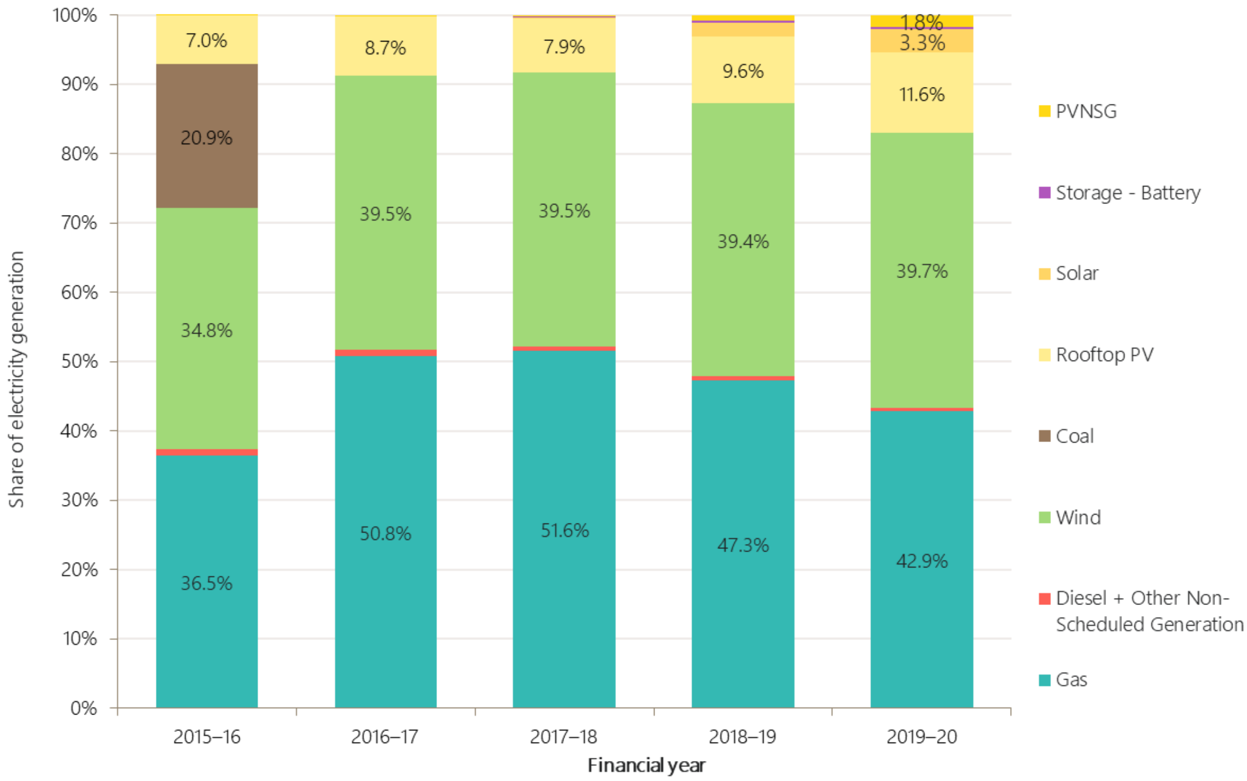


Table 5 expands on the data in Figure 16, focusing on the differences between 2018-19 and 2019-20, and including interconnector flow metrics. Section 5 provides further insights on interconnector changes.

Between 2018-19 and 2019-20 demand reduced, resulting in a reduction of the energy consumption of gas-powered generation (GPG). However, at this same time demand became more variable and diesel and SNSG (combined) were used more frequently, underlining the importance of firm supply options.

Despite the decrease, GPG continued to be the most prominent fuel type in the supply mix, representing 42.9% of South Australian generation. GPG and interconnector imports continued to be required to meet South Australian demand in periods with combinations of high demand, low sunshine and/or low wind.

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

Additionally, system security constraints add to the requirement for GPG operation as it provides critical services for the power system. See the South Australian Generation Forecasts for more information about the changing energy mix in South Australia[46].

Table 5 South Australian electricity supply by fuel type (GWh), comparing 2018-19 to 2019-20

Supply source	2018-19 (GWh)	2019-20 (GWh)	Change (GWh)	Percentage change (%)	2018-19 Percentage share (%)	2019-20 Percentage share (%)
Gas	6,877	6,278	-599	-8.7%	47.3%	42.9%
Wind	5,725	5,798	73	1.3%	39.4%	39.7%
Diesel + ONSG	77	62	-15	-19.5%	0.5%	0.4%
Rooftop PV	1,399	1,692	293	20.9%	9.6%	11.6%
Solar	303	485	182	60.1%	2.1%	3.3%
PVNSG	108	258	150	138.9%	0.7%	1.8%
Storage – Battery	41	47	6	14.6%	0.28%	0.32%
Total	**14,530**	**14,621**	**90**	**0.6%**	**100.00%**	**100.00%**
Interconnector net imports	-468	-413	55	-11.8%		
Interconnector total imports	1,253	1,329	76	16.7%		
Interconnector total exports	785	916	131	6.1%		

Wind generation summary

South Australia has the second highest registered wind capacity in Australia after Victoria.

Table 6 shows the total capacity for all South Australian semi-scheduled and non-scheduled wind farms registered with AEMO with their maximum 5-minute generation output, from 2015-16 to 2019-20, and information on registered wind capacity.

Table 6 shows that registered wind capacity has not changed in 2019-20, after four years of increasing capacity year-on-year. Annual generation increased overall by 1.3% with the commissioning of Lincoln Gap and Willogoleche wind farms during 2018-19, which continued to ramp up to higher levels in 2019-20. This was offset by an increase in curtailment of wind generation in South Australia to maintain the power system within secure limits – see Section 8.9.1.

[46] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/sa_advisory/2020/2020-south-australian-generation-forecasts.pdf?la=en.

Table 6 Total South Australian wind generation and capacity

Financial year	Annual wind generation (GWh)	Annual change in wind generation (%)	Annual average capacity factor[A] (%)	Registered capacity (MW)[B]	Reason for increase in capacity	Maximum 5-minute generation (MW)[B]
2015-16	4,322	-	32.3%	1,577	NA	1,384
2016-17	4,343	0.5%	29.7%	1,698	Hornsdale Stage 2 (102.4 MW), Waterloo expansion (19.8 MW)	1,546
2017-18	5,563	28.1%	34.7%	1,810	Hornsdale Stage 3 (112 MW)	1,618
2018-19	5,725	2.9%	34.7%	2,141	Lincoln Gap[C] (212.4 MW), Willogoleche (119.36 MW)	1,712
2019-20	5,798	1.3%	32.1%	2,141	NA	1,820

A. Based on the average capacity factor across all wind farms. Periods before a wind farm first reached 90% of registered capacity are excluded from the capacity factor calculation, or where this period was for too short a length of time in the financial year. Willogoleche was excluded from the calculation in 2018-19. Lincoln Gap has been excluded from the calculation in 2018-19 and 2019-20.
B. Data is captured from when each wind farm was entered into AEMO systems and includes the commissioning period.
C. 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 (12 November 2020).

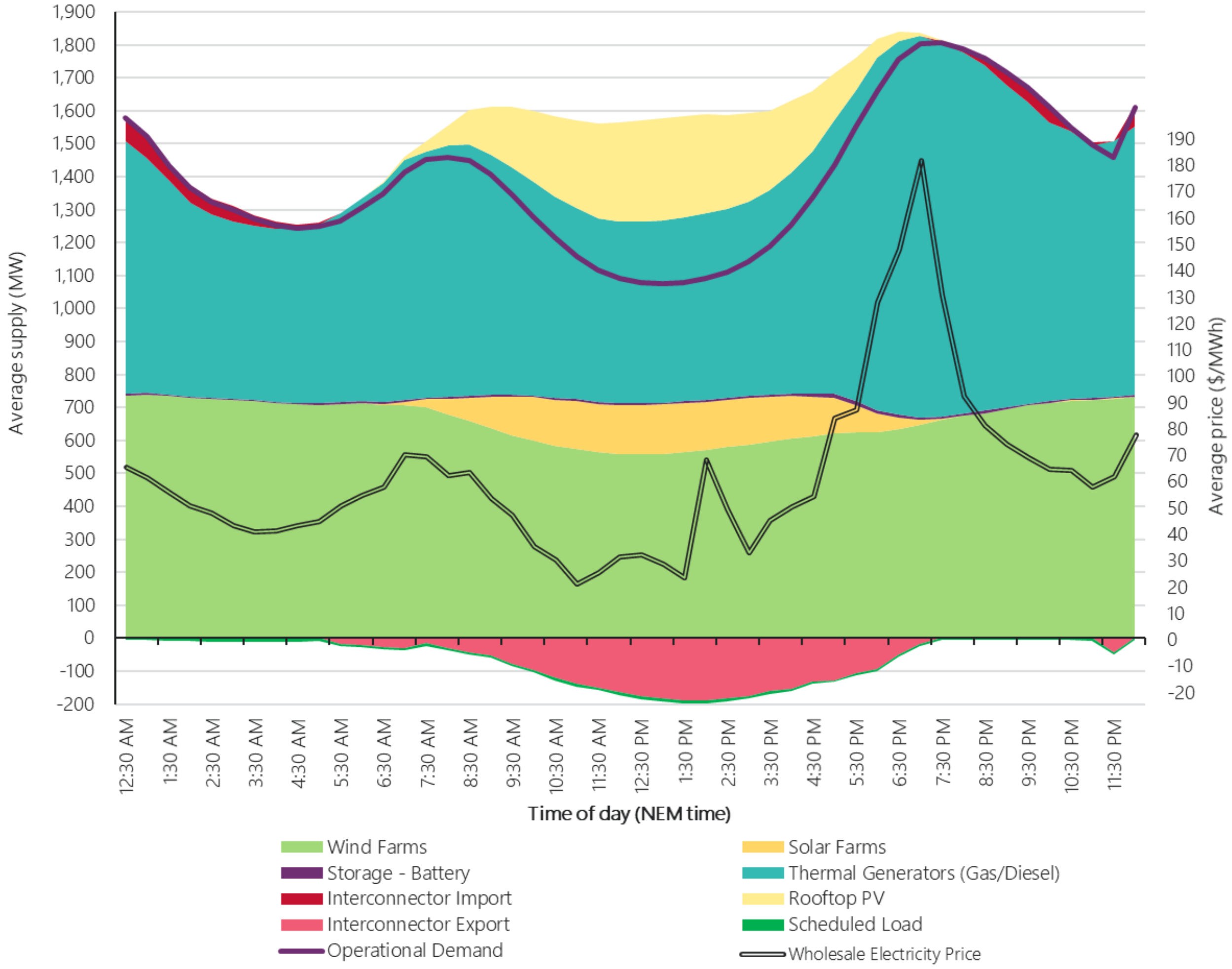
4.3 Daily supply profile

The average daily supply profile for South Australia, seen in Figure 17, shows the supply (in MW) split between wind, solar, thermal (gas and diesel), and combined interconnector flows, and spot price (in $/MWh) for each 30-minute trading interval of a day, averaged over the 2019-20 financial year. Rooftop PV is displayed above the demand curve and shows the underlying energy that is consumed "at the power point" level.

Figure 17 shows that:

- On average, wind output is slightly higher during the evening and early morning periods, complementing average distributed PV generation, which produces most of its output between 8.00 am and 6.00 pm. In practice, wind output was highly variable, sometimes producing little output (resulting in reliance on GPG and interconnector imports to meet demand), and other times wind output was curtailed to maintain the power system within secure limits – see Section 8.9.1 for details.
- Scheduled generation contributed the most to the daily profile, providing the requisite energy when necessitated by higher demand or when other generation sources were low.
- The average price correlates closely with average demand, particularly in the early morning hours. Price peaks in the evening are in line with increases in demand from residential loads occurring at the same time as solar generation is declining.
- Interconnector imports mainly occurred in the off-peak periods when solar was not operational.

Figure 17 Daily supply profile for South Australia averaged for the 2019-20 financial year

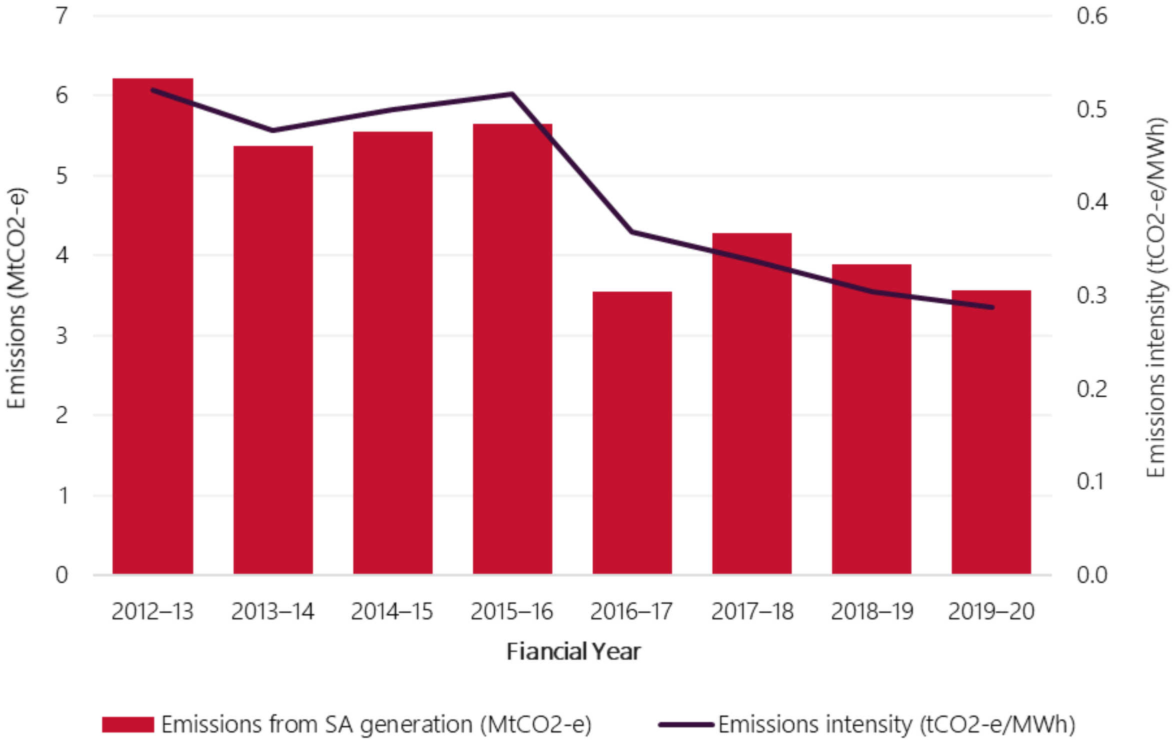


4.4 Emissions intensity

Annual NEM emissions intensity for the 2019-20 financial year was the lowest on record[47]. In South Australia, as Figure 18 shows, total emissions from generation in 2019-20 decreased 0.32 metric tonnes or 8.2% compared to 2018-19, while the emissions intensity in South Australia reduced by 5.7% from 0.3 t/MWh to 0.29 t/MWh, the lowest levels to date . Lower emissions were a function of decreased local GPG, and the continued decline in emissions intensity reflects increased wind and solar penetration in the region.

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

Figure 18 South Australian annual emissions and emissions intensity



4.5 Changes to supply

4.5.1 Summary of existing and committed generation

The nameplate capacity of existing or withdrawn generation, and committed projects, in South Australia is shown by energy source in Table 7. This includes scheduled, semi-scheduled, and non-scheduled generation information, based on AEMO's 12 November 2020 generator survey results for South Australia[48].

[48] The total South Australian capacity in Table 4 in Section 4.1.1 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 7.

Table 7 Capacity of existing or withdrawn generation, and committed projects (MW) at 12 November 2020

Status	CCGT[A]	OCGT[B]	Gas other	Solar[C]	Wind	Water	Biomass	Storage – battery and VPP	Other	Total
Existing[D]	713.4	1,259.0	1,250.0	365.8	2,053.3	3.2	18.2	205.5	180.7	**6,049.1**
Announced withdrawal[E]	180.0	0.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	**420.0**
Existing less announced withdrawal	533.4	1,259.0	1,010.0	365.8	2,053.3	3.2	18.2	205.5	180.7	**5,629.1**
Committed	0.0	0.0	0.0	86.6	296.4	0.0	0.0	11.0	0.0	**394.0**
Upgrade	0.0	15.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.0**
Withdrawn	0.0	0.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	**240.0**

A. CCGT: Combined-cycle gas turbine.
B. OCGT: Open-cycle gas turbine.
C. Solar is large-scale solar and excludes rooftop PV installations
D. Existing includes announced withdrawal.
E. Withdrawal from the NEM has been announced as occurring at a future date.

4.5.2 Generation capacity for the year ahead

Table 8 shows scheduled, semi-scheduled, and significant non-scheduled generation expected available capacity for summer 2020-21 for both peak and typical temperatures and winter 2021, compared with the previous year's reported values for summer 2019-20 peak temperatures and winter 2020 respectively.

The figures in Table 8 have been provided by market participants as part of AEMO's Generation Information data collection, and include existing and committed generation capacity installations and withdrawals. Differences in scheduled and semi-scheduled generation available capacity between seasons arise from seasonal temperature variations. In general, summer available capacity for gas generators is lower than winter available capacity, due to higher thermal generation efficiencies at cooler ambient temperatures. Scheduled GPG capacity during summer 2020-21 is lower than the previous summer partly due to the retirement of Torrens Island units 2 and 4.

Table 8 Scheduled, semi-scheduled, and significant non-scheduled generation available capacity

Energy source	Summer Peak available capacity[A] (MW)		Summer typical available capacity (MW)[D]	Winter available capacity[A] (MW)	
	2019-20	2020-21	2020-21	2019-20	2020-21
Diesel (scheduled)[B]	236	331	353	263	388
Gas (scheduled)	2,757	2,369	2,451	2,724	2,605
Wind (semi-scheduled)	1,660	1,375	1,659	1,660	1,681
Wind (significant non-scheduled)[C]	386	386	386	386	386
Solar (semi-scheduled)	315	329	337	315	347
Storage - Battery (scheduled)	165	205	205	165	205
Total	**5,519**	**4,997**	**5,391**	**5,513**	**5,613**

A. AEMO Generation Information for South Australia, published 12 November 2020, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.
B. Excludes SA Temporary Generation North diesel generator (Section 7.4.1 has details of their 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 and represent the capacity available over summer during typical temperatures

4.5.3 Committed supply developments

As of 12 November 2020[49], 11 MW of VPP projects and approximately 296 MW of new wind and 87 MW of solar generation projects are committed in South Australia:

- SA Government VPP – Stage 2 (5 MW).
- Simply Energy VPP (6 MW/16 MWh).
- Morgan To Whyalla Pipeline No 3 PS (7.4 MW of solar), due to be operational by January 2021.
- Lincoln Gap Wind Farm Stage 2[50] (86.4 MW), due to be operational by February 2022.
- Port Augusta Renewable Energy Park (79.2 MW of solar and 210 MW of wind), due to be operational by March 2022.

4.6 Additional supply developments

As at 12 November 2020[51], new generation investment in South Australia continues to focus on renewable developments and energy storage/VPP, with the largest projects in these categories being:

[49] Date based on latest (12 November 2020) 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.

[50] 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, 12 November 2020.

[51] Date based on latest AEMO Generation Information Page at 12 November 2020. 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.

- Goyder South hub – wind (1,200 MW).
- Yorke Peninsula Wind Farm (up to 636 MW).
- Palmer Wind Farm (375 MW).
- Woakwine Wind Farm (up to 304 MW).
- Goyder South Hub – solar (600 MW).
- Bridle Track Solar Project (300 MW).
- Goyder South Hub – Battery Energy Storage System (BESS) (900 MW).
- SA Government VPP – stage 3 (245 MW).

Torrens Island unit 2 (120 MW) and unit 4 (120 MW) were closed (decommissioned and deregistered) on 30 September 2020. Torrens Island unit 1 (120 MW) was mothballed from 30 September 2020[52] with plans to close on 30 September 2021. Torrens Island unit 3 (120 MW) remains operational and in service until it is mothballed on the 30 September 2021[53] with plans to close on 30 September 2022[54,55] On 14 November 2020, AGL announced a proposed 250 MW, four-hour-duration battery system to be built in stages on the site of its Torrens Island Power Station[56].

Given the penetration of renewable generation, there will be increasing 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 or pumped hydro storages, or flexible thermal generation.

As at 12 November 2020, AEMO's Generation Information update identified 60 non-committed electricity generation and storage developments in South Australia, totalling 9,926 MW. Table 9 aggregates these developments by energy source; Figure 19 shows the volume of connection interest within South Australia[57].

It is worth noting that despite an increase of 13 projects between November 2019 and November 2020 there has been an overall net decrease in proposed capacity. This is mainly driven by a number of larger projects (of greater than 150 MW capacity) either becoming committed, removed from publication or no longer going ahead. A number of smaller projects (of less than 15 MW capacity) have been proposed more recently, totalling 421 MW, This has resulted in a net decrease of 739 MW of proposed capacity[58].

The South Australian Government is supporting the development of the world's largest VPP, through the Home Battery Scheme – see Section 2.3.

In addition, the South Australian Government is also supporting several green hydrogen projects as part of its efforts in scaling up the South Australian hydrogen industry[59]. Most recently, on 5 November 2020, the South Australian Government announced their 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.

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[52] This unit remains registered and available for service on six-month recall until its closure date, when it will then be decommissioned and deregistered.

[53] 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.

[54] See the change log of AEMO Generation Information Page at 12 November 2020, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[55] 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.

[56] See https://www.pv-magazine-australia.com/2020/11/16/agl-grows-massive-battery-storage-in-the-shadow-of-retiring-fossil-fuelled-power-stations/.

[57] Refer to NEM generation maps, 15 October 2020, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/nem-generation-maps.

[58] See "Change log" sheet in the Generation Information Page for more detailed updates https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

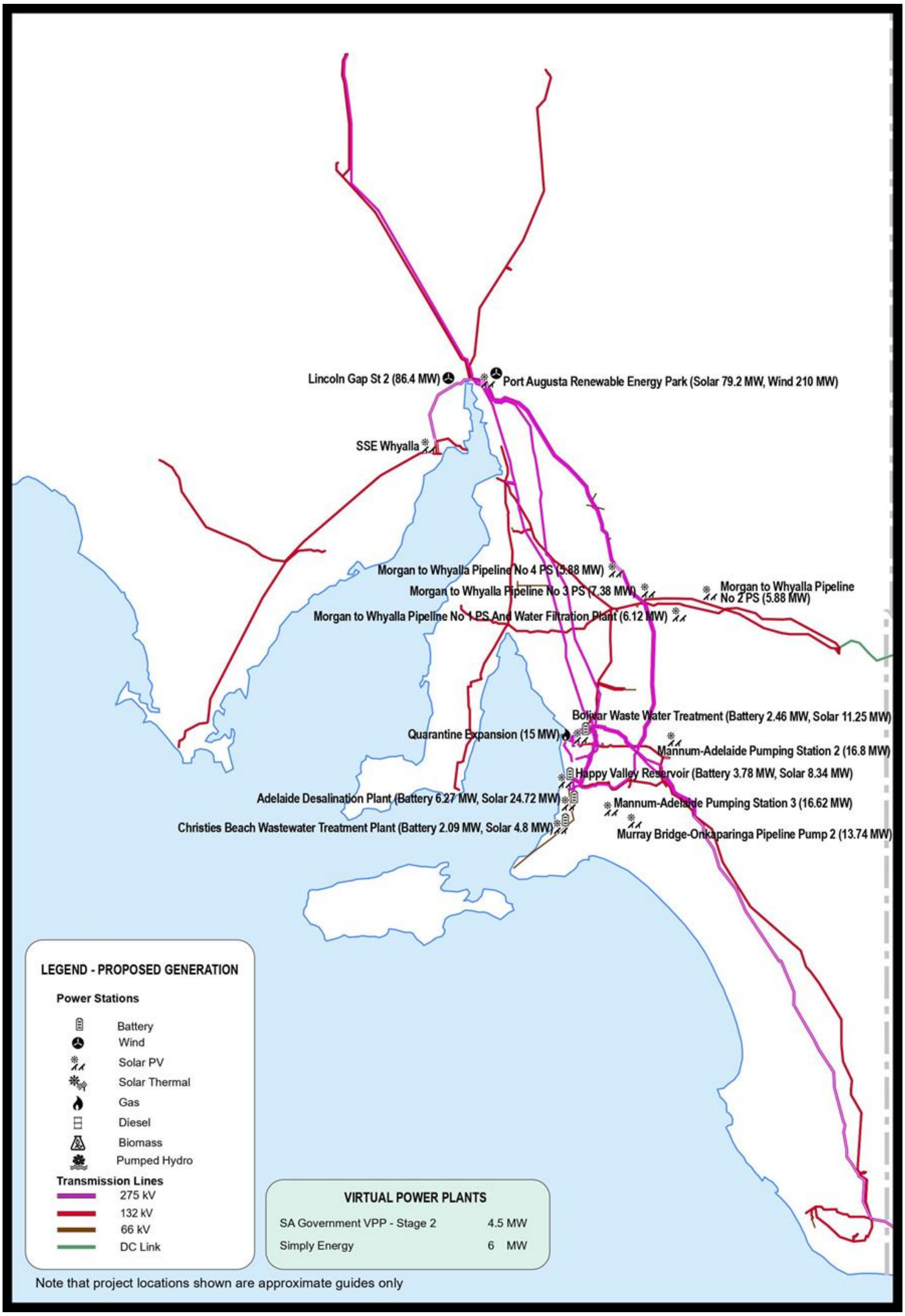
[59] For more information, see http://www.renewablessa.sa.gov.au/topic/hydrogen/hydrogen-projects.

Table 9 South Australian prospective generation projects by energy source, as at 12 November 2020

Energy source	Number of projects	Capacity (MW)	Capacity (% of total projects tracked)	Change in number of projects from November 2019	Change in capacity from November 2019 (MW)
Gas	6*	803.2	8.1%	0	88.2
Diesel	1	154	1.6%	1	154
Solar	29	2,783	28.0%	7	-487.8
Biomass	0	0	0.0%	0	0
Wind	11	3,623.4	36.5%	1	-317.6
Water	5	995	10.0%	0	0
Storage – battery and VPP	14	1,567.6	15.8%	4	-176.4
Total	**60**	**9,926.2**	**100.0%**	**13**	**-739.6**

* Gas projects include an upgrade to Quarantine Power Station of 15 MW.

Figure 19 Location and capacity of South Australian generation projects



5. Existing and future transmission

South Australia is connected to the rest of the NEM via two interconnectors, Heywood and Murraylink. A new interconnector between South Australia and New South Wales (Project EnergyConnect) is planned for service in 2024. While imports to South Australia had been growing until the closure of Hazelwood Power Station in Victoria in 2017, the trend has since reversed, with South Australia being now a net exporter.

5.1 Historical imports and exports

South Australia currently imports and exports power to the rest of the NEM through two interconnectors – Heywood and Murraylink:

- The Heywood interconnector represents the 275 kilovolts (kV) lines between Heywood substation in Victoria and South East substation in South Australia. This interconnector was originally commissioned in 1989 and was upgraded in 2015-16 to a nominal design limit of up to 650 MW in either direction of flow. However, due to stability issues identified during the black system event in 2016, inter-network testing underway at that time was suspended, and Heywood's nominal capacity has been 600 MW from Victoria to South Australia since August 2016. Nominal flow from South Australia to Victoria has been 500 MW since December 2015 but was increased in December 2019 to 550 MW, following completion of the South Australian over-frequency generation shedding scheme.
- On 19 July 2020, one of the static VAR compensators (SVCs) at Para in South Australia experienced a forced outage, with an expected return to service in mid-2021. The primary impact of the outage is that flows from South Australia to Victoria on the Heywood interconnector have since been restricted to 420 MW.
- Murraylink is the direct current (DC) cable between Red Cliffs in Victoria and Monash in South Australia. It is a 220 MW DC cable that was commissioned in 2002.

Figure 20 shows the total actual interconnector imports and exports for South Australia from 2010-11 to 2019-20. South Australia has been a net exporter into Victoria since the closure of Hazelwood Power Station in 2017.

In Figure 20:

- The orange column bars above the 0 GWh line (x-axis) show the annual energy imported into South Australia from Victoria. From 2009-10 to 2016-17, there was a steady increase in annual imports from Victoria to South Australia, but average annual imports decreased to almost one-third this level once Hazelwood retired.
- The yellow bars below the line show the energy exported from South Australia to Victoria. Over the past 10 years, the highest annual export occurred in 2019-20, with 2017-18 and 2018-19 also recording comparatively high exports.
- The red circle points show net flows for the financial years, with positive values showing net importing and negative values indicating net exporting.

Figure 20 Combined interconnector total imports and exports, and net flows

Figure 21 shows the annual flow patterns for combined interconnector imports from Victoria to South Australia, averaged by the time of day (with times expressed in NEM time).

Figure 21 Combined interconnector daily 5-minute average flow

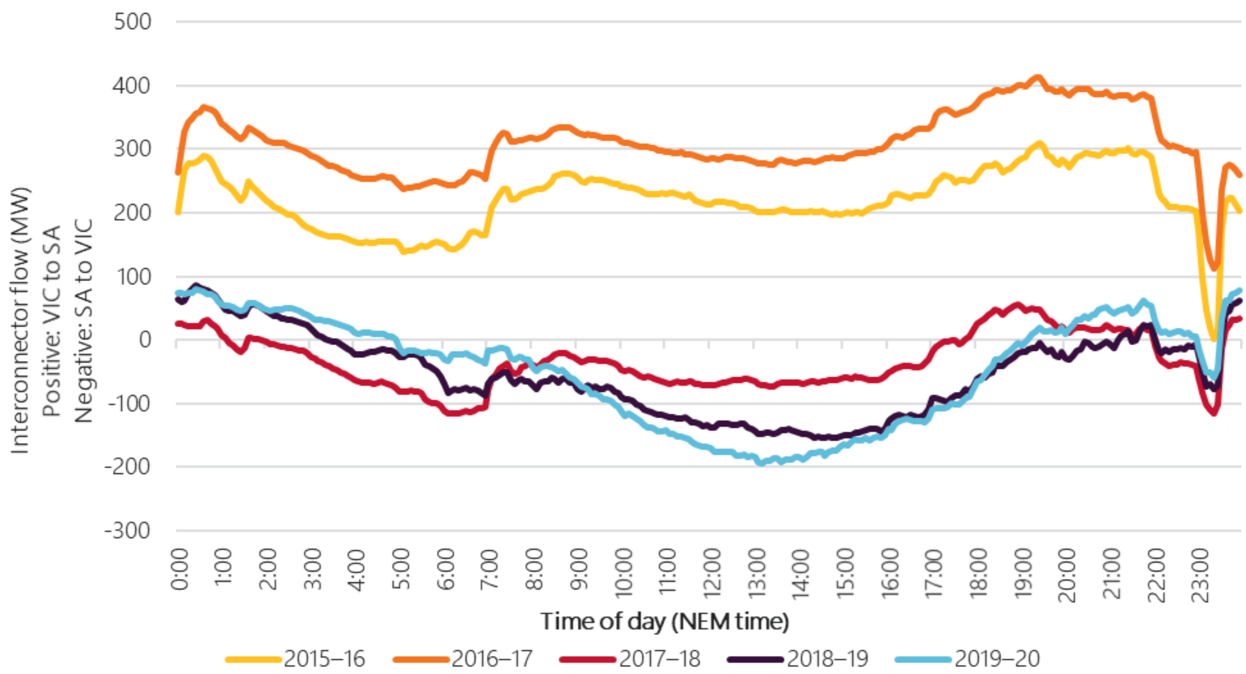


Figure 21 shows that, on average, in 2019-20, combined interconnector flow followed a similar trend as 2018-19, where South Australia tended to export electricity, except during early off-peak- hours (around midnight to 3.00 am), when the region tended to import. On average, the highest exports were between approximately 10.00 am and 5.00 pm with exports during this time increasing slightly from previous years –

coinciding with increased output from grid-scale and distributed PV during the middle of the day and into the early evening. As with previous years, the sudden dip and subsequent spike in imports occurring around 11.30 pm to midnight is caused by automated "off-peak" electric hot water systems in South Australia.

5.2 Progress of transmission upgrade projects

To facilitate better sharing of reserves at times of low renewable generation and better export opportunities at times of high renewable generation, South Australia will benefit from stronger interconnection to neighbouring regions.

Below is a summary of the status of a series of upgrades and new projects.

Heywood

The transfer limit in the direction from Victoria to South Australia is presently 600 MW. Further work is required to increase the transfer limit in this direction, including but not limited to completion of the System Integrity Protection Scheme (SIPS) upgrade and successful completion of necessary internetwork tests.

An over-frequency generation shedding (OFGS) scheme has recently been commissioned by ElectraNet, which has increased the transfer limit in the direction from South Australia to Victoria to 550 MW. Further assessment and tests by ElectraNet will be necessary to increase the transfer limit to the design limit of 650 MW. However, as discussed in Section 5.1, one of the SVCs at Para has experienced a forced outage, with an expected return to service in mid-2021. Flows from South Australia to Victoria on the Heywood interconnector have been restricted to 420 MW until the SVC is returned to service.

Increases in Heywood transfer limits may necessitate a repeat of system assessments conducted for the interconnector tests in 2015. This is due to the changed system conditions that have occurred over the past five years in demand, distributed PV installations, and growth in utility-scale wind and solar generation. AEMO is working to support ElectraNet in its assessment of changed conditions and existing transfer capability to maximise the interconnection between the South Australia and Victoria regions.

Murraylink

There are operational limits to the Murraylink transfer capacity due to transient voltage stability risks in the Western Murray Region. AEMO is reviewing the New South Wales Murraylink Very Fast Runback (VFRB) scheme, to reduce the risk of voltage collapse and network issues in southern New South Wales. Once successfully updated, the VFRB could potentially allow increased utilisation of the bi-directional Murraylink transfer capacity of up 200 MW and remove some pre-contingent constraints in the AC network. This will improve the transfer capacity between the South Australia and Victoria regions.

Project EnergyConnect – a new interconnection between South Australia and New South Wales

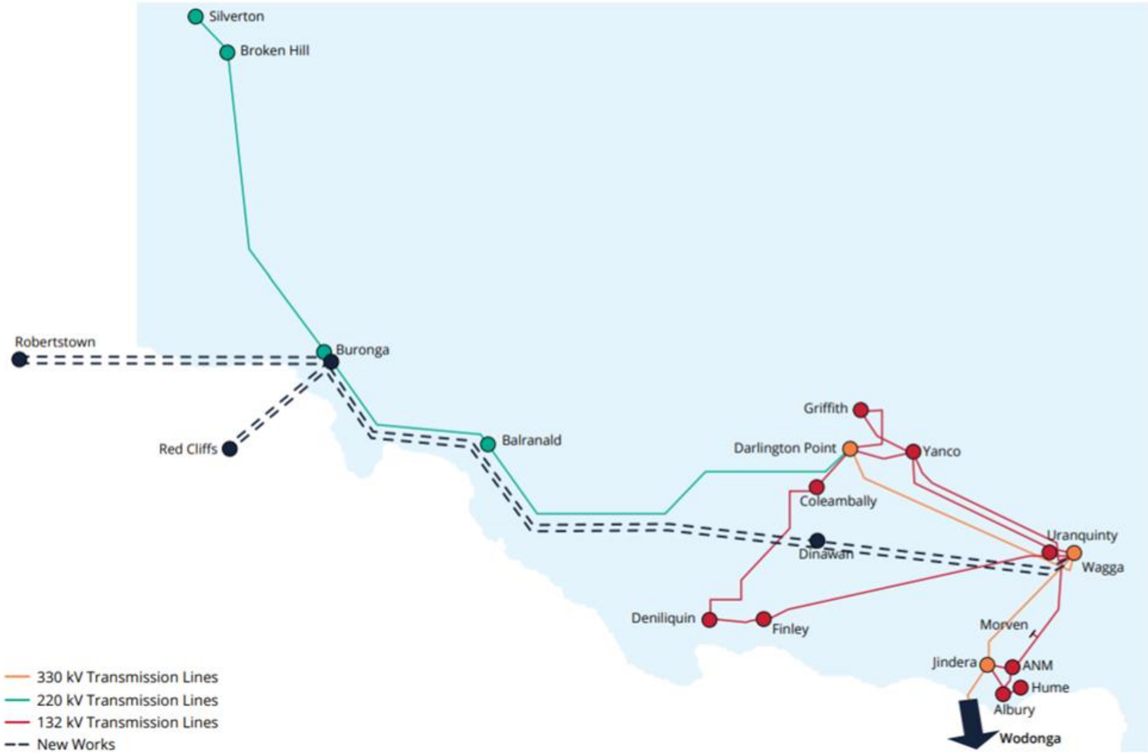
The 2020 ISP identified Project EnergyConnect as an actionable ISP project, delivering net market benefits through:

- Efficient energy production – lowering dispatch costs, initially in South Australia, through increasing access to low-cost supply options across regions.
- Transformation – facilitating the transition to a lower carbon emissions future through improving access to high quality renewable resources across regions.
- Security – enhancing security of electricity supply in South Australia, including management of inertia, frequency response and system strength in South Australia.

In January 2020, the Australian Energy Regulator (AER) approved ElectraNet's preferred option in the South Australia Energy Transformation Regulatory Investment Test for Transmission (RIT-T)[60], being the construction of a new 330 kV interconnector over a route of approximately 860 km between Robertstown in South Australia and Wagga Wagga in New South Wales and a 220 kV spur from Buronga in New South Wales to Red Cliffs in Victoria.

The South Australian portion of the option recommended by ElectraNet is consistent with the 2020 ISP[61]. In New South Wales, TransGrid optimised the route of the interconnector with a direct path from Buronga to Wagga, bypassing Darlington Point substation where entry of new transmission lines is physically constrained. This resulted a new substation at Dinawan, south of Darlington Point (see Figure 22).

Figure 22 Interconnector option assessed by TransGrid in the 2020 TAPR



Source: TransGrid, 2020 Transmission Annual Planning Report, at https://www.transgrid.com.au/what-we-do/Business-Planning/transmission-annual-planning/Documents/2020%20Transmission%20Annual%20Planning%20Report.pdf

On 30 September 2020, TransGrid and ElectraNet submitted their final contingent project applications to the AER seeking increases in their allowed revenues to construct the transmission assets in Project EnergyConnect[62]. The full cost of the project is forecast to be $2.4 billion:

- The New South Wales component is forecast to cost $1.9 billion. TransGrid's application seeks the incremental revenue required to construct the New South Wales component within its allowed regulated revenues.
- The South Australia component is forecast to cost $471 million. ElectraNet's application seeks the incremental revenues required to construct the South Australia component within its allowed regulated revenues.

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[60] See https://www.aer.gov.au/news-release/aer-approves-south-australia-%E2%80%93-nsw-interconnector-regulatory-investment-test for more information.

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

[62] See https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/transgrid-and-electranet-–-project-energyconnect-contingent-project.

The AER is currently reviewing and undertaking public consultation on the contingent project applications, with its final determination expected from the end of December 2020. In parallel with this determination, ElectraNet has submitted an urgent rule change request to adjust the revenue setting process for this project so it can maintain an investment grade credit rating[63]. TransGrid has also submitted a similar derogation request.

ElectraNet has advised that, subject to satisfactory regulatory and other approvals, it is currently working towards completing construction by 31 December 2023[64].

Following completion of construction, there will be a period of testing and commissioning to progressively release the transfer capacity of the new interconnector. The duration of tests will be contingent on suitable market conditions to carry out tests being available. ElectraNet and TransGrid, in consultation with AEMO, are currently preparing to develop the necessary inter-regional test programs to be able to securely and safely release transfer capacity of the new interconnector. The development of this test program, and consultation with the market ahead of any testing, is a mandatory requirement of the Project EnergyConnect proponents in accordance with the National Electricity Rules (NER).

5.3 Renewable energy zones

The 2020 ISP considered candidate REZs in South Australia, as well as transmission network augmentations required to support the development of generation within the REZs.

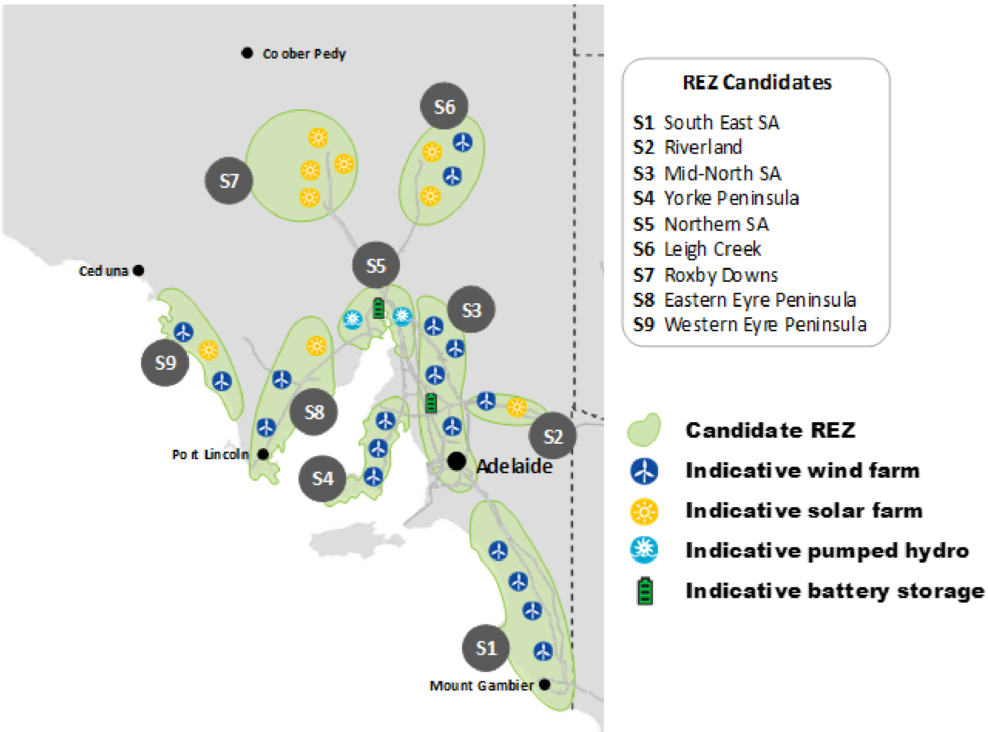
The 2020 ISP noted the potential development of solar in the Riverland REZ enabled by Project EnergyConnect and noted that generation development in Roxby Downs REZ (solar) and Mid-North REZ (wind) could be supported by network upgrades between Davenport and Para.

The ISP also noted that the development of wind generation in South East SA REZ would require the support of a future ISP project to connect generation. In general, the ISP anticipates the development of these REZs in the 2030s. Figure 23 shows the South Australian REZ candidates included in the analysis.

[63] AEMC. Participant derogation – financeability of ISP Projects (ElectraNet), at https://www.aemc.gov.au/rule-changes/participant-derogation-financeability-isp-projects-electranet.

[64] At https://www.aer.gov.au/system/files/ElectraNet%20-%20Project%20EnergyConnect%20Contingent%20Project%20Application%20-%2030%20September%202020.pdf.

Figure 23 South Australian renewable energy zone candidates



6. Electricity spot price

South Australia's average wholesale electricity price fell from the record high levels of 2018-19 to their lowest levels since 2015-16, following the NEM-wide trend of falling prices. Factors driving the NEM-wide reductions included lower-priced offers from black coal-fired generation, falling gas market prices, and increased variable renewable energy (VRE) output.

FCAS prices were significantly higher than in 2018-19, primarily due to extreme price volatility in November 2019, January 2020, and February 2020 resulting from power system separation events.[65]

6.1 Historical wholesale electricity prices

Table 10 shows that in 2019-20, South Australia's time-weighted average price (TWAP) was $62/MWh, the lowest average since 2015-16, representing a 43% decrease from 2018-19. For the first financial year since 2015-16, South Australia was no longer the highest-priced region in the NEM; its TWAP was below Victoria ($74/MWh) and New South Wales ($72/MWh).

Table 10 2019-20 time-weighted average prices for the NEM

	Queensland	New South Wales	Victoria	South Australia	Tasmania
Time-weighted average ($/MWh)	53.41	71.95	73.74	62.04	55.05

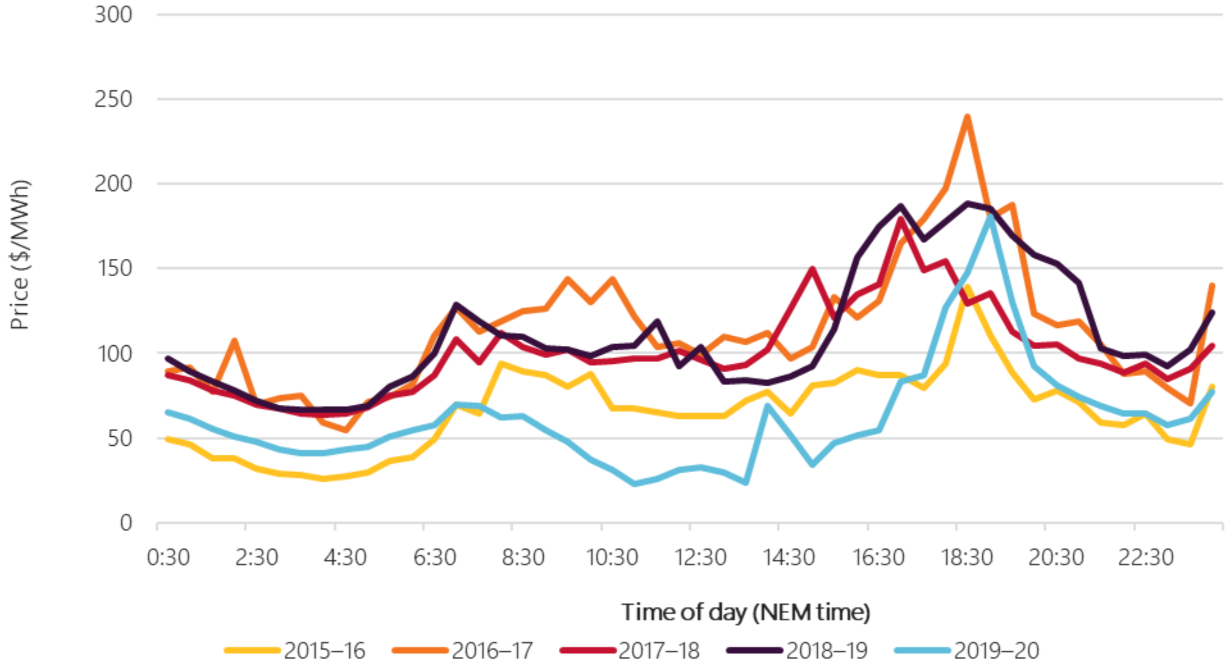
Compared to 2018-19, key contributors to the price decrease in South Australia included (ordered by most important driver to least):

- Inter-regional pricing dynamics – in 2019-20, South Australia's spot price was set by non-South Australian units 73% of the time, averaging $61/MWh during these dispatch intervals, down significantly from $107/MWh in 2018-19.
  - Drivers of the NEM-wide reduction in spot electricity prices included lower-priced offers from black coal-fired generation, falling gas prices, and increased VRE output.
- Lower gas prices – wholesale gas prices in South Australia decreased to $7.13 a gigajoule (GJ) on average from record highs of $10.10/GJ in 2018-19. Lower gas prices were reflected in lower-priced GPG offers; in 2019-20, the average availability of South Australian GPG priced below $75/MWh increased by almost 100 MW compared to 2018-19.
- Reduced high price volatility – see Section 6.2.1.
- Reduced daytime operational demand – the rapid uptake in rooftop PV in South Australia continued to reduce daytime operational demand. Average operational demand reduced by 38 MW compared to 2018-19, driven by increased rooftop PV generation (+35 MW) and slightly lower underlying demand (-2 MW). The large increase in solar generation (both grid-scale and distributed PV) was a key factor in the significant reduction in South Australia's daytime prices (Figure 24).

[65] Please note all times in section 6 are in NEM time.

- Increased VRE output – despite increased curtailment, average VRE output increased by 27 MW, with grid-scale solar leading the increase (+20.5 MW) followed by wind (+6.5 MW).

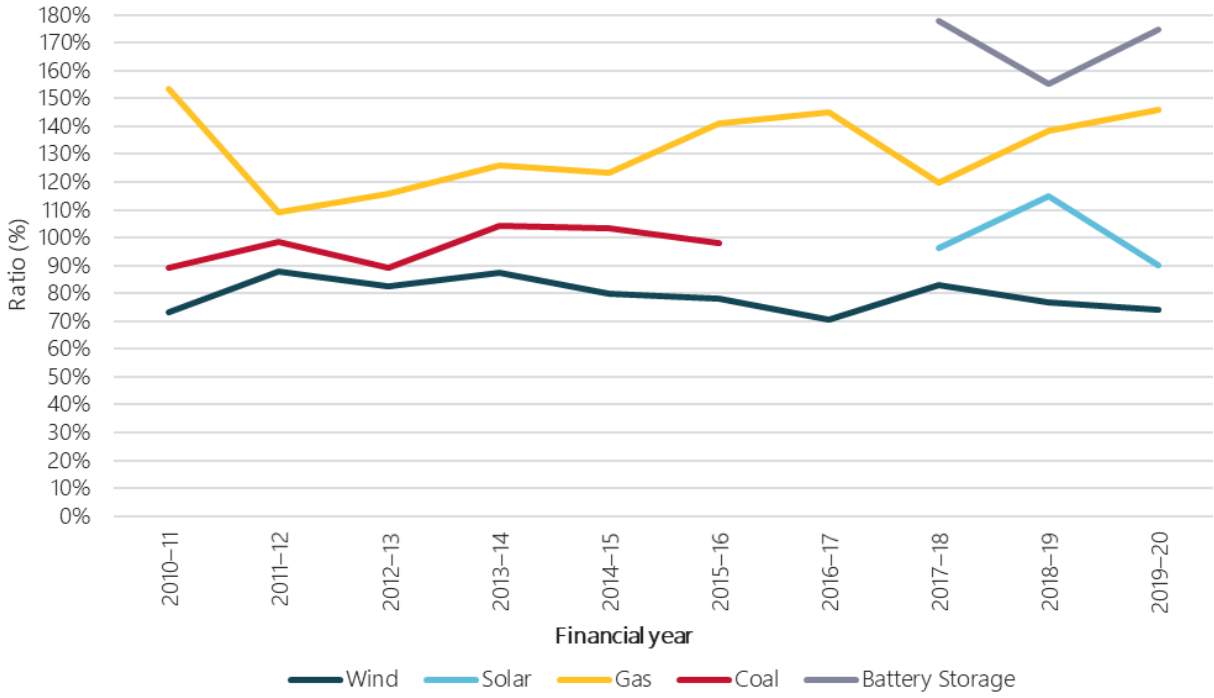
Figure 24 Average South Australian spot electricity price by time of day (real June 2020 $/MWh)



The volume-weighted 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 2019-20:

- **Gas** – the VWAP remained above the TWAP, reflecting the tendency for gas generators to operate at elevated levels during high priced events and operate less (or cycle offline) during low prices (unless directed to maintain system security). While the number of high priced periods remain relatively unchanged compared to 2019-20, the ratio of VWAP to TWAP increased from 138% to 146%. This was largely due to South Australian gas generators running at lower levels during the lower-priced daytime trading intervals. Compared to 2018-19, output between 7.00 am and 5.00 pm reduced by 122 MW on average.
- **Wind** – the VWAP remained below the TWAP, as high wind generation (typically bid at negative prices to ensure dispatch) tends to drive down the wholesale prices. Also, average wind generation tends to be higher during late evening and early morning periods, which is also when demand and prices are typically low.
- **Solar** – the VWAP fell below the TWAP this year, mainly due to the significant drop in average daytime prices (7.00 am to 5.00 pm) from $121/MWh to $62/MWh.
- **Battery** – VWAP to TWAP ratio increased from 155% to 175%. It remained the highest among all fuel types, because 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 low or negative priced intervals.

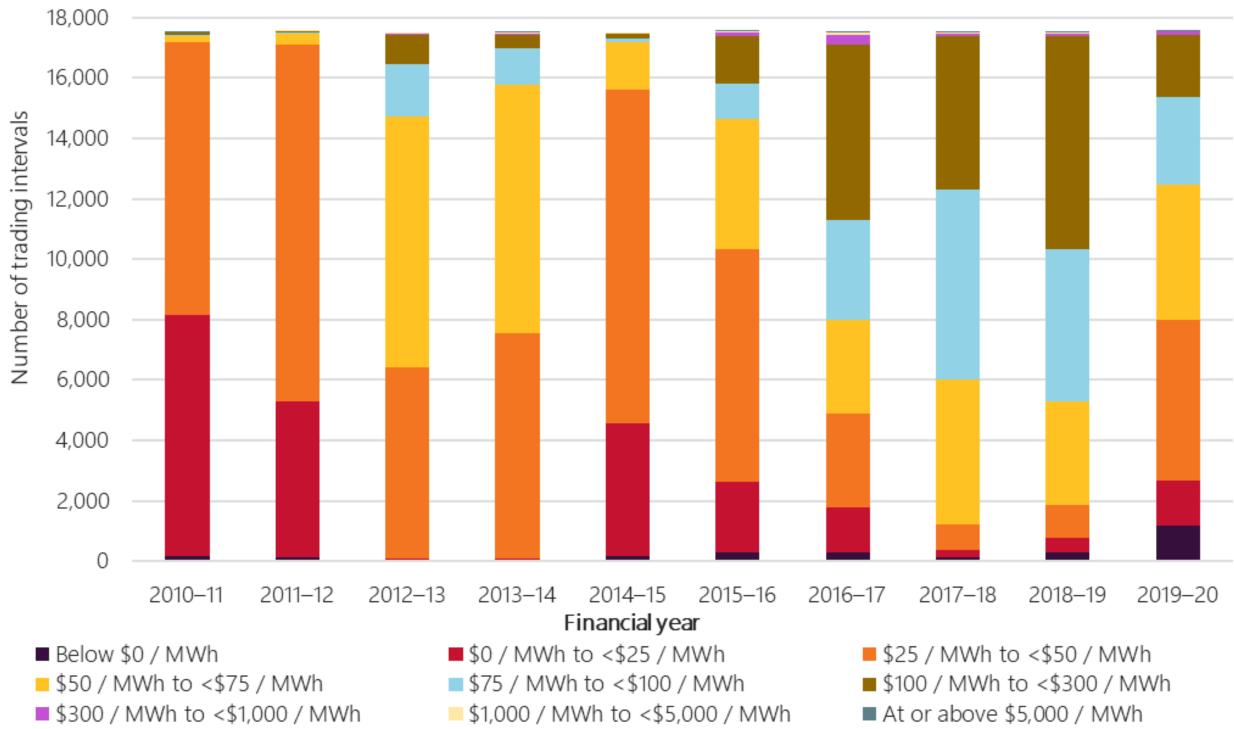
Figure 25 Ratio of VWAP by fuel to total TWAP for South Australian generators (based on real June 2020 $/MWh)



6.2 Price volatility

In 2019-20 there were mixed results for South Australian wholesale electricity price volatility. The occurrence of prices above $300/MWh remained relatively unchanged at 0.77% of trading intervals, while negative price occurrences increased to record levels, as shown in Figure 26 below.

Figure 26 Frequency of occurrence of spot prices for South Australia



6.2.1 High prices

Prices exceeded $300/MWh 0.77% of the time in 2019-20, similar to 2018-19 levels where prices exceeded $300/MWh 0.78% of the time. While the number of periods where price exceeded $300/MWh remained relatively unchanged, annual cap returns[66] fell from $14.52/MWh to $6.14/MWh.

Key contributors to the declining price volatility in South Australia included:

- Fewer high demand periods due to milder summer temperatures – compared to the third quarter of 2018-19, there was a 62% reduction in trading intervals in which operational demand exceeded 2,600 MW, due to reduced cooling load resulting from milder conditions in February and March 2020. No high demand periods (operational demand exceeding 2,600 MW) were recorded during February or March.
- Increased VRE during high demand periods – South Australian VRE output during high demand periods averaged 722 MW, representing an 88% increase on Q3 2018-19 levels.

Key high-priced events included:

- **19 December 2019** – extreme Adelaide heat (45°C), coupled with low wind output and limits on the Murraylink interconnector, resulted in South Australia's spot price spiking to the market price cap ($14,700/MWh) for one hour and a daily average price of $823/MWh.
- **30 January 2020** – an east coast heatwave leading to very high demand, coupled with thermal unit outages and low wind capacity factors, resulted in very high prices across several NEM regions, including South Australia. The South Australian spot price exceeded $2,000/MWh for two and a half hours, contributing to a daily average price of $774/MWh.
- **31 January 2020** – at approximately 1.25 pm, a severe storm brought down several 500 kV transmission towers in southwest Victoria, leading to separation of the South Australian and Victorian power systems, and a sudden drop in South Australian GPG and wind output. This, coupled with hot conditions, led to the South Australian spot price spiking to $9,832/MWh for one trading interval, and a daily average price of $304/MWh.

6.2.2 Negative prices

In 2019-20, the frequency of negative spot prices in South Australia reached record levels; spot prices were negative 6.8% of the time compared to 1.6% in 2018-19, representing a 423% increase (Figure 27). Negative spot prices reduced the average South Australian spot price by $6.22/MWh in 2019-20, compared to $1.12/MWh in 2018-19.

While negative spot prices have been a part of the South Australian market for several years, typically the highest prevalence has occurred between July and September. This year, however, negative prices continued into other shoulder months during periods of low operational demand.

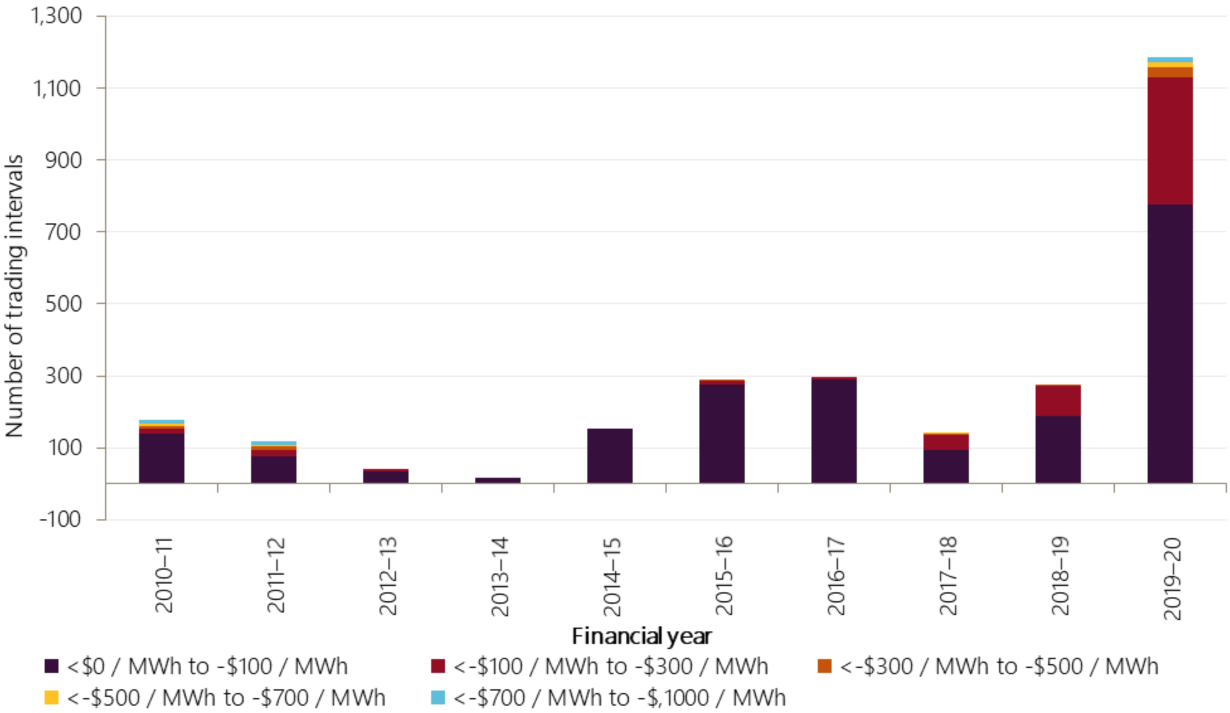
Key points relating to the increase in negative price periods in 2019-20 include:

- Lower daytime operational demand – rapid uptake of distributed PV has driven daytime demand reductions in South Australia, with around 71% of negative price intervals occurring during that period.
- Increased interconnector constraints – both Heywood and Murraylink interconnectors were binding at their limits for 22% and 31% of the year, respectively, which was approximately 80% more often than in 2018-19. The average limit for transfers from South Australia to Victoria on the Heywood interconnector was 428 MW in 2019-20, down 7% on 2018-19.
  - Increased constraints contributed to the high frequency of negative spot prices, particularly during periods of high VRE and low operational demand. Approximately 63% of negative price intervals occurred when Heywood interconnector was constrained.

[66] A measure of volatility in electricity prices is the presence of high price events (prices 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.

- Directed GPG – in December 2019, the Australian Energy Market Commission (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[67]. On average, 159 MW of GPG was directed during negative spot prices in the second half of 2019-20.

Figure 27 Count of negative price trading intervals per year



Wind and solar response to negative prices

South Australian wind and solar farms were increasingly responsive to negative spot prices in 2019-20, rebidding output to higher prices and subsequently not being dispatched by AEMO. The increased occurrence of negative prices this year led to higher self-curtailment from wind and solar farms in order to avoid paying to generate. On average, 21 MW of VRE output self-curtailed in response to negative prices, up from 4 MW in 2018-19.

Self-curtailment from VRE projects during the year was largest on days with extended negative spot prices. For example, a record high 968 MW of South Australian VRE output was curtailed[68] at 1.00 pm on 11 November 2019 (see Figure 28), coinciding with low daytime demand, transmission outages, and a spot price of -$343/MWh. Self-curtailment in response to negative spot prices, as well as the South Australian system strength constraint, were key drivers of curtailment on this day.

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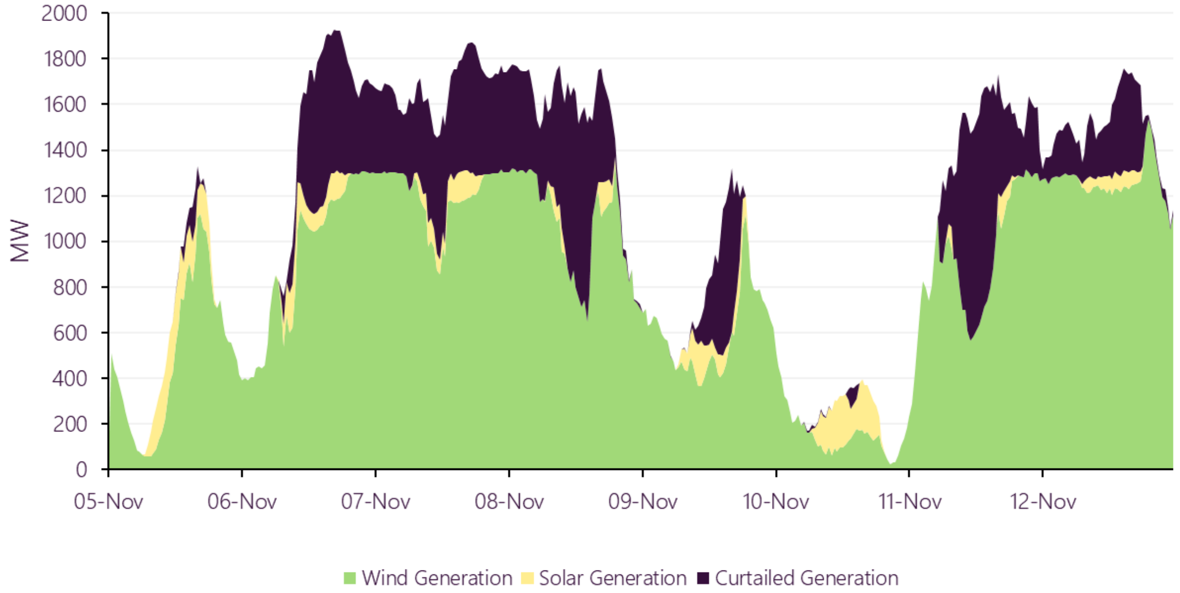
[67] When an intervention event brings on additional capacity and counteractions are not implemented, the prices produced by the what-if run will generally be higher than those produced by the dispatch run. This is because the what-if run will continue to signal the price associated with the supply demand 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.

[68] VRE curtailment only includes semi-scheduled generators.

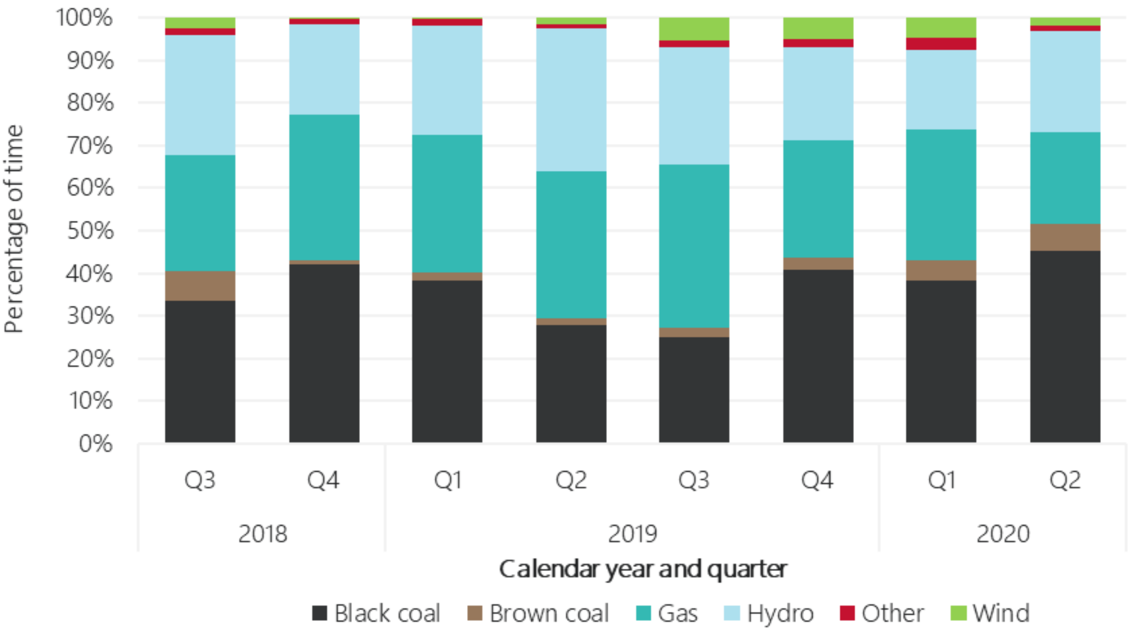
Figure 28 South Australian VRE output and curtailment, 5-12 November 2019



6.3 Price setting outcomes

Figure 29 shows South Australia's quarterly price setting outcomes by fuel type for 2018-19 and 2019-20.

Figure 29 South Australian price setting by fuel type



Key price setting outcomes in 2019-20 included:

- Wind farms set South Australia's price 4.2% of the time, up from 1.1% in 2018-19. This was due to the record occurrence of negative spot prices (see Section 6.2.2).
- GPG's price setting role reduced slightly from 32% of the time in 2018-19 to 29.5% in 2019-20. This was largely due to lower NEM-wide prices resulting from increased lower-priced offers, particularly in the last quarter of the financial year (Q2 2020), with contributing factors including:
  - Lower gas and coal prices.

– Easing of coal constraints at Mount Piper in New South Wales.
– Increased rainfall (and hydro output).
– New renewable supply.

- Similar to 2018-19, the most common price setting power stations were Torrens Island Power Station (which set the price 12% of the time), followed by Murray Power Station in Victoria (which set the price around 8% of the time) and Eraring Power Station in New South Wales (also 8% of the time).

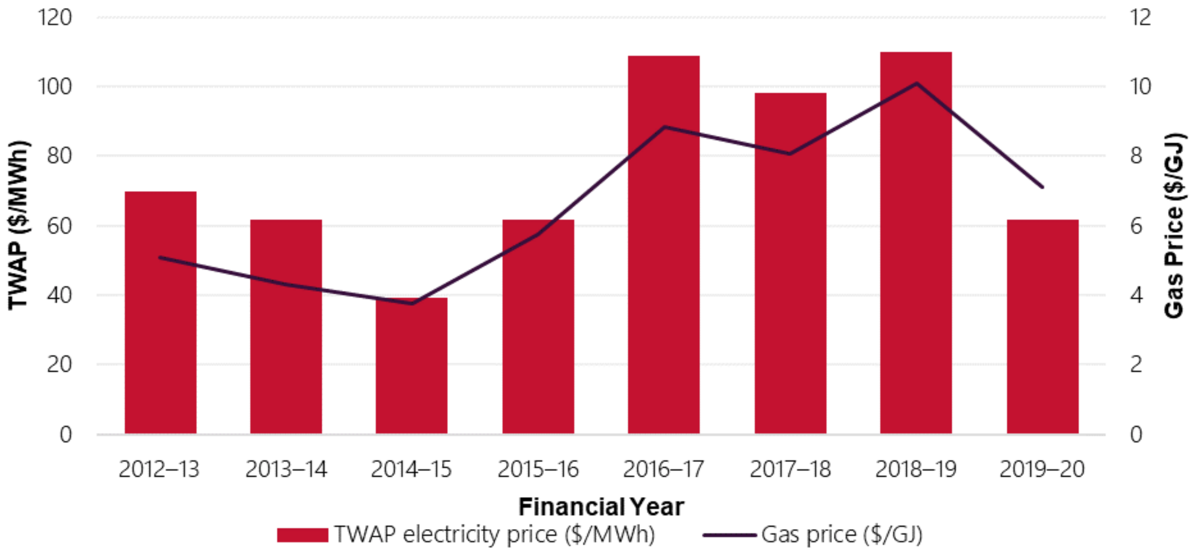
6.4 Impact of changes in generation mix

6.4.1 South Australian energy and price trends

Historical average electricity and gas price trends are shown in Figure 30. Both electricity and gas prices have fluctuated each year, following a similar trend to each other. This demonstrates the inter-relationship between the two, given the relatively large role of GPG in the South Australian energy mix.

Between 2018-19 and 2019-20, South Australia's average electricity TWAP decreased by 44%, while average gas prices in Adelaide's Short-Term Trading Market (STTM) decreased by 29% to $7.13/GJ.

Figure 30 South Australian electricity prices relative to gas prices



6.4.2 Gas spot price impact on electricity spot prices

Despite low wholesale gas prices, South Australian GPG gas consumption in 2019-20 was 9% lower than in 2018-19, and was particularly low in the second half of 2019-20. This was due to reduced operational demand, coupled with increased imports from lower-priced generation in Victoria.

With reduced local GPG and spot prices in all NEM regions, GPG set the electricity spot price less frequently in 2019-20 than in 2018-19 - see Section 6.3. With lower gas market prices, GPG units lowered the price of their electricity offers, contributing to GPG setting South Australia's price at an average of $92/MWh, down from $127/MWh in 2018-19.

In 2019-20, lower gas market prices coupled with reduced international coal prices, and increased renewable penetration, influenced offers from black coal-fired generators in New South Wales and Queensland. Compared to 2018-19, an average of 1,294 MW more capacity was offered at prices below $50/MWh, contributing to the NEM-wide reduction in spot prices.

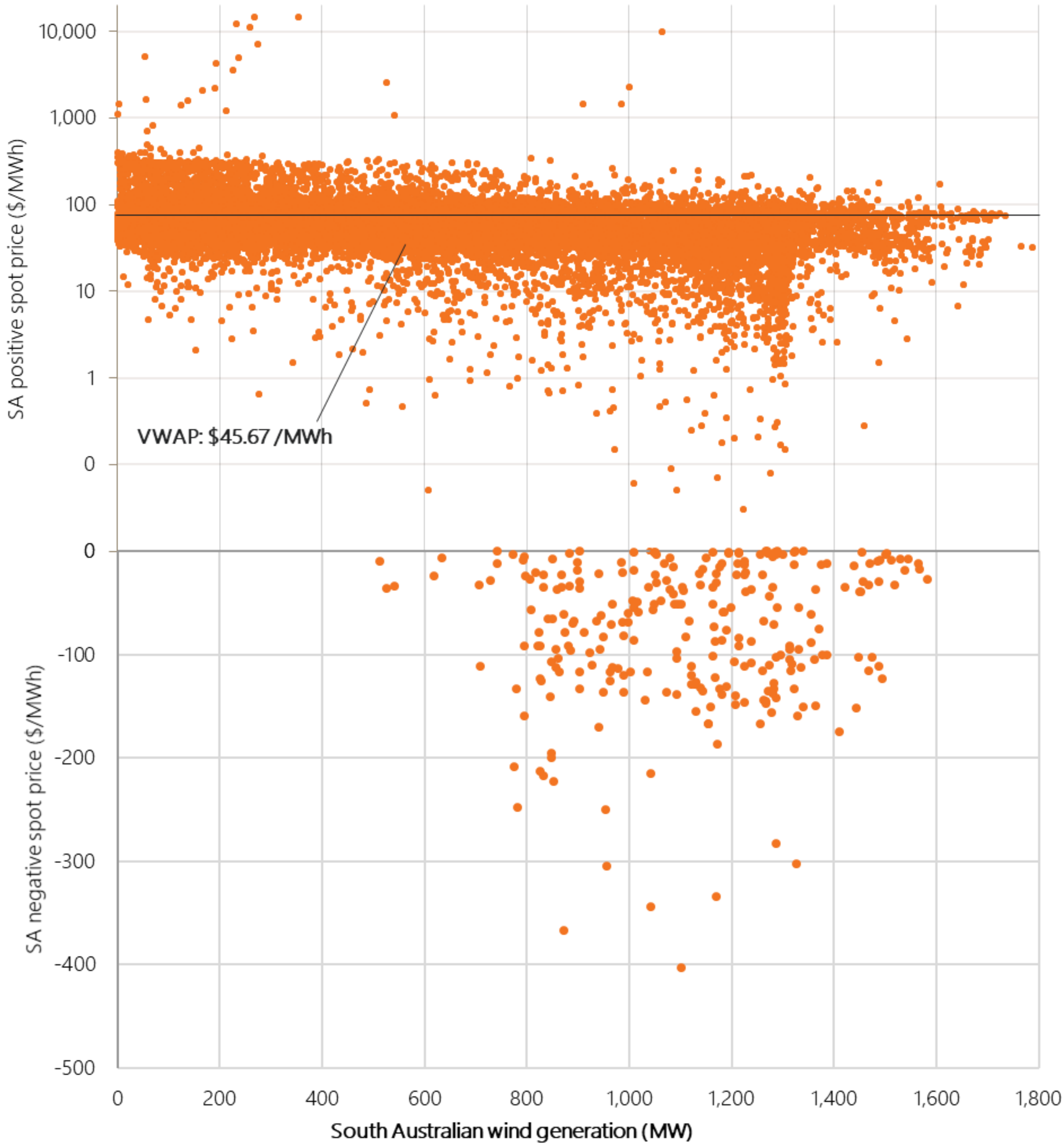
Gas prices were lower across all wholesale gas markets in 2019-20 than in 2018-19. The largest decrease occurred during the second half of 2019-20, with the Adelaide STTM price averaging $5.70/GJ compared to $10.36/GJ during the same period in 2018-19. East coast gas price decreases during this period were due to decreased demand (from Queensland's liquified natural gas (LNG) consortia, and GPG), and the continuation of more gas being offered at lower prices into the markets. These lower-priced offers coincided with declining international oil and gas prices, and lower NEM prices.

6.4.3 Spot prices and wind generation

Market prices are not typically set by wind generators, except during periods of high wind and low demand. However, the volume of wind generation online does reduce the need for conventional thermal generation, influencing spot prices even if wind generators are not setting them by being the marginal generator.

Figure 31 shows spot prices for the South Australian region and the corresponding average wind generation levels for each 30-minute dispatch interval for 2019-20.

Figure 31 South Australian 30-minute spot prices and average wind generation for 2019-20



Key points include:

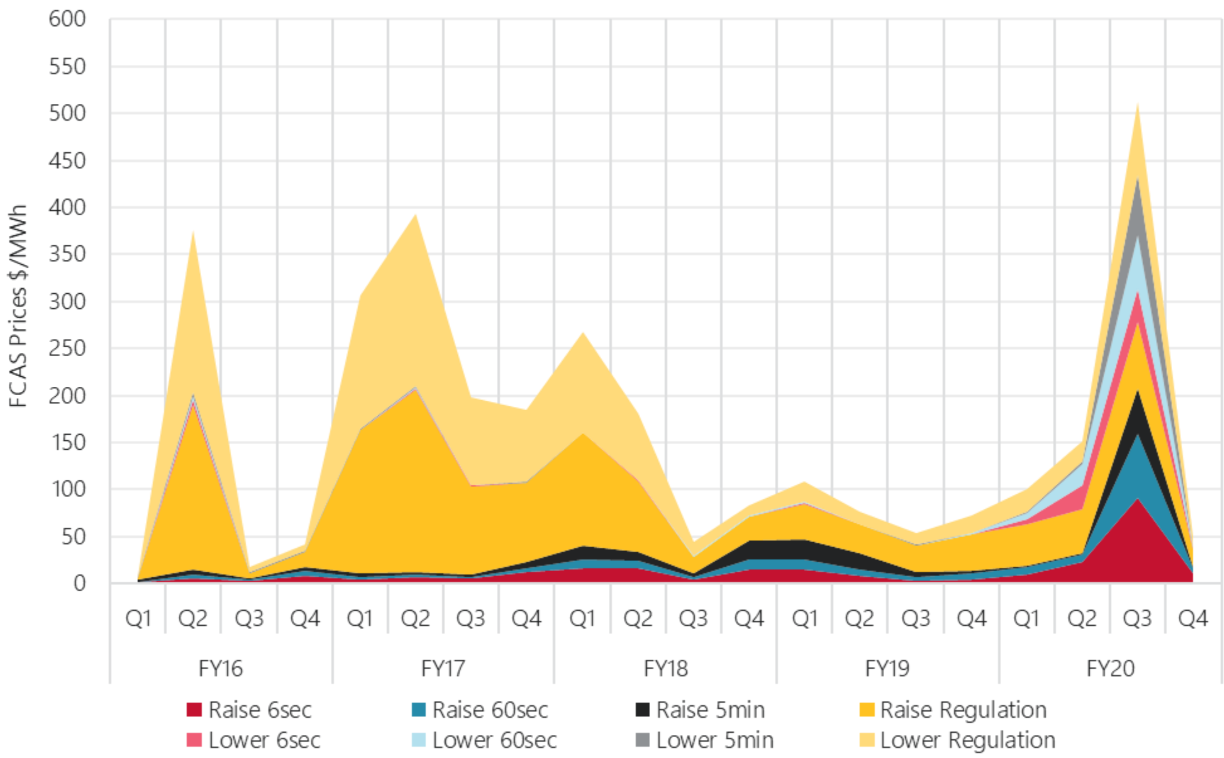
- 75% of prices above $1,000/MWh occurred when wind generation was lower than 400 MW.
- 49% of the negative prices occurred when wind generation was greater than 1,000 MW.

6.5 Frequency control ancillary services market prices

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 the imbalances between supply and demand in real time[69].

During 2019-20, South Australian FCAS prices were significantly higher than in 2018-19 (shown in Figure 32), primarily due to extreme FCAS price volatility in November 2019, January 2020, and February 2020 resulting from power system separation events and local FCAS requirement in the region.

Figure 32 Quarterly average South Australian FCAS prices by service



Power system separation events often result in FCAS prices spiking to extremely high levels, due to:

- Increased FCAS demand – due to FCAS requirements needing to be set on a local regional basis, rather than the typical NEM-wide basis.
  - For example, during the 18-day separation of the South Australian power system from the rest of the NEM (31 January to 17 Feb 2020), the average amount of Lower 5 Minute FCAS enabled in the region

[69] Regulation FCAS is enabled to continually correct the generation/demand balance in response to minor deviations in load or generation. Contingency FCAS is enabled to correct the generation/demand balance following a major contingency event, such as the loss of a generating unit or major industrial load, or a large transmission element. Contingency services are enabled in all periods to cover contingency events, but are only occasionally used (if the contingency event actually occurs). There are eight types of FCAS: six types of Contingency FCAS, and two types of Regulation FCAS, to raise or lower frequency at different speeds. For more details see AEMO, *Guide to ancillary services in the National Electricity Market*, at www.aemo.com.au/-/media/Files/PDF/Guide-to-Ancillary-Services-in-the-National-Electricity-Market.ashx.

increased by 98%, and the average amount of Raise 6 Second FCAS enabled increased by 10%. This increased local demand was mostly met by increased FCAS supply from GPGs.

- FCAS demand can only be provided by local supply, which can lead to a tight supply/demand balance and/or increased market concentration.

Key high-priced events included:

- **9 November 2019**[70]. AEMO invoked local Contingency FCAS requirements for South Australia due to heightened risk of islanding. Similar to the 16 November event, shortage of supply in the Lower 6 Second and Lower 60 Second markets resulted in prices hitting the cap for 85 minutes, and approximately $6 million in FCAS costs for the day.
- **16 November 2019**[71]. A trip of the Heywood Interconnector resulted in South Australia islanding from the rest of the NEM for around five hours. The Heywood trip followed an unexpected trip of the Murraylink Interconnector on the previous day. During the islanding, AEMO invoked local FCAS requirements for South Australia, with scarcity of supply in three FCAS markets resulting in very high FCAS prices.
  - A shortage of Lower 6 Second and Raise 6 Second supply led to these markets hitting the price cap ($14,700/MWh) for 100 minutes and 65 minutes, respectively.
  - These high prices resulted in $8 million in South Australian FCAS costs for the day.
- **31 January – 17 February 2020**[72]. On 31 January 2020, at approximately 1.24 pm, several towers supporting two 500 kV transmission lines in southwest Victoria were destroyed by a severe storm event, resulting in the disconnection of the South Australian region, Alcoa Portland aluminium smelter and Mortlake Power Station from the rest of the NEM power system. These systems were re-connected on 17 February 2020.
  - Extremely high South Australian FCAS prices occurred throughout this separation event. Of note was the extended price spike of the Raise 6 Second FCAS market in South Australia from 31 January to 1 February 2020, hitting $14,700/MWh for 365 minutes. This resulted in the Cumulative Price Threshold[73] being exceeded, leading to an Administered Price Period for FCAS markets in the region.
  - During this period, limited local supply of FCAS existed, with South Australia's Contingency Raise requirements were being set by Mortlake Power Station[74]. These combined factors led to periods of insufficient Raise 6 Second supply in the region to meet AEMO requirements.
- **2 March 2020**[75]. A circuit breaker at Heywood Terminal Station tripped, resulting in disconnection of the South Australian region and Mortlake Power Station from the rest of the NEM power system for approximately eight hours.
  - The sudden occurrence of local requirement led to South Australia's FCAS price spiking to $10,000/MWh or more in all eight markets, for between 45 minutes and 100 minutes.

[70] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2019/nem-event--direction-to-south-australian-generators-02-to-09-november-2019.pdf?la=en&hash=B547DB6565CA21C540FD2B51692DB683.

[71] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2019/preliminary-incident-report---16-november-2019---sa---vic-separation.pdf?la=en&hash=F26C20C49BD51164AE700A30F696A511.

[72] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/final-report-vic-sa-separation-31-jan--2020.pdf?la=en.

[73] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/2020/guide-to-administered-pricing-jul-2020.pdf?la=en.

[74] Although Mortlake Power Station is located in Victoria, the separation effectively resulted in it being part of the South Australian power system.

[75] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2020/direction-to-market-participants-in-sa-aemo-ies-6519-20200828.pdf?la=en.

7. Reliability of supply

South Australia is forecast to meet the reliability standard and the Interim Reliability Measure (IRM) in nine of the next 10 years. The retirement of Osborne Power Station in December 2023 increases the forecast expected unserved energy (USE) slightly. The inclusion of Project EnergyConnect would result in substantial reduction in forecast expected USE, more than offsetting the impact of Osborne's retirement.

7.1 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 USE exceeding the reliability standard[76] and the IRM.

The assumptions used to develop 2020 ESOO's reliability forecasts are outlined in the 2020 IASR[77].

Interim Reliability Measure

A new IRM, agreed by the former COAG Energy Council and introduced by *the National Electricity Rules (Interim Reliability Measure) Rule 2020* in August 2020, sets a maximum of expected USE to no more than 0.0006% in any region in any financial year[78]. This rule change supplements the existing reliability standard, allowing AEMO to procure out of market reserves for up to three years where an exceedance of the IRM has been forecast in the first year.

On 18 November 2020, the Energy Security Board (ESB) published a set of changes to *the National Electricity Rules* to amend the triggering arrangements for the Retailer Reliability Obligation (RRO) to align with the IRM[79]. The IRM addresses immediate concerns about reliability, while the ESB's Post 2025 work program aims to deliver market solutions to improve the NEM's reliability and security over the longer term.

7.1.1 South Australian reliability outlook for the next 10 years

The 2020 ESOO reliability assessment for South Australia improved compared to the 2019 ESOO. Supply shortfall risk remains below both the reliability standard and the IRM for all but the final year of the Central scenario, as shown in Figure 33. This is when the first units of Yallourn Power Station in Victoria are expected to close.

The improvement in reliability since last year is mostly due to lower forecast operational demand in all three scenarios and new generation capacity committed to come online in the coming years, including South Australia Temporary Generation South, Lincoln Gap wind farm stage 2, and upgrades to the Hornsdale Power Reserve battery.

The 2020 ESOO reliability assessment includes all existing and committed generation and storage reported in the Generation Information page published in July 2020[80], as well as committed transmission augmentations[81]. Existing generators are retired at the end of the expected closure year (calendar year end)

[76] The reliability standard specifies that expected USE should not exceed 0.002% of total energy consumption in any region in any financial year.

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

[78] See http://www.coagenergycouncil.gov.au/reliability-and-security-measures/interim-reliability-measures.

[79] See http://www.coagenergycouncil.gov.au/publications/energy-security-board-rro-trigger-rule-change.

[80] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[81] This includes major and minor committed augmentations. See Section 3.3 of the 2020 ESOO for more details.

or at the specified closure date if notice of cessation of registration has been received. These dates are provided by participants and reported on the Generation Information page.

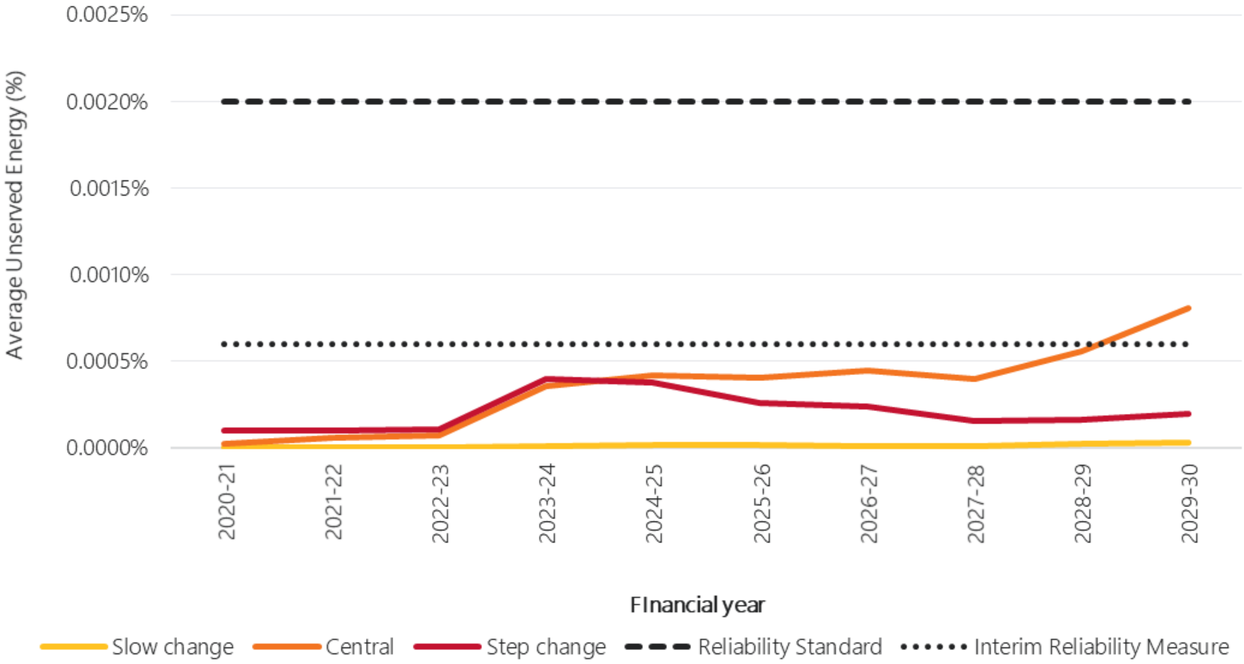
Specifically, the reliability projections:

- Do not include major transmission investments that have not yet completed all necessary approvals, such as Project EnergyConnect.
- Include the temporary diesel generator, Temporary Generation South, that has been leased by Infigen Energy (previously available for RERT).
- Do not include the temporary diesel generator, Temporary Generation North, due to be leased by Nexif Energy, as this does not meet the requirements to be classified as committed. Once these requirements are met, the supply adequacy outlook in South Australia would further improve.
- Do not include any additional capacity that could be made available through RERT[82].

The reliability forecasts also represent USE outcomes before any equitable load shedding principles are applied.

Although still relatively low, the risk of load shedding is forecast to increase after the retirement of Torrens Island A Power Station (TIPS A) and Osborne Power Station, from 2023-24 onwards.

Figure 33 Forecast USE outcomes for South Australia – existing and committed projects only



Although expected USE remains below the IRM for most of the ESOO horizon, in 2029-30 additional strategic reserves would be required in the Central scenario to reduce expected USE to below 0.006% of regional consumption (not considering the impact of the commissioning of Project EnergyConnect). The 0.002% reliability standard is not expected to be exceeded in South Australia within the ESOO horizon.

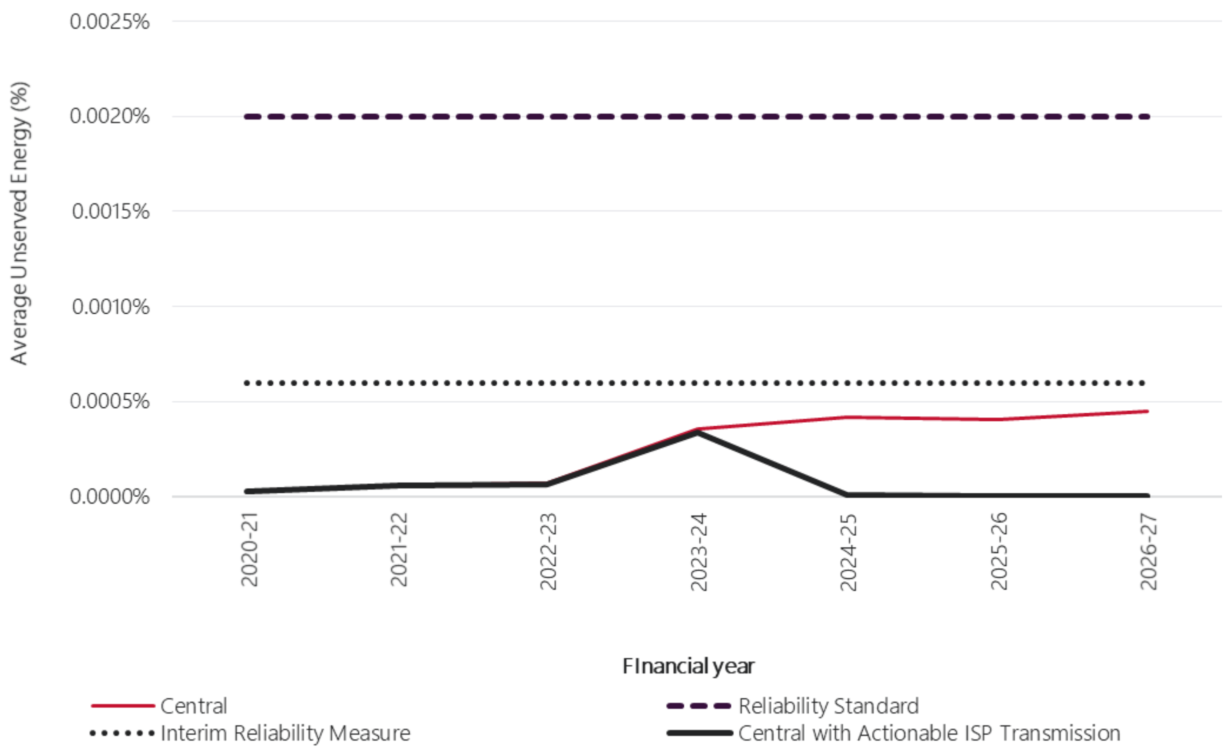
[82] The exception being demand side participation (DSP) responses from RERT panel members delivered outside RERT, which have been included in the DSP forecasts. See DSP methodology for more details, at https://aemo.com.au/consultations/current-and-closed-consultations/demand-side-participation-forecast-methodology-consultation.

Table 11 Additional reserves required to reduce expected USE to below 0.0006% of regional consumption

Financial year	Additional reserves (MW) required to reduce the gap to below 0.006%
2020-21	0
2021-22	0
2022-23	0
2023-24	0
2024-25	0
2025-26	0
2026-27	0
2027-28	0
2028-29	0
2029-30	148

With the inclusion of Project EnergyConnect, there is a substantial reduction in forecast USE from 2024-25 onwards, as shown in Figure 34. By increasing the import capability at times of high demand, Project EnergyConnect is forecast to more than offset the reliability impact of the retirement of Osborne and TIPS A.

Figure 34 Impact of actionable ISP transmission augmentations, South Australia



7.1.2 Managing forecast reliability risks

As no regions have forecast expected USE that exceeds the IRM this summer, any potential risk of load shedding will be mitigated with short-run RERT.

7.2 Managing reliability to date

RERT for summer 2019-20

During the summer of 2019-20, AEMO had 330 MW of RERT in South Australia available on Short Notice (SN) Panel Agreements that could be activated in the event of an actual LOR. On 30 January, in response to an actual LOR 2 condition in South Australia and Victoria, 227 MW of RERT was contracted in South Australia and 60 MW in Victoria, for a reserve shortfall of 165 MW in South Australia and 495 MW in Victoria. While AEMO contracted this short notice RERT in South Australia, ultimately it was not activated[83]. Consequently, no costs were incurred on 30 January associated with contracting of short-notice reserves.

RERT for summer 2020-21

As the 2020 ESOO did not project expected USE to exceed the reliability standard or the new interim reliability measure this summer in any region, no long notice contracts (LN) RERT Reserve will be contracted. AEMO is currently in the process of considering expressions of interest for Short Notice Panel Agreements in South Australia for the 2020-21 Summer.

AEMO expects to enter into agreements for approximately 200 MW of Short Notice RERT within South Australia. The reduction in Short Notice RERT compared to 2019-20 is because a generator that previously supplied RERT now participates in the energy market and can no longer participate in RERT.

Improving transparency and extending duration of the Medium Term Projected Assessment of System Adequacy (MT PASA)

In February 2020, the AEMC made a Final Determination and Rule to improve the transparency and accuracy, and extend the projected outlook of the MT PASA[84]. The MT PASA is a key part of the reliability framework in the NEM and requires AEMO to publish information on prevailing and forecast conditions, including when expected USE may exceed the reliability standard, to prompt a market response. The Final Rule provides for greater detail on projected assessments of system reliability and generation availability, which in turn allows participants to make more informed and efficient decisions. AEMO is currently implementing this rule change with a target date for delivery of all changes in December 2020.

7.3 AEMO/ARENA demand response pilot program

This pilot program was a three-year joint initiative between AEMO and ARENA, seeking to enable up to 160 MW of demand response in Victoria, South Australia, and New South Wales. The aim was to trial a strategic reserve model (referencing international market designs) for reliability or emergency demand response, to inform future market design as well as contributing reserves for the 2018, 2019, 2020 and future summers.

This program made 141 MW available in year 1 (2017-18) and up to 190 MW available in year 2 (2018-19), rising to up to 202 MW in year 3 (2019-20), across New South Wales, Victoria, and South Australia. Details of trial year 2 are available from ARENA[85], with a summary of year 3 expected to be published next year.

The ARENA RERT program has concluded operations and as a measure of the program's success most of the participants have elected to submit EOI's to join AEMO's RERT program for the 2020-21 summer.

7.4 Wholesale Demand Response Mechanism

Wholesale demand response is expected to contribute to improving reliability in the NEM.

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[83] See https://aemo.com.au/-/media/files/electricity/nem/emergency_management/rert/2020/rert-quarterly-report-q1-2020.pdf?la=en.

[84] See https://www.aemc.gov.au/sites/default/files/documents/erc0270_-_mt_pasa_final_determination.pdf.

[85] See https://arena.gov.au/assets/2020/09/demand-response-rert-trial-year-2-report.pdf.

The AEMC made a Final Determination and Rule in June 2020 to facilitate a wholesale demand response in the NEM, through implementing the Wholesale Demand Response Mechanism (WDRM)[86]. This mechanism will allow consumers to sell demand response in the wholesale market directly or through aggregators, promoting greater demand side transparency and price and reliability benefits. Key elements of the Final Rule include:

- Introduction of a new market participant category, a demand response service provider (DRSP).
- Placing obligations on DRSPs that largely replicate those applied to other scheduled participants.
- Establishing a process for having baseline methodologies determined and applied to wholesale demand response units.
- Providing for DRSPs to be settled in the wholesale market for the wholesale demand response at the prevailing spot price.

AEMO is currently implementing the WDRM Rule change, with a go live date of 24 October 2021. This market change will allow for a Demand Response Service Provider (DRSP), a market participant other than the retailer, to classify large market load connection points as wholesale demand response units (WDRUs). These WDRUs will take part in the standard central dispatch processes as scheduled plant in the NEM, either individually or as an aggregation. It is expected that WDRUs will be dispatched into the market at a time when supply is tight, and prices are high.

The level of participation is yet to be understood, however a significant number of barriers to participation have been removed during the market design process. These include exemption from telemetry requirements for smaller loads and exclusion from regulation FCAS causer pays and other cost recovery processes. The DRSPs will be required to support short-term forecasting through standard bidding processes and medium-term forecasting through information submitted to AEMO's Demand Side Participation Information (DSPI) portal.

[86] See https://www.aemc.gov.au/sites/default/files/documents/final_determination_-_for_publication.pdf.

8. Challenges and opportunities in a high renewables environment

This section discusses managing security today in light of the changing generation mix, increased distributed PV uptake and decreasing minimum operational demand.

The power system is adapting to the decommissioning of thermal generation in South Australia and Victoria, increasing levels of renewable generation, and rapidly reducing minimum demand levels as a result of continued distributed PV growth.
AEMO is working closely with the South Australian Government, ElectraNet, SA Power Networks and industry during this energy transition to enable a secure and reliable power system at lowest costs for consumers.

8.1 Background

With South Australia leading Australia in DER penetration rates, it is critical to understand the opportunities that are likely to emerge and the power system challenges that will need to be addressed.

Most distributed PV systems in the NEM today operate in a passive manner – they are not subject to the same performance requirements as large-scale sources and are not visible or controllable by DNSPs or AEMO, even under emergency conditions. This has begun to pose challenges to both distribution network and transmission power system operation.

Better integrating this fleet with the needs of the power system, through improved performance standards and minimum levels of emergency back stop capabilities, will help to address some of these challenges. Other forms of DER – such as storage and EV charging, and demand response – can also assist by 'soaking up' excess distributed PV generation in the daytime, but could also create their own challenges if not harnessed and integrated effectively.

AEMO has a major program of work underway, the DER Program[87], to establish the standards and frameworks necessary for secure operation of a high DER power system. This will ensure customers can continue to invest in and derive the maximum value from their distributed assets. AEMO has released various reports including the Renewable Integration Study Stage 1 report[88] which share insights from this work program. Ongoing work will continue to reveal new insights.

System strength, and inertia, and Network Support and Control Ancillary Services (NSCAS) requirements during low demand conditions will be considered in dedicated reports due for release in December 2020.

[87] AEMO, DER Operations, https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/operations.

[88] AEMO, Renewable Integration Study Stage 1 – Appendix A: High Penetrations of Distributed Solar PV, April 2020, at https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-a.pdf?la=en.

In collaboration with the ESB and AEMC, AEMO is concurrently pursuing development of suitable market and regulatory frameworks improving system security in a high DER power system. These are summarised in Section 8.10. These market and regulatory measures have been informed by AEMO analysis that has identified a number of system security challenges that arise as distributed PV levels grow, especially in the absence of an increase in underlying demand (either through active DER management or load shifting):

- Unintended disconnection of distributed PV in response to power system disturbances.
- Minimum demand thresholds to maintain supply of system security services.
- Steady state and dynamic reactive power resources to control voltages across the transmission network.
- Frequency control to arrest and recover frequency following an event, including impacts on emergency frequency control schemes (EFCSs), such as under frequency load shedding (UFLS).
- Ensuring sufficient inertia to reduce the rate of change of frequency (RoCoF) following an event.
- Implications for system strength[89].
- Impacts on system restart processes.

Each system service has a unique and important role in maintaining the security of the South Australian power system, and with the availability of these services changing, the way these system services are obtained will also have to change[90].

DER program

AEMO has established a DER Program[91] focused on optimising the integration of these resources into the grid. The aim is to create a DER market that will allow consumers to maximise the full value of their systems by enabling them to not just generate and export energy, but for DER to also provide system security services or potentially peer-to-peer energy trading.

To deliver this, the DER Program is trialling VPPs, implementing a DER Register, and working on improving inverter Standards. These Standards will ensure DER deliver state-of-art capabilities that support system security while also enabling consumers to access such new services at a time of their choosing.

Renewable Integration Study

The Renewable Integration Study (RIS) Stage 1 report[92] was published in April 2020. The RIS is the first stage of a multi-year plan to identify actions needed to maintain system security in a future NEM with a high share of renewable resources. The findings and the actions in the Stage 1 report reflect both day-to-day experience operating the NEM power system, and the results of extensive RIS modelling and analysis.

The RIS report took the Draft 2020 ISP's resource mix projections and investigated in detail the challenges in the short term, to 2025, of maintaining power system security while operating this resource mix at very high instantaneous penetrations of wind and solar generation. The report recommended actions and reforms needed to keep operating the NEM securely, now and as the power system transitions.

The report aimed to provide foundational engineering perspectives for the ISP, ESB, industry, market institutions, and policy-makers. The RIS's technical perspectives have informed regulations, and market designs to securely operate the NEM power system with very high instantaneous penetrations of wind and solar generation. A number of rule changes submitted to the AEMC have referenced the RIS as the evidence base.

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[89] System strength is an evolving concept. AEMO sees system strength as the ability of the power system to maintain and control the voltage waveform at any given location in the power system, both during steady state operation and following a disturbance. For more, see AEMO, System Strength Explained, March 2020, at https://aemo.com.au/-/media/files/electricity/nem/system-strength-explained.pdf.

[90] AEMO, Power System Requirements, updated July 2020, at https://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf.

[91] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program for more information.

[92] See https://aemo.com.au/en/energy-systems/major-publications/renewable-integration-study-ris.

Since the publication of the Stage 1 report, AEMO has engaged with stakeholders[93] to refine and progress the recommended actions, including assessing the potential roles of both existing and emerging technologies.

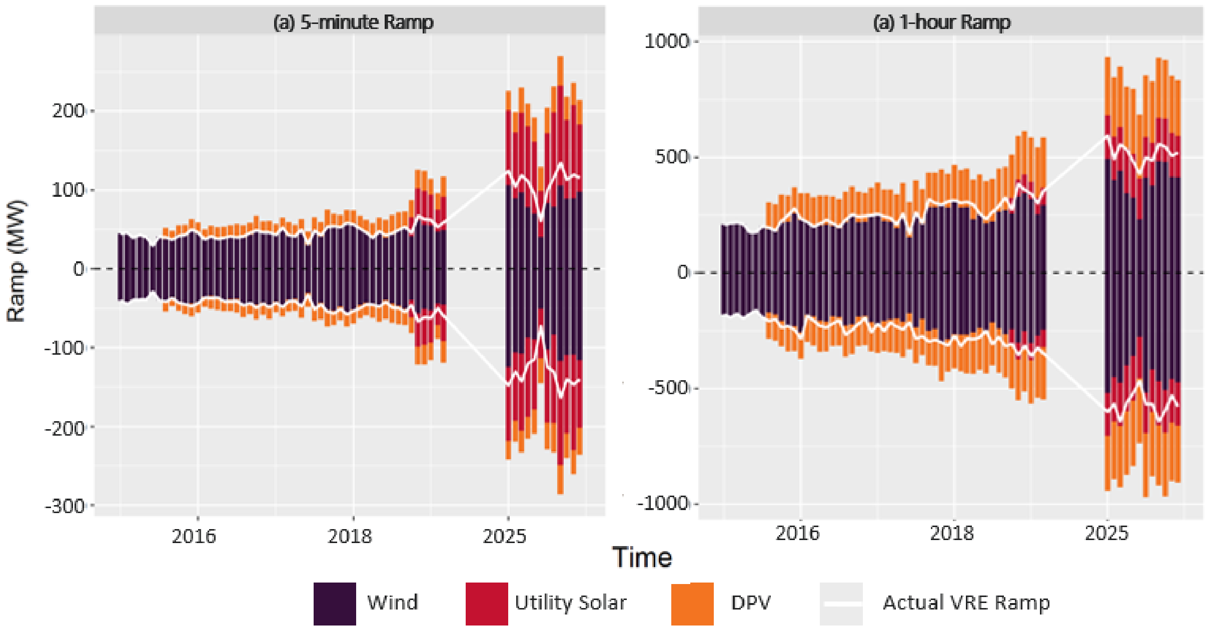
The Stage 1 report recommended 15 actions, of which five specifically reference South Australia. An update on the status of all actions is planned for December 2020. Appendix A of the RIS considered the power system challenges associated with increasing levels of passive distributed PV generation in the NEM. Further information can be found in the report and recorded webinars available online[94].

The second stage of the RIS is currently being developed, with an update planned for December 2020. The aim is to increase industry engagement on the technical work required to continue progressing recommended actions for system security, and to broaden the scope to look at questions related to increasing efficiency and resiliency in operating the future NEM.

8.1.1 Increasing variability of generation

Growth in solar and wind generating capacity results in increased variability of generation output, which needs to be managed. To effectively integrate higher levels of VRE, while maintaining a secure and reliable grid, flexibility needs to be harnessed in all parts of the power system. Analysis in the RIS focused on the ability of the system to act flexibly to fully utilise the VRE that is projected to be built out to 2025[95]. Figure 35 below provides the projected variability of generation in South Australia. A detailed case study that demonstrates this variability and uncertainty can be found in the RIS Variability and Uncertainty webinar and the full report[96].A

Figure 35 Butterfly plot: montly top 99% percentile upward and downward VRE ramps in SA



Interpreting butterfly plots: the butterfly plots show the monthly 99th percentile ramp between 2015 to 2019 and projected for 2025 (calendar years). These are the values that are exceeded in only 1% of cases. The **coloured bars** are the monthly 99th percentile ramp observed in each region for different VRE types (wind, utility solar and distributed PV). Stacked together they represent the top 1% theoretical ramp for a region if all VRE types had their 99th percentile ramp simultaneously. The **white (net ramp) line** represents the observed monthly 99th percentile ramp that resulted from the overall movement in wind, solar and distributed PV.

[93] See https://aemo.com.au/-/media/files/major-publications/ris/2020/submissions/response-to-stakeholder-submissions.pdf?la=en.

[94] See https://aemo.com.au/en/energy-systems/major-publications/renewable-integration-study-ris.

[95] For the purpose of the RIS, the generation expansion plan utilised was per that in the Draft 2020 Integrated System Plan (ISP), Central scenario. See https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/draft-2020-isp-archive.

[96] At https://aemo.com.au/en/energy-systems/major-publications/renewable-integration-study-ris.

8.1.2 Rapidly reducing minimum demand levels

Minimum demand has occurred during the daytime for the past five years in South Australia. This is projected to continue (See Section 3.1.3), with ongoing rapid reduction in minimum demand as growth in distributed PV continues, unless large quantities of market-based solutions such as utility-scale energy storage, coordinated EV charging and demand response emerge.

AEMO is collaborating with SAPN to ensure the power system can be operated securely during minimum demand conditions and identify any technical limits to DER export into the transmission system. To address identified issues, the South Australian Government has launched a series of measures under the Smarter Homes initiative[97].

8.2 Unintended disconnection of distributed PV in disturbances

AEMO now has considerable evidence that many distributed PV systems unintentionally disconnect in response to short duration voltage dips caused by faults on the network[98]. This has been demonstrated consistently across laboratory testing of distributed PV inverters[99], field measurements from thousands of individual distributed PV inverters during a series of voltage disturbances occurring during 2016 to 2020[100], and high speed monitoring at selected load feeders in the distribution network[101].

Loss of distributed PV generation might exceed potential load disconnection following plausible transmission disturbances. If coincident with the loss of other generation, this could result in a contingency exceeding the largest credible risk in the region today. Eventually, without action, as distributed PV penetration continues to increase, contingency sizes may become unmanageably large, especially for regions of the NEM that may operate as an island under some conditions.

As highlighted in the 2020 ESOO, AEMO's analysis demonstrates that a severe but credible fault near the Adelaide metropolitan area on the 275 kV transmission network would likely cause disconnection of both:

- 39-43% of the distributed PV in the South Australian region, and
- 14-25% of the underlying demand in the South Australian region.

In calendar year 2020, under the most severe credible fault, the size of distributed PV disconnection is expected to be larger than the underlying demand reduction approximately 12% of the time. In the highest distributed PV conditions in calendar year 2020, distributed PV disconnection could increase the size of the largest contingency in South Australia by approximately 170 MW in the Central scenario in the ESOO, and 230 MW in the Central Downside High DER sensitivity from the ESOO.

Without proposed mitigation measures to improve DER disturbance ride-through capabilities, by calendar year 2025 analysis suggests that distributed PV disconnection in the highest PV periods could increase the largest credible contingency by around 310 MW under the Central scenario and 390 MW in the Central

[97] Government of South Australia, Department for Energy and Mining, Regulatory Changes for Smarter Homes, at https://www.energymining.sa.gov.au/energy_and_technical_regulation/energy_resources_and_supply/regulatory_changes_for_smarter_homes.

[98] AEMO (April 2019) Technical Integration of Distributed Energy Resources – Improving DER capabilities to benefit consumers and the power system, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/Technical-Integration/Technical-Integration-of-DER-Report.pdf.

[99] Bench testing of individual PV inverters was conducted by UNSW Sydney as part of an ARENA funded collaboration with AEMO. Testing demonstrated that 14 out of 25 inverters tested (including a mix across both the 2005 and 2015 standards) disconnected or significantly curtailed when exposed to a 100 ms voltage sag to 50 V. Further information is available at https://research.unsw.edu.au/projects/addressing-barriers-efficient-renewable-integration and individual test results are available at http://pvinverters.ee.unsw.edu.au/.

[100] For each disturbance, data from a sample of individual distributed PV inverters was provided by Solar Analytics, under a joint ARENA funded project. Data was anonymised to ensure that system owner and address could not be identified. In some cases, up to 40% of inverters in a region were observed to reduce power to zero (indicative of disconnection) immediately following a voltage disturbance. PV disconnection behaviour was confirmed to be related to the severity of the voltage disturbance, and proximity of the fault to PV sites. See https://arena.gov.au/projects/enhanced-reliability-through-short-time-resolution-data-around-voltage-disturbances/.

[101] Energy Queensland provided AEMO with high speed measurements at various load feeders. The data demonstrated apparent increases in load following significant voltage disturbances in high PV generation periods, consistent with PV disconnection behaviour.

Downside, High DER sensitivity. By calendar year 2025, the size of distributed PV disconnection is expected to be larger than the underlying demand reduction approximately 20% of the time.

This has the following implications for power system security:

- **Imports on the Heywood interconnector may need to be limited in some periods** – if the Heywood interconnector is importing at significant levels into South Australia, a large generation contingency (involving a large generating unit and an associated net loss of distributed PV) in South Australia could lead to activation of the SIPS, and in the worst case, possible separation from the rest of the NEM. As discussed below, UFLS may not be sufficient to prevent cascading failure if separation occurs under high distributed PV conditions. To maintain power system security, imports on the Heywood interconnector need to be limited in some periods. A preliminary constraint has been implemented, and ElectraNet is completing analysis to refine its network limit advice.
- **If islanded, maintaining system security at times of high distributed PV will be challenging** – when South Australia is operating as an island, AEMO's studies indicate that it is becoming increasingly more challenging to maintain the Frequency Operating Standards for certain credible faults if they occur during periods with high levels of distributed PV operating. This means AEMO may no longer have the means to operate a South Australian island securely at times of high distributed PV generation. Security risks will grow rapidly as more distributed PV is installed, if the mitigating actions discussed below are not implemented. AEMO is now taking distributed PV disconnections into account in the assessment of inertia requirements and shortfalls, and will progressively incorporate these findings into other power system security assessments.

Further details are available in the 2020 ESOO[102].

8.3 Minimum demand thresholds

AEMO provided a detailed report to the South Australian Government on minimum demand thresholds in South Australia in May 2020[103]. AEMO has since updated these thresholds as published in the 2020 ESOO.

Figure 36 shows historical minimum operational demand levels (as generated) in South Australia, compared with forecasts, and identified demand thresholds.

Figure 36 shows:

- Minimum demand forecasts are well below the thresholds for secure operation of a South Australian island. This means there is an urgent need to establish a back stop mechanism to restore operational demand to a level that allows secure power system operation (by curtailment of distributed PV generation) when rare and extreme events occur, such as when the South Australian region is operating as an island or under elevated risk of separation. See Section 8.5 for measures being taken to implement emergency PV curtailment capability.
- By 2022, under certain conditions, South Australia will fall below the threshold at which it will be essential to export to Victoria, based upon the necessity of operating a minimum number of synchronous generating units in South Australia.

The anticipated staged commissioning of the Project EnergyConnect (PEC) interconnector[104] (see Section 5.2) should significantly reduce the likelihood of islanding.

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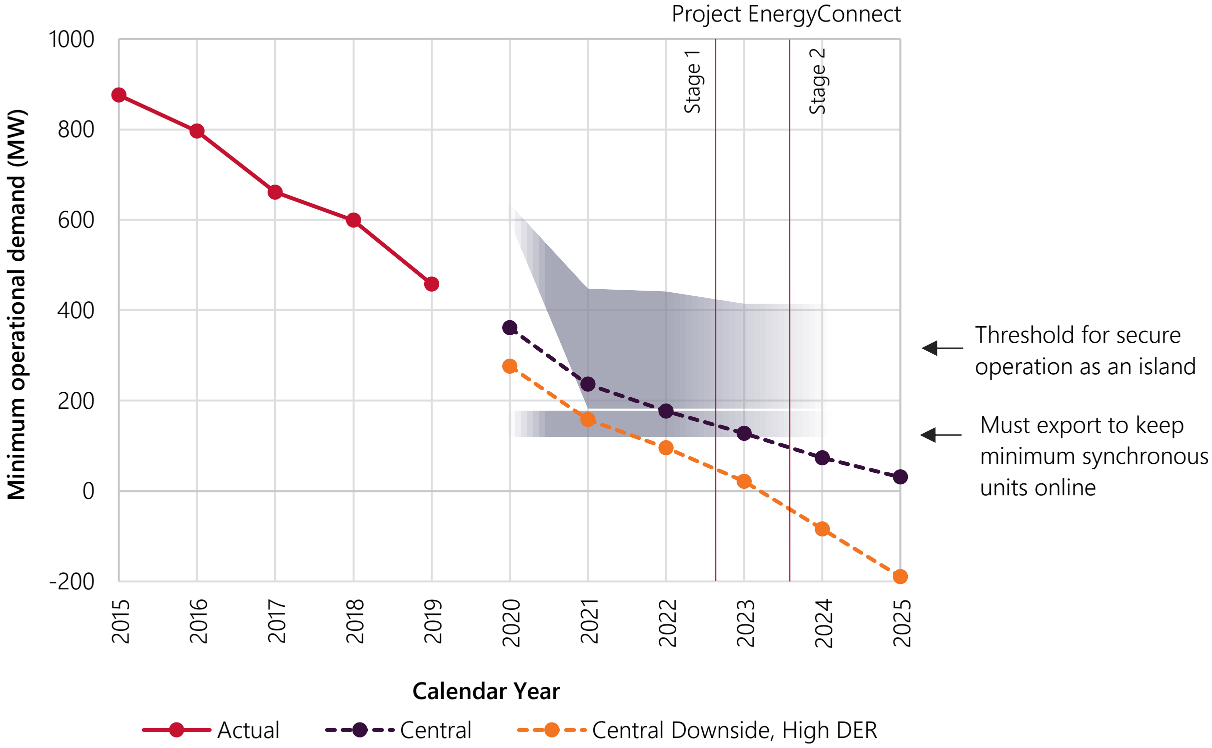
[102] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

[103] AEMO (May 2020) Minimum operational demand thresholds in South Australia, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/sa_advisory/2020/minimum-operational-demand-thresholds-in-south-australia-review.pdf?la=en&hash=BBB27149A93B9259C63B47A8ECDB0B6E.

[104] Project EnergyConnect is an actionable ISP project and is modelled in service from July 2024. The implementation of this project is tracking to schedule with commissioning targeted in stages between late 2022 and late 2023. Network capacity is intended to be released in stages following the asset commissioning process.

Figure 36 Minimum operational demand thresholds in South Australia (90% POE as generated)



This figure presents "as generated" minimum demand values, which are slightly higher than the 'sent out" values presented earlier in this report as they include auxiliary loads.

8.4 Under frequency load shedding

AEMO has also identified that the South Australian UFLS scheme is no longer adequate to prevent cascading failure in the event of a double circuit loss of the Heywood interconnector in some periods with high levels of distributed PV generation[105]. AEMO is implementing a series of measures to manage the identified risks, including the addition of new loads to the UFLS scheme, and updating and expanding constraint sets to reduce imports on the Heywood interconnector in periods where the UFLS is known to be inadequate[106].

AEMO is preparing a request to the Reliability Panel to declare the separation of South Australia as a protected event, allowing a wider range of management mechanisms to be implemented.

The behaviour of distributed PV is also now being taken into account in AEMO's assessment of inertia and system strength shortfalls, and was a contributing factor in AEMO's recent declaration of an inertia and fast frequency response (FFR) shortfall in South Australia[107] – see Section 8.8.

8.5 Requirement for emergency PV curtailment capability

AEMO is collaborating closely with SAPN and ElectraNet to update operating procedures for low demand periods and implement new capabilities to actively manage distributed PV when necessary.

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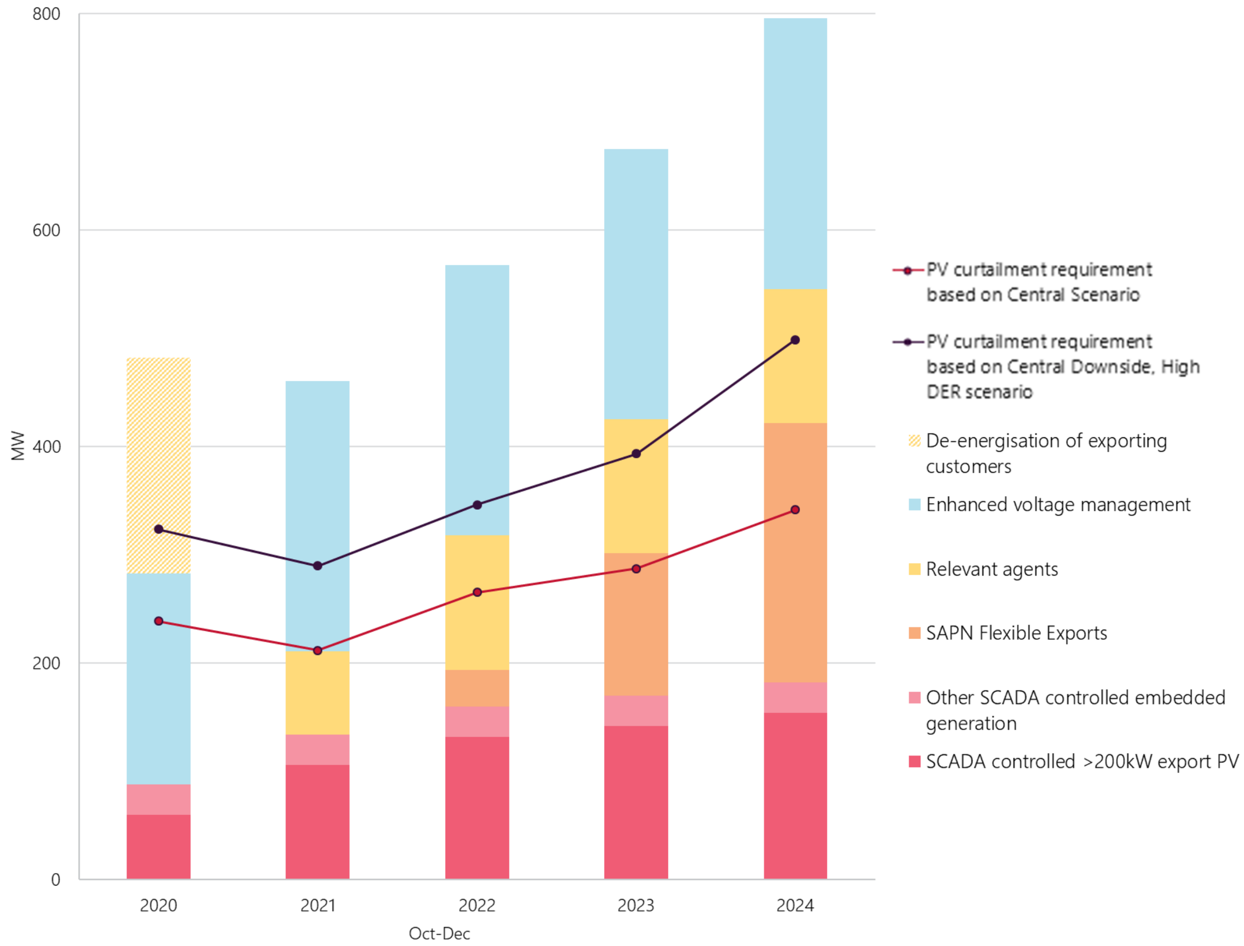
[105] AEMO (July 2020) 2020 Power System Frequency Risk Review – Stage 1 – Final Report, Appendix A1, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/psfrr/final-2020-power-system-frequency-risk-review-stage-1.pdf?la=en&hash=C1EA01AAC28C7DF0D4F69700B8FC439B.

[106] AEMO (October 2020) Heywood UFLS constraints, at https://aemo.com.au/-/media/files/initiatives/der/2020/heywood-ufls-constraints-fact-sheet.pdf?la=en&hash=066F80AE0EE3CF9701A0509818A239BB.

[107] AEMO (August 2020) Notice of South Australia Inertia Requirements and Shortfall, at https://www.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&hash=673E32C8547A8170C9F4FA34323F3A8F.

The 2020 ESOO published the capacity of new emergency PV curtailment capability projected to be required in each year (see Figure 37 below), based on the levels of operational demand required to operate a secure island. Around 300 MW to 400 MW of new PV curtailment capacity would ideally be available immediately, and emergency PV curtailment capabilities are required for almost all new entrant distributed PV capacity installed beyond this point.

Figure 37 Emergency PV curtailment capacity required in South Australia with estimated response from identified approaches (90% POE minimum demand)



Note. Values shown for each year (including 2020) are based on anticipated minimum demand which is likely to occur during September-December. The response size shown for each mechanism is approximate, dependent upon the PV forecast, and considers reductions in response from using preceding mechanisms (for example, curtailment via Flexible Exports or PV de-energisation will reduce the response from enhanced voltage management).

A range of approaches are being pursued to meet technical requirements, including smart meter PV curtailment and enhanced voltage management:

- **Smart meter PV curtailment** – upon installation of a new PV system, customers typically also install a smart meter, which has all of the required capability to curtail PV, as long as the PV is installed on a controllable circuit (separate from the customer's load). This means that with some minor changes to meter specifications, smart meter functionality may provide emergency PV curtailment capabilities with minimal additional cost, when applied to new installations[108].

[108] AEMO is pursuing this in collaboration with Metering Coordinators and the South Australian Government. Government of South Australia, Department for Energy and Mining, Consultation on the Proposed Smart Meter Minimum Technical Standards in South Australia, at http://www.energymining.sa.gov.au/__data/assets/pdf_file/0010/364663/Attachment_4_Consultation_on_the_Proposed_Smart_Meters_in_South_Australia.pdf.

- **Enhanced voltage management** – SAPN has identified that introducing dynamic fine-grained voltage control capability would improve distribution voltage management and reduce customer impacts related to high voltages. As a side benefit, this also introduces the capability to improve system security via the ability to induce a temporary slight increase in voltages to cause a controlled curtailment of distributed PV. SAPN's trials of this capability have indicated that it is effective, safe, and has minimal customer impact. This approach also has the significant benefit of enabling emergency PV curtailment capability for a proportion of legacy PV systems, without the need for costly retrofitting at each individual site.

It is estimated that the combined contribution of these approaches can meet the identified emergency PV curtailment requirements in South Australia, if implemented promptly

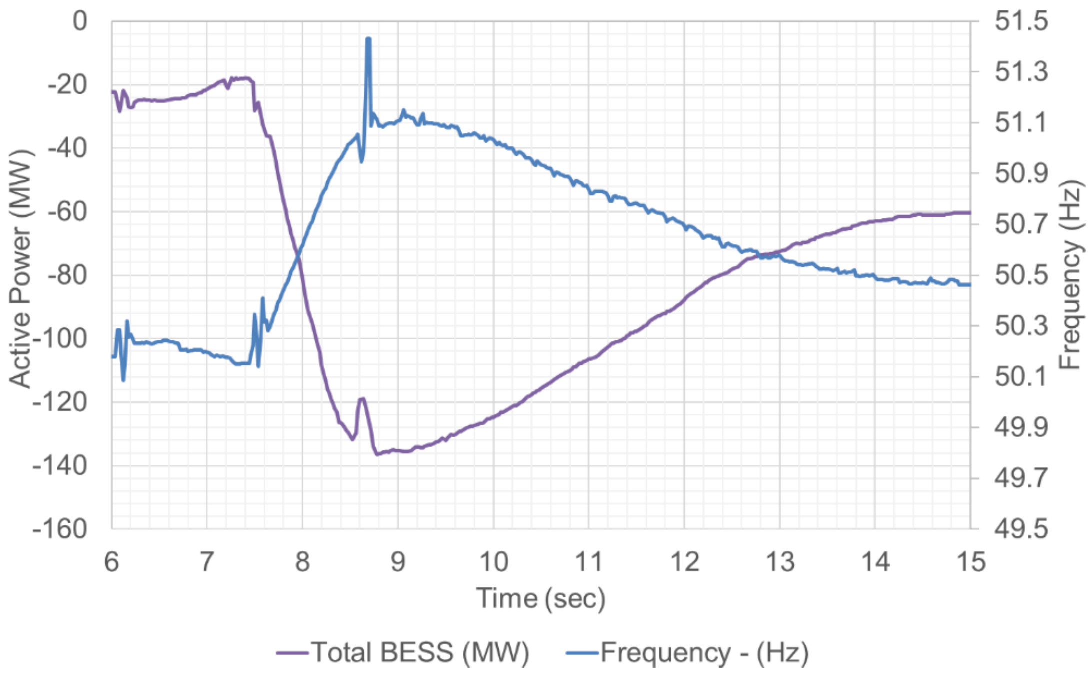
8.6 Contribution of inverter-based technologies to frequency response

Over the past few years, grid-connected inverter based resources (IBR) such as BESS have demonstrated their ability in rapid delivery of a sustained response to a change in frequency and thereby contributing to South Australia's system security. This rapid response from IBR is particularly helpful following a disturbance.

Grid-connected batteries

During the South Australian separation event on 31 January 2020[109], it was observed that all grid-connected BESS responded to the over-frequency event in a sub-second time frame. Prior to the event, they were absorbing approximately 20 MW collectively from the grid. In response to over-frequency conditions, they absorbed an additional 120 MW to arrest frequency, as shown in Figure 38. The frequency response provided by the BESS is a simple proportional response. For a one Hz change the output from the BESS would change by its rated capacity[110].

Figure 38 Total response from South Australia BESS



[109] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/final-report-vic-sa-separation-31-jan--2020.pdf?la=en.

[110] Including deadband.

Grid-connected solar farms

The South Australian power system has three transmission connected solar farms – Coorong (Tailem Bend) Solar Farm and Bungala 1 and 2 Solar Farms – with a collective nameplate capacity of 353 MW. These solar farms are connected to the transmission network via inverters with a droop characteristic, similar to that of a BESS.

Responses from all three grid-connected solar farms during the South Australia separation event on 31 January 2020 revealed that, despite similarities in inverter technology used, each solar farm responded differently to the change in frequency, depending on how its control system, particularly frequency response, is configured.

The following was observed in relation to how transmission connected solar farms responded to a frequency event thereby contributing to system security:

- Coorong (Tailem Bend) Solar Farm started to respond immediately after the event without noticeable time delay. The response contributed towards arresting the frequency.
- Bungala 1 Solar Farm started to respond soon after the event, however, the response in terms of change in the amount of generation to a change in the frequency was slow. This means Bungala 1 Solar Farm had relatively low contribution towards arresting the frequency.

It should be noted that, unlike BESS, currently solar farms are not offering FCAS. Therefore, despite their capability, similar response is not guaranteed in the future. Further information is available in the Final Report – Victoria and South Australia Separation Event on 31 January 2020[111].

8.7 Possibility of VPPs providing grid services

In July 2019 AEMO, in collaboration with ARENA, launched the VPP Demonstration program[112], to establish a framework to allow VPPs to demonstrate their capability to extend battery operations beyond energy markets, and provide contingency frequency control ancillary services (FCAS)[113].

There are four VPPs from South Australia participating in the VPP Demonstrations:

- South Australian VPP (SA VPP), enrolled in September 2019 and has progressively increased its registered capacity to 10 MW in September 2020.
- AGL VPP, enrolled in February 2019 with 3 MW of capacity.
- Simply Energy VPP, enrolled in September 2020 with 3 MW of capacity.
- Shinehub VPP, enrolled in November 2020 with 1 MW of capacity.

The VPP Demonstrations allow participating VPPs to trial a new specification to deliver Contingency FCAS, and AEMO will observe how VPPs respond to energy market price signals as non-scheduled resources. By trialling VPP operations while their aggregated fleets remain small in scale, the VPP Demonstrations aim to inform the effective integration of VPPs into the NEM before they reach large scale.

The operational visibility and capabilities shown in the VPP Demonstrations project represent foundational building blocks to enable AEMO to operate the power system with high levels of DER. AEMO has published two knowledge sharing reports[114] that highlight the key insights from the project so far, including:

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[111] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/final-report-vic-sa-separation-31-jan--2020.pdf?la=en.

[112] AEMO, NEM VPP Demonstrations, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program/Pilots-and-Trials.

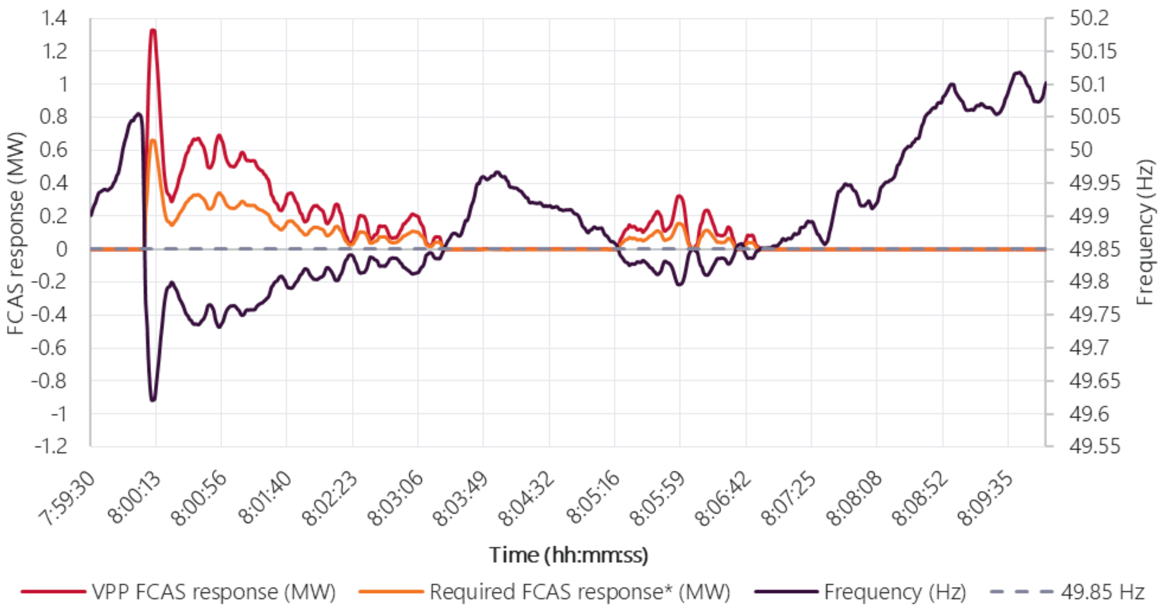
[113] FCAS are services that help AEMO balance supply and demand to maintain system frequency. Contingency FCAS is called on when frequency is disturbed by a contingency event, such as the sudden failure and disconnection of a generator or load.

[114] At https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/pilots-and-trials/virtual-power-plant-vpp-demonstrations.

- VPPs continue to demonstrate their effective capability to respond to both contingency FCAS events and energy market price signals.
- VPPs have demonstrated promising capability to accurately forecast their performance. Evidence indicates that 1-hour-ahead forecasts are most accurate, and that there are only minor variances between the other intra-day and day ahead forecasts. Accurate forecasting would be an important capability for VPP participation in potential ahead markets in future.
- Evidence indicates that VPPs could alleviate operational challenges such as low generation reserves and low minimum demands as they grow in scale and take advantage of both high prices during peak demand and low/negative prices during peak exports/low minimum demand events.

On 9 October 2019, there was a 748 MW trip of a generating unit at Kogan Creek Power Station in Queensland, resulting in an instantaneous drop in frequency to 49.61 Hertz (Hz) (see Figure 39). The SA VPP (operated by Energy Locals and Tesla) was enabled for 1 MW of Raise Contingency FCAS at the time, and automatically responded as expected to the frequency excursion. This is a real-world example of how VPPs with household consumer devices can contribute to power system security and earn new value streams that can be shared with consumers.

Figure 39 VPP FCAS response to contingency event, 9 October 2019



* Based on 0.7% drop and 1MW Raise Contingency FCAS dispatch.

8.8 Inertia requirements

In the 2020 Notice of South Australia Inertia Requirements and Shortfall[115] AEMO declared updated inertia requirements for South Australia as well as an inertia shortfall. The updated requirements reflect:

- Findings form the South Australia islanding events in early 2020.
- A larger potential daytime contingency event size due anticipated increases in levels of distributed PV.
- The implications of declining minimum daytime demand in the region.

[115] See 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&hash=673E32C8547A8170C9F4FA34323F3A8F.

Minimum threshold level of inertia

The minimum threshold level of inertia remains unchanged at 4,400 megawatt-seconds (MWs).

Secure operating level of inertia

Compared to the 2018 inertia requirements, the secure level of inertia requirement for when South Australia is islanded rises from 6,000 MWs of synchronous inertial support, to at least 7,605 MWs for 2020-21 and to 14,390 MWs for 2021-22 if no additional FFR is procured in addition to that already available.

However, installing the quantity of synchronous machines needed within South Australia to meet this requirement is not feasible. Recognising practical, technical and economic realities, AEMO has therefore determined the secure operating level of inertia based on an assumption that ElectraNet, as the Inertia Service Provider, will provide some level of FFR to contribute to reducing the inertia shortfall, rather than assuming all contribution of synchronous inertial response from synchronous machines.

The 2020 Notice of South Australia Inertia Requirements and Shortfall has further details on the combinations of synchronous inertia and FFR which can address the shortfall. The more FFR that is provided, the less inertia will be required from synchronous machines. The declaration has been staged, with Stage 1 addressing the inertia requirements before the installation of the four synchronous condensers with flywheels (see Section 8.9), and Stage 2 considering inertia requirements post installation of the synchronous condensers.

Shortfall declaration until mid-2022

In the 2020 Notice of South Australia Inertia Requirements and Shortfall, AEMO has not determined inertia requirements beyond 2021-22, due to high levels of uncertainty regarding the impact of distributed PV beyond this timeframe[116]. AEMO considers it very likely that no inertia shortfalls will be declared in South Australia following the commissioning of Project EnergyConnect[117], as a second AC interconnector would significantly reduce the likelihood of the South Australia region being islanded from the NEM.

Next steps

The NER put the responsibility for providing services to address shortfalls in inertia on the local Inertia Service Provider, which is ElectraNet. AEMO has asked ElectraNet that services be made available to address the Stage 1 shortfall which is already open, but in the meantime, to the extent possible, operational arrangements will continue to be used to securely operate the South Australia power system if it is islanded. AEMO has agreed with ElectraNet that the required services for Stage 2 will be made available from 31 July 2021.

8.9 Maintaining system strength

System strength is the ability of the power system to maintain the voltage waveform at any given location, with or without a disturbance. This includes resisting changes in the magnitude, phase angle, and waveshape of the voltage.

Synchronous machines (hydroelectric, gas, and coal generation, and synchronous condensers) are traditional sources of system strength. A synchronous condenser operates in a similar way to large electric motors and generators. Synchronous condensers fitted with flywheels are an important source of system strength and inertia and are essential irrespective of future new interconnection development.

Increasing penetration of IBR (batteries, wind, and solar generation) is requiring new approaches to maintain system strength.

The current electricity market environment may not adequately incentivise sufficient synchronous generators to stay online to maintain minimum system strength in the South Australian power system. Under those circumstances, AEMO directs the necessary synchronous generators to stay online. AEMO has published

[116] AEMO is currently preparing to release the 2020 System Strength Report by the end of 2020.

[117] See https://www.projectenergyconnect.com.au/.

studies outlining the minimum number of synchronous machines required to maintain the minimum required fault current levels in South Australia[118].

The 2020 ISP affirms that the installation of four synchronous condensers currently underway by ElectraNet will address the identified system strength gap. However, AEMO does not assume that the four synchronous condensers would address all requirements for system security in South Australia. AEMO applies a planning assumption that following the installation of the four synchronous condensers and before the implementation of Project EnergyConnect, at least two large synchronous generator units in South Australia would be required online at all times.

8.9.1 System strength in the current operating environment

Operating procedures are currently in place to ensure a minimum number of synchronous generating units are in service in South Australia at all times to prevent the power system breaching secure operating limits, until a permanent technical solution is completed.

AEMO's operating procedures identify the conditions and generator dispatch combinations needed to satisfy current system strength requirements. Where natural market outcomes do not deliver the specific minimum secure fault current level, AEMO has powers under the National Electricity Law and the NER to direct the necessary resources into service.

In 2019-20, AEMO issued around 253 directions (lasting 7,514 hours) to South Australian generator units to ensure the correct level of fault current was always maintained[119]. This is an increase from 2018-19 of about 65% (and an increase of 133% in the total number of directed hours). These were security directions for the provision of fault current; in contrast, there were no reliability directions in South Australia in 2019-20. The large increase in directions can be partly attributed to the South Australia – Victoria separation event that occurred in January 2020[120].

Figure 40 compares the total number of directions issued in the NEM over the last 10 financial years (both reliability and security directions), and Table 12 shows the equivalent directed hours.

[118] At https://www.aemo.com.au/Media-Centre/South-Australia-System-Strength-Assessment.

[119] Of the 253 directions, 28 directions were to semi-scheduled and non-scheduled generators to disconnect or reduce MW output (usually 0 MW) during times SA was separated from the rest of the NEM.

[120] AEMO, Final Report – Victoria and South Australia Separation Event, 31 January 2020, published November 2020, at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/final-report-vic-sa-separation-31-jan--2020.pdf?la=en.

Figure 40 Total number of directions issued by AEMO for the NEM

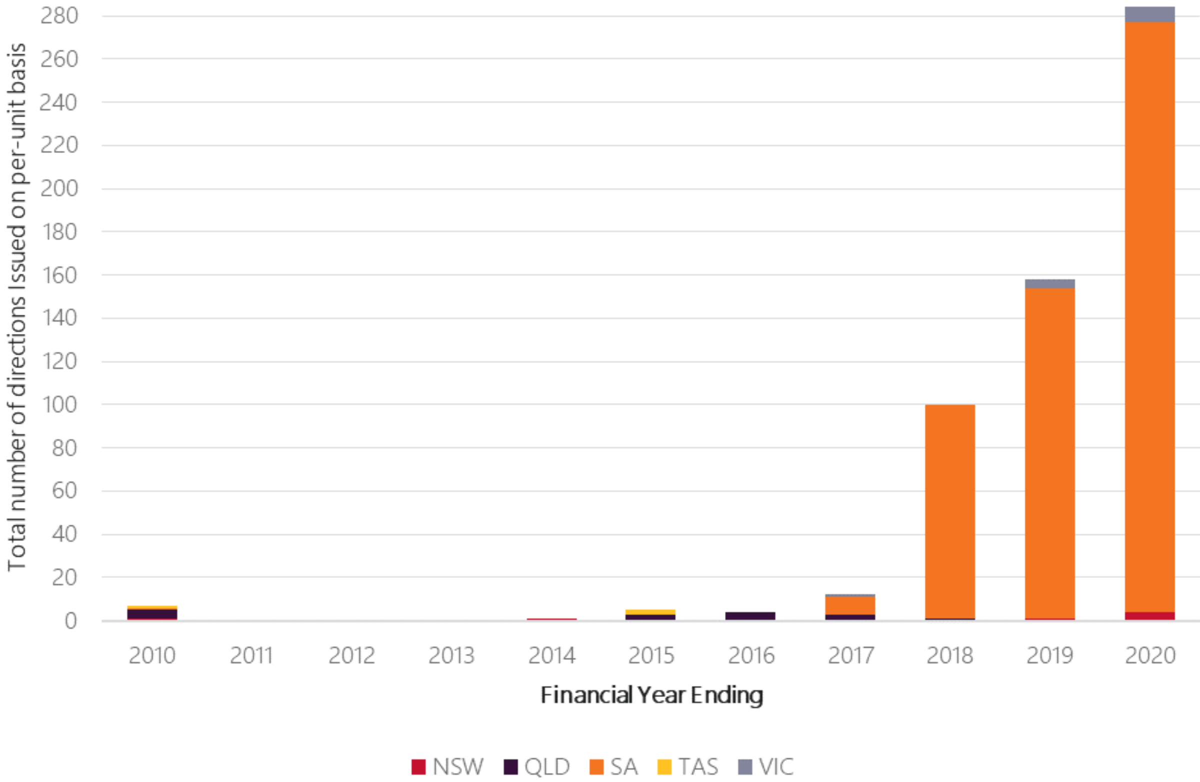


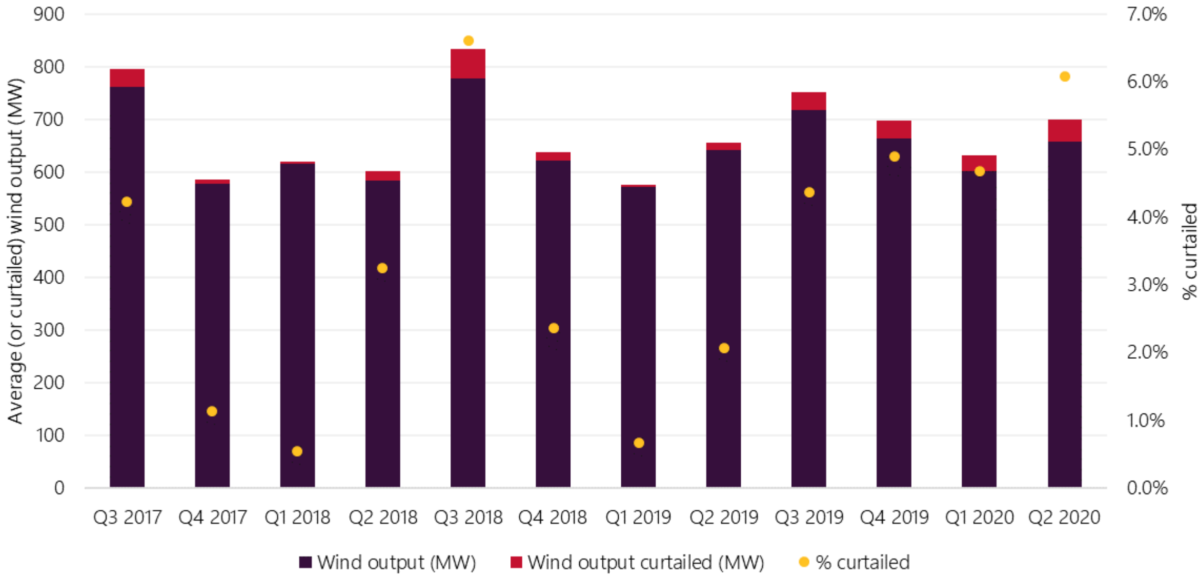
Table 12 Total number of directed hours from AEMO directions across the NEM

Financial year ending	NSW	QLD	SA	TAS	VIC
2010	1.58	12.07	0.17	0.83	
2011					
2012					
2013					
2014	4.67				
2015		12.08		1.17	
2016		5.25			
2017	1.05	13.33	60.95		5.25
2018		0.67	1,912.17		
2019	4.6		3,214.50		67.17
2020	8.67		7,652.4		1,561.02

Another aspect of AEMO's system strength arrangements for South Australia involves the curtailment of non-synchronous generation during periods of very high wind output.

During 2019-20, approximately 5% of South Australian wind output was curtailed to maintain the power system within secure limits. This was an increase from 1.8% of wind generation curtailed in 2018-19, as illustrated in Figure 41.

Figure 41 Estimated curtailment of South Australian wind generation for system security reasons



Increased system curtailment compared to 2018-19 was a function of:

- Increased periods of very high wind output due to the commissioning of two wind farms in 2018-19 (Lincoln Gap and Willogoleche wind farms), which continued to ramp up to higher levels in 2019-20.
- The January 2020 separation event – during the 18-day separation of the South Australian and Victorian power systems from 31 January 2020, output at six wind farms was curtailed to zero for system security purposes. The event contributed an estimated average curtailment of 72 MW (on a quarterly basis).

8.9.2 System strength requirements

Minimum three phase fault level

The system strength requirements for South Australia were last determined in the System Strength Requirements Methodology – System Strength Requirements and Fault Level Shortfalls report[121] published in July 2018[122]. The system strength requirements for South Australia are currently under review, and updated requirements are due to be published by AEMO in December 2020.

The requirement for system strength is represented by the minimum three phase fault level at nominated fault level nodes within a region. The minimum three phase fault level is used as a proxy to represent system strength and ElectraNet must ensure the minimum three phase fault level is maintained. The minimum three phase fault levels reported in the 2018 report for South Australia are summarised in the following table.

[121] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

[122] In October 2020, AEMO updated the transfer limit advice explaining the application of the existing system strength requirements – see 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.

Table 13 Minimum three phase fault level (MVA)

Fault level nodes	Minimum three phase fault level (MVA)
Davenport 275 kV	1,150
Robertstown 275 kV	1,400
Para 275 kV	2,200

System strength outlook from the Integrated System Plan

The 2020 ISP[123] investigated system strength requirements for all regions using the 2018 System Strength Requirements Methodology[124]. The analysis conducted to determine the system strength requirements in the ISP for South Australia factored in the effect of the installation of the four new synchronous condensers (two at Davenport and two at Robertstown). At the time of publishing the ISP the results of the system strength requirements for South Australia were still in draft form, and these are reported in the following table.

Table 14 Draft minimum three phase fault level (MVA) reported in 2020 ISP

Fault level nodes	Minimum three phase fault level (MVA)
Davenport 275 kV	1,800
Robertstown 275 kV	2,000
Para 275 kV	2,000

8.10 Regulatory changes to improve security

Several important changes to the NEM's regulatory framework have been, or are being, implemented that will support security (and reliability) of the South Australian power system, and the broader NEM, as discussed in the sections below.

Mandatory Primary Frequency Response

In March 2020, the AEMC made a Final Determination and Rule to introduce a mandatory requirement for generators to activate an existing capability to provide primary frequency response (as defined by a proposed instrument, the Primary Frequency Response Requirements) to improve frequency control in the NEM[125]. The mandatory requirement applies to all scheduled and semi-scheduled generators for a period of three years. The first tranche of generators (all those with capacity over 200 MW) are on track to ensure this capability is activated by end of 2020. AEMO is continuing to collaborate with the AEMC and the ESB about potential new market and incentive-based mechanisms for frequency control, and in September 2020 AEMO published its frequency control workplan[126].

[123] See https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp.

[124] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

[125] See https://www.aemc.gov.au/sites/default/files/documents/final_determination_-_for_publication.pdf.

[126] See https://aemo.com.au/-/media/files/electricity/nem/system-operations/ancillary-services/frequency-control-work-plan/external-frequency-control-work-plan.pdf?la=en.

System restart services, standards, and testing

The NEM power system continues to transition away from the traditional synchronous generation and load centres that characterised the grid when the current system restart ancillary services (SRAS) framework was introduced. To maintain reliable and sustainable capability to restart the NEM power system following a major blackout, AEMO submitted a rule change proposal to the AEMC in July 2019 to change the NER for the purposes of:

- Incentivising the provision of both system restart and restoration support capabilities from a range of different technologies.
- Facilitating more extensive testing to verify the viability of system restart paths, increasing the level of assurance that system restoration will succeed.

In April 2020, the AEMC published a Final Determination and Rule[127], having consolidated AEMO's rule change request with a related rule change request from the AER to improve the clarity and transparency of obligations of parties involved in the SRAS framework. The Final Rule made changes relating to the procurement, testing and deployment of SRAS, increasing the likelihood that energy supply can be restored promptly following a major blackout. AEMO published the final SRAS guideline in October 2020 to incorporate these changes[128].

Interim security measures

In March 2020, the former COAG Energy Council requested the ESB coordinate action across the market bodies to implement six interim measures to improve visibility of and confidence in system security services, while more fundamental reforms are designed and implemented. The AER has led the development of two of these measures which relate to semi-scheduled generator dispatch obligations. An expedited rule change request has been made by the AER, following its own extensive consultation process[129]. The AEMC has agreed to fast-track the rule change request and expects to complete the consultation process by February 2021[130]. The other four interim security measures are being progressed by AEMO over the next six months.

New protected event declaration

Following the 28 September 2016 black system event in South Australia, AEMO initiated an operational action plan to limit flow on the Heywood interconnector during destructive wind conditions in South Australia (under NER 4.3.1(v)). For transparency, and to provide certainty to the market, AEMO submitted a request to the Reliability Panel to declare these conditions as a protected event, which was approved by the Reliability Panel in June 2019.

In July 2020, AEMO published its 2020 Power System Frequency Risk Review (Stage 1) which recommends a new protected event for non-credible separation of South Australia. This would allow Heywood interconnector flows into the region to be limited in periods when the UFLS schemes in South Australia are not effective to prevent cascading failures and a potential black system. AEMO expects to make a request for a new protected event declaration to the Reliability Panel in early 2021.

Mechanisms to enhance power system resilience

The AEMC's December 2019 Final Report on Mechanisms to Enhance Resilience identified and reported on systemic issues which contributed to, or affected the response to, the black system event in South Australia on 28 September 2016. The report made a number of recommendations to provide AEMO with new operational measures to better manage risks from "indistinct" events. These include:

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[127] See https://www.aemc.gov.au/sites/default/files/documents/system_restart_services_standards_and_testing_-_final_determination.pdf.

[128] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/sras-guideline/final-stage/sras-guideline-2020.pdf?la=en.

[129] See https://www.aemc.gov.au/rule-changes/semi-scheduled-generator-dispatch-obligations.

[130] See https://www.aemc.gov.au/sites/default/files/2020-11/Semi%20scheduled%20dispatch%20obligations%20-%20draft%20determination%20-%20for%20publication.pdf.

- Implementing a General Power System Risk review process to effectively identify emerging risks to the power system from all sources.
- Introducing "protection operation" as an AEMO operational tool to enhance the resilience of the power system to indistinct events that are associated with abnormal conditions. Protected operation will either be pre-defined or ad hoc.
- Clarifying the applicability of rule arrangements during a period of market suspension, providing AEMO with limited additional flexibility to prioritise system security where compliance with a Rule would place a material risk on its ability to maintain power system security during a period of spot market suspension.

In May 2020, the former COAG Energy Council submitted three Rule change requests, seeking to implement the AEMC's review recommendations. The AEMC is expected to commence consultation on these rule changes shortly.

ESB's Post 2025 market design program

The COAG Energy Council tasked the ESB with developing advice on a long-term, fit-for-purpose market framework to support reliability that could apply from the mid-2020s.

The ESB's review has a broad scope and is considering issues around efficient investment in resources to provide reliability of supply and power system security, particularly as the aging thermal generation fleet is displaced from dispatch and eventually exits the market, and mechanisms that deliver efficient operation of resources, including extracting value from demand flexibility and DER.

In September 2020, the ESB published a consultation paper that sets out the challenges and opportunities associated with the energy transition. The consultation paper also proposes various potential market reform options that the ESB plans to further develop with input from stakeholders.

The ESB advice to Energy Ministers, planned for mid-2021, will include an integrated package of reforms to enable the provision of the full range of services to customers necessary to deliver a secure, reliable and lower emissions electricity system at least cost.

System strength review

The AEMC has conducted a system strength review to examine potential changes to system strength frameworks to meet current and future needs efficiently and effectively. This review follows the introduction of frameworks to manage system strength in 2017, and has been undertaken within the context of the ESB's broader system security work program.

The AEMC identified a number of key issues to be considered by the review, including whether changes could be made to:

- More effectively identify and address low levels of system strength as they arise in NEM regions.
- Allow for the provision of increased levels of system strength to enable greater output from lower-cost generation sources, to deliver lower-cost electricity for consumers.
- Increase transparency and efficiency for remediating the system strength effects from large numbers of new connecting generators.

A Final Report was published on 15 October 2020.

System services Rule changes

The AEMC has received seven Rule change requests that relate to arrangements in the NER for the provision of system services that are necessary for the secure and reliable operation of the power system. System services are physical services that are essential for fundamental power system requirements to be met.

The Rule change requests seek amendments to the provision of system services – namely inertia, frequency response, system strength, voltage control and operating reserves – and are listed below:

- Synchronous services market (requested by Hydro Tasmania).

- Efficient management of system strength on the power system (requested by TransGrid).
- Fast frequency response market ancillary service (requested by Infigen Energy).
- Operating reserve market (requested by Infigen Energy).
- Capacity commitment mechanism for system security and reliability services (requested by Delta Energy).
- Introduction of ramping services (requested by Delta Electricity).
- Primary frequency response incentive arrangements (requested by AEMO).

In July 2020, the AEMC published a consultation paper to initiate the rule change requests as well as provide an update on the status of AEMO's rule change request on primary frequency incentive arrangements[131]. The first of these to be considered will be the efficient management of system strength on the power system rule change, which will be informed by the AEMC's final report for the investigation into system strength frameworks in the NEM[132].

The issues raised by these Rule change requests relate to the reform work being considered by the ESB through its Post 2025 market design program. These processes complement and will inform each other, taking into account technical input from AEMO. The AEMC will progress consideration and draft determination of the Rule changes in late 2020 and through 2021, informed by policy decisions on the Post 2025 market design.

The AEMC's system services consultation paper and AEMO's RIS highlighted a need for a more holistic engineering framework to help ensure a common focus for the relevant processes that are planned or already underway. See Section 8.1 for further information on the engineering framework, which will complement existing work being progressed across industry.

DER minimum standards and governance of standards

The ESB and AEMO have proposed rule changes which recognise the need to improve technical standards and standardise DER performance capabilities in order to address operational challenges associated with higher penetrations of DER, particularly around maintaining system security.

In May 2020, AEMO initiated a Rule change request to establish a framework for setting minimum technical standards for DER across the NEM[133]. The Rule change request proposed the establishment of a subordinate instrument (the Initial DER minimum technical standard) that specifies the minimum technical standards and what those standards apply to. To establish the proposed framework without delay, AEMO's consultation process for the Initial DER minimum technical standard[134] coincides with the Rule change process. The AEMC expects to publish a Draft Determination and Rule in early December 2020, while AEMO expects to complete its Initial DER minimum technical standard consultation process by early January 2021.

In September 2020, the ESB made a Rule change request to establish enduring governance arrangements for DER technical standards across the NEM, noting that the AEMO Rule change request and Initial DER minimum technical standard seek to address immediate system security challenges[135]. The proposed changes include creating DER technical standards in the NER or subordinate instrument, providing for compliance enforcement of those standards, and establishing the AEMC as the decision-maker for creating the DER technical standards (pending initiation by the AEMC).

[131] See https://www.aemc.gov.au/sites/default/files/2020-07/System%20services%20rule%20changes%20-%20Consultation%20paper%20–%20%202%20July%202020.pdf.

[132] See https://www.aemc.gov.au/news-centre/media-releases/new-timeframes-set-system-services-arrangements.

[133] See https://www.aemc.gov.au/rule-changes/technical-standards-distributed-energy-resources.

[134] See https://www.aemo.com.au/consultations/current-and-closed-consultations/der-initial-standard.

[135] See https://www.aemc.gov.au/rule-changes/governance-distributed-energy-resources-technical-standards.

Short duration undervoltage disturbance ride-through test procedure

AEMO has developed a test procedure to apply as an interim measure in South Australia, to ensure inverters, and distributed PV by extension, respond appropriately during short duration undervoltage disturbance events to mitigate potential for disruption and improve power system security[136]. The need for the test procedure was identified through analysis of recent power system events that highlighted a severe but credible fault near the Adelaide metropolitan area that could cause disconnection of up to half the distributed PV in the South Australian region. The development of the test procedure for South Australia preceded the DER Initial Standard consultation, which is the subject of AEMO's DER Minimum Standard Rule Change request. The implementation of the test procedure, which was facilitated by the South Australian Government and SAPN, requires all new inverters installations be limited to those that demonstrate short duration undervoltage withstand capacity.

Updates to Australian Standards

Current performance standards for smaller distribution-connected generation require updating to optimise and support a secure power system under high levels of DER penetration, support energy affordability and allow consumers to pursue individualised services. AEMO is currently participating in the revision of AS/NZS4777.2 (Inverter Requirements Standard) to better support power system security, including amendments to:

- Specify conditions in which the inverter should remain connected and generating power to the electricity grid or disconnect to help prevent major events.
- Optimise and coordinate parameters to maximise the value of the capabilities offered with 'smart' inverters to provide improved power quality to customers and grid support functions for networks. This will increase the hosting capacity of DER, allowing more customers the opportunity for DER uptake.
- Define the accuracy and stability of measurement systems used in inverters, to improve the reliability of performance characteristics providing guaranteed responses to different conditions.
- Improve and introduce testing procedures to ensure enhanced device level compliance is met.

These adaptations are occurring as part of the Australian Standards processes.

Integrating energy storage systems into the NEM

In August 2020, the AEMC initiated a consultation process, following AEMO's Rule change request in August 2019 to more efficiently accommodate increasing numbers of connection points with bi-directional electricity flows[137]. Various elements of this proposal would support power system reliability and security outcomes, including:

- Clarifying the treatment of bi-directional facilities in the reliability standard and the RRO.
- Improving the way in which bi-directional facilities are accounted for in market forecasting processes.
- Improving the information in the central dispatch process for bi-directional facilities.
- Applying appropriate technical requirements and performance standards to bi-directional facilities.

The AEMC is currently contemplating how best to update the regulatory framework to recognise storage and hybrid facilities with bi-directional flows and the increasing role of new technologies and new business models. As part of the consultation process, the AEMC is seeking stakeholder views on the extent and timing of the proposed Rule change in the context of the ESB's Post 2025 market design reforms, in particular the proposed two-sided market reform.

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[136] See https://aemo.com.au/-/media/files/electricity/nem/der/2020/vdrt-test-procedure.pdf.

[137] For more on this Rule change request, see https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem.

9. Gas supply for gas-powered generation

AEMO's 2020 *Gas Statement of Opportunities*[138] (GSOO) for eastern and south-eastern Australia highlights that the gas supply-demand balance is projected to remain tight, with production in southern Australia continuing to decline, and potential supplies from Queensland limited by pipeline capacity.

Recent summers have highlighted the increasingly variable demand for GPG due to South Australia's reliance on VRE and vulnerability to interconnector outages. It is also worth noting that COVID-19 has softened international commodity markets, and this has substantially reduced the gas spot prices in Australia, potentially impacting investment. The results presented here are based on assumptions formed prior to COVID-19.

The 2021 GSOO is due to be published in March 2021.

The 2020 GSOO forecasts the potential for supply gaps from 2024 onwards, unless additional southern reserves and resources, or alternative infrastructure, are developed. The 2020 GSOO also identifies that the outlook is highly uncertain, particularly between 2022 and 2024; certain market outcomes could increase the utilisation of GPG and thereby increase tightness of supply. Decreasing field production is projected to put additional stress on existing infrastructure and there is already evidence of strong reliance on stored gas from the Iona Gas Plant during periods of low wind and solar production.

The 2020 GSOO contains information on gas adequacy, and on potential opportunities for infrastructure investment or reserves development, under a range of future scenarios.

9.1 South Australian gas consumption forecasts

Over the next 10 years, South Australia's total demand for natural gas is expected to vary substantially, due primarily to forecast utilisation of GPG, as shown in Figure 42.

This GPG projection is based on generation and interconnector development from AEMO's Draft 2020 ISP (the most current information available at the time the 2020 GSOO was published). The GPG projection was consistent with new interconnector development and high penetration of new renewable generation and storage technologies. In this forecast, gas consumption from GPG is expected to decline over the next few years. Although annual consumption has reduced, gas remains a critical component of the South Australian energy supply mix, particularly with regards to the supply of system security services and in being able to firm up VRE output. As the penetration of VRE increases, so too does the variability in GPG generation, for example to ramp up in the early evening as generation from large-scale and distributed PV reduces.

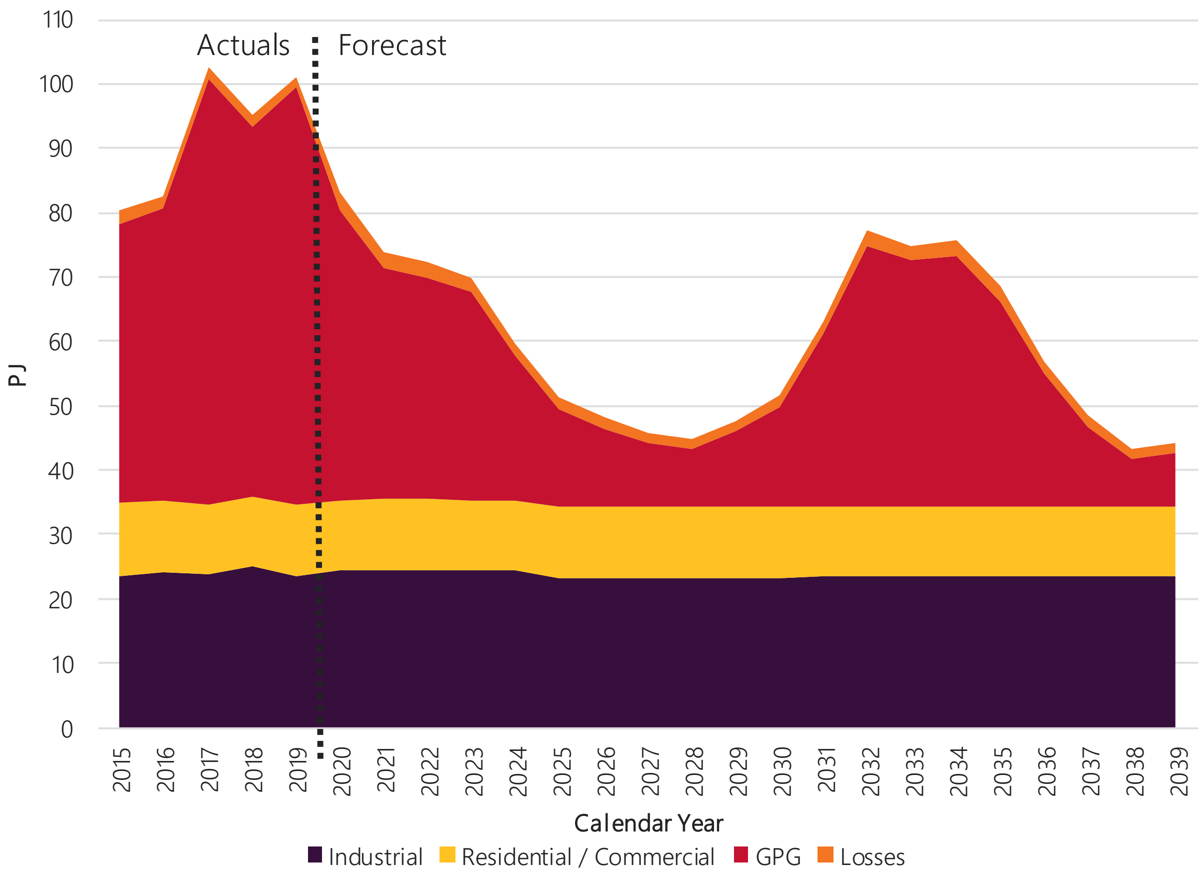
[138] AEMO, 2020 GSOO, March 2020, at http://aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities. The published GSOO report does not include region-specific forecasts, but forecast data is available at http://forecasting.aemo.com.au/.

When wind generation is low in South Australia, GPG remains a vital source, in addition to imports from Victoria, in being able to supply load outside daylight hours. This was well demonstrated on 11 October 2020, when solar power provided 100% per cent of South Australia's electricity needs for one hour during the middle of the day and gas supplied 95% of the electricity needs at 6.00 pm.[139] The anticipated construction of the PEC interconnector between South Australia and New South Wales in 2023-24 (see Section 5.2), combined with new renewable generation driven by the Victorian Renewable Energy Target (VRET), are forecast to lead to further reductions in annual generation from South Australian GPG, particularly as AEMO assumes that PEC would reduce the number of synchronous generating units required to be online for system security under system normal conditions in South Australia[140].

Annual GPG usage in South Australia is forecast to decrease until 2026-27. Around this time, further coal generation is forecast to retire in the NEM, resulting in an increase in GPG requirements. Although AEMO does not forecast GPG returning to the levels seen in recent years, the requirement for GPG peaking capacity continues.

Over this same period, residential and commercial gas consumption is forecast to be reasonably stable, due to connections growth being offset by the expectation of further energy efficiency measures and increases in fuel switching (using electrical appliances instead of gas). The 2020 GSOO also forecasts that the industrial sector will remain stable at current levels over the forecast period, with no strong drivers for growth identified that would alter consumption patterns for the industrial direct-use gas customers.

Figure 42 South Australian gas consumption – historical and forecast (Central scenario), 2015 to 2039



139 See Section 3.1.3.

140 See Appendix 7 of the 2020 ISP, page 54.

9.2 Natural gas reserves and resources, and infrastructure

South Australia has traditionally sourced natural gas from the Cooper and Eromanga basins[141] and from the Otway Basin since 2004 following the commissioning of the South East Australia (SEA) Gas Pipeline from Port Campbell, Victoria. Over the past several years, LNG developments in Queensland have changed domestic contract dynamics, such that a large portion of the supply from the Cooper and Eromanga basins is now being used for LNG export. Declining supplies from the Otway basin are resulting in increased opportunity for gas from Cooper and Eromanga (and further supplies from Queensland) to be transported south to meet demand in the southern states (South Australia, New South Wales, Victoria and Tasmania), subject to pipeline capacity.

In the 2020 GSOO, eastern and south-eastern Australian proven plus probable (2P) natural gas reserves[142] totalled 37,393 petajoules (PJ), of which 15,090 PJ was classified as developed. The total sales gas consumed across eastern and south-eastern Australia during 2019 calendar year was 1,948 PJ (including LNG exports).

Based on advice from gas producers, and as reported in the 2020 GSOO (before COVID-19 and the international oil price decline), total gas production across eastern and south-eastern Australia is forecast to increase from 2,031 PJ in 2020 to 2,122 PJ in 2022, before reducing to 1,947 PJ by 2024. These production forecasts, however, include volumes from anticipated fields that are not yet producing. If these anticipated projects are delayed or deferred then the east coast production forecasts would reduce by 27 PJ in 2020, 249 PJ in 2022, and 419 PJ in 2024. Production in the southern states is expected to reduce year on year and the increase in Queensland production may not be accessible to southern demand centres due to existing pipeline constraints.

Table 15 lists the major gas pipelines that supply natural gas to South Australian consumers, and Figure 43 shows the gas producing basins and infrastructure supplying eastern and south-eastern Australia. Gas can flow to South Australia from Queensland via the South West Queensland Pipeline and the Moomba Gas Plant in the Cooper Basin, up to the capacity of the Moomba to Adelaide Pipeline System. Gas supplied from Victoria can be delivered to South Australia either:

- From the offshore Otway Basin fields and the Iona underground gas storage facility, directly along the SEA Gas Pipeline, or
- From the offshore Gippsland and Bass basins via multiple pipelines in an anti-clockwise direction through the Victoria – New South Wales Interconnector, the Moomba to Sydney Pipeline, then south along the Moomba to Adelaide Pipeline System.

Table 15 Major gas pipelines relating to South Australia

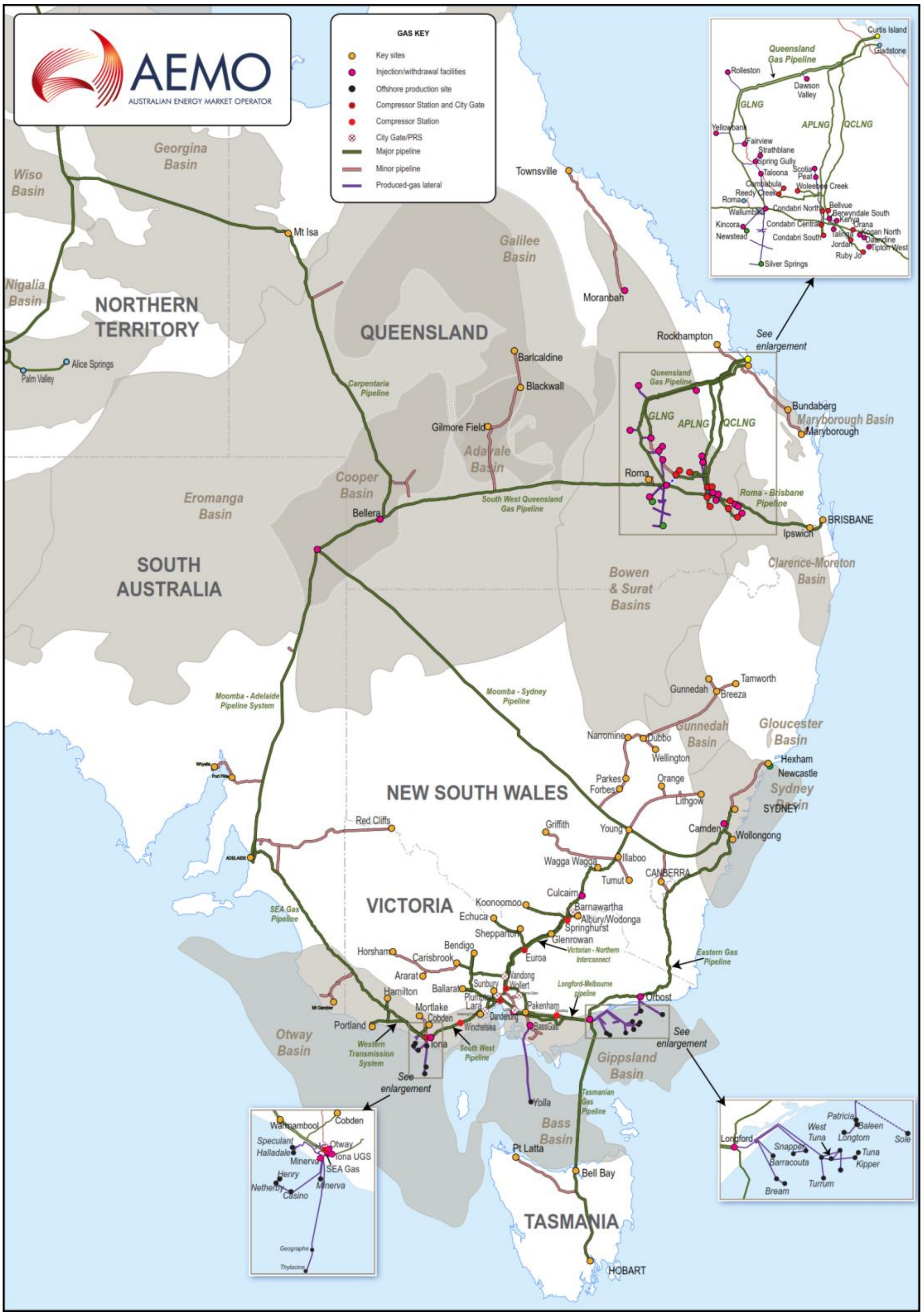
Gas pipeline	Length (km)	Year of first gas flow	Capacity reported (terajoules [TJ]/d)
Moomba to Adelaide Pipeline	1,185	1969	246 (South), 85 (North)
Moomba to Sydney Pipeline	2,030	1998	489 (South-East), 120 (North-West)
SEA Gas Pipeline	680	2004	250**
South West Queensland Pipeline*	937	1996	404 (West), 340 (East)
Victoria – New South Wales Interconnector	143	1998	223 (North), 159 (South)

* Includes the Queensland – South Australia – New South Wales (QSN) Link.
** SEA Gas Pipeline capacity has been reduced to 250 TJ/d as some of the capacity has been converted to storage.

[141] The Cooper and Eromanga basins span South Australia, New South Wales, and Queensland, and the point of gas extraction may not necessarily be in South Australia.

[142] 2P is considered the best estimate of commercially recoverable reserves.

Figure 43 Gas producing basins and infrastructure supplying eastern and south-eastern Australia



9.2.1 Daily demand for gas-powered generation supply

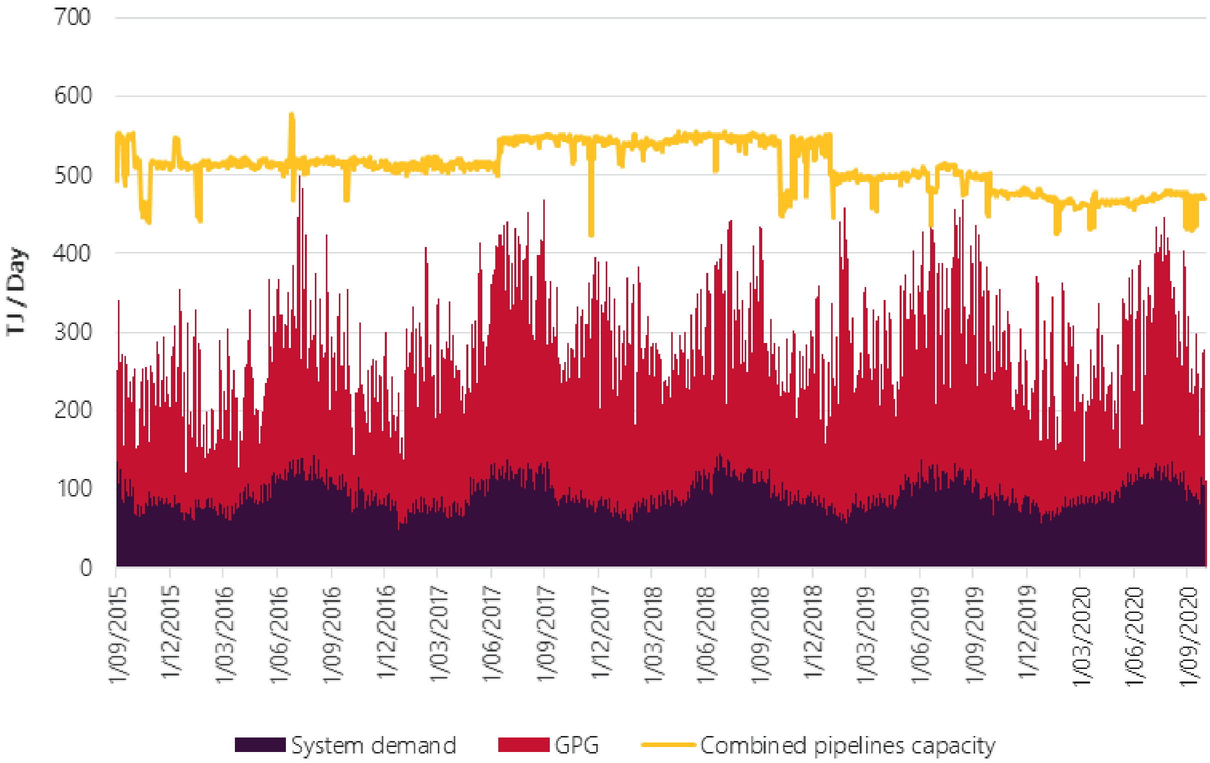
In 2019-20, GPG continued to play an important role in meeting South Australia's electricity demand, particularly when VRE output was low, as shown in (Section 4.2).

Since the closure of Northern Power Station in May 2016 and Victoria's Hazelwood Power Station in March 2017, South Australia's reliance on GPG when wind and solar generation is low has increased, leading to more frequent gas demand peaks. Recent summers highlight the increasingly variable demand for GPG. Loss of interconnection, from the Victoria and South Australia separation event on 31 January 2020[143] further underlined the present importance of gas for South Australian electricity supply.

Figure 44 shows that since 2016 there has been an increase in the number of days when total gas demand (gas system demand[144] and power generation) exceeded 400 terajoules (TJ)/day. However, the total consumption in 2020 has also been suppressed, due to mild weather conditions and displacement by VRE output lowering GPG.

The figure also shows that, over the same time period, combined gas pipeline capacity (Moomba to Adelaide Pipeline and SEA Gas Pipeline) has been reducing, principally due to some of the SEA Gas pipeline capacity being reserved for storage, The daily demand for gas came close to total pipeline capacity several times in 2019 and 2020.

Figure 44 South Australian daily gas usage and pipelines capacities (September 2015 to September 2020)



Note: Data is derived from analysis of GBB flows and capacities, and NEM generation data. Historical averages were used where industrial consumption data was not yet available for 2020; this was deemed acceptable due to the consistent nature of that demand.

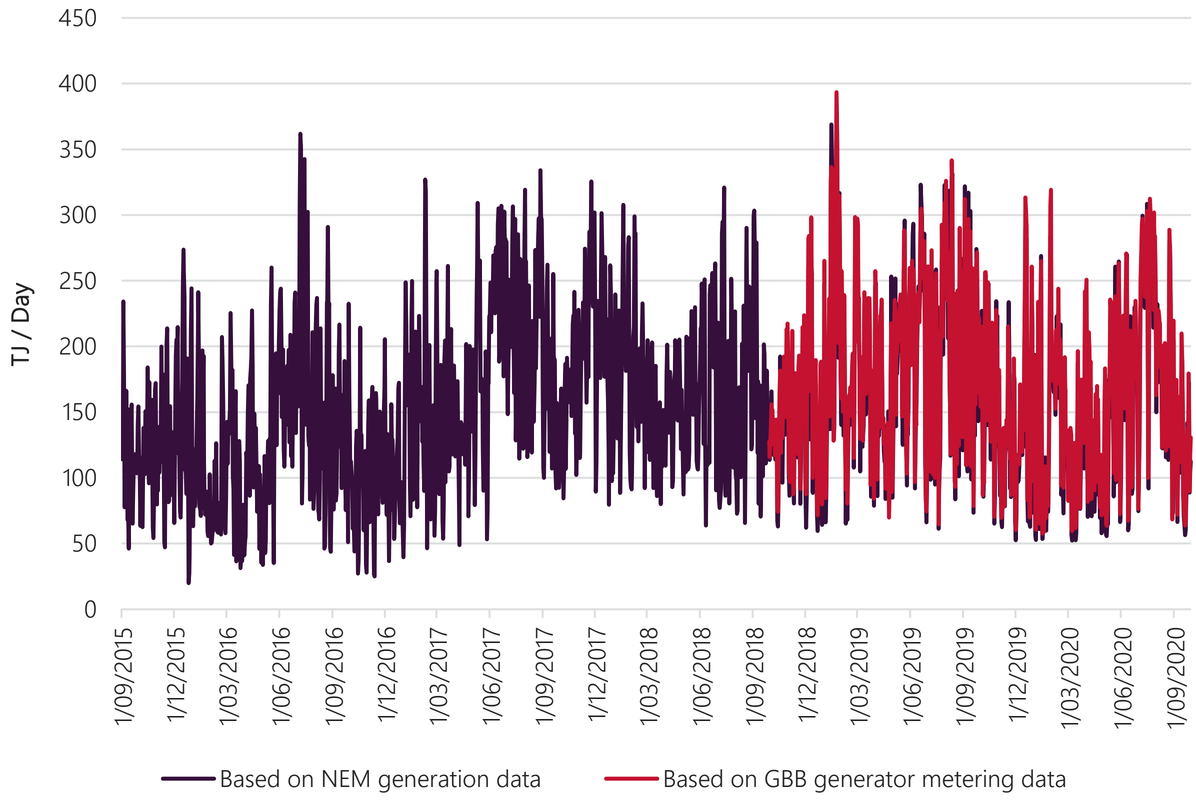
During periods of very high South Australian GPG, liquid fuel (usually diesel) is used to supplement gas supplies. Figure 45 compares the output of GPG to natural gas usage information from the Gas Bulletin Board (GBB)[145]. Outside of Victoria, AEMO does not have real-time gas pipeline flow information, and it does not have access to liquid fuel usage and inventories for any power stations. Discrepancies, where more generation is supplied than the gas consumption would anticipate, indicate when liquid fuel may have been used to supplement gas supplies. Such events usually occur when GPG demand changes rapidly.

[143] AEMO, Final Report – Victoria and South Australia Separation Event, 31 January 2020, published November 2020, at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/final-report-vic-sa-separation-31-jan--2020.pdf?la=en.

[144] System demand comprises of residential, commercial and industrial gas usage.

[145] This additional information has only been available on the GBB since 1 October 2018.

Figure 45 South Australian gas generation demand (September 2015 to September 2020)



A1. Data sources and reporting methodology

A1.1 Introduction

This section outlines and clarifies the various data sources used throughout the 2020 SAER and its corresponding data files, as well as relevant analysis/reporting methodologies employed.

Each aspect considered can be assumed to apply throughout the report and data files, except where noted by any listed exceptions.

A1.2 Times and dates

Timestamps shown in analysis (figures and tables) are NEM time (market time) – that is, Australian Eastern Standard Time (AEST) with no daylight savings, unless otherwise indicated. However, where times are written throughout the report text, they will be in local time (Adelaide time, and adjusted where necessary for daylight savings). An exception is section 6 where all times are in NEM time.

In line with electricity industry seasonal forecasting and reporting, "summer" refers to the period from 1 November to 31 March, and "winter" from 1 June to 31 August. "Shoulder" refers to 1 September to 31 October and 1 April to 31 May.

For selected metrics, denoted in their title by use of the word "workday", all Saturdays, Sundays and gazetted South Australian public holidays have been excluded from analysis.

A1.3 Prices

A1.3.1 Electricity

Electricity price analysis used 30-minute (ending) spot prices for each NEM region as relevant to the metric. Unless otherwise stated in the title of the metric, analysis is using nominal dollar values. For certain metrics labelled as "real June 2020", the trends (or input to the trends) are presented in real June 2020 dollars, using the Adelaide Consumer Price Index (CPI) as the basis for adjustment.

A1.3.2 Gas

Reported prices come from the average of daily ex-ante price for each market analysed. The markets referenced, with regards to the figures as numbered in the data file, are:

- Short Term Trading Market (STTM) Adelaide Hub for "ADL" in Figure 6.5, and "South Australia" in Figure 6.14.
- STTM Sydney Hub for "SYD" in Figure 6.5.
- STTM Brisbane Hub for "BRI" in Figure 6.5.
- Victorian declared wholesale gas market (DWGM) for "VIC" in Figure 6.5.

A1.5 Generation capacity

The SAER and its data files report on a variety of capacities for the supply sources reported on. The megawatt capacity used in any given analysis will depend on what is available and what is reasonable for the metric being sought.

The general principles for capacity sources are:

- AEMO registered capacity is used for registered generators.
  - ONSG references AEMO registered capacity if available, otherwise an approximate value obtained by AEMO.
- Estimated aggregate capacity is used for rooftop PV and PVNSG, as outlined in Section A1.8.
- Nameplate capacity (including forecast nameplate capacity) is used for metrics concerning AEMO published Generation Information.
- Interconnector capacity is not included in analysis of generation capacity, but where reporting on interconnector power flows, it is sometimes compared to its nominal capacity at a point in time (without considering shorter-term constraints that can apply).

Capacity analysis rules include:

- Exclusion of wind farm output and/or capacity applies for the time before the wind farm first reached 90% of registered capacity, unless specifically noted otherwise.
- For "capacity factor" analysis, all generators exclude periods when, for the analysis period in question, there was not a long enough portion of the time that had generator at normal availability. Such exclusion reasons could include market withdrawals or commissioning periods.

A1.6 Data sources for generation and supply

Most of the analysis for electricity generation and supply (including consumption and demand) is based on 5-minute averages of AEMO's SCADA metering, including scheduled generators and loads, significant non-scheduled wind farms and diesel generators, as well as interconnector flows. In cases where analysis is at the 30-minute level, the six relevant 5-minute averages are averaged further to a 30-minute value.

Exceptions include:

- Rooftop PV and PVNSG – refer to Section A1.8.
  - Note that Figure 9 uses ASEFS2 estimates for rooftop PV rather than the ESOO modelling used in the rest of the reporting.
- ONSG – aggregated from settled market meter data.
- Historical minimum or maximum operational demand as measured over a given period, for example, daily, seasonal and yearly values in various figures and tables – these are taken from 30-minute averages of AEMO's SCADA metering.

A1.7 Consumption and demand definitions

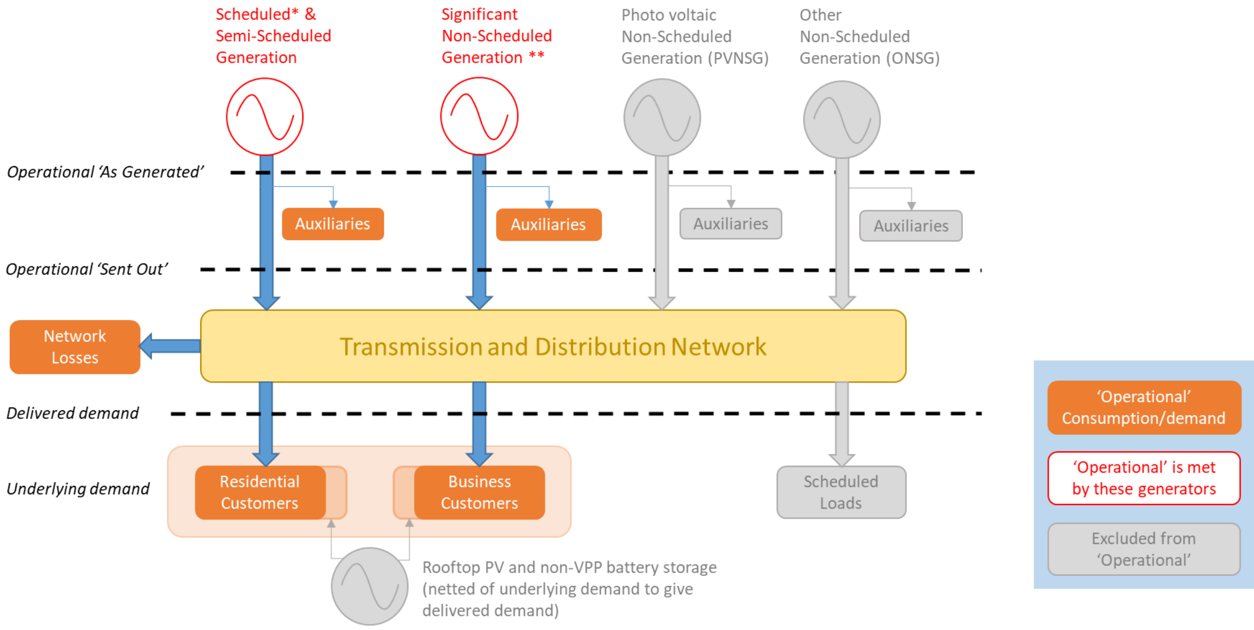
Consumption refers to electricity used over a period of time and is measured in GWh, whereas demand refers to electricity used at a particular time (or the average over a short period of time like five or 30 minutes) and is measured in MW.

This report generally considers consumption or demand over reporting periods such as a financial year, summer, winter or calendar month.

For historical and forecast consumption or demand based on annual or seasonal periods, the 2020 SAER uses outcomes from the 2020 ESOO, noting that the 2019-20 annual consumption value builds on the 2020 ESOO value by providing full year actual estimates.

Demand definitions used in this document

Figure 46 Demand definitions used in this document



* Including VPP from aggregated behind-the-meter battery storage
** For definition, see: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf

A1.7.1 Operational reporting

This report often presents AEMO's operational data for historical results, estimates, and forecasts. Operational data comprises the electricity consumed by the NEM's transmission and distribution networks to supply residential and business customers, as well as the inherent electrical losses in the networks.

Furthermore, operational reporting is defined as that electricity supplied by scheduled, semi-scheduled, and significant non-scheduled generating units, and includes net interconnector imports when reporting on a particular NEM region. It excludes electricity used by scheduled loads (such as scheduled battery storage units) or electricity supplied by ONSG and distributed PV.

Table 4.12 in the data file lists the South Australian generators included in the operational reporting for the 2020 SAER.

A1.7.2 Underlying reporting

Underlying consumption and demand refer to electricity consumed by customers at their premises, supplied from both the grid and distributed PV combined (including any estimated battery storage assumed charge/discharge patterns), but it does not include any contribution from ONSG.

A1.7.3 "Sent-out" versus "as-generated" data

Sent-out data is measured at each generating system's connection point. This represents the electricity supplied to the market and excludes its auxiliary loads. As-generated data, measured at each generating unit terminal, represents its entire output, including the energy supplied to its auxiliary loads.

A1.8 Generator fuel grouping

When reporting on generation supply by fuel or energy groupings, whether for capacity or generation:

- Gas refers to scheduled gas generation only.
- Wind refers to semi-scheduled and significant non-scheduled wind farms.
- Solar refers to semi-scheduled solar PV farms only.
- "Storage – Battery" refers to the generation output of scheduled battery energy storage systems.
- Rooftop PV refers to behind-the-meter rooftop solar PV systems up to 100 kW capacity (so excluding PVNSG).
- PVNSG refers to PV non-scheduled generation as described in Section 2.2 of the report.
- Distributed PV refers to Rooftop PV plus PVNSG
- ONSG refers to other non-scheduled generation as described in Table 4.16 of the data file. Note that the fuel types in the ONSG category could overlap with other categories, but the reporting remains in the ONSG category only.
- "Diesel + ONSG" refers to scheduled diesel units, the Temporary Generation South generator and ONSG.
  - Diesel, if mentioned apart from the above definition, comprises only scheduled and diesel units plus Temporary Generation South generator.

A1.9 Solar PV estimates

A1.9.1 Rooftop PV

AEMO's Electricity Demand Forecasting Methodology Information Paper[146] provides a description of the methodology for both rooftop PV capacity and generation forecasts – as used across AEMO's forecasting and planning publications, including the 2020 NEM ESOO. A short summary of capacity and generation estimation methods is provided in Section 2.1.1.

Furthermore, in the 2020 SAER and data files, the rooftop PV capacity and generation estimates build further on those used for the 2020 ESOO, incorporating updated estimates principally for 2019-20.

A1.9.2 PVNSG

AEMO forecasts PVNSG based on the following data sources:

- Publicly available information.
- Data provided by network businesses.
- Projection of PV uptake (as forecast by the consultants, in 2020 CSIRO and Green Energy Markets).

The PVNSG include PV installations above 100 kW but below 30 MW. Until 2016, this was combined with ONSG. In 2017 this was forecast separately for the first time, although based on growth rates for commercial rooftop PV. From 2018, this sector has been forecast with a different approach; larger projects require special purpose financing and their uptake has been forecast by AEMO's consultants by modelling whether the return on investment for different size systems meets a required rate of return threshold for a given year and region.

[146] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

Further details on the methodology for PVNSG generation forecasts can be found in AEMO's Electricity Demand Forecasting Methodology Information Paper[147].

A1.10 Interconnector flows

In some interconnector-related metrics, individual interconnectors are reported on separately, and will be named as appropriate (Heywood or Murraylink).

However, for many metrics, the "combined" or "total" interconnector flows are reported, and this is assumed to be the case even without these qualifying descriptors denoted.

In these cases, the data reported is taken as the time-aligned net MW flow in to or out of South Australia, at every 5-minute (averaged) period considered. The time-aligned data is then averaged further (to say 30 minutes) or aggregated, to say an annual GWh amount.

Thus, the combined or total interconnector metrics represent analysis of net boundary flows to or from South Australia at each point in time.

[147] At https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/2020-electricity-demand-forecasting-methodology-information-paper.pdf

Glossary, measures, and abbreviations

Glossary

This document uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified.

Term	Definition
Battery energy storage system (BESS)	A system that stores energy that will be used at a later time. This storage system makes use of battery technology. There are a large range of battery technologies that form the generic term Battery Energy Storage System.
Committed projects	Generation that is considered to be proceeding under AEMO's commitment criteria (see Generation Information on AEMO's website, link in Table 1).
Co-ordinated (EV) charging	Charging of electric vehicles is coordinated to be optimised for prevailing market and/or demand conditions, for example as part of a virtual power plant (VPP).
Convenience (EV) charging	Charging of electric vehicles that are assumed to have no incentive to charge at specific times.
distributed PV (DPV)	Includes rooftop systems and other smaller non-scheduled PV capacity.
electrical energy	Average electrical power over a time period, multiplied by the length of the time period.
electrical power	Instantaneous rate at which electrical energy is consumed, generated, or transmitted.
Firm capacity	Firm capacity can be dispatched to maintain balance on the power grid. It can include generation on the grid, storage, demand resources behind the meter, flexible demand, or flexible network capability.
generating capacity	Amount of capacity (in megawatts) available for generation.
generating unit	Power stations may be broken down into separate components known as generating units and may be considered separately in terms (for example) of dispatch, withdrawal, and maintenance.
installed capacity	The generating capacity (in megawatts) of the following (for example): • A single generating unit. • A number of generating units of a particular type or in a particular area. • All of the generating units in a region. For rooftop PV, the total amount of cumulative rooftop PV capacity installed at any given time.
maximum demand	Highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season, year) either at a connection point or simultaneously at a set of connection points.
mothballed	A generation unit that has been withdrawn from operation but may return to service at some future point.

Term	Definition
non-scheduled generation	Generation by a generating unit that is not scheduled by AEMO as part of the central dispatch process and has been classified as a non-scheduled generating unit in accordance with Chapter 2 of the NER.
operational consumption	The electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled generating units, less the electrical energy supplied by small non-scheduled generation.
reliability standard	The reliability standard for generation and inter-regional transmission elements in the NEM is defined in NER 3.9.3C as a maximum expected unserved energy (USE) in a region of 0.002% of the total energy demanded in that region for a given financial year.
unserved energy	Unserved energy is the amount of energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of consumer supply). The USE that contributes to the reliability standard excludes unserved energy resulting from multiple or non-credible generation and transmission events, network outages not associated with inter regional flows, or industrial action (NER 3.9.3C(b)).

Units of measure

Abbreviation	Expanded name
GW	Gigawatt
GWh	Gigawatt hour
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt hour
MW	Megawatt
MWh	Megawatt hour
MWs	Megawatt-seconds
PJ	Petajoule
TJ	Terajoule

Abbreviations

Abbreviation	Expanded name
ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australia Energy Market Operator
AER	Australian Energy Regulator
AEST	Australian Eastern Standard Time
ARENA	Australian Renewable Energy Agency
BESS	Battery Energy Storage System
BoM	Bureau of Meteorology

Abbreviation	Expanded name
CCGT	Combined-cycle gas turbine
CER	Clean Energy Regulator
COAG	Council of Australian Governments
CPI	Consumer Price Index
CSG	Coal seam gas
CSIRO	The Commonwealth Scientific and Industrial Research Organisation
DC	Direct current
DER	Distributed energy resources
DPV	Distributed photovoltaic
DRSP	Demand response service provider
DSP	Demand side participation
EE	Energy efficiency
ENA	Energy Networks Australia
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunities
EV	Electric vehicle
FCAS	Frequency control ancillary services
FFR	Fast frequency response
GPG	Gas-powered generation
GSOO	Gas Statement of Opportunities
IBR	Inverter based resources
IRM	Interim reliability measure
ISP	Integrated System Plan
LGC	Large-scale generation certificate
LNG	Liquefied natural gas
LOR	Lack of Reserve
LRET	Large-scale renewable energy target
MT PASA	Medium Term Projected Assessment of System Adequacy
NEM	National Electricity Market
NER	National Electricity Rules
NSCAS	Network Support and Control Ancillary Services
OCGT	Open-cycle gas turbine

Abbreviation	Expanded name
OFGS	Over-frequency generator shedding
PEC	Project EnergyConnect
PHEV	Plug-in hybrid electric vehicle
POE	Probability of exceedance
PV	Photovoltaic
PVNSG	Photovoltaic non-scheduled generation
RERT	Reliability and Emergency Reserve Trader
REZ	Renewable energy zone
RIS	Renewable Integration Study
RIT-T	Regulatory investment test for transmission
RRO	Retailer Reliability Obligation
SAAF	South Australian Advisory Functions
SAER	South Australian Electricity Report
SAET	South Australia Energy Transformation
SAPN	SA Power Networks
SIPS	System Integrity Protection Scheme
SNSG	Small Non-scheduled Generation
SRAS	System Restart Ancillary Services
STTM	Short Term Trading Market
TAPR	Transmission Annual Planning Report
TNSP	Transmission network service provider
TWAP	Time-weighted average price
UFLS	Under frequency load shedding
USE	Unserved energy
VFRB	Very Fast Runback
VPP	Virtual power plant
VRE	Variable Renewable Energy
VRET	Victorian Renewable Energy Target
VWAP	Volume-weighted average price
WDRM	Wholesale Demand Response Mechanism
WEM	Wholesale Electricity Market (in Western Australia)