SOUTH AUSTRALIAN
Electricity Development Plan

Energy Forecasting and Planning
The Office of the Technical Regulator

2025

SOUTH AUSTRALIA

Government of South Australia
Department for Energy and Mining

Through innovation, collaboration, and rigorous planning, South Australia is demonstrating that a modern electricity system can operate securely and sustainably while delivering benefits to households, industry, and the broader community.

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Foreword

South Australia's electricity system continues to be one of the most advanced and complex in the world.

The 2025 Electricity Development Plan (EDP) reflects this change and sets out a pathway to maintain reliability and affordability while advancing toward net 100 per cent renewable electricity. Robust stakeholder engagement remains central to this work. Collaboration with network service providers (NSP), market participants, investors, and communities ensure that the state's electricity planning process reflects a shared understanding of emerging challenges, technology pathways, and investment opportunities. This engagement strengthens the credibility of the EDP and ensures decisions are informed by practical industry insight and regional perspectives.

Households are at the centre of South Australia's energy transition. Rooftop photovoltaic (PV) and other Consumer Energy Resources (CER) now supply a significant share of South Australia's energy needs, reducing bills and empowering consumers to participate in the energy market. However, this growth introduces new operational challenges, including managing minimum demand events and ensuring system stability during periods of high distributed generation. Coordinated integration of CER, through initiatives such as flexible exports and virtual power plant, will be critical to unlocking their full value for South Australian consumers whilst still maintaining security.

South Australia's electricity demand is forecast to double over the next decade, driven by industrial expansion, electrification of transport, and continued uptake of rooftop PV. This growth presents both opportunities and challenges and while it underpins South Australia's ambition to lead in green industries, it also requires timely investment in transmission, storage, and firming technologies to ensure the system can meet rising load without compromising affordability.

This expected growth in demand only strengthens reliability as a cornerstone of the transition. Recent operational events have highlighted the need for fast-response firming capacity and robust contingency planning. The introduction of the Firm Energy Reliability Mechanism (FERM) and the setting of the Firm Energy Target (FET) provide a structured framework to secure long-duration dispatchable resources, ensuring South Australia can navigate the retirement of conventional generation and the variability of renewable output with confidence.

Through innovation, collaboration, and rigorous planning, South Australia is demonstrating that a modern electricity system can operate securely and sustainably while delivering benefits to households, industry, and the broader community. This plan reaffirms our commitment to a reliable, affordable, and clean energy future.

Rob Faunt

Director, Technical Regulation

The Office of the Technical Regulator

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ES EXECUTIVE SUMMARY

South Australia's renewable advantage positions the state as a global leader in clean industry and advanced energy management.

Purpose of the South Australian Electricity Development Plan

The 2025 South Australian Electricity Development Plan (EDP) provides an annual assessment of the future pathway for the development of South Australia's power system.

It consolidates technical modelling, market analysis, and stakeholder feedback to guide planning and policy decisions during a period of significant structural change.

Household and industrial growth

South Australia's electricity demand is forecast to double over the next decade, rising from around 14 TWh in Financial Year (FY) 2025-26 to approximately 28 TWh by FY2035-36. This growth will be driven primarily by incoming industrial load, rooftop photovoltaic (PV) increases and the expected uptake of electric vehicles (EV). An increase in industrial loads, expected to reach 10 TWh by FY2035-36, will reshape South Australia's demand profile, deepening the midday trough and amplifying the evening peak. Minimum demand events will also become more frequent and severe, requiring advanced coordination of Consumer Energy Resources (CER) and dynamic operating envelopes to maintain system stability.

It is worth noting that there is also an expected widening of the uncertainty band for future investments in South Australia's power system as the majority of the forecasted industrial load increases included in the EDP forecasts are not in the 'committed' phase. Careful planning and continued coordination with the industry, other government planning agencies and network providers is required to manage this uncertainty.

This shift in demand will also place additional pressure on transmission infrastructure, which across Australia has experienced rising costs and delivery risks. Inflationary pressure has escalated transmission building costs between 25 and 100 per cent in only two years[1] which combined with social licence challenges, threatens the timely completion of critical projects. As a result, alternatives such as storage co-location and demand-side participation are emerging as options to defer network augmentation.

The scale of industrial electrification will largely determine the size of South Australia's future electricity system, while the effectiveness of the CER coordination shapes the intensity of evening peak demand. Even in the most moderated scenarios, operational peaks remain firmly concentrated in the late afternoon and early evening window, reinforcing that peak supply and ramping capability are critical to South Australia's long-term reliability needs.

Altogether, the forecast demand presents both challenges and opportunities for South Australia. Rapid growth in industrial electrification, EVs, and CER will reshape when and how energy is used. These shifts will test the grid's capacity, flexibility, and stability, demanding timely investment and coordination. Yet, supported by the State Prosperity Project and Hydrogen and Renewable Energy Act, this transformation also positions South Australia to lead in clean industry, advanced energy management, and decarbonised growth, turning demand growth into a strategic economic advantage.

Reliability

There have been substantial changes in system performance and market behaviour in South Australia over the past financial year. Wind and solar now supply more than 70 per cent of annual generation, supported by increasing levels of rooftop PV capacity and CER. These developments have driven a shift in market dynamics, impacting prices where frequent negative intervals during periods of high renewable output are offset by occasional high price events when renewable generation is low.

The recent dispatch behaviour of both batteries and gas fired generation reinforces the idea that both technologies are necessary in South Australia's future power system, batteries for their flexibility and speed, and gas for their reliability during extended renewable droughts. In particular FY2024-25 marked a key milestone in South Australia's transition toward a more flexible, storage driven system. Battery discharge set prices in 7 per cent of all five-minute intervals at an average of $472/MWh while battery charging set prices in 9 per cent of intervals at $51/MWh.

Despite these advances, some reliability risks remain in South Australia's network. Significant operational events in FY2024–25, including severe storms that damaged transmission infrastructure and an unforeseen Lack of Reserve (LOR2) event during extreme summer conditions, highlighted the need for fast-response firming capacity. Upcoming retirements of gas generation, totalling 1.1GW by 2030, and the delayed completion of Project EnergyConnect (PEC) result in interim reliability challenges. Modelling undertaken by the Forecasting and Planning function indicated that an additional 400 MW of long-duration firm capacity will be required by FY2028–29 to maintain reliability in South Australia under credible stress scenarios.

Government activity

The South Australian Government (the Government) undertook a range of activities over the last year that ensured the security of the network.

Some of these were:

- The Government has implemented the Firm Energy Reliability Mechanism (FERM). Operational from September 2025, it provides a structured framework for securing long-duration dispatchable capacity through competitive procurement.
- A temporary emergency reserve rule change enabled mothballed diesel plants to operate as out-of-market reserves during the FY2024–25 summer period, while the extension of Torrens Island Power Station B (TIPS B) to 30 June 2028 provides critical bridging capacity until new firming and interconnection projects are delivered.
- The Government has also initiated a sale process for the turbines originally procured under the Hydrogen Jobs Plan (HJP), ensuring these assets remain available within South Australia's supply mix.

Moving forward

South Australia's renewable advantage positions the state as a global leader in clean industry and advanced energy management. The opportunities presented by this transition are significant, but success depends on timely delivery of additional renewables, firming capacity, and network infrastructure. To support this, the Forecasting and Planning function will continue to refine its modelling approach to assess and plan for the mitigation of reliability risks and the integration of forecasted industrial load growth and CER.

01 INTRODUCTION

The South Australian Forecasting and Planning function was formed in 2024 to undertake regular assessments related to the future pathway for the development of the South Australian power system.

This annual report, the Electricity Development Plan (EDP), is an overview of the work undertaken by the Forecasting and Planning function to provide an evolving pathway for South Australia's power system through the upcoming period of uncertainty as the National Electricity Market (NEM) transitions away from existing, fossil fuel generation.

The interface between the EDP and other key policies and documents is summarised in Figure 1 to support understanding of how these interrelate and contribute to the larger on-going transition. Importantly, under the Renewable Energy Transformation Agreement (RETA) between the South Australian Government (the Government) and the Australian Government, South Australia has committed to establishing its own specific grid reliability mechanism and benchmark to be used in place of the national framework, and to be responsible for identifying and delivering new projects and technologies that will maintain reliability to that standard.

Purpose

This report, the South Australian EDP, represents work undertaken throughout 2025 by the Forecasting and Planning function to consider reliability and resiliency in the South Australian network.

This iteration of the EDP aims to:

- Assess key trends and events in the South Australian market to determine the progress being made in the energy transition.
- Explain the near-term challenges and opportunities for South Australia's electricity system.
- Present the activities that were executed by the Forecasting and Planning function throughout 2025 to support the reliability and resilience of the South Australian market.
- Provide awareness of the activities to be undertaken in 2026 by the Forecasting and Planning function in developing the next iteration of the plan.

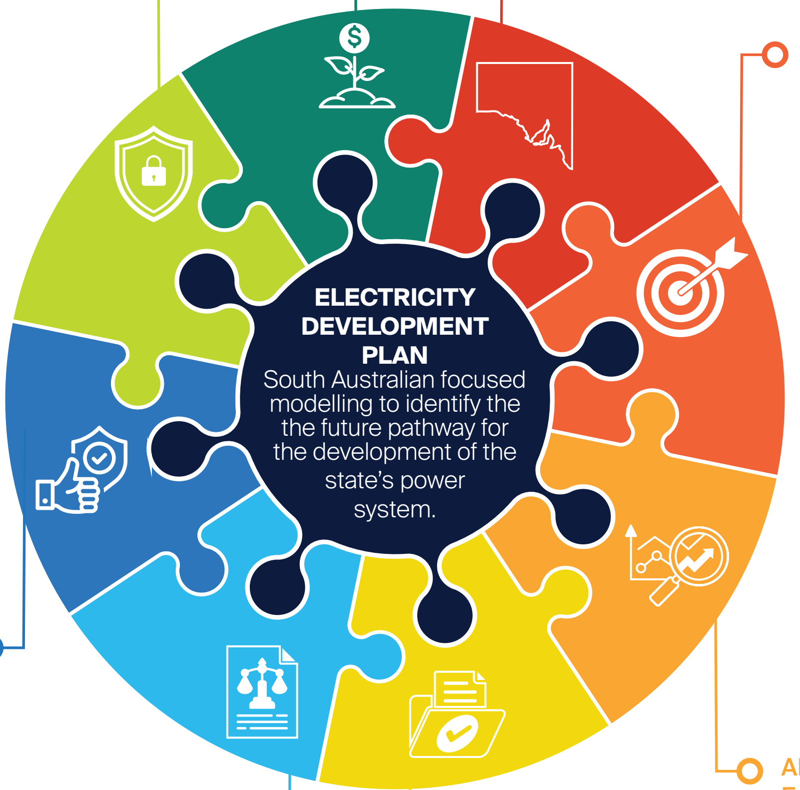
Interfaces with other policies and initiatives

Australian Government's Capacity Investment Scheme
Encourages more renewables and short duration storage (< 4 hours).

State Prosperity Project
Is a coordinated initiative to unlock the full potential of renewable energy, critical minerals and green manufacturing in the state.

Orderly Exit Management Framework
Provides additional ways for the Government of South Australia to ensure the reliability at least cost to consumers.

South Australia Renewable Energy Target
Is a legislated target forming a signal to industry for 100 per cent of demand to be supplied from renewables by 2027.



Reliability and Emergency Reserve Trader
Is a last resort mechanism for additional capacity to be available in emergencies.

AEMO Planning and Forecasting Activities
Assesses current and future system-wide requirements.

Hydrogen and Renewable Energy Act 2023
Streamlines licencing and approvals process for hydrogen and renewable energy projects, supporting delivery of capacity in South Australia.

Firm Energy Target and Firm Energy Reliability Mechanism
Ensures South Australia will maintain enough dispatchable energy capacity to meet demand requirements during periods of low renewable generation.

Figure 1

Information sources

The EDP has been developed by consolidating a range of industry perspectives with the Forecasting and Planning function's own modelling and analysis work. The main external sources are:

- Australian Energy Market Operator's (AEMO) 2024 South Australian Electricity Report (SAER), 2024 Integrated System Plan (ISP) and 2025 Electricity Statement of Opportunities (ESOO)
- SA Power Network's (SAPN) 2024 Distribution Annual Planning Report (DAPR)
- Electranet's 2025 Transmission Annual Planning Report (TAPR)
- Australian Energy Regulator's (AER) State of the Energy market 2025 report.

Noting that a variety of other sources from industry and government entities were also used

Intended audience

- The EDP is primarily intended for an audience that is familiar with power system modelling and the South Australian power system. Throughout the report, 'key takeaway' boxes (as per below) are provided to support readability and understanding for a broader audience.

KEY TAKEAWAY Summarising key concepts and results of the work undertaken.

Stakeholder engagement

The EDP is released annually, providing opportunities for external stakeholders to contribute to and improve on the information used in the annual modelling effort. In early 2025, the Forecasting and Planning function established a Reference Group comprising representatives from network providers, consumer groups and AEMO. The purpose of the group was to promote industry wide collaboration in the support of more granular modelling of the South Australian power system to define necessary areas for investigation to maintain reliability and reduce costs to consumers. The 2024 EDP feedback was gathered separately through a broader consultation process, and a summary of the outcomes was presented to the reference group for discussion.

A high-level summary of the feedback on the 2024 EDP is as follows:

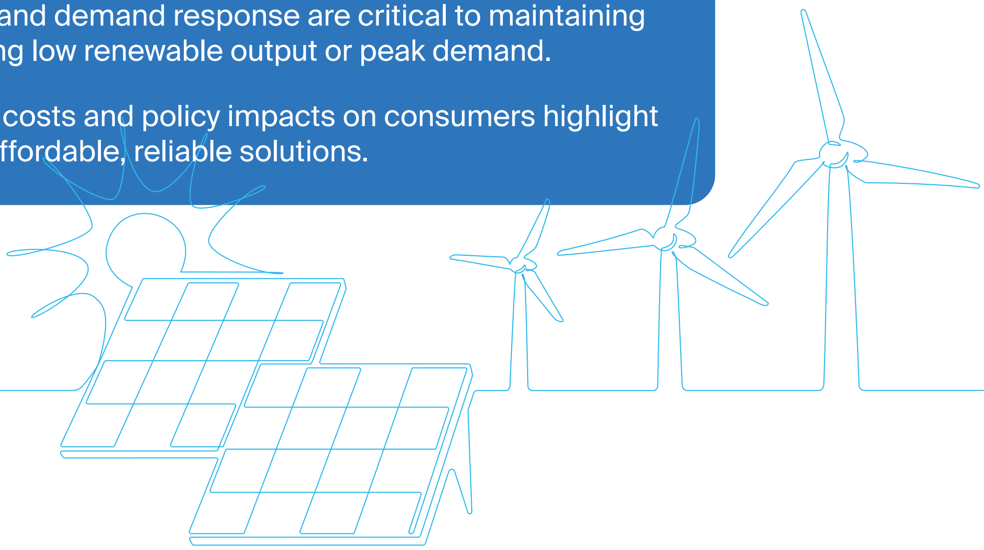
- The group all agreed that continuing to effectively support South Australia's transition to renewable energy would require a coordinated government and industry effort.
- Emphasis was placed on the importance of balancing the integration of renewable energy whilst ensuring the reliability and affordability of electricity for the market.
- All stressed the role that firm dispatchable capacity (like storage, gas, or demand response) would need to play to keep energy supply stable, particularly during high demand or low variable renewable energy (VRE) periods.

- The competitive advantage between long term battery storage and gas fired generation was also discussed. However, the ongoing gas supply chain issues (transport availability and commodity costs) were identified as a challenge that was impacting the ability of gas fired generators to provide adequate baseload support to the network.
- There was a shared concern about rising energy costs. The enablement and promotion of affordable solutions was raised as a remedy, with the group also commenting on the impact that various policy changes are having on South Australian consumers.
- A need for improved demand forecasting based on detailed and reliable data was also identified. Large industrial load growth, in line with current expectations, should be integrated into the forecast to support future network planning.
- Finally, the developing role of Consumer Energy Resources (CER) in the South Australian grid was highlighted with consideration given to the costs associated with its coordination and integration (e.g. solar soakers and Virtual Power Plants (VPPs)). The group wanted to better understand CER's co-optimisation with centralised generation particularly during low/minimum demand shock events (loss of CER on a mild weather day).

A similar process will be undertaken for obtaining feedback on the 2025 EDP.

KEY TAKEAWAY

- A coordinated government–industry approach is essential for a successful renewable energy transition.
- Storage, gas, and demand response are critical to maintaining reliability during low renewable output or peak demand.
- Rising energy costs and policy impacts on consumers highlight the need for affordable, reliable solutions.



02 SOUTH AUSTRALIA'S ELECTRICITY MARKET

A YEAR IN REVIEW

South Australia is a world leader in renewable energy integration and continues to undergo significant changes as renewable generation becomes the primary source of supply. Wind and solar now provide on average more than 70 per cent of annual electricity generation, supported by increasing levels of rooftop photovoltaic (PV) capacity and CER. These developments are driving a shift in system operation, with greater variability in generation, lower minimum demand levels, and new requirements for maintaining stability and reliability.

During FY2024–25, the system experienced several significant operational events in conjunction with continued investment in interconnection, storage, and system services. This reflects the ongoing transition of South Australia's network and market to high levels of VRE and the operational challenges this creates.

This chapter provides an overview of South Australia's network performance over the past year, including reliability outcomes, major incidents, demand and generation trends, and market behaviour.

Significant events

An overview of the significant events that occurred in South Australian electricity market between June 2024 and July 2025 are shown on the next page. Events were chosen based upon (1) their apparent impact on the operation of the South Australian market and (2) their effect on South Australia's energy transition objectives.

Reliability case studies

To provide context on how the South Australian power system responds under stress and maintains reliability during unforeseeable events, two case studies have also been provided. These examples illustrate the emerging challenges of a power system that is increasingly weather-dependent and consequently requires a higher level of coordination, from both an operational and policy perspective.

Wind and solar now provide on average more than **70 per cent** of annual electricity generation, supported by increasing levels of rooftop PV capacity and CER.

12-month lookback at the South Australian Electricity Market

August 2024
Blyth BESS
+239MW / 477MWh)

Goyder South
WF 1B
+196MW

Mannum BESS
+100MW / 200MWh

Templers BESS
+111 MW / 285MWh

October 2024

- Severe weather conditions in South Australia (SA) led to the collapse of twenty-three transmission towers and six stobie poles on 17 October 2024.
- SA experienced a record -232 MW of negative operational demand.

November 2024

- The Firm Energy Reliability Mechanism (FERM) is announced.

December 2024

- Frequency Performance Payments (FPP) market reform began its non-financial operating period. The new process seeks to incentivise positive plant frequency behaviour using a five-minute contribution factor (effectively replacing the existing Causer Pays framework).
- FERM Stage 1 Consultation closed.
- 2024 Electricity Development Plan (EDP) is released.
- Most solar generation over a calendar month in SA (518.7 GWh).
  - Most solar generation in a day in SA (21.9 GWh) on 4 December 2024.
  - Most solar generation in an interval in SA (2.4 GW) at 1:00 PM on 12 December 2024.

January 2025

- AEMC announces temporary rule change allowing the use of the Port Lincoln and Snuggery Stations as an emergency reserve for the next two years. This was prompted by Engie announcing the early mothballing of these power stations (from 1 July 2024) with the SA Minister for Energy and Mining submitting a Rule Change request to the AEMC due to a forecasted reliability shortfall.

  Project EnergyConnect (PEC) Stage 1 energises providing 150 MW of bidirectional interconnection between SA and NSW.

February 2025

- Unforecasted low VRE generation coincided with extreme demand in SA leading to AEMO to declare 'Actual Lack of Reserve Level 2' (LOR2) for the region on 12 February 2025.

May 2025

- Most battery charge in an interval (492 MW) at 2:05 PM on 13 May 2025.

June 2025

- FPP goes live following the end of the non-financial operation period.

  Most renewable generation over a day in SA (48,546 MWh).

  Most battery charge in a day in SA (2.2 GWh) on 30 June 2025.

July 2025

- The Market Price Cap (MPC) increases to $20,300/MWh.
- Most wind generation over a calendar month in SA (744.7 GWh).
- Most wind generation in a day in SA (47.1 GWh) on 25 July 2025.
- Most wind generation in an interval in SA (2.2 GW) occurred at 6:55 AM on 25 July 2025.
- Most battery charge over a calendar month in SA (44.5 GWh).
- Most battery discharge over a calendar month in SA (37.2 GWh).
- Most battery discharge in a day in SA (1.9 GWh) on 11 July 2025.
- FERM Stage 2 Consultation closed.
- To address forecasted reliability risks in SA, AGL and the SA Government agreed to an in-principle agreement to extend the operation of Torrens Island Power Station (TIPS) B for additional 2 years post its official report closure date of 30 June 2026. Note a final agreement was reached in late September 2025.

Figure 2

CASE STUDY

Impact of losing transmission infrastructure

What happened?

On the evening (16:04) of 17 October 2024, a severe storm (high winds and lightning) caused physical damage to high-voltage transmission infrastructure in South Australia's far north. Twenty nine transmission towers and six 132 kV 'Stobie' poles were damaged, leaving transmission lines out of service and local supply disrupted.

Figure 3 Map of Incident Locations

- **Brinkworth – Redhill – Bungama 132 kV tee-connected line:** Tripped due to the failure of eight stobie poles.
- **Clements Gap Wind Farm:** Disconnected ~43 MW of output in conjunction with the network damage.
- **Leigh Creek and Neuroodla areas:** ~0.5 MW of customer load disconnected.
- **Davenport - Olympic Dam West 275 kV line:** Tripped, caused by the failure of two transmission towers located approximately 145 km north of Davenport. This resulted in the disconnection of 155 MW of customer load in the Olympic Dam area.

What did the market do?

AEMO issued a market notice around 18:30 on 17 October 2024 stating that the widespread abnormal conditions (destructive winds) increased the likelihood of non-credible contingency events and they temporarily reclassified any non-credible contingency in South Australia as credible (effective from 18:30). This classification was subsequently cancelled at 22:30.

In coordination with AEMO, once the storm conditions had abated, ElectraNet, the Transmission Network Service Provider (TNSP), and SAPN, the Distribution Network Service Provider (DNSP), deployed crews to inspect the damaged transmission and distribution network assets to determine the best path to return to service. Whilst the majority of affected consumers were able to be reconnected within 24 hours of the event occurring, where on-grid electricity supply restoration was expected to take some time, backup generation was used. Quorn, Leigh Creek and Hawker were provided with temporary generation while permanent transmission repairs were undertaken. Final repairs were completed by SAPN on the 15 February 2025.

What did we learn?

AEMO has a critical role in these types of incidents: The storm and damaged transmission assets increased the chance that South Australia could become electrically isolated (or operate with constrained import capability). AEMO's temporary reclassification of contingencies reflects the operator's ability to raise the risk profile and prepare for more onerous system security actions if further failures occurred. Also, with transmission elements out of service, AEMO and its market dispatch engine applied constraints that were able to manage local dispatch outcomes and prices in South Australia's sub-regions until full restoration.

Fit for purpose operational safeguards and industry coordination mechanisms are critical for an effective response: The response to the incident required a high level of monitoring, effective coordination and considered intervention. Ongoing collaboration between AEMO, the Government, Network Service Providers (NSP) and consumers is critical to maintain the security of South Australia's network throughout events of this nature.

KEY TAKEAWAY

This event highlights the NEM's dependence on transmission resilience and the need for rapid coordination between AEMO, TNSPs and local DNSPs.

CASE STUDY

Managing extreme unforeseen demand

What happened?

During the evening of 12 February 2025, a unique combination of both weather and market factors led to a non-forecasted Actual Lack of Reserve (LOR) level two event being declared by AEMO in South Australia. This type of event signals an operational shortfall with a “non-trivial” probability of involuntary load curtailment (or load shedding) unless additional capacity is provided by the market (beyond current forecasted levels).

Typically, these types of events are flagged in advance by AEMO as they are identified in the availability forecasts provided via pre dispatch and Short-Term Projected Assessment of System Adequacy (STPASA). This allows AEMO to put certain measures in place to manage any expected shortfall in generation.

Throughout most of the day, actual demand (underlying and operational) was trending below the pre-dispatch forecast with no indication that demand would increase above expected levels. However, at 16:30, a combination of emerging cloud cover and extremely hot temperatures (Adelaide reached a five year high of 43.3 degrees Celsius), resulted in a reduction in the available rooftop PV generation in the network which in turn caused demand to ramp faster ahead of the forecasted afternoon peak.

What did the market do?

At 19:15, AEMO issued a LOR2 market notice following the identification of a low level of wind output and constrained interconnection over VIC-SA due to concurrent conditions occurring in Victoria. The actual LOR2 event last 30 minutes, with AEMO identifying a ~100MW shortfall in reserve capacity.

The market responded sufficiently to manage the risk of reserve shortfall through the LOR as the signal from high prices in South Australia appears to have effectively mobilised the higher marginal cost capacity (Figure 4).

Also at that time, South Australia did have access to ~190 MW of Reliability and Emergency Reserve Trader (RERT) that could have been activated if the event were identified earlier. However, due to the short lead time between the identification of the LOR event and the RERT request, the assets contacted by AEMO were unable to be dispatched.

What did we learn?

South Australia needs more fast response dispatchable firming capacity: While the cause of the event was low wind during a high-demand evening peak, the networks inability to absorb that shortfall without triggering an LOR2 reflects deeper structural constraints. The integration of new reliable (and available) firming capacity is critical to covering the gap arising from the mothballing and closure of South Australia's conventional generation fleet.

Strategic reserve options are crucial to maintaining South Australia's reliability: Spot pricing encourages generators and participants to respond when forecasts prove positive, however reliance on high price events alone is not sufficient to manage reliability events. The recent jurisdictional derogation from the AEMC and the framework to establish an out of market capacity reserve highlights how policy, system operation, and market design intersect in managing reliability risks during the energy transition.

A need to improve how we manage the uncertainty associated with VRE forecasts: In the days and hours prior to the event, AEMO had signalled tight conditions. By the evening, actual conditions had diverged from these signals as demand reached the higher end of forecasts (~3.3 GW at 19:00), while wind output remained low resulting in a much smaller reserve margin. This illustrates how forecast uncertainty converged into a real-time reserve deficit, forcing AEMO to declare an Actual LOR2.

KEY TAKEAWAY

- Fast ramping demand on extreme weather days can pose reliability risks to the South Australia's system.
- More fast-response firming capacity is required to backfill renewables during peaks.
- Strategic reserves (IRR/RERT) remain vital, as price signals alone are not enough.

12 February 2025, generation mix and operational demand and South Australian Regional Reference Price (RRP)

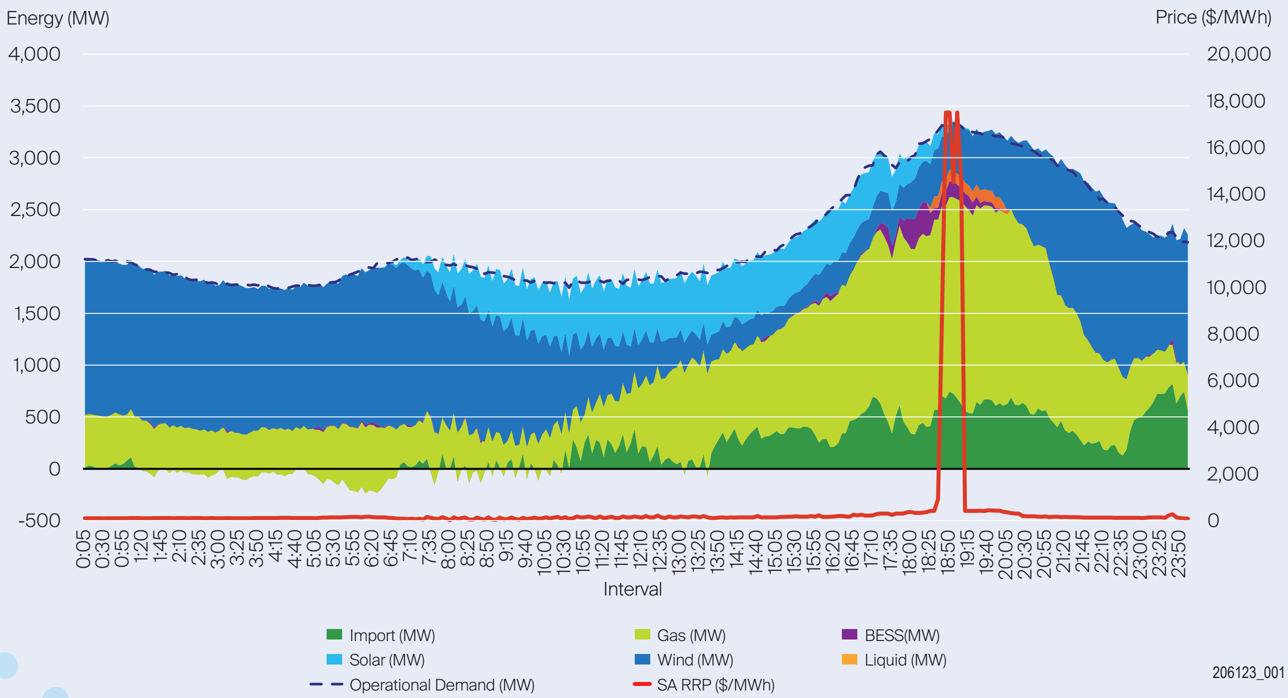


Figure 4

The demand supply balance

The section below explains in detail key observations in both demand and supply aspects of the South Australian market.

Evolving Operational Demand Profile

South Australia's operational demand profile is undergoing rapid transformation, primarily due to the growth of rooftop PV, growing EV uptake and increasing household/business electrification. This shift is changing the way the system operates across the day as the gap between minimum and peak demand continues to increase. New challenges for balancing supply and demand are being created as at very low demand levels, stability risks increase due to insufficient synchronous generation whilst at high demand levels, adequate firming resources must be available to ensure supply during periods of low renewable output.

Minimum demand has continued to decline steadily over the last decade (Figure 5). Since recording its first instance of negative operational demand in November 2021 (-46 MW), South Australia has had multiple other events where specific weather circumstances, such as sunny mild temperature days, result in rooftop PV output exceeding total grid demand.

AEMO is projecting a consistent reduction of minimum demand year on year as more rooftop PV is installed across households and businesses. Whilst lower daytime demand reduces the need for grid supplied electricity, it can make it difficult to maintain sufficient synchronous generation to provide essential system services such as inertia and voltage control.

South Australian minimum and maximum demand

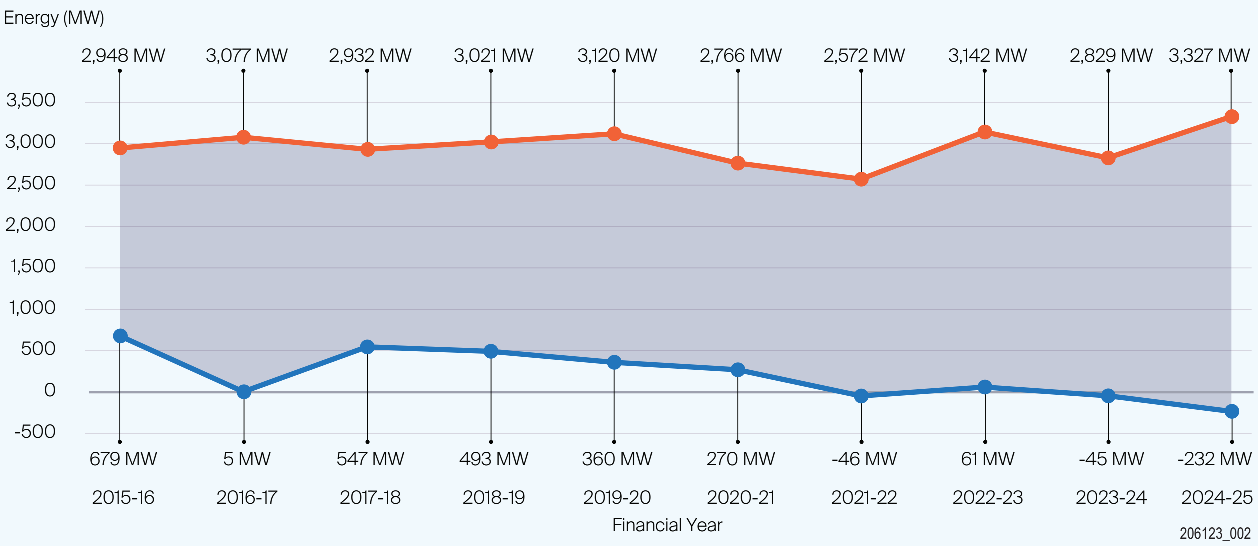


Figure 5

While daytime demand is falling, maximum demand remains high. The combined impact of high summer temperatures, widespread air conditioning use, and declining solar output after sunset are all contributing factors. Furthermore, maximum demand is not expected to decline into the future, and the ongoing electrification of transport and industry will place further upward pressure on evening peaks.

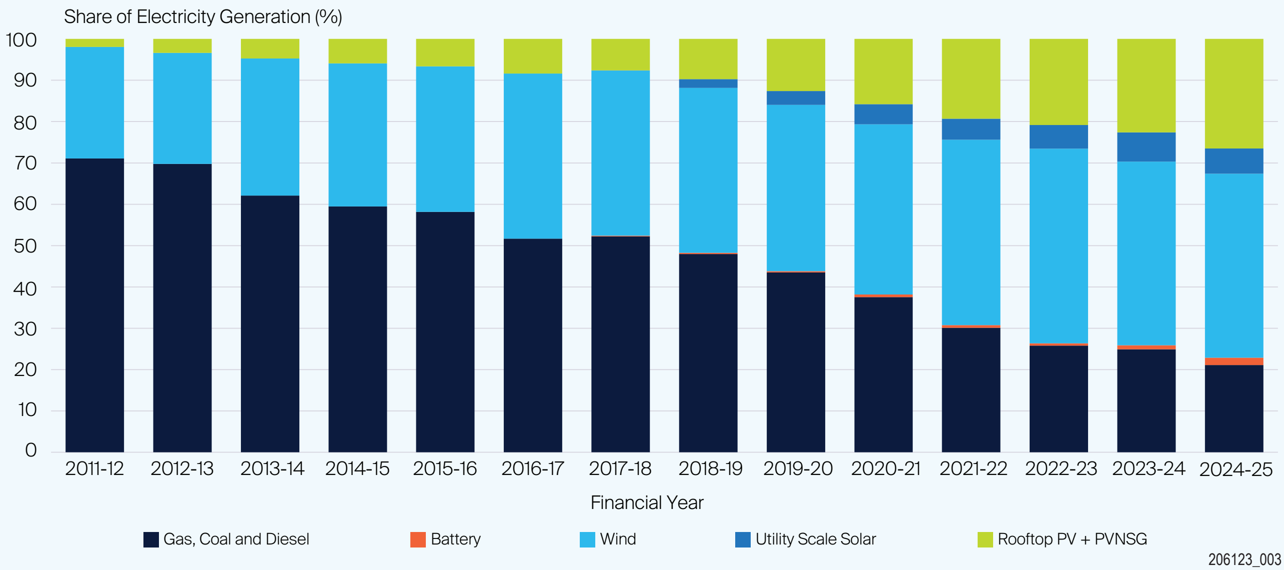
Current Generation mix

Wind remains the largest single contributor to electricity supply in South Australia (Figure 6). In FY2024-25, wind farms accounted for 44.5 per cent of total generation. While this output is variable and weather-dependent, South Australia's geographically diverse fleet of wind farms helps reduce the risk of simultaneous low-wind periods. Wind output is also typically higher during the night and in winter, providing a useful complement to daytime solar generation.

KEY TAKEAWAY

- The operational demand profile is undergoing rapid transformation, creating new challenges for balancing supply and demand as the gap between minimum and peak demand continues to increase.
- Wind and solar make up a major portion of the generation mix, while the share of gas continues to decline and is increasingly used as a firming resource.

Proportion of renewable electricity generation in South Australia



Source: AEMO 2025 SAER

Figure 6

Annual energy generation, selected South Australian power stations

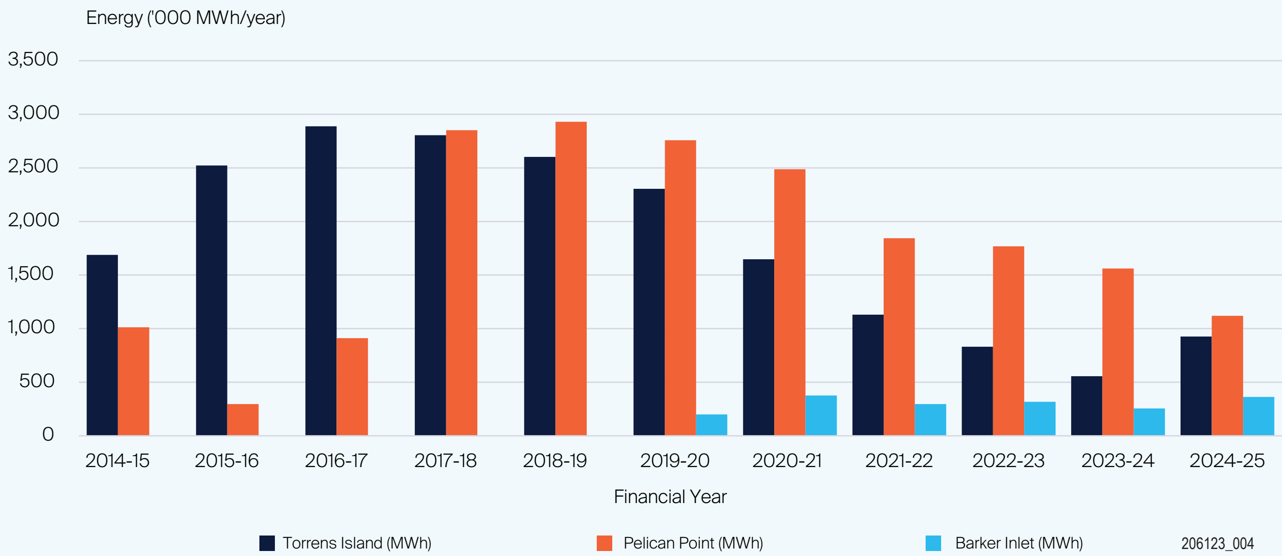


Figure 7

Solar generation is also playing a rapidly growing role in South Australia's electricity system. Rooftop PV and non-scheduled PV (PVNSG) provided 26 per cent of total generation in FY 2024-25, with capacity continuing to expand as households and businesses invest in the technology. Large scale solar contributed a further 6.1 per cent of generation across the same period and combined solar generation (rooftop and large-scale) now produces more electricity than gas fired generation in South Australia, highlighting its central role in the state's energy transition.

Gas fired generation remains the second largest source of supply in South Australia, although its share is rapid declining (Figure 7). In FY2024-25, gas provided 20.8 per cent of the South Australia's electricity, down from 24.2 per cent the previous year. Gas generators are increasingly being operated as a firming resource, running during periods of high demand, low VRE output or interconnector constraints. The declining share of gas reflects both rising renewable penetration and increased imports. However, the flexibility that these generators provide to the South Australian network remains central to reliability planning and system resilience.

Interconnection

Interconnectors remain a key element of system resilience, allowing South Australia to share resources across the NEM and draw on support during extreme system events.

Currently South Australia has three active interconnectors:

- **Heywood Interconnector (V-SA):** 275 kV AC lines providing 600 MW of flow between Heywood substation in Victoria and the Southeast substation in South Australia.
- **Murraylink (V-S-MNSP1):** 150kV DC lines providing 220 MW flow between Red Cliffs in Victoria and Monash in South Australia.
- **Project EnergyConnect (PEC) Stage 1:** 330 kV AC lines providing 150 MW flow between Buronga in New South Wales and Robertstown in South Australia.

PEC Stage 2 is also under construction and, once complete, it will increase the flow capacity from 150 MW to 800 MW (both directions). Expected to be operational in late 2027, it will also increase the capacity of the Heywood Interconnector to 750 MW in both directions whilst also reducing the joint flow to limits on Heywood and PEC.

Table 1 Interconnector Nominal Capacities

Interconnector(s)	Direction	Limit
Heywood	VIC to SA	600 MW
(V-SA)	SA to VIC	550 MW
Murraylink	VIC to SA	220 MW
(V-S-MNSP1)	SA to VIC	200 MW
PEC Stage 1 (PEC)	SA to NSW	150 MW
	NSW to SA	
PEC Stage 2	SA to NSW	**(650 MW)** 800 MW
(Under Development)	NSW to SA	

South Australia's utilisation of interconnection increased significantly in FY2024-25. Exports to Victoria increased over the period with Net Imports dropping from 927 GWh in FY2023-24, to 668 GWh.

KEY TAKEAWAY

- PEC Stage 2 is expected to be operational in late 2027 and will increase bidirectional flow capacity.
- Net imports from Victoria declined, reflecting higher energy exports while the import levels remained steady.

South Australia Interconnection

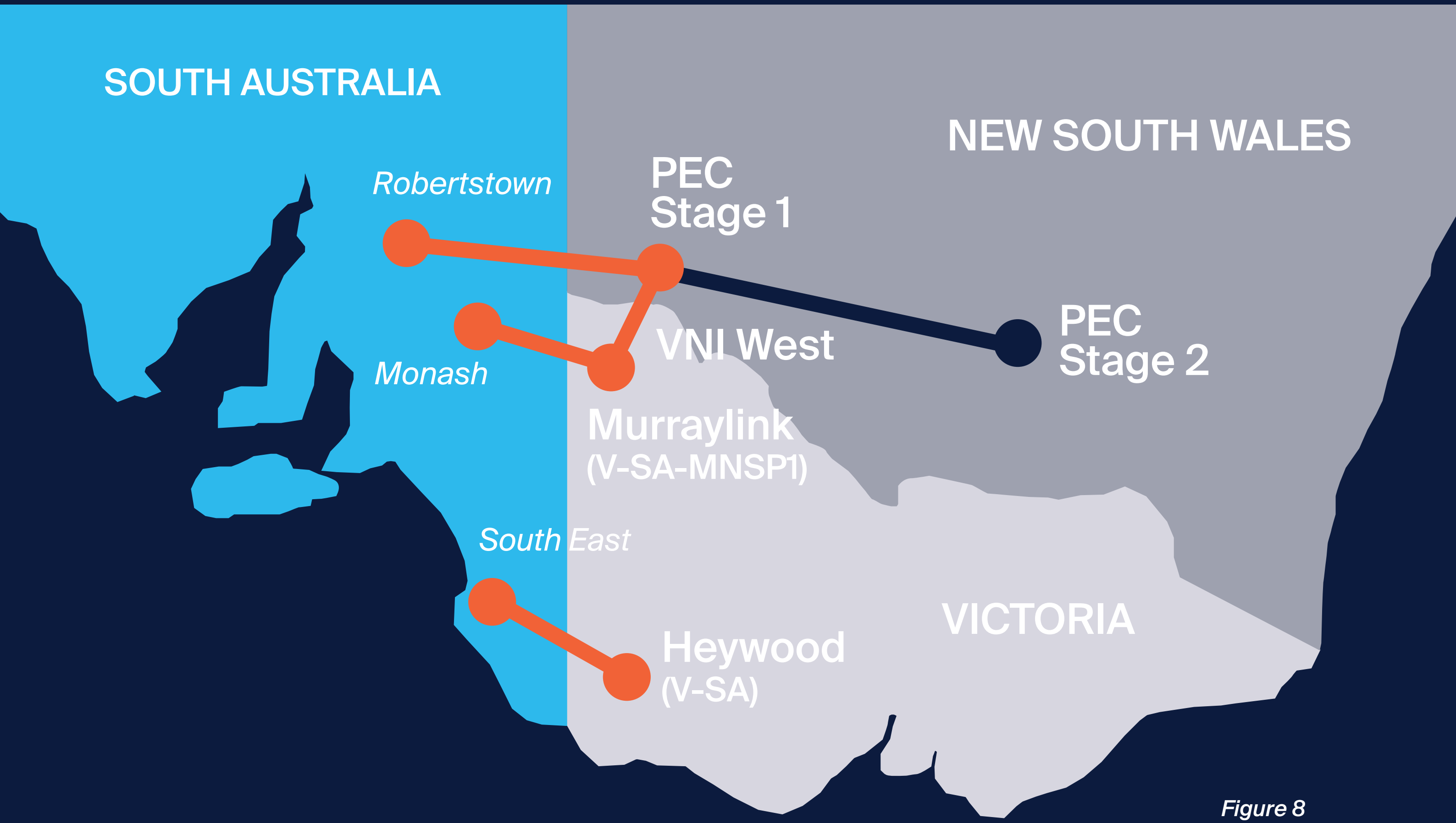


Figure 8

South Australian electricity market

This section examines recent developments in market price trends and generation behaviour, focusing on how structural changes in supply and demand have produced a price environment where frequent negative intervals are offset by occasional scarcity pricing. It also explores how Battery Energy Storage Systems (BESS) and gas fired generators are adapting their operations and revenue strategies within this new landscape, and what these behaviours reveal about the future balance between flexibility and reliability in South Australia's power system.

Market price trends

Following the recent demand trends, South Australia's market has shifted from one dominated by mid-range pricing and conventional generators to a far more polarised environment characterised by frequent negative prices, interspersed with occasional high-price intervals (Figure 9).

While extreme volatility in FY2016–17 was a product of constrained supply and limited interconnection, subsequent years have seen a steady rise in very low and negative prices throughout the middle of the day, particularly as rooftop PV and utility-scale renewables have expanded.

At the same time, the middle ground of $50–$100/MWh has all but disappeared whilst the frequency of $100-$300/MWh prices (particularly end of day) has increased significantly. This has left a market in which most intervals now clear at very low levels, punctuated by short bursts of high pricing above $300/MWh.

Frequency of occurrence of spot prices in South Australia

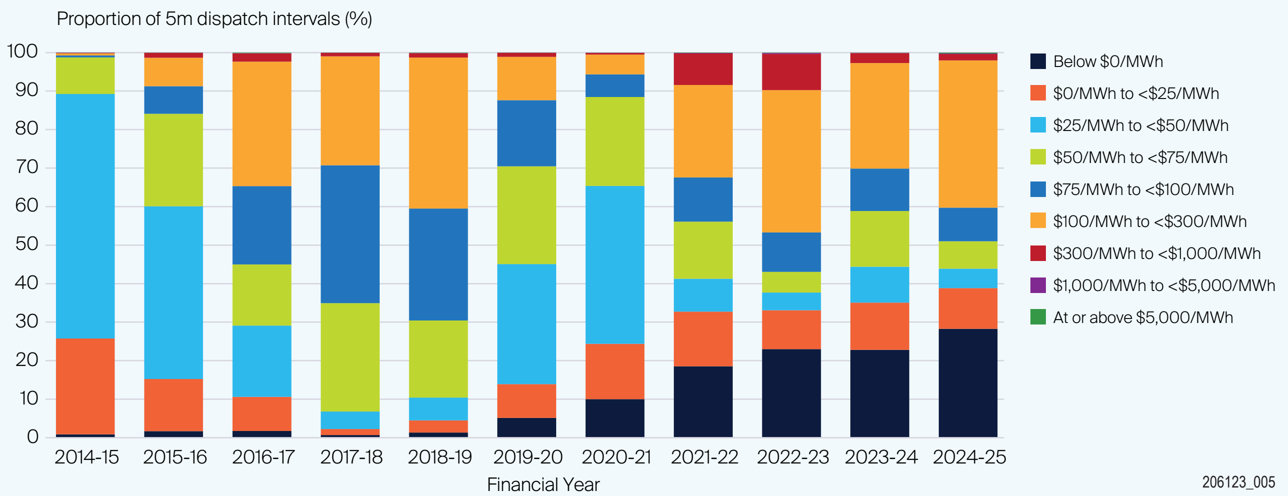


Figure 9

Average monthly dispatch prices (Figure 10), reinforce this picture. Most years now follow a seasonal pattern, with higher prices observed in winter months when demand is elevated, and renewable output is less predictable. FY2022-23 stands out as an outlier, with prices consistently elevated across the year and peaking at more than $300/MWh in July and August, reflecting the NEM-wide shock driven by global fuel shocks and domestic supply constraints. In contrast, FY2023-24 showed a return to more moderate levels, while FY2024-25 demonstrated a renewed but temporary spike in winter prices, followed by a sharp decline into the spring shoulder period.

South Australia has historically been one of the largest contributors to frequency control costs in the NEM, reflecting both its high renewable penetration and periods of system separation. However, average yearly prices for all Regulation and Contingency Frequency Control Ancillary Services (FCAS) have fallen markedly since the peak of FY2016–17, when prices for key contingency services such as fast raise and fast lower surged to well above $100/MWh (Figure 11). Those years coincided with heightened system security risks following the 2016 blackout, repeated islanding events, and the limited availability of local fast-response services.

Average monthly South Australian energy dispatch prices

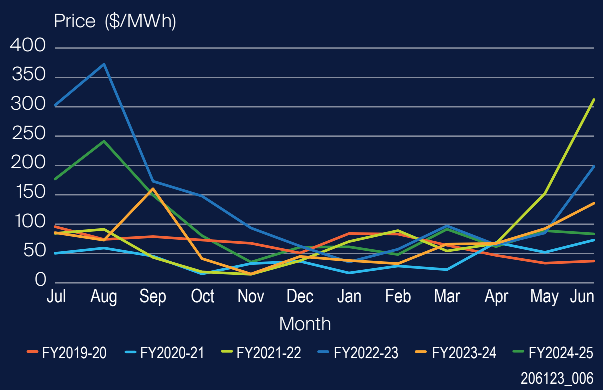


Figure 10

Average yearly South Australian FCAS prices

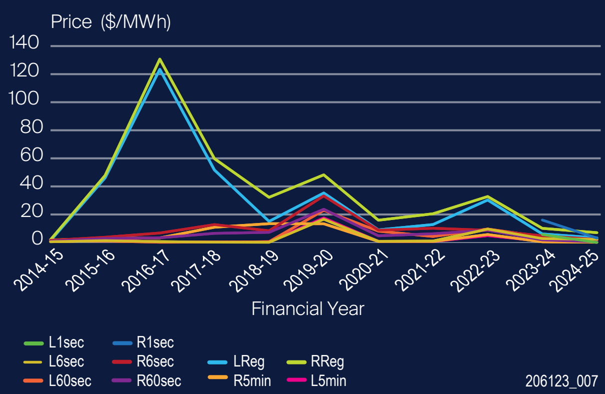


Figure 11

KEY TAKEAWAY

- The market swings between mostly very low or negative prices, with occasional high-price spikes.
- Renewables drive low prices as increased levels of rooftop PV and wind have reduced mid-range pricing.
- FCAS costs have fallen as fast-response services and better system management have reduced frequency control costs.

Market influence of dispatchable capacity

These price trends have a direct influence on the bidding behaviour and revenue strategies of both battery and gas-fired generators. Batteries have adapted quickly to the new conditions, leveraging advanced auto-bidding to charge when prices are negative or near zero, and discharging strategically into peak intervals.

Batteries' role in FCAS has historically been central, dominating the provision of fast-response services through low-priced bids that ensured consistent dispatch. However, in recent years, FCAS across the NEM have declined as new entrants and greater competition have reduced market volatility. This has compressed FCAS revenues for individual providers, particularly in South Australia, and has placed greater emphasis on wholesale arbitrage as the primary revenue stream for batteries. Even so, the combination of arbitrage and ancillary services continues to deliver a diversified income profile, supporting the case for further storage investment.

Gas fired generators, by contrast, have experienced a contraction in operating hours as low and negative prices increasingly crowd them out of the market. Their offers typically span a wide range of price points, reflecting fuel and start-up costs as well as technical constraints, but their revenue profile has shifted decisively toward scarcity pricing. Gas units no longer run as frequently as they once did, but their importance lies in their ability to deliver firm capacity during evening peaks, and periods of low interconnector support. In practice, this means that their income realisation is now concentrated across a small number of high-price intervals, while they play only a marginal role in FCAS markets.

These behavioural patterns highlight the complementary but distinct roles of BESS and gas in South Australia's evolving power system (Figure 12). Batteries are increasingly central to managing volatility, smoothing frequency, and shifting energy across short periods, though they now rely more heavily on capturing value from wholesale market price spreads than on ancillary services. The underlying price dynamics of the South Australian NEM (more frequent negative prices, a thinning of mid-range prices, and a persistence of high-price spikes) provide the foundation for these strategies. It reinforces the idea that both technologies are necessary in South Australia's future power system, batteries for their flexibility and speed, and gas for their reliability during extended renewable droughts. This is provided that these resources are incentivised to align their commercial interests with the needs for a reliable and resilient system.

Average South Australian RRP versus BESS and GFG

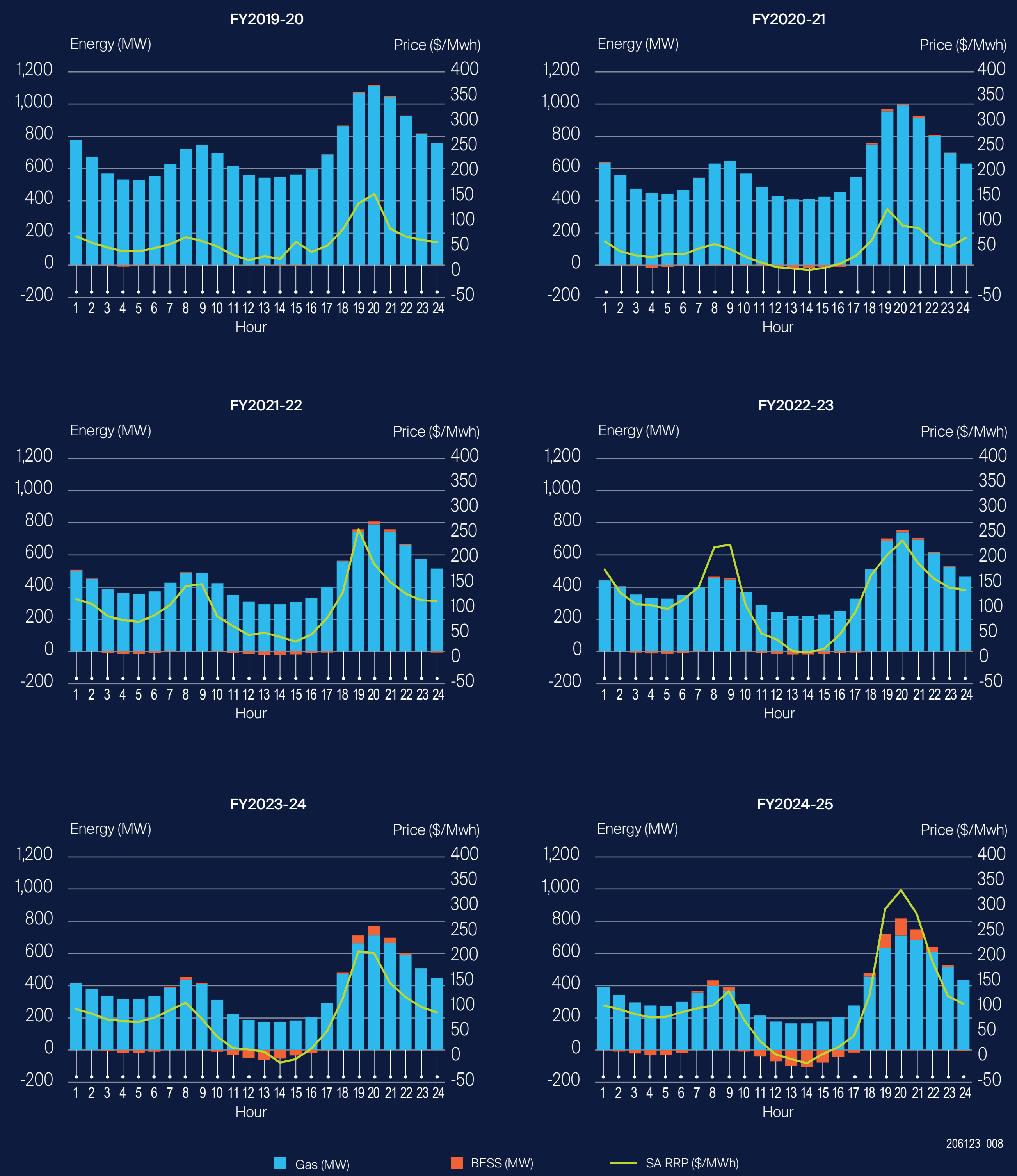


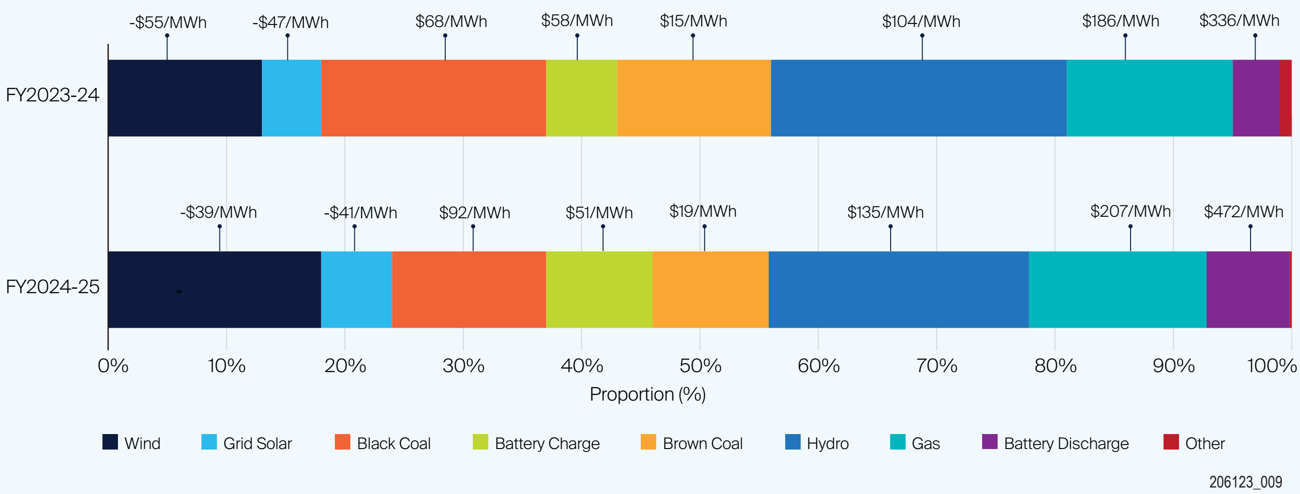
Figure 12

Who is setting the price?

FY2024–25 is price-setting outcomes (Figure 13), highlight South Australia's continued progression through its energy transition, as renewable and storage technologies increasingly influence market dynamics. Wind and grid-scale solar collectively set prices in 24 per cent of dispatch intervals, up from 18 per cent in FY2023–24, underscoring their growing role in a system characterised by high renewable penetration. This increase was driven by higher renewable availability and expanded solar capacity, particularly evident in the December quarter when renewables set prices in almost one-third of all intervals.

The shift in price-setting away from thermal generation continues to characterise South Australia's evolving supply mix. The share of price-setting intervals attributable to black and brown coal via interconnection continued to decline, consistent with reduced coal-fired generation across the NEM. An interesting development was large scale BESS participation in price formation, marking a key milestone in South Australia's transition toward a more flexible, storage driven system. Battery discharge set prices in 7 per cent of all intervals at an average of $472/MWh while charging set prices in 9 per cent of intervals at $51/MWh. This illustrates how batteries are increasingly shaping both high and low-price periods, supporting system stability and providing arbitrage opportunities as renewable penetration grows.

South Australian price setting fuel type and average price



Source: AEMO 2025 SAER

Figure 13

System strength, inertia, and frequency control

Compared to other regions in the NEM, South Australia is characterised by a high share of inverter-based resources, such as wind and solar generation. While these resources reduce emissions and lower long-term costs, they do not naturally provide the system strength and inertia traditionally supplied by synchronous machines such as gas turbines. Maintaining adequate levels of these services is essential to avoiding voltage instability, cascading outages, or system black events.

The 2016 South Australian blackout occurred on the 28 September when severe storms and tornadoes damaged transmission lines, causing multiple voltage disturbances. The resulting loss of generation led to a rapid frequency drop and separation from the National Electricity Market, leaving the entire state without power.

The 2016 blackout demonstrated South Australia's exposure to low inertia and weak system strength events. Following the event, AEMO and ElectraNet conducted extensive reviews that led to the installation of four large synchronous condensers at Davenport and Robertstown. The system strength, inertia, and fault current provided by these units (without the generation of electricity) allowed AEMO to reduce the number of minimum synchronous generators required to be online in the network to two units. In August 2025, AEMO decided to further reduce the minimum number of synchronous generators in South Australia to only a single unit representing a significant step forward from the post 2016 blackout recovery period.

While system inertia and fault levels remain low under these conditions, stability is maintained through fast frequency response from batteries and support via interconnectors. This significant step in the journey to achieving the net 100 per cent renewables target as being able to safely run with one synchronous generator unit is a clear signal that South Australia has now progressed from a system once dependent on synchronous generation for stability to one capable of securely operating with predominantly inverter-based resources.

This operational flexibility delivers a range of benefits by:

- ✓ Reducing the need to keep current gas units online.
- ✓ Allowing for higher levels renewable output.
- ✓ Lowering minimum generation requirements.
- ✓ Providing more frequent periods of net exports.

03 CHALLENGES AND OPPORTUNITIES FACING SOUTH AUSTRALIA

This chapter outlines the principal challenges facing the South Australian power system from a policy and planning perspective, including maintaining system strength and reliability under higher renewable penetration, transmission readiness uncertainty and substantial new demand potentially entering the grid.

At the same time, the transition presents significant opportunities for South Australia to leverage its renewable advantage. This ranges from attracting clean industry investment, supporting national and state emissions goals, and strengthening its position as a leader in energy innovation.

The policies and planning decisions made over the coming years will determine how effectively these opportunities are realised while managing the associated technical and market risks.

Net 100 per cent renewables

South Australia continues to lead the nation in renewable electricity generation and integration. Via the Climate Change and Greenhouse Emissions Reductions (Targets) Amendment Bill, the Government legislated a target of achieving net 100 per cent renewable electricity by 2027, bringing forward the previous 2030 goal in recognition of rapid progress and strong investor confidence.

$$\text{Net SA Renewables \%} = \frac{\text{Total SA Renewable Generation (MWh)*}}{\text{Total SA Generation (MWh)} + \text{Total SA Imports (MWh)}}$$

*Does not include BESS Discharge (MWh)

This target represents a central pillar of the Government's energy transition, aligning decarbonisation with economic opportunity. It underpins growth in Green Industry and renewable energy exports, positioning South Australia as a global example of a secure, high-renewable electricity system.

Progress to date

South Australia has made substantial progress toward realising its net 100 per cent renewables target, achieving world-leading levels of renewable generation and integration. In FY2024-25 (Figure 14), South Australia achieved a net renewables proportion of 70 per cent, which is remarkable progress over a 20-year period (was less than one per cent in FY2005-06).

South Australia has also experienced an increasing number of five minute intervals where VRE generation has met all the state's electricity demand. In 2024 alone, there were 286 days where this occurred with 25 per cent of all trading intervals across the year in the state being fully met by renewables sources.

While the transition is progressing strongly, achieving a reliable and sustainable net 100 per cent renewable system requires ongoing management of technical and market challenges.

- **Firming and grid stability:** As renewable penetration deepens, the grid's reliance on fast-response firming resources increases. Additional investment in firming technologies and demand-response services is required to maintain reliability during low-renewable or peak-demand periods.
- **Transmission and interconnection:** Completion of PEC Stage 2 and the reinforcement of key transmission corridors remain essential for balancing imports and exports, managing network congestion, and ensuring security of supply during high renewable output periods.

South Australian yearly net renewable percentage

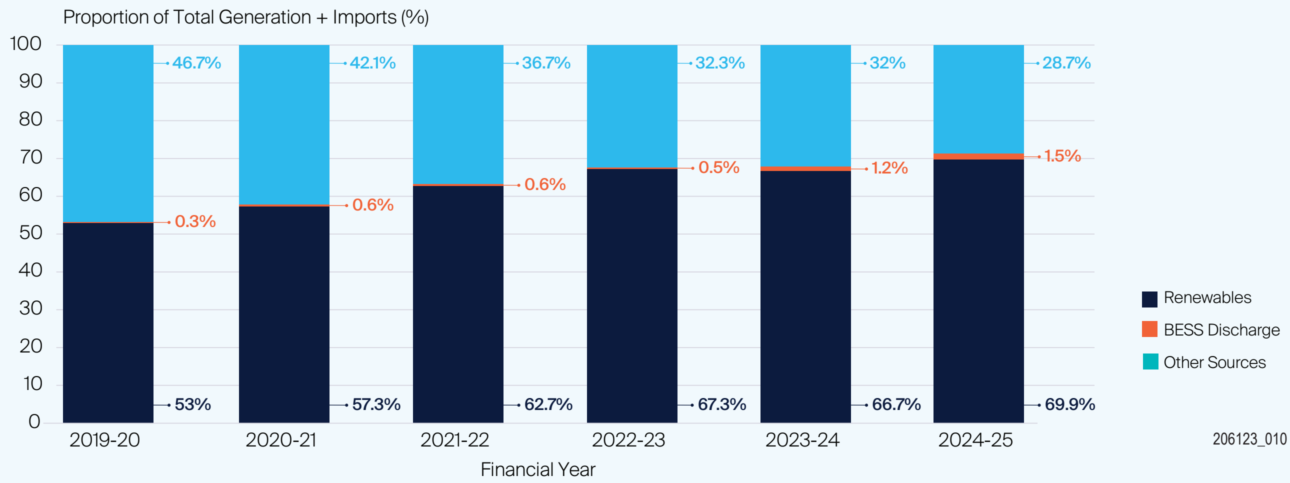


Figure 14

- **Rising demand and new industrial loads:** Electrification of transport, new large industrial loads and data-centre development are expected to significantly increase energy demand. Proactive planning and alignment between generation growth and network capacity are needed to maintain system balance.
- **Dependence on net imports:** While the state frequently operates at 100 per cent renewable generation, it continues to rely on imports and gas generation at certain times. Enhancing local firming capacity and long-duration storage will be crucial to achieving a truly self-sufficient renewable system.

Outlook to 2027

South Australia has made strong progress towards achieving net 100 per cent renewables by 2027. The state's generation mix, policy framework, and investment pipeline collectively position it as a global leader in renewable integration. The next phase of the transition will emphasise firming, flexibility, and resilience, supported by completion of PEC, large-scale storage deployment, and expansion of demand-side resources. These developments will strengthen system reliability, enhance export capability, and sustain affordable energy outcomes.

By 2027, South Australia is expected to demonstrate that a modern electricity system can operate reliably, securely, and economically on a net 100 per cent renewable basis, providing a blueprint for Australia's national energy transition.

KEY TAKEAWAY

- South Australia has made strong progress towards the net 100 per cent renewables target with 70 per cent net renewables achieved in 2025.
- The continued development of storage and interconnection projects positions the state as a global leader in energy transition.
- However, there are still some challenges that need to be addressed relating to firming capacity, on time transmission upgrades, rising demand levels and reducing reliance on imports during peak periods.

South Australia's future demand profile

The section below describes the findings of a demand forecasting exercise conducted by the Government. Refer to Appendix A – Forecasting and Planning's Demand Forecast for further detail.

Electricity demand in South Australia is on track for a profound transformation over the coming decade. Total electricity consumption is expected to double from around 14 TWh in FY2025-26 to approximately 28 TWh by FY2035-36, driven by widespread electrification across industry, households and transport (Figure 15). This growth reshapes both the quantity and profile of demand, introducing new operational challenges and opportunities.

Industrialisation as the engine of growth

The most significant contributor to rising demand is the rapid growth in new large industrial loads. Industrial consumption is forecast to reach approximately 10 TWh by FY2035-36, accounting for more than one-third of the South Australia's total demand. This reflects the ongoing shift to large-scale electricity use in range of industries, mining, critical minerals processing, data centres and material production facilities, many of which are being supported under the State Prosperity Project (SPP) and Hydrogen and Renewable Energy (HRE) Act frameworks.

These industries are concentrated in regional zones designated for clean energy-intensive development, such as the Upper Spencer Gulf and Eyre Peninsula. Their continuous and high-load operations will drive power requirements but at the same time improve network utilisation, which has been low during some periods of the day due to the abundance of solar generation.

Delivering power to industrial regions under the SPP and HRE Act will require a coordination of major transmission augmentation, strategic firming investments, and grid-forming technologies to provide the stable supply required for continuous industrial operations. However, this needs to be undertaken with the appropriate cost considerations in mind. The uncertainty, and non-delivery risk, associated with these new loads also needs to be considered in any planning decisions, as most are still in the 'pre-committed' phases of development.

South Australian demand forecast: Electricity consumption by category

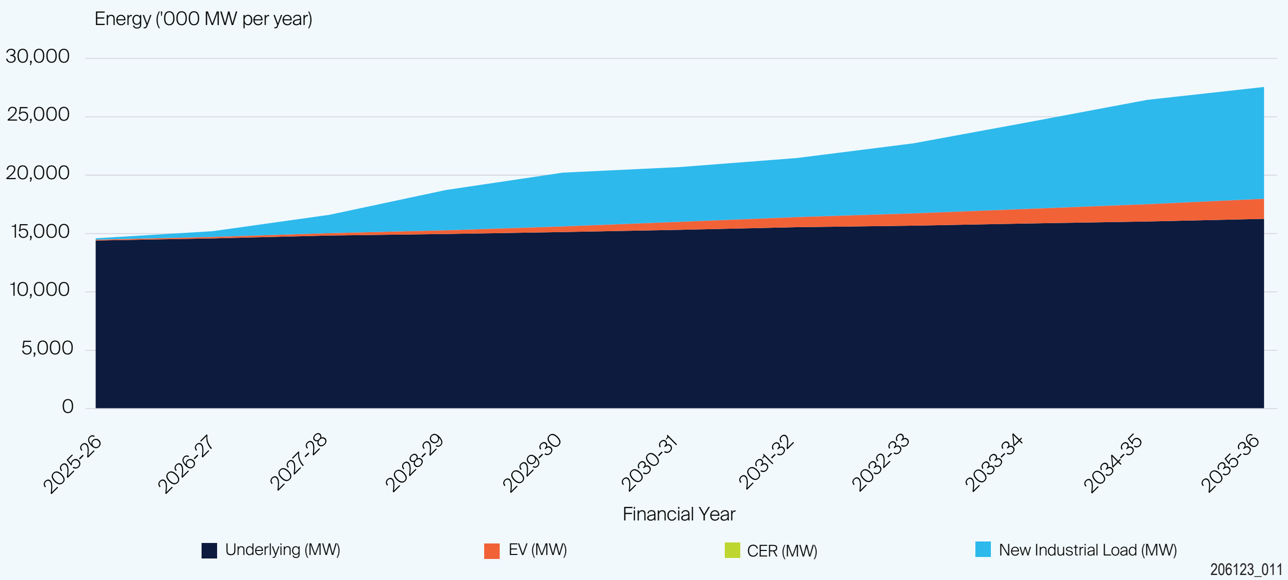


Figure 15

Supporting Factors: Electrified transport and rooftop PV

While industry leads the forecasted growth, other sectors are also strong contributors:

- EVs are projected to grow to around 2 TWh by 2036, adding new load mostly in residential and fleet charging.
- Rooftop PV generation will rise sharply from 3 TWh to over 7 TWh annually, offsetting some household and commercial consumption but not enough to counterbalance industrial demand.

As a result, total operational grid demand will climb from its current level of ~11 TWh to ~21 TWh by FY2035-36, (Figure 16) even as more energy is produced behind the meter.

Operational trends and the deepening "Duck Curve"

The growing mix of rooftop PV and industrial demand reshapes South Australia's daily load profile. By FY2035-36, the average operational demand curve shows a deeper midday trough and sharper evening ramp, with industrial processes sustaining higher daytime and overnight consumption while rooftop PV peaks at midday (Figure 17). This intensifies the late afternoon ramping requirement, demanding more flexible generation, storage, and dispatchable capacity to balance renewable variability and maintain reliability.

South Australian demand forecast: Operational demand and rooftop PV generation

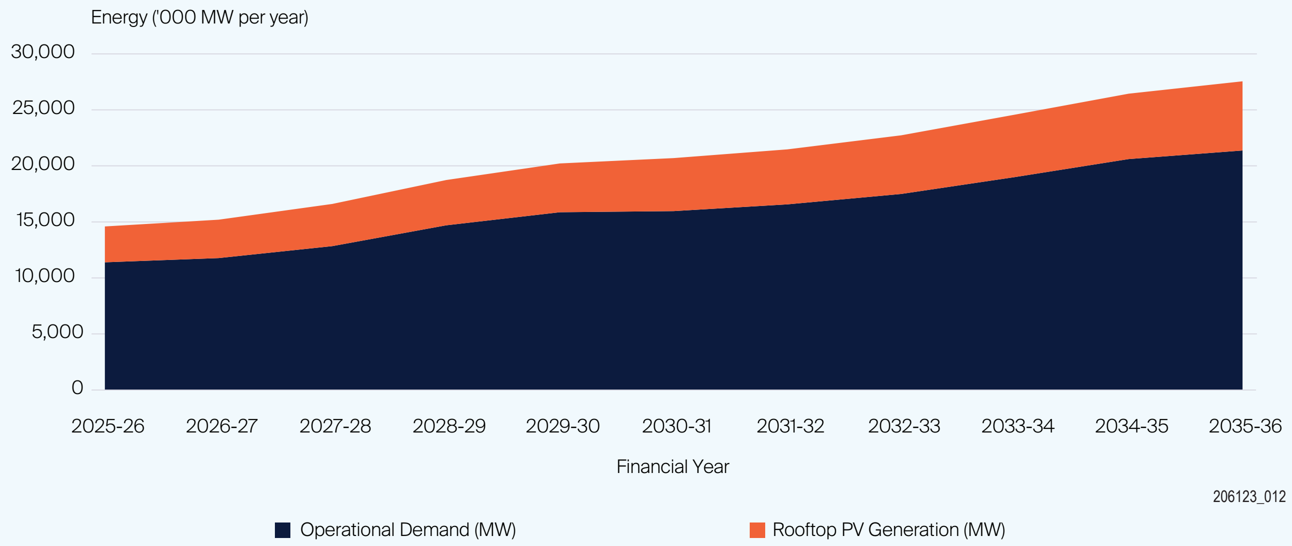
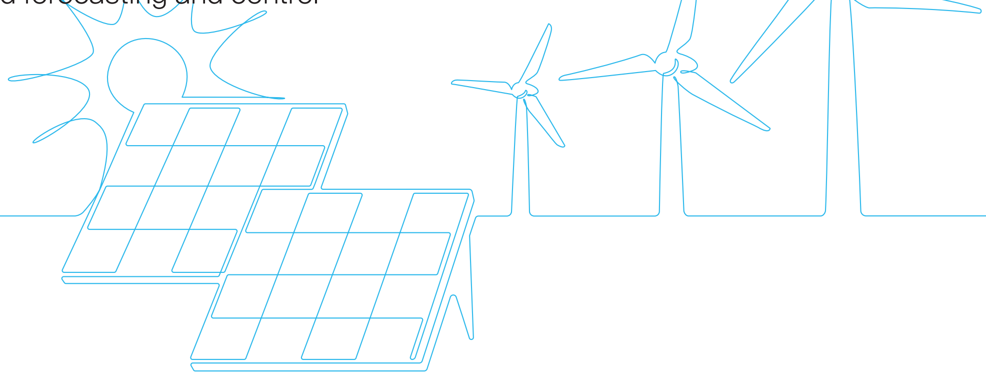


Figure 16

Managing Minimum System Load (MSL) and variable resources

Rising rooftop PV capacity means MSL events are more likely to occur when operational demand drops to critically low levels. During such periods, the system must maintain enough synchronous generation for inertia and frequency stability, even as demand from industrial centres persists elsewhere on the grid. This contrast between urban solar surpluses and industrial regional loads introduces new operational dynamics that require sophisticated forecasting and control systems.

While interconnection with other regions in the NEM can assist by allowing excess solar generation to be exported and absorbed elsewhere, those regions are also experiencing significant growth in distributed solar. As a result, effective management of MSL conditions in South Australia continues to rely on active monitoring, coordinated dispatch, and dedicated operational safeguards. In the longer term, managing these challenges will require enhanced visibility of CER, dynamic curtailment tools, and coordinated investment in transmission and storage.



South Australian demand forecast: Average daily demand profile

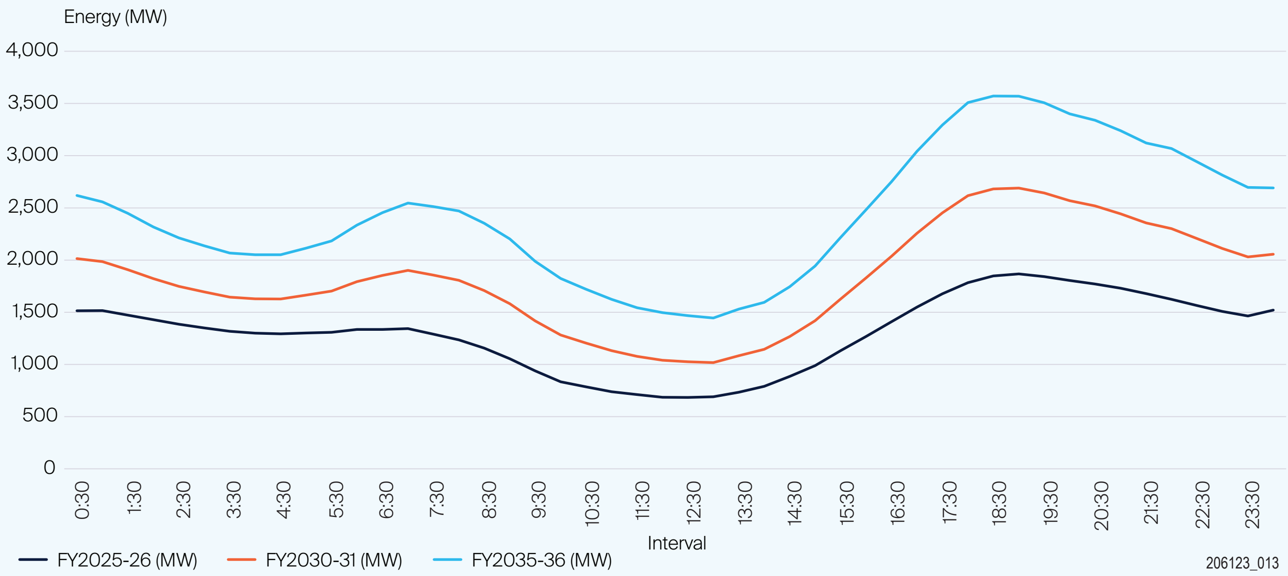


Figure 17

Altogether, the forecasted demand presents both challenges and opportunities for South Australia. Rapid growth in industrial electrification, EVs, and CER will reshape when and how energy is used.

These shifts will test the grid's capacity, flexibility, and stability, demanding timely investment and coordination. Yet, supported by the SPP and HRE, this transformation also positions South Australia to lead in clean industry, advanced energy management, and decarbonised growth, turning demand growth into a strategic economic advantage.

KEY TAKEAWAY

- South Australia's electricity consumption is predicted to double from ~14 TWh in FY2025-26 to ~28 TWh by FY2035-36, driven mainly by industrial electrification.
- Industrial load is the growth engine, reaching ~10 TWh by FY2035-36.
- Expected EV uptake is projected result in a load of ~2 TWh whilst rooftop PV is also forecast to grow beyond 7 TWh, further deepening the daily "duck curve."
- Maintaining grid flexibility and stability at these new demand levels will require major transmission upgrades, additional firming capacity, and advanced control systems to manage low-load periods and variability.

Retirements across South Australia and other NEM regions

The next phase of South Australia's energy transition involves the retirement of several ageing gas fired generation assets and the strategic management of renewable facilities reaching the end of their operational lives. With some gas fired units scheduled for withdrawal early in the current planning horizon, there is a heightened need to manage the resulting interim reliability risks. For instance, any delay to PEC Stage 2 could increase the likelihood of temporary capacity shortfalls during periods of low VRE output, underscoring the importance of timely interconnector delivery.

By 2030, a total of 1.1 GW of gas capacity is expected to be retired, reflecting the continued decline in dispatch requirements for older thermal generation. To address the resulting capacity gap, the Government is progressing a suite of market and policy measures, including the introduction of the Firm Energy Reliability Mechanism (FERM) and participation in the Australian Government's Capacity Investment Scheme (CIS). These initiatives aim to provide clear investment signals for new dispatchable and long-duration storage assets to ensure ongoing system reliability.

At the same time, as shown in Table 2, multiple renewable energy facilities are approaching the end of their operational life, meaning decisions will be required on whether to repower, re-energise, or decommission these assets. Each option carries different implications for land use, grid connection, and regional economic outcomes. A strategic evaluation process will need to be undertaken by the owner of each asset to determine the most suitable pathway for each facility, taking into account factors such as asset condition, technological advancements, market conditions, regulatory requirements, and existing land-use agreements.

Table 2 Upcoming South Australia generation retirements

Facility	Capacity (MW)	Reported Closure Date*	Technology
Torrens Island B	600	30/06/2028†	Gas
Osborne	124	31/12/2027	Gas
Port Lincoln GT	73.5	1/01/2028	Gas
Snuggery	63	1/01/2028	Gas
Wattle Point Windfarm	91	2029	Wind
Dry Creek GT	156	2030	Gas
Cathedral Rocks Windfarm	66	2030	Wind
Mt Millar Windfarm	70	2030	Wind
Mintaro GT	90	2030	Gas
Dalrymple BESS	30	2030	Battery
Lake Bonney Battery Energy Storage	25	2034	Battery
Millicent Windfarm	46	2035	Wind
Lake Bonney Stage 1 Windfarm	81	2035	Wind

* Please note Closure Dates are based upon current publicly available information. These dates could change post the release of this document.
† In line with the recent agreement with the South Australian Government.
Source: AEMO Report, ESOO 2025 and NEM Generation Information October 2025

Meanwhile, the transition underway in the eastern states will significantly affect South Australia. The retirement of coal-fired generation in New South Wales and Victoria (shown in Table 3) is expected to impact South Australia's ability to rely on interstate firm capacity via interconnection. Furthermore, as renewable penetration increases across the NEM, periods of low wind or solar output in South Australia may coincide with similar conditions in the east, limiting the support available from interconnectors. The progressive withdrawal of coal also reduces synchronous generation in the market, lowering inertia and complicating system operations in a state that already operates with relatively low levels of synchronous support.

Collectively, these retirement considerations highlight the need for proactive planning to maintain adequate capacity while supporting a sustainable and economically efficient transition of South Australia's generation fleet.

Table 3 Upcoming Victoria and New South Wales coal generation retirements

Facility	Capacity (MW)	Closure Date*	Technology
Eraring (NSW)	2,880	19/08/2027	Black Coal
Yallourn (VIC)	1,450	1/07/2028	Brown Coal
Loy Yang A (VIC)	560	2035	Brown Coal

* Please note Closure Dates are based upon current publicly available information. These dates could change post the release of this document.
Source: AEMO ESOO 2025

The National Electricity Market Wholesale Market Settings Review (or the Nelson Review[2]) reinforces these priorities, noting that uncertainty around the timing of generator retirements remains one of the largest risks to reliability and investment across the NEM. It recommends ensuring 'entry before exit', meaning new firming and renewable assets should be operational before legacy plants withdraw. The Nelson Review also calls for greater transparency of retirement schedules, stronger investment signals for long-duration storage and firming, and improved coordination between regions to manage the loss of synchronous generation. These recommendations align closely with South Australia's use of mechanisms such as FERM, which aim to facilitate an orderly, well-sequenced transition while maintaining system security.

KEY TAKEAWAY

- 1.1 GW of gas capacity to close in South Australia by 2030, increasing interim reliability risks.
- Several large scale South Australian renewable assets are facing key end-of-life decisions (repower, re-energise, or decommission).
- Timely delivery of PEC Stage 2 is critical to avoid capacity shortfalls during low renewable output.
- New South Wales and Victoria generation closures will reduce synchronous support, heightening system stability challenges for South Australia and the broader NEM which are being actively monitored and planned for via a range of AEMO system security initiatives.

Reassessing transmission buildout

Transmission infrastructure is central to Australia's energy transition. It provides the imperative support for the NEM linking Renewable Energy Zones (REZs), balancing supply and demand between regions, and supporting reliability across the system. For South Australia, where renewable penetration is among the highest in the world, transmission also enables export of surplus wind and solar while securing imports during periods of low renewable generation.

The AEMO has consistently highlighted the scale of coordinating transmission buildout. Its ISP 2024 identifies around 5,000 km of new and upgraded transmission is essential to reaching the Australian Government's target of 82 per cent renewables by FY2029-30. However, while the need is clear, the environment for delivery has shifted sharply with rising costs, project delays and heightened concerns around social licenses.

This section outlines these challenges, with a focus on cost escalation, delivery risks, implications for South Australia, and the growing role of alternatives to new transmission.

A shifting cost environment

Transmission projects have always been capital-intensive, but the assumptions underpinning their cost have changed dramatically in just a few years.

The 2025 Electricity Network Options Report (ENOR)[3] shows that transmission construction costs have continued to rise sharply. After adjusting for inflation, overhead line costs were estimated to be 25–55 per cent higher than in the previous update, while substation costs had increased by 10–35 per cent.

In some cases, the 2025 ENOR recorded cost increases approaching 100 per cent compared with the same costs in 2023.

Inflationary pressure in transmission construction is an ongoing risk. Even as early as 2023, cost uncertainty had already been a concern. The 2023 Inputs, Assumptions and Scenarios Report (IASR)[4] and 2023 Transmission Expansion Report[5], informed by CSIRO's GenCost 2022–23[6], had noted significant construction cost escalation across most technologies. A review by Aurecon at that time found that the more than 25 per cent growth in energy project costs over five years was largely driven by labour shortages, the commodity price increases, and supply chain disruptions.

The 2025 ENOR identifies the cost drivers as:

- **Supply chain and workforce:** Ongoing shortages of transformers, conductors, and skilled trades.
- **Market competition:** Multiple mega-projects tendering simultaneously, raising contractor margins.
- **Social licence:** More comprehensive engagement and compensation for landholders, such as Victoria's long-term easement payments, have added to project costs.
- **Risk and contracting:** Higher contingencies are now built into engineering, procurement, and construction (EPC) contracts.
- **Planning and environment:** More detailed biodiversity offsets and approvals have increased compliance costs.

These drivers are not short-term fluctuations but instead represent a structural rise in baseline transmission costs.

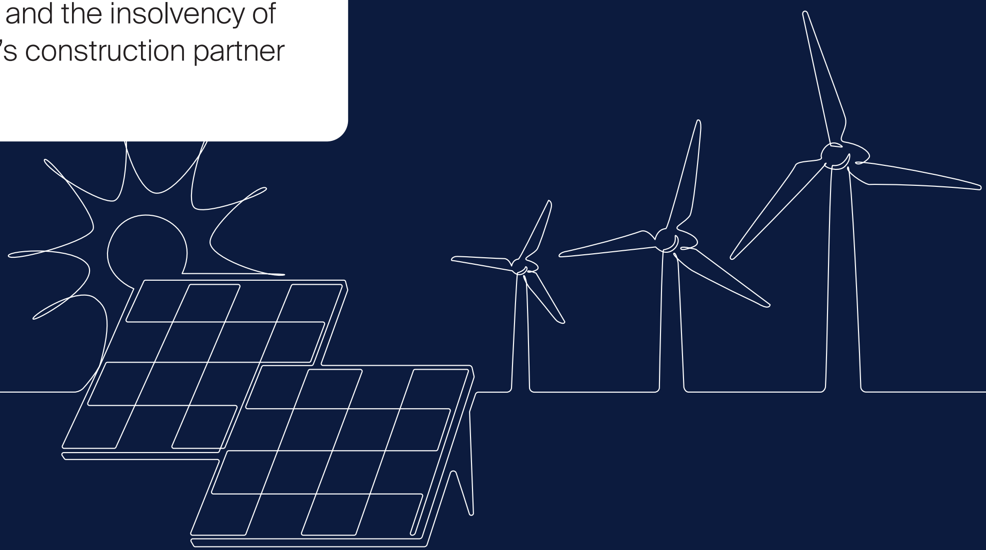
Current Transmission Construction Challenges in Australia

Project EnergyConnect

The 330KV transmission line will connect between Robertstown (South Australia) and Wagga Wagga (New South Wales), via Red Cliffs (Victoria). The initial assessment published in 2018 planned for the line to be energised from 2023, at a cost of $1.5 billion. While the South Australian side of the transmission was completed in 2023 and has enhanced transmission capacity between South Australia and Victoria, the New South Wales component is still underway and has now been projected to finish construction and energise by November 2027 (ESOO 2025). Earlier this year, Transgrid (New South Wales TNSP) provided a cost revision of $3.6 billion, which reflects 'unforeseeable factors such as COVID-related global supply chain impacts on key equipment and materials, critical labour shortages, record inflation, the impacts of the war in Ukraine, flooding and the insolvency of Elecnor Australia's construction partner Clough.'[7]

VNI West
(Victoria to New South Wales Interconnector West)

A proposed 500 kV double-circuit overhead transmission line that will connect the high-voltage networks of Victoria and New South Wales. It was first identified in AEMO's ISP 2020 as an "actionable project", one of the priority transmission projects, to be completed by the end of 2028. However, at the start of 2025, the expected delivery period was revised to late 2030. While the original cost was estimated to be $3.9 billion, AEMO has re-estimated the total to be $7.6 billion, with the upper bound as high as $11.4 billion upon project completion[8].



CopperString 2032

A Queensland government-owned project to build the largest electricity transmission network expansion in Australia, connecting Queensland's Northwest Minerals Province to the national grid. The project will construct new high-voltage transmission lines from near Townsville to Mount Isa, creating jobs, and support in a critical minerals resources boom. Although construction began in 2024 with a projected 2029 completion, the project has experienced cost increases and is now seeking private funding for the Townsville to Mount Isa section. CopperString full cost was revealed as almost $14 billion, nearly $12 billion more than originally announced[9].

HumeLink

A transmission project intended to connect the Snowy 2.0 pumped hydro scheme into the New South Wales transmission grid. In 2020 planning, TransGrid estimated that HumeLink might complete by FY2024–25 with a cost around $1.35 billion (for two single-circuit lines). In 2021, the cost was revised to $3.3 billion and in December 2023, to $4.8 billion[10]. The more recent approvals (New South Wales Government and Australian Government) foresaw completion around 2027 for HumeLink, a delay of at least two years[11].

Regarding generation assets, the 2025 IASR, informed by the GenCost 2024-25 report, shows a divergence in cost trajectories relative to the 2023 IASR (a comparison is provided in Table 4).

This highlights an uncertain and challenging environment to coordinate the network and generation asset buildout. As the ISP is conducted only once every two years, it may not timely capture these challenges and uncertainties, potentially locking in decisions that may be optimal at the time but prove costly over a longer run once the risks are revealed.

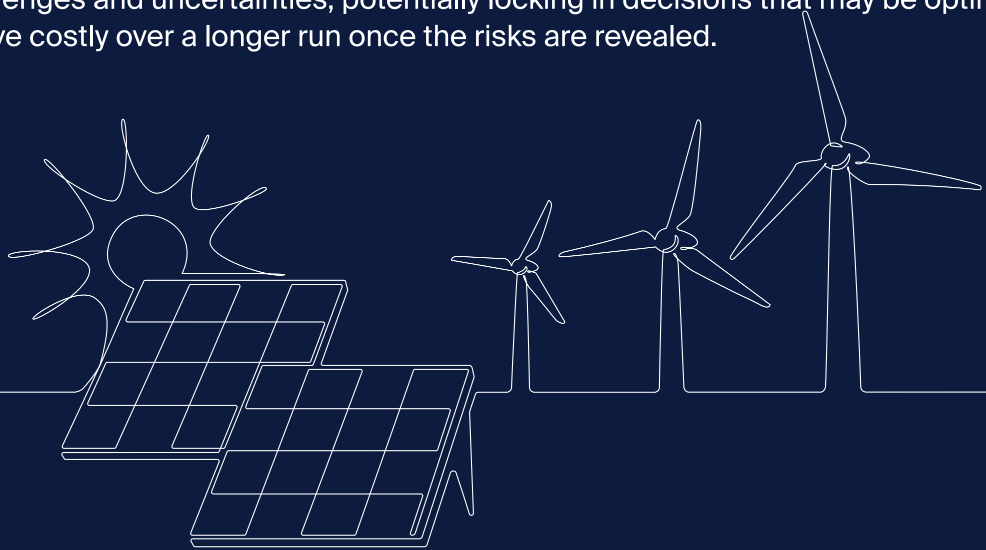


Table 4 GenCost update cost trajectory comparison

Technology	Trend/Cost Update 2023 Inputs (GenCost 2022-23)	Trend/Cost Update 2025 Inputs (GenCost 2024-25)
Large Scale Batteries	Estimates had increased by up to 20-35 per cent compared to the previous year.	Build cost estimates have decreased and are reported as being at pre-pandemic levels in real terms.
Onshore Wind	Estimates had increased by 35 per cent compared to the previous year.	Costs for wind are now generally applying the standard learning rate approach rather than being subject to the full supply chain constraints observed previously.
Offshore Wind (Fixed)	Costs were subject to significant inflationary pressure in the near term.	Has seen a more significant drop in costs compared to the projection in the previous year's GenCost.
Gas Generation (CCGT/OCGT)	Cost trajectories forecast decreases after the initial inflationary period.	GenCost 2024-25 incorporates hydrogen fuel readiness, leading to an increase in costs relative to previous estimates.
Hydrogen (Electrolysers)	GenCost 2022-23 projections were used.	The 2025 projections for alkaline electrolysers show an increase in cost in the long term compared to the 2023-24 projections for PEM electrolysers. This increase is due to updated analysis of balance of plant costs and slower cost reductions over time.
Pumped Hydro Energy Storage (PHES)	Costs were noted as originating from the Entura 2018 report and Hydro Tasmania data.	Build costs across all depths are expected to increase in real terms post-2030 due to escalating installation costs and lack of learning rate reductions. Additionally, 10-hour duration PHES is considered more expensive than 24-hour PHES, aligning closer to 48-hour estimates

Source: CSIRO Reports, GenCost 2022-23 and GenCost 2024-25

Implications for South Australia

South Australia is uniquely exposed to transmission outcomes. With renewable generation often exceeding local demand, efficient export is essential to prevent curtailment and to capture economic value. At the same time, the state requires firm interconnection to manage reliability during low renewable output. The uncertainty surrounding completion date of the PEC, coupled with some earlier than expected retirements of in-state firm capacity set the context for the FERM to be in place.

ElectraNet earlier this year published the TAPR[12] and proposed four key projects to address accelerating demand and unlock renewable energy zones over the next decade:

- As decided by the ISP 2024[13] , the Northern Transmission Project (NTx) is an actionable project progressing through the Regulatory Investment Test for Transmission (RIT-T) process, planned for completion between 2029 and 2033. It involves new line construction connecting Adelaide, Bundey, and Cultana.
- The Eyre Peninsula Upgrade is planned for 2027–2030, focused on upgrading the Cultana to Yadnarie lines from 132 kV to 275 kV.

- The Southeast Expansion (Stage 1), planned for 2029, involves restringing a vacant 275 kV circuit between Tailem Bend and Tungkillo to increase transfer capacity.
- The Mid North Reinforcement is proposed to rebuild parts of the 275 kV line between Para and Brinkworth as a high-capacity double circuit.

Transmission buildout is critical to unlock supply potential and accommodate increased demand of electricity. This is of particular importance for the Northern South Australia region, where industrialisation is a significant economic driver. At the same time, these projects should only proceed with cost to consumers front of mind.

The optimal development path

The ISP provides a roadmap for delivering a secure, affordable, and sustainable grid. Its Optimal Development Path (ODP) is intended to identify the most efficient sequence of investments. However, with costs rising and schedules slipping, periodically redefining what is "optimal" is required.

AEMO has acknowledged this and the 2025 ENOR states that the 2026 ISP will revisit all projects not already too advanced, considering the changed cost environment. They face a challenge in balancing the need to make transmission projects actionable early enough to ensure timely completion, while also retaining the ability to reassess them in the face of changing a consumer landscape or potential cost overruns. For South Australia, where the Mid-North and Eyre Peninsula REZs are central to future development, this uncertainty complicates decision-making.

In this uncertain planning environment, AEMO's initiatives are considering different pathways to enhance supply adequacy. In system planning, AEMO explicitly considers non-network options, including generation investment, storage technologies, and demand response, as alternatives to transmission augmentation, aiming to 'defer or avoid the capital costs of large network augmentation.'[14] Crucially, the 2026 ISP modelling now incorporates distribution network opportunities to support CER. Alleviating constraints at the distribution level to facilitate CER operation may "delay or reduce the need for utility-scale generation at the transmission level" . Finally, if Demand Side Participation (DSP) and coordinated CER are achieved reliably, they may significantly reduce the required scale of network and utility-scale investments.

KEY TAKEAWAY

- Transmission is vital for renewable integration and reliability, especially in South Australia.
- Project costs have surged 25–100 per cent due to supply chain, labour, and social licence pressures.
- Rising costs make storage and demand-side alternatives increasingly attractive.

Summary of transmission, retirements and industrial load development

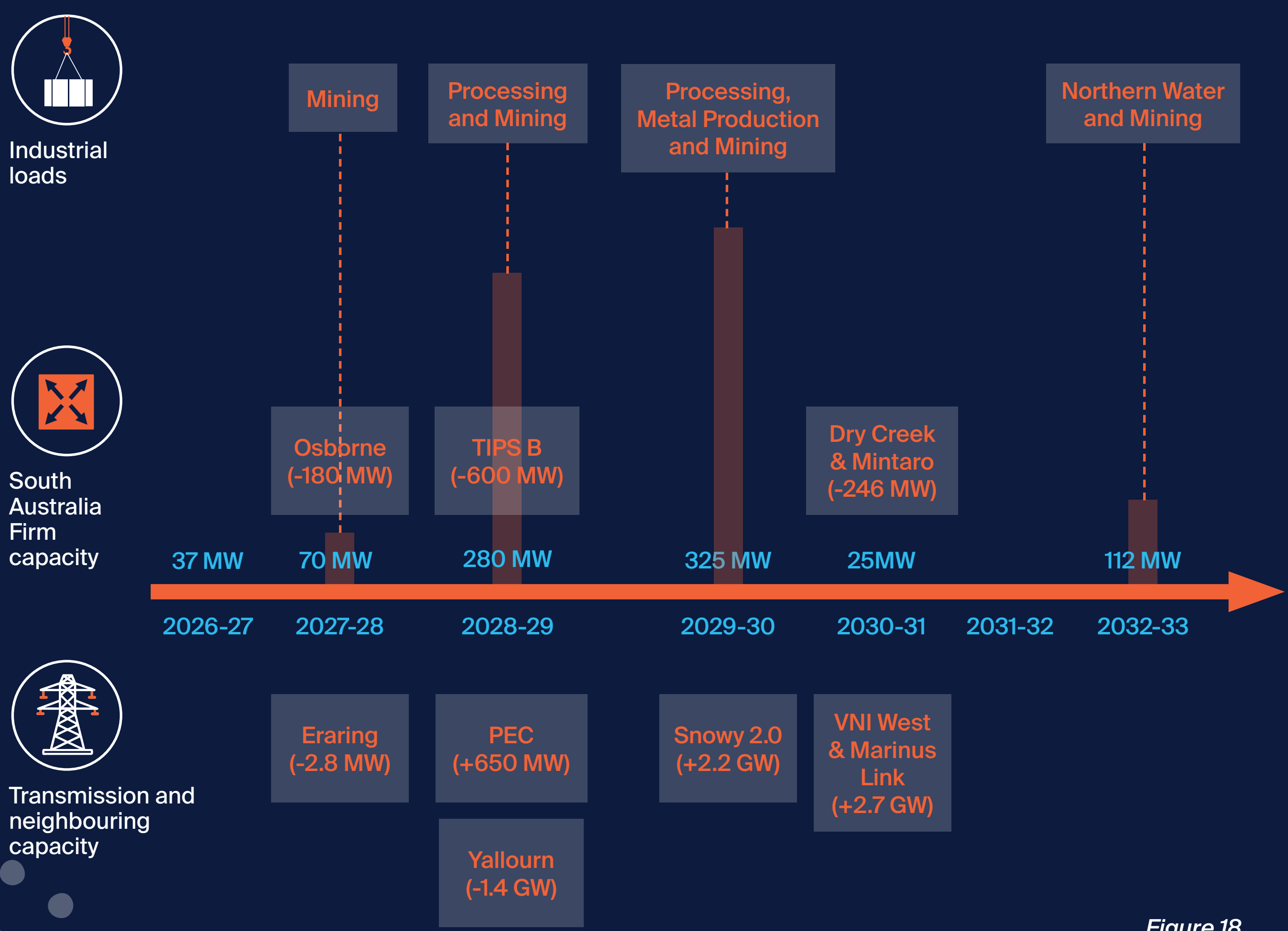


Figure 18

04 SECURING SOUTH AUSTRALIA'S SUPPLY

Against the context provided in the previous chapters, securing South Australia energy supply requires deliberate and coordinated action to complement market outcomes. The Government, in partnership with the AEMO, the AER and industry stakeholders, is actively managing the near-term risks of system shortfall while facilitating the investment pipeline of firming, storage, and transmission assets necessary to underpin long-term reliability. This includes transitional measures, such as the Torrens Island negotiation with AGL, alongside structural reforms to support demand response, frequency control, and new forms of dispatchable capacity.

AEMC Emergency Reserve Rule Change

In mid-2024, ENGIE announced the mothballing of its 63 MW Snuggery and 75 MW Port Lincoln diesel peaking power stations, with plans for full closure by 2028. These facilities had historically provided critical emergency and peak-load capacity to the South Australian electricity system. Their unavailability, combined with delays to the PEC interconnector, raised immediate reliability concerns for the 2024–25 summer period. AEMO projected a potential shortfall of ~200 MW, heightening the risk of load shedding during periods of high demand or low renewable output.

In response to these developments, the Government took several decisive steps:

- The Energy Minister requested the Australian Energy Market Commission (AEMC) to grant the Government authority to direct ENGIE to utilise the mothballed power stations as emergency reserves for the 2024–25 summer period. This request emphasised the critical need to maintain system reliability during peak demand events.

- The Government engaged with the AEMC to expedite the rule change process, ensuring that the necessary regulatory frameworks were in place to facilitate the temporary use of the mothballed power stations.

Following these actions by the Government, the AEMC approved a temporary rule change under a jurisdictional derogation for South Australia. This rule change allowed AEMO to consider the mothballed Snuggery and Port Lincoln stations as emergency reserves, enabling their use out-of-market for the 2024–25 summer. The derogation was designed to be time-limited, remaining in effect until 31 March 2025, and provided a mechanism to secure immediate reliability while broader market solutions are implemented.

The temporary rule change underscored the importance of maintaining emergency backup capacity, supporting the orderly transition away from fossil-fuel generators, and ensuring that short-term operational gaps do not compromise the state's electricity security. Lessons from this experience will inform future policy design, including the procurement of long-duration firm capacity and the integration of emerging dispatchable technologies.

The Government's response also underscores the importance of maintaining flexible and responsive mechanisms to ensure grid stability during the transition to a renewable energy future. By proactively addressing potential reliability risks, the government aims to safeguard against power shortages and support the integration of renewable energy sources into the state's electricity grid[15].

KEY TAKEAWAY

- The Government secured an AEMC emergency rule change allowing these plants to operate as out-of-market reserves until March 2025.
- The measure ensured short-term reliability amid PEC delays and high renewable variability.
- This highlights the need for flexible mechanisms and lessons for future firming capacity procurement during the energy transition.

Firm Energy Reliability Mechanism

The FERM has been established by the Government to secure long-duration dispatchable capacity and maintain system reliability. It is a key component of the state's broader energy security and transition framework, designed to ensure reliable supply while supporting South Australia's pathway to net-zero emissions.

FERM provides a structured mechanism to identify, procure, and sustain sufficient long-duration firm capacity (generation or storage resources) capable of delivering electricity continuously over extended periods, particularly during times of low renewable output or peak demand. This capability is essential to managing operational risks, maintaining reliability standards, and ensuring the orderly exit of ageing fossil-fuel generation as new technologies enter the market.

Objectives

The primary objectives of FERM are to:

- **Enhance system reliability:** By securing long-duration dispatchable resources, the mechanism mitigates the operational risks arising from intermittent renewable generation.
- **Support the energy transition:** FERM facilitates the integration of new technologies and the orderly retirement of aging fossil-fuel generators, providing a structured approach to long term system transformation.
- **Ensure affordability:** Competitive procurement and efficient contracting aim to deliver firm capacity at the lowest sustainable cost to consumers.

Operation of FERM

FERM operates through an integrated process of planning, market engagement, and contracting:

- **Firm Energy Target (FET):** The Government sets a rolling target for long-duration firm capacity required over a five-year horizon to meet reliability objectives. The FET provides a benchmark for assessing existing and prospective resources against expected system needs.
- **Notice of Intention (NOI):** Existing generation and storage providers submit information regarding their operational plans, including expected availability, retirement timelines, and technical capabilities. This process informs the Government's assessment of current and future long duration firm capacity supply.
- **Competitive Tendering and Contracting:** FERM enables new and existing assets to compete for contracts to provide firm capacity. Successful providers receive contracts with mechanisms that balance revenue certainty and market efficiency, incentivising the timely delivery of reliable capacity while maintaining competitive pressure.

In October 2025, the Government has completed the regulatory framework underpinning FERM, with the *National Electricity (South Australia) (Firm Energy Reliability and Orderly Exit Management) Regulations 2025* which were formally gazetted on the 18 September 2025. This milestone marks the transition of FERM from policy design to operational readiness. AusEnergy Services Limited (ASL) has been appointed as the Scheme Administrator with a role in tender management, scheme governance and financial vehicle appointment[16].

Summary of 2025 FET determination

The FET defines the level of long-duration firm capacity required to maintain system reliability over a forward five-year horizon. It provides the quantitative foundation for FERM and is derived from detailed technical analysis of system demand, supply, and risk.

Determining the FET involved detailed modelling and analysis to assess South Australia's firm capacity requirements over a forward five-year horizon. The modelling drew on AEMO's ISP 2024 and applied the Government's assumptions on demand growth, generation retirements, project commissioning schedules, and interconnection capability. Using these inputs, the framework tested system performance across a base case and two credible shock events, namely the loss of transmission to New South Wales via PEC and Pelican Point generator being out of service. The aim was to understand the incidence, origin and nature of the system reliability risks.

Each scenario was assessed in terms of unserved energy (USE), being the proportion of demand that cannot be supplied by available generation or imports. The FET was then defined as the quantity of long-duration firm capacity required to reduce projected USE. This ensured that the target reflected both expected operating conditions and credible stress events.

Modelling showed that reliability pressures were expected to increase toward FY2028–29, as ageing gas capacity retired, and the electrification of industry and transport accelerated. USE was likely to happen only on days of extreme weather, for a short period in the early evening when demand increases coincided with solar capacity ramping down. While new storage projects and interconnection will help balance supply and demand, modelling indicated that hypothetically, an additional 400 MW of long-duration firm capacity would materially improve South Australia's reliability outcomes, particularly under concurrent low-renewable and high-demand conditions.

In summary, the FERM establishes the overarching policy and procurement framework, while the FET provides the analytical foundation for determining the level of firm capacity needed to maintain reliability in South Australia's evolving, high-renewables power system.

Further detail on the assumptions, scenario design, and sensitivity analysis that underpinned the FET are set out in *Appendix B - Firm Energy Target Determination.*

KEY TAKEAWAY

- The FERM is a mechanism to secure long-duration dispatchable capacity and maintain reliability in a high-renewables grid.
- It establishes the FET which is a rolling target based on modelling of demand, retirements, and credible stress events, ensuring sufficient firm capacity.
- Competitive tendering and contracting provide cost-efficient procurement, with ASL appointed as scheme administrator.
- Modelling indicates an additional 400 MW of long-duration firm capacity is needed by FY2028–29 to manage reliability risks as gas plants retire and electrification accelerates.

Torrens Island Power Station Unit B Negotiations

In November 2022, AGL announced the retirement of all four remaining units at Torrens Island Power Station B (TIPS B) by the 30 June 2026. This combined with delays to PEC and uncertainty around the timing of full interconnection capacity created a potential reliability gap for South Australia over the FY2026–27 summer period.

Modelling undertaken by the Planning and Forecasting team indicated that allowing TIPS B to retire as scheduled would increase the risk of use under extreme demand and low renewable output conditions. Updated analysis incorporating recent changes in the generation and demand outlook confirmed that retaining some TIPS B capacity would significantly improve those reliability outcomes. The results showed that maintaining partial operation of TIPS B would reduce the likelihood and severity of USE events and support system stability until new firming and interconnection capacity became fully available.

In October 2025 the South Australian Government reached an agreement with AGL to extend the operational life of the TIPS B by two years, from its previously scheduled closure on 30 June 2026 to 30 June 2028. Under the negotiated arrangement, the three operating Torrens Island B units, which provide ~600 MW of dispatchable gas-fired generation, will continue to operate through the extension period. Financial contributions from the State will ensure the facility can be maintained and operated during this transition phase, though the specific commercial terms remain confidential between the Government and AGL.

The extension plays a critical bridging role, reducing the forecast reliability gap identified by AEMO in the 2025 ESOO. It provides the state with additional headroom to accommodate minimum system load events and maintain security during periods of low VRE output.

KEY TAKEAWAY

- The two-year extension of Torrens Island Power Station B to 30 June 2028 provides critical reliability support while transmission and firming projects are completed.
- Modelling confirmed that partial operation reduces unserved energy risks and supports system stability.
- The agreement with AGL acts as a short-term, transitional bridge balancing near term energy security with South Australia's long-term decarbonisation goals.

Hydrogen Turbine Sale process

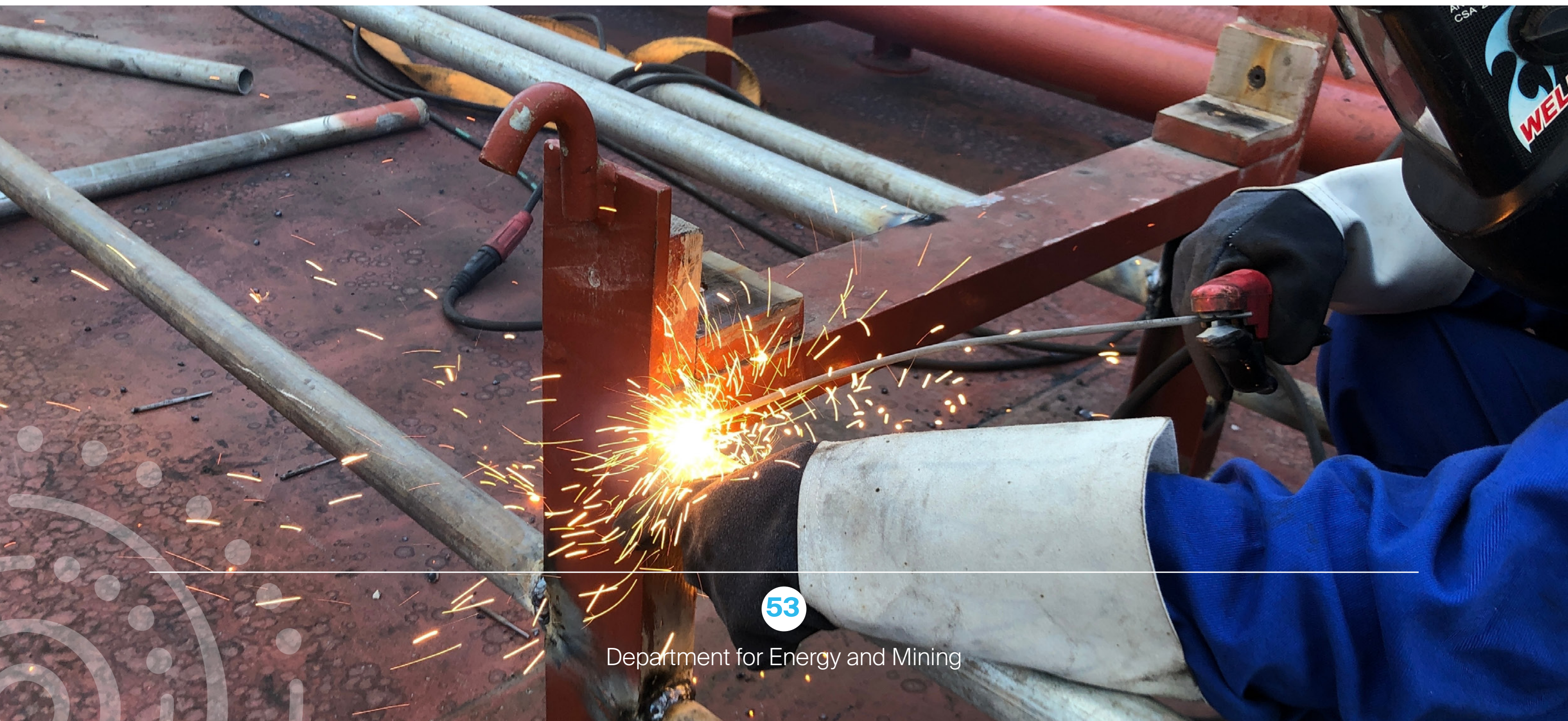
In 2025, as part of the broader Whyalla Transformation Plan, the Government undertook a comprehensive review of the HJP and its associated infrastructure program. Following this review, it was determined that the proposed Whyalla hydrogen power plant would not proceed in its originally planned form. While the project represented a world-first opportunity to integrate large-scale hydrogen electrolysis, storage, and generation within a single facility, the Government recognised the need to recalibrate its investment priorities to align with emerging industrial requirements, fiscal responsibility, and regional economic resilience.

This decision reflected updated project risk assessments, evolving market conditions, and the imperative to support the transformation of critical industrial assets in Whyalla, particularly the steelworks and surrounding manufacturing ecosystem. Within this context, the hydrogen program remains an important strategic pathway, but its delivery is now being integrated into the broader decarbonisation and industrial renewal agenda under the Whyalla Transformation Plan.

As part of the initial procurement phase of the HJP, the Government had secured four GE Vernova LM6000VELOX aeroderivative turbines, which are fully capable of operating on 100 per cent renewable hydrogen. To ensure that this investment delivered value for South Australians, the Government initiated a turbine sale process. Under this process, the turbines will be sold at or above their original purchase price, with a binding condition that they must be deployed within South Australia. This condition is designed to preserve their potential contribution to the state's dispatchable capacity and while also recovering public funds invested in their procurement.

KEY TAKEAWAY

The sale of the HJP turbines is expected to provide new dispatchable generation capacity in the South Australian energy system.



Supply security in the context of NEM transition

The NEM is undergoing a fundamental transition that is reshaping how electricity is produced, traded, and delivered across a major part of Australia. Coal and gas power stations that have supplied the bulk of generation for decades are closing faster than expected, while large amounts of wind, solar, and battery capacity are being added to the grid. At the same time, electricity demand patterns are changing as households and industry electrify their energy consumption. These changes are placing new pressures on a system originally designed for predictable, centralised generation. In response, governments and energy market bodies, including the Australian Government, the AEMC and the AEMO are progressing a series of reforms to modernise how the NEM functions.

AEMO's NEM Reform Program[17] is overhauling the NEM to become a modern energy system that fits the consumer needs, towards net-zero. The Nelson Review[18] is re-examining price signals for introduced capacity and the Commonwealth's CIS is supporting new clean generation and storage projects. Together, these initiatives aim to build a power system that can stay reliable and affordable while supporting Australia's transition to net zero.

With some of the highest levels of renewable generation in the country and limited interconnection to neighbouring states, South Australia experiences sharper swings between surplus and shortage than most of the NEM. To manage this, the Government has implemented targeted mechanisms such as the AEMC emergency reserve rule change, which allows mothballed diesel peaking plants to be reactivated in emergencies, the FERM which secures contracts for long-duration firming capacity and the TIPS B extension, which keeps existing gas generation available until new storage and interconnector projects are complete.

These measures are designed to maintain reliability during a period of rapid change, complementing national reforms. By ensuring there is enough dispatchable supply while new market frameworks and investments are being developed and delivered, South Australia helps to safeguard consumers and provides a practical model for managing the energy transition across the wider NEM.

KEY TAKEAWAY

- National initiatives like the Nelson Review and CIS aim to maintain reliability and affordability during the transition from coal and gas to renewables and storage.
- Mechanisms such as FERM, the emergency reserve activation, and TIPS B extension provide stability.

05 2026 ELECTRICITY DEVELOPMENT PLAN

The 2026 EDP will build upon the work undertaken in the 2024 and 2025 plans to support the delivery of the forward looking pathway for the development of South Australia's power system to meet the state's demand requirements and emission reduction commitments.

Focus areas

The key focus areas for the Forecasting and Planning function (to culminate in the 2026 EDP) are summarised in Table 5. Please note that given the fast pace of the transition and movements within South Australia (and across the NEM), this list of focus areas may be revised or added to as appropriate, particularly to incorporate stakeholder feedback.

Table 5 2026 EDP Focus Areas

Focus Areas	Description
Impact of new and emerging industries	Assessing the potential for new industry developments to provide greater demand side flexibility whilst also maintaining a balanced grid.
Distribution level infrastructure considerations	Further improvements will be made to Forecasting and Planning's modelling capability through integration of distribution level infrastructure resources into the current forecasting framework.
2026 long duration firm capacity assessment and FET	A similar methodology will be undertaken throughout 2026 to determine South Australia's required level of firm dispatchable capacity to ensure future reliability, forming the basis of the FET.
Demand forecast update	Building upon the work undertaken in 2025, the Forecasting and Planning function will update its forecast of South Australia's demand outlook to ensure that the state's power system development aligns with anticipated load growth requirements.

Key activities

A summary of some of the modelling tasks and activities that will be undertaken is provided:

Gathering model inputs and assumptions

Model inputs and assumptions will be determined following a consultation process, in line with DEM's stakeholder engagement framework and policy. The consultation process will aim to determine the scenario-based values of the critical inputs, including (but not limited to): fuel costs; asset build costs; demand growth and shapes; as well as outages and delays to construction completion. Consultation participants may include (but not necessarily limited) SAPN, ElectraNet, the South Australian Chamber of Mines and Energy (SACOME), the South Australian Council of Social Service (SACOSS), South Australia Business Chamber, AEMO and other market participants in the NEM.

Least-cost modelling

Modelling work will be conducted to periodically assess the FET and other cost-benefit analyses, against the new inputs and assumptions. The work is to be done in PLEXOS.

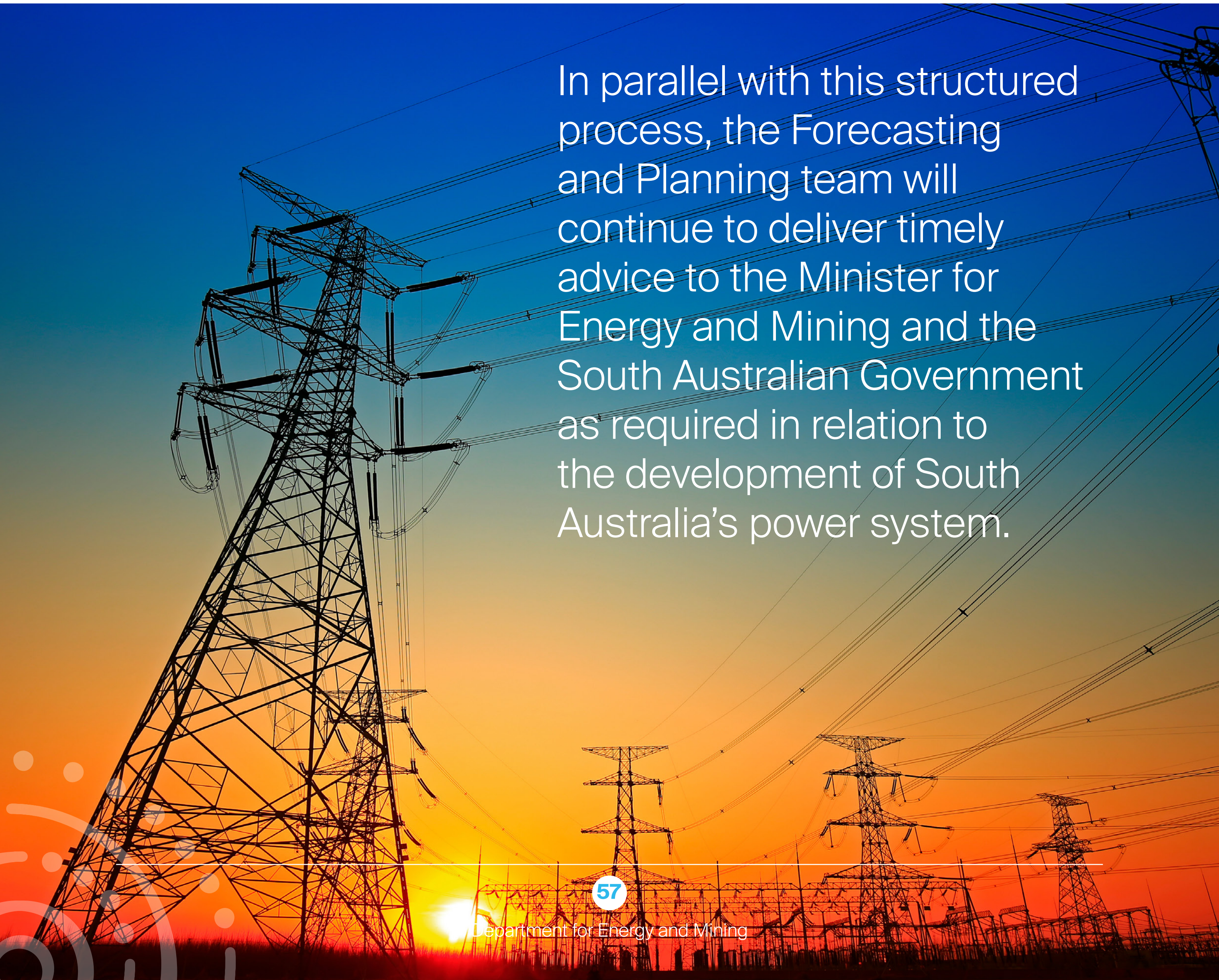
Engineering assessment

Modelling will be undertaken using Power System Simulator for Engineering (PSS®E) platform for system stability analysis. The expansion pathway for generation, storage, and transmission identified in PLEXOS analysis can be input back into the capacity outlook model, and then further refined using the PSS®E platform.

High level schedule of activities

The high-level schedule in Table 6 summarises the flow of activities anticipated throughout 2026 to lead towards the 2026 EDP.

Table 6	**Indicative Schedule of Activities for 2026**
December 2025 to January 2026	▪ Define workplan for 2026 ▪ Receive feedback on 2025 EDP
February 2026 to April 2026	▪ Align on methodology ▪ Gather inputs and assumptions
May 2026 to August 2026	▪ Undertake modelling ▪ Review results
September 2026 to December 2026	▪ Reporting for 2026 ▪ Begin Planning for 2027



In parallel with this structured process, the Forecasting and Planning team will continue to deliver timely advice to the Minister for Energy and Mining and the South Australian Government as required in relation to the development of South Australia's power system.

A

APPENDIX A – FORECASTING AND PLANNING'S DEMAND FORECAST

The Government, via the Forecasting and Planning function, maintains its own electricity demand forecasting framework to complement AEMO's, Electranet's and SAPN's existing forecast publications. The Government's forecasts focus on supporting South Australian focused planning priorities and policy outcomes.

The key motivations for this separate forecast are outlined below.

- **Industrialisation Ambition:** The Government's forecasts are designed to support the state's industrial growth objectives. By anticipating future industrial electricity needs, the Government ensures that energy supply aligns with South Australia's broader economic development agenda and regional investment priorities.
- **Proactive Planning:** Developing independent demand forecasts allows the Government to anticipate future energy requirements earlier, reducing the risk that electricity supply becomes a barrier to economic growth. This forward-looking approach supports coordinated infrastructure development and informed policy decisions.
- **Model Inputs and Risk Management:** The Government's modelling provides critical data to identify, assess, and manage risks to energy reliability, security, and affordability. By maintaining an in-house forecasting capability, the Government can evaluate alternative scenarios and stress-test assumptions to strengthen system resilience and investment certainty.
- **Stakeholder Engagement:** A dedicated forecasting process enables the Government to work closely with key stakeholders, including industry, NSPs, and government agencies. This collaboration improves the quality of modelling inputs and facilitates joint exploration of opportunities, challenges, and potential policy responses.

Together, these factors ensure that the Government's forecasts provide a strong evidence base for energy planning and policy design tailored to the South Australia's unique industrial and economic context.

Data collection and methodology

Demand forecast timeframes

The demand forecast covers a 30-year period, with FY2035-36 as a key inflection point.

2026–2036

The next decade is a critical transition phase for South Australia's power system as renewable penetration increases. Market uncertainties, including transmission project timing and generation retirements, necessitate close policy oversight and higher forecast precision.

Beyond 2036

The remaining period adopts a less granular approach, extending the assumptions from the first decade to reflect long-term drivers of demand and peak load.

Data sources and processes

The data collection process builds on demand traces provided by AEMO but diverges from AEMO's forecasts where Government has access to more detailed, bottom-up information.
Table 7 summarises the data sources used for the demand forecast.

Table 7 Summary of data sources for the demand forecast

Component	Until 2036	Post 2036 – Base case
Underlying Demand	AEMO ISP 2024 Step Change	AEMO ISP 2024 Step Change
Rooftop PV	Data obtained from SAPN	Growth rate of pre-2035 to linearly continue
EVs	AEMO ISP 2024 Step Change	AEMO ISP 2024 Step Change
New Industrial Loads	ElectraNet's connection inquiries and Government inputs	Assuming industrial load will grow on average 145 MW a year.
CER	AEMO ISP 2024 Step Change	AEMO ISP 2024 Step Change

Underlying demand

Underlying demand represents the residential, commercial and existing industrial base in South Australia. This component is linked to weather patterns using machine learning models. These models capture the historical relationship between temperature, humidity, and demand at different times of day and across seasons, allowing the simulation of how demand would behave under various weather years. The primary assumption of the underlying demand growth comes from AEMO's ISP 2024 – Step Change Scenario.

New industrial loads

There is a need to capture new industrial loads separately as they represent the fastest growing component of South Australia's demand. Industrial loads were forecast using transmission inquiries from ElectraNet and these inquiries represent prospective loads that are coming into the network in the near term. The Government reassessed the likelihood of these load connections by triangulation with other internal databases, such as the expected mining royalty database, or through consultation with internal subject matter experts.

This approach differs from AEMO's method where industrial loads are only included once they reach a Final Investment Decision stage. While AEMO's approach is prudent in avoiding speculative load forecasts and is appropriate for the ISP's purpose, it may not fully reflect the evolving trajectory of industrial activity as network connections progress (for example, a connection that eventually comes into grid in 2030 may only be captured in the 2028 forecast or later). However, ensuring sufficient electricity supply to meet these emerging loads often requires much longer lead times. For the load forecast to be of use in the modelling works within the Government, such as the FET, the industrial load forecast needs to more proactively capture the emergence of these activities.

Across the long-term horizon, it is assumed that industrial load will grow at 145 MW per year, which is the average industrial load addition in the near term.

Rooftop PV

Rooftop PV capacity was collected from SAPN for the first ten years. Beyond the first ten years, PV capacity is expected to continue the growth of 11 per cent as observed in the first period.

EV

The EV profiles were obtained from AEMO's ISP 2024, Step Change Scenario. These profiles are weighed by projections of number of EVs, and composition by charging behaviour (e.g., more coordinated vs less coordinated).

CER

CER profiles were obtained from AEMO's ISP 2024, Step Change scenario.

Further sensitivities

Beyond 2036, uncertainty increases around both industrial activity and the role of CER. To explore this, two sensitivities were developed alongside the Base Industrial scenario.

- The **Slow Industrial Demand** sensitivity reflects a future where the strong industrial growth seen to 2036 is not sustained, with no major new industrial loads added thereafter. Although an abrupt halt is unlikely, this scenario provides a lower bound on long-term demand growth and tests how the system performs if the electrification of industry slows.
- The **CER High Growth** sensitivity assumes higher investment and coordination of rooftop PV, batteries and automated load control, aligned with the Green Energy Exports case in the 2024 ISP. This results in a more moderated operational peak as CER contributes more actively to meeting demand.

These sensitivities apply only after 2036 and are considered less likely than the base case. They are used to test the robustness of planning against a range of long-term demand outcomes.

Demand forecast outcomes

Short-term outlook (to 2036)

Total electricity consumption in South Australia increases from around 14 TWh in FY2025-26 to about 28 TWh in FY2035-36 (Figure 19), effectively doubling over the decade. This growth is driven primarily by new industrial activities in the state, many of which will become heavily electrified.

The underlying component, still the largest single category, will see its share of total consumption declines as new electrified loads scale up. The most significant change occurs in new industrial consumption, which

South Australian demand forecast: Electricity consumption by category

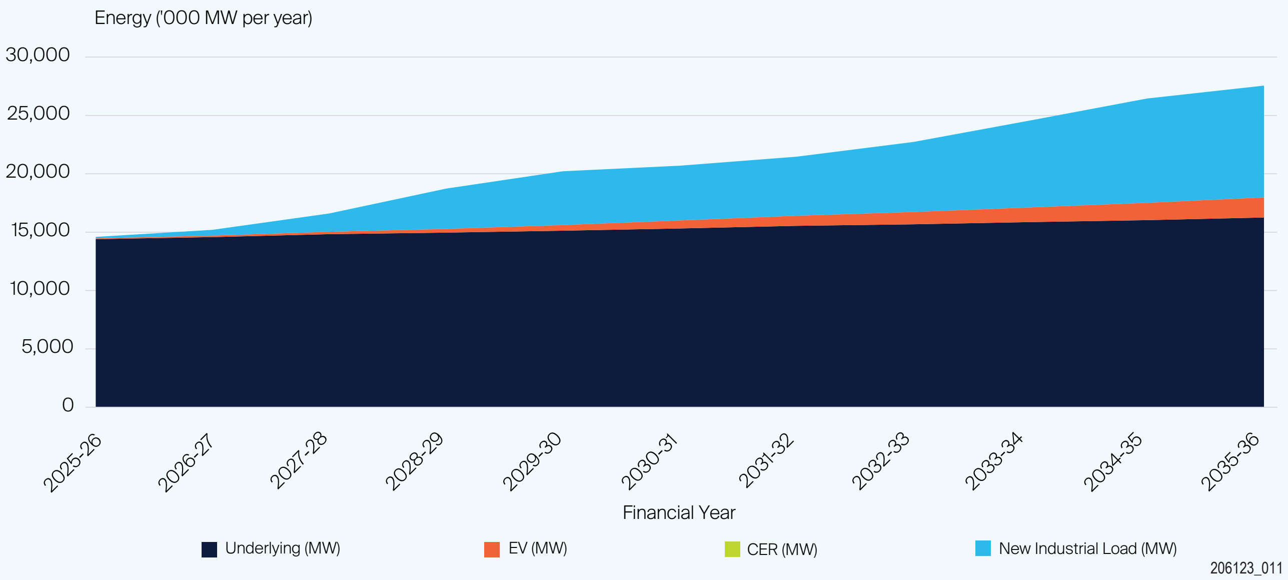


Figure 19

is expected to be ~10 TWh by FY2035-36, over a third of the total consumption. This reflects the increasing use of electricity in large-scale industrial processes that will be newly connected to the grid. EV charging also becomes a visible part of the load profile, increasing to ~2 TWh by FY2035-36.

Rooftop PV generation is expected to grow from ~3 TWh to more than 7 TWh a year, substantially reducing daytime load on the grid (Figure 20). However, the scale of new industrial electrification outweighs these reductions, so total consumption still rises sharply. Regarding operational demand, even with rooftop PV supplying more energy behind the meter, the electricity grid must still deliver much more energy and capacity by FY2035-36. Operational consumption is forecasted to increase from ~11 TWh today to ~21 TWh by FY2035-36, effectively doubling. Operational power requirements rise accordingly with average daily operational demand estimated to grow from ~1.3 GW to ~2.4 GW, while the yearly peak demand increases from ~3 GW to ~4.8 GW across the decade.

The combination of higher industrial demand and continued rooftop PV growth is projected to result in a progressively steeper 'duck curve' over the decade. The average demand profile shifts from a relatively modest midday dip in FY2025-26 to a much deeper trough by FY2035-36, with electrified industry lifting daytime and overnight consumption while evening demand continues to rise once rooftop PV output declines (Figure 21). This may create a more challenging late-afternoon peak as the system transitions from high solar availability to high consumption periods, reinforcing the growing importance of having the fit for purpose capacity.

South Australian demand forecast: Operational demand and rooftop PV generation

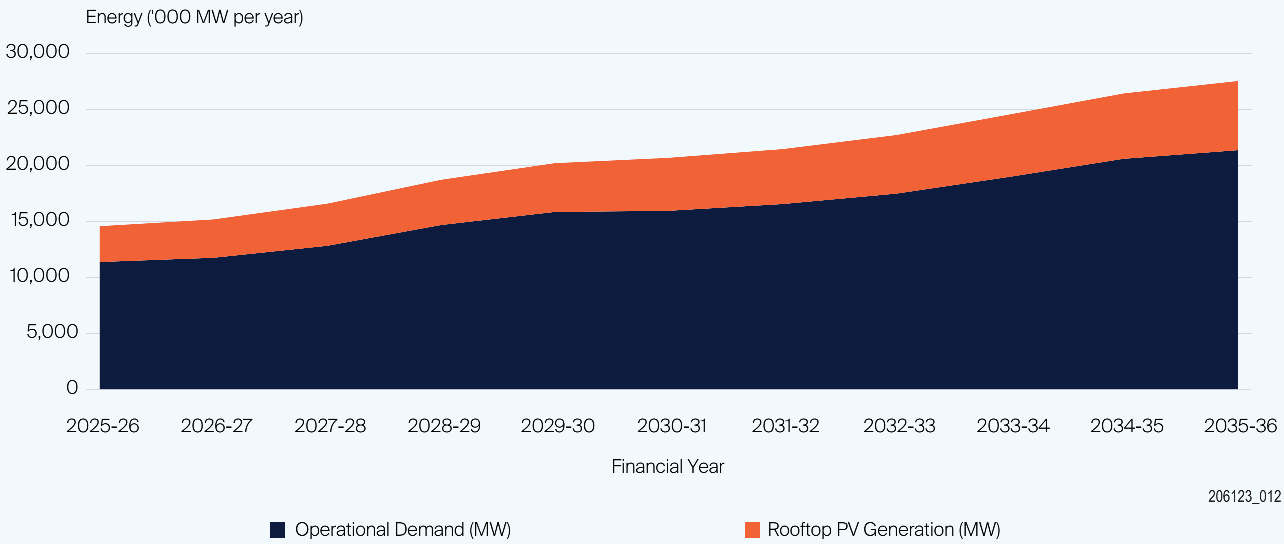


Figure 20

South Australian demand forecast: Average daily demand profile

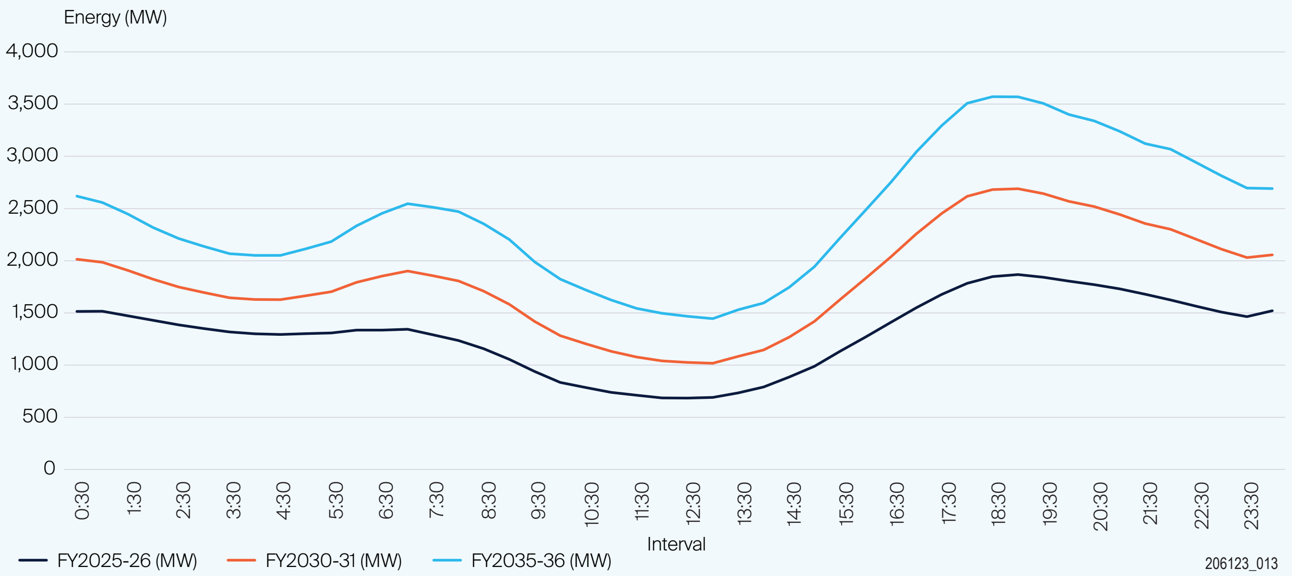


Figure 21

Longer-term perspective (beyond 2036)

Outlook for beyond FY2035-36 sees peak demand diverging meaningfully depending on the pace of industrial growth and the effectiveness of coordinated CER (Figure 22). In the Base scenario, peak operational demand continues to climb steadily as further industrial facilities electrify and expand operations, reaching ~8.8 GW by FY2053-54. This represents a continuation of the strong growth trend established before 2036. Under the Slow Industrial Growth sensitivity, where fewer major industrial loads materialise after the early 2030s, the rise in peak demand is more modest, reaching ~6 GW by FY2053-54. Although lower in scale, the system retains the evening peak and still requires substantial firming capability. By contrast, the CER High Growth sensitivity demonstrates the moderating influence of widespread and coordinated rooftop PV, batteries, and controllable demand. Peak demand in this case remains considerably below the Base trajectory through the 2040s and early 2050s, landing at ~8.3 GW by FY2053-54. While still growing, the curve rises at a slower pace due to CER dampening the height of the evening peak.

Average daily demand profiles increasingly diverge after FY2035-36. In 2041, the Base and CER High Growth scenarios remain similar in shape, while Slow Industrial Growth tracks lower due to reduced electrified industry. By FY2045-46 and FY2050-51, industrial demand lifts overnight in the Base Case, resulting in a higher and steeper evening peak. The CER High Growth scenario still follows the same overall pattern, but with a slightly lower and earlier evening peak as coordinated CER provides some support during the ramp. Slow Industrial remains the smallest system but retains a strong sunset peak, showing that lower demand alone does not remove peak pressure.

Taken together, these results show that the scale of industrial electrification largely determines the size of the future electricity system, while the effectiveness CER coordination shapes the intensity of evening peak demand. Even in the most moderated scenario, operational peaks remain firmly concentrated in the late-afternoon and early evening window, reinforcing that peak supply and ramping capability remain central to South Australia's long-term reliability needs. The divergence between the scenarios is substantial by mid-century, with as much as a 4 GW spread in peak operational load outcomes. That scale of uncertainty underscores the need for planning to remain flexible, forward-looking, and robust across multiple potential pathways.

South Australian demand forecast: Annual peak demand by sensitivities

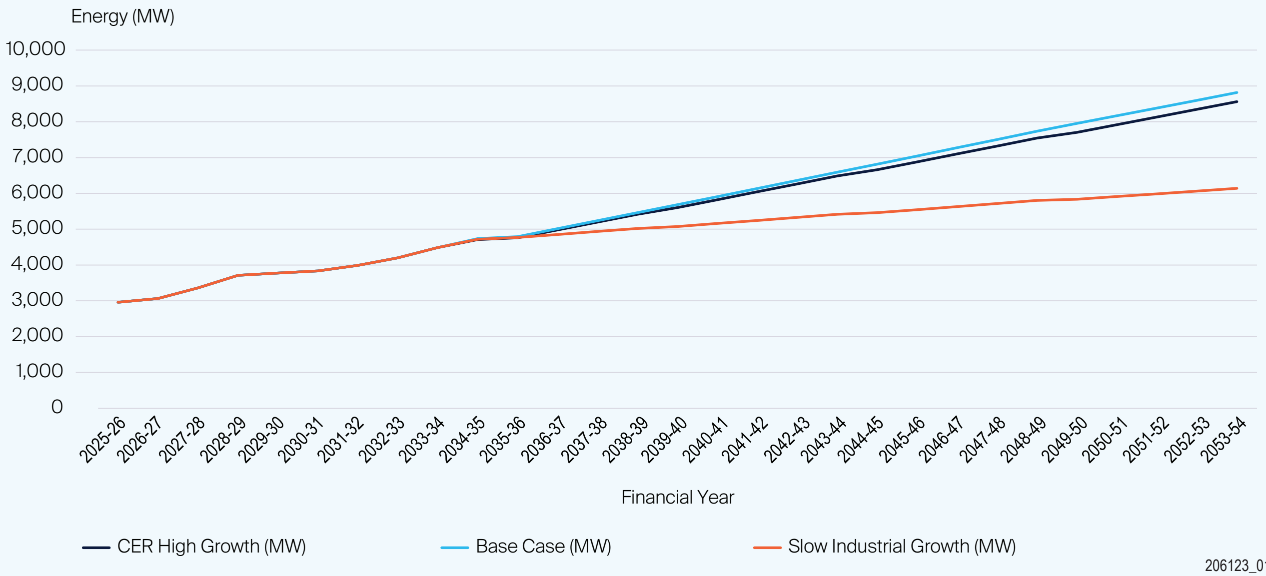


Figure 22

B

APPENDIX B – FIRM ENERGY TARGET DETERMINATION

As South Australia's electricity system continues its rapid transition, the role of firm, dispatchable generation has become increasingly critical. Meeting peak demand, managing MSL events, and maintaining system security requires capacity that is not only dispatchable but also able to sustain output over long durations. This chapter presents an assessment of South Australia's long duration firm capacity requirements, considering both current and projected energy system conditions.

Methodology

Building upon the work undertaken in last year's EDP, the Forecasting and Planning function has continued to utilise a risk-based approach to assessing South Australia's future long duration firm capacity requirements. Risks (shocks to the South Australian power system) were identified through consultation with industry, assessed through stages of market modelling and then managed through the identification of an appropriate amount of long duration firm capacity.

The horizon of the assessment is between FY2027-28 and FY2031-32. The Government identified this period as critical, in which significant industrial activities are planned to come into South Australia, while several gas fired generators are currently expected to retire, to be replaced by interstate firm capacity supplied via future transmission buildout. Given the historical delays in transmission and generation asset constructions, this period poses a risk to the resilience of the electricity network.

A key metric provided by the model is USE. The model forecasts USE as occurring in both in the Base case (business as usual based on a reference year's demand) and in the shock cases where additional unplanned loss of transmission or generation is forecasted to occur. Note that a modelled occurrence of USE on a specific date does not necessarily mean that a supply shortfall will happen. Instead, it is an indicative assessment of the duration and severity of a probable event when multiple

Modelling methodology overview

IDENTIFY

BUILD POWER SYSTEM MODEL(S) AND IDENTIFY SHOCKS

Compile power system models representing the South Australian power system and interconnected states as required. Identify risks to the South Australian power system to be tested through the modelling.

ASSESS

LONG DURATION CAPACITY ASSESSMENT

Identify the least cost generation mix in the NEM for each financial year, given changes to demand, retirements and policy incentives.

SHORT DURATION DISPATCH

Undertake dispatch modelling (using the generation mix for each financial year) to mimic AEMO's NEM dispatch engine and assess periods of system stress.

RESILIENCE MODELLING

Apply shocks (e.g. a transmission outage) to assess the impacts on the short-term dispatch behaviour as well as the additional amount of long duration firm capacity required to mitigate USE. Assess the risk for each shock identified based on any observed USE.

MANAGE

LONG DURATION FIRM CAPACITY REQUIREMENTS

Define the appropriate level of long duration firm capacity for the up-coming five years, based on the results of the base-case and shock modelling results.

Figure 23

strenuous conditions occur simultaneously in the South Australian electricity network so that a mitigating risk management strategy can be considered.

An initial iteration of the FET assessment was conducted last year based on modelling undertaken by Endgame Analytics. This year's assessment adopted many of last year's assumptions, with modifications reflecting the new developments and updates in the electricity market.

The modelling process is based on the publicly available ISP 2024 published by AEMO. Most of the assumptions were carried forward from the model designed by Endgame Analytics except for the revised assumptions on industrial demand and generation retirements.

Demand growth

Forecasted demand growth coming from the industrial sector continues to have a significant impact (Figure 24). For a state with a relatively low and stable population like South Australia, it only takes a small number of projects eventuating to increase the demand by a large amount, hence the need to periodically review the prospects of industrial activities.

Non-industrial demand continued to rely on reference year 2015 as previously done in the last year's assessment. 2015 was a particularly challenging year with several extreme weather days resulting in high demand, coupled with poorer-than-expected wind and solar outputs. These traces are available from AEMO.

Cumulative large industrial load forecast in South Australia

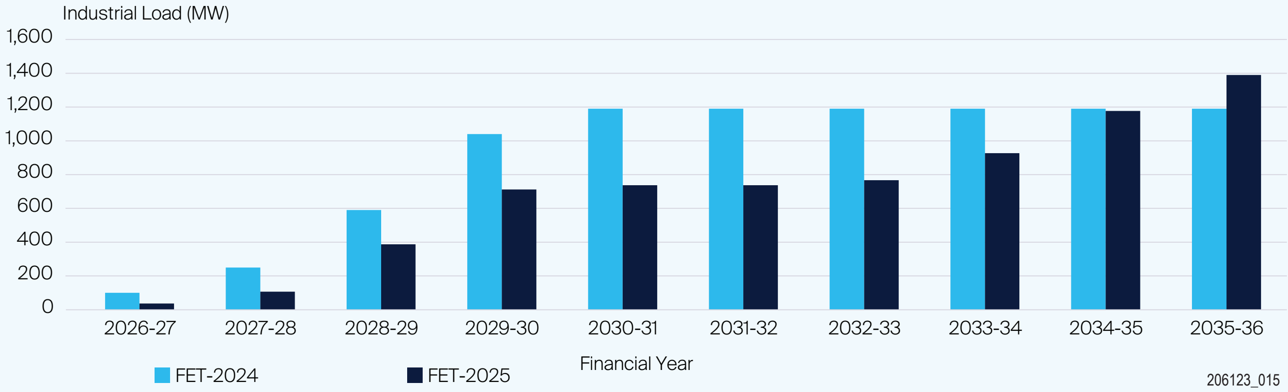


Figure 24

Supply outlook

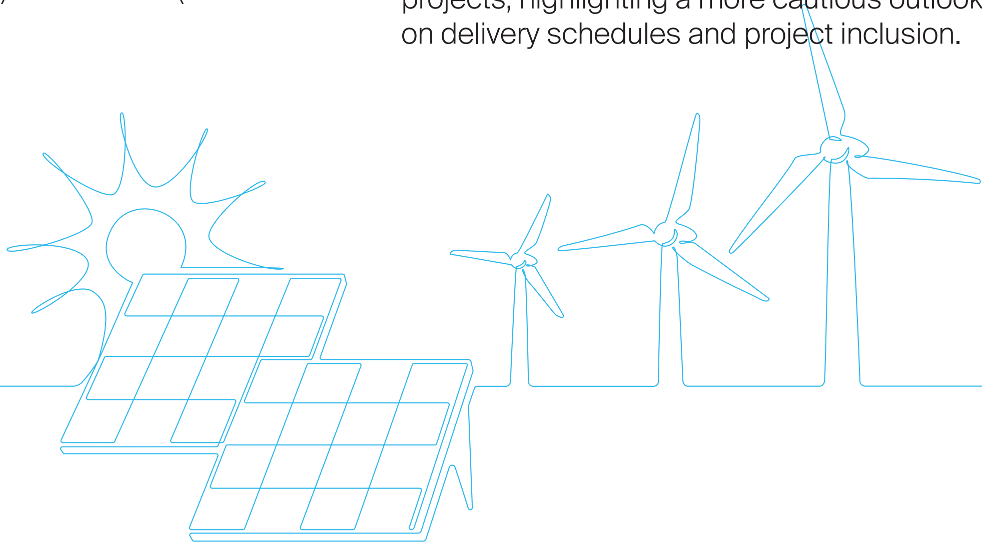
Table 8 outlines the changes included in this year's reassessment of South Australia's supply outlook:

Table 8 Supply outlook changes 2024 EDP to 2025 EDP

Generation/ Transmission Component	2024 Assessment	2025 Assessment
Osborne (180 MW)	Retired June 2026	Retired January 2028
Dry Creek + Mintaro (246 MW)	Retired July 2029	Retired July 2030
HJP turbine (200 MW)	Commenced December 2025	Commenced December 2028
Snowy Hydro (2.2 GW)	Commenced December 2028	Commenced December 2029
PEC	150 MW has been included, remaining 650 MW in July 2027	Remaining 650 MW introduced November 2027
VNI West	Commenced December 2029	Commenced December 2030
Mid North Augmentation	Commenced July 2029	Excluded

Compared with the 2024 FET assessment, South Australia saw some relief from the delayed retirements of Osborne (180 MW), Dry Creek, and Mintaro (246 MW combined). Conversely, the deferred introduction of the Hydrogen Jobs Plan turbine (200 MW) created some pressure on supply in the early FY2027-28. Snowy Hydro 2.0 was also pushed out to December 2029, a year later than in the previous assessment. Other significant expected asset retirements continue to be Eraring in New South Wales (2.8 GW in FY2027-28) and Yallourn (1.4 GW in FY2028-29).

The current update also reflected changes in timing and scope for key transmission projects. PEC was assumed to be fully energised on November 2027, in accordance with the latest update in the ESOO, while VNI West entered the model in December 2030. In contrast, the Mid North Augmentation, which was previously considered, was excluded entirely to represent a more conservative view of the current transmission building environment. In this environment, these adjustments show that the assumptions have shifted toward slightly later commissioning dates and a reduced set of projects, highlighting a more cautious outlook on delivery schedules and project inclusion.



Other assumptions carried from last year's assessment are shown in Table 9.

Table 9 Assumptions carried over from 2024 EDP

Area	Assumption / Approach	Implications
Interconnector constraints	Modelled only to rated transfer capacities, without stability or other constraint types	May overstate firm capacity available from outside South Australia
VRE build limit	Annual cap on renewable builds (e.g. 3 GW in FY2024–25, incl. max 1 GW wind)	Reflects supply chain, labour, and approval challenges; constrains pace of renewable rollout
Demand response	Not included in modelling	Reliability ensured without load reduction, but may understate practical ability to reduce USE
CER	SAPN forecasts for South Australia; AEMO ISP traces for rest of NEM	Captures distributed generation trends
Carbon budget	No explicit budget applied	Decarbonisation instead driven by coal retirement schedule
Renewable energy policies	State targets included national CIS targets excluded (but largely met)	Ensures alignment with policy while avoiding double-counting with VRE limits
System shocks	Four representative shocks modelled in both summer and winter	Tests resilience but does not cover full range of possible events

Capacity outlook

The modelling produced a forecast outlook of generation capacity in South Australia up until FY2031-32, accounting for 'committed' projects in the near term and the model's optimisation of supply and demand balance based on the least cost trajectory.

Capacity built by technology from the long term model - FET 2024

Capacity built by technology from the long term model - FET 2025

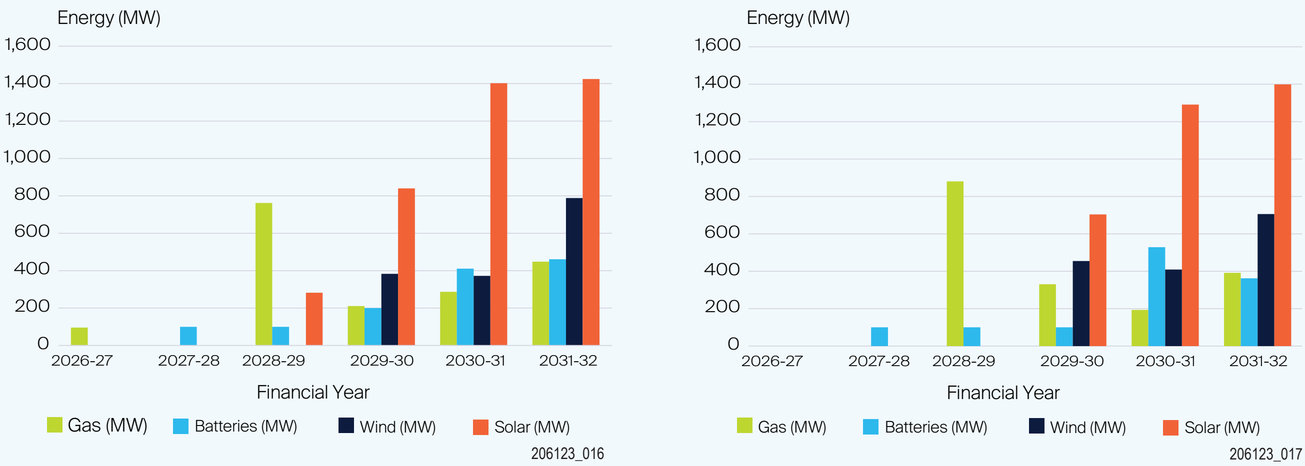


Figure 25

As shown in Figure 25, while the need for firm capacity was not as high as the 2024 assessment, the model still saw the FY2028-29 as a critical point for firm capacity requirements. This continued to be driven by:

- A large level of capacity either retired or deferred across Victoria and New South Wales, even though by then, transmission between New South Wales and South Australia is assumed to reached energisation.
- A significant jump in demand from new industrial loads.

Another point of comparison is the delayed need for renewables compared to the 2024 assessment. The model introduced wind build in FY2029-30, which coincided directly with the retirements of Dry Creek and Mintaro. In contrast, the firm capacity needed from FY2029-30 was similar between the two assessments.

The modelling continued to highlight that South Australia's reliance on electricity imports from Victoria and New South Wales is projected to peak in FY2028–29 as demand grows faster than local firm capacity. The least-cost building trajectory suggests that with the PEC in place, South Australia can draw firm capacity from New South Wales when needed, in addition to what will be supplied via the existing connection with Victoria. This dependence carries risks if interstate transfers are limited by network or system security constraints. Another risk is that over time, large interstate coal generators are also expected to retire, potentially reducing the ability to rely on interconnection. From FY2029–30, while increasing renewable generation within the state reduced import needs, imports will still remain critical during peak and stress periods. This interstate dynamic will be looked at in more detail in the dispatch models.

Resilience assessment

The modelling exercise provided a multi-year view (2028–2032) of USE incidents in South Australia, highlighting the drivers behind supply shortfalls and interactions with Victoria and New South Wales.

The baseline case models a future scenario where no new firm capacity beyond the current existing amount was introduced. New renewable capacity was also only introduced according to the least-cost trajectory from the long-term model. This was done to understand the duration and severity of supply shortfall incidents if new firm capacity were not introduced into South Australia.

From the results of the baseline case, the main 'at risk' period for each year, where there was a high frequency of USE events occurring, is summer (November to March). In particular, high demand lingering around the peak into the evening posed a significant risk to the system.

There are several common themes that emerged from the analysis of the baseline case where USE events are projected to occur:

- These events were typically triggered by the rapid ramp down of available solar generation and low availability of other variable resources (e.g. low wind).
- The structural limitations of interconnector flows (PEC and Heywood) inhibited their ability to assist during USE events.
- With only existing firm capacity included in the baseline model, some of which is expected to be retired by 2032, maximum availability of this capacity was not sufficient to meet the supply requirements during these extreme condition events.

- Over time, the frequency and magnitude of USE events grew, reflecting the system's increasing vulnerability as renewable penetration deepened and in-state firm capacity became more limited.
- During early event occurrences, the shortfalls of supply only lasted up to 3.5 hours (from 16:30 to 18:00-19:00). From FY2030-31, as forecasted load growth coincided with the expected capacity withdrawal of Dry Creek and Mintaro, USE event duration increased into the late evening (from 16:30 to 23:00).

Observations of these USE incidents highlighted a hypothetical scenario where South Australia demand, being unable to be met solely by the state' own supply mix primarily made up of renewables, looked to other regions in the NEM for support. However, in this scenario, interstate support was also limited as both Victoria and New South Wales were also experiencing tight conditions with limited transmission capacity. These occurrences of these events become larger in size toward the end of the modelled horizon.

Solar ramp down and evening peaks

The most consistent driver of USE throughout the period is the steep decline of solar generation (including rooftop PV) in late afternoon and early evening. During these USE events, solar generation was strong during the day but by mid-afternoon, generation decreased rapidly while demand remained high.

On most summer days where USE was observed, solar power provided at least 70 per cent of the state's demand. However, output started to drop from around 14:30 to almost zero by 18:00. On a USE Day in December 2029, for example, this represented a 92 per cent loss of solar output within four hours. The system, already running gas units at maximum capacity and receiving only modest wind output, was left with no further capacity to meet the gap.

Wind aligns poorly with demand

Wind output consistently underperformed during USE events. Wind capacity factor was at a maximum of 13 per cent between 18:00 and 19:00 during some events days with it being as 5 per cent in others. These figures confirm the challenge of wind non-arrival conditions, where low wind coincided with high demand and collapsing solar output.

Interconnectors: Vital but Constrained

PEC became an essential source of connection to New South Wales firm capacity once it was in place. Transmission flow into South Australia was consistently at or near the full 800 MW capacity during the forecasted USE incidents. Even when New South Wales had spare generation, this cap prevented additional flows into South Australia. This changed from summer FY2029-30, when New South Wales firm capacity was no longer sufficient to support the competing needs of the native demand and both neighbouring regions (Victoria and South Australia). The transmission support for South Australia was then below PEC's maximum capacity, suggesting that even if transmission was available, the lack of generation capacity was the root cause of USE.

The Heywood interconnector to Victoria also provided important support but was seldom used at full capacity. It rarely went beyond 300–400 MW during stress events, even when technical limits suggested it could. This indicated that tight supply/demand conditions often occur in tandem between South Australia and Victoria which prevents the provision of support (Figure 26).

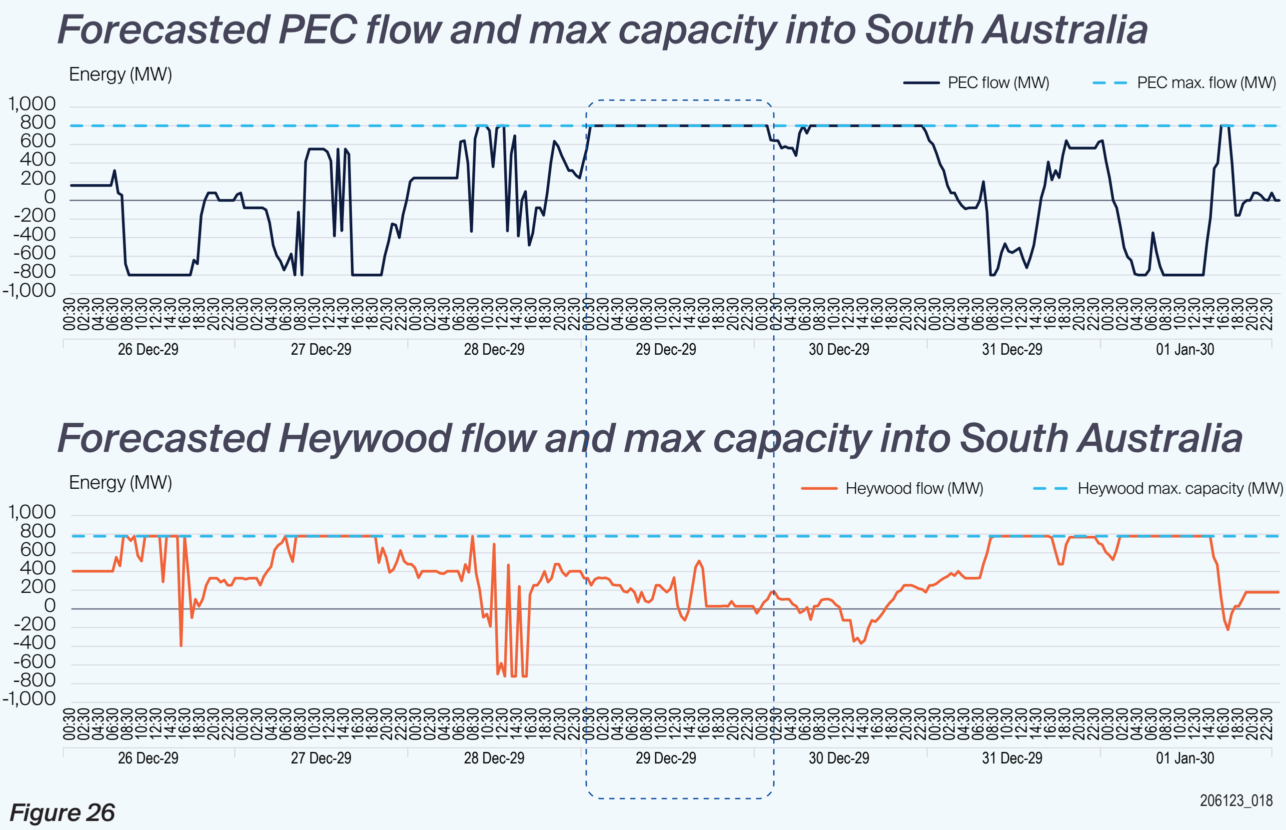


Figure 26

Limited Gas Capacity to cover USE

Gas was observed to be always at or near maximum during USE events. Across all years, dispatch sat around 1.3 to 1.5 GW during the USE events (summer derating applied), with an additional 200 MW (168 MW during summer) from HJP from December 2028. Once this ceiling was reached, there was no additional buffer to respond to solar collapse or surge in demand.

The vulnerability of this reliance on gas was most evident in summer FY2030-31, when Dry Creek and Mintaro units are expected to be no longer available. On an extreme day, demand was expected to spike above 6 GW, and the absence of those plants meant the system had less firm capacity to rely on. South Australia would need ~1 GW of supply to cover the shortfall in the hour when USE happens.

Victoria and New South Wales Dynamics

The outcomes in South Australia were heavily shaped by conditions in Victoria and New South Wales. Victoria experienced similar challenges to South Australia, rapid solar ramp-down and high evening demand. This means Victoria often could not provide support, even when technically possible. New South Wales tended to be more secure, but the PEC cap limited its contribution. On occasions when New South Wales did assist, the flows were also sometimes directed first to Victoria rather than South Australia, reflecting competing priorities in a stressed network. It is worth noting that the demand traces of all NEM regions used in the modelling have the percentage of exceedance of 10 per cent (or POE 10). This means that actual demand was expected to be higher than this level only once every ten years. Using these traces for all regions hypothesises a stronger than usual system stress across the NEM.

The graph below (Figure 27) is an extract of the modelling results for a USE Day in January 2030, illustrating the contribution of each generation type to meeting demand and highlighting the context in which USE happens. The figure also provides insight into South Australia's future generation mix if firm capacity is not added in time to meet growing demand.

In the early morning, demand rises steadily, with thermal generation and wind meeting much of the load. As the sun rises, rooftop and grid-scale solar ramp up quickly, becoming the dominant sources of supply by late morning. Around midday, solar reaches its peak output, allowing more expensive thermal generation to scale back, while batteries absorb excess supply for later use.

Through the afternoon, demand continues to climb, leading into the critical evening peak. Solar output declines rapidly after 17:00 and has almost disappeared by 20:00. Wind generation strengthens during this time and thermal generation ramps up to maximum output, but these contributions are not enough to fill the large shortfall left by solar.

Imports from Victoria and New South Wales operate at maximum transfer capacity, although this represents an unlikely stress case. Batteries discharge briefly during the evening, providing some relief, but their limited energy reserves restrict the duration of support.

Ultimately, from 18:30 to 22:00, the system is unable to fully meet demand, resulting in USE. This reflects the difficulty of maintaining supply during periods of high evening demand when renewable output is falling, and all other firming resources are already fully utilised.

Example of generation profile on a day with insufficient capacity in FY2029-30

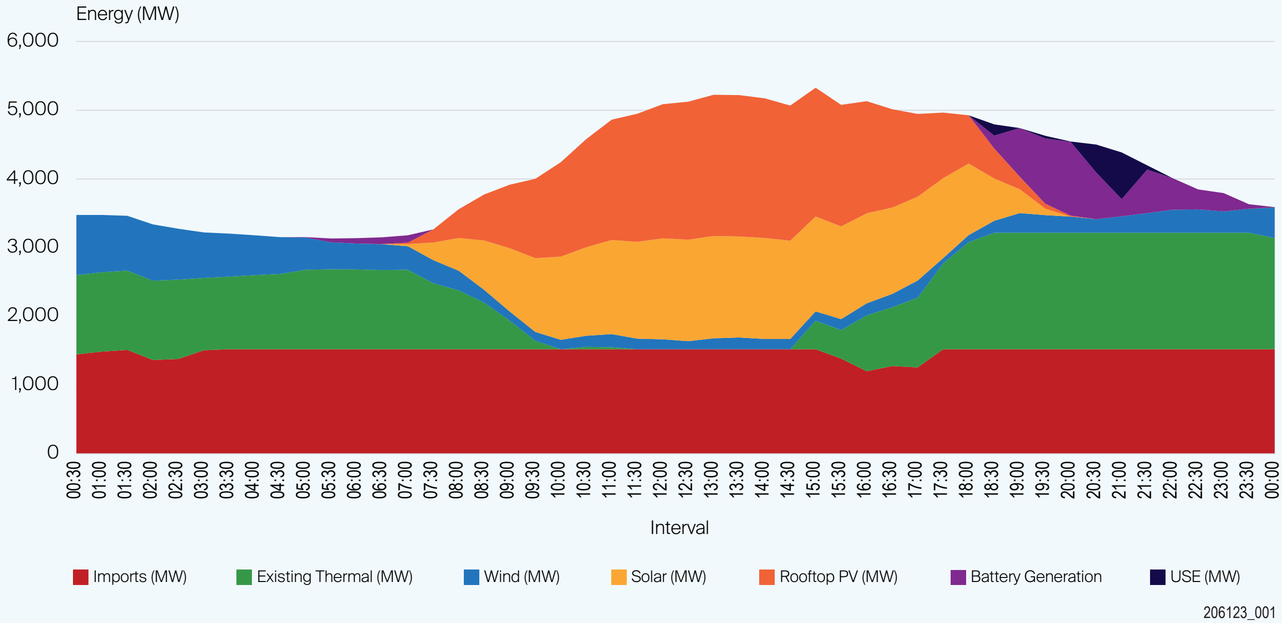


Figure 27

Shock case analysis

Mirroring the process from last year's assessment, further shocks beyond the baseline were tested, representing a hypothetical condition where a critical component of the South Australian electricity grid was out of service for a week each summer and winter in an already stressed system. Last year's analysis deemed South Australia to be most vulnerable during disruptions caused by Pelican Point power station and the PEC transmission line, hence our continued intention to focus on these scenarios to evaluate further USE levels. In each case, we further hypothesised an introduction of a 700 MW generator to buffer the impact of the outages and evaluated the contribution of this generator to improving USE severity and/or duration.

Pelican Point shock scenario

The Pelican shock scenario represented the loss of a key local generator and highlighted the role of local firm capacity in maintaining supply. Without new firming capacity, USE increased rapidly. In FY2028-29 and FY2029-30, shortfalls of 9.7–11 GWh occurred, with peaks rising to 1.5 GW. By 2031, USE grew further to 15 GWh with a peak of 2.1 GW.

One distinction to the baseline is that USE occurrences also appeared in winter, with two days recorded in FY2030-31 and three in FY2031-32. This expansion of shortfalls into winter reflected the absence of firming headroom showing how with one large gas plant unavailable, the system is at risk when VRE output is low.

Adding 700 MW of new capacity significantly reduced these outcomes. Across 2029–2032, annual USE fell to between 0.5 and 2.8 GWh. Winter USE also disappeared completely. In effect, the additional firming almost fully offset the lost plant, covering demand when solar declined and avoiding seasonal reliability issues.

PEC outage shock scenario

Of the modelled scenarios the PEC shock scenario is the most severe as it restricts South Australia's ability to draw support from New South Wales. This import restriction in conjunction with no new gas capacity, increased the frequency of USE events dramatically. In FY2028-29 and FY2029-30, shortfalls already reached 14 GWh per annum. By FY2030-31 and FY2031-32, USE exceeded 23 GWh per year, with peaks above 2 GW. Winter USE was also frequent, with six days recorded in both FY2030-31 and FY2031-32. These outcomes clearly demonstrated South Australia's reliance on PEC because once this interconnector was constrained, South Australia's local resources proved insufficient with large-scale USE emerging in both summer and winter.

By adding 700 MW of new firm gas capacity, the outcomes from this shock scenario were still challenging but much improved. Annual USE in 2029–2032 fell to 3–5 GWh, compared with 14–24 GWh without firming. Winter USE occurrences, while not eliminated, dropped to just a single day in 2031. This demonstrated that even under the most constrained conditions, firm capacity can moderate both the scale and severity of USE.

Key Takeaways

The key takeaways from the modelling exercise are:

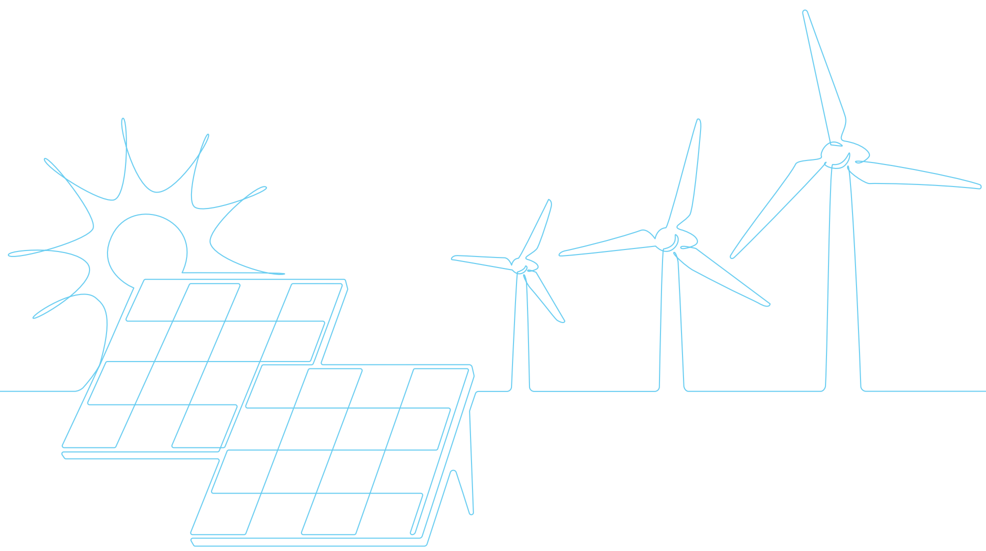
- **USE event triggers remained consistent:** they were rapid solar ramp-down, maxed-out gas capacity, weak wind output and limited interconnector flows.
- **Additional Firm supply was required to manage future summer shortfalls:** Without new firm capacity, South Australia saw growing summer shortfalls, rising to >20 GWh in shock years, with peaks above 2 GW. Winter USE events also occurred under stress scenarios.
- **Firming provides resilience:** Added gas capacity reduced both total USE and peak event size, ensuring more stable outcomes through the early 2030s. By adding an additional 700 MW of available gas capacity, USE events were eliminated from the baseline case, moderated in Pelican shock, and reduced by 70–85 per cent in PEC shock. Winter USE was also removed in nearly all cases.

Further considerations

Demand applied for the modelling is POE10 for all regions in the NEM. This means that the whole NEM is modelled to always experience one-in-ten-year demand events and concurrently. This was reflected in the constant lack of generation capacity to assist South Australia from neighbouring regions during USE as each region coped with its own supply shortfalls.

The reference year chosen for this modelling exercise was 2015, which was the year South Australia experienced number of days where record low solar and wind generation coincided with high demand. A less severe reference year may yield smaller magnitudes of unserved energy.

In all cases, new renewable energy capacities were still allowed to come in. However, as these capacities also followed the reference year 2015 dispatch profiles, the untimely coordination of these capacities was repeated over the horizon. In reality, South Australia will not necessarily experience USE every summer, but events are more likely if conditions like those experienced in 2015 re-emerge.



ACRONYMS AND DEFINITIONS

$/kWh	Dollar per kilowatt hour
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BESS	Battery energy storage system
BTM	Behind-the-meter
CCGT	Combined Cycle Gas Turbines
CER	Consumer Energy Resources
CIS	Capacity Investment Scheme: the Commonwealth's framework to encourage new investment in renewable capacity, such as wind and solar, as well as clean dispatchable capacity, such as battery storage (up to 4 hrs).
CWO REZ	Central-West Orana Renewable Energy Zone
CQ-SQ Stage 1	Central Queensland (CQ) to Southern Queensland (SQ) Stage 1
DCCEEW	(Australian Government) Department of Climate Change, Energy, the Environment and Water
DEM	Department for Energy and Mining
DNSP	Distribution Network Service Provider: South Australia has one DNSP, SA Power Networks.
DMO	Default Market Offer: the annual maximum bill amount (called a reference price) retailers can charge for the 'standing offer' prices.
DUID	Dispatchable Unit Identifier
EDP	Electricity Development Plan
GW	Gigawatt
GWh	Gigawatt-hour
HRE Act	*Hydrogen and Renewable Energy Act 2023*
ISP	Integrated System Plan – AEMO's roadmap for the transition of the NEM power system.

IEA	International Energy Agency
LOR	Lack of Reserve (events): LOR events are declared by AEMO by way of market notice and refer to a situation where the available reserve capacity (i.e. the surplus capacity beyond the forecasted peak demand) falls below a specified threshold. AEMO classifies LOR conditions into levels: ▪ LOR1 (Low reserve condition): Spare reserves are lower than the usual requirement, but still enough to cover a major generation or transmission failure. The system remains secure, but margins are tight. ▪ LOR2 (Inadequate reserves for a single contingency): Reserves are not enough to withstand the loss of the largest generating unit or interconnector. If such an event happens, there may be load-shedding (controlled blackouts) to keep the system stable. ▪ LOR3 (Actual load-shedding required): Demand already exceeds available supply. Controlled blackouts are happening or imminent to prevent a system-wide failure.
Long Duration Firm Capacity	Generators >30 MW capacity that can dispatch at rated output for eight hours of continuous output.
MW	Megawatt
MWh	Megawatt-hour
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
Non-Credible Contingency Event	A non-credible contingency event is an event, typically involving the simultaneous failure of multiple power system components, which is considered so rare and unlikely to occur that it is not normally planned for in the system's standard operational resilience.
OCGT	Open Cycle Gas Turbines
ODP	Optimal Development Pathway
OEMF	Orderly Exit Management Framework – an opt-in framework intended to support an orderly transition through preventing the early exit of a generator that would create a system needs shortfall.
Operational Demand	Operational demand is the demand to be met by the grid, after behind-the-metre generation has been subtracted from the native demand. The operational demand curve over the course the day exhibits a dip in the middle of the day where solar generation is strongest, and the morning and evening peaks colloquially known as the “duck curve”.
OTR	Office of the Technical Regulator
PEC	Project EnergyConnect
POE10	10 per cent Probability of Exceedance
POE50	50 per cent Probability of Exceedance
PV	(solar) Photovoltaic

QNI Connect	Queensland to New South Wales Interconnector Connect
Reliability	A reliable power system ensures demand is met through sufficient generation capacity, considering both seasonal variability and longer-term demand trends.
Resilience	A resilient power system can sustain supply and recover from unplanned events including high-impact, low probability shocks.
RERT	Reliability and Emergency Reserve Trader
RETA	Renewable Energy Transformation Agreement
RRP	Regional Reference Price is the time-weighted average of the dispatch prices at that regional reference node in a trading interval.
SA	South Australia
SACOME	South Australian Chamber of Mines and Energy
SACOSS	South Australian Council of Social Service
SAPN	South Australia Power Networks
SFV	Scheme Financial Vehicle
TIPS B	Torrens Island Power Station B
TW	Terawatt
TWh	Terawatt-hour
TNSP	Transmission Network Service Provider: South Australia has one TNSP, ElectraNet.
USE	Unserved energy: Indicates the amount of demand shortfall that cannot be met by any supply sources at a given point in time.
VCR	Value of Customer Reliability: the value different customers place on reliable electricity supply.
VNI West	Victoria to New South Wales Interconnector West
VPP	Virtual Power Plant
VRE	Variable renewable energy: commonly used to refer to generation such as wind and solar.
100% Renewables	The term net 100 per cent renewables refer to a system where, over a full year, renewable energy generation (including large-scale and distributed solar and wind) equals or exceeds total electricity consumption (total generation and imports), allowing for periods of firming generation and imports during times of low renewable output.

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Acknowledgement of Country

We acknowledge and respect Aboriginal people as the state's first peoples and nations, and recognise them as traditional owners and occupants of land and waters in South Australia. Further, we acknowledge that the spiritual, social, cultural and economic practices of Aboriginal peoples come from their traditional lands and waters, that they maintain their cultural and heritage beliefs, languages and laws which are of ongoing importance, and that they have made and continue to make a unique and irreplaceable contribution to the state.

We acknowledge that Aboriginal peoples have endured past injustice and dispossession of their traditional lands and waters.

Published December 2025

16/12/2025-206123

SOUTH AUSTRALIA

Government of South Australia
Department for Energy and Mining