2020 Electricity Statement of Opportunities

August 2020

A report for the National Electricity Market

Important notice

PURPOSE

AEMO publishes the National Electricity Market Electricity Statement of Opportunities under clause 3.13.3A of the National Electricity Rules.

This publication has been prepared by AEMO using information available at 1 July 2020. Information made available after this date may have been included in this publication where practical.

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VERSION CONTROL

Version	Release date	Changes
1	27/8/2020	Initial release
2	16/9/2020	Section 3.2.1, pp. 48-49: replace Figure 21, update descriptions of Figure 21 and Figure 22 to correct description of aggregation method in modelling forced outage rates. Chapter 4, p. 53: correct summaries of Victorian and NEM VRE capacity values. Section A4.5.1, p. 127: correct value for commissioning VRE capacity in Victoria.

Executive summary

The *Electricity Statement of Opportunities* (ESOO) forecasts electricity supply reliability in the National Electricity Market (NEM) over a 10-year period to inform decisions by market participants, investors, and policy-makers. The ESOO includes a reliability forecast identifying any potential reliability gaps in the coming five years, as defined according to the Retailer Reliability Obligation (RRO)[1]. The final five years of the 10-year ESOO forecast provide an indicative forecast of any future material reliability gaps.

Key findings

The expected reliability outlook has improved for summer 2020-21 and across the five-year outlook, due to lower forecast peak demand (which includes the projected impacts of COVID-19 next summer), minor generation and transmission augmentations, and significant development of large-scale renewable resources. However, as a result of COVID-19 and other factors, the uncertainty range of this outlook has increased compared to previous years:

- In summer 2020-21, expected unserved energy (USE) is not forecast to exceed the reliability standard[2], nor to exceed the Interim Reliability Measure (IRM)[3], in any NEM region.
  - Although expected USE in Victoria has declined substantially since the 2019 ESOO, some risks of load shedding remain, particularly if peak demands reach 10% probability of exceedance (POE)[4] levels and coincide with low renewable generation, or prolonged generation or transmission outages reoccur.
  - Due to fire damage incurred on one of ElectraNet's static VAR compensators in July 2020, the transfer capability between Victoria and South Australia will be reduced in both directions for the next 12 months, but is not expected to materially impact USE.
  - Delays in the commissioning of over 1,900 megawatts (MW) of variable renewable energy (VRE) expected to become operational in late 2020 would increase forecast USE in Victoria, although not to levels that would exceed the reliability standard.
  - AEMO will seek to mitigate these risks through the use of medium-notice and short-notice Reliability and Emergency Reserve Trader (RERT).
  - While COVID-19 has reduced peak demand and energy consumption expectations for the coming summer, it also creates a significant new uncertainty. The current forecast would require an update if recently observed sector impacts change prior to or during next summer. Furthermore, COVID-19 could cause delays in the return to service of generators on forced outages or defer maintenance

[1] The RRO came into effect on 1 July 2019. For more information, see http://www.coagenergycouncil.gov.au/publications/retailer-reliability-obligation-rules.

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

[3] The IRM is a new interim reliability measure, agreed to at the March 2020 COAG Energy Council and introduced by the National Electricity Rules (Interim Reliability Measure) Rule 2020, that sets a maximum expected USE of no more than 0.0006% in any region in any financial year. It is intended to supplement the existing reliability standard for a limited period of time and allows AEMO to procure reserves if the ESOO reports that this measure is expected to be exceeded. The proposed National Electricity Rules (RRO trigger) Rule 2020 would also allow the RRO to be triggered by a forecast exceedance of the IRM. AEMO has prepared the reliability forecast against the existing 0.002% reliability standard and against the IRM of 0.0006%. For more information, see the ESB website at http://www.coagenergycouncil.gov.au/reliability-and-security-measures/interim-reliability-measures.

[4] POE is the probability a forecast will be met or exceeded. The 10% POE forecast is mathematically expected to be met or exceeded once in 10 years and represents demand under more extreme weather conditions than a 50% POE forecast.

required for summer readiness. AEMO continues to carefully monitor COVID-19's impacts as the situation evolves, and will issue an ESOO update should circumstances change materially.

- Beyond next summer:
  - New South Wales' reliability outlook after the Liddell Power Station retires has improved since the 2019 ESOO, as a result of the committed augmentation of the Queensland to New South Wales Interconnector (QNI) in 2022-23 and the development of local new renewable generation (900 MW). Absent additional investment, the region is forecast to exceed the IRM from 2023-24 onwards, and to be vulnerable to the coincidence of high demands, generator outages, and low renewable generation until Snowy 2.0 is commissioned and transmission augmentations allow Snowy 2.0 to help meet peak demand. However, the reliability standard is not forecast to be exceeded until 2029-30.
  - From 2023-24 onwards, expected USE levels increase in New South Wales, and to a lesser extent in Victoria, as coal-fired generation is projected to become less reliable as plant ages.

Forecast minimum operational (grid) demand is declining rapidly, in all NEM regions, due to increasing contributions of distributed photovoltaic (PV) generation[5] to meet consumer demand in the daytime:

- By 2025, all regions are expected to experience minimum operational demand in the daytime, not overnight. Expected reductions are most evident in Victoria and South Australia, and continue across the full 10-year forecasting horizon.
- Declining minimum demand could lead to issues with managing voltage, system strength, and inertia. It is creating near-term operational and planning challenges for sustaining a reliable and secure power system that must be addressed[6].
- Effective market and regulatory arrangements that incentivise more demand during the middle of the day would help minimise the occurrence of these extreme minimum load conditions. Innovative solutions could include providers/aggregators of distributed energy resources (DER) offering services such as increased PV controllability, load flexibility, storage, and load shifting.
- Urgent action is required to ensure all new distributed PV installations have suitable disturbance ride-through capabilities and emergency PV shedding capabilities to be enabled under rare circumstances as a last resort to maintain system security. AEMO is working with stakeholders to introduce these capabilities.

A summer of unprecedented weather events, followed by the COVID-19 pandemic, demonstrates the need for increased vigilance in supporting the reliable delivery of affordable energy while taking necessary steps to increase system resilience to minimise disruptions for consumers and businesses:

- While the 2020 ESOO analysis captures some climate change trends, the calculated USE excludes the impact of numerous climate hazards and other high impact lower probability (HILP) events that affect generation and transmission infrastructure.
- Absent additional investment, resilience analysis highlights the risk of potentially catastrophic reliability outcomes in New South Wales if the conditions experienced during the bushfire activity of 4 January 2020 were to occur during a period of high demand after the retirement of Liddell.
- AEMO is continuing to work with climate scientists, governments, industry, consumer groups and market bodies to ensure energy supply is protected from the effects of increasing frequency, extremity and scale of climate-induced weather events and other emerging threats.

[5] Distributed PV includes rooftop systems and other smaller non-scheduled PV capacity.

[6] AEMO is working with transmission network service providers (TNSPs) to consider the impact of declining minimum demand as part of existing network planning activities, and will provide more detail on actions underway in system strength, network support, and inertia reports due by the end of 2020.

Summer outlook (2020-21)

This ESOO has been prepared while the COVID-19 pandemic is still spreading, and the full extent of its impact is therefore uncertain. COVID-19 recovery will be influenced by risks of new waves of infection, the duration of lockdown measures (both in Australia and key trading partners), and potential development of a vaccine. There is no history available to guide how a global pandemic will affect a modern economy, although observed changes in residential and business demand patterns in the past few months can serve as a guide.

In light of this uncertainty, AEMO has run numerous sensitivities, varying economic and behavioural assumptions, to understand how this pandemic may impact residential and business consumption, large industrial loads, and DER technology forecasts.

In all sensitivities, peak demand and energy consumption is forecast to reduce in the coming summer. While the magnitude of the reduction is highly uncertain, the sensitivity analysis highlights that demand growth is unlikely to be a material driver of supply scarcity risk in the short term.

The NEM continues to see the connection of large amounts of new VRE[7] capacity, with an additional 4,300 MW of new capacity forecast to be operational this summer compared to what was available last summer. Over 1,900 MW of new VRE capacity is expected to be commissioned in the remainder of 2020 in Victoria alone. The 2020 ESOO also includes an increase in scheduled capacity available, due to generator upgrades, battery storage expansions, and the inclusion of generation leased from the South Australian Government.

The reliability of the thermal generation fleet fell to historically low levels in 2019-20, and the outlook from the majority of plant operators is that future reliability of plant will either remain the same as recent history, or continue to deteriorate. This has resulted in AEMO increasing forward-looking forced outage rates for the fleet in aggregate in this 2020 ESOO. Unlike last year, there are currently no generators on extended forced outages with a risk of their return to service pushing into the critical summer months. However, some concern remains that the logistical challenges presented by COVID-19 may extend repair times for plant on planned or unplanned outages.

As a result of the reduction in forecast demand, new generation capacity, and the full return to service of units on prolonged outages last year, the reliability forecast for the coming summer shows a considerable improvement relative to last year, particularly in Victoria. Expected USE in all regions is forecast to remain below the IRM.

Risks remain that under high demand conditions, or if prolonged generation or transmission outages were to occur again, there may be insufficient generation to meet demand, and this risk increases if the VRE due to be commissioned in 2020 is delayed until after summer. AEMO will mitigate these risks with the use of medium-notice and short-notice RERT in the first instance.

While the 2020 ESOO analysis captures some climate change trends, the calculated USE still excludes the impact of numerous acute climate hazards and other HILP events that affect generation and transmission infrastructure. To better explore tail risks to reliability outcomes, AEMO conducted analysis on the bushfire activity of 4 January 2020, identifying the potential for undesirable outcomes in New South Wales should these events reoccur under peak demand conditions. AEMO will use this and other case studies to help inform discussions on the role for governments and/or markets in preparing risk management solutions to help mitigate these and other emerging risks.

Demand and supply trends and uncertainties beyond this summer

In the next two to five years, the consumer demand outlook is driven by projections of post-COVID economic recovery, continued investments in energy efficiency (EE) activities, and an increase in DER including distributed PV systems and battery storage. In particular, the forecast of distributed PV has been revised

[7] Including solar, wind, and other variable renewable energy resources at the utility level.

upwards since the 2019 ESOO, due to the volume of sales observed in 2019, data supporting inclusion of the Victorian Solar Homes Scheme, and improvements in the DER forecast models.

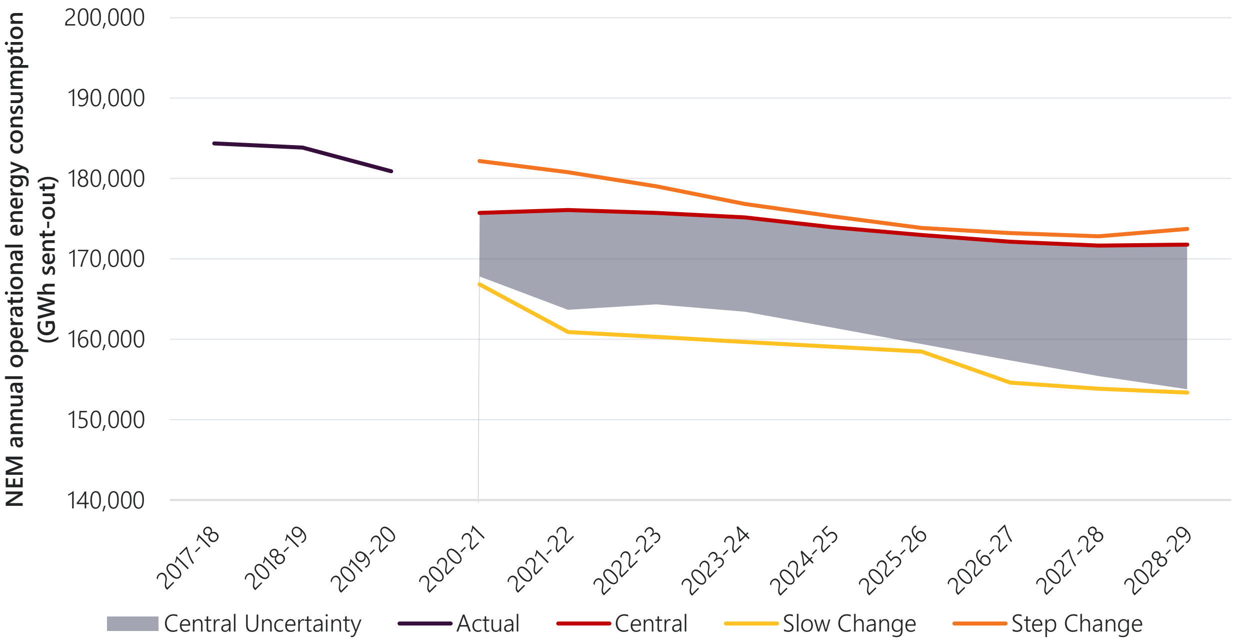
Collectively, these drivers lead to forecast operational consumption[8] remaining relatively steady under the Central scenario, reducing only slightly from 180 terawatt hours (TWh) in 2019-20 to 178 TWh in 2024-25, although reductions could be far more significant if impacts of COVID-19 lead to permanent closure of energy-intensive loads.

In the longer term (10-20 years), many NEM regions are forecast to return to growth in operational energy consumption and maximum demand, driven by electric vehicles (EVs) and a level of saturation in distributed PV and EE investments.

The economic impacts of COVID-19, while uncertain, are projected to be felt for several years, and this uncertainty is reflected in the range of energy forecasts across scenarios (from 167 TWh in the Slow Change scenario to 182 TWh in the Step Change scenario in 2022-23).

This is illustrated in Figure 1, which compares consumption forecasts under the Central, Step Change, and Slow Change scenarios. This figure also includes downside sensitivities in the Central scenario that reflect the potential for a more sustained economic downturn due to COVID-19, potential industrial closures, and a higher uptake of distributed PV.

Figure 1 Uncertainty in NEM operational consumption



Across most NEM region forecasts, close to record high maximum operational demand[9] periods are still being observed, despite annual operational consumption growth declining due to DER uptake. This is because operational maximum demand now typically occurs at time periods closer to sunset, when distributed PV provides little contribution.

[8] Operational consumption is all demand met by local scheduled generation, semi-scheduled generation, and non-scheduled wind/solar generation of aggregate capacity ≥ 30 MW, and by generation imports to the region, excluding the demand of local scheduled loads. For more definitions, see AEMO, Demand Terms in EMMS Data Model, 2019, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/dispatch-information/policy-and-process-documentation.

[9] Maximum operational demand refers to the highest amount of electrical power delivered over a defined period (day, week, month, season or year); the ESOO forecasts annual maximum demand.

Following the impacts of COVID-19 this summer, under the Central scenario, maximum demand is forecast to:

- Rebound to current levels in **New South Wales** and then increase only slightly in the next decade as continued strong efforts on EE offset underlying growth drivers.
- Grow in **Queensland** as underlying growth in large industrial loads (early on) and the business sector more generally exceed the expected improvements in EE.
- Initially grow slightly in **South Australia** driven mainly by large industrial loads, then remain flat until 2029-30 as growth in underlying residential and business load is offset by increasing EE.
- Continue to decline in **Victoria** until 2025-26, as growth in underlying residential and business load is offset by strong growth in EE, but start increasing beyond that point.
- Increase initially in **Tasmania** driven by large industrial loads returning towards previous levels, then generally stay flat.

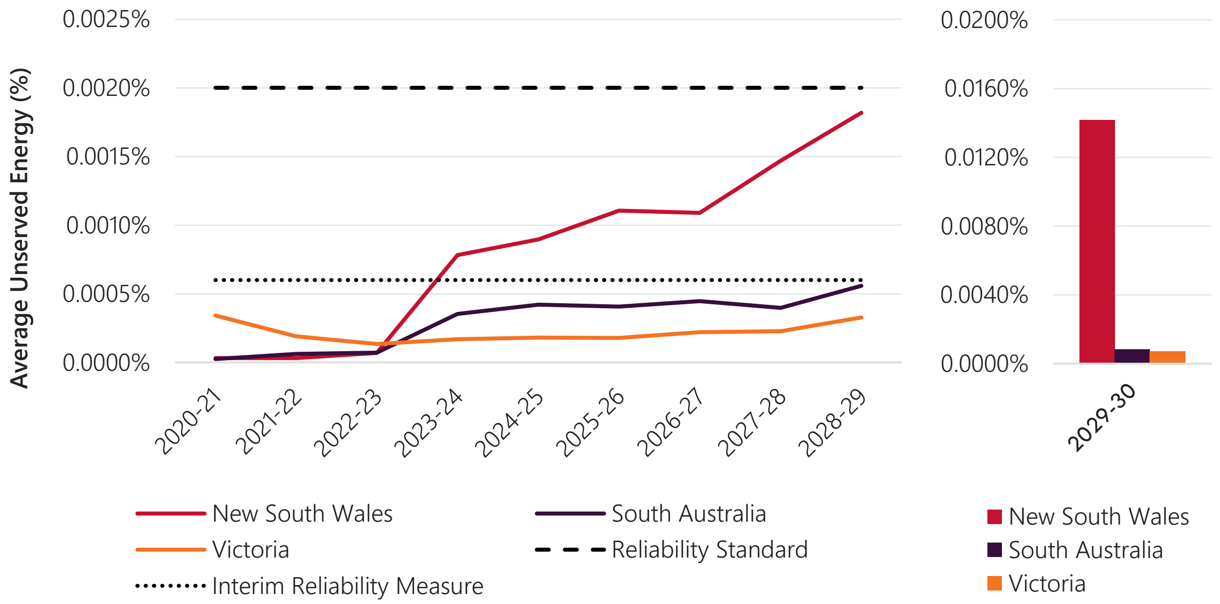
From a supply perspective:

- There is 3,205 MW of committed VRE expected to commence commercial operations by summer 2020-21.
- Beyond this summer, there is 631 MW of committed VRE capacity.
- Committed new scheduled capacity is limited to the Snowy 2.0 project (2,040 MW).
- The current pipeline of 57,334 MW of proposed new generation capacity includes 41,532 MW of VRE.

Reliability forecast and indicative reliability forecast

Figure 2 shows the reliability forecast and indicative reliability forecast[10] under the Central scenario for the next 10 years, from 2020-21 to 2029-30. The value for 2029-30 is shown separately, due to the significant increase in expected USE forecast for that year.

Figure 2 Expected unserved energy, Central scenario, 2020-21 to 2029-30



[10] The reliability forecast identifies any potential reliability gaps in the coming five years, as defined according to the RRO. The indicative reliability forecast provides an indicative forecast of any future material reliability gaps in the final five years of the 10-year ESOO forecast. The full reliability forecast that satisfies clause 4A.B.1 of the NER is set out in Chapter 5 of this ESOO.

In summer 2021-22 (the T-1 year for the RRO), the reliability forecasts remain below both the reliability standard and the IRM, given the flat demand outlook and minimal changes in supply.

Forecast USE increases by 2023-24 (the T-3 year for the RRO) in New South Wales and South Australia, due to the retirements of Liddell Power Station and Osborne Power Station:

- The forecast USE in South Australia remains below the IRM, as the additional peaking generation and battery storage capacity added over the past year helps to offset the impact of the Osborne retirement.
- In New South Wales, the forecast USE sits above the IRM but below the reliability standard. While announced too late to be modelled, the New South Wales Government's commitment to provide capital projects funding to 170 MW of dispatchable capacity under its Emerging Energy Program is expected to reduce expected USE to below the IRM in 2023-24.
- In general, the reliability forecast for 2023-24 has improved since the 2019 ESOO, as a result of the committed augmentation of the QNI in 2022-23 and the development of new renewable generation (900 MW) in New South Wales.

The indicative reliability forecast indicates that expected USE is forecast to remain below the reliability standard in all regions until 2029-30 when Vales Point is expected to close. At this point, generation from further afield is needed to meet Sydney's load, but is constrained from doing so during peak demand periods due to network limitations. The 2020 Integrated System Plan (ISP) identified preparatory activities on a future ISP project to support power transfer into Sydney, Newcastle and Wollongong following the retirement of Vales Point. Without this investment, expected USE in New South Wales is forecast to exceed 0.014%.

While the reliability forecasts are within the reliability standard in all but the last year of the ESOO horizon, expected USE does progressively increase over time, most notably in New South Wales where it exceeds the IRM (or equivalent if changes to market design introduce a more permanent measure).

For the first time, the 2020 ESOO applied forced outage rate trajectories that consider the impact of generators aging, maintenance programs, and deteriorating performance as generators approach retirement. This contributes to the forecast increase in USE after Liddell's closure, despite a flat outlook for maximum demand.

The inclusion of Snowy 2.0 from 2025-26 has a negligible impact on USE outcomes without associated transmission being committed. The HumeLink transmission augmentation is not yet included in the reliability forecast, because it has not yet formally received its regulatory approval. It is necessary for the addition of Snowy 2.0 to provide firm supply to New South Wales when most needed. Project EnergyConnect, if completed before 2024-25[11], is also expected to play a key role in reducing supply scarcity risks across the NEM by increasing transfer capacity between New South Wales and South Australia.

A sensitivity which included actionable ISP projects shows that when these augmentations progress, they will help address the deterioration in reliability; however, New South Wales remains vulnerable in the period between the retirement of Liddell and the addition of Snowy 2.0 and HumeLink.

For regions where forecast reliability gaps are close to, or exceed, the reliability standard or IRM, Table 1 shows the megawatts projected to be required to achieve both the reliability standard and the IRM.

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

Table 1 Forecast reliability gap (in MW) to meet the reliability standard and IRM

	Gap to meet reliability standard			Gap to meet IRM		
	Victoria	South Australia	New South Wales	Victoria	South Australia	New South Wales
2020-21	0	0	0	0	0	0
2021-22	0	0	0	0	0	0
2022-23	0	0	0	0	0	0
2023-24	0	0	0	0	0	154
2024-25	0	0	0	0	0	305
2025-26	0	0	0	0	0	525
2026-27	0	0	0	0	0	472
2027-28	0	0	0	0	0	895
2028-29	0	0	0	0	0	1,001
2029-30	0	0	1,480	166	148	2,045

Note. The forecast reliability gaps identified in this table apply to particular periods within the financial year stated.

Challenges and opportunities during low demand periods

The 2020 ESOO highlights the minimum demand-related challenges and opportunities arising from increasing penetration of distributed PV.

Minimum demand is extremely sensitive to forecast growth in distributed PV. Evidence of strong sales and installations in 2019 have strengthened the confidence that consumers continue to look for energy savings through PV installations, and distributed PV forecasts have been revised upwards accordingly. COVID-19 has been assumed to temper some installation growth, however, as at the end of June, there was limited evidence to confirm any real slowdown of distributed PV installations. Additionally, in some regions such as Victoria, policy is driving accelerated uptake. Victoria's Solar Homes Program has now been included in the long term projections in the Central Scenario[12].

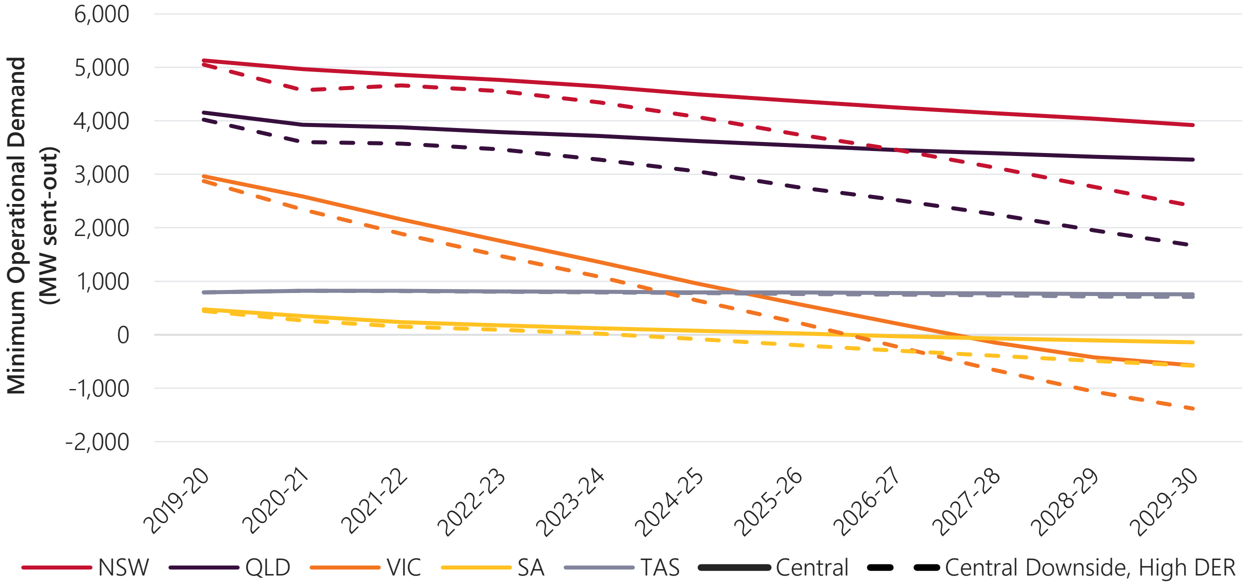
Due to the continued strong uptake of distributed PV projected, forecast minimum operational demand is declining rapidly.

By 2025, all regions are expected to experience minimum operational demand in the daytime, not overnight, and in South Australia and Victoria minimum demand could potentially be negative towards the end of the next decade.

Given the uncertainty in both the uptake of distributed PV and the impact of COVID-19 on demand, the decline in minimum demand could be even more extreme, as shown in the Central Downside, High DER sensitivity in Figure 3.

[12] The 2019 Central scenario did not apply the full magnitude of the proposed Solar Homes Program. The program was included in full in the 2019 Step Change scenario. With increased evidence of policy success, this 10-year policy has been included in all scenarios in this 2020 ESOO.

Figure 3 Forecast minimum operational demand (full lines = Central scenario, dashed lines = Central Downside, High DER sensitivity)



Market and regulatory arrangements that effectively incentivise load to increase in the daytime and 'soak up' excess distributed PV generation will enable this generation to be more efficiently utilised and reduce the likelihood of extreme minimum demand conditions. There are opportunities for technical, market, and regulatory enablers to unlock value from:

- Load and storage flexibility, including storage and coordinated EV charging and demand response in daylight hours.
- Aggregators and third-party providers of active DER participation services, particularly those that can provide a reliable control of distributed PV capability at low cost to customers.
- Improving unit flexibility and reducing the minimum generation levels of synchronous generating units so they can continue to remain on-line during low demand periods.
- Fast active power response (FAPR) (sub-second response), with anticipated development of market frameworks that reward this capability.

In addition to the mechanisms above, some important actions are urgently required to introduce system security "back-stops", improve DER performance, and address emerging system security challenges in periods with low load and high levels of distributed PV. Operational challenges associated with increasing shares of distributed PV generation in the daytime include:

- **Unintended disconnection of distributed PV** – distributed PV demonstrates disconnection behaviour when exposed to power system disturbances. The sudden loss of a large capacity of distributed PV can coincide with the loss of the largest generating unit, meaning the largest credible contingency size increases. This affects network limits, frequency control, and other aspects of power system operation. Management options include improving distributed PV disturbance ride-through characteristics, adapting network constraints, and adapting frequency control arrangements. System strength and inertia requirements may also be affected by distributed PV behaviour, and will be considered in a dedicated report due for release by the end of 2020.
- **Minimum demand thresholds** – some NEM regions, such as South Australia and Queensland, occasionally separate from the rest of the NEM and need to operate as a secure island. When separation occurs, it must be possible to recover sufficient operational demand to maintain the necessary units online to provide security services such as system strength, inertia, and frequency control. Even in regions that are unlikely to separate from the rest of the NEM, challenges may arise in managing network limits as the

proportion of non-dispatchable distributed PV increases, and there may be limited potential to export in high distributed PV periods due to co-incident low demand in all regions. This can be addressed by introducing emergency PV shedding capabilities for new distributed PV installations. It is anticipated that PV shedding would only be enabled under rare circumstances, as a last resort to maintain system security under abnormal conditions.

- **Voltage management** – as demand levels decrease, it can become increasingly challenging to manage transmission network voltages. Switching out major transmission lines may become necessary, reducing the robustness of the network. This can be addressed by investment in suitable network equipment, such as reactive power capability. Network Support and Control Ancillary Services (NSCAS) requirements will be considered in a dedicated report due for release by the end of 2020.
- **Emergency frequency control schemes** – under-frequency load shedding (UFLS) is a type of emergency frequency control scheme (EFCS) designed to arrest a severe under-frequency disturbance via the automatic disconnection of customer loads. Distributed PV reduces the net load available for shedding, and under-frequency disconnection behaviour exacerbates disturbances. This means this important 'last resort' mechanism is much less effective for managing severe disturbances. Management options include increasing availability of FAPR, adding more load to the UFLS, exploring options for more granular load shedding at the customer site level, and introducing network constraints.
- **System restart** – a minimum quantity of stable load is required to restart the large synchronous units that provide System Restart Ancillary Services (SRAS) to enable system restoration after a major blackout. With large quantities of distributed PV operating, there may not be sufficient stable load, and DER behaviour may be difficult to manage in a small island during the restart process. This can be addressed by introducing emergency PV shedding capabilities with functionality that can prevent distributed PV from reconnecting during a restart process until the power system island is stable.

The issues associated with high distributed PV uptake create an imperative for urgent reform of standards and markets for DER. AEMO is collaborating with market bodies, the Energy Security Board (ESB), and the wider industry on actions necessary to efficiently integrate increasing levels of distributed PV and other DER in the NEM.

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Figures

1. Introduction

1.1 Purpose and scope

The *Electricity Statement of Opportunities* (ESOO) forecasts electricity supply reliability in the National Electricity Market (NEM) over a 10-year period to inform decisions by market participants, investors, and policy-makers. It includes information on:

- Existing, committed, and proposed electricity supply and network capabilities.
- Planned generating plant retirements.
- Operational consumption, maximum and minimum demand forecasts.
- Potential unserved energy (USE) in excess of the reliability standard and Interim Reliability Measure (IRM) that has been identified over a 10-year outlook period under a range of demand and supply scenarios.

For the purposes of the National Electricity Rules (NER) clause 3.13.3A(a), the following information should be considered part of the 2020 ESOO:

- The 2020 ESOO report and supplementary information published on the 2020 ESOO webpage[13].
- The July 2020 Generation Information page update[14].
- The 2020 *Inputs, Assumptions and Scenarios Report* (IASR) and accompanying workbook[15].

To meet the obligations under the Retailer Reliability Obligation (RRO)[16], the ESOO furthermore includes:

- **Reliability forecasts** identifying any potential reliability gaps for each of this financial year and the following four years, as per Section 1.2.
- An **indicative reliability forecast** of any potential reliability gaps for each of the final five years of the 10-year ESOO supply adequacy forecast.

Reliability forecast under the RRO

In the 2020 ESOO, the reliability forecasts and indicative reliability forecasts published in accordance with the RRO constitute Chapter 5 in this report. Key component forecasts and inputs include:

- Consumption and demand forecasts (see Sections 2.2, 2.3, and 2.4).
- Supply forecasts (see Chapter 3).
- The accompanying July 2020 Generator Information Page.
- The 2020 IASR[17].

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

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

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

[16] The RRO came into effect on 1 July 2019 through changes to the National Electricity Law, the National Electricity Rules, and South Australian regulations. For more information, see http://www.coagenergycouncil.gov.au/publications/retailer-reliability-obligation-rules.

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

Operational consumption and maximum demand forecasts are provided over a 20-year period from the financial year 2020-21 to 2039-40, because these forecasts are used by stakeholders for a range of purposes, including longer-term planning studies.

1.2 Key definitions

Reliability forecast components

The NEM **reliability standard** is set to ensure that sufficient supply resources exist to meet 99.998% of annual demand for electricity in each region. The standard allows for a maximum expectation of 0.002% of energy demand to be unmet in a given region per financial year.

Unserved energy (USE)[18] is the amount of energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of customer supply). This may be caused by factors such as insufficient levels of generation capacity, demand response, or network capability to meet demand.

The **Interim Reliability Measure (IRM)**, introduced by the National Electricity Amendment (Interim Reliability Measure) Rule 2020 (IRM Rule) is intended to reduce the risk of load shedding across the NEM by helping keep USE in each region to no more than 0.0006%. This interim measure is intended to support reliability in the system while more fundamental reforms are designed and implemented.

Reliability forecast under the RRO

For the RRO, components of any reliability forecast or indicative reliability forecast must include the USE, and whether or not there is a **forecast reliability gap**. Such a gap exists for a NEM region, and is considered material if the forecast expected USE exceeds the reliability standard. If there is a forecast reliability gap, the reliability forecast must also include:

- The **forecast reliability gap period** (start and end date), and trading intervals in which forecast USE is likely to occur.
- The **expected USE for that forecast reliability gap period**.
- The **size of the forecast reliability gap** (expressed in megawatts).

AEMO's calculation of the size of the forecast reliability gap represents the additional megawatts of firm capacity required to reduce the annual expected USE to the reliability standard. This capacity is assumed to be 100% available during all identified trading intervals within the forecast reliability gap period only,

At the time of 2020 ESOO publication, a proposed RRO amendment – the National Electricity Amendment (Retailer Reliability Obligation trigger) Rule 2020 (RRO trigger Rule) – was soon to be released for consultation. From its commencement date[19] until 30 June 2025, this RRO trigger Rule is drafted such that AEMO's reliability forecast will be measured against the IRM of 0.0006% USE for the purpose of determining a forecast reliability gap.

AEMO has prepared the reliability forecast against the 0.002% reliability standard and against the IRM.

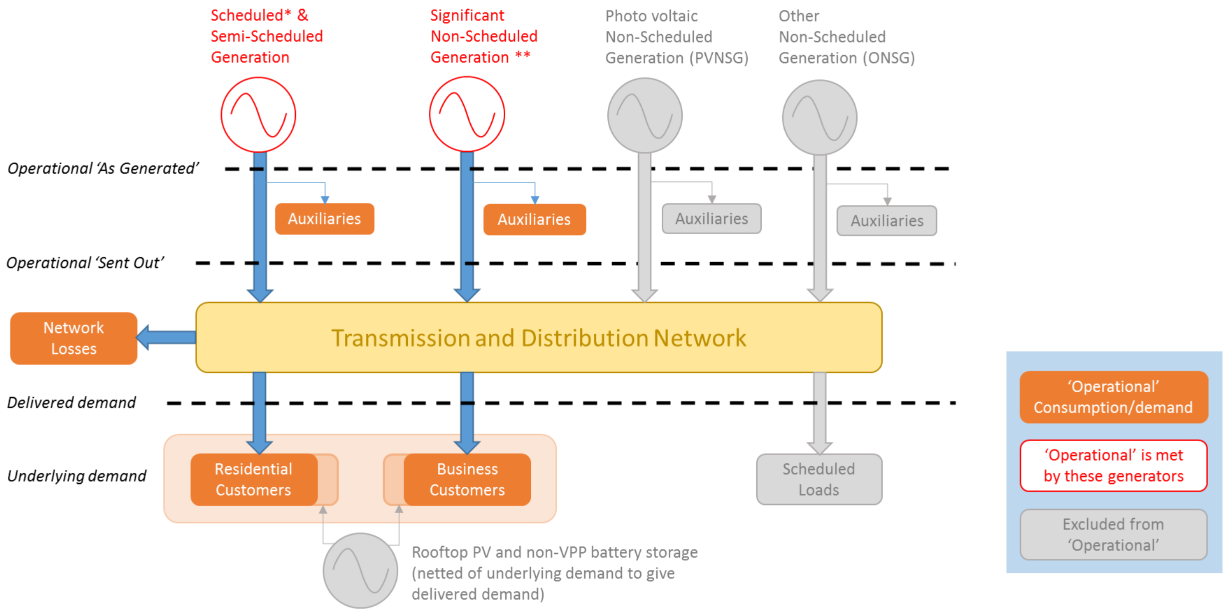
[18] The USE that contributes to the reliability standard excludes power system security incidents resulting from events such as multiple or non-credible generation and transmission events, network outages not associated with inter-regional flows, or industrial action (NER 3.9.3C(b)(2)). 'Expected' in this ESOO refers to the mathematical definition of the word, which describes the weighted-average USE outcome.

[19] Yet to be determined.

Demand forecasts

Electricity consumption and instantaneous demand can be measured at different places in the network. The forecasts in this report refer to **operational consumption/demand (sent out)**[20] unless otherwise stated. This is the consumption to be supplied to the grid by scheduled, semi-scheduled, and significant non-scheduled generators (excluding their auxiliary loads, or electricity used by the generator). Demand definitions are shown in Figure 4.

Figure 4 Demand definitions used in this report



* Including virtual power plants (VPPs) from aggregated behind-the-meter battery storage.
** For definitions, see https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/2020/demand-terms-in-emms-data-model.pdf.

Consumption forecasts for each sector (residential and business) are **delivered consumption**, meaning the electricity delivered from the grid to household and business consumers. Annual operational consumption forecasts include this forecast delivered consumption for all consumer sectors, plus electricity expected to be lost in transmission and distribution.

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

Maximum and minimum demand means the highest and lowest level of electricity drawn from the grid at any one time in a year. These forecasts are presented **sent out** (the electricity measured at generators' terminals) and **as generated** (including auxiliary loads).

Maximum and minimum demand forecasts can be presented with:

- A **50% probability of exceedance (POE),** meaning they are expected statistically to be met or exceeded one year in two, and are based on average weather conditions, or
- A **10% POE** (for maximum demand) or **90% POE** (for minimum demand), based on more extreme conditions that could be expected one year in 10 (and also called one-in-10).
- A **90% POE** (for maximum demand) or **10% POE** (for minimum demand), based on less extreme conditions that could be expected nine years in 10.

NEM time – the NEM is operated on Australian Eastern Standard Time, which does not include daylight savings. Time is reported on that basis unless otherwise noted.

[20] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Demand-Forecasts/Operational-Consumption-definition.pdf.

1.3 Forecasting reliability

Overall approach to forecasting reliability

Following extensive stakeholder consultation, AEMO has forecast reliability of supply for the NEM in the 2020 ESOO, by:

- Developing new demand forecasts for all regions, taking into account the latest information on economic and population drivers and trends in behaviour by household and business consumers, including the forecast impact of COVID-19. The forecasts for operational or delivered consumption also reflect forecasts for advances in energy efficiency (EE) and growth in distributed solar generation and battery storage systems.
- Updating the supply available to meet this demand to include the latest information on existing and committed generation in the NEM and expected closures.
- Reviewing the performance of existing conventional generation based on historical performance data, and incorporating forward-looking projections of plant reliability for some generators that take into account the impact of maintenance plans, deterioration due to age, and reductions in maintenance as generators approach retirement.
- Applying a statistical simulation approach[21] which assesses the ability of existing and committed[22] generation to meet forecast demand in all hours. The model calculates expected USE over a number of demand and renewable generation outcomes (based on 10 historical reference years of weather) and random generator outages, weighted by likelihood of occurrence, to determine the probability of any supply shortfalls. These shortfalls have been expressed in terms of the forecast expected USE.

Pain sharing is not included in the ESOO modelling. Instead, the annual USE reported in a region reflects the source of any supply shortfall, and is intended to provide participants with the most appropriate locational signals to drive efficient market responses.

More details on the methodologies used to develop the demand and supply forecasts and assess expected USE are available in the accompanying information listed in Section B.

The assumptions used to develop the reliability forecasts are outlined in the July 2020 Generator Information Page, and the 2020 IASR[23].

USE and investment needs

The expected USE calculated through the statistical model is compared against the maximum threshold specified by the reliability standard and the IRM.

For the RRO, if a reliability gap is determined to be material, AEMO calculates the reliability gap size, indicating the need (in megawatts) for dispatchable generation or equivalent within the reliability gap period to reduce USE so the standard will be met.

Further investment is possible with sufficient lead time, provided a conducive investment landscape exists. In the medium to longer term, the ESOO indicative reliability forecast highlights the opportunities for market investment to meet customer needs, and the risks if investment is not forthcoming.

1.4 Scenarios and sensitivities

The reliability forecasts presented in the ESOO are impacted by two key factors in the 10-year outlook:

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[21] See ESOO Methodology Report, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

[22] Commitment criteria are listed and explained under the Background Information tab in each regional spreadsheet on AEMO's Generation Information web page, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

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

- Demand forecasts, including the trends in distributed energy resources (DER), as outlined in Chapter 2.
- Supply forecasts, including generation, transmission, and storage developments, and availability of these, as outlined in Chapter 3.

For RRO purposes, the Australian Energy Regulator's (AER's) interim best practice forecasting guidelines require the reliability forecast and indicative reliability forecast to be determined on the neutral forecast, which is AEMO's Central scenario. The 2020 ESOO therefore focuses on AEMO's Central scenario, but also assesses supply adequacy for two alternative futures, as outlined in Table 2.

These three scenarios are a subset of the five developed in consultation with industry and consumer groups for use in AEMO's 2019 and 2020 forecasting and planning publications, including the *Integrated System Plan* (ISP). Further information on the scenarios are available in the 2020 IASR[24]. The latest inputs and assumptions applied to these scenarios have been consulted on since December 2019, and are also outlined in the IASR.

Three sensitivities around the Central scenario have been also considered in the 2020 ESOO, that explore possible impacts on electricity consumption and maximum and minimum demand should COVID-19 impacts persist longer than expected:

- *Central Downside* captures a more sustained economic downturn and lower manufacturing activity before returning to trend by 2023-24.
- *Central Downside, High DER* captures the same economic downturn as the Central Downside sensitivity but examines how higher distributed PV uptake, possibly stimulated by Government recovery efforts, could affect grid consumption.
- *Central Downside, High DER + Industrial closures)* captures the same economic downturn and PV uptake as the Central Downside, High DER sensitivity but applies a larger shock to the manufacturing sector, with only a partial return of load by 2023-24.

For each of the scenarios modelled in the ESOO's supply adequacy assessment, the NEM's available supply reflects only the existing and committed generation (as discussed in Chapter 3). The analysis therefore identifies whether there is sufficient available and committed capacity to meet the reliability standard under each scenario without any further market response.

AEMO has also undertaken two additional sensitivities beyond those in Table 2:

- The *Actionable ISP Projects* sensitivity, which includes the major actionable transmission augmentations specified in the 2020 ISP.
- A sensitivity that reflects key supply scarcity risks for summer 2020-21 related to new generation commissioning delays or outages this summer and further described and presented in Chapter 4.

Table 2 Scenario drivers of most relevance to the NEM demand forecasts used in this 2020 ESOO

Driver	Scenarios			Sensitivities		
	Slow Change	Central	Step Change	Central Downside	Central Downside, High DER	Central Downside, High DER + industrial closures)
	Demand drivers					
Economic growth and population outlook	Slower growth	Central	Higher growth	Central (Downside)[A]	Central (Downside)	Central (Downside)
EE improvements	Low	Moderate	High	Moderate	Moderate	Moderate

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

Driver	Scenarios			Sensitivities		
	Slow Change	Central	Step Change	Central Downside	Central Downside, High DER	Central Downside, High DER + industrial closures)
DSP	Low	Moderate	High	Moderate	Moderate	Moderate
	DER uptake					
Distributed PV	Low	Central	High	Central	High	High
Battery storage installed capacity	Low	Moderate	High	Central	High	High
EV uptake	Low	Central	High	Central	Central	Central
	COVID-19 settings					
Restrictions time period	15-18 months	6-9 months	6-9 months	15-18 months	15-18 months	15-18 months
Business	Slow recovery	Moderate recovery	Quick recovery	Slow recovery	Slow recovery	Slow recovery
Industrial	Closures of at-risk industrial facilities	Limited impact	Limited impact	Limited impact (U-shaped recovery)[B]	Limited impact (U-shaped recovery)	Early closures (L-shaped recovery)
Max demand offset[C]	Lower	Central	Upper	Central	Upper	Central
Min demand offset[C]	Lower	Central	Upper	Central	Lower	Lower

A. A downside economic outlook provided by economic consultants BIS Oxford, based on second wave of contagion and slower recovery. See the IASR for more details.
B. The terminology used by economists for recession shapes denotes the type of recovery owing to the shape of the economic data during a recession. In this case the U-shape refers to an energy usage downturn that has a visible trough, but recovers to trend. The L-shape refers to a more severe downturn in energy consumption that does not return to growth.
C. An explanation of maximum demand offset and minimum demand offset is in Appendix A3.

1.5 Additional information for 2020 ESOO

Table 3 provides links to additional information provided either as part of the 2020 ESOO accompanying information suite, or in related AEMO planning information.

Table 3 Links to supporting information

Information source	Website address and link
2020 ESOO supplementary results, data files, methodologies and constraints, including: 2020 ESOO model and user guide 2020 ESOO Constraints Workbook Market modelling methodology report Demand Forecasting Methodology Information Paper Demand Side Participation (DSP) Forecasting Methodology	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities
Interim Reliability Forecast Guidelines ESOO and Reliability Forecast Methodology Document	https://aemo.com.au/en/consultations/current-and-closed-consultations/interim-reliability-forecast-guidelines
Reliability Standard Implementation Guidelines (RSIG)	https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/reliability-standard-implementation-guidelines#:~:text=3D%20of%20the%20National%20Electricity,will%20implement%20the%20reliability%20standard.
Demand forecasting data portal	http://forecasting.aemo.com.au
Forecasting Accuracy Reporting	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Forecasting-Accuracy-Reporting
Forecast Accuracy Report Methodology *(under consultation)*	https://aemo.com.au/consultations/current-and-closed-consultations/forecast-accuracy-report-methodology
Generation Information web page	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information
Medium Term Projected Assessment of System Adequacy (MT PASA)	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Market-Management-System-MMS/Projected-Assessment-of-System-Adequacy
Integrated System Plan	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan
Interim Forecasting Best Practice Guidelines Compliance Report	To be provided to the AER at the time of publishing.
Consultant reports supporting the development of the 2020 ESOO	
BIS Oxford Economics, 2020 Macroeconomic forecasts	**Primary forecasts:** https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/bis-oxford-economics-macroeconomic-projections.pdf?la=en **COVID-19 update:** https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/bis-oxford-economics-macroeconomic-central-scenario-and-downside-scenario-forecast.pdf?la=en

Information source	Website address and link
CSIRO, 2020 projections for small-scale embedded technologies	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/csiro-der-forecast-report.pdf?la=en
Green Energy Markets, 2020 projections for distributed energy resources	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/green-energy-markets-der-forecast-report.pdf?la=en
AEP Elical – Assessment of Ageing Coal-Fired Generation Reliability	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

2. Demand forecasts

This chapter discusses the forecast input drivers, operational electricity consumption, and maximum and minimum demand for the next 20 years, and highlights the uncertainty in near-term forecasts resulting from COVID-19.

Key insights

- COVID-19 is changing energy usage patterns as a result of disrupted economic and social activities and changing work arrangements, and the short to medium-term impact on electricity consumption is highly uncertain, despite the net impact on total consumption to date being relatively modest:
  - Projections for population growth, Gross Domestic Product (GDP), and household construction have reduced in the short to medium term in light of COVID-19, subject to substantial uncertainty.
  - Consistent with input projections and observed changes in consumption patterns, forecast maximum demand and business operational energy consumption has reduced slightly compared to the 2019 ESOO forecasts, as a consequence of COVID-19, while forecast residential consumption has increased due to people staying in their homes.
  - As this situation remains dynamic throughout 2020, AEMO has used the Slow Change scenario and Central downside sensitivities to explore possible impacts on electricity consumption and demand extremes should the consequences of the pandemic persist longer than initially expected.
- In the medium term (to 2030), operational energy consumption and maximum demand forecasts are relatively flat in most regions as EE and distributed PV are projected to offset growth drivers:
  - Australia's population growth is expected to be a strong driver of underlying growth in consumption for the residential sector, and along with mining activity, is a key contributor to forecast economic and consumption growth in the business sector.
  - Expected increases in EE, continuing structural change in the economy away from energy-intensive industries, and further increases in distributed PV installations are expected to temper growth in both operational consumption and maximum demand in the next 10 years.
  - Forecasts for distributed PV installations have been revised upwards. While this further offsets potential growth in operational energy consumption, it does not materially impact maximum operational demand forecasts, due to distributed PV having already driven the timing of maximum demand towards sunset in most NEM regions.
- Minimum operational demand forecasts are dominated by projected growth in distributed PV:
  - Victoria and South Australia are forecast to experience rapid declines in minimum demand due to a high projected uptake of distributed PV. New South Wales and Queensland are expected to experience a more moderate decline, while Tasmania is forecast to have the slowest decline.
- In the longer term (10-20 years), many NEM regions are forecast to return to growth in operational energy consumption and maximum demand, driven by electric vehicles (EVs) and a level of saturation in distributed PV and EE investments.

2.1 Input drivers of demand

The scenarios and sensitivities explored in this ESOO are predicated on a wide array of inputs and assumptions, which are documented in AEMO's accompanying 2020 IASR[25]. Input considerations include:

- Economic and population growth.
- DER including distributed PV and customer batteries.
- EE.
- EVs.
- Weather and climate.

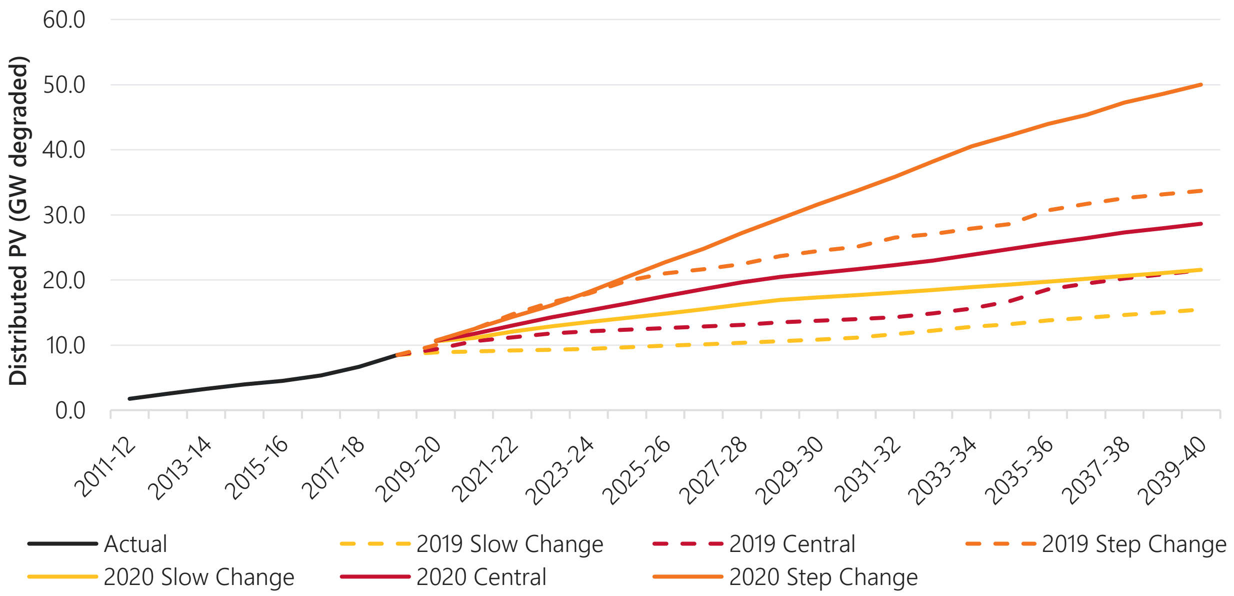
Changes in consumption and maximum and minimum demand forecasts compared to the 2019 ESOO are influenced by two material factors: revised forecasts for distributed PV and the COVID-19 pandemic. These key changes are explored in further detail below.

Distributed PV

Distributed PV systems – including residential, commercial, and larger embedded and PV non-scheduled generation (PVNSG) systems[26] – have seen very strong growth over 2019 and early 2020, leading to approximately 2.1 gigawatts (GW) of new installations over the 2019 calendar year, and a total capacity of distributed PV systems in the NEM of about 10.7 GW[27].

A comparison of the 2019 and 2020 distributed PV forecasts is shown in Figure 5.

Figure 5 NEM distributed PV installed capacity



The 2020 PV forecasts are higher than the 2019 forecast, driven by influences including:

- A revision to CSIRO's short-term forecast methodology, in response to recent strong installation rates.
- Broader inclusion of Victoria's Solar Homes program.

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

[26] Residential and commercial systems are defined as systems smaller than or equal to 100 kW. PVNSG defines systems greater than 100 kW, up to 30 MW. Distributed PV covers all residential, commercial, and PVNSG systems.

[27] Installed capacity estimate as at 30 June 2020, unadjusted for degradation.

- Lower PV cost assumptions.
- An increase in forecast average PV system sizes.
- Tempered short-term growth in distributed PV, assuming a slowing effect from COVID-19[28].

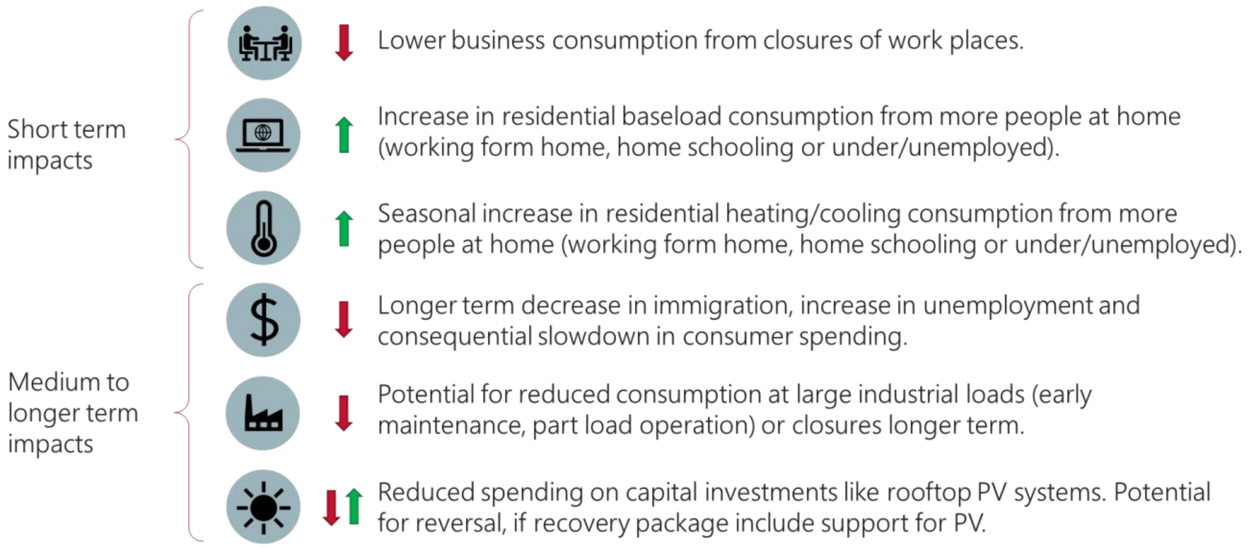
The upwards revision in forecast distributed PV has a dampening effect on operational energy consumption forecasts, and is a key driver of the forecast rapid decline in minimum operational demand. The implications of low minimum operational demand levels are further explored in Chapter 7.

COVID-19's impact on the demand outlook

The COVID-19 pandemic has introduced an unprecedented level of near-term uncertainty around the international and domestic economic outlook, population migration and associated energy consumption, and maximum and minimum demand forecasts.

AEMO has sought to investigate, research, measure and model possible impacts on the electricity forecasts, taking into account the complex interaction of impacts that differ between sectors, across the day, and season by season. This has been summarised in Figure 6.

Figure 6 Complex interaction of COVID-19 impacts on demand



As the interaction is complex and unprecedented, the overall impact is highly uncertain. AEMO has used a number of techniques to deal with this uncertainty, including:

- Running sensitivities on short-term consumption with three specific downside sensitivities (see Section 1.4).
- Updating Central scenario economic assumptions, using 'book-ends' to estimate near-term best-case and worst-case (downside) outlooks.
- Capturing the expected slowdown in the outlook for new connections.
- Updating the DER outlook to reflect a potential COVID-19 related slowdown in distributed PV sales, but also considering implications if there is no slowdown (which is more in line with the latest sales figures for June and July 2020).
- Observing usage changes detected through monitoring the different consumption sectors.
- Statistically analysing time-of-use consumption patterns to estimate impacts at times of maximum and minimum demand.

[28] The degree to which growth is tempered varies across scenarios.

- Continually monitoring emerging trends and discussing these at industry forums.

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

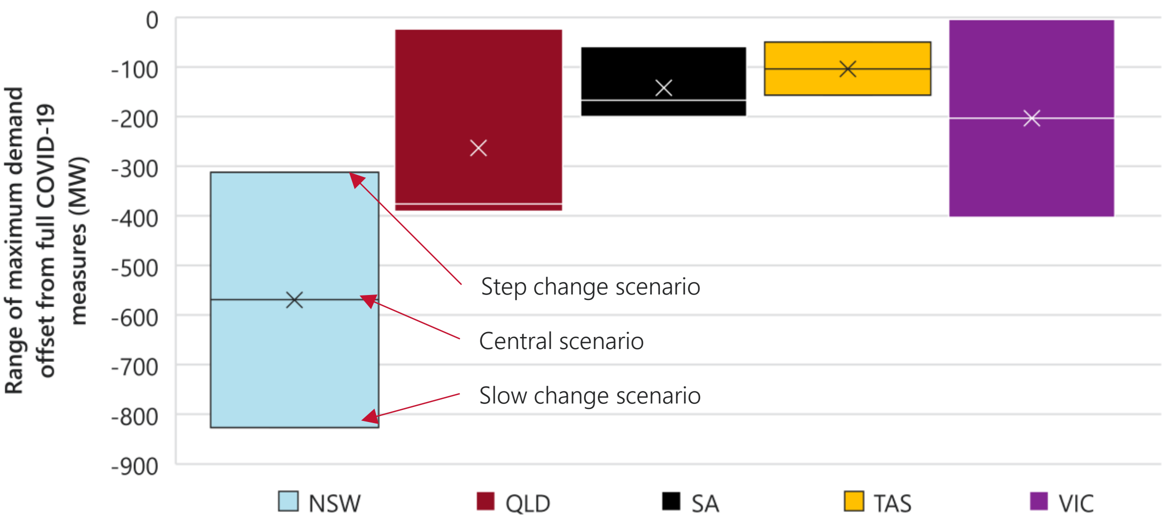
AEMO engaged with stakeholders to understand and improve COVID-19 related forecasts across three extra Forecasting Reference Group (FRG) meetings in April, May, and June 2020. Additional meetings were also convened with Energy Networks Australia (ENA) members on the same topic.

For maximum operational demand, AEMO projected the impacts of COVID-19 through comparing model outcomes before and after COVID-19 at a half-hourly level. This revealed intra-day variations in energy usage patterns, as residential customers have worked from home and businesses have been shut down. This results in a later morning peak and an earlier evening peak.

At the time of maximum demand, which is during the early evening in summer in most regions, COVID-19 is projected to lower demand in 2020-21 compared to what it otherwise would have been. When supplemented with further statistical analysis, a large uncertainty in the estimated impacts is apparent. To reflect this, AEMO has used a range of forecast operational maximum demand impacts across the different scenarios and sensitivities, as illustrated in Figure 7.

Figure 7 highlights a forecast reduction in demand due to COVID-19 across all scenarios and sensitivities, with the reductions being most significant in New South Wales and Queensland, driven by lower business consumption, in particular from the manufacturing sector.

Figure 7 Illustrative impacts of COVID-19 on regional all seasons maximum demand by ESOO scenario for 2020-21



The range of possible outcomes illustrates the large short-term uncertainty in the possible impacts of COVID-19, with significant potential reductions in the Slow Change scenario arising from a severe downturn of business consumption, including large industrial loads. The downward adjustment for the Step Change scenario in comparison is far smaller, and underlying growth (discussed in Section 2.2) leads to a minor increase in forecast maximum demand in some regions.

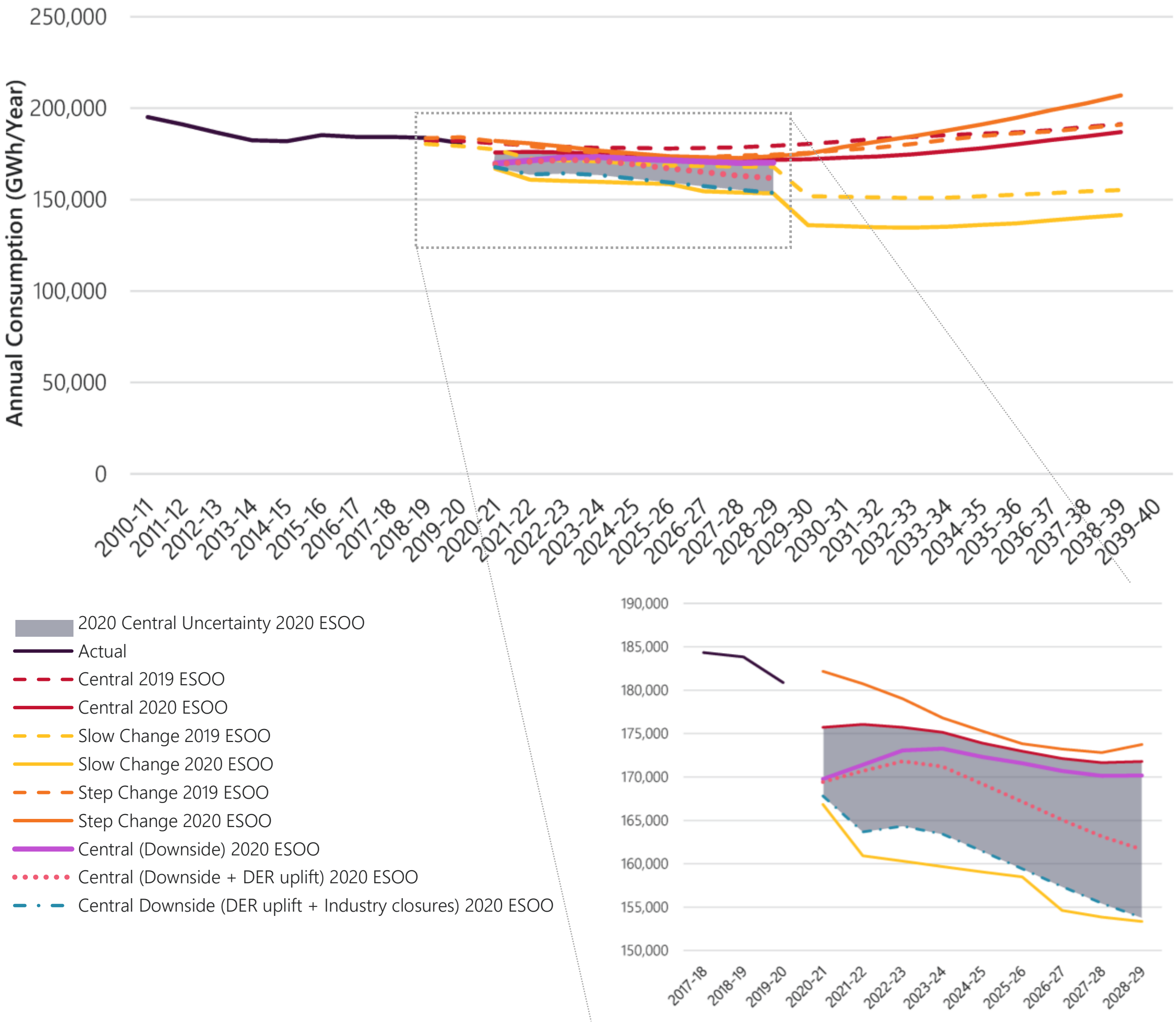
Consumption growth is correlated to broader economic and population growth; however, different sectors in the economy have different electricity intensities and impacts will vary. Without historical precedent, it is likely AEMO's normal forecast models understate the impacts of the pandemic. Analysis of consumption in the second quarter of 2020 indicates that, compared to the same time last year, if weather conditions had been similar, COVID-19 would have reduced energy consumption by approximately 2.1%[29] and the medium-term impact on businesses is, as yet, unknown. To adjust for this COVID-19 impact, AEMO has assumed an additional temporary (elastic) shock, proportional to the % Gross Value Added (GVA) as forecast in the updated economic outlook. This results in an approximate 3 terawatt hours (TWh) reduction in annual consumption in the Central scenario for 2020-21. The Slow Change scenario is associated with an approximate 7 TWh reduction and a slower recovery, incorporating a higher risk of permanent demand destruction. In Figure 8 in the next section, the range of potential short- to medium-term impacts of COVID-19 on consumption under the various sensitivities is depicted by the grey shaded area.

For further information, including the impacts applied for the sensitivities, see Appendix A2.

2.2 Operational energy consumption

Figure 8 compares the 2020 ESOO and 2019 ESOO forecasts for annual consumption across the scenarios and sensitivities introduced in Section 1.4.

Figure 8 Forecast NEM operational consumption as sent out, actual and forecast, all scenarios, 2010-11 to 2039-40, for the 2020 ESOO and compared to the 2019 ESOO



[29] See AEMO, Quarterly Energy Dynamics Q2 2020, at https://www.aemo.com.au/-/media/files/major-publications/qed/2020/qed-q2-2020.pdf.

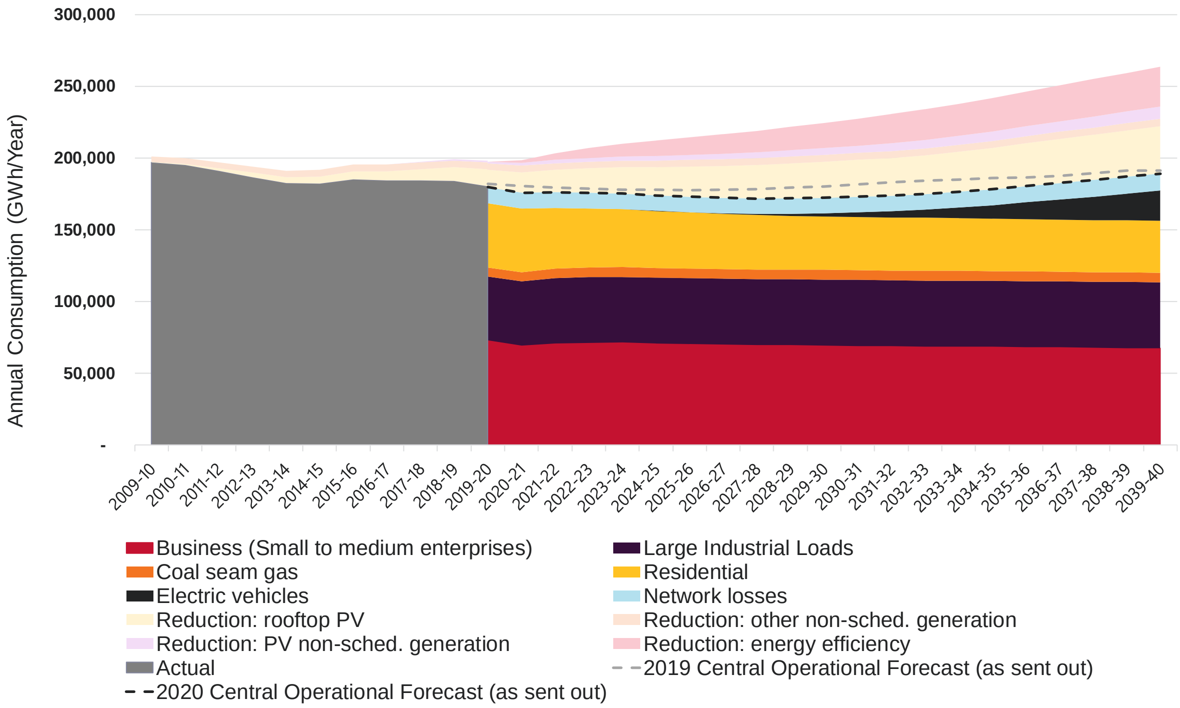
Differences include:

- The inclusion of COVID-19 across the scenarios, resulting in lower consumption than forecast in the 2019 ESOO, and an increase in uncertainty in the short term. The Slow Change scenario includes industrial closures and a larger shock factor (resulting in further demand destruction) for sectors of the economy, in particular the energy-intensive manufacturing sector, identified to be at heightened risk from the disruptions caused by COVID-19.
- More distributed PV in both the residential and business sector (an increase of about 16.5 TWh by 2029-30 in the Central scenario) offsetting consumption growth throughout the 2020s.
- A significantly higher EV forecast (of 100% electrification by 2049-50) in the 2020 Step Change scenario.

Further regional details are in Appendix A1.

Figure 9 shows forecast growth in electricity consumption for the Central scenario, disaggregated into AEMO's component sectors. These sectors, explored further in the remainder of this chapter, include those components projected to reduce operational consumption, such as DER and EE activities.

Figure 9 NEM electricity consumption, actual and forecast, 2009-10 to 2039-40, Central scenario



Residential sector

Figure 10 shows forecasts for underlying and delivered consumption for the 2020 Central scenario in the residential sector, highlighting that PV and EE activities are projected to temper growth in grid consumption that would otherwise be expected from ongoing new connections.

The forecast growth in new connections heavily influences the scenario projections for underlying consumption. The average consumption per household across the NEM is 6.2 MWh per year. An increase of 10,000 connections will therefore increase consumption by approximately 62 MWh (or 0.1% of the current residential sector size) all else being equal. Differences in EE savings and distributed PV uptake will modify this relationship between new connections and expected consumption growth over time.

The forecast for new connections varies depending on the scenario:

- In the 2020 Central scenario, the number of connections is forecast to increase from 9.2 million in 2019-20 to 11.8 million in 2039-40 (1.3% average annual growth rate).

- In the Step Change scenario, the connections forecast is higher (1.7% average annual growth rate).
- In the Slow Change scenario, the projected growth in connections is lower (1% average annual growth rate).

Figure 10 Forecast underlying residential demand, delivered residential demand without EVs (sourced from grid), distributed PV, and additional energy efficiency savings, Central scenario

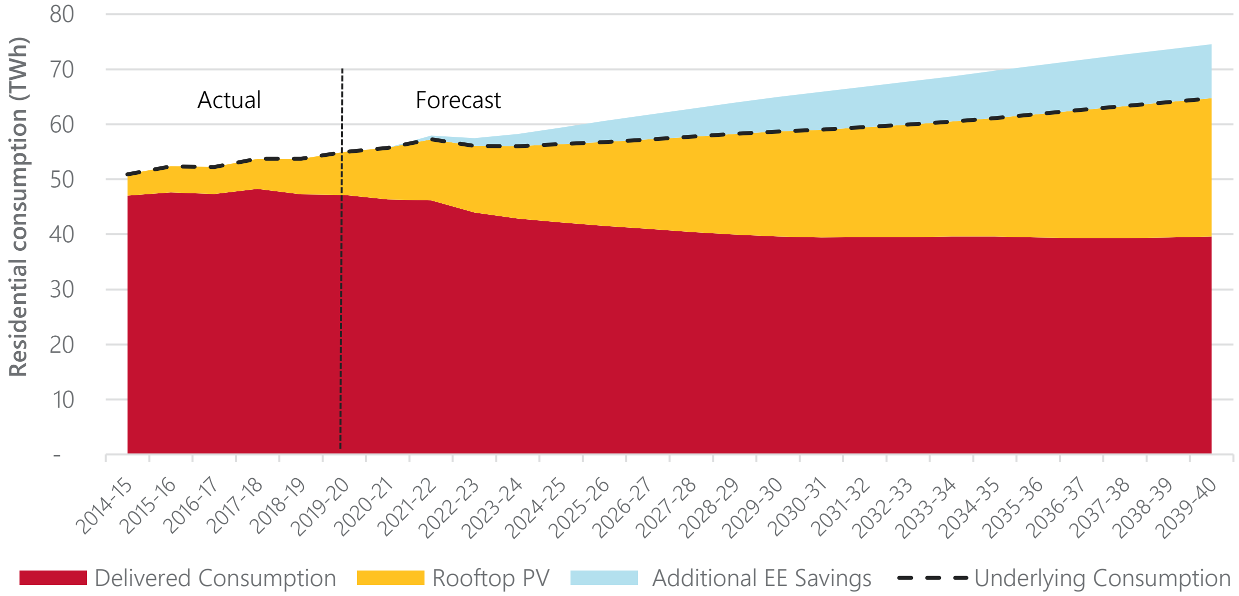
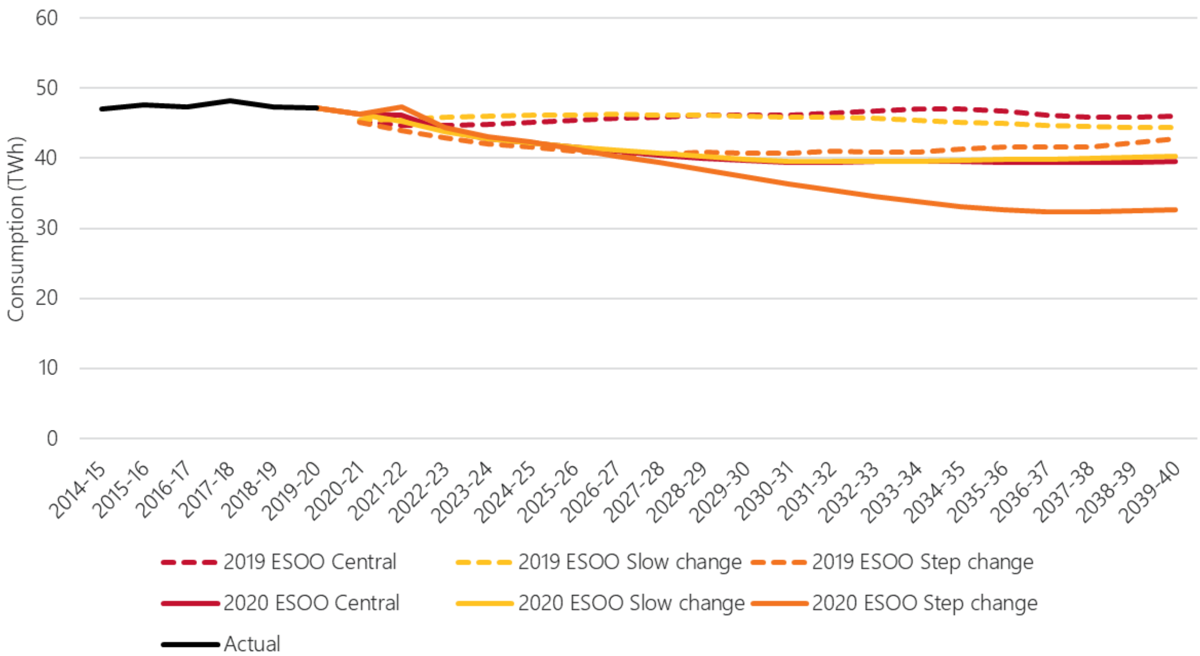


Figure 11 shows the residential forecast across the 2020 ESOO scenarios compared to the 2019 ESOO scenarios, and actual delivered demand.

Figure 11 NEM delivered residential electricity consumption forecast without EVs, all scenarios, 2020-21 to 2039-40, and compared to the 2019 ESOO



In the first two years of the forecast, residential consumption is projected to be higher, in part due to the modelled impact of COVID-19 leading to greater "work from home" energy consumption. Beyond this point, a forecast return to near pre-COVID-19 mobility levels in all three scenarios reduces residential consumption. Over the 20-year forecast period, the 2020 ESOO forecast is trending lower than the 2019 ESOO forecast for all scenarios. This is mainly due to stronger projections in the uptake of distributed PV and moderately higher EE savings in the forecast

As shown in Figure 11:

- Residential delivered consumption in 2019-20 was 47.1 TWh. In the 2020 Central scenario, by 2029-30, this consumption is forecast to drop to 39.6 TWh, due to a lower forecast for new dwellings and higher distributed PV uptake compared to the 2019 Central forecast. This represents an average annual rate of change of -1.7% over the first decade. Consumption (excluding EVs) is then forecast to remain steady to 2039-40.
- Residential delivered electricity consumption in the 2020 Slow Change scenario is forecast to decline in the short to medium term, despite lower uptake of distributed PV and EE than the 2020 Central scenario. This is due to lower forecasts for new dwellings, leading to a forecast average annual rate of change to 2029-30 of -1.6% compared to residential delivered consumption in 2019-20. Consumption in the 2020 Slow Change scenario is forecast to remain stable over the second decade, due to the lower forecast in new dwellings.
- The 2020 Step Change scenario forecast reflects higher new dwellings compared to the 2020 Central scenario, but also greater DER and EE measures. The residential delivered consumption in the Step Change scenario is forecast to drop to 37.4 TWh by 2029-30, due to stronger uptake of distributed PV and additional measures increasing EE savings. This represents an average annual growth rate of -2.3% over the first decade. The decline is forecast to continue until the mid-2030s and then to remain steady, with some level of distributed PV and EE saturation reducing the offsetting effect of these factors on the projected growth of new dwellings. This leads to a forecast average annual rate of change of -1.4% over the second decade.

Small to medium enterprises (SME)

The majority of businesses in the Australian economy are SMEs, and AEMO applies a dedicated SME model to capture the structural changes taking place in the economy outside of large energy users. In general, large-scale industrial production is expected to continue shrinking as a proportion of Australia's economic output, as energy-intensive manufacturing (captured by the large industrial load [LIL] sector) continues to be displaced by growth in the services sector.

The SME sector includes all businesses which are not included in the LIL sector, and consists primarily of businesses in the services sector and smaller manufacturing businesses:

- The services sector is dominated by financial services, transport, retail, education, health care, and telecommunications.
- Smaller manufacturing activities include food processing and the fabrication and repair of metal and other products, machinery, and equipment.

Forecast consumption from SME businesses is strongly linked to economic growth, the changing sectorial mix, customer responses to electricity prices, and investment in EE and onsite generation (distributed PV). Of these variables, economic growth is the dominant growth driver for long-term consumption growth, with distributed PV and EE the dominant drivers for long-term declining consumption.

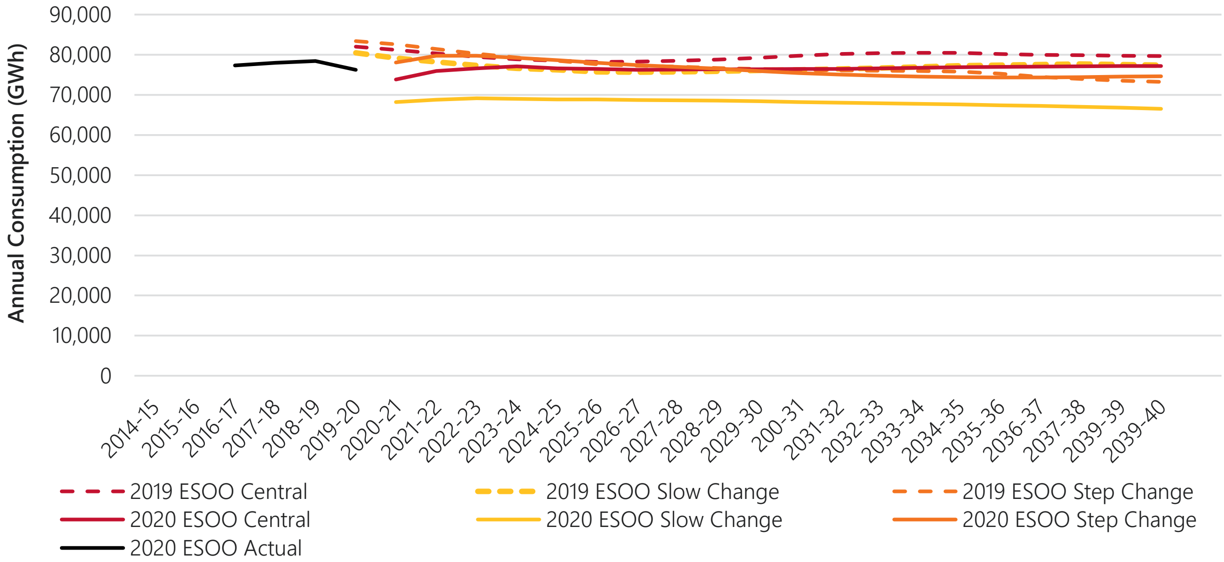
Figure 12 shows the trend in forecast SME business consumption for the 2020 ESOO scenarios, and compares these to the 2019 ESOO scenario demand forecasts.

The 2020 business forecasts project:

- In the Central scenario, increases in consumption due to growth in GSP and population is forecast to be offset by increased energy productivity and EE savings and commercial distributed PV growth. By 2039-40, total SME delivered consumption is expected to hold steady at 77 TWh – this includes the approximate net effect of offsets for distributed PV of approximately 7 TWh, and EE of 18 TWh.

- In the Step Change scenario, the impacts of higher economic activity, EV uptake, and population growth are projected to be offset by much higher EE measures increasing energy productivity. This results in the 2020 Step Change scenario crossing below the 2019 Central scenario by 2029-30, with new EE measures projected to offset consumption by a further 27 TWh by 2039-40.
- In the Slow Change scenario, there is greater downside risk for energy consumption, due to a greater and more permanent impact modelled from COVID-19, along with milder economic and population growth projections in the long term (that is, reduced business confidence and sluggish export markets). Consumption remains lower than the Central scenario throughout the forecast horizon.

Figure 12 NEM delivered SME electricity consumption forecast, all scenarios, 2020-21 to 2039-40, and compared to the 2019 ESOO forecast



Large industrial loads (LIL)

The LIL component includes the aggregation of the coal mining, water infrastructure, and manufacturing sub-sectors, as well as other large energy users outside these sectors:

- Coal mining loads are those mainly engaged in open-cut or underground coal mining.
- Coal-seam gas (CSG) loads are those engaged in the extraction and processing of CSG to service domestic gas customers and exports of liquefied natural gas (LNG).
- Water infrastructure facilities are those loads mainly engaged in the production, management and treatment of water for residential and industrial users.
- Manufacturing loads include those involved in transforming materials, substances, or components into new products. Key industries in this sector include basic chemical manufacturers, primary metal manufacturers (including aluminium smelting), food manufacturers, paper manufacturers, and metal ore mining.

For the 2020 ESOO, AEMO conducted detailed interviews and surveys with LILs to identify broad market dynamics affecting these sites, as well as industry-specific opportunities and threats. AEMO sought stakeholder feedback when presenting both the survey design and survey results in FRG meetings. The data gathering process[30] focused particularly on the current and future implications of COVID-19 on energy consumption, although the bulk of the interviews were conducted in April 2020 when there was significant uncertainty about COVID-19 impacts. This process revealed that many LILs face challenging economic conditions in the near term, with some facing decisions about their ongoing domestic operations. The uncertainty around the sustainability of these operations is reflected in the Slow Change scenario and one of the COVID-19 Central sensitivities.

Survey and interview feedback uncovered a number of projects potentially affecting energy consumption, such as EE programs, technological improvements, site expansions, and on-site generation. The assumed impacts of such developments are present in all scenarios, but are most prevalent in the Step Change scenario.

For the 2020 forecasts:

- In the Central scenario, the forecast trend is for modest increases in electricity consumption for LILs over the 20-year outlook. Industry feedback generally identified little incentive for new major investment.
- The Step Change scenario forecast shows a modest increase in electricity consumption for LILs prior to 2025-26. Following this, a slight decline in electricity consumption is observed towards the end of the forecast horizon, with several on-site generation projects considered under this scenario.
- Under the Slow Change scenario, consumption is forecast to fall over the short to medium term, with some closures of loads perceived to be most at-risk assumed in the forecast. These risks were assumed to increase over the 20-year outlook, due to persisting weak economic conditions eroding business resilience in this scenario.

Coal seam gas sector forecasts

The impact of COVID-19 on the global economy is expected to reduce global LNG demand beyond 2020. Given that current LNG exports are pre-contracted, it is unlikely eastern Australian LNG production will be curbed to the extent observed in many parts of the world[31]. As at July 2020, no decline in Australian exports due to lockdown restrictions had been observed, indicating that Australian exports are yet to react to any shifts in international demand[32]. AEMO continues to closely monitor the impacts of COVID-19 on eastern Australia CSG production.

Electricity forecasts for the CSG sector, shown in Figure 13, reflect the grid-delivered electricity projected to be consumed by east coast LNG consortia in the extraction, processing and transportation of CSG to export facilities.

Electricity consumption forecasts reflect CSG production forecasts provided to AEMO by the LNG consortia that are consistent with the 2020 *Gas Statement of Opportunities* (GSOO). In summary:

- In the Central scenario, electricity consumption is forecast to increase slightly in the short term, as the LNG consortia increase gas supply to the domestic market and two of the three LNG facilities are assumed to push towards full nameplate capacity. In the long term, consumption is projected to remain flat, at levels sufficient to meet contractual obligations, as increasing global competition reduces the incentive to increase production to capitalise on further spot market opportunities.
- The Slow Change scenario projects a decline in consumption in the second half of the outlook period, capturing a fall in contract quantity reflecting facility onsite gas usage and a lowered estimate of remaining contract obligations.

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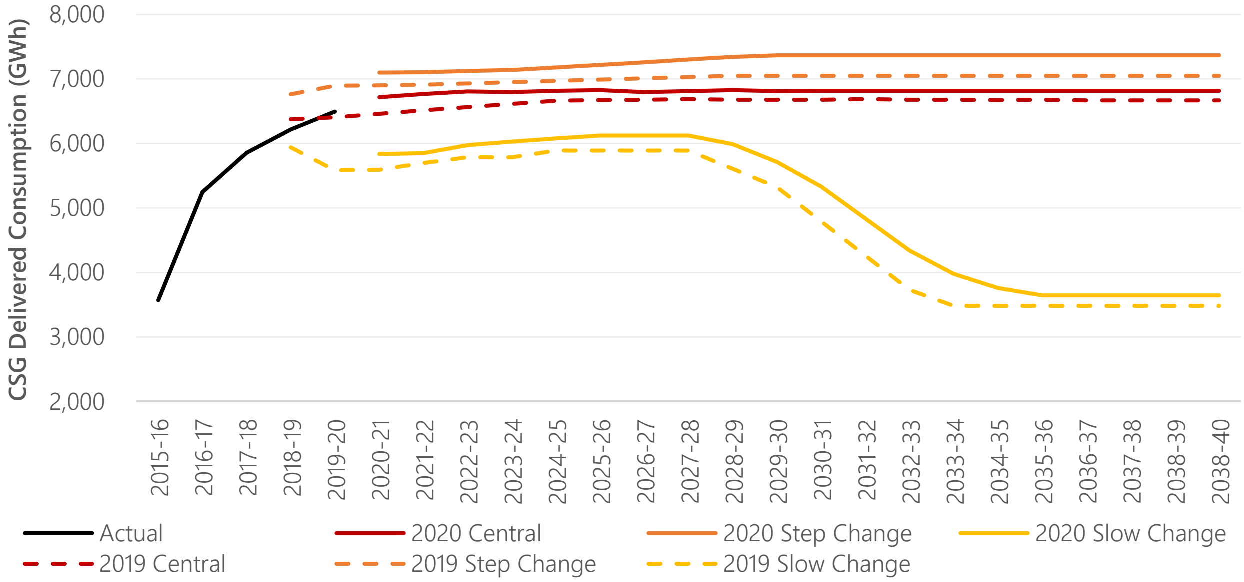
[30] AEMO's LIL survey process is outlined in greater detail in Section 3 of AEMO's *Demand Forecasting Methodology Information Paper*, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

[31] BloombergNEF, Covid-19 Indicators Update: Australian Power and Gas Markets, July 2 , 2020.

[32] There has been some increase in maintenance activities of the Curtis Island LNG facilities in recent months, but as yet these outages do not suggest extended withdrawals of capacity.

- The Step Change scenario assumes that all three projects[33] operate at full capacity throughout the forecast.

Figure 13 NEM delivered CSG electricity consumption forecast, all scenarios, 2019-20 to 2039-40, and compared to the 2019 ESOO



The 2020 ESOO CSG electricity consumption forecasts are higher than 2019 ESOO forecasts across all three scenarios. This can be attributed to updated actual consumption data, which is higher than previously forecast.

Electrification of transport

Electrification of the transport sector could be the dominant driver of growth in electricity consumption in future. EVs presently are estimated to represent less than 1% of the total vehicle fleet across the NEM. Based on the current level of uptake, and in the absence of any policy incentives, AEMO's forecast projects that the uptake of EVs across the NEM will reach only 3%, or half a million vehicles, by 2029-30 in the Central scenario. Growth is forecast to accelerate from 2030, due to assumptions of greater model choice and charging infrastructure availability, and falling costs. As a result, electrification of the transport sector is projected to accelerate in the late 2020s and into the 2030s (in line with the timing of accelerated growth forecast in the 2019 ESOO forecast).

The 2020 EV consumption forecasts are higher than the 2019 forecasts, as shown in Figure 14 below.

The 2020 EV annual consumption forecasts in Figure 14 represent consumption across a range of assumed charging profiles (further explained in the 2020 IASR). From 2030-31 onwards, this includes a proportion of vehicles assumed to participate in 'coordinated' EV charging arrangements, such as virtual power plants (VPPs), that optimise vehicle charging for demand and/or market conditions.

Key reasons for the higher EV consumption forecasts compared to the 2019 ESOO include:

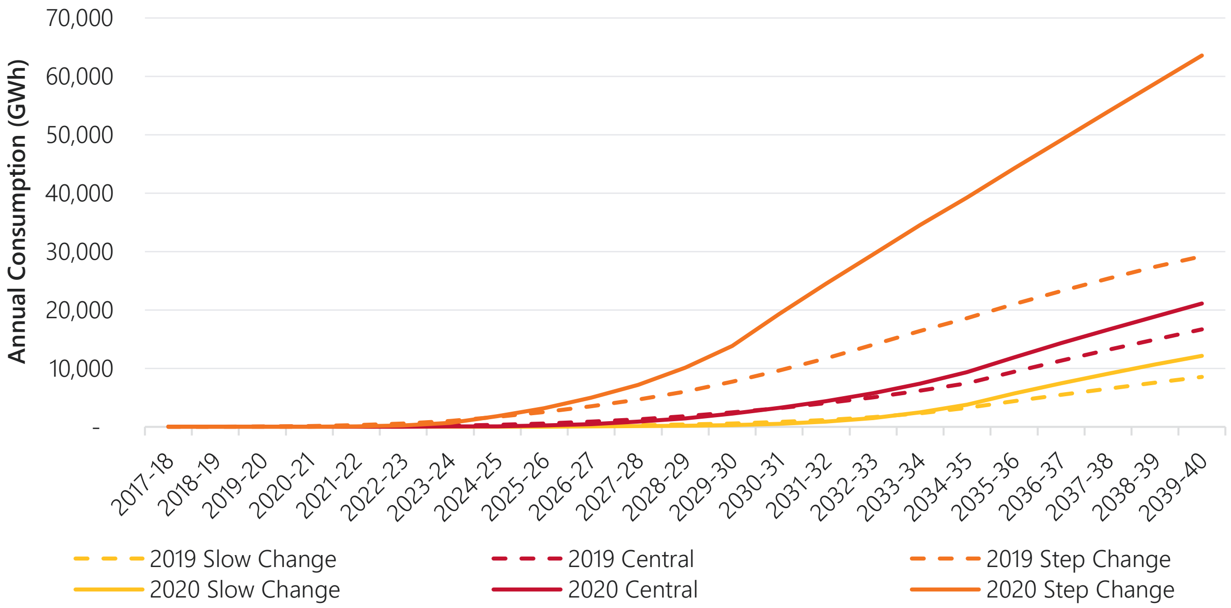
- Projections now include articulated trucks, which consume approximately 50 times more electricity per kilometre than cars[34].

[33] The three CSG projects on Curtis Island are Australia Pacific LNG (APLNG), Gladstone LNG (GLNG), and Queensland Curtis LNG (QCLNG).

[34] See Table 2-2 of CSIRO, *2020 projections for small-scale embedded technologies*, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/csiro-der-forecast-report.pdf?la=en.

- Restrictions on vehicle imports were relaxed in the forecasting model, leading to higher uptake and therefore higher energy consumption in the Central scenario.
- A greater proportion of renters have been assumed to have access to an external power supply in the Slow Change and Central scenarios to charge EVs, leading to increased vehicle uptake, which drives higher energy consumption.
- There was increased consideration for transport sector decarbonisation in the Step Change scenario, reaching a zero emissions transport fleet by 2050. To achieve this target, strong regulations and/or incentives would need to be enacted; for example, a ban on new internal combustion engine (ICE) vehicle sales by 2030 and incentivised scrapping of remaining ICE vehicles in the late 2040s. For heavier vehicles, modelling has assumed 50% of the articulated truck fleet transitions to hydrogen fuel cells as an alternative fuel.

Figure 14 NEM EV annual consumption forecast, 2017-18 to 2039-40, all scenarios, and compared to the 2019 ESOO



Distributed PV

In 2019-20, more than 13 TWh of electricity was produced by distributed PV, representing nearly 7% of total electricity production in the NEM. In the Central scenario, more distributed PV is forecast than in the 2019 ESOO, with the combined residential and business sectors forecast to produce 41.5 TWh of electricity in 2039-40, representing nearly 20% of total energy production in the NEM. The Slow Change and Step Change scenarios have 30.5 TWh and 74 TWh of forecast generation for 2039-40 respectively, reflecting uncertainty in the rate of expected continual growth.

Energy efficiency (EE)

EE means obtaining more output or service from each unit of energy[35].

AEMO's modelling considered the impact of government measures that mandate or promote EE in buildings, appliances and equipment. In the Central scenario, forecast savings from current and committed measures equate to 29.6 TWh relative to 2019-20, or approximately 13% less energy consumption by 2039-40 than would otherwise have been observed. Additional measures, representing feasible, yet ambitious, future

[35] From Murray-Leach, R. 2019, The World's First Fuel: How energy efficiency is reshaping global energy systems, Energy Efficiency Council, Melbourne, at https://www.eec.org.au/uploads/Documents/The%20Worlds%20First%20Fuel%20-%20June%202019.pdf.

standards for buildings and equipment to drive greater EE savings, were included in the Step Change scenario, resulting in approximately 42.3 TWh of forecast EE by 2039-40. The Slow Change scenario is forecast to deliver 25.3 TWh of savings by 2039-40, and assumed similar EE measures as the Central scenario, under lower economic and population growth settings.

Network losses

In addition to the above-mentioned components of operational consumption, AEMO forecasts transmission and distribution network losses. These represent energy lost due to electrical resistance and the heating of conductors as electricity flows through the transmission and distribution network.

AEMO sources these intra-regional and distribution losses as percentages (of the energy that is lost throughout the network) either from the AER (from the Regulatory Information Notice submitted by transmission or distribution network service providers) or sourced directly from the transmission or distribution service providers. AEMO uses the loss percentage for the latest financial year for the forecast period. Interconnector losses are modelled explicitly, predominantly as function of regional load and flow.

In this 2020 ESOO, AEMO forecasts intra-regional transmission and distribution network losses of about 6%, and interconnector losses of less than 1%, proportional to operational energy consumption for the forecast horizon in the Central scenario. Major developments in the generation or transmission system that are not committed could materially increase or decrease the level of network losses in this forecast.

Other non-scheduled generation

Other non-scheduled generation (ONSG) refers to small-scale wind power, hydro power, gas or biomass based cogeneration, generation from landfill gas or wastewater treatment plants, and smaller peaking plants or emergency backup generators. ONSG represents a reduction to projected underlying consumption, as shown in Figure 9. This sector is forecast to remain relatively flat throughout the forecast period.

2.3 Maximum and minimum operational demand

Maximum (and minimum) demand outcomes vary significantly year-on-year, because they are heavily dependent on weather, time of day or week, and behavioural variations in response to those drivers. A single point forecast is therefore not meaningful, and AEMO presents these forecasts as a distribution given by the 10%, 50%, and 90% POE forecasts – see Appendix A1.

Both maximum and minimum demand are measured at the regional level. Because the peaks and lowest demands occur at different times in different regions, they cannot be added together and there is no NEM-wide coincident maximum or minimum against which supply is assessed.

The forecast maximum and minimum demand is influenced by the same drivers as consumption (see Section 2.1). However, the forecast trend differs somewhat from the forecast of consumption due to technology uptake impacting the load shape across the day.

Growth in distributed PV uptake lowers consumption from the grid (both delivered and operational consumption) substantially by midday, less in the late afternoon, and has no impact after sunset. Due to distributed PV already installed, the timing of operational maximum demand has moved to later in the day. Any additional distributed PV now installed therefore has a small impact on maximum operational demand, relative to its impact on annual consumption.

On the other hand, growth in distributed PV capacity starts to rapidly reduce minimum demand once a region is experiencing a midday trough.

2.3.1 Maximum demand

Short-term outlook (0-5 years)

Projected trends over the next five years are:

- All regions are expected to experience a decline in maximum operational demand (50% POE) in 2020-21 due to the effects of COVID-19 on economic activity, changing daily demand profiles, and some large industrial customers reducing output in response to economic conditions.
- Beyond the first forecast year, maximum operational demand (50% POE) in New South Wales, South Australia, Tasmania, and Victoria is expected to remain relatively steady or grow very slightly. The average annual growth rate for these regions is expected to be within +/-0.4%. Growth in residential load is projected to be offset by slight growth in distributed PV capacity and a decline in business load due to increasing EE.
- Queensland maximum operational demand (50% POE) beyond the first forecast year is expected to grow by around 0.6% average annual growth rate, due to growth in CSG and LIL demand, slightly offset by growth in distributed PV capacity.

The impacts of COVID-19 are uncertain, as explained in Section 2.1, and AEMO has used its scenarios and extra downside sensitivities to reflect this uncertainty, as demonstrated for Victoria in Figure 15.

Figure 15 Forecast operational summer maximum demand, sent-out, 50% POE for Victoria, across all scenarios and sensitivities

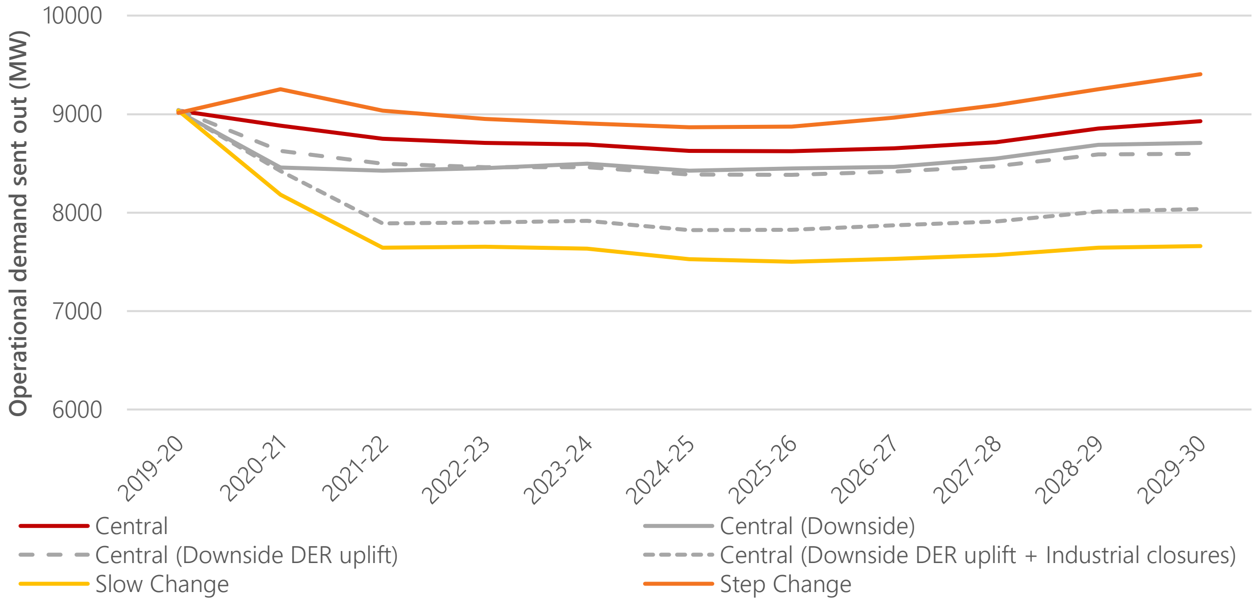


Figure 15 shows that, depending on a fast recovery (Step Change) or extended downturn with closures of some larger industrial loads (Slow Change), the forecast one-in-two year maximum demand in Victoria varies by more than 1,000 MW for the 2020-21 summer and by approximately 1,400 MW for the 2021-22 summer.

Medium-term to longer-term outlook (6-20 years)

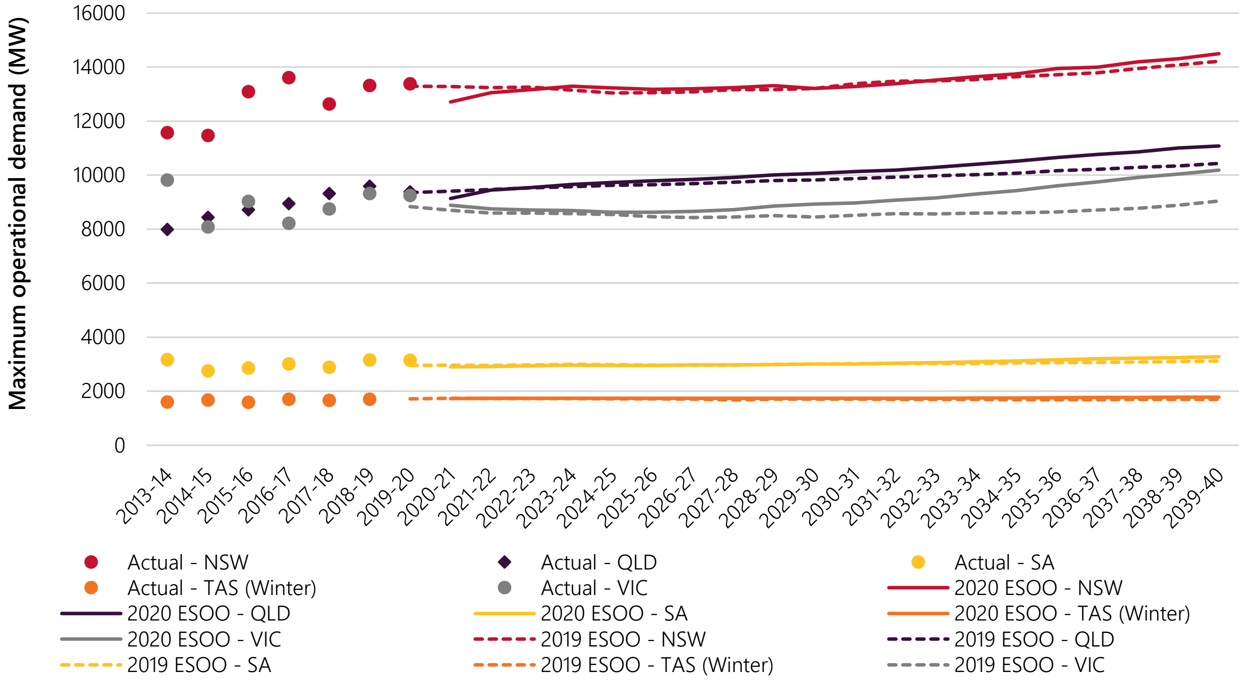
In general, the number of EVs is forecast to grow substantially towards the end of the next decade. The impact on maximum demand depends on the charging profile assumed, particularly whether or not charging is smartly managed to occur outside of peak periods. In the Central scenario, roughly half of EV owners are assumed to charge at their convenience ('convenience charging'), leading to greater evening charging and some impact on maximum demand (for more information on EV uptake and charging (see the 2020 IASR[36]).

By 2039-40, EV charging is projected to represent 2-16% of maximum demand, depending on the region and scenario assumptions.

Figure 16 shows the 50% POE maximum operation demand forecasts for the Central scenario for each region.

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

Figure 16 Regional summer (winter for Tasmania) 50% POE maximum operational demand (sent out) comparing 2020 ESOO and 2019 ESOO Central scenarios



It illustrates that from 2025-26 to 2039-40:

- Maximum demand (50% POE) in New South Wales and South Australia is forecast to experience slight growth, with 0.7% and 0.9% average annual growth rates respectively. This is due to some EE schemes being expected to taper off, as well as some EV charging at time of maximum demand (projected to represent 5.5% of demand [800 MW] in New South Wales and 4.5% of demand [140 MW] in South Australia by 2039-40).
- Maximum demand in Victoria and Queensland is forecast to continue growing by around 1.3% and 1.5% average annual growth rate, respectively, due to growth in residential and business load attributed to increasing SME business activity and population growth. This growth is projected to be marginally offset by growth in distributed PV, as well as EE. EV charging at time of maximum demand is projected to represent around 6.8% of demand (750 MW) in Queensland and around 7.1% of demand (720 MW) in Victoria by 2039-40.

Maximum demand in Tasmania is forecast to remain relatively flat compared to the other regions, with 0.2% average annual growth rate. In Tasmania, forecast declining residential load offsets expected growth in EV charging at time of maximum demand. EV charging at time of maximum demand is projected to represent around 1.6% of demand (roughly 22.5 MW) in Tasmania, by 2039-40.

Figure 16 also compares the 2020 ESOO forecast with the 2019 ESOO forecast. Following recovery from COVID-19, the projected maximum 50% POE operational demand growth rates:

- For New South Wales, South Australia and Tasmania, are very similar to those forecast last year. While EV uptake is now expected to be higher in the longer term, proportionally less is assumed to be charging during maximum demand periods.
- For Queensland, are stronger than in the 2019 ESOO, due to a mix of revised consideration of changes in underlying consumer demand at time of peak (for example, due to EE measures), and forecast increases in EV charging and economic growth.

- For Victoria, are stronger than in the 2019 ESOO from 2026-27 onwards, driven predominantly by revised consideration of changes in consumption at time of peak (for example, due to EE measures), to better align with the historical improvement rate observed.

Timing of maximum demand

Distributed PV uptake forecasts are expected to cause maximum demand in the mainland NEM regions to occur later in the day, with the mostly like time of maximum demand trending toward sunset:

- Over the next 10 to 20 years, maximum demand is forecast to shift later by around an hour across the mainland regions.
- Maximum operational demand is forecast to occur between 16:00 and 19:00 local time in Victoria and New South Wales and between 16:30 and 19:30 local time in South Australia until the mid to late-2030s.
- In Queensland, where sunset occurs earlier than the rest of the NEM, maximum operational demand is expected to occur between 16:00 and 18:30 .

Tasmania is not projected to see any change in the timing of maximum demand. It currently peaks in either the morning or the evening in winter, and is expected to continue doing so in the 20-year forecast horizon.

For more information on the forecast timing of maximum operational demand, see Appendix A1.

2.3.2 Minimum demand

Minimum operational demand occurs either overnight, due to low underlying consumer demand, or in the middle of the day, when underlying consumer demand is offset by distributed PV generation.

For regions that currently experience midday troughs (Queensland, South Australia, and Victoria), a 1 MW increase in installed distributed PV capacity results in an approximate 0.7 to 0.8 MW decrease in minimum operational demand, all other things being equal. However, most regions in the 2020 ESOO are forecast to experience some degree of underlying demand growth in both the short and long term due to EVs and annual growth drivers such as population growth, complicating this rule of thumb. In regions that do not yet experience minimum operational demand in the middle of the day, additional distributed PV capacity first pushes the time of minimum demand to noon before reducing minimum operational demand itself.

Minimum operational demand for the Central scenario is forecast to decline more rapidly than in the 2019 ESOO in South Australia and Victoria and, to a lesser degree, in New South Wales and Tasmania. This is due to higher forecast distributed PV capacity, in particular in South Australia and Victoria.

Queensland, however, is forecast to experience higher minimum operational demand than in the 2019 ESOO. This is due in part to lower forecast distributed PV capacity in the short term. In the long term, it is due to higher forecast demand growth due to increasing SME business activity and population growth, as well as higher forecast battery storage and non-coordinated EV charging at time of minimum demand.

The minimum operational demand forecasts presented and discussed in this section are on the basis of uncontrolled minimum demand. There are potential market-based solutions to increase system load in the daytime – including storage, coordinated EV charging, and demand response – that could provide relief to the challenges associated with lower minimum demand. These solutions have not been included in the minimum operational demand forecasts presented in the 2020 ESOO, in order to emphasise the opportunities for these solutions.

Short-term outlook (0-5 years)

Over the next five years, minimum operational demand (50% POE) in the Central scenario[37] is forecast to decline across all the NEM regions, due to projections for uptake of distributed PV growing more than positive demand drivers such as connections growth, appliance uptake, and EVs. Forecast minimum operational demand (50% POE) in each region is:

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[37] For the forecast outcomes for the Slow Change and Step Change scenarios, see AEMO's data portal at http://forecasting.aemo.com.au.

- South Australia – falls from 378 MW in 2020-21 to 107 MW in 2024-25 (-20% to -26% average annual rate of change), due to a forecast rapid uptake in distributed PV (see Figure 17). Distributed PV capacity uptake over the same time period is forecast to be 375 MW in South Australia (see Figure 5).
- Victoria – falls from 2,745 MW in 2020-21 to 1145 MW in 2024-25 (-20% to -26% average annual rate of change), also due to a forecast rapid uptake in distributed PV (see Figure 18). Distributed PV capacity uptake over the same period is forecast to be 2.3 GW in Victoria (see Figure 5).
- New South Wales and Queensland – shows relatively subdued declines. Forecast PV capacity growth in both regions is relatively low compared to projected demand from the high proportion of LILs in those regions. The forecast average annual rate of decline in New South Wales and Queensland is around -2%.
- Tasmania – declines more slowly than in the other NEM regions, with an average annual growth rate around -0.8%. Tasmania's minimum operational demand is largely driven by industrial loads representing 60% of minimum operational demand in the region. The forecast growth in distributed PV capacity to 2024-25 is 7% of 2020-21 minimum operational demand (60 MW between 2020-21 and 2024-25). In the first year, LIL is forecast to expand slightly, causing demand to increase by 30 MW.

Figure 17 Forecast shoulder 50% POE minimum operational demand (sent out) by scenario, South Australia

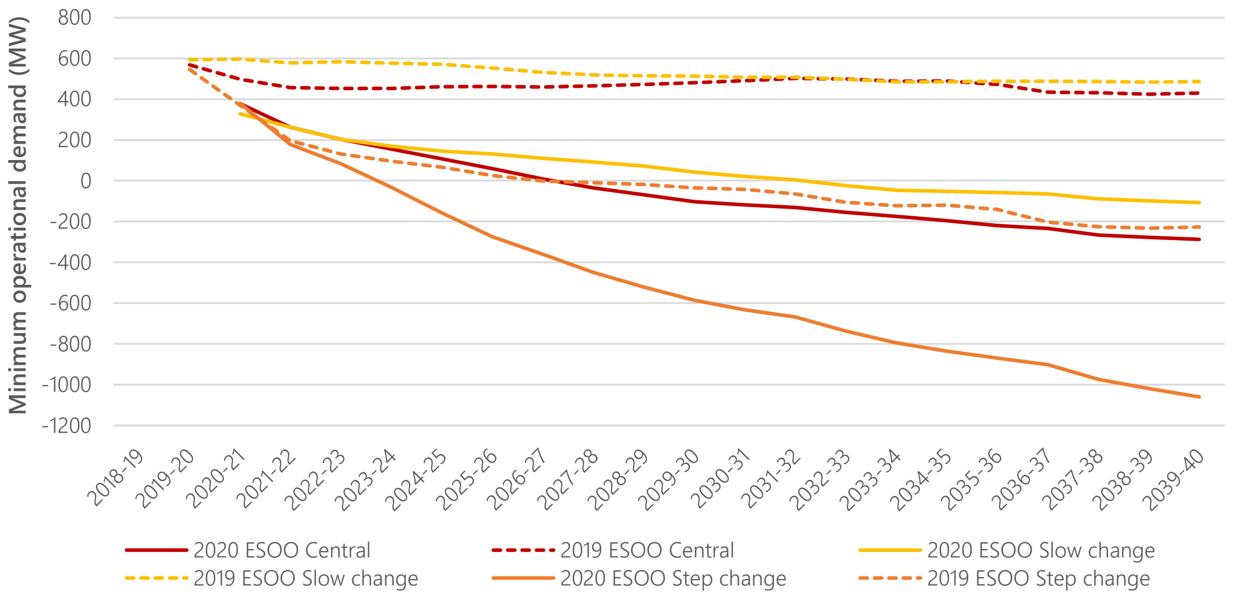
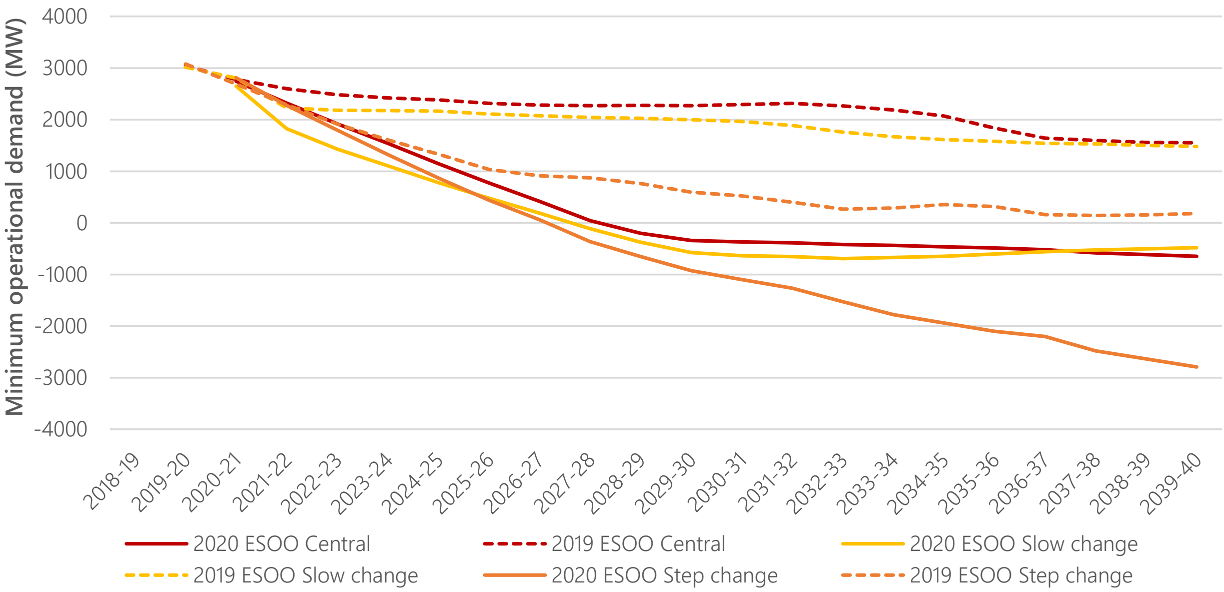


Figure 18 Forecast shoulder 50% POE minimum operational demand (sent out) by scenario, Victoria



Medium-term to longer-term outlook (6-20 years)

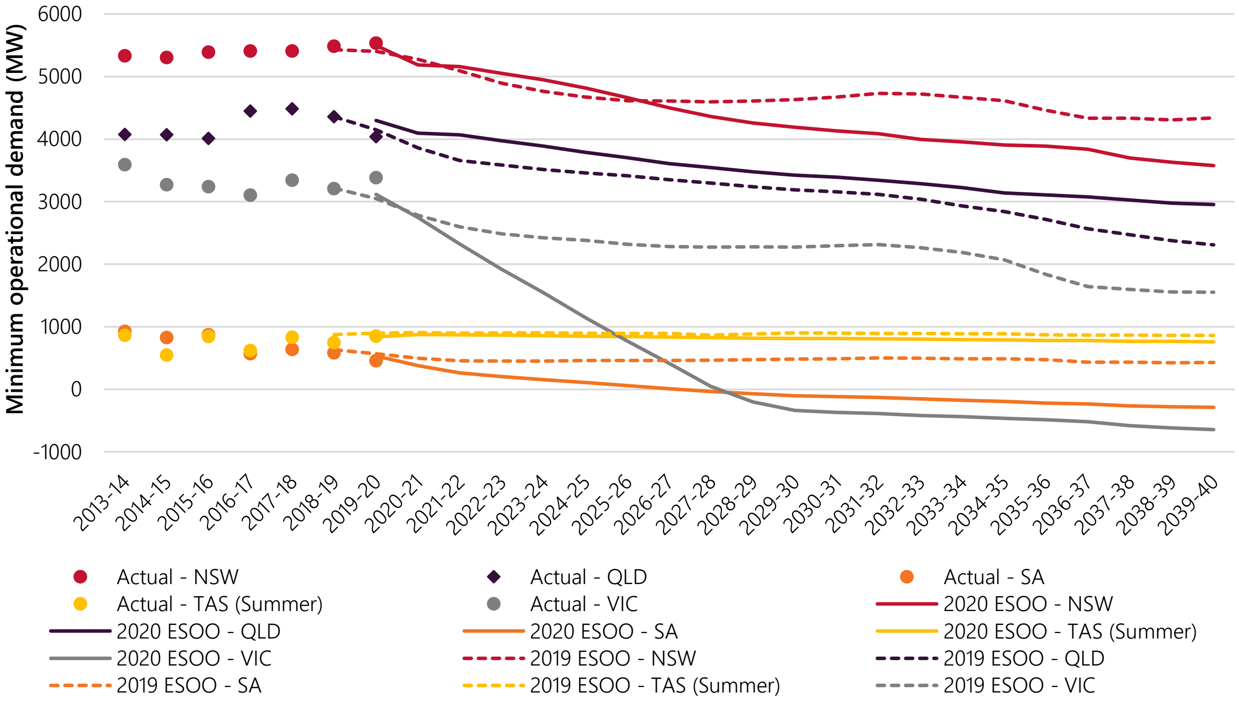
For the Central scenario, over the next six to 20 years, minimum operational demand (50% POE) is forecast to continue its decline across all NEM regions due to the estimated uptake of distributed PV capacity. By the late 2020s, non-coordinated charging EV penetration is forecast to start becoming noticeable on the grid, while distributed PV uptake slows, causing the rate of decline in minimum demand to reduce.

Coordinated EV charging is assumed to commence from 2030-31. As this is a solution controlled by an aggregator or operator that could be used to mitigate risks at time of minimum operational demand, it was not included in the minimum demand figures in Figure 19 (that is, the actual minimum is likely to be higher from 2030-31 onwards if these innovative solutions emerge, supported by appropriate market incentives).

Across the regions, in the absence of any market-based solutions to increase system load:

- Victoria and South Australia – minimum demand is forecast to become negative by around 2027 and 2028 due to high projected distributed PV capacity uptake. After 2030, underlying demand growth drivers such as growth in new connections and non-coordinated EV and battery storage charging, particularly in Victoria, are forecast to dampen the decline of minimum demand.
- New South Wales and Queensland – minimum operational demand is forecast to decline more steadily through the entire forecast period. The average annual rate of change in New South Wales and Queensland is around -1.9% and -1.7% respectively between 2021 and 2040. This is due to gradual but persistent projected growth in distributed PV capacity throughout the forecast horizon.
- Tasmania – minimum operational demand is forecast to decline steadily throughout the forecast horizon. The average annual rate of change in Tasmania is around -0.8%, the slowest decline of the NEM regions.

Figure 19 Regional annual 50% POE minimum operational demand (sent out), comparing 2020 ESOO and 2019 ESOO, Central scenario



Timing of minimum demand

South Australia has experienced minimum operational demand during the solar trough (middle of the day) for several years. Queensland has experienced it for the past two years. Victoria experienced it for the first time in 2019 due to recent growth in distributed PV capacity. New South Wales is currently on the cusp of shifting to midday minimum operational demand, with as much forecast probability of minimum operational demand occurring overnight as during the solar trough. Minimum demand in Tasmania still occurs overnight in summer (rather than in shoulder periods like the other regions) and is expected to slowly shift to noon over the next few years, due to its relatively high industrial load and low distributed PV capacity uptake (as a proportion of its minimum operational demand).

For more information on timing of minimum operational demand, see Appendix A1.

2.4 Demand side participation forecast

For the 2020 ESOO, AEMO updated its estimate of demand side participation (DSP) responding to price and reliability signals. The estimates are based on information provided to AEMO by all registered market participants regarding the DSP portfolios as of April 2020, using the methodology described in AEMO's DSP forecasting methodology paper[38].

Forecast DSP this year is higher than forecast in the 2019 ESOO, driven by an increase in the observed DSP response during periods in 2019-20 with Lack of Reserve 2 (LOR2) conditions met[39]. DSP forecasts and statistics[40] are in Appendix A3.

[38] At https://aemo.com.au/consultations/current-and-closed-consultations/demand-side-participation-forecast-methodology-consultation.

[39] Any demand side response provided through Reliability and Emergency Reserve Trader (RERT) was excluded in this analysis (see the DSP methodology).

[40] To fulfil the requirements under NER 3.13.3A(a)(8) and NER 3.7D (d).

3. Supply forecasts

This chapter outlines the supply forecasts for the next 10 years, including supply changes, key input assumptions, and methodological improvements that have been made in assessing supply adequacy in the 2020 ESOO.

Key insights

- The 2020 ESOO forecasts an increased amount of market-based dispatchable capacity this summer relative to last summer, including 110 MW of existing generator upgrades/expansions, the commitment of an extra 70 MW of large-scale battery, and some of the temporary generator capacity in South Australia (123 MW).
- The forecast includes 2,589 MW of generation currently in commissioning phase and 6,234 MW of committed generation, primarily from variable renewable energy (VRE) and Snowy 2.0 (2,040 MW). Nearly 70% of this capacity is scheduled to be operational at some point during summer 2020-21.
- Reliability of the thermal generation fleet fell to historically low levels in 2019-20. As a result, AEMO has applied increased forced outage rates in modelling for this ESOO. Forward-looking forced outage rates have also been included in this year's ESOO for the first time; these take into account the impact of maintenance programs and deteriorating performance as generators approach retirement.
- Additional to committed generation, there are over 41 GW of proposed wind and solar projects known to AEMO. A further 15 GW of hydro, gas, and battery storage capacity is proposed but not yet committed.
- AEMO has included several committed minor transmission augmentations in the ESOO modelling. Larger actionable ISP augmentations[41], not yet committed, have been included in a sensitivity.

3.1 Generation changes in the ESOO

The supply adequacy assessment in the 2020 ESOO considers existing and new generation and battery storage projects that meet the commitment criteria published in AEMO's Generation Information update on 31 July 2020.

The data published in this update reflects information provided to AEMO by both NEM participants and generation/storage project proponents up to this date. This includes information under the three-year notice of closure rule, but precise closure dates have not been provided to AEMO beyond the three-year period. For the purpose of the ESOO, closure dates beyond the three-year period are assumed to be on 31 December of the stipulated expected closure year.

The 2020 ESOO includes projects classified in the Generation Information update as either:

[41] For definitions and more information, see 2020 ISP at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.

- Committed[42] or
- Committed* – projects under construction and well advanced to becoming committed[43].

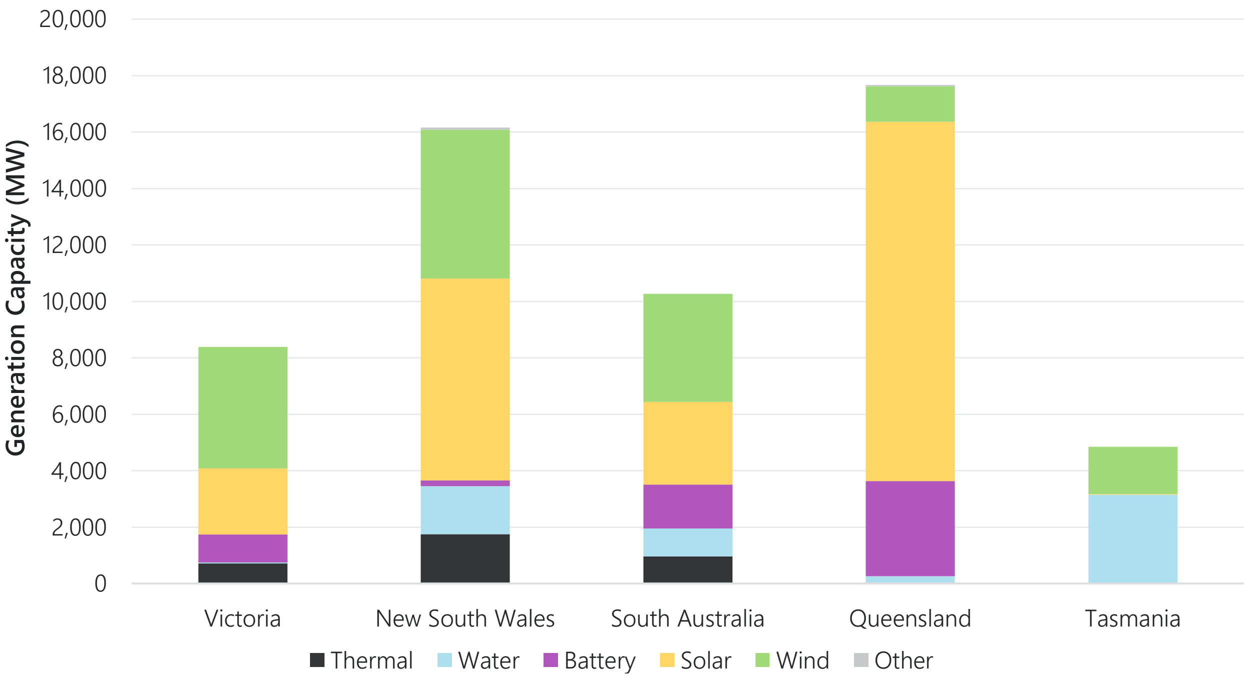
Committed projects were considered to become operational on dates provided by the participants, and for ESOO purposes include projects that are classified as advanced and under construction.

Committed* projects were assumed to commence operation after the end of the next financial year (1 July 2022), reflecting uncertainty in the commissioning of these projects. For further details, please refer to the *ESOO and Reliability Forecast Methodology Document*[44].

3.1.1 Pipeline of future projects

There is a substantial pipeline of future projects not yet committed but in various stages of development, from publicly announced to advanced stages of planning. The 57.3 GW of future projects are spread across all regions, with Queensland having the most in terms of capacity. Figure 20 shows the pipeline of projects by region and type of generation, beyond already committed projects.

Figure 20 Proposed projects by type of generation and NEM region, beyond those already committed



Source: July 2020 Generation Information, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

With retirement of existing plant, additional energy resource projects will be needed to reduce the risk of USE in the NEM. Over 72% of future projects currently tracked by AEMO are VRE generators, and over 21% are battery storage or hydro projects. Approximately 4 GW of additional dispatchable capacity, including thermal generation, hydro generation, and batteries, have been added to the pipeline of future projects over the past year.

Further details are on AEMO's Generation Information page, including capabilities of proposed generating units which meets AEMO's obligation to publish generating unit capabilities under 3.13.3A(a)(3) of the NER.

[42] Committed projects meet all five of AEMO's commitment criteria (relating to site, components, planning, finance, and date). For details, see https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[43] In AEMO's Generation Information page these projects are called committed* or Com*. They are classified as Advanced; that is, they meet AEMO's site, finance, and date criteria but are required to meet one of either the components or planning criteria, and they are under construction.

[44] See Section 2.6, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

3.2 Generation availability

To improve forecasts of generation availability over the 10-year outlook period, AEMO has implemented three methodology changes in this year's ESOO:

- **Application of forward-looking forced outage rates** – forced outage rate assumptions have now taken into account the recent historical plant performance, impact of maintenance programs, and deteriorating performance as generators approach retirement.
- **Separate treatment of long duration outages** – generation outages of duration in excess of five months have been classified as high impact low probability (HILP) outages with a lower outage rate applied within the statistical simulation approach.
- **Two-tiered assessment of generator ratings during summer** – two summer ratings have now been applied to generators: one during near-maximum demand periods, where generator ratings are reflective of the ambient conditions associated with 10% POE demand events, and one more aligned with average summer temperatures, that is applied in all other summer periods. The ratings have been provided by registered participants and are reported in the 2020 Generation Information page.

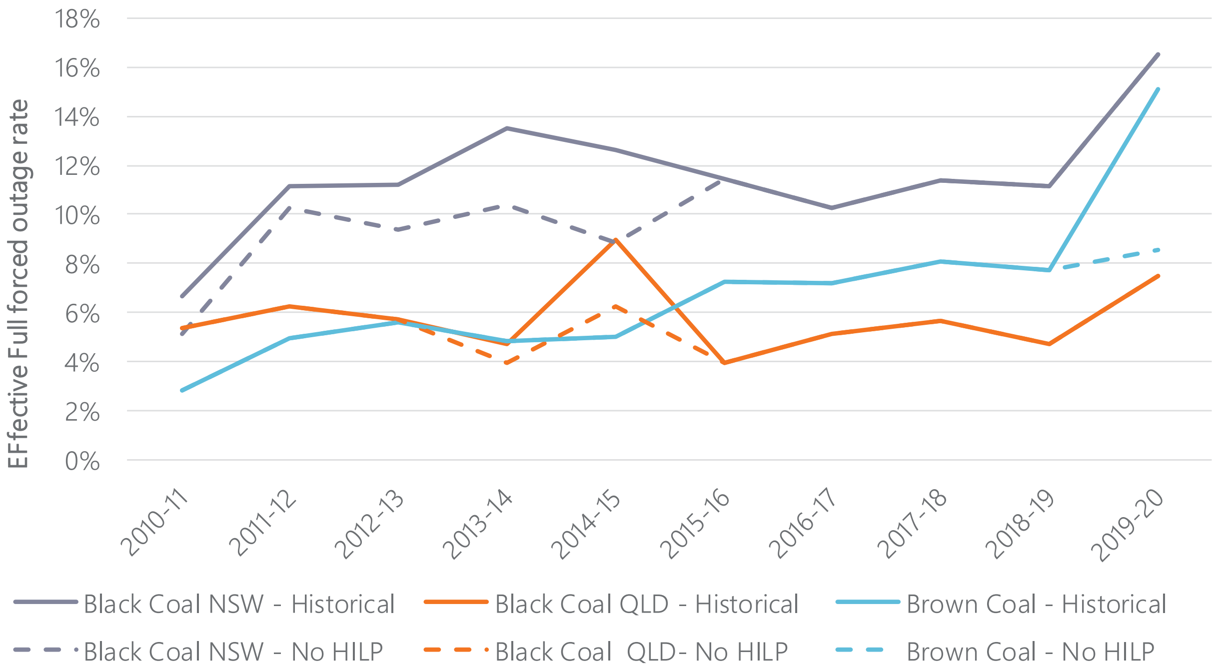
See the *ESOO and Reliability Forecast Methodology Document*[45] for more detail about generation availability.

3.2.1 Forced outage rates

AEMO separately collects information from all generators via an annual survey process on the timing, duration, and severity of historical unplanned forced outages. This data is used to calculate the probability of full and partial forced outages for each financial year. In previous years, AEMO has relied solely on this historical data to estimate future forced outage rates, focusing on the last four years of history to capture emerging trends.

Figure 21 shows the aggregate historical effective forced outage rates for all currently in-service coal-fired generators, illustrating the reduction in reliability in each region over the past year. The dotted lines show the outage rates with HILP outages removed, as these are included in projections separately.

Figure 21 Historical outage rates for coal-fired generator technologies



45 See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

Analysis of this historical outage data has affirmed that:

- Some categories of plant have experienced a deterioration in reliability compared with their longer-term historical performance.
- A backward-looking approach is failing to adequately capture changes in outage rates.
- The presence of a HILP generator outage can significantly influence the average annual outage rate, particularly if relying solely on the last four years of data.

To address these limitations, AEMO has applied forward looking outage rate trends to base outage rates[46]. AEMO calculated base outage rates using the last four years of historical data by:

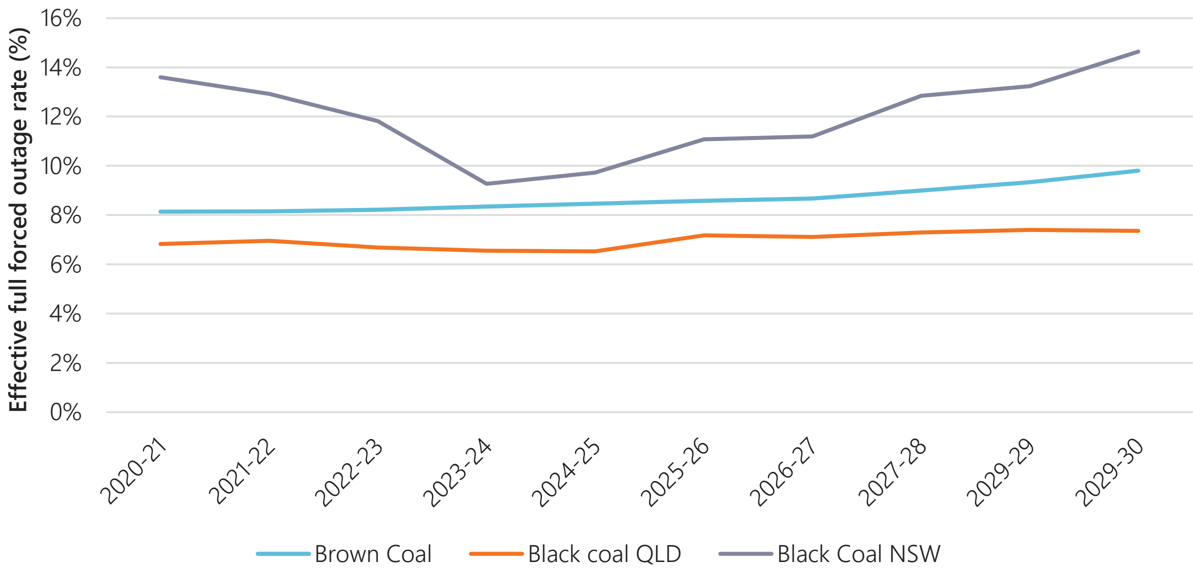
- Removing the impact of HILP outages from historical data.
- Calculating station-level outage rates (except hydro and peaking generators with units smaller than 150 MW, where aggregation continues to be used).
- Applying any adjustments provided by power station operators, who are given the opportunity to review outage rate calculations and supply feedback.

Future trends in generation outage rates are uncertain and are likely to change as plants age, approach retirement, and go through maintenance cycles. Best estimates of these trends were obtained by requesting data from the operators of coal-fired and combined-cycle gas turbine (CCGT) generators. AEP Elical[47] was also commissioned to provide forward-looking outage rates for coal-fired generators. AEMO used a combination of the two data sources, but generally relied on information provided by participants, reverting to AEP Elical where a participant did not provide a forward-looking view.

Both data sources projected a combination of improvements and deteriorations in outage performance across the generation fleet. In general, drivers of the changing rates included planned maintenance to remediate known issues, expected changes in generation behaviour, and the impact of age and reduced maintenance as generators approach retirement.

Figure 22 shows the trend in generator reliability to 2029-30 for each coal-fired generation technology category applied to the base outage rate data, incorporating HILP outages. The annual effective forced outage rate is affected by changes to assumed reliability and retirements of generators over the horizon.

Figure 22 Effective full forced outage rate projections for coal-fired generation technologies



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[46] See 2020 IASR for base outage rate values and comparison to assumptions used in 2019 ESOO.

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

To capture random year-on-year variations in outage rates, AEMO applied four sets of outage parameters (from each of the previous four years of data provided) in the statistical simulation model, such that they were equally weighted. This is the same approach as was adopted in the 2019 ESOO. The four sets of outage parameters were scaled up and down over time, ensuring that the average outage rate in any given year matched the rates shown in Figure 22.

3.2.2 Forced outage rates – high impact low probability (HILP) outages

Generation outages of duration in excess of five months have been classified as HILP. These events have a separate outage rate calculated for each technology and based on the full 10 years of historical data that AEMO has available.

The full HILP outage rate assumptions that were used in ESOO modelling are shown in Table 4 below.

Table 4 HILP outage assumptions

Technology	HILP outage rate (%)	MTTR (hours)*
Brown coal	0.65	5,290
Black coal New South Wales	0.84	5,568
Black coal Queensland	0.23	4,656
Open cycle gas turbine (OCGT)	0.43	4,032

*MTTR = Mean time to repair: this parameter sets the average duration (in hours) of generator outages.

3.3 Transmission limitations

The ESOO model applied a comprehensive set of network constraint equations that represent the thermal and stability limits that currently constrain dispatch in the NEM. These constraint equations act at times to limit generation, but also frequently limit interconnector transfer capacity. Additionally, transmission outage constraints are applied for simulated unplanned outages (see the 2020 IASR for more details).

The 2020 ESOO modelling included committed major and minor transmission augmentations in the Central scenario. Any augmentations that are still undergoing the regulatory investment test for transmission (RIT-T) process have been excluded, but the actionable augmentations identified in the 2020 ISP were considered in a sensitivity. Further details are provided in Chapter 6.

Major augmentations included in 2020 ESOO

- Queensland New South Wales Interconnector (QNI) upgrade, Option One A by December 2022.
- Victoria New South Wales Interconnector (VNI) upgrade (Option One Victoria side work only) by December 2022[48].

Additional minor augmentations included in 2020 ESOO

- Red Cliffs to Buronga line uprating, by December 2020.
- Gin Gin substation rebuild by December 2021.
- Installation of synchronous condensers in South Australia by July 2021.
- Western Victoria minor line uprating by July 2021.
- Installation of capacitors at the Armidale and Wagga substation by July 2022.

[48] As listed in Appendix 3 of the 2020 ISP and according to advice from the relevant transmission network service provider (TNSP) that the Victorian components of the VNI upgrade have passed all regulatory and procurement milestones, and should be considered committed.

- Darlington Point wave fault detector installation by December 2023.
- Smartwires on Jindera – Wagga 62 by December 2023.
- Installation of capacitor at South East substation by December 2023.
- Western Victoria Transmission Upgrade by December 2024.

Major augmentation sensitivity

As a sensitivity, AEMO considered the potential impact of the interconnector augmentations identified as actionable in the 2020 ISP on reliability in the NEM over the next seven years (see Chapter 6).

4. Supply scarcity risks this summer

This chapter discusses supply scarcity risks this summer arising from the demand and supply forecasts.

Key insights

- Forecast USE in the coming summer has declined substantially compared to last year, particularly in Victoria where the level of expected USE remains below the IRM.
- Uncertainty in the forecast has, however, increased:
  - The supply forecast relies heavily on successful and timely commissioning of over 1,900 MW of VRE in Victoria ahead of summer 2020-21.
  - The impact of COVID-19 on maximum demand or on the timely completion of generation maintenance or repairs remains uncertain.
  - As more VRE is developed, the reliability of the system is increasingly exposed to the weather.
  - Thermal generation reliability continues to decline, increasing uncertainty around its availability when most needed.

Reduction in forecast USE in Victoria compared to last summer

The change in outlook for this summer is in part due to last summer's outlook being heavily influenced by uncertainty around the delayed return to service in Victoria of units of Loy Yang and Mortlake power stations that were on extended forced outages.

Further changes, in particular a reduction in forecast demand, an increase in DSP, and an increase in VRE capacity, have more than offset the effect of higher forced outage rates (see Section 3.2.1).

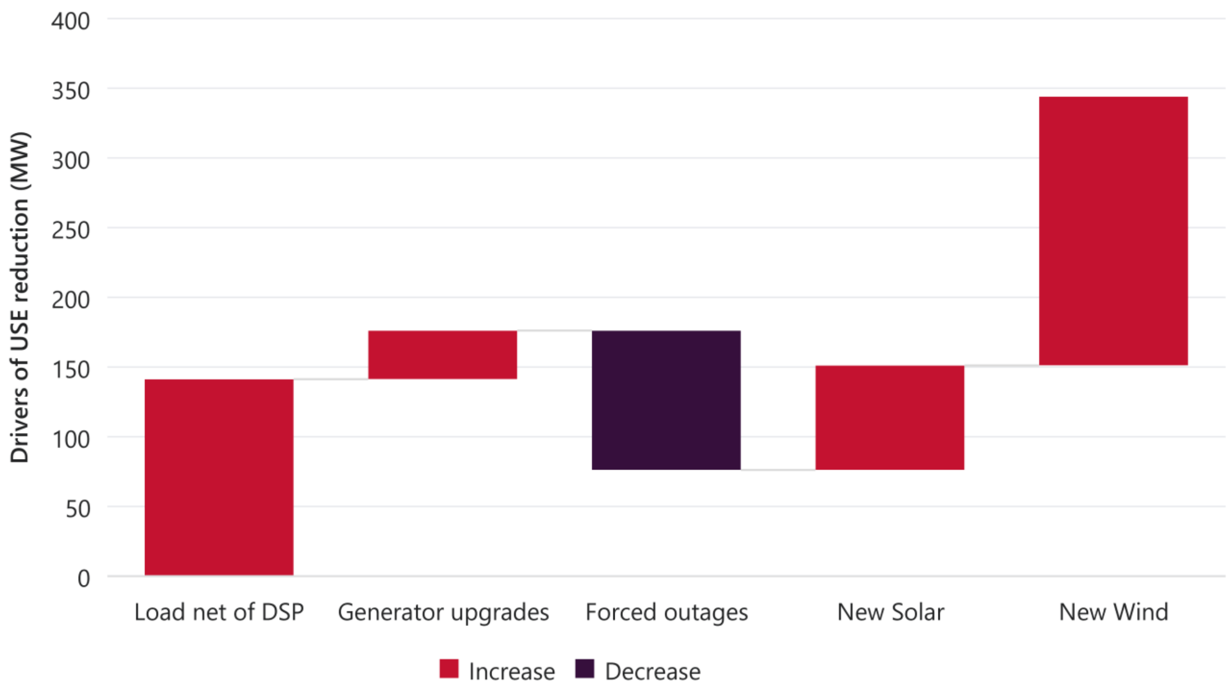
Figure 23 provides estimates of the impact of a range of factors on the reduction in expected USE in Victoria for next summer (ignoring delays in return to service), noting a number of these factors are subject to uncertainty:

- The impact of COVID-19, while still highly uncertain, is estimated to reduce the level of peak demand across the NEM this summer.
  - The expected reduction in maximum demand due to COVID-19 relies on an assumption that recent growth in distributed PV will push the timing of maximum demand further into the evening, typically to 18:00 or later. At this time, commercial cooling load is scaling back and residential homes are pre-cooled because people have been working from home, resulting in a lower cooling need than would otherwise occur. If extreme weather meant maximum demand occurred at an earlier time, when commercial cooling and residential cooling were both still operating, demand could be higher.

- Approximately 4,300 MW of additional VRE summer capacity is expected to be available NEM wide, compared to what was available last summer. This includes 1,900 MW of additional VRE summer capacity in Victoria, compared to what was available last summer. Most of this new Victorian VRE capacity is expected to be fully commissioned in late 2020. This summer's forecast also includes minor thermal upgrades in Victoria and 150 MW of additional firm capacity in South Australia.
  - Over the past two years, commissioning delays have been common due to a range of issues, and continuing COVID-19 restrictions in Victoria particularly could further increase the likelihood of delays.
- Forced outage rates have increased due to the performance of the generating fleet in 2019-20, which drives an increase in forecast USE.
  - The forced outage assumptions do not take into account the impacts of COVID-19, which could include longer outage durations due to social distancing requirements, labour availability, and other impacts. Plant reliability could also be influenced by the ability to successfully complete maintenance work associated with summer readiness in the lead-up to this summer.

As Figure 23 shows, the forecast reduction in forecast peak load and increase in DSP accounts for approximately 40% of the projected reduction in USE. The forecast impact of minor generator upgrades is projected to be more than offset by increased forced outage rates (described in detail in Section 3.2.1).

Figure 23 Drivers of expected USE reduction in Victoria (2020 ESOO forecast of 2020-21 vs 2019 ESOO forecast of 2019-20) – excluding Loy Yang A/Mortlake outage impact



Risks related to new generation commissioning delays or outages this summer

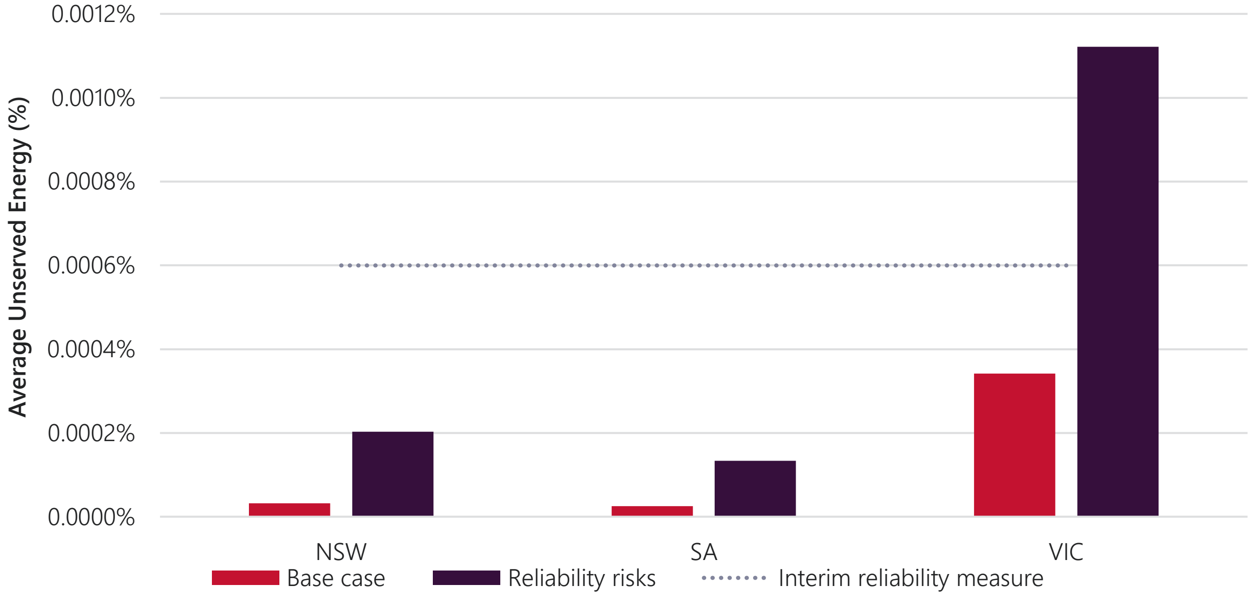
The largest driver of the reduction in expected USE is the substantial increase in large-scale wind and solar generation forecast for Victoria, an increase of 1,900 MW VRE summer capacity compared to what was available last year. Much of the expected additional VRE capacity in Victoria is expected to be commissioned in late 2020.

On 19 July 2020, one of the static VAR compensators (SVCs) at Para in South Australia experienced a forced outage, with an expected return to service in mid-2021. The primary impact of the outage is that flows from South Australia to Victoria on the Heywood interconnector are restricted to 420 MW. Given that South Australia and Victoria frequently experience high temperatures at the same time, South Australia is generally not able to export significant volumes of energy to Victoria when supply-demand balance is tight. The outage was not included in the ESOO modelling as the impact on USE outcomes is relatively minor.

Through the forced outage rate collection process, AEMO also requested participants provide any indication on the possible impacts of COVID-19 on generator reliability this summer. Some participants indicated that the impact could be that the duration of outages extends by up to 50%. This would effectively result in a significant reduction in the expected reliability of the generation fleet this summer.

To test the impact of all three of these risks, AEMO has simulated a sensitivity that assumed approximately half the capacity due to be commissioned in late 2020 is not available this summer, a 50% increase in the duration of forced outages occurs, and the unavailability of the Para SVC continues. The projected impact is most evident in Victoria, where forecast USE increases to well above the IRM, but remains below the reliability standard.

Figure 24 Impact of reliability risks on USE in 2020-21



If a major unexpected disruption occurred in the lead-up to summer, such as an extended outage at a generator or another key transmission asset, AEMO would reassess whether expected USE exceeded the IRM, communicate any changes through the release of an ESOO update, and may seek to secure either interim reliability or medium notice reserve.

Risks related to weather

Figure 25 shows the level of USE forecast in Victoria for the 2020-21 summer in each of the reference years modelled.

This shows that under the weather conditions associated with the 2011-12, 2013-14, and 2017-18 reference years, the forecast level of USE would exceed the IRM. The primary driver of the difference between reference years is the contribution from VRE at times of high demand, which is shown in Figure 26 using the Effective Load Carrying Capacity (ELCC) measure[49]. The lower the ELCC, the weaker the contribution from VRE during high demand periods. These three years are characterised by a lower contribution from VRE, although other factors also contribute such as the level of coincidence in demand between regions, or the duration of time demands were at peak levels.

[49] ELCC represents the difference between maximum demand and highest demand net of VRE production. It is one measure of the contribution from renewable generation, noting that no single measure fully explains the contribution of VRE to reliability outcomes.

This analysis shows that the risk of load shedding would increase this summer if peak demands were to coincide with a relatively low contribution from VRE in Victoria, such as that experienced in 2013-14.

Figure 25 Impact of different reference years on expected USE in Victoria 2020-21, Central scenario

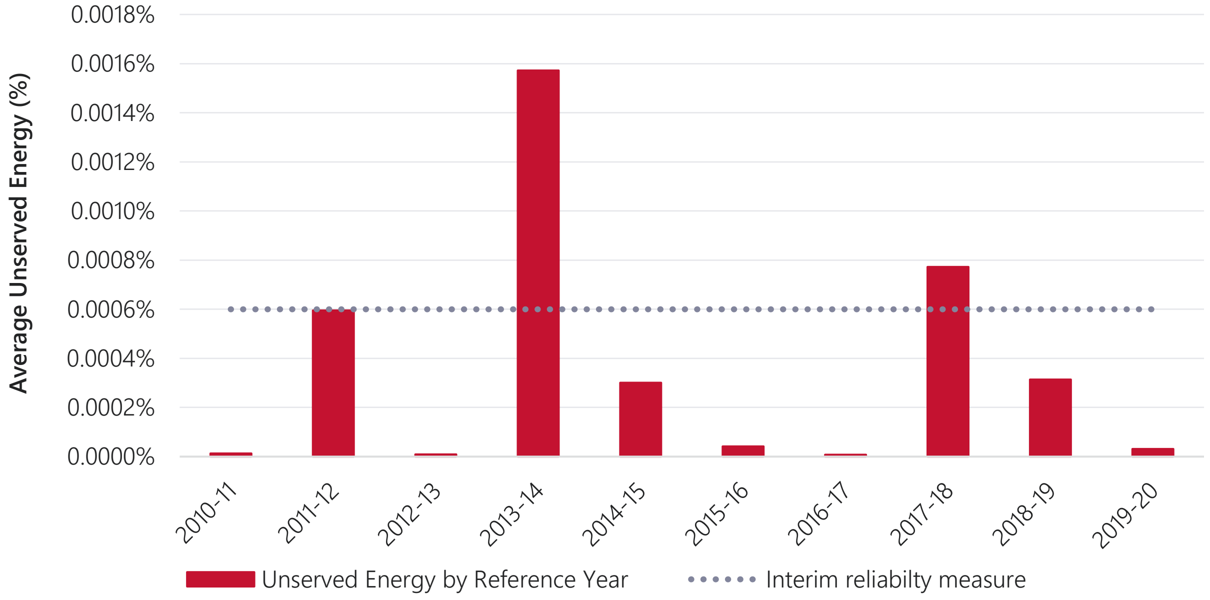


Figure 26 ELCC by reference year in Victoria 2020-21, Central scenario

Summer readiness

AEMO has already commenced its summer readiness program for summer 2020-21. As with previous years, this will include collaboration with industry to identify the preparedness of the system for summer, and any residual risks that may be present.

In addition to supply adequacy, as discussed in this ESOO, AEMO will review operational processes, contingency planning, and communications.

5. RRO reliability forecasts

This chapter meets AEMO's obligations under Section 4A.B.1 of the NER related to the publishing of a reliability forecast and an indicative reliability forecast. This chapter provides the details required under 4A.B.2, including AEMO's forecast of expected USE and whether there is a forecast reliability gap.

As changes to the RRO associated with the RRO trigger Rule are soon to be released for consultation, AEMO has prepared the reliability forecast against the 0.002% reliability standard and against the IRM.

Key insights

- The forecast level of expected USE is below the reliability standard in all regions in 2021-22 (T-1).
- Absent additional investment, USE is forecast to increase to above the IRM, and below the reliability standard, in New South Wales in 2023-24 (T-3) after the retirement of the Liddell Power Station.
- The increase in forecast expected USE in New South Wales after the retirement of Liddell has moderated since the 2019 ESOO, partly due to the planned commissioning of the QNI Minor[50] augmentation by December 2022. Despite this, in the absence of further actions, there remain high risks of load shedding during extreme heat events after Liddell retires. Any delay in the commissioning of QNI Minor would exacerbate this risk.
- Reliability in New South Wales is forecast to continue to deteriorate over the 10-year outlook due to the impact of increasing forced outage rates as generators age and near retirement.
- Without further timely network investment, USE in New South Wales is expected to increase well above the reliability standard in 2029-30 after the retirement of Vales Point Power Station.
- Expected USE risks remain in all years in Victoria, New South Wales and South Australia if there were multiple long-duration generation or transmission outages coinciding with high demand, as was experienced in Victoria last year.

5.1 Key assumptions

This reliability assessment includes all existing and committed generation and storage reported in the Generation Information page published in July 2020[51], as well as committed transmission augmentations (see Section 3.3). Existing generators are retired at the end of the expected closure year (calendar year end) or at

[50] This committed ISP project is a minor upgrade of the existing interconnector, adding over 150 MW capacity in both directions, and is on track to be commissioned in 2021-22.

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

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

Specifically, the assessments:

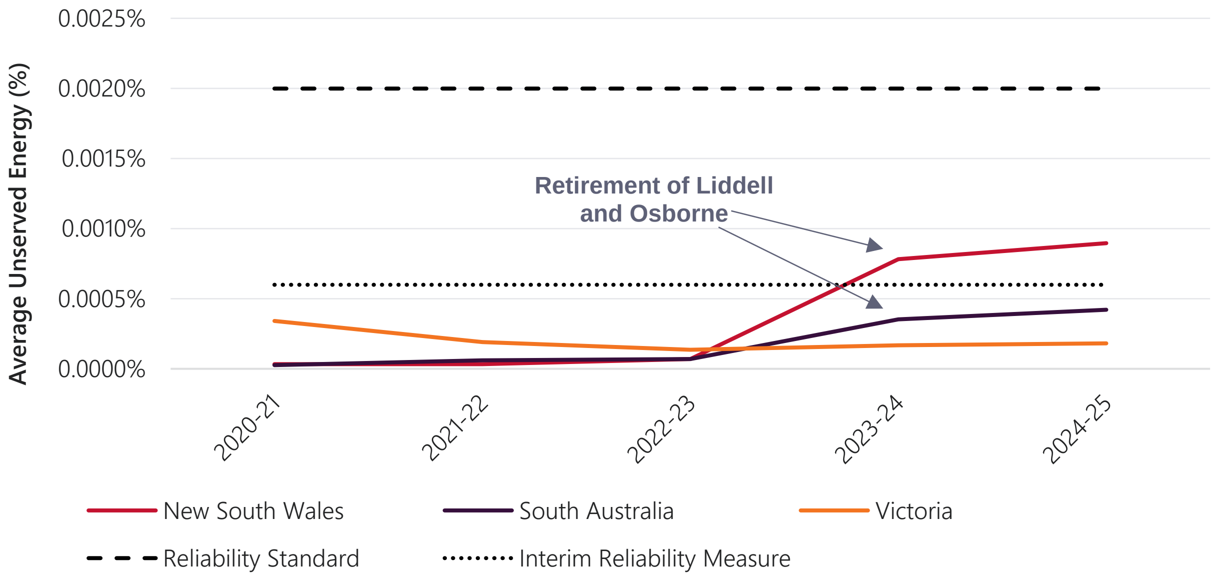
- Do not include major transmission investments that have not yet completed all necessary approvals, such as:
  - Project EnergyConnect (new interconnection between South Australia and New South Wales).
  - HumeLink (the new transmission development to unlock congestion and enable the benefits of Snowy 2.0 to be delivered to the NEM).
- Include the temporary diesel generator in South Australia that has been leased by Infigen Energy.
- Do not include the temporary diesel generator in South Australia due to be leased by Nexif Energy, as this does not meet the requirements to be classified as committed. Once these requirements are met, the supply adequacy outlook in South Australia would further improve.
- Do not include any additional capacity that could be made available through Reliability and Emergency Reserve Trader (RERT)[52].

As the level of forecast USE observed in Queensland and Tasmania is negligible, these regions have been removed from the presentation of USE outcomes in this chapter.

5.2 The reliability forecasts (first five years)

Forecast USE remains below the reliability standard in all regions in all five years of the reliability forecast (2020-21 to 2024-25), as shown in Figure 27.

Figure 27 Reliability forecasts (first five years)



Key outcomes include:

- Victorian USE is forecast to decrease slightly over this period, mainly due to declining maximum demands.

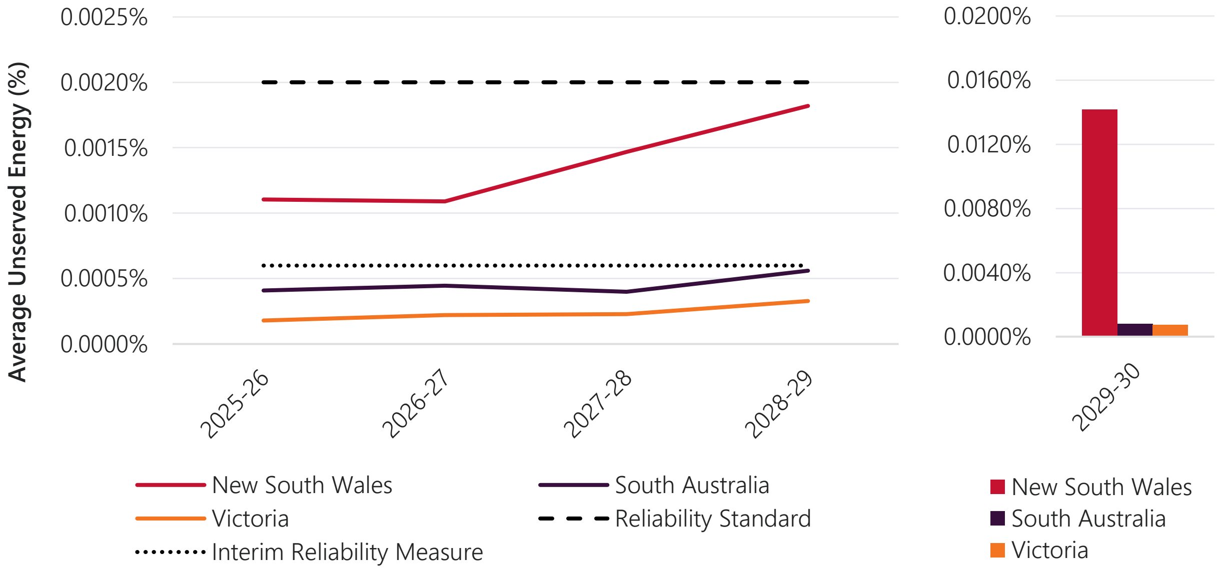
[52] The exception being DSP responses from RERT panel members delivered outside RERT, which have been included in the DSP forecasts. See DSP methodology for more details, at https://aemo.com.au/consultations/current-and-closed-consultations/demand-side-participation-forecast-methodology-consultation.

- USE is forecast to increase from 2023-24 in South Australia after the retirement of Osborne Power Station, but to remain below both the IRM and the reliability standard.
- Forecast USE exceeds the IRM in New South Wales in 2023-24 and 2024-25 following the retirement of Liddell, but remains below the reliability standard.

5.3 The indicative reliability forecasts (second five years)

The forecast of USE over the second five years of the 2020 ESOO (2025-26 to 2029-30) is shown in Figure 28.

Figure 28 The indicative reliability forecasts (second five years)



Reliability is forecast to deteriorate over this period in New South Wales and, to a lesser extent, in Victoria and South Australia. This is due to the assumed increase in forced outage rates of coal-fired generators and retirement of Callide B in 2028-29, Vales Point in 2029-30, and the first unit of Yallourn in 2029-30.

The commissioning of Snowy 2.0 in 2025 does not have a material impact on expected USE in this outlook, because the HumeLink augmentation is not classified as committed and was therefore not included in the analysis. This augmentation is necessary to unlock the reliability benefits provided by the additional firm capacity at Snowy 2.0.

In the final year, expected USE increases sharply in New South Wales to over 0.014% after the retirement of the Vales Point Power Station. The transmission network in Sydney and the surrounding area[53] was designed in large part to connect large coal generators (such as Vales Point) in the Hunter Valley to the Sydney load centres. When these coal generators retire, generation from further afield is needed to meet Sydney's load, but is constrained from doing so during peak demand periods due to network limitations.

The 2020 ISP identified preparatory activities on a future ISP project to reinforce Sydney, Newcastle and Wollongong supply that would help support power transfer into the Sydney load centre following the retirement of Vales Point[54]. AEMO recommends that both network and non-network options be explored for this project.

In Victoria and South Australia in 2029-30, expected USE exceeds the IRM, largely due to the retirement of the first unit at Yallourn Power Station, co-inciding with retirement of Vales Point.

[53] Essentially this is the Hunter Valley, Greater Sydney area, New South Wales Southern Tablelands, and just west of the Blue Mountains.

[54] See https://www.aemo.com.au/-/media/files/major-publications/isp/2020/appendix--3.pdf?la=en.

5.4 Reliability forecast components

5.4.1 Measurement against the reliability standard

Under 14G(1) of the National Electricity Law, a forecast reliability gap occurs when the amount of electricity forecast for a region, in accordance with the NER, does not meet the reliability standard to an extent that, in accordance with the NER, is material.

The NER clause 4A.A.2 defines a forecast reliability gap in a region in a financial year to be material if it exceeds the reliability standard. Expected USE is not forecast to exceed the reliability standard of 0.002% in any region in this reliability forecast and therefore there is no forecast reliability gap.

Reliability forecast

Forecast reliability gap in the reliability forecast (based on 0.002% reliability standard)

In the 2020 ESOO, no forecast reliability gap has been identified in any region in the reliability forecast.

Indicative reliability forecast

In the indicative reliability forecast (second five years), a forecast reliability gap occurs in New South Wales in 2029-30 as expected USE in the financial year exceeds the reliability standard of 0.002%. The reliability forecast components associated with this forecast reliability gap are summarised below. The size of the forecast reliability gap is calculated as the additional megawatts of firm capacity forecast to be required over the forecast reliability gap period, to meet the existing reliability standard[55].

Forecast reliability gap in the *indicative* reliability forecast (based on 0.002% reliability standard)

In the 2020 ESOO, a forecast reliability gap has been identified in New South Wales in 2029-30:

- The forecast reliability gap period is from 1 December 2029 to 31 March 2030.
- The expected USE for the reliability gap period is 8,871 GWh.
- The size of the forecast reliability gap is 1,480 MW.

5.4.2 Measurement against the IRM

The proposed RRO trigger Rule changes currently under consultation would replace any RRO reference to the reliability standard with the IRM until 30 June 2025. This means a forecast reliability gap would be material if expected USE exceeds 0.0006% of the total energy demanded in that region for a given financial year.

This section outlines any forecast reliability gaps that would arise based on this amendment, and where relevant, the associated reliability forecast components.

Reliability forecast

In the reliability forecast (first five years), a forecast reliability gap occurs in New South Wales in 2023-24 and in 2024-25 as expected USE in both financial years exceeds the IRM of 0.0006%. The reliability forecast components that would be associated with this forecast reliability gap are summarised below.

[55] See *ESOO and Reliability Forecast Methodology Document*, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

Forecast reliability gap in the reliability forecast (based on 0.0006% IRM)

In the 2020 ESOO, forecast reliability gaps would be identified in New South Wales in 2023-24 and 2024-25 if expected USE materiality is determined based on the IRM.

For 2023-24:

- The forecast reliability gap period is from 1 January 2024 to 29 February 2024.
- The expected USE for the reliability gap period is 0.431 GWh.
- The size of the forecast reliability gap is 154 MW.
- The likely trading intervals are weekdays in January and February 2024 for trading intervals that fall between 15:00 and 20:00.

For 2024-25:

- The forecast reliability gap period is from 1 January 2025 to 28 February 2025.
- The expected USE for the reliability gap period is 0.47 GWh.
- The size of the forecast reliability gap is 305 MW.
- The likely trading intervals are weekdays in January and February 2025 for trading intervals that fall between 15:00 and 20:00.

Indicative reliability forecast

In the indicative reliability forecast (second five years), a forecast reliability gap occurs in New South Wales in every year, and in South Australia and Victoria in 2029-30, as expected USE exceeds the reliability standard of 0.0006% for these regions in these financial years. For New South Wales, three forecast reliability gap periods are identified in the 2029-30 year, two in winter (beginning and end of the financial year) and one in summer.

The reliability forecast components associated with this forecast reliability gap are summarised below.

Forecast reliability gap in the *indicative* reliability forecast (based on 0.0006% IRM)

In the 2020 ESOO, forecast reliability gaps would be identified in New South Wales 2023-24 and 2024-25 if expected USE materiality is determined based on the IRM.

For South Australia in 2029-30:

- The forecast reliability gap period is from 1 January 2030 to 31 January 2030.
- The expected USE for the reliability gap period is 0.084 GWh.
- The size of the forecast reliability gap is 148 MW.

For Victoria in 2029-30:

- The forecast reliability gap period is from 1 January 2030 to 31 January 2030.
- The expected USE for the reliability gap period is 0.187 GWh.
- The size of the forecast reliability gap is 166 MW.

For New South Wales in all five years of the indicative reliability forecast:

Financial year	Size of forecast reliability gap (MW)	Forecast reliability gap period	Expected USE for the reliability gap period (GWh)
2025-26	525	1 January 2026 to 28 February 2026	0.522
2026-27	472	1 January 2027 to 28 February 2027	0.549

Financial year	Size of forecast reliability gap (MW)	Forecast reliability gap period	Expected USE for the reliability gap period (GWh)
2027-28	895	1 January 2028 to 29 February 2028	0.791
2028-29	1,001	1 January 2029 to 28 February 2029	1.034
2029-30*	2,045	1 July 2029 to 31 July 2029	0.076
2029-30	2,045	1 December 2029 to 31 March 2030	8.871
2029-30	2,045	1 June 2030 to 30 June 2030	0.653

* A minor adjustment to the methodology for calculation of the size of this forecast reliability gap was made to ensure the IRM of 0.0006% was reached in this financial year. A 5% LOLP was applied, rather than the 10% LOLP applied for all other forecast reliability gaps per the methodology detailed in ESOO and Reliability Forecast Methodology Document. If the RRO trigger Rule comes into effect, methodological adjustments such as this may be necessary to overcome issues with current approach when applied to cover tail risks anticipated by the IRM.

5.4.3 One-in-two year peak demand forecast

In accordance with NER clause 4A.A.3, AEMO must specify the forecast one-in-two year peak demand in the reliability forecast.

For this, AEMO uses its 50% POE operational maximum demand forecast on an 'as generated' basis. Performance of these demand forecasts will be included in future *Forecast Accuracy Reports*[56].

Table 5 AEMO's one-in-two year peak demand forecast (50% POE, as generated)

Year	New South Wales	Queensland	South Australia	Tasmania	Victoria
2020-21	13,140	9,658	2,958	1,746	9,267
2021-22	13,496	9,982	2,964	1,753	9,132
2022-23	13,618	10,072	2,994	1,758	9,088
2023-24	13,710	10,194	3,011	1,763	9,072
2024-25	13,647	10,267	2,999	1,760	9,013

The only difference between Table 5 and the operational maximum demand values reported by region in Appendix A1 on a 'sent out' basis is the inclusion of auxiliary load forecasts at time of maximum demand[57].

The forecast auxiliaries at the time of maximum demand for 50% POE demand conditions are shown in Table 6 below. These values have been determined based on modelling outcomes which model the auxiliary rates of each generating unit based on information provided by participants[58].

Auxiliary rates are forecast to remain relatively static over the next five years in all regions, except for a reduction in New South Wales coinciding with the retirement of the Liddell Power Station. With the retirement of Liddell, the reliance on imports into New South Wales at times of peak is projected to increase, and the reduction in local generation reduces auxiliary loads in the region.

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56 At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/forecasting-accuracy-reporting.

57 See AEMO's Electricity Demand Forecasting Information Paper, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

58 Previously, auxiliary rates were sourced from consultants. For the 2020 ESOO, auxiliary rates were collected via the Generation Information survey process, noting that individual unit and station auxiliary rates are confidential.

Table 6 Forecast auxiliary usage (in MW) forecast at time of one-in-two year peak demand (50% POE)

Year	New South Wales	Queensland	South Australia	Tasmania	Victoria
2020-21	429	529	56	23	382
2021-22	444	533	53	22	383
2022-23	447	533	53	22	380
2023-24	420	536	50	22	381
2024-25	417	537	49	22	385

Forecasting auxiliary loads much beyond the next five years is challenging, as it will depend on what new resources are developed, and where, in response to generator retirements and changes in demand.

6. Benefits from a more interconnected system

This section explores the projected improvements in reliability outcomes if actionable projects outlined in AEMO's 2020 ISP are delivered in a timely manner.

The 2020 ISP identified that major investment in the transmission system is required to support the development of VRE and dispatchable capacity that will be needed to replace the NEM's aging coal fleet. The Central scenario in the 2020 ESOO highlights that the risk of load shedding increases as generation retires (in the absence of future market response), highlighted by the impact on expected USE of the retirement of the Liddell, Osborne, Callide B, Yallourn (one unit) and Vales Point Power Stations.

The modelling in the ESOO includes only existing and committed generation, DSP, and transmission projects, and therefore includes only committed transmission augmentations (as detailed in Section 3.3).).

The 2020 ISP highlights four major actionable ISP projects that are due to be completed by 2026:

- **VNI Minor**[59], a minor upgrade to the existing Victoria – New South Wales interconnector which is close to completing its regulatory approval process, included from December 2022.
- **Project EnergyConnect**[60], a new 330 kilovolt (kV) double-circuit interconnector between South Australia and New South Wales, which is modelled in service from July 2024. The implementation of this project is tracking to schedule with commissioning targeted in stages between late 2022 and late 2023. Network capacity is intended to be released in stages following the asset commissioning process.
- **HumeLink**[61], a 500 kV transmission upgrade to reinforce the New South Wales southern shared network and increase transfer capacity between the Snowy Mountains hydroelectric scheme and the region's demand centres. This project is included from July 2025.
- **Central-West Orana REZ Transmission Link**[62], involving network augmentations to support the development of the Central-West Orana renewable energy zone (REZ) as defined in the New South Wales Electricity Strategy, and transfer capacity between the Central-West Orana REZ and major load centres of New South Wales. The project is included from July 2025.

The impacts of these augmentations have been included in a sensitivity (Actionable ISP Projects) that considers the impact on reliability of the transmission augmentations over the reliability forecast period, and up to 2026-27. Note that this assessment focuses entirely on reliability benefits; it does not consider other benefits addressed in the 2020 ISP such as fuel cost savings, access to high quality VRE resources, and enhanced security.

[59] TransGrid. Victoria to NSW Interconnector Upgrade Link, at https://www.transgrid.com.au/what-we-do/projects/current-projects/Victoria%20to%20NSW%20Interconnector/Pages/Victoria%20to%20NSW%20Interconnector%20Upgrade.aspx.

[60] Project EnergyConnect Link, at https://www.projectenergyconnect.com.au/.

[61] TransGrid. HumeLink, at https://www.transgrid.com.au/humelink.

[62] TransGrid. Central-West Orana REZ Transmission Link, at https://www.transgrid.com.au/centralwestorana.

Impact of VNI minor

The VNI Minor augmentation is projected to have a small impact on forecast USE. Some components of the augmentation do provide further reliability benefits, but these have already been included in the ESOO modelling.

Impact of Project EnergyConnect

The commissioning of Project EnergyConnect from 2024-25 is projected to deliver a noticeable reliability improvement in South Australia, as shown in Figure 29. Expected USE in Victoria also reduces, although to a lesser extent, due to the increased capacity available on the interconnectors linking New South Wales and South Australia to Victoria. The impact on reliability in New South Wales is far more muted, with only a slight reduction in USE evident. This is because at times of high demand in New South Wales the transmission network between southern New South Wales and Sydney is already congested, and the new capacity provided by Project EnergyConnect is limited by this congested network. The HumeLink augmentation is forecast to help unlock these benefits in later years.

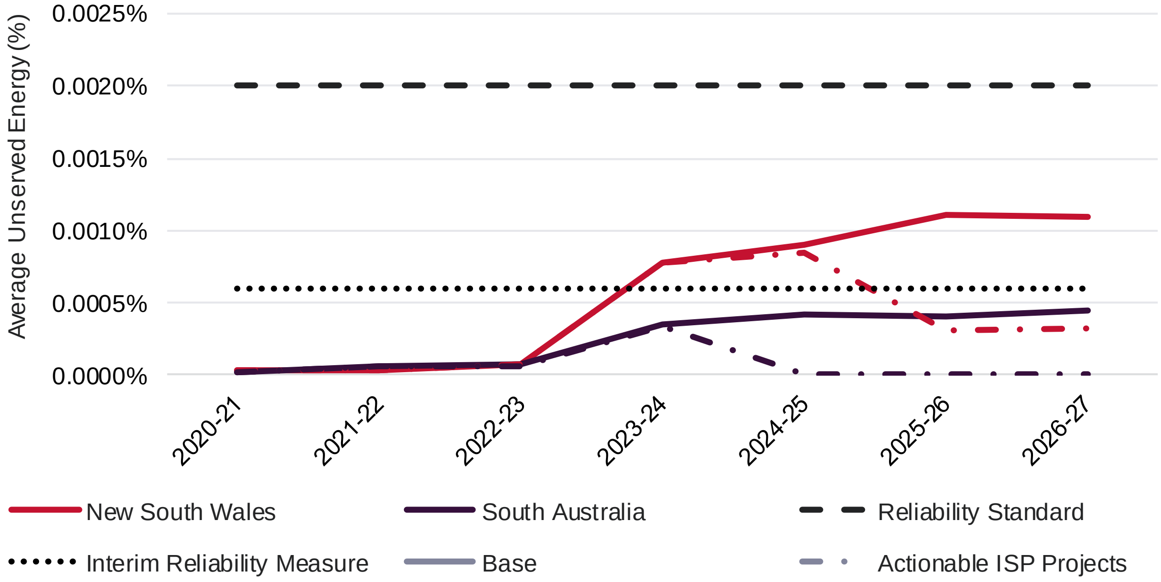
Figure 29 Reliability improvement forecast to be delivered by Project EnergyConnect, 2024-25

Impact of HumeLink

The timely development of HumeLink by 2025-26 is projected to unlock the additional firm supply provided by the Snowy 2.0 project and, at times, import from South Australia via Project EnergyConnect, providing a reliability improvement in New South Wales. The most significant reliability impacts of these low-regret actionable ISP projects are forecast to be in New South Wales and South Australia (see Figure 30).

As noted previously, in the ESOO modelling, the inclusion of Snowy 2.0 in isolation was forecast to have a limited impact on reliability. However, as shown in this sensitivity, when Snowy 2.0 is paired with HumeLink, the level of USE forecast in New South Wales would reduce, with expected USE falling to well below the IRM from 2025-26. More significant reliability benefits could be realised by further strengthening of the transmission network closer to Sydney.

Figure 30 Reliability impact of actionable ISP projects



Impact of Central-West Orana REZ Transmission Link

The augmentation is designed to unlock VRE capacity not yet committed in the Central-West region of New South Wales. Given that the generation expansion in this scenario did not extend beyond committed new entrant generation, the forecast benefits of this augmentation are not captured in the Actionable ISP Projects sensitivity.

7. Challenges and opportunities of low operational demand

This chapter discusses the power system security implications of continuing growth in distributed PV, causing reducing minimum demand. Novel opportunities are arising for stakeholders and customers that can assist in addressing emerging security risks and help support the transition to a secure and reliable power system with high levels of distributed resources.

For more information on power system requirements more generally, please refer to AEMO's July 2020 *Power System Requirements* reference paper[63].

Key insights

- Minimum demand is approaching thresholds where challenges will be encountered in managing voltage, system strength, and inertia.
- Effective market and regulatory arrangements that incentivise more demand during the middle of the day would help minimise the occurrence of extreme minimum load conditions.
- Emerging opportunities for stakeholders to assist in managing low demand periods include:
  - **Active DER management** – there is a growing need for active DER management and DER aggregation systems, increasing the sophistication and quantity of DER and load that can be actively managed and encouraged to align with power system needs.
  - **Load shifting** – low load periods provide opportunities for flexible loads and energy storage to 'soak up' excess distributed PV.
  - **Frequency control services** – there is likely to be a growing need for frequency control services to manage larger contingency sizes caused by unintended DER disconnection in response to faults. This includes fast (sub-second) active power response (FAPR), and also slower-acting but sustained frequency control services from providers such as aggregated loads.
  - **Transmission voltage control services** – there may be increasing opportunities for providers of transmission voltage control services, particularly for managing high transmission voltages that occur in low load conditions.
- In addition to the mechanisms above, immediate action is required to introduce emergency back stop mechanisms and improve DER performance so that system security can be maintained. With prompt

[63] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf.

action, it should be possible to continue to maintain power system security and simultaneously support a transition to greater amounts of DER. Delays will lead to serious security risks, and high costs to address these risks at a later date.

- The most important actions to support system security include:
  - **Disturbance ride-through capabilities** – ensure all new DER installed can ride through disturbances, by improving performance standards and enforcing compliance with those standards.
  - **Emergency PV shedding capabilities** – ensure all new distributed PV, of any capacity, has active shedding capabilities as a condition of connection. This needs to be implemented as soon as possible in a 'ready to use' form, with all the required communications capabilities for immediate instruction by AEMO's control room, in coordination with NSPs. It is anticipated that emergency PV shedding would only be enabled in rare circumstances, if severe abnormal operational conditions arise, and market mechanisms and other available approaches have been exhausted.
- AEMO is working with stakeholders to implement these actions immediately in South Australia, and this ESOO analysis indicates that **similar action is also required urgently in Victoria, and promptly in Queensland**. At this stage, New South Wales and Tasmania appear to present lower risks, but mitigation mechanisms should be considered for NEM-wide rollout for consistency and simplicity, to support NEM-wide operation, and to manage further risks that may be identified as analysis continues.
- By the end of this decade, mainland NEM-wide minimum operational demand is projected to approach a level where large quantities of flexible load and utility-scale energy storage are likely to become increasingly important for daily operation. With development of suitable market frameworks for storage and active DER and load participation in the coming years, emergency PV shedding should only need to be enabled very rarely, as a last resort back-stop to support system security during abnormal conditions.

7.1 Background

Parts of the NEM are leading the world in DER penetration, which provides the opportunity for pioneering and demonstrating world-first power system operation. South Australia is, to AEMO's knowledge, the first gigawatt-scale power system in the world to approach periods with 100% of energy being supplied by distributed resources. Distributed PV penetration levels are also growing rapidly in other NEM regions. This makes it timely to understand the manner in which such a power system will operate, the types of opportunities that are likely to emerge, and the challenges that will need to be addressed.

The changes necessary to facilitate successful integration of large quantities of DER will create new opportunities for service providers and consumers. Where possible, shifting load to better align with times of highest distributed PV will maximise the value of this distributed generation and reduce the power system's exposure to some of the risks identified in this chapter. Successful integration of other forms of DER, such as EVs, distributed batteries and virtual power plants, and active demand-side participants, as they grow in operational impact and significance, will also be critical to assist in successfully transforming the NEM.

AEMO has a major program of work underway to create the underpinning frameworks necessary for secure operation of a high DER power system, so that customers can continue to invest in and derive value from distributed assets.

There is evidence that a significant proportion of DER can disconnect or cease operation during power system disturbances. Analysis from these disturbance events has been used to incorporate DER behaviour into AEMO's power system models. Based on this analysis and modelling, further work is being completed to refine DER response to disturbances to support beneficial power system outcomes via updates to the AS/NZS4777.2 standards. AEMO has communicated findings from this work program as they become available, such as in the *Renewable Integration Study Stage 1 report*[64], and a series of other reports from the DER Program[65], and anticipates that ongoing work will continue to reveal new insights.

AEMO will continue to share these findings with stakeholders, so solutions can be explored and implemented collaboratively. Further, system strength, and inertia, and Network Support and Control Ancillary Services (NSCAS) requirements during low demand conditions, will be considered in dedicated reports due for release by the end of 2020.

AEMO is pursuing development of suitable market and regulatory frameworks for active DER and load participation, and improved frameworks for market investment in storage. These measures aim to facilitate efficient daily market operation, and avoid extreme operational circumstances.

In addition to these market and regulatory measures, AEMO's analysis has identified a number of challenges that arise as distributed PV levels grow, especially in the absence of an increase in underlying demand (either through active DER management or load shifting):

- Unintended disconnection of distributed PV in response to power system disturbances.
- Minimum demand thresholds to maintain supply of system security services.
- Transmission voltage management.
- Impacts on emergency frequency control schemes (EFCSs), such as under frequency load shedding (UFLS).
- Impacts on system restart processes.

These challenges are serious, and mitigation actions to introduce security back stop mechanisms and improve DER performance need to be pursued immediately. Delays will be costly, difficult to fix, and will lead to severe impacts and risks for consumers. However, if action is taken promptly to implement improved disturbance ride-through and emergency PV shedding capabilities for new DER installations, it should position the NEM to address any remaining issues using existing planning and operational avenues.

While the focus to date has been on challenges in South Australia, this ESOO analysis broadens the assessment to other mainland NEM regions, with projections based on the ESOO forecasts over the next five years. Forecast levels of distributed PV assumed in this analysis are based on the Central scenario and the Central Downside, High DER sensitivity (see Figure 5 and the 2020 IASR for more details).

7.2 Unintended disconnection of distributed PV in disturbances

AEMO now has considerable evidence that many distributed PV systems unintentionally disconnect in response to short duration voltage dips caused by faults on the network[66]. This has been demonstrated consistently across laboratory testing of distributed PV inverters[67], field measurements from thousands of individual distributed PV inverters during a series of voltage disturbances occurring during 2016 to 2020[68], and high speed monitoring at selected load feeders in the distribution network[69].

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

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

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

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

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

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

Similarly, short duration voltage dips cause a load reduction that partially offsets distributed PV disconnection. The load reduction is observed in SCADA demand measurements, and in distribution network high speed measurements during low solar periods.

AEMO used these observations to develop and calibrate dynamic power system models of distributed PV and load that reproduce their undervoltage disconnection behaviour in PSS®E.

In high distributed PV periods with low underlying demand, the volume of distributed PV disconnection in response to short duration voltage dips can be larger than the corresponding load reduction, leading to a rapid net reduction in supply.

It is credible that a single fault could cause distributed PV disconnection coincident with the sudden loss of a large generating unit. The size of the largest credible contingency therefore becomes the size of the largest generating unit plus the net reduction in supply from PV disconnection. AEMO needs to plan the power system to be secure for the largest credible contingency, so this impacts upon power system operation.

The analysis presented in this chapter is most comprehensive for South Australia, where power system security implications are already experienced, and this analysis is outlined in more depth in AEMO's recently released report on minimum demand thresholds in South Australia[70].

For this ESOO, AEMO has also conducted preliminary analysis of the impact of transmission faults in key locations in Victoria, Queensland and New South Wales. This initial analysis relies on power system snapshots representative of daytime periods with low demand and high distributed PV generation (31 January 2020) to determine the proportion of distributed PV disconnected and underlying demand reduced in response to short duration voltage dips. Using the ESOO forecasts for underlying demand and distributed PV in each half-hour period, AEMO then projected the net loss of load and distributed PV in each future year to determine whether largest contingency sizes are expected to increase in regions other than South Australia in the near future.

The initial findings discussed in the remainder of this section represent central estimates for select years. For more years of analysis, and an uncertainty range around these central estimates, refer to Appendix A5.

South Australia

AEMO's analysis based on the PSS®E models demonstrates that a severe but credible fault near the Adelaide metropolitan area on the 275 kV transmission network would likely cause disconnection of both:

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

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

Without proposed mitigation measures to improve DER disturbance ride-through capabilities, by calendar year 2025 analysis suggests that distributed PV disconnection in the highest PV periods could increase the largest credible contingency by around 310 MW under the Central scenario and 390 MW in the Central Downside, High DER sensitivity. The net distributed PV contingency is expected to be positive (that is, a net loss of generation) over 20% of the time. This has the following implications for power system security:

- **Imports on the Heywood interconnector may need to be limited in some periods** – if the Heywood interconnector is importing at significant levels into South Australia, a large generation contingency (involving a large generating unit and an associated net loss of distributed PV) in South Australia could lead to activation of the System Integrity Protection Scheme (SIPS), and in the worst case, possible

[70] AEMO (May 2020), *Minimum operational demand thresholds in South Australia*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/SA_Advisory/2020/Minimum-Operational-Demand-Thresholds-in-South-Australia-Review.

separation from the rest of the NEM. As discussed in Section 7.5, UFLS may not be sufficient to prevent cascading failure if separation occurs under high distributed PV conditions. To maintain power system security, imports on the Heywood interconnector need to be limited in some periods. A preliminary constraint has been implemented, and ElectraNet is completing analysis to refine its network limit advice. In collaboration with AEMO, ElectraNet is upgrading the existing SIPS to a Wide Area Protection Scheme (WAPS). This is not anticipated to significantly affect implications for operation with high distributed PV.

- **If islanded, maintaining system security at times of high distributed PV will be challenging** – when South Australia is operating as an island, AEMO's studies indicate that it is becoming increasingly more challenging to maintain the Frequency Operating Standards for certain credible faults if they occur during periods with high levels of distributed PV operating. This means AEMO may no longer have the means to operate a South Australian island securely at times of high distributed PV generation (see Section 7.3.1). Security risks will grow rapidly as more distributed PV is installed, if the mitigating actions discussed below are not implemented. AEMO is now taking distributed PV disconnections into account in the assessment of inertia requirements and shortfalls, and will progressively incorporate these findings into other power system security assessments.

Victoria

For Victoria, initial findings demonstrate that a severe but credible fault near Loy Yang A or B, or around the Melbourne metropolitan 500 kV network (Sydenham – South Morang), would likely cause disconnection of both:

- At least 40-45% of the distributed PV in the Victorian region, and
- 12-22% of the underlying demand in the Victorian region.

Based on these initial findings, voltage disturbances with relatively low amounts of distributed PV operating would lead to a net loss of load, since a 12-22% loss of underlying demand would exceed a 40-45% loss of regional distributed PV generation. This is consistent with AEMO's observations of net load and PV loss in past disturbances.

However, in future low demand periods as the quantity of distributed PV approaches the total load in the region, the disconnection of distributed PV will start to exceed the loss of load, resulting in an increase in the size of the largest generator contingency:

- In calendar year 2021, under the most severe credible fault:
  - The size of distributed PV disconnection is expected to be larger than any underlying demand less than 1% of the time.
  - In the highest PV generation period, distributed PV disconnection could increase the size of the largest credible contingency in Victoria by approximately 20 MW in the Central scenario, and 90 MW in the Central Downside, High DER sensitivity.
- By calendar year 2025, in Victoria, without proposed mitigation measures to improve DER disturbance ride-through capabilities:
  - Loss of distributed PV is expected to exceed load loss under the most severe credible fault 14% of the time in the Central scenario and 18% of the time in the Central Downside, High DER sensitivity.
  - Under the highest PV generation conditions, distributed PV disconnection could increase the largest credible contingency by approximately 600 MW in the Central scenario, and 740 MW in the Central Downside, High DER sensitivity.
  - If the current practice of de-energising 500 kV transmission lines during periods of low demand to manage voltages in the transmission network is discontinued (see Section 7.3.2), distributed PV disconnection could increase the largest credible contingency even further, by approximately 850 MW in the Central scenario, and 1,020 MW in the Central Downside, High DER sensitivity.

These are extremely large values to add to the largest credible contingency, highlighting the importance of improving disturbance ride-through capabilities for new distributed PV before these outcomes eventuate.

Queensland

For Queensland, the most influential fault locations are near Wivenhoe, the Brisbane metropolitan 275 kV network, or Tarong, Tarong North, Swanbank E, with faults in these locations likely causing disconnection of both:

- At least 30-33% of the distributed PV in the Queensland region, and
- 9-16% of the underlying demand in the Queensland region.

The analysis suggests that periods are now emerging where the net impact of a fault in certain locations would likely increase the largest credible contingency (loss of distributed PV exceeds load loss). As distributed PV levels continue to grow beyond this point, the impact on contingency sizes will escalate rapidly:

- In calendar year 2021, under the most severe credible fault:
  - The size of any distributed PV disconnection is expected to be larger than any underlying demand less than 1% of the time.
  - Under the highest PV generation conditions, distributed PV disconnection could increase the size of the largest credible contingency in Queensland by approximately 20 MW in the Central scenario, and 50 MW in the Central Downside, High DER sensitivity.
- By calendar year 2025, in Queensland, without proposed mitigation measures to improve DER disturbance ride-through capabilities:
  - Loss of distributed PV is expected to exceed load loss under the most severe credible fault 5% of the time in the Central scenario and 11% of the time in the Central Downside, High DER sensitivity.
  - Under the highest distributed PV generation conditions, distributed PV disconnection could increase the size of the largest credible contingency by approximately 200 MW in the Central scenario, and 380 MW in the Central Downside, High DER sensitivity.

New South Wales

For New South Wales, the most influential fault locations are on the Sydney metropolitan 330 kV network, or near Liddell or Vales Point, with faults in these locations likely causing disconnection of both:

- At least 19-24% of the distributed PV in the New South Wales region, and
- 8-17% of the underlying demand in the New South Wales region.

New South Wales is not forecast to encounter any periods in the next few years in which a credible fault could cause a net loss of distributed PV generation (in excess of load reduction). This is due to a number of factors:

- The installed distributed PV in New South Wales is spread across a range of areas (including Sydney, Canberra and Newcastle, and installations spread in other parts of the region), compared with more concentrated installations in other NEM regions.
- Voltage disturbances during faults appear to affect a smaller area in New South Wales, compared with other regions, likely due to the number and locations of synchronous units operating in typical periods.
- New South Wales has the highest demand level of any state, providing a larger load disconnection to offset distributed PV disconnection.

Although this analysis does not suggest that distributed PV disconnection will present security challenges in New South Wales in the near future, disconnection of load may cause operational challenges in high demand periods (with low generation from distributed PV). This is under further investigation.

Mitigating actions

The following mitigating actions are underway to manage the identified risks:

- **Improving DER performance standards** – improving disturbance ride-through capabilities for new distributed PV installations mitigates further increases in contingency sizes associated with distributed PV disconnection behaviour. AEMO has initiated:
  - A review of AS/NZS 4777.2 to collaboratively develop new performance requirements for low voltage connected inverters[71].
  - A program with SA Power Networks (SAPN) and the South Australian Government to accelerate the introduction of a requirement for voltage ride-through capabilities, to be required as a condition of connection for all new distributed PV in South Australia[72,73].
  - A Rule Change with the Australian Energy Market Commission (AEMC) to create a new framework for setting minimum technical standards for DER, to apply across all NEM regions, and allow accelerated timeframes for introduction of essential security capabilities for DER[74].
- **Improving compliance with DER performance standards** – AEMO's analysis suggests that there is a level of non-compliance of inverter responses to the existing standard (AS/NZS 4777.2:2015)[75], where a significant proportion of inverters that deliver the required responses under laboratory conditions do not deliver these responses in the field. This suggests an additional need to improve compliance in the installation process. AEMO is leading a consultation process with key stakeholders in developing a plan for improving compliance with essential requirements[76].
- **Network constraints –** AEMO has implemented constraints that limit flows on the Heywood interconnector to limit risks related to distributed PV disconnection[77]. The constraints, implemented in April 2020, consider the increase in the credible contingency size in South Australia when distributed PV is operating, and limit the risk of relying on emergency control schemes to manage a credible contingency. AEMO is working with ElectraNet to continually improve these constraints. These constraints are only required in rare periods with high levels of distributed PV operating, and have only bound for less than one hour during daylight periods during the first three months since they were implemented.

  AEMO may also need to modify network limits in Queensland and Victoria in future to manage system security based on the levels of distributed PV disconnection projected in this analysis, and these are under investigation.
- **Project EnergyConnect** – the need to operate South Australia as an island will be significantly reduced by the installation of Project EnergyConnect (providing a synchronous connection between South Australia and New South Wales). This significantly reduces the security risks outlined.

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[71] A draft of the revised AS/NZS 4777.2 standard is released for public comments until 10/09/2020, at https://sapc.standards.org.au/sapc/public/listOpenCommentingPublication.action.

[72] See https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/standards-and-connections/vdrt-test-procedure.

[73] Government of South Australia, Consultation on the Proposed new low voltage ride-through requirements for smart inverters in South Australia, at http://energymining.sa.gov.au/__data/assets/pdf_file/0009/364662/Attachment_3_Consultation_on_Voltage_Ride_Through.pdf.

[74] AEMC (25 June 2020) Technical standards for distributed energy resources, at https://www.aemc.gov.au/rule-changes/technical-standards-distributed-energy-resources#:~:text=The%20Commission%20has%20initiated%20a,distributed%20energy%20resources%20(DER).&text=If%20made%2C%20this%20rule%20change,minimum%20technical%20standards%20for%20DER.

[75] For example, AEMO incident reports for event on 26 November 2019 (Appendix A2) at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2019/incident-report-south-pine-incident-on-26-nov-19.pdf?la=en and 25 August 2018 (Appendix A1) at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2018/Qld---SA-Separation-25-August-2018-Incident-Report.pdf.

[76] Stakeholders should contact DERProgram@aemo.com.au if they are interested in contributing to this process.

[77] Refer to Market Notice 75464 for a list of the constraint equations affected, at https://aemo.com.au/market-notices?marketNoticeQuery=75464&marketNoticeFacets=.

Further opportunities

In addition to the mitigating actions above, the management of these emerging challenges is likely to create new opportunities for service providers, including:

- **Fast Active Power Response (FAPR)** – FAPR refers to a fast (sub-second) active power response from resources that can respond very quickly. Examples of FAPR providers include some types of inverter connected resources (such as battery energy storage systems [BESS] and solar farms), and some types of load response. This response can assist with rapidly correcting an energy imbalance, helping to arrest system frequency changes during severe disturbances. This response becomes increasingly valuable as contingency sizes grow, and inertia levels reduce with less synchronous generation online. If considered during design, some providers may have the ability to provide larger quantities of this service by utilising short term overload capabilities of the inverter.

  At present, there are limited regulatory pathways by which this service is procured and rewarded, but the value of the technical capability is increasing and likely to grow over time. A Rule Change has been initiated to consider establishment of new market ancillary services for this capability[78].

- **Frequency Control Ancillary Services (FCAS)** – in addition to faster frequency control services (noted above), FCAS in all response timeframes are likely to become increasingly required to manage escalating contingency sizes. Providers that can deliver these services with low minimum load requirements are likely to be particularly valuable.

7.3 Minimum demand thresholds

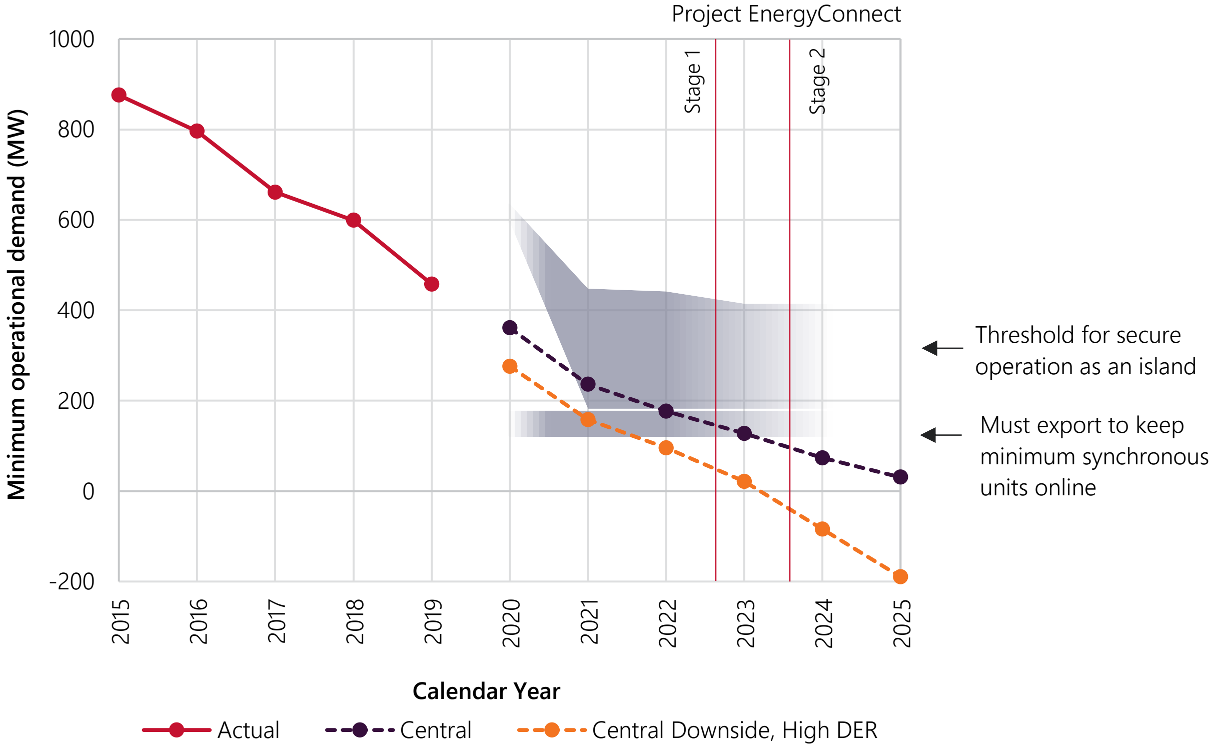
This section outlines minimum demand thresholds that may lead to operational challenges under some conditions, and the opportunities likely to arise for solutions that address these challenges (in Section 7.4).

7.3.1 South Australia

Figure 31 shows historical minimum operational demand levels (as generated) in South Australia, compared with forecasts, and identified demand thresholds (explained further below). As discussed in Section 2.3.2, minimum demand has occurred during the daytime for the past five years in South Australia. This is projected to continue, with ongoing rapid reduction in minimum demand as growth in distributed PV continues, unless large quantities of market-based solutions such as utility-scale energy storage, coordinated EV charging and demand response emerge.

[78] AEMC (2 July 2020) Fast frequency response market ancillary services, at https://www.aemc.gov.au/rule-changes/fast-frequency-response-market-ancillary-service

Figure 31 Minimum operational demand thresholds in South Australia (90% POE as generated)



Note: The "as generated" minimum demand values will be slightly higher than the 'sent out' values presented in Section 2.3.2 as they include auxiliary loads. Project EnergyConnect is an actionable ISP project and is modelled in service from July 2024. The implementation of this project is tracking to schedule with commissioning targeted in stages between late 2022 and late 2023. Network capacity is intended to be released in stages following the asset commissioning process.

Minimum demand for secure operation as an island

When South Australia is operating as an island, there is a need for sufficient demand to support the minimum loading levels for synchronous generating units in the region, required for secure provision of frequency control, inertia, and system strength services. Figure 31 shows an estimate of the minimum demand required for secure operation of the South Australian island, based upon a range of possible unit combinations (allowing flexibility for forced outages and unit maintenance windows).

AEMO estimates that, under some conditions, the threshold level of operational demand required to allow operation with a range of unit combinations will be around 600 MW in late 2020, reducing to around 400 MW from late 2021 (with four synchronous condensers installed).

This level of demand allows for islanded operation with a range of possible generating unit combinations, allowing for a range of operating conditions. If South Australia is operating as an island and operational demand falls below these minimum demand thresholds, there may be insufficient frequency control to meet the frequency operating standards following several credible contingencies, meaning the island could not be operated securely, as already discussed in Section 7.3.1. This could mean that supply disruption would result from a credible fault.

South Australia has already experienced operational demand as low as 458 MW[79]. As shown in Figure 31, this is projected to reduce further (under 1-in-10 year minimum demand conditions) to around 250-350 MW by spring 2020, and to close to zero in the Central Downside, High DER sensitivity by 2023.

These minimum demand forecasts are well below the thresholds for secure operation of a South Australian island. This means there is an urgent need to establish a back stop mechanism to restore operational demand to a level that allows secure power system operation (by shedding distributed PV generation) when rare and

[79] Occurring on 10 November 2019.

extreme events occur, such as when the South Australian region is operating as an island or under elevated risk of separation. Over time, active DER management and load shifting could help lift these minimum demand levels, but shedding distributed PV generation will remain required as an essential, emergency capability to support system security with such high levels of distributed PV generation. The ability to reduce power to zero when instructed is an essential capability for all large-scale generation, and this capability is now also required from distributed resources, given the very large capacity now installed. Load shifting, storage, and active DER management are a first preference for lifting minimum demand levels, and would minimise the frequency with which PV shedding needs to be enabled (as a last resort), but do not remove the requirement to have this capability in place to support system security.

Separation events, of the type that might require deployment of emergency PV shedding capabilities in the event other options are exhausted, are relatively rare. For example, South Australia has separated from the rest of the NEM on average about once per year. Separation events can occasionally occur for an extended duration. For example, following a non-credible separation event on 31 January 2020, AEMO operated South Australia as an island for a period of 18 days. This was due to severe damage to at least six transmission towers inhibiting restoration of the AC interconnection between Victoria and South Australia for an extended period[80]. Without action, if a similar event were to occur during low demand periods in spring 2020 or 2021, AEMO would not have the operational levers available to securely manage the South Australian system, with a risk of disruption to South Australia customers.

Based on 2020 ESOO one-in-10-year minimum demand forecasts, AEMO projects that emergency PV shedding capabilities of around 300-400 MW are required as a back stop in South Australia by spring 2020. Some proportion of this quantity of emergency PV shedding may need to be enabled when South Australia is operating as an island, if operational demand is below required thresholds for secure operation. These quantities are very large in comparison to available load and storage that could feasibly be enabled. Load and storage flexibility could assist to reduce the quantity of emergency PV shedding that needs to be activated in any particular scenario, but this does not remove the need to have this capability in place as a security back stop.

Minimum demand thresholds are sensitive to unintended distributed PV disconnection behaviour (discussed in Section 7.2). Unintended disconnection of 130 MW of distributed PV has been assumed in this analysis (in all years), and unintended disconnection of larger quantities of distributed PV was found to substantially escalate FCAS requirements, increasing minimum demand thresholds considerably. This analysis is outlined in more depth in AEMO's recently released report on minimum demand thresholds in South Australia[81].

Operational arrangements to manage growing quantities of distributed PV under abnormal circumstances may impact on AEMO's other assessments, such as minimum inertia thresholds. This will be considered as part of those assessment processes, as operating procedures are determined.

Minimum demand where South Australia must export

Figure 31 also shows the threshold below which South Australia must export to Victoria, based upon the necessity of operating a minimum number of synchronous generating units in South Australia. This is defined by combinations of synchronous generating units that provide sufficient system strength to withstand a credible fault and loss of a synchronous unit[82]. Minimum operational demand levels are projected to fall below this threshold in 2022 under certain conditions. Exporting surplus South Australian generation will exacerbate minimum demand challenges in Victoria, as discussed in Section 7.3.2.

[80] AEMO (April 2020) *Preliminary Report – Victoria and South Australia Separation Event, 31 January 2020*, at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/preliminary-report-31-jan-2020.pdf?la=en.

[81] AEMO (May 2020) *Minimum operational demand thresholds in South Australia*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/SA_Advisory/2020/Minimum-Operational-Demand-Thresholds-in-South-Australia-Review.

[82] AEMO (July 2020) Transfer Limit Advice – System Strength, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?la=en.

Project EnergyConnect

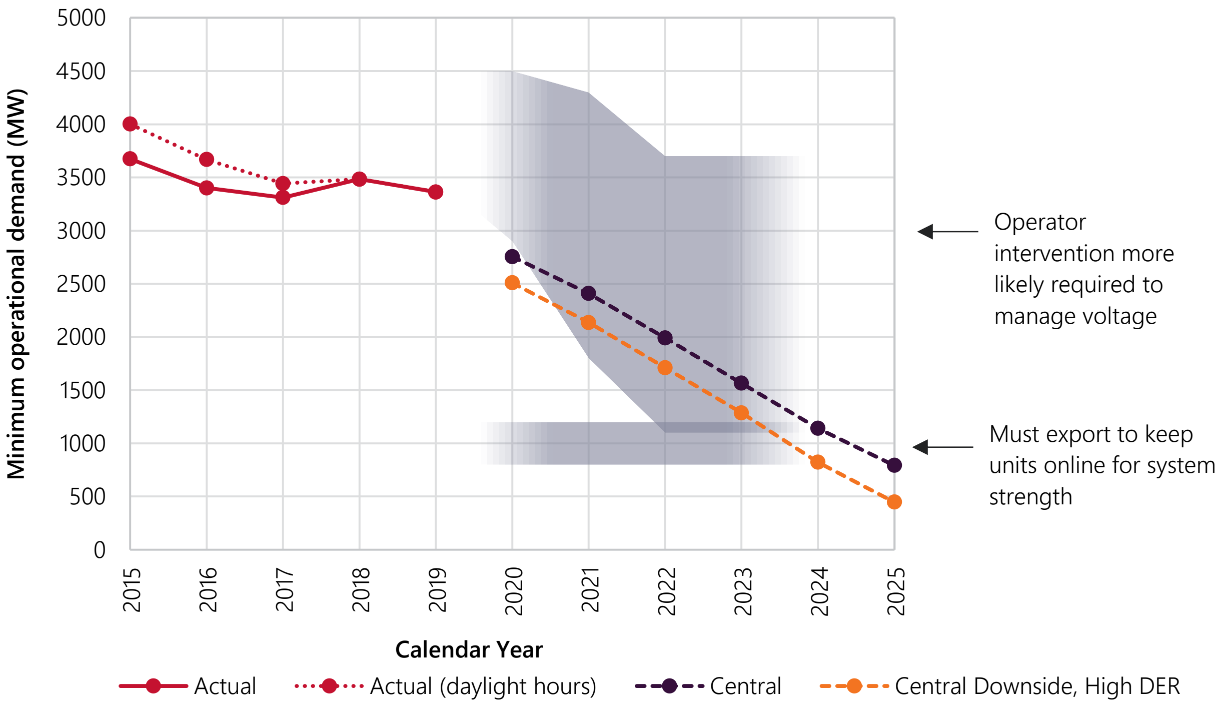
Figure 31 shows the anticipated staged commissioning of the Project EnergyConnect (PEC) interconnector[83], which should significantly reduce the likelihood of islanding. This will alleviate much of the identified risk associated with islanded operation since the chance of islanding will be significantly reduced.

It will remain important that emergency PV shedding capabilities are available, to manage very rare occasions as a back stop for managing power system security, for example to maintain the power system within secure limits during abnormal network conditions, or when demand is below thresholds across multiple regions.

7.3.2 Victoria

Figure 32 shows historical and forecast minimum operational demand levels (as generated) in Victoria. Minimum demand occurred during the daytime in Victoria for the first time in 2018, and is projected to continue to decrease rapidly as distributed PV is installed at a high rate.

Figure 32 Minimum operational demand thresholds in Victoria (90% POE as generated)



Voltage management

Operational challenges associated with voltage control in low load periods have already been experienced in Victoria. The need for operator intervention to manage voltage levels is dependent on network flows and the generating units online but at present is generally required when operational demand approaches 3.5 GW to 4.5 GW, as shown in Figure 32.

Some short-term operational measures are available to manage low load voltage challenges, and these can be suitable when issues arise rarely. This can include activation of contracts to bring additional generating units online to provide voltage control, or de-energisation of 500 kV circuits. De-energisation of circuits is used only after all standard practices have been exhausted because it can result in higher market costs, and reduced system resilience. Voltage control contracts may also have limitations that prevent them being activated, for example outages of generating units included in the contracts, or limitations in the terms of

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

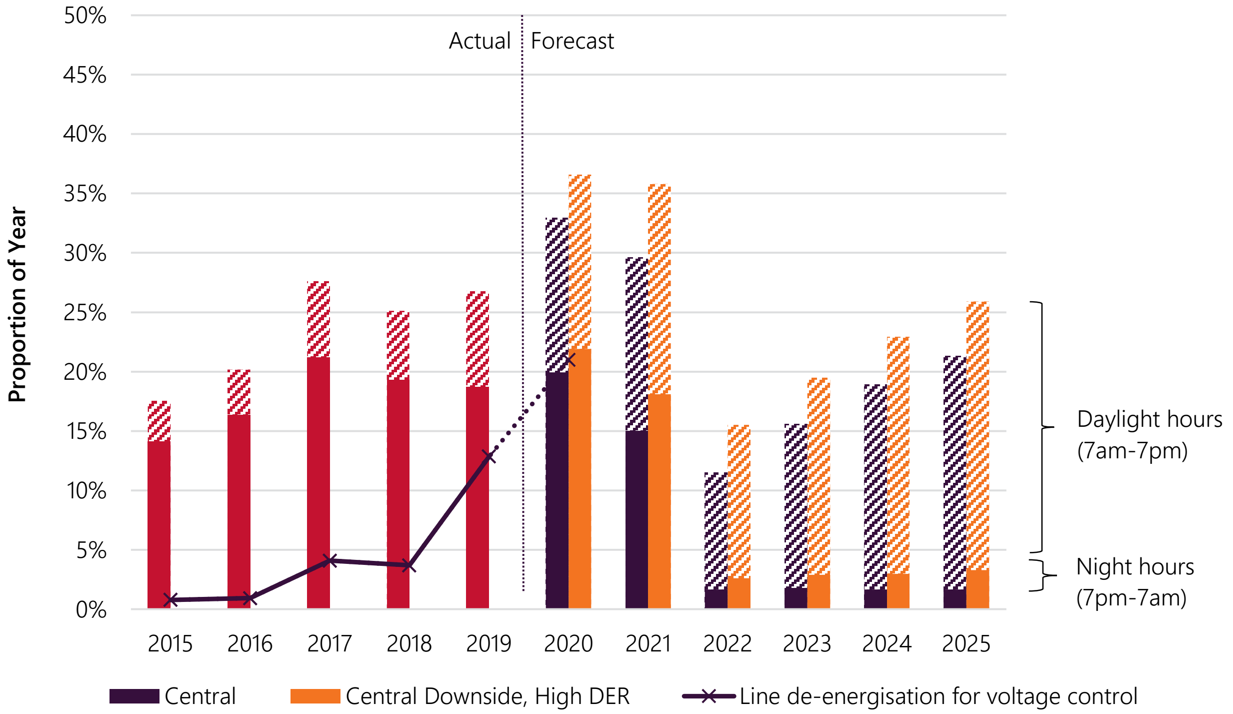
those contracts. The frequency and severity of these interventions has increased rapidly in Victoria. For these reasons, it is important to explore both operational and planning measures to address emerging voltage management challenges and minimise reliance on short term operational measures.

Reactive power equipment is also being procured to address this growing challenge in Victoria[84]. The commissioning of the proposed reactors in 2021 and 2022, along with new generation with higher levels of reactive power capabilities, is projected to reduce the demand threshold at which operator intervention is required to manage voltage, as illustrated in Figure 32.

The larger range in thresholds associated with operator intervention for voltage management beyond 2020 reflects the range of dispatch outcomes where new generation with improved reactive power capabilities may or may not be dispatched.

Until the reactors are commissioned, demand is forecast to fall below the threshold at which operator intervention may be required to manage voltage levels around 30-35% of the year, as shown in Figure 33. Once the reactors are installed, the threshold where intervention is likely to be required reduces, and is projected to be exceeded less often initially (10-15% of the year), but the frequency of exceedance steadily grows to 20-25% of the year in 2025. Further, an increasing proportion of these periods are projected to occur during daylight hours due to growth in distributed PV.

Figure 33 Proportion of year demand falls below upper threshold for intervention for voltage control (50% POE)



Values for line de-energisation in 2020 include actual data up to June. Values for demand below upper thresholds in 2020 include actual data up to June and forecast data from July.

Intervention may not be required in all of these periods and will depend on network flows and the generating units online. For example, operator intervention (line de-energisation, as shown in Figure 33) for voltage control increased in 2017 due to the retirement of Hazelwood Power Station and the subsequent reduction in reactive power control capabilities in Victoria. Operator intervention increased again in 2019 due to an

[84] AEMO (December 2019) Victorian Reactive Power Support – Regulatory Investment Test for Transmission Project Assessment Conclusions Report, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/2019/reactive-power-rit-t/victorian-reactive-power-support-pacr.pdf. Reactors will be delivered on an accelerated timeframe (by late 2022) due to identified cost efficiencies.

increase in low demand periods and prolonged unplanned outages of Victorian generating units[85]. However, in the absence of network investment in further reactive power support such as SVCs, synchronous condensers or STATCOMS, or implementation of other options such as use of storage, an increase in low demand periods will likely correspond to an increase in operator action and require attention and resources from the AEMO control room.

Options for further investment beyond the planned reactors will be explored with transmission network service providers (TNSPs) as part of the joint planning process, including through the AEMO Network Support and Control Ancillary Services (NSCAS) annual review which will release AEMO's assessment of NSCAS needs and any NSCAS gaps by the end of 2020.

Minimum demand where Victoria must export

To maintain system strength in Victoria, various combinations of synchronous units must always remain online, as outlined in AEMO's Transfer Limit Advice[86]. These unit combinations have an aggregate minimum generation requirement between 800 MW and 1200 MW. This range represents the operational demand threshold below which Victoria must export to neighbouring regions to access enough demand for generators to remain operating at minimum generation levels to provide the necessary system strength. This threshold is illustrated in Figure 32. Minimum demand is projected to reach this level around 2024. Exports to other regions may not always be possible, for reasons such as:

- While Victoria has strong interconnection to other regions, its export capacity can be significantly reduced by planned or unplanned line outages, severe weather, or separation from one or more regions[87].
- Other NEM regions are likely to experience low load at similar times, and will have limited ability to accept imports from Victoria. For example, from as early as 2021 in some scenarios South Australia is projected to reach minimum operational demand levels that necessitate exports to Victoria to maintain sufficient synchronous units online (as shown in Figure 31). Analysis of daytime operational demand in 2019 shows that these low demand periods in South Australia often coincide with low demand in Victoria.

Under these circumstances, either synchronous generation units would need to increase flexibility to operate at lower minimum generation levels, or distributed PV would need to be shed to maintain system security. Alternatively, investment in greater interconnection combined with large quantities of deep storage (such as Snowy 2.0) could extend operability.

It is also possible that Victoria may need to operate as a combined island with South Australia, if separation from New South Wales occurs (similar to the separation event on 4 January 2020). Given the high levels of distributed PV in South Australia, and the strong correlation of low demand periods across both regions, the possibility of circumstances of this nature highlights the immediate need for introducing emergency PV shedding capabilities so that these rare but important events can be managed effectively. This is discussed further in Section 8.3.1.

7.3.3 Queensland

Figure 34 shows minimum operational demand levels (as generated) in Queensland, which started to occur during the daytime from 2017 onwards. Forecast minimum demand levels are shown for the Central scenario, and Central Downside, High DER sensitivity.

Voltage management

Based on operational experience, AEMO intervention may be necessary to manage transmission voltages when operational demand falls below approximately 4 GW to 5GW[88], depending on network flows and the

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[85] Prolonged unplanned outages occurred at Loy Yang A2 (May 2019 to December 2019) and a unit at Mortlake Power Station (July 2019 to December 2019).

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

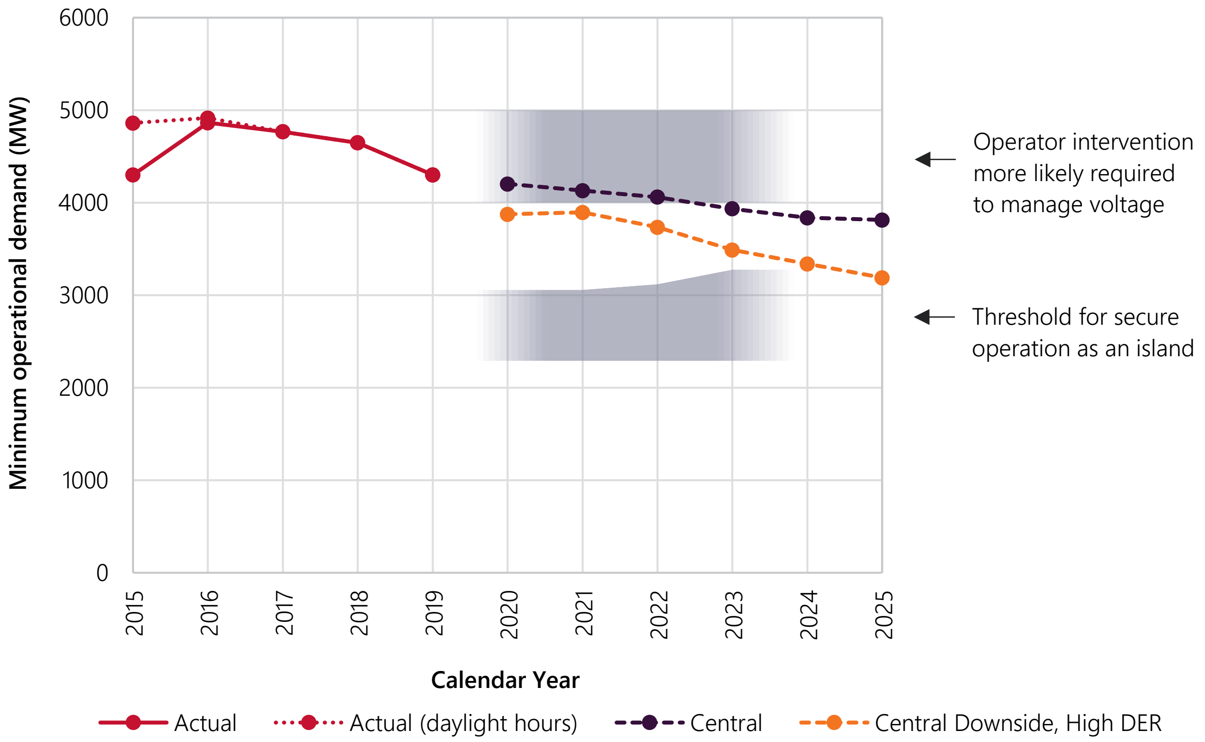
[87] Such as the extended separation between Victoria and South Australia in January to February 2020, or the separation between Victoria and New South Wales due to bushfires in January 2020.

[88] Such as the de-energisation of a 275 kV line in Queensland on 7 November 2019 when demand fell to approximately 5.1 GW.

combination of units online. Both the Central scenario and Central Downside, High DER sensitivity show minimum operational demand levels falling below this threshold from 2020.

This suggests that in the absence of mitigating measures, operator intervention may increasingly be required to manage transmission voltages in some locations during low load conditions in Queensland. The economic and technical feasibility of various options will be explored with TNSPs as part of the joint planning process, including through the AEMO NSCAS annual review which will release AEMO's assessment of NSCAS needs and any NSCAS gaps by the end of 2020.

Figure 34 Minimum operational demand thresholds in Queensland (90% POE as generated)



Islanded operation

Similar to South Australia, Queensland can unexpectedly separate from the rest of the NEM, and may need to operate as an island in some periods. Figure 34 shows the range of minimum operational demand required to maintain secure operation as an island, based on existing requirements for system strength and inertia, and assessing frequency control requirements associated with distributed PV disconnection increasing the largest credible contingency. Around 3 GW of operational demand is estimated to be required for operation of a secure island, with a range of synchronous unit combinations to account for possible unit outages. The threshold increases somewhat from 2022 due to the largest credible contingency increasing from unintended disconnection of distributed PV in response to faults. Further growth should be mitigated by improvements to DER performance standards.

As shown in Figure 34, the Central Downside, High DER sensitivity is projected to approach the threshold where Queensland can no longer be securely operated as an island from 2025 (on the basis of insufficient load for operation of the necessary units). AEMO notes that:

- Other operational challenges may emerge earlier than this date. For example, there may be challenges managing intra-regional network limits prior to these dates, which have not been considered in this analysis.
- There may be sub-regional requirements. The minimum combinations of generating units that must be operating in Queensland require aggregate minimum generation levels of approximately 1 GW in the

Central Queensland subregion and 700 MW in the Southern Queensland subregion, which interacts with the need for sufficient availability of intra-regional interconnection.

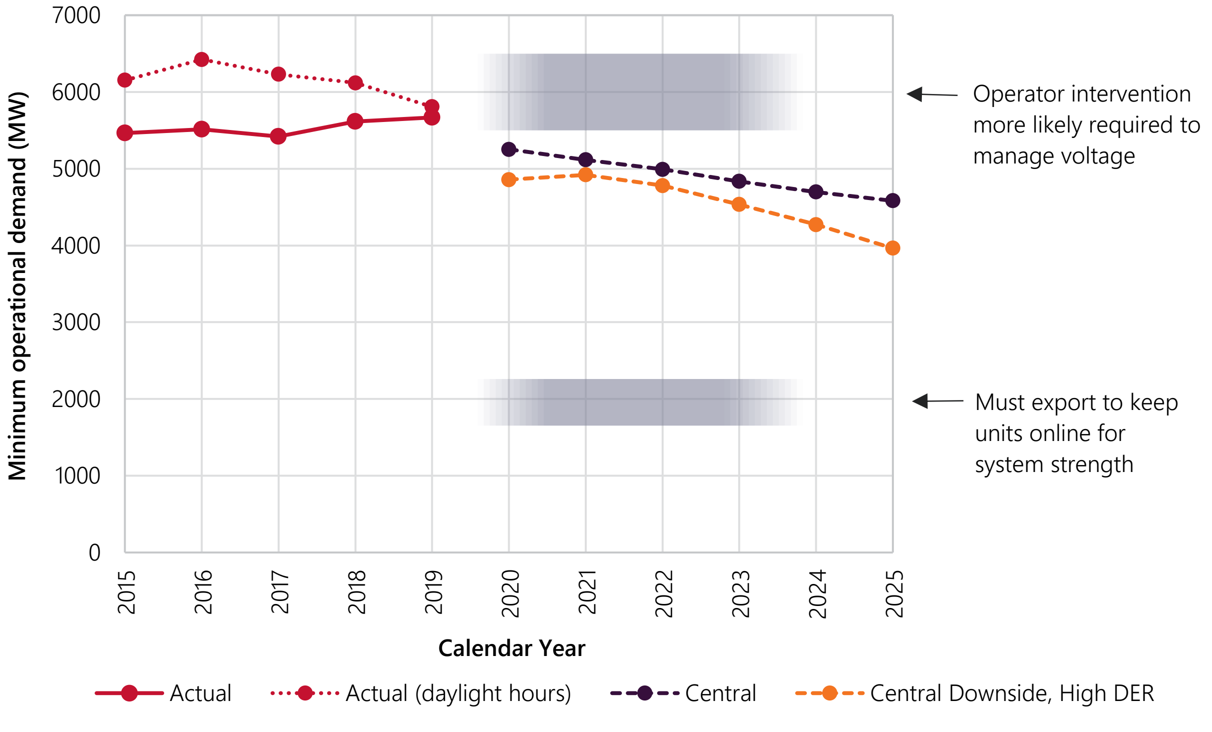
- Distributed PV behaviour will interact with AEMO's other assessment processes such as minimum system strength and inertia requirements. AEMO will be reviewing minimum inertia and system strength requirements in Queensland by the end of 2020, and this assessment will be informed by these findings on distributed PV.
- Demand could be lower than forecast if outages of major industrial customers coincide with low load periods.

Given the complexity in establishing active DER management capabilities, and the time involved in implementing these at scale, this analysis indicates that work should commence now to develop a program of work to promptly implement emergency PV shedding capabilities in Queensland. Assuming development of suitable market and regulatory frameworks for DER and load participation, and market development of suitably sized storage, it is anticipated that emergency PV shedding would be enabled rarely as a last resort to manage system security under abnormal conditions. This is discussed further in Section 7.4.

7.3.4 New South Wales

Figure 35 shows minimum demand projections for New South Wales. Minimum demand is projected to decrease with ongoing growth in distributed PV, although not as rapidly as in other NEM regions.

Figure 35 Minimum operational demand thresholds in New South Wales (90% POE as generated)



Voltage management

AEMO intervention such as line switching may be required to manage transmission voltages when minimum demand falls below approximately 6 GW, which has already occurred in some periods[89]. As indicated in Figure 35, minimum demand is projected to fall well below this range from 2020 onwards. This can be addressed with a range of approaches as described in previous sections, and will be considered as part of the

[89] Such as the de-energisation of a 132 kV line in South West New South Wales on 4 April 2020 and 6 April 2020 when demand fell to approximately 5.6 GW and 5.8 GW respectively.

joint planning process, including through the AEMO NSCAS annual review which will release AEMO's assessment of NSCAS needs and any NSCAS gaps by the end of 2020.

Minimum demand where New South Wales must export

The various combinations of synchronous units that must remain online to provide minimum levels of system strength in New South Wales have an aggregate minimum generation requirement of between 1.6 – 2.2 GW. When demand falls below this level, it will be necessary for New South Wales to export to remain in secure operation. Given that other NEM regions are approaching minimum demand thresholds faster than New South Wales, it is unlikely that other regions will have the ability to accept exports from New South Wales at these times. As shown in Figure 35, minimum operational demand in New South Wales is not projected to fall below this level until well beyond 2025. However, given neighbouring regions approaching minimum demand thresholds in similar intervals, New South Wales may be increasingly affected by other regions' need to export.

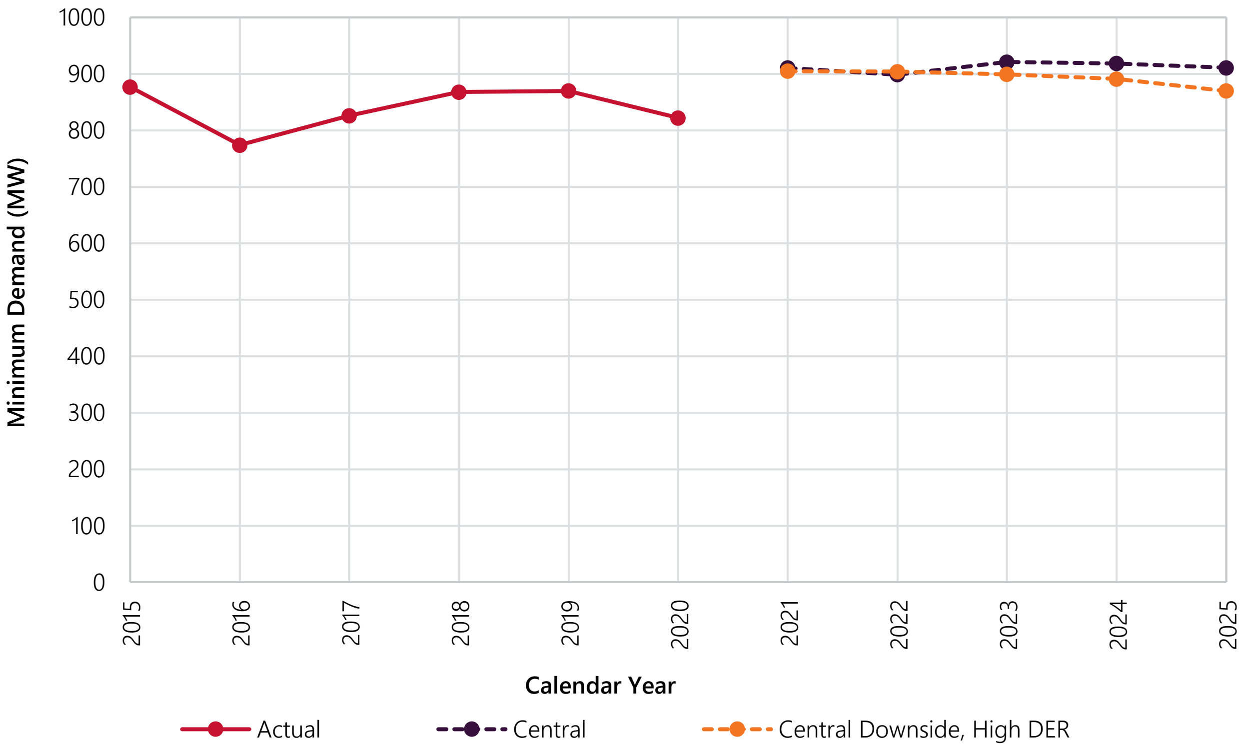
Intervention may also be required to manage intra-regional network flows and network outages prior to these thresholds.

7.3.5 Tasmania

Figure 36 shows the minimum demand projection for Tasmania. AEMO's forecasts indicate minimal growth in distributed PV in Tasmania, and suggest that minimum demand levels are not likely to reduce significantly over the next few years. While other NEM regions generally experience minimum demand in spring, minimum demand in Tasmania often occurs in summer.

Tasmania has a large capacity of hydro generation that can operate as synchronous condensers, and are therefore able to provide essential system security services at very low (or zero) generation levels. This makes it relatively easier to manage low demand levels in Tasmania compared with other NEM regions. For these reasons, AEMO does not anticipate significant challenges managing minimum demand levels in Tasmania over the forecast horizon.

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



Due to its small size, and high concentration of industrial loads, lower demands can be experienced when large industrial loads are shed through EFCSs in response to contingency events. This load reduction may lead to instances of lower demand than shown in the forecast[90]. The permanent connection of new industrial load, or the permanent disconnection of existing industrial loads, would have a material impact on minimum demand in Tasmania.

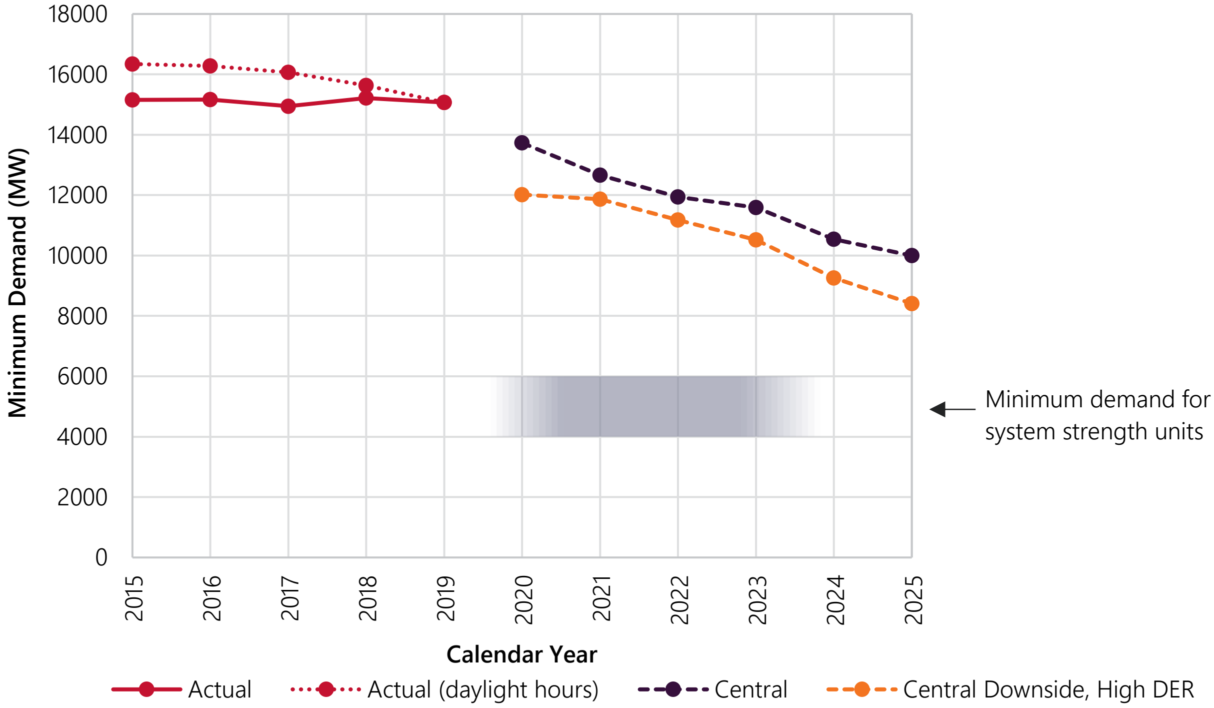
7.3.6 NEM mainland (excluding Tasmania)

Inter-regional interconnection assists with managing low demand periods. However, all NEM regions are likely to experience low demand in similar intervals. All regions will experience low economic activity on weekends and national public holidays at similar times, and could experience similar weather conditions (with mild temperatures and clear skies) leading to the lowest operational demand levels. The north-south orientation of the NEM also means that midday peak solar insolation levels occur at close to the same time across most of the NEM. This means that there is likely to be limited potential to export excess energy to other regions in low demand periods.

The Basslink interconnector can have extended outages, meaning that the NEM mainland may need to operate without a connection to Tasmania in some periods. This may become increasingly challenging in low load periods.

As shown in Figure 37, aggregate minimum demand on the NEM mainland (excluding Tasmania) has been flat over the last five years. However, minimum demand across the NEM occurred in the daytime for the first time in 2019, on 29 September at 12:30, and is projected to decrease further as distributed PV levels grow.

Figure 37 Minimum demand on the NEM mainland (excluding Tasmania) (90% POE as generated)



The combinations of synchronous units that must remain online to provide minimum levels of system strength in the NEM (excluding Tasmania) have an aggregate minimum load of between 4 GW and 6 GW (calculated by summing the minimum generation requirements of the various combinations of minimum

[90] Intervals with load loss contingency events have been excluded in Figure 36, which leads to minimum demand projections being higher than reported elsewhere. In March 2020, Tasmania experienced low demand due to reduced industrial load, and this is expected to be the minimum demand for 2020 (Tasmania, unlike other NEM regions, typically experiences minimum demand during summer).

generating units required for system strength in each region). In the absence of intervention, it would be extremely difficult to operate a secure power system with NEM demand below these levels, and this does not include any additional allowance that would be required for frequency control, dispatch management, and other system services. This may require at least another 2-3 GW of capacity.

As shown in Figure 37, operational demand across the whole NEM (excluding Tasmania) is projected to reach 8 GW to 10 GW by 2025, reducing steadily by around 1 GW per year. This means NEM-wide thresholds are being rapidly approached. As discussed in the 2020 ISP[91], the entry of a large quantity of shallow, medium, and deep utility-scale energy storage (such as pumped hydro energy storage) considered in projects such as Snowy 2.0 could act to increase minimum demand levels if charging, and slow decline towards these thresholds.

Voltage management

Generally, when a region is exporting, the demand threshold at which operator action is necessary to manage voltage is lower. Flows on lightly loaded transmission lines generally increase when a region is exporting, and more generators in the region can remain online and provide reactive power support. When neighbouring regions both experience low demand, they cannot export to each other, and the demand threshold at which operator action is necessary to manage voltage is likely to occur at the upper bound of the threshold ranges presented. This indicates that simultaneous low demand in neighbouring regions could exacerbate voltage management issues beyond those indicated by looking at each region in isolation.

7.4 Opportunities for managing minimum load thresholds

A range of options spanning technical, market, and regulatory arrangements should be progressed to address the identified challenges, and unlock value for consumers, creating new opportunities as outlined below. Some of these solutions would help increase minimum demand such that the issues requiring intervention are less likely to occur in the first instance:

- **Flexible demand** – market participants with flexible demand that can increase in low load times will see increasing benefits. For example, large industrial customers may benefit from increasing demand in periods with low (or negative) electricity prices.
- **New demand sources** – new sources of demand that can concentrate operation in low load periods. For example:
  - Growth in EVs and other forms of electrified transport could assist with boosting demand in low load periods. Representing the potential for this is the forecast of coordinated EV consumption after 2029-30, which creates substantial additional demand beyond the forecast minimum operational demands presented in this ESOO (see Appendix A1 for further detail). It is important that suitable arrangements are in place for this demand to be responsive and flexible, coordinated, and that suitable performance standards are in place to ensure disturbance ride-through capabilities.
  - There may be opportunities for establishment of new large industrial customers, particularly those that can operate flexibly and concentrate demand in low priced periods.
  - Electrification of industrial processes that have previously relied on other energy sources may become increasingly feasible and cost effective, especially where this load can be scheduled flexibly.
- **New dispatchable energy storage** – the 2020 ISP identified between 6 GW and 19 GW of flexible, dispatchable resources are needed by 2040 to back up renewable generation. This includes:
  - Utility-scale pumped hydro, large-scale battery energy storage systems, distributed batteries, and VPPs, all capable of charging at times of high distributed PV, if appropriately incentivised, to help increase minimum demand levels.

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[91] At https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en&hash=6BCC72F9535B8E5715216F8ECDB4451C.

- To secure the benefits of all dispatchable resources, market reforms currently being pursued through the Energy Security Board's (ESB's) post 2025 market design process should be continued at pace, otherwise necessary resources may not be delivered on time and the system will have to rely on other mechanisms, such as transmission investment

- **Active DER management services** – active DER management will allow active dispatch of load and DER when it is most valuable. This includes:
  - Increasing the quantity and sophistication of active customer load management, involving larger quantities of conventional resources such as air conditioning, hot water and pool pumps, as well as other types of flexible load now becoming progressively more accessible through "smart home" devices.
  - Increasing the capacity of actively managed distributed battery systems, and their participation in active response schemes.
  - Provision of frequency control services from load and DER. Aggregated load may be particularly well suited to providing slower frequency raise services, perhaps participating in the five minute or 60-second FCAS markets. This could become increasingly valuable over time to complement the faster frequency services offered by large-scale batteries, and assist with managing battery state of charge limitations[92].

  Suitable market frameworks need to be established to provide full incentives and reflect the full value of these services to customers.

- **Increasing dispatch flexibility** – there is a growing need for increasing the flexibility of generating units, to both dispatch energy and to offer system services such as inertia, system strength, voltage control and frequency control at lower generation levels.
- **Increasing DER visibility** – as the power system moves to higher levels of DER, AEMO and network service providers will have growing needs to accurately analyse, model and predict the behaviour of the various types of DER in the system, on an increasingly granular (but anonymised) level. Complexity is growing rapidly. Service providers that can offer innovative, competitive and accurate DER visibility services are likely to see growing markets for these services. AEMO is working with a number of stakeholders (including ARENA, Solar Analytics, Wattwatchers, and a number of inverter manufacturers) to expand capabilities. In addition to distributed PV visibility, there will be a growing need for visibility of the operation of distributed batteries, EVs, responsive demand, and any other kind of DER that reaches significant scale.
- **Frequency control services** – similarly to the mitigation actions outlined in Section 7.2, these challenges create emerging opportunities for providers of frequency control services including FCAS and FAPR. AEMO's analysis shows that minimum operational demand thresholds reduce considerably with the entry of new battery energy storage systems providing FAPR[93].

AEMO will continue to collaborate with market bodies, the ESB, and the wider industry on actions necessary to efficiently integrate increasing levels of distributed PV and other DER in the NEM.

Voltage management

NSPs are responsible for planning, designing, and operating their networks so that voltages at connection points are within technical limits. AEMO operates the power system to maintain voltage levels across connection points in the transmission network within limits set by NSPs and to a target voltage range. This involves the coordination of available reactive power resources in the network and from generators.

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[92] Large batteries can typically respond very rapidly and flexibly, but can only sustain a response for a limited duration before the battery reaches the end of its state of charge limits. There is likely to be a growing need for other slower acting services that can sustain a response to complement batteries in managing and recovering from frequency events.

[93] AEMO (May 2020) *Minimum operational demand thresholds in South Australia*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/SA_Advisory/2020/Minimum-Operational-Demand-Thresholds-in-South-Australia-Review.

This analysis indicates that management of transmission voltages in minimum demand periods is likely to be an emerging challenge in almost all regions of the NEM in the near term. AEMO and the relevant TNSPs will consider the available operational and planning measures to address these voltage challenges in low load periods. Options include:

- Switching transmission elements in and out of service to redirect network flows. This should be done rarely, since it reduces resilience of the network, impacts the market, and reduces export capabilities.
- Investment in reactive power support equipment, such as SVCs, synchronous condensers or STATCOMS.
- Consideration of non-network options, such as utilisation of storage to increase low demand when required.
- Contracts with generating units to provide reactive power and voltage management services under specific circumstances.
- PV shedding – as an emergency last resort (see below).

Planning measures will be considered as part of the joint planning process, including through the AEMO NSCAS annual review which will release AEMO's assessment of NSCAS needs and any NSCAS gaps by the end of 2020.

Emergency PV shedding capability

This analysis reaffirms the need to establish a security back stop that allows AEMO to shed distributed PV when extreme and unusual operational circumstances arise, such as major line outages, or the need to operate a region of the NEM as an island for an extended duration under low load conditions.

Emergency PV shedding capability can be considered analogous to load shedding capability. Load shedding is utilised in rare, extreme and unusual conditions as a last resort to maintain power system security when demand is high. Emergency PV shedding is the parallel capability required for managing power system security, if rare, extreme, and unusual operating conditions arise. All large-scale generation output is controllable when necessary. This is now an essential capability for distributed resources, given they supply a large proportion of generation at some times.

Emergency PV shedding would only be required when there are unusual power system outages or when other abnormal conditions occur. If the other mitigating actions recommended are implemented, and suitable markets for active DER and load participation come to fruition, emergency PV shedding should be activated rarely.

AEMO is working with stakeholders to implement mitigating actions immediately in South Australia (outlined in more detail in Appendix A5), and this analysis indicates action is also required urgently in Victoria, and promptly in Queensland.

AEMO recommends that this becomes a condition of connection for all new distributed PV in the NEM as soon as practical. This will provide AEMO with the levers required to operate a secure system under a range of conditions, including network outages and other abnormal conditions.

AEMO is consulting with stakeholders on the various approaches to introduce emergency PV shedding capabilities in the timeframes required[94], and has submitted a Rule Change proposal to the AEMC to explore frameworks to introduce technical standards for DER under the NER, including shedding capabilities[95].

[94] Interested stakeholders should contact derprogram@aemo.com.au.

[95] AEMC (25 June 2020) *Technical standards for DER*, at https://www.aemc.gov.au/rule-changes/technical-standards-distributed-energy-resources.

7.5 Other challenges in low load periods

Under frequency load shedding

EFCSs are designed to arrest the frequency change following non-credible contingency events. UFLS is one type of EFCS which involves automatic disconnection of load when a severe under-frequency event is detected.

AEMO's studies show that distributed PV reduces the effectiveness of UFLS by reducing the net load on UFLS circuits. Furthermore, when circuits move into reverse flows, tripping those circuits acts to exacerbate the under frequency event, rather than helping to correct it. The disconnection of distributed PV in response to low frequency also exacerbates severe under-frequency events. Detailed analysis is outlined in the 2020 *Power System Frequency Risk Review*[96].

AEMO is collaborating with SAPN, ElectraNet, and the South Australian Government to implement a suite of complementary actions to mitigate the identified risks in South Australia. This includes implementing constraints on Heywood imports in periods where UFLS is inadequate, increasing and optimising the load in the UFLS, and introducing dynamic arming of UFLS relays. Analysis is also underway for other NEM regions, where similar challenges are likely to emerge.

AEMO's analysis indicates that FAPR provides an effective complement to UFLS capabilities, and in future this could be an important contributor to EFCS. There also may be a growing role for more granular load shedding technologies that allow automatic under-frequency disconnection of selective loads at the customer site (without disconnection of the customer distributed PV system).

System restart

In the rare event of a black system, AEMO must have resources available to restart and restore the system as quickly as possible. During this process, sufficient stable load must be available to support the minimum loading levels of the first generators brought online. If there is not enough load (due to high levels of distributed PV operation, for example), it may not be possible to bring online the units required. There may also be challenges associated with the behaviour of distributed PV in the small initial island.

To address these challenges, AEMO is seeking to introduce emergency PV shedding capabilities for all new distributed PV connected to the NEM, so that the reconnection of distributed PV can be actively managed during a restart process. The communications systems utilised will need to be reliable and available during black system conditions. Improving DER behaviour during power system disturbances via adjustments to performance standards and compliance processes will also assist.

The emerging opportunities associated with managing DER during a restart process are likely to include services to actively manage distributed PV, and services to provide increased levels of stable load. The AEMC recently implemented a Rule Change[97] to enhance frameworks for system restart and restoration, allowing AEMO to procure a wider range of services to effectively and promptly restore supply to consumers. AEMO is currently consulting with industry to define capabilities for a new restart service (restoration support) in the System Restart Ancillary Services (SRAS) Guideline.

[96] AEMO (July 2020) 2020 *Power System Frequency Risk Review – Stage 1*. Appendix A1, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/psfrr/psfrr-stage-1-after-consultation.pdf?la=en.

[97] AEMC (2 April 2020) System restart services, standards and testing, at https://www.aemc.gov.au/rule-changes/system-restart-services-standards-and-testing.

8. Climate and resilience

This chapter outlines:

- Key vulnerabilities of energy systems to climate, and applicable modelling methods.
- The results of an extreme event case study.

Key insights

- Extreme weather is a material risk to the effective operation of Australia's energy systems, which when compounded by a changing system is a major cause of a loss of energy system resilience.
- While AEMO works to include the chronic effects of climate changes in quantitative reliability and market modelling, many acute hazards remain excluded.
- Through the use of extreme event case studies, AEMO intends to explore risks to society and work with industry, consumer groups, market bodies and governments to assess the benefits of investments, procedures and systems that mitigate these risks.
- A single case study explored in this 2020 ESOO confirms the potential for undesirable outcomes should the 2019-20 black summer bushfires re-occur in 2024 with less favourable timing.

8.1 Context

The 2019-20 black summer was particularly challenging for Australia's physical gas and electricity infrastructure, with notable increases in heat and fire impacts consistent with climate change projections. A recent review[98] noted the impacts observed both generally and in the last summer, including:

- The increasing impact of both heat and fire on electricity systems, including both conventional and renewable generators like wind generation.
- The vulnerability of key transmission lines and other major energy infrastructure to fire impacts. This highlights the need to integrate resilience measures into the planning, routing, design and assessment of transmission projects and upgrades.
- The impact on gas infrastructure (required for gas-fired electricity generation) of increasing temperature periods that are at or above the design tolerance of pipelines and plant.

The unprecedented weather events of last summer, followed by the COVID-19 pandemic, demonstrates the need for increased vigilance in supporting the reliable delivery of affordable energy while taking necessary steps to increase system resilience to minimise disruptions for consumers and businesses.

Power system resilience is the ability of the system to limit the extent, severity, and duration of system degradation following an extreme event[99]. It has long been embedded in good energy system planning and

[98] AEMO. 2020. *Summer 2019-20 NEM Operations Review*, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/summer-operations-report.

[99] CIGRE C4.47 WG Members. 2019. *Defining power system resilience reference paper*. Electra No.306 – October 2019.

operation practices but is in long-term decline, necessitating a renewed focus. The 2020 ISP[100] describes various compounding factors that are driving the decline in resilience:

1. Climate change is increasing the frequency and magnitude of physical weather hazards.
2. Cyber hazards are increasing risks to software-based system solutions.
3. New generation sources are increasingly being dispersed from central locations with strong network links to the main load centres, into the remote, electrically weaker, areas of the grid distant from the load centres, changing the risks and vulnerabilities of the system.
4. System control services are increasingly complex, and the power system is reliant on the integrated testing and performance of these systems to avoid the risks of cascading system impacts.
5. Societal services are increasingly interconnected risking cascading societal impacts.
6. An increasing focus on quantitative cost benefit analysis over good design principles excludes mitigation for risks that are difficult to quantify and value.

Energy systems are located throughout most populated regions of Australia and are therefore exposed to many varied weather and climate effects. Asset specifications and planning processes used in the sector have extensive consideration for Australia's extreme climate, but need to be regularly reviewed in light of climate change. Without appropriate review, specifications and processes may become insufficient to capture increasing physical climate impacts, leading to a loss of power system resilience. Table 7 summarises possible climate impacts.

Table 7 Summary energy system climate vulnerabilities

Vulnerability (projection for NEM regions)	Impact
Temperature (Projected increases in both average and extreme temperatures)	Reduces generator and network capacity and increases failure rates or maintenance/replacement costs. Extreme temperatures are also relevant to asset design specifications.
Bushfire (Likely increases in extreme bushfire weather)	Increasing frequency of dangerous fire weather poses a threat to most assets, with a particularly high operational risk to transmission lines due to heat and smoke. It also an important consideration in transmission line route selection and design.
Wind and cyclones (Possible decrease in high wind events and cyclone frequency, possible increase in cyclone magnitude)	Wind generation is sensitive to any reduction in average wind-speed as well as to the frequency and magnitude of destructive gusts. Thus, it affects wind generation output, plant profitability and design specifications. High winds also reduce the capacity and threaten the integrity of transmission lines; making it an important consideration for network capacity assessments, design specifications and analysis of failure rates.
Rainfall, dam inflows and flooding (Likely decrease in precipitation, possible increase in extreme rainfall events)	Reduces water available for hydro generation. Increases requirement for desalination loads. Flood events require consideration for asset design specifications and expected failure rates.
Coastal inundation (Projected increase in sea level)	Increasing sea levels may impact on some low-lying generation, distribution and transmission assets.
Compound extreme events (Possible increase in frequency or magnitude)	Compound events, where extremes in multiple variables occur simultaneously or in close sequence, have the potential to cause substantial disruption. These events can be compounded by associated non-climatic factors such as infrastructure failure or staff fatigue.

[100] AEMO. 2020. 2020 *Integrated System Plan* – Appendix 8 Resilience and Climate Change, at https://aemo.com.au/-/media/files/major-publications/isp/2020/appendix--8.pdf.

AEMO formally collaborates with the Bureau of Meteorology (BoM) and CSIRO through the Electricity Sector Climate Information (ESCI) project[101] to improve its modelling of weather and climate trends. Through this collaboration, further work is underway so the effects of climate change on all elements of the electricity system can be considered. While AEMO seeks to quantify all material climate change impacts in its reliability modelling, limitations in both climate data[102] and energy system modelling prohibit full quantification of extreme event risks. The question of who should pay for strengthening power system resilience against extreme events also needs to be resolved.

To complement quantitative reliability and market modelling, and help inform discussions with governments and industry on this complex issue, AEMO has developed extreme weather and power system case studies to explore the implications of these events.

Resilience planning incorporates all aspects of hazard management, including consideration for how the system might resist, absorb, accommodate to, or recover from the effects of a hazard in a timely and efficient manner[103]. Given the breadth of consideration, solutions that might enhance system resilience to increasingly frequent and coincident hazards may come in many forms. These solutions might include investments in assets to provide redundancy or reduce system vulnerabilities, technical specifications that may resist hazards, control systems that could minimise cascading failures, or emergency service collaboration that minimises societal impacts or accelerates recovery.

8.2 Climate and weather in the 2020 ESOO

Customer demand and system supply are highly responsive to weather, which is subject to short-term, medium-term, and long-term trends. Demand and supply forecasting processes are not fitted to a specific weather prediction, but instead simulate many weather years around a long-term climate trend. These simulations aim to capture all relevant weather trends, including seasonal variability, El Niño/La Niña, and climate change. For more information on the use of reference years to simulate weather uncertainty, see the Market Modelling methodology[104].

The impacts of increasing heat on customer demand have been considered since the 2018 ESOO through temperature scaling, while climate change impacts on generator supply and system availability are still being evaluated.

The three 2020 ESOO scenarios considered varying atmospheric carbon concentrations, impacting the degree of climate change. Average temperature increases vary substantially between scenarios in the long term, as shown in Figure 38, which shows the projected mean Australian temperature for the Step Change scenario (RCP2.6) and the Slow Change scenario (RCP8.5)[105].

With the help of the BoM and CSIRO, AEMO uses publicly available projections data[106] to downscale and project half-hourly temperature data per region. The half-hourly methodology recognises that climate change impacts minimum, average, and maximum temperatures differently.

Climate change has the effect of reducing heating load in winter and increasing cooling load in summer. For the impact on annual consumption, see Section 2.2, and for the impact on maximum demand, see Section 2.23.

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[101] For more information, see https://climatechangeinaustralia.gov.au/en/climate-projections/future-climate/esci/.

[102] 'The projection of compound extreme events is regarded as a significant scientific challenge'. BOM. 2018. State of the climate 2018 – Australia's changing climate, at http://www.bom.gov.au/state-of-the-climate/australias-changing-climate.shtml.

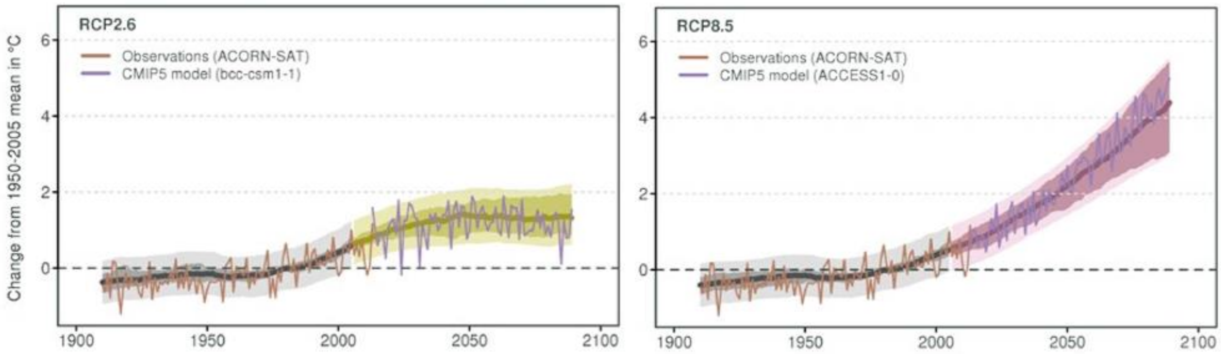
[103] Paraphrasing the definition of resilience from: United Nations Resolution 69/283. *Sendai Framework for Disaster Risk Reduction.* 2015-203017.

[104] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Market-Modelling-Methodology-Paper.pdf.

[105] For more information on Representative Concentration Pathways (2.6, 4.5, 6.0, 8.5) see https://www.climatechangeinaustralia.gov.au/en/publicationslibrary/technical-report/. Additional RCPs (1.9, 3.4, 7.0) are emerging through work by the Intergovernmental Panel on Climate Change (IPCC) sixth assessment, due to be published in 2020-21, and are developed on a comparable basis.

[106] At www.climatechangeinaustralia.gov.au.

Figure 38 Time series for Australian average temperatures as simulated relative to 1950-2005 mean



Source: https://www.climatechangeinaustralia.gov.au/media/ccia/2.1.6/cms_page_media/168/CCIA_2015_NRM_TR_Chapter%207.pdf.

8.3 Extreme event case studies

AEMO is developing a collection of extreme weather and power system case studies to better explore emerging risks to customers. These case studies will be useful to identify and distinguish risk management solutions for managing power system resilience against increasingly frequent and coincident hazards.

A single case study was developed for inclusion in this 2020 ESOO based on the December 2019 to January 2020 black summer bushfires. It explores the reliability outcomes that may occur should these weather and power system events reoccur in January-February 2024, coincident with high demand.

Events such as this are excluded from the reliability assessments reported in this ESOO as assigning a probability to the event is extremely challenging. The probability of any one event occurring in a given year in the way it is imagined in a case study is near to zero, but the likelihood that any one of a large range of potential extreme events could occur is much higher as evidenced by recent history. As such, the case study demonstrates the value of such analysis to inform discussions that will ultimately help AEMO and industry better prepare for future extreme events. While observed events are helpful to prove capability and value, future case studies should include events that may not be represented in the history but are supported by climate science and have potential to be destructive.

8.3.1 Black summer (2019-20) bushfires

In 2019, Australia as a whole experienced its warmest and driest year on record. Large areas of Australia had their highest accumulated Forest Fire Danger Index (FFDI) for December since records began.

December 2019 and January 2020 included a number of periods with extreme heat, and on 4 January 2020 the most extreme heat occurred in eastern New South Wales and the Australian Capital Territory[107]. The hot conditions combined with the dry landscape and strong winds produced dangerous fire conditions and some of the worst and most prolonged fires in recent Australian history. These conditions and resultant smoke are shown in Figure 39 and Figure 40.

[107] BOM. 2020. Special climate statement 73 – extreme heat and fire weather in December 2019 and January 2020, at http://www.bom.gov.au/climate/current/statements/scs73.pdf.

Figure 39 **Forest fire danger index deciles for December 2019**

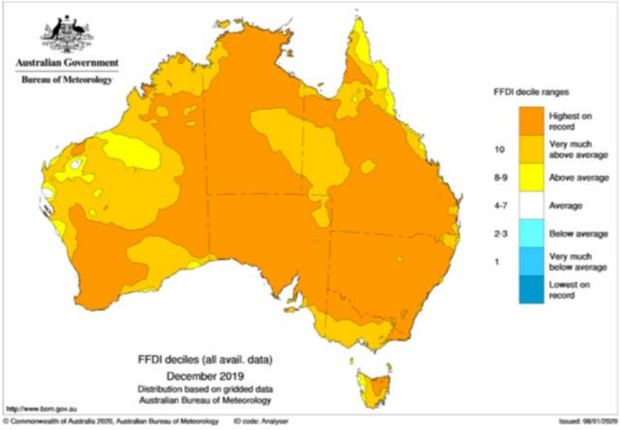
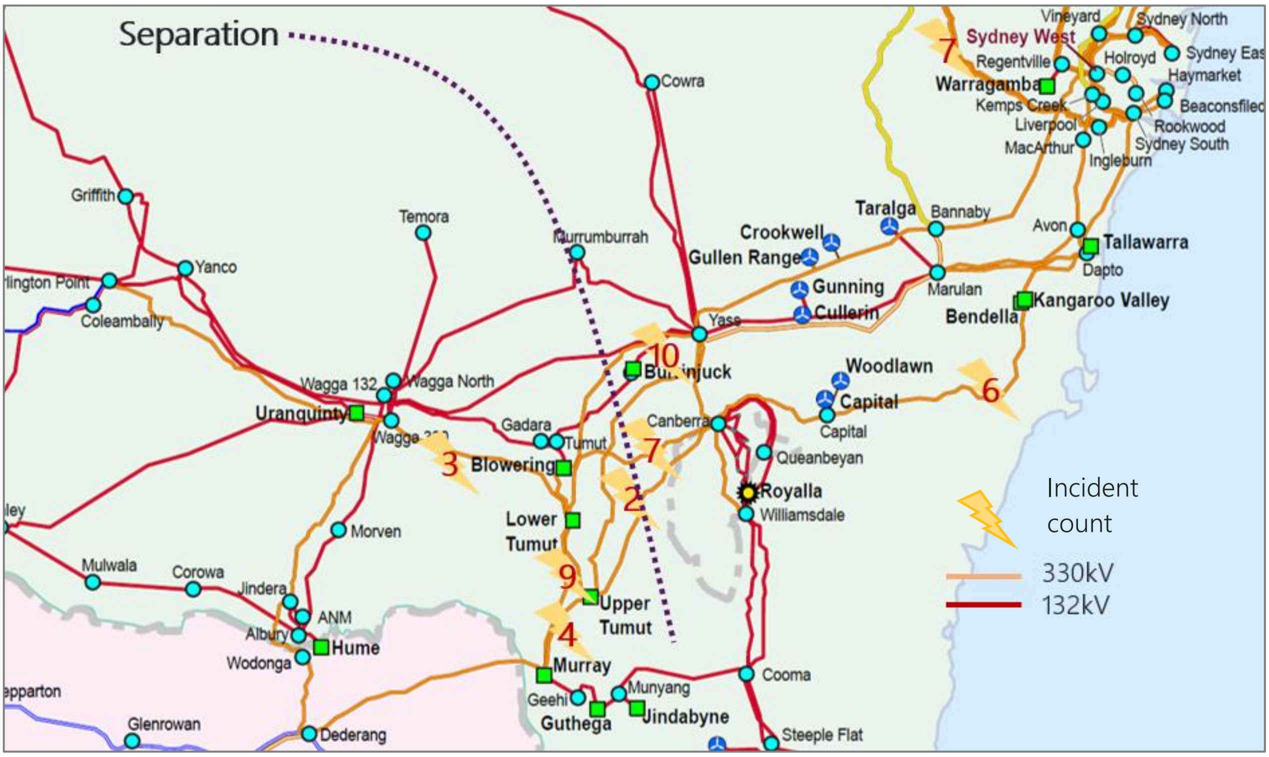


Figure 40 **4 January 2020 Himawari 8 Japanese weather satellite imagery**

Source: BoM Presentation to the Royal Commission into National Natural Disaster Arrangements, at https://naturaldisaster.royalcommission.gov.au/publications/exhibit-1-11-bom5020010001-bom-presentation-dr-karl-braganza-influence-climate-variability-and-change-2019-2020-australian-bushfire-season

The black summer fire season was particularly challenging for the electricity system. On 4 January 2020, over 55 incidents occurred, with 28 unplanned outages of 330 kV transmission lines in southern New South Wales due to bushfires resulting in the separation of the NEM into two islands, north and south of this area[108]. Incidents also resulted in the disconnection of generation and load, and a reduction in generation availability. Some damage was sustained until 26 of January. Figure 41 shows the location of incidents and resultant separation.

Figure 41 **4 January 2020 separation during 2019-20 black summer bushfires**



108 AEMO. 2020. *Preliminary report – New South Wales and Victoria Separation Event on 4 January 2020*, at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/preliminary-report-nsw-and-victoria-separation-event-4-jan-2020.pdf.

In response, AEMO declared an actual Lack of Reserve 2 (LOR2) condition in New South Wales and RERT services were activated to mitigate the risk of load shedding[109].

Collectively, these incidents reduced the ability for AEMO to dispatch generation to meet demand. Other transmission outages disconnected load and risked further disconnection of loads in the Canberra region.

While the season was challenging for the electricity system, the 4 January timing minimised the risk of USE for consumers. Peak demand periods for New South Wales occurred later in summer when school holidays were over, when high temperatures coincided with higher industrial and commercial business activity

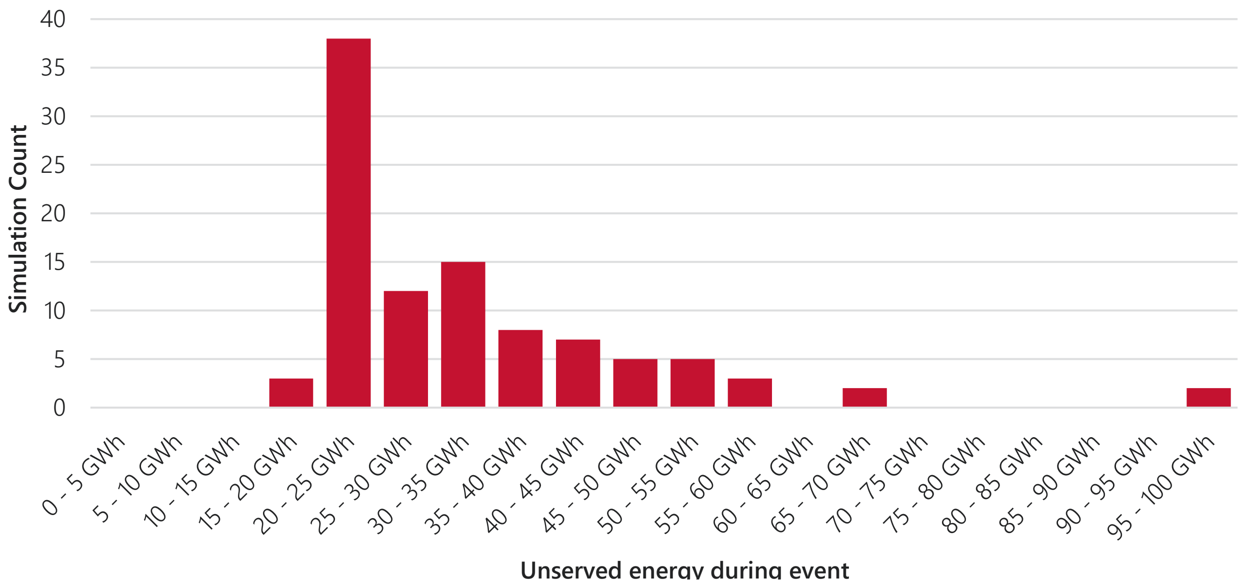
Supply scarcity risks

To simulate the possible impacts on consumers during peak demand conditions, AEMO applied the coincident transmission and generation constraint set observed in the 4 January 2020 16:00 dispatch interval to a peak demand period in late January to early February 2024. Consumer demand in this period will not be suppressed due to school holidays, and New South Wales is already subject to forecast supply scarcity risk in this year due to the retirement of the Liddell Power Station. All other characteristics used by the simulation match the reliability assessments used in the 2020 ESOO. The risk of USE arising from an inability to connect load was excluded from this case study (unlike what was observed during the incident last summer), because these simulations focus on the ability of the system to match supply with demand. In this case study, the disaster reduces the ability of the system to maintain supply, while the primary location of demand is not directly affected.

AEMO applied the identified constraints using 100 simulations to a peak demand period from 10% POE demand traces consistent with the ESOO model. This modelling demonstrates resilience risks following the retirement of the Liddell Power Station with no further market response and the coincident occurrence of 10% POE demand and an extreme bushfire event. While extreme, it is constructive to study system performance in the context of increasingly frequent and coincident hazards.

Every simulation resulted in forecast USE, with results for New South Wales varying between 16 GWh and 99 GWh USE (equivalent to 0.023% to 0.146% of annual energy demanded). Numerous instances were identified where USE exceeded 3 GW which would represent a need to disconnect over 1,000,000 households. The range of simulated USE for this case study is shown in Figure 42.

Figure 42 Projected 2024 New South Wales USE during coincident black summer fires and high demand



[109] AEMO. 2020. *Summer 2019-20 NEM operations review*, at https://www.aemo.com.au/-/media/files/electricity/nem/system-operations/summer-operations/2019-20/summer-2019-20-nem-operations-review.pdf.

This range extends well beyond the range typically reported in reliability analysis, yet is plausible under certain extreme circumstances. While reliability risks are often mitigated by increasing supply availability, resilience risks like these require the consideration of a different combination of risk mitigation strategies, including those that might allow the system to resist, absorb or recover quickly from a hazard.

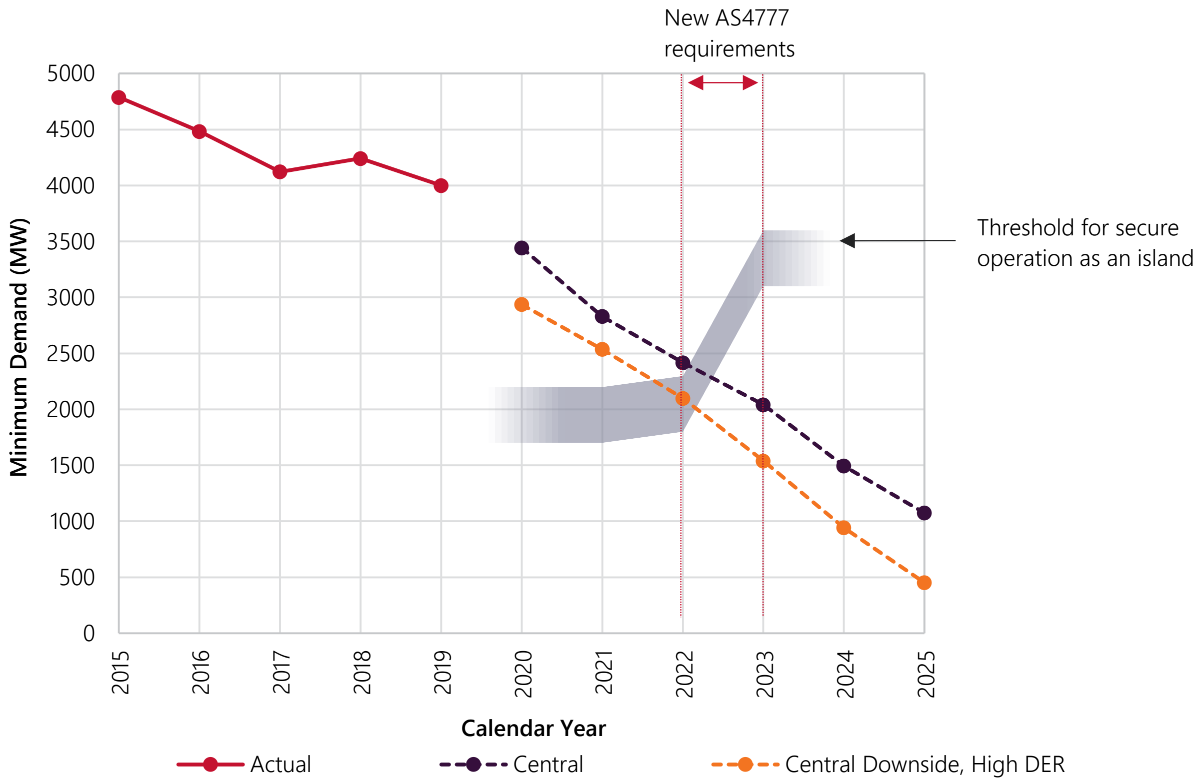
System security risks

A variation on this case study is also instructive when considering system security risks. For example, if a separation of the Victorian and New South Wales regions occurred (similar to events on 4 January 2020 due to major bushfires[110]) in a period when the Basslink interconnector to Tasmania was unavailable, this could result in an island with only South Australia and Victoria connected (at least until Project EnergyConnect, VNI West, and/or Marinus Link were commissioned).

The Basslink interconnector has experienced some extended outages. In 2019, it was unavailable for more than one month due to equipment failure, while in 2018, damage during maintenance left it unavailable for more than two months. This followed the outage of almost six months beginning in 2015 due to a fault on the subsea cable[111]. It is therefore important to plan to be able to securely operate a combined Victoria and South Australia island, in the absence of the Basslink interconnector.

Figure 43 shows an estimate of the minimum demand required for secure operation of the combined Victoria and South Australia island. This corresponds to the minimum output of the synchronous generating units needed to provide required levels of frequency control, inertia, and system strength, across both regions combined[112].

Figure 43 Minimum demand in combined South Australia and Victoria island (90% POE as generated)



[110] AEMO (March 2020) *Preliminary Report – New South Wales and Victoria Separation Event on 4 January 2020*, at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/preliminary-report-nsw-and-victoria-separation-event-4-jan-2020.pdf?la=en.

[111] The dates of these outages were 24 August to 29 September 2019, 24 March to 5 June 2018, and 20 December 2015 to 13 June 2016.

[112] Based on existing transfer limit advice for system strength, existing inertia requirements, and the Frequency Operating Standards for an island system. Inter- and intra-regional network limits, such as on the Heywood interconnector, have not been considered in this estimate, and may necessitate a higher demand threshold than that presented

The threshold grows rapidly between 2022 and 2023, primarily due to the increasing size of distributed PV disconnection contingencies (see Appendix A5 and Section 7.2) which necessitates increasing amounts of frequency control services[113] to manage a fault at Loy Yang power station in Victoria[114]. This demonstrates the urgency of introducing improved disturbance ride-through capabilities for new distributed PV in Victoria. The new AS/NZS 4777.2 requirements should come into effect in this time, and this analysis suggests that earlier introduction will considerably improve AEMO's ability to operate a secure power system in Victoria.

If Victoria and South Australia are operating as a combined island and operational demand falls below these minimum demand thresholds, there may be insufficient frequency control to meet the Frequency Operating Standards following credible contingencies, meaning the island could not be operated securely. This could lead to supply disruption for customers in response to a credible event. Combined minimum demand across the two regions is projected to fall below this threshold in 2022 under 1-in-10 year demand conditions.

Risks will be considerably reduced by prompt implementation of the mitigation measures outlined in Section 7.2 to improve distributed PV disturbance ride-through capabilities. This analysis shows that these initiatives should be implemented as an urgent priority in Victoria, in addition to South Australia

Next steps

AEMO will use this reliability and system security information to better prepare strategies to mitigate these risks in both operational and planning time frames, consistent with consumer expectations. This may require changes to planning standards and other industry processes to ensure these risks are managed comprehensively, the benefits of resilience are captured and valued, and any mitigation costs are borne by those most likely to benefit.

AEMO will continue to work with climate scientists, industry, consumer groups, market bodies and governments to guide our work, using this, and other case studies yet to be developed to build an evidence base for enhancing system resilience.

[113] Registered FCAS quantities from existing plant have been assumed, with growth in FCAS from VPPs based upon distributed BESS forecast in the Central scenario. APD is assumed to contribute a large proportion of fast raise capability; if APD retires, this would increase the threshold and also decrease demand, exacerbating challenges.

[114] The size of the net distributed PV disconnection considered is the average of the lower and upper bounds for the Central scenario presented in Section 1.2. Net distributed PV loss could be significantly higher.

A1. Regional demand forecast outlook

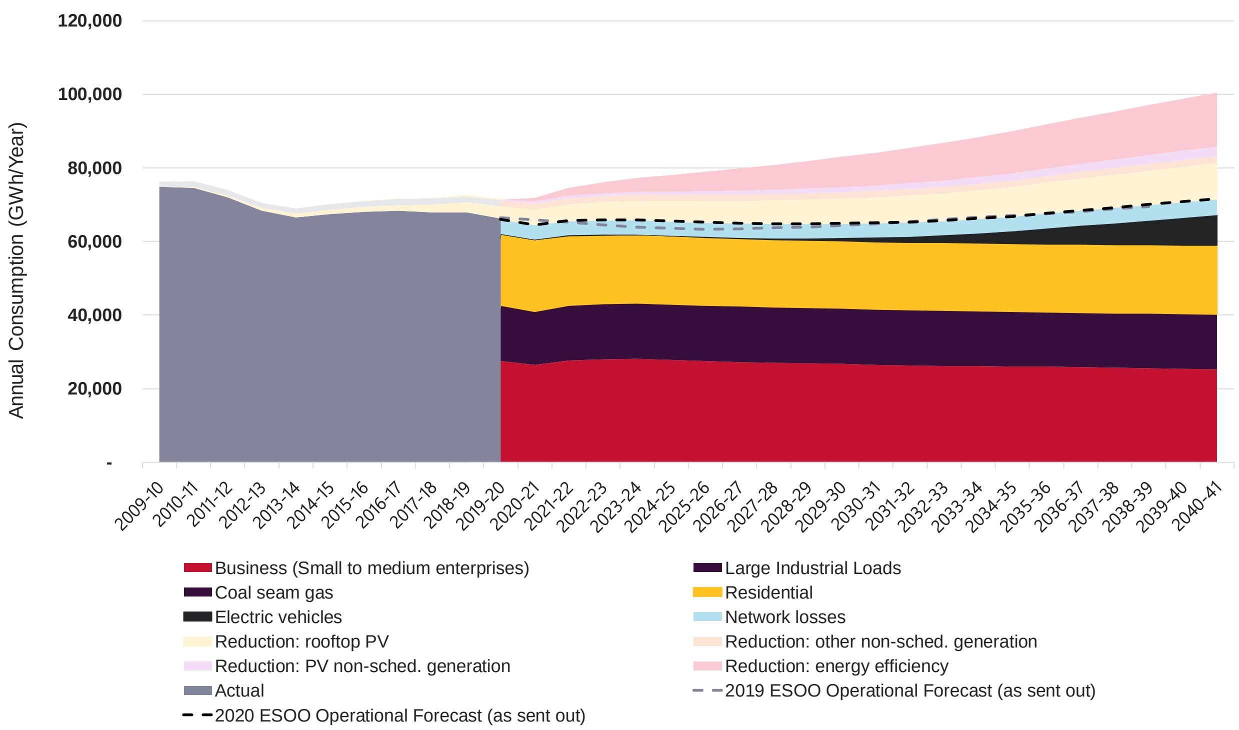
The following sections outline consumption, maximum demand and minimum demand outlooks for each region for the Central scenario[115]. Each section also explains what time of day maximum demand is likely to occur and how this may change in the forecast period.

A1.1 New South Wales

Annual consumption outlook

Figure 44 shows the component forecasts for operational consumption in New South Wales.

Figure 44 New South Wales operational consumption in MWh, actual and forecast, 2009-10 to 2039-40



In 2020-21, the effect of COVID-19 on the economy is expected to lower consumption for the business sector, although this is forecast to be partly offset by a moderate increase for the residential sector as more people are expected to be at home. As the impact of COVID-19 dissipates, consumption is expected to recover. Longer term, the 2020 ESOO Central scenario forecasts a higher number of connections and higher electricity

[115] Data for additional scenarios is at http://forecasting.aemo.com.au.

usage in the business sector compared to the 2019 ESOO. Offsetting this is continued investment in distributed PV, and extension of the New South Wales Energy Savings Scheme (ESS) (with a higher target), resulting in a similar overall outlook by 2039-40. Consumption growth in the last decade is largely a result of projected EV uptake.

Maximum demand outlook

- Short term (0-5 years) – maximum operational demand is expected to decline in the first year and then recover and remain relatively flat, driven by COVID-19 and the impact of LIL demand on underlying consumption.
- Medium to long term (5-20 years) – forecast maximum demand recovers to a level generally aligned with that in the 2019 ESOO.

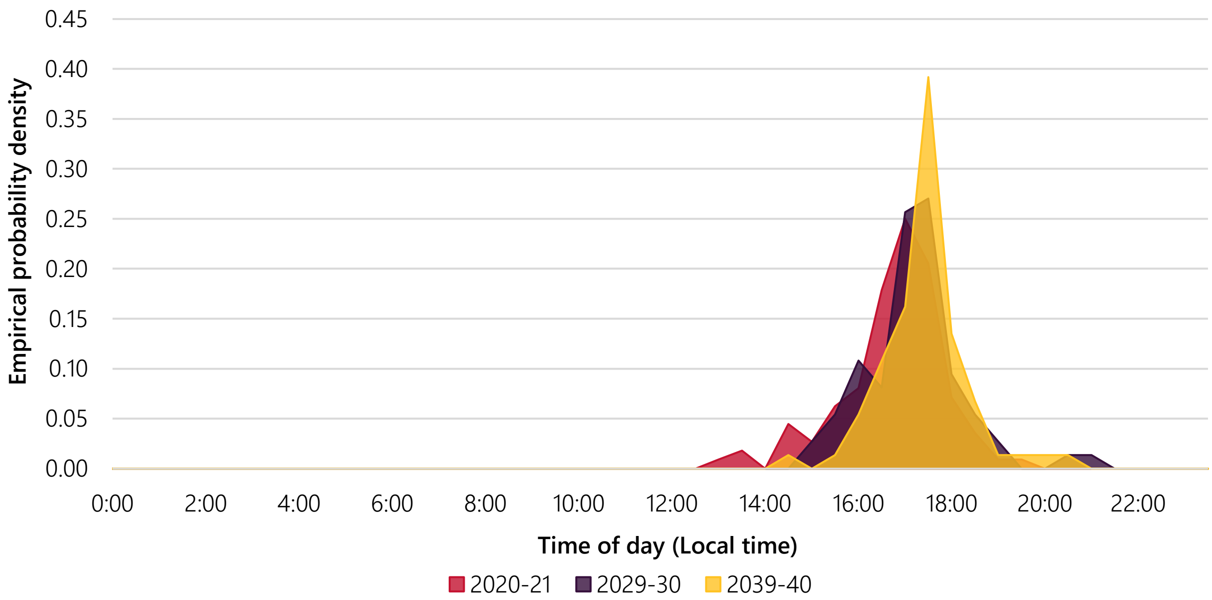
Table 8 shows maximum summer and winter operational demand (sent out) forecasts for 10% POE and 50% POE for the Central scenario[116].

Table 8 Forecast maximum operational demand (sent out) in New South Wales, Central scenario (MW)

Financial year	Summer		Calendar year	Winter	
	10% POE	50% POE		10% POE	50% POE
2020-21	13,786	12,711	2021	12,641	11,929
2024-25	14,400	13,230	2025	13,084	12,369
2029-30	14,523	13,208	2030	13,220	12,518
2039-40	15,794	14,500	2040	14,508	13,794

New South Wales currently experiences maximum operational demand in the evening, and with further growth of distributed PV, maximum demand is forecast to shift later in the day (see Figure 45).

Figure 45 Distribution of forecast time of 50% POE summer maximum demand in New South Wales



[116] For the 90% POE forecasts and forecasts for the Slow Change and Step Change scenarios in general, see AEMO's data portal at http://forecasting.aemo.com.au.

Minimum demand outlook

- Short term (0-5 years) – minimum operational demand is expected to decrease in the coming year due to the impact of COVID-19 and LILs. Minimum demand forecasts then continue to decline as distributed PV generation at time of minimum demand increases, and minimum demand periods occur more frequently in the middle of the day.
- Medium to long term (5-20 years) – minimum demand in New South Wales is expected to decline over the forecast horizon, driven by increasing distributed PV capacity.

Table 9 shows minimum operational demand (sent out) forecasts for 90% POE and 50% POE[117] and relevant contributing factors at the time of minimum demand.

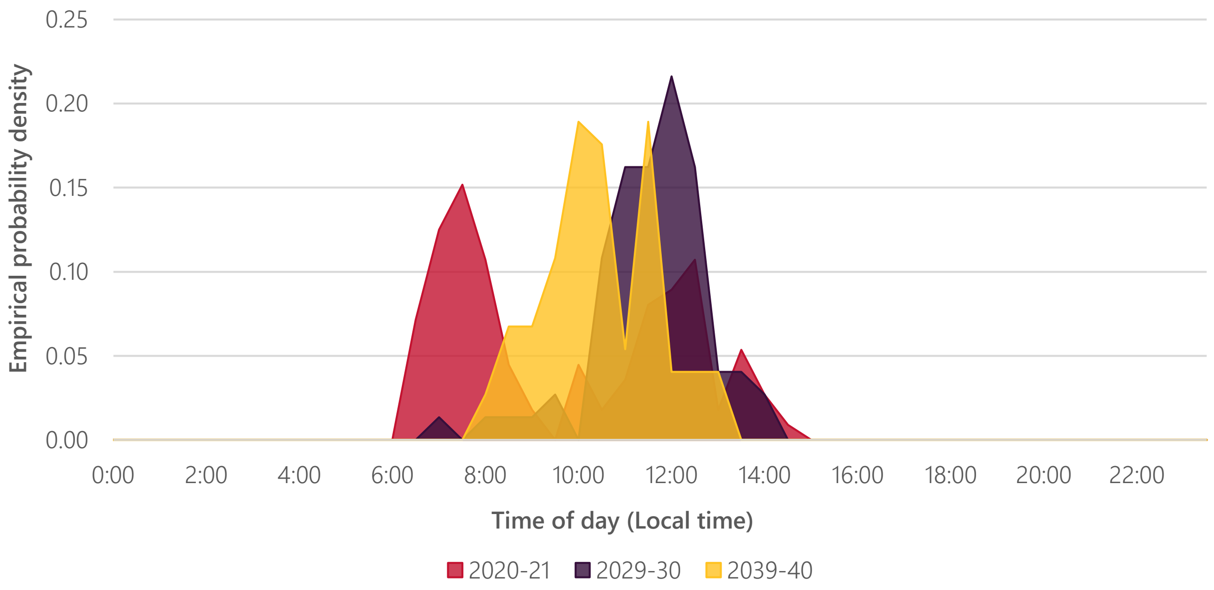
Table 9 Forecast minimum operational demand (sent out) in New South Wales, Central scenario (MW)

Financial year	Minimum operational demand (sent out)		Coordinated EV charging at time of minimum operational demand (MW)[A]		Distributed PV generation at time of minimum operational demand (MW)	
	50% POE	90% POE	50% POE	90% POE	50% POE	90% POE
2020-21	5,187	5,037	0	0	1,803	1,867
2024-25	4,815	4,671	0	0	2,817	2,864
2029-30	4,187	4,021	0	0	3,698	3,768
2039-40	3,575	3,368	499	461	5,462	5,498

A. Note this charging amount is additional to minimum operational demand figures.

Timing of minimum operation demand in New South Wales is bi-modal and currently experiences daily minimum demand in the early morning or around noon, generally driven by moderate temperatures or high solar output. Over the forecast horizon, distributed PV is expected to have an increasing impact on daily minimum demand levels, and minimum demand is expected to shift to the middle of the day.

Figure 46 Distribution of forecast time of 50% POE shoulder minimum demand in New South Wales



[117] For the 10% POE forecasts, forecasts for other seasons, and forecasts for the Slow Change and Step Change scenarios in general, see AEMO's data portal at http://forecasting.aemo.com.au.

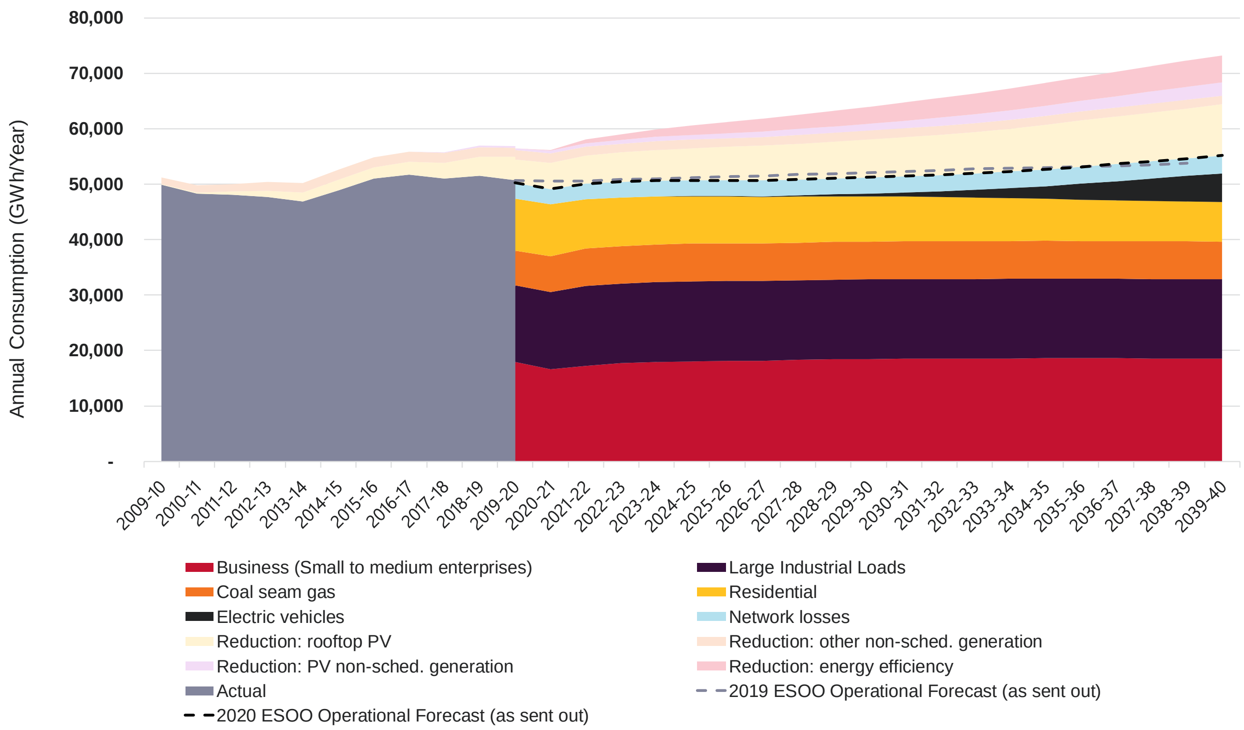
A1.2 Queensland

Annual consumption outlook

A drop in operational consumption is forecast for 2020-21 as business consumption falls and connection growth slows in response to COVID-19. As the economy recovers, ongoing investment in PV and continual EE improvements offset growth in grid consumption. Longer term, expected uptake of EVs throughout the 2030s results in a similar operational consumption forecast by 2039-40 to that in the 2019 ESOO.

Figure 47 shows the component forecasts for regional consumption in Queensland.

Figure 47 Queensland operational consumption in MWh, actual and forecast, 2009-10 to 2039-40



Maximum demand outlook

- Short term (0-5 years) – maximum operational demand is expected to decline slightly in 2020-21, driven by a reduction in underlying consumption due to the impact of COVID-19. Maximum demand is forecast to recover and continue to grow from 2021-22, due to an increase in CSG and LIL electricity consumption.
- Medium to long term (5-20 years) – maximum demand in Queensland is forecast to be higher than in the 2019 ESOO, growing at an average annual rate of 1.3%. This is driven largely by a reduced impact of EE on maximum demand, and an increase in assumed EV charging at times of maximum demand.

Table 10 shows maximum summer and winter operational demand (sent out) forecasts for 10% POE and 50% POE for the Central scenario[118].

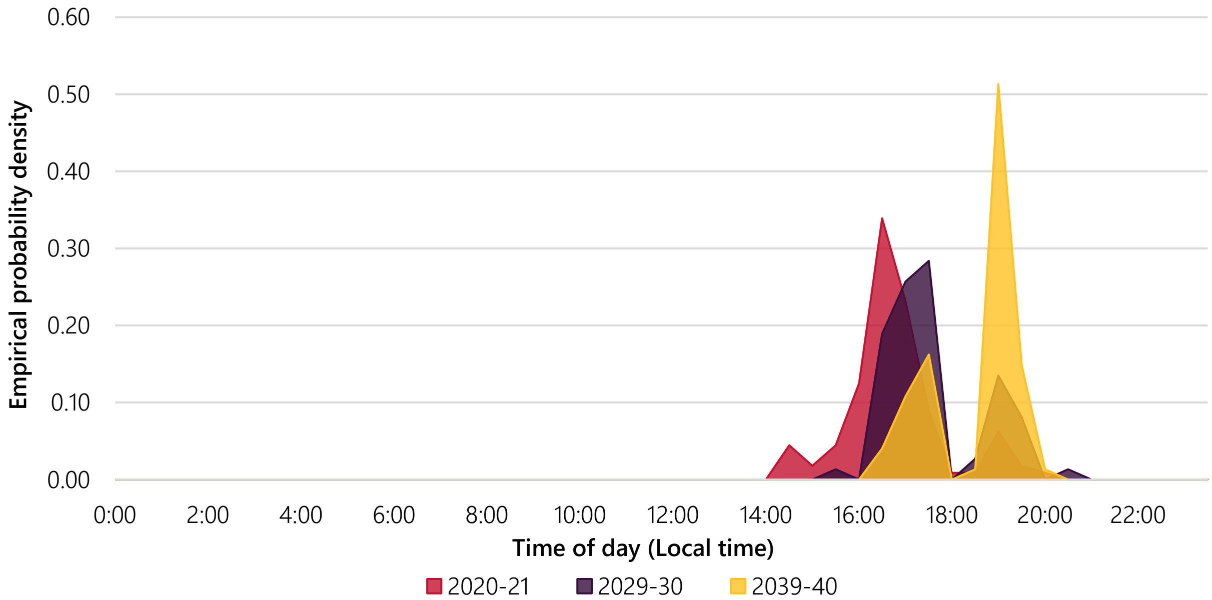
[118] For 90% POE forecasts and forecasts for Slow Change and Step Change scenarios, see AEMO's data portal at http://forecasting.aemo.com.au.

Table 10 Forecast maximum operational demand (sent out) in Queensland, Central scenario (MW)

Financial year	Summer		Calendar year	Winter	
	10% POE	50% POE		10% POE	50% POE
2020-21	9,523	9,129	2021	8,126	7,805
2024-25	10,143	9,730	2025	8,620	8,264
2029-30	10,509	10,062	2029	8,994	8,600
2039-40	11,559	11,081	2040	10,053	9,638

Currently, Queensland typically experiences daily maximum operational demand in the afternoon or early evening. The time of daily maximum demand is expected to move later in the day, as shown in Figure 48, over the medium and long term. By 2039-40, maximum demand is expected to be around 19:00 (which is after sunset), and driven by non-coordinated EV charging.

Figure 48 Distribution of forecast time of 50% POE summer maximum demand in Queensland



Minimum demand outlook

- Short term (0-5 years) – minimum operational demand is forecast to decline by 4.7% in 2020-21, and to continue to decline at an average rate of 1.9% per annum. Despite these declines, the minimum demand forecast is higher than in the 2019 ESOO, due to a slightly lower forecast of PV capacity installation and a higher forecast of LIL and CSG load.
- Medium to long term (5-20 years) – minimum demand in Queensland is expected to continue declining across the entire forecast horizon. The decline in minimum demand is forecast to stabilise from 2034-35 onwards, as projected EV uptake increases notably beyond 2034-35.

Table 11 shows minimum operational demand (sent out) forecasts for 90% POE and 50% POE[119] and relevant contributing factors at the time of minimum demand.

[119] For 10% POE forecasts, forecasts for other seasons, and forecasts for Slow Change and Step Change scenarios, see AEMO's data portal at http://forecasting.aemo.com.au.

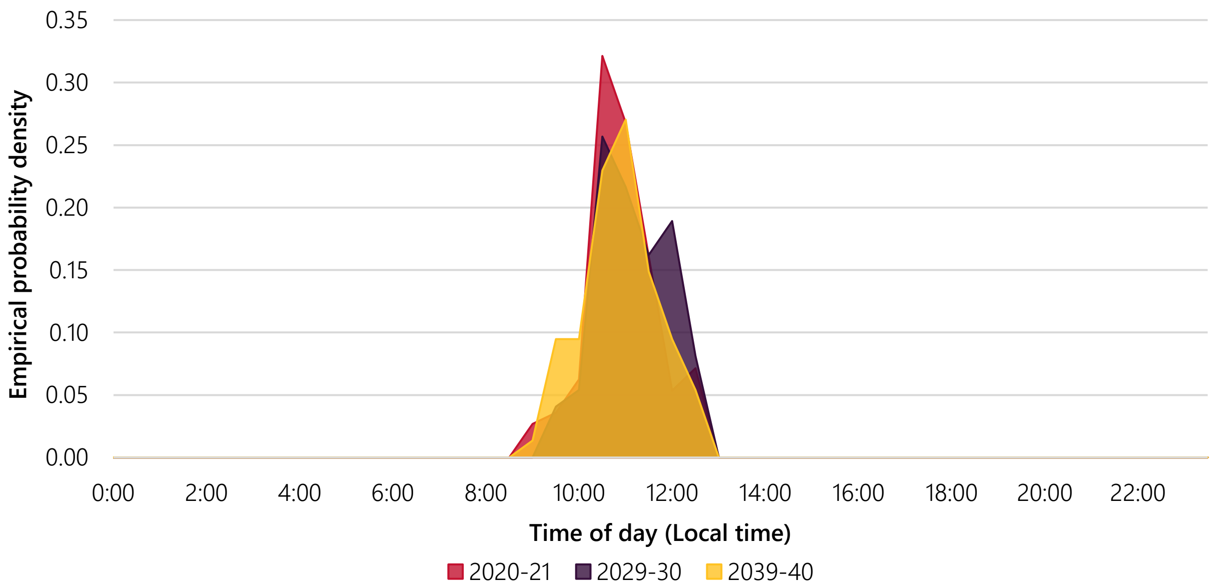
Table 11 Forecast minimum operational demand (sent out) in Queensland, Central scenario (MW)

Financial year	Minimum operational demand (sent out)		Coordinated EV charging at time of minimum operational demand (MW)A		Distributed PV generation at time of minimum operational demand (MW)	
	50% POE	90% POE	50% POE	90% POE	50% POE	90% POE
2020-21	4,096	3,963	0	0	2,316	2,357
2024-25	3,790	3,653	0	0	2,966	2,994
2029-30	3,422	3,276	0	0	3,589	3,663
2039-40	2,955	2,780	465	426	5,178	5,205

A. Note this charging amount is additional to minimum operational demand figures.

Daily minimum operational demand generally occurs late morning and middle of the day, as shown in Figure 49, and is expected to continue doing so across the forecast horizon.

Figure 49 Distribution of forecast time of 50% POE shoulder minimum demand in Queensland



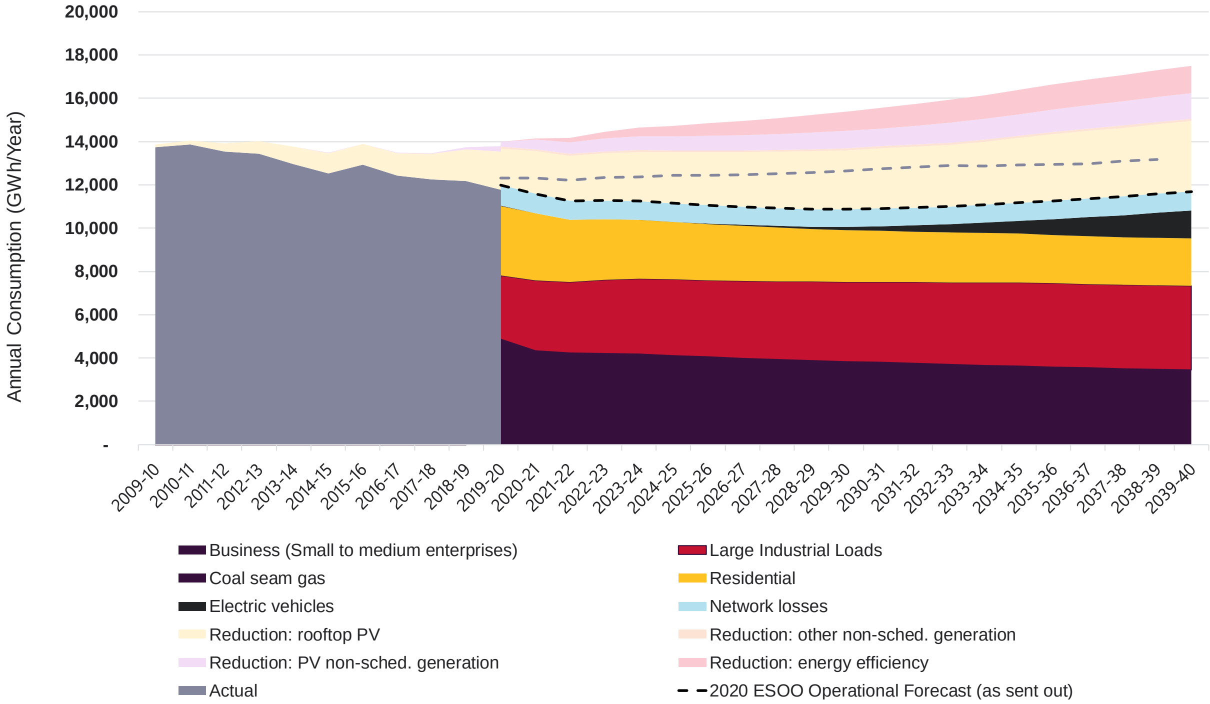
A1.3 South Australia

Annual consumption outlook

In 2020-21, the effect of COVID-19 on the economy is forecast to lower consumption for the business sector, and to be partly offset by a moderate increase in residential sector consumption as more people are expected to be at home. Consumption is expected to recover alongside an economic recovery, however projected continuing advances in EE and a much higher PV forecast result in much lower operational consumption outlook than that forecast in the 2019 ESOO.

Figure 50 shows the component forecasts for regional consumption in South Australia.

Figure 50 South Australia operational consumption in GWh, actual and forecast, 2006-07 to 2039-40



Maximum demand outlook

- Short term (0-5 years) – maximum operational demand is forecast to decline in the first year, driven by COVID-19, then to grow slightly as the economy recovers, resulting in an average year-on-year growth rate of 0.34% in the next five years.
- Medium to long term (5-20 years) – maximum operational demand growth is forecast to grow slightly, driven by accelerating growth in EVs and increased connections and/or population growth. The South Australian Government is providing 40,000 households with access to home battery systems, which is projected to have some dampening effect on operational demand during evening peak periods. Forecast EV growth is higher than in the 2019 ESOO forecast; however, due to an expectation of more frequent overnight charging, this has a minor impact on forecast maximum operational demand.

Table 12 shows maximum summer and winter operational demand (sent out) forecasts for 10% POE and 50% POE for the Central scenario[120].

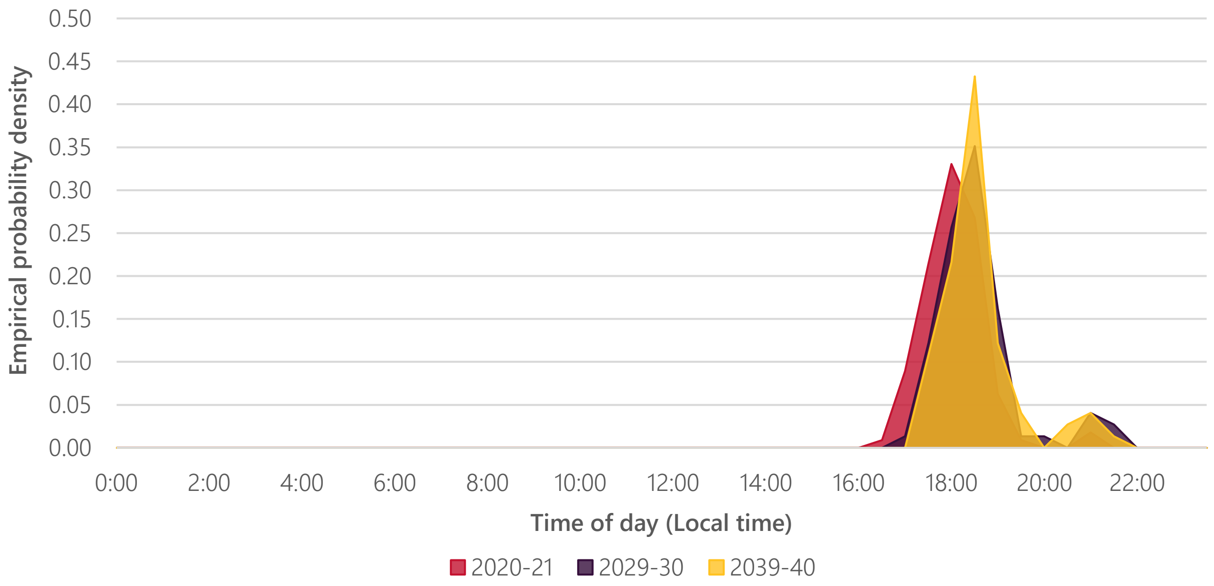
Table 12 Forecast maximum operational demand (sent out) in South Australia, Central scenario (MW)

Financial year	Summer		Calendar year	Winter	
	10% POE	50% POE		10% POE	50% POE
2020-21	3,245	2,902	2021	2,440	2,353
2024-25	3,320	2,950	2025	2,452	2,365
2029-30	3,346	3,000	2030	2,488	2,401
2039-40	3,644	3,278	2040	2,739	2,654

[120] For the 90% POE forecasts and forecasts for the Slow Change and Step Change scenarios in general, see AEMO's data portal at http://forecasting.aemo.com.au.

South Australia currently experiences maximum operational demand in the late afternoon to early evening (during the summer months). As maximum demand occurs late in the day, the growth of distributed PV is expected to have little impact on forecast maximum operational demand. The time of maximum operational demand is forecast to remain the same in the long term, as shown in Figure 51.

Figure 51 Distribution of forecast time of 50% POE summer maximum demand in South Australia



Minimum demand outlook

- Short term (0-5 years) – minimum operational demand is forecast to decline significantly due to an increase in PV installations, resulting in a 28% average annual decline throughout this period.
- Medium to long term (5-20 years) – minimum operational demand is forecast to continue declining, and reach negative minimum demand by 2026-27. Similar to maximum demand, the South Australian Government is providing 40,000 households with access to home battery systems, which will reduce some of the impact of the high distributed PV capacity uptake.

Table 13 shows minimum operational demand (sent out) forecasts for 90% POE and 50% POE[121] and relevant contributing factors at the time of minimum demand.

Table 13 Forecast minimum operational demand (sent out) in South Australia, Central scenario (MW)

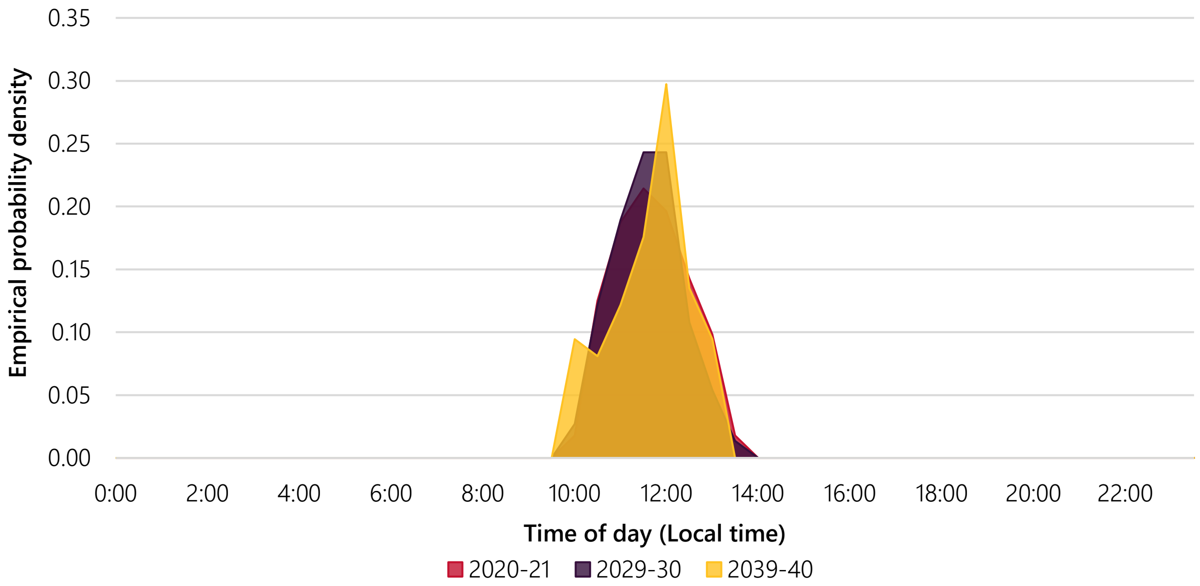
Financial year	Minimum operational demand (sent out)		Coordinated EV charging at time of minimum operational demand (MW)[A]		Distributed PV generation at time of minimum operational demand (MW)	
	50% POE	90% POE	50% POE	90% POE	50% POE	90% POE
2020-21	378	348	0	0	1,076	1,084
2024-25	107	73	0	0	1,373	1,414
2029-30	-103	-141	0	0	1,636	1,682
2039-40	-287	-331	134	130	2,036	2,071

A. Note this charging amount is additional to minimum operational demand figures.

[121] For the 10% POE forecasts, forecasts for other seasons, and forecasts for the Slow Change and Step Change scenarios in general, see AEMO's data portal at http://forecasting.aemo.com.au.

Daily minimum operational demand generally occurs during the middle of the day, as shown in Figure 52, and is expected to continue doing so across the forecast horizon.

Figure 52 Distribution of forecast time of 50% POE shoulder minimum demand in South Australia



A1.4 Tasmania

Annual consumption outlook

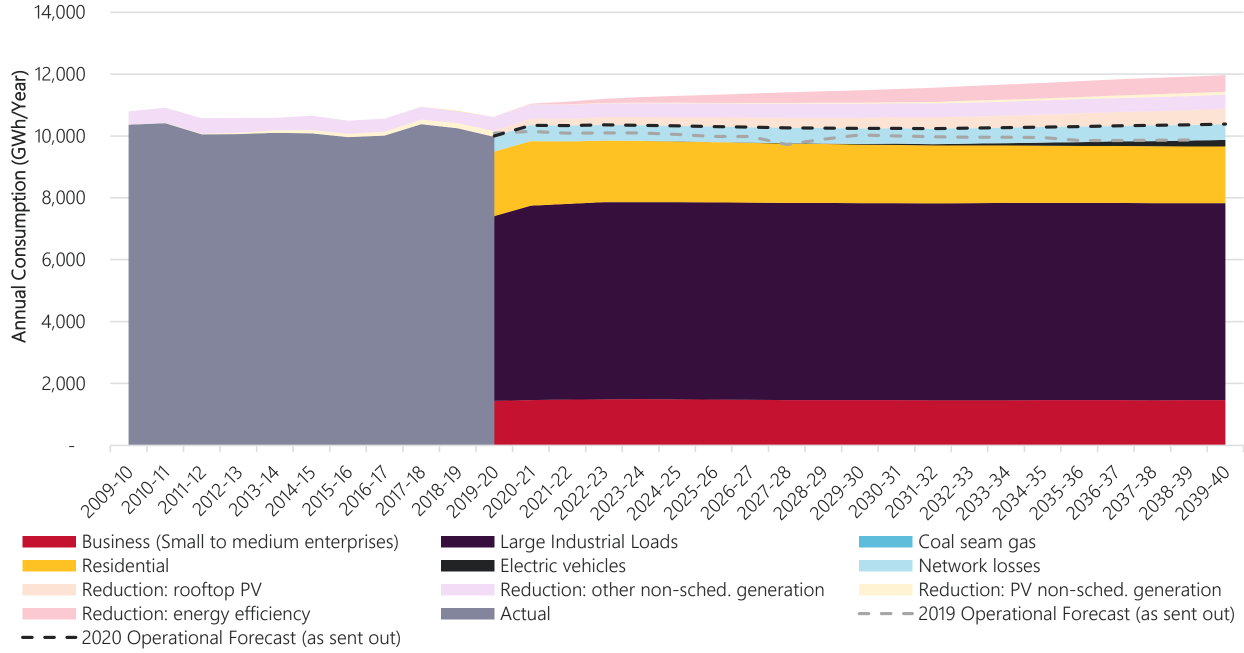
Forecast operational consumption in Tasmania is relatively flat in the Central scenario across the entire forecast horizon.

Residential consumption is expected to temporarily increase in 2020-21 due to COVID-19 restrictions, however long-term growth for the sector in new connections is forecast to be slower than other regions (though higher than in the 2019 forecast).

Conversely, business consumption is forecast to decrease moderately due to COVID-19, with the economic recovery counterbalanced by increased EE measures. Consumption forecasts are marginally higher in the Central scenario than in the 2019 ESOO, principally due to forecast higher connections growth but counterbalanced by projected higher PV uptake and increased EE measures.

Figure 53 shows the component forecasts for regional consumption in Tasmania.

Figure 53 Total Tasmania operational consumption in MWh, actual and forecast, 2009-10 to 2039-40



Maximum demand outlook

- Short term (0-5 years) – Tasmania continues to experience its maximum operational demand in winter, due to heating demand from the residential sector. The maximum operating demand forecast is lower than in the 2019 ESOO forecast, mainly due to COVID-19. After initial projected growth in LIL demand, maximum operational demand in Tasmania is forecast to remain relatively flat.
- Medium to long term (10-20 years) – forecast maximum operational demand is flatter (-0.2% average annual growth from 2025-26 to 2029-30) but slightly higher than in the 2019 ESOO forecast, due to slightly higher large industrial load over the forecast period, as well as battery storage and EV truck charging activity in the morning.

Table 14 shows maximum summer and winter operational demand (sent out) forecasts for 10% POE and 50% POE for the Central scenario[122].

Table 14 Forecast maximum operational demand (sent out) in Tasmania, Central scenario (MW)

Financial year	Summer		Calendar year	Winter	
	10% POE	50% POE		10% POE	50% POE
2020-21	1,373	1,334	2021	1,774	1,724
2024-25	1,410	1,370	2025	1,786	1,738
2029-30	1,403	1,365	2030	1,783	1,734
2039-40	1,435	1,396	2040	1,829	1,780

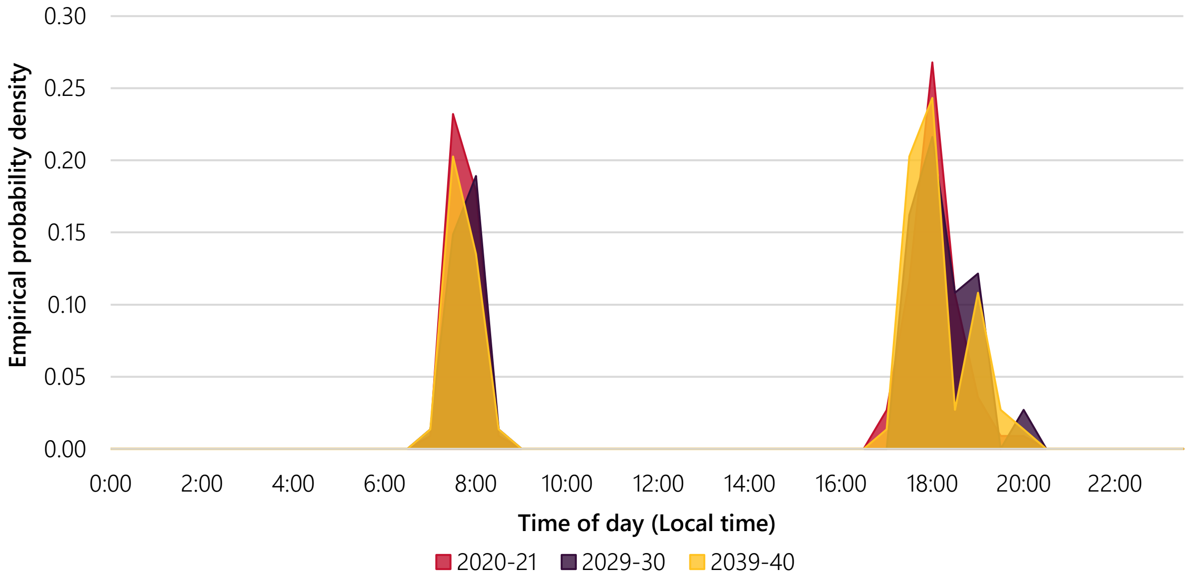
Tasmania has significantly different characteristics at time of maximum demand compared to other regions, being the only region to observe a winter maximum demand, with a large proportion driven by residential

[122] For the 90% POE forecasts and forecasts for the Slow Change and Step Change scenarios in general, see AEMO's data portal at http://forecasting.aemo.com.au.

heating load and large industrial load. While heating load is a strong driver, the relative size of the large industrial load makes Tasmania less sensitive to weather effects like temperature, humidity, and solar irradiance than other regions.

Maximum operational demand in Tasmania has historically occurred in the early winter mornings, in circumstances where distributed PV generation is low and heating load is at peak levels. Tasmanian maximum operational demand is also forecast to frequently occur during the early morning or evening for the same reasons, as shown in Figure 54.

Figure 54 Distribution of forecast time of 50% POE winter maximum demand in Tasmania



Minimum demand outlook

- Short term (0-5 years) – after a decline in the first year, minimum operational demand is forecast to recover due to an expected increase in LIL demand.
- Medium to long term (5-20 years) – minimum operational demand is forecast to decline, driven by moderate growth in distributed PV.

Table 15 shows minimum operational demand (sent out) forecasts for 90% POE and 50% POE[123] and relevant contributing factors at the time of minimum demand.

Table 15 Forecast minimum operational demand (sent out) in Tasmania, Central scenario (MW)

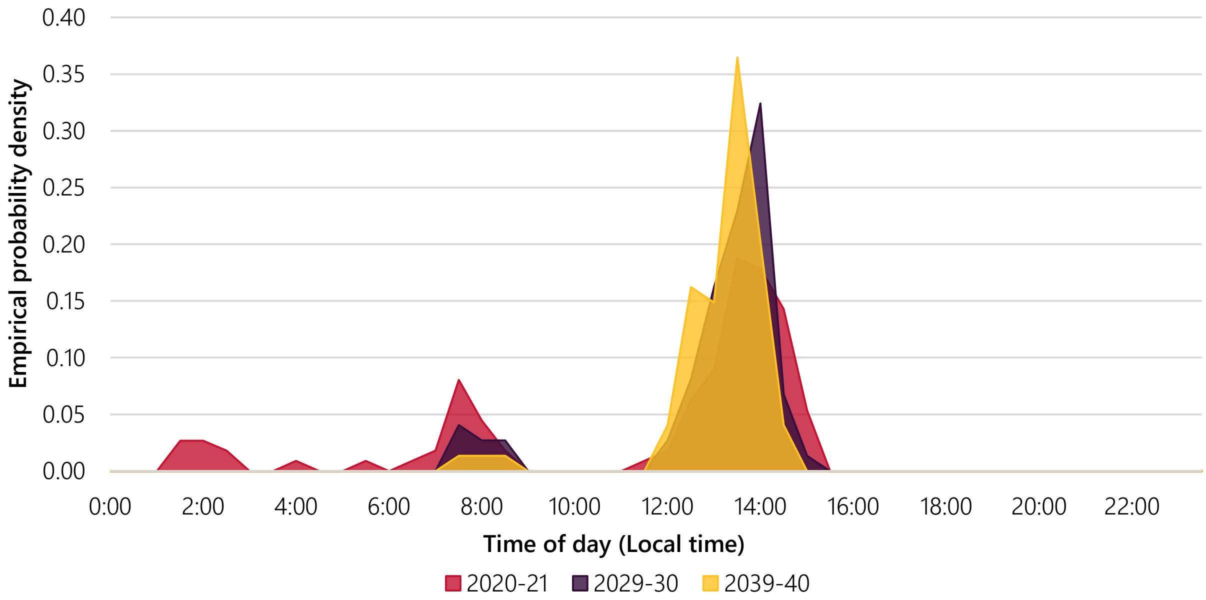
Financial year	Minimum operational demand (sent out)		Coordinated EV charging at time of minimum operational demand (MW)A		Distributed PV generation at time of minimum operational demand (MW)	
	50% POE	90% POE	50% POE	90% POE	50% POE	90% POE
2020-21	875	824	0	0	89	98
2024-25	847	792	0	0	138	136
2029-30	813	757	0	0	190	187
2039-40	757	700	34	35	299	299

A. Note this charging amount is additional to minimum operational demand figures.

[123] For 10% POE forecasts, forecasts for other seasons, and forecasts for Slow Change and Step Change scenarios, see http://forecasting.aemo.com.au.

Daily minimum operational demand often occurs during the early afternoon, as shown in Figure 55, and is expected to do so more frequently in the longer term.

Figure 55 Distribution of forecast time of 50% POE summer minimum demand in Tasmania



A1.5 Victoria

Annual consumption outlook

A drop in operational consumption is forecast for 2020-21 as business consumption falls and connections growth temporarily slows in response to COVID-19. As the economy recovers, consumption is expected to grow from higher long-term connections growth, however the effect of residential and business consumption growth is projected to be offset by stronger distributed PV uptake and EE measures (based on revised analysis of Victorian Energy Upgrades [VEU] Program[124] data).

The Central scenario operational consumption forecast is lower than that in the 2019 ESOO, a main driver being the inclusion of Victoria's Solar homes program[125] for distributed PV in the 2020 ESOO Central scenario. For the 2019 ESOO, the Victorian Solar homes program was incorporated in the Step Change scenario only (see Figure 56). The net impact of a higher distributed PV forecast in the 2020 ESOO is a lower operational consumption forecast (of 4.5 TWh in 2028-29).

[124] More information on the VEU Program is at https://www.esc.vic.gov.au/victorian-energy-upgrades-program.

[125] More information on Victoria's Solar homes program is at https://www.solar.vic.gov.au/.

Figure 56 Victoria distributed PV installed capacity for the 2020 ESOO compared to the 2019 ESOO

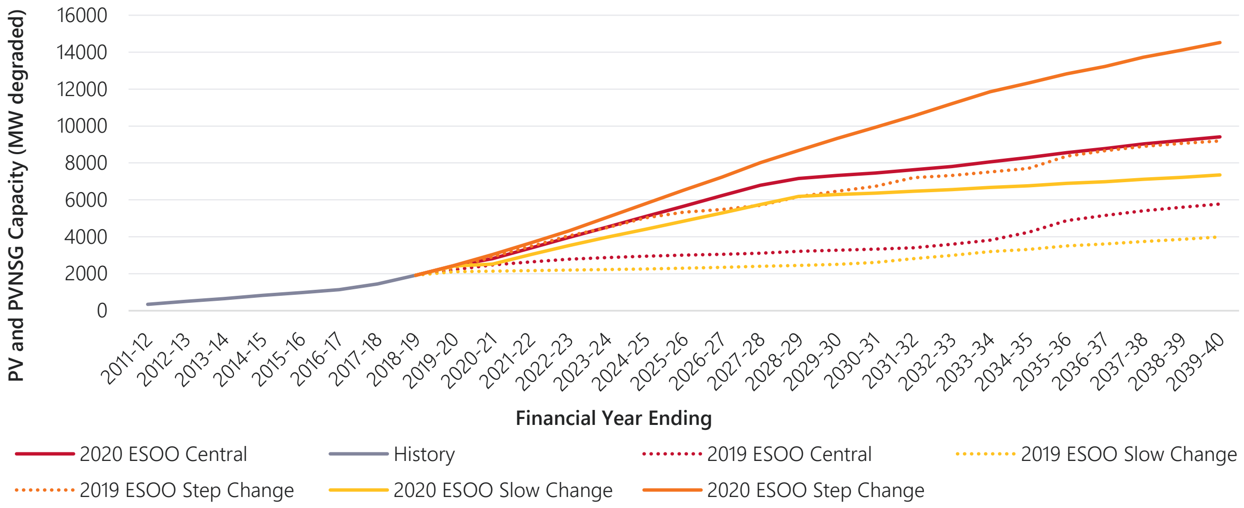
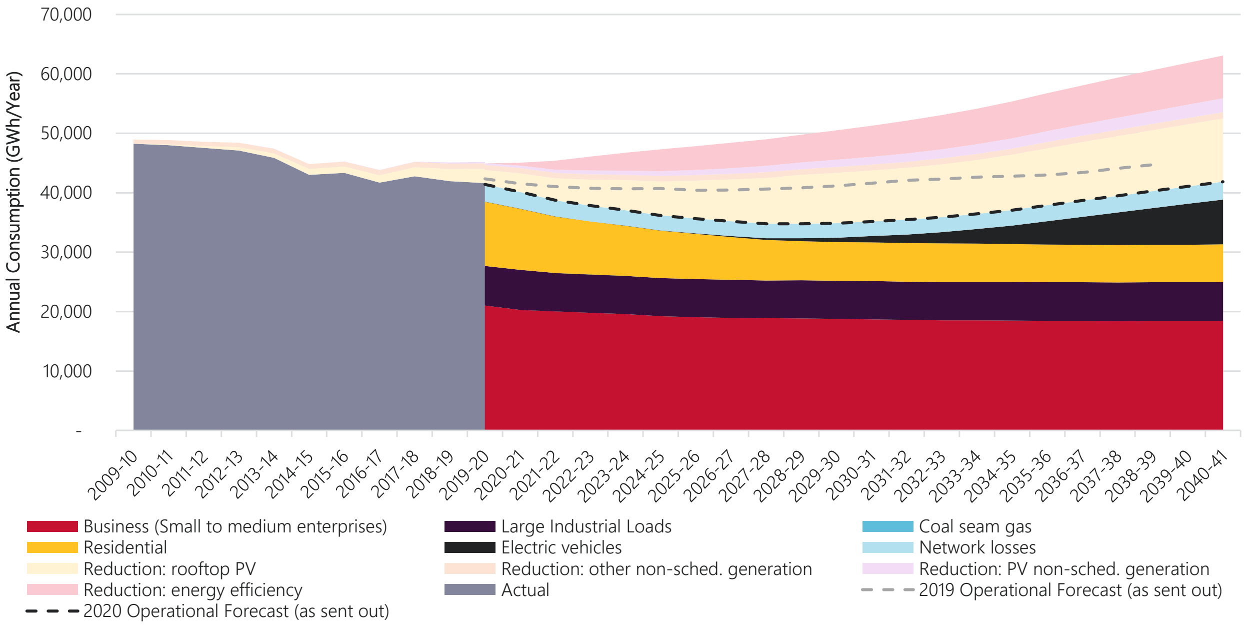


Figure 57 shows the component forecasts for operational consumption in Victoria.

Figure 57 Victoria operational consumption in MWh, actual and forecast, 2009-10 to 2039-40



Maximum demand outlook

- Short term (0-5 years) – after an initial projected decrease in demand in the first year due to a reduction in large industrial load and business sector consumption, due to COVID-19, Victoria's maximum underlying demand is forecast to flatten. This is due to the combined effect of slow growth in connections and economic growth.
- Long term (5-20 years) – Victoria's maximum operational demand is forecast to grow as EV capacity begins to grow, in addition to growth in connections, business and economic growth. Compared to the 2019 ESOO forecast, projected growth over the next 10 years is similar. EV charging-related consumption is forecast to be higher than in the 2019 ESOO, however due to an assumed increase in overnight charging its contribution towards maximum operational demand remains relatively unchanged.

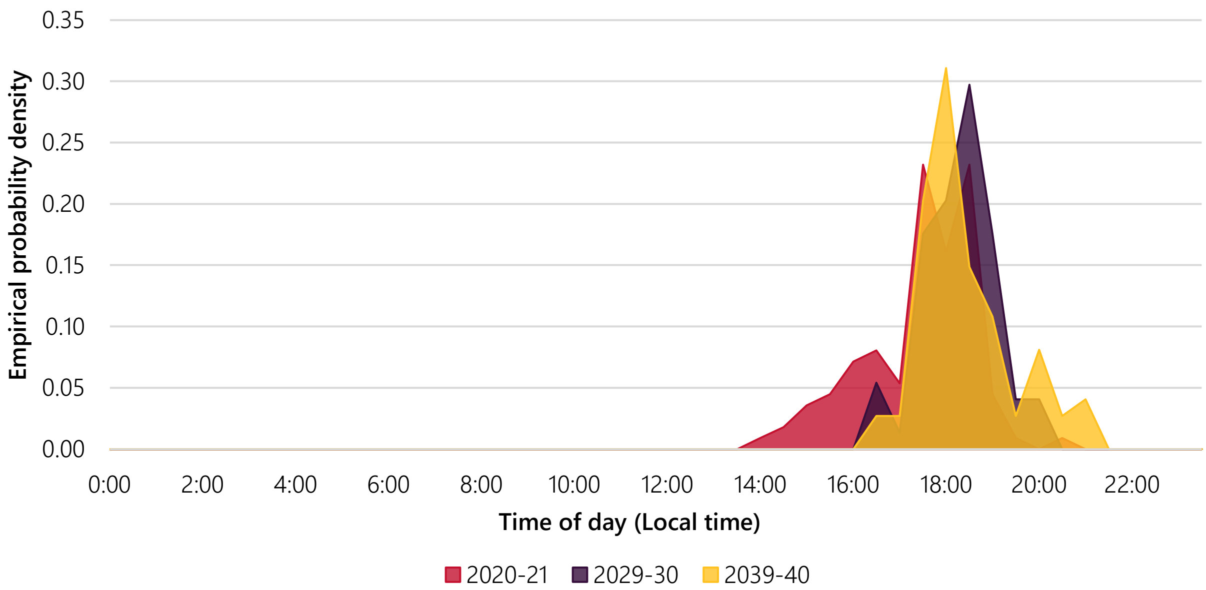
Table 16 shows maximum summer and winter operational demand (sent out) forecasts for 10% POE and 50% POE for the Central scenario[126].

Table 16 Forecast maximum operational demand (sent out) in Victoria, Central scenario (MW)

Financial year	Summer		Calendar year	Winter	
	10% POE	50% POE		10% POE	50% POE
2020-21	9,859	8,885	2021	7,377	7,119
2024-25	9,605	8,628	2025	7,252	7,002
2029-30	9,939	8,928	2030	7,596	7,330
2039-40	11,207	10,185	2040	8,865	8,576

Currently, Victoria's daily operational maximum demand typically occurs in the evening, and is expected to do so more frequently as PV uptake increases across the forecast horizon, as shown in Figure 58. PV generation at the time of maximum demand varies between 200 MW and 400 MW. This is largely governed by the expected time of day maximum demand may occur.

Figure 58 Distribution of forecast time of 50% POE summer maximum demand in Victoria



Minimum demand outlook

- Short term (0-5 years) – minimum operational demand is forecast to experience a projected 12% average annual decline during this period due to a significant increase in distributed PV installation.
- Long term (5-20 years) – minimum operational demand is forecast to continue declining and reach negative mid-day demand by 2028-29, driven by accelerating growth in distributed PV. After 2029-30, minimum operational demand in Victoria is projected to decline less rapidly, due to a slower uptake of distributed PV as well as increasing uncoordinated EV and energy storage system (ESS) charging.

[126] For 90% POE forecasts and forecasts for Slow Change and Step Change scenarios, see AEMO's data portal at http://forecasting.aemo.com.au.

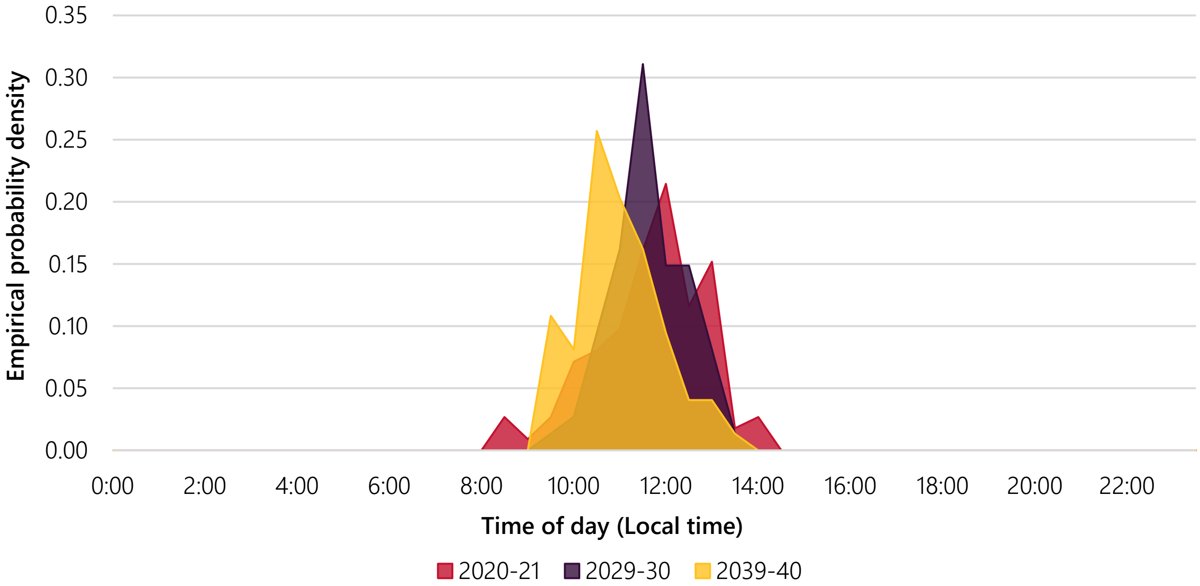
Table 17 Forecast minimum operational demand (sent out) in Victoria, Central scenario (MW)

Financial year	Minimum operational demand (sent out)		Coordinated EV charging at time of minimum operational demand (MW)A		Distributed PV generation at time of minimum operational demand (MW)	
	50% POE	90% POE	50% POE	90% POE	50% POE	90% POE
2020-21	2,745	2,586	0	0	1,707	1,720
2024-25	1,146	954	0	0	3,192	3,322
2029-30	-339	-575	0	0	4,981	5,137
2039-40	-645	-901	604	610	6,383	6,719

A. Note this charging amount is additional to minimum operational demand figures.

Across the forecast horizon, distributed PV is expected to have an increasing impact on minimum demand levels, as minimum demands occur during the daytime when solar irradiance is high (see Figure 59).

Figure 59 Distribution of forecast time of 50% POE shoulder minimum demand in Victoria



A2. COVID-19 impacts on maximum/minimum demand

As Australia has introduced significant lockdown measures to counter the spread of COVID-19, changes to the consumption of electricity have resulted.

The overall impact on consumption and maximum demand is explained in Section 2.1 and Section 2.2, considering a range of outcomes for different COVID-19 sensitivities. This Appendix provides more detail on how the impacts of COVID-19 on maximum (and minimum) demand were estimated. Further detail on the impacts of COVID-19 on consumption forecasts is available in the IASR.

In summary, the impacts on maximum and minimum demand have been estimated:

- In the short term:
  - Through statistical analysis of time-of-use demand data post COVID-19, estimating the impact on demand from a full lockdown at time of maximum and minimum demand relative to what it would have been without COVID-19.
  - Scaling the impact as lockdown measures are expected to be relaxed and people return to work.
- In the medium to longer term:
  - By assuming impacts on maximum and minimum demand reflect general COVID-19 impacts on consumption (from changes to population and economic forecasts), including assumed closures of large industrial loads, and forecast impacts on DER uptake.

Short-term impacts

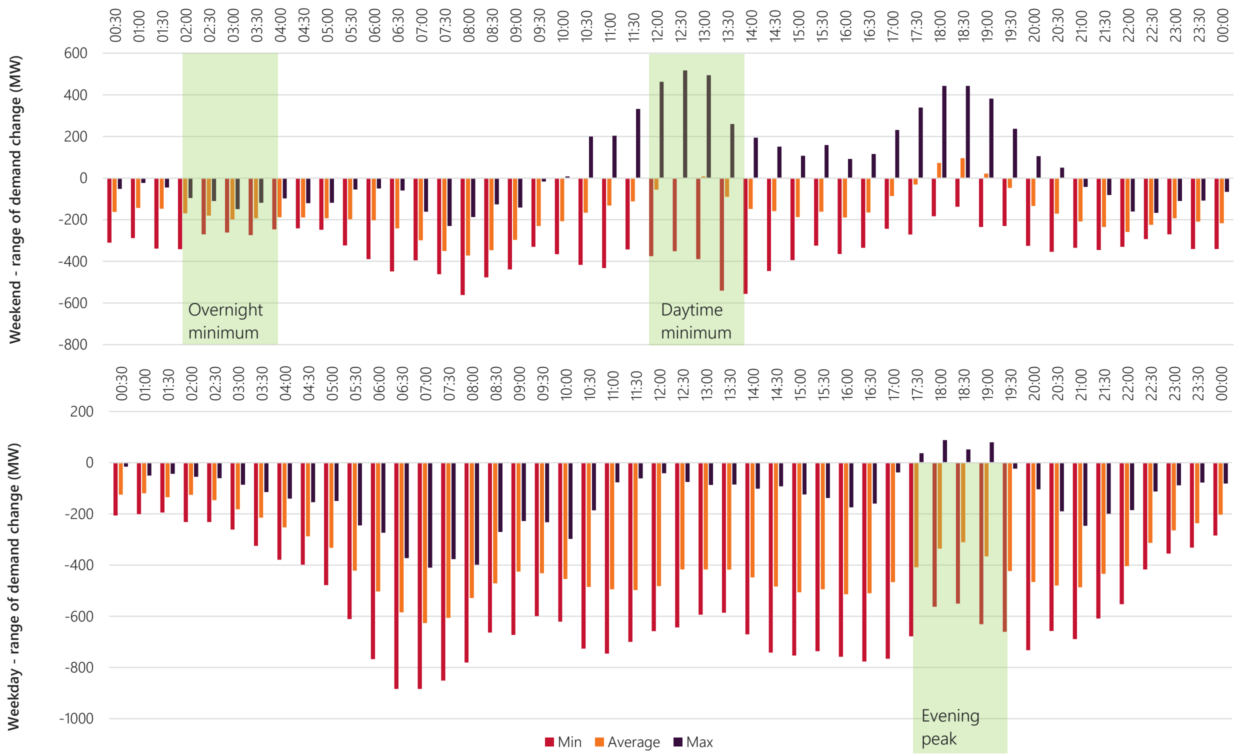
AEMO derived the impact on maximum and minimum demand from two different forecast approaches:

1. Comparison of half-hourly outcomes from forecast models, trained with and without COVID-19 impacts.
2. Statistical impact assessment (introducing the COVID-19 impact as a dummy variable).

The analysis of half-hourly impacts focused on the time of typical maximum demand (weekday late afternoon, early evening) and minimum demand (weekend overnight or mid-day).

An example is shown in Figure 60 for New South Wales based on April 2020 data, comparing differences in forecasts from the models trained with and without the COVID-19 impacts. It shows generally a reduction in forecast demand at time of overnight minimums and evening peaks. The impacts on a mid-day weekend – typical for when minimum demand occurs in many regions – could however both be positive and negative, depending on prevailing conditions.

Figure 60 Estimated impact of COVID-19 in New South Wales by weekdays and weekends, April 2020



AEMO used later time periods (up to the end of May, which was the cut-off point for the ESOO demand forecasts) to assess the likely impact on colder days, using the early-winter cold snaps to see if there was a different impact when a significant residential space heating requirement existed. This caused a different estimate to be used for a winter mid-day minimum, where demand was typically higher than before COVID-19. This estimate was also used for summer, assuming cooling demand will have a similar impact.

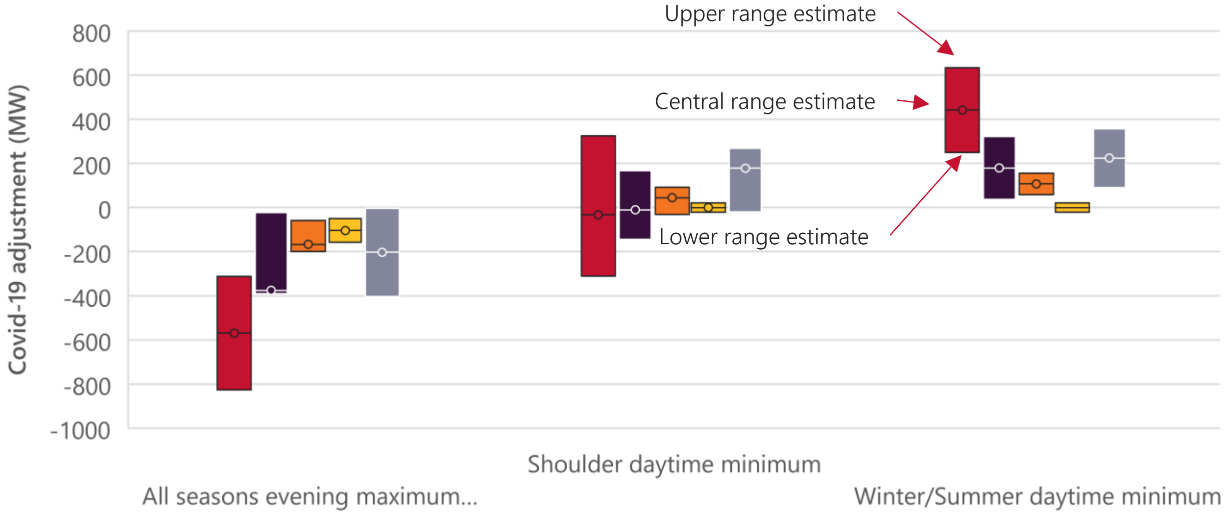
AEMO supplemented this with the other statistical impact assessment approach to establish a range of possible outcomes for each region, represented by upper, central and lower estimates of the demand offsets representing the impacts. These have been assigned to the scenarios and sensitivities outlined in Table 2 (Section 1.4).

Figure 7 in Section 2.1 showed the range for evening maximum demand. Figure 61 includes the estimated ranges for both maximum and minimum demands that reflect the observed impacts of full COVID-19 measures if all regions were to remain in lock-down as was the case in April and May this year.

As noted, the impact on maximum demand is always negative. This is a result of the assumption that recent growth in distributed PV pushes the occurrence of maximum demand to 18:00 or later in all regions, where commercial cooling load is scaling back and those who have been working from home have their houses pre-cooled, resulting in a lower cooling need than would otherwise occur. This is the most probable case, but there are other potential outcomes, including an earlier daily peak, where the combination of commercial cooling and residential cooling could cause an increase in demand overall, compared to what demand would have been without COVID-19.

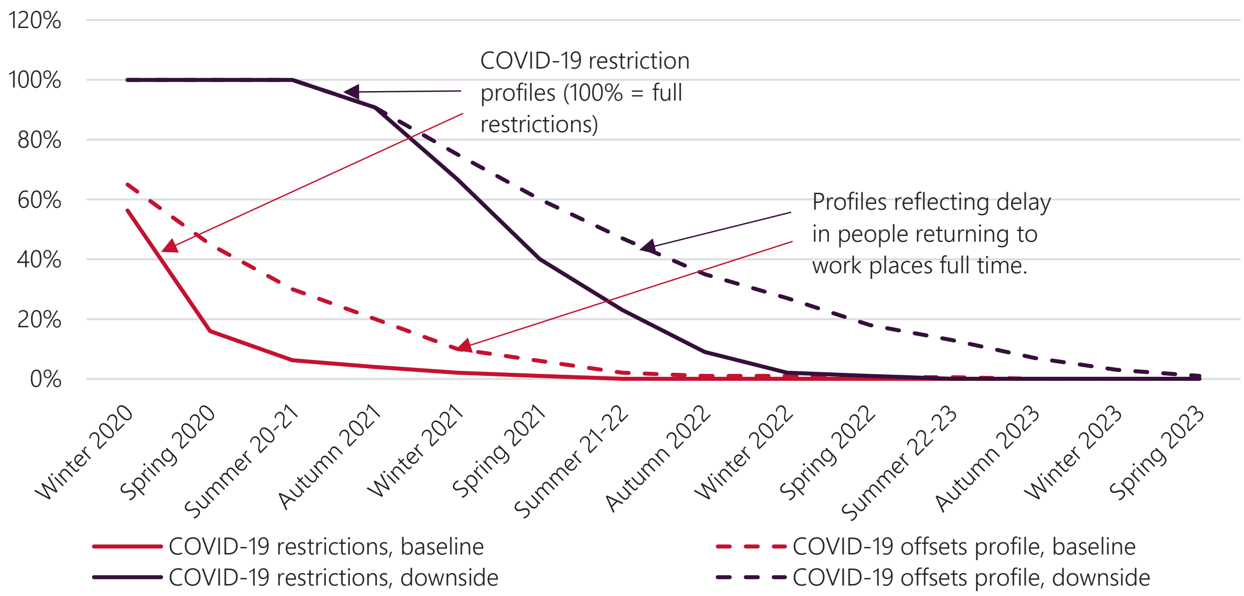
As COVID-19 measures are relaxed, the impact has been assumed to reduce in a way that reflects a staged return to normal, with a proportion of workers continuing to work from home. To represent this, AEMO used the scaling profiles shown in Figure 62, showing the estimated lifting of restrictions (full lines) and the delayed response used in the modelling (dotted lines). The COVID offsets profile baseline was used in AEMO's Central and Step Change scenarios, while the COVID offsets profile downside was used in the Slow Change scenario and the downside sensitivities to the Central scenario.

Figure 61 Maximum and minimum demand offsets for COVID-19



* Tasmanian range represents an overnight minimum; the range for other regions represents mid-day minimum demand.

Figure 62 Scaling profile applied to COVID-19 maximum and minimum demand offsets



Longer-term impacts

Even with all restrictions removed, COVID-19 is expected to continue to impact the Australian economy for a long time, and to be reflected in lower economic growth, lower immigration and hence population growth, and the direct impact of any closures of large industrial loads. These drivers are discussed in AEMO's 2020 IASR.

To ensure consistency with trends in consumption, AEMO applies a growth factor to underlying maximum demand reflective of growth in underlying consumption. AEMO then applies the forecast growth in distributed PV uptake and other DER technologies (as outlined in the 2020 IASR) to derive operational demand.

Due to this linkage to the consumption drivers, the longer-term impacts of COVID-19 are captured in the forecast.

A3. Demand Side Participation forecast

AEMO must publish details, no less than annually, on the extent to which, in general terms, DSP information received under rule 3.7D of the NER has informed AEMO's development or use of load forecasts for the purposes of the exercise of its functions under the NER.

For the 2020 ESOO, AEMO has updated its forecast for DSP based on the methodology AEMO consulted on in early to mid-2020[127]. This appendix outlines AEMO's DSP forecast for the 2020 ESOO, in fulfilment of its obligation under the NER, and explains the key differences from the 2019 forecast.

A3.1 DSP definition

Demand flexibility describes the capability of customers to shift or adjust their demand. This flexibility is usually achieved through use of (automated) technology but involving manual adjustments to load or generation resources, typically in response to price signals.

Demand flexibility exists in many ways, from residential customers on time-of-use tariffs or using battery storage, to large industrial facilities reducing consumption (or starting embedded generators) during high price events.

AEMO's DSP forecast only include some categories of this wider form of demand flexibility, to avoid double counting with types that are more suited to being included in the demand forecast or modelled as a power supply resource. The categories that are included in DSP are listed in the middle column of Figure 63 below. All demand flexibility categories are included in AEMO's reliability forecasts, although they are represented differently, depending on the type of DSP, as discussed below.

The categories listed to the left in Figure 63 are all captured in AEMO's demand forecasts. These generally operate based on daily patterns which are unrelated to wholesale price or reliability signals. Categories that are dispatched as generation (such as aggregated storage systems operated as VPP) are modelled as supply in AEMO's forecasting processes (right column).

The inclusion of Other Non-Scheduled Generation (ONSG) peaking plant in this year's forecast is a change from last year, as outlined in AEMO's Forecast Improvement Plan following its review of forecast performance in the 2019 *Forecast Accuracy Report*[128].

It should also be noted that AEMO's DSP forecast specifically excludes RERT. The DSP forecast is used in the ESOO and the Medium Term Projected Assessment of System Adequacy (MT PASA), which highlight the risk of shortfalls to determine the need for RERT capacity, so the analysis needs to exclude it in the first instance. One change in this year's forecast, however, is the inclusion of demand response from RERT providers outside the RERT program itself.

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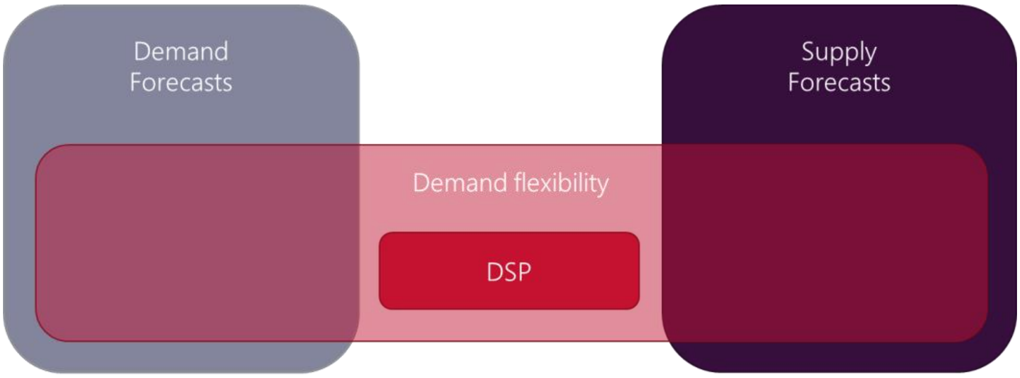
[127] See https://www.aemo.com.au/consultations/current-and-closed-consultations/demand-side-participation-forecast-methodology-consultation.

[128] See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/accuracy-report/forecast_accuracy_report_2019.pdf.

Figure 63 Flexible demand sources included in AEMO's DSP forecast



- Hot water load control
- Time of Use tariffs
- Energy storage
- EV charging
- ONSG – non peaking

- Market exposed cust.
- ONSG - peakers
- Aggregated customer response
- Network reliability programs

- Energy storage VPP
- Scheduled loads (pumped storage)

A3.2 DSP forecast by component

The forecast was based on DSP information collected by registered participants through AEMO's DSP Information Portal during April 2020. It is mandatory for participants to provide this information to AEMO every year.

The forecast has been broken down into two main components, explained in detail below:

- Price-driven response.
- Reliability response.

Price-driven response

This is determined by examining how flexible loads, as reported to AEMO (including those with embedded generators), have responded to various price levels in recent history (past three years).

The response is determined as the difference between the observed consumption and the calculated baseline consumption. This is done for an aggregation of sites/programs with similar characteristics for which the same baseline method is appropriate. AEMO uses the 50th percentile as a single point representation of the distribution of responses observed when these price levels have been reached.

Table 18 Price-driven DSP forecast (cumulative response in MW)

Trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
>$300/MWh	30	35	12	0	1
>$500/MWh	35	36	27	28	26
>$1,000/MWh	38	37	33	33	30
>$2,500/MWh	43	49	50	33	41
>$5,000/MWh	43	49	58	33	47
>$7,500/MWh	43	49	61	33	53

There have been some updates to the DSP forecast relative to the 2019 ESOO reflecting changes in observed behaviour and the inclusion of ONSG peakers in this year's DSP forecast. It should be noted that the inclusion of ONSG peakers in this year's DSP forecast is not improving reliability over what was seen last year, because this component moved out of the demand forecast and into the DSP forecast, leading to a net zero change overall at high price and reliability event times.

For DSP observed when prices exceed $7,500/MWh, relative to the 2019 ESOO, there is:

- Less observed DSP in New South Wales (43 MW vs 93 MW) and Victoria (53 MW vs 60 MW).
- An unchanged estimate for Tasmania (< 3 MW difference).
- More observed DSP in Queensland (49 MW vs 32 MW) and South Australia (61 MW vs 33 MW).

For South Australia, the change also reflects an easing of the restriction of excluding any response from RERT providers used in 2019 (as highlighted in Section 2.4 and in accordance with the revised DSP methodology[129] AEMO finished consulting on in August 2020).

Reliability response

The reliability response represents the estimated DSP response during reliability events, which AEMO defines as cases where an actual LOR2 or LOR3 is declared[130].

The estimates are based on the estimated price response for half-hourly price exceeding $7,500/MWh (50th percentile as above) along with any network event programs and any additional adjustments to reflect responses that have not otherwise been captured[131].

In this year's program, AEMO has modelled network event programs in Queensland and Victoria. Excluding any loads overlapping with RERT, these amount to:

- 52 MW in Queensland.
- 25 MW in Victoria.

AEMO has been advised these programs are only available in summer, causing different aggregate DSP forecasts to exist for summer and winter.

Compared to the 2019 forecast, the estimate for Queensland has been adjusted up based on further information from the operating organisation.

AEMO has also made upwards adjustments in New South Wales and Victoria, to reflect significant responses observed from RERT providers outside what was contracted (and/or on periods where RERT was not needed). These adjustments reflect the average of the response seen across the periods where LOR2 conditions were in the regions and sum to:

- 242 MW in New South Wales.
- 122 MW in Victoria.

Based on this, the combined DSP forecasts for the coming summer 2020-21 and winter 2021 are shown in Table 19 and Table 20 respectively. The reliability response estimate is the key input to the ESOO process, showing the MW of estimated demand reduction possible to avoid USE during supply shortfalls.

As AEMO has no information about committed additional DSP resources, the estimates have been used for the entire 10-year horizon of the ESOO.

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[129] See https://aemo.com.au/consultations/current-and-closed-consultations/demand-side-participation-forecast-methodology-consultation.

[130] See AEMO's reserve level declaration guidelines, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/reserve-level-declaration-guidelines.pdf.

[131] The reliability response is estimated with reference to a high price trigger (half-hourly prices rarely reach $7,500) and during actual LOR2 or LOR3 events prices are often lower than assumed above. This is, however, not considered to have led to any overestimation of DSP, as the level of response is rather consistent at the higher price levels, as seen in Table 18.

Table 19 Estimated DSP responding to price or reliability signals, summer 2020-21

Trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
> $300/MWh	30	35	12	0	1
> $500/MWh	35	36	27	28	26
> $1000/MWh	38	37	33	33	30
> $2500/MWh	43	49	50	33	41
> $5000/MWh	43	49	58	33	47
> $7500/MWh	43	49	61	33	53
Reliability response	285	102	61	33	200

Table 20 Estimated DSP responding to price or reliability signals, winter 2021

Trigger	New South Wales	Queensland	South Australia	Tasmania	Victoria
> $300/MWh	30	35	12	0	1
> $500/MWh	35	36	27	28	26
> $1000/MWh	38	37	33	33	30
> $2500/MWh	43	49	50	33	41
> $5000/MWh	43	49	58	33	47
> $7500/MWh	43	49	61	33	53
Reliability response	285	49	61	33	175

A3.3 DSP statistics

Understanding the status of demand flexibility in the NEM, both within the categories included in AEMO's DSP forecast and also more widely, is important for both market participants, network operators, and policy-makers.

Furthermore, following the rule change on wholesale demand response in 2020[132], NER clause 3.7D(c) will require AEMO from October 2021 to include analysis of volumes and types of demand response in its reporting, including:

- Information on the types of tariffs used by NSPs to facilitate demand response and the proportion of retail customers on those tariffs; and
- An analysis of trends, including year-on-year changes, in the DSP information in respect of each relevant category of Registered Participant.

The following presents statistics on the full set of submitted DSP information to provide transparency about demand flexibility in the NEM. As it covers demand flexibility beyond what was in included in the DSP forecast, the reported potential in MW differs from the forecast above.

[132] See https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism.

A3.3.1 Participant programs delivering demand flexibility

Table 21 presents the change in program numbers as submitted by participants to AEMO's DSP information portal over time. Note that 2019 was the first year where all parties with significant DSP resources (to AEMO's knowledge) submitted information, so 2018 data is not directly comparable with subsequent years.

As Table 21 shows, programs offering retail time-of-use tariffs and network controlled load are stable. On the other hand, there is an increase in the number of market-exposed connections programs and network event programs, and more programs monitoring or managing connections with energy storage.

The 'Other' category reflects larger programs as specified in the DSP Information Guidelines[133], and the increase in 2020 is particularly attributed to a number of sites with embedded generation being submitted as individual programs to reflect the differences of each site. For 2021, AEMO is seeking to have the "Other (larger programs)" category replaced with specific program characteristics to improve visibility of the nature of the programs[134].

Table 21 Program numbers from DSP Information portal, 2018-20

Category	2018	2019	2020
Market exposed connections	12	20	49
Connections on network event tariffs	1	1	7
Connections on retail time-of-use tariffs	20	29	29
Connections with energy storage	7	11	16
Connections with network controlled load	54	58	58
Other (larger programs)	35	45	117

A3.3.2 Statistics by program category

Table 22 summarises category-level information from submissions to AEMO's DSP information portal in 2020. Participants report each individual customer connection, based on their national meter identifiers (NMIs), that belong to each program. Some may belong to multiple programs; for example, a residential customer's NMI could appear both with having controlled hot water tank (network controlled load) and a battery storage.

As further noted in the following section, the number of connections submitted through the portal this year saw a reduction of 8% from last year's number. This is entirely due to a larger network controlled load program not reporting NMI numbers in 2020; had it been reported (assuming similar to last year), the number of connections would instead have increased by 1%.

The participants may also for each program report its potential response in MW. Table 22 highlights that, in many cases, the potential response of the program is not known or reported. This makes it more difficult for AEMO to use the provided values as verification of the calculated DSP. AEMO is therefore reliant on the historical analysis of observed responses against estimated baseline consumption. AEMO is consulting on proposed changes to the guidelines to make it mandatory in future for some DSP categories to report the potential response[135].

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133 See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/electricity_consultations/2017/dspig/demand-side-participation-information-guidelines.pdf.

134 See https://www.aemo.com.au/consultations/current-and-closed-consultations/DSPI-Guidelines .

135 See https://www.aemo.com.au/consultations/current-and-closed-consultations/DSPI-Guidelines .

Table 22 Program statistics grouped by program category for 2020 submissions

Category	Number of programs	Number of connections (connections may appear in more than one program)	Number of programs that included potential response information in submission
Market exposed connections	49	5,836	8
Connections on network event tariffs	7	4,018	3
Connections on retail time-of-use tariffs	29	1,069,526	0
Connections with energy storage	16	15,461	2
Connections with network-controlled load	58	2,193,058	52
Other (larger programs)	117	327,088	106

A3.3.3 Load types of reported connections

The types of connections reported to the DSP information portal are mainly residential, however a significant portion of the connections were not specified. The load type categories for 2020 are summarised in Table 23, with the numbers of distinct connections reported in 2019 for comparison. The unreported number of NMIs for one program in 2020 explains most of the drop in residential connections that are part of a DSP program.

Table 23 Load types of reported connections

Load type	Number of distinct connections (2019)	Number of distinct connections (2020)	Dominant program category in each load type as percentage (2020)
< not specified >	1,662,335	1,701,821	58% connections on retail time-of-use tariffs, 33% connections with network-controlled load
Aggregated	78	0	Not applicable in 2020.
Commercial	2,602	2,884	100% connections on network event tariffs
Industrial	47	361	74% Market exposed
Residential	2,106,990	1,674,967	97% connections with network-controlled load

A3.3.4 Number of connections by category and type

Table 24 lists the number of connections in each category, but also by DSP type. Of note, just over 2.5 million connections were reported to be on a network-controlled load program, engaging in load reduction. This number is primarily attributed to residential controlled load tariffs for water heating.

Table 24 also includes the sum of all reported potential megawatt responses of each program, including programs excluded from AEMO's DSP calculation. In total, it suggests 4,336 MW of potential response exists although more could be unquantified or simply not reported. The number does include a number of PV sites under embedded generation that potentially could respond to zero/negative prices, but will not affect maximum demand. Excluding the other/larger programs embedded generation is a better proxy for what is available at time of maximum demand; the total potential response sums to 2,380 MW.

A significant proportion, for example, 1,380 MW of network controlled load, is reflected in AEMO's demand forecast directly, rather than being forecast as DSP. Therefore, the numbers here cannot directly be reconciled with the forecast DSP presented earlier.

Some quoted potential responses, however, may represent rated capacities that may not be fully realised in practice. In its current consultation on the DSP Information Guidelines[136], AEMO seeks to get more entries that specify potential response and better clarity whether the entries represent a maximum potential or a firm (guaranteed) potential.

Table 24 Number of connections grouped by program category and DSP type

Category	DSP type	Distinct number of connections	Reported sum of potential response (MW)	Number of programs
Market exposed connections	Load reduction	294	90	34
	<not specified>	5,494	0	9
	Load reduction; embedded generation	16	15	1
	Embedded generation	30	20	5
Connections on network event tariffs	Load reduction	3,847	14	3
	<not specified>	72	0	3
	Load reduction; embedded generation	75	20	1
Connections on retail time-of-use tariffs	<not specified>	988,072	0	29
Connections with energy storage	Energy storage	0	48	0
Connections with network controlled load	Load reduction	0	1,380	0
	<not specified>	87	0	3
Other (larger programs)	Load reduction	80,888	620	20
	<not specified>	122	160	25
	Energy storage	952	10	1
	Embedded generation	245,104	1,956	70
	Embedded generation; load reduction	8	3	1

136 See https://www.aemo.com.au/consultations/current-and-closed-consultations/DSPI-Guidelines.

A4. Regional supply adequacy

This appendix provides, for each NEM region, a summary of committed new entrant generation, the expected retirement of existing generation, and an overview of supply adequacy in the absence of any further market response. Each section also examines the impact of the actionable ISP transmission augmentations on reliability outcomes.

A4.1 New South Wales

Key insights

- Absent additional investment, New South Wales is forecast to exceed the IRM from 2023-24 onwards, due to the retirement of the Liddell Power Station. The impact of the retirement on USE in the forecast is partly offset by the inclusion of the committed augmentation of QNI in 2022-23.
- From 2023-24 onwards, the forecast level of USE increases due to the impact of increasing forced outage rates associated with plant aging and approaching retirement.
- USE is projected to be well above the reliability standard after the Vales Point Power Station retirement in 2029-30.
- The commissioning of Snowy 2.0 is projected to deliver minimal benefits without the HumeLink transmission augmentation included. When the HumeLink augmentation is included, the reliability outlook improves significantly.
- There remains a period of two years, after Liddell retires and before Snowy 2.0 is developed, when expected USE exceeds the IRM.
  - The recent announcement by New South Wales government to provide capital projects funding to 170 MW of dispatchable capacity under its Emerging Energy Program[137] will help reduce expected USE in this time period.

A4.1.1 Generation and storage changes

In New South Wales, the 2020 ESOO includes 1,676 MW of committed VRE projects, 2,040 MW of pumped hydro and 105 MW of thermal generator upgrades, summarised in Table 25. All of the committed solar and wind projects are expected to be operating during the 2020-21 summer.

[137] See https://energy.nsw.gov.au/renewables/clean-energy-initiatives/emerging-energy-program (not modelled).

Table 25 New committed generation and retirements in New South Wales

Category	Project	Capacity (MW)	Commercial operation or retirement date
Large-scale solar	Molong Solar Farm	36	Dec 2020
	Sunraysia Solar Farm	229	Dec 2020
	Darlington Point Solar Farm	275	Sep 2020
	Goonumbla Solar Farm	70	Sep 2020
	Limondale Solar Farm 1	220	Dec 2020
	Wellington Solar Farm	211	Feb 2021
Wind	Collector	227	Dec 2020
	Crudine Ridge Wind Farm	138	Apr 2021
	Biala Wind Farm	111	Dec 2020
	Bango 973 Wind Farm	159	Apr 2021
Hydro	Snowy 2.0	2,040	Mar 2025
Generator upgrades	Bayswater	25	Jul 2021
		25	Jul 2022
		25	Jun 2023
	Mt Piper	30	Jan 2021
Black coal retirement	Liddell	500	Apr 2022
	Liddell	1,500	Apr 2023
	Vales Point B	1,320	Dec 2029

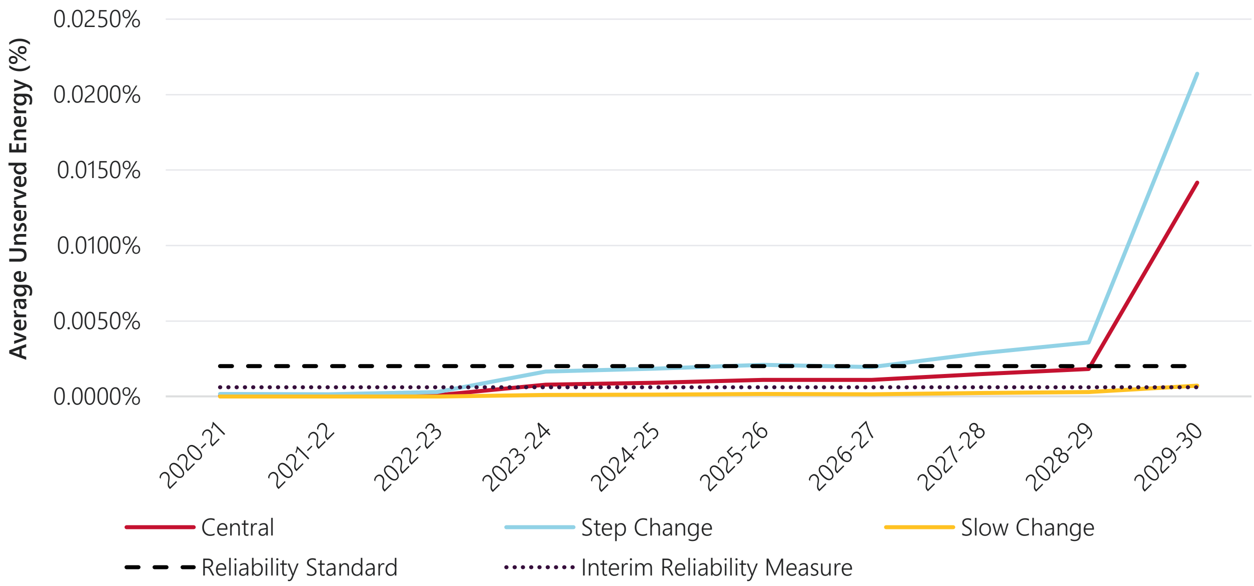
A4.1.2 Supply adequacy assessment

Figure 64 shows forecast USE in New South Wales across the Central, Slow Change and Step Change scenarios. The risk of load shedding is forecast to be minimal over the first three years. Following the retirement of Liddell, forecast USE increases to above the IRM in both the Central and Step Change scenarios. The increase in USE is lower than forecast last year, due to additional committed VRE generation and the inclusion of the QNI Minor augmentation (which increases import capabilities from Queensland and/or reduces wind farm curtailment in northern New South Wales at times of high demand).

Forecast USE continues to increase due to the increasing forced outage rates of coal-fired generators, illustrated in Figure 21 (in Section 3.2.1). Following the retirement of Vales Point in 2029-30, expected USE increases substantially, to well above the reliability standard.

USE remains low across all years in the Slow Change scenario, due to the lower forecast peak demand.

Figure 64 Forecast USE outcomes, New South Wales

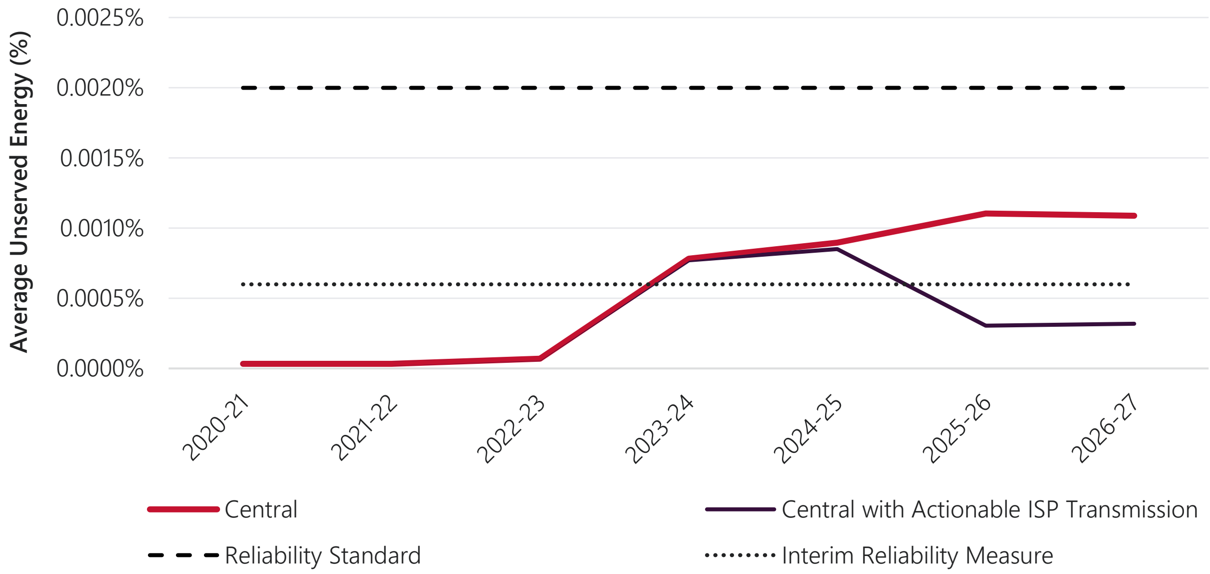


Impact of actionable ISP transmission augmentations

In the forecasts above, an additional 2,040 MW of firm capacity provided by Snowy 2.0 from 2025-26 has a negligible impact on reliability In New South Wales. This is because the associated transmission augmentation required to unlock these benefits is not classified as committed (and therefore has been excluded from the Central scenario).

However, in the Actionable ISP Projects sensitivity, the delivery of the HumeLink project is projected to increase the delivery of additional firm capacity from Snowy 2.0 to Sydney, with a projected reduction in USE from 2025-26 as shown in Figure 65.

Figure 65 Impact of actionable ISP transmission augmentations, New South Wales



A4.2 Queensland

Key insights

- After the expected closure of Callide B in 2028, Queensland begins to see some instances of forecast USE, however USE is forecast to remain well below the IRM.
- While the committed QNI Minor upgrade is primarily forecast to provide additional reliability benefits to New South Wales, it is also projected to provide some reliability improvement in Queensland following the Callide B retirement.

A4.2.1 Generation and storage changes

The ESOO includes 303 MW of committed VRE generation in Queensland, listed in Table 26. The retirement of Mackay GT in early 2021 and the retirement of Callide B (700 MW) at the end of 2028 have also been included.

Table 26 New committed generation and retirements in Queensland

Category	Project	Capacity (MW)	Commercial operation or retirement date
Large-scale solar	Gangarri Solar Farm	120	March 2021
	Kennedy Energy Park	15	July 2022*
	Maryborough Solar Farm	35	July 2020
	Middlemount Solar Farm	26	July 2022*
	Warwick Solar Farm 1	64	November 2020
Wind	Kennedy Wind Farm	43	July 2022*
Black coal retirement	Callide B	700	December 2028
Diesel retirement	Mackay GT	34	April 2021

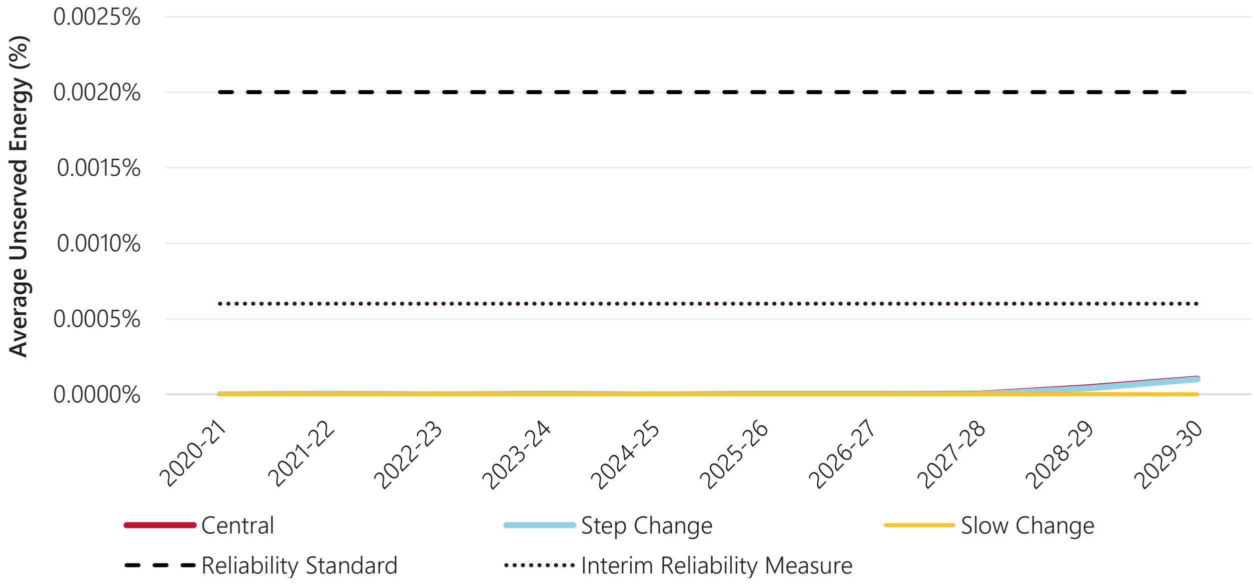
* These commercial operation dates reflect the treatment of Comm* projects described in Section 3.1.

A4.2.2 Supply adequacy assessment

Figure 66 shows minimal USE forecast in Queensland, with a minor increase upon retirement of Callide B.

The committed QNI Minor upgrade commissioned at the end of 2022 primarily provides reliability benefits to New South Wales. The augmentation has no material impact on Queensland reliability in the early years of its operation, as Queensland has negligible forecast USE. In the later years of the horizon, the augmentation does provide some forecast reliability benefit in Queensland, demonstrated by flows into Queensland from New South Wales at times of supply scarcity exceeding current capabilities.

Figure 66 Forecast USE outcomes, Queensland



A4.3 South Australia

Key insights

- The reliability forecast for South Australia continues to improve (as compared with the 2019 ESOO) due to the inclusion of new firm capacity such as the Infigen leased temporary diesel generators and the Hornsdale battery expansion.
- Following the retirement of Osborne in December 2023, the risk of load shedding increases but forecast USE remains below the IRM.
- The inclusion of Project EnergyConnect results in substantial reductions in forecast USE by increasing the import capability at times of high demand, more than offsetting the reliability impact of the retirement of Osborne.

A4.3.1 Generation and storage changes

The 2020 ESOO modelling includes 86 MW of committed VRE generation as well as 50 MW of additional battery storage capacity, 15 MW of gas generator upgrades, and 123 MW of additional liquid-fuelled generation in South Australia.

Torrens Island A Power Station (480 MW) is in the process of completing its retirement over the next two years, and Osborne Power Station (180 MW) is scheduled for retirement in December 2023.

Table 27 shows new committed generation projects, upgrades and retirements of existing generators in South Australia.

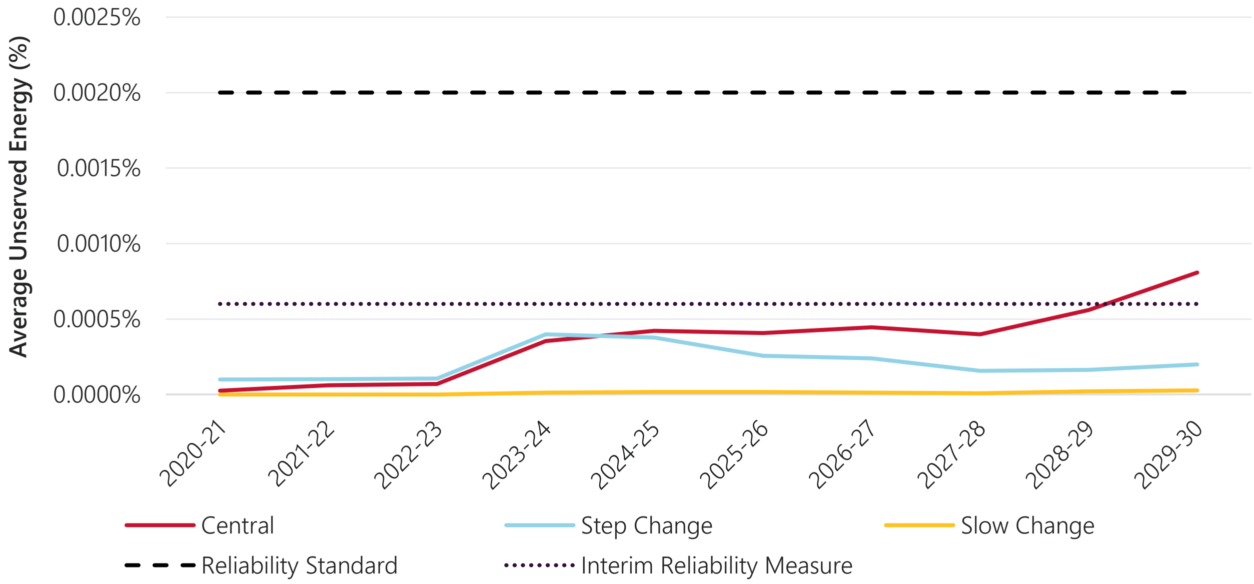
Table 27 New committed generation, upgrades and retirements in South Australia

Category	Project	Capacity (MW)	Commercial operation or retirement date
Liquid fuel	South Australia Temporary Generation South	123	August 2020
Wind	Lincoln Gap Wind Farm Stage 2	86	October 2021
Large-scale batteries	Hornsdale Power Reserve Upgrade	50	July 2020
Generator upgrades	Quarantine Upgrade 3	5	September 2021
	Quarantine Upgrade 2	5	September 2022
	Quarantine Upgrade 4	5	September 2023
Natural gas retirement	Torrens Island A 1	120	October 2021
	Torrens Island A 2	120	October 2020
	Torrens Island A 3	120	October 2022
	Torrens Island A 4	120	October 2020
	Osborne	180	January 2024

A4.3.2 Supply adequacy assessment

Figure 67 shows forecast USE outcomes for South Australia.

Figure 67 Forecast USE outcomes, South Australia

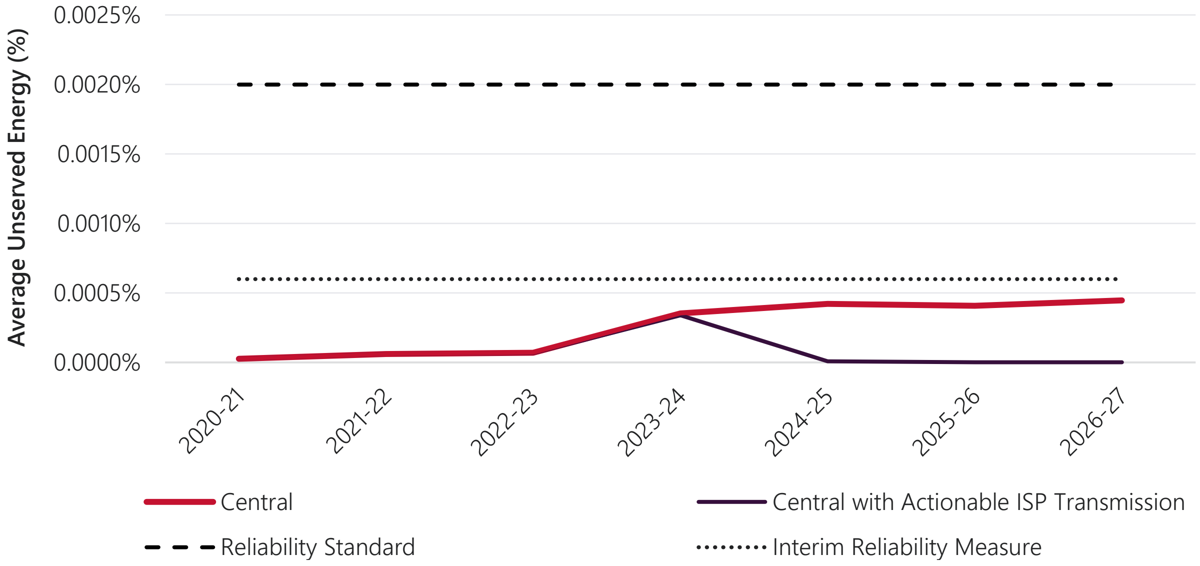


Impact of actionable ISP transmission augmentations

The inclusion of Project EnergyConnect reduces expected USE in South Australia from 2024-25 onwards, with the increase in import capability more than sufficient to offset the impact of Osborne Power Station's closure.

Figure 68 shows the Central scenario USE outcomes compared with the Actionable ISP Projects sensitivity, where it is evident that the additional imports provided by Project EnergyConnect are projected to result in USE returning to negligible levels.

Figure 68 Impact of actionable ISP transmission augmentations, South Australia



A4.4 Tasmania

Key insights

- No committed projects in Tasmania.
- The 2020 ESOO projects no USE in any scenario in Tasmania, which has a significant surplus in generation capacity, despite supply being limited at times due to reservoir storage levels. The resilience of the Tasmanian electricity supply to rainfall conditions is further detailed in AEMO's Energy Adequacy Assessment Projection (EAAP)[138].

A4.4.1 Generation and storage changes

There are currently no committed projects expected to commence commercial operations in Tasmania during the ESOO modelling horizon.

[138] Further information on the EAAP is available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/energy-adequacy-assessment-projection-eaap.

A4.5 Victoria

Key insights

- Forecast reliability for the coming summer has improved significantly compared to the forecast for last summer, with expected USE remaining below the IRM.
- The key drivers of reliability improvements in Victoria are new VRE capacity, lower peak demand forecasts, and minor generator upgrades. These factors more than offset the lower level of reliability forecast for the thermal generation fleet. Risks of load shedding remain, particularly if peak demands reach 10% POE levels and coincide with either low VRE generation or with long-duration outages, as experienced at times in recent years.
- There is a large amount of VRE due to be commissioned in Victoria in late 2020. Any delays to the commissioning of projects would increase the likelihood of load shedding this summer.
- Although the impacts are not as large as in New South Wales, the ISP augmentations are expected to reduce forecast USE in Victoria, primarily attributable to Project EnergyConnect.

A4.5.1 Generation and storage changes

There are 1,771 MW of nameplate capacity committed to come online in Victoria from VRE projects, and an additional 927 MW of VRE projects undergoing commissioning (see July 2020 Generation Information page).

There is 372 MW of brown coal scheduled to retire in the final year of the modelling period (the first unit of Yallourn).

The key generation entry and exit assumptions are summarised in Table 28.

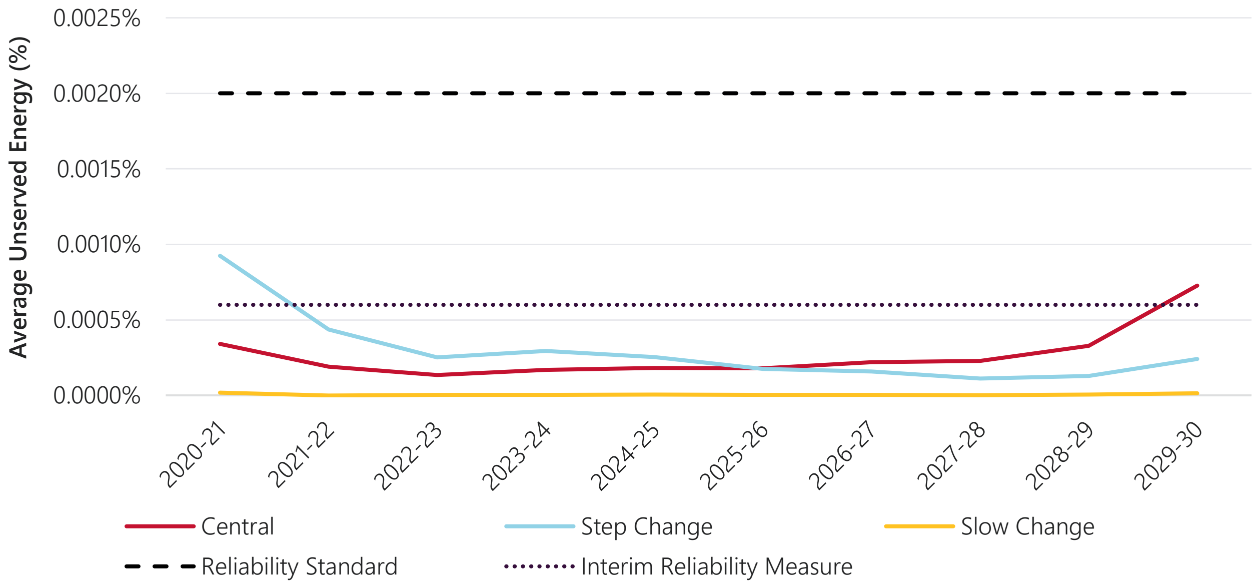
Table 28 New committed generation and retirements in Victoria

	Project	Capacity (MW)	Commercial operation or retirement date
Large-scale solar	Cohuna Solar Farm	31	April 2021
	Glenrowan Solar Farm	132	April 2021
	Kiamal Solar Farm	200	November 2020
	Winton Solar Farm	85	March 2021
	Yatpool Solar Farm	94	September 2020
Wind	Berrybank Wind Farm	181	October 2020
	Bulgana Green Power Hub Wind Farm	204	December 2020
	Moorabool Wind Farm	312	December 2020
	Stockyard Hill Wind Farm	532	December 2020
Large-scale batteries	Bulgana Green Power Hub BESS	20	November 2020
Generator upgrades	Loy Yang B unit 1	45	November 2020
Brown coal retirement	Yallourn W unit 1	372	January 2030

A4.5.2 Supply adequacy assessment

Figure 69 shows expected USE for the Central, Step Change, and Slow Change scenarios.

Figure 69 Forecast USE outcomes, Victoria



The expected USE in Victoria this summer has declined substantially relative to the forecast of last summer in the 2019 ESOO. Section 4 explores in detail both the causes of this reduction and the risks this summer. Forecast USE is above the IRM in the Step Change scenario in 2020-21 due to a higher assumption for peak demand.

In the Central scenario, USE is forecast to be flat and below both the reliability standard and the IRM for most of the forecasting horizon. Only in the final year of the horizon is the expected USE is above the IRM, primarily due to the expected retirement of one of the Yallourn Power Station units and the retirement of Vales Point Power Station in New South Wales. Although the forecast USE is relatively low, it rises steadily over the modelling horizon due to increasing forced outage rates of the coal-fired generators, with no new supply yet committed to commence operation after April 2021. Maximum demand in Victoria is forecast to remain relatively constant over this period, and to increase towards the end of the period as EV uptake is projected to grow.

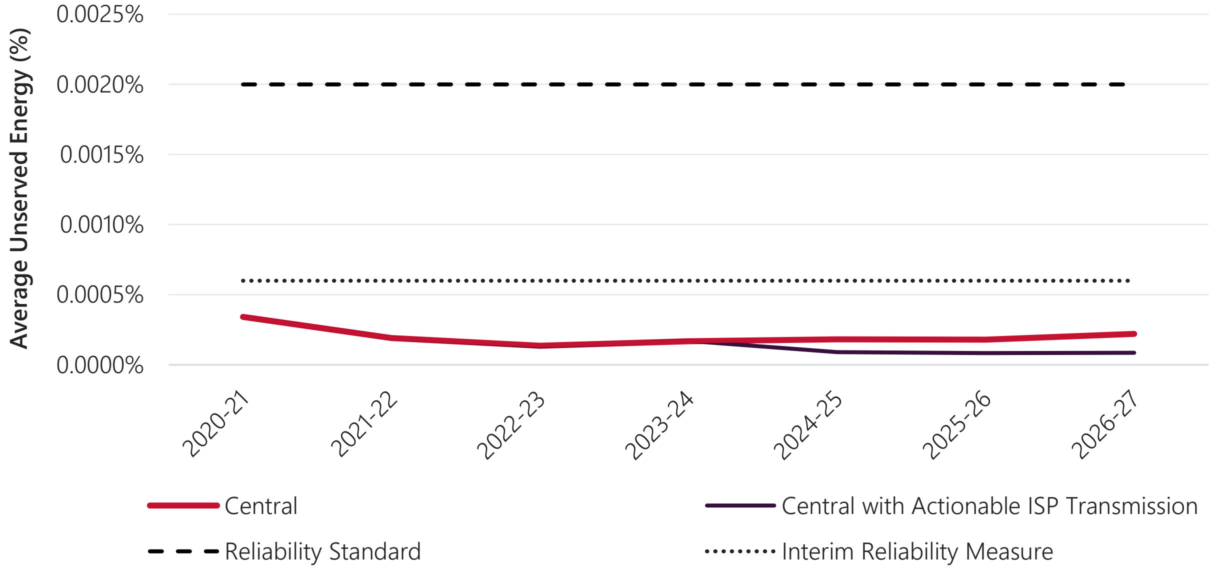
Despite higher peak demand, the Step Change scenario has lower forecast USE than the Central scenario in later years, due to a higher assumed uptake of VPP which acts to limit the risk of USE by discharging effectively during periods of high demand. Expected USE remains negligible in all years in the Slow Change scenario due to lower peak demand assumptions.

Impact of actionable ISP transmission augmentations

Figure 70 shows that the impact of the actionable augmentations identified by the ISP in Victoria is forecast to be relatively minor.

Under the Actionable ISP Projects sensitivity, the delivery of Project EnergyConnect is projected to lead to a reduction in forecast USE in Victoria, although not to the same extent as observed in South Australia. The VNI Minor augmentation provides some reliability benefits in Victoria, but the components of this augmentation that deliver reliability benefits in Victoria are already included in the Central scenario.

Figure 70 Impact of actionable ISP transmission augmentations, Victoria



A5. Power system security analysis

This Appendix outlines more detailed results for the analysis presented in Section 7, on the challenges and opportunities of low operational demand.

A5.1 Unintended disconnection of distributed PV

As outlined in Section 7.2, AEMO now has considerable evidence that many distributed PV systems disconnect in response to short duration voltage dips caused by faults on the network. This has been demonstrated consistently across laboratory testing of distributed PV inverters, field measurements from thousands of individual distributed PV inverters during a series of voltage disturbances occurring during 2016 to 2020, and high speed monitoring at selected load feeders in the distribution network. AEMO used these observations to develop and calibrate dynamic power system models of distributed PV and load that reproduce their undervoltage disconnection behaviour in PSS®E.

AEMO has conducted preliminary analysis of the impact of transmission faults in key locations in Victoria, Queensland and New South Wales, with initial findings summarised in Table 29. AEMO is continuing to refine the load and DER models used for this assessment, and is exploring power system behaviour over a wider range of operational periods and conditions. These results will therefore be further refined over time.

Table 29 Summary of preliminary findings on distributed PV and load disconnection during low demand periods

	Influential fault locations	Disconnection of regional distributed PV	Disconnection of regional load
South Australia	Adelaide metropolitan 275kV network (eg. Pelican Point, Torrens Island)	39-43 %	14-25 %
Queensland	Brisbane metropolitan 275 kV network, or Tarong, Tarong North, Swanbank E	32-36 %	9-16 %
Queensland	Wivenhoe	30-33 %	9-15 %
Victoria	Loy Yang A or B	40-45 %	12-22 %
Victoria	Loy Yang A or B with de-energisation of Hazelwood – South Morang Line 1	35-38 %	12-22 %
Victoria	Melbourne metropolitan 500 kV network (Sydenham – South Morang)	43-47 %	12-21 %
New South Wales	Sydney metropolitan 330 kV network, or Liddell, Vales Point	19-24%	8-17%

Note. Percentage disconnection values are based upon power system snapshots representative of daytime periods with low demand and high PV generation (31 Jan 2020). Sensitivities with higher distributed PV generation were also explored. Outcomes with different combinations of generating units operating or other variations to system conditions are under exploration.

Table 30 shows a forward projection of the net distributed PV disconnection associated with the most severe credible fault, during the most severe period (with high levels of distributed PV operating). The range of uncertainty is based on the uncertainty in the load and DER models utilised for this analysis, estimated based upon comparison of a selection of validation studies.

Table 30 Net distributed PV disconnection (in MW) for most severe credible fault during the most severe period (central estimate and uncertainty range)

	Calendar year	Central scenario (90% POE)			Central Downside, High DER sensitivity (90% POE)		
		SA	VIC	QLD	SA	VIC	QLD
Historical	2019	110 (30-210)	-	0 (0-90)	110 (30-210)	-	0 (0-90)
Forecast	2020	170 (80-290)	0 (0-170)	0 (0-260)	230 (150-360)	0 (0-220)	20 (0-290)
	2021	*210 (130-330)*	20 (0-340)	20 (0-330)	*230 (150-360)*	90 (0-380)	50 (0-350)
	2022	*240 (160-370)*	170 (0-480)	80 (0-390)	*270 (180-390)*	250 (20-560)	130 (0-440)
	2023	*260 (180-390)*	*310 (90-670)*	*120 (0-440)*	*300 (220-430)*	*410 (180-760)*	*220 (0-530)*
	2024	*290 (200-420)*	*460 (230-790)*	*160 (0-490)*	*340 (260-480)*	*580 (350-920)*	*300 (50-620)*
	2025	*310 (220-440)*	*600 (370-940)*	*200 (0-530)*	*390 (300-530)*	*740 (500-1,100)*	*380 (140-730)*

Note. Values shown in grey italics (beyond 2021 in South Australia and 2023 in Victoria or Queensland), indicate that if proposed mitigation mechanisms summarised below are implemented this should improve DER disturbance ride-through capabilities and prevent further growth in distributed PV contingency sizes beyond that date. This analysis has not included potential for replacement of aging stock, or potential for firmware updates to improve disturbance ride-through behaviour, which may reduce contingency sizes. Values for Victoria are based on a fault at Loy Yang A or B, with de-energisation of Hazelwood – South Morang Line 1 whenever load is below the thresholds outlined in Section 7.3.2, accounting for commissioning of new reactors.

Table 31 shows the percentage of the year where a fault at critical locations could increase the size of the largest generation contingency. This is indicative of the proportion of periods where intervention of some kind may be required. South Australia shows the largest number of periods affected at present, and in the absence of intervention periods affected in Victoria and Queensland are likely to rapidly escalate.

Table 31 Percentage of year that net distributed PV contingency is positive (net loss of generation)

	Calendar year	Central Scenario (90% POE)			Central Downside, High DER Scenario (90% POE)		
		SA	VIC	QLD	SA	VIC	QLD
Historical	2019	3 %	0 %	0 %	3 %	-	0 %
Forecast	2020	12 %	0 %	0 %	13 %	0 %	0 %
	2021	*13 %*	<1 %	<1 %	*15 %*	<1%	1 %
	2022	*16 %*	2 %	1 %	*18 %*	3 %	3 %
	2023	*17 %*	*6 %*	*2 %*	*19 %*	*9 %*	*5 %*
	2024	*19 %*	*10 %*	*4 %*	*21 %*	*13 %*	*8 %*
	2025	*20 %*	*14 %*	*5 %*	*23 %*	*18 %*	*11 %*

Note. Values are shown in grey (beyond 2021 in South Australia and 2023 in Victoria or Queensland), indicating that if proposed mitigation mechanisms are implemented this should improve DER disturbance ride-through capabilities and prevent further growth in distributed PV contingency sizes beyond that date.

A5.2 Management options in South Australia

As outlined in Section 7.3.1, there is an urgent need to establish emergency PV shedding capabilities in South Australia. Figure 71 shows the capacity of new emergency PV shedding capability projected to be required in each year, based on the levels of operational demand required to operate a secure island. Around 300 MW to 400 MW of new PV shedding capacity would ideally be available by spring 2020, and emergency PV shedding capabilities are required for almost all new entrant distributed PV capacity installed beyond that date.

SAPN is proceeding with introduction of flexible export capability as part of its regulatory determination for 2020-25, and AEMO strongly supports this program to facilitate distribution management and future DER market engagement. SAPN has advised that the earliest date when these capabilities could come to fruition at scale is 2022 to 2023; stop-gap measures will be required before this time.

AEMO and SAPN have identified the following two measures that can be introduced rapidly at scale, and meet the technical requirements:

- **Smart meter PV shedding** – upon installation of a new PV system, customers typically also install a smart meter, which has all of the required capability to shed PV, as long as the PV is installed on a controllable circuit (separate from the customer's load). This means that with some minor changes to meter specifications, smart meter functionality may provide emergency PV shedding capabilities with minimal additional cost, when applied to new installations. AEMO is pursuing this in collaboration with Metering Coordinators and the South Australian Government[139].
- **Enhanced voltage management** – SAPN has identified that introducing dynamic fine-grained voltage control capability would improve distribution voltage management and reduce customer impacts related to high voltages. As a side benefit, this also introduces the capability to improve system security via the ability to induce a temporary slight increase in voltages to cause a controlled shedding of distributed PV. SAPN's initial trials of this capability indicate that it is effective, safe, and has minimal customer impact. This approach also has the significant benefit of enabling emergency PV shedding capability for a proportion of legacy PV systems, without the need for costly retrofitting at each individual site.

SAPN is also continuing to require SCADA control for any distributed PV systems exceeding 200 kW export, and is working to streamline the real-time management of these systems.

Due to the large quantity of emergency PV shedding response required by spring 2020 (as shown in Figure 71), AEMO is also exploring the option of selectively shedding whole customers that are exporting PV generation, via smart meter de-energisation. Preliminary investigation suggests this can be implemented relatively quickly at existing legacy sites, with minimal upfront cost, and would deliver a large PV shedding benefit. However, it would involve de-energising customers' load, as well as their PV systems, and therefore would be reserved as a last resort, emergency measure, only enabled when essential for system security, and after all other measures have been exhausted. This approach is preferable to de-energisation of whole feeders that are exporting into the grid, since many fewer customers would be interrupted to achieve the same benefit for power system security. With successful implementation of the other approaches discussed, it should not be necessary to enable this method beyond spring 2020.

As shown in Figure 71, it is estimated that the combined contribution of these approaches can meet the identified emergency PV shedding requirements in South Australia, if implemented promptly.

Project EnergyConnect and improvements to DER performance standards and compliance mechanisms will also assist with mitigating the identified risks, by reducing the need for additional frequency control services.

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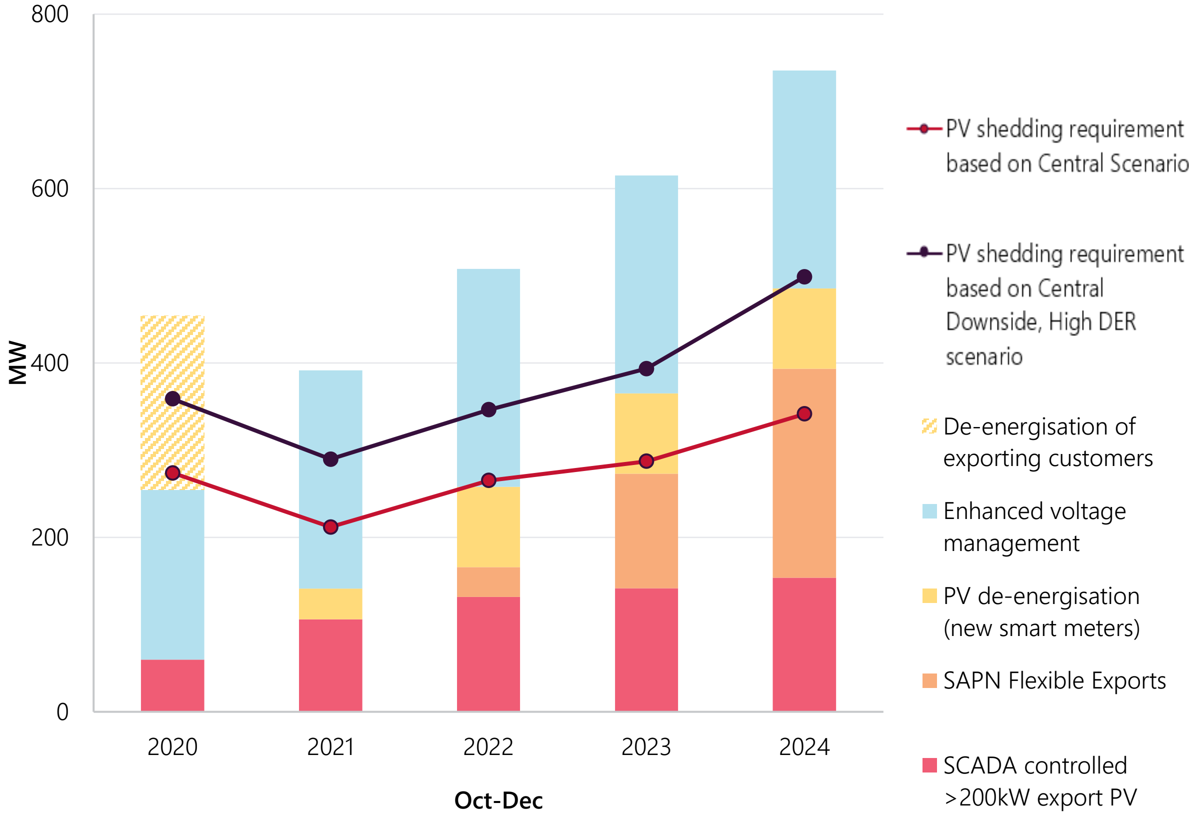
[139] Government of South Australia, Department for Energy and Mining, Consultation on the Proposed Smart Meter Minimum Technical Standards in South Australia, at http://www.energymining.sa.gov.au/__data/assets/pdf_file/0010/364663/Attachment_4_Consultation_on_the_Proposed_Smart_Meters_in_South_Australia.pdf.

Figure 71 Emergency PV shedding capacity required in South Australia with identified options (90% POE minimum demand)



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

Measures and abbreviations

Units of measure

Abbreviation	Full name
GW	Gigawatt
GWh	Gigawatt hour/s
kV	Kilovolt
kW	Kilowatt
MW	Megawatt
MWh	Megawatt hour/s
TWh	Terawatt hour/s

Abbreviations

Abbreviation	Full name
ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
BoM	Bureau of Meteorology
CCGT	Closed-cycle gas turbine
CER	Clean Energy Regulator
CSG	Coal seam gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DER	Distributed energy resources
DSP	Demand side participation
EAAP	Energy Adequacy Assessment Projection
EE	Energy efficiency
ENA	Energy Networks Australia

Abbreviation	Full name
ESB	Energy Security Board
ESS	New South Wales Energy Savings Scheme
ESOO	Electricity Statement of Opportunities
EV	Electric vehicle
FRG	Forecasting Reference Group
GSP	Gross State Product
HIA	Housing Industry Association
ISP	Integrated System Plan
LIL	Large Industrial Load
MT PASA	Medium Term Projected Assessment of System Adequacy
MTTR	Mean time to repair
NEM	National Electricity Market
NER	National Electricity Rules
POE	Probability of exceedance
PV	Photovoltaic
PVNSG	PV non-scheduled generation
QNI	Queensland New South Wales Interconnector
RCP	Representative Concentration Pathway
RERT	Reliability and Emergency Reserve Trader
REZ	Renewable energy zone
RIT-T	Regulatory investment test for transmission
RRO	Retailer Reliability Obligation
USE	Unserved energy
VNI	Victoria New South Wales Interconnector
VPP	Virtual power plant
VRE	Variable renewable energy
VRET	Victorian Renewable Energy Target

Glossary

Term	Definition
committed and committed* projects	Generation that is considered to be proceeding under AEMO's commitment criteria, defined under the Background information tab on the Generation Information page at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.
distributed PV	Includes rooftop systems and other smaller non-scheduled PV capacity.
electrical energy	Average electrical power over a time period, multiplied by the length of the time period.
Co-ordinated (EV) charging	Charging of electric vehicles is coordinated to be optimised for prevailing market and/or demand conditions, for example as part of a virtual power plant (VPP).
Convenience (EV) charging	Charging of electric vehicles that are assumed to have no incentive to charge at specific times.
electrical power	Instantaneous rate at which electrical energy is consumed, generated, or transmitted.
Firm capacity	Firm capacity can be dispatched to maintain balance on the power grid. It can include generation on the grid, storage, demand resources behind the meter, flexible demand, or flexible network capability.
generating capacity	Amount of capacity (in megawatts (MW)) available for generation.
generating unit	Power stations may be broken down into separate components known as generating units, and may be considered separately in terms (for example) of dispatch, withdrawal, and maintenance.
installed capacity	The generating capacity (in megawatts (MW)) of (for example) a single generating unit, a number of generating units of a particular type or in a particular area, or all the generating units in a region. Distributed PV installed capacity is the total amount of cumulative distributed PV capacity installed at any given time.
maximum demand (MD)	Highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season, or year) either at a connection point, or simultaneously at a defined set of connection points.
mothballed	A generation unit that has been withdrawn from operation but may return to service at some future point.
non-scheduled generation	Generation by a generating unit that is not scheduled by AEMO as part of the central dispatch process, and which has been classified as a non-scheduled generating unit in accordance with Chapter 2 of the NER.
operational consumption	The electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled generating units, less the electrical energy supplied by small non-scheduled generation.
reliability standard	The reliability standard for generation and inter-regional transmission elements in the NEM is defined in NER 3.9.3C as a maximum expected unserved energy (USE) in a region of 0.002% of the total energy demanded in that region for a given financial year.
unserved energy	Unserved energy is the amount of energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of consumer supply). The USE that contributes to the reliability standard excludes unserved energy resulting from multiple or non-credible generation and transmission events, network outages not associated with inter regional flows, or industrial action (NER 3.9.3C(b)).