Appendix 4. System operability

June 2022

Appendix to 2022 ISP for the National Electricity Market

Important notice

Purpose

This is Appendix 4 to the 2022 *Integrated System Plan* (ISP), available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.

AEMO publishes the 2022 ISP under the National Electricity Rules. This publication has been prepared by AEMO using information available at 15 October 2021 (for Draft 2022 ISP modelling) and 19 May 2022 (for 2022 ISP modelling). AEMO has acknowledged throughout the document where modelling has been updated to reflect the latest inputs and assumptions. Information made available after these dates has been included in this publication where practical.

Disclaimer

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Version control

Version	Release date	Changes
1.0	30/6/2022	Initial release.

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

ISP Appendices

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A4.1 Introduction

This appendix supports the 2022 ISP by providing deeper insights into the reliability and operability of development paths identified in the ISP. It reports on the results and insights from market modelling regarding VRE penetration, coal operation, storage behaviour, and gas generation.

This relies on AEMO's short-term time sequential model, which forecasts dispatch of the electricity market on a 30-minute basis; see AEMO's *ISP Methodology*[1]. This model enables a granular assessment of the dynamics and challenges that may emerge as the power system transitions.

The appendix focuses on the most-likely *Step Change* scenario, unless otherwise stated, and on the reliability aspects of operability. Other elements of system operability – such as system security and system services – are covered in Appendix 7, which focuses mainly on system strength and inertia system services. This appendix does not consider the requirements for effective frequency and voltage control in the power system.

This appendix sets out:

- A4.2.1: Changes to the demand profile due to rising electrification and DER.
- A4.2.2: The increased penetration of VRE and the rising need for flexibility.
- A4.2.3: The implications of these changes for flexibility.
- A4.2.4: The implications of these changes for system reliability
- A4.2.5: The role of storage in ensuring reliability and maximising use of VRE.
- A4.2.6: Potential curtailment of VRE as consequence of an economic balance between generation, storage, and transmission capacity.
- A4.2.7: Implications on the operation of coal-fired generation.
- A4.2.8: The ongoing role of gas generation in firming the system.

[1] At https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/isp-methodology.

A4.2 NEM-wide operability outlook

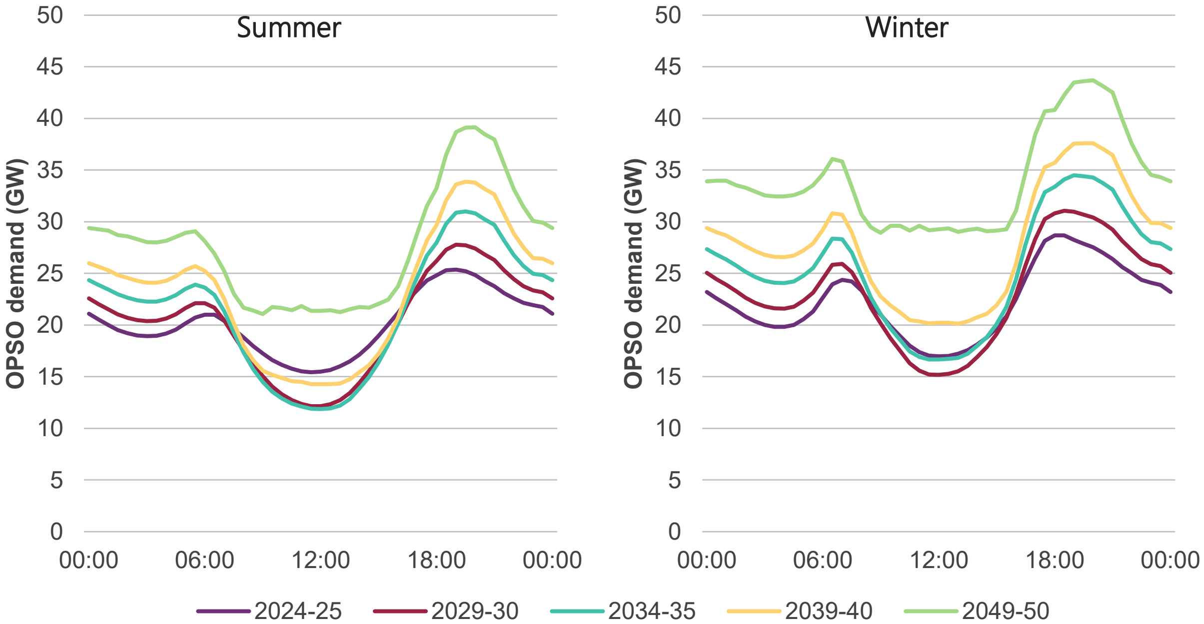
A4.2.1 Changing demand profile due to electrification and DER

Consumer behaviour is forecast to change compared to recent history, driven primarily by increasing electrification and continuous uptake of DER. This will see consumption patterns evolve over time, impacting the requirements on the power system to deliver to the needs of consumers.

One of the main drivers of the changing shape of demand is the function DER devices provide to consumers, specifically distributed PV, batteries and EVs. Distributed PV has reduced, and will continue to reduce, the energy drawn from the transmission system during the day. The emergence of battery storages at consumer premises will supplement this local generation, enabling behind-the-meter shifting of daytime surplus energy to discharge during evenings and overnight (although they not expected to provide complete energy independence for battery-installed consumers). EVs likewise may significantly impact the consumer load shape. Vehicle charging could potentially become a significant evening load if charging follows a 'convenience' mode, or may ease the integration (and increase the value) of consumer excess local generation if charged during daylight hours.

These dynamics are illustrated in Figure 1, showing the forecast time-of-day average operational sent-out demand (OPSO) profile[2] for summer and winter seasons across future years, assuming a degree of coordination of DER devices, including a growing role for VPPs for batteries and V2G services for EVs. While the daily pattern is projected to be very similar between the two seasons, winter demand rises faster, driven by lower solar output and increasing electrification of heating loads which will add to consumption throughout the day.

Figure 1 Forecast NEM time-of-day average OPSO demand, 2024-25 to 2049-50, *Step Change*, comparing seasonal demand profiles



[2] The electricity consumption profiles presented in this section exclude electricity consumed in the production of hydrogen.

As consumers' energy needs evolve, particularly during daylight hours, minimum operational demand in *Step Change* is expected to rapidly decline in all regions, with South Australia forecast to reach negative minimums in the short term, driven by strong DER growth. These low minimum levels will create power system operability issues, particularly relating to system security (see Appendix 7 for more details).

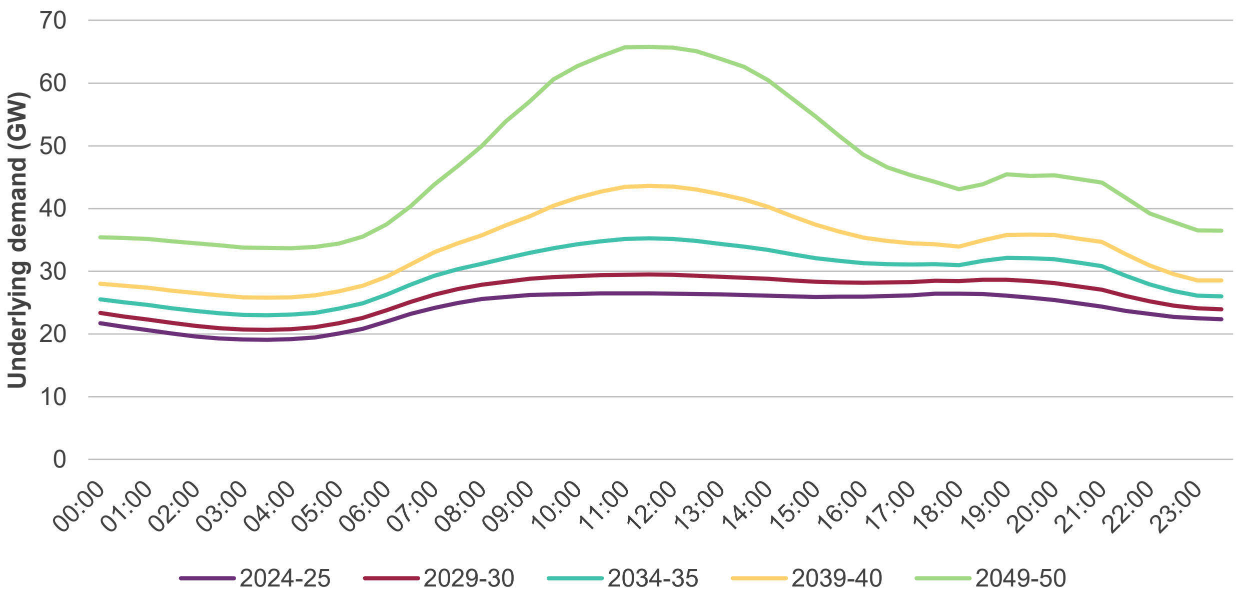
In addition to declining minimum active demand (megawatts [MW]), all regions in the NEM are currently also experiencing a change in the reactive power profile (megavolt amperes reactive [MVAr]) which has implications for future voltage control and stability. This trend is being driven by both:

- A steady and continual changeover of devices to more efficient devices which use power electronics such as switched mode supplies.
- Increasing applications of low voltage cables for new housing estates.

The effects are more prevalent and observable in locations with significant residential and commercial loads. This is changing the power factor of loads. As DER and energy efficiency increase, not only is active demand decreasing, but reactive demand is also decreasing. This is a reinforcing effect that leads to further voltage challenges as the system load decreases.

Figure 2 shows the forecast average time-of-day profile of underlying demand[3] in *Step Change*. It shows the scale of energy growth forecast over the next 30 years in response to growing population trends, electrification of other sectoral energy loads, and also the opportunity for behavioural and technological change to increase daytime loads, including those associated with home batteries following a daily charge and discharge cycle.

Figure 2 Forecast NEM annual time-of-day average underlying demand profiles, 2024-25 to 2049-50, *Step Change*



The emerging load associated with EV charging further increases the complexity of operating the power system. EV charging may be flexible depending on the availability of, and incentives to use, charging infrastructure during the day to absorb excess distributed PV generation. An additional complexity for EV

[3] In this appendix, underlying demand includes transmission and distribution losses, in addition to demand met by local generation.

charging is that the load is not locationally static in the grid. It is a mobile load, and EV owners could easily charge their vehicles at different locations at different times of the day (for example, at home overnight, or in car parks during the day).

The *Step Change* scenario assumes increasingly engaged consumers charge their vehicles in the middle of the day, incentivised by market-driven price signals and enabled through appropriate charging infrastructure installations. Further, the modelling assumed that the majority of EV charging will be coordinated, but with some charging adding to demand in the evening and overnight, creating a more pronounced evening peak.

A4.2.2 Renewable energy penetration

In all scenarios modelled in this ISP, the NEM is forecast to continue its significant transformation towards increased penetration of renewable energy, including world-leading levels of VRE output (utility-scale and DER) measured as a percentage of annual generation as well as instantaneous generation.

As the penetration of utility-scale wind and solar and DER increases, so does the complexity of managing the operation of these variable resources. Furthermore, the need for complementary dispatchable resources and grid services that ensure the grid is both reliable and secure becomes more critical than ever.

A key focus and priority of AEMO is managing the NEM as it transitions towards high instantaneous penetration of renewable generation, in particular preparing the power system to be capable of operating securely through periods of 100% instantaneous renewable energy within the next five years; that is, periods where all electricity dispatched to meet demand is produced by renewable sources.

Figure 3 shows the forecast NEM-wide annual share of total generation from renewable sources[4] and renewable resource potential[5] (that is, periods when renewables could provide all of the NEM generation based on their availability) from 2025 to 2050 in *Step Change*.

The renewable share of annual electricity generation is projected to rise from approximately 33% in 2021-22 to approximately 98% by 2050. There are also projected to be times where all NEM generation could be produced from renewables, with increasing frequency across the forecast horizon. By 2025, there could be sufficient renewable generation potential to generate 100% of grid demand during a small number of dispatch periods, equivalent to half a day per year.

At times the renewable resource potential could exceed the instantaneous electricity demand, with storage helping absorb the excess. By 2030, all generation could be sourced from renewable energy for 7% of the year. By 2040, the 100% threshold could be achieved for over a third of the year, and by 2050 it could rise to almost two-thirds[6].

The share of potential resource that is actually dispatched at any time depends on a range of technical, price and other market factors. Engineering the power system to operate securely with high level of renewable generation penetration will be critical. Appendix 7 discusses in more detail the power system security outlook

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[4] This measure is calculated on an annual basis using the NEM share of total generation. Renewable generation includes utility-scale wind and solar, distributed PV, hydro generation, biomass, utility-scale and distributed storage. Excludes storage load and hydro pumping.

[5] This measure is calculated on a half-hourly basis using the NEM share of total generation. The definition of renewable generation is consistent with the annual share of total generation except for VRE. The share of utility-scale wind and distributed PV is based on resource availability rather than actual energy dispatched and therefore is to be interpreted as potential (theoretical) VRE production.

[6] Indicative figures based on a sample historical weather pattern.

and some of the operational challenges and potential solutions associated with increasing renewable penetration.

Figure 3 Forecast NEM annual share of renewable generation and 100% resource potential, 2024-25 to 2049-50, *Step Change*

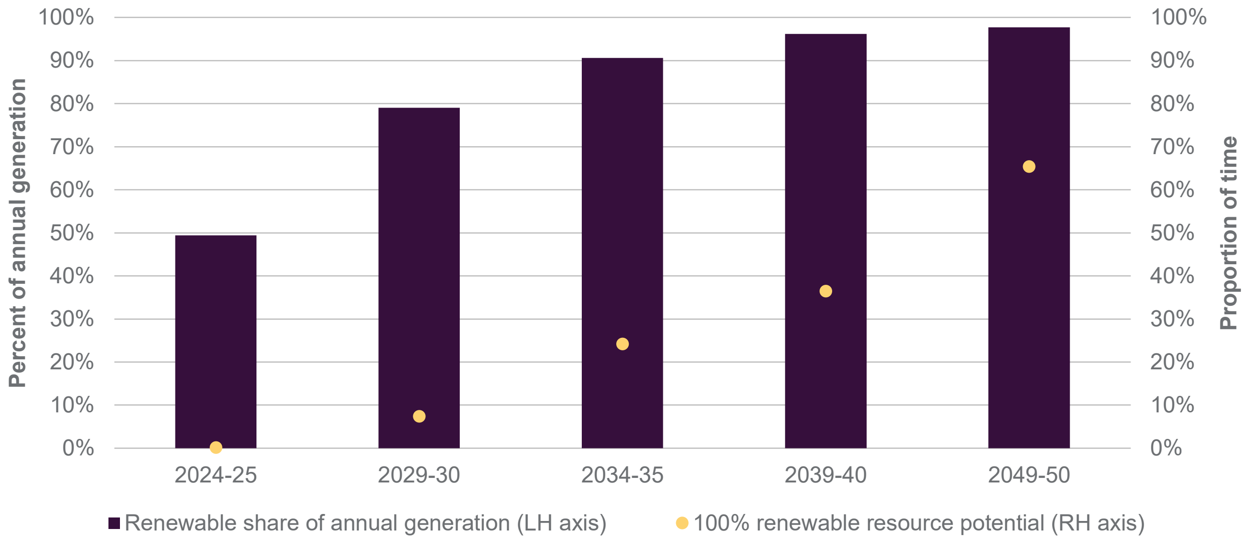
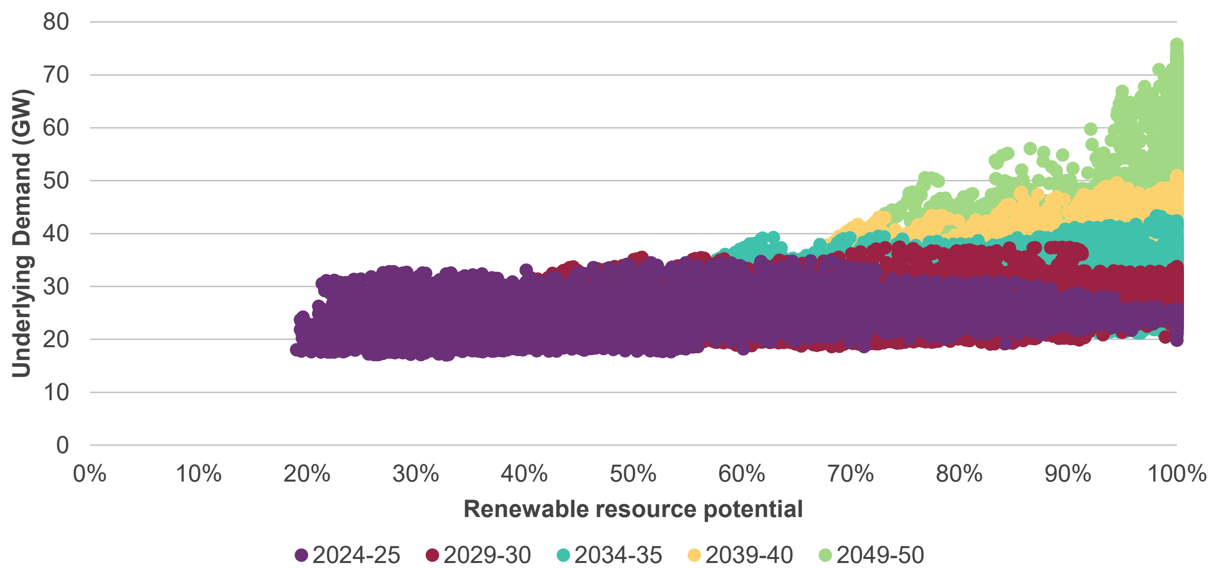


Figure 4 below shows how the renewable resource potential is projected to evolve over time and relative to underlying demand in *Step Change*.

In 2024-25, renewable resource potential is forecast to range from as little as 19% to as high as 100%. Periods of low demand are forecast to see the highest potential – up to 100% in some periods. As the system transitions, the range will narrow and periods of 100% potential may occur more frequently, as well as occurring during periods of elevated demand when thermal generation has traditionally been relied on to provide the bulk of the energy needed.

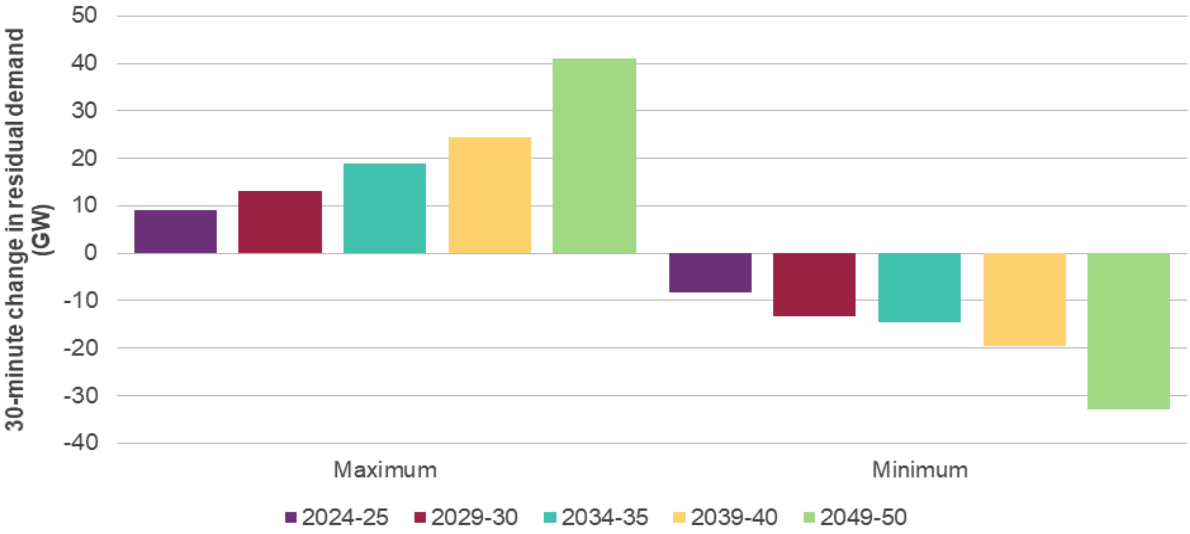
Figure 4 Forecast renewable resource potential, 2024-25 to 2049-50, calculated for *Step Change*, reference year 2015



A4.2.3 Implications for system flexibility

As the amount of VRE in the NEM continues to increase, levels of residual demand (representing demand net of utility-scale wind and solar and distributed PV) will both decrease and become more variable. Figure 5 below shows the increasing maximum and minimum changes forecast in half-hourly residual demand over a year for *Step Change*.

Figure 5 Forecast maximum and minimum changes in half-hourly residual demand, 2024-25 to 2049-50, *Step Change*



This forecast is an indicator for the level of flexibility required from dispatchable generation and storage. The NEM is projected to experience larger and more frequent residual demand fluctuations over time, both positive and negative, requiring the dispatchable fleet to be more flexible, more frequently.

A possible consequence of having insufficient flexibility in the dispatchable fleet could be the need to curtail VRE leading into or out of periods of rapid residual demand change (for example, curtailing solar as the sun is rising to manage the technical capacity for inflexible units to ramp down their operational output).

Figure 6 and Figure 7 show the forecast evolution of the distribution of half-hourly residual demand changes for the NEM over the course of the day, in 2024-25 and 2039-40 respectively. The periods of greatest change in residual demand are projected to occur at dawn and dusk, reflecting the profile of solar generation. The pattern is expected to become more extreme as the share of capacity of both utility-scale and distributed solar generation grows. While on a NEM level the largest half-hourly changes in residual demand are expected to occur during these periods, individual regions may experience more severe and unexpected variations outside these hours and on a shorter timeframe, primarily driven by the intermittent nature of solar and wind resources.

Figure 6 Forecast time-of-day distribution of half-hourly residual demand changes, 2024-25, *Step Change*

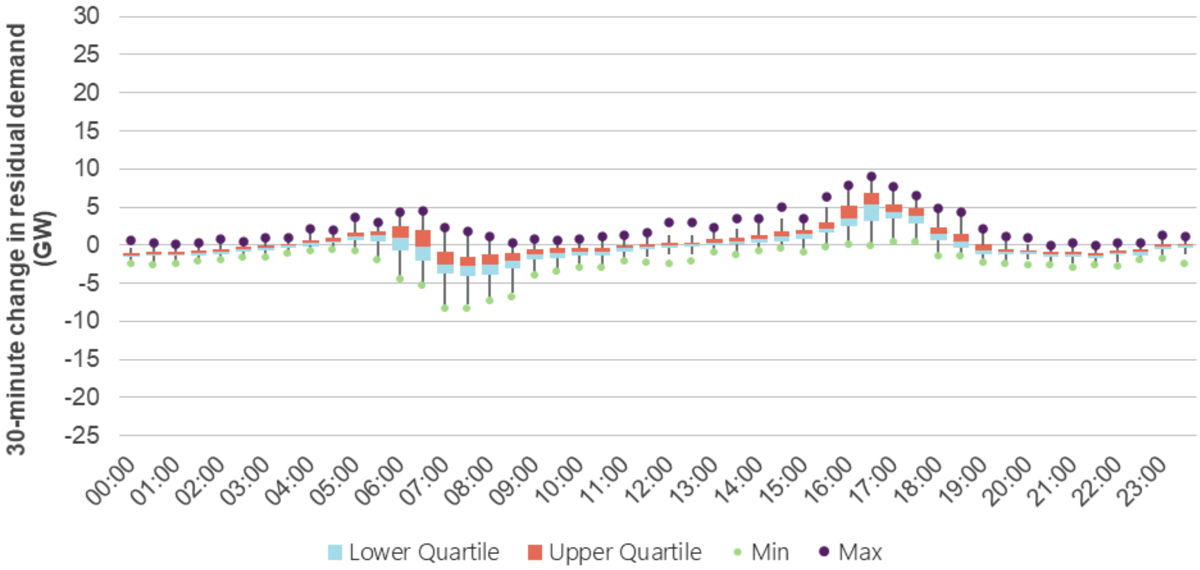
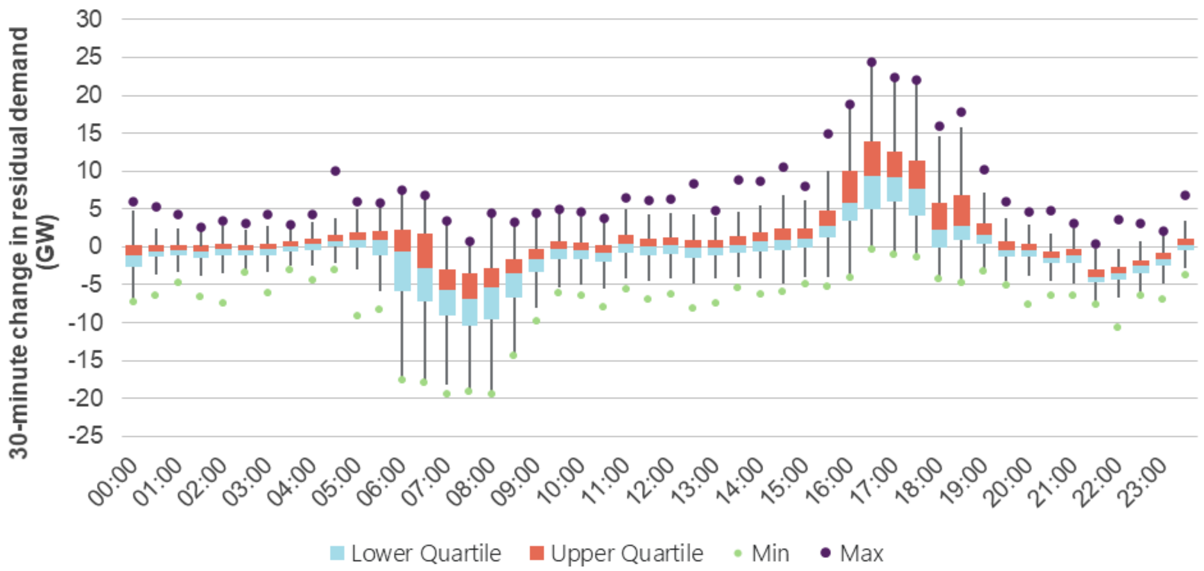


Figure 7 Forecast time-of-day distribution of half-hourly residual demand changes, 2039-40, *Step Change*



This analysis demonstrates that ensuring sufficient flexible system resources are available when needed will become increasingly important, to handle both predictable and unpredictable fluctuations.

Figure 8 shows the projected maximum ramp up capability (gigawatts [GW] per 30-minute period) across the dispatchable generation fleet[7]. While gas generation and hydro resources will continue to provide a significant amount of ramping capacity, all types and depths of storage are forecast to become the primary provider of flexibility in the future NEM.

[7] Ramp-up capability is presented as it is considered it will be most critical to manage sudden reduction in VRE output. Capability estimated for storage assumes starting from a neutral position – neither charging nor discharging.

Figure 8 Forecast maximum ramping capability of dispatchable generation, 2024-25 to 2049-50, *Step Change*

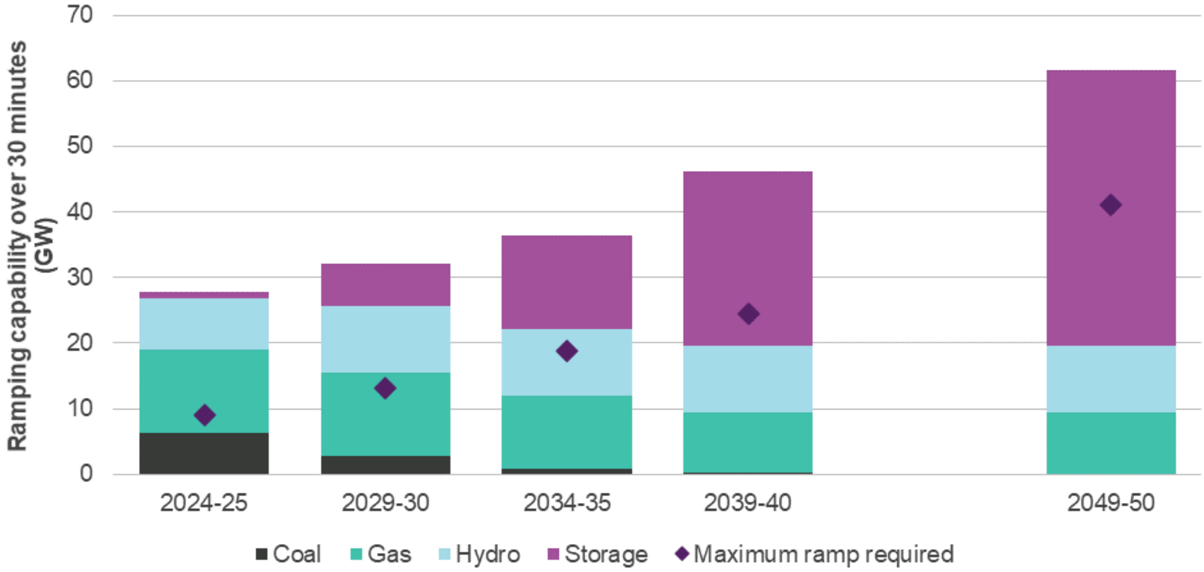


Figure 8 also shows that there is forecast to be sufficient physical ramping capability to meet the highest ramping requirements. However, whether a unit can ramp up and down at a certain time depends on several factors – such as availability, online status, and whether it is already generating at minimum or maximum capacity – and for storage it will depend on the level of available energy in its storage facility at that time. Storage dispatchability will become a critical operational consideration; that is, ensuring storage has sufficient discharge capacity and stored energy available to generate when flexibility up and down is required. Market incentives will need to be present to enable a commercial willingness to operate in this manner to manage the operability of the power system.

It will also be important to have a portfolio of storage technologies to meet longer and higher ramping events which may not be able to be met efficiently by shallow storages. Availability of deeper storages will help minimise the need for alternative dispatchable supplies to operate for grid firming. The need to retain some stored energy across the portfolio of storages (including traditional hydro generators) for challenging weather conditions will also influence the ability and efficiency for deep storage to provide firming capacity where shallow storage cannot. At times, alternative dispatchable resources may therefore be dispatched ahead of deep storage.

This analysis does not consider the operational challenges of maintaining the security of the grid, such as the provision of critical frequency control and voltage control services to support the power system. Appendix 7 and AEMO's Engineering Framework[8] provide more detail regarding the system security and additional engineering requirements for secure operation of the future power system. These considerations will become just as important as the amount of active power (megawatts) to supply the demand. The whole range of system services needed to maintain a secure operating power system will be even more crucial to managing and securing the energy transition.

[8] See https://www.aemo.com.au/initiatives/major-programs/engineering-framework.

A4.2.4 Implications for maintaining reliability

Changing seasonality of reliability risks

The transition to higher renewable energy penetration coupled with thermal generation withdrawals, as well as a changing electricity demand, has significant implications for not just the reliability of the NEM, but also the seasons where reliability risks are most likely to emerge.

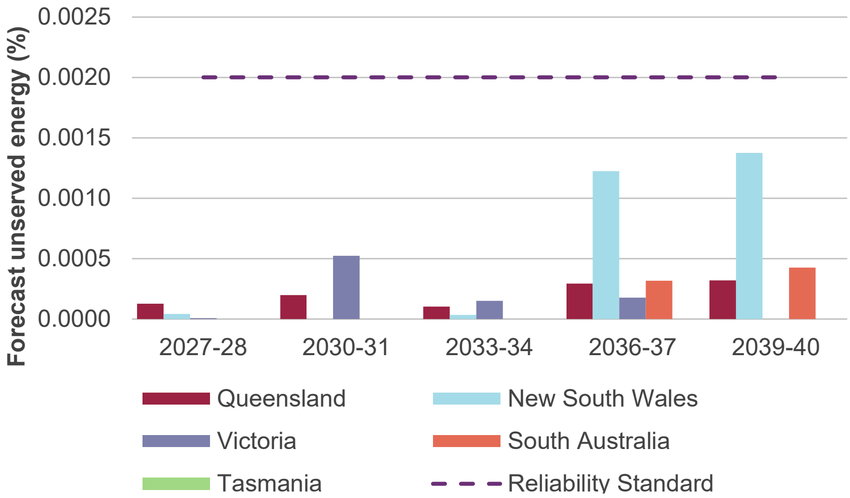
The NEM reliability standard requires that expected unserved energy (USE) in a region is 0.002% or less of the total annual energy needs in that region, or put simply, that at least 99.998% of forecast consumer demand must be met each year[9]. The reliability of the power system relies on the availability of sufficient firm, dispatchable resources to ensure consumer demand can be always met, irrespective of prevailing weather conditions. There is also a key role for the transmission system to enable the sharing of resources more efficiently. Strongly interconnected geographical and technically diverse generation improves the resilience of the power system to fluctuations in localised weather patterns, reducing the scale of firming resources required overall. Storage similarly improves the capacity to share resources, across time rather than geography.

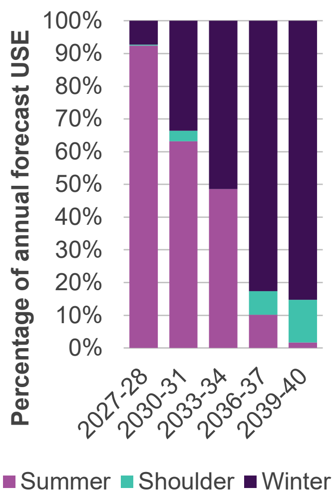
AEMO has assessed the forecast reliability outcomes for the ODP (based on outcomes from the Draft 2022 ISP in *Step Change*). This analysis has been produced using an approach similar to the NEM *Electricity Statement Of Opportunities*[10], accounting for weather variability and Monte Carlo simulated generator outages.

This assessment found that the ISP development opportunities are likely to maintain reliability within the standard for all regions, for all years.

Figure 9 shows the expected USE for selected years of the *Step Change* least-cost development path, as well as the seasonal share of these reliability events.

Figure 9 Forecast expected unserved energy in *Step Change* (left) and seasonal share of NEM-wide reliability events (right), 2027-28 to 2039-40





[9] The ISP optimises development opportunities in generation, storage and transmission investments to meet the NEM Reliability Standard. The current Interim Reliability Measure (requiring forecast USE to not exceed 0.0006% in each region annually) will cease in 2025 and is therefore not an appropriate planning standard to apply across the ISP horizon.

[10] Given the much longer time horizon for the ISP, AEMO has forecast reliability using fewer Monte Carlo simulations of generator availability than deployed for the ESOO.

The seasonal profile of electricity demand is projected to shift with greater electricity consumption forecast for winter than has been observed historically, as traditional winter heating loads (for example) electrify.

The implication of this shift for reliability risks is demonstrated in the right-side figure in Figure 9 above. The chart shows that most of the expected USE in any given year will start occurring outside summer. While hot days in summer are still projected to lead to tight supply-demand conditions, an emerging reliability risk is forecast in winter, characterised by shorter days with less daylight (reducing PV generation) and when wind conditions are calmer (reducing wind generation). Storage management will be increasingly important during winter months to manage these challenging conditions.

The following sections expand on this analysis and present insights form a range of case studies that explore forecast NEM dispatch during long dark and still conditions and outline the benefits of geographical and technological diversity and the importance of storage coordination and optimisation. These sections consider the impact of perfect foresight, as well as testing resilience to coincident extreme weather events and outages affecting transmission and generation.

Operating the power system during long, dark and still conditions

A VRE-dominant power system must be resilient in its ability to provide consumers with the energy they demand during all weather conditions, including when there is minimal or no sunshine or wind for extended periods. The conditions typically can last from a few hours to a few days, although these conditions are most challenging when they persist for multiple days. This is most likely to occur during winter, when solar generation is naturally lower than other seasons due to the shorter days. These conditions, also referred to as renewable droughts, may lead to energy shortages in a system with very high VRE penetration, and may cause reliability risks if insufficient firming is developed to complement the expansion of such variable energy sources.

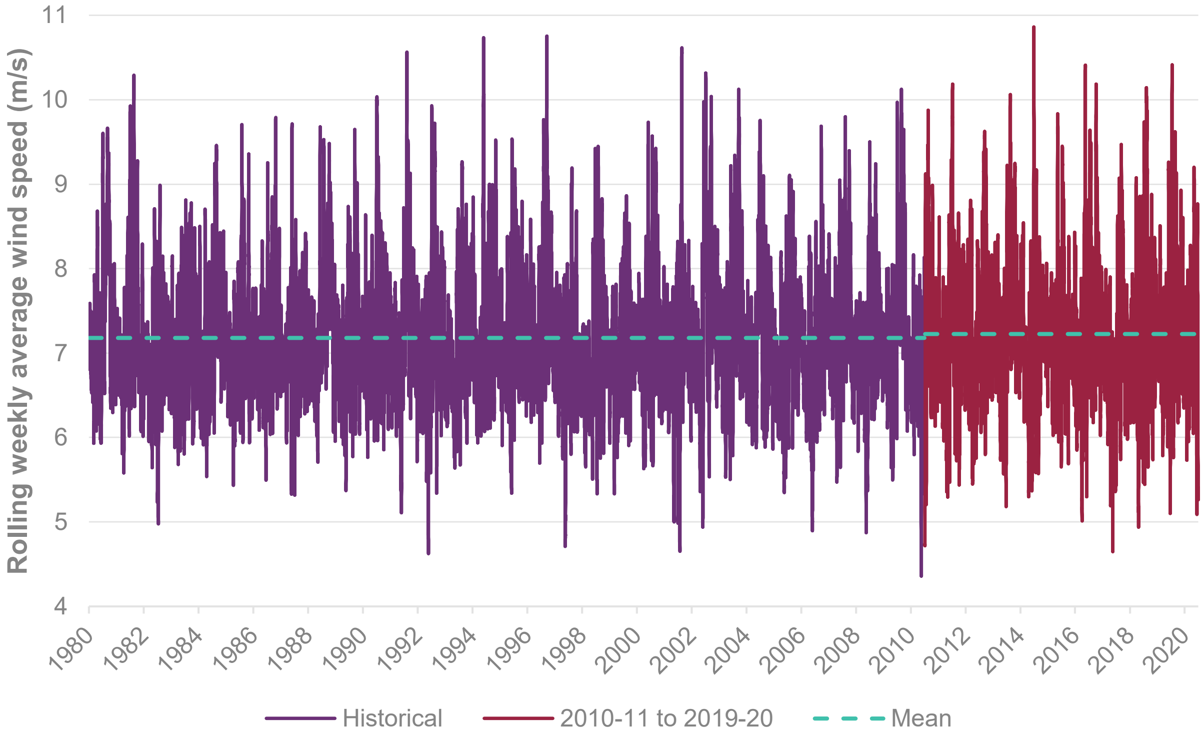
Figure 10 shows the rolling weekly average wind speeds across the NEM between January 1980 and June 2020[11].

AEMO's ISP modelling applies weather patterns from 2010-11 to 2019-20 (the red portion of the figure) and analyses the operability of the power system during future conditions, modelled off the historically observed weather. In comparison to this more recent period, historical average wind speeds back to 1980 show a similar average wind speed and comparable spread of both extremely high and extremely low wind events. While not definitive, it demonstrates that the most recent 10 years are a reasonable representation of the observed weather conditions over the past 40 years.

Given the absence of any significant trend, these more recent historical reference years should provide reasonable coverage for assessing a broad range of potential extreme weather conditions in the future NEM, and the operational impacts of these weather conditions.

[11] Wind speeds from 1980 to 2010 have been derived from data sourced through the Electricity Sector Climate Information (ESCI) project – see https://www.climatechangeinaustralia.gov.au/en/projects/esci/. Wind speeds from 2010 onwards are based on data provided by CSIRO used to produce generation profiles for wind generators.

Figure 10 Historical NEM-wide rolling weekly average wind speeds, 1980-2020



Within the range of modelled weather conditions, and considering the geographic and technological diversity forecast in the ISP, AEMO's analysis observes that these long, 'dark and still' periods tend to be localised, with low risk of a NEM-wide event. Delivering diversity of resources is a strong benefit of the REZ expansions forecast in the ISP; transmission that enables this diversity will improve the reliability of the grid during these conditions.

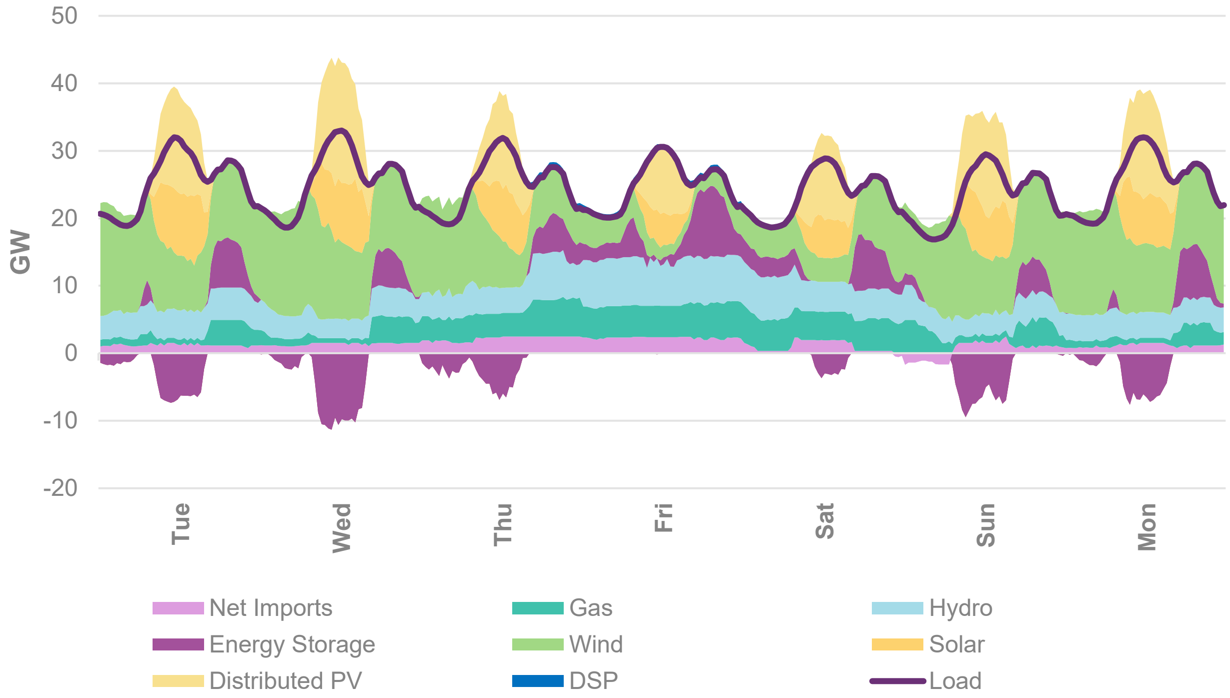
The southern regions of the NEM face more significant risks of long 'dark and still' periods in winter, having lower sun angles and shorter days than regions further north, and higher relative energy demands for heating. Geographical diversity of utility-scale PV in the northern part of the NEM, especially Queensland, will help reduce seasonal variation in solar output. However, the northern regions are not immune to events that significantly limit solar and wind availability in some areas, such as recent severe weather associated with La Niña, summer cyclones and storms.

Low wind will be the most impactful weather condition affecting future energy availability, given the natural predictability of solar performance, and this impact will be most strongly felt in southern NEM regions.

Figure 11 shows the forecast dispatch across New South Wales, Victoria, South Australia and Tasmania for a sample week in June 2040 which is forecast to have high residual demand due to low wind production in these southern regions.

Queensland is excluded from this visualisation. During this sample week, Queensland is forecast to experience stronger renewable energy availability and compensate for low availability in the south. However, its ability to support southern consumers will be limited by the transfer capacity of the transmission system.

Figure 11 Forecast winter operability across southern regions, experiencing a three-day low VRE period, June 2040, *Step Change*



In this sample week:

- Weather conditions are calm, cloudy and cool across these regions, leading to higher heating loads and limited renewable energy availability.
- The most severe renewable energy shortfall is forecast to run from Thursday to Saturday, when there is little wind generation. During this period the system relies heavily on gas and hydro generation, requiring continuous operation at high levels of output over more than a day. Some voluntary customer responses in the form of DSP would be required to maintain reliability.
- Firm hydro resources in New South Wales and Tasmania, accessible through the strengthened transmission network, provide critical support at low cost.
- Queensland has a surplus of VRE and contributes to meeting demand in these regions throughout the week (shown as net imports into the southern regions in the figure).
- Shallow and medium storages fill the troughs and shave the peaks of the demand profile. However, there is not enough renewable energy produced during the worst days (Thursday and Friday) to re-fill these storages. Deep storage will therefore be critical in shifting energy from days prior to the shortage (such as the Tuesday and Wednesday shown).
- Stronger wind conditions in northern New South Wales assist on most days, filling energy storages where it can then be used to meet peak load in the evening.
- Technology diversity also helps manage the risks associated with these conditions, with wind and solar generators at times providing complementary generating patterns across the week.

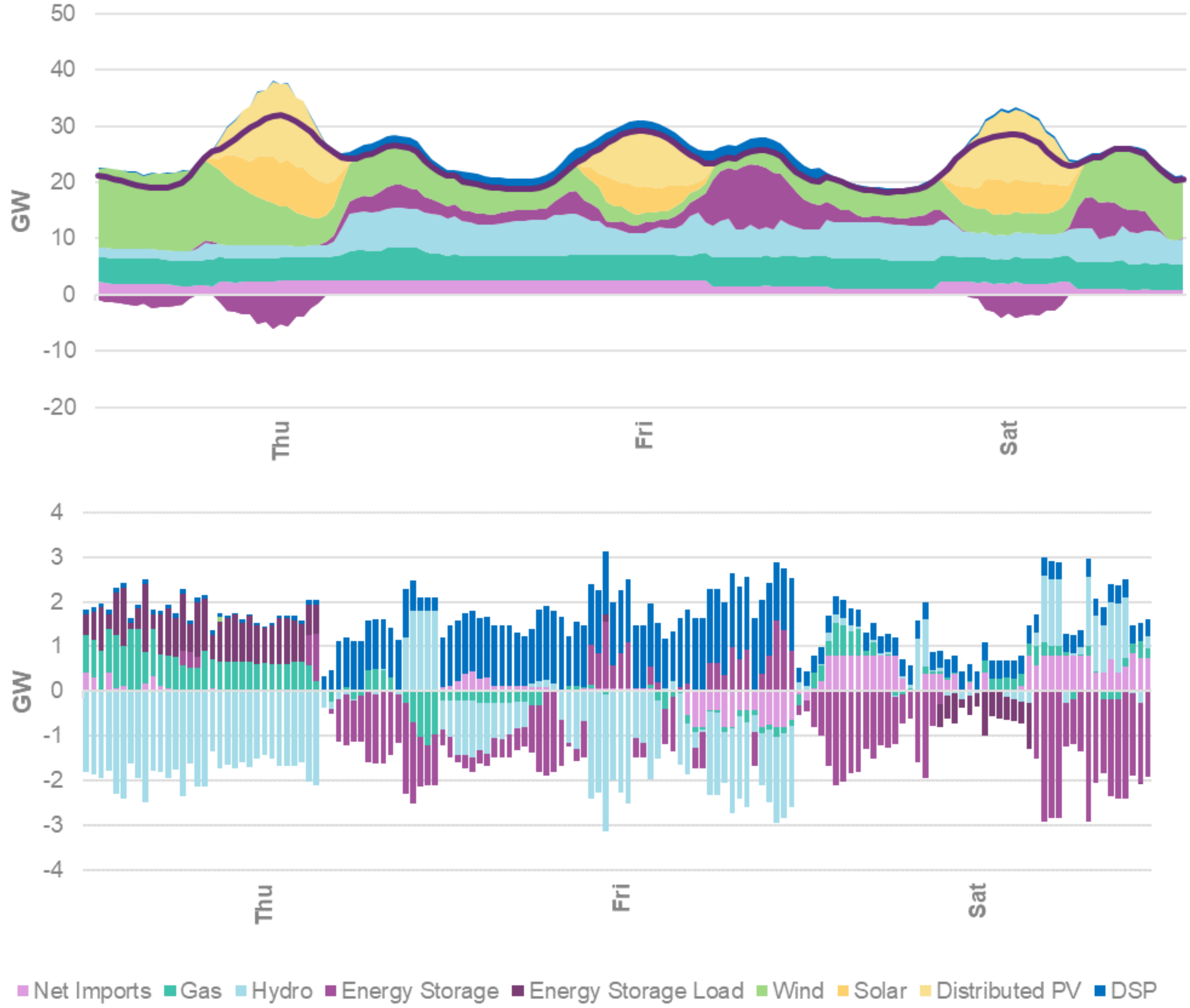
Operating a VRE-based grid with limited foresight of long, dark and still conditions

As the system relies more on storage, the accuracy of weather forecasting across longer durations (a week ahead) will become more important to operate this storage effectively.

AEMO modelled the sample event shown in Figure 11 with perfect foresight of when the low VRE period would start, and when these conditions would end. This foresight enables deep storages and hydro reservoirs to fill in advance and hold energy in reserve in preparation for these conditions. In reality, there will be uncertainty around future weather events ("imperfect foresight").

Figure 12 shows the forecast dispatch by fuel type with imperfect foresight during the most severe three-day period from the week shown in Figure 11.

Figure 12 Forecast winter operability across southern regions experiencing a three-day low VRE period, June 2040, *Step Change*, with imperfect foresight (top) and difference in dispatch relative to perfect foresight conditions (bottom)



With more limited foresight, storages operate in a more constrained capacity, as they are not effectively replenished in advance of the event. The power system must therefore rely more on imports and gas generation. Storage can still provide critical support during the event, but it is less effective and more costly to charge if the window to fill the storage cost-effectively is short. Presently, energy limits impact a number of thermal generators in the NEM, including gas-fired generators which may face fuel supply limitations due to gas network constraints; for example, if such limitations apply to New South Wales gas-fired generators in 2040, more DSP would be required for longer periods of time.

The effect of imperfect foresight highlights:

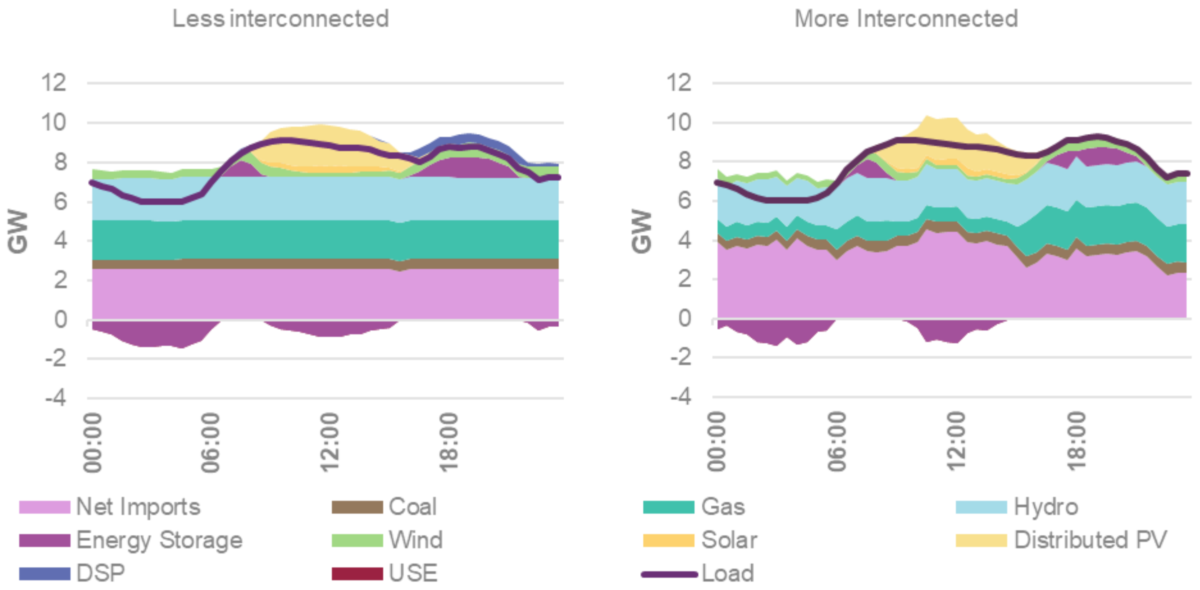
- The additional operational challenges for managing energy limits across various technologies.
- The increasing opportunities for DSP, and the potential need for DSP providers to offer reduce load for extended durations during these conditions. Depending on the limitations individual DSP providers place on duration of their flexibility, a larger DSP portfolio may be needed to enable staging of shorter periods of reduced operation from each provider to deliver the longer flexibility when needed.
- The importance of continuing to improve the accuracy and granularity of weather forecasting systems to increase foresight, which will support improved resource coordination and more efficient scheduling of the NEM, including operation of storage, in a highly renewable energy future.

Increased geographic and technological diversity reduces the impact of long, dark and still conditions

Geographic diversity, supported by transmission, is a key solution to mitigate the impacts of long, dark and still periods. Inland locations for utility-scale PV not only receive more solar irradiance than coastal locations, they also provide diversity to shading of distributed PV by clouds in coastal metro areas. Locating wind farms across different REZs likewise reduces the likelihood they all will experience calm conditions at the same time.

Figure 13 shows how the operability of the grid changes with alternative access to transmission, during a sample long dark and still event in Victoria in June 2032 in *Step Change*.

Figure 13 Forecast Victorian supply mix on a winter day during a long dark and still event in a more interconnected and less interconnected system, June 2032, *Step Change*



AEMO applied imperfect foresight conditions on hydro and deeper storages, similar to the previous analysis. On the left is a development path without the actionable ISP projects that increase Victorian import capabilities, and on the right is a development path with greater import capability, including Marinus Link (two cables) and VNI West.

As the figure on the left shows, without significantly expanded import capability, local gas generators must run all day to provide energy, and the interconnectors also import at full capacity for most of the day. There may also be a greater need for DSP providers to reduce demand, depending on how much the weather conditions limit local renewable generation.

As the figure on the right shows, with increased investment in transmission, the supply needed from gas generation is forecast to be significantly reduced, and it may be possible to avoid an extended need for DSP. Unserved energy risks will also reduce.

Boosting resilience with route diversity

Actionable and future ISP projects identified in this ISP will strengthen the main transmission flow paths of the NEM. These projects will deliver a more resilient power system, capable of operating more securely and efficiently across future weather conditions. This analysis considers some specific cases of extreme weather events that might impact the capability of the transmission network, to provide examples of how appropriate network design can support improved resilience. AEMO's *Power System Frequency Risk Review* (PSFRR)[12] complements this assessment by further exploring the capability of the power system to withstand related power system events without leading to cascading outages or major supply disruptions.

Extreme weather events increase the likelihood of major transmission outages, and also increase the stress on the electricity supply system. For this 2022 ISP, AEMO has considered three case studies of coincident extreme weather[13] and interconnector outages that highlight the benefit of route diversity from transmission projects in *Step Change*. The three case studies are described in Table 1.

Given the high-impact low-probability nature of these compound extreme conditions, this analysis is not intended to quantify the reliability risk of these events, but rather to illustrate how the system might be able to operate under such extreme conditions with different levels of generation reserves and import headroom available under CDP1 and CDP11.

Table 1 Resilience to major contingencies – case studies assessed in *Step Change*

Contingency	Timing and weather conditions	Alternative supply routes
Double-circuit failure of Heywood Interconnector due to a damaging storm	June 2032 – during low VRE conditions in New South Wales, Victoria and South Australia.	Project EnergyConnect, VNI West, Marinus Link
Double-circuit failure of Dederang – South Morang 330 kV lines due to severe bushfire	January 2032 – during hot weather conditions across Victoria and New South Wales.	VNI West, Marinus Link
Double-circuit failure of QNI due to severe thunderstorm and/or lightning	January 2028 – during hot weather conditions across Victoria and New South Wales.	HumeLink

12 At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/power-system-frequency-risk-review.

13 AEMO has selected these extreme weather conditions from historical weather patterns.

Loss of Heywood

On 31 January 2020[14], strong winds associated with thunderstorms resulted in the collapse of several transmission towers in south-western Victoria. This left Heywood, the interconnector between South Australia and Victoria – as well as the Alcoa Portland aluminium smelter, Mortlake Power Station and Portland and Macarthur wind farms – separated from the rest of the Victorian network. Damage to the transmission lines was significant, such that South Australia was completely separated from the rest of the NEM for 18 days and it took more than a month for all circuits to be restored.

This case study considers a similar loss of the Heywood Interconnector taking place in July 2032, during low VRE (both solar and wind) and high winter demand conditions in all southern states, with the most severe impact on Victoria. Similar to the earlier described long dark and still conditions, in this case study Queensland still provides reasonable geographical diversity, such that the prevailing conditions in the south are not experienced in the north. In the study, the route diversity provided by Project EnergyConnect (creating a new flow path between South Australia and New South Wales), Marinus Link (providing additional capacity between Tasmania and Victoria) and VNI West (strengthening connection between Victoria and New South Wales) is expected to provide significant benefits in the event of the modelled contingency.

By July 2032, CDP11 has commissioned all actionable ISP projects, including VNI West and both cables of Marinus Link. CDP1, on the other hand, delays some actionable ISP projects, and only Project EnergyConnect and the first cable of Marinus Link would be commissioned in this pathway.

With the loss of Heywood, South Australia can no longer support Victoria directly and Victoria needs to import more from the remaining interconnectors. However, without VNI West, imports from South Australia (indirectly through Project EnergyConnect and then VNI), Queensland (through QNI and VNI) and New South Wales (through VNI) are constrained. Marinus Link in this development pathway can only provide partial capacity support, with only one of the two cables commissioned.

Without access to alternative routes, the case study shows that higher cost generation in all regions would be required to step up. During the contingency, Victoria could potentially experience a very tight supply-demand balance and heightened reliability risk exacerbated by weather and generation outage conditions.

Figure 14 presents half-hourly generation reserve (including DSP) and import headroom[15] in Victoria during the modelled Heywood outage. It shows that:

- In most periods, the development pathway with greater interconnection (CDP11) has significantly more reserves than the CDP1. CDP11 is therefore more resilient, with additional reserves available, if other events were to occur.
- However, on Thursday and Friday, both cases operate on low reserve margin due to a large number of simulated generator outages in Victoria and New South Wales. During such periods, where low VRE conditions further diminish supply available in adjacent regions, the benefits of route diversity are not realised.

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[14] AEMO, *Final Report –Victoria and South Australia Separation Event on 31 January 2020* at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/final-report-vic-sa-separation-31-jan--2020.pdf; AEMO, Quarterly Energy Dynamics report covering the operational and market consequences of the separation, at https://aemo.com.au/-/media/files/major-publications/qed/2020/qed-q1-2020.pdf.

[15] Interconnector support is estimated as the maximum energy supply available to the region from neighbouring regions after the demand to be met from supply is satisfied in neighbouring regions.

Figure 15 compares duration curves of half-hourly reserve capacity and import headroom between CDP1 and CDP11 across the full year 2031-32. It clearly demonstrates that the level of reserves in Victoria is higher in most of the year with stronger interconnection, increasing resilience to extreme events.

Figure 14 Forecast generation reserves and import headroom in Victoria during a one-week outage on Heywood in a more interconnected (CDP11) and less interconnected (CDP1) system, July 2032, *Step Change*

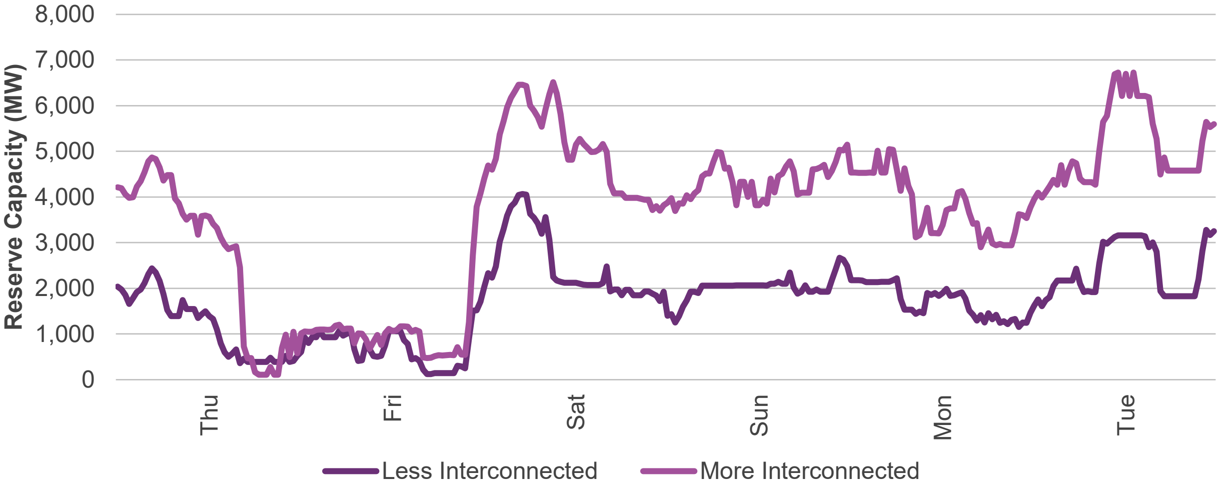
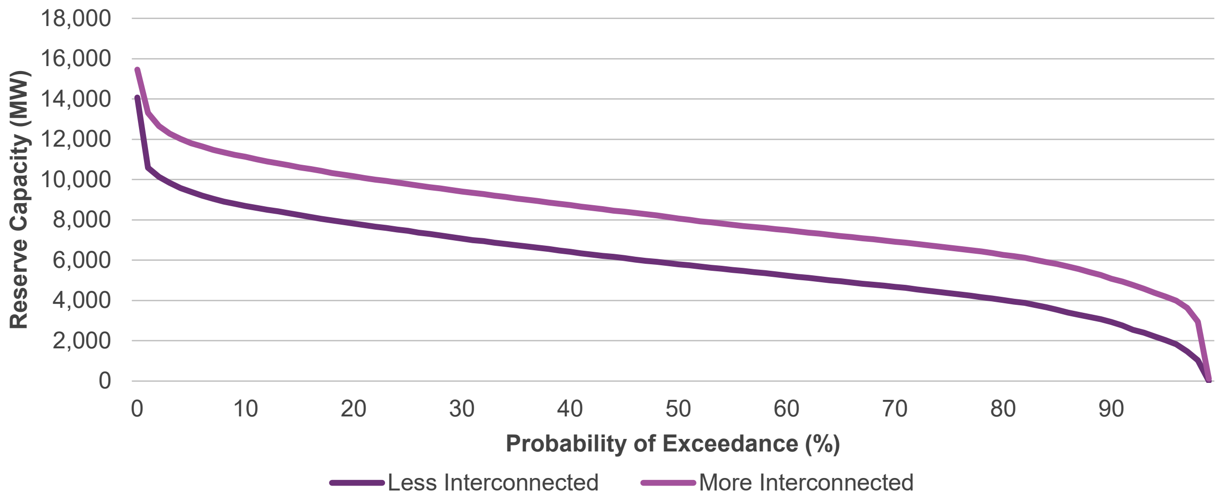


Figure 15 Forecast duration curves for generation reserves and import headroom in Victoria in a more interconnected (CDP11) and less interconnected (CDP1) system, 2031-32, *Step Change*



Loss of Dederang–South Morang 330 kV lines

In the 2019-20 'Black Summer', Australia faced severe bushfires which had a significant impact on network performance, particularly in New South Wales where the number of unplanned transmission outages saw a sharp increase relative to the previous year[16]. As climate change projections suggest that Australia's fire weather will increase in intensity and duration, AEMO has assessed the operability of the power system during a bushfire event, represented in this case study as a double-circuit failure on the Dederang – South

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

Morang 330 kV lines in northern Victoria, on which transfer limit and availability have been impacted by bushfire events in the past[17]. As noted, this section demonstrates some of the benefits that an appropriate network design can provide for extreme weather events, while the PSFRR currently focusses on the capability of the power system to withstand related power system events.

Dederang – South Morang is a critical path to import electricity from New South Wales to Victoria, as well as the only access to hydroelectric generation in Northern Victoria, most importantly the Murray Power Station in the Snowy Mountain Scheme. An outage of both Dederang – South Morang lines due to bushfire could lead to contingencies that may be costly to manage without alternative transmission corridors like VNI West.

Outage of both Dederang – South Morang lines for this case study is modelled in January 2032, during heat wave conditions in Victoria. By then Victoria would have access to alternative routes via both cables of Marinus Link and VNI West under CDP11. Route diversity would be limited under CDP1, which is a slower development path, with only the first cable of Marinus Link to offer alternative access to Tasmanian resources by this time.

To supply local peak demand without VNI West during the conditions simulated would require all gas generation available in Victoria and South Australia to operate, activation of DSP resources[18], and maximum imports over Project EnergyConnect and the Bass Strait cables (Basslink and Marinus Link). With VNI West in place, most of the capacity from Murray Power Station remains available to the system, with flows routing through the alternative interconnector. This puts the system in a situation of adequate reserves, with 1,790 MW of supply capacity in reserve for Victoria.

Figure 16 presents the generation reserves and import headroom in Victoria during the simulated conditions for the duration of the Dederang – South Morang outage, with the less interconnected development path CDP1 operating with a very low reserve margin of only 449 MW during the Thursday. This is below the current largest single credible generation contingency in Victoria of 600 MW, which (based on current operational procedures) may require use of any off-market reserves through directions or activating Reliability and Emergency Reserve Trader (RERT).

[17] ESCI, Case study: Bushfire risks for transmission networks, at https://www.climatechangeinaustralia.gov.au/media/ccia/2.2/cms_page_media/720/ESCI%20Case%20Study%203_Bushfish%20risk%20for%20transmission%20090721.pdf.

[18] The magnitude of DSP depends on the availability of gas generation, but in the simulated conditions approximately 142 MW of demand response is required.

Figure 16 Forecast generation reserves and import headroom in Victoria during a one-week outage of both Dederang – South Morang lines in a more interconnected (CDP11) and less interconnected (CDP1) system, January 2032, *Step Change*

Loss of QNI

The transmission lines making up QNI pass through an area that often experiences thunderstorms and bushfires, with lightning frequently impacting the availability of the network. The most significant outage of QNI to date was a lightning strike on 25 August 2018[19] that led to the loss of the interconnector for just over an hour, however it is plausible for this flow path to be disrupted for an extended period due to damage to the lines from wind (such as a microburst produced by a thunderstorm) or bushfire as in the above case studies.

This case study considers a week-long loss of QNI taking place in January 2028, during hot weather conditions, which sees demand in New South Wales rise close to peak level. This case study's major contingency would cause islanding of Queensland, and New South Wales would lose the ability to import via this corridor. AEMO has considered the resilience of the system to this event across CDP11 (where HumeLink is operational during the event) and CDP1 (where HumeLink is not yet operational).

AEMO's modelling highlights that New South Wales could face a reliability risk under CDP1. Without HumeLink there is limited access to the generation capacity in Southern New South Wales (SNSW) to meet summer peak in the rest of the region, especially the major load centres in the Sydney area. Higher-cost generation and DSP are required to manage these conditions. Without the added resilience of increased inter-connection with Queensland projected by the ISP (or with expanded firm generation developments within New South Wales) load shedding might be triggered in these circumstances. HumeLink provides greater access to dispatchable resources in the Snowy Mountains and a geographically diverse VRE portfolio in Southern New South Wales REZs, which increases power system resilience.

Figure 17 presents the reserve capacity levels in New South Wales (accounting for congestion between SNSW and Central New South Wales) during the QNI outage. The level of reserve capacity under CDP1 is generally lower due to SNSW generation being transmission constrained, with significant reliability risks on the

[19] AEMO, *Final Report – Queensland and South Australia system separation on 25 August 2018*, 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.

Wednesday in this simulation (no reserves), whereas CDP11 during the same conditions still operates safely with almost 2,000 MW of spare generation and import capacity.

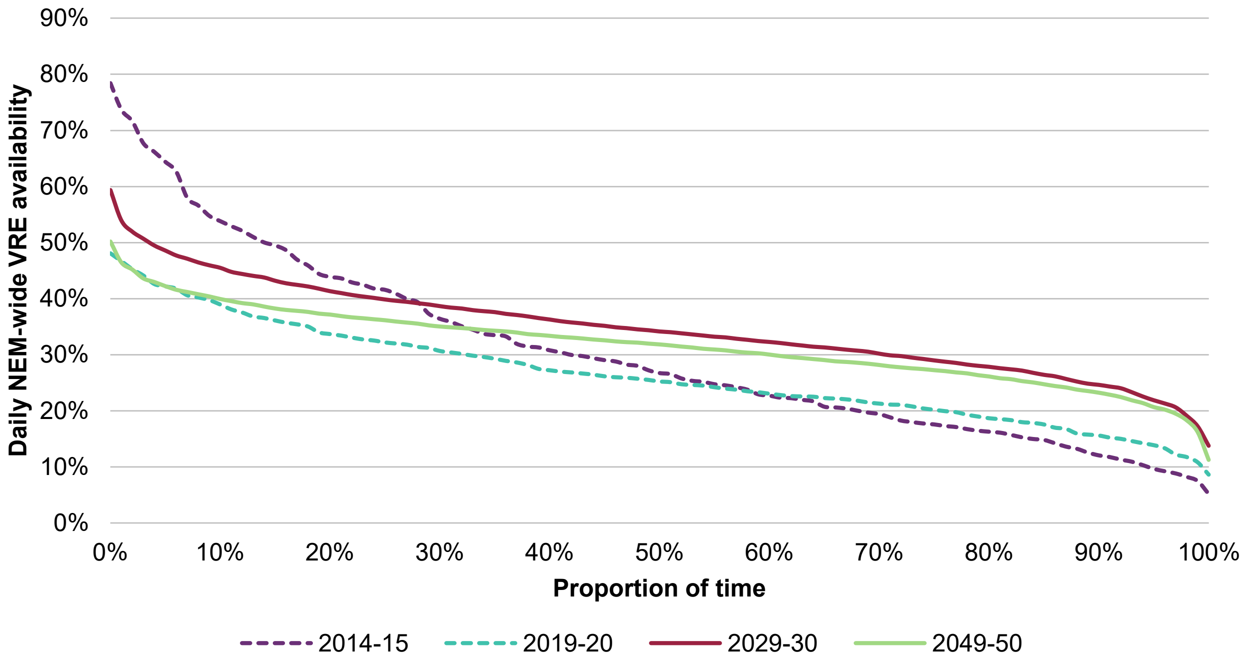
Figure 17 Forecast generation reserves and import headroom in New South Wales during a one-week outage on QNI in a more interconnected and less interconnected system in January 2028, *Step Change*

The value of diversity increases with stronger interconnection

A geographically and technically diverse range of generating assets will ensure greater consistency in fleet-wide generation potential and help reduce the likelihood of periods with low VRE generation across the NEM.

Error! Reference source not found. shows the history and evolution of the daily performance of utility-scale VRE at a NEM-wide level (not including distributed PV), using duration curves of daily capacity factors; that is, daily average availability as a percentage of installed capacity across the NEM, with days ordered from highest proportional availability to lowest.

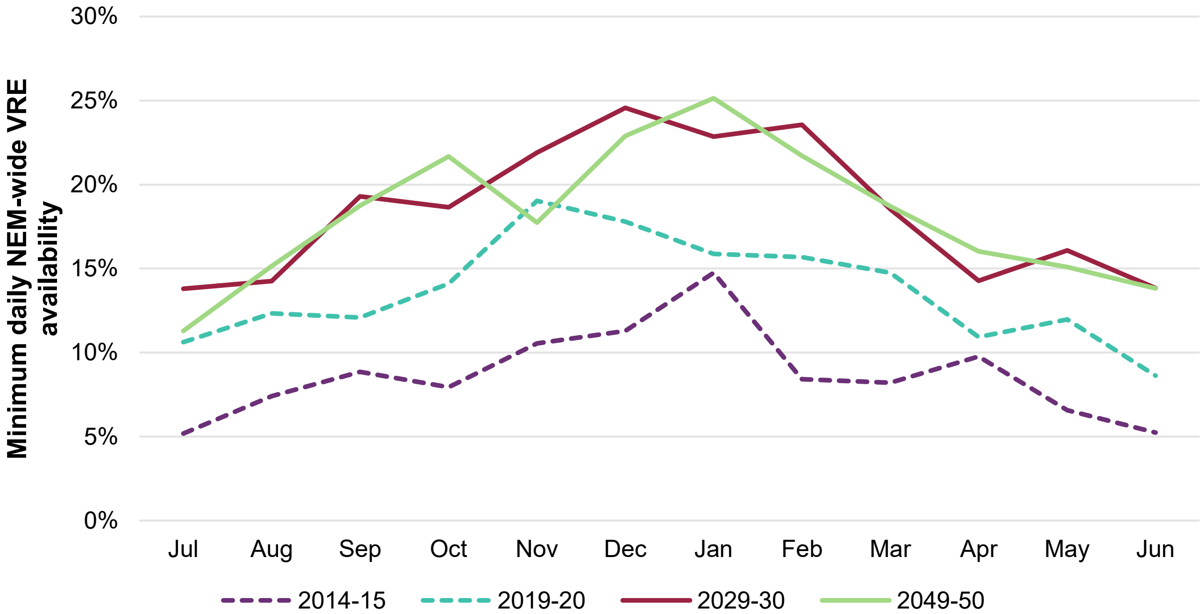
Figure 18 Actual and forecast daily NEM-wide VRE capacity factors (based on availability), duration curves, 2014-15 to 2049-50, *Step Change*



It shows a flattening curve shape from history, to 2029-30 and then to 2049-50. This demonstrates that with the increasing diversity in the future with REZ expansions, the aggregated output of VRE across the NEM is forecast to become much less variable than what has been observed historically. A greater share of utility-scale solar in the generation mix in 2049-50 compared to 2029-30 provides additional technological diversity but also results in lower capacity factors overall, as solar farms have a lower capacity factor than wind farms

Figure 19 presents the minimum of these capacity factors by month. While the shapes of these curves reflect the natural availability of solar resources throughout the year, the differences between historical and forecast years within each month show that days with extremely low VRE production are generally projected to be avoided as the NEM evolves and becomes more diverse, with the worst days expected to be less extreme. It also highlights that winter may become harder to manage .[20] Periods of low VRE output may last longer than what shallow storage can cover, necessitating deep storage support to effectively manage surplus energy over longer timeframes. The ODP includes a mixture of network and storage investment to address this future need efficiently.

Figure 19 Actual and forecast daily NEM-wide VRE capacity factors (based on availability), monthly minimums, 2014-15 to 2049-50, *Step Change*



Case study: how the NEM of 2035 would perform in the June 2017 ‘wind drought’

In June 2017, parts of southern Australia experienced an extended period of low wind speeds, or a ‘wind drought’, leading to some of the slowest wind conditions on record. With over 75% of the installed utility-scale wind capacity in the NEM being concentrated in South Australia (41%) and Victoria (36%) at the time, this wind drought together with minimal geographic diversity led to combined wind output being its lowest in five years, with a NEM-wide capacity factor of just 16% across the month. In comparison, the average wind capacity factor at the same time in the previous year was much stronger, at 36%.

[20] Winter also typically sees higher gas loads for heating residential and commercial consumers, impacting the availability of the gas networks to supply gas for electricity generation. This compounding issue was not simulated in this analysis.

With wind assets operating well below their average output, the requirement for gas generation rose, which contributed to spikes in wholesale energy prices. The wind drought occurred shortly after the closure of the Hazelwood Power Station, exacerbating tight supply-demand conditions in South Australia and Victoria.

As the rapid transition to VRE continues, the geographic diversity of solar and wind resources will be crucial to minimise the impact of localised events such as this, as well as those that affect multiple NEM regions.

For this case study, AEMO has analysed how the system is forecast to perform if presented with the same weather conditions as in June 2017, but with the generation and storage investments of *Step Change* for 2034-35 with the actionable and future ISP projects from the ODP. In this forecast year, installed wind capacity is much more diverse across the NEM than it was in 2017, as shown in Figure 20. This figure shows average monthly capacity factors considering the availability of the generators.

Figure 20 demonstrates the diversity benefit of developing REZs in northern New South Wales, Queensland and Tasmania during conditions affecting more severely some South Australian and Victorian sites. With a wider spread of wind farms in this generation mix, the NEM-wide average wind capacity factor under the same conditions as in June 2017 improves to 29% across the month (compared to the capacity factor of 16% in June 2017 noted above).

The NEM has an opportunity to utilise its strong geographic diversity by strengthening the transmission system. Greater geographic diversity can limit the exposure to poor or extreme weather conditions. Network investment will improve the capacity to share these diverse resources, reducing the severity of events that reduce wind and/or solar availability.

Figure 20 Installed utility-scale wind capacity in the NEM in 2017 and 2034-35, with average monthly capacity factors (based on availability) under June 2017 conditions, *Step Change*

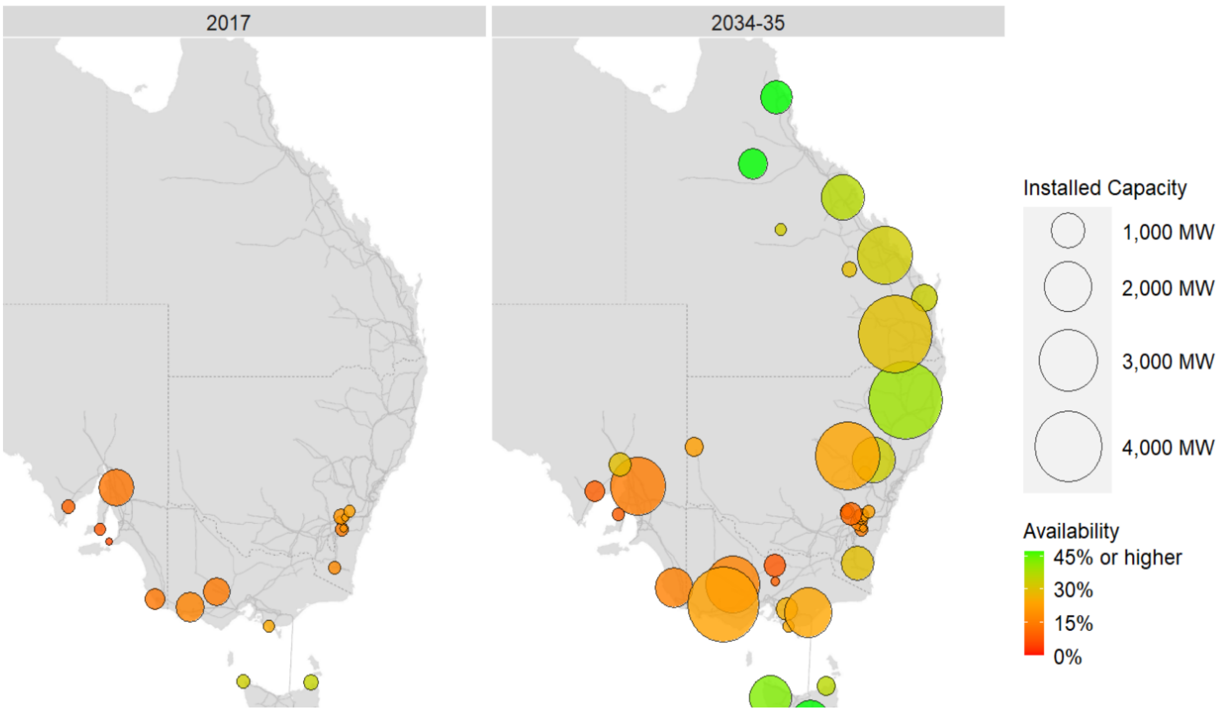


Figure 21 shows that the increased geographic diversity will also reduce the volatility of wind capacity factors on a day-to-day basis. Similar to Figure 18, the figure shows the increased minimum average output with improved diversity, but also the lower peaks, focused on the June 2017 conditions.

Figure 21 Actual and forecast daily average capacity factors (based on availability) for wind generation in the NEM under June 2017 conditions, *Step Change*

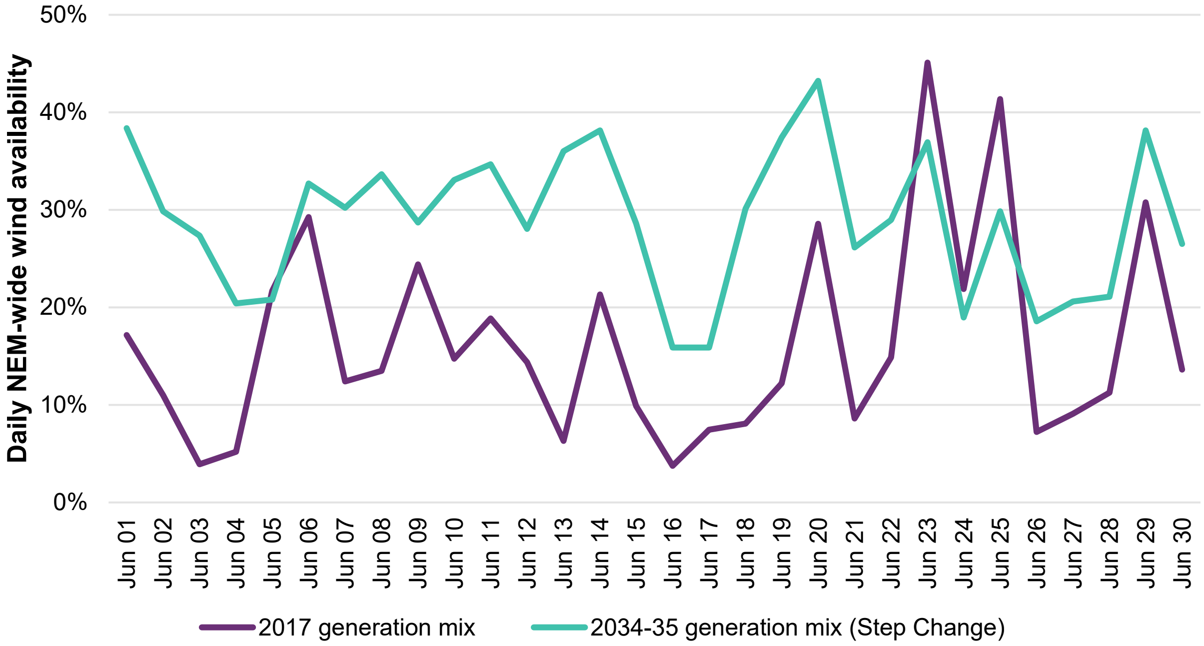
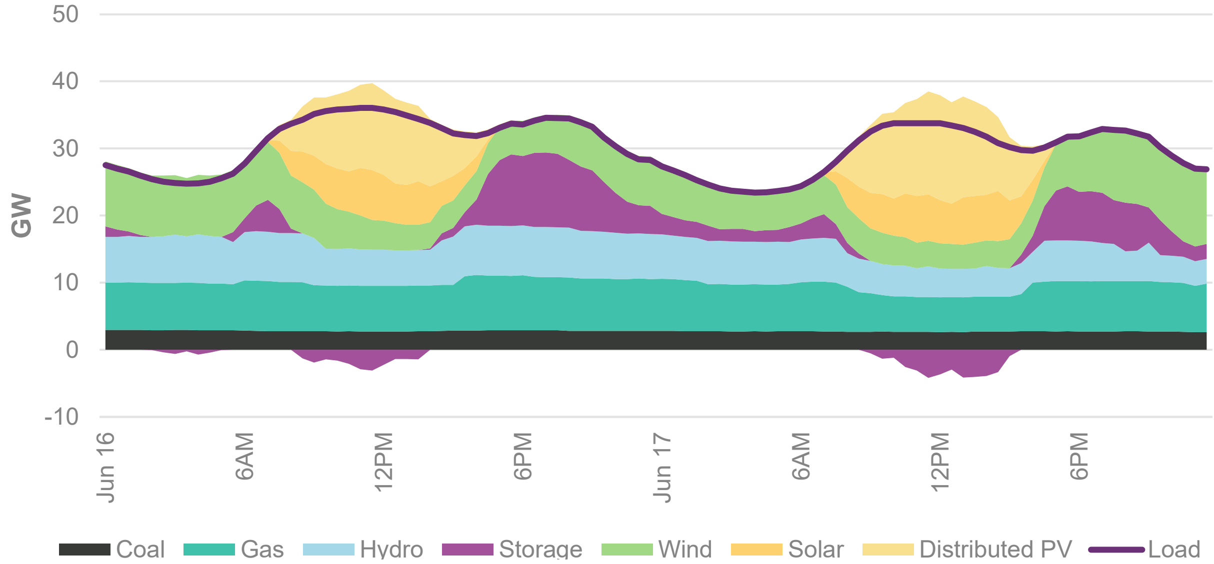


Figure 22 shows the NEM supply mix on the two lowest wind generation days (June 16 and 17) in 2034-35 shown in Figure 21. With reduced output from wind, contribution from coal, gas and hydro generation across the two days is needed to meet consumer demand. This is coupled with reasonable daytime solar generation (distributed PV and utility-scale). Energy storages across a range of depths provide discharge of stored energy during the evenings and overnight. Despite low wind conditions and growth in winter consumption from electrification, these weather events, with the appropriate generation, storage and network investments, do not present material reliability risks.

Figure 22 Forecast NEM supply mix on lowest wind days under June 2017 wind drought conditions in 2034-35, *Step Change*



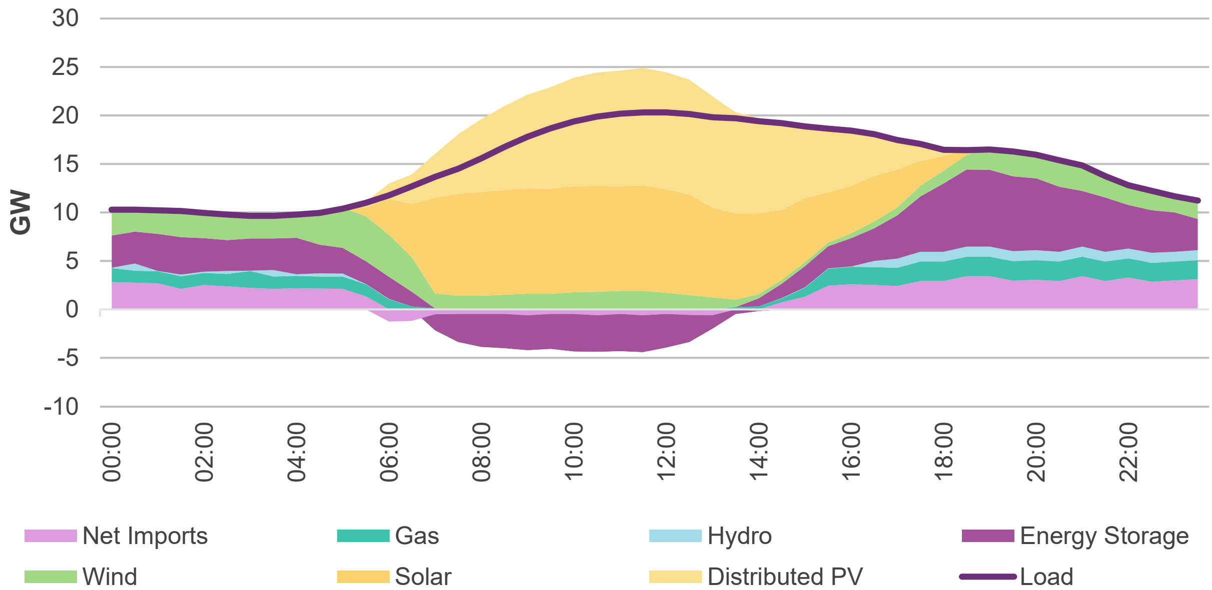
Meeting peak day load

Compared to meeting winter long dark and still events, meeting a summer peak is more often a question of having sufficient generation capacity available, rather than sufficient energy. High load in summer is driven by hot weather, and correlates strongly with solar PV availability. Storage is only required to generate for a few hours in the evening.

Figure 23 shows an example of a peak day in New South Wales in 2040 in *Step Change*. On this day, the forecast peak in underlying load is mid-day, but the forecast peak in operational load (net of distributed PV) occurs just after sunset, at 1900 hrs. There is projected to be no solar available, and just 2.3 GW of wind generating from 15.6 GW installed (approximately 15%).

Energy storage is forecast to provide 8.0 GW – nearly half the generation delivered at peak – having filled from excess solar on this day and the days prior. Gas generation and hydro are projected to provide additional firm energy, while the improved transmission links to neighbouring regions are projected to allow 3.5 GW of imports at peak. In this example, gas generation runs continuously overnight, but, unlike the long dark and still events, is not required during most of the daytime period. Further detail on the changing role for gas generation is provided in Section A4.2.8.

Figure 23 Ability for forecast capacity to meet a summer peak day in New South Wales in 2040, *Step Change*



A4.2.5 Storage to firm renewables

A portfolio of storage will be needed to support accelerated transition to a NEM dominated by VRE. Different types and depths of storage play very different roles in the system (see box below).

Different types and depths of storage

- **Coordinated DER storage** – includes behind-the-meter battery installations that are enabled and coordinated via VPP arrangements. This category also includes EV with V2G capabilities.
- **Distributed storage** – includes non-aggregated behind-the-meter battery installations designed to support the consumer's own load
- **Shallow storage** – includes grid-connected energy storage with durations less than four hours. The value of this category of storage is more for capacity, fast ramping and FCAS (not included in AEMO's modelling) than for its energy value.
- **Medium storage** – includes energy storage with durations between four and 12 hours (inclusive). The value of this category of storage is in its intra-day energy shifting capabilities, driven by the daily shape of energy consumption by consumers, and the diurnal solar generation pattern.
- **Deep storage** – includes energy storage with durations greater than 12 hours. The value of this category of storage is in covering VRE 'droughts' (long periods of lower-than-expected VRE availability) and seasonal smoothing of energy over weeks or months.

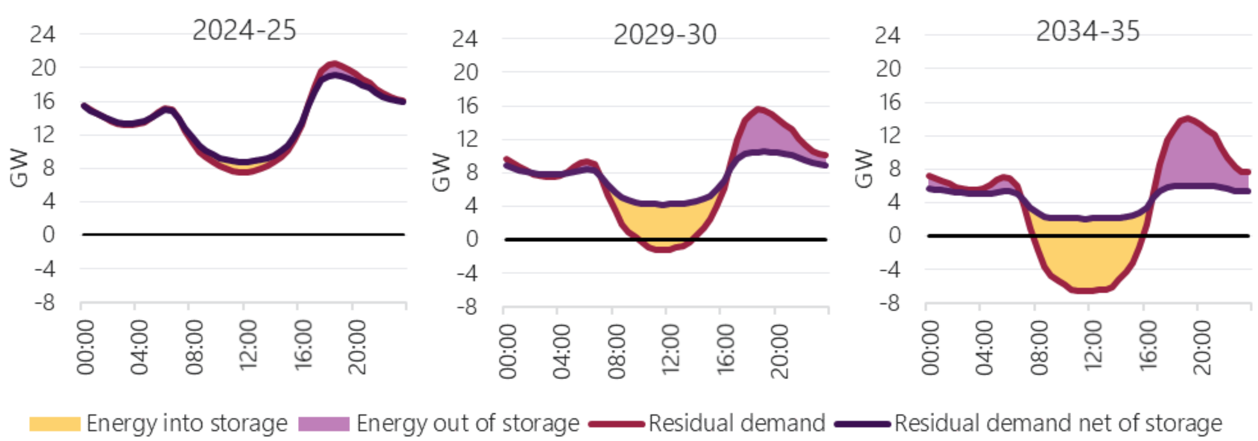
Intra-day and inter-day storage operation

Both electricity demand and solar PV generation exhibit robust daily cycles that create opportunities for storage to time-shift energy from day to evening and night. The Draft ISP identified a strong role for storage technologies of various depths in all scenarios.

As VRE penetration increases and more storages are developed, energy storage will play an increasingly important role in energy-shifting surplus VRE generation at times of renewable energy abundance (such as the middle of the day) to periods of high residual demand (such as in the evening, after solar has reduced operation).

Figure 24 shows the forecast time-of-day average profile of residual demand, that is demand net of VRE generation, and the forecast daily operation of storage.

Figure 24 Forecast time-of-day average profile of residual demand, 2024-25 to 2034-35, *Step Change*



In the next 10 to 15 years, as VRE penetration increases and coal-fired generation retires, residual demand is forecast to reduce and the importance of storage to shift surplus solar generation to evening and overnight periods increases. As the depth and capacity of storage increases, the opportunity to shift more surplus daytime energy and reduce longer periods of evening peak demands will improve.

By 2030, VRE is forecast to regularly be able to provide more power than the NEM needs during the middle of the day, so residual demand is negative. Storage allows the capture of this excess and the use of the stored energy to flatten the evening peak. This allows the remaining dispatchable generation to operate to a flatter profile.

Utilising hydro-electric storage for seasonal energy security

The NEM presently stores energy from season to season in the form of potential energy, through the operation of hydro-electric facilities with deep water reservoirs, particularly in Tasmania. Over time, development of shallow storages, dispatchable capacity and transmission may change the optimal use of stored water at these deep hydro facilities to support longer periods of high residual demand, particularly during winter.

Figure 25 shows how the forecast seasonal pattern of energy stored in new deep storages and hydroelectric reservoirs changes over the period 2024-25 to 2049-50 in *Step Change*. Over time, with more solar and shallow storage added, and as electrification adds energy consumption across the year, deep storages and hydro reservoirs are forecast to shift to discharging more in autumn and winter, subject to water inflows and other irrigation and environmental restrictions.

Figure 25 Forecast energy stored in deeper storages and traditional hydroelectric reservoirs over a year, 2024-25 to 2049-50, *Step Change*

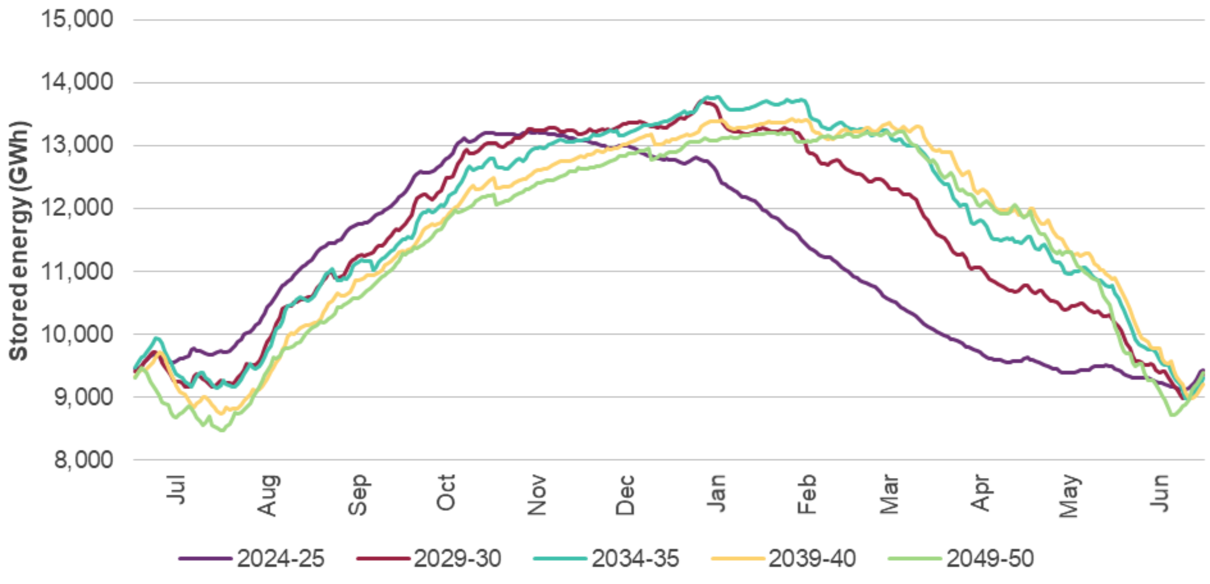
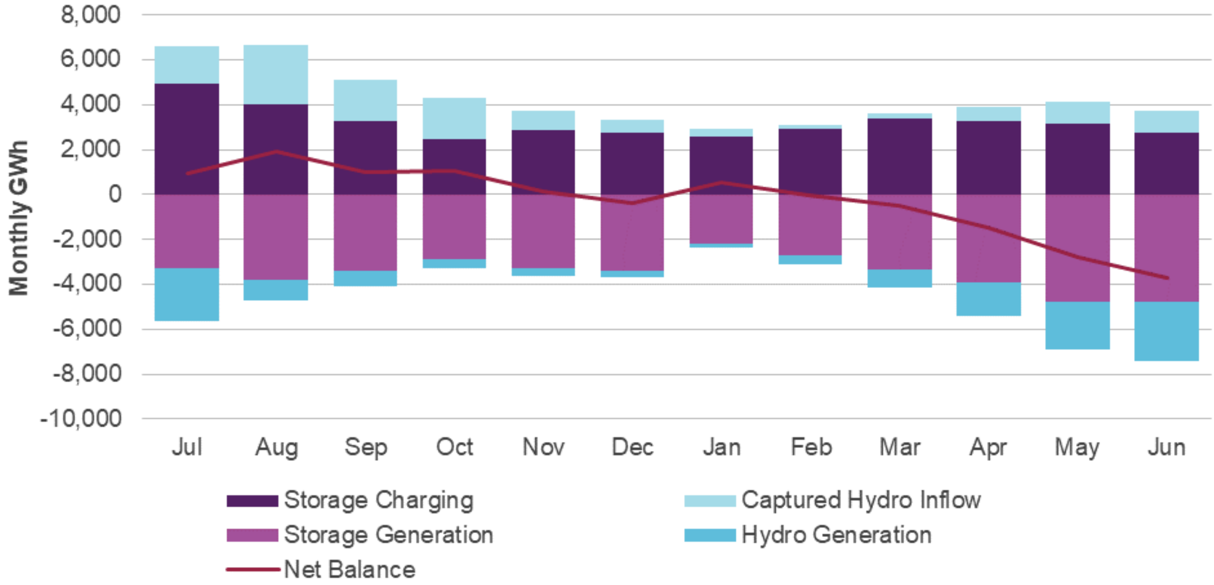


Figure 26 below shows the forecast of monthly energy used to charge or fill energy storages, and subsequently discharged from all storages, in 2039-40 in *Step Change*. Positive values represent total energy flowing into storage during the month, while negative values represent total discharge. A positive net balance indicates that storage generate more than the inflows it receives in that month and vice versa.

Figure 26 Forecast monthly energy balance of all storages (battery and hydro), 2039-40, *Step Change*



The shallower storages operate at a consistent rate throughout all months of the year, shifting energy intra-day. In contrast, (depending on the location of the facilities) hydro receives its main inflows in the spring from snowmelt (or during normally wetter months) and has the flexibility to store VRE-surplus in summer, to provide much needed firming in the autumn and winter months.

The 'optimal' management of storage across the year to cater for months of high and low renewable energy and water inflow yields will depend on the accuracy of medium and long-range weather forecasts, and the commercial incentives for storage operators to retain potential energy for when it is needed most to support reliability and security of supply.

The implications of imperfect weather, load and renewable energy forecasting, and of imperfect foresight in planning and investment models, is likely to increase the value of transmission (increasing diversity of flow paths) and storage depth (and/or other forms of dispatchable generation to increase reserves).

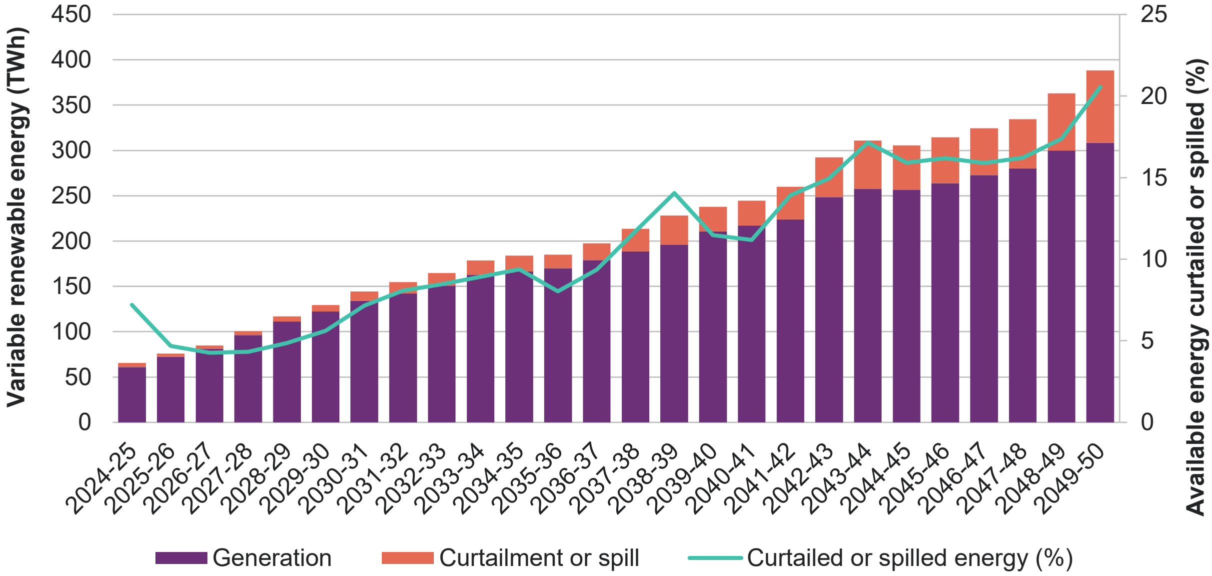
A4.2.6 Renewable generation curtailment

AEMO modelling shows that the economic development of VRE, storage and transmission may lead to periods where VRE does not generate at its full available capacity. From an overall system perspective, it is efficient to overbuild VRE capacity relative to the transmission system capacity, even if this means that sometimes part of this generation will be curtailed[21] ('spilled'). This could arise due to system security or other operability constraints in the network, or could simply be due to over-abundant renewable energy being available with insufficient demand for it, and insufficient energy storage to store the surplus.

Figure 27 shows the trajectory of energy forecast to be curtailed or spilled in *Step Change*.

[21] Curtailment happens when generation is constrained down or off due to operational limits.

Figure 27 Forecast NEM curtailment or spill of variable renewable generation, 2024-25 to 2049-50, *Step Change* with new transmission

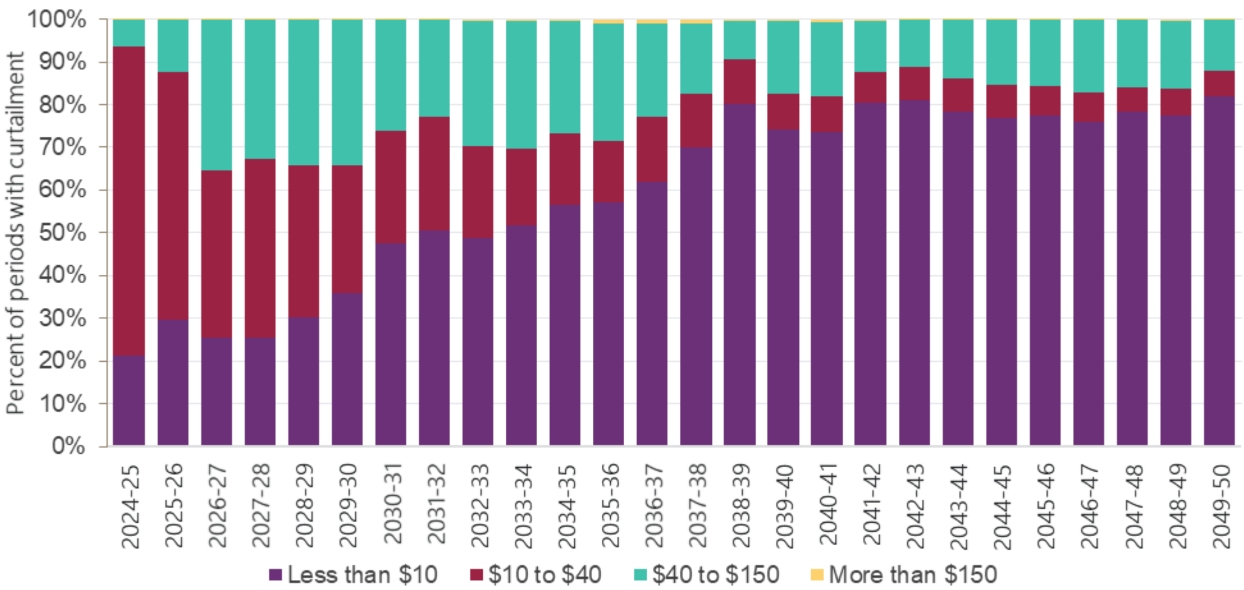


Curtailment and spill of renewable generation is forecast to trend upwards as the share of VRE increases, despite the increased capacity to absorb excess energy across the grid from new transmission augmentations and energy storage.

Prices during generation curtailment or spill

Figure 28 shows the forecast distribution of generation curtailment or spilled across wholesale price bands due to transmission limitations and the inability to deliver local generation to the consumer. This is a proxy of lost value as well an indication of the opportunity cost of developing additional transmission and storage capacity to soak up this excess.

Figure 28 Forecast NEM price distribution of generation curtailment or spill, 2024-25 to 2049-50, *Step Change*



Most of the excess is projected to occur during periods of relatively low wholesale prices. By the end of the horizon, the distribution narrows and over 80% of the total is forecast to occur at prices below $10/MWh

Figure 29 shows average generation capacity forecast to be curtailed or spilled across the day in 2039-40. Generation curtailment is strongly correlated with daylight hours and therefore solar output. Some generation curtailment is projected to occur at night, but in smaller proportion.

Figure 29 Forecast NEM average time-of-day generation curtailment or spill in 2039-40, *Step Change*

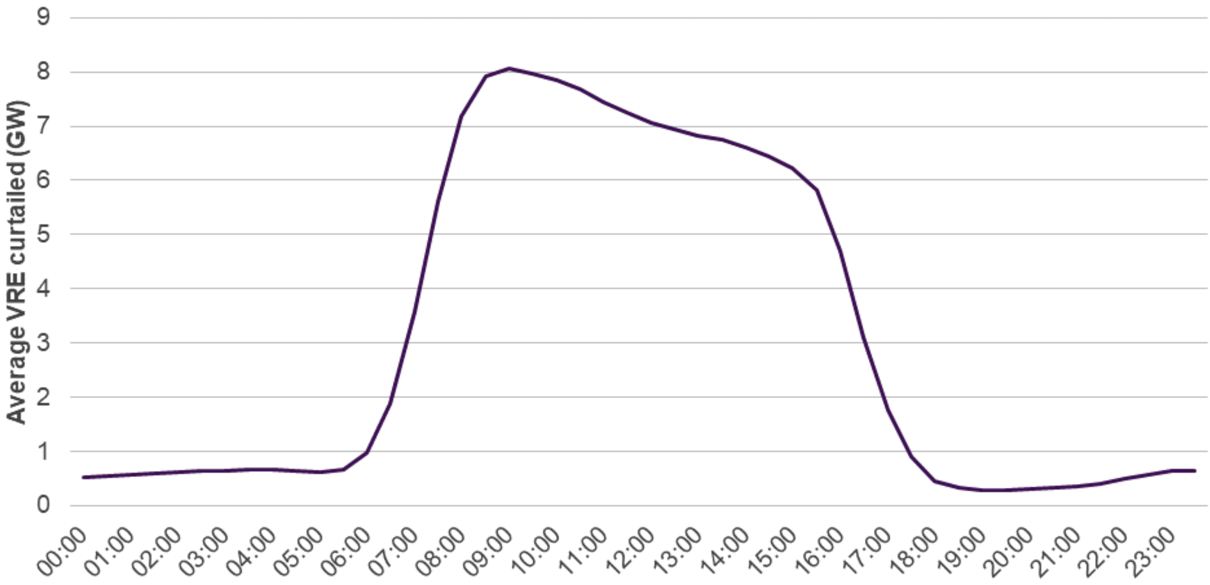
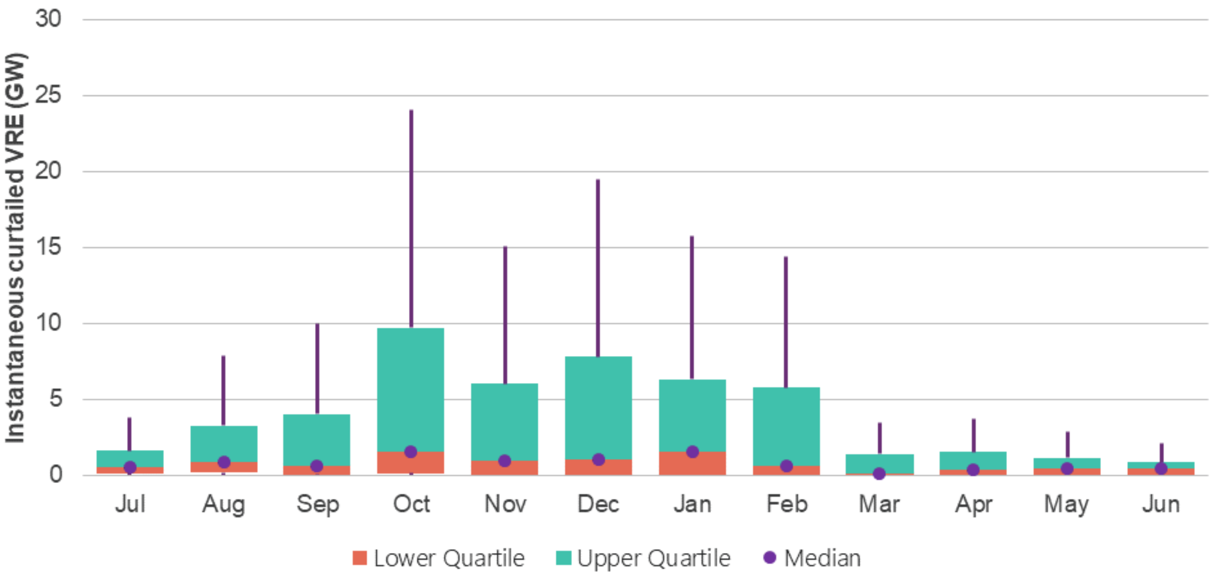


Figure 30 shows the distribution of generation curtailment or spill forecast at a monthly level in 2039-40. It shows that this is pr0jected to occur most frequently during spring and summer months as solar irradiation improves. These months also feature the largest variability, as they are characterised by abundant renewable generation coupled with modest demand. This means there are likely to be more instances in these months where the generation curtailed or spilled is significantly higher than the median value.

Figure 30 Forecast NEM frequency of spare available VRE capacity in 2039-40, *Step Change*



This seasonal pattern also indicates that further investments in storage capacity would not necessarily be able to soak up this lost energy as part of an intra-day cycle, but could assist in shifting this energy seasonally if there were sufficient depth and value to do so.

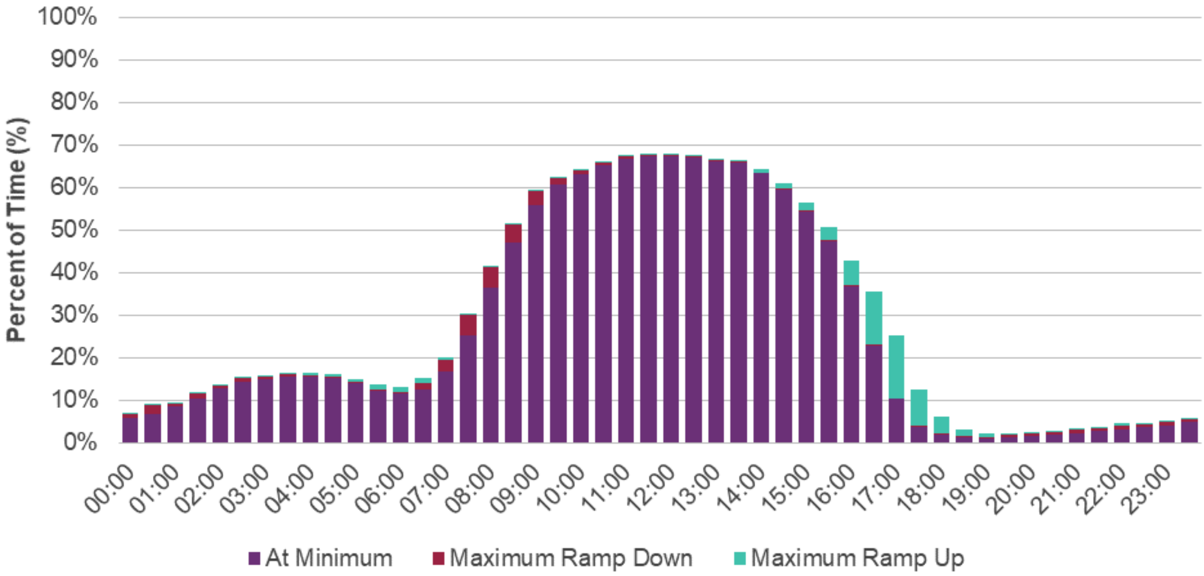
A4.2.7 Implication for coal operation and revenue sufficiency

This section describes what the continued transformation of the NEM may mean for the operation and economics of existing coal generators.

AEMO forecasts that the volume of energy produced by coal generators will reduce, displaced by cheaper sources of generation, particularly in periods of high VRE generation (which is forecast to increase) or low operational demand (which is forecast to reduce significantly).

In these conditions, coal generators will increasingly need to operate at minimum generation levels for longer periods (see Figure 31), and potentially may be called on to ramp up and down more frequently depending on the commercial signals. This has implications for the future duty on the power station, including maintenance and refurbishment, and operating costs and commercial returns[22].

Figure 31 Forecast black coal percentage of time at maximum ramp and minimum load, 2024-25, *Progressive Change*



AEMO's consideration of coal retirements in the ISP

AEMO has applied two alternative approaches to forecast coal retirements, depending on the scenario assessed:

- Approach 1 uses a revenue forecasting and least-cost hybrid retirement approach and was applied to those scenarios which have periods that are not influenced by an explicit emission constraint (often referred to as a carbon budget) in the electricity sector, such as *Progressive Change*.
- Approach 2 uses a pure least-cost approach in scenarios where an explicit emissions constraint was implemented. These scenarios, such as *Step Change*, incorporate carbon budgets that limit the emissions

22 AEMO's modelling does not capture this potential additional cost or possible implications for plant maintenance/reliability.

intensity of the electricity system and therefore incorporate the effects of earlier retirements to meet climate objectives considering the least-cost means rather than evaluation of revenue sufficiency.

The following outlines the outcomes of AEMO's coal retirement assessment for *Progressive Change* using Approach 1. The analysis focuses on the revenue sufficiency of the coal fleet based on the Draft ISP modelling to inform retirement trajectory up until 2030.

In Approach 1, expected closure years that apply prior to 2030 may be brought forward from announced closure years by considering the forecast wholesale market profitability of each generator[23]. Consideration of early retirements was limited to the period beyond any NEM or jurisdictional notice of closure requirements and up to 2030 after which emission constraints are expected to become a more influential driver of coal withdrawals in this scenario.

As outlined in the *ISP Methodology* (section 2.4.1)[24], the criteria for early retirement due to unprofitability considered whether both the following were met before deciding on an earlier retirement:

1. The magnitude of negative returns, relative to the cost of bringing forward any retirement/rehabilitation cost (provided in the 2021 IASR Workbook, by technology), and
2. The duration of consistent negative returns to 2030 or the expected closure year/closure date. Other retirements beyond 2030 were only brought forward before expected closure years if determined in the capacity outlook modelling, rather than because of profitability analysis.

In its determination of coal retirements, AEMO also considered other factors, such as government agreements, notice of closure requirements, supply arrangements, and state policy objectives, where applicable. These considerations and outcomes of the revenue sufficiency assessment for *Progressive Change* using Approach 1 are detailed below by state:

- For New South Wales generators, AEMO used the retirement trajectory available in the most recent Consumer Trustee report (the December 2021 *Development Pathways Report* or DPR) as a starting point for coal generators retirements. The DPR trajectory in some cases forecast retirements earlier than the expected closures dates. No subsequent changes to retirement timings were found for New South Wales generators based on the revenue sufficiency assessment of Approach 1.
- For Victorian generators, AEMO assumed that Yallourn retirement was fixed to 2028-29, based on the agreement reached between Energy Australia and the Victorian Government[25] to deliver an orderly retirement of the power station. No other brown coal units were considered to retire before Yallourn[26] and following that, no early retirements were found due to unprofitability.
- For Queensland generators, AEMO assumed that Gladstone Power Station was not considered for early retirement due to the complexity and long-term nature of the Interconnection and Power Pooling Agreement[27], including its supply arrangements to the Boyne Island Smelter. AEMO forecast that only one

[23] Forecasts of wholesale prices and generator profitability rely on generation cost and technical assumptions listed in the 2021 IASR. Generator market offers (that is, the bids that are submitted to the dispatch process) were calibrated in the model to align with cleared market offers over 12 months in 2020-21, being the most recent full financial year available, and spot market prices were simulated based on dispatch with these bids. These bids were kept static for the period assessed.

[24] At https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-isp-methodology.pdf.

[25] See https://www.energyaustralia.com.au/about-us/energy-generation/yallourn-power-station/energy-transition.

[26] In Victoria, generators must give five years notice of closure.

[27] ACCC Determination at https://www.accc.gov.au/system/files/public-registers/documents/D10%2B3621896.pdf.

generator in this state would become insufficiently profitable up to 2030 resulting in an early closure (bringing forward its retirement three years) based on Approach 1.

AEMO acknowledges that retirement decisions are highly complex and uncertain. Asset owners will consider factors and information which is commercially sensitive and not known to AEMO, along with other plant- or portfolio- specific factors. Therefore, the closure forecast for *Progressive Change* is just one possible path for coal withdrawals; actual withdrawals may occur more rapidly, or at different stations. However, recent years have seen coal stations bringing forward expected closures years, and current coal availability challenges demonstrate that there are potential catalysts for earlier closures.

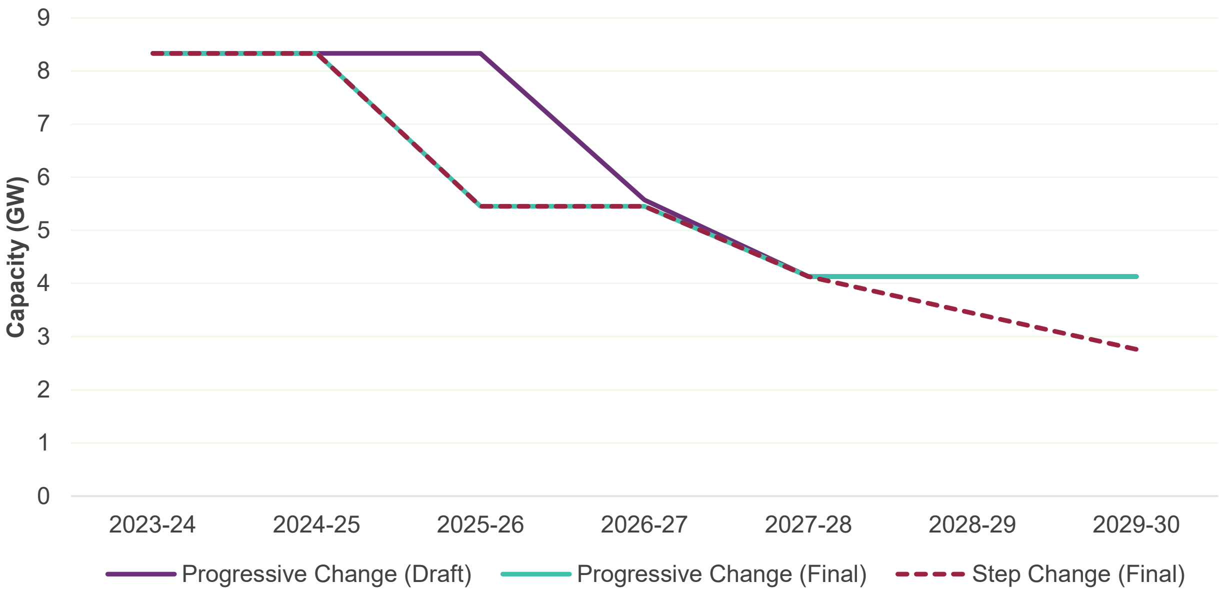
Impact on retirements trajectory due to Eraring early closure

In February 2022, Origin Energy announced[28] the potential early retirement of the Eraring Power Station in August 2025, five years earlier than the previously announced gradual withdrawal which had been set to commence in 2030. This accelerated closure is broadly in line with the Draft ISP, and AEMO has used Approach 1 to assess the impact of the Eraring possible early withdrawal on the timing of other coal retirements due to unprofitability under *Progressive Change*.

Based on the updated assessment considering this recent market development, and as shown in Figure 32:

- The Eraring Power Station closure is equivalent to a New South Wales coal closure one year earlier than forecast in the Draft ISP.
- This chart also shows that the updated trajectory of *Progressive Change* for New South Wales is now consistent with the *Step Change* projection to 2027-28.
- Other than this one-year realignment, the retirement schedule remains as was forecast in the Draft ISP, responding after 2030 to the influence of the scenario's carbon budget.

Figure 32 Forecast installed coal capacity in New South Wales in Draft and Final ISP, 2023-24 to 2029-30, *Progressive Change* (Draft and Final) and *Step Change*



28 At https://www.originenergy.com.au/about/investors-media/origin-proposes-to-accelerate-exit-from-coal-fired-generation/.

Options for coal to mitigate the impacts of increasing VRE penetration

Across the 2021-22 year, some coal power stations have operated at lower levels than previously observed minimum generation levels, and further differences in recent operation relative to historical daily generation profiles have been observed. Emerging strategies also include economic decommitment/seasonal mothballing where units are either taken offline or delayed in returning to service after an outage due to subdued market conditions. Each of these approaches has implications for the system services the NEM relies on from these types of generation.

Deploying these strategies at times of low residual demand and price may improve the profitability of coal generators. Temporary withdrawal of supply from the market may result in higher wholesale prices, which can increase total portfolio revenue, subject to commercial positions. While some strategies may increase maintenance costs, others may reduce other operating costs, for example if capacity withdrawal reduced the ramping needs across the station.

This ISP modelling considered coal seasonal mothballing and how that might affect early retirement decisions in *Progressive Change* up to 2030. Based on discussion with stakeholders including coal generator operators, AEMO considers short-term (that is, intra-day) decommitment unlikely, and instead only allowed the modelling process to optimise for decommitments of one week or longer at a time.

AEMO conducted a modelled assessment of potential decommitment benefits based on forecast wholesale energy revenue with no direct consideration of contract positions (or FCAS markets). In this assessment, if a generator was forecast to experience wholesale energy market losses for the week ahead, and these were greater than the estimated cost of turning off and eventually re starting a unit, then it was assumed that the unit would decommit for that week. The assessment was performed across multiple units in all regions on a rolling weekly basis and assuming stations with higher operating costs were likely to decommit first.

Based on modelled assumptions, this assessment identified that some coal generators would be potentially more profitable in future with a more flexible operational strategy, turning off during extended periods of low prices. While the decommitment increased some generators' revenue, this increase was found to be insufficient to warrant extending the life of any coal units. Seasonal decommitment strategies did not alter the early retirement timings in *Progressive Change*.

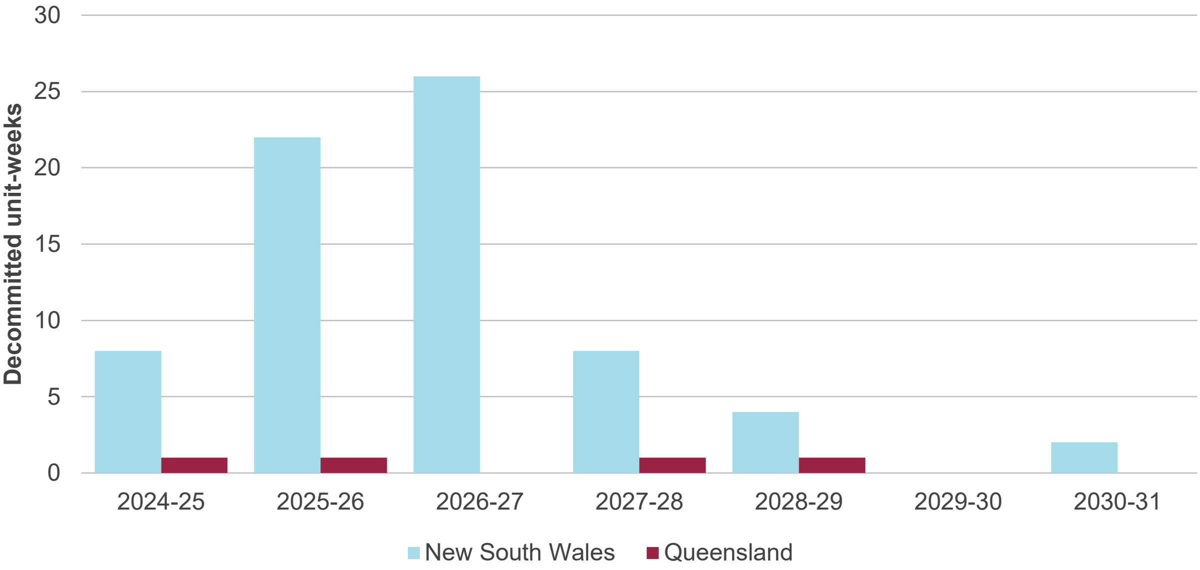
Figure 33 below shows the additional decommitment (beyond standard planned and unplanned maintenance) of black coal units across Queensland and New South Wales based on the Draft ISP outcomes. Decommitment strategies for brown coal generators did not suggest this to be appropriate for those generators in the ISP modelling.

Beyond coal generator profitability, seasonal decommitment also results in less VRE curtailment, as it reduces the level of baseload generation during periods of low prices. The reduced coal generation with decommitment is replaced mainly by other coal units, with gas generation providing additional support during peak conditions.

In addition to the potential for coal generators to benefit from occasional decommitment with the strong transition to renewable energy, there is also an increasing need for more flexible coal operations, to the extent possible given the operational characteristics of the fleet.

Generation owners may need to invest in aging coal units to improve their ramping capability to meet evening peak demand unless other firm supply is available to the market. However, additional ramping may increase the operating and maintenance cost of coal units, and further increase the likelihood of earlier retirements, or deterioration in reliability.

Figure 33 Forecast additional time on outage due to forecast decommitments, 2024-25 to 2030-31, *Progressive Change*



A4.2.8 Role of gas-fired generation

Gas-fired generators will play a crucial role as significant coal generation retires, particularly in the transition to a net zero emissions economy. Gas-fired generation will help manage extended periods of low VRE output and provide power system services to support grid security and stability. Gas-fired generation is expected to complement energy storages to provide the firming capacity and flexibility needs of the grid, ensuring the grid is operable during extreme market events and weather conditions, as well as continuing to be a key technology that can respond to the needs of the power system during planned and forced outage conditions.

As coal-fired generators retire and more VRE enters the system, gas generation is forecast to become more peaking and primarily to be relied on during periods of low VRE output such as long dark and still events, as well as at times of peak demand.

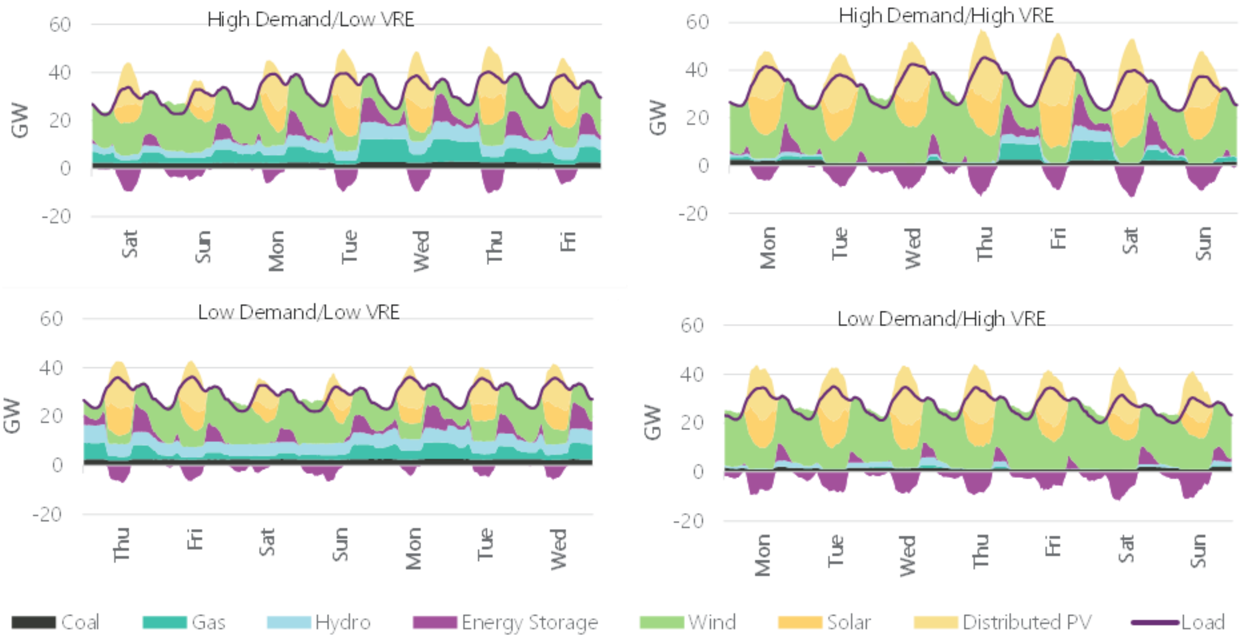
This is illustrated by Figure 34, which shows four additional examples of a week's variable conditions in 2034-35. It demonstrates the complementary role that storage, hydro and gas-fired generation will need to play to efficiently operate beside renewable generation. In all examples, gas-fired generation has a key role, except when there is an abundance of VRE and limited consumer demand (shown in the bottom right example), and sufficient alternative firming technologies to manage VRE variability.

Figure 34 demonstrates four conditions which illustrate the range of total NEM generation from gas-fired generation in a selection of years in *Step Change*:

- **Low renewable output and high demand (top left)** – the system relies more on hydro, and gas generation complemented in the evening peak by shallow storage (including VPPs) charged from distributed PV and utility-scale solar during the day. Existing mid-merit gas-fired generators assist through the night, with peaking gas-fired generators needed in the evening and occasionally the morning peaks.
- **High renewable output and high demand (top right)** – gas-fired generation is needed to meet the demand peaks just after sunset, and to keep going through the night to cover for wind variability.

- **Low renewable output and low demand (bottom left)** – gas-fired generation is needed through the night, particularly during winter, when solar output is lower.
- **High renewable output and low demand (bottom right)** – with VRE output far exceeding total demand, gas generation is barely needed. Deeper storages fill their reservoirs from the excess energy.

Figure 34 Forecast indicative generation mix in the NEM, 2034-35, *Step Change*

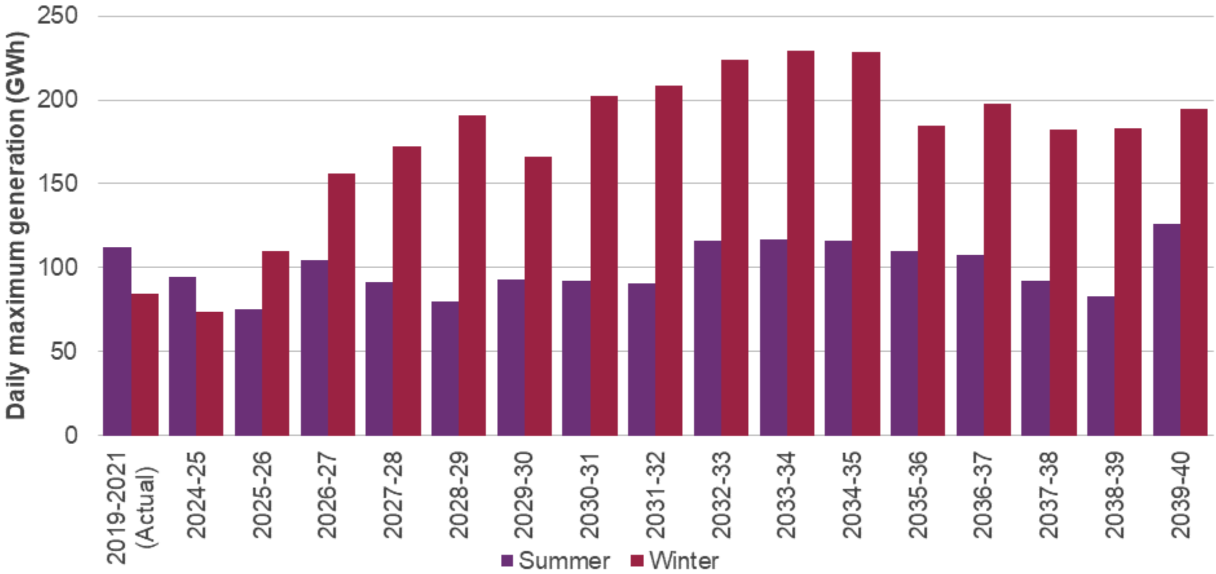


The seasonal behaviour of gas-fired generation is also changing, with an increasing shift in daily generation towards winter, with shorter days leading to less solar generation. This may initially have implications for gas supply adequacy, given direct-use gas consumption is already winter peaking due to heating requirements (at least until more of this heating load is electrified, and/or alternative fuels, such as hydrogen, provide an appropriate alternate fuel to substitute for natural gas as needed).

Figure 35 below compares historical maximum daily gas generation for summer and winter with the forecast in *Step Change*. For more in-depth analysis of the annual energy and peak day gas generation forecasts across a range of scenarios, and the potential implications for the east coast gas system, see the 2022 *Gas Statement of Opportunities* (GSOO)[29].

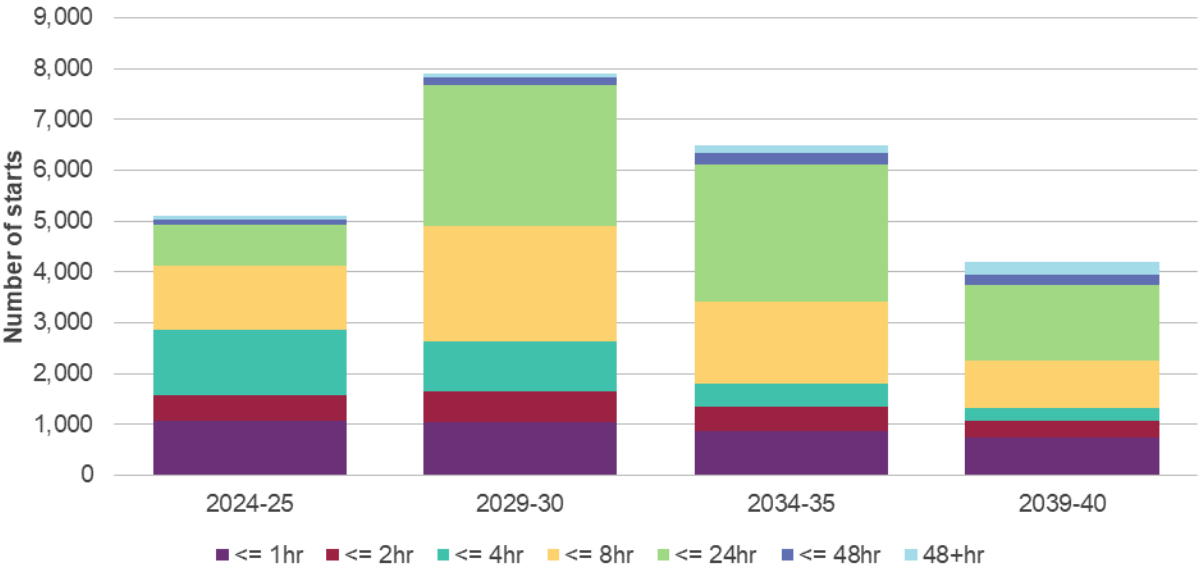
[29] At https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2022/2022-gas-statement-of-opportunities.pdf.

Figure 35 Actual and forecast summer and winter maximum daily gas generation, 2024-25 to 2039-40, *Step Change*



As coal-fired generation capacity declines, gas-fired generators are projected to start more frequently and run for longer periods of time (as seen in Figure 36 below), depending on the investments made in energy storage, and even more if coal-fired generators cannot operate as flexibly as assumed for sustained periods.

Figure 36 Forecast number of starts and duration of gas generation operation, 2024-25 to 2039-40, *Step Change*



In the longer term, further investment in longer duration storage is forecast to reduce the need for gas-fired generators to operate for extended periods, but not to eliminate it. As illustrated in Section A4.2.4, gas generators are forecast to continue to play a pivotal role during challenging weather conditions, both in conditions driving high demand, and also in longer periods of low VRE output that are beyond what shallow and medium storage can meet.

Responding to multi-day long dark and still events implies running more intensely for longer periods but on fewer days of the year, leading to less starts and increased variability in daily gas offtake. The role of gas-fired generators in providing an on-demand fuel source for extended operating periods could also be delivered by alternative technologies such as hydrogen turbines, or potentially greater investment in long-duration storages. However, under current assumptions, gas remains the most cost-effective solution for this role.