Appendix 4. System operability

December 2021

Appendix to Draft 2022 ISP for the National Electricity Market

Important notice

Purpose

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

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Version control

Version	Release date	Changes
1	10/12/2021	Initial release.

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Consultation on development of inputs, assumptions and scenarios

Consultation on scenario weightings

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A4.1 Introduction

Section 4 of the Draft ISP sets out how different forms of dispatchable capacity are needed to complement network transmission and renewable generation as the NEM transforms.

This appendix supports the Draft ISP by providing deeper insights into the reliability and operability of development paths identified in the Draft 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 operability 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 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.

Details of the impact of forecast operation on power system security, including system strength, inertia and network support and control ancillary services (NSCAS), are provided in Appendix 7.

[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

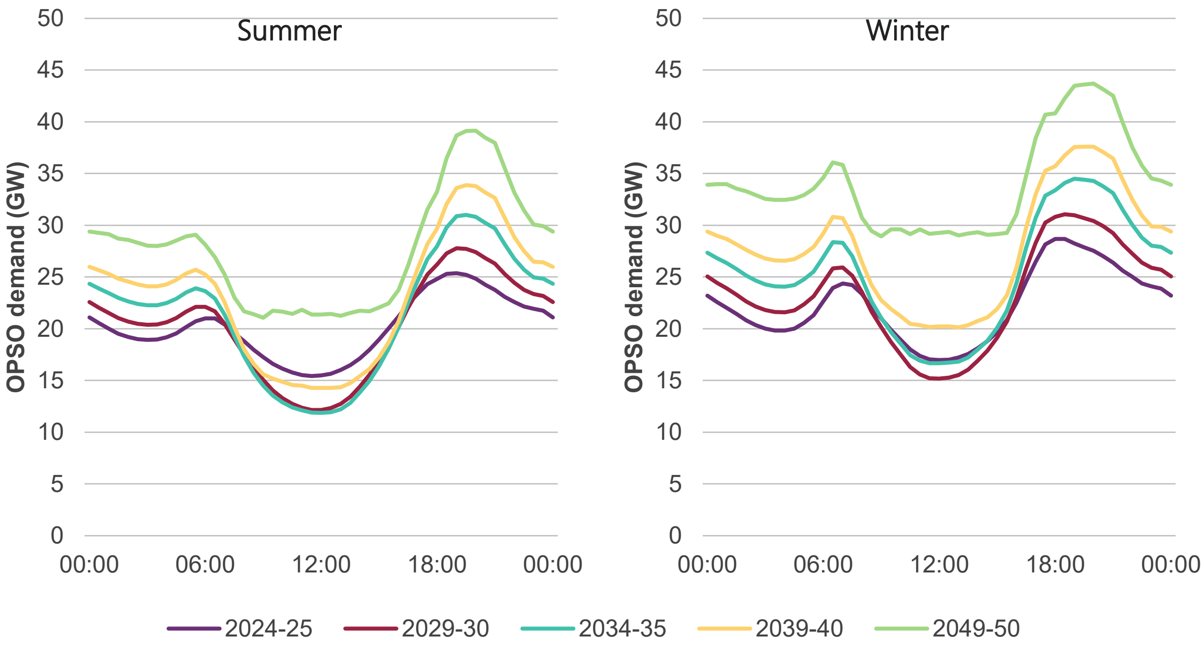
A4.2.1 Changing demand profile due to electrification and DER

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

One of the main drivers of the changing shape of demand is the relationship between DER devices – specifically distributed PV, batteries and EVs. Distributed PV has and will continue to reduce the energy drawn from the transmission system during the day. The emergence of battery storages at customer premises will temper this pattern, enabling behind-the-meter shifting of daytime surplus energy to discharge during evenings and overnight.

These dynamics are illustrated in Figure 1, showing the average time of day operational sent-out demand (OPSO[2]) profile for summer and winter seasons. While the daily pattern is 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 NEM average OPSO demand, *Step Change* scenario, comparing seasonal demand profiles



As identified and discussed in the 2021 *Electricity Statement of Opportunities* (ESOO)[3], minimum operational demand in the *Step Change* scenario is expected to rapidly decline in the short term with Victoria and South Australia forecast to reach negative minimums, driven by strong DER growth. These low minimum levels will create power system operability issues, particularly relating to system security (see the 2021 ESOO for more).

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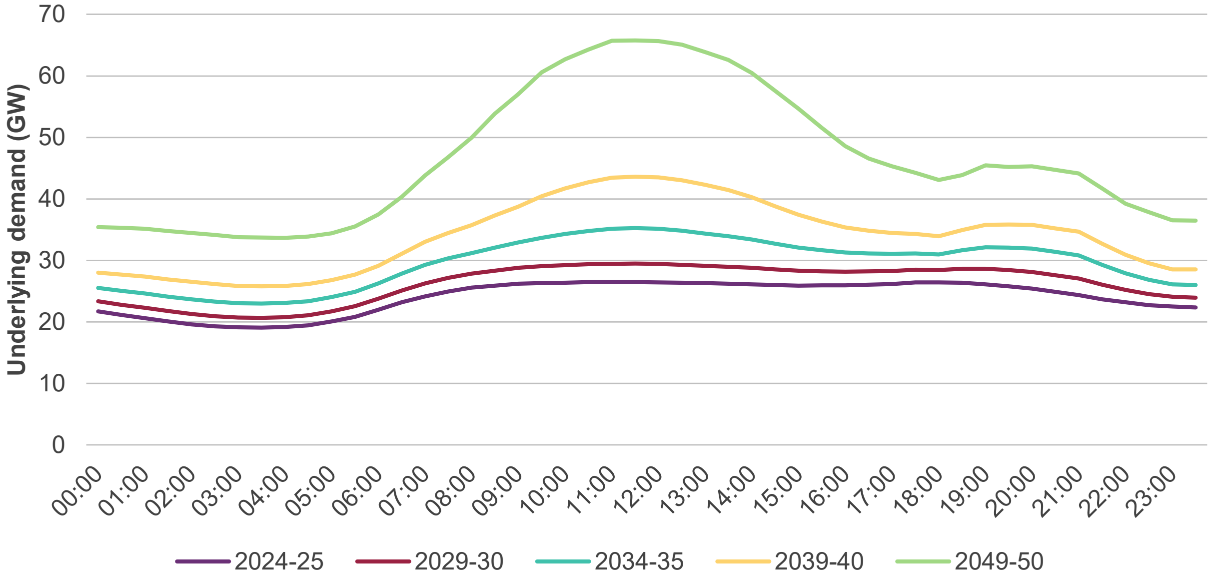
[2] Note the electricity consumption profiles presented in this section excludes electricity consumed in the production of hydrogen.

[3] 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.

Figure 2 shows the average time of day profile of underlying demand[4] in the *Step Change* scenario. It shows the scale of energy growth forecast over the next 30 years, in response to electrification of other sectoral energy loads, and also the opportunity for behavioural and technological change to increase daytime loads

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. The *Step Change* scenario assumes increasingly engaged consumers use this infrastructure in the middle of the day, incentivised by market-driven price signals. EV charging will also add demand in the evening, creating a more pronounced evening peak.

Figure 2 NEM annual average time-of-day underlying demand profiles, *Step Change* scenario



A4.2.2 Renewable energy penetration

In all scenarios modelled in this Draft ISP, the NEM power system will continue its significant transformation to world leading levels of renewable energy (utility-scale and DER) output measured as a percentage of annual generation as well as instantaneously, period by period.

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

A key focus and priority of AEMO is managing the NEM as it transitions towards high instantaneous penetration of renewable generation, and engineering the power system to operate it securely through periods of 100% instantaneous penetration that are expected within the next five years; that is, dispatch periods where all electricity generated to meet demand is produced by renewable sources.

[4] In this appendix underlying demand includes transmission and distribution losses.

Figure 3 shows the forecast NEM-wide annual share of total generation from renewable sources[5] and instantaneous penetration[6] from 2025 to 2050 in the *Step Change* scenario. The renewable share will rise from approximately 28% in 2020-21 to approximately 97% by 2050. There also will be times where all NEM generation will be produced from renewables, with increasing frequency across the forecast horizon. By 2025, there could be sufficient renewable potential to hit 100% instantaneous penetration during a small number of dispatch periods. At times the renewable penetration will exceed the instantaneous demand for electricity from consumers, 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 could rise to almost two-thirds[7].

Figure 3 NEM annual share of renewable generation and instantaneous penetration, 2025-50, *Step Change* scenario

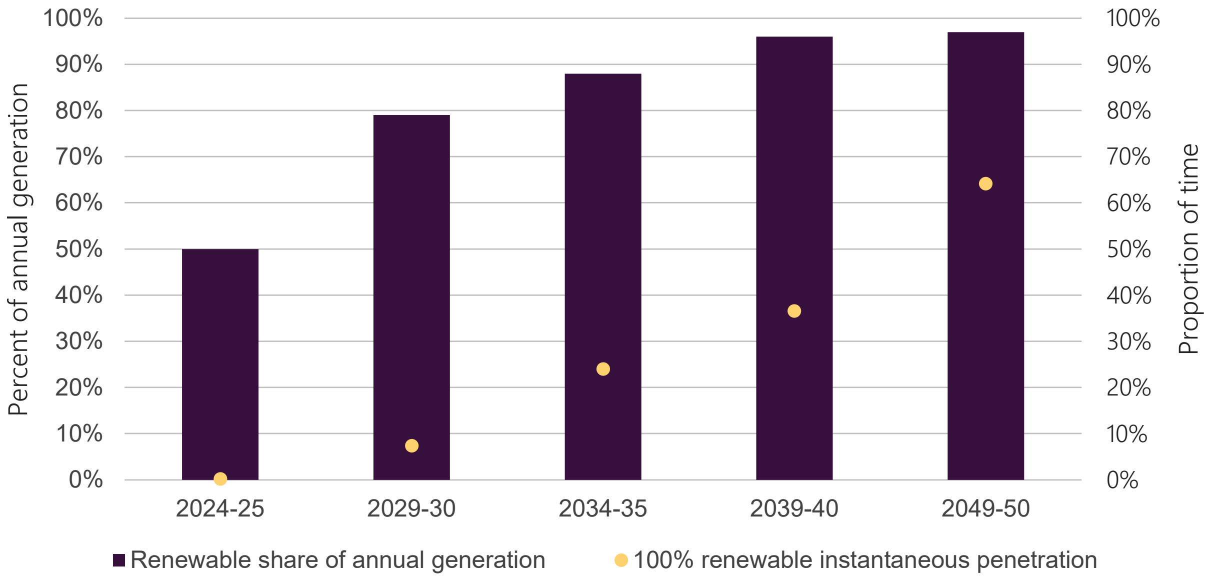


Figure 4 below shows how the instantaneous penetration of renewable energy is projected to evolve over time and relative to underlying demand under the *Step Change* scenario.

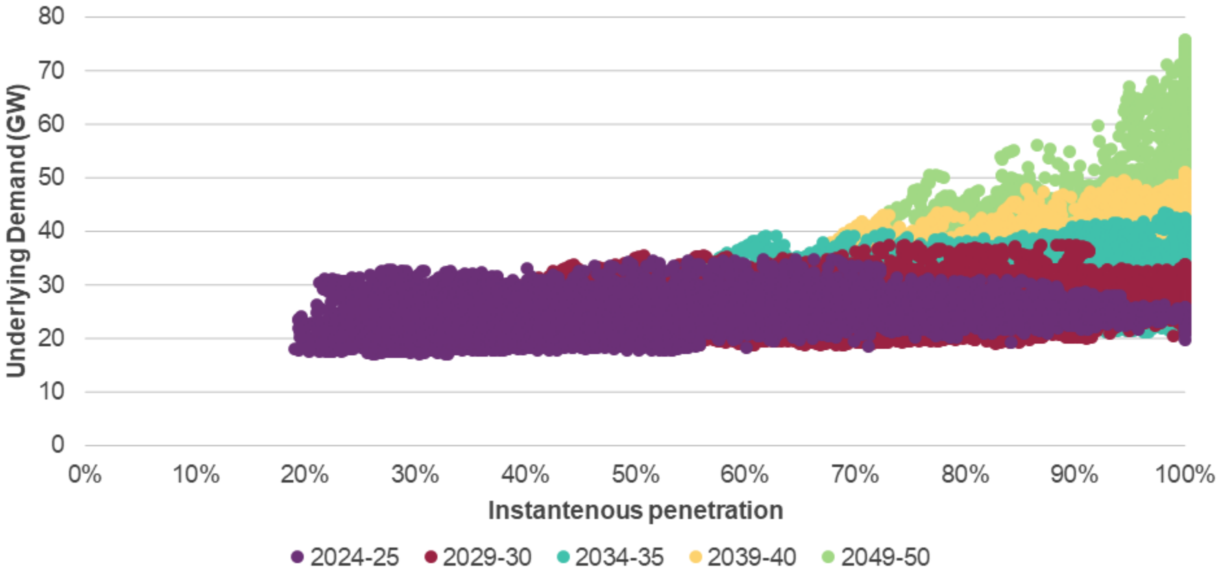
In 2024-25, instantaneous renewable penetration ranges from as little as 19% to as high as 100%. Periods of low demand are forecast to see the highest penetration up to 100% in some dispatch periods. As the system transitions, the range will narrow and periods of 100% penetration will occur more frequently,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

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

[6] Instantaneous renewable penetration 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. In this appendix this metric is based on VRE resource potential, that is, availability rather than generation.

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

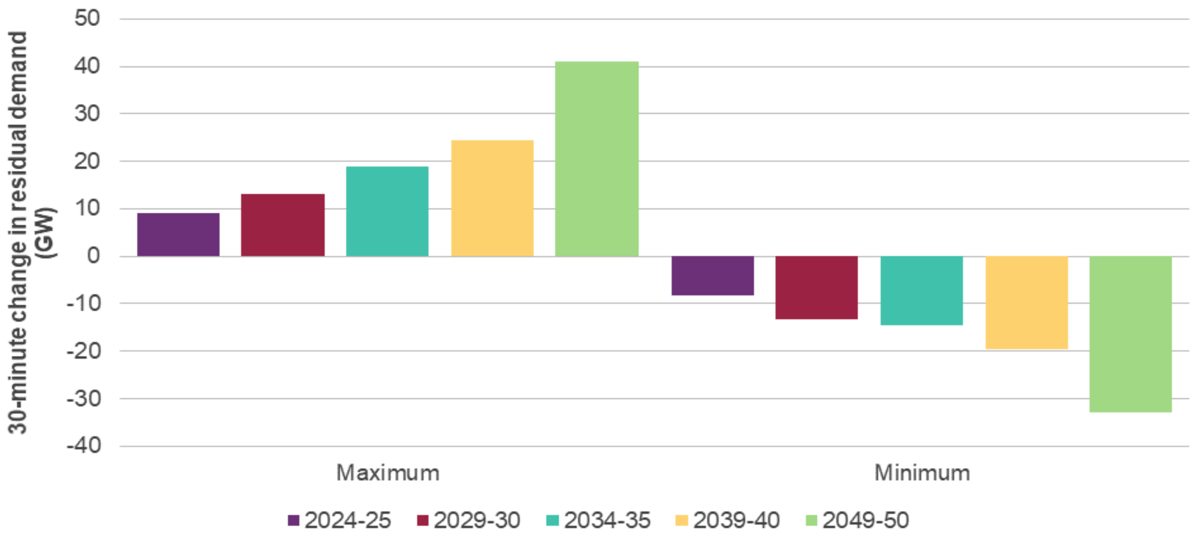
Figure 4 Instantaneous renewable penetration, calculated for *Step Change*, reference year 2015



A4.2.3 Implications for system flexibility

As the amount of VRE in the NEM continues to increase, levels of residual demand will both decrease and become more variable. Figure 5 below shows the increasing maximum and minimum changes in half-hourly residual demand over a year for the *Step Change* scenario, where residual demand represents demand net of renewable energy generation, including utility-scale wind and solar generation.

Figure 5 Projected maximum and minimum changes in half-hourly residual demand, *Step Change* scenario



This 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 inflexible units slowly ramping down).

Figure 6 and Figure 7 show the 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 The time-of-day distribution of half-hourly residual demand changes, *Step Change* scenario, 2024-25

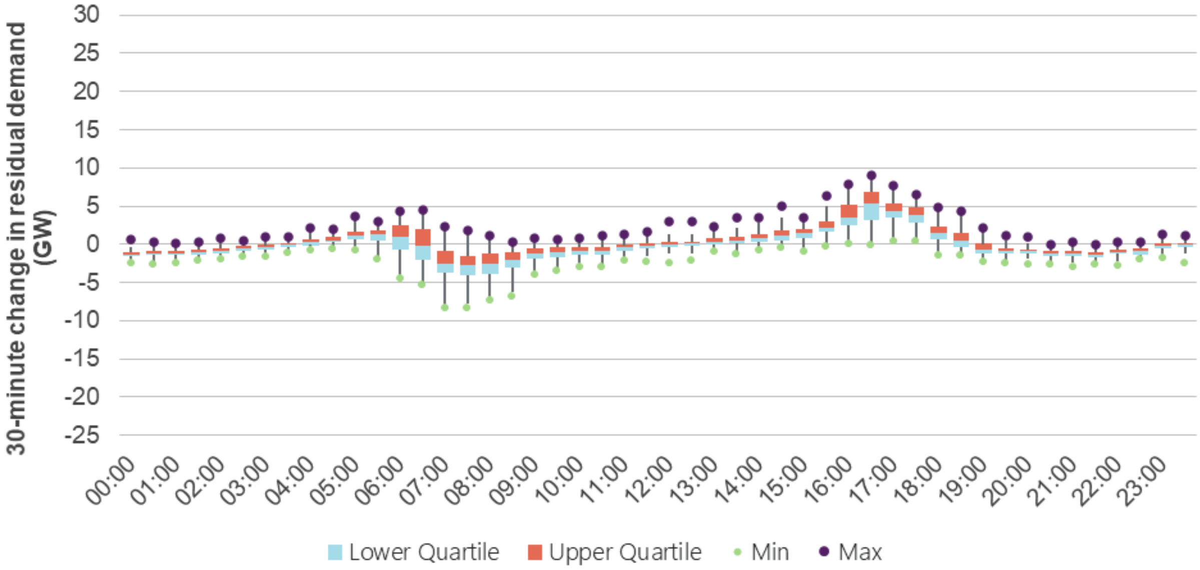
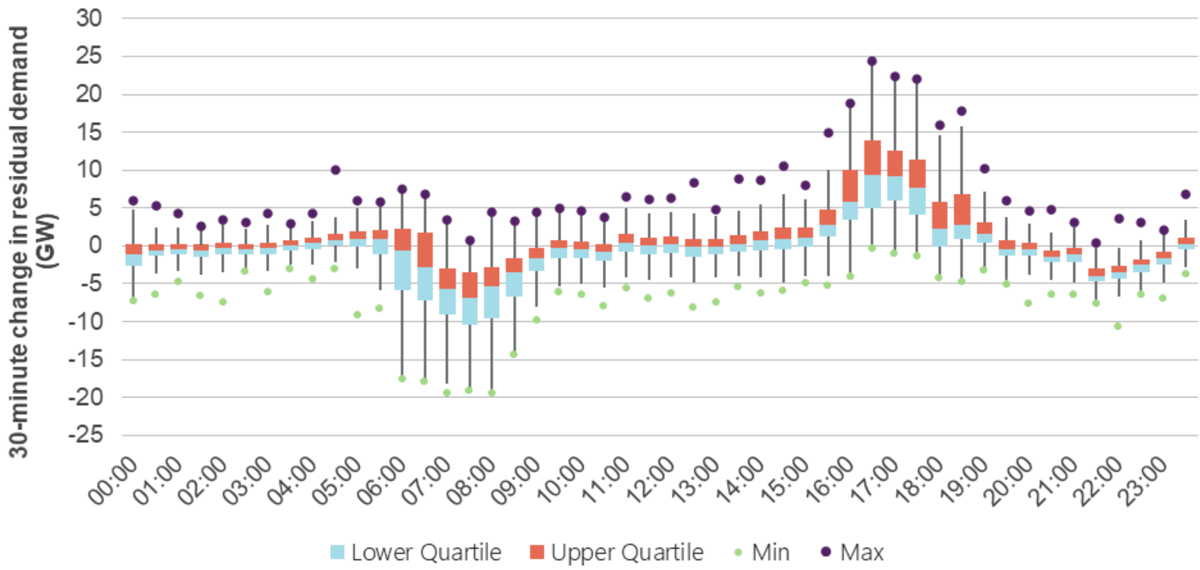


Figure 7 Time-of-day distribution of half-hourly residual demand changes, *Step Change* scenario, 2039-40



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

Figure 8 Forecast maximum ramping capability of dispatchable generation, *Step Change*

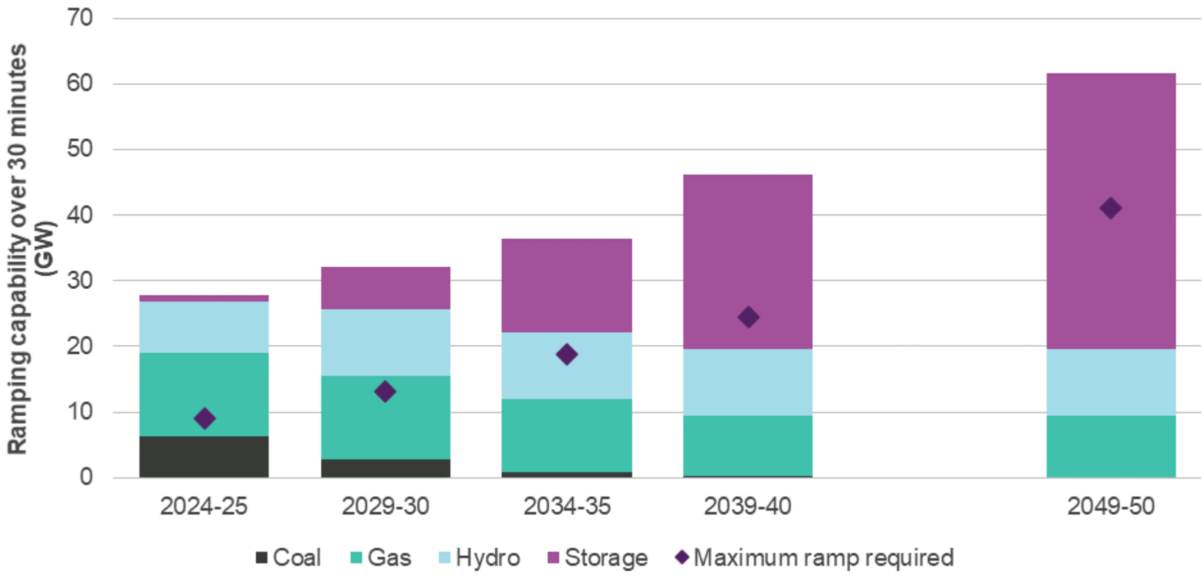


Figure 8 also shows that there is sufficient physical ramping capability to meet the highest ramping requirements. However, whether a unit can ramp up and down at a certain time depends on several factors – availability, online status, whether it is already generating at minimum or maximum capacity – and for storage it will depend on its state of charge at that time. Storage dispatchability will become a critical operational consideration, that is, ensuring storage has sufficient discharge capacity and state of charge headroom readily available and willing to generate when flexibility up and down is required. 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.

This analysis does not consider the operational challenges of maintaining the security of the grid, such as the provision of FCAS to support active power management of the power system. AEMO's Engineering Framework[9] provides more detail regarding the engineering requirements of the future power.

Within operational timeframes, further consideration must be given on the capacity of the power system to respond to fluctuations in the grid's stability, and the capacity for resources to provide fast frequency response. These grid services may be provided by either traditional thermal generators, or IBR. Battery providers that operate to service the generation ramping requirements to meet half-hourly fluctuations in demand, may also need to operate within a narrower operational range to ensure they can still provide FCAS as required in both raise/lower directions if needed.

[8] 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.

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

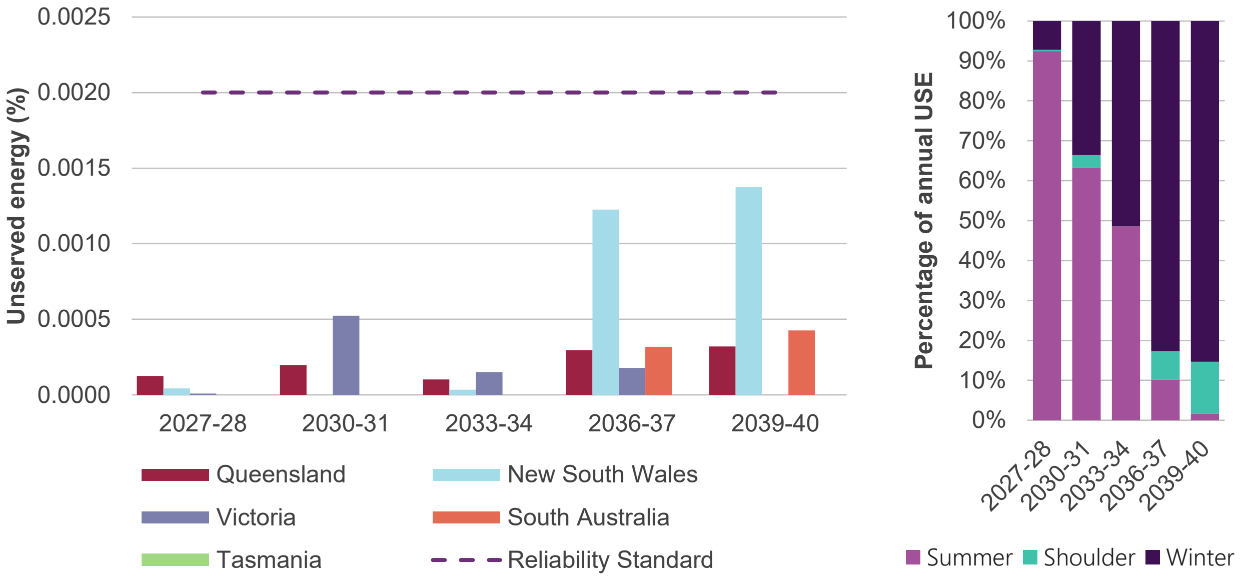
A4.2.4 Implications for maintaining reliability

Changing seasonality of reliability risks

The accelerated transition to higher renewable energy penetration, thermal generation withdrawals, as well as greater fuel switching to electricity and hydrogen have implications for the reliability of the NEM. 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. The reliability of the power system relies on the availability of firm, dispatchable resources to ensure consumer demand can be met at all times, irrespective of prevailing weather conditions. There is also a key role for the transmission system to enable the sharing of resources more efficiently and resiliently across locations (and enabling storage to share resources across time), reducing the scale of firming resources required by increasing the connectivity of geographical and technically diverse generation.

The ISP development opportunities included in the draft ODP maintain reliability below the reliability standard in all regions and any given year. 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* Scenario (left) and seasonal share of NEM-wide reliability events (right)



The seasonal profile of electricity demand is projected to shift with greater electricity consumption forecast for winter than has been observed historically. The implication of this shift for reliability risks is demonstrated in the right-side figure in Figure 9. The chart shows that most of the projected 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 by 2040, the reliability risk is heightened during mild and cold weather. These winter and shoulder reliability events are likely to be experienced in all regions and are characterised by shortages of wind energy lasting longer than the duration of most storages.

Dunkelflaute

“Dunkelflaute” is a German term that means dark doldrums or dark wind lull, and essentially describes events where there is minimal or no sunshine and wind for extended periods. The conditions can last from a few hours to a few days, although the significance of these conditions is if they persist for multiple days. They most frequently therefore occur during winter, when solar conditions are naturally lesser than other seasons. Dunkelflaute, also referred to as renewable drought, may lead to energy shortages in a system with very high VRE penetration such as is forecast for the NEM, if insufficient firming and storages are not developed to complement the expansion of VRE.

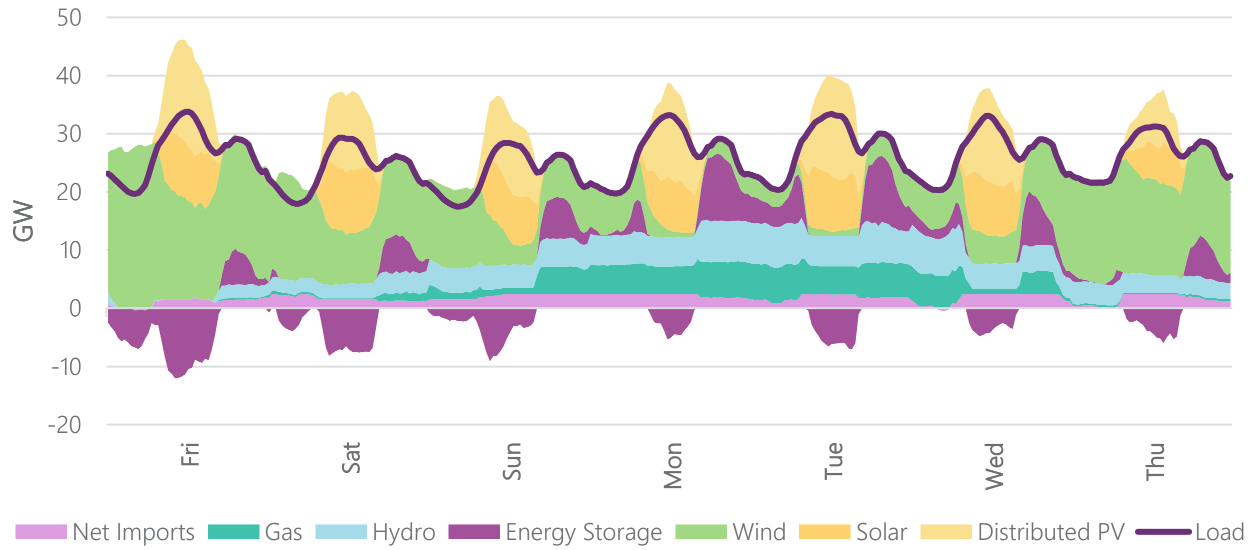
AEMO has explored Dunkelflaute-type events in the future NEM, considering projected weather patterns based on historical conditions from 2010-11 to 2019-20. While future weather conditions may differ to historical observations, this modelling shows how Dunkelflaute-type events may occur in the future NEM, and the operational impact of these.

Within the range of weather modelled and considering the geographic and technological diversity forecast in the Draft ISP, AEMO does find severe Dunkelflaute-type events tend to be localised, with lesser risk of a NEM-wide event. The diversity of resources is a strong benefit of the REZ expansions forecast in the ISP; transmission that enables this diversity will improve the operability of the grid during these conditions.

The southern regions of the NEM are more susceptible to Dunkelflaute-type events in winter. This is due to high energy demands coinciding with low sun angles and short days which reduce the performance of solar PV. Investment in wind generation, which generally performs well in winter, provides ample energy on the days when it is available. Queensland requires less heating load and experiences less seasonal variation in solar energy, so is less susceptible.

Low wind will be the most impactful weather condition for future operability, given the natural predictability of solar performance, and the forecast expansion of wind resources in AEMO’s *Step Change* scenario, particularly in southern NEM regions. Figure 10 shows the forecast dispatch across all NEM regions excluding Queensland (which has less challenging weather than the south) in a week in July 2039 with high residual demand across New South Wales, Victoria, South Australia and Tasmania.

Figure 10 A week in the NEM (excluding Queensland) when southern regions are experiencing a three-day low VRE period, July 2039



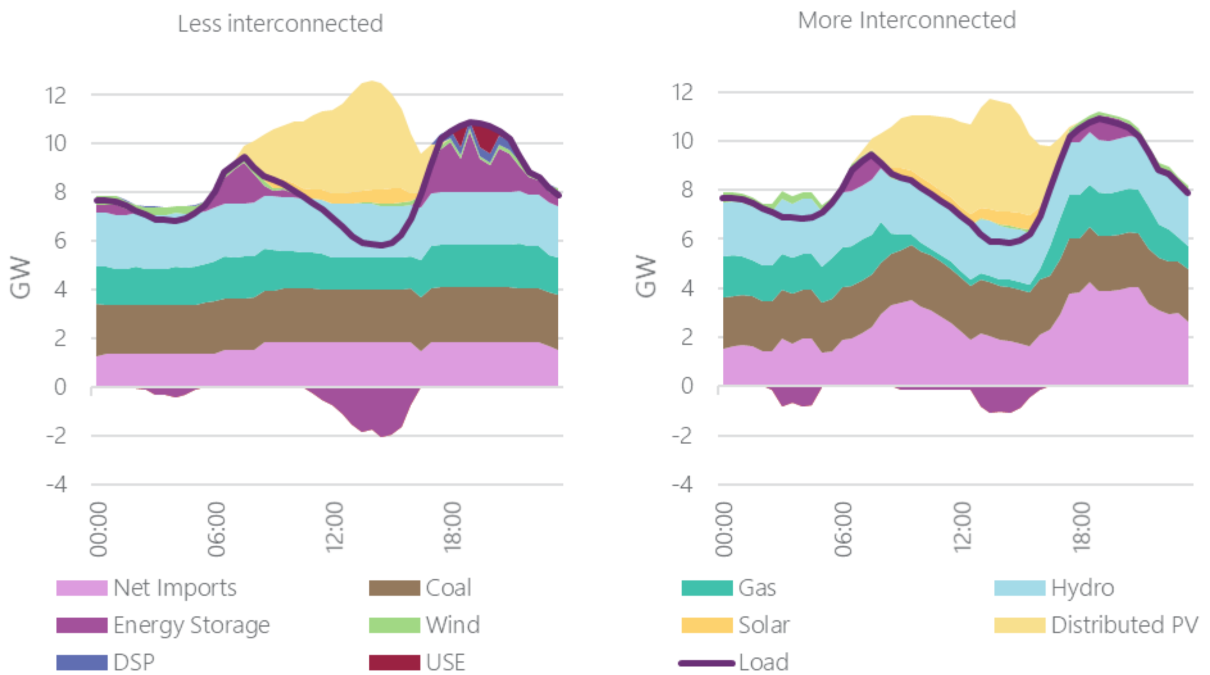
In this sample week, weather conditions are calm, cloudy and cool, leading to higher heating loads and limited renewable energy availability. The most severe renewable energy shortfall runs from Sunday to Wednesday, when there is almost no wind generation. During this period the system relies heavily on gas and hydro generation, requiring continuous operation over more than 36 hours. 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 relative to demand over most of the week, and is able to export excess available energy throughout the week. Short- and medium-duration storages fill the troughs and shave the peaks of the demand profile, using much of their power and energy capacity to do so. Deeper storages are also able to shift energy from days prior to the shortage (such as the Friday shown).

Stronger wind conditions in northern New South Wales assist, filling energy storages where it can then be used to meet peak load in the evening. Technology diversity also helps manage the risk associated with Dunkelflaute, with both wind and solar generators providing strong contributions at different times across the week.

Geographic diversity, supported by transmission, is a key solution to mitigate the impacts of Dunkelflaute events. Inland locations for large-scale PV receive not only more solar irradiance, they also are less likely to be shaded by cloud at the same time as distributed PV in coastal metro areas. Locating wind across different regions reduces the likelihood that all wind farms will experience calm conditions at the same time.

Figure 11 shows how the operability of the grid changes with alternative access to transmission, during a Dunkelflaute event in Victoria in 2035 in the *Progressive Change* scenario. On the left is a system without significant new interconnectors and on the right is one with transmission augmentations, including Marinus Link (two cables) and VNI West – two ISP Projects which have direct impact on Victoria. With limited transmission, gas generation must run all day to provide energy, and the interconnectors also import at full capacity for most of the day. There is also increasing utility in customer load flexibility, via demand response arrangements. Nonetheless, some USE is observed in the counterfactual without transmission.

Figure 11 Victorian supply mix on a winter day during a Dunkelflaute event in a transmission-oriented and a storage-oriented development path



Given the forecast diversity of resources across the NEM (and across REZs within any single region), severe low VRE days such as shown in Figure 10 require coincident weather patterns that have not occurred very often in recent history. The day featured in Figure 11, for example, is the second-most severe low VRE day for Victoria in the 10 weather reference years modelled.

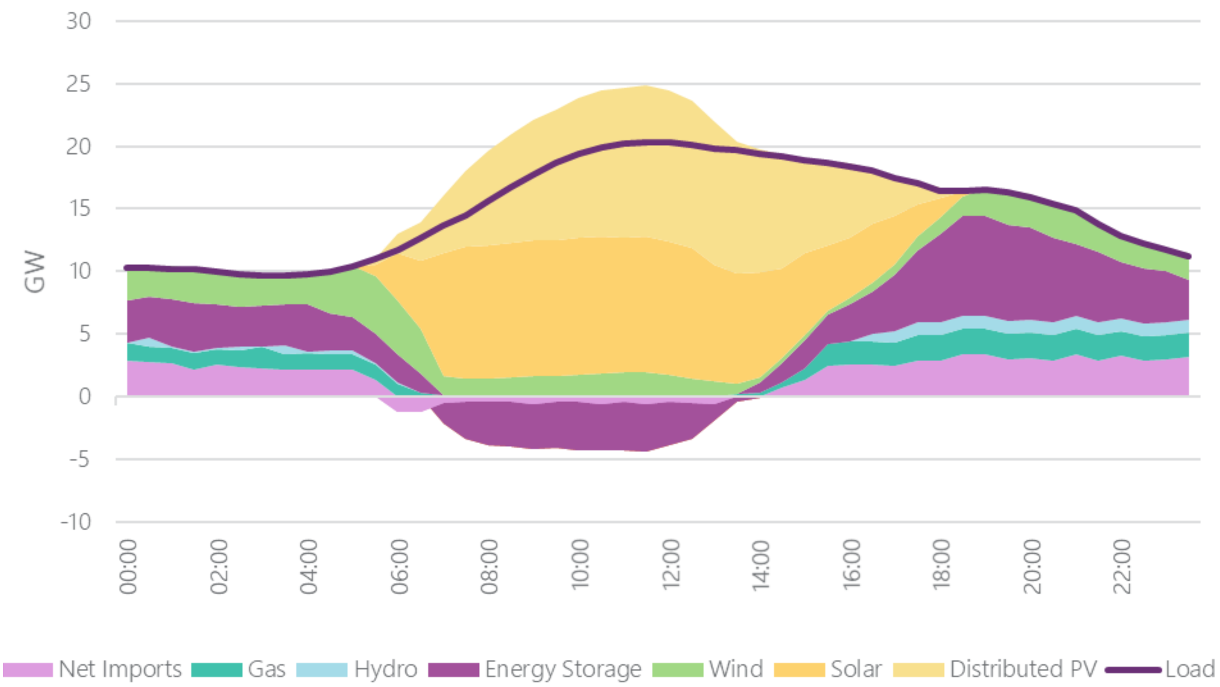
With sufficient investment in transmission, it may be possible to avoid USE on such a day. The likelihood of these conditions affecting multiple REZs, in multiple inter-connected regions, will likely reduce with greater sharing of resources across the NEM via transmission.

Meeting peak day load

Compared to meeting winter Dunkelflaute events, meeting a summer peak is more often a question of having sufficient generation capacity than sufficient energy available. Figure 12 shows an example of a peak day in New South Wales in 2040 in the *Step Change* scenario. On this day the peak in operational load occurs just after sunset, at 1900 hrs. There is no solar available and just 2.3 GW of wind is generating from 15.6 GW installed (approximately 15%).

Energy storage provides 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 provide additional firm energy, while the improved transmission links to neighbouring regions allow 3.5 GW of imports at peak. In this example, gas generation runs continuously overnight; further detail on the changing role for gas generation is provided in Section A4.2.8.

Figure 12 Meeting a peak day in New South Wales in 2040



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 customer'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.

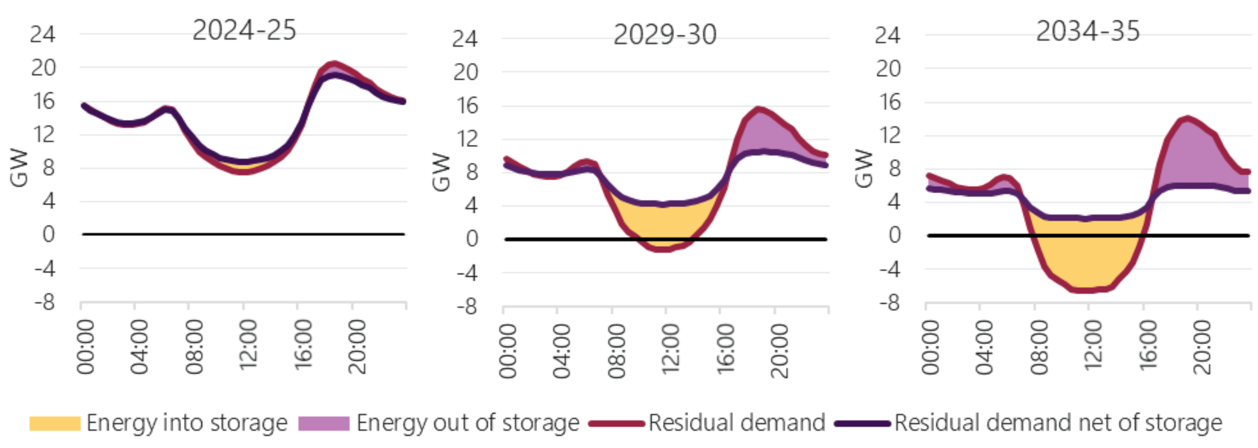
Intra-day and inter-day storage operation

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 identifies a strong role for storage technologies of various depths in all scenarios.

As the VRE penetration increases and more storages are developed, energy storages 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 13 shows the average time-of-day profile of residual demand and the forecast daily operation of storage.

Figure 13 Average time of day profile of residual demand, *Step Change*



In the next 10 to 15 years, as VRE penetration increases and coal-fired generation retires, the importance of storage to offset solar production in particular and shift this energy to evening and overnight periods increases. In 2024-25, much like today, storage technologies have relatively small installed capacity and storage operation will focus on filling in the deepest part of the daytime residual demand trough and shaving the very tip of the evening peak. By 2030, VRE is regularly providing 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 use the stored energy to flatten the evening peak. This allows the remaining dispatchable generation to operate to a flatter profile.

Unlocking deep hydro-electric storage

The NEM presently holds a high capacity to store 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. Additional 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 14 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 the *Step Change* scenario. Over time, with more solar and shallow storage added, and as electrification in particular adds energy consumption across the year, the energy adequacy concerns shift from summer to winter, so deep hydro shifts to discharging more in autumn and winter.

Reservoirs fill up after winter rains, and spring snow-melt, but rather than release water for generation in summer, there are only minimal releases for environmental or irrigation purposes over this season, storing most of the water as potential energy for use between April and July.

Figure 14 Daily energy stored in deeper storages and traditional hydroelectric reservoirs over a year

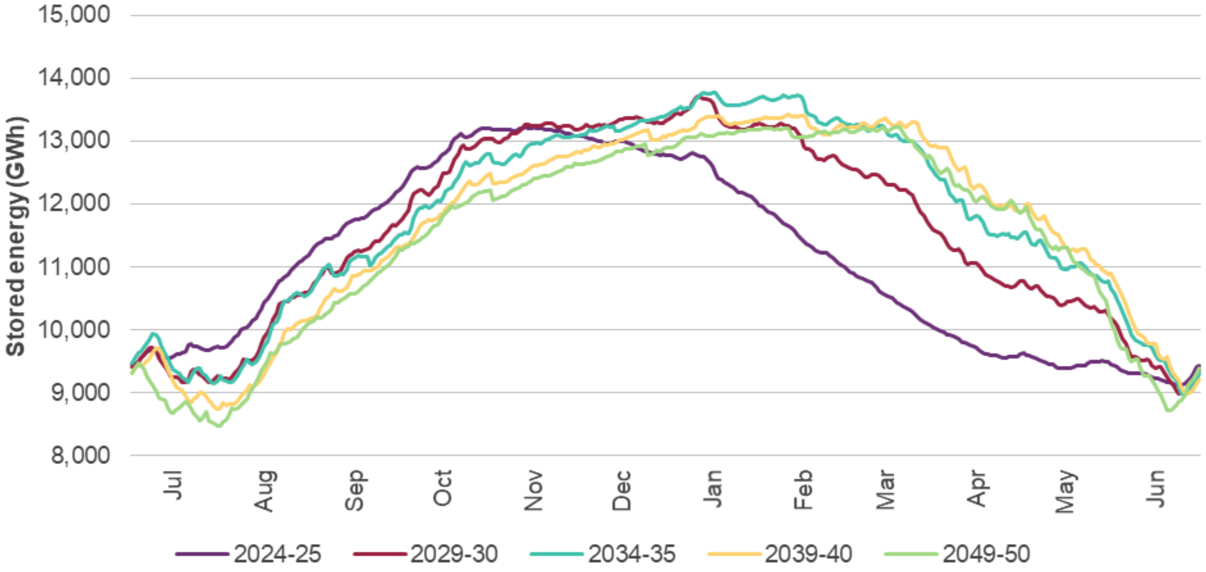
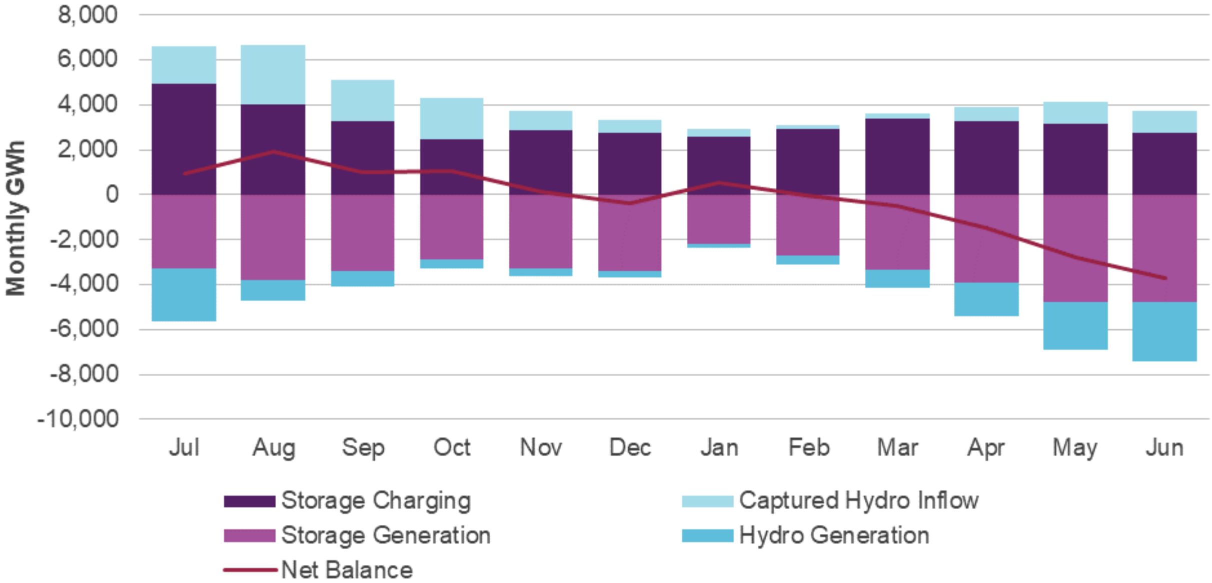


Figure 15 below shows the monthly energy that is charged, and discharged, from all storages in 2039-40 in the *Step Change* scenario. The shallower pumped hydro and battery storages operate at a consistent rate throughout all months of the year, shifting energy intra-day. Hydro receives its inflows in the spring and reduces its generation during the VRE-surplus months from September to March, to provide much needed firming in the winter months.

Figure 15 Monthly energy balance of all storages (battery and hydro), in *Step Change* in 2039-40

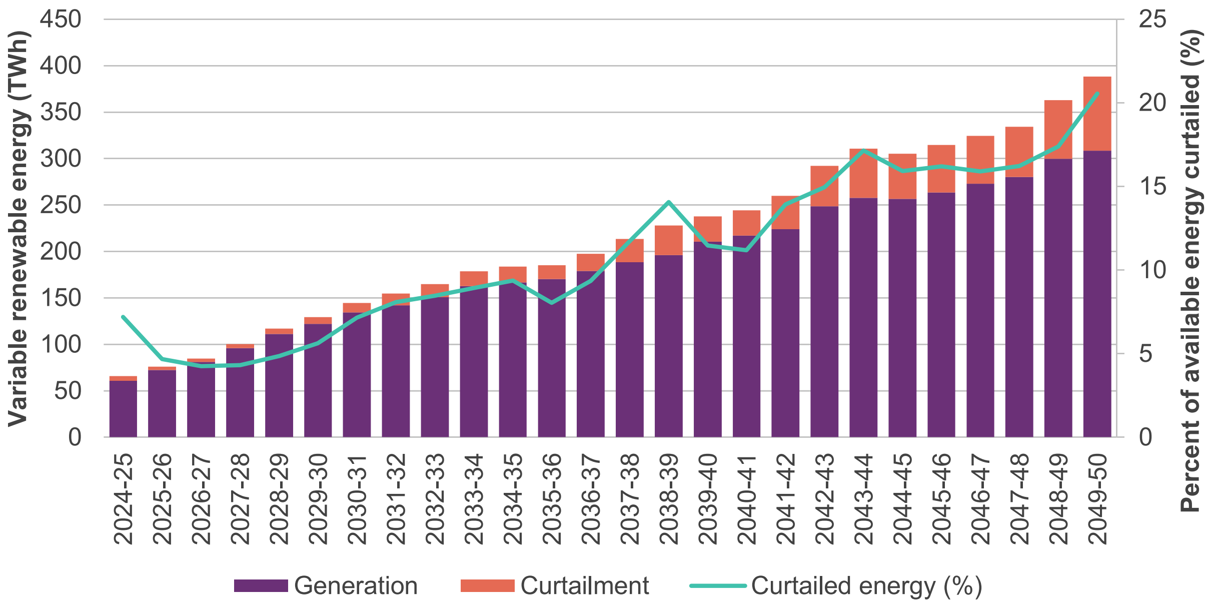


A4.2.6 Renewable generation curtailment

AEMO modelling shows that the economic development of VRE, storages and transmission may lead to periods where VRE does not generate at its full available capacity. It is sometimes more efficient to curtail or 'waste' some generation. This is due to system security or other operability constraints in the network, or to there simply being over-abundant renewable energy available with insufficient load or energy storage to consume the surplus.

Figure 16 shows the trajectory of energy curtailed in the *Step Change* scenario.

Figure 16 NEM variable renewable generation curtailment, *Step Change with new transmission*



Curtailment trends 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. The primary cause of the loss of potential VRE output is surplus, with system security and other network constraints representing a much smaller share.

Prices during curtailment

Figure 17 show the distribution of curtailment across wholesale price bands due to transmission limitations and the inability to deliver local generation to the customer. 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. 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 will occur at prices below $10/MWh.

Figure 17 *Step Change* price distribution of curtailment in NEM

Figure 18 below shows average capacity curtailed across the day in 2039-40. Curtailment is strongly correlated with daylight hours and therefore solar output. Some curtailment is projected to occur at night but in smaller proportion.

Figure 19 shows the distribution of curtailment at monthly level in 2039-40. It shows that curtailment occurs 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 energy curtailed is significantly higher than the median value. 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.

Figure 18 *Step Change* **NEM average time of day curtailment in 2039-40**

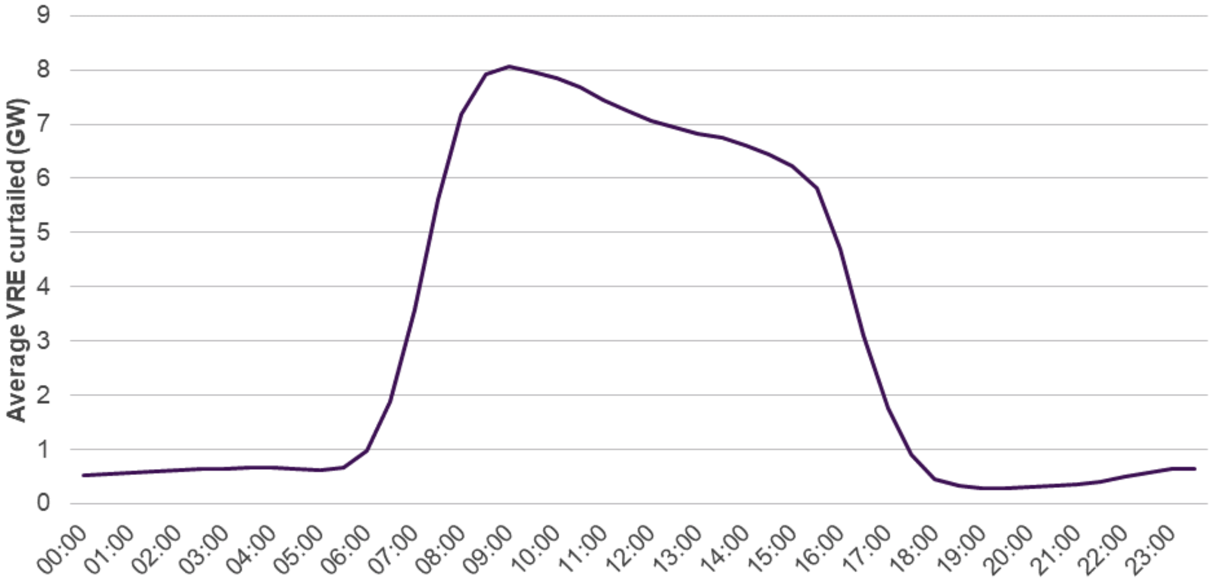
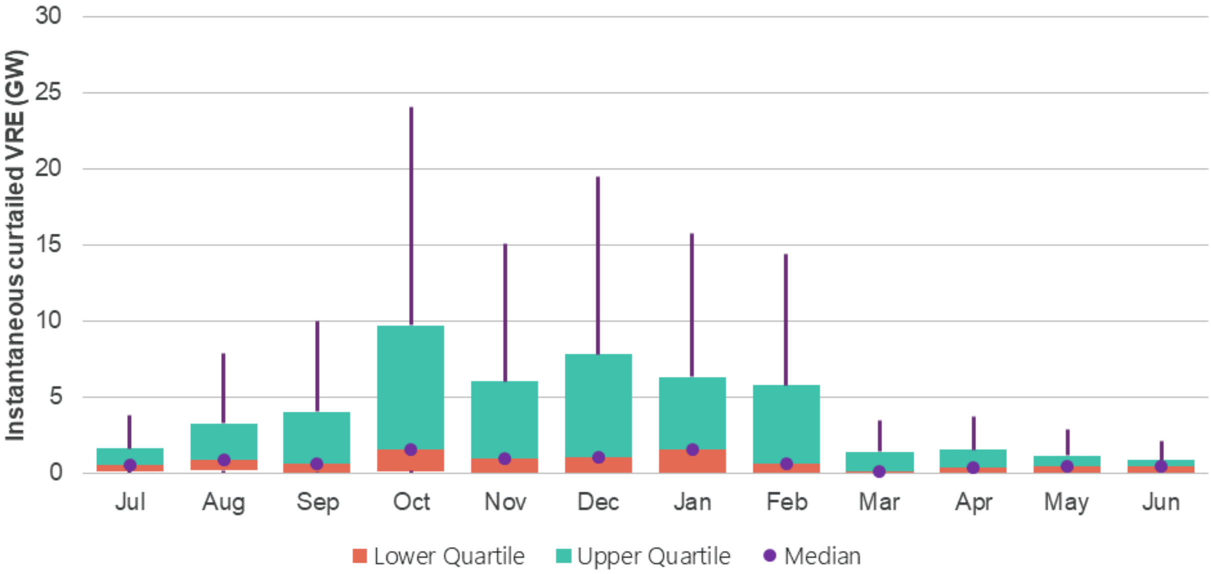


Figure 19 *Step Change* **frequency of spare available VRE capacity in 2039-40 for the NEM**

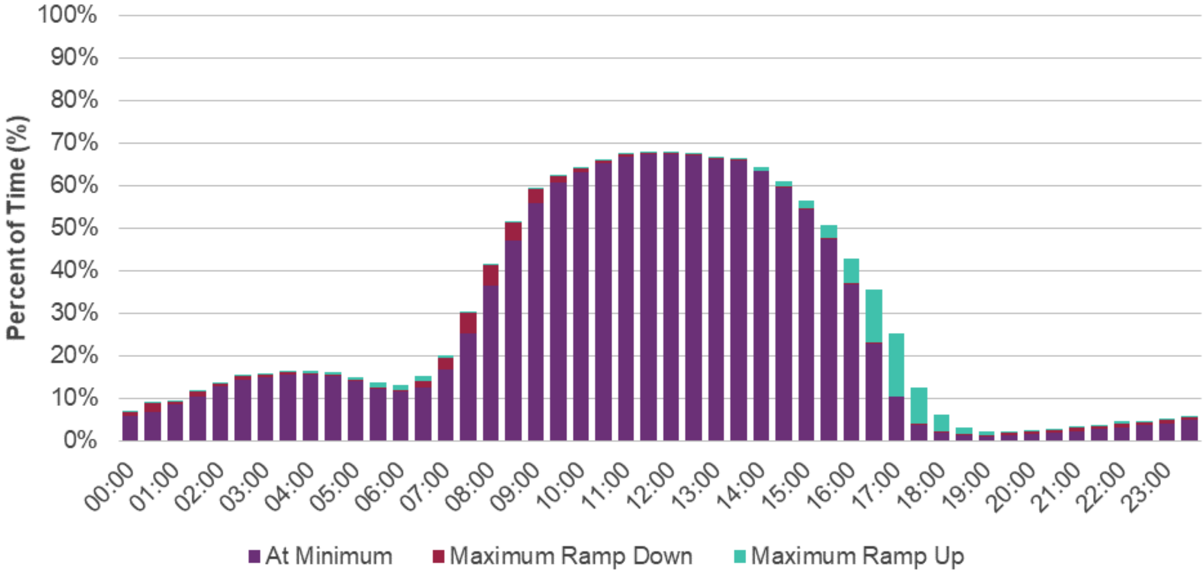


A4.2.7 Implication for coal operation and revenue sufficiency

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

As outlined in Appendix 2, AEMO forecasts that the operation of coal generators will reduce, displaced by cheaper sources of generation, particularly in periods of low load when operational demand is forecast to reduce dramatically. In these conditions, coal generators will increasingly be required to operate at minimum generation levels for longer periods (see Figure 20), and ramp up and down more frequently. This may lead to more wear and tear on plant, more frequent and prolonged outages, and more costly maintenance, and plant may experience longer outages as a result of more challenging operational decisions. Eventually, plant retirement decisions may be considered by owners (although these decisions are complex and must account for a myriad of factors).

Figure 20 Black coal percentage of time at max ramp and min load in *Progressive Change*, 2024-25



AEMO's consideration of coal retirements in the ISP

AEMO has assessed the revenue sufficiency of the coal fleet under the *Progressive Change* scenario to inform the retirement trajectory up until 2030, after which decarbonisation targets are expected to become a more influential driver of coal withdrawals in that scenario.

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 projection forecast for the *Progressive Change* scenario 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 as such the assumption all coal generation will continue to operate until current nominated closure years is likely to be an optimistic assumption.

Options for coal to mitigate the impacts of increasing VRE penetration

To mitigate the impacts of increasing DER and VRE penetration and other forms of market competition, AEMO expect that coal generators will continue to search for ways to operate more flexibly. In recent months some coal power stations have operated at lower levels than previously observed minimum generation levels, and 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 wear and tear costs, others may reduce operating costs, for example if capacity withdrawal reduced the ramping needs across the station.

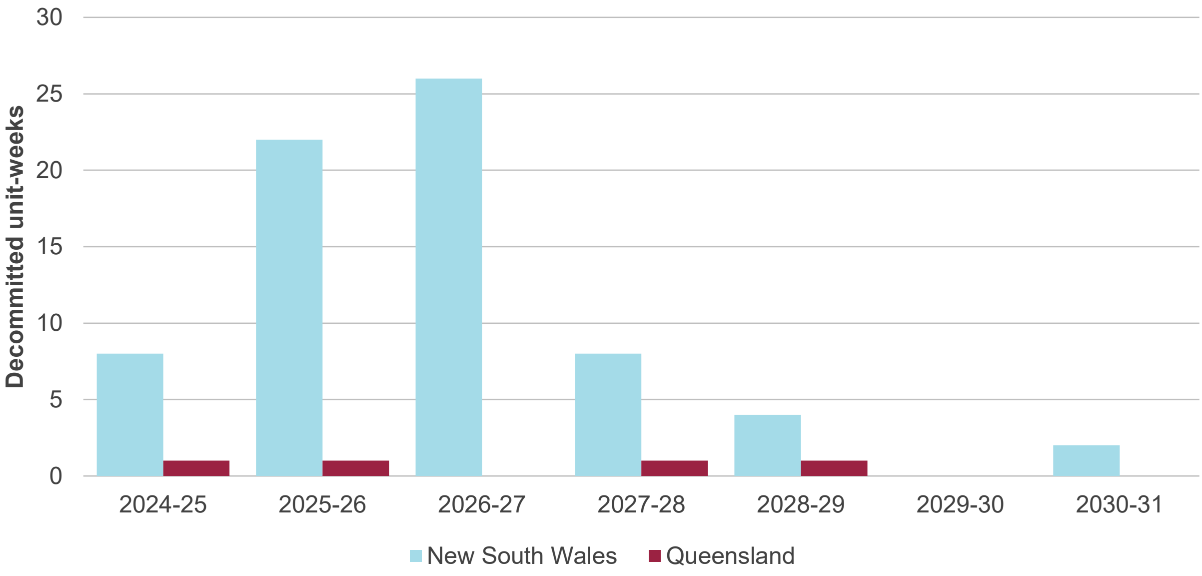
This ISP modelling tested coal decommitment options. Based on discussion with stakeholders including coal generator operators, AEMO considers short-term (that is, intra-day) decommitment unlikely, and instead only allowed the modelling process to optimise for decommitments of one week or longer at a 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 are therefore not expected to materially alter the modelled retirement timings in the *Progressive Change* scenario.

Figure 21 below shows the additional decommitment (beyond standard planned and unplanned maintenance) of black coal units across Queensland and New South Wales. Decommitment strategies for brown coal generators did not suggest this to be appropriate for those generators in the ISP modelling.

Figure 21 Additional time on outage due to forecast decommitments in the *Progressive Change* scenario



Beyond coal generator profitability, seasonal decommitment also results in less VRE curtailment, as it reduces the level of baseload generation during low prices periods. 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.

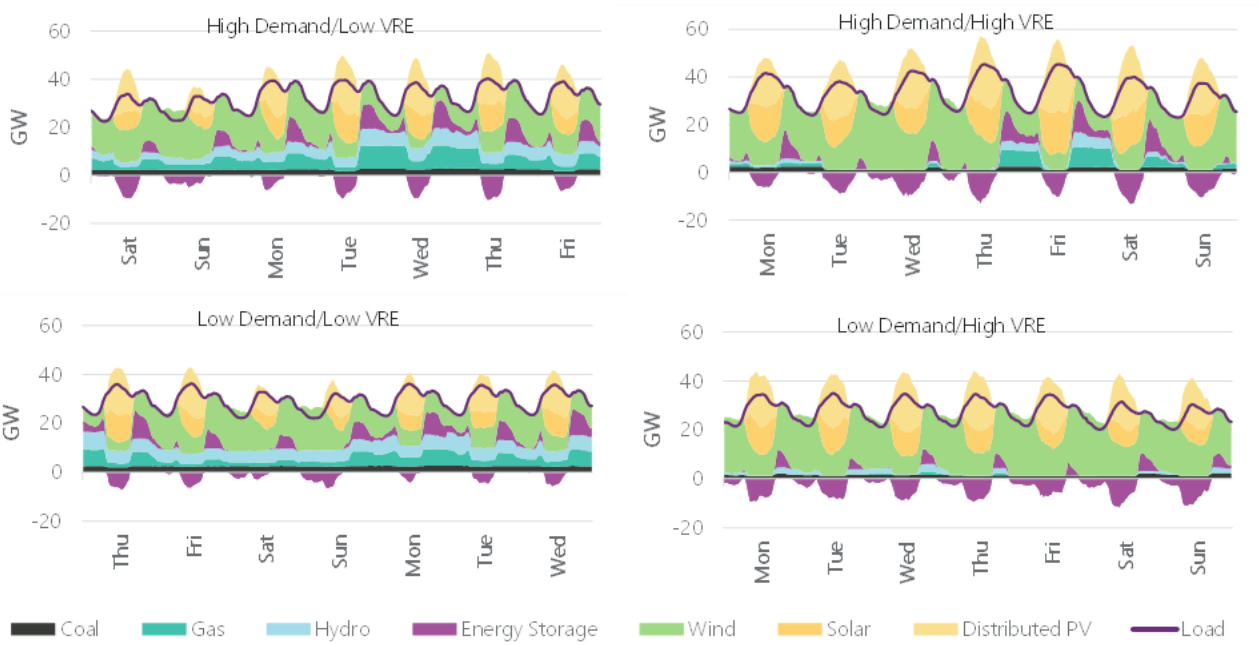
A4.2.8 Role of gas generation

Gas generators will play a crucial role as significant coal generation retires, both to help manage extended periods of low VRE output and to provide power system services to provide grid security and stability. Gas 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 VRE continues to enter the system, gas generation is forecast to become more peaking and primarily being relied on during periods of low VRE output, as well as at times of peak demand. As coal generators withdraw or retire, the significance of gas operations is projected to increase.

This is illustrated by Figure 22 below, which shows four additional examples of a week's variable conditions in 2034-35. It demonstrates the complementary role that storage, hydro and gas generation will need to play to efficiently operate beside renewable generation.

Figure 22 Indicative generation mix in the NEM, *Step Change* scenario, 2034-35



The figure demonstrates four conditions:

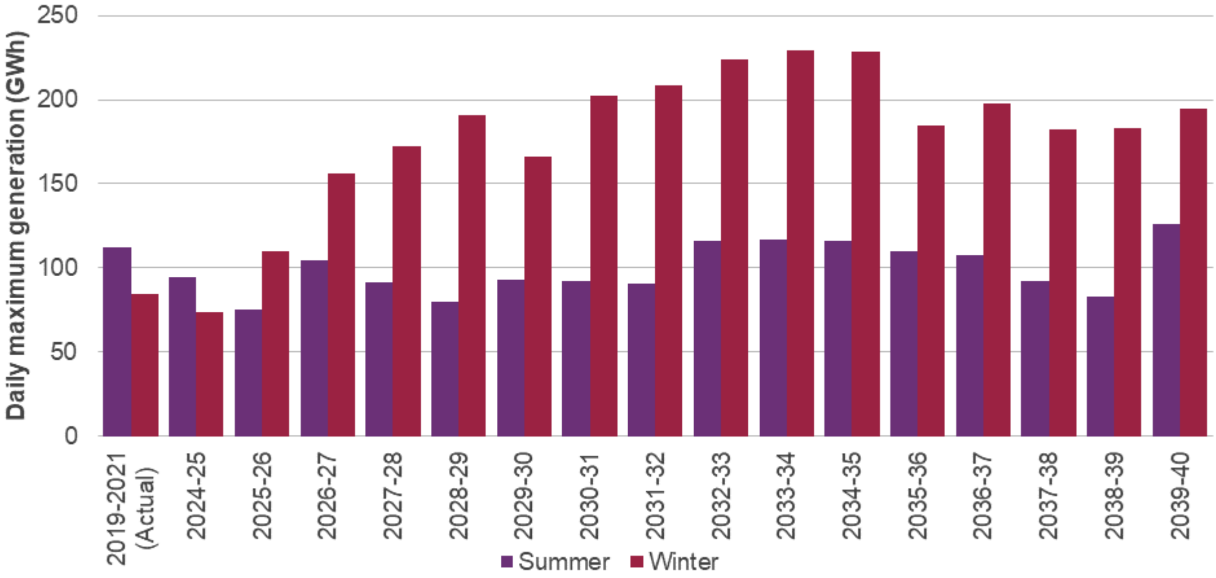
- **Low renewable output and high demand (top left)**: the system relies more on hydro, and gas, complemented in the evening peak by shallow storage (including VPPs) charged from distributed PV and utility-scale solar during the day. Existing mid-merit gas generators assist through the night, with peaking gas generators needed in the evening and occasionally the morning peaks.
- **High renewable output and high demand (top right)**: gas 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 is needed through the night, particularly during winter, when solar output is lower.
- **High renewable output and low demand (bottom right)**: With VRE output well in excess of total demand, gas generation is barely needed. Deeper storages fill their reservoirs from the excess energy which shows the range of total NEM generation from gas generation in a selection of years in the *Step Change* scenario.

The seasonal behaviour of gas 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 gas as needed).

Figure 23 below compares the projected and historical maximum daily gas generation for summer and winter in the *Step Change* scenario.

Figure 23 Summer and winter maximum daily gas generation, 2024-25 to 2039-40, *Step Change*



As coal capacity declines, gas generators are projected to start more frequently and run for longer periods of time (as seen in Figure 24 below), depending on the investments made in energy storage – more so, if coal generators cannot operate as flexibly as assumed for sustained periods.

In the longer-term, further investment in longer duration storage reduces the need for gas generators to operate for extended periods, but does not eliminate it. As illustrated in Section A4.2.4, gas generators are forecast to continue to play a pivotal role during challenging weather conditions. The role of gas 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, utilising gas for this role remains the most cost-effective solution.

Figure 24 Number of starts and duration of gas generation operation, *Step Change*