Appendix 4. System Operability

December 2023

Appendix to the Draft 2024 Integrated System Plan for the National Electricity Market

Important notice

Purpose

This is Appendix 4 to the Draft 2024 Integrated System Plan (ISP) which is available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp. AEMO publishes the Draft 2024 *Integrated System Plan* (ISP) pursuant to its functions under section 49(2) of the National Electricity Law (which defines AEMO's functions as National Transmission Planner) and its supporting functions under the National Electricity Rules. This publication is generally based on information available to AEMO as at 30 October 2023 unless otherwise indicated.

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Version control

Version	Release date	Changes
1.0	15/12/2023	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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Executive summary

AEMO's *Integrated System Plan* (ISP) is a roadmap for the transition of the National Electricity Market (NEM) power system, with a clear plan for essential infrastructure to meet future energy needs. The ISP's optimal development path sets out the needed generation, firming and transmission, which would deliver significant net market benefits for consumers and economic opportunities in Australia's regions.

This appendix details the modelling AEMO has undertaken to assess the operability and reliability of the ODP identified in the ISP. This relies on a short-term time sequential model, which forecasts dispatch of the electricity market on a 30-minute basis. The analysis of modelling results shows the system can operate reliably across all timeframes under more variable and sometimes extreme conditions.

The National Electricity Market (NEM) is forecast to be reliable out to 2050

The ODP set out in the Draft 2024 ISP is forecast to maintain NEM reliability in all regions for all years. The *reliability standard* requires that expected annual unserved energy (USE) does not exceed 0.002% of the total annual energy needs in each region. The *interim reliability measure* (IRM) is also in place until 2028 and requires expected USE to not exceed 0.0006% of total annual energy needs in each region.

The way consumers use electricity will continue to evolve

The way that consumers use electricity supplied through the electricity transmission and distribution networks is set to continue to change, and potentially evolve significantly with the continued uptake of consumer energy resources (CER), the electrification of industry, businesses, homes, and transportation, and the development of hydrogen-related loads.

Daily load patterns will become more variable, with distributed photovoltaic (PV) systems embedded within the distribution system supplying an increasing proportion of customer loads, and operational demand (that which is delivered from the transmission system) will therefore become even more variable. Seasonal variations will become more pronounced during winter with higher energy consumption as heating loads are electrified and reduced distributed PV output on the shorter days of the year. Resource flexibility and deep energy storages will be required to manage increased variability in operational demand across varying weather conditions and increasingly seasonal energy production profiles.

VRE penetration increases operational complexity

Operating the power system reliably with more VRE and fewer synchronous generators will present daily, weekly and seasonal challenges. Investments in transmission, VRE and storage will enable surplus energy to be used to meet demand where and when resources are less available. Solar will become the main energy source during daylight hours, complemented by wind energy and storage in the evening and overnight. Geographic and technological diversity of the supply mix will help to reduce the risks of poor weather conditions.

During longer periods of low VRE generation the system will rely on transmission to deliver resource diversity, as well as on deeper storage technologies, hydro and gas-powered generation (GPG). The highly variable residual demand (the demand that is met by scheduled units, net of VRE and CER output) will require generators with sufficient ramping capability and available energy across all operational timeframes to balance and firm renewable generation.

Longer, dark and still weather conditions will increase operability difficulties

From time to time, the power system will experience extended long, dark and still weather patterns over a wide area, meaning VRE output is low for several consecutive days. These extended VRE ‘droughts’ are rare and, over the longer term, extremely difficult to predict in duration and intensity. Resource diversity – particularly geographical diversity – will help mitigate the effects of localised low renewable conditions associated with adverse weather in a single area, but occasionally weather systems across larger areas of the NEM can reduce overall availability. By applying some of the most severe weather conditions observed historically and extending their duration significantly, the ODP has demonstrated resilience to extreme weather conditions, through the effective operation of diverse VRE resources, storage, GPG and hydro generation.

GPG provides critical support but gas supply can be constrained

Gas generators are a critical part of the current and future supply mix, and the role GPG plays is changing. The flexibility gas provides to support peak demands and maintain energy adequacy is expected to be particularly important during periods of low VRE generation.

AEMO anticipates that GPG may become constrained during peak periods when demand for gas heating and industry is also high, which will lead to the need for secondary fuels and utilisation of other back-up forms of generation at times. Future gas supply, gas infrastructure and on-site storage of fuels as well as accessibility to the electrical loads they are developed to service will all be necessary considerations for future flexible gas developments.

A4.1 Introduction

This appendix supplements the Draft 2024 ISP with additional analysis on the operability and reliability aspects of the ODP. It presents a granular assessment of operational dynamics and reliability challenges as the power system transitions to much higher levels of variable renewable energy (VRE).

This appendix presents a NEM-wide view and provides regional breakdowns where appropriate for the analysis AEMO has used in this assessment. In this appendix:

- A4.2 examines how demand profiles will continue to evolve and the impacts on power system operations.
- A4.3 provides forecasts and analysis for VRE penetration and curtailment.
- A4.4 analyses the requirement for resource flexibility to manage increased variability in supply and demand.
- A4.5 tests the operational resilience of the ODP during extended long, dark, and still weather conditions.
- A4.6 investigates the role of storage technologies in firming VRE and examines alternative approaches to modelling for imperfect foresight of short-duration storage devices.
- A4.7 examines the operational challenges for coal-fired power stations during the transition and analyses approaches to maintaining profitability.
- A4.8 presents integrated modelling and analysis across the gas and electricity systems and examines the impacts of gas system adequacy on power system operability.
- A4.9 summarises the reliability outcomes for the Draft 2024 ISP ODP and analyses the seasonal risks facing the power system.

The content in this appendix is complemented by:

- Appendix 7 which quantifies NEM system security requirements and provides insights into the nature, timing, and geography of the services needed to address them.

Key changes from the 2022 ISP

Key changes since the 2022 ISP that have impacts on the system operability outcomes in this Appendix are:

- Changes to demand profiles and higher operational demand resulting from changes to consumer adoption of CER, electrification, energy efficiency and business consumption.
- Higher levels of flexible scheduled load for production of green hydrogen.
- Lower levels of 100% instantaneous VRE penetration driven by increased consumption forecasts and slightly later forecast coal retirements.

New aspects of system operability considered in this Appendix, but not included in the 2022 ISP are:

- An analysis of the impacts of perfect foresight on battery storage modelling, and an assessment of potential options to address it.
- An investigation into gas system constraints and the impact on Draft 2024 ISP outcomes.

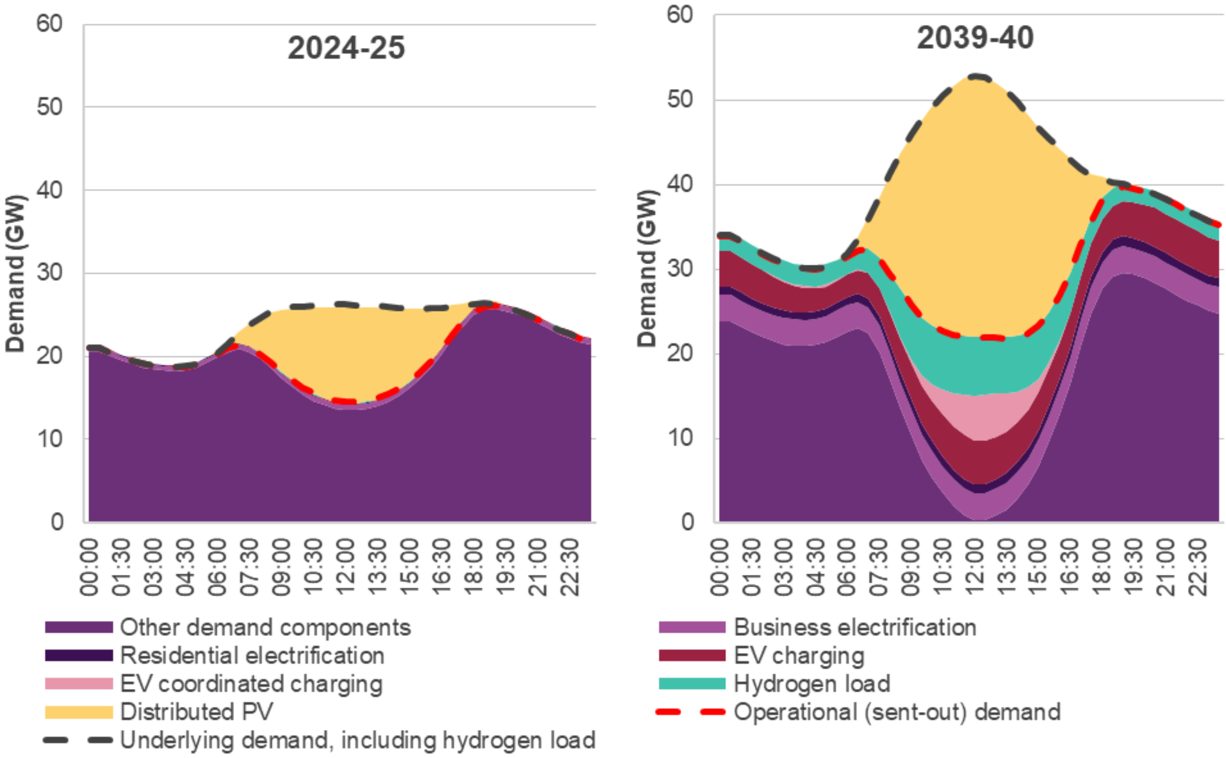
A4.2 The NEM's demand profiles will continue to evolve

Future electricity usage is forecast to continue to change and the electricity system will need to adapt appropriately to meet the needs of consumers. Fuel switching away from traditional fossil fuels is anticipated as households and businesses seek to reduce emissions, leading to a rise in electricity consumption and peak demand.

Economic drivers such as population growth and increased economic activity are projected to continue increasing the demands on the power system to supply energy, while improvements to building and appliance efficiency, and the uptake of rooftop solar are expected to moderate growth in household consumption. The emergence of new technologies such as hydrogen production and electrified transport charging are projected to increase operational demand. Daily usage patterns will be influenced by consumer energy resources (CER), including distributed PV, electric vehicles (EVs), and household or community batteries which will provide new incentives for consumers to use energy from the grid more flexibly.

Figure 1 illustrates the role of CER, electrification, and emerging technologies such as hydrogen production in the evolution of demand in the NEM, which shows the average annual time-of-day demand profiles forecast for 2024-25 and 2039-40 in the *Step Change* scenario.

Figure 1 Average annual demand profile for the NEM, 2024-25 and 2039-40, *Step Change* (GW)



Demand definitions

- **Operational (sent-out) demand** refers to demand supplied from the national power system (or grid).
- **Minimum operational demand** means the lowest level of demand from the grid in any day, week or year.
- **Underlying demand** encompasses all the electricity used by consumers, including electricity sourced from the grid and other sources including consumers' rooftop photovoltaic (PV) and battery storage.
- **Residual demand** refers to demand that cannot be met by VRE generation technologies and must be met by other generators or storage.

The daily demand profile is forecast to change significantly by 2039-40, as a result of growth in:

- **EV charging** which will increase underlying demand significantly over the forecast horizon. The impact on daily demand profiles will depend on consumer charging behaviours and be influenced by the availability of charging infrastructure and the capacity of vehicles to store charge. Some vehicle owners may prefer to 'top up' their batteries daily, enjoying the convenience of a full charge, while others may charge less frequently when the battery level falls below a certain threshold.
  - Charging behaviour is not anticipated to be uniform, and patterns that focus on driver 'convenience' will contrast with behaviours that are incentivised to reduce electricity system impacts. Convenience charging may add to peak demand as drivers plug in their vehicles when they return home.
  - Smarter charging patterns are expected to become more widespread over time as vehicle owners shift away from convenience charging towards middle-of-day charging. This could be encouraged by appropriate time-of-use (TOU) electricity tariffs and enabled by more widespread availability of charging infrastructure.
- **EV (coordinated) charging and vehicle-to-home services** which contribute to CER orchestration and help to reduce operational demand. Automated smart-charging of EVs use predictive AI to optimise vehicle charging to time periods when operational demand is low and PV generation is high. EVs also have potential to be dynamically controlled to provide vehicle-to-home and vehicle-to-grid services by charging at home or work during the day and discharging during the evening to reduce peak demand from the grid.
- **Electrification** of household and business gas appliances and viable industrial processes, which is forecast to substantially increase underlying demand. While industrial electrification introduces little additional seasonality, residential electrification of heating will lead to higher demand in winter compared to summer[1].
- **Distributed PV system** uptake, which is forecast to continue and further reduce daytime operational demand. **Consumer-owned storage** uptake is projected to increase, reducing households' reliance on electricity sourced from the grid and enabling surplus daytime energy to be stored and discharged later in the evening. Independently operated **passive CER storage** systems can also be **coordinated CER storage** through a virtual power plant (VPP) program via software and can receive instructions to charge and discharge at times compatible with power system requirements.
- **Hydrogen load** (electricity demand from hydrogen electrolysis or ammonia production), which could be substantial but depends on the development of domestic and global hydrogen industries.

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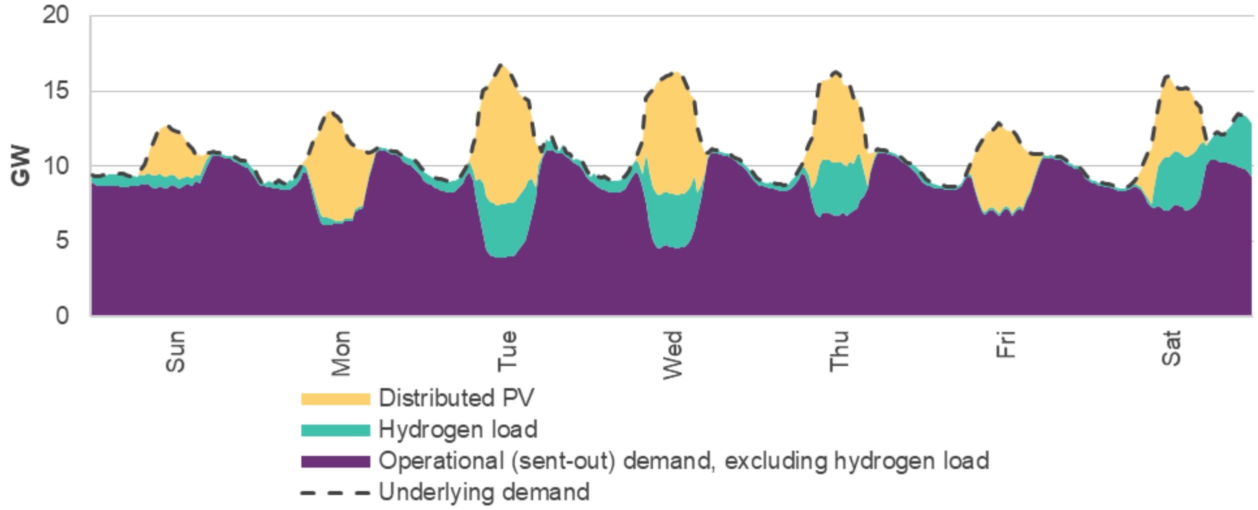
[1] Figure 1 depicts an average annual demand profile, therefore the impact of higher heating demand in winter is diluted by averaging across the other seasons where electrification of heating load is not as pronounced.

- Hydrogen electrolysers are assumed to be operate flexibly, potentially reducing when renewable energy resources are limited (during dark or still conditions, including overnight) and consuming more during daylight hours when excess solar energy is abundant.
- Hydrogen load is therefore expected to lift minimum demand and have minimal impact at times of peak demand. It is also expected to be technically capable of providing flexibility by turning off for whole days when weather conditions are unfavourable, depending on the commercial implications of doing so.

Figure 2 illustrates the potential scale of hydrogen load flexibility in Queensland across a sample week in 2040, where hydrogen load follows high solar or wind generation and fills troughs in operational demand.

Figure 2 Projected week of hydrogen electrolyser load in Queensland in 2040, *Step Change* (GW)



- **Other demand components** such as demand management programs and smart home management systems could shift appliance load to the middle of the day when distributed PV output is typically highest.

Figure 3 shows the forecast evolution of the average time-of-day demand profile for summer and winter seasons. During summer, demand profiles exhibit lower midday troughs due to higher distributed PV output, despite being offset by additional load from hydrogen production and EV charging. In the absence of hydrogen production, the average midday summer demand would be only 15 GW in 2049-50. During winter, demand is expected to increase as electrification of heating loads causes daytime operational demand to rise with lower distributed PV output.

Figure 3 Operational sent-out demand average time-of-day forecasts, summer and winter, *Step Change*, 2024-25 to 2049-50 (GW)

Note: Operational sent-out demand profiles include electricity consumed in the production of hydrogen or ammonia.

A4.3 VRE penetration and curtailment

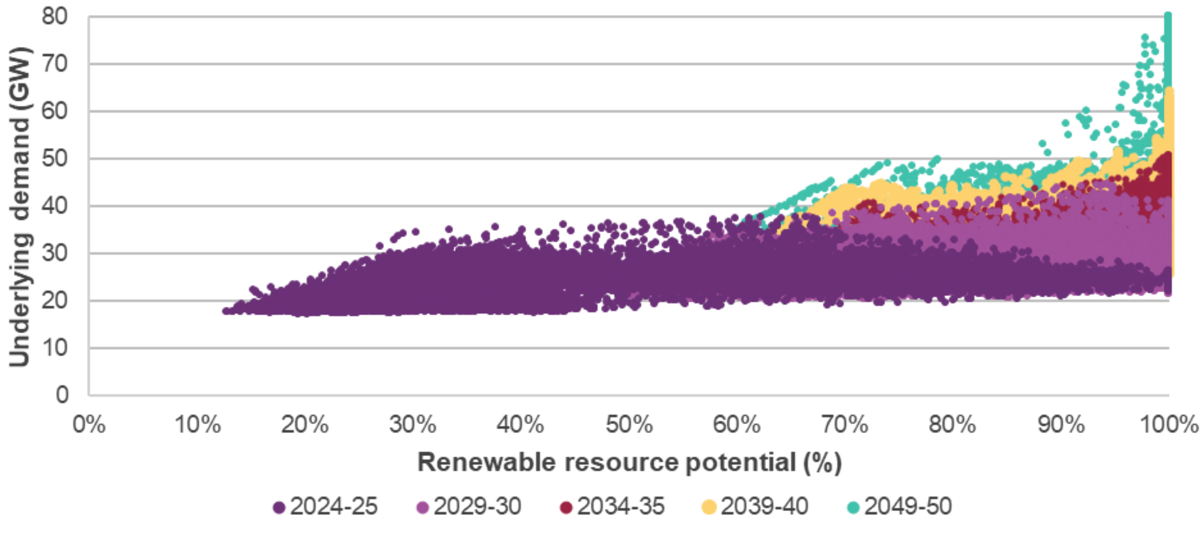
AEMO's *Engineering Roadmap to 100% Renewables* report[2] outlines AEMO's plan to prepare for higher instantaneous penetration of VRE. In future, periods with sufficient potential VRE to meet 100% of demand will become more frequent, but operating the system securely and reliably with fewer large synchronous generators may be challenging without appropriate grid services. Continued investment in solar and wind generation will increase VRE capacity, and investments in storage will enable surplus generation to be used to meet demand when resources are less available.

The highest levels of instantaneous penetration of VRE are limited by the commercial strategies of coal-fired generators. Coal generators typically bid to maintain some level of operation in all periods, to avoid the high cost of starting and stopping their units. System security requirements for inertia and other system services also impact the requirements for synchronous generation. Given commercial and security requirements, it is forecast to be more economically efficient to 'spill' excess VRE generation than to build sufficient transmission and storage to allow all excess generation to be used or stored for future use.

VRE penetration

At the time of writing, NEM renewable resource potential[3] has reached a high point at 99.7% of demand across a 30-minute period[4]. By 2025, it is projected that periods of over 100% renewable potential (when hydro generation plus available VRE exceeds forecast demand) will occur regularly, particularly during lower underlying demand intervals. As renewables replace thermal generation, the range of renewable potential experienced by the NEM becomes higher and narrower, and 100% renewable potential occurs more frequently at higher underlying demand levels. Figure 4 shows the forecast changes to renewable resource potential relative to underlying demand from 2024-25 to 2049-50 in *Step Change*.

Figure 4 Forecast renewable resource potential, 2024-25 to 2049-50, *Step Change* (GW)



[2] At https://aemo.com.au/en/initiatives/major-programs/engineering-framework.

[3] Renewable resource potential is defined as total available power from wind and solar, plus the actual generation from dispatchable renewables.

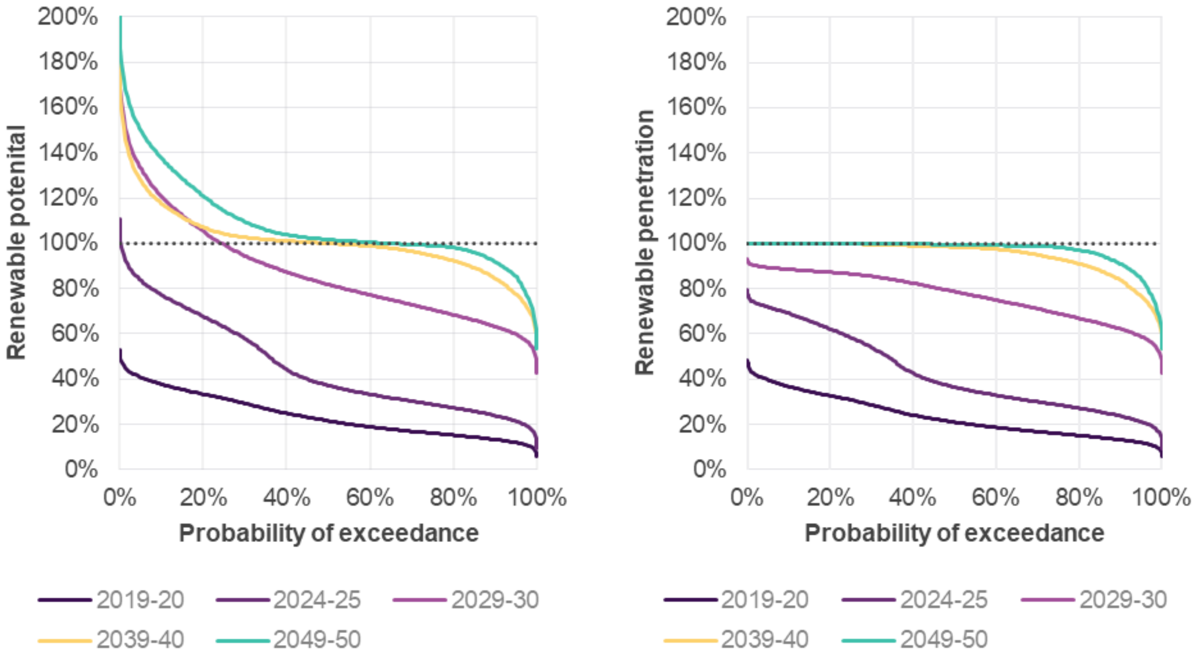
[4] Observed on 1 October 2023.

However, this does not mean these periods of renewable resource potential will result in instantaneous renewable penetration of 100%. Instantaneous renewable penetration outcomes are lower than renewable resource potential due market behaviours, network constraints, system security requirements and distribution network considerations. Records for instantaneous renewable penetration or share of total energy supplied from renewable sources, recently surpassed 70%[5] and the Draft 2024 ISP generation mix is only forecast to reach 100% instantaneous NEM penetration when the last coal units retire in 2037 and possibly earlier if seasonal withdrawal of coal capacity occurs.

Figure 5 shows the distribution of renewable potential and penetration for every half-hour in 2019-20 (historical) and the forecast years 2024-25, 2029-30, 2039-40 and 2049-50. Renewable potential is projected to be sufficient to meet all demand occasionally by 2024-25 and approximately 25% of the time in 2029-30. In these years, continued operation of coal-fired generators prevent 100% instantaneous penetration from being achieved, even if renewable resource potential meets or exceeds electricity demand.

Geographic diversity of VRE resources is developed through network expansion and additional REZs, and VRE potential is forecast to rise as a result across nearly all half-hour periods during the year, especially between 2024-25 and 2039-40. Increased use of storage technologies will help shift excess daytime generation from periods of renewable energy surplus to times of lower VRE availability and will rely on appropriate storage management and storage depth to achieve this.

Figure 5 Distribution of forecast VRE potential and penetration, 2019-20, 2024-25, 2029-30, 2039-40 and 2049-50, *Step Change*



[5] See AEMO media release 23 October 2023, at https://aemo.com.au/newsroom/media-release/renewables-push-nem-electricity-prices-down-to-historical-levels.

VRE curtailment

Modelling undertaken for the Draft 2024 ISP forecasts instances where VRE generators will not operate at maximum potential capacity. There are a range of reasons for this, including:

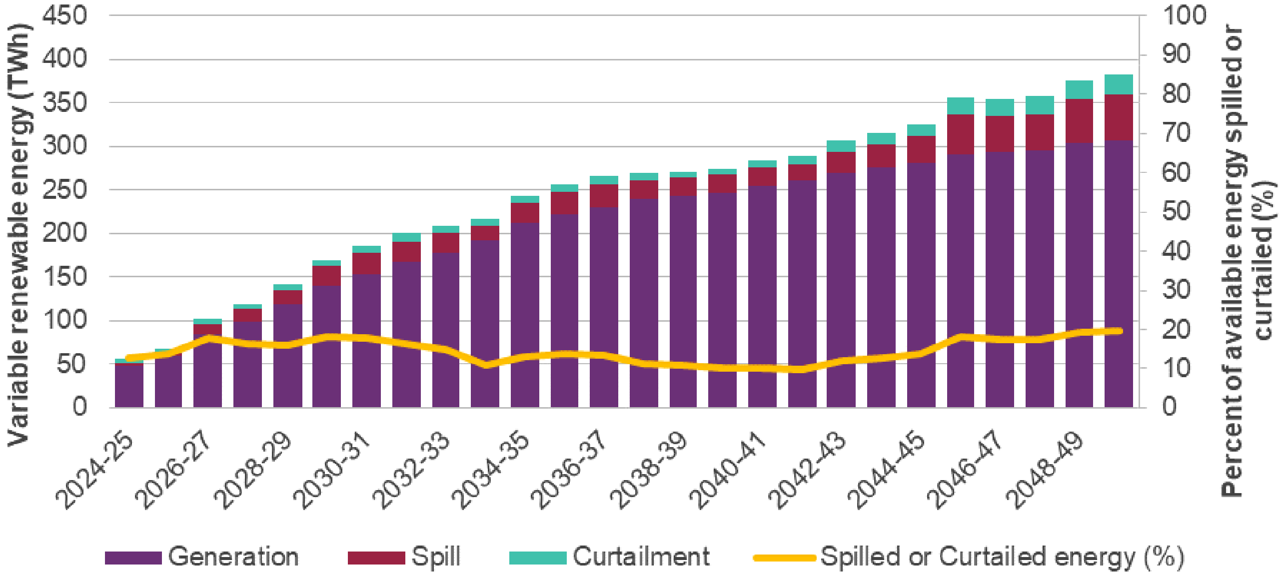
- Periods when VRE resource potential exceeds demand, particularly at times of low operational demand.
- Insufficient transmission capacity to transport VRE to demand centres.
- Network security or other functional constraints for system strength or security.
- Lack of storage capacity to absorb the excess VRE generation.

These conditions may lead to economic 'spill' of energy when generators reduce output due to low market prices or lack of available demand, or to network curtailment where insufficient transmission capacity exists for generators to continue to operate. The Draft 2024 ISP forecasts that it is uneconomic to develop transmission and/or storage capacity to accommodate all peak VRE generation potential, meaning some degree of spill or curtailment is inevitable to keep total system costs as low as possible. As the seasonal load profiles diverge, generation development is increasingly needing to be developed to meet the energy consumption requirements of winter when consumption is high and VRE production is reduced, and therefore summer periods may exhibit increased periods of spill or curtailment when renewable resources are higher.

Figure 6 shows the total VRE potential that is utilised (generation) or not (spill and curtailment) out to 2049-50. As coal capacity closes and transmission is expanded the level of available VRE spilled or curtailed is forecast to remain between 10 and 20% annually across the horizon.

The majority of unused VRE potential is the result of economic spill, rather than curtailment due to transmission limits[6]. High solar generation during spring and summer will lead to an oversupply of energy, some of which is forecast to be spilled.

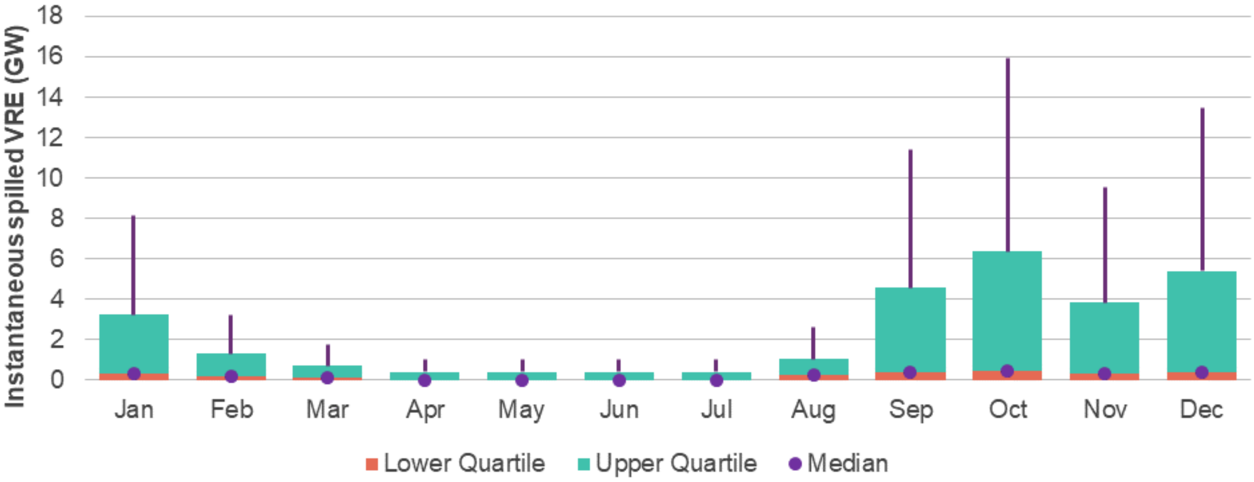
Figure 6 Forecast VRE generation and spilled or curtailed energy 2024-25 to 2049-50, *Step Change* (TWh)



[6] See Draft 2024 ISP Appendix 3 Figure 6.

Figure 7 shows the forecast monthly distribution of instantaneous economic spill in 2039-40 and illustrates the months with excess energy generation potential.

Figure 7 Forecast NEM frequency of spilled VRE capacity in 2039-40, *Step Change* (GW)



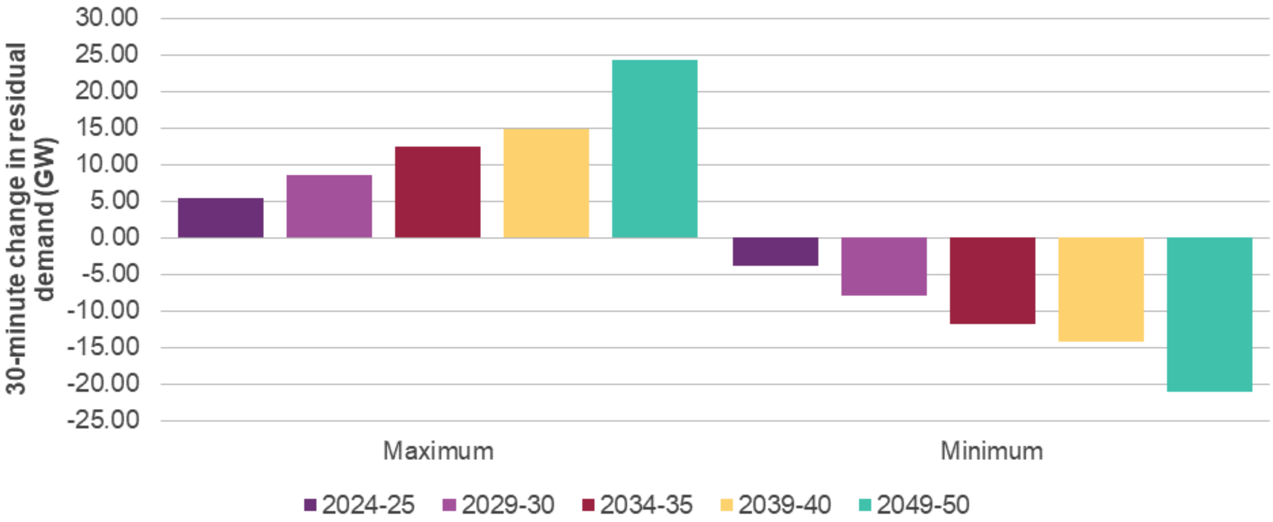
The large majority of spill is projected to occur during daylight hours on sunny and windy days, with much more VRE spilled in December than in June. The reduced solar resource in winter may lead solar developers to target winter yields in their solar farm designs. The seasonal trend of VRE curtailment also indicates long-duration storages could have a key role shifting energy on a seasonal basis to provide strategic energy reserves. AEMO views this as an important role to be performed by deep-reservoir hydro (see Section A4.6, Figure 18 and Figure 19).

A4.4 System flexibility manages increased variability

Resource flexibility is required to manage increased variability of electricity generation and demand. Residual demand is the electricity demand to be met by dispatchable generation, in other words demand net of VRE generation. Rapid and more frequent changes to residual demand across the power system will require sufficient ramping capability of firm resources across all operational timeframes. Increased ramping requirements are associated with daily diurnal solar profiles, and much faster, less predictable ramps from clusters of distributed PV due to localised cloud movements. Managing the operational requirements of firming technologies including consideration of real-time ramping requirements to support the variability of VRE and CER will be important to operating the NEM securely and reliably.

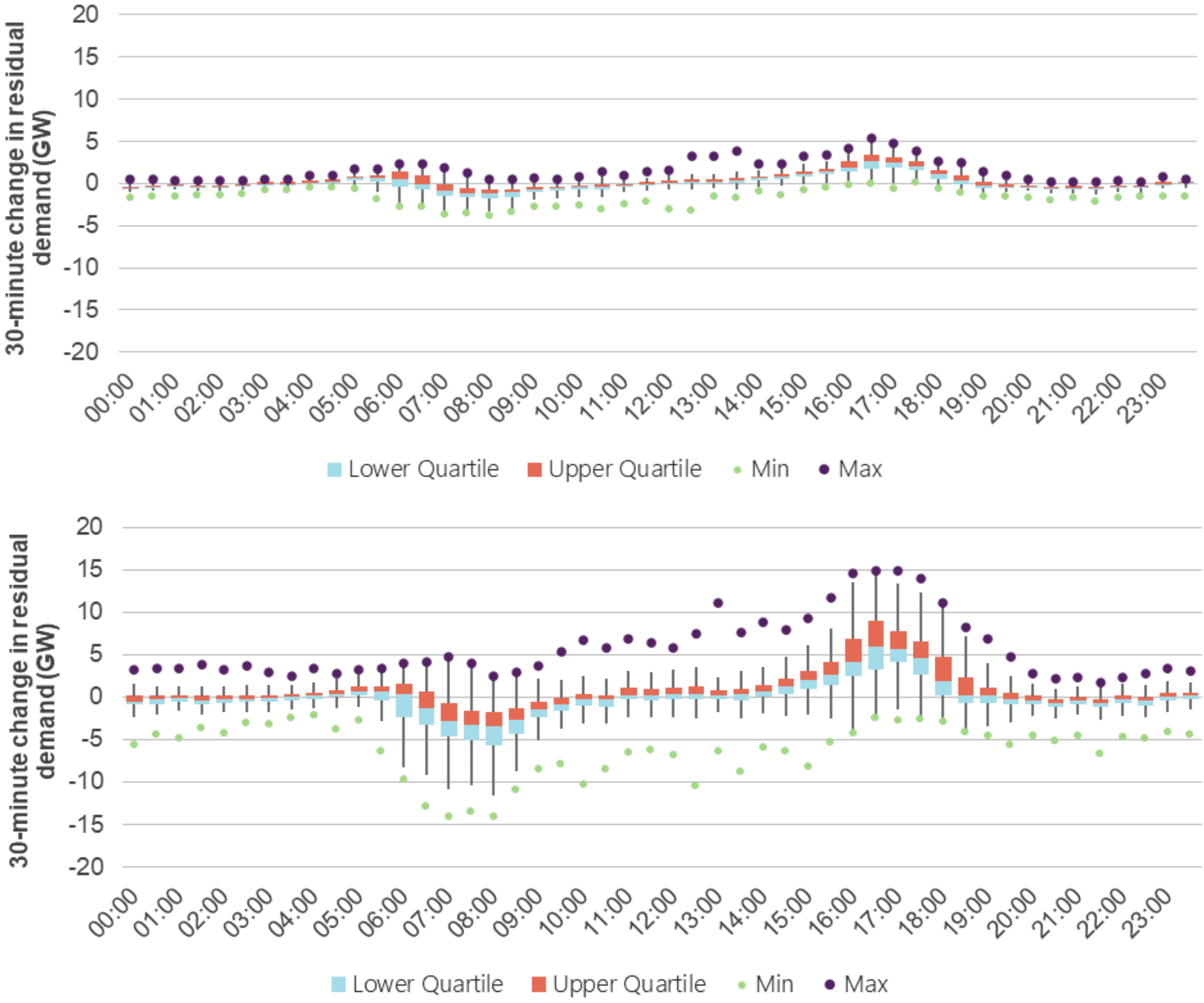
During the period to 2049-50, residual demand that cannot be met by VRE technologies is forecast to reduce significantly but also become much more variable. Figure 8 below shows the maximum and minimum changes forecast in half-hourly residual demand over a year in *Step Change*.

Figure 8 Forecast maximum and minimum changes in half-hourly residual demand, 2024-25 to 2049-50, *Step Change* (GW)



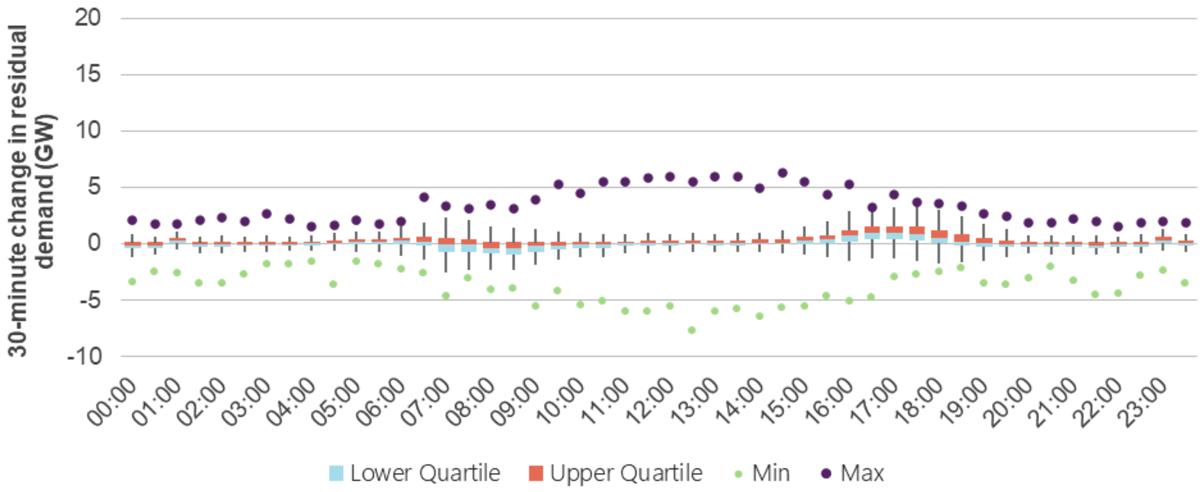
Residual demand fluctuations become more extreme as utility-scale and distributed solar capacity grows. The periods of greatest changes are forecast to be at dawn and dusk which are highly predictable and thus less challenging for NEM operations. Figure 9 shows the forecast distribution of residual demand changes for each half-hourly period over the course of a day in 2024-25 and 2039-40.

Figure 9 Forecast time-of-day distribution of half-hourly NEM residual demand changes, 2024-25 (top) and 2039-40 (bottom), *Step Change* (GW)



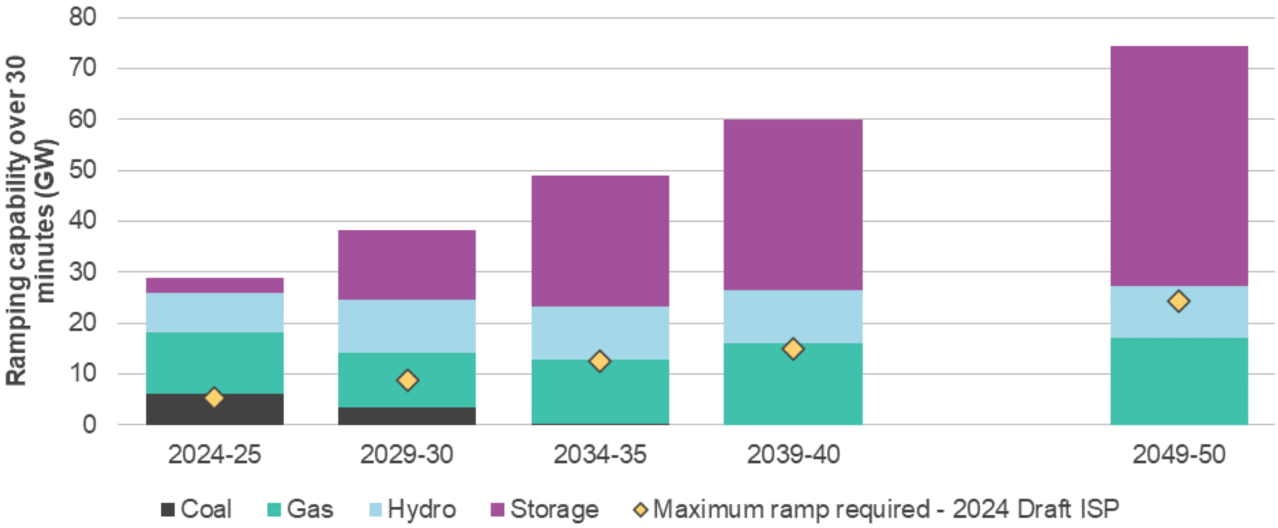
Smaller and less predictable changes to residual demand at other times of the day are expected to present a more significant challenge to future NEM operations. Figure 10 demonstrates the forecast variability for Victoria demonstrating an example where a large distribution of ramp up (Max) or down (Min) requirements is forecast during the middle of the day as a result of fast-changing weather patterns between 1000 hrs and 1600 hrs.

Figure 10 Forecast time-of-day distribution of half-hourly residual demand changes in Victoria, 2039-40, *Step Change* (GW)



In the future, grid-scale and distributed storage devices are forecast to become the primary providers of system flexibility but GPG and hydro continue to provide significant ramping capacity. Figure 11 shows the projected maximum ramp up capability in gigawatts for each 30-minute period across the dispatchable generation fleet. The Draft 2024 ISP ODP is forecast to develop firm capacity throughout the forecast horizon to match growing demand and balance VRE intermittency and availability. During daily operation the actual ramping capacity of a unit will vary according to online status, current generation, and in the case of storage the level of stored energy at that time.

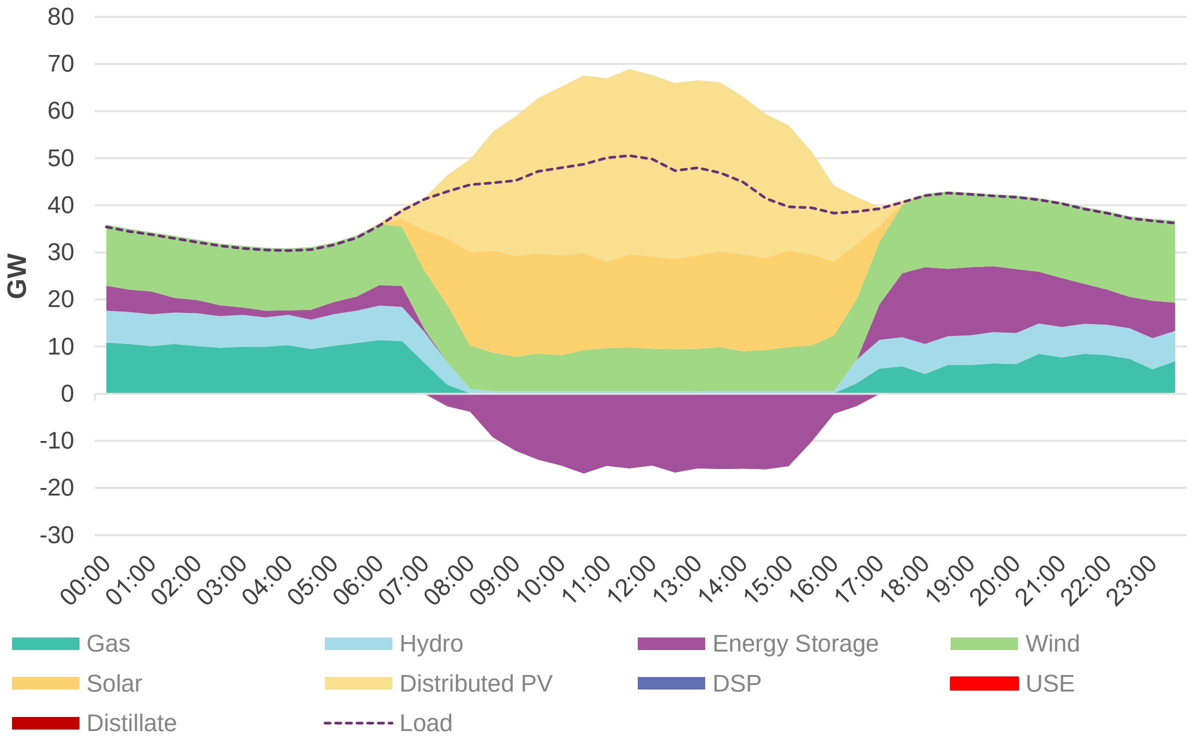
Figure 11 Forecast maximum ramping capability of dispatchable generation, 2024-25 to 2049-50, *Step Change* (GW)



Note: Biomass, diesel, and hydrogen generators are aggregated into the Gas category.

Figure 12 presents the forecast NEM generation mix during a day in 2040 when a peak 15 GW ramp up equivalent to 40% of underlying load is required at approximately 1700 hrs due to significant generation reduction from solar when load remains relatively high. Storage technologies contribute most of the rapid increase in generation by discharging stored energy, with gas and hydro generators providing the rest of the ramping requirement. In cases where stored energy and other dispatchable generation is insufficient to meet demand, demand side participation (DSP) and demand response may be deployed.

Figure 12 Forecast NEM generation mix on a day with maximum ramp in 2040, *Step Change* (GW)



Storage dispatchability is forecast to become crucial to the reliability and security of the power system. Therefore, market settings that incentivise storage operators to reserve energy for discharge during high demand periods will be important. Periods of VRE scarcity when demand is relatively high will typically elevate market prices and encourage storage operators to reserve adequate ramping capability. Further discussion on the topic of storage dispatch behaviour to firm up supply-demand variations is in Section A4.6

This assessment does not address maintaining grid security and the provision of critical frequency and voltage control services. Appendix 7 provides more detail regarding system security and engineering requirements for secure operation of the power system.

A4.5 Operating the power system during long, dark, and still conditions

Resilience during VRE droughts

The NEM must be resilient in its capability to provide energy in all weather conditions, including when there is minimal or no sunshine or wind for prolonged periods. The Draft 2024 ISP ODP delivers resilience during long, dark and still periods through transmission augmentations enabling delivery of a more diversified resource mix to regions experiencing tighter VRE supply conditions, and a mix of flexible gas generation and storages of various depths.

The development of medium (4 hr to 12 hr duration) and deep storages (12 hr duration or longer) are important to complement GPG and hydro generators, providing the capacity to store energy and dispatch it over longer periods. The Draft 2024 ISP ODP forecasts storage capacities needed to complement VRE developments and provide dispatchable and firm sources of supply.

Storage definitions

- **Consumer-owned storage** (or distributed or CER storage) – behind-the-meter household, business or industrial batteries, including EVs that may be able to send electricity back into the grid. Coordinated CER storage is managed as part of a virtual power plant, while passive CER storage is not.
- **Shallow storage** – grid-connected storage to dispatch electricity for less than four hours, valued for both their system services and their energy value.
- **Medium storage** – to dispatch electricity for four to 12 hours. This may be battery or pumped hydro (or other emerging technologies in future) which can shift large quantities of electricity to meet evening or morning peaks.
- **Deep storage** – strategic reserves that can dispatch electricity for more than 12 hours, to shift energy over weeks or months (seasonal shifting) or cover long periods of low sunlight and wind (renewable droughts), backed up by gas-powered generation.

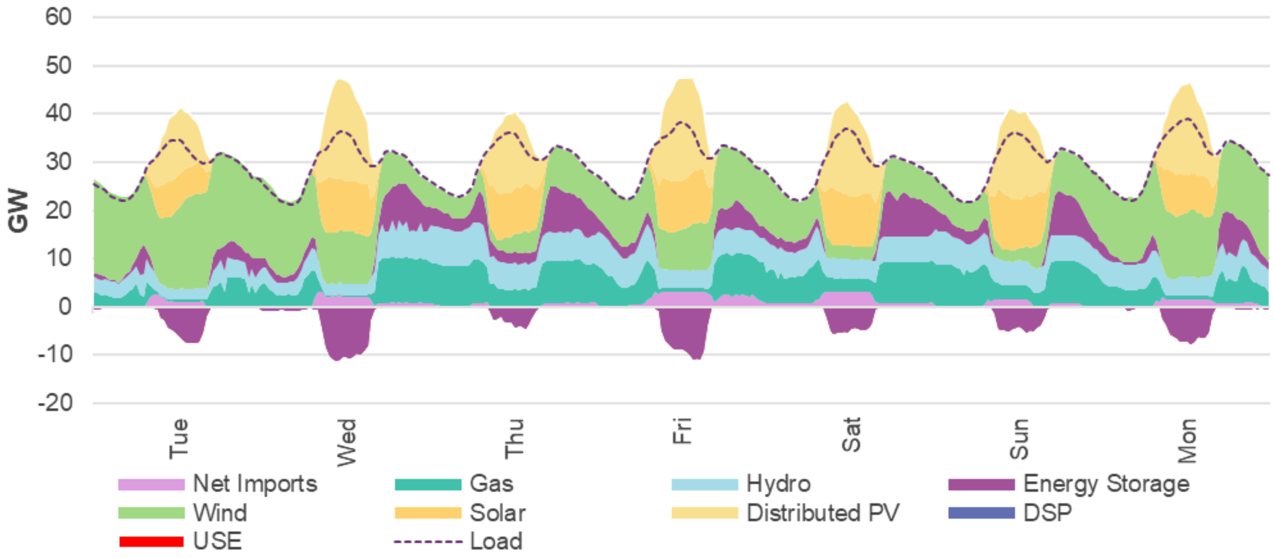
Long, dark and still conditions typically can last for hours or a whole day but are most problematic for system operability on the rare occasions they persist for multiple days. These weather conditions are most likely to occur during winter and cause longer VRE droughts when lower solar generation coincides with still wind conditions. In a system with high levels of VRE, the resulting energy shortage may cause reliability risks if sufficient firming resources are not developed. Delivering geographical diversity of generation and firming resources is a strong benefit of the transmission expansions forecast in the ISP and will improve system resilience.

By 2040 in *Step Change*, all coal-fired power stations are forecast to be out of service and generation in the NEM will be dominated by VRE and CER with firming provided by storage, hydro and flexible gas. With these resources, the NEM is forecast to operate reliably through VRE droughts observed in recent history[7].

[7] AEMO's ISP modelling applies weather patterns from 2010-11 to 2021-22 and analyses the operability of the power system during future conditions, modelled off the historically observed weather. This analysis has indicated that 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.

Figure 13 shows the forecast dispatch mix[8] in June 2040 during a severe VRE drought event based on a historical severe dark and still weather event observed in June 2019. It shows southern regions (New South Wales, Victoria, South Australia, and Tasmania) experiencing extremely high residual demand due to low wind production. Queensland is experiencing stronger VRE availability during this time but the ability for Queensland to export surplus generation is limited by the capacity of the transmission system.

Figure 13 Forecast operability across the NEM (excluding Queensland) experiencing a three-day low VRE period in June 2040, *Step Change* (GW)



In this VRE drought event, the forecast for June 2040 shows that:

- Southern states experience high heating loads and little VRE availability due to still, cloudy, and cool weather conditions across these regions.
- The worst VRE droughts last for approximately three days in a row from Thursday to Saturday in the above example, when there are low solar production and minimal wind outputs. On these days, gas and hydro are required to run almost continuously at peak output to cover the VRE shortfalls.
- During this event, the gas system may become constrained to deliver sufficient gas to operate GPGs, depending on the coincident needs from gas consumers. More detailed modelling and analysis on this topic is presented in Section A4.8
- Sustained support is provided from deep storages (hydro) in New South Wales and Tasmania, made more accessible by transmission augmentations.
- Surplus VRE from Queensland contributes to meeting demand via the upgraded QNI (shown as Net Imports in Figure 13). In addition, net imports from Queensland are sometimes required to help fill southern storages during the middle of the day.

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[8] Distillate (diesel), biomass, and hydrogen are aggregated in the gas category.

- Shallow and medium storages recharge during the days to dispatch during the afternoon peaks. However, during the worst days (Thursday and Saturday), these storages will not fully recharge due to limited VRE production. Deep storage is critical in shifting energy from days prior to the shortage.
- Stronger wind conditions in northern New South Wales assist on most days, enabling the filling of energy storages to meet evening load. Some voluntary DSP may be expected to reduce the magnitude of the peak demand periods.

NEM resilience through prolonged VRE droughts

The timing, severity and duration of prolonged dark and still weather conditions over a wide area are difficult to forecast and indications are these events are very rare. AEMO's modelling is based on 12 years of weather data covering a broad range of weather patterns but it is not guaranteed that this historical period includes the worst possible VRE drought conditions. Climate conditions are expected to change over coming decades across the diverse regions of the NEM. To anticipate the possible effects of these changes, AEMO has performed exploratory modelling to test the resilience of a power system dominated by VRE to prolonged VRE drought events.

Whilst modelling prolonged VRE droughts, AEMO focused on "what-if" analysis where the most impactful three-day VRE drought is extended to an eight-day event with the most severe day (Thursday, 21 June 2040) lasting for five days longer. In the absence of appropriate climate data to accurately predict future weather conditions, algorithms have been applied to historical data to extend the duration of observed extreme weather conditions to simulate a more volatile future climate. This approach retains the inherent internal consistency between supply, demand, and transmission models by using historical weather rather than future synthetic weather patterns.

Figure 14 shows the forecast dispatch mix during this extended VRE drought event running between 19 June 2040 to 28 June 2040, showing the extended drought period plus the preceding and following days. The NEM is projected to operate all available dispatchable resources (predominantly deep storages and gas) to meet the high residual demand, and shallow and medium storages are critical in shifting energy to meet the afternoon peaks.

Figure 14 Forecast operability across the NEM (excluding Queensland) experiencing an extended eight-day VRE drought, June 2040, *Step Change* (GW)

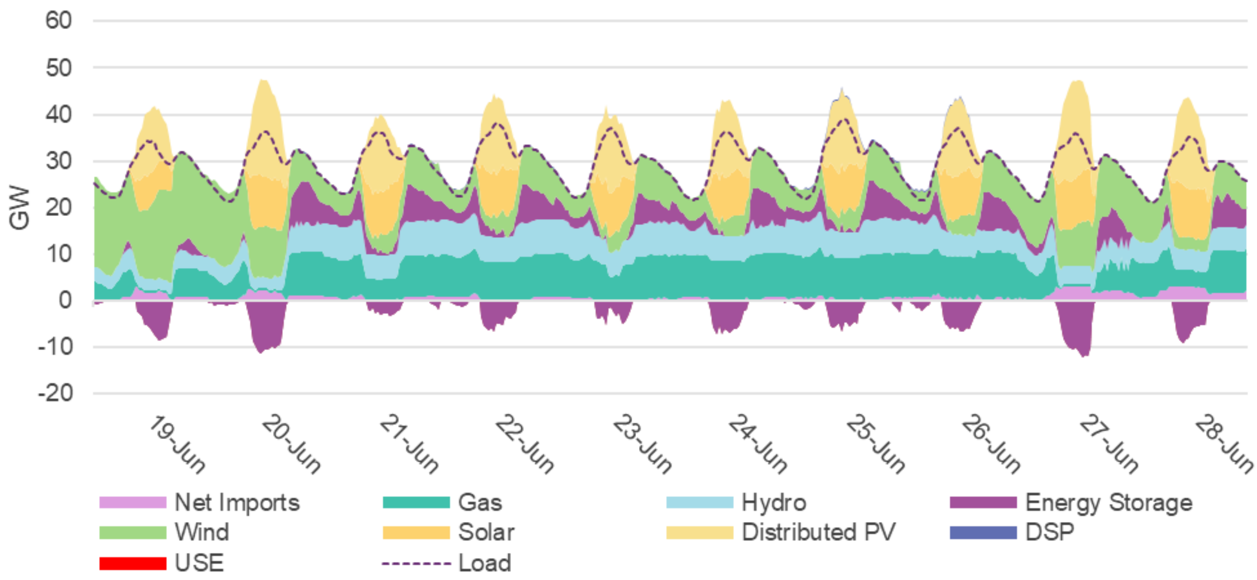
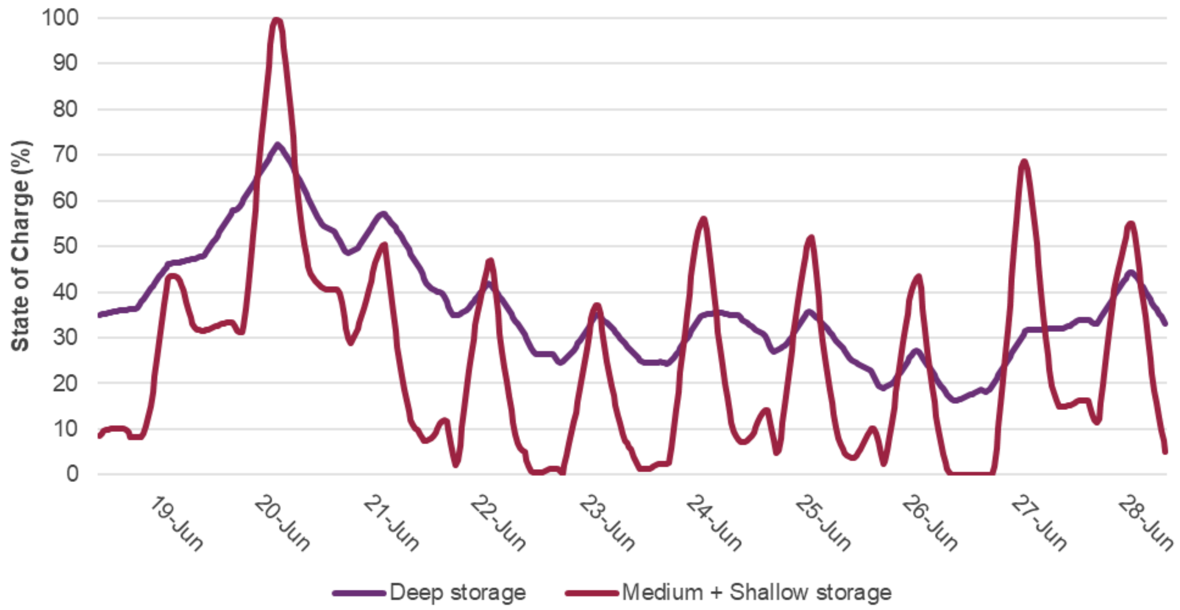


Figure 15 shows there will be insufficient spare generation to fully recharge all shallow and medium storages (VPPs and utility scale storages) on these days. These facilities must operate at lower capacity or for shorter periods during the most severe five days (from 21 June to 26 June). Deeper storages provide energy that has been previously stored, entering the renewable drought period at around 70% state of charge[9] from previous days. With this level of stored energy and considering the capacity to refill reservoirs on these days, reserve levels are getting dangerously low from losing 10-15% of stored energy or water each day.

Figure 15 State of charge of shallow, medium and deep storage in southern states during an extended eight-day VRE drought, June 2040, *Step Change*

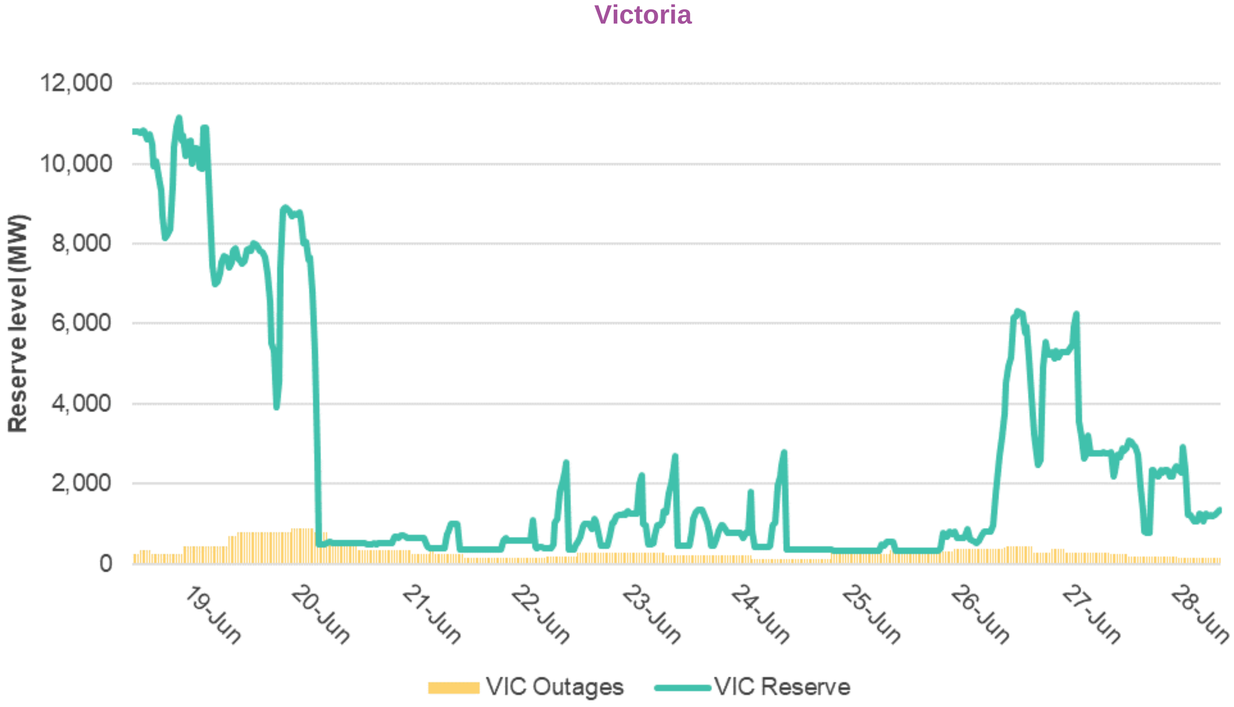


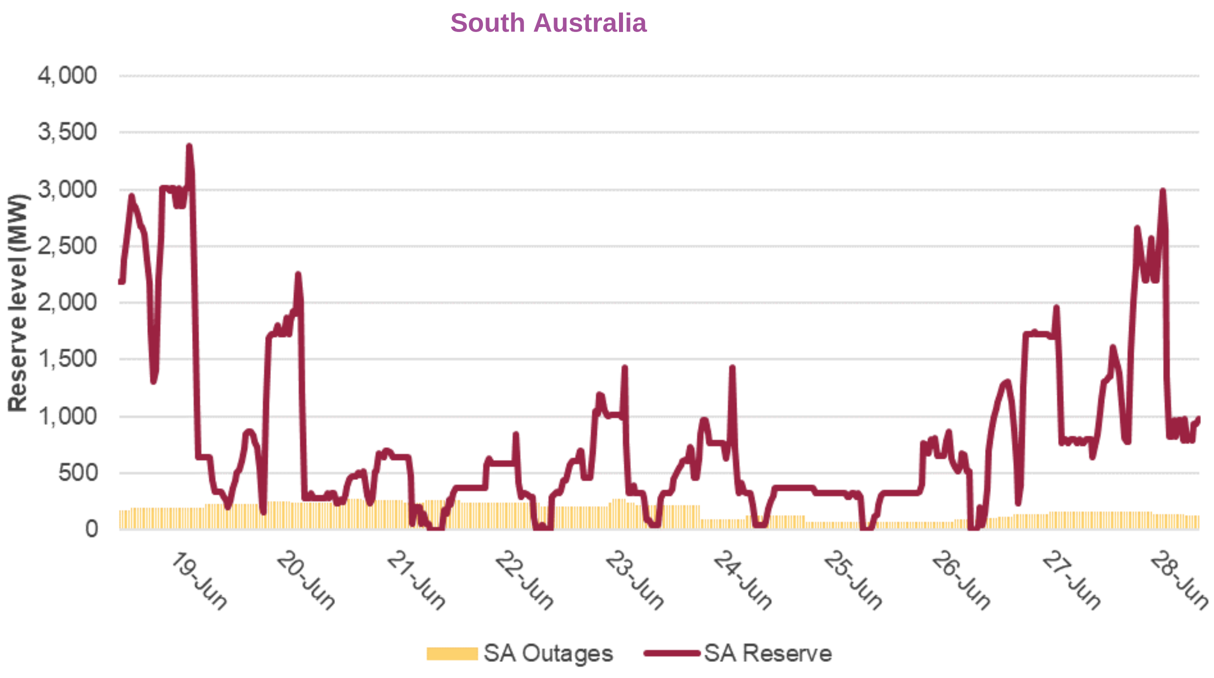
On the last day of the event (26 June 2040), deep storages only hold around 16% of their storage capacity. At this point, if the VRE drought were to continue much longer, deep storages in the southern states may become incapable of providing further energy.

Figure 16 shows Victoria and South Australia are operating on very thin reserve margins so if a coincident major contingency event occurs both states are at additional risk of experiencing USE.

[9] AEMO modelling assumes weather forecasts provide reasonable notice prior to this event and therefore, storages are sufficiently charged in advance.

Figure 16 Reserve level (MW) in Victoria and South Australia during an extended eight-day VRE drought, *Step Change* (MW)





Note: Reserve level refers to the available generation capacity in a region plus the region's import headroom. Interconnector support is estimated as the maximum energy supply available to the region from neighbouring regions' surplus generation.

This analysis suggests the Draft 2024 ISP ODP is resilient to VRE droughts of eight days with sufficient cover from storages, GPG and hydro generation. Although high prices are likely and voluntary DSP may be required in this example, the NEM is forecast to be capable of operating reliably through droughts two or three times longer than historically observed. In this simulated test of extreme weather resilience, no USE was forecast. However, if multiple generation failures coincided with this eight-day VRE drought, then serious reliability risks would be placed on the system.

To minimise the risks posed by extreme VRE droughts and maintain reliability, AEMO modelling indicates the need for:

- Fuel supplies to be available for flexible gas to operate at maximum capacity for prolonged periods. This may require greater fuel diversity with onsite storage of secondary fuels. More detailed modelling and analysis on this topic is presented in Section A4.8.
- Weather forecast accuracy will influence the degree of foresight of extended dark and still weather to allow accumulation of sufficient energy (or water) in deep storages prior to periods of VRE drought. While careful management of shallow storages would be required during these conditions, the availability of deep storages to efficiently supply the load centres most at risk is important to ensure resilience to these unpredictable periods. More detailed modelling and analysis on this topic is presented in Section A4.6.
- Maintenance schedules of dispatchable generators need to be carefully managed and coordinated during winter when VRE droughts are more likely to occur.
- Strategic reserves in dispatchable capacity, and energy reservation of deep storages, may be required to provide appropriate resilience to forecasting errors, imperfect foresight, unavailability risks and fuel supply risks.

A4.6 Storage technologies will firm VRE

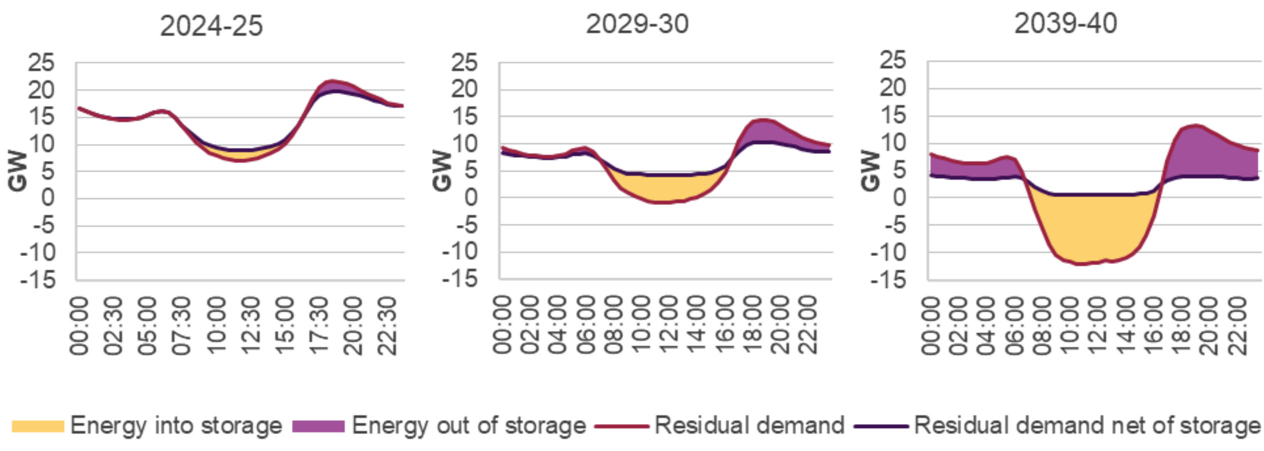
Storage technologies of different types and depths will provide a range of services in a NEM dominated by VRE. Storages currently provide load shifting, system balancing and active power reserves, in addition to advanced power system services such as synthetic inertia and system strength support. As the installed capacity of batteries in the NEM increases, operational strategies will shift away from providing system services and towards providing energy arbitrage. This section demonstrates the important role of energy storage systems in supporting the future operation of the power system, from an energy arbitrage perspective.

Shallow and medium storages provide intra-day load shifting

The NEM will increasingly rely on shallow and medium storages to provide intra-day load shifting. Storages participating in energy arbitrage will charge when low-cost, surplus daytime VRE is plentiful and discharge fast-response ramping services and firming generation during peak demand periods when prices are high. This reduces more regular dependence on alternative firming technologies such as flexible gas and hydro generation.

Figure 17 shows the forecast evolution of time-of-day average profiles of residual demand and the growing impacts of storage technology. As wind and solar penetration increases (utility scale and CER) and coal-fired generators retire, residual demand is forecast to decrease and feature greater daytime troughs. Forecast increases in storage capacity and depth will enable greater volumes of surplus energy to be time-shifted to service evening demand peaks over longer durations. Storages will also help to smooth the evening residual demand peak, allowing generators with less flexibility to operate at a flatter profile.

Figure 17 Forecast time-of-day average profile of residual demand, *Step Change*, 2024-25, 2029-30 and 2039-40 (GW)



Long-duration storages provide seasonal energy security

While short-and medium-duration storages such as batteries will increasingly provide intra-day firming for VRE, hydro-electric facilities with deep water reservoirs (such as Lake Eucumbene in New South Wales and Lake Gordon in Tasmania) will provide a strategic reserve by allowing energy to be stored and shifted seasonally to support longer periods of low VRE generation, particularly if market settings encourage this behaviour.

Figure 18 shows the forecast monthly generation mix and maximum instantaneous residual demand in 2039-40 has strong seasonal dependence:

- Solar output is higher on longer bright summer days with seasonality most prominent in southern regions.
- Wind output is greater on average, but more volatile during winter months.
- Residual demand is higher during winter, due to higher underlying heating load and reduced solar output.
- Operation of seasonal energy storages and GPG are forecast to become more winter-focused to support lower solar output and more volatile wind output, but may still have a critical need during extreme demand days during summer.
- Battery and pumped hydro storages operate consistently, but cycling[10] is maximised during periods with greater daily fluctuations in residual demand which create stronger arbitrage opportunities.

Figure 18 Generation mix and maximum monthly residual demand, *Step Change*, 2039-40

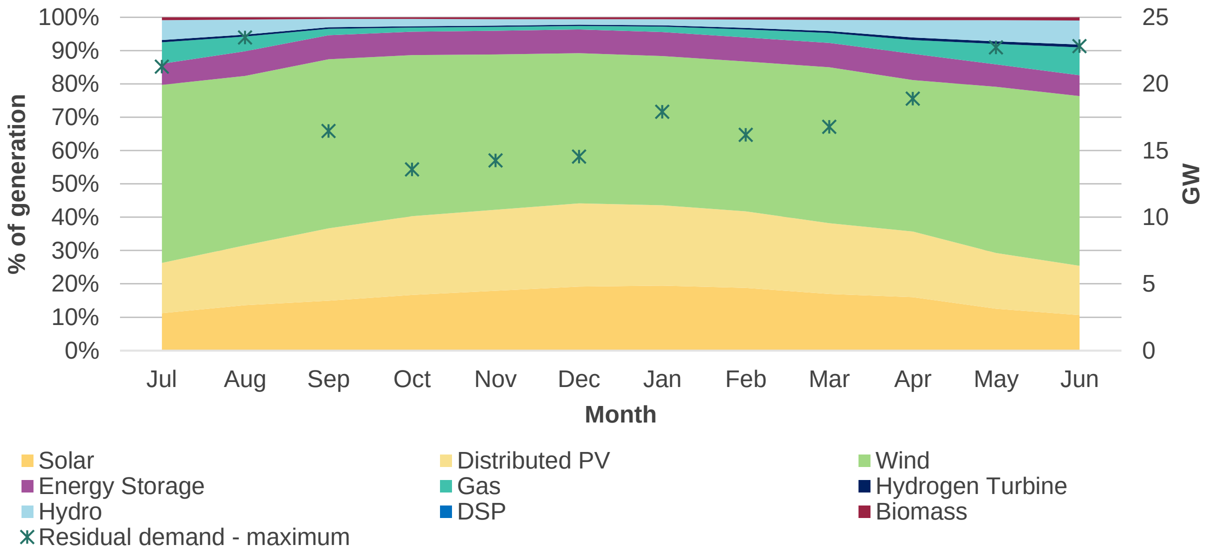


Figure 19 shows how the forecast seasonal pattern of energy stored in deep storages and hydro-electric reservoirs changes over the periods between 2024-25 and 2049-50 in *Step Change*. In the near term, modelling indicates hydro storages will dispatch into intervals of summer peak demand and accordingly store lower amounts of energy over warmer months. Over time, the monthly profiles of energy stored in deep reservoirs shifts from depleting over the summer towards holding energy into early winter. As thermal generators exit and VRE capacity increases, hydro will need to play an important deep storage role, supporting the system through longer periods of high residual demand that are more prevalent during winter months.

[10] As batteries and pumped hydro charge and discharge electricity, the level of stored energy cycles between low and high levels.

Figure 19 Daily energy forecast to be stored in deep storages and traditional hydro reservoirs over a year, *Step Change* (GWh)

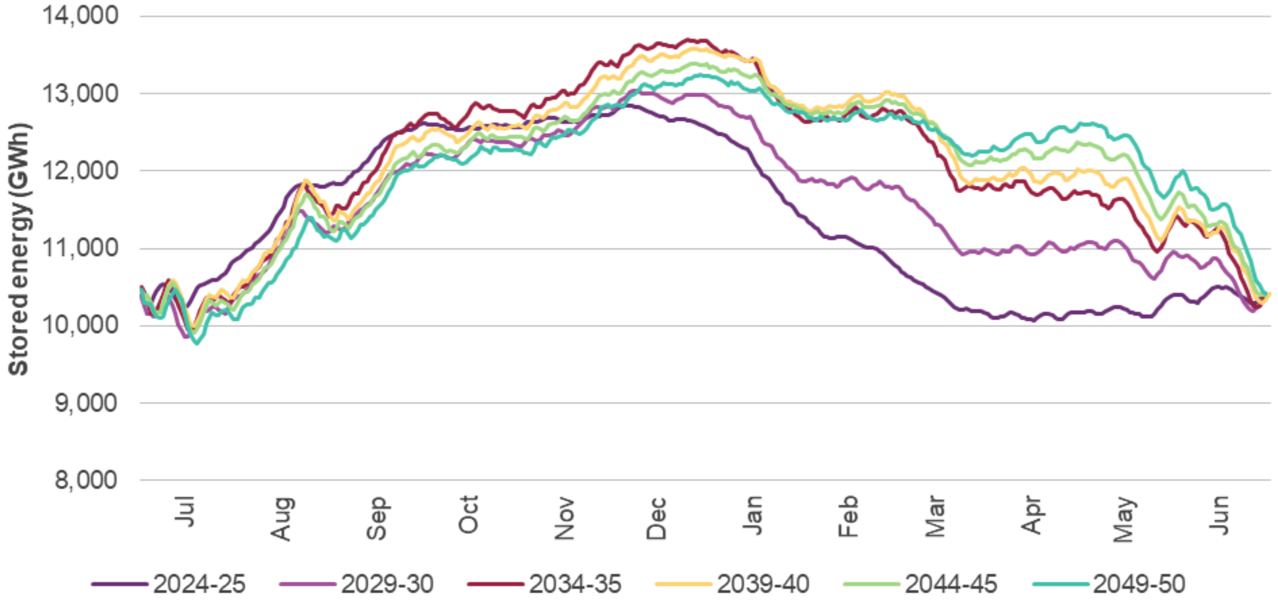
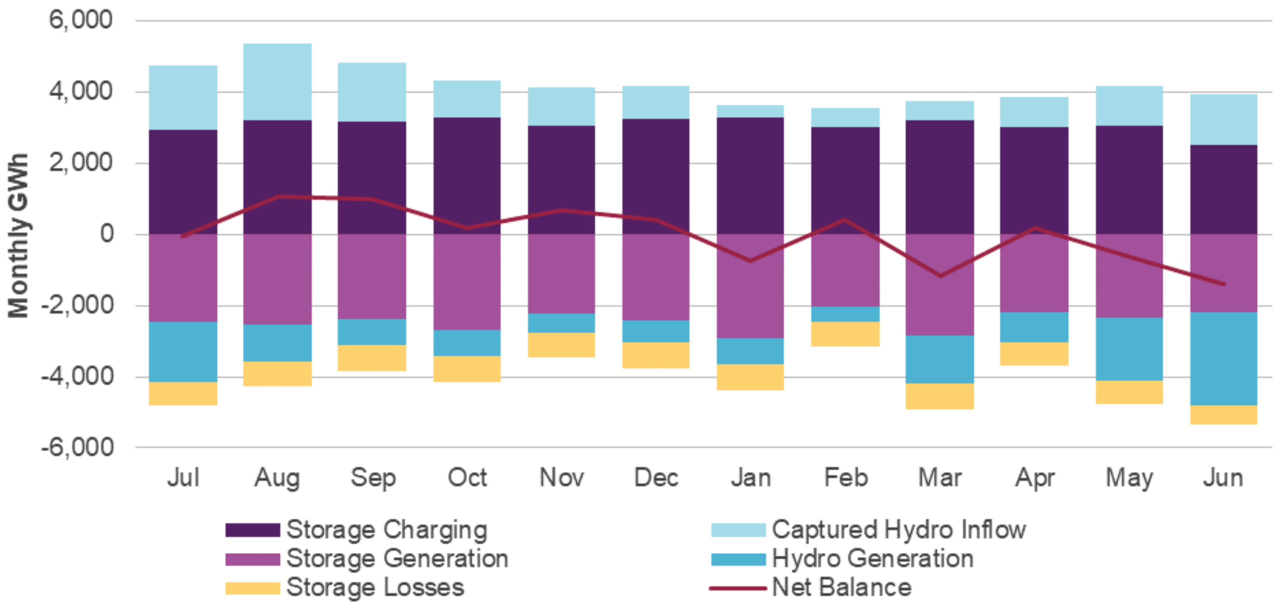


Figure 20 shows the *Step Change* 2039-40 forecast for monthly energy discharged and used to charge (or fill), energy storages (battery and pumped hydro), in comparison with deep hydro reservoirs. Positive values represent total energy flowing into storage during the month, while negative values represent total discharge. A positive net balance indicates storages generating more energy than inflows received.

Figure 20 Forecast monthly energy balance of storage (shallow and medium) and hydro (deep), *Step Change*, 2039-40 (GWh)



Deep hydro-electric storage reservoirs in southern alpine regions are typically replenished by snowmelt over springtime and rainfall over wetter months. Pumped hydro technology can utilise VRE surplus in summer to return water to higher elevations then discharge this over the autumn and winter months when residual demand is higher. Shallow and medium storage technologies will provide more intra-day and inter-day shifting to meet peak demand. If appropriately utilised, shallow storages (and VPP devices) can reduce the reliance on deeper storages to operate frequently, enables the deeper storages and hydro reservoirs to reserve more energy to weekly, monthly or seasonal energy shifting.

The forecast shift for hydro storages towards winter-discharging will require consideration of irrigation management and assessment of flooding risks. During winter 2022, hydro-electric generation was high to compensate for high unavailability of coal generation, but prior wet years had saturated dam catchments which constrained generation from the Snowy Hydro scheme[11]. This highlights coordination between hydro operators and water authorities is required to realise the full potential of hydro generation for seasonal energy shifting, and that externalities to energy models will exist that mean broader strategic reserves and deep storage will improve system resilience to unpredictable conditions.

Impact of imperfect foresight of battery operation

AEMO's energy market modelling is optimised with the benefit of perfect foresight of VRE output and operational demand within each simulated day. This enables a near-perfect management of the state of charge and enable efficient energy arbitrage operations for shallow, medium and deep storage technologies, and CER storage technologies. Actual energy storage operation involves imperfect foresight so AEMO has examined imperfect foresight in more detail to ensure time-sequential modelling outcomes are representative.

Figure 21 compares the modelled dispatch profile of shallow storage large-scale batteries against actual performance during 2021-22, illustrating that the modelled optimisation of shallow storage based on current observed behaviour, tends to overstate utilisation of energy storage dispatching into evening peaks. This is in large part due to these storages prioritising provision of FCAS over time-shifting of energy and is not representative of how storages may behave in the future.

Figure 21 Actual and modelled average hourly dispatch profile of large-scale batteries in 2021-22 (MW)

[11] See AER, State of the Energy Market 2022 report, at https://www.aer.gov.au/system/files/State%20of%20the%20energy%20market%202022%20-%20Full%20report.pdf.

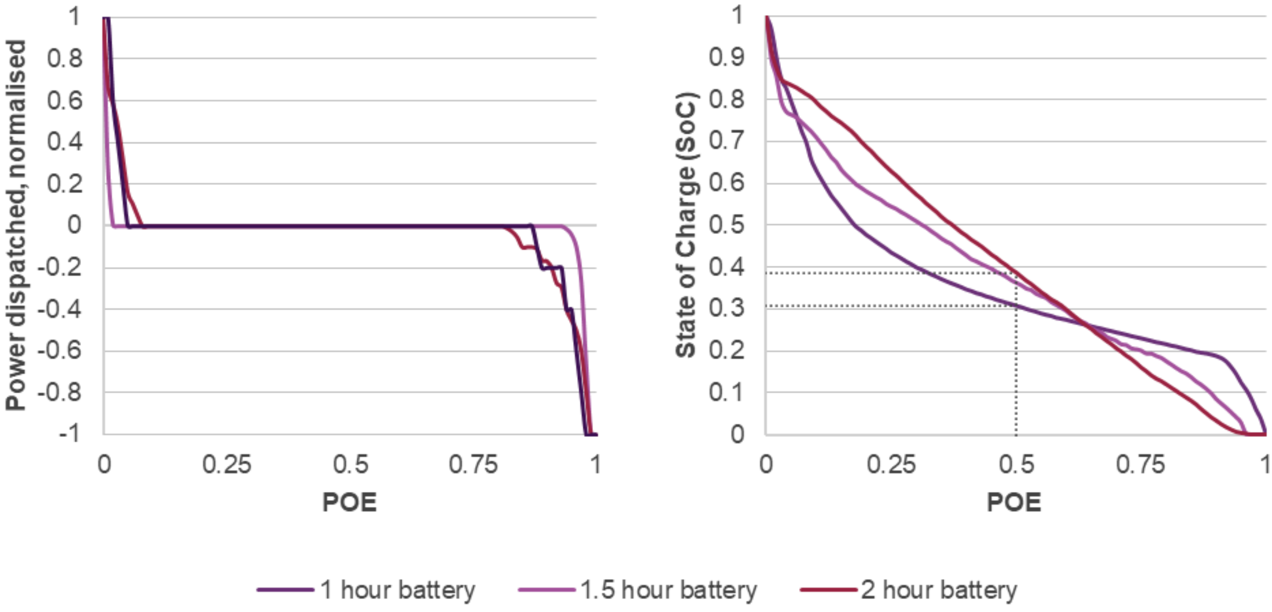
As storage becomes more prominent in the energy market, lack of foresight as to when high price events will occur may cause shallow storages to discharge before the time of maximum value or retain energy for future periods when the market opportunity is perceived to be greater. AEMO has considered several modelling approaches in time-sequential modelling for the Draft 2024 ISP to examine the impact of this potential issue.

Analysis of existing battery behaviour

Analysing the operational behaviour of existing batteries has informed the evaluation of options available to address imperfect foresight in time-sequential modelling. Figure 22 shows the duration curves for a battery's state of charge, and normalised power dispatched (megawatts dispatched as a proportion of maximum power capacity) of large-scale grid batteries across the NEM over 2022-23. While batteries are generally capable of accessing the full range of their rated power capacity (shown by normalised power dispatch reaching unity) they typically retain some margin of energy (megawatt hours) and remain close to a 30-40% charge state.

This behaviour allows battery operators to manage market uncertainty but will limit their ability to fully discharge during extended high price periods. Co-optimisation between energy and FCAS markets also encourages battery operators to reserve sufficient headroom and footroom capacity to respond to contingency events. In the future, as batteries are increasingly used for energy shifting, reserving power for the provision of FCAS is likely to become less widespread, but retaining some margin for contingencies will remain as a risk management strategy.

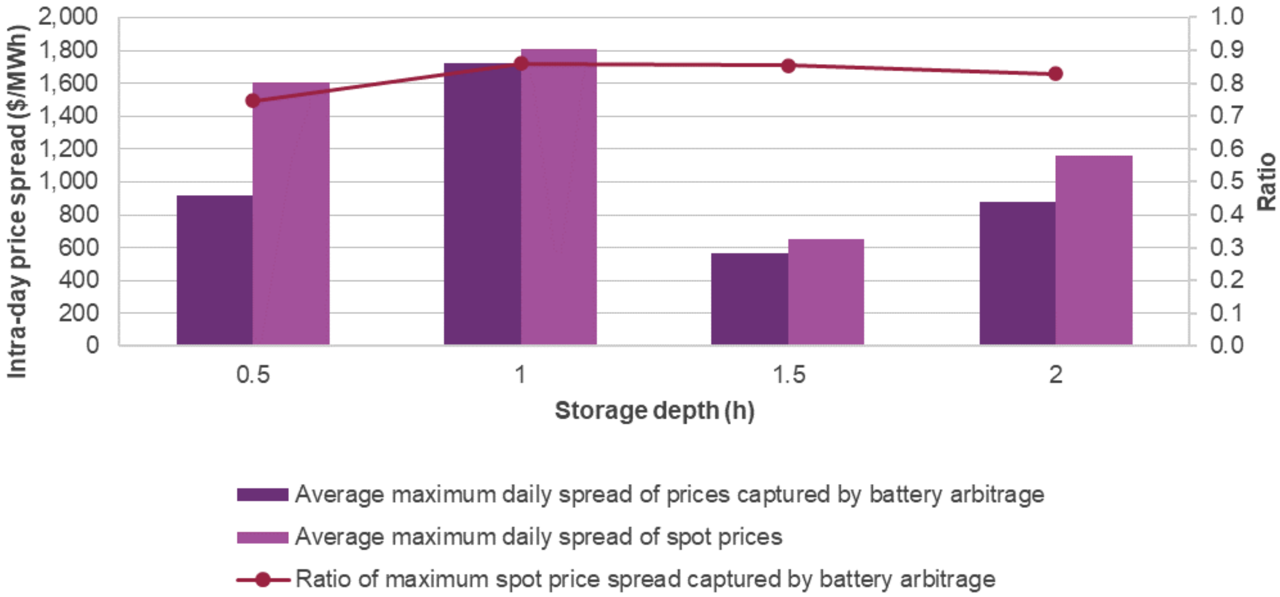
Figure 22 Duration curve of large-scale battery normalised power dispatch (left) and state of charge (right), 2022-23



Notes: excludes large-scale grid batteries operated with known contracts that reserve energy capacity or power capacity, and batteries with attached plant loads that do not principally target arbitrage of the wholesale energy market. Normalised power dispatch refers to the dispatched power (megawatts) as a proportion of the battery's rated power capacity.

Inaccurate forecasts of variability in cloud cover, wind speeds and operational demand mean battery operators often fail to perfectly dispatch into high price intervals. Figure 23 shows the impact of weather forecast inaccuracy affecting the expected operation of VRE, and its impact on battery operation by comparing the average daily maximum arbitrage opportunity captured by batteries, to the maximum spot price range. During 2022-23, batteries captured between 75% and 85% of the maximum intra-day price spread, with short-duration batteries (0.5 hour) missing substantially more maximum intra-day price spreads compared to longer duration batteries.

Figure 23 Average daily maximum spot price arbitrage potential captured by existing large-scale grid batteries, 2022-23 (MWh)



Evaluation of alternative approaches to modelling imperfect foresight

AEMO's response to the ISP Methodology consultation included a commitment to explore alternative approaches to modelling imperfect foresight in the Draft 2024 ISP. To investigate the impact of imperfect foresight on storage operation AEMO has evaluated three modelling approaches detailed below.

- **Derating storage capacity (MWh):** introduces the storage capacity constraints proposed in the ISP Methodology consultation.
  - For devices with less than two hours of storage, reduce storage capacity by 50%.
  - For devices with two to (less than) four hours of storage, reduce storage capacity by 25%.
  - For devices with four to (less than) eight hours of storage, reduce storage capacity by 10%.
- **Capacity reserves:** introduce headroom and footroom reserves that provide sufficient risk mitigation for batteries to capture unexpected system events.
  - The amount of headroom and footroom reserve is equivalent to energy dispatched at maximum power over a five-minute interval, which correlates with the Frequency Operating Standard for the time of frequency restoration (depending on the type of contingency event). This also correlates to observed battery energy management of existing grid-scale batteries.
  - The headroom and footroom reserves are implemented as soft constraints, with the cost of violation priced below the market price cap, to enable discharge if required to avoid a low energy reserve outcome.
- **Battery unavailability:** introduce randomised battery unavailability events to represent the risk of missing an interval of arbitrage opportunity. The likelihood and severity of an unavailability event is set based on

the historical observations shown in Figure 23 regarding the chance of generating at maximum power during peak periods, and the average power dispatched during peak periods, respectively.

- For devices with less than one hour of storage, implement unavailability events 80% of the time, during which only 10% of maximum power is available.
- For devices with two to (less than) four hours of storage, implement unavailability events 40% of the time, during which 50% of maximum power is available.
- For devices with four to (less than) eight hours of storage, implement unavailability events 20% of the time during which 90% of maximum power is available.

These imperfect foresight tests effectively apply greater relative constraints to shorter duration batteries compared to longer duration storages as shallower storages are at greater risk of missing a peak price event and losing value due to forecast inaccuracy. Of the over 36.5 GW of grid-connected shallow storages forecast to be required by 2040 under *Step Change*, almost 10 GW is shallow storage, and another approximately 18 GW is CER storage embedded within the distribution system.

Compared to the perfect foresight case, all foresight tests lowered battery generation, with derating storage capacity and battery unavailability having similarly strong impacts on the total amount of energy dispatched, as opposed to holding headroom and footroom energy reserves. In the latter case, energy reserves may be violated to serve tight market conditions, and under extreme circumstances, allow batteries to access retained energy that may have otherwise been discharged earlier, during periods of lesser energy scarcity.

The applied foresight tests did not reduce battery generation to the low levels observed historically, allowing some margin for future foresight improvement. As more batteries are rolled out it is expected operators will increasingly prioritise energy market arbitrage rather than FCAS revenues.

Figure 24 shows a *Step Change* summer forecast in 2039-40 for Victoria when there is strong reliance on battery operation. In cases where energy limitations have been imposed on batteries by derating or holding reserves, storages are less capable of charging so capture less surplus VRE during daytime hours. Meanwhile, imposing unavailability events cause batteries to miss out on charging during some low-price intervals. In all cases (top chart), batteries enter evening peak periods with less energy stored, compared to when modelled with perfect foresight, resulting in lower discharges from storage when that capacity is needed. The resultant generation profile under perfect foresight conditions (second chart) is presented alongside that when shallow storage has been derated (third chart).

In the perfect foresight case, stored energy can meet most of the post-sunset dispatchable demand, except for during low wind conditions. Under imperfect foresight conditions imposed by battery derating, impaired battery operation requires alternative generation to be supplied by other dispatchable generation such as gas, and additional imports from neighbouring regions where available. The degree of foresight therefore impacts short duration storage's ability to shift energy across the day. While a key operational observation, as outlined in the ISP Methodology this setting has not been applied in the capacity outlook models for the Draft 2024 ISP.

Figure 24 Forecast impact of battery foresight on summer operability in Victoria, *Step Change*, 2039-40 – energy stored in batteries (first chart), generation mix under perfect foresight conditions (second chart), generation mix with battery derating (third chart), and difference in dispatch relative to perfect foresight conditions (bottom chart)

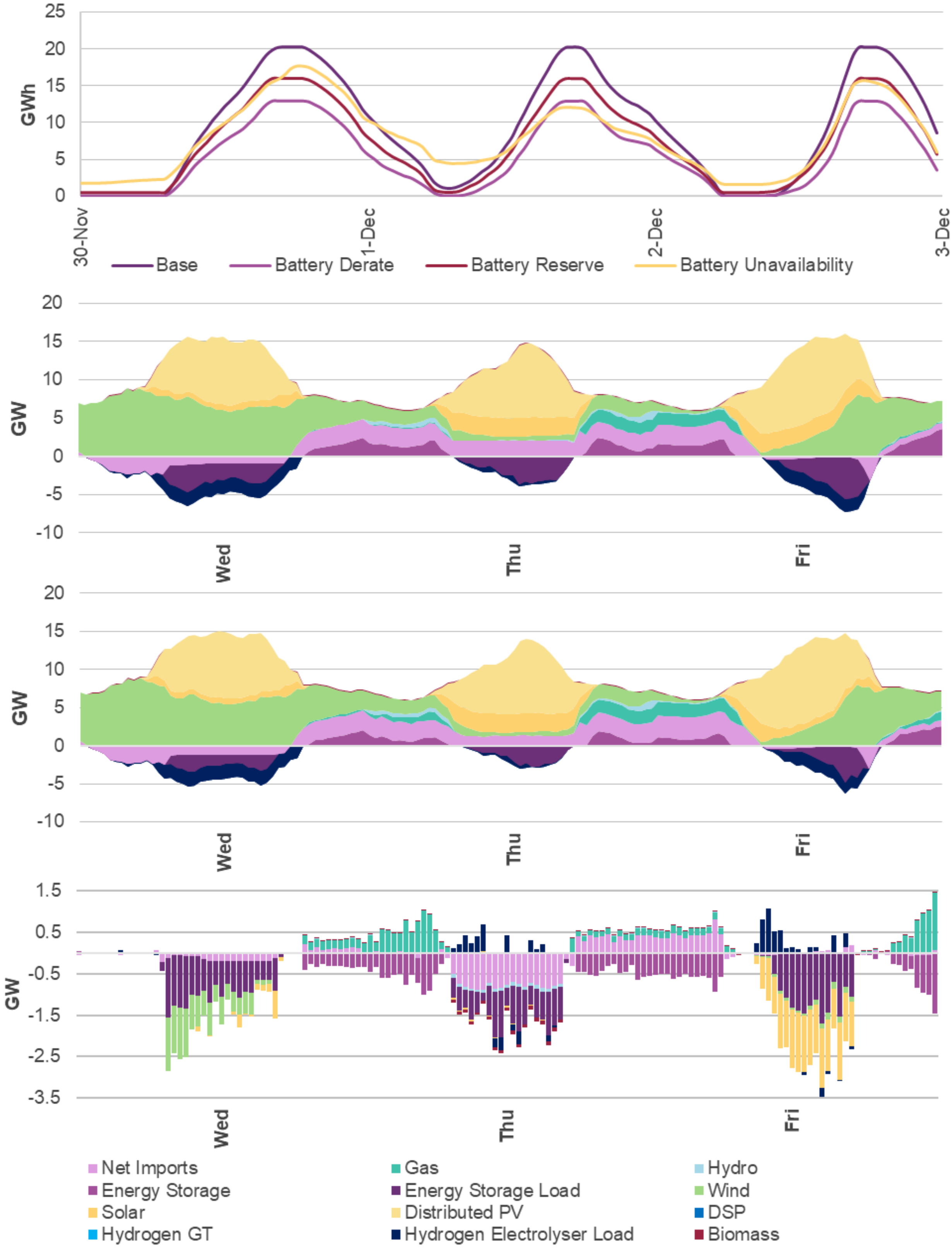
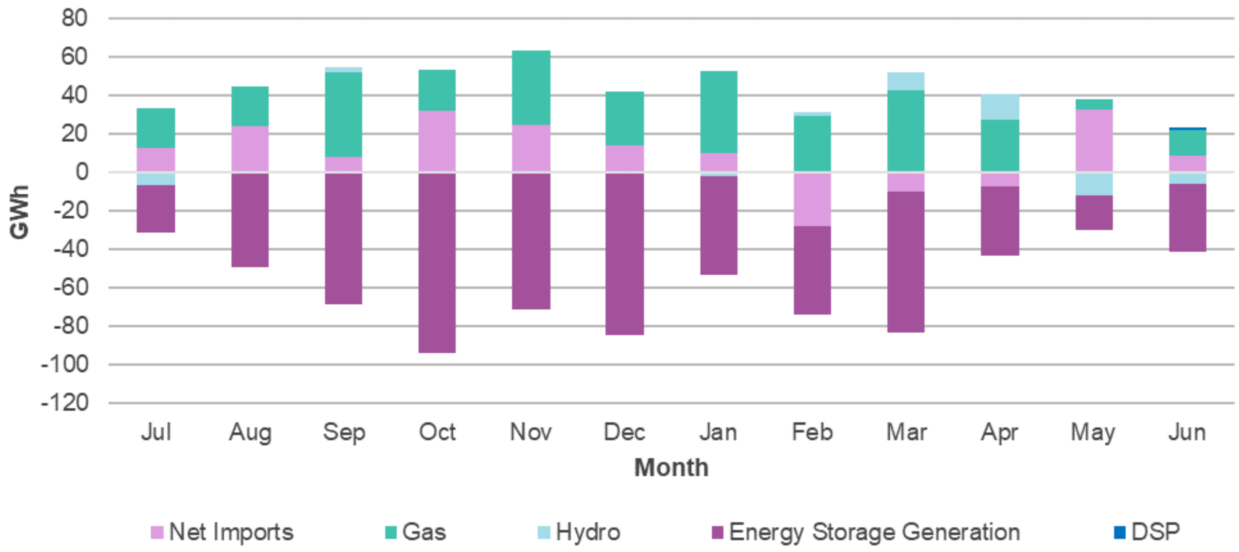


Figure 25 shows that generation from batteries due to modelling with perfect foresight are higher during warmer months in Victoria when batteries cycle regularly provide intra-day shifting. Modelling outcomes are less impacted during winter months with reduced battery activity due to higher and flatter residual demand profiles.

Figure 25 Forecast difference in monthly generation between perfect foresight conditions and conditions with battery derating in Victoria, *Step Change*, 2039-40 (GWh)

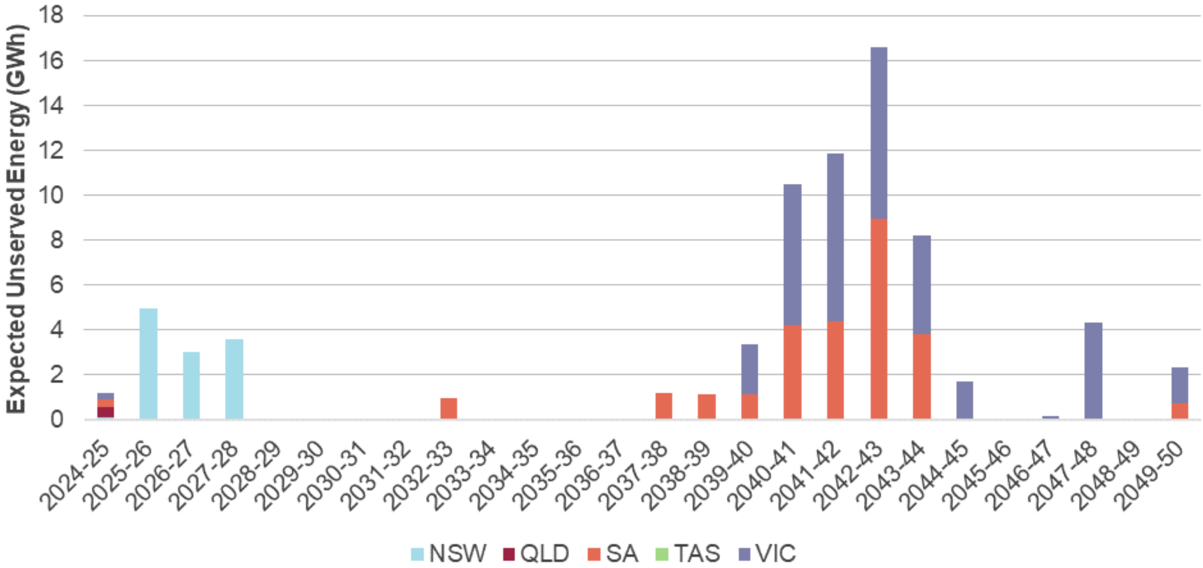


Note: positive generation in this figure refers to higher dispatch with battery derating, while negative generation refers to higher dispatch with perfect foresight. With battery derating, more gas generation is forecast to be used to compensate for imperfect storage management.

Storage availability may impact system reliability, and require more strategic reserves to mitigate forecast inaccuracy and imperfect foresight risks. This is demonstrated in Figure 26, which shows the increased forecast USE when stored energy derating is applied on a one-in-10 year extreme maximum demand forecast. This demonstrates the volatility in reliability risk is focused in the long term on regions with the highest relative growth in winter peak demands from electrified heating, and therefore greatest exposure to reliability risks during winter VRE lulls. During these periods of low reserve, having some extra headroom of storage capacity or other reserves would help to overcome imprecise storage operations.

This modelling highlights the risk to reliability from imperfect management of stored energy. If storages are likely to be well below full going into VRE lulls, then additional dispatchable and firm capacity may be required, depending on the duration of those VRE lulls which is hard to predict accurately. Improvements in weather forecasting, and increased coordination of stored energy operation at a system level may diminish the impact of imperfect foresight on modelled outcomes. The availability of other resources such as flexible gas (or hydrogen) generators with appropriate fuel availability will also reduce the impact of imperfect energy management.

Figure 26 Forecast increase in annual expected USE due to battery derating, *Step Change*, 2024-25 to 2049-50, during a one-in-10 year maximum demand forecast (GWh)

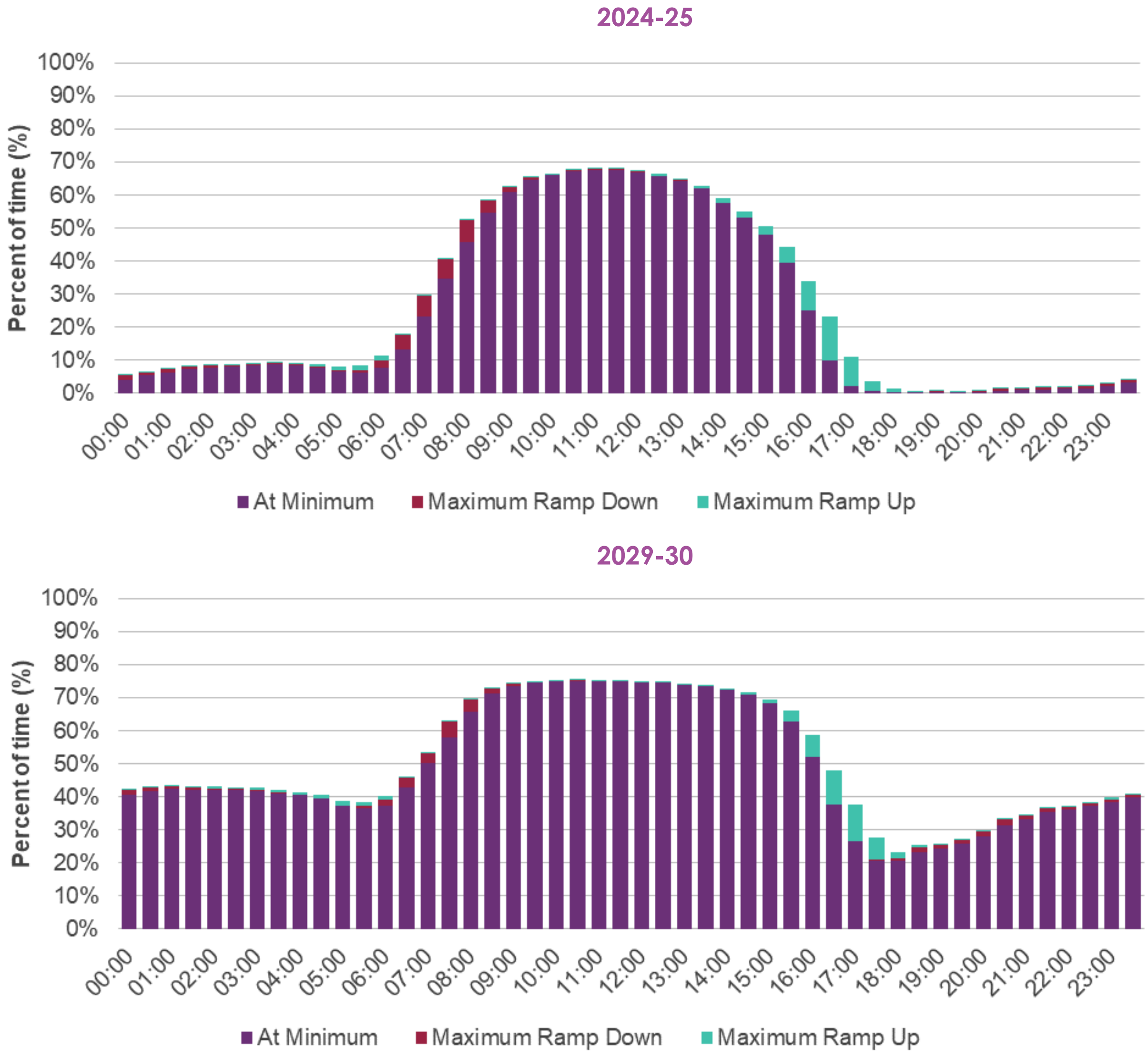


A4.7 Implications for coal operation during the transition

Coal-fired units are forecast to adjust the way they operate with projected increases in VRE penetration. Coal units typically have limited flexibility to ramp output up and down quickly to accommodate supply and demand fluctuations. Coal generators in the future are more likely to operate for longer periods at minimum stable levels with high penetration of VRE. This may lead to some operators mothballing or seasonally withdrawing coal capacity during sustained periods of high VRE availability, particularly in spring when energy availability is high, and demand is low leading to more frequent low-priced periods.

Figure 27 shows the percentage of time in each hourly period black coal generators in New South Wales and Queensland are forecast to operate at minimum generation levels in 2024-25, and also in 2029-30.

Figure 27 Forecast black coal percentage of time at maximum ramp and minimum load, *Step Change*, 2024-25 (top) and 2029-30 (bottom)



These generators are forecast to be required to ramp down when the sun rises, with utility-scale solar expected to be dispatched ahead of coal. They are then anticipated to operate at minimum generation levels during the day before ramping up to meet evening peak demand. The projected increase in the penetration of wind generation to 2029-30 is expected to impact coal generators causing more frequent operation at minimum generation levels, in both the day and the night.

Seasonal operation of coal-fired power plants may improve the economics of operating some coal generators. Operating a generator at a spot-market loss position may be avoided if operators consider that temporarily withdrawing the unit will result in a lower re-start cost than operating during VRE surpluses. Coal generators with higher operating costs may benefit from withdrawing their units to avoid operating losses if sufficient alternative generation were available to maintain an appropriate reliability position, and to cover retail or contract positions.

A4.8 Impacts of gas system adequacy on system operability

Transition of GPG from mid-merit to flexible generation

GPG is expected to continue to play an important role in the NEM by helping manage longer periods of low VRE generation and providing firming when other dispatchable sources are unavailable. GPG's role also extends to providing critical power system services.

GPG is forecast to be used less frequently during daily peak demand periods but will be critical to maintaining reliability during less frequent periods of more widespread low VRE output and during longer dark and still events (see Section A4.5). This is expected to be more likely during winter periods as electrified heating loads increase energy consumption during that season.

Figure 28 shows annual consumption of gas for electricity generation returning to recent historical levels during the mid-2030s, due to the combined effect of coal retirements, electricity consumption growth, and the need to firm high levels of VRE. Daily maximum demand for gas will increase significantly during winter as a result of electrification of heating loads and longer periods of lower VRE production.

Mid-merit generators (primarily combined cycle gas turbine (CCGT) technology) will be gradually replaced by new flexible generators (primarily open cycle gas turbine (OCGT) technology). OCGT technology is less fuel efficient, has lower up-front capital costs and can operate more flexibly. Consequently, it is a more appropriate replacement technology both technically and economically when operating at lower annual utilisation factors.

Figure 28 Actual and forecast NEM GPG annual consumption (PJ/y) and seasonal maximum daily demand (TJ/d) in *Step Change*, 2018-19 to 2040-41, averaged across different reference years (PJ/a)

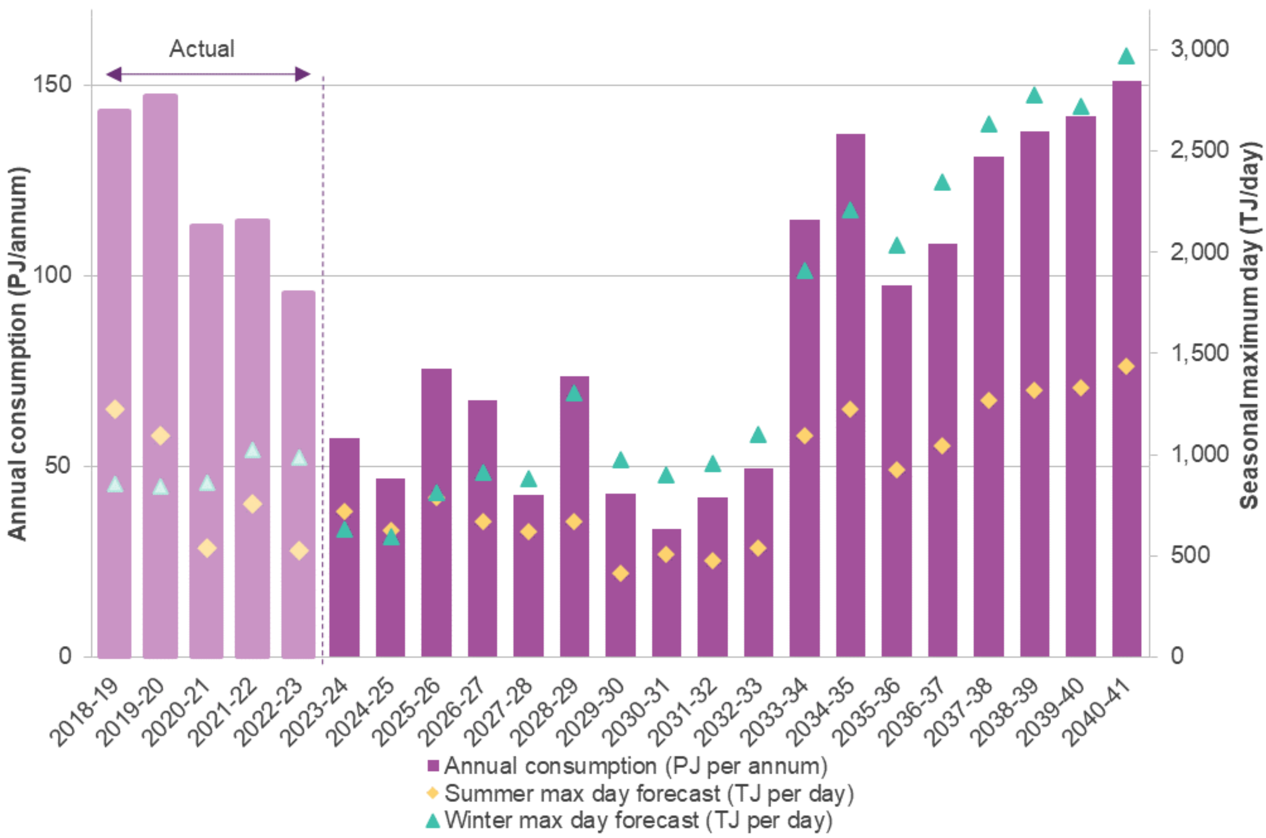
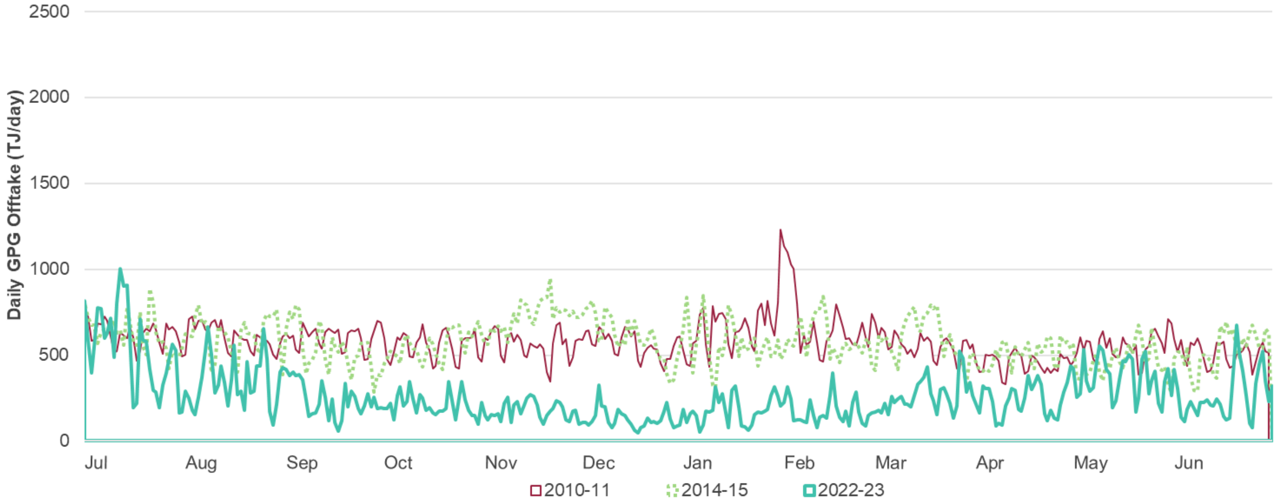


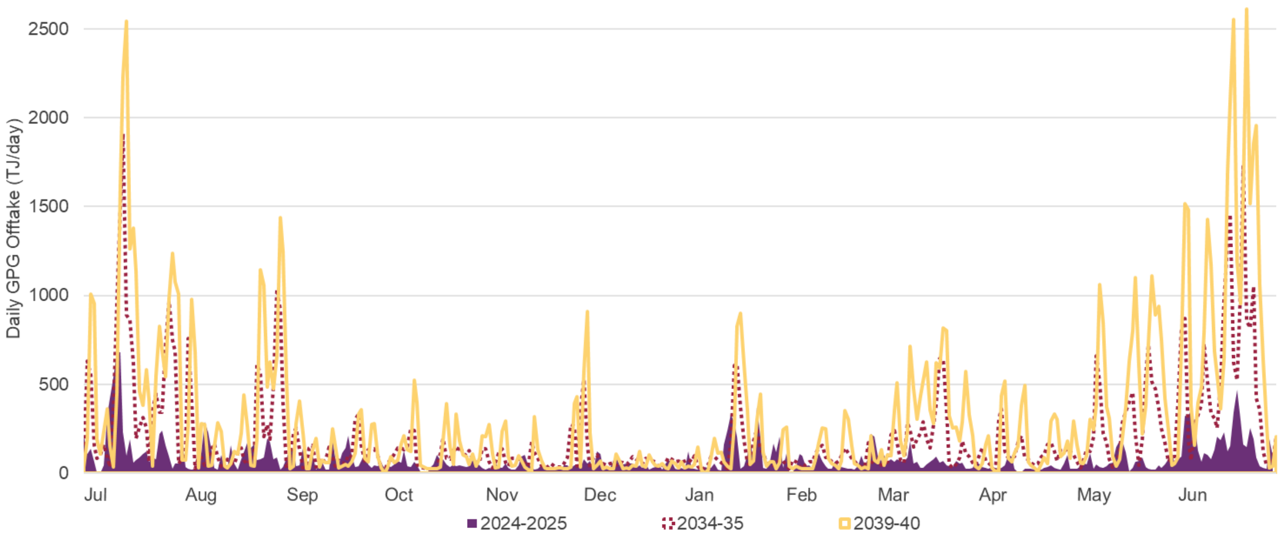
Figure 29 shows the profile of gas offtake (TJ/day) for power generation throughout the year in 2010-11, 2014-15 and 2022-23. In earlier years, higher usage occurred throughout the year, with marginally higher consumption during November to March and some high summer daily peaks. By 2022-23, the utilisation of gas has generally declined through the year, with some increases in offtake during winter operations.

Figure 29 Historical daily NEM GPG offtake in 2011-12, 2014-15 and 2022-23, *Step Change*, (TJ)



In contrast to the flatter generation profiles during 2010-11 and 2014-15, Figure 30 shows the increasing role flexible gas is forecast to play in supporting winter peak electricity demand from 2024-25 to 2039-40, and generally increase during winter (during non-peak demand events) when VRE generation is relatively low. The increasing requirement to operate GPG in winter will increase the challenges of operating the gas system to deliver higher volumes of gas during shorter periods. Secondary fuels or on-site storages may be needed to provide appropriate fuel security and deliver an appropriate operational reserve.

Figure 30 Forecast daily NEM GPG offtake in 2024-25, 2034-35 and 2039-40, *Step Change*, (TJ)



Pipeline capacity limits may constrain supply for peak GPG

AEMO has forecast the interaction of the gas and electricity systems considering the availability of existing, committed and anticipated mid-stream gas infrastructure of the east coast gas system, to examine the capability of that infrastructure to meet gas consumers' needs as well as gas generators' needs, using the *2023 Gas Statement of Opportunities* (2023 GSOO)[12] gas demand and infrastructure capacity forecasts.

In this assessment, gas supply is assumed to become available during the outlook period from prospective and uncertain gas resources across the East Coast Gas System as needed. If required to operate at times coincident with high gas consumer demands, GPG may be impacted by gas delivery constraints during peak periods. Given the generation and storage developments included in the Draft 2024 ISP's *Step Change* outlook, sufficient alternative back-up fuels (biomass, hydrogen, and distillate) and demand response are expected to be available for reliability to be maintained in the event of gas delivery risks, but this is subject to the scale of domestic gas demand, the availability of electricity storages, the availability of gas storages and the location of gas generators. If a major contingency event coincides with high demand for gas for heating and for electricity generation, then reliability risks in the NEM may increase without appropriate alternative capacity in addition to that forecast.

The 2023 GSOO identifies during peak days that larger inter-regional pipelines may become congested and unable to supply additional gas from northern producers. Gas transmission pipelines are forecast to become more constrained at peak times during the 2030s if flexible gas generators draw on high gas volumes when other gas users also have high gas loads. As a result, GPG may be unable to operate at maximum capacity using pipeline gas, particularly during extreme winter conditions.

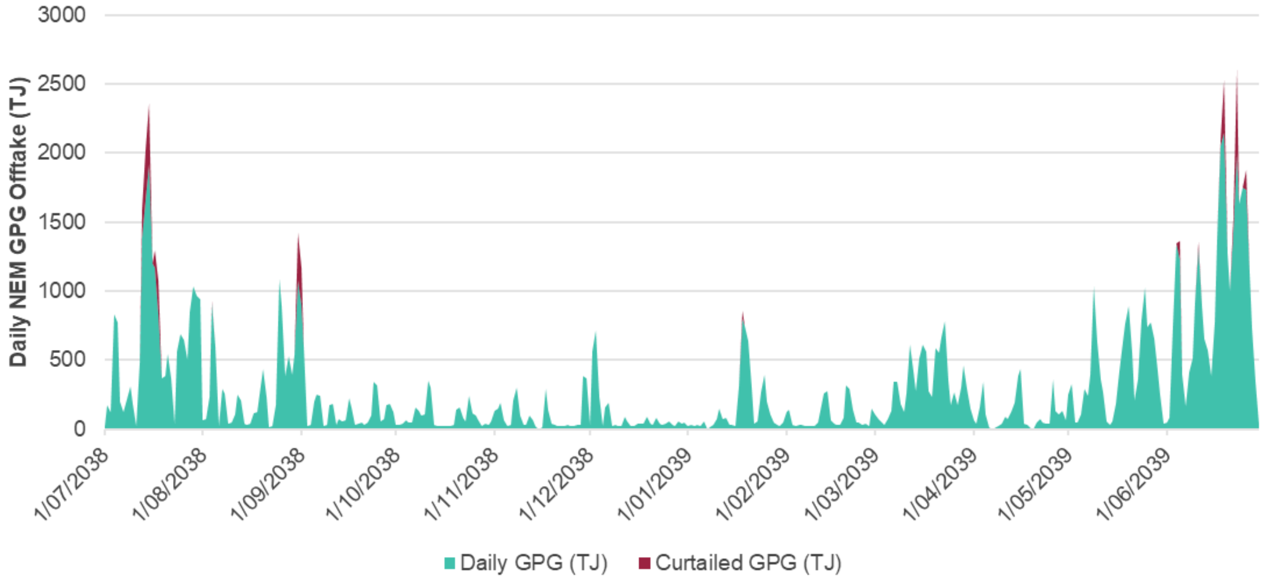
Figure 31 shows forecast daily GPG demand during 2038-39 when gas supply is at risk of being constrained. The model indicates gas supply for flexible gas generation may be curtailed by up to 600 TJ per day during short periods in the winter of 2038 and 2039 in these example extreme conditions[13]. This gas constraint may result in the curtailment of up to 2,200 MW[14], equivalent to 15% of total NEM GPG installed generation capacity at this time, unless secondary fuels were available or on-site gas storages were used to smooth pipeline delivery risks during coincident high gas demand periods. Future gas location decisions will need to consider expected availability of gas infrastructure (including pipelines and gas storages), future gas supplies, secondary fuels and the proximity to electrical loads.

[12] At https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

[13] Modelled under one-in-10 year NEM and one-in-20 year east coast gas system winter conditions.

[14] Based on the average heat rate of 10.93 GJ/MWh by OCGT technology.

Figure 31 Forecast daily GPG demand offtake and curtailment in the NEM, *Step Change*, reference year 2019, 2038-39 (TJ/day)

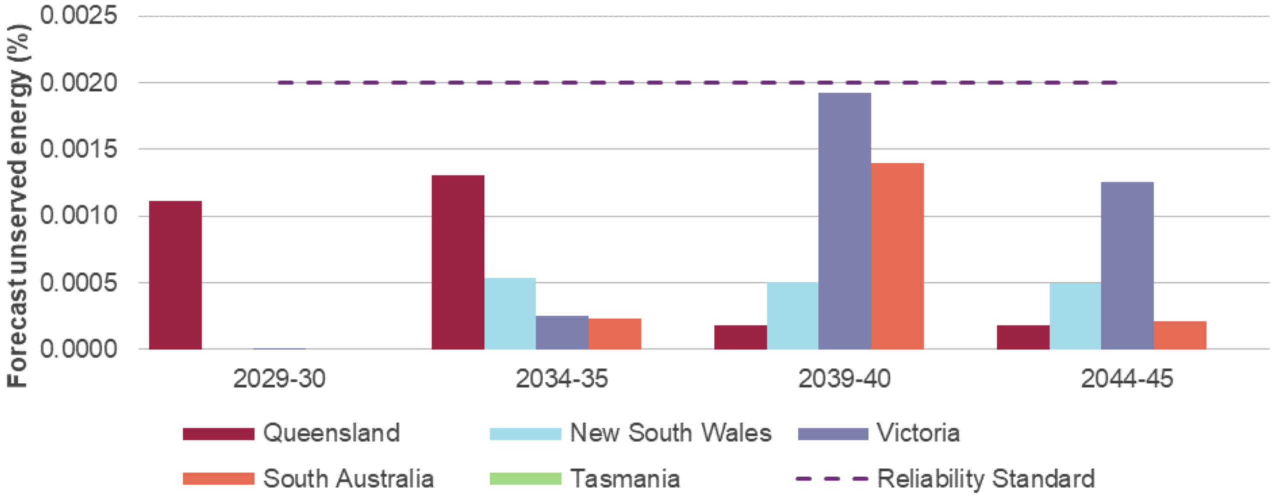


A4.9 Maintaining reliability during the transition

AEMO has forecast reliability outcomes for the Draft 2024 ISP development pathway using an approach consistent with the reliability assessments conducted for the NEM 2023 *Electricity Statement of Opportunities*[15] (2023 ESOO) accounting for weather variability and generator outages[16].

The reliability standard is a measure of expected USE in each region of no more than 0.002% of energy demanded in any financial year. With the Draft 2024 ISP's generation, storage and transmission developments, expected USE is forecast to be within the reliability standard in all regions over the medium and longer term, as shown from 2029-30 in Figure 32.

Figure 32 Forecast reliability outcomes by region, *Step Change*, 2029-30 to 2044-45



Reliability risk shifts from summer to winter

The 2023 ESOO forecasts the highest risk of expected USE to be during hot evenings in summer as demand for cooling increases operational demand and when solar generation provides no material contribution. Reliability risks are most likely to arise if large generation units experience forced outages, particularly when there is coincident low wind generation output across regions in the NEM.

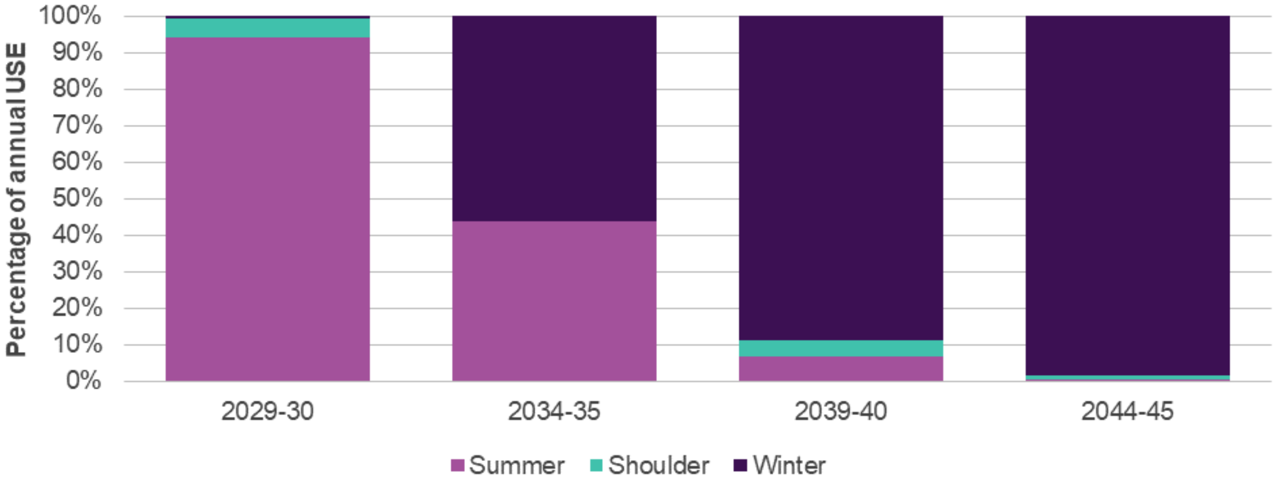
With the increased electrification of heating loads in winter, reliability risks are forecast to shift seasons in all mainland regions. During winter, high demand for electrified heating loads is forecast to coincide with reduced solar performance, particularly in the south where days are shorter. When wind output is also low, the imbalance between VRE production and high demand creates a tight supply-demand balance.

Figure 33 shows the seasonal share of reliability risks, as indicated by the volume of expected USE, across a range of forecast conditions between 2029-30 and 2044-45.

[15] 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.

[16] To manage simulation complexity, this reliability analysis has simulated fewer random generator outage patterns than the ESOO.

Figure 33 Seasonal share of expected USE, *Step Change*, 2029-30 to 2044-45



These forecast outcomes are driven by real differences in the frequency and severity of weather events resulting in reliability risks. Table 1 summarises the differences between summer and winter reliability events.

Table 1 Comparison of forecast summer and winter reliability risks

	Summer events	Winter events
Reliability challenge	Adequate available generation capacity for the hottest days.	Energy adequacy throughout winter, particularly for southern regions with relatively high heating loads.
Key weather driver	High temperatures create high cooling loads.	Cool temperatures create high heating loads. Exceptionally widespread calm weather pattern over south-east Australia. Low wind availability over a 1-to-5-day period.
Factors affecting reliability	Concurrent low wind, unavailable generation capacity, transmission outages.	Concurrent cloud cover limiting solar energy, cold conditions driving up heating load, firm generation outages, transmission outages.
Time of day (intra-day) reliability challenges	During early evening as solar output reduces to zero, but load remains high.	Beginning during the night and into the early morning as shallow and medium storages run empty.
Limiting (bounding) factors	The gap between the maximum instantaneous demand and maximum available generation supply.	Duration of low VRE event and geographical area impacted.
Key supply-side risk	Capacity unavailable at peak due to generation or transmission outage.	Energy unavailable over wind-drought period due to lack of access to energy reserves (deep storage or GPG).

Forecasting future weather conditions is a key uncertainty, and highly influential on the future reliability of the NEM. Weather conditions directly influence not only the magnitude of weather-induced demand peaks, but also the duration and frequency of extreme wind and solar drought conditions. See Section A4.5 for additional 'what-if' analysis regarding the operation of the ODP under longer duration renewable energy droughts than have been observed historically, highlighting the role of storages and flexible gas to maintain energy adequacy and reliability.

Glossary

This glossary has been prepared as a quick guide to help readers understand some of the terms used in the ISP. Words and phrases defined in the National Electricity Rules (NER) have the meaning given to them in the NER. This glossary is not a substitute for consulting the NER, the Australian Energy Regulator's (AER's) Cost Benefit Analysis Guidelines, or AEMO's *ISP Methodology*.

Term	Acronym	Explanation
Actionable ISP project	-	Actionable ISP projects optimise benefits for consumers if progressed before the next ISP. A transmission project (or non-network option) identified as part of the ODP and having a delivery date within an actionable window. For newly actionable ISP projects, the actionable window is two years, meaning it is within the window if the project is needed within two years of its earliest in-service date. The window is longer for projects that have previously been actionable. Project proponents are required to begin newly actionable ISP projects with the release of a final ISP, including commencing a RIT-T.
Actionable New South Wales project and actionable Queensland project	-	A transmission project (or non-network option) that optimises benefits for consumers if progressed before the next ISP, is identified as part of the ODP, and is supported by or committed to in New South Wales Government or Queensland Government policy and/or prospective or current legislation.
Anticipated project	-	A generation, storage or transmission project that is in the process of meeting at least three of the five commitment criteria (planning, construction, land, contracts, finance), in accordance with the AER's Cost Benefit Analysis Guidelines. Anticipated projects are included in all ISP scenarios.
Candidate development path	CDP	A collection of development paths which share a set of potential actionable projects. Within the collection, potential future ISP projects are allowed to vary across scenarios between the development paths. Candidate development paths have been shortlisted for selection as the ODP and are evaluated in detail to determine the ODP, in accordance with the ISP Methodology.
Capacity	-	The maximum rating of a generating or storage unit (or set of generating units), or transmission line, typically expressed in megawatts (MW). For example, a solar farm may have a nominal capacity of 400 MW.
Committed project	-	A generation, storage or transmission project that has fully met all five commitment criteria (planning, construction, land, contracts, finance), in accordance with the AER's Cost Benefit Analysis Guidelines. Committed projects are included in all ISP scenarios.
Consumer energy resources	CER	Generation or storage assets owned by consumers and installed behind-the-meter. These can include rooftop solar, batteries and electric vehicles. CER may include demand flexibility.
Consumption	-	The electrical energy used over a period of time (for example a day or year). This quantity is typically expressed in megawatt-hours (MWh) or its multiples. Various definitions for consumption apply, depending on where it is measured. For example, underlying consumption means consumption being supplied by both CER and the electricity grid.
Cost-benefit analysis	CBA	A comparison of the quantified costs and benefits of a particular project (or suite of projects) in monetary terms. For the ISP, a cost-benefit analysis is conducted in accordance with the AER's Cost Benefit Analysis Guidelines.
Counterfactual development path	-	The counterfactual development path represents a future without major transmission augmentation. AEMO compares candidate development paths against the counterfactual to calculate the economic benefits of transmission.
Demand	-	The amount of electrical power consumed at a point in time. This quantity is typically expressed in megawatts (MW) or its multiples. Various definitions for demand, depending on

Term	Acronym	Explanation
		where it is measured. For example, underlying demand means demand supplied by both CER and the electricity grid.
Demand-side participation	DSP	The capability of consumers to reduce their demand during periods of high wholesale electricity prices or when reliability issues emerge. This can occur through voluntarily reducing demand, or generating electricity.
Development path	DP	A set of projects (actionable projects, future projects and ISP development opportunities) in an ISP that together address power system needs.
Dispatchable capacity	-	The total amount of generation that can be turned on or off, without being dependent on the weather. Dispatchable capacity is required to provide firming during periods of low variable renewable energy output in the NEM.
Distributed solar / distributed PV	-	Solar photovoltaic (PV) generation assets that are not centrally controlled by AEMO dispatch. Examples include residential and business rooftop PV as well as larger commercial or industrial "non-scheduled" PV systems.
Firming	-	Grid-connected assets that can provide dispatchable capacity when variable renewable energy generation is limited by weather, for example storage (pumped-hydro and batteries) and gas-powered generation.
Future ISP project	-	A transmission project (or non-network option) that addresses an identified need in the ISP, that is part of the ODP, and is forecast to be actionable in the future.
Identified need	-	The objective a TNSP seeks to achieve by investing in the network in accordance with the NER or an ISP. In the context of the ISP, the identified need is the reason an investment in the network is required, and may be met by either a network or a non-network option.
ISP development opportunity	-	A development identified in the ISP that does not relate to a transmission project (or non-network option) and may include generation, storage, demand-side participation, or other developments such as distribution network projects.
Net market benefits	-	The present value of total market benefits associated with a project (or a group of projects), less its total cost, calculated in accordance with the AER's Cost Benefit Analysis Guidelines.
Non-network option	-	A means by which an identified need can be fully or partly addressed, that is not a network option. A network option means a solution such as transmission lines or substations which are undertaken by a Network Service Provider using regulated expenditure.
Optimal development path	ODP	The development path identified in the ISP as optimal and robust to future states of the world. The ODP contains actionable projects, future ISP projects and ISP development opportunities, and optimises costs and benefits of various options across a range of future ISP scenarios.
Regulatory Investment Test for Transmission	RIT-T	The RIT-T is a cost benefit analysis test that TNSPs must apply to prescribed regulated investments in their network. The purpose of the RIT-T is to identify the credible network or non-network options to address the identified network need that maximise net market benefits to the NEM. RIT-Ts are required for some but not all transmission investments.
Reliable (power system)	-	The ability of the power system to supply adequate power to satisfy consumer demand, allowing for credible generation and transmission network contingencies.
Renewable energy	-	For the purposes of the ISP, the following technologies are referred to under the grouping of renewable energy: "solar, wind, biomass, hydro, and hydrogen turbines". Variable renewable energy is a subset of this group, explained below.
Renewable energy zone	REZ	An area identified in the ISP as high-quality resource areas where clusters of large-scale renewable energy projects can be developed using economies of scale.

Term	Acronym	Explanation
Renewable drought	-	A prolonged period of very low levels of variable renewable output, typically associated with dark and still conditions that limit production from both solar and wind generators.
Scenario	-	A possible future of how the NEM may develop to meet a set of conditions that influence consumer demand, economic activity, decarbonisation, and other parameters. For the 2024 ISP, AEMO has considered three scenarios: *Progressive Change*, *Step Change* and *Green Energy Exports*.
Secure (power system)	-	The system is secure if it is operating within defined technical limits and is able to be returned to within those limits after a major power system element is disconnected (such as a generator or a major transmission network element).
Sensitivity analysis	-	Analysis undertaken to determine how modelling outcomes change if an input assumption (or a collection of related input assumptions) is changed.
Spilled energy	-	Energy from variable renewable energy resources that could be generated but is unable to be delivered. Transmission curtailment results in spilled energy when generation is constrained due to operational limits, and economic spill occurs when generation reduces output due to market price.
Transmission network service provider	TNSP	A business responsible for owning, controlling or operating a transmission network.
Utility-scale or utility	-	For the purposes of the ISP, ‘utility-scale’ and ‘utility’ refers to technologies connected to the high-voltage power system rather than behind the meter at a business or residence.
Virtual power plant	VPP	An aggregation of resources coordinated to deliver services for power system operations and electricity markets. For the ISP, VPPs enable coordinated control of CER, including batteries and electric vehicles.
Variable renewable energy	VRE	Renewable resources whose generation output can vary greatly in short time periods due to changing weather conditions, such as solar and wind.