Summary Note of Key Drivers of Changes from 2022

2023 CECV Update

Australian Energy Regulator | 29 June 2023

DISCLAIMER

This report was commissioned by the Australian Energy Regulator (AER) to provide an explanation of the factors that have driven the changes in the customer export curtailment values (CECVs) since they were first developed in 2022.

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1. Background and objective of the paper

As noted by the AER in the *Final CECV methodology*[1]:

> *Prior to 1 July each year we will consider whether input assumptions under the ISP's Step change scenario* have materiall*y changed to reflect new information or forecasts.*
>
> - *If there are material changes, we will re-estimate CECVs using the new assumptions, update these values in the DNSP model and make subsequent changes to the number and nature of characteristic days in the DNSP model.*
> - *If there are no material changes, we will only update CECV estimates to account for changes in inflation, to ensure that in economic terms, real values of CECV are maintained between CECV reviews. The annual adjustment mechanism is detailed in Appendix A. Instead of estimating new values for the 20th year of the analysis period, we will calculate new values based on the terminal value methodology discussed in section 4.2.1 (with the average of the final three years of values used as the new value for each half-hourly interval).*
>
> *New CECV estimates will be published by 1 July each year, as well as an updated list of data sources used for model inputs.*

This Note provides information on the key inputs to the calculation of the 2023 CECVs. As requested by the AER, this includes:

- Any inputs used this year that differ materially from those used in 2022
- The degree to which those inputs (in aggregate) have resulted in changes to the CECVs themselves.

These changes are included in the file of CECVs and used to update the DNSP model, both of which are published separately by the AER.

1 AER, *Final CECV methodology*, June 2022, p 10.

2. Overview of the CECV methodology

No changes have been made to the methodology used to calculate the CECVs for 2023-24 from that used in 2022.

The main aspects of the CECV methodology are very briefly summarised below; full details can be found in the AER document entitled *Final CECV methodology* (June 2022).[2]

2.1. Wholesale market modelling

Wholesale market modelling is the primary means by which the value that incremental DER export enabled by additional DER hosting capacity in the distribution network will be quantified. This initial version of the methodology quantifies the impact of incremental DER export on:

- Wholesale market production cost (as opposed to price), accounting for aggregated headroom and footroom allowances for FCAS services, and
- Transmission and distribution losses.

The wholesale market modelling derives the half-hourly impact of additional DER export on each of the value streams noted above (or as expanded in the future) and combines them into a single CECV for each half-hour in each NEM region.

2.2. Value streams not estimated in the methodology

Potential value streams not included in the CECV methodology are:

- Other wholesale market value streams, such as
  - Possible changes to generation or transmission system investment costs, as this would require knowledge of the system wide net effect of all alleviation projects
  - Changes in ESS provision where these might result in material differences to either the total amount of headroom and footroom allowances already included in the analysis or its allocation across the various FCAS services (i.e., 6 second, 60 second and 5 minutes)
- Network sector value streams, including avoided/deferred capex and avoided opex
- Potential competition benefits that additional export from DER systems could provide in the market
- The potential willingness of all customers to pay for the ability of the network to allow additional export from customer energy resources.[3]

2 This and other key documents related to the CECV methodology can be found at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/customer-export-curtailment-value-methodology/final-decision.

3 A full discussion of the value streams included in the CECV methodology can be found in AER, *DER integration expenditure guidance note*, June 2022, pp 220-26.

3. Changes to inputs and associated rationale

This section provides information on key changes to the inputs to the calculation of the 2023 CECVs and the rationale for the changes.

3.1. ISP scenario used

The 2022 CECVs were based on AEMO's draft ISP 2022 Step Change. The 2023 CECVs are based on AEMO's Draft 2023 Inputs, Assumptions and Scenarios Report (IASR) for the 1.8[0] Orchestrated Step Change Scenario.

The Orchestrated Step Change Scenario was chosen because:

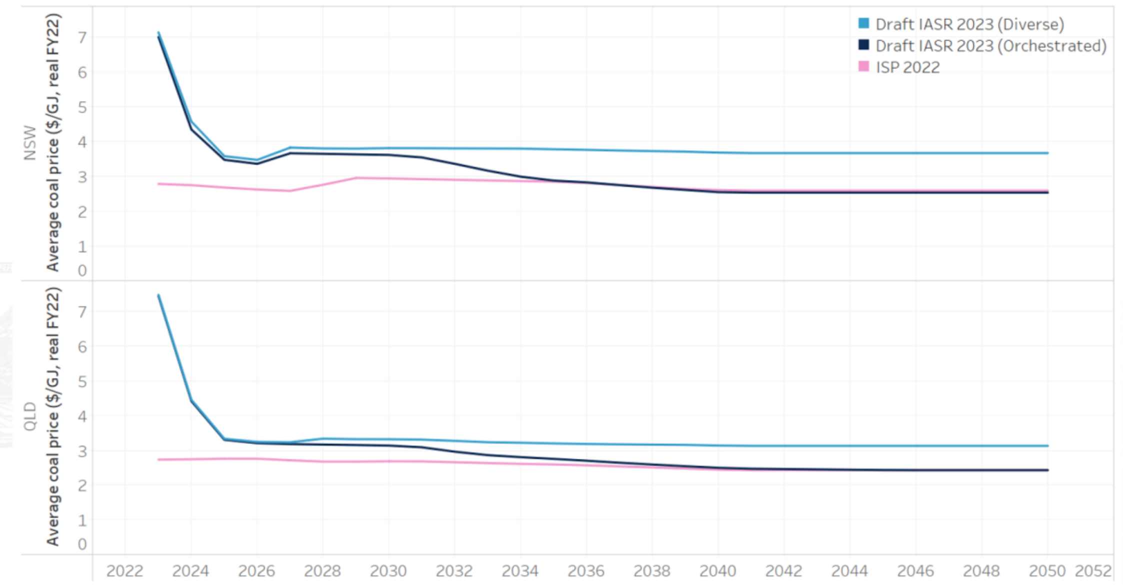
- AEMO describes it as a refinement of the 2021 Step Change scenario[4]
- Its characteristics were felt to more closely reflect several characteristics of the electricity market in the near term, but also trend closer to the 2022 Step Change in the longer term, as will be seen in the discussion below of the specific fuel cost and certain other inputs.

3.2. Changes in specific inputs

3.2.1. Coal prices

Coal prices in the 2023 IASR Orchestrated Step Change are significantly higher than the 2022 ISP Step Change scenario (but similar to current prices) in the early years, and converge to similar levels after 2030, as shown in the figure below.

Figure 1: Coal price forecasts from the 2022 ISP and the Draft IASR Diverse and Orchestrated scenarios



Source: Endgame Economics

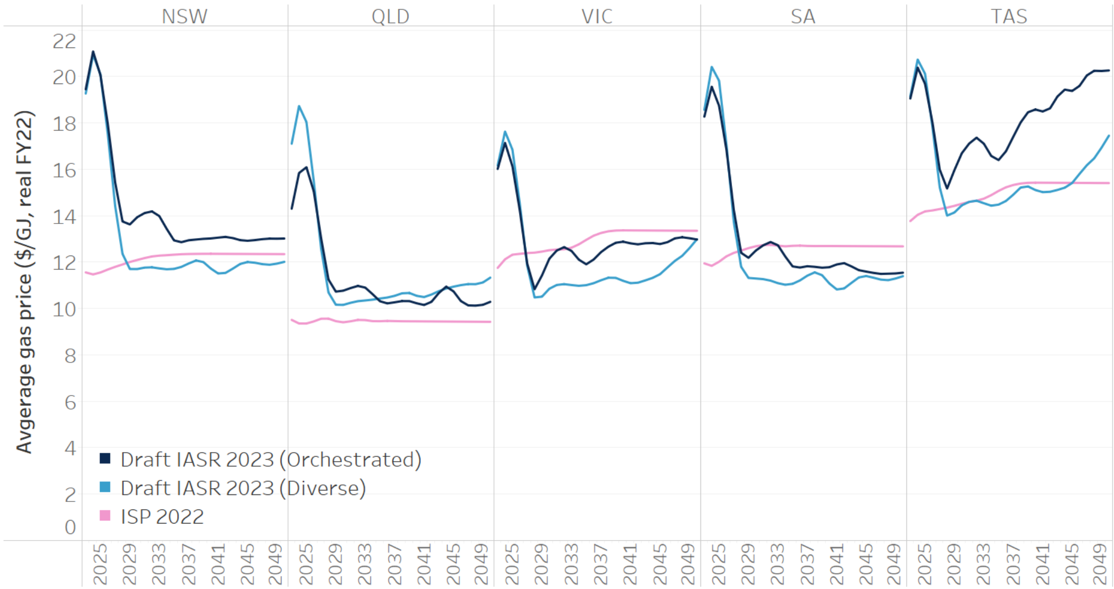
4 AEMO, *Draft 2023 Inputs, Assumptions and Scenarios Report*, December 2022, p 5.

The AER elected to use AEMO's Orchestrated Step Change forecast of coal prices values instead of the capped values currently in place in the market because using the capped values would have an immaterial impact on the rooftop-PV weighted CECVs, as coal generators bidding in to stay online at minimum stable generation levels will not be setting the price. and gas generators are not frequently running during midday hours.

3.2.2. Gas prices

Similarly, gas prices in the IASR Orchestrated Step Change are higher than the 2022 ISP Step Change scenario (but closer to current market price) in the early years, and gradually fall back to levels similar to those in the 2022 Step Change scenario, as shown in the figure below.

Figure 2: Gas price forecasts from the 2022 ISP and the Draft IASR Diverse and Orchestrated scenarios



Source: Endgame-Economics

The AER also cited immateriality of the gas price to CECV outcomes in making the decision to use the 2023 Orchestrated Step Change scenario gas price forecasts rather than those from the 2022 Step Change, noting that gas generators do not frequently running during the midday hours which are of prime importance to the CECV.

3.2.3. Plant commitment and retirement schedules

The modelling undertaken for the 2023 CECVs incorporates updated information on the expected commitment of new plants and the retirement of existing ones.

The information on new project commitment dates was taken from AEMO's May 2023 Generation Information. The vast majority of newly committed projects are wind, solar and short-duration (1-2 hours) of battery energy storage systems (BESS).

We have also assumed that the commissioning of Snowy 2.0 will be delayed to 1 December 2029 based on recent announcements to the market.

We have also changed two retirement dates:

- Osborne GT's retirement date is now delayed to the end of FY2026

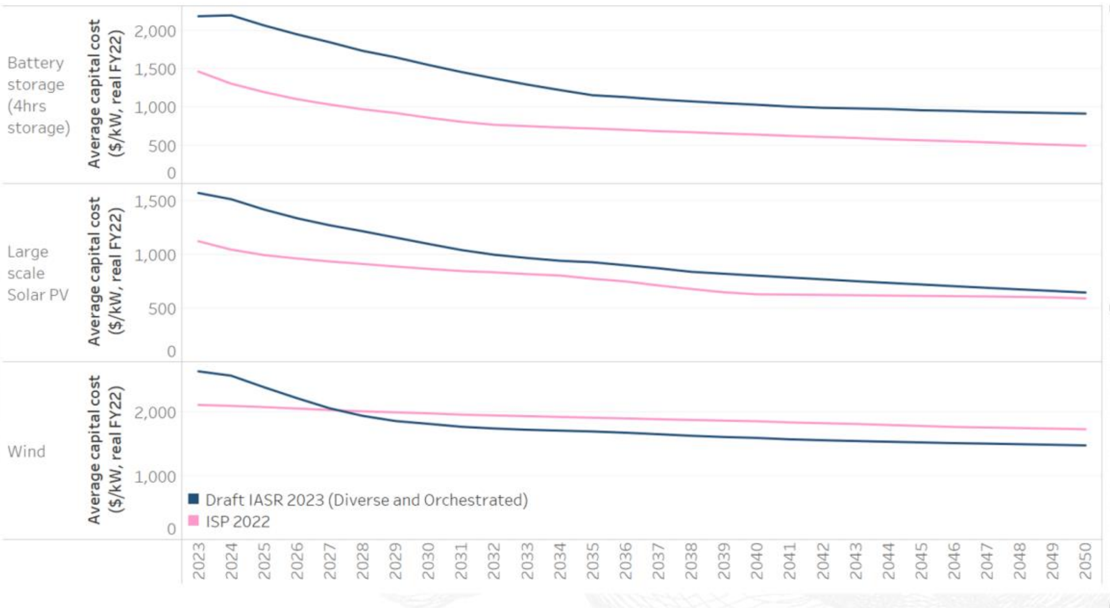
- Torrens Island Power Station B's retirement is now the end of FY2026.

3.2.4. BESS and VRE capex

As shown in the figure below,

- BESS and solar CAPEX have increased substantially in the 2023 IASR Step Change scenarios
- By contrast, wind CAPEX starts at a higher level in the 2023 IASR Step Change scenarios but quickly falls below the 2022 ISP Step Change level.

Figure 3: BESS, large-scale PV and wind capex requirements from the 2022 ISP and the Draft 2023 IASR



Source: Endgame-Economics

The changes in the CAPEX assumptions have the following implications:

- Solar/BESS CAPEX increased with the new draft 2023 IASR inputs relative to the 2022 inputs, whereas wind CAPEX has decreased. This means the long-term generation mix will have less solar but more wind, which leads to higher CECVs during daylight periods.
- Further, the increase in BESS CAPEX also increases the costs of cycling the BESS asset. Unlike solar and wind, which have $0/MWh SRMC for generation, BESS have a limit on the total number of times they can be cycled. Running an extra cycle means bringing forward the asset's replacement, which represents a real resource cost. In our SRMC-based dispatch modelling we account for cost of BESS cycling as an SRMC.[5]

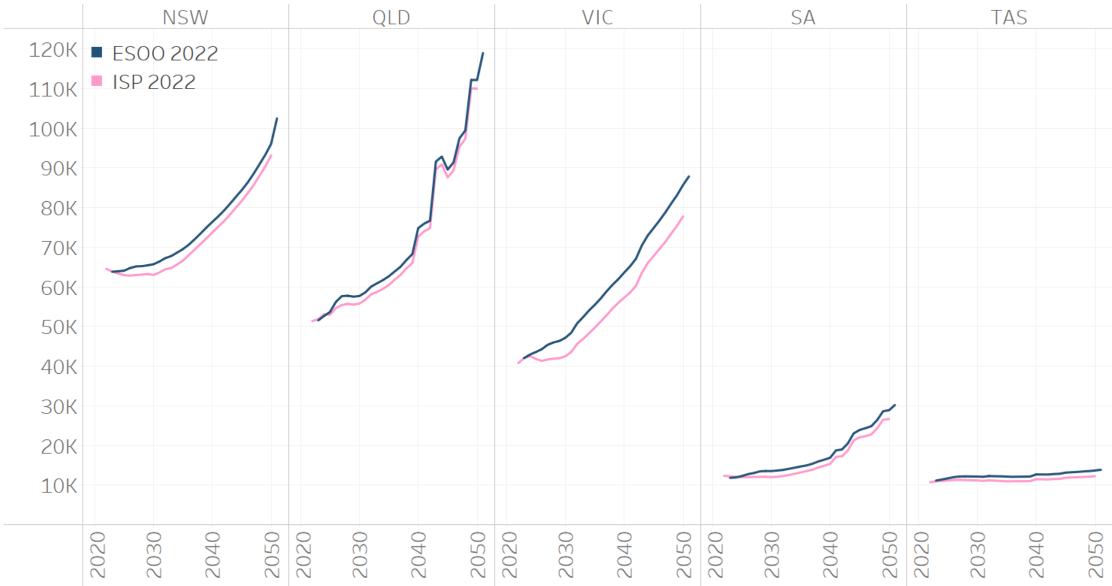
3.2.5. Consumption and maximum demand forecast

The modelling undertaken for the 2023 CECVs is based on the ESOO 2022 Central scenario demand forecast. This source was selected because the 2022 ESOO was published after the 2022 ISP and its updated operational demand (both annual consumption and maximum demand) is higher than in the ISP Step Change scenario.

5 For the avoidance of doubt it should be noted that pumped hydro facilities do not have a cycling limit.

As shown in Figure 4 below, this difference is minimal in QLD, larger in NSW and material in VIC.

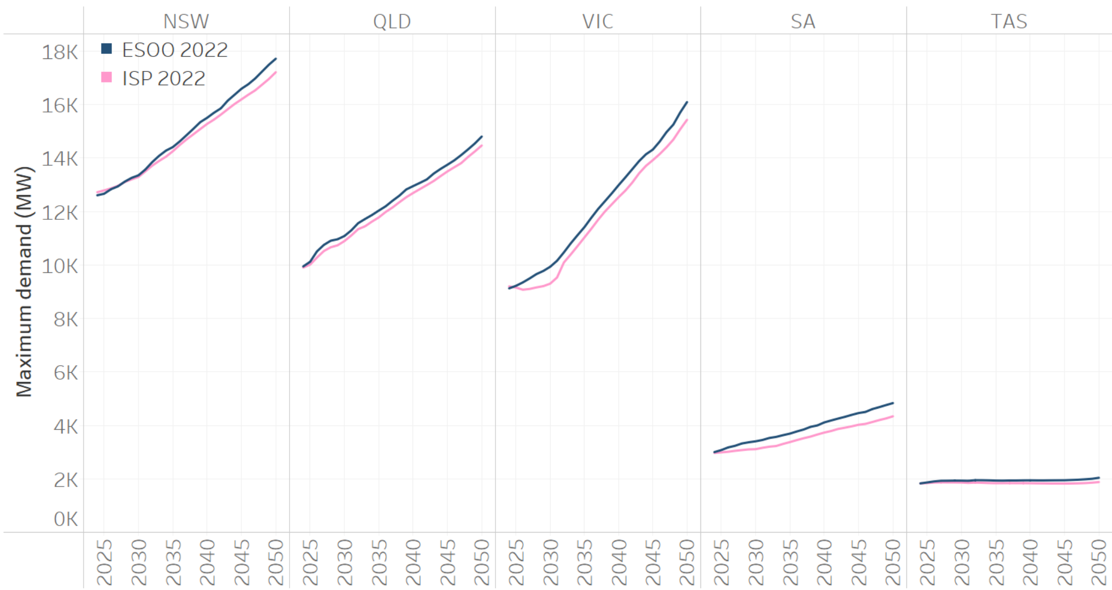
Figure 4: Annual consumption forecasts from the 2022 ISP and the 2022 ESOO



Source: Endgame-Economics

The differences in the two forecasts is less pronounced in regard to maximum demand, but the difference in the two forecasts remains largest in the case of VIC, as shown in Figure 5 below.

Figure 5: Maximum demand forecasts (50POE) from the 2022 ISP and the 2022 ESOO



Source: Endgame-Economics

3.3. VPP take-up

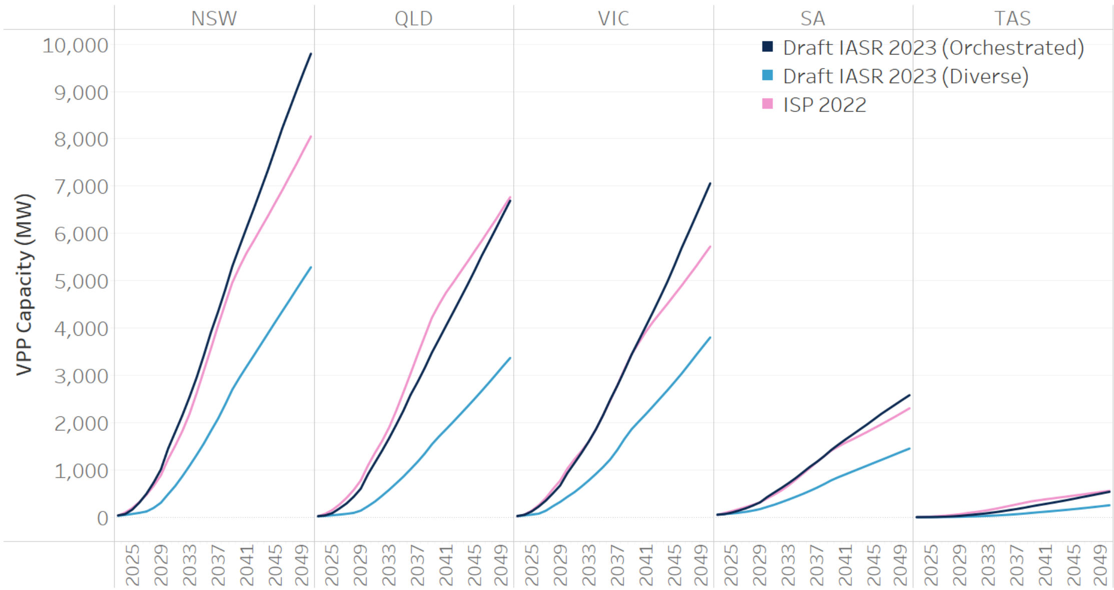
The level at which consumer energy resources participate in VPP arrangements is a key consideration for the CECV levels because stronger uptake of VPP can be expected to lead to higher midday prices due to VPP operation resulting in a material level of demand shifting. This occurs because the VPP coordinates behind-the-meter battery charging to occur during low demand periods and discharging during higher demand periods.

Figure 6 compares forecast VPP take-up in AEMO's 2022 ISP Step Change scenario with two scenarios in 2023 IASR. As can be seen, the 2023 IASR Orchestrated Step Change scenario forecast of VPP take-up is more closely aligned to the VPP forecast in the 2022 ISP Step Change scenario, and therefore has been used in the 2023 CECV modelling.

The figure also shows that:

- The 2023 IASR Orchestrated Step Change has higher VPP uptake than the 2022 ISP Step Change scenario in NSW and in later years in VIC.
- The VPP uptake in QLD is slightly lower than the 2022 ISP Step Change.

Figure 6: Comparison of VPP take-up in the 2022 ISP Step Change scenario and two scenarios in the 2023 Draft IASR



Source: Endgame-Economics

3.4. State renewable energy policies

Information on state renewable policies that had changed since the 2022 ISP were updated to ensure they are consistent with the assumptions in the draft 2023 IASR report.

State level policies that were added to the modelling included:[6]

- Victoria
  - Storage targets of 2.6 GW storage by 2030 and 6.3 GW by 2035

6 It should be noted that state energy policies are not included in the ESOO forecasts of consumption and maximum dmand discussed in section 3.2.5.

  - Extension of the VRET to 65% of the state's electricity generation by 2030 and 95% by 2035.[7]
- Queensland Energy and Jobs Plan (QEJP)
  - Extension of the QRET to 70% of the state's electricity generation by 2032 and 80% by 2035[8]
  - Commissioning of two pumped hydro energy storage (PHES) plants to smooth the state's wholesale price profile:
    - Borumba - 2GW/24hr from 2030
    - Pioneer Burdekin - 2.5GW/24hr from 2032 for stage 1 and 2.5GW/24hr from 2035 for stage 2.

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7 Note that extension of the VRET is unlikely to materially change the results in VIC as the state's brown coals are assumed to retire before FY2035.

8 As in the case of VIC, extension of the QRET is unlikely to have much impact on the CECV modelling results due to the assumed closure dates of the QLD coal plants.

4. Summary of CECV outputs

This section summarises key factors that drive the CECVs, including forecast operational demand and the resulting generation profile, as well as several characteristics of the CECVs they produce over the analysis period.

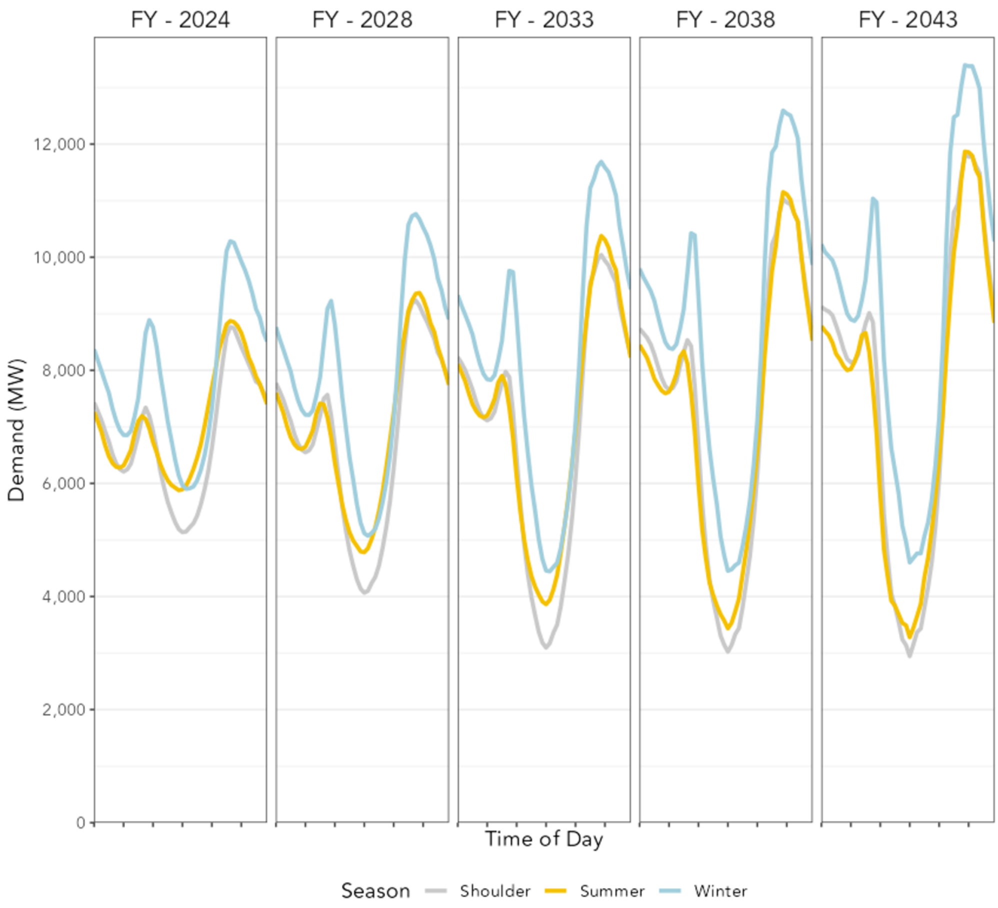
4.1. Operational demand

Figure 7 shows the seasonal operational demand in NSW in selected years to provide an example of the change in operational demand over the analysis period. It should be noted that the shape of operational demand is taken from AEMO's demand trace data from the ISP Step Change scenario and reflects the impact of behind-the-meter rooftop PV generation, EV, and uncoordinated storage. The impact of coordinated BTM storage (i.e., VPP) is modelled endogenously and has not been incorporated into the chart.

As can be seen, the general shape of the operational demand within each season remains essentially the same over the years, but:

- The difference in the peak and trough of each season increases over time as more rooftop solar enters the system, and
- This difference is more pronounced in the summer and shoulder seasons when solar generation is greater.

Figure 7: NSW operational demand in selected years



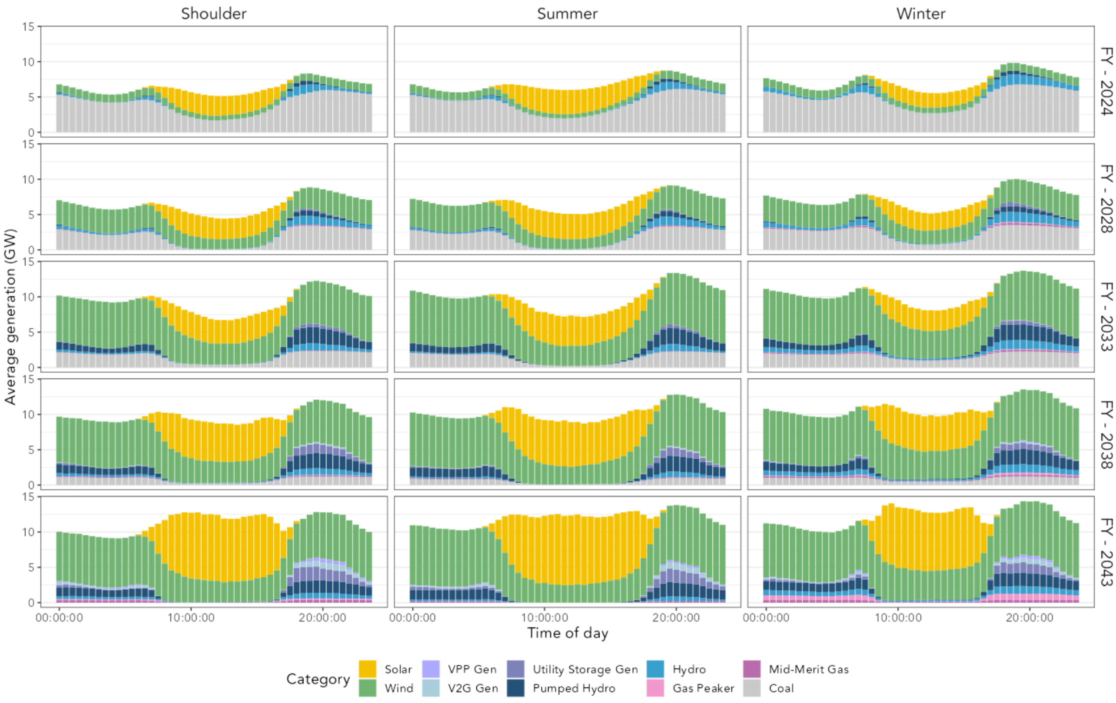
Source: Endgame-Economics

4.2. Generation profile

Figure 8 shows the seasonal generation profile for NSW that results from the operational demand shown in Figure 7 above.

The changing capacity mix leads to significant changes in the generation profile, with later years showing greater production particularly by wind and solar, and the retirement of base coal and gas. As coal retires from the system and demand grows over time, gas plays a larger (though still minor) role outside daylight hours in winter months due to the occasional low availability of wind generation.

Figure 8: Seasonal generation profile for NSW in selected years



Source: Endgame-Economics

The bulge in solar production in the middle of the day in the later years of the analysis period is not a product of native demand but rather the result of the deployment of large-scale BESS which charges in the middle of the day and then time shifts the solar production by discharging to meet demand in early to mid- evening hours.

4.3. Annual CECVs

Figure 9 on the following page shows how three different measures of the average annual CECVs change over the analysis period for each of the NEM jurisdictions:

- The annual average time-weighted CECV
- A rooftop-PV output-weighted CECV (average of the CECV in all periods of rooftop PV electricity generation)
- The average CECV during periods of very high roof-top PV electricity generation (half-hour periods in which rooftop PV production is in the top 1%, which is when curtailment is assumed to be most likely to occur).

Figure 9: Annual CECVs by jurisdiction over the analysis period

Source: Endgame-Economics

As can be seen, annual average CECV trends upwards in all regions. This is mostly due to increasing overnight prices as traditional baseload plants leave the system. We note that these are time-weighted, not dispatch-weighted costs, and do not represent an average of the time periods when most electricity is consumed. Also, it is an estimate of costs, rather than prices, which can differ significantly.

At the other end of the spectrum, CECVs at those times when rooftop PV output is at its highest (the Top 1% RfPV scenario) decrease rapidly and substantially (approaching zero) in all jurisdictions, due to increased rooftop and large-scale solar penetration exerting downward pressure on mid-day prices.

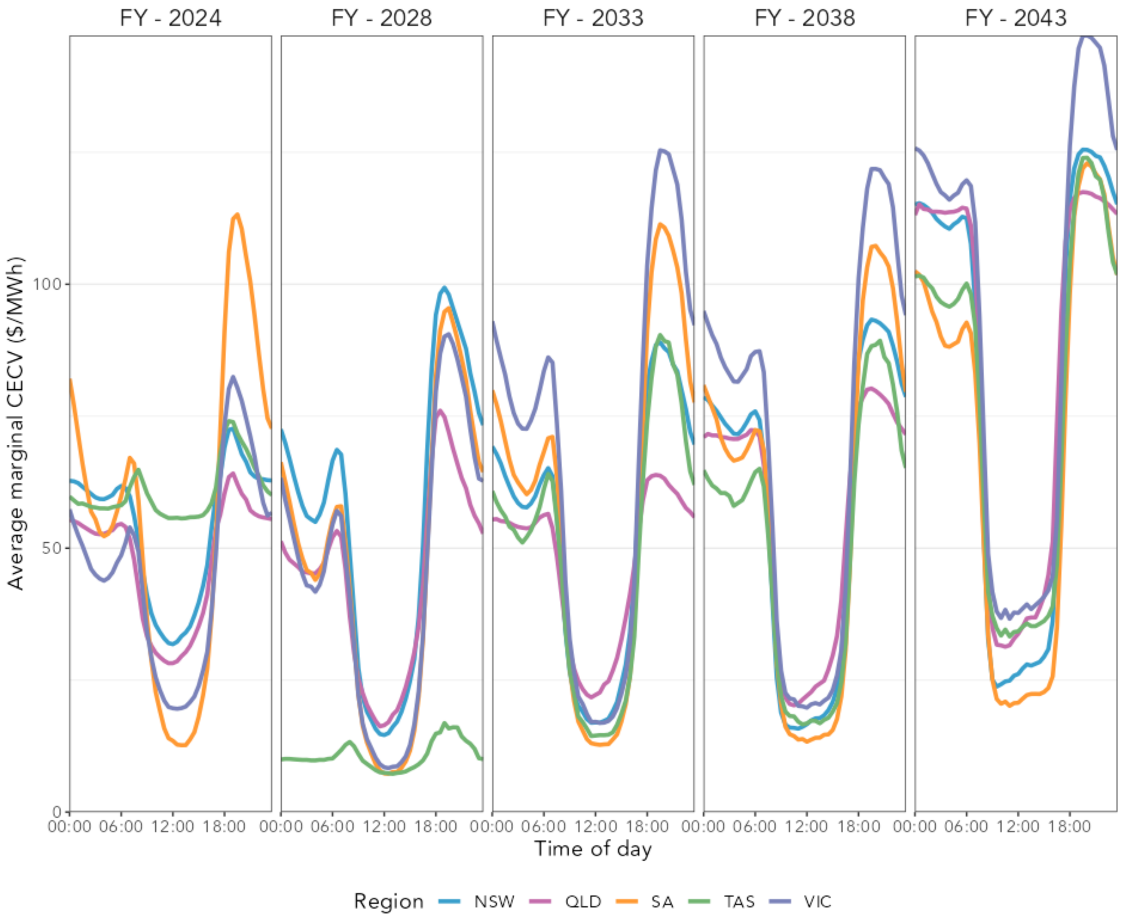
In between the two, the Rooftop PV-weighted CECV is the most stable over time in all jurisdictions. It increases slightly in later years in QLD, VIC and SA. This is driven by a combination of assumed commissioning of large QLD pumped hydro units (7 GW in total as in the Queensland Job and Energy Plan), which soaks up excess solar generation and tends to lift daytime CECV. Further, less solar entry in the capacity mix (due to higher solar CAPEX in the draft 2023 IASR) also contributes to a more stable daytime average CECV in the long term.

4.4. CECVs by time of day

Figure 10 on the following page shows how the CECV varies by time of day in each NEM region in selected years.

Increased solar penetration leads to suppressed prices during midday. Prices outside daylight hours trend upwards due to the retirement of coal and mid-merit gas generators, leading to the system relying on gas peakers and storage to meet overnight demand.

Figure 10: Average annual time-of-day CECVs by NEM region for selected years



Source: Endgame-Economics

The odd CECVs shown for FY2028 are a product of its export capacity and coal retirements on the mainland. In the late 2020s, TAS exports heavily to the mainland due to ISP-assumed coal closure. This causes Basslink to constantly reach its export limit and hence causing price separation between TAS and the mainland. The pure SRMC bidding in the modelling amplifies this effect as TAS has low-cost generation. The effect is removed once Marinus Link enters in FY2030, which significantly reduces the instances of there being a constraint on TAS export capacity and results in TAS prices being more closely linked to the mainland.

5. 2023 and 2022 CECVs compared

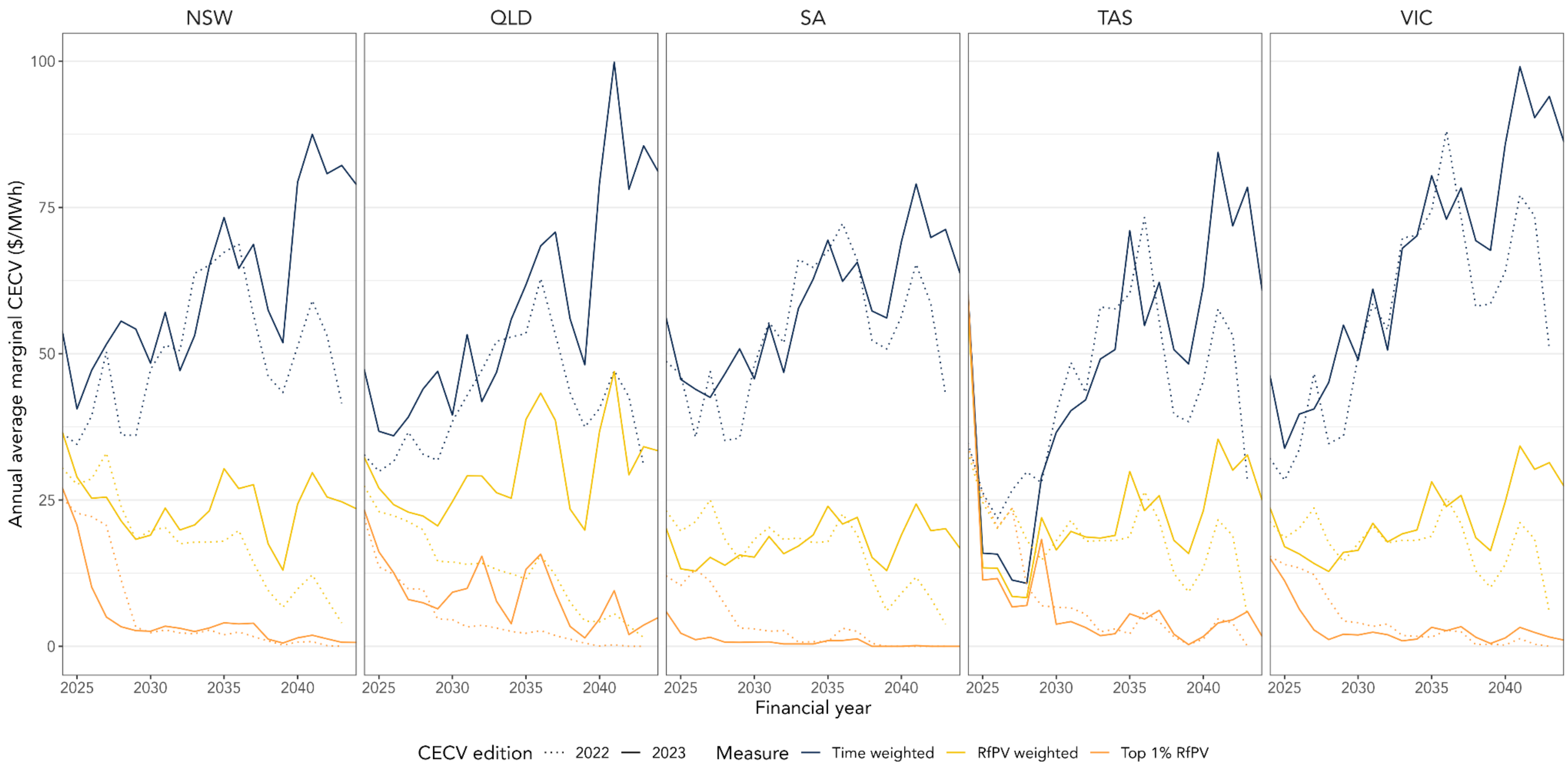
The following pages provide figures that compare:

- The average annual CECVs for each of the three CECV metrics (time-weighted, RfPV weighted and Top 1% PV output half hours) for each NEM region across the analysis period
- The average seasonal daily CECVs for each NEM region for selected years.

Compared to the 2022 results, the annual average 2023 CECV is generally higher in later years. This is mainly driven by higher BESS cycling costs increasing overnight CECVs. As discussed earlier, due to their cycling limitation, each BESS cycle will bring forward the replacement of the asset, and hence represents an actual resource cost. The BESS cycling cost is higher in the 2023 modelling due to the higher upfront capital cost of this technology that is assumed in the new draft 2023 IASR. In addition, Queensland has higher rooftop PV-weighted average CECVs in the 2023 results. This is primarily driven by the new Queensland Pumped Hydro entrants post 2030 which are assumed in the 2023 draft IASR. In total, there will be 2GW new pumped hydro energy systems by 2030 (Borumba) and an additional 5GW by FY2035 (Pioneer Burdekin). This additional 7GW of pumped hydro significantly improves midday prices as it soaks up excess solar output. Less utility solar investment in the long-term (due to higher solar CAPEX in the draft 2023 IASR) also reduces the downward pressure on daytime CECVs.

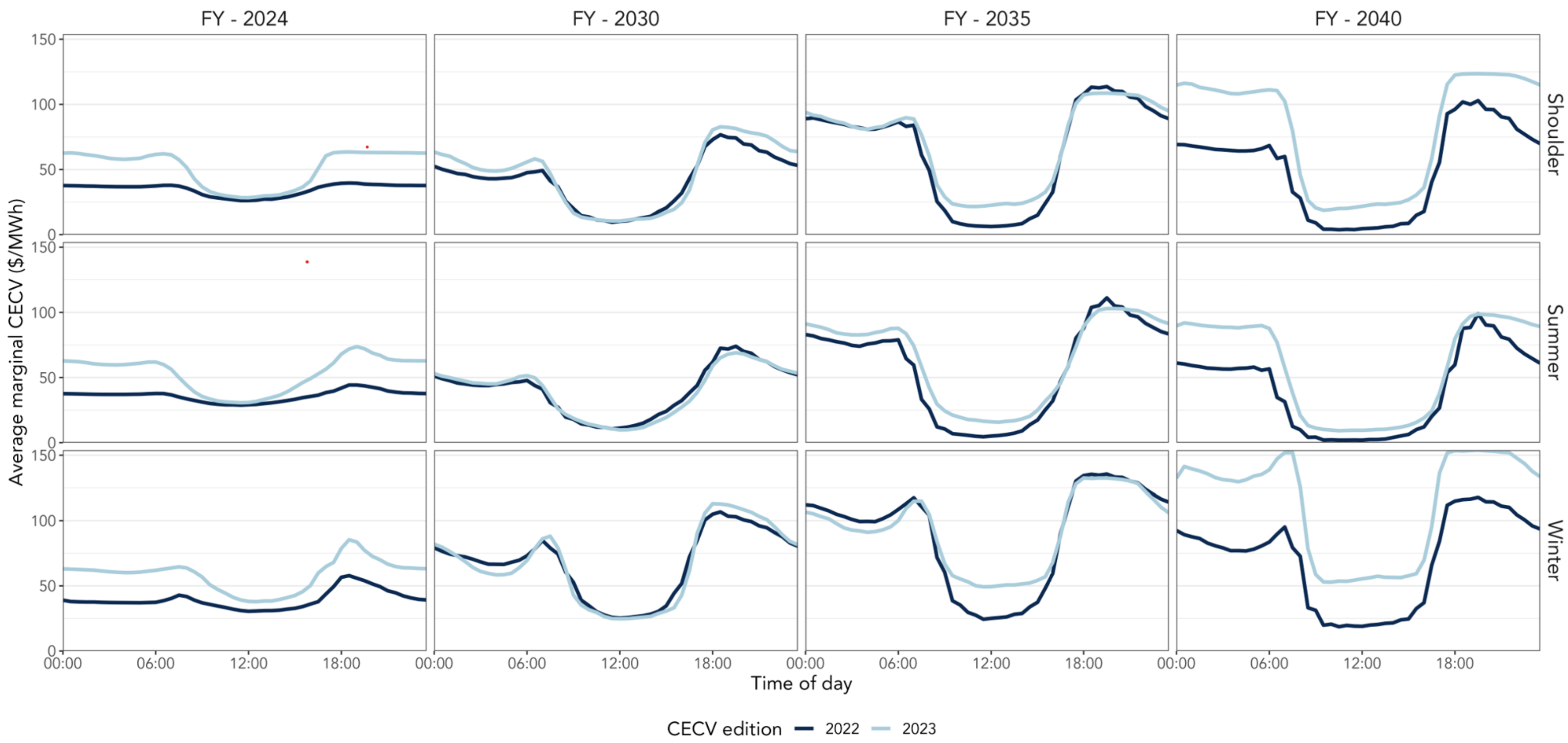
In terms of daily shape, the 2023 results have higher CECV values during peak periods in FY2024, reflecting higher gas prices in early years. In later years, midday CECVs are higher, particularly in NSW and QLD due to the assumption of significant amounts of QLD pumped hydro entering post 2030. There are also higher overnight CECV values which result from higher BESS cycling costs.

Figure 11: Average annual CECVs for each NEM region across the analysis period



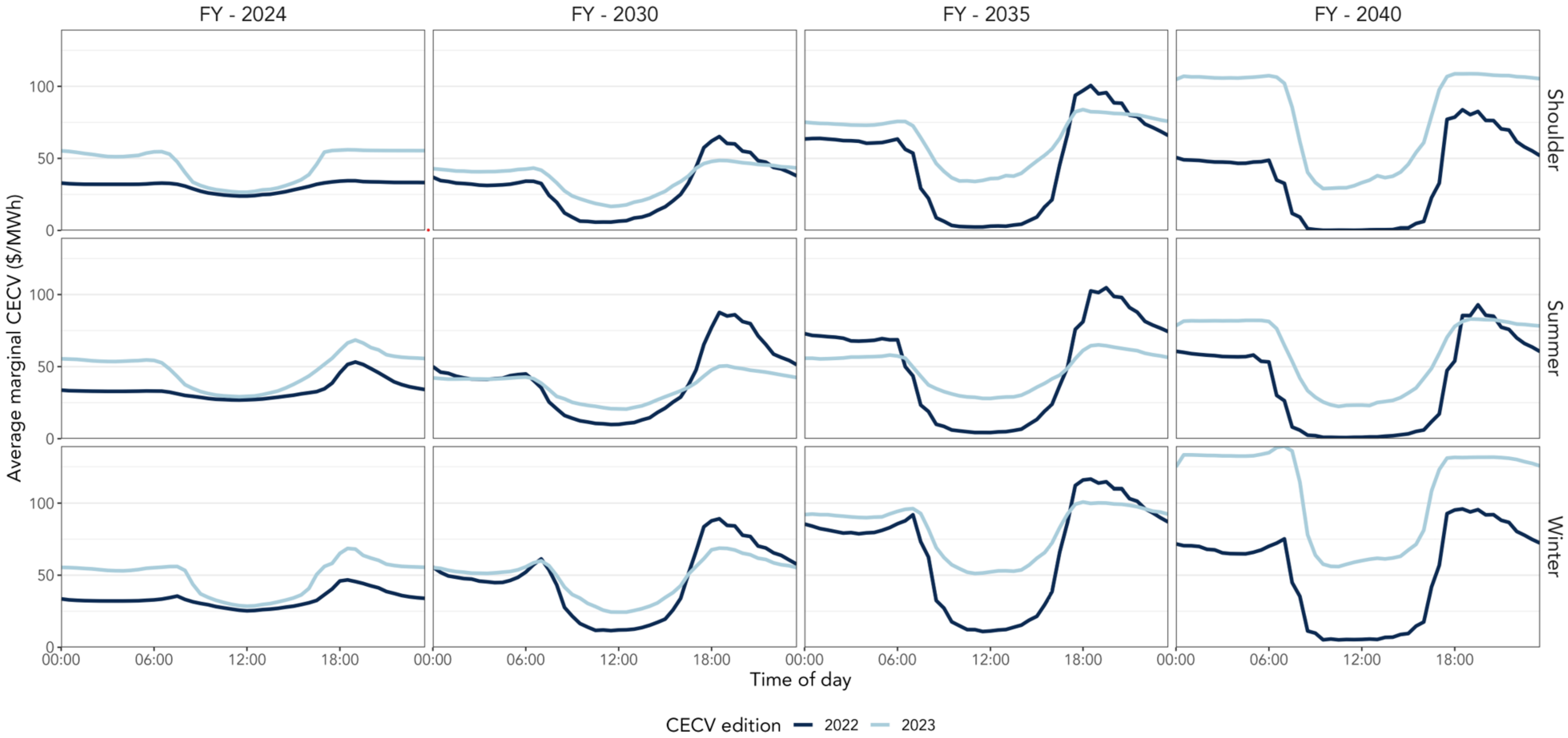
Source: Endgame-Economics

Figure 12: NSW average seasonal daily CECVs for selected years



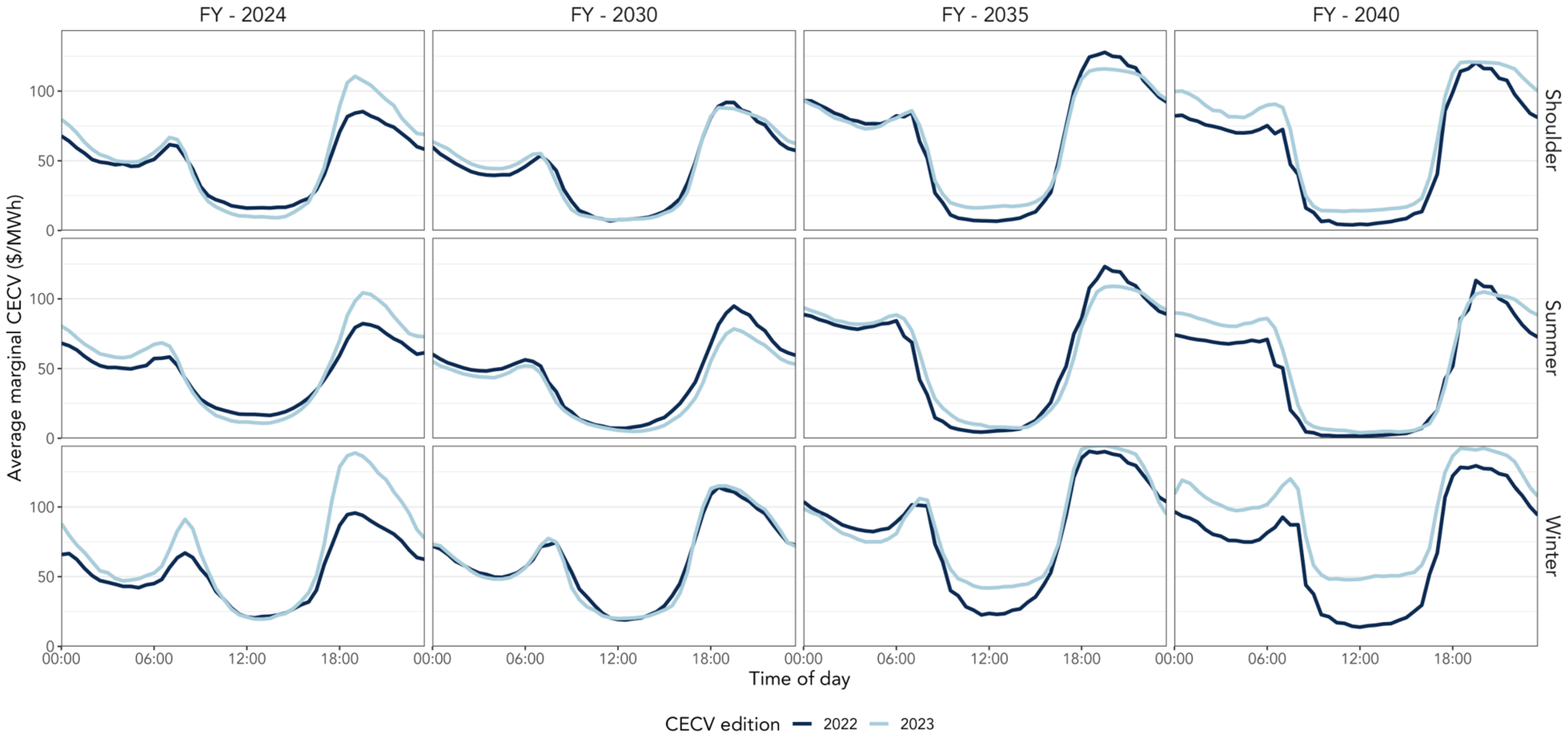
Source: Endgame-Economics

Figure 13: QLD average seasonal daily CECVs for selected years



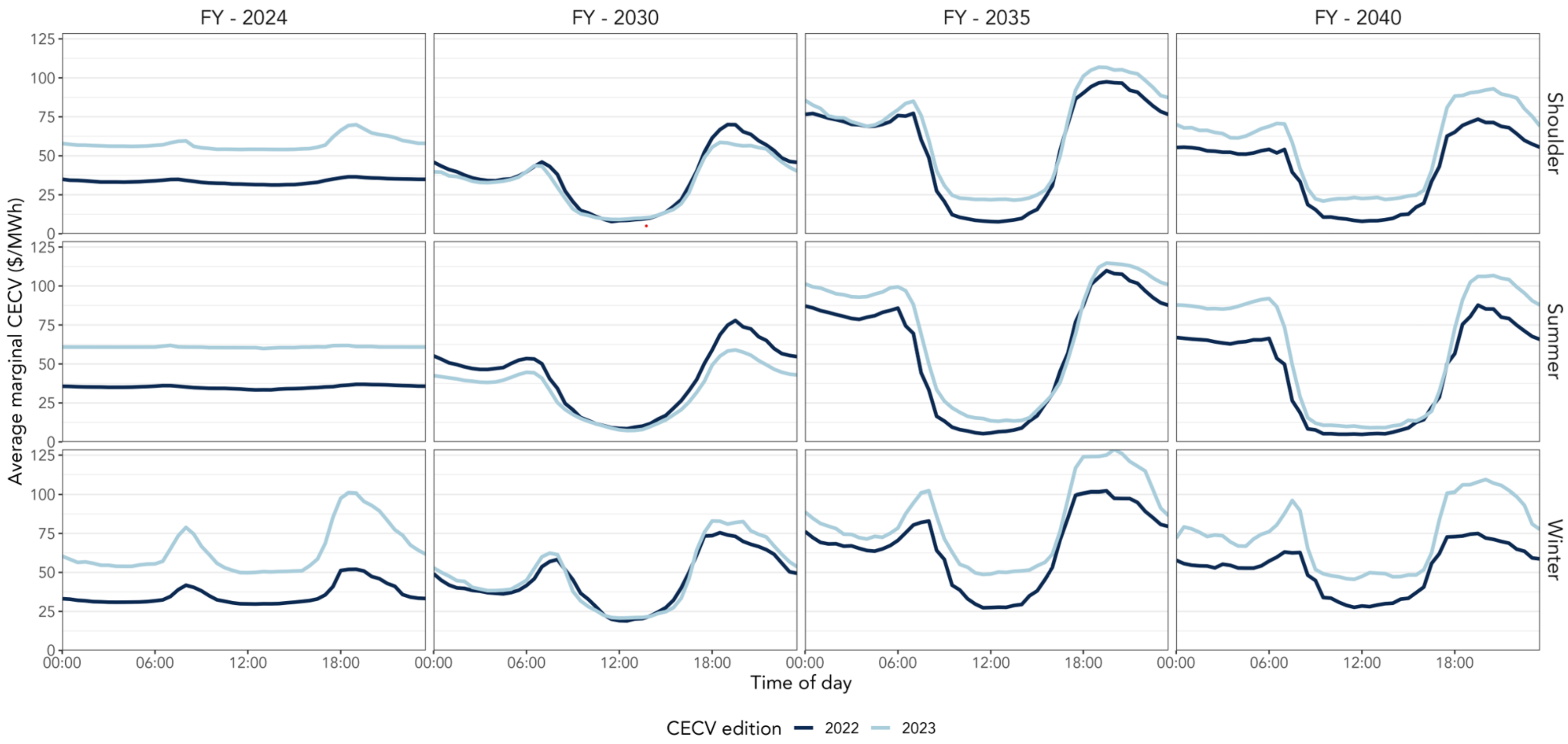
Source: Endgame-Economics

Figure 14: SA average seasonal daily CECVs for selected years



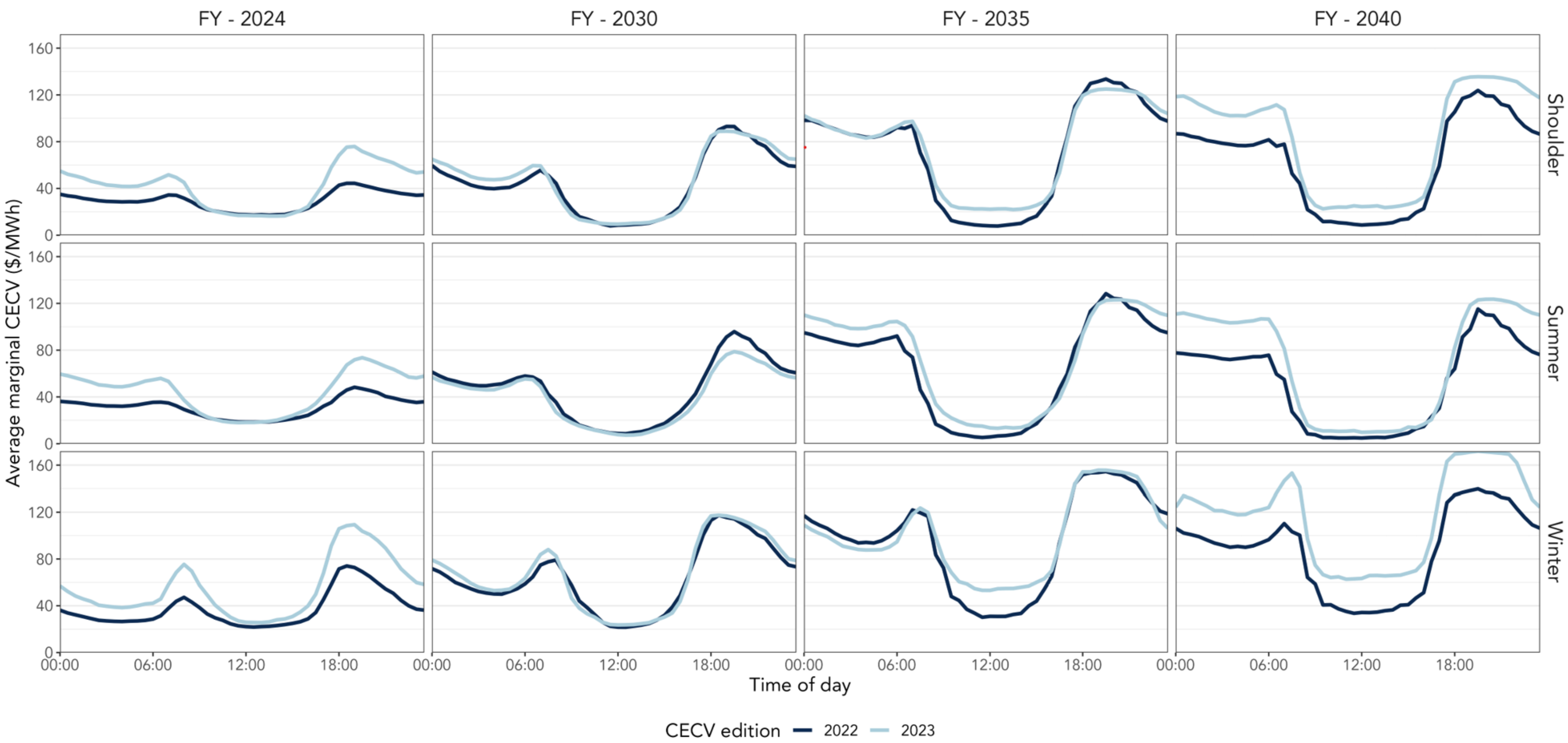
Source: Endgame-Economics

Figure 15: TAS average seasonal daily CECVs for selected years



Source: Endgame-Economics

Figure 16: VIC average seasonal daily CECVs for selected years



Source: Endgame-Economics