ACIL ALLEN

Default Market Offer 2025-26

Wholesale energy and environment cost estimates for DMO 7 Draft Determination

13 March 2025

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Report to:

Australian Energy Regulator

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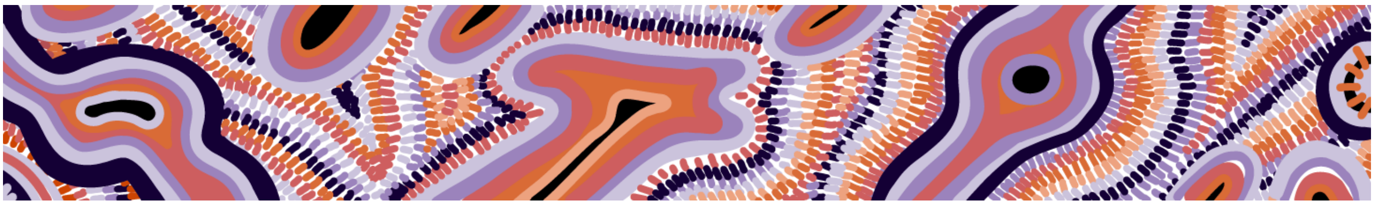

Goomup, by Jarni McGuire

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1 Introduction

ACIL Allen has been engaged by the Australian Energy Regulator (AER) to support the AER in estimating specific cost inputs required for the determination of Default Market Offer (DMO) prices. Specifically, ACIL Allen is required to provide consultancy services to the AER to estimate the underlying wholesale and environmental cost inputs to inform the determination for 2025-26 (DMO 7).

These estimates are to be based on the relevant cost drivers for a retailer supplying electricity to residential and small business customers in non-price regulated jurisdictions (excluding Victoria).

This report provides estimates of the wholesale energy, environmental, and other costs for use by the AER in its Draft Determination for DMO 7, using the methodology in our Final Determination report to the AER for DMO 6, as well as considering stakeholder feedback in response to the AER’s Issues Paper.

The report is presented as follows:

— Chapter 2 summarises our methodology.

— Chapter 3 provides responses to submissions made by various stakeholders following the release of the AER’s *Default market offer prices 2024–25 Draft determination* (March 2024), where those submissions refer to the methodology used to estimate the cost of energy in regulated retail electricity prices.

— Chapter 4 summarises our derivation of the energy cost estimates.

2 Overview of approach

2.1 Introduction

In determining the DMO, the Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019 (the Regulations) requires the AER to determine the annual consumption and annual retail bill amounts based on the following principles and policy objectives:

— Reduce unjustifiably high standing offer prices and continue to protect consumers from unreasonable prices.

— Allow retailers to recover their efficient costs of providing services, including a reasonable retail margin and costs associated with customer acquisition and retention.

— Maintain incentives for competition, innovation and investment by retailers, and incentives for consumers to engage in the market.

The overall objective of estimating the DMO is to ensure that the projected change in costs from one determination to the next is as accurate as possible.

With the objectives of the DMO in mind, presented in this chapter is a summary of the methodology used for DMO 7, including refinements based on stakeholder feedback from the Issues Paper, as well as directions ACIL Allen has received from the AER.

2.2 Components of the total energy cost estimates

ACIL Allen is required to estimate the Total Energy Costs (TEC) component of the DMO. Total Energy Costs comprise the following components (as shown in Figure 2.1):

— Wholesale energy costs (WEC) for various demand profiles

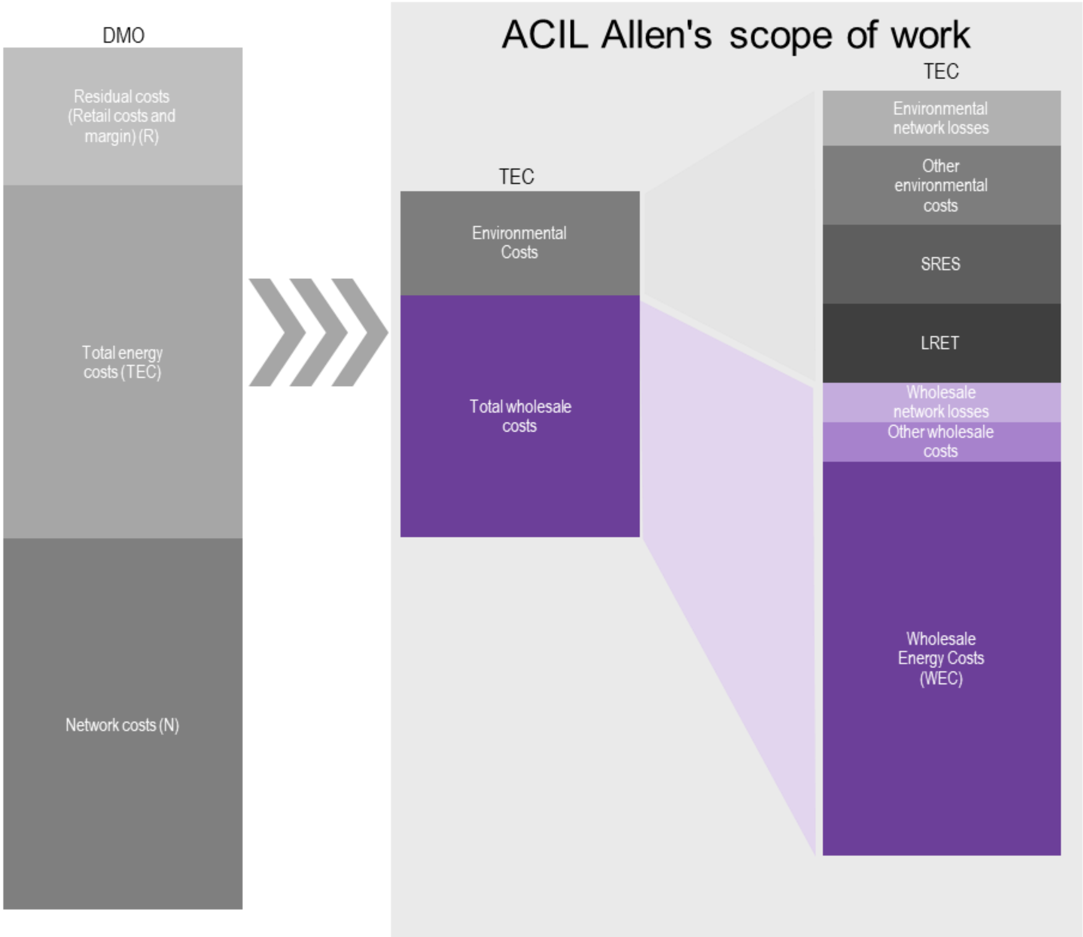
— Environmental Costs: costs of complying with state and federal government policies, including the Renewable Energy Target (RET).

— Other wholesale costs: including National Electricity Market (NEM) fees, ancillary services charges, Reliability and Emergency Reserve Trader (RERT) costs, AEMO direction costs, and costs of meeting prudential requirements. In addition, this determination will also account for the known costs associated with the market interventions due to the triggering of administered pricing and spot market suspension that occurred in the NEM in June 2022 that were not finalised at the time of the 2023-24 and 2024-25 Final Determinations.

— Energy losses incurred during the transmission and distribution of electricity to customers.

— For the purpose of the DMO, the AER has requested ACIL Allen to present the estimates of the TEC components in two broad groupings – Wholesale and Environmental – in the manner shown in Figure 2.1.

Figure 2.1 Components of DMO and TEC



Source: ACIL Allen

2.3 Methodology

The ACIL Allen methodology adopted for DMO 7 (and DMO 2 to 6) estimates costs from a retailing perspective. This involves estimating the energy and environmental costs that an electricity retailer would be expected to incur in a given determination year. The methodology includes undertaking wholesale energy market simulations to estimate expected spot market costs and volatility, and the hedging of the spot market price risk by entering into electricity contracts with prices represented by the observable futures market data. Environmental and other energy costs are added to the wholesale energy costs and the total is then adjusted for network losses.

Estimating the WEC - market-based approach

Energy purchase costs are incurred by a retailer when purchasing energy from the NEM spot market to satisfy their retail load. However, given the volatile nature of wholesale electricity spot prices, which is an important and fundamental feature of an energy-only market (i.e. a market without a separate capacity mechanism), and that retailers charge their customers based on fixed rate tariffs (for a given period), a prudent retailer is incentivised to hedge its exposure to the spot market.

Hedging can be achieved by a number of means – a retailer can own or underwrite a portfolio of generators (the gen-tailer model), enter into bilateral contracts directly with generators, purchase over the counter (OTC) contracts via a broker, or take positions on the futures market. Typically, a retailer will employ a number of these hedging approaches. In addition, a retailer may choose to leave a portion of their load exposed to the spot market.

At the core of the market-based approach is an assumed contracting strategy that an efficient retailer would use to manage its electricity market risks. Such risks and the strategy used to mitigate them are an important part of electricity retailing. The contracting strategy adopted generally assumes that the retailer is partly exposed to the wholesale spot market and partly protected by the procured contracts.

The methodology simulates the cost of hedging by building up a portfolio of hedges consisting of base and peak swap contracts, and cap contracts (and this is discussed in more detail below).

Conceptually, in a given half-hourly settlement period, the retailer:

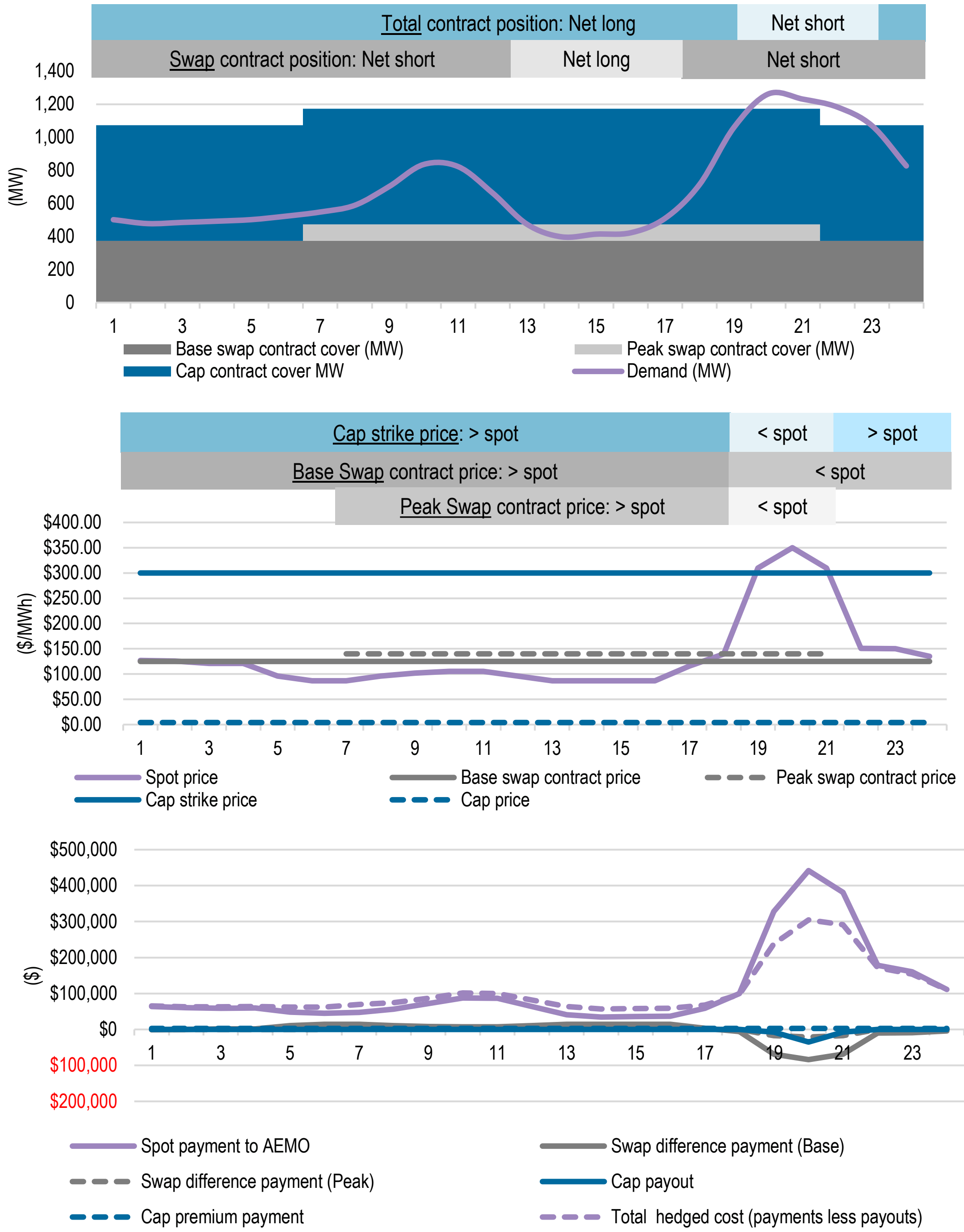
- Pays AEMO the spot price multiplied by the demand.
- Pays the contract counterparty the difference between the swap contract strike price and the spot price, multiplied by the swap contract quantity. This is the case for the base swap contract regardless of time of day, and for the peak swap contract during the periods classified as peak. If the spot price is greater than the contract strike price than the counter party pays the retailer.
- Pays the contract counterparty the cap price multiplied by the cap contract quantity.
- If the spot price exceeds $300/MWh, receives from the contract counter party the difference between the spot price and $300, multiplied by the cap contract quantity.

Figure 2.2 shows an illustrative example of a hedging strategy for a given load across a 24-hour period.

In this example:

- The demand profile:
  - Varies between 400 MW and 1,300 MW.
  - Peaks between 6 pm and 10 pm, with a smaller morning peak between 9 am and 11 am.
- The hedging strategy:
  - Consists of 375 MW of base swaps, 100 MW of peak period swaps, and 700 MW of caps.
  - Means that demand exceeds the total of the contract cover between 7 pm and 10 pm by about 100 MW. Hence during these periods, the retailer is exposed to the spot price for 100 MW of the demand, and the remaining demand is covered by the hedges.
  - Demand is less than the hedging strategy for all other hours. Hence, during these periods the retailer in effect sells the excess hedge cover back to the market at the going spot price (and if the spot price is less than the contract price this represents a net cost to the retailer, and vice versa).

Figure 2.2 Illustrative example of hedging strategy, prices and costs



Source: ACIL Allen

With this in mind, the WEC for a given demand profile for a given year is therefore generally a function of four components, the:

1. demand profile
2. wholesale electricity spot prices
3. forward contract prices
4. hedging strategy.

Use of financial derivatives in estimating the WEC

As discussed above, retailers purchase electricity in the NEM at the spot price and use a number of strategies to manage their risk or exposure to the spot market. Market-based approaches adopted by regulators for estimating the WEC make use of financial derivative data given that it is readily available and transparent. This is not to say regulators are of the view that retailers only use financial derivatives to manage risk – it simply reflects the availability and transparency of data.

Some retailers also use vertical integration and Power Purchase Agreements (PPAs) to manage their risk. However, the associated costs, terms and conditions of these approaches are not readily available in the public domain. Further, smaller retailers may not be in a position to use vertical integration or PPAs and hence rely solely on financial derivatives.

Additionally, the value of long-dated assets associated with vertical integration and PPAs is determined by conditions in the market at a given point in time. The price in a PPA or the annualised historical cost of generation reflects the long term value of the generation anticipated at the time of commitment when the investor was faced with a variety of uncertain futures. As a consequence, there are considerable difficulties in using the price of PPAs or the annualised historical cost of generation as a basis for estimating current hedging costs.

In essence, the methodology uses available and transparent financial derivative data as a proxy for the range of other hedging instruments adopted by retailers.

Use of demand profiles in estimating the WEC

Our scope of work requires the estimation of the WEC for residential and small business demand in each distribution zone.

The following demand profiles are required for the given determination year:

— System demand (or regional demand) for each region of the NEM (that is, the load to be satisfied by scheduled and semi-scheduled generation) – used to model the regional wholesale electricity spot prices.
— Net System Load Profiles (NSLPs), controlled load profiles (CLPs), and interval meter demand data for residential and small business customers - used to model the cost of procuring energy for residential and small business customers for the following:
  — New South Wales: Ausgrid, Endeavour, Essential
  — Queensland: Energex
  — South Australia: SAPN.

Historical demand data is available from AEMO – as shown in Table 2.1.

ACIL Allen investigated estimating separate WECs for residential and small business customers as part of its methodology review for DMO 3 and reached the conclusion that developing WECs for residential and non-residential customers does not guarantee to improve accuracy due to a lack of readily publicly accessible and quality assured load profile data, and is largely arbitrary. It ignores, and does not account for, the large variety of non-residential load profile shapes that exist and the different mixes of these profiles that each retailer may have, and for some non-residential customers their profile may well be closer related to a residential profile given the nature of their business and hours of operation. Nor does it account for the difference in residential customers with and without rooftop solar PV – which are more likely to have very different load profiles.

Table 2.1 Sources of load data

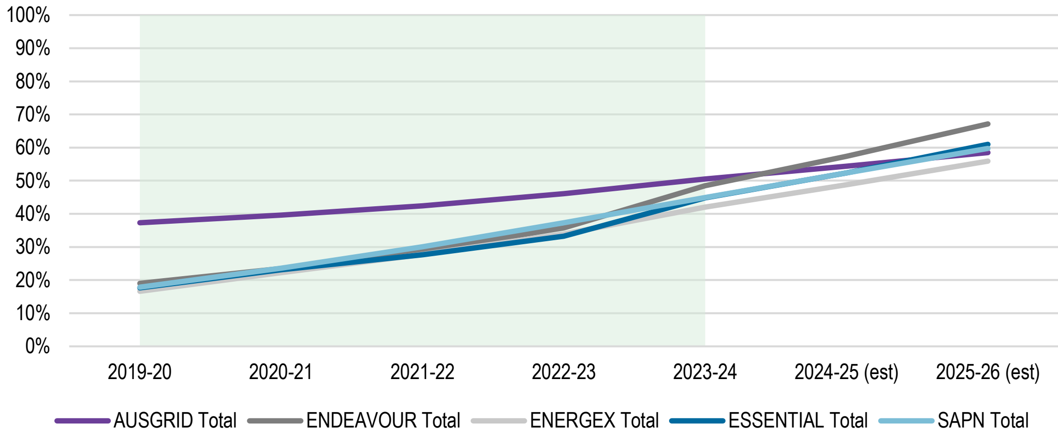
Region	Distribution Network	Load Type	Load Name	Source
New South Wales	NA	System Load	NSW1	MMS
	Ausgrid	NSLP	NSLP,ENERGYAUST	MSATS
		Residential and small business customers on interval meters	Ausgrid Residential < 100 MWh and Business < 100 MWh	AER data request to AEMO
		CLP	CLOADNSWCE,ENERGYAUST	MSATS
		CLP	CLOADNSWEA,ENERGYAUST	MSATS
	Endeavour Energy (Endeavour)	NSLP	NSLP,INTEGRAL	MSATS
		Residential and small business customers on interval meters	Endeavour Residential < 100 MWh and Business < 100 MWh	AER data request to AEMO
		CLP	CLOADNSWIE,INTEGRAL	MSATS
	Essential Energy (Essential)	NSLP	NSLP,COUNTRYENERGY	MSATS
		Residential and small business customers on interval meters	Essential Energy Residential < 100 MWh and Business < 100 MWh	AER data request to AEMO
		CLP	CLOADNSWCE,COUNTRYENERGY	MSATS
Queensland	NA	System Load	QLD1	MMS
	Energex	NSLP	NSLP,ENERGEX	MSATS
		Residential and small business customers on interval meters	Energex Residential < 100 MWh and Business < 100 MWh	AER data request to AEMO
		CLP	QLDEGXCL31,ENERGEX	MSATS
		CLP	QLDEGXCL33,ENERGEX	MSATS
South Australia	NA	System Load	SA1	MMS
	SA Power Networks (SAPN)	NSLP	NSLP,UMPLP	MSATS
		Residential and small business customers on interval meters	SAPN Residential < 100 MWh and Business < 100 MWh	AER data request to AEMO
		CLP	CLP,UMPLP	MSATS

Source: AEMO

Use of interval meter data for residential and small business customers

Since the Power of Choice reforms in 2017, new rooftop solar PV installations require the replacement of an existing accumulation meter with a new interval meter. In previous DMOs the NSLP has been used as the representative load profile for residential and small business customers because the majority (about 90 per cent in 2020, and 80 per cent in 2021) of residential and small business customers were on accumulation (or basic) meters. And those customers with interval (or smart) meters were in the minority. However, ACIL Allen estimates the penetration of interval meters in 2023-24 increased to about 40-50 per cent.

Figure 2.3 Penetration of interval meters for Residential and Small Business Customers (aggregated)



Source: ACIL Allen of AEMO data

With the likely continued roll out of interval meters due to, in part by retailers responding to various market incentives, the end-of-life replacement of older accumulation meters, and due to the AEMC's recommendation of a target of 100 per cent uptake of smart meters by 2030, it is probable that customers on interval meters will be the majority in the next 1 to 2 years.

In this determination, we have used a combination of the NSLP and interval meter data in our estimation of the WEC. The use of interval meter data improves the estimation of the cost of supplying energy to small customers because the interval meter data in addition to the NSLP better reflects the shape of small customers' load imported from the grid.

As with the 2024-25 determination, for the 2025-26 determination we have been able to exclude the PV export carve out from the customer demand profile when estimating the WEC by using more recent post-5MS interval meter load data supplied by AEMO, and have aggregated the NSLP and interval meter data for small customers. This is appropriate because the DMO is a price for consumption drawn from the grid (imports), not for PV exports and not for imports net of exports.

It is worth noting that the wholesale spot price modelling of the NEM continues to include the PV export carve out in the regional demand profiles (that is, the demand to be satisfied by scheduled and semi-scheduled generation), since this what occurs in the NEM.

Key steps to estimating the WEC

The key steps to estimating the WEC for a given load and year are:

1. Forecast the hourly demand profile – generally as a function of the underlying demand forecast as published by the Australian Energy Market Operator (AEMO), and accounting for further uptake of rooftop solar PV (including PV exports which are deducted from the regional demand profiles for the spot price modelling). A stochastic demand and renewable energy resource model to develop 54 weather influenced annual simulations of hourly demand and renewable energy resource traces which are developed so as to maintain the appropriate correlation between the various regional and NSLP/CLP/interval meter demands, and various renewable energy zone resources.
2. Use a stochastic availability model to develop 11 annual simulations of hourly thermal power station availability.
3. Forecast hourly wholesale electricity spot prices by using ACIL Allen's proprietary wholesale energy market model, *PowerMark*. *PowerMark* produces 594 (i.e. 54 by 11) simulations of hourly spot prices of the NEM using the stochastic regional demand and renewable energy resource traces and power station availabilities as inputs.
4. Estimate the forward contract price using ASX Energy contract price data, verified with broker data. The book build is based on the observed trade volumes and the price estimate is equal to the trade volume weighted average price.
5. Adopt an assumed hedging strategy – the hedging strategy represents a strategy that a retailer would undertake to hedge against risk in the spot price in a given year. It is generally assumed that a retailer's risk management strategy would result in contracts being entered into progressively over a two- or three-year period, resulting in a mix (or portfolio) of base (or flat), peak and cap contracts.
6. Calculate the spot and contracting cost for each hour and aggregate for each of the 594 simulations – for a given simulation, for each hour calculate the spot purchase cost, contract purchase costs, and different payments, and then aggregate to get an annual cost which is divided by the annual load to get a price in $/MWh terms.

The above steps produce a distribution of estimated WECs which vary due to variations in demand, and spot prices. Wholesale electricity spot prices will vary depending on the actual demand (which will vary based on weather conditions), renewable generator resource (which also varies with weather outcomes), and availability of thermal power stations. It is this variability, and associated risk, that incentivises retailers to enter into hedging arrangements. However, this variability also changes the values of the spot purchase costs and difference payments incurred by a retailer (even though the contract prices and strategy are fixed).

The distribution of outcomes produced by the above approach is then analysed to provide a risk assessed estimate of the WEC. In earlier determinations, ACIL Allen adopted the 95th percentile WEC from the distribution of WECs as the final estimate. In practice, the upper part of the distribution of WECs from the simulations exhibits a relatively narrow spread when compared to estimates based on the load being 100 per cent exposed to the spot market, which is to be expected since they are hedged values. The shape of the distribution of hedged values tends to be the mirror image of the shape of the distribution of spot values, since a spot price spike will result the retailer receiving a large difference payment if its hedge position is greater than its load. Choosing the 95th percentile reduces the risk of understating the true WEC, since only five per cent of WEC estimates exceed this value. However, for this current Determination, and consistent with the Final Determinations of DMO 4 to 6, the AER has determined that the 75th percentile WEC be adopted.

Choosing the appropriate hedging strategy

As mentioned above, multiple hedging strategies are tested by varying the mix of base/cap contracts for each quarter. This is done by running the hedge model for a large number[1] of simulations for each strategy

[1] When testing the different strategies, we do not run the full set of 594 simulations as this is time prohibitive. However, we run the full set of 594 simulations once the strategy has been chosen.

and analysing the resulting distribution of WECs for each given strategy – and in particular, keeping note of the spread in WEC for each strategy. We select a strategy that is robust and plausible for each load profile, and minimises the spread in WEC, noting that:

— some strategies may be effective in one year but not in others
— in practice, retailers do not necessarily make substantial changes to the strategy from one year to the next
— our approach is a simplification of the real world, and hence we are mindful not to over-engineer the approach and give a false sense of precision.

The hedging strategy is not necessarily varied for every determination year – it tends to change when there is a sufficient change in either the shape of the load profile (for example, due to the continued uptake of rooftop PV) or a change in the relationship between contract prices for the different contract products (for example, in some years base contract prices increase much more than peak contract prices, which can influence the strategy).

Demand-side settings

The seasonal peak demand and annual energy forecasts for the regional demand profiles are referenced to the central scenario from the latest available Electricity Statement of Opportunities (ESOO) published by AEMO and take into account past trends and relationships between the NSLPs and interval meter loads and the corresponding regional demand.

It is usual practice to use a number of years of historical load data together with the P10, P50 and P90 seasonal peak load, and energy forecasts from the AEMO neutral scenario to produce multiple simulated representations of the hourly load profile for the given determination year using a Monte Carlo analysis. These multiple simulations include a mix of mild and extreme representations of demand – reflecting different annual weather conditions (such as mild, normal and hot summers).

The key steps in developing the demand profiles are:

— The half-hourly demand profiles of the past two[2] years are obtained. The profiles are adjusted by 'adding' back the estimated rooftop PV generation for the system demand and each NSLP and interval meter demand profile (based on the amount of rooftop PV in each distribution network).
— A stochastic demand model is used to develop about 54 weather influenced simulations of hourly demand traces for the NSLPs and interval meter demands, each regional demand, and each renewable resource – importantly maintaining the correlation between each of these variables. The approach takes the past three years of actual demand data, as well as the past 54 years of weather data and uses a matching algorithm to produce 54 sets of weather-related demand profiles of 17,520 half-hourly loads. This approach does not rely on attempting to develop a statistical relationship between weather outcomes and demand – instead, it accepts there is a relationship and uses a matching algorithm to find the closest matching weather outcomes for a given day across the entire NEM from the past three years to represent a given day in the past.
— The set of 54 simulations of regional system demands is then grown to the AEMO demand forecast using a non-linear transformation so that the average annual energy across the 54 simulations equals the energy forecast, and the distribution of annual seasonal peak loads across the 54 simulations generally matches the distribution of peak loads inferred by the P10, P50 and P90 seasonal peaks from the AEMO demand forecast.

[2] Normally we use two to three years of data, however for this determination, we have used data spanning 1 October 2023 to 30 September 2024 as this allows the analysis is exclude the initial temporary artificial step up in NSLPs in Queensland and South Australia.

— A relationship between the variation in the NSLPs and interval meter demand profiles, and the corresponding regional demand from the past two years is developed to measure the change in NSLP and interval meter load as a function of the change in regional demand. This relationship is then applied to produce 54 simulations of weather related NSLP and interval meter demand profiles of 17,520 half-hourly demands which are appropriately correlated with system demand, but also exhibit an appropriate level of variation in the NSLP and interval meter demand across the 54 simulations.
— The projected uptake of rooftop PV for the determination year is obtained (using our internal rooftop PV uptake model).
— The half-hourly rooftop PV output profile is then grown to the forecast uptake and its share is deducted from the system demand and NSLPs, and the share of the PV output profile net of exports is deducted from the interval meter demands.

AEMO adjustment to the Energex and SAPN NSLP demand data used in the analysis

An important input to estimate the WEC is the demand trace for small customers. The shape of the demand trace and its variability, together with spot price levels, shape and volatility, influences how a retailer manages risk for this segment of the market.

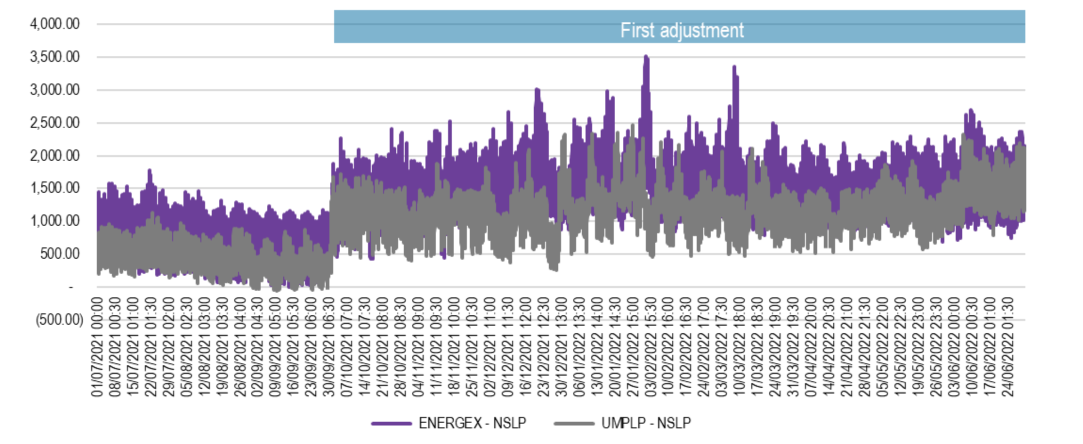
Therefore, an appropriate representation of the demand trace of small customers to be served by retailers in 2025-26 is required to estimate the WEC as accurately as possible. The more accurate the demand trace representation for 2025-26, the more accurate the WEC estimate.

Typically, the methodology uses the past two to three years of actual NSLP demand trace data to generate multiple representations of the demand trace for the given determination year. Adopting this usual approach would mean using actual NSLP data spanning 1 July 2021 to 30 June 2024.

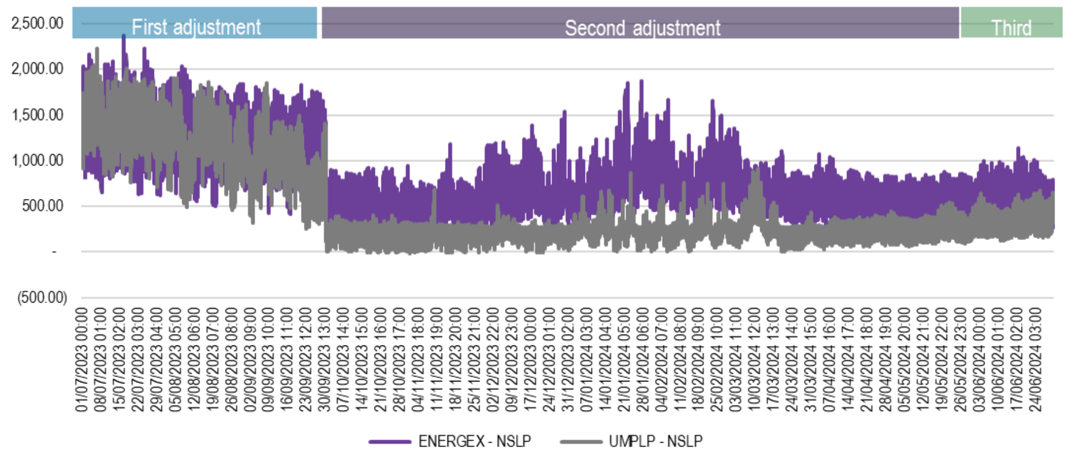
However, as shown in Figure 2.4 and noted in DMO 6, we observe that between 1 October 2021 and 30 September 2023 there was a step change in the NSLP demand trace for Energex and SAPN.

Figure 2.4 Energex and SAPN NSLP (MW) – July 2021 to June 2024

Energex NSLP



SAPN NSLP



Source: ACIL Allen analysis of AEMO data

The cause for this step change was not due to a sudden change in consumer behaviour or consumption patterns. The cause was AEMO making an initial adjustment to manage an issue relating to negative demand values coinciding with the commencement of 5MS. AEMO's adjustment resulted in an "artificial uplift" to the Energex and South Australia NSLP traces during this period.

This artificial uplift would have impacted how AEMO settled the NSLP with retailers during the period 1 October 2021 and 30 September 2023. However, we observe, and AEMO notes, that this artificial uplift was temporary and ceased from 1 October 2023, from which point the adjustment approach was revised. We note there is no discernible change in the shape of the NSLPs after 1 October 2023.

This means the artificial uplift will not impact retailers in 2025-26.

Therefore, we identify five options in assisting the AER develop a set of viable options for developing a set of representative demand traces for 2025-26:

1. Take the usual approach and use the actual NSLP data spanning 1 July 2021 to 30 June 2024. This would mean that the simulated demand traces for 2025-26 will include the temporary artificial uplift. Plainly this is inaccurate since the artificial uplift ceased from 1 October 2023 and will not be present in 2025-26. Further, the temporary artificial uplift applied to the Energex and SAPN NSLPs only, and therefore continuing to include the uplift would result in 2025-26 WEC estimates for these two networks inconsistent with those of the New South Wales networks.
2. Use older NSLP data prior to the temporary artificial uplift to represent the NSLP demand trace in 2024-25. This would mean using data from 1 July 2019 to 30 June 2021. This data is between 4 to 6 years old and runs the risk of not representing the trace for 2024-25 given the movement of small customers away from the NSLP due to the ramp up in the rollout of interval meters. It also means that the spot price modelling will be based on regional system demand trace data that is also 3 to 5 years old (recalling that to maintain internal consistency between the spot price modelling and hedge model is critical to use coincident NSLP and regional system demand traces from the same period).
3. Use the latest available NSLP data as per option 1, but remove the artificial uplift given it will not be present in 2025-26. This has the advantage of using the latest available data which will also allows for the pairing up with the latest available interval meter demand trace data, and also means the spot price modelling is based on the latest regional system demand traces.
4. Use data from 1 October 2023 to 30 September 2024, avoiding the need to remove the temporary uplift.
5. Ignore the NSLP data and rely on the interval meter demand data only.

On balance, ACIL Allen recommends that option 4 is the appropriate option to adopt for DMO 7, it allows for the use of the combined NSLP and interval meter data which better represents the load profile of small customers, and avoids including or removing the temporary artificial uplift of AEMO's initial adjustment. We note that for DMO 6 we recommended option 3. This was because option 4 was not available for DMO 6 given the October 2023 to September 2024 data were not in existence.

Using 1 year of data could increase the risk of the data set containing less variability than that observed in a 3 year data set. ACIL Allen has analysed the variability in the demand, weather, and renewable energy resource outcomes between 1 October 2023 and 30 September 2024 and concludes there is sufficient variability in these compared with a longer dated data set.

Supply side settings

ACIL Allen maintains a Reference case projection of the NEM, which it updates each quarter in response to supply changes announced in the market in terms of new investment, retirements, fuel costs, and plant availability. In this analysis, for 2025-26 we use our December 2024 Reference case projection settings which, in the short term, with the exception of fuel prices, are closely aligned with AEMO's latest Integrated System Plan (ISP) and ESOO Step Change case. Table 2.2 summarises the key assumptions adopted in the Reference case for the spot price modelling pertinent for the 2025-26 period.

ACIL Allen incorporates changes to existing supply where companies have formally announced the changes – including, mothballing, closure and change in operating approach. Near term new entrants are included where the plants are deemed by ACIL Allen to be committed projects.

Table 2.2 Overview of Reference case assumptions

Assumption	Details
Macro-economic variables	– Exchange rate of AUD to USD of 0.70 AUD/USD. – The brent crude oil price is assumed to converge from current levels to USD65/barrel by the mid-2020s and remain at this level in the long-term. – International thermal coal prices are assumed to be about USD$140/t in 2025-26.
Electricity demand	**Underlying demand** – AEMO 2024 ISP Step Change scenario (energy and peak demand). **Rooftop PV** ACIL Allen's in-house model of Rooftop PV uptake: NEM-wide Rooftop PV uptake is about 5% lower than AEMO's Step Change scenario forecast in 2025-26, reflecting the recent observed slower growth in installations. **Behind-the-meter BESS** ACIL Allen's in-house model of behind-the-meter BESS uptake (linked to rooftop PV model): Modest uptake in 2025-26. **Electric vehicles** ACIL Allen's in-house model of electric vehicle uptakes: Modest impact on demand in 2025-26.
Electricity supply (beyond new supply driven by state-based and federal schemes)	**Committed projects** – Identified new entrant projects are included in the modelling where there is a high degree of certainty that these will go ahead (i.e., project has reached financial close) Where appropriate, existing and committed new investment is accounted for in the state based and federal schemes to avoid double counting **Assumed new entry and closures** Committed or likely committed generator closures included where the closure has been announced by the participant (Torrens Island B in 2026).
Gas prices into gas-fired power stations	– The East Coast Gas Market (ECGM) is modelled by ACIL Allen's GasMark model, which produces projections of seasonal gas prices delivered into the NEM's gas fired generators. – Gas prices for mid merit CCGTs are projected to be around $9-$15/GJ (summer – winter) – Gas prices for peaking OCGTs are assumed to around $16-$26/GJ (summer – winter)
Coal prices into coal-fired power stations	Based on ACIL Allen's in-house understanding of the cost of thermal coal to the NEM's coal-fired power stations, based on existing contracts with domestic mines and the plant's exposure to the international export market.

Assumption	Details		
	New South Wales The delivered marginal coal prices in NSW are assumed to be linked to export parity and therefore follow the assumed movement in export coal prices. Marginal coal prices are assumed to be around $6-8/GJ in 2025-26.	Queensland Most generators' fuel supply is not linked to export pricing. Marginal coal prices range from $2 to $7/GJ in 2025-26	Victoria Coal mined for power generation in Victoria is unsuitable for export and hence not affected by fluctuations in export prices. Marginal coal prices range from $0.50 to $0.80/GJ in 2025-26,.
Marginal loss factors	ACIL Allen's projections of average annual marginal loss factors (MLF) by generator DUID, developed using commercial power flow software. Our latest calibration with AEMO's forecast has shown over 95% of connection point values deviating by no more than 0.02 from the latest AEMO values for 2024-2025.		
Interconnectors	ISP committed and actionable projects included: – EnergyConnect (ramping up from December 2024, and fully commissioned by July 2027) – Heywood upgrade (July 2027)		

Source: ACIL Allen

New committed supply

Table 2.3 shows the near-term entrants that ACIL Allen considers committed projects and are therefore included in the Reference case. These projects are not yet registered in the market but are expected to come online in the near-term future.

Table 2.3 Near-term addition to supply

Region	Name	Generation Technology	Capacity (MW)	First energy exports
NSW	Glanmire BESS	Battery	60	Q4 2026
NSW	Glanmire Solar Farm	Solar	60	Q4 2026
NSW	Goulburn River Solar Farm	Solar	450	Q3 2026
NSW1	Big Canberra Battery	Battery	250	Q1 2026
NSW1	Culcairn Solar Farm	Solar	350	Q1 2026
NSW1	Eraring Big Battery Stage 1	Battery	460	Q4 2025
NSW1	Liddell Battery	Battery	250	Q1 2025
NSW1	Limondale Battery	Battery	50	Q1 2026
NSW1	New England BESS Stage 1	Battery	50	Q4 2026
NSW1	New England BESS Stage 2	Battery	150	Q4 2026
NSW1	New England Solar Farm Stage 2	Solar	320	Q1 2026
NSW1	Orana BESS	Battery	415	Q4 2026
NSW1	Quorn Park BESS	Battery	20	Q1 2026
NSW1	Quorn Park Solar Farm	Solar	98	Q1 2026
NSW1	Smithfield BESS	Battery	65	Q4 2025
NSW1	Tilbuster Solar Farm	Solar	152	Q1 2025
NSW1	Uungula BESS	Battery	150	Q1 2026
NSW1	Uungula WF	Wind	414	Q1 2026
NSW1	Waratah Super Battery	Battery	850	Q1 2025
NSW1	Yanco Solar Farm	Solar	60	Q1 2025
QLD	Boulder Creek Wind Farm	Wind	228	Q4 2026
QLD	Hopeland Solar Farm	Solar	250	Q1 2026
QLD	Woolooga BESS	Battery	200	Q3 2026
QLD1	Aldoga Solar Farm	Solar	380	Q4 2025
QLD1	Ardranda Battery	Battery	200	Q1 2025
QLD1	Ardranda photovoltaic	Solar	175	Q1 2025
QLD1	Brendale BESS	Battery	205	Q3 2025
QLD1	Brigalow Peaking Power Plant	Natural gas	400	Q1 2026
QLD1	Broadsound BESS	Battery	180	Q3 2026
QLD1	Broadsound Solar Farm	Solar	296	Q3 2026
QLD1	Bundaberg Solar Farm	Solar	100	Q3 2025
QLD1	Greenbank BESS	Battery	200	Q1 2025
QLD1	Gunsynd Solar Farm	Solar	94	Q3 2025
QLD1	Herries Range Wind Farm	Wind	750	Q3 2026
QLD1	Kidston Storage Hydro	Pumped Hydro	250	Q1 2025
QLD1	Moah Creek Wind Farm	Wind	372	Q3 2025
QLD1	Mt Fox Battery	Battery	300	Q1 2025
QLD1	Supernode BESS	Battery	250	Q4 2025
QLD1	Swanbank BESS	Battery	250	Q3 2025
QLD1	Tarong West Wind Farm	Wind	500	Q1 2026
QLD1	Ulinda Park BESS	Battery	155	Q4 2025
QLD1	Western Downs Battery Stage 2	Battery	270	Q1 2026
SA	Goyder North Wind Farm Stage 1	Wind	300	Q3 2025
SA1	Clements Gap BESS	Battery	60	Q1 2026
SA1	Hallett BESS	Battery	50	Q4 2026

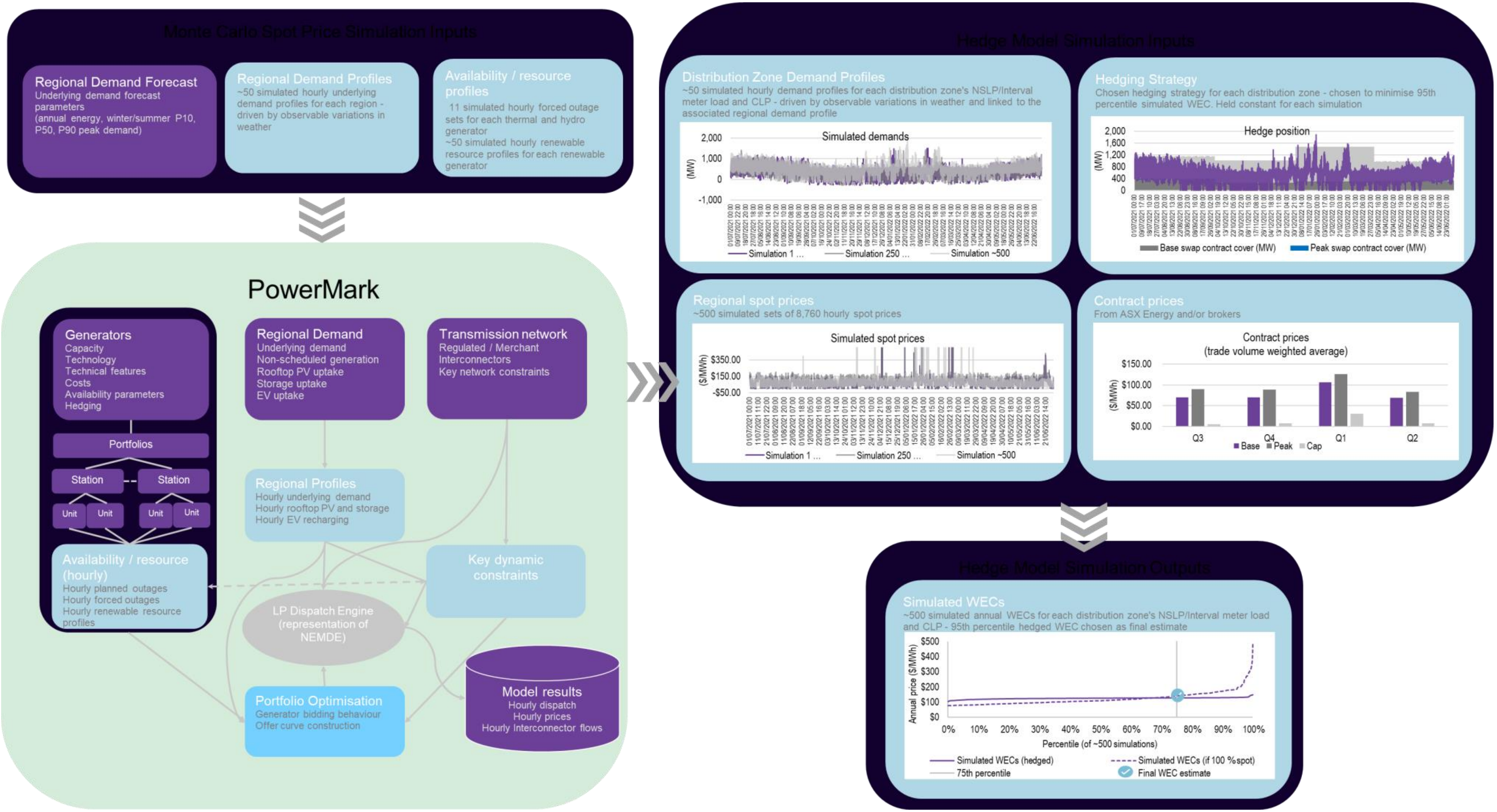
Region	Name	Generation Technology	Capacity (MW)	First energy exports
SA1	Solar River BESS	Battery	256	Q3 2026
SA1	Templers BESS	Battery	111	Q3 2025
VIC	Campbells Forest Solar Farm	Solar	205	Q3 2025
VIC	Elaine Solar Farm	Solar	125	Q1 2026
VIC	Kentbruck Wind Farm	Wind	600	Q1 2026
VIC	Mokoan Solar Farm	Solar	46	Q3 2025
VIC	Terang BESS	Battery	100	Q3 2026
VIC	West Mokoan Solar Farm	Solar	300	Q3 2026
VIC1	Derby Battery	Battery	85	Q1 2025
VIC1	Fulham Battery	Battery	80	Q1 2025
VIC1	Fulham Solar Farm	Solar	80	Q1 2025
VIC1	Gnarwarre Battery	Battery	250	Q1 2025
VIC1	Golden Plains Wind Farm	Wind	756	Q3 2025
VIC1	Horsham Battery	Battery	50	Q1 2025
VIC1	Horsham Solar Farm	Solar	118.8	Q1 2025
VIC1	Kiamal Battery	Battery	150	Q1 2025
VIC1	Kiamal Solar Farm Stage 2	Solar	150	Q2 2025
VIC1	Koorangie ESS	Battery	185	Q2 2025
VIC1	Mortlake Battery	Battery	300	Q1 2025
VIC1	Rangebank Battery	Battery	200	Q1 2025
VIC1	The Melbourne REH	Battery	600	Q4 2025

Source: ACIL Allen

Summary infographic of the approach to estimate the WEC

Figure 2.5 provides an illustrative infographic type summary of the data, inputs, and flow of the market-based approach to estimating the WEC.

Figure 2.5 Estimating the WEC – market-based approach



Source: ACIL Allen

WEC estimation accuracy

The estimated WEC for any determination will invariably be different to the actual WEC incurred. This will be a function of several factors, including the actual hedging strategy adopted by a retailer (noting different retailers may have different strategies) compared with the simplified hedging strategy adopted in the methodology, the actual load profiles, spot price and contract price outcomes.

Although we attempt to minimise the error of the estimate by undertaking a large number of simulations to account for variations in weather related demand, thermal plant availability, renewable energy resource, and spot price outcomes, the methodology does not attempt to predict the final trade weighted average contract price for each of the assumed contract products adopted in the hedging strategy. Instead, the methodology relies on contract data available at the time the Determination is made.

Contract prices are a key driver of the WEC estimate. In some years, contract prices may increase after the Final Determination is made, in other years they may decrease, and in some cases, they may remain relatively stable. Figure 2.6 provides three examples of this phenomenon for quarter one base contracts in Queensland over the past four years. The graphs show the daily contract prices, the moving trade weighted average price, as well as the trade weighted average price at the time of the respective Final Determination.

After the date the 2020-21 Final Determination was made, Q1 2021 traded prices decreased consistently resulting in an actual trade weighted average price about $8.50 lower than that used in the Final Determination. This is an example of a decreasing market price environment – resulting in an overestimate of the WEC (all other things equal).

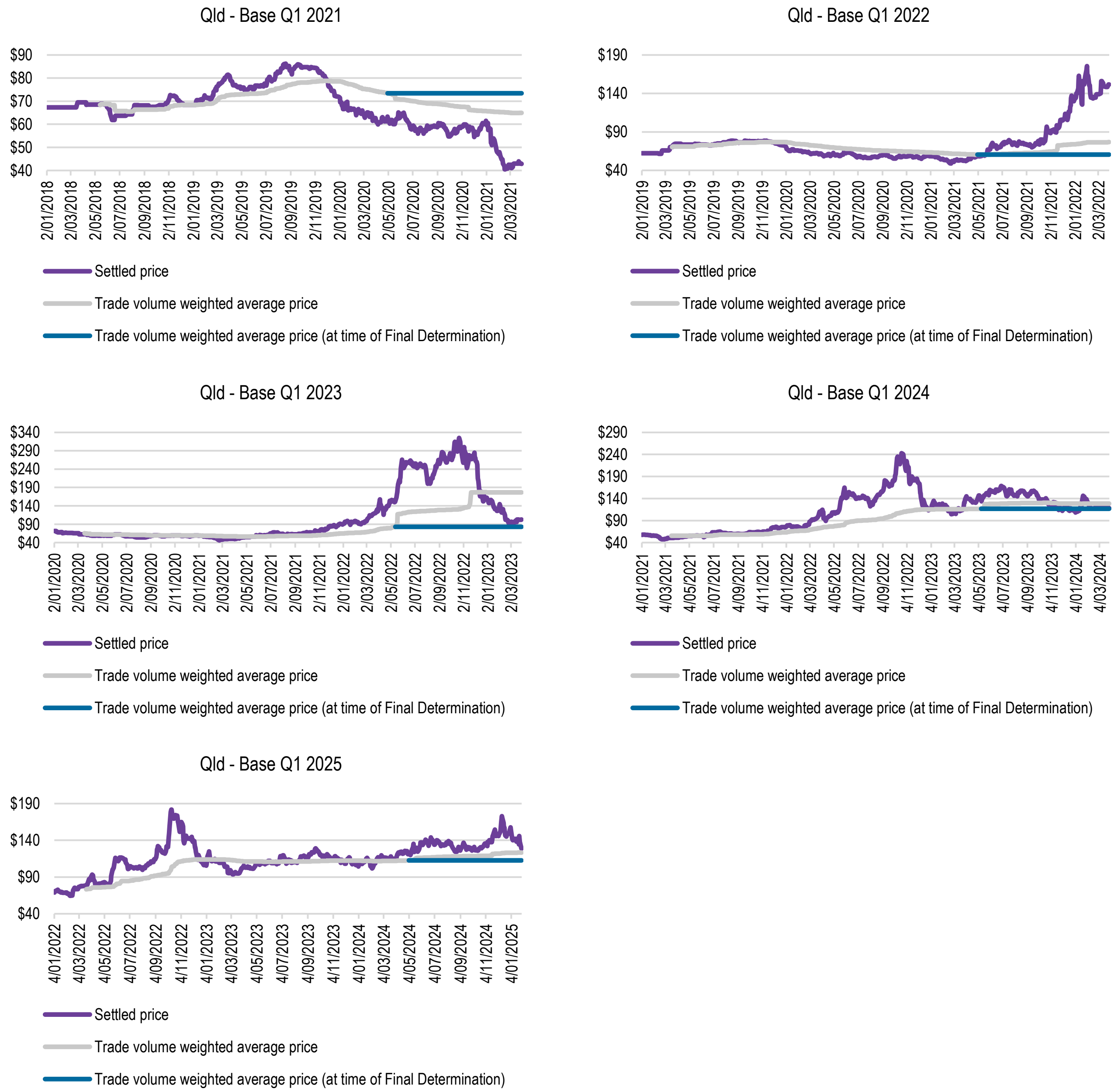
After the date the 2021-22 Final Determination was made, Q1 2022 traded prices increased consistently resulting in an actual trade weighted average price about $17.00 higher than that used in the Final Determination. This is an example of an increasing market price environment – resulting in an underestimate of the WEC (all other things equal).

After the date the 2022-23 Final Determination was made, Q1 2023 traded prices increased substantially resulting in an actual trade weighted average price about $90.00 higher than that used in the Final Determination. This is another, and more extreme, example of an increasing market price environment – resulting in a substantial underestimate of the WEC (all other things equal).

After the date the 2023-24 Final Determination was made, Q1 2024 traded prices increased slightly and then decreased slightly resulting in an actual trade weighted average price very similar to that used in the Final Determination. This is an example of a relatively stable market price environment post Final Determination (at least in terms of the trade weighted average price) – resulting in a reasonably close estimate.

After the date the 2024-25 Final Determination was made, Q1 2025 traded prices increased slightly and have decreased over the past 2 months resulting in an actual trade weighted average price very similar to that used in the Final Determination. This is an example of a relatively stable market price environment post Final Determination (at least in terms of the trade weighted average price) – resulting in a reasonably close estimate.

Figure 2.6 Daily settlement prices and trade volume weighted prices ($/MWh) for Q1 base contracts in Queensland



Source: ACIL Allen analysis of ASX Energy data

The graphs in Figure 2.6 demonstrate a number of important points about the WEC estimation methodology:

— It is much easier to estimate the WEC during periods of market and contract price stability.

— It is much more challenging to estimate the WEC during periods of increasing or decreasing contract prices.

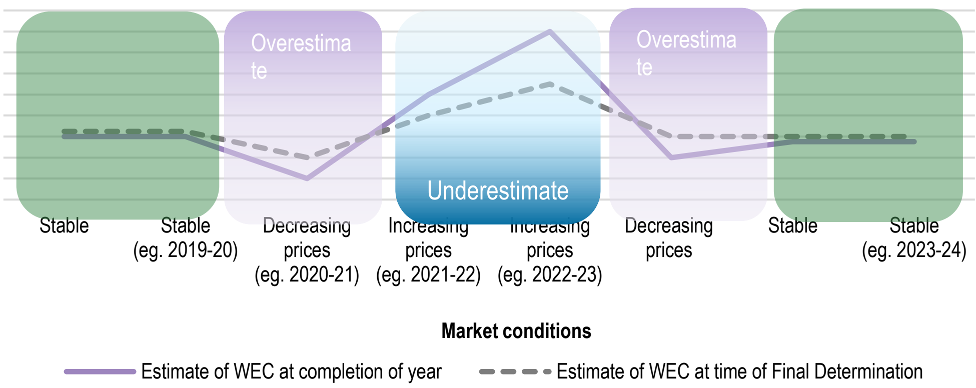
— The error in the WEC estimate, due to contract price variation, is likely to be greater in an environment of increasing prices, than it is in an environment of decreasing prices. This is because of the skewed nature of wholesale electricity prices in the NEM – prices can increase a lot more than they can decrease – and demonstrates the risk faced by retailers. This is another reason to adopt a higher percentile of the simulated WECs.

— Adopting a bookbuild period from the date of the first trade, rather than artificially constraining it to a shorter time frame, means that the trade weighted average contract price has a greater chance of smoothing out temporary fluctuations in contract prices.

In some years contract prices will increase, and in others they will decrease after the Final Determination is made. It is unlikely that the market will enter into an extended period of seemingly ever-increasing or -decreasing prices – at some point, the market will respond accordingly with investment and/or retirement of capacity.

Hence, it is likely that over the long run, the market will follow some form of pattern of increasing, decreasing and stable price outcomes. With this in mind, the methodology may well result in a comparatively smooth WEC estimate trajectory – underestimating outcomes in an increasing price environment, and overestimating outcomes in a decreasing price environment – as illustrated in Figure 2.7.

Figure 2.7 Illustrative comparison of WEC estimation accuracy given market environment



Source: ACIL Allen

Other wholesale costs

Market fees and ancillary services costs

Market fees and ancillary service costs are estimated based on data and policy documents published by AEMO.

NEM fees

NEM fees are payable by retailers to AEMO to cover operational expenditure, costs associated with full retail contestability (FRC), the Energy Consumers Australia (ECA), DER, IT upgrade costs associated with 5MS and the NEM 2025 Reform Program.

The approach for estimating market fees is to make use of AEMO's latest budget report. AEMO's 2024-25 draft budget report was released in June 2024 and adopted for the Draft Determination. If available, we will use AEMO's 2025-26 budget report for the Final Determination.

Consistent with the 2024-25 Final Determination, we have not converted the weekly charges to a variable $/MWh charge to better reflect the practices of retailers when billing customers. This adjustment to the approach also allows for a more accurate estimate of the NEM fees since no assumptions are made about the consumption volume of each customer. The variable NEM fees contained in AEMO's budget continue to be expressed in $/MWh terms in this Determination.

Ancillary services charges

Ancillary services charges cover the costs of services used by AEMO to manage power system safety, security and reliability. AEMO recovers the costs of these services from market participants. These fees are published by AEMO on its website on a weekly basis.

The approach used for estimating ancillary services costs is to average the most recent 52 weeks of costs to recover ancillary services from customers, which is published on the AEMO website. This is done on a region-by-region basis.

Prudential costs

Prudential costs, for AEMO, as well as representing the capital used to meet prudential requirements to support hedging take into account:

- the AEMO assessed maximum credit limit (MCL)
- the future risk-weighted pool price
- participant specific risk adjustment factors
- AEMO published volatility factors
- futures market prudential obligation factors, including:
- the price scanning range (PSR)
- the intra month spread charge
- the spot isolation rate.

Prudential costs are calculated for each NSLP. The prudential costs for the NSLP are then used as a proxy for prudential costs for the controlled load profiles.

AEMO publishes volatility factors two years in advance. Similarly, ASX Energy publishes initial margin parameters two years in advance.

AEMO prudential costs

AEMO calculates a maximum credit limit for each counterparty in order to determine the requirement for any or a combination of:

- bank guarantees
- reallocation certificates
- prepayment of cash.

There is no fundamental requirement to reallocate prudential obligations – it is a retailer's choice to do so. Assuming no reallocation and no vertical integration (either owned generation or PPAs), a retailer is required to provide suitable guarantees to the AEMO assessed maximum credit limit (MCL) which is calculated as follows:

MCL = OSL + PML

Where for the Summer (December to March), Winter (April to August) and Shoulder (other months):

OSL = (Average daily load x Average future expected spot price x Participant Risk Adjustment Factor * OS Volatility factor x (GST + 1) x 19[3] days

PML = (Average daily load x Average future expected spot price x Participant Risk Adjustment Factor * PM Volatility factor x (GST + 1) x 7 days

The cost of funding a bank guarantee for the MCL associated with the single MWh is assumed to be a 2.5 percent annual charge for 36 days or 2.5%*(36/365) = 0.247 percent.

Hedge prudential costs

ACIL Allen relies on the futures market to determine hedging costs. The futures market includes prudential obligations by requiring entities to lodge initial margins (we assume cash) when contracts are purchased or sold. We understand that the cash that is lodged as an initial margin receives a money market related return which offsets some of the funding costs. The money market rate used in this analysis is 3.10 per cent. Additional margin calls may apply where contracts move unfavourably for the purchaser or seller. However, as these may be favourable or unfavourable, we have assumed that they average out over time.

We understand that the initial margin is set based on three parameters being:

— the price scanning range (PSR) expressed as a percentage of the contract face value and is set for each of the base, peak and cap contract types
— the intra monthly spread charge and is set for each of the base, peak and cap contract types
— the spot isolation rate and is set for each of the base, peak and cap contract types.

Using the annual average futures price and applying the above factors gives an average initial margin for each quarter. This is divided by the average hours in the given quarter. Then applying an assumed funding cost but adjusted for an assumed return on cash lodged with the clearing results in the prudential cost per MWh for each contract type.

Reliability and Emergency Reserve Trader (RERT)

Given the RERT is called upon under extreme circumstances only, ACIL Allen is of the opinion that it is difficult to project into the future. Although it may be possible to make use of previous costs of the RERT and relate these to AEMO's projection of USE in the ESOO, there is little data available at this point to take this approach.

Therefore, as with the ancillary services, we use the RERT costs as published by AEMO for the 12-month period prior to the Determination. ACIL Allen expresses the cost based on energy consumption, by taking the reported cost in dollar terms from AEMO for the given region and prorating the cost across all consumers in the region on a consumption basis.

Retailer Reliability Obligation

The Retailer Reliability Obligation (RRO) started on 1 July 2019 to help manage the risk of declining reliability of supply in response to the recent large amounts of investment in intermittent renewable projects coupled with recent and potential closures of thermal power stations.

If the RRO is triggered for a given quarter and region of the NEM, then retailers need to secure sufficient *qualifying contracts* to cover their share of a one-in-two-year peak demand.

[3] The AEMC in December 2024 released in Final Determination in relation to reducing the settlement cycle which in effect reduces the OSL period from 35 to 19 days (https://www.aemc.gov.au/sites/default/files/2024-12/Shortening%20the%20settlement%20cycle%20-%20ERC0384%20-%20Final%20determination_final.pdf)

The RRO is currently not triggered for 2025-26 in New South Wales, Queensland or South Australia, and hence we are not required to account for the RRO in the wholesale costs for 2025-26. However, it is worth noting that this cost component should be included as part of the wholesale cost if the RRO is triggered in future determinations.

We think that entering into a mix of firm base and cap contracts satisfies the qualifying contract definition. As part of the current WEC estimation methodology, an algorithm is run to determine the optimal hedge cover for a given distribution zone for each quarter of the given determination period.

The total optimal cover is expressed as a percentage of the P50 annual peak demand for the given quarter – which is analogous to a one-in-two-year peak demand referred to in the RRO.

Our approach to account for the triggering of the RRO in the estimated WEC is:

— If the overall level of the optimal contract cover is less than 100 per cent of the P50 annual peak demand, then increase the overall level of contract cover to 100 per cent. This will result in an increase in the WEC value since the cost of the additional contracts will be included.
— If the overall level of the optimal contract cover is equal to or greater than 100 per cent of the P50 annual peak demand then no change is required, and hence the RRO has no impact on the WEC.

AEMO Direction costs

Under the National Electricity Rules (NER) AEMO can, if necessary, take action to maintain security and reliability of the power system. AEMO can achieve this by directing a participant to undertake an action – such as directing a generator to operate even though the spot price in the NEM is less than that generator’s operating cash costs. In such instances, compensation may be payable to the participant. This compensation needs to be recovered from other market participants. It is worth noting that such directions issued by AEMO are separate to ancillary services.

There are two types of system security direction:

1. Energy direction – the cost of which is recovered from customers
2. Other direction – the cost of which is recovered from customers, generators, aggregators.

Details of the recovery methodology are provided in AEMO’s NEM Direction Compensation Recovery paper published in 2015[4].

In recent years, AEMO has directed selected gas fired generators in South Australia to maintain a certain level of generation to ensure the security of the power system in maintained – this is classified as an energy direction and hence its associated compensation is recovered from customers.

AEMO publishes the direction cost recovery data on a weekly basis. However, the files are prone to regular updates, as the required information to calculate the amount of compensation becomes available, and its apparent that there is a lag between the time the direction event occurs and final settlement.

AEMO also publish summaries of the costs associated with direction events in their Quarterly Energy Dynamics reports.

To arrive at the estimate of the AEMO Direction compensation costs, ACIL Allen takes the sum of the quarterly Direction costs by region for the most recent past four quarters, as presented in AEMO’s latest available Quarterly Energy Dynamics Report (the latest report available at the time of undertaking our analysis for the Determination) and divided by the corresponding annual regional customer energy.

[4] https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2015/direction-recovery-reconciliation-file-v13.pdf

Costs associated with June 2022 NEM events

Between 12 and 23 June 2022 a series of events triggered administered pricing, spot market suspension and market interventions in the NEM consistent with the NER. As noted by AEMO in its Compensation Update published on 6 January 2023[5], these events have associated compensation and contract payments, which under the NER are to be recovered from Market Customers (mainly electricity retailers). The costs will be recovered in proportion to energy purchased in each relevant region. Hence these costs should be included in the Determination.

The AEMO Compensation Update published on 6 January 2023 summarises the costs, and groups them into the following categories:

— RERT payments
— Directions compensation
— Suspension pricing compensation
— Administered pricing compensation.

It is important to note that for this Determination, any RERT or Directions costs associated with the June 2022 events will be reported here and excluded from the usual RERT and Directions costs (to avoid double counting).

As with the 2023-24 and 2024-25 determinations, we continue to use AEMC's published compensation costs (in $ terms) and allocate them to NEM regions in proportion to energy purchased in each relevant region (in $/MWh terms), in accordance with the National Electricity Rules.

Compensation costs that were published prior to the 2023-24 Final Determination cut-off date of 10 May 2023 were included in the 2023-24 Final Determination energy costs. There were no compensation costs published in the lead up to the 2024-25 Final Determination. Any outstanding compensation amounts published after the cut-off date will be included in future determinations.

Environmental costs

Large-scale Renewable Energy Target (LRET)

By 31 March each compliance year, the Clean Energy Regulator (CER) publishes the Renewable Power Percentage (RPP), which translates the aggregate LRET target into the number of Large-scale Generation Certificates (LGCs) that liable entities must purchase and acquit under the scheme.

The RPP is determined ex-ante by the CER and represents the relevant year's LRET target (in fixed GWh terms) as a percentage of the estimated volume of liable electricity consumption throughout Australia in that year.

The estimated cost of compliance with the LRET scheme is derived by multiplying the RPP and the determined LGC price to establish the cost per MWh of liable energy supplied to customers. Since the cost is expressed as a cost per MWh, it is applicable across all retail electricity tariffs.

Market-based approach

A market-based approach is used to determine the price of a LGC, which assumes that an efficient and prudent electricity retailer builds up LGC coverage prior to each compliance year.

[5] https://aemo.com.au/-/media/files/electricity/nem/data/mms/2022/june-2022-nem-events-compensation-jan-6.pdf?la=en

This approach involves estimating the average LGC price using LGC forward prices for the two relevant calendar compliance years in the determination period. Specifically, for each calendar compliance year, the trade-weighted average of LGC forward prices since they commenced trading is calculated.

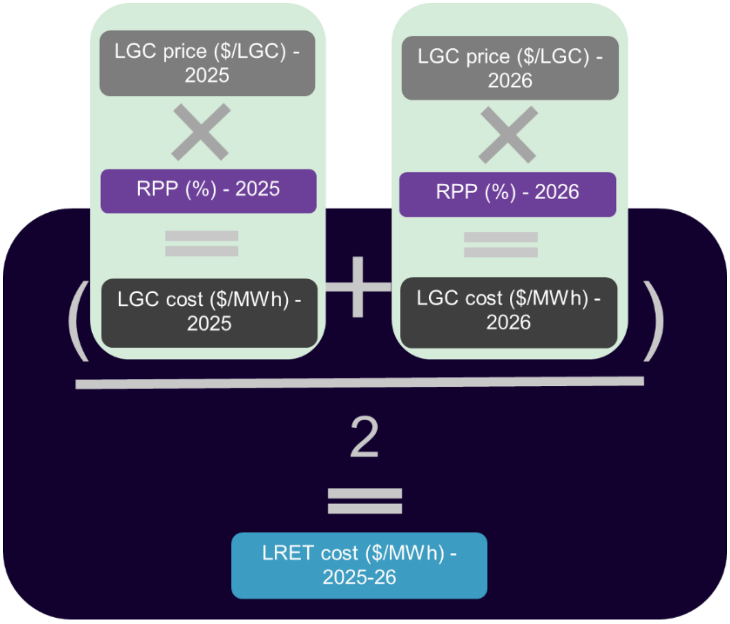
To estimate the costs to retailers of complying with the LRET for 2025-26, ACIL Allen uses the following elements:

— The average of the trade-weighted average of LGC forward prices for 2025 and 2026 from brokers TraditionAsia

— the Renewable Power Percentage (RPP) for 2025, published by the CER

— the estimated Renewable Power Percentage (RPP) for 2026[6].

Figure 2.8 Steps to estimate the cost of LRET



Source: ACIL Allen

Small-scale Renewable Energy Scheme (SRES)

Similar to the LRET, by 31 March each compliance year, the CER publishes the binding Small-scale Technology Percentage (STP) for the year and non-binding STPs for the next two years.

The STP is determined ex-ante by the CER and represents the relevant year's projected supply of Small-scale Technology Certificates (STCs) as a percentage of the estimated volume of liable electricity consumption throughout Australia in that year.

The estimated cost of compliance with the SRES is derived by multiplying the estimated STP value.

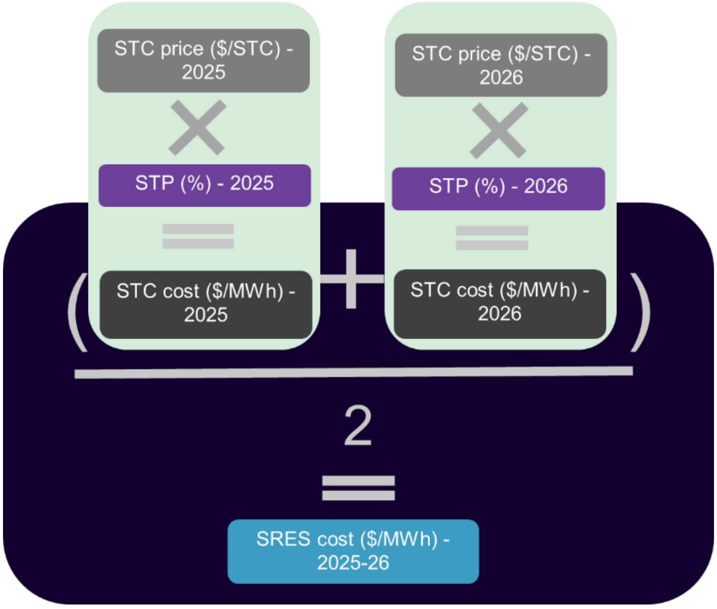
To estimate the costs to retailers of complying with the SRES, ACIL Allen uses the following elements:

— the binding Small-scale Technology Percentage (STP) for 2025 as published by the CER

[6] The estimated RPP value for 2026 is estimated using ACIL Allen's estimate of liable acquisitions and the CER-published mandated LRET target for 2025 and 2026.

— an estimate of the STP value for 2026[7]
— CER clearing house price[8] for 2025 and 2026 for Small-scale Technology Certificates (STCs) of $40/MWh.

Figure 2.9 Steps to estimate the cost of SRES



Source: ACIL Allen

Other environmental costs

New South Wales Energy Savings Scheme (ESS)

The Energy Savings Scheme (ESS) is a New South Wales Government program to assist households and businesses reduce their energy consumption. It is a certificate trading scheme in which retailers are required to fund energy efficiency through the purchase of certificates.

To estimate the cost of complying with the ESS, ACIL Allen uses the following elements:

— Energy Savings Scheme Target for 2025 and 2026 of 10.5 and 11 per cent respectively, as published by IPART
— Historical Energy Savings Certificate (ESC) market forward prices for 2025 and 2026 from brokers TFS.

[7] The STP value for 2026 is estimated using estimates of STC creations and liable acquisitions in 2026, taking into consideration the CER's non-binding estimate.

[8] Although there is an active market for STCs, ACIL Allen is not compelled to use market prices. This is mainly because historical prices might not be the best indicators of future prices as the market is designed to clear every year – so in theory prices could be $40 or at least very close to it. This assumes that the CER provides an accurate forecast of created certificates underpinning the STP for the next year.

New South Wales Peak Demand Reduction Scheme (PDRS)

The New South Wales Government established the Peak Demand Reduction Scheme (PDRS) in September 2021. The scheme commenced on 1 November 2022 and its primary objective is to create financial incentives to encourage peak demand reduction activities. Similar to the ESS, the PDRS is a certificate trading scheme in which retailers are required to fund peak demand reduction through the purchase of peak reduction certificates (PRCs). A PRC is equivalent to 0.1 kW of peak demand reduction capacity averaged across one hour.

To estimate the cost of complying with the PDRS, ACIL Allen uses the following elements:

— The peak demand reduction target for 2025-26 of 5.5 per cent, as published by the New South Wales and Department of Planning, Industry and Environment

— Historical PRC market forward prices for 2025 and 2026 from brokers TFS.

South Australia Retailer Energy Productivity Scheme (REPS)

The Retailer Energy Productivity Scheme (REPS) requires energy retailers with sales and customer numbers above certain thresholds (obliged retailers) to provide energy productivity activities to South Australian households and businesses to meet annual Ministerial targets. The REPS replaces the Retailer Energy Efficiency Scheme (REES), which was included up to DMO 3 inclusive.

The targets are set by the South Australian Minister of Energy and Mining, and Essential Services Commission of South Australia (ESCOSA) administer the scheme and allocates the target to each obligated retailer.

The cost of the REPS is recovered directly through retail electricity tariffs, and therefore should be considered as part of the environment cost component – but care needs to be taken that these costs are not double counted in the retail cost component.

ESCOSA in its annual report on the REPS published in August 2024 provides costs of the scheme, which we use in this determination.

Energy losses

Some electricity is lost when it is transported over transmission and distribution networks to customers. As a result, retailers must purchase additional electricity to allow for these losses when supplying customers.

The components of the wholesale and environmental costs are expressed at the relevant regional reference node (RRN). Therefore, prices expressed at the regional reference node must be adjusted for losses in the transmission and distribution of electricity to customers – otherwise the wholesale and environmental costs are understated. The cost of network losses associated with wholesale and environmental costs is separate to network costs and are not included in network tariffs.

Distribution Loss Factors (DLF) for each distribution zone and average Marginal Loss Factors (MLF) for transmission losses from the node to major supply points in the distribution networks are applied to the wholesale energy cost estimates to incorporate losses.

The loss factors used are published by AEMO one year in advance for all NEM regions. Average transmission losses by network area are estimated by allocating each transmission connection point to a network based on their location. Average distribution losses are already summarised by network area in the AEMO publication.

As described by AEMO[9], to arrive at prices at the customer terminal (price at load connection point) the MLF and DLF are applied to the prices at the regional reference node (RRN) as follows:

*Price at load connection point = RRN Price * (MLF * DLF)*

The MLFs and DLFs used to estimate losses for the Draft Determination for 2025-26 are based on the final 2024-25 MLFs and DLFs published by AEMO (at the time of this analysis the draft 2025-26 MLFs and DLFs were not available).

The MLFs and DLFs used to estimate losses for the Final Determination for 2025-26 will be based on the final 2025-26 MLFs and DLFs to be published by AEMO in early April 2025.

[9] See Page 23 of the AEMO publication *Treatment of loss factors in the national electricity market- July 2012*

3 Responses to submissions to Issues Paper

The AER forwarded to ACIL Allen a total of 15 submissions in response to its Issues Paper. ACIL Allen reviewed the submissions to identify issues that related to our methodology and required our consideration. A summary of the review is shown below in Table 3.1.

The key issues raised in the submissions cover the following broad areas:

— Blending of NSLP and interval meter profiles
— Control Load Profiles (NSW)
— Solar PV exports and hedging costs
— Separate WECs for residential and small business customers
— Spot price simulations
— Use of the 95th percentile simulated WEC.

Table 3.1 Review of issues raised in submissions in response to Issues Paper

ID	Stakeholder	WEC	Hedge model	Environmental costs	NEM fees	Other costs	Energy losses
1	JEC SACOSS ACOSS	Yes	Nil	Nil	Nil	Nil	Nil
2	Energy Consumers Australia	Nil	Nil	Nil	Nil	Nil	Nil
3	Engie	Yes	Yes	Nil	Nil	Nil	Nil
4	Energy Locals	Yes	Yes	Nil	Nil	Nil	Nil
5	EnergyAustralia	Yes	Yes	Nil	Nil	Nil	Nil
6	Origin Energy (Origin)	Yes	Yes	Nil	Nil	Nil	Nil
7	SACOSS	Yes	Nil	Nil	Nil	Nil	Nil
8	AGL	Yes	Yes	Nil	Nil	Nil	Nil
9	Australian Energy Council	Nil	Nil	Nil	Nil	Nil	Nil
10	SA Business Chamber	Nil	Nil	Nil	Nil	Nil	Nil
11	Alinta Energy	Yes	Yes	Nil	Nil	Nil	Nil
12	Shell Energy	Yes	Yes	Nil	Nil	Nil	Nil
13	Red Energy / Lumo Energy	Yes	Yes	Nil	Nil	Nil	Nil
14	Ausgrid	Nil	Nil	Nil	Nil	Nil	Nil
15	AER Customer Consultative Group	Nil	Nil	Nil	Nil	Nil	Nil

Note: Yes = an issue was raised that required ACIL Allen's consideration

Source: ACIL Allen analysis of AER supplied documents

3.1 Blending of NSLP and interval meter profiles

A number of submissions supported option 2, blending the NSLP and interval meter demand spanning the October 2023 to September 2024 date range. These include:

- ENGIE
- AGL
- Alinta Energy
- Red Energy / Lumo Energy
- Origin.

AGL notes that the NSLP

> *still reflects a significant proportion of a retailer's customer load*

Alinta Energy notes that the

> *blended approach to DMO 6 was more reflective of the variance in residential customer load than that ultimately use in DMO 6 and is similar to option 2 presented in the issues paper*

Energy Australia, Shell Energy prefer adopting option 1 - using 2 years of interval meter data only to simulate the load profile, rather than blending with the NSLP – suggesting this future proofs the methodology.

ACIL Allen response

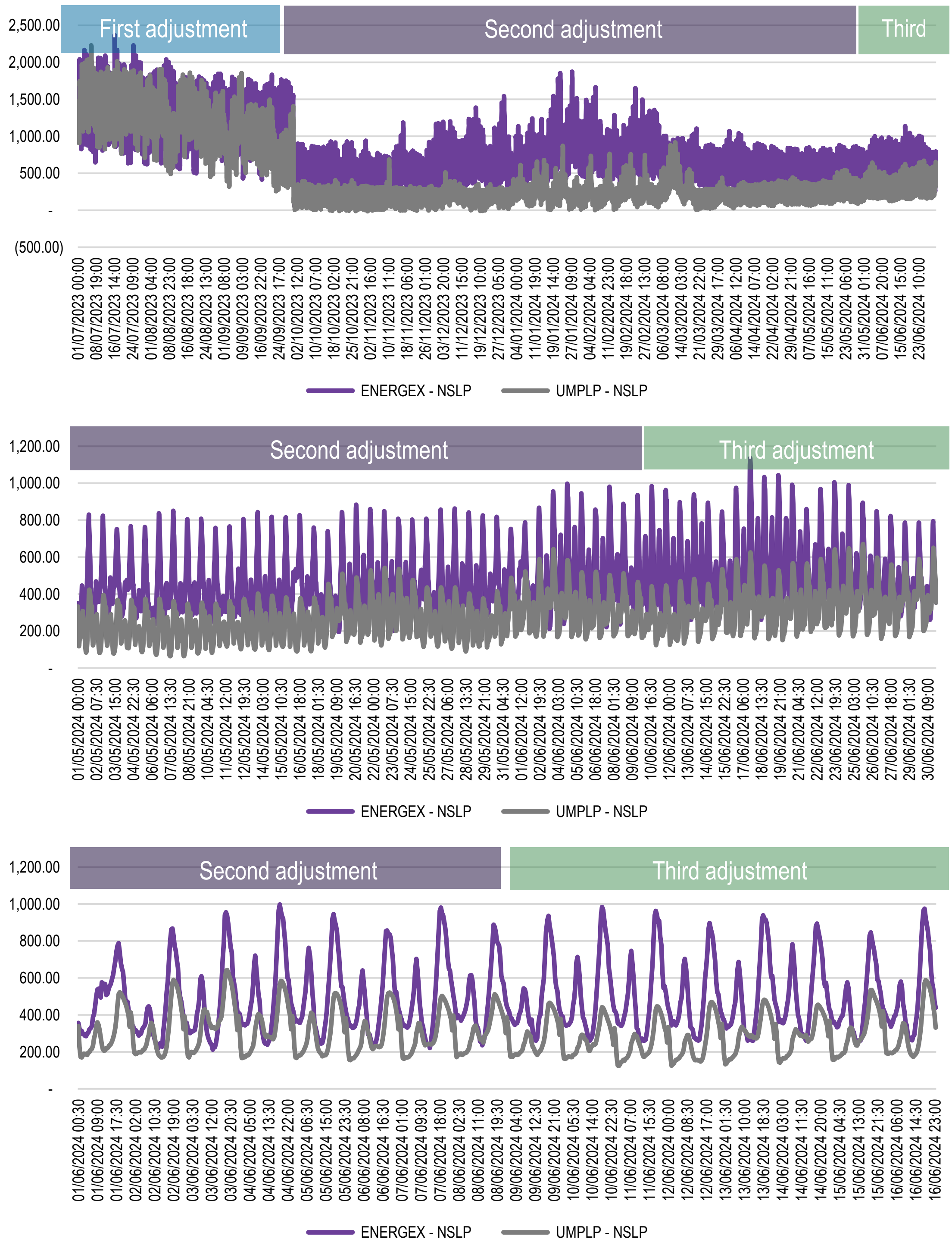
ACIL Allen acknowledges the argument from submissions that adopting Option 1, using the interval meter data only, future proofs the methodology. However, Option 2, blending the NSLP and interval meter demand, is also future proof. As customers move onto interval meters the proportion of customer demand on the NSLP will naturally diminish over time and hence the NSLP will have less influence on the overall combined profile.

Option 2, for this determination at least, requires the use of data spanning a shorter date rage (October 2023 to September 2024) – a shorter date range than usually used in the WEC methodology.

Adopting this shorter date range avoids using NSLP data subject to AEMO's initial adjustment (which we referred to as the *temporary artificial uplift* in DMO 6) as shown in Figure 3.1.

We note there is no discernible difference in the NSLP demand profiles when transitioning from AEMO's second to third adjustment – suggesting the NSLPs are largely consistent across the October 2023 to September 2024 date range.

Figure 3.1 Energex and SAPN NSLPs (MW)

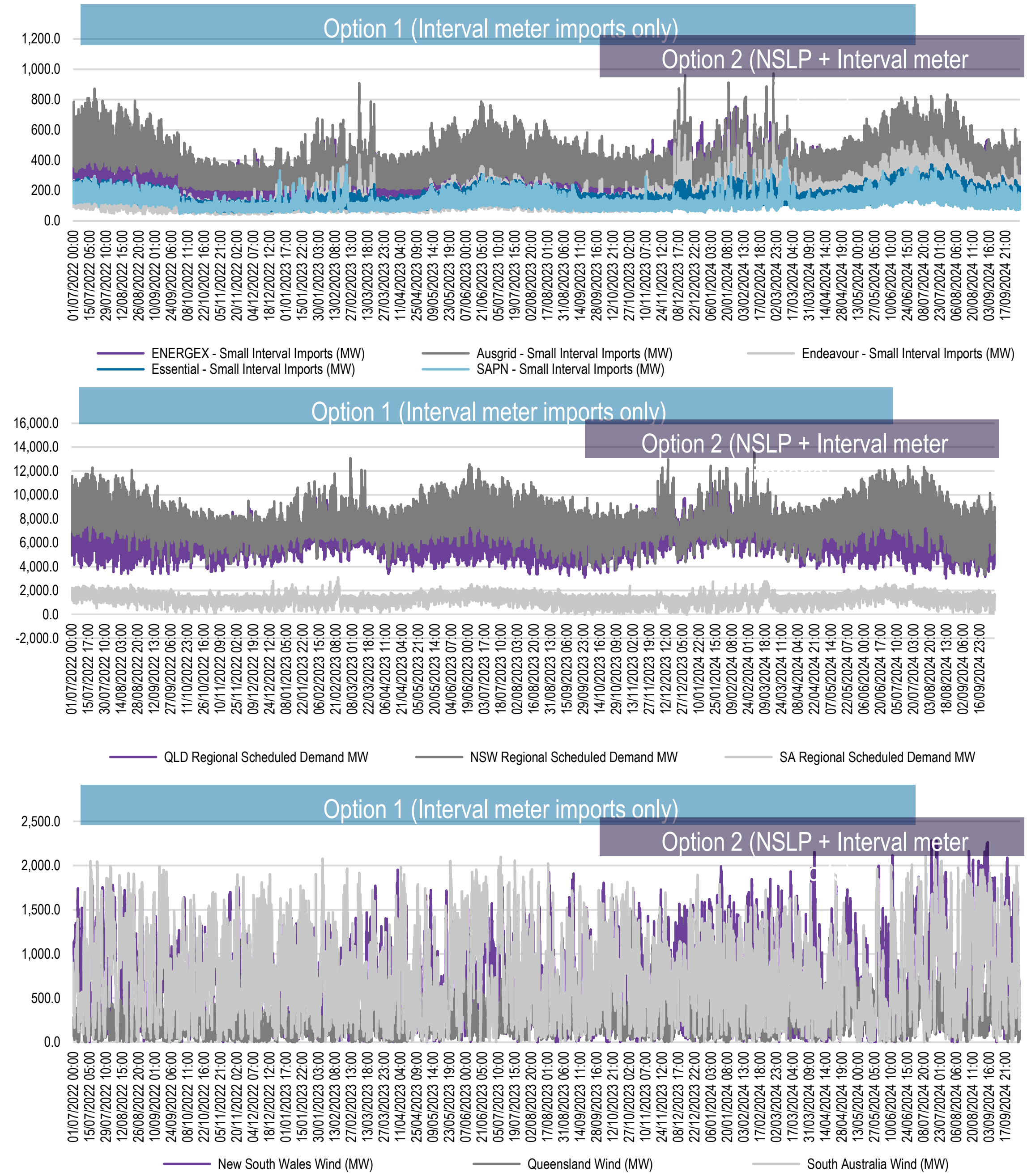


Note: The three charts show the same data but over different date ranges

Source: ACIL Allen analysis of AEMO data

Adopting option 2 potentially increases the risk of understating variations in weather driven outcomes due to using a shorter date range for this particular determination. However, ACIL Allen has analysed the variations in outcomes between the 2 options (as shown in Figure 3.2), and is satisfied there is sufficient variation between October 2023 and September 2024, when compared with the longer date range of option 1.

Figure 3.2 Comparison of half-hourly interval meter and regional demands and wind resource (MW)



Source: ACIL Allen

Noting that the adoption of option 2 in future determinations will naturally include a longer date range (with the inclusion of an additional year's worth of data), and that option 2 avoids AEMO's initial adjustment of the NSLP, and the importance of including both the NSLP and interval meter demand data to better represent the overall small customer retail load, ACIL Allen recommends adopting option 2.

3.2 Control Load Profiles (NSW)

Origin supported option 1, using the historical CLP, on the basis there has not been a significant change in the CLP load shape to date.

ENGIE, AGL, Alinta Energy, Shell Energy, Red / Lumo Energy support option 2, blending the NSLP and CLP data on the basis it aligns more closely with a prudent retailer's hedging strategy.

EnergyAustralia support option 3 – using the WEC for residential flat rate customers. However, this is contingent on interval meter data being adopted in the estimation process.

JEC SACOSS ACOSS in their joint submission stated that the CLPs adopted in the Determination should assume retailers efficiently manage CLP so the loads are activated during daylight hours.

ACIL Allen response

ACIL Allen is of the view that option 1, which continues to derive a separate WEC for CLP, allows for retailers to offer a product that blends general consumption and control load. This in effect achieves the objective of option 2 – although noting the blended WEC from option 1 would be based on the combined NSLP and interval meter data.

Option 2, blending the CLP and NSLP, would be inconsistent if the general consumption WEC was based on the combined NSLP and interval meter demand data. Ideally, the interval meter demand data would be separated into general consumption and control load. This does not appear to be possible at this point in time based on discussions with AEMO, however, it may be possible that DNSPs are able to provide the interval meter data on this basis for future determinations.

Our recommendation is to adopt option 1 for DMO 7, which is the status quo, and work with DNSPs ahead of DMO 8 to investigate the possibility of separating interval meter demand data into general consumption and control load.

3.3 Solar PV exports and hedging costs

Consumer groups support the continued exclusion of rooftop PV exports in the load profiles. With most of these submissions noting retailers can recover any additional costs associated with rooftop PV exports from those customers exporting to the grid.

ENGIE, Alinta Energy support the inclusion of rooftop PV exports in the load profiles when calculating the hedging strategy, noting excluding solar exports flattens the load profiles and therefore underestimates the costs of the contracts that retailers need to purchase to hedge their net load.

Energy Locals, EnergyAustralia Shell Energy, and Red/Lumo Energy continue to advocate for the inclusion of rooftop PV exports in the load profiles for the calculation of the WEC as well as for calculating the hedging strategy.

ACIL Allen response

ACIL Allen provided its detailed response in relation to the inclusion of rooftop PV exports in the demand profiles when calculating the WECs in a separate report to the AER for DMO 6[10]. What follows below is further consideration of the option of accounting for PV exports when deriving the hedging strategy.

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[10] https://www.aer.gov.au/documents/acil-allen-final-determination-default-market-offer-prices-2024-25-wholesale-energy-costs-and-rooftop-pv-exports-interaction-dmo-wec-estimation-methodology-solar-fits

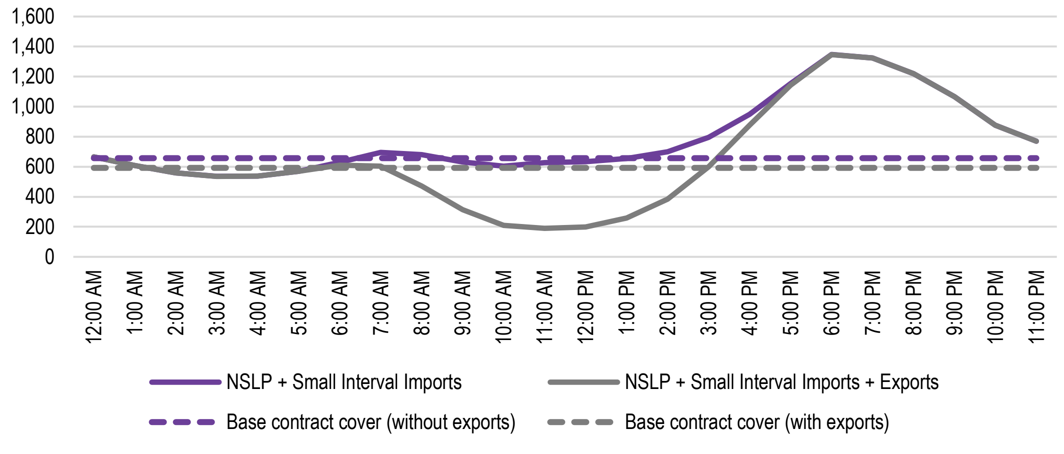
ACIL Allen agrees that the inclusion of PV exports in the demand profile when estimating the hedging strategy will most likely result in a different mix of contracts, as noted in some submissions. Inclusion of the PV exports carves out the daytime demand and this would result in a hedging strategy with a higher proportion of cap contracts (and a lower proportion of base contracts) all other things equal.

ACIL Allen has tested this and finds the impact to be minimal. Recalling that the methodology sets the overall level of contract cover as a function of the 50th percentile of the quarterly peak demands from the simulated demand sets, and then sets the level of base contracts to be a percentage of the overall quarterly average demand across the demand sets, with the difference being the level of cap contract cover. Including PV exports does not notably alter the annual peak demands (which tends to occurs in the evening) – this means that the overall level of contract cover tends to stay the same. Including PV exports reduces the average demand and hence reduces the level of base contracts as shown in Figure 3.3 for Energex. However, the change in the contract mix is relatively small – this case just under 100 MW. This is because the reduction in demand due to the PV export carve out is in effect being smeared across the entire day (since base contracts apply to all hours, not just daylight hours).

Applying this slightly different hedging strategy to the combined NSLP and interval meter imports results in a slightly different WEC. But this does not necessarily mean the WEC will be higher if the hedging strategy accounts for the PV export carve out, as shown in Figure 3.4. Whether the WEC is higher or lower depends on the relative value of base and cap contract prices. In any case, the impact of this small change in hedging strategy is typically less than one per cent.

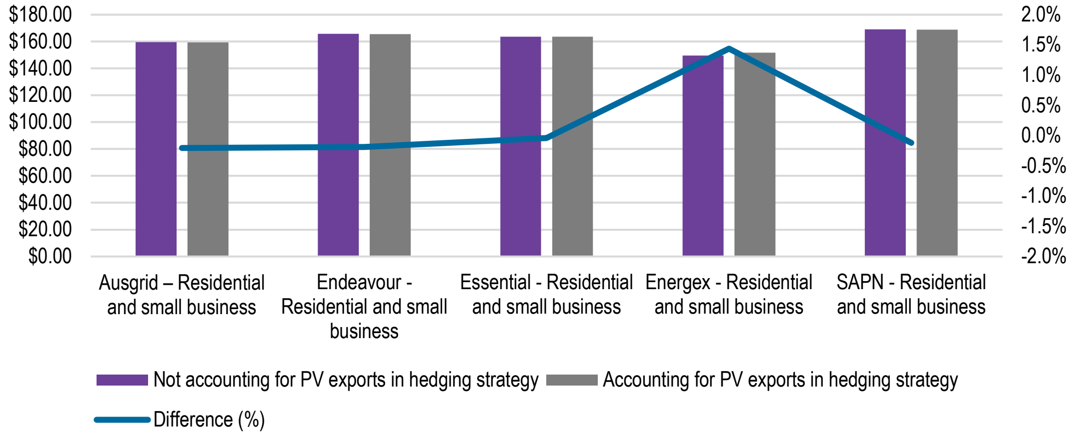
ACIL Allen remains of the view that any additional costs or savings arising from a slightly different hedging strategy when accounting for PV exports ought to be factored into the feed in tariff, and not the import tariff. That said, the AER have requested ACIL Allen take into account the this slightly different hedging strategy when estimating the WECs for the 2025-26 Draft Determination. Consequently, the estimates of the WECs presented in this report account for interval meter rooftop PV exports when deriving the hedging strategy, but exclude the interval meter PV exports when calculating the WEC.

Figure 3.3 Average time of day demand for Energex NSLP and interval meter demand compared with Base contract position (MW)



Source: ACIL Allen

Figure 3.4 Comparison of WEC ($/MWh) – with and without accounting for rooftop PV exports in hedging strategy



Source: ACIL Allen

3.4 Separate WECs for residential and small business customers

The AER in its Issues Paper asked stakeholders whether separate WECs should be calculated for residential and small business customers.

Some stakeholders supported the continuation of a single WEC for residential and small business customers given that retailers tend to consider the combined profile when considering their hedging strategy, and that it maintains consistency in approach compared with previous DMO determinations.

Other stakeholders supported the separation of estimates for residential and small business customers.

ACIL Allen response

In previous determinations, ACIL Allen was not supportive of estimating separate WECs for residential and small business customers given the inability to separate the NSLP demand data into different customer types, and the previously lower penetration of interval meters.

However, as we noted in our DMO 6 report, this is something that might be considered for future DMOs when the majority of customers are on interval meters and there is increased confidence that the interval meter load profiles are also representative of those customers remaining on the NSLP. It would also require the DMO to use only the interval meter data and discard the NSLP data to maintain internal consistency.

On balance, we are of the view that this represents a major change in methodology, and as such ought to be investigated thoroughly by the AER outside of the 'live' DMO process. Therefore, we recommend not to estimate separate WECs for residential / small business / solar / non-solar customers for DMO 7.

3.5 Spot price simulations

A few submissions raised concerns around the use of a single set of fuel price inputs in the spot price simulations, and the propensity for cap payouts.

EnergyAustralia states that the methodology:

> *does not fully capture the volatility that exists in real-world market conditions. This is particularly relevant in the short-term, where single fuel prices and external shocks can lead to significant fluctuations.*

But note that:

> *Overall, we are unsure whether adding this complexity into additional variability will improve outcomes.*

Origin expresses concern of the lack of variability in spot prices below $300/MWh:

> *Incorporating variability in fuel prices and plant outage levels should assist with addressing this, as these factors can have a material impact on energy prices.*

and that

> *This lack of variability in energy prices is likely driven by the fixing of fuel prices across all simulations, as this assumption removes a key driver of spot price volatility and risk in the National Electricity Market (NEM).*

EnergyAustralia expresses concern at the degree of price volatility in the spot price modelling:

> *It is our belief that the wholesale methodology assumes a cap pay out every year. So in the DMO wholesale cost modelling – after running simulations, prices are run against a hedge strategy. If a retailer is long to high prices the retailer receives a windfall gain which reduces the average cost. If there is no volatility – there is no cost saving or windfall gain. While the concept of cap payouts holding over the long term may be valid, a prudent retailer does not assume any particular year will yield a return on a cap contract. Rather, cap contracts function as an insurance product for retailers.*

ACIL Allen response

Fuel prices

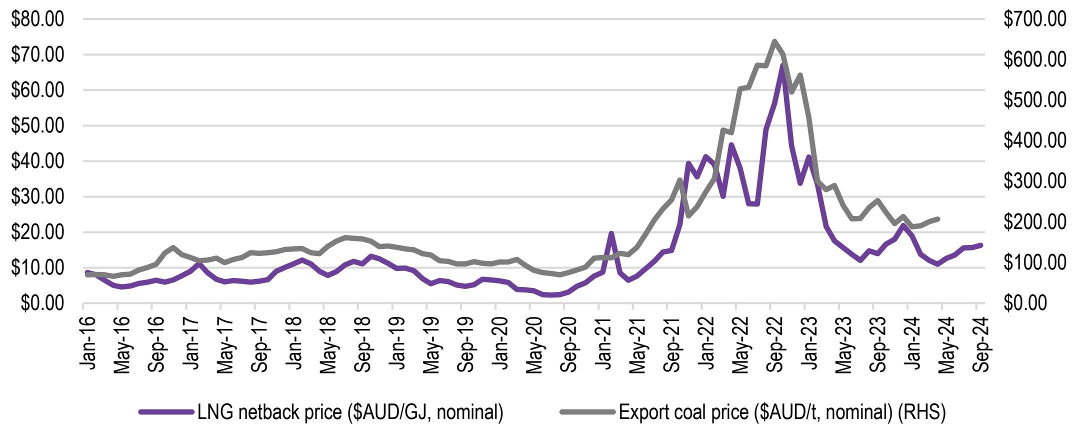
Unlike variability in price spikes, which are driven by stochastic influences, ACIL Allen does not expect the variability in sub-$300 prices to be as great as what has been observed historically. There are good reasons for this. There have been fundamental structural changes in the NEM over the past decade which influence the historical variability in sub-$300 price outcomes – structural changes that are hard to imagine being undone over the next 12 months, such as the commissioning of nearly 20,000 MW of wind and solar farm capacity, the closure of multiple coal plant, the change in the demand profile to be satisfied by NEM scheduled and semi scheduled generation.

The simulations are looking forward one year and therefore have a higher degree of clarity around any potential future structural changes.

We responded to this issue in our report to the DMO 6 Determination, noting that although it is possible to include a high and low fuel price scenario in addition to the fuel price scenario adopted in the spot price simulations, and this would increase the variability in price outcomes below $300/MWh, it is likely to have little impact on the final WEC outcome.

We have again investigated this point, and have run two sensitivities on the DMO 6 analysis by rerunning the spot price simulations by varying the coal and gas price inputs. We used historical fuel price data from the past 10 years (as shown in Figure 3.5), and took the 75th and 25th percentile fuel prices as inputs into the spot price simulations for coal and gas.

Figure 3.5 Monthly prices for export coal and LNG – 2016 to 2024



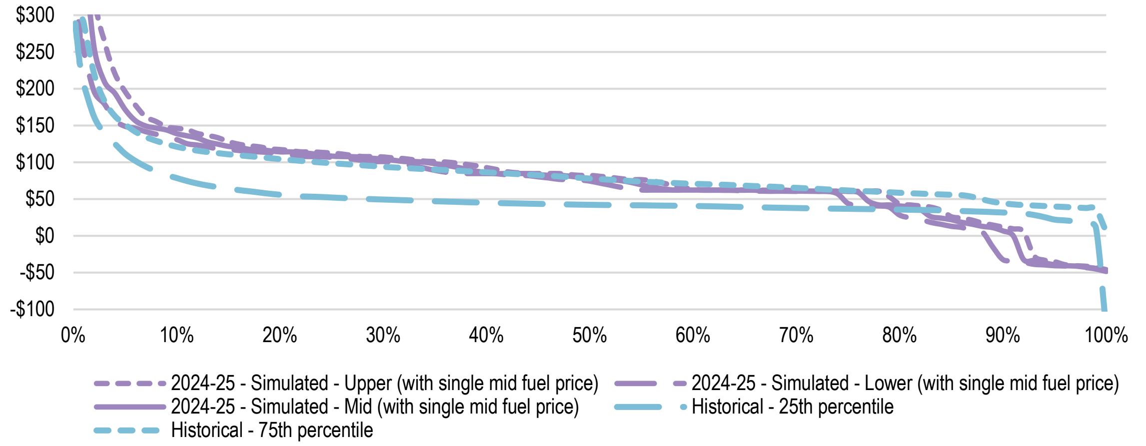
Source: ACIL Allen analysis of various sources

These represent a 60 per cent increase and 30 per cent decrease respectively around the 50th percentile observation. These two variations were applied to the mid fuel price series adopted in DMO 6, and therefore include a substantial degree of asymmetry.

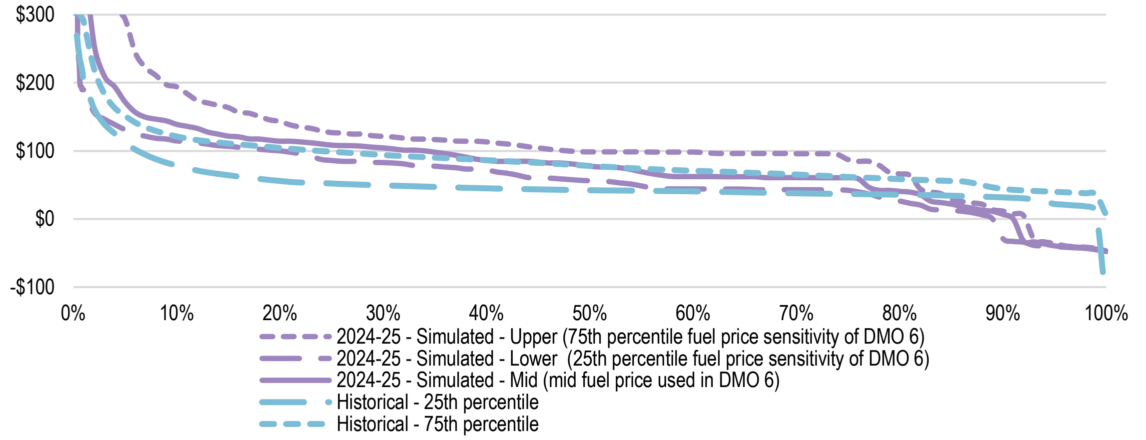
Including the variation in fuel prices in the analysis increases the spread in sub-$300 simulated spot prices across the simulations to reflect the historical spread as shown in Figure 3.6 for New South Wales.

Figure 3.6 Comparison of simulated hourly price duration curves ($/MWh) for 2024-25 and range of actual outcomes in past years – New South Wales - DMO 6

Using a single set of fuel price inputs



Including a variation in fuel price inputs



Source: ACIL Allen

The spot price outcomes from these two variations were then run through hedge model to calculate WEC. The simulated WECs from all three fuel price series inputs then combined (using a weighting of 50 per cent for the mid fuel price WECs, and 25 per cent each for the high and low fuel price WECs), and 75th percentile WEC derived.

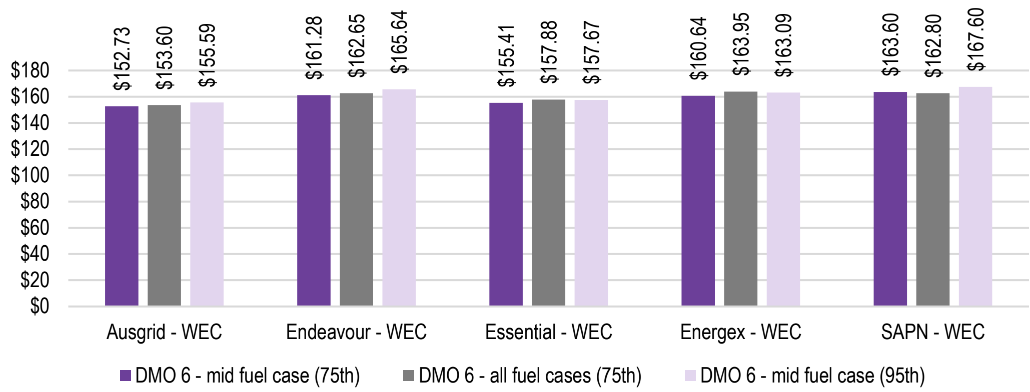
The WECs derived from the three fuel price series are marginally different to DMO 6 WEC:

— The WECs in New South Wales and Queensland are between 0.6 per cent and 2 per cent higher

— The WEC in South Australia is about 0.5 per cent lower due to the higher gas prices impacting above $300/MWh prices given the region is more reliant on gas, and hence retailers receive more cap payouts.

To put these differences into context, the increase in WEC if variations in fuel price are included are likely to be less than increase in moving back to adopting the 95th percentile WEC from the mid fuel price simulations.

Figure 3.7 Comparison of WEC ($/MWh, nominal) for DMO 6 - based on single (mid) fuel price series and including high/low fuel price series



Note: Values presented are for blended the NSLP and interval meter import demand sets

Source: ACIL Allen

Our preference is to exclude variations in fuel prices for the following reasons:

— The impact on the final WEC estimate is minimal.
— It introduces conjecture on what the high and low fuel price sensitivities ought to be.
— It introduces conjecture on whether each sensitivity is given the same weight.
— The choice of a lower percentile WEC might also need to be considered (introducing further conjecture) in recognition of the revised methodology covering off fuel price risk.

On this basis, ACIL Allen recommends that the current methodology does not require a change.

Cap payouts

It appears EnergyAustralia is advocating for the WEC methodology to take into account the cost of cap contacts, and to "cap" the cap payout to the trade weighted average value of the caps. That is, if the trade weighted average value of the cap is $10, and a particular spot price simulation results in a cap value of $15, then the simulated cap value should be capped at $10 when calculating the cap payout for that given simulation. The premise of this suggestion seems to be that cap contracts are viewed by retailers as an insurance product.

Whether a retailer views a cap contract as an insurance product does not alter the requirement of our analysis which is to estimate the cost of procuring wholesale electricity in a prudent manner.

Further, "capping" the cap payout in effect results in a biased view of price volatility – the maximum cap payout from the simulations will always be less than or equal to the trade weighted cap rice. Which infers the average cap value or degree of spot price volatility from the simulations will be well below that expected by the market.

On this basis, ACIL Allen recommends that the current methodology does not require a change.

3.6 Use of the 95th percentile simulated WEC

As with DMO 4 to DMO 6, the notable issue raised in submissions relates to adopting the 75th percentile WEC.

A number of retailers reiterated their support to revert to the previous approach of using the 95th percentile simulated WEC as the final estimate of the WEC. Most of these stakeholders point to the heightened uncertainty as a reason for reverting to use the 95th percentile.

Some retailers also note that adopting the 95th percentile could be a way a accounting for differing views around the treatment of rooftop PV exports in the WEC methodology, as well as accounting for potential variations around spot price inputs such as fuel prices.

ACIL Allen has presented the rationale for adopting the 95th percentile simulated WEC in its methodology papers for DMO 2 and 3. Estimating the WEC inherently involves a degree of uncertainty. Adopting a high percentile estimate from the simulations as the final estimate of the WEC minimises the risk of underestimating the true value of the WEC – noting the DMO is a form of price cap. It also recognises that the risk inherently sits with retailers rather than consumers.

ACIL Allen response

The AER has requested ACIL Allen to continue to present the 75th percentile WEC for this Determination as the final estimate of the WEC. Consequently, the final estimates of the WECs presented in this report are the 75th percentiles of the simulated WECs.

4 Estimation of energy costs

4.1 Introduction

In this chapter we apply the methodology described in Chapter 2, and summarise the estimates of each component of the Total Energy Cost (TEC) for each of the blended NSLPs and interval meter demand profiles, and CLPs for 2025-26.

Historic demand and wholesale electricity spot price outcomes

Figure 4.1 to Figure 4.3 show the average time of day spot price for the Queensland, New South Wales, and South Australia regions of the NEM respectively, and the associated average time of day load profiles for the past 7 years. The graphs are useful in understanding the dynamics of the absolute and relative wholesale electricity price changes in the profiles.

Annual average wholesale electricity prices in Queensland, New South Wales and South Australia in 2021-22 increased by about $100/MWh, $70/MWh and $60/MWh respectively when compared with 2020-21. This substantial increase is despite the continued uptake of rooftop PV putting downward pressure on price outcomes during daylight hours. The main reasons for the increase in prices overall are the:

- substantial increases in coal costs for the New South Wales and Queensland coal fired power stations that are exposed to the export coal market which experienced an increase in price from about USD$150/t in July 2021 to about USD $400/t in June 2022 due to the:
  - war in Ukraine and subsequent embargo of Russian trade in thermal coal
  - supply from some producers being voluntarily curtailed in late 2020 in response to the low export prices
  - a number of weather events also impacted coal supply chains
  - domestic reservation policies being invoked in Indonesia placing further pressure on supply.
- increase in coal price increased NEM spot price outcomes overnight and during the day when coal was at the margin.
- increase in gas costs across the NEM due to the strong increase in LNG netback (export) prices from around AUD$11/GJ in July 2021 to about AUD$40/GJ by May 2022, which increased NEM spot prices during the evening peak when gas was at the margin.
- Thermal power station outages, particularly in Queensland with the continued outage of Callide C Unit 4 as well as other plant outages (such as Kogan Creek in the first quarter of 2022) which contributed to an increase in price volatility across the evening peak periods.

In 2022-23:

- Export coal prices remained at about USD$400/t until January 2023 at which point, they declined to about USD$230/t.
- LNG netback prices in the first quarter of 2022-23 continued to grow to a peak of about AUD$70/GJ in October 2022, and then declined to about AUD$25/GJ.
- This resulted in wholesale electricity prices averaging around $145/MWh in Queensland and New South Wales, and about $123/MWh in South Australia.

— We observe some impacts of the Government's December 2022 intervention of capping coal and gas prices, on wholesale electricity spot prices.

In 2023-24:

— Export coal prices declined further to about USD$130/t.

— LNG netback prices declined further to about AUD$15/GJ from the beginning of the 2023-24 financial year.

— However, during this period the Australian Government set an effective cap for the price of coal used for electricity generation at $AUD125/t, as well as a cap on gas prices at $12/GJ for new domestic wholesale gas contracts by east coast producers.

— This resulted in wholesale electricity prices reducing by about 39, 30 and 36 per cent, averaging around $88/MWh, $102/MWh, and $79/MWh in Queensland, New South Wales and South Australia respectively.

In 2024-25 to date:

— Export coal prices commenced the financial year at about USD$130/t but have declined to about USD$105/t (although this is largely offset by a weakening Australian dollar such that the export coal price is largely stable in AUD terms).

— LNG netback prices have increased to about AUD$20/GJ.

— This has resulted in wholesale electricity prices increasing by about 26, 27 and 30 per cent, averaging around $111/MWh, $129/MWh, and $102/MWh in Queensland, New South Wales and South Australia respectively.

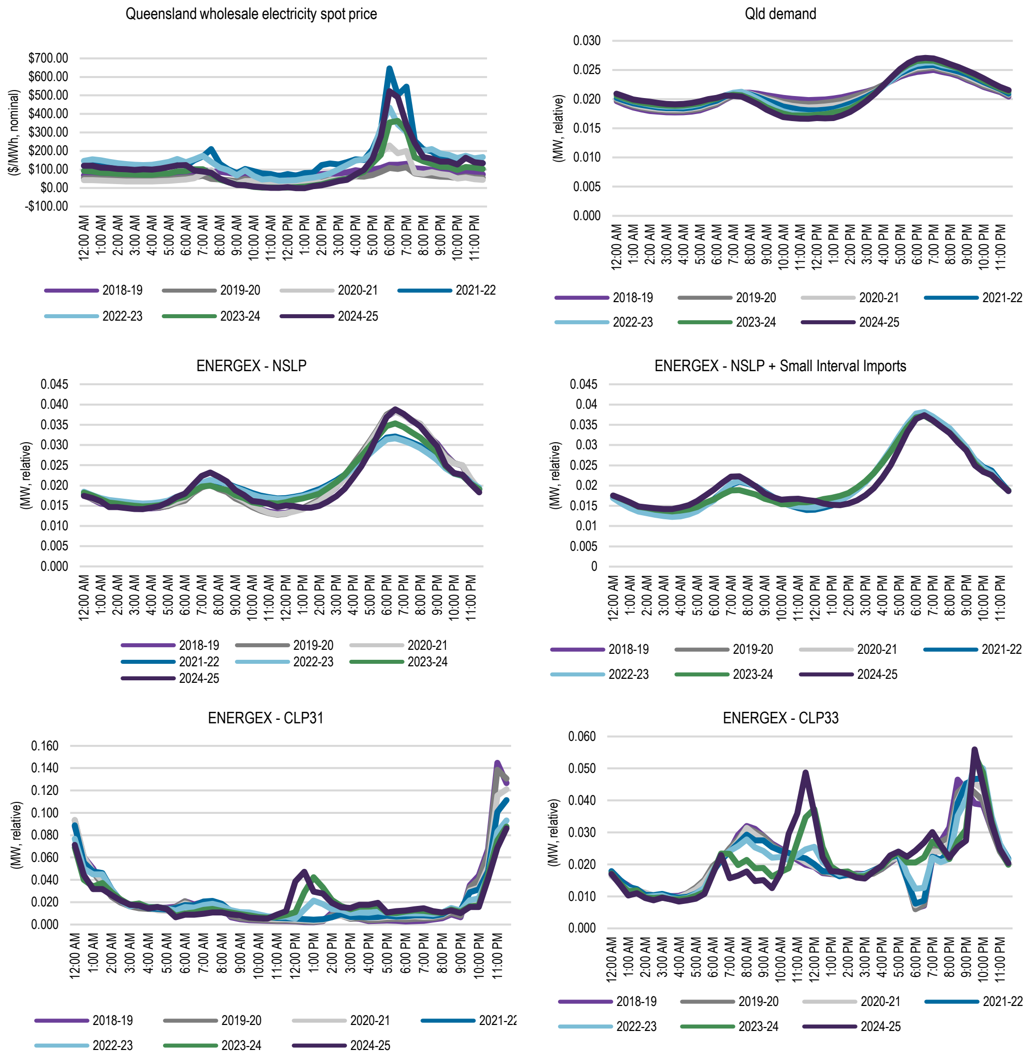
Between 2011-12 and 2019-20, the Queensland, and particularly the South Australian, NSLP load profiles, and to some degree, the New South Wales NSLPs, experienced a carving out of load during daylight hours with the increased penetration of rooftop solar PV. This resulted in the load profile becoming peakier over time and consequently, the demand weighted spot prices[11] (DWP) for the NSLP load profiles have increased relative to the corresponding regional time weighted average spot price (TWP). This is particularly the case in South Australia in 2021-22 and 2022-23 (to date) – the increase in solar output has greatly reduced prices during daylight hours which will increase the hedging costs for that region's NSLP.

However, over the past few years the rate of carve out of the NSLPs has slowed and this is most likely due to new rooftop solar PV installations being paired with the installation of interval meters – removing those consumers from the NSLP. For this reason, data has been obtained for residential and small business customers on interval meters. It can be seen that when combining the NSLP and interval meter data, the trend in carve out of demand during daylight hours has slowed – reflecting the separation of the PV exports from the profile since October 2021.

Finally, we note the change in shape of the Energex CLPs, and to a lesser extent the Endeavour and Essential CLPs, over the past two to three years – which shows that an increasing portion of controlled load is being shifted in to the daylight hour periods – when spot prices are much lower due to the large amounts of rooftop and utility scale PV generating into the market. This will have implications for the WEC estimates for this determination.

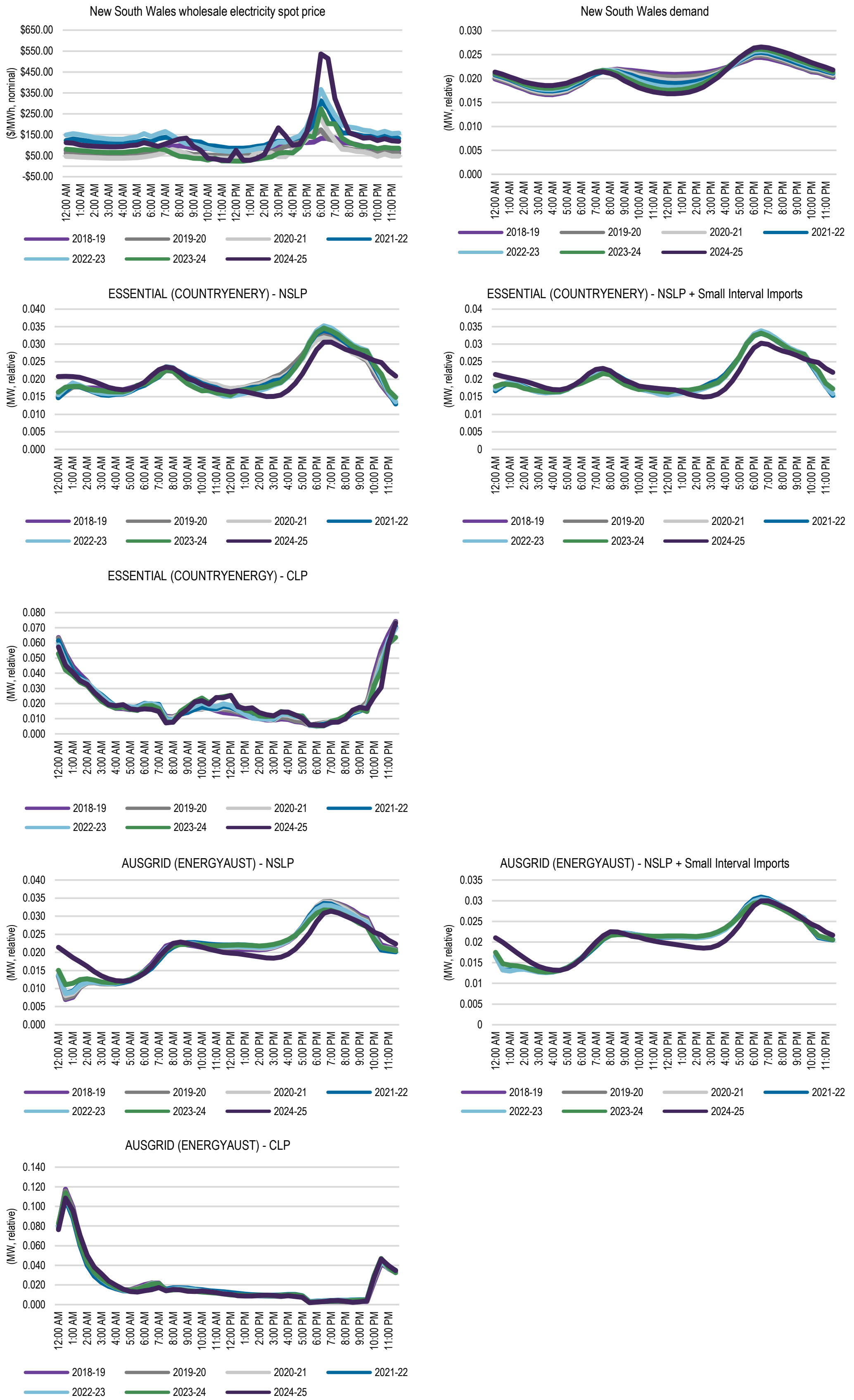
[11] The demand weighted price is in effect the unhedged wholesale energy cost that the retailers pay AEMO for the NSLP.

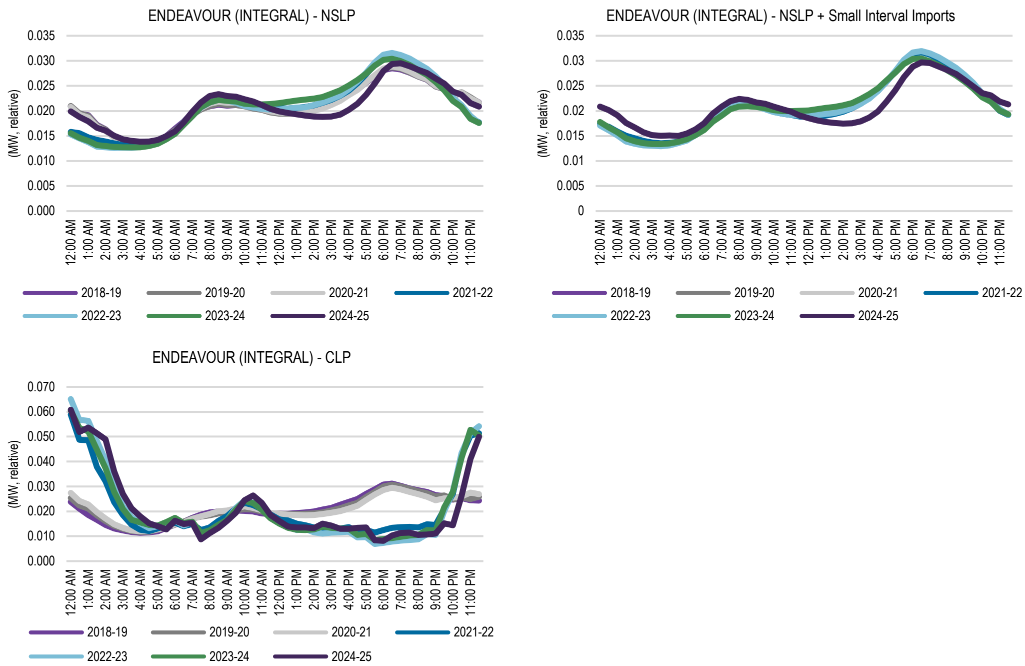
Figure 4.1 Actual average time of day wholesale electricity spot price ($/MWh, nominal) and load profiles (MW, relative) – Queensland – 2018-19 to 2024-25



Source: ACIL Allen

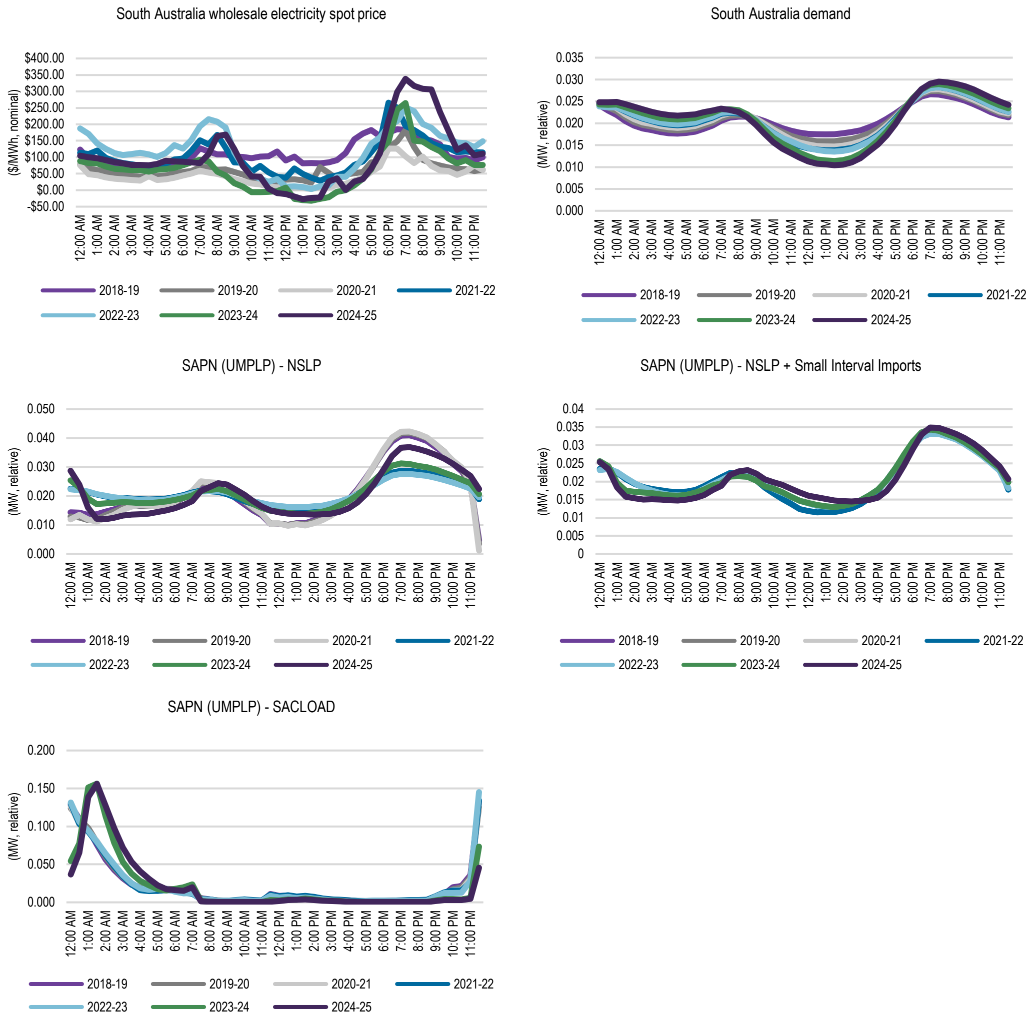
Figure 4.2 Actual average time of day wholesale electricity spot price ($/MWh, nominal) and load profiles (MW, relative) – New South Wales – 2018-19 to 2024-25





Source: ACIL Allen

Figure 4.3 Actual average time of day wholesale electricity spot price ($/MWh, nominal) and load profiles (MW, relative) – South Australia – 2018-19 to 2024-25

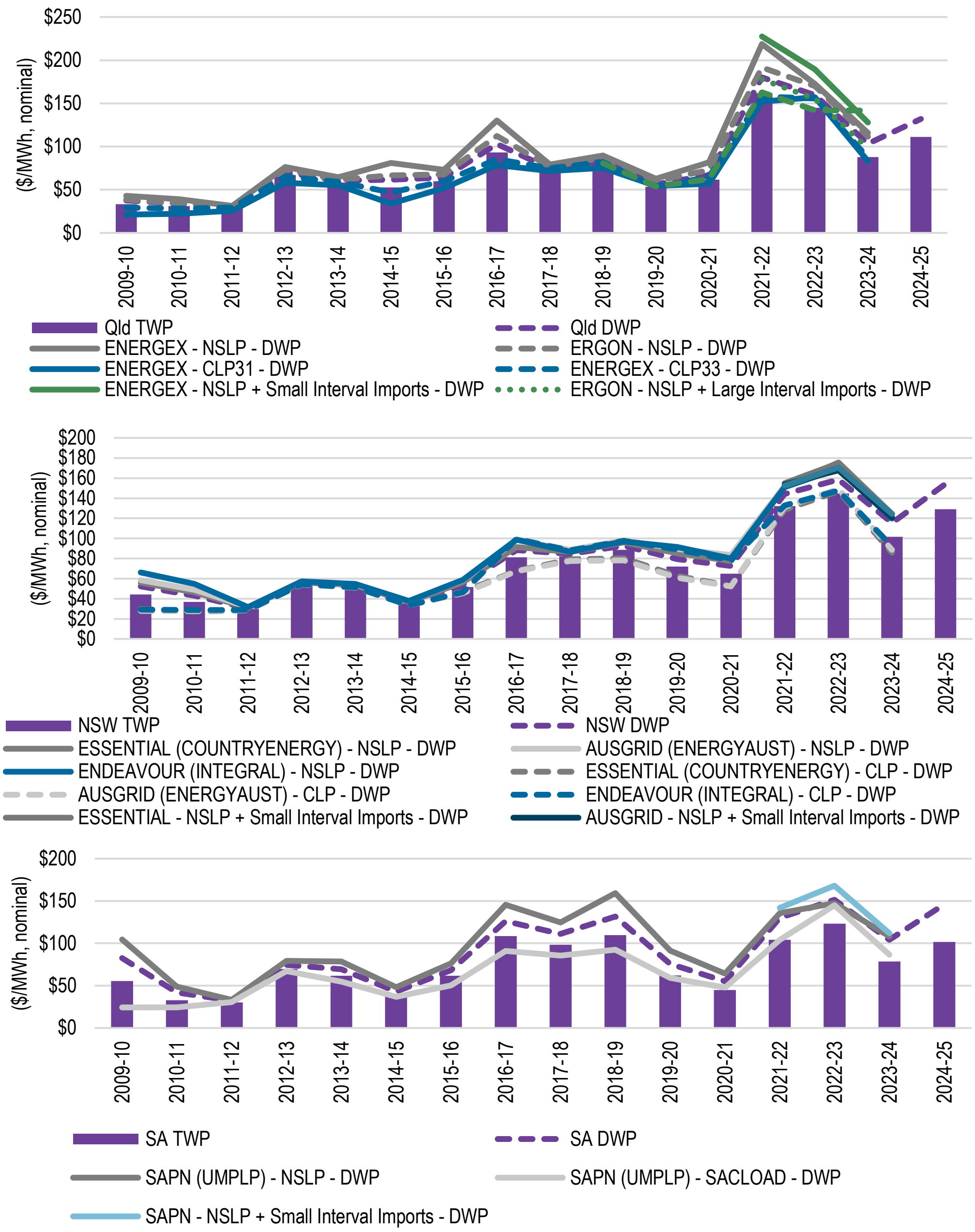


Source: ACIL Allen

The graphs in Figure 4.4 show the actual annual DWP for each of the profiles compared with the regional TWP over the past 16 years. The DWP for the combined NSLP and small interval meter import profiles are at about a 39, 20 and 38 per cent premium to the TWP on average over the past three years in Queensland, New South Wales, and South Australia respectively. The premium reflects the correlation between the time of day level of demand and spot price outcomes.

As expected, the DWPs for the CLPs are below the DWP for the combined NSLP and small interval meter import profiles in each year. Although the rank order in prices by profile within each region has been consistent in each year, the dollar value differences between the prices has varied from one year to the next. For example, in 2011-12, the flat half-hourly price profile across all three regions resulted in the profiles having relatively similar wholesale spot prices (within their respective region). Conversely, in 2016-17, the increased price volatility across the afternoon period resulted in the NSLP DWPs diverging away from the CLP DWPs. Further, the time shifting of energy into daylight hours for some of the CLPs over the past few years has resulted in further separation in the CLP DWP from the combined NSLP and small interval meter import profile DWP.

Figure 4.4 Actual annual average demand weighted price ($/MWh, nominal) by profile and regional time weighted average price ($/MWh, nominal) – 2009-10 to 2023-24



Note: Values reported are spot (or uncontracted) prices. 2024-25 price series includes data up to January 2025. Insufficient NSLP/CLP/Interval meter data available for 2024-25.

Source: ACIL Allen

The volatility of spot prices (timing and incidence) provides the incentive to a retailer to hedge their load, since hedging of the loads reduces a retailer's exposure to the volatility. The suite of contracts (as defined by base swap, cap and quarter) considered by the methodology does not change from one year to the next. However, the movement in contract price is the key contributor to movement in the estimated wholesale energy costs of the different profiles year on year, as is shown in Figure 4.5.

Compared with the 2024-25:

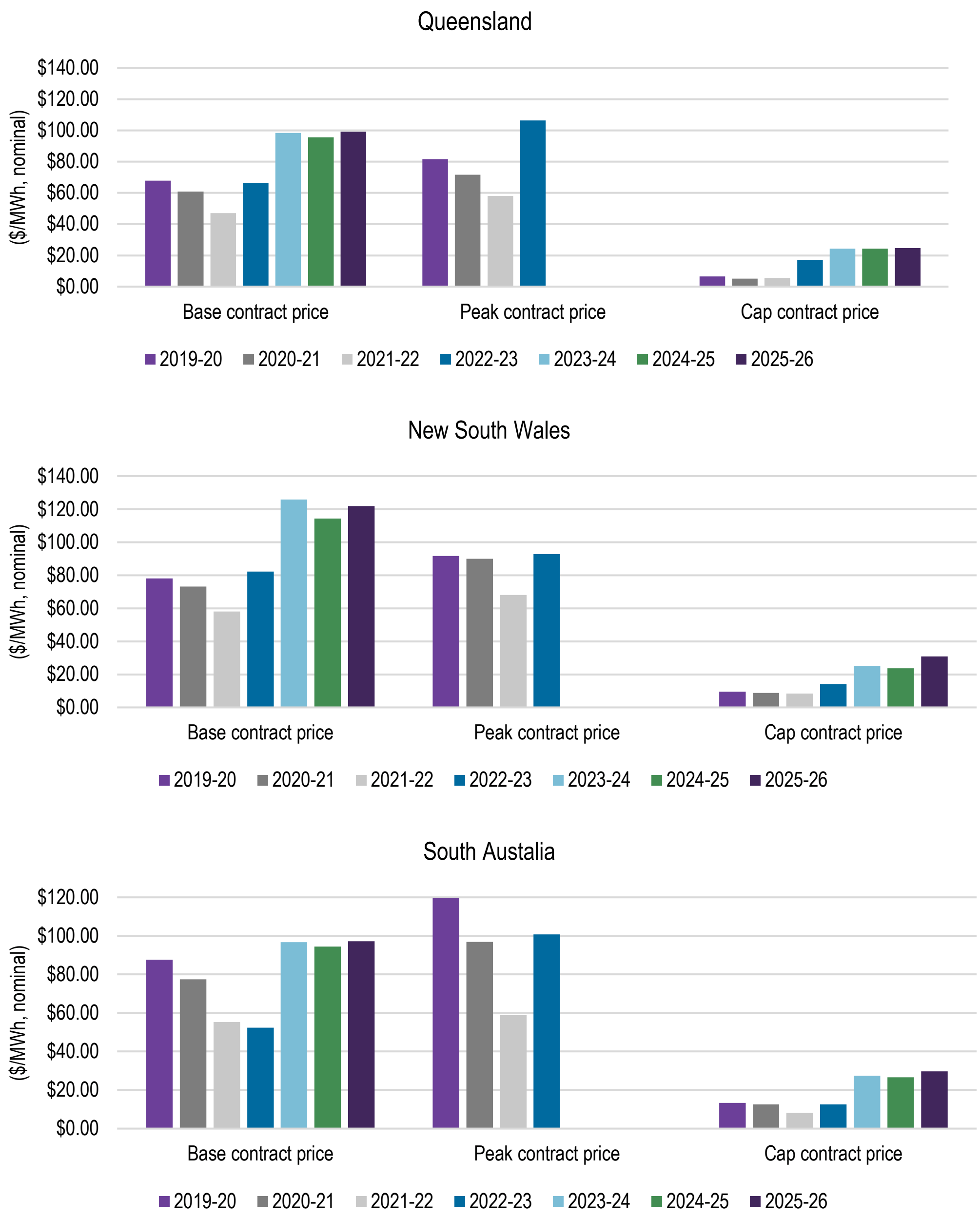
— Futures base contract prices for 2025-26 on an annualised and trade weighted basis to date, have:
  – increased by about $3.50/MWh for Queensland
  – increased by about $7.70/MWh for New South Wales
  – increased by about $2.80/MWh for South Australia.
— Cap contract prices for 2025-26 on an annualised and trade weighted basis to date, have:
  – increased by about $0.30/MWh for Queensland
  – increased by about $7.20/MWh for New South Wales
  – increased by about $3.20/MWh for South Australia.

In New South Wales and South Australia, the base and cap contract prices have increased by a similar value – suggesting the market is expecting the majority of the overall price change between 2024-25 and 2025-26 to be driven by an increase in price volatility.

In previous determinations, we have noted that the cost of hedging the NSLP and small interval meter load is exacerbated by the expected continued uptake of rooftop PV carving out the system demand during daylight hours, coupled with the commissioning of utility scale solar. This continues to be the case for the 2025-26 determination, but it is worth noting that over the next 12-18 months about 7 GW of utility scale storage capacity is committed to enter the market. This additional storage capacity will soak up excess solar generation during daylight hours, so it is likely that there may be a stabilisation in price outcomes during daylight hours, rather than a continued increase I the propensity for negative price outcomes that has been observed over the past few years.

Regardless, low spot price outcomes occurring during daylight hours - much less than the base contact price, means that the retailer will need to pay its contract counterparty for the difference between the base contract price and the very low spot price when it is over hedged.

Figure 4.5 Base, and Cap trade weighted average contract prices ($/MWh, nominal) – 2019-20 to 2025-26



Source: ACIL Allen analysis of ASX Energy Data

4.2 Estimation of the Wholesale Energy Cost

Estimating contract prices

Contract prices for the 2025-26 year were estimated using the trade-weighted average of ASX Energy settlement prices of individual trades of contracts and exercised base options (including the trade weighted average premium for exercised and expired base options) since the contract was listed up until 21 February 2025. The inclusion of exercised options' strike prices and option premiums in this determination is a refinement of the methodology and reflects the increasing use of options in the futures market over the past 2 to 3 years.

Table 4.1 to Table 4.3 show the estimated quarterly base and cap contract prices for 2025-26.

Table 4.1 Estimated contract prices ($/MWh, nominal) - Queensland

	Q3	Q4	Q1	Q2
2024-25				
Base	$96.17	$87.24	$111.73	$87.71
Cap	$18.60	$20.17	$39.48	$19.42
2025-26				
Base	$96.42	$89.46	$119.36	$91.67
Cap	$18.88	$20.12	$42.02	$18.01
Percentage change from 2024-25 to 2025-26				
Base	0%	3%	7%	5%
Cap	2%	0%	6%	-7%

Source: ACIL Allen analysis using ASX Energy data

Table 4.2 Estimated contract prices ($/MWh, nominal) – New South Wales

	Q3	Q4	Q1	Q2
2024-25				
Base	$127.09	$98.48	$115.79	$115.81
Cap	$20.84	$17.78	$34.28	$22.16
2025-26				
Base	$125.39	$108.42	$126.28	$127.82
Cap	$27.69	$25.05	$42.58	$28.64
Percentage change from 2024-25 to 2025-26				
Base	-1%	10%	9%	10%
Cap	33%	41%	24%	29%

Source: ACIL Allen analysis using ASX Energy data

Table 4.3 Estimated contract prices ($/MWh, nominal) – South Australia

	Q3	Q4	Q1	Q2
2024-25				
Base	$101.79	$68.60	$105.49	$102.16
Cap	$20.68	$16.60	$45.66	$23.91
2025-26				
Base	$110.94	$68.81	$98.27	$111.24
Cap	$25.80	$20.95	$47.91	$24.78
Percentage change from 2024-25 to 2025-26				
Base	9%	0%	-7%	9%
Cap	25%	26%	5%	4%

Source: ACIL Allen analysis using ASX Energy data

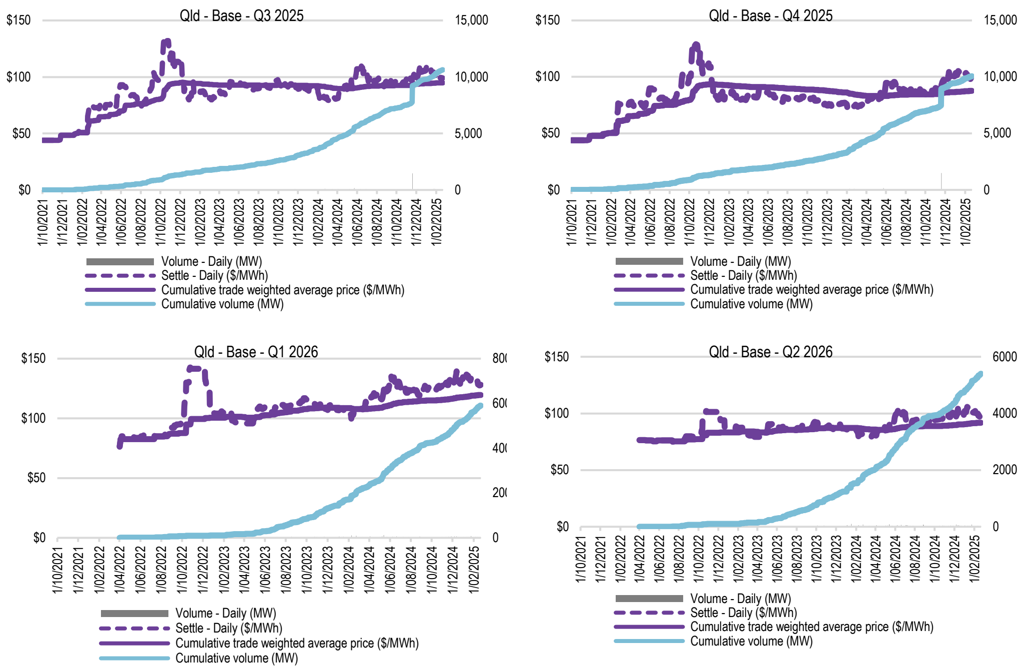
The following charts show daily settlement prices and trade volumes for 2025-26 ASX Energy quarterly base and cap futures contracts up to 21 February 2025. It can be seen that the trading of these contracts tends to commence from mid to late 2022. That said, the volume of trades prior to 2023 is minimal, representing less than 25 percent of all trades to date (and for some products less than 10 per cent).

There is no trade in peak contracts which is not surprising given the carve out of demand during daylight hours. The traditional definition of the peak period (7am to 10pm weekdays) appears to be no longer relevant to market participants when considering managing spot price risk. Hence peak contracts are excluded from the analysis and are assumed not to contribute to the hedge portfolio, as per DMO 4 to 6.

There was a temporary spike in contract prices in 2022 due to the energy market crisis at the time, prior to the Government's intervention in late 2022. However, very few trades for 2025-26 occurred during this period.

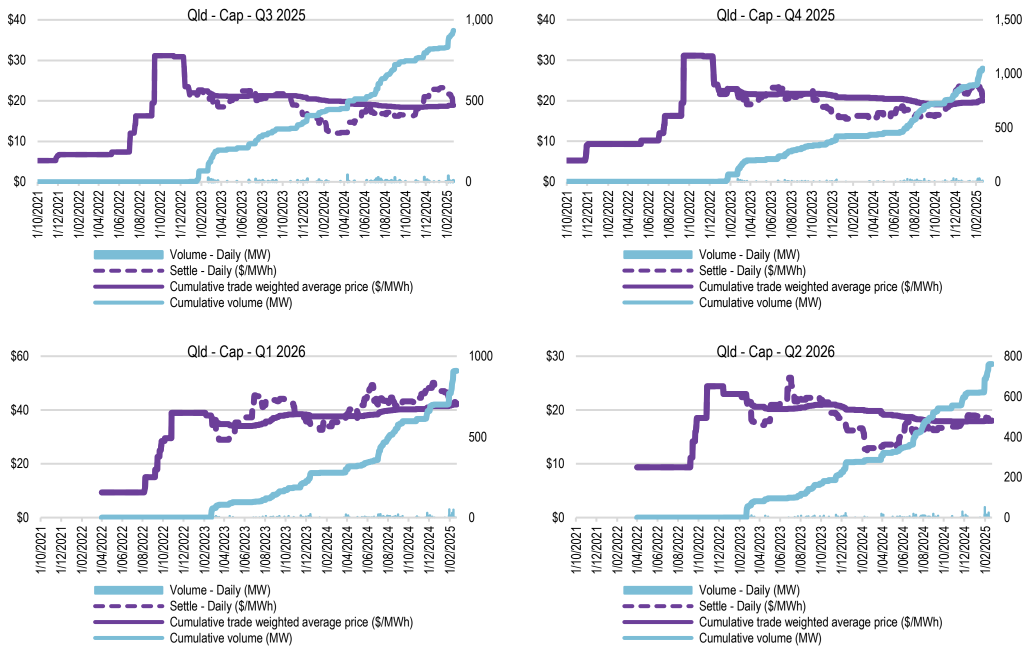
Contract prices tended to increase in mid-2024 – corresponding with the increase in LNG prices as shown in Figure 4.12.

Figure 4.6 Time series of trade volume and price – ASX Energy base futures - Queensland



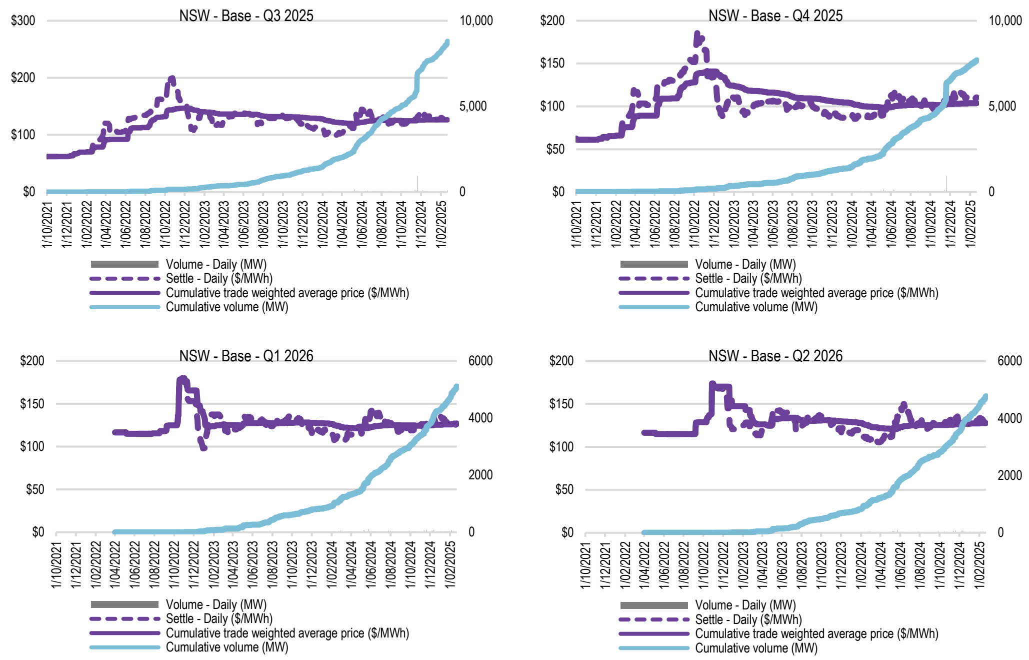
Source: ACIL Allen analysis using ASX Energy data

Figure 4.7 Time series of trade volume and price – ASX Energy $300 cap futures - Queensland



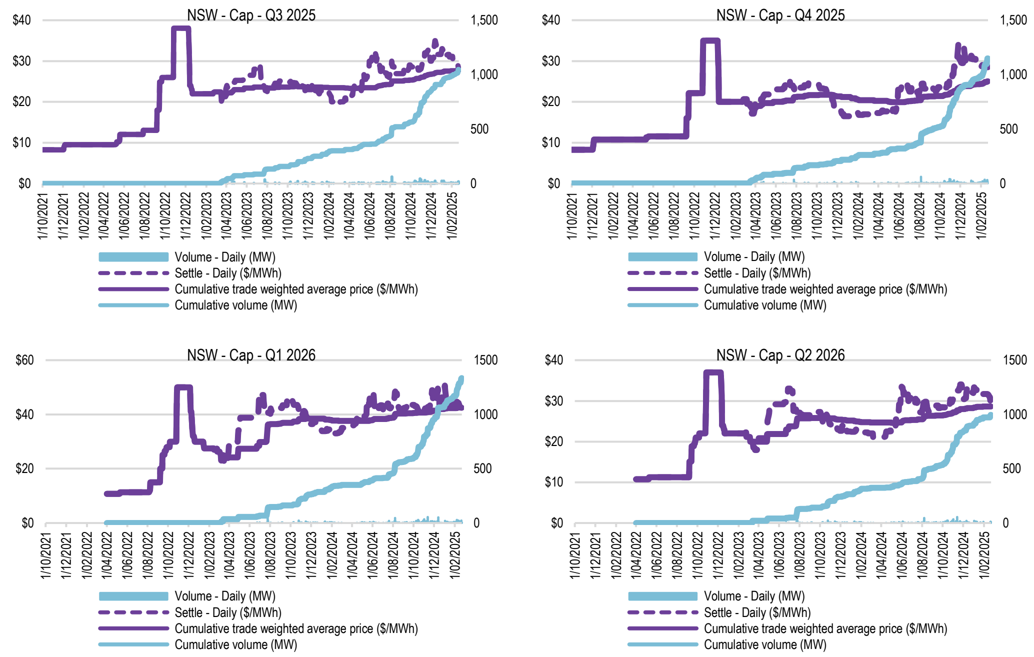
Source: ACIL Allen analysis using ASX Energy data

Figure 4.8 Time series of trade volume and price – ASX Energy base futures – New South Wales



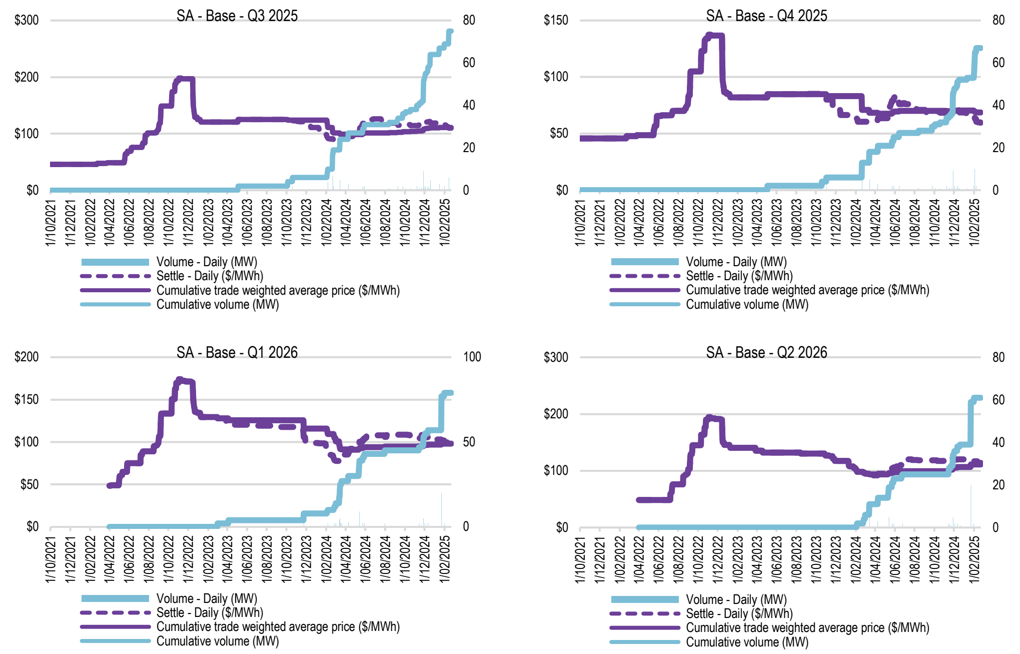
Source: ACIL Allen analysis using ASX Energy data

Figure 4.9 Time series of trade volume and price – ASX Energy $300 cap futures – New South Wales



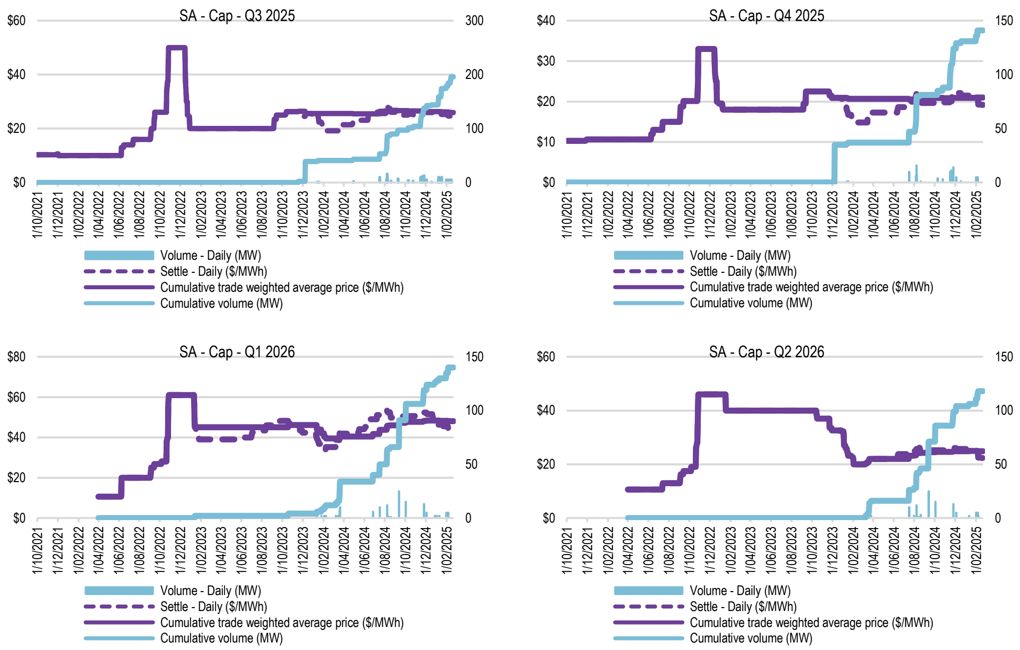
Source: ACIL Allen analysis using ASX Energy data

Figure 4.10 Time series of trade volume and price – ASX Energy base futures –South Australia



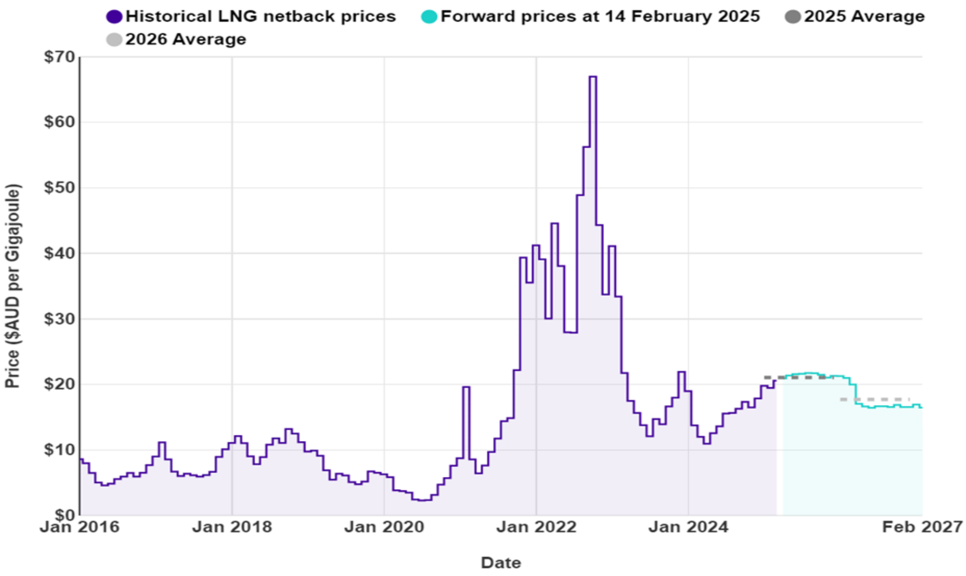
Source: ACIL Allen analysis using ASX Energy data

Figure 4.11 Time series of trade volume and price – ASX Energy $300 cap futures – South Australia



Source: ACIL Allen analysis using ASX Energy data

Figure 4.12 LNG netback prices



Source: ACCC (https://www.accc.gov.au/inquiries-and-consultations/gas-inquiry-2017-30/lng-netback-price-series)

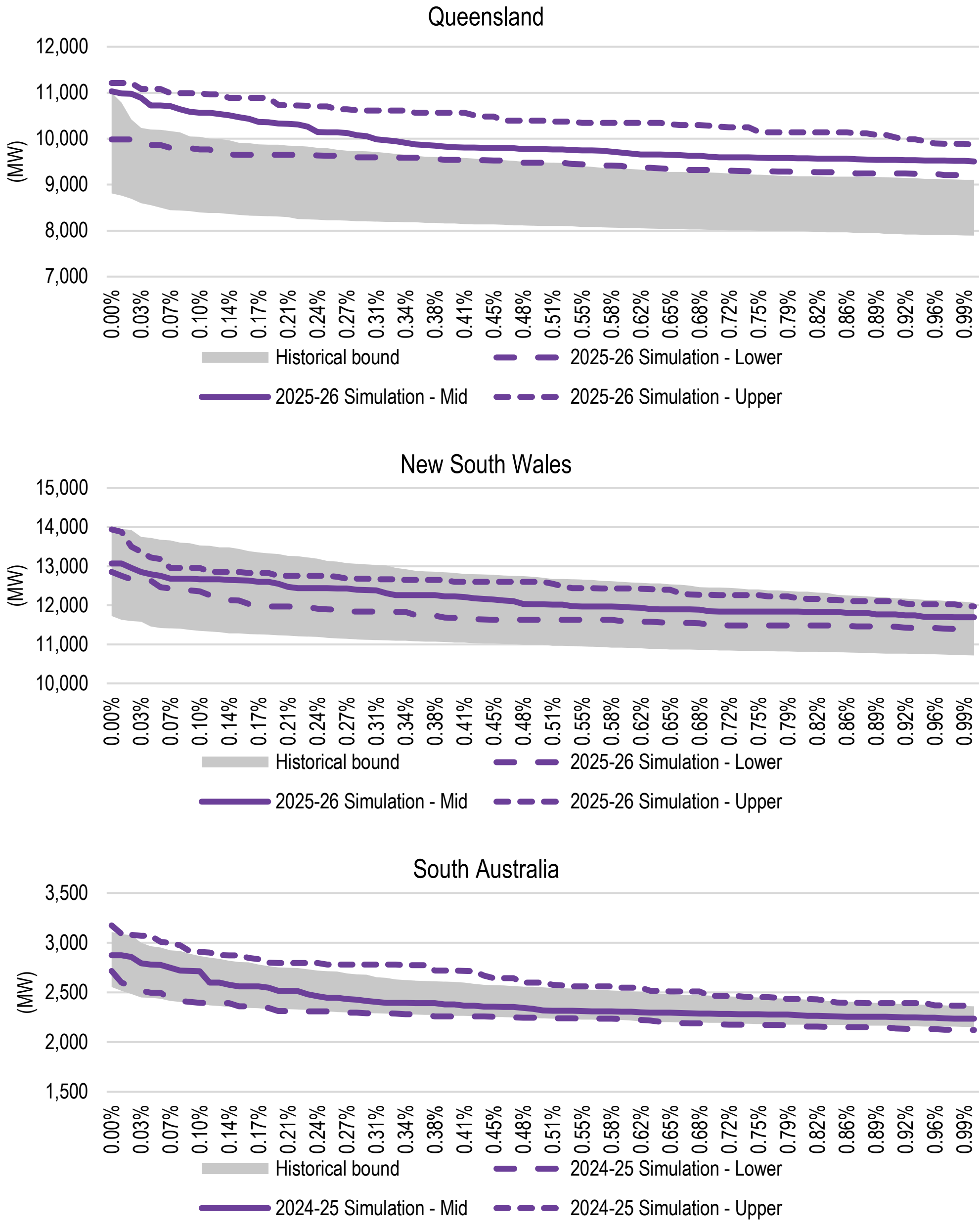
Estimating wholesale spot prices

ACIL Allen's proprietary electricity model, *PowerMark* was run to estimate the hourly regional wholesale spot prices for the 594 simulations (54 demand and 11 outage sets).

Figure 4.13 shows the range of the upper one percent segment of the demand duration curves for the 54 simulated Queensland, New South Wales and South Australia regional system demand sets resulting from the methodology for 2025-26, along with the range in historical demands since 2014-15. The simulated demand curves in the charts represent the upper, lower, and middle of the range of demand duration curves across all 54 simulated sets. It can be seen that the demand duration curves of the simulated demand sets for 2025-26 have a variation similar to that observed over the past five years - that is, the variation between the simulated demand sets does not just occur at the single peak annual demand but across a reasonable portion of the demands within the given simulation. This variation in demand contributes to the variation in modelled pool price outcomes as discussed further in this section.

We do not expect the simulated demand sets to line up perfectly with the historical demand sets, in terms of their absolute location. For example, the simulated demand sets for 2025-26 are generally higher than the pre-2016-17 observed demand outcomes in Queensland due to the step increase in demand due to the in-field compression associated with the LNG export projects in Gladstone. Further, the demand forecast for 2025-26 from AEMO's ESOO/ISP includes some growth due to the commencement of electrification in some sectors of the economy. What is important, is that the range in simulated outcomes reflects the range experienced in the past, indicating that the methodology is accounting for an appropriate degree of uncertainty.

Figure 4.13 Comparison of upper one per cent of hourly regional system demands of 2025-26 simulated hourly demand sets with historical outcomes



Source: ACIL Allen analysis and AEMO data

Figure 4.14 shows the range of the simulated NSLP and interval meter imports envelope recent actual outcomes. This variation results in the annual load factor[12] of the 2025-26 simulated demand sets ranging between:

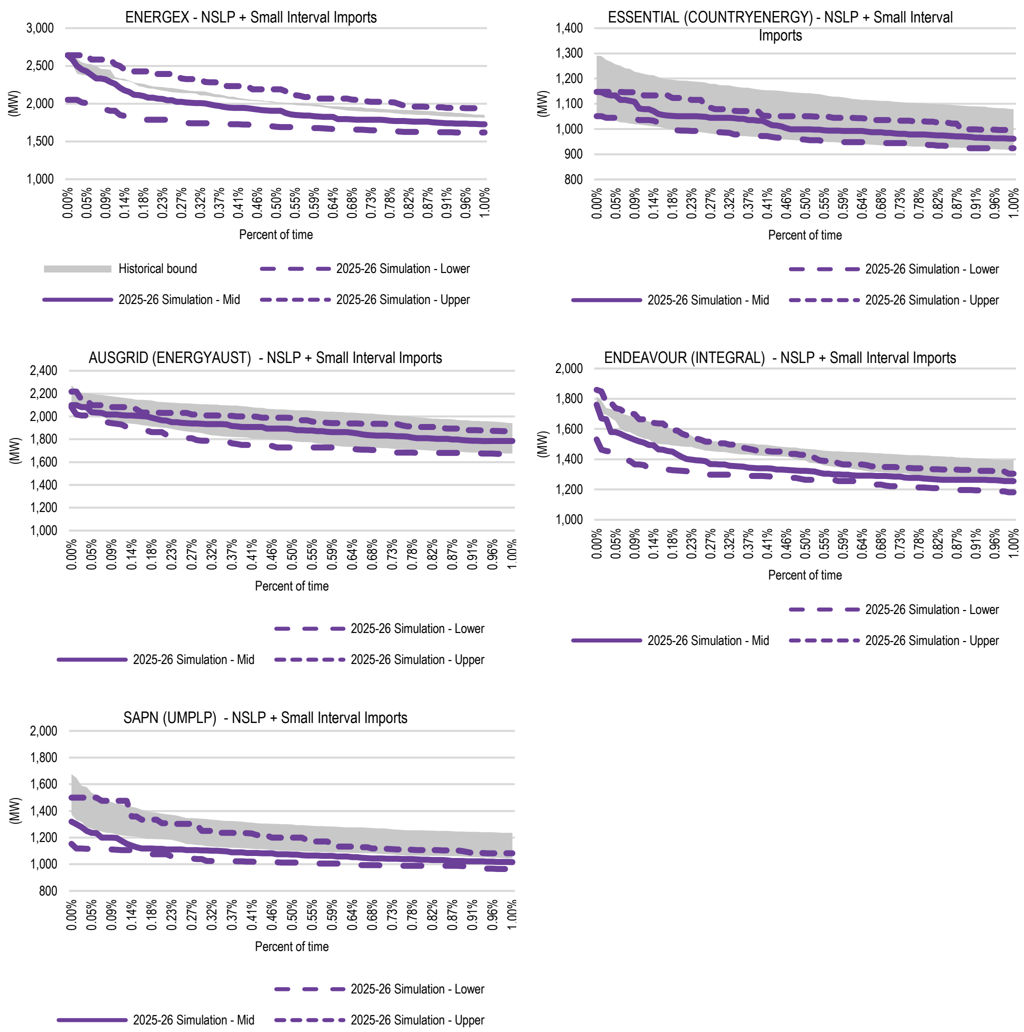
— 28 per cent and 36 per cent compared with a range of 28 per cent to 31 per cent for the actual Energex NSLP and small customer interval meter demands (as shown in Figure 4.15)

[12] The load factor is a measure of the peakiness in the half hourly load profile across a given period of time. The annual load factor is the average of the half hourly loads for the given year divided by the maximum of the half hourly loads for that same given year.

- 40 per cent and 45 per cent compared with a range of 39 per cent to 44 per cent for the actual Essential NSLP and small customer interval meter demands
- 38 per cent and 42 per cent compared with a range of 38 per cent to 42 per cent for the actual Ausgrid NSLP and small customer interval meter demands
- 32 per cent and 38 per cent compared with a range of 32 per cent to 37 per cent for the actual Endeavour NSLP and small customer interval meter demands
- 25 per cent and 34 per cent compared with a range of 28 per cent to 33 per cent for the actual SAPN NSLP and small customer interval meter demands.

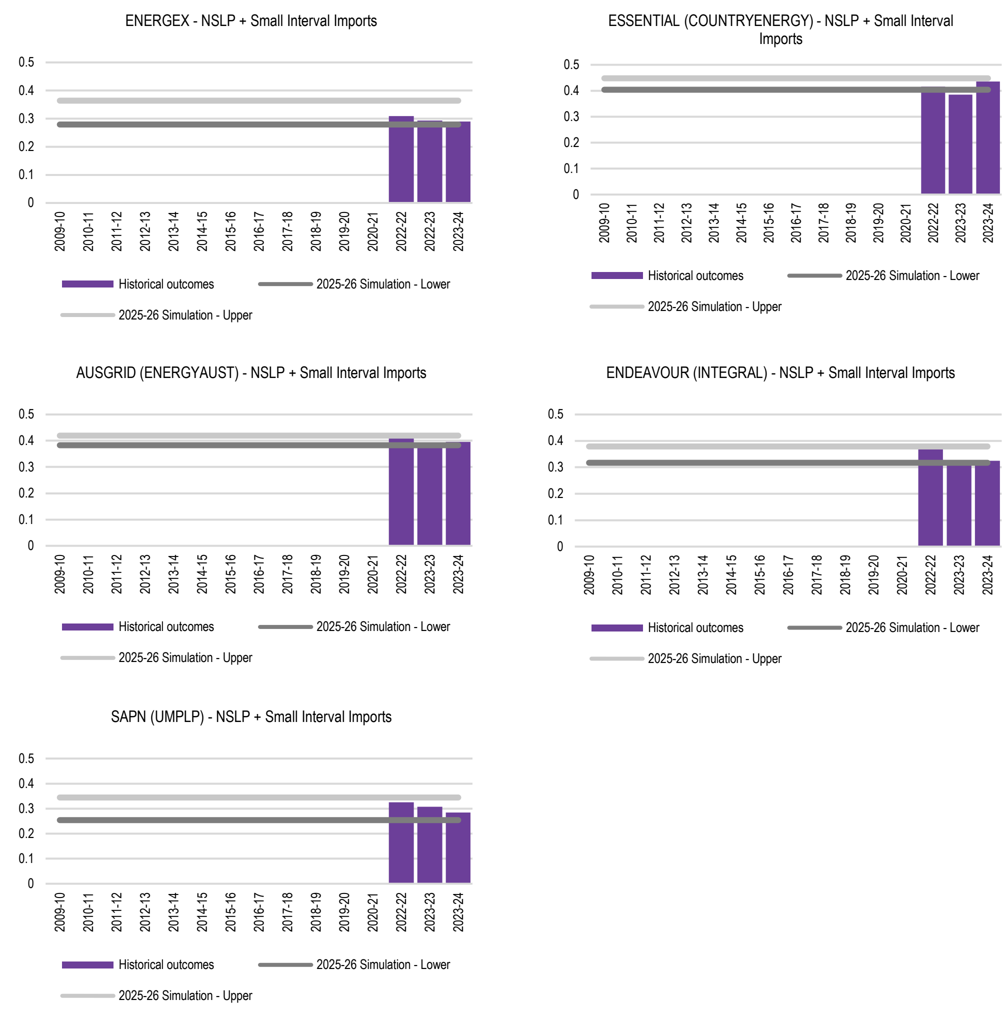
All other things being equal, an increased peakiness of the load, which is hedged under the methodology, is likely to result in a larger degree of over hedging across the general day-time peak periods, resulting in a larger degree of over hedging overall on an annual basis, which means estimated hedging costs will increase. And the converse also holds.

Figure 4.14 Comparison of upper one per cent of hourly NSLP and small interval meter import demands of 2025-26 simulated hourly demand sets with historical outcomes



Source: ACIL Allen analysis and AEMO data

Figure 4.15 Comparison of load factor of 2025-26 simulated hourly demand sets with historical outcomes – NSLP and small interval meter import demand



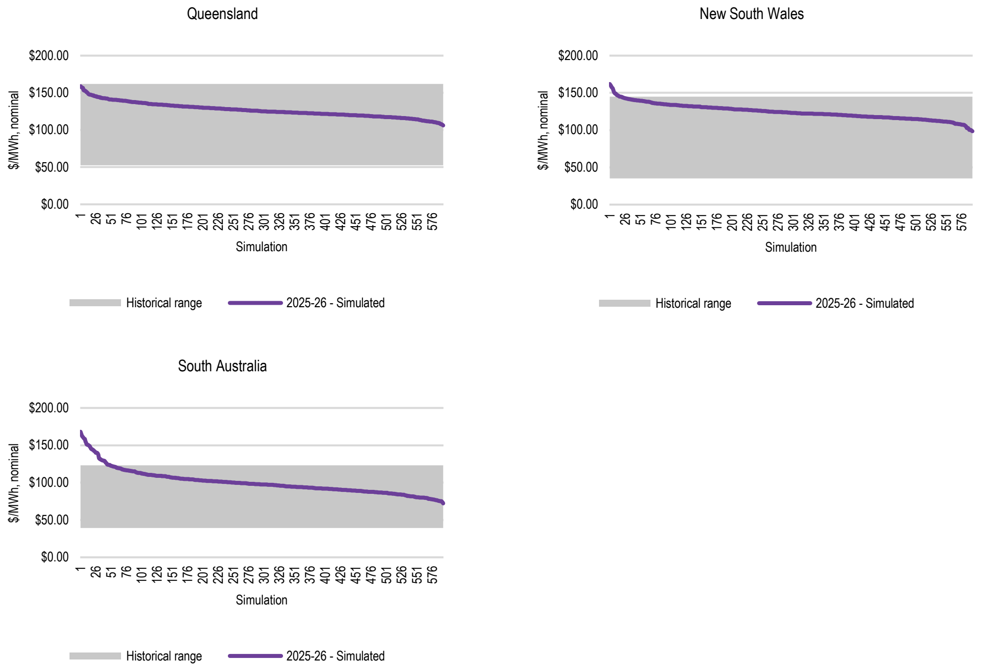
Note: Based on data available for October 2021 to June 2024.

Source: ACIL Allen analysis and AEMO data

Figure 4.16 compares the modelled annual regional TWP for the 594 simulations for 2025-26 with the regional TWPs from the past 10 years. Although there have been changes to both the supply and demand side of the market, the graph clearly shows that the simulations cover a wide range in potential annual price outcomes for 2025-26 when compared with the past 10 years of history.

It is worth noting that the simulations project larger range in annual average spot price outcomes in South Australia for 2025-26 compared with history. This is due to the recent commencement of stage 1 of Project Energy Connect (PEC) – an interconnector directly linking the South Australian and New South Wales markets for the first time since the NEM's inception. The inclusion of PEC will influence a harmonisation of price outcomes between the two regions - that is the price outcomes in South Australia will be influenced by market conditions in New South Wales and Victoria directly, rather than by Victoria only.

Figure 4.16 Simulated annual TWP for Queensland, New South Wales, and South Australia for 2025-26 compared with range of actual annual outcomes in past years

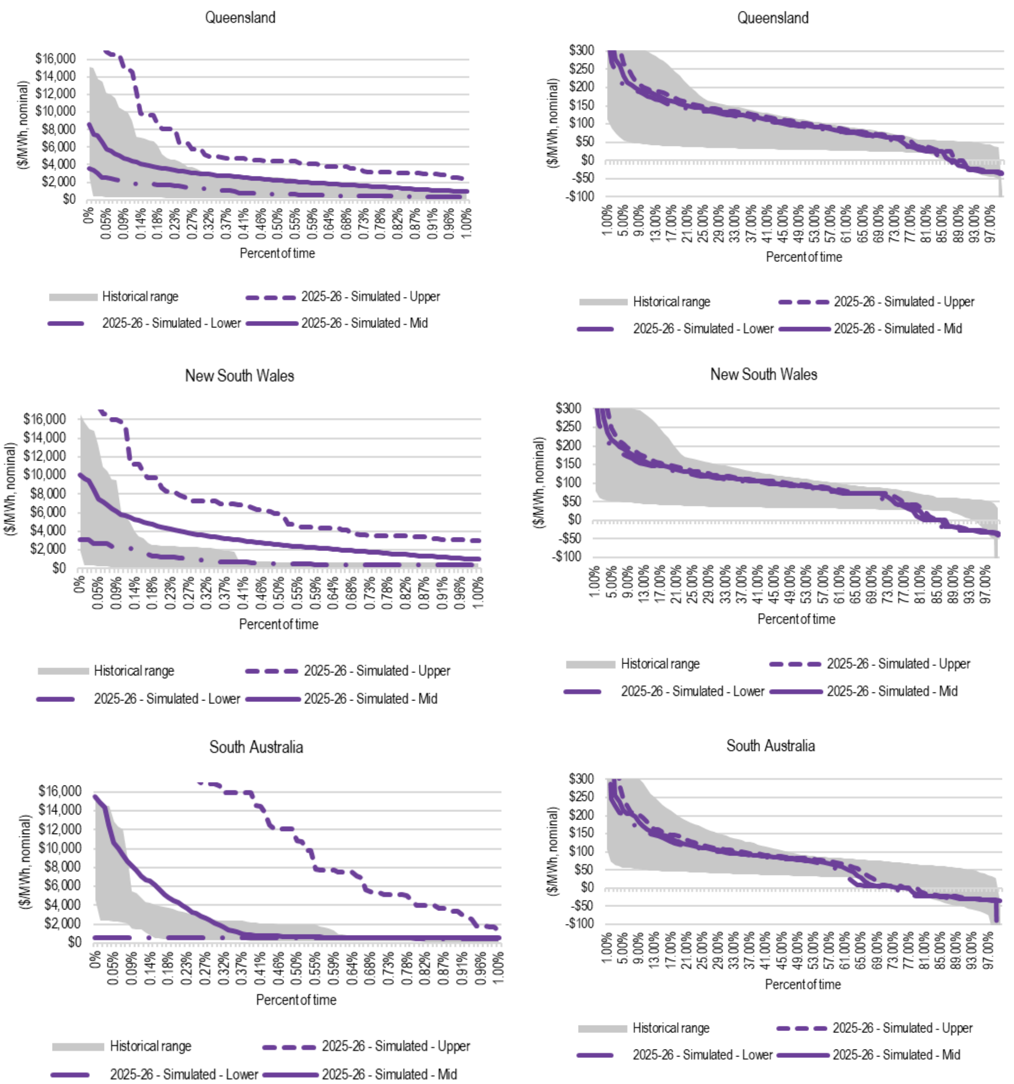


Source: ACIL Allen analysis and AEMO data

Comparing the upper one percent of hourly prices in the simulations with historical spot prices shows the spread of the hourly prices from the simulations also more than adequately covers the historical spread of spot prices, as shown in the left panel of Figure 4.17. It is also notable, that as would be expected, the distribution of simulated price outcomes demonstrates a strong positive skewness. The right panel of Figure 4.17 also shows the increase in propensity for hourly prices to settle at $0/MWh or lower as a result of the continued uptake of rooftop PV, as well as the commissioning of utility scale solar projects.

The variation in the simulated hourly price duration curves in the right panels of Figure 4.17 is less than observed over the past 10 years. This is due to a single assumption of fuel prices adopted in the simulations, whereas the historical data will reflect changes in fuel prices over time.

Figure 4.17 Comparison of simulated hourly price duration curves for Queensland, New South Wales, and South Australia for 2025-26 and range of actual outcomes in past years

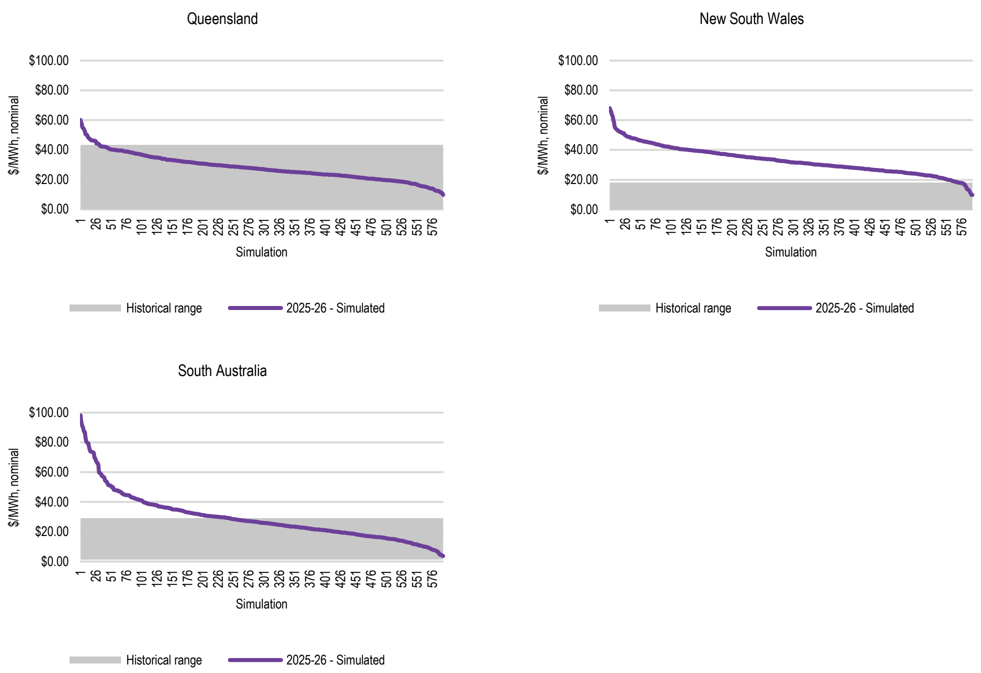


Note: Graphs in left column show upper one per cent of price outcomes; graphs in right column show lower 99 per cent of price outcomes.

Source: ACIL Allen analysis and AEMO data

ACIL Allen is satisfied that *PowerMark* has performed adequately in capturing the extent and level of high price events based on the demand and outage inputs for the 594 simulations. The range in annual average contribution to the TWP, of hourly prices above $300/MWh, for the 594 simulations is consistent with those recorded in history as shown in Figure 4.18. For some of the 2025-26 simulations the contribution of price spikes is greater than historical levels, reflecting the greater variability in thermal power station availability, the commissioning of further utility scale variable renewable power stations, continued high gas prices, and the general tightening of the demand-supply balance in the market during the evening peak.

Figure 4.18 Annual average contribution to the Queensland, New South Wales, and South Australia TWP by prices above $300/MWh in 2025-26 for simulations compared with range of actual outcomes in past years



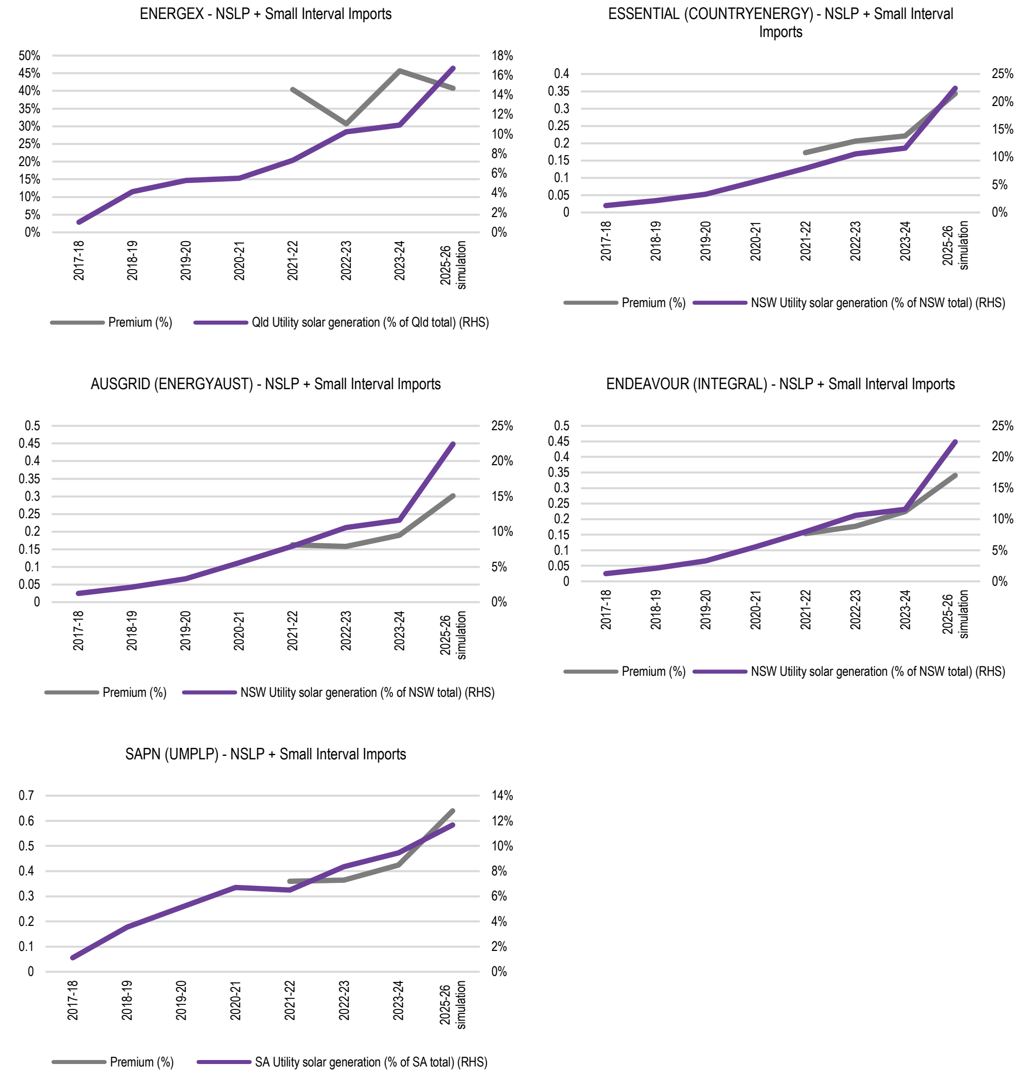
Source: ACIL Allen analysis and AEMO data

The maximum demand of the load profile is not in isolation a critical feature in determining the cost of supply. The shape and volatility of the load profile and its relationship to the shape and volatility of the regional demand/price traces is a critical factor in the cost of supplying the demand.

A test of the appropriateness of the simulated demand shape and its relationship with the regional demand shape can be undertaken by comparing the annual demand weighted price (DWP) for the given demand profile with the corresponding regional TWP. Figure 4.19 shows that, for the past three financial years, the DWP for NSLP and small interval meter loads as a percentage premium over the corresponding regional TWPs has varied from a low of 15 percent in New South Wales to a high of 45 percent in Queensland. In the 594 simulations for 2025-26 for each NSLP and interval meter demand profile, this percentage varies from 30 percent to 60 percent.

The modelling suggests a greater range and generally higher level in the premium for 2025-26 as a result of greater variability in thermal power station availability and the increasing influence of variability in renewable energy resource availability coupled with a decline in price outcomes during daylight hours, due to the commissioning of utility scale PV, when the NSLP and small interval meter demand is at its lowest. Included in Figure 4.19 is a comparison showing the correlation in the growth in premium over the past few years and the increasing market share of utility scale solar output.

Figure 4.19 Simulated annual DWP for NSLP and Interval meter demand as a percentage premium of annual TWP for 2025-26 compared with range of actual outcomes in past years, and market share of utility scale solar (%)



Source: ACIL Allen

ACIL Allen is satisfied the modelled regional wholesale spot prices from the 594 simulations cover the range of expected price outcomes for 2025-26 across all three regions in terms of annual averages and distributions. These comparisons clearly show that the 54 simulated demand and renewable energy resource traces combined with the 11 thermal power plant outage scenarios provide a sound basis for modelling the expected future range in spot market outcomes for 2025-26.

Applying the hedge model

The hedging methodology uses a simple hedge book approach based on standard quarterly base swaps and cap contracts as a proxy for a retailer's hedging strategy.

Contract volumes for 2025-26 are calculated based on the blended NSLP and interval meter import demand, and including the PV export carve out[13] for each quarter as follows, and are largely unchanged since DMO 3:

— The base contract volume is set to equal the 50th percentile for Energex, Essential, and SAPN, and the 60th percentile for Ausgrid and Integral, of all hourly demands across all 54 demand sets for the quarter.

— The cap contract volume is set at 100 per cent for all profiles, of the median of the annual peak demands across the 54 demand sets minus the base contract volumes.

These same hourly hedge volumes (in MW terms) apply to each of the 54 demand sets for a given NSLP and year, and hence to each of the 594 simulations. To be clear, we are not altering the hedge volume (in MW terms) on an ex-post basis for each of the 54 demand sets. Therefore, the approach we use results in a hedging strategy that does not rely on perfect foresight but relies on an expectation of the distribution of hourly demands across a range of weather-related outcomes.

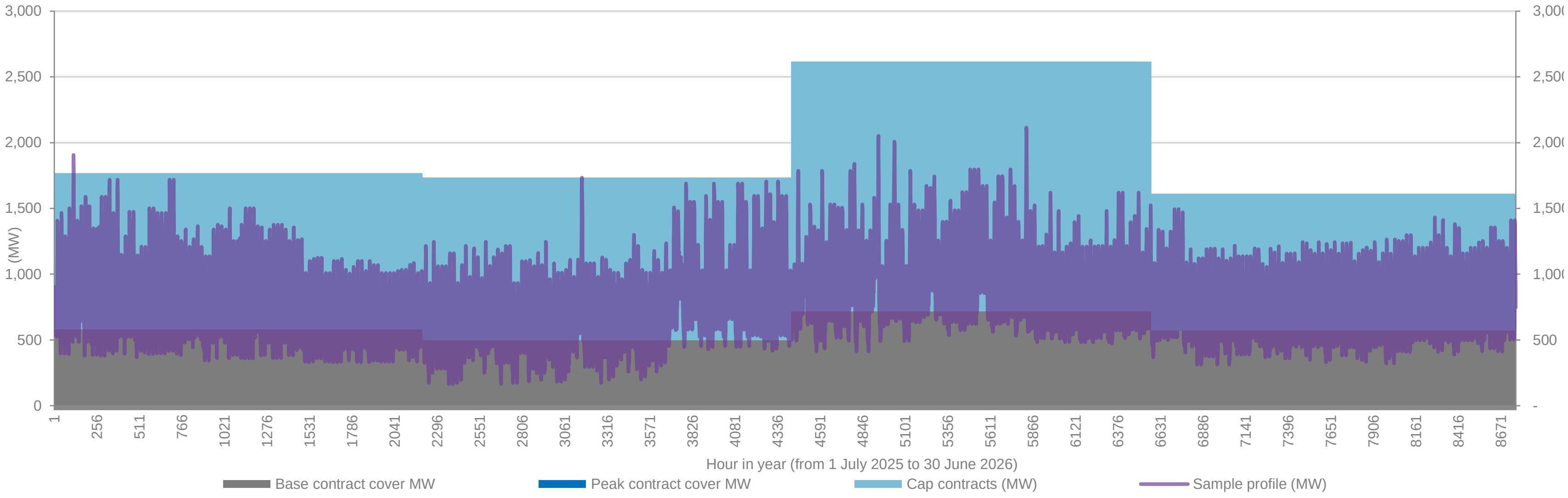
Once established, these contract volumes are then fixed across all 594 simulations when calculating the wholesale energy cost. The contract volumes used are shown in Figure 4.20 to Figure 4.24.

The contracting strategy places no reliance on peak contracts. This is not surprising – the carve out of demand during daylight hours (which makes up a reasonable part of the peak hours on business days), and the corresponding low spot prices during those hours makes the peak contacts generally unappealing. It is during these periods that the load will be over contracted and hence in effect retailers will be selling back to the market the extent of this over contracted position at the much lower spot prices. Further, the strategy's non-reliance on peak contracts matches well with the very small or nil volume of peak contracts traded relative to base contracts in the actual futures market.

The example profile in Figure 4.20 is from a simulation that includes loads above the P50 peak in some cases and hence are not 100 per cent covered by hedge contracts.

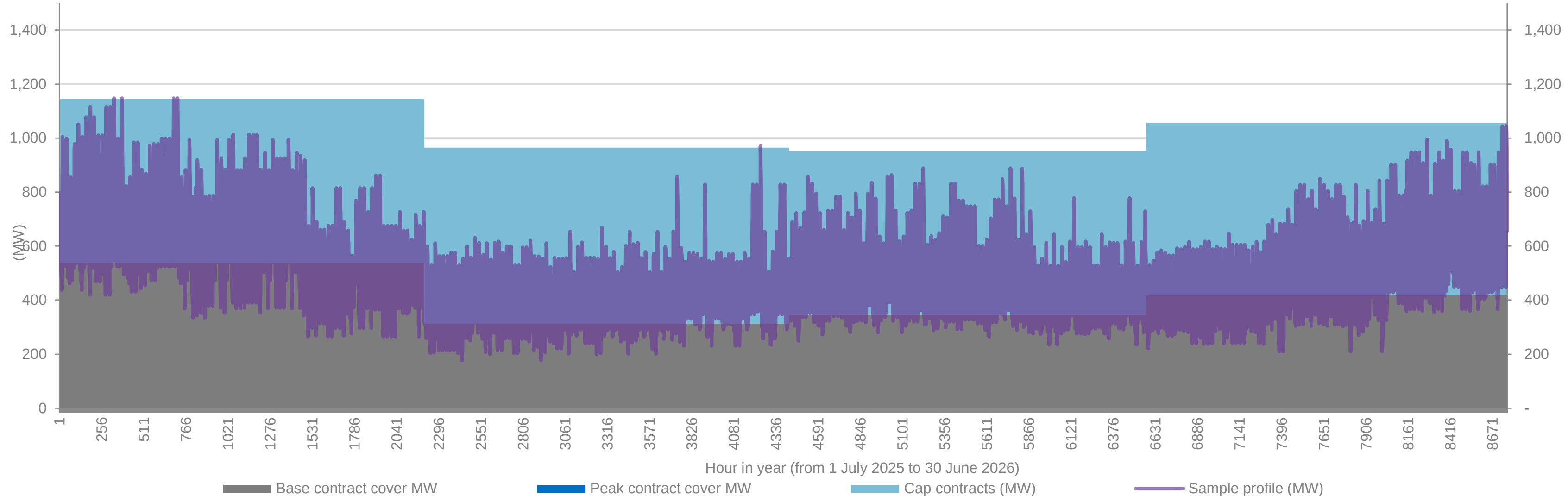
[13] The interval meter PV exports are included in the profiles to estimate the hedging strategy only. Beyond that point of the WEC estimation process, the PV exports are excluded from the profiles.

Figure 4.20 Contract volumes used in hedge modelling of 594 simulations for 2025-26 for Energex



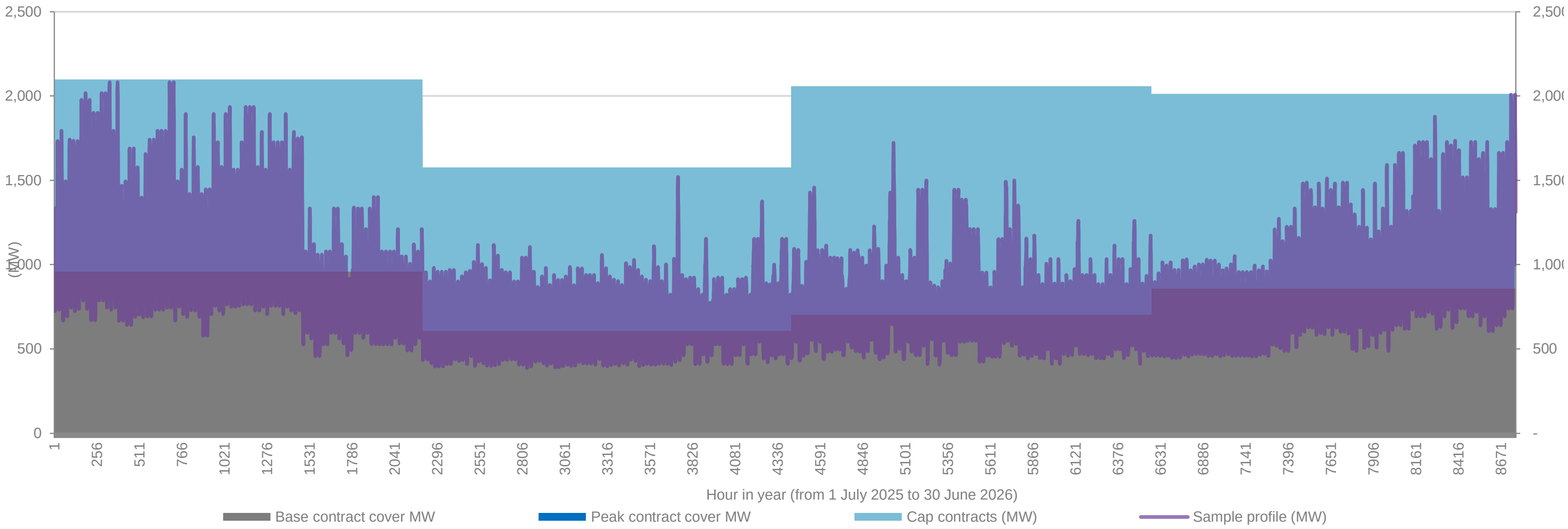
Source: ACIL Allen

Figure 4.21 Contract volumes used in hedge modelling of 594 simulations for 2025-26 for Essential (COUNTRYENERGY)



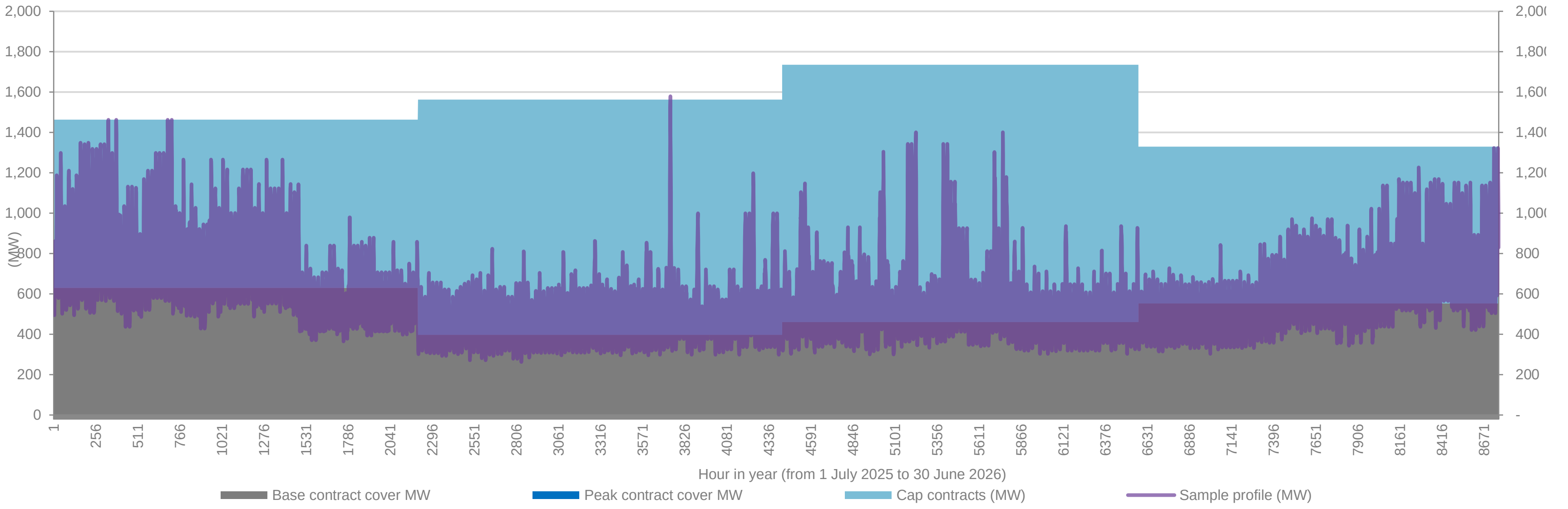
Source: ACIL Allen

Figure 4.22 Contract volumes used in hedge modelling of 594 simulations for 2025-26 for Ausgrid (ENERGYAUST)



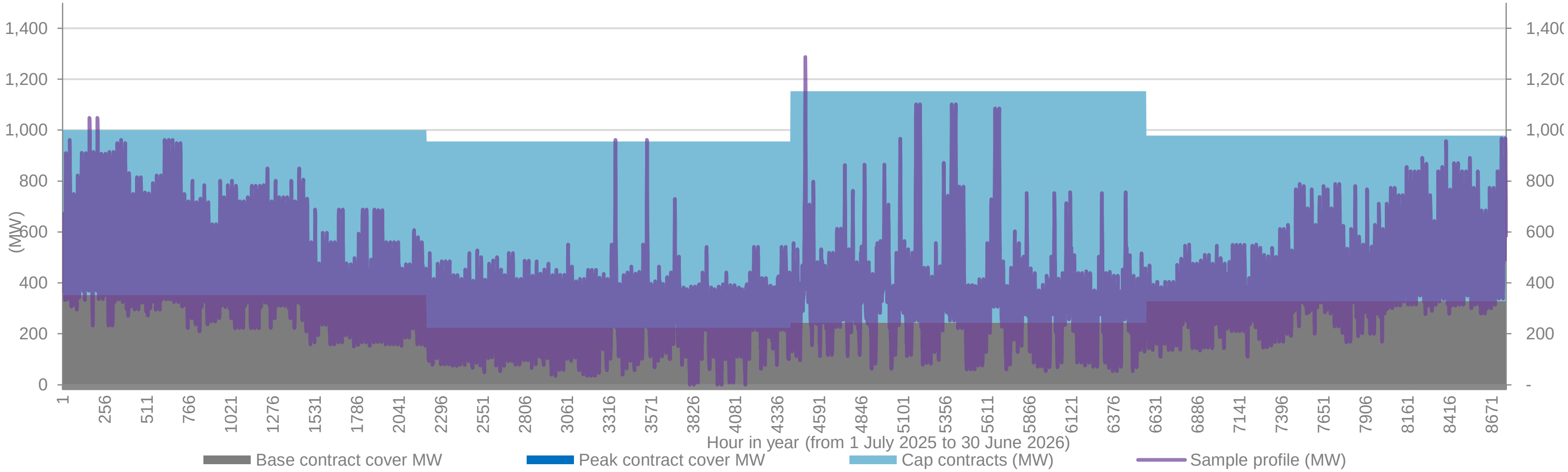
Source: ACIL Allen

Figure 4.23 Contract volumes used in hedge modelling of 594 simulations for 2025-26 for Endeavour (INTEGRAL))



Source: ACIL Allen

Figure 4.24 Contract volumes used in hedge modelling of 594 simulations for 2025-26 for SAPN (UMPLP)

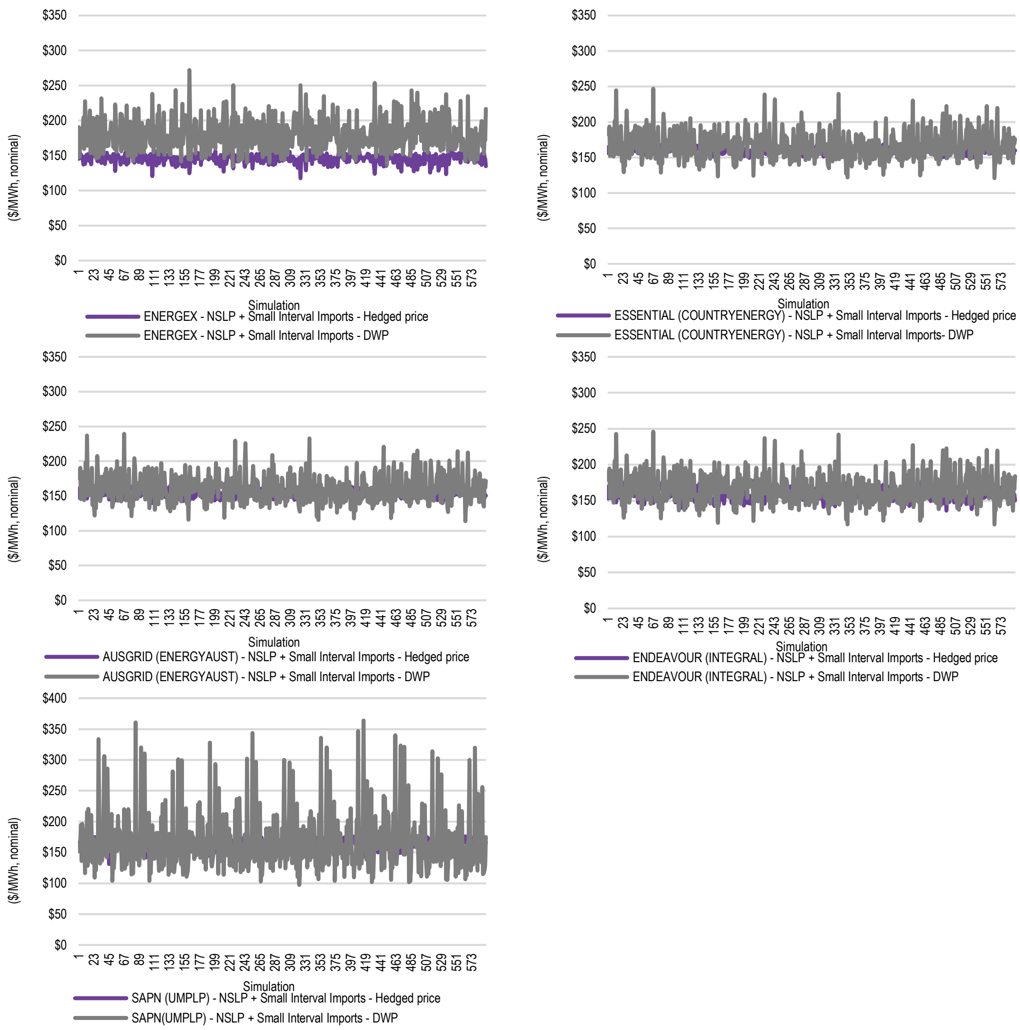


Source: ACIL Allen

Figure 4.25 shows that, by using the above contracting strategies, the variation in the annual hedged price for each demand profile is far less than the variation if the profile was to be supplied without any hedging and relied solely on spot price outcomes.

It is worth noting the hedged price outcomes for the NSLP plus small interval meter load are higher than the spot price outcomes in some of the simulations. This is a result of the trade weighted average contract prices being lower than the spot price simulations, and lower than the current consensus view of outcomes for 2025-26.

Figure 4.25 Annual hedged price and DWP ($/MWh, nominal) for NSLP + small interval meter demands for the 594 simulations – 2025-26



Source: ACIL Allen

Summary of estimated Wholesale Energy Cost

After applying the hedge model, the final WEC estimate is taken as the 75th percentile of the distribution containing 594 WECs (the annual hedged prices). ACIL Allen's estimate of the WEC for each demand profile for 2025-26 are shown in Table 4.4 and compared to the WEC estimates in the 2024-25 Final Determination.

Table 4.4 Estimated WEC ($/MWh, nominal) for 2025-26 at the regional reference node

Settlement class	2024-25 – Final Determination	2025-26 – Draft Determination	Change from 2024-25 to 2025-26 (%)
Ausgrid – Residential and small business	$152.73	$159.26	4.28%
Endeavour - Residential and small business	$161.28	$165.56	2.65%
Essential - Residential and small business	$155.41	$163.57	5.25%
Ausgrid - CLP1	$98.37	$114.50	16.40%
Ausgrid - CLP2	$98.23	$112.83	14.86%
Endeavour - CLP	$99.07	$117.30	18.40%
Essential - CLP	$98.34	$114.47	16.40%
Energex - Residential and small business	$160.64	$151.68	-5.58%
Energex – CLP31	$93.98	$101.16	7.64%
Energex – CLP33	$101.83	$107.56	5.63%
SAPN - Residential and small business	$163.60	$168.84	3.20%
SAPN - CLP	$89.89	$101.55	12.97%

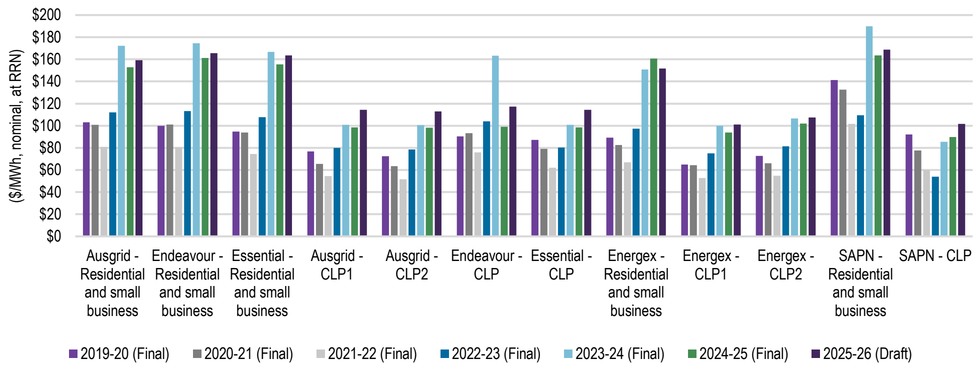
Source: ACIL Allen

The 2025-26 WECs for the NSLP plus small interval meter import demands increase by between 2.7 and 5.3 per cent in New South Wales, decrease by about 5.6 per cent in Queensland and increase by about 3.2 per cent in South Australia compared with 2024-25 – reflecting the slight increase or stabilising in contracts prices, and the continued decline in spot prices during daylight hours when demand is at its lowest point and hence over contracted. The WEC in Queensland decreases due to the slight flattening out of the demand profile and a higher reliance on caps which have increased only marginally in price compared with the other states.

The WEC for each profile is unlikely to change by the same amount between determinations – whether in dollar or percentage terms – due to their different demand shapes and differences in how the demand shapes and spot price shapes are changing over time.

Figure 4.26 shows the trend in WEC over the past DMO determinations.

Figure 4.26 Estimated WEC ($/MWh, nominal) for 2025-26 at the regional reference node in comparison with WECs from previous determinations



Source: ACIL Allen

Do the changes in WEC make intuitive sense?

There has been an increase in wholesale spot prices over the past 12 months, and this generally aligns with the trend in the estimated WECs. However, the WEC for the Energex NSLP and small interval meter import demand has decreased slightly.

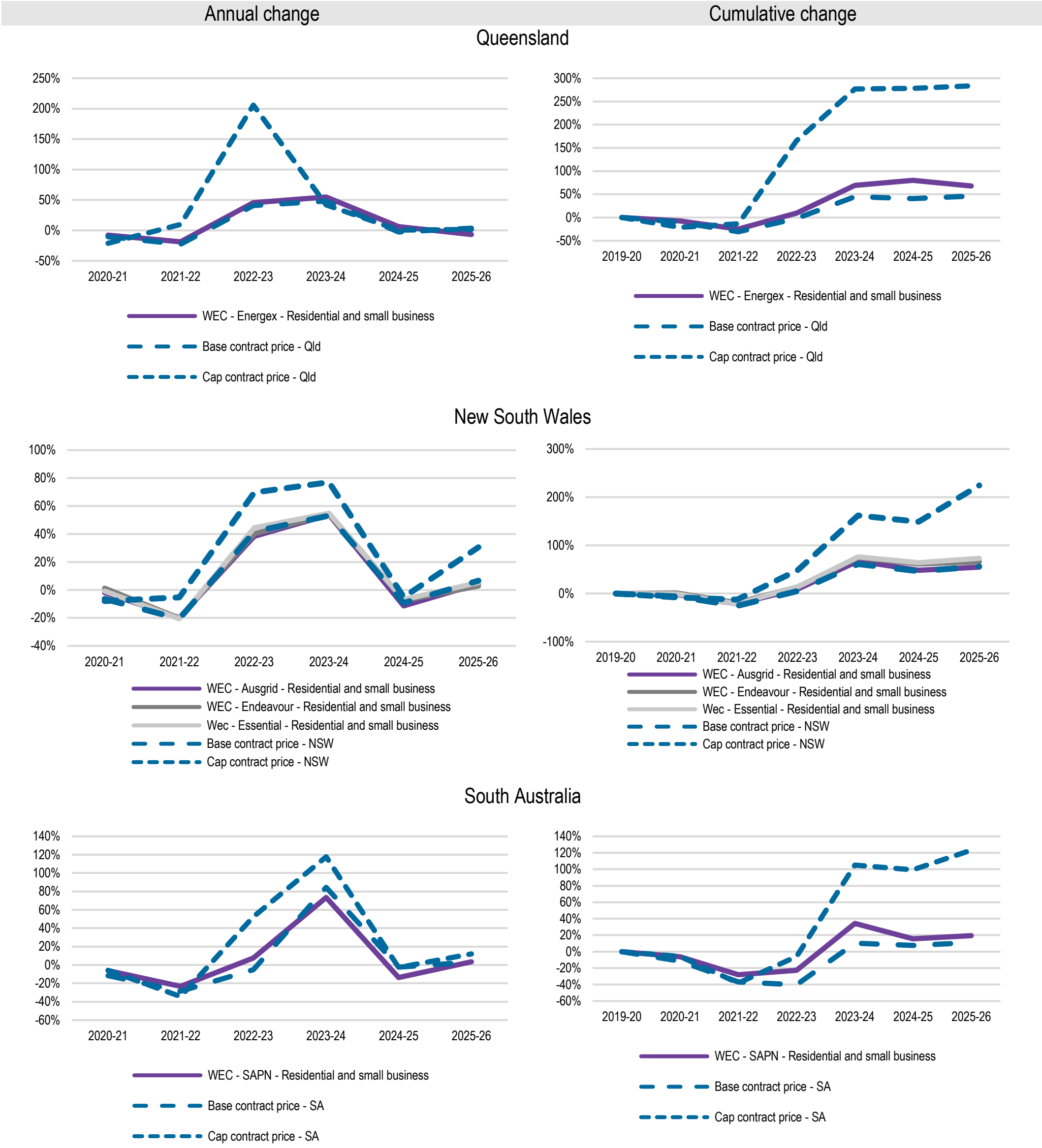
Hence the estimated WECs warrant further investigation to ensure the estimated changes align with what is observed in the market. The charts below plot the changes in WECs and trade weighted contract prices from this Determination together with previous final determinations.

The charts in the left column plot the annual change, and the chart in the right column plot the cumulative change since 2019-20 (using 2019-20 as the base observation). Key features of the charts are:

— Overall, the year-on-year trend in estimated WECs follows the trend in contract prices.
— The trend in WECs aligns very closely to the trend in base contract prices. This is not surprising given the stronger reliance on base contracts in the hedging strategy.
— However, the trend in WEC is also influenced by the change in cap prices. The charts show changes in percentage terms, and given that cap contract prices are lower than base contract prices in dollar terms, it is not surprising that the percentage changes in cap contact prices are larger than changes in the base contract prices and WECs (since they are starting from a lower base).
— There has been no occasion in which the movement in the WEC is at odds with the movement in observable trade weighted average contract prices. The possible exception is the Queensland WEC in 2025-26 – which decreases slightly even though there is a small increase in the trade weighted average base contract prices. This is largely due to the slight flattening of the profile over the past 12-18 months as demonstrated in Figure 4.1 .

On this basis, ACIL Allen is satisfied that the methodology is appropriately estimating the WECs for 2025-26, and that the estimated WECs reflect the consensus view of market conditions for the given determination year in the two to three year period leading up to the time the determination was made – reflecting that retailers build up their hedge book over time, and in the case of 2025-26, purchased hedges in 2023-24 and 2024-25 when the expectation at that time was that prices in 2025-26 were going to remain at elevated levels or even increase slightly.

Figure 4.27 Change in WEC and trade weighted contract prices (%) – 2019-20 to 2025-26



Note: Cumulative change uses 2019-20 as the base observation.

Source: ACIL Allen analysis

4.3 Estimation of renewable energy policy costs

Renewable energy scheme (RET)

The RET scheme consists of two elements – the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). Liable parties (i.e. all electricity retailers[14]) are required to comply and surrender certificates for both LRET and SRES.

Energy costs associated with the LRET and the SRES have been estimated using price information from brokers TraditionAsia, information published by the Clean Energy Regulator (CER) and modelling by ACIL Allen.

Retailer compliance with these schemes operates on a calendar year basis and hence estimates are required for 2025 and 2026 calendar years, with the costs averaged to estimate the 20253-26 financial year costs.

To estimate the costs to retailers of complying with both the LRET and SRES, ACIL Allen uses the following elements:

— historical Large-scale Generation Certificate (LGC) market forward prices for 2025 and 2026 from brokers TraditionAsia
— estimated Renewable Power Percentages (RPP) values for 2025 and 2026 of 17.91 per cent[15]
— binding Small-scale Technology Percentage (STP) value for 2025 of 13.89 per cent, as published by CER
— estimated STP value for 2026 of 11.79 per cent[16]
— CER clearing house price[17] for 2025 and 2026 for Small-scale Technology Certificates (STCs) of $40/MWh.

LRET

To translate the aggregate LRET target for any given year into a mechanism such that liable entities under the scheme may determine how many LGCs they must purchase and acquit, the LRET legislation requires the CER to publish the RPP by 31 March within the compliance year.

The RPP is determined ex-ante by the CER and represents the relevant year's LRET target (in fixed GWh terms) as a percentage of the estimated volume of liable electricity consumption throughout Australia in that year.

The estimated cost of compliance with the LRET scheme is derived by applying the RPP to the determined LGC price to establish the cost per MWh of liable energy supplied to customers. Since the cost is expressed as a cost per MWh, it is applicable across all retail tariffs.

[14] Emissions Intensive Trade Exposed (EITE) industries such as aluminium are wholly or partially exempted and receive Partial Exemption Certificates (PEC) to be surrendered to the named liable entity.

[15] The RPP values for 2025 and 2026 are based on the CER's published RPP for 2025 and assumes no change in liable acquisitions and the CER-published mandated LRET targets for 2025 and 2026.

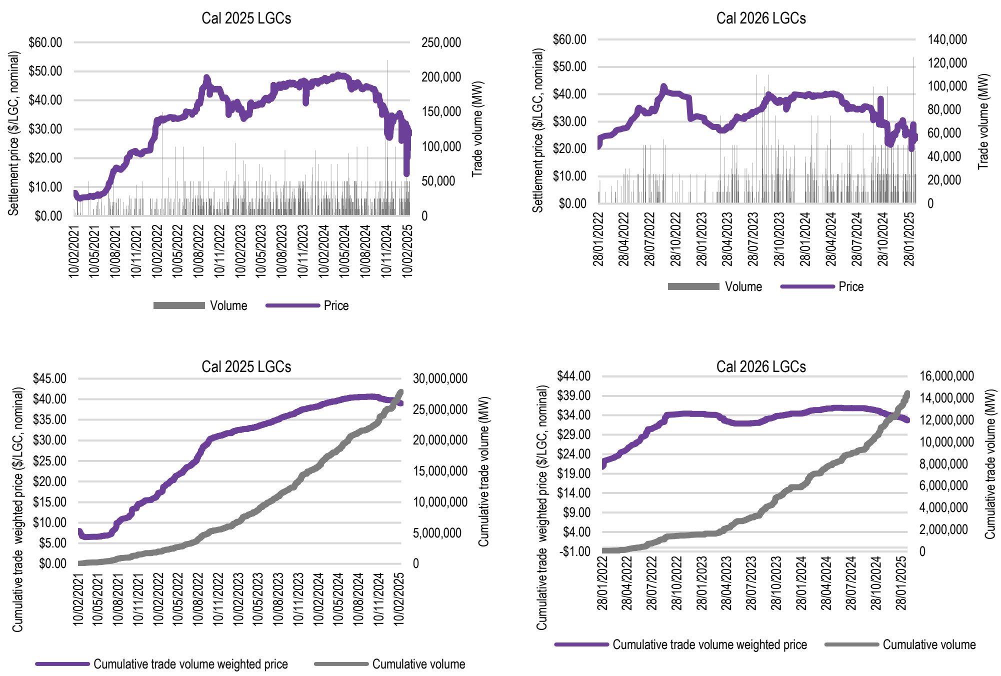
[16] The STP value for 2026 is the CER's published non-binding value and align closely with ACIL Allen's estimate of the non-binding STP based on our engagement with the CER (see https://cer.gov.au/document/stc-modelling-report-acil-allen-august-2024).

[17] Although there is an active market for STCs, ACIL Allen is not compelled to use market prices. This is mainly because historical prices might not be the best indicators of future prices as the market is designed to clear every year – so in theory prices could be $40 or at least very close to it. This assumes that the CER provides an accurate forecast of created certificates underpinning the STP for the next year.

ACIL Allen has estimated the average LGC price using LGC forward prices provided by broker TraditionAsia up to 21 February 2025.

The LGC price used in assessing the cost of the scheme for 2025-26 is found by taking the trade-weighted average of the forward prices for the 2025 and 2026 calendar years, respectively, since the contracts commenced trading. This is typically about 2.5 years prior to the commencement of the compliance year (see Figure 4.28). The average LGC prices calculated from the TraditionAsia data are $38.98/MWh for 2025 and $32.68/MWh for 2026**.**

Figure 4.28 LGC prices and trade volumes for 2025 and 2026 ($/LGC, nominal)



Source: ACIL Allen analysis of TraditionAsia

The RPP value for 2026 is yet to be set by the CER. Therefore, the RPP value for 2026 is estimated by using the mandated target of 33 TWh and the CER's published cumulative adjustment and estimate of electricity acquisitions in 2025 of 178.90 TWh. In other words, ACIL Allen has assumed electricity acquisitions remain constant in 2025 and 2026, and hence the RPP values for 2025 and 2026 are both 17.91 per cent.

Key elements of the 2025 and 2026 RPP estimation are shown in Table 4.5.

Table 4.5 Estimating the 2025 and 2026 RPP values

	2025	2026 (estimate based on 2025 RPP)
LRET target, incl. cumulative adjustment, MWh (CER)	32,049,603	32,049,603
Relevant acquisitions minus exemptions, MWh (CER)	178,900,000	178,900,000
Estimated RPP	17.91%	17.91%

Source: ACIL Allen analysis of CER data

ACIL Allen calculates the cost of complying with the LRET in 2025 and 2026 by multiplying the RPP values for 2025 and 2026 by the trade volume weighted average LGC prices for 2025 and

2026, respectively. The cost of complying with the LRET in 2025-26 was found by averaging the calendar estimates.

Therefore, ACIL Allen estimates the cost of complying with the LRET scheme to be $6.42/MWh in 2025-26 as shown in Table 4.6.

Table 4.6 Estimated cost of LRET – 2025-26

	2025	2026	Cost of LRET 2025-26
RPP %	17.91%	17.91%	
Trade weighted average LGC price ($/LGC, nominal)	$38.98	$32.68	
Cost of LRET ($/MWh, nominal)	$6.98	$5.85	$6.42

Source: ACIL Allen analysis of CER data

SRES

The cost of the SRES is calculated by applying the estimated STP value to the STC price in each compliance (calendar year). The average of these calendar year costs is then used to obtain the estimated costs for 2025-26.

ACIL Allen estimates the cost of complying with SRES to be $5.14/MWh in 2025-26 as set out in Table 4.7.

Table 4.7 Estimated cost of SRES – 2025-26

	2025	2026	Cost of LRET 2025-26
STP %	13.89%	11.79%	
STC clearing house price ($/STC, nominal)	$40.00	$40.00	
Cost of SRES ($/MWh, nominal)	$5.56	$4.72	$5.14

Source: ACIL Allen analysis of CER data

Summary of estimated LRET and SRES costs

Adding these component costs gives a total cost requirement for 2025-26 as set out in Table 4.8.

Since the 2024-25 estimate, the cost of LRET has decreased by around 15 per cent, driven by lower LGC prices for 2025-26, and the cost of SRES has decreased by 35 per cent, driven by the decrease in the STP.

Table 4.8 Total renewable energy policy costs ($/MWh, nominal) – 2025-26

	2024-25	2025-26
LRET	$7.54	$6.42
SRES	$7.85	$5.14
Total	$15.39	$11.56

Source: ACIL Allen analysis of CER data

New South Wales Energy Savings Scheme (ESS)

The Energy Savings Scheme (ESS) is a New South Wales Government program to assist households and businesses reduce their energy consumption. It is a certificate trading scheme in which retailers are required to fund energy efficiency through the purchase of certificates.

To estimate the cost of complying with the ESS, ACIL Allen uses the following elements:

— Energy Savings Scheme Target for 2025 and 2026 of 10.5 and 11 per cent respectively, as published by IPART

— Historical Energy Savings Certificate (ESC) market forward prices for 2025 and 2026 from brokers TraditionAsia.

The cost of the ESS is calculated by applying the estimated ESS target to the ESC price in each compliance (calendar year). The average of these calendar year costs is then used to obtain the estimated costs for 2025-26, as set out in Table 4.9. The 2025-26 estimate of $2.18/MWh is 20 per cent lower than the 2024-25 estimate of $2.71/MWh – reflecting lower certificate prices which more than offset the increase in the ESS target.

Table 4.9 Estimated cost of ESS ($/MWh, nominal) – 2025-26

	2025	2026	Cost of ESS 2025-26
Average ESC price ($/MWh, nominal)	$19.95	$20.57	
ESS target	10.50%	11.00%	
Cost of ESS ($/MWh, nominal)	$2.09	$2.26	$2.18

Source: ACIL Allen analysis of IPART and TFS data

New South Wales Peak Demand Reduction Scheme (PDRS)

To estimate the cost of complying with the PDRS for 2025-26, ACIL Allen has used the following elements:

— The peak demand reduction target for 2025-26 of 5.5 per cent, as published by the New South Wales and Department of Planning, Industry and Environment. Using the New South Wales summer peak demand forecast for 2025-26 of 14,326 MW as published by AEMO in its 2024 ESOO, this equates to 787,909 kW of peak demand reduction.

— The peak demand period for the scheme, which is currently defined as the six-hour period between 2.30pm to 8.30pm AEST.

— A trade volume weighted average PRC price of $2.52 from TraditionAsia.

— The annual energy requirements for New South Wales in 2025-26 of 63,680 GWh as published by AEMO in its ESOO.

The estimated cost of the PDRS for 2025-26 is $1.87/MWh.

Table 4.10 Estimated cost of PDRS ($/MWh, nominal) – 2025-26

Item	Value
PRC price ($/PRC, nominal) per 0.1kW of peak demand reduction capacity averaged across one hour	$2.52
PDRS target (percentage reduction in peak demand)	5.5%
PDRS target (kW reduction in peak demand)	787,909
PRC target (certificates)	47,274,528
Total cost of PDRS ($, nominal)	$119,089,721
Cost of PDRS per certificate ($/PRC, nominal)	$0.83
NSW operational energy requirements (GWh)	63,680
Cost of PDRS ($/MWh)	$1.87

Source: ACIL Allen and TFS data

South Australia Retailer Energy Productivity Scheme (REPS)

The Retailer Energy Productivity Scheme (REPS) requires energy retailers with sales and customer numbers above certain thresholds (obliged retailers) to provide energy productivity activities to South Australian households and businesses to meet annual Ministerial targets. The REPS replaces the Retailer Energy Efficiency Scheme (REES), which was included in previous DMOs.

ESCOSA in its annual report on the REPS published in August 2024 reports an average cost of delivering the energy savings required under the scheme as $13.43/GJ. We multiplied the $13.43/GJ by the target for 2025 of 3,750,000 GJ, and then divided the total cost by the total customer energy in South Australia, to give a cost of $4.06/MWh.

4.4 Estimation of other energy costs

The estimates of other energy costs for the Final Determination provided in this section consist of:

- market fees and charges including:
  - NEM management fees
  - Ancillary services costs
- pool and hedging prudential costs
- the Reliability and Emergency Reserve Trader (RERT).

NEM management fees

NEM management fees are payable by retailers to AEMO to cover operational expenditure, costs associated with full retail contestability (FRC), the Energy Consumers Australia (ECA)[18], DER, IT system upgrades for 5MS and the NEM 2025 Reform Program.

The estimate for the NEM management fees is taken from AEMO's 2024-25 budget and fees report and are the same as those adopted for the DMO 6 Final Determination. This estimate will be updated for the Final Determination for DMO 7 upon publication of AEMO's 2025-26 budget and fees.

Based on the fees provided by AEMO's *FY25 Budget and Fees June 2024,* we provisionally estimate the total NEM fees for 2025-26 to be $0.50/MWh and $0.23/week for the variable and fixed components respectively. The breakdown of total fees is shown in Table 4.11.

Table 4.11 NEM management fees ($, nominal) – 2025-26

Cost category	2024-25 (variable, $/MWh)	2024-25 (fixed, $/week)	2025-26 (variable, $/MWh)	2025-26 (fixed, $/week)
NEM fees (admin, registration, etc.)	$0.29525	$0.09228	$0.29525	$0.09228
FRC - electricity	$0.00000	$0.03609	$0.00000	$0.03609
ECA - electricity	$0.00000	$0.01343	$0.00000	$0.01343
DER fee	$0.01344	$0.00420	$0.01344	$0.00420
IT upgrade and 5MS/GS compliance	$0.0986	$0.03082	$0.0986	$0.03082
National Electricity Market (NEM) 2025 Reform Program	$0.0968	$0.05151	$0.0968	$0.05151
Total NEM management fees	$0.50409	$0.22833	$0.50409	$0.22833

Source: ACIL Allen analysis of AEMO reports

Ancillary services

AEMO provides weekly aggregated settlements data for ancillary service payments in each interconnected region. Using the average costs in each region over the preceding 52 weeks (as at 21 February 2025) of available NEM ancillary services data as a basis for 2025-26, the estimates cost of ancillary services is shown in Table 4.12.

There is a reasonable increase (in percentage terms at least) in the Queensland ancillary services costs compared with the value used in the 2024-25 determination. According to AEMO's *Quarterly Energy Dynamics Q4 2024* report, on 11 October 2024, Queensland incurred ancillary services costs of $22 million – this cost for the single day equates to about 37 per cent of the NEM's cost for

[18] ECA requirements are measured in terms of connection points for small customers. It is not clear in AEMO's *Electricity Final Budget and Fees 2023-24* of the assumed number of connection points for small customers used in the estimate, therefore ACIL Allen has used DNSP customer numbers to estimate the cost of ECA requirements in $/MWh terms.

the entire quarterly. Planned network outages affecting QNI increased Queensland's risk of separating from the NEM, thus requiring local enablement of frequency control ancillary services (FCAS), which drove the local price for the contingency raise 6-second (R6SE) service to the market price cap.

Table 4.12 Ancillary services ($/MWh, nominal) – 2025-26

Region	2024-25	2025-26
Queensland	$0.21	$0.74
New South Wales	$0.25	$0.16
South Australia	$0.97	$0.61

Source: ACIL Allen analysis of AEMO data

Prudential costs

Prudential costs have been calculated for each jurisdiction NSLP and interval meter load profile. The prudential costs for the profiles are then used as a proxy for prudential costs for the controlled load profiles in the relevant jurisdiction.

AEMO prudential costs

AEMO calculates a maximum credit limit for each counterparty in order to determine the requirement for any or a combination of:

— bank guarantees
— reallocation certificates
— prepayment of cash.

There is no fundamental requirement to reallocate prudential obligations – it is a retailer's choice to do so. Assuming no reallocation and no vertical integration (either owned generation or PPAs), a retailer is required to provide suitable guarantees to the AEMO assessed maximum credit limit (MCL) which is calculated as follows:

MCL = OSL + PML

Where for the Summer (December to March), Winter (April to August) and Shoulder (other months):

OSL = (Average daily load x Average future expected spot price x Participant Risk Adjustment Factor * OS Volatility factor x (GST + 1) x 35 days

PML = (Average daily load x Average future expected spot price x Participant Risk Adjustment Factor * PM Volatility factor x (GST + 1) x 7 days

Taking a 1 MWh average daily load and assuming the inputs in Table 4.13 for each season for the Energex NSLP and small interval meter load gives an estimated MCL of $16,086.

However, as this applies for a rolling 42 days it actually covers 42 MWh of retailer purchases. Hence the portion of the MCL applicable to each MWh in the Energex NSLP is $16,086/42 = $383/MWh.

The cost of funding a bank guarantee for the MCL associated with the single MWh is assumed to be a 2.5 percent annual charge for 42 days or 2.5%*(42/365) = 0.288 percent. Applying this funding cost to the single MWh charge of $383 gives $1.10/MWh.

The components of the AEMO prudential costs for each of the other jurisdictions' profiles are shown in Table 4.13 to Table 4.17.

Table 4.13 AEMO prudential costs for Energex – 2025-26

	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$197.85	$138.85	$91.68
Participant Risk Adjustment Factor	1.4834	1.2143	1.2991
OS Volatility factor	1.51	1.53	1.48
PM Volatility factor	2.86	2.26	1.90
OSL	$20,780	$10,945	$7,735
PML	$4,156	$2,189	$1,547
MCL	$24,936	$13,134	$9,282
Average MCL		$16,086	
AEMO prudential cost ($/MWh, nominal)		$1.10	

Source: ACIL Allen analysis of AEMO data

Table 4.14 AEMO prudential costs for Ausgrid – 2025-26

	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$157.34	$183.00	$90.57
Participant Risk Adjustment Factor	1.0747	1.1498	0.7573
OS Volatility factor	1.48	1.54	1.35
PM Volatility factor	2.94	2.34	1.85
OSL	$9,989	$13,376	$3,102
PML	$1,998	$2,675	$620
MCL	$11,987	$16,052	$3,723
Average MCL		$11,630	
AEMO prudential cost ($/MWh, nominal)		$0.80	

Source: ACIL Allen analysis of AEMO data

Table 4.15 AEMO prudential costs for Endeavour – 2025-26

	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$157.34	$183.00	$90.57
Participant Risk Adjustment Factor	1.2725	1.1624	0.8161
OS Volatility factor	1.48	1.54	1.35
PM Volatility factor	2.94	2.34	1.85
OSL	$12,869	$13,597	$3,470
PML	$2,574	$2,719	$694
MCL	$15,443	$16,316	$4,164
Average MCL		$12,997	
AEMO prudential cost ($/MWh, nominal)		$0.89	

Source: ACIL Allen analysis of AEMO data

Table 4.16 AEMO prudential costs for Essential – 2025-26

	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$157.34	$183.00	$90.57
Participant Risk Adjustment Factor	1.1714	1.1862	1.0010
OS Volatility factor	1.48	1.54	1.35
PM Volatility factor	2.94	2.34	1.85
OSL	$11,366	$14,018	$4,715
PML	$2,273	$2,804	$943
MCL	$13,639	$16,821	$5,657
Average MCL		$12,983	
AEMO prudential cost ($/MWh, nominal)		$0.89	

Source: ACIL Allen analysis of AEMO data

Table 4.17 AEMO prudential costs for SAPN – 2025-26

	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$123.06	$151.84	$68.90
Participant Risk Adjustment Factor	1.5000	1.1727	0.8199
OS Volatility factor	1.77	1.56	1.43
PM Volatility factor	4.11	2.61	2.10
OSL	$15,405	$11,581	$2,816
PML	$3,081	$2,316	$563
MCL	$18,486	$13,897	$3,380
Average MCL		$12,796	
AEMO prudential cost ($/MWh, nominal)		$0.88	

Source: ACIL Allen analysis of AEMO data

Hedge prudential costs

ACIL Allen has relied on the futures market to determine hedging costs. The futures market includes prudential obligations by requiring entities to lodge initial margins (we assume cash) when contracts are purchased or sold. We understand that the cash that is lodged as an initial margin receives a money market related return which offsets some of the funding costs. The assumed money market rate is 4.10 per cent. Additional margin calls may apply where contracts move unfavourably for the purchaser or seller. However, as these may be favourable or unfavourable, we have assumed that they average out over time.

We understand that the initial margin is set based on three parameters (in this case for Queensland region) being:

— the price scanning range (PSR) expressed as a percentage of the contract face value and currently set at around 18 percent on average for a base contract, and 21 percent for a cap contract

— the intra monthly spread charge currently set at $12,300 for a base contract of 1 MW for a quarter, and $5,900 for a cap contract

— the spot isolation rate currently set at $1,500 for a base contract, and $600 for a cap contract.

Using the annual average futures price and applying the above factors gives an average initial margin for each quarter (rounded up) as shown for Queensland in Table 4.18. This is divided by the average hours in a quarter. Then applying the assumed funding cost of 9.15 per cent but adjusted for an assumed 4.10 per cent return on cash lodged with the clearing (giving a net funding cost of 5.05 percent) results in the prudential cost per MWh for each contract type.

Average initial margins for Queensland, New South Wales, and South Australia, using their corresponding initial margin parameters, and the resulting prudential cost per MWh are shown in Table 4.18 to Table 4.20, respectively.

Table 4.18 Hedge Prudential funding costs by contract type – Queensland 2025-26

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$99.14	$53,000	$1.22
Cap	$24.68	$24,000	$0.55

Source: ACIL Allen analysis of ASX Energy and RBA data

Table 4.19 Hedge Prudential funding costs by contract type – New South Wales 2025-26

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$121.94	$56,000	$1.29
Cap	$30.93	$23,000	$0.53

Source: ACIL Allen analysis of ASX Energy and RBA data

Table 4.20 Hedge Prudential funding costs by contract type – South Australia 2025-26

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$97.27	$66,000	$1.52
Cap	$29.77	$29,000	$0.67

Source: ACIL Allen analysis of ASX Energy and RBA data

However, the hedge model used is designed to conservatively cover all load at the extremes and so results in an over-contracted position against the average load. The volume of hedges (MWh) in each category have been calculated as a proportion of the average annual load in each jurisdiction NSLP and interval meter demand to give a proportional factor. The product of the prudential cost per MWh for each contract type and the proportion of each contract in the hedge model profile provides the total hedge prudential cost per MWh associated with each contract type. These are then summed to establish the total hedge prudential costs for each jurisdiction as shown in Table 4.21 to Table 4.25.

Table 4.21 Hedge Prudential funding costs for ENERGEX – 2025-26

	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.22	0.8718	$1.07
Cap	$0.55	1.7133	$0.95
Total cost		$2.01	

Source: ACIL Allen

Table 4.22 Hedge Prudential funding costs for Ausgrid – 2025-26

	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.29	1.0255	$1.32

	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Cap	$0.53	1.2456	$0.66
Total cost		$1.98	

Source: ACIL Allen

Table 4.23 Hedge Prudential funding costs for Endeavour – 2025-26

	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.29	0.9957	$1.29
Cap	$0.53	1.6236	$0.86
Total cost		$2.15	

Source: ACIL Allen

Table 4.24 Hedge Prudential funding costs for Essential – 2025-26

	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.29	0.9338	$1.21
Cap	$0.53	1.2651	$0.67
Total cost		$1.88	

Source: ACIL Allen

Table 4.25 Hedge Prudential funding costs for SAPN – 2025-26

	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.52	0.9098	$1.38
Cap	$0.67	2.0401	$1.36
Total cost		$2.75	

Source: ACIL Allen

Total prudential costs

Adding the AEMO and hedge prudential costs gives a total prudential requirement for 2025-26 as set out in Table 4.26 . Prudential costs for 2025-26 are higher than 2024-25 due to higher contract prices expected across 2025-26.

Table 4.26 Total prudential costs ($/MWh, nominal) – 2025-26

Jurisdiction	2024-25	2025-26
Energex	$2.30	$3.12
Ausgrid	$2.64	$2.78
Endeavour	$2.93	$3.04
Essential	$2.58	$2.77
SAPN	$3.32	$3.63

Source: ACIL Allen

Reliability and Emergency Reserve Trader (RERT)

As with the ancillary services, we take the RERT costs as published by AEMO for the 12-month period prior to the Determination.

Excluding the June 2022 NEM events, AEMO activated the RERT once for the 12-month period prior to the Draft Determination in New South Wales and South Australia.

AEMO contracted 10 MW of Interim Reliability Reserve (IRR) in South Australia with a contract period from 1 January 2024 to 31 March 2024. AEMO reported the costs of this activation to be $83,850. When dividing this value by the total energy requirements in South Australia, the cost of the RERT is about 0.7 cents per MWh.

On 27 November 2024, AEMO activated reserve contracts in New South Wales, due to an actual Lack of Reserve (LOR) Condition 2. AEMO reported the costs of this activation to be $3,557,700. When dividing this value by the total energy requirements in New South Wales, the cost of the RERT is about 5.3 cents per MWh.

There has been no activation of the RERT (outside of the June 2022 events) in Queensland over the past 12 months.

Retailer Reliability Obligation

The RRO is not currently triggered for the DMO regions for 2025-26.

AEMO Direction costs

To arrive at the estimate of the AEMO Direction compensation costs, ACIL Allen takes the sum of the quarterly Direction costs by region for the most recent past four quarters, as presented in AEMO's latest available Quarterly Energy Dynamics Report (the latest report available at the time of undertaking our analysis for the Determination) and divided by the corresponding annual regional customer energy.

Direction costs in South Australia over the past 12 months equate to $5.98/MWh.

These directions costs exclude those related to the June 2022 NEM events.

June 2022 NEM events

To estimate the costs of the June 2022 NEM events, ACIL Allen uses AEMO's published estimates of the costs of the June 2022 events, as well as AEMC's final decisions on administered pricing compensation claims.

The AEMC released a report on 12 September 2024 relating to its decision on a claim from Origin for the June 2022 NEM events. The total cost of this claim was $4.88 million, relating to operations of their Uranquinty, Quarantine and Mortlake power stations. The cost equates to $0.03/MWh in each of New South Wales and South Australia.

Summary of estimated total other costs

Adding these component costs gives a total other cost requirement as set out in Table 4.27 to Table 4.31. These tables exclude the fixed NEM Fees cost of $0.23 per week per customer – which averages about $1-2/MWh depending on the level of consumption.

Table 4.27 Total of other costs ($/MWh, nominal) – Energex – 2025-26

Cost category	2024-25	2025-26
NEM management fees	$0.50	$0.50
Ancillary services	$0.21	$0.74
Hedge and pool prudential costs	$2.30	$3.12
Reserve and Emergency Reserve Trader costs	$0.00	$0.00
AEMO Direction costs	$0.00	$0.00
June 2022 NEM events	$0.00	$0.00
Total	$3.02	$4.36

Note: The values exclude the fixed NEM Fees cost of $0.23 per week per customer – which averages about $1-2/MWh depending on the level of consumption.

Source: ACIL Allen analysis

Table 4.28 Total of other costs ($/MWh, nominal) – Ausgrid – 2025-26

Cost category	2024-25	2025-26
NEM management fees	$0.50	$0.50
Ancillary services	$0.25	$0.16
Hedge and pool prudential costs	$2.64	$2.78
Reserve and Emergency Reserve Trader costs	$0.00	$0.05
AEMO Direction costs	$0.00	$0.00
June 2022 NEM events	$0.00	$0.03
Total	$3.39	$3.52

Note: The values exclude the fixed NEM Fees cost of $0.23 per week per customer – which averages about $1-2/MWh depending on the level of consumption.

Source: ACIL Allen analysis

Table 4.29 Total of other costs ($/MWh, nominal) – Endeavour – 2025-26

Cost category	2024-25	2025-26
NEM management fees	$0.50	$0.50

Cost category	2024-25	2025-26
Ancillary services	$0.25	$0.16
Hedge and pool prudential costs	$2.93	$3.04
Reserve and Emergency Reserve Trader costs	$0.00	$0.05
AEMO Direction costs	$0.00	$0.00
June 2022 NEM events	$0.00	$0.03
Total	$3.68	$3.78

Note: The values exclude the fixed NEM Fees cost of $0.23 per week per customer – which averages about $1-2/MWh depending on the level of consumption.

Source: ACIL Allen analysis

Table 4.30 Total of other costs ($/MWh, nominal) – Essential – 2025-26

Cost category	2024-25	2025-26
NEM management fees	$0.50	$0.50
Ancillary services	$0.25	$0.16
Hedge and pool prudential costs	$2.58	$2.77
Reserve and Emergency Reserve Trader costs	$0.00	$0.05
AEMO Direction costs	$0.00	$0.00
June 2022 NEM events	$0.00	$0.03
Total	$3.33	$3.51

Note: The values exclude the fixed NEM Fees cost of $0.23 per week per customer – which averages about $1-2/MWh depending on the level of consumption.

Source: ACIL Allen analysis

Table 4.31 Total of other costs ($/MWh, nominal) – SAPN – 2025-26

Cost category	2024-25	2025-26
NEM management fees	$0.50	$0.50
Ancillary services	$0.97	$0.61
Hedge and pool prudential costs	$3.32	$3.63
Reserve and Emergency Reserve Trader costs	$0.003	$0.007
AEMO Direction costs	$8.44	$5.98
June 2022 NEM events	$0.00	$0.03
Total	$13.23	$10.76

Note: The values exclude the fixed NEM Fees cost of $0.23 per week per customer – which averages about $1-2/MWh depending on the level of consumption.

Source: ACIL Allen analysis

4.5 Estimation of energy losses

The estimated wholesale energy costs resulting from the analysis is referenced to the Regional Reference Node (RRN). These estimates need to be adjusted for transmission and distribution losses associated with transmitting energy from the Regional Reference Node to end-users. Distribution Loss Factors (DLF) for each jurisdiction and average Marginal Loss Factors (MLF) for transmission losses from the node to major supply points in the distribution networks are applied to the wholesale energy cost estimates to incorporate losses.

AEMO is yet to publish the MLFs/DLFs for 2025-26, consequently we have used the estimates from the DMO 6 Determination.

These will be updated for the Final Determination based on the MLFs and DLFs expected to be published around April 2025.

The estimation of transmission and distribution loss factors for the settlement classes to be used in calculating energy costs for 2025-26 is shown in Table 4.32**.**

Table 4.32 Estimated transmission and distribution losses

	2024-25			2025-26		
	Distribution loss factor (DLF)	Transmission marginal loss factor (MLF)	Total loss factors (MLFxDLF)	Distribution loss factor (DLF)	Transmission marginal loss factor (MLF)	Total loss factors (MLFxDLF)
Ausgrid – Residential and small business	4.31%	0.09%	1.044	4.31%	0.09%	1.044
Endeavour - Residential and small business	6.24%	-0.87%	1.053	6.24%	-0.87%	1.053
Essential - Residential and small business	5.94%	-2.96%	1.028	5.94%	-2.96%	1.028
Ausgrid - CLP1	4.94%	0.09%	1.050	4.94%	0.09%	1.050
Ausgrid - CLP2	4.94%	0.09%	1.050	4.94%	0.09%	1.050
Endeavour - CLP	6.24%	-0.87%	1.053	6.24%	-0.87%	1.053
Essential - CLP	5.94%	-2.96%	1.028	5.94%	-2.96%	1.028
Energex - Residential and small business	6.64%	0.75%	1.074	6.64%	0.75%	1.074
Energex – CLP31	6.64%	0.75%	1.074	6.64%	0.75%	1.074
Energex – CLP33	6.64%	0.75%	1.074	6.64%	0.75%	1.074
SAPN - Residential and small business	11.61%	-0.56%	1.110	11.61%	-0.56%	1.110
SAPN - CLP	11.61%	-0.56%	1.110	11.61%	-0.56%	1.110

Source: ACIL Allen analysis of AEMO data

As described by AEMO[19], to arrive at prices at the customer terminal (price at load connection point) the MLF and DLF are applied to the prices at the regional reference node (RRN) as follows:

*Price at load connection point = RRN Spot Price * (MLF * DLF)*

[19] See Page 23 of the AEMO publication *Treatment of loss factors in the national electricity market- July 2012*

4.6 Summary of estimated energy costs

Drawing together the analyses and estimates from the previous sections of this report, ACIL Allen's estimates of the 2025-26 total energy costs (TEC) for each of the profiles are presented in Table 4.33 and Table 4.34.

These tables exclude the fixed NEM Fees cost of $0.23 per week per customer – which averages about $1-2/MWh depending on the level of consumption.

Table 4.33 Estimated TEC for 2025-26 ($/MWh, nominal)

Profile	2024-25 Total energy costs at the customer terminal ($/MWh, nominal)	2025-26 Total energy costs at the customer terminal ($/MWh, nominal)	Change from 2024-25 to 2025-26 ($/MWh, nominal)	Change from 2024-25 to 2025-26 (%, nominal)
Ausgrid – Residential and small business	$182.63	$186.24	$3.61	1.98%
Endeavour - Residential and small business	$193.51	$194.76	$1.25	0.65%
Essential - Residential and small business	$182.52	$187.81	$5.29	2.90%
Ausgrid - CLP1	$126.60	$140.31	$13.71	10.83%
Ausgrid - CLP2	$126.45	$138.56	$12.11	9.58%
Endeavour - CLP	$128.01	$143.94	$15.93	12.44%
Essential - CLP	$123.86	$137.33	$13.47	10.88%
Energex - Residential and small business	$192.29	$180.01	($12.28)	-6.39%
Energex – CLP31	$120.70	$125.75	$5.05	4.18%
Energex – CLP33	$129.13	$132.62	$3.49	2.70%
SAPN - Residential and small business	$218.44	$216.70	($1.74)	-0.80%
SAPN - CLP	$136.62	$142.00	$5.38	3.94%

Note: The values exclude the fixed NEM Fees cost of $0.23 per week per customer – which averages about $1-2/MWh depending on the level of consumption.

Source: ACIL Allen analysis

Table 4.34 Estimated TEC for 2025-26 ($/MWh, nominal)

	WEC at regional reference node ($/MWh, nominal)	Other wholesale costs at regional reference node ($/MWh, nominal)	Network loss factor	Wholesale network losses ($/MWh, nominal)	Total wholesale costs at the customer terminal ($/MWh, nominal)	LRET costs at regional reference node ($/MWh, nominal)	SRES costs at regional reference node ($/MWh, nominal)	Other environmental costs at regional reference node ($/MWh, nominal)	Environmental network losses ($/MWh, nominal)	Total environmental costs at the customer terminal ($/MWh, nominal)	Total energy costs at the customer terminal ($/MWh, nominal)
Ausgrid – Residential and small business	$159.26	$3.52	1.044	$7.16	$169.94	$6.42	$5.14	$4.05	$0.69	$16.30	$186.24
Endeavour - Residential and small business	$165.56	$3.78	1.053	$8.98	$178.32	$6.42	$5.14	$4.05	$0.83	$16.44	$194.76
Essential - Residential and small business	$163.57	$3.51	1.028	$4.68	$171.76	$6.42	$5.14	$4.05	$0.44	$16.05	$187.81
Ausgrid - CLP1	$114.50	$3.52	1.050	$5.90	$123.92	$6.42	$5.14	$4.05	$0.78	$16.39	$140.31
Ausgrid - CLP2	$112.83	$3.52	1.050	$5.82	$122.17	$6.42	$5.14	$4.05	$0.78	$16.39	$138.56
Endeavour - CLP	$117.30	$3.78	1.053	$6.42	$127.50	$6.42	$5.14	$4.05	$0.83	$16.44	$143.94
Essential - CLP	$114.47	$3.51	1.028	$3.30	$121.28	$6.42	$5.14	$4.05	$0.44	$16.05	$137.33
Energex - Residential and small business	$151.68	$4.36	1.074	$11.55	$167.59	$6.42	$5.14	$0.00	$0.86	$12.42	$180.01
Energex – CLP31	$101.16	$4.36	1.074	$7.81	$113.33	$6.42	$5.14	$0.00	$0.86	$12.42	$125.75
Energex – CLP33	$107.56	$4.36	1.074	$8.28	$120.20	$6.42	$5.14	$0.00	$0.86	$12.42	$132.62
SAPN - Residential and small business	$168.84	$10.76	1.110	$19.76	$199.36	$6.42	$5.14	$4.06	$1.72	$17.34	$216.70
SAPN - CLP	$101.55	$10.76	1.110	$12.35	$124.66	$6.42	$5.14	$4.06	$1.72	$17.34	$142.00

Note: The values exclude the fixed NEM Fees cost of $0.23 per week per customer – which averages about $1-2/MWh depending on the level of consumption.

Source: ACIL Allen analysis

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