ACIL ALLEN

Default Market Offer 2026-27

Wholesale energy and environment cost estimates for DMO 8 Draft Determination

17 March 2026

About ACIL Allen

ACIL Allen is a leading independent economics, policy and strategy advisory firm, dedicated to helping clients solve complex issues.

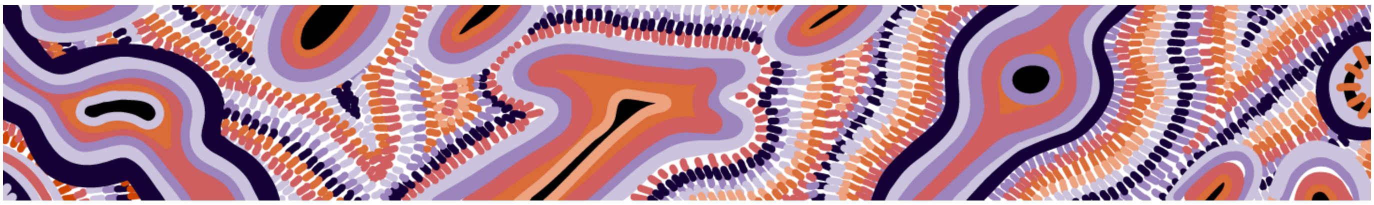
Our purpose is to help clients make informed decisions about complex economic and public policy issues.

Our vision is to be Australia's most trusted economics, policy and strategy advisory firm. We are committed and passionate about providing rigorous independent advice that contributes to a better world.

Report to:

Australian Energy Regulator

ACIL Allen acknowledges Aboriginal and Torres Strait Islander peoples as the Traditional Custodians of the land and its waters. We pay our respects to Elders, past and present, and to the youth, for the future. We extend this to all Aboriginal and Torres Strait Islander peoples reading this report.



Goomup, by Jarni McGuire

Contents

Figures

Contents

Contents

Tables

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 2026-27 (DMO 8).

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 the methodology, data inputs, and resulting estimates of the wholesale energy, environmental, and other costs for consideration by the AER when making its Determination for DMO 8. We have used the same methodology as provided in our Final Determination report to the AER for DMO 7, but have considered stakeholder feedback[1] in response to the AER's Issues Paper, as well as adopting any of the AER's decisions on changes to the methodology.

The report is presented as follows:

— Chapter 2 summarises the methodology.

— Chapter 3 summarises the derivation of the energy cost estimates.

[1] Unlike previous determinations, ACIL Allen is not required to explicitly respond to stakeholder submissions, but has considered stakeholder feedback when providing explanations and considerations throughout this report.

2 Overview of approach

2.1 Introduction

Presented in this chapter is a summary of the methodology used to estimate the wholesale and environmental cost components for DMO 8, including refinements based on 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

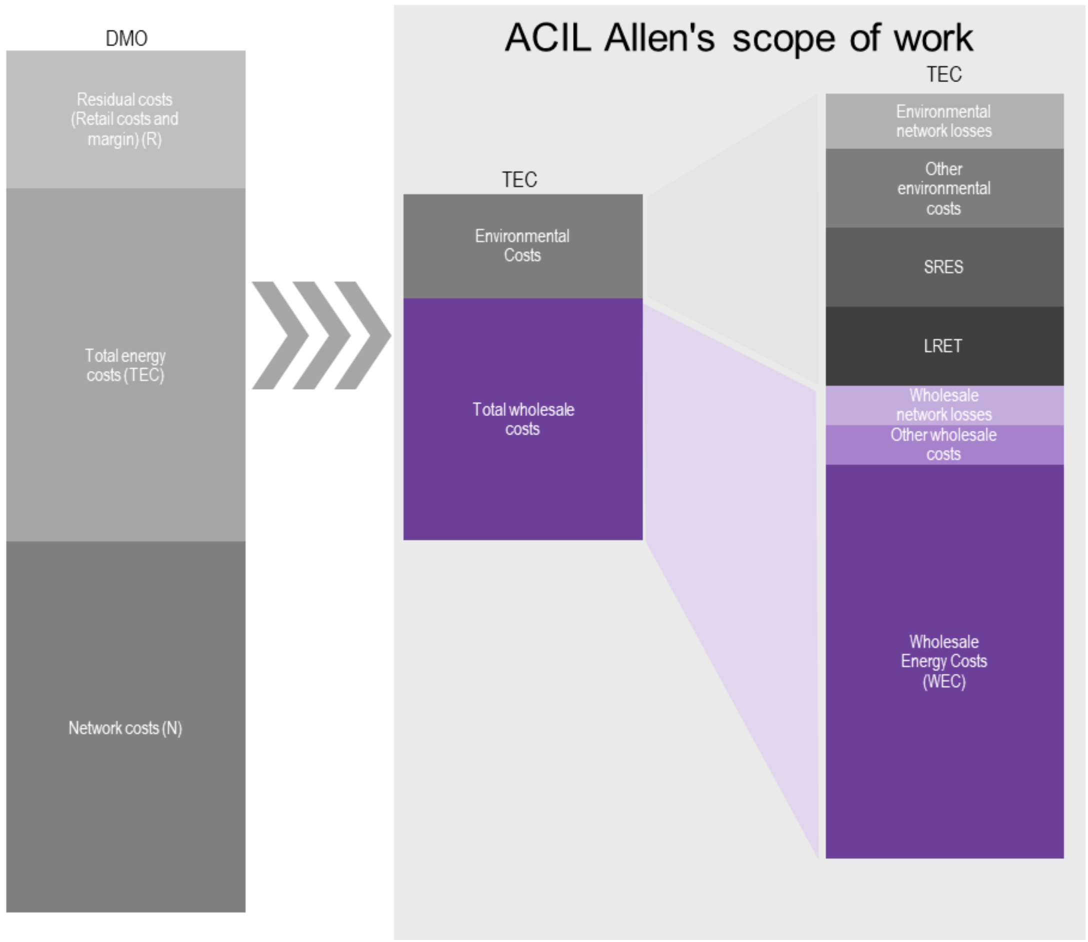
— Environmental Costs: costs of complying with state and federal government policies, including the Renewable Energy Target (RET).

— 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.

— 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 methodology used by ACIL Allen for DMO 8 (and DMO 2 to 7) 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 prudent contracting strategy that a 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 in the methodology generally assumes that the retailer's demand is partly exposed[2] 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.

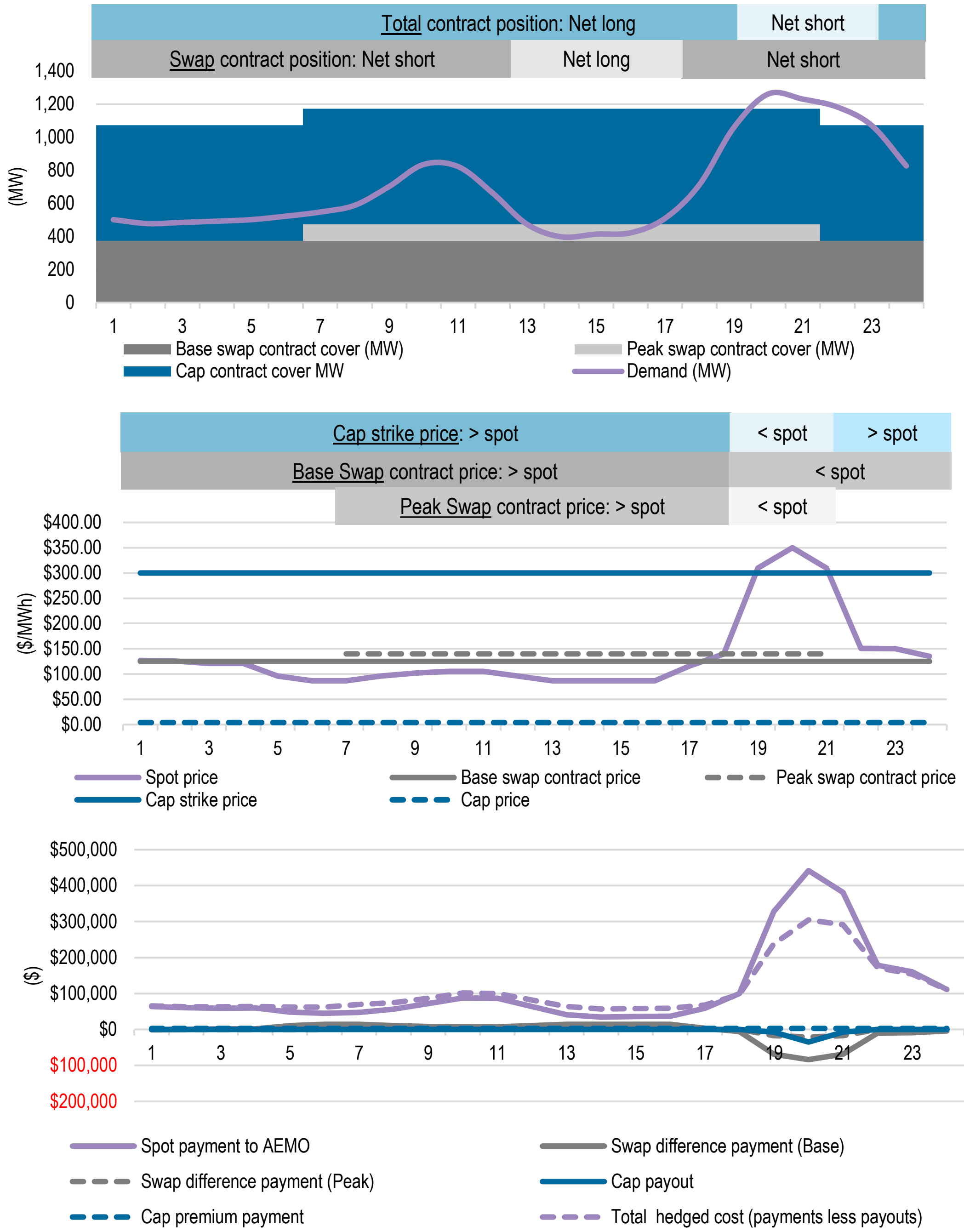
Figure 2.2 shows an illustrative example of a hedging strategy for a given load across a 24-hour period.

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).

[2] Noting that exposure occurs when the demand is either under- or over-hedged.

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, and that financial derivatives are a reasonable proxy for costs faced by retailers when managing spot market risk.

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.

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

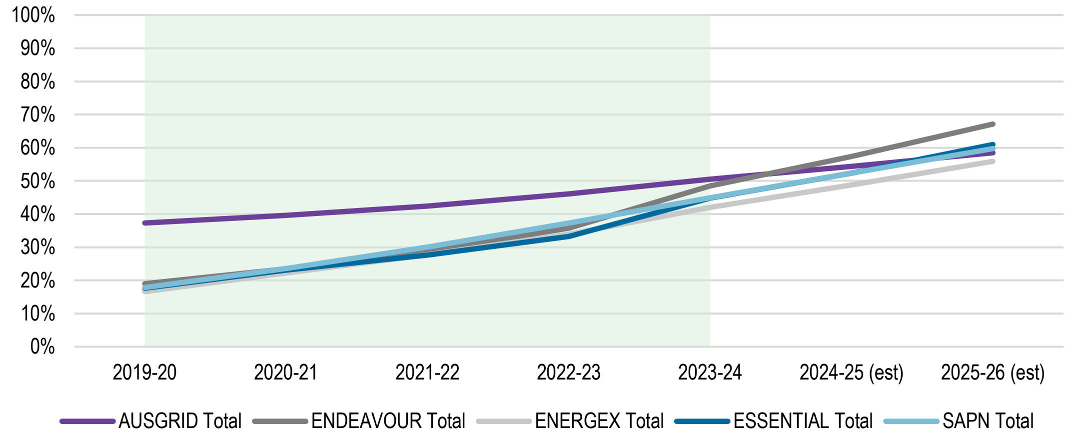
Region	Distribution Network	Load Type	Load Name	Source
		CLP 1	EA030	AER data request to Ausgrid
		CLP 2	EA040	AER data request to Ausgrid
	Endeavour Energy (Endeavour)	NSLP	NSLP,INTEGRAL	MSATS
		Residential and small business customers on interval meters	Endeavour Residential < 100 MWh and Business < 100 MWh	AER data request to AEMO
		CLP 1	N50	AER data request to Endeavour
		CLP 2	N54	AER data request to Endeavour
	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	BLNC1AU	AER data request to Essential
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 1	Super Economy (9000)	AER data request to Energex
		CLP 2	Economy (9100)	AER data request to Energex
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	CL	AER data request to SAPN

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 2024-25 increased to about 50-60 per cent.

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



Source: ACIL Allen analysis 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, customers on interval meters are now in the majority.

In this determination (as with DMO 6 and 7), a combination of the NSLP and interval meter data is used in estimating 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 and 2025-26 determinations, for the 2026-27 determination the PV export carve out has been excluded from the customer demand profile when estimating the WEC by using more recent post-5MS interval meter load data supplied by AEMO, and has aggregated the NSLP and interval meter data for small customers.

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.

In this determination, it has ben possible to strip out control load volumes from the general use interval meter load data provided by AEMO. This has been achieved by using interval meter control load profiles as well as control load volume information contained in the corresponding Standard Control Services (SCS) pricing models, provided to the AER from each of the DNSPs.

Further, given the availability of the interval meter control load data and the cessation of the accumulation meter control load data samples published by AEMO for New South Wales and South Australia, the analysis for this determination uses the interval meter control load data to estimate the WECs for control loads for all 3 DMO jurisdictions.

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 55 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 605 (i.e. 55 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) and cap contracts.
6. Calculate the spot and contracting cost for each hour and aggregate for each of the 605 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. For this current Determination, the AER has determined that the 50th percentile WEC be adopted, coupled with a volatility allowance (equal to 10 percent of the difference between the 100th and 50th percentile WEC). This in effect results in a final WEC estimate that sits above the 50th percentile WEC.

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 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[3] of simulations for each strategy and analysing the resulting distribution of WECs for each given strategy – and in particular, keeping note of the spread in WEC for each strategy. A strategy that is robust and plausible for each load profile, and minimises the spread in WEC is selected, 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

— the 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 cap 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[4] 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 55 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 55 years of weather data and uses a matching algorithm to produce 55 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 two years to represent a given day in the past.

— The set of 55 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 55 simulations equals

[3] When testing the different strategies, we do not run the full set of 605 simulations as this is time prohibitive. However, we run the full set of 605 simulations once the strategy has been chosen.

[4] For this determination, we have used data spanning 1 October 2023 to 30 September 2025 as this allows the analysis to exclude the initial temporary artificial step up in NSLPs in Queensland and South Australia.

the energy forecast, and the distribution of annual seasonal peak loads across the 55 simulations generally matches the distribution of peak loads inferred by the P10, P50 and P90 seasonal peaks from the AEMO demand forecast.

— 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 55 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 55 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

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.

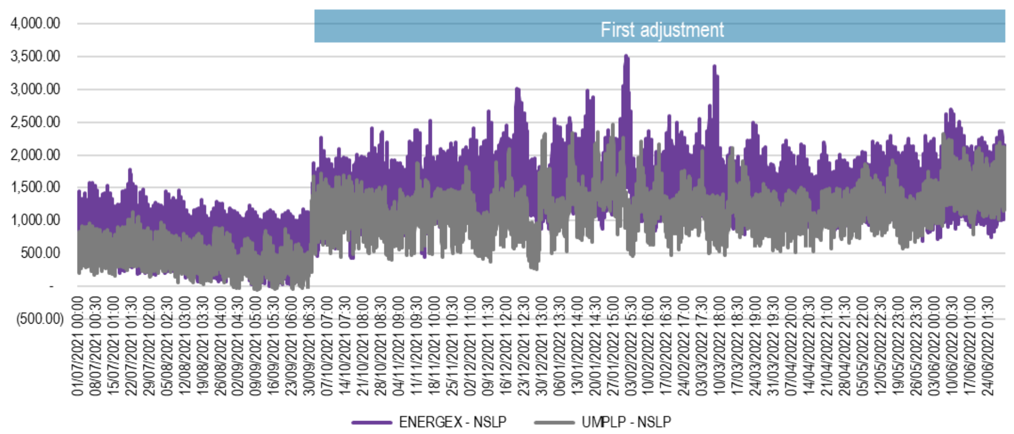
Therefore, an appropriate representation of the demand trace of small customers to be served by retailers in 2026-27 is required to estimate the WEC as accurately as possible. The more accurate the demand trace representation for 2026-27, the more accurate the WEC estimate.

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 2022 to 30 June 2025.

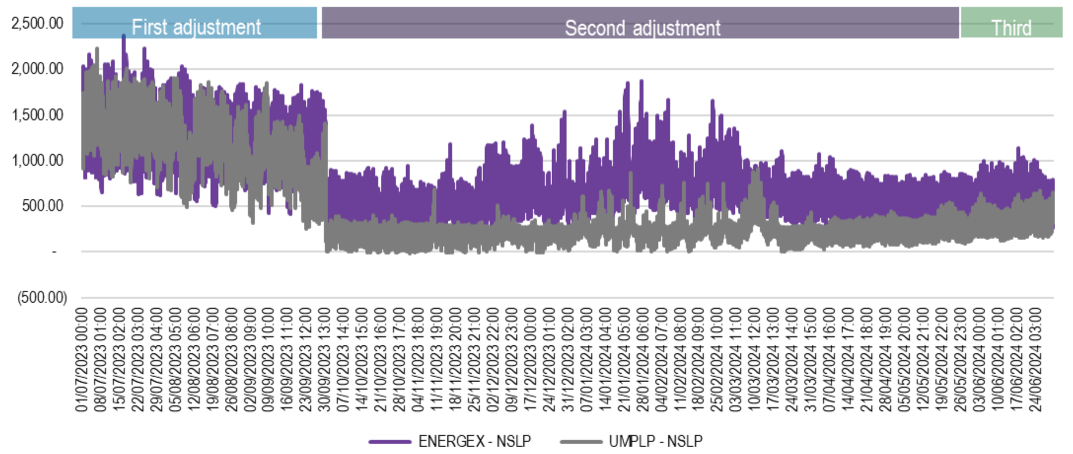
However, as shown in Figure 2.4 and noted in DMO 6 and 7, we observe that between 1 October 2021 and 30 September 2023 there was a step change in the NSLP demand trace for Energex and SAPN.

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 2026-27 (just as it did not in 2025-26).

As with DMO 7, data prior to 1 October 2023 has been excluded from the analysis avoiding the period of the temporary uplift.

This means 2 years of load data is used for DMO 8, spanning 1 October 2023 to 30 September 2025.

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 2026-27 we use our December 2025 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 2026-27 period.

The Reference case 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 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 to late 2020s. – International thermal coal prices are assumed to be about USD$107/t in 2026-27.
Electricity demand	**Underlying demand:** – AEMO 2025 ESOO Step Change scenario (energy and peak demand). **Rooftop PV:** AEMO 2025 ESOO Step Change scenario **Behind-the-meter BESS:** AEMO 2025 ESOO Step Change scenario **Electric vehicles:** AEMO 2025 ESOO Step Change scenario
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 2028).
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-$14/GJ (summer – winter) – Gas prices for peaking OCGTs are assumed to around $10-$15/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 $4-6/GJ in 2026-27.	Queensland Most generators' fuel supply is not linked to export pricing. Marginal coal prices range from $2 to $5/GJ in 2026-27	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 2026-27.
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 2025-2026.		
Interconnectors	ISP committed and actionable projects included: – EnergyConnect (fully commissioned by July 2027) – Heywood upgrade (July 2027)		

Source: ACIL Allen

New committed supply

Table 2.3 shows the near-term entrants that are considered committed projects and are therefore included in the Reference case.

A remarkable 8,700 MW of utility scale BESS capacity is projected to enter the NEM in the 12 months prior to the start of the determination period. By 2027 about 14,500 MW of utility scale BESS capacity is projected to be participating in the NEM. This represents a significant, and single largest recorded, change in the capacity mix in the NEM, over a very short period of time – with the aggregate utility scale BESS capacity being equivalent to 40 per cent of the NEM's peak demand. This will have important implications for wholesale spot price outcomes, and in particular, the time of day price shape.

Table 2.3 Near-term addition to supply

Region	Name	Generation Technology	Capacity (MW)	First energy exports
NSW	Stoney Creek BESS	Battery	125	2026 Q1
NSW	Goulburn River Solar Farm	Solar	450	2026 Q3
NSW	Bendemeer Energy Hub	Battery	150	2026 Q4
NSW	Bendemeer Energy Hub	Solar	252	2026 Q4
NSW	Glanmire BESS	Battery	60	2026 Q4
NSW	Glanmire Solar Farm	Solar	60	2026 Q4
NSW	Bulabul 2 BESS	Battery	100	2027 Q2
NSW	Ridgey Creek BESS	Battery	130	2027 Q2
NSW	Thunderbolt Wind Farm	Wind	230	2027 Q2
NSW1	Eraring Big Battery Stage 1	Battery	460	2025 Q4
NSW1	Smithfield BESS	Battery	65	2025 Q4
NSW1	Big Canberra Battery	Battery	250	2026 Q1
NSW1	Culcairn Solar Farm	Solar	350	2026 Q1
NSW1	Limondale Battery	Battery	50	2026 Q1
NSW1	New England Solar Farm Stage 2	Solar	320	2026 Q1
NSW1	Quorn Park BESS	Battery	20	2026 Q1
NSW1	Quorn Park Solar Farm	Solar	98	2026 Q1
NSW1	Uungula BESS	Battery	150	2026 Q1
NSW1	Uungula WF	Wind	414	2026 Q1
NSW1	New England BESS Stage 1	Battery	50	2026 Q4
NSW1	New England BESS Stage 2	Battery	150	2026 Q4
NSW1	Orana BESS	Battery	415	2026 Q4
NSW1	Eraring BESS Stage 2	Battery	240	2027 Q1
NSW1	Maryvale BESS	Battery	172	2027 Q1
NSW1	Maryvale Solar Farm	Solar	172	2027 Q1
QLD	Banksia Solar Farm	Solar	72	2025 Q4
QLD	Hopeland Solar Farm	Solar	250	2026 Q1
QLD	Woolooga BESS	Battery	200	2026 Q3
QLD	Boulder Creek Wind Farm	Wind	228	2026 Q4
QLD	Ganymirra Solar Farm	Solar	150	2027 Q1
QLD	Major Creek Solar Farm	Solar	150	2027 Q1
QLD1	Brendale BESS	Battery	205	2025 Q3
QLD1	Bundaberg Solar Farm	Solar	100	2025 Q3
QLD1	Gunsynd Solar Farm	Solar	94	2025 Q3
QLD1	Moah Creek Wind Farm	Wind	372	2025 Q3
QLD1	Swanbank BESS	Battery	250	2025 Q3

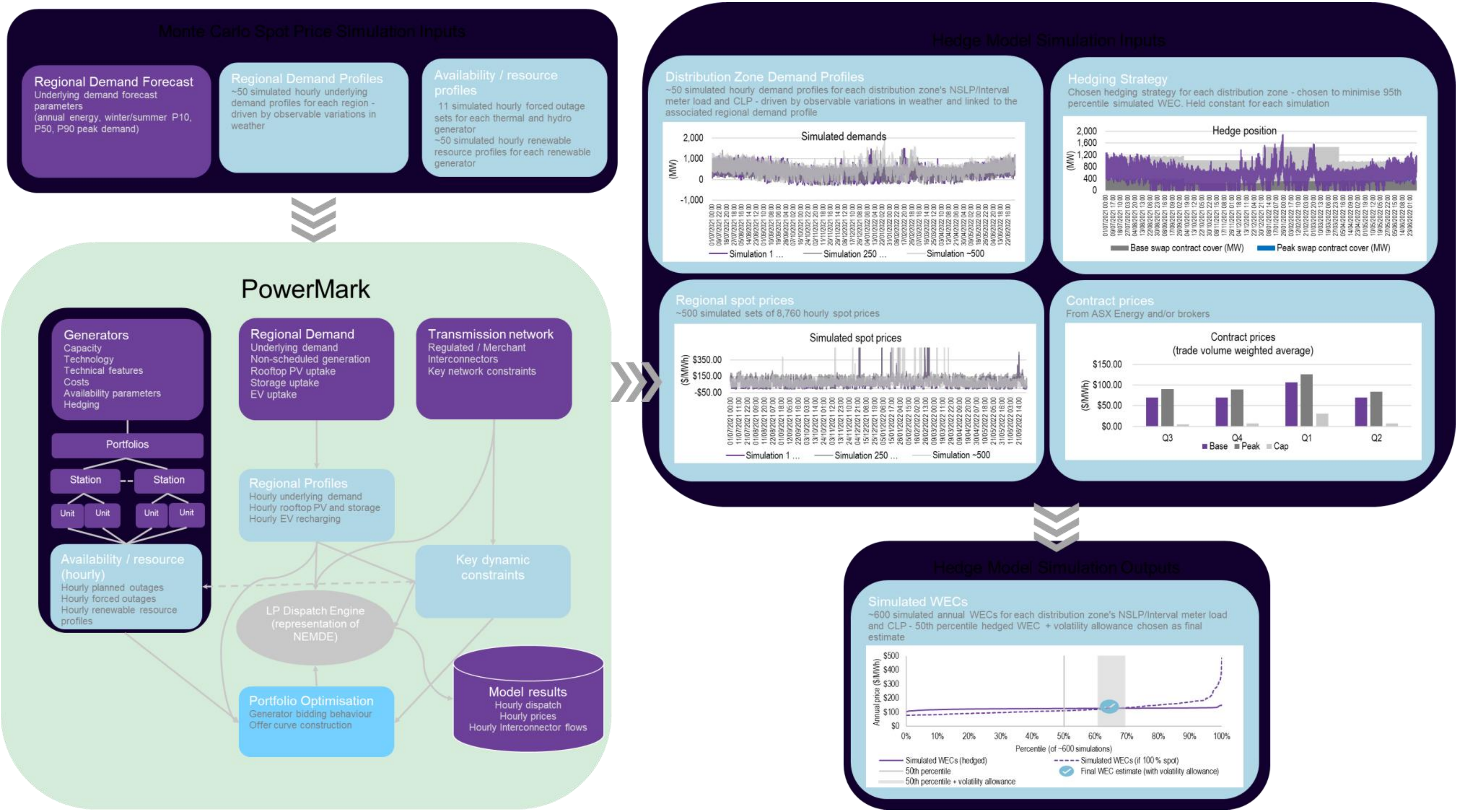
Region	Name	Generation Technology	Capacity (MW)	First energy exports
QLD1	Aldoga Solar Farm	Solar	380	2025 Q4
QLD1	Supernode BESS	Battery	250	2025 Q4
QLD1	Ulinda Park BESS	Battery	155	2025 Q4
QLD1	Brigalow Peaking Power Plant	Natural gas	400	2026 Q1
QLD1	Tarong West Wind Farm	Wind	500	2026 Q1
QLD1	Western Downs Battery Stage 2	Battery	270	2026 Q1
QLD1	Broadsound BESS	Battery	180	2026 Q3
QLD1	Broadsound Solar Farm	Solar	296	2026 Q3
QLD1	Herries Range Wind Farm	Wind	750	2026 Q3
QLD1	Lotus Creek Wind Farm	Wind	285	2027 Q1
SA	Goyder North Wind Farm Stage 1	Wind	300	2025 Q3
SA	Koolunga BESS	Battery	200	2026 Q3
SA	Koolunga BESS	Battery	200	2026 Q3
SA	Limestone Coast North Energy	Battery	250	2026 Q4
SA	Summerfield BESS	Battery	240	2027 Q1
SA1	Templers BESS	Battery	111	2025 Q3
SA1	Clements Gap BESS	Battery	60	2026 Q1
SA1	Solar River BESS	Battery	256	2026 Q3
SA1	Hallett BESS	Battery	50	2026 Q4
SA1	Limestone Coast West BESS	Battery	250	2027 Q1
VIC	Campbells Forest Solar Farm	Solar	205	2025 Q3
VIC	Mokoan Solar Farm	Solar	46	2025 Q3
VIC	Elaine Solar Farm	Solar	125	2026 Q1
VIC	Kentbruck Wind Farm	Wind	600	2026 Q1
VIC	Carwarp Energy Park	Solar	171	2026 Q3
VIC	Lancaster Solar Farm	Solar	106	2026 Q3
VIC	Terang BESS	Battery	100	2026 Q3
VIC	West Mokoan Solar Farm	Solar	300	2026 Q3
VIC	Goorambat East Solar Farm	Solar	250	2027 Q1
VIC	Kiamal BESS	Battery	220	2027 Q1
VIC	Kiamal BESS	Battery	220	2027 Q1
VIC	Little River BESS	Battery	350	2027 Q1
VIC	Little River BESS	Battery	350	2027 Q1
VIC	Mornington BESS	Battery	240	2027 Q1
VIC	Supernode BESS Stage 2	Battery	270	2027 Q1
VIC	Barwon Solar Farm	Solar	250	2027 Q2
VIC	Joel Joel BESS	Battery	250	2027 Q2
VIC	Joel Joel BESS	Battery	250	2027 Q2
VIC1	Golden Plains Wind Farm	Wind	756	2025 Q3
VIC1	The Melbourne REH	Battery	600	2025 Q4
VIC1	Goorambat Solar Farm	Solar	250	2027 Q1
VIC1	Springvale Energy Hub	Battery	115	2027 Q1

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

Time varying WECs

The requirement to estimate time varying WECs for small customers means the load profile is to be time sliced into period types. The WECs are to be based on the overall (or flat) WEC for small customers for a given DNSP.

The AER has provided ACIL Allen with the following specifications of the time slices for the period types for three different time varying WECs:

- Time varying WEC for Ausgrid small customers
  - Peak: 3pm-9pm, Nov-March and June-August
  - Off-peak: all other times.
- Time varying WEC for Endeavour small customers
  - HS Peak: $/kWh, 4pm-8pm, Nov-March
  - LS Peak: $/kWh, 4pm-8pm, April-Oct
  - Solar Soak: $/kWh, 10am-2pm
  - Off-peak: all other times.
- Time varying WEC for Essential small customers
  - Peak: 7am – 10am, 3pm – 10pm
  - Off-peak: all other times.
- Time varying WEC for Energex small residential customers
  - Peak: 4pm – 9pm
  - Off-peak: 11am – 4pm
  - Shoulder: all other times.
- Time varying WEC for Energex small business customers
  - Peak: 5pm – 8pm, Mon-Fri
  - Off-peak: 11am –1pm
  - Shoulder: all other times.
- Time varying WEC for SAPN small residential customers
  - Peak: 6am – 10am, 4pm – 12am
  - Off-peak: 12am – 6am
  - Solar soak: 10am – 4pm.
- Time varying WEC for SAPN small residential customers CLP
  - Peak: 6:30am-9:30am, 4:30pm-11:30pm
  - Off-peak: 11:30pm-6:30am
  - Solar soak: 9:30am-4:30pm.
- Time varying WEC for SAPN small business customers
  - Peak: 5pm-9pm Nov-Mar
  - Off-peak: 9pm-7am Mon-Fri, 9pm-5pm Sat-Sun Nov-Mar, all day Sat-Sun Apr-Oct
  - Shoulder: all other times.

For each simulation, the WEC for a given period type, p, is calculated as follows: WECp = DWPp * WECt / DWPt.

That is, the WECp equals the ratio WECt for the total (t) demand profile to the DWPt for the total demand profile, multiplied by the spot DWPp of the period type, p.

In effect, the method assumes the ratio of the WEC to DWP is the same for all period types.

The 50th percentile WEC is then chosen for each period type. These are then scaled so that the sumproduct of the final scaled TOU WECs and the TOU energy equals the product of the total energy and total WEC.

Adopting this approach, rather than taking the TOU WECs from the same simulation as the 50th percentile total WEC results in more stable TOU WECs, driven by the underlying fundamentals of the market conditions across all simulations, rather than being unduly influenced by the specific simulation of the 50th percentile flat WEC (which may have its own peculiarities).

And it is likely to provide the behavioural signals sought by this type of tariff – since the DWP during daylight hours will be less than the DWP for other period types.

The volatility allowance added to the TOU WECs is the flat WEC volatility allowance.

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 the methodology attempts 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).

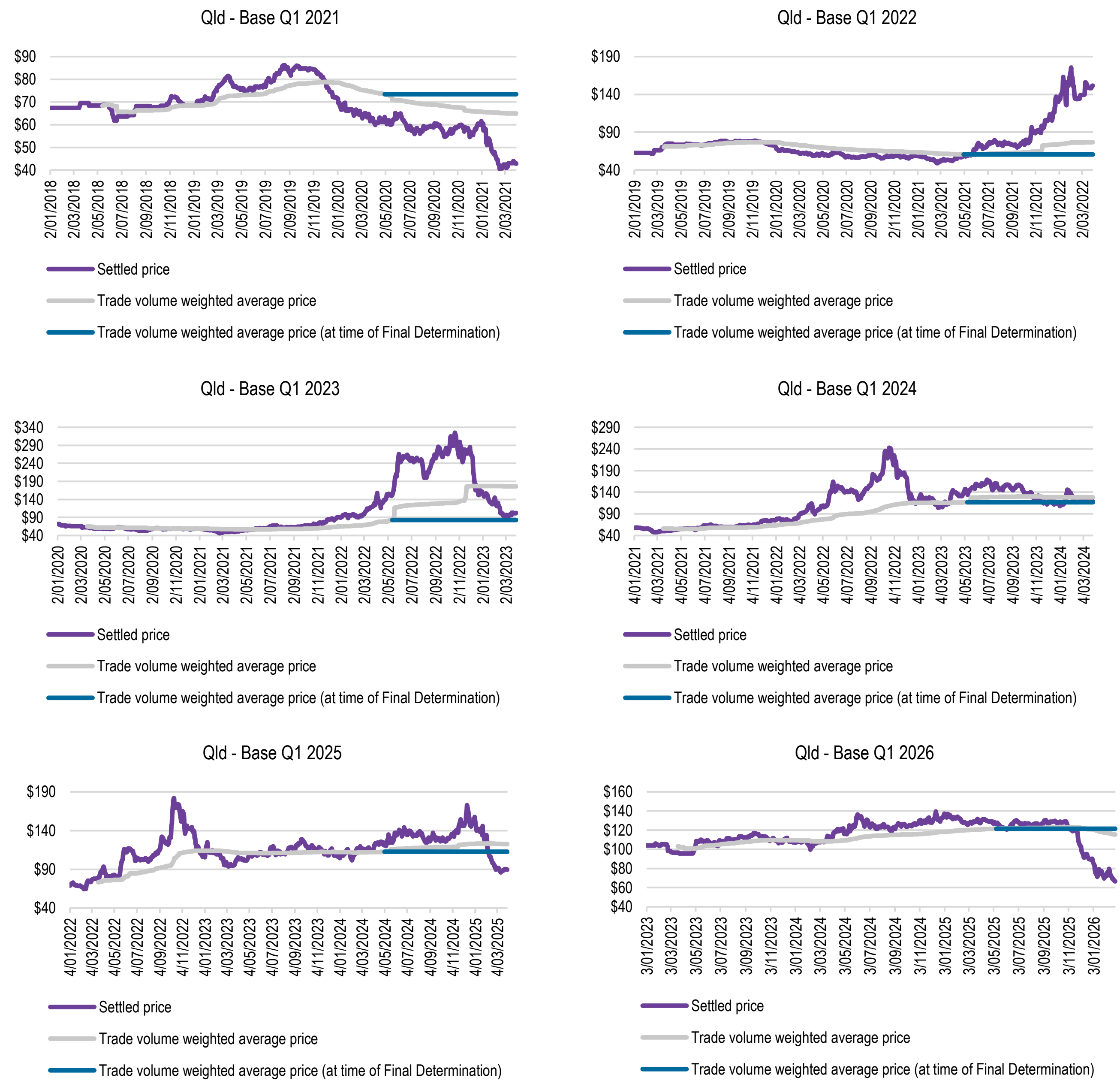
After the date the 2022-23 Final Determination was made, Q1 2023 traded prices increased substantially resulting in an actual trade weighted average price about $90.00 higher than that used in the Final Determination. This is another, and more extreme, example of an increasing market price environment – 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 3 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.

After the date the 2025-26 Final Determination was made, Q1 2026 traded prices increased slightly and have decreased substantially over the past 3 months resulting in an actual trade weighted average price slightly below that used in the Final Determination. This is an example of a declining market price environment post Final Determination but the volume of trades in contracts post Final Determination were relatively low and hence have not results in a strong change in the volume weighted average contact price.

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.
— 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.

A further discussion on WEC estimation accuracy is provided in section 2.4.

Solar Sharer Offer

Implementation of the Solar Sharer Offer (SSO) does not impact the WEC estimation methodology. There remains a requirement to calculate a WEC as per the previous determinations. Further, the application of the SSO does not change the hedging requirements of a retailer – the wholesale market risk remains.

Whilst there may be a change in overall load shape as a result of the SSO, it is difficult to project the extent of the change, and whether it will be sustained, at this early stage. The risk of attempting to project the change in load shape is that the WEC may be overestimated (if the actual load shape is flatter than what is assumed) or underestimated (if the actual load shape is peakier than what is assumed).

Further, with over 50% of households in Queensland and South Australia, and nearly 40% of households in New South Wales, with rooftop PV, there has existed an incentive for these customers to shift their usage to the middle of the day where possible to soak up any excess solar generation (since the prices paid for PV exports are very low).

Hence, ACIL Allen recommends not altering the load shape, and instead observe the change over time which will then be included in future determinations (given the rolling 2-3 year window of demand data used in the analysis).

Finally, we note that there is no requirement for ACIL Allen to make adjustments to the WECs to account for the SSO, as this task will be undertaken by the AER.

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 2026-27 draft budget report will be released in April 2026 and will be adopted for the Final Determination.

Consistent with the 2025-26 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[5] 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

The methodology 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 3.85 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, 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, RERT costs published by AEMO for the 12-month period prior to the Determination are used. The RERT costs are expressed 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.

[5] 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)

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.

The RRO is currently not triggered for 2026-27 in New South Wales, Queensland or South Australia, and hence we are not required to account for the RRO in the wholesale costs for 2026-27. 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.

Entering into a mix of firm base and cap contracts is assumed to satisfy 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.

The 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 and Network support and control ancillary services (NSCAS) 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 on AEMO's NEM Direction Compensation Recovery web page[6].

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.

Additionally, network support and control ancillary services (NSCAS) agreements were activated for voltage control in South Australia over the past 12 months. AEMO aggregates the relevant payments for each

[6] https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/settlements-data/direction-compensation-recovery

trading interval and each type of NSCAS and recovers them fully from market participants on a consumption basis.

AEMO publishes the direction and NSCAS 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 it is 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 and NSCAS compensation costs, the quarterly Direction and NSCAS 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), are summed and divided by the corresponding annual regional customer energy.

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[7], these events have associated compensation and contract payments, which under the NER are to be recovered from Market Customers (mainly electricity retailers) as determined by the AEMC. The costs are recovered in proportion to energy purchased in each relevant region. Hence these costs should be included in the Determination.

It is ACIL Allen's understanding that all compensation costs associated with the June 2022 events have been accounted for in the previous DMO determinations, and there are no outstanding amounts to be recovered in DMO 8.

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.

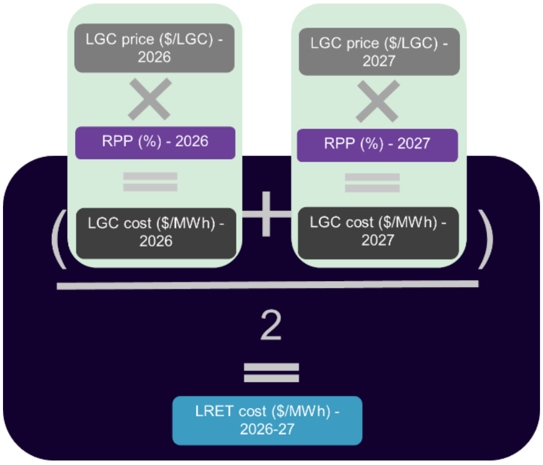
[7] https://aemo.com.au/-/media/files/electricity/nem/data/mms/2022/june-2022-nem-events-compensation-jan-6.pdf?la=en

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 2026-27, the following elements are used:

— the average of the trade-weighted average of LGC forward prices for 2026 and 2027 from brokers TraditionAsia
— the Renewable Power Percentage (RPP) for 2026, published by the CER
— the estimated Renewable Power Percentage (RPP) for 2027[8].

Figure 2.7 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, the following elements are used:

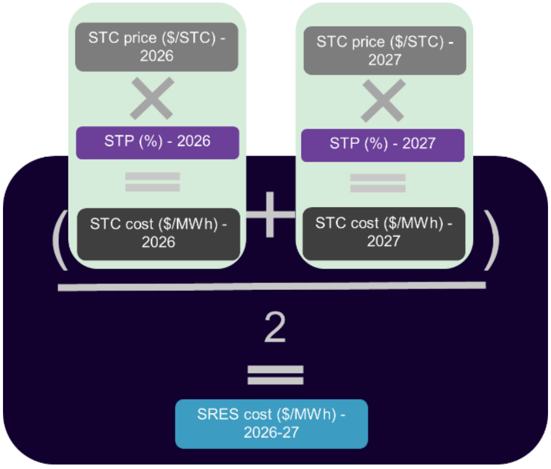
— the binding Small-scale Technology Percentage (STP) for 2026 as published by the CER
— an estimate of the STP value for 2027[9]
— CER clearing house price[10] for 2026 and 2027 for Small-scale Technology Certificates (STCs) of $40/MWh.

[8] The estimated RPP value for 2027 is estimated using ACIL Allen's estimate of liable acquisitions and the CER-published mandated LRET target for 2026 and 2027.

[9] The STP value for 2027 is estimated using estimates of STC creations and liable acquisitions in 2027, taking into consideration the CER's non-binding estimate.

[10] Although there is an active market for STCs, there is no compelling reason 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

Figure 2.8 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, the following elements are used:

— Energy Savings Scheme Target for 2026 and 2027 of 11 and 11.5 per cent respectively, as published by IPART

— Historical Energy Savings Certificate (ESC) market forward prices for 2026 and 2027 from brokers TraditionAsia.

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, the following elements are used:

$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.

- The peak demand reduction target for 2026-27 of 0.5 per cent[11], as published by the New South Wales and Department of Planning, Industry and Environment[12].
- Historical PRC market forward prices for 2026 and 2027 from brokers TraditionAsia.

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 September 2025 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[13], 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 DMO Draft Determination for 2026-27 are based on the 2025-26 DMO Final Determination.

[11] On 31 October 2025, the 2026-27 PDRS target was revised to 0.5%, down from 7.5%.

[12] https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/energy-security-safeguard/peak-demand-reduction-scheme

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

The MLFs and DLFs used to estimate losses for the Final Determination for 2026-27 *will be* based on the 2026-27 MLFs and DLFs *to be* published by AEMO in April 2026.

2.4 Back casting to assess the WEC estimation accuracy: estimation error versus efficiency versus retailer profit

Summarised below is an extension of the assessment of the WEC methodology provided in the AER's supplementary report for the DMO 8 issues paper, *Assessing the performance of the wholesale cost model*.

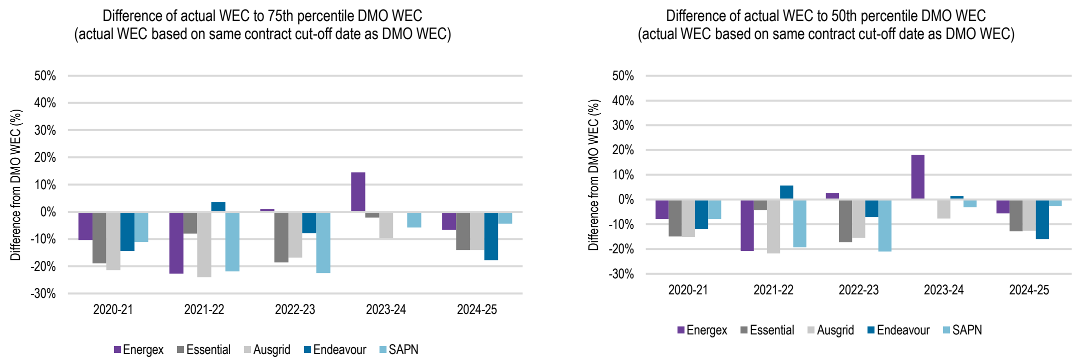
The WEC estimation methodology as it stands attempts to derive an estimate of the WEC taking into account the following requirements:

1. It ought to be the best unbiased estimate of the true WEC incurred by an efficient and prudent retailer, reflecting contemporary market conditions.
2. It needs to be based on transparent and publicly available data.
3. It needs to be based on the latest available data at the time of the determination.
4. It is applicable to all small customers and all retailers (affected by the DMO). That is, a single WEC is required within each DNSP for all small customers (it does not distinguish different customer types, or different customer mixes targeted by different retailers).

The simplistic hedging strategy is a proxy for the various strategies adopted by retailers, and is necessary given requirements 2 and 3. This of course means that for some retailers, it is possible that their true WEC is less than the estimated WEC given they can pursue more bespoke hedging strategies. That said, more bespoke hedging strategies are not necessarily less risky than the strategy adopted by the DMO, and retailers will price that risk into their market offer accordingly. Conversely, a retailer's hedging strategy may include long dated contracts (PPAs with earlier wind farms for example) which are now relatively expensive (and we have advocated for not using long dated contracts since they may well not reflect contemporary market conditions).

As noted by the AER in its Issues Paper, and shown in Figure 2.9, the back casting exercise shows that the *actual* WEC is typically lower than the estimated DMO WEC (noting that the actual WEC is to some extent a construct given it is based on the assumed DMO hedging strategy, and distinct to the *true* WEC of a retailer).

Figure 2.9 Comparison of actual WEC to DMO WEC



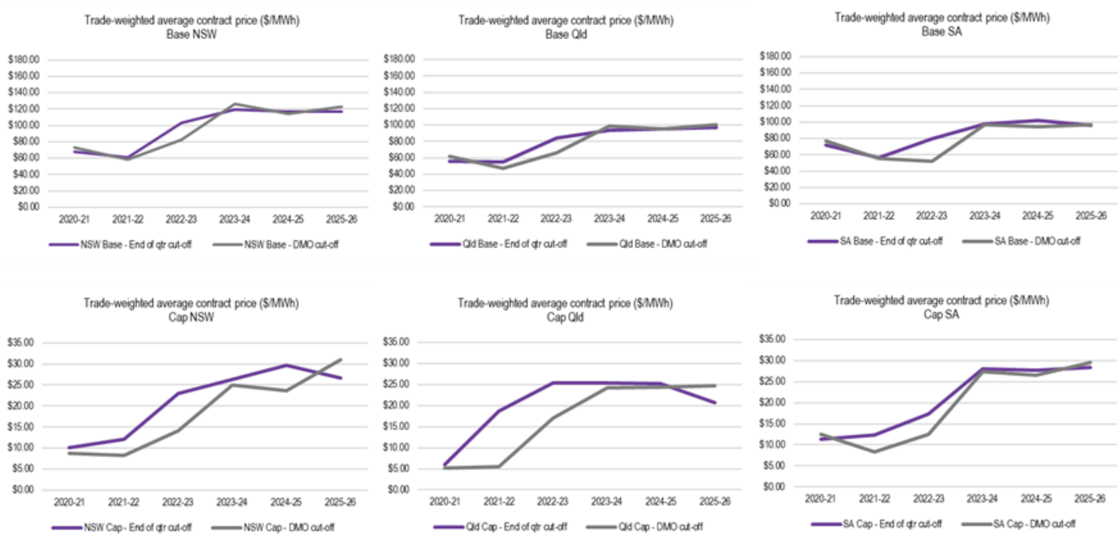
Source: ACIL Allen

However, the back casting presented in the AER Issues Paper used the same contract cut-off date as that adopted for the AER's determination. In practice, retailers will continue with their bookbuild well after the determination date – with ASX Energy closing trades on the preceding day of the last day of any given quarter.

Calculating the trade weighted average contract price using all data up to the date of the last trade results in noticeable differences in the resulting contract prices, compared with the DMO contract price (shown in Figure 2.10). Typically, the movement in contract prices has resulted in the trade weighted average contract price either stabilising since the date of the determination or increasing. And if they increased, it has been by a noticeable amount – in some cases by over $20/MWh (driven by, for example, major power stations outages or global fuel price shocks). Trade weighted average contract prices have decreased too on some occasions, but the downward movement is relatively small. Retailers face these asymmetric price movements.

We note that the increases in contract prices post determination over the past five years have been driven by events that may well be considered to have a very low probability. But it is these low probabilistic events and their associated substantial impacts on outcomes that retailers need to manage when operating in the NEM.

Figure 2.10 Comparison of trade weighted average contract prices when adopting the date of last trade instead of DMO cut-off date



Note: 2025-26 "End of qtr cut-off" includes data up to February 2026

Source: ACIL Allen analysis of ASX Energy data

Notwithstanding the relatively short time period of the assessment, when accounting for the updated contract prices, the resulting actual WECs are much closer to the estimated DMO WECs (as shown in Figure 2.11).

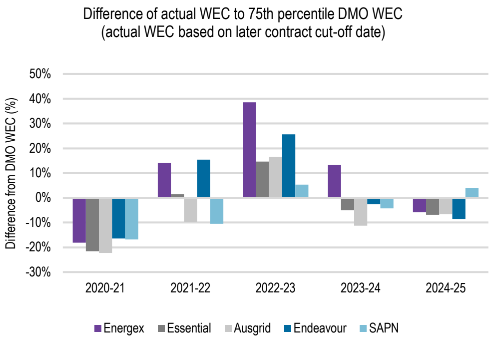
Using the contract prices based on the later cut-off dates to calculate the actual WEC:

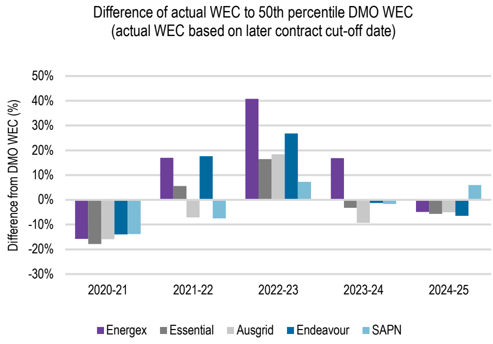
— The 75th percentile DMO WEC is greater than the actual WEC 60% of the time, instead of 88% of the time.

— The 75th percentile DMO WEC is on average 1.5% higher than the actual WEC, instead of 11% higher.

— If the DMO WEC was based on the 50th percentile, then on average it would be 0.9% lower than the actual WEC, compared with 8.4% higher.

Figure 2.11 Comparison of actual WEC to DMO WEC – when accounting for contract price movements post determination

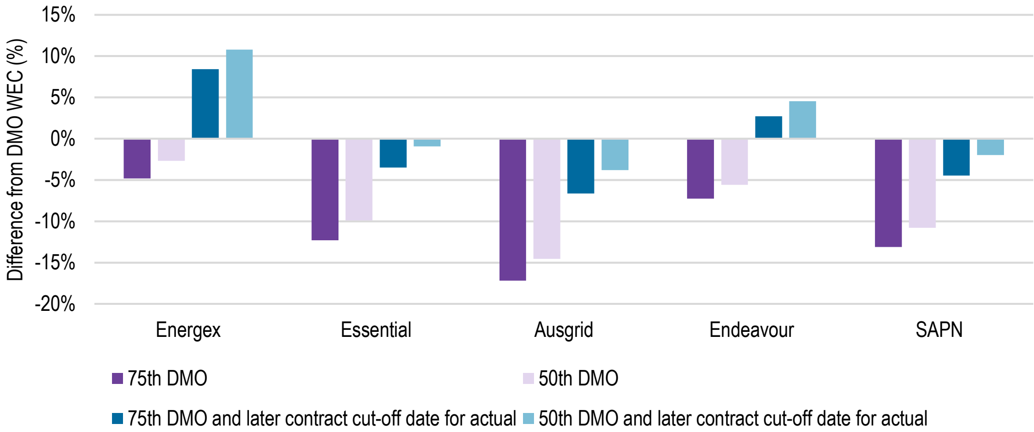




Source: ACIL Allen

When taking the average difference between the actual WEC and DMO WEC across determinations 2 to 6, it can be seen that the error in the estimates is not the same for each region. For example, on average across the five determinations, the actual WEC for south-east Queensland is about 8% higher than the 75th percentile DMO WEC, when taking into account contract price movements post determination, compared with 7% lower for Ausgrid.

Figure 2.12 Average difference of actual WEC to DMO WEC - 2020-21 to 2024-25



Source: ACIL Allen

3 Estimation of energy costs

3.1 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 2026-27.

Historic demand and wholesale electricity spot price outcomes

Figure 3.1 to Figure 3.3 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:

— Export coal prices commenced the financial year at about USD$130/t but declined to about USD$106/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 increased to about AUD$20/GJ by the end of 2024, before declining to about USD$16/GJ by June 2025.
— This has resulted in wholesale electricity prices increasing by about 25, 26 and 33 per cent, averaging around $109/MWh, $128/MWh, and $104/MWh in Queensland, New South Wales and South Australia respectively.

In 2025-26 to date:

— Export coal prices commenced the financial year at about USD$106/t, but after a temporary decline in September 2025, have increased slightly to about USD$118/t.
— LNG netback prices decreased to about AUD$12/GJ by the end of 2025, and have largely stabilised.
— There has been a large influx of utility scale BESS projects entering the market over the past 12 months.
— The combination of the lower gas prices and increase in BESS capacity has resulted in wholesale electricity prices decreasing by about 40, 37 and 24 per cent, averaging around $65/MWh, $81/MWh, and $79/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[14] (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.

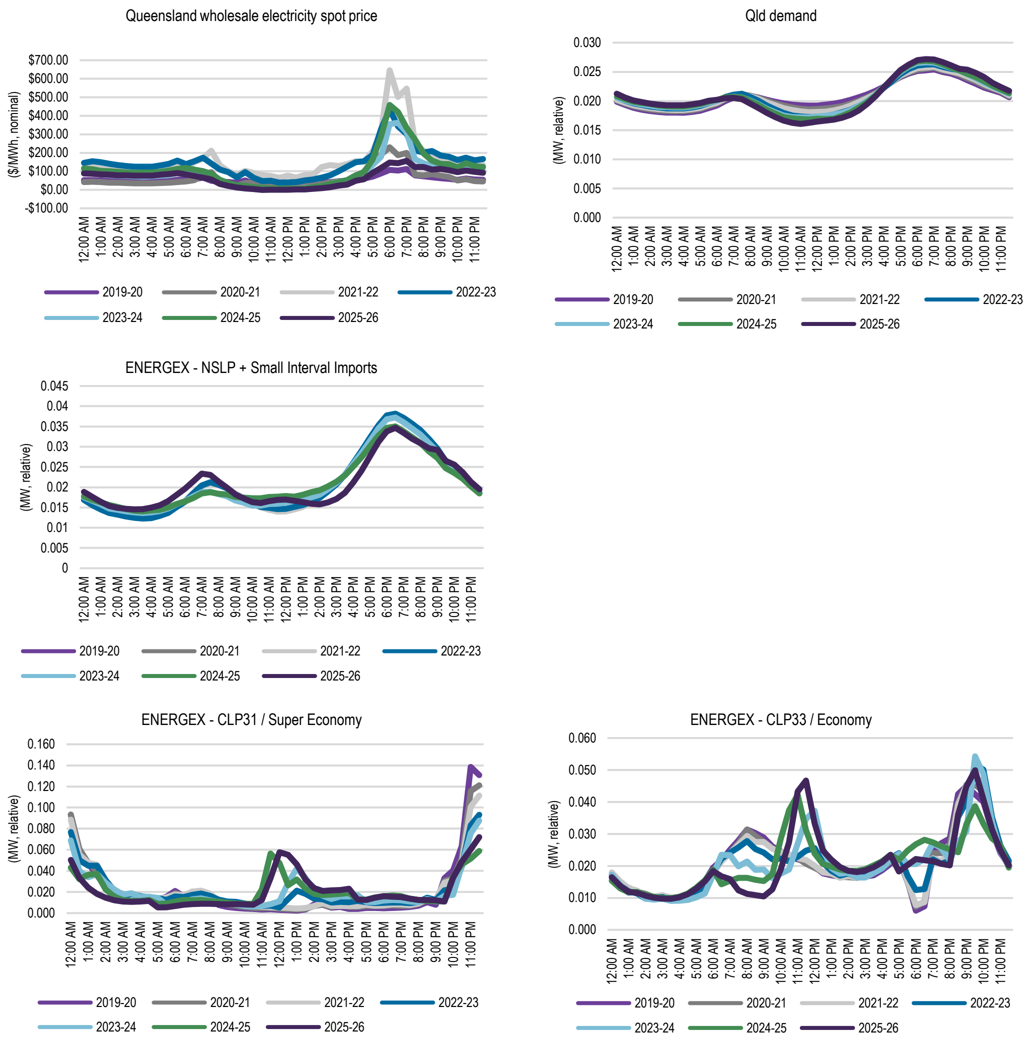
However, over the past few years the rate of carve out of the NSLPs has slowed and this is most likely due to new rooftop solar PV installations being paired with the installation of interval meters – removing those consumers from the NSLP. For this reason, data has been obtained for residential

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

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.

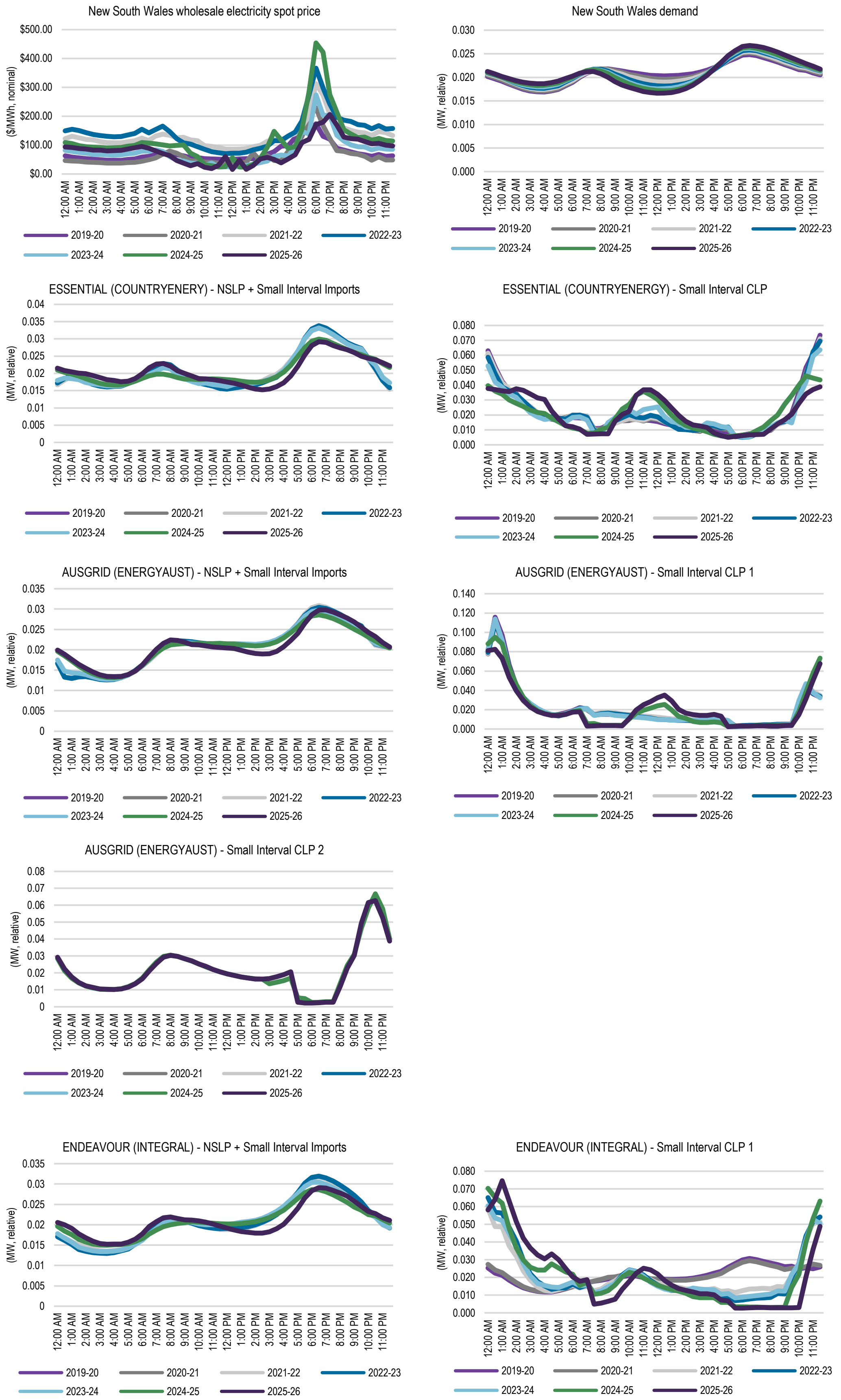
Finally, we note the change in shape of the CLPs, with the WEC estimation methodology now using interval meter CLP data direct from the DNSPs, rather than the accumulation meter sample set from AEMO. In all cases the interval meter CLP data show an increased trend in shifting load to daylight hours – when spot prices are much lower due to the large amounts of rooftop and utility scale PV generating into the market.

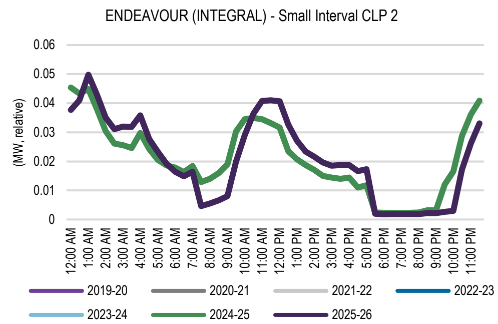
Figure 3.1 Actual average time of day wholesale electricity spot price ($/MWh, nominal) and load profiles (MW, relative) – Queensland – 2019-20 to 2025-26



Source: ACIL Allen

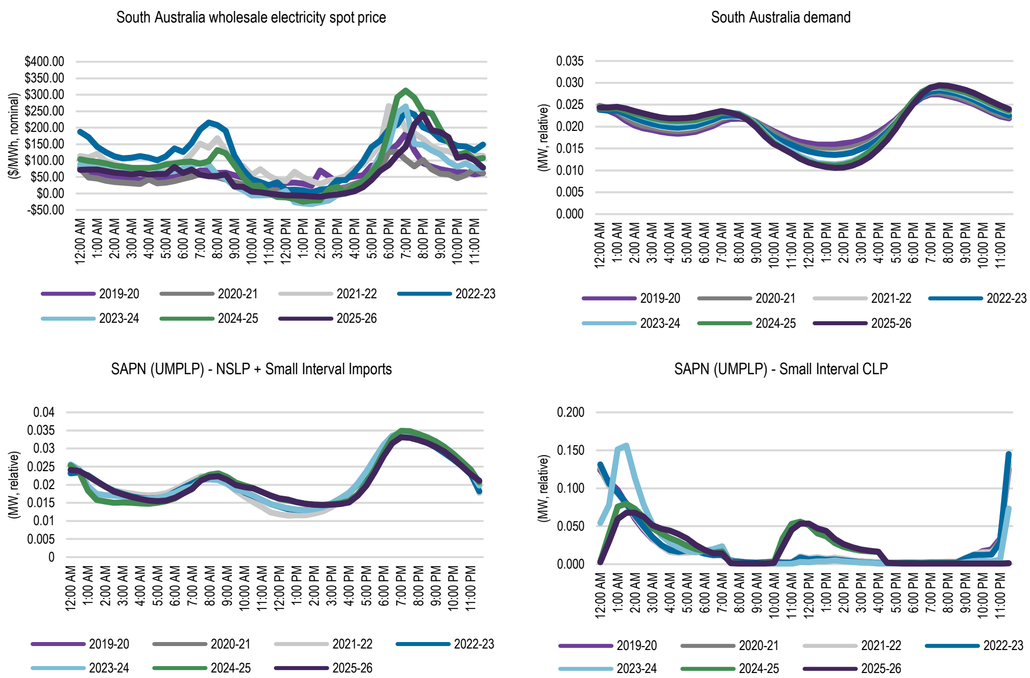
Figure 3.2 Actual average time of day wholesale electricity spot price ($/MWh, nominal) and load profiles (MW, relative) – New South Wales – 2019-20 to 2025-26





Source: ACIL Allen

Figure 3.3 Actual average time of day wholesale electricity spot price ($/MWh, nominal) and load profiles (MW, relative) – South Australia – 2018-19 to 2024-25

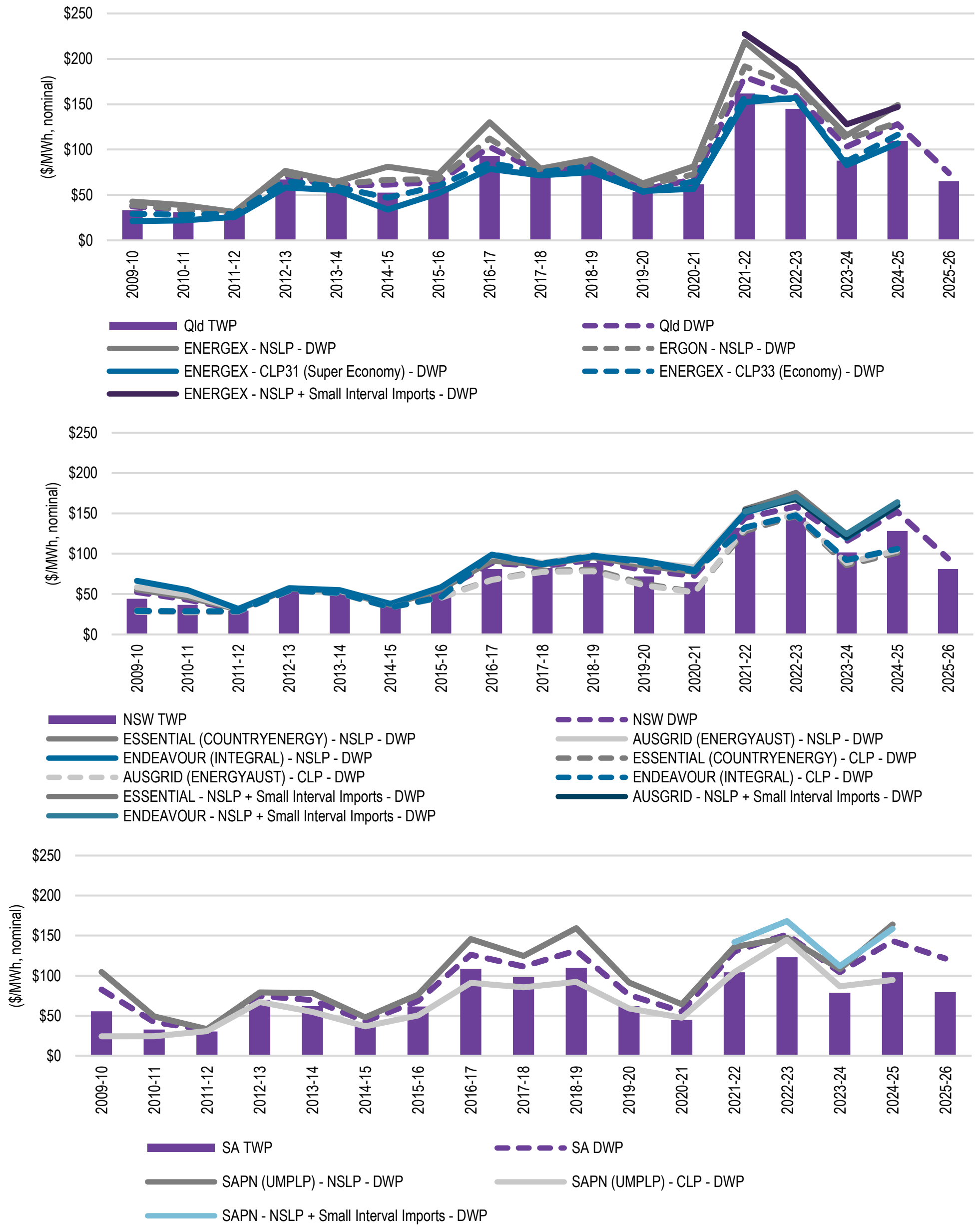


Source: ACIL Allen

The graphs in Figure 3.4 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 37, 23 and 44 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 3.4 Actual annual average demand weighted price ($/MWh, nominal) by profile and regional time weighted average price ($/MWh, nominal) – 2009-10 to 2024-25



Note: Values reported are spot (or uncontracted) prices. 2025-26 price series includes data up to February 2026. Insufficient NSLP/CLP/Interval meter data available for 2025-26

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 3.5.

Compared with the 2025-26:

— Futures base contract prices for 2026-27 on an annualised and trade weighted basis to date, have:
  – decreased by about $4.20/MWh for Queensland
  – decreased by about $8.20/MWh for New South Wales
  – decreased by about $2.90/MWh for South Australia.
— Cap contract prices for 2026-27 on an annualised and trade weighted basis to date, have:
  – decreased by about $4.30/MWh for Queensland
  – decreased by about $4.20/MWh for New South Wales
  – decreased by about $4.40/MWh for South Australia.

In Queensland, the base and cap contract prices have decreased by a similar value – suggesting the market is expecting the majority of the overall price change between 2025-26 and 2026-27 to be driven by a decrease in price volatility.

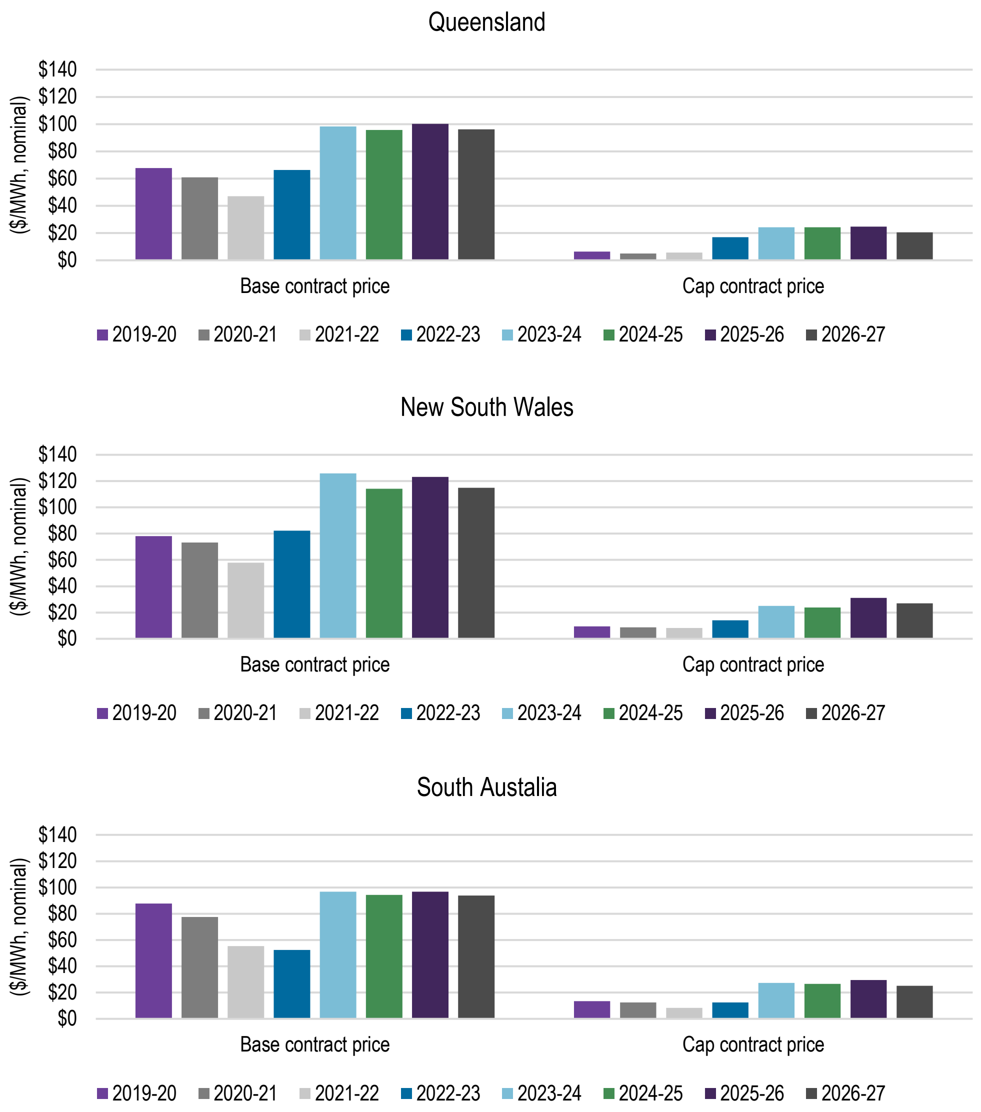
Whereas in New South Wales, the stronger decrease in base contract prices suggests the market is expecting the decrease to be driven more by a reduction in the underlying price. And the converse holds true for South Australia.

In our reports for 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 is no longer the case – there is a stabilisation of the load profiles due to the relatively strong uptake of behind the meter BESS which offsets to continued uptake of rooftop PV.

And as noted earlier, over the next 12-18 months about 8.7 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 in 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 3.5 Base, and Cap trade weighted average contract prices ($/MWh, nominal) – 2019-20 to 2026-27



Source: ACIL Allen analysis of ASX Energy Data

3.2 Estimation of the Wholesale Energy Cost

Estimating contract prices

Contract prices for the 2026-27 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 20 February 2026.

Table 3.1 to Table 3.3 show the estimated quarterly base and cap contract prices for 2026-27.

Table 3.1 Estimated contract prices ($/MWh, nominal) - Queensland

	Q3	Q4	Q1	Q2
		2025-26		
Base	$97.19	$90.36	$120.99	$92.89
Cap	$19.10	$20.39	$41.90	$17.97
		2026-27		
Base	$93.37	$91.35	$111.57	$88.37
Cap	$15.63	$17.35	$33.43	$15.58
		Percentage change from 2025-26 to 2026-27		
Base	-4%	1%	-8%	-5%
Cap	-18%	-15%	-20%	-13%

Source: ACIL Allen analysis using ASX Energy data

Table 3.2 Estimated contract prices ($/MWh, nominal) – New South Wales

	Q3	Q4	Q1	Q2
		2025-26		
Base	$129.30	$108.95	$126.20	$128.10
Cap	$27.65	$25.96	$42.38	$28.54
		2026-27		
Base	$120.42	$106.38	$112.87	$119.84
Cap	$25.74	$23.17	$34.02	$24.79
		Percentage change from 2025-26 to 2026-27		
Base	-7%	-2%	-11%	-6%
Cap	-7%	-11%	-20%	-13%

Source: ACIL Allen analysis using ASX Energy data

Table 3.3 Estimated contract prices ($/MWh, nominal) – South Australia

	Q3	Q4	Q1	Q2
		2025-26		
Base	$111.21	$66.14	$98.26	$111.84
Cap	$25.58	$20.89	$47.24	$24.57
		2026-27		
Base	$109.20	$61.07	$95.82	$109.74
Cap	$22.47	$17.99	$39.14	$20.93
		Percentage change from 2025-26 to 2026-27		
Base	-2%	-8%	-2%	-2%
Cap	-12%	-14%	-17%	-15%

Source: ACIL Allen analysis using ASX Energy data

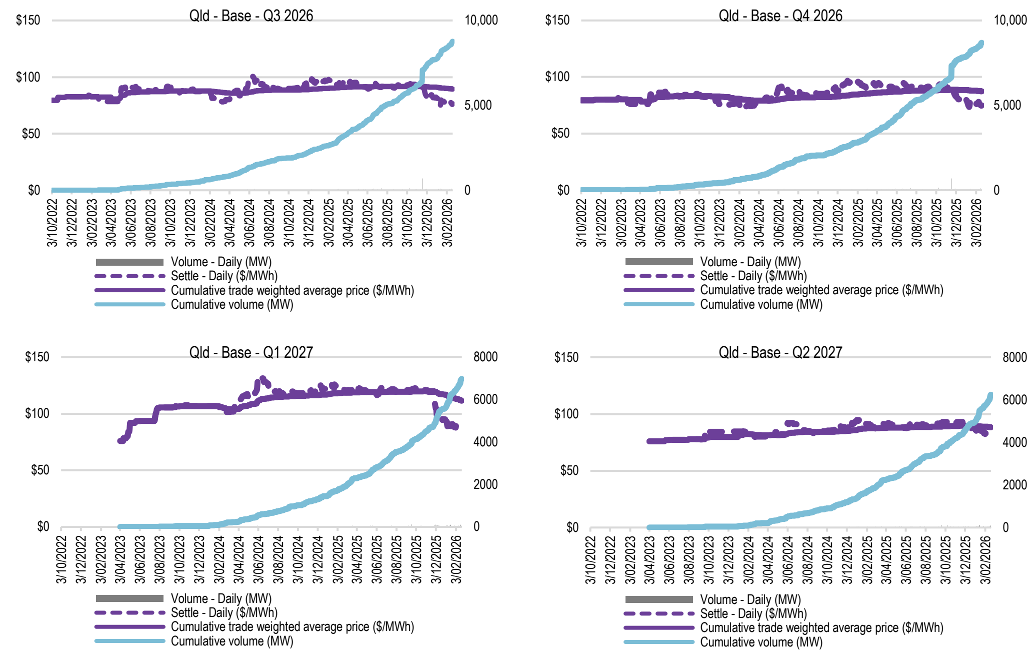
The following charts show daily settlement prices and trade volumes for 2026-27 ASX Energy quarterly base and cap futures contracts up to 20 February 2026. It can be seen that the trading of these contracts tends to commence from mid to late 2023. That said, the volume of trades prior to

2024 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 7. Although ASX Energy now facilitates trade in morning and evening peak contracts, very few trades have occurred to date. ACIL Allen will continue to monitor the development of the market for these new hedge products.

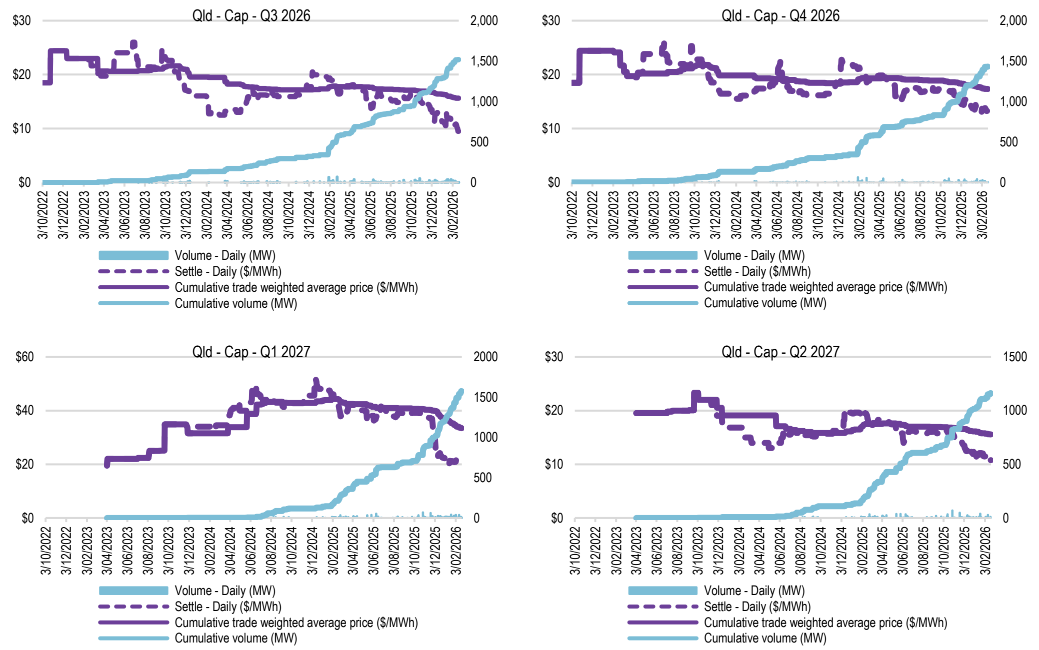
Contract prices tended to decrease in mid-2025 to late-2025 – corresponding with the decrease in LNG prices as shown in Figure 3.12. There has been a further decline at the end of 2026 – possibly due to the increase in the amount of committed BESS capacity coming into the market in 2026-27, as well as the delay in closure of three of the Torrens Island B generator units in South Australia.

Figure 3.6 Time series of trade volume and price – ASX Energy base futures - Queensland



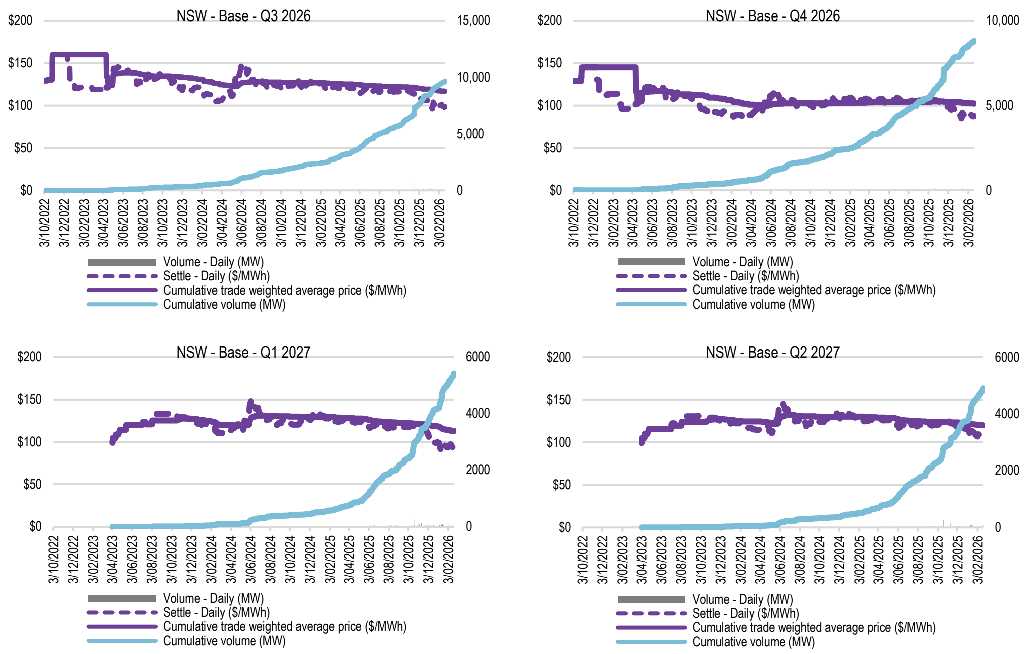
Source: ACIL Allen analysis using ASX Energy data

Figure 3.7 Time series of trade volume and price – ASX Energy $300 cap futures - Queensland



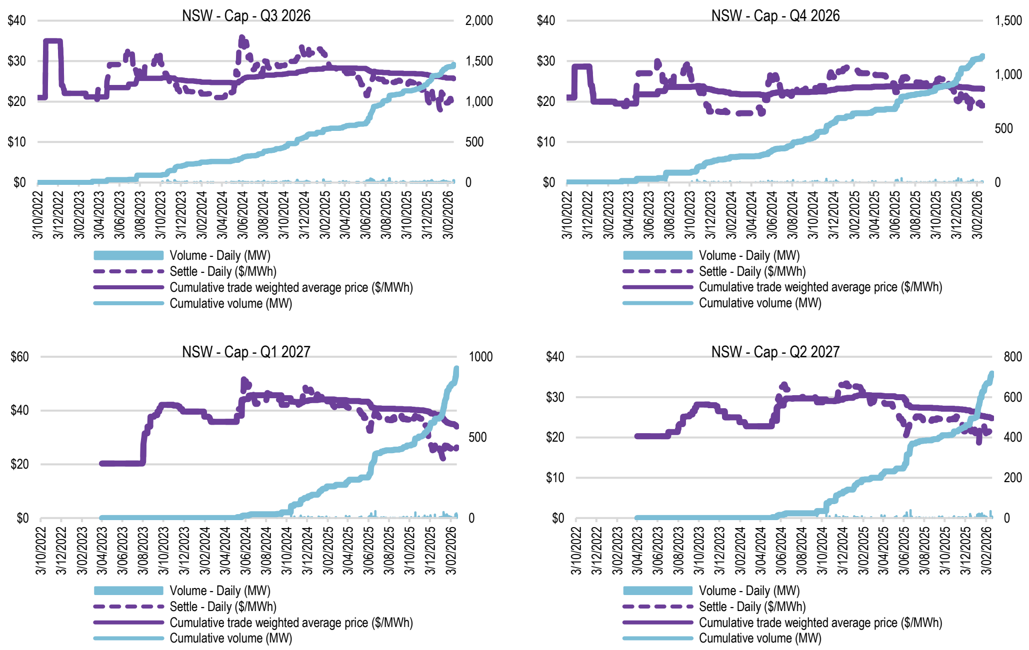
Source: ACIL Allen analysis using ASX Energy data

Figure 3.8 Time series of trade volume and price – ASX Energy base futures – New South Wales



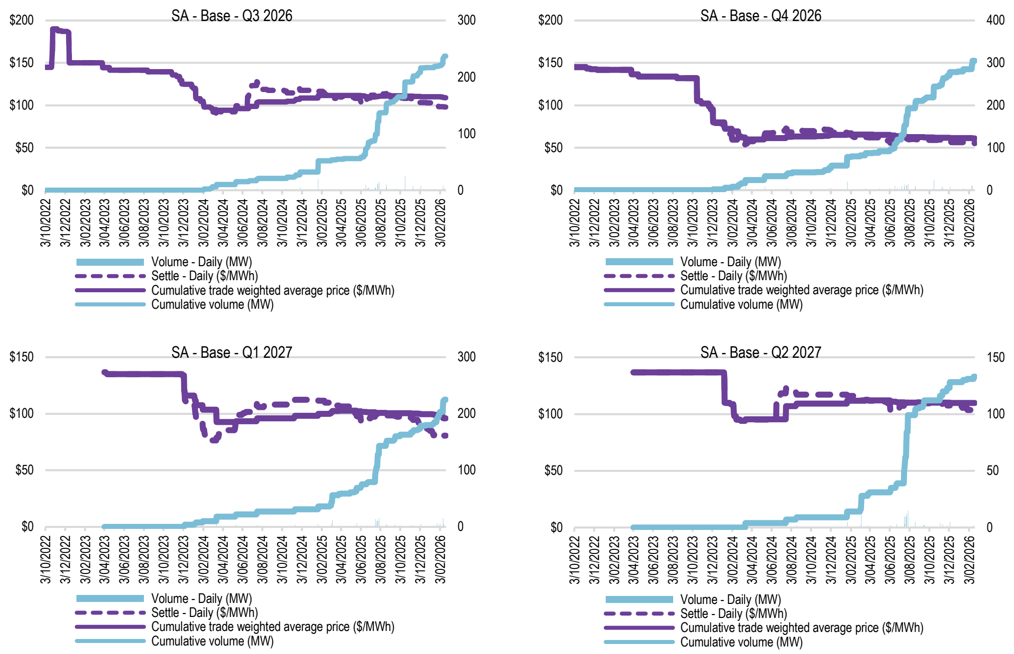
Source: ACIL Allen analysis using ASX Energy data

Figure 3.9 Time series of trade volume and price – ASX Energy $300 cap futures – New South Wales



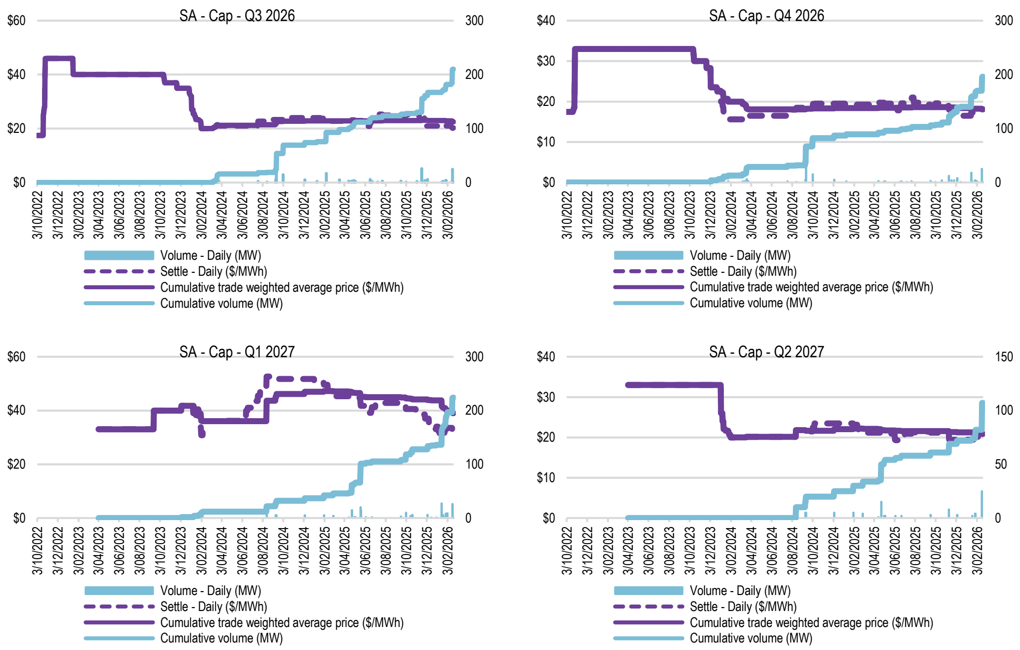
Source: ACIL Allen analysis using ASX Energy data

Figure 3.10 Time series of trade volume and price – ASX Energy base futures –South Australia



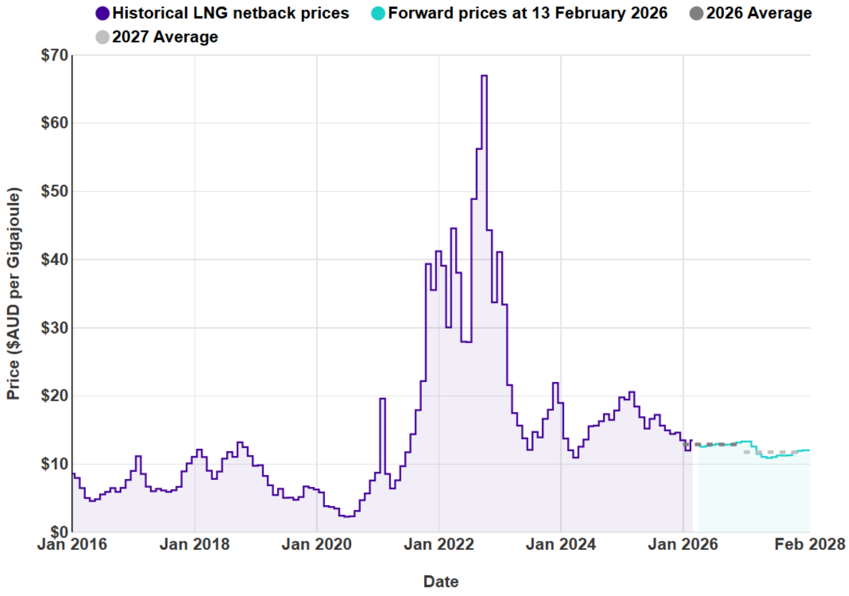
Source: ACIL Allen analysis using ASX Energy data

Figure 3.11 Time series of trade volume and price – ASX Energy $300 cap futures – South Australia



Source: ACIL Allen analysis using ASX Energy data

Figure 3.12 LNG netback prices



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

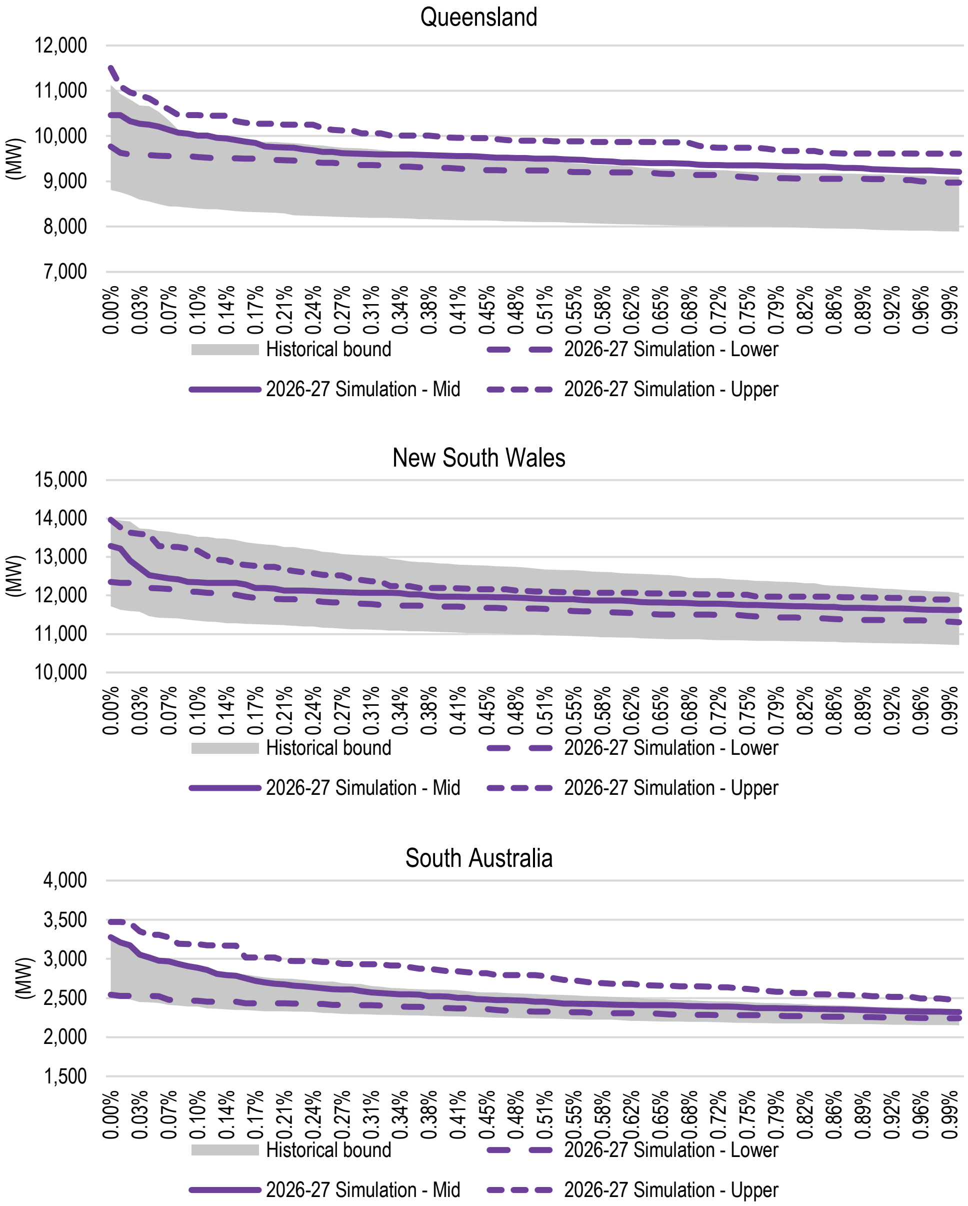
Estimating wholesale spot prices

ACIL Allen's proprietary electricity model, *PowerMark* was run to estimate the hourly regional wholesale spot prices for the 605 simulations (55 demand and 11 outage sets).

Figure 3.13 shows the range of the upper one percent segment of the demand duration curves for the 55 simulated Queensland, New South Wales and South Australia regional system demand sets resulting from the methodology for 2026-27, 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 55 simulated sets. It can be seen that the demand duration curves of the simulated demand sets for 2026-27 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.

It should not be expected that the simulated demand sets line up perfectly with the historical demand sets, in terms of their absolute location. For example, the simulated demand sets for 2026-27 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 2026-27 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 3.13 Comparison of upper one per cent of hourly regional system demands of 2026-27 simulated hourly demand sets with historical outcomes



Source: ACIL Allen analysis and AEMO data

Figure 3.14 shows the range of the simulated NSLP and interval meter imports envelope recent actual outcomes. This variation results in the annual load factor[15] of the 2026-27 simulated demand sets ranging between:

— 27 per cent and 35 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 3.15)

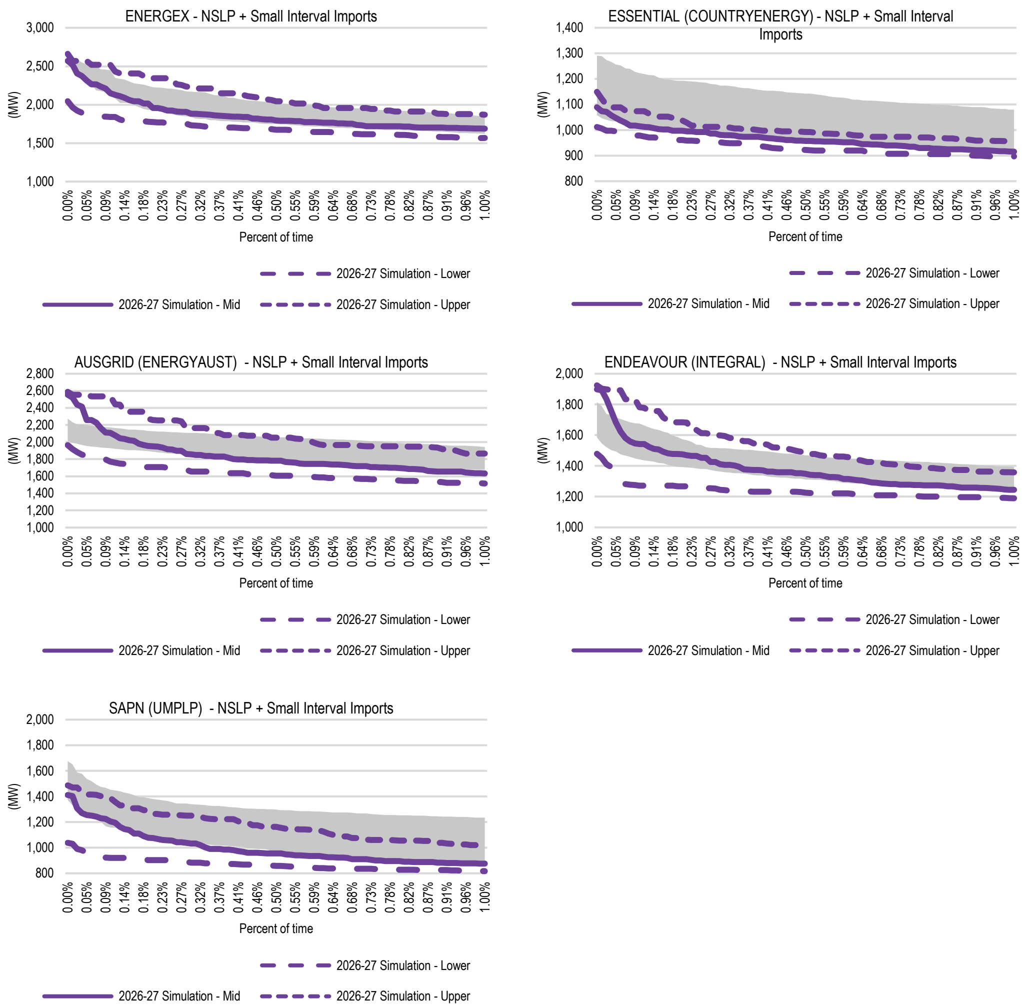
— 39 per cent and 45 per cent compared with a range of 39 per cent to 45 per cent for the actual Essential NSLP and small customer interval meter demands

[15] 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.

— 30 per cent and 42 per cent compared with a range of 38 per cent to 43 per cent for the actual Ausgrid NSLP and small customer interval meter demands
— 29 per cent and 38 per cent compared with a range of 32 per cent to 38 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 25 per cent to 33 per cent for the actual SAPN NSLP and small customer interval meter demands.

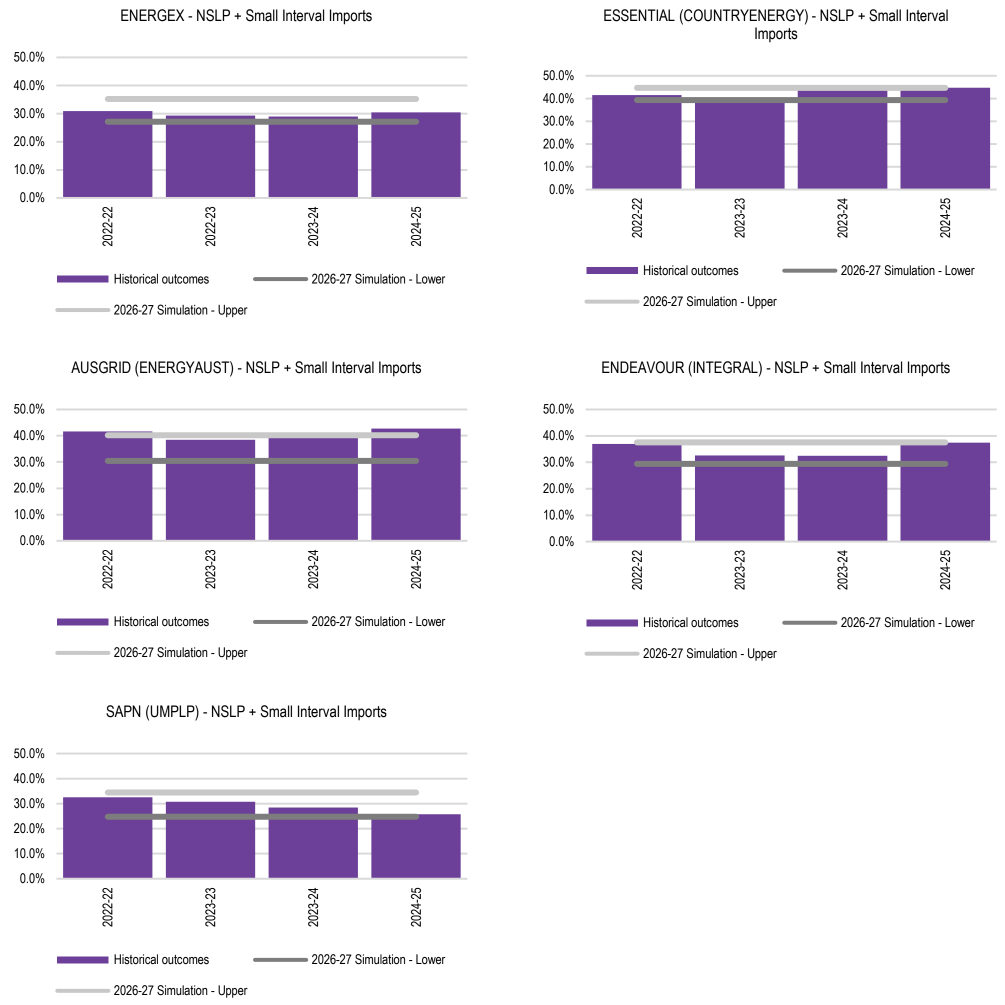
All other things being equal, an increased peakiness of the load, which is hedged under the methodology, is likely to result in a larger degree of over hedging across the general day-time peak periods, resulting in a larger degree of over hedging overall on an annual basis, which means estimated hedging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

Figure 3.14 Comparison of upper one per cent of hourly NSLP and small interval meter import demands of 2026-27 simulated hourly demand sets with historical outcomes



Source: ACIL Allen analysis and AEMO data

Figure 3.15 Comparison of load factor of 2026-27 simulated hourly demand sets with historical outcomes – NSLP and small interval meter import demand



Note: Based on data available for October 2021 to June 2025.

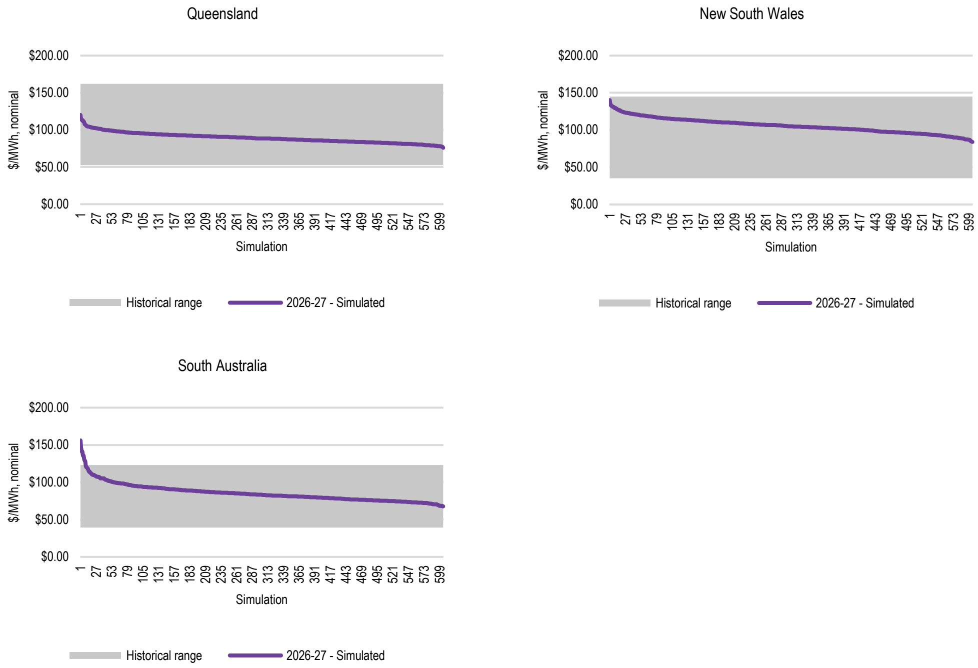
Source: ACIL Allen analysis and AEMO data

Figure 3.16 compares the modelled annual regional TWP for the 605 simulations for 2026-27 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 2026-27 when compared with the past 10 years of history.

It is worth noting that the simulations project a larger range in annual average spot price outcomes in South Australia for 2026-27 compared with history. The simulations include 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. Following completion of testing in January 2025, AEMO commenced including stage 1 of PEC in the NEMDE from 11 April 2025[16]. 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 directly only.

[16] Refer to AEMO's market notice MN126466 at https://www.aemo.com.au/market-notices.

Figure 3.16 Simulated annual TWP for Queensland, New South Wales, and South Australia for 2026-27 compared with range of actual annual outcomes in past years

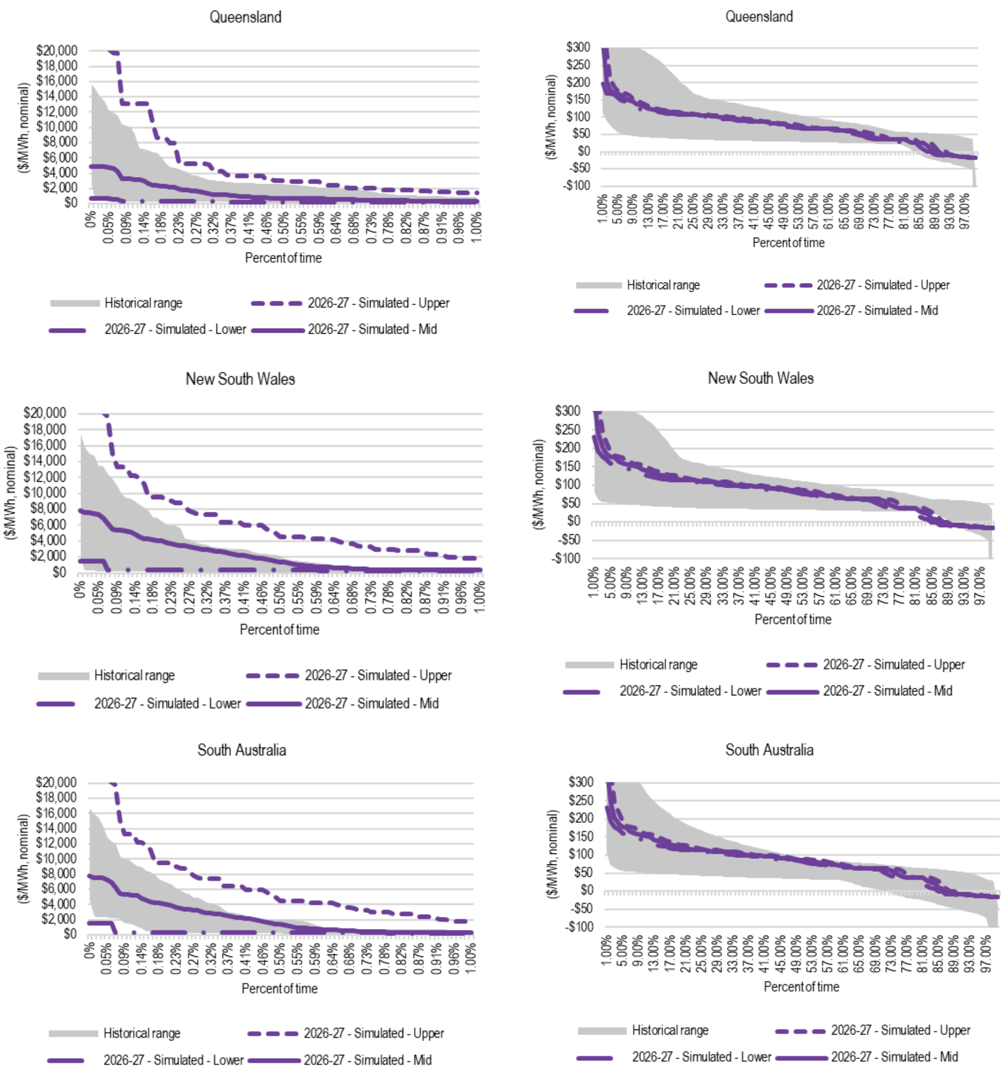


Source: ACIL Allen analysis and AEMO data

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 3.17. 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 3.17 also shows there is longer an 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 – this is due to the rapid uptake of behind the meter BESS and commissioning of utility scale BESS.

The variation in the simulated hourly price duration curves in the right panels of Figure 3.17 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 3.17 Comparison of simulated hourly price duration curves for Queensland, New South Wales, and South Australia for 2026-27 and range of actual outcomes in past years

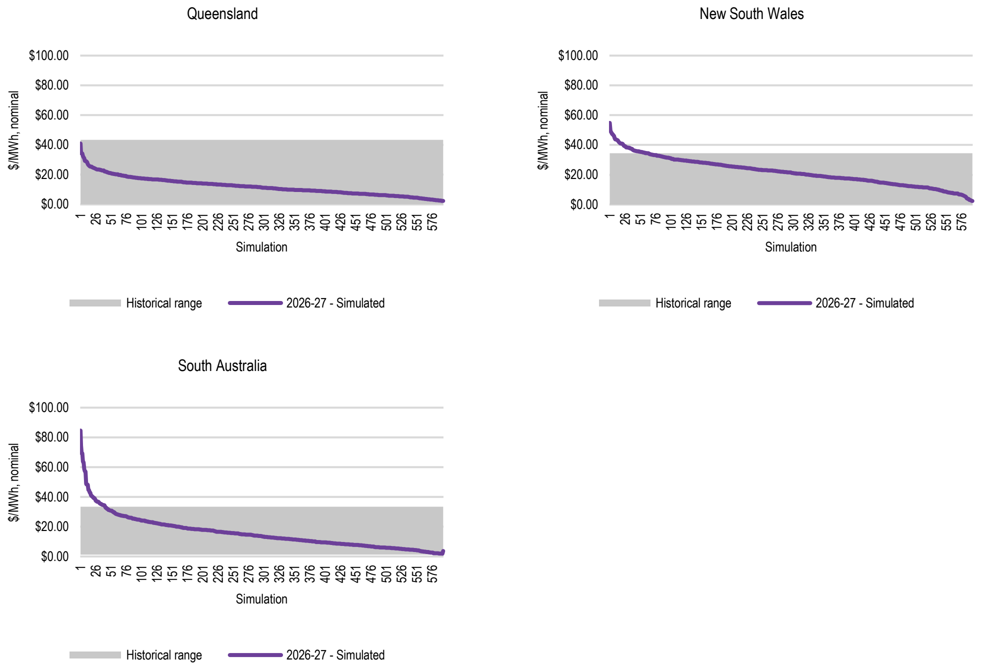


Note: Graphs in left column show upper one per cent of price outcomes; graphs in right column show lower 99 per cent of price outcomes.

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 605 simulations. The range in annual average contribution to the TWP, of hourly prices above $300/MWh, for the simulations is consistent with those recorded in history as shown in Figure 3.18. For some of the 2026-27 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 3.18 Annual average contribution to the Queensland, New South Wales, and South Australia TWP by prices above $300/MWh in 2026-27 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.

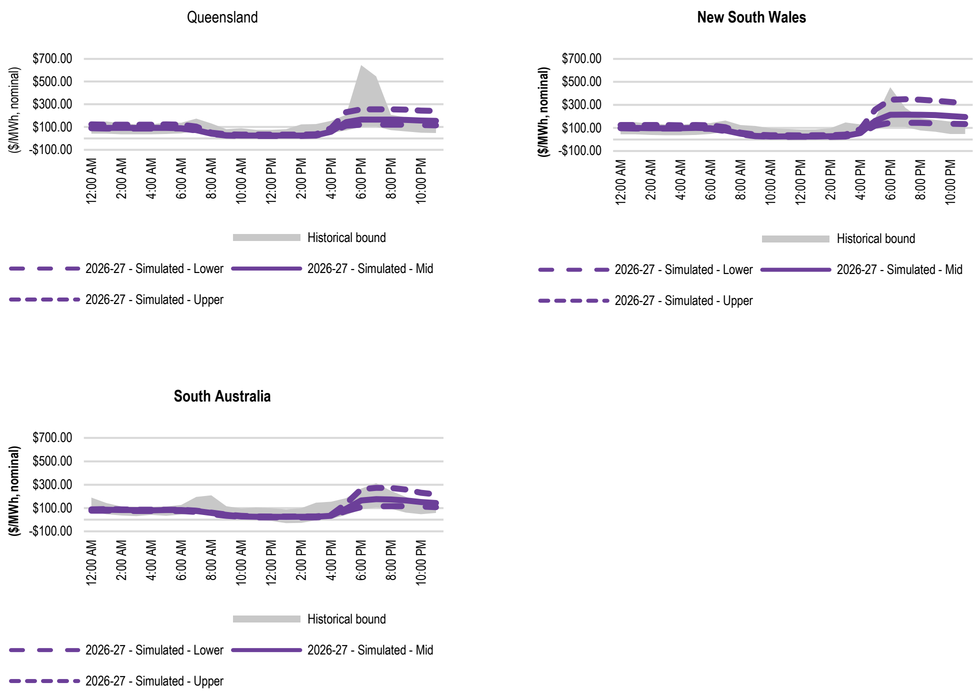
A test of the appropriateness of the simulated demand shape and its relationship with the regional demand shape can be undertaken by comparing the annual demand weighted price (DWP) for the given demand profile with the corresponding regional TWP. Figure 3.19 shows that, for the past four financial years, 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 605 simulations for 2026-27 for each NSLP and interval meter demand profile, this percentage varies from 17 percent to 21 percent.

The modelling undertaken for previous determinations suggested an increasing trend in the premium as a result of 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 (as shown in Figure 3.19). However, this is not the case for the 2026-27 simulations. As noted earlier, the rapid rollout of utility scale BESS is projected to substantially change the time-of-day wholesale spot price profile in 2026-27 by stabilising prices during daylight hours (when BESS are recharging and hence increasing demand) and smoothing out the evening peak, which is resulting in a decline in the shape premium (as shown in Figure 3.20).

Figure 3.19 Simulated annual DWP for NSLP and Interval meter demand as a percentage premium of annual TWP for 2026-27 compared with range of actual outcomes in past years, and market share of utility scale solar (%)

Source: ACIL Allen

Figure 3.20 Annual average time of day wholesale spot prices for New South Wales, and South Australia in 2026-27 for simulations compared with range of actual outcomes in past years



Source: ACIL Allen

ACIL Allen is satisfied the modelled regional wholesale spot prices from the 605 simulations cover the range of expected price outcomes for 2026-27 across all three regions in terms of annual averages and distributions. These comparisons clearly show that the 55 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 2026-27, including the change in price shape due to the rapid entry of utility scale and behind the meter BESS.

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 (using the approach described in section 2.3).

Contract volumes for 2026-27 are calculated based on the blended NSLP and interval meter import demand 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 Endeavour, of all hourly demands across all 55 demand sets for the quarter[17].

[17] The selection of different percentiles for base contracts reflects the different shapes of the demand sets – with Ausgrid and Endeavour generally having a relatively lower carve out during daylight hours, and hence a relatively flatter profile which lends itself to a higher coverage with base contracts.

— The cap contract volume is set at 100 per cent for all profiles, of the median of the annual peak demands across the 55 demand sets minus the base contract volumes.

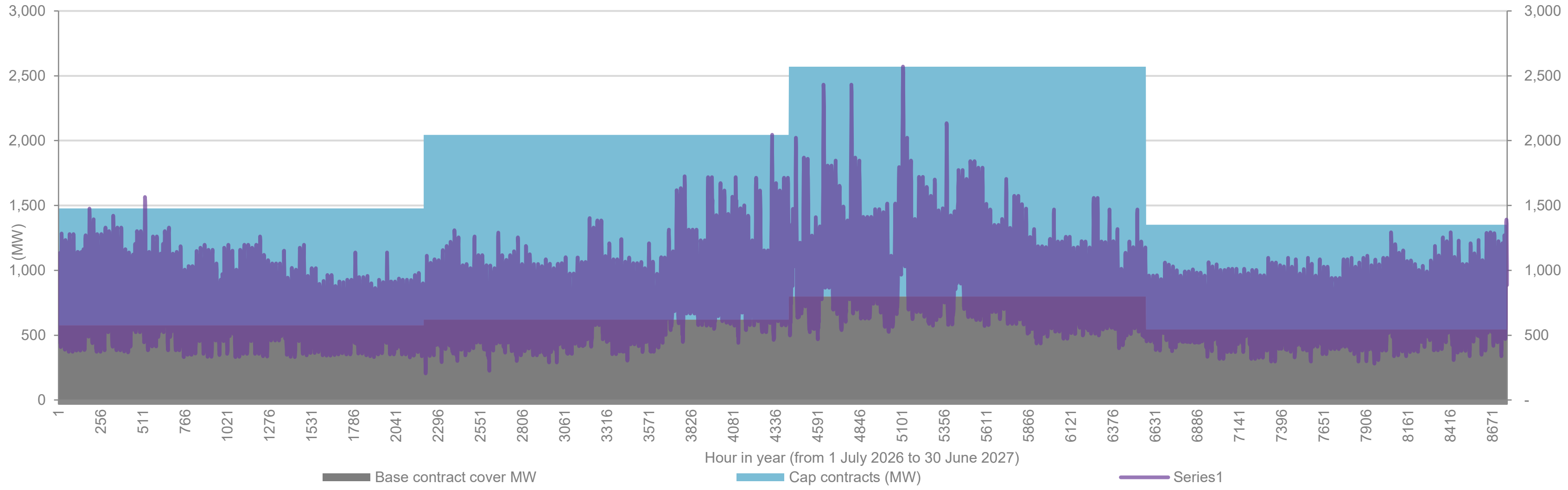
These same hourly hedge volumes (in MW terms) apply to each of the 55 demand sets for a given NSLP and interval meter import demand and year, and hence to each of the 605 simulations. To be clear, the hedge volumes (in MW terms) are not altered on an ex-post basis for each of the 55 demand sets. Therefore, the approach adopted 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 605 simulations when calculating the wholesale energy cost. The contract volumes used are shown in Figure 3.21 to Figure 3.25.

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.

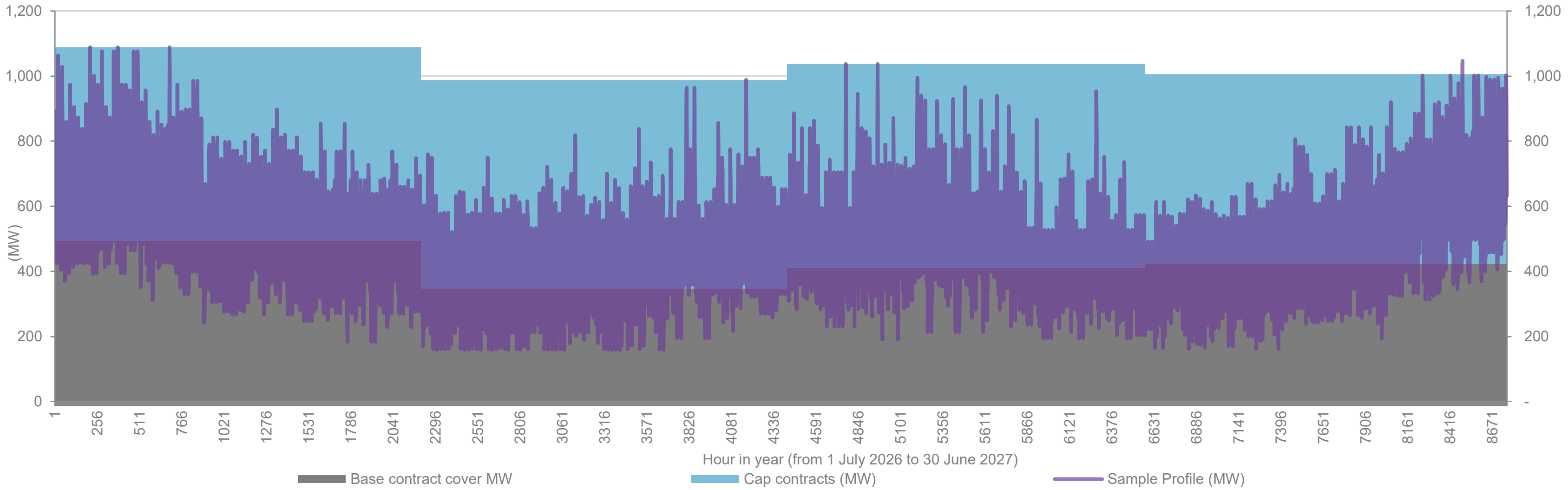
The example profile in Figure 3.21 is from a simulation that includes loads above the P50 peak in some cases and hence are not 100 per cent covered by hedge contracts.

Figure 3.21 Contract volumes used in hedge modelling of 605 simulations for 2026-27 for Energex



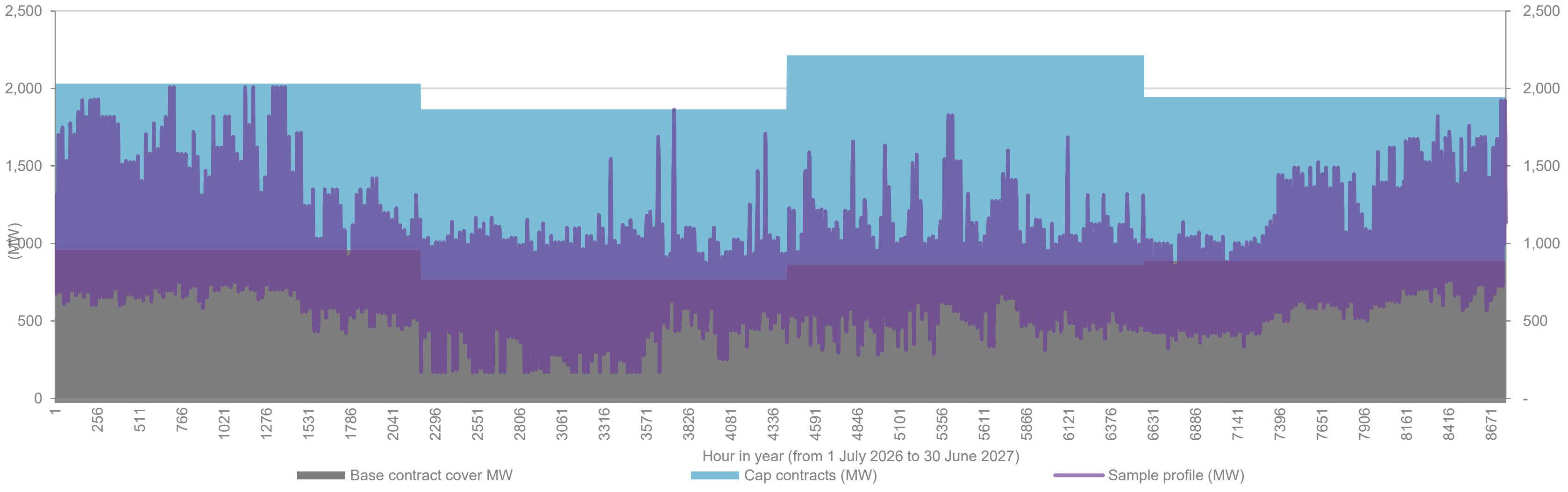
Source: ACIL Allen

Figure 3.22 Contract volumes used in hedge modelling of 605 simulations for 2026-27 for Essential (COUNTRYENERGY)



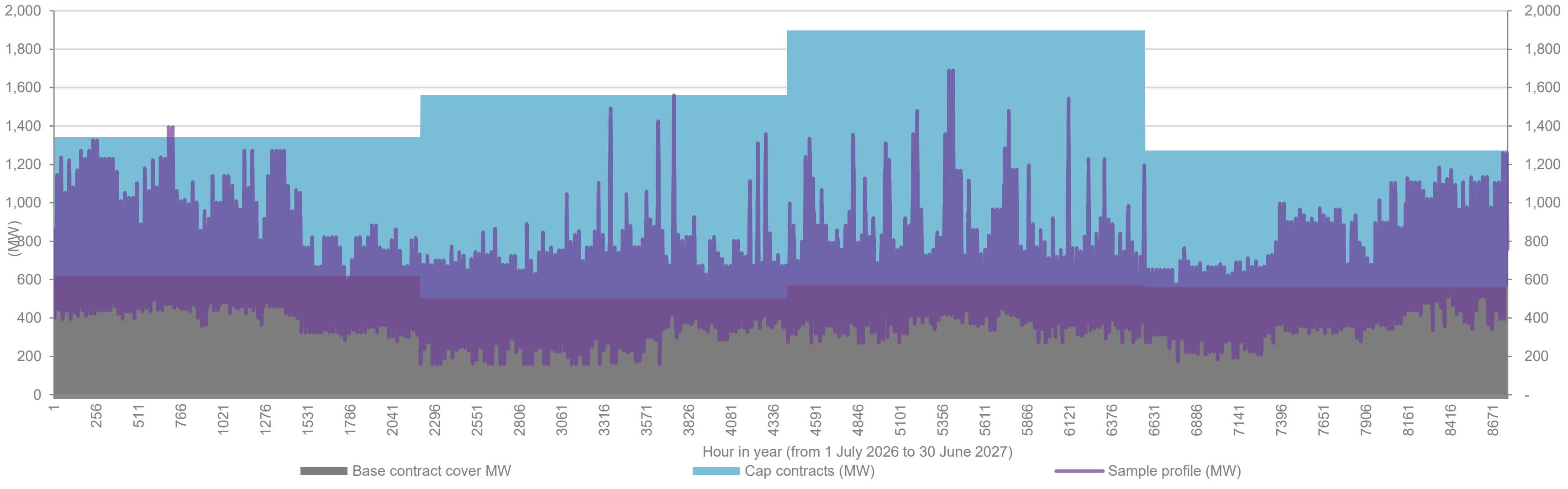
Source: ACIL Allen

Figure 3.23 Contract volumes used in hedge modelling of 605 simulations for 2026-27 for Ausgrid (ENERGYAUST)



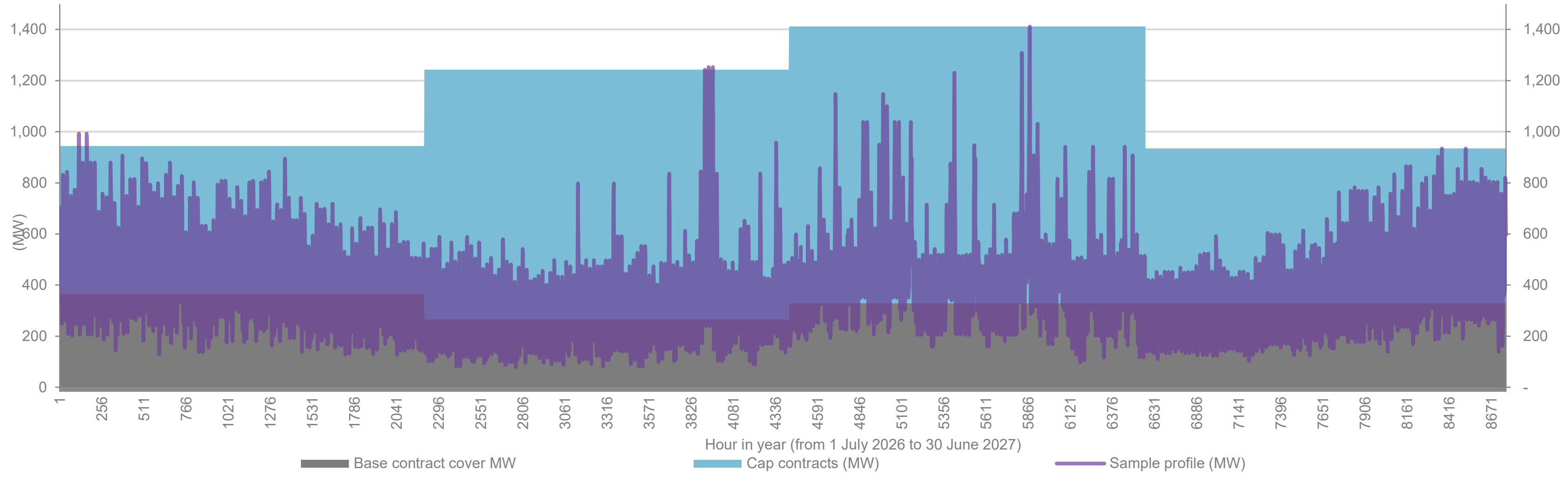
Source: ACIL Allen

Figure 3.24 Contract volumes used in hedge modelling of 605 simulations for 2026-27 for Endeavour (INTEGRAL))



Source: ACIL Allen

Figure 3.25 Contract volumes used in hedge modelling of 605 simulations for 2026-27 for SAPN (UMPLP)

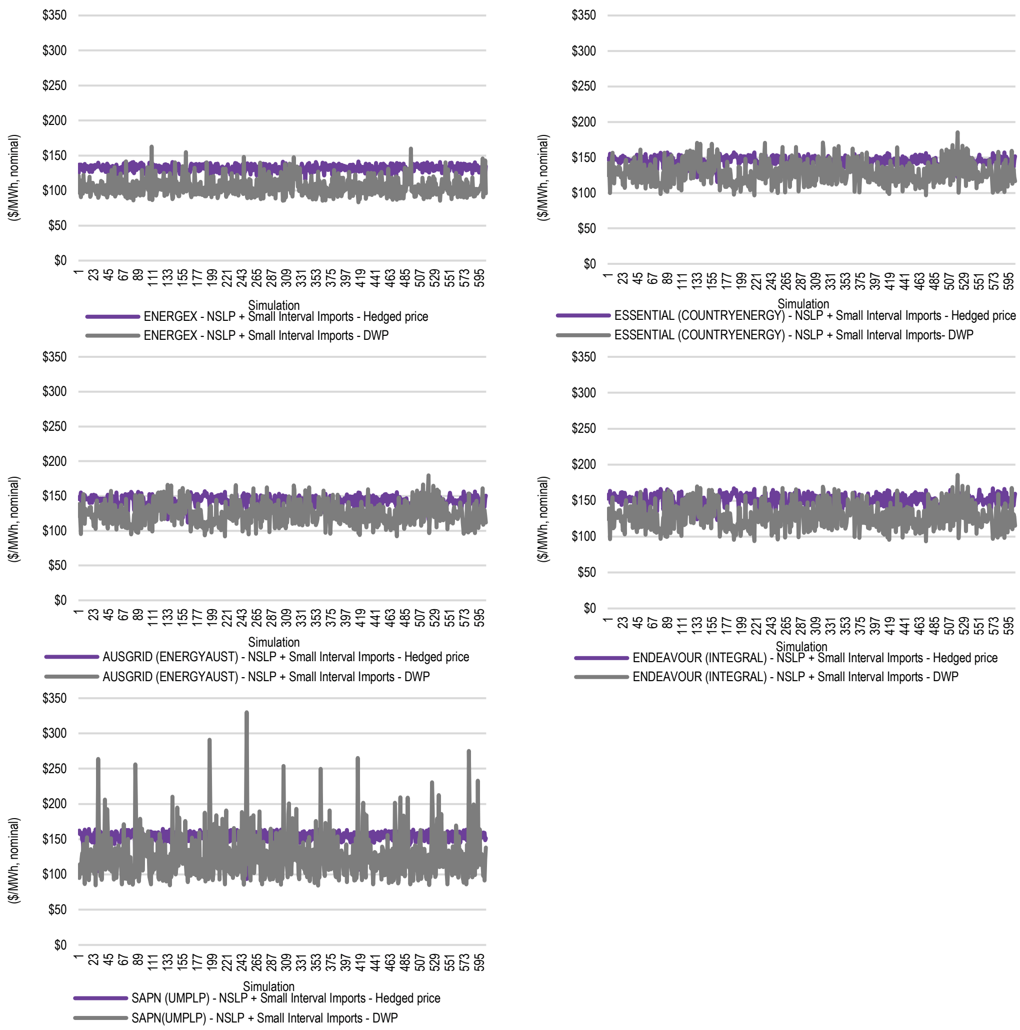


Source: ACIL Allen

Figure 3.26 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 higher than the spot price simulations, and higher than the current consensus view of outcomes for 2026-27.

Figure 3.26 Annual hedged price and DWP ($/MWh, nominal) for NSLP + small interval meter demands for the 605 simulations – 2026-27



Source: ACIL Allen

Summary of estimated Wholesale Energy Cost

After applying the hedge model, the final WEC estimate is taken as the 50th percentile of the distribution containing 605 WECs plus 10% of the difference between the 100th and 50th percentile WECs. The estimate of the WEC for each demand profile for 2026-27 are shown in Table 3.4 and compared to the WEC estimates in the 2025-26 Final Determination.

Table 3.4 Estimated WEC ($/MWh, nominal) for 2026-27 at the regional reference node

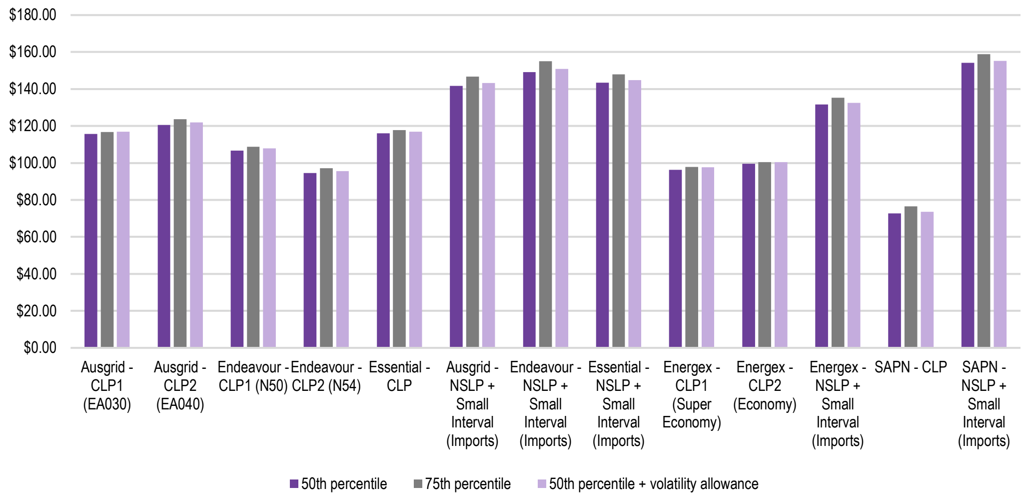
Customer class	2025-26 – Final Determination	2026-27 – Draft Determination	Change from 2025-26 to 2026-27 (%)
Ausgrid – Residential and small business	$161.07	$143.20	-11.09%
Endeavour - Residential and small business	$167.47	$150.93	-9.88%
Essential - Residential and small business	$165.17	$144.81	-12.33%
Ausgrid - CLP1	$113.70	$116.87	2.78%
Ausgrid - CLP2	$115.48	$122.03	5.67%
Endeavour – CLP1	$118.46	$107.90	-8.91%
Endeavour – CLP2	NA	$95.57	NA
Essential - CLP	$115.47	$116.84	1.19%
Energex - Residential and small business	$150.63	$132.60	-11.97%
Energex – CLP31	$102.21	$97.63	-4.49%
Energex – CLP33	$108.67	$100.48	-7.54%
SAPN - Residential and small business	$168.16	$155.29	-7.66%
SAPN - CLP	$101.46	$73.64	-27.42%

Note: The WECs for 2025-26 are the 75th percentile WEC; the WECs for 2026-27 are the 50th percentile WEC plus the volatility allowance.

Source: ACIL Allen

When adding on the volatility allowance, the resulting WEC sits between the 50th and 75th percentile WEC as shown in Figure 3.27

Figure 3.27 Estimated WEC ($/MWh, nominal) for 2026-27 at the regional reference node



Source: ACIL Allen

The 2026-27 WECs for the NSLP plus small interval meter import demands decrease by between 7 and 12 per cent – reflecting the decrease in contracts prices, and the stabilisation of spot prices during daylight hours when demand is at its lowest point and hence over contracted.

The WEC for some of the New South Wales CLPs increase slightly reflecting the change in load shape.

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.

Provided below are the unscaled WECs for the various time of use tariffs.

Table 3.5 Estimated unscaled TOU WEC ($/MWh, nominal) for 2026-27 at the regional reference node

Customer class	Period type	2026-27 – Draft Determination
Ausgrid – Residential and small business	Off-peak	$134.71
	Peak	$171.39
Endeavour - Residential and small business	HS Peak	$129.19
	LS Peak	$198.50
	Off-peak	$172.12
	Solar Soak	$40.30
Essential - Residential and small business	Off-peak	$126.47
	Peak	$163.56
Energex - Residential	Shoulder	$134.48
	Off-peak	$36.96
	Peak	$190.13
Energex - Small Business	Shoulder	$129.08

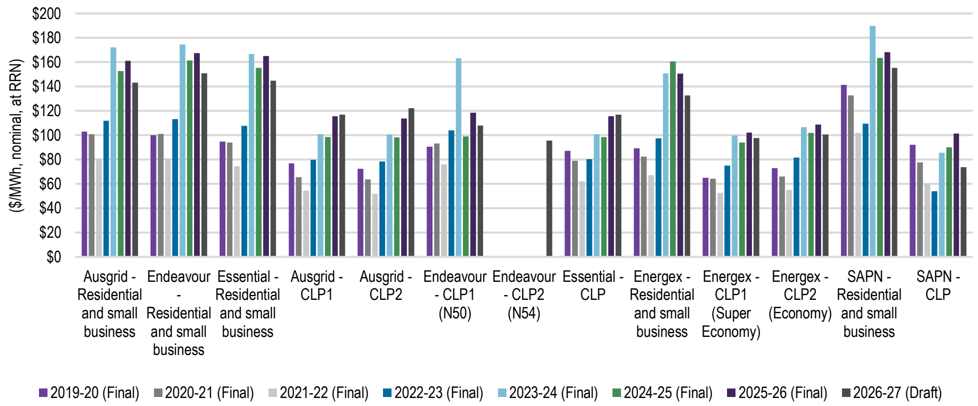
Customer class	Period type	2026-27 – Draft Determination
	Off-peak	$36.02
	Peak	$199.43
SAPN - Residential	Peak	$200.41
	Off-peak	$113.11
	Solar Soak	$41.70
SAPN - CLP	Peak	$106.45
	Off-peak	$99.06
	Solar Soak	$32.82
SAPN - Small Business	Peak	$297.74
	Off-peak	$144.89
	Shoulder	$127.02

Note: The WECs for 2026-27 are the 50th percentile WEC plus the volatility allowance. These values will be scaled by the AER such that the sumproduct of the scaled WECs and energy across the period types equals the product of the flat WEC and total energy.

Source: ACIL Allen

Figure 3.28 shows the trend in WEC over the past DMO determinations.

Figure 3.28 Estimated WEC ($/MWh, nominal) for 2026-27 at the regional reference node in comparison with WECs from previous determinations



Note: The WECs for 2026-27 are the 50th percentile WEC plus the volatility allowance.

Source: ACIL Allen

Do the changes in WEC make intuitive sense?

There has been a decrease in wholesale spot prices over the past 12 months, and this generally aligns with the trend in the estimated WECs.

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.

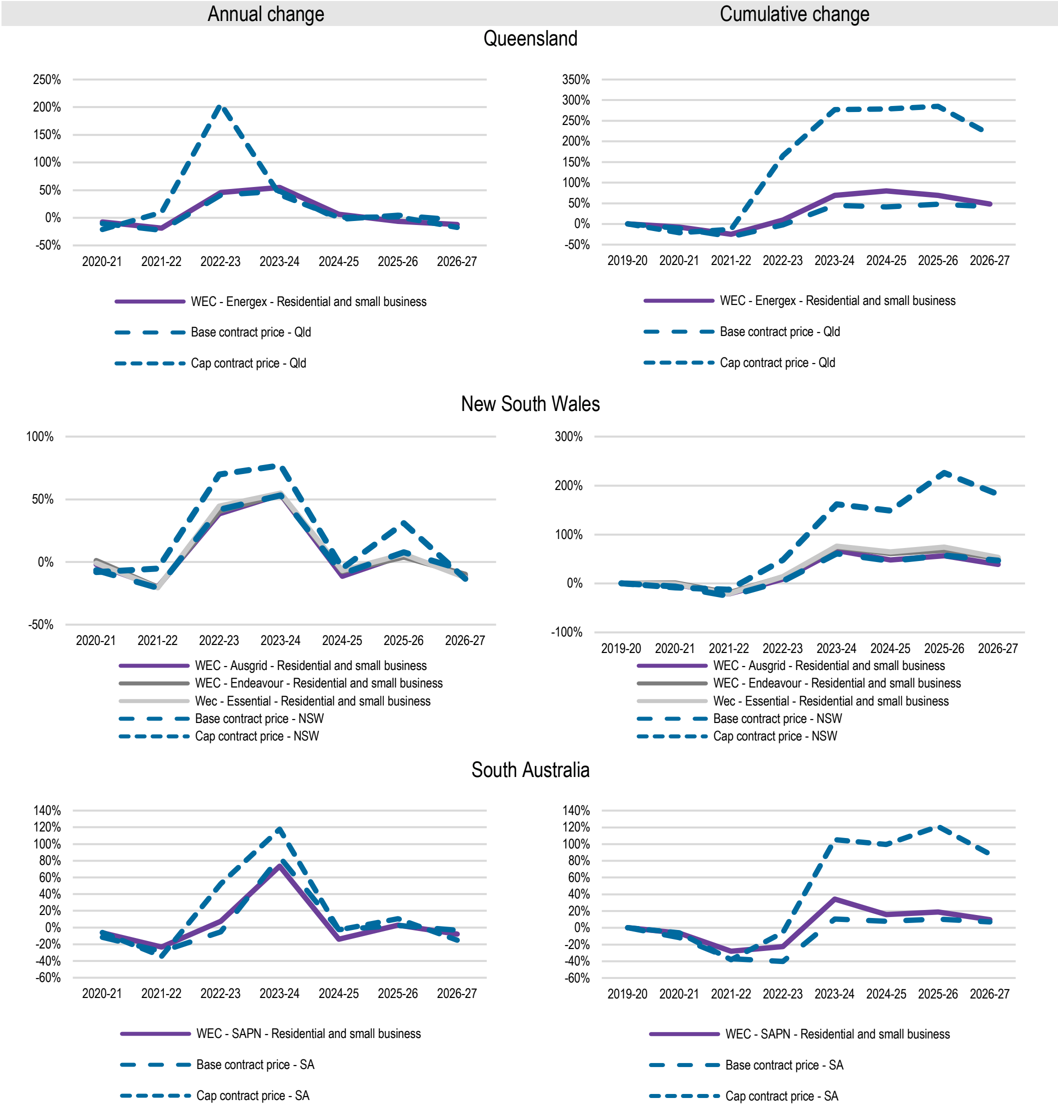
— The trend in WECs aligns very closely to the trend in base contract prices. This is not surprising given the stronger reliance on base contracts in the hedging strategy.

— 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 decreased slightly even though there was a small increase in the trade weighted average base contract prices. This was largely due to the slight flattening of the profile as discussed in our report for the 2025-26 determination.

On this basis, ACIL Allen is satisfied that the methodology is appropriately estimating the WECs for 2026-27, 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.

Figure 3.29 Change in WEC and trade weighted contract prices (%) – 2019-20 to 2026-27



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

Source: ACIL Allen analysis

3.3 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[18]) 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.

[18] 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.

Retailer compliance with these schemes operates on a calendar year basis and hence estimates are required for 2026 and 2027 calendar years, with the costs averaged to estimate the 2026-27 financial year costs.

To estimate the costs to retailers of complying with both the LRET and SRES, the following elements are used:

— historical Large-scale Generation Certificate (LGC) market forward prices for 2026 and 2027 from brokers TraditionAsia
— estimated Renewable Power Percentages (RPP) values for 2026 and 2027 of 16.67 per cent[19]
— binding Small-scale Technology Percentage (STP) value for 2026 of 11.67 per cent, as published by CER
— estimated STP value for 2027 of 10.75 per cent[20]
— CER clearing house price[21] for 2026 and 2027 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.

The average LGC price has been estimated using LGC forward prices provided by broker TraditionAsia up to 20 February 2026.

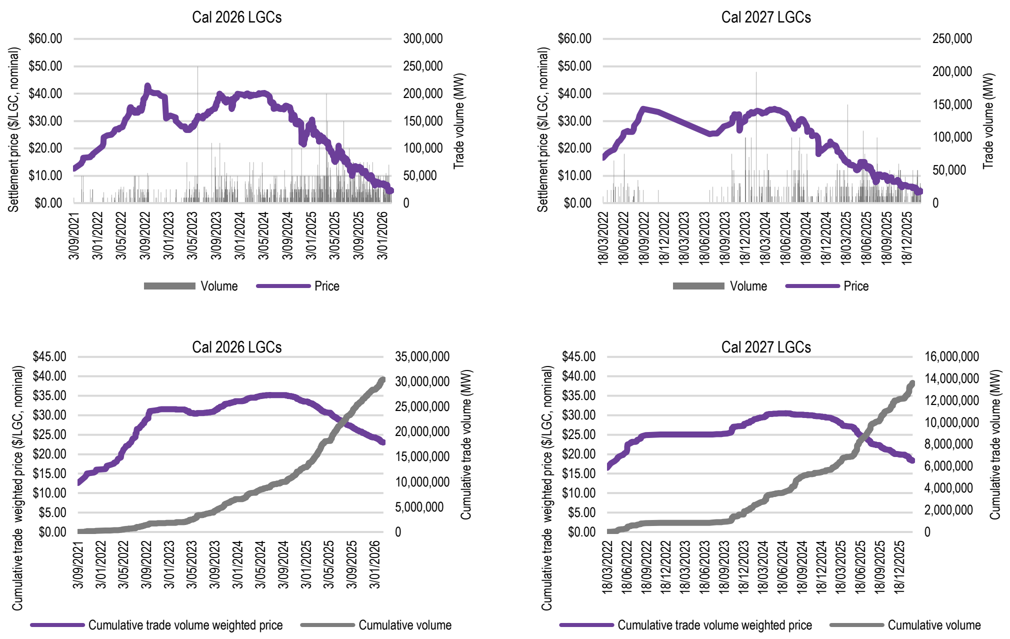
The LGC price used in assessing the cost of the scheme for 2026-27 is found by taking the trade-weighted average of the forward prices for the 2026 and 2027 calendar years, respectively, since the contracts commenced trading. This is typically about 2.5 years prior to the commencement of the compliance year (see Figure 3.30). LGC prices have decreased noticeably over the past 18 months – reflecting the market's expectation of an increasing degree of oversupply as more large-scale renewable energy projects are commissioned. The average LGC prices calculated from the TraditionAsia data are $23.04/MWh for 2026 and $18.28/MWh for 2027.

[19] The RPP values for 2026 and 2027 are based on the CER's published RPP for 2026 and assumes no change in liable acquisitions and the CER-published mandated LRET targets for 2026 and 2027.

[20] The STP value for 2027 is the CER's published non-binding value and aligns closely with ACIL Allen's estimate of the non-binding STP based on our engagement with the CER (see https://cer.gov.au/document/small-scale-technology-certificate-projections-acil-allen-january-2026).

[21] Although there is an active market for STCs, there is no compelling reason 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.

Figure 3.30 LGC prices and trade volumes for 2026 and 2027 ($/LGC, nominal)



Source: ACIL Allen analysis of TraditionAsia

The RPP value for 2027 is yet to be set by the CER. Therefore, the RPP value for 2027 is estimated by using the mandated target of 33 TWh and the CER's published cumulative adjustment and estimate of electricity acquisitions in 2026 of 178.90 TWh. In other words, it is assumed electricity acquisitions remain constant in 2026 and 2027, and hence the RPP values for 2026 and 2027 are both 16.67 per cent.

Key elements of the 2026 and 2027 RPP estimation are shown in Table 3.6.

Table 3.6 Estimating the 2026 and 2027 RPP values

	2026	2027 (estimate based on 2026 RPP)
LRET target, incl. cumulative adjustment, MWh (CER)	30,689,929	30,689,929
Relevant acquisitions minus exemptions, MWh (CER)	184,147,676	184,147,676
Estimated RPP	16.67%	16.67%

Source: ACIL Allen analysis of CER data

The cost of complying with the LRET in 2026 and 2027 is calculated by multiplying the RPP values for 2026 and 2027 by the trade volume weighted average LGC prices for 2026 and 2027, respectively. The cost of complying with the LRET in 2026-27 was found by averaging the calendar estimates.

Therefore, the cost of complying with the LRET scheme is estimated to be $3.44/MWh in 2026-27 as shown in Table 3.7.

Table 3.7 Estimated cost of LRET – 2026-27

	2026	2027	Cost of LRET 2026-27
RPP %	16.67%	16.67%	
Trade weighted average LGC price ($/LGC, nominal)	$23.04	$18.28	
Cost of LRET ($/MWh, nominal)	$3.84	$3.05	$3.44

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 2026-27.

The cost of complying with SRES is estimated to be $4.48/MWh in 2026-27 as set out in Table 3.8.

Table 3.8 Estimated cost of SRES – 2026-27

	2026	2027	Cost of SRES 2026-27
STP %	11.67%	10.75%	
STC clearing house price ($/STC, nominal)	$40.00	$40.00	
Cost of SRES ($/MWh, nominal)	$4.67	$4.30	$4.48

Source: ACIL Allen analysis of CER data

Summary of estimated LRET and SRES costs

Adding these component costs gives a total cost requirement for 2026-27 as set out in Table 3.9.

Since the 2025-26 estimate, the cost of the LRET has decreased by around 44 per cent, driven by lower LGC prices for 2026-27, and the cost of the SRES has decreased by 13 per cent, driven by the decrease in the STP.

Table 3.9 Total renewable energy policy costs ($/MWh, nominal) – 2026-27

	2025-26	2026-27
LRET	$6.12	$3.44
SRES	$5.14	$4.48
Total	$11.26	$7.92

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, the following elements are used:

— Energy Savings Scheme Target for 2026 and 2027 of 11 and 11.5 per cent respectively, as published by IPART

— Historical Energy Savings Certificate (ESC) market forward prices for 2026 and 2027 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 2026-27, as set out in Table 3.10. The 2026-27 estimate of $2.63/MWh is 27 per cent higher than the 2025-26 estimate of $2.13/MWh – reflecting higher certificate prices and the increase in the ESS target.

Table 3.10 Estimated cost of ESS ($/MWh, nominal) – 2026-27

	2026	2027	Cost of ESS 2026-27
Average ESC price ($/MWh, nominal)	$23.53	$23.30	
ESS target	11.00%	11.50%	
Cost of ESS ($/MWh, nominal)	$2.59	$2.68	$2.63

Source: ACIL Allen analysis of IPART and TraditionAsia data

New South Wales Peak Demand Reduction Scheme (PDRS)

To estimate the cost of complying with the PDRS for 2026-27, the following elements are used:

— The peak demand reduction target for 2026-27 of 0.5 per cent, as published by the New South Wales and Department of Planning, Industry and Environment (compared with 5.5 per cent for 2025-26). Using the New South Wales summer peak demand forecast for 2026-27 of 14,186 MW as published by AEMO in its 2025 ESOO, this equates to 70,930 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 $2.81 from TraditionAsia.

— The annual energy requirements for New South Wales in 2026-27 of 64,477 GWh as published by AEMO in its ESOO.

The estimated cost of the PDRS for 2026-27 is $0.19/MWh.

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 earlier DMOs.

ESCOSA in its annual report on the REPS published in September 2025 reports an average cost of delivering the energy savings required under the scheme as $14.23/GJ. We multiplied the $14.23/GJ by the target for 2026-27 of 1,650,000 GJ, and then divided the total cost by the total customer energy in South Australia, to give a cost of $1.89/MWh.

3.4 Estimation of other energy costs

The estimates of other energy costs for the 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), DER, IT system upgrades for 5MS and the NEM 2025 Reform Program.

At this stage, the estimates are based on the fees provided by AEMO's *FY26 Budget and Fees,* we estimate the total NEM fees for 2026-27 to be $0.57/MWh and $0.27/week for the variable and fixed components respectively. The breakdown of total fees is shown in Table 3.11.

The final estimate for the NEM management fees will be taken from AEMO's 2026-27 budget and fees report, which will be published in time for the Final Determination.

Table 3.11 NEM management fees ($, nominal) – 2026-27

Cost category	2025-26 (variable, $/MWh)	2025-26 (fixed, $/week)	2026-27 (variable, $/MWh)	2026-27 (fixed, $/week)
NEM fees (admin, registration, etc.)	$0.30854	$0.09515	$0.30854	$0.09515
FRC - electricity	$0.00000	$0.04330	$0.00000	$0.04330
ECA - electricity	$0.00000	$0.02058	$0.00000	$0.02058
DER fee	$0.04031	$0.01243	$0.04031	$0.01243
IT upgrade and 5MS/GS compliance	$0.1134	$0.03497	$0.1134	$0.03497

Cost category	2025-26 (variable, $/MWh)	2025-26 (fixed, $/week)	2026-27 (variable, $/MWh)	2026-27 (fixed, $/week)
National Electricity Market (NEM) 2025 Reform Program	$0.1122	$0.05890	$0.1122	$0.05890
Total NEM management fees	$0.57443	$0.26533	$0.57443	$0.26533

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 20 February 2026) of available NEM ancillary services data as a basis for 2026-27, the estimates cost of ancillary services is shown in Table 3.12.

There is a large increase in the South Australia's ancillary services costs compared with the value used in the 2025-26 determination. According to AEMO's *Quarterly Energy Dynamics Q3 2025* report, in August 2025 there was very high wind generation in SA coupled with a network outage which increased the contingency lower 1-second (L1SE) requirements. Participants able to provide local L1SE were restricted to those within South Australia located north-west of the network outage, causing tight supply-demand conditions and extreme prices.

Table 3.12 Ancillary services ($/MWh, nominal) – 2026-27

Region	2025-26	2026-27
Queensland	$0.74	$0.39
New South Wales	$0.15	$0.13
South Australia	$0.59	$7.17

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 3.13 for each season for the Energex NSLP and small interval meter load gives an estimated MCL of $8,785.

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 is $8,785/42 = $209.16/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 $209.16 gives $0.60/MWh.

The components of the AEMO prudential costs for each of the other jurisdictions' profiles are shown in Table 3.13 to Table 3.17.

Table 3.13 AEMO prudential costs for Energex – 2026-27

	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$90.24	$118.82	$79.84
Participant Risk Adjustment Factor	1.2075	1.0813	1.1103
OS Volatility factor	1.47	1.53	1.61
PM Volatility factor	2.87	2.44	2.28
OSL	$6,167	$7,568	$5,495
PML	$2,408	$2,414	$1,556
MCL	$8,575	$9,982	$7,051
Average MCL		$8,785	
AEMO prudential cost ($/MWh, nominal)		$0.60	

Source: ACIL Allen analysis of AEMO data

Table 3.14 AEMO prudential costs for Ausgrid – 2026-27

	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$95.05	$156.54	$97.23
Participant Risk Adjustment Factor	1.0042	1.0515	0.8888
OS Volatility factor	1.46	1.54	1.57
PM Volatility factor	2.95	2.74	2.19
OSL	$5,365	$9,760	$5,224
PML	$2,168	$3,473	$1,457
MCL	$7,534	$13,233	$6,681
Average MCL		$9,710	
AEMO prudential cost ($/MWh, nominal)		$0.67	

Source: ACIL Allen analysis of AEMO data

Table 3.15 AEMO prudential costs for Endeavour – 2026-27

	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$95.05	$156.54	$97.23
Participant Risk Adjustment Factor	1.1350	1.0902	1.0196
OS Volatility factor	1.46	1.54	1.57
PM Volatility factor	2.95	2.74	2.19
OSL	$6,064	$10,118	$5,992
PML	$2,451	$3,601	$1,672
MCL	$8,515	$13,719	$7,664
Average MCL		$10,484	
AEMO prudential cost ($/MWh, nominal)		$0.72	

Source: ACIL Allen analysis of AEMO data

Table 3.16 AEMO prudential costs for Essential – 2026-27

	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$95.05	$156.54	$97.23
Participant Risk Adjustment Factor	1.0618	1.0939	1.0572
OS Volatility factor	1.46	1.54	1.57
PM Volatility factor	2.95	2.74	2.19
OSL	$5,673	$10,152	$6,213
PML	$2,293	$3,613	$1,733
MCL	$7,966	$13,765	$7,947
Average MCL		$10,392	
AEMO prudential cost ($/MWh, nominal)		$0.71	

Source: ACIL Allen analysis of AEMO data

Table 3.17 AEMO prudential costs for SAPN – 2026-27

	Summer	Winter	Shoulder
Load Weighted Expected Price ($/MWh, nominal)	$120.04	$130.55	$75.60
Participant Risk Adjustment Factor	1.3498	1.1173	0.8840
OS Volatility factor	1.72	1.64	1.44
PM Volatility factor	3.94	2.88	2.52
OSL	$10,729	$9,209	$3,705
PML	$4,915	$3,234	$1,297
MCL	$15,644	$12,444	$5,002
Average MCL		$11,649	
AEMO prudential cost ($/MWh, nominal)		$0.80	

Source: ACIL Allen analysis of AEMO data

Hedge prudential costs

The methodology 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 assumed money market rate is 3.85 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 3.18. This is divided by the average hours in a quarter. Then applying the assumed funding cost of 9.20 per cent but adjusted for an assumed 3.85 per cent return on cash lodged with the clearing (giving a net funding cost of 5.35 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 3.18 to Table 3.20, respectively.

Table 3.18 Hedge Prudential funding costs by contract type – Queensland 2026-27

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$96.10	$52,000	$1.27
Cap	$20.44	$25,000	$0.61

Source: ACIL Allen analysis of ASX Energy and RBA data

Table 3.19 Hedge Prudential funding costs by contract type – New South Wales 2026-27

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$114.88	$55,000	$1.34
Cap	$26.90	$24,000	$0.59

Source: ACIL Allen analysis of ASX Energy and RBA data

Table 3.20 Hedge Prudential funding costs by contract type – South Australia 2026-27

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$93.91	$73,000	$1.78
Cap	$25.07	$30,000	$0.73

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 3.21 to Table 3.25.

Table 3.21 Hedge Prudential funding costs for ENERGEX – 2026-27

	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.27	0.8767	$1.11
Cap	$0.61	1.6905	$1.03
Total cost		$2.15	

Source: ACIL Allen

Table 3.22 Hedge Prudential funding costs for Ausgrid – 2026-27

	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.34	1.0253	$1.38

	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Cap	$0.59	1.3501	$0.79
Total cost		$2.17	

Source: ACIL Allen

Table 3.23 Hedge Prudential funding costs for Endeavour – 2026-27

	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.34	0.9956	$1.34
Cap	$0.59	1.6814	$0.99
Total cost		$2.32	

Source: ACIL Allen

Table 3.24 Hedge Prudential funding costs for Essential – 2026-27

	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.34	0.9224	$1.24
Cap	$0.59	1.3451	$0.79
Total cost		$2.03	

Source: ACIL Allen

Table 3.25 Hedge Prudential funding costs for SAPN – 2026-27

	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Hedge prudential cost per MWh
Base	$1.78	0.8760	$1.56
Cap	$0.73	2.1948	$1.61
Total cost		$3.17	

Source: ACIL Allen

Total prudential costs

Adding the AEMO and hedge prudential costs gives a total prudential requirement for 2026-27 as set out in Table 3.26 . Prudential costs for 2026-27 are lower than 2025-26 due to lower contract prices expected across 2026-27.

Table 3.26 Total prudential costs ($/MWh, nominal) – 2026-27

Jurisdiction	2025-26	2026-27
Energex	$3.27	$2.75
Ausgrid	$2.86	$2.83
Endeavour	$3.13	$3.04
Essential	$2.85	$2.74
SAPN	$3.69	$3.97

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.

AEMO activated the RERT twice for the 12-month period prior to this Determination in New South Wales and once in South Australia.

AEMO entered into Short Notice (SN) RERT contracts on Wednesday 27 November 2024 for 605 MW of SN reserves in New South Wales. Of this, 184MW of reserves were pre-activated and 65MWh were activated.

From 1 December 2024 to 31 March 2025, 85 MW of Interim Reliability Reserve (IRR) was contracted in New South Wales. In South Australia a total of 127 MW of IRR was contracted for the period from 1 January 2025 to 31 March 2025.

The cost of RERT for New South Wales is estimated to be $0.13/MWh in New South Wales, and $1.03/MWh in south Australia.

There has been no activation of the RERT in Queensland over the past 12 months.

Retailer Reliability Obligation

The RRO is not currently triggered for the DMO regions for 2026-27.

AEMO Direction costs

To arrive at the estimate of the AEMO Direction compensation costs, 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 the analysis for the Determination), is taken and divided by the corresponding annual regional customer energy.

Direction and NSCAS costs in South Australia over the past 12 months equate to $5.61/MWh.

Summary of estimated total other costs

Adding these component costs gives a total other cost requirement as set out in Table 3.27 to Table 3.31. These tables exclude the fixed NEM Fees cost of $0.27 per week per customer – which averages about $1-2/MWh depending on the level of consumption.

Table 3.27 Total of other costs ($/MWh, nominal) – Energex – 2026-27

Cost category	2025-26	2026-27
NEM management fees	$0.57	$0.57
Ancillary services	$0.74	$0.39
Hedge and pool prudential costs	$3.27	$2.75
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	$4.58	$3.71

Note: The values exclude the fixed NEM Fees cost of $0.27 per week per customer – which averages about $1-2/MWh depending on the level of consumption.

Source: ACIL Allen analysis

Table 3.28 Total of other costs ($/MWh, nominal) – Ausgrid – 2026-27

Cost category	2025-26	2026-27
NEM management fees	$0.57	$0.57
Ancillary services	$0.15	$0.13
Hedge and pool prudential costs	$2.86	$2.83
Reserve and Emergency Reserve Trader costs	$0.05	$0.13
AEMO Direction costs	$0.00	$0.00
June 2022 NEM events	$0.12	$0.00
Total	$3.75	$3.66

Note: The values exclude the fixed NEM Fees cost of $0.27 per week per customer – which averages about $1-2/MWh depending on the level of consumption.

Source: ACIL Allen analysis

Table 3.29 Total of other costs ($/MWh, nominal) – Endeavour – 2026-27

Cost category	2025-26	2026-27
NEM management fees	$0.57	$0.57
Ancillary services	$0.15	$0.13
Hedge and pool prudential costs	$3.13	$3.04
Reserve and Emergency Reserve Trader costs	$0.05	$0.13
AEMO Direction costs	$0.00	$0.00
June 2022 NEM events	$0.12	$0.00
Total	$4.02	$3.87

Note: The values exclude the fixed NEM Fees cost of $0.27 per week per customer – which averages about $1-2/MWh depending on the level of consumption.

Source: ACIL Allen analysis

Table 3.30 Total of other costs ($/MWh, nominal) – Essential – 2026-27

Cost category	2025-26	2026-27
NEM management fees	$0.57	$0.57
Ancillary services	$0.15	$0.13
Hedge and pool prudential costs	$2.85	$2.74
Reserve and Emergency Reserve Trader costs	$0.05	$0.13
AEMO Direction costs	$0.00	$0.00
June 2022 NEM events	$0.12	$0.00
Total	$3.74	$3.57

Note: The values exclude the fixed NEM Fees cost of $0.27 per week per customer – which averages about $1-2/MWh depending on the level of consumption.

Source: ACIL Allen analysis

Table 3.31 Total of other costs ($/MWh, nominal) – SAPN – 2026-27

Cost category	2025-26	2026-27
NEM management fees	$0.57	$0.57
Ancillary services	$0.59	$7.17
Hedge and pool prudential costs	$3.69	$3.97
Reserve and Emergency Reserve Trader costs	$0.01	$1.03
AEMO Direction costs	$5.71	$5.61
June 2022 NEM events	$0.05	$0.00
Total	$10.62	$18.35

Note: The values exclude the fixed NEM Fees cost of $0.27 per week per customer – which averages about $1-2/MWh depending on the level of consumption.

Source: ACIL Allen analysis

3.5 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 2026-27, consequently we have used the estimates from the DMO 7 Determination.

These will be updated for the Final Determination based on the MLFs and DLFs expected to be published around April 2026.

The estimation of transmission and distribution loss factors for the settlement classes to be used in calculating energy costs for 2026-27 is shown in Table 3.32.

Table 3.32 Estimated transmission and distribution losses

	2025-26			2026-27		
	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	4.47%	0.01%	1.045	4.47%	0.01%	1.045
Endeavour - Residential and small business	7.28%	-0.85%	1.064	7.28%	-0.85%	1.064
Essential - Residential and small business	6.13%	-2.08%	1.039	6.13%	-2.08%	1.039
Ausgrid - CLP1	4.47%	0.01%	1.045	4.47%	0.01%	1.045
Ausgrid - CLP2	4.47%	0.01%	1.045	4.47%	0.01%	1.045
Endeavour - CLP	7.28%	-0.85%	1.064	7.28%	-0.85%	1.064
Essential - CLP	6.13%	-2.08%	1.039	6.13%	-2.08%	1.039
Energex - Residential and small business	5.23%	0.64%	1.059	5.23%	0.64%	1.059
Energex – CLP31	5.23%	0.64%	1.059	5.23%	0.64%	1.059
Energex – CLP33	5.23%	0.64%	1.059	5.23%	0.64%	1.059
SAPN - Residential and small business	8.11%	-0.80%	1.072	8.11%	-0.80%	1.072
SAPN - CLP	8.11%	-0.80%	1.072	8.11%	-0.80%	1.072

Source: ACIL Allen analysis of AEMO data

As described by AEMO[22], 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)*

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

3.6 Summary of estimated energy costs

Drawing together the analyses and estimates from the previous sections of this report, the estimates of the 2026-27 total energy costs (TEC) for each of the profiles are presented in Table 3.33 and Table 3.34.

These tables exclude the fixed NEM Fees cost of $0.27 per week per customer – which averages about $1-2/MWh depending on the level of consumption.

Table 3.33 Estimated TEC for 2026-27 ($/MWh, nominal)

Profile	2025-26 Total energy costs at the customer terminal ($/MWh, nominal)	2026-27 Total energy costs at the customer terminal ($/MWh, nominal)	Change from 2025-26 to 2026-27 ($/MWh, nominal)	Change from 2025-26 to 2026-27 (%, nominal)
Ausgrid – Residential and small business	$188.18	$164.69	($23.49)	-12.48%
Endeavour - Residential and small business	$198.70	$176.14	($22.56)	-11.35%
Essential - Residential and small business	$191.34	$165.33	($26.01)	-13.59%
Ausgrid - CLP1	$138.68	$137.17	($1.51)	-1.09%
Ausgrid - CLP2	$140.54	$142.57	$2.03	1.44%
Endeavour – CLP1	$146.55	$130.35	($16.20)	-11.05%
Endeavour – CLP2	NA	$116.91	NA	NA
Essential - CLP	$139.70	$136.27	($3.43)	-2.46%
Energex - Residential and small business	$176.29	$152.74	($23.55)	-13.36%
Energex – CLP31	$125.01	$115.71	($9.30)	-7.44%
Energex – CLP33	$131.85	$118.73	($13.12)	-9.95%
SAPN - Residential and small business	$208.07	$196.66	($11.41)	-5.49%
SAPN - CLP	$136.57	$109.13	($27.44)	-20.09%

Note: The values exclude the fixed NEM Fees cost of $0.27 per week per customer – which averages about $1-2/MWh depending on the level of consumption.

Source: ACIL Allen analysis

Table 3.34 Components of estimated TEC for 2026-27 ($/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	$143.20	$3.66	1.045	$6.61	$153.47	$3.44	$4.48	$2.82	$1.05	$11.22	$164.69
Endeavour - Residential and small business	$150.93	$3.87	1.064	$9.91	$164.71	$3.44	$4.48	$2.82	$1.06	$11.43	$176.14
Essential - Residential and small business	$144.81	$3.57	1.039	$5.79	$154.17	$3.44	$4.48	$2.82	$1.04	$11.16	$165.33
Ausgrid - CLP1	$116.87	$3.66	1.045	$5.42	$125.95	$3.44	$4.48	$2.82	$1.05	$11.22	$137.17
Ausgrid - CLP2	$122.03	$3.66	1.045	$5.66	$131.35	$3.44	$4.48	$2.82	$1.05	$11.22	$142.57
Endeavour – CLP1	$107.90	$3.87	1.064	$7.15	$118.92	$3.44	$4.48	$2.82	$1.06	$11.43	$130.35
Endeavour – CLP2	$95.57	$3.57	1.064	$6.34	$105.48	$3.44	$4.48	$2.82	$1.06	$11.43	$116.91
Essential - CLP	$116.84	$3.57	1.039	$4.70	$125.11	$3.44	$4.48	$2.82	$1.04	$11.16	$136.27
Energex - Residential and small business	$132.60	$3.71	1.059	$8.04	$144.35	$3.44	$4.48	$0.00	$1.06	$8.39	$152.74
Energex – CLP31	$97.63	$3.71	1.059	$5.98	$107.32	$3.44	$4.48	$0.00	$1.06	$8.39	$115.71
Energex – CLP33	$100.48	$3.71	1.059	$6.15	$110.34	$3.44	$4.48	$0.00	$1.06	$8.39	$118.73
SAPN - Residential and small business	$155.29	$18.35	1.072	$12.50	$186.14	$3.44	$4.48	$1.89	$1.07	$10.52	$196.66
SAPN - CLP	$73.64	$18.35	1.072	$6.62	$98.61	$3.44	$4.48	$1.89	$1.07	$10.52	$109.13

Note: The values exclude the fixed NEM Fees cost of $0.27 per week per customer – which averages about $1-2/MWh depending on the level of consumption.

Source: ACIL Allen analysis

Melbourne
Suite 4, Level 19, North Tower
80 Collins Street
Melbourne VIC 3000 Australia
+61 3 8650 6000

Sydney
Suite 603, Level 6
309 Kent Street
Sydney NSW 2000 Australia
+61 2 8272 5100

Brisbane
Level 15, 127 Creek Street
Brisbane QLD 4000 Australia
+61 7 3009 8700

Canberra
Level 6, 54 Marcus Clarke Street
Canberra ACT 2601 Australia
+61 2 6103 8200

Perth
Level 12, 28 The Esplanade
Perth WA 6000 Australia
+61 8 9449 9600

Adelaide
167 Flinders Street
Adelaide SA 5000 Australia
+61 8 8122 4965

ACIL Allen Pty Ltd
ABN 68 102 652 148

acilallen.com.au