Australian Government

AUSTRALIAN ENERGY REGULATOR

Default market offer guidelines

Draft guidelines for consultation

September 2026

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Amendment record

Version	Date	Pages
1.0	18 September – Draft guidelines for consultation	

Contents

Glossary

Term	Definition
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
DMO	Default market offer
DMO 8	2026–27 default market offer
DNSP	Distribution network service provider
EBITDA	Earnings before interest, tax, depreciation and amortisation
kWh	Kilowatt hours
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
NSW	New South Wales
RERT	Reliability and Emergency Reserve Trader
SSO	Solar Sharer Offer
TOU	Time of use
TSS	Tariff structure statement
WEC	Wholesale energy cost

1 Introduction

These guidelines set out the AER's proposed approach and methodology to determining the default market offer (DMO). We refer to them as the DMO guidelines.

1.1 Requirement to determine DMO guidelines

Section 18B of the Competition and Consumer (Industry Code—Electricity Retail) Regulations 2019 (the Regulations) requires us to determine the DMO guidelines, setting out:[1]

- the approach and methodology we propose to use to identify and determine the cost components for the comparison price set by the AER for non-regulated tariffs
- the approach and methodology we propose to use to identify and determine the cost components for determining tariff caps for regulated tariffs
- the information and data we intend to use to determine those cost components
- the approach and methodology we propose to use to determine free usage periods for Solar Sharer Offer (SSO) regulated tariffs
- any additional tariff type that we consider should be determined as a regulated tariff
- the process we propose to undertake for the purposes of making determinations for the purposes of section 15A and subsections 16(1) and (1A), and 18(1) and (4)[2]
- any other matters we consider relevant to achieving the DMO objective, which is to provide small customers that are supplied with electricity at standing offer prices with a fair, trusted and reasonably priced electricity option that reflects the costs of supplying small customers with an essential service.

Unless otherwise stated, the approach and methodology for determining each component or matter applies to both regulated and non-regulated tariffs, as well as to both residential and small business customers.

1.2 Relationship to DMO determinations

We must have regard to the DMO guidelines when determining the comparison price and tariff cap for each regulated tariff and the comparison price for non-regulated tariffs.[3] We must also have regard to the DMO guidelines for the purposes of meeting the DMO objective.[4]

The DMO guidelines are intended to enhance transparency and improve regulatory certainty.[5] The DMO guidelines embed this intention to improve stability in our approach,

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1 Regulations, s. 18B(1)(a–f).

2 This includes determining additional types of regulated tariffs, model annual usage, comparison prices, tariff caps, free usage periods for the SSO and reasonable use tariff cap for the SSO.

3 Regulations, s. 16(4)(cb).

4 Regulations, s. 9A(2).

5 DCCEEW, Review Outcomes: 2025 reforms to the Default Market Offer, Department of Climate Change, Energy, the Environment and Water, 4 November 2025, p. 45.

while also preserving flexibility where needed to respond to changes in market conditions, data availability and other relevant circumstances.

1.3 Process for revision

We may amend the DMO guidelines on our own initiative.[6] Before amending the DMO guidelines, we must publish a draft of the amendments on our website and invite submissions for at least 21 days.[7] However, we are not required to comply with this requirement if the matters in the proposed amendment were already consulted on through a DMO draft determination and subsequently included in the final determination.[8]

6 Regulations, s. 18D(1).

7 Regulations, s 18C.

8 Regulations, s. 18D(2).

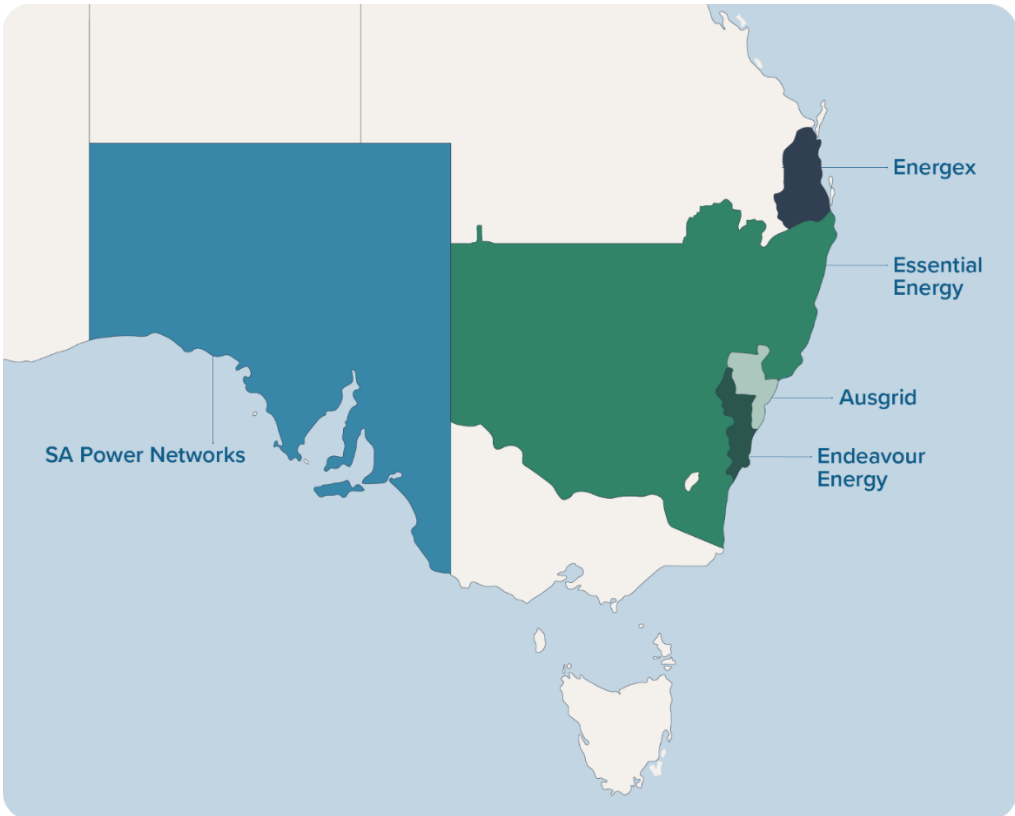
2 DMO process

We must outline the process we undertake to determine tariff caps for regulated tariffs; comparison prices and model annual usage for regulated and non-regulated tariffs; free usage periods and reasonable use tariff caps for the SSO; and additional types of regulated tariffs.[9] We must consult on a draft DMO determination before publishing a final determination, and our final determination must be made no later than the first business day after 25 May. When undertaking the DMO process, we apply the relevant legislative framework and must have regard to the mandatory considerations specified in the Regulations.[10]

2.1 What we determine

The AER's role is to determine DMO prices and tariffs annually. Our DMO determination applies to residential and small business customers.[11] We must do this for distribution network regions where standing offer electricity prices are not already set or capped under a state or territory law – NSW (Endeavour Energy, Essential Energy and Ausgrid), South East Queensland (Energex) and South Australia (SA Power Networks).[12]

Figure 2.1 The DMO regions



9 Regulations, s. 18B(1)(e).

10 Regulations, ss. 16 and 17.

11 Regulations, s. 6.

12 Regulations, s. 8.

The DMO caps the prices a retailer can charge a standing offer customer.[13] It also serves as a comparison price for market offers in these regions.[14] The Regulations set out the regulatory framework for the DMO.

Under the Regulations, we are required to determine standing offer tariff caps for the following regulated tariffs:

- flat rate tariffs for residential and small business customers
- flexible tariffs for residential and small business customers
- controlled load tariffs for residential customers
- a SSO regulated tariff.[15]

We also have discretion to determine additional types of regulated tariffs.[16] Chapter 10 of these guidelines sets out the factors we will have regard to when considering whether an additional tariff type should be determined as a regulated tariff. This chapter outlines the process we propose to undertake when making these determinations.

Under the Regulations, we are also required to set a comparison price for each regulated tariff and a comparison price for non-regulated tariffs:

- For regulated tariffs, the annual usage and pattern of supply is applied to the tariff cap to convert it to a comparison price to calculate discounts in the annual price of market offers in retailer pricing communications. For example, a retailer will calculate the annual cost of a flat rate market offer using the annual usage amount and timing or pattern of supply determined by the AER and compare that with the annual cost of the flat rate tariff cap.[17]
- For non-regulated tariffs, we must determine a comparison price that applies to all market and standing offers that are not able to be compared with the regulated tariffs – for example, because they have different structures or characteristics. This comparison price is a reasonable per-customer annual price for the year for supplying electricity under the non-regulated tariff.[18] Under the Regulations, non-regulated tariff market offers must be compared with the comparison price in retailers' pricing communications, based on our determination of an amount of annual usage and timing or pattern of supply.[19]

We are also required to determine the annual usage amounts and timing or patterns of supply for each regulated tariff and non-regulated tariff, as well as free usage periods and the reasonable use tariff cap for the SSO.[20] Chapters 8 and 9 set out our approach to the model annual usage, timings or pattern of supply and the SSO in more detail, respectively.

13 Regulations, ss. 10, 10A and 11A.

14 Regulations, s. 12.

15 Regulations, ss. 16(1A)(c) and 5 (a) – (f) for the definition of 'regulated tariff'.

16 Regulations, ss. 15A and 5(g).

17 Regulations, s. 16(1A) and 12.

18 Regulations, s. 16(1).

19 Regulations, s. 12.

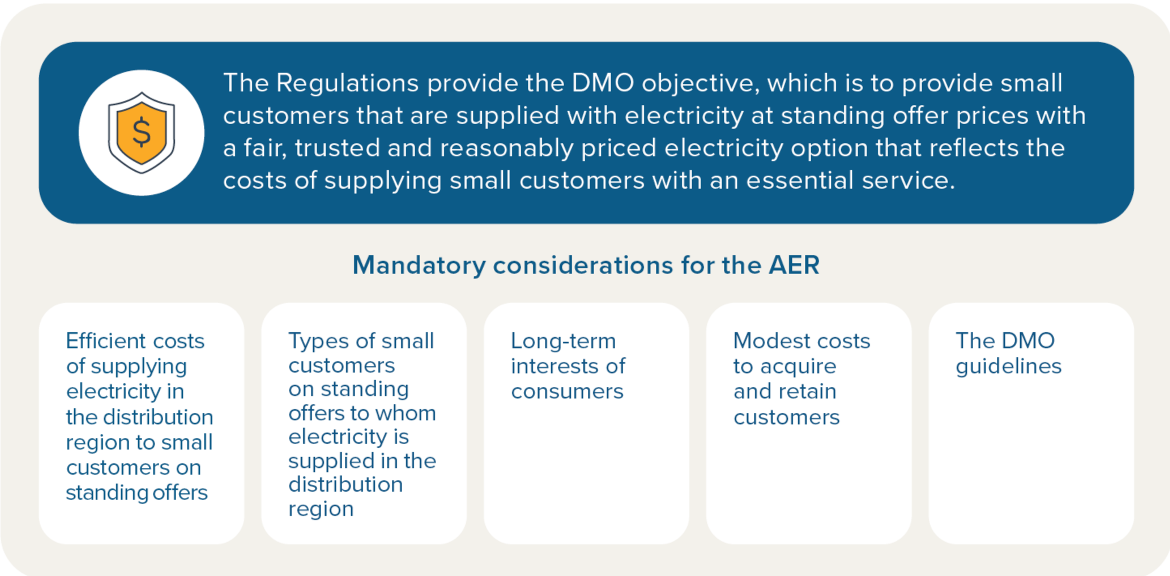
20 Regulations, ss. 16 (1)(a),16(1A)(a), 18(1) and 18(4).

Mandatory considerations

The Regulations prescribe a range of matters that we must have regard to when determining comparison prices and tariff caps (mandatory considerations):

- the efficient costs of supplying electricity in the distribution region to small customers on standing offers
- the types of small customers on standing offers to whom electricity is supplied in the distribution region
- the long-term interests of consumers
- the wholesale cost of electricity in the region
- the cost of distributing and transmitting electricity in the region
- the cost of complying with the laws of the Commonwealth and the relevant state or territory to supply electricity in the region
- if relevant to the region – the modest cost of acquiring and retaining small customers
- the DMO objective, which is to provide small customers that are supplied with electricity at standing offer prices with a fair, trusted and reasonably priced electricity option that reflects the costs of supplying small customers with an essential service
- the DMO guidelines
- any other matter we consider relevant.[21]

Figure 2.2 DMO objective and mandatory considerations



21 Regulations, ss. 16(4) and 9A(1).

2.2 Information collection

Formal information collection

We may issue compulsory information notices under section 44AAFA of the *Competition and Consumer Act 2010* to obtain information and documents that are relevant to the mandatory considerations. We have previously used the compulsory notice power to obtain information to ascertain and quantify retail costs.[22] We have also used this power to collect confidential over-the-counter contract market data to validate our approach to determine wholesale costs.[23]

We will have regard to the burden of the compulsory notice on the recipient, and the value of the information to the AER, before exercising our powers.

Voluntary information collection

We may also seek information through voluntary requests.

When considering a voluntary information request, we may engage with stakeholders to understand the feasibility, availability and likely burden associated with providing the requested information. This engagement can help ensure that requests are appropriately targeted and that the information sought can support robust and relevant analysis.

Other information

We may also collect and analyse other available information, including:

- distribution network service providers' (DNSP) tariff structure statements and approved annual pricing proposals
- Australian Energy Market Operator (AEMO) data
- Australian Securities Exchange (ASX) contract data
- over-the-counter trade data we obtain through the Electricity Market Monitoring Information Order.

2.3 Determination process

The determination process applies to all determinations we make under the Regulations.

Initiation

The annual determination process begins with collecting and assessing information relevant to the DMO. This information collection occurs over months and can include information obtained through compulsory information notices, voluntary information requests, publicly available information, stakeholder engagement and other relevant information.

[22] Regulations, ss. 16(4)(a) and 16(4)(c)(iv).

[23] Regulations, s. 16(4)(c)(i).

Request for comment paper and consultation

We may publish a request for comment paper to consult on specific issues for the annual DMO determination. A request for comment paper is typically published in October or November.

Draft determination and consultation

We must publish a draft determination and invite submissions for at least 21 days.[24]

The draft determination gives stakeholders an opportunity to provide feedback. In making our final determination, we must consider any submissions received by the submission closing date. Stakeholder consultation may take the form of written submissions, bilateral meetings or workshops. We prefer that all views and comments be publicly available to facilitate an informed and transparent consultative process.

Final determination

After considering all relevant information and stakeholder feedback, we will make and publish a final determination no later than the first business day after 25 May. The final determination will set out the final DMO tariffs and prices and the reasons for our decision, including any changes from the draft determination. The final determination is made in accordance with the legislative framework and takes effect on 1 July of the relevant year.

2.4 Adapting our approach and methodology

We must have regard to these guidelines when determining model annual usage, comparison prices for regulated and non-regulated tariffs, as well as tariff caps for regulated tariffs.[25]

We may depart from the approach and methodology set out in these guidelines when making a determination if we consider the circumstances warrant a different approach or methodology. If this occurs, we may use the DMO determination process to engage on this change. In this instance, we would undertake early engagement and provide reasons for the proposed departure in a request for comment paper or the draft DMO determination and seek stakeholder feedback.

As discussed in chapter 1, we may also amend the DMO guidelines on our own initiative. To do this, we must publish and invite submissions on the draft amendments for at least 21 days and consider any submissions received.[26] However, we are not required to comply with this requirement if the matters in the proposed amendment were already consulted on through a draft determination and included in a final determination.[27] If the DMO guidelines are amended through a determination, we will revise and publish the updated guidelines as soon as practicable.

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24 Regulations, s. 17(1)(a) and (b).

25 Regulations, s. 16(4)(cb).

26 Regulations, s. 18C.

27 Regulations, s. 18D(2).

Matters or circumstances that may warrant departing from or amending the approach and methodology set out in the DMO guidelines may include:

- material changes in electricity market conditions or regulatory frameworks that are supported by robust evidence demonstrating that the current methodology cannot sufficiently address the relevant changes
- stakeholder feedback and consultation identifying issues with the operation of the DMO guidelines
- the introduction of new tariff types
- other changes necessary to support meeting the DMO objective and where the benefits of the proposed change demonstrably outweigh the associated costs.

3 Wholesale costs

Wholesale costs are costs retailers incur to purchase electricity from the National Electricity Market (NEM) on behalf of their customers. The Regulations require us to have regard to the mandatory considerations, including the wholesale cost of electricity in the region.

3.1 Identification of wholesale costs

To establish an efficient forecast of wholesale costs for the DMO, we aim to reflect how a prudent retailer might purchase energy. As such, the wholesale costs for the DMO will include:

- wholesale energy costs (WEC) – the estimated cost incurred by a prudent retailer to purchase electricity from the NEM
- non-WEC wholesale costs – AEMO fees (or NEM fees), ancillary services costs, Reliability and Emergency Reserve Trader (RERT) costs, AEMO direction costs, costs of meeting prudential requirements and NEM market event costs (e.g. June 2022 market event costs)
- adjustment for energy losses.

3.2 Approach and methodology to determine wholesale costs

To determine wholesale costs in the DMO, we will sum the WEC and variable non-WEC wholesale costs. The resulting total will be adjusted for energy losses, multiplied by usage assumptions in the relevant region, and reflected in the usage charge tariff cap. Fixed AEMO fees will be added directly to the daily supply charge tariff cap.

3.3 Wholesale energy costs

We will use a market-based approach to estimate the WEC. Our approach is to model the costs of a prudent, standalone retailer (rather than a vertically integrated entity) purchasing wholesale electricity from the NEM on behalf of its customers. Numerous WEC simulations will be run to produce a large distribution, from which the median result is selected.

The key steps to estimating the WEC for a given year and region will be:

1. Forecast the representative retailer load profile in the region.
2. Forecast wholesale electricity spot prices in the region.
3. Repeat until a distribution of spot price and load outcomes that reasonably reflects the range of possible market outcomes has been produced.
4. Estimate forward contract prices.
5. Adopt the assumed hedging strategy of a prudent, standalone retailer.
6. Calculate WECs for each simulation by settling the assumed hedging strategy against the forecast spot prices, contract prices and load profile.

7. Apply the median WEC from the distribution to the DMO price.

The sum of contract payments and payouts, along with settlement against the spot market, will be divided by the total energy demanded by the modelled retailer to produce a WEC in dollars per megawatt hour ($/MWh) terms for each simulation.

3.3.1 Forecasting representative retailer load profile

A retailer's customer load profile measures the timing of its demand for electricity from the spot market and determines the amount the retailer must pay AEMO for the electricity its customers use.

We will use a single aggregate market load profile for residential and small business customers in each region as the basis for forecasting the load profile of the modelled retailer. We will use the most recent 2 years of available historical data. The stochastic variation in the selected load profile will be modelled to align with a range of possible weather scenarios. This modelling will determine the quantity of electricity the modelled retailer is assumed to demand from the spot market in any given spot market interval. The load profile will be based on gross demand, meaning behind-the-meter generation will not be subtracted from the quantity demanded.

Information and data

For general use energy, the assumed load profile will be based on a blended load profile containing both interval and accumulation meter demand data:

- Interval meter customers will be represented by the aggregate demand of small customers (both residential and small business), based on AEMO Market Settlement and Transfer Solutions data for the relevant distribution region.[28] Controlled load demand will be removed from this dataset.
- Accumulation meter customers will be represented by AEMO's Net System Load Profile in the relevant region, where available and accurate.[29]
- The blended load profile will be the sum of interval and accumulation meter demand, as quantified by the Market Settlement and Transfer Solutions and Net System Load Profile datasets for each individual interval.
- If the Net System Load Profile ceases to accurately reflect accumulation meter demand, we will transition to general use profiles based exclusively on Market Settlement and Transfer Solutions small customer interval meter data.

We will use controlled load profiles for interval meters only as a basis for forecasting a retailer's controlled load demand profile. The controlled load profiles will be provided by the relevant DNSP.

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[28] AEMO, Market Settlement and Transfer Solutions (MSATS), Australian Energy Market Operator, n.d., accessed 18 August 2026.

[29] AEMO, Load Profiles, Australian Energy Market Operator, n.d., accessed 18 August 2026.

3.3.2 Forecasting spot prices

Spot prices are prices paid to generators by retailers (via settlement by AEMO) for each unit of electricity they demand within a given spot market interval. The spot market can be highly volatile, so retailers and generators enter into derivative contracts to smooth or hedge this volatility. The extent to which a contract counterparty pays or receives payment for their contract cover in each 30-minute spot interval depends on the proximity of the spot price to a pre-agreed contract 'strike price'.

Stochastic wholesale energy market simulations will be used to estimate spot prices for the upcoming financial year – the same year to which the DMO determination will apply. Spot prices will be a function of the modelled bidding behaviour of existing and committed generation capacity, as utilised according to forecast system demand (including the netting effect of behind-the-meter generation).

The supply-side assumptions of the spot price modelling will be determined by reviewing changes in new committed generation projects and investments, generator retirements or closures, fuel cost changes and existing generation based on power station availability and operating practices. The assumptions will mirror the AEMO Integrated System Plan and the latest AEMO Electricity Statement of Opportunities 'Step Change' scenario assumptions because we consider these are the most authoritative available forecasts of future generation capacity, demand and system conditions in the NEM.

Regional demand forecasts will be based on AEMO's latest Electricity Statement of Opportunities central scenario, using seasonal peak demand and annual energy forecasts. It will also consider historical relationships between Net System Load Profiles, interval meter demand and regional electricity demand to develop representative regional demand profiles.

Information and data

Spot prices will be calculated based on:

- AEMO Market Management System report, Integrated System Plan and Electricity Statement of Opportunities Step Change scenario.[30]

3.3.3 Contract price methodology

Contract prices can refer to either the strike price or premium attached to a derivative contract. For base futures contracts, we will need to determine an assumed strike price for input into the wholesale cost modelling. For cap contracts, we will assume the standard strike price of $300/MWh because this is what is traded on the ASX. However, we will need to determine an assumed premium for holding such contracts because the cap premium varies depending on market factors. Valuing contracts in the future is likely to require similar exercises.

The modelled retailer's book build period will commence from the date the product was first traded until a cut-off date selected by us, usually within one month before the DMO final determination is made. The modelling will assume that all contracts that are included in the

[30] AEMO, Market Management System (MMS), Australian Energy Market Operator, n.d., accessed 18 August 2026; AEMO, Integrated System Plan (ISP), Australian Energy Market Operator, n.d., accessed 18 August 2026; AEMO, NEM Electricity Statement of Opportunities (ESOO), Australian Energy Market Operator, n.d., accessed 18 August 2026.

hedging strategy are purchased by the modelled retailer at the quarterly trade-weighted average prices observed over the book build period.

Information and data

Where possible, we will endeavour to use only publicly observable contract price and volume data (such as that available on the ASX) to calculate the trade-weighted average price. However, if publicly available trade data does not produce an accurate trade-weighted average price relative to volumes of a given product traded overall, we may choose to supplement publicly recorded trades with over-the-counter trades we obtain through the Electricity Market Monitoring Information Order.

3.3.4 Choosing the hedging strategy

A retailer's hedging strategy will be represented by a portfolio of derivatives contracts designed to reduce the risk posed by the volatility and unpredictability of spot electricity prices. Hedging can reduce or increase a retailer's costs depending on the positioning of its contract cover relative to the spot prices that eventuate, although effective hedging strategies usually protect a retailer from the most extreme spot price outcomes.

To determine whether a specific individual contract type (either new or existing) is included in the DMO hedging strategy, we will consider whether sufficient liquidity exists – that is, whether an average retailer would generally be able to acquire a sufficient volume of the contract if desired. We will not prescribe universal liquidity thresholds and metrics for all contract types. Instead, we will determine whether sufficient liquidity exists for individual contract types by reviewing volumes traded on the ASX and over-the-counter, and through stakeholder submissions to the annual DMO consultation process. To avoid including contracts traded only by financial speculators, we will also ensure the contract is being traded by retailers.

Multiple hedging strategies will be evaluated by varying the volume of included contracts before selecting the hedging strategy that applies for the DMO determination. The strategy that results in the lowest variance in WEC outcomes across the distribution of modelled spot prices will be selected. The resulting hedge volumes will be fixed and applied unchanged across all wholesale cost simulations for each region. Therefore, different WEC outcomes will reflect different wholesale cost outcomes as they interact with the selected hedging strategy, rather than different hedging strategies.

3.3.5 Selecting a single WEC from the distribution

The stochastic modelling process described above will create a large distribution of WEC results, of which only one may be applied to the DMO price. The results will be ordered from lowest to highest and assigned a percentile rank.

We will consider the median of this distribution (the 50th percentile) to represent the expected cost of prudent hedging. We will consider results above the median to represent varying degrees of forecast error resulting in overestimation, while the inverse will apply to results below the median. We will apply the median WEC estimate from the simulated distribution to the DMO price.

3.3.6 Volatility allowance

We will apply a volatility allowance in addition to the WEC, to facilitate retailers' accumulation of capital reserves to manage the forecast risk posed by potential WEC underestimation.

The volatility allowance will be a variable cost component. We will calculate the volatility allowance by multiplying the weighted average cost of capital by the difference between the maximum and median WECs from the distribution of spot price simulations. We will also add a volatility allowance to the time of use WECs used to determine the DMO for time of use offers, equal to the flat rate WEC volatility allowance.

3.3.7 Time of use WECs

We will apply time-varying WECs to time of use offers to reflect changes in the cost of purchasing electricity throughout the day. This will differ from flat rate offers, where only a single WEC will be used across the day.

We calculate time of use WECs by scaling the flat rate WEC for specific time periods according to the ratio of their respective demand-weighted prices compared with the overall load profile. Therefore, time of use WECs are equivalent to the flat rate WECs on an annualised, volume-weighted basis.

3.4 Non-WEC wholesale costs

Non-WEC wholesale costs include prudential costs, ancillary services, RERT, NEM management fees, market making and other obligations (including the Retailer Reliability Obligation), AEMO direction costs and NEM market event compensation as separate cost categories when determining wholesale costs.

3.4.1 Prudential costs

Retailers incur prudential costs to provide credit and collateral required by AEMO and contract counterparties to manage the risk the retailer may default on its payment obligations.

Prudential costs will be calculated by adding the AEMO and contract prudential costs together to produce a $/MWh (nominal) figure for the year. These will be calculated for each region's load profile. The prudential costs for these profiles will then be used as a proxy for prudential costs for the controlled load profiles in the relevant region.

AEMO prudential costs represent the amount of collateral a retailer needs to provide. AEMO calculates a maximum credit limit based on estimates of settlement exposures and market risk. The maximum credit limit for a representative retailer will be calculated and converted into a per MWh amount. The assumed financing cost will then be applied to estimate the $/MWh allowance.

Contract prudential costs will be calculated as a weighted average of the prudential costs of all contracts in the model portfolio. Contract prudential costs will be calculated by estimating the initial margin required for each futures hedge product, applying the net cost of funding that margin, converting the result to a $/MWh basis, and weighting the costs according to the modelled hedging strategy in each region.

3.4.2 Ancillary costs

Retailers incur costs for market and non-market frequency control ancillary services, which manage power system security.[31]

The average of the AEMO published ancillary service payment costs will be calculated in each interconnected region over the preceding 52 weeks of available data (up to the wholesale data cut-off date) as a basis for the DMO year. The estimated cost of ancillary services is provided as $/MWh, nominal.

Information and data

Ancillary costs will be calculated based on:

- AEMO-published ancillary service payment costs.[32]

3.4.3 Reliability and Emergency Reserve Trader (RERT)

RERT is a mechanism that allows AEMO to procure emergency reserves when there is a risk that the market alone will not have enough supply to meet demand. The costs are recovered from market participants (including retailers) through market charges.

RERT costs will be calculated by using costs ($/MWh) as published by AEMO for the 12-month period prior to the final DMO determination's wholesale data cut-off date. RERT costs will be expressed by taking the cost reported by AEMO in dollar terms for the given region and proportionately distributing the cost across all consumers in the region according to consumption.

Information and data

RERT costs will be calculated based on:

- AEMO RERT Quarterly Report and End of Financial Year Report.[33]

3.4.4 NEM management fees

NEM management fees are payable by retailers to AEMO to cover the costs of managing the power system.

AEMO's latest published annual Budget and Fees report[34] will be used to estimate the NEM fees in $/MWh for the variable components and $/week for the fixed components.

Information and data

NEM management fees will be calculated based on:

- AEMO-published annual Budget and Fees report.

31 National Electricity Rules (NER) clause 3.11.2.

32 AEMO, Ancillary Services and Frequency Performance Payments, Australian Energy Market Operator, n.d., accessed 18 August 2026.

33 AEMO, RERT Reporting, Australian Energy Market Operator, n.d., accessed 18 August 2026.

34 AEMO, Energy market fees and charges, Australian Energy Market Operator, n.d., accessed 18 August 2026.

3.4.5 Market making and other obligations

Retailers can be obligated by a variety of policy initiatives to enter into financial contracts to support liquidity, reliability or other public goods. When such initiatives are triggered, we will reflect their efficient costs as part of the wholesale cost.

3.4.6 AEMO direction costs

AEMO direction costs are compensation costs that arise when AEMO directs a market participant to act to maintain power system security and reliability.

We will include any AEMO direction costs incurred during the previous 4 quarters leading up to a determination, while avoiding double-counting any costs also classified as ancillary services. These costs will be calculated by summing quarterly direction costs by region from AEMO's latest available Quarterly Energy Dynamics Report[35] and dividing the result by the corresponding annual regional customer energy demand.

Information and data

AEMO direction costs will be calculated based on:

- AEMO's latest available Quarterly Energy Dynamics Report.

3.4.7 NEM market event compensation cost recovery

NEM market event cost recovery is the amount retailers are expected to pay to fund compensation arising from market suspension events. We will include any event cost recovery as a $/MWh cost per region. The costs will be calculated from AEMO's published estimates of the NEM event costs and the Australian Energy Market Commission-approved administered pricing compensation costs, the regional share of the energy purchased and the customer load:

$$\text{event cost allowance (\$/MWh)} = \frac{\text{regional share of event costs}}{\text{regional customer load}}$$

Information and data

NEM market event costs will be calculated based on:

- AEMO-published NEM Events Compensation Updates[36]
- Australian Energy Market Commission administered pricing compensation costs.[37]

3.5 Energy losses

Some energy is inevitably lost as it is transported over transmission and distribution networks to customers, resulting in a cost incurred by retailers. WEC estimates will be adjusted for these losses to avoid understating costs.

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35 AEMO, Quarterly Energy Dynamics (QED), Australian Energy Market Operator, n.d., accessed 18 August 2026.

36 AEMO, NEM events and reports, Australian Energy Market Operator, n.d., accessed 18 August 2026.

37 AEMC, Compensation – administered pricing, market suspension, and directions, Australian Energy Market Operator, n.d., accessed 18 August 2026.

The costs will be calculated at the regional reference node, and we will apply transmission and distribution loss adjustments using AEMO-published marginal loss factors and distribution loss factors.[38] The calculation will be:

total loss factor = marginal loss factors × distribution loss factors

We will calculate the total energy loss cost by summing all the variable wholesale cost components and multiplying by the total loss factor. The variable wholesale cost components include the WEC, ancillary costs, variable NEM management fees, RERT, prudential costs, volatility allowance and NEM event costs. The calculation is:

total variable wholesale costs × total loss factor = energy loss cost

Information and data

Energy losses will be calculated based on:

- AEMO-published marginal loss factors and distribution loss factors.[39]

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38 AEMO, Loss factors and regional boundaries, Australian Energy Market Operator, n.d., accessed 18 August 2026.

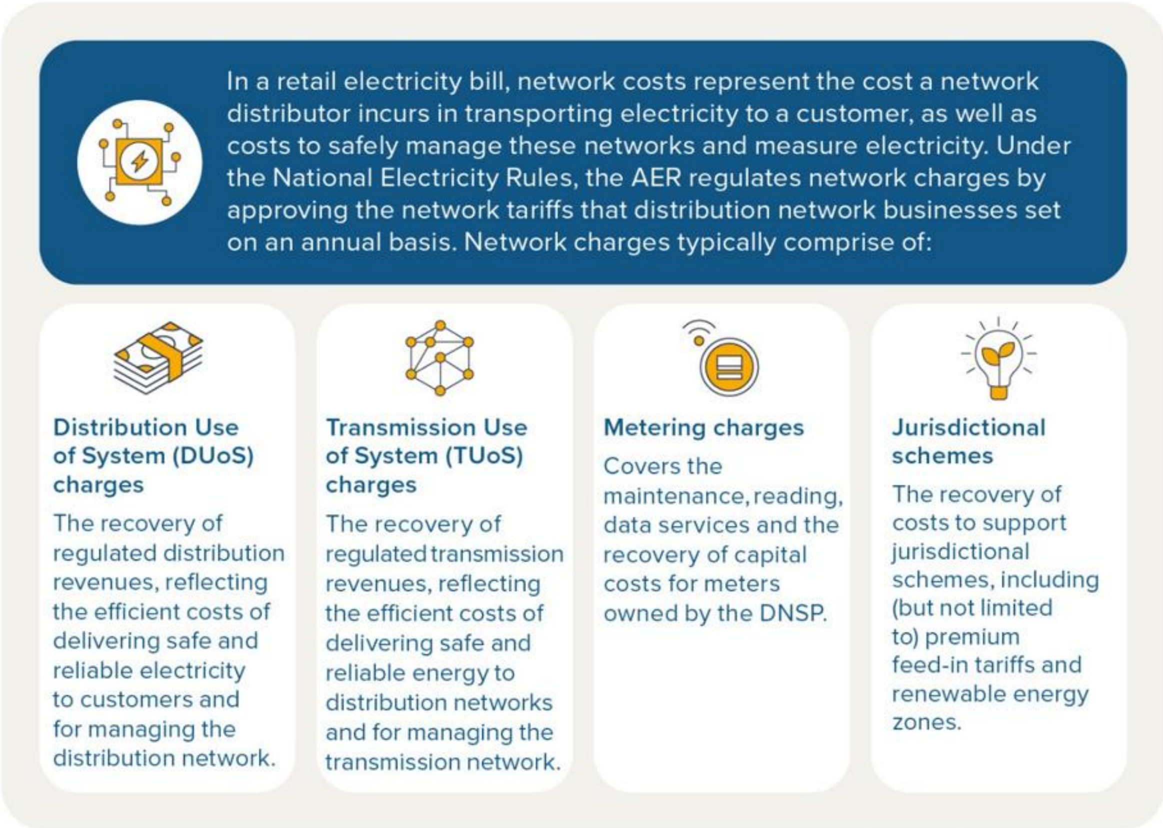
39 AEMO, Loss factors and regional boundaries, Australian Energy Market Operator, n.d., accessed 18 August 2026.

4 Network costs

The network costs component of the DMO reflects retailers' costs incurred for the distribution and transmission of electricity. The Regulations require us to have regard to the mandatory considerations, including the cost of distributing and transmitting electricity in the region.[40]

4.1 Identification of network costs

To establish a forecast of network costs, we aim to reflect the efficient network costs a retailer incurs to serve small customers on standing offers.



4.2 Approach and methodology to determine network costs

To determine the network costs for regulated tariffs – that is, for the comparison price and tariff cap determination – we will pass on as closely as possible the actual costs for flat rate and time of use network tariffs from each DNSP for each defined customer type.

To determine the network costs for non-regulated tariffs, we will apply the corresponding time of use network tariff from each DNSP for each customer type.

40 Regulations s. 16(4)(c)(ii).

4.3 Regulated tariff caps and comparison prices

The Regulations require us to set tariff caps and comparison prices for certain types of regulated tariffs, including flat rate and flexible tariffs.[41] The definition of a flexible tariff is a tariff with charges that varies during the day and cannot be a demand tariff. Therefore, it only applies to time of use tariffs. We determine network costs to be recovered in the flat rate and time of use tariff caps.

Flat rate network costs

To determine network costs for the flat rate DMO tariff caps and comparison prices, we will apply a weighted average of the most representative flat rate and time of use network tariffs from the DNSPs' approved annual pricing proposals. The flat rate and time of use network tariff weightings will be based on the proportions of flat rate retail tariff customers with legacy meters[42] and smart meters, respectively.

We will determine the flat rate network costs for each DNSP and customer type by:

1. calculating the respective annual fixed and variable costs of the flat rate network tariff and the time of use network tariff at the assumed DMO usage and pattern of supply
2. calculating the weighted average of these 2 sets of annualised fixed and variable costs – the weightings accord with the proportions of flat rate retail customers with legacy meters or smart meters installed
3. converting the annualised fixed and variable network costs into tariff components by dividing the annual fixed cost by 365 days, or 366 days for a leap year, and by dividing the annual cost of weighted usage charges by the assumed annual usage.

Time of use network costs

To determine the network costs for the time of use DMO tariff caps and comparison prices, we will use the underlying prices and structure of the applicable time of use network tariff. This will typically be the default network tariff as set out in the DNSPs' tariff structure statements (TSSs).

Where a DNSP's default network tariff is unsuitable, we will apply the most representative tariff from the DNSP's TSS. For example, for DMO 8 we used Ausgrid's most common time of use network tariff because the default network tariff included demand charges. The Regulations state that a time of use DMO flexible tariff cannot include demand charges.[43]

We will also consider changes DNSPs make in their TSS network resets, where they may introduce or remove tariffs that may result in a change in the default network tariff. In this case, we will continue to use the above approach of applying the default time of use network tariff or, if the default tariff assignment is not a time of use network tariff, we will apply the most representative time of use network tariff.

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41 Regulations, ss. (1A)(b) and (c).

42 Legacy meters are those that are not smart meters; they may be an accumulation meter or a manually read interval meter. AEMO, [Metering installation type codes](), Australian Energy Market Operator.

43 Regulations, s. 5.

Controlled load network costs

To determine the network costs for the controlled load DMO tariff caps and comparison prices, we will use the underlying prices and structure of the applicable controlled load network tariffs. In some DNSP regions, multiple controlled load network tariffs can apply for different controlled load circuits (for example, Controlled Load 1, Controlled Load 2, Controlled Load 1 and 2, Controlled Load TOU). In these cases, we will determine separate network costs based on these different controlled load network tariffs for the separate controlled load DMO tariff caps and comparison prices.

4.4 Information and data

DNSPs' tariff structure statements

We will use the AER-approved TSSs[44] for Ausgrid, Endeavour Energy, Essential Energy, Energex and SA Power Networks to obtain information on each network's tariff classes, tariff allocations and charging windows.[45] These must be made in accordance with the National Electricity Rules and are public documents.[46]

We will deploy this data for determining both the flat rate and time of use network costs.

DNSPs' annual pricing process

We will use DNSPs' annual pricing proposals submitted to and approved by the AER to obtain the network prices for tariffs each year over the 5 years of the TSS.[47] Network prices are sourced to calculate annual network costs for the DMO draft determination (from the DNSPs' indicative forecasts submitted in February) and for the DMO final determination (from the DNSPs' pricing proposals submitted in April). The AER-approved DNSPs' pricing proposals are published on the AER's website.[48]

We will deploy this data for determining both the flat rate and time of use network costs.

AER compulsory information notices

We intend to seek meter and tariff type data through our compulsory notice power. We have previously used the compulsory retail cost notices to obtain historic customer counts by meter and tariff type as at the previously completed financial year (30 June), and projected customer counts by meter and tariff type up to the mid-point of the DMO regulatory period (31 December). Customer counts are updated to reflect the increased uptake of smart meter installations (from 30 June to 31 March).

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44 For each 5-year regulatory period, each DNSP must submit to the AER for approval a TSS setting out the DNSP's tariff structures, including charging windows and indicative tariff levels.

45 Ausgrid, Tariff Structure Compliance Document 2024-2029; Endeavour Energy, Tariff Structure Statement 2024-2029; Essential Energy, Planning for the future 2024-2029 Revised Tariff Structure Statement; Energex, Tariff Structure Statement. In support of the Regulatory Determination Proposal 2025-2030; SA Power Networks, Tariffs Overview, 2025-2030 Regulatory Proposal.

46 National Electricity Rules, Clause 6.18.1A.

47 These tariff structures must match the already-approved TSS.

48 AER, Network pricing proposals and tariff variations, 2026-2027, Australian Energy Regulator.

For DMO 8, the compulsory retail cost information notices included a set of retailers that had over 1,000 small customers across all DMO regions based on the AER’s latest quarterly retail performance data. This represented 98% of the market.

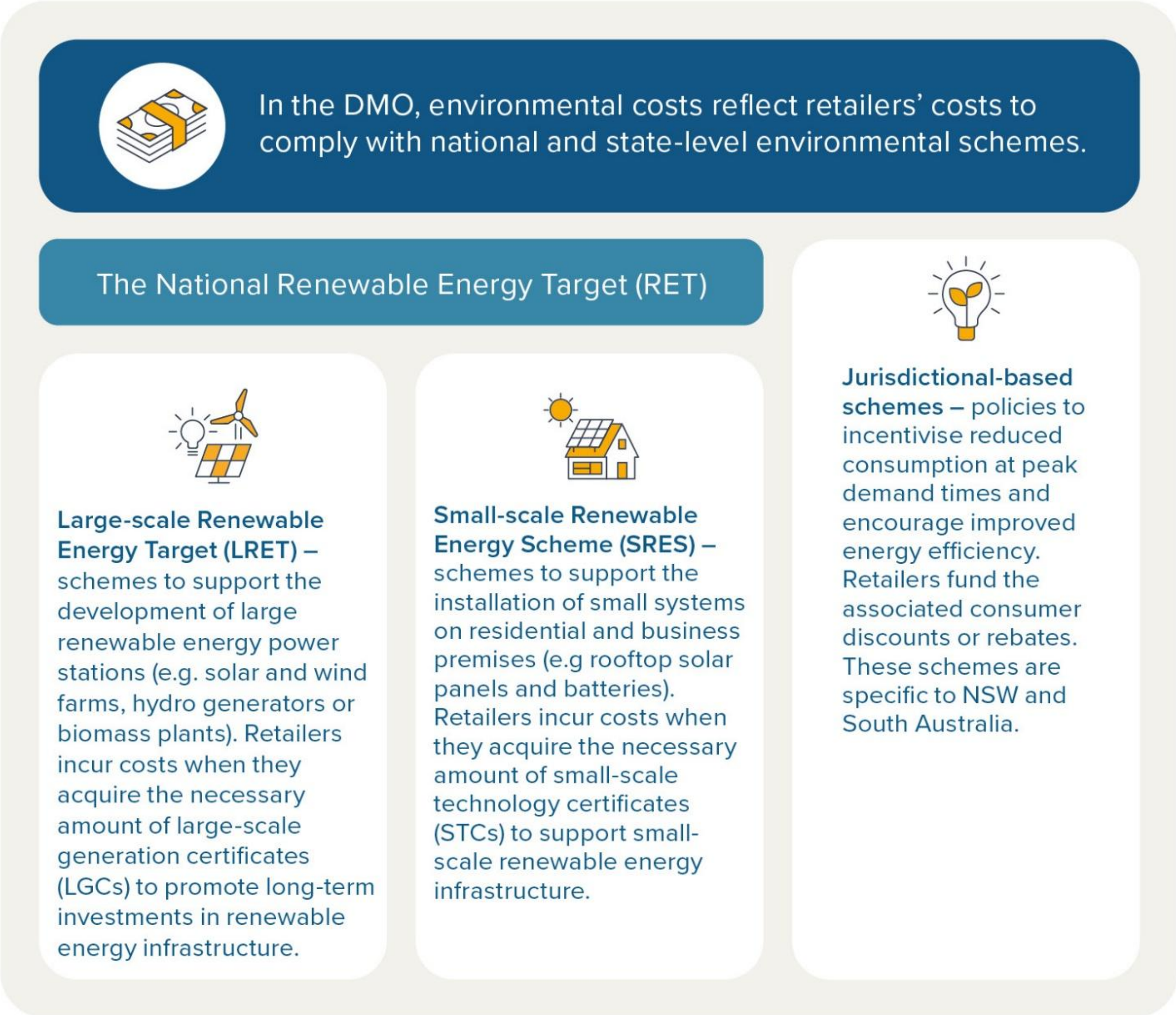
We will use this data specifically for the flat rate network cost calculations.

5 Environmental costs

National and state-based environmental schemes require retailers to procure some energy from renewable sources. In the DMO, environmental costs reflect retailers' costs to comply with these schemes. The Regulations require us to have regard to the mandatory considerations, including the cost of complying with relevant Commonwealth and state-level laws in relation to supplying electricity in the region.[49]

5.1 Identification of environmental costs

Environmental costs fall into 3 main categories:



49 Regulations, ss 16(1), (1A), (4).

5.2 Approach to determining environmental costs

We will use a market-based approach to forecasting environmental costs.

5.2.1 Large-scale Renewable Energy Target

We will estimate the cost of complying with the scheme by multiplying the renewable power percentage by the determined large-scale generation certificate price to establish the cost per MWh of liable energy supplied to customers.

We will determine the large-scale generation certificate price by using large-scale generation certificate forward prices for the 2 relevant calendar compliance years in the determination period. For each year, this will be calculated as the trade-weighted average of large-scale generation certificate forward prices since trading commenced. This assumes an efficient and prudent retailer builds up large-scale generation certificate coverage before each compliance year.

Information and data

Large-scale renewable energy target costs will be calculated based on:

- Clean Energy Regulator published renewable power percentages for the determination year.[50]
- The trade-weighted average of large-scale generation certificate forward prices for 2 years from brokers.

5.2.2 Small-scale Renewable Energy Scheme

The small-scale technology percentage is determined ex-ante by the Clean Energy Regulator. It reflects the projected small-scale technology certificates supplied as a percentage of the estimated volume of liable electricity consumption throughout Australia in that year. We will calculate the estimated cost of compliance with the scheme by multiplying the estimated small-scale technology percentage value with the small-scale technology certificates price.

Information and data

Small-scale renewable energy scheme costs will be calculated based on:

- Clean Energy Regulator published binding small-scale technology percentage.[51]
- Clean Energy Regulator small-scale technology certificates clearing house price for 2 years.[52]

5.2.3 State-based schemes

We will estimate state-based scheme costs by identifying each relevant compliance obligation and applying an expected certificate or scheme cost to that obligation. The calculation typically combines:

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50 CER, Renewable power percentage, Clean Energy Regulator, n.d., accessed 18 August 2026.

51 CER, Small-scale technology percentage, Clean Energy Regulator, n.d., accessed 18 August 2026

52 CER, Buy and sell small-scale technology certificates, Clean Energy Regulator, n.d., accessed 18 August 2026.

- the regulatory target or obligation set by the relevant authority
- forecast or market-based certificate prices (or other scheme costs) expected to apply during the determination period
- any scheme-specific cost information published by regulators or administrators.

Information and data

Where available, actual scheme cost data published by the scheme administrator may be used instead of certificate price modelling.

6 Retail costs

Retail costs are the costs retailers incur to provide retail services to customers.

The Regulations require us to have regard to mandatory considerations, including:

- the efficient costs of supplying electricity to small customers on standing offers, including retail costs[53]
- if relevant to the distribution region, the modest cost of acquiring and retaining small customers.[54]

6.1 Identification of retail costs

To establish a forecast of retail costs for the DMO, we aim to reflect the efficient costs a retailer incurs to serve small customers on standing offers, as well as the modest costs associated with acquiring and retaining new customers. As such, the retail costs for the DMO will include:

- **retail and other costs** – costs to serve, costs to acquire and retain customers and other costs
- **bad debt –** costs associated with writing off actual bad debt
- **smart meter costs** – costs of operating and managing smart meters.

6.2 Approach and methodology to determine retail costs

To determine the retail costs, we will sum the costs to serve and other costs, costs to acquire and retain, bad debt and smart meter costs. The resulting total is a fixed annual cost, which is reflected in the daily supply charge tariff cap.

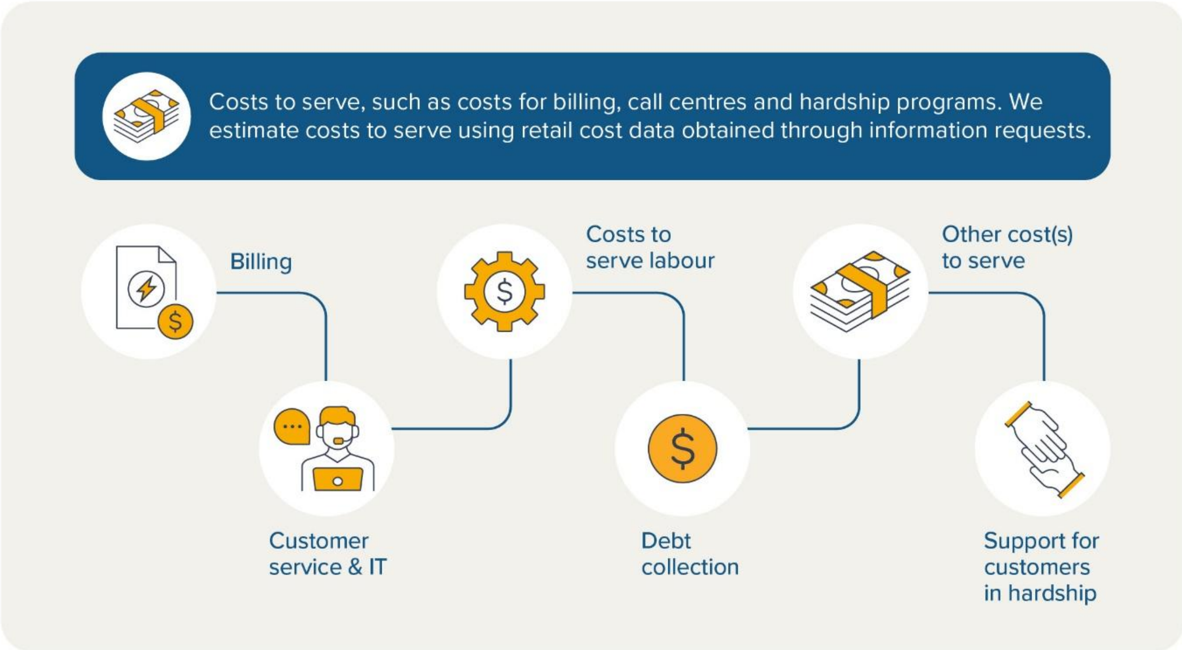
53 Regulations, s. 16(4)(a).

54 Regulations, s. 16(4)(c)(iv).

6.3 Retail and other costs

6.3.1 Costs to serve and other costs

Retailer costs to serve include the following sub-components:



We will determine efficient per-customer costs to serve and other costs by applying a customer-weighted average, excluding outliers. For each DMO region and customer type, the customer-weighted averages are derived by dividing the retailers' total costs to serve by the average number of customers.

We will remove outliers before computing the customer-weighted average. For a given DMO region and customer type, a retailer is identified as an outlier if its Z-score is greater than 2 (that is, a retailer's reported retail and other costs is 2 or more standard deviations above or below the customer-weighted average of retail and other costs). We then exclude all data for that outlier from the customer-weighted average calculations.

6.3.2 Costs to acquire and retain customers

Retailer costs to acquire and retain customers include the following sub-components:

We will determine the modest costs to acquire and retain customers by applying a standing offer customer-weighted average, excluding outliers. For each DMO region and customer type, the standing offer customer-weighted average is determined by weighting each retailer's per-customer costs to acquire and retain customers with their respective share of standing offer customers and then aggregating these costs.

Similar to costs to serve and other costs, if a retailer is identified as an outlier (its Z-score is greater than 2), all its data is excluded from the standing offer customer-weighted average calculations.

6.4 Bad debt

We will estimate the efficient per-customer bad debt costs by using actual written-off debt reported by retailers and applying a customer-weighted average, excluding outliers. For each DMO region and customer type, the customer-weighted averages are derived by dividing the total actual written-off debt by the average number of customers.

We will identify a retailer as an outlier if its Z-score is greater than 2 (that is, a retailer's reported actual written-off debt is above or below the customer-weighted average of actual written-off debt) and remove all data for that outlier from the customer-weighted average.

6.5 Smart meter costs

We will estimate efficient smart meter costs by applying a customer-weighted average, excluding outliers. Smart meter costs will include a cost of capital allowance to account for the projected shortfall in the smart meter allowance at the midpoint of the DMO due to additional meters being installed.

Using smart meter data, we will quantify the smart meter allowance for each DNSP and customer type by:

1. estimating the average cost per smart meter by dividing the total smart meter costs by the number of customers on smart meters
2. calculating the proportion of customers on smart meters relative to the total number on accumulation and smart meters
3. calculating the smart meter cost by multiplying the average cost per smart meter with the proportion of customers on smart meters.

We will then quantify the capital allowance by:

1. projecting the total smart meter costs at the midpoint of the relevant DMO period by multiplying the average cost per smart meter by the projected number of customers on smart meters at that midpoint
2. projecting the smart meter cost per customer at the midpoint of the relevant DMO period by dividing the projected total smart meter costs above by the total number of projected customers on accumulation and smart meters
3. calculating the shortfall in smart meter allowance by using the difference between the smart meter cost per customer at the midpoint of the relevant DMO period and the smart meter cost at the end of the data reporting period (for example, 31 December 2026 projected costs compared with 30 June 2025 reported costs)
4. applying a weighted average cost of capital of 10%.

Outliers will be removed before performing these calculations. As with other retail costs, if a retailer is identified as an outlier for a given DMO region and customer type (its Z-score is greater than 2 – that is, a retailer's costs per smart meter is 2 or more standard deviations above or below the average cost per smart meter) all its data is excluded from the smart meter cost calculations.

Between the draft and final DMO determinations, we intend to update these smart meter costs to reflect the increased uptake of smart meter installations at 31 March. We intend to obtain this information through our compulsory information notice powers following the release of the draft determination.

Information and data

We intend to obtain retail cost data through our compulsory information notice powers for the most recently completed financial year.

The information we intend to use will include a set of retailers that, according to the AER's latest quarterly retail performance data, have over 1,000 small customers across all DMO regions. For DMO 8, this represented 98% of the market. The data we intend to use will cover the previous financial year's customer numbers, costs to serve, costs to acquire and retain customers, bad debt and other retail costs.

We also intend to obtain smart meter data via our compulsory information notice powers. The smart meter data we intend to use will include smart meter costs, historic customer counts by meter and tariff type as at the previously completed financial year (30 June), and projected customer counts by meter and tariff type up to the midpoint of the DMO regulatory period (31 December). For the final determination, customer counts will be updated to include the increased uptake of smart meter installations across the 9 months from 30 June to 31 March.

Retail cost data excludes fines and penalties, costs otherwise accounted for in the DMO cost assessment model and any costs attributed to anything other than the sale of electricity.

We will apply the Reserve Bank of Australia's forecast inflation[55] to occur from the date of the data to the end of the relevant DMO period to retain the value of these costs in real terms.

55 We will rely on the latest available RBA Statement on Monetary Policy, Detailed forecast information table, forecast Consumer Price Index.

7 Retail margin

Retail margins reflect the return on retailer risk. The Regulations require us to have regard to mandatory considerations, including the efficient costs of supplying electricity to small customers on standing offers, inclusive of retail margins, when determining the standing offer price.[56]

7.1 Identification of retail margins

The Regulations require the inclusion of retail margins as part of retailers' efficient costs to supply small customers on standing offers.[57]

Efficient retail margins are an essential part of the DMO to ensure consumers are not paying more than they need to while also allowing the retail market to remain competitive and innovative.

7.2 Approach and methodology to determine efficient margins

Our approach is to apply retail margins as a percentage of total DMO costs. The retail margin percentage will be based on the previous determination values unless there is strong evidence that these values are no longer representative of efficient margins. The current retail margin percentage is set at 6% of the DMO price.

We will determine the appropriate quantum of retail margins by considering a range of methodologies applied to different data sources to calibrate an overall amount for the retail margin component of the DMO cost stack.

All analysis is considered at both the mass market level and disaggregated customer type level, with further disaggregation by DMO region and size of retailer[58] where possible.

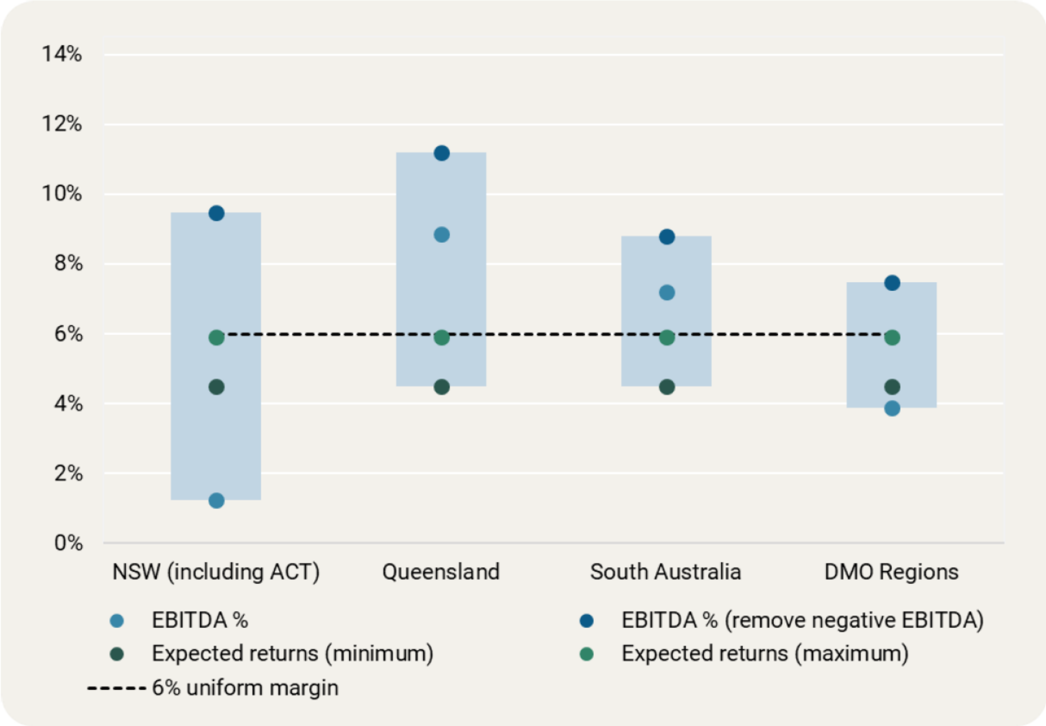
Figure 7.1 illustrates an example of our approach to quantifying retail margins.

56 Regulations, s. 16(4)(a); Explanatory Statement, *Competition and Consumer (Industry Code – Electricity Retail) Amendments Regulations 2026*, item 41.

57 Regulations, s. 16(4)(a); Explanatory Statement, *Competition and Consumer (Industry Code – Electricity Retail) Amendments Regulations 2026*, item 41.

58 We group retailers into Tier 1 (AGL, EnergyAustralia, Origin Energy), Tier 2 and Tier 3 retailers.

Figure 7.1 Range of EBITDA margins for mass market customers, by DMO region



EBITDA: Earnings before Interest, Tax, Depreciation and Amortisation.
Source: AER, [DMO 8 Final determination](), Australian Energy Regulator, 20 May 2026, p. 71.

7.2.1 Earnings before interest, tax, depreciation and amortisation (EBITDA) margins methodology and data

We will estimate average retailer margins on an EBITDA basis, derived from retailers' financial data collected through formal information requests. This dataset includes all retailers who supply electricity to over 1,000 small customers across DMO regions and contains observed EBITDA margins achieved within competitive markets.

EBITDA margins are calculated by aggregating all retailers' reported EBITDA values and expressing them as a percentage of retailers' total revenue. A lower bound of EBITDA is calculated by considering all retailers' EBITDA and revenue, including retailers that reported a loss (negative EBITDA). A higher bound of EBITDA is calculated by excluding all retailers' EBITDA and revenue that reported a loss (negative EBITDA).

7.2.2 Inferring margins from prices of advertised market offers methodology and data

We will infer retail margins on prices of advertised market offers and DMO costs.

Data on market offers will be sourced from our Energy Made Easy portal. Using this data, we will infer these retail margins by:

1. estimating the total annual bill at the commencement of each new DMO period for each retail market offer, customer type and DMO region

2. inferring annual margin available in that total bill by deducting, for each retail market offer, the wholesale electricity energy costs, environmental costs, network costs and retail costs
3. expressing the retail margin as a percentage of the total annual bill.

Since advertised market offers tend to be lower priced than expired market offers to attract new customers, this may underestimate the overall margins achieved by retailers. Therefore, we will treat this analysis as the lower bound of an efficient retail margin.

7.2.3 Inferring margins using the Australian Competition and Consumer Commission's (ACCC) retail pricing information methodology and data

We will also use the annual ACCC Inquiry into the National Electricity Market reports to infer retail margins from current pricing data.

The ACCC reports on actual prices that customers have been charged in the last monitoring period, lists all the market offers with existing customers and includes plans that are no longer offered to new or switching customers. Using this pricing data, the ACCC derives customer-weighted average annual prices by DMO region and customer type.

We will take the ACCC's customer-weighted annual prices and subtract our most recently determined DMO costs (including retail, wholesale, environmental and network costs) to infer margins for residential and small business customers. These margins will be expressed as a percentage of the customer-weighted annual prices.

7.2.4 Benchmarking regulatory decisions from other jurisdictions

We will also consider the determinations of other bodies with similar regulatory functions, including the Essential Services Commission of Victoria, Independent Competition and Regulatory Commission and Office of the Tasmanian Economic Regulator and use their decisions to benchmark the DMO quantum for efficient retail margins.

This may also include the expert reports and modelling relied on by other regulatory bodies in making their determinations.

7.2.5 Extent of impact of DMO margins on market using retail performance reporting data

We will also monitor whether the retail electricity market in DMO regions has been impacted by our margin settings in DMO prices.

We will measure and consider:

- market concentration for the residential and small business cohorts and use the Herfindahl-Hirschman Index using retail performance reporting data
- price dispersion in market offers on Energy Made Easy, including size of discounts in most competitive offers and proportion of offers at or above the DMO price
- new entrants and exits from the retail market.

8 Model annual usage

The Regulations require us to determine 'broadly representative' annual supply amounts and the patterns of consumption for small customers within each DMO region. Annual usage and the timing or pattern of supply over a year are jointly referred to as 'model annual usage'.

We must determine model annual usage for a DMO in a given financial year, by legislative instrument, for both regulated and non-regulated tariffs.

We must consider the following matters to be broadly representative when making a determination:

- annual per-customer amounts of electricity supplied
- the timing or pattern of the supply.[59]

8.1 Annual usage amounts

The annual usage amount is our determination of a broadly representative per-customer amount of electricity supplied over a year.[60]

We must determine annual usage amounts for each relevant small customer and tariff type within a DMO region that will broadly reflect the electricity consumption of those customer and tariff types. Annual usage amounts will be expressed in kilowatt hours (kWh) consumed in a financial year. Our determination on annual usage amounts will be included in the accompanying legislative instrument for the associated financial year.

When determining broadly representative annual usage amounts for an upcoming financial year, we will have regard to the most relevant information on annual usage available. In assessing the appropriateness of information for this purpose, we will have regard to:

- whether the information is specific to the relevant small customer and tariff types for each DMO region
- how recent the information is
- whether the information has been subject to appropriate quality assurance.

This approach enables us to determine annual usage amounts that are broadly representative of customer supply while remaining responsive to changes in underlying usage patterns.

While we will consider the most relevant and up-to-date information available, we also recognise the value in maintaining broadly consistent usage amounts over time.

59 Regulations, ss 16(1), (1A).

60 Regulations, ss 16(1)(a)(i), (1A)(a)(i).

Annual usage amounts will be slightly increased[61] to reflect an additional day if the relevant determination year is a leap year.

Information and data

To determine the annual usage amounts, we intend to collect and consider data from:

- relevant DNSPs
- retailers in DMO regions
- other sources we consider as appropriate when setting annual usage amounts
  - for example, DMO consultations and determinations have previously given regard to the ACCC's *Electricity market monitoring inquiry* reports when assessing the appropriateness of our determinations of annual usage.[62]

8.2 Timing or pattern of supply

The timing or pattern of supply is our determination of a broadly representative pattern of electricity consumption over a day for each relevant customer and tariff type within a DMO region. Determining the time of use pattern is a separate role from determining a load profile to forecast wholesale prices.

When determining broadly representative timing or patterns of supply for the financial year we will:

- have regard to the most relevant information available
- retain a single 24-hour usage profile to describe the pattern of usage
- specify usage at 30-minute intervals in kWh
- assume the same usage occurs every day (with no variation for weekday or weekend)
- apply no seasonal weighting; that is, kWh consumed are assumed to be the same on each day of the year.

Our determination on timing or pattern of supply will be contained in the accompanying legislative instrument for the associated financial year.

Information and data

In determining a broadly representative timing or pattern of supply, we intend to update the 24-hour usage profile using AEMO interval meter data for each region, averaged over 3 years. We may also collect and have regard to other information as appropriate when setting timing or pattern of supply for each DMO region.

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61 Leap year annual usage amounts will be increased by approximately 0.27% relative to non-leap years, which is 1 additional day divided by 365.

62 For example; AER, Default Market Offer Prices 2026–27 Issues Paper, Australian Energy Regulator, November 2025.

9 Solar Sharer Offer

The Solar Sharer Offer (SSO) is an opt-in time of use standing offer tariff for residential customers with a smart meter that includes a designated 3-hour free usage period. In determining the SSO, the Regulations require us to:

- determine a daily 3-hour free usage period for each DMO region when electricity usage up to 24 kWh is free[63]
- have regard to periods of high solar generation (rooftop and large-scale) and low wholesale and network costs in a DMO region, and align the free usage period with these periods as far as practicable[64]
- determine a reasonable use tariff cap for any electricity usage over 24 kWh during the free usage period.[65]

The Regulations also require us to determine a model annual usage, tariff caps and a comparison price for the SSO.[66]

In determining an SSO price, the Regulations also require us to have regard to the mandatory considerations.[67]

9.1 Free usage periods

The SSO tariff includes a 3-hour free usage period during which the usage charge for electricity is zero.

We will determine free usage periods at local time year-round to provide a consistent free usage period start time for SSO customers. Some customers in the Essential Energy region (NSW) observe the South Australian time zone (Australian Central Standard Time / Australian Central Daylight Time). For these customers, the free usage period should begin in accordance with local time (South Australian time).

We will also align free usage periods across NSW for practicality and simplicity.

To determine the optimal timing of the free usage period for each DMO region, we must have regard to periods of high solar generation (both rooftop and large-scale) and low wholesale prices and network costs in each DMO region, and align the free usage period with these periods as far as practicable.[68]

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63 Regulations, s.18(1) – (2). The Australian Government has set the reasonable use cap at 24 kilowatt hours as per s.11A(2) of the Regulations.

64 Regulations, s.18A(a) – (b).

65 Regulations, s.18(4).

66 Regulations, s.16(1A).

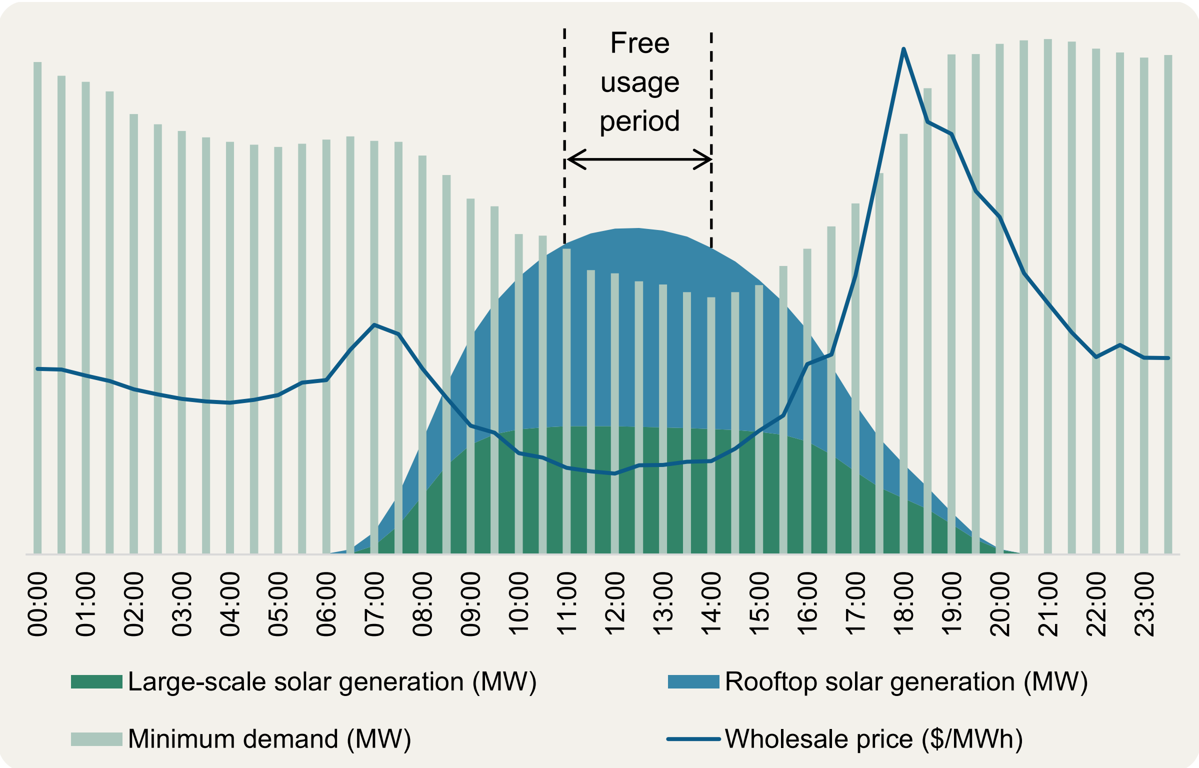
67 Regulations, s.16(4).

68 Regulations, s.18A(a) – (b).

The Regulations also allow us to have regard to other relevant system and market factors if we consider it relevant and appropriate to do so.[69] We will consider minimum demand as an explicit additional factor due to it being referenced in the government's SSO outcomes paper and its relevance as a system factor that reflects periods of increased system vulnerability and surplus generation.[70]

Our approach to determining free usage periods is illustrated in Figure 9.1. We will use the most recent 5 years of state-level data for solar generation, wholesale prices and minimum demand, adjusted to reflect local time and daylight savings. To identify periods of low network costs, we will assess default time of use network tariffs and other time of use network tariffs with low-cost periods in the middle of the day as approved by us through DNSPs' annual pricing proposals for the relevant DMO determination year. The free usage periods will be based on the continuous 3-hour interval that best aligns high rooftop and large-scale solar generation and low wholesale costs, network costs and minimum demand.

Figure 9.1 Illustrative example of our approach to identifying the free usage periods



Note: Rooftop solar generation is stacked on top of large-scale solar generation to give an indication of total solar generation. Network costs are not included in Figure 9.1 due to visualisation constraints.

69 Regulations, s.18A(c).

70 DCCEEW, Solar Sharer Offer consultation outcomes paper, Department of Climate Change, Energy, the Environment and Water, 23 January 2026, p. 8.

Information and data

To inform our determination of the free usage periods we will use:

- state-level data sourced from AEMO – we will assess each factor using the average per 30-minute interval over the most recent 5 years:
  - rooftop solar output
  - large-scale solar output
  - spot price
  - native demand
- AER-approved time of use network tariffs for the relevant DMO determination year for each DNSP.

9.2 SSO tariff structure and pricing

We will set the SSO tariffs by overlaying the designated free usage periods onto the corresponding DMO region's tariff used for the time of use DMO. Basing the SSO on the time of use DMO helps ensure retailers can recover their efficient costs to supply SSO customers. This means the SSO will reflect the time of use DMO structure and cost components, including wholesale, network, environmental, retail costs and margin. The total annual bill of a representative customer for the SSO would then align with the time of use DMO.

The SSO is a new tariff, so we will monitor market and customer responses to the SSO and may consider alternative tariff structures and cost bases where appropriate.

9.2.1 Cost recovery

In pricing the SSO tariffs, we will aim to balance the government's design principle that customers who shift load should be better off overall while allowing retailers to recover the efficient costs of supplying SSO customers.[71]

Retailers will incur costs during the free usage period, including variable network, wholesale and environmental costs. To enable retailers to recover their efficient costs to supply customers on the SSO, we will estimate costs incurred during the free usage period using the applicable pattern of supply and time of use DMO costs and reallocate them across the non-free usage periods. This means estimated costs incurred during the free usage period are recovered through slightly higher usage charges in non-free usage periods.

As a baseline, we will reallocate all costs estimated to be incurred during the free usage period into non-free usage periods on a volume-weighted basis. Under this approach, we will reallocate recoverable costs by the assumed volume of electricity consumed in each non-free usage period. This will effectively increase the usage charges for all non-free usage periods by the same amount.

We will observe the balance of outcomes for customers and retailers and how customers shift electricity usage. We may consider alternative approaches to cost recovery if appropriate.

[71] In accordance with design principles 1 and 4 from the Australian Government's SSO outcomes paper.

9.2.2 Assumed customer behaviour

Assumptions on how customers use electricity while on the SSO impacts how we estimate costs incurred by retailers during the free usage period. Assuming a customer shifts a portion of their usage into the free usage period (or uses additional electricity) when pricing the SSO increases the estimated costs incurred by a retailer during the free usage period. This results in higher usage charges in non-free periods than if no load shift or additional usage was assumed.

The SSO was launched on 1 July 2026. In the absence of robust data on SSO customer behaviour, we will not assume any customer load shift or additional consumption when pricing SSO tariffs.

We will monitor customer behaviour and consider whether adjustments are needed. When considering any adjustment to our approach, we will continue to balance ensuring customers who shift load are better off overall while allowing retailers to recover efficient costs.

Information and data

We will request data from retailers periodically to understand customer responses to the SSO and outcomes for retailers and customers. This data will inform any potential adjustments to how we set SSO tariffs. This SSO customer data may include:

- load profiles
- bill outcomes
- the extent to which SSO customers exceed the reasonable use cap
- whether SSO customers have rooftop solar or a home battery.

9.3 Reasonable use tariff cap

The reasonable use tariff cap applies to electricity usage over 24 kWh during the free usage period.[72]

We will set the reasonable use tariff cap at the applicable SSO tariff rate for the free usage period, such as the off-peak or solar soak rate.

We may consider alternative approaches after assessing how often customers exceed the reasonable use cap and cost recovery implications for retailers. We may also consider potential risks for customers with high electricity usage levels.

[72] Regulations, s. 18(4). The Australian Government has set the reasonable use cap at 24 kilowatt hours as per s.11A(2) of the Regulations.

10 Additional types of regulated tariffs

The Regulations state that we may determine, by legislative instrument, additional types of tariffs for the purpose of defining a new regulated tariff.[73]

The Regulations require us to set out in the DMO guidelines any additional tariff type that the AER considers should be determined as a regulated tariff.[74]

10.1 Additional regulated tariff

We consider that a controlled load tariff for small business customers should be determined as a regulated tariff.

10.2 Approach to determining a new regulated tariff

When assessing whether we should determine an additional tariff as a regulated tariff type, we will consider:

- the number of customers on these tariffs
- the degree to which tariff caps and comparison prices for this type of tariff can be fair, trusted and reasonably priced, considering:
  - the complexity of the tariff
  - how varied or similar the tariff is across retailers
  - how sensitive the tariff and comparison price is to individual customer patterns of consumption
  - if it is instead more appropriate to remain a non-regulated tariff subject to the annual non-regulated comparison price level based on general usage amounts
- the outcomes of the tariff cap protection – we will assess whether changing the treatment of this type of tariff from a non-regulated to a regulated tariff will:
  - improve protections for standing offer customers
  - improve comparability for market offers and facilitate competition
  - restrict competition by increasing the compliance burden with a stricter tariff cap regime
- any other matter we consider relevant.

73 Regulations, ss. 15A and 5(g).

74 Regulations, s. 18B(1)(d).

11 Other matters

The Regulations require us to set out in the DMO guidelines any other matters we consider relevant to achieve the DMO objective.[75] We consider the other matters are:

- apportionment of fixed and variable costs to the tariff caps
- approach to determining comparison prices.

11.1 Apportionment of fixed and variable costs

The Regulations require us to set maximum amounts for regulated tariffs, known as tariff caps, for the fixed and variable charges that electricity retailers charge small customers. When doing so we must have regard to the mandatory considerations, which include a range of associated costs.[76] The apportionment of fixed and variable costs refers to how we allocate the recovery of the costs retailers incur into either the fixed or variable charge components of the DMO tariff caps.

Fixed charge: also referred to as the daily supply charge, means the retailer's charge for supplying electricity that does not vary according to the customer's usage of the electricity. Fixed charges are typically presented in dollars per day ($/day).

Variable charge: also referred to as the usage charge, means the retailer's charge for supplying electricity that varies according to the customer's usage of the electricity. Variable charges are presented in cents per kilowatt hour (c/kWh).

We consider retailers' costs of supplying electricity are generally driven by:

- the number of customers served (fixed costs), like billing, customer service and advertising costs
- the volume of electricity sold (variable costs), such as wholesale electricity and environmental scheme costs.

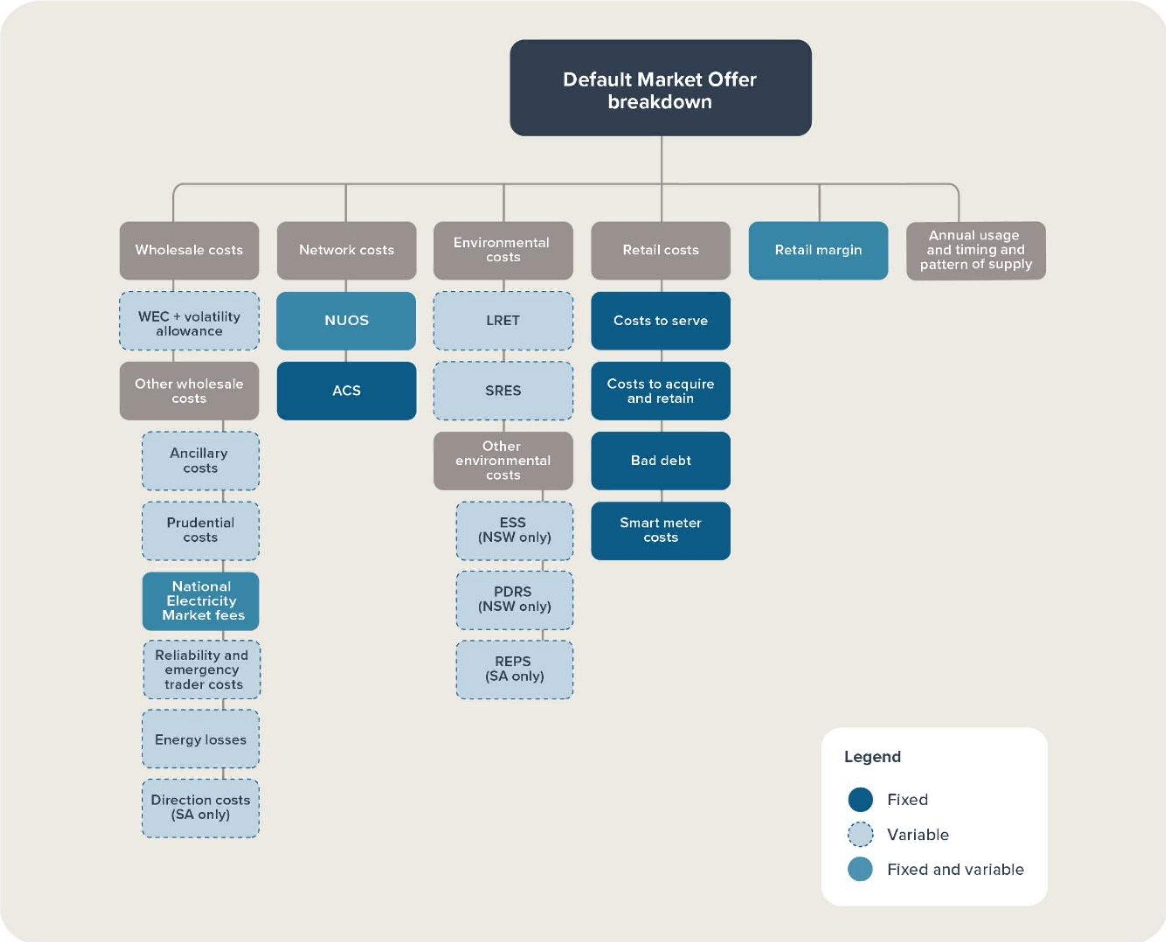
Costs are categorised as either fixed or variable components, or a combination of both. For all DMO tariff caps, we allocate the recovery of:

- fixed costs to the daily supply charge
- variable costs to the usage charge or charges.

[75] Regulations,

[76] Regulations, ss. 16(1A)(c) and (4).

Figure 11.1 DMO cost allocation



Acronyms are defined as follows: WEC – Wholesale energy cost, NUOS – Network Use of System charges, ACS – Alternative Control Services charges, LRET – Large-scale Renewable Energy Target costs, SRES – Small-scale Renewable Energy Scheme costs, ESS – Energy Savings Scheme, PDRS – Peak Demand Reduction Scheme, REPS – Retailer Energy Productivity Scheme.

11.2 Comparison price

The DMO has a comparison price role (previously called the reference price) for market offers. The Regulations require the comparison price be set based on what the AER considers would be a reasonable per-customer annual price for the year for supplying electricity under regulated and non-regulated tariffs.[77] In determining the comparison price we must have regard to the mandatory considerations.[78]

11.2.1 Comparison price for regulated tariffs

To determine the comparison price for regulated tariffs, we will apply our model annual usage amount, timing or pattern of supply and the number of days in the year to the relevant

77 Regulations, ss. 16(1)(b) and (1A)(b).

78 Regulations, s. 16(4).

tariff caps for a particular customer type, tariff type and DMO region. This establishes the appropriate comparison price.

Comparison price = (annual usage amount/s × variable tariff cap/s) + (days × fixed tariff cap)

11.2.2 Comparison price for non-regulated tariffs

We must also determine the comparison price for non-regulated tariffs, which customers can use to compare market offers that cannot easily be compared against a regulated tariff, such as offers with demand tariffs.

The comparison price represents what we consider would be a reasonable per-customer annual price for the year for supplying electricity to a customer under a non-regulated tariff, based on our determination of annual usage and timing or pattern of supply.[79] Our starting position is that the comparison price for non-regulated tariffs will be based on the time of use DMO tariff cap using the standard annual usage amounts and patterns of supply for small customers.

However, we may consider alternative approaches to setting the comparison price for non-regulated tariffs where it is more appropriate to do so. When determining a comparison price for a non-regulated tariff, we will seek to ensure that it supports meaningful comparisons between offers and is based on the best available information.

79 Regulations, s. 16(1)(b).