Default market offer prices 2025–26

Issues paper

October 2024

AUSTRALIAN ENERGY REGULATOR

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AER reference: 17356883

Amendment record

Version	Date	Pages
Published	11 October 2024	52

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Invitation for submissions

Interested parties are invited to make submissions on this issues paper by 8 November 2024. Submissions should be sent to: DMO@aer.gov.au.

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Submissions should be in PDF, Microsoft Word or another text readable document format.

We prefer that all views and comments be publicly available to facilitate an informed and transparent consultative process. Views and comments will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information should:

- clearly identify the information that is the subject of the confidentiality claim
- provide a non-confidential version of the submission in a form suitable for publication.

All non-confidential information will be placed on our website. For further information on our use and disclosure of information provided to us, see the ACCC/AER Information Policy (June 2014).

Glossary

Term	Definition
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASX	Australian Securities Exchange
CLP	Controlled load profile
CPI	Consumer Price Index
DMO	Default market offer
DMO 1	Default market offer determination for 2019–20
DMO 2	Default market offer determination for 2020–21
DMO 3	Default market offer determination for 2021–22
DMO 4	Default market offer determination for 2022–23
DMO 5	Default market offer determination for 2023–24
DMO 6	Default market offer determination for 2024–25
DMO 7	Default market offer determination for 2025–26
NEM	National Electricity Market
NSLP	Net System Load Profile
OTC	Over-the-counter
WEC	Wholesale energy cost

1 Introduction

This is the Australian Energy Regulator's (AER) issues paper for the retail electricity default market offer (DMO) prices to apply from 1 July 2025 to 30 June 2026 (known as DMO 7). The issues paper is the first step in our process to determine DMO 7 and outlines the proposed updates and refinements aimed at improving our methodology to set the DMO price.

The DMO is an electricity price 'safety net' protecting consumers from unjustifiably high prices, while also allowing retailers to recover costs. It is the maximum price an electricity retailer can charge standing offer customers.[1]

Standing offers are intended to provide a level of protection to customers not engaged in the retail electricity market. This may be due to various reasons, such as: they have never switched to a retailer's market offer, or they have defaulted to a standing offer at the end of their market offer benefit period. Every retailer must have a standing offer. Customers have the right to ask for one and their current retailer must place them on it if requested.

The AER's role is to determine the DMO price annually. Our DMO price determination applies to residential and small business customers in New South Wales (NSW), South East Queensland (SE Queensland) and South Australia.

The DMO price for each region also acts as a reference price for comparing residential and small business electricity offers. When advertising or promoting an offer, retailers must show the price of the offer in comparison to the DMO.

The *Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019* sets out the legislative framework for the DMO. Part 3 of the Regulations confers price setting functions on the AER. Specifically, we are required to determine:

- how much electricity a broadly representative small customer of a particular type in a particular distribution region would consume in a year and the pattern of that consumption (the model annual usage)
- a reasonable total annual price for supplying electricity (in accordance with the model annual usage) to small customers of a type in a region (the DMO price).

When the DMO Regulations were introduced, the Australian Government also provided policy objectives.[2] These include:[3]

[1] The cap on standing offer prices does not apply to customers on demand tariffs or small business customers on flexible or time of use (TOU) tariffs.

[2] The DMO objectives are set out in several sources including: the ACCC Retail Electricity Pricing Inquiry final report, June 2018; the Explanatory Statement accompanying the DMO Regulations, 2019; Treasurer's and Minister for Energy's request to the AER to develop a DMO, 22 October 2018; and the Minister for Climate Change and Energy's letter, 2024.

[3] The Regulations s.16(4)(d), state 'the AER must also have regard to…any other matters we consider relevant'.

REDUCE

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

ALLOW

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

MAINTAIN

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

When making each determination, the AER has also had regard to advice received from governments and prevailing economic conditions. The Australian, NSW, Queensland and South Australian governments have encouraged the AER to consider broader economic conditions and cost-of-living pressures when exercising the flexibility afforded to us under the Regulations to determine a reasonable price, and in balancing the policy objectives.

1.1 Summary of key issues for consultation

During DMO 6 we consulted on key aspects of our DMO methodology, including:

- our approach to the customer load profile that is used to model wholesale costs given the availability of updated interval meter data, increased solar photovoltaic (PV) penetration and Net System Load Profile (NSLP) data challenges
- different wholesale forecasting methods for South Australia given the low levels of Australian Securities Exchange (ASX) contract market liquidity
- the appropriateness of our approach to the retail margin and competition allowance.

After taking account of views received during consultation across both the issues paper and the draft determination, refinements were made for the final DMO 6 determination, including:

- using a blended load profile that included interval meter data and excluded rooftop solar exports, to determine the wholesale cost component
- splitting the retail allowance into separate components – the retail margin and competition allowance – with the retail margin being set as a percentage of the DMO costs. This provided greater transparency on the individual components within the DMO price, including the requirement in the Regulations that the DMO allows retailers to achieve a reasonable profit and our consideration of the DMO's competition objectives
- having regard to the cost-of-living (measured using the Consumer Price Index (CPI)) in deciding whether to apply the competition allowance, while also considering retail market competition.

We are mindful that stakeholders value stability and have requested consistency in our methodology. In this issues paper we are seeking stakeholder feedback and information on further refinements to improve the methodology, and also if such changes are warranted or desired by stakeholders. Stakeholder feedback will be considered for DMO 7 draft and final determinations.

The key aspects of the methodology where we are considering refinements include:

- How to best estimate an assumed load profile for residential customers given various ongoing data changes to the NSLP. In late September 2024 AEMO made a third adjustment to the NSLP dataset, which will be factored into our considerations.
- Requesting retail cost data from a broader range of retailers than captured by the ACCC cost stack dataset to inform our retail costs and competition allowance calculations for DMO 7. This broader group of retailers will include more smaller retailers (those with more than 1,000 customers) and represent 99.1% of residential and 99.5% of small business customers.
- Whether we should determine residential customer network costs under a blended network tariff approach.

We are also considering how the DMO determination could apply to customers in embedded networks if the Regulations are changed to extend the DMO price protections to this group of customers.

1.2 Next steps

Our timetable for the development of DMO 7 prices is as follows:

DMO 7 timetable

2 Drivers of market change for DMO 7

This chapter discusses the changes observed in the market and the key drivers of the DMO price.

2.1 Current state of the wholesale market

Wholesale electricity prices began to rise in late 2021 driven by a combination of factors including generator outages and constraints, fuel supply issues and potential supply shortages, and extremely high international coal and gas prices. Contract prices reached record high levels in mid to late 2022, before easing in October 2022 following indications there would be government intervention in the fuel markets. Contract prices then fell sharply in early December 2022 following the announcement of the Australian Government's Energy Price Relief Plan. 2023–24 saw lower wholesale prices than in the 2 financial years prior, but prices remain elevated compared with historical averages.

To forecast the wholesale component of the DMO we engage an external consultant to model expected spot market prices and produce a wholesale cost of energy which reflects the hedging strategies used by retailers to manage these spot prices on behalf of their customers. We use the volume-weighted average price of base and cap futures contracts traded for the 2025–26 financial year as a key input in determining a retailer's hedging costs. This ensures we reflect actual trading activity across the wholesale market. The mixture of these futures contracts will be dependent on the respective DMO region's contract market. In South Australia, cap contracts are the most traded contract type, and therefore have a greater impact on estimated costs. This differs from the other jurisdictions, where cap contracts are typically less commonly traded than base futures.

Using all futures contracts traded for the 2025–26 financial year will result in a small number of contracts traded during the higher prices of 2022 being reflected in the DMO 7 wholesale cost. However, as there was a very small volume of trading occurring for 2025–26 contracts at that time, we expect this will have a minimal impact on wholesale costs for DMO 7. In Figure 2.1 base futures contracts are used to illustrate the period over which trades for 2025–26 contracts are captured in our methodology. As at mid-September 2024 base futures contracts were trading at $103 per megawatt hour (MWh) in Queensland, $103/MWh in South Australia and $122/MWh in NSW. Cap price movements are depicted in Figure 2.2. [4]

These contract prices can provide a guide to the wholesale cost included for DMO 7, but there is still a significant volume to be contracted before the start of the DMO 7 period. The price of these future contracts will depend on the supply and demand in the contract market, which can be driven by number of factors including consumption demand, weather conditions, generation outages and fuel availability.

[4] Base future prices provided are as at 11 September 2024.

Figure 2.1 Base future prices for the financial year 2025–26

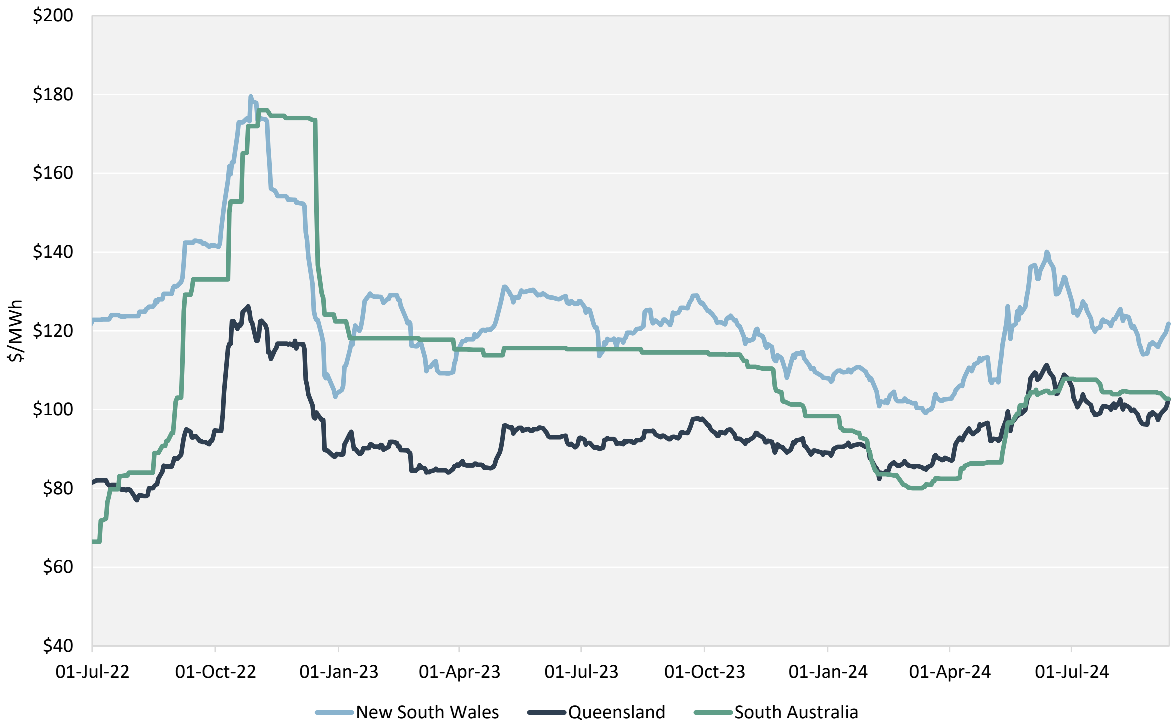
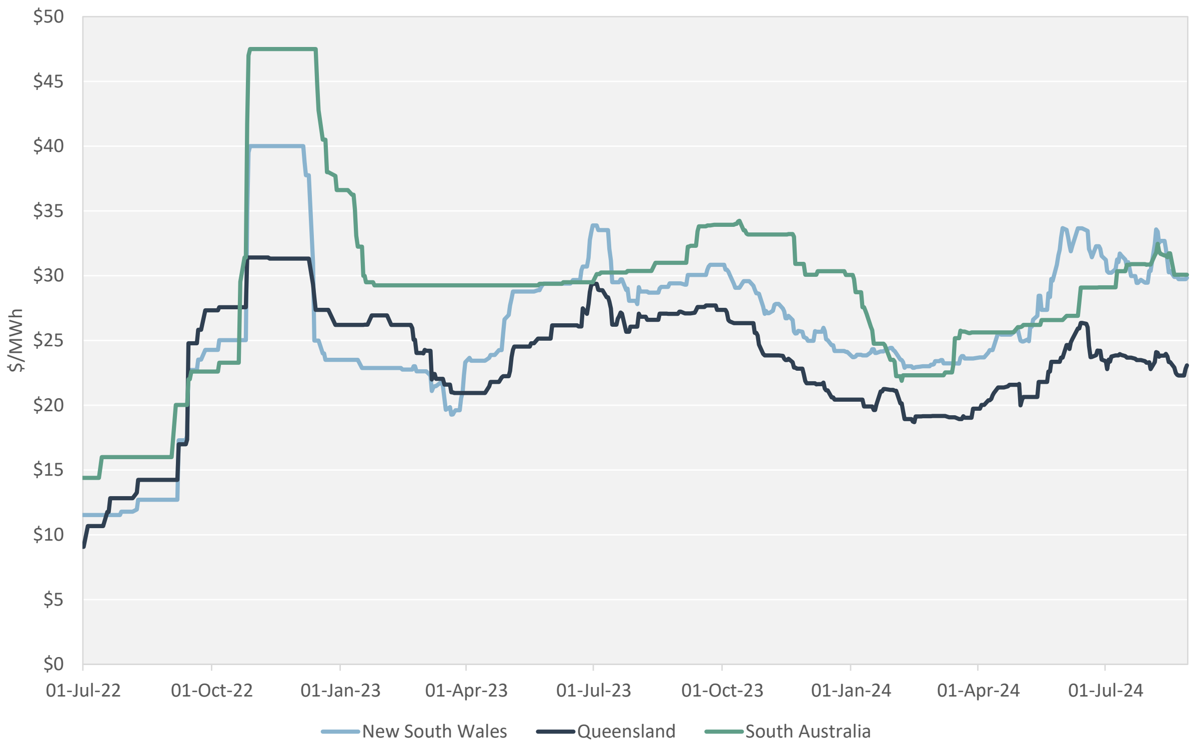


Figure 2.2 Cap prices for the financial year 2025–26

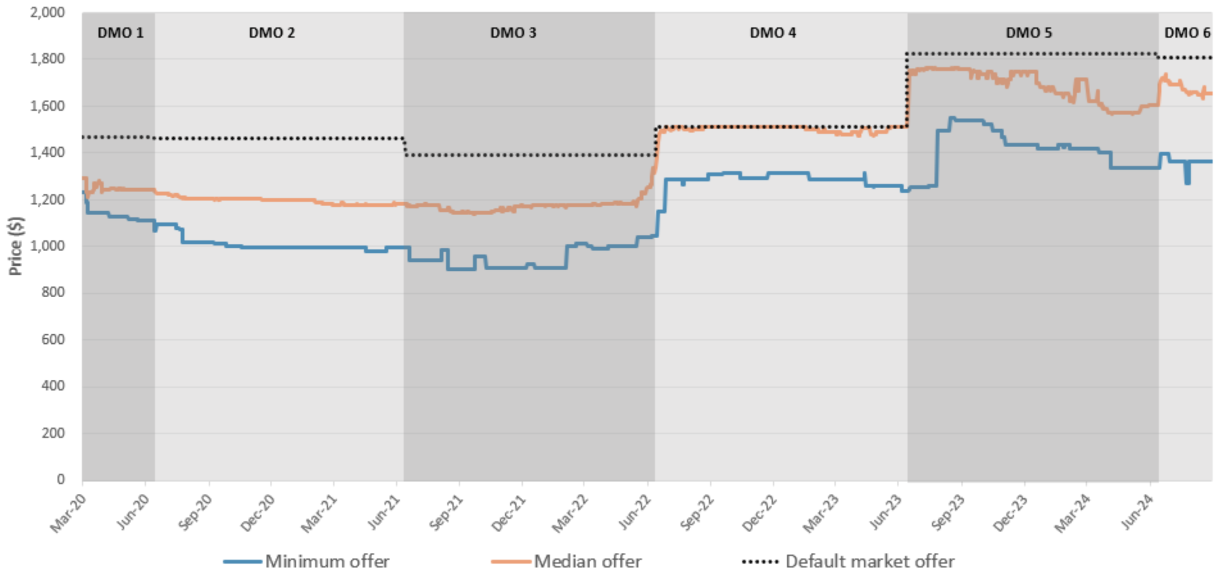


2.2 Current state of the retail market

Market offers are energy contracts advertised by retailers that consumers actively enter into. These differ from standing offers, which are energy contracts that consumers are placed on by default if they do not enter into a market contract. (Consumers can also specifically request to be on a standing offer contract.) The DMO does not provide a price cap on the market offers set by retailers, but retailers must provide a comparison to the DMO when advertising these offers, to help consumers understand the benefits.

Typically, a retailer will set their market offers below their standing offers and the DMO price. This is done to incentivise new customers or retain their existing customer base. This is demonstrated in Figure 2.3, which illustrates the relationship between the DMO and market offers over the DMO 1–6 period (for the Ausgrid region).

Figure 2.3 Historical market offer (for Ausgrid) trend compared with DMO price



During the DMO 4 period the median market offer converged on the DMO price and had little to no discounting. This reflected unprecedented high wholesale prices. Despite that, retailers continued to compete and offer discounted market offers, with the minimum market offer continuing to offer significant discounts from the DMO price.

The DMO 5 period saw a return of the typical pricing structure seen in past DMO periods (prior to DMO 4). The median market offer was below the DMO price and significant discounts were available in the minimum market offer.

Market offer analysis carried out on 1 September 2024 indicates that retailers are still competing and offering prices well below DMO 6, despite the DMO 6 price not including a competition allowance:

- Across DMO regions, the median residential market offer ranges from 6% to 11% below the DMO 6 price. Residential customers switching from the DMO 6 price to the cheapest offer could achieve discounts of $459 to $522 in NSW, $496 in SE Queensland and $495 in South Australia. These discounts amount to 21% to 25% below the DMO 6 price.
- Across DMO regions, the median small business market offer ranges from 4% to 10% below the DMO 6 price. Small business customers switching from the DMO 6 price to the cheapest offer could achieve discounts of $1,177 to $1,454 in NSW, $811 in SE Queensland and $874 in South Australia. These discounts amount to 16% to 27% below the DMO 6 price.
- More market offer analysis is set out in Appendix B.

2.3 Network sector developments

The network component of the DMO consists of distribution and transmission network costs, meter costs and costs of jurisdictional-specific schemes. We determine the revenues of electricity networks for upcoming 5-year regulatory periods, to ensure that consumers pay no more than necessary for network infrastructure.

Under the regulatory framework we administer, higher interest rates and higher inflation have contributed to higher network revenues in our recent determinations. Recent determinations have also reflected the need for networks to efficiently integrate increasing consumer energy resources, implement cyber security measures, maintain reliability, address concerns about network resilience and contribute to the energy transition.

Over DMO 5 and DMO 6, we have seen an increase in costs in NSW associated with introduction of a new jurisdictional scheme, the NSW Electricity Infrastructure Roadmap,. We expect some increase for NSW customers in DMO 7.

Jurisdictional scheme costs in South Australia and SE Queensland are predominantly related to grandfathered premium feed-in tariff schemes, for which the costs should remain stable in DMO 7.

2.4 Embedded networks

In 2022 the Australian Government Department of Industry, Science, Energy and Resources, now known as the Department of Climate Change, Energy, the Environment and Water (DCCEEW), completed a post-implementation review of the DMO Regulations.[5] One outcome of the review was to consult on the best approach to include embedded network customers in the DMO.

In our submission to the review outcomes we supported the proposal to extend the current DMO prices to equivalent customers in embedded networks in DMO regions, noting this approach would align pricing protections for Distribution Network Service Provider (DNSP) connected and embedded network customers. The AER also supported amending the DMO code so that it requires authorised retailers supplying ‘energy only’ offers in DMO regions to not charge more than the DMO price minus the network component. This would prevent customers on energy only offers in DMO regions from being charged twice for network costs.

We continue to support and advocate for extending protections to embedded network customers within DMO regions.

5 The Department of Climate Change, Energy, the Environment and Water, Default Market Offer Post-review consultation – Implementation of the 2022 review outcomes of the Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019, March 2023.

3 Wholesale forecasting methodology

To establish a reasonable forecast of wholesale costs for the DMO, we aim to reflect how a prudent retailer might purchase energy. This involves forecasting demand (also known as load) and spot electricity market outcomes, as well as building a hypothetical hedging strategy to protect the retailer and its customers against the extreme price volatility that can occur in the wholesale spot market.

We refer to our forecasting approach for wholesale costs as 'market based'. Our wholesale cost forecast is a function of energy supply and demand forecasts, the assumed hedging strategy of a retailer to manage their exposure to the spot market, and any final exposure to the spot market.

The hedging strategy adopts the position of a hypothetical prudent retailer, which progressively purchases hedging contracts, decreasing most of its exposure to the wholesale electricity market in the lead-up to each DMO period.

We use an external consultant to assist us with determining wholesale costs in the DMO. This consultant develops wholesale energy market simulations based on demand and supply forecasts. The simulations estimate spot market price outcomes, representative of volatility in the spot market. Publicly available ASX electricity contract prices and traded volumes are used to model the cost of implementing a single hedging strategy across the different simulations, which is designed to minimise exposure to spot market price outcomes. The cost for each simulation is then distributed, where costs around the median represent those that are likely to eventuate, while those at the extreme high and low ends are less likely to occur. Since DMO 4 we have adopted the 75th percentile estimate of modelled wholesale energy cost (WEC) outcomes as the key input into our wholesale cost, which we consider strikes the right balance between retailers recovering the efficient costs for providing their services and the allocation of risks to consumers.

For DMO 7 we are seeking feedback on 5 main areas of our wholesale methodology:

- how to best estimate an assumed load profile for residential and small business customers given various methodological changes made to the Net System Load Profile (NSLP) by AEMO
- how to best estimate a load profile for controlled load customers in NSW given the removal of the NSW Controlled Load Profile
- whether and how to consider the impacts of residential and small business customers' solar exports on retailer hedging costs
- alternative methodologies to benchmark modelled wholesale costs in South Australia
- whether and how we introduce greater variability to the inputs and assumptions used in the wholesale forecasting methodology.

3.1 Load profile assumptions

The aggregate customer consumption profile, or load profile, is a key input into forecasting annual wholesale costs in the DMO.

In calculating the wholesale cost component of the DMO, we aim to reflect underlying wholesale market conditions for the upcoming financial year. This is achieved by developing a simulated hedging strategy designed to reduce exposure to fluctuating wholesale spot prices. This hedging strategy, and the extent of exposure to the spot price, is informed by the simulated load profile. To ensure the wholesale cost we produce reasonably reflects the cost of procuring electricity, it is important that the historical data used to simulate the load profile is similar to the conditions expected during the upcoming DMO period.

3.1.1 Net System Load Profile and interval meter data

The load profiles used for DMOs 1 to 4 utilised the NSLP as published by AEMO. This data includes the aggregated electricity consumption of all customers with accumulation meters. Our methodology up to that point used the past 2 to 3 years of actual NSLP data to generate multiple representations of the load profile for the given determination year. A time series of multiple years has historically been used to ensure atypical events do not have an outsized impact on the simulated load profile. To ensure consistency in the modelling process, all load profile data should cover the same period across all regions. Specifically, the data used for the NSLP, interval meter profiles and controlled load profiles, together with the regional demand profile adopted for the spot market forecasting, should all be derived from the same timeframe.

We endeavour to ensure our simulated load profiles are as reflective of actual market conditions as possible. Given the continued rollout of interval meters, for the DMO 6 process we blended AEMO's NSLP with interval meter data for the first time. This aimed to ensure that interval meter customers were captured in our methodology, alongside accumulation meter customers represented by the NSLP. However, we also had concerns about whether AEMO's adjustments to the NSLP (made to resolve settlement issues in the SA Power Networks and Energex regions) had reduced the extent to which it remained reflective of actual market outcomes. These concerns caused us to pivot from our standard methodology in both DMO 5 and DMO 6.

During DMO 6 we consulted with stakeholders on the impact of this issue. In making our DMO 6 determination, we were concerned that relying on the AEMO NSLP data would flatten the load profile in a way that would not reasonably reflect the future costs to hedge energy purchases for the DMO 6 period. However, we were also concerned that an attempt to adjust the NSLP ourselves would lead to an overly peaky and expensive load shape. Therefore, we considered it reasonable to take the mid-point between the wholesale cost forecasts that these 2 options produced.

AEMO has since made further adjustments to the NSLP methodology.[6] The second adjustment (Figure 3.1) occurred in October 2023. This adjustment more closely aligned with the load shape observed before 5-minute settlement began, but was not used for DMO 6 given the lag in publication of NSLP data and internal data cut-off timelines.[7]

The third adjustment to the NSLP was implemented on 29 September 2024 (Figure 3.1). The implementation of the third adjustment impacts the NSLP data relevant to 9 June 2024

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6 AEMO, July 2023 Retail Market Procedures Consultation.

7 There is a delay of several months between the distribution and consumption of electricity and its publication as part of the NSLP.

onwards, given the lag in publication of NSLP data. A full time series post implementation of this adjustment that reflects seasonal variation will not be available for use in DMO 7.

Figure 3.1 NSLP timeline for SA Power Networks and Energex regions

Note: While AEMO's third adjustment was implemented on 29 September 2024, it will impact NSLP data relevant to 9 June 2024 onwards.

Consideration of issues

As illustrated in Figure 3.1, if we were to follow our standard procedure of using the most recent 2 years of data, this would overlap with AEMO's initial adjustment, which resulted in the mid-point option for DMO 6, rather than solely using the NSLP as published by AEMO.

Therefore, we continue to hold concerns that the historical NSLP data will differ from that which will apply during DMO 7.

Consequently, we are seeking stakeholder views on whether use of an alternative data source or methodology may be appropriate. As the wholesale model requires alignment in the historical time series of all variables used in its forecasting, the timeframe used to simulate load profiles in Energex and SA Power Networks regions will also need to be applied to NSW regions. Options for addressing these data issues are presented below.

In our issues paper for DMO 6 we explored the value in developing separate load profiles for residential and small business customers. We noted there were likely different impacts resulting from solar exports on the two customer types, however considered retailers would take a combined view when determining their hedging strategy. In the DMO 6 draft determination we decided to maintain a combined residential and small business load profile. This was due to differences in stakeholder opinions on the issue and also recognising that the interval meter load shape was more representative of a residential load shape, which is what the majority of stakeholders considered important to reflect. However, given the underlying issues with the load profile data, we consider this issue is worth revisiting, as stakeholders may hold alternative views based on which load profile data is ultimately decided to be used for DMO 7.

When deciding on which load profile data should be used for DMO 7, we will be considering the following factors in our decision making:

- Reflection of market outcomes – we consider we should strive to include load profile data that is an appropriate reflection of a load profile shape a retailer would hedge against for its small customers during the DMO 7 period
- Data transparency – we are aware of strong support from stakeholders to base the DMO on publicly available data (where possible), however note the trade-off that may occur as confidential data often provides greater insights to market outcomes

- Longevity of the decision – we are aware that consistency in the DMO methodology remains important to stakeholders. We will factor in how any decision on load profiles may continue to be upheld as market conditions continue to change into the future.

Option 1: Use 2 years of interval meter data only to simulate the load profile, rather than blending with the NSLP

- This data has the benefit of being unadjusted and available for the 2-year period preceding DMO 7. Additionally, we could extend the range to 3 years if a larger time series which captured an increased range of outcomes was considered a better option.
- An advantage of this option is that interval meter data is now likely the most representative sample available regarding the load shape of small customers. Our wholesale consultant ACIL Allen estimates that all DMO regions will have greater than 50% interval meter penetration by the start of the DMO 7 period. Currently 47% of residential customers and 44% of small business customers in DMO regions have installed an interval meter.
- Additionally, the interval meter data captures solar exports and allows us to exclude these from the load profile, as we did in the decision set out in the DMO 6 final determination. We note that the NSLP includes exports from accumulation meter customers which cannot be excluded.
  - Section 3.2 further discusses the relationship between customers' solar exports and retailers' hedging costs.
- We consider this approach beneficial because we are aware from engagement with stakeholders that interval meter data is used by several retailers in their load forecasting methodology. We consider interval meter data will play an increasingly important role in retailer hedging strategies as the interval meter rollout continues.
- Another advantage of using interval meter data is that it would mitigate further changes to the load profile methodology in future determinations. The proportion of customers settled on interval meters is increasing and close to 100% of customers are likely to have installed an interval meter by 2030.[8]
- One disadvantage of this approach is that the aggregated interval meter data produced by AEMO is provided to us on a confidential basis and we are currently unable to make it publicly available.
- Another disadvantage is that without using the NSLP, the load of customers with accumulation meters would not be captured within the DMO methodology. We are aware that several retailers still rely on this data in their approach to some extent, when hedging for small customer load.

Option 2: Use only one year of NSLP data to simulate the load profile, from October 2023 to October 2024, blended with interval meter data

- This option has the benefit of using publicly available NSLP data.

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8 See Accelerating smart mater deployment on the AEMC's website for more information.

- We are concerned that the use of a shorter time series may increase the risk that atypical events have an impact on the data when determining the shape of the load profile.
- A disadvantage of this approach is that it would not reflect the adjustment methodology that will be in place for the DMO 7 period, given the third adjustment in late September 2024 (impacting data from 9 June 2024 onwards).
- An additional disadvantage is the resulting time series would contain two differing adjustment methodologies, being the second and third adjustment. This could create modelling difficulties, depending on the extent to which data produced under each adjustment differ from one another.
- The NSLP includes some solar exports and these cannot be removed from the dataset for customers with an accumulation meter and rooftop PV.
- As with option 1, a disadvantage of this approach is that the aggregated interval meter data produced by AEMO is provided to us on a confidential basis and we are currently unable to make it publicly available. We consider this option is likely to result in further review of the load profile methodology for DMO 8 because we would need to assess how the third AEMO adjustment has impacted the NSLP data. This concern is compounded by our uncertainty as to whether the third adjustment to the NSLP will be the last.

We have also considered the below approach, but do not consider it appropriate for use in DMO 7.

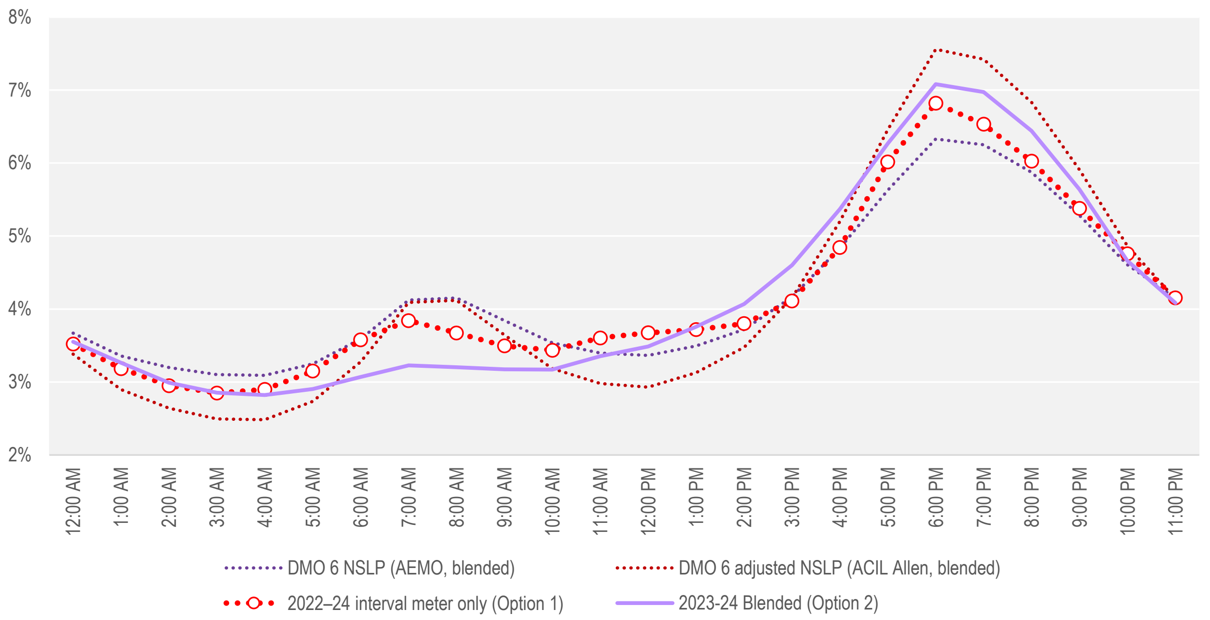
Use the most recent 2 years of NSLP data, regardless of their underlying adjustment methodology, blended with interval meter data

- The benefit of this approach is that it uses the most recent publicly available data and maintains consistency in this aspect of the wholesale methodology.
- A disadvantage of this approach is that contrasting adjustment methods have been applied by AEMO during the earlier and later parts of the time series. One section of the time series (October 2022 to end of September 2023) would be impacted by AEMO's initial adjustment. This saw an artificial uplift in demand, which resulted in a flatter load profile. for the period from October 2023 to beginning of June 2024, the initial adjustment and corresponding uplift in demand was removed. We expect the large difference in demand and resulting load profile shapes across the time series would overstate seasonal demand volatility, resulting in an excessive hedging strategy and inflating the WEC forecast.
- Another disadvantage of this approach is that due to AEMO's third methodological adjustment impacting data from June 2024, the majority of this dataset may not be consistent with what is in place for the DMO 7 period.
- As with options 1 and 2, a disadvantage of this approach is that the aggregated interval meter data produced by AEMO is provided to us on a confidential basis and we are currently unable to make it publicly available.

Alternatively, we could attempt to devise an adjustment similar to the one used in DMO 6, which created a range of wholesale cost outcomes from which we selected the mid-point. However, as the period affected by NSLP data changes grows, it becomes more difficult to determine a reasonable approach to doing this, noting underlying electricity consumption patterns continue to change and the proportion of customers on accumulation meters declines.

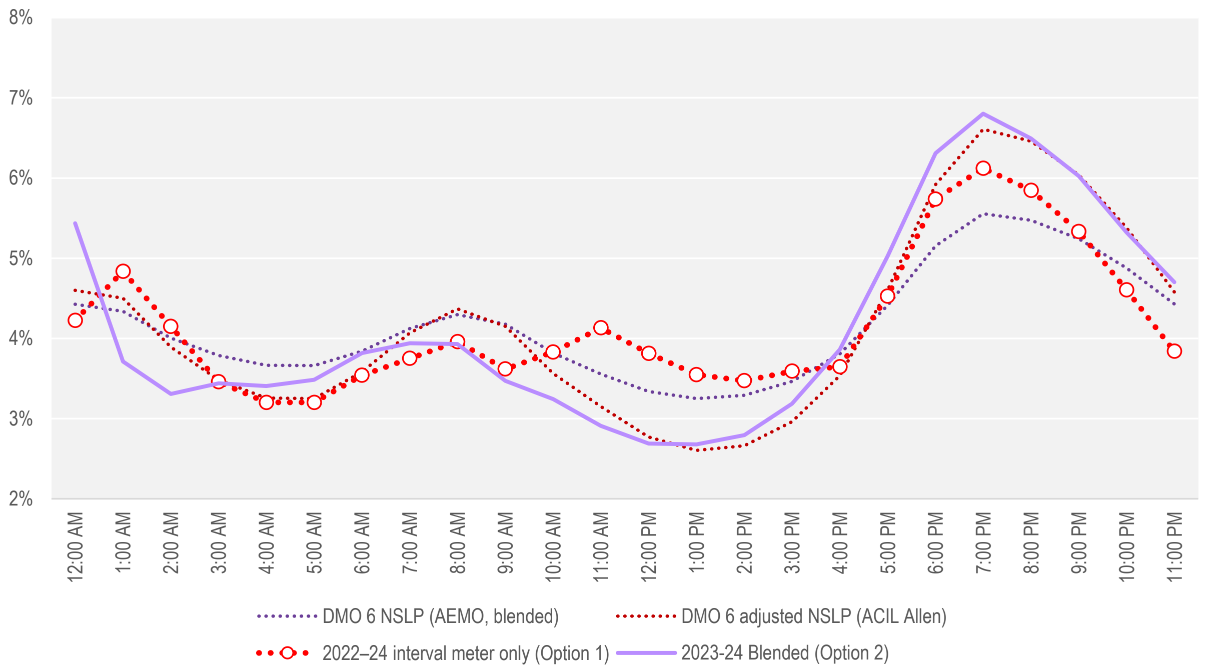
Considering the advantages and disadvantages discussed above, Option 1 may better align with the factors we have stated we will consider when making this decision. However, we seek stakeholder feedback on this. Figure 3.2 to Figure 3.6 present the load profile shape of each option, compared with what was used in DMO 6.

Figure 3.2 Load profile options for the Energex region



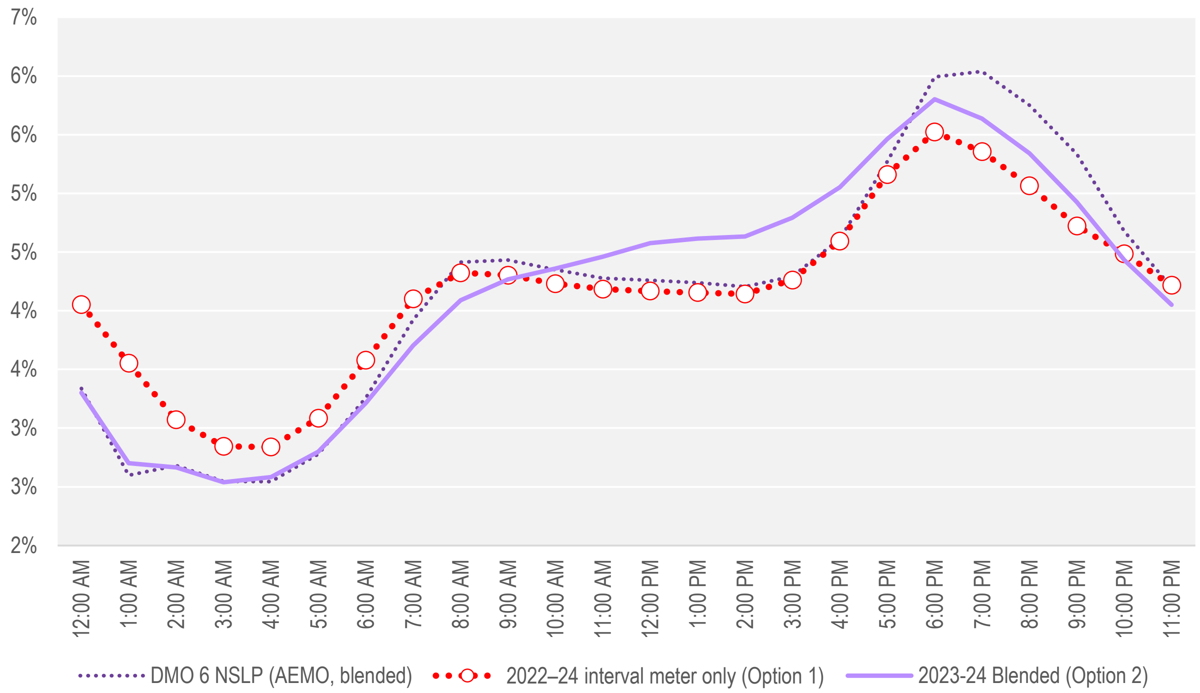
Note: All options would use data up to October 2024 for the final determination, but data was only available up to May 2024 for the issues paper stage of the analysis. Option 2 would use data spanning from October 2023 to October 2024 for the final determination. The interval meter series shown uses 2 years of data but could be extended to 3 years.
Source: AER and ACIL Allen analysis using AEMO data.

Figure 3.3 Load profile options for the SA Power Networks region



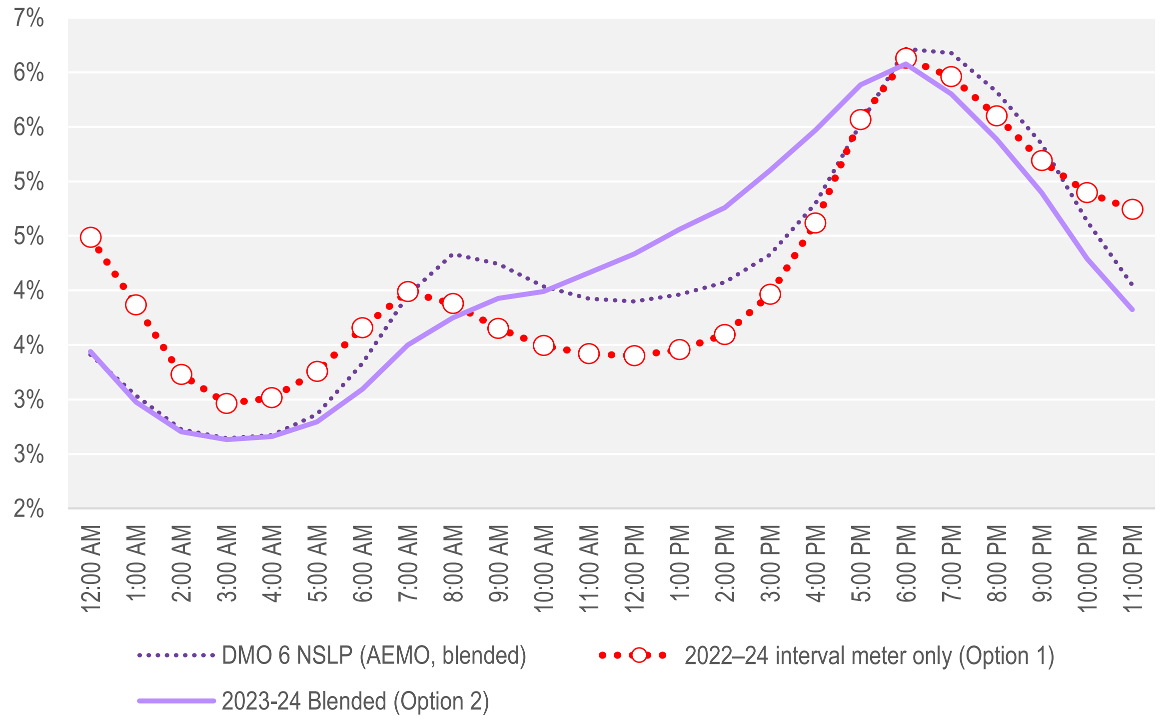
Note: All options would use data up to October 2024 for the final determination, but data was only available up to May 2024 for the issues paper stage of the analysis. Option 2 would use data spanning from October 2023 to October 2024 for the final determination. The interval meter series shown uses 2 years of data but could be extended to 3 years.
Source: AER and ACIL Allen analysis using AEMO data.

Figure 3.4 Load profile options for the Ausgrid region



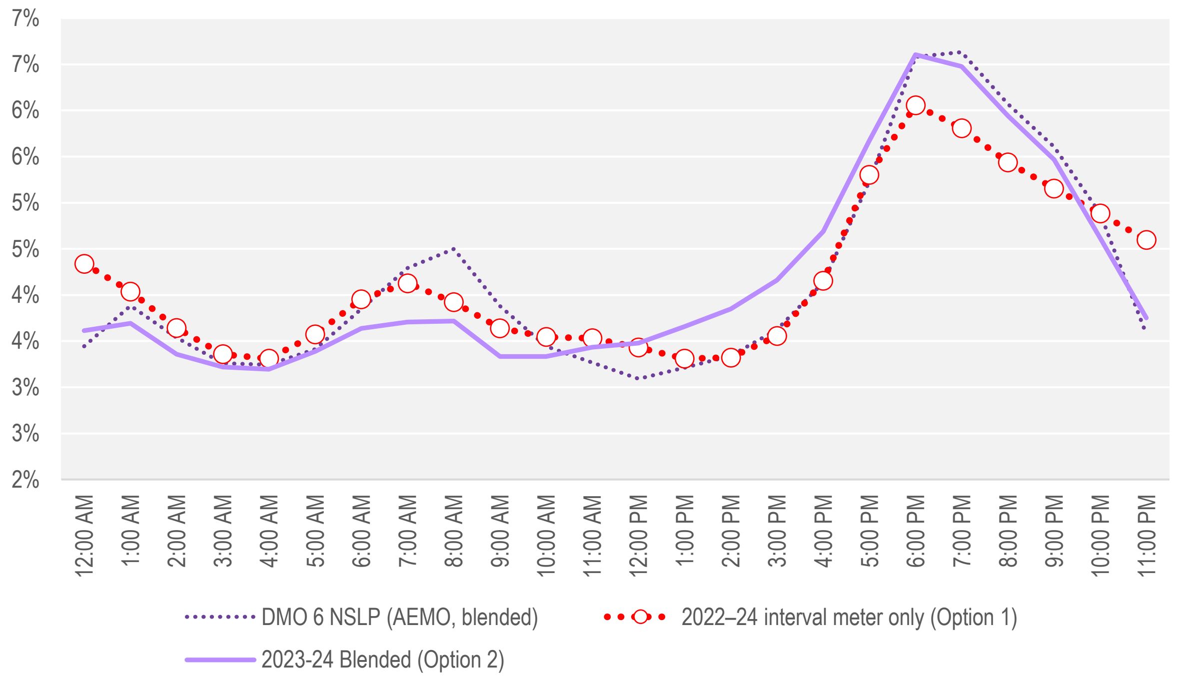
Note: All options would use data up to October 2024 for the final determination, but data was only available up to May 2024 for the issues paper stage of the analysis. Option 2 would use data spanning from October 2023 to October 2024 for the final determination. The interval meter series shown uses 2 years of data but could be extended to 3 years.
Source: AER and ACIL Allen analysis using AEMO data.

Figure 3.5 Load profile options for the Endeavour Energy region



Note: All options would use data up to October 2024 for the final determination, but data was only available up to May 2024 for the issues paper stage of the analysis. Option 2 would use data spanning from October 2023 to October 2024 for the final determination. The interval meter series shown uses 2 years of data but could be extended to 3 years.
Source: AER and ACIL Allen analysis using AEMO data.

Figure 3.6 Load profile options for the Essential Energy region



Note: All options would use data up to October 2024 for the final determination, but data was only available up to May 2024 for the issues paper stage of the analysis. Option 2 would use data spanning from October 2023 to October 2024 for the final determination. The interval meter series shown uses 2 years of data but could be extended to 3 years.
Source: AER and ACIL Allen analysis using AEMO data.

Question 1: Which option do you prefer and why?

Question 2: Is there another available dataset that could be used to simulate the residential customer load profile that the AER is not currently considering? Is it publicly available?

Question 3: Do you have access to, or know of, any data which highlights the difference in the consumption profile of accumulation and interval meter customers, excluding the impact of solar exports?

Question 4: If you are a retailer, are you making changes to your hedging strategies or positions in light of AEMO's third adjustment to the NSLP?

Question 5: If you are a retailer, do you use AEMO's NSLP in your hedging strategy, and if so, how do you weight it alongside any other data sources – for example, your own customer book?

Question 6: Given issues with the available load profile data, should the AER determine separate load profiles and associated wholesale cost forecasts for residential and small business customers? Are there factors we should consider, depending on which load profile data option is used?

3.1.2 Controlled Load Profile (NSW)

As part of the DMO wholesale methodology, we also forecast wholesale costs for customers' controlled load. For all prior DMO determinations, this has been based on the Controlled Load Profile (CLP) produced by AEMO.

Following a request from the Federal Minister for Climate Change and Energy on behalf of the Energy Minister Sub Group to remove the requirement for AEMO to develop a CLP for NSW from AEMO's Metrology Procedures, AEMO amended its Metrology Procedures accordingly.[9] NSW distributors are no longer required to maintain CLP sample meters, reducing costs associated with their maintenance. National Meter Identifiers (NMIs) with controlled load transitioned to the NSLP between 31 May and 1 September 2024.[10]

As a result, the energy previously captured and settled under the NSW CLPs will be recorded and settled under the NSLP. From 1 September 2024 onwards, the NSW NSLPs will be impacted by the controlled load now included in that dataset. The CLP which we have historically used to model wholesale costs will also no longer be published, or relevant to retailers' settlement of controlled load across the DMO 7 period (Figure 3.7).

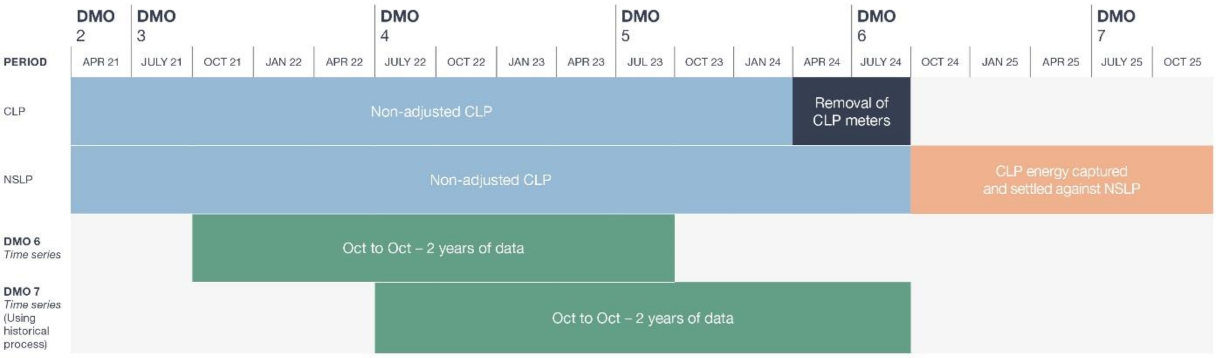
Consultation on the discontinuation of the controlled load profile in South Australia is also currently underway.[11]

9 AEMO, Removal of Controlled Load Profile – NSW, p. 3.

10 AEMO, Removal of Controlled Load Profile – NSW, p. 8.

11 SA Department for Energy and Mining, Controlled load profile and sample meters: Consultation paper, July 2024.

Figure 3.7 NSW CLP changes



Consideration of issues

We are seeking feedback from stakeholders on whether a change to the underlying load profile data used to forecast controlled load wholesale costs is needed, given the historical controlled load dataset is being discontinued.

As controlled load NMIs will now be settled against the NSLP over the DMO 7 period, retailers' valuation of the energy dispatched to satisfy demand from these NMIs may change, as indicated by some retailers during our early engagement for the DMO 7 process. This change may also be reflected in some retailer hedging strategies. While the historical CLP is unlikely to reflect market conditions for the upcoming financial year, it likely influenced hedging strategies for that period. Therefore, this raises questions in relation to whether we should maintain our historical approach of using the most recent 2 years of controlled load data.

As highlighted in our consultants' report for the DMO 6 final determination, there are distinct differences in the CLP compared with the NSLP for NSW distribution regions. All CLPs have overnight peaks with primarily flat load throughout daylight hours, while the NSLPs include morning and evening peaks, with varying levels of reduction in consumption in the middle of the day.[12]

We are also considering this issue in the context of the decision on the load profile data discussed in section 3.1.1, as more customers move on to interval meters and retailers and distribution networks adapt their management of controlled load.

Currently, we are considering 3 options to simulate the controlled load profile for DMO 7:

Option 1: Use the historical CLP to forecast the load shape in NSW

- This approach has the advantage of closely reflecting the actual energy used by controlled load NMIs, given the profile shape of controlled load customers has not changed substantially for the last few years.
- A disadvantage of this approach is that it would not reflect the new basis for controlled load settlement and what we understand retailers will need to hedge for, which will be an aggregation of controlled load NMIs and the NSLP.

12 ACIL Allen, Default market offer 2024–25: Wholesale energy and environment cost estimates for DMO 6 final determination, 22 May 2024.

Option 2: Blend historical controlled load data with the NSLP

- The resulting load profile would have the merit of reflecting the basis for settlement and likely hedging of controlled load demand during the DMO 7 period, potentially reflecting the way that retailers value the associated energy.
- The NSLP in NSW has the benefit of being unadjusted by AEMO.
- A potential disadvantage of this approach is the underlying load profiles of the NSLP and CLP are different across each NSW distribution network. Therefore, it is unlikely to reflect the actual demand patterns of controlled load customers within each distribution network, as it would be impacted by the inclusion of the NSLP load.
- An additional disadvantage is that the actual time-of-day volume of controlled load energy from customers with accumulation meters in NSW is unknown, as the CLP is based on a sample set of NMIs. We would need to estimate the CLP's volume in order to blend its historical shape with the NSLP. The volume of controlled load energy relative to the volume of the NSLP will determine the extent to which its inclusion will change the shape of the resulting profile. We currently have two methods available for estimating the volume of controlled load, the first would be to apply the controlled load sample meter shape to the annual consumption figure provided to us by DNSPs. The second would be to weight the controlled load volume based on the assumed volumes used in the DMO.

Option 3: Use the wholesale energy cost for residential flat rate customers, if interval meter data is adopted for section 3.1.1

- In this option, our consultant would no longer separately model a WEC for controlled load, rather we would use the WEC produced for standard energy consumption.
- This may better align with how retailers consider customers with controlled load who have an interval meter.
- A disadvantage of this approach is that it does not capture customers with controlled load on an accumulation meter, and the different load shape these customers may have.

Question 7: Which option do you prefer and why?

Question 8: If you are a retailer, are you making changes to your hedging strategies or positions in light of the removal of the NSW controlled load profiles?

Question 9: If you are a retailer, do you consider AEMO's CLP in your hedging strategy, and if so, how do you weight it alongside any other data sources – for example, your own customer book?

Question 10: If you are a retailer, does controlled load settlement against the NSLP change your valuation of the associated energy? If so, to what extent?

Question 11: Is there an alternative approach for modelling the controlled load profile in NSW the AER is not currently considering?

Question 12: If Option 1 were adopted, how should the AER estimate the volume of controlled load energy in NSW?

Question 13: Do you have or are you aware of any data to show the load shape for customers with controlled load on an accumulation meter compared to those on an interval meter?

3.2 Solar PV exports and hedging costs

The interval meter dataset, which was first included in our load profile data for DMO 6, can be split into customers' imports (consumption) and solar PV exports (generation). Therefore, blending interval meter data in the load profiles for DMO 6 gave rise to a decision on whether solar exports should be included or excluded within the load profiles.

We decided to exclude solar exports on the basis that the DMO seeks to set a price for customer consumption. We considered the demand profiles used in the wholesale cost methodology should reflect the profile used by retailers to bill their customers for consumption imported from the grid. This meant the load profiles were still influenced by the decrease in consumption of customers with solar (self-consumption), but energy that these customers physically exported into the network was excluded. We considered that excluding exports resulted in WEC estimates that were reasonably reflective of wholesale costs retailers were likely to face across the relevant DMO period, without resulting in an over-recovery of costs from consumers.

As raised by some retailers in submissions to DMO 6, we recognised that there is a cost exposure for retailers during times where their net load is negative and combined with a negative spot price. We also recognised that the value of solar exports is highly dependent on spot market outcomes. For example, retailers can potentially financially benefit when a retailer's net load is negative due to customer exports, and this is combined with positive spot prices in the wholesale market. We therefore did not consider the specific occurrence during negative price intervals to be a reason to include solar exports in the interval meter data for DMO 6. We also considered that any cost exposure for retailers arising from these spot market outcomes could be managed through adjustments to feed-in tariffs paid, among other strategies. However, the Regulations state that we must disregard any amount a retailer pays in feed-in tariffs.[13]

Additionally, the final report from our consultant noted the carve out resulting from solar exports in the regional system demand profiles is still included in the spot market price simulations. This influences the amount of zero or negative price periods that are modelled, which was up to 28% of all modelled hourly prices in the South Australia region for DMO 6.[14]

While we still consider it appropriate to exclude solar exports from the interval meter dataset used to create the load profiles for DMO 7, we are conscious of the impact the presence of solar exports could have on retailers' hedging needs, including the hedging strategies they use.

Some retailers have indicated they use a varying range of strategies to manage the exposure arising from solar exports beyond adjustments to feed-in tariffs, such as sophisticated contracting products and load-shifting measures. Some also use load-following hedges that are available at a premium which reflects how closely they follow customer consumption. These strategies cannot readily be accounted for directly in the wholesale cost methodology. However, for DMO 7 we are seeking input from stakeholders on how we could capture the

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13 Regulations, s. 8A.

14 ACIL Allen, Default market offer 2024–25: Wholesale energy and environment cost estimates for DMO 6 final determination, 22 May 2024, p. 41.

impact of solar exports on retailers' hedging strategies, including any reasonable proxies for the strategies described above.

We have considered a potential approach, involving comparing WEC estimates on a load profile that excluded exports, but from two modelled hedging strategies – one for a profile including solar exports, and another excluding, with the difference representing an approximated additional hedging cost arising from solar exports. However, we note this approach may be limited in its ability to reflect actual hedging costs faced by retailers and are seeking input from stakeholders on alternative approaches.

We would favour options which draw upon publicly available data and with a strong evidence base that supports their use to estimate a reasonable wholesale cost.

In the event we decide not to use the NSLP in DMO 7, as explored in section 3.1, our approach to exclude exports from the interval meter dataset would have a greater impact on load profile shapes used to model WEC estimates.

Question 14: What are your views on whether the AER should consider accounting for any additional hedging costs arising from customers' solar exports? If you are a retailer, how does the presence of customers' solar exports impact your hedging strategy and how could these additional costs be quantified within the wholesale methodology?

3.3 South Australian wholesale methodology

Our current wholesale cost methodology uses publicly available ASX trade data, including prices and volumes of relevant base futures and cap contracts. This methodology relies heavily on a liquid contract market, where retailers can actively acquire contracts in the years leading up to the DMO period.

To investigate concerns about contract market liquidity in South Australia, for DMO 5 and 6 we sought additional contract market data from market participants in South Australia to assess whether ASX data in isolation provides an accurate reflection of the hedging costs a retailer faces. The data request included confidential over-the-counter (OTC) contract data. The OTC data provided to the AER suggested that relevant OTC trades are broadly consistent with ASX traded contract prices and volumes. Therefore, we continued to base the wholesale cost methodology on the publicly available ASX data only.

We have continued to monitor traded volumes in South Australia relevant to the DMO 7 period and note these remain at low levels. Therefore, we intend to again collect OTC contract information from retailers and generators to assess whether there are any differences in the prices traded in the different contract markets for the South Australia region. We consider this approach will continue to provide a measure of the representativeness of the ASX-traded contracts (including price and volume) as an input to a reasonable wholesale cost. It will also allow us to assess if there are different types of contract products being readily used in the OTC market compared with the ASX.

Additionally, due to our ongoing concerns with liquidity levels in South Australia, we are continuing to investigate other comparative data sources to assess our wholesale cost methodology for South Australia. For DMO 6, we had our consultant model a long-run marginal cost (LRMC) estimate for South Australia, to use as another comparative data point against our wholesale cost methodology. The LRMC analysis produced comparable but slightly lower WEC estimates than our existing methodology. We are considering repeating the LRMC analysis in early 2025 which would allow us to factor in our review of the first tranche of OTC data analysis and our view of traded volumes in South Australia at that time.

We welcome views from stakeholders on repeating this LRMC analysis and any alternative methodologies the AER could investigate to benchmark wholesale cost forecasts in South Australia.

Question 15: Further to analysis of OTC contract information, are there other methodologies the AER could investigate to benchmark wholesale cost forecasts in South Australia?

Question 16: Should the AER repeat the LRMC analysis for DMO 7 as a comparative data point for wholesale energy costs in South Australia?

3.4 Inputs into wholesale modelling

To model spot prices for the upcoming financial year, our consultant forecasts the hourly demand profiles using 53 weather-influenced scenarios. These scenarios are then combined with 11 simulations of thermal power availability, resulting in 583 total spot price simulations.[15]

Some submissions to previous DMO determinations expressed concern about a lack of variability in our consultant's modelled spot prices below $300 per MWh. These submissions considered the lack of variability results from fixed inputs into the wholesale energy cost model – for example, fixed fuel costs or rates of generator outages.

DMOs 1–5 used a single fuel cost input for each fuel type for the entirety of the relevant year. These inputs were based on historical trends and adjusted for any known future developments. For DMO 6, we introduced winter and non-winter gas prices. This change was informed by clear evidence that market conditions were more varied than what a single annual input could reflect.

Consideration of issues

We consider that additional variation of inputs could potentially further improve the accuracy of the wholesale cost model, provided that these additional inputs are accurate. Additional variability in inputs would increase the volatility in modelled spot prices below $300 per MWh, which would more closely align with the volatility observed in the NEM. Similarly to our decision to introduce seasonal gas prices, any additional variation of inputs would need to be based on an objective data source.

We consider that if additional inputs are to be introduced, both a high and a low-cost scenario should be reflected, though these would not necessarily need to be weighted equally. To inform potential weighting of higher and lower cost scenarios, we compared fuel cost inputs from DMO 3 to DMO 6 with historical price outcomes. This comparison found that prices of some fuel types exceeded their relevant inputs more often than they fell below, and usually by

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15 ACIL Allen, Default Market offer 2024–25: Wholesale energy and environmental cost estimates for DMO 6 determination, pp. 9–38.

a greater magnitude. The opposite was true for costs of other fuel types, though to a lesser extent.

We consider that historical performance of inputs against actual prices could form a relatively objective basis for determining the weighting of any additional inputs. However, the exact method for using this historical data to calculate future input weighting would still require further consideration, including the potential impact of outlier fuel prices on future determinations.

Any additional variation in inputs would need to materially improve the accuracy of wholesale cost forecasting. Specifically, the benefit of including an additional input would need to outweigh any additional complexity or subjectivity its inclusion may introduce to the modelling process.

We seek stakeholder feedback as to whether objectively producing additionally varied inputs is appropriate, as well as suggestions regarding how this might be achieved.

Question 17: Would any of our modelling inputs specifically benefit from additional variability? If so, what objective data sources could be used to inform the creation of additional inputs?

Question 18: If you propose to adopt additionally varied inputs, to what extent should these differ from the inputs the AER has used historically?

3.5 Other wholesale cost issues

For all other aspects of the wholesale cost methodology, we currently propose to maintain consistency in our approach from DMO 6.[16] This includes:

- use of the 75th percentile estimate of modelled WEC outcomes
- the length of the book build period, which uses all available trades on the ASX
- use of ASX options
- pass through of known compensation costs
- other wholesale cost modelling assumptions, including the approach to AEMO fees, AEMO prudential requirements and unaccounted for energy.

While these topics have not been explored within this issues paper, we welcome views from stakeholders supported with data and evidence on whether the approach to any of these aspects should be reconsidered in DMO 7.

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16 Details on our position and approach for these aspects of the wholesale cost methodology are detailed in section 5.3 of our final determination for DMO 6.

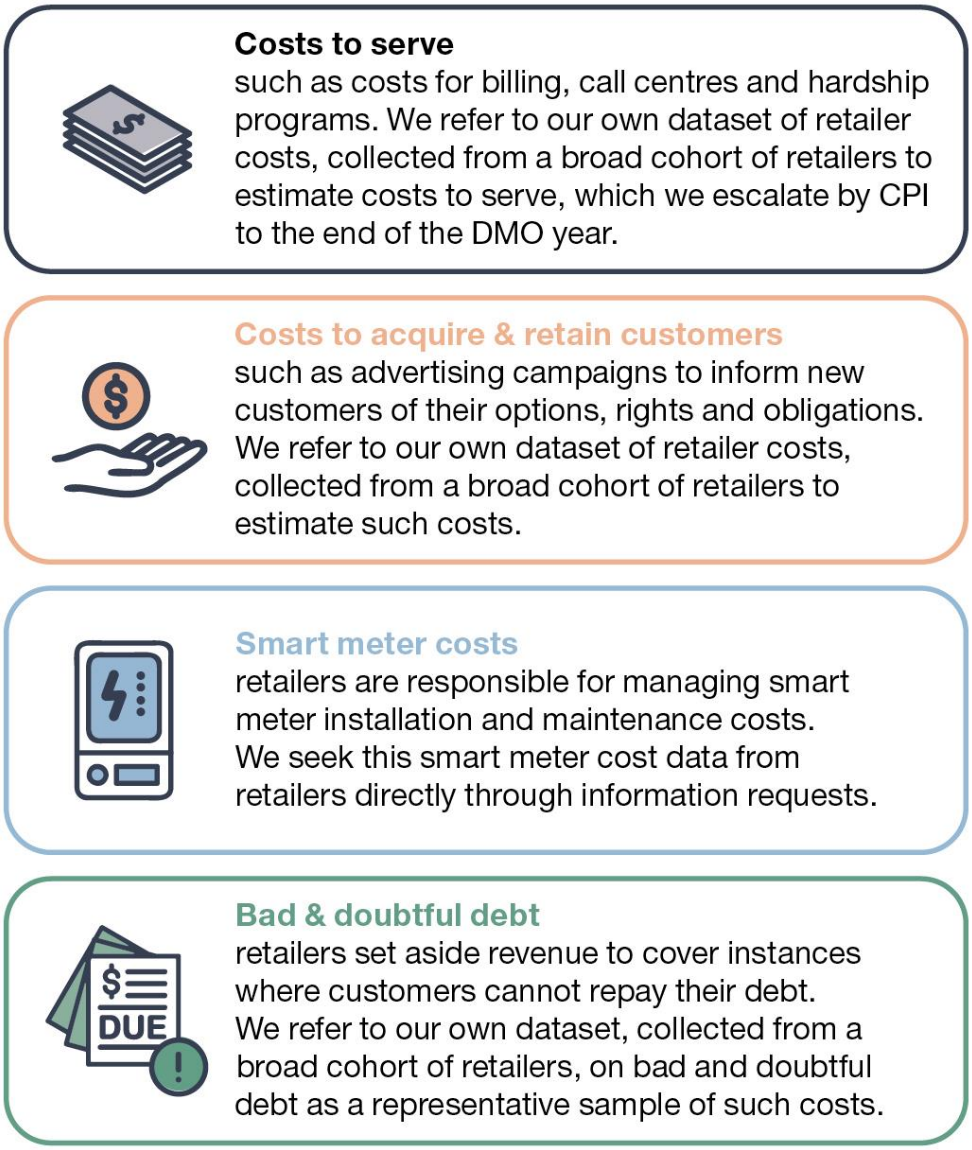
4 Retail cost calculation methodology

4.1 Methodology

Since DMO 4 we have used a ‘cost-stack’ methodology to calculate retail costs. We consider this the most appropriate approach for meeting the DMO objectives because it provides:

- transparency by separately determining retail costs and setting a retail allowance
- consistency in pricing between regions.

As discussed in section 4.2, we are seeking to create our own retail cost dataset which will be used in DMO 7 and future draft and final determinations. It is noted that previous DMOs have utilised the ACCC Inquiry costs incurred when selling electricity, as shown below:



We propose to maintain this methodology for DMO 7, albeit with a broader dataset than previously used (as discussed in section 4.2).

Since DMO 4, we have based our costs to serve, costs to acquire and retain, and bad and doubtful debt costs on calculations from an ACCC cost dataset. That dataset comprised reported cost data from Tier 1 retailers[17] and several smaller retailers, in total representing 84% of residential and 81% of small business customers.

For DMO 7 and future DMOs, the AER will develop its own dataset of costs to serve, costs to acquire and retain, and bad and doubtful debt costs for small customers based on data collected from a broader cohort of retailers.

4.2 Improving the quality of our inputs

The DMO 6 draft determination discussed the AER's intention to develop its collection of retailer cost information with an aim to capture a broader sample of retailers.[18]

In prior DMO years, smaller retailers have argued the ACCC average retailer costs included in the DMO price were not representative of the costs of many smaller retailers or new entrants.

On 25 September 2024, we commenced the process of obtaining an expanded retailer cost dataset from a larger cohort of 25 retailers.[19] This information request:

- replicates the cost categories requested by the ACCC in its electricity market inquiry in relation to retail costs, customer numbers and energy sold
- represents 99.1% of residential and 99.5% of small business customers in DMO regions.

We consider that obtaining our own retail cost information from a broader cohort of retailers could better inform our decision-making process. This broader dataset will be used to inform the DMO 7 draft and final determinations and will provide:

- a more comprehensive sample of retailer costs to serve, acquire and retain small customers
- insights into the extent to which economies of scale drive retail costs to serve
- insights into the extent to which the ACCC's published average retail costs to serve were appropriate for smaller retailers
- the option to base any possible competition allowance calculation on a broader group of retailers.

Additionally, with the ACCC Inquiry into the NEM entering its final fiscal year (concluding on 31 August 2025), the AER is aware that an alternative approach to our methodology will be required for DMO 8.

Replicating the ACCC information request before the ACCC inquiry concludes (during the DMO 7 timeframe) will allow the AER to calibrate its own analysis with the ACCC and avoid undue changes in retail cost findings due to inadvertent methodological differences.

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17 The definitions of 'Tier 1 retailers' is AGL, Origin Energy and EnergyAustralia.

18 AER, [Default Market Offer prices, draft determination](), Australian Energy Regulator, 19 March 2024, p. 44.

19 This dataset includes the retailers providing retailer cost information to the ACCC electricity market inquiry and from additional retailers that have at least 1000 small customers across the DMO regions (SE Queensland, NSW and South Australia.

4.3 Bad and doubtful debt

In DMO 6 we included ACCC bad and doubtful debt costs of $24 to $40 for residential customers and $42 to $65 for small business customers.

Bad and doubtful debts are the costs incurred and written off as unpaid bills. Retailers set aside revenue to cover these costs, such as unbilled (accrued) revenue earnt but not yet billed or an estimated provision for customer debt (based on a retailer's subjective forecast of expected non-payment).

We have continually tried to refine our process for calculating bad and doubtful debts. For DMO 4 we considered the weighted average of this cost from publicly listed retailers (AGL, Origin Energy and Red Energy and Lumo Energy) for our calculations. More recently for DMO 5 and 6, we based our calculations on the ACCC Electricity Inquiry data (comprised of data sources from 15 retailers).

Our retail cost information request (discussed in section 4.2) includes bad and doubtful debt data. We propose to use this new data in DMO 7.

4.4 Smart meter costs

We propose continuing the approach for DMO 6 basing the smart meter allowance on actual installations as at 31 March 2025 with a cost of capital allowance included, and continuing to include a cost of capital allowance to cover the projected shortfall in the smart meter allowance at the midpoint of DMO 7 (31 December 2025).

Like in DMO 6, we once again intend to issue voluntary data requests in or around September 2024 and March 2025 seeking:

- the historic number of customers by meter and tariff type at 30 September 24 and 31 March 2025
- the projected customer numbers as of 31 December 2025
- smart meter costs.

By seeking retailer data on actual and projected smart meter installations and associated costs, we can better understand relevant cash flow impacts (that is, operational and capital expenditure) and how such costs should be included in the DMO price.

4.4.1 AEMC smart meter deployment rule change

As discussed in the DMO 6 final determination,[20] we anticipate a change in the rate of retailer installations once the AEMC's upcoming legacy meter retirement rule change is in effect.

The AEMC extended the final determination date for their smart meter deployment rule change to 28 November 2024 to allow for further consultation on enhancing consumer protections.[21]

20 AER, Default Market Offer prices, final determination 2024–25 (track changes comparison), Australian Energy Regulator, 7 June 2024, p. 55.

21 AEMC extension of consultation date for smart meter deployment, www.aemc.gov.au, accelerating-smart-meter-deployment

Consequently, the commencement date for the legacy meter retirement plan target period has now been pushed back 6 months (to 1 December 2025) and is now based on calendar years, with the first annual interim target to be 31 December 2026, which will be within the DMO 8 determination process.

4.4.2 Queensland and South Australia revenue determinations and legacy meter costs

We consider it appropriate to update the smart meter allowance methodology to reflect changes in how legacy metering costs are recovered by distribution businesses as part of their network revenue determination.

In previous DMO determinations distribution businesses had different legacy meter cost recovery approaches for customers with legacy meters and smart meters. However, in DMO 6 updates were made to the smart meter allowance methodology in NSW following the NSW network business revenue determinations.[22] Similarly for DMO 7, SA Power Networks and Energex have their upcoming network revenue determinations in 2025, which are likely to involve changes to legacy meter cost recovery approaches. We consider it appropriate that DMO 7 reflects the revised legacy meter cost recovery approaches of SA Power Networks and Energex.

Question 19: Do you consider these current methodologies appropriate and, if not, what alternatives should be considered?

Question 20: What additional operational considerations or capital expenditure costs should the AER consider in determining the cost recovery of advanced metering costs?

22 See AER, Default Market Offer prices, final determination 2024–25 (track changes comparison), Australian Energy Regulator, 7 June 2024, p. 77 for a discussion of legacy smart meter recovery processes.

5 Retail margin and competition allowance

The Regulations direct that in determining a reasonable per customer annual price we are to have regard to the principle that an electricity retailer should be able to make a reasonable margin in supplying electricity.

For DMOs 1–3, we used a 'retail residual' which included retailer operating costs along with margin. However, since then we have been calculating retailer components of the DMO in an increasingly granular way.

For DMO 4 and 5 we separated our calculation of retailer operating costs from a retail allowance. The retail allowance was set to reflect a return on retailer risk, allow for differences in retailers' costs and provide room for competition. We also considered it desirable that DMO prices included a similar level of allowance regardless of DMO region.

For DMO 6, the AER adjusted the approach for the retail allowance by separately determining a retail margin and a competition allowance. We considered this:

- enabled greater transparency on the individual components
- allowed the efficient margin component to function as a percentage of costs and the revenue at risk
- provided us with more flexibility to balance the DMO objectives and other matters the AER considers relevant to its determination.

5.1 Retail margin

The retail margin is set to allow a prudent retailer faced with the typical costs of supplying electricity to customers to achieve a reasonable profit.[23] In the DMO 6 determination we set the 6% and 11% margins for residential and small business customers, respectively. These margins were applied as a percentage of the DMO price before the addition of any competition allowance.

Our approach in DMO 6 considered:

- ACIL Allen analysis inferring margins from advertised offers available between 1 July 2023 and 31 August 2023 by backing out DMO 5 costs
- our own analysis inferring margins within the ACCC's findings of the actual retail prices charged to customers on 1 August 2023 by backing out DMO 5 costs.

ACIL Allen evaluated the merits of different methodologies to determine reasonable retail margins and quantify those margins using a recommended approach. We considered that ACIL Allen's approach used for DMO 6 is reasonable because it is transparent and can be updated annually based on current and readily available data.

For DMO 7, we propose to maintain the 6% and 11% margins for residential and small business customers, respectively. However, to confirm that these margin values remain

[23] S16(4)(b) of the Regulations.

appropriate, we will replicate the analysis carried out in DMO 6 using updated market offer data and DMO 6 costs, which will also consider:

- decisions from other regulatory bodies such as Essential Services Commission of Victoria and Independent Competition and Regulatory Commission
- retail margins observed by the upcoming ACCC Electricity Inquiry Report
- stakeholder submissions to the issues paper and draft determination.

Question 21: Do you consider the proposed retail margins appropriate? If not, what alternatives should be considered?

5.2 Competition allowance

Our approach for determining the competition allowance in DMO 6 considered the range of per-customer costs to serve, acquire and maintain customers among the retailers that report to the ACCC.

After examining this range, we determined that an appropriate competition allowance for DMO 6 would have been $66 and $291.50 (inc. GST) for residential and small business DMO prices, respectively.

However, we decided to exclude the competition allowance in DMO 6. This decision was made with regard to the economic conditions, cost-of-living pressures and energy affordability issues experienced by consumers. These are matters that we consider relevant under s16(4)(d) of the Regulations and had regard to in making our DMO 6 determination.

We consider the AER’s framework for determining whether to include or exclude the competition allowance is still appropriate.

The primary factor we will use is cost of living and price pressures as measured by 12-month movements in the Consumer Price Index (CPI), reported quarterly by the Australian Bureau of Statistics. Where CPI is materially above the Reserve Bank of Australia’s (RBA) target band (of 2 to 3%) for a sustained period, we will not apply the competition allowance to prioritise consumer protection. In making this decision we will also have regard to the state of retail competition.

We consider this approach transparent, objective and providing some predictability about how we will respond to economic conditions. This allows the AER and stakeholders to regularly assess economic conditions and whether the competition allowance will be included or excluded for the upcoming DMO final determination, including at issues paper and draft determination stages.

In relation to deriving the value for the competition allowance, should it be applied, we intend using our own collected retail cost data for DMO 7 (based on retail cost data collected from a broader cohort of retailers). We consider using an AER dataset will have the following benefits:

- it will include a greater number of retailers and should provide greater insight into the ranges of costs to serve, acquire, and maintain customers among retailers in DMO regions

- it should permit greater transparency for discussing the derivation of the competition allowance, our analysis and findings with stakeholders.

Question 22: What is the most appropriate approach to incorporating a diverse range of retailer costs to serve in DMO prices?

Question 23: What other factors, if any, should the AER consider in deciding whether to apply the competition allowance?

6 Other DMO costs and considerations

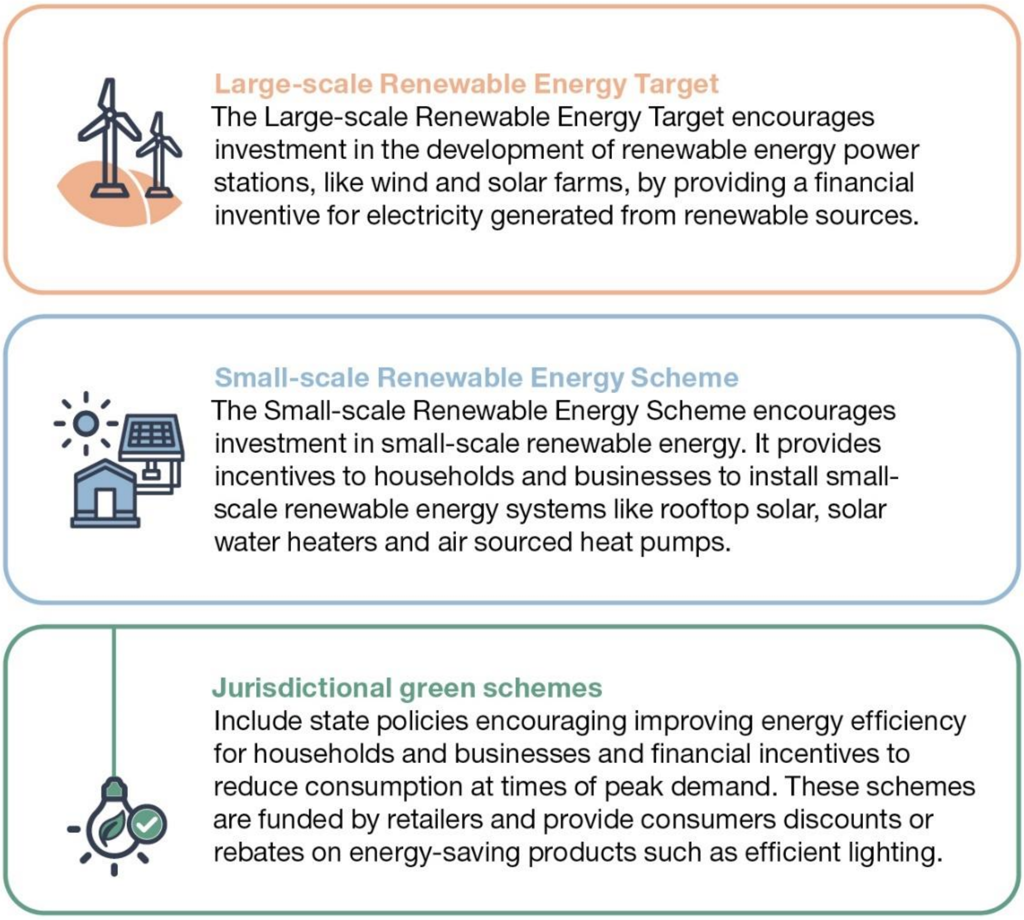
This chapter discusses our methodology for determining other DMO components such as environmental costs, network costs, NSW Renewable Energy Zone costs (NSW Roadmap costs), as well as annual usage and timing and pattern of supply.

We consider that many approaches and assumptions used in the DMO 6 final determination relating to these costs remain appropriate for DMO 7. However, we welcome any feedback or additional information from stakeholders on these factors.

6.1 Environmental costs

As stated in previous DMO determinations, environmental schemes, at both national and state levels, require retailers to procure electricity supply from renewable sources and improve customer energy efficiency. The costs of these schemes are incurred by retailers and are included as a cost component of the retail price for electricity.

Environmental costs broadly fall into 3 main categories:



The Regulations require us to have regard to the costs retailers incur in complying with all federal and state/territory laws when determining the DMO price.

Most environmental costs relate to complying with the Renewable Energy Target, where retailers have an obligation to purchase renewable energy certificates and surrender them to the Clean Energy Regulator in proportion to the overall amount of energy consumed by their customers.

The Renewable Energy Target is made up of the Large-scale Renewable Energy Target and the Small-scale Renewable Energy Scheme. Large-scale Renewable Energy Target costs are incurred by retailers to acquire the necessary amount of Large-scale Generation Certificates. Similarly, Small-scale Renewable Energy Scheme costs are incurred by retailers to acquire the necessary amount of Small-scale Technology Certificates.

For the DMO 6 final determination, we decided to continue to retain our market-based approach to environmental cost estimations with updates for new and amended schemes.[24]

We consider this approach remains reasonable for DMO 7, noting that most stakeholder submissions on our DMO 6 draft determination did not discuss or raise any issues or objections with the approach we had proposed for DMO 6 on environmental cost estimations.

6.2 Network costs

Network costs in a retail electricity bill represent the cost of transporting electricity through transmission and distribution networks, and the cost of accumulation meters operated by network businesses to measure customers' electricity consumption.

Under the National Electricity Rules, the AER regulates network charges by approving the network tariffs that distribution network businesses set on an annual basis. Network charges are typically comprised of 2 components:

Network Use of System charges
recovers the costs of providing transmission and distribution of electricity through network infrastructure, including costs of jurisdiction-specific schemes. For NSW DNSPs, it includes NSW Roadmap costs.

Metering (Alternative Controlled Service) charges
relates to DNSP businesses' installation and maintenance of type 5 manually read interval meters and type 6 accumulation meters.

The DMO price is adjusted each year to reflect changes in network costs for the relevant customer classes and DNSP.

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24 AER, Default Market Offer prices Final determination 2024–25, Australian Energy Regulator, pp. 40–41, sections 6.1 & 6.2.

6.2.1 Flat rate and time of use network tariffs

Since DMO 2, network costs have been based on flat rate network tariffs. However, a growing proportion of customers are being assigned time of use network tariffs. Some stakeholder submissions responding to the DMO 6 issues paper argued that a network cost which blends flat and time of use network charges may better reflect the costs retailers incur.[25] However, others considered the current approach of using the flat rate network tariff remained reasonable and provided regulatory consistency and maintained transparency.[26]

This issues paper again seeks stakeholder feedback on this possible methodology change, including whether:

- it would improve the extent to which the DMO network cost component reflects reasonable retailer costs
- any benefit in this regard outweighs complexity and lack of stability in the methodology which may come from this change.

If we proceeded with a blended network tariff, we would estimate annual network costs under both the flat rate network tariff and the time of use network tariff. We would then blend them based on a customer weighted average within each distribution region. For example, if 60% of residential customers in a distribution region were on the flat rate network tariff and 40% were on the time of use network tariff, these respective weightings would be applied to the annual cost of flat rate and time of use network tariffs to develop to blended average.

However, an average or 'typical' annual time of use network cost for a DMO customer is more complex to calculate than a flat rate network tariff, as it requires information on the amount of energy consumed in each of the distribution business' charging windows ('peak', 'off-peak' and 'shoulder' periods) for an average or 'typical' customer. We would draw on the published pricing models provided within distributors' pricing proposals to model this. These models include inputs, calculations and outputs related to energy consumption, charging periods and average customers on each tariff.

However, there are potential issues applying this information to network tariffs for DMO determinations:

Using historic consumption information in the pricing models may have limitations and may not be suitable for future network tariffs. For example, if the peak period window is widened in network tariffs applying in DMO 7, then the historic proportion of energy consumption falling in the previous peak period could be underestimated.

- For small business customers, the DMO only applies to flat rate tariffs.
  - To accurately calculate a blended network tariff cost we would need to know the separate proportions of flat-rate small business customers with flat rate network tariffs and time of use network tariffs.

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25 Simply Energy, *Submission to the DMO 6 issues paper,* 3 November 2023, p.5; 1st Energy, *Submission to the DMO 6 issues paper,* 3 November 2023 p.4; Alinta Energy, *Submission to the DMO 6 issues paper,* 3 November 2023 p.8; Powershop, *Submission to the DMO 6 issues paper,* 3 November 2023, p.7;

26 Origin Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 2, 18; Alinta Energy, *Submission to DMO 6 issues paper*, 3 November 2023, p. 3; Red and Lumo Energy, *Submission to DMO 6 issues paper*, 9 November 2023, p. 5

- – The AER does not currently have network tariff information disaggregated to this level of detail. It is unclear what weightings for flat rate and time of use network tariffs are appropriate to derive a small business blended network cost.
- – The AER could consider requesting relevant retail and network tariff information from retailers to accurately calculate blended network costs. However, this could impact retailers who are already responding to a number of information requests.
- – Retailers will report this information under the new retail performance reporting guidelines that come into effect for Q1 2025–26, which should be suitable for developing blended network costs, but will only be available for use in DMO 8 and future determinations.

We will engage with network businesses to understand the suitability of the network price model data, whether additional information is available to assist calculations and if this information can be published.

Question 24: Should network costs be based on a blend of flat rate and time of use network tariffs? Why or why not? How could the issues above be overcome – particularly for small business network tariffs – if we were to create a blended cost?

6.2.2 Energex and SA Power Networks revenue determinations

Network revenues are smoothed across a 5-year regulatory period to reduce fluctuations between years and allow for relatively predictable price movements. Larger changes can occur through a revenue determination, which sets the revenues for the next 5-year regulatory period.

During the timeframe of finalising the DMO prices for 2025–26, both Energex and SA Power Networks DNSP's are required to submit their revised revenue proposals for the next 5-year regulatory period. Approval of these revenues and relevant network tariffs will be undertaken as follows:

- DNSPs submit revised revenue proposals by end of November 2024.
- The AER determines the DNSPs' revenues by end of April 2025.
- DNSPs submit final network tariffs for 2025–26 by 21 May 2025.
- The AER approves revenue determinations by mid-to-late June 2025.

Given the AER's revenue determinations for these DNSPs are due by end of April 2025, the final revenue numbers will not be available in time for the DMO 7 draft determination.

During the DMO 6 determination, NSW DNSPs (Ausgrid, Endeavour and Essential Energy) underwent their 5-year regulatory period revenue determination. To manage this process in DMO 6 the AER engaged with these DNSPs to identify what information was available at different phases of the DMO 6 determination and how changes could impact network costs for these DNSPs. This enabled a more accurate estimate of approved network tariffs for the draft determination and minimised changes in the network cost component from the draft to final determination.

Similar to the process in DMO 6 for NSW DNSPs, we intend to regularly engage with Energex and SA Power Networks to obtain the most recent estimates for DMO 7 network prices at various stages of the DMO 7 determination process. This proactive engagement allows for early identification of any pricing issues and reduces variations between network prices used in the draft DMO, network prices proposed by DNSPs, and network prices used in the final DMO. The AER will receive these DNSPs' proposed network tariffs before the DMO 7 final determination, which ideally will be approved in time for the DMO final determination.

6.2.3 NSW Roadmap costs

In 2020, NSW enacted the *Electricity Infrastructure Investment Act 2020 (NSW)* ('EII Act'), which introduced a regime for renewable energy zones to implement the NSW Electricity Roadmap. It included new arrangements for the planning and procurement of transmission in NSW and for the underwriting of new generation, storage and firming projects.

The AER was appointed as a regulator under the EII Act in 2021 and has a number of discrete functions, centred on the economic regulation of transmission projects. One function is to make contribution determinations under section 56 of the EII Act, by a statutory deadline of 28 February each year. These determinations set the annual dollar amount to be recovered from NSW DNSPs so that an entity called the NSW Scheme Financial Vehicle can pay the costs of implementing NSW's Electricity Roadmap. The key cost elements captured by these contribution determinations are:

- cost for payments to network operators associated with new transmission projects
- costs associated with contracts to underwrite generation/storage/firming projects (known as long-term energy service agreements)
- the administrative costs of scheme entities.

For the purposes of DNSPs' annual pricing of network tariffs, these costs are captured as jurisdictional scheme amounts. For DMO 6, we did not need to separately estimate NSW Roadmap costs as these were included in the contribution determinations. We consider this approach will remain reasonable for the DMO 7 draft and final determination.

6.3 Annual usage and time of use pattern

Under Part 3 of the Regulations, we are required to determine 'broadly representative' annual supply amounts for residential and small business customers in each distribution region, from which a DMO price and reference price can be calculated. In this document we refer to annual supply as annual usage.

We must also determine the timing and pattern of supply to residential customers. The Regulations refer to these elements in combination as the 'model annual usage'.

6.3.1 Annual usage

In our DMO 6 final determination we retained the same usage amounts as previous determinations for residential customers and small business customers for general usage and controlled usage.

The ACCC's June 2024 Inquiry into the National Electricity Market report included the most recent findings on residential and small business usage.

When compared with the ACCC observations of residential customers[27] with and without controlled load, we note that the corresponding residential annual usage amounts assumed in previous DMO determinations are:

- comfortably within the interquartile range
- approximate to the medians observed by the ACCC
- around 19% below to 1% above the ACCC observed median for customers without controlled load
- around 16% to 53% above the ACCC median for customers with a controlled load.

The ACCC has continued to observe a much wider range of usage for small business customers, reflecting the variety of small businesses and the different ways they use electricity to produce goods and services. The 10,000 kWh small business usage amount assumed in the DMO sits above the median, but within the interquartile range.

The annual usage amounts assumed in previous DMO determinations compare similarly to ACCC observations in the June 2023 and 2022 electricity reports.[28]

Given such a wide range in usage amounts among small businesses, it is difficult to determine a single figure that accurately represents all small businesses. We question whether a different annual usage amount is more broadly representative.

We have noted in previous issues papers that altering our approach would add complexity and may not provide major benefits to stakeholders. For example, increasing the assumed annual usage amounts from DMO 6 to DMO 7 would in turn increase the DMO price associated with assumed annual usage. This would make it more difficult to compare annual changes in the DMO price due to changes in DMO cost components. Customers engaging in the market may also find it more difficult to compare prices, as the DMO reference price would increase and could create a perception that new market offers provide worse value for money than prior market offers calculated under a lower usage amount.

Question 25: What are your views on whether the AER should consider adopting new annual usage amounts? What alternative sources should be considered, and/or what values would be more broadly representative than the current assumptions?

6.3.2 Timing or pattern of supply

The timing or pattern of supply we are required to determine is used to convert time of use offers into annual prices. This allows time of use standing offers to be assessed for compliance with the annual DMO price and time of use market offers to be compared to the DMO reference price in retailer price communications. Determining the time of use pattern is a

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27 ACCC, *Inquiry into the National Electricity Market, June 2024 report*, Australian Competition and Consumer Commission, Appendix E, Table A3.2.

28 See AER analysis of prior ACCC June reports in AER, Issues Paper - Default market offer – Price determination 2024–25, pp. 27–28; AER, Issues Paper- Default market offer – Price determination 2023–24, pp. 24–25.

different role to determining a load profile to forecast wholesale prices discussed in chapter 3 and uses a different set of consumption data.

A timing or pattern of supply is required to convert time of use offers to annual prices because the cost of electricity consumed on the general use circuit (and not the controlled load circuit, with some exceptions[29]) varies throughout the day with different prices for electricity consumed in ‘peak’, ‘off peak’ and ‘shoulder’ periods.

In our DMO 6 final determination we decided to update the timing or pattern of supply usage profiles using new AEMO interval meter data – but retain key assumptions from previous determinations. That is:

- assume the same usage occurs every day (with no variation for weekday, weekend or season), as in previous determinations
- use the same proportional allocations of annual controlled load usage across multiple controlled loads
- retain a single 24-hour usage profile to describe the pattern of usage
- update the 24-hour usage profile using the AEMO interval meter data for the region, averaged over 3 years
- specify usage at 30-minute intervals.[30]

Since DMO 2 we have used AEMO Market Settlement and Transfer System (MSATS)[31] aggregate interval consumption data covering both residential customers with and without controlled load. Aggregate data was used due to limitations with AEMO’s MSATS data, which could not provide the AER with separate consumption information for residential customers with and without controlled load. This results in the following limitations when determining patterns of supply:

- The inclusion of controlled load in consumption profiles may ‘flatten’ or under-allocate energy consumption to peak periods on the general use circuit (which have higher pricing than other periods).
- Applying these consumption profiles to time of use retail offers may on average underestimate the annual cost of time of use offers.
- This could be having a material impact on load shape in South Australia, as the ACCC found in its June 2024 report that 40% of residential time of use customers have controlled load. The ACCC has not published data for other regions.
- Consumption profiles could differ for customers with and without controlled load, as some appliance use is shifted to nighttime or another off-peak period. Preliminary analysis is set out in Figure 6.1 demonstrating the difference between patterns of consumption with and without controlled load.

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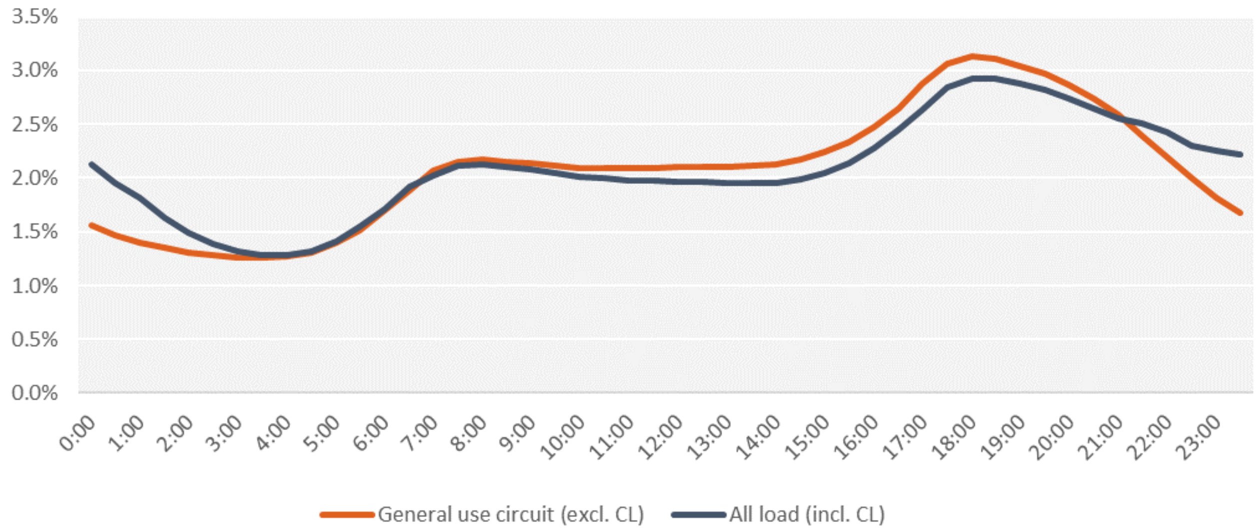
29 SA Power Networks have time of use pricing for controlled load circuits, see SA Power Networks, *Tariff Price List 1 July 2024 – 30 June 2025*, p.5.

30 AER, Default Market Offer prices Final determination, Australian Energy Regulator, p. 69, section 9.3.2.

31 MSATS is a system designed to facilitate the efficient settlement and transfer of market transactions.

- Stakeholders may desire more granular patterns of consumption reflecting seasonal and weekday/weekend variation. However, the current uncertainty due to the presence of controlled load means it likely overrides additional ‘accuracy’ of separating consumption profiles into seasons and/or weekday/weekend.

Figure 6.1 preliminary analysis comparing residential consumption patterns including and excluding controlled load.



Source: AER analysis of AEMO MSATS data for 2022–23 year in Ausgrid distribution region for residential customers. The ‘All load’ profile includes both general use circuit and controlled load consumption.

However, it is not clear if changing the methodology for timing and pattern of supply is warranted as:

- it could introduce complexity for retailers in preparing retail pricing for the final determination, and
- as noted in previous DMOs, it is arguable that any time of use pattern aiming to represent all customers is unlikely to capture many possible drivers in individual usage patterns such as climate or individual household characteristics.

We propose to assess the methodology for deriving the timing and pattern of supply. We are engaging with AEMO to understand whether improvements such as removing controlled load from the MSATS data are feasible.

Question 26: What benefits do you see in further consideration of improvements to the methodology of timing and pattern of supply? How material may this be and how could we address any additional complexity it causes?

Appendix A – List of stakeholder questions

Question number	Stakeholder question
Wholesale costs	
Net System Load Profile and interval meter data	
Question 1	Which option do you prefer and why?
Question 2	Is there another available dataset that could be used to simulate the residential customer load profile that the AER is not currently considering? Is it publicly available?
Question 3	Do you have access to, or know of, any data which highlights the difference in the consumption profile of accumulation and interval meter customers, excluding the impact of solar exports?
Question 4	If you are a retailer, are you making changes to your hedging strategies or positions in light of AEMO's third adjustment to the NSLP?
Question 5	If you are a retailer, do you use AEMO's NSLP in your hedging strategy, and if so, how do you weight it alongside any other data sources – for example, your own customer book?
Question 6	Given issues with the available load profile data, should the AER determine separate load profiles and associated wholesale cost forecasts for residential and small business customers? Are there factors we should consider, depending on which load profile data option is used?
Controlled Load Profile (NSW)	
Question 7	Which option do you prefer and why?
Question 8	If you are a retailer, are you making changes to your hedging strategies or positions in light of the removal of the NSW controlled load profiles?
Question 9	If you are a retailer, do you consider AEMO's CLP in your hedging strategy, and if so, how do you weight it alongside any other data sources – for example, your own customer book?
Question 10	If you are a retailer, does controlled load settlement against the NSLP change your valuation of the associated energy, and if so, to what extent?
Question 11	Is there an alternative approach for modelling the controlled load profile in NSW that the AER is not currently considering?
Question 12	If Option 1 were adopted, how should the AER estimate the volume of controlled load energy in NSW?

Question number	Stakeholder question
Question 13	Do you have or are you aware of any data to show the load shape for customers with controlled load on an accumulation meter compared to those on an interval meter?
Solar PV exports and hedging costs	
Question 14	What are your views on whether the AER should consider accounting for any additional hedging costs arising from customers' solar exports? If you are a retailer, how does the presence of customers' solar exports impact your hedging strategy and how could these additional costs be quantified within the wholesale methodology?
South Australian wholesale methodology	
Question 15	Further to analysis of OTC contract information, are there other methodologies the AER could investigate to benchmark wholesale cost forecasts in South Australia?
Question 16	Should the AER repeat the LRMC analysis for DMO 7 as a comparative data point for wholesale energy costs in South Australia?
Inputs into wholesale modelling	
Question 17	Would any of our modelling inputs specifically benefit from additional variability? If so, what objective data sources could be used to inform the creation of additional inputs?
Question 18	If you propose to adopt additionally varied inputs, to what extent should these differ from the inputs the AER has used historically?
Retail costs	
Question 19	Do you consider these current methodologies appropriate and, if not, what alternatives should be considered?
Question 20	What additional operational considerations or capital expenditure costs should the AER consider in determining the cost recovery of advanced metering costs?
Retail margin and allowance	
Question 21	Do you consider the proposed retail margins appropriate and, if not, what alternatives should be considered?
Question 22	What is the most appropriate approach to incorporating a diverse range of retailer costs to serve in DMO prices?
Question 23	What other factors, if any, should the AER consider in deciding whether to apply the competition allowance?
Other DMO costs and considerations	
Question 24	Should network costs be based on a blend of flat rate and time of use network tariffs and why or why not? How could the issues above be overcome – particularly for small business network tariffs – if we were to create a blended cost?

Question number	Stakeholder question
Question 25	What are your views on whether the AER should consider adopting new annual usage amounts? What alternative sources should be considered, and/or what values would be more broadly representative than the current assumptions?
Question 26	What benefits do you see in further consideration of improvements to the methodology of timing and pattern of supply? How material may this be and how could we address any additional complexity it causes?

Appendix B – History of the DMO

Background

The AER is the independent regulator for Australia's national energy market.

Our functions include regulating electricity networks and covered gas pipelines in all jurisdictions except Western Australia. We enforce the laws for the NEM and spot gas markets in southern and eastern Australia. We monitor and report on the conduct of market participants and the effectiveness of competition.

Across all our functions and objectives we strive to maintain a healthy energy sector and promote the long-term interests of consumers.[32] We achieve this by exercising our functions under the National Energy Retail Law in a manner that contributes to achieving the national energy retail objective and is compatible with developing and applying consumer protections for small customers.[33] Our retail energy market functions cover NSW, South Australia, Tasmania, the Australian Capital Territory (ACT) and Queensland. Under the Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019, our role is to set the DMO price each year for non-price regulated network distribution regions – NSW (Endeavour Energy, Essential Energy and Ausgrid), SE Queensland (Energex) and South Australia (SA Power Networks).

Policy context

In the final report of its 2018 Retail Electricity Pricing Inquiry (REPI), the ACCC raised concerns that the retail electricity market had evolved in such a way that standing offers – originally intended as a default protection for electricity consumers who were not engaged in the market – were often set at a high level, which enabled retailers to advertise high headline discounts for market offers.[34]

The ACCC report found standard retail contracts were not operating as an effective default offer and were not delivering essential consumer protections that justified the high price of the offer.[35]

To address these concerns the ACCC recommended the introduction of a DMO to cap the amount that retailers can charge residential and small business standing offer customers. It recommended the AER set the maximum price for the default offer in jurisdictions where there is no retail price regulation.

The purpose of the DMO was to act as a fall-back for consumers who are not engaged in the market. It was not intended to be a low-priced alternative to a market offer. The ACCC provided clear guidance about how the DMO price should be set by the AER, and

32 AER, AER Strategic Plan 2020–25, 14 December 2020.

33 National Energy Retail Law, s. 205.

34 Customers on standing offers are identified as those who have not taken up a market offer since the introduction of retail competition in that jurisdiction, are supplied under a retailer's 'obligation to supply', have moved into a premise and receive supply from the existing retailer supplying the premises but are yet to contact the retailer, or have defaulted to a standing offer following the expiry of a market contract.

35 ACCC, Restoring electricity affordability and Australia's competitive advantage: Retail Electricity Pricing Inquiry – Final Report, Australian Competition and Consumer Commission, June 2018, p. 240.

recommending the AER set the maximum price for the default offer in jurisdictions where there is no retail price regulation. In the letter, the ministers referred to four recommendations from the REPI report (Table B.1).[36]

Table B.1 ACCC REPI report recommendations

Number	Recommendation
30	In non-price regulated jurisdictions, the standing offer and standard retail contract should be abolished and replaced with a default market offer at or below the price set by the AER.
32	If a retailer chooses to advertise using a headline discount claim it must calculate the discount from the reference bill amount published by the AER.
49	The ACCC's recommendation to abolish the standing offer and replace it with a 'default offer' at or below a price set by the AER (recommendation 30) should be extended to all generally available offers including offers for Small and Medium Enterprise (SME) customers that are considered small customers under the National Energy Retail Law.
50	The ACCC's recommendation that all discounts must be calculated from a reference bill amount set by the AER (recommendation 32) should be extended to all generally available offers including offers for SME customers. The AER should develop a benchmark for representative usage levels for an average SME customer. Similarly, restricting conditional discounts to the reasonable savings that a retailer expects to make if a consumer satisfies the conditions (recommendation 33) should also apply to offers for business.[37]

In October 2018, the then Australian Government Treasurer and then Australian Government Minister for Energy requested the AER immediately commence developing the DMO to cap the amount that retailers can charge residential and small business standing offer customers.

On 4 April 2019 the Government introduced the Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019, with the first DMO to come into effect on 1 July 2019.[38]

Customers on standing offers

Most customers on standing offers are served by the 3 largest retailers, referred to as 'Tier 1' retailers – AGL, EnergyAustralia and Origin Energy. The Tier 1 retailers in the DMO regions are also the designated 'local area retailers' under the NERL.[39]

The AEMC and ACCC identified customers on standing offers as those who:

- have not taken up a market offer since the introduction of retail competition in that jurisdiction

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36 Treasurer and Minister for Energy, Letter to AER, October 2018, p. 1.

37 ACCC, Restoring electricity affordability and Australia's competitive advantage: Retail Electricity Pricing Inquiry – Final Report, Australian Competition and Consumer Commission, June 2018, pp. xxii, xxv.

38 Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019 (now superseded).

39 National Energy Retail Law, s 11.

- are supplied under a retailer's 'obligation to supply' (for example, if a poor credit history means other retailers will not supply them)[40]
- have moved into a premises and receive supply from the existing retailer supplying the premises but are yet to contact the retailer[41]
- have defaulted to a standing offer following the expiry of a market contract.[42]

All retailers must have, and must publish on their websites, a standard retail contract and standing offer prices.[43]

Every retailer must have a standing offer and customers have the right to ask for one.[44] However, for those with an existing electricity connection, only their existing retailer is obliged to supply them on these standing offer terms.[45] Customers seeking a standing offer can make that request of their existing retailer, knowing it will be met and that they will be protected by the DMO price cap. Retailers must ensure they comply with this obligation.[46]

Table B.2 sets out the number and proportions of customers on standing offers for DMO areas in Q4 2023–24.

Table B.2 Standing offer customers in DMO areas

Area	Residential customers (No. and %)	Small business customers (No. and %)
NSW	260,951 (7.5%)	49,306 (15.7%)
SE Queensland	128,861 (8.5%)	20,129 (17.2%)
South Australia	58,018 (7.1%)	13,456 (15.5%)
Total standing offer customers	447,830 (7.7%)	82,891 (16.0%)

Note: Customer numbers for SE Queensland have been extrapolated from all of Queensland by excluding Ergon Energy retail customers. Other retailers have customers numbers in regional Queensland, so customer numbers are approximate.
Source: AER, Retail market performance update, Quarter 4 2022–23.

40 Unlike other retailers, under s. 22 of the National Energy Retail Law, local area retailers cannot refuse to supply customers.

41 AEMC, *Advice to Council of Australian Governments Energy Council: Customer and competition impacts of a default offer*, 20 December 2018, p. 15.

42 Section 10 of the Regulations makes clear the DMO price only applies to customers on an electricity retailer's standing offer. It does not apply to customers who are on ongoing market contracts where discounts have expired. In practice these customers may be paying a retailer's standing offer prices. We do not know how many customers may be in this situation.

43 National Energy Retail Law, ss. 23, 25.

44 National Energy Retail Law, ss. 23, 25.

45 National Energy Retail Law, s. 22.

46 ACCC and AER, Joint Compliance Bulletin, May 2023.

DMO regulatory framework

The legislative framework for implementing DMO prices and the reference bill mechanism are contained in the Regulations.

Part 3 of the Regulations confers price setting functions on the AER. Specifically, we are required to determine:

- how much electricity a broadly representative small customer of a particular type in a particular distribution region would consume in a year and the pattern of that consumption[47] (the model annual usage)[48]
- a reasonable total annual price for supplying electricity (in accordance with the model annual usage) to small customers of a type in a region (the DMO price).[49]

The DMO price applies to residential and small business customers on standing offers in distribution regions that are not subject to retail price regulation.[50] These regions are:

- NSW – Ausgrid, Essential Energy and Endeavour Energy
- South Australia – South Australian Power Networks
- SE Queensland – Energex.

The Regulations set out that we must determine DMO prices for 'small customers' of certain types. These types are:

- **Residential customers** – on flat rate or TOU tariffs who use electricity mainly for personal, household or domestic use, and whose prices do not include a controlled load tariff.
- **Residential customers with controlled load** – on flat rate or TOU tariffs who use electricity mainly for personal, household or domestic use, and whose prices include a controlled load tariff. A controlled load tariff applies to a separately metered part of a customer's load, for appliances such as electric hot water storage systems or underfloor heating.
- **Small business customers** – on flat rate tariffs with no controlled load and who use less than 100 MWh per year.

The Explanatory Statement of the Regulations provides further details on each category, which includes customers with solar tariffs.[51]

We are not currently required to determine an annual price and usage for customers on other tariff types, such as:

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47 The AER is not required to determine the pattern of consumption in the case of small business customers.

48 Regulations, s. 16(1)(a).

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

50 Section 8 of the Regulations specifies that the instrument would not apply in a distribution region if any standing offer prices, or maximum standing office prices, for supplying electricity in the year in the region to a small customer are set by or under a law of a state or territory.

51 *Explanatory Statement, Competition and Consumer Act 2010*, Competition and Consumer Legislation Amendment (Electricity Retail) Regulations 2020.

- tariffs with a demand charge
- small business controlled load and TOU tariffs
- tariffs offered in embedded networks.

To determine a reasonable annual price, the Regulations require us to have regard to a range of specific matters and costs.[52] These form the basis for the DMO cost stack methodology and align with the chapters of this issues paper. The matters are:

- the prices electricity retailers charge for supplying electricity in the region to that type of small customer (considered when formulating the margins discussed in Chapter 5)
- the principle that an electricity retailer should be able to make a reasonable profit in relation to supplying electricity in the region (refer to Chapter 5).

The costs we must have regard to are:

- the cost of distributing and transmitting electricity in the region (refer to Chapter 6)
- the wholesale cost of electricity in the region (refer to Chapter 3)
- the cost of complying with the laws of the Commonwealth and the relevant state or territory in relation to supplying electricity in the region (included in Chapter 6 where these laws relate to costs associated with environmental obligations, but also covered by retail costs in Chapter 4 and some wholesale costs in Chapter 3)
- the cost of acquiring and retaining small customers, which is the case in all DMO regions (refer to Chapter 4)
- the cost of serving small customers (refer to Chapter 4).

We may also have regard to any other matter the AER considers relevant.

Reference price provisions

Part 2 of the Regulations prescribes a mandatory industry code (the Code for the purposes of Part IVB of the *Competition and Consumer Act 2010*). The Code contains the DMO reference price provisions that require:

- standing offer prices for small customers must not exceed a price determined by the AER[53]
- small customers must be told how a retailer's prices compare with the AER determined annual price[54]
- the most prominent price related feature in an advertisement must not be a conditional discount, and any conditions on other discounts must be clearly displayed.[55]

Under these requirements, the DMO price acts as a 'reference price', against which customers can easily compare market offers. The ACCC is responsible for enforcement and compliance with these provisions.

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[52] Regulations, s. 16(4).

[53] Regulations s. 10.

[54] Regulations s. 12.

[55] Regulations s. 14.

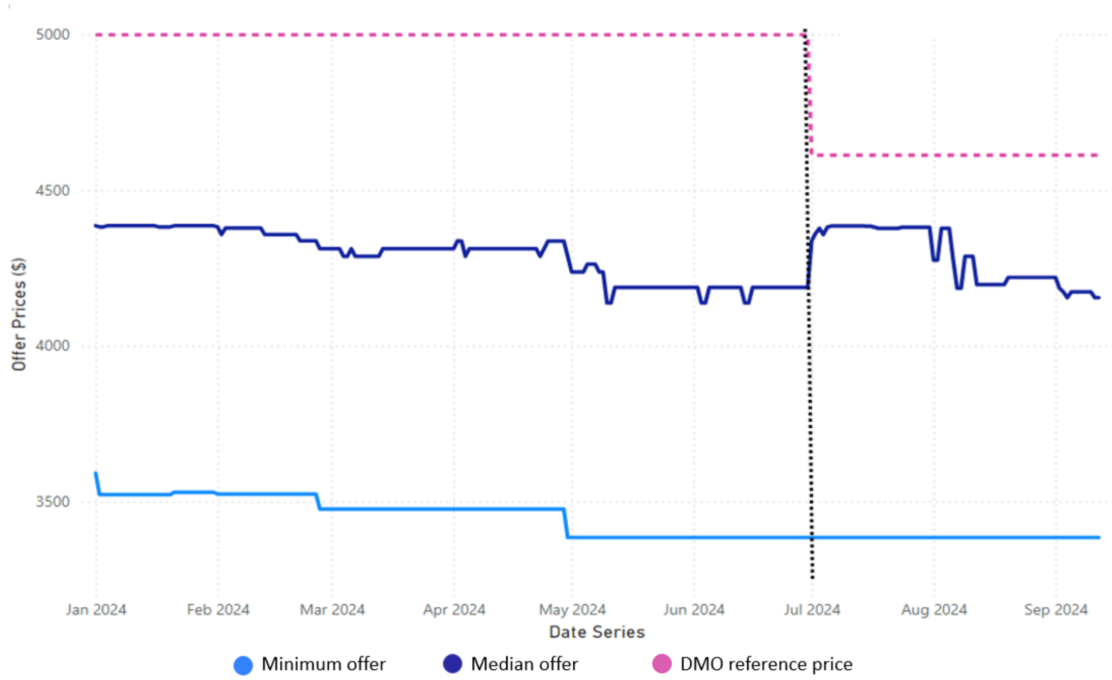
Appendix C – Market offer analysis

Figure C.1 to Figure C.10 in Appendix C outline the jurisdictional breakdowns of the market offers over the period of 1 January 2024 (DMO 5) to 1 September 2024 (representing the first 2 months of DMO 6). We have also provided the DMO price, alongside the small business customer type. As noted in section 2.2, although the specific discounts from the DMO price from median and minimum market offers differ among the DMO regions, there is a consistent trend across the DMO regions.

Ausgrid

Figure C.1 DMO price and median and minimum market offers – residential

Figure C.2 DMO price and median and minimum market offers – small business



Endeavour

Figure C.3 DMO price and median and minimum market offers – residential

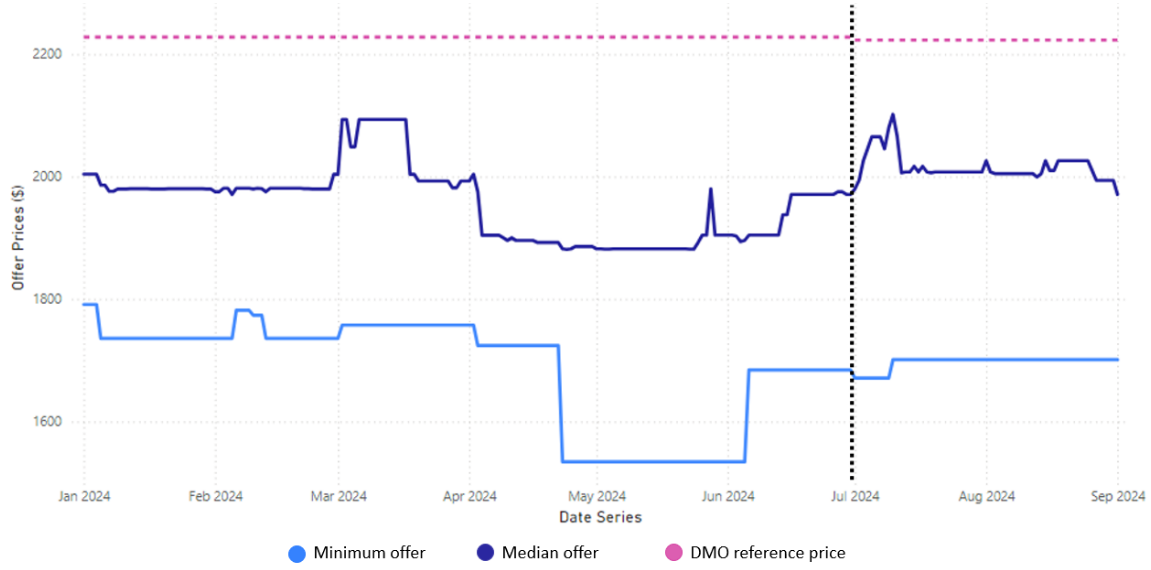
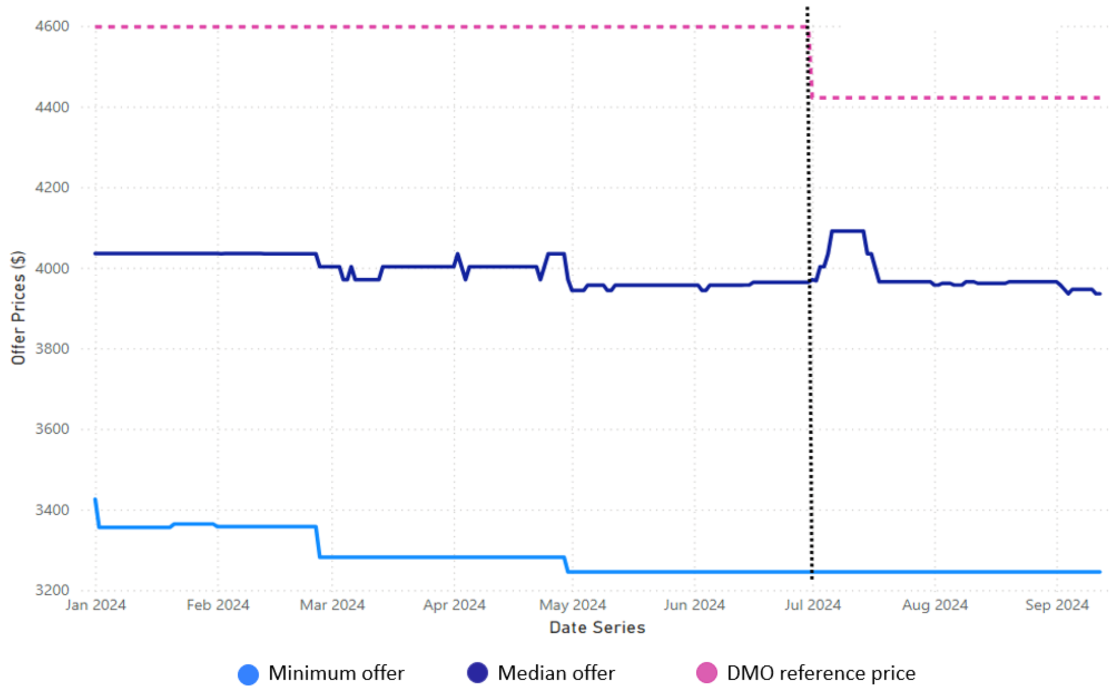


Figure C.4 DMO price and median and minimum market offers – small business



Essential

Figure C.5 DMO price and median and minimum market offers – residential

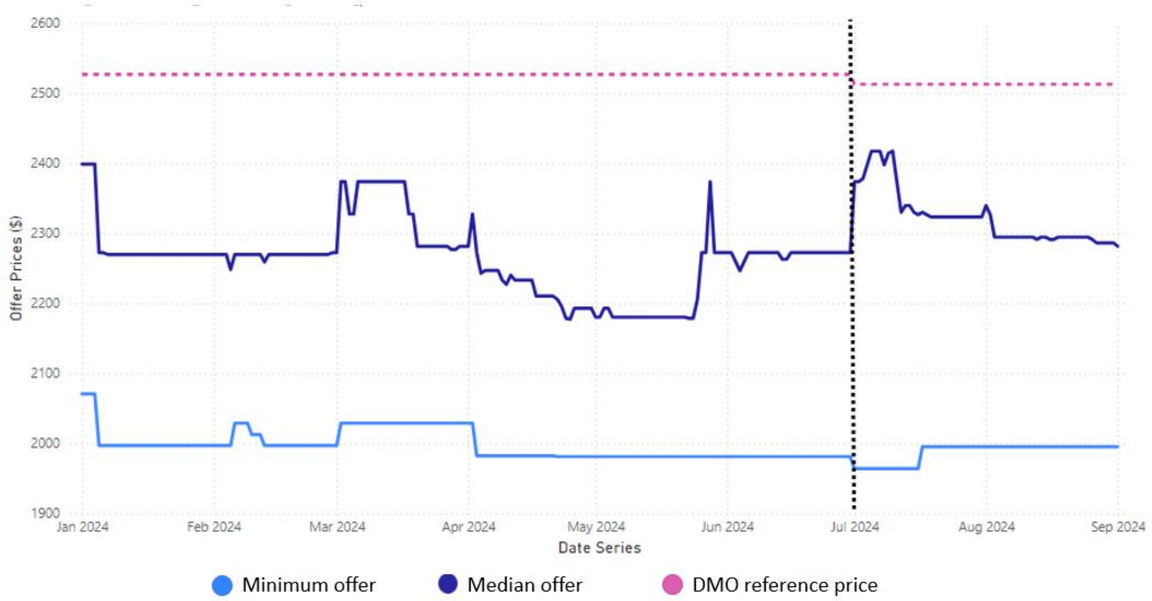
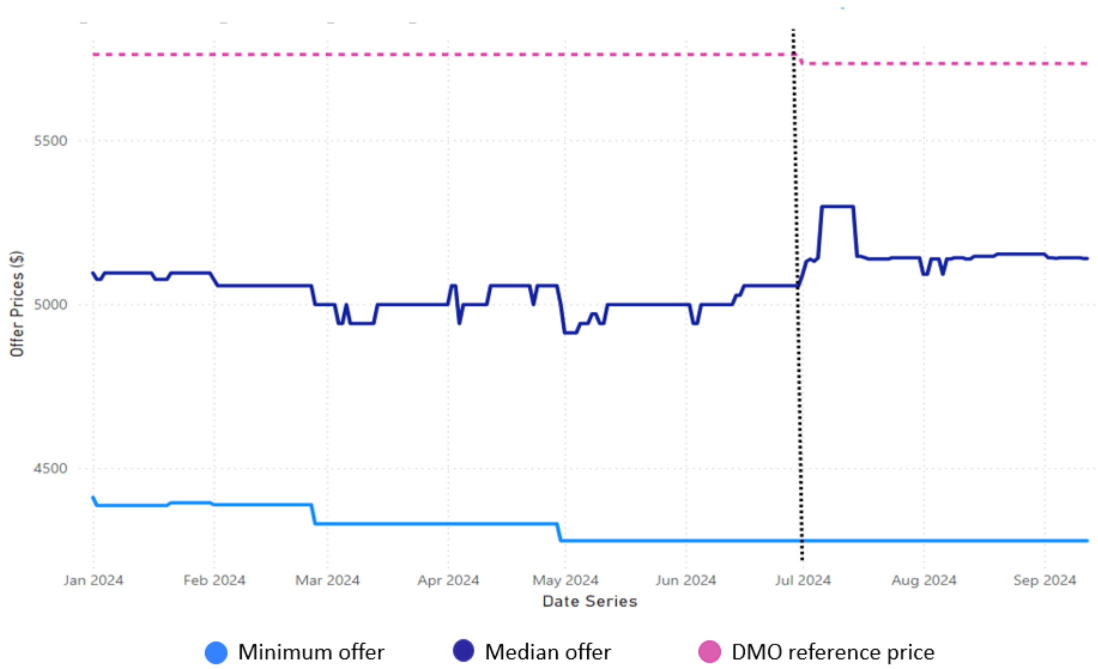


Figure C.6 DMO price and median and minimum market offers – small business



Energex

Figure C.7 DMO price and median and minimum market offers – residential

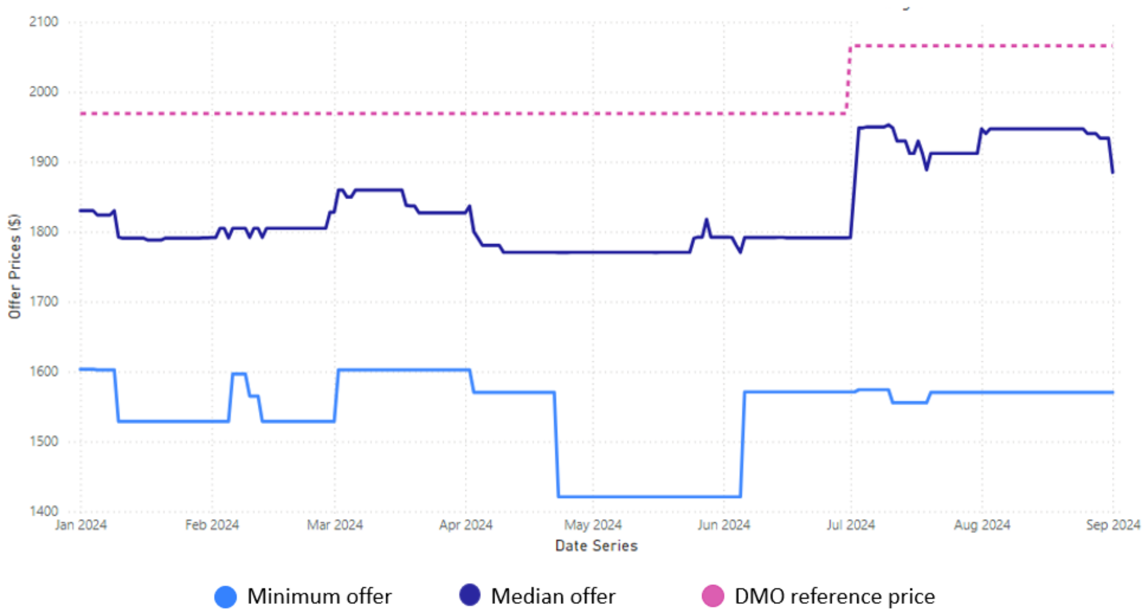
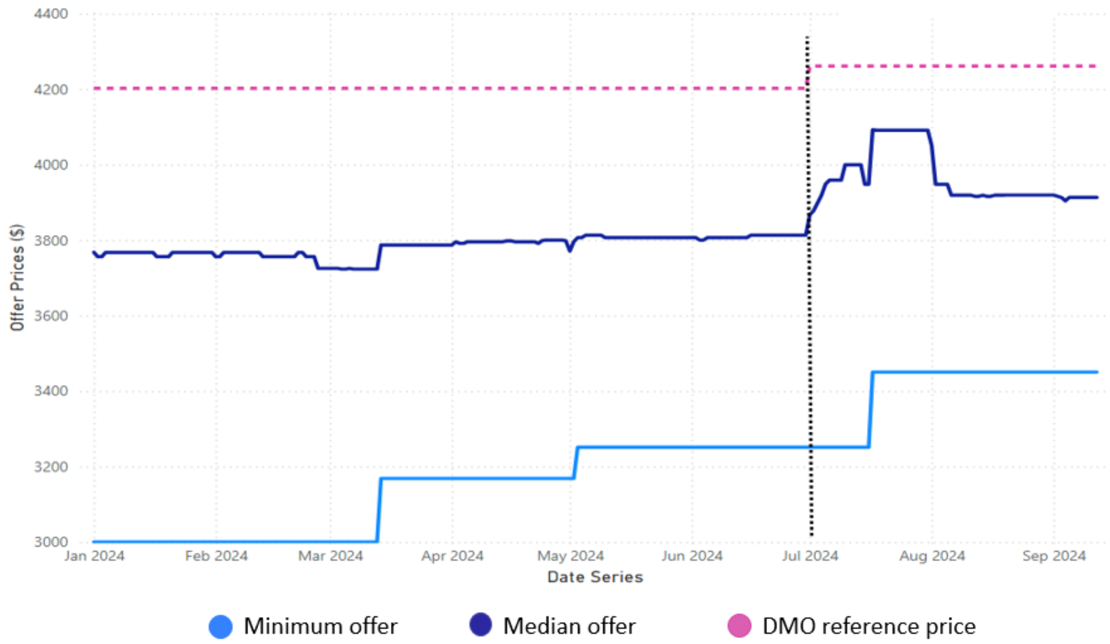


Figure C.8 DMO price and median and minimum market offers – small business



SA Power Networks

Figure C.9 DMO price and median and minimum market offers – residential

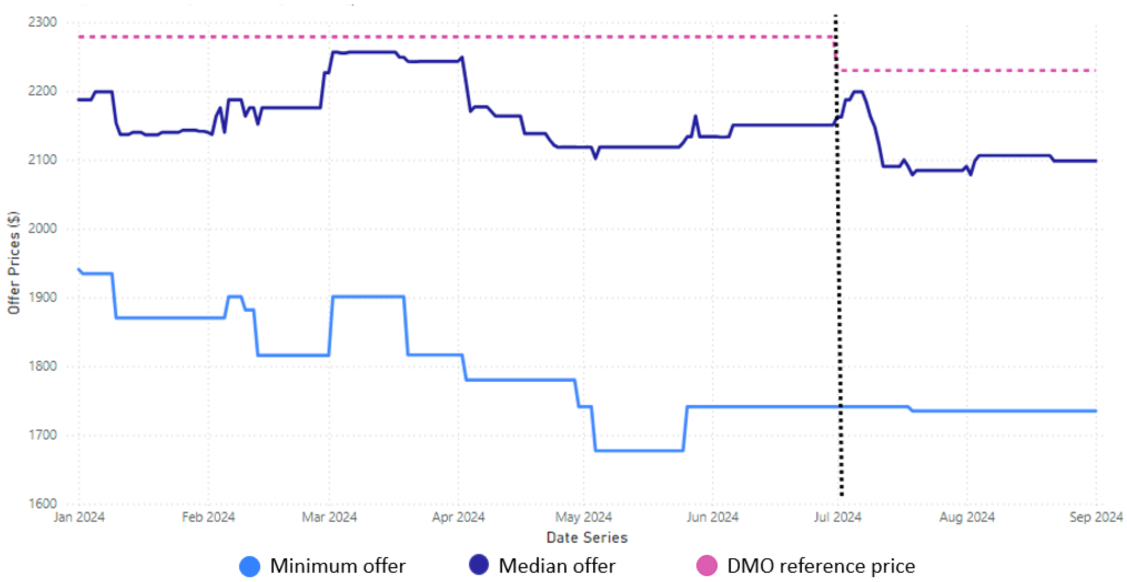


Figure C.10 DMO price and median and minimum market offers – small business