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Default market offer prices

Draft determination

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Contents

Invitation for submissions

Interested parties are invited to make submissions on this draft determination by close of business, 3 April 2025. We will consider all submissions received by this date in our final determination.

Submissions can be sent to DMO@aer.gov.au or to:

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Australian Energy Regulator
Level 17, 2 Lonsdale Street
Melbourne VIC 3000

Please ensure submissions are 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 note their confidentiality claim in the email attaching the submission. Ensure it clearly identifies the information that is the subject of the confidentiality claim and 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 regarding our use and disclosure of information provided to us, see the ACCC/AER Information Policy (June 2014).

Glossary

Term	Definition
ACS	Alternative control services
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACOSS	Australian Council of Social Service
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASX	Australian Securities Exchange
CECV	Customer export curtailment value
CL	Controlled load
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
DMO 8	Default market offer determination for 2026–27
DNSP	Distribution network service provider
EBITDA	Earnings before interest tax depreciation and amortisation
ECA	Energy Consumers Australia
ESC	Essential Services Commission
GST	Goods and services tax
ICRC	Independent Competition and Regulatory Commission
JEC	Justice and Equity Centre
kWh	Kilowatt hour
LRET	Large-scale Renewable Energy Target

Term	Definition
MWh	Megawatt hour
MSATS	Market Settlement and Transfer Solutions
NEM	National Electricity Market
NMI	National Metering Identifier
NSLP	Net System Load Profile
NSW REZ	New South Wales Renewable Energy Zone
OTC	Over-the-counter
OTTER	Office of the Tasmanian Economic Regulator
RBA	Reserve Bank of Australia
RRO	Retailer reliability obligation
SACOSS	South Australian Council of Social Service
SE Queensland	South East Queensland
SRES	Small-scale Renewable Energy Scheme
TOU	Time of use
VDO	Victorian Default Offer
WEC	Wholesale energy cost

1 Executive summary

This is the AER's draft determination for retail electricity default market offer (DMO) prices to apply from 1 July 2025 to 30 June 2026, known as DMO 7.

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 that a retailer can charge standing offer customers in New South Wales (NSW), South East Queensland (SE Queensland) and South Australia.[1] Standing offers are intended to provide a level of protection to customers who have not engaged, or cannot engage, in the retail electricity market.[2] The DMO price also acts as a 'reference price' for all other market offers in each distribution region. DMO prices are designed to aid consumers compare energy plans across different providers.

1.1 Market drivers of draft DMO 7 prices

The draft prices reflect general cost pressures across nearly all components of the DMO prices. Wholesale market and network costs, the two largest components of DMO prices, have seen increases of 2% to 12% for most customers. While wholesale costs have increased across all regions and customer types, network costs also increased except for some customer types in Queensland and South Australia. Retail costs have also increased by 20% to 41%. This has resulted in DMO 7 draft determination prices increasing compared with DMO 6.

Wholesale market costs are one of the largest components of DMO prices, comprising around 31% to 44% of the DMO cost stack. Average wholesale market spot prices increased across 2024, partially driven by individual market events that resulted in a number of high prices across DMO regions. These events were driven by a range of factors, such as high demand, coal generator and network outages, low solar and wind output or a combination of all factors. Electricity contract prices relevant to DMO 7 have lifted in kind, suggesting the market expects these volatile conditions to continue. In the 12 months up to February 2025, DMO 7 base futures contracts have increased between 11% and 26%. While retailers progressively accumulate contracts, the majority of contracts were purchased at elevated prices compared with DMO 6.

This rising wholesale cost environment has resulted in an increase in wholesale costs in DMO 7 of 2% to 3% in Queensland, 3% to 8% in NSW and 10% to 11% in South Australia. Increases in all regions are due mainly to an increase in the cost of both base futures and cap contracts. In South Australia, increases are also being driven by a change in the shape of the load profile. Compared with other regions, flatter wholesale costs in Queensland are the result of more base futures and cap contracts purchases occurring at lower prices across 2023, offsetting contracts purchased at higher prices throughout 2024 and early 2025.

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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 Further information on standing offers and how the DMO protects customers on standing offers can be found in chapter 3.

However, if Queensland contract prices remain at current high prices, wholesale costs are likely to increase in the final determination.

Network costs are also a large component of DMO prices, comprising around 33% to 48% of DMO prices. During February 2025, the AER received updated network tariff estimates from each distribution network service provider (DNSP), which showed increases for most customers ranging from 3% (Energex) to 12% (Endeavour Energy). There have also been some decreases for residential customers of 2% (SA Power Networks) to 5% (Energex).

Increases in network costs for NSW customers are driven by the price paths set in our 2024–29 regulatory determinations, with a key driver across each of these determinations being market factors (higher inflation and interest rates) causing a higher rate of return. The determined NSW Roadmap cost increases and forecast increases in transmission costs (which will be finalised for the final determination) are also driving increases. Increasing forecast energy consumption levels act to partially offset price increases for Endeavour Energy's customers.

Increases in network costs for Queensland customers are driven by the price path proposed in Energex's 2025–30 revised regulatory proposal, which the AER is still assessing. These are largely driven by market factors (higher interest rates), causing a higher rate of return. Cost pass-throughs that have either been proposed to the AER (for storm related costs in 2024) or approved by the AER (for retailer of last resort cost recovery) are also contributing to these increases. These are partially offset by the return of previously over-recovered distribution revenues.

Increases in network costs for South Australian small businesses are driven by the price path proposed in SA Power Networks' 2025–30 revised regulatory proposal, which the AER is still assessing. These are driven largely by market factors (higher interest rates), causing a higher rate of return. This is partially offset by the return of previously over-recovered revenues. Decreases in costs for South Australian residential customers are driven by a forecast reduction in the allocation of transmission costs (which will be finalised for the final determination) to the residential flat rate tariff and the return of previously over-recovered revenues. This is partially offset by SA Power Networks' proposed price path in its revised regulatory proposal.

Network costs used are currently the best available information and will be updated for the final determination. Energex and SA Power Networks are in the process of undergoing network revenue determinations. We expect to have made our final decisions by the end of April 2025, receive pricing proposals from these businesses and be able to approve network tariffs for inclusion in the final DMO prices.

Environmental costs are a small component of the DMO at 3% to 4% of the DMO prices. Environmental costs decreased for all customers by 17% in NSW, 22% in South Australia and 25% in Queensland. Decreases in federal renewable energy target schemes drove decreases in all region Decreases in South Australian renewable energy target schemes also contributed to the decreases in South Australia, while an increase in one of the NSW renewable energy target schemes slightly offsets the decreases in NSW.

Retail and other costs are also a smaller component of the DMO (around 11% to 16% for residential customers and 7% to 10% for small business). This component has increased in

DMO 7 due to growing costs reported by retailers, including bad and doubtful debts and implementation of smart meters. Small and medium retailers have also increased spending on acquiring and retaining customers.

1.2 Our approach to DMO 7

The *Default market offer prices 2025–26 issues paper* was published on 11 October 2024. Noting that stakeholders value stability and consistency in the methodology, we sought feedback on whether improvements to the methodology were warranted or desired by stakeholders. In the issues paper we consulted on various components relevant to DMO 7, including:

- which data inputs to use to create the consumption (or load) profile for our wholesale cost methodology
- how to calculate wholesale costs for controlled load energy in NSW, noting the Australian Market Energy Operator's (AEMO) Controlled Load Profile is no longer published
- whether and how to introduce additional variability to wholesale cost modelling inputs
- whether to calculate network costs solely from flat rate network tariffs or a blend of different network tariffs
- the most appropriate approach to incorporating the range of reported retailer costs to serve in the DMO.

Decisions on different aspects of the draft determination methodology reflect the ongoing need to balance methodological stability with the need to respond to fundamental changes in energy market, while also taking into account stakeholder views. While we have maintained a consistent methodology for most aspects, we have made some changes. The draft determination also highlights areas we consider need further investigation and consultation to ensure the DMO reflects developments in the changing market.

1.2.1 Wholesale methodology

Load profile assumptions

To ensure the consumption patterns of customers with both accumulation meters and interval meters are captured in the load profiles used to model wholesale costs, we have used a blended dataset to simulate the load profiles. While this decision results in only 1 year of historical data available to simulate the load profiles, it maintains consistency with the DMO 6 methodology and will allow the data used to create the load profiles to naturally capture all small customers as the smart meter rollout continues.

We have excluded rooftop solar exports from the interval meter dataset used to create the blended load profiles. The DMO wholesale cost methodology is based on hedging against load, so we do not consider it appropriate to include the impact of exports (or generation) in the load profiles. We also continue to have concerns that including exports would likely result in an overestimation of actual retailer costs. However, we also acknowledge that solar exports would likely alter the hedging strategies of retailers because the presence of rooftop solar impacts the shape of the profile a retailer hedges against to manage exposure to fluctuating spot prices. Therefore, we have included a solar hedging adjustment for the DMO

7 draft determination. This adjustment aims to reflect the difference in hedging strategies if exports were factored in. We have provided the results for stakeholder consideration ahead of the final decision for DMO 7.

NSW controlled load profiles

For DMO 7, we propose to continue using the Controlled Load Profile as reported by AEMO to calculate wholesale costs relevant to controlled load in NSW.

Noting AEMO recently ceased publication of the NSW Controlled Load Profiles, for the data that is available relevant to DMO 7, we consider it still produces the most realistic controlled load profile shape and is appropriate to use when calculating resulting costs. We acknowledge this method does not account for the new method of NSW controlled load settlement against the Net System Load Profile (NSLP). However, attempting to replicate settlement results in a profile shape that differs significantly from the known shape of controlled load demand.

As relevant controlled load profile data will not be available for DMO 8, we will engage with stakeholders on how to best produce a reflective controlled load profile across the DMO 8 process.

Inputs into wholesale modelling

The issues paper sought feedback on whether, for select inputs such as generator fuel costs, we should adjust the wholesale model to increase variability in modelled spot prices below $300 per megawatt hour (MWh). This would result in multiple generator fuel cost scenarios being simulated in the modelling, rather than the current singular fuel cost input.

We have not introduced additionally varied inputs in this draft determination as we continue to hold concerns that adopting additional inputs would result in greater complexity and subjectivity in the modelling process and reduce overall transparency and predictability. Also, most stakeholders provided feedback that they valued methodological consistency, simplicity and transparency in the wholesale modelling.

Our consultant tested the impact of varied modelling inputs on wholesale costs, noting our preference that both high and low cost scenarios should be included (although not necessarily equally weighted). The test demonstrated additional fuel cost inputs would not materially impact wholesale costs, even if the inputs utilised were to give greater weight to higher cost scenarios than lower cost scenarios. Given the lack of materiality and of a specific, objective and publicly available data source to inform the creation of additional inputs, we do not consider any potential for improved modelling accuracy would outweigh the additional complexity resulting from this adjustment.

South Australian methodology

We continued to collect South Australian over-the-counter (OTC) contract market data for DMO 7 due to ongoing low volumes of contracts traded on the Australian Securities Exchange (ASX). The OTC data continues to show a general price alignment of comparable OTC and ASX contracts. Therefore, we have continued to base the wholesale cost methodology only on the publicly available ASX data.

1.2.2 Efficient margin and competition allowance

For DMO 7 we will continue the approach adopted in DMO 6, which separately calculates a retailer margin and a competition allowance in the DMO prices.

The retail margin is based on our view of a reasonably efficient margin and is set as a percentage of the DMO price (before a competition allowance). This margin allows retailers to make a reasonable profit when selling electricity to standing offer customers in DMO regions.

We have also determined a competition allowance that is applied after the retail margin is calculated. This reflects the higher costs of some of the smaller retailers in the market that enter and bring competitive tension that benefits customers. We did not add the competition allowance onto the DMO price in DMO 6 to take account of economic conditions. Our measure for this is the extent to which the Consumer Price Index (CPI) is above the Reserve Bank of Australia's (RBA) target band on a material and sustained basis. While economic conditions appear to have moderated since DMO 6, the RBA has noted the economic outlook remains uncertain.[3] The draft DMO 7 price does not include a competition allowance based on underlying inflation remaining elevated in the most recent economic data.

We have set the efficient margin at 6% of residential prices and 11% of small business prices.

1.2.3 Network costs

The issues paper sought feedback on whether we should calculate network costs solely from flat rate network tariffs or a blend of different network tariffs.

The DMO 7 draft determination continues the previous approach of using flat rate network tariffs to determine network costs. Stakeholders had mixed views on which was the best approach to take in DMO 7, some considered a blended approach may improve the accuracy of network costs and others noted it would increase methodological complexity.

Revenue reset determinations for Energex and SA Power Networks for DMO 7 introduce challenges for obtaining additional network tariffs, customer counts and usage profiles required to develop blended network costs in time for DMO 7 draft and final determinations. We note more disaggregated data that could assist in calculating more accurate blended network costs could be available for DMO 8. We will reassess whether adopting a blended approach is appropriate in DMO 8.

1.2.4 Retailer costs

In prior DMO years, smaller retailers have argued that the average retailer costs included in the DMO price, sourced from Australian Competition and Consumer Commission (ACCC) reporting, were not representative of the costs of many smaller retailers or new entrants. For DMO 7 we obtained an expanded retailer cost dataset from a larger cohort of retailers selling to 99% of customers in DMO regions, including all smaller retailers with more than 1,000 customers in DMO regions.

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3 RBA, Statement on Monetary Policy February 2025, Reserve Bank of Australia, 18 February 2025.

Our draft determination includes retail operating costs based on the weighted average of these retailers’ costs.

1.3 DMO 7 draft prices

The price for residential customers without controlled load in SE Queensland is $2,185, which is an increase of 5.8% since DMO 6. For customers with controlled load, the price is $2,475, which is an increase of 2.5%. These prices amount to increases of 3.4% and 0.1% respectively above forecast inflation.[4]

In South Australia the price for residential customers without controlled load is $2,344, an increase of 5.1% since DMO 6. Those with controlled load face a price of $2,881, which is a 4.4% increase. These prices amount to increases of 2.7% and 2.0% respectively above forecast inflation.

NSW residential customers without controlled load will see prices of $1,969 to $2,713, which range from an increase of 7.8% to 8.8% since DMO 6. These prices amount to increases of 5.4% to 6.4% above forecast inflation, depending on their distribution network region. Customers with controlled load will see prices of $2,714 to $3,174, amounting to increases of 8.2% to 8.9%. These prices amount to increases of 5.8% to 6.5% above forecast inflation.

For small business customers, prices will be between $4,439 and $6,183. Compared with DMO 6, these prices represent a 4.2% to 8.2% increase. These prices amount to increases of 1.8% to 5.8% above forecast inflation depending on their region.

These outcomes are based on indicative network prices for 2025–26 and are expected to change once final prices are approved.

Where customers receive government rebates and concessions, the effective price they pay for electricity will be lower. Bill relief, rebates and concessions are currently offered by the Australian, Queensland, NSW and South Australian governments. Consumers can identify which forms of assistance they may be eligible for at Rebates and assistance.

[4] We have used RBA February 2025 forecast inflation for June 2025 (2.4%) and June 2026 (3.2%).

2 DMO 7 draft prices

Draft DMO prices for 2025–26 for each customer type in each distribution region are set out in Table 2.1. The table also shows the changes from DMO 6 in both real terms (that is, adjusted for forecast inflation) and nominal terms. The draft DMO prices are based on the most recent data available. The draft prices will be adjusted for our final determination as required based on:

- updated data received
- how market conditions have developed
- public consultation.

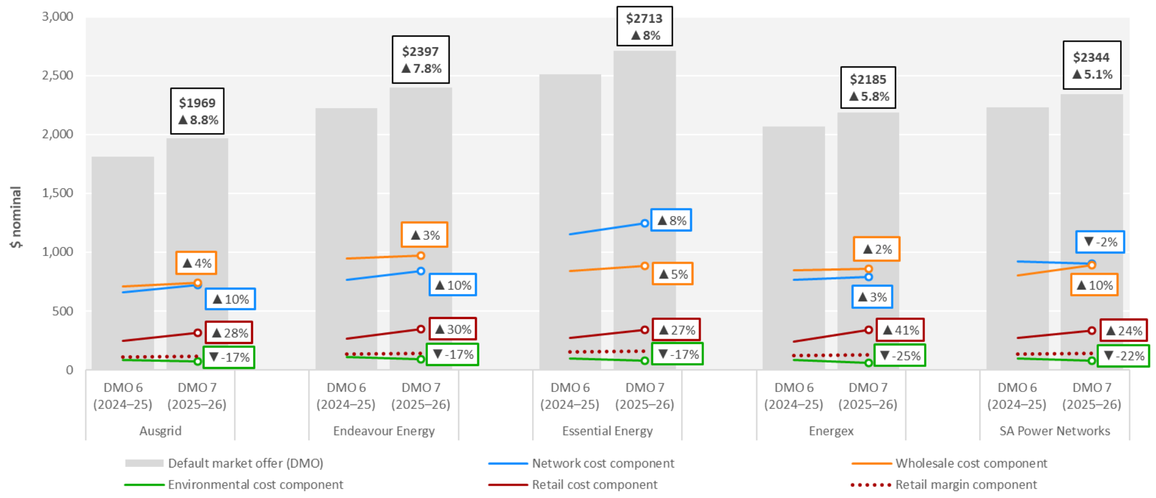
Table 2.1 DMO 2025–26 draft determination prices, including changes from DMO 6 (nominal and real terms)

Distribution region	Description	Residential (without controlled load)		Residential (with controlled load)		Small business (without controlled load)	
Ausgrid	DMO price		$1,969		$2,714		$4,988
	For annual usage of		3,900 kWh		Flat rate 4,800 kWh + CL 2,000 kWh		10,000 kWh
	Change y-o-y	+$159	(8.8%)	+$205	(8.2%)	+$376	(8.2%)
	Change y-o-y (real)	+$116	(6.4%)	+$145	(5.8%)	+$265	(5.8%)
Endeavour Energy	DMO price		$2,397		$3,050		$4,762
	For annual usage of		4,900 kWh		Flat rate 5,200 kWh + CL 2,200 kWh		10,000 kWh
	Change y-o-y	+$174	(7.8%)	+$249	(8.9%)	+$340	(7.7%)
	Change y-o-y (real)	+$121	(5.4%)	+$182	(6.5%)	+$234	(5.3%)
Essential Energy	DMO price		$2,713		$3,174		$6,183
	For annual usage of		4,600 kWh		Flat rate 4,600 kWh + CL 2,000 kWh		10,000 kWh
	Change y-o-y	+$200	(8.0%)	+$243	(8.3%)	+$450	(7.8%)
	Change y-o-y (real)	+$140	(5.6%)	+$173	(5.9%)	+$312	(5.4%)
Energex	DMO price		$2,185		$2,475		$4,439
	For annual usage of		4,600 kWh		Flat rate 4,400 kWh + CL 1,900 kWh		10,000 kWh
	Change y-o-y	+$119	(5.8%)	+$61	(2.5%)	+$178	(4.2%)
	Change y-o-y (real)	+$69	(3.4%)	+$3	(0.1%)	+$76	(1.8%)
SA Power Networks	DMO price		$2,344		$2,881		$5,707
	For annual usage of		4,000 kWh		Flat rate 4,200 kWh + CL 1,800 kWh		10,000 kWh
	Change y-o-y	+$114	(5.1%)	+$121	(4.4%)	+$355	(6.6%)
	Change y-o-y (real)	+$60	(2.7%)	+$55	(2.0%)	+$227	(4.2%)

Note: Real comparisons with DMO 6 are based on RBA 2024–25 inflation forecast of 2.4% in its February 2025 Statement on Monetary Policy.

Figure 2.1 shows the movement in the 2 key cost components (wholesale and network costs) since DMO 6. It illustrates that all cost components, except for environmental costs, have increased. Further detail on each of these cost components is provided in chapters 4 to 8 following.

Figure 2.1 Composition of the draft default market offer (DMO 6 and DMO 7 (nominal terms))



Note: Prices displayed are for residential customers without controlled load.

3 Role of the AER

As an independent regulator, the AER is responsible for enforcing the laws for the National Electricity Market (NEM) and spot gas markets in southern and eastern Australia. We report on the conduct of market participants and the effectiveness of competition, and we regulate electricity networks and covered gas pipelines in all jurisdictions except Western Australia.

Across all our functions and objectives we strive to maintain a healthy energy sector and promote the long-term interests of consumers.[5] 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.[6] Our retail energy market functions cover NSW, South Australia, Tasmania, the Australian Capital Territory (ACT) and Queensland. In Victoria, we are responsible for overseeing the retailer of last resort arrangements.[7] Under the Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019 (the Regulations), 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).

3.1 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 reference price determining 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)[8]
- 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).[9]

The DMO price applies to residential and small business customers on standing offers in NSW, SE Queensland and South Australia.[10]

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5 AER, [AER Strategic Plan 2020–25](), Australian Energy Regulator, 14 December 2020.

6 National Energy Retail Law, s. 205.

7 The AER became responsible for the retailer of last resort arrangements in Victoria on 30 July 2024 with the commencement of the National Energy Retail Law (Victoria) Act 2024.

8 Regulations, s. 16(1)(a) – note that the AER is not required to determine the pattern of consumption in the case of small business customers.

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

10 Regulations, s. 8 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.

The Regulations set out that we must determine DMO prices for the following types of small customers, including:[11]

- residential customers – on flat rate or time of use (TOU) tariffs
- residential customers with controlled load – these are separately metered tariffs used for appliances such as electric hot water storage systems, pool pumps or underfloor heating
- small business customers – on flat rate tariffs.[12]

The Explanatory Statement of the Regulations provides further details on each category, which includes customers with solar tariffs.[13] However, the Regulations state we must disregard any amount a retailer pays in feed-in tariffs.[14]

To determine a reasonable annual price, the Regulations require us to have regard to a range of specific matters and costs.[15] These form the basis for the DMO cost stack methodology and align with the chapters of this report. The matters are:

- the prices electricity retailers charge for supplying electricity in the region of that type of small customer (considered when formulating the margins in chapter 8)
- the principle that an electricity retailer should be able to make a reasonable profit in relation to supplying electricity in the region (see chapters 8 and 9).

The costs we must have regard to are:

- the cost of distributing and transmitting electricity in the region (see chapter 4)
- the wholesale cost of electricity in the region (see chapter 5)
- 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, and also covered by retail costs in chapter 7 and some wholesale costs in chapter 5)
- the cost of acquiring and retaining small customers, which is the case in all DMO regions (see chapter 7)
- the cost of serving small customers (see chapter 7).

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

The Regulations also prescribe a mandatory industry code with DMO reference provisions requiring:[16]

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11 Regulations, s. 6.

12 Small business customers are those who use less than 100 MWh per annum. We are not required to determine an annual price and usage for customers on other tariff types, such as tariffs with a demand charge, small business controlled load and TOU tariffs and tariffs offered in embedded networks.

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

14 Regulations, s. 8A.

15 Regulations, s. 16(4).

16 The Code for the purposes of Part IVB of the *Competition and Consumer Act 2010*.

- standing offer prices for small customers not to exceed a price determined by the AER[17]
- small customers to be told how a retailer's prices compare with the AER determined annual price[18]
- the most prominent price-related feature in an advertisement must not be a conditional discount and any conditions on other discounts are clearly displayed.[19]

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.

3.2 Policy objectives guide the DMO

When the DMO Regulations were introduced, the government of the time also provided policy objectives.[20] These policy objectives are the matters we considered relevant when setting a reasonable price:[21]

Throughout 2023–24, for the DMO 6 determination, we also received letters from the Australian and state governments to consider under the flexibility afforded to us in the Regulations to have regard to matters we consider relevant. These letters included requests for the AER to take into account broader economic conditions and acute periods of cost-of-living pressures for consumers.[22] The Australian Government Minister for Climate Change

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17 Regulations, s. 10.

18 Regulations, s. 12.

19 Regulations, s. 14.

20 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.

21 The AER must have regard to…any other matters we consider relevant, Regulations s.16(4)(d).

22 The Hon Chris Bowen MP, Minister for Climate Change and Energy, Submission to DMO 6 issues paper, 2023; The Hon Penny Sharpe MLC, Minister for Energy, Submission to DMO 6 issues paper, 8 November 2023; The Hon Mick de Brenni MP, Minister for Energy and Clean Economy Jobs, Submission to DMO 6 issues paper, 29 February 2024; The Hon Mick de Brenni MP, Minister for Energy and Clean Economy Jobs, Submission to DMO 6 issues paper, 5 March 2024; South Australian Department for Energy and Mining, Submission to DMO 6 issues paper, 10 November 2023; The Hon Mick de Brenni MP, Minister for Energy and Clean Economy Jobs, Submission to DMO 6 draft determination, 9 April 2024; South Australian Department for Energy and Mining, Submission to DMO 6 draft determination, 9 April 2024.

and Energy's letter at the time noted the request was a temporary measure to lessen the impacts of electricity bills on customers where the DMO applies, and to be considered on balance with the objectives.[23]

We must meet the requirements in the Regulations in determining a reference price. We weigh up the policy objectives, including the advice we receive from governments on these, and economic conditions for consumers and energy retailers in considering how best to do this.

How the DMO differs from other state and territory reference price determinations

The DMO differs in its role to that of other regulated electricity prices set by other regulators in Victoria (the Essential Services Commission (ESC)), Tasmania (Office of the Tasmanian Economic Regulator (OTTER)), the ACT (Independent Competition and Regulatory Commission (ICRC)) and for regional Queensland (Queensland Competition Authority).

Guidance provided at the inception of the DMO was that its objectives are not the same as for these other regulated prices. For regional Queensland, the ACT and Tasmania, where there is limited retail electricity competition, regulated prices are intended to be efficient prices in markets, due to the lack of competitive tension between retailers.

In Victoria, where there is retail competition, the objectives for the ESC in setting the Victorian Default Offer (VDO) are similar to those of the DMO in that it must be a ‘simple, trusted and reasonably priced electricity option that safeguards consumers unable to engage in the electricity retail market’.[24] However, the pricing order expressly states that the ESC must not include headroom, which is defined as an allowance that does not reflect efficient costs and may only include modest costs for consumer acquisition and retention.[25]

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[23] The Hon Chris Bowen MP, Minister for Climate Change and Energy, Submission to DMO 6 issues paper, 2023.

[24] Essential Services Commission, Victorian Default Market Offer 2024–25 Final Decision Paper, 20 May 2024, p. 3.

[25] Order made pursuant to s. 13, Electricity Industry Act 2000.

3.3 Standing offer customers

The Australian Energy Market Commission (AEMC) and ACCC have identified customers on standing offers 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' (for example, if a poor credit history means other retailers will not supply them)

- have moved into a premise and receive supply from the existing retailer supplying the premises but are yet to contact the retailer[26]

- have defaulted to a standing offer following the expiry of a market contract.[27]

Every retailer must have a standing offer and customers have the right to ask for one.[28]

However, for those with an existing electricity connection, only their existing retailer is obliged to supply them on these standing offer terms.[29] 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.[30]

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26 AEMC, Advice to the Council of Australian Governments Energy Council: Customer and competition impacts of a default offer, Australian Energy Market Commission, 20 December 2018, p. 15.

27 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.

28 National Energy Retail Law s. 23 and s. 25.

29 National Energy Retail Law s. 22.

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

In networks where the DMO applies, a minority of residential and small business customers are on standing offers. Table 3.1 presents the number of customers on standing offers in DMO regions. Most customers on standing offers are served by the 3 largest retailers, referred to as 'Tier 1' retailers – AGL, EnergyAustralia and Origin Energy.

Table 3.1 Customers on standing offers in DMO regions

Customer type	DMO	NSW (number and % of customers)	SE Queensland (number and % of customers)	South Australia (number and % of customers)	Total standing offer customers (number and % of customers)
Residential customers	DMO 7	277,248 (8.0%)	133,484 (8.8%)	60,150 (7.3%)	**470,882 (8.1%)**
Small business customers	DMO 7	56,455 (18.1%)	21,168 (18.0%)	14,418 (16.5%)	**92,041 (17.8%)**
Residential customers	DMO 6	293,470 (8.6%)	140,713 (9.4%)	61,701 (7.6%)	**495,884 (8.6%)**
Small business customers	DMO 6	57,093 (18.2%)	23,106 (19.7%)	14,600 (16.7%)	**94,799 (18.3%)**
Residential customers	DMO 5	320,362 (9.4%)	156,986 (10.5%)	62,600 (7.8%)	**539,948 (9.5%)**
Small business customers	DMO 5	55,995 (18.1%)	21,267 (19.3%)	13,778 (15.9%)	**91,040 (18.0%)**
Residential customers	DMO 4	347,483 (10.4%)	167,520 (11.5%)	65,516 (8.2%)	**580,519 (10.4%)**
Small business customers	DMO 4	64,211 (19.2%)	24,234 (21.7%)	13,701 (15.6%)	**102,146 (19.1%)**

Note: SE Queensland figures extrapolated from all of Queensland by excluding Ergon Energy customers. Other retailers have customers in regional Queensland, so Queensland figures are approximate. Standing offer customers have been calculated by subtracting market offer customers from total customers.
Source: AER retail market performance update, Quarter 1 2024–25.

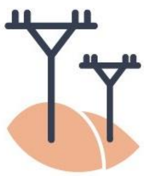
4 Network costs

- For the DMO 7 draft determination we have decided that a flat rate network cost approach remains the most appropriate methodology.
- Network costs make up between 33% and 48% of the DMO 7 draft prices.
- Network prices are increasing across all distribution regions, customer types and tariff structures except Energex residential with controlled load and SA Power Networks residential with and without controlled load. Increases are between 2.7% and 11.6% and decreases between 2.3% and 4.8%.

Under the National Electricity Rules, the AER regulates network charges by approving the network tariffs that distribution network businesses set on an annual basis. The DMO network cost component is adjusted each year to reflect changes in distributor network costs for each customer type under the DMO.

The network costs used in the draft determination are forecast network tariffs for 2025–26 provided by distributors in February 2025. This is currently the best available information and will be updated for the final determination using the final approved network tariffs.

Network tariffs 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 (ACS) charges
relates to DNSP businesses' installation and maintenance of type 5 manually read interval meters and type 6 accumulation meters.

4.1 Issues paper

4.1.1 Whether to blend flat rate and time of use network costs

The issues paper acknowledged the growing proportion of customers transitioning to time of use network tariffs. The issues paper also noted that we have previously received stakeholder feedback that a blend of flat network and time of use network tariffs may be more representative of actual network costs incurred by retailers. We again sought feedback from stakeholders on whether a change in methodology to a blended network tariff would improve the extent to which the DMO network cost component reflects reasonable retail costs and whether any benefit in this methodology change outweighs the additional regulatory load to industry participants and added complexity and instability to the methodology.

Specifically, we proposed a methodological change that would blend both flat rate and cost-reflective network tariffs, such as time of use, through a customer-weighted approach and then be applied to the relevant consumption profile, jurisdiction and customer type.

We also highlighted some issues that could arise under this approach, including limitations in using historical consumption information and the availability of detailed small business network tariff information considering the DMO only applies to flat rate retail tariffs for small business customers.

4.1.2 SA Power Networks and Energex revenue reset

SA Power Networks and Energex are in the process of undergoing network revenue determinations being approved by the AER for the period from 1 July 2025 to 30 June 2030. We proposed to regularly engage with distributors to ensure we have the best available information to include in the draft determination, similar to our approach in DMO 6 for NSW distributors. For the final determination, we will receive updated final network costs in late April 2025 for SA Power Networks and Energex.

4.2 Stakeholder views

4.2.1 Whether to blend flat rate and time of use network costs

Ten stakeholders provided feedback on whether the AER should consider using a blend of flat rate and time of use network tariffs. The support for a blended network cost approach varied across stakeholders, some also raised additional considerations for the AER when determining the decision for network costs.

We received 7 submissions that supported blending flat rate network tariffs and cost-reflective network tariffs or provided an alternative option for considering cost-reflective network tariffs. Shell Energy and Red Energy and Lumo Energy supported our considered blended approach using a customer-weighted average to establish a consumption profile for each customer type and distribution network.[31] ENGIE recommended establishing an average consumption profile for each distribution network through a volume-weighted approach.[32]

In addition to being supportive of a change to a blended network tariff, 2 submissions highlighted the network tariff mismatch risks associated with the AEMC Accelerating smart meter deployment rule change that allows customers to choose to remain on a flat rate network tariff after a smart meter has been installed while the retailer incurs an underlying time of use network cost from the distributor.[33] Energy Locals contended they would be commercially disadvantaged once these protections have been implemented and this should

31 Shell Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 7; Red Energy and Lumo Energy, Submission to DMO 7 issues paper, 18 November 2024, p. 5.

32 ENGIE, Submission to DMO 7 issues paper, 8 November 2024, p. 9.

33 Alinta Energy, Submission to DMO 7 issues paper, 14 November 2024, p. 5.

be reflected in the DMO.[34] ENGIE raised concerns that the accelerated deployment of smart meters will further exacerbate the difficulty in managing the network tariff mismatch to retailers.

Ausgrid's submission recommended the AER be open to including all other tariff structures, such as demand network tariffs.[35]

Three retailers recommended maintaining the current approach of flat network tariffs because it reduces complexity in the methodology. Origin Energy and AGL supported maintaining the existing methodology and suggested the AER should delay blending network tariffs until more accurate and transparent data can be provided to ensure an accurate allocation of flat rate and time of use network tariffs.[36] EnergyAustralia proposed that a margin of error be incorporated to offset the added complexity of blending network tariffs.[37]

The South Australian Council of Social Service (SACOSS) raised concerns around South Australian consumers being transferred to time of use network tariffs without their consent following smart meter installations to avoid the risk of a network tariff mismatch for retailers.[38] SACOSS reasoned that these consumers should be able to compare their current offer to a time of use DMO price.

Across stakeholders there was general acknowledgment that adopting a blended network tariff approach would be complex and difficult to implement. Furthermore, there was similar agreement across submissions that establishing an average time of use profile for small business customers would be challenging due to the varied nature of small business electricity consumption.

4.2.2 SA Power Networks and Energex revenue reset

We received limited feedback around accounting for the network revenue determinations for SA Power Networks and Energex. The feedback we did receive supported our recommended and historical approach for managing a DNSP in a network revenue reset.[39]

4.3 Draft determination

4.3.1 Whether to blend flat rate and time of use network costs

We have considered feedback from stakeholders and acknowledge the perspective that including a blended network cost is now likely more reflective of an actual retailer's circumstances.

We consider a flat network cost approach remains the most appropriate methodology for DMO 7.

34 Energy Locals, Submission to DMO 7 issues paper, 14 November 2024, p. 6.

35 Ausgrid, Submission to DMO 7 issues paper, 8 November 2024, p. 2.

36 AGL, Submission to DMO 7 Issues Paper, 12 November 2024, p. 7; Origin Energy, Submission to DMO 7 issues paper, 14 November 2024, p. 9.

37 EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, p. 8.

38 SACOSS, Submission to DMO 7 issues paper, 14 November 2024, p. 16.

39 Origin Energy, Submission to DMO 7 issues paper, 14 November 2024, pp. 9–10.

We agree with stakeholders that adopting a blended network tariff approach would be difficult to implement and introduces methodological complexity. We note that SA Power Networks and Energex are currently undergoing revenue resets, which includes the introduction of new tariff structure statements. As a result, there are significant challenges in obtaining timely and accurate additional network tariff, customer number and consumption information required to calculate blended network costs to include in our DMO 7 draft and final determinations. This issue will not be present in the next 3 determinations as none of the DMO regions will be undergoing revenue resets during this period.

We also note there is a particular methodological challenge in deriving appropriate weightings for blending small business network tariffs to reflect average DMO network costs because the small business DMO price only applies small business flat rate retail tariffs. Currently, the AER does not have network tariff information for the subset of small business customers on flat rate retail tariffs. However, we consider the AER's new retail performance reporting guidelines being implemented from Q1 2025–26 provide greater granularity of network tariffs and retail tariffs, which should facilitate development of suitable weightings for a blended network tariff in DMO 8 and future determinations.

As stated in our submission to the AEMC Accelerating smart meter deployment rule change,[40] we do not consider retailers would uniformly be worse off facing a cost-reflective network tariff that they cannot directly pass on to customers. Without any customer behaviour change, cost reflective tariffs may increase costs relating to some customers and will result in lower costs relating to others.[41] We observe retailers may have a range of options to help manage cost risks, including working with customers to change consumption behaviour through the provision of helpful information and new products and services. We also acknowledge that in practice different customer segments vary in their ability and propensity to shift behaviour and that retailer strategies will be informed by the cohorts that make up their customer base.

This rule change addresses the concern raised by SACOSS about customers being transferred to a time of use tariff without their consent. It prohibits retailers from varying a customer's retail tariff structure in the 2 years following a smart meter deployment unless the customer provides their explicit informed consent for the change. At the end of 2 years, retailers must provide a customer at least 30 business days' notice when varying the tariff.[42] In Queensland, designated retailers are required to offer a flat rate standing offer to customers with either a smart meter or interval meter.[43]

[40] AER, Submission to Accelerating Smart Meter Deployment Directions Paper, Australian Energy Regulator, 19 September 2024.

[41] AEMC, Directions Paper: Accelerating Smart Meter Deployment, Australian Energy Market Commission, 15 August 2024, p. 11.

[42] AEMC, National Electricity Amendment (Accelerating Smart Meter Deployment) Rule, Australian Energy Market Commission, 28 November 2024.

[43] On 19 September 2024, the Queensland Government made a derogation (effective from 20 September 2024) under the National Energy Retail Law (Queensland) Amendment Regulation (No. 2) 2024 requiring retailers operating in Queensland to provide a flat tariff standing offer to interval meter customers under section 22(1a) of the National Energy Retail Law (Retail Law).

4.3.2 SA Power Networks and Energex revenue reset

SA Power Networks and Energex are currently undergoing revenue resets. We have been regularly engaging with SA Power Networks and Energex to determine the most accurate information available. We have used the best possible estimates to calculate network costs for these jurisdictions for the draft determination. We expect to have made our final decisions by the end of April 2025, receive pricing proposals from these businesses and be able to approve network tariffs for inclusion in the final DMO prices.

4.3.3 Treatment of NSW Renewable Energy Zone (NSW REZ) costs

The AER has determined a contribution recovery for the NSW Roadmap costs for 2025–26 of $493.18 million. For each DNSP, the costs to be recovered are:

- Ausgrid: $212.77 million
- Endeavour Energy: $184.71 million
- Essential Energy: $95.70 million.

These allocations are based on each network's volume of electricity transported and peak demand.

NSW DNSPs have developed network prices that include the recovery of the 2025–26 NSW REZ costs.

4.3.4 Drivers for changes in costs since DMO 6

The main drivers for changes in the updated and forecasted network tariffs for 2025–26 provided by distributors in February 2025 compared with DMO 6 network costs are:

- Increases in network costs for NSW customers are driven by the price paths set in our 1 July 2024 to 30 June 2029 regulatory determinations, with a key driver across each of these determinations being market factors (higher inflation and interest rates) causing a higher rate of return. The determined NSW Roadmap cost increases, and forecast increases in transmission costs (which will be finalised for the final determination), are also driving increases. Increasing forecast energy consumption levels act to partially offset increases for Endeavour Energy's customers.
- Increases in network costs for Queensland customers are driven by the price path proposed in Energex's 2025–30 revised regulatory proposal, which we are still assessing. These are largely driven by market factors (higher interest rates), causing a higher rate of return. Cost pass-throughs that have either been proposed to us (for storm related costs in 2024)[44] or approved by us (for retailer of last resort cost recovery)[45], are also contributing to these increases. These are partially offset by the return of previously over-recovered distribution revenues.
- Increases in network costs for South Australian small businesses are driven by the price paths proposed in SA Power Networks' 2025–30 revised regulatory proposal, which we are still assessing. These are also driven largely by market factors (higher interest rates),

[44] AER, Energex cost pass through application – South East Queensland storms, Australian Energy Regulator.

[45] AER, Origin retailer of last resort cost recovery applications, Australian Energy Regulator.

causing a higher rate of return. This is partially offset by the return of previously over-recovered revenues. Decreases in costs for South Australian residential customers are driven by a forecast reduction in the allocation of transmission costs (which will be finalised for the final determination) to the residential flat rate tariff and the return of previously over-recovered revenues. This is partially offset by SA Power Networks' proposed price path in its revised regulatory proposal.

The network tariffs that are used to assess network costs for each DNSP are set out in Table 4.1. The network costs resulting from these network tariffs are shown in Table 4.2.

Table 4.1 Network tariffs (with network codes) to assess the change in network costs

Region	Residential flat rate	Residential controlled load	Small business 10,000 kWh
Ausgrid	Residential Non TOU EA010	EA030 - Controlled load 1 EA040 - Controlled load 2	EA050 Small business non-TOU
Endeavour Energy	Residential Flat tariff N70	Controlled load 1 N50 Controlled load 2 N54	General Supply Block Tariff N90
Essential Energy	Residential Anytime BLNN2AU	Energy Saver 1 BLNC1AU Energy Saver 2 BLNC2AU	Small Business Anytime BLNN1AU
Energex	Residential Flat NTC8400	Super Economy NTC9000 Economy NTC9100	Business Flat NTC8500
SA Power Networks	Residential Single Rate RSR (SR)	Residential Single Rate RSR (controlled load)	Business Single Rate BSR

Table 4.2 AER estimates of 2025–26 network costs (including GST)

Region	Customer type	2024–25 $	2025–26 $	Year-on-year change ($)	Year-on-year change (%)
Ausgrid	Residential flat rate	$657	$720	$62.9	9.6%
	Residential controlled load	$855	$928	$73.7	8.6%
	Small business 10,000 kWh	$1,756	$1,929	$173.2	9.9%
Endeavour Energy	Residential flat rate	$765	$841	$76.7	10.0%
	Residential controlled load	$934	$1,043	$108.7	11.6%
	Small business 10,000 kWh	$1,454	$1,612	$157.7	10.8%
Essential Energy	Residential flat rate	$1,155	$1,244	$88.6	7.7%
	Residential controlled load	$1,276	$1,376	$99.2	7.8%
	Small business 10,000 kWh	$2,743	$2,951	$208.5	7.6%
Energex	Residential flat rate	$768	$788	$20.5	2.7%
	Residential controlled load	$870	$828	-$42.2	-4.8%
	Small business 10,000 kWh	$1,475	$1,585	$109.7	7.4%
SA Power Networks	Residential flat rate	$922	$901	-$21.7	-2.3%
	Residential controlled load	$1,105	$1,077	-$27.8	-2.5%
	Small business 10,000 kWh	$2,206	$2,299	$93.0	4.2%

5 Wholesale energy costs

For the DMO 7 draft determination we have decided to:

- use one year of Net System Load Profile (NSLP) data to simulate the load profiles, blended with interval meter data (which has been published with the draft determination)
- maintain a single load profile for residential and small business customers
- continue to exclude solar exports from the interval meter dataset used to create the load profiles, but apply a hedging adjustment
- use the historical Controlled Load Profile to simulate the controlled load shape for NSW
- continue to base the wholesale cost methodology for South Australia on publicly available ASX data
- not introduce any variation to wholesale modelling inputs, such as fuel prices
- maintain all other aspects of the wholesale cost methodology, including the 75th percentile of modelled wholesale cost outcomes and book build approach.

Wholesale costs represent approximately 31% to 44% of the DMO 7 draft prices and have increased 2% to 11% since DMO 6.

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 electricity spot 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.

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. We use an external consultant, ACIL Allen, to assist us with determining wholesale costs in the DMO.

5.1 Issues paper

5.1.1 Load profile assumptions

Net System Load Profile and interval meter data

Previously our methodology has relied on at least 2 years of NSLP data to model the costs to retailers of purchasing energy for residential and small business customers. This data includes the aggregated electricity consumption of all customers with accumulation meters. For DMO 6, we blended NSLP data with interval meter data for the first time to ensure interval meter customers were captured in our methodology alongside accumulation meter customers represented by the NSLP. A time series of 2 years of data has historically been used to ensure atypical events do not have an outsized impact on the simulated load profile.

The issues paper highlighted that all load profile data used within the wholesale modelling must cover the same period across all regions to ensure consistency in the modelling process. 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, all need to be derived from the same timeframe.

The issues paper also highlighted adjustments to the NSLP by AEMO to resolve settlement issues in the SA Power Networks and Energex regions across the previous 2 to 3 years (Figure 5.1). During DMO 6 we were concerned that relying on the AEMO NSLP data following the initial adjustment 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 asking our consultant to adjust the NSLP would lead to an overly peaky and expensive load shape. Therefore, we considered it reasonable to pivot from our standard methodology by taking the midpoint between the wholesale cost forecasts that these 2 options produced for DMO 6.

AEMO made a second adjustment to the NSLP in October 2023 that more closely aligned with the load shape prior to the initial adjustment, but was not used for DMO 6 due to a lag in publication of the data. A third adjustment was implemented in September 2024, with its impact backdated to NSLP data from 9 June 2024 onwards. At the time of publication of the DMO 7 issues paper, we had concerns that the third adjustment would have a material impact on the data and, therefore, the historical NSLP data would differ from that which would apply during DMO 7.

Figure 5.1 NSLP timeline for SA Power Networks and Energex regions

Note: While AEMO's third adjustment to the NSLP was implemented on 29 September 2024, its impact was backdated to 9 June 2024 onwards.

Therefore, we sought stakeholder views on whether use of an alternative data source or methodology may be appropriate to simulate the load profiles for DMO 7. We included the following factors that would guide our decision-making for load profiles:

- Reflection of market outcomes – we considered 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 – stakeholders strongly support basing the DMO on publicly available data (where possible). However, we noted the trade-off that may occur because confidential data often provides greater insights to market outcomes.
- Longevity of the decision – consistency in the DMO methodology remains important to stakeholders. We noted that we would factor in how any decision on load profiles may continue to be upheld as market conditions continue to change into the future.

The issues paper assessed 2 options to simulate the load profiles against the above decision-making factors:

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

We considered that option 1 would reflect the load shape of more than half of small customers in DMO regions by the start of the DMO 7 period due to the uptake of interval meters. Additionally, we noted this approach would mitigate further changes to the load profile methodology, as the number of customers on interval meters would continue to increase and reach close to 100% by 2030.

We considered that option 2 would best capture both accumulation meter and interval meter customers. However, we were concerned that the third adjustment to the NSLP data would not reflect the NSLP adjustment methodology in place for the DMO 7 period and what retailers would eventually be settled against. We were also concerned that a shorter time series would increase the risk of atypical events impacting the data used to simulate the load profiles.

Another potential approach was to use the most recent 2 years of NSLP data, regardless of the underlying adjustment methodology, blended with interval meter data. However, due to the 2-year time series intersecting different NSLP adjustments, we did not consider it appropriate for DMO 7.

Given the underlying issues with load profile data and the option to use interval meter data only, we reopened discussion on whether we should develop separate profiles for residential and small business customers.

Solar PV exports and hedging costs

The issues paper recounted our position adopted in DMO 6 – to exclude customers' solar PV exports from the interval meter dataset used to create the load profiles for the DMO. We considered this appropriate because the DMO seeks to set a price for customer consumption and 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.

We recognised that the value of solar exports is highly dependent on spot market outcomes and any cost exposure for retailers, such as times when a retailer's net load is negative and it coincides with a negative price interval, could be managed through adjustments to feed-in tariffs paid, among other strategies. However, the DMO Regulations explicitly require us to disregard feed-in tariffs paid.[46]

However, we were conscious that the presence of solar exports could impact retailers' hedging decisions. As a result, we sought feedback on how the wholesale cost methodology could capture the impact of customers' solar exports on retailers' hedging strategies.

We explored a potential approximation, involving comparing wholesale energy cost (WEC) estimates on a load profile that excluded exports, but from 2 modelled hedging strategies – one for a profile including solar exports and another excluding, with the difference

46 Regulations, s. 8A.

representing a hedging cost arising from solar exports. However, we were concerned this approach would be limited in its ability to reflect actual hedging costs faced by retailers and sought feedback on alternative approaches.

5.1.2 Controlled Load Profile (NSW)

The issues paper consulted on options for simulating the Controlled Load Profile in NSW regions for DMO 7. Historically, we have used AEMO's Controlled Load Profile to simulate the time of day shape of controlled load demand. AEMO's Controlled Load Profile approximates the time of day demand of accumulation metered controlled load using 200 sample meters. Our consultation on the method for simulating controlled load demand was prompted by the discontinuation of AEMO's sample Controlled Load Profile for NSW regions in September 2024.[47] As at September 2024, all accumulation meter controlled load energy is recorded under and settled against the NSLP, having been transitioned from the Controlled Load Profile between 31 May and 1 September 2024.[48]

The issues paper questioned whether settlement of controlled load energy against the NSLP would change the cost for retailers of purchasing that energy on behalf of their controlled load customers. We also noted that AEMO's Controlled Load Profile may have influenced hedging for the DMO 7 period while it was the official method for settlement, noting the stark differences in load shapes between NSW NSLPs and controlled load profiles.

Further, we recognised that decisions around the controlled load methodology may be influenced by decisions regarding the general use load profile methodology outlined above, changing market dynamics including increasing interval meter penetration and distribution networks adapting the management of controlled load.

Noting the above issues, the paper presented 3 options for simulating NSW controlled load profiles that were being considered:

- Option 1: Use the historical Controlled Load Profile to forecast the load shape in NSW
- Option 2: Blend historical controlled load data with the NSLP
- Option 3: Use the wholesale energy cost for residential flat rate customers, if interval meter data is adopted for the general consumption profiles.

The issues paper detailed the merits and disadvantages for each of the above options. Option 1 had the merit of closely resembling actual controlled load demand but had the disadvantage of not reflecting the new method of settling controlled load against the NSLP. Option 2 had the merit of reflecting settlement but the disadvantages of not reflecting actual controlled load demand and requiring estimation of controlled load accumulation meter volume. The paper stated that an advantage of option 3 was it may better align with how retailers consider interval meter controlled load customers, while having the disadvantage of excluding controlled load customers with accumulation meters.

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47 This followed a request from the Federal Minister for Climate and Energy, on behalf of the Energy Minister Sub Group that AEMO amend its metrology procedure to remove the requirement to maintain the sample profile, reducing associated costs.

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

5.1.3 South Australian wholesale methodology

Due to low contract market liquidity levels in South Australia, we have collected confidential contract market data from market participants in the region since DMO 5. We use this data to assess whether ASX data in isolation provides an accurate reflection of the hedging costs a retailer faces in the South Australia region. The issues paper noted our intention to continue collection of confidential contract market data in South Australia. We have since collected 2 tranches of over-the-counter (OTC) contracts covering the DMO 7 period.

We also sought feedback on repeating modelling from DMO 6 to produce a long-run marginal cost (LRMC) estimate to use as another comparative data point for wholesale costs in South Australia, along with any other methodologies the AER could investigate to benchmark wholesale cost forecasts in South Australia.

5.1.4 Inputs into wholesale modelling

The issues paper sought feedback on whether fixed inputs for fuel costs and outage rates in the wholesale model should be replaced by higher and lower cost scenarios. We chose to consult on this as a stakeholder expressed concern in submissions for previous DMO determinations that the wholesale model was not adequately reflecting variability in spot prices below $300/MWh.

The issues paper acknowledged that additional variation in fuel inputs could potentially improve the wholesale cost model's accuracy by better reflecting observed spot price volatility below $300/MWh, provided that any additional inputs were accurate. We noted that any additional inputs would need to reflect both high and low cost scenarios, although these would not necessarily need to be weighted equally.

The issues paper also noted that any additional variations in the wholesale modelling inputs should be based on objective data sources, while any improved forecasting accuracy would need to outweigh any additional complexity or subjectivity introduced into the modelling process.

5.1.5 Other wholesale cost issues

The issues paper noted our intention to keep all other aspects of the wholesale cost methodology consistent, including:

- 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 relevant to the DMO period
- 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.

5.2 Stakeholder views

5.2.1 Load profile assumptions

Net System Load Profile and interval meter data

Five retailers supported option 2 – using one year of NSLP data blended with interval meter data. Reasoning included that this approach would capture the different usage profiles of both accumulation and interval meter customers, better reflect retailers' hedging practices and maintain consistency in the wholesale cost methodology.[49]

AGL noted that the deployment of interval meters has not progressed far enough to warrant only using interval meter data. Additionally, it considered the NSLP following AEMO's second adjustment to be a reliable data source and that the third adjustment would not materially impact the data. It also considered that as NSLP volumes decline over time, any future issues with the NSLP data would be less material when blended with the significantly larger interval meter dataset.[50]

In contrast, EnergyAustralia and Shell Energy supported option 1 – using interval meter data only. They considered it would set a consistent approach to load profiles in future DMO determinations because the underlying methodology would no longer be impacted by changes in NSLP data.[51] EnergyAustralia noted its support was contingent on no adjustments being made to the underlying data and recognised this approach would not fully capture customers on accumulation meters.

Energy Locals did not support either option because both were based on excluding solar exports from the interval meter dataset, but it noted a preference for blending NSLP and interval meter data because the NSLP data includes solar exports. However, it considered interval meter data to be more reliable and accurate than the NSLP.[52]

Ausgrid did not explicitly support either option but noted support for a consistent approach to load profiles across all DMO regions and considered there to be merits in using at least 2 years of historical data.[53]

Some retailers re-emphasised their support for making interval meter data publicly available.[54] This sentiment was also shared during retailer workshops, where some retailers noted 5-minute data disaggregated by customer type and DMO region would be useful.

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49 ENGIE, Submission to DMO 7 issues paper, 8 November 2024, p. 3; AGL, Submission to DMO 7 issues paper, 12 November 2024, pp. 2–3; Alinta Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 3; Origin Energy, Submission to DMO 7 issues paper, 16 November 2024, p. 3; Red Energy and Lumo Energy, Submission to DMO 7 issues paper, 18 November 2024, pp. 3–4.

50 AGL, Submission to DMO 7 issues paper, 12 November 2024, pp. 2–3.

51 EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, p. 5; Shell Energy, Submission to DMO 7 issues paper, 15 November 2024, pp. 2–3.

52 Energy Locals, Submission to DMO 7 issues paper, 8 November 2024, pp. 1–2.

53 Ausgrid, Submission to DMO 7 issues paper, 8 November 2024, p. 1.

54 ENGIE, Submission to DMO 7 issues paper, 8 November 2024, p. 3; Shell Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 3.

Retailers' views on developing separate profiles for residential and small business customers were mixed. Alinta Energy, ENGIE and Shell Energy supported developing separate profiles, noting this would represent the different usage characteristics of these customer types.[55] EnergyAustralia did not have a strong view but noted a preference to maintain regulatory consistency with a single profile.[56] AGL considered this issue warranted further consideration and noted it is not possible to distinguish these profiles for accumulation meter customers.[57]

Consumer advocacy groups did not provide comments on options to simulate the load profiles.

Solar PV exports and hedging costs

Small to medium-sized retailers generally disagreed with the position to exclude solar exports from the interval meter dataset used to simulate the load profiles.[58] They noted that many retailers hedge against their net load and excluding solar exports would underestimate the volatility and hedging costs retailers face in practice. EnergyAustralia acknowledged that excluding solar exports would be the purist approach to simulating load profiles but considered this overlooks the complexities and hedging costs retailers face.[59]

Additionally, retailers considered that observable costs arising from solar exports during periods of net generation coinciding with negative spot prices should be reflected in the DMO. ENGIE and Shell Energy stated that this cost exposure could not be effectively managed through adjustments to feed-in tariffs paid.[60] Red Energy and Lumo Energy noted other strategies to manage this exposure could involve revised contracts with generators, changing the composition of its customer base or investing in other forms of generation, but these strategies are increasingly impacted by the prevalence of negative prices.[61]

Alinta Energy and ENGIE supported accounting for an additional hedging cost arising from solar exports, because exports have a direct impact on a prudent retailer's load shape and approach to hedging. [62] Alinta Energy supported the hedging adjustment approach proposed in the issues paper. AGL considered solar export hedging costs and the cost exposure associated with exporting to negative price intervals could be addressed by moving to the 95th percentile estimate of modelled outcomes because it would reflect uncertainties and risks faced by retailers.[63]

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55 Alinta Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 3; ENGIE, Submission to DMO 7 issues paper, 8 November 2024, p. 3; Shell Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 3.

56 EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, p. 5.

57 AGL, Submission to DMO 7 issues paper, 12 November 2024, p. 3.

58 Shell Energy, Submission to DMO 7 issues paper, 15 November 2024, pp. 3–4; Energy Locals, Submission to DMO 7 issues paper, 8 November 2024, p. 3; Red Energy and Lumo Energy, Submission to DMO 7 issues paper, 18 November 2024, pp. 2–3.

59 EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, p. 6.

60 Shell Energy, Submission to DMO 7 issues paper, 15 November 2024, pp. 3–4; ENGIE, Submission to DMO 7 issues paper, 8 November 2024, pp. 3–4.

61 Red Energy and Lumo Energy, Submission to DMO 7 issues paper, 18 November 2024, p. 3.

62 Alinta Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 4; ENGIE, Submission to DMO 7 issues paper, 8 November 2024, pp. 3–4.

63 AGL, Submission to DMO 7 issues paper, 12 November 2024, p. 5.

Consumer advocacy groups supported continuing to exclude exports from the load profiles on the basis the DMO is a default price for customer consumption. They did not support including an additional solar hedging cost in the DMO because it would risk fully compensating retailers for costs that may be mitigated in practice.[64]

Separately, SACOSS questioned how outcomes of the AER's customer export curtailment value (CECV) methodology reconciles with South Australian consumers facing higher wholesale costs because of increasing rooftop solar generation.[65]

5.2.2 Controlled Load Profile (NSW)

Origin Energy supported using AEMO's most recent sample Controlled Load Profile (option 1). It considered option 1 would be a satisfactory interim measure because any recent shift in the shape of controlled load demand in NSW is unlikely to have been significant.[66]

The joint submission from the Justice and Equity Centre (JEC), SACOSS and Australian Council of Social Service (ACOSS) expressed concern that the historical data used in option 1 would not reflect innovations in controlled load that provided opportunities for more active and dynamic management by retailers.[67] Similarly, Ausgrid noted that implementation of controlled load shifting capability within the network was likely to cause a significant difference in the shape of interval meter controlled load from the historical Controlled Load Profile's shape (which is based only on accumulation meters) in the near future.[68]

Most stakeholders expressed support for blending the historical Controlled Load Profile with the NSLP (option 2).[69] A common rationale among submissions that supported option 2 was that the NSW Controlled Load Profile remained relevant to retailer hedging strategies – as such, option 2 would reflect both a prudent retailer's hedging strategy and the new basis for settlement against the NSLP. Other submissions also considered it would be consistent with the blending of the NSLP with interval meter data, which was their recommended approach for the general use load profile (see section 5.1.1).[70] Some retailers characterised option 2 as an acceptable interim measure but did not advocate for its use in future determinations.[71]

EnergyAustralia expressed a preference for using the WEC for residential flat rate customers, if interval meter data were adopted (option 3), as this would avoid the approximations involved in using either the Controlled Load Profile or Controlled Load Profile/NSLP blend.[72] Red Energy and Lumo Energy expressed concern that option 3 would

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64 JEC/SACOSS/ACOSS, Submission to DMO 7 issues paper, 11 November 2024, pp. 4–5.

65 SACOSS, Submission to DMO 7 issues paper, 14 November 2024, p. 15.

66 Origin Energy, Submission to DMO 7 issues paper, 16 November 2024, p. 3.

67 JEC/SACOSS/ACOSS, Submission to DMO 7 issues paper, 11 November 2024, p. 4.

68 Ausgrid, Submission to DMO 7 issues paper, 8 November 2024, pp. 1–2.

69 ENGIE, Submission to DMO 7 issues paper, 8 November 2024, p. 3; AGL, Submission to DMO 7 issues paper, 12 November 2024, pp. 3–4; Alinta Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 3; Shell Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 3; Red Energy and Lumo Energy, Submission to DMO 7 issues paper, 18 November 2024, p. 4.

70 Alinta Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 3.

71 Shell Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 3.

72 EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, pp. 5–6.

not include controlled load customers with an accumulation meter and was unlikely to reflect market conditions.[73]

Energy Locals requested actual controlled load data be used but did not express support for any of the options presented.[74]

Multiple retailers noted in confidential submissions that hedging of controlled load was independent of AEMO's settlement approach.

5.2.3 South Australian wholesale methodology

Submissions received from retailers and SACOSS were generally supportive of continuing OTC data collection and analysis to ensure ASX data is reflects hedging costs a retailer may face.[75]

Energy Locals further noted the current methodology is the fairest way to benchmark wholesale costs retailers actually pay for, despite low volumes traded on the ASX.[76] Origin Energy added that beyond serving as a benchmark, if material misalignment in ASX and OTC trade prices is observed, this could indicate a need to consider alternative data sources to benchmark costs in South Australia. Additionally, Origin Energy noted the importance of using publicly available data that retailers typically rely on to inform their hedging related decisions.[77]

EnergyAustralia, while still supporting the current methodology, suggested considering the use of broker curves in response to alternative methodologies sought in the issues paper. It noted that broker curves take into account OTC activity as well as inter-regional trades, which could be more reflective of the current contract market in South Australia.[78]

Shell Energy submitted that the OTC data collection imposes unnecessary burden on participants and considered this information to already be available to the AER under its wholesale market monitoring function (separate from the DMO).[79]

The South Australian Business Chamber noted the AER should investigate and address the impact of wholesale market volatility and low liquidity on hedging practices of generators and retailers.[80] SACOSS also raised concerns about the impact of market volatility, low liquidity and retailers' hedging practices on increasing wholesale prices in South Australia's energy market. It considered high solar PV penetration in the region has not led to reduced wholesale costs for consumers. SACOSS advocated for market interventions to improve

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73 Red Energy and Lumo Energy, Submission to DMO 7 issues paper, 18 November 2024, p. 4.

74 Energy Locals, Submission to DMO 7 issues paper, 8 November 2024, p. 2.

75 ENGIE, Submission to DMO 7 issues paper, 8 November 2024, p. 4; Energy Locals, Submission to DMO 7 issues paper, 8 November 2024, p. 4; AGL, Submission to DMO 7 issues paper, 12 November 2024, p. 5; Origin Energy, Submission to DMO 7 issues paper, 16 November 2024, p. 6; Alinta Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 4.

76 Energy Locals, Submission to DMO 7 issues paper, 8 November 2024, p. 4.

77 Origin Energy, Submission to DMO 7 issues paper, 16 November 2024, p. 6.

78 EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, p. 7.

79 Shell Energy, Submission to DMO 7 issues paper, 15 November 2024, pp. 4–5.

80 South Australian Business Chamber, Submission to DMO 7 issues paper, 15 November 2024, p. 1.

liquidity and transparency, supporting ACCC recommendations for timely listing of new hedging products and government-backed renewable energy and storage projects.[81]

LRMC analysis

Retailers had mixed views on repeating the LRMC analysis. Some supported repeating the LRMC analysis as a comparative data point against the current wholesale cost methodology, whereas others questioned the value of the LRMC estimates.

ENGIE and EnergyAustralia supported the use of multiple data points that may provide further insight into cost trends faced by retailers in the South Australian market.[82]

Further to supporting the repeat of the analysis, AGL considered the greenfield approach a better approach for consideration of wholesale costs because it considers interconnectivity across regions. AGL also recommended including capital costs for assets in other regions that provide energy through interconnection.[83]

Shell Energy supported conducting the LRMC analysis if it is based on generation that would assist overall risk management for retailers with residential customers (noting gas generation or a portfolio of wind, solar and batteries) across the top 10% of events with both high demand and low wind scenario factors.[84]

Other retailers questioned the usefulness of the estimates. Energy Locals and Origin Energy considered it difficult to hedge an LRMC estimate and that the lower WEC results are not reflective of actual retailer costs.[85] Alinta Energy questioned the value of LRMC estimates lower than the WEC and how this would support competition and liquidity in the region's electricity market in the long term.[86]

SACOSS did not submit a strong view on the methodology but encouraged the AER to obtain the most relevant data required to determine a reasonable and prudent wholesale price for the DMO to support a fairer system that would benefit energy consumers.[87]

5.2.4 Inputs into wholesale modelling

Only retailers commented on inputs into wholesale modelling in submissions. While expressing support for the current modelling approach, AGL suggested that returning to the 95th percentile of modelled wholesale cost outcomes may help to address any uncertainty in the existing framework.[88]

81 SACOSS, Submission to DMO 7 issues paper, 14 November 2024, pp. 12–14.

82 ENGIE, Submission to DMO 7 issues paper, 8 November 2024, p. 4; EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, p. 7.

83 AGL, Submission to DMO 7 issues paper, 12 November 2024, p. 5.

84 Shell Energy, Submission to DMO 7 issues paper, 15 November 2024, pp. 4–5.

85 Energy Locals, Submission to DMO 7 issues paper, 8 November 2024, p. 4; Origin Energy, Submission to DMO 7 issues paper, 16 November 2024, p. 6.

86 Alinta Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 4.

87 SACOSS, Submission to DMO 7 issues paper, 14 November 2024, pp. 14, 25.

88 AGL, Submission to DMO 7 issues paper, 12 November 2024, p. 5.

EnergyAustralia did not adopt an explicit position but expressed uncertainty as to whether introducing additional complexity to the modelling process would improve outcomes.[89] It also noted that the cost-based model does not fully capture competitive tension or real-world volatility.

Origin Energy recommended modelling both high and low fuel price scenarios and varying levels of outage.[90] Origin Energy raised concerns that fixed inputs are driving a lack of variability in modelled spot prices below $300/MWh. Additionally, it considered underestimating the variability of spot prices may lead to an unrealistic simulated hedging strategy.

5.2.5 Other wholesale cost issues

75th versus 95th percentile

Retailers recommended the AER revert to using the 95th percentile of modelled cost outcomes because the 75th percentile does not reflect spot market volatility and actual costs faced by retailers.[91] The Australian Energy Council (AEC) and ENGIE recommended that the AER test whether the 75th percentile estimate was appropriate by assessing wholesale costs included in the DMO against actual spot prices.[92]

AGL considered that changes being considered to the wholesale cost methodology such as the hedging cost for solar exports and changes to modelling inputs could be addressed by reverting to the 95th percentile, which would more appropriately reflect the risks faced by retailers.[93]

Length of the book build period

Origin Energy was the only stakeholder to provide feedback on the book build period, stating it supported the existing book build process that occurs over a 2 to 3-year period and agreed pricing stability is important for customers.[94]

ASX options and other wholesale cost modelling assumptions

Origin Energy agreed that known AEMO and AEMC compensation costs should be passed through the wholesale component of the DMO.[95]

We received no comments on our approach to other wholesale cost modelling assumptions, including our treatment of ASX options, AEMO fees, AEMO prudential requirements and unaccounted for energy.

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89 EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, p. 7.

90 Origin Energy, Submission to DMO 7 issues paper, 16 November 2024, pp. 4–5.

91 ENGIE, Submission to DMO 7 issues paper, 8 November 2024, p. 4; EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, p. 2; AGL, Submission to DMO 7 issues paper, 12 November 2024, p. 5; Origin Energy, Submission to DMO 7 issues paper, 16 November 2024, p. 6; Alinta Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 1.

92 AEC, Submission to DMO 7 issues paper, 13 November 2024, p. 2; ENGIE, Submission to DMO 7 issues paper, 8 November 2024, p. 4.

93 AGL, Submission to DMO 7 issues paper, 12 November 2024, p. 5.

94 Origin Energy, Submission to DMO 7 issues paper, 16 November 2024, p. 6.

95 Origin Energy, Submission to DMO 7 issues paper, 16 November 2024, p. 6.

Other responses received from stakeholders

Energy Consumers Australia (ECA) and SACOSS noted that consumer advocates do not have access to detailed data used to model wholesale costs, creating information asymmetry when providing input into DMO determinations. ECA also considered that the DMO methodology already takes into account higher wholesale costs faced by smaller retailers, and it is unlikely to benefit consumers if these higher costs result in higher DMO prices.[96]

EnergyAustralia requested the AER provide clarity on which aspects of the methodology are not actively under review, noting many changes to the methodology over the years and that the AER is yet to revert to a previous option despite continuing to consult on them.[97] Additionally, some retailers considered attempts to improve precision in wholesale cost modelling increases complexity and can lead to modelling outcomes not reflecting market outcomes in practice.[98]

EnergyAustralia considered the assumed cap payout each year in the wholesale cost methodology warrants further examination because a prudent retailer does not assume any particular year will yield a return on a cap contract.[99]

Shell Energy considered the Retailer Reliability Obligation (RRO) should be factored into the wholesale cost calculation.[100] It considered the RRO adds a premium to operating costs because retailers must over-hedge their positions and secure contracts earlier than usual.

5.3 Draft determination

5.3.1 Load profile assumptions

Net System Load Profile and interval meter data

For the DMO 7 draft determination we have decided to adopt option 2 – using one year of NSLP data (October 2023 to October 2024) blended with interval meter data to simulate the load profiles for all regions.

We consider this approach is a better reflection of market outcomes and the load shape a retailer would need to hedge against during the DMO 7 period. We agree with most stakeholder views that this approach best reflects customers on both accumulation and interval meters. Roughly half of small customers in DMO regions still have their energy usage reflected in the NSLP and some retailers continue to use NSLP data as an input into load forecasting and hedging strategies. Therefore, we consider it appropriate to continue using NSLP data for DMO 7.

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96 ECA, Submission to DMO 7 issues paper, 8 November 2024, pp. 3–4; SACOSS, Submission to DMO 7 issues paper, 14 November 2024, p. 12.

97 EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, p. 1.

98 EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, p. 2; Alinta Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 1; ENGIE, Submission to DMO 7 issues paper, 8 November 2024, p. 2.

99 EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, p. 8.

100 Shell Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 5.

We requested AEMO provide the interval meter dataset and have published this data for the first time as supporting information alongside the DMO 7 draft determination. The data has been provided in 30-minute intervals with both customer types aggregated, split by DMO region. NSLP data continues to be publicly available for stakeholder use. This provides transparency in a key input to our wholesale energy cost modelling, allowing stakeholders to consider inputs in more detail.

As described above, we were initially concerned about the impact of AEMO's third adjustment on the NSLP data and potential risks of using a shorter time series of one year. Through assessment of additional NSLP data published by AEMO, noting only 3 months of data is available since the third adjustment has occurred, we have observed similarities in overall volumes and only slight differences in the average time of day shape.[101] Therefore, we are satisfied using NSLP data from October 2023 to October 2024 would reasonably reflect market outcomes for the DMO 7 period. Further, our wholesale consultant assessed the one-year time series of data and considers there is suitable variability in the underlying data (in terms of variation in factors such as weather outcomes, regional demand and wind generation).[102]

Given our initial concerns about continued use of NSLP data and a shorter time series have not materialised, we are satisfied this option maintains consistency and longevity in the wholesale cost methodology. While we recognise using interval meter data only would likely establish a consistent approach for future determinations, as raised by some stakeholders, we still consider it important to capture accumulation meter customers because they represent a large proportion of all small customers. The blended load profile is created by adding the volumes of the interval meter data and accumulation data meter together without any adjustments being made to the data. This means, as more customers transition to interval meters, the shape of the load profile will naturally change without any methodological intervention, as the volume of NSLP data gradually diminishes. Under this approach, we will continue to capture both accumulation meter and interval meter customers, while reflecting the gradual progression towards almost 100% of customers having interval meters by the target date of 2030 set within the Accelerating smart meter deployment rule change.[103]

An additional benefit of this approach is that it allows us to revert to using 2 years of blended NSLP and interval meter data for the load profiles in DMO 8, as per our historical approach to use a time series over multiple years.

We have also decided to maintain a single profile for residential and small business customers. Customer profiles cannot be distinguished within the NSLP data and attempting to do so would introduce additional elements of estimation and uncertainty to the wholesale cost methodology.

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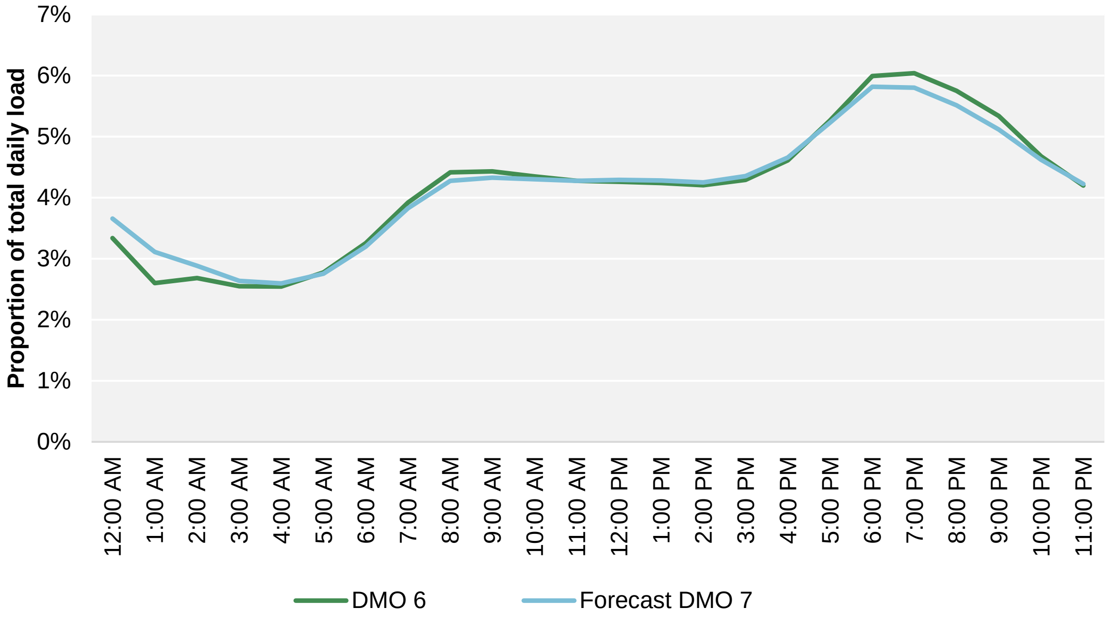
[101] ACIL Allen, *Default Market Offer 2025–26 Wholesale energy and environment cost estimates for DMO 7 Draft Determination*, 13 March 2025, p. 38.

[102] ACIL Allen, *Default Market Offer 2025–26 Wholesale energy and environment cost estimates for DMO 7 Draft Determination*, 13 March 2025, p. 19.

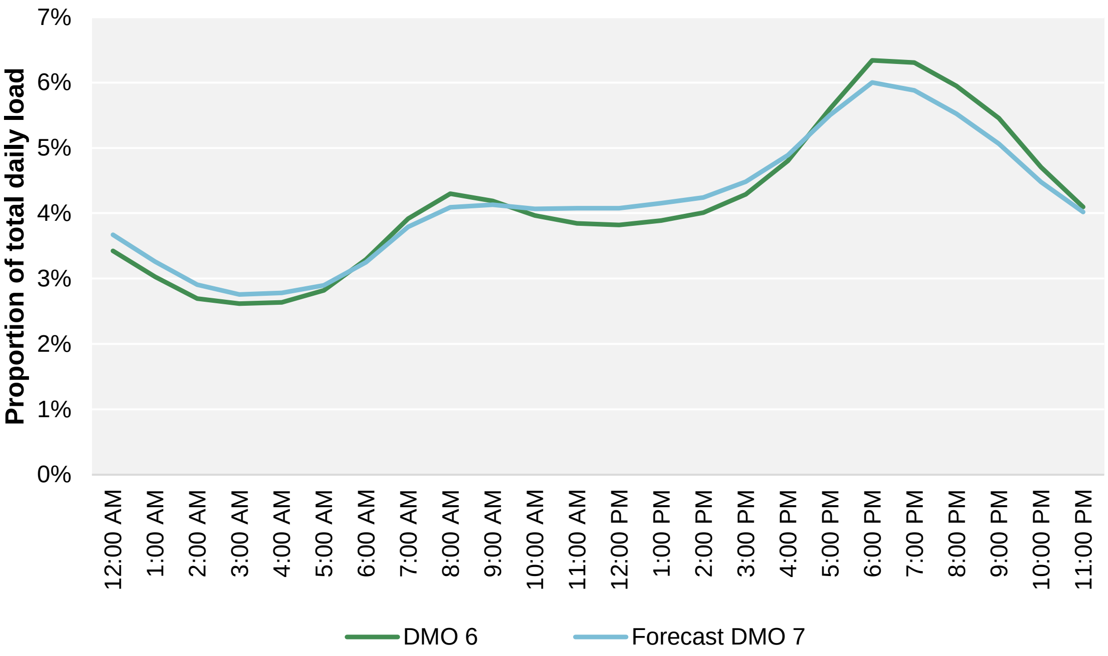
[103] AEMC, Accelerating smart meter deployment, Australian Energy Market Commission, 28 November 2024.

Figure 5.2 Average time of day load profile, Ausgrid



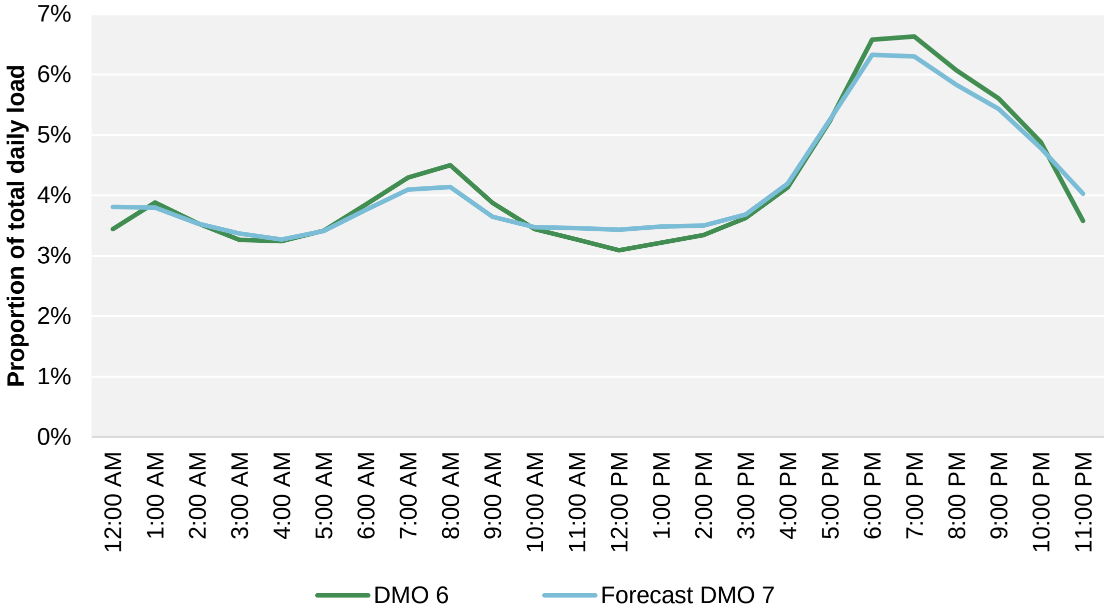
Note: Figures are based on data from October 2023 to October 2024.
Source: AER analysis using AEMO and ACIL Allen data.

Figure 5.3 Average time of day load profile, Endeavour Energy



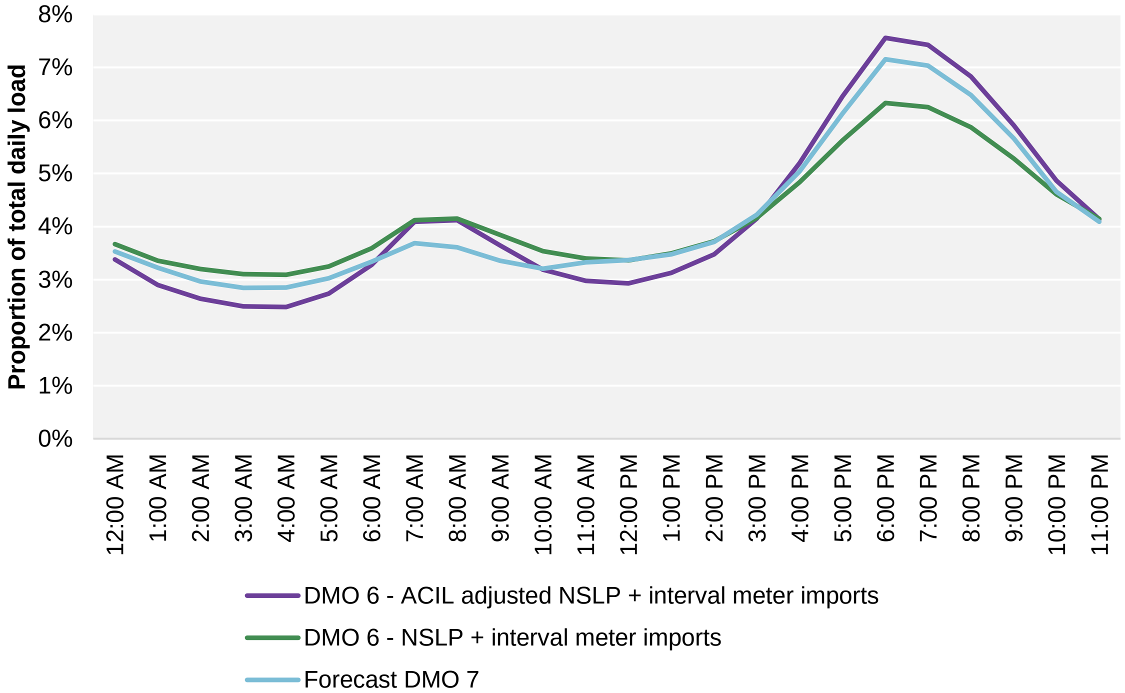
Note: Figures are based on data from October 2023 to October 2024.
Source: AER analysis using AEMO and ACIL Allen data.

Figure 5.4 Average time of day load profile, Essential Energy



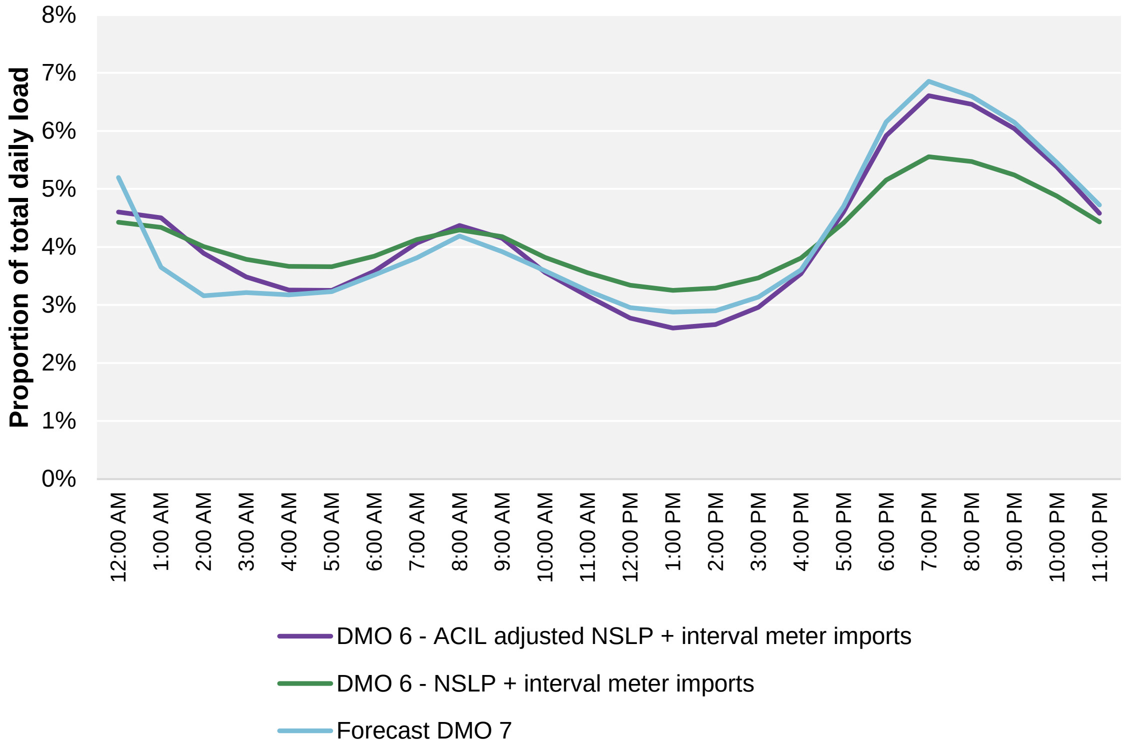
Note: Figures are based on data from October 2023 to October 2024.
Source: AER analysis using AEMO and ACIL Allen data.

Figure 5.5 Average time of day load profile, Energex



Note: Figures are based on data from October 2023 to October 2024.
Source: AER analysis using AEMO and ACIL Allen data.

Figure 5.6 Average time of day load profile, SA Power Networks



Note: Figures are based on data from October 2023 to October 2024.
Source: AER analysis using AEMO and ACIL Allen data.

Solar PV exports and hedging costs

Exclusion of solar exports from the interval meter dataset

We have maintained the methodology from DMO 6 that excludes small customer solar exports from the interval meter data used to simulate the load profiles. As the DMO is a price charged by retailers for customers' imports (or consumption), the wholesale cost methodology should be consistent. Therefore, it should be based on a retailers' hedging and spot market costs for consumption rather than the net of a customer's consumption and exports (which is how settlement occurs). While we acknowledge retailers are settled on the net load, which includes solar exports, we consider a load profile that includes solar exports overstates the costs of the daytime carve-out for retailers.

We also note retailers' views that excluding solar exports from the load profiles underestimates the volatility and hedging costs retailers face, however, we maintain that retailers continue to have alternative strategies available to flatten or manage their respective loads that cannot be accounted for within the wholesale cost methodology. To include solar exports and not account for available measures (such as adjustments to feed-in tariffs, hot water and electric vehicle charging orchestration, demand management programs and other solar soaking strategies), combined with other customer demand that is satisfied by customers exporting behind a Transmission Node Identifier, would result in a wholesale cost above what could be reasonably expected to occur. This would add additional costs to consumers. We acknowledge retailers' views on costs arising from small customer solar exports combined with negative wholesale spot prices, but consider this can be managed via the feed-in tariff offered to customers. Further, the Regulations state that we must disregard any amount a retailer pays in feed-in tariffs.[104]

The wholesale cost methodology also includes an increasing number of negative priced periods in its spot price modelling, which ensures this dynamic of the wholesale market is being captured within the DMO price through modelled hedging cost outcomes. In this way, increased frequency of negative price intervals within the modelling can increase WEC estimates due to higher hedging costs.

Hedging costs arising from solar exports

While we consider solar exports should not be included in the load profiles for wholesale forecasting for the reasons set out above, we do consider the presence of these exports changes the wholesale risk profile for retailers. Therefore, we have included a solar hedging adjustment based on the methodology set out in the issues paper. This involves comparing WEC estimates on a load profile that excludes exports, but from 2 modelled hedging strategies – one for a profile including solar exports and another excluding them. Overall, it seeks to reflect that a retailer’s hedging product mix could change when considering the presence of solar exports, and then approximate this difference within the wholesale cost methodology.

The outcomes of the adjustment are presented below for stakeholder consideration. Depending on modelling outcomes and contract prices in each region, this adjustment can either result in an increase or decrease in the WEC (Table 5.1).

Table 5.1 Impact of solar hedging adjustment on WEC estimates, $/MWh

DMO region	WEC with hedging strategy based on excluding solar exports (applied to profile excluding exports)	WEC with hedging strategy based on including solar exports (applied to profile excluding exports)	Hedging adjustment
Ausgrid	$159.58	$159.26	-$0.33
Endeavour Energy	$165.87	$165.56	-$0.31
Essential Energy	$163.63	$163.57	-$0.06
Energex	$149.53	$151.68	$2.15
SA Power Networks	$169.05	$168.84	-$0.21

Source: ACIL Allen

The hedging adjustment has resulted in very minor decreases in the WEC for all regions except for Energex, which increased by $2.15/MWh. The small impacts on the WEC reflect that there is only a small change to the hedging strategy when exports are included because the evening consumption peak where prices are often highest still needs to hedged for.

104 Regulations, s. 8A.

However, the modelled hedging strategy when exports are included has less base futures and more cap contracts.[105]

The larger impact in the Energex region in this draft determination is driven by the modelled retailer receiving less in base futures difference payments under the solar hedging adjustment scenario. This is a result of the current trade-weighted average base futures contract price being lower than modelled spot prices in Queensland. As there are less base futures in the hedging strategy, and therefore less base futures swap difference payments, the overall wholesale cost increases. In NSW and South Australia, current volume-weighted average base futures contract prices are at similar levels to modelled spot prices. Therefore, reduced weighting of base futures has minimal impact on the WEC overall in these regions. For all regions, while there is an increase in costs associated with cap contract premiums under the solar hedging adjustment, this is largely or completely offset by increases in cap contract payouts.

This solar hedging adjustment is dynamic due to fluctuating spot market modelling outcomes and variations in contract prices influencing the final adjustment value. Therefore, it is possible for the size and direction of this adjustment to dynamically shift between DMO determinations, and potentially between the draft and final determination for DMO 7.

We consider the fluctuating nature reflects complexities in hedging, but overall may not reflect costs faced by retailers in practice. We also acknowledge this approach introduces a change to the wholesale cost methodology and a relatively minor impact on WEC estimates. Therefore, we welcome stakeholder views on the extent to which this adjustment reflects market outcomes and whether it is appropriate to maintain this dynamic adjustment in the DMO 7 final determination. We also welcome views on alternative approaches, backed with detail and evidence on approaches to hedging, to capture hedging costs arising from customers' solar exports.

We do not consider it appropriate to address this issue by moving to the 95th percentile estimate of modelled wholesale cost outcomes. The percentile estimate selected reflects the variability of overall modelled market outcomes balanced between costs faced by retailers and prices paid by consumers. A higher percentile estimate could overstate costs faced by retailers. We consider it more appropriate and transparent to individually assess particular cost drivers, such as the impact of solar exports on retailers' hedging strategies, and how these could be reasonably reflected in the wholesale cost methodology.

We also acknowledge SACOSS's views about the AER's CECV methodology but do not consider there to be a direct relationship between this and the DMO methodology. From a wholesale perspective, the CECV methodology seeks to estimate dispatch costs in a given trading interval, which primarily reflect fuel and maintenance costs of centralised electricity generators. These dispatch costs are avoided as result of more solar exports, which differs from the DMO's wholesale cost methodology that seeks to reflect a prudent retailer's hedging costs for a given year.

105 ACIL Allen, *Default Market Offer 2025–26 Wholesale energy and environment cost estimates for DMO 7 Draft Determination*, 13 March 2025, p. 41.

5.3.2 Controlled Load Profile (NSW)

We have decided to maintain our current approach and use AEMO's historical Controlled Load Profile to simulate the controlled load profiles for NSW regions for the DMO 7 draft determination. Although we will consult further on this issue again for DMO 8, we consider that maintaining use of this dataset for DMO 7 provides consistency in the methodology between determinations and is preferable while AEMO's Controlled Load Profile still refers to data that is less than one year old, despite having been discontinued in September 2024.

The extent to which settlement of controlled load against the NSLP has changed the cost of hedging the associated energy is unclear, as was reflected in some confidential responses to the issues paper. Further, we agree with Origin Energy that the shape of controlled load in NSW is unlikely to have changed significantly since the discontinuation of AEMO's NSW Controlled Load Profiles.[106] To assist in this decision, we sought additional data from NSW distribution businesses on controlled load time of day consumption. While the data provided was based on interval meter controlled load, it showed relatively similar load profiles for controlled load to that of AEMO's Controlled Load Profile. Conversely, options 2 and 3 result in load profiles that reflect the shape of general use energy demand far more than controlled load energy demand, due to controlled load's smaller volume. This would result in morning and evening peaks, which dispatching controlled load typically avoids. For these reasons, we consider option 1 is the most reflective of market outcomes, based on the current data available.

While acknowledging that the majority of stakeholders supported option 2, we hold concerns that options 2 and 3 would overstate the cost of hedging controlled load, which has historically been less costly than general use energy due to the unique shape of its load profile and predictability around its time of dispatch. While option 2 may conceptually reflect the new method for settlement of accumulation meter controlled load against the NSLP, it would result in a shape that is the inverse of interval meter controlled load demand and the historical Controlled Load Profile, resulting in large cost increases.

Options 2 and 3 also fail to reflect the growing utility of interval meter controlled load. Engagement with all 3 NSW distribution businesses indicated interval meter controlled load is increasingly being flexibly dispatched by retailers to coincide with periods of negative prices and low demand (which would likely result in lower wholesale costs).[107] Interval meter controlled load also continues to be settled at its time of dispatch and is unimpacted by the change in settlement of accumulation meter controlled load. Further, we note interval meter controlled load currently makes up roughly half of controlled load National Metering Identifiers (NMI) in NSW. The number of interval meter controlled load NMIs will continue to grow as the smart meter rollout progresses, resulting in interval meter controlled load making up a greater portion of the controlled load energy that retailers hedge for.

We acknowledge that a departure from this methodology will be required in future DMO determinations, as the discontinued NSW Controlled Load Profiles become less recent and

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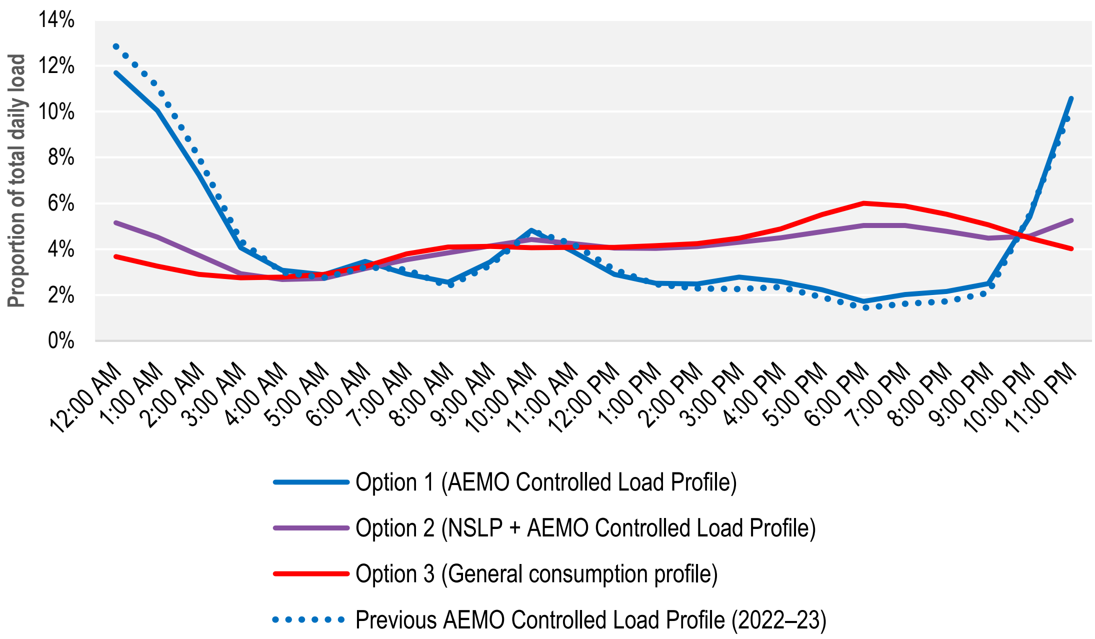
106 Origin Energy, Submission to DMO 7 issues paper, 16 November 2024, p. 3.

107 JEC/SACOSS/ACOSS, Submission to DMO 7 issues paper, 11 November 2024, p. 4.

other regions also discontinue their controlled load profiles.[108] Further, we consider the Controlled Load Profile used for the DMO should capture all residential customers with controlled load, regardless of meter type. We will work with both AEMO and distribution businesses to develop options on this aspect of the wholesale cost methodology and will consult with stakeholders as part of DMO 8.

Figure 5.7 illustrates the controlled load profiles resulting from each option, using Endeavour Energy as an example.

Figure 5.7 Options for simulating the controlled load profile, Endeavour Energy



Note: Figures are based on data from October 2023 to October 2024.
Source: AER analysis using AEMO and ACIL Allen data.

5.3.3 South Australian wholesale methodology

Maintaining our approach since DMO 5, we have continued to use ASX data for relevant base futures, cap contracts and premiums for call options for the DMO 7 draft determination. Due to our concerns on low market liquidity, we sought additional OTC contract market data from market participants for trades falling within the previous 3 years relevant to the DMO 7 period. This has enabled us to assess if the ASX data alone is a sufficient representation of costs faced by retailers.

Our analysis indicated OTC contracts continue to be broadly consistent with ASX traded contract prices and volumes (Figure 5.8). Based on this, we will continue to rely on publicly available data from the ASX for the wholesale cost methodology in South Australia, as supported by most retailers.

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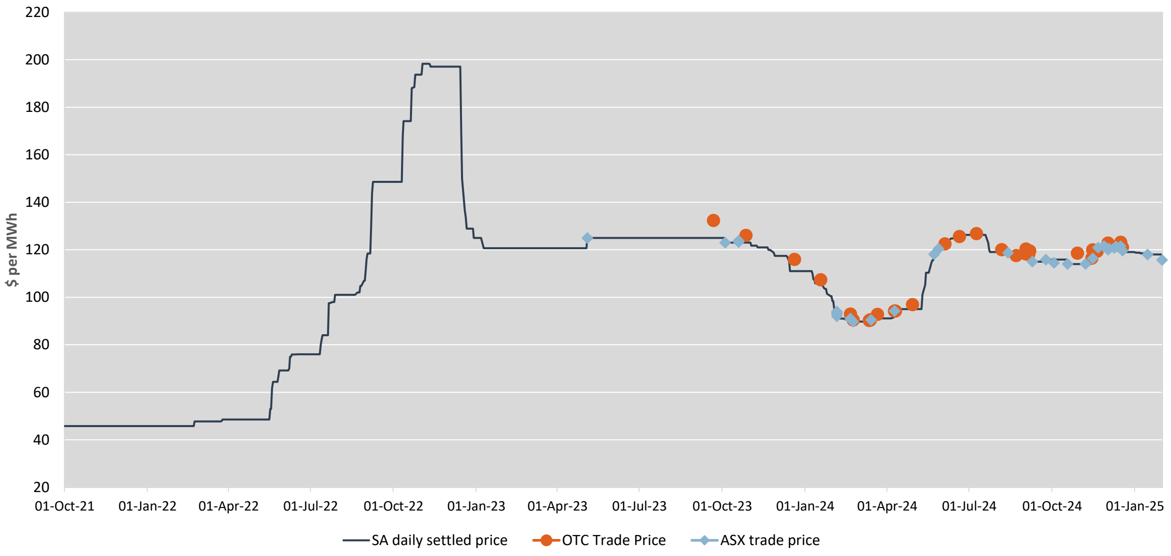
108 AEMO is currently undertaking expedited consultation regarding the removal of the SA Power Networks controlled load profile. Our focus on controlled load profiles in DMO 8 will also encompass how to best simulate a controlled load profile in South Australia.

We acknowledge comments from stakeholders that this data collection may not be required given our separate wholesale market monitoring functions. We are conscious of the reporting burden arising from information requests and seek to use existing data for DMO purposes when available and not make duplicative requests.

Figure 5.8 OTC and ASX trade price comparison, South Australia, Q3 2025



Source: AER analysis using ASX and OTC data.

Given our ongoing liquidity concerns in the South Australian contract market, we requested ACIL Allen repeat the LRMC estimate for South Australia. We use these results as a comparative data point to check against the outcome of our current wholesale cost methodology.

The AEMO 2024 Integrated System Plan 'Step Change' scenario data served as the basis for the LRMC analysis, which modelled both greenfield (modelling creates generation to meet supply at least cost) and brownfield (modelling based on current generation fleet) options. A WEC estimate was then generated by scaling down to South Australian load profiles.

The current DMO 7 WEC estimate sits between the greenfield and brownfield LRMC approaches, with greenfield having the highest estimate followed by the DMO 7 WEC estimate. The brownfield approach does not capture the up-front capital cost of the current generation fleet, so produced the lowest estimates. For comparison, DMO 6 LRMC estimates, which used the 2 load profile options used to create the 'midpoint', produced lower cost estimates for the unadjusted load profile, while for the adjusted load profile the LRMC estimates were higher (greenfield) and lower (brownfield), matching the current DMO 7 outcomes.

Although there have been changes to the underlying drivers of the LRMC estimates, as the results are similar in terms of the direction of cost changes from DMO 6 to 7, along with the current methodology sitting between the 2 estimates, it highlights that the LRMC remains a valid additional data source to consider wholesale costs for South Australia.

We acknowledge that EnergyAustralia continues to recommend broker curves in response to the questions of alternative methodologies that could be used to benchmark the wholesale cost in South Australia. However, we remain concerned these sources of data are unlikely to be transparent and representative of market conditions because of their proprietary and selective nature.

The LRMC analysis, in conjunction with OTC data, served as valid comparative data sources to assess wholesale costs in the region. We will retain our current methodology and continue to explore any other valid options given our concerns about low levels of liquidity in the South Australian contract market.

We acknowledge the South Australian Business Chamber and SACOSS's comments on investigating the impact of market volatility and low liquidity on hedging practices of retailers and wholesale costs in South Australia. We are aware of low liquidity levels in the region and collect confidential contract market information from market participants in South Australia to understand alternative hedging products used in the context of low liquidity levels. We have observed that prices across ASX and OTC markets are at similar levels, validating our methodology to use ASX data to determine wholesale costs for the DMO in South Australia. We have also observed retailers adopt a range of strategies for hedging in South Australia, including load-following hedges and internal transfers.

5.3.4 Inputs into wholesale modelling

We have decided to maintain use of fixed fuel price and outage rate inputs in the wholesale modelling for the DMO 7 draft determination. Noting support for this methodology change from stakeholders was limited, we consider varying fuel price inputs and outage rates would conflict with broader stakeholder feedback emphasising the importance of consistency and objectivity in the wholesale modelling. We are also concerned that adopting additional variability of modelling inputs would introduce subjectivity and complexity to the wholesale model. Overall, we are not convinced these disadvantages outweigh any material improvement in accuracy if additional inputs were included. We also do not consider there is a transparent and predictable method available for creation of any additionally varied inputs.

Our consultant has demonstrated that varying fuel price assumptions would not have a material impact on the composition of the hedging strategy or wholesale cost outcomes. To quantify the impact of fuel price variation, our consultant remodelled the DMO 6 WEC with additional higher and lower fuel price scenarios, which took into account our view that both high and low cost scenarios should be included, however did not necessarily need to be weighted equally. The 25th percentile of historical fuel price outcomes of the past 10 years was used to model the lower priced scenario, while the 75th percentile was used for the higher priced scenario. The additional inputs led to a 60% increase of higher fuel priced scenarios used for DMO 6, while lower priced scenarios only decreased by 30%. Despite being biased toward higher fuel costs, the inclusion of additional fuel price inputs did not materially impact the resulting WEC (Figure 5.9). While acknowledging the upside bias in historical fuel cost data, historical data may conflict the forward price curve in any given year, and specific fuel costs do differ amongst scheduled generation assets due to longer term fuel contracts and/or how much they are exposed to international fuel prices. Overall, we consider this highlights the difficulties of identifying objective or publicly available data to base a variation of fuel prices on.

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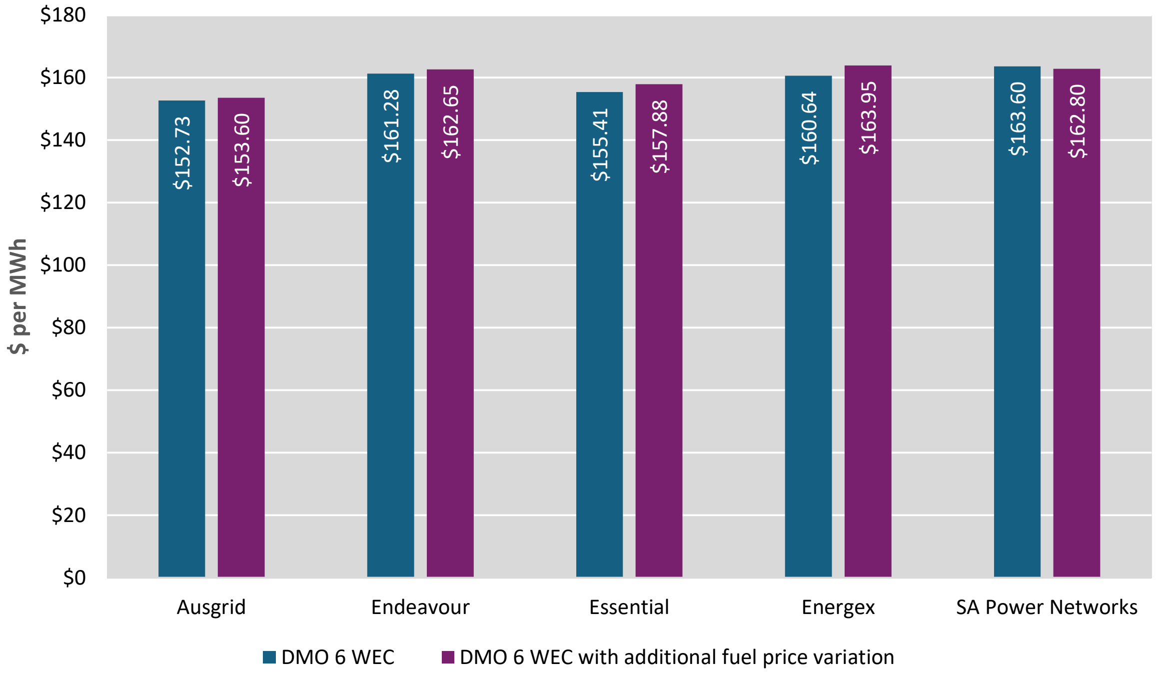
Figure 5.9 Impact of additional variation of fuel price inputs on DMO 6 WECs



Note: Energex and SA Power Networks' WECs were modelled based on the ACIL Allen adjusted load profile from the DMO 6 final determination, rather than the midpoint WEC used in the final DMO 6 prices. The midpoint WECs were based on the median of modelled 75th percentile results from the adjusted and unadjusted NSLPs; there is no specific simulation available to test how changes in the methodology may have impacted a midpoint WEC.
Source: ACIL Allen

With regard to varying the outage rate, we consider the current approach incorporates appropriate outage variability. Firstly, the model uses outage rates from AEMO's Integrated System Plan, which accounts for the aging coal generation fleet and incorporates the increasing outage rates observed in recent years. Secondly, instead of a single static outage scenario, the model generates 11 different sets of randomly generated outages to capture the potential variability in outage patterns and incorporates these into the wholesale modelling simulations. Lastly, the model also accounts for long-term outages, such as Callide C, ensuring that different levels of outage under the current market conditions are accurately reflected.

5.3.5 Other wholesale cost issues

We have made the following decisions on other wholesale cost issues for the DMO 7 draft determination.

75th versus 95th percentile

We have maintained our approach of using the 75th percentile of modelled wholesale price outcomes. We consider this strikes the right balance between retailers recovering efficient costs for providing their services and the allocation of risks to consumers. We do not consider a change to the 95th percentile should be adopted in response to other issues consulted on, such as hedging costs arising from solar exports and variability in modelling inputs. We consider it more appropriate to consider these aspects of the methodology individually rather than select a higher percentile estimate of modelled wholesale costs that would reflect nearly all potential market outcomes and could lead to an overstatement of wholesale costs.

Other aspects of the wholesale methodology

We have maintained our approach for the following aspects of our wholesale cost methodology. These aspects were either supported by stakeholders or received no responses.

- **Length of the book build period:** We will continue to use all available trades on the ASX relevant to the DMO 7 period. While hedging strategies will differ across retailers, we consider the current approach that smooths price movements in the DMO best captures all contract price movements for the relevant DMO 7 contracts.
- **ASX options:** Our treatment of options includes volume of base futures traded as a result of the exercise of base strip options at the trade-weighted strike price plus the trade-weighted average premium attached to all exercised and expired call options. Overall, we consider ASX options are a valuable indicator of the overall cost of energy, noting that retailers commonly use options as a hedging tool.
- **Treatment of compensation costs:** The DMO 7 draft determination reflects known compensation costs awarded by the AEMC since the DMO 6 final determination data cut-off date (3 May 2024). This includes compensation awarded to Origin Energy and EnergyAustralia Ecogen in September 2024 as a result of the June 2022 market events.[109]
- **AEMO fees:** We have maintained our approach to AEMO fees from DMO 6. To capture the fixed component of AEMO's fees, we adjusted the methodology in DMO 6 to include this additional cost as a fixed annual dollar per customer amount. For the DMO 7 draft determination this is $11.99. We have continued to capture the variable costs as directly expressed by AEMO, which we have multiplied by the individual small customer distribution usage amounts used within the DMO to produce an annual cost.
- **AEMO prudential requirements:** We have maintained our approach from DMO 6, where the winter months in ACIL Allen's modelling are set from April to August in line with AEMO's prudential requirements.
- **Unaccounted for energy:** We have maintained our approach to not make an allowance associated with unaccounted for energy. Limited data is available publicly to determine the materiality of these costs and we expect unaccounted for energy to be a very small percentage of total distribution losses.

Retailer reliability obligation

We acknowledge Shell Energy's submission but note that the RRO is already accommodated for within the modelled hedging strategy. When the RRO is triggered during

[109] See more information on compensation awarded from the June 2022 market events from the AEMC.

a DMO period, the modelled hedging strategy ensures there are sufficient qualifying contracts to meet RRO obligations.[110]

5.3.6 Other responses to stakeholder feedback

This section outlines our considerations and responses regarding issues raised in submissions that were not directly consulted on in the issues paper.

- **Information asymmetry:** We acknowledge statements from ECA and SACOSS that consumer advocates do not have access to the same depth of information when writing submissions as may be available to commercial stakeholders. Submissions from consumer advocacy groups are a vital aspect of the information we consider in each DMO determination. However, we acknowledge that engagement on technical aspects of the methodology from consumer groups is often limited. We are open to suggestions to improve our existing engagement approach such as our one-on-one meetings with consumer advocacy groups. We continue to engage with the AER's Customer Consultative Group forum for each DMO determination.
- **Aspects of the methodology not under review:** In response to EnergyAustralia's request for clarity around which aspects of the methodology are not under review, we refer to section 3.5 of the issues paper, which listed aspects of the methodology we did not propose to change for DMO 7. Both the issues paper and this draft determination note aspects of the methodology, such as Controlled Load Profiles, which we consider to be significantly impacted by ongoing market developments and will require ongoing consultation. However, we will also set out in the DMO 8 issues paper the parts of the methodology we do not intend to consult on.
- **Assumed cap payout:** We acknowledge EnergyAustralia's consideration that the cap payout should be reviewed because a prudent retailer would not expect to receive a cap payout in every year. We consider that this dynamic is already addressed in the wholesale model because not all modelled simulations include a cap payout large enough to offset the premium paid. However, this usually occurs at the 75th percentile WEC.

5.3.7 Wholesale energy costs

Wholesale energy costs are forecast to increase across all DMO regions and customer types between the DMO 6 and DMO 7 periods, except for flat rate customers in Energex.

This has been driven by increases in contract and spot market prices. In South Australia, the increase is also partly driven by a peakier load profile shape. The movements in base future and cap contract prices on an annualised and trade-weighted basis were:

- for NSW – an increase in base futures contract prices of $7.70/MWh and an increase in cap contract prices of $7.20/MWh
- for Queensland – an increase in base futures contract prices of $3.50/MWh and an increase in cap contract prices of $0.30/MWh

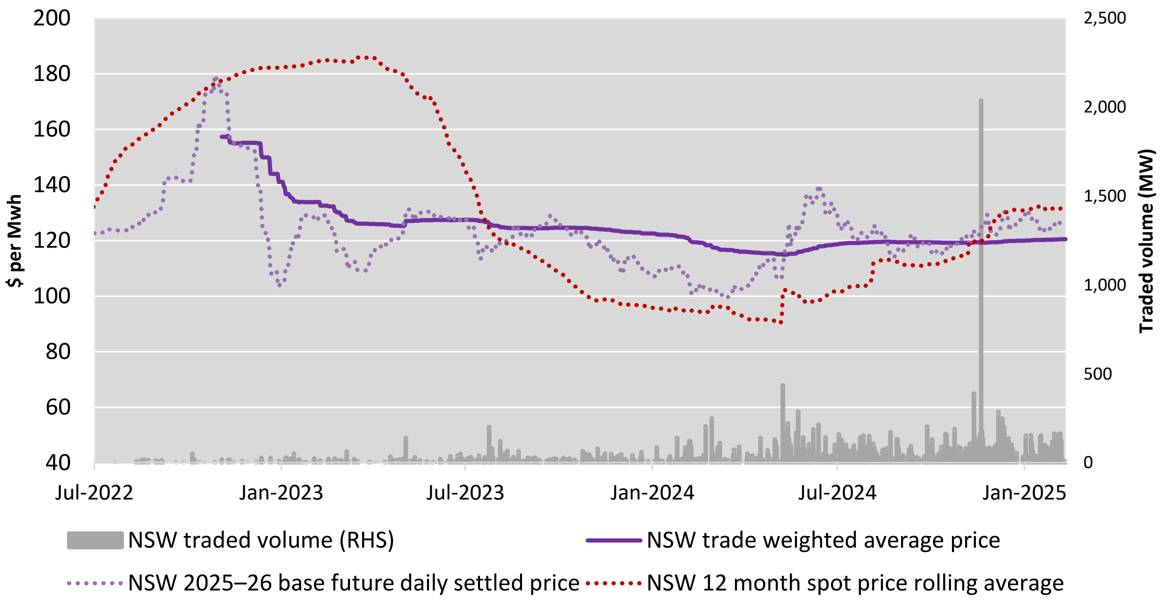
[110] ACIL Allen, *Default Market Offer 2025–26 Wholesale energy and environment cost estimates for DMO 7 Draft Determination*, 13 March 2025, pp. 29–30.

- for South Australia – an increase in base futures contract prices of $2.80/MWh and an increase in cap contract prices of $3.20/MWh.

Having moderated throughout 2023, contract prices increased in 2024, with particularly strong increases observed in May, coinciding with the market events that resulted in suspension of the NSW spot market. The summer of 2024–25 saw an above average number of high magnitude spot price spikes and several warnings of tight supply, which likely maintained the presence of a risk premium in contract prices and prevented them from falling meaningfully into 2025. Though cap premiums have experienced a substantial decline since the beginning of 2025, they remain elevated compared with historical averages.

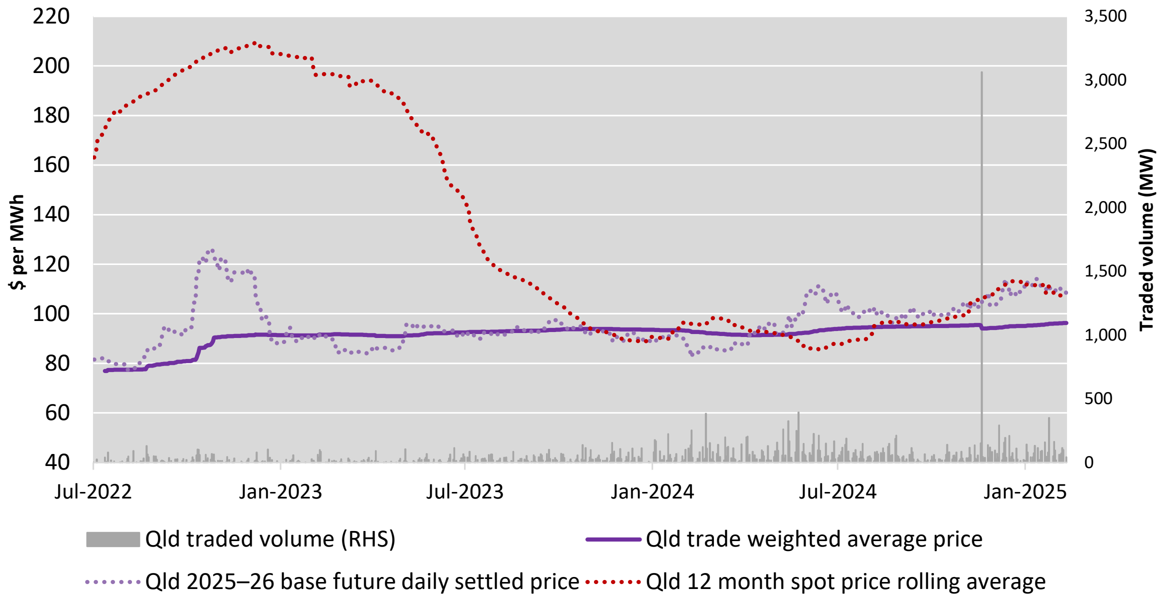
For most regions, the largest volume of trade was observed in the latter half of 2024 and early 2025. This resulted in the higher contract prices at this time having greater impact on trade-weighted average prices than the lower prices throughout 2023. Queensland was the only region to see significant traded volume during 2023, resulting in the lower prices at that time having greater impact on its trade-weighted average.

Figure 5.10 NSW base future daily settled price and trade-weighted average, 2025–26



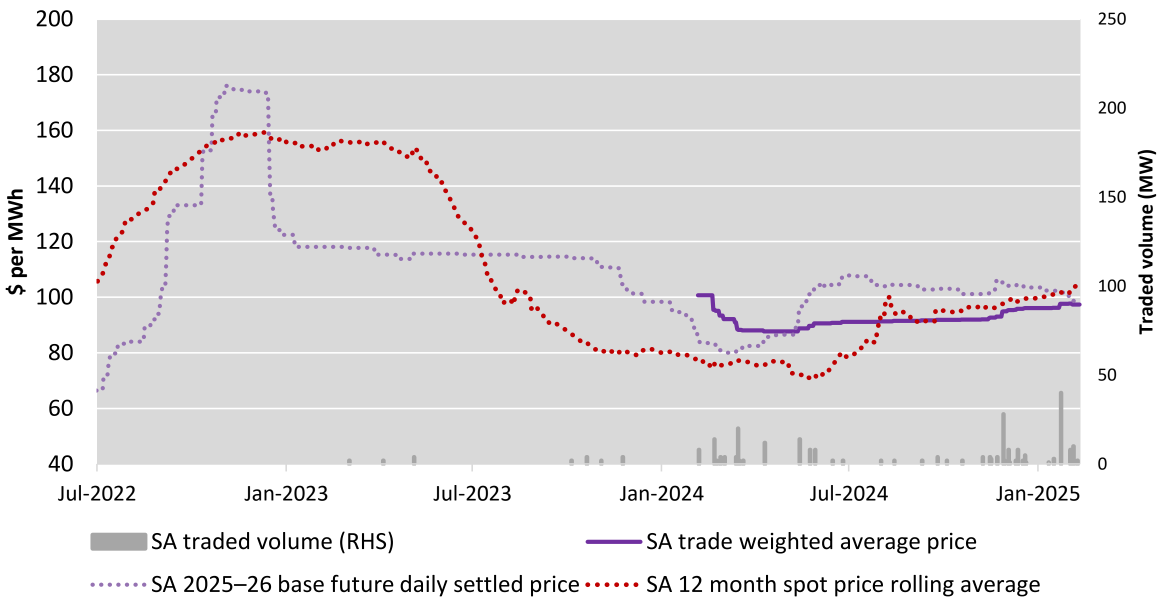
Note: The trade-weighted average price accounts for volumes traded in all 4 quarters of the DMO 2025–26 financial year.
Source: AER analysis using ASX, AEMO data.

Figure 5.11 Queensland base future daily settled price and trade-weighted average, 2025–26



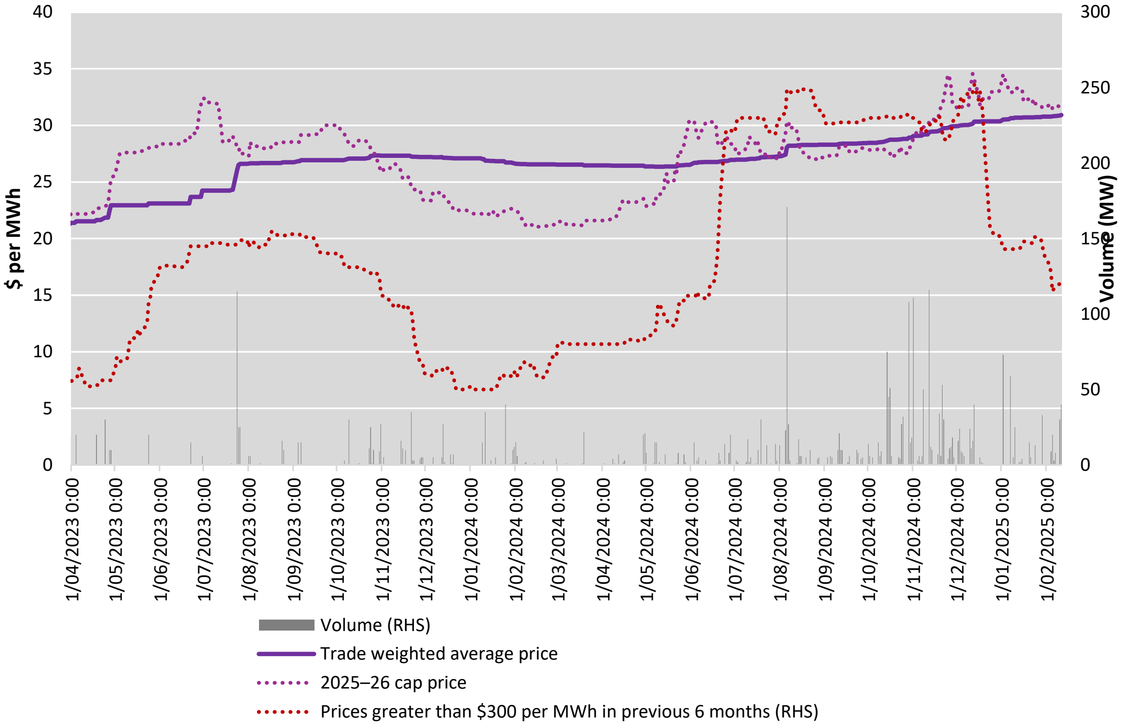
Note: The trade-weighted average price accounts for volumes traded in all 4 quarters of the DMO 2025–26 financial year.
Source: AER analysis using ASX, AEMO data.

Figure 5.12 South Australian base future daily settled price and trade-weighted average, 2025–26



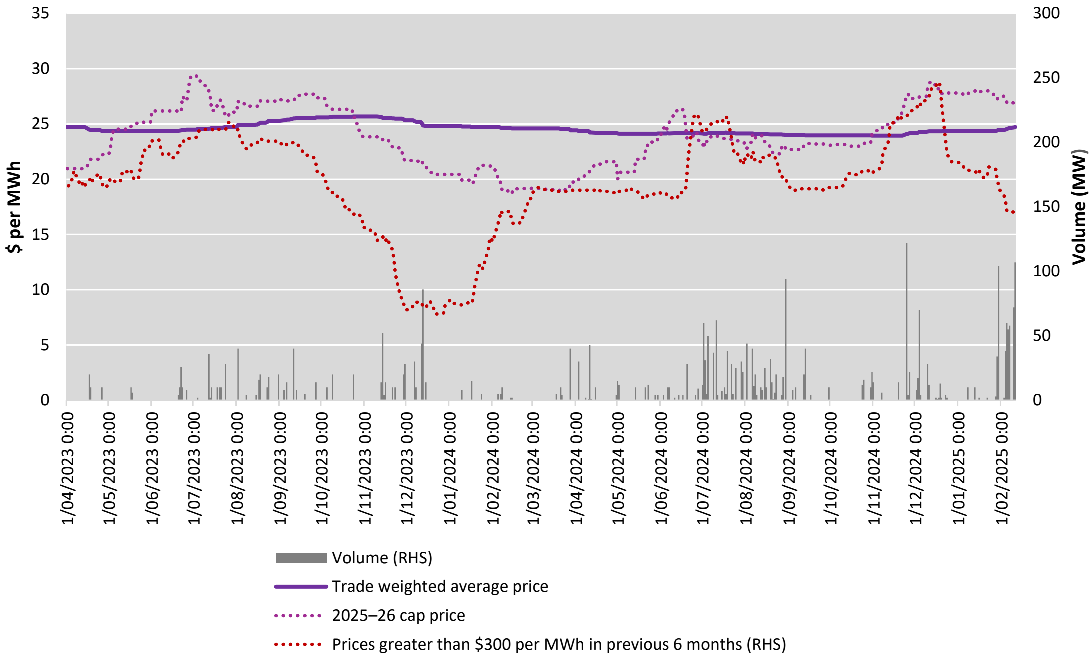
Note: The trade-weighted average price accounts for volumes traded in all 4 quarters of the DMO 2025–26 financial year. In the case of south Australia, a trade-weighted average price was not available until early 2024, because volume had not been traded for all quarters prior to that time.
Source: AER analysis using ASX, AEMO data.

Figure 5.13 NSW cap daily settled price and trade-weighted average, 2025–26



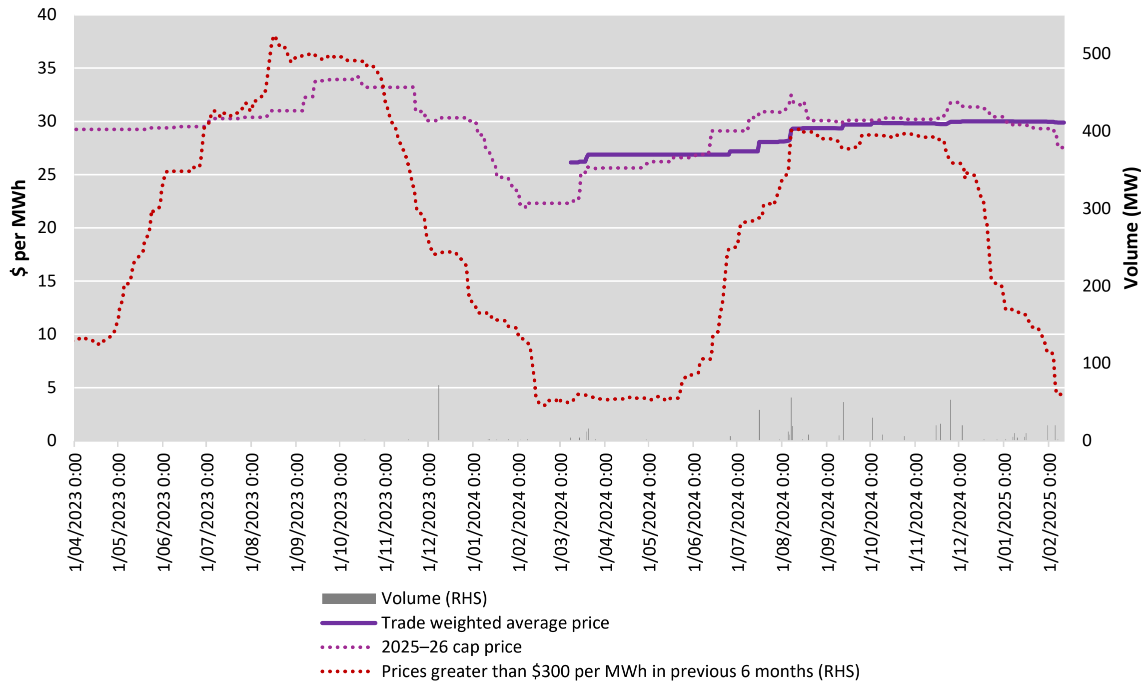
Note: The trade-weighted average price accounts for volumes traded in all 4 quarters of the DMO 2025–26 financial year.
Source: AER analysis using ASX, AEMO data.

Figure 5.14 Queensland cap daily settled price and trade-weighted average, 2025–26



Note: The trade-weighted average price accounts for volumes traded in all 4 quarters of the DMO 2025–26 financial year.
Source: AER analysis using ASX, AEMO data.

Figure 5.15 South Australian cap daily settled price and trade-weighted average, 2025–26



Note: The trade-weighted average price accounts for volumes traded in all 4 quarters of the DMO 2025–26 financial year. In the case of South Australia, a trade-weighted average price was not available until early 2024, because volume had not been traded for all quarters prior to that time.
Source: AER analysis using ASX, AEMO data.

If contract prices persist at current levels until the final determination, trade-weighted average prices will likely be higher again in NSW and Queensland when the DMO 7 final determination is released. At current prices, South Australian trade-weighted average prices would remain at similar levels to the draft determination.

Smaller components of the wholesale cost have remained stable since DMO 6. On a $/MWh basis, NSW regions saw increases of between 10 and 17 cents, driven by rising prudential costs. In Queensland, other wholesale costs rose by $1.34, driven by rising ancillary and prudential costs. In South Australia, other wholesale costs decreased by $2.99, driven by falling costs of directions for system security.

Table 5.2 Wholesale costs for 2025–26 DMO 7 draft determination, $/MWh (variable costs, excl. GST, nominal)

Distribution region	Customer type	2024–25 (final)	2025–26 (draft)	Change year-on-year
Ausgrid	Flat rate	$162.99	$169.94	4.3%
	CL 1	$106.85	$123.92	16.0%
	CL 2	$106.70	$122.17	14.5%

Distribution region	Customer type	2024–25 (final)	2025–26 (draft)	Change year-on-year
Endeavour Energy	Flat rate	$173.70	$178.32	2.7%
	CL 1	$108.20	$127.50	17.8%
	CL 2	$108.20	$127.50	17.8%
Essential Energy	Flat rate	$163.18	$171.76	5.3%
	CL 1	$104.52	$121.28	16.0%
	CL 2	$104.52	$121.28	16.0%
Energex	Flat rate	$164.97	$167.59	1.6%
	CL 1	$104.17	$113.33	8.8%
	CL 2	$112.60	$120.20	6.7%
SA Power Networks	Flat rate	$180.15	$199.36	10.7%
	CL 1	$114.46	$124.66	8.9%

Note: CL refers to controlled load.
Source: ACIL Allen.

6 Environmental costs

- For the DMO 7 draft determination we have retained our existing market-based approach to environmental cost forecasting.
- Environmental costs make up between 3% and 4% of the DMO 7 draft prices.
- Environmental costs have decreased since DMO 6 across all distribution regions, customer types and tariff structures by between 17% and 25%.

6.1 Issues paper

In our issues paper we proposed to maintain our market-based approach to calculating environmental costs, with updates for any new and amended schemes. We considered this approach would remain reasonable for DMO 7 and noted 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 Stakeholder views

Most stakeholder submissions to our issues paper did not raise issues with our established approach to calculate environmental costs. Only SACOSS's individual submission and the joint submission of JEC/SACOSS/ACOSS raised concerns about including environmental costs in the DMO cost stack.[111]

Both submissions called for reform of the DMO to exclude environmental costs because its inclusion could affect the electricity costs of vulnerable consumers. These submissions both suggested alternative means of accounting for environmental costs, such as the costs being incurred through government taxation, government revenue or industry.

SACOSS raised concerns about the inequitable impact the inclusion of environmental costs has on vulnerable consumers, particularly the non-energy services associated with energy costs.[112] SACOSS considered that energy consumers should not be required to pay the costs of retailers' compliance with environmental schemes within their energy bills. SACOSS argued there would be no incentive from industry to change its behaviour of procuring energy from renewable sources or improving energy efficiencies if environmental schemes are recovered by consumers.

In contrast, submissions from Origin Energy and Shell Energy supported our market-based approach to calculating environmental costs.[113]

111 SACOSS, Submission to DMO 7 issues paper, 14 November 2024, p. 19; JEC/SACOSS/ACOSS, Submission to DMO 7 issues paper, 11 November 2024, p. 11.

112 SACOSS, Submission to DMO 7 issues paper, 14 November 2024, p. 19.

113 Origin Energy, Submission to DMO 7 issues paper, 16 November 2024, p. 10; Shell Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 7.

6.3 Draft determination

Having considered stakeholder submissions and the available information on environmental costs, the DMO 7 draft determination retains our existing market-based approach to environmental cost forecasting.

We acknowledge the perspectives raised in the joint submission of JEC/SACOSS/ACOSS and the individual submission of SACOSS on the inclusion of environmental costs within the cost stack and note their commentary around our obligations to include environmental costs within the cost stack.[114] In setting the DMO price, we are required under the Regulations to determine the costs of complying with Commonwealth and state or territory laws for the supply of electricity for a region.[115] This means we are required to include environmental costs within the DMO price.

6.3.1 Environmental cost inputs

The environmental cost inputs for 2025–26 are shown in Table 6.1, together with inputs used for 2024–25 for comparison.

Reductions in environmental costs are largely due to lower Large-scale Renewable Energy Target (LRET) and Small-scale Renewable Energy Scheme (SRES) costs. LRET costs have decreased due to lower Large-scale Generation certificate prices.[116] SRES costs have decreased because retailers are required to surrender fewer small-scale technology certificates than in DMO 6.[117]

Table 6.1 Environmental costs for 2024–25 and 2025–26 (excl. GST, nominal)

DMO region	Tariff	2024–25 $/MWh	2025–26 $/MWh	Change year-on-year (%)
Ausgrid	Flat rate	$19.64	$16.30	-17.0%
	CL 1	$19.75	$16.39	-17.0%
	CL 2	$19.75	$16.39	-17.0%
Endeavour Energy	Flat rate	$19.81	$16.44	-17.0%
	CL 1	$19.81	$16.44	-17.0%
	CL 2	$19.81	$16.44	-17.0%
Essential Energy	Flat rate	$19.34	$16.05	-17.0%
	CL 1	$19.34	$16.05	-17.0%
	CL 2	$19.34	$16.05	-17.0%

114 JEC/SACOSS/ACOSS, Submission to DMO 7 issues paper, 11 November 2024, p. 11.

115 Regulations, s16(4)(c)(iii).

116 ACIL Allen, *Default Market Offer 2025–26 Wholesale energy and environment cost estimates for DMO 7 Draft Determination*, 13 March 2025, pp. 81–82.

117 CER, Small-scale technology percentage, Clean Energy Regulator, 13 February 2025.

DMO region	Tariff	2024–25 $/MWh	2025–26 $/MWh	Change year-on-year (%)
Energex	Flat rate	$16.53	$12.42	-24.9%
	CL 1	$16.53	$12.42	-24.9%
	CL 2	$16.53	$12.42	-24.9%
SA Power Networks	Flat rate	$22.16	$17.34	-21.8%
	CL 1	$22.16	$17.34	-21.8%

Note: CL refers to controlled load.
Source: ACIL Allen.

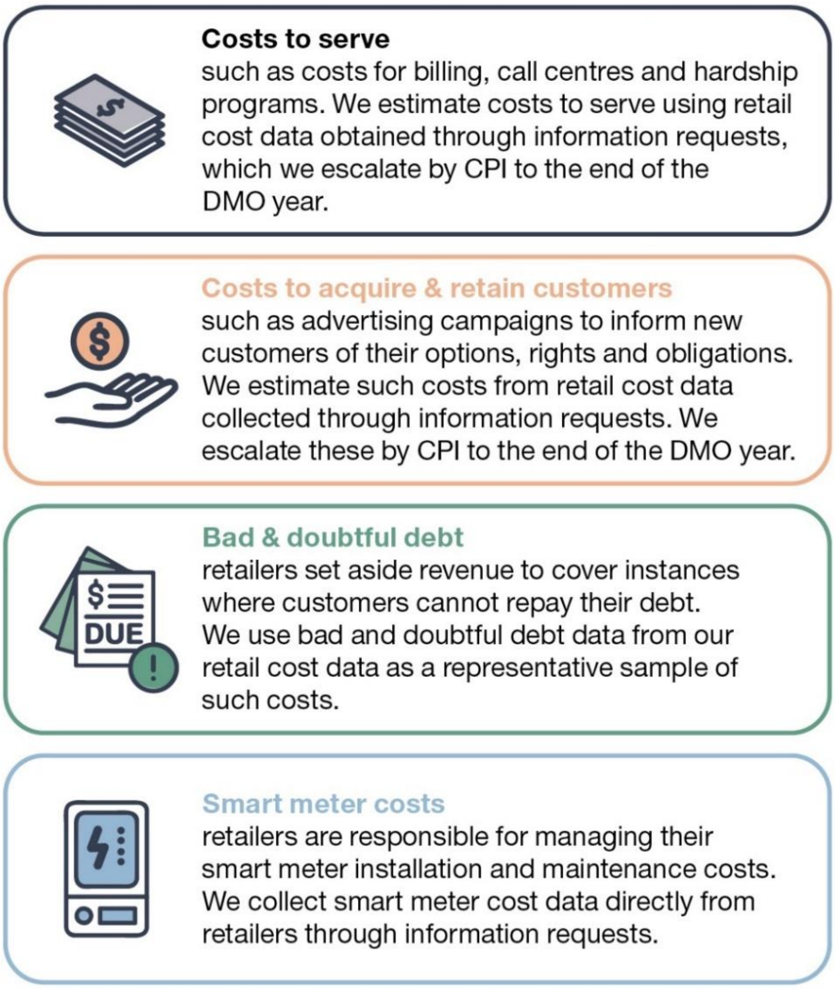
7 Retail costs

For the DMO 7 draft determination, we have:

- established a benchmark for retail and other costs and bad and doubtful debt using retail cost information obtained from retailers
- applied a customer-weighted average for retail and other costs, including costs to serve, costs to acquire and retain, and other costs
- applied a customer-weighted average cost for bad and doubtful debt
- based the smart meter allowance on actual installations, and included a cost of capital allowance to cover the projected shortfall in the smart meter allowance.

Retail costs represent between 7% and 16% of the DMO 7 draft prices, increasing by 20% to 41% since DMO 6.

Retail costs reflect a range of costs incurred by retailer, including:



Retail costs are set using a bottom-up ‘cost stack’ methodology. We consider this approach remains appropriate for the DMO 7 determination. It provides transparency by outlining the various retail costs individually and ensuring consistency with pricing between DMO regions.

For the DMO 7 draft determination, we:

- requested retail cost data to estimate retail and other costs and bad and doubtful debt, replacing data previously sought from the ACCC's Inquiry into the NEM reports. The retail cost dataset covers 99% of the small customer market.
- collected data from retailers selling to approximately 94% of small customers across all DMO regions on their rollout of smart meters.

All retail cost calculations, which are based on 2023–24 data, have been escalated by the inflation forecasted to occur to the end of the DMO 7 year.[118]

7.1 Issues paper

7.1.1 Retail and other costs

Retail and other costs include retailers' costs to serve, costs to acquire and retain customers, and other costs.

Since DMO 4, retail and other costs were informed by the ACCC's Inquiry into the NEM. The issues paper outlined that with the ACCC's inquiry concluding on 31 August 2025, we had initiated an independent process to collect retail cost information from a broader range of retailers, including smaller retailers.[119] Expanding this cohort of retailers enabled a more detailed and representative analysis of retailers' costs to serve and costs to acquire and retain.

Our issues paper sought stakeholder feedback on our methodology for estimating retail and other costs and whether alternative approaches should be considered.

7.1.2 Bad and doubtful debt

Bad and doubtful debts represent costs retailers incur when writing off unpaid bills. A retailer's debt is made up of:

- unbilled (accrued) revenue earnt but not yet billed
- customer debt earnt and billed
- an estimated provision for customer debt (based on a retailers' subjective assessment of expected non-payment).

For DMO 5 and 6, we obtained bad and doubtful debt data from the ACCC. In DMO 6, these costs ranged from $24 to $40 for residential customers and $42 to $65 for small business customers.

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118 RBA, February 2025 Statement on Monetary Policy, Table 3.1 Detailed forecast information, Reserve Bank of Australia. The RBA has forecasted 2.4% inflation in 2024–25 and 3.2% inflation for 2025–26. This amounts to 5.7% inflation.

119 Our retail cost dataset includes the same retailers that provided retail cost information to the ACCC for their Inquiry into the NEM December 2024 report. The additional retailers we have collected have at least 1,000 small customers across the DMO regions (NSW, SE Queensland and South Australia). The data provided relates to the 2023–24 year.

The DMO 7 issues paper sought stakeholder feedback on refining our process for calculating bad and doubtful debts.

7.1.3 Smart metering costs

Smart meter costs are the annual costs retailers incur for smart meters and include costs associated with installation, maintenance and IT. As smart meters are progressively installed in DMO regions, smart meter costs also increase across the DMO period, which results in a shortfall in the smart meter allowance in the DMO price. This shortfall in the smart meter allowance increases throughout the DMO period. We include a cost of capital allowance to cover the average shortfall in the smart meter costs across the DMO 7 period. This is calculated by projecting the number of installations that will have occurred at the midpoint of DMO 7 (31 December 2025). The midpoint of the DMO period is chosen to calculate the average shortfall because the shortfall will be smaller than this value and greater than this value for equal periods of time.

The issues paper proposed continuing the approach for DMO 7, basing the smart meter costs and allowance on actual installations, as at 30 September 2024 (draft determination) and 31 March 2025 (final determination), until Legacy Meter Replacement Plans are in place.[120]

Like in DMO 6, we issued voluntary data requests in October 2024 seeking:

- the historic numbers of customers by meter and tariff type at 30 September 2024
- the projected customer numbers as at 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.

AEMC Accelerating smart meter deployment rule change

We anticipate an increase in the rate of smart meter installations once the AEMC's Accelerating smart meter deployment rule change is in effect.[121] Smart metering costs could increase as more smart meters are deployed in the DMO 7 and 8 periods (and future DMO determinations).

Queensland and South Australia revenue determinations and legacy meter costs

In DMO 6, the smart meter cost methodology in NSW was updated to reflect changes in how legacy meters costs were recovered from customers under the network business revenue determinations for 2024–29.[122] Similarly, for DMO 7, we have updated the smart meter cost

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120 See the AEMC's rule determination for the Accelerating smart meter deployment rule change for more information on Legacy Meter Replacement Plans. AEMC, Accelerating smart meter deployment, Rule determination, Australian Energy Market Commission, 28 November 2024, pp. 10–19.

121 AEMC, Accelerating smart meter deployment, Australian Energy Market Commission, 28 November 2024.

122 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.

methodology for the SA Power Networks and Energex regions to reflect the updated legacy meter cost recovery approaches under the revenue determinations for 2025–30.

7.2 Stakeholder views

Fourteen stakeholders submitted feedback on issues relating to retailer costs and smart meters.

7.2.1 Retail and other costs

Most stakeholders supported the collection of retail cost data from a broader cohort of retailers.[123] Alinta Energy, Origin Energy, Red Energy and Lumo Energy and Shell Energy considered that a more comprehensive dataset will provide a better representation of the retail costs incurred by retailers, particularly smaller retailers.[124] Shell Energy, and Red Energy and Lumo Energy considered this approach would enable a better estimate of the retail cost stack, which includes retailers' costs to serve and the costs associated with acquiring residential and small business customers.[125] ENGIE and JEC/SACOSS/ACOSS also endorsed this approach.[126]

While there was broad support for collecting retail cost information directly from retailers, there were some concerns regarding the use of a weighted average approach when quantifying retail and other costs. ENGIE and Energy Locals highlighted limitations using a customer-weighted average approach, arguing that it mostly reflects the retail costs of larger retailers.[127] They contended that large retailers benefit from considerable cost advantages over smaller retailers, so adopting a weighted average approach may make it more challenging for smaller retailers to recover their costs. ENGIE and EnergyAustralia suggested undertaking statistical testing to identify a more suitable calculation methodology, such as using the median or percentiles instead of the customer-weighted average.[128] Similar views were expressed by other smaller retailers during our retailer workshops.

In contrast, the AER's Customer Consultative Group noted that the DMO price only acts as a price cap for customers on standing offers and that most of these customers are with larger

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123 AGL, Submission to DMO 7 issues paper, 12 November 2024, p. 5; Alinta Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 1; ENGIE, Submission to DMO 7 issues paper, 8 November 2024, p. 5; EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, p. 9; Energy Locals, Submission to DMO 7 issues paper, 8 November 2024, p. 4; JEC/SACOSS/ACOSS, Submission to DMO 7 issues paper, 11 November 2024, pp. 6–7; Origin Energy, Submission to DMO 7 issues paper, 16 November 2024, pp. 6–7; Red Energy and Lumo Energy, Submission to DMO 7 issues paper, 18 November 2024, pp. 4–5; Shell Energy, Submission to DMO 7 issues paper, 15 November 2024, pp. 5–6.

124 Alinta Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 1; Origin Energy, Submission to DMO 7 issues paper, 16 November 2024, pp. 6–7; Red Energy and Lumo Energy, Submission to DMO 7 issues paper, 18 November 2024, pp. 4–5; Shell Energy, Submission to DMO 7 issues paper, 15 November 2024, pp. 5–6.

125 Red Energy and Lumo Energy, Submission to DMO 7 issues paper, 18 November 2024, pp. 4–5; Shell Energy, Submission to DMO 7 issues paper, 15 November 2024, pp. 5–6.

126 ENGIE, Submission to DMO 7 issues paper, 8 November 2024, p. 5; JEC/SACOSS/ACOSS, Submission to DMO 7 issues paper, 11 November 2024, pp. 6–7.

127 ENGIE, Submission to DMO 7 issues paper, 8 November 2024, p. 5; Energy Locals, Submission to DMO 7 issues paper, 8 November 2024, p. 4.

128 EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, p. 9; ENGIE, Submission to DMO 7 issues paper, 8 November 2024, p. 5.

retailers. They considered that retail cost calculations would be different if the AER based the retail cost component only on the costs to serve for customers on standing offers with larger retailers, as opposed to other retailers that have customers on discounted market offers.[129]

ECA and JEC/SACOSS/ACOSS advocated for greater transparency in our reporting of the methodology used to quantify retail costs. They also encouraged the AER to disclose underlying retail cost data, including retailers' costs to serve and costs to acquire and retain customers.[130] ECA noted that more transparency over cost variations of larger and smaller retailers would be beneficial in understanding the true costs and benefits of increased consumer choice and competition. Both consumer group submissions also highlighted the risk of information asymmetry. They stressed that if the data remains opaque, consumer groups and policymakers cannot accurately assess whether the DMO is working as intended to protect disengaged customers from excessive prices.

Additionally, ECA and JEC/SACOSS/ACOSS opposed including retailers' costs to acquire and retain customers in the DMO retail cost calculation.[131] In their submission JEC/SACOSS/ACOSS argued that retailers typically recover these costs elsewhere, such as through older or expired market offers or higher-margin customers.[132] They proposed that these costs should be treated as part of retail expenditure or investment, rather than an explicit cost to be factored into the DMO.

Concerns have also been raised regarding regulatory compliance costs. Alinta Energy and Shell Energy highlighted increasing regulatory burdens, such as the RRO and upcoming rule changes, which will impact compliance costs.[133] They argued these compliance costs should be factored into the retail and other cost component of the DMO.

Red Energy and Lumo Energy contended that there may be inconsistencies in how retailers classify operating retail costs, including leasing expenses, acquisition costs and shared overheads.[134] They noted retailers may categorise these costs differently, which leads to inconsistencies in reporting. To address this, they asserted the AER should be more prescriptive in how retailers report this information to ensure a fair and accurate cost representation of retail costs across all retailers.

7.2.2 Bad and doubtful debt

Stakeholders had mixed views on the best approach to calculating bad and doubtful debt in the DMO price.

Origin Energy recommended the AER should continue to represent bad and doubtful debt data for residential and small business customers as a weighted average and as previously

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129 Customer Consultative Group, Submission to DMO 7 issues paper, 14 November 2024, p. 4.

130 ECA, Submission to DMO 7 issues paper, 8 November 2024, pp. 3–4; JEC/SACOSS/ACOSS, Submission to DMO 7 issues paper, 11 November 2024, pp. 6–7.

131 ECA, Submission to DMO 7 issues paper, 8 November 2024, pp. 3–4; JEC/SACOSS/ACOSS, Submission to DMO 7 issues paper, 11 November 2024, pp. 6–7.

132 JEC/SACOSS/ACOSS, Submission to DMO 7 issues paper, 11 November 2024, pp. 6–7.

133 Alinta Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 1; Shell Energy, Submission to DMO 7 issues paper, 15 November 2024, pp. 5–6.

134 Red Energy and Lumo Energy, Submission to DMO 7 issues paper, 18 November 2024, pp. 4–5.

reported by the ACCC.[135] ENGIE also supported our approach to use a broader representative sample of retailers to determine bad and doubtful debt.[136]

JEC/SACOSS/ACOSS urged the AER to examine whether bad and doubtful debt data provided to the AER represents the actual costs of debt incurred and written off by retailers or whether they are estimates or provisions of bad and doubtful debt.[132] They argued that this distinction could result in significant differences in the amount of bad and doubtful that retailers bear. While provisions serve as standard risk management tools, several factors may create discrepancies between projected and actual debt costs – for example, retailers can recover higher proportions of debt than initially anticipated or sell debts for partial recovery.

AGL advocated for greater transparency in how bad and doubtful debt is calculated. Given that the debt figures are based on historic payment trends, they state that they may not account for more sudden economic shocks like COVID-19.[137] AGL recommended implementing a mechanism that adjusts for bad and doubtful debt allowances, so the DMO remains responsive to significant events and to ensure fair cost recovery for retailers.

7.2.3 Smart metering costs

Stakeholders had mixed views on whether the smart meter allowance should be based on historic or projected smart meter installations. Consumer groups advocated for greater transparency and noted the risk of overestimating the smart meter allowance under an approach based on projected installations.

AGL, EnergyAustralia and Origin Energy supported the approach of using historic installation data until the Legacy Meter Replacement Plans are in place.[138] AGL acknowledged the AEMC Accelerating smart meter deployment rule change and noted that annual monitoring of the smart meter rollout is appropriate to monitor retail metering costs and will communicate any additional cost considerations in due course.[139]

Origin Energy supported allowing a working capital allowance to cover the shortfall between actuals and projected installations.[140]

ENGIE continued to suggest expanding the smart meter allowance to include actual and forecast installations, ensuring that the full range of smart meter costs are considered. It noted the historical data alone is unlikely to capture the true quantum of installations, which will continue to increase because of the mandated rollout. Retailers will incur unavoidable

135 Origin Energy, Submission to DMO 7 issues paper, 16 November 2024, p. 7.

136 ENGIE, Submission to DMO 7 issues paper, 8 November 2024, p. 5.

137 AGL, Submission to DMO 7 issues paper, 12 November 2024, p. 5.

138 AGL, Submission to DMO 7 issues paper, 12 November 2024, p. 6; EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, p. 10; Origin Energy, Submission to DMO 7 issues paper, 16 November 2024, pp. 7.

139 AGL, Submission to DMO 7 issues paper, 12 November 2024, p. 6.

140 Origin Energy, Submission to DMO 7 issues paper, 16 November 2024, p. 7.

costs to meet their 2026 interim targets due the commencement of the mandated smart meter rollout within the DMO 7 period.[141]

Shell Energy supported including any costs that arise as a result of the AEMC Accelerating smart meter deployment rule in the retail cost stack.[142] However, JEC/SACOSS/ACOSS believed smart meter costs should be excluded in retail cost calculations unless there is greater transparency on how retailers are incurring and recovering these costs. They suggested a regulated schedule of costs for smart meter installations and operations, including guidelines related to how costs are recovered from both individual consumers and the wider customer base.[143]

Our Customer Consultative Group noted the risk of overestimating smart meter costs if projections are not met and sought more clarification on the projection approach.[144]

Energy Locals noted concern with the financial burden for retailers in connection with the smart meter rule changes, suggesting we factor the following into our calculations of retailer cost and margins:[145]

- the number of meters specified for replacement during the relevant periods in the Legacy Meter Replacement Plans
- the realistic annual cost of the current proportion of smart meters
- average fees charged by the metering providers for smart meter replacements
- the distributor costs of the remaining basic meters
- the system upgrade and administrative costs required for retailer compliance.

7.3 Draft determination

7.3.1 Retail and other costs

For the DMO 7 draft determination we have set the benchmark for retail and other costs based on the customer-weighted average of retailers' reported retail and other cost information. This includes applying the weighted average to all retail and other cost subcomponents, which encompasses retailers' costs to serve, costs to acquire and retain, and other costs.

This weighted average accommodates the retail and other costs of retailers selling to 77% of residential customers and 70% of small business customers in DMO regions.

This approach is consistent with previous DMO determinations (DMO 4, 5 and 6) when we used the ACCC's retail cost data on retail and other costs. Similarly, we applied the customer-weighted average retail and other costs in DMO prices across all DMO regions, including NSW, SE Queensland and South Australia. Given the retail cost data we have

141 ENGIE, Submission to DMO 7 issues paper, 8 November 2024, p. 5.

142 Shell Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 5.

143 JEC/SACOSS/ACOSS, Submission to DMO 7 issues paper, 11 November 2024, p. 7.

144 Customer Consultative Group, Submission to DMO 7 issues paper, 14 November 2024, p. 5.

145 Energy Locals, Submission to DMO 7 issues paper, 8 November 2024, p. 4.

collected relates to the 2023–24 period, we have also applied forecast CPI using RBA forecast inflation for 2024–25 and 2025–26 to retain the value of these costs in real terms across the DMO 7 period.[146]

For future DMO determinations, we intend to continue collecting retail cost information from retailers and update the retail and other cost benchmark. These costs are likely to change over time and will be reflected in new benchmarks.

Table 7.1 provides a breakdown of retail and other cost components by DMO region.

Table 7.1 Retail and other costs ($/customer), by DMO region, including GST

Retail and other costs	NSW	SE Queensland	South Australia
Residential customers, with and without controlled load			
Cost to serve	$112.02	$114.71	$108.23
Cost to acquire and retain	$72.81	$60.45	$68.04
Other costs	$27.14	$44.44	$31.83
Total	**$211.97**	**$219.60**	**$208.10**
Small businesses			
Cost to serve	$157.69	$129.09	$129.06
Cost to acquire and retain	$80.34	$63.01	$72.58
Other costs	$54.79	$29.67	$36.77
Total	**$292.82**	**$221.78**	**$238.41**

Source: AER analysis of retail cost information.

We collected retailers’ cost data to determine a benchmark for retail and other costs

Since DMO 4 we have used retail costs identified by the ACCC in its Inquiry into the NEM reports as a central component of our retail cost determinations.

For DMO 7 we have obtained retail cost data based on information received from 26 retailers subject to a formal AER information request issued in October 2024. This information request replicated the cost categories requested by the ACCC in its inquiry, such as retail costs, customer numbers and energy usage. We consider this to be an appropriate approach because the sample collected includes retailers of a wide range of sizes and business models, serving approximately 99.1% of small customers. In comparison, the ACCC sample consists of 13 retailers, comprising a cumulative 94.3% small residential customer market share.

146 We have used Reserve Bank of Australia (RBA) February 2025 forecast inflation for June 2025 (2.4%) and June 2026 (3.2%).

Our broader dataset of retail cost information has better informed our decision-making process. For example, a more comprehensive sample of retailer costs to serve and costs to acquire and retain customers enabled a better understanding of the extent to which these costs are driven by larger and smaller retailers across all DMO regions, as well as the extent to which they are driven by economies of scale.

In relation to Red Energy and Lumo Energy's concern that retailers may categorise and report costs differently, we have adopted the same cost category definitions as the ACCC request to retailers for its NEM inquiry. We chose to maintain the cost categories to ensure consistent treatment of costs for each retailer year on year and avoid movements in retail costs from DMO 6 to DMO 7 due to definitional changes. This assisted retailers that had previously provided similar information to the ACCC and enabled us to check our approach and undertake analysis to ensure we produced similar results to the ACCC. To maintain this consistency, we have not been more prescriptive in the definitions.

We considered other statistical approaches to quantify retail and other costs

We acknowledge stakeholder concerns that a weighted average approach gives larger retailers greater weight in determining the benchmark and potentially impacting smaller retailers that typically have a lower customer market share and higher costs. Stakeholder submissions recommended exploring alternative approaches for consideration.

Applying a customer-weighted average to retail and other costs aligns with previous DMO determinations, while reflecting economies of scale better than other measures of central location. As noted above, this weighted average covers the costs of retailers selling to 77% of residential customers and 70% of small business customers in DMO regions, which includes several non–Big 3 and smaller retailers.[147]

We evaluated various approaches to setting the retail and other costs benchmark using alternative statistical measures, such as a simple average or median. While these alternative statistical measures result in higher values and would accommodate more retailers (including smaller retailers with costs below this benchmark), they are sensitive to fluctuations in costs, particularly as individual retailers' costs may vary significantly from year to year, which makes yearly comparisons difficult. In contrast, the weighted average approach provides greater stability. These approaches also deviate from previous DMO determinations and differ from how other regulatory bodies, such as the ESC and the ICRC, quantify retail and other costs.

The Customer Consultative Group proposed considering the retail costs of the Big 3 retailers. We do not consider an approach that aims to reflect the costs of the Big 3 is appropriate, because it does not reflect the costs of the majority of retailers, including competitors to the incumbents. This would be a significant departure from previous approaches and from other elements of the DMO price where we determine reasonable costs across a broad retailer cohort.

Our approach has considered the retail and other costs from a sample of 26 retailers that are representative of the small customer market. While we note there are several retailers of different sizes that have retail and other costs above the benchmark, the weighted average

[147] Big 3 retailers include AGL, EnergyAustralia and Origin Energy.

approach better reflects economies of scale and the efficient costs of selling electricity. It also provides incentives for retailers to reduce costs below this benchmark and improve their competitiveness in the industry, which ultimately benefits consumers.

The DMO applies to all customers, not just customers on standing offers

We note the Customer Consultative Group's argument that the DMO should consider the retail costs of the Big 3 retailers, as these retailers have the majority of standing offer customers who tend to pay the DMO price.

It is important to remember the DMO serves a dual purpose of protecting consumers and effectively regulating competitive markets as a reference price. We are cognisant the DMO Regulations require us to have regard to the costs retailers incur in serving, acquiring and retaining customers[148] and do not distinguish between standing and market offer customers in these costs.

The analysis we conducted is based on most of the small customer market that the DMO applies to; the retail cost information we collected covers approximately 99% of the small customer base. As previously outlined, this is currently the most accurate representative sample available to base our retail cost calculations on in the DMO model.

We also acknowledge retailers' concerns regarding regulatory compliance costs, with some stakeholders suggesting such costs should be included in the retail cost component of the DMO.[149] We agree that any costs incurred in meeting additional regulatory requirements should be included in the DMO price.

The retail cost information we collected from retailers should reflect the most up-to-date cost information available. Any additional costs incurred from changes in regulatory obligations during DMO 7 should be captured in subsequent information requests and will be included in retail costs in future DMO determinations.

Retail and other costs have increased from DMO 4 onwards

Figure 7.1 shows that retail and other costs have increased each year to 2023–24 across all DMO regions.[150] It shows that:

- Among the cohort of retailers that previously reported to the ACCC electricity market inquiry, retail and other costs increased between 25% and 31% from 2022–23 (used in DMO 6) to 2023–24 (DMO 7) for residential customers and between 4% and 24% for small businesses, depending on DMO region.
- Our inclusion of these new retailers has led to additional increases in the weighted averages compared with the weighted average of the ACCC cohort of retailers. Including

148 Regulations, s. 16(4)(c)(iv)-(v).

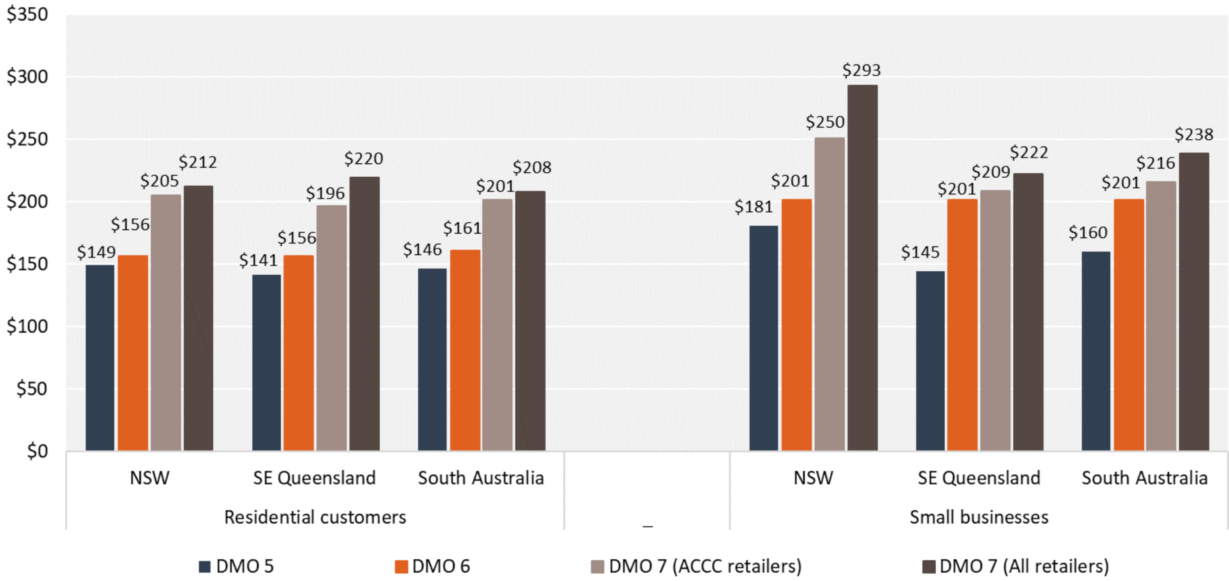
149 In response to Shell Energy's submission, the RRO is already accounted for in the wholesale cost methodology, and therefore are not considered as a retail compliance cost. See our Wholesale cost chapter, section 5.3.5 for further detail.

150 In this figure, the DMO 5 and 6 retail cost component represents the customer-weighted average of retail and other costs published by the ACCC. Values for DMO 7 represent a customer-weighted average of retailers subject to the ACCC's request for their December 2024 Inquiry, and all retailers subject to the AER's formal information request.

new retailers in our information request increased retail and other costs by between 3% and 12% for residential customers and between 6% and 17% for small businesses, depending on DMO region.

This analysis demonstrates that the main driver in the increase in retail costs from DMO 6 to DMO 7 are the year-on-year increases for the ACCC cohort of retailers. These retailers, particularly the Big 3, have increased spending on hardship program and debt collection costs, and increased spending on customer acquisition and retention costs.[151]

Figure 7.1 Time series of weighted average retail and other costs ($/customer) by DMO region and customer type, including GST



Source: AER analysis of retail cost information.

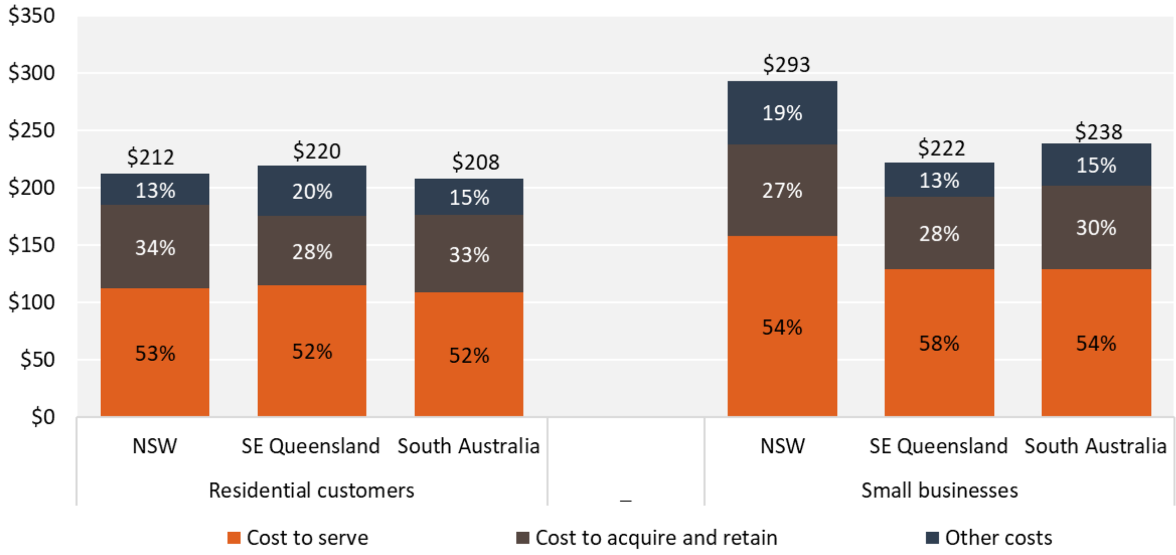
To provide greater transparency in the underlying retail cost data, we have provided a breakdown of the subcomponents of retail operating costs – costs to serve, costs to acquire and retain customers, and other costs. These breakdowns were presented only on a NEM-wide basis in previous reports.

Figure 7.2 shows that costs to serve accounts for at least half of the retail and other costs component of the cost stack, ranging between 52% and 58% depending on DMO region and customer type. In addition, retail and other costs are also generally higher for small business customers compared with residential customers.

This is followed by retailers' costs to acquire and retain, and other retail costs. Other costs are those that don't fall in previous categories due to differences in retailers' reporting systems and our cost stack template, such as corporate costs, which can vary in classification across retailers.

151 ACCC, Inquiry into the National Electricity Market, 30 December 2024 report, Australian Competition and Consumer Commission, p. 80.

Figure 7.2 Retail and other costs components ($/customer), by DMO region and customer type, including GST



Source: AER analysis of retail cost information.

We acknowledge stakeholder concerns about the lack of visibility of the cost variations between larger and smaller retailers. Stakeholders argued that greater transparency on these differences would improve their understanding of their impact on consumer choice and competition and the extent to which the DMO is effectively protecting engaged customers.

In response to these concerns, we have categorised our retail cost data into 3 groups: 'Big 3', 'non–Big 3', 'new retailers for DMO 7' (Figure 7.3).[152] This breakdown illustrates the spread of retail and other costs among these cohorts, how these costs differ among these groups and provide insights on competitive advantage.

Overall, the Big 3 retailers hold a significant competitive advantage in retail and other costs. These retailers account for over two-thirds of the small customer market, benefitting from economies of scale to maintain lower costs relative to other retailers. This is reflected in lower weighted average retail and other costs across both residential and small business customers.

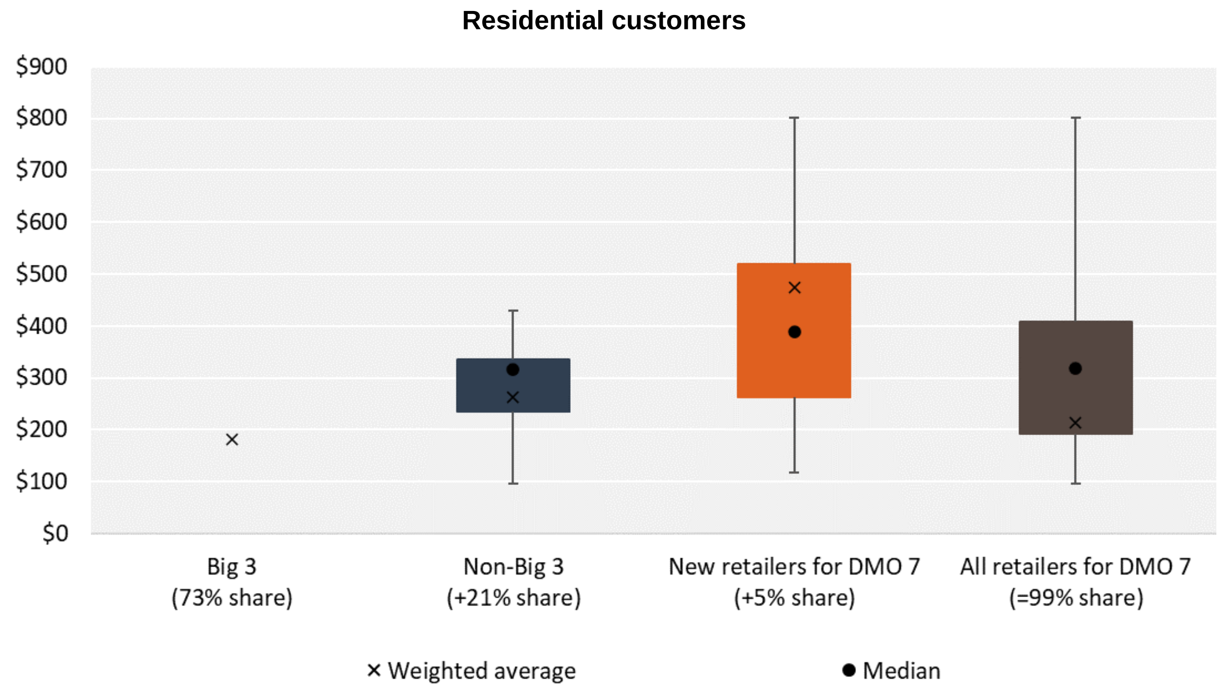
There is also considerable spread in retail and other costs among non–Big 3 retailers, which account for 21% and 17% of the residential and small business markets, and new retailers, that represent 5% and 7% of the residential and small business markets. The variation in retail and other costs is more pronounced when selling electricity to small businesses compared with residential customers.

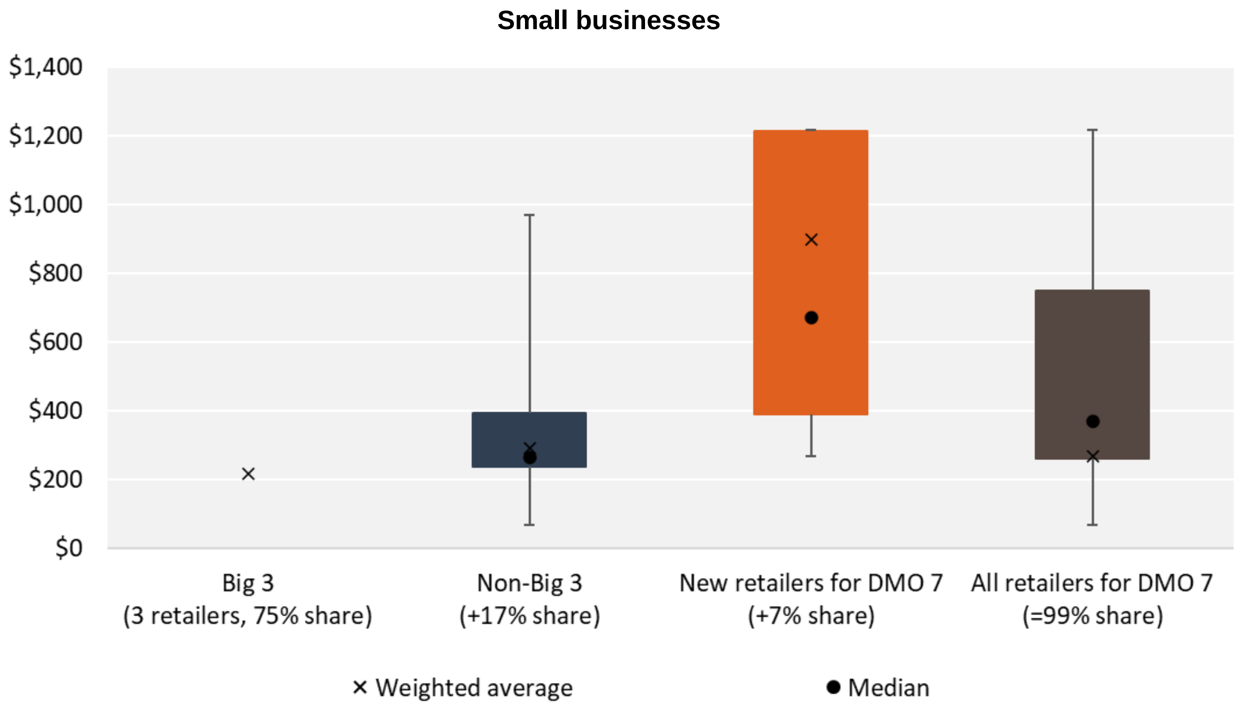
[152] Big 3 retailers consist of AGL, EnergyAustralia and Origin Energy. Non–Big 3 retailers include those covered by the ACCC's information request for their December 2024 Inquiry report (10 retailers). Our dataset captures retail cost information from both the Big 3 and non–Big 3 groups, as well as 13 small retailers that have not previously provided cost information before DMO 7 ('New retailers for DMO 7'). A total of 26 retailers are captured in our own information request. We excluded the minimum, maximum and interquartile ranges for the Big 3 retailers for confidentiality reasons. Only weighted averages are shown due to their small sample size.

This significant variation in per-customer costs is reflected from a broader interquartile range observed for new retailers, which is $256 per customer and $825 per customer for residential and small businesses, respectively. Retailers providing data for the first time in DMO 7 only account for 5% of the market and are likely to face different costs, such as higher customer acquisition expenses and potentially high investment or initial costs for market entry.

It is not always the case that retail costs are higher for retailers with smaller market share. There are a number of smaller retailers that have retail costs lower than the weighted average of the Big 3.

Figure 7.3 Distribution of retail and other costs ($/customer), by customer type, all DMO regions, including GST





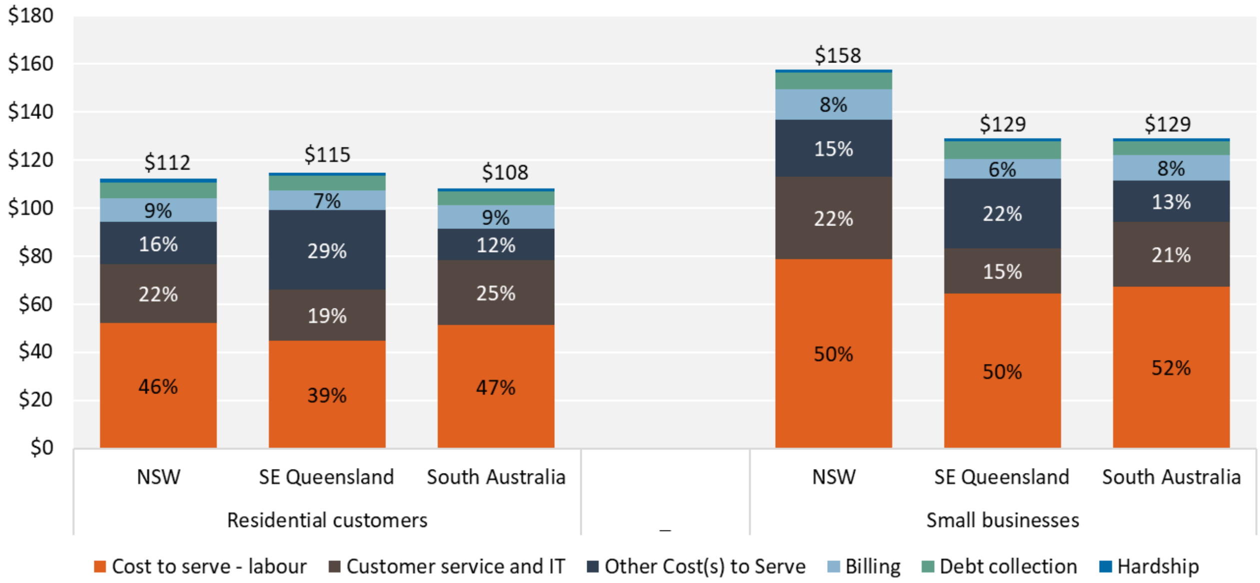
Source: AER analysis of retail cost information. Note that 2 retailers are excluded from this chart for residential customers due to high retail and other costs. Similarly, 2 other retailers are excluded from this chart for small businesses. However, their data was included in the weighted average calculations.

Costs to serve

We have provided a detailed breakdown of the costs to serve, which outline the various sub-components by DMO region and customer type (Figure 7.4).

Across both residential and small business customers, costs to serve labour, which includes payroll costs and contractor costs incurred by retailers to serve customers, is the largest component of a retailer’s cost to serve. However, the second largest sub-component of costs to serve varies by DMO region and customer type (for example, customer service and IT is the second largest component for NSW and South Australia but not for SE Queensland).

Figure 7.4 Cost to serve sub-components ($/customer), by DMO region and customer type, including GST



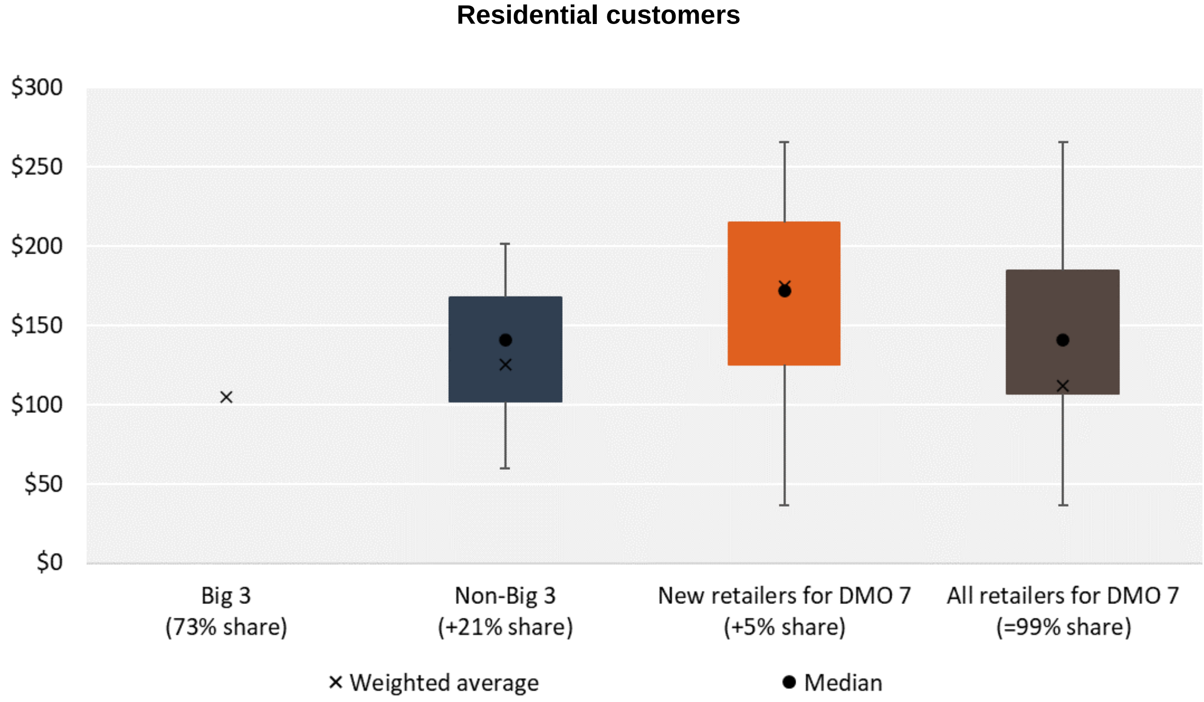
Source: AER analysis of retail cost information.

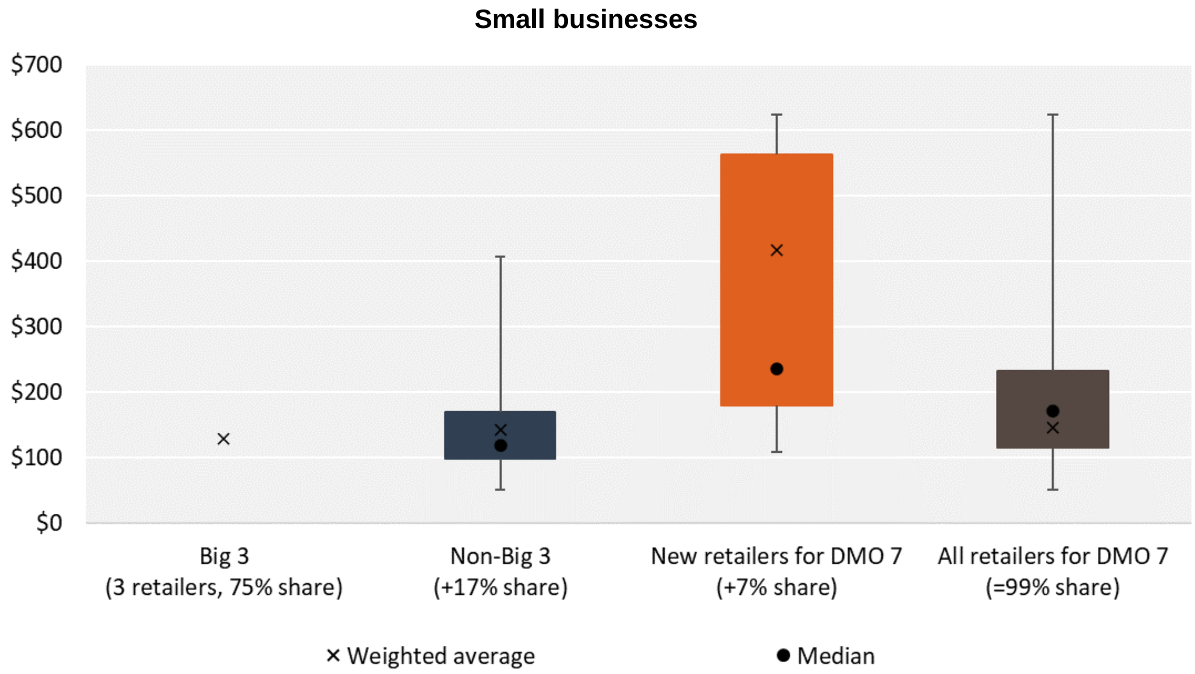
As illustrated in Figure 7.5, Big 3 retailers hold a competitive advantage in costs to serve customers incurred over non–Big 3 and newer retailers.

The spread of costs to serve is much more substantial when examining the interquartile ranges for small businesses. Given new retailers have a relatively low market share, the weighted average is more skewed towards the costs to serve of the Big 3 retailers, which account for approximately 75% of the small business market.

As with overall retail and other costs, there are a number of smaller retailers with lower costs to serve than the weighted average of the Big 3.

Figure 7.5 Distribution of costs to serve ($/customer), by customer type, all DMO regions, including GST



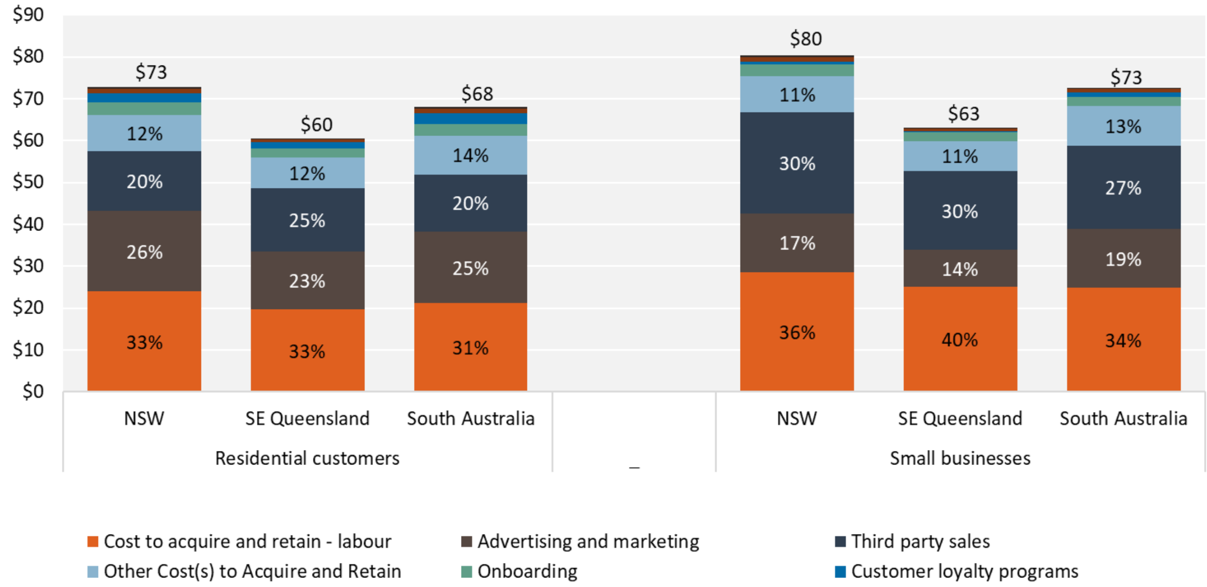


Source: AER analysis of retail cost information. Note that 2 retailers are excluded from this chart for residential customers due to high retail and other costs. Similarly, 2 other retailers are excluded from this chart for small businesses. However, their data was included in the weighted average calculations.

Costs to acquire and retain customers

Figure 7.6 shows a breakdown of the various subcomponents of retailers' costs to acquire and retain customers. The largest subcomponents are labour, followed by advertising and marketing and third-party sales, depending on DMO region. Costs to acquire and retain customers are slightly higher for small business customers compared with residential customers. This is most prominent in NSW, followed by South Australia and SE Queensland.

Figure 7.6 Costs to acquire and retain sub-components ($/customer), by DMO region and customer type, including GST

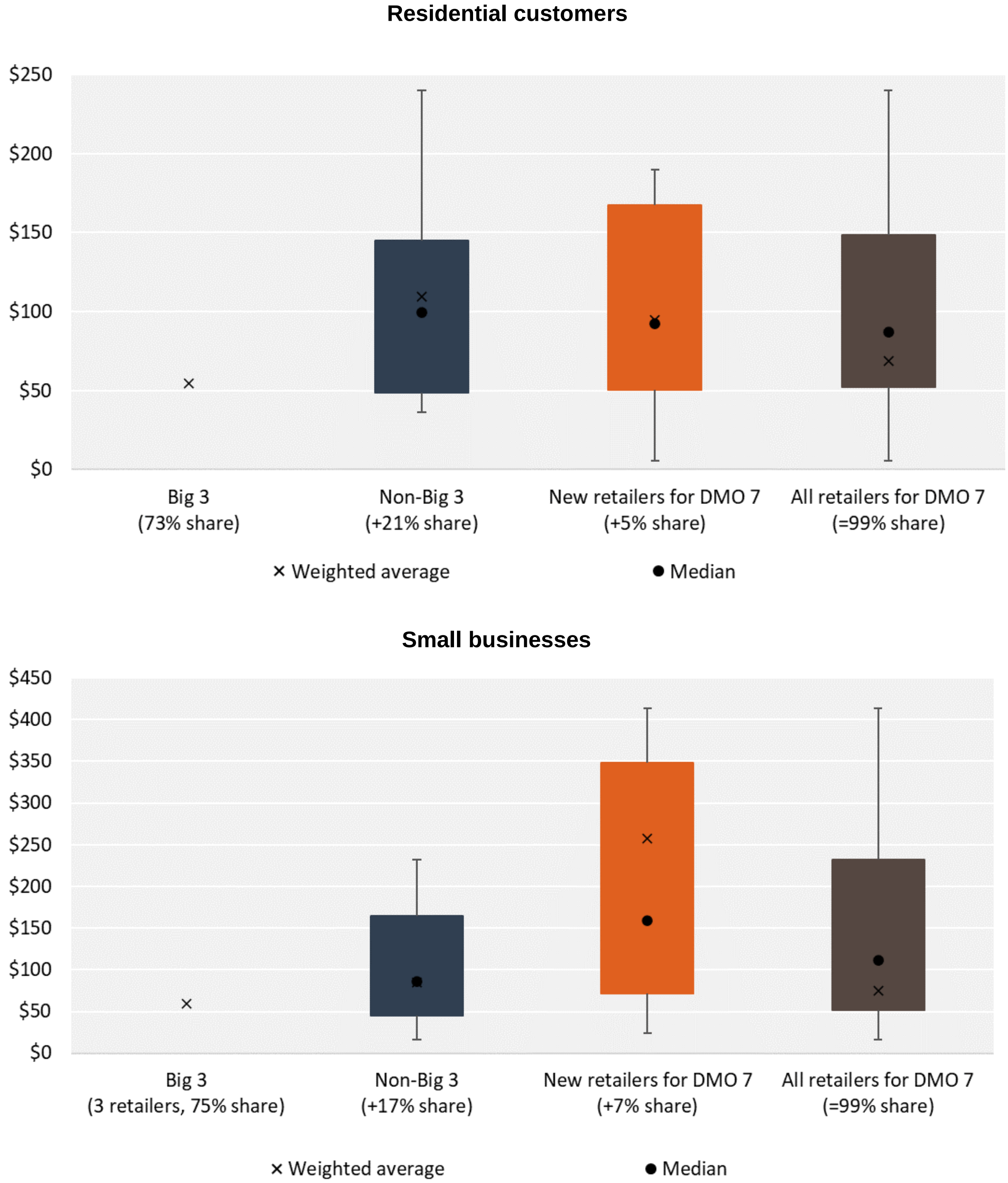


Source: AER analysis of retail cost information.

Figure 7.7 indicates that for residential customers the spread in costs to acquire and retain customers are similar for non–Big 3 retailers. This is demonstrated by the relatively comparable interquartile ranges of $96 per customer for non–Big 3 retailers and $117 per customer for new retailers. However, there is greater variation in costs to acquiring and retaining small business customers across these groups.

As with retail and other costs and costs to serve, there are a number of smaller retailers that have costs to acquire and retain customers lower than the weighted average of the Big 3.

Figure 7.7 Distribution of costs to acquire and retain customers ($/customer), by customer type, all DMO regions, including GST



Source: AER analysis of retail cost information. Note that two retailers are excluded from this chart for residential customers due to high retail and other costs. Similarly, two other retailers are excluded from this chart for small businesses. However, their data was included in the weighted average calculations.

7.3.2 Bad and doubtful debt

Bad and doubtful debt figures represent customer-weighted averages of bad and doubtful debt data obtained from our retail cost information. This includes the bad and doubtful debt data of 26 retailers that we consider to be a broader and more representative sample than data previously sourced from the ACCC's Inquiry into the NEM reports.

We acknowledge stakeholder concerns that it is important to recognise the distinction between actual bad and doubtful debt incurred by retailers, and the estimates or provisions reported to the AER. In our retail cost request we defined bad debts as the amount of uncollectible accounts received from customers, but did not specify whether these figures should reflect actual or estimated bad and doubtful debt figures. This definition is consistent with the ACCC's definition of bad and doubtful debt. For future DMO determinations, we will consider obtaining actual bad and doubtful debt figures from retailers to ensure that data collection is consistent across all retailers.

Table 7.2 shows the year-on-year change in bad and doubtful debt costs from DMO 6 (using ACCC's December 2023 Inquiry) to DMO 7 (using our retail cost information).

Relative to DMO 6, residential bad and doubtful debt has remained stable in SA Power Networks but increased between $9.13 and $13.65 for residential customers in other DMO regions. Bad and doubtful debt increased between $17.52 and $31.33 for small businesses, depending on DMO region.

Table 7.2 Bad and doubtful debt in DMO 7 ($/customer), including GST

DMO region	DMO 7 Bad and doubtful debt (AER retail data)	DMO 6 ACCC Bad and doubtful debt (December 2023 Inquiry)	Change year-on-year ($)
Residential customers, with and without controlled load			
Ausgrid	$42.13	$33.00	$9.13
Endeavour Energy	$42.13	$33.00	$9.13
Essential Energy	$42.13	$33.00	$9.13
Energex	$40.05	$26.40	$13.65
SA Power Networks	$43.94	$44.00	-$0.06
Small businesses			
Ausgrid	$101.01	$71.50	$29.51
Endeavour Energy	$101.01	$71.50	$29.51
Essential Energy	$101.01	$71.50	$29.51
Energex	$77.53	$46.20	$31.33
SA Power Networks	$74.72	$57.20	$17.52

Source: AER analysis of retail cost information.

7.3.3 Smart metering costs

Our retailer data request issued in October 2024 sought:

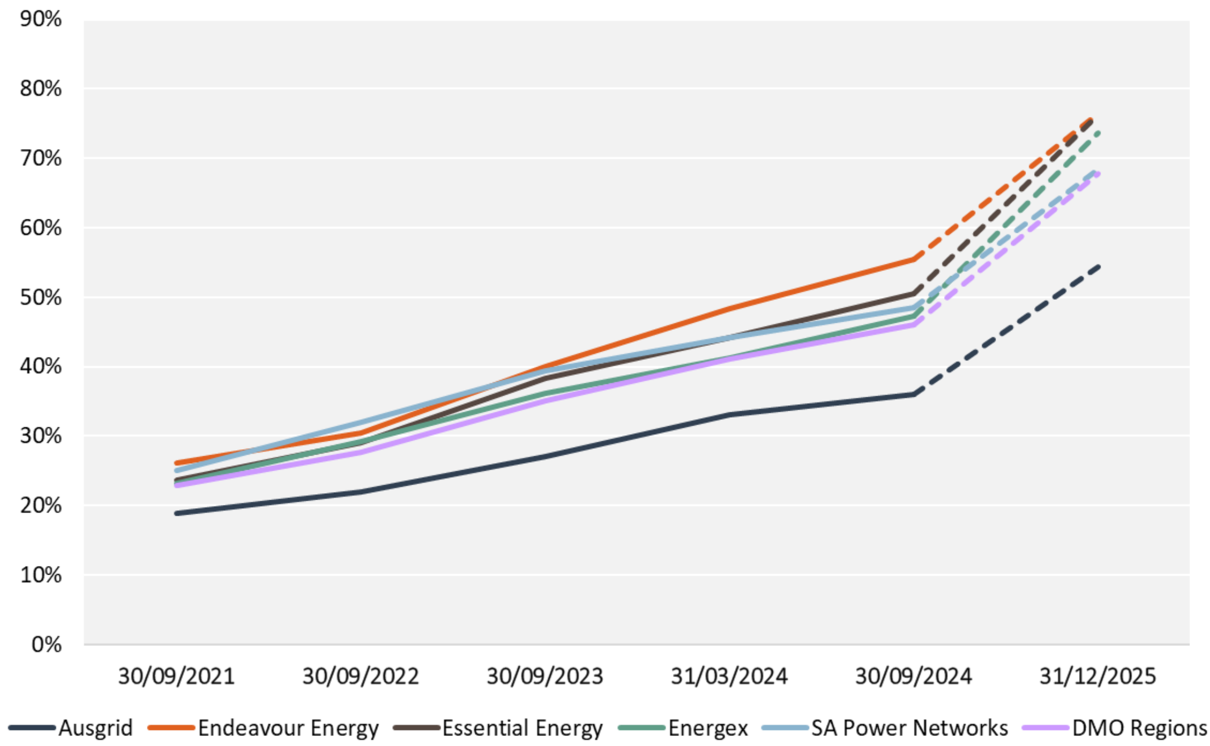
- the number of customers by meter and tariff type
- the projected customer numbers as at 31 December 2025

- smart meter costs
- up-front installation fees (if applicable).

A group of 11 retailers selling to approximately 94% of customers in DMO regions responded, with one new additional retailer compared to DMO 6. Smart meter installations have trended upwards over the last 4 years in all DMO regions. The proportion of smart meters in DMO regions increased from 35.1% in September 2023 to 46.1% in September 2024. We also expanded this year's voluntary request to capture more information about small business customers.

In addition to the customer numbers at 30 September 2024, staff requested retailers to provide their projected smart meter installations as at 31 December 2025. These retailer forecasts have a similar trend as in previous years in all DMO regions. The proportion of smart meters is projected by retailers to reach 67.8% of the customer base across all DMO regions as at 31 December 2025, as set out in Figure 7.8.

Figure 7.8 Historic and projected smart meter installations, residential customers and small businesses



The Customer Consultative Group expressed concerns that forecasts could over-estimate future smart meter installations. We note the forecast smart meter installations at the mid-point of DMO 7 are only used to estimate the average shortfall in the smart meter allowance across DMO 7 due to it being based on historic installations. This shortfall in the DMO smart meter allowance is then used to determine the resulting financing cost of the shortfall.[153] The smart meter allowance itself is based on historic installations (30 September 2024 for the draft determination and 31 March 2025 for the final determination). We consider this

153 See Appendix B for a detailed description of Smart Meter allowance calculations.

approach is consistent with ENGIE's recommendation that the calculation of smart meter costs considers forecast installation rates in addition to historic installation data.

We will continue the approach of using historic installation data. While only a small group of stakeholders supported this approach,[154] we consider this is more accurate than current forecasting. We will ask retailers to update their smart meter installation data to 31 March 2025 prior to the DMO 7 final determination to ensure inputs are as current as possible.

Smart meter costs for DMO 7 are set out in Table 7.3 and Table 7.4. Appendix B provides a detailed breakdown of our calculation of smart meter costs.

Table 7.3 Average residential smart meter cost, by DMO region, excluding GST

DMO region	Average annual cost per smart meter	Average annual cost per customer
Ausgrid	$116.77	$43.21
Endeavour Energy	$116.39	$68.67
Essential Energy	$116.87	$63.89
Energex	$113.21	$57.52
SA Power Networks	$114.62	$59.66

Table 7.4 Average small business smart meter cost, by DMO region, excluding GST

DMO region	Average annual cost per smart meter	Average annual cost per customer
Ausgrid	$128.42	$27.33
Endeavour Energy	$129.57	$46.88
Essential Energy	$131.84	$48.33
Energex	$135.93	$48.00
SA Power Networks	$133.06	$44.83

Queensland and South Australia network determinations and legacy meter cost recovery

In DMO 4 and DMO 5 the non-capital component of alternative control services (ACS) metering charges was subtracted from smart meter costs. This adjustment was necessary to avoid over-recovery for smart meters because:

- the full ACS metering charges were already included in the network costs component

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154 AGL, Submission to DMO 7 issues paper, 12 November 2024, p. 6; EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, p. 10; Origin Energy, Submission to DMO 7 issues paper, 16 November 2024, p. 7.

- most smart meter customers would not be charged the non-capital component.

In the lead up to DMO 6, NSW network businesses underwent network resets and changed their cost recovery approach to recover these costs from all customers regardless of whether they had a smart meter installed or not. In DMO 6 the AER updated the smart meter allowance calculation by removing the subtraction of the non-capital component of ACS metering charges.

Similarly, for DMO 7 we have accounted for recent changes to legacy meter cost recovery approaches for SA Power Networks and Energex from their recent draft network revenue determinations. Legacy meter costs will be recovered from all customers, including smart meter customers, which is the same approach for Endeavour Energy and Essential Energy.

The smart meter allowance calculations have been updated for SA Power Networks and Energex in DMO 7. Because of this, in addition to the steady increase in smart meter installations, smart meter costs for DMO 7 have increased in SA Power Networks and Energex.

Appendix B sets out a detailed breakdown of our calculation of smart meter costs.

7.4 Summary of determinations for retail costs

Table 7.5, Table 7.6 and Table 7.7 set out the components for our cost build-up approach in DMO 7.

Table 7.5 Residential without controlled load retail costs, excluding GST

DMO region	Retail and other costs	Smart meter costs	Bad and doubtful debt costs	Forecast CPI adjustment	Total	Difference to DMO 6 (%)
Ausgrid	$192.70	$43.21	$38.30	$15.57	$289.78	28.4%
Endeavour Energy	$192.70	$68.67	$38.30	$17.01	$316.69	29.5%
Essential Energy	$192.70	$63.89	$38.30	$16.74	$311.63	26.9%
Energex	$199.64	$57.52	$36.40	$16.67	$310.23	40.7%
SA Power Networks	$189.18	$59.66	$39.94	$16.39	$305.18	24.1%

Table 7.6 Residential with controlled load retail costs, excluding GST

DMO region	Retail and other costs	Smart meter costs	Bad and doubtful debt costs	Forecast CPI adjustment	Total	Difference to DMO 6 (%)
Ausgrid	$192.70	$43.21	$38.30	$15.57	$289.78	28.4%
Endeavour Energy	$192.70	$68.67	$38.30	$17.01	$316.69	29.5%
Essential Energy	$192.70	$63.89	$38.30	$16.74	$311.63	26.9%
Energex	$199.64	$57.52	$36.40	$16.67	$310.23	40.7%
SA Power Networks	$189.18	$59.66	$39.94	$16.39	$305.18	24.1%

Table 7.7 Small business retail costs, excluding GST

DMO region	Retail and other costs	Smart meter costs	Bad and doubtful debt costs	Forecast CPI adjustment	Total	Difference to DMO 6 (%)
Ausgrid	$266.20	$27.33	$91.82	$21.88	$407.23	37.3%
Endeavour Energy	$266.20	$46.88	$91.82	$22.99	$427.89	38.6%
Essential Energy	$266.20	$48.33	$91.82	$23.07	$429.43	39.4%
Energex	$201.61	$48.00	$70.48	$18.17	$338.27	21.2%
SA Power Networks	$216.73	$44.83	$67.93	$18.70	$348.20	20.3%

Figure 7.9 and Figure 7.10 illustrate the year-on-year increases in retail costs, and the impact on the customer-weighted average of retail costs, by including new retailers in the DMO 7 draft determination. These costs are averaged across all regions to summarise these movements.

Figure 7.9 Change in residential retail cost components from DMO 6 to DMO 7 ($/customer), all DMO regions

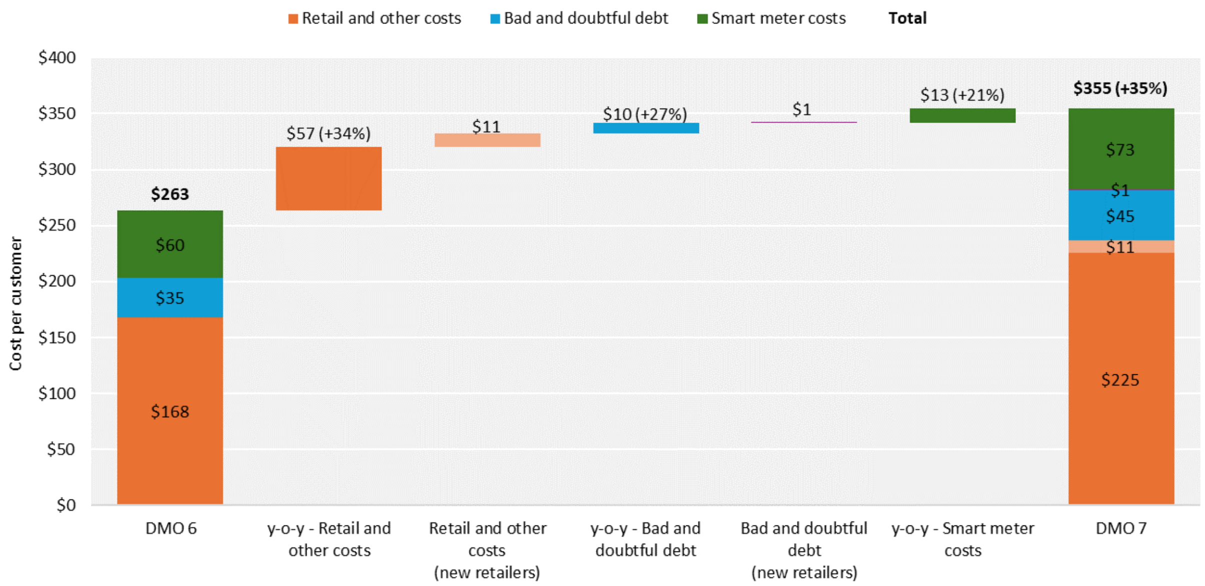
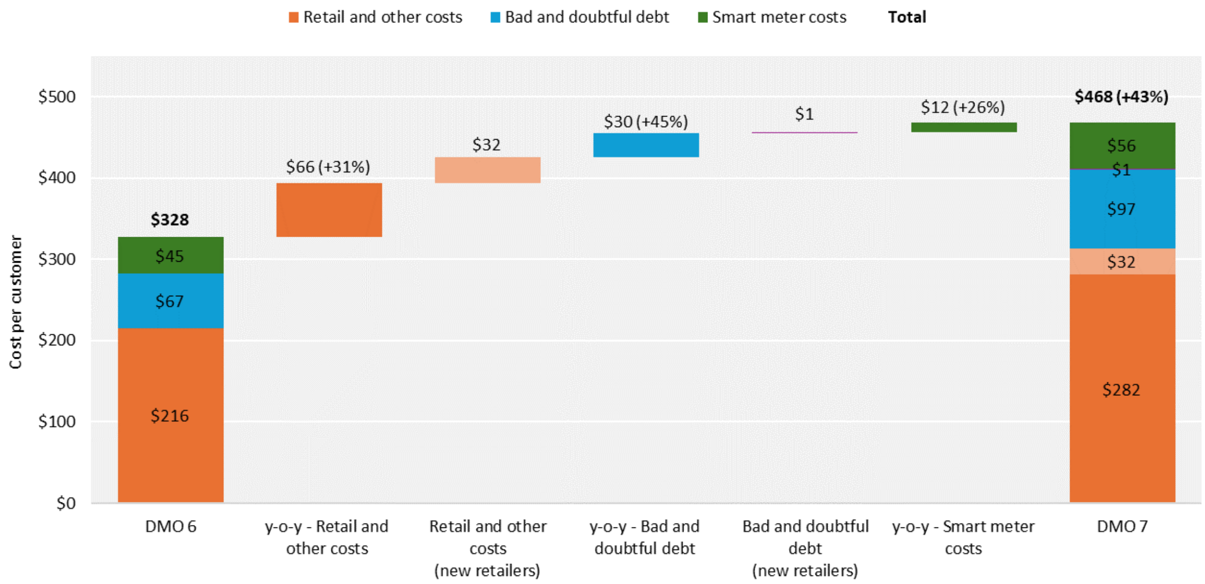


Figure 7.10 Change in small business retail cost components from DMO 6 to DMO 7 ($/customer), all DMO regions



8 Retail margin

- For the DMO 7 draft determination, we have decided to maintain the retail margins at 6% for residential customers and 11% for small business, excluding any competition allowance.
- Retail margins have increased in dollar terms between $3.68 and $14.93 for residential customers and between $19.59 and $49.47 for small businesses, depending on DMO region.
- Relative to DMO 6, this reflects an increase in the dollar value of margins of between 2.5% and 8.9% for residential customers and between 4.2% and 8.2% for small businesses.

The Regulations require the DMO price be set such that it allows retailers to make a reasonable profit in supplying electricity.[155]

In our DMO 6 determination, we split the retail allowance into separate efficient margin and competition allowance components. This chapter discusses our considerations of retail margins and chapter 9 discusses our consideration of the competition allowance.

8.1 Issues paper

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.[156]

In the DMO 6 determination we set the margins at 6% for residential and 11% for small business customers. These margins were applied as a percentage of the DMO price, exclusive of any competition allowance.

The DMO 7 issues paper proposed to maintain the 6% margins for residential and 11% margin for small business customers. To ensure these margins remain appropriate, the issues paper noted that retail margins would be evaluated for residential customers (with and without controlled load) and small business customers under various methodologies.

The issues paper also sought feedback on whether the proposed retail margins were appropriate and, if not, whether alternatives should be considered.

8.2 Stakeholder views

ENGIE and Origin Energy supported maintaining efficient retail margins for residential customers at 6% and small businesses at 11%.[157] ENGIE also considered a percentage-based approach appropriately reflects the risks that retailers face.[158] ENGIE encouraged the

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155 Regulations, s. 16(4)(b).

156 Regulations, s. 16(4)(b).

157 ENGIE, Submission to DMO 7 issues paper, 8 November 2024, pp. 6–7; Origin Energy, Submission to DMO 7 issues paper, 16 November 2024, p. 7.

158 ENGIE, Submission to DMO 7 issues paper, 8 November 2024, p. 7.

AER to commit to maintaining these retail margins for a set period to provide regulatory certainty for stakeholders.[159]

While EnergyAustralia also supported a percentage-based approach to setting retail margins, it argued the current margins may not adequately capture the full range of operational costs faced by a retailer, particularly smaller and new retailers.[160]

The AEC and Origin Energy stated that costs and risks of being a retailer in the NEM have not diminished since the last DMO decision and have persisted for multiple years.[161] The AEC noted that retail margins are currently at historic lows and cautioned that any reduction in retail margins by the AER would heighten risks to smaller retailers.[162] They argued the challenging operating environment for smaller retailers puts pressure on retailers to compete on price and innovate.

Energy Locals argued the AER's proposed margins are set too low and recommended expressing the retail margin as a fixed dollar amount, which would provide greater certainty for retailers on the absolute profitability per customer in the regulated price.[163] It also stated the margin should consider economic conditions, including rising inflation and cost-of-living pressures.

Consumer groups advocated for a consistent 6% retail margin to be applied uniformly across residential and small business customers.[164] ECA did not consider the retailer margins of 11% to be fair or justifiable for small business customers.[165] It considered small businesses should not be subject to higher retail margins than residential customers because there is no current evidence they are more costly to serve.

JEC/SACOSS/ACOSS considered the 6% retail margin for residential customers was towards the higher end of ranges outlined in previous DMO draft determinations.[166] They stated that if the retail margin was to be implemented, it should negate the need for any further energy retailer claims for additional cost allowances.

8.3 Draft determination

For the DMO 7 draft determination we have decided to maintain the retail margins of 6% for residential and 11% for small business customers.

While there is reasonable variation in inferred and reported margins across the approaches, there is insufficient evidence to justify changing retail margins, particularly given our analysis

159 ENGIE, Submission to DMO 7 issues paper, 8 November 2024, pp. 6–7.

160 EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, p. 10.

161 AEC, Submission to DMO 7 issues paper, 13 November 2024, p. 1; Origin Energy, Submission to DMO 7 issues paper, 16 November 2024, p. 7.

162 AEC, Submission to DMO 7 issues paper, 13 November 2024, p. 1.

163 Energy Locals, Submission to DMO 7 issues paper, 8 November 2024, p. 5.

164 ECA, Submission to DMO 7 issues paper, 8 November, p. 3; JEC/SACOSS/ACOSS, Submission to DMO 7 issues paper, 11 November 2024, p. 8; South Australian Business Chamber, Submission to DMO 7 issues paper, 15 November 2024, p. 1.

165 ECA, Submission to DMO 7 issues paper, 8 November, p. 3.

166 JEC/SACOSS/ACOSS, Submission to DMO 7 issues paper, 11 November 2024, p. 8.

of reported earnings before interest tax depreciation and amortisation (EBITDA) as a percentage of revenue indicates current margins reasonably reflect the retail market. Table 8.1 provides a summary of our retail margin analysis. Ranges have been provided because estimated retail margins vary by customer type and DMO region. Appendix F sets out detailed analysis of retail margins.

Table 8.1 Summary of margin results

<table>
<tr><th>Margin measure</th><th>Residential without CL</th><th>Residential with CL</th><th>Small businesses without CL</th></tr>
<tr><td>Inferred margins from advertised market offers (ACIL Allen approach)</td><td>-5.6% to 2.2%</td><td>-6.3% to 1.4%</td><td>7.0% to 10.7%</td></tr>
<tr><td>Reported EBITDA (AER retail cost request)[167]</td><td colspan="2">-39.9% to 29.4% (weighted average of 5.6%)</td><td>-33.4% to 29.4% (weighted average of 11.6%)</td></tr>
<tr><td>Reported EBITDA (ACCC December 2024 Inquiry report)</td><td colspan="2">4.2% (NSW), 9.2% (SE Queensland) 12.8% (South Australia), NEM wide 5.9%</td><td>9.5% (NSW), 11.5% (SE Queensland) 19.2% (South Australia), NEM-wide 9.0%</td></tr>
<tr><td>Inferred margins from ACCC customer-weighted average prices</td><td>-2.0% to 2.8%</td><td>3.1% to 10.5%</td><td>1.4% to 4.0%</td></tr>
</table>

Source: AER updated analysis of ACIL Allen's retail margin analysis on advertised market offers; AER analysis of retail margins (EBITDA) based on retailer data for 2023–24; AER analysis of ACCC customer-weighted prices paid on 1 August 2024. Margins inferred using DMO 6 costs.

The DMO 7 draft determination continues to set retail margins as a percentage of DMO prices

In competitive markets, suppliers of goods and services generally receive a margin that is commensurate with the level of risk associated with that industry (relative to systemic economy-wide risk).

When considering a reasonable margin in supplying electricity, we must consider the relevant risks retailers face and not consider risks that have been otherwise managed through other components of the DMO cost stack. Without seeking to quantify individual risks, we have taken this into account in our determination of margin.

Given the link to risk, we consider it is appropriate for the margin to be set as a percentage instead of a fixed dollar amount, as risks scale with underlying costs. This can be expressed as either a percentage of price or a percentage of cost. Treating the retail margin as a percentage of the DMO price (excluding the competition allowance) is consistent with

[167] One small retailer from our retail cost information request is an outlier, so was excluded from the ranges from this table. However, the data for this retailer is included in the weighted average calculation.

approaches among other economic regulators and we have expressed it in this way throughout this draft determination.

8.4 Summary

The DMO 7 draft determination maintains retail margins at 6% of residential and 11% of small business DMO prices, excluding any competition allowance.

This is summarised in Table 8.2.

Table 8.2 Efficient retail margins, DMO 7 draft determination and DMO 6 final determination (inc. GST)

Customer type	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Residential customers without controlled load					
Efficient margin	6%	6%	6%	6%	6%
Retail margin in DMO 7 ($)	$118.12	$143.80	$162.77	$131.07	$140.62
Retail margin in DMO 6 ($)	$108.61	$133.40	$150.75	$123.94	$133.80
Difference ($)	$9.51	$10.40	$12.01	$7.14	$6.82
Residential customers with controlled load					
Efficient margin	6%	6%	6%	6%	6%
Retail margin in DMO 7 ($)	$162.84	$182.99	$190.47	$148.52	$172.89
Retail margin in DMO 6 ($)	$150.56	$168.06	$175.89	$144.84	$165.58
Difference ($)	$12.28	$14.93	$14.58	$3.68	$7.31
Small businesses					
Efficient margin	11%	11%	11%	11%	11%
Retail margin in DMO 7 ($)	$548.66	$523.78	$680.11	$488.27	$627.78
Retail margin in DMO 6 ($)	$507.30	$486.39	$630.64	$468.67	$588.72
Difference ($)	$41.35	$37.39	$49.47	$19.59	$39.07

9 Competition allowance

- For the DMO 7 draft determination, we calculated competition allowance values that would allow retailers serving 90% of customers to make a reasonable profit.
- This results in a competition allowance of $20.71 for residential customers and $23.08 for small business customers, down from $60 for residential customers and $265 for small business customers calculated (but not included) in DMO 6.
- Due to sustained cost-of-living pressures and elevated underlying inflation the DMO 7 draft determination does not include the competition allowance.

The Regulations require us to set a reasonable price and have regard to the principle that retailers should be able to make a reasonable profit.[168] We also consider the policy objectives of:

- protecting consumers from unreasonably high prices
- allowing retailers to recover their efficient costs of providing services
- incentivising retailers to invest, innovate and compete in the market
- incentivising customers to engage in the market.

For DMO 4 and 5 we included a retail allowance in the DMO price to meet these objectives.

The retail allowance was set to reflect a return on retailer risk, allow for differences in retailers' costs and provide additional room for competition.[169] We also consider it desirable that DMO prices include a similar level of allowance regardless of DMO region.

In our DMO 6 determination, we split the retail allowance into separate efficient margin and competition allowance components. The competition allowance was calculated based on the spread of retailer costs to serve, so that we factor in the value for customers of the competitive tension that comes from smaller and new entrant retailers. However, we also determined not to include the competition allowance in DMO 6 to give greater weighting to the price protection objectives of the DMO during a period of sustained high inflation and heightened cost-of-living pressures.

9.1 Issues paper

9.1.1 Quantifying the competition allowance

The issues paper highlighted our intention to use our own collected retail cost data to derive the value for the competition allowance for DMO 7. We considered this approach beneficial because it would include a greater number of retailers, be more representative of costs and enable greater transparency to discuss the derivation of the competition allowance.

168 Regulations, s. 16(1)(b) and s. 16(4)(b).

169 The DMO prices also include a separate allowance for the costs of competition because they include the average costs to acquire and retain customers.

The issues paper sought stakeholder feedback on the best approach to incorporating the more diverse range of retailer costs to serve in quantifying the competition allowance.

9.1.2 Whether to include or exclude the competition allowance

Our issues paper noted our decision not to include a competition allowance in DMO 6 was based on an assessment of the prevailing economic conditions, specifically cost-of-living pressures and economic uncertainty. For these reasons, we determined the exclusion of the competition allowance from DMO 6 achieved the best balance of the consumer protections principles of the DMO.

Our issues paper also noted that we consider this framework remains appropriate in determining whether to include or exclude a competition allowance in DMO 7. Further, the primary factor we would have regard to in assessing cost-of-living pressures would be 12-month movements in the CPI. Where CPI is materially above the RBA’s target band of 2% to 3% for a sustained period, we stated we would exclude a competition allowance in order to prioritise consumer protections. In making this decision, we will also have regard to the state of retail competition.

The issues paper sought feedback on whether there were any other factors the AER should consider in determining whether to include or exclude a competition allowance from DMO 7.

9.2 Stakeholder views

9.2.1 Quantifying the competition allowance

Only 3 stakeholders directly discussed the methodology for setting the competition allowance.

Energy Locals supported the delineation between retail margin and competition allowance.[170] ENGIE advocated for a percentage-based allowance, but otherwise supported the methodology used in DMO 6.[171]

Origin Energy supported a margin-based competition allowance, such as the retail allowance methodology used in DMO 4 and 5.[172] It submitted that any element of a new methodology should be consulted on prior to implementation to promote open and transparent decision-making. Retailers echoed this feedback during the workshops.

9.2.2 Including or excluding the competition allowance

Retailers supported the inclusion of the competition allowance for DMO 7, submitting that a competition allowance was required to meet the DMO objectives of allowing retailers to compete and innovate.

170 Energy Locals, Submission to DMO 7 issues paper, 8 November 2024, p. 5.

171 ENGIE, Submission to DMO 7 issues paper, 8 November 2024, p. 7.

172 Origin Energy, Submission to DMO 7 issues paper, 16 November 2024, p. 1.

EnergyAustralia argued that the competition allowance should be included because it would provide a 'buffer' to the DMO price that could capture the full range of operational costs faced by a retailer, particularly smaller and new retailers.[173]

ENGIE and Shell Energy submitted that the CPI may not be the most accurate measure of cost-of-living pressures[174] and, along with Origin Energy and Red Energy and Lumo Energy, requested further guidance on how the AER would assess whether CPI was 'materially' above the RBA target band for a 'sustained' period of time.[175] Requests for further clarity on what constitutes 'materially' and 'sustained' in this matter were reiterated by retailers in workshops.

During the workshops retailers also proposed that the DMO was not the appropriate mechanism for addressing cost-of-living pressures, noting energy bill relief measures were more suitable.

ECA, the South Australian Business Chamber and a joint submission from JEC/SACOSS/ACOSS asserted that the competition allowance should be excluded because it is not an effective means of incentivising competition or innovation.[176] They also considered that the CPI should not be the primary factor in determining the inclusion or exclusion of the competition allowance because it does not cover the full scope of cost-of-living and energy affordability issues.

9.3 Draft determination

9.3.1 Approach to determining the competition allowance

We have determined the competition allowance method with regard to the spread of individual retailer costs to serve reported to the AER through formal information requests to retailers. While this is similar to the approach in DMO 6, it does not rely on data received by the ACCC under its electricity market inquiry. Our information request also covers more retailers than the ACCC's information gathering process – 26 retailers accounting for approximately 99% market share compared with 13 retailers at approximately 94% market share in DMO regions.[177]

173 EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, p. 10.

174 ENGIE, Submission to DMO 7 issues paper, 8 November 2024, p. 7; Shell Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 6.

175 Origin Energy, Submission to DMO 7 issues paper, 16 November 2024, p. 1; Red Energy and Lumo Energy, Submission to DMO 7 issues paper, 18 November 2024, p. 4.

176 ECA, Submission to DMO 7 issues paper, 8 November 2024, p. 2; South Australian Business Chamber, Submission to DMO 7 issues paper, 15 November 2024, p. 1; JEC/SACOSS/ACOSS, Submission to DMO 7 issues paper, 11 November 2024, p. 8.

177 AER analysis of the 13 retailers' customer numbers in Q3 2023–24 retail performance reporting data for NSW, SE Queensland and South Australia. Our calculation excludes Ergon customers to estimate customer numbers in SE Queensland. This is not directly comparable with the ACCC's figure that its sample of retailers covers approximately 85% of residential customers and 80% of small business customers in the NEM. The ACCC includes Ergon in its calculations to present market share on a NEM-wide basis. See ACCC, Inquiry into the National Electricity Market, 30 December 2024 report, Australian Competition and Consumer Commission, p. 90.

Many of these additional smaller retailers do not exhibit the economies of scale of the larger retailers and in some instances report costs to serve that are materially higher than the weighted average of all retailers. As such, for the DMO 7 draft determination we have determined to set the competition allowance such that retailers selling to 90% of the market would be able to make a reasonable profit with the competition allowance included in the DMO price.

We consider that setting the competition allowance to accommodate the costs to serve of retailers selling to 90% of customers in DMO regions further facilitates the DMO objective of incentivising competition because a significant proportion of retailers could achieve a reasonable profit. It also avoids the competition allowance being excessively large due to the impact of highly inefficient retailers, which would be inconsistent with the DMO pricing protection objectives.

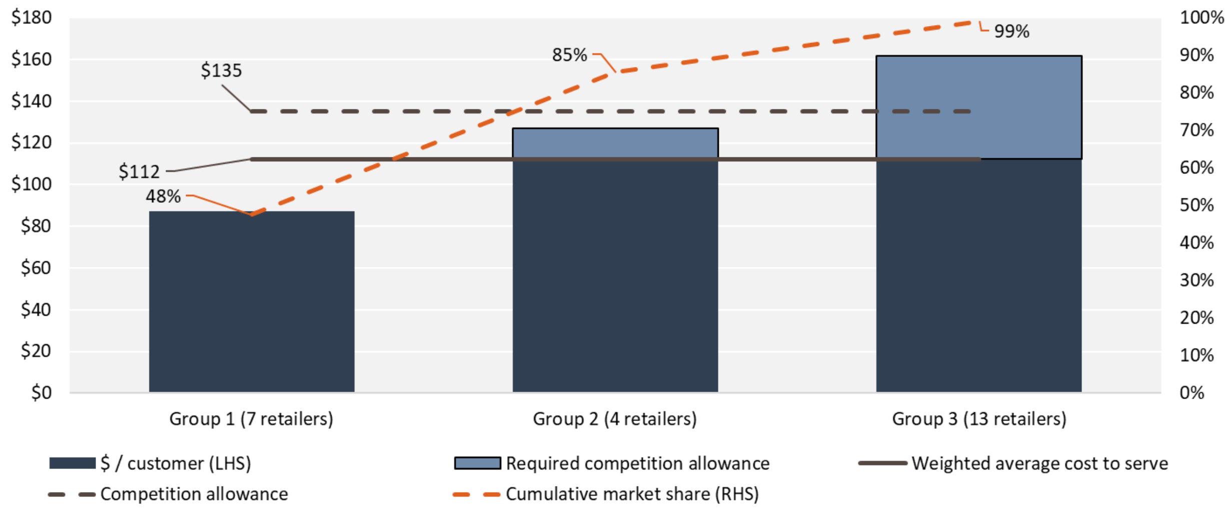
We acknowledge this approach requires regulatory judgement. Retailers’ costs to serve vary widely and the skew of these costs is different between residential and small business markets. However, we consider this approach best balances the DMO competition objectives because it ensures the competition allowance continues to reflect the most recent available data on variations in less efficient retailers’ costs to serve. Additionally, it also provides the most direct link between these retailers’ costs and the DMO price.

As with DMO 6, the competition allowance would be determined on a dollar per customer basis instead of a percentage basis. We consider this approach is more appropriate than setting a percentage amount as recommended by Origin Energy. This is because the competition allowance will move with updated retailer costs data each year, instead of with movements in other elements of the cost stack (which would occur if it were set as a percentage basis).

Our consideration of these factors results in competition allowances for DMO 7 of $20.71 for residential customers and $23.08 for small business customers (excluding GST). While these values are lower than those determined for DMO 6, they are set in addition to the weighted average retail and other costs considered in the DMO price. As discussed in chapter 7, the weighted average retail and other costs has increased from DMO 6 due to the inclusion of additional less-efficient retailers. Figure 9.1 and Figure 9.2 show the spread of retailers whose costs to serve:

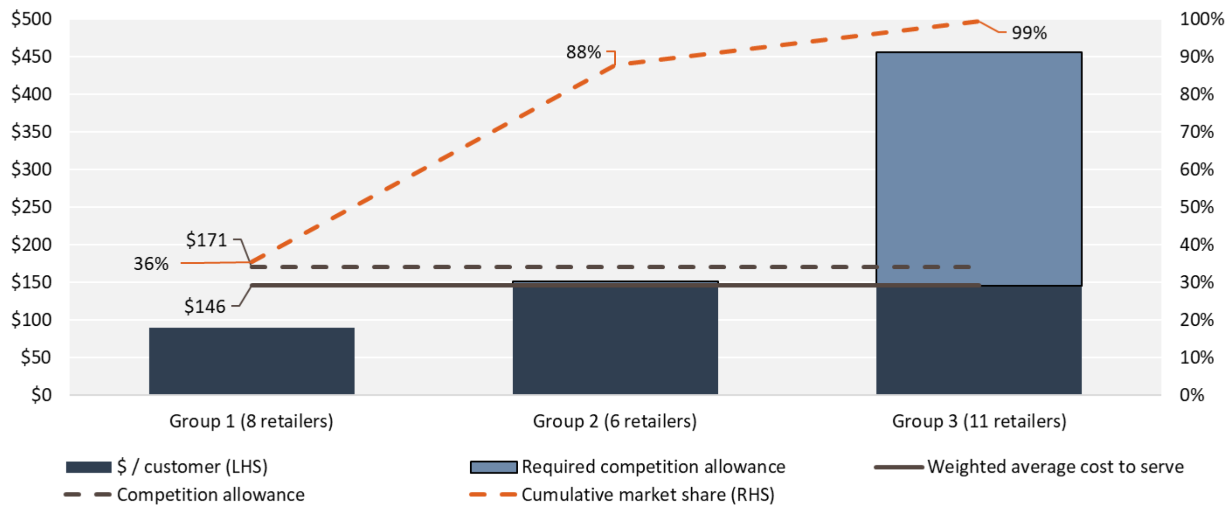
- are under the weighted average costs to serve within the retail and other costs component included in the DMO price
- are accommodated for when including the competition allowance
- and not accommodated for regardless of whether a competition allowance is included or excluded.

Figure 9.1 Competition allowance for residential customers (ex. GST)



Note: Retailers in group 1 have costs to serve below the average costs included in the DMO price, retailers in group 2 have costs to serve accommodated by the competition allowance, and retailers in group 3 are not accommodated for with the allowance. Costs are displayed as the weighted average cost to serve per group.

Figure 9.2 Competition allowance for small business customers (ex. GST)



Note: Retailers in group 1 have costs to serve below the average costs included in the DMO price, retailers in group 2 have costs to serve accommodated by the competition allowance, and retailers in group 3 are not accommodated for with the allowance. Costs are displayed as the weighted average cost to serve per group.

The approach to determining the competition allowance does not consider retailers' costs to acquire and retain customers because:

- the DMO price already allows recovery of typical competition costs through inclusion of average retailers' costs to acquire and retain customers
- we consider retailers have greater control on costs to acquire and retain customers than on costs to serve
- retailers with higher than average costs to acquire and retain have likely made strategic decisions to grow market share – in contrast, higher than average costs to serve likely reflect smaller retailers spreading fixed costs across a smaller customer base.

9.3.2 Including or excluding the competition allowance

In DMO 6 we determined that external economic conditions, experienced as cost-of-living pressures, were extremely challenging for customers. Evidence of this was the CPI had materially exceeded the RBA target band of 2% to 3% annual growth on a sustained basis since December quarter 2021.[178] Further, our retail performance monitoring found more customers were in debt and on hardship programs than the previous year. We considered these economic conditions to be relevant matters the AER must have regard to under s. 16(4)(d) of the Regulations. Therefore, we determined it was appropriate to exclude the competition allowance from DMO 6 and provide greater weighting to the DMO consumer protection objectives.

We indicated that for future determinations the primary factor we will use is cost-of-living and price pressures as measured by 12-month movements in the CPI, reported on quarterly by the Australian Bureau of Statistics (ABS). Where the CPI is materially above the RBA's target band for a sustained period, we would not apply the competition allowance to prioritise consumer protection. We also indicated that in making this draft decision we would have regard to the state of retail competition.

We consider that cost-of-living pressures remains a relevant matter and one that the AER must have regard to under s. 16(4)(d) of the Regulations.

At the time of publication of this draft determination, the most recent quarterly update by the ABS for annual CPI movements is for December 2024, with trimmed mean CPI inflation sitting at 3.2%. In exercising our regulatory judgement, we acknowledge the uncertainty regarding the interpretation of when CPI is considered to be 'materially above' the RBA target band – a point raised by many stakeholders in response to our issues paper. However, we have also considered the sustained nature of heightened 'core' or 'underlying' trimmed mean CPI inflation, which has remained above the RBA target band for 12 consecutive quarters.

We consider trimmed mean CPI is the most appropriate measure for these purposes because downward movements in headline CPI have been driven in part by reductions in electricity prices due to government electricity bill relief. This bill relief is intended to be temporary and ends before the onset of DMO 7. In its February 2025 Statement on Monetary Policy, the RBA noted the impact of energy bill relief on headline inflation, which it expected to increase in the September quarter of 2025 as the bill relief measures unwind.[179]

We consider use of the CPI as the primary factor in our decision-making promotes transparency and predictability, which may not be the case if we consider other factors alongside CPI as suggested by some stakeholders.

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178 Headline CPI exceeded the RBA target band since December 2021 quarter. Trimmed mean or 'underlying' inflation exceeded the RBA target band since March quarter 2022. ABS, *Consumer Price Index*, series 6401.0, Australian Bureau of Statistics, Tables 1 and 2.

179 RBA, *Statement on Monetary Policy,* February 2025, Reserve Bank of Australia, p. 33.

Therefore, we have determined to exclude the competition allowance from the DMO 7 draft determination. We consider the exclusion of the competition allowance achieves the best balance of the DMO objectives and takes into account submissions received.

We consider the decision to exclude the competition allowance is consistent with the requirement to have regard to retailers' ability to make a reasonable profit.[180] As discussed in chapter 7, the weighted average retail and other costs allows retailers selling to 77% of residential and 70% of small business customers, to recover costs and achieve a reasonable profit without the inclusion of the competition allowance.

Finally, we do not consider the exclusion of the competition allowance will unduly restrict competition. Although the competition allowance was excluded in DMO 6, we have observed that retailers continue to compete and advertise significant discounts in their market offers.

For the DMO 7 final determination, the ABS March 2025 quarter CPI data will be available. We will consider the updated CPI data and will reassess whether it remains appropriate to exclude the competition allowance for DMO 7 in our final determination.

9.4 Summary

The draft determination applies an approach to calculating competition allowances that reflects the range of costs to serve among retailers covering 90% market share. Under this approach, the 2025–26 amount would be $20.71 for residential customers and $23.08 for small business customers (excl. GST).

However, as a result of economic and market conditions as at December 2024, our draft determination is the competition allowance will not be applied to DMO 7. We will reassess for the final determination when new economic data is available.

[180] Regulations, s. 16(4)(b).

10 Annual usage amounts, and timing and pattern of supply

- The DMO 7 draft determination retains the current annual usage benchmarks for residential and small business customers, including the current controlled load amounts.
- We will retain our approach from DMO 6 for calculating the timing and pattern of supply, updating the usage profiles with new AEMO interval meter data.

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'.

10.1 Issues paper

10.1.1 Annual usage amounts

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 load usage.

The issues paper noted the ACCC's June 2024 Inquiry into the National Electricity Market report findings on residential and small business usage. The issues paper also sought stakeholder views on whether we should consider adopting new annual usage amounts, what alternative information we should consider and what alternative usage amounts would be more broadly representative than the current assumptions.

10.1.2 Timing and pattern of supply

In the issues paper we proposed to review the current methodology for calculating the timing and pattern of supply. We highlighted that we would engage with AEMO to understand if improvements could be made to the Market Settlement and Transfer Solutions (MSATS), such as removing controlled load from the consumption profile, to improve our calculations of the timing and pattern of supply.

10.2 Stakeholder views

10.2.1 Annual usage amounts

Five stakeholder submissions raised issues relating to annual usage amounts.

EnergyAustralia and AGL supported the current approach to setting annual usage amounts and the existing methodology. They stated usage assumptions remain close to real-world averages and are broadly representative.[181]

Alinta Energy considered the 10,000 kWh annual usage assumed for small business customers understates their actual usage, but noted that applying a single representative annual consumption demonstrates the difficulties of determining a small business reference price.[182]

Some stakeholder submissions recommended the AER consider a variety of data sources in determining annual usage amounts. Energy Locals recommended real data be used to ensure assumptions remain accurate.[183] SACOSS supported the AER liaising with DNSPs to obtain more granular consumption data, even if this meant a lack in transparency regarding the inputs used to determine the model annual usage.[184]

SACOSS also suggested considering the difference in usage amounts among general South Australian customers and hardship customers. SACOSS noted hardship customers have a median usage significantly above the DMO annual usage of 4,000 kWh per year. SACOSS also considered it is difficult to identify a representative customer in South Australia given high solar PV penetration and higher grid consumption.[185]

10.2.2 Timing and pattern of supply

Only 4 submissions discussed pattern of supply, with AGL and EnergyAustralia considering the current methodology for deriving the pattern of supply remained an acceptable approach.[186]

However, Alinta Energy and Energy Locals expressed the need for consumption profiles to be as accurate as possible and suggested that a review of the timing and pattern of supply profiles would improve the accuracy of the profiles.[187] Alinta Energy considered the current approach flattens the consumption profile and does not represent actual circumstances. Alinta Energy suggested this approach would not be within the long-term interests of consumers.[188] Similarly, EnergyAustralia was open to removing controlled load from the

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181 AGL, Submission to DMO 7 issues paper, 12 November 2024, p. 7; EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, p. 9.

182 Alinta Energy, Submission to DMO 7 issues paper, 15 November 2024, pp. 5–6.

183 Energy Locals, Submission to DMO 7 issues paper, 8 November 2024, p. 6.

184 SACOSS, Submission to DMO 7 issues paper, 14 November 2024, pp. 21–23.

185 SACOSS, Submission to DMO 7 issues paper, 14 November 2024, pp. 21–23.

186 AGL, Submission to DMO 7 issues paper, 12 November 2024, p. 7; EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, p. 9.

187 Alinta Energy, Submission to DMO 7 issues paper, 15 November 2024, p. 6; Energy Locals, Submission to DMO 7 issues paper, 8 November 2024, p. 7.

188 Alinta Energy, Submission to DMO 7 issues paper, 14 November 2024, p. 6.

pattern of supply because this would broadly correlate with higher usage levels during the day and lower usage levels during the night.[189]

Energy Locals suggested the consumption profiles consider weekdays/weekends and seasonality trends as consumption is significantly influenced by these factors. Its submission noted the consumption profile has remained static in recent years, while consumption patterns have changed based on controlled load appliances, rooftop solar and electric vehicles.[190] In contrast, EnergyAustralia considered there is no need to implement seasonal adjustments or separate profiles for residential customers with and without controlled load.[191]

10.3 Draft determination

10.3.1 Annual usage amounts

The draft determination for DMO 7 retains the current annual usage benchmarks for residential and small business customers, including the current controlled load amounts. The per-customer annual usage determination is set out in Appendix C.

Having considered stakeholder submissions and available information on residential annual usage, we consider the amounts remain broadly representative of residential and small business customer usage.

We consider there needs to be clear evidence in the data that our usage amounts are not broadly representative before we change them. This is because changing annual consumption amounts would introduce complexity for customers engaging in the market as year-on-year comparisons with DMO 6 prices would no longer be possible. Changing the annual usage amounts could also introduce administrative burden for retailers as they would be required to update all communications and advertisements of their prices for all their available offers.

Analysis of ACCC June 2024 Inquiry report and DNSP consumption data

As suggested in submissions from Energy Locals and SACOSS, we have considered consumption data from different sources.

Similar to previous DMO determinations, we have examined the consumption information published by the ACCC in its June 2024 Inquiry report.[192] We consider this provides an appropriate balance of transparency and accuracy in annual usage determinations.

We acknowledge and agree with SACOSS's point that determining broadly representative annual usage amounts is challenging. As seen in Figure 10.1 from the ACCC's June 2024

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189 EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, p. 9.

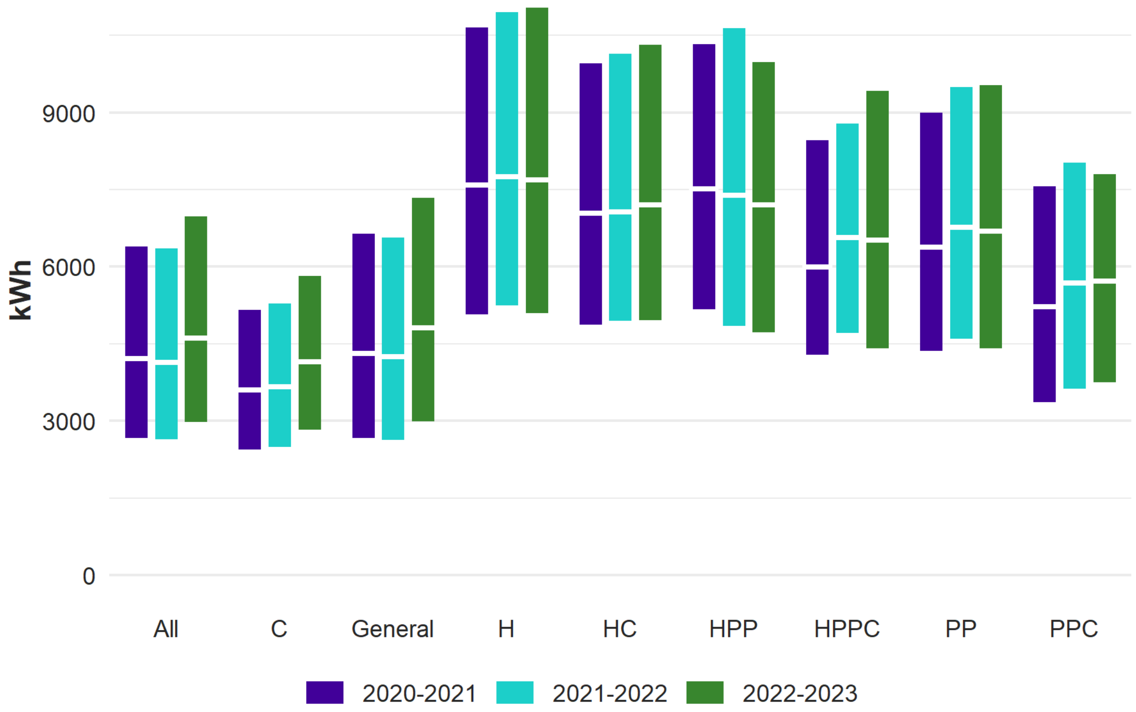
190 Energy Locals, Submission to DMO 7 issues paper, 8 November 2024, p. 7.

191 EnergyAustralia, Submission to DMO 7 issues paper, 8 November 2024, p. 9.

192 ACCC, Inquiry into the National Electricity Market report - June 2024, Australian Competition and Consumer Commission, Appendix E – Supplementary spreadsheet with billing data and figures – Inquiry into the National Electricity Market report.

Inquiry report,[193] hardship customers consume more usage than general customers. However, we have found a small 2.4% of residential customers in South Australia are hardship customers and 1.9% in all DMO regions.[194] Given we can use only one consumption amount for residential customers, we consider that a usage amount that reflects higher usage among hardship customers would not be broadly representative of all residential customers.

Figure 10.1 Annual grid usage by residential customers in South Australia



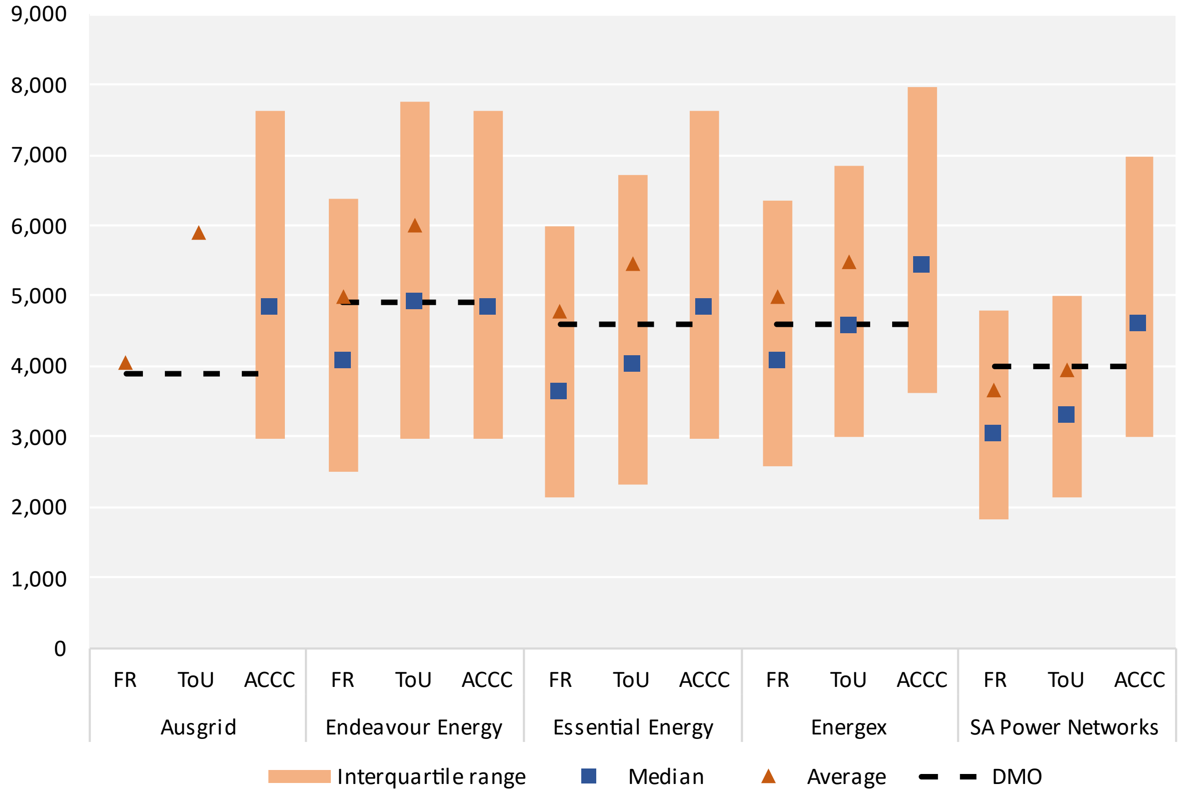
Note: C = Concession only, H = Hardship only, HC = Hardship with a concession, HPP = Hardship on a payment plan, HPPC = Hardship on a payment plan with a concession, PP = Payment plan only, PPC = Payment plan with a concession. See supplementary figures A3.18 to A3.22 for the Annual grid usage by different residential customer groups in other regions.
Source: ACCC, Appendix E – Supplementary spreadsheet with billing data and figures – Inquiry into the National Electricity Market report, June 2024 – Supplementary Figure A3.21.

We have collected data from each of the DNSPs in all DMO regions on the average consumption calculations (total gross consumption and average customer numbers for residential and small business customers) for the 2023–24 year. This included the 25th and 75th percentile, average consumption and the median kWh values that we use to compare against the DMO assumed annual usage.

193 ACCC, Inquiry into the National Electricity Market report - June 2024, Australian Competition and Consumer Commission, Appendix E – Supplementary spreadsheet with billing data and figures – Inquiry into the National Electricity Market report.

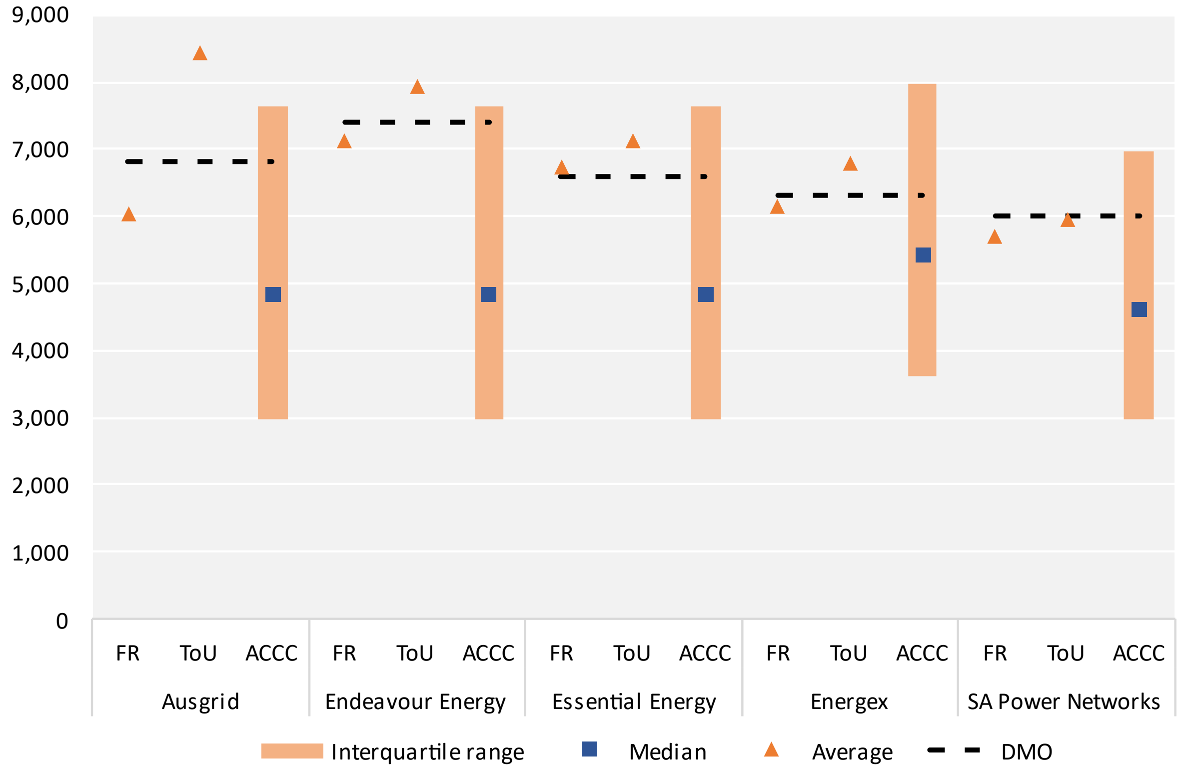
194 AER, Schedule 4 - Quarter 1 2024–25 retail performance data, Australian Energy Regulator, 20 December 2024.

Figure 10.2 Fixed rate and time of use DNSP usage for residential customers without controlled load



Note: FR = Flat rate network tariff consumption data, ToU = Time of Use network tariff consumption data, ACCC = ACCC June 2024 report consumption data.
Source: Data received from DNSPs of annual usage amounts for 2023–24 and ACCC, Appendix E – Supplementary spreadsheet with billing data and figures – Inquiry into the National Electricity Market report, June 2024.

Figure 10.3 Fixed rate and time of use DNSP usage for residential customers with controlled load

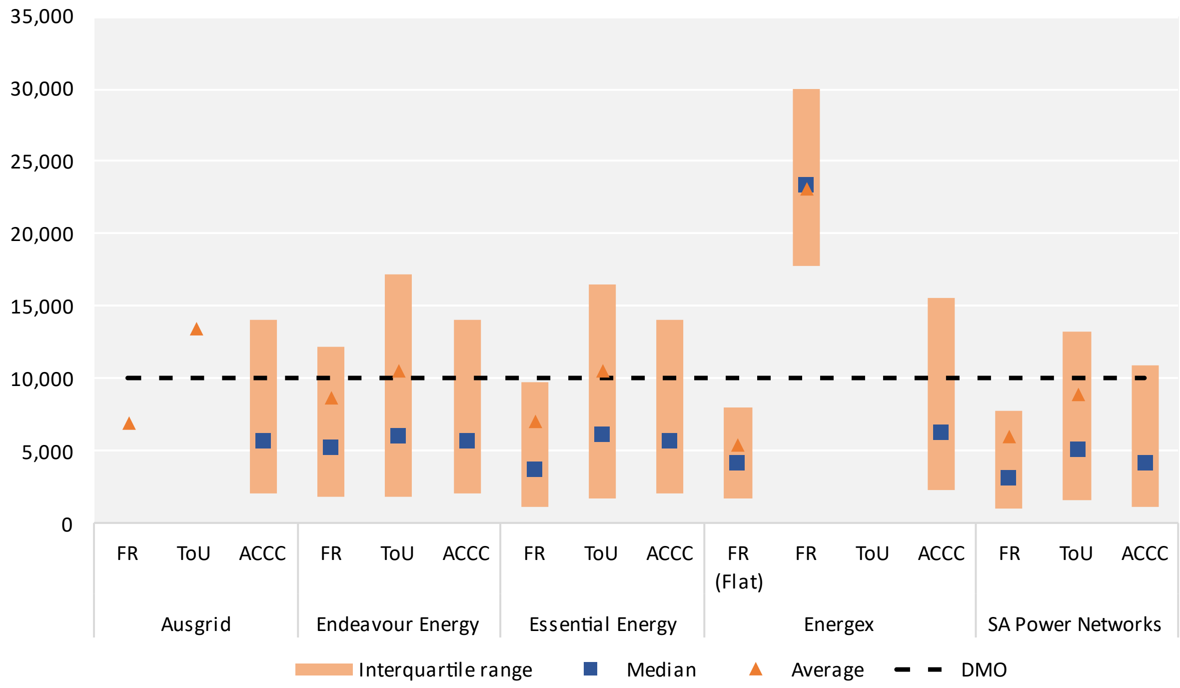


Note: FR = Flat rate network tariff consumption data, ToU = Time of Use network tariff consumption data, ACCC = ACCC June 2024 report consumption data. The median and interquartile ranges for the combined general use, controlled load circuit 1 and 2 is unable to be computed as they were only specified for each controlled load circuit.
Source: Data received from DNSPs of annual usage amounts for 2023–24 and ACCC, Appendix E – Supplementary spreadsheet with billing data and figures – Inquiry into the National Electricity Market report, June 2024.

Our analysis of the data presented in Figure 10.2 and Figure 10.3 suggests the residential usage amounts remain broadly representative. This is because they are:

- within the interquartile ranges from the ACCC data
- approximate to at least the median or average usage in the DNSP medians.

Figure 10.4 Fixed rate and time of use DNSP usage for small business customers without controlled load



Note: FR = Flat rate network tariff consumption data, ToU = Time of Use network tariff consumption data, ACCC = ACCC June 2024 report consumption data.
Source: Data received from DNSPs of annual usage amounts for 2023–24 FY and ACCC, Appendix E – Supplementary spreadsheet with billing data and figures – Inquiry into the National Electricity Market report, June 2024.

Figure 10.4 demonstrates a much wider range in small business usage, particularly in Energex, which has different flat rate network tariffs with distinct small business usage distributions. However, we consider the 10,000 kWh small business annual usage amount remains broadly representative. This is because it is within at least one measure of interquartile range among the DNSP and the ACCC usage amounts in the ACCC June 2024 Inquiry Report. This also suggests that Alinta Energy's concern that the annual usage amounts for small business customers are understated is not necessarily true and depends on which usage data is considered. We note that the 10,000 kWh amount is above the ACCC and DNSP median usage (excluding Energex's second flat rate network tariff).

10.3.2 Timing and pattern of supply

We have considered the updated MSATS data provided by AEMO with controlled load removed. Due to current limitations with the data, we will retain our approach from DMO 6 for calculating the timing and pattern of supply, updating the usage profiles with new AEMO interval meter data.

We recognise Alinta Energy's and Energy Locals' concerns and agree the accuracy of the consumption profiles is critical to our calculations of timing and pattern of supply.

We agree with EnergyAustralia's statements that the removal of controlled load from the consumption profile would create greater accuracy in the shape of the pattern of supply. We have engaged with AEMO to gather MSATS data that identifies smart meter consumption with associated controlled load network tariffs, so the controlled load can be excluded from the overall pattern of supply. However, there are discrepancies between this dataset and the information provided by network businesses. Further engagement with AEMO, network businesses and meter providers (responsible for populating the network tariff field in the MSATS data)[195] is required to address these limitations.

We acknowledge Energy Locals' concerns in relation to weekdays, weekends and seasonality influencing consumption profiles and the time of use consumption patterns across residential customers varies significantly based on individual household circumstances. Consumption patterns are influenced by many factors, including household, climate and regional factors Adding additional variables into the pattern of supply would increase methodological complexity without clear evidence it would benefit retailers and consumers.

For customers on time of use standing offers we continue to recommend customers take advantage of Energy Made Easy (EME)[196] by entering their National Metering Identifier (NMI) to compare offers based on their individual usage patterns over the past 12 months. By doing this, time of use customers will develop a more accurate annual bill estimate based on their individual consumption.

The approach using new AEMO interval meter data to determine the timing and pattern of supply to represent time of use customers updates the usage profiles but retains our key assumptions from previous determinations. That is, we will:

- 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
- update profiles using the AEMO interval meter data for each region, averaged over 3 years
- specify usage at 30-minute intervals.

We have updated the single day usage profile and specified usage for each 30-minute interval over a 24-hour period (see Appendix C).

[195] AEMO, Standing Data for MSATS, Australian Energy Market Operator, 15 November 2024, Table 18, p. 43.

[196] See Energy Made Easy for more information.

11 Appendices

Appendix A – Listening report

Appendix B – Smart meter costs

Appendix C – Draft DMO Legislative Instrument 2025–26

Appendix D – DMO 6 to DMO 7 price movements

Appendix E – State-based summaries of cost changes

Appendix F – Detailed analysis of retail margins

A. Listening report

AUSTRALIAN ENERGY REGULATOR

13 March 2025

DMO 7 Listening Report

Moving from issues paper to draft determination

Our initial engagement process for DMO 7 involved us undertaking consultation with a diverse range of key stakeholders.

We invited written submissions, conducted one-on-one meetings and facilitated in-person workshops to listen to and discuss stakeholders' perspectives on our issues paper published in October 2024. These discussions, workshops and submissions have enabled us to gather feedback from stakeholders openly and transparently. The consultation approach for DMO 7 has:

- enabled the AER to directly listen to key stakeholders' views before receiving written submissions
- allowed stakeholders to ask questions of AER staff before writing submissions
- provided an opportunity for stakeholders who do not provide a written submission to have input into our considerations for the DMO methodology
- ensured our rationale and decision-making process is transparent.

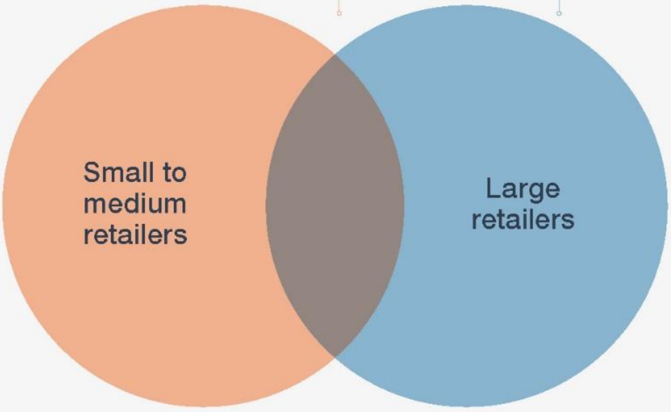
The topics presented in this Listening Report represent the verbal stakeholder feedback received during one-on-one meetings and group discussions in late 2024 and early 2025. The topics do not represent the written submissions that have been included in the DMO 7 draft determination and published on our website.

Engagement timeline for DMO 7

11 October 2024	Issues paper published for consultation
21 October 2024	Workshops with retailers
28 October 2024 – 8 January 2025	One-on-one meetings with industry, government agencies and consumer groups
8 November 2024	Deadline for written submissions
13 March 2025	Draft determination published

Wholesale

Load profiles and solar PV exports



Small to medium retailers

- There are challenges in managing solar exports, especially when no hedging products are available to manage the cost exposure when exporting to negative price intervals.
- Feed-in tariffs cannot be changed every day – they allow a retailer to be competitive rather than manage spot exposure risk.

Large retailers

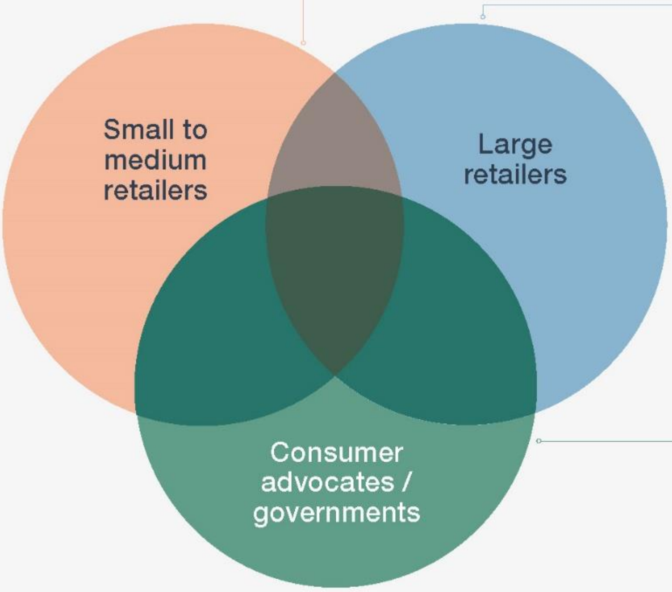
- Interval meter data alone may not be fully representative of a retailers' customer base; phasing toward interval meter data only may be more appropriate.
- The cost exposure associated with solar exports will increase as solar PV penetration increases. This could be addressed through the cost of hedging within the DMO.

Retailer agreement

- Solar exports should be reflected in the wholesale methodology.
- Negative prices are becoming more common, creating challenges in managing spot market exposure.

Retail

Competition allowance



Small to medium retailers

- Smaller retailers face significant market risks and competitive barriers. The inclusion of the competition allowance accounts for these risks.

Large retailers

- Alternative measures and considerations could be utilised to consider the inclusion of the competition allowance.

Retailer agreement

- The definition of the 'material' and 'sustained' decision from the 2024–25 determination to include or exclude the competition allowance and what would satisfy these parameters should be made clearer. Generally supported the inclusion of the competition allowance.

Consumer advocates/ government

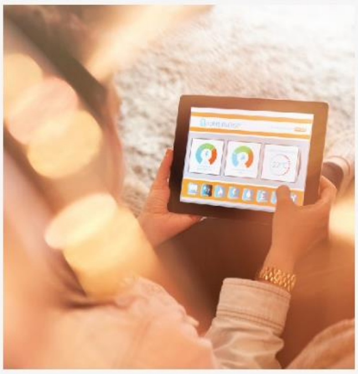
- The competition allowance should continue to be excluded based on cost-of-living challenges.

Stakeholder agreement

- There are cost-of-living pressures for consumers.

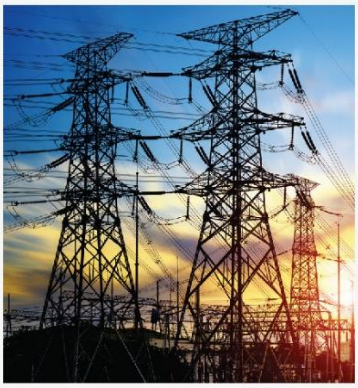
Load profiles – NSLP

- Retailer views were mixed on using interval meter data alone versus blending it with the Net System Load Profile (NSLP) data to simulate the load profiles.
- Retailers noted the materiality of NSLP changes by AEMO is an important factor in considering the approach to load profiles and that there is a need to carefully balance transparency, accuracy and simplicity in wholesale modelling.



Network costs

- Some retailers had views that the continuation of flat rate network tariffs was acceptable, because it reduces complexity and would be consistent with previous determinations.
- Other retailers highlighted that blending network tariffs to account for increased customers on time-of-use and demand network tariffs would better reflect actual circumstances and potentially create lower network costs.



Thank you for your feedback

18

stakeholder organisations engaged with through workshops and one-on-one meetings

15

written submissions received

11

retailers attended 2 separate in-person workshops, representing over 90% of residential and small business customers across NSW, SE Queensland and South Australia

7

one-on-one meetings

Continuing our engagement

We value the contributions stakeholders have provided during the consultation for our issues paper. We will continue our stakeholder engagement activities as part of our annual DMO process, engaging with a diverse range of stakeholders. The draft determination outlines how we have considered stakeholder feedback and includes our rationale behind each component of the draft determination.

We would like to thank participants for their involvement in this process and look forward to further positive engagement as part of the consultation for the draft determination and future engagements.

How we collected feedback

1 consumer group workshop held with the AER's Customer Consultative Group	**2** retailer workshops, one each with larger retailers and small/medium retailers, involving 12 organisations	**7** one-on-one meetings

One-on-one meetings

We conducted one-on-one meetings with a range of stakeholders including retailers, networks, industry representatives, consumer advocacy groups and government agencies. These meetings provided the opportunity for AER staff to listen to stakeholders and for stakeholders to ask questions of AER staff. The sessions provided valuable insights that helped us understand stakeholder views. These sessions were verbal discussions, so we have not attributed responses to particular participants.

Workshops

We hosted two face-to-face workshops with large and small-to-medium size retailers to discuss key topics featured in the issues paper. This gave retailers the opportunity to discuss key topics featured in the paper and ask any questions of AER staff.

We also held a workshop with the AER's Customer Consultative Group to gather insights from a consumer perspective.

Written feedback

We publicly invited stakeholders to contribute to our consultation process and received 15 written submissions from the following stakeholders:

- AGL
- Alinta Energy
- Ausgrid
- Australian Energy Council
- Customer Consultative Group
- Energy Consumers Australia
- Energy Locals
- EnergyAustralia
- ENGIE
- Justice and Equity Centre, South Australian Council of Social Service, Australian Council of Social Service
- Origin Energy
- Red/Lumo Energy
- South Australian Business Chamber
- South Australian Council of Social Service
- Shell Energy Australia

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B. Smart meter costs

We requested retailers selling to approximately 94% of customers in DMO regions to provide the number of customers on advanced meters and accumulation meters for each DMO region and customer type as at 30 September 2024, and projected installations for the mid-point of DMO 7 (31 December 2025). We also asked retailers to provide the average costs they incur per advanced meter and the extent to which a portion of these costs are recovered in up-front and/or one-off installation fees. Tables B.1 and B.2 set out our calculations for estimating advanced meter costs per residential and small business customer.

Table B.1 Residential advanced meter counts and per customer costs

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks	DMO
Total advanced meter costs incurred by retailers ($)	$65,271,363	$62,226,597	$44,895,279	$74,399,506	$45,549,925	**$292,342,671**
Total advanced meter customers	558,997	534,628	384,160	657,192	397,404	**2,532,381**
Average cost incurred per advanced meter ($) (ex GST)	$116.77	$116.39	$116.87	$113.21	$114.62	**$115.44**
ACS metering allowance included in network component ($) (ex GST)	$27.54	N/A				
Proportion of customers that do not incur an ACS charge (new connections with smart meters) (%)	6.96%	N/A				
Adjustment to ACS metering allowance reflecting not all customers incur this cost ($)	-$1.92	N/A				
Total customers	1,520,905	939,348	738,534	1,364,571	794,186	**5,357,544**
Customers with advanced meters (%)	36.8%	56.9%	52.0%	48.2%	50.0%	**47.3%**
Advanced meter cost per customer ($)	$41.00	$66.24	$60.79	$54.52	$57.35	**N/A**
Additional capital allowance adjustment (see Table B.3)	$2.21	$2.43	$3.10	$3.00	$2.31	**N/A**

Source: Retailer data request as at 30 September 2024.

Table B.2 Small business advanced meter counts and per customer costs

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks	DMO
Total advanced meter costs incurred by retailers ($)	$4,552,598	$2,923,532	$3,450,550	$4,749,816	$3,528,699	**$19,205,194**
Total advanced meter customers	35,450	22,564	26,173	34,943	26,519	**145,649**
Average cost incurred per advanced meter ($) (ex GST)	$128.42	$129.57	$131.84	$135.93	$133.06	**$131.86**
ACS metering allowance included in network component ($) (ex GST)	$38.16	N/A				
Proportion of customers that do not incur an ACS charge (new connections with smart meters) (%)	21.61%	N/A				
Adjustment to ACS metering allowance reflecting not all customers incur this cost ($)	-$8.25	N/A				
Total customers	133,351	64,825	74,084	101,098	80,729	**454,087**
Customers with advanced meters (%)	26.6%	34.8%	35.3%	34.6%	32.8%	**32.1%**
Advanced meter cost per customer ($)	$25.89	$45.10	$46.58	$46.98	$43.71	**N/A**
Additional capital allowance adjustment (see Table B.4)	$1.44	$1.78	$1.75	$1.02	$1.12	**N/A**

Source: Retailer data request as at 30 September 2024.

Table B.3 Calculation of residential capital allowance adjustment

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Smart meter allowance in DMO 7, based on actual installs at 30 September 2024	$41.00	$66.24	$60.79	$54.52	$57.35
Smart meter allowance based on retailer projected installations at 31 December 2025	$63.09	$90.54	$91.75	$84.51	$80.41
Projected shortfall in Smart Meter Allowance at 31 December 2025	$22.09	$24.30	$30.96	$29.99	$23.05
Weighted average cost of capital applied to shortfall	10%	10%	10%	10%	10%
Cost of capital for projected shortfall in smart meter allowance (excl. GST)	$2.21	$2.43	$3.10	$3.00	$2.31

Source: Retailer data request as at 30 September 2024

Table B.4 Calculation of small business capital allowance adjustment

Region	Ausgrid	Endeavour Energy	Essential Energy	Energex	SA Power Networks
Smart meter allowance in DMO 7, based on actual installs at 30 September 2024	$25.89	$45.10	$46.58	$46.98	$43.71
Smart meter allowance based on retailer projected installations at 31 December 2025	$40.25	$62.89	$64.13	$57.13	$54.87
Projected shortfall in Smart Meter Allowance at 31 December 2025	$14.36	$17.79	$17.55	$10.15	$11.16
Weighted average cost of capital applied to shortfall	10%	10%	10%	10%	10%
Cost of capital for projected shortfall in smart meter allowance (excl. GST)	$1.44	$1.78	$1.75	$1.02	$1.12

Source: Retailer data request as at 30 September 2024

C. Draft DMO Legislative Instrument 2025–26

Competition and Consumer (Industry Code – Electricity Retail) (Model Annual Usage and Total Annual Prices) Determination 2025

The Australian Energy Regulator makes the following determination.

Dated [ ] May 2025 Australian Energy Regulator

1. Name

This instrument is the *Competition and Consumer (Industry Code – Electricity Retail) (Model Annual Usage and Total Annual Prices) Determination 2025.*

2. Commencement

This instrument commences on 1 July 2025.

3. Authority

This instrument is made under section 16(1) of the *Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019* (the Regulations).

4. Definitions

In this Determination:

a) ***Regulations*** means the *Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019*; and

b) ***Residential Annual Usage without Controlled Load*** applies to the type of small customer considered in s 6(2)(b) of the Regulations; and

c) ***Residential Annual Price without Controlled Load*** applies to the type of small customer considered in s 6(2)(b) of the Regulations; and

d) ***Residential Annual Usage with Controlled Load*** applies to the type of small customer considered in s 6(2)(a) of the Regulations; and

e) ***Residential Annual Price with Controlled Load*** applies to the type of small customer considered in s 6(2)(a) of the Regulations; and

f) ***Small Business Annual Usage*** applies to the type of small customer considered in s 6(2)(c) of the Regulations; and

g) ***Small Business Annual Price*** applies to the type of small customer considered in s 6(2)(c) of the Regulations; and

h) ***General Usage*** means the non-controlled load usage of a small customer under s 6(2)(a) of the Regulations; and

i) ***Controlled Load Usage*** means the controlled load usage of a small customer under s 6(2)(a) of the Regulations.

j) Terms defined in the Regulations have the same meaning in this instrument.

5. Per-customer usage determination

In accordance with s 16(1)(a)(i) of the Regulations, the AER determines the per-customer amount of electricity supplied in specified distribution regions to small customers of the following types:

Per-customer annual usage determination (365 days p.a. in 2025-26)				
Distribution region	**Residential Annual Usage without Controlled Load**	**Residential Annual Usage with Controlled Load**		**Small Business Annual Usage**
		General Usage	***Controlled Load Usage***	
Ausgrid	3,900 kWh	4,800 kWh	2,000 kWh	10,000 kWh
Endeavour Energy	4,900 kWh	5,200 kWh	2,200 kWh	10,000 kWh
Energex	4,600 kWh	4,400 kWh	1,900 kWh	10,000 kWh
Essential Energy	4,600 kWh	4,600 kWh	2,000 kWh	10,000 kWh
SA Power Networks	4,000 kWh	4,200 kWh	1,800 kWh	10,000 kWh

6. Timing or pattern of supply determination

In accordance with s 16(1)(a)(ii) of the Regulations, the AER determines the timing or pattern of the supply of electricity in specified distribution regions to small customers:

a) Seasonality assumptions, all tariff and customer types

For all tariff and customer types, consumption has no seasonal weighting. That is, kilowatt hours consumed are assumed to be the same on each day of the year.

b) Daily usage profile for Flexible Tariffs (Time of Use tariffs, including the South Australian TOU controlled load tariff) – Residential Usage without Controlled Load and General Usage / Residential Usage with Controlled Load

i. Ausgrid distribution region

Flexible Tariff (Time of Use tariff) daily usage profile – Daily Residential Usage without Controlled Load (3,900 kWh/yr.)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2426**	**0.2352**	**0.2227**	**0.1973**	**0.1787**	**0.1630**	**0.1523**	**0.1457**	**0.1431**	**0.1430**	**0.1482**	**0.1570**	**0.1738**	**0.1948**	**0.2050**	**0.2158**	**0.2168**	**0.2136**	**0.2113**	**0.2079**	**0.2062**	**0.2035**	**0.2015**	**0.2013**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2022**	**0.2022**	**0.2014**	**0.2007**	**0.2006**	**0.2022**	**0.2061**	**0.2160**	**0.2298**	**0.2483**	**0.2701**	**0.2968**	**0.3123**	**0.3168**	**0.3120**	**0.3048**	**0.2996**	**0.2932**	**0.2821**	**0.2705**	**0.2668**	**0.2645**	**0.2575**	**0.2479**

Flexible Tariff (Time of Use tariff) daily usage profile – Daily General usage – Daily Residential Usage with Controlled Load (4,800 kWh/yr.)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2986**	**0.2895**	**0.2741**	**0.2428**	**0.2199**	**0.2006**	**0.1875**	**0.1793**	**0.1762**	**0.1760**	**0.1824**	**0.1932**	**0.2140**	**0.2398**	**0.2523**	**0.2656**	**0.2668**	**0.2628**	**0.2601**	**0.2559**	**0.2538**	**0.2505**	**0.2480**	**0.2478**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2489**	**0.2489**	**0.2478**	**0.2470**	**0.2468**	**0.2489**	**0.2536**	**0.2659**	**0.2828**	**0.3056**	**0.3325**	**0.3653**	**0.3844**	**0.3900**	**0.3841**	**0.3751**	**0.3688**	**0.3608**	**0.3472**	**0.3329**	**0.3284**	**0.3256**	**0.3170**	**0.3051**

ii. Endeavour Energy distribution region

Flexible Tariff (Time of Use tariff) daily usage profile - Daily Residential Usage without Controlled Load (4,900 kWh/yr.)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.3197**	**0.3125**	**0.2877**	**0.2475**	**0.2191**	**0.1990**	**0.1870**	**0.1813**	**0.1806**	**0.1813**	**0.1888**	**0.1999**	**0.2195**	**0.2438**	**0.2487**	**0.2586**	**0.2584**	**0.2531**	**0.2534**	**0.2519**	**0.2499**	**0.2487**	**0.2471**	**0.2474**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2473**	**0.2466**	**0.2452**	**0.2470**	**0.2513**	**0.2565**	**0.2657**	**0.2837**	**0.3044**	**0.3319**	**0.3551**	**0.3868**	**0.4017**	**0.4043**	**0.3973**	**0.3884**	**0.3772**	**0.3642**	**0.3474**	**0.3257**	**0.3257**	**0.3331**	**0.3289**	**0.3242**

Flexible Tariff (Time of Use tariff) daily usage profile - Daily General Usage – Daily Residential Usage with Controlled Load (5,200 kWh/yr.)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.3393**	**0.3316**	**0.3054**	**0.2626**	**0.2326**	**0.2112**	**0.1984**	**0.1924**	**0.1916**	**0.1924**	**0.2003**	**0.2121**	**0.2330**	**0.2588**	**0.2639**	**0.2745**	**0.2742**	**0.2686**	**0.2690**	**0.2674**	**0.2652**	**0.2639**	**0.2622**	**0.2626**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2625**	**0.2617**	**0.2602**	**0.2622**	**0.2667**	**0.2722**	**0.2820**	**0.3011**	**0.3230**	**0.3522**	**0.3769**	**0.4105**	**0.4262**	**0.4291**	**0.4216**	**0.4121**	**0.4003**	**0.3865**	**0.3686**	**0.3456**	**0.3457**	**0.3535**	**0.3491**	**0.3441**

iii. Energex distribution region

Flexible Tariff (Time of Use tariff) daily usage profile - Daily Residential Usage without Controlled Load (4,600 kWh/yr.)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2085**	**0.1935**	**0.1837**	**0.1741**	**0.1665**	**0.1614**	**0.1587**	**0.1578**	**0.1605**	**0.1663**	**0.1761**	**0.1887**	**0.2099**	**0.2301**	**0.2450**	**0.2482**	**0.2474**	**0.2423**	**0.2409**	**0.2393**	**0.2404**	**0.2478**	**0.2539**	**0.2592**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2586**	**0.2583**	**0.2581**	**0.2571**	**0.2605**	**0.2647**	**0.2741**	**0.2902**	**0.3090**	**0.3351**	**0.3656**	**0.3994**	**0.4169**	**0.4189**	**0.4043**	**0.3884**	**0.3769**	**0.3572**	**0.3348**	**0.3145**	**0.2977**	**0.2768**	**0.2552**	**0.2300**

Flexible Tariff (Time of Use tariff) daily usage profile - Daily General Usage – Daily Residential Usage with Controlled Load (4,400kWh/yr.)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.1995**	**0.1851**	**0.1757**	**0.1665**	**0.1593**	**0.1544**	**0.1518**	**0.1509**	**0.1535**	**0.1591**	**0.1685**	**0.1805**	**0.2008**	**0.2201**	**0.2343**	**0.2374**	**0.2366**	**0.2318**	**0.2304**	**0.2289**	**0.2300**	**0.2371**	**0.2428**	**0.2479**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2473**	**0.2471**	**0.2469**	**0.2459**	**0.2491**	**0.2532**	**0.2622**	**0.2776**	**0.2956**	**0.3206**	**0.3497**	**0.3820**	**0.3987**	**0.4007**	**0.3867**	**0.3715**	**0.3605**	**0.3416**	**0.3202**	**0.3008**	**0.2848**	**0.2648**	**0.2441**	**0.2200**

iv. Essential Energy distribution region

Flexible Tariff (Time of Use tariff) daily usage profile - Daily Residential Usage without Controlled Load (4,600 kWh/yr.)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2892**	**0.2811**	**0.2684**	**0.2540**	**0.2373**	**0.2169**	**0.2003**	**0.1899**	**0.1840**	**0.1831**	**0.1910**	**0.2036**	**0.2246**	**0.2417**	**0.2474**	**0.2519**	**0.2460**	**0.2339**	**0.2334**	**0.2314**	**0.2294**	**0.2328**	**0.2343**	**0.2338**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2361**	**0.2316**	**0.2256**	**0.2202**	**0.2184**	**0.2198**	**0.2263**	**0.2383**	**0.2539**	**0.2754**	**0.3077**	**0.3468**	**0.3713**	**0.3769**	**0.3686**	**0.3571**	**0.3500**	**0.3406**	**0.3305**	**0.3212**	**0.3240**	**0.3156**	**0.3061**	**0.3013**

Flexible Tariff (Time of Use tariff) daily usage profile - Daily General Usage – Daily Residential Usage with Controlled Load (4,600 kWh/yr.)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2892**	**0.2811**	**0.2684**	**0.2540**	**0.2373**	**0.2169**	**0.2003**	**0.1899**	**0.1840**	**0.1831**	**0.1910**	**0.2036**	**0.2246**	**0.2417**	**0.2474**	**0.2519**	**0.2460**	**0.2339**	**0.2334**	**0.2314**	**0.2294**	**0.2328**	**0.2343**	**0.2338**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2361**	**0.2316**	**0.2256**	**0.2202**	**0.2184**	**0.2198**	**0.2263**	**0.2383**	**0.2539**	**0.2754**	**0.3077**	**0.3468**	**0.3713**	**0.3769**	**0.3686**	**0.3571**	**0.3500**	**0.3406**	**0.3305**	**0.3212**	**0.3240**	**0.3156**	**0.3061**	**0.3013**

v. South Australian Power Networks distribution region

Flexible Tariff (Time of Use tariff) daily usage profile - Daily Residential Usage without Controlled Load (4,000 kWh/yr.)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2327**	**0.2720**	**0.2979**	**0.2782**	**0.2418**	**0.2110**	**0.1845**	**0.1683**	**0.1573**	**0.1529**	**0.1547**	**0.1624**	**0.1796**	**0.1875**	**0.2086**	**0.1980**	**0.1907**	**0.1808**	**0.1764**	**0.1888**	**0.2055**	**0.2312**	**0.2407**	**0.2344**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2272**	**0.2154**	**0.2074**	**0.2018**	**0.2022**	**0.2025**	**0.2070**	**0.2070**	**0.2233**	**0.2387**	**0.2726**	**0.3076**	**0.3277**	**0.3320**	**0.3274**	**0.3205**	**0.3115**	**0.2991**	**0.2824**	**0.2610**	**0.2367**	**0.2117**	**0.1918**	**0.2084**

Flexible Tariff (Time of Use tariff) daily usage profile - Daily General Usage – Daily Residential Usage with Controlled Load (4,200 kWh/yr.)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.2443**	**0.2856**	**0.3128**	**0.2921**	**0.2539**	**0.2216**	**0.1937**	**0.1767**	**0.1651**	**0.1606**	**0.1625**	**0.1705**	**0.1885**	**0.1969**	**0.2191**	**0.2079**	**0.2002**	**0.1898**	**0.1852**	**0.1982**	**0.2158**	**0.2428**	**0.2527**	**0.2461**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2385**	**0.2262**	**0.2178**	**0.2119**	**0.2123**	**0.2126**	**0.2174**	**0.2173**	**0.2345**	**0.2506**	**0.2863**	**0.3229**	**0.3441**	**0.3486**	**0.3437**	**0.3365**	**0.3271**	**0.3141**	**0.2965**	**0.2741**	**0.2485**	**0.2223**	**0.2014**	**0.2188**

Flexible Tariff (Time of Use tariff) daily usage profile - Daily Controlled Load usage – (1,800 kWh/yr.)

Time	00:00 - 00:30	00:30 - 01:00	01:00 - 01:30	01:30 - 02:00	02:00 - 02:30	02:30 - 03:00	03:00 - 03:30	03:30 - 04:00	04:00 - 04:30	04:30 - 05:00	05:00 - 05:30	05:30 - 06:00	06:00 - 06:30	06:30 - 07:00	07:00 - 07:30	07:30 - 08:00	08:00 - 08:30	08:30 - 09:00	09:00 - 09:30	09:30 - 10:00	10:00 - 10:30	10:30 - 11:00	11:00 - 11:30	11:30 - 12:00
Usage (kWh)	**0.1761**	**0.1761**	**0.1761**	**0.1761**	**0.1761**	**0.1761**	**0.1761**	**0.1761**	**0.1761**	**0.1761**	**0.1761**	**0.1761**	**0.1761**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.2466**	**0.2466**	**0.2466**	**0.2466**
Time	12:00 - 12:30	12:30 - 13:00	13:00 - 02:00	13:30 - 03:00	14:00 - 14:30	14:30 - 15:00	15:00 - 15:30	15:30 - 16:00	16:00 - 16:30	16:30 - 17:00	17:00 - 17:30	17:30 - 18:00	18:00 - 18:30	18:30 - 13:00	19:00 - 19:30	19:30 - 20:00	20:00 - 20:30	20:30 - 21:00	21:00 - 21:30	21:30 - 22:00	22:00 - 22:30	22:30 - 23:00	23:00 - 23:30	23:30 - 24:00
Usage (kWh)	**0.2466**	**0.2466**	**0.2466**	**0.2466**	**0.2466**	**0.2466**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.1761**

c) Controlled Load (CL) annual usage allocations

i. Ausgrid distribution region (kWh/year)

CL1 only	CL2 only	CL 1 and 2 (% of total)	
		CL1 (67%)	CL2 (33%)
2,000	2,000	1,340	660

ii. Endeavour Energy distribution region (kWh/year)

CL 1 only	CL 2 only	CL 1 and 2 (% of total)	
		CL 1 (67%)	CL 2 (33%)
2,200	2,200	1,474	726

iii. Energex distribution region (kWh/year)

CL 1 only	CL 2 only	CL 1 and 2 (% of total)	
		CL 1 (29%)	CL 2 (71%)
1,900	1,900	551	1,349

iv. Essential Energy distribution region (kWh/year)

CL 1 only	CL 2 only	CL 1 and 2 (% of total)	
		CL 1 (77%)	CL 2 (23%)
2,000	2,000	1,540	460

v. South Australian Power Networks distribution region (kWh/year)[197]

CL 1 only	CL 2 only	CL 1 and 2
1,800	NA	NA

[197] Refer to section 6.b)v. for the daily usage profile for the TOU controlled load tariff.

7. Per-customer annual price determination

In accordance with s 16(1)(b) of the Regulations, the AER determines what it considers the reasonable per-customer annual price for supplying electricity in specified distribution regions to small customers of the types set out below.

Per-customer draft annual price determination (all prices GST-inclusive)			
Distribution region	**Annual Residential Price without Controlled Load**	**Annual Residential Price with Controlled Load**	**Small Business Annual Price**
Ausgrid	$1,969	$2,714	$4,988
Endeavour Energy	$2,397	$3,050	$4,762
Energex	$2,185	$2,475	$4,439
Essential Energy	$2,713	$3,174	$6,183
SA Power Networks	$2,344	$2,881	$5,707

DATED THIS XX DAY OF
MAY 2025

Australian Energy Regulator

D. DMO 6 to DMO 7 price movements

The charts in this appendix show the movement in the DMO cost components between DMO 6 and the DMO 7 draft determination, with the overall height indicating the total DMO price for each DNSP.

We note that:

- Network and environmental cost components in the DMO 7 draft determination are calculated using predominately the same methodology as DMO 6, so the changes directly reflect year-on-year movement.
- Changes to the retail cost component reflect both year-on-year movement and also the impact of a broader retail cost dataset that covers 99% of the small customer market.
- Changes to the wholesale cost component reflect both year-on-year movement and also the impact of the methodological adjustments of applying a hedging adjustment for solar exports to the load profiles and using one year of NSLP data to simulate the load profiles instead of 2 years used in previous DMO determinations.
  - For DMO 6 we also used the 'mid-point' of two load profiles in Energex and SA Power Networks, due to challenges with load profile data.

Figure D.1 Residential without CL, % change from DMO 6 (nominal)

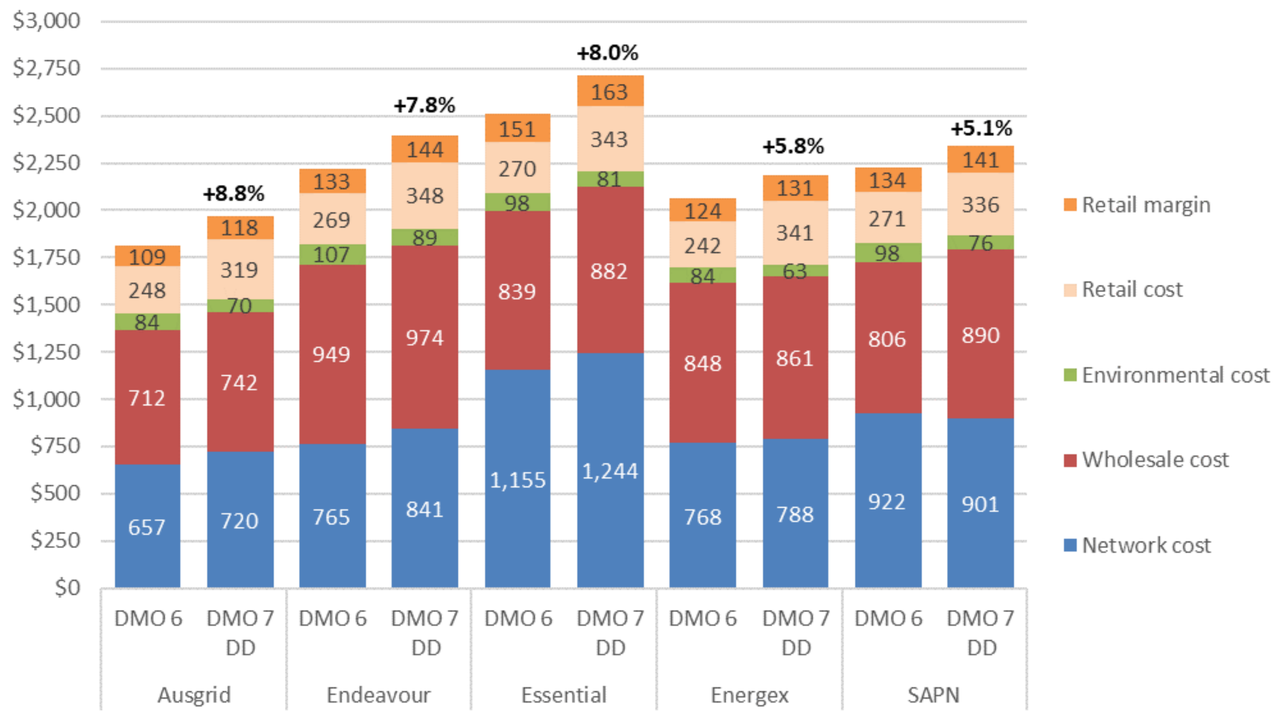


Figure D.2 Residential with CL, % change from DMO 6 (nominal)

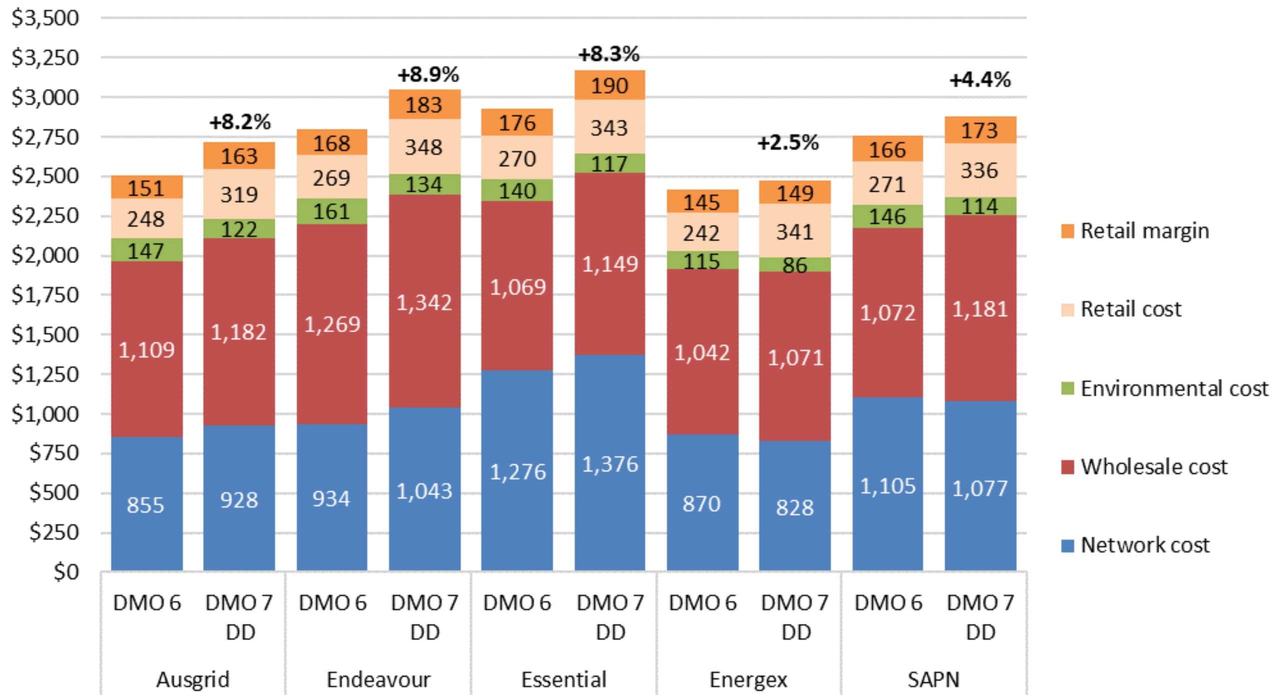
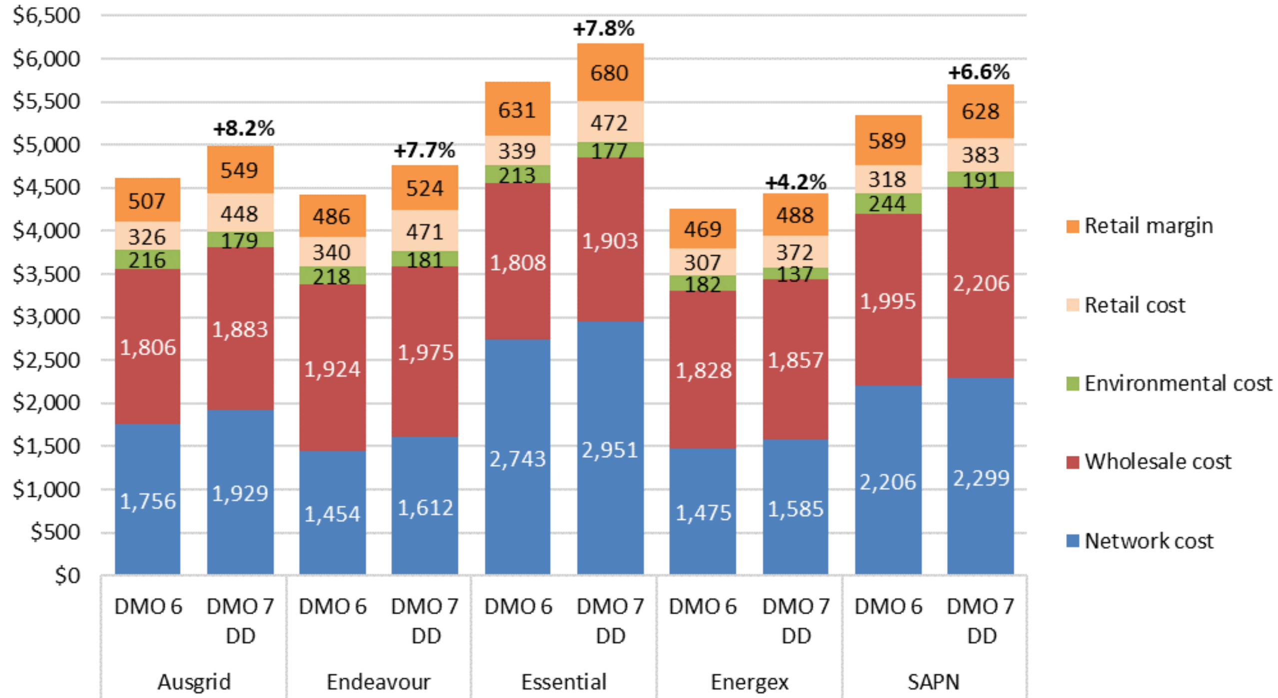


Figure D.3 Small business, % change from DMO 6 (nominal)



E. State-based summaries of cost changes

This appendix explains in further detail the DMO cost stack changes from the DMO 6 final determination to the DMO 7 draft determination for each state.

NSW summary

NSW **residential customers without controlled load** will see price increases of $159 or 8.8% (Ausgrid), $174 or 7.8% (Endeavour Energy) and $200 or 8.0% (Essential Energy). This is between 5.4% to 6.4% above forecast inflation. **Residential customers with controlled load** will see price increases of $205 or 8.2% (Ausgrid), $249 or 8.9% (Endeavour Energy) and $243 or 8.3% (Essential Energy). These are increases of between 5.8% and 6.5% above forecast inflation. **Small business customers** will see increases of $376 or 8.2% (Ausgrid), $340 or 7.7% (Endeavour Energy) and $450 or 7.8% (Essential Energy). These are increases of between 5.3% and 5.8% above forecast inflation.

As outlined in Tables E.1 to E.3, since the DMO 6 final determination we have observed:

- Across each region of NSW there have been increases in wholesale costs for all customer types, largely driven by movements in contract prices. Specific contract price movements for 2025–26 on an annualised and trade-weighted basis were increases in base futures contract prices of $7.70/MWh and in cap contract prices of $7.20/MWh.
- Across each region of NSW network costs have risen. Increases in network costs for NSW customers are driven by the price paths set in our 2024–29 regulatory determinations, with a key driver across each of these determinations being market factors (higher inflation and interest rates) causing a higher rate of return. The determined NSW Roadmap cost increases and forecast increases in transmission costs (which will be finalised for the final determination) are also driving increases. Increasing forecast energy consumption levels act to partially offset increases for Endeavour Energy's customers.
- Environmental costs have decreased across each region of NSW and all customer types. These decreases are primarily driven by decreases in both federal and state renewable energy target schemes, offset slightly by an increase in the NSW peak demand reduction scheme cost.
- Retail costs have risen for all customers in each region of NSW. For all customers this was primarily due to increases in retailers operating costs. There has also been an increase in bad and doubtful debt costs and smart meter costs which contributed to the overall increases.
- The dollar value of the retail margin has increased in DMO 7 due to increases in wholesale, network and retail costs. The retail margin is set at 6% of the total DMO price for residential customers and 11% for small business, so increases in other components of the cost stack cause the retail margin to also increase.

Table E.1 Residential without CL, change from final determination DMO 6 to draft determination DMO 7, NSW regions (nominal)

Distribution Region	Cost stack component	Final determination DMO 6		Draft determination DMO 7		Difference from DMO 6 to Draft DMO 7	
		$ inc GST	*margin*	*$ inc GST*	*margin*	*$ diff*	*% diff*
Ausgrid	Network cost	656.75		719.64		62.88	9.6%
	Wholesale cost	712.34		742.23		29.89	4.2%
	Environmental cost	84.26		69.93		-14.33	-17.0%
	Retail cost	248.17		318.76		70.59	28.4%
	Retail margin	108.61	6.0%	118.12	6.0%	9.51	8.8%
	Total	**1,810**		**1,969**		**159**	**8.8%**
Endeavour Energy	Network cost	764.81		841.49		76.67	10.0%
	Wholesale cost	949.36		974.34		24.98	2.6%
	Environmental cost	106.78		88.61		-18.16	-17.0%
	Retail cost	268.94		348.35		79.41	29.5%
	Retail margin	133.40	6.0%	143.80	6.0%	10.40	7.8%
	Total	**2,223**		**2,397**		**173**	**7.8%**
Essential Energy	Network cost	1,155.09		1,243.71		88.62	7.7%
	Wholesale cost	838.81		882.30		43.49	5.2%
	Environmental cost	97.86		81.21		-16.65	-17.0%
	Retail cost	270.03		342.80		72.77	26.9%
	Retail margin	150.75	*6.0%*	162.77	*6.0%*	12.01	8.0%
	Total	**2,513**		**2,713**		**200**	**8.0%**

Table E.2 Residential with CL, change from final determination DMO 6 to draft determination DMO 7, NSW regions (nominal)

Distribution Region	Cost stack component	Final determination DMO 5		Draft determination DMO 6		Difference from DMO 6 to Draft DMO 7	
		$ inc GST	*margin*	*$ inc GST*	*margin*	*$ diff*	*% diff*
Ausgrid	Network cost	854.76		928.49		73.73	8.6%
	Wholesale cost	1,108.68		1,181.83		73.15	6.6%
	Environmental cost	147.15		122.12		-25.03	-17.0%
	Retail cost	248.17		318.76		70.59	28.4%
	Retail margin	150.56	*6.0%*	162.84	*6.0%*	12.28	8.2%
	Total	**2,509**		**2,714**		**205**	**8.2%**
Endeavour Energy	Network cost	934.14		1,042.86		108.72	11.6%
	Wholesale cost	1,268.54		1,341.73		73.19	5.8%
	Environmental cost	161.25		133.82		-27.43	-17.0%
	Retail cost	268.94		348.35		79.41	29.5%
	Retail margin	168.06	*6.0%*	182.99	*6.0%*	14.93	8.9%
	Total	**2,801**		**3,050**		**249**	**8.9%**
Essential Energy	Network cost	1,276.37		1,375.56		99.19	7.8%
	Wholesale cost	1,068.76		1,149.11		80.35	7.5%
	Environmental cost	140.41		116.52		-23.89	-17.0%
	Retail cost	270.03		342.80		72.77	26.9%
	Retail margin	175.89	*6.0%*	190.47	*6.0%*	14.58	8.3%
	Total	**2,931**		**3,174**		**243**	**8.3%**

Table E.3 Small business without CL, change from final determination DMO 6 to draft determination DMO 7, NSW regions (nominal)

Distribution Region	Cost stack component	Final determination DMO 6		Draft determination DMO 7		Difference from DMO 6 to Draft DMO 7	
		$ inc GST	*margin*	*$ inc GST*	*margin*	*$ diff*	*% diff*
Ausgrid	Network cost	1,756.19		1,929.35		173.16	9.9%
	Wholesale cost	1,806.03		1,882.53		76.50	4.2%
	Environmental cost	216.04		179.30		-36.74	-17.0%
	Retail cost	326.29		447.96		121.66	37.3%
	Retail margin	507.30	*11.0%*	548.66	*11.0%*	41.35	8.2%
	Total	**4,612**		**4,988**		**376**	**8.2%**
Endeavour Energy	Network cost	1,453.95		1,611.61		157.66	10.8%
	Wholesale cost	1,923.84		1,974.71		50.87	2.6%
	Environmental cost	217.91		180.84		-37.07	-17.0%
	Retail cost	339.66		470.68		131.03	38.6%
	Retail margin	486.39	*11.0%*	523.78	*11.0%*	37.39	7.7%
	Total	**4,422**		**4,762**		**340**	**7.7%**
Essential Energy	Network cost	2,742.78		2,951.28		208.49	7.6%
	Wholesale cost	1,808.12		1,902.55		94.43	5.2%
	Environmental cost	212.74		176.55		-36.19	-17.0%
	Retail cost	338.81		472.37		133.56	39.4%
	Retail margin	630.64	*11.0%*	680.11	*11.0%*	49.47	7.8%
	Total	**5,733**		**6,183**		**450**	**7.8%**

SE Queensland summary

SE Queensland **customers without controlled load** face an overall price increase of $119 or 5.8% (3.4% above forecast inflation). **Customers with controlled load** will face an increase of $61 or 2.5% (0.1% above forecast inflation). **Small business customers** can expect an increase of $178 or 4.2% (1.8% above forecast inflation).

As outlined in the Table E.4, since the DMO 6 final determination we have observed the following in SE Queensland:

- A small increase in wholesale costs for all customer types, driven by movements in contract prices. Specific contract price movements for 2025–26 on an annualised and trade-weighted basis were increases in base futures contract prices of $3.50/MWh and in cap contract prices of $0.30/MWh. Compared to other regions flatter wholesale costs in Queensland result from significant volumes of base and cap contract purchases occurring at lower prices during 2023. These trades are offsetting contracts purchased at higher prices throughout 2024 and early 2025. If Queensland contract prices remain at their current higher prices wholesale costs are likely to increase in the final determination.
- Network costs have increased for residential and small business customers without controlled load and decreased for residential customers with controlled load. The changes are driven by the price path proposed in the 2025–30 revised regulatory proposal, which the AER is still assessing. These are largely driven by market factors (higher interest rates), causing a higher rate of return. Cost pass-throughs that have either been proposed to the AER (for storm related costs in 2024)[198], or approved by the AER (for retailer of last resort cost recovery) [199], are also contributing to these increases. These are partially offset by the return of previously over-recovered distribution revenues.
- Environmental costs have decreased across all customer types, driven by decreases in the federal renewable energy target schemes.
- Retail costs have increased across all customers by 21.2% for small business and 40.7% for residential customers. This has been primarily due to increases in operating costs, smart meter costs and increases in bad and doubtful debt costs.
- Retail margin has increased in DMO 7 due primarily to increases in network and retail costs. The retail margin is set at 6% of the total DMO price for residential customers and 11% for small business, so increases in other components of the cost stack cause the retail margin to also increase.

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[198] AER, Energex cost pass through application – South East Queensland storms, Australian Energy Regulator.

[199] AER, Origin retailer of last resort cost recovery applications, Australian Energy Regulator.

Table E.4 Summary of DMO price changes from final determination DMO 6 to draft determination DMO 7, SE Queensland (nominal)

Distribution Region	Cost stack component	Final determination DMO 6		Draft determination DMO 7		Difference from DMO 6 to Draft DMO 7	
		$ inc GST	*margin*	*$ inc GST*	*margin*	*$ diff*	*% diff*
Residential without CL, change from final determination DMO 6 to draft determination DMO 7 (nominal)							
Energex	Network cost	767.70		788.19		20.49	2.7%
	Wholesale cost	847.87		861.20		13.533	1.6%
	Environmental cost	83.64		62.85		-20.80	-24.9%
	Retail cost	242.45		341.25		98.80	40.7%
	Retail margin	123.94	*6.0%*	131.07	*6.0%*	7.14	5.8%
	Total	**2,066**		**2,185**		**119**	**5.8%**
Residential with CL, change from final determination DMO 6 to draft determination DMO 7 (nominal)							
Energex	Network cost	870.27		828.09		-42.18	-4.8%
	Wholesale cost	1,041.80		1,071.38		29.58	2.8%
	Environmental cost	114.55		86.07		-28.48	-24.9%
	Retail cost	242.45		341.25		98.80	40.7%
	Retail margin	144.84	*6.0%*	148.52	*6.0%*	3.68	2.5%
	Total	**2,414**		**2,475**		**61**	**2.5%**
Small business without CL, change from final determination DMO 6 to draft determination DMO 7 (nominal)							
Energex	Network cost	1,475.39		1,585.14		109.75	7.4%
	Wholesale cost	1,827.81		1,856.68		28.87	1.6%
	Environmental cost	181.83		136.62		-45.21	-24.9%
	Retail cost	306.97		372.09		65.13	21.2%
	Retail margin	468.67	*11.0%*	488.27	*11.0%*	19.59	4.2%
	Total	**4,261**		**4,439**		**178**	**4.2%**

Source: AER Default market offer 2025–26 cost assessment model.

South Australia summary

South Australian **residential customers without controlled load** will experience a price increase of $114 or 5.1% (2.7% above forecast inflation). Residential **customers with controlled load** face an increase of $121 or 4.4% (2% above forecast inflation). **Small business customers** will see an increase of $355 or 6.6% (4.2% above forecast inflation).

As outlined in Table E.5, since the DMO 6 final determination we have observed the following in South Australia:

- Wholesale cost increases across all customer types. This has been driven by movements in contract prices and the shape of the load profiles used for wholesale modelling:
  - Specific contract price movements for 2025–26 on an annualised and trade-weighted basis were increases in base futures contract prices of $2.80/MWh and in cap contract prices of $3.20/MWh.
  - The load profile used to model wholesale costs in South Australia become peakier during the evening, resulting in higher hedging costs.
- Network costs have decreased for residential customers with and without controlled load and increased for small business customers. Increases in network costs for small business customers are driven by the price path proposed in the 2025–30 revised regulatory proposal, which the AER is still assessing. These are largely driven by market factors (higher interest rates), causing a higher rate of return. These are partially offset by the return of previously over-recovered revenues. Decreases in costs for South Australian residential customers are driven by a forecast reduction in the allocation of transmission costs (which will be finalised for the final determination) to the residential flat rate tariff and the return of previously over-recovered revenues. This is partially offset by SA Power Networks' proposed price path in its revised regulatory proposal and market factors.
- Environmental cost decreases across all customers. This is mainly driven by decreases in both federal and state renewable energy target schemes.
- Retail cost increases across all customers. The year-on-year increase of 20.3% to 24.1% is primarily due to operating costs, increases in bad and doubtful debt costs and increase in smart meter costs.
- Retail margin has increased in DMO 7 due to increases in wholesale, network and retail costs. The retail margin is set at 6% of the total DMO price for residential customers and 11% for small business, so increases in other components of the cost stack cause the retail margin to also increase.

Table E.5 Summary of DMO price changes from final determination DMO 6 to draft determination DMO 7, South Australia (nominal)

Distribution Region	Cost stack component	Final determination DMO 6		Draft determination DMO 7		Difference from DMO 6 to Draft DMO 7	
		$ inc GST	*margin*	*$ inc GST*	*margin*	*$ diff*	*% diff*
Residential without CL, change from final determination DMO 6 to draft determination DMO 7 (nominal)							
SA Power Networks	Network cost	922.34		900.67		-21.67	-2.3%
	Wholesale cost	805.77		890.38		84.60	10.5%
	Environmental cost	97.50		76.30		-21.21	-21.8%
	Retail cost	270.61		335.69		65.09	24.1%
	Retail margin	133.80	*6.0%*	140.62	*6.0%*	6.82	5.1%
	Total	**2,230**		**2,344**		**114**	**5.1%**
Residential with CL, change from final determination DMO 6 to draft determination DMO 7 (nominal)							
SA Power Networks	Network cost	1,105.12		1,077.33		-27.79	-2.5%
	Wholesale cost	1,072.05		1,181.06		109.01	10.2%
	Environmental cost	146.26		114.44		-31.81	-21.8%
	Retail cost	270.61		335.69		65.09	24.1%
	Retail margin	165.58	*6.0%*	172.89	*6.0%*	7.31	4.4%
	Total	**2,760**		**2,881**		**121**	**4.4%**
Small business without CL, change from final determination DMO 6 to draft determination DMO 7 (nominal)							
SA Power Networks	Network cost	2,206.45		2,299.44		92.99	4.2%
	Wholesale cost	1,994.79		2,206.15		211.36	10.6%
	Environmental cost	243.76		190.74		-53.02	-21.8%
	Retail cost	318.27		383.02		64.75	20.3%
	Retail margin	588.72	*11.0%*	627.78	*11.0%*	39.07	6.6%
	Total	**5,352**		**5,707**		**355**	**6.6%**

Source: AER Default market offer 2025–26 cost assessment model.

F. Detailed analysis of retail margins

This appendix discusses the various sources of retail margins that we have considered in our draft determination and sets out detailed margin analysis of our retail cost information request.

Sources of retail margin analysis

We have examined a wide range of retail margin data to assess whether the DMO margins of 6% and 11% remain appropriate. These include data sources across government, such as the ACCC's December 2024 inquiry,[200] Energy Made Easy market offer data, and retailer data we collected through our own formal retail cost information request.

A summary of each approach and data source used to estimate retail margins is described in further detail below.

AER analysis of advertised market offers

In the DMO 6 determination, ACIL Allen estimated EBITDA margins for each customer type and DMO region by analysing advertised market offers available between 1 July 2023 and 31 August 2023.[201] This involved deconstructing estimated retail bills by deducting, for each market offer, the DMO 5 retail, wholesale, environmental and network costs.

We have updated ACIL Allen's retail margin analysis by deducting DMO 6 cost components from estimated residential bills for each retail market offer, while maintaining the same parameters, such as estimating these retail margins using the market offers as close to the commencement of the DMO 6 final determination as possible. As time passes after the DMO 6 final determination, projected wholesale energy costs may diverge, increasing the margin of error in retail margin calculations. Note offers targeted to new customers are excluded as they could represent loss leading or acquisition offers.

This approach is based on current data and represents the margin retailers are willing to receive in a competitive market. This approach also has the benefit of netting out any over- or under-estimates in the retail margin due to under- or over-estimates of underlying costs.

Using this approach, we found that retail margins ranged from -5.6% to 2.2% for residential customers without controlled load, -6.3% to 1.4% for residential customers with controlled load, and 7.0% to 10.7% for small business customers, depending on the DMO region.

AER EBITDA analysis

To estimate a reasonable retail margin, we considered financial data from retailers, collected through our formal retail cost information request. This analysis used 2023–24 EBITDA data across residential and small business customers, expressed as a percentage of retailers' revenue.

200 ACCC, Inquiry into the National Electricity Market, Australian Competition and Consumer Commission, December 2024 report.

201 ACIL Allen, Default Market Offer 2024–25 Methodologies for estimating the retail allowance and estimated values, 10 May 2024.

Additionally, we have considered the 2023–24 EBITDA margins published by the ACCC in its December 2024 Inquiry report, which covers a subset of 13 retailers included in the AER information request.

We consider this measure a relevant consideration in determining an efficient margin as it reflects the actual margins achieved by retailers in competitive markets. For residential customers we collected EBITDA data from 22 retailers who account for approximately 98% of residential customers. For small business customers, we collected data from 23 retailers who account for 99% of small business customers across all DMO regions.[202]

Our analysis of retailers' cost data indicates a weighted average EBITDA retail margin of 5.6% for residential customers and 11.6% for small businesses. Note our retail cost information does not include granular data on residential customers with controlled load and those without controlled load.

AER analysis of ACCC retail pricing information

In its December 2024 report, the ACCC analysed the average retail prices customers were charged on 1 August 2024. This dataset represents a sample of over 6.7 million residential customers and 400,000 small business customers in NSW, Victoria, SE Queensland and South Australia.

To compare prices with the DMO, the ACCC converted every plan's retail price to an annual cost based on DMO 6 usage amounts. The ACCC then developed customer-weighted average prices in each DMO region for residential without controlled load, residential with controlled load, and small business customers. We deducted DMO 6 costs from these average prices to infer our estimate of customer-weighted average EBITDA margin.

This measure is a relevant consideration when determining an efficient margin. This is because it reflects the actual margins retailers operating in a competitive environment are achieving across all market offer customers, including both engaged customers that switch to acquisition offers, and disengaged customers on closed market offers that return a greater margin.

This is a similar approach to the ACIL Allen analysis outlined above as it deducts DMO 6 costs from market offers to estimate EBITDA margins.

Benchmarking regulatory decisions in other jurisdictions

Retail margin determinations from other regulators are also relevant for consideration when determining an efficient margin for DMO prices.

These regulators have requirements to determine efficient and/or fair margins. ESC, ICRC and OTTER set uniform margins for small customers, covering both residential and small businesses.

202 Among the 26 retailers that provided retail cost data, 2 retailers do not serve residential customers, one does not serve small businesses, and 2 others did not provide EBITDA data for either residential or small businesses.

Table F.1 provides a comparison of retail margins across different regulators. In summary:

- The ICRC previously used a benchmarking approach and expressed the retail margins as a percentage of costs. However, in its final determination for 2024–27 the ICRC adopted a hybrid approach, applying a 50:50 weighting for the percentage and dollar amount.[203] Frontier Economics was engaged by the ICRC and found that:[204]
  - a margin, in percentage terms, overcompensates retailers as increased energy costs would reduce the risks retailers face
  - a margin, in dollar terms, undercompensates retailers as increased energy costs would increase fixed costs
  - equal weighting to both percentage and fixed-dollar term margins provided appropriate compensation to retailers.
- The ESC maintained the use of their benchmark approach and have adopted the same margin (5.3 per cent of costs) from their final decision in 2023–24 to 2024–25.[205]
- The OTTER determined a retail margin based on a percentage and then converted this to a dollar figure for use between 1 July 2022 to 30 June 2025. In this period, the regulator applied a retail margin of 5.25%.[206] For the 2025 determination, the OTTER has decided to maintain their benchmarking approach.[207]

Table F.1 Comparison of regulated retail margins by jurisdiction

Regulator	State	2023–24	2024–25
ICRC	ACT	5.6%	5.3% (50:50 split between percentage and dollar terms)
ESC	Victoria	5.3% (maintained retail margins in 2024–25)	
OTTER	Tasmania	5.25% (retail margin in 2023–24 and 2024–25 is $100.90, indexed by CPI)[208]	

Detailed analysis

This section provides detailed retail margin analysis for residential and small business customers.

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203 ICRC, Retail electricity price recalibration 2023–24: standing offer prices for the supply of electricity to small customers, June 2023, p. 20; ICRC, Retail electricity price investigation 2024–27, 23 May 2024, p. 28.

204 ICRC, Retail electricity price recalibration 2023–24: standing offer prices for the supply of electricity to small customers, June 2023, p. 20; ICRC, Retail electricity price investigation 2024–27, 23 May 2024, p. 45–46.

205 ESC, Victorian Default Offer 2023–24, Final Decision Paper, 25 May 2023, p. 10; ESC, Victorian Default Offer 2024–25, Final Decision Paper, 20 May 2024, p. 37.

206 OTTER, 2022 standing offer electricity pricing investigation, April 2022, p. 44.

207 OTTER, Review of the approach to regulating retail electricity prices, Final methodology paper, October 2024, pp. 33–37.

208 OTTER, Review of the approach to regulating retail electricity prices, Final methodology paper, October 2024, p. VI.

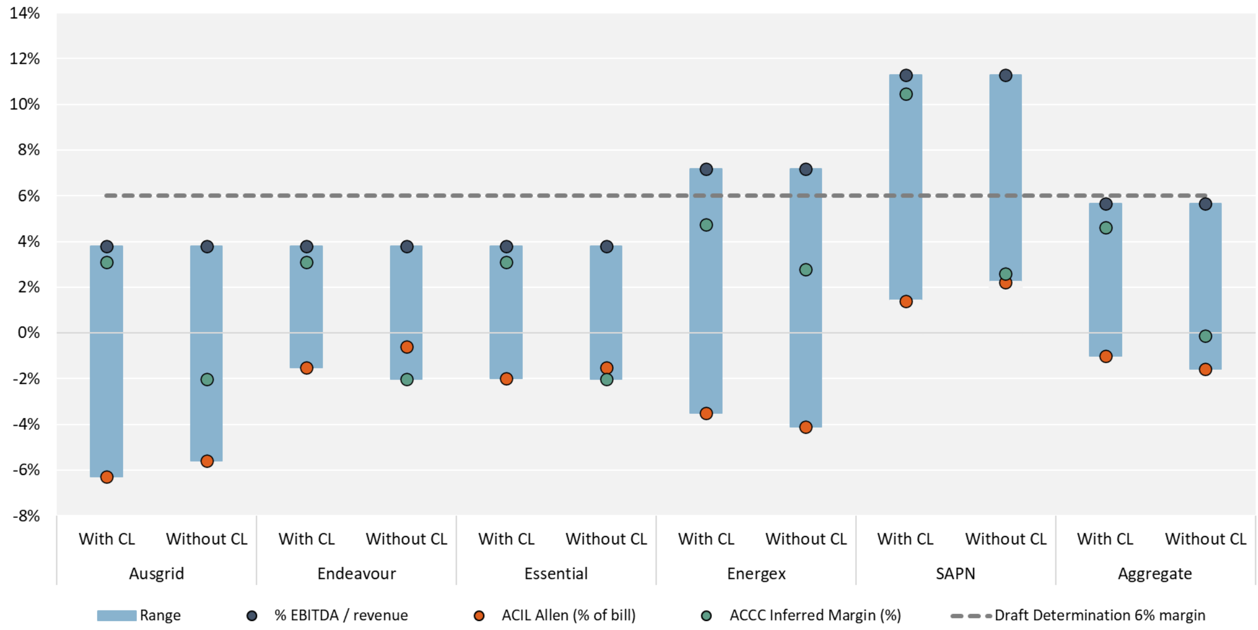
Residential customers

We have estimated a range of margins for residential customers, with and without controlled load, across all DMO regions (Figure F.1).

Margins inferred from market offer data, using ACIL Allen's approach, is significantly lower than the EBITDA margins reported by retailers across all DMO regions. Our analysis suggests that retailers have incurred losses when acquiring new residential customers, except in South Australia.

These differences reflect the scope of data used in each approach. ACIL Allen's approach, which focuses on using advertised market offers, would underestimate prices all customers pay, and thus, underestimate the margins achieved by retailers. Advertised market offers tend to be lower priced than expired market offers to attract new customers. However, these discounts tend to expire after a fixed period (e.g. 12 months) on which retailers tend to extract higher margins from customers who do not switch to a better deal. This aligns with the ACCC's December 2024 Inquiry report, which found customers on older or expired market offers are paying on average more than customers on newer market offers.[209] Therefore, we do not consider negative margins in advertised market offers indicates the DMO price should be set higher.

Figure F.1 Range of residential inferred margins from ACIL Allen, ACCC customer-weighted prices and EBITDA data from retail cost request



Source: AER updated analysis of ACIL Allen's retail margin analysis on advertised market offers; AER analysis of ACCC customer-weighted prices paid on1 August 2024. Margins inferred using DMO 6 costs; AER analysis of retail margins (EBITDA) based on retailer data for 2023–24.

209 ACCC, Inquiry into the National Electricity Market report, December 2024, p. 46. Newer offers are defined as offers that are less than 1 year old. Older offers are defined as offers older than 1 year.

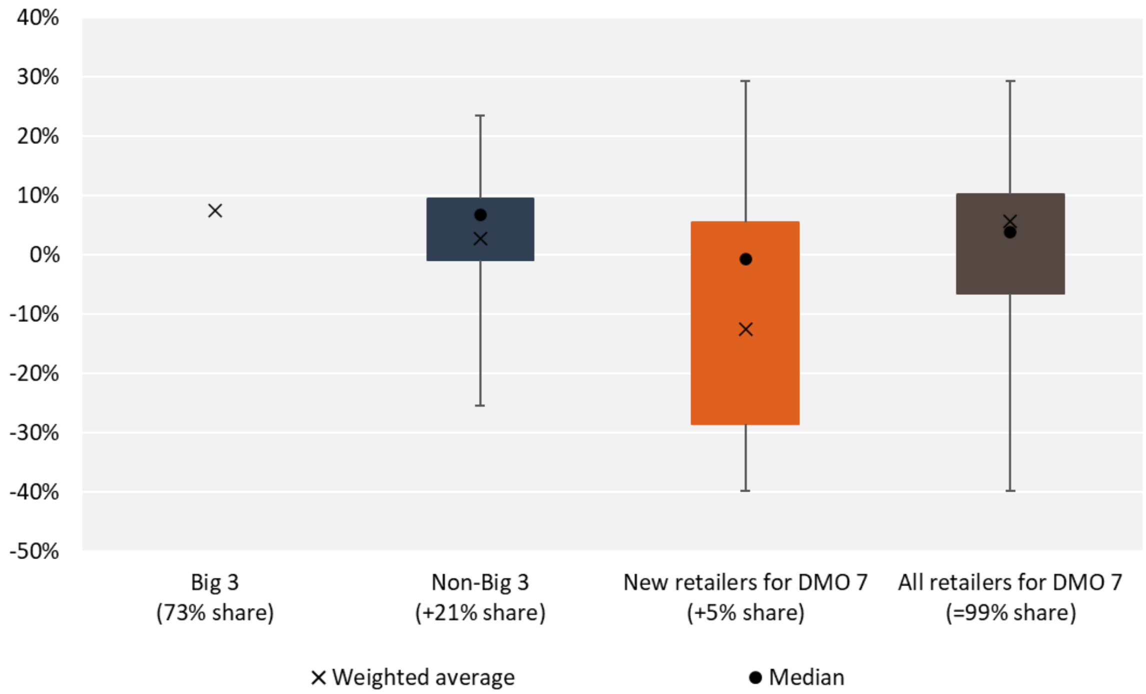
Using retailers' data, Figure F.2 illustrates the distribution of EBITDA margins for DMO 7 of the Big 3, non–Big 3, New retailers. Most new retailers that provided additional retail data to the AER have smaller customer bases than the retailers who provided data to the ACCC.

Big 3 retailers, who hold a dominant 73% share of the residential market, reported the highest residential retail margins with a customer-weighted average EBITDA margin of 7%. Non–Big 3 retailers, who serve 21% of the residential market, reported a weighted average of 3%. In comparison, new retailers reported negative EBITDA margins at -13%, indicating they have incurred losses when selling electricity to residential customers.

New retailers reported the highest variability in EBITDA margins, with an interquartile range of 33%, compared to 11% for the subset of non–Big 3 retailers that provided data to the ACCC. While there are some new retailers who reported positive EBITDA margins, many reported losses in the residential market.

Overall, the aggregate EBITDA margins across retailers serving approximately 99% of the residential market is 5.6%.

Figure F.2 Distribution of residential inferred margins[210]



Source: AER analysis of retail margins based on retail cost information.

A comparison of the 15 separate retail margins and their weightings to derive aggregate DMO 7 retail margins for residential customers are set out in Table F.2. It shows aggregate residential margins of -2.6% (ACIL Allen margins), 1.5% (inferred margins from ACCC's customer-weighted average prices) and 5.6% (inferred margins from retail cost data).

210 One small retailer was excluded from this figure due to being an outlier. However, their EBITDA data was included in the calculation of the customer-weighted average and median of retailers' reported EBITDA margins.

Table F.2 Range of inferred margins for residential customers

Customer type	DMO region	Number of applicable customers as a % of overall segment	EBITDA margins in retail cost data (% of revenue)	ACIL Allen inferred margins (% of price)	Inferred margin in ACCC customer-weighted price (% of price)	Aggregate ACIL Allen margin (% of price)	Aggregate inferred margin in ACCC price (% of price)	Aggregate EBITDA margins in retail cost data (% of revenue)
Residential without CL	Ausgrid	21.5%	3.8%	-5.6%	-2.0%	**-2.6%**	**1.5%**	**5.6%**
	Endeavour Energy	12.3%	3.8%	-0.6%	-2.0%	**-2.6%**	**1.5%**	**5.6%**
	Essential Energy	8.7%	3.8%	-1.5%	-2.0%	**-2.6%**	**1.5%**	**5.6%**
	Energex	10.4%	7.2%	-4.1%	2.8%	**-2.6%**	**1.5%**	**5.6%**
	SA Power Networks	12.3%	11.3%	2.2%	2.6%	**-2.6%**	**1.5%**	**5.6%**
Residential with CL	Ausgrid	8.6%	3.8%	-6.3%	3.1%	**-2.6%**	**1.5%**	**5.6%**
	Endeavour Energy	4.8%	3.8%	-1.5%	3.1%	**-2.6%**	**1.5%**	**5.6%**
	Essential Energy	9.0%	3.8%	-2.0%	3.1%	**-2.6%**	**1.5%**	**5.6%**
	Energex	8.1%	7.2%	-3.5%	4.7%	**-2.6%**	**1.5%**	**5.6%**
	SA Power Networks	4.3%	11.3%	1.4%	10.5%	**-2.6%**	**1.5%**	**5.6%**

Source: AER updated analysis of ACIL Allen's retail margin analysis on advertised market offers; AER analysis of ACCC customer-weighted prices paid on 1 August 2024. Margins inferred using DMO 6 costs; AER analysis of retail margins (EBITDA) based on retailer data for 2023–24. Customer proportions represent AER analysis of a voluntary data request to 11 retailers covering 94% of small customers as at 30 September 2024.

Small businesses

We also estimated retail margins for small businesses using various approaches. Figure F.3 illustrates aggregate small business margins of 2.1% (inferred margins from ACCC's customer-weighted average prices), 9.0% (ACIL Allen inferred margins) and 11.6% (inferred margins from retail cost data).

In contrast to the margins analysis for residential customers, the ACCC inferred margins are lower than the ACIL Allen analysis using market offer data and inferred margins reported by retailers in our retail cost request. This could be attributable to the usage assumptions under the DMO.

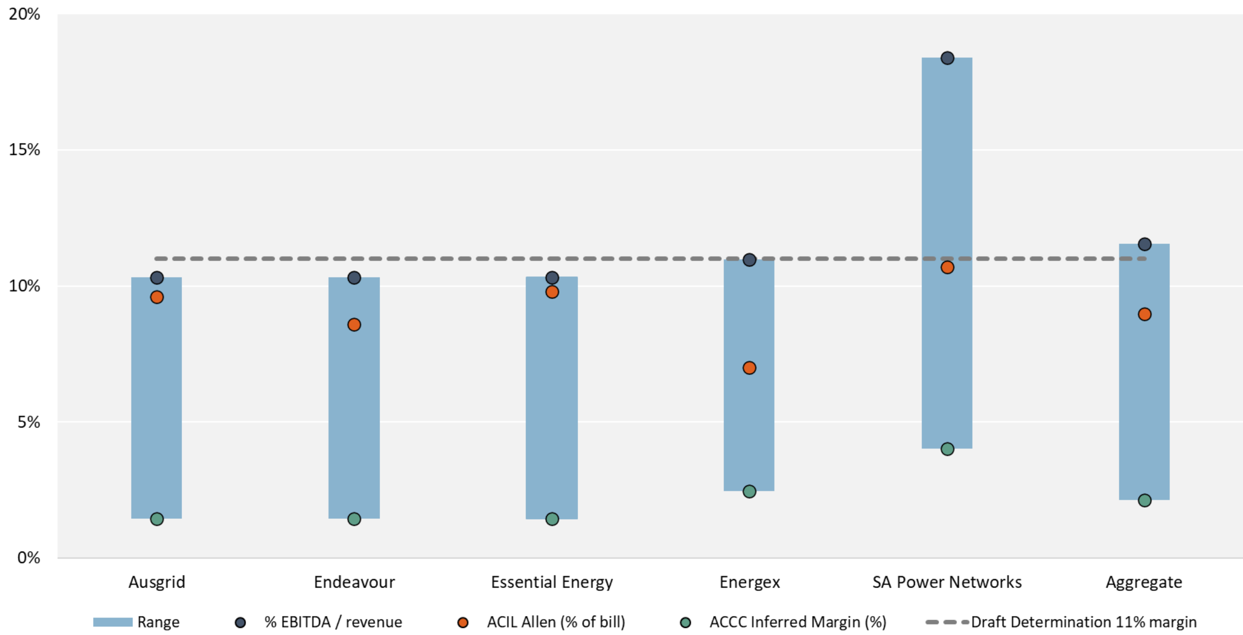
Under the ACIL Allen's approach, all market offers are priced and assessed based on an assumed DMO 6 annual usage of 10,000 kWh across all DMO regions. Similarly, the ACCC determined customer-weighted average retail prices (and inferred margins once DMO 6 costs are removed) use the DMO 6 small business usage amounts.

However, small businesses typically have a much wider variation in energy usage. Our retail cost information request also included energy sold and average customer numbers, allowing us to calculate each retailer's average small business usage. We found the average small business consumption across retailers varied significantly, with the 24 retailers' small business average usages ranging between approximately 5,000 kWh and 35,000 kWh per small business customer.[211]

Given such large variation in average small business usage across retailers, we consider the EBITDA margins in our retail cost request provide a more accurate reflection of the margins retailers achieve in practice than the other approaches that apply the fixed 10,000 kWh to infer margins.

Retailers in our retail cost information required reported higher EBITDA margins based on customers actual usage, with a weighted average of 11.6% across all retailers. This suggests the small business margin of 11% remains appropriate.

Figure F.3 Range of small business inferred margins from ACIL Allen, ACCC customer-weighted prices and EBITDA data from retail cost request



Source: AER updated analysis of ACIL Allen's retail margin analysis on advertised market offers; AER analysis of ACCC customer-weighted prices paid on 1 August 2024. Margins inferred using DMO 6 costs; AER analysis of retail margins (EBITDA) based on retailer data for 2023–24.

Figure F.4 shows the Big 3 retailers reported the highest retail margins, with a customer-weighted average of 14%. The non–Big 3 retailers reported a weighted average of 8%. New

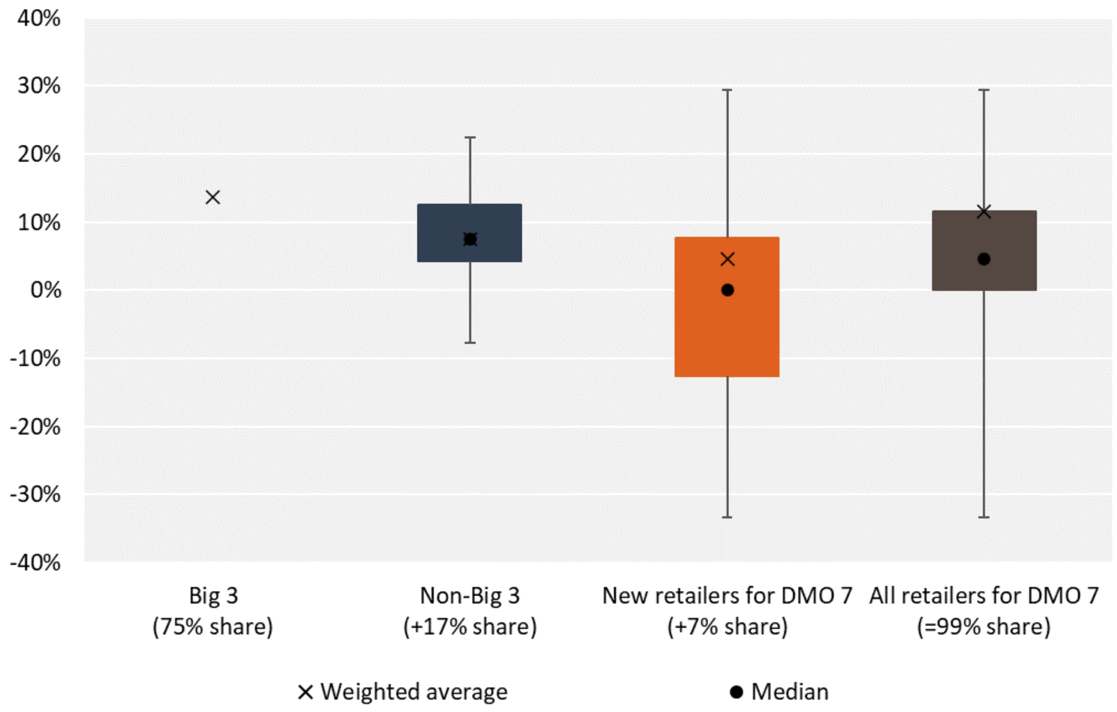
[211] See chapter 10 for a discussion on usage variability among small businesses.

retailers also demonstrated profitability in the small business segment, as they reported a weighted average of 5%.

Similar to the retail margins analysis conducted for residential customers, new retailers had the highest spread in EBITDA margins, with an interquartile range of 21%, compared with 12% for the subset of non–Big 3 retailers that provided data to the ACCC.

The aggregate EBITDA margins across retailers serving approximately 99% of the small business market is 11.6%.

Figure F.4 Distribution of small business retail margins



Source: AER analysis of retail margins based on retail cost information.

We note consumer group concerns around higher small business margins. However, our analysis on estimated margins across different approaches suggests that a uniform margin for both residential and small business customers may not be appropriate.

Our analysis on margins using retail cost data indicates a 5.6% margin for residential customers and 11.6% margin for small business customers. The small business margin is an approximately 6 percentage points higher than the residential margin. These findings also align with:

- small business margin findings from the ACCC December 2024 Inquiry report, which showed a significant increase in margins by region and across the NEM in the last financial year[212]

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212 ACCC, Inquiry into the National Electricity Market, December 2024 report, p. 79.

- an increased risk when serving small business customers for retailers, as indicated from higher levels of bad and doubtful debt figures per customer relative to residential customers in chapter 7
- higher inferred margins using ACIL Allen's approach.

A comparison of the 15 separate margins and their weightings to derive aggregate DMO 7 retail margins for residential customers are set out in in Table F.3.

Table F.3 Range of inferred margins for small businesses

Customer type	DMO region	Number of applicable customers as a % of overall segment	EBITDA margins in retail cost data (% of revenue)	ACIL Allen inferred margins (% of price)	Inferred margin in ACCC customer-weighted price (% of price)	Aggregate ACIL Allen margin (% of price)	Aggregate inferred margin in ACCC price (% of price)	Aggregate EBITDA margins in retail cost data (% of revenue)
Small businesses	Ausgrid	22.0%	10.3%	9.6%	1.4%	**9.0%**	**2.1%**	**11.6%**
	Endeavour Energy	22.8%	10.3%	8.6%	1.4%	**9.0%**	**2.1%**	**11.6%**
	Essential Energy	20.2%	10.3%	9.8%	1.4%	**9.0%**	**2.1%**	**11.6%**
	Energex	22.4%	11.0%	7.0%	2.5%	**9.0%**	**2.1%**	**11.6%**
	SA Power Networks	12.6%	18.4%	10.7%	4.0%	**9.0%**	**2.1%**	**11.6%**

Source: AER updated analysis of ACIL Allen's retail margin analysis on advertised market offers; AER analysis of ACCC customer-weighted prices paid on 1 August 2024. Margins inferred using DMO 6 costs; AER analysis of retail margins (EBITDA) based on retailer data for 2023–24. Customer proportions represent AER analysis of a voluntary data request to 11 retailers covering 94% of small customers as at 30 September 2024.