independent competition and regulatory commission

DRAFT REPORT

Retail electricity price investigation 2024-27

Report 1 of 2024, January 2024

The Independent Competition and Regulatory Commission (commission) is a Territory Authority established under the *Independent Competition and Regulatory Commission Act 1997* (the ICRC Act). We are constituted under the ICRC Act by one or more standing commissioners and any associated commissioners appointed for particular purposes. Commissioners are statutory appointments. Joe Dimasi is the current Senior Commissioner who constitutes the commission and takes direct responsibility for delivery of the outcomes of the commission.

We have responsibility for a broad range of regulatory and utility administrative matters. We are responsible under the ICRC Act for regulating and advising government about pricing and other matters for monopoly, near-monopoly and ministerially declared regulated industries, and providing advice on competitive neutrality complaints and government-regulated activities. We also have responsibility for arbitrating infrastructure access disputes under the ICRC Act.

We are responsible for managing the utility licence framework in the ACT, established under the *Utilities Act 2000* (Utilities Act). We are responsible for the licensing determination process, monitoring licensees' compliance with their legislative and licence obligations and determination of utility industry codes.

Our objectives are set out in section 7 and 19L of the ICRC Act and section 3 of the Utilities Act. In discharging our objectives and functions, we provide independent robust analysis and advice.

Correspondence or other inquiries may be directed to the commission at the following address:

Independent Competition and Regulatory Commission
PO Box 161
Civic Square ACT 2608

We may be contacted at the above address, or by telephone on (02) 6205 0799. Our website is at www.icrc.act.gov.au and our email address is icrc@act.gov.au.

How to make a submission

This draft report provides an opportunity for stakeholders to give feedback and views on the commission's draft decisions on the model and methodology it intends to use in making its decision on regulated retail electricity prices during the price investigation for the next regulatory period. It will also ensure that relevant information and views are made public, and the commission can consider relevant information and views in making its final decision on the model and methodology.

Submissions on the draft report close on **29 February 2024**.

Submissions may be mailed to the commission at:

Independent Competition and Regulatory Commission
PO Box 161
Civic Square ACT 2608

Alternatively, submissions may be emailed to the commission at icrc@act.gov.au. The commission encourages stakeholders to make submissions in either Microsoft Word format or PDF (OCR readable text format – that is, they should be direct conversions from the word-processing program, rather than scanned copies in which the text cannot be searched).

For submissions received from individuals, all personal details (for example, home and email addresses, and telephone and fax numbers) will be removed for privacy reasons before the submissions are published on the website.

The commission is guided by the principles of openness, transparency, consistency and accountability. Public consultation is a crucial element of the commission's processes. The commission's preference is that all submissions it receives be treated as public and be published on the commission's website unless the author of the submission indicates clearly that all or part of the submission is confidential and not to be made available publicly. Where confidential material is claimed, the commission prefers that this be under a separate cover and clearly marked 'In Confidence'. The commission will assess the author's claim and discuss appropriate steps to ensure that confidential material is protected while maintaining the principles of openness, transparency, consistency and accountability.

The commission may be contacted at the above address, by telephone on (02) 6205 0799 or via the commission's website at www.icrc.act.gov.au.

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Executive summary

On 1 June 2023, the Independent Competition and Regulatory Commission (commission) received the terms of reference from the ACT Government to determine a price direction for standing offer prices for the supply of electricity by ActewAGL Retail (ActewAGL) to small customers for the period 1 July 2024 to 30 June 2027. The terms of reference also required the commission to ensure the methodology has regard to a reasonable pricing offer for small customers that does not unduly disadvantage those who do not actively engage in the energy market, while balancing the competitiveness of the retail electricity market.

In preparing our draft decision, we considered the advice of our consultant, Frontier Economics, and submissions from energy retailers and community groups. This report sets out our findings of the investigation and draft decision on the proposed methodological changes to our pricing model and regulatory approach. It also sets out an estimate of the average price change for 2024-25 based on our draft decision. It is important to note that the estimated price change is based on information up to 30 November 2023 and therefore only provides an indication of likely price changes for 2024-25. Our estimates will be updated for more recent information prior to the start of the new regulatory period on 1 July 2024.

Draft decision on pricing model and regulatory approach

Table E.1 summarises our proposed changes to estimating the cost components in the current pricing model. The proposed changes result in cost estimates based on more up-to-date and efficient retailer practices, including a more efficient wholesale market hedging strategy, a recalibrated allowance for retail operating costs and the appropriate retail margin.

Table E.1 Current methodology and our draft decision

Component	Current approach	Draft decision
Wholesale energy costs		
Energy purchase cost	Use base swap, base cap and peak swap contracts to hedge against spot market price volatility. Contract prices based on the 23-month time-weighted average of forward prices from the ASX. The most recent 5 calendar years of data from AEMO used as the half-hourly profile of load and spot prices. Spot prices scaled using 23-month time-weighted average of base swap	Exclude peak swaps from the hedging strategy. Contract prices based on the 23-month volume-weighted average of forward prices from the ASX. The most recent 3 calendar years of data from AEMO used as the half-hourly profile of load and spot prices. Spot prices scaled using 40-day volume-weighted average of base swap prices to 30 April less 5% contract premium.

	prices to 30 April less 5% contract premium.	Continue to use basic meter load data to estimate the 2024-25 load profile and reassess this position in the final decision.
Volatility allowance	Adopt a volatility allowance based on the ESC's estimates for the VDO prices.	Adopt ESC's methodology but using ACT specific costs.
National green cost	Use publicly available LGC and STC spot prices averaged over 11 months to end May and include an allowance for holding costs based in half the annual cost of debt.	Maintain the current approach but change the averaging period for LGC and STC prices to the 12 months to the end of April.
Energy losses	Apply loss factors determined by AEMO to the energy purchase costs, national green costs and NEM fees.	Maintain the current approach.
NEM fees	Calculate ancillary fees using a 52-week averaging period and determine NEM fees using the observed AEMO cost data for the first year of the regulatory period, with subsequent years indexed by the CPI.	Use AEMO's draft budget to calculate NEM fees each year.
Retail costs		
Retail operating costs	A benchmarking approach indexed by the CPI from 2014.	A benchmark approach using customer-weighted average retail operating costs for competitive NEM regions indexed by CPI from 2025-26.
EEIS costs	Estimated using a methodology that is set to reflect the ACT Government's legislative requirements subject to a prudency and efficiency assessment.	Maintain the current approach.
Smart meters	Include estimates from ActewAGL with adjustment to account for the difference between forecast and actual costs in the previous year.	Maintain the current approach.
Pass-through costs	Include approved pass-through costs in the cost stack.	Maintain the current approach.
Network costs	Pass-through costs determined by the AER.	Maintain the current approach, but use information in Evoenergy's pricing proposal, rather than AER's final decision if the latter is not available by the cut-off date.

Retail margin	Apply a retail margin of 5.6% to cost components (equivalent to 5.3% to the total cost stack).	Apply a retail margin of 5.5% (equivalent to 5.2% of the total cost stack). Implement half of the margin as a dollar amount and half as a percentage.

We also propose a small number of changes to our regulatory approach to improve its operation. Specifically, our draft decision:

- re-instates the materiality threshold for regulatory change events in order to limit the pass-through of costs to those that have a material impact on the retail business and are not accommodated within the new retail operating cost allowance and
- allows the inclusion of controlled load tariffs as a component of the underlying tariff to provide ActewAGL with more flexibility in setting cost-reflective prices while maintaining protection for customers on standing offers.

Finally, we propose changes to ensure that retailers have adequate time to meet their legal obligations in terms of notifying customers of price changes and to share the costs of retail price regulation more fairly. Specifically, our draft decision:

- sets a cut-off date of 21 May for all inputs to the cost-stack by bringing forward the timing of national green costs by one month and using the network pricing proposal submitted by Evoenergy if approved network prices are not available by the cut-off date and
- spreads the standing offer review costs across all ACT retailers with a market share of 1% or higher.

Indicative electricity prices for 2024-25

Based on our draft decision and data up to 30 November 2023, we estimate that standing offer prices for 2024-25 will increase by approximately 17% in nominal terms or 12% excluding the impact of inflation (Table E.2). The price increase set out in this draft decision is an estimate at this point in time. We will determine the final average price change based on updated data and following public consultation.

We anticipate that the cost of the ACT Government's large-scale feed-in tariff (LFiT) scheme will drive most of the price increase for 2024-25. Last year, the scheme resulted in a rebate to ACT consumers, protecting them from the large increases in electricity prices experienced in other jurisdictions. In 2024-25, we estimate that the scheme will return to a positive amount. We have used a placeholder estimate of $16 per MWh in this report but will need to wait for the Minister's Reasonable Cost Determination to finalise our estimate.

As shown in Table E.2, our estimated price change excluding the ACT Government's LFiT scheme is 3.6% in nominal terms. The remaining 13.5% of the price change is based on our placeholder estimate of LFiT costs for 2024-25. The ACT Government's decision could be significantly different to this estimate, which will be reflected in our final decision.

Despite this indicative increase in regulated electricity prices, we expect that electricity bills for ACT customers on standing offers will remain some of the lowest in the country.

Table E.2 Draft decision on cost elements[1], 2024-25

Cost component	2023-24 ($/MWh)	2024-25 ($/MWh)	Dollar change ($/MWh)	Contribution to the price change (%)
Wholesale energy costs	176.56	177.96	1.40	0.5
Network costs	92.71	98.30	5.59	1.9
Retail costs	28.02	29.97	1.95	0.7
Retail margin	15.35	16.91	1.56	0.5
Total costs (excluding ACT Govt. LFiT costs)	**312.64**	**323.14**	**10.51**	**3.6**
ACT Government LFiT scheme costs	-23.14	16.00*	39.14	13.5
Total costs (including ACT Govt. LFiT costs)	**289.50**	**339.14**	**49.64**	**17.1**

Notes: *ACT Government LFiT scheme costs are determined by the Minister in February each year. In making this draft decision, we included our estimated costs for 2024-25 based on publicly available information in our cost stack for indication only. We will update this estimate in the final report with the Minister's determination, which may vary significantly from our current estimate.
Source: our calculations.

Our methodology provides an appropriate balance of delivering reasonable prices and competition in the ACT electricity market

Based on the market outcomes we have observed, we consider that our methodology for determining regulated prices in the ACT has delivered an appropriate balance between providing reasonable prices for customers and competition in the ACT electricity market. Despite being the smallest jurisdiction in the National Electricity Market, there are clear signs that the ACT market is more competitive than at the time of our last investigation in 2020. For example:

- There are now 17 active retailers in the ACT, serving residential and small business customers.
- ActewAGL's market share has declined from 82% in 2018-19 to 75% in 2022-2023, and the number of residential customers on standing offers has reduced significantly from 49% to 21% during the same period.
- There are market offers priced well below standing offers and the ACT's regulated prices are among the lowest in Australia.

Nevertheless, we recognise that some customers still find the electricity market difficult to navigate. While recent regulatory changes, including the introduction of the reference price and Better Bills Guideline, should assist customers in engaging in the market, we will continue to examine ways to reduce barriers that are preventing ACT customers from changing electricity plans and accessing lower-priced market offers.

[1] Wholesale energy costs comprise wholesale energy purchase costs, national green scheme costs (Large-scale Renewable Energy Target and Small-scale Renewable Energy Scheme costs), energy losses, volatility allowance and National Electricity Market fees. Network costs include transmission, distribution and jurisdictional schemes cost (e.g., ACT Government's small and medium scale FiT scheme costs and other government costs). Retail costs comprise retail operating costs, Energy Efficiency Improvement Scheme costs, smart meter costs, 5-minute & global settlement costs, and customer switching costs.

1. Introduction

1.1 Purpose of the investigation

The Independent Competition and Regulatory Commission (commission) is the Australian Capital Territory's (ACT) independent economic regulator. We regulate prices, access to infrastructure services and other matters in relation to regulated industries in the ACT.

On 1 June 2023, we received the terms of reference (TOR) from the ACT Government to determine a price direction for standing offer prices for the supply of electricity by ActewAGL Retail (ActewAGL) to small customers. The TOR covers the three-year regulatory period commencing 1 July 2024. The current price direction sets the maximum prices that ActewAGL can charge for its regulated retail tariffs from 1 July 2020 to 30 June 2024.

The TOR requires us to ensure the methodology for determining standing offer prices has regard to a reasonable pricing offer for small customers. The methodology must not unduly disadvantage those customers who do not actively engage in the energy market, while balancing the competitiveness of the retail electricity market. We must also consider changes to the timeframe for the yearly standing offer approval process. These changes are required to ensure adequate time is available for determination of the subsequent reference price by Ministers, and for retailers to fulfill their legal obligations under the *ACT Retail Electricity (Transparency and Comparability) Code* (ACT Code) and *National Energy Retail Rules* (NERR).

We released an issues paper on 1 August 2023 as the first step in the consultation process for this investigation. We received 7 submissions on the issues paper, which are available on the commission's website.[2] A summary of the submissions is provided in appendix 1. We have considered issues raised in the submissions in the relevant chapters of this report.

1.2 Our roles and objectives

Our objective, as set out in section 7 of the *Independent Competition and Regulatory Commission Act 1997* (ICRC Act), is to promote effective competition in the interest of consumers while facilitating an appropriate balance between economic efficiency, environmental and social considerations. When making price directions, section 19L of the ICRC Act also requires us to consider the interests of consumers in promoting efficient investment in, and operation of, regulated services into the future. These objectives, as well as the more detailed requirements of section 20 of the ICRC Act, guide our decision making.

We balance the objectives and requirements of the ICRC Act by ensuring that the regulated prices for electricity services are set at no more than the level of prudent and efficient costs of providing those services. This approach is in the interests of consumers as it ensures they pay no more than required for

[2] https://www.icrc.act.gov.au/energy/electricity/retail-electricity-prices-2024-27

their electricity services. It also accommodates the needs of the regulated business by allowing the recovery of efficiently incurred costs, including a reasonable margin. It encourages efficient operation and investment, as inefficient costs cannot be recovered through regulated prices. By allowing full cost recovery, and no more, our approach also encourages effective competition in retail electricity. Any retailer, with estimated costs equal to or below that of an efficient operator in the position of ActewAGL should be able to set competitive prices. However, a retailer's ability to compete will also depend on a range of other factors including service quality and innovation.

Our objectives under sections 7 and 19L of the ICRC Act and the provisions we must consider under section 20(2) of the ICRC Act are provided in appendix 2.

1.3 What do the terms of reference ask us to consider?

The TOR (reproduced in appendix 3) requires us to consider the following matters in this investigation:

- consider the direct impact on electricity costs of government policies and pass through of costs and savings to regulated prices
- consider the efficient and prudent costs of managing risk in the cost of purchasing electricity for the period of the price direction
- identify and report on the efficient costs of complying with the *Energy Efficiency (Cost of Living) Improvement Act 2012* for the period that the determination is being made
- identify and report on the cost allowance of the ACT Feed-in Tariffs (small and large scale) for the period that the determination is made.
- ensure the methodology for determining standing offer price has regard to a reasonable pricing offer for small customers that does not unduly disadvantage those who do not actively engage in the energy market, while balancing the competitiveness of the retail electricity market
- consider changes to the timeframe for the yearly standing offer approval process, such that adequate time is available for determination of the subsequent reference price by Ministers, and for retailers to fulfill their legal obligations under the ACT Code and the NERR.

We are required to release a final report within the period of 1 March 2024 to 5 June 2024.

As specified in the TOR, the price direction will be for the three-year period from 1 July 2024 to 30 June 2027.

1.4 Timeline for the investigation

Our timeline for the investigation is set out in Table 1.1.

Table 1.1 Indicative timeline for the retail electricity price investigation

Task	Date
Terms of reference notified	5 June 2023
Release of issues paper for public consultation	1 August 2023
Submissions on issues paper close	31 August 2023
Release of draft report for public consultation	29 January 2024
Public hearing	7 February 2024
Submissions on draft report close	29 February 2024
Final report and price direction	**30 May 2024**

The closing date for submissions on the draft report is 29 February 2024. We are required under section 17(4)(b) of the ICRC Act to conduct a public hearing for all price regulation investigations. We intend to conduct a hearing on 7 February 2024 to give interested stakeholders an opportunity to ask questions and provide feedback on the draft report. We propose releasing our final report and price direction by 30 May 2024.

1.5 Structure of the draft report

The remainder of this report is structured as follows:

- Chapter 2 discusses the feedback we received on pricing and competition in the ACT electricity market and sets out our draft findings and recommendations.
- Chapter 3 considers the stakeholder feedback we received on the approach to regulating retail prices in the ACT and provides our draft decision on these issues.
- Chapter 4 sets out our draft decision on each of the cost components of our retail electricity price model, considering the feedback received from stakeholders.
- Chapter 5 provides preliminary estimates of each of the cost components of our pricing model to provide an indication of the movement in prices for 2024-25. It is important to note that these estimates are provided for indicative purposes only and our final decision could be significantly different if there are large changes in the value of some inputs.
- Appendix 1 summarises the submissions we received on the issues paper.
- Appendix 2 lists our roles and objectives.
- Appendix 3 reproduces the terms of reference.
- Appendix 4 presents national green scheme costs calculation formula.
- Appendix 5 outlines the energy efficiency improvement scheme cost determination methodology.

2. Balancing reasonable pricing and competition in the ACT retail electricity market

The TOR requires us to ensure the methodology for determining standing offer prices has regard to a reasonable pricing offer for small customers that does not unduly disadvantage those who do not actively engage in the energy market, while balancing the competitiveness of the retail electricity market.

This chapter sets out our findings about the electricity price and competition outcomes in the ACT retail electricity market.

Summary of draft findings

We have assessed the electricity price and competition outcomes in the ACT. Based on the outcomes of this assessment, we concluded that our methodology to date has been successful in providing a balance between competition and reasonable pricing for customers not engaged in the market.

There are clear signs that the ACT market is more competitive than at the time of our last investigation in 2020. The key indicators include:

- There are now 17 active retailers in the ACT, serving residential and small business customers.
- ActewAGL's small customer market share has declined from 82% in 2018-19 to 75% in 2022-23.
- The number of residential customers on standing offers has reduced significantly from 49% in 2018-19 to 21% in 2022-23.
- There are market offers priced well below standing offers and the ACT's regulated prices are among the lowest in Australia.

While we found that our pricing methodology continues to be fit for purpose, we have identified several non-pricing issues inherent in the ACT electricity retail market that are impacting its operation and, potentially, the degree of competition that currently exists.

Recent regulatory changes should assist consumers to engage in the market. These include the application of the reference price to assist consumers in comparing offers and the introduction of the Better Bills Guideline to inform consumers about the availability of better offers.

2.1 Our approach

We have assessed the electricity price and competition outcomes in the ACT. Based on the market outcomes we have observed, we consider that our methodology for determining regulated prices in the ACT has delivered an appropriate balance between providing reasonable prices for consumers and competition in the ACT electricity market.

We gathered information for our analysis in a variety of ways. We used public sources such as Energy Made Easy and retailers' websites, as well as requesting information directly from electricity retailers in the ACT.

We examined how the ACT retail electricity market has developed over time. We looked at the number of customers on standing and market offers and changes in the number of those customers over time. We also reviewed the number of active electricity retailers in the ACT, market shares of retailers, and changes to those market shares over time.

We also evaluated ACT market performance in relation to prices and available offers. Specifically, we examined discounts available to customers on market offers and evidence that retailers offer differentiated and innovative products that meet customer preferences and needs.

We then examined how well customers are placed to be active participants in the market. We considered the extent to which consumers act on the available information and switch retailers or plans with their current retailer.

We also considered how regulators in other jurisdictions strike a balance between reasonable pricing and facilitating competition, as well as the specific market context in the ACT.

In addition, in our issues paper we sought stakeholders' views on electricity prices and competition in the ACT market and if there are other measures to improve outcomes for consumers.

2.2 Submissions on issues paper

ActewAGL stated that competition in the ACT electricity market has matured and is effective, despite having fewer active retailers compared to most other regions. ActewAGL highlighted a range of metrics to demonstrate the strength of retail competition in the ACT:

- a wide variety of electricity offers and related services available for customers
- retailers engaging with customers more proactively to win market share
- increase in the number of customers on market offers
- continuous reduction of ActewAGL's market share and
- relatively high switching rate.

ActewAGL considered that our regulated standing offer prices do not encourage further competition in the ACT because some cost components are set too low. For example, the allowance for retail operating costs is lower than that under the Default Market Offer (DMO) and Victorian Default Offer (VDO).

EnergyAustralia believed the TOR on price appears more closely aligned with the objectives of the DMO than the VDO. It suggested aligning with the objectives of the DMO should the commission change its methodology, as it covers both price protection and retail competition principles. Further, EnergyAustralia urged against mixing different DMO and VDO regulatory objectives.

ACT Council of Social Service (ACTCOSS), the Council on the Ageing (COTA), and Care Financial Counselling (Care)'s main feedback was the prevalence of significant barriers that prevent members of the community from engaging in the electricity market. These barriers include complexity, difficulties in navigating the market, lack of consistency in presentation, and inadequate information formats for diverse groups of consumers. They submitted that retailers are not acting in the best interests of consumers and failing to provide sufficient support to vulnerable customers. These organisations also suggested promoting increased consistency and extending the regulation of standing offer prices to all retailers, not just ActewAGL.

ACTCOSS, COTA, and Care also raised issues beyond the commission's control, such as the inadequacy of government income support payments to cover essential living costs in Canberra. This issue is compounded by the increasing number of customers facing cost of living challenges, primarily due to considerable eligibility constraints and administrative barriers hindering access to government assistance programs. They also emphasised the importance of addressing environmental issues once the cost of living and debt concerns have been addressed.

2.3 Retail price regulation in the ACT and other jurisdictions

This section discusses how regulators strike a balance between reasonable pricing and facilitating competition in other jurisdictions, as well as the specific context in the ACT. We note that the weight given to these considerations is different across jurisdictions due to the specific requirements in the TOR and underlying policy objectives.

2.3.1 How electricity pricing works in other jurisdictions

In Victoria, South Australia, New South Wales and South-East Queensland (SEQ) forms of price controls were introduced from 1 July 2019. This was done to reduce retail prices (and retail margins), which were perceived to be too high, particularly for inactive and vulnerable customers. In this context, the Australian Energy Regulator (AER) is implementing a DMO in South Australia, New South Wales and SEQ, and the Essential Services Commission (ESC) of Victoria is implementing a VDO.

The DMO and VDO serve as a price cap for standing offers. Each also has a substantial influence on the price for electricity within the relevant jurisdiction since it is the price against which retailers compete. The DMO and VDO also serve as a reference price. Retailers must display the percentage difference between any electricity plan they offer and the regulated standing offer. This is to help customers compare the plans on a like for like basis.

The AER’s Default Market Offer

The AER sets the DMO as a cap on standing offer electricity prices in South Australia, New South Wales and SEQ. The price cap is not intended to mirror the lowest price in the market. Rather, it strikes a balance among the following objectives:

- reducing unjustifiably high standing offer prices and continuing to protect consumers from unreasonable prices
- allowing retailers to recover their efficient costs of providing services, including a reasonable retail margin and costs associated with customer acquisition and retention and
- maintain incentives for competition, innovation and investment by retailers, and incentives for consumers to engage in the market.

The DMO price is calculated by adding together the components of a typical retailer’s ‘cost stack’. The cost stack includes wholesale electricity costs, network costs, environmental costs, and retail costs. A retail margin is added on top, as a percentage of the total cost stack.

The AER’s allowance for retail costs reflects the average costs of retailing electricity based on the actual data from retailers with more than 10,000 customers. Hence, the benchmark is set to reflect the costs faced by the overall industry, while the individual retailers may have costs which differ from the AER’s benchmark. The AER's retail margin includes headroom for competition, which ensures that retailers with higher-than-average costs are still able to compete in the market and make reasonable profits.[3]

The inclusion of headroom within the retail margin is a crucial component of the DMO methodology that allows it to achieve its objectives of encouraging competition. The DMO is not intended to be the lowest or most efficient price. Its purpose is to act as a fallback position for customers who are not engaged by preventing retailers from charging unjustifiably high prices. The inclusion of headroom ensures there is sufficient gap between 'efficient costs' and the DMO price so retailers can recover their costs and a reasonable margin, and that consumers still face an incentive to engage in the market and look for better deals that suit their circumstances.

The Victorian Default Offer

Victoria has a similar but separate default offer, referred to as the VDO. The VDO's objective is to provide a simple, trusted, and reasonably priced electricity option that safeguards consumers who are unable or unwilling to engage in the electricity market.

In contrast to the DMO, the VDO, set by the ESC, is priced to reflect 'efficient costs' of the sale of electricity by a retailer and so has smaller retail margins (without an additional allowance for headroom).

The VDO is also calculated as the sum of cost stack components. Like the AER, the ESC uses the average costs of retailing electricity from actual retailers' cost data to estimate the retail costs. However, it does not use that same data to determine customer retention and acquisition costs. This is because the ESC's terms of reference treats retail costs differently from customer acquisition and retention costs. It requires that only a 'modest' allowance for customer acquisition and retention costs is included in the VDO.

Such an approach supports the VDO in meeting its objective of representing a 'fair' price for electricity. It implies that new entrants or retailers with higher-than-average costs would need to fund their operations from equity or foregone profits and not through higher prices, until they can operate more efficiently or achieve other economies (i.e., build a customer base).[4]

Critiques of the VDO have argued that it would likely dampen competition in the market. This is because the VDO price may be set at a level that some retailers are not able to supply at, leading to them exiting the market. On the other hand, the advocates of the VDO consider that it puts pressure on retailers to reduce costs below the benchmark, innovate and improve their competitiveness for the benefit of electricity customers.

2.3.2 Regulatory arrangements in the ACT

We determine standing offer prices in accordance with the TOR provided to us by the ACT Government and the requirements set out in the ICRC Act. Notably, we must have regard to section 20 of the ICRC Act. Of particular relevance to this investigation are considerations related to:

- allowing cost recovery (section 20(2)(e) of the ICRC Act)
- promoting greater efficiency in the provision of electricity services (section 20(2)(c) of the ICRC Act) and
- considering the social impacts of our decisions (section 20(2)(g) of the ICRC Act).

In accordance with the objectives and requirements of the ICRC Act, we determine standing offer prices for an efficient operator in the position of ActewAGL. This means that we set regulated standing offer prices to

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3 AER 2022, p.2

4 ESC 2019

allow such a retailer to recover its efficient costs, but not result in customers paying too much. In practice, the task comes down to selecting a representative sample of retailers to calculate a benchmark retail operating cost allowance. In 2014, we aligned our allowance for retail costs with the allowance applied by the Independent Pricing and Regulatory Tribunal (IPART) in NSW. IPART set its retail operating costs based on information provided by EnergyAustralia and Origin.

Our regulated standing offer prices only apply to ActewAGL customers. However, our regulated standing offer prices provide some constraint on market prices and also protect consumers not actively engaged in the market.

Customers in the ACT also benefit from a reference price determined by the ACT Government. The ACT Government determines how much electricity a representative customer would use in a year (the representative consumption) and a reasonable annual price for that amount of electricity (the reference price). The ACT Government's practice has been to use our standing offer rates to determine the reference price. Retailers must compare their market offer prices against the reference price to allow like for like comparisons between plans and so customers can see when their plan is more expensive than the standing offer.

Under our current approach, any retailer with estimated costs equal to or below that of an efficient operator in the position of ActewAGL should be able to set competitive prices. However, a retailer's ability to compete also depends on a range of other factors including service quality and innovation. Retailers other than ActewAGL mostly have market offer customers and are predominantly affected by the regulated standing offer price in its capacity as a reference price for currently advertised market offers.

2.3.3 Implications for this investigation

In this draft report, we consider the specific context of the ACT market to assess the need for any adjustments to our pricing methodology to support competition. We would require strong evidence to demonstrate that allowing ActewAGL to charge higher standing offer prices would realise net benefits to customers and not just result in additional costs for the customers.

We consider that the evidence of actual retailers' costs that was gathered for the setting of the DMO and VDO can be useful for our decision-making. As we aim to ensure that the regulated pricing reflects the efficient costs of operating in the market, we consider there is good data available to assist us with setting the appropriate benchmark:

- The AER and ESC have estimated and reported retail operating costs, which means we have access to good estimates of benchmark costs.
- We consider retailers operating in the National Electricity Market (NEM) face similar costs to retailers operating specifically in the ACT. Hence, the use of these benchmarks is fit for purpose.
- The use of recent benchmarks will ensure that legitimate costs associated with retailing in the ACT market are included in the standing offer prices.

In addition, we collected confidential information from retailers active in the ACT to inform our decision-making. This gives us scope to adjust for any differences in costs between the characteristics of benchmarks from other jurisdictions and the characteristics of retail supply to small customers in ACT.

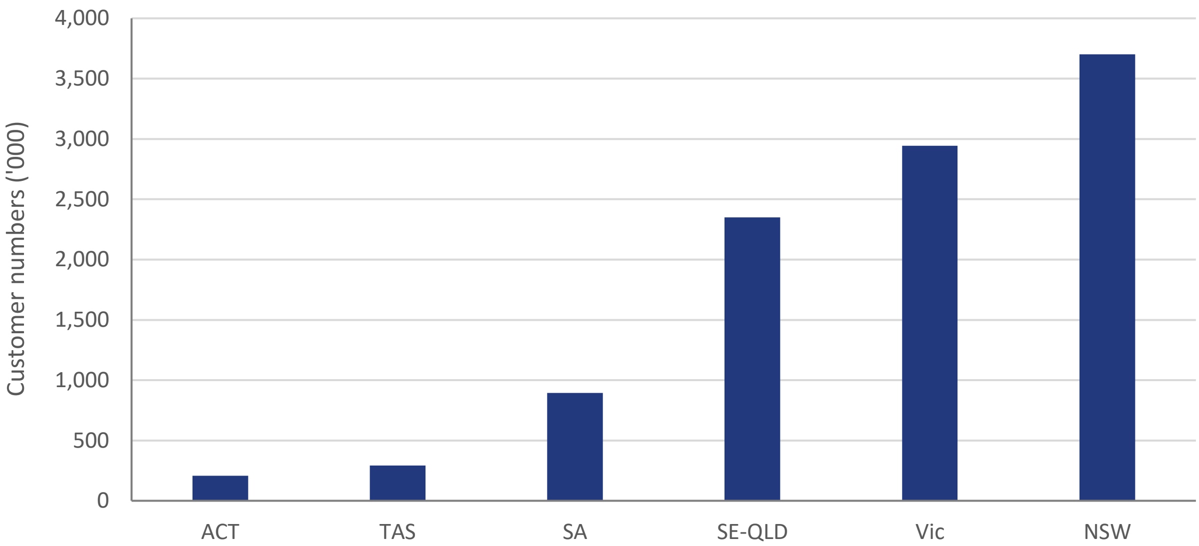
2.4 Competitive landscape in the ACT

Despite the limited size of the ACT electricity market there are increasing signs of competition, such as the increase in number of retailers and increase in customers on market contracts over the past 5 years. This means that the market has the potential to become more competitive and provide better outcomes for customers over time.

2.4.1 Unique characteristics of the ACT market

The ACT retail market is small relative to other retail markets in the NEM, with around 209,000 small customers, both residential and small business customers, as at 30 June 2023 (see Figure 2.1).

Figure 2.1 Electricity customer numbers, 30 June 2023



Sources: AER 2023a and ESC 2023c.

Similarly, the ACT is a relatively small market in terms of total electricity consumed when compared to other jurisdictions. In 2022-23, about 3,000GWh of electricity was consumed in the ACT. This compares to approximately 65,000GWh in NSW, 43,700GWh in Victoria, 54,100GWh in Queensland, 11,700GWh in South Australia and 11,000GWh in Tasmania.[5]

While the ACT market is relatively small, it has a comparably high electricity demand per customer, which may make it a more attractive market for electricity retailers. Residential customers in the ACT typically consume about 6,500kWh per year of electricity while the average residential customer in NSW consumes approximately 4,000kWh annually and the typical household in Victoria consumes about 4,500kWh per year.

The ACT Government's decision to phase out gas by 2045 will lead to switching from gas to electricity increasing demand for electricity. In addition, strong adoption of electric vehicles in the ACT will result in an increased demand for electricity. Specifically, the ACT has the highest uptake of Zero Emissions Vehicles (ZEVs), with 5,000 registered now. Around 20% of new cars are electric vehicles and ZEVs make up more than 1% of all vehicles registered in the ACT.[6] Although, we note that solar penetration and home batteries will offset growing demand to a degree.

Another potentially attractive characteristic of the ACT market is that incomes are relatively high in the ACT[7] which is seen to be beneficial in terms lower risk associated with bad debts.

5 Annual electricity consumption data is available at AER's website: https://www.aer.gov.au/industry/registers/charts/annual-electricity-consumption-nem.

6 ACT Government 2023

7 According to ABS 2022, the median household income in the ACT was $2,373 per week in 2021-22, compared to $1,829 in New South Wales, $1,759 in Victoria, $1,675 in Queensland, $1,455 in South Australia, and $1,358 in Tasmania.

However, the size of the market is small so there is a limited number of customers over which retailers can spread the fixed costs. Therefore, there is a risk to retailers that they may not capture a sufficient mass of customers to spread their upfront fixed costs.

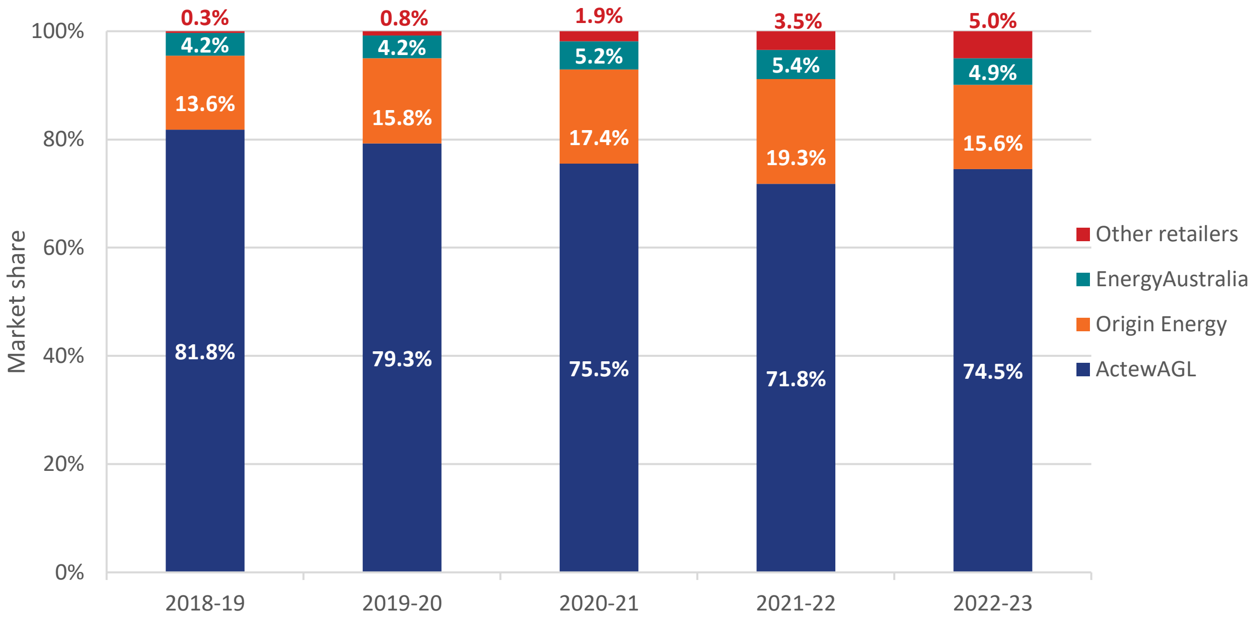
The fixed costs associated with ACT regulations and legislation may also affect the competitiveness of the market. For example, smaller retailers claimed that they were not able to meaningfully participate in the ACT Government Energy Efficiency Improvement Scheme due to lack of scale to deliver activities. They considered ActewAGL to be in a privileged position with respect to this scheme.[8]

2.4.2 Development of retailers in the ACT market

In New South Wales, Victoria and SEQ, there are now more than 35-40 retailers providing electricity services to small customers. ACT has experienced more limited entry but still has 17 active retailers (retailers with small customers).

As shown in Figure 2.2, ActewAGL's small customer market share has been declining over the last 5 years (from 82% in 2018-2019 to 74% in 2022-2023), with Origin and EnergyAustralia its principal competitors for market share. Competition among these three retailers resulted in a material reduction of customers supplied by ActewAGL. However, the entry of smaller retailers into the ACT retail market in recent years has not resulted in substantial erosion of market shares. Many of these retailers have very minor operations in the ACT.

Figure 2.2 Retail electricity market share in the ACT (residential and small business customers)



Source: AER 2023a.

While Origin and EnergyAustralia do not have an advantage of incumbency in the ACT market, they are national retailers and have advantages over smaller players, such as brand recognition, incumbency for those moving to the ACT, scale and wholesale market access.

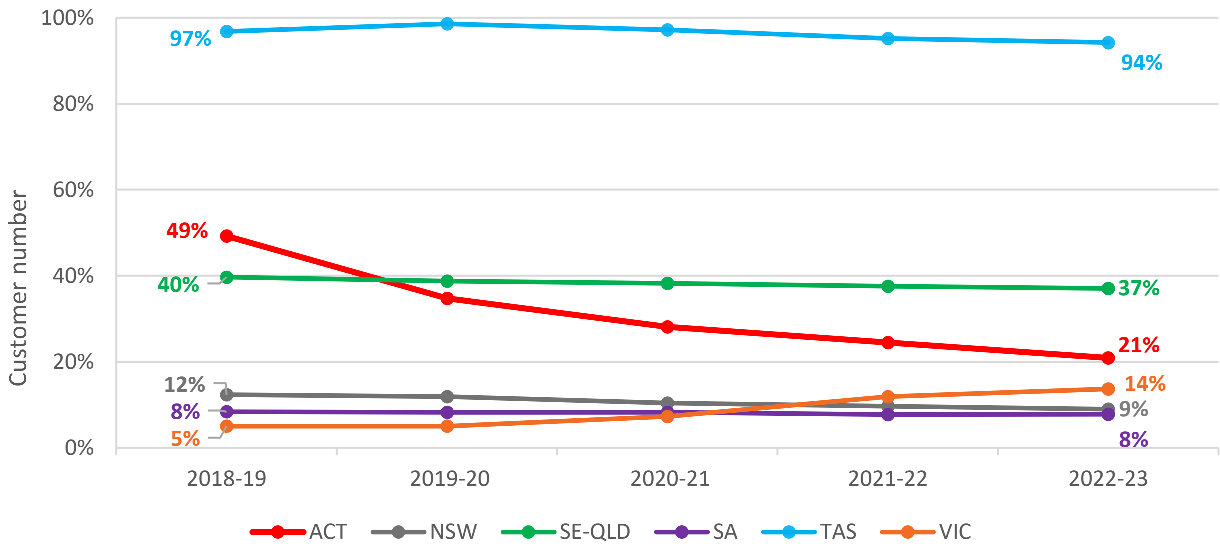
8 https://www.climatechoices.act.gov.au/__data/assets/pdf_file/0003/1221528/EEIS-Review-Part-7-Stakeholder-consultation-report-ACCESSIBLE.pdf, p.27.

In summary, despite the number of retailers in the ACT, supplier alternatives for small electricity customers have been limited to ActewAGL, Origin and EnergyAustralia, whereas other retailers have had limited success gaining market share. However, the presence of these small retailers is a positive sign that barriers to entry in the ACT retail electricity market are low.

2.4.3 The number of customers on standing offers is trending down

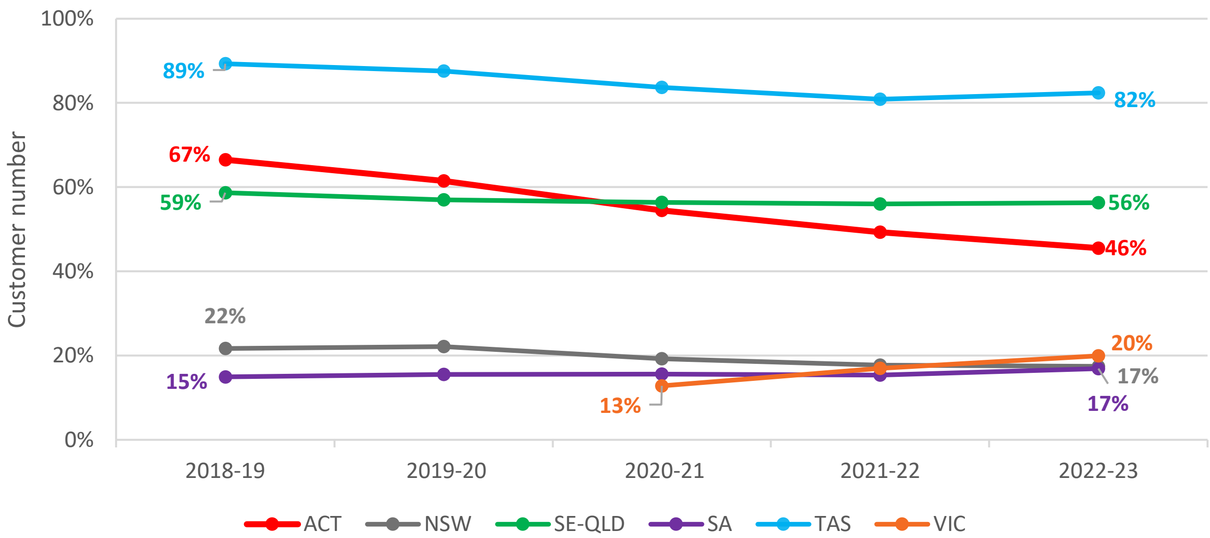
Around 21% of residential and 46% of small business customers remain on standing offers in 2022-23 (Figure 2.3 and Figure 2.4). This has reduced from our last investigation in 2020, where around 49% of residential and 67% of small business customers were on standing offers.

Figure 2.3 Share of residential customers on standing contracts



Sources: AER 2023a and ESC 2023c.

Figure 2.4 Share of small business customers on standing contracts



Note: Victorian data is not available for 2018-19 and 2019-20.

Sources: AER 2023a and ESC 2023c.

The number of ACT residential customers on standing offers remains high compared to other jurisdictions, such as New South Wales, South Australia and Victoria where the number of customers on standing offers is around 10% of total residential customers. However, it shows significant changes from recent efforts to encourage customers to participate in the market and choose a competitive offer.

It is sometimes suggested that standing offer consumers are more likely to be vulnerable consumers, however 93.6% of ActewAGL's current hardship customers are on a market offer. This is because ActewAGL took steps to help these customers to move to market offers. In addition, customers on hardship and payment plans may have a greater incentive to find better priced market offers and may have sought assistance from consumer groups to identify better offers.

2.4.4 Recent measures to boost competition

Since our last investigation, the ACT Government and the Australian Energy Market Commission (AEMC) introduced several measures that may contribute to improving overall competition in the ACT.

The ACT Government directed that we implement measures to improve transparency and comparability of electricity offers. We introduced the ACT Code in 2021. The Code requires retailers to:

- advertise their prices against a reference price to make it easier for consumers to compare offers,
- tell their customers about plans that might save them money, and
- give their customers tailored information to help them choose the best plan for them.

The ACT Code makes it simpler and faster for ACT residents to compare electricity plans and choose the best plan. The ACT Code also assists in promoting competition by improving consumer engagement. For example, it encourages more 'sticky' customers to engage with the market and either move to a new retailer, or at least to a better offer with their current retailer.

In 2019, the AEMC reforms established a process that allows customers to transfer retailers within two days after the end of the cooling off period. Under the old arrangements, customers had to wait until the next periodic meter read, which meant up to 90 days for the transfer to occur. Speeding up the transfer process allows customers to move to new offers quickly and limit the time available for 'losing' retailers to conduct save activity.

In addition to these measures, the AER introduced the Better Bills Guideline which requires retailers to make bills easier for customers to understand. Specifically, the Better Bills Guideline requires retailers to:

- use simple language, make the structure and design of the bill easy to understand and make the most important information most prominent
- include a message in the bill identifying whether a better offer is available to the customer.

We note that the Better Bills Guideline has been fully implemented recently. It remains to be seen whether, and by how much, it improves customer engagement and competition.

2.5 Price outcomes in the ACT

This section outlines the range of offers available to residential customers in the ACT based on our analysis of retailer websites and Energy Made Easy. We have also gathered information from ActewAGL on their offers and customer tenure to inform our investigation.

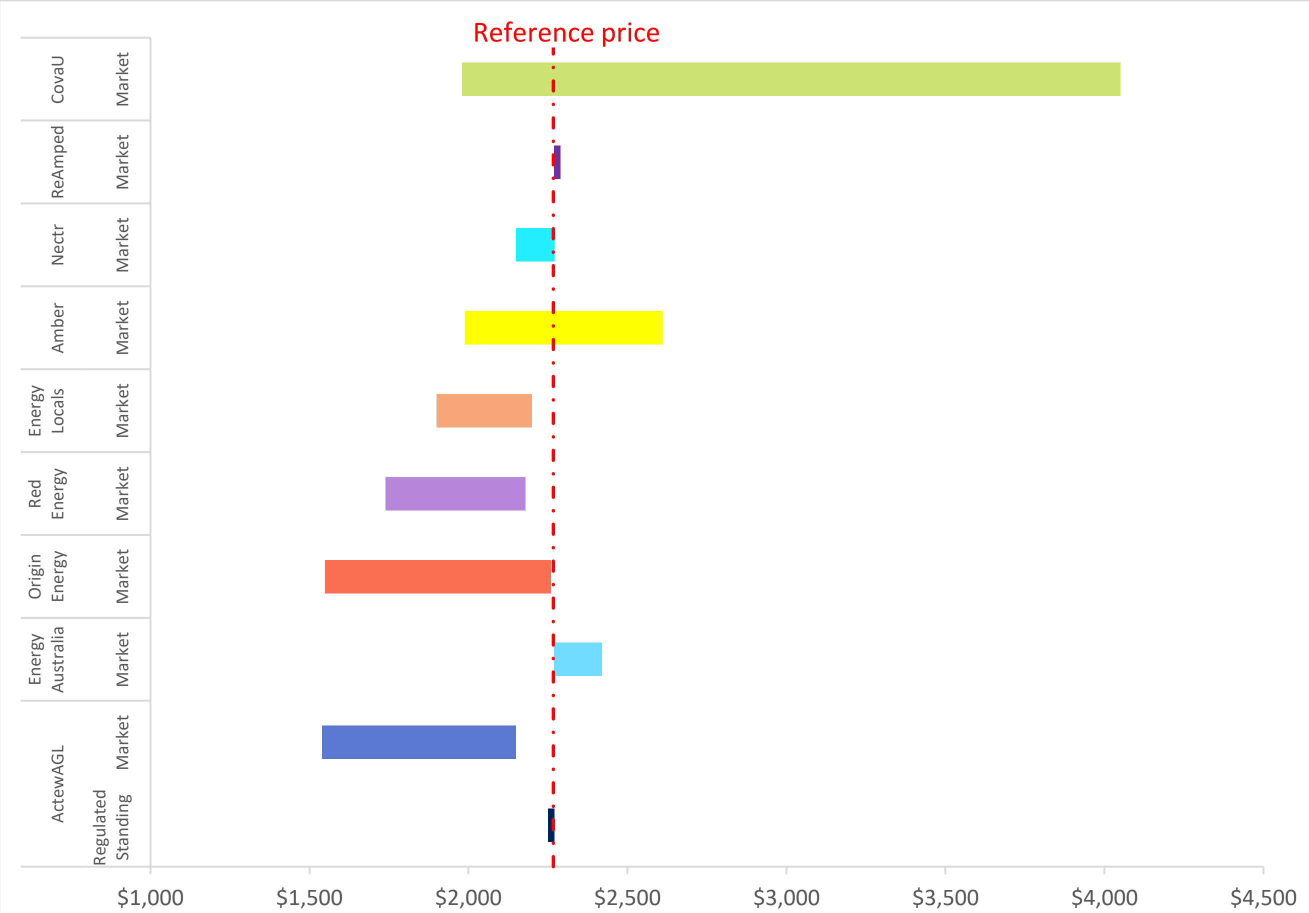
2.5.1 Retailers have been able to price market offers below standing offer rates

Figure 2.5 shows the ranges of regulated standing offers and market offers provided by ActewAGL and other selected retailers in the ACT.[9] Typically, retailers price their market offers below the regulated standing offer rates (or ACT Reference Price) to attract or retain customers. We observe that smaller retailers price their market offers close to the regulated standing offer rates, with some more expensive than the regulated standing offer rates.

Discounting of market offers indicates that retailers have been able to compete against regulated standing offer prices. It also suggests that there is an incentive for consumers to engage in the market.

Our analysis indicates that an average customer can save up to $700 per year by switching from a regulated standing offer to the lowest market offer. For customers who are already on a market offer, the benefit of switching is likely to be smaller. However, customers can still save money by shopping around.

Figure 2.5 Observations of electricity prices offered by selected retailers in the ACT, 2023



Notes: Bars represent range of standing and/or market offer prices. Bills are GST inclusive, and calculated based on single rate offers for residential customers and average annual consumption of 6,500 kWh. Some offers listed may not be available to all customers. ACT Reference Price is re-calculated based on annual consumption of 6,500 kWh.
Source: Our analysis based on offers listed on Energy Made Easy website, accessed in October 2023.

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9 Only the single rate offers are included in this analysis. Other offers, such as time-of-use and demand offers, are excluded.

2.5.2 A large number of electricity offers available in the ACT

We observed that more than 181 electricity offers (both single rate and time of use offers)[10] are available for ACT residential customers in 2023. This includes regulated standing offers and market offers provided by 9 retailers covering 99.94% of ACT residential electricity market (Table 2.1). This indicates that Canberra's residential electricity customers have many offers to choose from.

Table 2.1 Residential customer market share and number of electricity offers in the ACT, 2023

	Market share (%)	No. of single rate offers	No. of time-of-use offers	Total number of offers
ActewAGL	74.31	15	5	20
Origin	15.77	63	21	84
EnergyAustralia	4.83	7	7	14
Red Energy	3.76	21	7	28
Energy Locals	1.05	5	3	8
Amber Electric	0.11	5	-	5
Nectr Energy	0.10	3	3	6
ReAmped Energy	0.01	5	5	10
CovaU Energy	0.01	3	3	6
Total	**99.94**	**127**	**54**	**181**

Sources: AER 2023a and Energy Make Easy website, accessed in October 2023.

Our analysis found that retailers in the ACT are able to offer innovative products or offers featuring attributes that would be attractive to customers with distributed energy resources, such as roof top solar photovoltaic units, battery storage and batteries in electric vehicles used to export power back to the grid.

2.5.3 ACT electricity prices are lower than in other jurisdictions

Table 2.2 shows the estimated annual bills for a range of electricity offers (both single rate and time-of-use offers) available to residential customers in Canberra, Sydney, Brisbane, Adelaide, Melbourne and Hobart as of 19 October 2023 (based on a residential household consuming 6,500 kWh per year). It shows that the average annual bill in the ACT is the lowest across the six selected capital cities.

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10 This does not include offers which are only available for customers having battery installed. It also does not include offers with controlled loads (around 353 offers with controlled load are available in the ACT).

Table 2.2 Comparison of estimated annual bills[a] across 6 capital cities

Capital city	Regulated benchmark price[b], $	Single rate offers			Time-of-use offers		
		No.	Average price, $	Price range, $	No.	Average price, $	Price range, $
Canberra	2,267	127	1,939	1,540 – 4,050	54	2,011	1,550 – 3,980
Sydney	2,734 (Ausgrid) 2,772 (Endeavour)	132	2,650	2,280 – 3,340	216	2,594	2,270 - 3,050
Brisbane	2,543	122	2,489	2,110 – 2,580	113	2,518	2,150 – 2,980
Adelaide	3,374	118	3,246	2,600 – 4,080	119	2,871	2,260 – 3,940
Melbourne	2,288 (Citipower)	218	2,243	1,660 – 3,620	276	2,274	1,720 – 2,850
Hobart	2,363	8	2,308	2,120 – 2,540	9	2,143	2,000 – 2,640

Note: [a] Bills are inclusive of GST and discounts (if applicable) and based on average annual consumption of 6,500 kWh.
[b] Regulated benchmark prices are re-calculated using annual consumption of 6,500 kWh, based on ACT Reference Price, AER's DMO, Victorian VDO and OTTER's regulated prices for 2023-24.
Sources: Energy Make Easy and Victorian Energy Compare websites, accessed in October 2023; AER 2023b, ESC 2023a, OTTER 2023.

We note that potential benefits of switching from the regulated standing offer to the lowest market offer are the second highest in the ACT. As discussed in the previous section an average ACT customer can save up to $700 per year by switching from a regulated standing offer to the lowest market offer. The potential savings in other capital cities vary, ranging from a low of $400 in Hobart to a high of $1,100 in Adelaide.

2.6 Customer experience in the ACT retail electricity market

This section outlines our findings in relation to customer experiences in the ACT retail market. We consider there are two key aspects related to the customer's ability to engage with the market:

- awareness of competition and choice and
- the ability of consumers to obtain, understand and compare information about available plans.

To inform our analysis, we surveyed ACT electricity consumers to better understand their awareness and decision-making processes when it comes to household electricity plans. The survey was conducted using the ACT Government's YourSay Community Panel. The online survey was live between 21 and 27 August 2023 and in total, we received 1,409 responses. The detailed survey responses are available on our website.[11]

We also analysed results from the Energy Consumer Sentiment Survey (June 2023) published by Energy Consumers Australia (ECA). This helped us cross-check the outcomes of YourSay survey with the results of similar survey that targeted a different cohort of customers, noting the potential of the YourSay platform to capture more 'engaged' Canberrans.

To further inform our understanding of how actively customers engage with the retail market, we analysed switching behaviour and customer tenure with ActewAGL.

[11] https://www.icrc.act.gov.au/energy/electricity/retail-electricity-prices-2024-27

We have found that some ACT customers feel like there is limited choice of electricity retailers. This is likely to make customers 'sticky' and therefore more difficult to attract away from ActewAGL. The information gathered also shows that despite an increased range of initiatives designed to make it easier for customers to navigate the electricity market, it is still a difficult and time-consuming task to confidently choose an electricity plan.

2.6.1 YourSay survey findings

Many Canberrans still face challenges finding a better offer

The YourSay survey showed that 67% of total respondents express some confidence that they are on the best electricity plan for their circumstances. This figure has increased when compared with a 2019 survey (53%) and has been steady compared to last year's survey results where two-thirds of respondents (67%) express confidence in their electricity plan for their circumstances.

Overall, only 28% of all respondents considered it easy to find information about what different plans and providers are available. This indicates that even those customers who engage with the market regularly find it difficult to navigate.

These findings are consistent with a smaller survey of 201 ACT consumers conducted by the ECA, which found that only 51% of respondents were confident in their ability to make choices about energy products and services, such as which plan or supplier to choose, the lowest in Australia. The survey also showed that only 51% of respondents thought there is enough easily understood information available to them to make decisions about energy products and services, the second lowest in Australia.

Many customers do not engage with the market on a regular basis

57% of respondents shopped around for a new electricity plan in the last 12 months. Customers who did not engage in the market in the last 12 months cited the time and effort required to choose a new plan as the key barrier. Many respondents did not know much about what other plans and retailers are available in the market or thought the potential benefits of switching were not worth the effort.

Similarly, the ECA survey showed that 49% of respondents investigated changing their energy company or contacted their current retailer for a better offer in the last year. 42% of respondents indicated that they investigate switching less often than every 2 years.

Consumers can feel like there is limited choice in the ACT electricity market

Consumers expressed a sense of limited choice in the ACT electricity market, with just 16% agreeing that there is a good choice of different electricity providers and almost half (44%) disagreeing that this was the case. This sentiment has been recurrent since the 2022 survey and is also echoed in open-ended comments, which highlighted the lack of competition and difficulty in making informed choices due to retailer actions that do not prioritise consumers' interests. For example, intentionally creating obstacles for consumers to compare different offers or only sharing better plans when the consumer threatens to switch to another retailer.

Cost-of-living and price impacts are resonating

The YourSay survey findings reveal that consumers in the ACT prioritise price when choosing electricity plans. In 2023, 84% of respondents selected 'price' as one of the most important factors in their decision. This result remained consistent with 2022 report, where 83% of the respondents made the same choice.

Notably, several other factors recorded a significant drop compared to 2022, underscoring the continued prominence of 'price' in customers' minds when choosing an electricity plan.

Additionally, 76% of respondents indicated that their household electricity bills had increased compared to the same period the previous year, reinforcing the perception of rising electricity prices. 48% of the respondents also indicated that the increased electricity costs have impacted their household's discretionary spending. Notably, the respondents who perceived their bills as stable or decreasing expressed greater confidence in their plan choice.

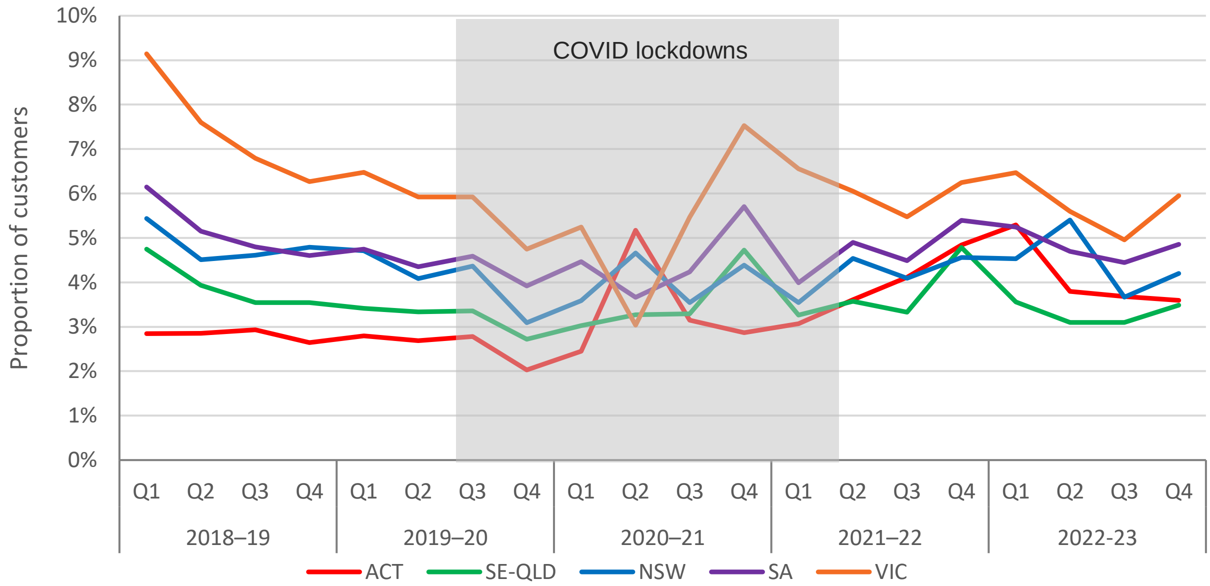
2.6.2 Switching behaviour

The rate at which customers switch between energy retailers provides some indication of how actively customers engage with the retail market. The data does not capture the customers switching from one offer to another within the same retailer.

Figure 2.6 shows the percentage of electricity customers that switched retailers over the past 5 years across jurisdictions. Switching rates are generally higher in jurisdictions considered more competitive, such as Victoria[12], New South Wales, SEQ and South Australia.

The switching rates in the ACT remained relatively stable at around 3% until Q4 2019-20. The sharp drop in this quarter may be due to the impacts from the start of the COVID-19 pandemic. Across 2020-21 quarterly switching rates have slowly started to increase to the pre-COVID level, while in Q2 2020-21 it increased sharply. From 2021-22 switching rates trended up significantly to above 5% in the early of 2022-23 and then down to 3.5% in Q4 2022-23.

Figure 2.6 Electricity switching rates, 2018-19 to 2022-23



Source: AER 2023a.

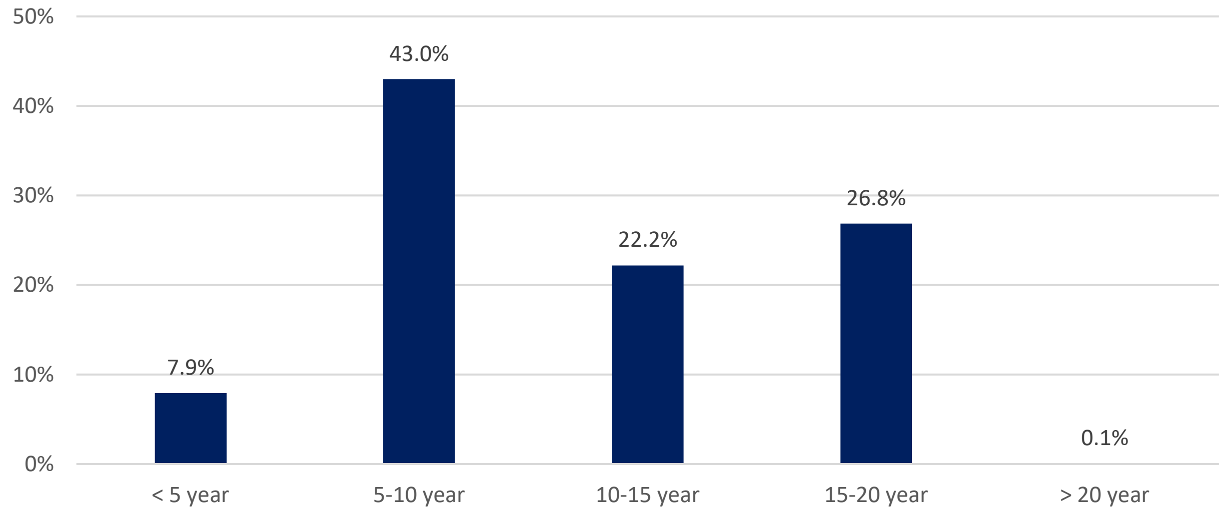
12 The Victorian Energy Compare website provides information to customers about the best priced electricity offers available to them and provides customers that use the process a $250 bonus, even if they choose not to switch retailers.

2.6.3 Customer tenure

Customer tenure is another measure that shows how well customers interact with and are engaged in the retail electricity market. We define customer tenure as the length of time a customer has been with the retailer.

The data from ActewAGL (Figure 2.7) shows that around half of ActewAGL's small customers have not changed retailer for over 10 years. This could be due the lack of awareness about other retailers in the market or customers being reluctant to switch away from ActewAGL because of their loyalty to its brand and overall satisfaction with the level of service.

Figure 2.7 ActewAGL' small customer tenure profile, 30 June 2023



Source: our calculation based on ActewAGL data.

2.7 Our consideration

We consider that our approach to date has been reasonably successful in providing a balance between competition and reasonable pricing for customers. This is because:

- Most retailers have offered market offers below, and sometimes well below, our regulated standing offer price.
- Our regulated standing offer prices are some of the lowest across the NEM jurisdictions.
- Market outcomes suggest that competition in the ACT retail electricity market has increased since our last investigation in 2020.

This is clearly benefiting those customers who are engaging in the market and finding deals that suit their circumstances. As discussed in this chapter, customers who are engaged and willing to switch plans or providers can access substantially lower prices though market offers (i.e., a saving of up to $700 per year).

As for those customers who are unable or unwilling to engage in the market, our regulated standing offers provide an important protection for these consumers. It limits the ability of retailers to price so far above the supply cost that it detrimentally impacts on standing offer consumers.

The number of customers on the regulated standing offer is:

- for households: around 21% of the ACT market (40,000 customers)

- for small businesses: around 46% (6,300 customers).

While most ACT customers are not on the regulated standing offer, it is still a higher number compared to other jurisdictions. We found that that hardship and payment plan customers are less likely to be on standing offers than other customers. We note that this is only one indicator of vulnerability, and there are potentially many vulnerable customers that are not on payment plans or in retailer hardship schemes.

We consider that our regulatory approach continues to be fit for purpose in the current ACT market and the components of our pricing methodology provide a reasonable balance between the objectives we seek to achieve. In this draft decision, we updated our pricing methodology to ensure that our cost estimates are based on more up-to-date and efficient retailer practices, including a more efficient wholesale market hedging strategy, a recalibrated allowance for the retail operating cost and the appropriate retail margin (see chapter 4).

We have considered issues raised by ACTCOSS, COTA, and Care in relation to the inadequacy of government income support payments to cover essential living costs in Canberra. We note that the ACT Government has energy concessions in place to assist vulnerable customers with the cost of electricity bills. These rebates are independent of the commission and its role. Nevertheless, we make it clear that our decisions have regard to the social implications pursuant to section 20 of the ICRC Act. Together, the various rebates and our regulatory obligations ensure that matters relevant to low-income households are considered in the supply of electricity to the ACT community.

EnergyAustralia argued that the new requirement in the terms of reference appears more closely aligned with the objectives of the DMO than the VDO. It suggested that we align our pricing methodology with the DMO approach, as it covers both price protection and retail competition principles. We disagree with this suggestion. As discussed in section 2.3.1, the key feature of the DMO approach is the inclusion of the headroom for competition. Such an approach would substantially increase standing offer prices in the ACT. We do not have compelling evidence to suggest that a competition allowance would realise net benefits in the long term, i.e., the cost burden faced by small customers in a short term would be offset by longer-term benefits of increased competition.

As part of our analysis, we have identified a number of non-pricing issues inherent in the ACT electricity retail market that are impacting on its operation and, potentially, the degree of competition that currently exists. We found that:

- Despite an increased range of initiatives designed to make it easier for customers to navigate the electricity market, it is still a difficult and time-consuming exercise to confidently choose an electricity plan.
- The lack of awareness of available electricity retailers in the market is likely to make customers 'sticky' and therefore more difficult to attract away from ActewAGL.
- Many customers do not shop around for the electricity plan on a regular basis or only approach their existing retailer for a better offer. This means there may be customers on market offers who are unaware that they are now paying more than necessary for electricity services.

While recent regulatory changes, including the introduction of the reference price and Better Bills Guideline, should assist customers in engaging in the market, we will continue to examine ways to reduce barriers that are preventing ACT customers from changing electricity plans and accessing lower-priced market offers.

The commission will monitor the impacts of the Better Bills Guideline and continue to work with retailers in relation to their obligations under the ACT Code. We have written to retailers in response to customer concerns about retailer compliance with Clear Advice Entitlement. We have also written to retailers where we were not satisfied with their compliance with the reference price obligation. The commission will continue to publicly report on retailer compliance in our Utility Licence Annual Report including any issues identified.

3. Regulatory approach for setting electricity prices in the ACT

This chapter sets out our draft decision on the regulatory controls that we use to regulate electricity prices in the ACT. Regulatory controls refer to the arrangements by which regulated retail electricity prices are set and adjusted during the regulatory period.

Summary of our draft decision on regulatory approach

Our draft decision on the regulatory approach for setting regulated retail electricity prices in the ACT is summarised in Table 3.1.

Table 3.1 Our draft decision on the regulatory approach

Component	Draft decision
Regulatory period	Three years, from 1 July 2024 to 30 June 2027 (specified in the TOR)
Form of price control	Maintain the cost-index approach to setting regulated prices for ActewAGL
Method for adjusting prices	Continue using a weighted average price change form of control with a 2.0 percentage point upper bound side constraint. Allow ActewAGL to include controlled load tariffs as a component of the underlying tariff for the purpose of compliance with the price control mechanism
Annual recalibrations	Undertake an annual recalibration of the parameters of the retail electricity cost-index model to determine regulated retail prices for 2025-26 and 2026-27.
Cost pass-through arrangements	Re-instate the materiality threshold for regulatory change events at the level of $200,000 per event.
Cut off dates for inputs to the cost stack	Set a cut-off date of 21 May for all inputs to the cost stack by: • bringing forward the timing of national green costs by one month • using the network pricing proposal submitted by Evoenergy to the AER if approved network prices are not available by the cut-off date • using Evoenergy's LFiT adjustments to network prices if available by the cut-off date or otherwise using the commission's estimate of the impact of LFiT on network prices • including a true-up in the following year for any material difference between estimated and actual network prices and the LFiT

3.1 Approach for setting regulated prices

We use a cost index approach to set regulated electricity prices in the ACT. Under this approach, we estimate the likely change in the costs of supplying electricity to small customers. In broad terms, we derive an index (the maximum allowable percentage change) for a particular year by comparing the total cost of supplying electricity in this year with the cost of supplying electricity in the preceding year.

To derive this index, we estimate the individual cost components that would be incurred by a benchmark retailer when providing electricity services to small customers on regulated tariffs. We do so by modelling wholesale energy costs, including hedging and environmental schemes, using a pass through of network costs from the AER's regulatory decisions and providing an allowance for retail operating costs and a retail margin. We discuss the individual components of our model in chapter 4.

The index then determines the amount by which ActewAGL can change its regulated prices. Under the current weighted average price cap form of regulation, ActewAGL can decide how to adjust the individual prices for its different standing offers, as long as the total adjustment does not exceed the maximum allowable percentage change for the overall price cap. In addition, a side constraint restricts the weighted average price for each individual regulated tariff to be within 2 percentage points above the weighted average price change. This provides some flexibility to ActewAGL to align its tariffs with underlying costs while also protecting standing offer customers from potentially large price increases.

3.1.1 Submissions on issues paper

ACTCOSS argued that to assist in encouraging competition and protecting consumers, it would be more consistent if the standing offer applied to all retailers operating in the ACT, rather than just ActewAGL.[13] ACTCOSS, COTA and Care all noted that anything that can help streamline or increase consistency across retailers would be welcome.[14]

While ActewAGL was generally supportive of the weighted average price cap form of regulation, it argued that the side constraint restricts ActewAGL's ability to pass-through legitimate changes in costs, particularly with respect to tariffs that are significantly different in composition to the cost stack.[15] As an example, ActewAGL noted that year-on-year changes in controlled load energy charges reflect changes in energy purchase costs, and the network component of these tariffs is very low. However, the side constraint is based on the composition of the cost stack, of which network charges have historically been the largest cost and energy purchase costs the second largest.[16]

ActewAGL noted that this approach differs to other jurisdictions and provided the example of the DMO where retailers have the discretion to structure their individual supply and usage charges for single rate, time-of-use and controlled load tariff types so long as the annual bill for an indicative usage customer meets the overall price constraint.[17] ActewAGL considered having the standing offer price approved at a particular level for individual customer groups does not directly align with the objectives the standing offer price seeks to achieve. ActewAGL suggested the side constraint be removed from the commission's control formula going forward.[18]

13 ACTCOSS 2023, p.12
14 ACTOSS, Care and COTA 2023, p.2
15 ActewAGL 2023, p. 7
16 ActewAGL 2023, p.7
17 ActewAGL 2023, p.7
18 ActewAGL 2023, p.7

3.1.2 Our consideration and draft decision

Currently, the cost-index approach to setting regulated retail prices in the ACT applies only to ActewAGL. By regulating ActewAGL's standing offer prices we effectively constrain the prices that can be charged by other retailers operating in the ACT. We consider our approach to be a lighter level of regulation than the DMO and VDO that applies in New South Wales, South Australia, SEQ and Victoria. Under both the DMO and VDO, all retailers, regardless of size, must provide a standing offer consistent with the DMO and VDO price determinations. Given our current approach to regulating retail prices has been effective in balancing reasonable prices and competition in the ACT market (see chapter 2), we do not consider there is any basis at this time for extending retail price regulation further.

In terms of the side constraint issue raised by ActewAGL, we introduced the side constraint for the 2020-24 regulatory period to provide a balance between price stability for consumers and price flexibility for ActewAGL.[19] In the absence of the side constraint, ActewAGL could increase prices for individual tariffs by any amount, so long as it met the overall price constraint across all its regulated tariffs. In our view, this left some customers vulnerable to significant price increases, which was inconsistent with the objectives of the ICRC Act.

The side constraint still provides ActewAGL with significant flexibility to change individual tariffs and the individual components of tariffs, as well as the opportunity to outperform the price cap. In our view, the weighted average price cap with the side constraint still provides more flexibility than would be available under the DMO or VDO style of regulation where the absolute level of prices is regulated, rather than the change in prices across a basket of tariffs. Under the DMO for example, the AER sets the annual price in dollar terms that retailers can charge in each distribution zone based on annual usage assumptions. While retailers can set the fixed and variable components of the charges, the absolute dollar amount they can charge is fixed.

One exception is for controlled load, which ActewAGL uses as an example in its submission. Currently, controlled load tariffs are treated as stand-alone tariffs for the purpose of compliance with the price control mechanism. This means that the side constraint applies to controlled load tariffs. In reality, the controlled load tariff is not a stand-alone tariff but is taken as an option with other underlying tariffs. The AER recognises this in the DMO by having a separate regulated tariff with controlled load so that retailers can set the individual components of the tariff, including controlled load, at whatever level they choose so long as they do not exceed the total annual price determination amount.

Our draft decision is to maintain the side constraint of 2 percentage points at the tariff level but to allow ActewAGL to include controlled load tariffs as a component of the underlying tariff for the purpose of compliance with the price control mechanism. This means that the side constraint would no longer apply to the controlled load tariff on its own, but instead to the total tariff that includes a controlled load component.

3.2 Cost pass-through arrangements

Pass-through arrangements apply to events that are unexpected, or whose extent was uncertain, and that are beyond the control of the regulated entity. We currently allow for pass-through arrangements for a range of regulatory change and tax change events. Pass-through reviews for these regulatory and tax change events are undertaken as part of the annual reset process.

[19] ICRC 2020, p.13-18

In the 2010-2014 retail price determination, we noted the need for a materiality threshold for pass-through applications and introduced a threshold of 0.25% of annual regulated revenue. We considered a range from 0.25% to 1% and determined that the lower level was appropriate. The rationale was that pass-throughs introduce administrative and regulatory burdens in addition to the annual price resets and therefore only events that had substantial cost impact should be passed through.

However, we removed the materiality threshold in the 2014-17 decision, as the annual recalibration of the cost-index model parameters does not have a materiality consideration. We did not find it appropriate for consistency reasons to apply it to possible pass-throughs that occur as part of an annual reset process.

In the issues paper, we flagged our intention to reconsider our decision on a materiality threshold for pass-through applications.

3.2.1 Submissions on issues paper

ActewAGL did not support reinstating a materiality threshold for cost pass through applications. It stated that a materiality threshold would add additional regulatory complexity and may prevent legitimate costs from being passed through and reflected in the standing offer price.

ActewAGL considered that imposing a materiality threshold is likely to reduce competition if prudent and efficient costs are not passed on to customers. It also argued that the costs incurred during the application process already act as the equivalent of a materiality threshold.

In a case in which we decide to include a materiality threshold in the price direction, ActewAGL considered that a threshold of approximately $400,000 for the total cost of the regulatory change event would be appropriate. ActewAGL proposed to use total costs as the threshold as opposed to costs allocated to standing offer customers. This would ensure that it only invests the time in developing the pass-through application if it meets the threshold. This is because there are different ways to allocate the costs to standing offer customers. If we apply an allocation methodology that was different to ActewAGL's, like was the case during 2023-24 annual reset, then it could end-up failing the materiality threshold and ActewAGL would have wasted time and effort in developing the application.

Origin considered that a materiality threshold is not necessary when the timing of application is aligned with the annual price reset. This is because the administrative costs for regulators and retailers are considerably less if cost pass through reviews are made concurrently with the annual price reset.

3.2.2 Our consideration and draft decision

Our retail operating costs are assumed to include some costs to meet regulatory obligations. Also, as part of this draft decision we have aligned our allowance for retail operating costs with the allowance applied by other regulators, following a detailed bottom-up assessment of retail operating costs by Australian Competition and Consumer Commission (ACCC) and information returns from ACT retailers.

Under the current approach, we index the retail operating costs allowance by the change in the Consumer Price Index (CPI). It is our view that incremental cost changes due to small regulatory events would generally be compensated by the CPI indexation.

We consider that a materiality clause should be included in the price direction for regulatory change events to:

- limit the pass-through of costs to those that have a material impact on ActewAGL's financial position
- ensure that the pass-through amount is sufficient to outweigh the administrative costs of making, reviewing and approving a cost pass-through application.

ActewAGL submitted that making cost pass-through applications involves administrative costs, which reduces its incentive to seek the pass-through of immaterial costs. ActewAGL also argued that there is an implied materiality threshold in relation to cost pass-through amounts, such as that the event needs to have an impact on the nature, scope, standard, risk and manner of providing services. We consider that a materiality threshold would improve transparency around our decision-making and provide greater certainty for ActewAGL. It will ensure that ActewAGL would only invest the time in developing the pass-through application if it was satisfied that the costs met the threshold.

As mentioned earlier, we had a materiality threshold in price directions covering the period between 2010 and 2014. During that time, pass-through events were subject to a materiality threshold of 0.25% of ActewAGL's revenue from regulated retail tariffs in the 12 months to March of the most recent year. The threshold was cumulative across pass-through events.

We consider that the materiality threshold should be on a per event basis rather than cumulative. This will prevent ActewAGL from passing through several small costs incurred as a result of a number of events. It will also provide ActewAGL with incentives to minimise the cost impacts of small events that would not be passed-through, by appropriate business practices, and for these to be managed within the retail operating allowance.

In considering the level of materiality for inclusion in the price direction, we considered both a percentage of revenue and a fixed dollar amount. We consider that a materiality threshold expressed as a fixed dollar amount of $200,000 per event adequately balances risks between the regulated business and customer, including consideration of the administrative costs involved in assessing applications. If this materiality threshold had applied at the time of assessing ActewAGL's pass-through applications for regulatory change events in 2023-24, it would not have changed the outcome.

It is important to note the following in relation to our draft decision on the materiality threshold for pass-throughs:

- only regulatory change events would be subject to the materiality threshold, no threshold would apply to tax change events
- to satisfy the materiality threshold ActewAGL will be able to aggregate the costs across multiple regulatory years, if these costs relate to a single event
- any regulatory events that took place during the course of the current price direction do not need to meet the materiality threshold.

We note ActewAGL's concerns about the methodology to calculate a share of costs relevant to standing offer customers. We consider that the cost-allocation methodology based on energy volumes provides the most balanced measurement of customer segments and avoids the potential to discriminate in favour of large customers. It is also consistent with the calculation of costs within our cost-index model, as well as with the commission's past decisions relating to cost pass through applications.

ActewAGL suggested a threshold of approximately $400,000 for the total cost of the regulatory change event would be appropriate. Our preference in not to set the materiality threshold by reference to costs not regulated by our price direction. We recognise that setting a dollar threshold may result in an effective increase in the threshold if the number of customers on standing offers declines over the regulatory period. However, given the regulatory period is limited to 3 years we do not consider this to be a significant issue and we can reconsider the level of the threshold in the next price investigation based on market movements.

A pass-through for a regulatory change event will only be made where it results in ActewAGL incurring materially higher or lower costs in providing services covered by the price direction such that the impact on costs ActewAGL has incurred, as a result of this event, exceeds $200,000.

3.3 Timeline for setting the standing offer and reference price

The TOR requires the commission to consider changes to the timeframe for the yearly standing offer approval process, such that adequate time is available for determination of the subsequent reference price by the ACT Government, and for retailers to fulfil their legal obligations under the ACT Code and NERR.

3.3.1 Submissions on issues paper

The submissions received voiced concerns regarding the timeframe and the challenges faced by retailers in fulfilling their legal obligations to notify customers of price changes.

ActewAGL argues that the current timing of the national green scheme costs, which are provided on 31 May each year, causes unnecessary delays in the final output of the cost-index model that informs the commission's final decision on the standing offer. ActewAGL argues that this has a cascading effect that impacts the timing of the final decision, the commission approving ActewAGL's tariff compliance and the ACT Government publishing its reference price.

To comply with the NERR, ActewAGL states that it must inform customers in writing through a price variation letter of new prices with a minimum 5 business days' notice. To meet its obligations in the ACT Code, ActewAGL must compare new prices from 1 July with the new Reference Price as outlined in the ACT Government's Reference Price Determination. To ensure compliance, ActewAGL must update data in its billing system, print and send letters no later than mid-June. It identifies 13 June as the last date to update and send data to printers to meet NERR requirements. ActewAGL notes that in some years the ACT Government's Reference Price Determination has been published later than this date.

ActewAGL also indicates that if actual network costs are unavailable by 30 April, it would support using estimates based on publicly available data from the AER.

Similarly, Red and Lumo Energy believe that retailers are given very limited time to update all systems and customer collateral as well as meet the existing obligations to notify customers of price changes. They recommend that the publication of standing offer prices should align with the timing of the final decision of the VDO and DMO, which occurs no later than 25 May. Further, they suggest to also have a published and agreed timeframe for the release of the reference price to retailers.

Origin does not have recommendations but generally supports bringing forward the cut-off date for the data to ensure the commission can release its final decision in a timely manner. If this leads to any differences in costs, they suggest reflecting that in the annual price recalibration process.

3.3.2 Our consideration and draft decision

To date, the timing of our final decision on the allowed change in regulated retail prices has been determined by the calculation of national green scheme costs, which relied on data up to 31 May. This meant we could not complete our cost stack calculation until 1 June at the earliest. Following our decision on the final cost stack, ActewAGL completes its compliance model, which sets out the level of its proposed prices for each tariff included in the standing offer tariff basket. We then review this model and, if compliant, we provide the ACT Government with the information required to determine the reference price. The reference price is then notified by the ACT Government.

As discussed in section 4.3, we propose bringing forward the date for large- and small-scale renewable energy certificate prices by one month so that the finalisation of these costs no longer holds up the finalisation of our decision on the cost stack. However, there remain difficulties with completing the cost stack calculation for 2024-25 within a timeframe that permits the timely determination of the reference price. Given that 2024-25 is a reset year for Evoenergy, the availability of approved network prices has the potential to delay our final decision. The timing of the AER's network determination and Evoenergy's subsequent pricing proposal are set out in the *National Electricity Rules* (NER) as follows:

- the AER must make a final determination on Evoenergy's network costs by 30 April[20] (at least 2 months prior to the start of the regulatory period)
- Evoenergy has up to 15 business days to submit an initial pricing proposal to the AER[21] (if the AER makes its final determination on 30 April, then the initial pricing proposal must be submitted by 21 May 2024)
- The AER must, as soon as practicable, approve Evoenergy's initial pricing proposal.[22]

Based on the timing set out in the NER, the timing of our final decision for 2024-25 and subsequent determination of the reference price by the ACT Government is likely to extend well into June 2024 (see Figure 3.1). Even this timing is not certain given the NER specifies that the AER must approve Evoenergy's pricing proposal 'as soon as practicable' and following this there may be a further delay because Evoenergy needs to calculate network prices including the Large-scale Feed-in Tariff (LFiT) Scheme cost.

In our view, we need to have all inputs to the cost-stack available by 21 May for the ACT Government to be able to adequately bring forward its reference price determination. A reference price determination made by approximately 30 May would provide retailers with sufficient time to meet their legal obligations to notify customers about price changes.

We understand that the AER is reviewing its timelines for the 2024-25 network pricing determinations and pricing proposals in consultation with distribution businesses.[23] If the AER and Evoenergy can bring forward the timing of the network determination and pricing proposal process, then it may be possible that approved network prices will be available by 21 May. However, this may not eventuate, particularly if the AER identify issues with Evoenergy's pricing proposal and if there are any delays in Evoenergy providing LFiT-inclusive network prices.

Draft decision

If approved network prices are not available by our cut-off date of 21 May, we propose using the network pricing proposal submitted by Evoenergy to the AER, which the NER specifies must occur no later than 15 business days after 30 April (21 May). If Evoenergy is unable to provide LFiT-inclusive network prices for 2024-25 by 21 May 2024, we propose estimating the impact of LFiT on network prices. This should then allow us to make a final decision in time for the reference price to be determined by 30 May 2024 (see Figure 3.2).

If there are material differences between the network prices we use for our 2024-25 decision and network prices approved by the AER, then we propose a true-up in the following year.

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20 NER, clause 6.11.2
21 NER, clause 6.18.2(a)(1)
22 NER, clause 6.18.8(c2)
23 AER 2023d, p.27

Figure 3.1 Timeline for 2024-25 without changes to the network costs

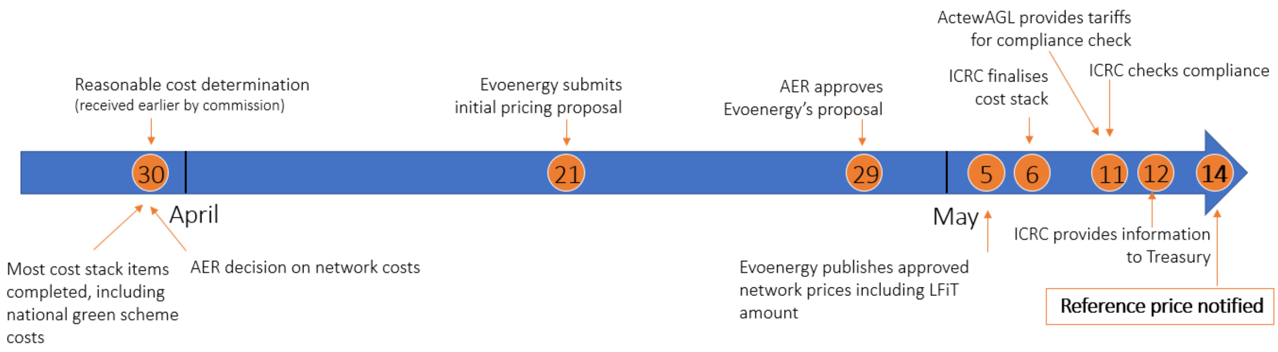
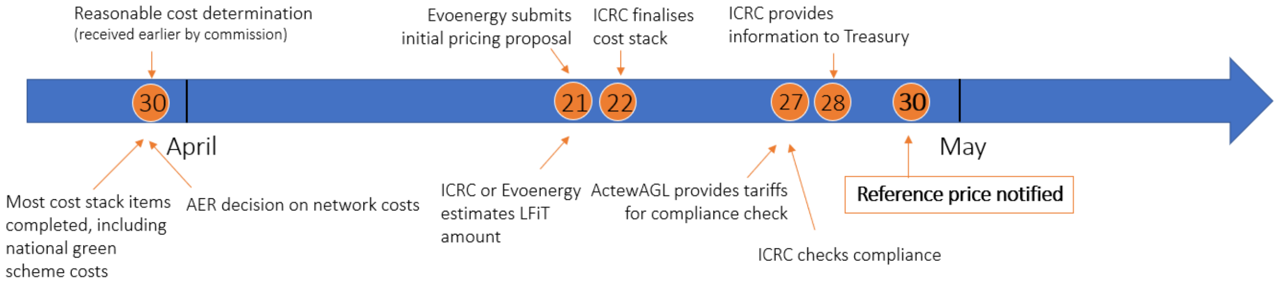


Figure 3.2 Timeline for 2024-25 with proposed changes to the network costs



Timing is less challenging for the subsequent 2 years of the retail electricity regulatory period, 2025-26 and 2026-27. During these years, which represent the second and third year of Evoenergy's regulatory control period, the NER sets out the following timing for Evoenergy's annual network pricing proposal:

- Evoenergy must submit its annual pricing proposal to the AER at least 3 months before the commencement of the regulatory year[24] (that is, no later than 31 March each year).
- The AER must publish an approved pricing proposal within 30 business days from the date of submission of an annual pricing proposal[25] (if Evoenergy submits its annual pricing proposal on 31 March then the AER would be required to publish an approved pricing proposal by early May).

For 2025-26 and 2026-27, we propose to use the AER's approved network pricing proposal in the cost stack. We propose using Evoenergy's published network prices including LFiT if this is available by 21 May. If it is not available by 21 May, we propose estimating the impact of LFiT to meet the required timeline and true-up for any material differences in the following year. The proposed timeline for 2025-26 and 2026-27 are set out in the Figure 3.3 below.

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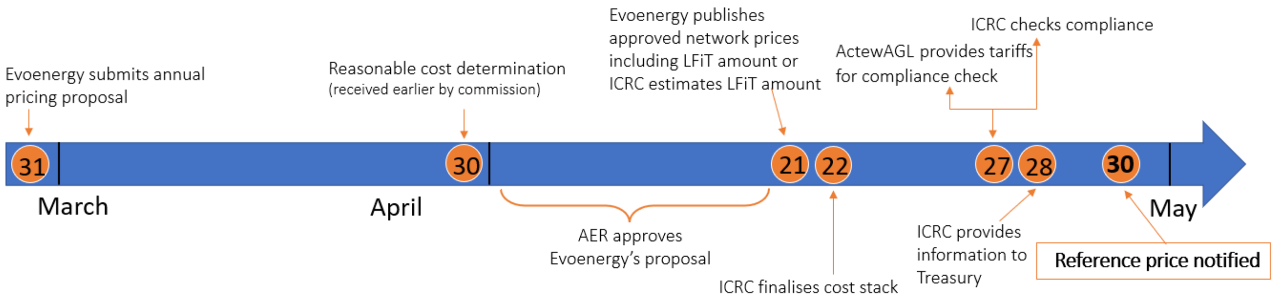
[24] NER, clause 6.18.2(a)(2)

[25] NER, clause 6.18.8(c3)

Figure 3.3 Timeline for 2025-26 and 2026-27



4. Components of pricing model for the regulatory period 2024-27

We use our pricing model to determine the maximum average percentage increase that ActewAGL can apply to its suite of regulated tariffs each year. We do so by estimating the individual cost components that would be incurred by an efficient retailer in a similar position as ActewAGL when providing electricity supply services to small customers on regulated tariffs. This chapter sets out our draft decisions on the model inputs and proposed approach to setting retail electricity prices for the 2024-27 regulatory period.

Summary of our draft decisions on cost components

Table 4.1 summarises our draft decisions on the components of the pricing model for the regulatory period 2024-27.

Table 4.1 Draft decisions on the retail electricity pricing model

Component	Current approach	Draft decision
Wholesale energy costs		
Energy purchase cost	Use base swap, base cap and peak swap contracts to hedge against spot market price volatility. Contract prices based on the 23-month time-weighted average of forward prices from the ASX. The most recent 5 calendar years of data from AEMO used as the half-hourly profile of load and spot prices. Spot prices scaled using 23-month time-weighted average of base swap prices to 30 April less 5% contract premium.	Exclude peak swaps from the hedging strategy. Contract prices based on the 23-month volume-weighted average of forward prices from the ASX. The most recent 3 calendar years of data from AEMO used as the half-hourly profile of load and spot prices. Spot prices scaled using 40-day volume-weighted average of base swap prices to 30 April less 5% contract premium. Continue to use basic meter load data to estimate the 2024-25 load profile and reassess this position in our final decision.
Volatility allowance	Adopt a volatility allowance based on the ESC's estimates for the VDO prices.	Adopt ESC's methodology but using ACT specific costs.
National green cost	Use publicly available LGC and STC spot prices averaged over 11 months to end May and include an allowance	Maintain the current approach but change the averaging period for LGC

	for holding costs based in half the annual cost of debt.	and STC prices to the 12 months to the end of April.
Energy losses	Apply loss factors determined by AEMO to the energy purchase costs, national green costs and NEM fees.	Maintain the current approach.
NEM fees	Calculate ancillary fees using a 52-week averaging period and determine NEM fees using the observed AEMO cost data for the first year of the regulatory period, with subsequent years indexed by the CPI.	Use AEMO's draft budget to calculate NEM fees each year.
Retail costs		
Retail operating costs	A benchmarking approach indexed by the CPI from 2014.	A benchmark approach using customer-weighted average retail operating costs for competitive NEM regions indexed by CPI from 2025-26.
EEIS costs	Estimated using a methodology that is set to reflect the ACT Government's legislative requirements subject to a prudency and efficiency assessment.	Maintain the current approach.
Smart meters	Include estimates from ActewAGL with adjustment to account for the difference between forecast and actual costs in the previous year.	Maintain the current approach.
Pass-through costs	Include approved pass-through costs in the cost stack.	Maintain the current approach.
Network costs	Pass-through costs determined by the AER.	Maintain the current approach, but use information in Evoenergy's pricing proposal, rather than AER's final decision if the latter is not available by the cut-off date.
Retail margin	Apply a retail margin of 5.6% to cost components (equivalent to 5.3% to the total cost stack).	Apply a retail margin of 5.5% (equivalent to 5.2% of the total cost stack). Implement half of the margin as a dollar amount and half as a percentage.

4.1 Energy purchase cost

Energy purchase costs (EPC) are the costs incurred by the benchmark retailer in purchasing electricity from the wholesale electricity market. Under the settlement rules in the NEM, retailers purchase the electricity they require from the wholesale electricity market based on spot prices, which can vary significantly from one 5-minute interval to the next. To manage the risk that arises from inherently volatile spot prices, retailers typically enter into hedging arrangements.

While there are several ways that retailers can hedge their exposure to spot prices, we assume a retailer will use financial derivatives traded on the Australian Securities Exchange (ASX). These contracts include swap contracts that effectively lock in a spot price and cap contracts which cap the spot price for the retailer. This approach is also used by other regulators including the AER and ESC, as it is a hedging strategy available to retailers and is transparent.

In practice, retailers may use a mix of different hedging strategies including vertical integration and power purchase agreements as well as purchasing over-the-counter hedging contracts, which are traded through brokers not on the ASX. These approaches may offer advantages over financial derivatives and therefore our approach may overstate the costs and/or risk outcomes that retailers can achieve.

Our current approach to estimating EPC involves 4 steps:

- determining the appropriate hedging strategy (also referred to as the contracting heuristic)
- determining contract prices
- developing a half-hourly profile of load and spot prices
- calculating settlement payments and difference payments.

The EPC accounts for a large proportion of the total costs of providing retail electricity services. In 2023-24, the EPC accounted for $160 per MWh or 55% of the total estimated costs of providing retail electricity services in the ACT.

We engaged Frontier Economics (Frontier) to provide advice on the appropriate methodology for estimating EPC.[26]

4.1.1 Hedging strategy

The hedging strategy is the volume of swap and cap contracts a benchmark retailer is assumed to use to hedge against wholesale spot price risk. The hedging strategy is expressed in relation to load. Our current EPC model assumes that the hedging strategy uses base swap, peak swap and base cap contracts. We determine the mix of these contracts that a benchmark retailer will use by estimating a prudent hedging strategy and then applying this to the ACT electricity load to determine the contract position.

In our issues paper, we sought feedback from stakeholders on the appropriate hedging strategy noting other regulators have removed peak swap contracts from their estimate.

Submissions on issues paper

ActewAGL supported the current EPC methodology.[27] ActewAGL considers the assumption that a prudent retailer will hedge their exposure to risk by purchasing hedging contracts on the ASX remains appropriate because the ASX futures market is transparent and highly liquid. In terms of determining the appropriate contract position, ActewAGL proposed this be approached in an evidence-based way and supports an independent review of the optimal hedge portfolio strategy.

Origin considered ASX futures trades continue to provide a good market-wide representation of how retailers manage both their energy and capacity positions and the associated costs.[28] Origin also believed it is far more common for retailers to use financial derivatives to hedge risk than other approaches. It also noted that information on ASX trades is publicly available and verifiable, which are important attributes for regulated pricing. Origin argued that incorporating a broader suite of products would generally increase

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26 Frontier' report is available on our website (https://www.icrc.act.gov.au/energy/electricity/retail-electricity-prices-2024-27).

27 ActewAGL 2023, p.10-11

28 Origin 2023, p.2

complexity and reduce transparency, limiting the extent to which stakeholders could meaningfully interpret and engage with the analysis, while also reducing the predictability and stability of regulated prices.

In terms of the benchmark hedging strategy, Origin argued that the inclusion of peak swaps is necessary to obtain an efficient level of hedge cover.[29] It argued that the removal of peak swaps by both the AER and ESC has increased the risk profile of the hedging strategy with retailers more exposed to high demand/price periods relative to previous decisions. Origin stated that this approach to hedging is fundamentally inconsistent with the risk management practices of a prudent retailer.

Our consideration and draft decision

To inform our draft decision, we have considered the analysis and advice from Frontier as well as stakeholders' submissions.

Frontier recommends the exclusion of peak swaps from the hedging strategy.[30] While peak swaps have been used historically for estimating the EPC, the available data shows that retailers are no longer using peak swaps as part of the contract mix. Volumes for peak swaps for 2024-25 are very low, with only a handful of trades in 2024-25 on ASX. Frontier states that this decline in the volume of peak swaps has been part of a longer-term trend, driven by greater levels of solar PV. The peak periods covered by ASX contracts now cover times of very low demand (due to higher solar PV during the middle of the day) and periods of high demand (in the evenings when demand is high and solar PV is not available). Based on available evidence, Frontier concludes that the contract position should be limited to base swaps and caps.

Frontier uses their portfolio optimisation model – *STRIKE* – to determine the efficient mix of hedging products that a prudent retailer would likely adopt. *STRIKE* calculates an efficient frontier, which represents the contracting positions that provide the lowest EPC for a given level of risk. The contract position that Frontier use to calculate the wholesale energy cost is based on the most conservative contracting position on the efficient frontier, which is the point with the lowest risk (but highest cost). See section 2.4 of Frontier's report for further details on the methodology used to determine the hedging strategy and contract position.

The resulting hedging strategy recommended by Frontier is presented in Table 4.2. The volume of base swaps is expressed as a percentile of load for all the half-hourly intervals in the quarter, where the percentile is equal to the contracting level determined by *STRIKE*. The volume of caps is expressed as a percentage of load in the highest demand half-hourly interval in the quarter, less the volume of base swaps.

Table 4.2 Hedging strategy recommended by Frontier

Quarter	Base swap volume, expressed as a percentile of half-hourly load in the quarter	Cap volume, expressed as a percentage of the maximum half-hourly demand in the quarter, less base swap volumes
1	70th	100%
2	20th	100%
3	20th	100%
4	10th	100%

Source: Frontier 2023, p.29

29 Origin Energy 2023, p.2
30 Frontier 2023, p.19

Our draft decision is to accept Frontier's recommendation on the hedging strategy. While we note Origin's position on the inclusion of peak swap contracts, the available evidence suggests that these contracts are no longer being used by retailers and therefore we agree with Frontier's recommendation to exclude them from the hedging strategy. Consistent with our current approach, we propose maintaining the same hedging strategy for the regulatory period, noting that the contract position will change each year as we update the load data.

4.1.2 Contract prices

Contract prices refer to the forward prices of hedging instruments used by a benchmark retailer. In our current model, we use a 23-month time-weighted average of ASX data (between 1 June to 30 April) to calculate the forward prices for each instrument.

In our issues paper, we sought feedback on the appropriate averaging period, noting ESC uses a 12-month trade-weighted average of ASX contract prices and AER uses trade-weighted average contract prices based on a book build period from the date of the first trade.

Submissions on issues paper

ActewAGL proposed increasing the current 23-month averaging period for determining contract prices to 24 months from 1 May to 30 April and notes that this would not impact the timing of the commission's final decision.

Origin generally supported the 23-month averaging period for contract prices but believed there may be merit in assigning a higher weighting to contract trades and prices that occur closer to the relevant period, which would better account for more up to date pricing expectations.

Our consideration and draft decision

In coming to our draft decision, we considered the analysis undertaken by Frontier and the submissions received from stakeholders.

Frontier's view is that economic decisions in competitive markets will be based on the market value of contracts, regardless of when those contracts are purchased. Frontier considers 40-day average prices a good proxy for this market value. However, Frontier also recognises that there may be good reasons for a regulator choosing a different period. For example, a regulator may want to reflect the fact that retailers can set prices at different times through the year, with a longer averaging period better reflecting these costs. Also, a longer averaging period would be expected to provide more stable prices over time and would also be likely to better reflect an incumbent retailers' actual historic costs (since most retailers will buy contracts over a period of time leading up to the settlement year).

Frontier examined a range of averaging periods and time-weighted versus volume-weighted contract prices and reports the following observations:

- The 40-day time-weighted prices have the most volatile results as the short averaging period means that the resulting average contract prices are more likely to reflect either temporarily high or temporarily low contract prices.
- Conversely, the 23-month time-weighted prices have the least volatility across the time horizon. The reason is that the longer averaging period means that it takes longer for either increases in contract prices, or decreases in contract prices, to flow through to the estimated EPC.
- The 23-month volume-weighted and 12-month volume-weighted prices are very similar. This is because the majority of the volume is traded in the twelve months to April.

See section 2.3 of Frontier's report for further details on the analysis of contract prices.

Our draft decision is to maintain our current approach of using a 23-month averaging period for contract prices from ASX from 1 June to 30 April for each hedging instrument. This averaging period reflects the fact that retailers typically hedge in advance of the year in which they supply customers. It also smooths out both upward and downward fluctuations in forward prices, providing consumers with price stability. While we could extend the averaging period by one month further into the past, as proposed by ActewAGL, this would have little impact on the results (particularly under the volume-weighted methodology).

Our draft decision also involves moving from a time-weighted average to a volume-weighted average methodology as proposed by Origin. The volume-weighted approach better reflects the contract prices that retailers pay, as it takes into account the timing of when trades occur. It is also consistent with the approach adopted by the AER and ESC. In our view, this approach provides a better balance between economic efficiency and social considerations, as required under the ICRC Act, compared with the time-weighted approach.

4.1.3 Half-hourly profile of load and spot prices

To determine the EPC, the half-hourly profile of load and spot prices is required. Currently, we use the most recent 5 calendar years of load and spot price data from the Australian Energy Market Operator (AEMO), as it is transparent and easy to implement.

The half-hourly spot prices for each quarter are scaled up to the average base swap forward price for the relevant quarter less the forward price margin. This ensures that spot prices are aligned with future expectations. We currently use an averaging period of 23 months for calculating an average forward price for the purpose of scaling spot prices, consistent with the period used to average contract prices. The forward price margin (also known as a contract premium) is set at 5% in our model.

The issues paper sought feedback on whether the current approach of using actual load data for 5 calendar years remains appropriate. We also proposed to investigate the inclusion of interval meter data in the estimated load profile.

Submissions on issues paper

ActewAGL supported the current approach of using actual load data for 5 calendar years. In terms of including interval meter data in the load profile, ActewAGL proposed revisiting this issue in the next methodology review when more data is available. ActewAGL considered it critical that whatever approach is taken, the EPC model should remain replicable. However, following its submission, ActewAGL contacted the commission to propose that interval meter data be considered as soon as possible given its potential to significantly impact the load profile.

Origin also supported the continued use of 5 years of actual load data but suggested that the commission examine interval meter data to determine what the implication of a change in the NSLP would have on prices and what transition methods would, if any, need to be applied.

Origin noted the volatility in wholesale electricity prices and the challenges this poses for forecasting spot prices. It suggested that a higher margin for forecast error is a conservative approach to recognising the varying degrees of spot price uncertainty.

Our consideration and draft decision

Our draft decision is based on consideration of the analysis undertaken by Frontier, stakeholders' submissions, and interval meter data provided by Evoenergy and AEMO.

Frontier considers the best source of data about half-hourly patterns of customer load and spot prices to be historical data, as it reflects all complex factors that drive both spot prices and customer load as well as the interactions between them, which are difficult to accurately capture using forecasting models. Based on their analysis of historical load and spot price data, Frontier finds:

- the load factor (measuring the peakiness of the load) has been very stable over time
- there has been a modest increase in load during the day for the most recent 2 years, 2021 and 2022, which may reflect the increasing incidence of working from home in the ACT
- daily profiles of spot prices for the last 3 calendar years are more similar to each other, with relative prices during the day that are materially lower and relative prices during the evening that are materially higher, a trend apparent across the NEM
- the load premium (which combines the historical load and spot price data) is materially higher for the last 3 calendar years than the prior 2 years.

Based on their analysis, Frontier recommends the use of the 3 most recent calendar years of historical data, as they reflect quite different patterns than the previous 2 years.

In addition, Frontier found little difference between the approach of using a simulated year to calculate the EPC and using 3 years of historical data. Frontier recommends scaling historic spot prices using quarterly base swap prices from ASX less an assumed contract premium of 5%. Frontier uses a 40-day average to represent the market's current view of spot prices for each quarter of 2024-25. Section 2.2 of Frontier's report provides full details of their analysis.

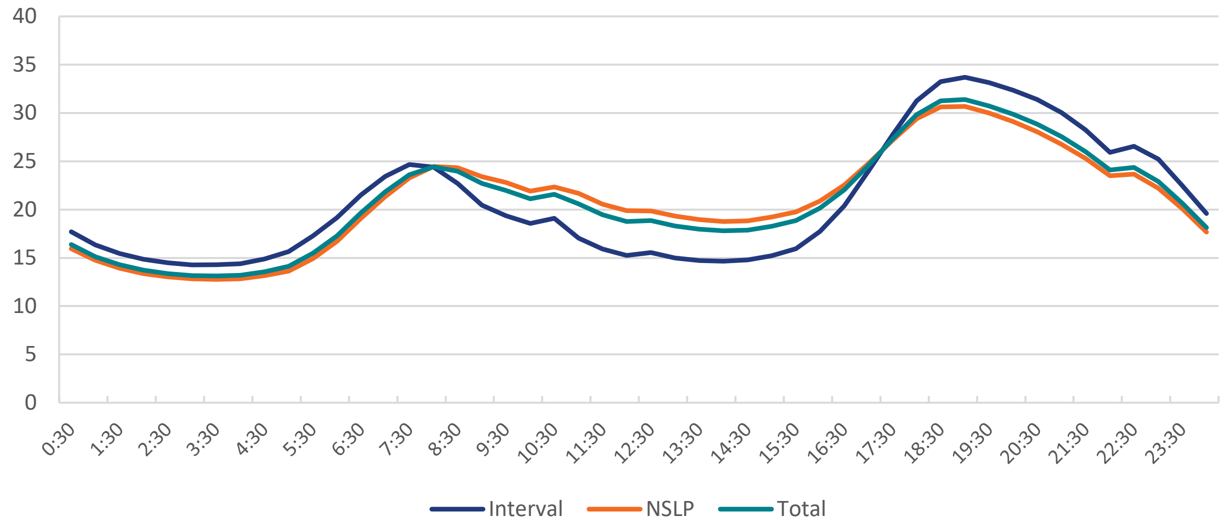
We agree with Frontier's recommendations to use the 3 most recent calendar years of data and to scale historical spot prices using a 40-day average of base swap contract prices less a contract premium of 5%. Given the very small difference between using a single simulated year (based on 3 years of historic data) and using the 3 full years of historic data, our draft decision is to maintain our current approach. Using the full 3 years of historic data provides greater transparency and allows the commission's estimates to be replicated by stakeholders.

Frontier's analysis is based on Net System Load Profile (NSLP) data from AEMO, which only captures basic meters, not interval meters. We were able to obtain interval meter consumption data from Evoenergy for small customers.[31] This data suggests that the load profile for customers on interval meters is significantly different from that of customers on basic meters, reflecting the high take-up of solar PV systems and hence lower consumption during the day. However, the data provided by Evoenergy suggests that interval meter consumption accounts for 24% of the total load for the period 2020-21 to 2022-23 and, as a result, the impact on the total load profile is minimal (see Figure 4.1). We estimate that using the load profile inclusive of interval meter data increases the EPC by approximately $1 per MWh.

For the purposes of the draft decision, we have continued to use the NSLP to estimate the load profile for 2024-25, as this is the basis for the hedging strategy estimated by Frontier. We are mindful that the proportion of load from interval meter consumption is likely to accelerate going forward. We will reconsider the issue for the final decision and determine whether an update to the hedging strategy is required.

[31] We did request interval meter data from AEMO, however, at the time of preparing this draft decision only net load data could be provided for the required time period (net of exports back to the grid).

Figure 4.1 Load profile for small customers, 2020-21 to 2022-23



Note: Load data has been scaled to 1 GWh per day to separate the load profile from the load volumes.
Source: Data provided by AEMO and Evoenergy.

4.2 Volatility allowance

A typical hedging strategy adopted by the benchmark retailer leaves some residual level of exposure to volatile spot prices because buying contracts to cover all possible spot price and demand scenarios can be very expensive. The residual risk can be accounted for by holding some working capital (i.e., cash) to fund spot market purchases in the event that electricity demand is larger than accounted for by the hedging strategy. The cost of holding this working capital is known as a volatility allowance.

We currently use a benchmarking approach to set the volatility allowance at the start of each regulatory period, using the ESC's volatility allowance as our benchmark. The ESC estimates the volatility allowance by taking the difference between the wholesale energy cost estimated for the median simulated year and the costliest simulated year and applying a cost of capital of 7.5%.

Under our current approach, we:

- first: take the simple average of the ESC's volatility allowance across the five Victorian distribution zones, separately for residential and business customers
- second: calculate the weighted average volatility allowance across residential and small business customers using ActewAGL's residential versus small business electricity demand as the weights.

In our 2023-24 pricing model, the volatility allowance counted for $0.30 per MWh or 0.1% of the total cost of supplying retail electricity in the ACT. Given that the volatility allowance accounts for a very small proportion of total costs, we hold the volatility allowance constant for the regulatory period.

4.2.1 Submissions on issues paper

ActewAGL supported the inclusion of a volatility allowance but considered the current estimate too low[32]. ActewAGL considers it prudent and timely to review and update the methodology to make it consistent with other jurisdictions where retailers are facing similar volatility risks.

Origin considered that the current approach to calculating the volatility allowance takes no account of the likely corresponding variance in price and suggested that a better alternative would be to adopt a higher margin for forecast error, which would circumvent the need for a volatility allowance.[33]

4.2.2 Our consideration and draft decision

Our draft decision is to retain the volatility allowance in the estimation of retail electricity costs and to continue using the ESC's methodology. However, rather than using the median and highest EPC calculated for Victorian distribution businesses, we propose using the median and highest EPC calculated for the ACT. Consistent with the methodology used by the ESC, we propose calculating the volatility allowance by taking the difference between the median and highest EPC and applying a cost of capital.

Given the volatility allowance accounts for a very small proportion of total costs, we propose holding the value constant for the regulatory period.

4.3 LRET and SRES costs

Under the Australian Government's Renewable Energy Target scheme, retailers have an obligation to purchase renewable energy certificates and surrender them to the government in proportion to the overall amount of energy consumed by their customers. The costs of purchasing these certificates are passed on to all customers.

The Renewable Energy Target scheme is made up of the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). The LRET and SRES costs are incurred to acquire the necessary amount of Large-scale Generation Certificates (LGC) and Small-scale Technology Certificates (STC). LGC and STC surrender for each retailer is determined annually using the Renewable Power Percentage (RPP) and Small-scale Technology Percentage (STP), respectively, which are set by the Clean Energy Regulator each year. [34]

We currently adopt a market-based approach to determine the efficient LRET and SRES costs, by taking the following elements:

- determining LGC and STC prices based on publicly available spot price data over an 11-month period (from 1 July to 31 May each year)
- applying an allowance for certificate holding cost to recognise the legitimate costs associated with holding these certificates prior to surrender
- apportioning calendar year costs based on the half-yearly load weights to derive LRET and SRES costs for a financial year[35]

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32 ActewAGL 2023, p.11
33 Origin Energy 2023, p.4
34 More information on the LRET and the SRES schemes can be found on the Clean Energy Regulator's website: www.cleanenergyregulator.gov.au/Renewable-Energy-Target/Pages/default.aspx.
35 LREST and SERS obligations accrue in calendar year terms, and our pricing model is configured in financial year terms.

- providing a cost adjustment each financial year to account for the difference between the estimated RPP at the time of the price determination and the actual RPP that is subsequently published by the Clean Energy Regulator.

As noted in our issues paper, the main difficulty with our current approach is that it holds up the finalisation of our pricing model until early June. The TOR for the current inquiry requires us to consider changes to the timeframe for the yearly standing offer approval process to ensure that there is adequate time available for determination of the reference price and for retailers to fulfill their legal obligations.

In addition to the timing of the LRET and SRES costs, we also need to determine the appropriate holding costs for the certificates. Our current methodology involves using the estimated cost of debt based on non-financial corporate BBB rated 3-year bond yields using an 11-month average to the end of March. The Reserve Bank of Australia (RBA) data that is relied on for this calculation is typically published 10 business days after the end of the month so is available in mid-April, consistent with the TOR on the timeframe. We take the cost of debt for a half year period based on the assumption that a prudent retailer would purchase certificates evenly throughout the year.

For 2023-24, estimated LRET and SRES costs accounted for $14.06 per MWh of 5.2% of total retail electricity costs for the ACT.

4.3.1 Submissions on issues paper

ActewAGL supported using a 12-month averaging period for LRET and SRES costs but proposed bringing forward the spot price period by one month to 30 April, to align with the date other data in the EPC model is available.[36] ActewAGL noted that the using an averaging period to 31 May each year unnecessarily delays the commission's final decision and has a cascading effect on the publication of the reference price and compliance with the NERR, under which retailers must inform customers in writing through a price variation letter with at least 5 business days' notice. ActewAGL proposed an alternative timeline for setting the standing offer and reference price each year. This is discussed in section 3.3.

Origin supported the commission's market-based approach to determine environmental costs and supported bringing forward the cut-off date to ensure the final decision is released in a timely manner[37].

We note that the ESC used a 12-month trade weighted average LGC price to 28 April in its model for the latest VDO determination and the AER estimated the average LGC price by using pricing information up to 10 May in its recent DMO 5 decision.

4.3.2 Our consideration and draft decision

Our draft decision is to maintain the current market-based approach for calculating the LRET and SRES costs but to change the averaging period for LGC and STC prices to the 12 months to the end of April. This will ensure that the estimation of these costs do not hold up the final decision on standing offer prices. This is consistent with the TOR which requires us to ensure that adequate time is available for determination of the subsequent reference price by Ministers and for retailers to fulfill their obligations.

We received no submissions on the methodology for estimating holding costs and our draft decision is to maintain the current approach of using the estimated cost of debt based on non-financial corporate BBB rated 3-year bond yields using an 11-month average to the end of March. We consider it appropriate to

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[36] ActewAGL 2023, p.11-13

[37] Origin 2023, p.4

leave the holding cost unchanged during the regulatory period given it accounts for a small proportion of the total cost.

4.4 NEM fees

The NEM is managed by AEMO. AEMO is responsible for managing power system security and reliability, market operations and systems, wholesale metering, settlements and prudential supervision as well as longer-term energy forecasting and planning. In addition to these core functions, AEMO is responsible for facilitating retail market competition in the east coast and southern states of Australia by managing and supporting retail market functions and customer transfers, data for settlement purposes, market procedure changes and business to business processes.[38] AEMO recovers its costs from market participants, including electricity retailers. The costs allocated to electricity retailers are recovered equally through a combination of charges on the number of connections and usage.

AEMO also procures ancillary services to assist in maintaining or restoring a safe and secure power system.[39] AEMO provides ancillary services separately for each market it operates, and service costs can vary substantially from period to period.

In 2023-24, NEM fees, including ancillary charges, accounted for $1.41 per MWh or 0.5% of the total estimated cost of supplying retail electricity in the ACT. Our current methodology involves estimating each component of the NEM fees using AEMO's draft budget and ancillary services reports for the first year of the regulatory period. For the following three to four years of the regulatory period, the NEM fees are escalated by CPI.

This approach differs to that used in other jurisdictions[40] where NEM fees are recalculated each year using AEMO's draft budget[41] and ancillary services report.[42] This approach more accurately captures annual changes in NEM fees which may arise because of new regulatory obligations or changes in AEMO's allocation methodology.

4.4.1 Submissions on issues paper

ActewAGL considered that NEM fees should be treated similarly to network costs and passed through and reflected directly in the cost stack, rather than indexed by CPI each year.[43]

AEMO proposed that we use this approach to setting retail prices for 2022-23, as there was a substantial uplift in NEM core fees for that year. Given 2022-23 was within a regulatory period, we did not change our approach.

No other submissions provided feedback on the calculation of NEM fees.

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38 AEMO 2023a, p.45
39 AEMO 2023b, p.3
40 See ACIL Allen 2023a, p. 89-90; ESC 2023b, p.46-47; ACIL Allen 2023b, p.28; and OTTER 2022, p.47.
41 The draft budget is published by AEMO in April each year so is available in time for making annual pricing decisions. The final budget is published too late for this purpose.
42 Ancillary service charges are taken for the preceding 52-week period, usually to the end of April.
43 ActewAGL 2023, p.14

4.4.2 Our consideration and draft decision

Given that it is administratively simple and more accurate to calculate NEM fees each year using AEMO's draft budget and ancillary services reports, our draft decision is to recalculate NEM fees for each year of the three-year regulatory period from 1 July 2024 to 30 June 2027.

The categories of costs we propose to include in the NEM fees are as follows[44]:

- NEM management fees
- Electricity retail market fees
- Global and 5-minute settlement fees
- Distributed Energy Resources Integration Program (DER) fees
- Energy Consumers Australia (ECA) fees
- Ancillary service charges

All the above categories of fees with the exception of ancillary services charges would be taken from the AEMO draft budget for the relevant year. AEMO's draft budget includes the forecasts of connection points and consumption that underly its budget. These forecasts would be used to convert the per connection point charges to charges per MWh to align with our pricing model. The exception to this is ECA fees, which are only allocated to small customers. For 2023-24, AEMO's draft budget did not include the forecast usage to allow the conversion from a per connection to per MWh charge. If AEMO's draft budgets for the three-year period covered by our price investigation do not include forecast usage for small customers, then we propose to use the volume of regulated customers and usage in the ACT to perform this conversion.

Ancillary service charges would be taken from AEMO's Ancillary Service Recovery reports. We propose to include charges for the preceding 52-week period ending as close as possible to the end of April. As the ACT is part of the NSW market, the data relevant to our analysis is for the NSW region.

4.5 Retail operating costs

Retail operating costs are the efficient costs incurred by the retailer in providing retail services to its customers. As noted in our issues paper, our current model uses a benchmark retail operating cost determined by IPART in 2013[45], which is indexed annually by CPI. The IPART analysis is 10 years old, and we believe that it is appropriate for the retail cost benchmark to be updated.

In 2023-24, retail operating costs accounted for $17.71 per MWh or 6% of the total estimated cost of supplying retail electricity in the ACT.

We engaged Frontier to provide advice on the benchmark for retail operating costs.

4.5.1 Submissions on issues paper

ActewAGL supported a review of the retail operating cost allowance, noting that both the DMO and VDO approaches produce materially higher estimates.[46] ActewAGL considers that regulatory costs should be clearly identified so it is clear what costs qualify under pass through provisions. ActewAGL also argued that the current approach does not reflect increased competition in the ACT and some cost categories such as

[44] In the event that AEMO includes further charges relevant to electricity retailers, these will be included in our NEM fee cost category.

[45] IPART 2013, p 97-107

[46] ActewAGL 2023, p.14-16

customer acquisition and retention costs should be higher and separately estimated in the cost stack. ActewAGL supported the annual adjustment of retail operating costs by CPI subject to a review and rebasing of the current retail cost allowance.

Origin stated that the AER and ESC have recently moved away from using the IPART cost benchmark.[47] It noted that the AER has commenced using ACCC data, which it believes would be a pragmatic choice of data for the commission. Origin noted that it is transparent and consistent and updated regularly. The ACCC data combines NSW and ACT data, which Origin believes is appropriate on the basis it is representative of retail businesses operating at scale, similar to ActewAGL. Therefore, it provided an appropriate point of comparison of how retail costs are moving from year to year in a more competitive environment than the ACT, where ActewAGL holds the vast majority of market share.

4.5.2 Our consideration and draft decision

In making our draft decision we considered the analysis undertaken by Frontier, stakeholders' submissions, confidential data supplied by the three largest retailers operating in the ACT, data collected and published by the ACCC and other regulatory decisions.

Retail operating costs are generally defined as the cost to serve (CTS) plus customer acquisition and retention costs (CARC).

Frontier found that while there were differences across businesses and regulators in the definition of CTS, it is generally agreed they consist of the following:

- Customer service and IT
- Billing and revenue collection costs
- Bad and doubtful debts
- Call centre costs
- Customer information costs
- Corporate overheads
- Energy trading costs
- Regulatory compliance costs.

Similarly, while CARC can be categorised in different ways, it is generally agreed to consist of the following:

- the costs of acquisition channels (such as third-party comparison websites, telemarketing or door-to-door sales)
- the costs of retention teams
- marketing costs targeted at driving acquisition or retention.

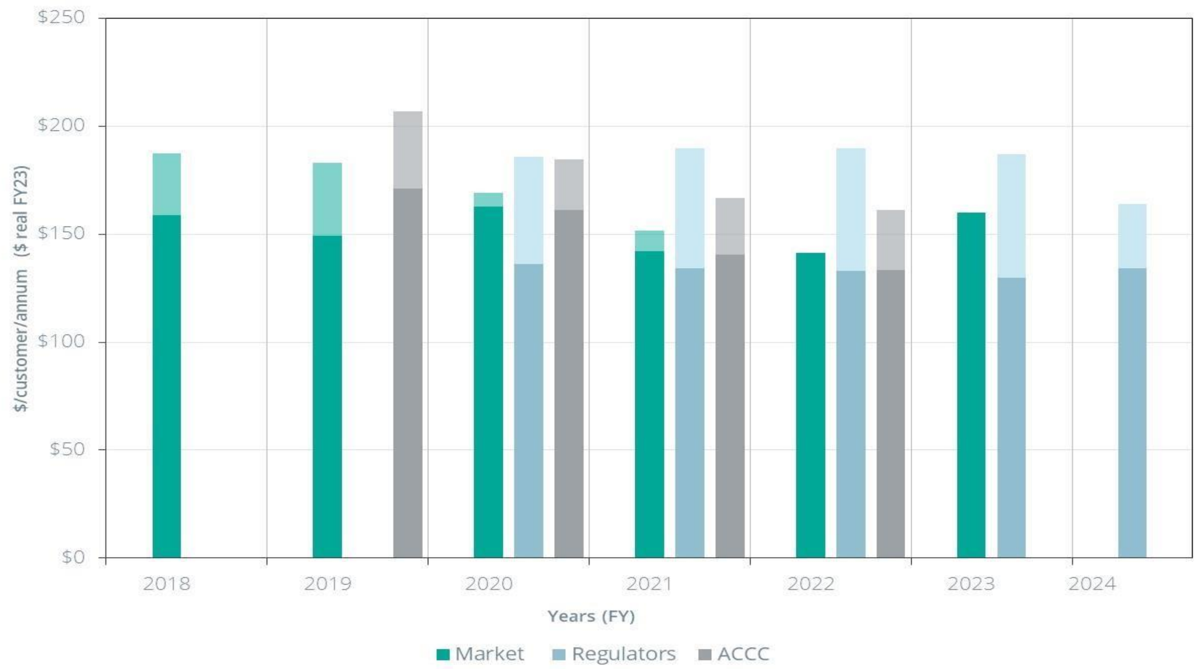
Frontier found that while the general descriptions of the categories are quite similar across retailers and regulators, there remains uncertainty as to how specific cost elements are treated, particularly common costs. There are different approaches to defining and setting an allowance for CARC.

Frontier considered the data published by the ACCC, other regulatory decisions, publicly available market data and the confidential data provided by ActewAGL, Origin and EnergyAustralia. It found that retail operating costs from different sources have been converging in recent years (see Figure 4.2). It found that the commission's retail operating cost allowance lies at the bottom end of the regulator range and is lower

[47] Origin 2023, p.5

than the weighted average cost for the largest retailers operating in the ACT. See section 3 of Frontier's report for a full analysis of retail operating costs.

Figure 4.2 Summary of retail operating cost benchmarks



Note: Confidential cost information from ACT retailers has been excluded from this chart.

Source: Frontier 2023.

Given the difficulties with comparing the individual components of retail operating costs across different sources, we propose using an aggregate benchmark and cross-checking that benchmark with total retail operating costs for ACT retailers. Given Frontier's finding around the convergence of different estimates at the aggregate level, we consider this to be a reasonable approach.

Our draft decision is to estimate the benchmark retail operating costs using the retail operating costs for competitive NEM regions as reported by the AER (DMO for 2023-24) and the ESC for Victoria (VDO for 2023-24). These benchmarks all include CTS, an allowance for CARC and bad and doubtful debt. We have excluded smart meter costs from the AER's figures as these costs are captured separately in our cost stack.

For each region where separate figures are reported for residential and business customers, we have calculated a blended figure using customer numbers and energy consumed in each region. We sourced this information from data provided to the AER in the networks' Regulatory Information Notices (RIN). The retail operating costs per customer across competitive NEM regions is between $163 in Queensland and $176 in Victoria with a customer-weighted average value of $173 (see Table 4.3).

Table 4.3 Retail operating cost benchmarks for competitive NEM regions, per customer

	Retail operating costs, $2023-24
NSW	174.3
South Australia	170.6
Queensland	163.4
Victoria	175.9
Weighted average (customer numbers)	172.7

Source: our calculation based on data from AER 2023b and ESC 2023a.

We have compared these results with the average retail operating costs reported by the three largest retailers in the ACT – ActewAGL, Origin and EnergyAustralia. The average customer weighted retail operating costs for the three retailers is consistent with the range of retail operating cost benchmarks presented in Table 4.3.

We are unable to rely on the ACT-specific benchmark alone because:

- This is the first time we collected retailers' cost data and we do not have sufficient confidence in the appropriateness of using this data, noting that some retailers made assumptions about how to attribute the costs to the ACT.
- There are only three retailers in our sample, so we are unable to report the ACT-specific benchmark because of concerns that it could reveal the costs of individual retailers.

We propose setting our benchmark as the customer-weighted average of retail operating cost allowances provided by other regulators in competitive NEM regions, which involves a significant increase to our current benchmark of $143 per customer. We are satisfied that our proposed approach addresses the issues raised in stakeholder submissions and is appropriate given the increased competition evidenced in the ACT electricity market. Consistent with our current methodology, we propose adjusting the benchmark for CPI for the remainder of the regulatory period.

Our draft decision is to set the retail operating cost allowance of $172.7 per customer per year in 2023-24 dollar terms. Adjusting for inflation, this is an equivalent of $181.20 per customer per year for inclusion in 2024-25 prices.

We propose to continue collecting the cost data from retailers over the course of the regulatory period. At the time of our next investigation, we will consider the range and trends in actual costs as well as benchmarks from other regulatory decisions.

4.6 Retail margin

The retail margin represents the return on the investments made by the benchmark retailer in providing retail electricity services. Once all the other cost categories of the model are estimated, they are added together and multiplied by the retail margin to produce the total cost.

We set the retail margin in the last two regulatory periods drawing on research undertaken by Strategic Finance Group (SFG) for IPART in 2013.[48] In our 2020–24 price investigation, we applied a retail margin of 5.6% throughout the regulatory period.

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[48] IPART 2013, p 89-96

As noted in our issues paper, the retail margin relies on a study that is now 10 years old, and we consider it appropriate to update this benchmark.

In addition to the level of the retail margin, there is also the issue of how the margin is applied. The retail margin is currently applied to the total cost stack to convert it from a percentage margin to $/MWh. This means when costs are relatively stable so is the retail margin. However, when there are large movements in other costs components, either upwards or downwards, the retail margin in $/MWh may also increase or decrease significantly. These changes are unlikely to reflect changes in costs faced by retailers.

In 2023-24, the retail margin accounted for $15.35 per MWh or 5.3% of the total estimated cost of supplying retail electricity in the ACT.

We engaged Frontier to provide advice on the level and the application of the retail margin.

4.6.1 Submissions on issues paper

ActewAGL considered the current retail margin does not provide a reasonable or efficient return.[49] ActewAGL stated that the risks of retailing electricity in the ACT have increased since the last review of the retail margin, with 7 Retailer of Last Resort (ROLR) events in 2022/23 across the NEM and with marked changes in wholesale cost and interest rates since 2020. ActewAGL supported updating the methodology to provide a reasonable retail margin with the standing offer price methodology. It suggested that this could include updating the SFG study using the latest available information or undertaking an additional independent study that takes into account current risks facing electricity retailers in the ACT.

Origin stated that the retail allowance is a crucial part of achieving and ultimately balancing the various components of a regulated price.[50] It argued that the allowance should be set such that it allows retailers to recover a reasonable margin (commensurate with the level of risk) and incentivises innovation/competition in the market and consumer engagement, while also ensuring customers are protected from unreasonably high prices. Origin noted this is a delicate balance made even more challenging by an environment of increasing costs and considers a conservative approach would be to retain the current allowance.

4.6.2 Our consideration and draft decision

Our draft decision relies on the analysis undertaken by Frontier in section 4 of its report. Frontier uses both a benchmarking approach and an expected returns approach to assess the appropriate retail margin. The latter methodology is consistent with the approach recommended by ActewAGL, which involves updating the SFG study. This approach is also consistent with Origin's recommendation to allow the recovery of a reasonable margin, as the expected returns approach is aimed at estimating the margin that is required to compensate investors in the business for systematic risk.

Frontier's benchmarking results indicate that regulatory allowances, with the exception of the AER, have been between 5% and 6% (see Figure 4.3). The AER's DMO4 decision announced an intention to transition to a consistent retail allowance across the NEM of 10% for residential customers and 15% for small business customers. The AER's retail allowance includes both a retail margin and an allowance to maintain incentives for competition, innovation and investment. The inclusion of a competition allowance in the retail margin is unique to the AER's methodology and reflects the DMO policy objectives. The AER is currently reviewing its approach for the retail margin for its DMO6 decision.[51]

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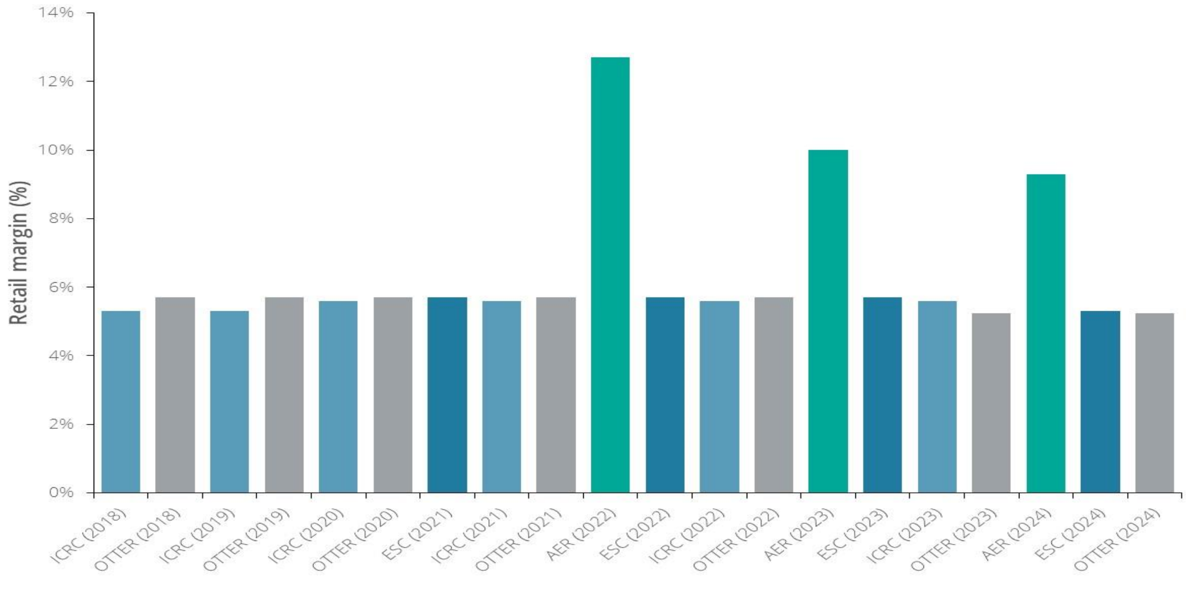
49 ActewAGL 2023, p.16-17
50 Origin 2023, p.5
51 AER 2023d

Figure 4.3 Summary of retail margin regulator benchmarks



Source: Frontier 2023, p.56.

Frontier also implemented the expected returns approach first developed by SFG for IPART. The key objective of the expected returns approach is to estimate the minimum retail margin required to compensate equity investors in a notional electricity retailer for the systematic (i.e., non-diversifiable) risk they bear when committing equity capital to the firm.

The expected returns approach involves five main steps:

1. derive an estimate of the benchmark Weighted Average Cost of Capital (WACC) for a notional retailer
2. forecast the future cash flows and returns of the notional retailer under different economic conditions
3. forecast the future returns on the market in different states of the market[52]
4. use the forecast returns of the notional retailer and the market to compute the implied systematic risk of the notional retailer
5. solve for the retail margin that equalises the systematic risk implied by the retailer's forecast cash flows and the systematic risk associated with the benchmark WACC

Each of these steps is explained in section 4.2.2 of Frontier's report.

Frontier considers a range of parameter values to estimate a low, base and high EBITDA margin giving results of 4.5%, 5.2% and 5.9%, respectively.

In terms of implementing the margin, Frontier explores the impact of using either a percentage margin or a dollar margin. Given that the volatility in the cost stack over time is driven primarily by changes in the EPC, Frontier examines the impact on the margin, as wholesale energy costs increase and decrease. Frontier finds that both approaches are likely to lead to overcompensation or under-compensation:

- constant margin as a percentage ignores that increasing energy costs reduce the risk faced by the retailer and so overcompensates the retailer as energy costs increase, whereas

[52] The 'market' in this context refers to the market for all assets in the economy. In principle, this market would include all assets, tradeable (including all financial and real assets) and non-tradeable (including human capital). In practice, the returns on the market are estimated using data on the stock market, assuming that a well-diversified stock index such as the All Ordinaries Index is a reasonable proxy for the market as a whole (which is, by definition, a perfectly diversified asset).

- constant margin as a dollar ignores that some fixed costs have increased so that the retailer is undercompensated as energy costs increase.

Frontier finds that a hybrid approach, giving equal weight to both the percentage margin and the dollar margin appears to provide appropriate compensation.

Our draft decision is to use the base case of the expected returns approach estimated by Frontier. This scenario produces an EBITDA margin of 5.2%, which is equivalent to 5.5% when applied to the cost stack excluding the margin.[53] The base case scenario uses input values that we consider to be reasonable, and the resulting margin is consistent with the relevant regulatory benchmarks. We propose implementing the margin using a 50/50 weighting for the dollar amount and the percentage. Frontier finds that this approach appropriately compensates retailers for systematic risk as wholesale energy costs rise or fall. We also consider that this approach provides a more reasonable balance between providing a return to retailers and more stable prices for consumers than the current approach of using only a percentage margin.

In terms of calculating the dollar amount to implement our proposed approach, we have calculated the average margin in dollar terms for the past 5 years using a 5.5% margin (see Table 4.4). This results in a margin for 2024-25 of $8.05 per MWh plus 2.75% of the total cost stack (excluding the margin).

Table 4.4 Margin in dollar terms over past 5 years

Year	Total cost stack excluding margin ($ nominal)	Retail margin, applied 5.5%, ($ nominal)	Retail margin, applied 5.5%, ($2024-25)
2023-24	274.15	15.08	15.78
2022-23	263.21	14.48	16.23
2021-22	266.55	14.66	17.07
2020-21	238.1	13.10	15.33
2019-20	245.06	13.48	16.07
Average			16.10
50% of average			8.05

Source: our calculations.

4.7 Standing offer review costs

We do not explicitly identify standing offer review costs in our cost index model but consider there is sufficient room in our retail operating cost allowance to recover these costs over the regulatory period.

4.7.1 Submissions on issues paper

In its submission, ActewAGL stated that the costs of the commission's review of the ACT standing offer are likely to be material. With the introduction of the ACT Retail Electricity (Transparency and Comparability) Code in 2021, the standing offer now informs a Reference Price which all retailers in the ACT are required to use. Given the broader function of the review, it is appropriate that the costs of the commission's

[53] The conversion is 5.2%/(1-5.2%) = 5.5%. For example, if the total cost stack excluding the margin was $300/MWh, then applying a margin of 5.5% results in a margin of $16.50/MWh and a total cost stack of $316.50/MWh including the margin. The margin, in EBITDA terms, is $16.50/$316.50 or 5.2%.

current review are recovered from all retailers through an industry levy. The costs of the review should also be transparently itemised in the cost stack methodology.

4.7.2 Our consideration and draft decision

The commission agrees with the points made by ActewAGL in terms of recovery of standing offer review costs. Even though the TOR specify that the price direction is to only apply to ActewAGL, the regulation of ActewAGL's standing offer prices imposes a constraint on retail pricing more generally in the ACT electricity market. In addition, the Reference Price must be used by all retailers in the ACT. Given that retail price regulation is applicable to the whole ACT electricity market, the commission agrees that the cost of regulation should be shared across all retailers operating in the ACT.

Therefore, our draft decision is to spread the costs of the standing offer review across all retailers in the ACT to the extent practicable. Specifically, we propose recovering standing offer review costs from retailers with a market share of 1% or higher (measured in terms of MWh).

We do not agree with ActewAGL that the costs of the review need to be transparently itemised in the cost stack methodology. Based on our draft decision on retail operating costs, we are satisfied that the costs of the review and other regulatory costs are adequately accounted for in the cost stack.

4.8 Other cost components

4.8.1 Energy losses

Some electricity is lost in transporting from generators to customers via transmission and distribution networks. Retailers purchase additional electricity to allow for these losses. The loss factors are calculated by AEMO and are used by all regulators to determine the energy loss allowances where regulated tariffs apply. We determine the energy losses component by applying AEMO's transmission and distribution loss factors to the energy purchase cost component, LRET and SRES costs and the NEM fees. We have been applying this approach since 2014.

In 2023-24, energy losses accounted for $0.17 or 0.1% of the total estimated cost of supplying retail electricity in the ACT.

4.8.2 Network costs

The network costs are the transmission and distribution charges paid by ActewAGL. Transmission and distribution charges are determined by the AER and released each year around mid-May. We pass through these charges.

Network costs also include ACT Government scheme costs (referred to as jurisdictional scheme costs). These costs comprise of Feed-in-Tariff scheme costs (small, medium and large), energy industry levy and utilities network facilities tax.

Large-Scale Feed-in Tariff (LFiT) scheme

Under the LFiT scheme, the ACT Government sources renewable electricity from large-scale wind and solar farm generators in the ACT, South Australia, Victoria, and New South Wales. The ACT Government has agreed to pay these generators a 'contract price' for the electricity they feed into the grid. This arrangement encouraged the contracted generators to invest in supplying renewable energy because they have certainty that they will recover the costs of their investments.

Evoenergy, as the ACT electricity distributor, administers the scheme for the ACT Government.

The 'contract price' is fixed and, therefore, can be above or below the wholesale electricity spot price at any given time. Where wholesale spot prices are below the fixed contract price, Evoenergy makes a top-up payment to the generator to honour the agreed contract price. However, when market prices are high, generators return earnings above the agreed fixed contract price to Evoenergy.

In 2023-24, the AER did not include the LFiT scheme in its approved network charges because the scheme generated a rebate for customers. Instead, the LFiT amount was returned to ACT customers via a rebate determined by Evoenergy, which applied a separate, downwards adjustment to the AER's approved network charges for 2023-24.[54]

On 17 November 2023, Evoenergy made an application to the AER requesting that the LFiT should cease to be a jurisdictional scheme under the National Electricity Rules. The AER approved Evoenergy's request on 11 December 2023. This means that the AER is no longer responsible for approving the network tariff adjustments to pass through the LFiT amounts (whether positive or negative). Going forward, Evoenergy will calculate tariff adjustments to pass through LFiT amounts to electricity customers. The scheme will continue to be administered under the mechanisms of the *Electricity Feed-in (Large-scale Renewable Energy Generation) Act 2011* and there will be no change to outcomes for customers.[55]

4.8.3 Energy Efficiency Improvement Scheme (EEIS) costs

The ACT Government's EEIS places a mandatory obligation on all active retailers in the ACT to promote energy efficiency measures in households and small businesses. The current EEIS, which was initially legislated to expire in 2020, has been modified and extended to 2030.

We determine the EEIS cost allowance using cost estimates provided by ActewAGL, subject to a forward-looking prudency and efficiency assessment. Since our methodology relies on forecast and estimated costs in advance of the actual cost being incurred, provision is made for an ex-post adjustment (that is, a true up to account for the actual costs of complying with the EEIS).

As a part of the prudency and efficiency assessment, we need to satisfy ourselves that ActewAGL has undertaken a robust expenditure decision making process to meet its EEIS compliance requirements and that its proposed costs are below the cost ceiling we determined based on the scheme's penalty rate for non-compliance.

Appendix 5 provides more information about our methodology for determining EEIS costs.

4.8.4 Pass-through costs

In our 2023-24 price recalibration decision[56], we approved pass-through costs for a number of regulatory reforms (five-minute settlement, global settlements and customer switching) as well as market intervention payments. The capex component of the regulatory reform cost pass-throughs was spread over 5 years from 2023-24 to 2027-28.

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[54] Evoenergy 2023, p.16

[55] https://www.aer.gov.au/documents/determination-cessation-jurisdictional-scheme-act-large-scale-feed-tariff-scheme-dec-2023, accessed on 10 January 2024.

[56] ICRC 2023, p.9-16

4.8.5 Smart meter costs

In our final decision for the 2020-24 price investigation, we included the cost of smart meters in the pricing model.[57] This approach spreads the cost of smart meters across the total base of small electricity customers rather than the cost falling solely on the customer that is having the smart meter installed. Our decision to include smart meter costs was largely based on equity and fairness considerations.

To estimate smart meter costs for each year of the regulatory period, ActewAGL provides an annual forecast of the weighted average cost per smart meter and a forecast of the number of smart meters. We verify these costs using available comparators. We true-up each year for the difference between forecast and actual costs. In 2023-24, smart meter costs accounted for $3.46 per MWh or 1.2% of the total estimated cost of supplying electricity in the ACT.

Submissions on issues paper

We received no submissions on other cost components in response to the issues paper.

However, following the release of the issues paper, the AEMC released its final metering review report.[58] The AEMC recommends accelerating the deployment of smart meters to achieve universal take-up of smart meters by 2030 in NEM jurisdictions. The AEMC identifies a range of benefits from accelerating smart meter deployment including improved customer outcomes, economies of scale and efficiency, promoting innovation and flexibility, supporting decarbonisation of the electricity system and promoting safety, security and reliability of the electricity system.

The plans for the accelerated roll-out would be led by distribution businesses, which would develop an annual schedule to retire legacy accumulation and manually read meters. Retailers would then be responsible for installing smart meters at these sites over the five-year acceleration period, starting July 2025.

To support a positive customer experience in the transition, the AEMC has identified new customer safeguards and improvements to existing arrangements. These include prohibiting retailers from charging upfront costs for meter replacements under the acceleration deployment program, requiring retailers to provide their customers with sufficient notice when transitioning to a different price structure (i.e., 30 business days) and providing customers with additional information on how to understand and monitor their usage and manage change.

The AEMC also recommends a framework for allowing customers access to their smart meter data in real-time and for helping distribution businesses get efficient access to power-quality data from smart meters.

Our consideration and draft decision

For network costs, we propose no change in our methodology other than a potential change in the source of information we use to ensure retailers have sufficient time to meet their legal obligations in terms of notifying customers about price changes for 2024-25. This is discussed separately in section 3.3.

For energy losses and EEIS costs, our draft decision is to make no changes to our current methodology.

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[57] ICRC 2020, p. 47-48
[58] AEMC 2023

For pass-throughs, we propose to include the remainder of the pass-through values that were approved in the 2023-24 recalibration process. Therefore, these costs will be included in each year of the 2024-27 regulatory period and amount to $0.47/MWh per year (2023-24 dollars).

In coming to a draft decision on smart meter costs, we considered the approach used by other regulators and the AEMC's final decision on the smart meter acceleration.

Other regulators include smart meter costs in their total estimated costs of supplying retail electricity, although the approach differs across jurisdictions.

For New South Wales, South Australia and SEQ, the AER includes the installation and ongoing operational costs of advanced meters in its calculation of DMO retail costs.[59] The AER requests information from retailers each year on the rate and costs of advanced meter installation. For DMO 5, the AER refined its advanced meter calculation by deducting up-front advanced meter installation fees from the DMO cost to avoid the over-recovery of costs. Based on data provided by 2 retailers, the AER deducted $5 per residential customer and $8 per small business customer.[60] For 2023-24, the AER's estimate of advanced meter costs ranged from $106.32 per meter to $125.73 per meter (2021-22 dollars, excluding GST).[61]

For Tasmania, the Office of the Tasmanian Economic Regulator (OTTER) allows the inclusion of metering charges for both accumulation and advanced meters, the ongoing annual capital cost associated with accumulation meters that have been replaced by advanced meters, depreciation associated with capital expenditure required to meet the set-up costs associated with the start of metering competition and fee-based metering services recovered on an annual basis.[62]

For regional Queensland, the QCA includes the costs for standard type 6 meters and the costs retailers incur for small customer advanced metering services. Including costs for all meters in the overall costs ensures that customers pay the same amount, regardless of which type of meter they have. The QCA's costs exclude meter wiring and equipment to house the meters (switchboard or meter box), which are the responsibility of customers. As the QCA relies on the AER's DMO estimate of smart meter costs, its costs also exclude installation fees separately recovered from customers.

In Victoria, a mandated smart meter program put in place by the Victorian Government and overseen by the AER has seen nearly universal deployment of smart meters. The deployment of smart meters in Victoria was done by distribution businesses and the costs are included in their network charges approved by the AER and passed through by the ESC in the VDO.

While we expect that smart meter costs will increase in the short-term as the accelerated roll-out occurs, these costs will be captured under our current methodology. Given that the AEMC's recommendations would prevent retailers from recovering smart meter costs from up-front fees, we do not believe that the AER's approach of deducting up-front fees is relevant to our methodology going forward. We have also confirmed with ActewAGL that it does not charge upfront fees for smart meter replacements. Therefore, our draft decision is to retain our current methodology for estimating smart meter costs.

59 AER 2023b, p.30
60 AER 2023b, p.31-32
61 AER 2023b, p.36
62 OTTER 2022, p.16-18

5. Estimate of efficient costs for 2024-25

This chapter sets out our estimates of the efficient costs of supplying electricity in 2024-25 to small customers on regulated retail tariffs. The estimates are based on the latest available data and the method outlined in chapter 4. We will use more up to date data in estimating efficient supply costs for the final decision.

5.1 Energy purchase cost

As discussed in section 4.1, our method of estimating EPC requires determination of a contract position and contract prices.

5.1.1 Contract position

We determined the contract position based on the heuristic specified in section 4.1.1. For this draft report, we applied the heuristic to the half hourly ACT load data from 1 January 2021 to 5 August 2023 (the latest date for which data is available). The resulting contract positions are shown in Table 5.1. For the final report, we will update these positions using data for the period 1 January 2021 to 31 December 2023.

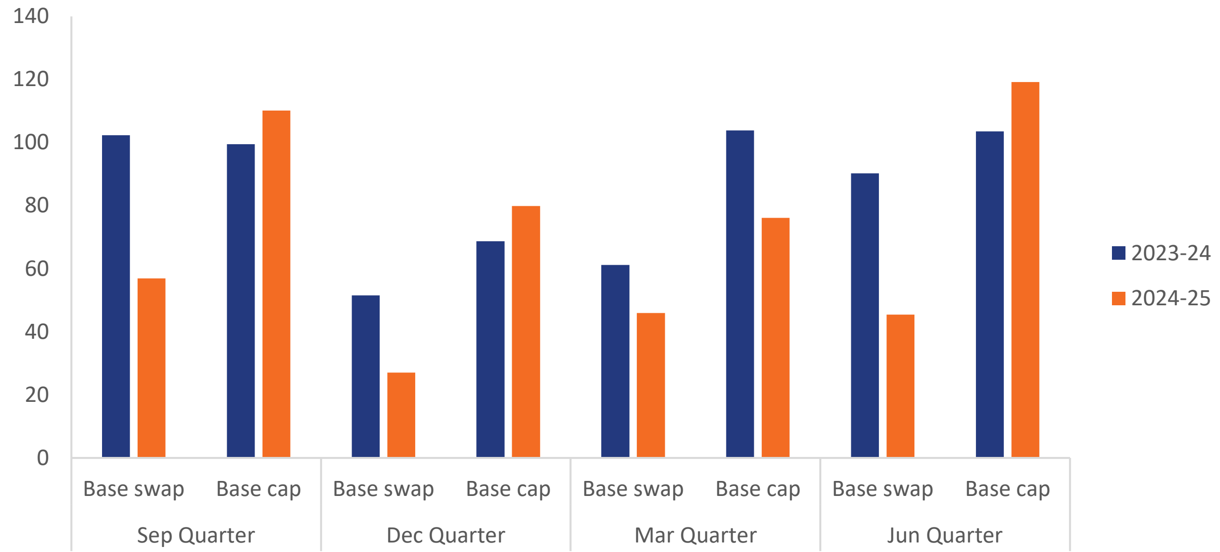
Table 5.1 Quarterly contract positions (MW per half-hour), 2023-24 and 2024-25

Contract type	2023-24				2024-25			
	Sep quarter	Dec quarter	Mar quarter	Jun quarter	Sep quarter	Dec quarter	Mar quarter	Jun quarter
Base swap	102.28	51.55	61.2	90.22	56.53	28.13	45.98	45.44
Base cap	99.49	68.73	103.82	103.52	106.61	78.38	76.16	119.17
Peak swap	6.45	13.83	11.56	7.04	N/A	N/A	N/A	N/A

Note: For 2023-24 price reset, the hedging strategy uses base swap, peak swap and base cap contracts. For 2024-25, peak swap contracts have been removed from our model.
Source: our estimation using AEMO data.

Figure 5.1 shows that the quarterly positions for base swap contracts in 2024-25 are lower compared with 2023-24. The base cap positions for 2024-25 are generally higher than for 2023-24, except the March quarter.

Figure 5.1 Quarterly contract positions (MW per half-hour), 2023-24 and 2024-25



Note: For 2023-24 price reset, the hedging strategy uses base swap, peak swap and base cap contracts. For 2024-25, peak swap contracts have been removed from our model.
Source: our estimation using AEMO data.

5.1.2 Contract prices

Our proposed approach to determining the contract prices for 2024-25 is to use the 23-month volume-weighted average of forward prices from ASX Energy. For the draft report, we used the 18-month average from 1 June 2022 to 30 November 2023 (the latest available data). We will update the data for the remaining months in the final report. The contract prices used in the draft report are summarised in Table 5.2.

Table 5.2 Quarterly contract prices ($ per MWh), 2023-24 and 2024-25

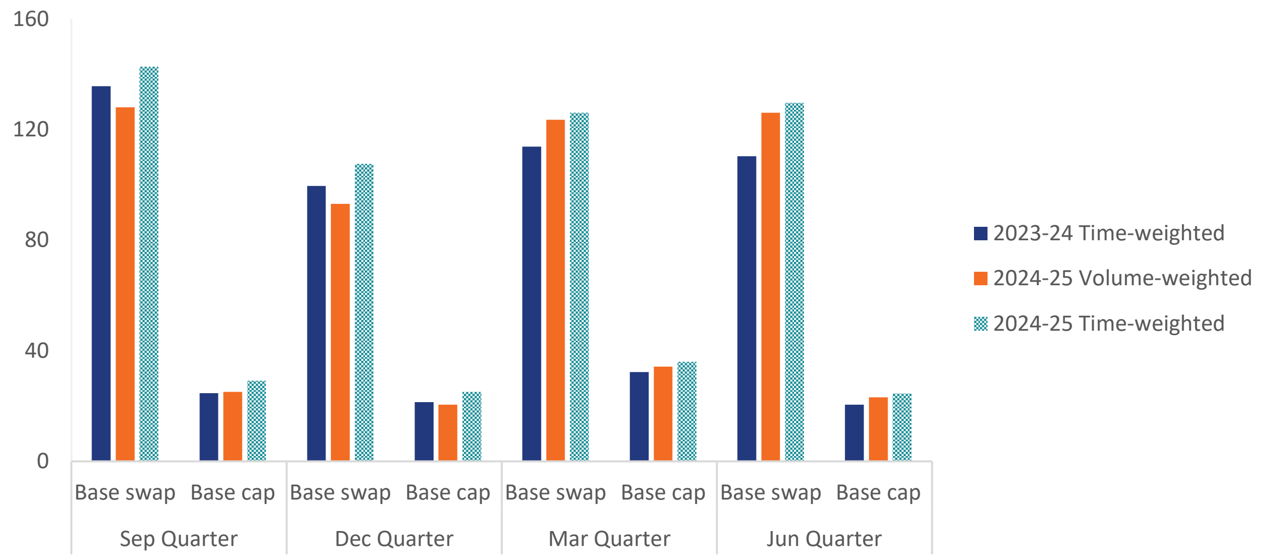
Contract type	2023-24				2024–25			
	Sep quarter	Dec quarter	Mar quarter	Jun quarter	Sep quarter	Dec quarter	Mar quarter	Jun quarter
Base swap	135.70	99.62	113.81	110.32	128.06	93.10	123.50	126.05
Base cap	24.63	21.46	32.34	20.51	25.13	20.45	34.26	23.15
Peak swap	170.47	131.11	172.94	159.25	N/A	N/A	N/A	N/A

Note: For 2023-24 price reset, the hedging strategy uses base swap, peak swap and base cap contracts, and average contract prices are calculated at time-weighted. For 2024-25, peak swap contracts have been removed from our model and average contract prices are calculated at volume-weighted.
Source: our estimation using ASX data.

The contract prices for 2024-25 are in general slightly higher than those for the previous year, except base swap contract prices in September quarter and December quarter (Figure 5.2). We note that our proposed volume-weighted average approach results in lower contract prices compared to the current approach of time-weighted average (see Figure 5.2).

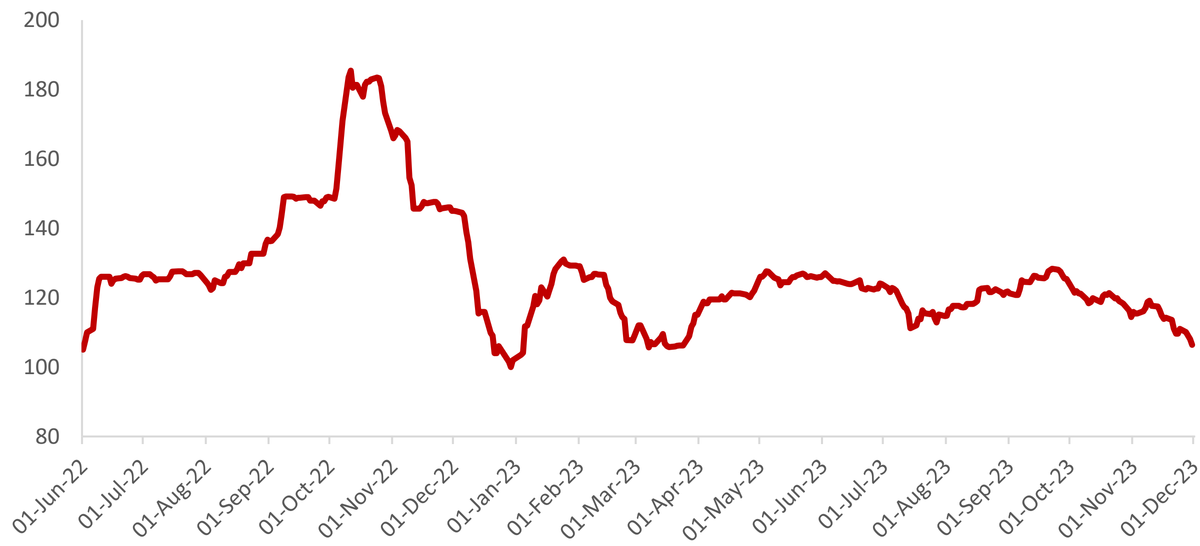
Recently, forward prices for 2024-25 have declined substantially from high levels observed in 2022, indicating that the market now expects lower priced outcomes than was the case in 2022 (Figure 5.3). If this trend continues, it may lead to a lower energy purchase cost for 2024-25 in our final decision than currently estimated.

Figure 5.2 Quarterly contract prices ($ per MWh), 2023-24 and 2024-25



Note: For 2023-24 price reset, the hedging strategy uses base swap, peak swap and base cap contracts, and average contract prices are calculated at time-weighted. For this draft report, peak swap contracts have been removed from our model and average contract prices are calculated at volume-weighted. The time-weighted average contract prices for 2024-25 are included for comparison purpose only.
Source: our estimation using ASX data.

Figure 5.3 Daily forward prices ($ per MWh), July 2022 to November 2023



Source: our estimation using ASX data.

5.1.3 EPC estimate for 2024-25

We estimated the EPC using the contract prices and the contract positions described above. This resulted in an EPC of $158.40 per MWh for 2024-25. This is 0.76% lower than the cost for 2023-24 of $159.62 per MWh. The main driver of the lower EPC is the use of trade-weighted rather than volume-weighted contract prices. For 2024-25, trade-weighted prices are significantly lower than time-weighted based on the contract prices to date.

5.2 Volatility allowance

We calculated the volatility allowance using the method described in section 4.2 of the report. This approach involved calculating the volatility allowance based on the median and highest EPC calculated for the ACT. This approach resulted in a volatility allowance of $0.50/MWh.[63]

5.3 National green scheme costs

We calculated the costs of complying with the national green scheme requirements using publicly available data and the equations in appendix 4. Table 5.3 presents the key inputs used in the calculations, and Table 5.4 sets out our draft decision.

Table 5.3 National green scheme costs components, 2024 and 2025

National green scheme cost component	2024	2025
Parameters common for LRET and SRES		
Half-yearly load weights	0.550	0.450
Cost of debt for half year (%)	2.84%	2.84%
Large-scale renewable energy target (LRET) data		
Renewable power percentage (RPP) (%)	18.96%	18.96%
Average Lage-scale generation certificate (LGC) spot price ($/certificate)	$54.72	$53.20
Small-scale renewable energy scheme (SRES) data		
Small-scale technology percentage (STP) (%)	17.99%	14.79%
Average small-scale technology certificate (STC) spot price ($/certificate)	$40.00	$39.89

Sources: our calculation using data from Clean Energy Regulator, ICAP, AEMO, and RBA.

5.3.1 Holding cost

The holding cost is calculated by using the estimated cost of debt based on non-financial corporate BBB rated 3-year bond yields using an 11-month average to the end of March. For the draft report, we calculated the cost of debt as the 7-month average of non-financial corporate BBB rated 3-year bond yields to 30 November 2023. This was 5.68% based on data from the Reserve Bank of Australia. This means that the holding cost applied to LGC and STC prices in the draft report is 2.84% per year.

We will update this value as the 11-month average to 31 March 2024 for the final report.

5.3.2 Large-scale renewable energy target (LRET) cost

The LRET cost for 2024-25 is calculated using two components: the renewable power percentages for 2024 and 2025 calendar years, and the estimated average LGC prices in these two years, as described in

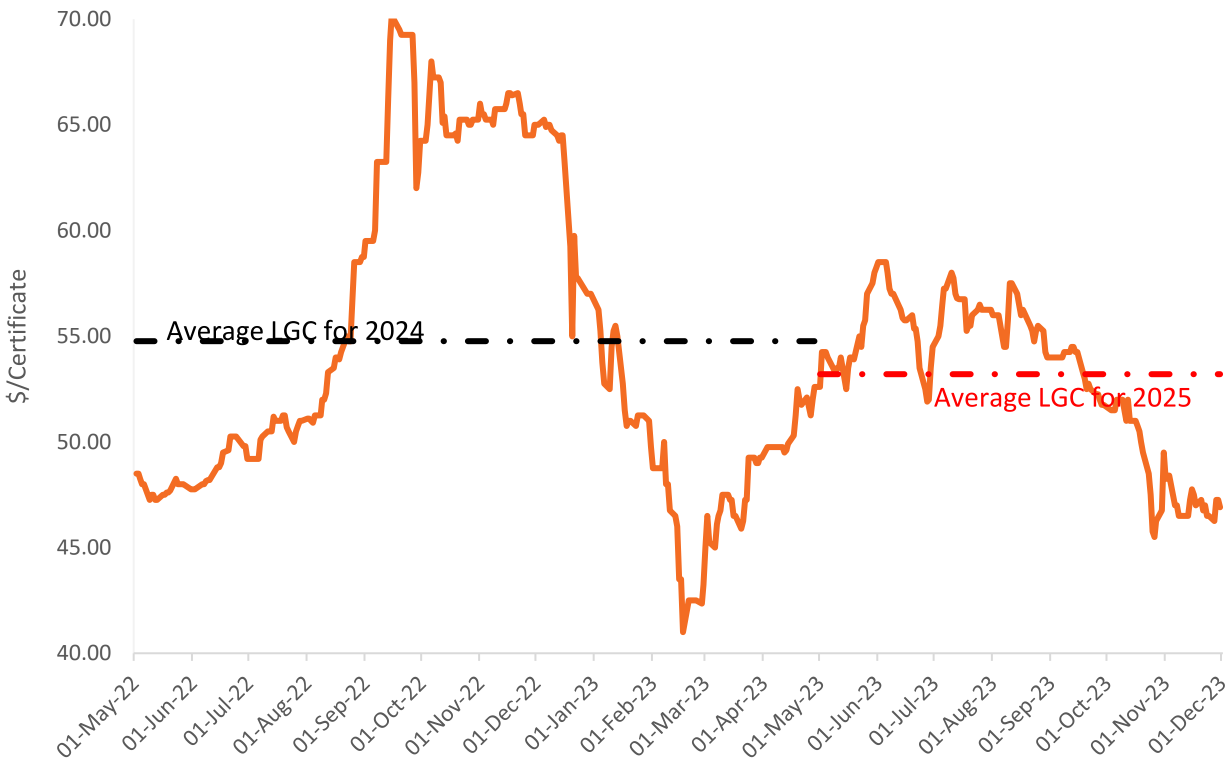
[63] Frontier 2023, p.31

section 4.3. Half hourly weights are calculated using ActewAGL's load data to convert calendar year values to financial years.

Renewable power percentages for each calendar year are published by the Clean Energy Regulator in March each year; hence 2024 and 2025 values are not yet available. For the draft report, we estimated the renewable power percentages for both years using the Clean Energy Regulator's default formula and the data for energy savings target. The estimated renewable power percentage for both 2024 and 2025 is 18.96%.

The LGC price for 2024 is $54.72 per certificate, which is the 12-month average price to 30 April 2023. This increases to $56.27 per certificate when holding costs are applied. The estimated LGC price for 2025 is $53.20 per certificate, which is calculated as the 7-month average of LGC prices from 1 May 2023 to 30 November 2023 for this draft report. This increases to $54.71 per certificate when holding costs are applied. We will update the estimates for the final report when the data becomes available for the remaining 5 months to 30 April 2024.

Figure 5.4 LGC spot prices ($ per certificate), May 2022 to November 2023



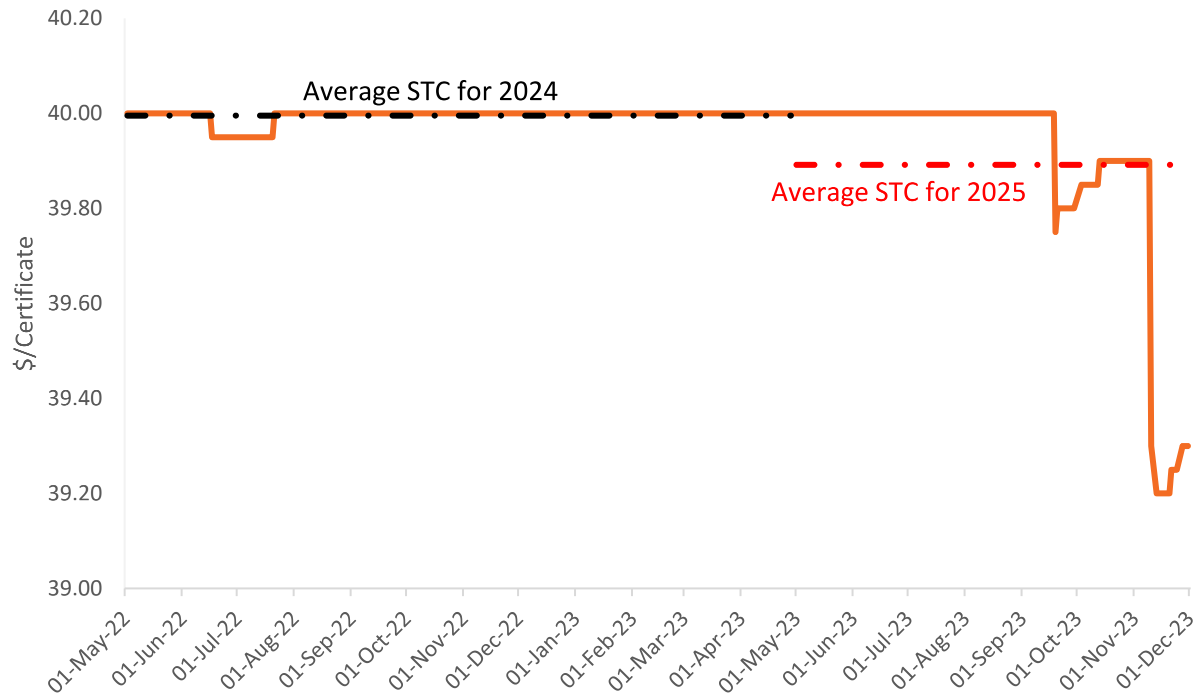
Source: ICAP.

5.3.3 Small-scale renewable energy scheme (SRES) cost

The small-scale technology percentages used in this draft report are the estimates released by the Clean Energy Regulator. These estimates for 2024 and 2025 are 17.99% and 14.79% respectively. We will update these estimates in the final report when the Clean Energy Regulator releases new values in March 2024.

The STC price for 2024 is $40.00 per certificate, which is a 12-month average of STC prices until 30 April 2023. This increases to $41.13 per certificate when holding costs are applied. The estimated STC price for 2025 is $39.89 per certificate, which is calculated as the 7-month average of LGC prices from 1 May 2023 to 30 November 2023 for this draft report. This increases to $41.02 per certificate when holding costs are applied. We will update this for the final report when the data becomes available for the remaining 5 months to 30 April 2024.

Figure 5.5 STC spot prices ($ per certificate), May 2022 to November 2023



Source: ICAP.

5.3.4 Cost adjustment

As described in section 4.3, we make a cost adjustment to account for any differences between the actual and estimated values for the renewable power percentage and small-scale technology percentage. For this draft report, we have not included a cost adjustment in the LRET and SRES costs for 2023-24, as the actual values have not been available yet. We will include the cost adjustment in the final report.

5.3.5 Estimated national green scheme cost

Our draft estimate of total national green scheme cost allowance for 2024-25 is $17.34 per MWh based on the cost components described above. Table 5.4 shows our estimates of the total national green scheme costs and its components. This is 15.1% higher than the allowance provided in 2023-24, mainly due to higher LGC prices and higher holding costs. We will include a cost adjustment allowance in the final report.

Table 5.4 LRET and SRES allowance, 2023-24 and 2024-25 ($ per MWh)

National green scheme cost component	2023-24	2024-25
LRET	9.29	10.54
SRES	6.84	6.80
Cost adjustment	-1.07	0
Total cost	**15.06**	**17.34**

Source: our estimates.

5.4 Energy losses

We determine the energy losses component by applying AEMO's energy loss factors to the energy purchase cost, national green scheme costs and NEM fees, as outlined in section 4.8.1.

For this draft report, we used the 2023-24 distribution and marginal loss factors. This generates a draft energy loss cost components of $0.25 per MWh for 2024-25. This allowance is about $0.08 higher than in 2023-24.

5.5 NEM fees

For our draft decision, we estimated NEM fees using AEMO's final 2023-24 budget. For our final decision, we will update this estimate using AEMO's draft 2024-25 budget. For 2024-25, our draft NEM fee cost allowance is $1.48 per MWh. Table 5.5 presents the components of the NEM fees.

Table 5.5 NEM fees

Component ($/MWh)	2023-24
NEM management fees	0.57
Electricity retail market fees	0.09
Global and 5-minute settlement fees	0.20
Distributed Energy Resources Integration Program (DER) fees	0.02
Energy Consumers Australia (ECA) fees	0.08
Ancillary service charges	0.45
Total cost	**1.41**
Total cost for 2024-25, adjusted for CPI	**1.48**

Note: For this draft report, our calculation is based on cost information from AEMO's 2023-24 final budget. We calculated ancillary service charge by averaging weekly ancillary fees for the period of 10 October 2022 to 1 October 2023.

Sources: our calculations based on AEMO's data.

5.6 Retail operating costs

The 2024-25 retail operating costs are calculated by adjusting the updated benchmark allowance of $172.7 per customer by the change in CPI of 4.94%. This adjustment takes the per customer allowance to $181.20 for 2024-25.

This value is then converted into an allowance per MWh for retail operating costs using estimated customer numbers and energy usage provided by ActewAGL for the year up to 31 March 2024. This converts to an allowance of $22.61 per MWh for 2024-25 representing a 27.62% increase over the 2023-24 cost allowance of $17.71 per MWh.

In the final report, we will update this cost allowance with actual ActewAGL's customer numbers and energy usage for the year to 31 March 2024.

5.7 EEIS

We have not received EEIS cost data from ActewAGL ahead of finalising the draft report. We have therefore used the 2023-24 EEIS cost allowance in the pricing model. Our draft EEIS allowance for 2024-25 is $2.90 per MWh.

We will update EEIS cost allowance in the final report based on cost data from ActewAGL.

5.8 Network costs

Network costs in our pricing model include the costs of transmission, distribution, basic metering, and ACT Government schemes. Transmission and distribution costs are regulated by the AER and ACT Government scheme costs are passed through in the network costs.

For this draft report, we estimated the 2024-25 distribution and metering costs based on the 2023-24 costs and the AER's draft decision for Evoenergy's revenue determination for the 2024-29 regulatory period. For other network components, including transmission costs, the ACT Government's small and medium FiT scheme and other government charges, we applied CPI to the 2023-24 costs. We will update these costs in the final report based on AER's final decision on Evoenergy's network costs for 2024-25 or Evoenergy's pricing proposal as discussed in section 3.3.

We estimated the 2024-25 LFiT costs using our methodology and publicly available information. It may vary significantly in the final report. We will update the LFiT costs based on the Minister's determination on the reasonable cost for 2024-25 ahead of finalising the final report.

Our draft network cost allowance associated with standing offer customers for 2024-25 is $114.30 per MWh (Table 5.6). We will update the network cost allowance in the final report.

Table 5.6 Network costs for standing offer customers

Component ($/MWh)	2024-25
Distribution use of system cost	**66.27**
Transmission use of system cost	**17.79**
ACT Government scheme cost	**19.92**
FiT small and medium scale cost	5.65
FiT large-scale cost	16.00
Other ACT Government scheme costs	2.65
Metering costs	**5.93**
Total cost	**114.30**

Source: our calculations.

5.9 Pass through costs

As part of 2023-24 price reset, we allowed ActewAGL to recover $1.09 million over 5 years (from 2023-24 to 2027-28) for a range of regulatory reform costs, including 5-minute settlement, global settlement and customer switching costs from standing customers. This results in a pass-through amount of $0.56 per MWh for 2024-25.

Our draft decision of per MWh value is based on estimated electricity usage for the year to 31 March 2024. For the final report, we will use the actual usage for 31 March 2024.

5.10 Retail margin

Our draft decision is for a retail margin of 5.5 per cent over the regulatory period. Applying a 50/50 weighting for the dollar amount and the percentage, we have calculated a margin for 2024-25 of $8.05 per MWh plus 2.75% of the total cost stack (excluding the margin). This results in a retail margin allowance of $16.91 per MWh for 2024-25.

5.11 Summary of draft decisions on cost components

Table 5.7 presents our draft decision on each of the cost components used to determine the maximum allowed change in the regulated retail electricity price for 2024-25. Our draft decision provides for an average nominal increase of 17.1% (or 11.6% excluding CPI) in ActewAGL's basket of regulated tariffs.

Table 5.7 Draft decision on cost components[64], 2024-25

Cost component	2023-24 ($/MWh)	2024-25 ($/MWh)	Dollar change ($/MWh)	Contribution to the price change (%)
Wholesale energy costs	176.56	177.96	1.40	0.5
Network costs	92.71	98.30	5.59	1.9
Retail costs	28.02	29.97	1.95	0.7
Retail margin	15.35	16.91	1.56	0.5
Total costs (excluding ACT Govt LFiT costs)	**312.64**	**323.14**	**10.51**	**3.6**
ACT Government Large-scale FiT scheme costs	-23.14	16.00*	39.14	13.5
Total costs (including ACT Govt. LFiT costs)	**289.50**	**339.14**	**49.64**	**17.1**

Note: *ACT Government LFiT scheme costs are determined by the Minister in February/March each year. In making this draft decision, we included our estimated costs for 2024-25 based on publicly available information in our cost stack for indication only. We will update it in the final report with the Minister's determination, which may vary significantly from our current estimate.
All numbers are rounded to two decimal places.
Source: our calculations.

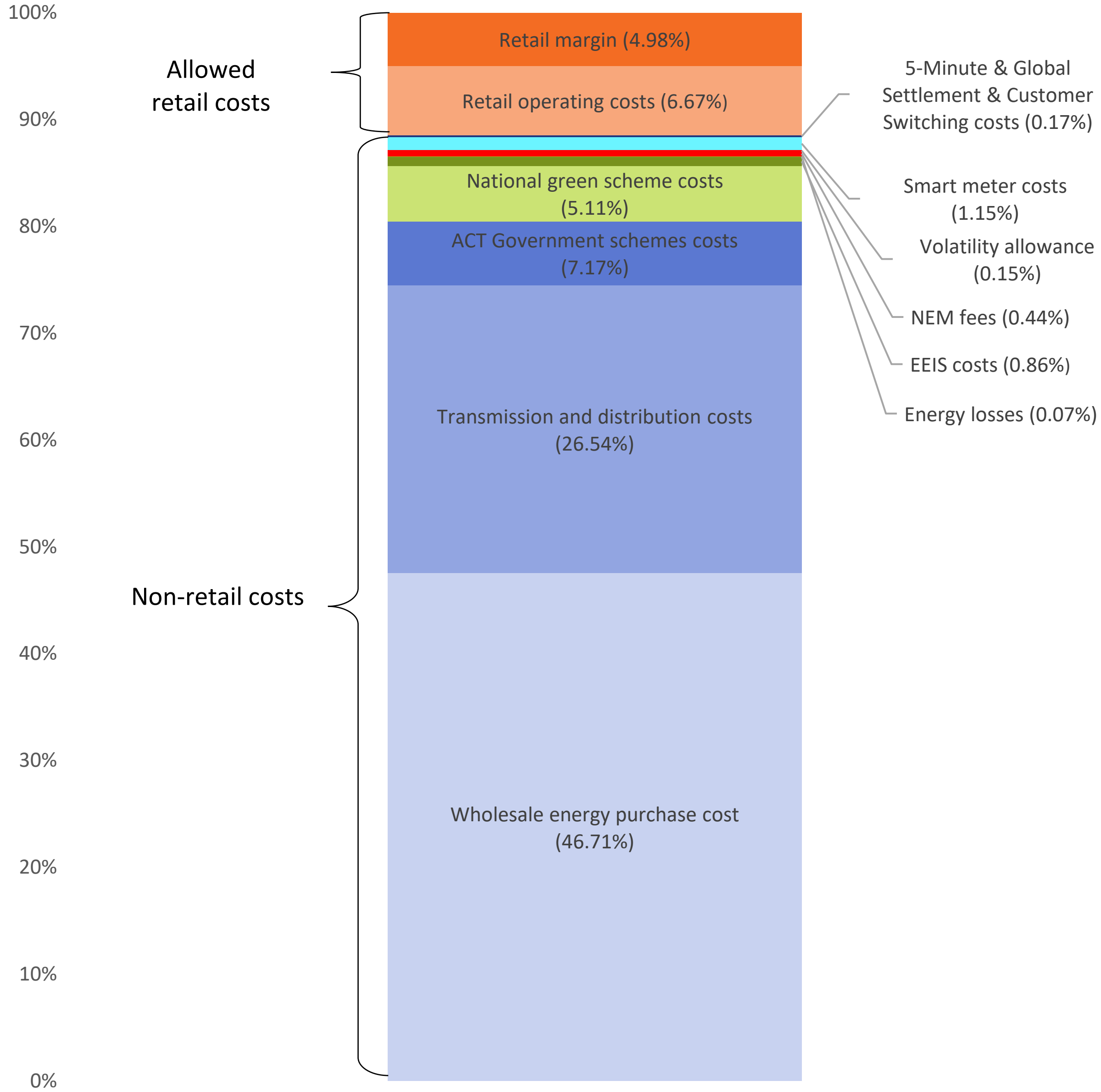
64 Wholesale energy costs comprise wholesale energy purchase costs, national green scheme costs (Large-scale Renewable Energy Target and Small-scale Renewable Energy Scheme costs), energy losses, volatility allowance and National Electricity Market fees. Network costs include transmission, distribution and jurisdictional schemes cost (e.g. ACT Government's small and medium scale FiT scheme costs and other government costs). Retail costs comprise retail operating costs, Energy Efficiency Improvement Scheme costs, smart meter costs, 5-minute & global settlement costs, and customer switching costs.

Table 5.7 also shows the contribution of each of the key cost components to the change in the total cost stack from 2023-24 to 2024-25. The estimated change in the LFiT from a rebate in 2023-24 to a cost in 2024-25 accounts for most of the difference.

Figure 5.6 shows the proportion of each cost component in total costs. An analysis of these cost components shows that most costs are outside the control of the retailer. The costs that the retailer cannot control and that are not regulated by the commission include:

- the cost of purchasing electricity from the NEM (except for the ability to implement different hedging strategies)
- the costs of complying with Commonwealth and Territory environmental obligations
- costs associated with energy lost in transmission and distribution
- NEM fees payable to the AEMO for operating the wholesale market, and
- the charges for the transport of electricity through the poles and wires.

Figure 5.6 Proportion of cost components to total costs 2024-25, %



Source: our calculations.

Appendix 1 Summary of submissions

On 1 August 2023, we released an issue paper outlining our approach to the 2024-27 electricity price investigation. Following the release, we invited stakeholder submissions by Thursday, 31 August 2023. We received a total of 7 submissions: ACTCOSS, ActewAGL, Origin, EnergyAustralia, Red and Lumo Energy, Conservation Council, and a joint submission by ACTCOSS, Care and COTA.

A.1.1 Regulatory Perspectives

A.1.1.1 ActewAGL submission

ActewAGL noted that competition in the ACT electricity market has matured and is effective, despite having fewer active retailers compared to other regions. It highlighted that customers still have access to a wide range of offers and competitive prices.

ActewAGL provided their opinion and recommendations on several aspects of the investigation approach, including various components of the cost stack.

Overall, ActewAGL expressed support for:

- weighted average price cap control but recommends the removal of the 2-percentage point side constraint as it restricts ActewAGL's ability to pass-through legitimate changes in costs
- current EPC methodology but supports a review of optimal hedging strategy and wants the methodology to remain replicable
- inclusion of volatility allowance but needs to be updated to make it consistent with other jurisdictions where retailers are facing similar volatility risks
- using 12-month averaging period for LRET/SRES costs and bringing forward the end date to 30 April to bring forward the timing of the final decision.
- using estimates, possibly with true-ups, in the event network costs are not available by 30 April
- review of retail operating costs as it is currently below other jurisdictions, and it is set too low and
- updating the retail margin methodology to reflect increased risks of retailing in the ACT.

ActewAGL raised its disagreement for:

- reinstating a materiality threshold for pass-through applications as it may add additional regulatory complexity and prevent legitimate costs from being passed through and reflected in the standing offer prices

ActewAGL made suggestions for various aspects of the investigation approach:

- NEM fees should be passed through and reflected in the cost stack as per AEMO's budget each year
- CARC should be separately estimated in the cost stack to better reflect the increased competition in ACT

- standing offer review costs should be recovered from all retailers through an industry levy and transparently itemised in the cost stack and
- the inclusion of smart meter data should be re-visited in the next methodology review as the required data is not fully available yet.

A.1.1.2 Origin submission

Origin generally supported the pricing methodology and the commission’s approach but has expressed concerns about the impact of increased wholesale price volatility on retailers’ efficient costs. It has provided various comments in their submission.

Origin expressed support for:

- the use of ASX future trades, as it is publicly available and verifiable
- the use of a 23-month averaging period but suggested assigning a higher weight to contract trades occurring closer to the relevant period
- the use of a 5-year NSLP but suggested considering smart meter data to determine the implications that changing of NSLP will have on prices and the transition methods that may need to be applied and
- the approach to LRET/SRES and the proposal to bring forward the timing by 1 month.

Origin expressed disagreement for:

- reinstating materiality threshold for pass-through application as a broader regulatory/ policy intervention is needed to capture the extraordinary costs that ActewAGL is unable to absorb for a year
- the removal of peak swaps, because in its view it is fundamentally inconsistent with the risk management practices of a prudent retailer.

Origin also made recommendations for:

- adopting higher margin forecast error instead of volatility allowance
- the use of ACCC combined data for ACT and NSW to determine retail operating costs as it is transparent and consistent and
- maintaining the current allowance for retail margin due to a conservative approach considering rising inflation and interest rates and the impact of these in the derivation of WACC.

A.1.1.3 EnergyAustralia submission

EnergyAustralia believes the TOR on price appears more closely aligned with the objectives of the DMO than the VDO. EnergyAustralia suggested aligning with the objectives of the DMO should the commission change its methodology, as it covers both price protection and retail competition principles. Further, the retailer urged against mixing different DMO and VDO regulatory objectives.

A.1.1.4 Red and Lumo Energy submission

Red and Lumo emphasised aligning the standing offer approval process with the DMO final decision of no later than 25 May and suggested that we develop a published and agreed timeframe for the release of the reference price.

A.1.2 Consumer Advocacy and Perspectives:

A.1.2.1 ACTCOSS, COTA, and Care submission

ACTCOSS, COTA, and Care ’s main feedback was the prevalence of significant barriers that prevent members of the community from engaging in the electricity market. These barriers include complexity, difficulties in navigating the market, lack of consistency in presentation, and inadequate information formats for diverse groups of consumers. They believe the retailers are not acting in the best interests of consumers and failing to provide sufficient support to vulnerable customers. These organisations also suggested promoting increased consistency and extending the regulation of standing offer prices to all retailers, not just ActewAGL. The organisations also raised issues beyond the commission’s control, such as the inadequacy of government income support payments to cover essential living costs in Canberra. This issue is compounded by the increasing number of customers facing cost of living challenges, primarily due to considerable eligibility constraints and administrative barriers hindering access to government assistance programs. They also emphasised the importance of addressing environmental issues once the cost of living and debt concerns have been addressed.

A.1.2.2 Conservation Council submission

The Conservation Council emphasised that electricity pricing should align with and accelerate the ACT Government's policy objective of achieving net-zero emissions by 2045. It suggested a forward-looking and responsive price modelling, including scenarios for accelerating the adoption of new technologies. It recommend conducting annual reviews that explicitly investigate the impact of pricing on various streams of electrification and gas disconnection.

The Conservation Council suggested that retailers should proactively communicate with customers about electrification, provide cost comparisons between gas and electric appliances, and offer incentives and assistance to facilitate the transition. Its suggestion includes employing case managers to guide households through the process of electrification. The Conservation Council emphasised the importance of genuine investment in renewable generation and transparency regarding retailers' exposure to fossil fuel projects.

Appendix 2 Our roles and objectives

Under the ICRC Act, we have the following objectives as set out in section 7 and 19L (Box 1).

Box 1 Sections 7 and 19L: Commission objectives

Section 7:

(a) to promote effective competition in the interests of consumers;

(b) to facilitate an appropriate balance between efficiency and environmental and social considerations;

(c) to ensure non-discriminatory access to monopoly and near-monopoly infrastructure.

Section 19L:

To promote the efficient investment in, and efficient operation and use of regulated services for the long term interests of consumers in relation to the price, quality, safety, reliability and security of the service.

When making a price direction, in addition to the terms of reference and legislative objectives, we need to consider the provisions set out in section 20(2) of the ICRC Act (Box 2).

Box 2 Section 20(2): Commission's considerations

(a) the protection of consumers from abuses of monopoly power in terms of prices, pricing policies (including policies relating to the level or structure of prices for services) and standard of regulated services; and

(b) standards of quality, reliability and safety of the regulated services; and

(c) the need for greater efficiency in the provision of regulated services to reduce costs to consumers and taxpayers; and

(d) an appropriate rate of return on any investment in the regulated industry; and

(e) the cost of providing the regulated services; and

(f) the principles of ecologically sustainable development mentioned in subsection (5);

(g) the social impacts of the decision; and

(h) considerations of demand management and least cost planning; and

(i) the borrowing, capital and cash flow requirements of people providing regulated services and the need to renew or increase relevant assets in the regulated industry; and

(j) the effect on general price inflation over the medium term;

(k) any arrangements that a person providing regulated services has entered into for the exercise of its functions by some other person.

Appendix 3 Terms of reference

Independent Competition and Regulatory Commission (Price Direction for the Supply of Electricity to Certain Small Customers on Standard Retail Contracts) Terms of Reference Determination 2023

Disallowable instrument DI2023– 97

Made under the Independent Competition and Regulatory Commission Act 1997 (‘the Act’), Section 15 (Nature of Industry References) and Section 16 (Terms of Industry References).

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1 Name of instrument

This instrument is the *Independent Competition and Regulatory Commission (Price Direction for the Supply of Electricity to Small Customers on Standard Retail Contracts) Terms of Reference Determination 2023.*

2 Interpretation

In this instrument:

“National Energy Retail Law (ACT)” has the same meaning as in the *National Energy Retail Law (ACT) Act 2012*.

“***small customer***” has the same meaning as in the ***National Energy Retail Law (ACT)***.

“standing offer prices” has the same meaning as in the ***National Energy Retail Law (ACT)***.

“ActewAGL Retail” means the partnership of Icon Retail Investments Limited (ACN 074 371 207) and AGL ACT Retail Investments Pty Ltd (ACN 093 631 586).

2 Commencement

This instrument commences on the day after it is notified.

3 Reference for investigation under Section 15

In accordance with section 15(1) of the Act, I provide a reference to the

Independent Competition and Regulatory Commission (the 'Commission') to determine a price direction for the standing offer prices for the supply of electricity to small customers who consume less than 100MWh of electricity over any period of 12 consecutive months.

The price direction will be for the period of 1 July 2024 to 30 June 2027.The price direction must make provision for annual recalibrations to be undertaken and the determination of the reference price.

In accordance with 15(4) of the Act, the price direction determined by the Commission under this reference is to only apply to the electricity retailer ***ActewAGL Retail***.

4 Terms of reference for investigation under section 16

In accordance with 16(1) of the Act, I require that the Commission must consider the following matters in relation to the conduct of the investigation.

1. The Commission must consider:
   a. The direct impact on electricity costs of government policies and pass through of costs and savings to regulated prices including, but not restricted to:
      i. the ACT retailer obligations under the Energy Efficiency Improvement Scheme;
      ii. the Commonwealth Government's Large-scale Renewable Energy Target and Small-scale Renewable Energy Scheme;
      iii. any other schemes implemented to address climate change relevant to electricity pricing; and
      iv. any other policies or schemes that may directly impact on pricing in the retail or wholesale electricity market.
   b. The efficient and prudent cost of managing risk in the cost of purchasing electricity for the period of the price direction.
2. The Commission must identify and report on the efficient costs of complying with the Energy Efficiency (Cost of Living) Improvement Act 2012 for the period that the determination is being made.
3. The Commission must identify and report on the cost allowance of the ACT Feed-in Tariffs (small and large scale) for the period that the determination is being made.
4. The Commission will ensure the methodology for determining standing offer price has regard to a reasonable pricing offer for small customers that does not unduly disadvantage those who do not actively engage in the energy market, while balancing the competitiveness of the retail electricity market.
5. The Commission must consider changes to the timeframe for the yearly standing offer approval process, such that adequate time is available for determination of the subsequent reference price by Ministers, and

forretailers to fulfill their legal obligations under the *ACT Retail Electricity (Transparency and Comparability) Code* and the *National Energy Rules.*

6. The Commission must release its final report within the period of 1 March 2024 to 5 June 2024, to provide sufficient time to allow ActewAGL Retail to make any necessary changes to its billing system, and to provide information on the new tariff to customers in time for implementation effective 1 July 2024.

Andrew Barr MLA Treasurer
June 2023

Appendix 4 Equations to calculate the green scheme cost

LRET costs (including a holding allowance) for financial year 2024-25 is calculated using the below formula.

$$\begin{aligned}\text{LRET cost}_{2024-25} &\\ &= \text{LW}_{2024} \times \text{RPP}_{2024} \times [\text{LGCspot}_{2024} \times (1+\text{HC})] + \text{LW}_{2025}\text{RPP}_{2025} \times [\text{LGCspot}_{2025} \times (1+\text{HC})] \\ &+ \text{CA}_{2023-24}\end{aligned}$$

where the following are defined for each year:

- LW denotes the half-yearly load weight for the calendar year
- RPP denotes the renewable power percentage for the calendar year
- LGCspot denotes the average LGC spot price for the calendar year (dollars per LGC), calculated as the 11-month average ending 30 April in the prior year
- HC denotes the holding cost percentage based on half of the cost of debt parameter
- CA denotes the LRET cost adjustment from the previous financial year.

SRES costs (including a holding allowance) for financial year 2024–25 is calculated using the below formula.

$$\begin{aligned}\text{SRES cost}_{2024-25} = \text{LW}_{2024} \times STP_{2024} \times [\text{STCspot}_{2024} \times (1+\text{HC})] &\\ + \text{LW}_{2025} \times STP_{2025} \times [\text{STCspot}_{2025} \times (1+\text{HC})] + \text{CA}_{2023-24}\end{aligned}$$

where the following are defined for each year:

- LW denotes the half-yearly load weight for the calendar year
- STP denotes the small-scale technology percentage for the calendar year
- STCspot denotes the average STC spot price for the calendar year (dollars per STC), calculated as the 11-month average ending 30 April in the prior year
- HC denotes the holding cost percentage based on half of the cost of debt parameter
- CA denotes the SRES cost adjustment from the previous financial year.

Appendix 5 EEIS cost determination methodology

A.5.1 Background information

The EEIS is an energy efficiency obligation scheme for electricity retailers in the ACT to promote energy efficiency measures in households and small businesses. the EEIS was first legislated in 2012 under the *Energy Efficiency (Cost of Living) Improvement Act 2012* (Energy Efficiency Act) to run from 2013 to 2015. After reviews that found it to be effective, the scheme was extended to 2030.

The EEIS is a non-certificate scheme, as it imposes direct obligations on retailers rather than using tradeable 'certificates' of greenhouse gas abatement generated by eligible activities that any accredited certificate provider can deliver and then sell to obligated parties in the compliance market (retailers).

The EEIS requires retailers to achieve an energy savings obligation. Currently it sets a Territory-wide energy savings targets at 14.6% of total electricity sales for 2024.[65] Individual electricity retailers will apply the energy saving target to their electricity sales to determine their obligation. Section 13 of the Energy Efficiency Act provides a retailer's obligation, expressed as a number of megawatt hours of energy, is calculated as follows:

$$\text{Energy Saving Target (percentage)} \times Electricity\ Sales\ (MWh)$$

In order to meet these obligations, retailers are required to implement approved eligible activities[66] such as:

- lighting upgrades
- install high efficiency air conditioning heat pumps
- removal and disposal of low efficiency refrigerator or freezer and
- install ceiling insulation.

The EEIS applies to both tier 1 and tier 2 retailers operating in the ACT.[67] ActewAGL is the only current tier 1 retailer in the ACT.

Tier 1 retailers can meet their energy savings obligation by undertaking eligible activities or by acquiring approved energy savings factors from other retailers who undertake eligible activities. In addition, to ensure that a proportion of energy savings are delivered in low-income households, the tier 1 retailer must achieve a priority household target each year.

Tier 2 retailers can meet their energy savings obligation by undertaking eligible activities, acquiring approved energy savings factors from other retailers who undertake eligible activities, or by paying an Energy Savings Contribution. The Energy Savings Contribution is determined by the ACT Government based

[65] Energy Efficiency (Cost of Living) Improvement (Energy Savings Target) Determination 2022 (DI2022-150) and the Energy Efficiency (Cost of Living) Improvement (Energy Savings Target) Determination 2023 (DI2023-154).

[66] Details of eligible activities are determined by the Government, available at https://www.legislation.act.gov.au/View/es/db_66901/current/html/db_66901.html.

[67] Tier 1 retailers are the electricity retailers with more than 500,000 MWh of electricity sales in the ACT per year and at least 5,000 ACT customers. Tier 2 retailers are those with less than 500,000 MWh of sales in the ACT per year and/or less than 5,000 ACT customers.

on the estimated cost of compliance for a tier 1 retailer and is set at $27.43 per MWh for 2024.[68] This measure is in place to avoid imposing an unfair burden on retailers that have relatively small market share but would face relatively high fixed costs to set up and administer compliance activities.

Retailers can incur financial penalties if they do not meet their savings targets. A retailer not meeting its energy saving obligation currently faces a penalty of $71.32 per MWh for 2024.[69]

A.5.2 EEIS cost estimation methodology

All retailer costs of scheme compliance are passed through to electricity customers in the ACT through their electricity bills after our assessment.

We determine the EEIS allowance using the methodology set out in Box 3 below and using cost estimates provided by ActewAGL, subject to a prudency and efficiency assessment. As the EEIS cost allowance is determined before the actual cost is known, a provision is made for an ex-post adjustment.

Box 3 ACT EEIS cost estimation formula

We estimate the EEIS allowance ($/MWh) for a financial year (for example 2024-25) using the following equation:

$$\text{EEIS allowance}_{2024-25} = ESF_{2024-25} \times EST_{2024-25} + \text{CA}_{2023-24}$$

where the following are defined for each year:

- $ESF\ is\ the\ estimated\ cost\ per\ Energy\ Savings\ Factor\ (\$/MWh);$

$$\text{ESF}_{2024-25} = \frac{ForecastTotalEEISComplianceCost_{2024-25}}{ForecastEnergySavingsObligation_{2024-25}}$$

- $EST\ is\ the\ energy\ saving\ target\ determined\ under\ the\ Energy\ Efficiency\ Act\ (\%);and$
- $CA\ is\ the\ cost\ adjustment\ from\ the\ previous\ financial\ year\ (\$/MWh).$

A.5.3 Prudency and efficiency assessment

We currently assess the prudency and efficiency of ActewAGL's EEIS costs as follows.

ActewAGL's forecast expenditure on the scheme is deemed prudent if ActewAGL can demonstrate that it is reasonably necessary to meet its legislative requirements under the Energy Efficiency Act.

We undertake a two-part efficiency assessment. First, we assess the robustness of the processes and practices that ActewAGL undertook when delivering EEIS related activities. This includes an assessment of tender processes. Second, we assess whether expenditure exceeds a cost ceiling, above which it would be deemed inefficient. The cost ceiling is described in Box 4.

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68 See the Energy Efficiency (Cost of Living) Improvement (Energy Savings Contribution) Determination 2023 (DI2023-155), available at https://www.legislation.act.gov.au/View/di/2023-155/current/html/2023-155.html.

69 See the Energy Efficiency (Cost of Living) Improvement (Penalties for noncompliance) Determination 2023 (DI2023-156), available at https://www.legislation.act.gov.au/View/di/2023-156/current/html/2023-156.html.

Box 4 Cost ceiling

Should a tier 1 retailer not meet its energy savings obligation, it is required to pay a penalty of $71.32 per MWh. This amount reflects the opportunity cost of ActewAGL not meeting its obligations and may be considered as the ceiling for efficient costs of implementing energy efficiency activities under the scheme.

In assessing the efficiency of ActewAGL’s expenditure on the EEIS, we use this penalty rate as a ceiling above which costs will be deemed inefficient. That is, it is not efficient for ActewAGL to spend more on complying with the scheme than the costs associated with non-compliance.

Abbreviations and acronyms

ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
ACTCOSS	ACT Council of Community Services
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASX	Australian Securities Exchange
CARC	Customer acquisition and retention costs
CTS	Cost to serve
COTA	Council on the Ageing
DER	Distributed Energy Resources Integration Program
DMO	Default Market Offer
EBITDA	Earnings before interest, taxes, depreciation and amortisation
ICRC	Independent Competition and Regulatory Commission
CPI	Consumer Price Index
ECA	Energy Consumers Australia
EEIS	Energy Efficiency Improvement Scheme
EPC	Energy purchase cost
ESC	Essential Services Commission
GWh	Gigawatt Hour
kWh	Kilowatt Hour
ICRC	Independent Competition and Regulatory Commission
IPART	Independent Pricing and Regulatory Tribunal

LGC	Large-scale Generation Certificate
LFiT	Large-scale Feed-in Tariff
LRET	Large-scale Renewable Energy Target
MWh	Megawatt hour
NEM	National Electricity Market
NER	National Electricity Rules
NERR	National Energy Retail Rules
NSLP	Net System Load Profile
NSW	New South Wales
OTTER	Office of the Tasmanian Economic Regulator
RBA	Reserve Bank of Australia
ROLR	Retailer of Last Resort
RPP	Renewable power percentage
SEQ	South-East Queensland
SFG	Strategical Finance Group
STC	Small-scale Technology Certificate
STP	Small-scale Technology Percentage
SRES	Small-scale Renewable Energy Scheme
TOR	Terms of Reference
VDO	Victorian Default Offer
WACC	Weighted Average Cost of Capital
ZEV	Zero Emissions Vehicle

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