2025 REGULATED RETAIL ELECTRICITY PRICING INVESTIGATION

DRAFT REPORT

FEBRUARY 2025

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INVITATION TO MAKE SUBMISSIONS

The Tasmanian Economic Regulator is seeking written submissions on this Draft Report from interested parties by close of business 24 March 2025.

Submissions do not need to address all of the issues referred to, or questions raised, in the Draft Report. It is the Regulator's policy to publish all submissions on the Office of the Tasmanian Economic Regulator's (OTTER) website unless the author requests all or parts of the submission be kept confidential. Those parts of a submission requested to be kept confidential should be submitted in an attachment separate to the parts suitable for publication.

The Regulator will not publish submissions which contain material that the Regulator believes is, or could be viewed as, derogatory or defamatory.

Submissions and enquiries may be made to:
office@economicregulator.tas.gov.au

If any assistance is required in preparing a submission, please contact OTTER at the above email address or by phone: (03) 6145 5899.

OVERVIEW

Context

The Tasmanian Economic Regulator is conducting a price investigation to determine how Aurora Energy can charge small customers who pay standing offer (regulated) prices for electricity. This investigation will determine how prices will be set for the period from 1 July 2025 to 30 June 2028.

The methodology used

The Regulator has decided to continue using a method known as a cost build-up approach to set regulated prices at a level that enables Aurora Energy to recover the costs it incurs supplying electricity to customers on standard retail contracts. These costs include:

- wholesale electricity costs;
- network costs;
- Aurora Energy's retail costs (cost to serve);
- renewable energy target (RET) costs;
- metering costs; and
- other costs, such as Australian Energy Market Operator (AEMO) costs.

In addition to these costs, a retail margin is applied to reflect the risks Aurora Energy incurs in providing retail services to small customers under standard retail contracts.

Each of these components are summed to arrive at a total value of forecast costs for the year which is referred to as the Notional Maximum Revenue (NMR).

The Regulator acknowledges that around 87 per cent of the total costs are outside of Aurora Energy's control. These include: wholesale electricity costs (29 per cent); network costs (45 per cent); renewable energy target costs (five per cent); metering costs (seven per cent) and AEMO costs (one per cent).

Aurora Energy has control over the remaining 13 per cent of its costs, being the cost to serve and the retail margin.

Aurora Energy's proposed NMR and the Regulator's indicative NMR

Based on the cost build up and its proposals on the treatment of the cost to serve and retail margin, Aurora Energy proposed an NMR of $631.51 million for 2025-26.

The Regulator has analysed each of the cost components and based on the draft decisions from that analysis set out in this report, the Regulator has calculated an indicative NMR of $622.34 million for 2025-26.

The Regulator's draft decisions reduce the amount Aurora Energy can recover from its regulated customers in 2025-26 by around $9 million. This translates to an average price increase of 1.43 per cent, compared to a 2.92 per cent average increase based on Aurora Energy's proposal.

Tariff changes

As set out in Aurora Energy's draft regulated tariff strategy, its current regulated tariffs do not accurately reflect the underlying costs of each tariff. To address this imbalance, Aurora Energy is seeking greater flexibility to be able to adjust the structure of its tariffs during the next regulatory period. Aurora Energy has proposed adjusting the components of tariffs such that the bill outcomes for a typical customer with median usage on a tariff is no more than five per cent higher than the outcomes under the average price increase approved by the Regulator.

The Regulator's draft decision is to allow Aurora Energy more flexibility in restructuring its tariffs, but that the changes be made at a slower rate than Aurora Energy has proposed to minimise the impacts on customers. In this regard, the Regulator's draft decision is to allow Aurora Energy to adjust its tariffs so that no typical customers will face an increase of more than three per cent above average price increase approved by the Regulator.

In line with the recent Australian Energy Market Commission rule change, the Regulator has made the draft decision to require Aurora Energy to offer regulated flat rate tariffs to all small customers during the next regulatory period.

Summary of draft decisions

Table O.1 summarises the Regulator's draft decisions as set out in this report. The Regulator invites feedback on any matters set out in this report and, in particular, the draft decisions.

Table O.1: Summary of the Regulator's draft decisions

Chapter reference	Topic	Draft decision
		Aurora Energy's costs
4	Cost to serve	While Aurora Energy proposed a cost to serve allowance of $196 ($2023-24) per customer, the Regulator's draft decision is to allow a cost to serve allowance of $172.70 ($2023-24) per customer. When indexed, the Regulator's draft decision is estimated to result in an allowance of $184.58 per customer in 2025-26.
4	Cost to serve	The Regulator intends not applying an explicit efficiency factor to Aurora Energy's cost to serve for this determination as the Regulator is of the view that in the assessment of Aurora Energy's costs, an efficiency factor has implicitly been factored into the cost to serve allowance for the next regulatory period.
5	Retail margin	The Regulator intends allowing Aurora Energy a retail margin of 5.25 per cent based on a fixed dollar amount and percentage of costs.
6	Wholesale electricity price	The Regulator intends modifying the methodology for calculating the wholesale electricity price for the final two years of the regulatory period. The new method will only use historical prices that are available at the time of calculation. The Regulator also acknowledges that the new method is subject

		to some implementation details being worked out.
7	Network costs	To provide flexibility, the Regulator intends adding a separate interconnector network cost component to the Notional Maximum Revenue calculation to cater for the possibility that the Australian Energy Regulator decides to regulate Basslink.
9	Metering costs	The Regulator intends continuing to use the current approach to calculating metering costs and extend the current approach for excluding market contract customers on Tariff 22 to all tariffs that have customers on market contracts for basic meter cost calculation.
9	Metering costs	In accordance with the AER's determination, the Regulator also intends continuing to allow Aurora Energy to pass through TasNetworks' capital costs in relation to accumulation meters.
10	AEMO charges	The Regulator intends continuing with the current approach for calculating AEMO costs subject to the treatment of unaccounted for energy.
11	Under and over recoveries and adjustments	The Regulator intends to consider Aurora Energy's costs associated with the implementation of major national regulatory changes as an adjustment of the Notional Maximum Revenue instead of under Aurora Energy's cost to serve.
11	Under and over recoveries and adjustments	The Regulator intends continuing with the current approach for calculating under and over recoveries and adjustments.

12	Unaccounted for energy	The report treats unaccounted for energy as part of Aurora Energy's wholesale electricity costs rather than as a separate cost component. The Regulator acknowledges that Aurora Energy has raised concerns over the treatment of unaccounted for energy in its submission to the Regulator dated 20 February 2025. Therefore, the Regulator considers that further work may need to be undertaken fully understand the impact that the treatment of unaccounted for energy has on Aurora Energy's costs.
Aurora Energy's regulated tariff strategy		
3	Regulated Tariff strategy	The Regulator intends applying a side constraint of three per cent to any tariff rebalancing proposal made by Aurora Energy as part of its annual price proposal.
3	Regulated Tariff strategy	The Regulator intends requiring Aurora Energy to make a regulated flat rate tariff available to small customers for the duration of the next regulatory period.
3	Regulated Tariff strategy	The Regulator intends requiring Aurora Energy to seek and obtain the Regulator's approval prior to abolishing a regulated tariff or making a regulated tariff obsolete.
Other		
12	Late payment fee	The Regulator intends approving an increase in Aurora Energy's late payment fee from $5 to $9.
12	Interest on overdue accounts	Aurora Energy may charge interest on accounts not paid in full by the fifth day past the due date at the Reserve Bank of Australia's 90-day

		bank accepted rate plus a premium of six per cent.
14	Time-of-Use tariffs and daylight savings	The Regulator intends requiring Aurora Energy to investigate adjusting the peak and off-peak periods for time-of-use tariffs to account for daylight savings and report to the Regulator with findings and a proposed solution, including implementation timeframes, by close of business 26 September 2025.
14	Preliminary submission	The Regulator intends issuing a written notice under section 15 of the *Electricity Supply Industry Act 1995* requiring Aurora Energy to provide information to the Regulator that is required for the conduct of the pricing investigation for the regulatory period commencing on 1 July 2028. Further, the Regulator intends issuing the notice by no later than 30 June 2027 with the notice requiring Aurora Energy to provide its submission by close of business 15 October 2027.

The Regulator has also prepared a draft determination which is available here. The draft determination sets out how prices paid by small customers on standard retail contracts are to be determined for each of the three financial years of the next regulatory period.

Table O.2 outlines the indicative outcomes from the Regulator's draft decisions and estimates based on data available to date, while Table O.3 outlines the contribution to the indicative average price increase for 2025-26 for each cost component.

Table O.2: Summary of indicative outcomes for 2025-26

Component	Indicative outcome / estimate
NMR	$622 million, 1.5 per cent lower than Aurora Energy's proposal.
Uniform price change	Uniform price increase of 1.4 per cent, compared to an increase of 2.9 per cent in Aurora Energy's proposal.
Cost to serve	$49.87 million $184.58 per customer (indexed from $2023-24)
Retail margin	$31.61 million $116.97 per customer
Wholesale electricity costs	$181.88 million
Wholesale electricity price	$77.60 / MWh
Network costs	$279.53 million
Renewable energy target costs	$29.00 million
Metering costs	$44.27 million
Australian Energy Market Operator costs	$6.18 million

Table O.3: Contributions to indicative average price increase, 2025-26

Cost component	Aurora Energy's proposal		Regulator's draft decisions	
	Cost contribution	Contribution to average price increase	Cost contribution	Contribution to average price increase
Energy Cost	$181 881 304	-2.6%	$181 881 304	-2.6%
Cost to Serve	$56 602 989	1.8%	$49 874 164	0.7%
Network Costs	$279 533 398	4.1%	$279 533 398	4.1%
Forecast RET Costs	$28 826 818	-1.8%	$28 995 704	-1.8%
Forecast AEMO Charges	$7 073 031	0.2%	$6 177 090	0.0%
Metering Costs	$44 270 693	0.9%	$44 270 693	0.9%
Retail Margin	$33 323 917	0.5%	$31 605 997	0.2%
Total costs to be recovered	$631 512 151	2.9%	$622 338 350	1.4%

Next steps

The Regulator is seeking submissions on the draft decisions set out in this report. All information obtained by the Regulator during the investigation will be taken into account in the preparation of the Regulator's Final Report, which is to be released by 2 May 2025.

After completing the investigation and releasing the Final Report, the Regulator will also issue a Price Determination, which sets out how Aurora Energy's maximum standing offer prices are to be determined over the next regulatory period.

In May each year, Aurora Energy will be required to submit its proposed standing offer prices for the following financial year, which the Regulator will assess for approval during June each year.

1 DETERMINING MAXIMUM PRICES

Regulated prices are set at a level that enables Aurora Energy to recover the costs of supplying electricity to customers on standard retail contracts. These costs include:

- wholesale electricity costs;
- network costs;
- Aurora Energy's retail costs (cost to serve);
- renewable energy target (RET) costs;
- metering costs; and
- other costs, such as Australian Energy Market Operator (AEMO) costs.

In addition to these costs, a retail margin is applied to reflect the risks Aurora Energy incurs in providing retail services to small customers under standard retail contracts.

Other inputs used in the calculation of these components are loss factors, forecast customer numbers and forecast total load (together the latter two inputs are referred to as the Notional Tariff Base or NTB).

This methodology is referred to as a cost build-up approach. Under this approach, each component is summed to arrive at a total value of forecast costs for the year which is referred to as the Notional Maximum Revenue (NMR).

The NMR is calculated solely for the purpose of determining maximum standing offer prices. The NMR is a notional figure relating only to small customers on standard retail contracts paying standing offer prices and the costs that make up the NMR are not reconcilable to Aurora Energy's actual financial performance information. Further, Aurora Energy's actual costs may vary from the allowances used in calculating the NMR for price setting purposes.

It is by examining each cost component that the Regulator seeks to ensure that standing offer customers pay no more than they should for the services they receive.

In determinations made by the Regulator after completing past pricing investigations, the NMR has been calculated using the following formula:

NMR = WEC + NC + RET + CTS + M + MARGIN + AEMO + K + C + A

Figure 1 sets out, in diagram form, the cost components and inputs used to calculate Aurora Energy's annual NMR.

1.1 Regulator's approach for the 2025 Determination

1.1.1 Cost components and NMR formula

As set out in the Regulator's Final Methodology Paper released on 3 October 2024, the Regulator has decided to continue to use the cost build-up approach for the 2025 investigation and determination.

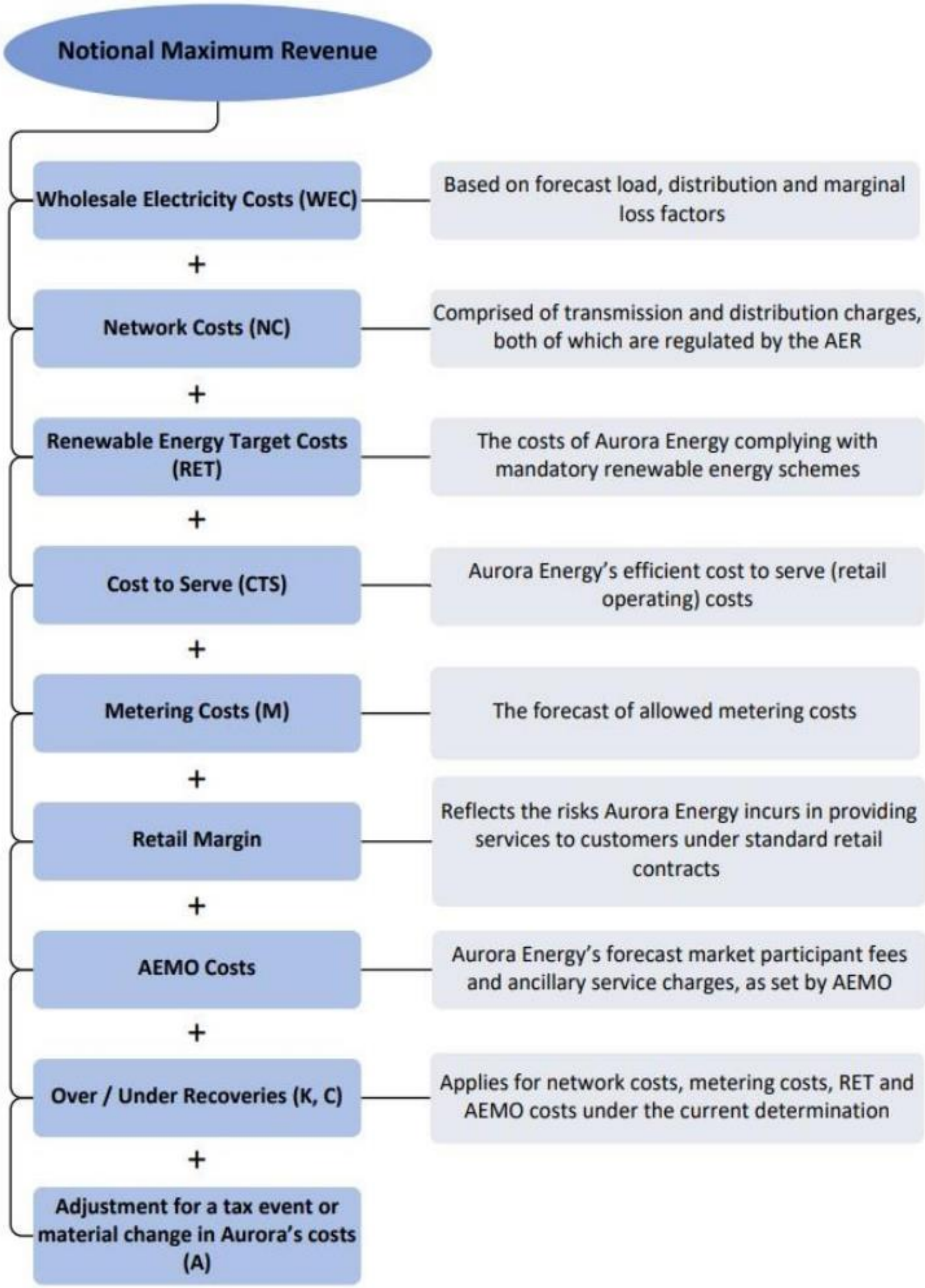
While the general approach is the same, the Regulator intends adding a separate Basslink network cost component to the NMR formula. This component will only be used if the Australian Energy Regulator (AER) approves APA Group's application to convert Basslink from a market network service provider to a prescribed transmission service provider and the Regulator determines that only some of those costs should be passed through to customers on standard retail contracts.

Chapter 7 contains further discussion on this issue.

The formula the Regulator intends using to calculate the NMR for the 2025 Determination is as follows:

NMR = WEC + NC + NC (Basslink) + RET + CTS + M + MARGIN + AEMO + K + C + A

Figure 1: Cost components and inputs used to calculate the NMR



The Regulator's intentions with respect to the other inputs used in calculating the NMR cost components are set out in sections 1.1.2 to 1.1.4 inclusive.

1.1.2 Customer numbers

As set out in the Final Methodology Paper, the Regulator has decided to continue to set customer numbers using the approach applied in the current regulatory period. That is, using the mid-point of actual customer numbers as at 31 March prior to the start of each year and a forecast of customer numbers as at 31 March during the year.

1.1.2.1 Regulator's draft decision - customer numbers

In the absence of more up to date information the Regulator has used the customer numbers approved by the Regulator for 2024-25 for the purposes of calculating the indicative NMR for 2025-26 as set out in Table 1.1.

Table 1.1: Regulator's draft decision – Customer numbers

	2025-26
Customer numbers	270 202

1.1.3 Load

Load represents Aurora Energy's annual forecast of the volume of electricity it will need to purchase in the spot market to supply its small customers for each financial year of the regulatory period.

1.1.3.1 Regulator's draft decision - load

In the absence of more up to date information, the Regulator has used the load approved by the Regulator for the 2024-25 financial year for the purposes of calculating the indicative NMR for 2025-26 as set out in Table 1.2.

Table 1.2: Regulator's draft decision – Load

	2025-26
Load	2 242.56 GWh

As part of the annual standing offer price approval process in June prior to the commencement of each year of the regulatory period, Aurora Energy will submit its estimated load for the Regulator's approval.

1.1.4 Loss factors

As electricity flows through the transmission and distribution systems, energy is lost due to electrical resistance and the heating of conductors. Due to these losses the amount of electricity generated must be greater than actual demand or load. To account for the difference between the demand for electricity (load) and the amount of electricity generated to meet that demand, the load is ‘grossed up’ by one or more loss factors.

The distribution loss factor (DLF) represents the average energy loss incurred when electricity is transmitted over the distribution network. AEMO is required to publish DLFs by 1 April each year to apply to the following financial year.

The marginal loss factor (MLF) represents the average energy loss incurred when electricity is transmitted over the transmission network. AEMO determines and publishes MLFs for each NEM region for each financial year. AEMO publishes MLFs in late May / early June each year to apply to the following financial year.

1.1.4.1 Regulator’s draft decision - loss factors

Pending AEMO’s release of the loss factors for 2025-26 and for the purposes of calculating the indicative NMR for 2025-26, the Regulator has used AEMO’s approved 2024-25 loss factors as set out in Table 1.3.

Table 1.3: Regulator’s draft decision – Loss factors

	2025-26
DLF	1.0412
MLF	1.0038

As part of the annual standing offer price approval process in June prior to the commencement of each year of the regulatory period, Aurora Energy will submit a weighted average DLF and MLF for the Regulator’s approval, which will be used in calculating the wholesale energy costs and the NMR for each Period.

2 INDICATIVE NMR AND INDICATIVE UNIFORM PRICE CHANGES

This chapter presents an indicative NMR based on the proposals set out in Aurora Energy's Submission, an indicative NMR based on the Regulator's draft decisions as set out in this report and the uniform price changes that would apply under each indicative NMR.

2.1 Introduction

After the lodgement of its Submission, Aurora Energy provided the Regulator with an estimate of its NMR for 2025-26 based on the proposals set out in its Submission.

The NMR is indicative only, due to:

(a) the unavailability of up to date information for a number of inputs (load, loss factors and customer numbers) and some cost components (e.g. network costs); and

(b) the wholesale electricity price being calculated approximately three months prior to the final calculation date.

For these reasons, Aurora Energy had to make a number of assumptions when calculating its indicative NMR; these assumptions, together with the assumptions the Regulator has made in calculating its indicative NMR, are set out in Appendix 2.

2.2 Indicative NMR

Aurora Energy's indicative NMR for 2025-26 is estimated to be $631.51 million, as set out in Table 2.1.

The Regulator's indicative NMR, calculated based on the draft decisions set out in this report, is estimated to be $622.34 million, as shown in Table 2.2.

Table 2.1: Aurora Energy's indicative NMR for 2025-26

Determination Component	Description	NMR Contribution
WECy	Energy Cost	$181 881 304
CTSy	Cost to Serve	$56 602 989
NCy	Network Costs	$279 533 398
RETy	Forecast RET Costs	$28 826 818
AEMOy	Forecast AEMO Charges	$7 073 031
My	Metering Costs	$44 270 693
CFy	2016 Determination Recoveries	$0
Ky	2022 Determination Recoveries	$0
Ay	Determination Adjustments	$0
Ry	Retail Margin	$33 323 917
Total		$631 512 151

Table 2.2: Regulator's indicative NMR for 2025-26

Determination Component	Description	NMR Contribution
WECy	Energy Cost	$181 881 304
CTSy	Cost to Serve	$49 874 164
NCy	Network Costs	$279 533 398
RETy	Forecast RET Costs	$28 995 704
AEMOy	Forecast AEMO Charges	$6 177 090
My	Metering Costs	$44 270 693
CFy	2016 Determination Recoveries	$0
Ky	2022 Determination Recoveries	$0
Ay	Determination Adjustments	$0
Ry	Retail Margin	$31 605 997
Total		$622 338 350

2.3 Average price change

Based on the proposals in its Submission, the information presented in Table 2.1 and Aurora Energy's estimate of the other cost components, Aurora Energy is predicting an average price change of 2.9 per cent for 2025-26. Most notably, network costs contribute 4.1 per cent of that price increase while wholesale electricity costs reduce prices by 2.6 per cent.

Based on the draft decisions set out in this report and the information presented in Table 2.2, the Regulator has calculated an indicative average price change for 2025-26 of 1.4 per cent.

2.4 Customer impacts

Based on the indicative NMRs in Table 2.1 and Table 2.2, the impacts on customers' bill for 2025-26 from an average price increase are shown in Table 2.3 and Table 2.4.

Table 2.3: Customer bill impacts from average price increase with Aurora Energy's indicative NMR for 2025-26

Tariff		Number of Customers	$ Price Movement			% Price Movement		
			Low	Median	High	Low	Median	High
Small Business	22	20 816	$25	$46	$87	2.92%	2.92%	2.92%
	75	2 399		$125			2.92%	
	94	5 492		$98			2.92%	
Residential	31	10 639		$39			2.92%	
	31/41	153 031	$55	$67	$82	2.92%	2.92%	2.92%
	31/41/61	14 587		$89			2.92%	
	93	63 168		$67			2.92%	

Table 2.4: Customer bill impacts from average price increase with the Regulator's indicative NMR for 2025-26

Tariff		Number of Customers	$ Price Movement Low	$ Price Movement Median	$ Price Movement High	% Price Movement Low	% Price Movement Median	% Price Movement High
Small Business	22	20 816	$12	$22	$43	1.43%	1.43%	1.43%
	75	2 399		$61			1.43%	
	94	5 492		$48			1.43%	
Residential	31	10 639		$19			1.43%	
	31/41	153 031	$27	$33	$40	1.43%	1.43%	1.43%
	31/41/61	14 587		$43			1.43%	
	93	63 168		$32			1.43%	

3 AURORA ENERGY'S REGULATED TARIFF STRATEGY

Aurora Energy submitted its draft regulated tariff strategy to the Regulator in December 2024.

The purpose of the regulated tariff strategy is to set out the tariffs Aurora Energy intends offering during the next regulatory period.

Under section 6(2) of the *Electricity Supply Industry Act 1995* (ESI Act), the Regulator has statutory objectives that include promoting competition and protecting the interests of consumers of electricity.

While the Regulator does not prescribe which tariffs Aurora Energy may or may not offer to its customers, the Regulator will not approve Aurora Energy's regulated tariff strategy if it considers the tariffs being offered to customers or the changes proposed to be made to the tariffs did not meet the Regulator's statutory objectives.

Appendix 3 provides explanations of the following key terms referred to in this Chapter and in Aurora Energy's draft regulated tariff strategy:

- rebalancing;
- grandfathering;
- cost reflective tariffs;
- uniform price changes; and
- side constraints.

3.1 Summary of Aurora Energy's draft strategy

A summary of the key components included in Aurora Energy's draft strategy is set out in Table 3.1.

Table 3.1: Key components in Aurora Energy's draft regulated tariff strategy

Issue	Aurora Energy's draft position
Tariff rebalancing	A key component of Aurora Energy's draft strategy is to undertake further tariff rebalancing during the next regulatory period. Tariff rebalancing may involve changes in overall tariffs, where one tariff changes at a different rate than another tariff, as well as changes in the fixed and variable components of tariffs (i.e. the daily supply charges and the electricity usage charges). Tariff rebalancing will result in non-uniform price changes. Therefore, the change in a customer's annual electricity bill will vary depending on both the tariff/s they receive electricity under, their electricity usage and, for those customers on time-of-use tariffs, when they use electricity. Aurora Energy proposes tariff rebalancing based on the premise that in each year of the regulatory period no median typical customer bill will be greater than that under a uniform price increase plus five per cent. Aurora Energy considers that this will provide adequate protection for customers while tariffs are transitioned be cost reflective. Based on applying the proposed five per cent side constraint each year, Aurora Energy estimates it will be able to reach cost reflective tariffs within the next three-year regulatory period. The actual time to reach cost reflectivity will be subject to the annual underlying uniform price change.
Flat rate tariffs	Since 1 July 2024, Aurora Energy has not been offering flat rate standing offer tariffs to new customers. Instead, new customers are either placed on a time-of-use standing offer tariff or offered choice of two flat rate market retail contracts if Aurora Energy considers that it is the best option for the customer.
New tariffs	While Aurora Energy has not proposed any new tariffs, Aurora Energy supports the continuation of the process outlined in the Regulator's Standing Offer Price Approval Guideline for the 2022 Determination with regards to introducing new tariffs. Under that process, Aurora Energy needs to consult with its

	customers and estimate the bill impacts arising from the proposed introduction of a new tariff.
Obsolete and abolished tariffs	Aurora Energy supports maintaining Clause 5.1(2)(f) of the 2022 Standing Offer Price Approval Guideline which enables Aurora Energy to abolish a tariff or make it obsolete provided it justifies the reason for abolishing the tariff or making it obsolete and specifies the impact on customers.
Customer consent	Aurora Energy states that it will never move a customer in an existing premise on to an alternative tariff without their consent.

The Regulator considers Aurora Energy's draft strategy raises three main issues:

1. Tariff rebalancing;
2. Flat rate tariffs; and
3. Obsolete and abolished tariffs.

3.2 Tariff rebalancing

Aurora Energy is proposing to accelerate the rebalancing of its tariffs so that most tariffs will be cost reflective by the end of the next regulatory period.

Recent standing offer price changes have had uniform price changes applied to all tariffs as well as to both the fixed and variable tariff components. Aurora Energy argues that the application of uniform price changes has led to a divergence in the level of revenue collected from individual tariffs and the tariff's underlying costs, as well as in the revenue collected from the fixed and variable components of tariffs compared to the fixed and variable costs of each tariff.

Movements in network costs, which account for approximately 45 per cent of the costs included in Aurora Energy's NMR, have changed at a different rate to retail tariffs. Over time, there has been a decrease in the variable component of some network tariffs relative to an increase in the fixed component.

Aurora Energy states that its fixed charges are substantially less than its fixed costs. The rebalancing in the past two years has addressed this at an aggregate level but not at individual tariff level. Aurora Energy claims that the difference between the fixed charges recovered and its fixed costs means that it has higher forecasting and financial risk.

As noted in Aurora Energy's draft strategy, Aurora Energy has undertaken some rebalancing in the past.

In 2023-24, the Regulator approved an average price increase of 9.51 per cent but applied a one per cent side constraint to the typical customer bill. The one per cent side constraint meant that no typical customer bill could increase by more than one percentage point above the 9.51 per cent average increase (i.e. 10.51 per cent).

This meant that the price of some tariffs changed at different rates as well as the fixed and variable charges for tariffs changing at different rates. Aurora Energy increased the fixed charge of all tariffs except Tariff 22[1] by 15 per cent and the variable component of all tariffs by 8.38 per cent.

In 2024-25, the Regulator approved an average price increase of 0.5 per cent but again applied a one per cent side constraint to the typical customer bill. The resulting price movements ranged from a 6.8 per cent increase in the fixed charge of all tariffs except Tariff 22[2] to a one per cent decrease in the variable charge component of all tariffs.

For the next regulatory period Aurora Energy is proposing a side constraint where "No median typical customer bill outcome is more than 5 per cent higher than it otherwise would be under a uniform price change."

For the purposes of comparison, the impact on customers' bills of Aurora Energy's proposed side constraint applied to the Regulator's average price increase of 1.43 per cent are shown in Table 3.2.

As Aurora Energy proposed a side constraint of five per cent only on median consumption typical customers, the impacts of tariff rebalancing on other typical customer groups could be quite different. As an illustrative example of the maximum bill impacts that could be experienced by low and high typical usage customers, a 10 per cent side

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1 The fixed charge for Tariff 22 increased by 10 per cent.

2 The fixed charge for Tariff 22 increased by 4 per cent.

constraint has been applied to low consumption typical customers and a zero per cent side constraint has been applied to high consumption typical customers in Table 3.2.

Table 3.2: Indicative maximum bill impact based on the Regulator's average price increase of 1.43 per cent with five per cent side constraint on typical customers with median usage only

Tariff		Number of Customers	$ Price Movement			% Price Movement		
			Low	Median	High	Low	Median	High
Small Business	22[3]	20 816	$98	$100	$43	11.43%	6.43%	1.43%
	94[4]	5 492		$216			6.43%	
Residential	31/41[5]	153 031	$213	$147	$40	11.43%	6.43%	1.43%
	93[6]	63 168		$146			6.43%	

This proposal could result in customers with lower consumption facing significantly higher price increases compared to customers with higher consumption, as increased fixed charges will comprise a larger component of a customer's bill.

The Regulator considers a side constraint applied equally to all typical customers is more equitable. For comparison, the Regulator has calculated a five per cent side constraint applied to all customers to illustrate the maximum bill impacts that could be experienced by any typical customer. Table 3.3 shows that the price increases are now proportionate to a customer's consumption.

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3 Typical annual consumption for a small business on Tariff 22 is 1 179kWh (low), 3 508kWh (median) and 8 782kWh (high).

4 Typical annual consumption for a household on Tariff 94 is 12 180kWh (median).

5 Typical annual consumption for a household on Tariff 31 / 41 is 5 567kWh (low), 7 428kWh (median) and 9 664kWh (high).

6 Typical annual consumption for a household on Tariff 93 is 7 932kWh (median).

Table 3.3: Indicative maximum bill impact based on the Regulator's average price increase of 1.43 per cent with five per cent side constraint on all typical customers

Tariff		Number of Customers	$ Price Movement Low	$ Price Movement Median	$ Price Movement High	% Price Movement Low	% Price Movement Median	% Price Movement High
Small Business	22[7]	20 816	$55	$100	$192	6.43%	6.43%	6.43%
	94[8]	5 492		$216			6.43%	
Residential	31/41[9]	153 031	$120	$147	$180	6.43%	6.43%	6.43%
	93[10]	63 168		$146			6.43%	

The proposed tariff rebalancing is considerably higher than in previous years, as Aurora Energy claims that it requires a higher side constraint to accommodate future changes in costs and to address legacy imbalances. The Regulator considers Aurora Energy has not provided sufficient evidence to justify the higher side constraint nor has it discussed the alternative of lower side constraints over a longer period.

With respect to the size of the side constraint, the Regulator has calculated a three per cent side constraint applied to all typical customers. Table 3.4 shows the maximum bill impacts of an illustrative three per cent side constraint applied to all customers.

The Regulator's analysis indicates most tariffs will become cost reflective during the next regulatory period with a three per price side constraint applied to all customers.

The main exception is Tariff 94, which due to different time periods that apply to the underlying network tariff, will not be cost reflective until the subsequent regulatory period.

The Regulator considers the nature of Tariff 94 should not be a driver for potentially higher prices for most customers on other tariffs.

[7] Typical annual consumption for a small business on Tariff 22 is 1 179kWh (low), 3 508kWh (median) and 8 782kWh (high).

[8] Typical annual consumption for a household on Tariff 94 is 12 180kWh (median).

[9] Typical annual consumption for a household on Tariff 31 / 41 is 5 567kWh (low), 7 428kWh (median) and 9 664kWh (high).

[10] Typical annual consumption for a household on Tariff 93 is 7 932kWh (median).

Table 3.4: Indicative maximum bill impact based on the Regulator's average price increase of 1.43 per cent with three per cent side constraint on all customers

Tariff		Number of Customers	$ Price Movement Low	$ Price Movement Median	$ Price Movement High	% Price Movement Low	% Price Movement Median	% Price Movement High
Small Business	22	20 816	$38	$69	$132	4.43%	4.43%	4.43%
	94	5 492		$149			4.43%	
Residential	31/41	153 031	$83	$101	$124	4.43%	4.43%	4.43%
	93	63 168		$101			4.43%	

3.2.1 Draft decision - tariff balancing

The Regulator intends approving tariff rebalancing based on a three per cent side constraint applied to all typical customer's bills, as this will result in a more equitable outcome for low consumption customers.

3.3 Flat rate tariffs

The Australian Energy Market Commission (AEMC) has recently reviewed its rules in relation to the deployment of smart meters. This review included the availability of flat rate tariffs for customers. Aurora Energy's draft regulated tariff strategy refers to the AEMC's draft determination in relation to the advanced meter rollout. As noted by Aurora Energy in its draft regulated tariff strategy, the AEMC did not state in its draft determination whether the requirement to offer a flat rate tariff should be within standing offers or market offers. As such, Aurora Energy stated that its decision to offer flat rate market contracts satisfies the AEMC's requirements.

Aurora Energy currently has two flat rate market contracts which are offered to customers who Aurora Energy has determined would not benefit from being on regulated time-of-use tariffs. Aurora Energy has not provided details of the criteria that are used to identify the customers these contracts would be offered to.

In a departure from its draft determination, the AEMC's final determination released on 28 November 2024 states that designated retailers must make a standing offer flat rate tariff available to customers with an advanced meter once the rule change has been implemented in a jurisdiction.[11] The decision was informed by feedback from stakeholders which highlighted that many customers cannot understand the more complicated dynamic pricing tariffs; cannot change their consumption sufficiently to benefit from these tariffs; and do not have the resources to invest in technology that would allow them to benefit from these tariffs.

In response, the Queensland Government has mandated electricity retailers to offer a flat rate regulated option for customers with smart meters to ensure that those customers have access to electricity that is predictable with an easy-to-understand bill. The move recognises that some customers' electricity usage does not enable them to benefit from time-of-use and or demand tariffs.

The Regulator considers that there may be merit in having a local instrument in place that enforces the AEMC rule change to ensure that ongoing regulated flat rate tariffs are available to all small customers in Tasmania.

The Regular also notes that during consultation on the structure of Aurora Energy's tariffs as part of the Regulator's 2024 Methodology Review, consumer groups considered that a regulated flat rate tariff should be available for new customers. This mirrors the feedback in other jurisdictions and that provided to the AEMC on its draft rule determination.[12]

The Regulator considers that it is evident that customers have varied preferences with regards to tariffs. Customers and their circumstances also vary considerably. The inability to change electricity consumption, and/or invest in technologies such as solar panels and batteries to maximise time-of-use tariffs, means some customers may be disadvantaged by time-of-use tariffs. Additionally, customers who are not better off on time-of-use tariffs may not want the uncertainty

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[11] AEMC, *Rule Determination - National Electricity Amendment (Accelerating Smart Meter Deployment) Rule and National Energy Retail Amendment (Accelerating Smart Meter Deployment) Rule*, 28 November 2024, page 31.

[12] AEMC, *Rule Determination - National Electricity Amendment (Accelerating Smart Meter Deployment) Rule and National Energy Retail Amendment (Accelerating Smart Meter Deployment) Rule* - Draft rule determination, *4 April 2024*

associated with market contracts and prefer the ease, simplicity and certainty of regulated flat rate tariffs.

The Regulator considers that the evidence supports customers wanting access to a variety of tariffs, including a regulated flat rate tariff and the flexibility to move to a tariff that aligns with their personal preferences and consumption patterns.

The AEMC[13] also considered the costs associated with requiring retailers to offer a standing offer flat rate tariff. In its final rule determination, the AEMC states that it did not consider retailers will be uniformly worse off by incurring network tariffs that do not directly align with tariffs they are required to offer, noting that these costs may be offset by lower costs for other tariffs.

3.3.1 Draft decision - regulated flat rate tariffs

The Regulator intends requiring Aurora Energy to offer a regulated flat rate tariff to all small customers.

3.4 Obsolete and abolished tariffs

The current standing offer price approval guideline states if a tariff is proposed to be made obsolete or abolished, Aurora Energy must:

- provide justification for making the tariff obsolete or abolished; and
- specify the impact on customers.

However, the Regulator considers the obligations on Aurora Energy should extend beyond justifying its proposal and that the Regulator's approval should be sought before Aurora Energy makes a regulated tariff obsolete or abolishes a regulated tariff.

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13 AEMC, *Rule Determination - National Electricity Amendment (Accelerating Smart Meter Deployment) Rule and National Energy Retail Amendment (Accelerating Smart Meter Deployment) Rule*, 28 November 2024, page 32.

3.4.1 Draft decision - obsolete and abolished tariffs

The Regulator intends requiring Aurora Energy to seek and obtain the Regulator’s approval prior to abolishing a regulated tariff or making a regulated tariff obsolete.

4 COST TO SERVE

Aurora Energy's CTS reflects the Regulator's assessment of the efficient level of operating costs Aurora Energy requires to provide services to customers on standard retail contracts. Aurora Energy's CTS currently includes costs relating to:

- billing and revenue collection;
- marketing;
- providing advice and answering customer queries;
- the aurora+ app;
- corporate overheads;
- allowance for bad debts; and
- regulatory compliance.

The current CTS allowance is expressed as a dollar per customer amount.

4.1 2022 Determination

For the 2022 Determination, the Regulator approved a CTS allowance for 2022-23 of $156.31 per customer ($2020-21). The CTS allowance was determined using a combination of a cost build-up approach based on Aurora Energy's actual retail costs in 2020-21 and benchmarking against the average retail costs of other retailers as reported by the Australian Competition and Consumer Commission (ACCC) in its Inquiry into National Electricity Market report.

The actual CTS allowance for 2022-23 was adjusted to take into account the general increases in wages and other costs since 2020-21, together with an efficiency factor.

For the second and third year of the current regulatory period, the Regulator adjusted the CTS amount for each year by:

- indexing Aurora Energy's labour cost components using changes in Tasmania's Wage Price Index;

- indexing all non-labour cost components using changes in the Hobart Consumer Price Index; and
- applying an efficiency factor of 3.4 per cent for each year.[14] [15]

Table 4.1: Aurora Energy's CTS per customer for the 2022 Regulatory period ($nominal)

	2022-23	2023-24	2024-25
CTS per customer	$154.55	$167.36	$168.45

4.2 Regulator's approach for the 2025 Determination

As set out in the Final Methodology Paper, the Regulator decided to:

- use a cost build-up together with benchmarking information to assess Aurora Energy's CTS;
- apply an efficiency factor;
- adjust the CTS for inflation for each year other than the first year of the regulatory period;
- remove the adjustment mechanism that accounts for changes in customer numbers;
- further consider the treatment of cloud-based software costs during the price investigation; and
- require Aurora Energy to submit its cost allocation manual at the same time as it lodges its submission in relation to the pricing investigation.

4.3 Aurora Energy's Submission

In its Submission, Aurora Energy proposed a CTS allowance of $196 per customer for 2025-26 ($2023-24 dollars). Aurora Energy used a

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[14] An efficiency factor of 1.78 per cent was applied for 2022-23 in recognition of the fact that Aurora Energy had already applied a 1.62 per cent efficiency factor to its costs for that year.

[15] The 2022 Determination also included a mechanism for adjusting the CTS to reflect changes in customer numbers. However, the criteria required to trigger this mechanism were not met during the current regulatory period and the mechanism has therefore not been activated.

benchmarking approach, and its proposed CTS is based on the average residential retail cost for non-big 3 retailers from the ACCC's *Inquiry into the National Electricity Market: December 2023.* The retail costs from the ACCC's report include a CTS component and a cost to acquire and retain customer (CARC) component.

In addition to its Submission, Aurora Energy provided the Regulator with a detailed model of its operating costs (CTS Model). The CTS Model categorises costs into core and support functions directly related to providing electricity retail services for customers on standard retail contracts. Similar to information provided in past investigations, the costs associated with customer acquisition and retention have been included in its core function costs, rather than being separately identified.

Aurora Energy also provided the Regulator with the cost information it provided to the ACCC in accordance with the ACCC's notice under Section 95ZK of the *Competition and Consumer Act 2010.*[16] As required by the notice, Aurora Energy split its costs into a CTS component and a CARC component. This has allowed the Regulator to compare Aurora Energy's CTS and CARC with the average residential and small business retail costs for the big 3 and non-big 3 retailers.

4.4 Cost allocation manual

Aurora Energy provides electricity and gas retailing services in Tasmania, and its customers include both regulated customers and unregulated customers. Its regulated customers are residential and small business electricity customers on standard retail contracts. Its unregulated customers are residential and small business electricity customers on market contracts, commercial and industrial customers, and gas customers.

Since commencing operations as a standalone retailer in 2005, Aurora Energy has not been required to maintain separate regulatory accounts nor maintain activity-based costing data.

As a result, the Regulator did not have expenditure data at an activity level for the 2022 investigation and therefore was unable to verify

16 This information has been provided to the Regulator and treated as commercial in confidence.

whether direct and indirect non-recurrent CTS costs had been appropriately accounted for. Nor did the Regulator have access to audited historical data that clearly separated actual CTS expenditure outcomes from Aurora Energy's broader whole-of-business expenditure.

The Regulator therefore decided, during the current regulatory period, to examine the merits of introducing separate regulatory accounts and activity-based costings prior to conducting this pricing investigation. This examination led to the Regulator deciding that the costs of introducing regulatory accounts or activity-based costing likely outweighed the benefits of doing so.

The Regulator therefore decided to require Aurora Energy to compile and provide the Regulator with a more detailed Cost Allocation Manual (CAM) prior to the commencement of the 2025 investigation.

Aurora Energy provided the requested CAM on 22 October 2024.

4.5 Cost build-up analysis

Aurora Energy's CTS Model categorises its operating costs into three categories:

- cost to serve;
- bad debt expense; and
- national regulatory costs.

The Regulator has examined Aurora Energy's costs and identified one-off adjustments to the base year and has considered whether an efficiency factor should be imposed on Aurora Energy for the next regulatory period.

4.5.1 Bad debt expenses

Aurora Energy has estimated its bad debt expense using a benchmark from the ACCC's average bad debt expense across the NEM from its Inquiry into the National Electricity Market report for the past three years. This led to Aurora Energy's CTS model including a bad debt expense allowance that exceeded Aurora Energy's bad debt expense allowance from the previous regulatory period.

In its Submission, Aurora Energy noted the marked increases in the levels of total energy debt for residential customers in Tasmania, as shown in the AER's 2022-23 Annual Retail Market Report. In particular, Aurora Energy is concerned that its bad debt expense will increase over the next regulatory period[17] and considers benchmark bad debt expense to be an appropriate figure.

The Regulator notes that the AER's 2023-24 Annual Retail Market Report shows that the proportion of residential customers with energy debt fell in Tasmania in 2023-24, as did the average value of residential energy debt.[18]

The Regulator has also reviewed Aurora Energy's quarterly retail performance data for the past five years, together with data for another retailer operating in Tasmania. This review shows that in the most recent quarters, while the number of small business customers in debt and the total value of small business debt has been trending up, the number of residential customers in debt and the total value of residential debt has been trending down.[19] In the most recent quarters, the overall trend has therefore been that Aurora Energy's total debt has been decreasing.

This trend was confirmed by Aurora Energy during its appearance at the House of Assembly Government Business Enterprise Scrutiny hearings in December 2024:

> "…Tasmania is actually only one of two jurisdictions which saw a reduction in debt over the last financial year." [20]

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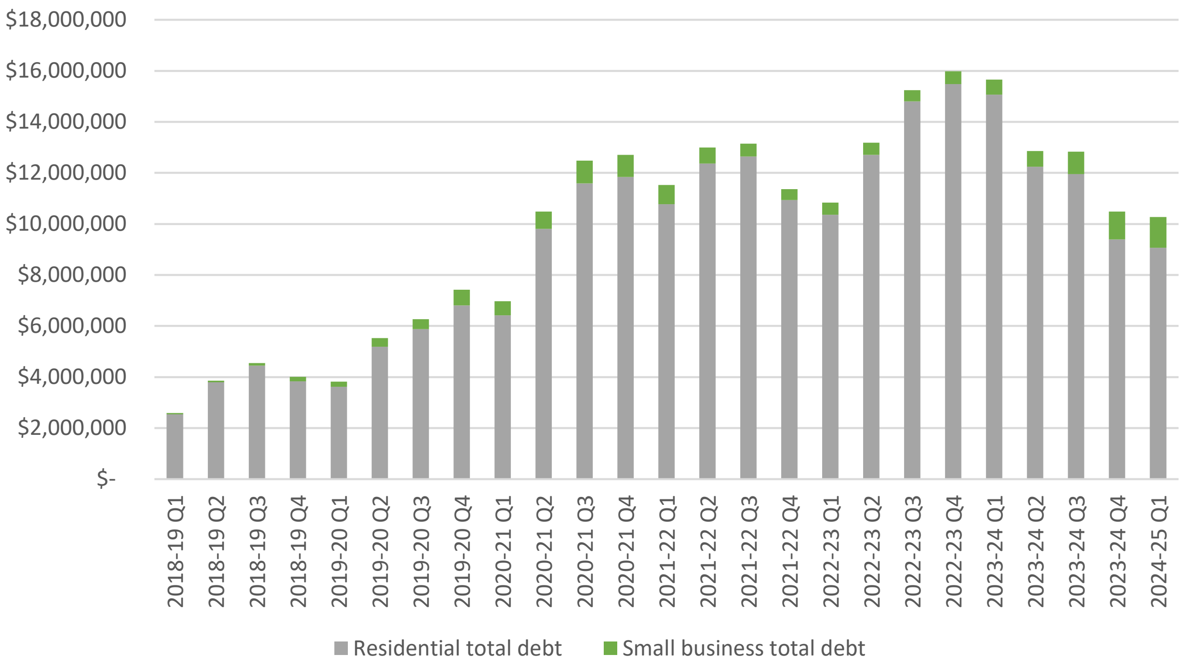
[17] Aurora Energy's Preliminary Submission, page 18.

[18] AER Annual Retail Market Report 2023-24, pages 67-68.

[19] These trends have also been observed in the quarterly retail performance data for other retailers operating in Tasmania.

[20] House of Assembly, 4 December 2024, page 16.

Figure 4.1: Trends in Aurora Energy's total debt for regulated customers



Based on the trends shown in the AER's 2023-24 Annual Retail Market Report and Aurora Energy's quarterly retail performance data, the Regulator considers there is insufficient evidence to conclude Aurora Energy will face higher bad debt expenses during the next regulatory period.

Aurora Energy reports on a range of measures relating to debt in its annual reports including the amount of debt written off as uncollectable.

The debt written off is the amount of debt owing by customers that has been assessed by independent auditors as no longer able to be collected. Aurora Energy's debt written off is summarised in Table 4.2.

Table 4.2: Aurora Energy's debt written off ($nominal)

	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Debt written off as uncollectable	$3.8m	$3.3m	$4.2m	$3.1m	$4.1m	$3.9m	$2.9m

Source: Aurora Energy annual reports.

The Regulator considers that the amount of debt written off as uncollectable is the most appropriate measure to represent Aurora Energy's bad debt expense. This is consistent with the measures used by the ACCC for its inquiry report, where the bad debt expense is the amount customers were unable to pay that is ultimately written off as unrecoverable.[21]

As shown in Table 4.2, Aurora Energy's uncollectable debt has been relatively stable over the past seven years.

The Regulator also notes that the amount of debt collected by Aurora Energy has been stable over the past four years. Based on cost breakdown data provided by Aurora Energy, its operating costs attributable to debt collection have also been low over the same period.

4.5.1.1 Draft decision - Bad debt expenses

The Regulator intends using debt written off as uncollectable that is attributable to regulated customers as the bad debt expense for Aurora Energy's CTS.

4.5.2 National regulatory costs

Aurora Energy has shown national regulatory costs separately in its CTS model and estimated a national regulatory cost component for the next regulatory period based on its average national regulatory costs between 2019-20 and 2023-24.

Aurora Energy's national regulatory costs over the five-year period have been dominated by the implementation of the five-minute settlement change in 2019-20 and 2020-21 with this change accounting for 94 per cent of its total national regulatory costs over this period.

The Regulator considers that benchmarking against a five-year average is inconsistent with Aurora Energy's choice to benchmark against the three-year average for other costs such as bad debt expenses. Furthermore, the Regulator notes that a major regulatory change such as the implementation of five-minutes settlements is unusual for any given year and if such a major rule change was to occur, the costs associated with the implementation in relation to regulated customers is

[21] ACCC, Inquiry into National Electricity Market report - November 2021, page 35.

more suited to be considered for pass through to those customers via the A_y component of the NMR.

The A_y component is an adjustment calculated in accordance with a methodology approved by the Regulator, consistent with regulation 8 and regulation 12 of the *Electricity Supply Industry (Pricing and Related Matters) Regulations 2023*. Regulation 8 defines 'adjustment' to include "a material change in costs to the regulated offer retailer, to which the determination relates, in relation to the provision to small customers of services under standard retail contracts."

By allowing Aurora Energy to recover the costs associated with major national regulatory changes through the A_y cost component rather than CTS, the Regulator is able to review the costs associated with major national regulatory changes as a part of the annual price approval process rather than providing Aurora Energy with a set amount in its CTS that regulated customers pay for through standing offer prices irrespective of whether changes occur or without regard to the accuracy of the cost estimates made in advance of the changes actually being implemented.

4.5.2.1 Draft decision - National regulatory costs

The Regulator intends using an average of Aurora Energy's national regulatory costs from the past three years as its national regulatory costs (i.e. excluding the costs associated with the five-minute settlements change).

Further, the Regulator will consider requests from Aurora Energy seeking approval to pass-through the efficient costs associated with implementing major national regulatory changes that may arise during the regulatory period through the A_y cost component.

4.5.3 Treatment of cloud-based software costs

The International Financial Reporting Standards Interpretations Committee issued two final agenda decisions on cloud computing arrangements in March 2019 and April 2021. Under the decisions, on-going subscription costs for usage of cloud-based software are treated as operating costs and the configuration or customisation costs for cloud-based software are treated as operating costs as well.

Prior to the 2022 Standing Offer Price Investigation, costs associated with Aurora Energy's IT systems were treated as capital expenditure subject to depreciation and were therefore not included in its CTS.[22] However, commencing in 2020 and concluding in 2024, Aurora Energy introduced a new cloud-based Software as a Service (SaaS) billing system. Under the revised accounting standard, costs associated this system should be treated as operating expenditure.

The Regulator is not bound by the accounting standard, and as noted in the Final Methodology Paper, decided to further consider the treatment of cloud-based software costs during the pricing investigation.

In Victoria, the Essential Services Commission (ESC) has provided guidance to its water businesses in relation to the treatment of these costs under the updated accounting standard. This guidance stated that "…the development and implementation costs of a new IT system might be justified as capital expenditure in pricing models and recovered over the expected life of the new system, while any licensing and ongoing operating costs would remain as operating expenditure."[23]

The AER in its draft decision on SA Power Networks' distribution determination has also accepted the treatment of non-recurrent integration costs associated with the implementation of cloud-based software into the business' existing infrastructure as a capital expense and the ongoing licence costs of the cloud-based software as operating expenses.[24]

While the Regulator does not require Aurora Energy to maintain a regulated asset base, Aurora Energy's financing costs and depreciation are covered by its retail margin.

4.5.3.1 Draft decision - Cloud based IT costs

The Regulator intends applying the ESC and the AER's approach and require Aurora Energy to capitalise the design and delivery costs of its

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22 Depreciation was accounted for in Aurora Energy's retail margin.

23 Essential Service Commission, Central Highlands Water final decision, June 2023, page 30.

24 AER Overview SA Power Networks distribution determination 2025-30, page 19

new IT system (the depreciation relating to these costs is to be accounted for in Aurora Energy's retail margin).

4.5.4 One-off adjustments

As Aurora Energy's CTS model uses its actual operating costs for 2023-24 to estimate an efficient CTS for the next regulatory period, it is required to remove costs incurred in 2023-24 that will not be incurred in the next regulatory period, as well as forecast and include costs it expects to incur in the next regulatory period that it didn't incur in 2023-24.

Aurora Energy made a number of one-off adjustments to its 2023-24 operating costs, including:

- removing project / investment costs, as an allowance for system investment was provided via the retail margin in the Regulator's 2022 Determination;
- removing duplicated costs associated with the old billing system; and
- removing the additional labour costs associated with the new retail billing system migration.[25]

The Regulator accepts Aurora Energy's reasoning for the one-off adjustments it has made to its 2023-24 operating costs and has identified an additional adjustment to remove the costs associated with the implementation of the Energy Bill Relief program. The Regulator considers Aurora Energy would have incurred a one-off cost for the implementation of the program in 2023-24 which would continue into 2024-25, but not occur in 2025-26.

The Regulator has also accepted Aurora Energy adding its forecast costs associated with the introduction of the Consumer Data Rights framework, which is a regulatory requirement from the ACCC.

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[25] In June 2024, Aurora Energy completed the migration of its customers to its new billing system. The new platform was implemented over several years and involved multiple operational teams (Aurora Energy Annual Report 2023-24, page 12).

4.5.5 Review of cost allocations

The Regulator reviewed Aurora Energy's CAM together with the CTS Model and is satisfied with Aurora Energy's principles for allocating costs and the cost drivers identified. However, the Regulator notes there are some differences between how Aurora Energy categorises its costs in the CAM and in its CTS model.

The Regulator has identified a number of core functions where Aurora Energy's cost allocations do not appear to be appropriate based on information Aurora Energy has provided to the Regulator to date. These findings and the Regulator's draft conclusions from its analysis are set out in Table 4.3.

Table 4.3: Aurora Energy's core functions, cost drivers and the Regulator's draft conclusions

Core function	Aurora's cost driver	Regulator's draft conclusions
Data and technology	Customer numbers	Customer number weighted by technology team FTE effort on programs
Revenue and credit	Customer numbers	Billing team FTE effort
Finance and commercial analysis	Customer numbers	Revenue
Payment and revenue	Customer numbers	Revenue

The Regulator considers that for functions that are revenue orientated, such as point of sale and revenue assurance, unless other more specific cost drivers have been identified, the costs for these functions should be allocated based on revenue rather than customer numbers.

In its CTS model, Aurora Energy has identified commercial functions undertaken by its IT staff. The Regulator considers these costs, and any other commercial costs, should not be recovered from regulated customers.

In its CAM, Aurora Energy also notes that the cost driver for billing should be the amount of employee effort attributable to regulated and non-regulated customers. In its CTS model, Aurora Energy has combined billing, credit and metering to form the revenue and credit department. For this cost analysis the Regulator has used the billing employee effort for the revenue and credit department as the cost driver for the allocation of the relevant costs.

4.5.6 Efficiency factor

In its Submission, Aurora Energy stated that it considers the efficiency factor should be removed, as achieving efficiency improvements becomes increasingly challenging as a business gets close to an efficiency frontier. Aurora Energy also notes that actual retail costs are increasing across retailers.

As previously noted, the Regulator applied an efficiency factor to Aurora Energy's CTS in the current regulatory period.

The Regulator's analysis of Aurora Energy's CTS model indicated that Aurora Energy had already removed one-off costs totalling more than $2.7 million from its CTS (4.35 per cent of its total costs). This adjustment related to the additional costs Aurora Energy incurred implementing its new billing system:

> "...in the last three or so years, the [staff] numbers increased fundamentally due to the billing system transition that the company was going through. So, it led to a build-up that [will] ... naturally lead to some decrease over the coming years."[26]

As discussed in section 4.8, the Regulator intends approving a CTS allowance for Aurora Energy in 2025-26 that is slightly below its total cost build up. As such, an efficiency factor is implicitly included in Aurora Energy's CTS for the first year of the next regulatory period.

4.5.7 Draft decision - efficiency factor

The Regulator intends not applying an explicit efficiency factor to Aurora Energy's cost to serve for this determination as the Regulator is of the view that in the assessment of Aurora Energy's costs, an efficiency

[26] Legislative Council GBE Scrutiny Hearing, 3 December 2024, page 32.

factor has implicitly been factored into the cost to serve allowance for the next regulatory period.

4.6 Summary of outcomes from cost analysis

The Regulator has reviewed Aurora Energy's proposed CTS by examining Aurora Energy's detailed CTS model based on its base year level of expenditure for 2023-24, the retail operating cost model it provided to the ACCC and its CAM.

As a result of this analysis, the Regulator has identified the adjustments to Aurora Energy's CTS as set out in Table 4.4.

Table 4.4: Adjustments identified from the Regulator's analysis of Aurora Energy's costs

Description	Adjustment
Using alternative cost drivers for the allocation of some costs	-$4 137 684
Removing one-off costs associated with the implementation of the Energy Bill Relief program	-$551 176
Using Aurora Energy's recent bad debts written off instead of the proposed NEM benchmark of bad debt expense	-$5 245 135
Calculating national regulatory costs based on a five-year average rather than a three-year average	-$906 843
Capitalising the design and delivery costs relating to the implementation of the new cloud-based billing system	-$2 721 123

After making these adjustments, the Regulator's estimated efficient CTS for 2025-26 is $174.81 per customer ($2023-24).

4.7 Benchmarking

In benchmarking Aurora Energy's CTS, the Regulator has considered the ACCC's most recent findings together with other regulators' recent decisions.

Further, notwithstanding the information and analysis in sections 4.5 and 4.6, the Regulator notes that Aurora Energy's proposed CTS for the next regulatory period is not directly linked to its operating costs. Rather, it has been benchmarked against the non-big 3 retailers' average residential customers' total retail costs for 2022-23.

4.7.1 ACCC

Table 4.5: Average retail costs per residential customer for Big 3 and Non-big 3 retailers based on the ACCC's report ($2023-24[27])

		CTS	CARC	Total retail costs
Big 3	Residential	$70	$39	$109
Non-big 3	Residential	$127	$70	$196

In its Submission, Aurora Energy argued that benchmarking against the non-big 3 retailers' retail costs is appropriate because of Aurora Energy's relatively smaller size compared to the big 3 retailers and "Aurora Energy's inability to operate beyond the Tasmanian market limits potential cost advantages from economy of scale".

While the Regulator agrees that Aurora Energy's smaller market share means it cannot achieve the same economies of scale as the big 3 retailers, the Regulator also considers it inappropriate to use the average residential retail cost for non-big 3 retailers for the following reasons:

- Aurora Energy's retail cost breakdown between CTS and CARC is very different from the average of the big 3 retailers and the average of the non-big 3 retailers; and

[27] The retail costs were indexed by the weighted average of eight capital cities CPI from June 2023 to June 2024.

- while Aurora Energy's size is consistent with a non-big 3 retailer, it is the dominate retailer in the Tasmanian retail market and, consequentially, has more market power than a typical non-big 3 retailer.

Based on Aurora Energy's cost breakdown from the model it provided to the ACCC, Aurora Energy's CARC for residential and small business customers are similar and are significantly less than average CARC for the big 3 retailers and the non-big 3 retailers. This is consistent with its dominance in the Tasmanian retail market. The only CARC Aurora Energy has identified relate to advertising and marketing costs and the costs of onboarding new customers.

From the ACCC's report, non-big 3 retailers tend to incur a higher CARC for residential customers due to the lack of dominance of any retailer in the market and the consequent need to spend more money to acquire and retain customers.

The Top 10 retailers in the NEM and their respective shares of the markets they operate in are set out in Table 4.6.

The Regulator considers, based on market share, market power and regulatory frameworks, the most appropriate benchmark for Aurora Energy's retail costs is ActewAGL. Similar to Aurora Energy, ActewAGL offers price regulated retail tariffs and remains the retailer for the majority of small customers in the ACT. ActewAGL is also not a big 3 retailer, and while it offers retail services in NSW, the majority of its small customers are in the ACT.

The Regulator notes that the main difference between Aurora Energy and ActewAGL is that ActewAGL is a joint venture between the Australian Gas Light Company (AGL) and Icon Water Limited (formerly ACTEW Corporation), an ACT Government owned corporation, and AGL is one of the big 3 retailers. While the operation of ActewAGL is ringfenced from AGL, ActewAGL may benefit from the economies of scale achieved by a bigger retailer. However, this impact cannot be quantified.

Table 4.6: Top 10 retailers' NEM market share[28]

	Retailer	Market share
Big 3 retailers	Origin Energy	26.2%
	AGL	21.8%
	EnergyAustralia	13.8%
Non-big 3 retailers	Ergon Energy	9.8%
	Red Energy	7.1%
	Alinta	4.5%
	Aurora Energy	3.6%
	ActewAGL	2.6%
	Simply Energy	1.9%
	Energy Locals	1.0%

The Regulator further notes that the customer churn rate in the ACT is higher than in Tasmania. Therefore, it is reasonable to assume that ActewAGL will incur higher CARC than Aurora Energy.

4.7.2 CTS allowances in other jurisdictions

The CTS allowances set by other regulators are discussed below.

28 The respective market shares have been calculated using Schedule 2 of the AER's Q1 2024-25 retail performance report, and present each retailer's share of the combined residential and small business electricity market they operate in.

4.7.2.1 ICRC

The ICRC regulates standing offer electricity prices for small customers in the ACT. Under the ICRC's framework, retail costs are inclusive of CTS and customer acquisition and retention costs.

The ICRC released its final price direction for the 2024-27 regulatory period in May 2024. It estimated customer weighted average retail operating costs using data from the three largest retailers operating in the ACT. However, due to the small sample size, accuracy of data concerns and commercial in confidence considerations, ICRC cross-checked the retail operating costs of ActewAGL (the regulated retailer) against those reported by the AER in its Default Market Offer (DMO), as well as the ESC's decision on the Victorian Default Offer (VDO). ActewAGL's retail operating costs are adjusted by CPI each year.

The ICRC's approved retail costs per customer is $172.70 ($2023-24).

4.7.2.2 ESC

Under the ESC's cost stack framework, retail costs are comprised of retail operating costs and customer acquisition and retention costs. Retail operating costs are calculated as the weighted average of Victorian retailers' actual operating costs, using data from the previous two financial years, adjusted for inflation. Regarding customer acquisition and retention costs, the ESC uses the ACCC's 2013-14 retail and electricity pricing inquiry as a benchmark, also adjusted for inflation, with the ACCC's inquiry considered to be more robust than the retailer customer acquisition and retention data.

The ESC's approved retail costs per customer is $186 ($2023-24).

4.7.2.3 AER

The AER sets the DMO for South-East Queensland, South Australia and New South Wales. In the AER's final decision for the DMO in 2024-25, retail costs are made up of CTS, cost to acquire and retain customers, smart meter costs and bad and doubtful debt costs.

The AER benchmarked the CTS and cost to acquire and retain customers by region using the ACCC's Inquiry into the National Electricity Market - December 2023 report.

The AER's approved retail costs per customer range from $142 to $183 ($2022-23).

4.7.2.4 QCA

The costs of supplying electricity in regional Queensland are much greater than in south-east Queensland (SEQ). For this reason, the Queensland Government implemented the Uniform Tariff Policy (UTP), which is a subsidy to ensure that customers in regional Queensland do not pay more for electricity than customers in SEQ. QCA sets prices for regional Queensland based on the cost of supplying small customers (residential and small business) in SEQ, which is an unregulated competitive market. This arrangement benefits regional customers, who would otherwise incur much greater prices for electricity.

QCA takes a different approach to setting notified prices compared with other regulators. Its methodology is broadly split in two - a network component and a retail component. To ensure consistency with the UTP, standard retail tariff costs for small customers are based on the competitive Energex distribution area of SEQ. The retail component is comprised of energy costs (wholesale electricity costs, Renewable Energy Target and energy losses), metering services and retail costs (operating costs and a retail margin). Both energy and retail costs are assessed by consultants.

The QCA does not separate retail operating costs (i.e. CTS) and the retail margin. The Regulator is therefore unable to make use of the QCA's methodology when setting Aurora Energy's CTS.

The QCA's retail costs represent 7.25 per cent of a residential customer's bill and 18.7 per cent of a small business customer's bill.

4.7.3 Summary of outcomes from benchmarking

The Regulator considers ActewAGL's CTS to be an appropriate benchmark for Aurora Energy's CTS.

4.8 Draft decisions

Considering the outcomes from the Regulator's analysis of Aurora Energy's costs and the results from inter-jurisdictional benchmarking, the Regulator's draft decision is to use ActewAGL's benchmarked figure of $172.70 ($2023-24) as Aurora Energy's CTS for 2025-26.

This figure is approximately $23 per customer lower than proposed by Aurora Energy, but around $10 higher than Aurora Energy's CTS allowance per customer in 2024-25 ($2023-24).

It is also similar to the CTS of $174.67 ($2023-24) estimated by the Regulator based on its analysis of Aurora Energy's costs.

For the purposes of this report and the calculation of the indicative NMR, the Regulator has indexed ActewAGL's CTS of $172.70 ($2023-24) to express it in $2025-26, as shown in the Table 4.7.

Table 4.7: Regulator's draft CTS allowance for 2025-26 ($2025-26)

	Per customer	Total
CTS	$184.58	$49.874 m

An updated indicative CTS allowance for 2025-26 will be included in the Regulator's Final Report and Price Determination and will be expressed in current year dollars.

However, the final CTS allowance for 2025-26 will not be determined until June 2025 when the Regulator considers Aurora Energy's pricing proposal for that financial year.

As set out in the draft Price Determination, the final CTS allowance for 2025-26 will be indexed for 2026-27 and 2027-28 to take account of inflation, including wage inflation as follows:

- using Tasmania's Wage Price Index (ABS Cat No. 6345.0) to index Aurora Energy's labour cost components; and
- using the Hobart Consumer Price Index (ABS Cat No. 6401.0) to index all non-labour cost components.

5 RETAIL MARGIN

The retail margin is intended to compensate Aurora Energy for the risks it faces providing retail services to customers on standard retail contracts.

Under Section 40AB(1)(b) of the ESI Act, the Regulator is to:

> "…take into account the principle that the maximum prices that may be imposed by the retailer under standard retail contracts in respect of small customers are to be such as will enable the retailer, after the operational costs are taken into account, to make a reasonable return on its investment in respect of the provision of standard retail services, taking into account the risk of making that investment."

As Aurora Energy is an electricity retailer rather than an infrastructure business it is not required to maintain a regulated asset base and therefore it does not receive a return on capital.

However, the retail margin is designed to allow Aurora Energy to recover financing and depreciation costs that are not otherwise accounted for in its NMR. For example, the retail margin for the current regulatory period covered depreciation on capital expenditure relating to the previous billing system. Further, as discussed in Chapter 4, depreciation on the costs associated with the implementation of Aurora Energy's new cloud-based billing system are included in the retail margin for the next regulatory period.

The retail margin is included in Aurora Energy's NMR and is therefore reflected in standing offer prices approved by the Regulator.

5.1 Current regulatory period

For the current regulatory period, the Regulator used a benchmarking approach in setting the retail margin. This took into account the Regulator's assessment of the risks Aurora Energy may face in Tasmania compared with retailers operating in other jurisdictions, including energy price risk and volume-related wholesale electricity price risk.

Having considered national trends and Aurora Energy's risks, the Regulator decided on a retail margin based on 5.25 per cent of approved costs over the past two years. The percentage chosen was the mid-point between the minimum of 4.8 per cent estimated by Frontier Economics[29] and Aurora Energy's retail margin at the time.

Prior to the 2022 Determination, the retail margin was applied to the sum of the cost components. This meant that any increase in costs led to a bigger retail margin in dollar terms and vice versa. The Regulator considered that there was no justifiable basis for the total retail margin varying directly with movements in Aurora Energy's costs and decided to calculate the retail margin on a dollar amount per customer basis for the current regulatory period. Specifically, the margin was calculated as 5.25 per cent of the average of the costs the Regulator approved for 2020-21 and 2021-22.

The retail margin allowances for the current regulatory period are set out in Table 5.1.

Table 5.1: Regulator approved retail margin per customer in 2022-23, 2023-24 and 2024-25 (nominal)

	2022-23	2023-24	2024-25
Retail Margin	$100.90	$108.38	$112.68

5.2 Regulator's approach for the 2025 Determination

As set out in the Final Methodology Paper, the Regulator has decided to continue to apply a benchmarking approach to setting the retail margin. Under this approach, the following have been taken into account:

- the retail margins set by other regulators;
- Aurora Energy's risks compared to the risks facing retailers operating in other Australian states and territories; and

[29] Frontier Economics, Retail Costs and Margin: A report for the Essential Services Commission, April 2019.

- the outcomes from the ACCC's Inquiry into the National Electricity Market.

The Regulator also examined calculating the retail margin as a fixed dollar amount or as a combination of a fixed amount and a percentage of costs and decided to further consider this issue during the pricing investigation.

5.3 Other regulators' approaches

The following is a summary of arrangements in other jurisdictions.

5.3.1 ICRC

The ICRC has previously used a benchmarking approach when determining a retail margin and expressed this as a percentage of costs. However, in its final determination for 2024-27, it has used a different approach. The ICRC engaged Frontier Economics to examine a benchmarking approach and an expected returns approach to assess an appropriate retail margin.

Frontier's benchmarking results indicated that regulatory allowances, except for the AER, have been between five per cent and six per cent. The AER's retail allowance generally 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. Hence, Frontier did not include the AER's decisions in its benchmark.

The expected returns approach estimates the minimum retail margin required to compensate equity investors in a notional electricity retailer for the systematic or non-diversifiable risk (such as economic, political, or social risks) that they bear when committing equity capital to the firm.

Using this method, Frontier found an acceptable range for the retail margin of 4.5 per cent to 5.9 per cent of total revenue, with a midpoint of 5.2 per cent. This is equivalent to a range of 4.7 per cent to 6.3 per cent of cost of goods sold, with a midpoint of 5.5 per cent.

Frontier Economics also explored the impact of using either a percentage margin or a fixed dollar margin. It considered that a retail margin as a percentage ignores that increasing energy costs reduce the risk faced by the retailer and so overcompensates the retailer, whereas a constant margin as a dollar amount ignores that some fixed costs have increased so that the retailer is undercompensated as energy costs increase. Frontier Economics concluded that a hybrid approach, giving equal weight to both the percentage margin and the dollar margin, appears to provide appropriate compensation.

In its final decision, the ICRC used the midpoint of the expected returns approach estimated by Frontier Economics. This equated to a percentage of 5.5 per cent of total costs (excluding the margin) and was a decrease from the previous regulatory period where a retail margin of 5.6 per cent was approved.

The ICRC also decided to calculate the margin using a 50:50 weighting for the percentage and dollar amount. The ICRC considered that this approach provides a more reasonable balance between providing a return to retailers and more stable prices for consumers than its previous approach of only using a percentage margin. The fixed dollar amount was based on the approved costs over the past five years.

As a result of using this hybrid approach, the ICRC's retail margin was approximately $128 per customer in 2024-25.

5.3.2 ESC

In its final decision for 2024-25, the ESC decided to continue using a benchmarking approach when setting the retail margin and to retain the same margin, 5.3 per cent of costs, as was applied in 2023-24.

To ensure that the margin was still appropriate, the ESC considered the following factors:

- margins set by other Australian regulators;
- a comparison of Victorian market offer prices relative to Victorian Default Offer (VDO) prices;
- analysis prepared by Frontier Economics on the expected returns approach; and
- Victorian retailers' actual margins and actual margins of retailers operating in the NEM as presented in the ACCC's Inquiry.

In 2024-25, the ESC's retail margin was $80 per customer.

5.3.3 QCA

The QCA does not provide a specific allowance for a retail margin. Rather, the QCA's approach focuses on estimating an efficient level of retail costs, which includes a retail margin component.

5.3.4 AER

In its final determination for the 2024-25 DMO, the AER estimated an 'efficient margin' by using a number of different approaches, including the analysis of:

- retailer margins inferred from customer weighted average prices retailers charge market offer customers;
- retailer margins inferred from offers to new customers; and
- ACCC analysis of actual retailer margins as set out in its December 2023 report.[30]

As a result of this analysis, the AER decided to set the retail margin as a percentage of DMO costs; six per cent for residential customers and 11 per cent for small business customers. These margins are lower for most customers compared to the previous year's determination.

Having regard to economic conditions, cost-of-living pressures and energy affordability issues experienced by consumers, the AER did not include a competition allowance in its 2024-25 DMO.

In 2024-25, the AER's retail margin allowance ranged from $109 to $175 per residential customer.

5.3.5 ACCC

The ACCC's 2019 Inquiry into the National Electricity Market presented, by jurisdiction for 2018-19, the actual retail margins achieved by electricity retailers. The ACCC used data obtained directly from retailers through the use of its information gathering powers. This information is not otherwise publicly available.

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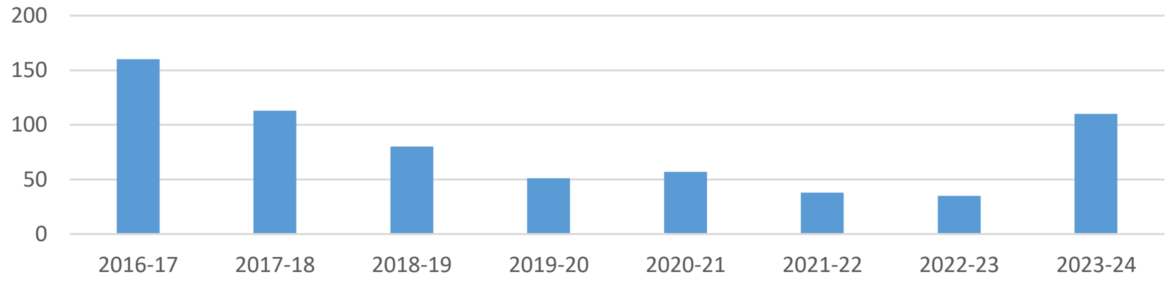
[30] ACCC, Inquiry into the National Electricity Market, December 2023.

In its updated NEM report released in December 2024, the ACCC estimated an average retail margin of $110 per residential customer in 2023–24 (Figure 3.13 in the ACCC's report).

Figure 5.1: Estimated retail margin per average residential customer in the NEM ($/customer)



Source: ACCC Inquiry into the National Electricity Market (December 2024), page 74.

As shown in Figure 5.1 and according to the ACCC's report, there has been a sharp increase in the average retail margin in 2023-24. The ACCC considers that the increase could have been driven by unique circumstances in this year. Higher overall costs, primarily driven by wholesale costs, caused most retailers to increase their prices from July 2023. However, the ACCC considers that some retailers were able to avoid some of these cost increases which could have created an opportunity to set retail prices that were competitive with their rivals while earning higher margins. Importantly, the ACCC's report also found that the average retail margin in the NEM was heavily influenced by the retail margin of the largest three retailers. On average, the margin of the largest three retailers increased from $14 per customer in 2023-23 to $120 per customer in 2023-24. This was significantly higher than the average margin for smaller retailers which, on average, reduced from $87 per customer in 2022-23 to $84 per customer in 2023-24.

However, the ACCC findings need to be treated with caution as the following factors limit using those findings to inform the determination of Aurora Energy's retail margin:

- The retail margin estimated by the ACCC was the difference between electricity retailers' reported revenues and costs. This difference for any one year may not be a reliable benchmark for setting regulated retail margins. For example, the ACCC reported that, for 2021-22 and 2022-23, retail margins in South-East Queensland were negative.

- Many large retailers in the NEM, including the three largest retailers, are vertically integrated companies that operate generation and retail businesses. During 2023-24, the ACCC considered that vertically integrated retailers might have had some cost advantages due to the natural hedge that generation assets provide against high wholesale prices.
- The retail margin estimated by the ACCC is based on past data and does not necessarily mean that average margins will continue to increase in the future. Indeed, due to the unique circumstances in 2023–24 and relatively lower margins in recent years, the ACCC considers it is unclear whether increased profitability, on average, will persist in the medium term.

5.3.6 Summary

A variety of approaches to calculating the retail margin are applied in other jurisdictions. These are summarised in the table below.

Table 5.2: Summary of approaches to calculating the retail margin in other jurisdictions

	Approach	Margin per customer
ICRC	5.5 per cent of costs using a 50:50 weighting for the percentage:dollar amount	$128 in 2024-25
ESC	5.3 per cent of costs	$80 in 2024-25
QCA	No specific allowance for a retail margin	n/a
AER	Six per cent of costs	Range of $109 to $175 in 2024-25

Frontier Economics	Using an expected returns approach, Frontier Economics consider an acceptable range for the retail margin to be 4.5 per cent to 5.9 per cent of total revenue	n/a
ACCC	Actual margins of retailers operating in the NEM	$110 in 2023-24

5.4 Discussion of risks

As set out in the Final Methodology Paper, the Regulator decided to continue to adopt a benchmarking approach to setting the retail margin that takes into account the risks faced by Aurora Energy. This is also consistent with the requirement in the ESI Act which refers to Aurora Energy making a reasonable return on its investment, taking into account the risks it faces in making that investment.

The Regulator has therefore examined the specific risks that Aurora Energy faces.

5.4.1 Energy price risk

Retailers operating in the NEM are required to purchase electricity through the wholesale spot market. To manage the risks associated with variations in wholesale energy prices, retailers and generators enter into financial risk contracts. Retailers in other NEM jurisdictions have more liquid forward contract markets than those available to retailers operating in Tasmania.

As set out in Chapter 6, there is extensive regulation of the wholesale electricity price (WEP) in Tasmania under the Wholesale Contract Regulatory Instrument (Instrument). The Instrument is designed to replicate the type of products that are available in other NEM jurisdictions with more liquid forward contract markets.

Under the Instrument, specified minimum volumes are set for products, such as load following swaps[31], for future quarters up to two years ahead. To the extent that any one product is not taken up by market participants, greater quantities of the other products must be offered.

The Regulator calculates the WEP that is used in setting standing offer prices each year using the prices of future load following swaps offered over the previous eight quarters as set out in the Regulator's Standing Offer Price Approval Process Guideline.

Importantly, Aurora Energy knows in advance how the Regulator will calculate this WEP. This is unlike how wholesale electricity costs are estimated by the AER for default market offers, where draft forecasts of wholesale costs are prepared by a consultant and the costs are subject to a public consultation process.

Aurora Energy can adopt purchasing strategies, using the load following swap offers from Hydro Tasmania under the Instrument, to reduce its wholesale electricity price risk for a specified volume of electricity such as its forecast total load. The provisions in the Instrument that relate to the volumes of products that Hydro Tasmania must offer therefore assist Aurora Energy in managing its wholesale electricity price risk.

As noted in its submission, Aurora Energy does face the risk that the Regulator may change the Guideline such that the purchasing strategy that Aurora Energy may have commenced would no longer result in the average wholesale price it pays being similar to the WEP. As discussed in Chapter 6, the Regulator is also proposing a new method for calculating the WEP. However, the Regulator is also proposing that the new method would not commence for the first year of the next regulatory period to allow retailers (including Aurora Energy) time to adjust their wholesale contracting arrangements.

Based on the preceding discussion, the Regulator has concluded Aurora Energy can adopt a range of strategies to manage its wholesale electricity price risks, including purchasing unregulated products from Hydro Tasmania or not hedging some spot market purchases.

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[31] A load following swap sets the price that Tasmanian electricity retailers pay to purchase a certain amount of electricity in a given future quarter of the year at a certain time interval of the day.

Resultingly, these risks are not significantly different from those faced by other retailers operating in Tasmania or in other Australian jurisdictions.

5.4.2 Volume-related price risks

Aurora Energy also faces a set of risks relating to the volume of electricity it sells and the number of customers it has.

As for all retailers, Aurora Energy commits to meeting the entire load of its customers at a set price, but it does not know in advance what this load will be at different times of any day or over every day, week or month of each year of the regulatory period.

As discussed in the previous section, for a specified volume of electricity, Aurora Energy can adopt a purchasing strategy that would result in the average price it pays for its wholesale electricity being very similar to the WEP. However, the actual load in any quarter or over the year may be quite different from the forecast load, which requires Aurora Energy to enter into contracts and adopt other strategies to manage the price risks associated with this volume uncertainty.

Factors that affect Aurora Energy's load include changes in customer numbers, changes in the volume of electricity used by each customer and changes in the load profile as a result of variations in weather, the installation of energy efficiency measures and changed patterns of work due to, for example, more people working from home.

In its Submission, Aurora Energy stated that competition in Tasmania has steadily grown and that it remains highly exposed to the threat of existing and potential new participants.[32] However, around 94 per cent of all residential and small business customers in Tasmania are Aurora Energy's customers. This is a much larger share of the retail electricity market than any mainland retailers hold in their respective retail electricity markets.

Further, Aurora Energy does not currently face, nor has it faced in the past, competition from any of the 'Big Three' retailers. Additionally, to date, no other retailers in Tasmania are competing on price. In practice,

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[32] Aurora Energy, Preliminary Submission - 2025 Price-regulated Retail Service Pricing Investigation, November 2024, page 28.

Tasmanian standing offer prices are presently a de facto reference price other retailers use to price their tariffs off.

The Regulator has therefore concluded that Aurora Energy is subject to less risk of large-scale changes in load and customer numbers due to customer switching compared to other retailers operating in the NEM.

The Regulator accepts that, in the absence of liquid and competitive forward contract markets, Aurora Energy faces some additional risks, such as potentially not being able to sell contracts in Tasmania if it finds itself in a long contract position.

Considering these factors, the Regulator has concluded that, with respect to electricity sales, Aurora Energy does not face volume-related risks that are significantly different from the volume-related risks faced by other retailers across Australia.

5.4.3 Other risks

Aurora Energy faces risks that are faced by all electricity retailers including unexpected increases in operating costs.

In relation to the treatment of some cost components, the Regulator has concluded that Aurora Energy may face lower risks than many mainland retailers.

For example:

- For some cost components that are based on estimated values, if the actual costs are greater, Aurora Energy is able to recover, with the Regulator's approval, the difference in the following year. Many retailers in competitive markets would be reluctant to increase their prices to recover unanticipated costs if there is strong price competition and so would wear the revenue loss. Therefore, across years, Aurora Energy has greater certainty that it will be able to recover its costs than retailers in competitive markets.
- Aurora Energy is able to seek the Regulator's approval of adjustments to compensate it for the impacts of a material change in its costs or tax changes.

Alternately, the Regulator acknowledges that Aurora Energy has a relatively small number of market offer electricity customers and gas customers to recover its costs from and, by Ministerial direction, is unable to operate outside Tasmania. In comparison, larger NEM retailers can spread costs and risks over a larger customer base and over a wider range of activities.

The Regulator also acknowledges that, as a standalone retailer, in some areas Aurora Energy faces more risks than retailers that are part of a vertically integrated enterprise.

In its Submission, Aurora Energy stated that due to historical government intervention in price setting, it faces further risks due to its inability to set cost-reflective tariffs. As part of its draft regulated tariff strategy, the Regulator notes that Aurora Energy has proposed tariff rebalancing to help address these issues. This is discussed further in Chapter 3.

5.4.4 Summary

It is not straightforward to compare Aurora Energy's risks with the risks faced by other electricity retailers operating in the NEM given the features of the Tasmanian electricity market, including the regulatory arrangements for wholesale electricity.

Nor is it straightforward to quantify Aurora Energy's risks or determine the impact of specific risks in the context of determining Aurora Energy's retail margin.

As discussed, the Regulator has concluded that Aurora Energy faces lower risks than other retailers operating in the NEM in some areas but faces higher risks in other areas.

However, on balance, the Regulator's draft conclusion is that Aurora Energy's risks are, on average, not significantly different from risks faced by other retailers across Australia.

5.5 Options

Having considered the arrangements in other jurisdictions and risks that Aurora Energy faces, the Regulator has examined three options for calculating the retail margin.

These options are:

1. Aurora Energy's proposal of a 5.5 per cent margin with 50 per cent a fixed dollar amount and 50 per cent variable;

2. Hybrid approach - retain the current 5.25 per cent margin, with a fixed dollar amount and percentage of costs; and

3. Fixed dollar amount - retain the current 5.25 per cent margin.

Each of these options are discussed below.

1. Aurora Energy's proposal

In its submission, Aurora Energy proposed a 5.5 per cent retail margin and that 50 per cent of the margin be fixed and 50 per cent variable. The fixed portion of the margin is based on 5.5 per cent of the average of Aurora Energy's approved costs (excluding its margin) in the two most recent years and the variable proportion is based on 5.5 per cent of approved costs in the current year.

Aurora Energy has estimated that this approach results in a retail margin of approximately $125 per customer in 2025-26 as set out in Table 5.3.

Table 5.3: Retail margin under Aurora Energy's proposal

Advantages	Disadvantages
As noted by the ICRC and Frontier Economics, this option strikes a balance between providing a return to retailers and stable prices for consumers.	The estimated margin would be approximately $12 per customer higher than the retail margin approved by the Regulator for 2024-25.
	A portion of the retail margin would vary directly with movements in Aurora Energy's costs.

2. Hybrid approach - fixed dollar amount and percentage of costs

Under this option, the proposed retail margin is 5.25 per cent (the current margin) and 50 per cent of the margin would be fixed and 50 per cent variable. The fixed proportion of the proposed margin is based on 5.25 per cent of the average of Aurora Energy's approved costs (excluding its margin) over the past five years and the variable proportion is based on 5.25 per cent of approved costs in the current year.

The retail margin under this option is estimated at $117 per customer in 2025-26 as set out in Table 5.4.

Table 5.4: Retail margin under the hybrid approach

Advantages	Disadvantages
This option strikes a balance between providing a return to retailers and stable prices for consumers.	The estimated margin would be approximately $4 per customer higher than the retail margin approved by the Regulator for 2024-25.
The retail margin is calculated using data over five years and so is not unduly influenced by data from a particular year.	A portion of the retail margin would vary directly with movements in Aurora Energy's costs.

3. Fixed dollar amount

Under this option, the proposed margin is based on 5.25 per cent of the average of Aurora Energy's approved costs (excluding its margin) over the past five years. This is the same as the current approach except that the retail margin is based on average costs over the past five years instead of two years.

The retail margin under this option is estimated at $117 per customer in 2025-26 as set out in Table 5.5.

Table 5.5: Retail margin under the fixed dollar amount approach

Advantages	Disadvantages
The retail margin would not vary directly with movements in Aurora Energy's costs.	The estimated margin for 2025-26 would be approximately $4 per customer higher than the retail margin approved by the Regulator for 2024-25.
The retail margin is calculated using data over five years and so is not unduly influenced by data from a particular year.	Expressing the margin as a fixed dollar amount ignores that some fixed costs may increase so that the retailer is undercompensated as energy costs increase.

As noted, each of these options has advantages and disadvantages. The Regulator acknowledges that this list of options is not exhaustive.

5.6 Summary

The ESI Act requires the Regulator to allow Aurora Energy to receive a reasonable return on the investment it has made in its retail electricity business.

Given that one of the Regulator's statutory objectives is to promote competition, setting the retail margin too low may stifle the development of competition, making the Tasmanian market less attractive for existing and prospective retailers. Conversely, setting the retail margin too high may result in customers paying more than they should.

The Regulator also acknowledges that Aurora Energy's retail margin allowance was reduced significantly in the 2022 Determination to reflect, in part, national trends at that time.

5.7 Draft decision

The Regulator's draft decision is to set the retail margin based on Option 2, hybrid approach - fixed dollar amount and percentage of costs, with a retail margin of 5.25 per cent.

Under this option, the margin:

(a) strikes a balance between providing a return to retailers and stable prices for consumers; and

(b) is based on Aurora Energy's costs over five years.

The Regulator's indicative retail margin for Period 1 (2025-26) is shown in Table 5.6.

Table 5.6: Regulator's draft decision – Retail margin

2025-26	Per customer	Total ($m)
Retail margin	$117	$31.61

The Regulator also intends indexing the fixed component of the retail margin by the Hobart CPI in each of the second and third years of the next regulatory period.

The retail margin to apply for each year of the next regulatory period will be determined as part of the annual standing offer price approval process in May each year prior to the commencement of each of those periods. The calculated retail margin will then be used to calculate the NMR for each of those periods.

6 WHOLESALE ELECTRICITY COSTS

6.1 Background

Under the 2022 Determination, the estimate of the wholesale energy costs (WEC) component of the NMR is based on the wholesale electricity price (WEP), forecast customer load and distribution and marginal loss factors. The methodology for calculating the WEP is set out in a standing offer guideline issued by the Regulator for each regulatory period.[33]

The WEP may differ from the overall price Aurora Energy actually pays for wholesale electricity which will be determined by spot prices and its hedging strategy for the financial year in which the prices will apply.

Hydro Tasmania is the dominant generator in Tasmania and controls the majority of the generation capacity in the State. Consequently, Hydro Tasmania is the sole provider of financial hedge contracts for the Tasmanian region of the NEM. In response to perceptions about Hydro Tasmania's market power, the Tasmanian Government has, since 2014, required Hydro Tasmania to offer regulated wholesale financial contracts at regulated prices to authorised retailers operating in Tasmania.

Section 43G of the ESI Act requires Hydro Tasmania to offer four financial risk contract types, approved by the Regulator, with the objective of providing retailers in Tasmania with similar conditions and levels of risk as retailers operating in other regions of the NEM. The details of each approved financial contract type, including how prices are calculated, are specified in the Instrument. The Instrument documents a rule-based methodology for calculating the prices for each contract type in the wholesale pricing model.

Section 43G(3) of the ESI Act requires the Regulator to approve a regulated load following swap contract (LFS) as one of the approved

[33] The current guideline is the *Standing Offer Price Approval Process in Accordance with the 2022 Standing Offer Price Determination*.

contract types. The LFS sets the price that Tasmanian electricity retailers pay to purchase a specific volume[34] of electricity for each trading interval in a given future quarter of the year. Importantly, the regulated LFS differs from the electricity spot price and is a product available to retailers to mitigate the risks of paying spot prices for the electricity they need to meet their customer's demand

Section 40AB(3) of the ESI Act requires WEP, and therefore the wholesale electricity costs, must be based on regulated LFS prices.

6.2 Approach for the current regulatory period

For the current regulatory period, the Regulator calculates the WEC as follows:

$$WEC_y = (\text{forecast load}_y \times WEP_y \times DLF_y \times MLF_y)$$

Where:

forecast load_y	=	an estimate of the volume of electricity a retailer must purchase in the spot market to supply small customers for period_y
WEP_y	=	wholesale electricity price for period_y as calculated by the Regulator using the method set out in the Standing Offer Price Approval Guideline
DLF_y	=	load weighted average distribution loss factor for period_y
MLF_y	=	load weighted average marginal loss factor at the regional reference node for Tasmania for period_y

[34] The volume is defined in clause 2 of Schedule 3 of the Wholesale Contract Regulatory Instrument.

In relation to the calculation of the WEP, section 40AB(3) of the ESI Act states that:

> The *wholesale electricity costs* of a regulated offer retailer in relation to the provision of standard retail services consist of the costs of the retailer in purchasing electricity for the purposes of providing those services, including any adjustment to the costs that would be made if the regulated offer retailer and the Hydro-Electric Corporation were to enter into a contract that –
>
> > (a) was a contract in an approved standard form determined under section 43G(1) for a load following swap; and
> >
> > (b) contained prices calculated in accordance with the approved methodology in relation to contracts in that approved standard form; and
> >
> > (c) related to the same number of units of electricity as the number of units of electricity purchased by the retailer for the purposes of providing those services.

Consequently, the Regulator is required to calculate a WEP based on the regulated LFS where the price is set in cents / kWh and in $ / MWh based on a specified load profile.

Since 2014, the Regulator has calculated the WEP using a weighted average of 104 weeks (i.e. eight quarters) of LFS prices prior to the start of each quarter of the next regulatory period having regard to the volume for each quarter as specified in Schedule 1 of the Instrument.

As the Regulator calculates the WEP in the third week in May, there are no LFS prices available for approximately 25 percent of the weeks prior to the start of each quarter. For all future weeks for which there is no regulated LFS price at the time the Regulator calculates the WEP, the Regulator uses the price in the third week in May for all the remaining weeks in each of the four quarters for which prices are required. That is, five weeks for Q1, 18 weeks for Q2, 31 weeks for Q3 and 44 weeks for Q4 so that there are 104 LFS prices for each quarter.

Appendix 4 shows, in diagram form, how the Regulator currently calculates the WEP using this methodology.

6.3 Other regulators' approaches

To estimate future wholesale electricity costs in their respective cost build-ups, each of the ESC, the AER, ICRC, and QCA use an electricity futures market-based approach and engage consultants to assist with this task. For example, the ICRC estimates energy purchase costs by calculating the average of NSW electricity futures prices, plus an uplift factor that compensates for the spot price volatility risk in the NEM.

In calculating wholesale electricity prices for 2024-25, regulators in other jurisdictions used the ASX listed contract price as follows:

- ESC used trade weighted ASX Energy contract prices from the previous 12 months, with prices as at the last Friday in April used as the final price.
- AER and QCA used trade weighted average daily ASX Energy contract prices from the date the contract was listed until 3 May 2024.
- ICRC used the 23-month average of ASX Energy contract prices from 1 June 2022 to 30 April 2024.

In summary, regulators in other jurisdictions estimate wholesale electricity prices for the following year at an earlier point in time than the Regulator currently does in Tasmania. This is discussed further in the following section.

6.4 Calculation of the WEP

For the current regulatory period, the Regulator has calculated the WEP in accordance with the method outlined in clause 4.1(1) of the Guideline. Under this method, the Regulator is required to calculate and provide the WEP to Aurora Energy on or before 24 May each year.

6.4.1 Review of the approach to regulating retail electricity prices

In its Draft Methodology Paper, the Regulator presented analysis on changing the timing of the WEP calculation. Three approaches were assessed:

1. The current method - the WEP is calculated in the last week in May and that week's prices are used in the WEP calculation for all weeks for which prices are not yet available;

2. April calculation - using the same method as currently but using the last Tuesday in April as the cut-off point to calculate the WEP for the following year; and

3. Historical price method[35] - the current method except that there are no prices and no volume for any of the weeks after the WEP calculation date.

During consultation on the Draft Methodology Paper, stakeholders presented mixed views on the options for calculating the WEP. Both Aurora Energy and Hydro Tasmania supported retaining the current approach, while the Tasmanian Small Business Council and Solstice Energy supported changing to the historical price method.

In its Final Methodology Paper, the Regulator considered that the historical price method had merit and stated that it intended consulting further on this method with stakeholders, including other electricity retailers, during the pricing investigation.

6.4.2 Consultation with stakeholders

In its Submission, Aurora Energy stated that:

- its preferred approach to calculating the WEP is the current method, and it does not support a change to the historical price method;
- volume weighted costs to hedge the Tasmanian small customer load profile are fully reflected in the WEP calculation;
- it is not supportive of any change to the WEP methodology that comes into effect prior to 1 July 2027 at the earliest; and

[35] This method was referred to as the 'No future price method' during the Regulator's methodology review.

- consultation on changes to the WEP, the timing of any such changes, and risks associated with these, should be focused on Aurora Energy.

In its submission on the Draft Methodology Paper, Solstice Energy supported adopting the historical price method in order to reduce the reliance on a forecast when calculating the WEP and considered that May is a more relevant time to carry out this calculation. Solstice Energy commented that as marginal loss factors are only available in late May / early June for the following year, it may be prudent to maintain the current timing of the WEP calculation. Further, it commented that the Tasmanian contract prices have been known to lag Victorian contract market in recent years. Therefore, it considered that setting the WEP in May, in effect, uses Victorian prices from late April.

The Regulator also raised this issue with other retailers, which considered that using the LFS price from the calculation date for future weeks after that date is not representative of the price a retailer may face and estimating the LFS price in this way introduces risks to retailers.

Further, both Solstice Energy and 1st Energy suggested that any change in the WEP methodology should only come into effect after at least 12 months into the 2025 Determination period to account for retailers' hedging arrangements. Solstice Energy considered that, due to the averaging nature of how the WEP is currently set, any changes made to the WEP methodology will have an adverse impact on retailers' management of hedging risks for the 2025-26 financial year, which would effectively have been hedged by then on the assumption that the approach applied under the 2022 Determination for setting the WEP would continue to be used.

6.4.3 Discussion

6.4.3.1 WEP calculation method

In its Final Methodology Paper, the Regulator considered that the WEP is based on the premise that prudent retailers use forward contracts to reduce their exposure to volatile spot prices.

However, the Regulator also acknowledged that there is no perfect method for estimating the WEP and using an historical LFS price for future weeks, which is currently the case, is not ideal.

The issue with the current method is that around 25 percent of the prices used to calculate the WEP are not based on market derived prices for the relevant future weeks. Therefore, using the prices from a single week, or even the average of several weeks, to populate the remainder of the weeks under the current method gives a false indication as to the precision applied to the determination of the WEP. That is, this approach implies prices in future weeks are forecast prices.

Furthermore, the wholesale electricity market is volatile with weekly prices often fluctuating considerably. Therefore, using a single week's prices gives undue weighting on one price which may not be reflective of the general price trend. The proposed method reduces the likelihood of the WEP being affected by isolated events and does not make an implicit assumption about future prices.

The historic price method also aligns with other regulators' methods of determining the wholesale prices as summarised in section 6.3.

Having considered retailers' views on this matter, regulators' practices in other jurisdictions, and the Regulator's own analysis, the Regulator intends adopting the historical price method for the annual WEP calculation. The Regulator acknowledges that the new method is subject to some implementation details being worked out.

6.4.3.2 Timeframes for applying the historical price method

In accordance with the requirements set out in the Instrument, Hydro Tasmania is required to offer approved wholesale contracts for eight future quarters.

The Regulator acknowledges the feedback provided by retailers that any change in the calculation of WEP may impact on retailers' management of hedging risks in the first year of the next regulatory period.

6.4.3.3 WEP calculation - applicable volume

Noting that LFS set the price for wholesale electricity in a future quarter, the WEP calculation is a weighted average of two years of historic LFS prices for each quarter of the year in which the regulated prices will apply.

As the standing offer prices apply only to small customers, the prices in the WEP are weighted by an estimate of the volume of small customer load for each week in each quarter. Since the introduction of the Instrument, the Regulator has used the weekly Absolute Minimum Capacity Offer volume in the Instrument as the relevant volume number.

However, the continuing changes in the electricity market means possible changes to the Instrument that could result in the weekly Absolute Minimum Capacity Offer volume no longer being an appropriate volume. As there is no alignment between the timing of next standing offer pricing investigation and the next Instrument investigation, the Regulator considers it prudent to include an alternative mechanism for determining the applicable volume in the WEP calculation. Consequently, the Regulator proposes to use an average of two years of historic small customer load as provided by retailers operating in the Tasmanian small customer market.

6.4.3.4 Regulator's draft decision - WEP

Based on the feedback provided by retailers, applying the methodology set out in the Regulator's draft guideline and using the data available as at 14 January 2025, the Regulator's estimated WEP for 2025-26 is shown in Table 6.1.

The Regulator also intends stating in the standing offer guideline for the next regulatory period that the WEP will be calculated under the current method for the 2025-26 financial year and under the historical price method for the 2026-27 and 2027-28 financial years (see further discussion on this in Chapter 13).

Table 6.1 Regulator's draft decision – Wholesale Electricity Price

	2025-26
WEP	7.760 c/kWh

6.5 Draft decision

Applying the Regulator's draft decisions with respect to loss factors, load and the WEP, and the formula set out in section 6.2 of this report, the Regulator's indicative WEC for 2025-26 is shown in Table 6.2.

Table 6.2 Regulator’s draft decision – Wholesale Electricity Costs

	2025-26
WEC ($m)	$181.88

The WEP to apply for each year of the next regulatory period will be determined as part of the annual standing offer price approval process in May each year prior to the commencement of each of those periods. The calculated WEPs will then be used to calculate the WEC and the NMR for each of those periods.

7 NETWORK COSTS

7.1 Background

Network costs comprise transmission use of system and distribution use of system charges.

Network costs are regulated by the AER. The AER reviews and approves TasNetworks' transmission revenue and distribution regulatory revenue every five years, with the current determination covering the period from 1 July 2024 to 30 June 2029. The AER also reviews and approves TasNetworks' schedule of tariffs each year for compliance with the National Energy Rules (NER) and the five-year regulatory determination. The approved tariffs apply for 12 months from 1 July of each year and are usually set in April or May of the previous year.

Network tariffs comprise a fixed daily charge, consumption charges and, for some tariffs, a demand-based charge. Network tariffs are grouped by network tariff class, which are based on the physical characteristic of the electricity connection (e.g. high voltage) or customer type (e.g. residential or business).

In its Draft Methodology Paper, the Regulator noted that the APA Group Limited (APA), Basslink's current owner, had applied to the AER for approval to convert Basslink from a Market Network Service Provider to a regulated Transmission Network Service Provider (TNSP). Subject to the AER's approval, pricing for Basslink's services would be regulated by the AER for a five-year regulatory control period commencing on 1 July 2025.[36]

In the event that the AER approves APA's proposal, the costs associated with transmission services provided by Basslink could be passed on to small consumers in Tasmania via their retailer.

In its Final Methodology Paper, the Regulator considered that, because the AER's assessment process had not concluded at that time, more

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[36] Australian Energy Regulator, Basslink Conversion Application and Electricity Transmission Determination, November 2023; APA Group, Basslink Transmission Revenue Proposal Attachment 4: Revenue and Pricing Methodology, 15 September 2023, page 114.

information was needed before the Regulator could make a decision on the treatment of these costs should Basslink become a regulated TNSP.

7.2 2022 Determination

The network cost component of Aurora Energy's NMR for the period from 1 July 2022 to 30 June 2025 inclusive was determined by multiplying the applicable TasNetworks' network tariff by forecast billing days and customer load for each retail tariff and then summing the resultant values. The billing days were then reconciled with the forecast of the customer numbers used in the NTB.

If for some reason the charges were not known when the NMR is calculated (e.g. if the AER did not approve TasNetworks' charges in time for Aurora Energy to incorporate the approved charges in its annual pricing proposal), network costs would be based on an estimate of the charges (e.g. based on TasNetworks' draft price proposal) for the next year and then an adjustment would be made in the subsequent year for any difference between the estimated and the actual charges.

7.3 Other regulators' approaches

The approach taken by the ICRC, ESC and QCA in relation to network costs is to pass through the network costs to retailers as calculated by the AER each year. ESC and ICRC allow for adjustments in subsequent periods for these costs where the pass-through costs are based on an estimate at the time of setting prices.

7.3.1 ICRC

The ICRC calculates a per MWh network cost by applying the AER approved network tariffs and prices to customer numbers and electricity consumption for the previous 12 months to 31 March each year.

7.3.2 QCA

The QCA sets retail tariffs to apply in regional Queensland and uses the applicable network prices approved by the AER in determining regulated retail prices:

- For small customers on standard retail tariffs, network costs are based on the costs of supply in Southeast Queensland (Energex distribution area).

- For large customers and small customers on limited access obsolete tariffs, network costs are based on the costs of supply on Ergon Distribution's lowest cost region that is connected to the NEM.

7.3.3 ESC

The approach used in the ESC's Victorian Default Offer varies depending on the distribution zone. The regulated electricity prices in each zone include network prices approved by the AER for the distribution network service provider in that zone. The ESC structures the network costs in one of two ways:

- Flat Network Tariffs: a daily supply charge ($ per day) and a flat usage charge ($ per kWh); or
- Two-period time-of-use network tariffs: a daily supply charge ($ per day) and peak usage and off-peak usage charge ($ per kWh).

7.4 Treatment of costs relating to Basslink

Hydro Tasmania entered into a network services agreement with Basslink Pty Ltd (Basslink) on 21 October 2022.[37] The agreement expires on the earlier of 30 June 2025 or the day Basslink is regulated (unless extended by mutual agreement between Hydro Tasmania and Basslink). The payments made under this agreement are currently unregulated and these costs, therefore, are not currently part of Aurora Energy's NMR.

On 19 May 2023, APA, Basslink's current owner, applied to the AER for approval of a five-year regulatory control period from 1 July 2025 to 30 June 2030 with respect to the regulation of Basslink's services. Specifically, APA:

- proposed converting Basslink's network services from a market network service provider to a prescribed transmission service provider; and
- requested AER commence, and specify, the process of making a transmission determination for Basslink.

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[37] Hydro Tasmania, Updated Basslink agreement (hydro.com.au), 24 October 2022.

On 17 December 2024, the AER released its draft decision which was not to accept Basslink's application to convert its market network service to a prescribed transmission service. The AER considered that the high degree of uncertainty associated with achieving benefits when compared against the significance and irreversibility of the decision is a key reason for the draft decision.[38]

It is possible that the AER's final decision will not be released until after the Regulator's investigation concludes. Therefore, to provide some flexibility, the Regulator intends adding a separate interconnector network cost component to the NMR formula to cater for the possibility that the AER decides to approve APA's application to convert Basslink to a prescribed transmission service provider. Under this approach, there would be two network cost components in the NMR formula - one for the Basslink network costs and one for the remaining network costs.

In the event that the AER's final decision is to regulate Basslink, TasNetworks has advised that these costs would be treated like any other transmission cost and would be proportionally allocated to different customer groups via its network tariffs. Importantly, this indicates that not all Basslink costs would be passed on to customers on standard retail contracts should Basslink become regulated.

Further, section 40AB(4) of the ESI Act states that:

> For the purposes of this section, the transmission and distribution costs of the regulated offer retailer in relation to the provision of standard retail services consist of –
>
> (a) the prices, as determined in accordance with any relevant distribution determination made under the National Electricity Rules, charged to the regulated offer retailer for the distribution of electricity; and
>
> (b) the prices, as determined in accordance with any relevant transmission determination made under the National Electricity Rules, charged to the regulated offer retailer for the transmission of electricity –

38 Australian Energy Regulator, Draft decision - Application for Basslink network service to be described as a prescribed transmission service, 17 December 2024, pages 1-2.

but only in so far as the costs relate to electricity used in the provision of standard retail services.[39] [emphasis added]

Therefore, despite any distribution or transmission determination made by the AER, the Regulator has the power to decide to not pass on network costs that are not required to deliver network services to customers on standard retail contracts.

Should the AER's final decision remain the same as its draft decision to not approve APA's application, the Basslink network cost component would be set at zero. Similarly, should the AER's final decision be to approve APA's application, and should the Regulator consider that TasNetworks' proportion of Basslink costs to be passed through to customers on standard retail contracts is reasonable, then the Basslink network cost adjustment would also be set to zero.

Conversely, should Basslink become regulated, and the Regulator considers that TasNetworks' proportion of Basslink costs to be passed through to customers on standard retail contracts is not reasonable, then the Basslink network cost component would be a negative amount.

The treatment of interconnector-related network costs will likely arise again in the future should the proposed Marinus Link be constructed and commence operation.

Further, the purpose of the proposed Marinus Link is to facilitate the importation of low-cost renewable energy, such as surplus solar, into Tasmania while reserving hydropower and storing the extra energy in the State, so as green hydropower in Tasmania can be exported to the mainland grid when it is needed most.[40] Therefore, unlike Basslink which is required, at least to some extent, to deliver network services to customers paying standing offer prices, the Marinus Link will not be required to deliver those services to these customers.

Due to this fundamental difference in purpose, the Regulator considers that its final decision on the treatment of Basslink costs is unlikely to set a precedent for the future treatment of Marinus Link costs in the context

[39] Standard retail services, in relation to a regulated offer retailer, means services to be provided by the retailer under standard retail contracts in respect of small customers.

[40] Marinus Link Pty Ltd, Overview Marinus Link

of section 40AB(4) of the ESI Act, Aurora Energy's NMR and standing offer prices.

7.5 Draft decision

As the AER's final decision is yet to be released, the Regulator has not been able to make a draft decision on the treatment of Basslink costs.

However, to provide some flexibility, the Regulator intends adding a separate interconnector network cost component to the NMR formula to cater for the possibility that the AER decides to approve APA's application to convert Basslink from a market network service provider to a prescribed transmission service provider after the release of the Regulator's investigation final report and determination. This component would allow the Regulator to decide the extent to which these costs are to be passed through to customers on standard retail contracts.

The Regulator's indicative network costs for 2025-26 are shown in Table 7.1.

Table 7.1 Regulator's draft decision – Network costs

	2025-26
NC ($m)	279.53

The actual network costs to apply for each year of the regulatory period will be determined as part of the annual standing offer price approval process in June each year prior to the commencement of each of those periods. The calculated network costs will then be used to calculate the NMR for each of those periods.

8 RENEWABLE ENERGY TARGET COSTS

8.1 Background

The NMR includes an estimate of the annual costs Aurora Energy incurs complying with the Australian Government's Renewable Energy Target (RET) scheme.

The scheme creates a guaranteed market for renewable energy, using a mechanism of tradable certificates with each certificate representing one-megawatt hour of renewable electricity generated. Electricity consumers pay for this Australian Government requirement through obligations imposed on retailers. Aurora Energy then seeks the Regulator's approval to pass through these costs to customers.

The RET scheme has two elements:

- the Large-scale Renewable Energy Target (LRET); and
- the Small-scale Renewable Energy Scheme (SRES).

The LRET supports the development of large-scale projects such as wind farms. Electricity retailers must purchase and surrender a specific number of Large-scale Generation Certificates (LGCs) each year. The number of LGCs to be surrendered each calendar year is calculated using the Renewable Power Percentage (RPP), which is determined annually by the Clean Energy Regulator (CER), and the quantity of electricity purchased by the retailer.

The SRES supports investment in smaller technologies such as rooftop solar panels and solar hot water systems through the generation of Small-scale Technology Certificates (STCs). The number of STCs that retailers must purchase and surrender over the course of each calendar year is calculated using the Small-scale Technology Percentage (STP) which is also determined annually by the CER.

The RPP and STP are applied to the amount of wholesale electricity purchased by the retailer in a calendar year. In March of each year, the CER publishes the final binding percentages for that calendar year for the RPP and the STP and also issues non-binding STPs for the following two calendar years.

This means that in April or May each year, a retailer cannot estimate with accuracy the quantity of LGCs it must acquit for the following financial year as the RPP is only known up to December in that year.

LGC and STC prices are determined in an open market. However, STCs can also be sold through the STC Clearing House for a fixed price of $40 per certificate (excluding GST).[41]

In summary, an electricity retailer's annual costs of complying with the RET are determined by the RPP, the STP, the price of LGCs and STCs and the quantity of electricity purchased by the retailer (the liable MWh).

8.2 Approach for the current regulatory period

8.2.1 Large-scale Renewable Energy Target costs

The formula for estimating the total LRET costs for the current regulatory period is:

Total LRET cost = Cattle Hill PPA MWh × $/LGC Cattle Hill PPA + (RPP × liable MWh - Cattle Hill PPA MWh × $/LGC Market)

Where:

Cattle Hill PPA MWh	=	The volume of LGCs purchased under the Cattle Hill Wind Farm Power Purchase Agreement (PPA)[42] for the relevant year
$/LGC Cattle Hill PPA	=	The LGC price under the Cattle Hill PPA for the relevant year

41 The CER operates the STC Clearing House, which facilitates the exchange of STCs between buyers and sellers. The STC Clearing House is accessible via the Renewable Energy Certificate Registry.

42 A PPA is a contract that allows an electricity retailer to purchase LGCs at predetermined prices over a long time period (typically around 10 years) as a way of managing the risks relating to supply issues and price volatility in the LGC market.

RPP	=	RPP published by CER
liable MWh	=	Amount of liable MWh for the relevant year
$/LGC Market	=	The forward LGC price for the remaining volume of LGCs that Aurora Energy is required to purchase for the relevant year under the RET scheme

The CER publishes its RPP by 31 March on a calendar year basis. However, the allowance for RET costs is calculated on a financial year basis. Under the 2022 Determination, the Regulator used the CER's RPP for the first half of each financial year of the regulatory period. For the second half of each financial year of the regulatory period, the Regulator used the formula outlined in section 39(2)(b) of the *Renewable Energy (Electricity) Act 2000 (Cwlth)* to calculate the forecast RPP.

This formula is:

$$\text{Renewable power percentage for the previous year} \times \frac{\text{Required GWh of renewable source electricity for the year}}{\text{Required GWh of renewable source electricity for the previous year}}$$

The required GWh of renewable source electricity for each calendar year from 2001 to 2030 inclusive is specified in section 40 of the Renewable Energy (Electricity) Act.

8.2.2 Small-scale Renewable Energy Scheme costs

The formula for estimating the SRES costs is:

Total SRES cost = (STP x $/STC x liable MWh)

As with the RPP, the CER publishes its binding STP by 31 March on a calendar year basis. Under the 2022 Determination, the Regulator used the CER's binding STP for the first half of each financial year of the regulatory period. For the second half of each financial year of the regulatory period, the Regulator used the CER's non-binding STP.

The Regulator required Aurora Energy to use the latest available forecast STC price. However, in allowing for over and under recoveries, the Regulator effectively allows Aurora Energy to recover its actual RET costs.

8.3 Other regulators' approaches

The ICRC, QCA and ESC estimate their respective retailers' costs of complying with the Australian Government's mandatory renewable energy schemes using market-based approaches.

8.3.1 ICRC

The ICRC applies a market-based approach for determining efficient LRET and SRES costs. The ICRC's model determines LGC and STC prices based on publicly available spot price data averaged over a 12-month period to the end of April. The ICRC then applies the CER's RPP and STP percentages to the forecast prices and holding costs to the forecast customer load. The ICRC uses the CER's RPP for the first half of the calendar year and then estimates the RPP for the second half.

The Commission's pricing model operates on a financial year basis. LRET and SRES costs for a financial year are therefore derived by apportioning calendar year costs based on the half-yearly load weights provided by the regulated retailer, ActewAGL.

In addition to the timing of the LRET and SRES costs, the ICRC also includes a green scheme certificate holding cost in its pricing model, which is calculated by estimating the cost of debt.

This is because retailers typically buy certificates in advance to manage price volatility and to avoid being unable to purchase enough certificates to meet their obligations.

8.3.2 QCA

QCA uses a consultant to estimate LRET costs using a market-based approach. Under this approach, LGC prices are based on forward prices for certificates provided by broker TraditionAsia. The consultant uses the CER's RPP for the first half of the price period and estimates the RPP for the second half of the price period.

The consultant estimates SRES costs using the STP for the first half of the price period and the latest available non-binding STP for the second half of the price period. STC prices were based on the clearing house price of $40 per certificate as historically the spot prices have been at or close to this price.

The QCA only allows for an adjustment to the SRES due to the binding small scale technology percentage for the second half of the financial year not being published at the time the prices are set. The QCA uses forward LGC energy prices in setting prices and makes no further adjustment on these.

8.3.3 ESC

The ESC has a separate environmental cost component that includes the costs of complying with the LRET and the SRES. The ESC uses a market-based approach to estimate LRET costs. The applicable market price for LGCs is determined by taking 12-month volume-weighted average of LGC forward trades for each year as reported by Demand Manager, an energy broker. The ESC uses the CER's RPP for the first half of the calendar year and then estimates the RPP for the second half.

To estimate the SRES, the ESC uses the binding STP and the most recent non-binding STP. The ESC uses the clearing house price of $40 per certificate.

8.4 Conclusions

As set out in the Final Methodology Paper, the Regulator intends continuing to set the LGC price for each of the 2025-26, 2026-27 and 2027-28 financial years on the basis of a weighted price calculated using:

- the LGC price and the volume of LGCs purchased by Aurora Energy under the Cattle Hill PPA for the relevant year; and
- the forward LGC price for the remaining volume of LGCs that Aurora Energy is required to purchase for the relevant year under the RET scheme.

In relation to STC prices, the Regulator also intends continuing with the current approach. That is, the forward price for STCs in the relevant year is to be estimated by Aurora Energy as the average of ten months of weekly forward STC prices in the previous year (the average of forward

LGC prices from the first Wednesday in July through to the last Wednesday in April).

However, the Regulator acknowledges that there may be limited liquidity in the forward market for STCs in some months.

The Regulator considers that the use of an average of the forward prices that are available is the preferred option as this reflects a plausible STC purchasing strategy and is likely to reduce year on year price volatility.

In addition to the direct LGC and STC costs, and in accordance with past practice, the Regulator intends continuing to allow Aurora Energy to recover brokerage and acquittal costs.

8.5 Draft decision

The Regulator's draft RET costs for 2025-26 are shown in Table 8.1.

Table 8.1 Regulator's draft decision – Renewable Energy Target costs

	2025-26
RET ($m)	29.00

The RET costs to apply for each year of the next regulatory period will be determined as part of the annual standing offer price approval process in June each year prior to the commencement of each of those periods. The calculated RET will then be used to calculate the NMR for each of those periods.

9 METERING COSTS

9.1 Background

Metering costs comprise the costs associated with installing, maintaining and reading meters together with the costs associated with the introduction of metering competition.

There are two types of meters:

- Basic accumulation meters. These are analogue meters which measure the total electricity consumed over a period and require manual reading; and
- Advanced meters, which record usage in real time and are read in 15 or 30-minute intervals. These meters are also able to record usage against multiple tariffs and can be read remotely.

The NER requires that any new or replacement meter must be an advanced meter.

Under the NER, retailers are also responsible for engaging a Metering Co-ordinator for their small customers with respect to advanced meters. Metering Co-ordinators and the services they provide are not price regulated.

Aurora Energy has engaged two Metering Co-ordinators since metering competition started in 2016 (TasMetering and Yurika (formerly Metering Dynamics)) while TasNetworks continues to be responsible for the basic accumulation meters.

The Tasmanian Liberal Party gave a commitment before the May 2021 election to replace all accumulation meters in Tasmania with advanced meters by 2026.

Aurora Energy currently estimates it will have replaced 90 per cent of basic accumulation meters with advanced meters by June 2025 and by December 2026 there will be approximately 10 000 or 3.7 per cent of customers without an advanced meter.

Aurora Energy has advised the Regulator that the remaining 10 000 installations are expected to be more difficult, and will therefore take longer, due to some of these properties being in remote locations and the prevalence of asbestos in some switchboards.

9.2 Current regulatory period

For the current regulatory period, the Regulator permitted Aurora Energy to recover the following metering costs:

- the aggregate of metering charges based on tariff, meter type and billing days 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 (costs to be written off over six years commencing on 1 December 2017 and ending on 30 November 2023); and
- fee-based metering services recovered on an annual basis.

The Regulator also approved Aurora Energy using a weighted average calculation of metering costs per tariff multiplied by the number of billing days to forecast its metering costs.

Currently, when calculating TasNetworks' weighted average cost of servicing existing basic meters, a factor is applied to the total number of customers on Tariff 22 (General Business customers) to account for the proportion of these customers on market contracts rather than standard retail contracts. The factor applied is Aurora Energy's Tariff 22 installation forecast as a proportion of the total Tariff 22 installations from TasNetworks. For advanced meters, Aurora Energy estimates a cost per customer by using the actual total cost incurred from existing advanced meters in the past twelve months and divides this by the total number of existing advanced meters by the end of the twelve months. This cost per customer is then multiplied by the number of advanced meters including the forecast new installation for a given month.

9.3 Other regulators' approaches

The treatment of metering costs differs between jurisdictions as set out in the following sections.

9.3.1 AER

In May 2024, the AER released its final determination for retail electricity default market offers in New South Wales, South Australia and South East Queensland. The AER includes advanced meter costs as a component of retail costs for its DMO determination.

Retailers in NSW, South Australia and South East Queensland are responsible for managing advanced meter installation and maintenance costs.

9.3.2 ICRC

On 23 May 2024, the ICRC released its final report and price direction following the completion of its 2024-27 retail electricity price investigation for the ACT.

The 2024-27 price direction continues the same treatment of metering costs as the 2020 price direction. The approach spreads the cost of advanced meters across the total base of small electricity customers rather than charging individual customers for installation and meter reading (the same approach as currently adopted by the Regulator). This approach was based on fairness and equity considerations.

To estimate advanced meter costs, the ACT's electricity retailer and advanced meter installer, ActewAGL, provides an annual forecast of the weighted average cost per advanced meter and a forecast of the number of advanced meters. The ICRC expects that advanced meter costs will increase as the accelerated rollout continues.

Prior to its 2020 price direction, the ICRC did not include the costs of advanced meters in its electricity pricing model.

9.3.3 QCA

As outlined in its final determination released on 7 June 2024, the QCA includes small customer metering service costs in the retail cost component of customer tariffs. Metering costs are based on metering and advanced metering services and the installation rate for advanced meters in regional Queensland.

9.3.4 ESC

The ESC does not include a separate cost component for metering when determining its annual VDO. This is because electricity distribution businesses in Victoria are required to install advanced meters for all small customers. As a result of past policies, advanced meters have been compulsory in all Victorian homes and businesses since 2006. To recover the cost of metering (which includes meter reading and other on-going costs), the AER approves Victorian distribution network businesses charging retailers for advanced meters on a per customer basis. Metering costs are therefore factored into the network cost component for retailers, based on customer weighted average metering costs.

9.4 Conclusions

In the Final Methodology Paper, the Regulator decided to continue with the current method of calculating metering costs, including the current rollout rate of advanced meters. In that paper, the Regulator also noted the capital expenditure associated with the commencement of metering competition had been fully depreciated.

The Regulator also decided to:

- refine the method for calculating the proportion of regulated customers on various tariffs for the purpose of attributing metering costs; and
- consider the extent to which Aurora Energy can recover the capital costs associated with accumulation meters from TasNetworks.

In attributing metering costs, the Regulator notes that Aurora Energy's advanced metering costs relate only to customers on standard retail contracts; therefore, there is no need to extend the approach to exclude market offer customers when calculating advanced metering costs.

With respect to the second point, for the regulatory period from 1 July 2024 to 30 June 2029, the AER's Electricity Distribution Determination for TasNetworks set the amount that TasNetworks can recover in relation to ongoing capital costs of accumulation meters replaced by advanced meters. In its determination of 30 April 2024, the AER decided that all accumulation meters should be fully depreciated by 30 June 2029. Further, the Regulator notes that TasNetworks did not provide separate capital and non-capital charges for metering services for 2024-25, therefore there is no obvious method for determining a partial pass-through amount of the accumulation meter capital costs from TasNetworks. In addition, despite the acceleration in TasNetworks' capital cost recovery, Aurora Energy's basic meter costs decreased by $1.08 million between 2023-24 and 2024-25. The Regulator notes that Aurora Energy's metering cost component has increased significantly over the last five years from $21.3 million in 2020-21 to $38.8 million in 2024-25 in line with the accelerated installation of advanced meters.

However, there are also other metering costs that are outside the metering cost component of the NMR. In particular, the labour costs Aurora Energy incurs facilitating meter exchanges which include tasks such as raising service orders, monitoring service orders, communicating with customers and developing reporting tools in relation to metering data are included in the CTS component of its NMR.

The metering costs referred to above therefore represent only the metering costs component of the NMR and do not represent the full metering costs Aurora Energy incurs.

9.5 Draft decisions

The Regulator intends continuing to use the current approach to calculating metering costs and extend the current approach for excluding market contract customers on Tariff 22 to all tariffs that have customers on market contracts for basic meter cost calculation.

In accordance with the AER's determination, the Regulator also intends continuing to allow Aurora Energy to pass through TasNetworks' capital costs in relation to accumulation meters.

Based on the Regulator's analysis, and for the purposes of calculating the indicative NMR for 2025-26, the Regulator's estimated metering costs for 2025-26 are shown in Table 9.1.

Table 9.1 Regulator's draft decision – Metering costs

	2025-26
M ($m)	44.27

The metering costs to apply for each year of the next regulatory period will be determined as part of the annual standing offer price approval process in June each year prior to the commencement of each of those periods. The calculated metering costs will then be used to calculate the NMR for each of those periods.

10 AEMO CHARGES

10.1 Background

AEMO's operating costs are funded through annual fees levied on market participants. Retailers are liable to pay a portion of these fees.

AEMO's fees include:

- NEM fees. These fees are intended to recover AEMO's costs associated with market operations and systems, wholesale metering, settlements and prudential supervision and longer-term energy forecasting and planning services.
- Full Retail Contestability (FRC) fees. These fees are intended to facilitate retail market competition by managing and supporting data for settlement purposes, customer transfers, business to business processes, and the implementation of market procedure changes.

AEMO is also responsible, under the NER, for ensuring that the power system is operated in a safe, secure and reliable manner. In fulfilling this obligation, AEMO controls key technical characteristics of the power system such as frequency and voltage and system restarts through the ancillary services market. The NER provide for AEMO purchasing these services, from frequency control ancillary service providers, and recovering a proportion of these costs from retailers according to a set of recovery rules.

10.2 Current regulatory period

Under the current approach, the Regulator estimates the AEMO fees Aurora Energy incurs to participate in the NEM and for FRC each year of the regulatory period using the customer numbers from the NTB, the DLF and the fees as determined by AEMO, and allows Aurora Energy to recover these costs from customers through standing offer prices.

The Regulator also estimates Aurora Energy's ancillary service fees by multiplying the average monthly rate of ancillary fees ($/MWh) based on a 12-month period prior to April in the year immediately before the price period by the forecast small customer load in the NTB adjusted by the DLF. As for AEMO fees, the Regulator allows Aurora Energy to recover these costs from customers through standing offer prices.

10.3 Other regulators' approaches

The approach taken by the ICRC, QCA and ESC in relation to AEMO fees is similar to that adopted by the Regulator.

10.4 Draft decision

The Regulator intends continuing with the current approach for calculating AEMO costs, subject to the treatment of unaccounted for energy (see Chapter 12).

Based on the Regulator's analysis, and for the purposes of calculating the indicative NMR for 2025-26, the Regulator's estimated AEMO costs for 2025-26 are shown in Table 10.1.

Table 10.1 Regulator's draft decision – AEMO costs

	2025-26
AEMO ($m)	6.18

The AEMO costs to apply for each year of the next regulatory period will be determined as part of the annual standing offer price approval process in June each year prior to the commencement of each of those periods. The calculated AEMO costs will then be used to calculate the NMR for each of those periods.

11 UNDER AND OVER RECOVERIES AND ADJUSTMENTS

11.1 Introduction

The prices to apply to the next financial year are currently approved by the Regulator in June of the preceding financial year, using a building block approach to arrive at an NMR. Some cost components for the financial year, such as the wholesale electricity cost, are already known at the time prices are approved.

However, some cost components must be based on an estimate when calculating the NMR, as the final values will not be known at the time standing offer prices are approved. In the absence of confirmed data from relevant sources, the Regulator estimates these costs based on the most appropriate method. These estimates may be higher or lower than the actual values once they become available.

Given the above, the Regulator has allowed Aurora Energy to recover additional costs in any year if actual values exceed the forecast costs for the previous year (and the fourth quarter of the year before). This results in Aurora Energy's NMR and prices being higher than they otherwise would have been (other costs held constant). If actual costs for the previous year are less than the forecast costs, the Regulator reduces Aurora Energy's costs, and its NMR and prices for the next year are lower than they otherwise would have been.

The Regulator seeks to keep under and over recoveries to a minimum. This is because a slightly different set of customers benefit through prices being lower than they otherwise would be in the next period or are penalised through prices being higher than they otherwise would be. These adjustments can also lead to greater price volatility from year to year, which the Regulator seeks to avoid.

11.2 2022 Determination

The NMR formula in the 2022 Determination allowed for three types of adjustments. These adjustments were:

- Ky = an aggregate of approved under and/or over recoveries for metering costs, RET costs and AEMO fees from the current regulatory period covered by the 2022 Determination.
- CFy = an aggregate of under and/or over recoveries from the previous period covered by the 2016 Determination.
- Ay = an adjustment made as a result of a tax event, a material change in circumstances, or a material change in Aurora Energy's costs in relation to the provision to small customers under standard retail contracts.

Metering costs, RET costs and AEMO fees are not always available at the time of publication. Therefore, the adjustment K_y allowed Aurora Energy to recover any of these costs over and above the forecast costs used within the 2022 Determination, or, if actual costs were less than forecast costs, to reduce the allowable NMR in subsequent periods.

Similarly, CF_y allowed Aurora Energy to recover any costs above forecast costs from the last period covered by a previous determination or, if actual costs were less than forecast costs, to reduce the allowable NMR in subsequent periods.

Regulation 12 of the Pricing Regulations provides that the Regulator's price determination may allow an adjustment to Aurora Energy's prices as a result of a tax event or a material change in circumstances in relation to the provision to small customers of services under standard retail contracts. Given this requirement, the Regulator included a component, A_y, in the NMR formula in the 2022 Determination. This component was not used during the current regulatory period.

11.3 Other regulators' approaches

The arrangements in other jurisdictions are discussed below.

11.3.1 ICRC

The ICRC carries out an annual recalibration of the cost component parameters as follows:

- The ICRC determines the energy purchase cost component based on data available to 30 April, and energy losses based on the latest

AEMO data as at 30 May. The ICRC updates forward prices, spot prices, load and the contract position based on this data.

- Network costs are updated for the regulated customer load as soon as they are approved by the AER.
- The ICRC also updates the costs associated with advanced meters to account for the difference between forecast and actual costs in the previous year.
- ActewAGL, the Australian Capital Territory's regulated retailer, submits to the ICRC on or before 8 May, its load weights for LRET and SRES costs.

In addition, the ICRC updates spot prices and provides for a cost adjustment to account for the difference between the estimated RPP at the time of the price determination and the actual percentage that is subsequently published by the CER. Based on the information above, the ICRC determines the percentage by which it will adjust the regulated price for the following year. In undertaking the annual price recalibration process, the ICRC also allows for a regulatory change or tax change event review.

11.3.2 ESC

The ESC has an adjustment mechanism for the under or over recovery of network costs. Further, the ESC includes an adjustment to account for any discrepancy between the level of the non-binding STC percentage and the binding STC percentage. The ESC also includes a limited mechanism that provides for variations to a price determination in the event of a material unforeseen change or error at the time of making the price determination, if the change is sufficiently material to impact the benchmark originally established.

11.3.3 QCA

The QCA only allows an adjustment for SRES costs. At the time of QCA's final determination for notified prices, only the SRES liabilities for the first half of the financial year are known, while liabilities for the second half are based on forecasts from the CER. The CER typically determines the final SRES liabilities for the second half of the financial year about nine months after the QCA's final determination. Any discrepancies between the CER's forecast and its final determination for SRES liabilities can lead to an over or under recovery of SRES costs by retailers. The QCA considers that any under recovery of SRES costs, unlike other cost components, is driven by factors outside the control of the regulated retailer. To account for the over or under recovery of SRES costs, the QCA applies a cost pass-through adjustment for the next regulatory period.

11.4 Conclusions

As set out in the Final Methodology Paper, the Regulator intends that under and/or over recoveries included in the K_y or CF_y costs:

- continue to be limited to metering costs, AEMO charges and some RET costs; and
- apply only to the extent that the relevant cost component per unit price is not known at the time prices are set for the next price period.

The Regulator has also decided that under and over recoveries are to be calculated using the costs as calculated on the customer numbers and load used to determine the initial costs and prices, i.e. the NTB, and not the actual customer numbers and load in that year. Therefore, customer numbers and load will not be taken into account when calculating under and over recoveries. In calculating the over and under recovery of RET costs, the Regulator will allow for changes in the RPP and/or STP, which are set by the CER, during the relevant period.

In the 2025 Determination, CF_y will apply to the period covered by the 2022 Determination.

The prices used to calculate RET costs in each year will also be used when calculating any preliminary and final adjustments in relation to RET costs with respect to each year i.e. the LGC and STC prices used when calculating prices in 2025-26 must be used when calculating preliminary and final adjustments in 2026-27 and 2027-28 respectively. In the case of over and under recovery of RET costs relating to years under the 2022 Determination (CF_y), the LGC and STC prices used in calculating the approved prices in the relevant year will be used.

The Regulator has decided that no changes will be made to the current approach to calculating adjustments (A_y). As discussed in Chapter 5, the Regulator intends to consider Aurora Energy's costs associated with implementation of major national regulatory changes under A_y instead of under the CTS. This gives the Regulator the ability to assess the efficient costs for Aurora Energy's implementation of major national regulatory changes annually as the costs arise, instead of providing Aurora Energy a set amount for major national regulatory changes irrespective of whether changes occur or without regard to the accuracy of the cost estimates made in advance of the changes actually being implemented.

11.5 Draft decision

The Regulator intends to consider Aurora Energy's costs associated with the implementation of major national regulatory changes as an adjustment under the A_y component of the NMR instead of under the CTS component.

The Regulator intends to continue with the current approach for calculating under and over recoveries and adjustments.

12 OTHER COSTS

12.1 Unaccounted For Energy

Unaccounted for Energy (UFE) is the difference between the amount of electricity that goes into a defined area and the amount of electricity consumed in that area as recorded by meters. UFE excludes distribution and transmission losses and unmetered but billed electricity consumed.

There will always be some UFE in an electricity network. Among the reasons the AEMC decided to move away from settlement by difference to global settlements was to allow for competition among retailers on equal terms. Prior to the introduction of global settlements in 2022, settlement by difference resulted in UFE only being billed to local retailers (Aurora Energy in Tasmania) through the load the local retailer was liable for. Other retailers did not share the cost of UFE.

With the increase in smart metering AEMO is now able to allocate UFE across all retailers. UFE is apportioned based on each retailer's 'accounted for'[43] load and included in the load that each retailer is liable for. Consequently, the local retailer's share of UFE is has now reduced. The changed treatment is illustrated in Figure 12.1.[44]

While UFE is not a discrete line item for settlement purposes, AEMO produces reports which enable retailers to calculate their share of UFE. A notable aspect of UFE is that it appears to materially change between preliminary, final, and revised statements which may cause some volatility in the load value. While the unpredictability of UFE was noted by the AEMC, the AEMC also concluded that UFE was an immaterial component of the load retailers are liable to pay for.[45]

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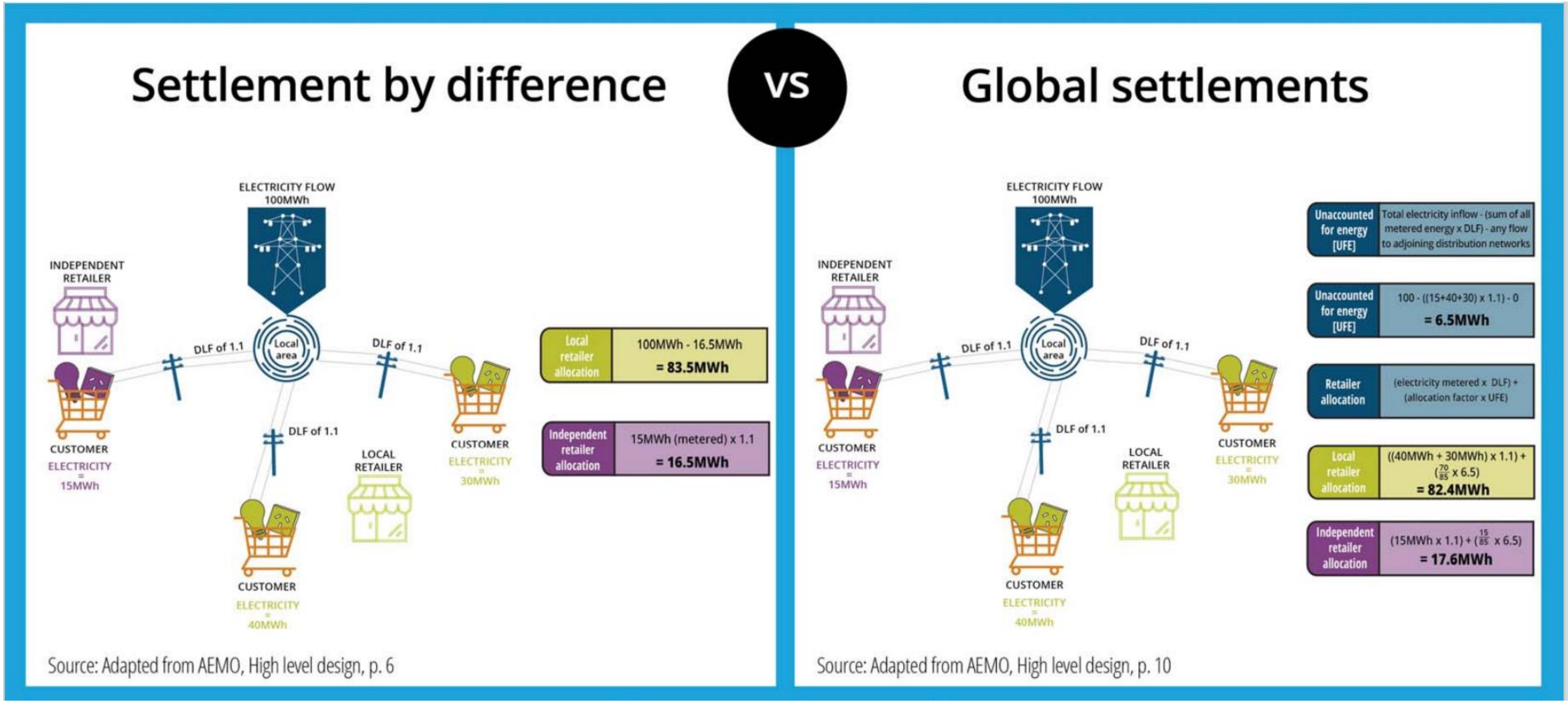
[43] Accounted for energy includes metered electricity consumption, profiled electricity consumption and marginal and distribution loss adjustments.

[44] AEMO, Global settlement info sheet and example.pdf

[45] AEMC, Removal of UFE from liable load in the RRO, Final determination

Figure 12.1: Comparison of UFE under Settlements for Difference and Global Settlements



12.1.1 Other regulators' approaches

The AER did not explicitly include UFE in its calculation of the DMO for 2024-25. Further, ACIL Allen, in its report on wholesale and environmental costs estimates for DMO6, stated that UFE varies with each trading interval but across the year can be expected to be a very small percentage of total distribution losses and did not include UFE in wholesale costs. In its Default Market Offer Prices 2025-26 Issues Paper[46], the AER does not propose changing how wholesale costs are calculated.

The ESC likewise did not include UFE in the VDO for 2024-25.[47] The ESC stated in its draft decision that UFE was immaterial in the context of the VDO. The ESC's analysis of publicly available information concluded that UFE appears to make up less than one per cent of energy dispatched across the Victorian network and as such, maintained its draft decision not to include an adjustment for UFE.

12.1.2 Aurora Energy's proposal

In its Submission[48], Aurora Energy stated that it does not include UFE in the NMR as the load value shown in AEMO's invoices is different to the load value used to calculate the Wholesale Electricity Costs in the NMR resulting in Aurora Energy "absorbing the difference".

Aurora Energy proposed that since UFE can now be reliably quantified, it should be included as a separate item and included in the K_y cost component (pass though cost recoveries) in the NMR cost build up.

Aurora Energy also proposed that UFE with respect to 2023-24 and 2024-25 under the 2022 Determination be passed through to the NMR in the 2025 Determination.

12.1.3 Regulator's conclusions

Based on information provided by AEMO, UFE is not included in settlement statements as a separate line item. Rather, it is included in

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46 ACIL Allen - Draft determination - Default market offer prices 2024–25 - Wholesale and environmental costs

47 Victorian Default Offer 2024-25 Final Decision Paper 20240520.pdf

48 Aurora Energy - Preliminary Submission - October 2024.docx

the volume of electricity charged to retailers. Retailers can use reports provided by AEMO to determine the UFE included in the volume they are required to settle on. In calculating the NMR, Aurora Energy uses the same load value for all cost components (grossed up by the relevant loss factor/s). This implies that Aurora Energy's load value is inclusive of UFE.

The Regulator notes there is very little publicly available discussion on UFE. Energy consultants have issued explanatory notices that there may be additional charges for UFE, but this information is aimed at larger electricity users who purchase electricity via market contracts which separately itemise each cost component based on the metered volume. This contrasts with smaller customers who pay electricity prices which factor in all cost components.

The Regulator contacted Solstice and 1st Energy regarding their treatment of UFE and both stated that they include UFE in their wholesale costs in the cost build up used to determine prices.

With regards to including the UFE attributable to periods 2 and 3 of the 2022 Determination in the next determination, it seems unlikely that UFE was not factored into the volume used to calculate wholesale electricity costs in the NMR. Therefore, allowing the pass-through of UFE from previous years would result in double dipping.

The Regulator also considers that allowing UFE to be recovered as a separate cost component would unnecessarily complicate the NMR calculation. The load to calculate the wholesale electricity costs would need to be net of UFE while the load used for calculating the other costs components, such as network costs and RET costs would need to include UFE.

The Regulator acknowledges that AEMO's changed approach to the treatment of UFE is complicated. Further, Aurora Energy has raised concerns regarding the treatment of UFE as part of wholesale electricity costs in its submission to the Regulator dated 20 February 2025. Therefore, the Regulator considers that further work may need to be undertaken to address this matter prior to the release of the final report.

12.1.4 Draft decision

Based on the AER's and ESC's conclusions, the report accounts for UFE under wholesale electricity costs rather than as a separate cost item.

However, the Regulator acknowledges that further work may need to be undertaken to fully understand the impact that the treatment of UFE has on Aurora Energy's costs.

13 LATE FEES AND INTEREST ON OVERDUE ACCOUNTS

13.1 Interest on overdue accounts

Aurora Energy currently charges a late fee of $5 for accounts not paid on time and is proposing increasing this fee by 140 per cent to $12.

Aurora Energy states that the fee has not changed in over twenty years and is significantly less than the late fees imposed by other similar businesses, such as the following:

- ActewAGL $15.00
- AGL $12.00
- Energy Australia $10.90
- Origin Energy $12.00
- Simply Energy $12.00
- Telstra $15.00

The late fee is a discretionary fee and is not linked to the recovery of costs. Aside from a comparison to selected businesses, Aurora Energy has not provided any other justification, such as an increase in administrative expenses, for the proposed increase.

The Regulator considers that while the late fee should be sufficient to motivate customers to pay their account by the due date, more than doubling the current fee may be excessive given the current concerns about cost-of-living pressures. It would also have been preferable if Aurora Energy had adjusted the late fee in smaller increments on a regular basis, rather than proposing a single large increase.

13.1.1 Draft decision

Given that the late payment fee is a non-cost recovery charge and indexing the current $5 fee for inflation over twenty years would result in a fee of $8.78 in 2024 dollars, the Regulator intends approving a late fee of $9.

13.2 Interest on overdue accounts

Aurora Energy proposes continuing to apply interest on accounts not paid in full by the fifth day past the due date.

Aurora Energy further proposes continuing to use the same formula to determine the interest payable as set out in the current Determination:

Interest = [(N/365) x I] x O

Where:

N = the number of days the account is overdue

I = the reference rate + 6 per cent

O = the overdue amount

13.2.1 Regulator's conclusions

It is common practice for businesses, including government businesses[49], to charge interest on overdue accounts and to charge a premium interest rate with reference to a publicly available rate as a way of incentivising customers to pay their bills on time and to not use the business as a de facto bank.

The objective of this approach is to both motivate customers to pay their account by the due date and to compensate Aurora Energy for the opportunity cost of not receiving revenue by the due date.

13.2.2 Draft decision

Consistent with the approach adopted by other entities and the Regulator's current and past approach with respect to Aurora Energy, the Regulator draft decision is for Aurora Energy to continue to apply interest on overdue accounts.

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[49] See for example, the Tasmanian State Revenue Office: Rates of interest, TasWater: Outstanding debts and the Australian Taxation Office: General interest charge.

The Regulator has also decided to continue to use the current formula as set out in section 13.2 of this report in the 2025 Determination, to calculate the interest amount payable.

14 PRICE APPROVAL PROCESS

14.1 Annual price approval process

Under sections 40 and 41 of the ESI Act, Aurora Energy must obtain the Regulator's approval before fixing its standing offer prices and can only amend those prices with the Regulator's approval.

Specifically, section 41 of the ESI Act states:

> Approval of standing offer prices
>
> (1) A standing offer price may not be fixed under section 40(1), and an amendment of a standing offer price may not be made under section 40(4), unless-
>
> (a) a draft of the standing offer price, or a draft amendment of the standing offer price, has been approved by the Regulator under subsection (3); and
>
> (b) the standing offer price fixed, or the draft amendment made, is in the same terms as the draft of the standing offer price, or the draft amendment of the standing offer price, approved by the Regulator under subsection (3).

In the 2022 Determination, the Regulator adopted an annual approval process supported by a standing offer price approval guideline. The guideline sets out the information that Aurora Energy must provide in its annual standing offer pricing proposals. It also details the obligations of Aurora Energy and the Regulator regarding the approval of prices for each year of the regulatory period covered by that Determination.

As stated in the Final Methodology Paper, the Regulator has decided to continue with an annual price approval process supported by a standing offer price approval guideline.

Further, the Regulator has decided to publish the WEP once it has been calculated. The Regulator will also publish Aurora Energy's draft pricing proposal as soon as practicable after receipt.

While the publication of the WEP and Aurora Energy's draft pricing proposal will improve the transparency of the annual price approval process, the Regulator notes that with Aurora Energy's pricing proposal not submitted until the end of May each year, there is insufficient time to consult on the proposal prior to the Regulator's consideration and subsequent approval of the proposal by mid-June. Consistent with past practice, the Regulator intends publishing a final version of Aurora Energy's proposal in mid-June.

14.2 Draft decision

The Regulator intends issuing a guideline that:

- sets out the annual price approval process;
- provides for the introduction of the revised WEP methodology to calculate the WEP for the 2026-27 and 2027-28 financial years;
- provides for the Regulator to publish the WEP once the price has been calculated; and
- provides for the Regulator to publish Aurora Energy's annual pricing proposal as soon as practicable after receipt.

The Regulator has prepared a draft of the Guideline which is available here.

15 OTHER MATTERS

15.1 Embedded networks

In some sites (typically retirement villages, caravan parks and shopping centres) the electrical wiring is configured in such a way as to enable the owner of the site to sell energy to all the tenants or residents based there. This is known as an embedded network.

In recent years, the Regulator has received complaints from some caravan park residents in relation to electricity prices. However, under the current legislative framework, the Regulator does not have any powers or functions in relation to embedded network and cannot intervene where embedded network customers are paying electricity prices above standing offer prices.

15.2 Time-of-use tariffs and daylight savings

At present, the peak and off-peak periods for Aurora Energy's time-of-use tariffs are expressed in Australian Eastern Standard Time (AEST). For example, a peak period for Tariff 93 (the time-of-use tariff for residential customers) is currently 7am to 10am AEST.

Customers have asked the Regulator why the peak and off-peak periods are not adjusted for daylight savings. That is, why can't the peak period for Tariff 93 remain at 7am to 10am during Australian Eastern Daylight Savings Time instead of being changed to 8am to 11am during that period?

Aurora Energy has advised that it is not currently practical to adjust the peak and off-peak periods during daylight savings, as there are still a significant number of interval meters operating in Tasmania which lack the functionality to change the peak and off-peak periods without manual intervention. Further, the underlying network tariffs set by TasNetworks are also expressed in AEST.

With the roll-out of advanced meters nearing completion, the Regulator expects the existence of interval meters in Tasmania will cease to be an impediment to adjusting the peak and off-peak periods.

15.2.1 Draft decision

The Regulator requires Aurora Energy to investigate this issue further and report to the Regulator with findings and a proposed solution, including implementation timeframes, by close of business 26 September 2025.

15.3 Review of confidentiality provisions

As set out in the 2022 Investigation Final Report, the Regulator considers it to be highly desirable and in the interests of an open, public, transparent and fair process that as much information as possible is made public. This is particularly important during pricing investigations as it allows stakeholders to consider information and provide more informed feedback on the Regulator's draft decisions and intended courses of action.

To ensure that the confidentiality arrangements are best practice, the Regulator committed to reviewing its confidentiality provisions prior to conducting the next pricing investigation in 2024-25.

15.3.1 Draft decision

The Regulator has reviewed its confidentiality policy and has released a revised draft for public consultation which closes on 14 March 2025. More information is available here.

15.4 Lodgement of Preliminary Submission

Prior to the expiry of a price determination and to mark the commencement of each pricing investigation, Aurora Energy lodges a submission which sets out its proposals for the upcoming regulatory period.

The later than expected lodgement of Aurora Energy's Submission for this investigation reduced the time available for the Regulator to conduct its investigation.

To avoid the issues caused by this delay in future investigations, the Regulator has considered options for requiring Aurora Energy to lodge its submission by a specified date.

15.4.1 Draft decision

The Regulator intends issuing a written notice under section 15 of the ESI Act which will require Aurora Energy to provide information to the Regulator that the Regulator requires to be able to conduct the pricing investigation for the regulatory period commencing on 1 July 2028.

The information is to be provided in the form of a preliminary submission.

The Regulator intends issuing the notice by no later than 30 June 2027 with the notice requiring Aurora Energy to provide its submission by close of business 15 October 2027.

APPENDIX 1: LEGISLATIVE REQUIREMENTS

The Regulator regulates electricity prices that Aurora Energy may charge small customers under standard retail contracts in accordance with the requirements set out in the ESI Act. Under this Act, Aurora Energy proposes, and the Regulator considers for approval, standing offer electricity prices.

Periodic pricing investigations are conducted by the Regulator in accordance with the process set out in the Pricing Regulations.

Under Section 40AA of the ESI Act, the Regulator must determine the maximum prices that Aurora Energy may charge, or a method for determining those maximum prices. Further, under Regulation 8 of the Pricing Regulations, a price-regulated retail service price determination may be expressed in one or more of the following terms or manners:

(a) maximum prices or the maximum rate of increase or the minimum rate of decrease in maximum prices;

(b) average prices or average rates of increase or decrease in average prices;

(c) pricing policies or principles;

(d) by reference to a general price index, the cost of production, revenue, a rate of return on assets or any other factor;

(e) by reference to quantity, location or period of provision of the services to small customers under standard retail contracts;

(f) by reference to a maximum revenue; and

(g) any other terms the Regulator considers appropriate.

Section 40AB of the ESI Act requires the Regulator to estimate Aurora Energy's operational costs in providing standard retail services.[50] Section 40AB(2) specifies the components of Aurora Energy's operational costs that the Regulator must consider, including wholesale electricity costs, transmission and distribution costs, cost to serve and any other costs Aurora Energy incurs providing those services.

50 These are the services provided by a regulated offer retailer under standard retail contracts in respect to small customers.

APPENDIX 2: ASSUMPTIONS USED IN INDICATIVE NMR CALCULATIONS

Aurora Energy

Aurora Energy has made the following assumptions when calculating its indicative NMR:

- Customer Numbers, Load and Loss Factors are assumed consistent with the inputs approved by the Regulator for 2024-25;
- Network prices are as per TasNetworks' approved pricing for 2024-25;[51]
- The Wholesale Energy Price is as per Aurora Energy's calculation of \$77.60 / MWh on 10 December 2024;
- CTS and Retail Margin are as per Aurora Energy's submission, noting the fixed portion of the retail margin has been calculated based on the last two years of observable cost data consistent with the approach approved under the 2022 Determination;
- AEMO costs are assumed to increase by CPI, and UFE has been added to $AEMO_y$ based on average annual costs apportioned to standing offer customers for the 2022-23 and 2023-24 financial years;
- Metering costs are based on approximately 15 000 advanced meters being installed during 2025-26;
- No allowance has bene made for under / over recoveries as the Clean Energy Regulator is yet to publish its Small-scale Technology Percentage for the 2025 calendar year; and
- No allowance has been made in Network costs for Basslink costs (i.e. in the event that the link is regulated).

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[51] Regulated Distribution Pricing - TasNetworks - Access prices by expanding the "Standard Control Services (SCS) Prices" section >> 2024-25 Annual SCS Pricing Model >> "Indicative prices" tab.

Regulator

The Regulator has made the following assumptions when calculating its indicative NMR:

- Customer Numbers, Load and Loss Factors are assumed consistent with the inputs approved by the Regulator for 2024-25;
- Network prices are as per TasNetworks' approved pricing for 2024-25;
- The Wholesale Energy Price is as per the Regulator's calculation of $77.60 / MWh on 10 December 2024;
- CTS and Retail Margin are as per the Regulator's draft decisions set out in this Report on these two components;
- AEMO costs are assumed to increase by CPI based on average annual costs apportioned to standing offer customers for the 2022-23 and 2023-24 financial years;
- No separate allowance has been made for UFE;
- Metering costs are based on Aurora Energy's estimate of approximately 15 000 advanced meters being installed during 2025 26;
- No allowance has been made for under / over recoveries as the Clean Energy Regulator is yet to publish its Small-scale Technology Percentage for the 2025 calendar year; and
- No allowance has been made in Network costs for Basslink costs (i.e. in the event that the link is regulated).

APPENDIX 3: EXPLANATION OF KEY TERMS

Cost reflective tariffs

Tariffs are cost reflective if the daily supply charge and usage charges for individual tariffs result in the revenue raised from each tariff recovering the fixed and variable costs, respectively, for each tariff.

Grandfathering

From a point in time, existing customers on grandfathered tariffs are permitted to remain on those tariffs but new customers are unable to access the grandfathered tariffs.

Side constraints

Side constraints limit how much, in dollar terms, electricity prices or customer bills can change in a particular year compared to a uniform price change.

In the case of a customer bill side constraint a customer’s bill should not change by more than the side constraint however prices may differ for the individual tariffs a customer received electricity under. Consequently, price changes will not be uniform.

Side constraints are usual determined by reference to a ‘typical customer’s’ electricity usage. A typical customer’s usage is intended to represent the usage of a group of customers.

Tariff rebalancing

This process aims to align the tariffs customers pay with the costs a retailer incurs in retailing electricity. While the overall costs are recovered from customers, there is a misalignment between the amount of fixed and variable charges recovered from customers relative to the fixed and variable nature of the underlying costs. This is at both an aggregate level i.e. the amount of revenue from fixed charges versus that from variable charge; and at an individual tariff level. Network costs have been shifting to an increased fixed charge component relative to the variable charge component. The increase in fixed charges has not been directly reflected in retail tariffs due to Aurora Energy having unform prices changes and mandated price changes which were different to the changes in the underling costs.

Rebalancing is also due to cross subsidies between tariffs where the prices for a tariff are less that the costs of providing that tariff, necessitating other tariffs to be higher than the cost of proving those tariffs or must be funded out of the retailer’s profit margin.

Tariff misalignment means customers usage in not based on the actual costs of providing electricity consequently the retailer may be exposed to increased financial risks.

Tariff misalignment can be addressed through tariff rebalancing and may involve applying some form of side constraints to minimise customer impacts.

Uniform price changes

Under a uniform price change, fixed charges and variable charges for individual tariffs change by the same percentage.

APPENDIX 4: CURRENT APPROACH TO WEP CALCULATION

	Q1 AMCOV	Q2 AMCOV	Q3 AMCOV	Q4 AMCOV
	8 quarters			
	7 quarters	8 quarters		
	6 quarters	7 quarters	8 quarters	
	5 quarters	6 quarters	7 quarters	8 quarters
	4 quarters	5 quarters	6 quarters	7 quarters
	3 quarters	4 quarters	5 quarters	6 quarters
	2 quarters	3 quarters	4 quarters	5 quarters
May = WEP calculation date	1 quarter	2 quarters	3 quarters	4 quarters
	1 quarter	2 quarters	3 quarters	4 quarters
	Q1 Jul-Sep	1 quarter	2 quarters	3 quarters
		Q2 Oct-Dec	1 quarter	2 quarters
			Q3 Jan-Mar	1 quarter
				Q4 Apr-Jun

AMCOV = Absolute Miniumum Capacity Offer Volume (MW weekly)

8 quarters = 104 weeks

Weekly historic regulated LFS prices * applicable quarterly AMCOV

No LFS prices available

Start of quarter in which the weekly LFS prices will apply

APPENDIX 5: GLOSSARY

Term	Meaning
Absolute Minimum Capacity Offer volume	Has the same meaning as it has in the Wholesale Contract Regulatory Instrument
ACCC	Australian Competition and Consumer Commission
ACCC Inquiry	ACCC's Inquiry into the National Electricity Market
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Aurora Energy	Aurora Energy Pty Ltd ABN 85 082 464 622
CER	Clean Energy Regulator
CPI	Consumer Price Index
DLF	Distribution Loss Factor
DMO	Default Market Offer, as determined by the AER
Economic Regulator Act	*Economic Regulator Act 2009*
ESC	Essential Services Commission, Victoria

ESI Act	*Electricity Supply Industry Act 1995*
FRC	Full Retail Competition
Guideline	Guideline - Standing Offer Price Approval Process in accordance with the 2022 Standing Offer Electricity Price Determination (29 April 2022)
Hydro Tasmania	Hydro Electric Corporation ABN 48 072 377 158
ICRC	Independent Competition and Regulatory Commission, Australian Capital Territory
LGC	Large-scale Generation Certificate
Load	Electricity consumed by electricity users
Load Following Swap	One of the types of financial contracts Hydro Tasmania is required to offer to retailers under the Wholesale Contract Regulatory Instrument which set prices for quarter in the future. The Regulator is required to use the LFS price in estimating Aurora Energy's WEP and, consequentially, its WEC.
LRET	Large-scale Renewable Energy Target
Mainland Tasmania	All parts of Tasmania other than any off-shore island of Tasmania (except for Bruny Island)
Market retail contract	A contract between a retailer and a small customer who decides not to

	remain on a standard retail contract. Terms and conditions in market retail contracts can vary from contract to contract and are not regulated by the Regulator
MLF	Marginal Loss Factor
MW	Megawatt
MWh	Megawatt-hour
NEM	National Electricity Market
NER	National Electricity Rules
Next regulatory period	The regulatory period commencing on 1 July 2025
NMR	Notional Maximum Revenue. The Regulator allows Aurora Energy to recover its NMR through its standing offer prices. That is, by applying the prices under each tariff to the billing days and load relating to the forecast number of customers under that tariff, a notional amount of annual revenue is calculated for each tariff. The total of these notional annual revenues for all tariffs must not exceed the Notional Maximum Revenue.
NTB	Notional Tariff Base. The NTB comprises the customer numbers and loads for all small customers connected to the distribution network that are eligible to take supply under a regulated tariff.

Price approval process	The process under which a regulated offer retailer submits its proposed standing offer prices for the Regulator's approval
Price period	A 12-month period from 1 July to 30 June (e.g., Period 1, Period 2, Period 3) to which Aurora Energy's annual pricing proposal and the Regulator's associated price approval relate.
Pricing Regulations	*Electricity Supply Industry (Pricing and Related Matters) Regulations 2023*
QCA	Queensland Competition Authority
Regulated offer retailer	An authorised retailer who is declared to be a regulated offer retailer in accordance with an order made under section 38B(1) of the ESI Act
Regulated tariff	A tariff to which a standing offer price, as approved by the Regulator, applies
Regulated Tariff Strategy	Document setting out Aurora Energy's intentions with respect to, among other things, the structure of its tariffs and rebalancing of its tariffs during the next regulatory period.
Regulator	The Tasmanian Economic Regulator, appointed under the Economic Regulator Act

Regulatory period	The total period to which a determination relates (typically several price periods)
RET	Renewable Energy Target
Small customer	All residential customers and small business customers using less than 150MWh of electricity per annum
SRES	Small-scale Renewable Energy Scheme
STC	Small-scale Technology Certificate
STP	Small-scale Technology Percentage
Standard retail contract	A contract under which a regulated offer retailer provides standard retail services to small customers. The retailer is unable to change the terms and conditions set out in a standard retail contract. A small customer electing not to enter into a market retail contract with a retailer receives supply under a standard retail contract.
Standard retail services	Services provided by a regulated offer retailer under standard retail contracts in respect of small customers
Standing offer price approval guideline	The guideline issued by the Regulator following each price investigation that sets out Aurora Energy's and the Regulator's obligations in relation to the submission, and approval, of annual price proposals

Standing offer prices	The standing offer prices, fixed, or amended under section 40 of the ESI Act. Standing offer prices are approved by the Regulator under section 41 of the ESI Act.
TasNetworks	Tasmanian Networks Pty Ltd, ABN 24 167 357 299
VDO	Victorian Default Offer, as determined by the ESC.
WEC	Wholesale Electricity Cost
WEP	The Wholesale Electricity Price is estimated by the Regulator based on wholesale contract prices generated by the Wholesale Pricing Model in accordance with the requirements of the Wholesale Contract Regulatory Instrument using a method set out in the Regulator's standing offer price approval guideline.
Wholesale Contract Regulatory Instrument	The instrument containing the approvals made by the Regulator from time to time under section 43G(1) of the ESI Act and Regulation 20 of the Pricing Regulations, having taken into account the principles set out in section 43H of the ESI Act.
Wholesale pricing model	The model based on the requirements and criteria set out in the Wholesale Contract Regulatory Instrument that is used to calculate the weekly prices for each of the wholesale contract types approved by the Regulator.