2022 STANDING OFFER ELECTRICITY PRICE INVESTIGATION

INVESTIGATION OF MAXIMUM STANDING OFFER PRICES FOR SMALL CUSTOMERS ON MAINLAND TASMANIA

1 JULY 2022 TO 30 JUNE 2025

DRAFT REPORT

FEBRUARY 2022

THE TASMANIAN ECONOMIC REGULATOR

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HOW TO MAKE A SUBMISSION

This Draft Report provides an opportunity for stakeholders to provide information and views to the Regulator which will be considered in the development of the Final Report and Price Determination.

Comments and submissions may be emailed to the Regulator at:
office@economicregulator.tas.gov.au.

Alternatively, comments and submissions may be mailed to the Regulator at:

Office of the Tasmanian Economic Regulator GPO Box 770, Hobart TAS 7001.

Unless the author requests confidentiality in relation to the submission (or any part of the submission), it is the Regulator's policy to publish all submissions on its website: www.economicregulator.tas.gov.au. Those parts of a submission requested to be kept confidential should be submitted as an attachment to the parts suitable for publication.

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

Stakeholders are encouraged to make submissions in either Microsoft Word format or PDF (OCR readable text format – that is, they should be direct conversions from the word-processing program, rather than scanned copies in which the text cannot be searched).

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

The Regulator may be contacted at the address above or by telephone on: (03) 6145 5899.

Submissions on the draft report close on 25 March 2022.

EXECUTIVE SUMMARY

Regulated electricity prices are the maximum prices that Aurora Energy, as Tasmania's regulated energy retailer, can charge residential customers and small business customers using less than 150MWh of electricity per annum under standard retail contracts on mainland Tasmania (including Bruny Island). In effect, regulated prices provide a safety net for small customers.

The current price determination for regulated electricity prices, the *Aurora Energy Pty Ltd 2016 Standing Offer Price Determination* (2016 Determination), expires on 30 June 2022. The Regulator is required to make a new price determination and has decided that it will cover a three year period from 1 July 2022 to 30 June 2025. Before making the new price determination, the Regulator is required to conduct a pricing investigation.

In September 2021, the Regulator released its *Retail Electricity Standing Offer Price Methodology Review Paper* (Approach Paper), which sets out the methodology that the Regulator intends to apply during the pricing investigation. A copy of the Approach Paper is available for download at www.economicregulator.tas.gov.au.

This Draft Report is part of the investigation process. It sets out the Regulator's draft assessment of Aurora Energy's submission and the Regulator's draft conclusions and findings. A Draft Determination, the *Draft 2022 Standing Offer Price Determination*, has been published alongside this Draft Report. The Draft Determination is available separately at www.economicregulator.tas.gov.au.

As with previous determinations, the Regulator has decided to retain the 'building block' approach to set regulated prices. Under this approach, regulated prices are set to enable a retailer to recover the costs of supplying electricity to customers on standard retail contracts.

The costs of providing retail services are:

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

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

The Regulator allows Aurora Energy to recover these costs and so this estimated total cost is set as the Notional Maximum Revenue (NMR) for each year. The maximum retail prices that Aurora Energy may then charge under the different tariffs are then set such that Aurora Energy's total revenue does not exceed the NMR. That is, if the prices under each tariff are applied to the billing days and load relating to the forecast number of customers under that tariff, the aggregate revenue for the year must not exceed the NMR.

By examining all of Aurora Energy's costs, including allowances set by the Regulator, the Regulator seeks to ensure that customers pay no more than necessary for the services they receive.

Wholesale electricity costs

Wholesale electricity costs are a significant component of the retail price of electricity. The Regulator intends to calculate 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*

Aurora Energy is responsible for estimating the annual load. The Regulator is required to calculate a WEP based on regulated load following swap prices, which is in a financial hedge contract where the price per kWh is set and the volume in the contract is based on a specified load profile. Since 2014, the Regulator has calculated the WEP using a weighted average of load following swap prices and intends to continue with this approach. The values for electricity losses are provided by the AEMO.

Network costs

Electricity retailers incur a number of costs over which they have no control and which they seek to recover in their prices to customers. Of these costs, network charges are the most significant.

The Regulator intends to calculate the network cost component of Aurora Energy's NMR by multiplying the applicable TasNetworks' network tariff by forecast billing days and customer load for each retail tariff and then summing the resultant values.

As set out in its Approach Paper, the Regulator intends to reconcile the billing days used in deriving network costs with the forecast of the customer. That is, the billing days used when forecasting network costs are to relate directly to the forecast of customers numbers.

Renewable Energy Target costs

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

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. LGC and STC prices are determined in an open market.

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).

To determine the cost allowance for RET-related costs, the Regulator intends to include the LGC price and the volume of LGCs purchased by Aurora Energy under the Cattle Hill Power Purchase Agreement for the relevant year, and an average forward price for the remaining LGCs and for the STCs.

Metering costs

Metering costs comprise the costs associated with the installation, maintenance and reading of meters, and the costs associated with the introduction of metering competition and fee-based metering services.

The Regulator intends to continue to use the current approach to calculating metering costs. That is, a weighted average calculation of metering costs per tariff multiplied by the number of billing days. The Regulator also intends to require Aurora Energy to reconcile billing days used in deriving metering costs with the forecast of the customer numbers.

Cost to serve

The cost to serve (CTS) allowance reflects the Regulator's view of the efficient level of operating costs Aurora Energy requires to provide retail services to customers on standing offer tariffs over the 2022 determination period.

The Regulator intends to approve including Aurora Energy's aurora+ costs in the CTS allowance, as proposed by Aurora Energy, so that the product is not separately charged to Aurora Energy customers.

Aurora Energy's retail costs include:

- billing and revenue collection;
- marketing;
- providing advice and answering customer queries;
- contributing to corporate overheads;
- the costs relating to aurora+ and
- regulatory compliance.

As set out in the Approach Paper, the Regulator has estimated Aurora Energy's CTS allowance using a cost build-up approach and then tested the result against CTS allowances for retailers in other Australian jurisdictions. This involved conducting a detailed review of Aurora Energy's operating cost structure to calculate what the Regulator considers to be an efficient CTS figure.

To inform the Regulator's draft assessment on Aurora Energy's CTS, it engaged Utilities Regulation Advisory (URA) and Oakley Greenwood (OGW) to review the robustness of Aurora Energy's forecasting approach and whether the estimates reflect efficient costs. A summary of the URA's/OGW's findings are available on the Regulator's website.

Having reviewed Aurora Energy's operational costs, considered URA's/OGW's findings and examined arrangements in other jurisdictions, the Regulator intends determining a CTS allowance for Aurora Energy of $156.42 per customer in 2022-23, which is around $16.12 below the level proposed by Aurora Energy of $172.54 and around $8.10 or 5.5 per cent higher than the level in 2021-22 of $148.35.

The Regulator intends to include an efficiency factor in the CTS allowance for every year. This would reduce the CTS allowance in each year, resulting in the CTS allowance being around nine per cent lower in 2024-25 than without this efficiency factor.

These values are expressed in 2020-21 dollars. The actual CTS allowance for 2022-23 and the following two years will be adjusted to take into account the general increases in wages and other costs since 2020-21. The Regulator's Final Report and Price Determination will set the CTS allowance for 2022-23 in actual (current) dollars.

Retail margin

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

As set out in the Approach Paper, the Regulator intends to calculate the margin on a dollar amount per customer basis that takes into account the risks faced by Aurora Energy. The reason for this approach is that when the retail margin is set as a percentage of approved costs, the dollar value may fluctuate considerably from year to year. The value of Aurora's margin for any year depends on the level of Aurora Energy's costs such as network and wholesale electricity costs, even though the risks that Aurora Energy faces may not have been affected.

Having considered the sharply declining retail margins in other jurisdictions of Australia and the risks that Aurora Energy faces, the Regulator intends to set the retail margin in dollar terms at the average of the dollar value of a retail margin of 5.25 per cent of Aurora Energy's approved costs in 2020-21 and 2021-22, including the approved costs for aurora+ as if those costs had been included in 2020-21 and 2021-22.

The Regulator intends to set the retail margin at $96.25 per customer in 2022-23 (in 2020-21 dollars). This would be indexed by the Hobart CPI to determine the 2022-23 value in current dollars and then indexed again by CPI growth for 2023-24 and 2024-25. The Regulator's Final Report and Price Determination will set the retail margin for 2022-23 in actual (current) dollars.

This represents a decrease of $15.69 per customer from the retail margin proposed by Aurora Energy and also a decrease of $3.55 from the retail margin in 2021-22 (in $2020-21).

AEMO costs

AEMO is a not-for-profit public company funded wholly by participant fees. AEMO operates the energy markets and systems and also delivers planning advice in the NEM. Retailers including Aurora Energy are liable to pay a portion of the fees levied by AEMO.

The Regulator intends to continue to provide Aurora Energy with an allowance for AEMO fees. As set out in the Approach Paper, the Regulator intends that fees and charges are to be expressed on a per connection point basis or on a $/MWh basis as relevant and in line with how AEMO expresses the various costs in its annual budget.

Under and over recoveries

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. The Regulator estimates these costs based on the most appropriate method, dependent on the cost component being estimated. These estimates may be higher or lower than the actual values once they become available.

As set out in the Approach Paper, the Regulator intends that under and/or over recoveries will be limited to network costs, 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.

Maximum price estimates

This Draft Report does not include any estimates of maximum electricity prices from 1 July 2022 to 30 June 2025 as some future costs to Aurora Energy, such as wholesale electricity costs, network costs and some RET costs, are not currently available. However, as discussed above, this report does include an estimate of the draft CTS allowance as well as a draft retail margin in dollar terms.

The intended CTS allowance and retail margin would in combination, result in a negligible impact on maximum electricity prices in 2022-23, compared to Aurora Energy's standing offer prices in 2021-22, if all other costs are unchanged. Aurora Energy's proposed CTS allowance and retail margin would result in maximum electricity prices in 2022-23 increasing by almost two per cent from current levels, if all other costs are unchanged. The prices of other components, however, may change such that the maximum prices in 2022-23 could be significantly different from Aurora Energy's 2021-22 prices.

Next steps

The Regulator seeks comments and submissions on this Draft Report. All information obtained by the Regulator during the investigation, including comments and submissions received in response to this Draft Report, and all submissions received to date, will be taken into account in the preparation of the Regulator's Final Report, which is to be completed by 29 April 2022.

1 INTRODUCTION

Section 40AA of the *Electricity Supply Industry Act 1995* (the ESI Act) requires the Tasmanian Economic Regulator to determine the maximum prices, or a method of determining the maximum prices, that Aurora Energy may charge small customers under standard retail contracts on mainland Tasmania (including Bruny Island).

The current price determination, the *Aurora Energy Pty Ltd 2016 Standing Offer Price Determination* (2016 Determination), expires on 30 June 2022. The Regulator is required to make a new price determination and has decided that it will cover a three year period from 1 July 2022 to 30 June 2025. Before making the new price determination, the Regulator is required to conduct a pricing investigation.

In September 2021, the Regulator released its *Retail Electricity Standing Offer Price Methodology Review Paper* (Approach Paper) which set out the methodology that the Regulator intends to apply during the pricing investigation. A copy of the Approach Paper is included as Appendix 2 of this Report.

This Draft Report is part of the investigation process. It sets out the Regulator draft assessment of Aurora Energy's submission and the Regulator's draft conclusions and findings. This draft report does not include any estimates of electricity prices from 1 July 2022 to 30 June 2025 as some future costs to Aurora Energy, such as wholesale electricity costs and network costs, are not currently available. This report does include an estimate of the draft cost to serve allowance and also the draft retail margin.

1.1 Matters to be considered

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.[1] Under this Act, Aurora Energy proposes, and the Regulator considers for approval, standing offer electricity prices under a range of tariffs offered by Aurora Energy.

Price investigations are conducted by the Regulator in accordance with the process set out in the *Electricity Supply Industry (Pricing and Related Matters) Regulations 2013* (Pricing Regulations).

Under section 40AB of the ESI Act, the Regulator is to consider the following matters in making its standing offer price determination:

(a) any interstate or international benchmarks for prices, costs, revenues and return on assets in bodies providing a service similar to the services, under a standard retail contract with a small customer, to which the determination relates;

(b) the effects of inflation;

[1] Small customers are all residential customers and small business customers using less than 150MWh of electricity per annum.

(c) the impact on pricing policies of any borrowing, capital, dividend, and taxation, obligations of the regulated offer retailer, including obligations to renew or increase assets;

(d) the quality of the provision of services to small customers under standard retail contracts of the regulated offer retailer;

(e) any licence, obligation or retailer authorisation under the Act, any regulations made under the Act, the National Energy Retail Law (Tasmania), the National Energy Retail Regulations (Tasmania), the National Energy Retail Law (Tasmania) Act 2012 and any regulations made under that Act, that apply, or are likely to apply, to the regulated offer retailer;

(f) the Tasmanian Electricity Code;

(g) the National Electricity Rules;

(h) any costs (including capital expenditure) incurred by the regulated offer retailer at the direction of the Regulator;

(i) the public interest; and

(j) any other matter the Regulator considers relevant.

In addition, under section 40AB(1) of the ESI Act, in determining the maximum standing offer prices Aurora Energy may charge to small customers, the Regulator must:

(a) estimate the operational costs of the retailer in providing standard retail services; and

(b) 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; and

(c) take into account the principle that small customers should be protected from the adverse effects of the exercise of substantial market power by –

   a. the Hydro-Electric Corporation; or

   b. the regulated offer retailer in relation to prices, pricing policies and standard of service in respect of the provision of standard retail services by regulated offer retailers; and

(d) take into account the principle that, for the purpose of benefitting the public interest, there is a need for efficiency in the provision of standard retail services.

Further, section 6(2) of the ESI Act specifies that in exercising powers and functions under the Act, the Regulator is to promote efficiency and competition in the electricity supply industry and protect the interests of consumers of electricity.

1.2 Tasmanian context

The structure of the Tasmanian electricity market is significantly different from the market in other jurisdictions on mainland Australia. Compared to mainland Australia, Tasmania has some major industrial customers that account for a relatively large share of electricity consumption. Residential and small business customers therefore account for a much smaller share of total electricity consumption compared to Australia as a whole.

Over 90 per cent of electricity generated in the State is produced by entities fully or partly owned by the State Government. The major generator, Hydro Tasmania accounts for 85 per cent of all on-island electricity generation. TasNetworks, which operates the State's transmission network and the distribution network, is also State-owned. The Aurora Energy, also a State-owned company, is the major retailer with currently around 97 per cent of residential customers and 97 per cent of small business customers.[2]

As a result of Hydro Tasmania's very large market share of electricity generation in the State, the ESI Act includes regulation of Hydro Tasmania's wholesale electricity financial risk contracts. Hydro Tasmania is required to offer certain financial risk contracts that are approved by the Regulator. These contracts are available to retailers such as Aurora Energy. TasNetworks operates under regulatory oversight of the Australian Energy Regulator (AER), which includes network prices, and the Regulator.

Since full retail competition was introduced into mainland Tasmania on 1 July 2014, retailers other than Aurora Energy have been able to offer products to residential customers and small business customers. The entry of new retailers into the Tasmanian market (particularly the residential sector) has been relatively recent with 1st Energy entering the residential customer market in early 2019. Since then, other retailers have entered the residential market.

Regulated prices provide a safety net price for small customers, and are the maximum prices that Aurora Energy can charge small customers, except in cases where Aurora Energy sells electricity under market contracts. Aurora Energy currently does not offer any market contracts to residential customers but does sell electricity to some small business customers under market contracts.

Aurora Energy offers a range of tariffs to residential and small business customers that are regulated, including time-of-use tariffs such as Tariff 93 and Tariff 94 and tariffs designed for particular customers, such as its irrigation time-of-use tariff (Tariff 75).

1.3 Consultation process

In August 2020, the Regulator decided to review the methodology to be used in determining Aurora Energy's standing offer prices. In April 2021, the Regulator released its draft Retail Electricity Standing Offer Price Methodology Review Approach Paper which set out the Regulator's intended approach for the 2022 price investigation. Nine submissions were received on the draft Approach Paper. Copies of the draft Approach Paper and submissions can be found on the Regulator's website: www.economicregualtor.tas.gov.au.

In September 2021, the Regulator released its Approach Paper. The Approach Paper includes the Regulator's responses to the issues raised by stakeholders during consultation on the draft Approach Paper.

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2 Based on data reported by retailers operating in Tasmania to the Australian Energy Regulator for quarter 4, 2020-21 (combined customer numbers for customers on standard retail contracts and customers on market offer contracts).

Notice of the 2022 price investigation was published on the Regulator's website in September 2021 and was revised in January 2022. As part of the revised notice, the Regulator advised stakeholders that it is seeking written submissions on this Draft Report by 25 March 2022.

1.4 Aurora Energy's submission

In October 2021, Aurora Energy provided two versions of its pricing submission to the Regulator - a public version and a commercial-in-confidence version. In accordance with section 16(1) of the ESI Act and its *Policy on the Treatment of Confidential Submission*s, the Regulator agreed not to publish the commercial-in-confidence submission due to commercial sensitivity considerations. The public version, titled *2022 Price-regulated Retail Service Pricing Investigation: Preliminary Submission*, is available on the Regulator's website.

On 28 Oct 2021, Aurora Energy provided a presentation on its submission to the OTTER Customer Consultative Committee (OCCC).

1.5 Next steps

The Regulator seeks comments and submissions on this Draft Report. All information obtained by the Regulator during the investigation including comments and submissions received in response to this Draft Report, and all submissions received to date, will be taken into account in the preparation of the Regulator's Final Report, which is to be completed by 29 April 2022.

After completing the Final Report, the Regulator will issue a Price Determination, which sets out how maximum prices are to be set for Aurora Energy's standing offer prices over the regulatory period (1 July 2022 until 30 June 2025).

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

2 APPROACH TO SETTING MAXIMUM STANDING OFFER PRICES

Regulated prices are set to enable a retailer to recover the costs of supplying electricity to customers on standard retail contracts.

The costs of providing retail services are:

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

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

The Regulator is adopting a 'building block' approach under which these costs are summed to arrive at a total value of forecast costs for the year. Some of these costs are set by other processes, such as network costs that are approved by the AER, while other costs are approved by the Regulator, such as the cost to serve and the retail margin.

The Regulator allows Aurora Energy to recover these costs and so this estimated total cost is set as the Notional Maximum Revenue or NMR) for each year. The maximum retail prices that Aurora Energy may then charge under the different tariffs is required to result in Aurora Energy's total revenue not exceeding the NMR. That is, if the prices under each tariff are applied to the billing days and load relating to the forecast number of customers under that tariff, the aggregate so obtained must not exceed the NMR.

The NMR is calculated solely for the purpose of setting maximum prices, based on a set of assumptions including customer numbers and the volume of electricity sold (load). Aurora Energy's actual total costs, and revenue, will be different, one reason for which is that customers numbers and load cannot be predicted with 100 per cent accuracy. The Regulator does not set any cap on Aurora Energy's actual total revenue. For these reasons, the revenue level set for pricing purposes only is described as notional.

By examining all of Aurora Energy's costs, including allowances set by the Regulator, the Regulator seeks to ensure that customers pay no more than necessary for the services they receive.

As set out in the Regulator's Approach Paper, the Regulator's approach is generally similar to the approach in the 2016 Determination. However, the retail margin will be set as a dollar amount per customer rather than as a percentage of total costs as under the 2016 Determination.

2.1.1 Calculating the NMR

The formula for the cost build-up method of determining maximum standing offer prices is:

$$NMR_y = WEC_y + NC_y + RET_y + M_y + CTS_y + AEMO_y + MARGIN_y + K_y + A_y + CF_y$$

where:

y	=	the relevant financial year, eg Year 1, 2 and 3.
NMR_y	=	the notional maximum revenue that Aurora Energy can receive and is calculated for each of periods 1, 2 and 3 during the annual standing offer price approval process.
WEC_y	=	the forecast of wholesale electricity costs and is based on the wholesale energy price (WEP), forecast load and distribution and marginal loss factors.
NC_y	=	forecast network costs. Network costs comprise two components: transmission and distribution charges.
RET_y	=	the forecast cost of Aurora Energy complying with the Australian Government's mandatory renewable energy schemes.
M_y	=	the forecast of allowed metering costs.
CTS_y	=	Aurora Energy's cost to serve.
$AEMO_y$	=	the total of Aurora Energy's forecast market participant fees and ancillary service charges, as set by AEMO.
$MARGIN_y$	=	the retail margin which is intended to reflect the risks Aurora Energy incurs in providing retail services to small customers under standard retail contracts.
K_y	=	an aggregate of approved under and/or over recoveries for network costs, metering costs, RET and AEMO costs under the 2022 Determination (and so only applying in years 2 and 3).

A_y	=	an adjustment made as a result of a tax event, a material change in circumstances or a material change in Aurora Energy's costs.
CF_y	=	an aggregate of under and/or over recoveries from the previous period covered by the 2016 Determination.

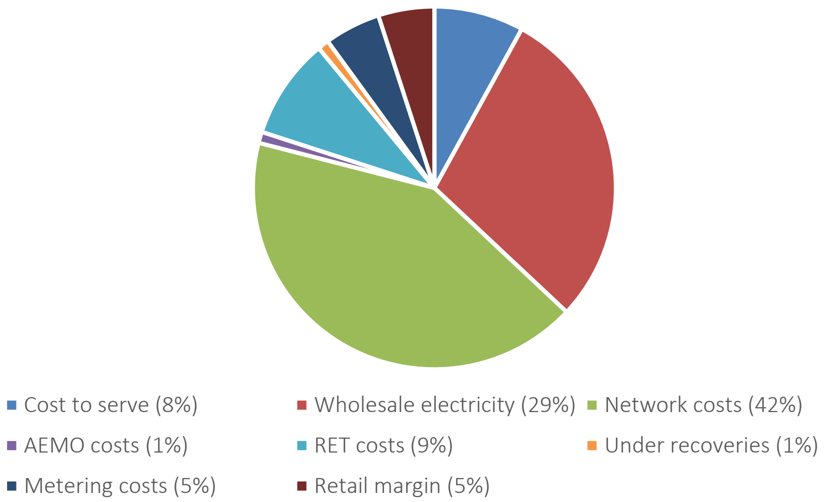
The Regulator has determined that the forecast of customer numbers will be the mid-point of actual customer numbers as at 31 March prior to the start of each year and a forecast of customer numbers as at 31 March during the year. Billing days, which refers to the number of days that a tariff is used by customers within a financial year, for network costs and metering costs will be reconciled to this forecast of customer numbers.

The Regulator has also determined that the load in the NTB will be a forecast of the total amount of electricity consumed by the forecast number of customers over the 12 month period from 1 April to the following 31 March.

2.1.2 Cost components in 2021-22

Figure 2.1 illustrates how each of the cost components contributed to Aurora Energy's NMR for 2021-22.

Figure 2.1 Cost components in 2021-22 (per cent)



For 2021-22, the NMR was $512 million. The largest cost components were network costs (42 per cent) and wholesale electricity costs (29 per cent).

3 WHOLESALE ELECTRICITY COSTS

Wholesale electricity costs are a significant component of the retail price of electricity. The estimate of the WEC is based on the wholesale energy price, forecast load and network loss factors.

3.1 Background

Under the National Electricity Market arrangements, Aurora Energy buys its electricity from the National Energy Market Operator (AEMO) in the spot market for the Tasmanian region (except for electricity purchased from feed-in tariff customers). Spot prices are very volatile. At times they may be negative, while at other times they may be 100 times or more above the average price. Retailers would be exposed to unacceptable risks if they purchased all their electricity from the spot market without any hedging contracts with electricity generators.

Hydro Tasmania is the dominant generator in Tasmania and controls the majority of the generation capacity in the state. Hydro Tasmania is also the principal 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 wholesale financial contracts at regulated prices that are available to authorised retailers operating in Tasmania.

Hydro Tasmania is required to offer four financial risk contract types (load following swaps, baseload swaps, peak period swaps, and baseload caps) approved by the Regulator, with the objective of providing retailers in Tasmania with similar conditions and levels of risk and duration as available to 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 *Wholesale Contract Regulatory Instrument* (Instrument). The Instrument documents a rules-based methodology for calculating the prices for each contract type. The Instrument produces weekly prices and specifies minimum volumes that Hydro Tasmania must offer for up to two years ahead. The Regulator monitors and regulates these prices.

As electricity flows through the transmission and distribution systems a portion 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. 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 (multiplied) 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. Distribution Network Service Providers determine the DLFs to apply in each financial year, and, after approval from the AER, provide the DLFs to AEMO for publication. 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 in late May/early June each year to apply to the following financial year.

3.2 2016 Determination

The 2016 Determination calculated the WEC as follows:

$$\mathbf{WEC}_y = (\textbf{forecast load}_y \times \mathbf{WEP}_y \times \mathbf{DLF}_y \times \mathbf{MLF}_y)$$

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*

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)[3] 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 load following swap, which is a financial hedge contract where the price per kWh is set and the volume in the contract is based on a specified load profile.

[3] Section 43G(1) of the ESI refers to the Instrument.

Since 2014, the Regulator has calculated the WEP using a weighted average of load following swap prices offered over the previous eight quarters (104 weeks). The WEP calculation method is set out in the Regulator's Guideline, titled *Guideline - Standing Offer Price Approval Process in Accordance with the 2016 Standing Offer Price Determination*. The WEP is determined in May or June each year prior to next financial year.

3.3 What other regulators do

To estimate future wholesale electricity costs in the cost build-up, the ICRC, QCA and ESC each 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, multiplied by an uplift factor that compensates for the spot price volatility risk in the NEM. The ICRC has engaged a consultant, Frontier Economics, to assist with calculating these costs.

3.4 Calculation of the WEP

In developing the current method to calculate a WEP, the Regulator took into consideration that:

- a retailer is unlikely to seek to hedge its exposure to spot market risk by purchasing a single block of contracts at one point in time (ie enough contracts to meet expected demand for the whole year); and
- even if a retailer chose to adopt this approach, Hydro Tasmania should not be required to contract for such a large volume under the Instrument.

The Regulator recognised that a retailer adopting a prudent hedging strategy would progressively buy contracts over a period of time. For these reasons, as set out in the current Standing Offer Price Approval Guideline, the Regulator developed the following weighted average method for calculating the WEP:

> (a) for those weeks where Hydro Tasmania is not required to offer regulated contracts, the respective Absolute Minimum Capacity Offer Volume will be set to zero and the LFS price for that week will also be set to zero;
>
> (b) multiply the weekly regulated load following swap (LFS) price by the weekly Absolute Minimum Capacity Offer Volume for that quarter for eight quarters preceding the start of each quarter of the relevant period;
>
> (c) use the weekly point-in-time LFS price for each quarter of the relevant period at the time that the Economic Regulator calculates the WEP for all future weeks remaining in each quarter for which there are no regulated LFS prices; and
>
> (d) divide the sum of the values calculated in accordance with clauses (b) and (c) by the sum of the weekly Absolute Minimum Capacity Offer Volumes for the eight quarters preceding the start of each quarter of the relevant period.

The Regulator assessed that the use of the Absolute Minimum Capacity Offer Volumes is appropriate as the volumes are intended to provide retailers with sufficient regulated contracts to meet Tasmania's small customer load. Further, as the volumes are weekly, prices can be incorporated weekly without creating a bias towards a particular week.

The Regulator also considered that a point-in-time price is the best estimate of future prices for each quarter as it incorporates all the information available to the market at the time. The method provides a transparent method for calculating the WEP consistent with section 40AB(3) of the ESI Act.

TasCOSS and the Tasmanian Small Business Council have stated that wholesale prices have fallen to historically low levels. They claim that this has led to a situation in recent years where the WEP has been set higher than actual wholesale prices in that year so that Aurora Energy has been in a position to benefit from such outcomes.[4]

The Regulator acknowledges that under the current approach, there will be years when the WEP is higher than prevailing electricity prices, but also periods when the WEP is lower.

An alternative approach to calculating the WEP is to place more weight on recent LFS prices and less weight on earlier prices. Under this approach the WEP may align more closely with current spot prices. It is likely, however, that prices would be volatile from year to year.

However, the Regulator recognises that the use of financial contracts means that Aurora Energy's actual wholesale electricity costs for any particular period may be materially different to the prevailing spot prices. These costs will depend on the volume of electricity subject to financial contracts and the forward prices in these financial contracts.

The Regulator considers that the current method reflects how retailers in other regions of the National Electricity Market might enter into financial risk contracts to hedge its spot market risk exposure.

On balance, the Regulator's draft assessment is to continue to use the current method to calculate the WEP. If there were a change in the method, it would have to take effect from 2023-24 or, more reasonably, 2024-25 as Aurora Energy would need sufficient time to adjust its contracting activities.

The method of calculating the WEP will be set out in the Standing Offer Price Approval Guideline that will apply under the 2022 Determination.

3.5 Draft assessment

The Regulator intends to continue to use the method outlined in the 2016 Determination and in the current Standing Offer Price Approval Guideline to calculate wholesale electricity prices and wholesale electricity costs for all years to which the 2022 Determination applies.

[4] TasCOSS and Small Business Council of Tasmania submission to the draft Approach Paper, 14 May 2021, page 11.

4 NETWORK COSTS

Electricity retailers incur a number of costs over which they have no control and which they seek to recover in their prices to customers. Of these costs, network charges are the most significant and often account for between 35 per cent and 45 per cent of all costs.

4.1 Background

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

Network costs are regulated by the Australian Energy Regulator. The AER conducts periodic pricing investigations and determinations on network pricing. Each year, TasNetworks submits its annual price proposal for the AER's approval and the AER assesses whether the proposal aligns with the AER's determination. The AER approves tariffs to apply for 12 months from 1 July of each year and are usually set in April or May of the previous year. The current price determination for TasNetworks is for the period from 1 July 2019 to 30 June 2024.

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

4.2 2016 Determination

In the 2016 Determination, the network cost component of Aurora Energy's NMR 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.

If the charges are not known when the NMR must be calculated (eg if the AER has not approved TasNetworks' prices by that time) Aurora Energy's network costs need to be based on an estimate of the charges (such as based on TasNetworks' draft price proposal) for the next year. An adjustment may have to be made in the subsequent year if there is a difference between the estimated and the actual charges. Adjustments are discussed further in Chapter 10.

4.3 What other regulators do

The Regulator's approach is consistent with that taken by the Independent Competition and Regulatory Commission (ICRC), Essential Services Commission (ESC) and Queensland Competition Authority (QCA) in relation to network costs. That is, the AER sets the network costs and the regulators allow these costs to be passed through to electricity retailers each year.

4.3.1 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.

Additionally, the ICRC allows for an adjustment to network costs if there is a different tariff mix during the price period compared to that forecast.

4.3.2 QCA

Where the underlying network tariff structure is similar to an existing retail tariff the QCA uses the applicable network prices approved by the AER in determining regulated retail prices.

Where, for historical reasons, the retail tariff is different from the network tariff eg the underlying network tariff has materially changed or is non-existent, the QCA uses an indexation approach. Under this approach, the previous year's network costs are modified by applying the relevant AER X-factors[5] used for revenue smoothing for transmission and distribution businesses. The resultant network tariffs are then applied in the cost build-up of individual tariffs.

4.3.3 ESC

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 uses the simplest network tariff in each zone, ie a daily supply charge ($ per day) and a usage charge ($ per kWh), in determining prices for each zone.

4.4 Draft assessment

The Regulator intends to adopt the current approach to forecast network costs. That is, the network cost component of Aurora Energy's NMR is 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.

As set out in its Approach Paper, the Regulator intends to reconcile the billing days used in deriving network costs with the forecast of the customer, ie the billing days used when forecasting network costs are to relate directly to the forecast of customers numbers.

The Regulator will only include network costs relating to services provided to customers on standard retail contracts in the network cost component of Aurora Energy's cost build-up.

5 X-factors are weights that are applied to allowable revenue for one year to calculate the allowable revenue for the next year using a CPI-X price formula.

5 RENEWABLE ENERGY TARGET COSTS

5.1 Introduction

The NMR includes an estimate of the annual costs of Aurora Energy 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 which then seek to pass through the 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).[6]

[6] The CER operates the STC Clearing House, which facilitates the exchange of small-scale technology certificates (STCs) between buyers and sellers. The STC Clearing House is accessible via the Renewable Energy Certificate Registry.

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).

5.2 2016 Determination

As set out in the 2016 Determination, the formula for estimating the LRET costs was as follows:

LRET cost = (RPP x $/LGC x liable MWh)

The CER publishes its RPP by 31 March on a calendar year basis. However, the Regulator's allowance for RET costs is calculated on a financial year basis. Under the 2016 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 applied a forecast RPP calculated using the formula in section 39(2)(b) of the *Renewable Energy (Electricity) Act 2000 (Cwlth)*.

The formula for estimating the SRES costs was as follows:

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. During the 2016 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.

During the period of the 2016 Determination, Aurora Energy's allowance for LGC costs and SRES costs was the actual costs incurred by Aurora Energy for the liable MWh for electricity sales to customers on standard retail contracts.

As the LRET and SRET schemes operate on a calendar year basis, it was necessary to allocate the estimated annual liable MWh between the first half of the financial year (ie 1 July to 31 December) and the second half of the financial year (ie 1 January to 30 June). Under the 2016 Determination, the Regulator allocated the annual load in the proportions of 55/45 for the first and second half of the each financial year. As part of the calculation of over and under recoveries for RET costs, Aurora Energy's actual load proportions are used.[7]

5.3 What other regulators do

The ICRC, QCA and ESC estimate their respective retailers' costs of complying with the Australian Government's mandatory renewable energy schemes using a similar method. However, the way the allowance for LGC and STC costs is determined differ as different approaches are adopted for setting the per unit price of the certificates. These differences are discussed below.

[7] For example, if the early winter months (May and June) were particularly cold, the actual proportions could be 50:50.

5.3.1 ICRC

In its 2020 Determination, the ICRC applied a market-based approach for determining LRET and SRES costs. The ICRC's model determined LGC and STC prices based on publicly available price data averaged over an 11-month period.

5.3.2 QCA

In its most recent Determination, the QCA used a consultant to estimate LRET costs using a market-based approach. Under this approach, LGC prices were based on forward prices for certificates published by the Australian Financial Markets Association. In comparison, STC prices were based on the clearing house price of $40 per certificate because the QCA considered that, historically, the spot prices have been at or close to this price.

5.3.3 ESC

In its 2021 Determination, the ESC used a market-based approach to estimate LRET costs. The applicable market price for LGCs was determined by taking 12-month volume-weighted average of LGC forward trades for each year as reported by Demand Manager, an energy broker. For STC prices, the ESC used the clearing house price of $40 per certificate.

5.4 Method to calculate LGC and STC prices

As set out in the Approach Paper, the Regulator intends to set the LGC price for each year from 2022-23 to 2024-25 to be a weighted price calculated using:

- the LGC price and the volume of LGCs purchased by Aurora Energy under the Cattle Hill Power Purchase Agreement (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.

The Regulator recognises that retailers that are wholly exposed to RET prices under spot prices or short term contracts may face unacceptable financial risks and pay more for LGCs than under a longer term contract. The Regulator also notes that PPAs enable retailers to manage these risks and understands that many retailers enter into PPAs for this reason. The Regulator has therefore decided to include Aurora Energy's long term contractual commitments under the Cattle Hill PPA to be included in the allowance for Aurora Energy's LGC costs.

In calculating the weighted LGC price for the relevant year, the proportion of LGCs purchased under the Cattle Hill PPA would be calculated as follows. Aurora Energy forecasts the percentage of its total LGC liability that will apply to the estimated load required to supply customers on standard retail contracts. Aurora Energy will then apply that percentage to the total number of LGCs purchased under the Cattle Hill PPA for that year to determine the number of LGCs to be included in the weighted LGC price. The remaining LGCs required for the estimated load required to supply customers on standard retail contracts will be priced at the forward price for that year.

The forward price for the remaining LGCs in the relevant year is to be estimated by Aurora Energy as the weighted average of ten months of weekly forward LGC prices in the previous year (the average of forward LGC prices from the first Wednesday in July through to the last Wednesday in April). The Regulator considers that this reflects a plausible strategy of a retailer to purchase LGCs. The Regulator considers that this approach is likely to result in less price volatility from year to year, and therefore less volatility in retail prices, compared to setting the forward price using the most recent price available.

This would require Aurora Energy to source the weekly forward prices from an independent market based source, such as an energy broker.

In relation to STC prices, the Regulator intends to apply a similar 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. For months where there is an absence of a forward market price, the Regulator has considered a number of options, including:

- using the most recent offer price for the relevant month(s);
- using the CER's clearing house price ($40); and
- using an average of monthly forward prices that have been available during the year up to the end of April.

The Regulator considers that the use of an average of the forward prices that are available is the preferred option as 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, the Regulator intends to allow Aurora Energy to recover brokerage and acquittal costs.

5.5 Draft assessment

To determine the cost allowance for RET-related costs, the Regulator intends to include the LGC price and the volume of LGCs purchased by Aurora Energy under the Cattle Hill PPA for the relevant year, and an average forward price for the remaining LGCs and for the STCs.

In all other respects, the Regulator intends to adopt the same approach in allowing RET-related costs as in the 2016 Determination.

6 METERING COSTS

Metering costs comprise the costs associated with the installation, maintenance and reading of meters, and the costs associated with the introduction of metering competition and fee-based metering services.

6.1 Background

Metering competition commenced on 1 December 2017. Under the Power of Choice reforms, Aurora Energy has been required to engage at least one a Metering Coordinator for its small customers since that date. The Metering Coordinator is responsible for providing metering services for customers for whom its meters are installed, and for managing service levels, rule compliance and performance reporting. Any new or replacement meter installed by the Metering Coordinator must be an advanced or interval meter.

There are currently two types of meters for Aurora Energy's customers and three parties/entities responsible for managing them:

- For Type 6 meters or accumulation meters, which are analogue meters that measure the total electricity consumed over a period and require manual reading, the meters are owned by TasNetworks, which is also responsible for reading these meters. Customers on Tariffs 31 and 41 (most residential customers are on this combination) are likely to have two Type 6 meters on their premises.
- Type 4 or interval meters, which are advanced meters that record usage in real time. These meters are also able to record usage against multiple tariffs and can be read remotely.
    - Aurora Energy appointed Yurika (previously Metering Dynamics) to manage the installation, maintenance and reading of Type 4 meters from 1 December 2017.
    - TasMetering was appointed as an additional Metering Coordinator from 1 June 2021 following the completion of a public tender procurement process. Since that time, all new meters are installed by TasMetering.

6.2 2016 Determination

In the 2016 Determination, the Regulator introduced a separate cost component for metering in the NMR formula in order to provide more transparency on these costs. The Regulator 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.

Under the 2016 Determination, 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 6 years commencing from 1 December 2017); and
- fee-based metering services recovered on an annual basis.

While the cost of an advanced meter is significantly higher than that of an accumulation meter, under Aurora Energy's tariffs, all customers pay the same for metering costs irrespective of the type of meter that they have.

The substantially higher cost of advanced meters can be observed through the increase in metering costs allowed by the Regulator over the regulatory period covered by the 2016 Determination in Table 6.1.

Table 6.1 Aurora Energy's metering costs, 2016-17 to 2021-22 ($nominal)

	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
Metering costs ($m)	13.2	12.0	14.1	16.1	21.3	25.9
% of total NMR	2.7%	2.4%	2.7%	3.0%	3.9%	5.1%

In the Regulator's draft Approach Paper, the Regulator advised that it was considering applying a separate metering charge, depending on whether the customer is on an advanced meter or accumulation meter. After considering the issues raised by stakeholders, the Regulator decided not to introduce a separate metering charge.

6.3 What other regulators do

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

6.3.1 ICRC

In its 2020 price determination, the ICRC included advanced meter costs in ActewAGL's allowances. The ICRC considered that it would be fairer to customers to 'smear' advanced meter costs across the regulated base. In addition, the ICRC noted that advanced meter costs are likely to increase over time as the number of advanced meters increases. Therefore, the ICRC considered that delaying the inclusion of advanced meters in the cost build-up would likely result in a larger price increase when they were included.

6.3.2 QCA

Prior to its 2022 Determination, the QCA did not allow notified prices to residential and small business customers to recover metering costs. This is because under Queensland's *Electricity Act 1994*, these charges cannot be included in notified prices. However, Ergon Energy, the regulated retailer, is able to charge customers a meter service charge which is separate to notified prices (ie these charges appear on a customer's bill as a separate item).

For the 2022 Determination, the QCA received Terms of Reference from the Minister responsible for Queensland's Electricity Act that required the QCA to consider setting charges for advanced meters for small customers in regional Queensland. The intention of this approach is to ensure that customers pay the same metering cost regardless of the type of meter installed at their premises.

6.3.3 ESC

The ESC does not include a separate cost component for metering when determining annual VDOs. This is because electricity distribution businesses in Victoria are required to install advanced meters for all small customers. 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 network costs.

6.4 Draft assessment

The Regulator intends to continue to use the current approach to calculating metering costs and also to require Aurora Energy to reconcile billing days used in deriving metering costs with the forecast of the customer numbers used in the NTB.

Currently, around one third of Aurora Energy's residential customers are on advanced meters. It is expected that by the end of the next regulatory period, the vast majority of Aurora Energy's residential customers will be on advanced meters.

7 RETAIL COST TO SERVE

This chapter examines Aurora Energy's cost to serve (CTS) allowance. The allowance reflects the Regulator's assessment of the efficient level of operating costs Aurora Energy requires to provide retail services to customers on standard retail contracts (standard contract customers) over the 2022 Determination period. These costs include:

- billing and revenue collection;
- marketing;
- providing advice and answering customer queries;
- contributing to corporate overheads;
- allowance for bad debt; and
- regulatory compliance.

7.1 2016 Determination

In the 2016 Determination, the Regulator estimated Aurora Energy's CTS allowance via a cost build-up approach and then compared the result against the CTS allowances approved by regulators in other jurisdictions. The cost build-up approach involved a detailed review of Aurora Energy's operating costs.

The CTS allowance included an allowance for customer acquisition and retention costs (CARC) on the assumption that Aurora Energy would be operating in a competitive market. The Regulator's primary consideration was to ensure that the cost to serve allowance reflected the efficient costs associated with acquiring and retaining customers.

For 2016-17, the Regulator determined Aurora Energy's CTS to be $138.45 per customer. This figure was then indexed by the growth in the Hobart Consumer Price Index (Table 7.1).

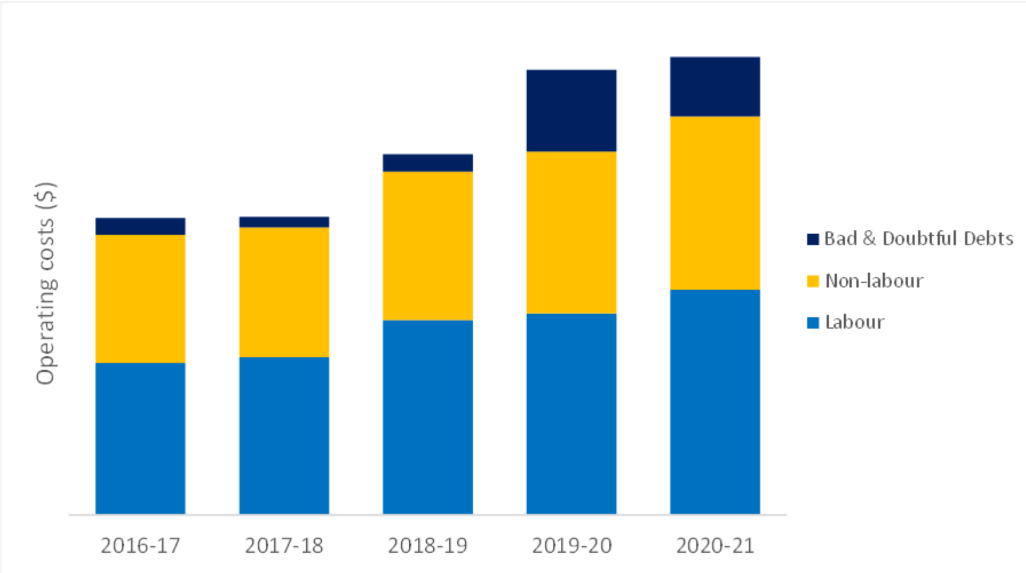
Table 7.1 Aurora Energy's CTS allowance from 2016-17 to 2021-22 ($ per customer, nominal)

	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
CTS per customer	$138.45	$140.50	$143.16	$145.69	$148.35	$149.22

Aurora Energy has provided its total business operating costs from 2016-17 to 2020-21 (Figure 7.1).[8] Aurora Energy's retail operating costs increased only marginally in real terms in 2017-18 and then by around 20 per cent per annum in 2018-19 and 2019-20 before falling to around one per cent in 2020-21.

[8] For commercial-in-confidence reasons, the Regulator has not shown the dollar amounts.

Figure 7.1 Trends in Aurora Energy's retail operating costs ($nominal)



Source: Aurora Energy.

In its submission, Aurora Energy states that several changes to its operating environment have placed upward pressure on its operating costs, particularly labour costs. These include the impact of COVID-19, the introduction of metering competition and the emergence of residential retail competition. Aurora Energy also stated that during the 2016 regulatory period there have been changes to customer engagement and expectations, and increased technology and information security requirements.

As shown in Figure 7.1, a step change in labour costs across Aurora Energy's total business is evident from 2017-18 to 2019-20. Aurora Energy states the key labour cost drivers have been the establishment of new teams and increased workforce to manage customer expectations and needs in a more competitive market. Operating costs for communications and information technology also stepped up in 2019-20 and again in 2020-21 compared to previous years.

Aurora Energy's bad and doubtful debt costs more than tripled in 2019-20, coinciding with the start of the COVID-19 pandemic, and have remained high. Aurora Energy stated that relative to other jurisdictions, residential customers in Tasmania have experienced marked increases in the levels of electricity-related debt.

During the 2016 Determination period, Aurora Energy decommissioned its pay-as-you-go (PAYG) pre-payment product, which was not regulated. Almost all of these customers (around 30 000) moved to Aurora Energy's standard retail contracts over the period of the 2016 Determination. This contributes to Aurora Energy having a much larger number of standard contract customers in the first year of the next regulatory period (estimated at 272 000) compared to the number in 2016-17 (around 239 500). This represents a 12.5 per cent increase, which may have enabled some economies of scale to be obtained in Aurora energy's retail operations relating to these customers.

7.2 Regulator's approach for the 2022 Determination

As set out in the Approach Paper, the Regulator has estimated Aurora Energy's cost to serve (CTS) allowance by using a cost build-up approach and then tested the result against CTS allowances for retailers in other Australian jurisdictions. This involved conducting a detailed review of Aurora Energy's operating cost structure to calculate what the Regulator considers to be an efficient CTS figure.

To inform the Regulator's assessment, the Regulator engaged Utilities Regulation Advisory (URA) and Oakley Greenwood (OGW) to review the efficiency of Aurora Energy's proposed CTS.

7.3 Review of Aurora Energy's proposed cost to serve

In its submission, Aurora Energy proposed a CTS allowance of $172.54 per customer in 2022-23 (expressed in 2020-21 dollars)[9] which includes costs related to its digital product, aurora+. Aurora Energy used a cost build-up approach to estimate the allowance and considers that its proposed CTS is broadly in line with recent NEM-wide estimates.

Aurora Energy has categorised its costs into core and support functions directly related to providing electricity retail services for standard contract customers on. Those costs associated with customer acquisition and retention have been included in its core function costs, rather than being separately identified.

As set out in the Approach Paper, the Regulator intends to allow Aurora Energy to continue to recover CARC in response to other retailers operating in the Tasmanian retail electricity market.

7.3.1 Aurora Energy's proposed operating costs

The Regulator sought details from Aurora Energy of its forecast operating costs for the 2022-25 regulatory period. In response, Aurora Energy provided its CTS model and additional information in response to specific information requests made by the Regulator.

In conducting its review, the Regulator also examined Aurora Energy's Annual Reports and Corporate Plans to assess whether any significant issues or events might impact on Aurora Energy's operating costs during the regulatory period.

The Regulator focussed on reviewing three areas:

1. the assumptions adopted by Aurora Energy in estimating its operating costs;
2. the allocation of expenses between standard contract customers and market contract customers; and
3. the nature of the expenses allocated to standard contract customers.

[9] The actual dollar amount will be greater in 2022-23 to allow for increases in price and wage levels. As an example if costs are inflated by 2.5 per cent per year, the value for 2022-23 would be around 5 per cent higher.

Aurora Energy adopted a base-step-trend (BST) framework for estimating its retail costs, except for aurora +. This involved the following steps:

1. establishing a base year cost level by using Aurora Energy's actual retail operating costs for 2020-21 and removing non-recurring expenditure and costs that relate to unregulated services; and

2. escalating the cost categories for each year of the regulatory period to account for wage growth, customer numbers and inflation over the regulatory period.

Aurora Energy separately forecast aurora+ costs for each year. From these estimates, Aurora Energy calculated forecasts of its total cost to serve for 2022-23 to 2024-25.

7.3.2 Consultant's review of Aurora Energy's cost to serve

URA/OGW assessed Aurora Energy's expenditure by reviewing Aurora Energy's costs for the base year (2020-21), and how Aurora Energy rolled forward those costs to account for scale growth, input price growth and efficiency improvements and adjustments for incremental changes to costs.

URA/OGW provided a report to the Regulator on its findings and recommendations. As the report contains commercial-in-confidence information, the report has not been published. A summary of the report has been published on the Regulator's website.

URA/OGW reviewed Aurora Energy's written submission and supporting information including Aurora Energy's CTS model. It also held discussions with Aurora Energy and the Regulator's Office before submitting a final report to the Regulator on 10 February 2022.

URA/OGW's review incorporated the following tasks:

- a review of Aurora Energy's forecasting methodology;
- a review of Aurora Energy's proposed base year cost level; and
- a review of Aurora Energy's proposed changes to costs for the three years from 2022-23 to 2024-25.

URA/OGW found that Aurora Energy's forecasting approach broadly aligns with a BST methodology, but that it had adopted a different approach for forecasting expenditure related to bad debt expenses.

URA/OGW found that Aurora Energy had appropriately adopted 2020-21 actual expenditures from Aurora Energy's general ledger data to develop base year cost estimates. URA/OGW noted that Aurora Energy does not have a documented process setting out how shared costs, such as labour and communications and information system costs, are allocated between Aurora Energy's regulated and unregulated activities. In the absence of this data, URA/OGW found that the application of cost allocations based on billing outcomes and customer numbers was conceptually appropriate and based on data.

URA/OGW reviewed Aurora Energy's costs for the base year and found that there was insufficient activity level cost data over recent years to assess whether these costs are efficient. Instead, URA/OGW assessed these base year costs against publicly available costs for retailers across Australia reach 'a high level' finding on the efficiency of Aurora Energy's costs. URA/OGW found that Aurora Energy's costs for its base were, on balance, reflective of the efficient costs of providing retail services in Tasmania.

URA/OGW considered that Aurora Energy's use of cost escalation factors broadly align with good practice regulatory practice. The exception was Aurora Energy's treatment of efficiency improvement as productivity gains were not fully accounted for in the changes in costs from year to year for the 2022 Determination period. This is discussed further below.

Further analysis provided by URA/OGW in its report to the Regulator is discussed in the context of specific cost categories in the sections below.

7.3.3 Productivity improvements

There are no explicit productivity gains in its CTS forecasts. Aurora Energy has, however allowed for labour cost savings in its estimates of labour costs in 2020-21, which have the effect of increasing productivity by 1.62 per cent in 2022-23.

URA/OGW has assessed whether this productivity growth factor is sufficient. URA/OGW considers that that changes over time in real retail costs per customer is a reasonable indicator of productivity gains achieved by retailers. URA/OGW reviewed the changes in retail operating costs for NEM retailers over the period from 2017-18 to 2020-21, as reported by the Australian Competition and Consumer Commission (ACCC) as part of its 2021 inquiry into retail electricity prices.[10] This was estimated at 3.4 per cent per year, using the changes in real retail costs per customer for all NEM retailers, except the largest three, for this four year period.

URA/OGW recommended that this should be the basis for productivity gains to be included in the CTS estimates. An efficiency factor was estimated by URA/OGW, which accounted for Aurora Energy's labour efficiency estimate. For 2022-23, URA/OGW recommends that the Regulator adopt an efficiency factor of 1.78 per cent applied to the CTS estimates provided by Aurora Energy.

The Regulator considers that given the significant reductions in retailer costs per customer in mainland Australia in recent years, which has not been reflected in Aurora Energy's CTS allowance over this period, Aurora Energy's retail costs should be adjusted to account for productivity improvements.

The Regulator intends to accept the URA/OGW recommendations, including accepting Aurora Energy's allocation of costs between regulated and non-regulated activities. The Regulator intends to apply an efficiency factor of 1.78 per cent to Aurora Energy's CTS in 2022-23. In 2023-24 and 2024-25, the Regulator intends to apply an efficiency factor of 3.4 per cent.

7.3.4 Bad debt expenses

Aurora Energy's estimate of its bad debt expenses includes a forecast of a bad debts over the regulatory period and a temporary premium to the bad debt to account for COVID impacts.

In its submission, Aurora Energy noted that the AER, in its *2019-20 Annual Retail Market Report*, found that Tasmania has the highest proportion of in-debt residential customers of

[10] ACCC, *Inquiry into the National Electricity Market – November 2021 report*, November 2021. This is discussed in more detail in section 7.4.

any AER authorised retailer jurisdiction (which excludes Victoria, West Australia and the Northern Territory). The Regulator notes that in the AER's *2020-21 Annual Retail Market Report*, Tasmania still has the highest proportion of in-debt residential customers (equal with South Australia), though the percentage declined from around 5.2 per cent in 2019-20 to around 3.5 per cent in 2020-21. The AER also reported that the average level of debt was highest in Tasmania, at just under $1 300, which compares with an overall average debt level of $1 000.[11]

The Regulator also notes that for small business customers, the proportion of Tasmanian customers in debt, as reported in the AER's *2020-21 Annual Retail Market Report*, was much lower in other jurisdictions, at around one half of the overall average percentage. The average debt level for these customers was reported at around $2 400, just under the overall average debt level of around $2 500.

Aurora Energy assumes that average debt per customer will be constant over the regulatory period. However, based on the statements made by Aurora Energy in its submission regarding the benefits of aurora+, URA/OGW concluded that it would be reasonable to assume that the average bad debt per customer would decline over the regulatory period.

The Regulator has reviewed Aurora Energy's estimates of its debt costs expenses per customer and considers that they are reasonable. This is consistent with the recommendation from URA/OGW.

The Regulator intends to accept the consultant's recommendation that an efficiency factor also be applied to Aurora Energy's bad debt expenses to reflect the potential reduction in bad debt per customer from the increased take up of aurora+. This is discussed in more detail in section 7.3.5.

7.3.4.1 Bad debts associated with COVID-19 restrictions

Aurora Energy has added a temporary premium to its forecast of bad debt to account for COVID-19 impacts, based on the regulatory precedent set by the ESC's 2021 Victorian default offer (VDO) determination. In this determination, made in November 2020, the ESC increased the allowance for bad debts by $6 per customer in 2021. Aurora Energy included a COVID-19 adjusted bad debt allowance of $4 per customer in 2022-23, declining by $2 each year to be zero in 2024-25.

For the VDO that commenced on 1 January 2022, the ESC removed the temporary COVID-19 allowance.[12]

Tasmania's economy has not been affected by the COVID-19 restrictions to the same extent as Victoria and several other jurisdictions. Tasmania's Gross State Product (GSP), for example, increased by 3.8 per cent in 2020-21, according the ABS, which compares with a decline of 0.4 per cent in Victoria. Tasmania's growth in GSP and GSP per capita over 2020-21 was the second highest in Australia. This trend is also apparent in other indicators such as the ABS's Wage Price Index, which has been increasing at a faster rate in Tasmania than in Victoria and nationally.

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[11] AER, *Annual Retail Market Report 2020-21*

[12] Essential Services Commission, *1 January 2022 Victorian Default Offer, Final Decision*, 25 November 2021.

The Regulator considers that economic conditions in Tasmania would support the removal of any COVID-19 adjustment for bad debts and intends to remove Aurora Energy's bad debt allowance for COVID-19 for all years.

7.3.5 Aurora+

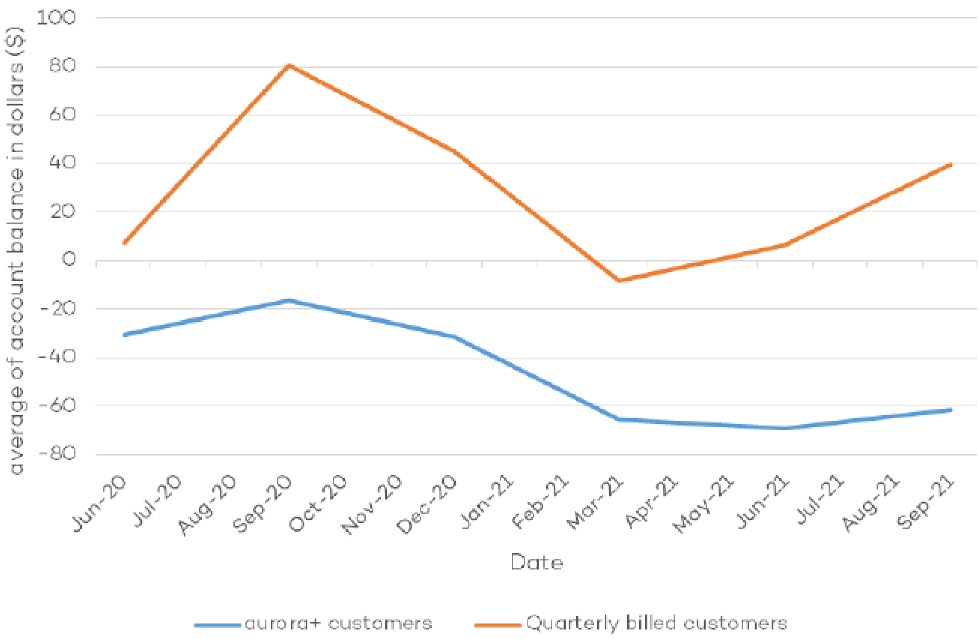
The aurora+ app allows customers with an advanced meter to review their energy usage and make payments, access bills and establish direct debit arrangements from their smartphone or device.

The aurora+ app was introduced in 2019 to replace the PAYG product. To access the app, Aurora Energy currently charges a separate product service fee of 11 cents per day. At the time of its submission in October 2021, Aurora Energy estimated that around 36 000 customers were using the product.

Aurora Energy is proposing that aurora+ costs is included in the regulated cost base under the 2022 Determination such that customers would no longer have to pay separately for the app. Aurora Energy claims that aurora+ provides significant benefits to customers by providing them with greater visibility and control over their electricity usage.

Aurora Energy provided data to show the differences in the outstanding debt level of aurora + customers compared to non-aurora+ customers. The debt levels have been significantly lower for customers with the aurora+ app (a lower account balance), especially around the winter months when quarterly bills are higher (Figure 7.2).

Figure 7.2 Average bill/outstanding debt level comparison of aurora+ customers to non-aurora+ customers



Source: Aurora Energy submission, page 27

Aurora Energy considers that, based on internal surveys, customers have experienced significant benefits on the product since it was introduced.

According to Aurora Energy, by 1 July 2022 it expects around 140 000 standard contract customers will have an advanced meter and therefore could use the aurora+ app. If the aurora+ costs are included in the cost to serve, at the start of the next regulatory period around one half of the standard contract customers would face electricity bills that include the aurora+ costs but would not be able to access the benefits of aurora+.

Aurora Energy is planning an extensive rollout of advanced meters over the next few years. According to Aurora Energy's projections, around 90 per cent of its standard contract customers will have advanced meters by the end of the next regulatory period. It is expected, therefore, that by 2024-25 a large majority of standard contract customers would be able to access the benefits of aurora+.

The Regulator intends to accept Aurora Energy's proposal to include the aurora+ costs in Aurora Energy's CTS so that, from 1 July 2022, Aurora Energy would no longer separately charge its customers for the app.

7.3.5.1 Including aurora+ in the cost base

Aurora Energy provided separate expenditure forecasts for aurora+. The proposed expenditure from 2021-22 to 2024-25 for aurora+ comprises labour (70 per cent), consultants and services (15 per cent), communications and IT (14 per cent) and bad debt expenses (1 per cent). Aurora Energy proposed the allowance for aurora+ of an average of $17.33 per customer over the three years (in $2020-21).

Aurora Energy's allocation of labour costs attributable to aurora+ includes those relating to its customer service centre. URA/OGW reviewed Aurora Energy's allocation of costs to aurora+. They found that the proposed expenditure on aurora+ was separately and appropriately accounted and that Aurora Energy's assumed call rate for aurora+ customers was reasonable.

URA/OGW also reviewed Aurora Energy's proposed allocations for bad debts relating to aurora+ and concluded that these costs should be removed ($0.07 million in 2022-23). This is because the basis for estimating this cost was not clear and it appeared that it was derived from the $40 per year annual cost of aurora+. The Regulator agrees with this assessment therefore intends to not include these costs in the CTS allowance.

A significant proportion of Aurora Energy's estimated costs for the aurora+ app relate to marketing. A high level of expenditure may have been reasonable when Aurora Energy was trying to encourage customers to take up the app. However, the Regulator considers that the type and overall level of marketing that is needed if an app has a separate cost to customers is different from the marketing needed if the app is free to users.

The Regulator has not been provided with evidence to justify the proposed level of marketing expenditure and intends to allow only one half of the proposed marketing expenditure over the regulatory period. The Regulator also intends to apply the efficiency factor to the aurora+ costs.

The aurora+ cost estimates assume an increasing rate of adoption of the app, from 100 000 customers in 2022-23 to 130 000 customers by 2024-25. This represents a large increase from the current level of around 40 000 customers. The Regulator will seek further information from Aurora Energy on these projections and will consider reducing the aurora+ cost allowances in the Final Report and Determination if the Regulator is not satisfied that the projections are plausible.

The Regulator intends to allow aurora+ costs of an average of $14.15 per customer (in $2020-21), over the next regulatory period, subject to being satisfied that the take up rates by Aurora Energy customers are plausible.

Based on information provided by Aurora Energy, with the current number of customers purchasing the app, revenue from the aurora+ app would be around $1.5 million per annum. By allowing aurora+ costs to be included in Aurora Energy's CTS under the Regulator's intended cost allowance, Aurora Energy's revenue would be around $3.8 million per annum and would be assured every year.

7.3.6 Platform and information technology costs

Platform and information technology costs include the provision and management of all technology in Aurora Energy. This covers all aspects of software, hardware and technology resources. In its submission, Aurora Energy has stated that these costs have been increasing due to the digitisation of customer services.

A key component of this cost category in the past have been costs relating to Aurora Energy's Customer Care and Billing (CC&B) system. Aurora Energy is in the process of transitioning to a new billing system which is expected to be fully operational in late 2022. The new billing system is a cloud-based billing product. Costs incurred by Aurora Energy for the system include those to configure or customise the system, and ongoing fees to obtain access to the application software.[13]

The Regulator notes that Aurora Energy has removed the implementation costs for the migration of the billing system. However, it appears that Aurora Energy has included some costs (licences, support and maintenance) that relate to its legacy billing system. The Regulator considers that these costs should be removed given that the current CC&B system is in the process of being decommissioned and will not be in operation for the bulk of the regulatory period. The Regulator therefore intends to remove these costs from the CTS.

7.3.7 Labour costs

In its submission, Aurora Energy states that changes to its operating environment over the 2016 Determination period have resulted in increased labour costs.

The Regulator notes the significant increase in Aurora Energy's labour costs in recent years and the changes in its operating environment. However, the Regulator is concerned that references to cost savings (both targets and achievements) in past annual reports[14] have disappeared in more recent annual reports.

As discussed earlier in this chapter, Aurora Energy has factored in some labour savings in its cost estimates. As with other cost components, the Regulator intends to apply the efficiency factor to Aurora Energy's labour costs.

13 Aurora Energy, *2020-21 Annual Report*, page 61.

14 See for example Aurora Energy's 2016-17 and 2017-18 annual reports.

7.3.8 Other costs

Aurora Energy has included a category for unspecified projects for each year. The Regulator understands, however, that no specific projects have been identified. While some projects that emerge over the regulatory period that would justify this expenditure, the Regulator considers that it is difficult to justify allocating costs to, and expecting regulated customers to pay for, projects that are unknown or uncertain at this time. The Regulator therefore intends to not include these costs in the CTS allowance.

7.3.9 Customer numbers

Aurora Energy states that its costs are largely fixed in nature and do not vary materially with variable components such as the number of customers and customer load.[15]

In its Approach Paper,[16] the Regulator acknowledged that if Aurora Energy's customer numbers change, Aurora Energy will have more or fewer customers from which to recover its fixed costs attributable to providing services under standard retail contracts. Therefore, the Regulator indicated it intended to allow the cost to serve allowance to vary in accordance with customer numbers by including a separate mechanism whereby the CTS is adjusted for the change (either upwards or downwards) in customers between periods.

7.3.10 Determining actual CTS allowances for each year

The Regulator will determine a final CTS allowance for 2022-23 in May/June 2022. As discussed above, the estimates prepared to date by Aurora Energy and the Regulator have been expressed in 2020-21 dollars. It is necessary, therefore, to index these estimates to ensure they take account of inflation, including wage inflation.

The Regulator intends to adjust the CTS amount for each year by:

- adjusting the CTS to reflect changes in customer numbers;
- using Tasmania's Wage Price Index (ABS CAT NO 6345.0) for Aurora Energy's labour cost components;
- using the Hobart Consumer Price Index (ABS CAT NO 6401.0) for all non-labour cost components; and
- applying the efficiency factor for the relevant year across all costs.

This is a different approach than in the 2016 Determination, under which all costs were indexed by changes in the national (eight capitals) Consumer Price Index. The Regulator considers that indexing Aurora Energy's retail costs to Tasmania's Wage Price Index, for labour costs, and to the Hobart Consumer Price Index, for non-labour costs, is likely to result in changes in the CTS allowance that more accurately reflect underlying cost changes for Aurora Energy.

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15 Aurora Energy submission, page 32.

16 Regulator, 2022 Standing Offer Determination Approach Paper, September 2021.

The CTS allowance for 2022-23 in the Regulator's Final Report and Price Determination will be expressed in nominal or current dollars.

7.4 CTS allowances in other jurisdictions

As discussed above, the Regulator's approach is to estimate Aurora Energy's cost to serve allowance using a cost build-up approach and test the result against the CTS allowances in other Australian jurisdictions.

The CTS allowances set by other regulators are discussed below.

7.4.1 ICRC

The 2014 allowance for retail operating costs was based on a benchmark review by IPART in 2012-13.[17] At the time, IPART determined an efficient retail operating cost for a standard retailer (on a per customer basis).[18] This involved undertaking a bottom up analysis, using information provided by retailers operating in NSW on their historic, current and forecast retail operating costs, and adjusting the results to remove costs recovered elsewhere, such as costs associated with late bill payment as these are recovered through a late payment fee.

In its 2020 Determination, the ICRC calculated that the CTS per customer was $127.84 in 2020-21. The ICRC did not separately estimate a CARC. Instead, when estimating retail operating costs as a whole, the ICRC used a benchmarking approach that considered both cost to serve and reasonable customer acquisition and retention costs.

The ICRC has indexed retail costs to CPI movements since 2014.

7.4.2 ESC

In estimating its most recent retail costs on a per customer basis, the ESC relied on the decision made by the ICRC in its 2017 price determination. These costs have been adjusted for inflation and include an allowance to reflect additional costs associated with operating in Victoria. As described above, the ICRC's 2017 (and 2020) benchmark was originally derived from IPART's 2012-13 benchmarking review.

For 2022, the ESC determined that the VDO's CTS per customer was $181 per residential customer.

7.4.3 QCA

The QCA undertook a comprehensive review of retail costs as part of its 2016-17 price determination. The assessment used a combination of bottom-up and benchmarking methods, using information from public sources (including retail market offers) and confidential information from retailers. Separate retail costs are applied to the fixed and variable cost components of retail prices.

[17] IPART 2013, *Review of regulated retail prices and charges for electricity – Final Report*.

[18] IPART defines a standard retailer as an incumbent retailer that has achieved economies of scale; serves retail customers; can offer retail customers standard form and negotiated customer supply contracts; and has an existing customer base to defend.

However, the QCA does not separate out retail operating costs (ie CTS) from its retail margin. The Regulator therefore considers there is limited value to be drawn from the QCA's recent decisions.

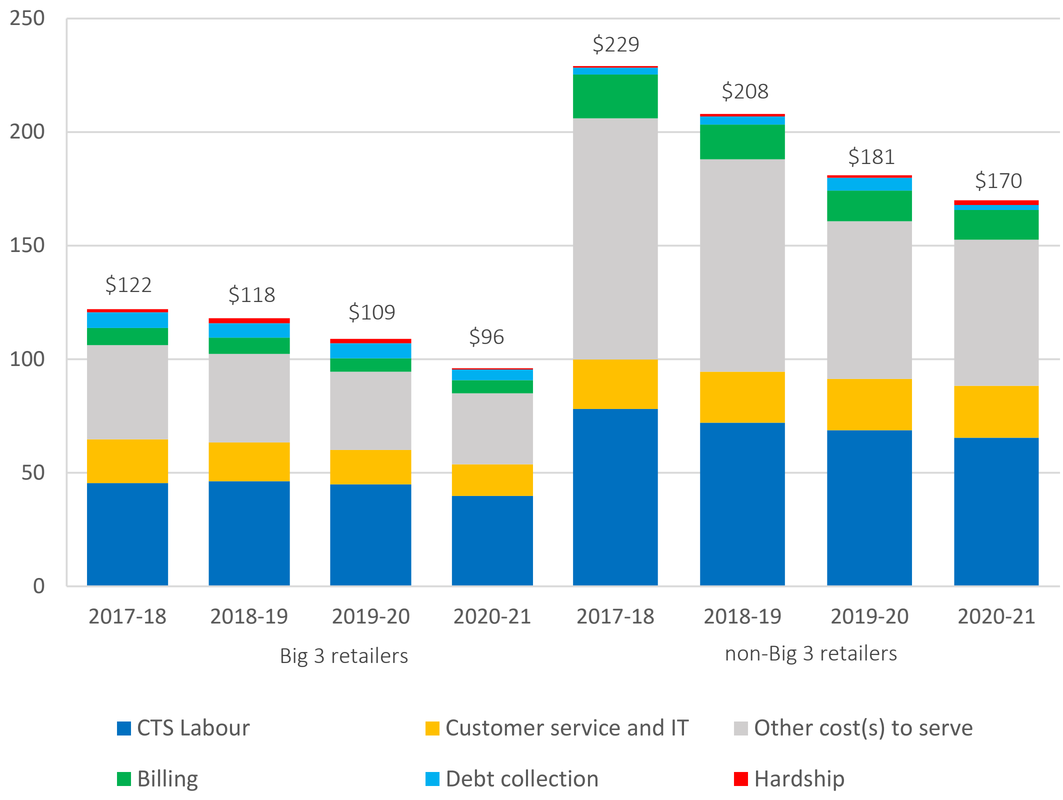
7.4.4 Estimates of Australian retailers' CTS

URA/OGW considered the most appropriate means of testing whether Aurora Energy's base year estimates reflect efficient costs is to compare its proposed costs to publicly available estimates of retailers' cost to serve.

The most recent information is contained in the Australian Competition and Consumer Commission's (ACCC) Inquiry into the National Electricity Market - November 2021 Report. This report breaks down the costs of providing electricity retail services within the NEM and compares the costs in different jurisdictions within the NEM, except Tasmania.

The reported expenditure outcomes in the ACCC's report are categorised between the big 3 retailers and non-big 3 retailers (see Figure 7.3).

Figure 7.3 Average retail and other costs per customer[19], 2017-18 to 2020-21 ($2020-21, excluding GST)



Source: Based on information from the ACCC's Inquiry into the National Electricity Market - November 2021 report, pages 34 and 37.

Two important findings emerge from these estimates. Firstly, the cost to serve has been falling very significantly in recent years in real terms for large and small retailers. By contrast, Aurora

19 The retail costs include two main categories of costs: cost to serve, and cost to acquire and retain (CARC).

Energy's cost to serve allowance has not fallen in real terms since 2016-17. The ACCC report stated:

> There have been multiple years of consecutive decreases in retail costs per customer in each region, except for Tasmania.[20]

This is the basis for the efficiency factor the Regulator intends to apply for the next regulatory period.

Secondly, economies of scale are evident in electricity retailers' operations. The average cost to serve of the big 3 retailers was estimated to be a little more than one half of the cost to serve of smaller retailers.

This is consistent with the Aurora Energy's submission, which stated:

> Aurora Energy's costs are largely fixed in nature and do no vary materially with variable components such as the number of customers and customer load.[21]

URA/OGW found that Aurora Energy's proposed CTS ($172.54 per customer) aligns closely with the average costs incurred by non-big 3 retailers ($170 per customer for 2020-21). However, as Aurora Energy's customer base is around three times the average of the non-big 3 retailers and given the opportunities for scale economies, the Regulator would expect an efficient level of Aurora Energy's cost to serve to be below the average of the non-big 3 retailers.

7.5 CTS review summary

The Regulator has reviewed Aurora Energy's estimates of its base year level of expenditure for 2020-21 and how these costs would flow through to cost to serve allowances from 2022-23 to 2024-25.

The Regulator is satisfied that Aurora Energy's approach to developing its cost to serve forecasts was robust. Based on the Regulator's review of Aurora Energy's operational costs and URA's/OWG's findings, the Regulator intends to change the CTS allowance by:

- applying an efficiency factor (1.78 per cent in 2022-23 and 3.4 per cent in 2023-24 and 2024-25) across all cost categories, including bad debts, contained in Aurora Energy's CTS. The efficiency factor is compounding and will be applied in each year of the regulatory period;
- removing the COVID-19 adjustment for bad debts;
- decreasing marketing costs for the aurora+ app;
- removing the allowance for revenue protection and bad debts relating to aurora+;
- removing some costs that relate to Aurora Energy's previous billing system; and

20 ACCC, Inquiry into the National Electricity Market - November 2021 report, page 30.

21 Aurora Energy, Submission to the 2022 Pricing Investigation, page 32.

- removing the allocation for unspecified projects.

This CTS estimate of $156.42 per customer is within the level of CTS allowances in recent decisions by regulators in Australia. It also aligns with the CTS estimates of the ACCC, as it is below the CTS of the non-big 3 retailers, that have around one third of the number of customers of Aurora Energy, but very much more than the CTS of the largest three retailers.

Having reviewed Aurora Energy's operational costs, considered URA's/OGW's findings and examined arrangements in other jurisdictions, the Regulator intends determining a CTS allowance for Aurora Energy of $156.42 per customer in 2022-23 (in $2020-21). This allowance for Aurora Energy's CTS for 2022-23 is around $16.12 per customer lower than proposed by Aurora Energy and around $8.10 per customer or 5.5 per cent higher than the level in 2021-22 of $148.35 in 2020-21 dollars (Table 7.2)[22]

Table 7.2 Comparison of Aurora Energy's approved CTS in 2021-22, Aurora Energy's proposed CTS and the Regulator's intended CTS allowance for 2022-23 ($2020-21)

	Per customer $
Aurora Energy's CTS in 2021-22	$148.35
Aurora Energy proposal for 2022-23	$172.54
Regulator's draft assessment for 2022-23	$156.42

[22] The actual CTS allowance in 2021-22 was $149.22. To express the CTS for that year in $2020-21 as in Table 7.3, this value has been discounted by the national CPI increase between 2020-21 and 2021-22. The CTS is the same dollar value as the actual CTS in 2020-21, as the CTS allowance is indexed to the CPI under the 2016 Determination

8 RETAIL MARGIN

8.1 Introduction

The retail margin is intended to compensate Aurora Energy for the risks it faces providing standard retail services to its customers. It also enables Aurora Energy to recover financing and depreciation costs that are not included in the cost to serve allowance.

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.

Further, section 6(2) of the ESI Act specifies that in exercising powers and functions under the Act, the Regulator is to promote efficiency and competition in the electricity supply industry and protect the interests of consumers of electricity.

As set out in the Approach Paper, the Regulator intends to calculate the margin on a dollar amount per customer basis that takes into account the risks faced by Aurora Energy.[23] The reason for this approach is that when the retail margin is set as a percentage of approved costs, the dollar value may fluctuate considerably from year to year. The value of Aurora Energy's margin, which may considered as its profit, for any year depends on the level of Aurora Energy's costs such as network and wholesale electricity costs, even though the risks that Aurora Energy faces may not have been affected.

This chapter discusses Aurora Energy's allowed retail margin. In any year, Aurora Energy's actual retail margin could be quite different. For example, Aurora Energy may face higher or lower average wholesale electricity prices than allowed in the Regulator's price determination. Aurora Energy's actual RET costs, or cost to serve, may also be higher or lower than the level allowed by the Regulator.

Aurora Energy does not set the same retail margin on all its regulated tariffs. Historically, the retail margin on tariffs to business customers was higher than on tariffs to residential customers. Also the retail tariffs on time-of-use tariffs such as Tariff 93 and Tariff 94 may be lower than the retail margin on tariffs such as Tariffs 31 and 41 and Tariff 22.

8.2 The 2016 Determination

In 2016, the Regulator adopted a benchmarking approach to setting Aurora Energy's retail margin. In determining the retail margin, the Regulator considered the margins set in other jurisdictions. At that time, the Regulator did not identify any evidence suggesting that Aurora

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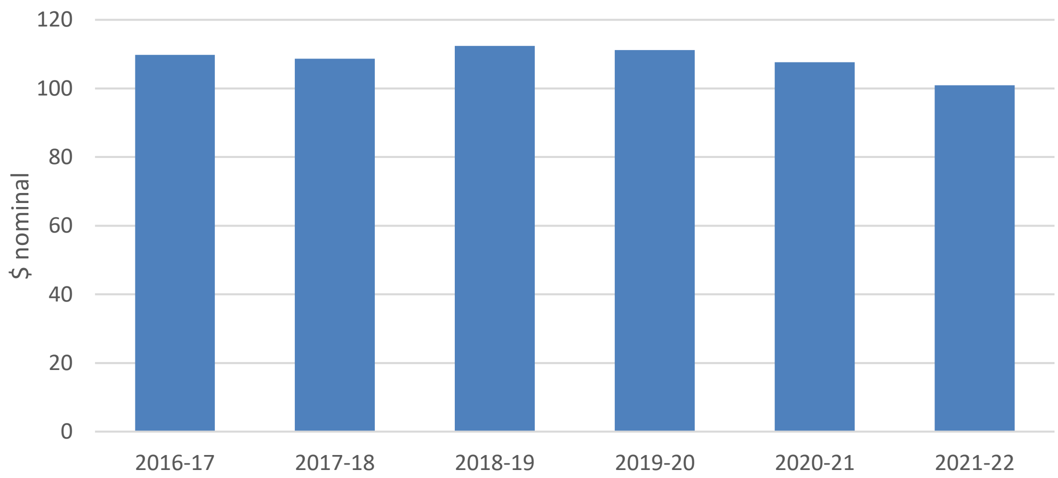
[23] Tasmanian Economic Regulator, *Retail Electricity Standing Offer Price Methodology Review Paper*, 24 September 2021.

Energy's risks were greater than the risks facing regulated offer retailers operating in other Australian states and territories. Consequently, the Regulator considered that it was appropriate to allow a retail margin that was comparable with the retail margins allowed by regulators in other jurisdictions.

The Regulator decided to provide Aurora Energy with a retail margin of 5.7 per cent per annum on total costs for each year of the current regulatory period.

The allowed retail margins on a dollars per customer basis over the regulatory period covered by the 2016 Determination ranged from approximately $101 in 2021-22 up to $112 in 2018-19 (Figure 8.1). Since 2018-19, the dollar value of the retail margin has decreased in nominal terms, on average, by around 3.5 percentage points each year.

Figure 8.1 Aurora Energy's allowed retail margin per customer ($ nominal)



Source: Aurora Energy's approved retail margin and customer numbers.

Aurora Energy's retail margin per customer fluctuates depending on the movement in costs and customer numbers. The decrease in the retail margin per customer in recent years largely reflects lower energy costs and the impact of adding APAYG customers to the number of customers on standard retail contracts in 2019-20 and 2020-21.

8.3 What other regulators do

Below is a summary of arrangements in other jurisdictions.

8.3.1 ICRC

The ICRC uses a benchmarking approach when determining the retail margin. In its 2020 determination, the ICRC considered other factors, including the current downward trend in wholesale energy prices which it considered warranted an increase in the retail margin on the basis that this trend represents an increased (wholesale price) risk to retailers. The ICRC assessed that the increase in the retail margin percentage would ensure that the dollar value of the retail margin would remain a reasonable profit margin.

The retail margin for ActewAGL (the regulated retailer in the ACT) is 5.6 per cent of approved costs and was $13.33 per MWh in 2020-21. The ICRC does not publish ActewAGL's load or customer numbers, so a retail margin per customer is not publicly available. However, using Aurora Energy's load and customer numbers, $13.33 per MWh is equivalent to approximately $110 per customer on standing offer prices.

8.3.2 ESC

The ESC also uses a benchmarking approach based on recent decisions by Australian energy regulators to estimate a retail margin for its Victorian Default Offer (VDO). The ESC's most recent margin is 5.7 per cent of approved costs which equates to a retail margin of $68 per residential customer for the 2022 calendar year. The margin has decreased in recent years from $79 in 2020 and $73 in 2021. While the retail margin, as a percentage, has been the same as in Tasmania, the dollar value been considerably lower in Victoria, due to the lower level of approved costs.

For its most recent margin, the ESC also examined the level of retail margins in Victoria by analysing retail electricity costs from the cost data submitted by Victorian retailers. The assessment indicated that the average retail margin recovered by retailers in Victoria in 2019-20 and 2020-21 was in line with the margin allowed in the VDO. This suggests that at a broad level there is no significant difference in the retail margins set by the ESC for the Victorian Default Offer and the existing margins in the Victorian retail electricity market.

8.3.3 QCA

The QCA's model does not have a specific allowance for a retail margin. Rather, the margin is included as part of retail costs. The QCA considered it unnecessary to estimate an efficient retail margin. Instead, the QCA's approach focuses on estimating an efficient total level of retail costs, which implicitly includes some retail margin. .

8.3.4 Frontier Economics' report on retail costs and margin

In 2019, the ESC engaged Frontier Economics to examine retail costs and margins. Frontier Economics used two approaches to estimate the retail margin - a benchmarking approach and an expected returns approach.[24]

In relation to the benchmarking approach, Frontier Economics reviewed the regulatory allowances used by the QCA (in 2015), the ICRC (in 2014), OTTER (in 2016) and IPART (in 2013). All of these retail margins were 5.7 per cent of approved costs.

Frontier Economics' also used an 'expected returns' approach to estimate a reasonable retail margin. The expected returns approach involves calculating the cost of compensation for the systematic risks associated with an efficient business using the weighted average cost of capital approach. Using this method, Frontier Economics concluded that an acceptable range for the retail margin was between 4.8 per cent and 6.1 per cent.

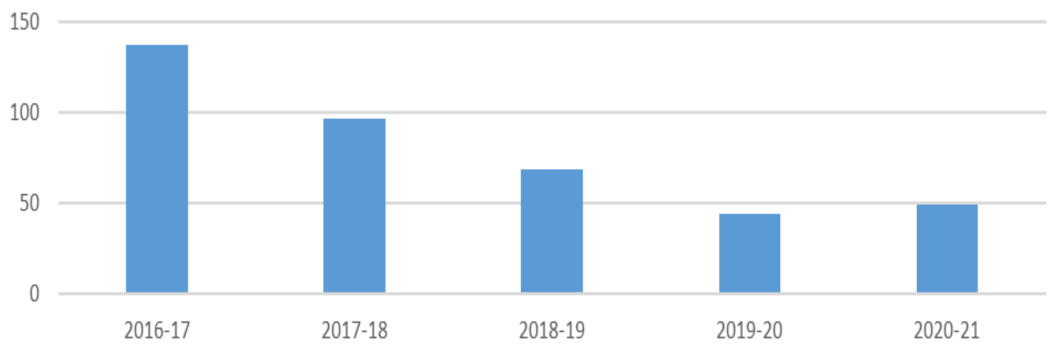
[24] Frontier Economics, *Retail Costs and Margin: A report for the Essential Services Commission*, April 2019.

8.3.5 ACCC Inquiry into the National Electricity Market

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

On 13 December 2021, the ACCC released an updated report - Inquiry into the National Electricity Market (November 2021). The average retail margin across the NEM was estimated at $49 per residential customer in 2020–21 (Figure 8.2) which equates to around a 3.4 per cent margin on their actual costs.

Figure 8.2 Estimated retail margin per average residential customer in the NEM ($/customer)



Source: ACCC Inquiry into the National Electricity Market (November 2021), page 31.

According to the ACCC's report, there has been a substantial decline in retail margins from 2016-17, when retail margins peaked at $137 per average residential customer. This represents a decline in the retail margin per customer of around 64 per cent from 2016-17 to 2002-21. The general trend of multi-year decreases in retail margins was observed for all NEM regions except for Tasmania where the ACCC did not separately report on retail costs and margins.

Although retail margins are trending down, the ACCC commented that it is difficult to identify the drivers. However, the ACCC did identify some potentially relevant factors:

- The introduction of the DMO and VDO in 2019 acted to reduce prices for those customers on standing offer prices. The ACCC considered that this could have directly contributed to reduced margins for retailers that previously had material numbers of customers on those higher-priced plans.
- Competition in retailer energy markets and relatively low barriers to entry. In January 2017, there were around 29 retailers that offered electricity contracts. By February 2021, this increased to 44 retailers. While this may not be sufficient to result in increased competition, the Australian Energy Regulator identified that retail markets for electricity in south-east Queensland, New South Wales, Victoria and South Australia have several

competitive characteristics, such as a diversity of sellers making offers, intensive marketing activity and customer switching.[25]

- The COVID-19 pandemic. The ACCC considered that the effect of the pandemic on retailers' margins is complex and the net impact is unclear. The ACCC noted substantial changes in usage which resulted in increased residential customer usage but decreases in business customer usage, with mixed effects on specific retailers' revenue depending on their market exposure. The ACCC stated that if, as a result of the pandemic, an increasing proportion of customers were unable to pay their electricity bills, this would decrease revenue and so final retail margins would fall.

The Regulator has identified some factors that limit the ACCC's findings in informing the allowance to be made for 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 2020-21 retail margins in South Australia and south-east Queensland were negative.
- Unlike the information provided on the cost to serve, the ACCC report did not publish separate retail margins for the largest three retailers and the other retailers. The reported average retail margin in the NEM was heavily influenced by the retail margin of the largest three retailers, whose combined customer market share in the NEM is around 70 per cent. The average number of customers of the largest three retailers is just under two million or around seven times the number of Aurora Energy's customers.
- Many large retailers in the NEM, including the three largest retailers, are vertically integrated companies that operate generation and retail businesses. These companies generally face lower risks than standalone retailers such as Aurora Energy.
- Furthermore, the ACCC report stated that the retail margin for a vertically integrated retailer is likely to be largely dependent on the price at which it buys wholesale electricity from its wholesale division and that this will affect the margin of the retail arm of the business.

Despite these factors, however, the Regulator notes that there has been a very significant decline in the retail margin in mainland Australia in recent years and that this is in contrast to the retail margin in Tasmania, which is relatively high in absolute dollar terms and has declined by a much lower amount.

8.4 Discussion of risks

In its submission, Aurora Energy claims that the only risks that should be taken into account should be 'systematic or non-diversifiable risks' only (such as economic, political, or social factors and not risks specific to Aurora Energy). This is consistent with the Capital Asset Pricing Model approach which is used to estimate a weighted average cost of capital.

Aurora Energy engaged Frontier Economics to prepare a report to assist in its response to OTTER's queries on the types of financial risks faced by Aurora Energy (a copy of the report

[25] Australian Energy Regulator, 'State of the Energy Market 2021', July 2021, p 244.

was provided to the Regulator on 30 November 2021). The Frontier Economics report concluded that:

- the regulated retail margin should be set to provide compensation for systematic risk only;
- recent regulatory determinations support a regulated retail margin of approximately 5.7 per cent of approved costs; and
- compensation for managing non-systematic risks are provided through other cost allowances.

The Regulator notes that the Capital Asset Pricing Model methodology is widely used for the pricing of regulated electricity network businesses, as well as businesses in the gas and water and sewerage industries. It can also provide a check on the return to equity implicit in a retail margin. However, there is no reference to the Capital Asset Pricing Model methodology in the Regulator's Approach Paper for this investigation, which instead states:

> The Regulator has decided to continue to adopt a benchmarking approach to setting the retail margin that takes into account the risks faced by Aurora Energy and to calculating the margin on a dollar amount per customer basis and including this amount as part of Aurora Energy's cost to serve. The Regulator notes that there is a trade-off between allowing over and under recoveries and the size of the retail margin. To the extent that Aurora Energy's risks are reduced by allowing over and under recoveries to be reflected in prices in the following years, a lower retail margin may be appropriate.[26]

This is also consistent with the requirement in Section 40AB(1)(b) of the ESI Act, reproduced in section 8.1 above, which refers to Aurora Energy making a reasonable return on its investment, taking into account the risks it faces in making that investment.

For this reason the Regulator has examined some specific risks that Aurora Energy faces.

8.4.1 Energy price risk

As discussed in earlier chapters, 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 a much more liquid and transparent forward contract markets than those in Tasmania.

Unlike in mainland Australia, there is extensive regulation of the wholesale electricity price in Tasmania under the Wholesale Contract Regulatory Instrument (WCRI), as discussed in Chapter 3. Under the Instrument specified minimum volumes are set for load following swaps, baseload swaps, peak period swaps, and baseload caps 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.

Chapter 3 also sets out how the Regulator calculates the wholesale electricity price (WEP) that is used in setting standing offer prices each year using the prices of future load following swaps

[26] Tasmanian Economic Regulator, *Retail Electricity Standing Offer Price Methodology Review Paper*, 24 September 2021, page 21.

offered over the previous eight quarters (104 weeks) as set out in the Regulator's Guideline, titled *Guideline - Standing Offer Price Approval Process in Accordance with the 2016 Standing Offer Price Determination*.

Importantly, Aurora Energy knows, well in advance, how the Regulator will calculate this WEP. 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.

Aurora Energy does face the risk, however, that the Regulator may change the *Guideline* (such as calculating the WEP over 52 weeks or 156 weeks) 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. While the Regulator may issue a revised *Guideline* that alters the method of calculating the WEP, it would only be in exceptional circumstances that a new *Guideline* would require a new method of calculating the WEP to commence immediately. It is much more likely that a new *Guideline* would require a new method to be implemented after allowing Aurora Energy some time to adjust its contracting activities.

As noted in Chapter 3, new arrangements could be implemented in 2023-24 but it would be more reasonable to implement any new arrangements in 2024-25. It is also relevant that the Regulator does not intend issued a revised Guideline that alters the WEP calculation method and that the final decision will be made a part of the 2022 Determination.

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, with the objective of purchasing electricity at a lower average price than the WEP.

Overall, the Regulator's draft assessment is that, compared to standalone retailers in other Australian jurisdictions, Aurora Energy has lower than average risks relating to the wholesale electricity price, setting aside volume-related risks.

8.4.2 Volume-related wholesale electricity price risks

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

As with all retailers, Aurora Energy commits to meeting the entire load of its customers at a set price charged to customers, yet it cannot 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 of its customers 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, which may be due to:

  - customers switching to and from other retailers;
  - population growth;
  - changes in household formation;
  - growth in the number of dwellings; and
  - changes in business conditions that affect the number of potential business customers.
- Changes in average volume of electricity sold per customer and the load profile, which may be due to :
  - variations in weather;
  - competition from other fuel sources;
  - increased customer consumption from installed generation systems such as solar PV rather than from electricity sold by Aurora Energy;
  - increased adoption of battery storage systems;
  - the uptake of energy efficiency measures, including more energy efficient space and water heating systems;
  - the uptake of electric vehicles that are charged at the home or from the premises of some business customers; and
  - changed patterns of work such as more persons working from home.

It is arguable that with recent technological advances, retailers face increasing challenges in forecasting their customers' load.

TasCOSS and the Tasmanian Small Business Council consider that Aurora Energy faces less risk from customer switching compared with retailers in other NEM jurisdictions, as it is claimed that Aurora Energy has low rates of switching to date.[27] Utilities Regulation Authority/Oakley Greenwood report, for example, that the churn rates that Aurora Energy is applying over the regulatory period are low (0.45 per cent), relative to other parts of the NEM.[28]

The Regulator notes that Aurora Energy considers that that any adjustment of its retail margin based on variations to customer numbers, load and load profile associated with customers switching between retailers, would be inappropriate.

Aurora Energy's customers comprise around 97 per cent of all residential and small business customers in mainland Tasmania. This is a much larger share than for all mainland retailers, including retailers with regulated tariffs. The Regulator's draft assessment is that Aurora Energy is subject to less risk (compared to other retailers) of large scale changes in load due to customer switching. It is not possible, for example, for Aurora Energy to experience a large increase in customer load due solely to customer switching, given its current market share. Aurora Energy may also expect to lose a smaller percentage of its customers than many

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[27] TasCOSS and Small Business Council of Tasmania submission to the draft Approach Paper, 14 May 2021, page 11.

[28] UGA/Oakley Greenwood, Aurora Energy Cost to Serve Review, February 2022, page 6.

retailers due to the small number of other retailers in Tasmania and their very small market share.

In all other respects, however, there is no basis for expecting that Aurora Energy faces volume-related risks, as they apply to electricity sales, that are significantly different from those of other retailers across Australia.

8.4.3 Other risks

Many risks that Aurora Energy faces are faced by all retailers including unexpected increases in operating costs, including IT-related costs. An increasing concern is cyber-related incidents, such as ransomware attacks, and ensuring the integrity and protection of customer data.

Aurora Energy faces asymmetric risks relating to its customer numbers as it at risk of losing a potentially large market share to other retailers, but has relatively little opportunity to increase its market share, as it has such a large share of the market.

In relation to the treatment of some cost components, the Regulator considers 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 the difference in the following year (equally, if some costs are lower than estimated, prices will be lower than otherwise in the following year). Many retailers in competitive markets would be reluctant to increase their prices to recover unanticipated costs in the previous year, if there is strong price competition and so would wear the revenue loss. Overall, across years, Aurora Energy has greater certainty that costs will be recovered in its revenue than retailers in competitive markets.
- To seek to ensure that Aurora Energy is able to recover its fixed costs, the Regulator has agreed that Aurora Energy's cost to serve allowance will be able to vary as customer numbers fluctuate. A smaller number of customers would result in an increase in the cost to serve allowance per customer. Many retailers in competitive markets that lose market share would be reluctant to increase their prices to recover their fixed costs as this could lead to further losses in market share.
- Aurora Energy is able to seek the Regulator's approval of an adjustment to compensate for the impacts of a material change in its costs or tax changes.
- The Regulator has agreed to include in Aurora Energy's RET costs, the prices in its long term Power Purchase Agreement (PPA) with Cattle Hill Wind farm. In practice, while retailers do enter into PPA's to reduce their exposure to short term RET prices, there may be no guarantee that they can recover these costs, if they face strong price competition.

However, the Regulator acknowledges that Aurora Energy is a relatively small retailer with a standing offer customer base of around 270 000 customers and is unable to operate beyond the Tasmanian market. In comparison, larger NEM retailers can spread costs over a larger customer base and spread costs over a wider range of activities (for example, shared marketing costs for electricity and gas).

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

8.4.4 Summary

The Regulator's draft assessment is that Aurora Energy faces lower risks in some areas than other electricity retailers operating in the NEM, especially those that are not part of a vertically integrated business. However, the Regulator acknowledges that it is difficult to quantify the difference in these risks and agrees with Frontier Economics' advice to Aurora Energy that it is not possible to reliably establish the financial risks faced by individual retailers.[29]

Aurora Energy's revenue from the retail margin is designed to enable Aurora Energy to recover its finance and depreciation costs that are not included in the cost to serve. The Regulator notes that net interest costs tend to be low (in 2020-21 they were negative) and that depreciation costs, other than for intangibles, have been low in recent years.

It appears that, nationally, the electricity retail industry is evolving into a relatively low cost, low margin industry. Aurora Energy's proposed margin remains substantially above the average retail margin across Australia in recent years, as estimated by the ACCC.[30] Maintaining a retail margin of around 5.7 per cent would not reflect the recent trend of sharply declining retail margin nationally.

An alternative retail margin for Aurora Energy that reflects:

- the results of the ACCC inquiry;
- the Frontier Economics' recent report for the ESC using an expected returns approach; and;
- the Regulator's draft assessment of Aurora-specific factors

is the mid-point between the minimum of 4.8 per cent estimated by Frontier Economics and Aurora Energy's current retail margin, which produces a retail margin of 5.25 per cent.

8.5 Options

The Regulator has assessed three options to set Aurora Energy's retail margin in dollar terms per customer.

These options are:

1. Aurora Energy's proposal;
2. Calculate the average of the dollar value of Aurora Energy's 2020-21 and 2021-22 retail margin using 5.25 per cent of approved costs, set that value for 2022-23 and then index that value by Hobart's Consumer Price Index; and
3. Calculate the average of the dollar value of Aurora Energy's 2020-21 and 2021-22 retail margin using 5.25 per cent of approved costs, including an allowance for

[29] Frontier Economics, Analysis of risk for the purposes of setting the retail margin allowance, November 2021, page 14.

[30] ACCC, Inquiry into the National Electricity Market - November 2021 report.

aurora+ costs, set that value for 2022-23 and then index that value by Hobart's Consumer Price Index.

In each case, the dollar value of the retail margin is calculated in 2020-21 dollars. The value would be indexed for 2022-23.

Each of these options are discussed below.

1. Aurora Energy's proposal

Aurora Energy's proposed retail margin in dollar terms is the average of the dollar values of the retail margins per customer from 2016-17 to 2021-22 under the 2016 Determination, converted to 2020-21 dollar values to allow for CPI increases. This includes some years when Aurora Energy's approved costs, especially the electricity wholesale price, were significantly higher than in recent years.

This equates to a retail margin of $111.94 per customer (in 2020-21 dollars). This value would be indexed by inflation to determine the 2022-23 value in current dollars.

It is then proposed that this retail margin increase by CPI growth for 2023-24 and 2024-25.

Advantages	Disadvantages
The retail margin is calculated using data over six years and so is not unduly influenced by very recent data.	If Aurora Energy's wholesale electricity and other costs remain around current levels over the regulatory period, this would result in a retail margin of around 6.4 per cent which is higher than regulated retail margins in Australia.
Aurora Energy has a buffer so that if wholesale electricity or other costs increase significantly, the retail margin is likely to remain around the average level of recent years, in percentage terms.	The calculated margin for 2022-23 would be higher than the retail margin in 2020-21 (equivalent to around $108 per customer) and 2021-22 (equivalent to around $100 per customer).
	The margin would be substantially higher than retail margins across the NEM in recent years and would not reflect the recent sharp decrease in retail margins.
	This option does not reflect the Regulator's draft assessment that Aurora Energy faces lower risks, on average, than many retailers in the NEM.

2. Average of 2020-21 and 2021-22 retail margin calculations using a 5.25 per cent retail margin

Under this option, the proposed margin in dollar terms is the average of the dollar value of a retail margin of 5.25 per cent of Aurora Energy's approved costs in 2020-21 and 2021-22 in $2020-21.

The retail margin under this option is calculated at $95.51 per customer in 2022-23 (in 2020-21 dollars) which would be significantly lower than under Option 1. . This value would be indexed by CPI growth to determine the 2022-23 value in current dollars and then be indexed again by CPI growth for 2023-24 and 2024-25.

Advantages	Disadvantages
The retail margin under this approach would reduce prices in 2022-23, compared to prices in 2021-22, if all other costs are around 2021-22 levels.	The retail margin would be on Aurora Energy's cost base that does not include Aurora Energy's aurora+ costs, as these costs were not included in 2019-20 and 2020-21. It would effectively set a retail margin of zero on this component of Aurora Energy's costs.
The retail margin would reflect declining retail margins nationally and more closely reflect Aurora Energy risks.	If costs increase appreciably during the next regulatory period, Aurora Energy's margin could fall to levels that do not reflect the risks it faces.
	Aurora Energy would face a reduction in its retail margin of $16.43 per customer or around $4.4 million, per year compared the margin its submission. Compared to the approved retail margin in 2021-22, Aurora Energy would face a reduction in its retail margin of $4.29 per customer or around $1.2 million per year.

3. Average of 2020-21 and 2021-22 retail margin calculations with an allowance for the additional aurora+ costs using a 5.25 per cent retail margin

As per Option 2, the proposed margin in dollar terms is the average of the dollar value of a retail margin of 5.25 per cent of Aurora Energy's approved costs in 2020-21 and 2021-22 but would also include the approved costs for aurora+, as if those costs had been included in 2020-21 and 2021-22.

This allows Aurora Energy to earn a margin on its approved aurora+ costs, unlike under Option 1 and Option 2.

The retail margin under this option is calculated at $96.25 per customer in 2022-23 (in 2020-21 dollars) which would be marginally higher than under Option 2 and still significantly lower than under Option 1. This value would be indexed by CPI growth to determine the 2022-23 value in current dollars and then be indexed again by CPI growth for 2023-24 and 2024-25.

Advantages	Disadvantages
The retail margin would reflect declining retail margins nationally and closer reflect Aurora Energy risks.	If costs increase appreciably during the next regulatory period, Aurora Energy's margin could fall to levels that do not reflect the risks it faces.
The retail margin under this approach would be based on all Aurora Energy's approved costs from 2022-23, including aurora+ costs.	Aurora Energy would face a reduction in its retail margin of $15.69 per customer or around $4.3 million, per year compared the margin its submission. Compared to the approved retail margin in 2021-22, Aurora Energy would face a reduction in its retail margin of $3.55 per customer or just under $1 million per year.
The retail margin under this approach would reduce prices in 2022-23, compared to prices in 2021-22, if all other costs are around 2021-22 levels.	

Each of these options has advantages and disadvantages. The Regulator acknowledges that this list of options is not exhaustive and is open to considering other options.

8.6 Draft assessment

Having considered the arrangements in other jurisdictions and risks that Aurora Energy faces, the Regulator considers that Aurora Energy's proposed retail margin (Option 1) is too high. The proposed margin would be higher in dollar terms than Aurora Energy's retail margins in recent years.

The Regulator's draft assessment is that a retail margin for Aurora Energy of 5.25 per cent better reflects Aurora Energy's risks and national trends in the electricity retail industry. The Regulator considers that Aurora Energy's retail margin should be set with reference to all its approved costs, including those relating to aurora+.

The Regulator intends to set the retail margin as under Option 3, at $96.25 per customer in 2022-23 (in 2020-21 dollars), indexed by the Hobart CPI to determine the 2022-23 value in current dollars and then indexed again by CPI growth for 2023-24 and 2024-25.

This represents a decrease of $15.69 per customer from the retail margin proposed by Aurora Energy and also a decrease of $3.55 from the retail margin in 2021-22 (in $2020-21).

9 AEMO COSTS

The Australian Energy Market Operator (AEMO) is a not-for-profit public company funded wholly by participant fees. AEMO operates the energy markets and systems and also delivers planning advice in the NEM. Retailers including Aurora Energy are liable to pay a portion of the fees levied by AEMO. These fees constitute a relatively small part of the NMR although as AEMO's funding requirements continue to increase[31], AEMO fees are expected to make a higher contribution to the NMR. In 2021-22, for example, these costs were approximately 1 per cent of the NMR.

9.1 Background

AEMO's market fees include the following fees:

- 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.
- Energy Consumers Australia (ECA) fees. The ECA is an independent body which works with the electricity sector.

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.

Ancillary service fees depend on the number of services required at any particular time and, as this can vary significantly from period to period, the fees will also vary from period to period.

9.2 2016 Determination

Under the 2016 determination, the Regulator estimated Aurora Energy's AEMO fees for participating in the NEM and for FRC electricity each year of the regulatory period by using the customer numbers from the NTB, the DLF and the fees as determined by AEMO.

For ancillary service fees, the Regulator determined these fees by multiplying the average monthly rate of ancillary fees ($/MWh) based on a 12 month period prior to April in the year

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31 https://www.abc.net.au/news/rural/2022-02-01/renewable-energy-levels-send-grid-management-costs-soaring/100792576.

immediately before the price period by the forecast small customer load in the NTB adjusted by the DLF.

However, from 2020-21, national transmission planner fees are not borne by market customers; instead they are payable by transmission network service providers and reflected in network costs. These fees will, therefore, no longer be included in the AEMO component of the cost build-up (these fees were not included in the AEMO component for 2020-21 and 2021-22 under the 2016 Determination).

From 1 July 2021, two new fee categories have been introduced by AEMO to recover the costs of the five-minute and global settlement rule changes and upgrades to related legacy IT systems and the costs of the integration of distributed energy resources (DER) into the NEM.

During the period covered by the 2016 Determination, delays in the release of AEMO's budget have resulted in the Regulator being required to estimate AEMO fees. It is hoped that AEMO is able to release its budget earlier so that economic regulators across Australia are able to include actual AEMO fees in their regulated prices.

9.3 What other regulators do

Other regulators also provide an allowance for AEMO fees.

Both the ICRC and QCA calculate the AEMO fee portion of their pricing models using observed AEMO cost data for the first year of the regulatory period, with subsequent years indexed by the CPI. The ESC, in contrast, estimates AEMO market fees using an average of the previous year and estimates for the year to which AEMO fees will apply.

To estimate ancillary fees, both the ESC and QCA use an average of the past 52 weeks of AEMO's ancillary service payments. In its first year of each regulatory period, the ICRC also uses this approach. For the subsequent years of each regulatory period, the ICRC indexes these costs by the CPI.

9.4 Draft assessment

The Regulator intends to continue its current approach to estimating AEMO fees. As set out in the Approach Paper, the Regulator intends that fees and charges are to be expressed on a per connection point basis or on a $/MWh basis as relevant and in line with how AEMO expresses the various costs in its annual budget.

10 UNDER AND OVER RECOVERIES AND ADJUSTMENTS

10.1 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, dependent on the cost component being estimated. 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 otherwise in the next period, or are penalised through prices being higher than otherwise. These adjustments can also lead to greater price volatility from year to year, which the Regulator seeks to avoid.

10.2 2016 Determination

The NMR formula in the 2016 Determination allowed for three types of adjustments. These adjustments were:

K_y = an aggregate of approved under and/or over recoveries for network costs, metering costs, RET costs and AEMO fees.

A_y = 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.

CF_y = an aggregate of under and/or over recoveries from the previous period covered by the 2013 Determination.

Network costs, 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 2016 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 2016 Determination. This component was not used.

10.3 What other regulators do

The arrangements in other jurisdictions are discussed below.

10.3.1 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 also 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.

10.3.2 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 of sufficiently material to impact the benchmark originally established.

10.3.3 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 (ie SRES liabilities are determined by the CER after a determination is made). As such, the QCA considers that an adjustment for any under or over recovery of SRES costs is appropriate.

To account for the over or under recovery of SRES costs, the QCA applies a cost pass-through adjustment for the next regulatory period.

10.4 Draft assessment

As set out in the Approach Paper, the Regulator intends that under and/or over recoveries included in the K_y or CF_y[32] costs:

- continue to be limited to network costs, 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, ie the Notional Tariff Base, 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.

[32] In the 2022 Determination, CFy will apply to the previous period covered by the 2016 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 ie the LGC and STC prices used when calculating prices in 2022-23 must be used when calculating preliminary and final adjustments in 2023-24 and 2024-25 respectively.

In the case of over and under recovery of RET costs relating to years under the 2016 Determination (CF_y), the LGC and STC prices used in calculating the approved prices in the relevant year will be used.

It is intended that no changes will be made to the current approach to calculating adjustments (A_y).

11 AURORA ENERGY'S TARIFF STRATEGY

As the majority of Tasmanian electricity consumers are on a standard retail contract, Aurora Energy's strategy for standing offer tariffs potentially impacts a large number of Tasmanians.

Aurora Energy's Standing Offer Tariff Strategy (Tariff Strategy) sets out its plans for communicating and managing tariffs over the term of the 2022 Determination. A copy of the Tariff Strategy is available on the Regulator's website.

The Tariff Strategy outlines how Aurora Energy intends to manage tariff changes and any rebalancing of fixed and variable components of standing offer prices. It also sets out how it intends to meet shareholder directives and expectations.

11.1 Background

During the regulatory period covered by the 2016 Determination, Aurora Energy's Tariff Schedule underwent some significant changes. Changes included the introduction of time-of-use tariffs for residential and business customers (Tariffs 93 and 94 respectively) as well as the removal of several tariffs.

Aurora Energy also incrementally adjusted the fixed and variable relativities of tariffs to reflect the underlying costs and undertook rebalancing between residential and business customer segments during the final period of the 2016 Determination (1 July 2021 to 30 June 2022).

As set out in the Approach Paper, Aurora Energy was required to prepare a Tariff Strategy relating to the regulatory period to be covered by the 2022 Determination. The Tariff Strategy was to detail and justify any proposed changes to tariffs and charges for the relevant period, including consultation with its customers. If a tariff is proposed to be made obsolete or abolished, Aurora Energy was required to provide justification and specify the impact on customers.

11.2 2022 Standing Offer Tariff Strategy

Aurora Energy submitted its Tariff Strategy to the Regulator in November 2021. It outlines the factors that underpin Aurora Energy's proposal including customer expectations, regulatory frameworks and future market developments.

Aurora Energy's Tariff Strategy identifies three key principles that will guide its future proposals within the regulatory period to be covered by the 2022 Determination:

- flexibility and simplicity - the ability to amend tariffs to ensure they are relevant, compliant and reflect terms and conditions of underlying network tariffs;
- commitment to cost reflectivity - opportunities to rebalance tariffs, but with regard for customer outcomes; and
- new tariff proposals - the ability to propose new tariffs to reflect evolving customer needs and market signals.

At this stage, there are no firm proposals for new tariffs from Aurora Energy across the 2022 Determination.

Aurora Energy has identified that changing customer expectations and an increasing trend towards digitalisation of retail service have shaped its approach to the products and tariffs it offers. Aurora Energy considers that the introduction of digital products, such as aurora+, will allow customers to benefit by changing their energy consumption behaviour.

The Tariff Strategy also recognises that the AER's Retail Pricing Information Guideline will shape the presentation of tariffs and how they are communicated with customers.

11.2.1 Regulatory environment

The Tariff Strategy identifies a number of developments that have the potential to impact Aurora Energy's tariffs over the 2022-25 regulatory period. In particular, Aurora Energy considers that the commencement of a new regulatory period for TasNetworks from 1 July 2024 may drive a transition away from flat rate network tariffs towards cost-reflective tariffs. Aurora Energy notes that detail on the future management of network tariffs will not be known until TasNetworks revenue reset is finalised in 2024, and that any material adjustment to underlying network tariffs will be a key input into Aurora Energy's Tariff Schedule during period 3 of the 2022 Determination.

Broader electricity market reforms currently being considered by regulatory bodies such as the Australian Energy Market Commission and Energy Security Board may also present opportunities for new tariff products for renewable energy such as distributed generation and electric vehicles. Aurora Energy notes that the format and outcome of these reforms are relatively undefined and therefore any impact on its Tariff Schedule are currently unknown.

11.2.2 Tariff Strategy implementation

Aurora Energy's implementation of its Tariff Strategy will be guided by the three key principles outlined above. Aurora Energy is seeking to retain flexibility in relation to whether tariff rebalancing is introduced for any period of the 2022 Determination.

11.3 Regulator's assessment

The Regulator acknowledges the high level of uncertainty around future developments in this space and intends to accept the three principles that Aurora Energy proposes as underpinning its Tariff Strategy. In the event that Aurora Energy's tariffs/tariff structure changes during the regulatory period, the Regulator will assess the impact of any price increases on customer.

12 STANDING OFFER PRICE APPROVALS

Under sections 40 and 41 of the ESI Act, Aurora Energy must fix its standing offer prices with the approval of the Regulator and is not permitted to amend those prices unless the Regulator has approved those prices.

Specifically, under section 41 of the ESI Act:

> (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).

The Regulator's *Standing Offer Price Approval Guideline* sets out the information Aurora Energy must provide in its annual standing offer pricing proposals under the 2022 Determination. It also details the obligations of Aurora Energy and the Regulator in regards to the approval of prices for each period, consistent with the provisions outlined in the ESI Act.

A Draft Standing Offer Price Approval Guideline for the 2022 Determination period has been prepared and issued for public consultation. A copy is available on the Regulator's website.

ATTACHMENT 1: GLOSSARY AND ACRONYMS

Term	Meaning
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Aurora Energy	Aurora Energy Pty Ltd, ABN 85 082 464 622
Authorised retailer	A person holding a retailer authorisation under the NERL
CARC	Customer acquisition and retention costs (costs incurred by a retailer in acquiring additional customers and retaining existing customers)
CER	Clean Energy Regulator
CPI	Consumer Price Index
DLF	Distribution Loss Factor
Economic Regulator Act	*Economic Regulator Act 2009*
ESI Act	*Electricity Supply Industry Act 1995*
FRC	Full Retail Competition
GWh	Gigawatt-hour (one Gigawatt-hour is 1 000 Megawatt hours or 1 000 000 kilowatt-hours)
Hydro Tasmania	Hydro Electric Corporation, from 1 July 1998, ABN 48 072 377 158
ICRC	Independent Competition and Regulatory Commission, Australian Capital Territory
IPART	Independent Pricing and Regulatory Tribunal of New South Wales
kWh	Kilowatt-hour
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. 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.
MLF	Marginal Loss Factor
MW	Megawatt
MWh	Megawatt-hour
NEL	National Electricity Law
NERL	National Energy Retail Law, as applied in Tasmania by the *National Energy Retail Law (Tasmania) Act 2012*
NEM	National Electricity Market
NER	National Electricity Rules
Next regulatory period	The regulatory period commencing on 1 July 2022
NMR	Notional maximum revenue
NTB	Notional Tariff Base. The notional tariff base 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 (eg 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 2013*
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
Regulator	The Tasmanian Economic Regulator, appointed under the *Economic Regulator Act 2009*
RET	Renewable Energy Target
Retailer authorisation	Authorisation issued by the AER under the National Energy Retail Law. Unless exempt from the requirement, a person must hold a retailer authorisation prior to engaging in the retail sale of energy.
RPP	Renewable Power Percentage

Small customer	A customer who is a small customer under the NERL
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 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.
Standing Offer Price 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 upcoming regulatory period.
TasNetworks	TasNetworks Pty Ltd, ABN 24 167 357 299
Treasury	Tasmanian Department of Treasury and Finance
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 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 developed by Concept Consulting Group Limited for Treasury that is used to calculate the wholesale electricity price.