frontier economics

Retail electricity price investigation 2024-27

Report for The Independent Competition and Regulatory commission | 21 November 2023

Frontier Economics Pty Ltd is a member of the Frontier Economics network, and is headquartered in Australia with a subsidiary company, Frontier Economics Pte Ltd in Singapore. Our fellow network member, Frontier Economics Ltd, is headquartered in the United Kingdom. The companies are independently owned, and legal commitments entered into by any one company do not impose any obligations on other companies in the network. All views expressed in this document are the views of Frontier Economics Pty Ltd.

Disclaimer

Contents

Tables

Figures

1 Introduction

1.1 Background

The Commission must determine a price direction for standing offer prices for small customers

The Independent Competition and Regulatory Commission (Commission) is the independent economic regulator for the Australian Capital Territory (ACT). On 1 June 2023 the Commission received the terms of reference (TOR) from the ACT Government to determine a price direction for standing offer prices for the supply of electricity by ActewAGL to small customers. Small customers consume less than 100MWh of electricity over any period of consecutive 12 months. The price direction will be for a period of three years from 1 July 2024 to 30 June 2027.

The TOR requires the Commission to ensure the methodology for determining standard offer prices has regard to a reasonable pricing offer for small customers that does not disadvantage customers not actively engaged in the electricity market, while balancing the competitiveness of the retail electricity market.[1]

The Commission ensures regulated prices are set at the prudent and efficient cost

The objective of the Commission is to promote effective competition in the interest of consumers, while facilitating an appropriate balance between economic efficiency, environmental and social considerations.[2] When making a price direction the objective of the Commission is to promote efficient investment in, and efficient operation and use of, regulated services for the long term interests of consumers.[3]

The Commission balances these objectives by ensuring regulated prices for electricity services are set at no more than the prudent and efficient costs of providing these services.[4] This approach ensures customers pay no more than required while allowing retailers to recover efficient costs, including a reasonable margin, promoting efficient operation and investment.[5]

1.2 Frontier Economics' engagement

Frontier Economics is advising on the methodology to determine energy purchase cost, retail operating cost and retail margin

In this context the Commission appointed Frontier Economics to advise on the methodology to determine three key components of its electricity pricing model, being:

- Energy purchase cost

[1] Independent Competition and Regulatory Commission (Price Direction for the Supply of Electricity to Certain Small Customers on Standard Retail Contracts) Terms of Reference Determination 2023, Paragraph X.

[2] Independent Competition and Regulatory Commission Act 1997, Part 2, Section 7.

[3] Independent Competition and Regulatory Commission Act 1997, Part 4, Section 19L.

[4] Independent Competition and Regulatory Commission, Standing offer prices for the supply of electricity to small customers from 1 July 2024: Issues paper, report 5 of 2023, August 2023, p2.

[5] Independent Competition and Regulatory Commission, Standing offer prices for the supply of electricity to small customers from 1 July 2024: Issues paper, report 5 of 2023, August 2023, p2.

- Retail operating cost
- Retail margin.

This report provides our advice on appropriate approaches and data for the estimation of wholesale energy costs, retail operating costs and the retail margin for the Commission, reflecting best practice. It is informed by information from a range of publicly available and confidential sources, including confidential data on retail operating costs collected from ActewAGL, Energy Australia and Origin Energy.

1.3 This report

This report sets out our methodology, assumptions and data sources, and presents our findings and recommendations. It is structured as follows:

- Section 2 discusses wholesale electricity costs
- Section 3 considers retail operating costs
- Section 4 examines the retail margin.

All dollar values in this report are recorded in June 2023 dollars, unless otherwise noted, to aid comparison. When adjusting to real June 2023 dollars we have used the same approach for adjusting for inflation that the Commission uses in its determination.[6]

6 The Commission adjusts for inflation by comparing the average value of CPI over the 4 quarters to March, on a lagging basis:

$$\boxed{CPI_t = \frac{CPI_{June(t-2)} + CPI_{Sep(t-1)} + CPI_{Dec(t-1)} + CPI_{March\,(t-1)}}{CPI_{June(t-3)} + CPI_{Sep(t-2)} + CPI_{Dec(t-2)} + CPI_{March\,(t-2)}} - 1}$$

2 Wholesale electricity costs

This Section discusses the methodology used to estimate wholesale electricity costs (WEC) for small customers in the ACT. Section 2.1 outlines our approach to assessing wholesale electricity costs. We then consider the key elements of this approach in turn:

- Section 2.2 considers half-hourly load
- Section 2.3 discusses contract prices
- Section 2.4 examines the contract position
- Section 2.5 presents our findings and recommendations on estimating wholesale electricity costs and the volatility allowance.

2.1 Approach to assessing wholesale electricity costs

Under the settlement rules in the National Electricity Market (NEM), retailers are responsible for purchasing electricity to meet the load of their customers in the wholesale electricity market. A retailer will pay, for each half hour (or for each five minute period, since the introduction of five minute settlement), its customer's electricity load in that interval multiplied by the relevant regional reference price from the wholesale electricity spot market for that interval. For customers in the ACT, the relevant regional reference price is the NSW regional reference price.

These settlement payments that retailers face can be extremely volatile. Electricity load for small customers can vary significantly from one interval to the next, and electricity spot prices can be anywhere between the Market Price Cap (which for 2023-24 is $16,600/MWh) and the market floor price (which is -$1,000/MWh). Since retailers will typically commit to supply their customers at a specified retail price for a period of time, this volatility in settlement payments can result in retailers paying more for electricity than they receive for that electricity through the retail price they have agreed with their customers. At worst, this exposes the retailers to the risk of financial failure.

To manage the risks associated with volatile load and spot prices, retailers will typically seek to hedge their exposure to spot prices by entering into hedging arrangements. There are several ways that retailers can hedge their exposure to spot prices. The most common are the following:

- Vertical integration through ownership of an electricity generator. A retailer that owns a generator has what is known as a natural hedge: when the spot price is high, the retailer will have to pay the high spot price for its customer's load but, as the owner of a generator, will also receive the high spot price for its electricity generation.
- Power purchase agreements with a generator. Power purchase agreements provide a similar hedging benefit to vertical integration, but they do so through contractual arrangements between a retailer and a generator, rather than through ownership.
- Financial derivatives. There are a range of financial derivatives that are available to retailers (and generators) to hedge their exposure to volatile spot prices. Common contracts include swap contracts (which effectively lock-in a spot price for the counterparties) and cap contracts (which effectively cap the spot price for a retailer). These are traded both on the stock exchange and over-the-counter between participants.

Retailers' energy purchase costs are typically taken to be the average cost to a retailer of purchasing electricity from the wholesale market for its customers, taking into account both the retailer's settlement payments to the Australian Energy Market Operator (AEMO) and the financial outcomes from the retailer's hedging arrangements.

Regulatory practice in Australia has typically focused on estimating the energy purchase cost for a benchmark retailer. In doing so, regulators have typically assumed that the benchmark retailer will make use of exchange-traded financial derivatives to hedge its exposure to spot prices. The assumption that a benchmark retailer will use exchange-traded financial derivatives is typically based on the following reasoning:

- Any retailer of a reasonable size should be able to hedge its exposure to wholesale spot prices using exchange-traded financial derivatives, while vertical integration and entering power purchase agreements can be impractical for retailers with a smaller retail position in a market or with a less certain retail position.

- Prices for exchange-traded financial derivatives are transparent since they are traded on the ASX. In contrast, the costs of building generation plant or entering into power purchase agreements is less transparent.

In practice, some retailers in the NEM do adopt a mix of hedging strategies, including vertical integration and power purchase agreements and purchasing over-the-counter (OTC) hedging contracts, which are traded through brokers not on the ASX. Retailers that are able to vertically integrate or enter into power purchase agreements, and choose to do so, presumably do so because they expect these strategies will offer advantages that financial derivatives cannot; by excluding vertical integration and power purchase agreements from consideration, therefore, regulators will, if anything, tend to overstate the costs that these retailers with a broader range of options will face, or understate the risk management that retailers can achieve.

We follow this typical approach of assessing the WEC that retailers face based on an estimate of the cost that a prudent retailer would face in supplying electricity to their customers, having regard to the hedging contracts that a prudent retailer is likely to enter into. The hedging contracts that we base this analysis on are quarterly base swaps and $300 caps, traded on ASXEnergy.[7]

To estimate WEC in this way, we need to answer four questions:

- What is the expected half-hourly load of the retailer's customers?

- What are the expected half-hourly spot prices that retailers will face?

- What is the cost of financial hedging contracts?

- What kind of hedging position is a prudent retailer likely to adopt?

From the answers to these questions, we can provide a contracting heuristic for the Commission to use in determining WEC, and we can calculate the WEC that a retailer would face.

We address these questions in the sections that follow.

2.2 Half-hourly spot prices and half-hourly load

This section addresses the first two questions we need to answer to estimate WEC:

- What is the expected half-hourly load of the retailers' customers?

- What are the expected half-hourly spot prices that retailers will face?

---

7 $300 caps are the only caps traded on ASXEnergy and have long been a standard cap contract in the NEM.

We deal with these questions together because we believe it is important to forecast half-hourly spot prices and half-hourly load in a way that accounts for the correlation between prices and load. After all, this correlation is a key driver of the risks that retailers face.

2.2.1 Historical data on half-hourly price and load

Our modelling of the WEC requires projections of half-hourly spot prices in the ACT and customer load to be supplied by retailers in the ACT.

In our view, the best source of data about half-hourly patterns of spot prices, half-hourly patterns of customer load, and the correlation between the two, is historical data. The historical data on prices and load will reflect all the complex factors that drive both spot prices and customer load, and the interactions between them, which are difficult to accurately capture at the half-hourly level using forecasting models. These historical data on prices and load can then be scaled to account for any trends in prices and load over the forecast period.

The historical data that we use is provided to us by the Commission in their 2023-24 EPC model, and consists of:

- For prices, the half-hourly spot prices for the NSW regional reference node as published by AEMO.
- For customer load, the half-hourly net system load profile (NSLP) data published by AEMO.

2.2.2 Selecting appropriate historical data

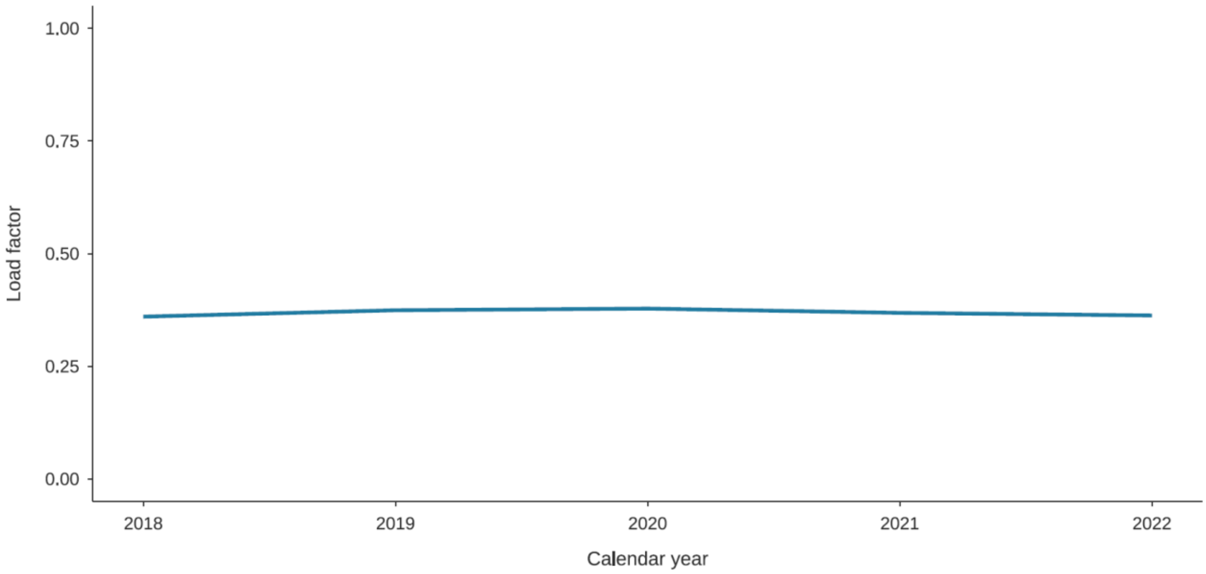
When using historical data on prices and load in this way, a useful starting point is to choose data on prices and load from an historical period that we think is likely to be most consistent with the forecast period. For example, the closure of coal-fired power stations may have substantial impacts on price levels and volatility. Likewise, the increasing adoption of rooftop solar PV is likely to materially affect load factors and prices over time.

Analysis of data

Figure 1 shows the annual load factor[8] for the NSLP load data published by AEMO for the last five calendar years. From this figure we can see that the load factor has been very stable over time. It is our view that there is not a clear trend towards a significantly higher or lower load factor over time.

[8] The load factor is a standard measure of how peaky a load is. An annual load factor is calculated by dividing average annual load in the year by the maximum half-hourly load in the year. The lower the load factor, the peakier the load is.

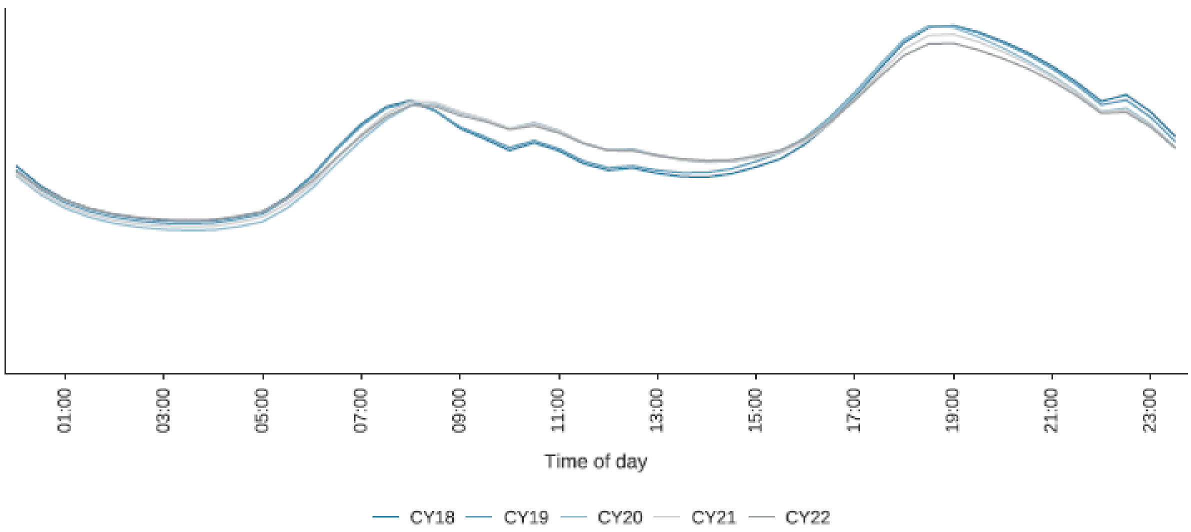
Figure 1: Load factor for ACT NSLP data



Source: Frontier Economics analysis of AEMO data

Figure 2 shows the average daily load profile for the NSLP published by AEMO for the last five calendar years. These daily profiles represent the consumption pattern of customer load during an average day. These profiles have been normalised to the same total annual consumption. That is, we scale total customer load in each calendar year to the same annual value of 1GWh. Scaling allows us to highlight the differences in *timing* of consumption (i.e., the shape of the load pattern) rather than differences in *total* annual consumption. These profiles are very similar between historical years. However, it is apparent that there has been a modest increase in load during the day for the most recent two years – calendar year 2021 and 2022. This may reflect an increasing incidence of working from home in the ACT. More generally across the NEM we have tended to see a decline in load during the day, driven by an increased adoption of solar PV. However, solar PV customers will have interval meters and, therefore, will not be reflected in this NSLP data.

Figure 2: Average daily profile for ACT NSLP data

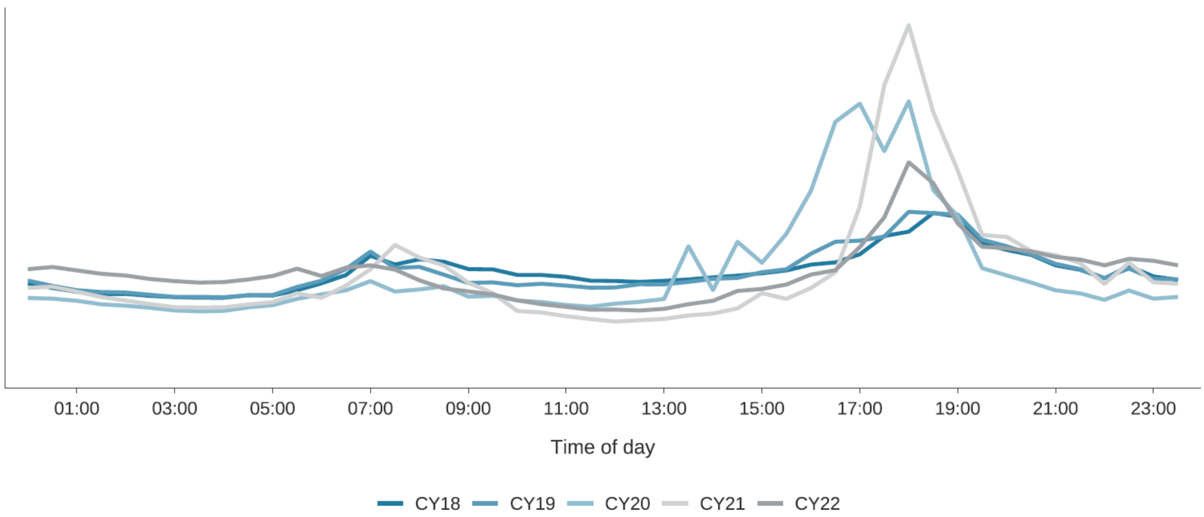


Source: Frontier Economics analysis of AEMO data

Figure 3 shows the average daily profile for NSW spot prices for the last five financial years, normalised to the same average annual price to highlight differences in the timing of daily prices. The ACT falls within the NSW region of the NEM, and ACT load is settled against the NSW spot price. It is no surprise to see that there is greater variability in daily patterns of spot prices than there is in daily patterns of customer load. However, despite this variability, in each year we do see similar patterns of low overnight prices, a price spike tending to occur in the morning, and further high prices tending to occur in the mid-afternoon to evening.

The daily profiles for the last three calendar years are the most similar to each other, with relative prices during the day that are materially lower, and relative prices during the evening that are materially higher. This trend towards lower prices, and even negative prices, during the middle of the day is apparent across the NEM, and reflects increasingly high levels of solar PV supplying the market during the day. With greater supply, we see lower prices.

Figure 3: Average daily profile for NSW spot prices



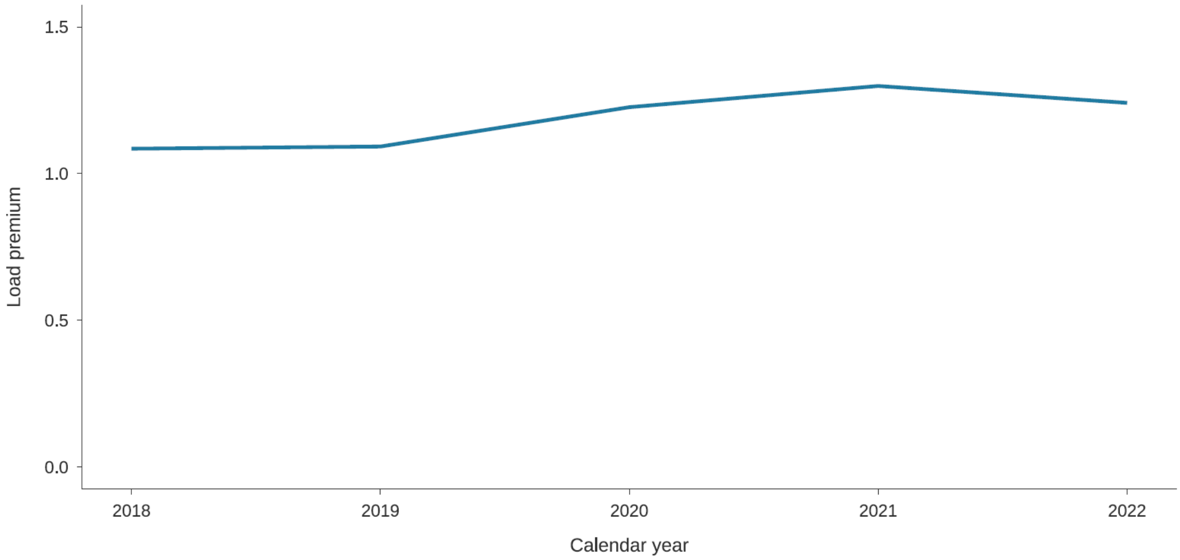
Source: Frontier Economics analysis of AEMO data

Figure 4 combines the historical customer load data and spot price data to report the load premium (calculated as the load-weighted price divided by the time-weighted price) for the ACT NSLP for each of the last five calendar years. In our experience, the load-weighted spot price (and, by extension, the load premium) is a reasonable guide to the WEC.

We can see from **Figure 4** that the load premium for the last three calendar years was materially higher than it had been previously. This is because:

- spot prices have tended to remain higher for longer in the early evening, when load also tends to be relatively higher, and
- spot prices in NSW have tended to be lower during the day, when load also tends to be relatively lower. This is observed consistently across the NEM, with lower prices during the middle of the day a result of higher levels of solar PV generation available during the middle of the day.

Figure 4: Load premium for ACT NSLP data, based on NSW spot prices

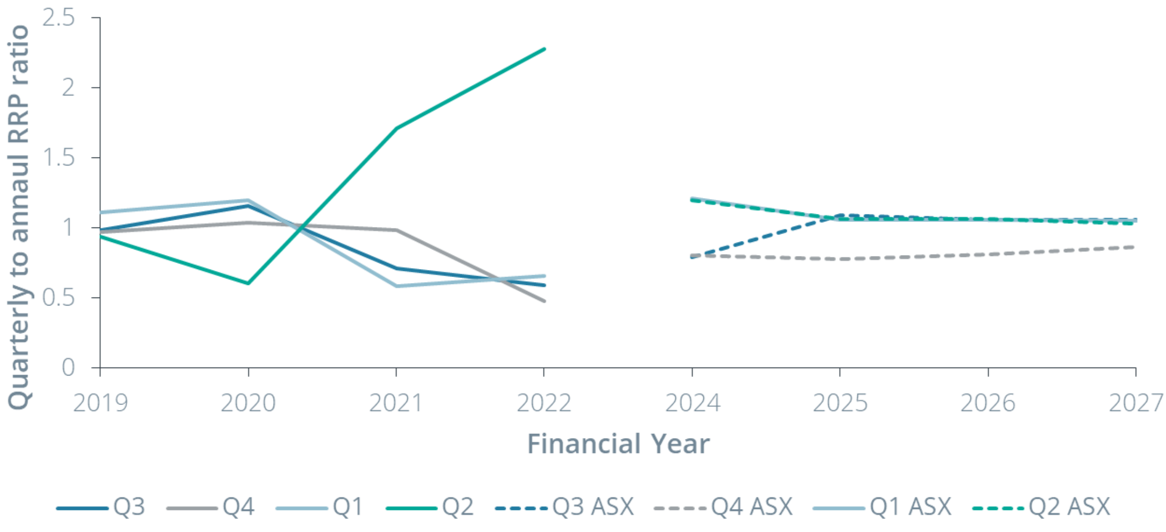


Source: Frontier Economics analysis of AEMO data

As well as examining historical data it can be useful to compare historical price outcomes with expectations of future prices, based on ASXEnergy contract prices. Since we will ultimately be scaling historical half-hourly prices to an average price based on ASXEnergy contract prices, it is helpful if the historical patterns in half-hourly prices are reasonably consistent with the pricing outcomes indicated by ASXEnergy contract prices.

Figure 5 examines quarterly patterns of spot prices and ASXEnergy prices. For each quarter, **Figure 5** presents the relationship between average quarterly prices and average annual prices: on an historical basis this relationship is based on historical NSW spot prices; on a forecast basis this relationship is based on ASXEnergy base-load swap prices for NSW. **Figure 5** reveals quite a degree of volatility in the relationship between quarterly prices over time. However, some trends in the historical data are apparent, and are carried through to the ASXEnergy data. For instance, Q1 and Q2 prices have tended to be higher than prices in other quarters, and this is reflected in the ASXEnergy data. Similarly, Q4 prices have tended to be lower than prices in other quarters, and this is reflected in the ASXEnergy data. The historical data for 2022 is clearly affected by the high price events in Q2 2022, with prices in that quarter being significantly higher. The ASXEnergy data suggests that the market does not expect these very high Q2 prices to occur again in the near future.

Figure 5: Quarterly patterns of spot prices and ASXEnergy prices



Source: Frontier Economics analysis of AEMO data and ASXEnergy data

Based on the analysis of historical half-hourly load and half-hourly prices set out above, our approach for this report is to include the 3 most recent calendar years - 2020, 2021 and 2022. This is a change to the approach that the Commission has adopted previously for their EPC model, which has made use of data from the 5 most recent calendar years.

The reason for the change is that some of the data that we have investigated – particularly the daily profiles for load and the daily profiles for prices – suggest that the data from the 3 most recent calendar years – 2020, 2021 and 2022 – are more alike, and the data for the earlier 2 financial years – 2018 and 2019 – reflect quite different patterns. There appears to be a trend towards lower demand and lower prices during the day, and the data from the 3 most recent calendar years are more likely to reflect this trend than the data from the 2 earlier calendar years.

2.2.3 Projecting half-hourly load and spot prices

As discussed, rather than take a single one of the years from 2020 to 2022 as representative of outcomes in 2024-25, we perform a Monte Carlo simulation on the three years of half-hourly load and price data. In our view there are two benefits of using a Monte Carlo analysis:

- Any single year will be subject to unique market conditions that are unlikely to be repeated. This creates the risk that any single year may not be representative of conditions that might be expected in the future. However, using a Monte Carlo approach based, in this case, on three years of data increases the likelihood of basing our analysis on a representative set of conditions.
- Using a Monte Carlo analysis allows us to create a distribution of market conditions, providing some insight into the expected distribution of the WEC.

The Monte Carlo simulation is used to generate a year of half-hourly data by randomly drawing one day of data, from the pool of available historical days, for each day of the forecast year. This random drawing of data is done from a pool of like days (where days are classified according to day type – weekday/weekend – and quarter). The Monte Carlo simulation is then performed 500 times to get a distribution of simulated years, which allows us to choose a simulated year from within this distribution to use in the modelling.

For example, a single simulated year will be generated as follows:

- The first day of 2024-25 is 1 July 2024, which is a Monday. Since this is a Monday in Q3, the half-hourly load and spot data for the first day of 2024-25 will be determined by randomly drawing a day's half-hourly data from all the Q3 weekdays that occurred in 2020 through to 2022.
- The second day of 2024-25 is 2 July 2024, which is a Tuesday. Since this is a Tuesday in Q3, the half-hourly load and spot data for the second day of 2024-25 will be determined by randomly drawing a day's half-hourly data from all the Q3 weekdays that occurred in 2020 to 2022.
- And so on for the 365 days that make up 2024-25, having regard, for each day, to its type and its quarter.

This process is then repeated 500 times to generate 500 simulated years, each year made up entirely of historical outcomes in 2020 through to 2022.

For each of these simulated years, load and prices are drawn at the same time (i.e. from the same historical day) so that the correlation between load and prices is maintained.

Once we have completed this Monte Carlo simulation, we make a last adjustment to the consumption data, normalising each of the simulated years to 1 GWh of annual consumption. This maintains the load shape and correlation between load and prices, but each year now has a uniform annual consumption.

We also make a further adjustment to the half-hourly spot prices. We consider that historical half-hourly spot prices provide the best source of information about patterns of half-hourly spot prices and how these are correlated with half-hourly load, but historical spot prices are not necessarily a good predictor of the future average level of NSW spot prices. There is no reason, for instance, that NSW spot prices over 2020 through to 2022 will, on average, be the same as NSW spot prices for 2024-25. In our view, the best available public information about the average level of NSW spot prices for 2024-25 is the contract prices published by ASXEnergy. These contract prices – particularly the prices of base swaps – provide the market's view on what will be the average spot price for 2024-25. Given this, for each simulated year, we assume that the average level of prices is consistent with ASXEnergy futures prices. Specifically, for each simulated year we scale the half-hourly prices so that the time-weighted average price in each quarter is equal to the relevant quarterly base swap prices for 2024-25 from ASXEnergy[9] (less an assumed contract premium of 5 per cent on the underlying prices). We use the 40-day average of ASXEnergy contract prices for quarterly base swap prices (up to 16 October 2023) as representing the market's current view of spot prices for each quarter of 2024-25.[10] This approach to generating half-hourly price forecasts results in:

[9] An alternative approach would be to attempt to scale half-hourly prices having regard to each of base swaps and cap prices. However, the scaling process would require subjective judgements about how to simultaneously scale to each of these prices. Given there would be little on which to base these subjective judgements our preference is to scale only to base swap prices, which is a mechanical process. We note, however, that the calculation of the WEC does use both swap and cap contract prices from ASXEnergy.

[10] We note that there is a difference in the averaging period that we use for estimating spot prices for 2024-25 and the averaging period we use for calculating contract prices to be used in estimating the WEC. As discussed, we use the most recent 40-day average ASXEnergy prices as the best guide to the market's view on spot prices that will occur in 2024-25. However, based on instructions from the ICRC, we use 23-month time weighted average ASXEnergy prices to set the contract price for retailers when determining the WEC. In our view, there is no necessity for these

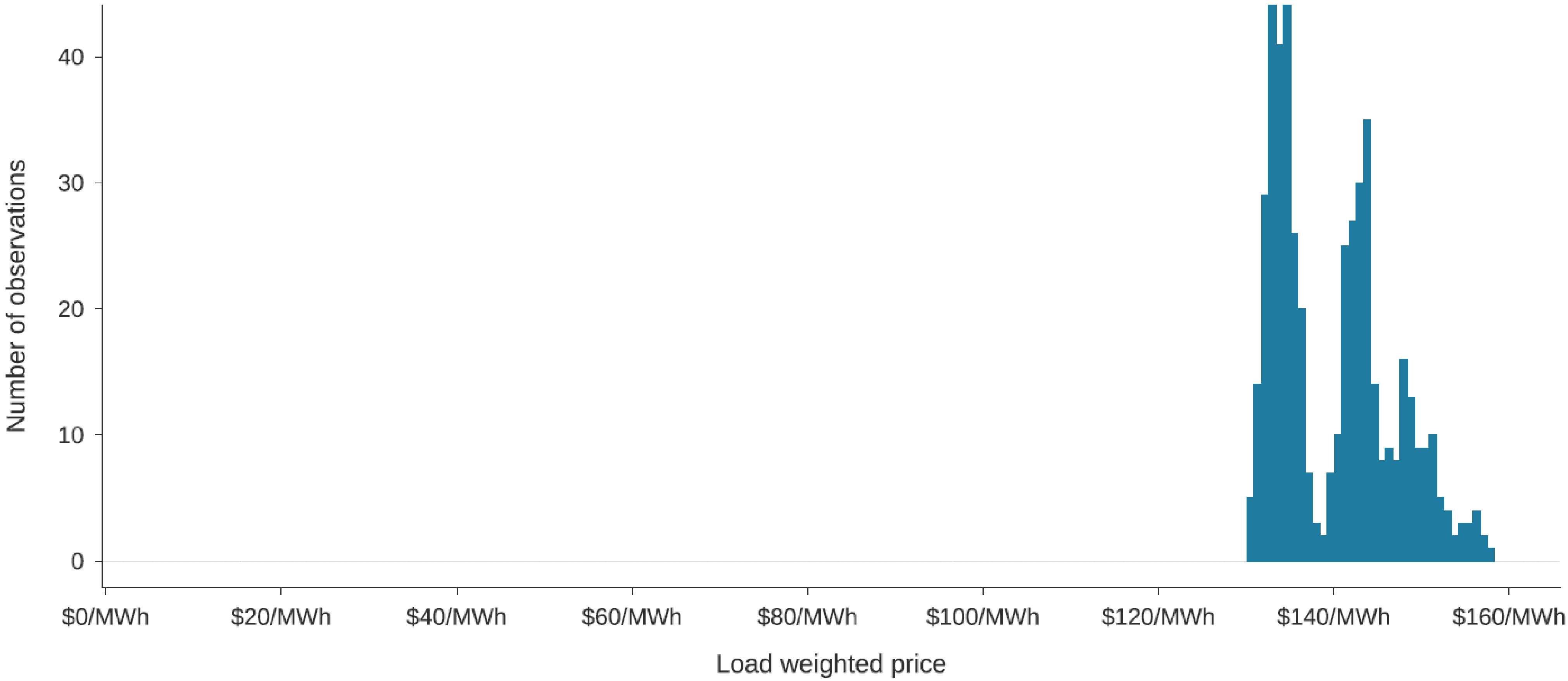
- The appropriate average level of spot prices (i.e. the time-weighted quarterly average price is consistent with ASXEnergy prices).
- The appropriate half-hourly profile of spot prices (i.e. the half-hourly profile of prices, and load, are consistent with historical outcomes).

Analysis of data

An indication of the results of our Monte Carlo simulation can be provided by calculating the load-weighted price for each of the 500 simulated years. As we discussed, in our experience the load-weighted price is a reasonable guide to the WEC. **Figure 6** shows the distribution of load-weighted prices for each of the 500 simulated years from our Monte Carlo analysis. As discussed, the average spot price in each of these simulated years is the same – based on the 40-day average ASXEnergy base swap price – but the half-hourly profile of both spot prices and load are different. It should be clear from **Figure 6** that the Monte Carlo simulation has resulted in a distribution of load-weighted prices driven by differences in the half-hourly patterns of spot prices and load.

averaging periods to be consistent. One way to think about the WEC that we are calculating using this approach is that we are estimating the contract payments that a retailer would face if that retailer had purchased its contracts for 2024-25 over the last 23 months (uniformly over the time period) and uses those contracts to hedge the risk it would face based on current expectations of spot prices.

Figure 6: Distribution of load-weighted price for simulated years



Source: Frontier Economics

2.3 Contract prices

This section addresses the third question we need to answer to estimate the WEC:

- What is the cost of financial hedging contracts?

As discussed, our approach to assessing the WEC that retailers face is based on an estimate of the cost that a prudent retailer would face in supplying electricity to their customers, having regard to the hedging contracts that a prudent retailer is likely to enter into. The hedging contracts that we base this analysis on are ASXEnergy contracts.

We consider ASXEnergy contracts

In our view it is appropriate to base the WEC on a contract position consisting only of ASXEnergy contracts. Although retailers often hold both ASXEnergy contracts and OTC contracts in their portfolio, data on the prices of OTC contracts is not publicly reported. The Australian Competition and Consumer Commission's (ACCC's) November 2022 NEM Inquiry report summarised data showing that while smaller retailers relied to a greater extent than normal on OTC contracts during May, June and July 2022, there appeared to be a return to more normal conditions involving a greater reliance on ASXEnergy contracts by August 2022.[11] We also note that when we have observed ASXEnergy contract prices and OTC prices, these prices have tended to be very similar. Given this, and the lack of publicly available data on OTC contract prices, our view is that relying on ASXEnergy contract prices is a reasonable approach for calculating the WEC.

We no longer consider peak swap contracts

Historically, we have included both base and peak swap contracts when estimating the WEC. However, the available data does show that retailers are no longer using peak swaps as a part of their contract mix. Volumes for peak swaps for 2024-25 are very low, with only a handful of trades in 2024-25 peak swaps on ASXEnergy. This decline in the volume of peak swaps has been part of a longer-term trend, presumably driven by the fact that greater levels of solar PV mean that peak periods covered by ASXEnergy contracts now cover times of very low demand (due to higher solar PV during the middle of the day) and periods of high demand (in the evenings when demand is high and solar PV is not available). Trade volumes for the 2024-25 financial year quarterly peak swap contracts are shown in Figure 7. This sharp decline in the volume of trade of peak swaps in consistent with evidence on the way that retailers hedge their position. The ACCC's November 2022 NEM Inquiry report summarised data that showed only one of 9 smaller retailers purchased peak swaps.[12]

Given this evidence, our view is that the mix of contracts included in the contract position for retailers in calculating the WEC should be limited to base swaps and caps, and we have adopted this approach for this report.

Contract price data

The contracts that we consider for hedging retailers' position are:

- Base swaps for each quarter.
- Base $300 caps for each quarter.

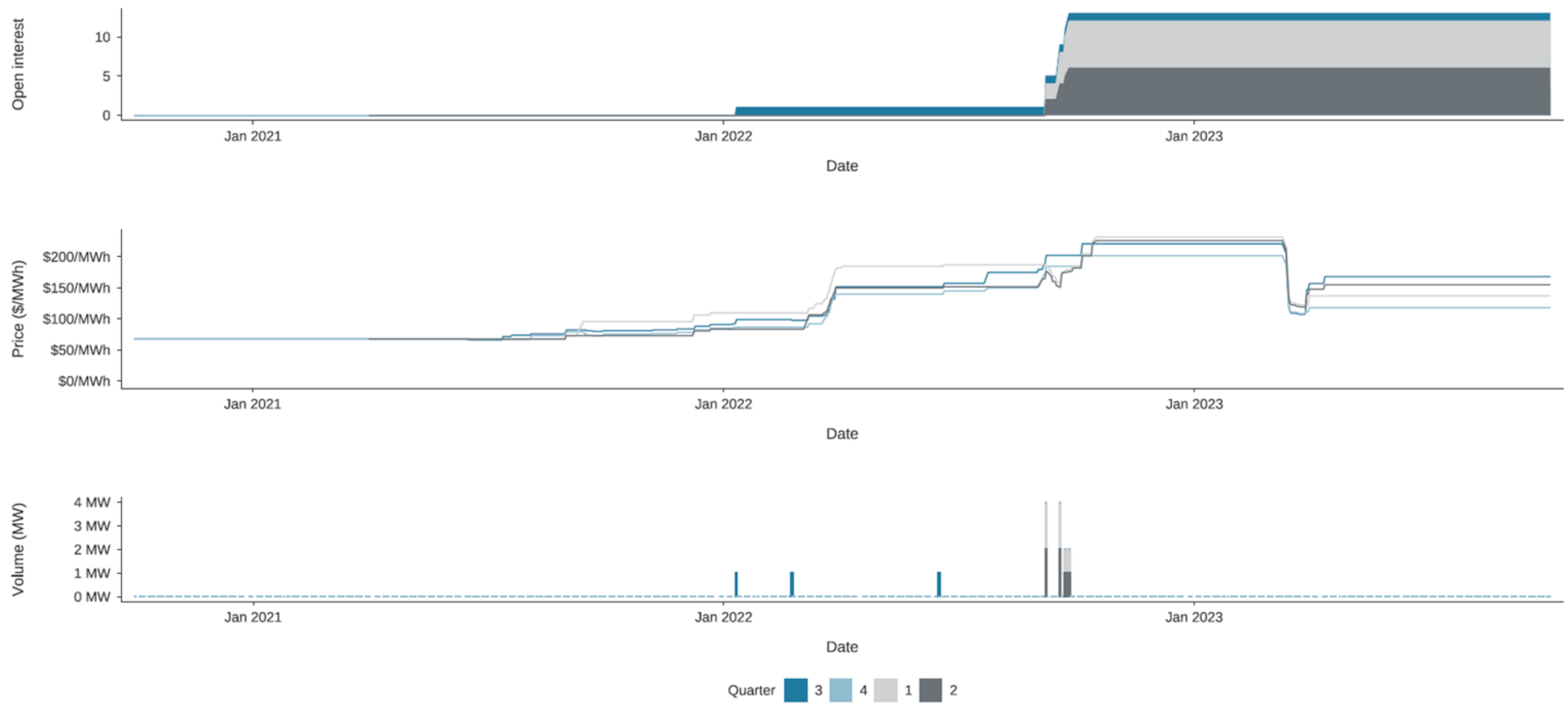
[11] ACCC, *Inquiry into the National Electricity Market*, November 2022 Report, page 49.

[12] ACCC, *Inquiry into the National Electricity Market*, November 2022 Report, page 45.

These contracts trade for several years in advance. Prices are published by ASXEnergy for each contract for each trading day.

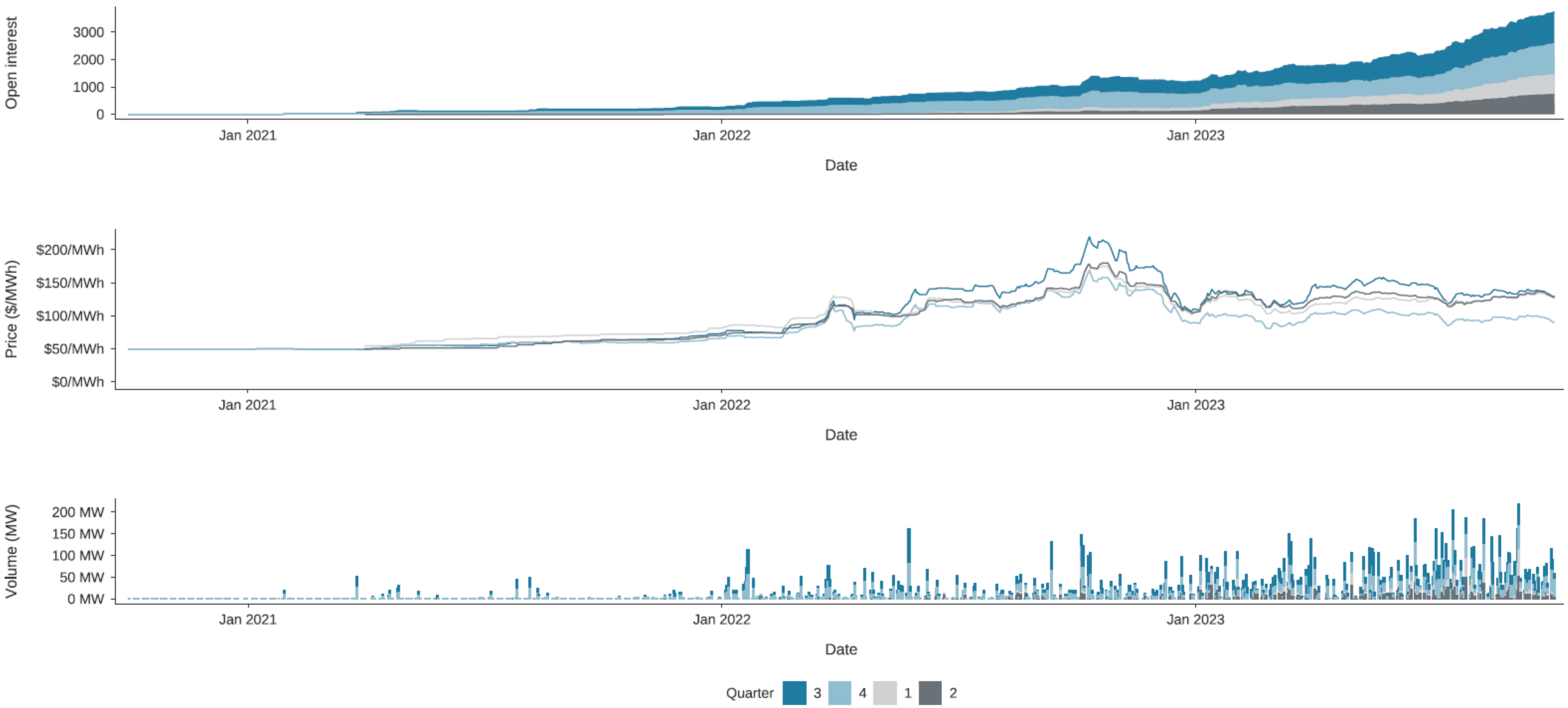
Figure 8 and Figure 9 set out the relevant trading data for base swaps and caps, for each quarterly product. The trading data that is presented is open interest (which measures the total volume of contracts in the market), the settlement price and the trading volume. We can see that base swap and cap contracts for 2024-25 are currently trading regularly. Indeed, we can see that trade in these contracts is occurring on most trading days. The regular trade in these contracts suggests that the daily prices provide a genuine indication of the market’s view of future prices.

Figure 7: NSW peak swaps – open interest, prices and volumes for 2024-2025



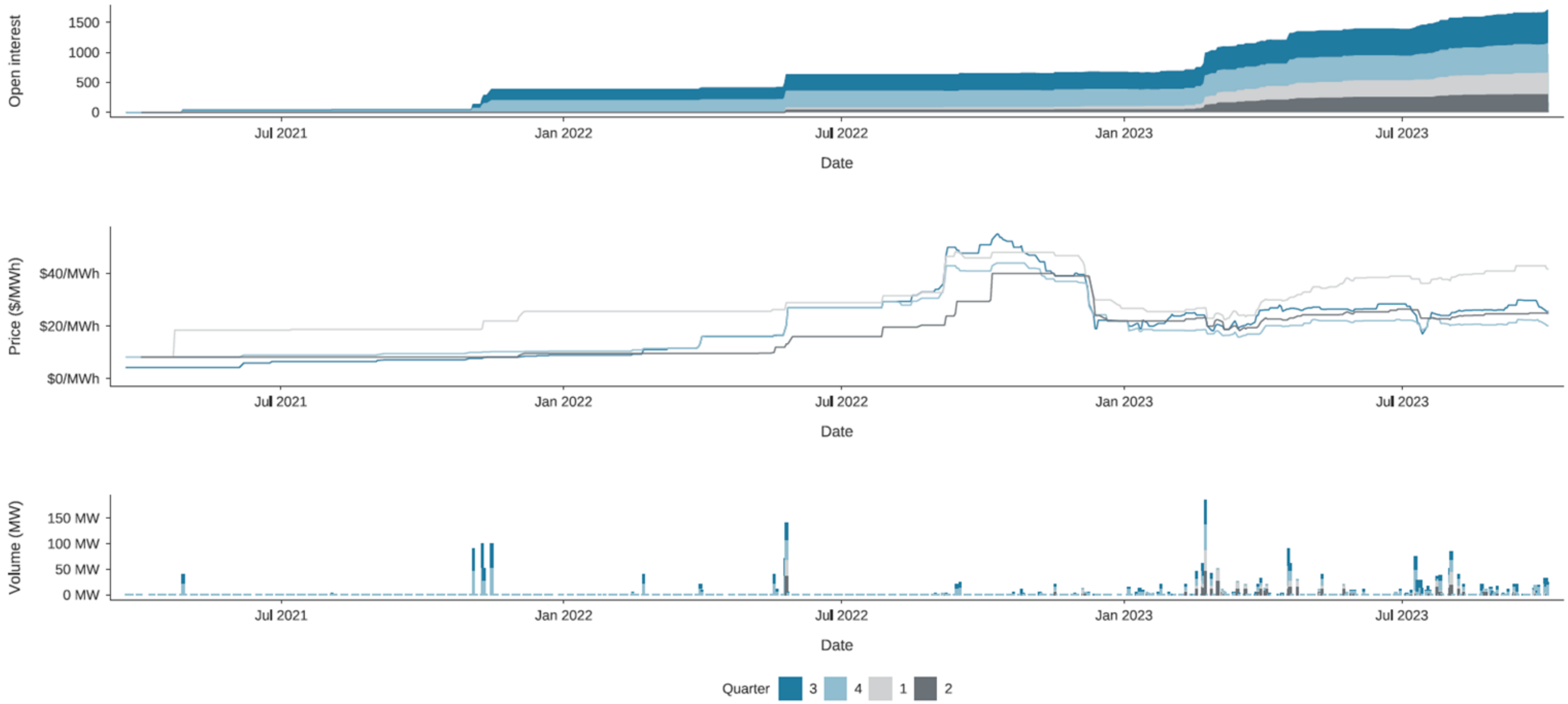
Source: Frontier Economics analysis of ASX data

Figure 8: NSW base swaps – open interest, prices and volumes for 2024-25



Source: Frontier Economics analysis of ASX data

Figure 9: NSW base $300 caps – open interest, prices and volumes for 2024-25



Source: Frontier Economics analysis of ASX data

The averaging period

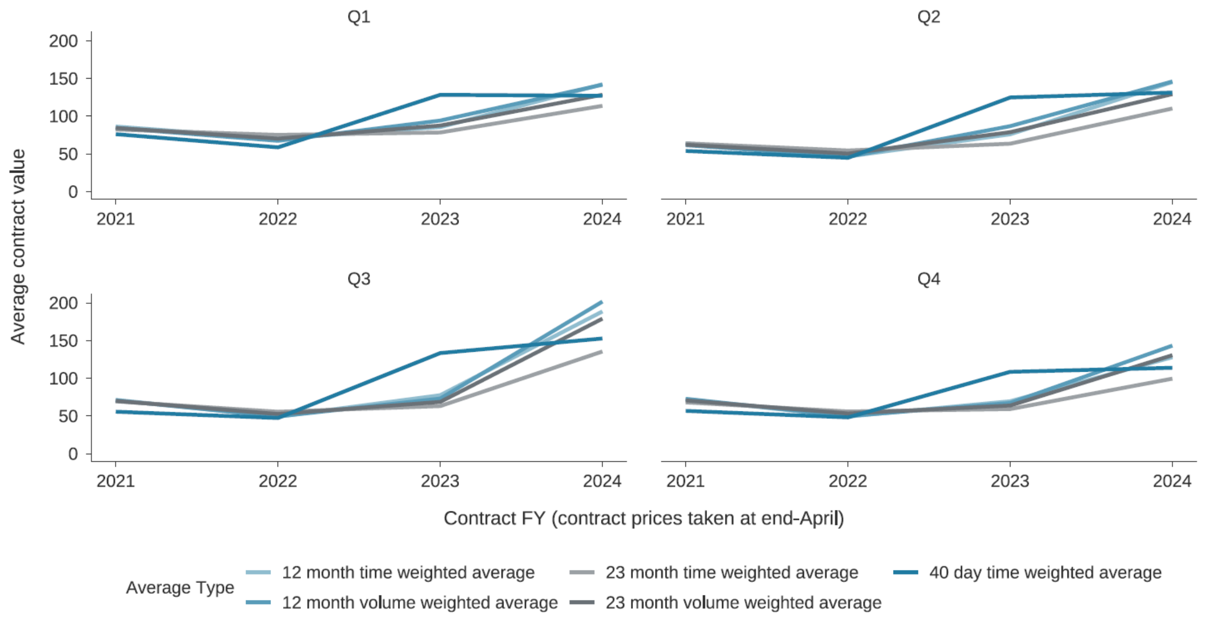
To determine the WEC we use historical contract price data to determine the cost of ASXEnergy contracts. Our view is that economic decisions in competitive markets will be based on the market value of contracts (and we consider 40-day average prices a good proxy for this market value), regardless of when those contracts are purchased. If a retailer has purchased contracts in the past at prices above the current market price, we would expect that competition from existing or new entrant retailers would force the retailer to make retail price offers based on the current cost of purchasing contracts; to do otherwise would be to risk losing customers to competitors able to enter or expand by purchasing contracts at the current cost and making retail price offers based on those current costs. Similarly, if a retailer has purchased contracts in the past at prices below the current market price, we would expect that maximising shareholder value would require them to make retail price offers based on the current cost of purchasing contracts; making retail price offers based on lower historical contract costs would result in less profit than simply selling the contracts again at the current contract price.

However, there may be good reasons that a regulator will choose to base regulated prices on something other than 40-day average contract prices. For instance, a regulator may want to reflect the fact that retailers can set prices at different times throughout the year, with a longer averaging period better reflecting costs at these different times through the year. Also, a longer averaging period, such as 12 months or 23 months, would be expected to provide regulated prices that are more stable over time and would also likely result in regulated prices that are more reflective of incumbent retailers' actual historical costs (since most retailers will buy contracts over a period of time leading up to the settlement year).

The ICRC currently uses 23-month time weighted contract prices in estimating the WEC. We have been asked to explore the impact of various averaging periods and average types. **Figure 10** illustrates the contract prices for financial year 2020-21 to 2023-24 under various averaging periods. In each financial year, the contract prices are taken up to the end of April of the preceding calendar year, consistent with the approximate timing of regulatory decisions for each year. For example, contract prices for financial year 2020-21 are taken as at 30 April 2020, around the time that regulatory decisions on prices for 2020-21 were made. There are a few important observations to draw from **Figure 10**:

- The 40-day time-weighted prices have the most volatile results as the short averaging period means that the resulting average contract prices are more likely to reflect either temporarily high or temporarily low contract prices.
- Conversely, the 23-month time-weighted prices have the least volatility across the time horizon. The reason is that the longer averaging period means that it takes longer for either increases in contract prices, or decreases in contract prices, to flow through to the estimated WEC.
- The 23-month volume-weighted and 12-month volume-weighted prices are very similar. This is because the majority of the volume is traded in the twelve months to April. See, for example in **Figure 8** that contract volume is materially higher in the most recent twelve months.

Figure 10: Comparison of various contract averaging approaches for the last four financial years



Source: Frontier Economics analysis of ASXEnergy data.

Consistent with the approach that the Commission has previously adopted, we calculate contract prices based on a 23-month time weighted approach, with one caveat. When the Commission comes to calculate the WEC for 2024/25 (which the Commission will do in the first half of next year) the Commission expects to use 23 months of data from 1 June 2022 to 30 April 2024. In order that our current calculation of contract prices is nearer to what the Commission's calculation will be next year, we use the same starting point of 1 June 2022, and we use data available up to 16 October 2023. This means that we are, in fact, using around 16.5 months of data, but the Commission will have the full 23 months of data available next year. Based on this approach of using contract prices from 1 June 2022 to 16 October 2023, the ASXEnergy contract prices are shown in **Table 1**.

Table 1: **23-month time-weighted average ASXEnergy derivative prices for NSW (2024-25 dollars)**

	Product	Status	Year	Quarter			
				Q3	Q4	Q1	Q2
TIME WEIGHTED	Swaps	Base	2024-25	$145.03	$109.64	$126.62	$130.29
	$300 caps	Base	2024-25	$29.70	$25.83	$35.64	$24.72

Source: Frontier Economics analysis of ASXEnergy data.

2.4 Contract position

This section addresses the final question we need to answer to estimate WEC:

- What kind of hedging position is a prudent retailer likely to adopt?

We use our portfolio optimisation model – *STRIKE* – to determine the efficient mix of hedging products that a prudent retailer would likely adopt. *STRIKE* calculates an efficient frontier, which represents the contracting positions that provide the lowest energy purchase cost for a given level of risk (as measured by standard deviation).

STRIKE applies a Minimum Variance Portfolio (MVP) approach to the task of hedging a retailer's exposure to wholesale spot prices. *STRIKE* incorporates an estimate of a retailer's exposure to the wholesale spot market, which is determined by the retailer's load and wholesale spot prices. There is an expected return and a variance associated with this. *STRIKE* also incorporates the types of hedging products that are typical in the electricity industry. These contracts – swaps and caps – generate cashflows that also have an expected return and a variance. Instead of assessing the expected return and associated risk for each asset in isolation, *STRIKE* applies the concepts of portfolio theory to evaluate the contribution of each asset to the risk of the portfolio as a whole. Based on this approach, *STRIKE* calculates efficient hedging strategies.

In order to determine a hedging position for the purposes of estimating the WEC for customers in the ACT, we make use of the following inputs in *STRIKE*:

- Forecast spot prices and load, as discussed in Section 2.2. As we discussed, we have developed 500 simulated years of half-hourly spot prices and load for 2024/25. There is a distribution of outcomes within these 500 simulated years. Our view is that an efficient retailer's hedging position should have regard to the uncertainty associated with what kind of year 2024/25 will be. For example, will 2024/25 be a year with high prices and high load corresponding, so that the load-weighted price is high, or will 2024/25 be a year with low prices and high load corresponding, so that the load-weighted price is low? To account for this uncertainty, we input 7 simulated years into *STRIKE*, representing those simulated years that represent the 99th, 95th, 75th, 50th, 25th, 5th and 1st percentile when the 500 simulated years are ranked according to load-weighted price.

- Contract prices, as discussed in Section 2.3. We present results for 23-month time weighted contract prices (noting that at this stage we are only using 16.5 months of data, but 23 months of data will be available to the Commission when determining prices next year).

As discussed, *STRIKE* calculates an efficient frontier, which represents the contracting positions that provide the lowest energy purchase cost for a given level of risk. The contract position that we use to calculate the WEC is based on the most conservative contracting position on the efficient frontier, which is the point on the efficient frontier with the lowest risk (but highest cost).

Outlined in **Figure 11** is the resulting contract positions at the conservative point for 2024-25. For each quarter (represented by the four vertical panels) the charts show the following:

- The distribution of half-hourly load for the 48 half-hours of the day (shown by the box plots, including the dots representing outliers, in the 'Load' panel).

- The distribution of half-hourly spot prices for the 48 half-hours of the day (shown by the box plots, including the dots representing outliers, in the 'Spot price' panel). The price chart is truncated at a spot price of $800/MWh to aid visibility of price outcomes.

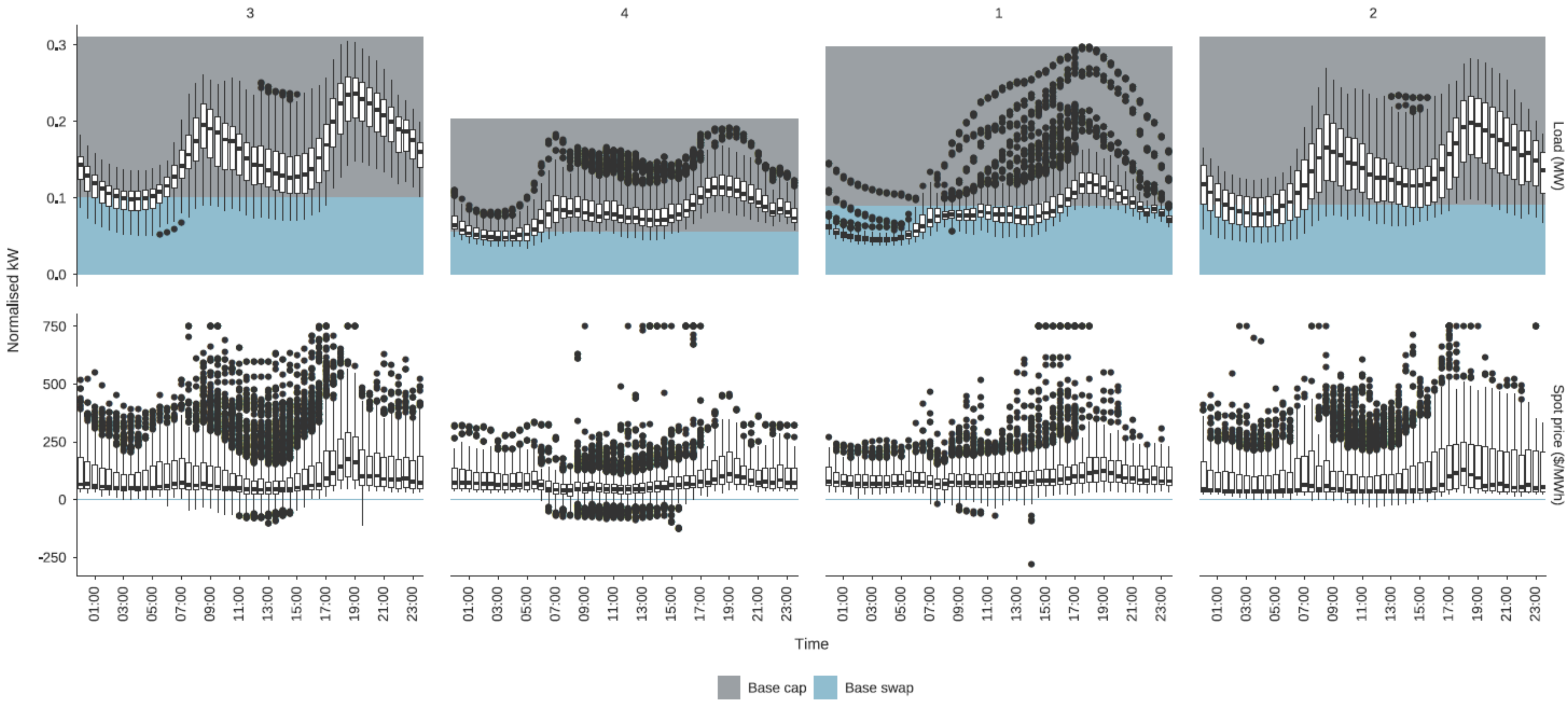
- The quantity of swaps and caps at the conservative point of the efficient frontier (shown by the coloured areas in the 'Load' panel).

In general, the contract position at the conservative point involves:

- purchasing swaps to cover to a level that is generally below average demand
- purchasing caps, on top of that, to cover to peak demand.

It should also be noted that the conservative point on the efficient frontier reflects the contract position that achieves the lowest risk given the projected state of the world that is input into *STRIKE*. In the event that different states of the world were input into *STRIKE*, the model would find a different contract position that achieves the lowest risk. In particular, if it were assumed, for instance, that next year will have an unusually large number of very high price events that coincided with high load, then the model would certainly find a different contract position that achieves the lowest risk. Load forecasts and price forecasts (and their correlation) are important to the costs that retailers face in supplying regulated customers. We use the best available information to develop load forecasts and price forecasts that are consistent with the observed peakiness of historic load and historic prices (and the observed correlation between) so that the *STRIKE* contract position is based on a good estimate of future conditions.

Figure 11: Contract position against load shape and prices for median STRIKE year



Note: Spot price chart truncated at a spot price of $800/MWh.

2.5 Wholesale electricity costs

Based on the data and modelling discussed in in the sections above, this section reports the WEC that we have estimated along with the contracting heuristic.

2.5.1 WEC

We estimate the WEC by calculating settlement payments and differences payments resulting from the half-hourly spot prices and load, contract prices and contract position that we have developed.

The WEC that we have estimated is based on half-hourly spot prices and load from the median simulated year (when these years are ranked according to WEC). The WEC that we have estimated is based on time weighted average ASXEnergy contract prices from 1 June 2022 (currently 16.5 months of data is available, but 23 months of data from 1 June 2022 will be available when the Commission determines prices next year). The WEC that we have estimated is based on the contract position from the conservative point on the efficient frontier.

We have estimated a WEC of $169.83/MWh (in $2024/25).

2.5.2 Contracting heuristic

As well as estimating a WEC, we determine a contracting heuristic by calculating the volume of base swaps and caps by quarter, expressed in relation to load. The contracting heuristic values are presented in **Table 2**. The volume of base swaps is expressed as percentile of load for all the half-hourly intervals in the quarter, where the percentile is equal the contracting level determined by *STRIKE*. The volume of caps is expressed as a percentage of load in the highest demand half-hourly interval in the quarter, less the volume of base swaps.

For example, in Quarter 1:

- The base swap contract volume is set to equal the 70th percentile of half hourly load in Quarter 1.
- The cap contract volume is set to equal the maximum demand interval for Quarter 1, less the contracted base swap volume for Quarter 1.

Table 2: Contracting Heuristic

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

Source: Frontier Economics analysis.

We note that there are two ways that this contracting heuristic could be used by the Commission on an ongoing basis to determine WEC. The first is to apply this contracting heuristic to a synthetic year of load and price data generated from a Monte Carlo analysis, as we have done when calculating the WEC of $169.83/MWh. However, to do this while making use of the most recent data on load and spot prices would necessitate re-running a Monte Carlo analysis on historical load and price data each time the Commission determines a WEC allowance. An alternative approach would be to use the same historical data, but to apply the contracting heuristic to the full set of historical data. In other words, rather than calculating the WEC by applying the contracting heuristic to a single synthetic year generated with a Monte Carlo approach using 3 years of historical load and price data, the Commission could calculate the WEC by applying the contracting heuristic to the 3 full years of historical load and price data. This latter approach would be equivalent to the approach that the Commission currently adopts.

We have estimated the WEC using both of these approaches and found that the difference in the result is very small: in this case, the WEC calculated using the 3 full years of historical data is only $0.44/MWh lower (0.25% lower) than the WEC calculated using a single synthetic year. Based on this, our view is that it is reasonable for the Commission to calculate the WEC using the 3 full years of historical data.

2.5.3 Volatility allowance

As discussed, the WECs that we have estimated are based on half-hourly spot prices and load from the median simulated year. The volatility allowance is intended to compensate retailers for the residual risk to which they are exposed, even when contracted at the conservative point. The volatility allowance is calculated based on the cost of holding working capital to fund cashflow shortfalls that could arise in years when the actual WEC is higher than we have estimated for the median simulated year. The working capital requirement is based on the difference between the WEC that we have estimated for the median simulated year and the WEC for the most costly simulated year. We then estimate the cost of holding sufficient working capital by applying a WACC of 8.16 per cent.[13]

We have estimated the volatility allowance to be $0.50/MWh.

[13] A real pre-tax WACC of 8.16% is equivalent to the nominal vanilla WACC of 9.38% from **Table** 6, accounting for dividend imputation credits.

3 Retail costs

This section considers the methodology for assessing retail costs.

The Commission currently uses a benchmark retail operating cost determined by the Independent Pricing and Regulatory Tribunal of NSW (IPART) in 2013, which is indexed annually by the consumer price index (CPI).[14] The Commission has flagged its intention to update the retail cost benchmark.[15]

There are two methodological issues that need to be addressed in determining retail costs:

- What are retail costs, and for which benchmark firm are retail costs estimated? We consider this question in Section 3.1
- What is the methodology for determining retail costs? We discuss the methodology and consider available evidence to inform the estimate of retail costs in Section 3.2.

Section 3.3 presents our findings and recommendations.

3.1 Defining retail costs

Retail costs are the costs incurred by the retailer in providing retail services to its customers. Retail costs for electricity businesses in Australia are often disaggregated into retail operating costs (ROC), also referred to as cost to serve (CTS), and customer acquisition and retention costs (CARC).

ROC or CTS are the direct costs that retailers incur in running their business. While different retailers and regulators will categorise CTS in different ways it is generally agreed to consist of the following:

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

While the general descriptions of CTS tend to be quite similar, there remains uncertainty about the treatment of specific cost elements by different retailers and regulators, particularly in regard to the allocation of common costs.

CARC is the cost of acquiring new retail customers and retaining existing customers. Again, while these will be categorised in different ways, CARC is generally agreed to consist of the following:

14 Independent Competition and Regulatory Commission, Standing offer prices for the supply of electricity to small customers from 1 July 2024: Issues paper, report 5 of 2023, August 2023, p16.

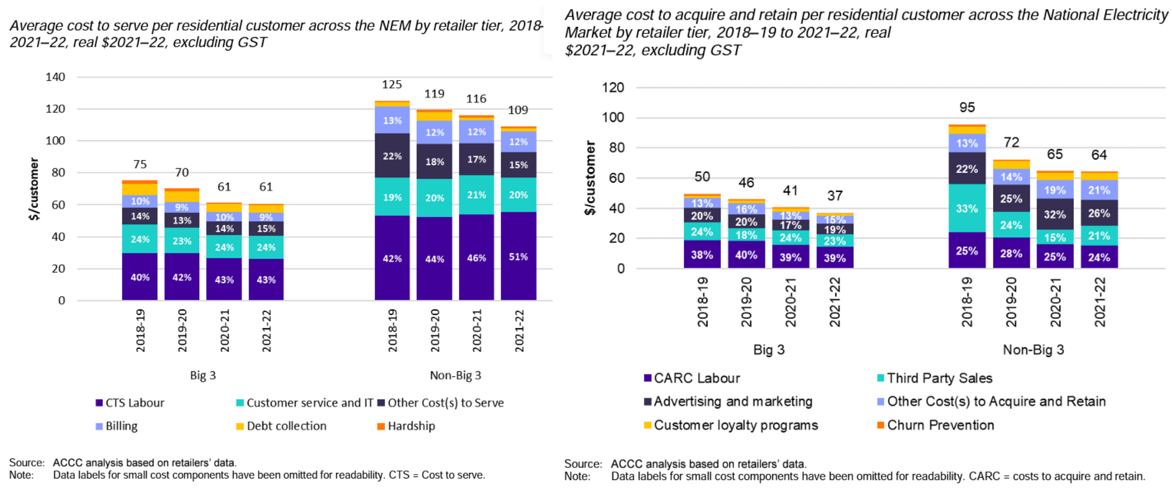
15 Independent Competition and Regulatory Commission, Standing offer prices for the supply of electricity to small customers from 1 July 2024: Issues paper, report 5 of 2023, August 2023, p16.

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

Some regulators in Australia adopt different methods when allowing for CTS and CARC. The Commission's retail operating cost allowance includes CTS as well as the reasonable costs of customer acquisition and retention. The ESC is required to develop a 'modest' estimate for CARC, while the AER aims to set a 'reasonable' rather than 'efficient' allowance. Many regulators do not distinguish between CTS and CARC in setting regulatory cost allowances, making it difficult to comment on the extent to which CARC is included in cost estimates.

An allowance for CTS and for CARC will, in principle, be set for a particular type of electricity business. When setting regulated prices the Commission considers the prudent and efficient costs of a hypothetical incumbent retailer in the same position as ActewAGL (the benchmark retailer), rather than a new entrant retailer or a smaller retailer.[16] This decision about the type of electricity business that should be used as the benchmark for determining an allowance for ROC and CARC can be important because different types of retail electricity businesses can have different costs. This is apparent in the ACCC's November 2022 NEM Inquiry report, in which the ACCC used confidential information provided by the retailers to demonstrate that the big three retailers – AGL, Origin Energy and EnergyAustralia – have CTS and CARC that are significantly lower than other retailers, including ActewAGL[17] (as seen in **Figure 12**). The ACCC attributed this to the cost advantages of incumbency and economies of scale.[18]

Figure 12: ACCC data on NEM-wide CTS and CARC for residential customers, by retailer tier



Source: Australian Competition and Consumer Commission, Inquiry into the National Electricity Market, November 2022 Report, 23 November 2022, p75.

16 Independent Competition and Regulatory Commission, Standing offer prices for the supply of electricity to small customers from 1 July 2024: Issues paper, report 5 of 2023, August 2023, p9.

17 Australian Competition and Consumer Commission, Inquiry into the National Electricity Market, November 2022 Report, 23 November 2021, p75.

18 Australian Competition and Consumer Commission, Inquiry into the National Electricity Market, November 2022 Report, 23 November 2022, p75.

In practice, when estimating CTS and CARC using a benchmarking approach, as we discuss below, the opportunity to establish an estimate of efficient CTS and CARC for a particular type of electricity business is limited by the benchmark information that is available. As we will see, most of that information is for large mass-market retailers. For example, the ACCC includes all retailers with more than 10,000 customers in their benchmarks. However, they weight aggregate data by customer numbers and so give more weight to cost estimates from large retailers.

3.2 Estimating retail costs

3.2.1 ACCC's NEM Inquiry

The ACCC separately reports CTS and CARC for each region in the NEM in its NEM Inquiry Reports. The retail cost data is drawn from confidential information collected from 15 retailers which together account for 86% of the residential customer base in the NEM.[19] The retail cost information is reported for residential and small business customers.

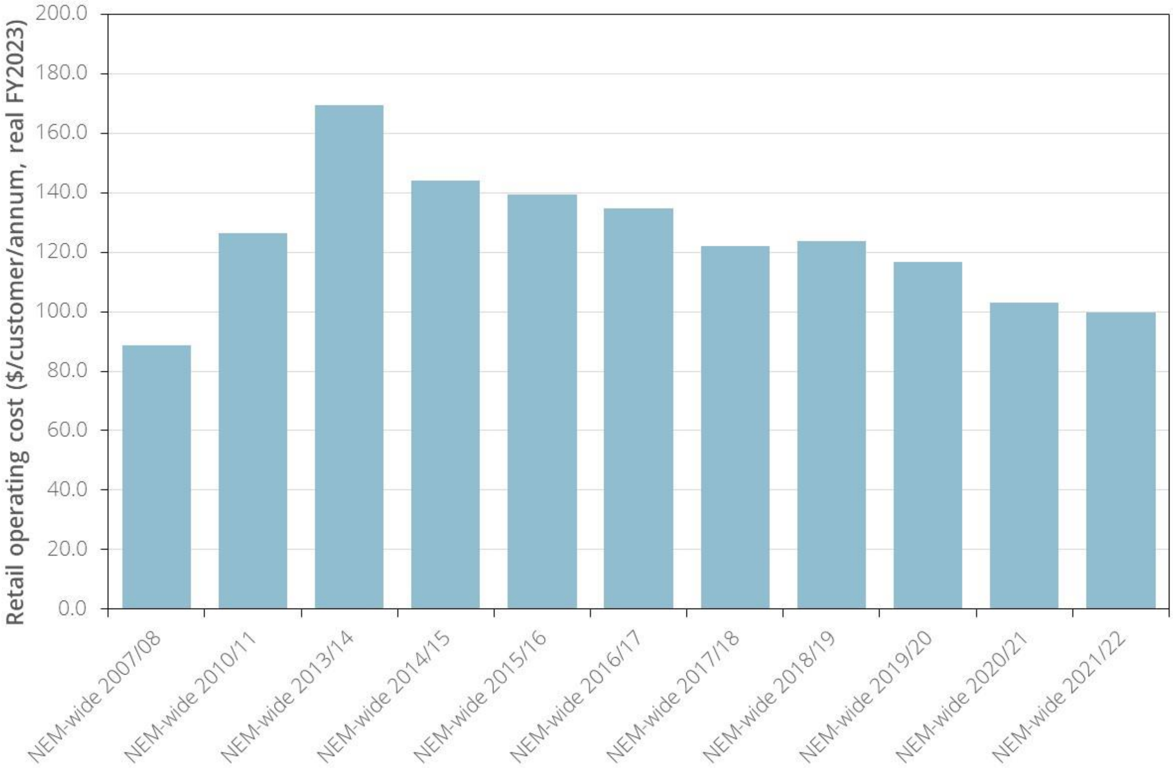
CTS

The ACCC defines cost to serve as "the operating costs retailers face in servicing their customers, including billing systems and processes, customer enquiries, management of debt and compliance with regulatory obligations".[20] The NEM-wide residential CTS reported by the ACCC in the November 2022 NEM Inquiry Report (including 'other costs') show continued reductions to the current level of $100/customer/annum (**Figure 13**).

19 Australian Competition and Consumer Commission, Inquiry into the National Electricity Market, November 2022 Report, 23 November 2022, p10.

20 Australian Competition and Consumer Commission, Inquiry into the National Electricity Market, November 2021 Report, 22 November 2021, p33.

Figure 13: ACCC data on NEM-wide CTS for residential customers



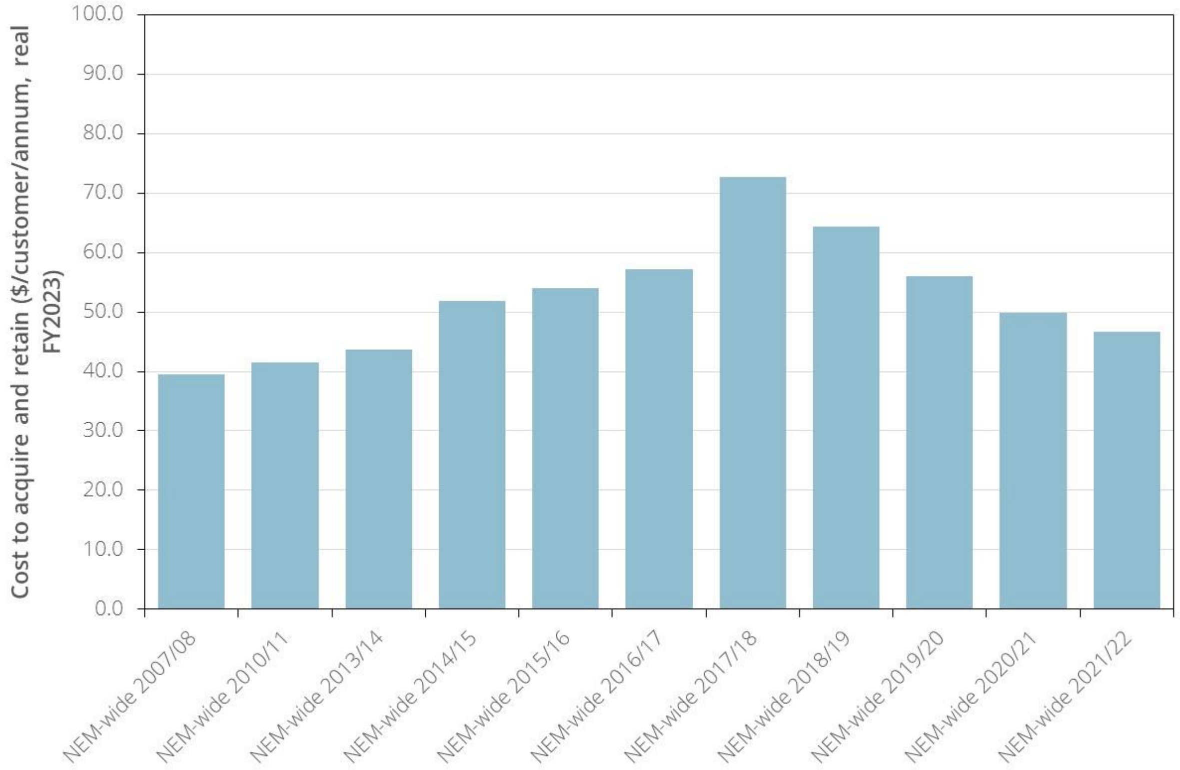
Source: Australian Competition and Consumer Commission, Inquiry into the National Electricity Market, November 2022 Report, Data appendix, Supplementary Table D14.3 and 14.8.

Note: June 2023 dollars

CARC

A retailer's cost to acquire and retain customers includes expenditure on marketing and advertising, customer loyalty programs, and third-party sales.[21] The ACCC reports the average cost to acquire and retain residential customers across the NEM is $47/customer/annum and, like CTS, has fallen, although at a slower rate in recent years.

Figure 14: ACCC data on customer acquisition and retention costs for residential customers



Source: Australian Competition and Consumer Commission, Inquiry into the National Electricity Market, November 2022 Report, Data appendix, Supplementary Table D14.8

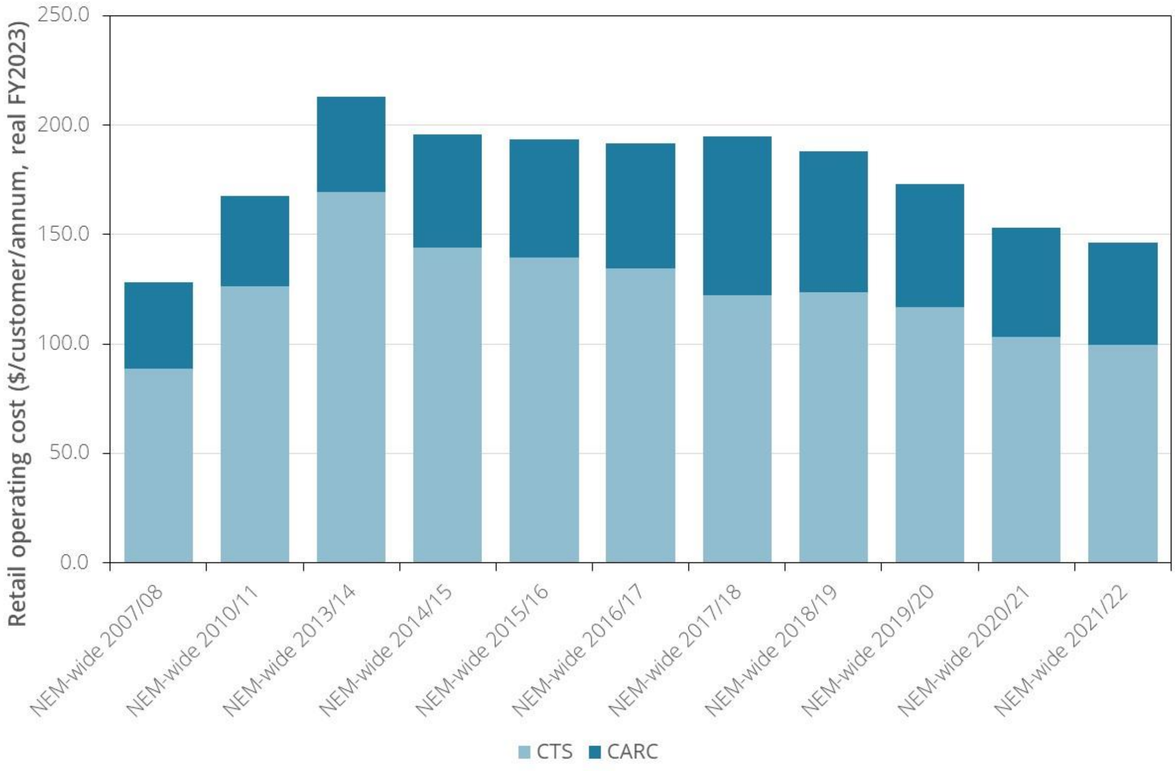
Note: June 2023 dollars

[21] Australian Competition and Consumer Commission, Inquiry into the National Electricity Market, November 2022 Report, 23 November 2022, p76.

Total

The ACCC's estimates of retail costs (CTS, including 'other costs' and CARC) across the NEM is $147/customer/annum. For individual jurisdictions, estimates of retail costs range from a low of $133/customer/annum to a high of $161/customer/annum.

Figure 15: ACCC data on retail costs (CTS and CARC) for residential customers



Source: Australian Competition and Consumer Commission, Inquiry into the National Electricity Market, November 2022 Report, Data appendix, Supplementary Table D14.3 and D14.8

Note: June 2023 dollars

3.2.2 Regulatory decisions

Regulators tend to determine an appropriate allowance for retail costs using one or both of two approaches:

- A **"bottom-up" assessment** of data on the retail costs of existing retailers
- A **benchmarking approach** which involves an assessment of allowances in other relevant regulatory decisions and of relevant public information on these costs.

The "bottom-up" approach relies on disaggregated information on the costs of the various activities undertaken by a retailer supplying small customers in the ACT. This information can be aggregated to determine an efficient annual cost per customer for providing retail supply. Disaggregated cost information of this type is not publicly available. A number of regulators have adopted this approach in the past, including most recently the ESC, OTTER and the AER, using detailed cost information provided by retailers to the regulator as part of the review or inquiry process.

The latter approach, typically known as the benchmarking approach, relies on aggregating available information on the annual cost per customer for providing retail supply. Although the benchmarking approach is not based on the actual cost data provided by retailers in the ACT, it is based, in part, on actual cost information from retailers. There are a number of ways information on retailers' actual costs will be incorporated in the benchmarking analysis:

- by benchmarking against regulatory decisions that have themselves been based, at least in part, on actual cost data provided by retailers
- by benchmarking against retailers' reported retail costs using publicly available market data
- by benchmarking against retail costs reported by the ACCC as part of its NEM Inquiry, which is based on actual cost data provided by retailers.

One challenge of the benchmarking approach given the limited information available is identifying and, if necessary, adjusting for any differences in costs between the characteristics of benchmark firms or jurisdictions and the characteristics of retail supply to small customers in ACT.

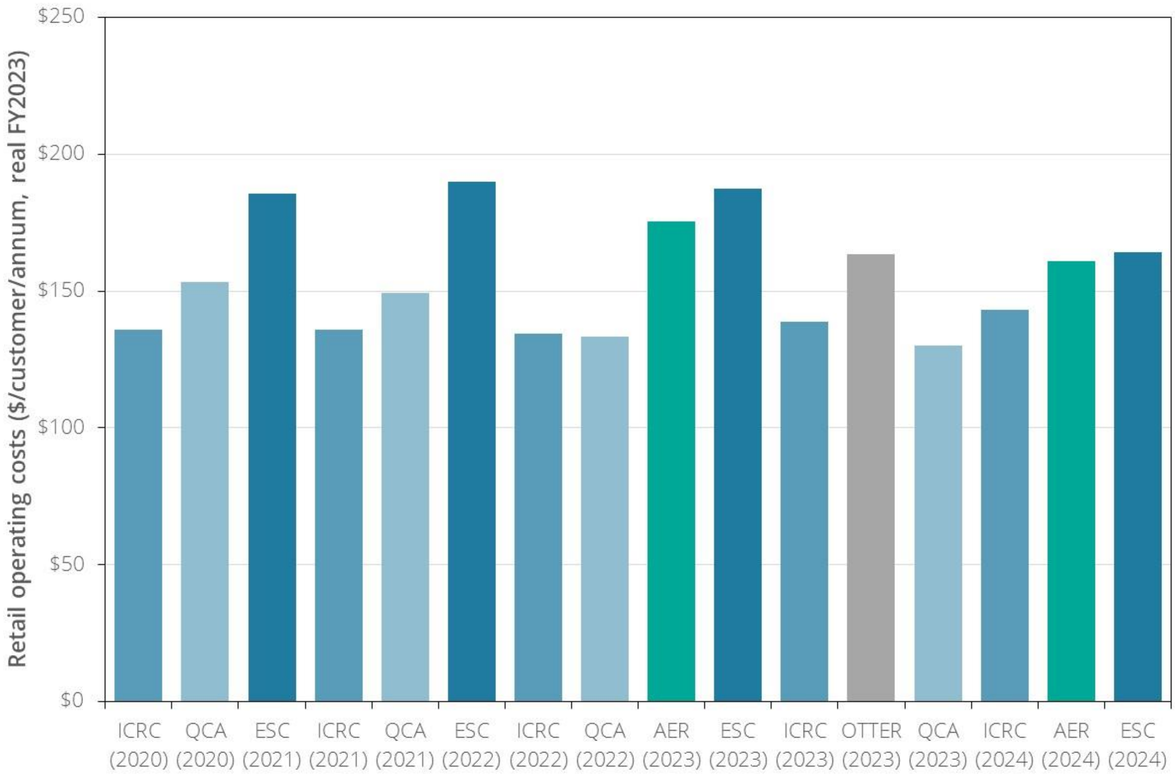
In this review we apply both the bottom-up and benchmarking approaches. The Commission collected confidential information from retailers active in the ACT to inform the application of the bottom-up approach.

The standing offer prices for small customers regulated by the Commission includes both residential and small business customers. As we discuss below, most regulators do not differentiate between residential and business customers when setting retail operating cost allowances.

Figure 16 demonstrates the Commission's retail operating cost allowances are amongst the lowest allowances. As we discuss in the following sections this can be explained by the relatively limited CARC included in the Commission's allowance (similar to OTTER) and the Commission's observation that bad debt risks in the ACT market are likely to be lower than in other Australian state markets.[22] The values reported below include bad and doubtful debt allowances, but exclude smart meter costs. All dollar values are reported as at June 2023 to aid comparison.

[22] Independent Competition and Regulatory Commission, Retail electricity price investigation: Final report, Report 9 of 2020, June 2020, p51.

Figure 16: Summary of regulatory retail operating cost benchmarks



Source: Frontier Economics analysis of regulatory decisions

Notes: June 2023 dollars, AER benchmarks are for a NSW residential customer

AER

Each year the AER determines the Default Market Offer (DMO), that is the maximum a retailer can charge a customer on a standing offer in NSW, South Australia and South East Queensland. Electricity retailers must make standing offers available to customers. The objectives of the DMO are to:

- protect customers from unreasonable prices
- allow retailers to recover their efficient costs (including a reasonable retail margin and costs associated with CARC)
- maintain incentives for competition, innovation and investment by retailers and incentives for consumers to engage in the market.[23]

The AER makes a distinction between these objectives and that of regulated prices set by the QCA, the ESC, OTTER and the Commission, noting the DMO is intended to be a reasonable price, rather than an efficient price in markets where there is limited competition.[24] Although the DMO is concerned with standing offers for residential and small business customers, like the retail prices the Commission is investigating, the distinction between a reasonable and efficient price made by the AER could influence their interpretation of cost and margin information.

To determine retail costs for DMO5 the AER continued to use the cost build up approach based on actual retail costs adopted in DMO4. Prior to DMO4 the AER used a top-down (DMO1) or

23 Australian Energy Regulator, Default market offer prices 2023-24: Final determination, May 2023, p7.

24 Australian Energy Regulator, Default market offer prices 2023-24: Final determination, May 2023, p8.

indexation approach (DMO2 and DMO3) to set the DMO, meaning information on retail costs was not used to inform its decision and therefore not published.

Retail costs for DMO5 are based on annual retail operating cost information by region collected by the ACCC and reported in its November 2022 NEM Inquiry report. The AER considers the retail operating cost data reported to the ACCC is reliable, publicly available and covers retailers that sell to around 90% of small customers in the DMO regions.[25] In setting retail costs the AER included both CTS and CARC reported by the ACCC. The AER does not separately specify these values in its decision, but a breakdown of the total amount for retail costs is provided by the ACCC in the supplementary data released with its November 2022 NEM Inquiry report.[26]

The ACCC retail cost data does not include advanced meter costs or bad and doubtful debt. The AER included an additional allowance for these costs based on:

- information requested from the retailers for advanced meter costs
- confidential information collected by the ACCC for bad and doubtful debts.[27]

An advanced meter cost is set for each customer type and distribution region. A single bad and doubtful debt allowance is set for residential and small business customers across each distribution region.

The bad and doubtful debt allowance in AER's DMO5 Draft Determination was based on costs reported in the 2021-22 financial report of three entities (AGL Energy, Origin Energy and Snowy Hydro). Following stakeholder submissions, the AER used confidential bad and doubtful debt information submitted by 15 retailers to the ACCC for its NEM Inquiry in its DMO5 Final Determination, which it considered to be a more representative sample.[28]

A DMO is set for each distribution region across NSW, South East Queensland and South Australia for three customer types: residential without controlled load, residential with controlled load and small business. Retail operating costs vary across distribution regions and between residential and small business customers to reflect:

- differences in the retail cost information published by the ACCC across region and between residential and small business customers
- differences in the AER's estimates of advanced meter costs by distribution region
- differences in the confidential cost information on bad and doubtful debts between customer types.

Since the Commission separately determines smart meter costs, we have excluded the AER's smart meter allowance in Table 3. The costs reported in Table 3 include the bad and doubtful debt allowance set by the AER of $19.17/customer/annum ($2023/24) for residential customers and $34/customer/annum ($2023/24) for business customers.

25 Australian Energy Regulator, Default market offer prices 2023-24: Final determination, May 2023, p31.

26 ACCC, *Inquiry into the National Electricity Market*, November 2022 Report, Data appendix, Sheet 14.

27 Australian Energy Regulator, Default market offer prices 2023-24: Final determination, May 2023, p31. Th AER requested information on advanced meter costs from nine retailers that together make up 93% if the customer base.

28 Australian Energy Regulator, Default market offer prices 2023-24: Final determination, May 2023, p34.

Table 3: AER retail cost allowance (CTS and CARC) for the 2023/24 DMO

Distribution zone	Residential without controlled load ($/customer/annum, $2023/24))	Small business ($/customer/annum, $2023/24))
NSW (Ausgrid, Endeavour Energy, Essential Energy)	$172.37	$220.21
Energex	$164.68	$184.01
SA Power Networks	$170.09	$199.43

Source: Australian Energy Regulator, Default market offer prices 2023-24: Final determination, May 2023.

ESC

The Victorian Default Offer (VDO) set by the ESC each year specifies the prices that may be charged for standing offers for residential and small business customers. The VDO is intended to be a reasonably priced option, based on efficient costs, to provide a safeguard to customers that are unwilling or unable to engage with the electricity market.[29]

All electricity retailers in Victoria must make the VDO available to customers who request it. The ESC asked all retailers in Victoria with more than 10,000 domestic and/or small business customers to provide information when setting the VDO.

In setting the VDO the ESC makes allowances for retail operating costs and CARC.

Retail operating costs

The ESC defines retail operating costs to include a range of expenses incurred by an electricity retailer, including:

- billing and revenue collection systems
- information technology systems
- call centre costs
- corporate overheads
- energy trading costs
- provision for bad and doubtful debts
- regulatory compliance costs.[30]

The ESC used a historical cost benchmark to set the retail cost component for the 2023-24 VDO. The ESC set the retail operating cost benchmark of $132.03/customer/annum ($2023/24) based on the customer weighted average of retailers' actual retail operating costs for 2021-22, indexed to account for the change in CPI. A single allowance applies across each distribution zone in Victoria.

[29] Essential Services Commission, Victoria Default Offer 2023-24, Final Decision Paper, 25 May 2023, p2.

[30] Essential Services Commission, Victoria Default Offer 2023-24, Final Decision Paper, 25 May 2023, p48.

This is a change of approach from previous VDOs, where retail operating costs were set based on IPART's 2013 benchmark. The ESC revised their approach after collecting retailers' cost data for several years, and confirming the range, median and customer weighted average of retailers' retail operating costs have been relatively stable over the last four years. Basing the benchmark on historic cost ensures retailers can recover efficient costs based on the most up-to-date cost information, and accounts for changes in costs and productivity improvements. Retail operating costs for 2023-24 were around 10% lower than those included in the 2022-23 VDO.

The ESC announced its intention to continue to collect cost data from retailers to update the retail operating cost benchmark to reflect productivity gains or new costs.

Customer acquisition and retention costs

The ESC is required under the pricing order to include a "modest" allowance for CARC in setting the VDO.[31] The ESC defines CARC to include:

- the cost of acquisition channels (including third-party comparison websites or telemarketing)
- the cost of retention teams
- marketing costs targeted at driving customer acquisition and retention.[32]

For the 2023-24 VDO the ESC set a benchmark of $43.89/customer/annum ($2023/24), based on a benchmark of $38 from the ACCC's 2019 Retail electricity pricing inquiry report adjusted for inflation. This is consistent with the approach adopted by the ESC in previous VDO determinations. This benchmark sits within the range of actual acquisition costs, but is lower than customer weighted average acquisition costs of $54 based on retailer data for 2021-22.[33] The ESC noted that some expenditure on CARC is efficient, because it makes customers aware of the offers available, but that retailers have an incentive to spend more on CARC than may be beneficial to customers and CARC has increased in recent years.[34] The ESC considered the 2013-14 benchmark is likely to include fewer unbeneficial acquisition costs than more recent estimates.[35]

Total

Table 4 summarises the ESC's benchmarks and the method used to derive this benchmark for the 2023-24 VDO.

31 Essential Services Commission, Victoria Default Offer 2023-24, Final Decision Paper, 25 May 2023, p39.

32 Essential Services Commission, Victoria Default Offer 2023-24, Final Decision Paper, 25 May 2023, p40.

33 Essential Services Commission, Victoria Default Offer 2023-24, Final Decision Paper, 25 May 2023, p41.

34 Essential Services Commission, Victoria Default Offer 2023-24, Final Decision Paper, 25 May 2023, p41.

35 Essential Services Commission, Victoria Default Offer 2023-24, Final Decision Paper, 25 May 2023, p41.

Table 4: **ESC decisions on retail operating cost and CARC for the 2023-24 VDO (residential and business combined)**

Item	Estimate ($/customer/annum, $2023/24))	Method
Retail operating cost	$132.03	Based on customer weighted actual retailer retail operating costs 2021-22
CARC	$43.89	Based on 2013-14 CARC from the ACCC REPI
Total	$175.92	

Source: Essential Services Commission, Victoria Default Offer 2023-24, Final Decision Paper, 25 May 2023

OTTER

OTTER periodically determines the maximum prices Aurora Energy may charge small customers under standard retail contracts on mainland Tasmania. OTTER is able to decide the period covered by the price determination, usually around three years, and must undertake a pricing investigation before making a new determination.

OTTER's objectives, set out under the *Electricity Supply Industry Act* (ESI Act), are to promote efficiency and competition in the electricity supply industry and protect the interests of customers. OTTER aims to set prices at a level that enable a retailer to recover the costs of supplying electricity to customers on standard retail contracts.[36]

OTTER is required under the ESI Act to estimate Aurora Energy's costs to provide retail services, including CTS. The CTS allowance reflects the Regulator's assessment of the efficient level of Aurora Energy's operating costs to provide retail services to customers on standing offer prices.

OTTER defines Aurora Energy's retail costs as including:

- billing and revenue collection
- marketing
- providing advice and answering customer queries
- contributing to corporate overheads
- the costs relating to the aurora+ App
- regulatory compliance.[37]

In the 2022 price review OTTER estimated the CTS allowance using a cost build-up approach and testing the allowance against those in other jurisdictions. OTTER set a CTS allowance of $156/customer/annum in 2021 dollars (including bad debt) ($163/customer/annum in $2022/23). The allowance set at the beginning of the regulatory period is adjusted each year to reflect:

36 Office of the Tasmanian Economic Regulator, 2022 Standing Offer electricity pricing investigation: Investigation of maximum standing offer prices for small customers on Mainland Tasmania 1 July 2022 to 30 June 2025, Final Report, April 2022, p4.

37 Office of the Tasmanian Economic Regulator, 2022 Standing Offer electricity pricing investigation: Investigation of maximum standing offer prices for small customers on Mainland Tasmania 1 July 2022 to 30 June 2025, Final Report, April 2022, pv.

- an efficiency factor of 1.78% in 2022-23 and 3.4% per annum in 2023-24 and 2024-25 across all cost categories (including bad debts)
- indexation at CPI (for CTS non-labour components) and at the wage price index (for CTS labour cost components).[38]

If customer numbers change by more than 2% each year the CTS will be adjusted to allow fixed costs to be recovered from a smaller or larger customer base.[39]

Meter costs are separately estimated and are not included in the CTS allowance.

QCA

The QCA sets regulated retail electricity prices for regional Queensland each year for those customers who choose not to move to a market offer. When setting prices the QCA is required to have regard to:

- the actual costs of making, producing or supplying the goods or services
- the effect of the determination on competition in the Queensland retail electricity market
- any other matters they consider relevant.[40]

The QCA sets prices for a series of tariffs, for residential, small business and large business customers. When setting prices, the QCA is required to use a cost build-up methodology for key cost elements including retail costs.

The QCA jointly considers and reports ROC and retail margin. The QCA defines retail operating costs as the costs associated with services provided by a retailer to its customers and typically includes the costs associated with customer administration, call centres, corporate overheads, billing and revenue collection, IT systems, regulatory compliance and CARC.[41] The retail margin compensates retailers for their exposure to systematic risk associated with providing customer retail services.[42]

Historically, the QCA estimated retail costs using established benchmark allowances established in 2016-17, adjusted for inflation. At that time the benchmark allowances were set based on publicly available market data and a bottom-up approach based on confidential information provided by the retailers.[43] The benchmark compromised a variable and fixed component, and was separately set for residential and small business customers.

The QCA revised their approach to estimating retail costs for the 2021-22 review, and maintained that approach for the 2022-23 review. For the 2021-22 review the QCA established new retail costs (including fixed costs and cost allocators for variable costs) for residential and small business customers based on up-to-date market information. Retail costs were updated by

---

38 Office of the Tasmanian Economic Regulator, 2022 Standing Offer electricity pricing investigation: Investigation of maximum standing offer prices for small customers on Mainland Tasmania 1 July 2022 to 30 June 2025, Final Report, April 2022, pv.

39 Office of the Tasmanian Economic Regulator, 2022 Standing Offer electricity pricing investigation: Investigation of maximum standing offer prices for small customers on Mainland Tasmania 1 July 2022 to 30 June 2025, Final Report, April 2022, pv.

40 Queensland Competition Authority, Regulated retail electricity prices in regional Queensland 2023-24, June 2023, p1.

41 ACIL Allen, 2021-22 regulated electricity price review: Updating retail costs, Final report to the Queensland Competition Authority, 28 May 2021, p1.

42 ACIL Allen, 2021-22 regulated electricity price review: Updating retail costs, Final report to the Queensland Competition Authority, 28 May 2021, p1.

43 ACIL Allen Consulting, Updating retail costs for the 2021-22 regulated electricity price review, Report to the Queensland Competition Authority, 8 December 2020, p1.

deconstructing the components of retail electricity tariffs available in south east Queensland to benchmark retail costs. Network costs and energy costs were deducted from tariffs to estimate retail costs.[44] The benchmarking analysis focused on flat tariffs due to methodological issues associated with other tariff structures.[45]

The retail allowance for residential flat tariffs is dominated by four retailers (Origin Energy, EnergyAustralia, Alinta Energy and AGL) who together account for 86% of market offers for residential customers in south east Queensland.[46] The small business estimate is dominated by Origin Energy, who accounts for around 68% of market offers.[47] The QCA accepted their consultant's cost estimates, which are specified as a fixed component in $/customer/year and a variable cost allocator (%). We have estimated the retail allowance in to be $134/customer/year ($2022/23) based on an average residential tariff and assuming a retail margin of 5.3% (consistent with recent regulatory decisions).

3.2.3 Market data

Retail operating costs

AGL and Origin Energy report retail operating costs (referred to as CTS or cost to maintain) in their Annual Reports. **Figure** 17 summarises the ROC reported by AGL and Origin Energy over the period 2012/13 to 2020/21.

It is clear from **Figure** 17 that the reported CTS has historically been very different between AGL and Origin Energy. Over the last ten years AGL has reported CTS that has been between $75/customer/annum and $103/customer/annum.[48] In contrast, over the same period Origin Energy has reported CTS that has been between $104/customer/annum and $182/customer/annum. In recent years the CTS for AGL and Origin Energy have converged, to around $100-130/customer/annum.

In our view these differences are likely to be significantly affected by differences in the way that these costs are reported by AGL and Origin Energy.

- One source of difference could be the way that costs are allocated between CTS and CARC. As we will see below, over this same period AGL's reported CARC has been materially higher than Origin Energy's, suggesting that some of the difference in ROC is a matter of cost allocation.
- A second source of difference could be the group of customers for which CTS is reported. As far as we can tell, neither AGL nor Origin Energy are specific about the category of customers to which the reported ROC relates: AGL's reported ROC relates to the 'Consumer Market' but it is not clear whether this is only residential customers or also includes small business customers. Origin Energy's reported ROC relates to electricity and natural gas accounts, and may include all customers, not just small customers. If so, this would explain why there is a

44 ACIL Allen, 2021-22 regulated electricity price review: Updating retail costs, Final report to the Queensland Competition Authority, 28 May 2021, piii.

45 ACIL Allen, 2021-22 regulated electricity price review: Updating retail costs, Final report to the Queensland Competition Authority, 28 May 2021, p28.

46 ACIL Allen, 2021-22 regulated electricity price review: Updating retail costs, Final report to the Queensland Competition Authority, 28 May 2021, p25.

47 ACIL Allen, 2021-22 regulated electricity price review: Updating retail costs, Final report to the Queensland Competition Authority, 28 May 2021, p27.

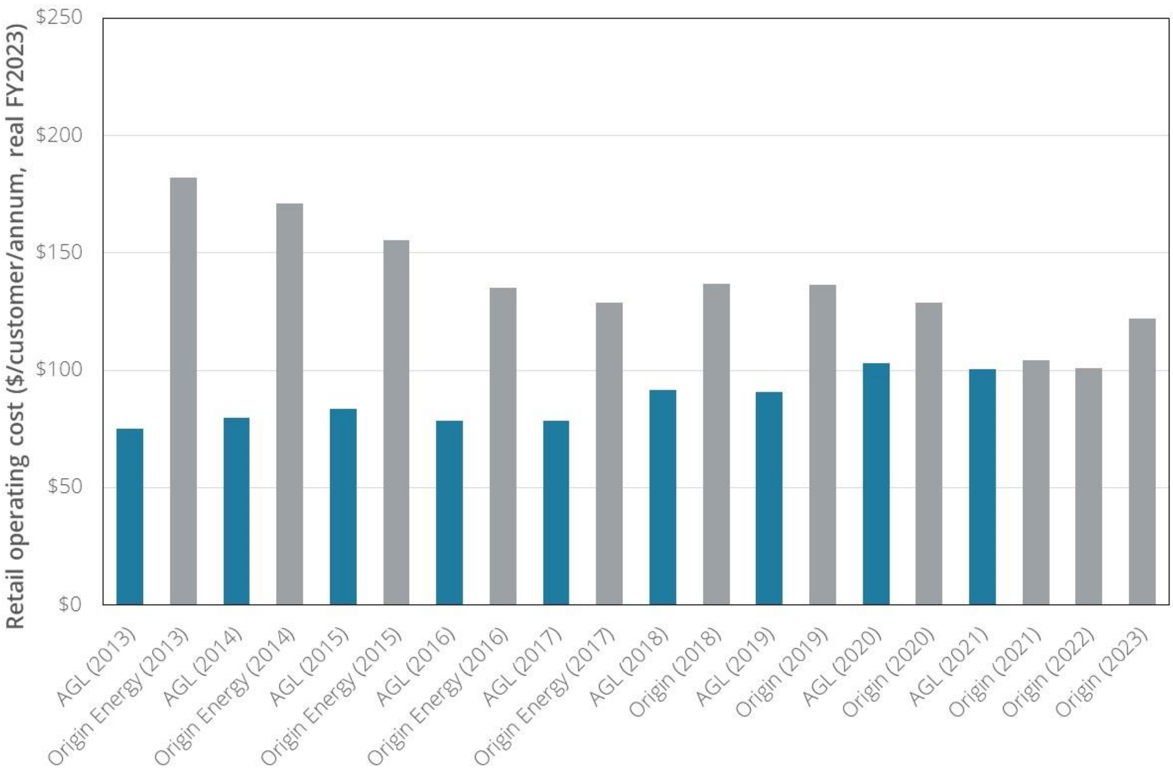
48 In 2023 dollars.

difference in reported ROC, since there is typically a higher ROC per customer associated with large customers.

- A third source of difference could be differences in the categories of costs that are classed as cost to serve or cost to maintain. It may be that costs that are typically considered retail operating costs in regulatory determinations are not classified as cost to serve or cost to maintain by AGL or Origin Energy.

Because of the difficulty identifying the basis on which the market data on CTS is reported, we have reservations in drawing too many conclusions from this data.

Figure 17: Market data on CTS



Source: Frontier Economics analysis of company reports

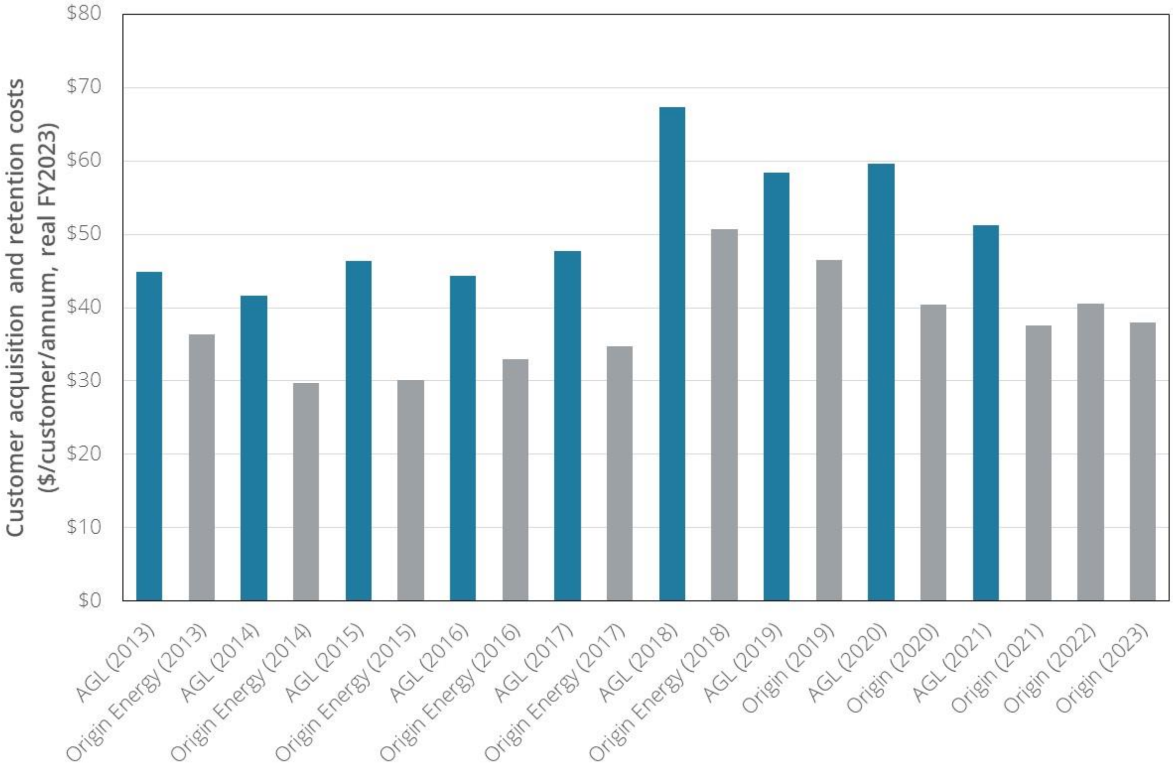
CARC

Figure 18 summarises the CARC reported by AGL and Origin Energy. Each of these businesses report CARC (referred to as cost to grow or cost to acquire/maintain) in their Annual Reports.

It is clear from **Figure** 18 that the reported CARC is very different between AGL and Origin Energy. Over the last ten years AGL has reported CARC that has been between $42/customer/annum and $67/customer/annum. In contrast, over the same period Origin Energy has reported CARC that has been between $30/customer/annum and $51/customer/annum.

As discussed in relation to ROC, in our view these differences are likely to be significantly affected by differences in the way that these costs are reported by AGL and Origin Energy. Because of the difficulty identifying the basis on which the market data on CARC is reported, we have reservations in drawing too many conclusions from this data.

Figure 18: Market data on CARC



Source: Frontier Economics analysis of company reports

3.2.4 Confidential retail data

The Commission collected data from retailers to inform the review. The information provided by retailers is confidential and is not included in this public report.

3.3 Conclusion

Figure 19 summarises the retail operating cost information collected from the retailers, reported to the market and allowed by regulators. The shaded areas for each bar show the range from the lowest estimate to the highest estimate for each data type and year.

Retail operating cost estimates from different sources have been converging in recent years, with recent decisions by other regulators approaching market and ACCC data. The Commission's retail operating cost allowance lies at the bottom end of the regulator range and is lower than ActewAGL's estimates of retail operating cost and lower than the customer-weighted average retail operating cost based on data presented to the Commission by retailers.

The retail operating cost allowances set by the AER and ESC for 2023/24 are relatively similar:

- The AER sets an annual retail operating cost per customer of between $153 and $161 for residential customers and between $172 and $206 for small business customers
- The ESC set a retail operating cost of $164/customer/annum for residential and small business customers, comprising a CTS of $123/customer/annum based on confidential data collected from retailers and a CARC of $41/customer/annum based on the ACCC Retail Electricity Price Inquiry benchmark.

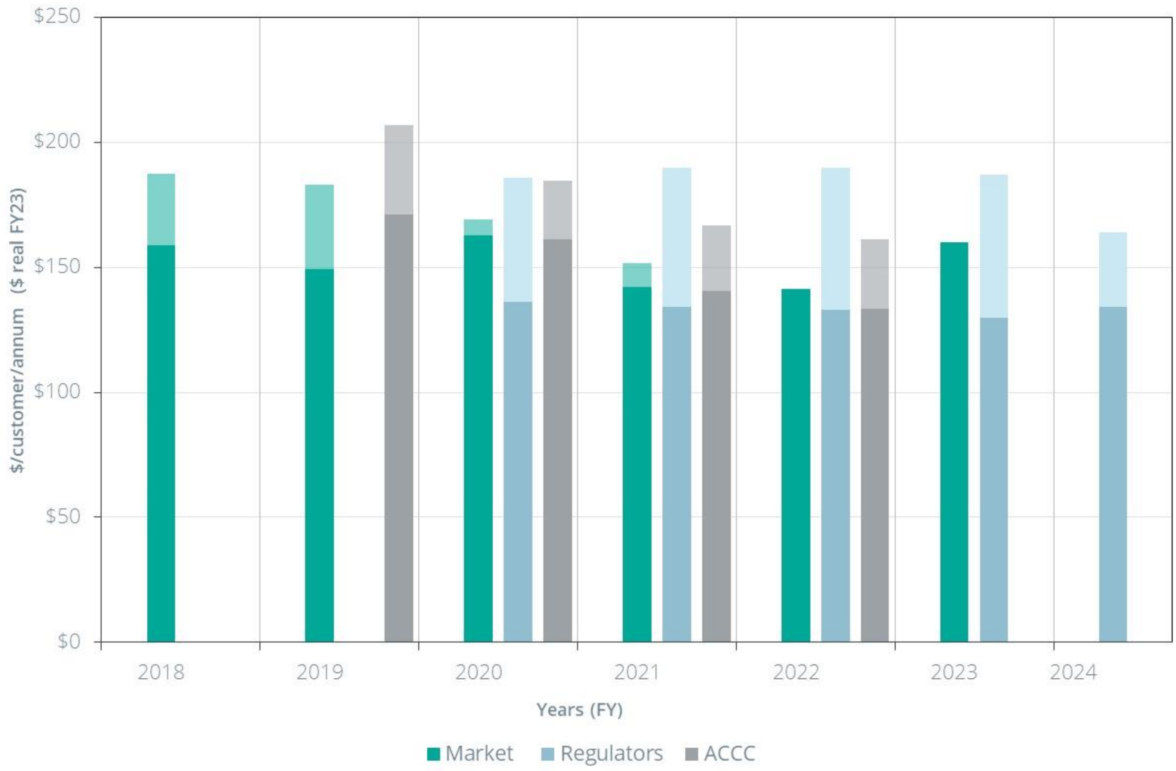
These allowances are similar to the retail operating cost allowance of $163/customer/annum set by OTTER based on Aurora's costs in 2022 and the market data on retail operating costs for 2023, at $160/customer/annum.

These allowances are also consistent with the customer-weighted average retail operating costs reported to ICRC.

The ESC is the only regulator that specifies a separate CTS and CARC allowance, recognising the difficulty in allocating these costs.

Most other regulators do include an allowance for bad and doubtful debts. This is an efficient cost of retailing and should be reflected in the retail cost allowance. The AER is the only regulator that specifies an allowance for bad and doubtful debts, with other regulators including these costs in CTS or retail operating cost allowances.

Figure 19: Summary of retail operating cost benchmarks



Source: Frontier Economics analysis

4 Retail margin

This section considers the methodology for assessing the retail margin. The Commission set the retail margin in the last two regulatory periods based on analysis prepared by the Strategic Finance Group for IPART in 2013, and has flagged its intention to update this benchmark.[49]

As with retail costs, there are two methodological issues that need to be addressed in determining the retail margin:

- What is the retail margin, and for what benchmark firm is the retail margin estimated? We consider this issue in Section 4.1
- What is the methodology for determining the retail margin? We explore this issue in Section 4.2

The Commission has flagged its intention to consider how the margin is applied.[50] The retail margin is currently applied as a percentage margin to all the other cost categories, to calculate the margin in $/MWh. Where there are large movements in other cost components the dollar value of the retail margin changes accordingly. The Commission has asked Frontier Economics to consider if this is appropriate; we discuss this issue in Section 4.3.

We present our findings and conclusions on the retail margin in Section 4.4

4.1 Defining the retail margin

The retail margin represents the return on the investments made by the retailer in providing retail electricity services.[51]

The retail margin for electricity businesses in Australia represents the return that a retailer requires to attract the capital needed to provide a retailing service. The retail margin required depends on the level of risk that a retailer faces: the greater the risk the greater the retail margin required to ensure capital invested in the business earns an appropriate return.

An allowance for the retail margin will, in principle, be set for a particular type of electricity business. In practice, however, as with retail costs, the opportunity to establish an estimate of the retail margin for a particular type of electricity business is limited by the information that is available.

The retail margin is commonly reported as either an EBIT margin or an EBITDA margin. EBIT refers to earnings before interest and tax, while EBITDA refers to earnings before interest, tax, depreciation and amortisation. An EBITDA margin will generally be higher than an EBIT margin because it includes an allowance for depreciation and amortisation costs. It is important that the decision on the basis for the retail margin is consistent with other cost allowances: specifically, it is important to ensure that allowance for depreciation and amortisation costs is provided once and only once.

Most regulators – against which we benchmark both retail operating costs and the retail margin – set the retail margin relative to the retailers' EBITDA because the retail operating cost allowance does not include an allowance for depreciation and amortisation costs. We adopt the

49 Independent Competition and Regulatory Commission, Standing offer prices for the supply of electricity to small customers from 1 July 2024: Issues paper, report 5 of 2023, August 2023, p17.

50 Independent Competition and Regulatory Commission, Standing offer prices for the supply of electricity to small customers from 1 July 2024: Issues paper, report 5 of 2023, August 2023, p17.

51 Independent Competition and Regulatory Commission, Standing offer prices for the supply of electricity to small customers from 1 July 2024: Issues paper, report 5 of 2023, August 2023, p17.

same approach in this report. This approach ensures that allowance for depreciation and amortisation costs is provided once and only once. We also note that in its NEM Inquiry report the ACCC reports EBITDA margins.

In our benchmarking and expected returns approach we report an EBITDA margin.

4.2 Estimating the retail margin

Regulators have tended to determine an appropriate allowance for retail margin using one or more of the following approaches:

- The **benchmarking approach** relies on aggregating the available public information on the retail margin. Benchmarking the retail margin is similar in principle to benchmarking retail costs although there are issues with benchmarking the retail margin against companies' financial reports that do not arise when benchmarking retail costs.

- The **expected returns approach** seeks to estimate the margin that is required in order to compensate investors in the business for systematic risk.

Historically some regulators have applied a **bottom-up approach** similar to the approach used to calculate the return on capital for regulated network businesses. This involves calculating the margin that is required to provide a return on capital that is based on an estimate of the weighted average cost of capital for the retailer multiplied by an estimate of the retailer's asset value (including intangibles and working capital). However, applying this approach to retail businesses is difficult, given there is no estimate of the regulated asset value of the retail business.

We apply the benchmarking approach in Section 4.2.1 and the expected returns approach in Section 4.2.2.

4.2.1 Benchmarking the retail margin

Available benchmarks

We benchmarked retail costs against other regulatory allowances, available market data for electricity retailers and data in the ACCC's November 2022 NEM Inquiry Report. However, there are issues with benchmarking against available market data for electricity retailers and data in the ACCC's NEM Inquiry Report. These issues, considered in turn below, have implications for our approach to benchmarking the retail margin.

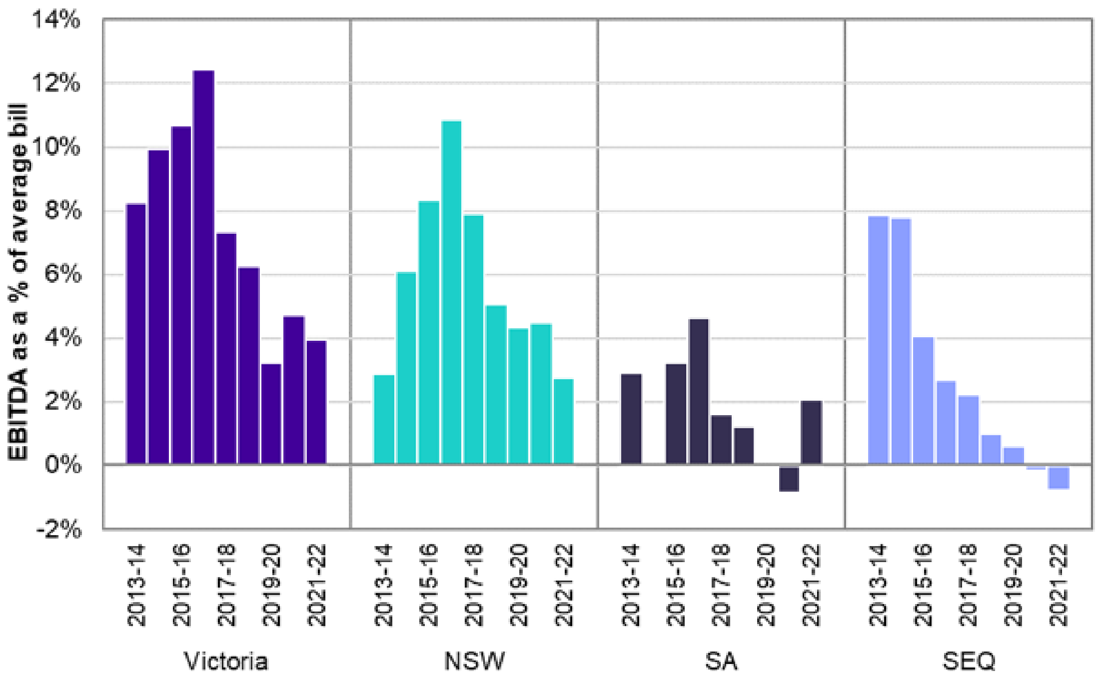
The first reflects the variable returns which are a function of the principal task of electricity retailers - to manage risk on behalf of their customers. Retailers do this by agreeing to supply their customers' future electricity consumption at a price that is set for a period in advance and is much less variable than the half-hourly spot price. In doing so, retailers take on the risk of exposure to the half-hourly spot price used to settle their customers' consumption on their customers behalf.

In some periods a retailer's reported financial performance will be good, because the hedging position that the retailer has entered into has been advantageous or because spot prices have been lower than expected; this would be reflected in a strongly positive margin. There will also be some periods during which a retailer's reported financial performance will be poor, because the hedging position that the retailer has entered into has been disadvantageous or because spot prices have been higher than expected; this would be reflected in a weakly positive margin or even a negative margin.

An indication of this is provided by the evident variability of EBITDA as a percentage of the average customer residential bill reported in the ACCC's NEM Inquiry November 2022 Report, and reproduced in **Figure** 20. EBITDA as a percentage of the average customer residential bill has varied from 12% to -1% over the period considered.

In a competitive market the average margins earned by a retailer over time would be expected to provide an appropriate return to attract the capital needed to provide a retailing service. But in any particular year or over any particular number of years there is the risk that the observed margin will not reflect the 'efficient' margin required in order to attract the capital needed to provide a retailing service.

Figure 20: EBITDA as a percentage of the average residential customer bill over time by NEM regions (2013-14 to 2021-22)



Source: ACCC, Inquiry into the National Electricity Market, November 2022 report, Data appendix

Another issue with benchmarking against available market data for electricity retailers and data in the ACCC's NEM Inquiry Report is that these benchmarks may reflect margins that are systematically higher than the 'efficient' margin required in order to attract the capital needed to provide a retailing service. This would be expected to be the case, for instance, if there were evidence that the market was not operating competitively.

For these reasons, we benchmark the retail margin only against other regulatory decisions.

Regulatory decisions

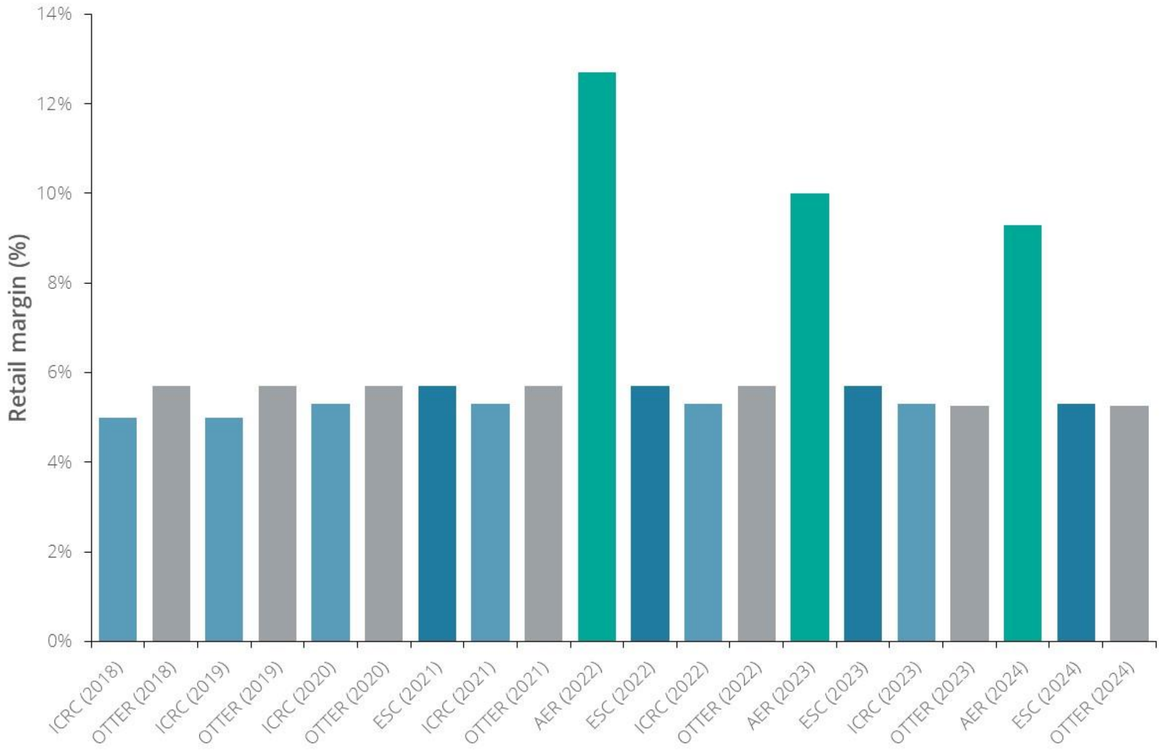
We benchmark against the most recent regulatory allowances for the retail margin, which confines our consideration to decisions by the ESC, OTTER, AER, QCA and IPART.

The Commission set the retail margin in the last two regulatory periods drawing on research undertaken by the Strategic Finance Group for IPART in 2013.[52] Historically, the Commission

[52] Independent Competition and Regulatory Commission, Standing offer prices for the supply of electricity to small customers from 1 July 2024: Issues paper, report 5 of 2023, August 2023, p17.

adopted a retail margin of 5.6% based on the SFG analysis. In 2017 the retail margin was reduced to 5.3% to reflect the substantial increases in other cost components.[53] In 2020 the Commission increased the retail margin from 5.3% to 5.6% to account for recent substantial falls in wholesale energy costs which will reduce the margin in dollar value terms.[54] The Commission applied a retail margin of 5.6% throughout the 2020-24 regulatory period. The Commission's margin of 5.6% is applied to the cost stack excluding the retail margin, and is equivalent to a 5.3% EBITDA margin.

Figure 21: Summary of retail margin regulatory benchmarks



Source: Frontier Economics analysis of regulatory decisions

Notes: AER margin for a NSW residential customer

ESC

The ESC set a retail margin of 5.3% of costs for the representative user for the 2023/24 VDO. This was a reduction from the 5.7% the ESC had historically adopted, and included in its Draft Decision for the 2023/24 VDO. Following stakeholder submissions on its Draft Decision the ESC reconsidered available evidence, in particular:

- Most retailers have offered market offers below, and sometimes well below, the VDO since 2020
- Retail margins set by other regulators have decreased

53 Independent Competition and Regulatory Commission, Electricity Model and Methodology Review 2018-19: Final report, Report 5 of 2019, May 2019, p31.

54 Independent Competition and Regulatory Commission, Retail electricity price investigation: Final report, Report 9 of 2020, June 2020, p6.

- Additional retailers have sought to enter the market
- 5.3% is within the range of retail margins produced by the expected returns approach (which suggested retail margins were in the range 4.8-6.1%)[55]
- Retailers' reported retail margins have decreased on average.[56]

The ESC noted that, with the exception of the AER, other regulators set margins between 3.9% and 5.3%. Reducing the retail margin to 5.3% brings the ESC's benchmark closer to the margins adopted by other Australian regulators, while remaining within the range produced by the expected returns approach.[57]

OTTER

OTTER's most recent (2022) decision set the retail margin for Aurora Energy at 5.25% of approved costs. OTTER adopted a benchmark approach to set the retail margin by considering the margins set in other jurisdictions, after assessing Aurora Energy's risks and concluding they were not greater than the risks facing retailers operating in other jurisdictions.[58]

The retail margin of 5.25% was estimated as the mid-point between:

- the retail margin of 5.7% set in OTTER's 2013 and 2016 decisions, which was benchmarked against the QCA, the ICRC and IPART
- the minimum of the retail margin estimated by Frontier Economics using the expected returns approach in its 2019 analysis for the ESC.[59]

OTTER concluded a margin of 5.25% reflects Aurora Energy's risks and recognises the national downward trend in retail margins.[60]

OTTER used this margin to set a per customer allowance which does not fluctuate with changes in wholesale and network costs.[61] When calculating the dollar value of the retail margin OTTER considered approved costs for the past two years only, that is 2020-21 and 2021-22, because in earlier years Aurora Energy's approved costs were higher.[62] Estimating a dollar value of the retail margin considering these earlier years could result in a retail margin allowance higher than 5.25%.

---

[55] Frontier Economics, Retail costs and margin: A report for the Essential Services Commission, 24 April 2019, p29.

[56] Essential Services Commission, Victoria Default Offer 2023-24, Final Decision Paper, 25 May 2023, p48.

[57] Essential Services Commission, Victoria Default Offer 2023-24, Draft Decision Paper, 15 March 2023, p43.

[58] Office of the Tasmanian Economic Regulator, 2022 Standing Offer electricity pricing investigation: Determination of maximum standing offer prices for small customers on Mainland Tasmania 1 July 2022 to 30 June 2025, Final Report, April 2022, p33.

[59] Office of the Tasmanian Economic Regulator, 2022 Standing Offer electricity pricing investigation: Investigation of maximum standing offer prices for small customers on Mainland Tasmania 1 July 2022 to 30 June 2025, Draft Report, February 2022, p46.

[60] Office of the Tasmanian Economic Regulator, 2022 Standing Offer electricity pricing investigation: Investigation of maximum standing offer prices for small customers on Mainland Tasmania 1 July 2022 to 30 June 2025, Draft Report, February 2022, p46.

[61] Office of the Tasmanian Economic Regulator, 2022 Standing Offer electricity pricing investigation: Investigation of maximum standing offer prices for small customers on Mainland Tasmania 1 July 2022 to 30 June 2025, Draft Report, February 2022, piii.

[62] Office of the Tasmanian Economic Regulator, 2022 Standing Offer electricity pricing investigation: Determination of maximum standing offer prices for small customers on Mainland Tasmania 1 July 2022 to 30 June 2025, Final Report, April 2022, p34.

AER

The AER sets a retail allowance or margin to:

- Include the retailer profit margin, with an additional allowance to
- Provide for the DMO policy objective to maintain incentives for competition, innovation and investment by retailers (amongst other objectives).[63]

The allowance is also intended to account for the variation in retail operating costs between retailers.[64]

In its DMO4 decision the AER announced its intention to transition to a consistent retail allowance across the NEM of 10% of the total bill for residential customers and 15% for small business customers over three years. The aim of this approach was to broadly preserve the aggregate retail allowance available in its earlier DMO decisions, while redistributing the allowance across NEM regions to ensure the same allowance for each customer type, regardless of region.[65] A transition to these targets were set to be in place by 2024-25.

The AER formed the view that a residential DMO retail allowance of 10% provides total allowances for retailers that are broadly consistent with the lower range of historic outcomes and appropriately balances the DMO policy objectives.[66] The AER observed profit margins for small business customers have typically been higher than for residential customers, and a 15% small business allowance would be consistent with allowances remaining at similar levels for most distribution regions.[67] The AER noted a 5.7% retail allowance, which was proposed in stakeholder submissions, goes beyond the DMO objective of protecting customers from unreasonable prices and is more consistent with a different objective of capping prices at efficient costs.[68]

In its most recent decision the AER paused the glide path for customers in the Energex region (for residential customers without controlled load) and the SA Power Networks region (for residential customers with and without controlled load), due to the very large price increases expected in DMO5.[69] In its final determination the AER also reduced the retail allowance from 10% to 9.3% for NSW residential customers who would otherwise be paying materially more in dollar terms because of changes in the underlying cost stack than customers in other regions.[70] Table 5 reports the AER retail allowances for DMO5.

63 Australian Energy Regulator, Default market offer prices 2023-24: Final determination, May 2023, p39.

64 Australian Energy Regulator, Default market offer prices 2023-24: Final determination, May 2023, p45.

65 Australian Energy Regulator, Default market offer prices 2022-23: Draft determination, February 2022, p44.

66 Australian Energy Regulator, Default market offer prices 2022-23: Draft determination, February 2022, p45.

67 Australian Energy Regulator, Default market offer prices 2022-23: Draft determination, February 2022, p45.

68 Australian Energy Regulator, Default market offer prices 2023-24: Draft determination, March 2023, p41.

69 Australian Energy Regulator, Default market offer prices 2022-23: Draft determination, February 2022, p46.

70 Australian Energy Regulator, Default market offer prices 2023-24: Final determination, May 2023, p43.

Table 5: AER margin allowances 2023-24

Customer type	Retail allowance (%) residential without controlled load	Retail allowance (%) residential with controlled load	Retail allowance (%) small business
Ausgrid	9.3	9.3	20
Endeavour Energy	9.3	9.3	16
Essential Energy	9.3	9.3	17.5
Energex	8.4	10.0	16.0
SA Power Networks	6.0	6.0	15.0

Source: Australian Energy Regulator, Default market offer prices 2023-24: Final determination, May 2023

QCA

Our benchmarking of the retail margin from the QCA does not include the most recent decisions from the QCA, since these decisions have been based on an approach to estimating retail costs and retail margin that does not result in separate allowances for ROC, CARC and the retail margin.

The QCA's 2015 decision was the latest that incorporated a specific amount for the retail margin. That amount was 5.7% of total costs (including the retail margin). This retail margin was rolled forward from the QCA's 2013 decision, at which point the QCA based its retail margin allowance of 5.7% on that used by IPART in its 2013 decision.

IPART

IPART's most recent decision – its 2013 decision – allowed a retail margin of 5.7%. In coming to this decision IPART had regard to three approaches to estimating the retail margin: benchmarking, the expected returns approach and the bottom-up approach.[71] The retail margin of 5.7% was chosen from within a recommended range for the retail margin of 5.3% to 6.1%.

4.2.2 The expected returns approach

This section explains the rationale and methodology underpinning the expected returns approach to estimating a regulated retail margin, and presents our recommendation on the retail margin using the expected returns approach.

Rationale

The expected returns approach to estimating the retail margin was first developed by SFG for IPART for the purposes of determining the allowed retail margin for regulated electricity retailers in NSW. The key objective of the expected returns approach is to estimate the minimum retail margin required in order to compensate equity investors in a notional electricity retailer for the systematic (i.e., non-diversifiable) risk they bear when committing equity capital to the firm.

71 IPART triangulated the regulated retail margin using the expected returns approach, the benchmarking approach and the bottom-up approach.

In financial economics, risk is defined as the likelihood of the variability of actual returns from investment around the expected (average) return associated with that investment.[72] The total risk borne by investors in any asset may be decomposed into two components:

- Non-systematic risk – that is, risk that can be eliminated through diversification. Risk that can be eliminated in this way is asset-specific risk; and
- Systematic risk – that is, risk that cannot be diversified away. This risk represents variability in the returns of the asset that is correlated with changes in the returns of all assets in the economy (i.e., the 'market' as a whole).

The relationship between total risk, non-systematic risk and systematic risk is represented graphically in **Figure 22** below. This Figure shows that an investor's exposure to non-systematic risk falls as they become increasingly diversified. However, their exposure to systematic risk remains unchanged, regardless of the extent to which they are able to diversify their asset holdings.

A fundamental principle in financial economics is that investors in efficient and competitive capital markets can expect to be compensated only for systematic risk.[73] This is because, in such markets, an investor that sought compensation for risk that could be diversified away would be outbid quickly by many other well-diversified investors who required a lower return from the same investment. The market price for risk would, by this means, be bid down to the level where all investors in the market may expect to be compensated only for systematic risk. That is, in efficient and competitive capital markets, the minimum return required by an investor will correspond to the return required to compensate for non-diversifiable risk.

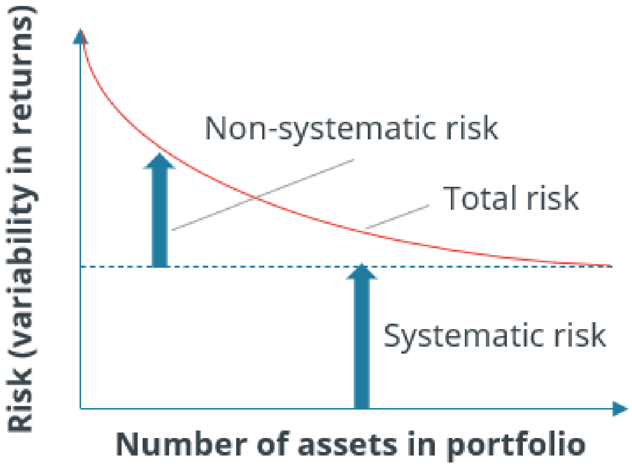
Economic regulators seek to mimic the outcomes that would obtain in competitive markets by setting cost allowances equal to the efficient level of costs. This is because in competitive markets, cost inefficiencies are driven out by the process of competition and competitive tension between rivals. The implication of this for the Commission is that it should set a regulated retail margin that (in expectation) just compensates investors in regulated electricity retailers for systematic risk but no more.

That is not to say that non-systematic (i.e., asset-specific) risks should be ignored altogether by regulators. Rather, any relevant asset-specific risks should be addressed through other cost allowances rather than the retail margin.

72 See, for example: Damodaran, A. (2001), Corporate Finance: Theory and Practice, 2nd edition, John Wiley & Sons: New Jersey, p. 150.

73 This is one of the key insights from the theory of the Capital Asset Pricing Model (CAPM).

Figure 22: Diversification eliminates asset-specific risk



Source: Brealey, Myers and Allen (2014), Principles of Corporate Finance, 11th ed, McGraw-Hill: New York, Figure 7.11

Methodology

The expected returns approach involves five main steps:

1. Derive an estimate of the benchmark Weighted Average Cost of Capital (WACC) for a notional retailer.
2. Forecast the future cash flows and returns of the notional retailer under different economic conditions.
3. Forecast the future returns on the market in different states of the market.[74]
4. Use the forecast returns of the notional retailer and the market to compute the implied systematic risk of the notional retailer.
5. Solve for the retail margin that equalises the systematic risk implied by the retailer's forecast cash flows and the systematic risk associated with the benchmark WACC.

We explain each of these steps in turn in further detail below.

Step 1: Derive estimate of the benchmark WACC for a notional retailer

The first step is to derive an estimate of the WACC of a notional retailer. The WACC represents the weighted average of the minimum rates of return that equity investors and debt investors in the retailer require in order to commit equity and debt capital to the business. The cost of equity and the cost of debt are weighted by an estimate of the gearing of the business, as shown in the formula below:

$$WACC = Cost\ of\ equity\ \times (1 - Gearing) + Cost\ of\ debt\ \times Gearing$$

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

One of the inputs to the cost of equity is an estimate of the systematic risk exposure of the notional retailer, captured by a parameter known as *beta*.[75] The cost of equity within the estimated WACC is therefore the minimum rate of return required in order to compensate equity investors for the systematic risk they would take on by investing in the notional retailer.

We have estimated WACC for a benchmark retailer, consistent with the ICRC's WACC methodology, but using up-to-date market parameters. The equity beta we have used is consistent with the equity beta we have previously used for estimating the retail margin for electricity retailers. The resulting WACC parameters are presented in **Table** 6.

Table 6: WACC parameters (nominal, vanilla)

Cost of capital	Low	Base	High
Risk-free rate	3.72%	4.22%	4.72%
Market risk premium	6.05%	6.30%	6.55%
Equity beta	1.00	1.00	1.00
Gearing	20%	20%	20%
Debt premium	0.11%	0.61%	1.11%
Gamma (value of imputation credits)	50%	50%	50%
Inflation	2.5%	2.5%	2.5%
Cost of equity	9.77%	10.52%	11.27%
Cost of debt	3.83%	4.83%	5.83%
WACC	8.58%	9.38%	10.18%

Source: Frontier Economics estimates

Step 2: Forecast future cash flows and returns of retailer

The second step is to forecast the future cash flows of the notional retailer using:

- a 'placeholder' assumed average retail electricity price
- forecast retail demand for electricity under different future states of the world (i.e., under varying economic conditions)
- assumed costs faced by the retailer
- an estimate of future inflation.

These forecast cash flows are then used to compute the annualised equity returns to the notional retailer over a 10-year horizon.

75 Beta in this context is defined as the covariance of returns on the market and returns to the notional retailer, divided by the variance of returns on the market.

Placeholder average retail electricity price

The placeholder retail electricity price is simply an assumed starting price used to obtain a future series of cash flows for the notional retailer, allowing for inflation. The precise starting level for this price is unimportant as this is the variable that is adjusted in Step 5 (below) to solve for the required margin.

Forecast growth in demand

The future demand for electricity is assumed to grow in exact proportion to the change in GDP. That is, we assume that a 1% increase/reduction in GDP is associated with a 1% increase/reduction in electricity demand. This assumption is based on the notion that demand for electricity is closely linked to economic growth, and was the basis of IPART's analysis when it applied the expected returns approach.[76] We estimated the annual variation in future demand by examining the historical standard deviation in GDP between 1960 and 2023.[77] This resulted in a base estimate of the annual change in demand of 1.7%.

Assumed costs

As the analysis was focused on estimating an appropriate retail margin rather than a price we assumed that total costs would equal $100/MWh in expectation, before applying inflation. However, these costs can be decomposed into variable and fixed costs, such that if demand increases the total costs would increase on a per MWh basis (reflecting higher variable costs).

To estimate the proportion of fixed costs we have used current estimates of each of the components of retail supply (including WEC, green costs, network tariffs, retail costs, retail margin and other costs) and, of those, have assumed that all retail costs, the fixed component of network tariffs, an amount for depreciation and amortisation and 8% of WEC is fixed. This is consistent with the approach that was previously adopted for IPART.

Also relevant to the cashflows are the levels of capital expenditure and depreciation. It is the difference between the two that is relevant to the expected returns analysis; we assumed that capex minus depreciation is equal to 0.52% of expected total costs in each year, consistent with values previously adopted for IPART.

Estimated future inflation

The future rate of inflation used in the model is assumed to be the midpoint of the Reserve Bank of Australia's inflation target range, 2.5%. This inflation rate is used to escalate costs within the model.

Constructing future cash flows

The cash flows of the notional retailer are constructed by building a binomial tree out to a horizon of 10 years, which represents:

- the future revenues of the retailer, which, in each year, would be impacted by demand either increasing or falling by 1.7% as demand changes in line with changes in GDP
- the future costs of the retailer, which will change as variable costs change in line with volumes.

Beyond year 10, cash flows are assumed to grow at a constant rate equal to the estimated long-run inflation rate of 2.5%.

[76] See SFG, The association between changes in electricity demand and GDP growth, 2 October 2009, and SFG, Estimation of the regulated profit margin for electricity retailers in New South Wales, 16 March 2010.

[77] GDP growth taken from ABS series 5206.0.

Constructing the returns implied by the forecast cash flows

Next, we calculate the annualised equity returns implied by the forecast cash flows. This is done by:

- Calculating a set of present values of the future cash flows of the retailer at year 10 (the terminal values) under various future states of the world that depend on how economic conditions have changed over time. These present values are computed using the assumed WACC of the retailer;
- Calculating the expected (i.e., probability-weighted) present value of the cash flows of the retailer between year 0 and year 10 (the opening value), again using the assumed WACC of the retailer; and
- Calculating the return to equity associated with each of the possible states of the market in year 10.

Step 3: Forecast future returns on the market

Next, we derive forecasts of the returns associated with investing in the stock market as a whole over a 10-year future horizon. The process we follow in order to do this mirrors the process used to forecast the returns of the retailer. We use the historical standard deviation of returns on the Australian stock market over the period 1900 to 2022,[78] to build a binomial tree that represents the future path of the stock market over a 10-year forward-looking horizon under different future states of the world. In each year the market index is assumed to either grow by one standard deviation more than expected, or one standard deviation less than expected.[79] This process results in a set of terminal values for the market index at year 10 that differ depending on how market conditions may evolve between year 0 and year 10. The forecast returns on the market are then calculated using the terminal values of the index and the starting value of the index.

Step 4: Calculate systematic risk implied by forecast future cashflows of the retailer

Having derived the future returns on the market and the returns of the retailer over a 10-year horizon, the systematic risk associated with the retailer's forecast cash flows are computed using the standard relationship implied by the Capital Asset Pricing Model (CAPM):

$$Systematic\ risk = \frac{Covariance\ (Market\ Returns, Retailer\ Returns)}{Variance\ (Market\ Returns)}$$

The overall estimate of systematic risk is derived as the probability weighted estimate of systematic risk under each possible future path of returns between year 0 and year 10. We refer to this overall estimate as the *implied* estimate of systematic risk, since it is the estimate of systematic risk implied by the forecast future cash flows of the notional retailer.

Step 5: Calculate the retail margin consistent with benchmark systematic risk

The final step is to compare the *implied* estimate of systematic risk with the *benchmark* level of systematic risk (i.e., beta) used in the WACC estimate:

- If the implied estimate of systematic risk is lower than the benchmark beta, that would imply that the forecast cash flows of the notional retailer are not risky enough to be consistent with benchmark level of systematic risk. This implies that the retail margin underpinning the forecast cash flows of the retailer is too high (thereby cushioning its returns too much) and

[78] Data presented by Brailsford, *Handley* and Maheswaran (2012) is appended to All Ordinaries accumulation returns.

[79] The base value of one standard deviation is 17%.

so would need to be adjusted downwards in order to be consistent with the benchmark beta.

- Conversely, if the implied estimate of systematic risk is higher than the benchmark beta, that would imply that the cash flows of the notional retailer are too risky relative to the benchmark beta. Under these circumstances, the retail margin is too low (providing an insufficient buffer to the returns of the retailer) relative to the benchmark level of systematic risk.

In order to arrive at a retail margin that is consistent with the benchmark level of systematic risk, we adjust the placeholder price in Step 1 above until the implied beta is equal to the benchmark beta. Thus, we solve for the regulated retail margin that ensures that the expected cash flows of the notional retailer is sufficient to cover its systematic risk.

In addition to three values for WACC (low, base and high), we allow different values for market volatility, demand (GDP) volatility, the share of total costs represented by fixed costs and the capex margin over depreciation.

Table 7: Parameter values considered

	Low	Base	High
WACC	8.58%	9.38%	10.18%
Standard deviation of market returns	12%	17%	22%
Non-volume-related costs (share of total costs)	25%	30%	35%
Standard deviation of GDP growth	1.2%	1.7%	2.2%
Capex margin over depreciation	0.02%	0.52%	1.02%

Source: Frontier Economics analysis

We perform the analysis for 243 potential scenarios: with three different states and five variables the number of scenarios is $3^5 = 243$.

In addition to the base scenario (base values for all four variables) we consider a reasonable range for the EBITDA margin to encompass the middle third of the rank-ordered estimated margins derived in the 243 scenarios.[80] This was the approach followed by IPART's adviser, SFG, when it implemented the expected returns approach. SFG explained the rationale for taking the middle third of ranked estimates as follows:[81]

> *A base case estimate for the required margin is computed using the mid-points of the assumptions discussed above. Similarly, a range for the required margin could be estimated with reference to the extreme (maximum and minimum) assumptions. However, this approach would result in a wide and relatively meaningless margin range. That is, the probability that all assumptions are at the extreme end of the reasonable range is small. For this reason, our margin analysis considered 81 potential scenarios. Each assumption outlined at the end of the previous section was assumed to take one of three values: high-point, mid-point and low-point. This resulted in a potential distribution for the required margin that incorporates*

80 Thus, the low range of the margin would be the 81st smallest of the 243 estimated margins.

81 SFG, Estimation of the regulated profit margin for electricity retailers in New South Wales, 4 June 2013, pp. 13-14.

uncertainty in the key assumptions. Our approach is to assume a reasonable range that incorporates the middle third of the 81 potential outcomes. In other words, the low and high results reported in Table 4 reflect the 33rd and 67th percentiles, of projections for each year.

We agree with this rationale and have therefore adopted this approach here to derive a reasonable range for the retail margin.

Results

The retail margin estimates are presented below in **Table** 8.

Table 8: EBITDA margin range

	Low	Base	High
EBITDA margin	4.5%	5.2%	5.9%

Source: Frontier Economics analysis

In addition, we undertook sensitivity analysis of the retail margin by varying each of the five variables in **Table 7** in turn to understand the impact of each on the total margin. For each variable of interest, we compare the estimated retail margin under low, base and high values of the variable, keeping the remaining four variables at their base value.

As **Table 9** shows, the margin is relatively insensitive to WACC: keeping all other variables at base values, the margin increases by 0.2% when the assumed WACC is increased from the low scenario to the high scenario—a difference of 160 basis points.

Table 9: Sensitivity of the estimated retail margin to four variables considered

Parameter varied	Low	Base	High	High minus low
WACC	5.1%	5.2%	5.3%	0.2%
Market volatility	7.1%	5.6%	4.1%	-3.0%
Fixed share	4.6%	5.15%	5.7%	1.1%
GDP volatility	4.1%	5.2%	6.3%	2.2%
Capex margin over depreciation	4.6%	5.2%	5.8%	1.2%

Source: Frontier Economics analysis

The margin is however sensitive to the other variables of interest:

- Keeping all other variables at base values, the margin decreases by 3.0% going from the low market volatility scenario to the high market volatility scenario.
- Keeping all other variables at base values, the margin increases by 1.1% going from the low fixed cost share scenario to the high fixed cost share scenario.

- Keeping all other variables at base values, the margin increases by 2.2% going from the low GDP volatility scenario to the high GDP volatility scenario.
- Keeping all other variables at base values, the margin increases by 1.2% going from the low capex margin over depreciation to the high capex margin over depreciation volatility scenario.

4.3 Form of the retail margin

The retail margin is currently applied as a percentage margin to all the other cost categories, to calculate the margin in $/MWh. Where there are large movements in other cost components the dollar value of the retail margin changes accordingly. In this section we examine the appropriate specification of the retail margin using an example to demonstrate the relationship between movements in costs and margin.

The expected returns approach is used to derive a margin on costs that adequately compensates a benchmark efficient retailer for systematic risk associated with retail activities. One source of risk is the volume risk – if volume decreases then the retailer's revenue would decrease yet the costs would not decrease by the same percentage as some costs are fixed.

In the base case we assumed that 30% of retail costs would be fixed and that 70% of costs would be variable. In particular, we assume retail operating costs, depreciation costs and a share of wholesale energy costs (WECs) are fixed. The share of WECs that are fixed reflects not only the fixed costs associated with energy trading, but also the risk exposure of retailers because of the inability to perfectly hedge energy purchases.[82] We adopt an assumption that 8% of WECs are fixed, consistent with historical analysis which was informed by consultation with retailers.[83] This assumption, combined with various other assumptions, resulted in a base case EBITDA margin of 5.2%.

Changing energy costs

The EBITDA margin of 5.2% was derived based on a cost stack that included a specified level of WECs. This yields an EBITDA margin of $5.39 in dollar terms on a cost stack of $98.95, or $100 inclusive of depreciation.

If energy costs were to increase, the fixed proportion of costs would decrease as energy costs tend to be more variable than other costs. This would reduce the risk of the retailer somewhat, so that the EBITDA margin implied by the expected returns approach would fall. However, the costs increase, so the EBITDA margin in dollar terms could potentially increase.

We understand that Commission may consider keeping the margin as a percentage constant, applying to changing costs of retailers. Alternatively, the margin may be expressed in constant in dollar terms. Our analysis suggests that both of these approaches are likely to lead to overcompensation or under-compensation:

- Constant margin as a percentage ignores that increasing energy costs reduces the risk faced by the retailer and so overcompensates the retailer as energy costs increase; whereas
- Constant margin as a dollar ignores that some fixed costs have increased so that the retailer is undercompensated as energy costs increase.

82 Strategic Finance Group, Estimation of the regulated profit margin for electricity retailers in New South Wales, 4 June 2013.

83 Strategic Finance Group, Estimation of the regulated profit margin for electricity retailers in New South Wales, 4 June 2013.

We find that, based on inputs selected for the expected returns approach the average of the two approaches would be a more reasonable margin to retailers, very close to what the revised margin would be if the expected returns approach were to be applied to the revised cost stack.

Consider a retailer with a cost stack of $100, with $30 fixed and $70 variable with respect to volume. If WEC increases by $50, the new fixed costs would be $34 ($30 plus 8% of $50) and the new variable costs would be $116, so that the fixed costs share falls to 23%. Using the expected returns approach, the appropriate EBITDA margin would be 4.4%, or $6.77. This is close to $6.75, the average of the original EBITDA margin of $5.39, and $8.12: the original EBITDA margin of 5.2% applied to the new cost stack.

Similarly, if WEC decreases by $50 the recalculated EBITDA margin would be $3.99, compared to $4.03: the average of the original EBITDA margin in dollar terms and the original EBITDA in percentage terms applied to the new cost stack.

Table 10: **Margin comparison**

	Base	Increase WEC	Decrease WEC
% Margin	5.2%	4.4%	7.5%
$ Margin	$5.39	$6.77	$3.99
$ Margin if keep % at base		$8.12	$2.67
$ Margin if keep $ at base		$5.39	$5.39
Average of (2) and (3)		$6.75	$4.03

Source: Frontier Economics analysis

We find that neither maintaining the percentage margin nor the dollar margin would appropriately compensate retailers for systematic risk as wholesale energy costs rise or fall. A hybrid approach, as illustrated above, appears to provide appropriate compensation without requiring the expected returns approach margin to be recalculated.

4.4 Conclusion

The most recent regulatory decisions of the ESC and OTTER provide for a retail margin of 5.3% and 5.25% of total costs including the retail margin (equivalent to an EBITDA margin). This is consistent with the expected returns analysis, which indicates a retail margin in the range 4.5-5.9% would be appropriate, with a midpoint of 5.2%. These more recent decisions are now closely aligned to the Commission's current retail margin of 5.6% (which is equivalent to an EBITDA margin of 5.3%).

Frontier Economics

Brisbane | Melbourne | Singapore | Sydney

Frontier Economics Pty Ltd
395 Collins Street Melbourne Victoria 3000

Tel: +61 3 9620 4488
www.frontier-economics.com.au

ACN: 087 553 124 ABN: 13 087 553 124