frontier economics

Wholesale electricity costs for 2022/23

A draft report for the Essential Services Commission | 28 February 2022

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1 Introduction

Frontier Economics has been engaged to advise the Essential Services Commission (ESC) on allowances for wholesale electricity costs for financial year 2022/23 for retailing electricity to small customers, for the purposes of determining the Victorian Default Offer (VDO).

1.1 Background

The ESC is required to determine prices for the VDO to apply from 1 July 2022. To inform this the ESC needs forecasts of retailers' wholesale electricity costs and of retailers' costs of complying with environmental programs for financial year 2022/23.

1.2 Frontier Economics' engagement

Frontier Economics has been engaged by the ESC to provide advice on two aspects of the VDO:

- The wholesale electricity cost (WEC) component of retailers' cost to supply small customers from 1 July 2022.
- The retailers' costs of complying with the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES) in supplying small customers from 1 July 2022.

1.3 This draft report

This draft report sets out our advice to the ESC on the WEC and costs of complying with the LRET and the SRES, for retailers in each of the five Victorian distribution network areas. This report is structured as follows:

- Section 2 provides an overview of the approach used to estimate wholesale energy costs.
- Section 3 discusses the half-hourly prices and half-hourly load used in our analysis.
- Section 4 discusses the contract prices used in our analysis.
- Section 5 discusses the contract position used in our analysis.
- Section 6 provides our estimate of the WEC.
- Section 7 provides our estimates of the costs of complying with the LRET and SRES.

In addition to this report, we also provide spreadsheets setting out details of half-hourly load and price forecasts, contract positions resulting from our modelling, and calculations for determining the WEC.

1.4 Previous advice to the ESC

Frontier Economics has previously advised the ESC on the WEC and the cost of complying with the LRET and the SRES for financial year 2019/20 and for calendar years 2020, 2021 and 2022.[1]

This draft report adopts substantially the same approach for estimating WEC and the costs of complying with the LRET and the SRES as we adopted previously. However, as discussed in Section 3, for this draft report we develop estimates of half-hourly prices and half-hourly load using only the three most recent years of historical data. In our previous work we developed estimates of half-hourly prices and half-hourly load using all available historical data (which at the time of our most recent report – for calendar year 2022 – consisted of five years of historical data). We have made this change in approach because of the evidence of changing trends in patterns of half-hourly prices and half-hourly load.

1 See, for example: Frontier Economics, *Wholesale Electricity Costs for 2022*, A final report for the Essential Services Commission, 22 October 2021. Available on the ESC's website: https://www.esc.vic.gov.au/electricity-and-gas/prices-tariffs-and-benchmarks/victorian-default-offer/victorian-default-offer-price-review-1-january-2022#tabs-container2v

2 Approach to assessing WEC

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 Victoria, the relevant regional reference price is the Victorian 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 2021/22 is $15,100/MWh) and the market floor price (which is -$1,000/MWh).[2] 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.

2 AEMC, *Schedule of reliability settings,* 25 February 2021. The reliability settings for 2022/23 are due to be published by 28 February. While these reliability settings for 2022/23 were not available in time for this draft report, they will be adopted for our final report.

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, retailers in the NEM do adopt a mix of hedging strategies, including vertical integration and power purchase agreements. Retailers will presumably vertically integrate or enter into power purchase agreements because they think these strategies 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 retailers 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, peak swaps and base caps, traded on ASXEnergy.

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 calculate the WEC that a retailer would face.

We address these questions in the sections that follow.

3 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?

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.

3.1 Historical data on half-hourly price and load

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

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.

Impact of five minute settlement

With the change to five minute settlement in 1 October 2021, it would be best to use historical five minute spot price and load data for the analysis of this report. This would allow us to best estimate the costs and risks associated with a retailer meeting their customers' load in the NEM in 2022/23.

However, given the data that is available, our view is that the best approach is to continue to make use of half-hourly prices and load, rather than attempt to undertake our analysis based on 5-minute data.

The only historical five minute price available prior to 1 October 2021 is the dispatch price. While this price will reflect the underlying demand and supply conditions in the electricity market during the five minute dispatch period, it is possible that the change to five minute settlement will change market participants strategic behaviour, so that these five minute dispatch prices are not a perfect guide to what would have been five minute settlement prices.

In any case, we would also require historical five minute load to match up against the five minute price. This historical data is currently unavailable.

For these reasons, for this report we continue to use the historical half hourly data we have used previously to estimate the WEC (although updated to include the latest data). As historical five minute settlement prices and load data becomes available in future we can make use of that data.

Thus, the historical data that we use is:

- For prices, the half-hourly spot prices for the Victorian regional reference node, as published by AEMO.
- For customer load, half-hourly load data that AEMO has directly provided to the ESC on customers with annual consumption less than 40MWh for each of the five distribution network areas in Victoria. AEMO has provided separate half-hourly load data for residential customers with annual consumption less than 40MWh and for business customers with annual consumption less than 40MWh.

We use this data directly provided by AEMO because it closely coincides with the customer groups to which the VDO will apply:

- For residential customers, the VDO will apply to all residential customers. The data provided by AEMO is only for residential customers with annual consumption less than 40MWh, but since very few residential customers will have annual consumption greater than 40MWh this is unlikely to make a material difference to the estimated WEC.
- For small business customers, the VDO will apply to small business customers, with small business customers defined as customers with aggregate consumption less than 40 MWh per annum. The data provided by AEMO aligns with the applicability of the VDO.

In contrast, the Manually Read Interval Meter (MRIM) data that is publicly available from AEMO includes aggregated half-hour electricity consumption for all type 5 meters in each of the five distribution network areas in Victoria. This includes a mix of residential and business customers with annual consumption up to 160MWh.

3.2 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.

The load data that is directly provided by AEMO is from 1 July 2016 to 31 December 2021 – a period of 5 and a half years.

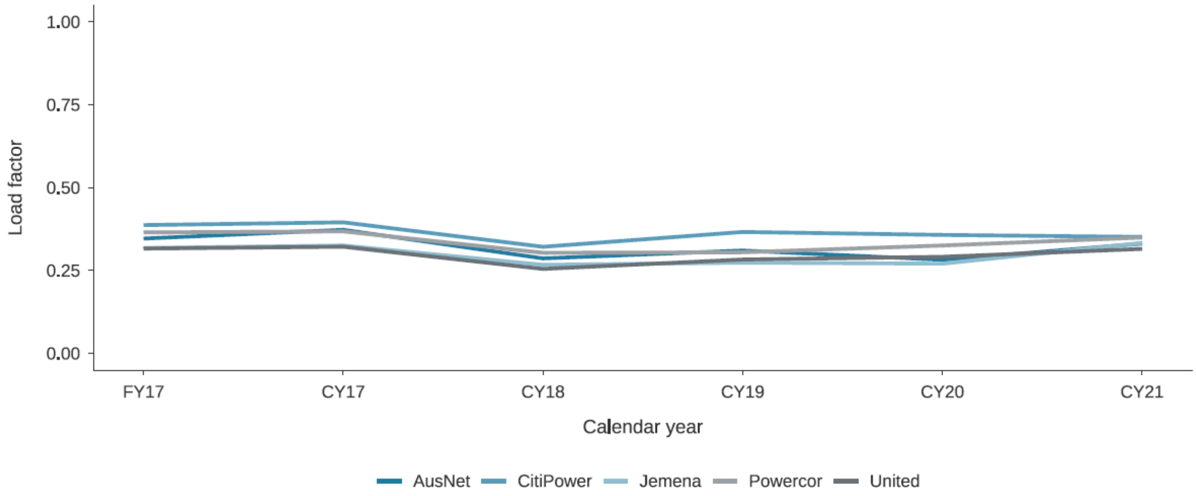
Analysis of data

Figure 1 shows the annual load factor for the residential data for each Victorian DNSP for the last five and a half years. So that we can present five and a half years of data on a consistent basis, **Figure 1** presents data for financial year 2016/17 and then data for calendar year 2017 to 2021. This means that six months of data is incorporated in **Figure 1** twice: once as part of financial year 2016/17 and a second time as part of calendar year 2017. To be clear, we do this only for the purposes of presentation, and do not use this data twice in calculating the VDO.

From **Figure 1** we can see that there is some variability over time in the residential load factor, but in our view there is not a clear trend towards a significantly higher or lower load factor over time.

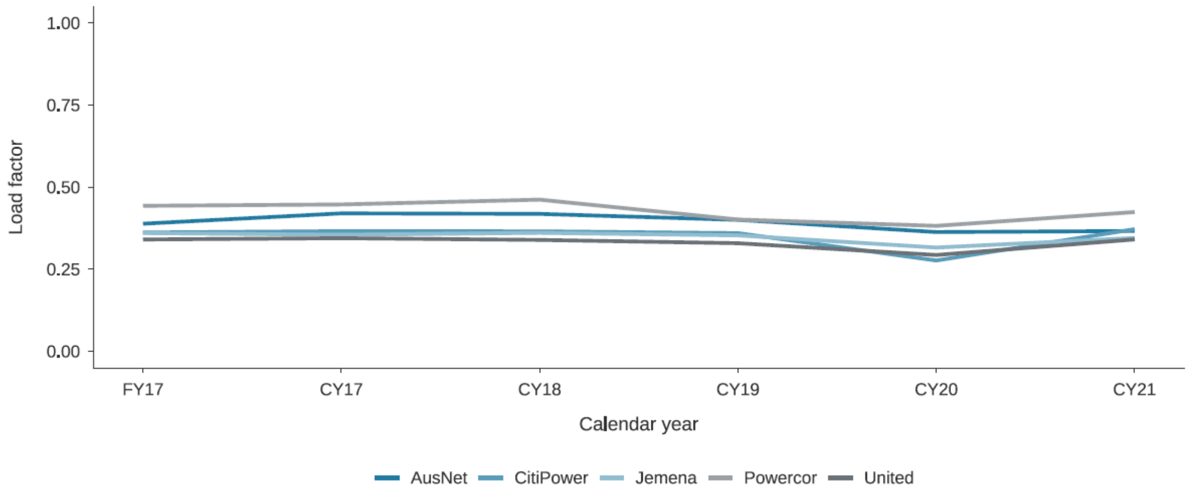
Figure 2 shows the annual load factor for business data for each Victorian DNSP for the last five and a half years, on the same basis as the residential load factor. As with the residential load factor, we can see some variability over time in the business load factor. This is particularly evident over the period from 2019 and 2021, and presumably reflects, at least in part, the impact of COVID-19 on many businesses. However, as with the residential load factor, in our view there is not a clear trend towards a significantly higher or lower load factor over time.

Figure 1: Load factor for residential customers



Source: Frontier Economics analysis of AEMO data

Figure 2: Load factor for business customers



Source: Frontier Economics analysis of AEMO data

Figure 3 and **Figure 4** show the average daily profile for residential and business customers respectively for each Victorian DNSP for the last five and a half years, normalised to the same annual consumption to highlight differences in the timing of daily consumption. As with the load factor data, these daily profiles are presented for financial year 2016/17 and then for calendar years 2017 to 2021, which means that six months of data is incorporated twice. To be clear, we do this only for the purposes of presentation, and do not use this data twice in calculating the VDO.

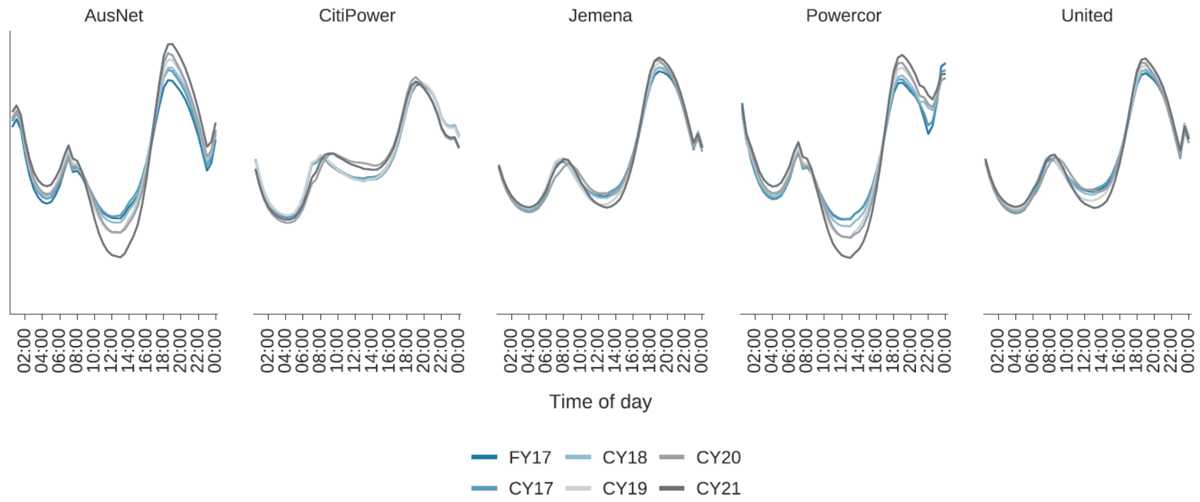
In our view, this data increasingly suggests that average daily profiles for both residential and business customers are changing.

For residential customers, we can see that 2021 had the lowest relative consumption during the day, and the highest relative consumption during the early evening, for most of the Victorian DNSPs. Furthermore, for most of the Victorian DNSPs, we can see that some combination of 2019, 2020 and 2021 have tended to show a similar pattern, with relatively lower consumption during the day and relatively higher consumption during the early evening, compared to earlier years.

For business customers, we can see a similar pattern in the last three years, with relatively lower consumption during the day and higher consumption at other times than. If anything, this pattern is more consistent across the Victorian DNSPs for business customers than it is for residential customers.

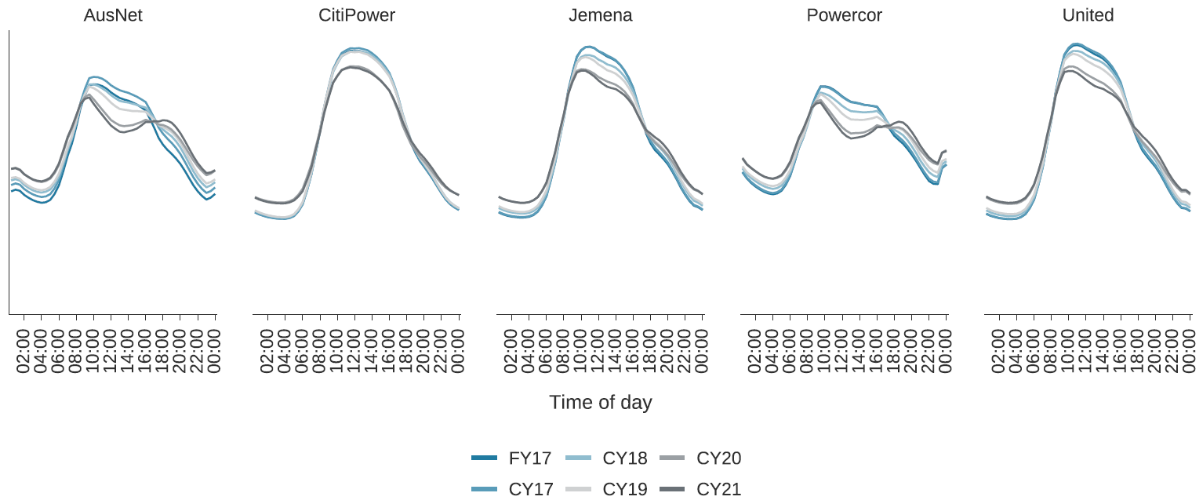
Including the data for 2021 with the data for earlier years suggests that some of the changes we see in the earlier years are likely to be part of a trend, rather than a result of year-to-year variability.

Figure 3: Average daily profile for residential customers



Source: Frontier Economics analysis of AEMO data

Figure 4: Average daily profile for business customers



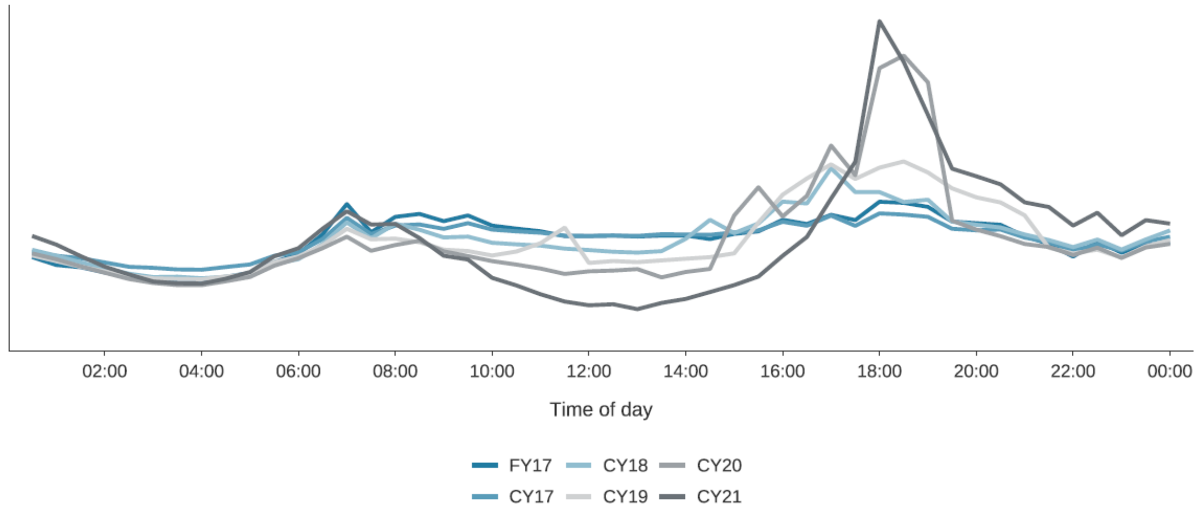
Source: Frontier Economics analysis of AEMO data

Figure 5 shows the average daily profile for Victorian spot prices for the last five and a half years, normalised to the same average annual price to highlight differences in the timing of daily prices. As with the load data, these daily profiles are presented for financial year 2016/17 and then for calendar years 2017 to 2021, which means that six months of data is incorporated twice. To be clear, we do this only for the purposes of presentation, and do not use this data twice in calculating the VDO.

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 profile for 2021 is most different to other years, with relative prices during the day that are materially lower, and relative prices during the evening that are materially higher. Calendar years 2020 and 2019 are most like 2021, indicating that there has been a trend over these three years to relatively lower prices during the day and relatively higher prices in the evening.

Figure 5: Average daily profile for Victorian spot prices



Source: Frontier Economics analysis of AEMO data

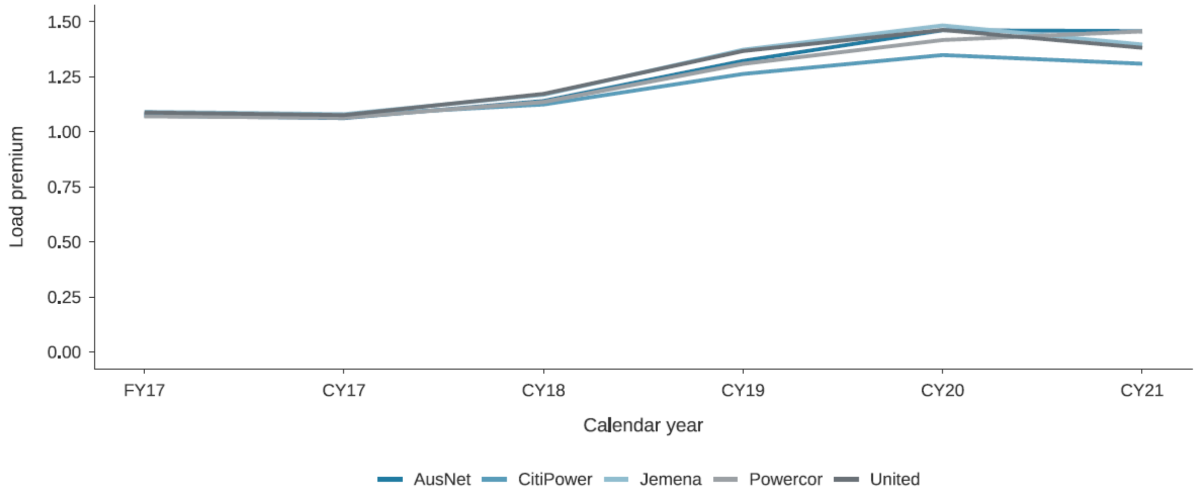
Figure 6 and **Figure 7** combine the historical customer load data and spot price data to report the load premium (calculated as the load-weighted price divided by the time-weighted price) for each customer type, for each Victorian DNSP and for each of the last five and a half years. As with the previous data, these load premiums are presented for financial year 2016/17 and then for calendar years 2017 to 2021, which means that six months of data is incorporated twice. To be clear, we do this only for the purposes of presentation, and do not use this data twice in calculating the VDO.

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 6** that for residential customers the load premium for 2019, 2020 and 2021 was materially higher than it had been in 2016/17, 2017 or 2018. This is largely because of spot prices remaining higher for longer in the early evening, but also because load has tended to be relatively higher in the evening. Compared to when we last looked at this historical time series of load premiums, the evidence is now stronger that the last 3 years are exhibiting different patterns of prices and load. When we last looked at this historical time series of load premiums, the difference between earlier years and later years was less marked, and the most recent year was lower for all DNSPs then previous years, raising questions about how sustained would be the difference.

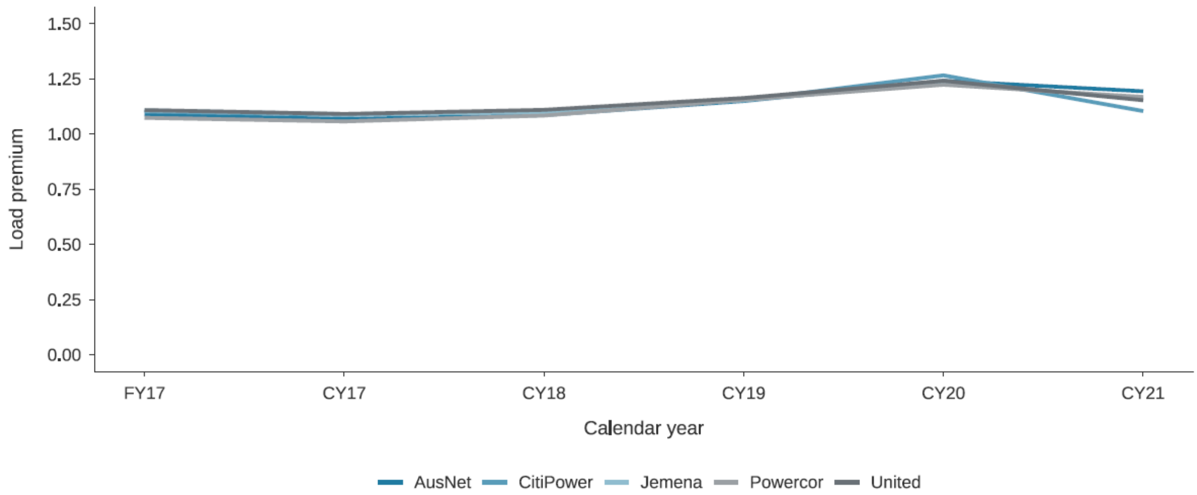
We can see from **Figure 7** that for business customers the load premium for the last 3 years is also higher than previous years, although the difference is smaller than it is for residential customers. When we last looked at this historical times series of load premiums, any difference between the earlier years and later years was less apparent.

Figure 6: Load premium for residential customers, based on Victorian spot prices



Source: Frontier Economics analysis of AEMO data

Figure 7: Load premium for business customers, based on Victorian spot prices



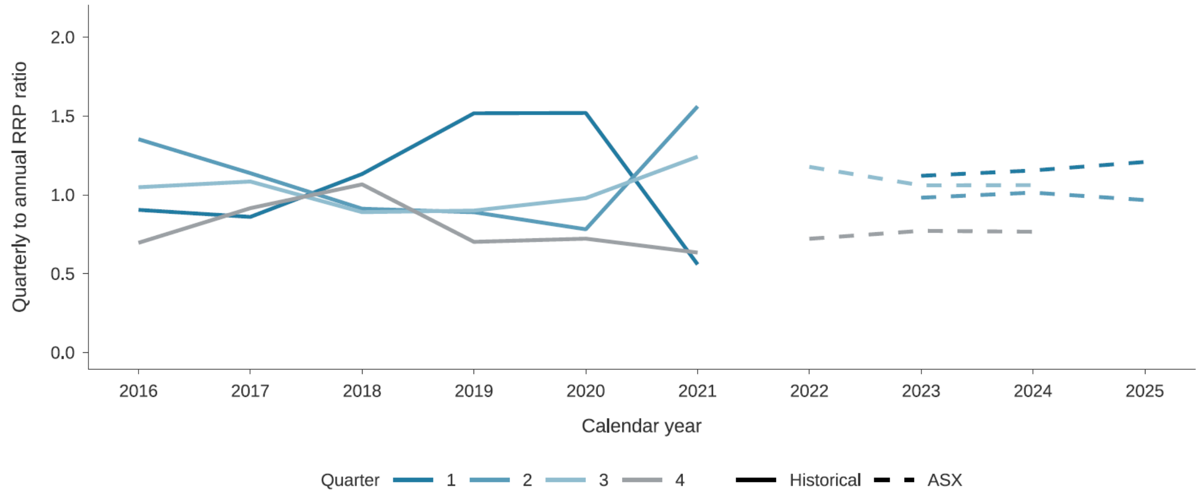
Source: Frontier Economics analysis of AEMO data

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 8 examines quarterly patterns of spot prices and ASXEnergy prices. For each quarter, **Figure 8** presents the relationship between average quarterly prices and average annual prices: on an historical basis this relationship is based on historical Victorian spot prices; on a forecast basis this relationship is based on ASXEnergy base-load swap prices for Victoria. **Figure 8** reveals quite a degree of volatility in the relationship between quarterly prices over time, and some instances in which the most recent data is not a good match for ASXEnergy prices. For instance, in calendar year 2021, prices in Q1 were the lowest of any quarter, but ASXEnergy forward prices suggest that in future Q1 prices will be the highest of any quarter. Similarly, prices in Q2 in 2021 were the highest of any quarter, but ASXEnergy forward prices suggest that in future Q2 prices will be middle of the range of quarterly prices. In our view, what **Figure 8** is revealing is that prices in 2021 were something of an outliner – prices began the year at very low levels (due to a combination of a mild summer and ample supply) but increased through the course of the year (in part due to rising fuel prices). If we were to base our expectations of future patterns of prices solely on historical prices from 2021, therefore, we would have pricing patterns that are inconsistent with ASXEnergy prices. However, by including a number of historical years in our analysis, we capture some years in which prices in Q1 were highest, so that the results of our Monte Carlo analysis are likely to be more consistent with ASXEnergy prices.

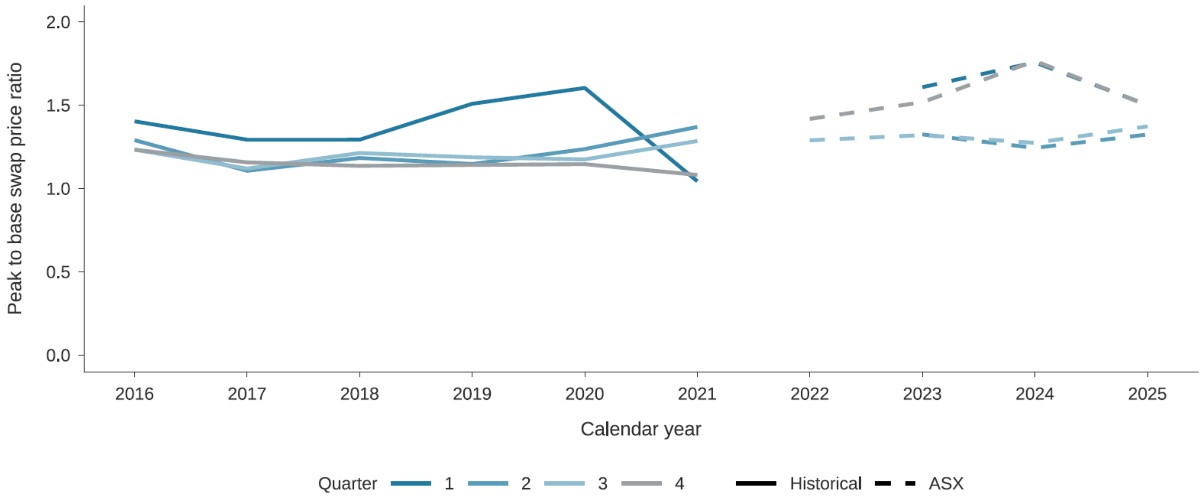
Figure 9 examines peak/off-peak patterns of spot prices and ASXEnergy prices. For each peak/off-peak period, **Figure 9** presents the relationship between average peak/off-peak prices and average annual prices: on an historical basis this relationship is based on historical Victorian spot prices; on a forecast basis this relationship is based on ASXEnergy base-load swaps prices for Victoria. **Figure 9** reveals the same as **Figure 8**: Q1 2021 is something of an outlier compared to other historical years, but including a number of historical years in our analysis is likely to deliver pricing patterns that are more consistent with ASXEnergy prices.

Figure 8: Quarterly patterns of spot prices and ASXEnergy prices



Source: Frontier Economics analysis of AEMO data and ASXEnergy data

Figure 9: Peak/off-peak 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 limit the data we include in our analysis to the 3 most recent years: 2019, 2020 and 2021. That is, we include data only from 2019, 2020 and 2021 in a Monte Carlo simulation when forecasting half-hourly load and half-hourly prices.

The reason for this is the increasing evidence that patterns of load and patterns of prices are exhibiting a trend, with load and prices both tending to be lower during the day. While the evidence of this trend is still somewhat mixed for load (given that we are considering load for two customer types and 5 DNSPs), the evidence of this trend is clearer at this stage for pricing patterns.

Unlike is previous years, our analysis of the most recent data also shows a clearer trend in the load premium.

For these reasons, we consider that restricting our analysis to the most recent 3 years of historical data will mean that our Monte Carlo analysis is more likely to deliver patterns of load and prices that load and price outcomes in 2022/23. We have examined the likely impact on the WEC of using 3 years of data, rather than all the available historical data, and have concluded that the likely impact is small – using 3 years of data results in prices that are less than 1 per cent higher than would be the case using all the available historical data. Reasons for this relatively small impact included that:

- Even with all the historical data these 3 most recent years will be 'over-represented' in the simulated years that are most expensive to hedge (which have a large impact on the hedging position).
- The hedging position we calculate changes to reflect the different prices and load in the synthetic years that are due to only using the most recent 3 years of historical data.

3.3 Projecting half-hourly load and spot prices

As discussed, rather than take a single one of the years from 2019 to 2021 as representative of outcomes in 2022/23, 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 2022/23 is 1 July 2022, which is a Friday. Since this is a Friday in Q3, the half-hourly load and spot data for the first day of 2022/23 will determined by randomly drawing a day's half-hourly data from all the Q3 weekdays that occurred in 2019 through to 2021.
- The second day of 2022/23 is 2 July 2022, which is a Saturday. Since this is a Saturday in Q3, the half-hourly load and spot data for the second day of 2022/23 will be determined by randomly drawing a day's half-hourly data from all the Q3 weekend days that occurred in 2019 to 2021.
- And so on for the 365 days that make up 2022/23, 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 2019 through to 2021.

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 Victorian spot prices. There is no reason, for instance, that Victorian spot prices over the period 1 January 2021 to 31 December 2021 will, on average, be the same as Victorian spot prices for 2022/23. In our view, the best available public information about the average level of Victorian spot prices for 2022/23 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 2022/23. 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 2022/23 from ASXEnergy[3] (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 28 January 2022) as representing the market's current view of spot prices for each quarter of 2022/23.[4] This approach to generating half-hourly price forecasts results in:

- 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

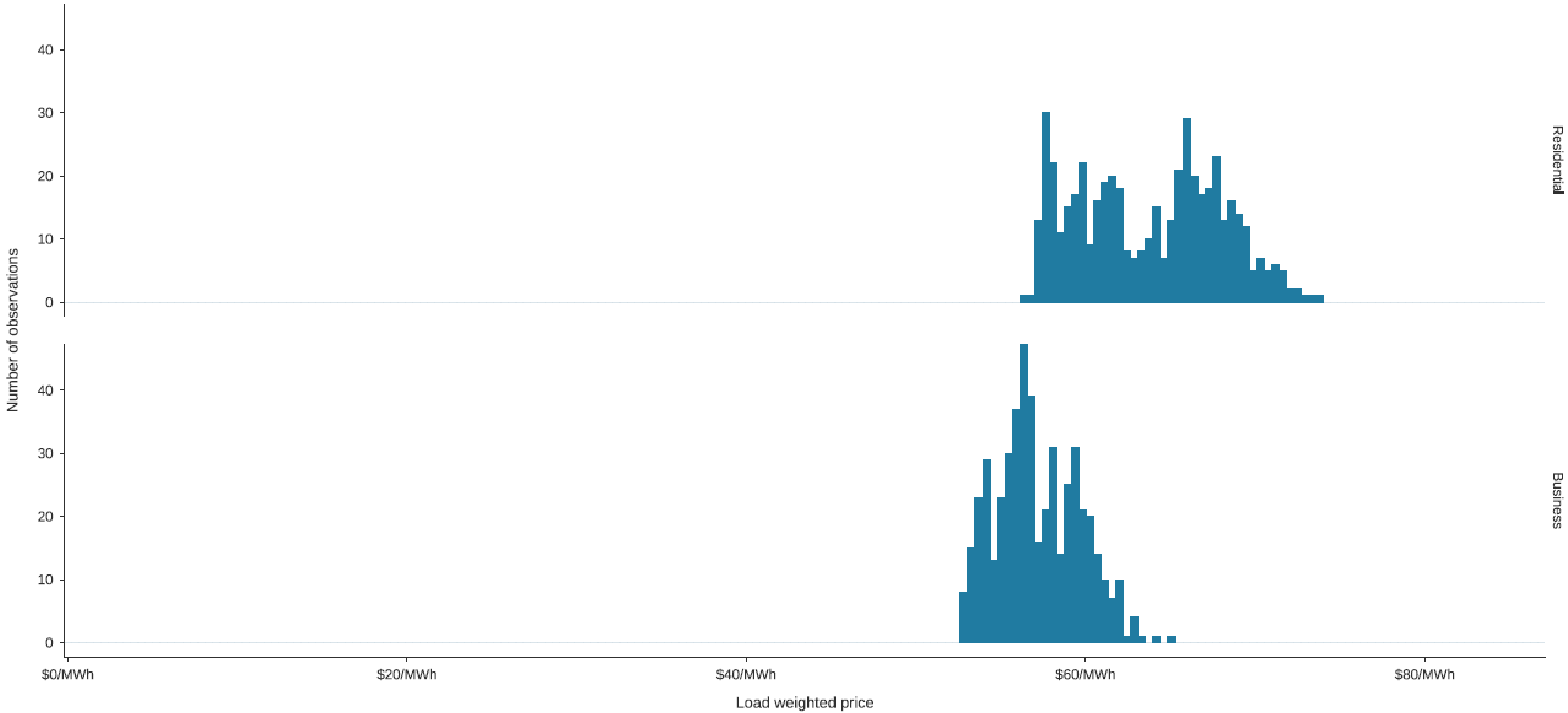
An indication of the results of our Monte Carlo simulation can be provided by calculating the load-weighted price for each of the 500 simulated years. As we discussed, in our experience the load-weighted price is a reasonable guide to the WEC. **Figure 10** through **Figure 14** show the

3 An alternative approach would be to attempt to scale half-hourly prices having regard to each of base swaps, peak 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 each of the contract prices from ASXEnergy.

4 We note that there is a difference in the averaging period that we use for estimating spot prices for 2022/23 and the averaging period we use for calculating contract prices to be used in estimating the WEC for the VDO. 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 2022/23. However, based on instructions from the ESC, we use 12-month trade weighted average ASXEnergy prices to set the contract price for retailers when determining the WEC. In our view, there is no necessity for these 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 2022 over the last 12 months (at the same time as trade occurs on ASXEnergy) and uses those contracts to hedge the risk it would face based on current expectations of spot prices.

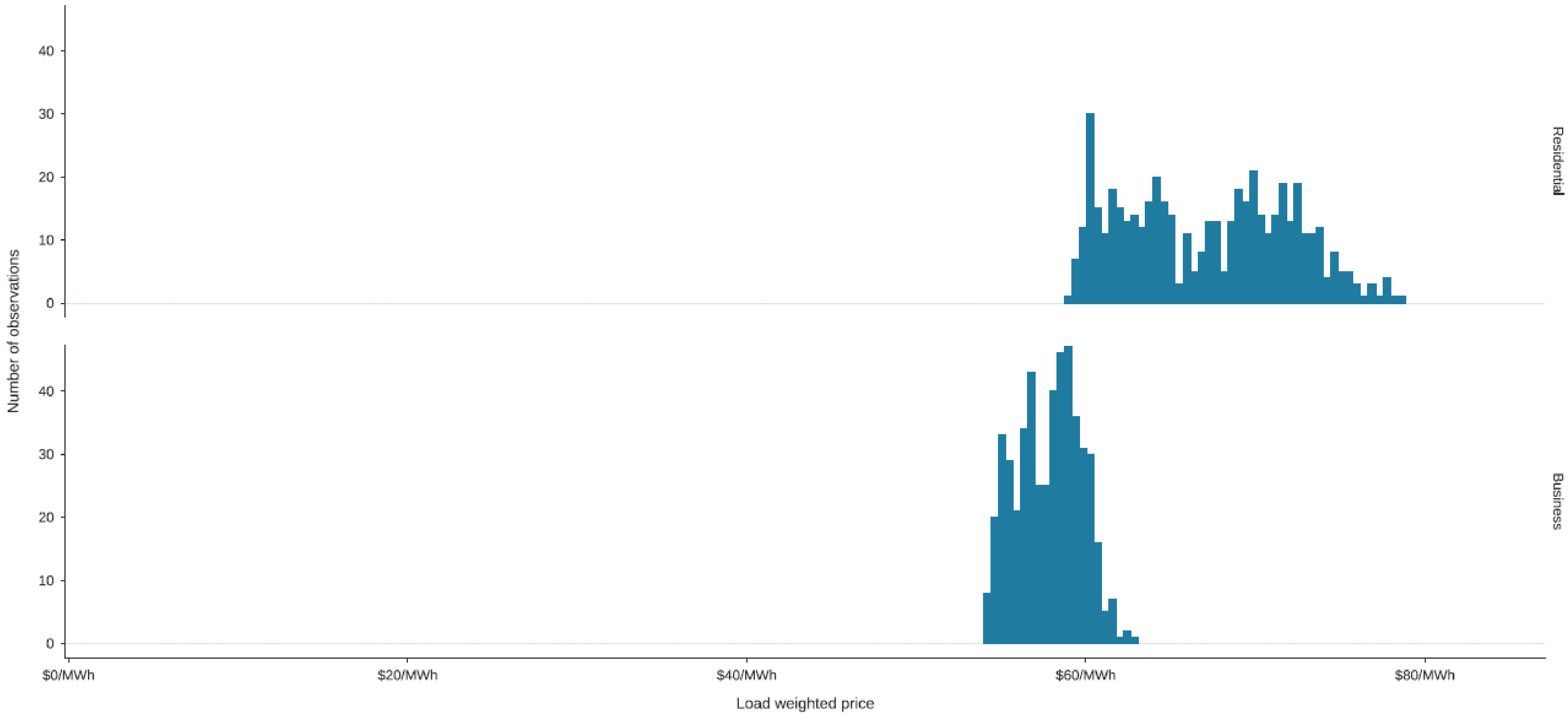
distribution of load-weighted prices for each of the 500 simulated years from our Monte Carlo analysis, for each distribution area and for each customer type. As discussed, the average spot price in each of these simulated years is the same – based on the 40-day average ASXEnergy base swap price – but the half-hourly profile of both spot prices and load are different. It should be clear from **Figure 10** through **Figure 14** 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.

Figure 10: Distribution of load-weighted price for simulated years for residential and business load – CitiPower



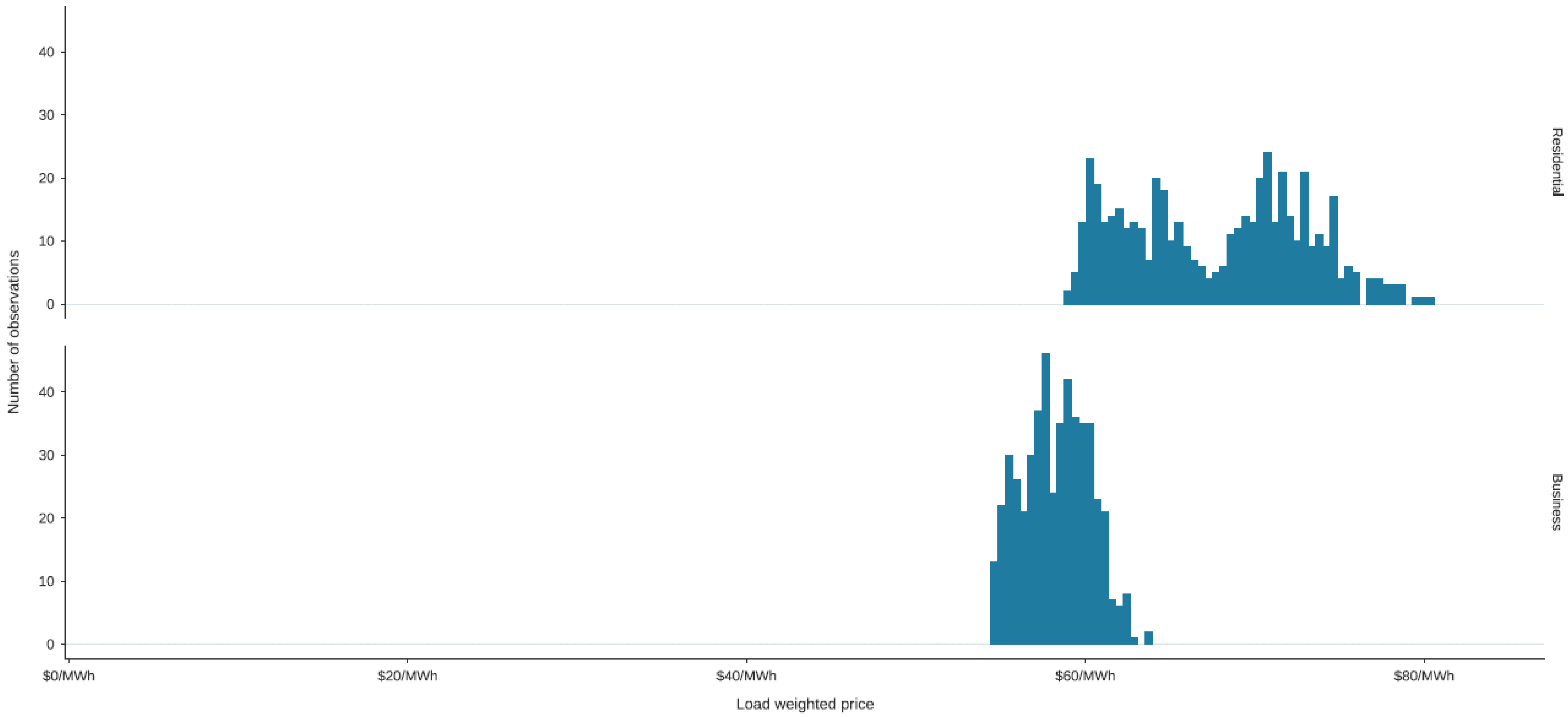
Source: Frontier Economics

Figure 11: Distribution of load-weighted price for simulated years for residential and business load – Powercor



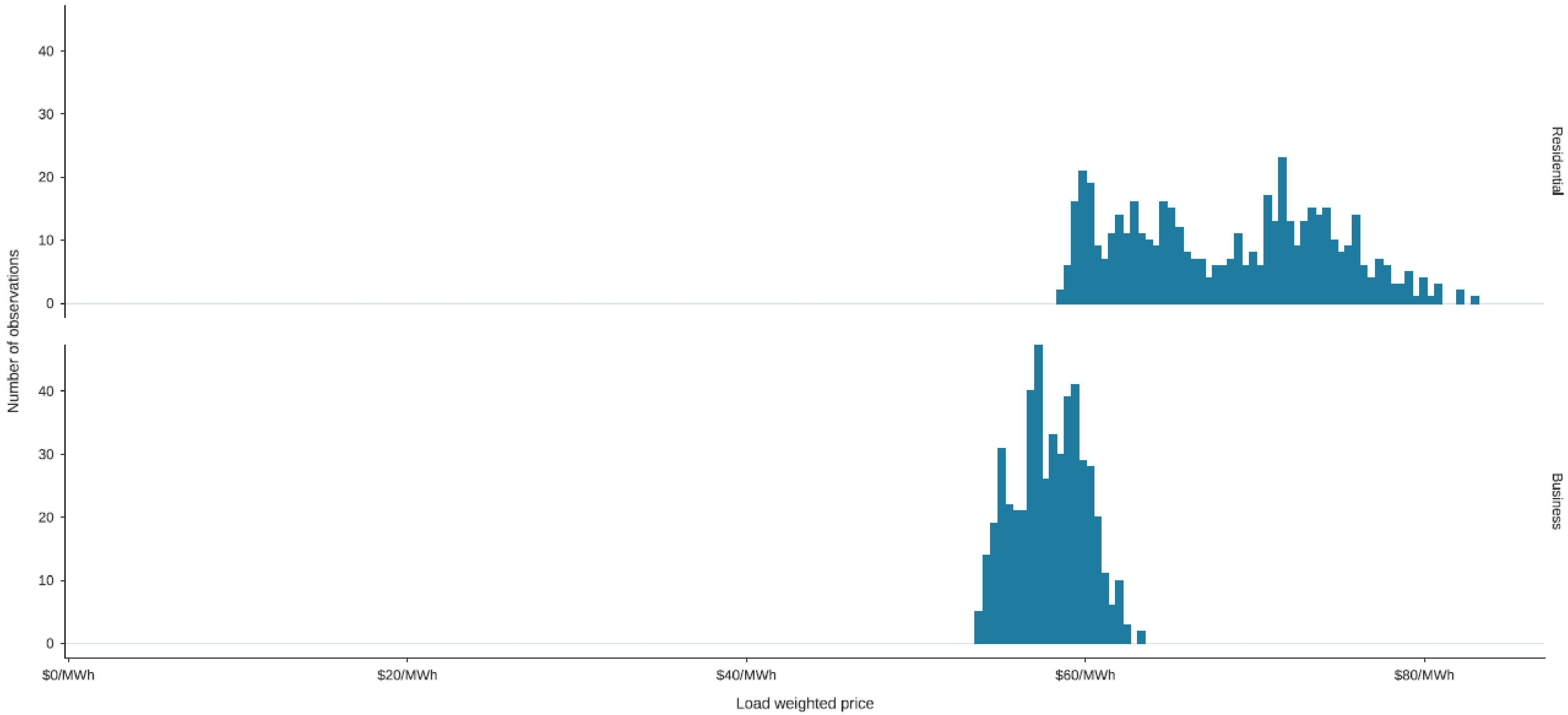
Source: Frontier Economics

Figure 12: Distribution of load-weighted price for simulated years for residential and business load – AusNet



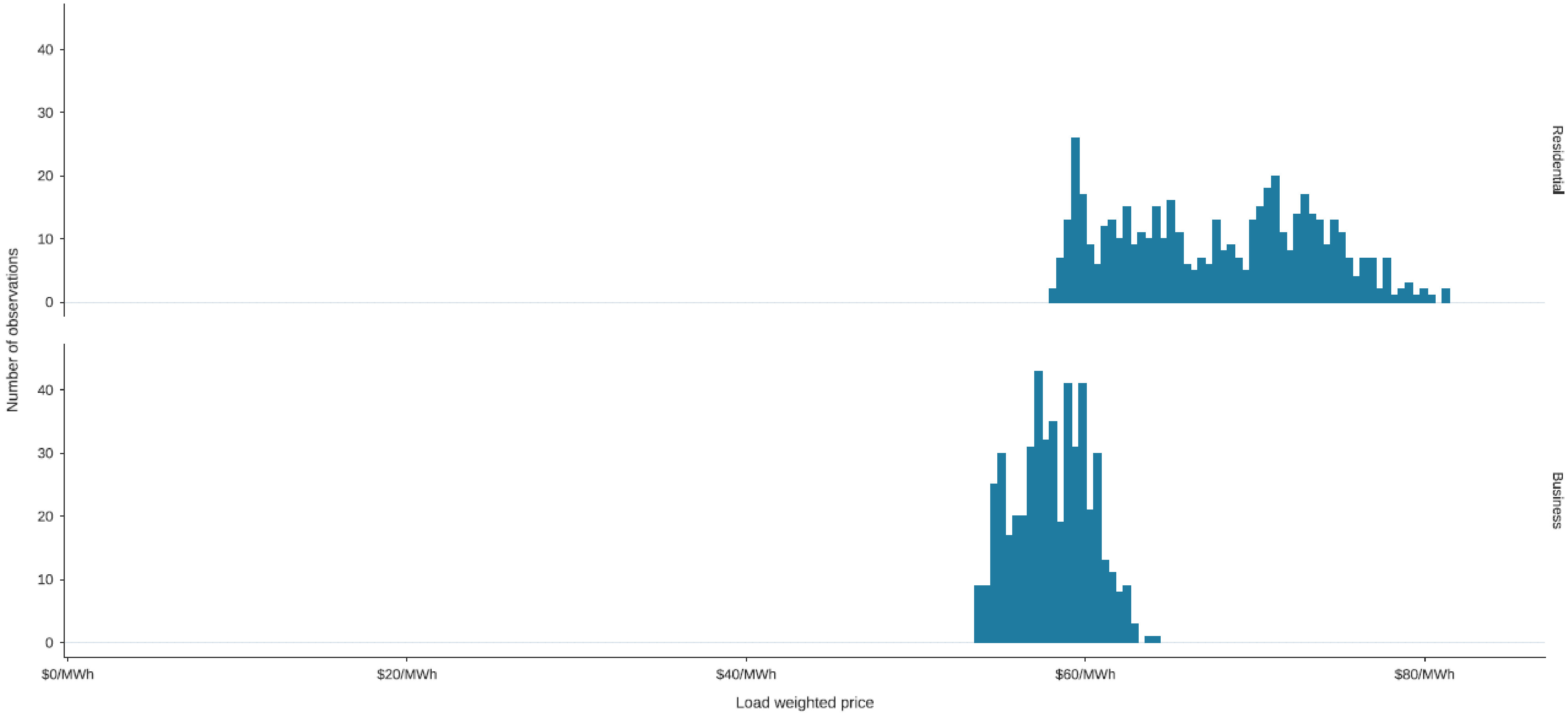
Source: Frontier Economics

Figure 13: Distribution of load-weighted price for simulated years for residential and business load – Jemena



Source: Frontier Economics

Figure 14: Distribution of load-weighted price for simulated years for residential and business load – United



Source: Frontier Economics

4 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. There are three main types of electricity contracts that are traded on ASXEnergy:

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

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

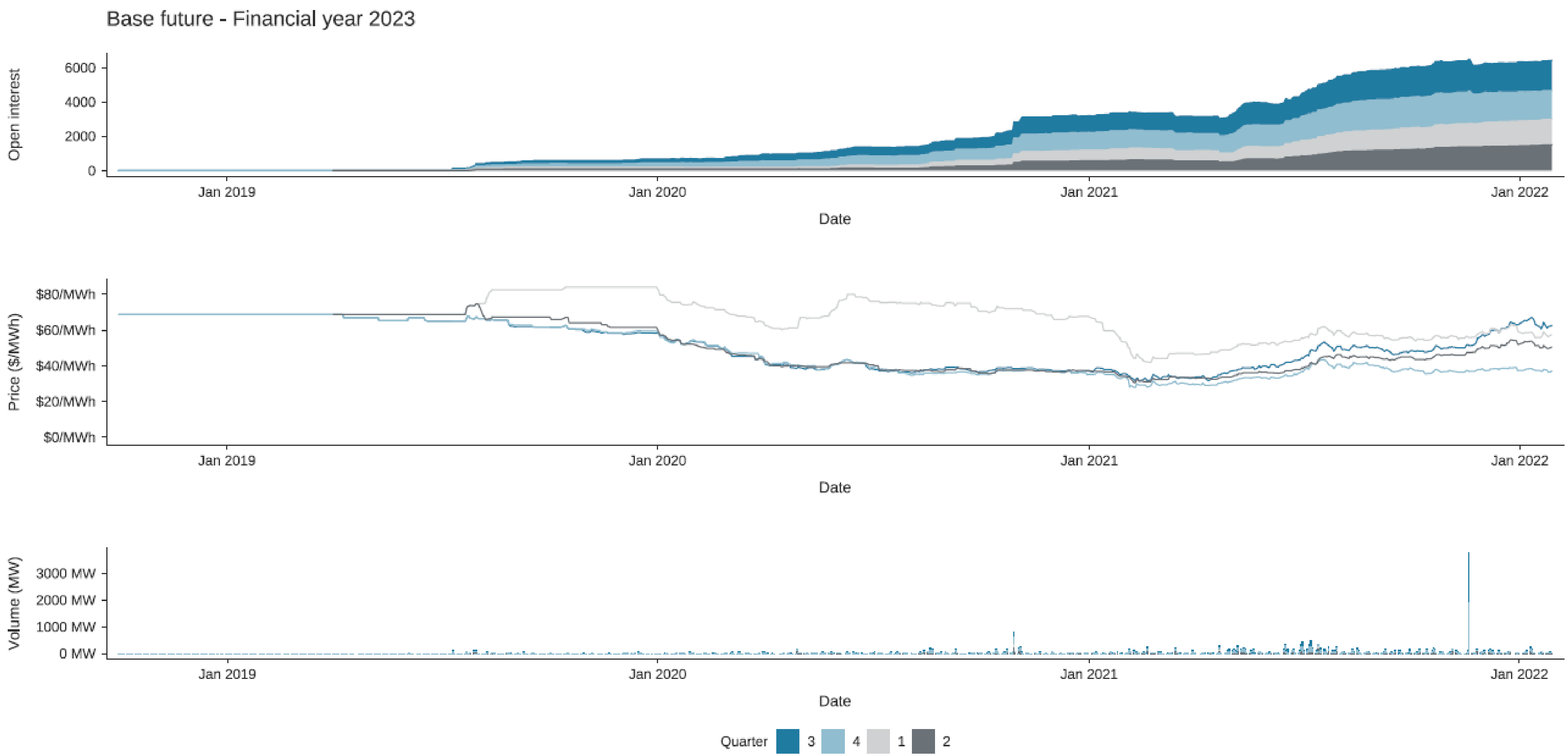
Contract price data

Figure 15 through **Figure 17** set out the relevant trading data for each of these three contract types, 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 from **Figure 15** through **Figure 17** that base swap contracts for 2022/23 are currently trading regularly. Indeed, we can see that trade in these contracts is occurring on most trading days. This suggests that the daily prices for base swaps does provide a genuine indication of the market's view of future prices. However, trade in caps, and particularly peak swaps, is a lot lower. Given that peak swaps have not traded in several months, there is the prospect that the available prices for peak swaps for 2022/23 may not represent the market's current view of likely price outcomes for 2022/23. We have observed this for peak swaps in previous years, but trade volumes are currently even lower for peak swaps than they have been in previous years.

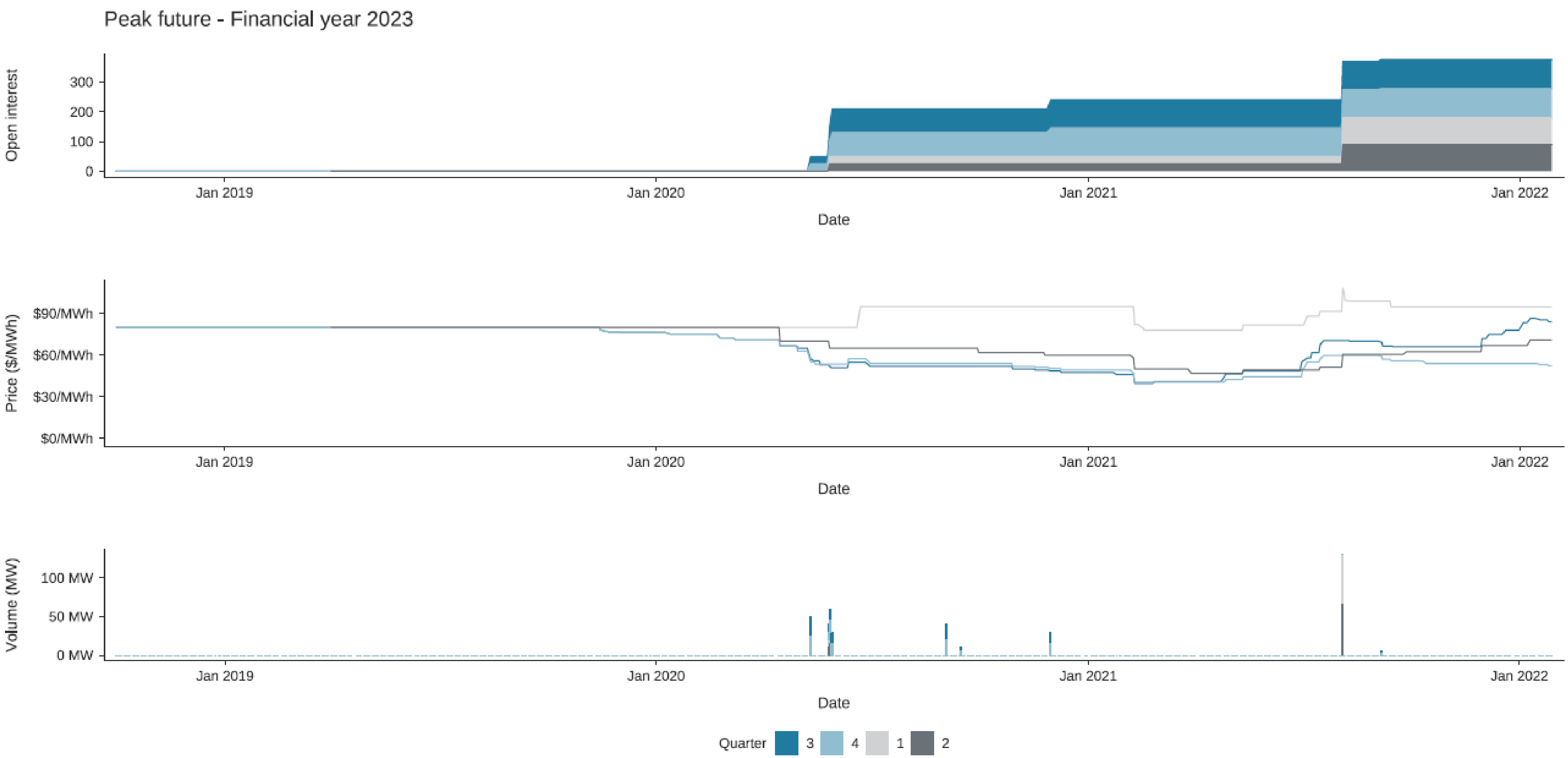
While trade volumes for peak swaps are currently very low, and trade has not occurred in several months, we do note that changes in the quoted settlement prices (which occur because settlement prices can be affected by bid-ask spreads even in the absence of trade) for peak swaps are reasonably aligned with changes in base swap prices over this period. For instance, prices for Q3 peak swaps have trended upwards over recent months, just as prices for Q3 base swaps have trended upwards. However, using a trade-weighted approach to estimating contract prices means that these recent price changes for peak swaps on days with no trade do not figure in the calculation of the peak swap price. Moving to a time-weighted approach would mean that these recent price changes on days with no trade would figure in the calculation of the peak swap price. We will continue to monitor trade volumes and prices for peak swaps in the period leading up to our final report.

Figure 15: Victorian base swaps – open interest, prices and volumes for 2022/23



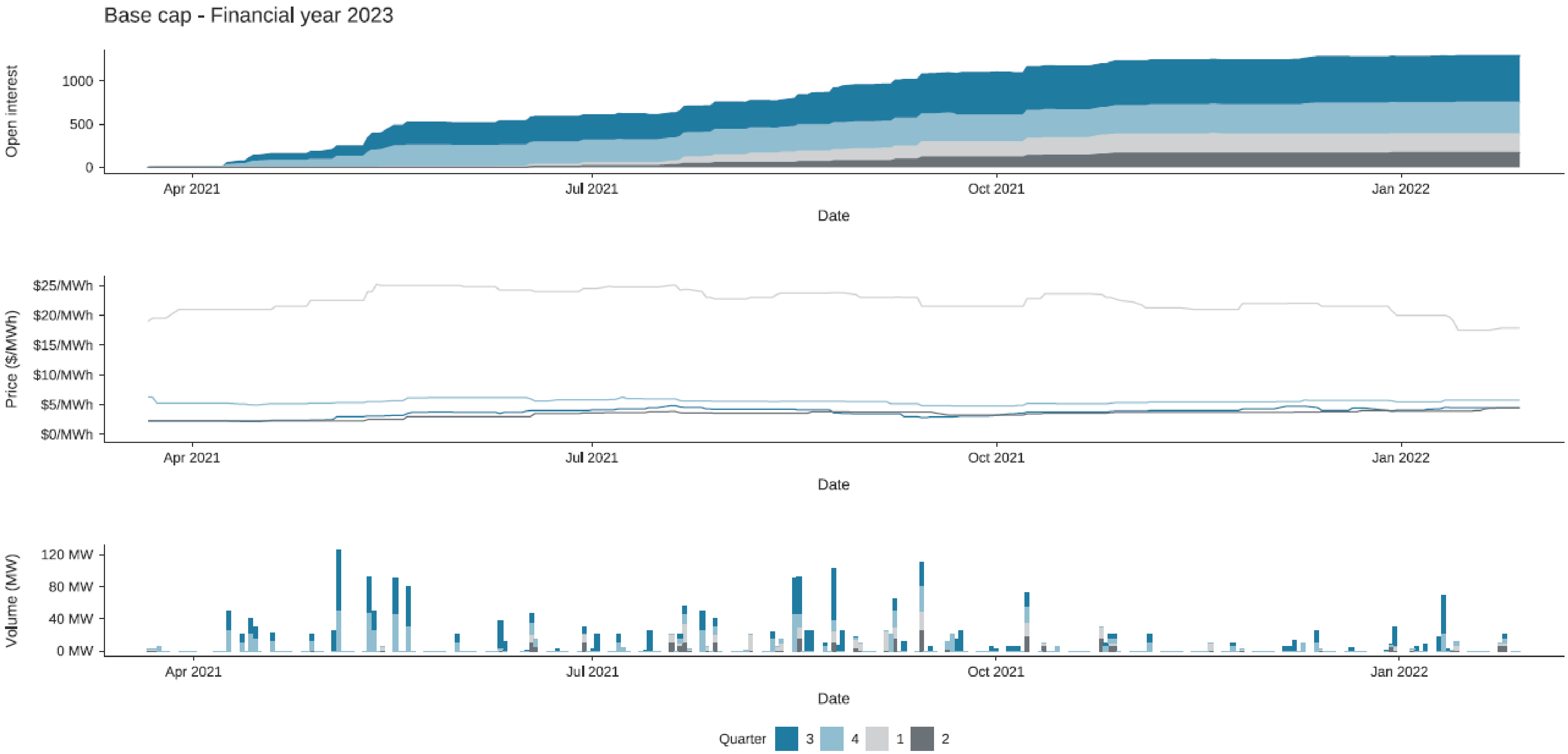
Source: Frontier Economics analysis of ASX data

Figure 16: Victorian peak swaps – open interest, prices and volumes for calendar year 2022



Source: Frontier Economics analysis of ASX data

Figure 17: Victorian base $300 caps – open interest, prices and volumes for calendar year 2022



Source: Frontier Economics analysis of ASX data

To determine the WEC we use this 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 longer averaging period, such as 12 months or 24 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 ESC has asked us to use 12-month trade weighted contract prices in estimating the WEC. We calculate the 12-month trade weighted contract price for each contract by taking an average of the daily settlement price for that contract over the last 12 months, but weighting each daily settlement price by the share of the total volume of trade over the last 12 months that happened on that day. This means that the settlement price on a day on which no trade occurred is given a weighting of zero in calculating the 12-month trade weighted contract price, while the settlement price on the day on which the most trades occurred in the last 12 months is given the highest weighting.

ASXEnergy contract prices are shown in **Table 1**, for the 12-month trade weighted average price, up to 28 January 2021.

Table 1: 12-month trade weighted average ASXEnergy derivative prices for Victoria (2022/23 dollars)

	Product	Status	Calendar year	Quarter			
				Q3	Q4	Q1	Q2
TRADE WEIGHTED	$300 Caps	Base	2022	$3.60	$5.44	$22.86	$3.66
	Swaps	Base	2022	$47.01	$36.33	$55.46	$42.36
	Swaps	Peak	2022	$69.31	$59.09	$108.27	$60.59

Source: Frontier Economics analysis of ASXEnergy data

Note: Caps for 2022 have only been trading since 22 March 2021 and so the price is not a 12-month average, but is still trade-weighted.

5 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 each customer type in each distribution area in Victoria, we make use of the following inputs in *STRIKE*:

- Forecast spot prices and load, as discussed in Section 3. As we discussed, we have developed 500 simulated years of half-hourly spot prices and load for 2022/23. 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 2022/23 will be; will 2022/23 be a year with high prices and high load corresponding, so that the load-weighted price is high, or will 2022/23 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 4. We present results for 12-month trade weighted contract prices.

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 18** to **Figure 27** are the resulting contract positions at the conservative point for 2022/23, for each load profile and for each distribution area. For each quarter (the vertical panels) and each peak/off-peak period (the horizontal 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 $300/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).

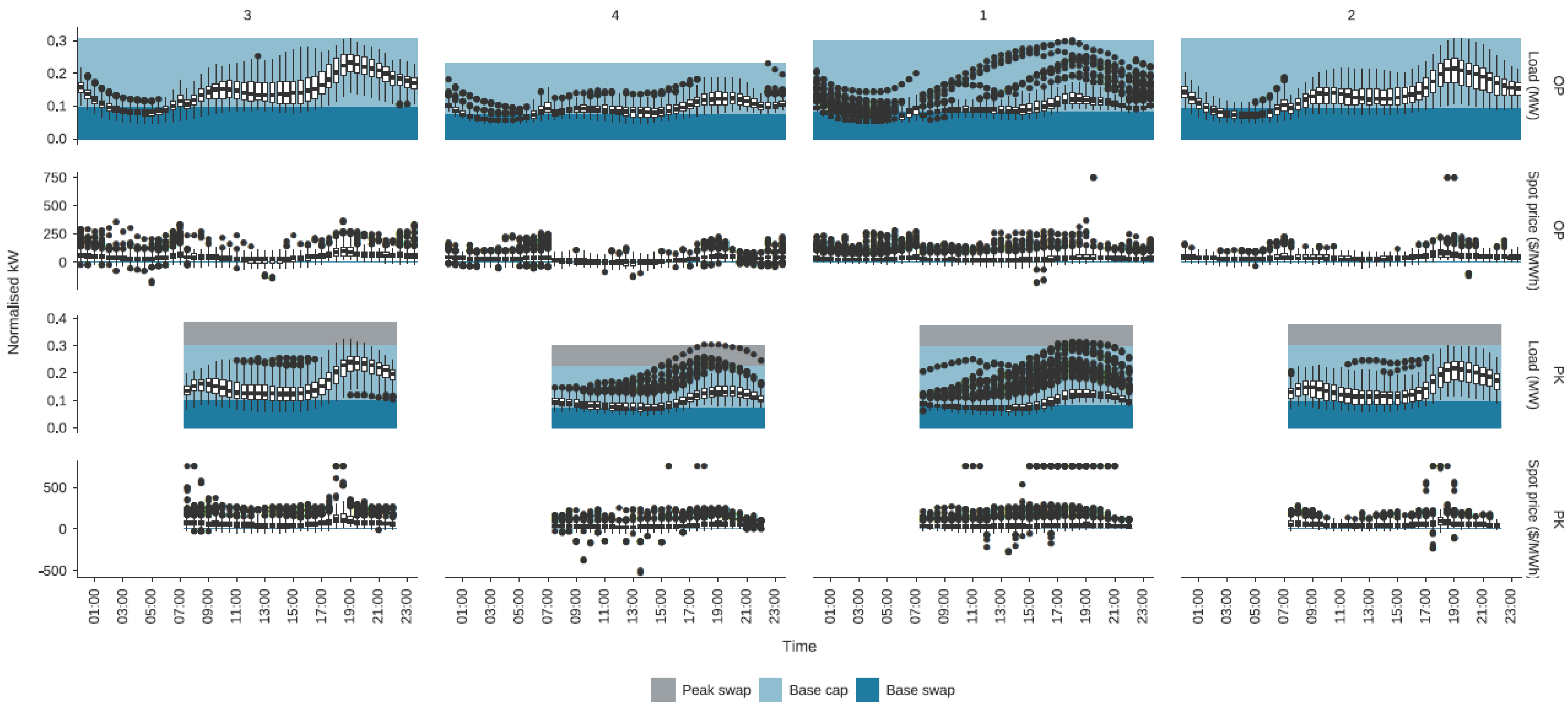
In general, the contract position at the conservative point involves:

- purchasing swaps to cover (approximately) average demand (or slightly lower in off-peak periods)
- purchasing caps, on top of that, to cover (approximately) to peak demand
- in some cases, incurring a small amount of pool exposure at absolute peak demand times.

As seen in **Figure 18** to **Figure 27**, the contract position at the conservative point generally results in complete coverage of the highest demand half hours, but does not always do so. The reason that there can remain some residual pool exposure even at the conservative point is that *STRIKE* balances the costs and risks of remaining exposed to the spot price at these highest demand half hours against the costs and risks associated with being over-contracted. Signing additional contracts is neither costless nor riskless, and while being exposed to the spot price during a small number of high demand half-hours can result in large payments, being over-contracted for a large number of lower demand half-hours can also result in large payments. Some retailers may have a preference for additional contract cover to meet forecast peak demand in all cases, but we note that the volatility allowance (discussed in Section 6.2) is intended to reflect the residual risk at the conservative point and could be used to purchase additional cap cover.

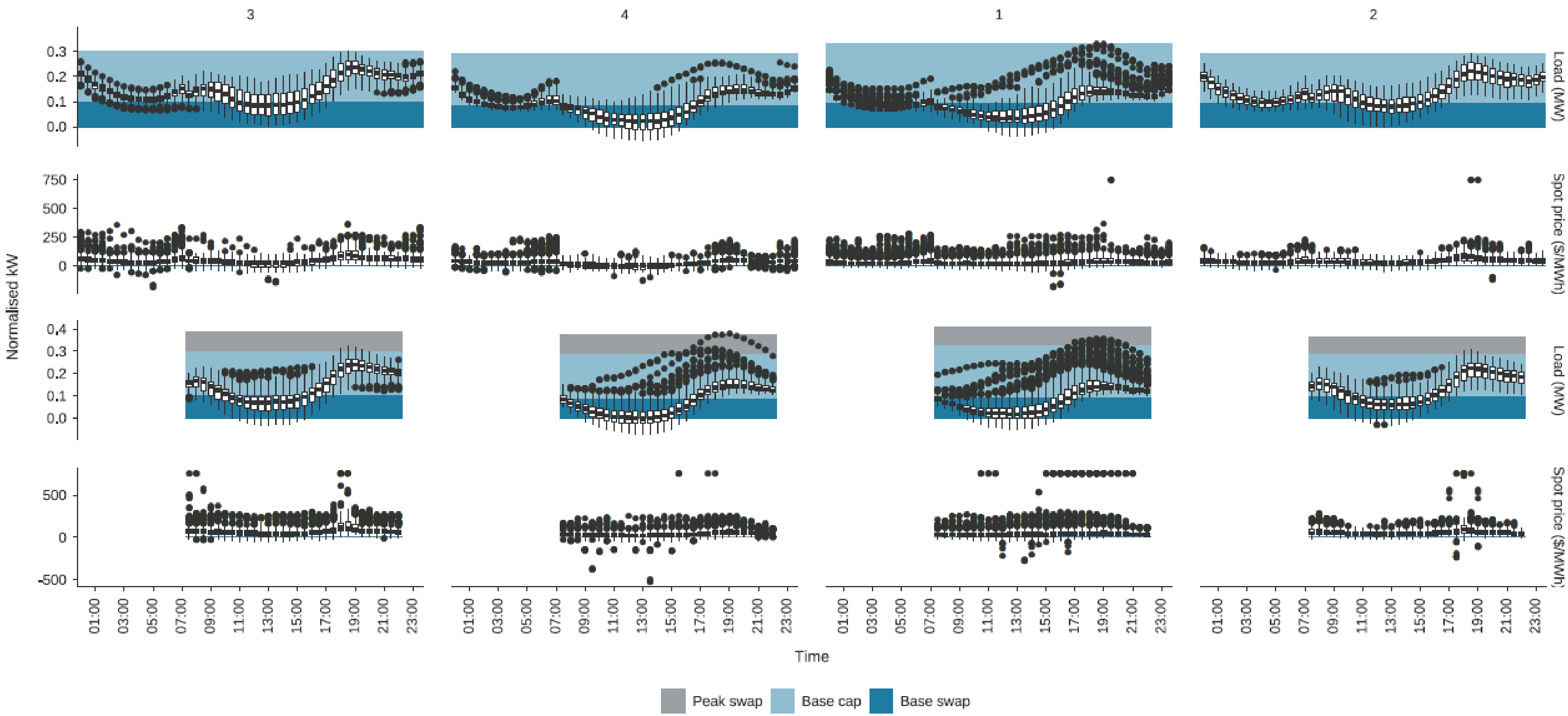
It should also be noted that the conservative point on the efficient frontier reflects the contract position that achieves the lowest risk given the projected state of the world that is input into *STRIKE*. In the event that different states of the world were input into *STRIKE*, the model would find 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. That load forecasts and price forecasts (and their correlation) are important to the costs that retailers face in supplying regulated customers is why 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 them).

Figure 18: Contract position for CitiPower residential load, ASXEnergy contract prices



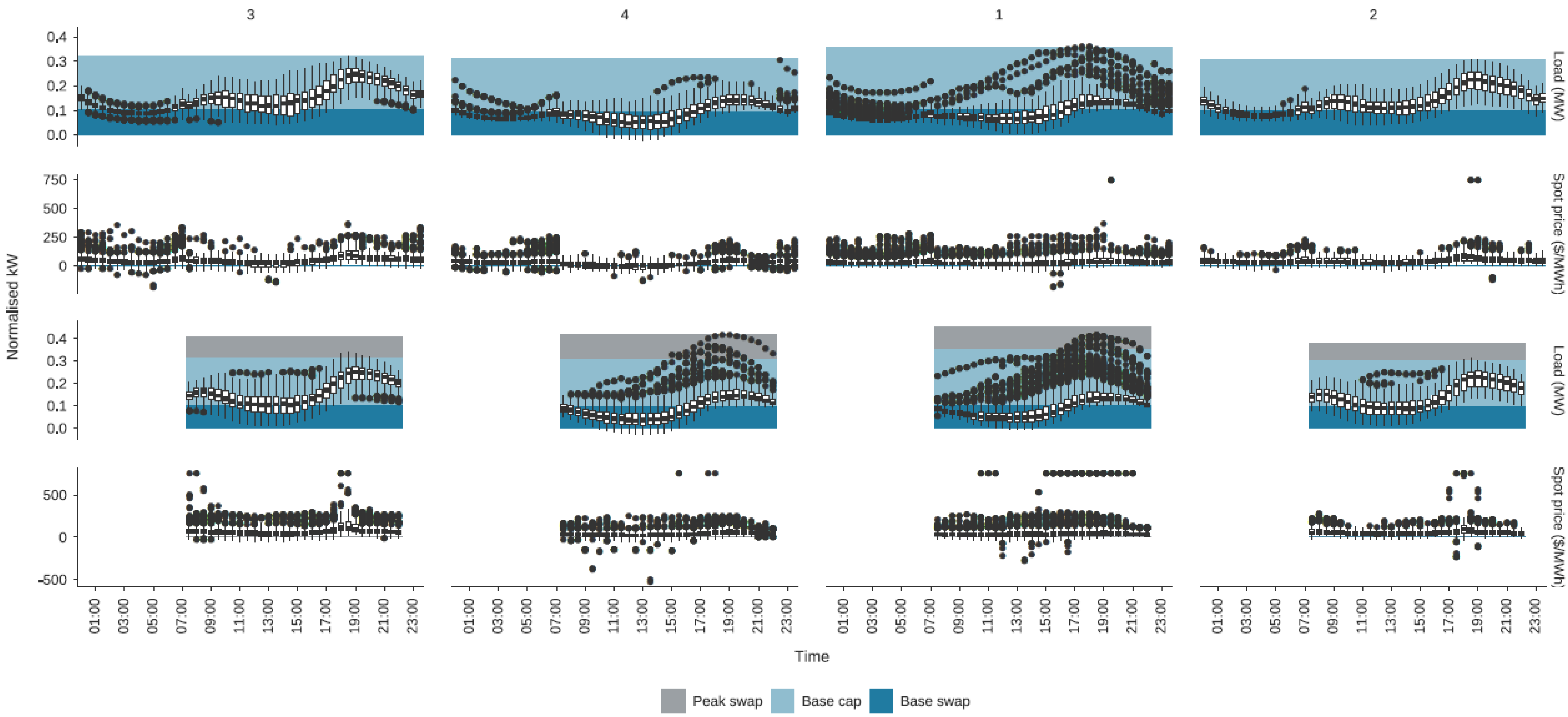
Note: Spot price chart truncated at a spot price of $300/MWh.

Figure 19: Contract position for Powercor residential load, ASXEnergy contract prices



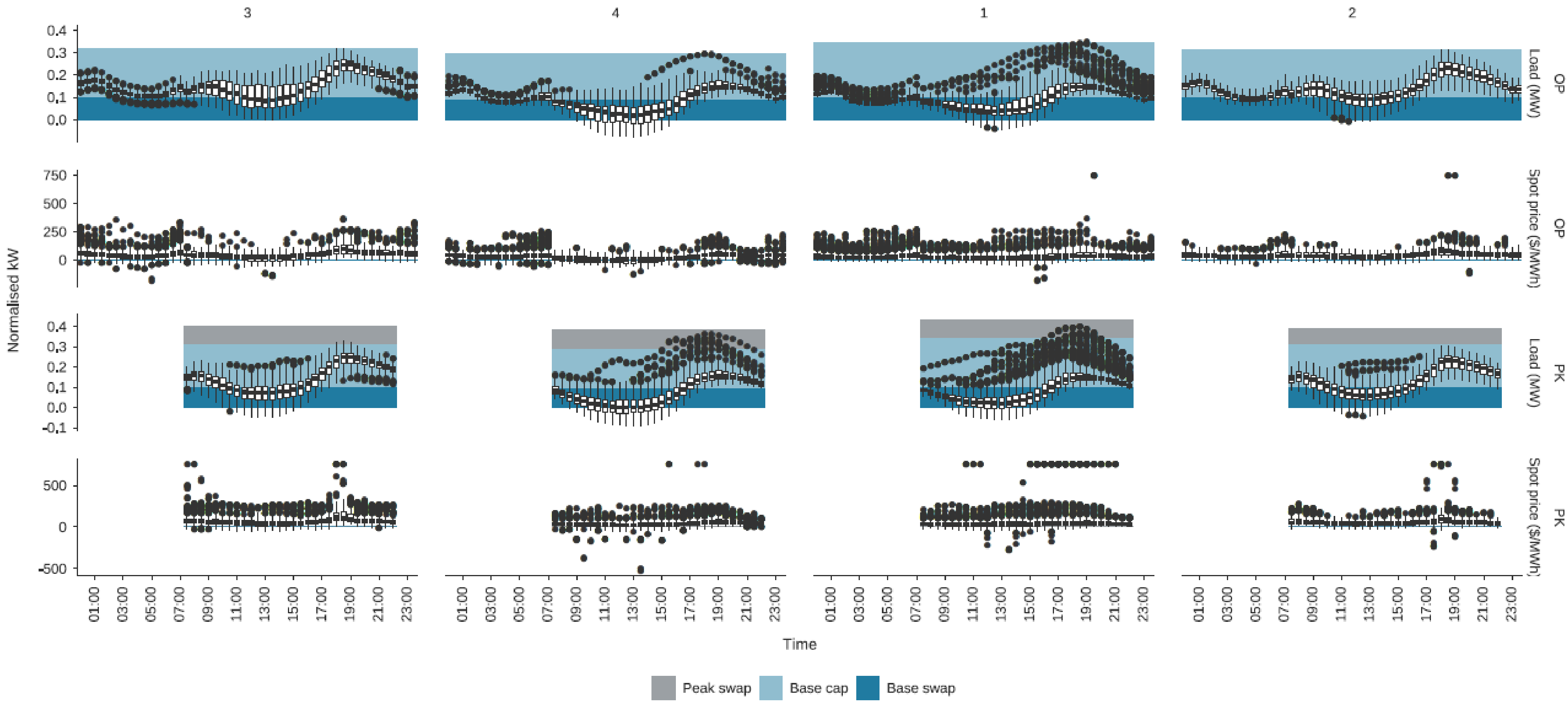
Note: Spot price chart truncated at a spot price of $300/MWh.

Figure 20: Contract position for Jemena residential load, ASXEnergy contract prices



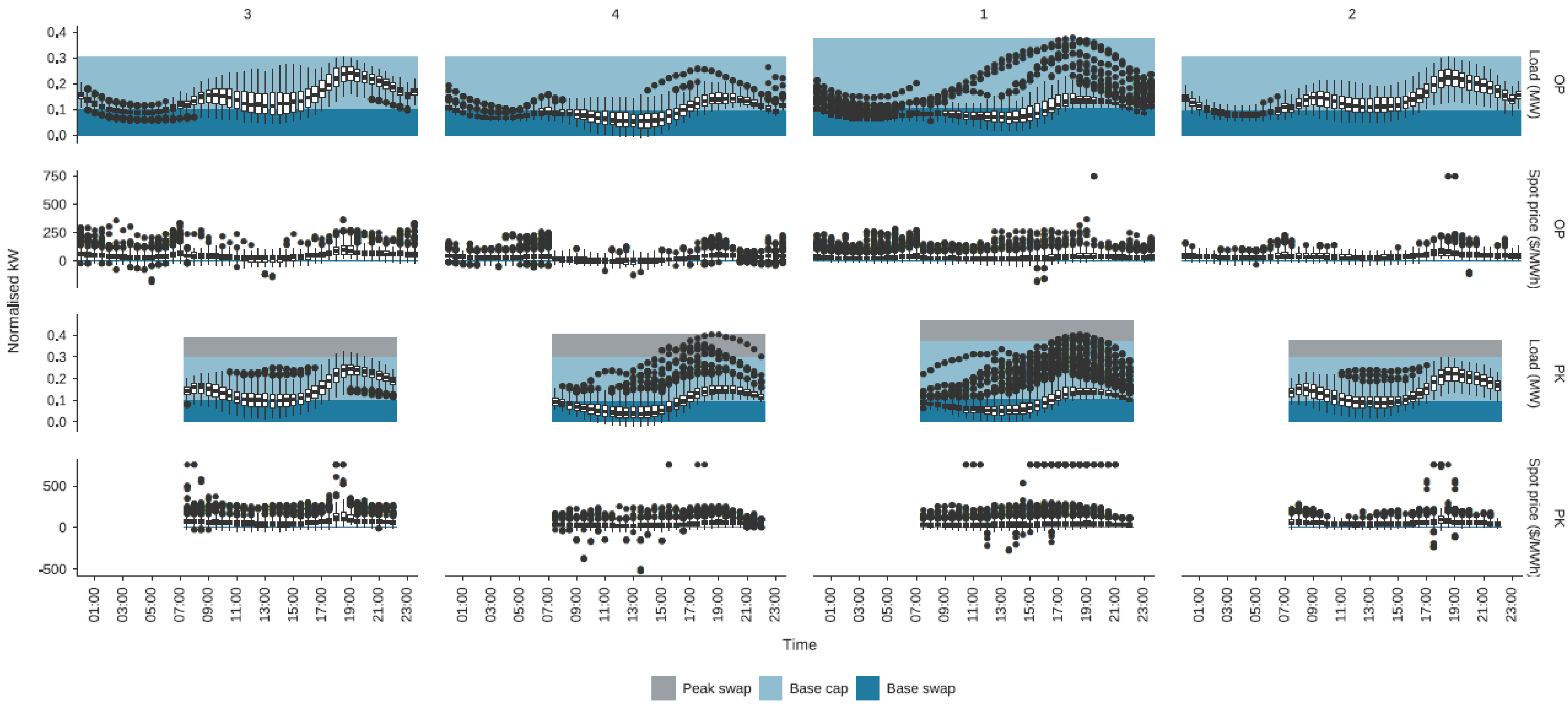
Note: Spot price chart truncated at a spot price of $300/MWh.

Figure 21: Contract position for AusNet residential load, ASXEnergy contract prices



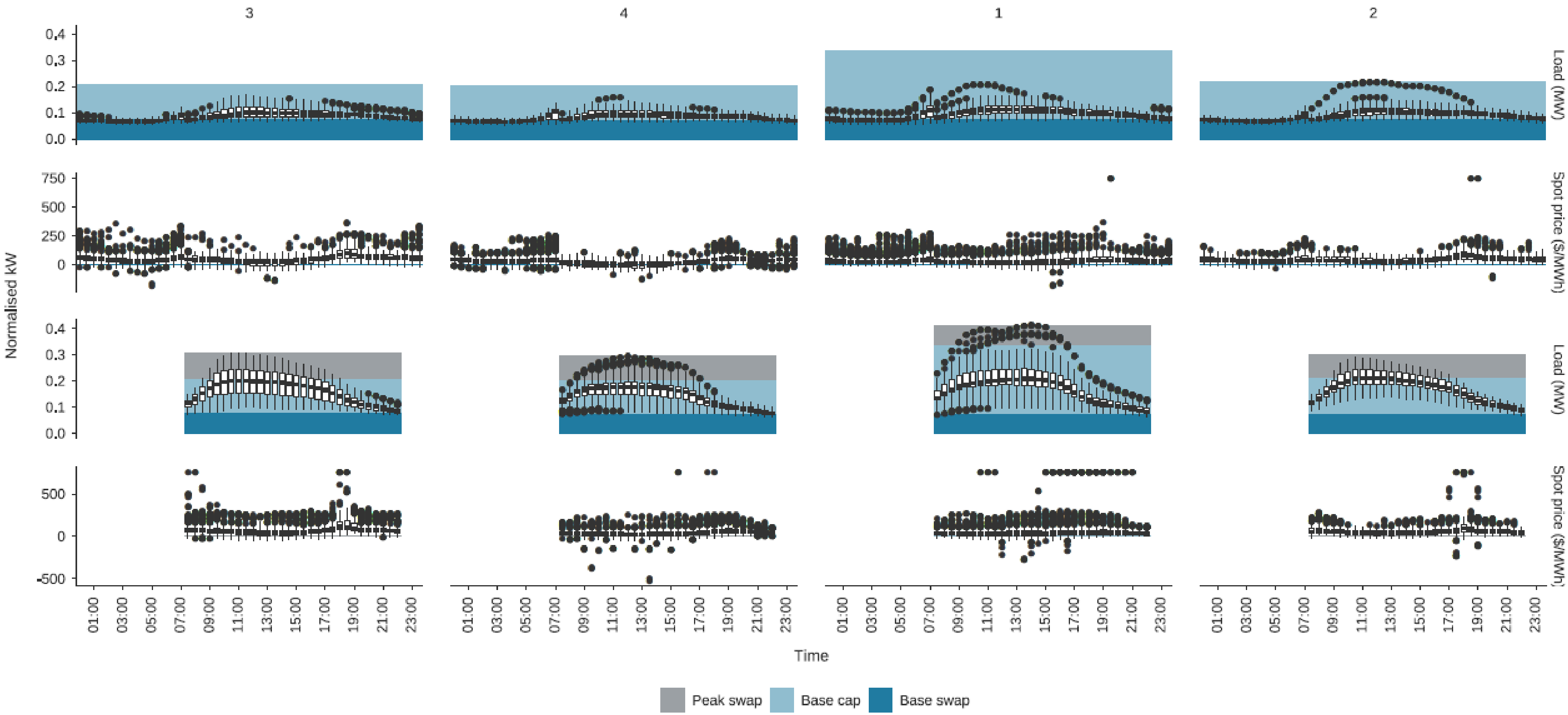
Note: Spot price chart truncated at a spot price of $300/MWh.

Figure 22: Contract position for United residential load, ASXEnergy contract prices



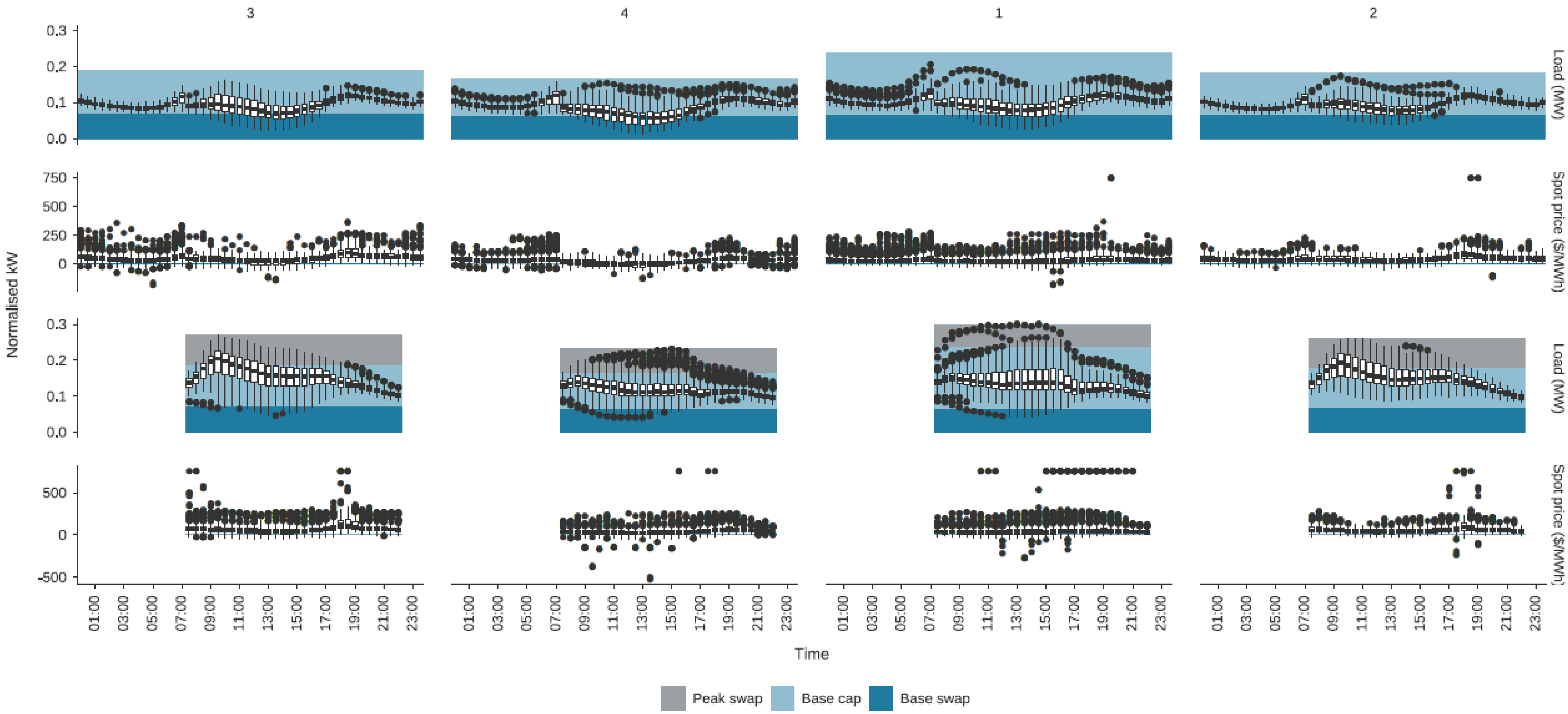
Note: Spot price chart truncated at a spot price of $300/MWh.

Figure 23: Contract position for CitiPower business load, ASXEnergy contract prices



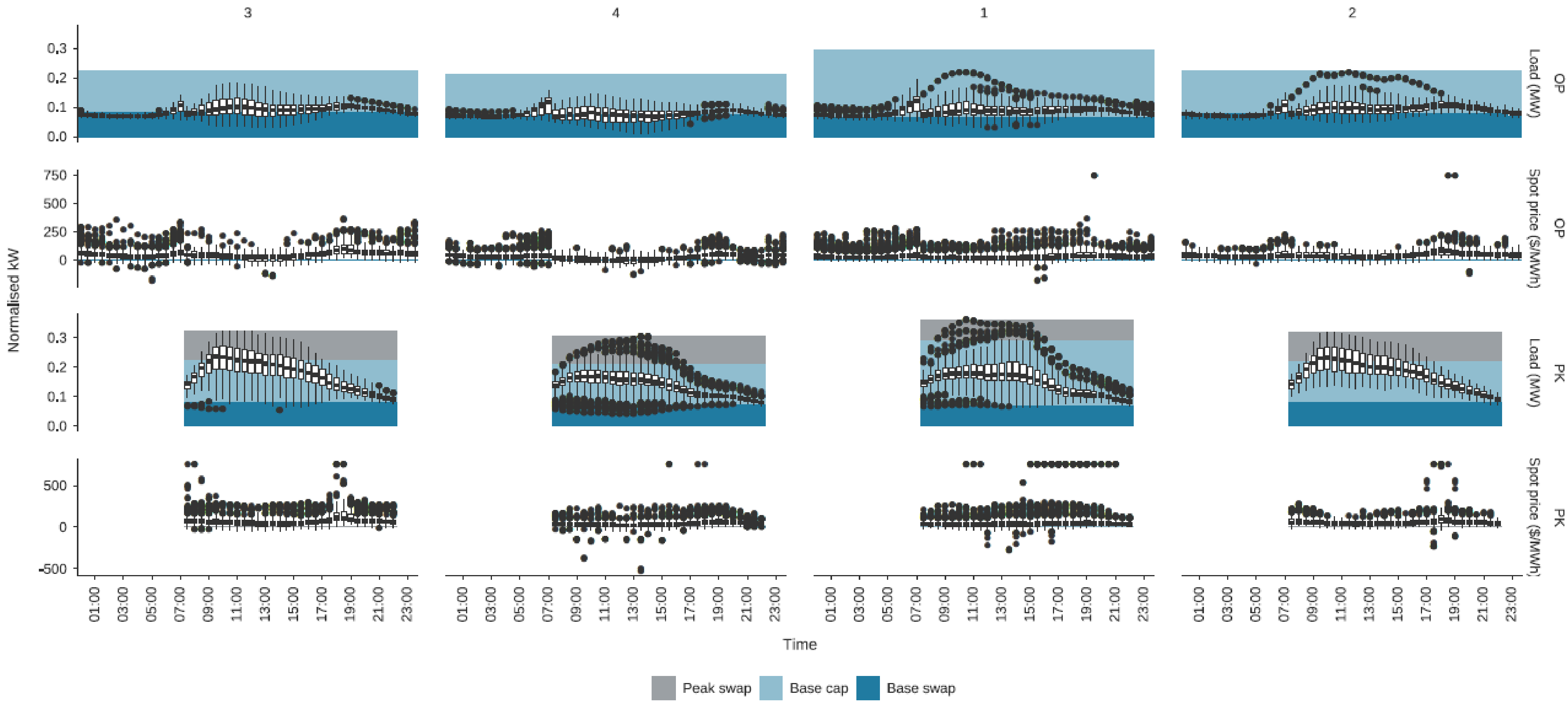
Note: Spot price chart truncated at a spot price of $300/MWh.

Figure 24: Contract position for Powercor business load, ASXEnergy contract prices



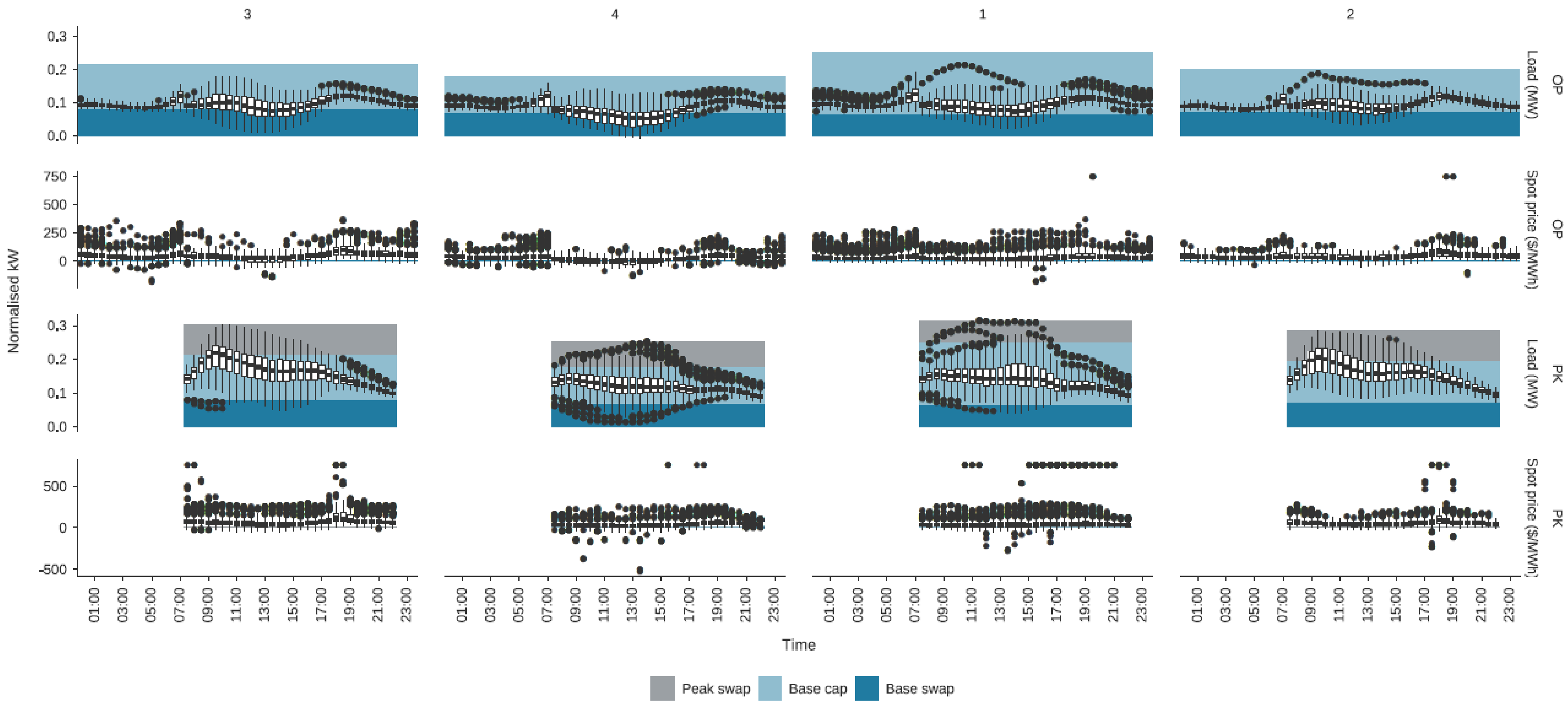
Note: Spot price chart truncated at a spot price of $300/MWh.

Figure 25: Contract position for Jemena business load, ASXEnergy contract prices



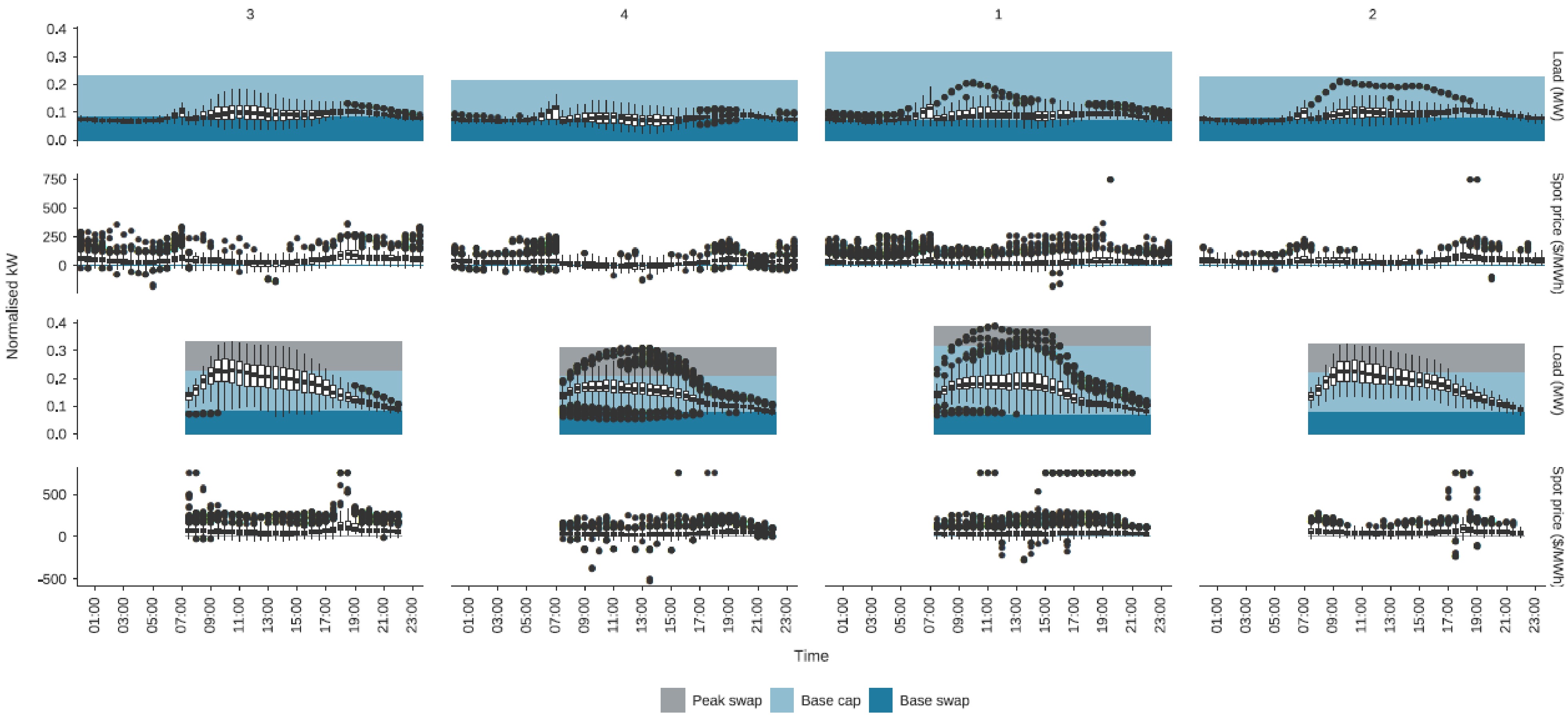
Note: Spot price chart truncated at a spot price of $300/MWh.

Figure 26: Contract position for AusNet business load, ASXEnergy contract prices



Note: Spot price chart truncated at a spot price of $300/MWh.

Figure 27: Contract position for United business load, ASXEnergy contract prices



Note: Spot price chart truncated at a spot price of $300/MWh.

6 Wholesale electricity costs

Based on the data discussed in Section 3 through Section 5, this section reports the WEC that we have estimated.

6.1 Wholesale electricity costs

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.

Results

The WECs that we have estimated are based on half-hourly spot prices and load from the median simulated year (when these years are ranked according to WEC). The WECs that we have estimated are based on 12-month trade weighted average ASXEnergy contract prices up to 28 January 2022. The WECs that we have estimated are based on the contract position from the conservative point on the efficient frontier for each DNSP.

These WECs are set out in **Table 2**.

Table 2: Modelled market-based wholesale electricity cost result

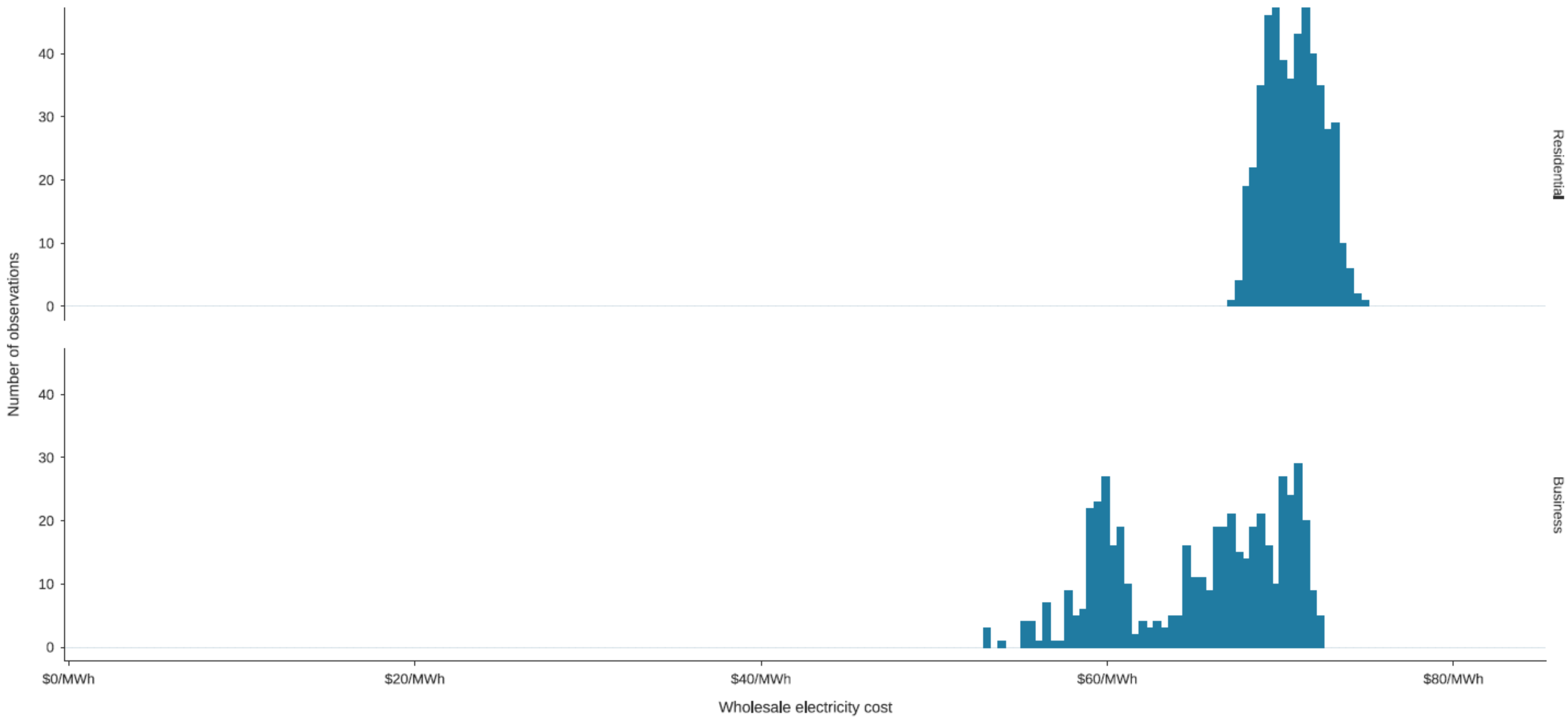
Entity	Wholesale electricity costs ($/MWh, real $2022/23)	
	Residential	Business
AusNet	$76.81	$64.87
CitiPower	$70.64	$66.54
Jemena	$77.59	$65.70
Powercor	$75.07	$63.68
United	$76.90	$66.55

Source: Frontier Economics

Figure 28 through **Figure 32** show the distribution of WEC for each customer type and for each DNSP area across the full set of 500 simulated years from our Monte Carlo analysis. For each of these 500 simulated years we use the same contract prices and the same contract position; all that changes between these 500 simulated years is the half-hourly profile of prices and the half-hourly load profile. Since each of these WECs is based on a hedged position, they are more concentrated than the load weighted prices.

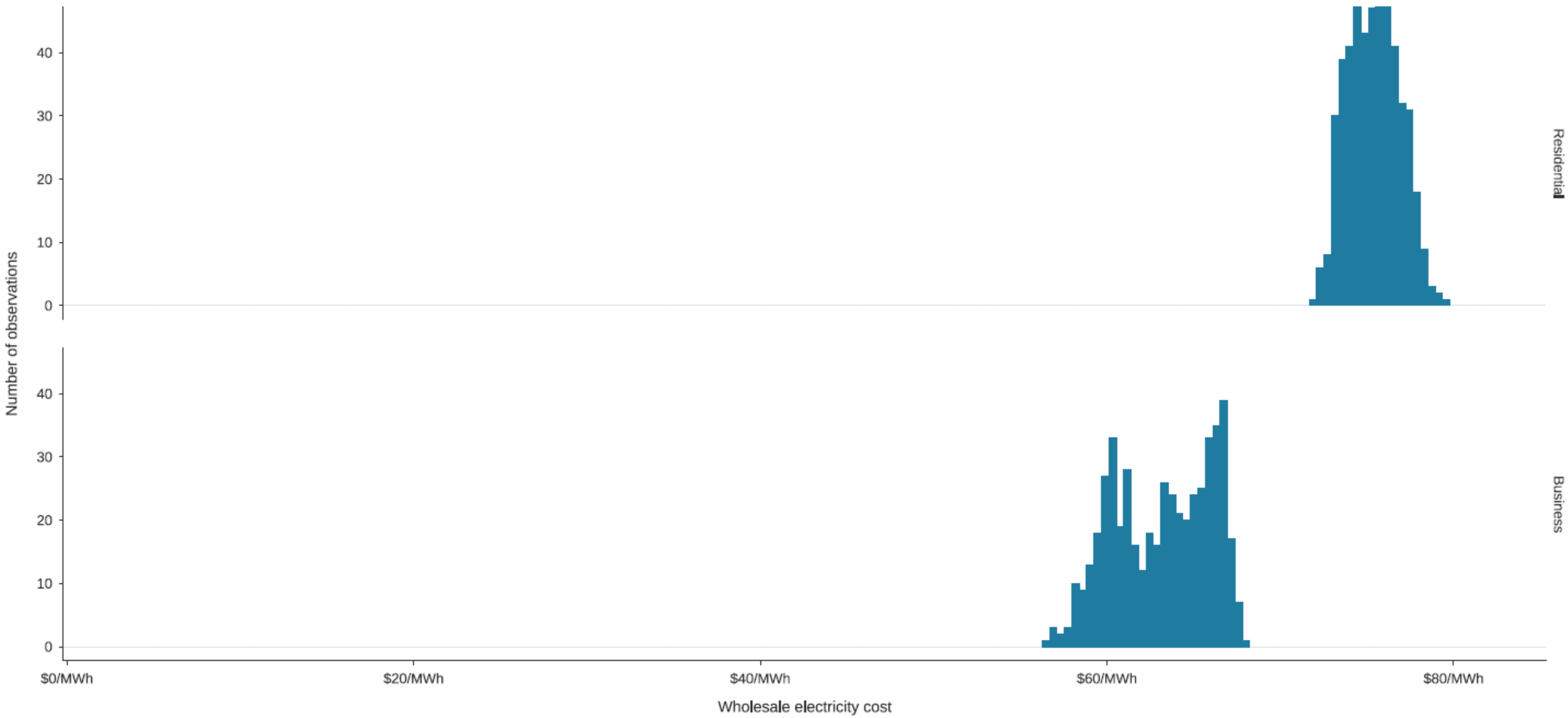
We note that these distributions do not reflect the distribution of all possible outcomes that retailers could face. If patterns of spot prices or load are materially different from the historical period on which we based our Monte Carlo analysis, or if average spot prices were too much different from suggested by current ASXEnergy contract prices, the wholesale energy cost could fall outside the range implied by these distributions.

Figure 28: CitiPower load wholesale electricity cost distribution



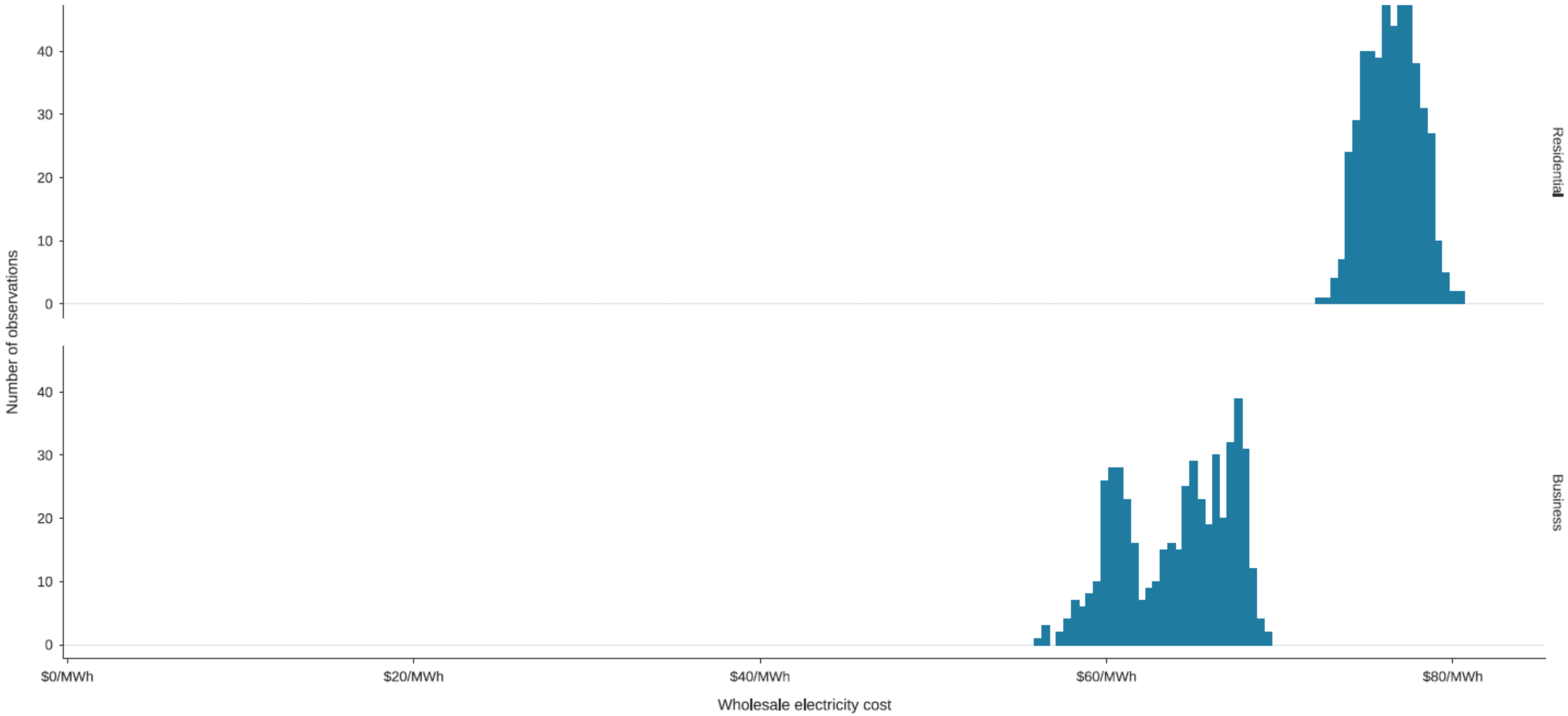
Source: Frontier Economics

Figure 29: Powercor load wholesale electricity cost distribution



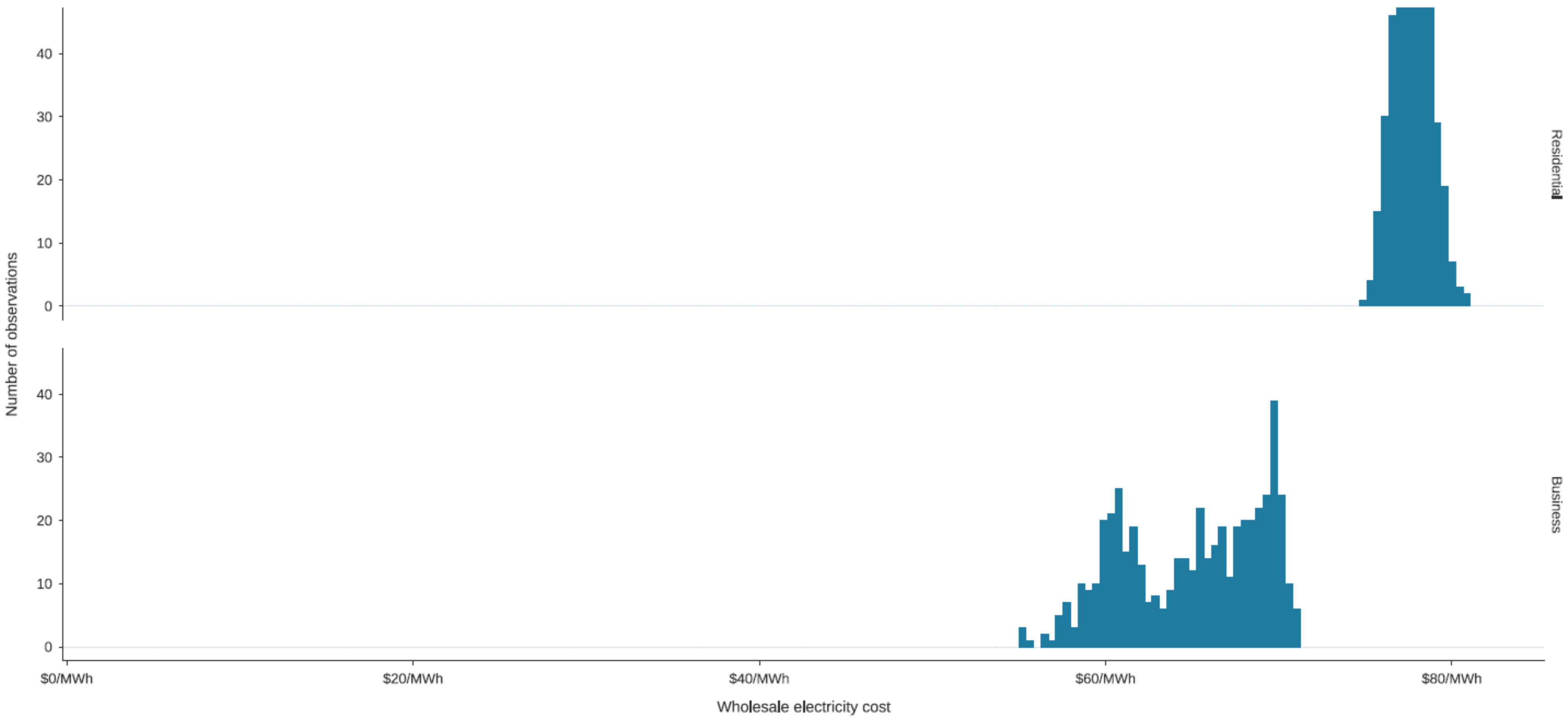
Source: Frontier Economics

Figure 30: AusNet load wholesale electricity cost distribution



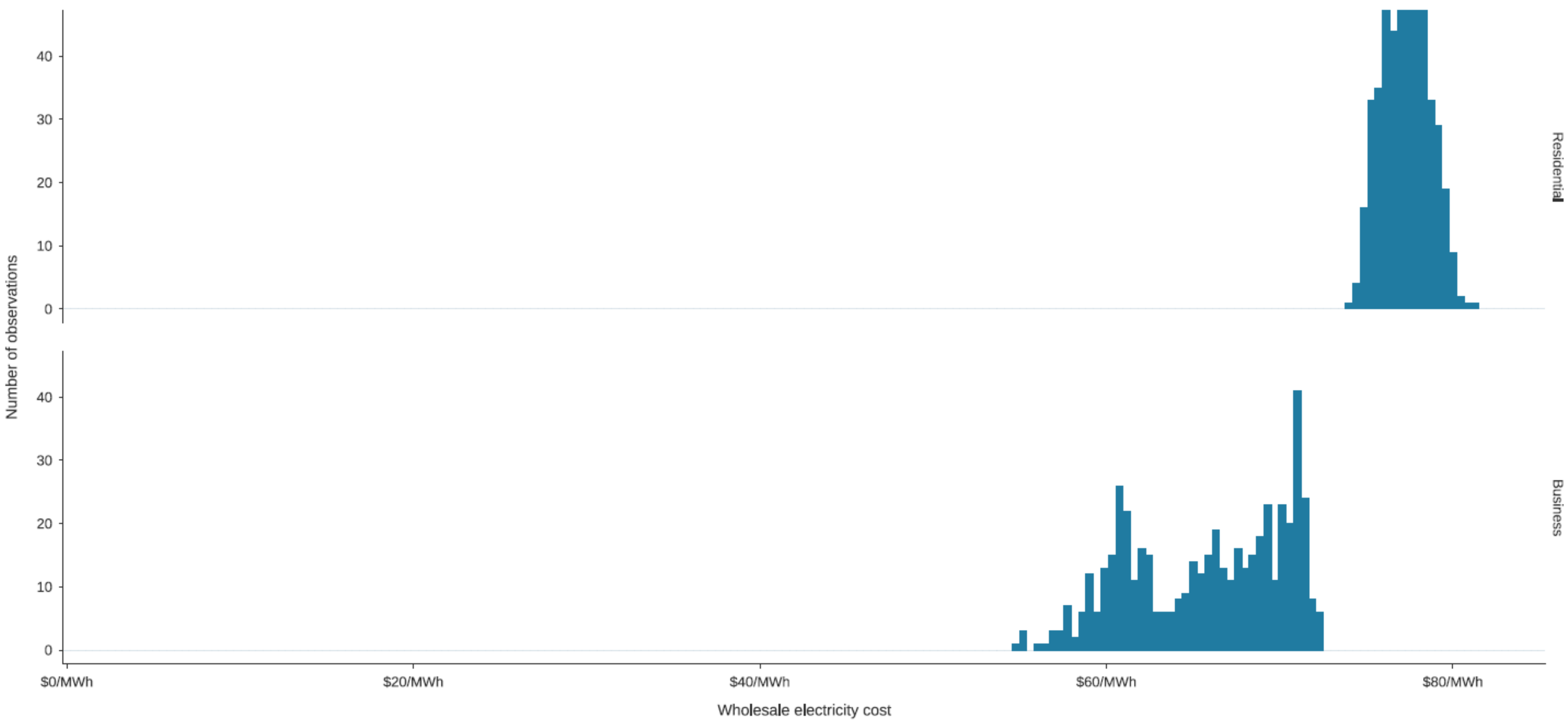
Source: Frontier Economics

Figure 31: Jemena load wholesale electricity cost distribution



Source: Frontier Economics

Figure 32: United load wholesale electricity cost distribution



Source: Frontier Economics

6.2 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 for each distribution area. We then estimate the cost of holding sufficient working capital by applying a WACC of 7.5 per cent.

The volatility allowances calculated using this framework are set out in **Table 3**.

Table 3: Modelled volatility allowance

Entity	Volatility Allowance ($/MWh real $2022/23)	
	Residential	Business
AusNet	$0.27	$0.32
CitiPower	$0.31	$0.44
Jemena	$0.25	$0.41
Powercor	$0.32	$0.31
United	$0.31	$0.45

Source: Frontier Economics

7 LRET and SRES

In addition to estimating the WEC, our scope of work also includes estimating the costs that a retailer will face as a result of the following schemes:

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

This section reports our estimate of these costs.

7.1 LRET

The LRET places a legal liability on wholesale purchasers of electricity to proportionately contribute towards the generation of additional renewable electricity from large-scale generators. Liable entities support additional renewable generation through the purchase of Large-scale Generation Certificates (LGCs). The number of LGCs to be purchased by liable entities each year is determined by the Renewable Power Percentage (RPP), which is set each year by the Clean Energy Regulator. LGCs are created by eligible generation from renewable energy power stations.

In order to calculate the cost to a retailer of complying with the LRET, it is necessary to determine the RPP for the retailer (which determines the number of LGCs that must be purchased) and the cost of obtaining each LGC.

Renewable Power Percentage

The RPP establishes the rate of liability under the LRET and is used by liable entities to determine how many LGCs they need to surrender to discharge their liability each year.

The RPP is set to achieve the renewable energy targets specified in the legislation. The Clean Energy Regulator is responsible for setting the RPP for each year.

The *Renewable Energy (Electricity) Act 2000* states that where the RPP for a year has not been determined it should be calculated as the RPP for the previous year multiplied by the required GWh’s of renewable energy for the current year divided by the required GWh’s of renewable energy for the previous year. This calculation increases the RPP in line with increases in the renewable energy target but does not decrease the RPP to account for any growth in demand. As a result, this calculation is likely to overestimate the RPP for a given year when energy demand is growing.

The Clean Energy Regulator has published a RPP for 2022 of 18.64%. Using this 2022 RPP, and applying the default calculation, results in the same RPP for 2023 of 18.64%, and an estimated RPP for 2022/23 that is also 18.64%.

Cost of obtaining LGCs

The cost to a retailer of obtaining LGCs can be determined either on the basis of the resource costs associated with creating LGCs, or on the basis of the market price at which LGCs are traded.

For this report, we have used a market price for LGCs to determine the cost of complying with the LRET. The market price for LGCs is determined by taking a 12 month trade weighted average of LGC prices reported by Demand Manager.[5] This 12 month trade weighted average LGC price is $40.28 per certificate ($2022/23).

Cost of complying with the LRET

Based on the RPP and the LGC price discussed above, the cost of complying with the LRET is $7.51/MWh ($2022/23).

7.2 SRES

The SRES places a legal liability on wholesale purchasers of electricity to proportionately contribute towards the costs of creating small-scale technology certificates (STCs). The number of STCs to be purchased by liable entities each year is determined by the Small-scale Technology Percentage (STP), which is set each year by the Clean Energy Regulator. STCs are created by eligible small-scale installations based on the amount of renewable electricity produced or non-renewable energy displaced by the installation.

Liable entities can purchase STCs on the open market or through the STC Clearing House. There is a guaranteed price of $40/STC through the Clearing House, but certificates may take some time to clear, delaying payment to sellers of STCs.

In order to calculate the cost to a retailer of complying with the SRES, it is necessary to determine the STP for the retailers (which determines the number of STCs that must be purchased) and the cost of obtaining each STC.

Small-scale Technology Percentage

The STP establishes the rate of liability under the SRES and is used to determine the number of STCs that liable entities are required to surrender each year. The STP is determined by the Clean Energy Regulator.

The STP is calculated in advance based on:

- the estimated number of STCs that will be created for the year[6]
- the estimated amount of electricity that will be acquired for the year
- the estimated number of all partial exemptions expected to be claimed for the year

The STP is to be published for each compliance year by March 31 of that year. The Clean Energy Regulator is also required to publish a non-binding estimate of the STP for the two subsequent compliance years by March 31. The binding and non-binding STPs for 2022 and 2023 are set out in **Table 4**.

5 Available at: http://www.demandmanager.com.au/. Accessed 8th October 2021

6 This is determined by the Clean Energy Regulator. In recent years it has estimated it based on the simple average of STC forecasts made by consultants to the Clean Energy Regulator.

Table 4: STPs published by the Clean Energy Regulator in 2021

Binding/Non-binding	Estimate/Forecast year	STP
Binding	2022	27.26%
Non-binding	2023	22.34%

Source: Clean Energy Regulator

Cost of obtaining STCs

For the purposes of this report, we assume that the cost of STCs is equal to this STC Clearing House price of $40/STC ($2022/23).

Historically, the reported spot price of STCs has typically been at, or close to, this price of $40/STC.

Cost of complying with the SRES

Based on the STC price discussed above, and the average of the binding 2022 STP and non-binding 2023 STP, the cost of complying with the SRES in 2022/23 is $9.92/MWh ($2022/23).

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