WHOLESALE ELECTRICITY COSTS

A REPORT FOR THE ESSENTIAL SERVICES COMMISSION

24 APRIL 2019

CONTENTS

Tables

Figures

1 INTRODUCTION

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

1.1 Background

On 18 December 2018 the ESC received a terms of reference requesting that it develop a methodology and recommend a VDO that will be available to residential and small business electricity customers from 1 July 2019. The VDO will:

- be available from 1 July 2019
- be offered unconditionally by all licensed retailers to small customers
- be the price that a retailer can charge under the VDO arrangements
- be established as the basis for retail discounts
- adopt the terms and conditions for standing offers
- be based on current marketing standard and approaches.

A VDO price will be set for each distribution zone and be based on the efficient cost to run a retail business. The price will also include an allowance for a maximum retail profit margin and a modest allowance for customer acquisition and retention costs. The VDO will not include an allowance for headroom.

1.2 Frontier Economics' engagement

Frontier Economics has been engaged 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 2019, as well as the costs of complying with the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES).
- The retail cost and retail margin components of retailers' cost to supply small customers from 1 July 2019.

This report covers the WEC and the cost of complying with green schemes. We have provided a separate report that covers the retail cost and retail margin components.

1.3 This final report

This final report sets out our advice to the ESC on the WEC component of retailers' cost to supply, for retailers in each of the five Victorian distribution network areas. This final report also includes our advice on the cost of complying with the Large-Scale Renewable Energy Target (LRET) and the Small-Scale Renewable Energy Scheme (SRES).

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 assumed contract position.
- 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 a spreadsheet setting out details of half-hourly load and price forecasts, contract positions resulting from our modelling, and calculations for determining the WEC.

1.4 Changes since draft report

We have made a number of changes to our modelling since the release of our draft report as a result of the availability of new information. This includes:

- We have been provided with two years of half-hourly load data for both residential and business customers using less than 40MWh per annum. We have used this data to calculate the standalone wholesale electricity costs for both residential and business customers, instead of using the MRIM data which was used in the draft report.
- We have used more recent ASXEnergy contract prices and LRET certificate prices.
- We have used more recent estimates of the Renewable Power Percentage and Small-scale Technology Percentage.

We have also made some changes to our approach:

- We have calculated the cost of complying with the LRET based on a 12-month average of LRET certificate prices.
- We have calculated wholesale energy costs based on trade-weighted average prices rather than time-weighted average prices.

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, its customer's electricity load in that half-hour multiplied by the relevant regional reference price from the wholesale electricity spot market for that half hour. 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 half hour to the next, and electricity spot prices can be anywhere between the Market Price Cap (which is currently $14,500/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 a number of 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. The most common are 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.

Retailer's 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, it is clear that 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 retailer's 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 of 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:

- For prices, the half-hourly spot prices for Victoria at the regional reference node, as published by AEMO.
- For customer load, data that AEMO has 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 data for residential customers with annual consumption less than 40MWh and business customers with annual consumption less than 40MWh.

Consistent with submissions from a number of stakeholders, we use this newly available data from AEMO in place of the MRIM data that we used for the draft report. This newly available data from AEMO closely coincides with the customer groups to which the VDO will apply:

- For residential customers, the terms of reference provided to the ESC has stated that 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 terms of reference provided to the ESC has stated that 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 MRIM data that we used for the draft report 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. This newly available data from AEMO is also more recent than the MRIM data.

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 over time.

As discussed, since the draft report we have swapped from using the MRIM data to more granular data for residential and business customers using less than 40MWh per annum. This data is more recent, but also for a shorter period of time, containing data from financial year 2016/17 and 2017/18.

Ideally, we would have a longer time series of data. If the price and load data for this longer time series were deemed likely to be a reasonable indication of outcomes for the forecast period, then the longer series of data would likely include a broader range of potential market outcomes that could be captured in our Monte Carlo analysis. We note, however, that the analysis of a longer series of MRIM data in our draft report showed that most of the years since 2012/13 have had similar daily patterns of load and prices; this suggests to us that only using data from 2016/17 and 2017/18 is unlikely to impair the usefulness of the Monte Carlo analysis. And, in our view, the benefit of having more recent data, and load data that better matches the customers to which the VDO will apply, clearly suggests the more recent data from AEMO is preferable.

Since we only have access to two years of data from AEMO, both are included in the analysis. This is based on our conclusion that analysis of historical data does not provide a good reason to exclude either of the historical years.

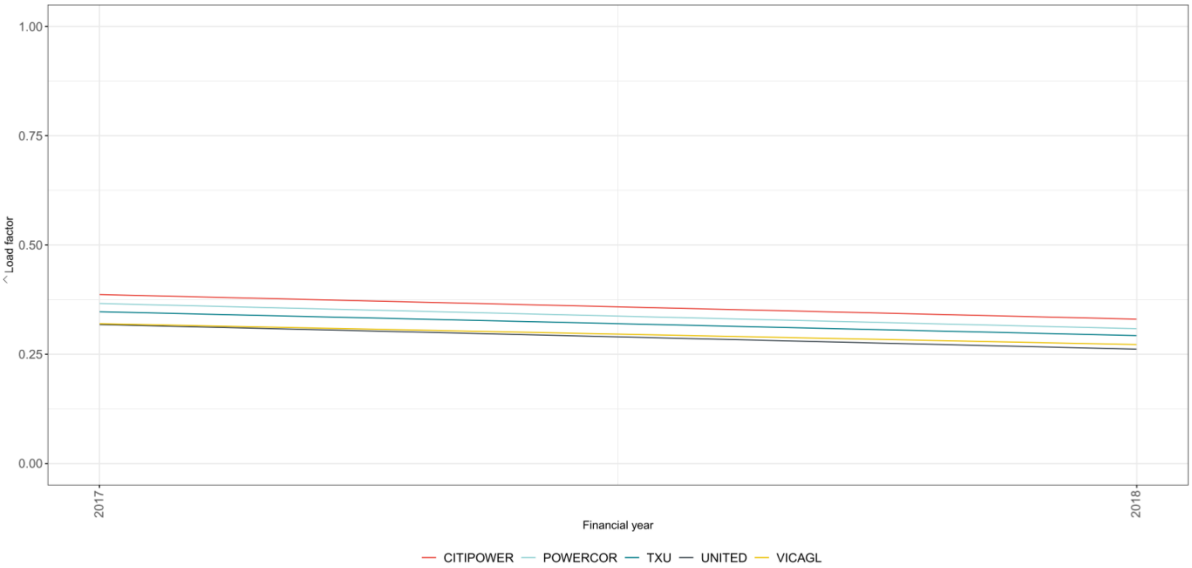
Figure 1 shows the annual load factor for the residential data for each Victorian DNSP for the last two financial years. We can see that there is a slight drop in load factor for every DNSP between 2017 and 2018.

Figure 2 shows the annual load factor for business data for each Victorian DNSP for the last two financial years. This shows that the load factor remained steady for most DNSPs between 2017 and 2018, with VicAGL[1] showing a slight increase.

Figure 3 and **Figure 4** show the average daily profile for residential and business data respectively for each Victorian DNSP for the last two financial years, normalised to the same annual consumption to highlight differences in the timing of daily consumption. These profiles are almost identical between years, with the only notable difference being a slight relative decrease in daytime consumption for business customers, particularly for Powercor, TXU and VicAGL.

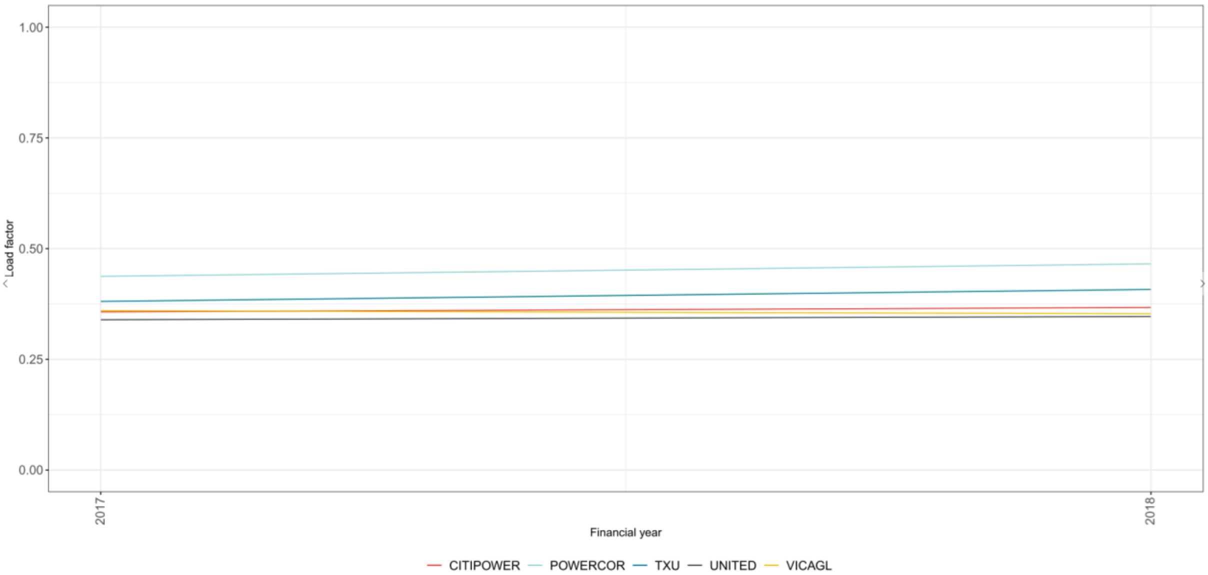
[1] To retain consistency with the draft report, this data refers to AusNet Services network as TXU and the Jemena Electricity Network as VicAGL.

Figure 1: Load factor for residential customers



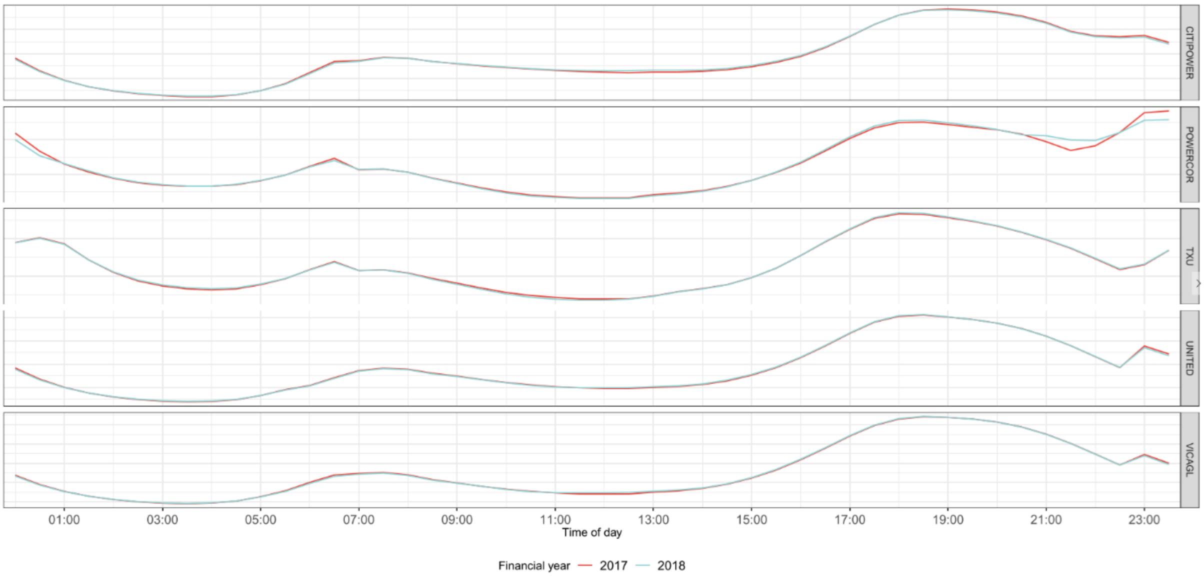
Source: Frontier Economics analysis of AEMO data

Figure 2: Load factor for business customers



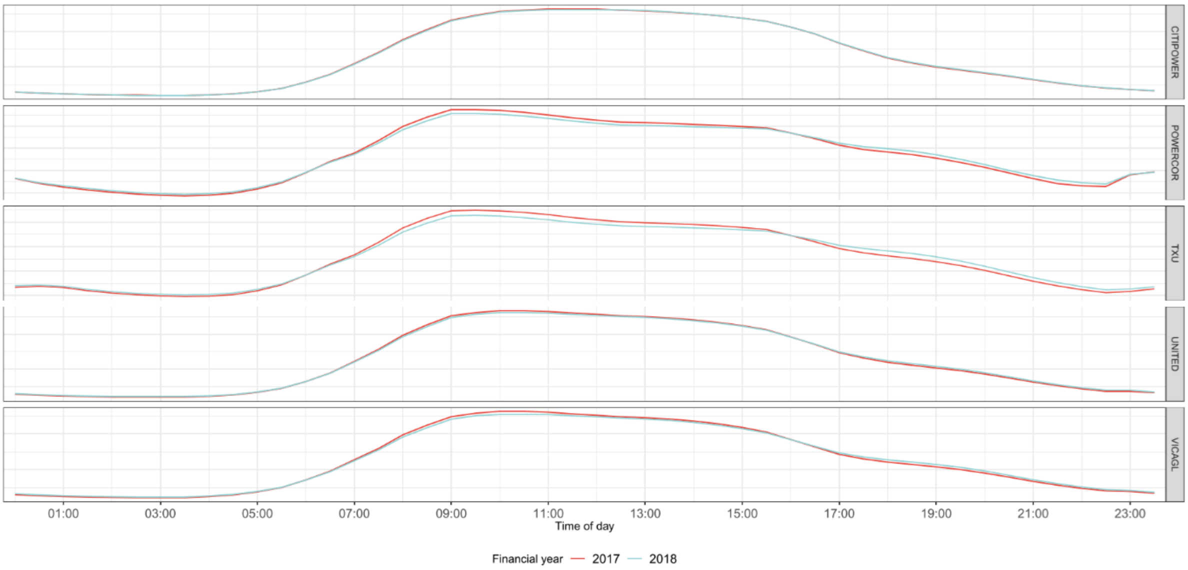
Source: Frontier Economics analysis of AEMO data

Figure 3: Average daily profile for residential customers



Source: Frontier Economics analysis of AEMO data

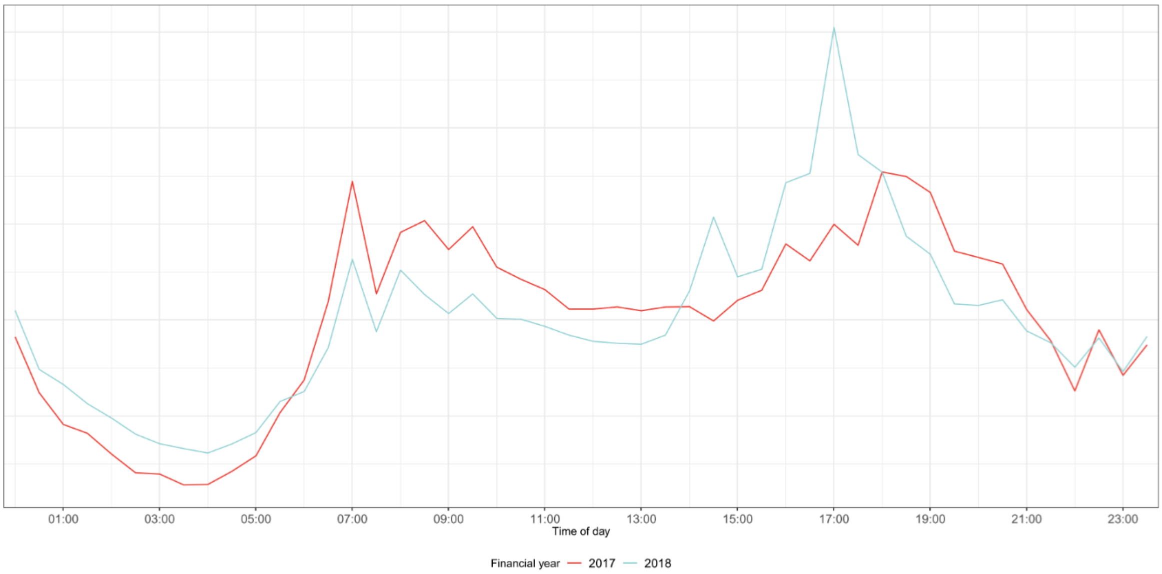
Figure 4: Average daily profile for business customers



Source: Frontier Economics analysis of AEMO data

Figure 5 shows the average daily profile for Victorian spot prices for the last two financial years. It is no surprise to see that there is greater volatility in daily patterns of spot prices than there is in daily patterns of customer load. Nevertheless, our view is that these patterns are sufficiently consistent for the two years that we would not rule out using either of these as the basis for forecasting future half-hourly spot prices. In each case we 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.

Figure 5: Average daily profile for Victorian spot prices

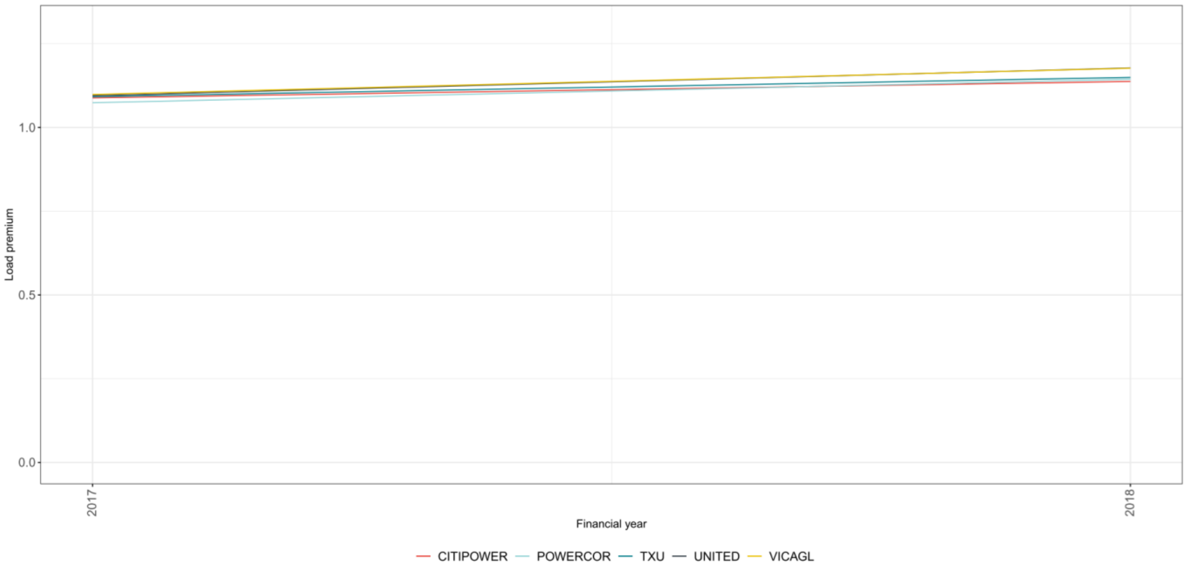


Source: Frontier Economics analysis of AEMO data

Figure 6 and **Figure 7** combine the historical customer load data and spot price data to report the load premium for each customer type and for each Victorian DNSP and for each of the last two financial years (calculated as the load-weighted price divided by the time-weighted price). 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** and **Figure 7** that the load premium over the last two financial years has been reasonably constant; it has increased a little for residential customers (presumably as a result of peakier residential consumption) but been relatively flat for business customers. On the whole we consider that half-hourly data for each of these last two financial years would provide a reasonable basis for forecasting half-hourly load and spot prices; in particular we note that the analysis of MRIM data for the draft report showed a drop in load premium for 2017, which might indicate that the increase for residential customers in 2018 is more of a return to longer-term average levels than a trend towards higher load premiums.

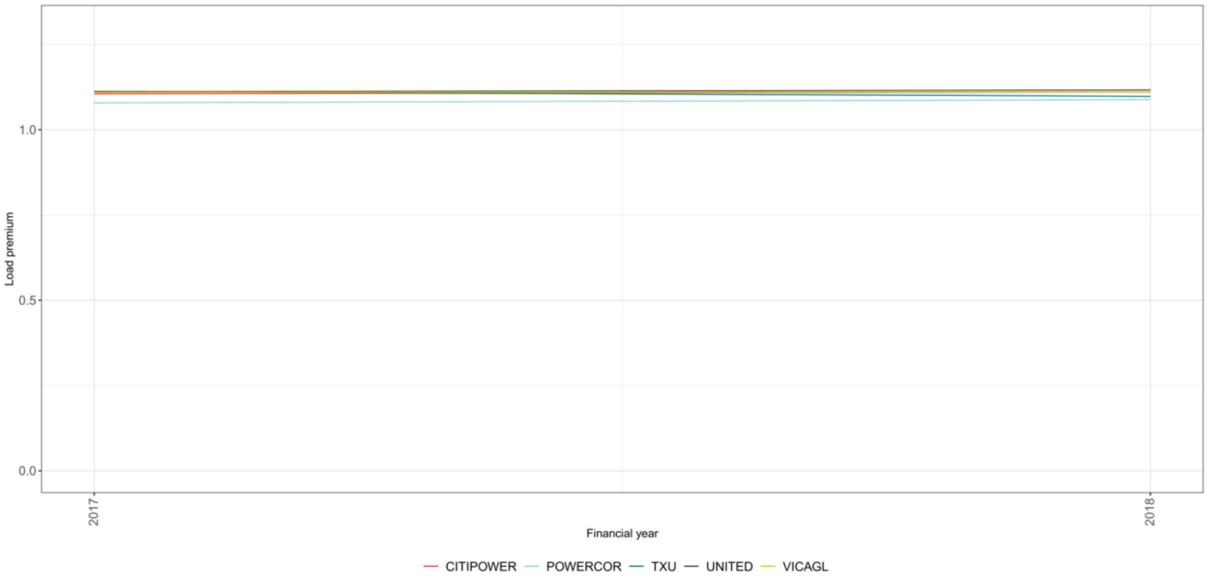
We do note that submissions from some stakeholders raised the prospect that load premiums are increasing, and pointed to the high price events in Q1 2019 as evidence of this. In our view it is impossible to say with any confidence whether the high price events in Q1 2019 are likely to be repeated in Q1 2020. However, we do note that to the extent that the market expects that the high price events in Q1 2019 are expected to be repeated in Q1 2020 this will be reflected in ASXEnergy contract prices for Q1 2020 and will result in a higher WEC estimate. We also note that while high price events are important to capture in our analysis, the contract position that we use (based on our *STRIKE* modelling) provides retailers with a substantial hedge to high price events.

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



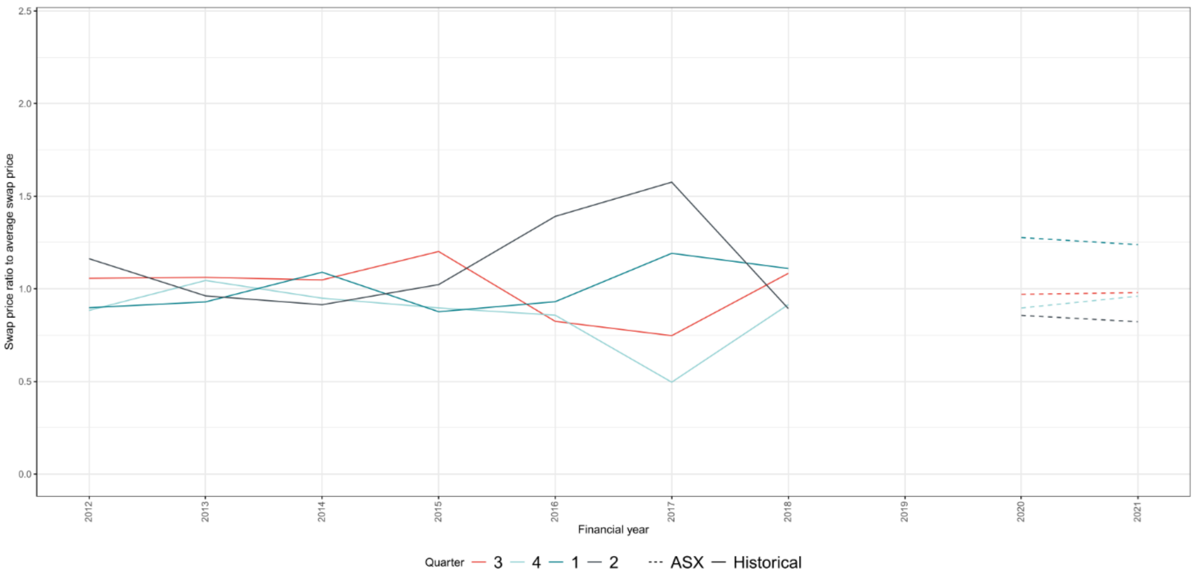
Source: Frontier Economics analysis of AEMO data

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 swaps prices for Victoria. **Figure 8** reveals quite a degree of volatility in the relationship between quarterly prices: average prices have tended to be highest in Q2 or Q3, but ASXEnergy prices are highest for Q1. Considering the two most recent years – 2016/17 and 2017/18 – it is clear that quarterly pricing patterns in 2016/17 were quite different from the market's expectations of patterns in 2019/20, but that quarterly pricing patterns in 2017/18 are much more consistent. To minimise any issues with using 2016/17 prices we scale historical half-hourly prices to ASXEnergy prices on a quarterly basis, so that the quarterly patterns of prices observed in the ASXEnergy data is also reflected in our forecast half-hourly prices. This is discussed in more detail in Section 3.3.

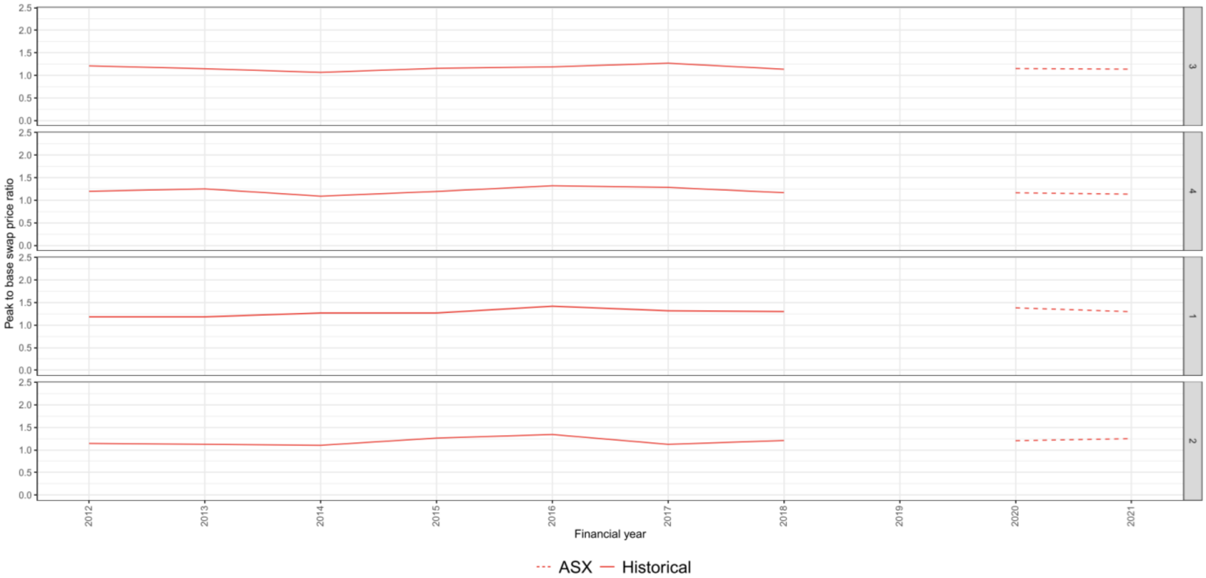
Figure 9 examines peak/off-peak patterns of spot prices and ASXEnergy prices. For each peak/off-peak period, **Figure 9** presents the relationship between average peak/off-peak prices and average annual prices: on an historical basis this relationship is based on historical Victorian spot prices; on a forecast basis this relationship is based on ASXEnergy base-load swaps prices for Victoria. **Figure 9** reveals that historically peak prices have tended to be higher than average and off-peak prices have tended to be lower than average (as would be expected) and that this pattern is also reflected in the ASXEnergy data.

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

3.3 Projecting half-hourly load and spot prices

Based on the analysis of historical data discussed above, we conclude that financial years 2016/17 and 2017/18 could reasonably be used as the basis for forecasting half-hourly load and half-hourly spot prices for 2019/20.

Rather than take a single one of these years as representative of outcomes in 2019/20, we perform a Monte Carlo simulation on the 2 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 may not be repeated, or may be 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 on 2 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 potential benefits of the Monte Carlo approach increase over time as a longer time series of load data becomes available to the ESC.

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 forecast 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 2019/20 is 1 July 2019, which is a Monday. Since this is a Monday in Q3, the half-hourly load and spot data for the first day of 2019/20 will determined by randomly drawing a day's half-hourly data from all the Q3 weekdays that occurred in 2016/17 and 2017/18.

- The second day of 2019/20 is 2 July 2019, which is a Tuesday. Since this is a Tuesday in Q3, the half-hourly load and spot data for the second day of 2019/20 will also be determined randomly drawing a day's half-hourly data from all the Q3 weekdays that occurred in 2016/17 and 2017/18.
- And so on for the 365 days that make up 2019/20, 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 2016/17 and 2017/18.

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 no further adjustments to the consumption data; we are implicitly assuming that there is no relevant trend to the half-hourly profile of the consumption data that would require an adjustment of the historical data before it could be used as a forecast for load in 2019/20.

However, we do 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 July 2016 to 30 June 2017 will, on average, be the same as Victorian spot prices for 2019/20. In our view, the best available public information about the average level of Victorian spot prices for 2019/20 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 2019/20. 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 2019/20 from ASXEnergy[2] (less an assumed contract premium of 5 per cent on the underlying prices)[3]. We use the 40-day average of ASXEnergy contract prices for quarterly base swap prices (up to 5 April 2019) as representing the market's current view of spot prices for each quarter of 2019/20.[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).

[2] 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.

[3] The contract premium cannot be directly observed, since it is the difference between an *expectation* at a point in time of future spot prices (which cannot be observed) and the observed forward contract prices at that point in time. However, by comparing data on out-turn spot prices and observed forward contract prices, an indication of the contract premium can be inferred. There will be significant volatility in this observed data point, because unexpected changes in market conditions will affect out-turn spot prices but not observed forward contract prices. Nevertheless, if this comparison is made over enough observations, an estimate of the contract premium can be developed. We have undertaken this analysis for the full set of data since the commencement of trade on ASXEnergy; based on that analysis, we consider that an assumption of a contract premium of 5% is reasonable.

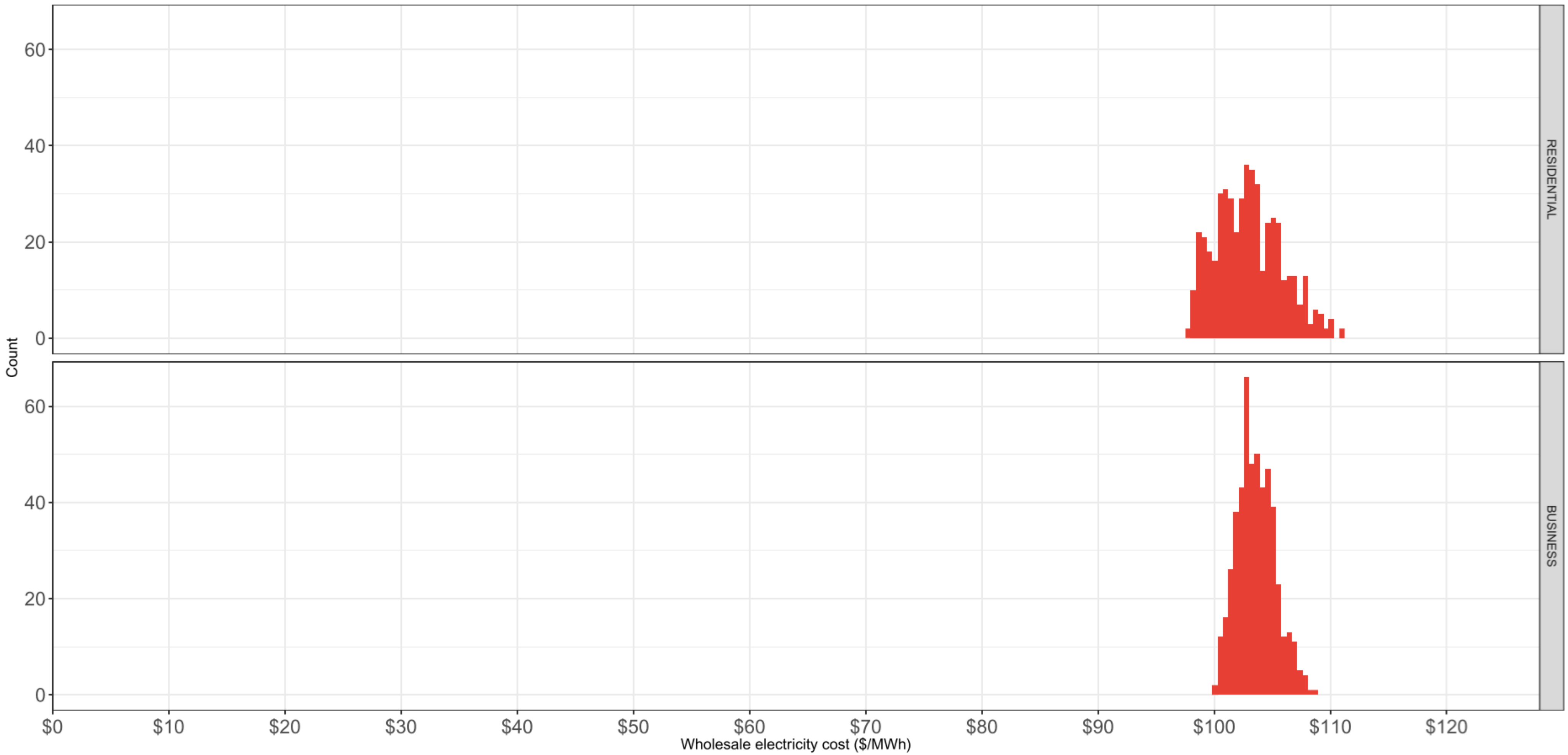
[4] We note that there is a difference in the averaging period that we use for estimating spot prices for 2019/20 and the averaging period we use for calculating contract prices to be used in estimating the WEC for the VDO. As discussed, we use the most recent 40-day average ASXEnergy prices as the best guide to the market's view on spot prices that will occur in 2019/20. However, based on advice 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 2019/20 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.

- The appropriate *half-hourly profile* of spot prices (i.e. the half-hourly profile of prices, and load, are consistent with historical outcomes).

An indication of the results of this 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 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.

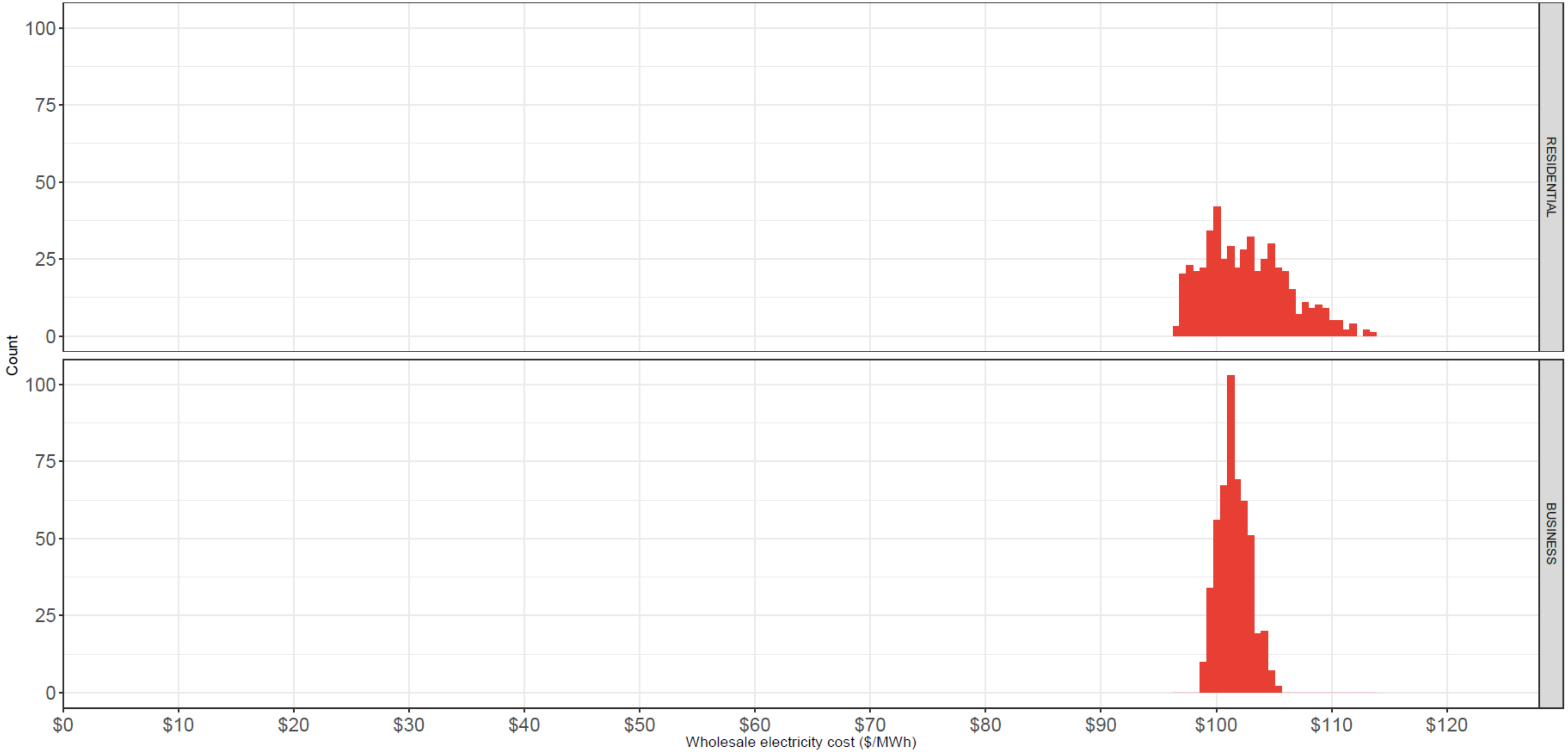
Submissions from some stakeholders have raised the point that this Monte Carlo process is not transparent. We acknowledge that we have not released the Monte Carlo model that generates prices and load for simulated years based on historical data. However, we consider that the process is reasonably transparent: the sequence of half-hourly prices and load that we use to calculate the WEC are simply a random sequence of days drawn from 2016/17 and 2017/18, with prices scaled to match the ASX forward curve, using the process we described above. We have not forecast load or prices, but merely drawn from recent history. Furthermore, as well as the summary data on load-weighted prices that are presented in **Figure 10** through **Figure 14**, we have released a spreadsheet for each distribution area that contains the full set of half-hourly load and price data for the median simulated year that we have used to calculated the WEC.

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



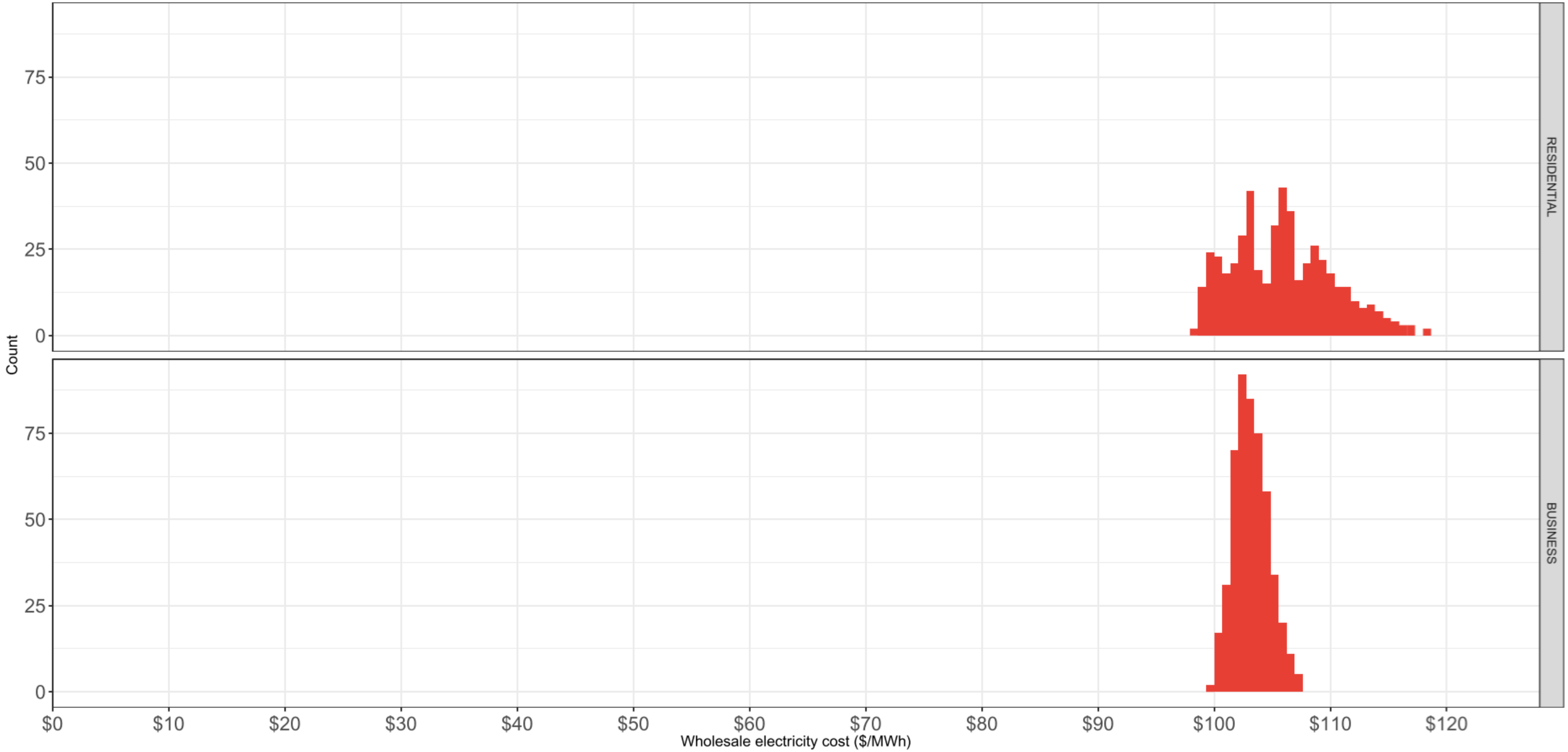
Source: Frontier Economics

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



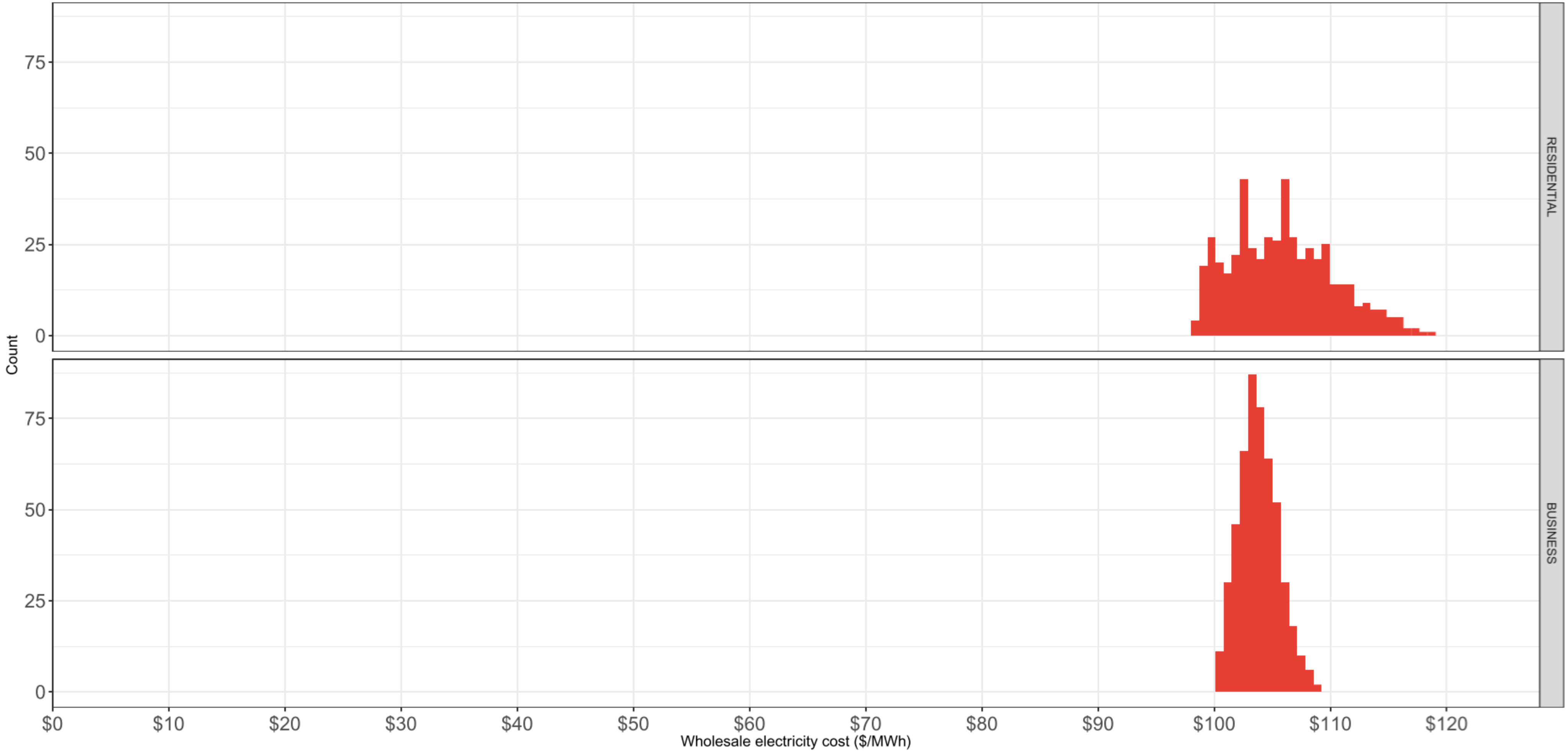
Source: Frontier Economics

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



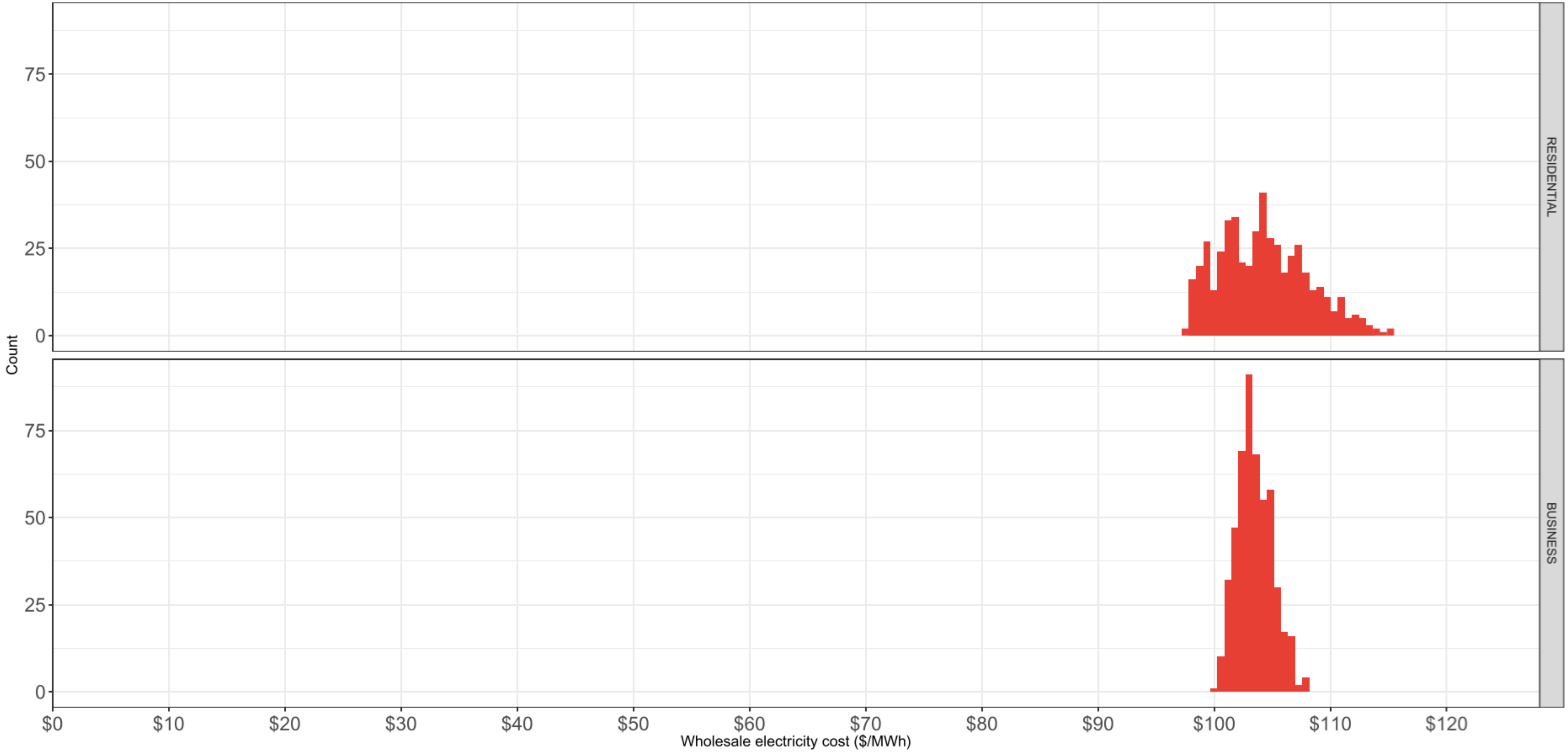
Source: Frontier Economics

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



Source: Frontier Economics

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



Source: Frontier Economics

4 CONTRACT PRICES

This section addresses the third question we need to answer to estimate 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 a number of years in advance. Prices are published by ASXEnergy for each contract for each trading day.

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 most contracts for financial year 2019/20 are currently trading regularly. In particular, we can see that trade in base swaps and caps is occurring on most trading days. This suggests that the daily prices for base swaps and caps does provide a genuine indication of the market's view of future prices. However, trade in peak swaps is a lot lower than base swaps and caps, which raises the prospect that the available prices for peak swaps for financial year 2019/20 may not represent the market's current view of likely price outcomes for 2020. While there is some risk to this, we would note that the relative level of peak swap prices, compared to base swap prices, is consistent with what we would generally expect. We also note that peak swaps generally form part of our estimate of an efficient portfolio of contracts, and excluding these from the analysis risks understating the costs that retailers face in hedging the higher load that they tend to face during peak periods.

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 are 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. We have not changed our view on this: we believe that market forces will result in retailer's pricing decisions being based on the current value of contracts in a competitive market.

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 retailers' actual historical costs (since most retailers will buy contracts over a number of years leading up to the 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 5 April 2019.

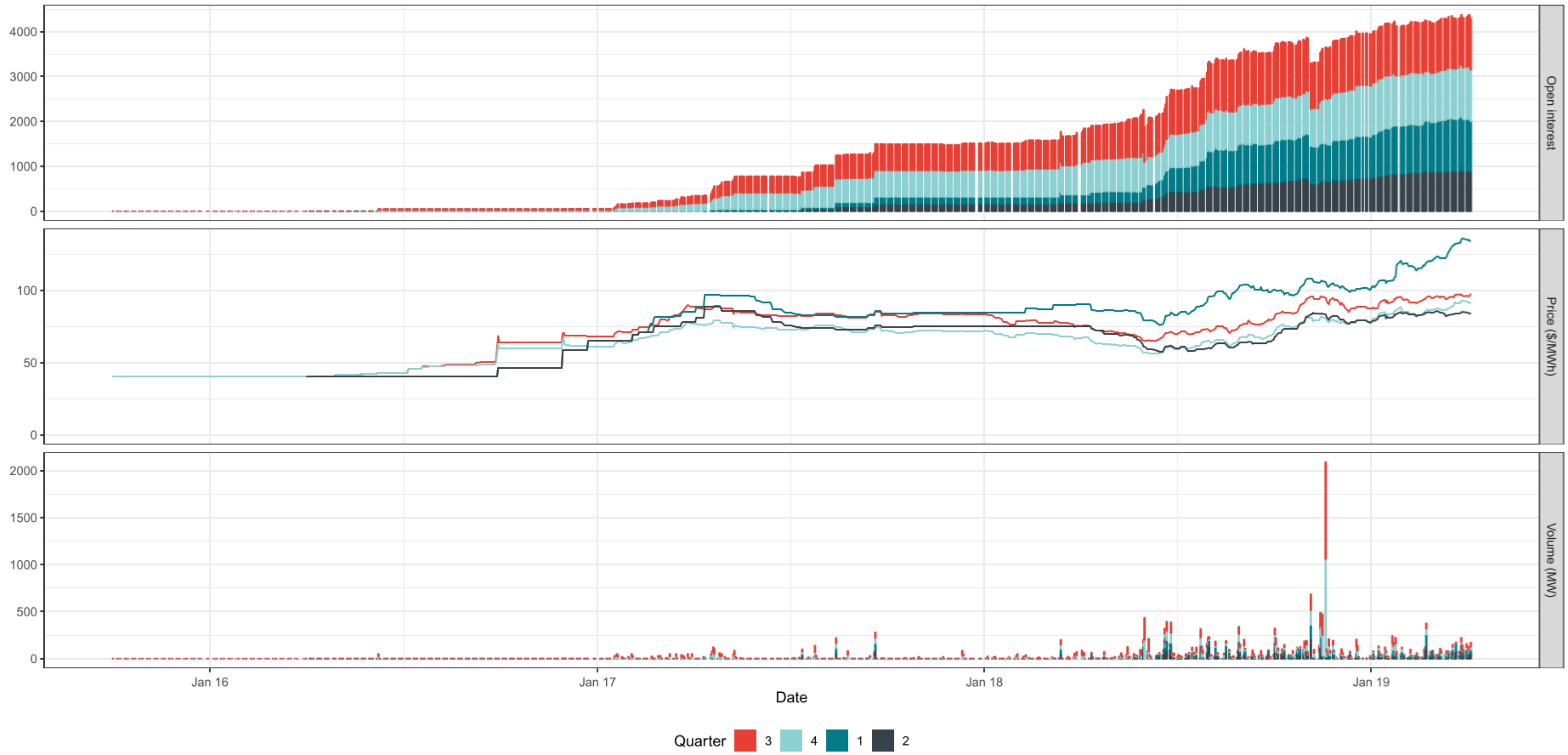
Table 1: 12-month trade weighted average ASXEnergy derivative prices for Victoria

	PRODUCT	STATUS	FINANCIAL YEAR	QUARTER			
				Q3	Q4	Q1	Q2
TRADE WEIGHTED	$300 Caps	Base	2020	$3.35	$5.51	$28.99	$3.57
	Swaps	Base	2020	$84.42	$74.55	$104.54	$73.16
	Swaps[5]	Peak	2020	$101.08	$88.46	$151.59	$96.42

Source: Frontier Economics analysis of ASXEnergy data

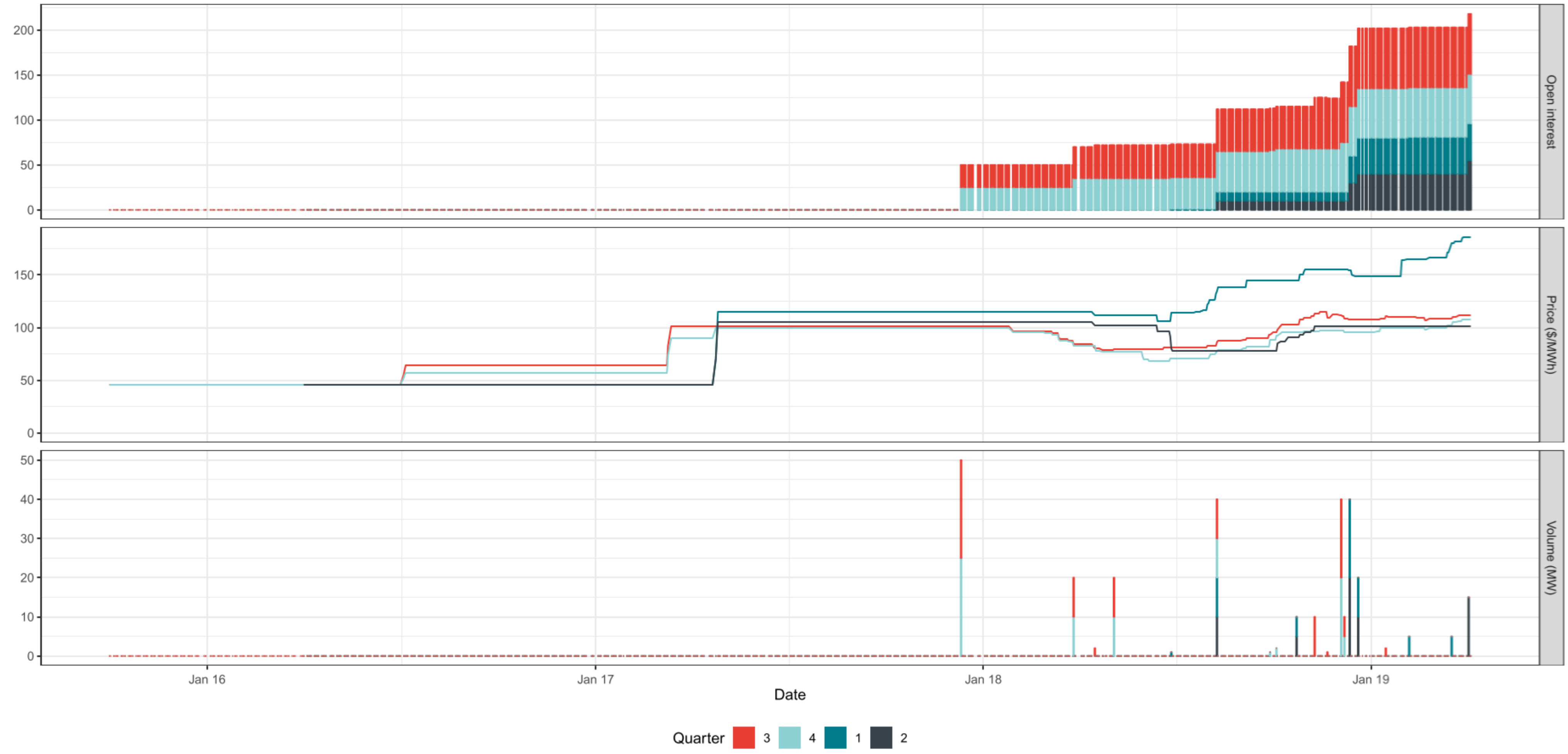
5 No peak swaps have been traded over the past 40 days

Figure 15: Victorian base swaps – open interest, prices and volumes for financial year 2020



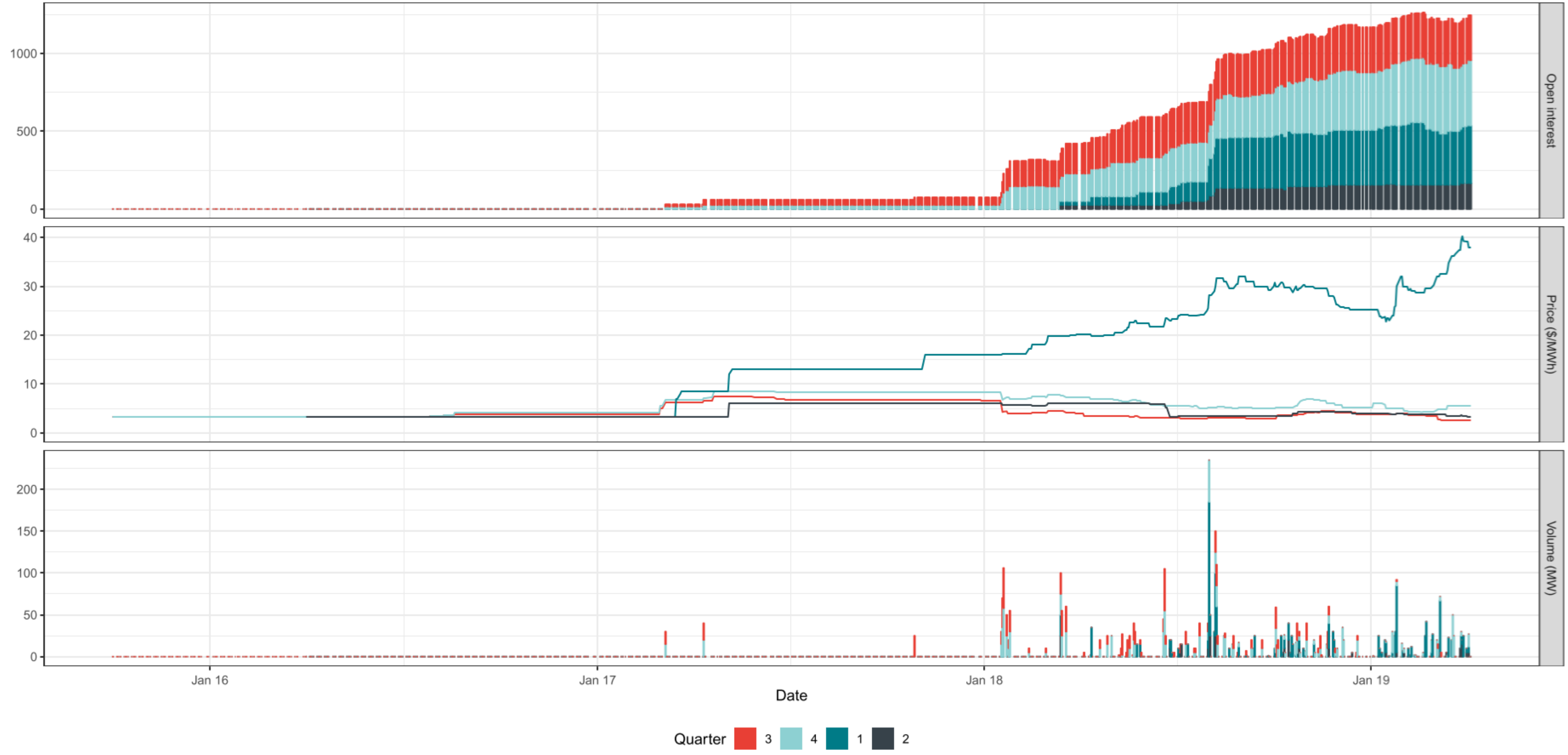
Source: Frontier Economics analysis of ASX data

Figure 16: Victorian peak swaps – open interest, prices and volumes for financial year 2020



Source: Frontier Economics analysis of ASX data

Figure 17: Victorian base $300 caps – open interest, prices and volumes for financial year 2020



Source: Frontier Economics analysis of ASX data

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 2019/20. 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 2019/20 will be; will 2019/20 be a year with high prices and high load corresponding, so that the load-weighted price is high, or will 2019/20 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 2019/20, for each load profile 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 in the 'Load/Contract Level' panel).

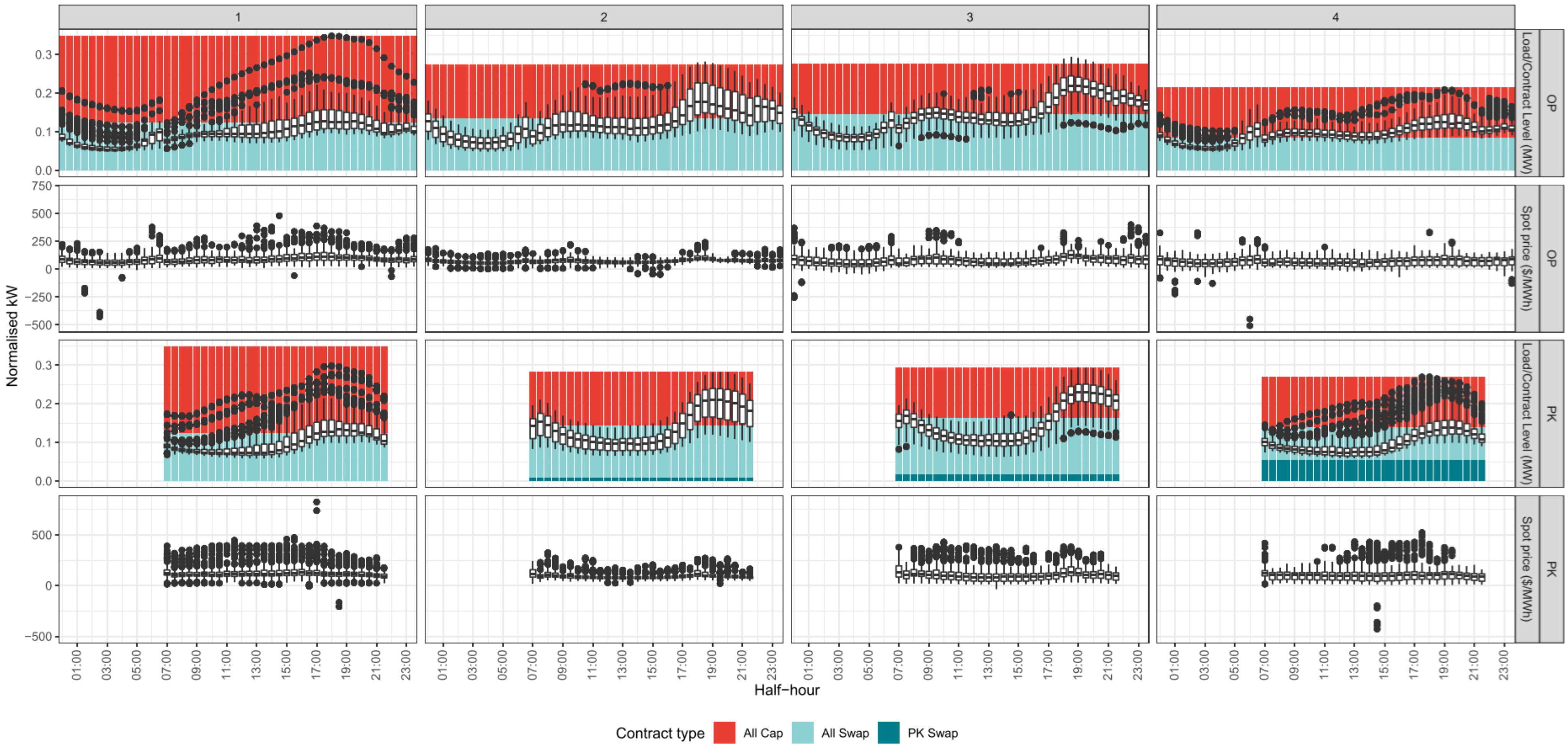
- The distribution of half-hourly spot prices for the 48 half-hours of the day (shown by the box plots in the 'Spot price' panel). The price chart is truncated at a spot price of $750/MWh.

- The quantity of swaps (dark and light teal bars) and caps (red bars) at the conservative point.

In general the contract position at the conservative point involves:

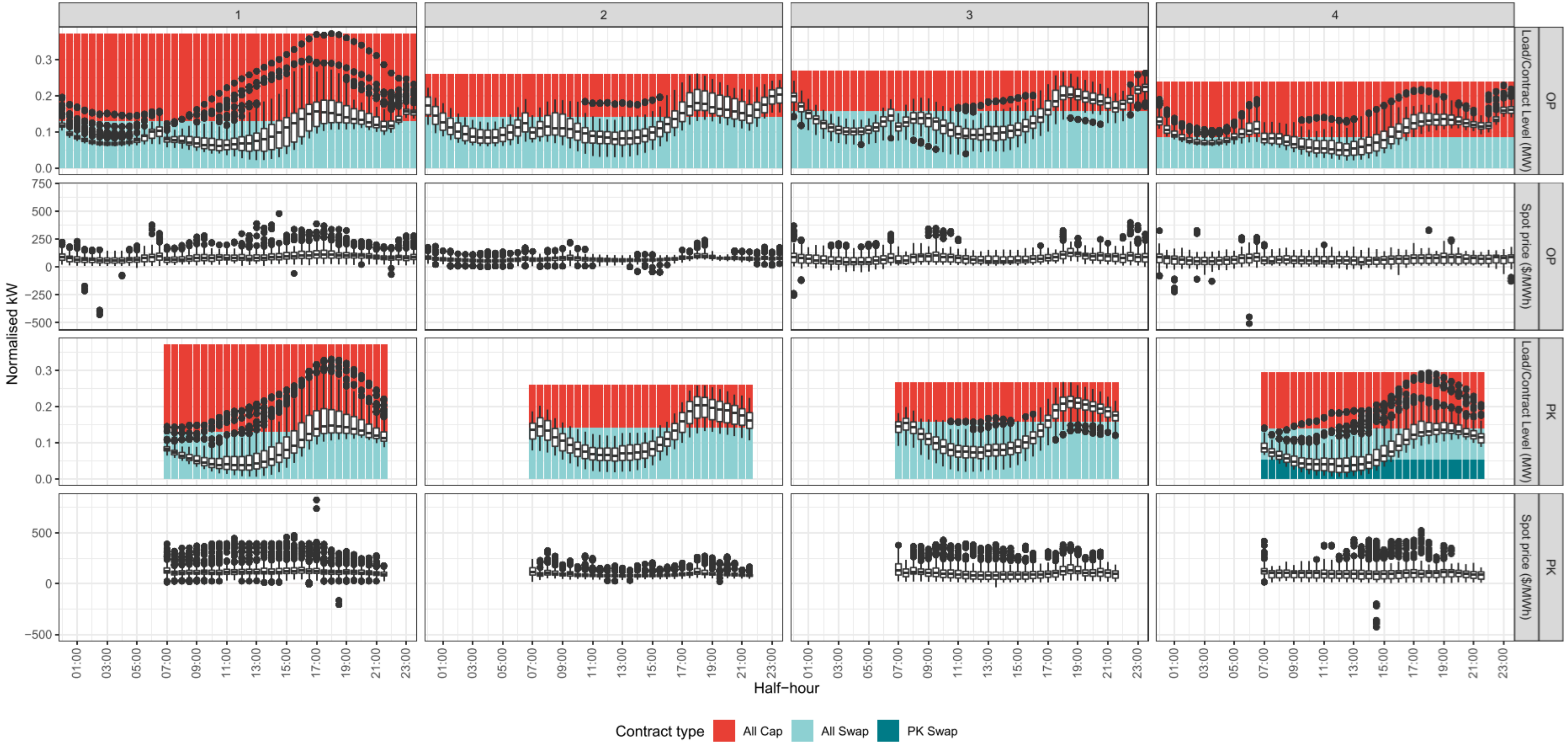
- purchasing swaps to cover (approximately) average demand
- purchasing caps, on top of that, to cover (approximately) to peak demand
- in some cases, incurring a small amount of pool exposure at absolute peak demand times.

Figure 18: Contract position for CitiPower residential load, ASXEnergy contract prices, 2019 (FY2020 dollars)



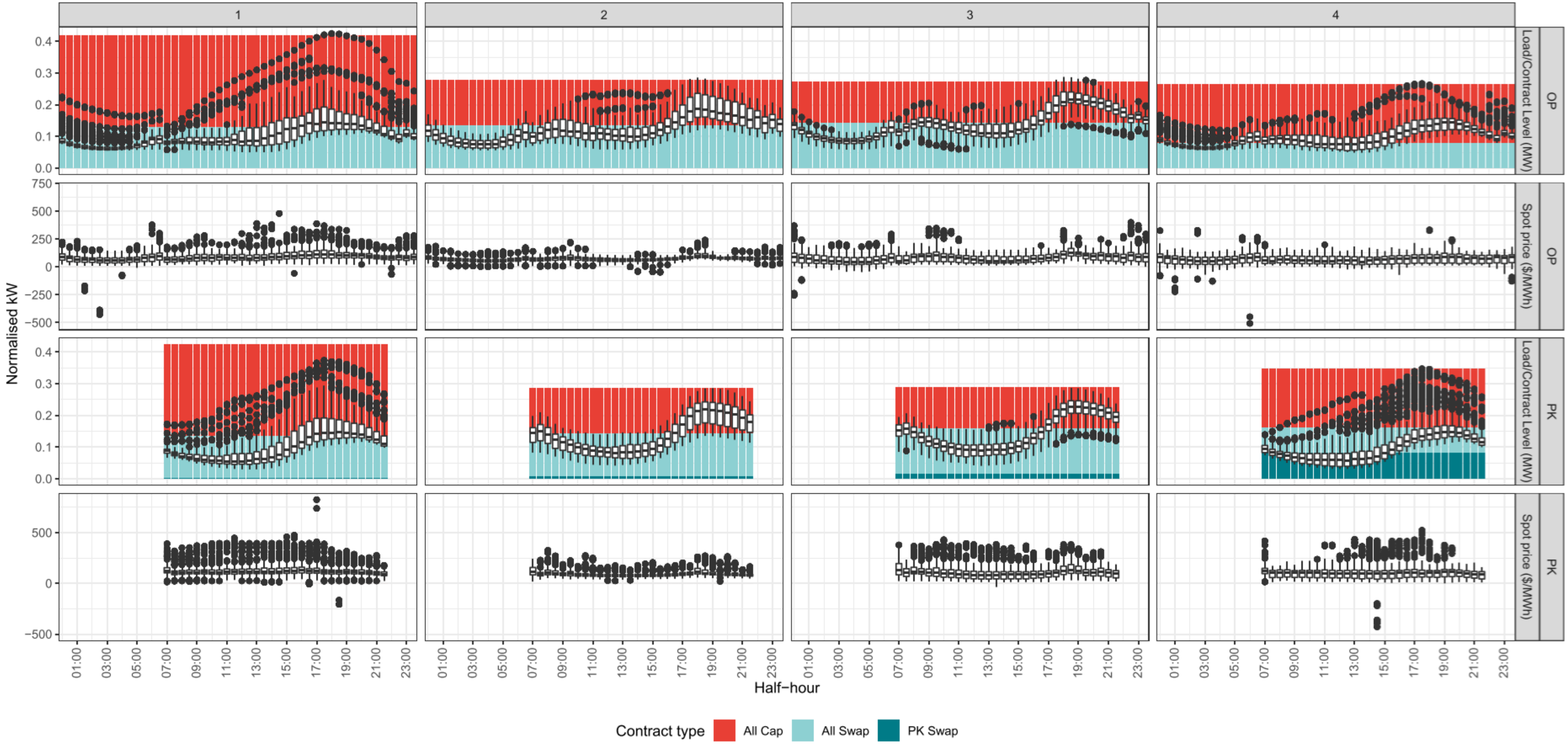
Note: Spot price chart truncated at a spot price of $750/MWh.

Figure 19: Contract position for Powercor residential load, ASXEnergy contract prices, 2019 (FY2020 dollars)



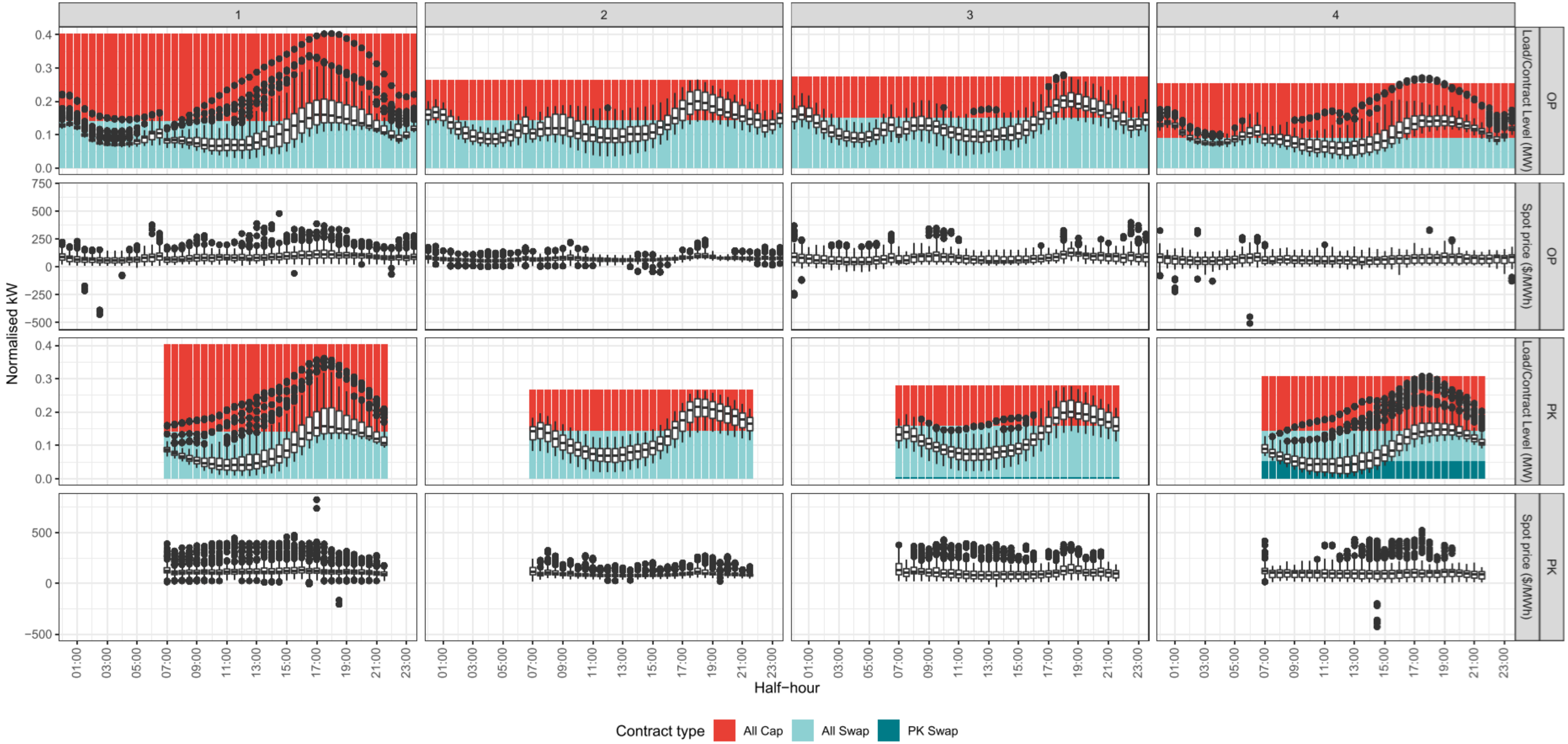
Note: Spot price chart truncated at a spot price of $750/MWh.

Figure 20: Contract position for VicAGL residential load, ASXEnergy contract prices, 2019 (FY2020 dollars)



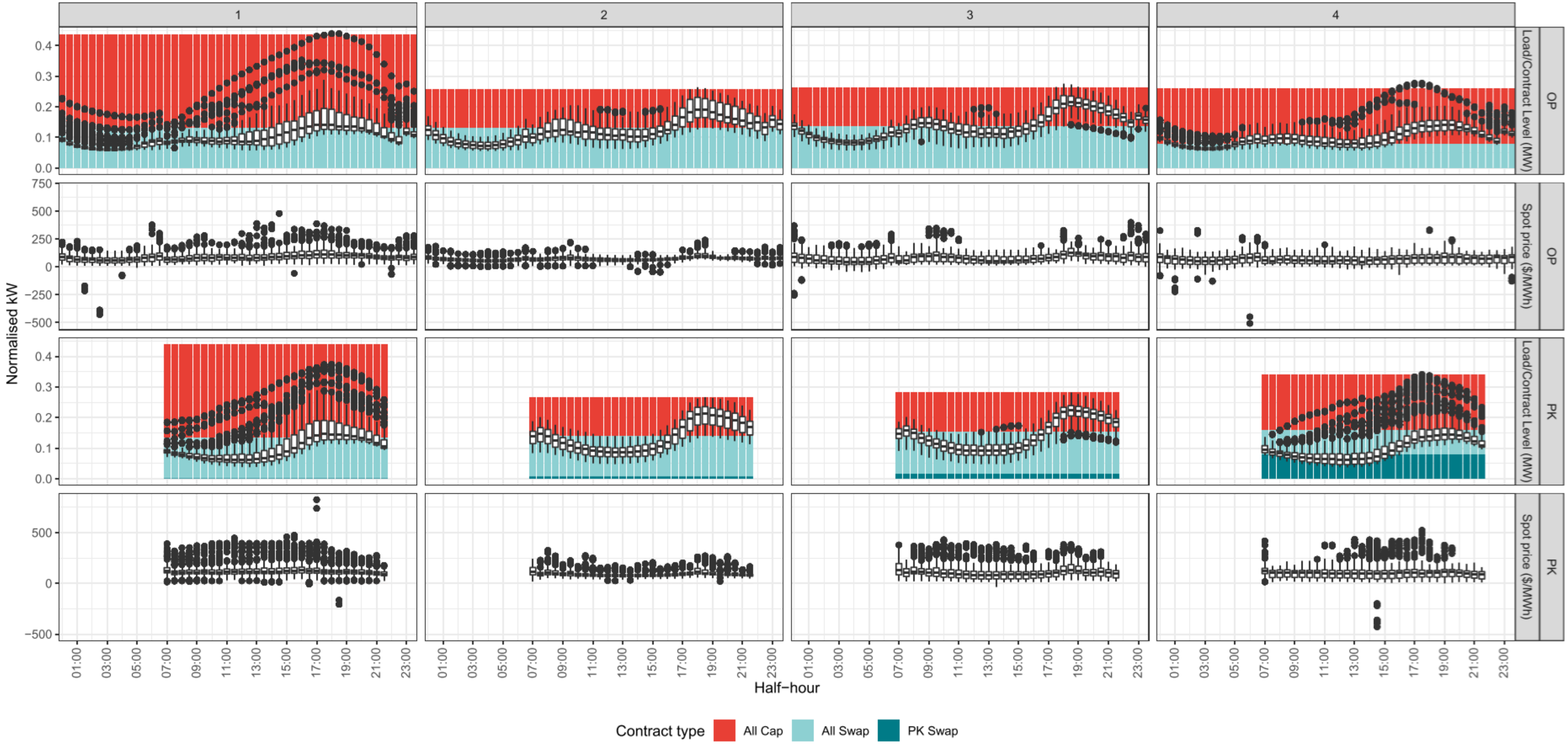
Note: Spot price chart truncated at a spot price of $750/MWh.

Figure 21: Contract position for TXU residential load, ASXEnergy contract prices, 2019 (FY2020l dollars)



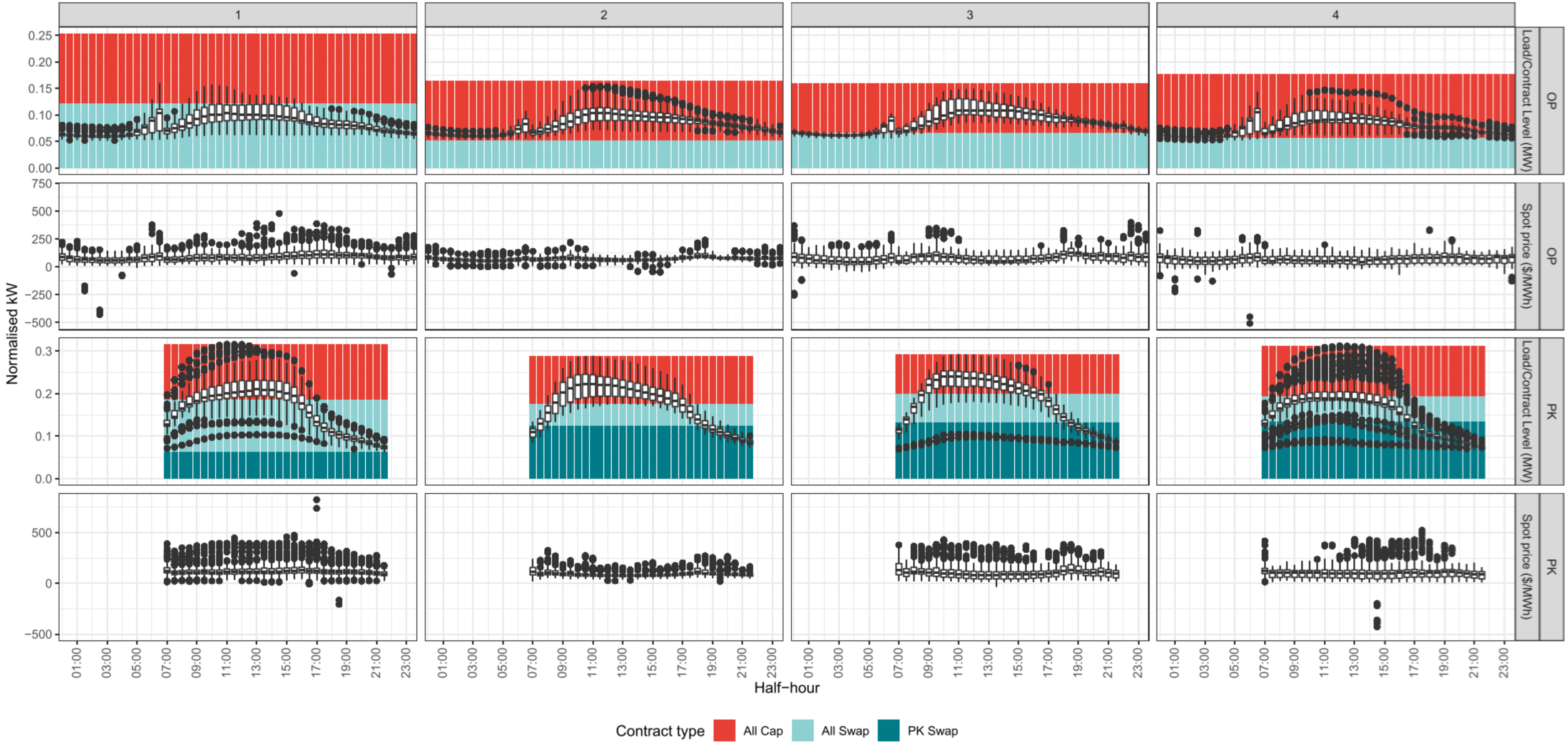
Note: Spot price chart truncated at a spot price of $750/MWh.

Figure 22: Contract position for United residential load, ASXEnergy contract prices, 2019 (FY2020 dollars)



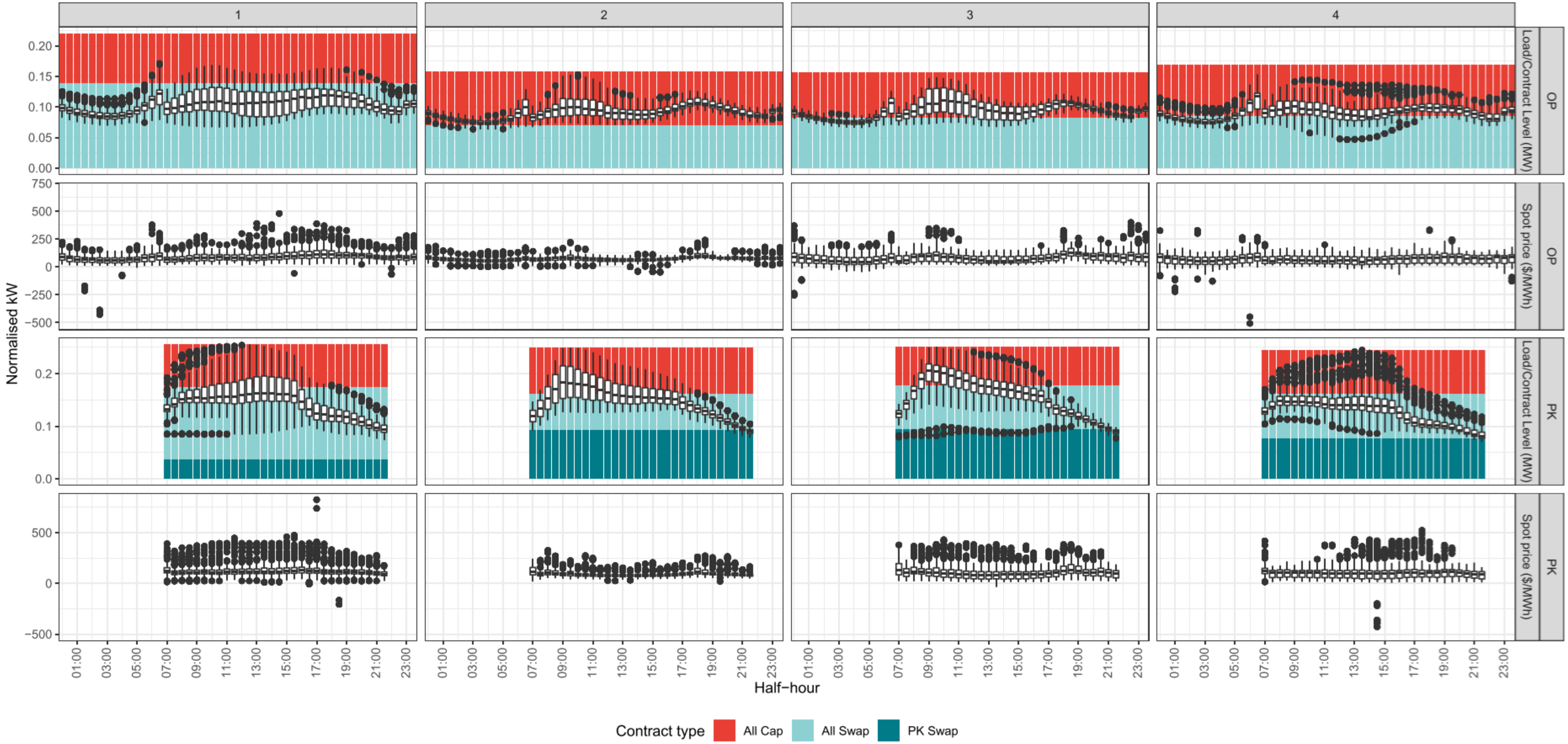
Note: Spot price chart truncated at a spot price of $750/MWh.

Figure 23: Contract position for CitiPower business load, ASXEnergy contract prices, 2019 (FY2020 dollars)



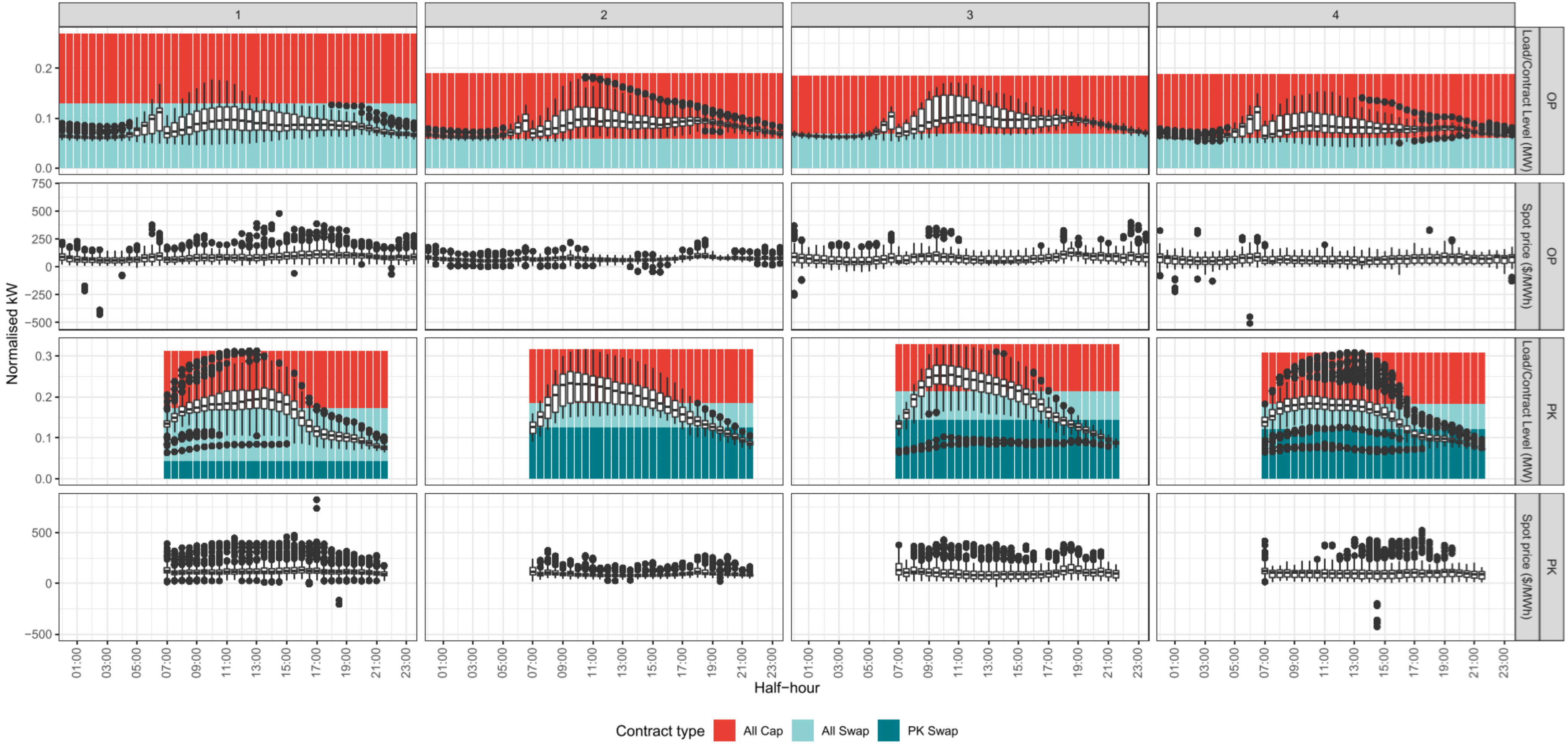
Note: Spot price chart truncated at a spot price of $750/MWh.

Figure 24: Contract position for PowerCor business load, ASXEnergy contract prices, 2019 (FY2020 dollars)



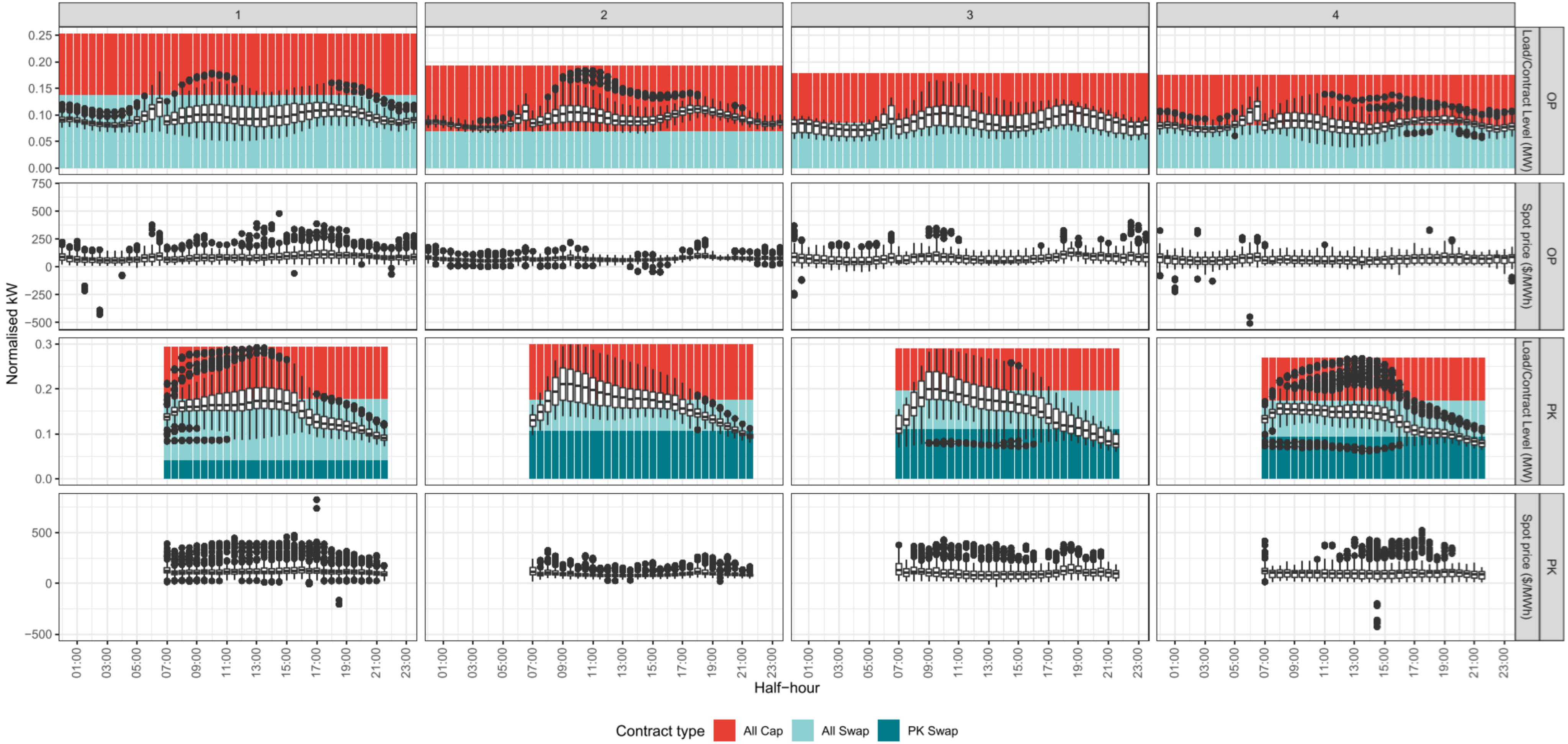
Note: Spot price chart truncated at a spot price of $750/MWh.

Figure 25: Contract position for VicAGL business load, ASXEnergy contract prices, 2019 (FY2020 dollars)



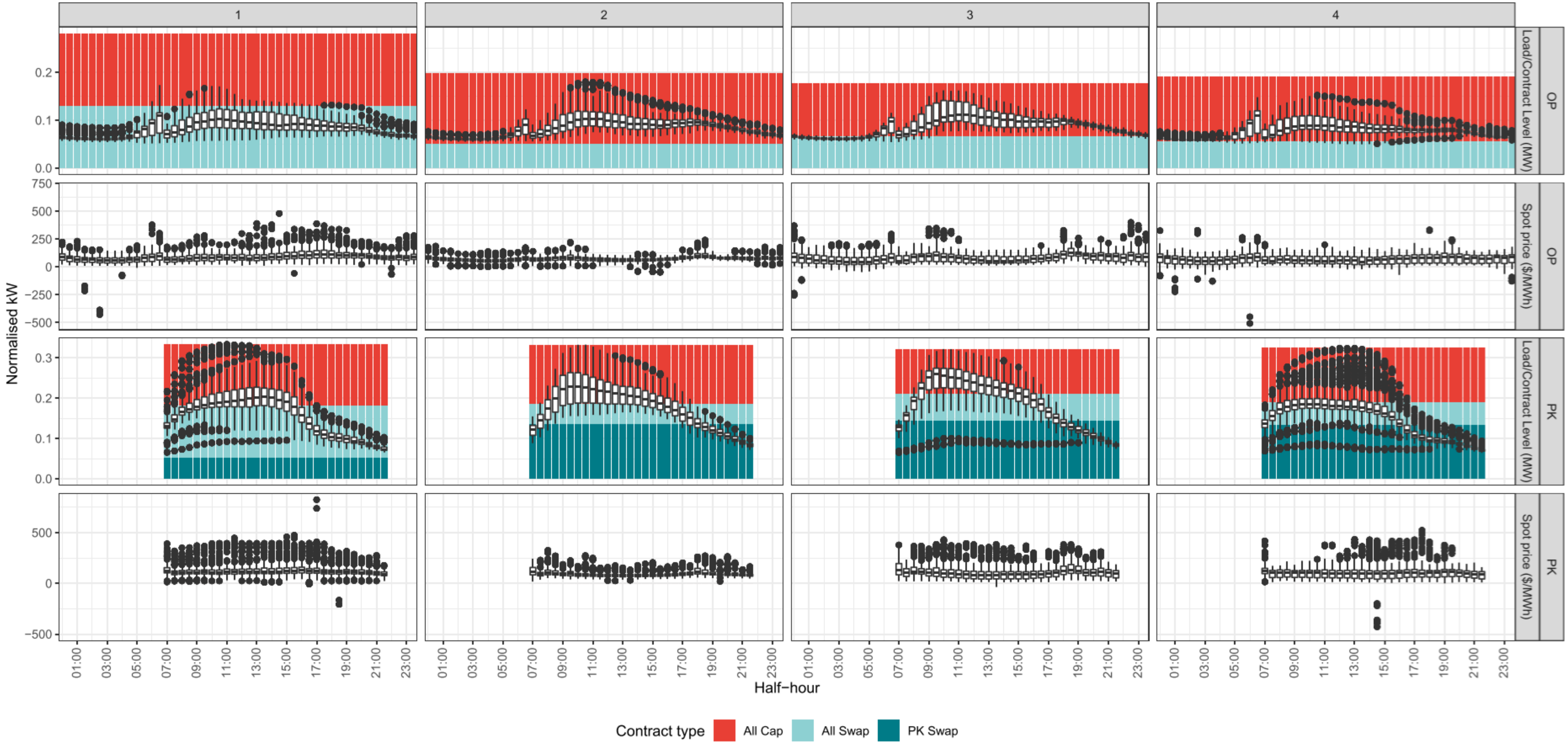
Note: Spot price chart truncated at a spot price of $750/MWh.

Figure 26: Contract position for TXU business load, ASXEnergy contract prices, 2019 (FY2020 dollars)



Note: Spot price chart truncated at a spot price of $750/MWh.

Figure 27: Contract position for United business load, ASXEnergy contract prices, 2019 (FY2020 dollars)



Note: Spot price chart truncated at a spot price of $750/MWh.

As seen in **Figure 18** to **Figure 27**, the contract position at the conservative point does not always result in complete coverage of the highest demand half hours. 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).

6 WHOLESALE ELECTRICITY COSTS

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

6.1 Wholesale electricity costs

We estimate 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 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 load-weighted price). The WECs that we have estimated are based on 12-month trade weighted average ASXEnergy contract prices up to 5 April 2019.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 FY2020)	
	RESIDENTIAL	BUSINESS
CITIPOWER	$103.05	$100.92
POWERCOR	$103.56	$96.40
TXU	$105.29	$99.45
UNITED	$108.91	$102.17
VICAGL	$108.57	$101.10

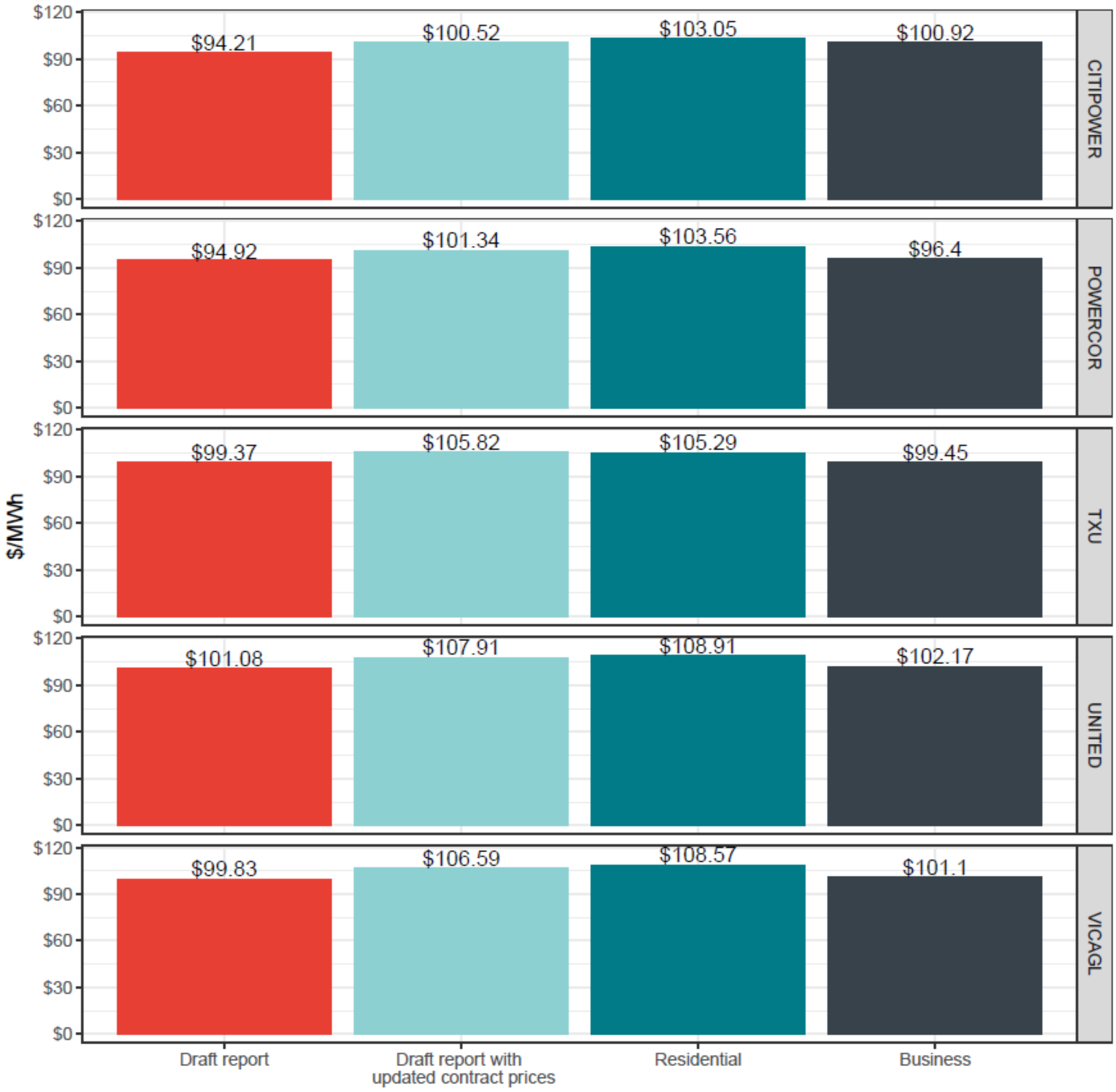
Source: Frontier Economics

There have been three key changes to the estimates of WEC since the draft report:

- We have updated contract prices and spot prices to reflect more recent data from ASXEnergy that is now available.
- We have updated contract prices to use the ESC's preferred trade weighted average approach, rather than a time weighted average approach.
- We have updated the customer load that we use.

An indication of the relative effect of these changes in the WEC is provided in **Figure 28**. The red columns show the WEC from the draft report, using 12-month time weighted average contract prices. The light blue columns show the effect of updating contract prices to the most recent 12-month trade weighted average contract prices, but continuing to use the MRIM load data. It is clear that this change in contract prices results in a material increase in the WEC, as a result of more recent contract prices being higher. The dark blue and black columns show the WEC from this final report, using the load data provided by AEMO. This load data tends to result in a higher WEC for residential customers, but a lower WEC for small business customers although there are some differences between network areas.

Figure 28: Effect of changes since the draft report



Source: Frontier Economics

Submissions from a number of stakeholders raised questions about the transparency of our estimate of the WEC. To address these concerns, with this final report we have released a set of spreadsheets that include all of the half-hourly price and load data, contract positions and contract prices that we use to calculate the WEC. These spreadsheets also show all of the calculations used to derive the WEC. We released equivalent spreadsheets with the draft report. The calculations in these spreadsheets make clear that the WEC accounts for the fact that a retailer cannot perfectly hedge the load of residential or small business customers using quarterly peak and off-peak contracts. Given the variability of the load of residential and small business customers there will be times when the hedge cover of a retailer is greater than the load of its customers and other times when the hedge cover of a retailer is less than the load of its customers; these outcomes are a determinant of the WEC.[6]

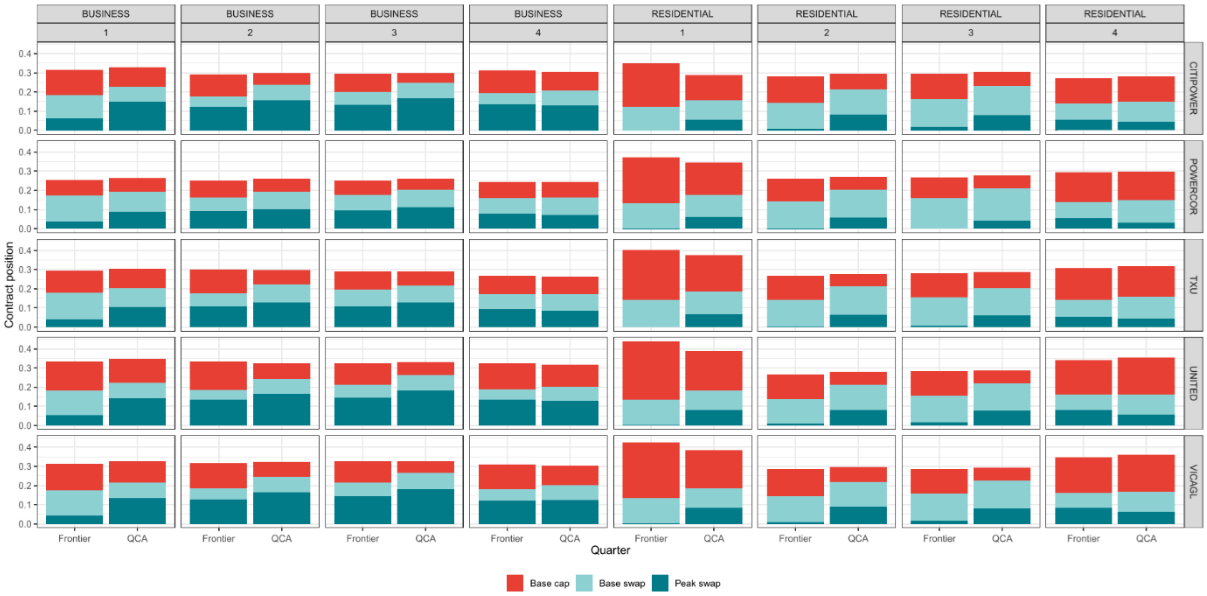
In our view there are only two inputs into this spreadsheet and these calculations that are not entirely transparent:

- The Monte Carlo process used to generate the sequence of half-hourly prices and load. While we have not released the code for this Monte Carlo simulation, we do think that the process is reasonably transparent. The sequence of half-hourly prices and load that we use to calculate the WEC are simply a random sequence of days drawn from 2016/17 and 2017/18, with prices scaled to match the ASX forward curve, using the process we described in Section 3.We have not forecast load or prices, but merely drawn from recent history.
- The *STRIKE* modelling used to generate the efficient contract position. While this model is proprietary, we are transparent about the resulting contract position, which is the only output from *STRIKE* that is used in estimating the WEC. We also consider that this resulting contract position is not so dissimilar to contract positions that are used by the QCA for the same purpose. A comparison between the contract positions under the two methods (as applied to the load data that we have used for this review) is shown in **Figure 29** (for each customer type and quarter in the vertical panels, and each network area in the horizontal panels). Obviously there are some differences in the composition of contracts, but the overall contract position is quite similar. The biggest difference is that our approach results in more contracts in total in Q1 for residential customers, likely because *STRIKE* has been applied across a range of simulated years. The rest of the positions are reasonably similar.

  While we could use the same heuristic approach used by the QCA to determine a benchmark contract position, or a similar heuristic approach, our view is that *STRIKE* is a better approach. *STRIKE* accounts for the fact that the risk that retailers seek to hedge depends on the expected volatility of spot prices and customer load, and the relationship between the two, so that the efficient hedging position will likely be different for different distribution areas and different customer types (due to different load profiles) and also likely be different over time (as load profiles and price outcomes change). *STRIKE* accounts for these in a way that a heuristic approach, in our view, does not.

[6] Globird Energy discusses the variability of actual demand and price compared to the hedged volume and price in its submission to the ESC. Globird Energy refers to the exposure to market pricing and customer demand uncertainty that remains even with hedging contracts in place as the Load Shape Variance Cost. Our view is that the calculations of settlement payments and difference payments that we undertake in estimating the WEC – which are set out in the spreadsheets released with this report – account for what Globird Energy refers to as the Load Shape Variance Cost.

Figure 29: Contract position comparison between Frontier's *STRIKE* model and the method used by the QCA

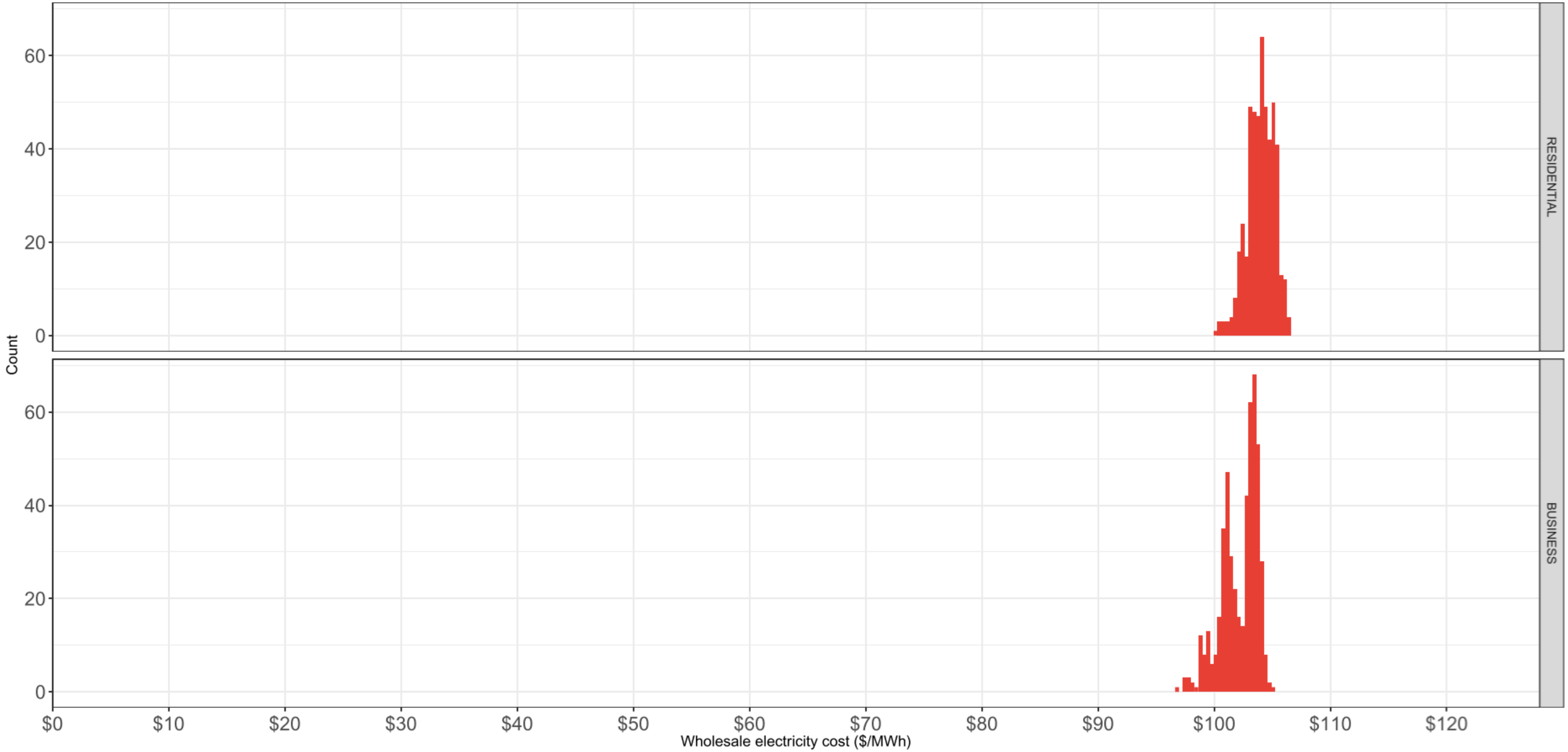


Source: Frontier Economics

Figure 30 through **Figure 34** show the distribution of wholesale electricity costs 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 quite concentrated, the spread from lowest to highest usually only being $5/MWh.

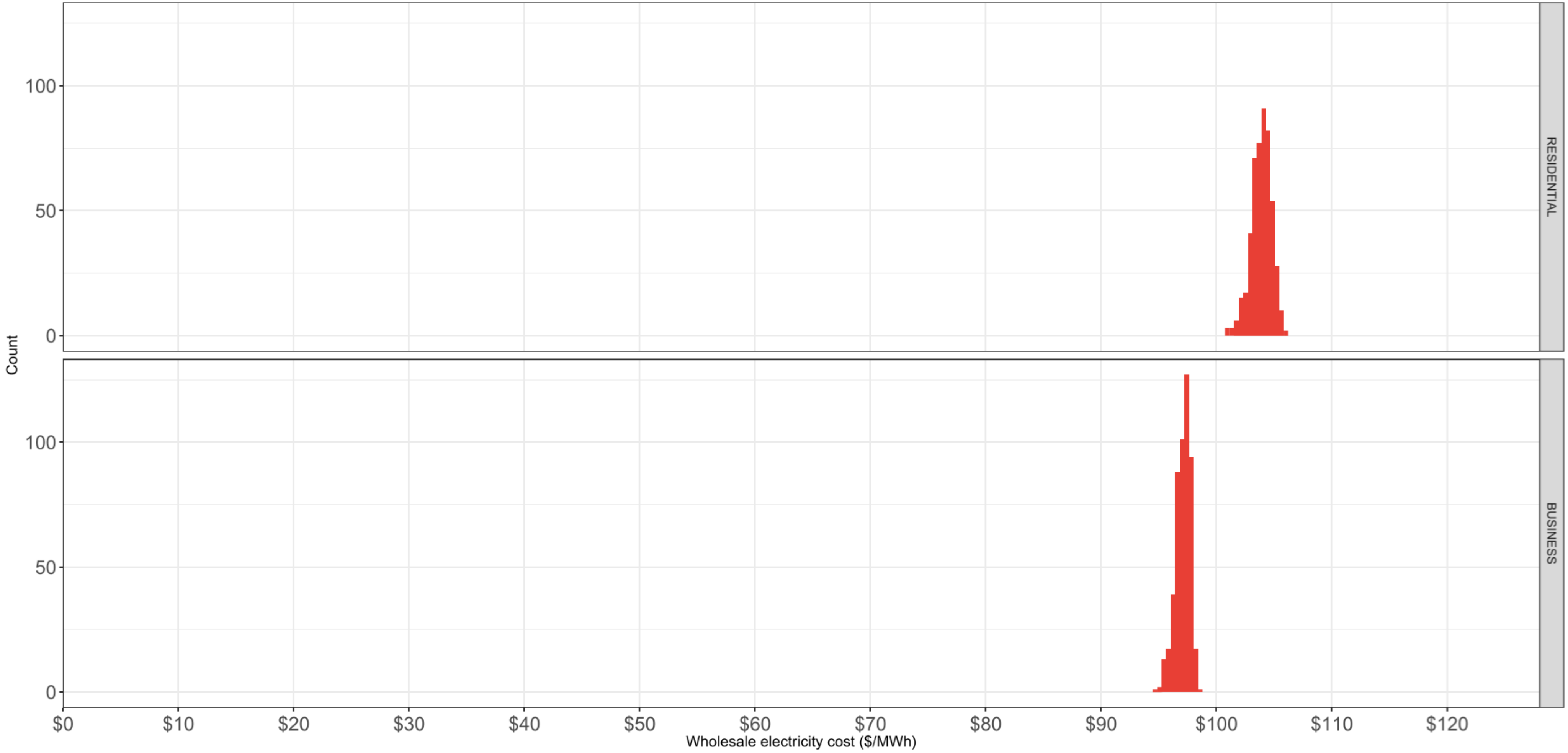
We note that these distributions do not reflect the distribution of all possible outcomes that retailers could face. If patterns of spot prices or load are materially different from the historical period on which we based our Monte Carlo analysis, or if average spot prices were too much different from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

Figure 30: CitiPower load wholesale electricity cost distribution



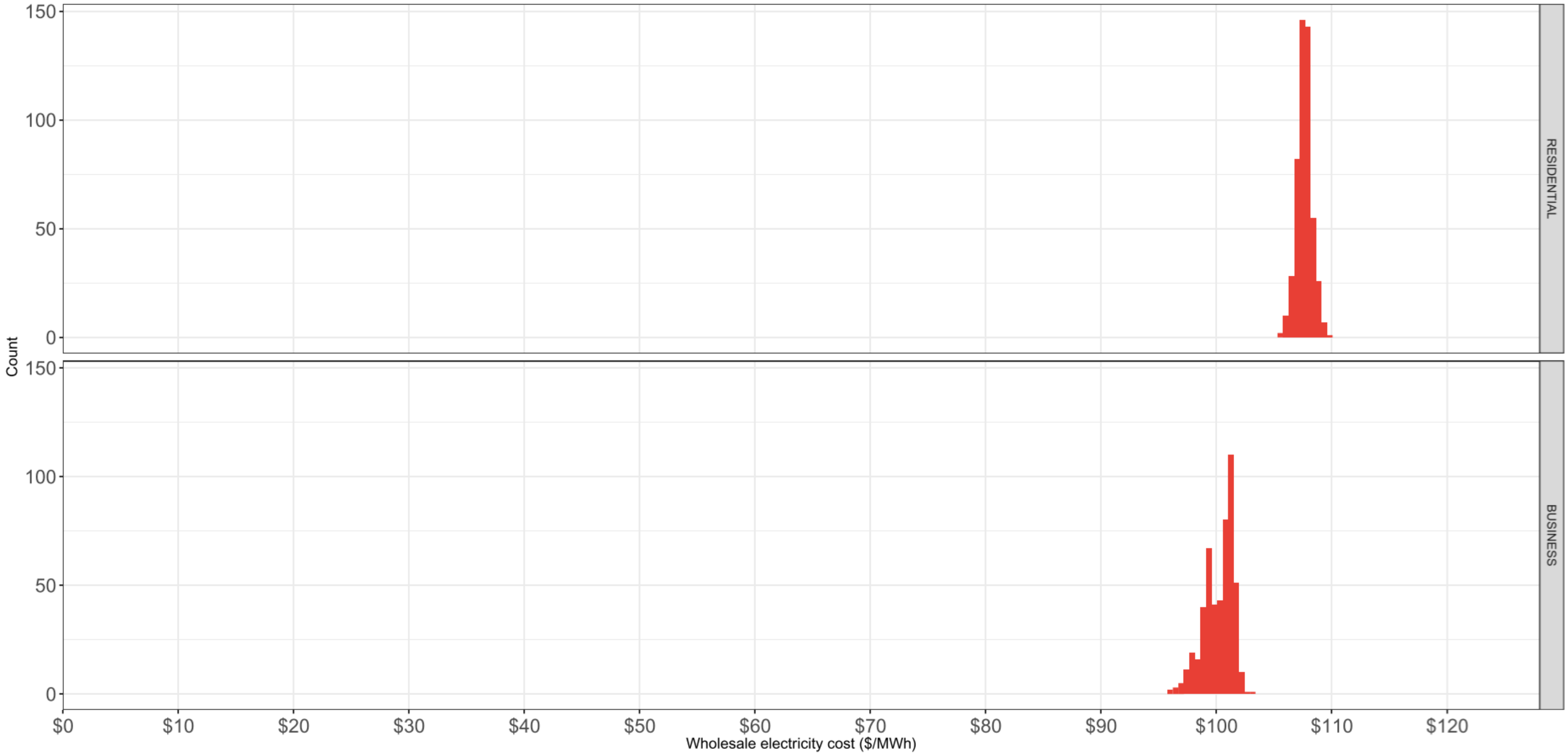
Source: Frontier Economics

Figure 31: Powercor load wholesale electricity cost distribution



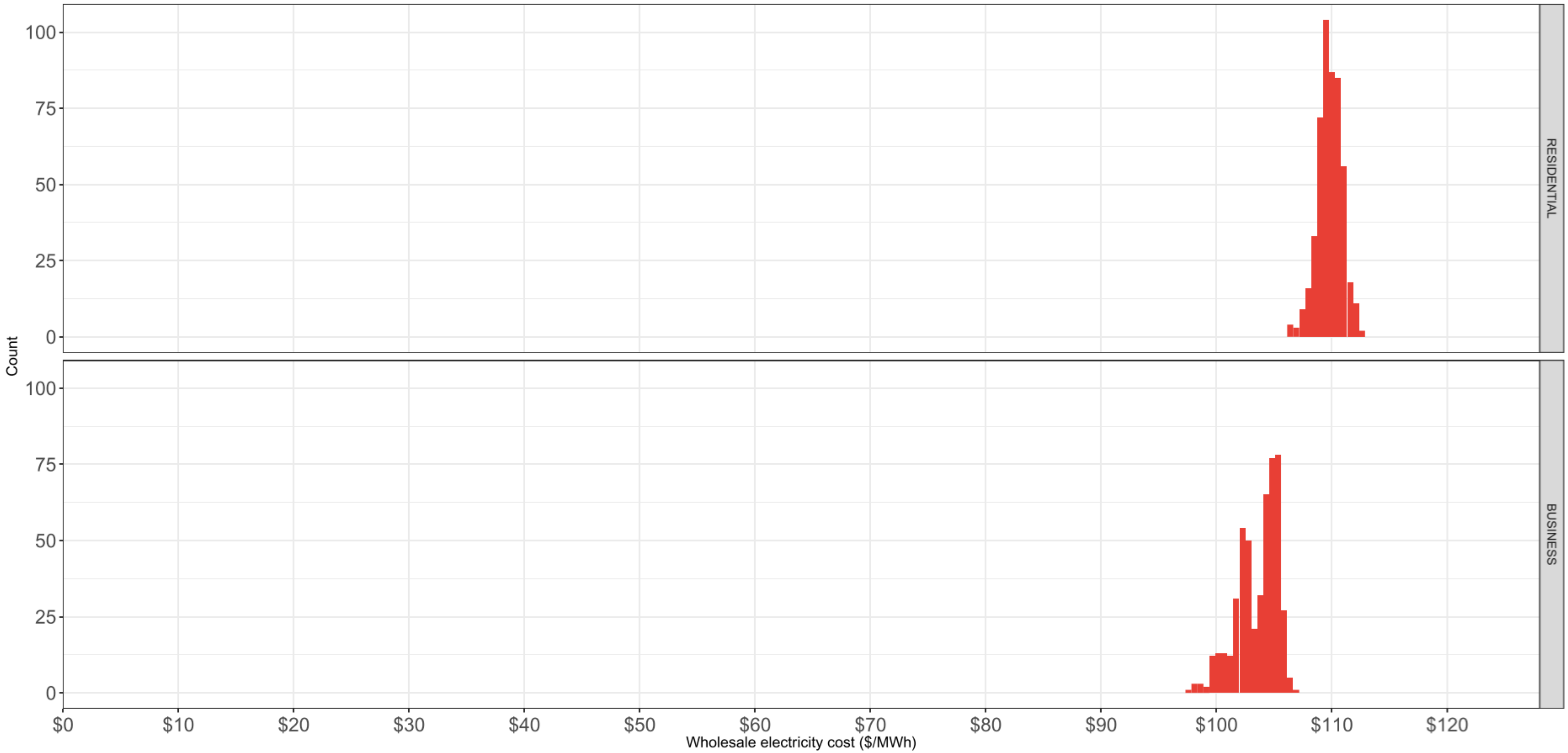
Source: Frontier Economics

Figure 32: TXU load wholesale electricity cost distribution



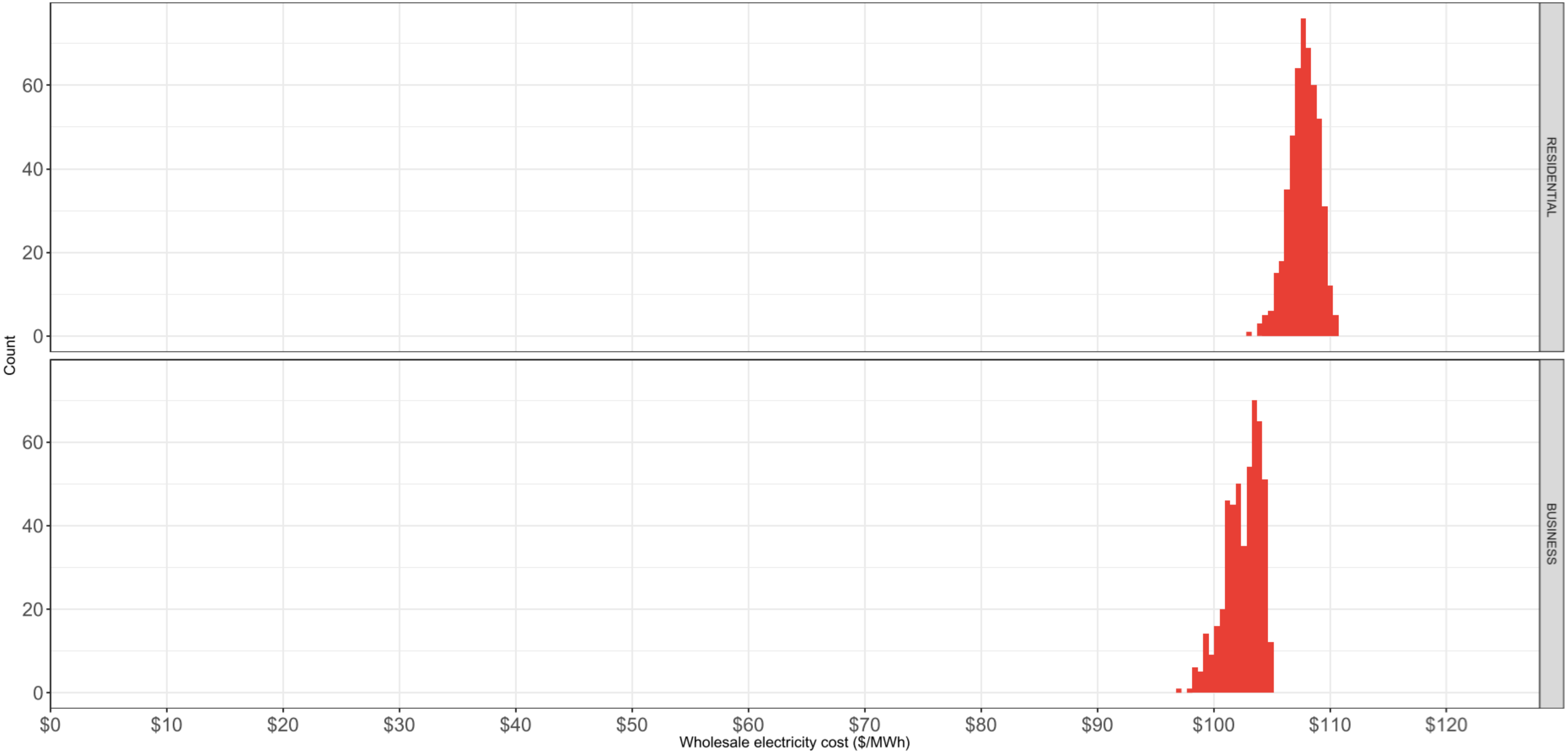
Source: Frontier Economics

Figure 33: United load wholesale electricity cost distribution



Source: Frontier Economics

Figure 34: VicAGL 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. We have updated the way that we calculate the volatility allowance, so that it is now 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 FY2020)	
	RESIDENTIAL	BUSINESS
CITIPOWER	$0.18	$0.17
POWERCOR	$0.16	$0.10
TXU	$0.16	$0.19
UNITED	$0.19	$0.19
VICAGL	$0.20	$0.17

Source: Frontier Economics

6.3 Allowance for prudential costs

Submissions from a number of stakeholders suggested that the WEC should include an allowance for the costs of prudential requirements associated with operating in the wholesale electricity market. Our view is that an allowance for these is already incorporated in retail operating costs. As we note in our separate report on retail operating costs and retail margin, we benchmark the allowance for retail operating costs against other regulatory decisions, market data and the ACCC's Retail Electricity Price Inquiry report. While it is not clear in all cases whether these benchmark allowances include an allowance for the costs of prudential requirements, it is at least clear for the regulatory benchmarks. As we note, most of these regulatory benchmarks are ultimately derived from an estimate of retail operating costs from IPART. IPART has explicitly noted that it considers that prudential costs are included in retail operating costs:[7]

> *EnergyAustralia submitted that there are also some cash flow mismatches that are not explicitly accounted for in the volatility allowance. We consider that these costs (for example the cost of meeting AEMO prudential requirements) are part of the normal costs for running a retail*

[7] IPART, *Review of regulated retail prices and charges for electricity, From 1 July 2013 to 30 June 2016*, Final Report, June 2013.

> *electricity business. These, along with other retail costs, are captured within our cost allowances.*

More recently, from its 2016/17 determination, the QCA has commenced providing a separate allowance for the costs of prudential requirements. In doing so, however, they have explicitly removed those costs from the retail operating cost allowance for avoid double counting:[8]

> *Prudential capital costs are the costs a retailer incurs to provide financial guarantees to AEMO and to lodge initial margins with hedge providers for futures contracts. These costs must be accounted for, as futures contracts are relied upon to derive wholesale energy cost estimates.*
>
> *In the 2015–16 determination, prudential capital costs were considered as part of retail operating costs, as they were implicitly included in the retail operating cost benchmark we used. However, as discussed in section 2.3.3 of ACIL's report on retail costs, these costs vary according to the amount of electricity being purchased by the retailer, as well as the level of volatility in the electricity market. As such, ACIL considered they should be included in the energy cost allowance. To avoid double counting, prudential costs have been excluded from the retail cost allowance.*

Since we benchmark against IPART's allowance and against QCA's allowances up to 2015/16, prudential costs are accounted for within these benchmarked retail operating costs.

[8] QCA, *Regulated retail electricity prices for 2016-17*, Final Determination, May 2016.

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).

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 default RPP for 2019 of 18.6%, which is set out in **Table 4**.

Table 4: Renewable Power Percentage

CALENDAR YEAR	RPP (% OF LIABLE ACQUISITIONS)
2019	18.6%

Source: Clean Energy Regulator, Frontier Economics

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 average of LGC prices reported by Mercari.[9]

Table 5: 2019 LGC future price from Mercari Rates

CALENDAR YEAR	LGC PRICE ($/CERTIFICATE, REAL FY2020)
12-month average	$61.27

Source: Mercari Rates

Cost of complying with the LRET

Based on the RPP set out in **Table 4** and the LGC price set out in **Table 5**, the cost of complying with the LRET is set out in **Table 6**.

Table 6: Cost of complying with the LRET

CALENDAR YEAR	COST OF COMPLYING WITH LRET ($/MWH, REAL FY2020)
12-month average	$11.40

Source: Frontier Economics

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. These 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.

9 Available at: http://lgc.mercari.com.au/. Accessed 5th April 2019

Small-scale Technology Percentage

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

The STP is determined by the Clean Energy Regulator and is calculated as the percentage required in order to remove STCs from the STC Market for the current year liability. The STP is calculated in advance based on:

- the estimated number of STCs that will be created for the year
- 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 must also publish a non-binding estimate of the STP for the two subsequent compliance years by March 31.

The Clean Energy Regulator has published a binding STP of 21.73% for 2019, which is set out in **Table 7**.

Table 7: Small-scale Technology Percentages

CALENDAR YEAR	STP (% OF LIABLE ACQUISITIONS)
2019	21.73%

Source: Clean Energy Regulator, Frontier Economics

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 as set out in **Table 8**.

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

Table 8: STC costs

CALENDAR YEAR	STC COST ($/CERTIFICATE, REAL FY2020)
2019	$40.50

Source: Frontier Economics

Cost of complying with the SRES

Based on the STP set out in **Table 7** and the STC price set out in **Table 8**, the cost of complying with the SRES is set out in **Table 9**.

Table 9: Cost of complying with the SRES

CALENDAR YEAR	COST OF COMPLYING WITH SRES ($/MWH, REAL 2020)
2019	$8.80

Source: Frontier Economics

frontier economics

BRISBANE | MELBOURNE | SINGAPORE | SYDNEY

Frontier Economics Pty Ltd
395 Collins Street Melbourne Victoria 3000

Tel: +61 (0)3 9620 4488
www.frontier-economics.com.au

ACN: 087 553 124 ABN: 13 087 553