WHOLESALE ELECTRICITY COSTS

A REPORT FOR THE ESSENTIAL SERVICES COMMISSION

22 FEBRUARY 2019

CONTENTS

1	**Introduction**	**3**
1.1	Background	3
1.2	Frontier Economics’ engagement	3
1.3	This draft report	3
2	**Approach to assessing WEC**	**5**
3	**Half-hourly spot prices and half-hourly load**	**7**
3.1	Historical data on half-hourly price and load	7
3.2	Selecting appropriate historical data	8
3.3	Projecting half-hourly load and spot prices	12
4	**Contract prices**	**17**
5	**Contract position**	**22**
6	**Wholesale electricity costs**	**30**
6.1	Wholesale electricity costs	30
6.2	Volatility allowance	36
7	**LRET and SRES**	**37**
7.1	LRET	37
7.2	SRES	38

Tables

Table 1: 40-day average ASX energy derivative prices for Victoria	18
Table 2: Modelled market-based energy purchase cost result	30
Table 3: Modelled volatility allowance	36
Table 4: Renewable Power Percentage	37
Table 5: 40-day average LGC future price from Mercari Rates	38
Table 6: Cost of complying with the LRET	38
Table 7: Small-scale Technology Percentages	39
Table 8: STC costs	39
Table 9: Cost of complying with the SRES	40

Figures

Figure 1: Load factor for MRIM 9

Figure 2: Average daily profile for MRIM 9

Figure 3: Average daily profile for Victorian spot prices 10

Figure 4: Load premium, based on MRIM and Victorian spot prices 11

Figure 5: Quarterly patterns of spot prices and ASXEnergy prices 12

Figure 6: Peak/off-peak patterns of spot prices and ASXEnergy prices 12

Figure 7: Distribution of load-weighted price for simulated years – Citipower 14

Figure 8: Distribution of load-weighted price for simulated years – Powercor 15

Figure 9: Distribution of load-weighted price for simulated years – TXU 15

Figure 10: Distribution of load-weighted price for simulated years – United 16

Figure 11: Distribution of load-weighted price for simulated years – VicAGL 16

Figure 12: Victorian base swaps – open interest, prices and volumes for financial year 2020 19

Figure 13: Victorian peak swaps – open interest, prices and volumes for financial year 2020 20

Figure 14: Victorian base $300 caps – open interest, prices and volumes for financial year 2020 21

Figure 15: Contract position for CitiPower MRIM load, ASXEnergy contract prices, 2019 (nominal dollars) 24

Figure 16: Contract position for Powercor MRIM load, ASX Energy contract prices, 2019 (nominal dollars) 25

Figure 17: Contract position for VicAGL MRIM load, ASX Energy contract prices, 2019 (nominal dollars) 26

Figure 18: Contract position for TXU MRIM load, ASX Energy contract prices, 2019 (nominal dollars) 27

Figure 19: Contract position for United MRIM load, ASX Energy contract prices, 2019 (nominal dollars) 28

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 draft report

This draft report sets out our draft 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 draft 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.

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 question 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, the Manually Read Interval Meter (MRIM) data for each of the five distribution network areas in Victoria, as published by AEMO.

The MRIM data includes aggregated half-hour electricity consumption for all type 5 meters in each of the five distribution network areas in Victoria. The majority of these MRIM meters are the advanced meters rolled out in Victoria from mid-2011. All of these MRIM meters will be for customers with annual consumption of less than 160 MWh (which means that these MRIM meters represent a mix of residential and small business customers).

The MRIM data does not directly coincide with the customer groups to which the VDO will apply. The ESC has stated that the VDO will apply to all residential and small business customers, with small business customers defined as customers with aggregate consumption less than 40 MWh per annum. This raises two issues with the use of MRIM data:

- The MRIM data does not provide separate load data for residential and business customers, limiting the extent to which separate estimates of WEC could be estimated for residential and small customers.
- The MRIM data includes customers up to 160 MWh. This will mean that there will be more business customers within the MRIM than would meet the 40 MWh per annum threshold, which

could have an effect on the half-hourly profile for the MRIM either because of the weighting of residential to business customers being affected or because larger business customers have different patterns of consumption that small business customers.

The ESC has provided us with alternative data for Citipower and Powercor's network which separately reports load for small business and residential customers (below 60 MWh per annum). We have investigated whether this combined small business and residential load shape (for each of Citipower and Powercor) would provide a different estimate of WEC than the MRIM load shape and have found that, for the historical data that we have used, the difference is relatively small (the WEC would differ by a couple of dollars per MWh).

At this stage we do not have access to a complete alternative data set, for multiple years and for each DNSP, that would enable us to estimate a WEC for small business and residential customers less than 40 MWh per annum. We understand that the ESC is investigating whether it will be able to access other sources of data in future.

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. We have examined historical MRIM data and historical spot price data to make this assessment. Since the last full financial year for which we have MRIM data is 2016/17, we limit our analysis to years up to 2016/17. If more up to date data is available in time for the final report we would make use of that.[1]

Figure 1 shows the annual load factor for the MRIM data for each Victorian DNSP for each of the last six financial years.

In the first year for which we have data we can see quite different patterns in the load factor: the calculated MRIM for TXU[2], for instance, was materially higher in 2011/12 than in any other year. We expect that this is a data issue and for this reason propose not to make use of data from 2011/12 for any of the DNSPs.

For the last five years we can see that the load factors for each Victorian DNSP have followed the same general pattern. This pattern seems to indicate that the load factor has been increasing over time (the load has become flatter). However, this data has not been weather-normalised, so we do not know to what extent this is driven by weather conditions over these years. The fact that the pattern across all Victorian DNSPs is similar suggests that it may be weather-related. In any case, the other analysis we undertake – including of the load-weighted price – suggests that this trend in load factor need not rule out historical years that occurred before the increase in load factor (2012/13 and 2013/14).

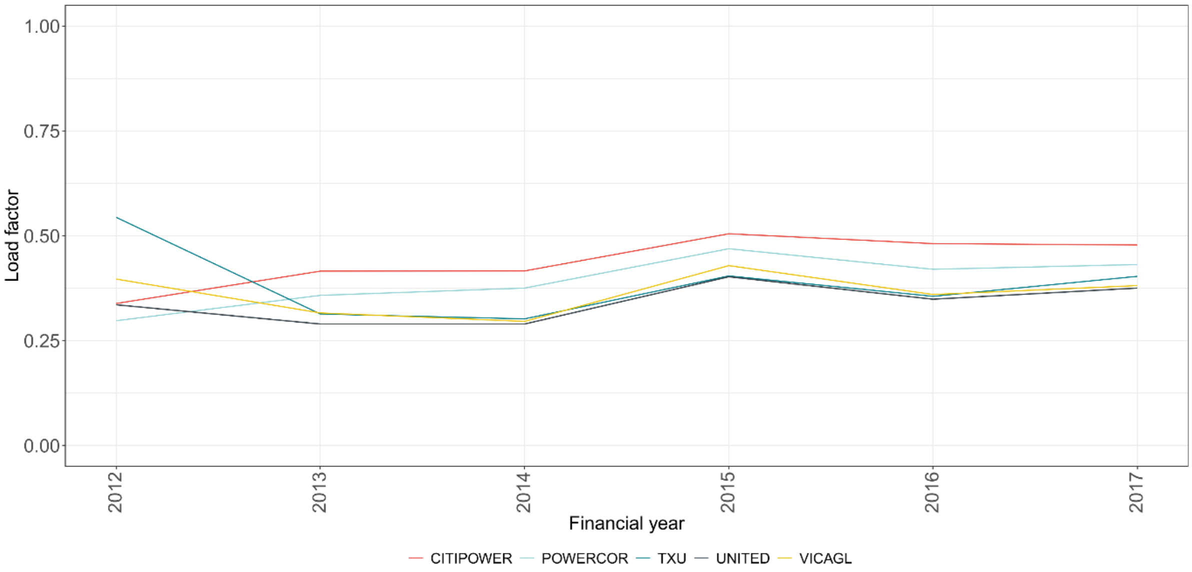
Figure 2 shows the average daily profile for the MRIM data for each Victorian DNSP for each of the last six financial years. Again, in the first year for which we have data we see quite a different daily

[1] The MRIM data is currently available up to March 2018; by limiting our analysis to the last full financial year – 2016/17 – we are not making use of the most recent nine months of data. An alternative would be to use historical data by treating a year as occurring from April to March, which would allow us to use the most recent available data. We have examined the data to March 2018 to assess whether this alternative approach would make a difference to our analysis and have concluded that it would not. In particular, it we calculate load premiums for years from April to March the results are quite consistent with those presented in **Figure 4**, and the final year – from April 2017 to March 2018 – is quite consistent with earlier years.

[2] The MRIM data refers to AusNet Services network as TXU and the Jemena Electricity Network as VicAGL.

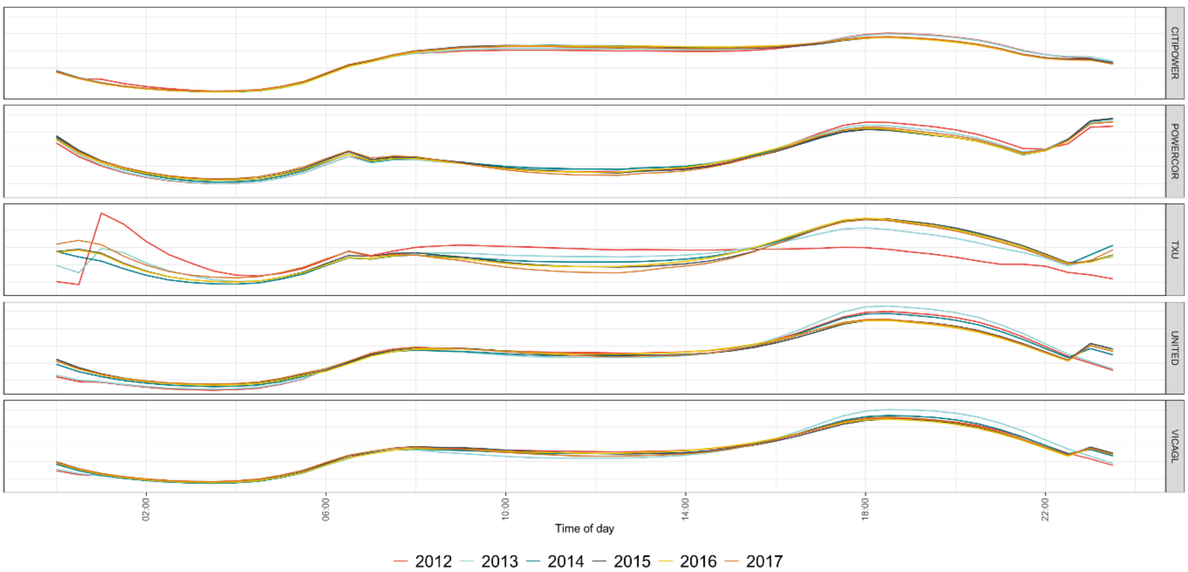
profile for TXU. Other than that our view is that these daily profiles are reasonable consistent over time.

Figure 1: Load factor for MRIM



Source: Frontier Economics analysis of AEMO data

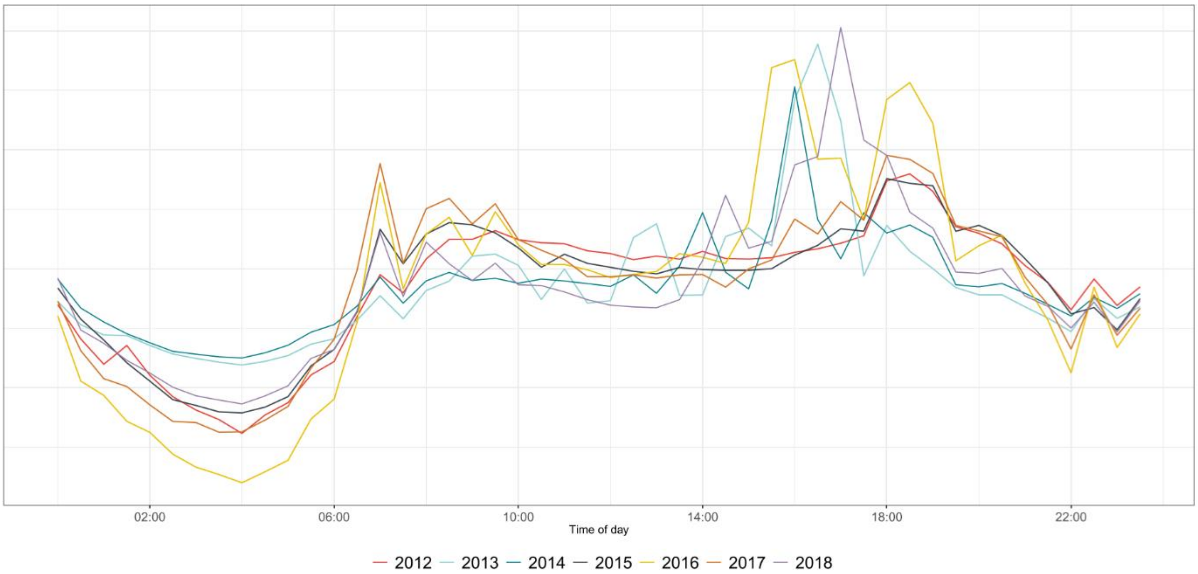
Figure 2: Average daily profile for MRIM



Source: Frontier Economics analysis of AEMO data

Figure 3 shows the average daily profile for Victorian spot prices for each of the last six 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 MRIM load. Nevertheless, our view is that these patterns are sufficiently consistent over time that we would not rule out using any 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. Highest prices have most often occurred between 4PM and 5PM, although in some years they have occurred later in the day, around 6PM. However, there is not a clear tend over time: both 2012 and 2017 have highest prices tending to occur later than other years.

Figure 3: Average daily profile for Victorian spot prices

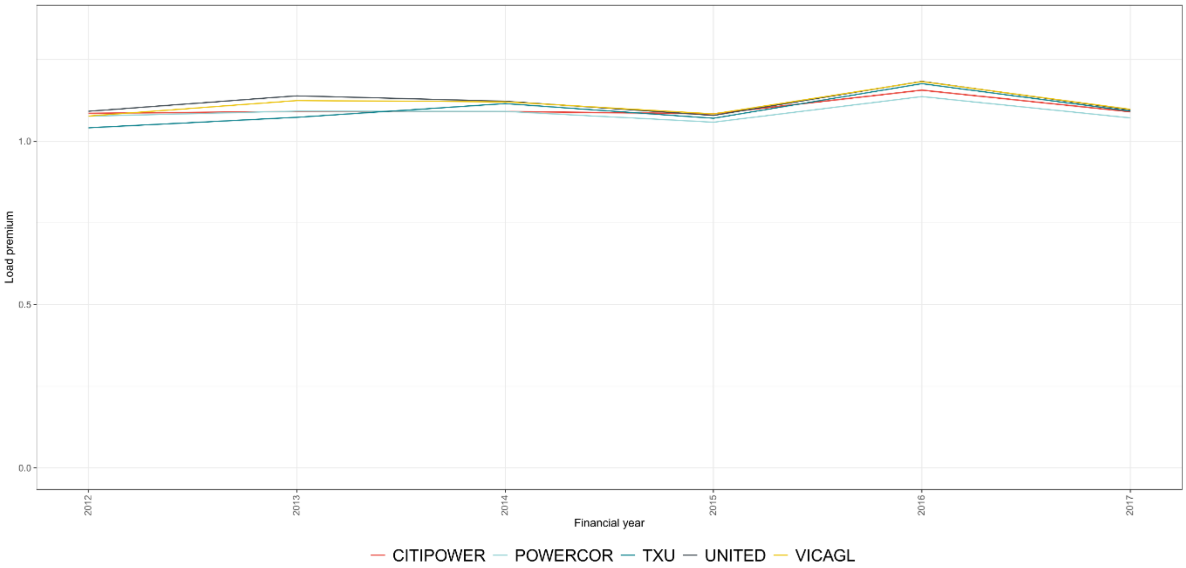


Source: Frontier Economics analysis of AEMO data

Note: We include 2017/18 data in this chart even though we do not use it for the modelling as we do not have the full set of MRIM data for 2017/18. Nevertheless, we can see that pricing patterns for 2017/18 are reasonably consistent with other years.

Figure 4 combines the historical MRIM and spot price data to report the load premium for each Victorian DNSP for each of the last six 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 4** that the load premium over the last five financial years has been reasonably constant. There has been a decrease in the load premium in 2014/15 and an increase in 2015/16, but on the whole our view is that there is no clear trend in the load premium. This suggests to us that half-hourly data from each of these last five financial years would provide a reasonable basis for forecasting half-hourly load and spot prices.

Figure 4: Load premium, based on MRIM and Victorian spot prices



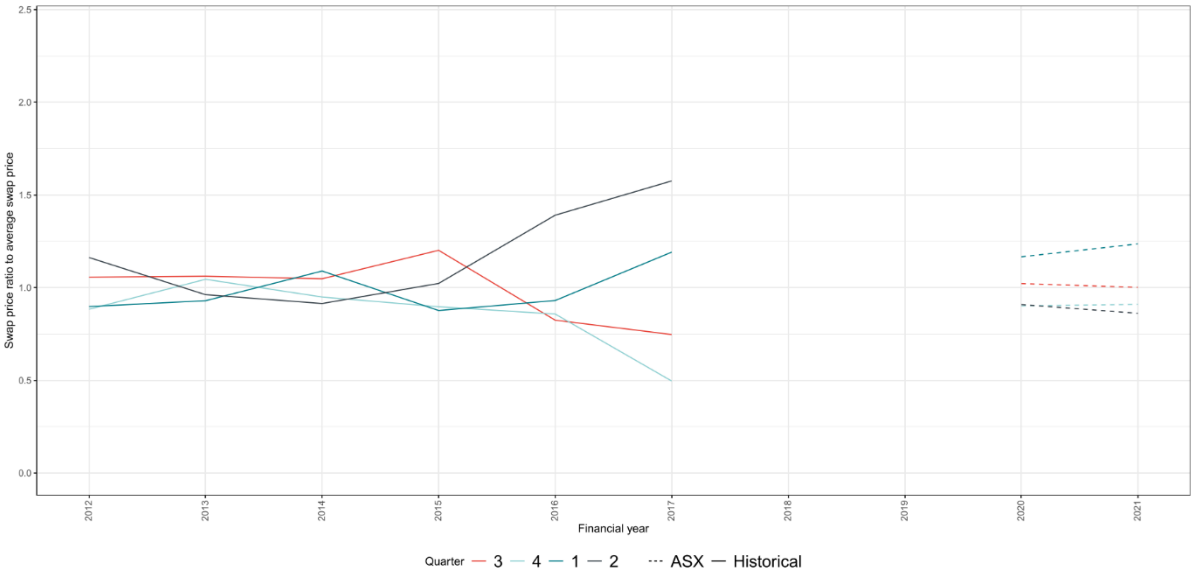
Source: Frontier Economics analysis of AEMO data

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 5 examines quarterly patterns of spot prices and ASXEnergy prices. For each quarter, **Figure 5** presents the relationship between average quarterly prices and average annual prices: on an historical basis this relationship is based on historical Victorian spot prices; on a forecast basis this relationship is based on ASXEnergy base-load swaps prices for Victoria. **Figure 5** 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. To reflect these differences, we propose to 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.

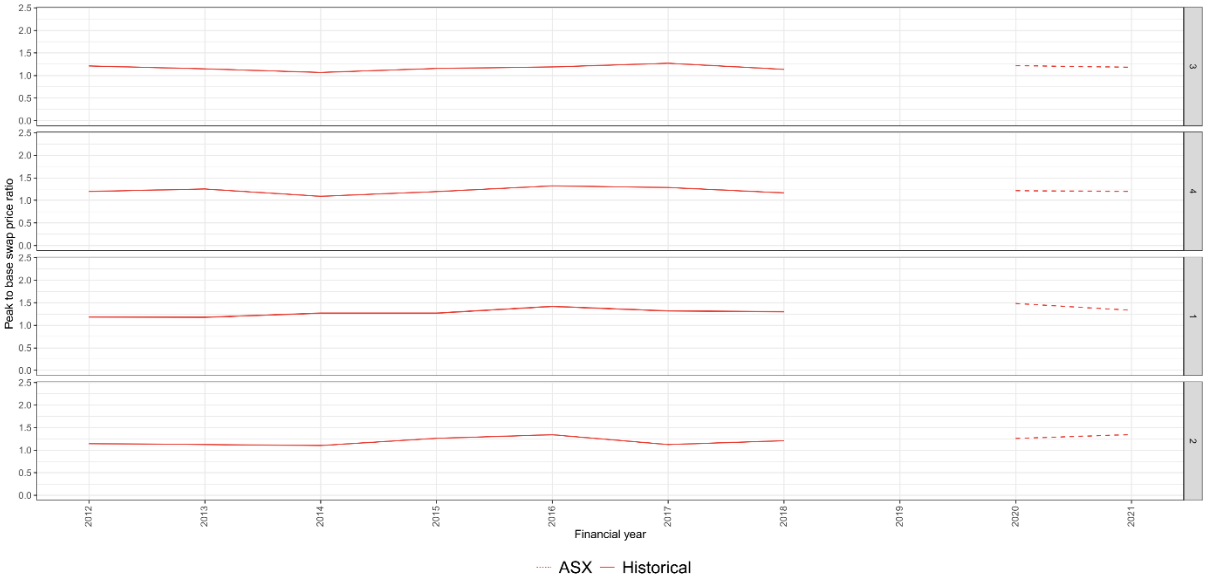
Figure 6 examines peak/off-peak patterns of spot prices and ASXEnergy prices. For each peak/off-peak period, **Figure 6** presents the relationship between average peak/off-peak prices and average annual prices: on an historical basis this relationship is based on historical Victorian spot prices; on a forecast basis this relationship is based on ASXEnergy base-load swaps prices for Victoria. **Figure 6** 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 reflect in the ASXEnergy data.

Figure 5: Quarterly patterns of spot prices and ASXEnergy prices



Source: Frontier Economics analysis of AEMO data and ASXEnergy data

Figure 6: 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 2012/13 to 2016/17 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 5 years of half-hourly load and price data. In our view there are two benefits of using a Monte Carl 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 5 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 Carl 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 between 2012/13 and 2016/17.
- 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 between 2012/13 and 2016/17.
- 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 between 2012/13 and 2016/17.

For each of these simulated years, load and prices are drawn at the same time (ie, 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 MRIM load; we are implicitly assuming that there is no relevant trend to the half-hourly profile of the MRIM 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. 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 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 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 (less an assumed contract premium of 5 per cent on the underlying prices)[3]. We use

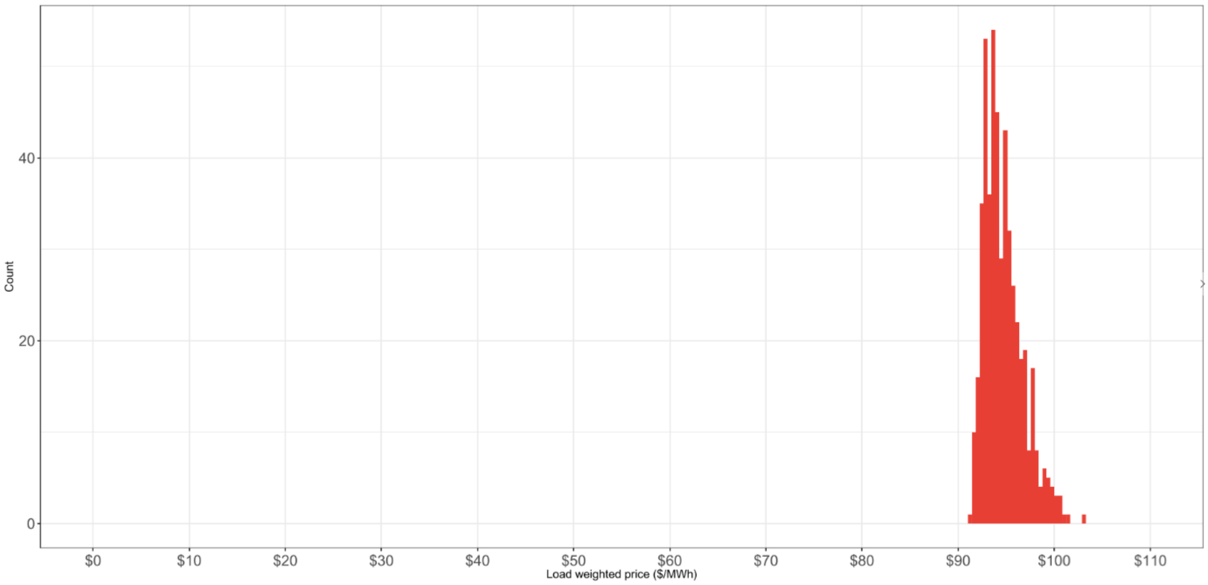
[3] The contract premium cannot be directly observed, since it is the difference between an *expectation* at a point in time of future spot prices (which cannot be observed) and the observed forward contract prices at that point in time. However, by comparing data on out-turn spot prices and observed 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

the 40-day average of ASXEnergy contract prices for quarterly base swap prices (up to 15 February 2019) as representing the market's current view of spot prices for each quarter of 2019/20. This approach to generating half-hourly price forecasts results in:

- The appropriate *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).

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 7** through **Figure 11** show the distribution of load-weighted prices for each of the 500 simulated years from our Monte Carlo analysis, for each distribution area. 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 7** through **Figure 11** 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.

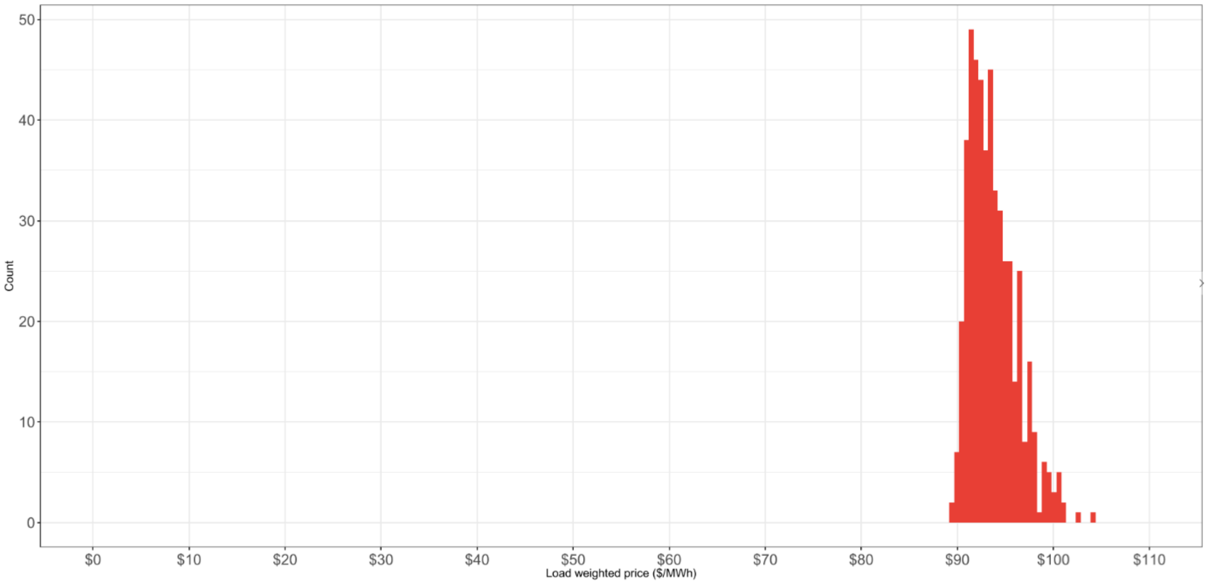
Figure 7: Distribution of load-weighted price for simulated years – CitiPower



Source: Frontier Economics

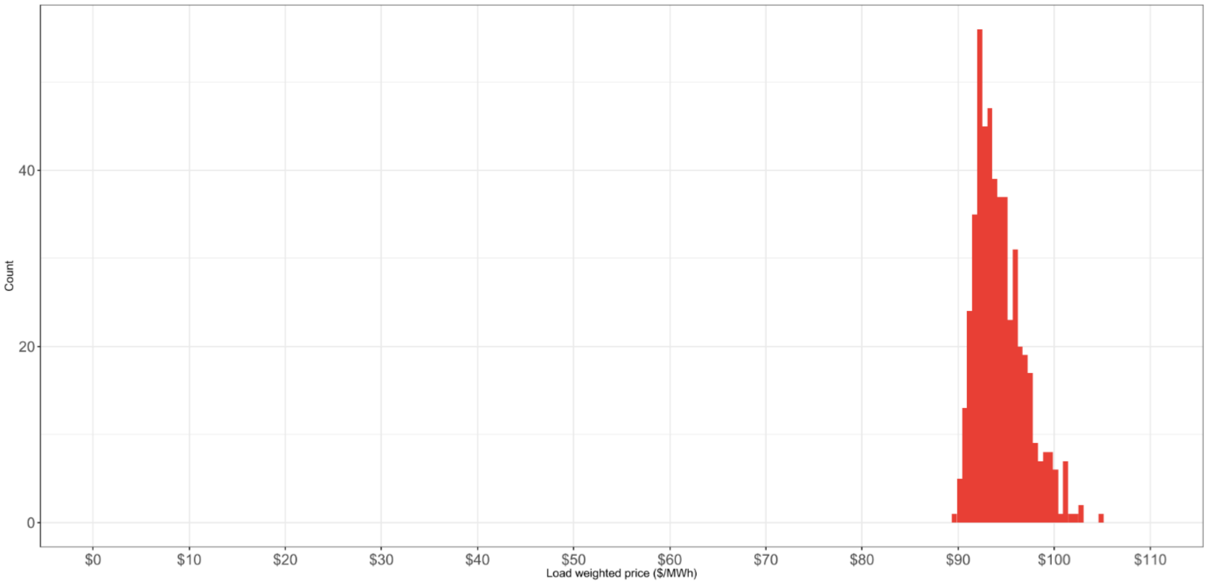
affect out-turn spot prices but not observed forward contract prices. Nevertheless, if this comparison is made over enough observations, an estimate of the contract premium can be developed. We have undertaken this analysis for the full set of data since the commencement of trade on ASXEnergy; based on that analysis, we consider that an assumption of a contract premium of 5% is reasonable.

Figure 8: Distribution of load-weighted price for simulated years – Powercor



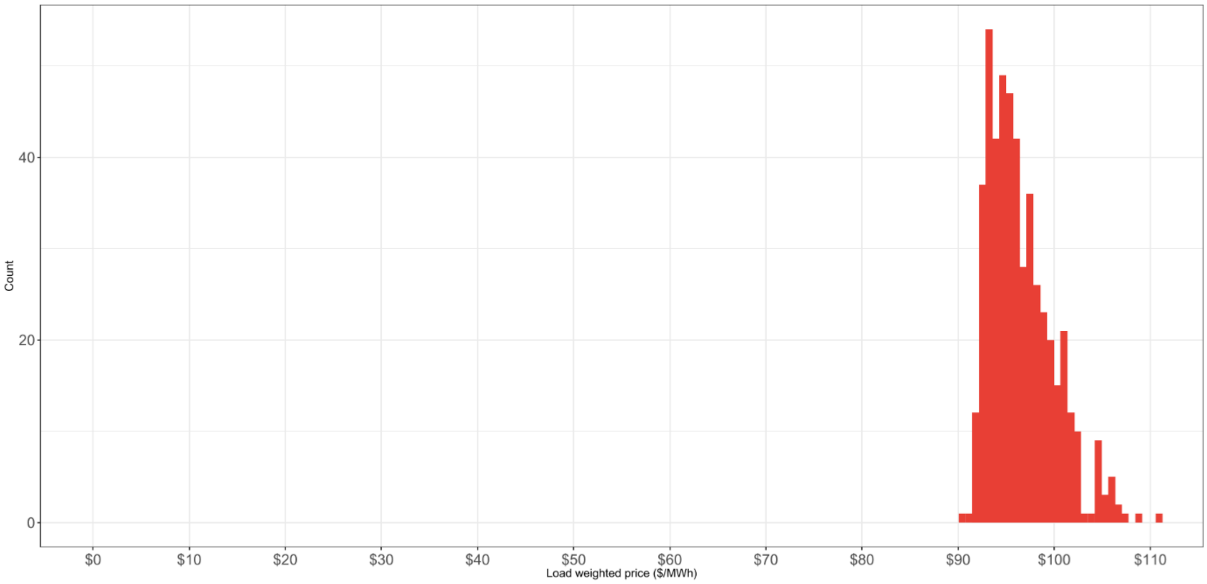
Source: Frontier Economics

Figure 9: Distribution of load-weighted price for simulated years – TXU



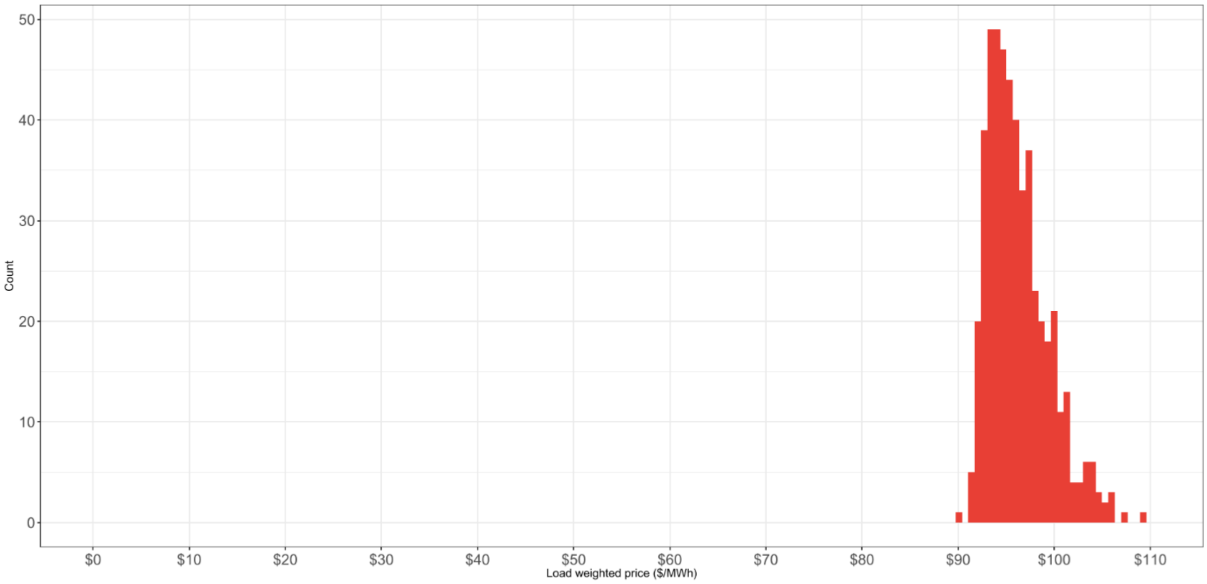
Source: Frontier Economics

Figure 10: Distribution of load-weighted price for simulated years – United



Source: Frontier Economics

Figure 11: Distribution of load-weighted price for simulated years – 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 12 through **Figure 14** 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 12** through **Figure 14** 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 understanding the costs that retailers face in hedging the higher load that they tend to face during peak periods.

ASXEnergy contract prices are shown from **Table 1** through **Table 3**, for 40-day, 12-month and 24-month averages respectively, up to 15 February 2019.

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.

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 of 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 costs (since most retailers will by contracts over a number of years leading up to the year).

Table 1: 40-day average ASXEergy derivative prices for Victoria

PRODUCT	STATUS	FINANCIAL YEAR	QUARTER			
			Q3	Q4	Q1	Q2
$300 CAPS	Base	2020	$3.77	$5.06	$26.50	$3.92
SWAPS	Base	2020	$91.22	$82.89	$109.11	$81.60
	Peak	2020	$109.13	$98.44	$154.13	$101.00

Source: Frontier Economics analysis of ASXEnergy data

Table 2: 12-month average ASXEnergy derivative prices for Victoria

PRODUCT	STATUS	FINANCIAL YEAR	QUARTER			
			Q3	Q4	Q1	Q2
$300 CAPS	Base	2020	$3.62	$5.99	$24.57	$4.62
SWAPS	Base	2020	$79.46	$69.96	$94.66	$71.62
	Peak	2020	$94.05	$86.62	$131.04	$95.04

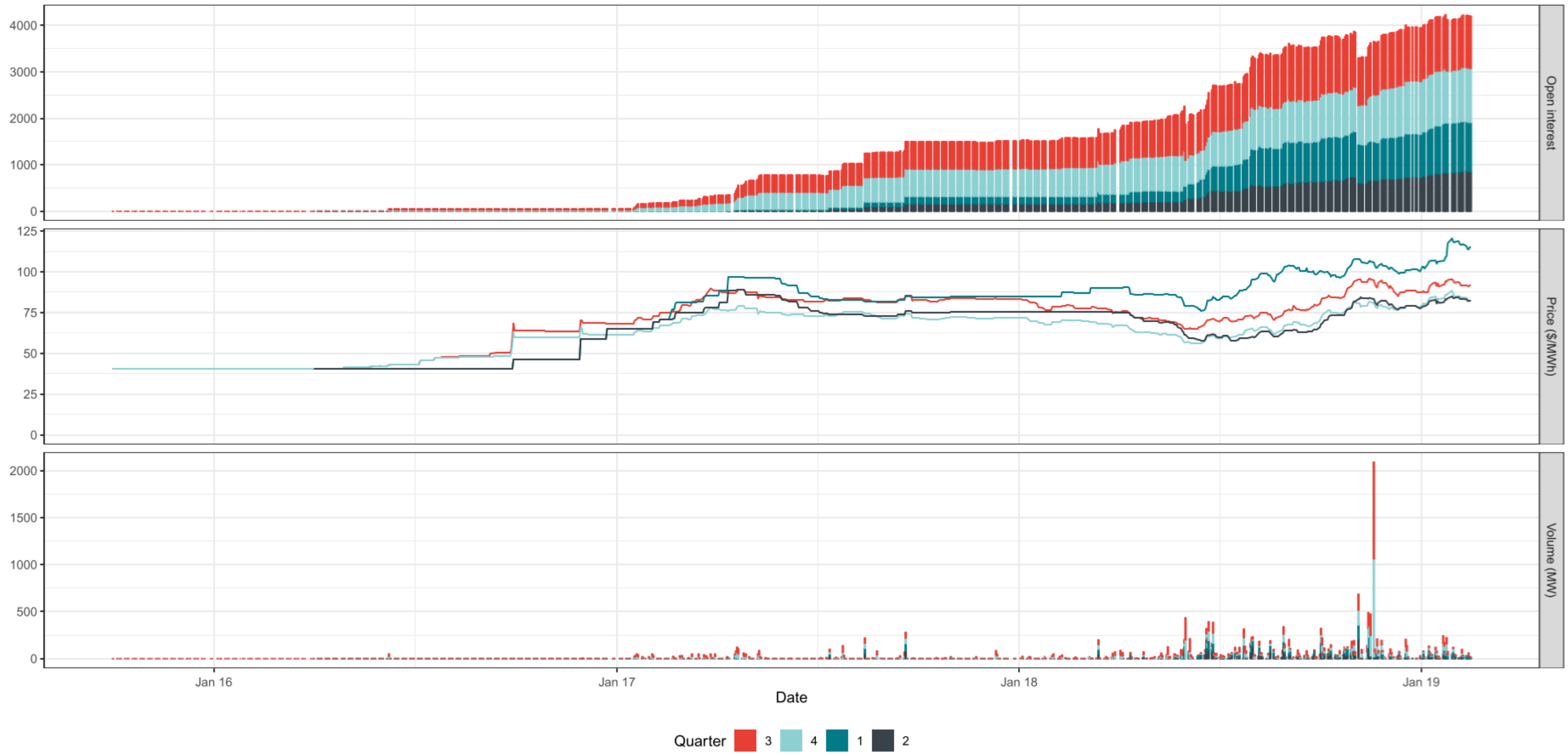
Source: Frontier Economics analysis of ASXEnergy data

Table 3: 24-month average ASXEnergy derivative prices for Victoria

PRODUCT	STATUS	FINANCIAL YEAR	QUARTER			
			Q3	Q4	Q1	Q2
$300 CAPS	Base	2020	$4.95	$6.75	$18.25	$4.89
SWAPS	Base	2020	$80.80	$71.13	$89.65	$73.75
	Peak	2020	$94.75	$89.34	$114.54	$92.24

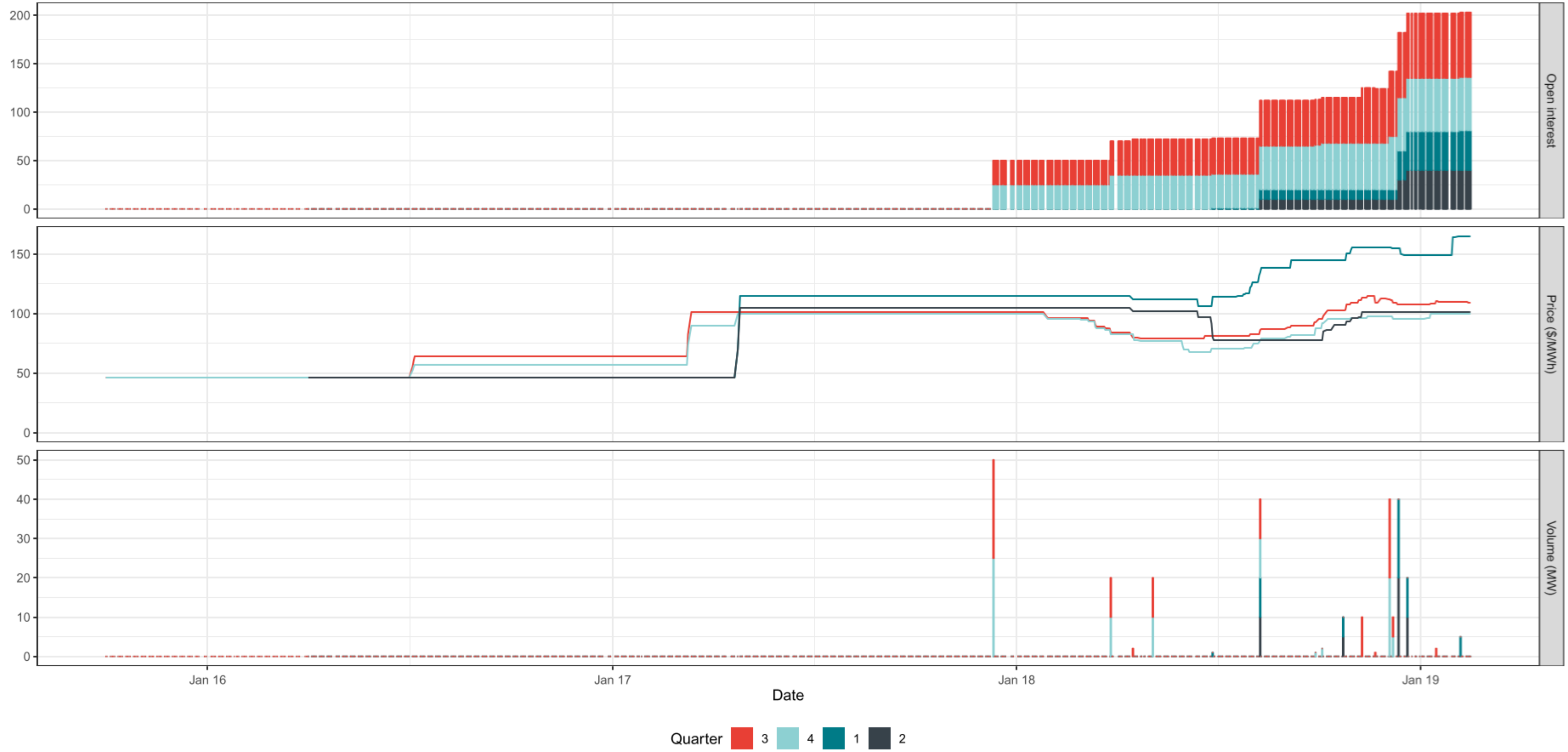
Source: Frontier Economics analysis of ASXEnergy data

Figure 12: Victorian base swaps – open interest, prices and volumes for financial year 2020



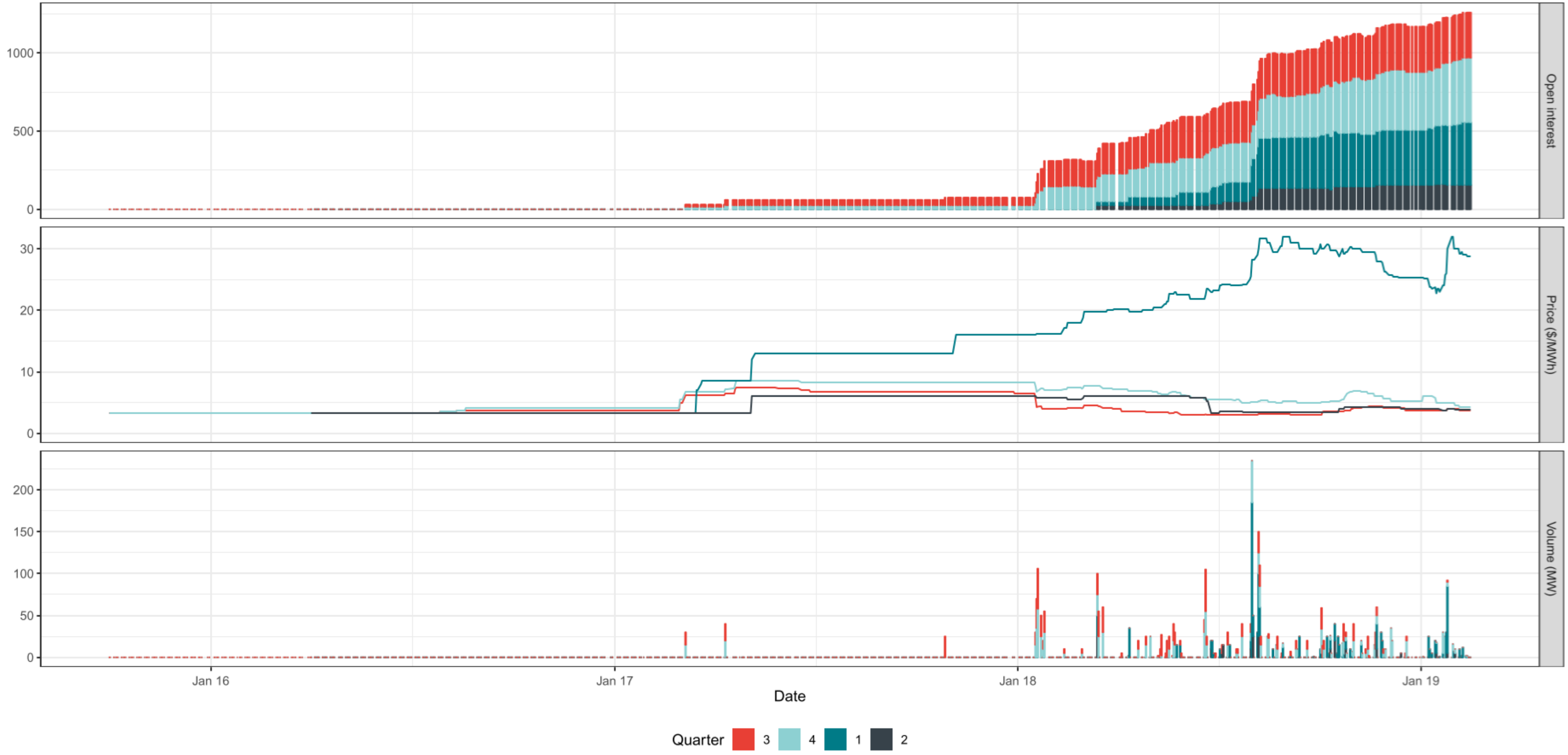
Source: Frontier Economics analysis of ASX data

Figure 13: Victorian peak swaps – open interest, prices and volumes for financial year 2020



Source: Frontier Economics analysis of ASX data

Figure 14: 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 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 each of 40-day, 12-month and 24-month 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 15** to **Figure 19** are the resulting contract positions at the conservative point for 2019/20, 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 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 15: Contract position for CitiPower MRIM load, ASXEnergy contract prices, 2019 (nominal dollars)

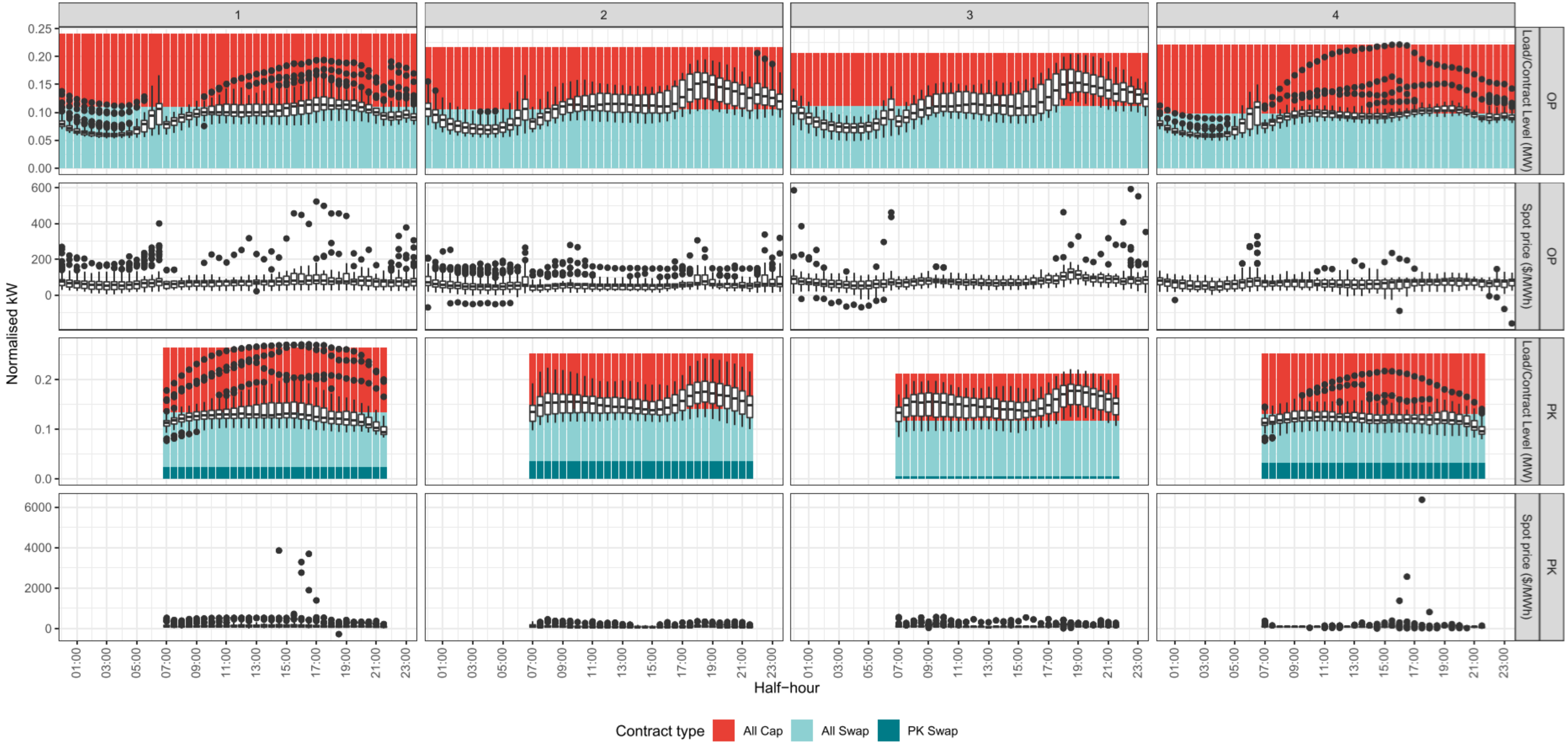


Figure 16: Contract position for Powercor MRIM load, ASXEnergy contract prices, 2019 (nominal dollars)

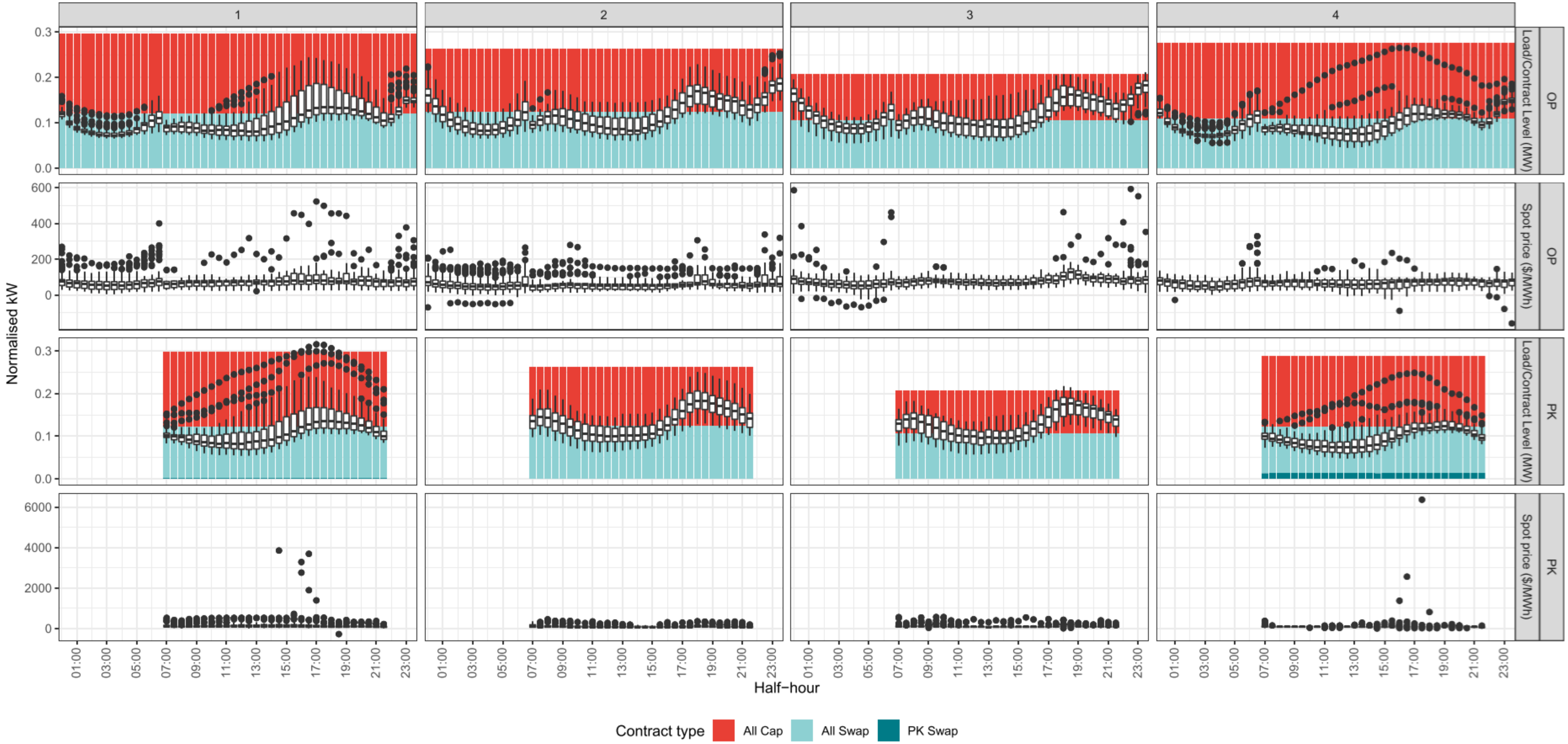


Figure 17: Contract position for VicAGL MRIM load, ASXEnergy contract prices, 2019 (nominal dollars)

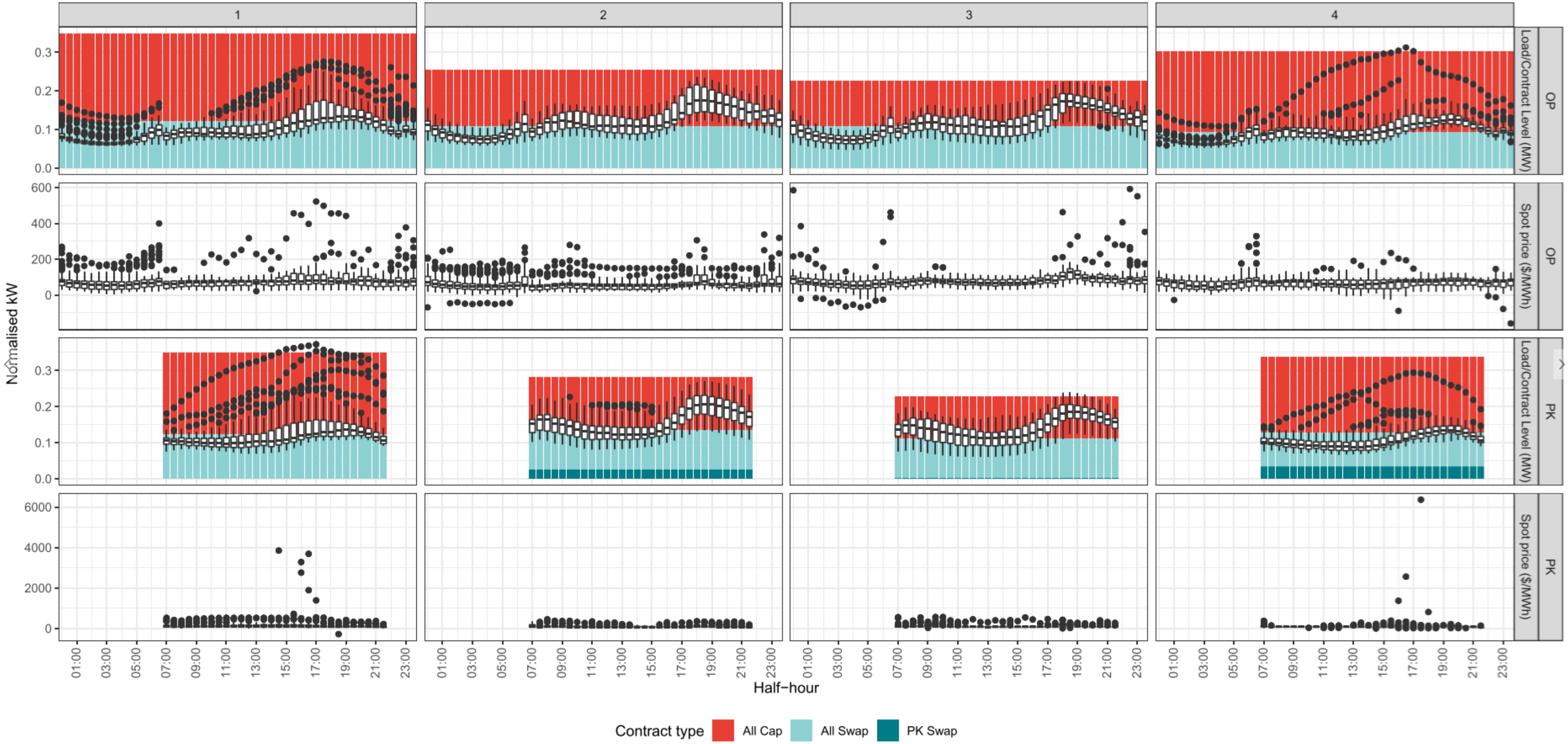


Figure 18: Contract position for TXU MRIM load, ASXEnergy contract prices, 2019 (nominal dollars)

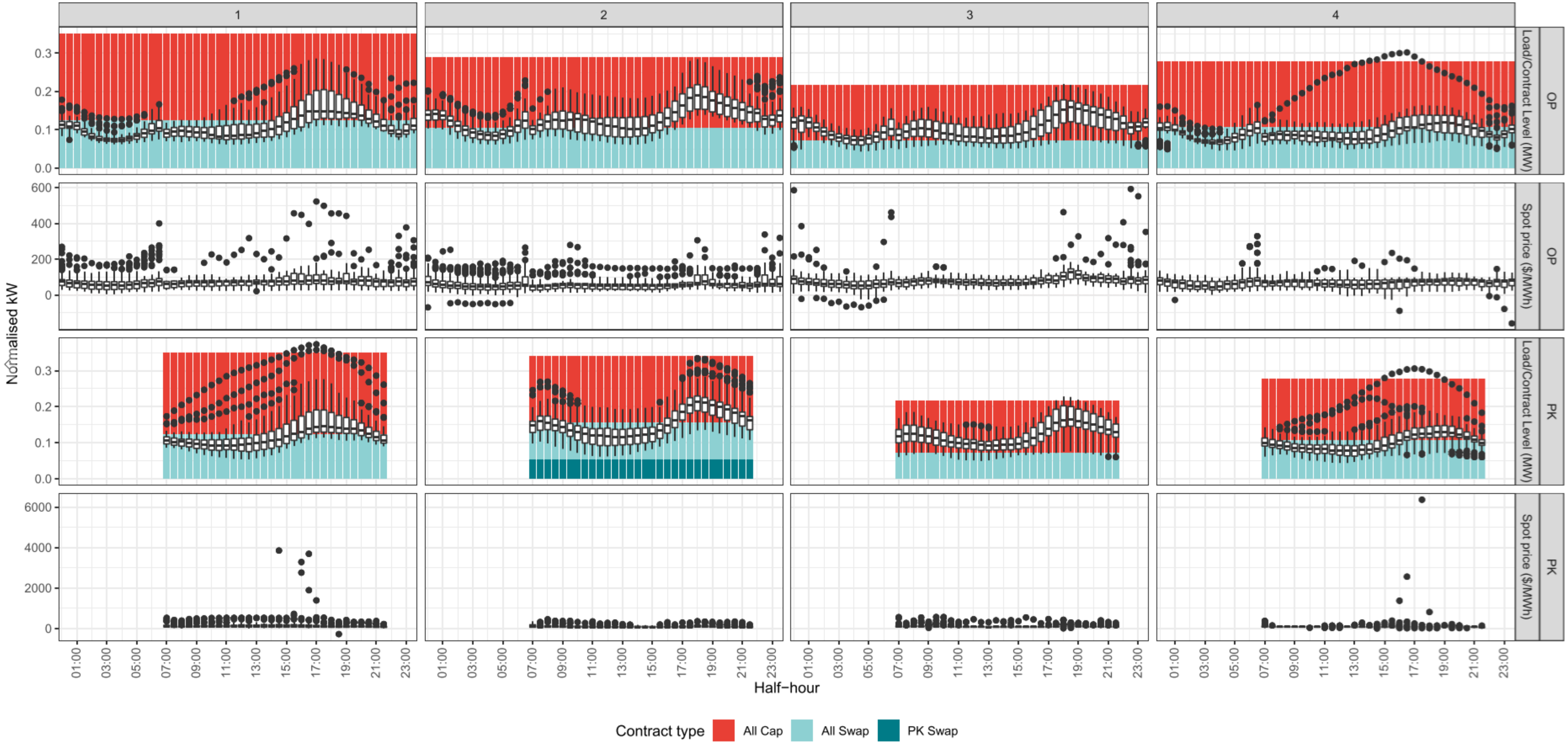
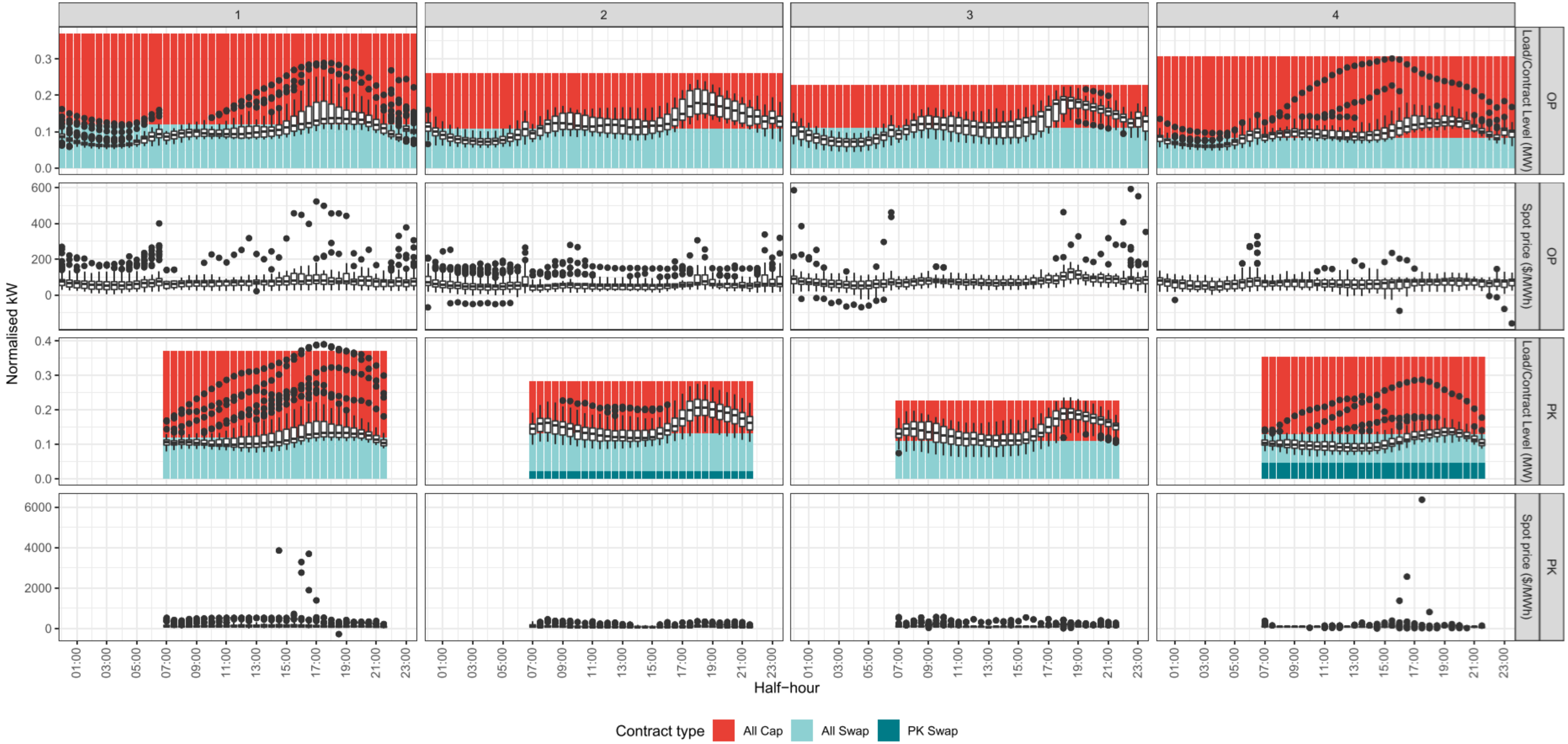


Figure 19: Contract position for United MRIM load, ASXEnergy contract prices, 2019 (nominal dollars)



As seen in **Figure 15** to **Figure 19**, the contract position at the conservative point does not result in complete coverage of the highest demand half hours. The reason that there remains 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 each of 40-day average, 12-month average and 24-month average ASXEnergy contract prices up to 15 February 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 4**.

Table 4: Modelled market-based wholesale electricity cost result

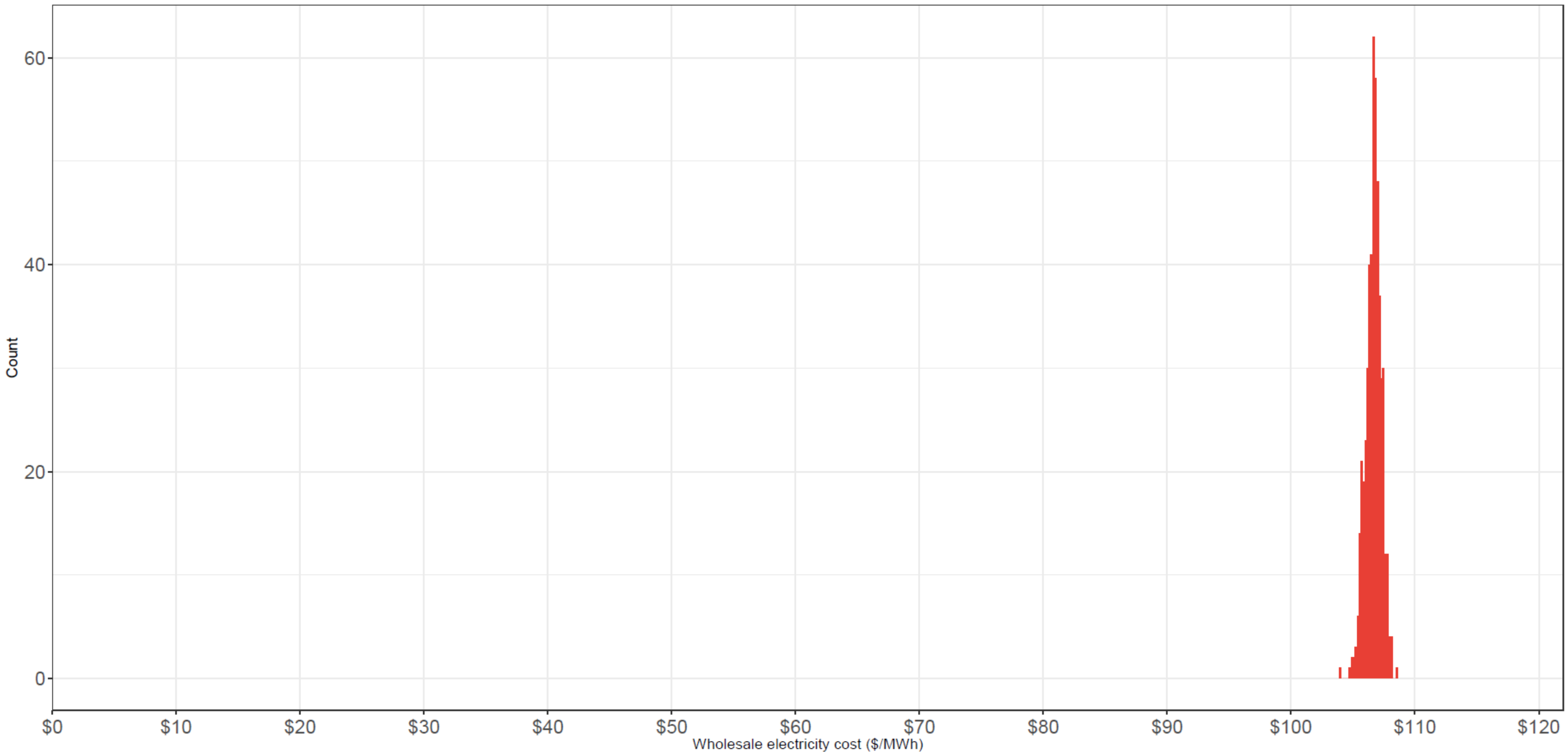
ENTITY	WHOLESALE ELECTRICITY COSTS ($/MWH, NOMINAL)		
	40-day average	12-month average	24-month average
CitiPower	$106.93	$94.21	$92.49
Powercor	$107.62	$94.92	$93.06
TXU	$111.16	$99.37	$96.59
United	$113.49	$101.08	$98.29
VicAGL	$112.41	$99.83	$97.29

Source: Frontier Economics

Figure 20 through **Figure 24** show the distribution of wholesale electricity costs 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.

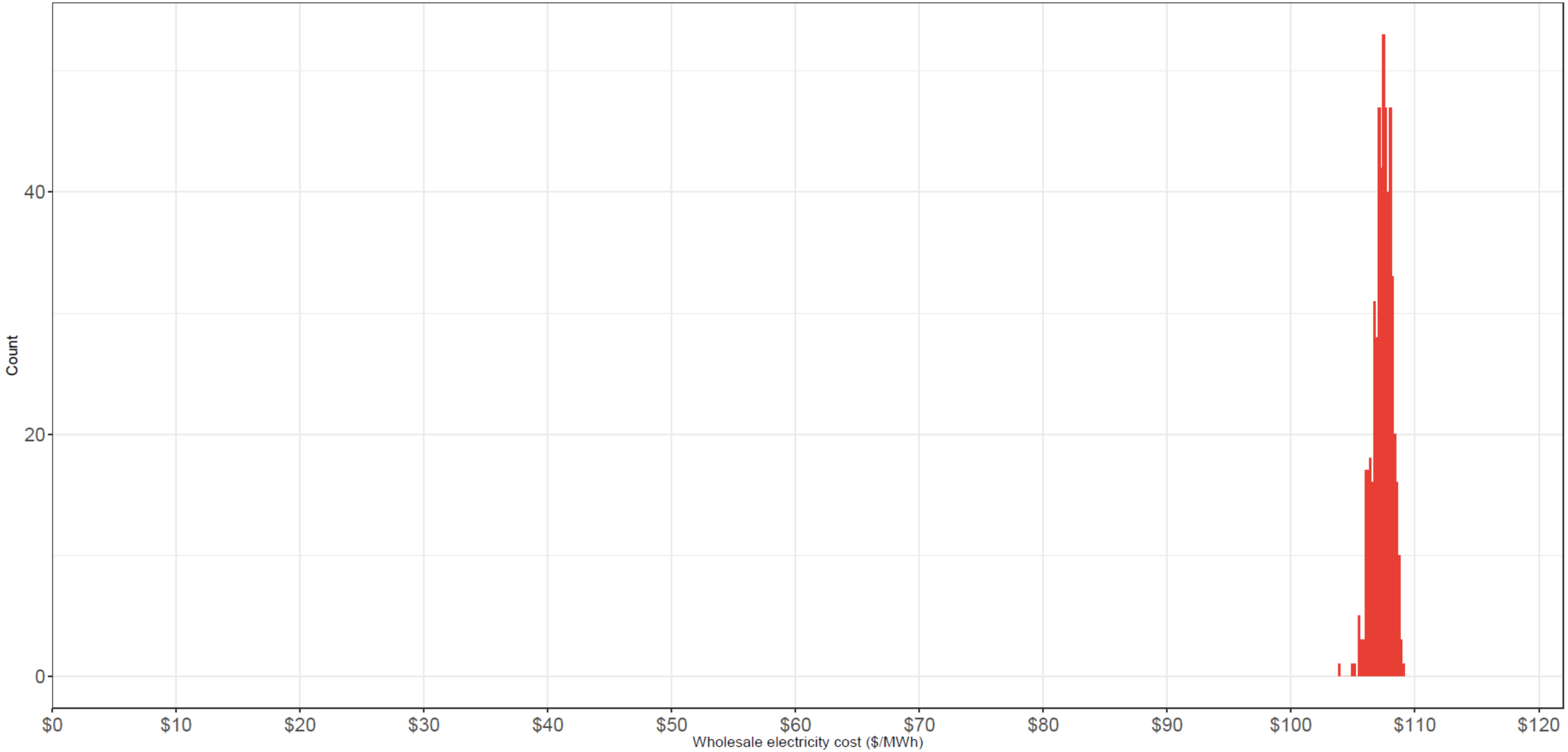
We note that these distributions do not reflect the distribution of all possible outcomes that retailers could face. If patterns of spot prices or load are materially different from the historical period on which we based our Monte Carlo analysis, or if average spot prices were to much different from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

Figure 20: CitiPower wholesale electricity cost distribution



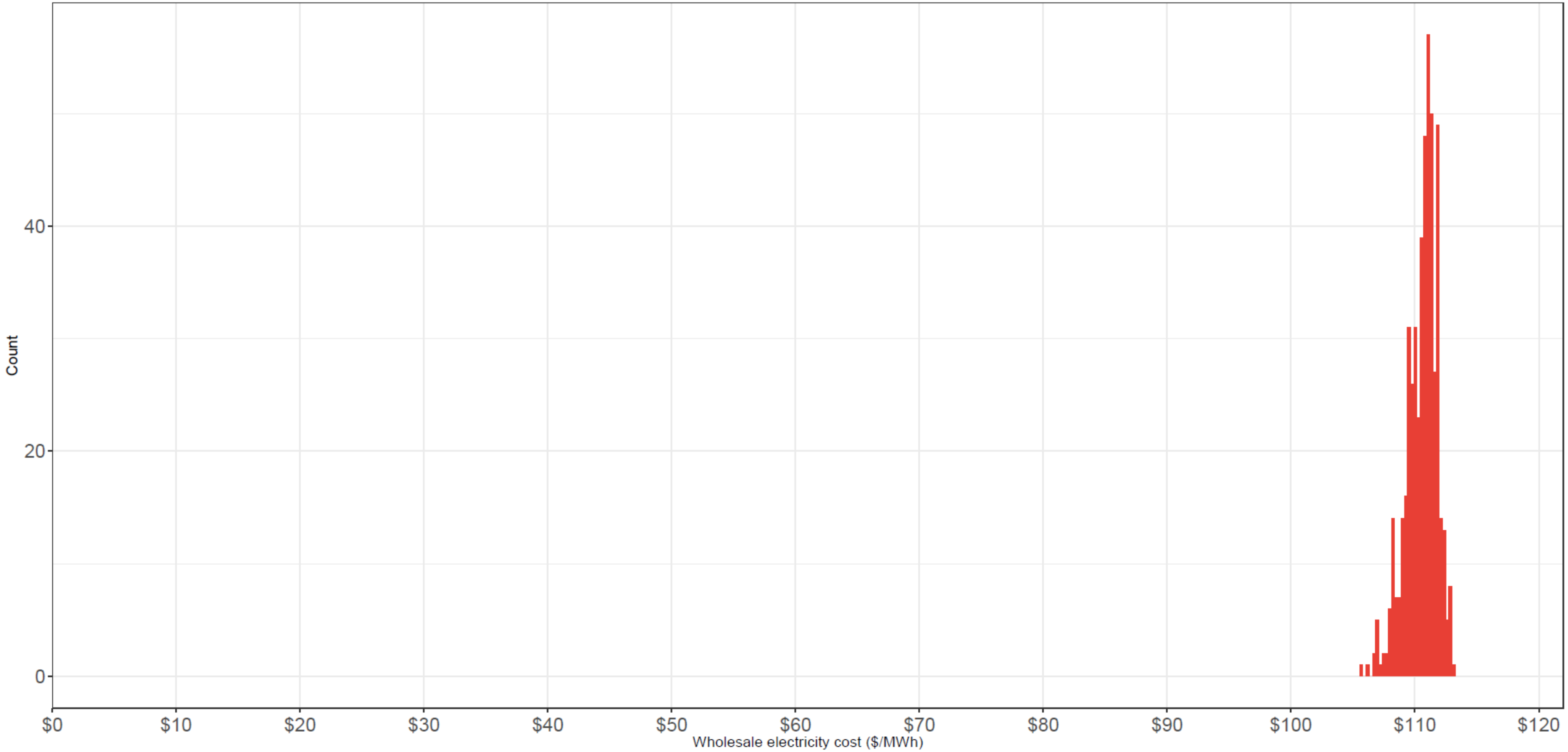
Source: Frontier Economics

Figure 21: Powercor wholesale electricity cost distribution



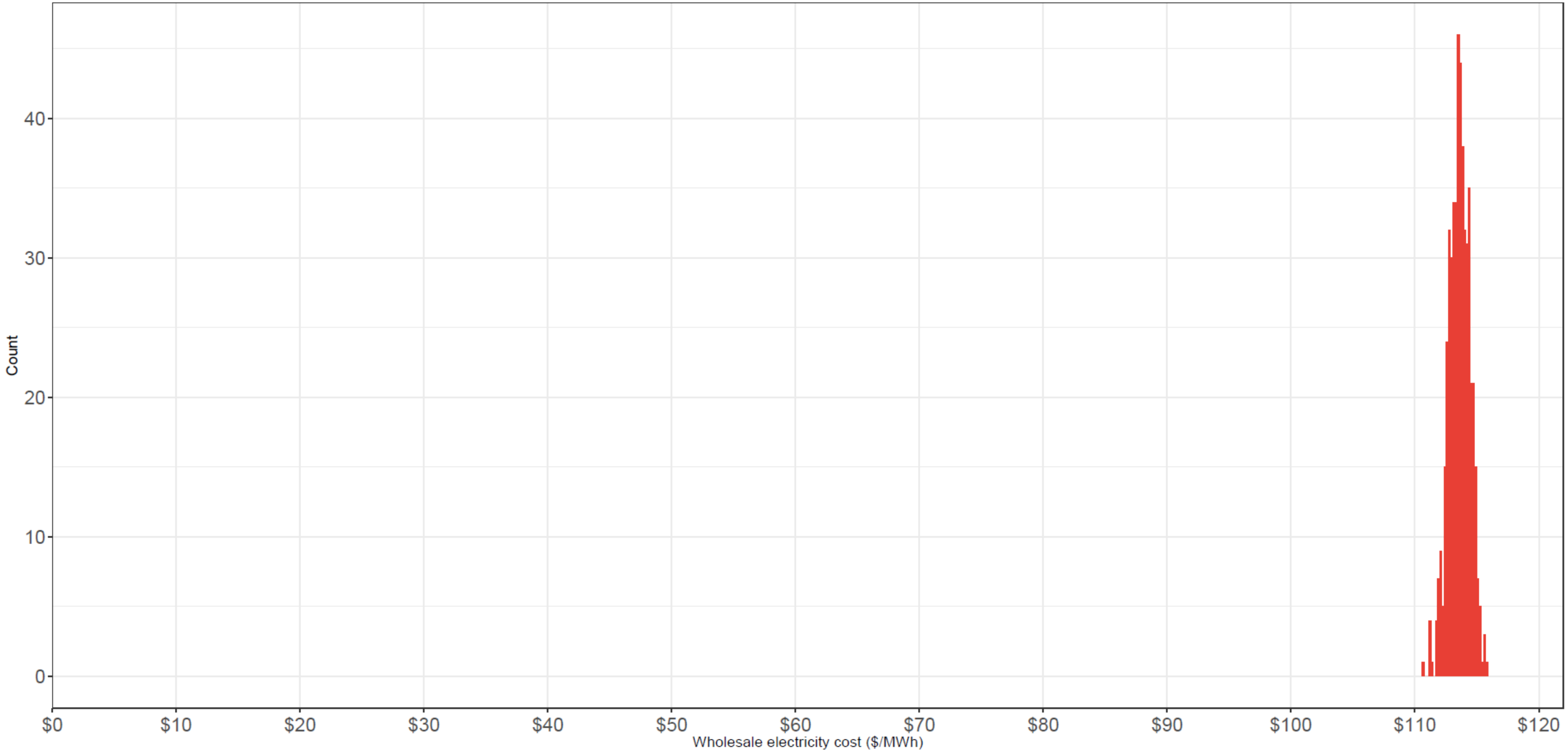
Source: Frontier Economics

Figure 22: TXU wholesale electricity cost distribution



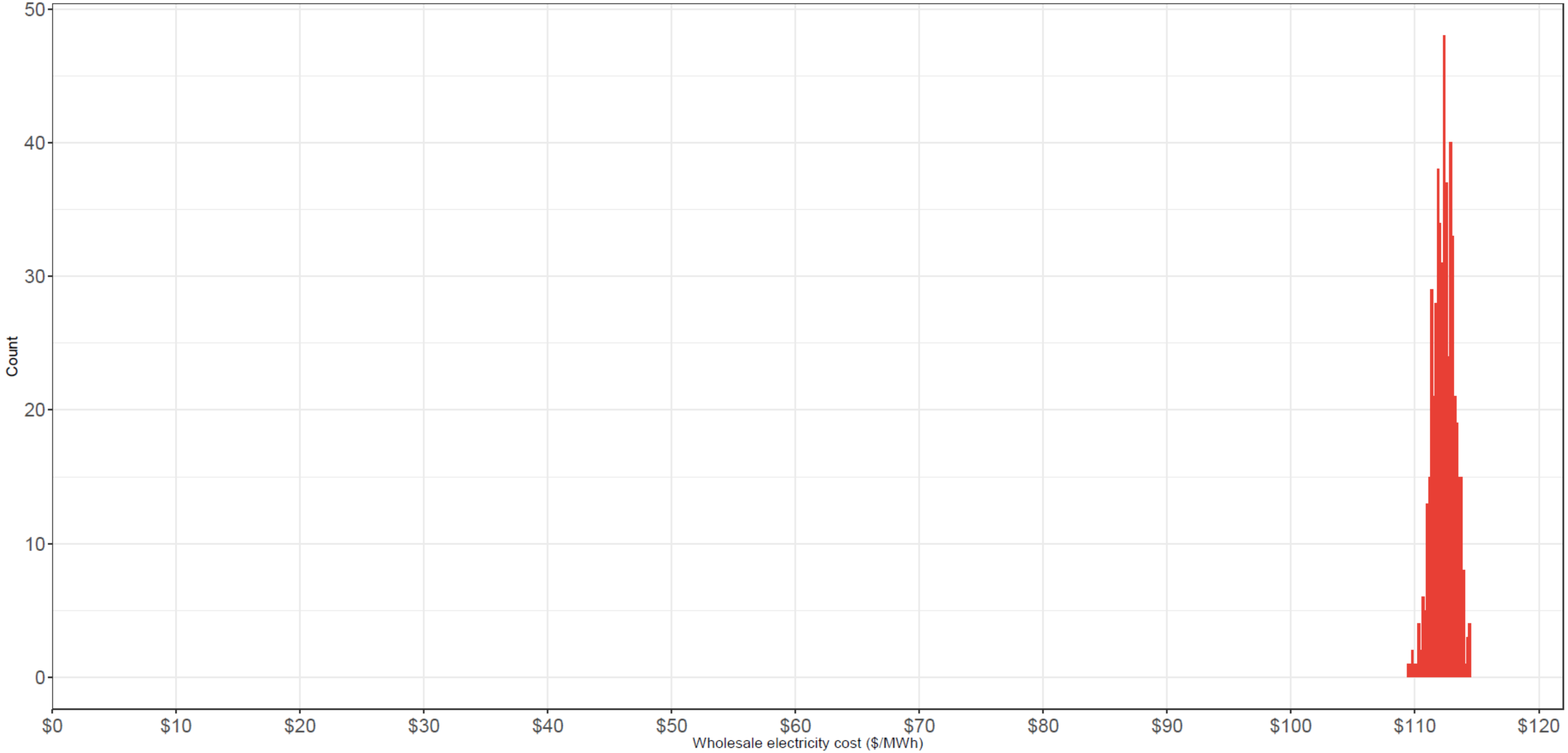
Source: Frontier Economics

Figure 23: United wholesale electricity cost distribution



Source: Frontier Economics

Figure 24: VicAGL 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 contract 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 5**.

Table 5: Modelled volatility allowance

DISTRIBUTION AREA	VOLATILITY ALLOWANCE ($/MWH, NOMINAL)
CitiPower	$0.15
Powercor	$0.12
TXU	$0.18
United	$0.17
VicAGL	$0.16

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).

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 17.52, which is set out in **Table 6**.

Table 6: Renewable Power Percentage

CALENDAR YEAR	RPP (% OF LIABLE ACQUISITIONS)
2019	17.52%

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 40-day average of LGC prices reported by Mercari.[4]

Table 7: 40-day average LGC future price from Mercari Rates

CALENDAR YEAR	LGC PRICE ($/CERTIFICATE, REAL FY2020)
2019	$44.72

Source: Mercari Rates

Cost of complying with the LRET

Based on the RPP set out in **Table 6** and the LGC price set out in **Table 7**, the cost of complying with the LRET is set out in **Table 8**.

Table 8: Cost of complying with the LRET

CALENDAR YEAR	COST OF COMPLYING WITH LRET ($/MWH, REAL FY2020)
2019	$7.84

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.

4 Available at: http://lgc.mercari.com.au/. Accessed 12th January 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 non-binding STPs of 12.13%, which is set out in **Table 9**. For the final report we would expect to make use of the updated estimate of the STP released by the Clean Energy Regulator.

Table 9: Small-scale Technology Percentages

CALENDAR YEAR	STP (% OF LIABLE ACQUISITIONS)
2019	12.13%

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 10**.

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

Table 10: 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 9** and the STC price set out in **Table 10**, the cost of complying with the SRES is set out in **Table 11**.

Table 11: Cost of complying with the SRES

CALENDAR YEAR	COST OF COMPLYING WITH SRES ($/MWH, REAL 2020)
2019	$4.91

Source: Frontier Economics

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