frontier economics

Wholesale electricity costs for 2021

A final report for the Essential Services Commission | 22 October 2020

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1 Introduction

Frontier Economics has been engaged to advise the Essential Services Commission (ESC) on allowances for wholesale electricity costs for calendar year 2021 for retailing electricity to small customers, for the purposes of determining the Victorian Default Offer (VDO).

1.1 Background

The ESC is required to determine prices for the VDO to apply from 1 January 2021. To inform this the ESC needs forecasts of retailers' wholesale electricity costs and of retailers' costs of complying with environmental programs for calendar year 2021.

1.2 Frontier Economics' engagement

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

- The wholesale electricity cost (WEC) component of retailers' cost to supply small customers from 1 January 2021.
- The retailers' costs of complying with the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES) in supplying small customers from 1 January 2021.

1.3 This final report

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

- Section 2 provides an overview of the approach used to estimate wholesale energy costs.
- Section 3 discusses the half-hourly prices and half-hourly load used in our analysis.
- Section 4 discusses the contract prices used in our analysis.
- Section 5 discusses the 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 spreadsheets setting out details of half-hourly load and price forecasts, contract positions resulting from our modelling, and calculations for determining the WEC.

1.4 Previous advice to the ESC

Frontier Economics has previously advised the ESC on the WEC and the cost of complying with the LRET and the SRES for financial year 2019/20 and calendar year 2020.[1] This final report adopts substantially the same approach for estimating WEC and the costs of complying with the LRET and the SRES for 2021 as we previously adopted for 2020.

1.5 Changes since the draft report

We have made a number of changes since our draft report as a result of the availability of new information:

- We have used more recent ASXEnergy contract prices. This includes using ASXEnergy cap prices for Q3 2021, which have become available since we undertook our modelling for the draft report.
- We have used more recent LRET certificate prices.

1 Frontier Economics, *Wholesale Electricity Costs*, A report for the Essential Services Commission, 24 April 2019. Available on the ESC's website: https://www.esc.vic.gov.au/electricity-and-gas/inquiries-studies-and-reviews/electricity-and-gas-retail-markets-review-implementation-2018/electricity-and-gas-retail-markets-review-implementation-2018-victorian-default-offer#tabs-container2 and https://www.esc.vic.gov.au/sites/default/files/documents/OTH%20-%20VDO%202020%20-%20Final%20wholesale%20electricity%20and%20enviro%20costs%20for%20final%20decision%2020191112.PDF

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 for 2020/21 is $15,000/MWh) and the market floor price (which is -$1,000/MWh).[2] Since retailers will typically commit to supply their customers at a specified retail price for a period of time, this volatility in settlement payments can result in retailers paying more for electricity than they receive for that electricity through the retail price they have agreed with their customers. At worst, this exposes the retailers to the risk of financial failure.

To manage the risks associated with volatile load and spot prices, retailers will typically seek to hedge their exposure to spot prices by entering into hedging arrangements. There are 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.

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

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

[2] AEMC, *Schedule of reliability settings,* 20 February 2020

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

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

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

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

3.2 Selecting appropriate historical data

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

The data that is directly provided by AEMO is for 2016/17, 2017/18, 2018/19 and 2019/20. 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 (discussed in Section 3.3). However, 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 data directly provided by AEMO is preferable to the longer set of publicly available MRIM data.

Analysis of data

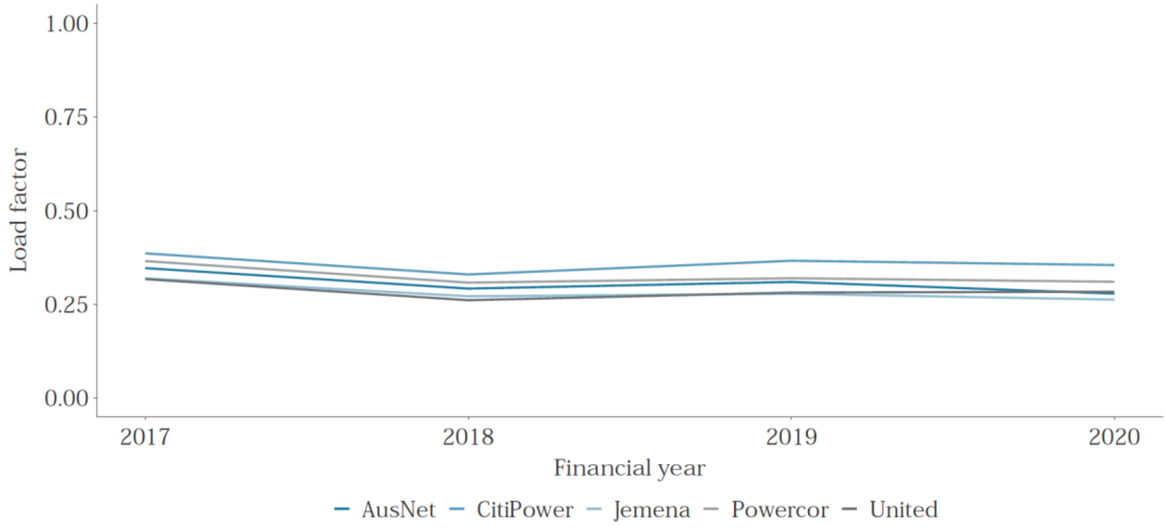
Figure 1 shows the annual load factor for the residential data for each Victorian DNSP for the last four financial years. We can see that there is a slight drop in load factor for every DNSP from 2016/17 to 2017/18, but since then the load factor has been relatively consistent.

Figure 2 shows the annual load factor for business data for each Victorian DNSP for the last four financial years. We can see that there was a slight increase in the load factor from 2016/17 to 2017/18 for AusNet and Powercor, but that on the whole the load factors have remained relatively steady.

Figure 3 and **Figure 4** show the average daily profile for residential and business customers respectively for each Victorian DNSP for the last four 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 only slight relative reductions in load during the day for residential and business customers in some network areas.

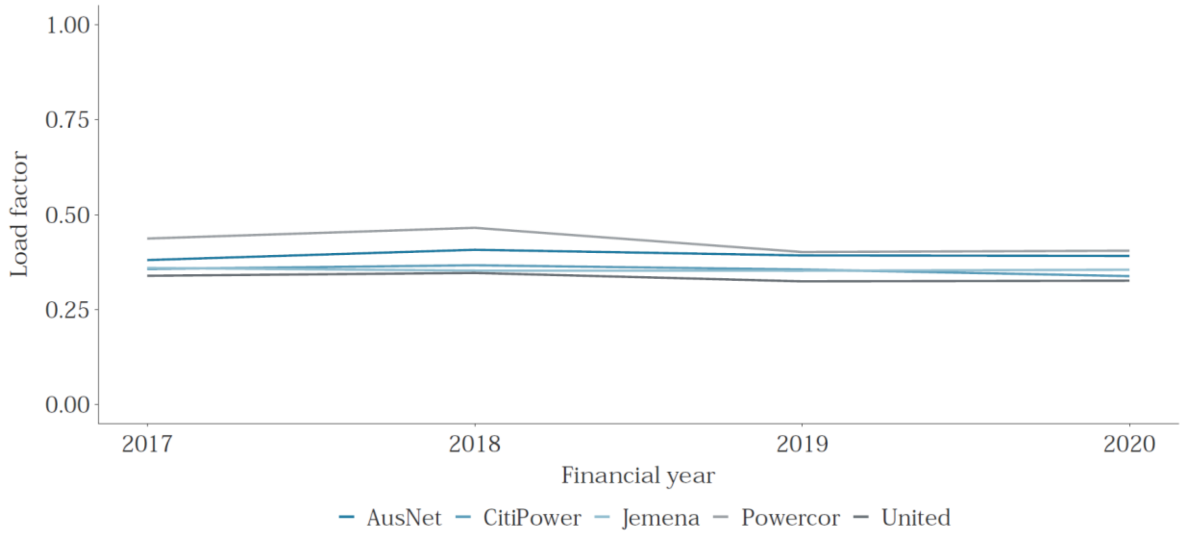
In addition to analysing the load data on an annual basis, we have also analysed data for 2020 on a weekly and monthly basis, and compared it with data from the previous years, to assess whether our response to COVID-19 has affected consumption. We found reasonable evidence that total consumption has changed as a result of our response to COVID-19 for each DNSP and each customer type; the evidence suggests that aggregate consumption for residential customers has increased and aggregate consumption for small business customers has decreased, but only from April onwards. There was not the same evidence of a consistent change in the average daily profile for each DNSP and each customer type. In some months and for some DNSPs there has been evidence of changes in load profile, but in other cases there has not been. The more recent evidence suggests that the response to the second wave of COVID-19 in Victoria has led to more material changes in load profile, although it is not clear whether this will persist. Given that it is the profile of consumption that drives the WEC, rather than aggregate consumption, we have not attempted to adjust the load profile for any assumed ongoing impact of COVID-19 in 2021. Our analysis of the impact of COVID-19 on load is summarised in Appendix A.

Figure 1: Load factor for residential customers



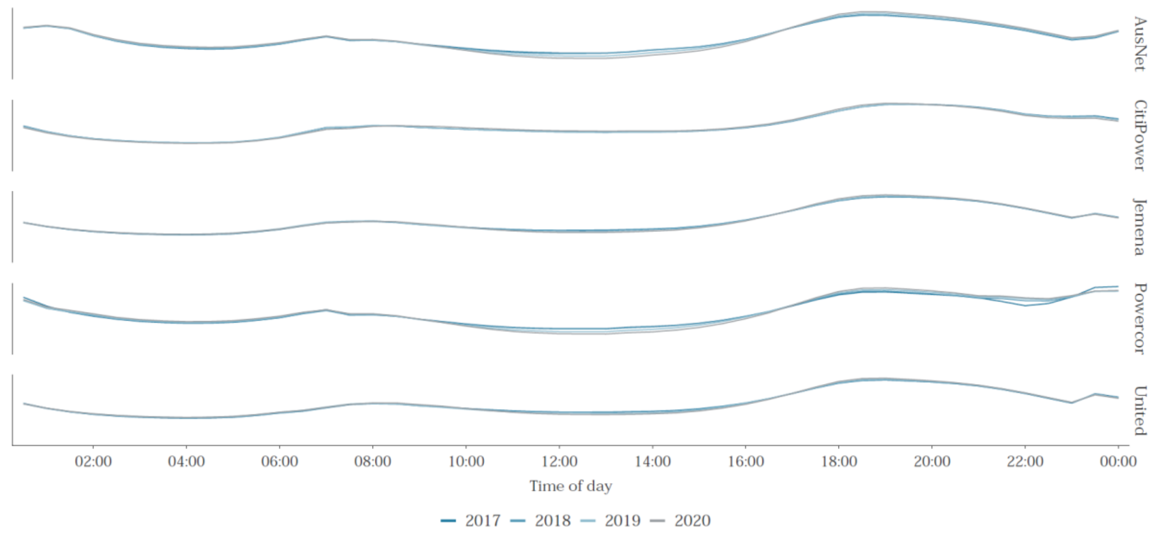
Source: Frontier Economics analysis of AEMO data

Figure 2: Load factor for business customers



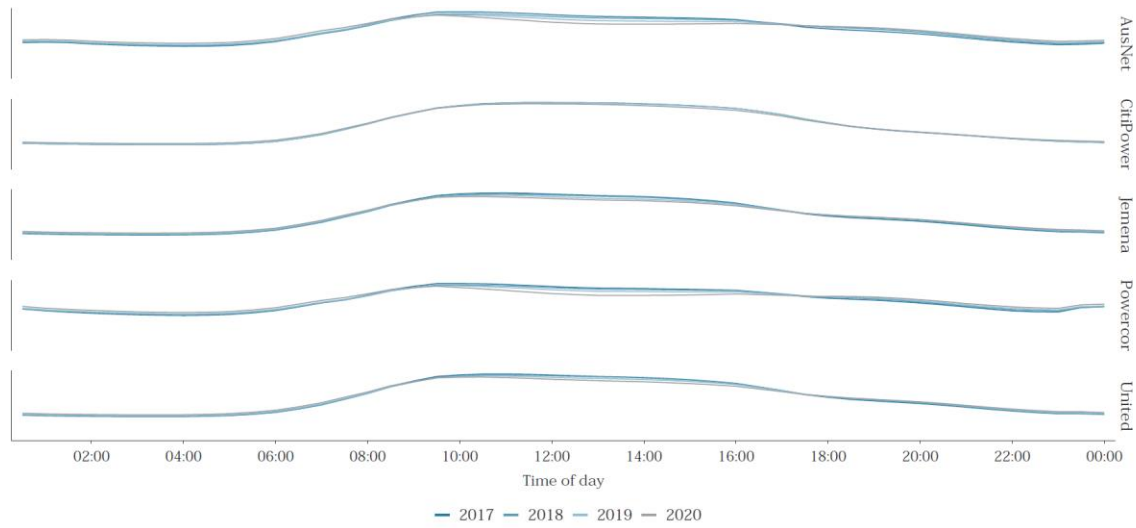
Source: Frontier Economics analysis of AEMO data

Figure 3: Average daily profile for residential customers



Source: Frontier Economics analysis of AEMO data

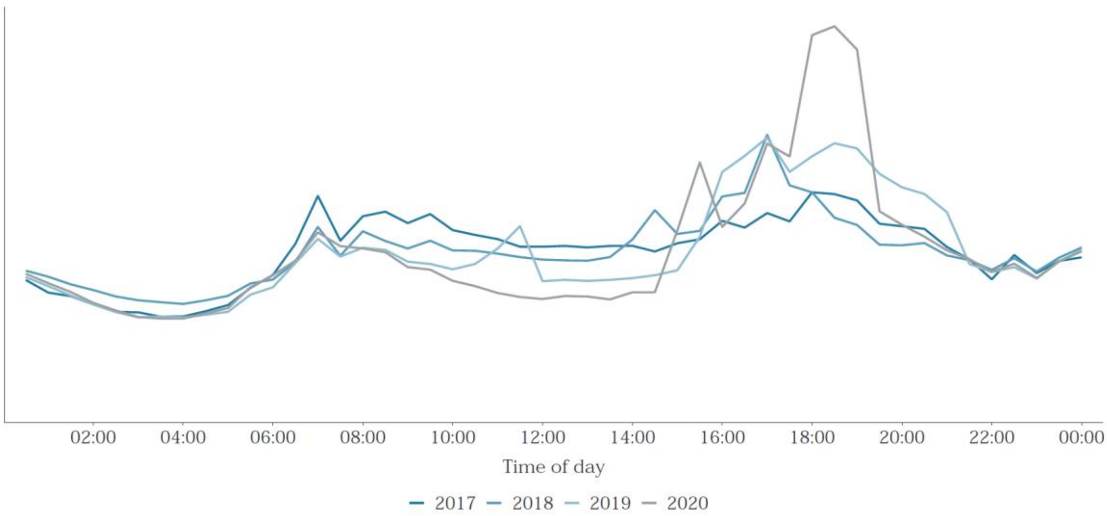
Figure 4: Average daily profile for business customers



Source: Frontier Economics analysis of AEMO data

Figure 5 shows the average daily profile for Victorian spot prices for the last four 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. However, in each case we do see similar patterns of low overnight prices, a price spike tending to occur in the morning, and further high prices tending to occur in the mid-afternoon to evening. The spot price data for 2019/20 shows that higher prices persisted for longer and higher in the evening in 2019/20 than they did in previous financial years.

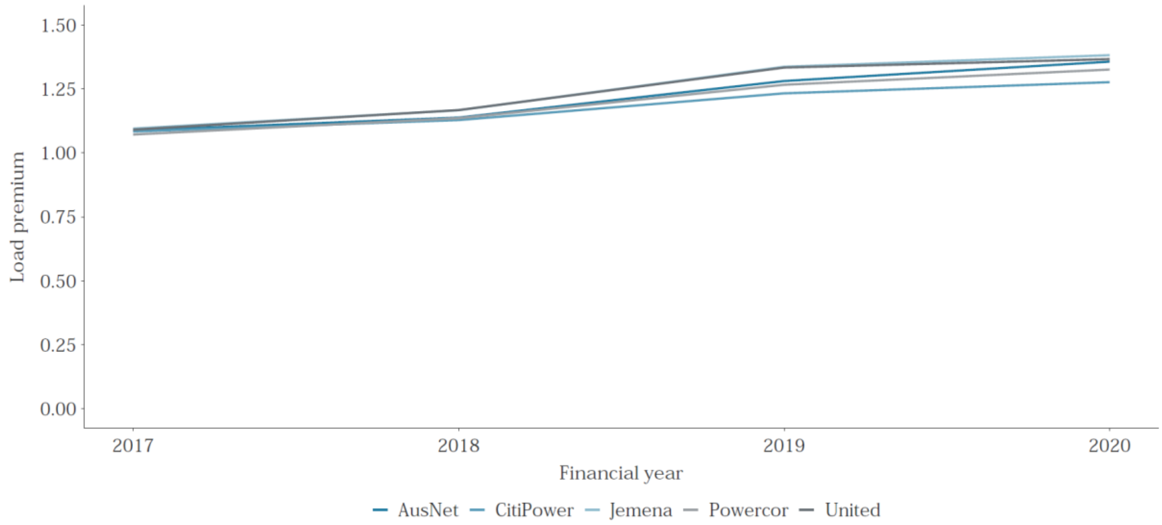
Figure 5: Average daily profile for Victorian spot prices



Source: Frontier Economics analysis of AEMO data

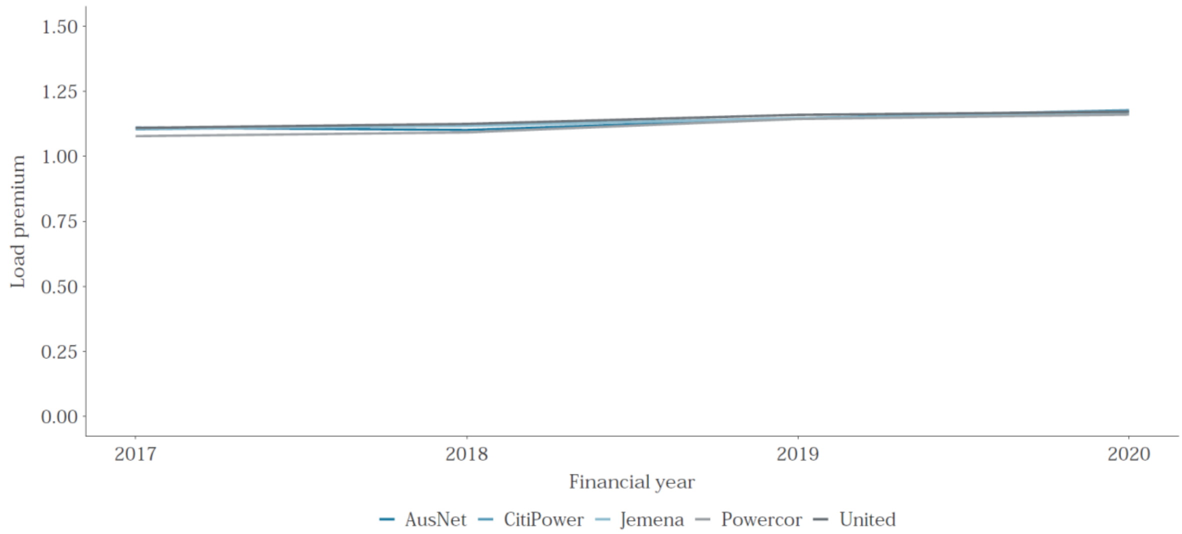
Figure 6 and **Figure 7** combine the historical customer load data and spot price data to report the load premium (calculated as the load-weighted price divided by the time-weighted price) for each customer type, for each Victorian DNSP and for each of the last four financial years. In our experience, the load-weighted spot price (and, by extension, the load premium) is a reasonable guide to the WEC. We can see from **Figure 6** and **Figure 7** that the load premium over 2016/17 and 2017/18 was reasonably constant, but increased more significantly since then, largely as a result of spot prices that remained higher for longer in the evening in 2018/19 and 2019/20.

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



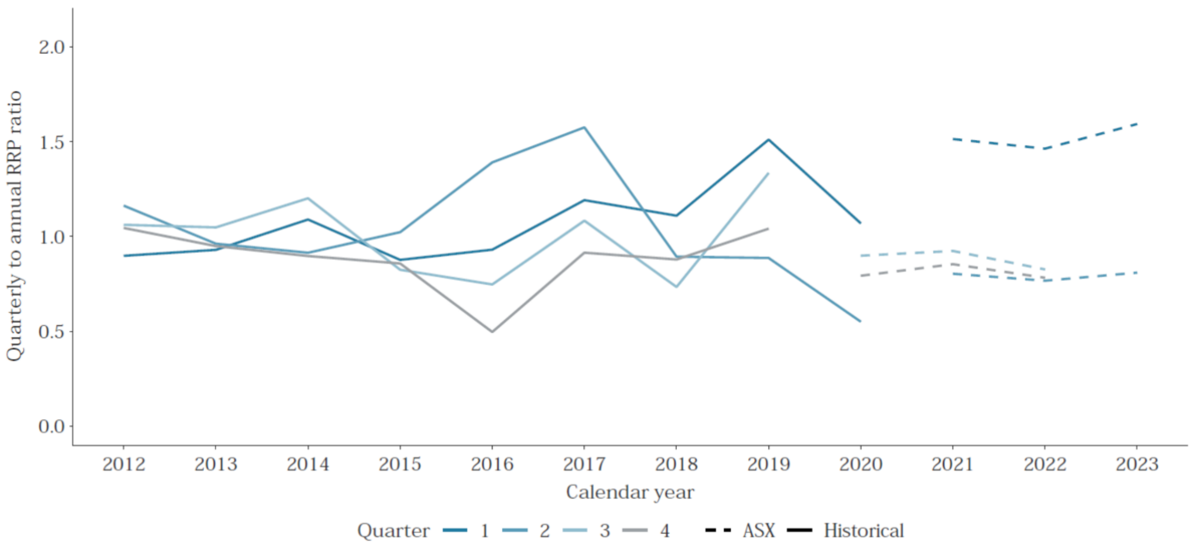
Source: Frontier Economics analysis of AEMO data

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 over time: average prices have tended to be highest in Q2 or Q3, but in recent years we have seen the highest prices in Q1. This is consistent with ASXEnergy data, which sees the highest prices for Q1 contracts. In any case, to minimise any potential issues with scaling historical half-hourly prices to ASXEnergy prices with a different quarterly pattern, 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.

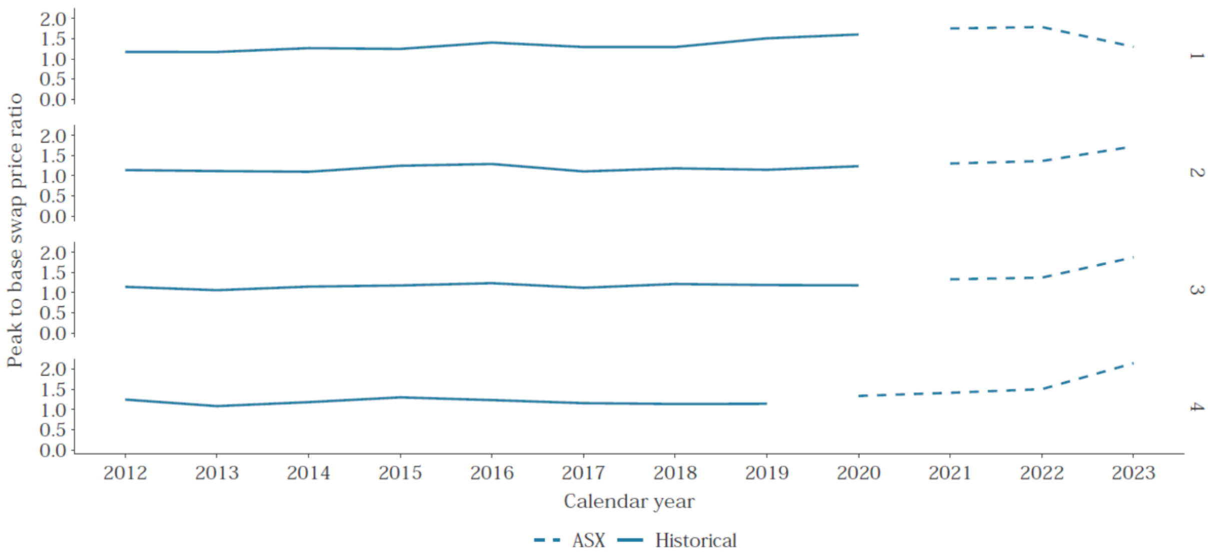
Figure 9 examines peak/off-peak patterns of spot prices and ASXEnergy prices. For each peak/off-peak period, **Figure 9** presents the relationship between average peak/off-peak prices and average annual prices: on an historical basis this relationship is based on historical Victorian spot prices; on 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

Based on the analysis of historical half-hourly load and half-hourly prices set out above, our approach for this report is to continue to adopt the approach that we adopted in our advice to the ESC for the VDO for 2020; that is, we continue to include all historical data available to us (in this case, data from 2016/17, 2017/18, 2018/19 and 2019/20) in a Monte Carlo simulation when forecasting half-hourly load and half-hourly prices. Implicit in this approach is the assumption that patterns of load and prices for each of these four historical years can provide useful information on patterns of load and price outcomes for 2021.

As we have seen above, there has been little change in the average daily load profile for residential or small business customers, and, in our view, it is reasonable to think that half-hourly load from 2016/17 through to 2019/20 can provide useful information on potential load and price outcomes for 2021. While there is some indication that load in the middle of the day is falling slightly – likely as a result of increased solar PV generation – the effect does not appear to be significant. Our assessment suggests that under current market conditions, these changes in load (and, more broadly, the effect that solar PV has on load) would not have a material impact on our estimate of the WEC. However, this will need to be monitored in future.

While there is little change in the average daily load profile, there have been more significant changes in price outcomes over the period 2016/17 through to 2019/20. In particular, the average daily profile for spot prices shows that the peak in spot prices in the mid-afternoon to evening period has become more pronounced each year from 2016/17 to 2019/20, and has persisted longer in the evening. This is primarily driven by an increasing number of high price events during the afternoon and evening in Q1. What is more, the analysis of ASXEnergy data that we have undertaken – including as summarised in **Figure 8** – suggests that the market is expecting similar high price events to occur during Q1 2021.

This raises the question of whether only using half-hourly prices (and load) from more recent years would be preferable to including data from all four historical years in a Monte Carlo simulation. For instance, as an alternative to using data from all four years from 2016/17 through to 2019/20 we could exclude data from 2016/17 on the basis that 2016/17 had fewer high price events during the afternoon and evening in Q1 than subsequent years. For this final report we continue to use all available data, consistent with the approach that we have adopted in previous years. However, we have investigated the effect of excluding data from 2016/17 on our estimate of the WEC and have found that it would result is a difference of less than 2% in the WEC.

3.3 Projecting half-hourly load and spot prices

As discussed, rather than take a single one of the years 2016/17, 2017/18, 2018/19 or 2019/20 as representative of outcomes in 2021, we perform a Monte Carlo simulation on the four years of half-hourly load and price data. In our view there are two benefits of using a Monte Carlo analysis:

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

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

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

- The first day of 2021 is 1 January 2021, which is a Friday. Since this is a Friday in Q1, the half-hourly load and spot data for the first day of 2021 will determined by randomly drawing a day's half-hourly data from all the Q1 weekdays that occurred in 2016/17 through to 2019/20.

- The second day of 2021 is 2 January 2021, which is a Saturday. Since this is a Saturday in Q1, the half-hourly load and spot data for the second day of 2021 will be determined by randomly drawing a day's half-hourly data from all the Q1 weekend days that occurred in 2016/17 through to 2019/20.
- And so on for the 365 days that make up 2021, 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 through to 2019/20.

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

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

We also make a further adjustment to the half-hourly spot prices. We consider that historical half-hourly spot prices provide the best source of information about patterns of half-hourly spot prices and how these are correlated with half-hourly load, but historical spot prices are not necessarily a good predictor of the future average level of Victorian spot prices. There is no reason, for instance, that Victorian spot prices over the period 1 January 2019 to 31 December 2019 will, on average, be the same as Victorian spot prices for 2021. In our view, the best available public information about the average level of Victorian spot prices for 2021 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 2021. 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 2021 from ASXEnergy[3] (less an assumed contract premium of 5 per cent on the underlying prices)[4]. We use the 40-day average of ASXEnergy contract prices for quarterly base swap prices

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

[4] 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. In its report for the Australian Energy Council, ACIL Allen recommended that "the appropriate level of contract premium is an outcome of the analysis rather than an input". We are unsure how this can be implemented and believe it would be incorrect to do so in any case. As discussed, the actual contract premium is by nature an unobservable value theoretically derived through comparing an expected outcome at a point in time to the observed outcome at the same point in time.

(up to 15 October 2020) as representing the market's current view of spot prices for each quarter of 2021.[5] This approach to generating half-hourly price forecasts results in:

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

Scaling half-hourly prices to base swaps and caps

Simply Energy submitted a concern they had regarding the difference between:

- the inferred price of caps from the half-hourly spot price forecasts we produce using the approach described above (which scales half-hourly prices to the price of base swaps on ASXEnergy), and
- the ASXEnergy price of caps.

As we only scale to base swap prices, there may be a difference between the inferred cap prices and ASXEnergy cap prices. In the median year chosen for the WEC, the inferred cap price was lower than the ASXEnergy prices, and Simply Energy was concerned that this would result in a WEC which was too low.

Our approach of scaling to base swap prices means that there is a mechanical approach that we can adopt to this scaling. However, additionally scaling the half-hourly price to match cap prices would require subjective decisions about the appropriate approach. For example, if we were to scale to cap prices, we could either scale all prices already above $300/MWh to match the cap price, increase all prices (both above and below $300) to match the cap price, or anything in between. Similar decisions would need to be made about how to rescale all the other price (below $300) to preserve the scaling to base swap prices. These decisions would reduce the predictability and transparency of our approach. For this reason, we prefer to retain the mechanical process of scaling only to base swaps.

However, to test the impact on the WEC of scaling to cap prices, we have investigated the impact under one possible approach of scaling the median year to both base swaps and caps. This was done by the following process:

- first scaling the entire series to match base swap prices on ASXEnergy,
- then re-scaling all prices above $300/MWh upwards to match the higher cap prices on ASXEnergy
- then re-scaling all the prices below $300/MWh downwards to ensure the average prices again match base swap prices on ASXEnergy.

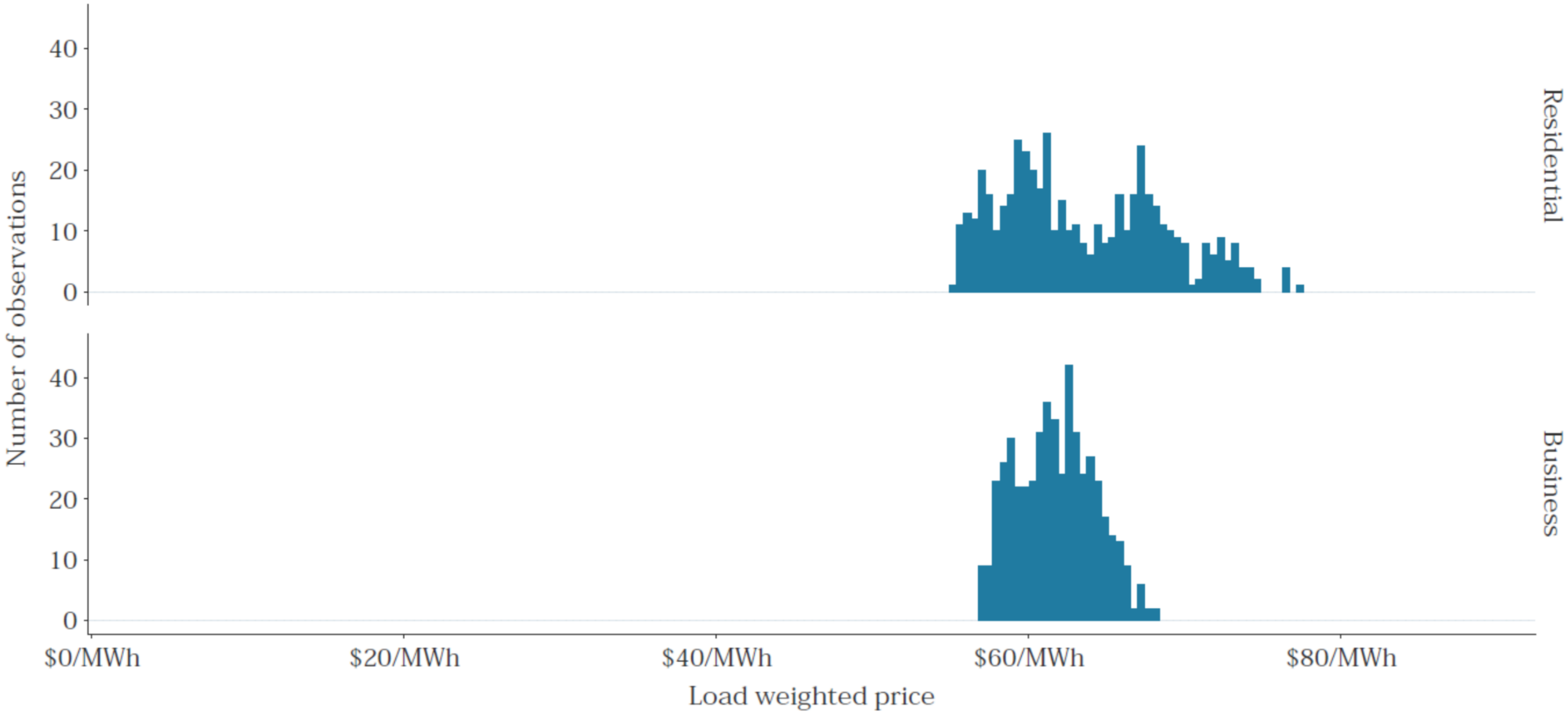
5 We note that there is a difference in the averaging period that we use for estimating spot prices for 2021 and the averaging period we use for calculating contract prices to be used in estimating the WEC for the VDO. As discussed, we use the most recent 40-day average ASXEnergy prices as the best guide to the market's view on spot prices that will occur in 2021. However, based on instructions from the ESC, we use 12-month trade weighted average ASXEnergy prices to set the contract price for retailers when determining the WEC. In our view, there is no necessity for these averaging periods to be consistent. One way to think about the WEC that we are calculating using this approach is that we are estimating the contract payments that a retailer would face if that retailer had purchased its contracts for 2021 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.

This resulted in a WEC which was less than the WEC under our standard approach. The reason is that under our approach we model a contract position in which the combined swap and cap coverage matches peak demand. This means that retailers are not exposed to prices higher than $300/MWh. However, retailers remain exposed to prices lower than $300/MWh, which are not covered by caps.

Analysis of data

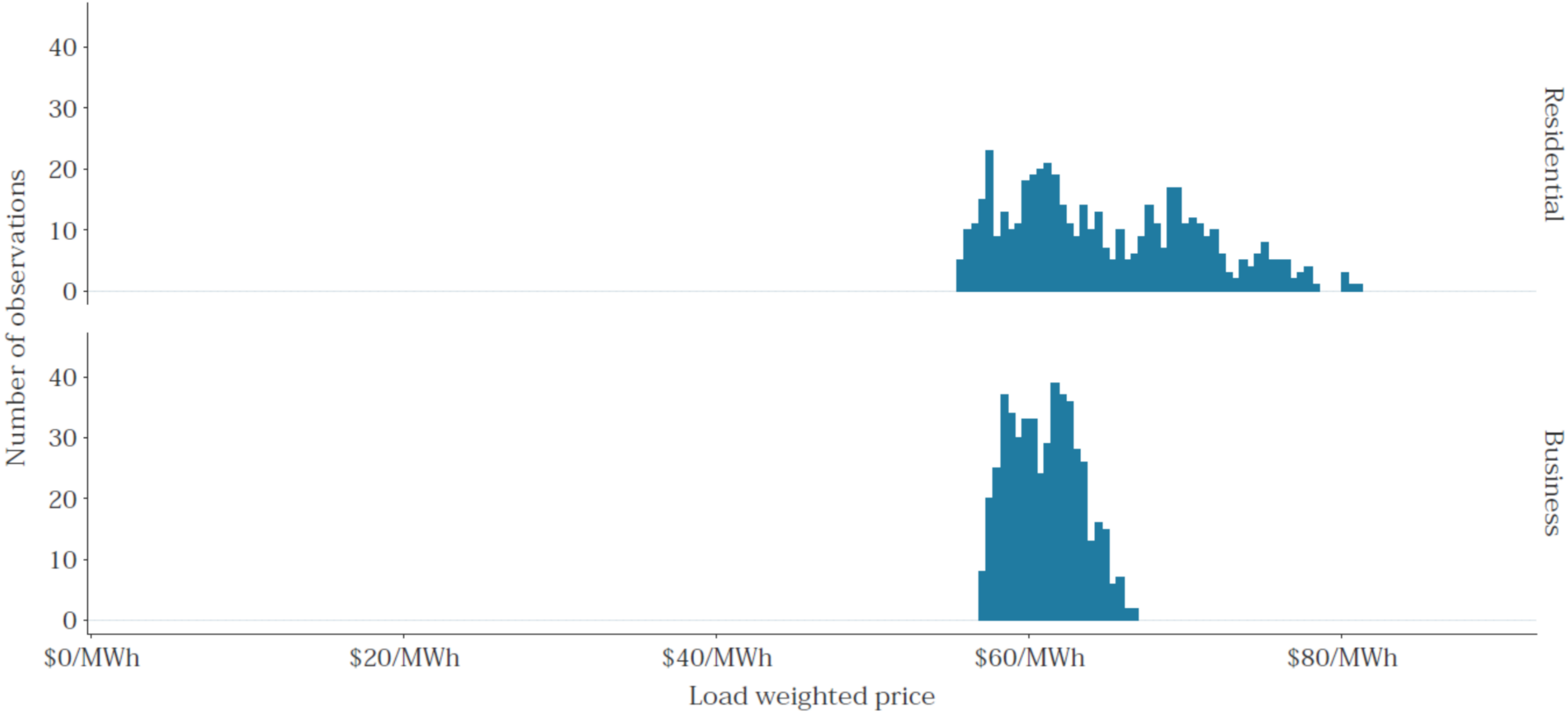
An indication of the results of our Monte Carlo simulation can be provided by calculating the load-weighted price for each of the 500 simulated years. As we discussed, in our experience the load-weighted price is a reasonable guide to the WEC. **Figure 10** through **Figure 14** show the distribution of load-weighted prices for each of the 500 simulated years from our Monte Carlo analysis, for each distribution area and for each customer type. As discussed, the average spot price in each of these simulated years is the same – based on the 40-day average ASXEnergy base swap price – but the half-hourly profile of both spot prices and load are different. It should be clear from **Figure 10** through **Figure 14** that the Monte Carlo simulation has resulted in a distribution of load-weighted prices driven by differences in the half-hourly patterns of spot prices and load.

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



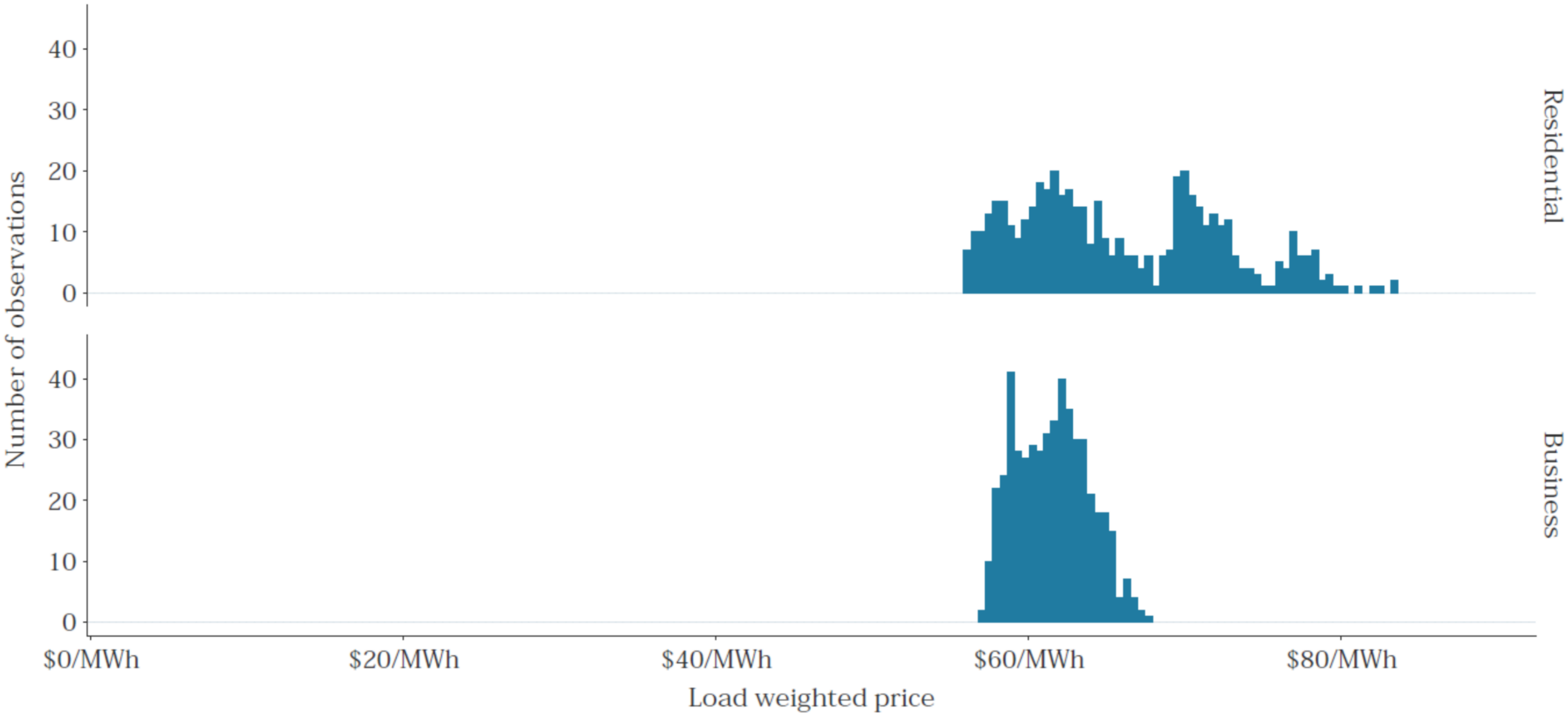
Source: Frontier Economics

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



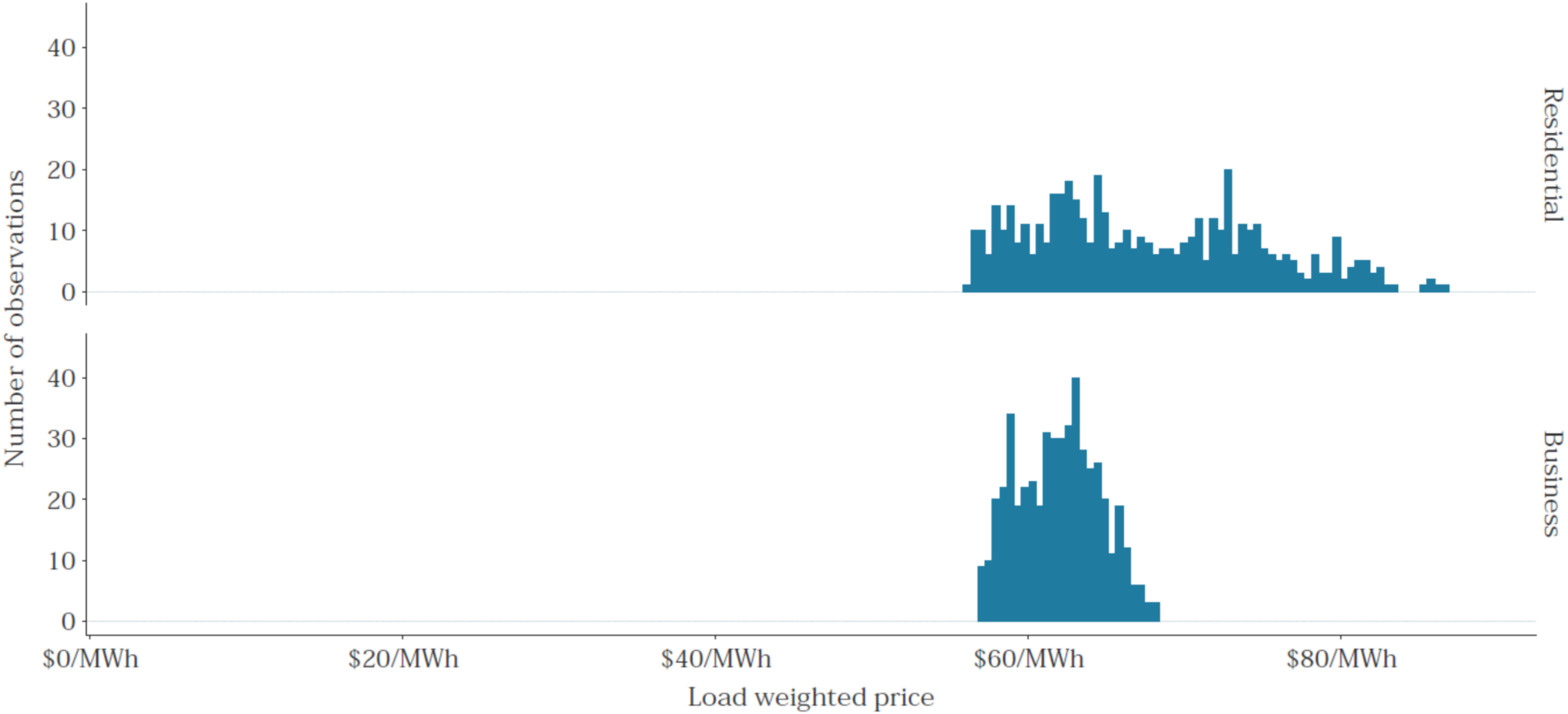
Source: Frontier Economics

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



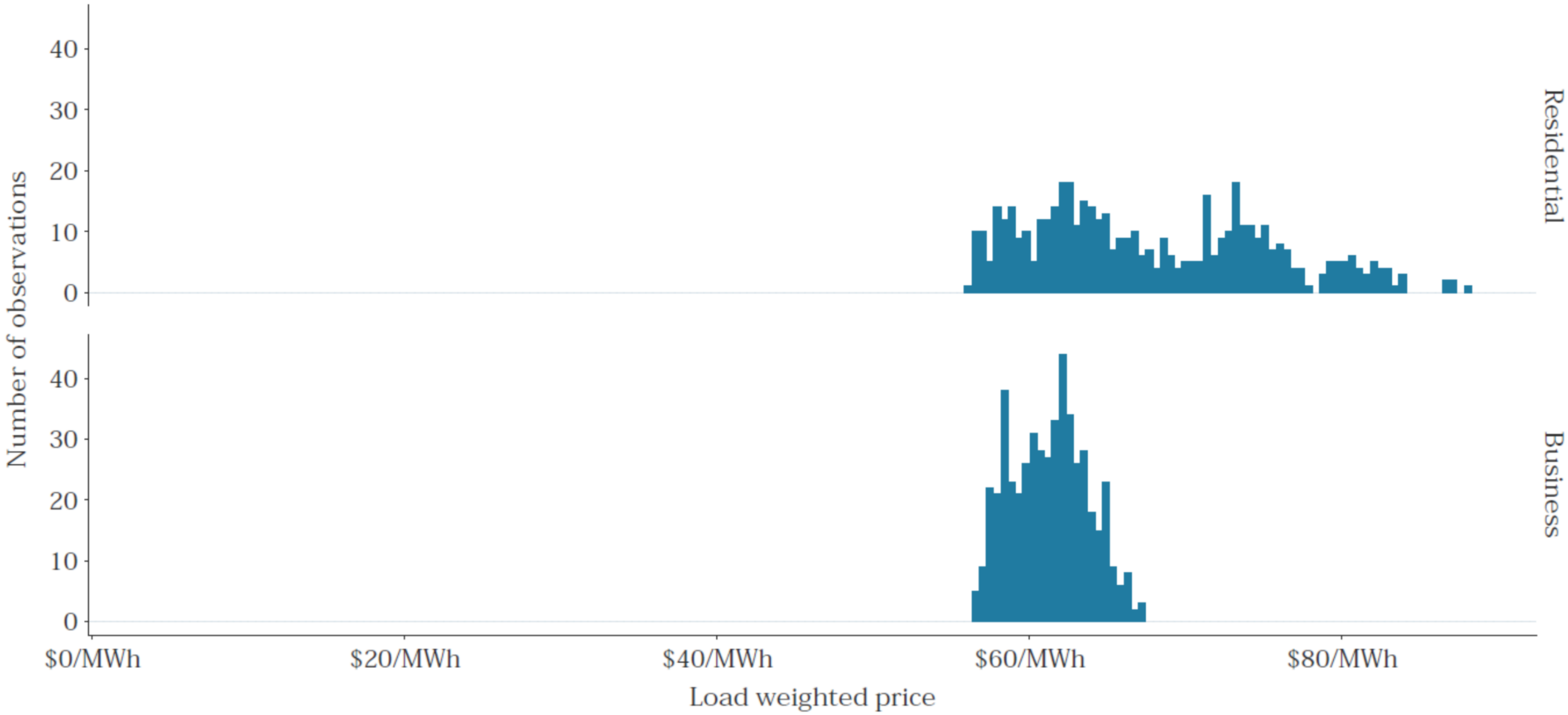
Source: Frontier Economics

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



Source: Frontier Economics

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



Source: Frontier Economics

4 Contract prices

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

- What is the cost of financial hedging contracts?

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

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

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

Cap contracts for Q3 and Q4

While Base $300 caps for each quarter have generally traded on ASXEnergy, these contracts were not available for Q3 and Q4 2021. ASXEnergy withdrew these contracts due to the forthcoming change to 5 minute settlement in the NEM.[6] However, due to the delay of 5 minute settlement by 3 months, Q3 caps for 2021 began trading again on 7 August.

The fact that Q4 cap contracts are not traded on ASXEnergy does not necessarily mean that retailers have no equivalent hedging opportunities. Retailers may be able to enter into these contracts over-the-counter, sign longer-term power purchase agreements with power stations, batteries or demand-side management providers, or vertically integrate.

For this final report we continue to include $300 caps in Q4 2021 as an option for retailers to hedge their load. Given that a price is not available for $300 caps in Q4 2021, we use the relationship between Q1 caps and Q4 caps from 2020, and the price of Q1 caps in 2021, to infer a price for Q4 caps in 2021.

Contract price data

Figure 15 through **Figure 17** set out the relevant trading data for each of these three contract types, for each quarterly product. The trading data that is presented is open interest (which measures the total volume of contracts in the market), the settlement price and the trading volume.

We can see from **Figure 15** through **Figure 17** that base swap contracts for calendar year 2021 and caps for Q1 are currently trading regularly. Indeed, we can see that trade in these contracts is occurring on most trading days. This suggests that the daily prices for base swaps and caps for Q1 does provide a genuine indication of the market's view of future prices.

[6] https://www.asxenergy.com.au/newsroom/industry_news/delisting-of-australian-elect

However, trade in peak swaps and in caps for Q2 is a lot lower, which raises the prospect that the available prices for peak swaps for calendar year 2021 and for caps for Q2 may not represent the market's current view of likely price outcomes for 2021. 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 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 incumbent 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 15 October 2020. It is clear from **Figure 15** through **Figure 17** that contract prices for calendar year 2021 have generally trended lower during 2020. These recent reductions bring down the 12-month trade weighted average prices shown in **Table 1**.

The recent reductions in contract prices for 2021 have been occurring at the same time that spot electricity prices have been falling. These reductions in spot prices are typically attributed, at least in part, to the effects of COVID-19. COVID-19 is generally considered one of the drivers of lower international prices for oil, gas and coal, which contributes to lower fuel prices for some power stations in the NEM. COVID-19 is also generally considered to cause lower aggregate electricity demand in the NEM. The combination of lower fuel prices and lower demand results in lower spot electricity prices. The expectation of a prolonged period of lower fuel prices and lower demand would account for the generally lower contract prices seen in **Figure 15** through **Figure 17**.

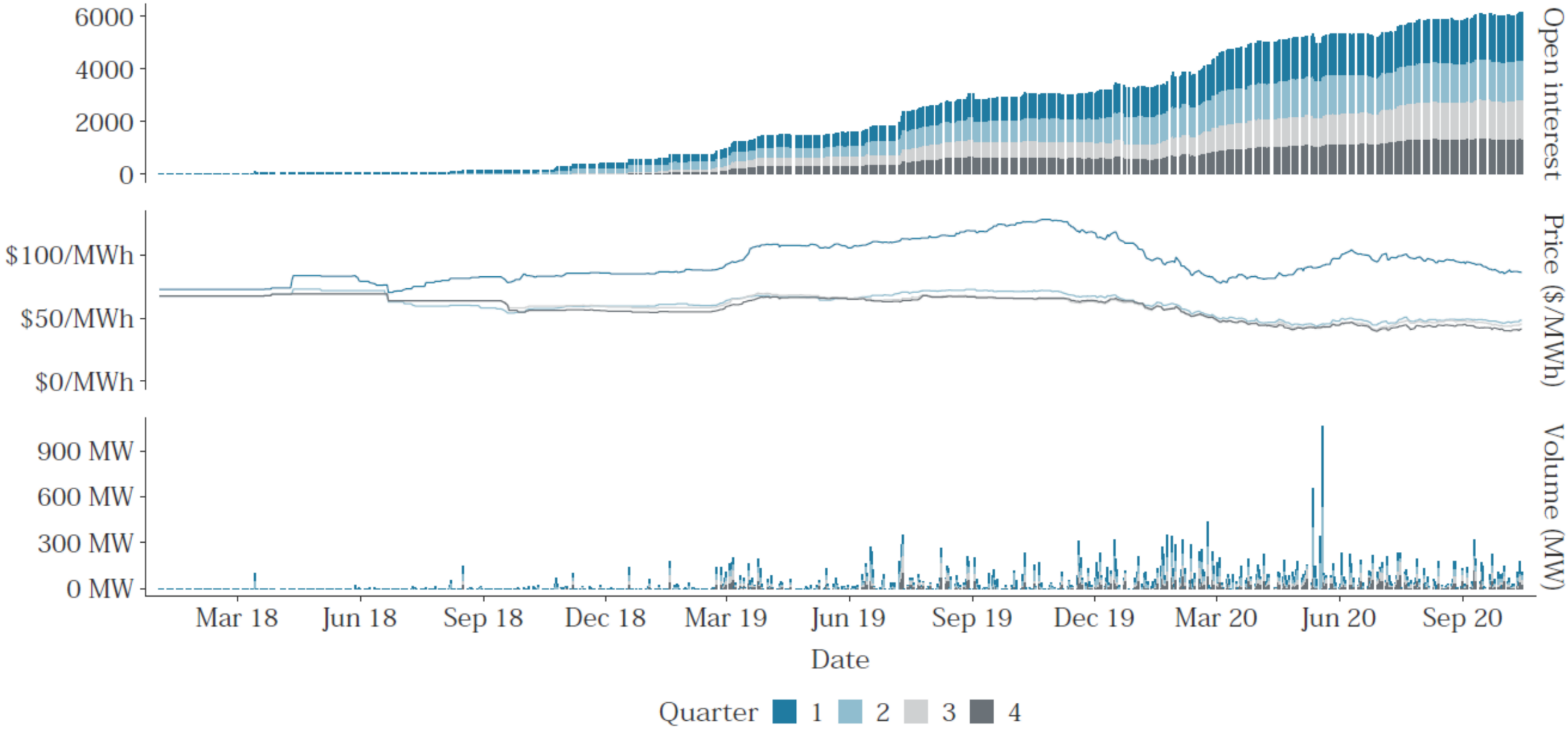
Table 1: 12-month trade weighted average ASXEnergy derivative prices for Victoria

	Product	Status	Calendar year	Quarter			
				Q1	Q2	Q3	Q4
TRADE WEIGHTED	$300 Caps	Base	2020	$35.72	$2.50	$2.25	$4.90
	Swaps	Base	2020	$95.01	$53.16	$49.77	$48.73
	Swaps	Peak	2020	$162.97	$65.34	$64.43	$64.41

Source: Frontier Economics analysis of ASXEnergy data

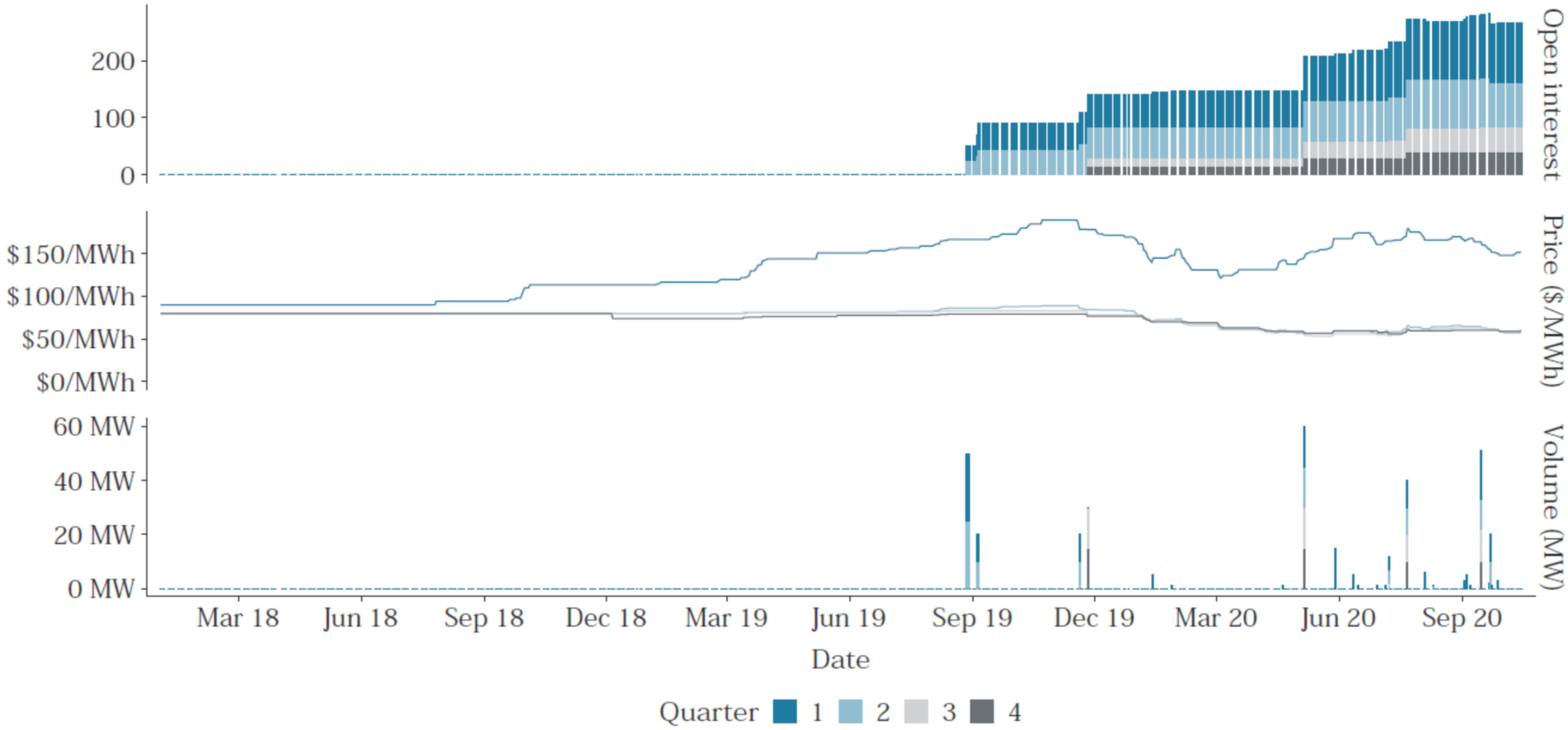
Note: Caps for Q3 have only been trading since the 7th of August and so the price is not a 12-month average, but is still trade-weighted. Prices for Q4 caps are inferred from prices of Q1 caps, as discussed.

Figure 15: Victorian base swaps – open interest, prices and volumes for calendar year 2021



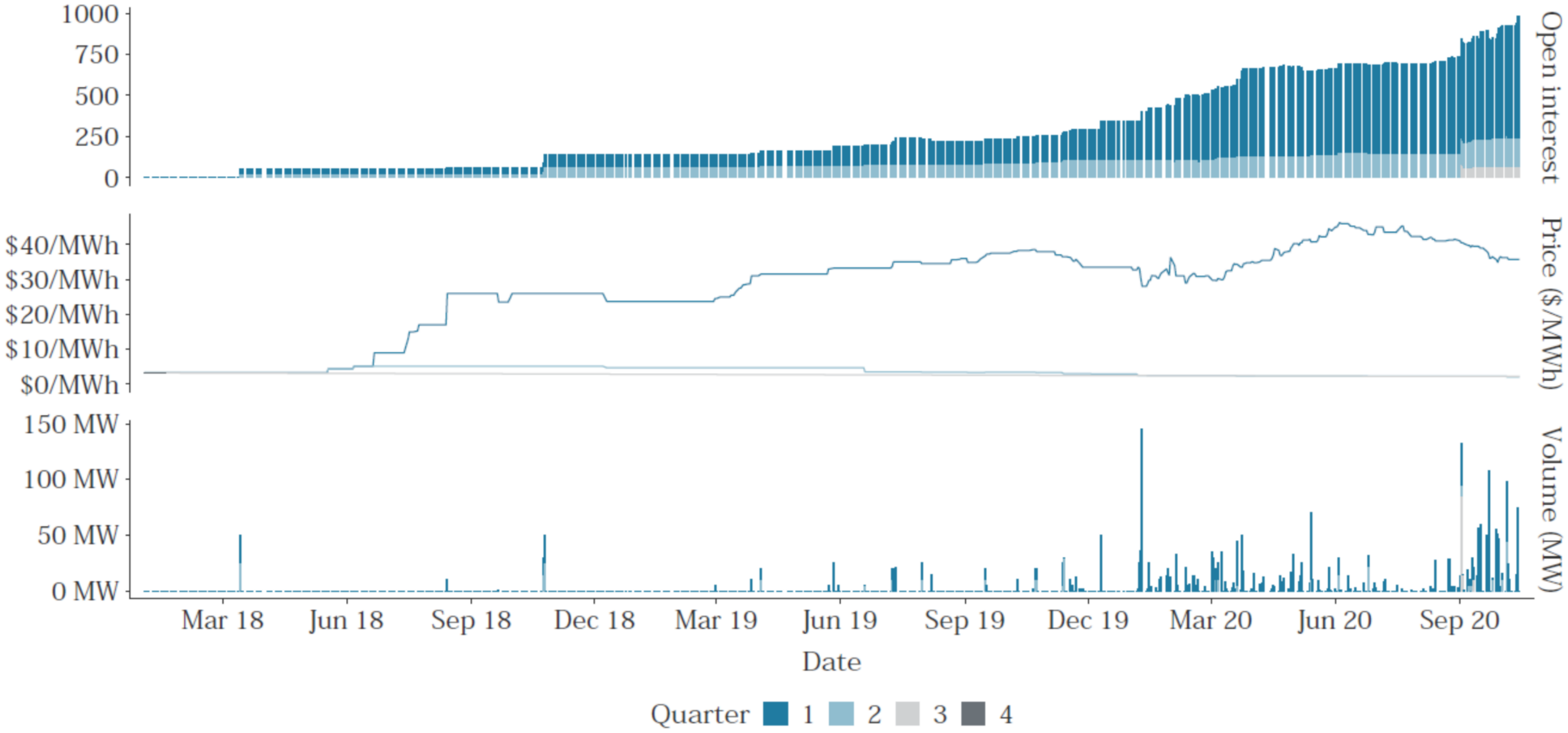
Source: Frontier Economics analysis of ASX data

Figure 16: Victorian peak swaps – open interest, prices and volumes for calendar year 2021



Source: Frontier Economics analysis of ASX data

Figure 17: Victorian base $300 caps – open interest, prices and volumes for calendar year 2021



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 2021. 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 2021 will be; will 2021 be a year with high prices and high load corresponding, so that the load-weighted price is high, or will 2021 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 2021, for each load profile and for each distribution area. For each quarter (the vertical panels) and each peak/off-peak period (the horizontal panels), the charts show the following:

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

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

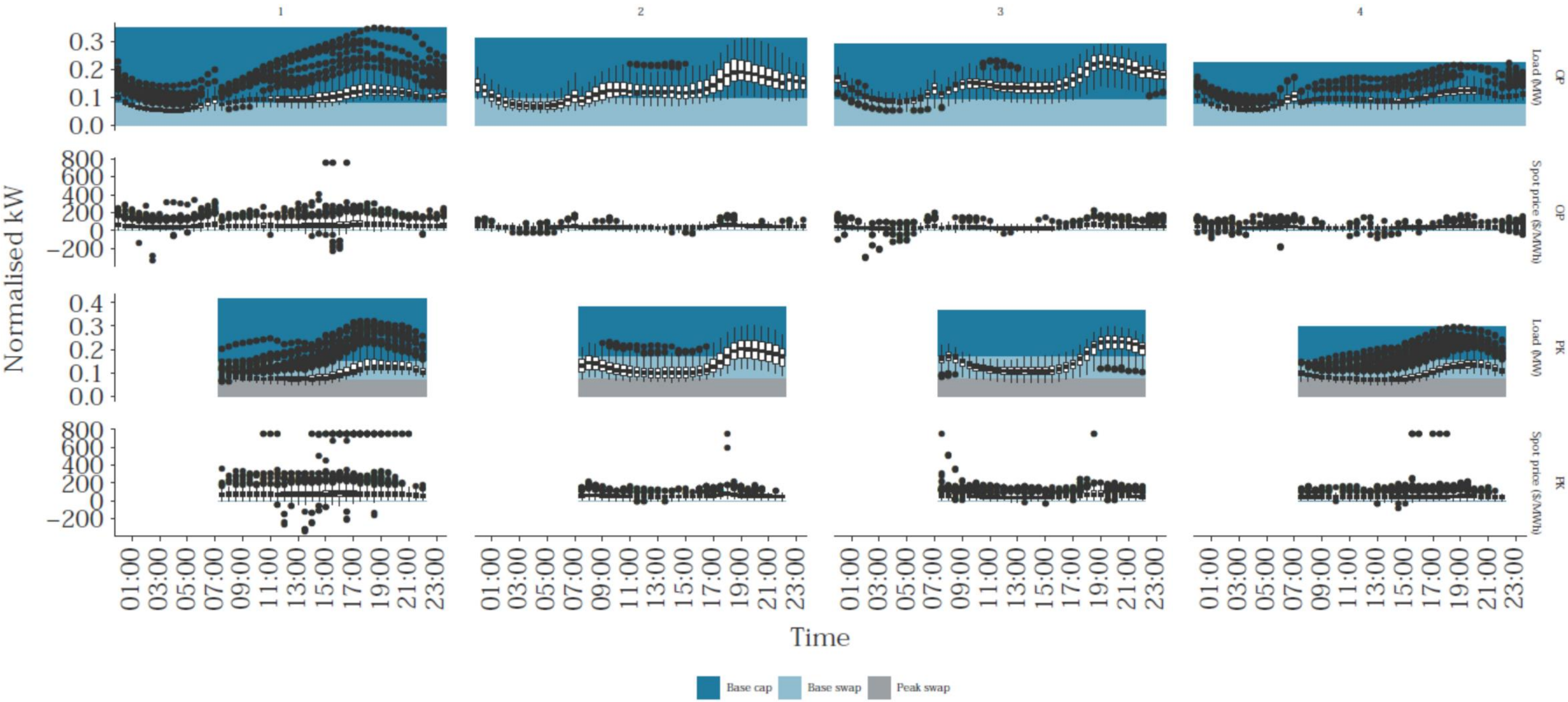
In general, the contract position at the conservative point involves:

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

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

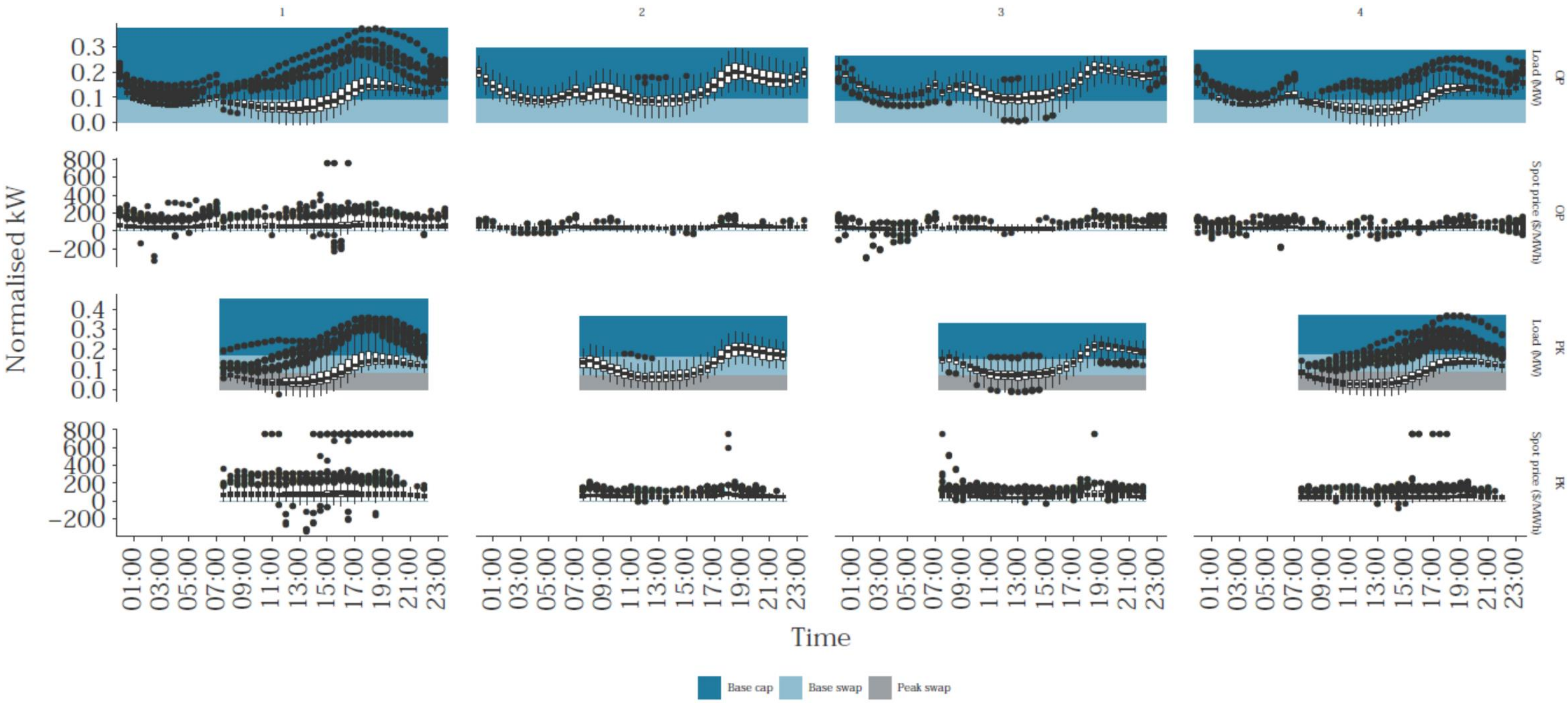
It should also be noted that the conservative point on the efficient frontier reflects the contract position that achieves the lowest risk given the projected state of the world that is input into *STRIKE*. In the event that different states of the world were input into *STRIKE*, the model would find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

Figure 18: Contract position for CitiPower residential load, ASXEnergy contract prices, calendar year 2021 (2020 dollars)



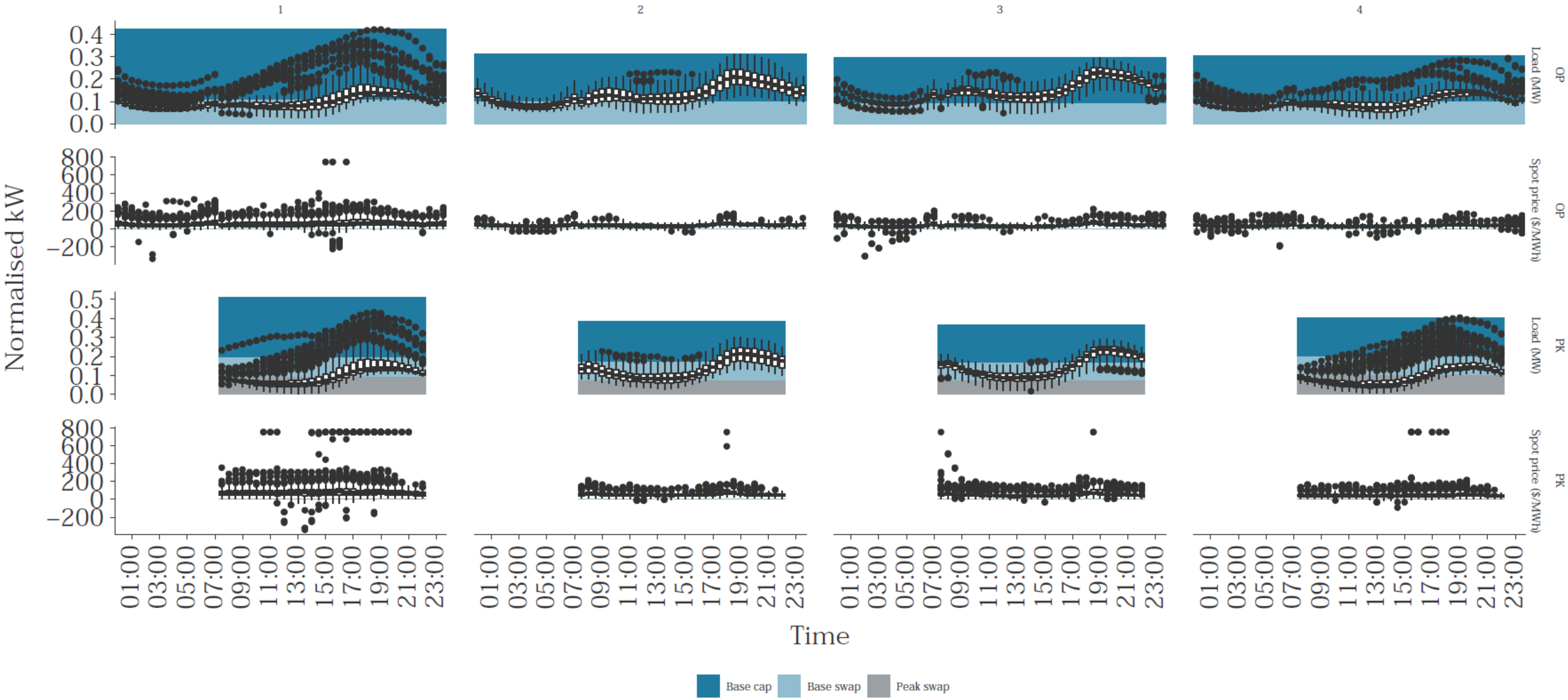
Note: Spot price chart truncated at a spot price of $750/MWh.

Figure 19: Contract position for Powercor residential load, ASXEnergy contract prices, calendar year 2021 (2020 dollars)



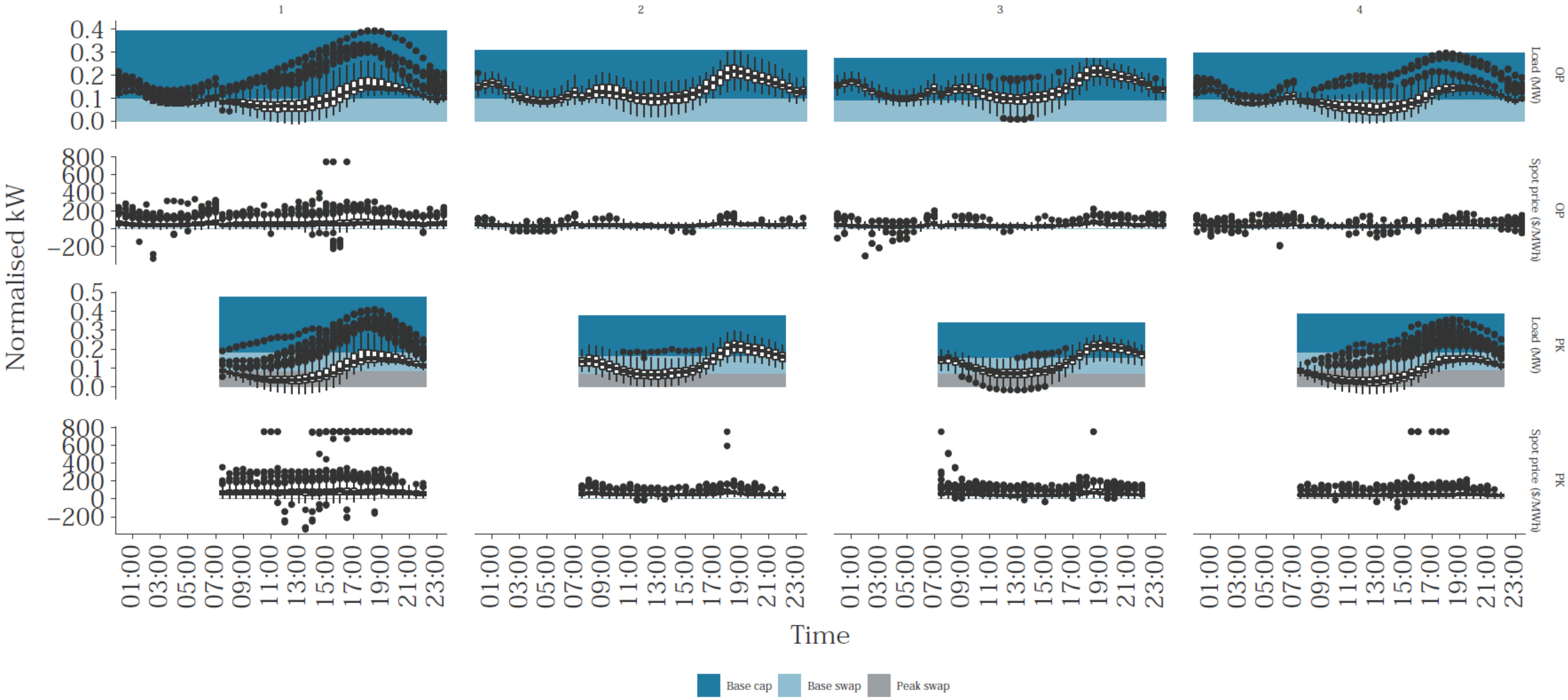
Note: Spot price chart truncated at a spot price of $750/MWh.

Figure 20: Contract position for Jemena residential load, ASXEnergy contract prices, calendar year 2021 (2020 dollars)



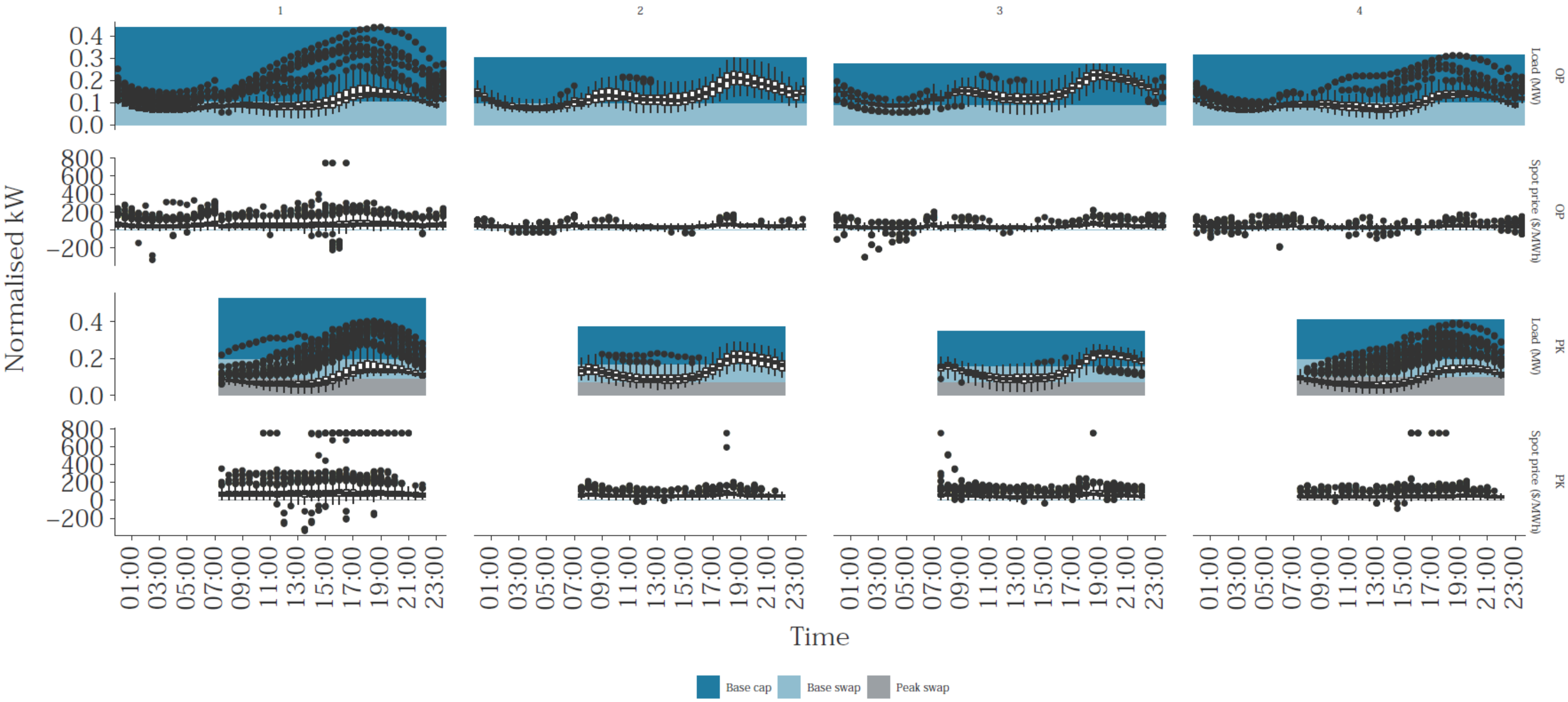
Note: Spot price chart truncated at a spot price of $750/MWh.

Figure 21: Contract position for AusNet residential load, ASXEnergy contract prices, calendar year 2020 (2021 dollars)



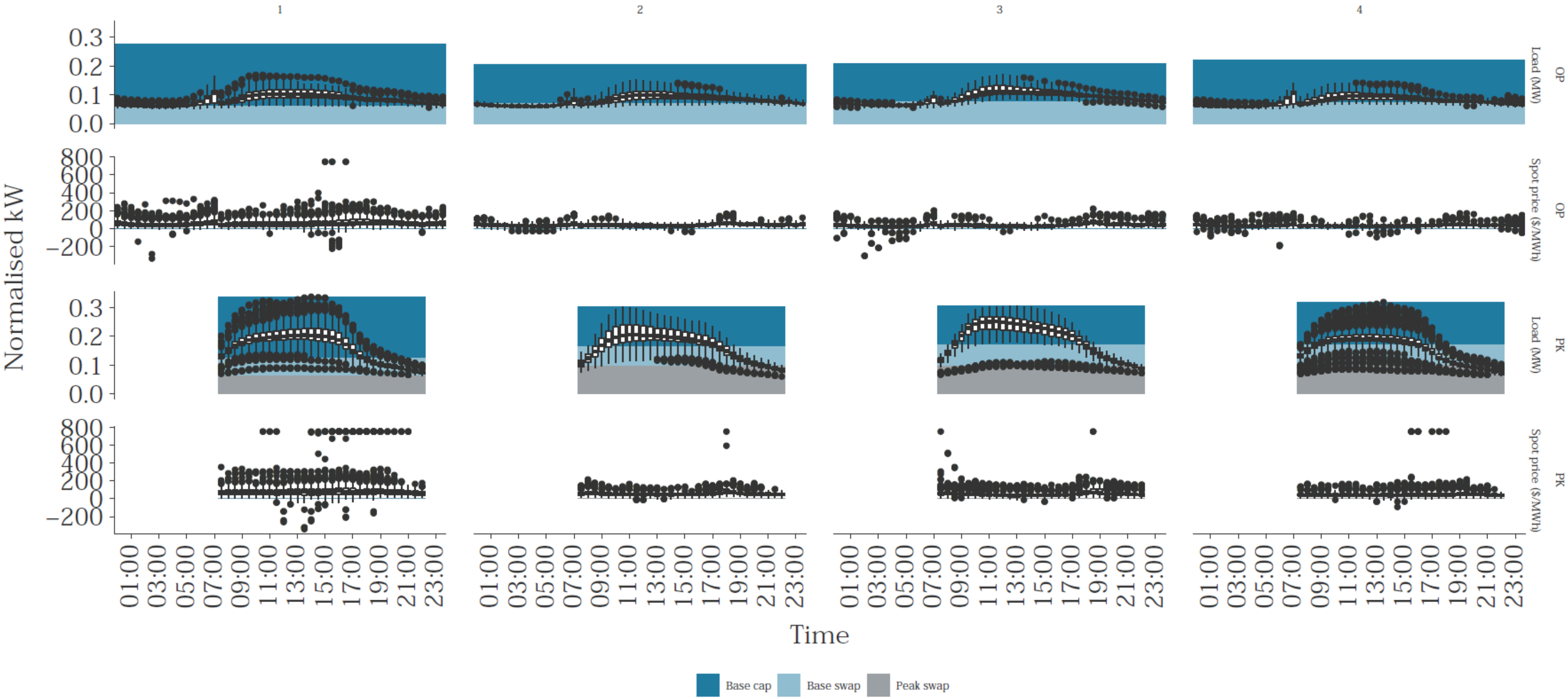
Note: Spot price chart truncated at a spot price of $750/MWh.

Figure 22: Contract position for United residential load, ASXEnergy contract prices, calendar year 2020 (2021 dollars)



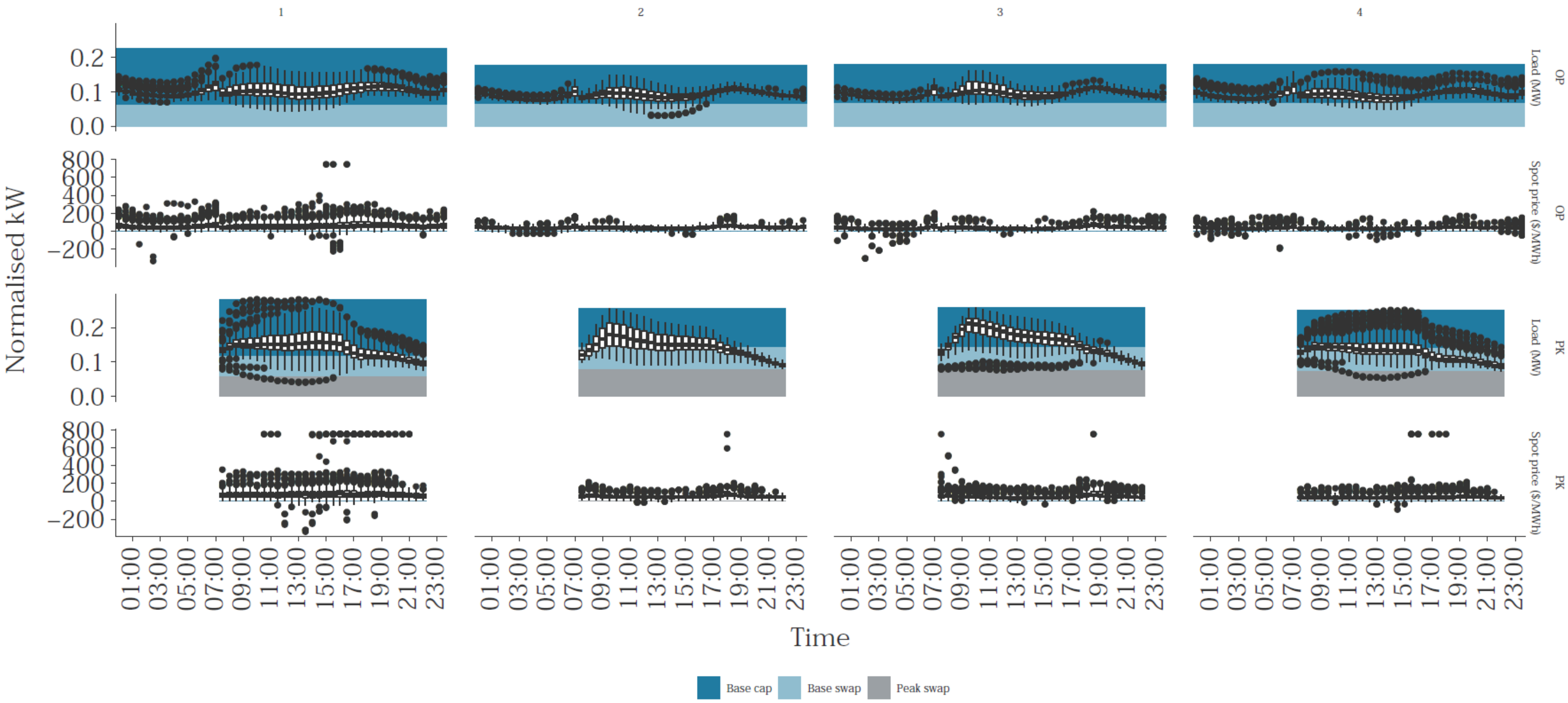
Note: Spot price chart truncated at a spot price of $750/MWh.

Figure 23: Contract position for CitiPower business load, ASXEnergy contract prices, calendar year 2021 (2020 dollars)



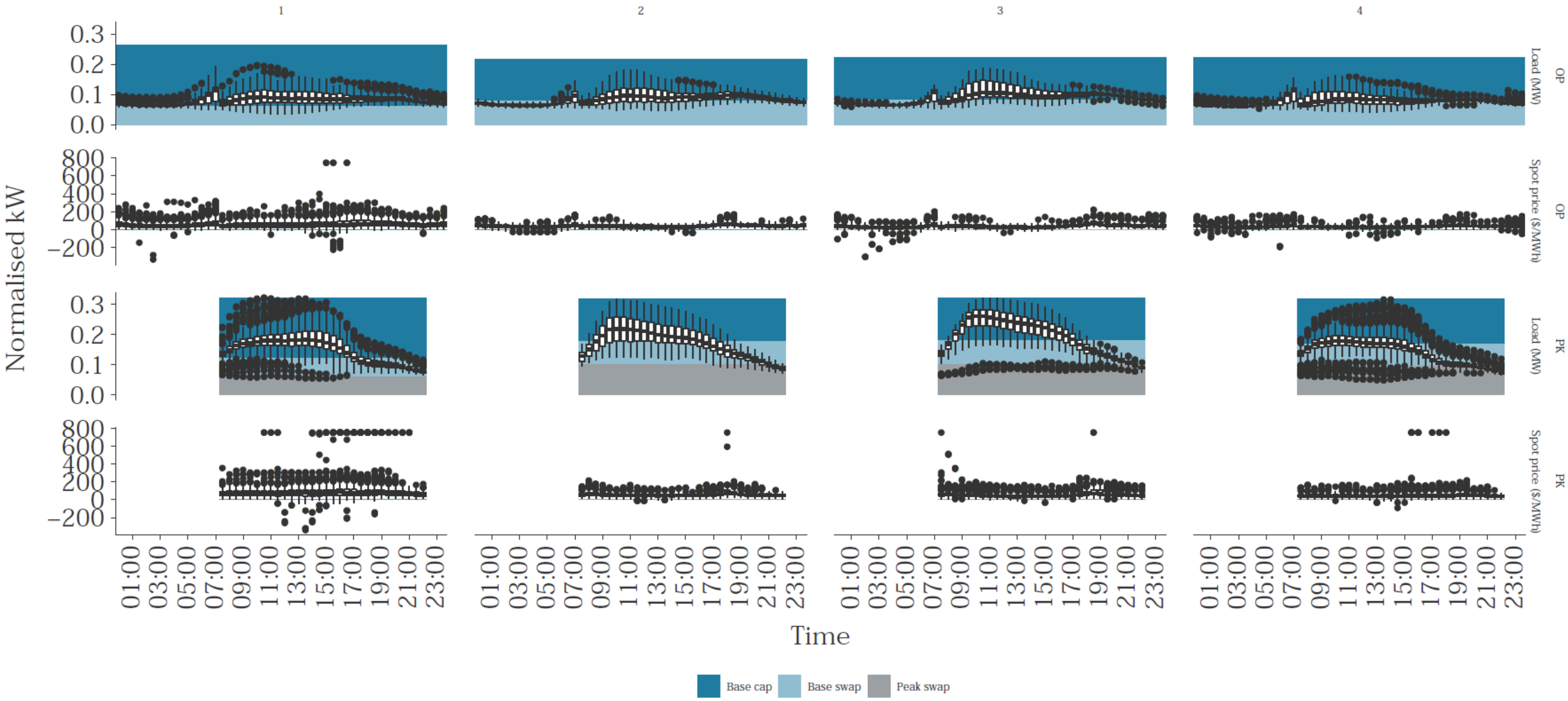
Note: Spot price chart truncated at a spot price of $750/MWh.

Figure 24: Contract position for PowerCor business load, ASXEnergy contract prices, calendar year 2021 (2020 dollars)



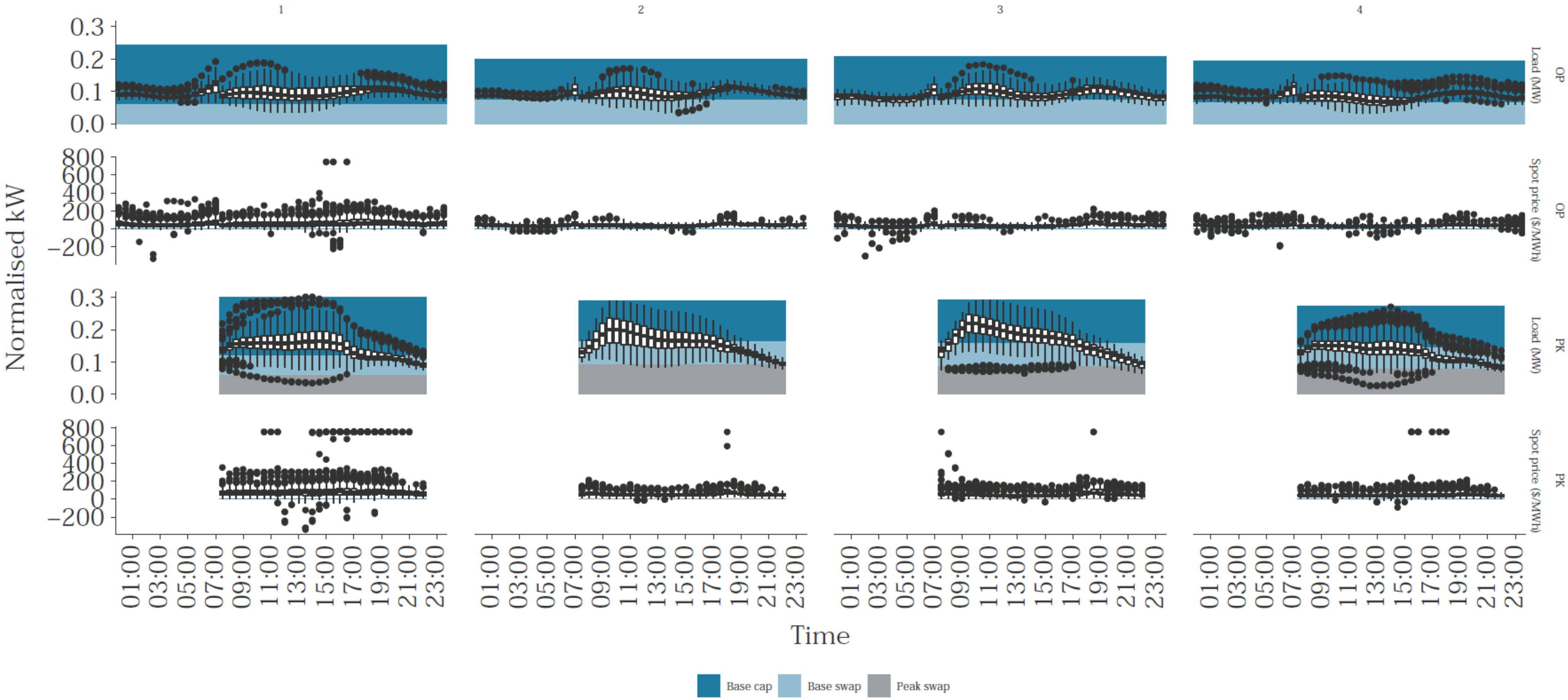
Note: Spot price chart truncated at a spot price of $750/MWh.

Figure 25: Contract position for Jemena business load, ASXEnergy contract prices, calendar year 2021 (2020 dollars)



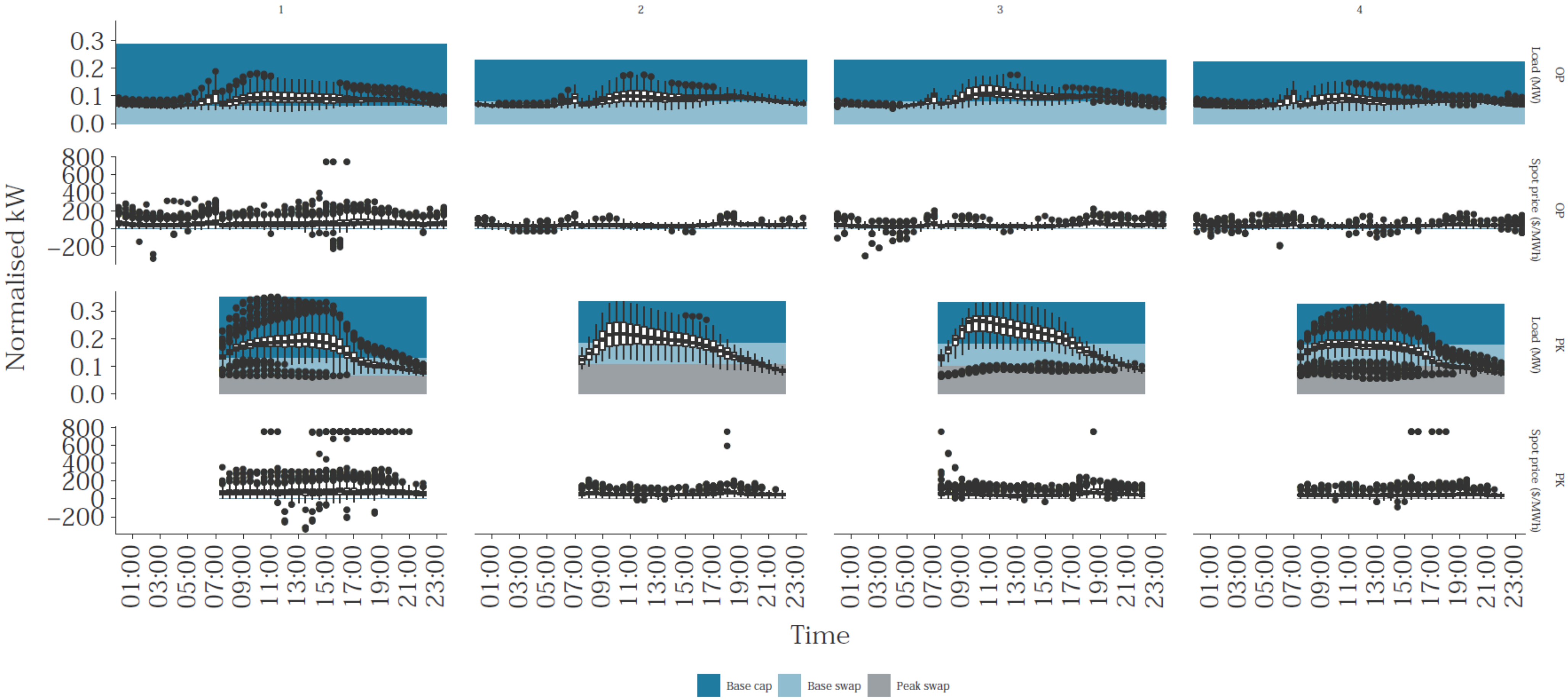
Note: Spot price chart truncated at a spot price of $750/MWh.

Figure 26: Contract position for AusNet business load, ASXEnergy contract prices, calendar year 2021 (2020 dollars)



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

Figure 27: Contract position for United business load, ASXEnergy contract prices, calendar year 2021 (2020 dollars)



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

6 Wholesale electricity costs

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

6.1 Wholesale electricity costs

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

Results

The WECs that we have estimated are based on half-hourly spot prices and load from the median simulated year (when these years are ranked according to WEC). The WECs that we have estimated are based on 12-month trade weighted average ASXEnergy contract prices up to 15 October 2020. 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

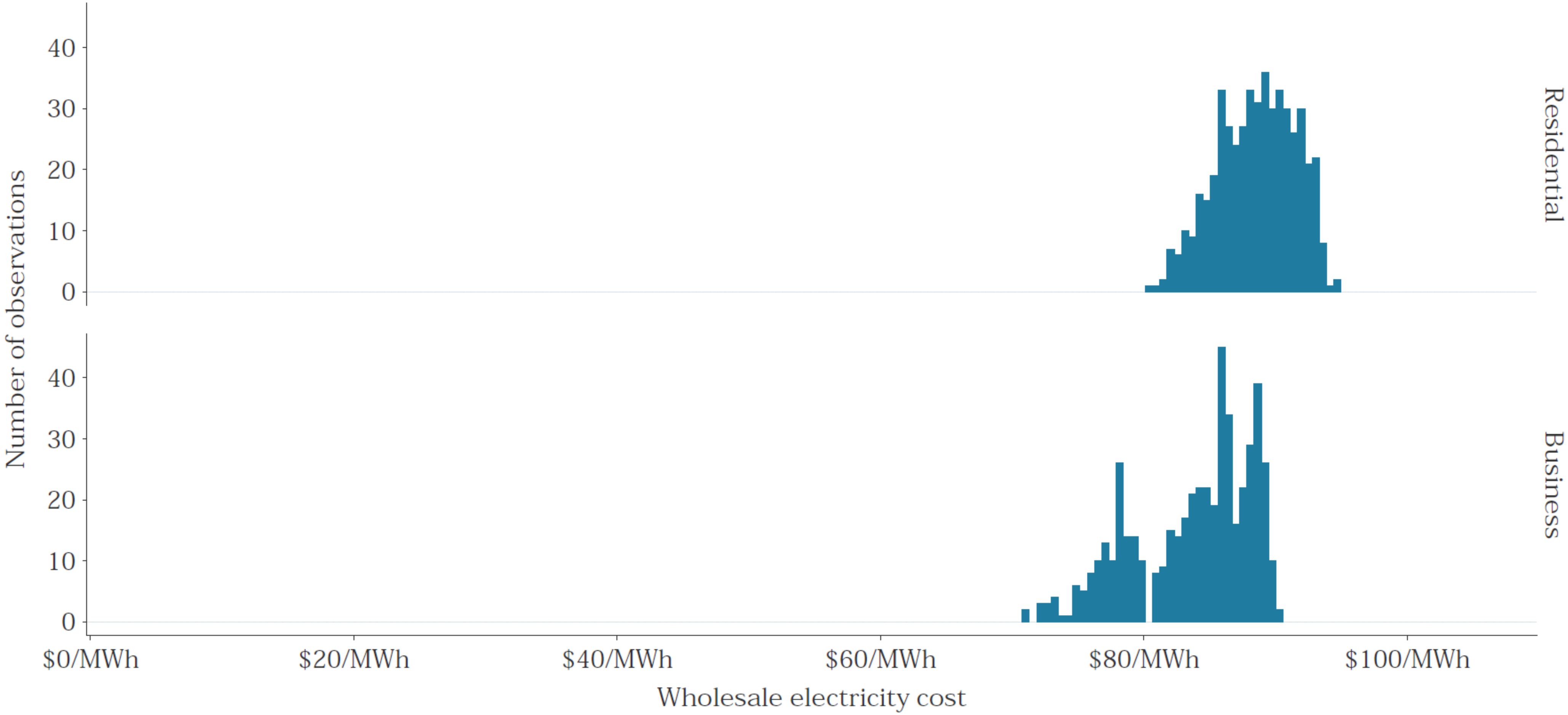
Entity	Wholesale electricity costs ($/MWh, real $2021)	
	Residential	Business
AusNet	$94.02	$82.28
CitiPower	$88.84	$85.08
Jemena	$97.80	$84.51
Powercor	$92.03	$80.11
United	$98.18	$86.63

Source: Frontier Economics

Figure 28 through **Figure 32** show the distribution of WEC for each customer type and for each DNSP area across the full set of 500 simulated years from our Monte Carlo analysis. For each of these 500 simulated years we use the same contract prices and the same contract position; all that changes between these 500 simulated years is the half-hourly profile of prices and the half-hourly load profile. Since each of these WECs is based on a hedged position, they are more concentrated than the load weighted prices. The average spread for the WEC is $15.23/MWh while the average spread for the load weighted price is $19.13/MWh.

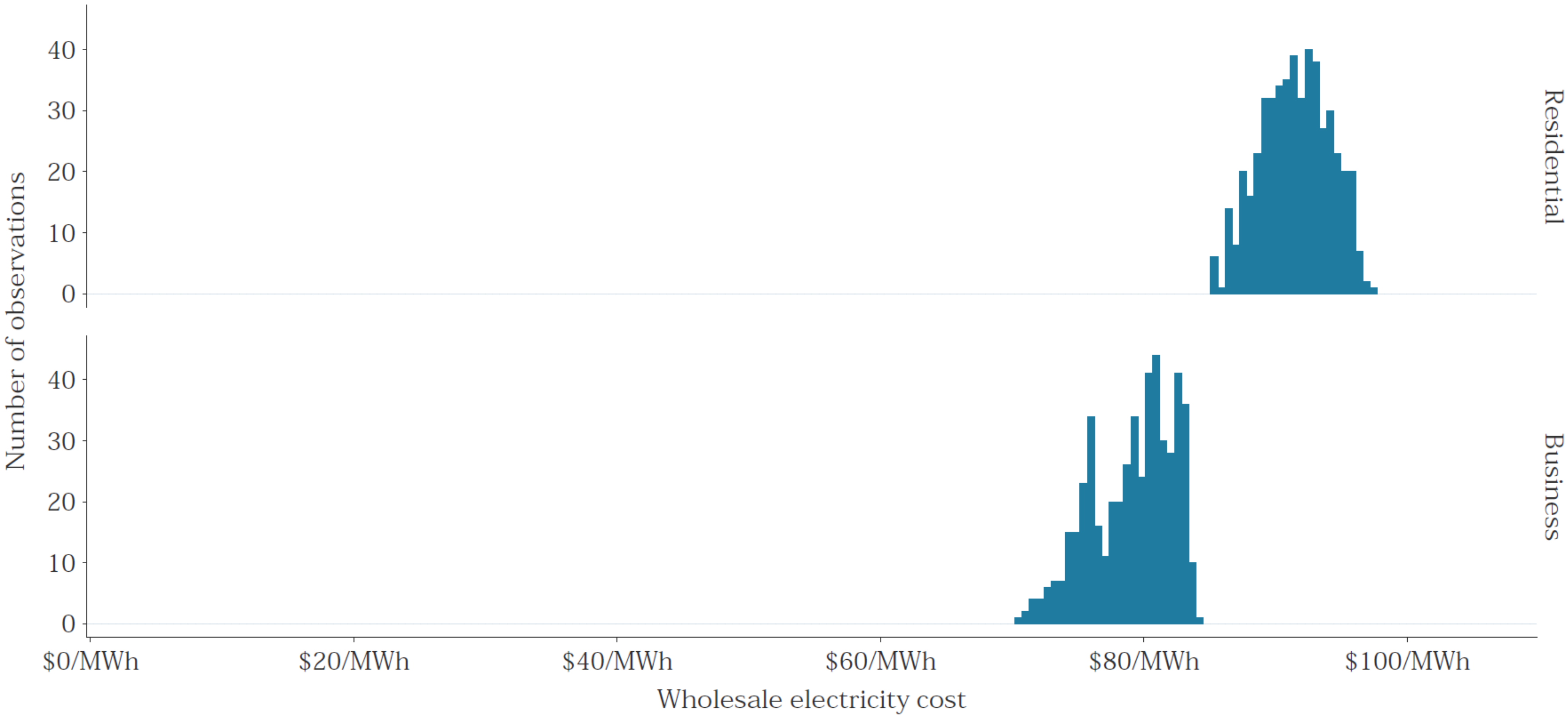
We note that these distributions do not reflect the distribution of all possible outcomes that retailers could face. If patterns of spot prices or load are materially different from the historical period on which we based our Monte Carlo analysis, or if average spot prices were too much different from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

Figure 28: CitiPower load wholesale electricity cost distribution



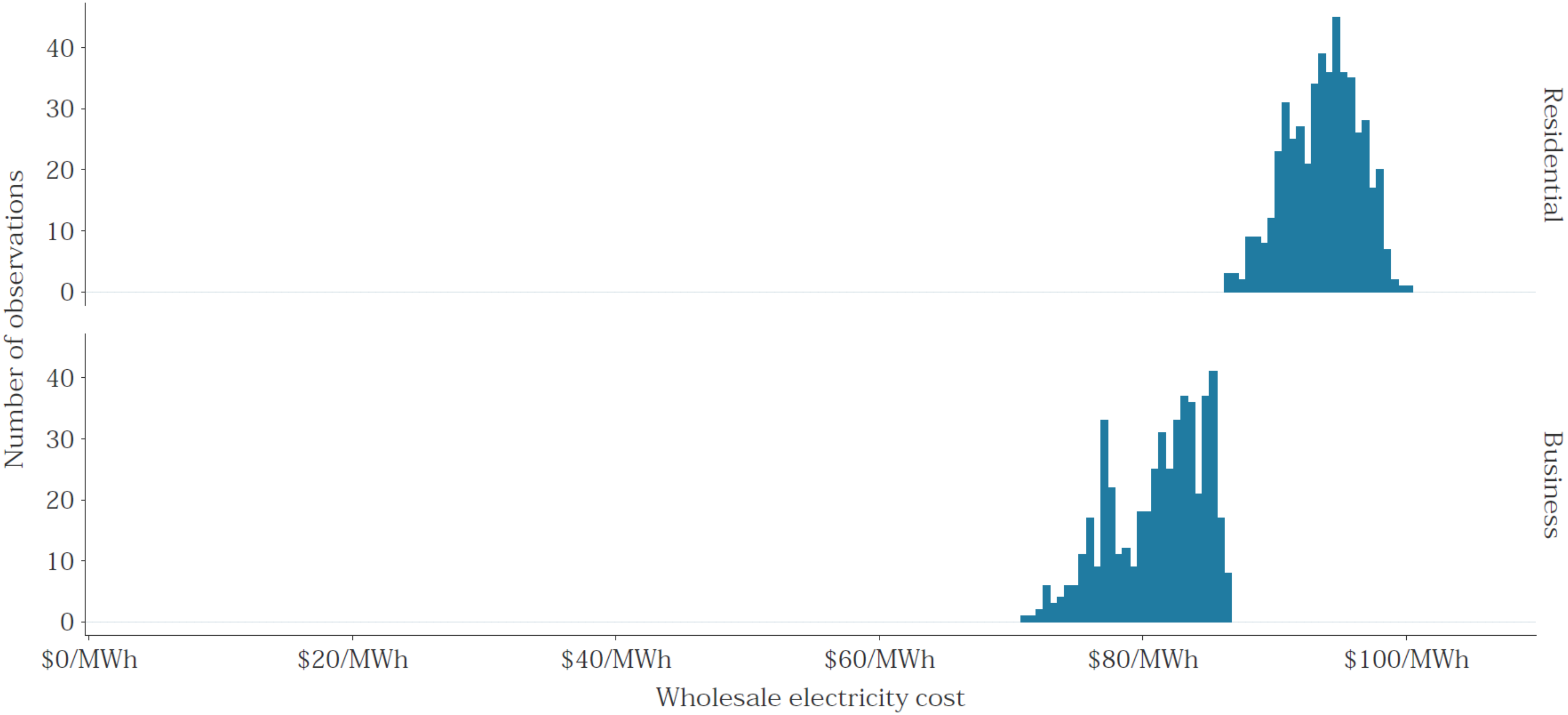
Source: Frontier Economics

Figure 29: Powercor load wholesale electricity cost distribution



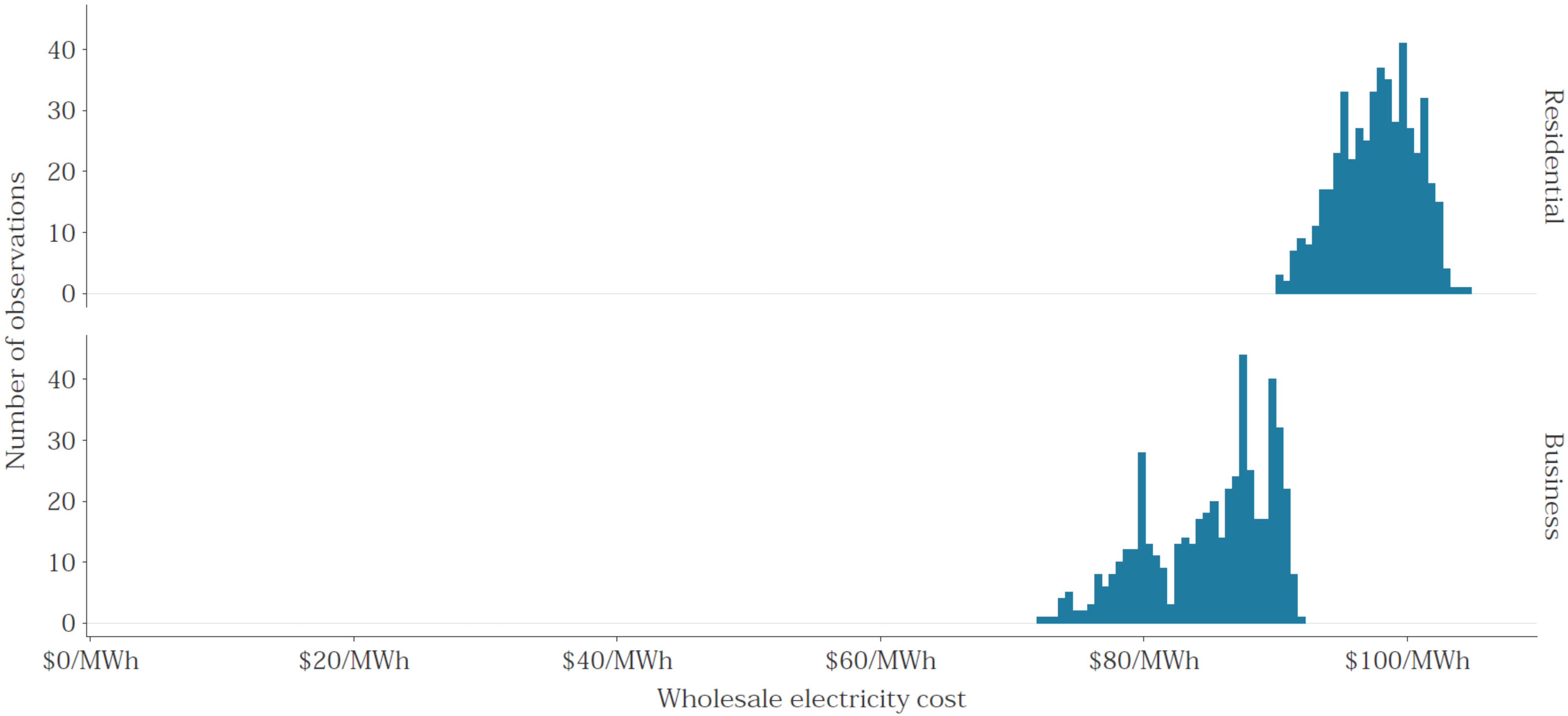
Source: Frontier Economics

Figure 30: AusNet load wholesale electricity cost distribution



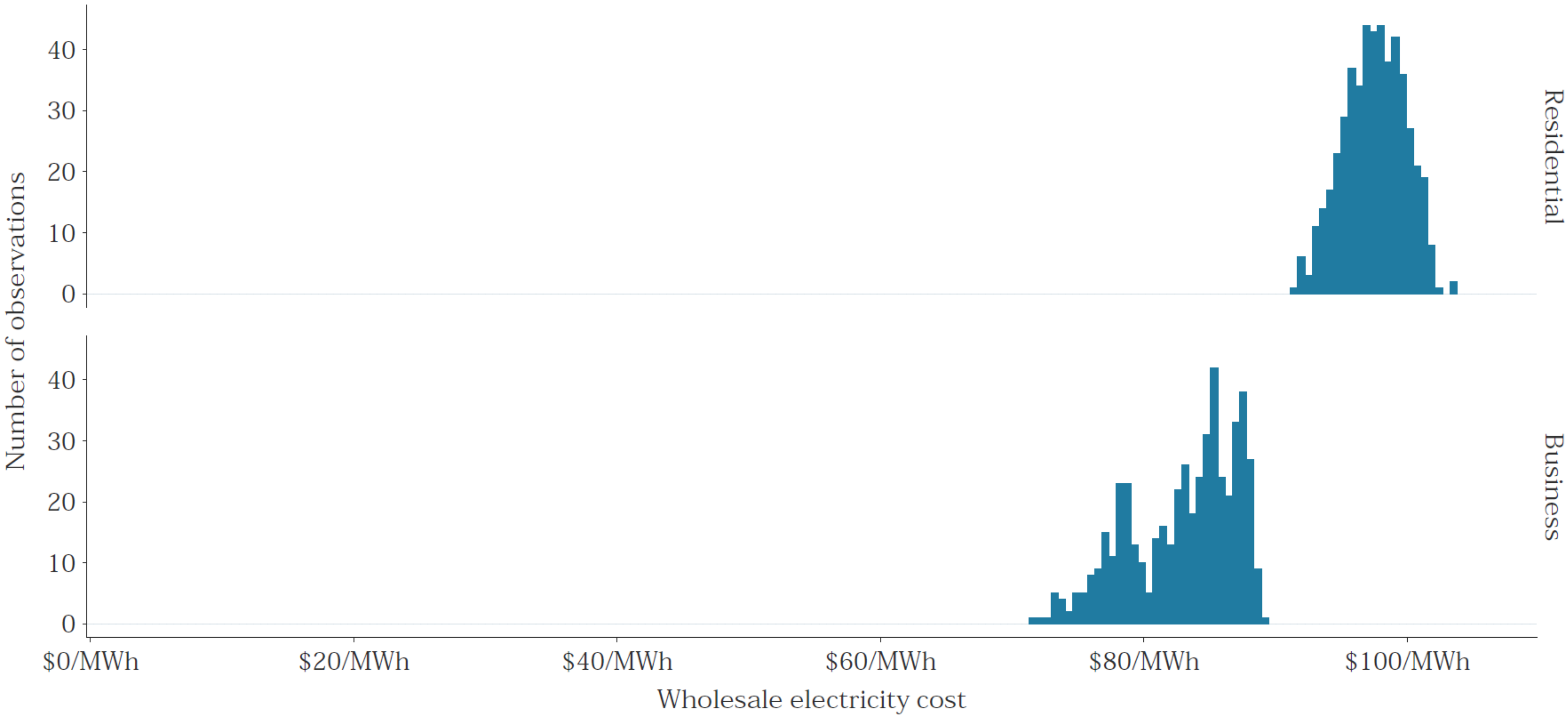
Source: Frontier Economics

Figure 31: United load wholesale electricity cost distribution



Source: Frontier Economics

Figure 32: Jemena load wholesale electricity cost distribution



Source: Frontier Economics

6.2 Volatility allowance

As discussed, the WECs that we have estimated are based on half-hourly spot prices and load from the median simulated year. The volatility allowance is intended to compensate retailers for the residual risk to which they are exposed, even when contracted at the conservative point. The volatility allowance is calculated based on the cost of holding working capital to fund cashflow shortfalls that could arise in years when the actual WEC is higher than we have estimated for the median simulated year. The working capital requirement is based on the difference between the WEC that we have estimated for the median simulated year and the WEC for the most costly simulated year for each distribution area. We then estimate the cost of holding sufficient working capital by applying a WACC of 7.5 per cent.

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

Table 3: Modelled volatility allowance

Entity	Volatility Allowance ($/MWh real $2020)	
	Residential	Business
AusNet	$0.48	$0.34
CitiPower	$0.47	$0.40
Jemena	$0.45	$0.36
Powercor	$0.42	$0.31
United	$0.49	$0.41

Source: Frontier Economics

7 LRET and SRES

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

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

This section reports our estimate of these costs.

7.1 LRET

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

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

Renewable Power Percentage

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

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

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

The Clean Energy Regulator has published a RPP for 2020 of 19.31%. Using this 2020 RPP, and applying the default calculation, results in an RPP for 2021 of 18.83%.

Cost of obtaining LGCs

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

For this report, we have used a market price for LGCs to determine the cost of complying with the LRET. The market price for LGCs is determined by taking a 12 month trade weighted average of

LGC prices reported by Demand Manager.[7] This 12 month trade weighted average LGC price is $35.75 per certificate ($2021).

Cost of complying with the LRET

Based on the RPP and the LGC price discussed above, the cost of complying with the LRET is $6.73 ($2021).

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.

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 most recent non-binding estimate of the STP for 2021 published by the Clean Energy Regulator is 19.40%.

[7] Available at: http://www.demandmanager.com.au/. Accessed 15th October 2020

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 ($2020).

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

Cost of complying with the SRES

Based on the STP and the STC price discussed above, the cost of complying with the SRES is $7.76 ($2021).

A Analysis of impact of COVID-19 on load

Victoria's response to COVID-19 has the potential to change patterns of electricity consumption for both residential customers and small business customers.

More people working from home, and restrictions on leaving home, have the potential to increase electricity consumption by residential customers, and also to change the times at which these customers tend to consume electricity.

Similarly, changes affecting the activities of small businesses have the potential to decrease electricity consumption by small business customers, and also to change the times at which these customers tend to consume electricity.

We have examined historical data from 2020, and compared it with data from previous years, to see what evidence there is that our response to COVID-19 has affected consumption. We demonstrate our findings below by summarising the load data in two ways.

First, **Figure 33** through **Figure 39** show average weekday consumption for each of February through August over the previous four years (five for July and August). The data is presented for each DNSP and for each customer type. The purpose of this data is to see whether Victoria's response to COVID-19 – which commenced in earnest in March 2020 – has resulted in changes in total consumption for these customers. Our view is that **Figure 33** through **Figure 39** show the following:

- For **small business customers**, average weekday consumption in February 2020 is quite consistent with average weekday consumption in February of 2017, 2018 and 2019. By March 2020 there is already some evidence that average weekday consumption is lower than in March of 2017, 2018 and 2019. The difference between average weekday consumption in 2020 and earlier years becomes more apparent in April, before decreasing again in subsequent months.
- For **residential customers**, average weekday consumption in February 2020 is lower than average weekday consumption in February of 2017, 2018 and 2019. In March, average weekday consumption is relatively consistent across the years. By April 2020, however, there is evidence that average weekday consumption is higher than in April of 2017, 2018 and 2019. This difference remains for the rest of the period to August.

Bearing in mind that this data has not been adjusted for weather conditions or other drivers of demand not related to COVID-19, we nevertheless think we can draw some conclusions from this data. First, the data suggests that small business consumption tends to be lower in periods of lock-down (which was particularly evident during March and April and again in August). Second, the data suggests that residential consumption tends to be materially higher as a result of COVID-19, with persistent increases in consumption from April through to August.

Second, **Figure 40** through **Figure 46** show the half-hourly pattern of load for an average weekday in each of February through August over the previous four years. The data is presented for each DNSP and for each customer type. The purpose of this data is to see whether Victoria's response to COVID-19 has resulted in changes to the typical daily patterns of consumption for these customers. Our view is that **Figure 40** through **Figure 46** do not provide strong evidence that there has been a widespread and consistent change in the daily patterns of consumption for either small business or residential customers. There is a degree of variability over the years in these daily patterns of consumption, which is evident even when comparing consumption in February and March. In our view, this variability persists in April through June, without any widespread and consistent change in daily patterns of consumption. It could be argued that in July and August there is a more obvious and consistent change in consumption patterns, particularly for residential customers. In particular, in July and August there appears to be more consistent evidence that residential consumption has a later morning peak and has relatively higher consumption during the day.

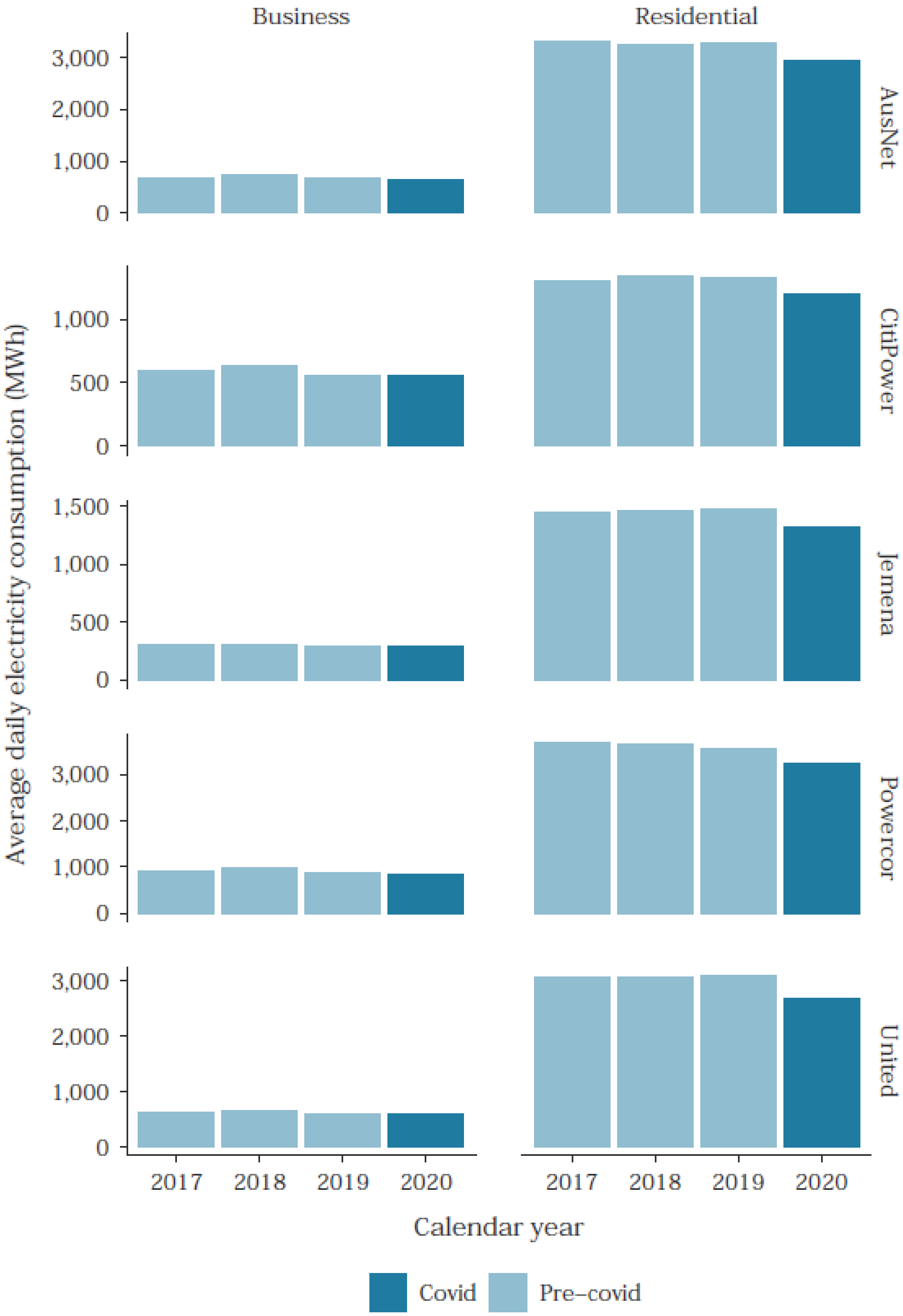
We have also calculated the load factors for each of the load profiles shown in **Figure 47** through **Figure 53**. The load factor is calculated as average load divided by maximum load. The load factor is a simple measure of how 'peaky' a load profile is, which is an important driver of the WEC. We found no widespread and consistent change in load factors for these customers as a result of COVID-19. Even looking at the data for July and August, for which the profiles provided the clearest evidence of a change in residential consumption patterns, the load factors are more ambiguous: the residential load factors for July 2020 are quote similar to load factors for July in previous years, while the residential load factors for August 2020 are noticeably lower than for August in previous years (indicating a peakier load).

At this stage we have not attempted to account for any change in load due to COVID-19. The main reasons for this are that:

- The evidence on the impact of COVID-19 on load for residential and small business customers is not clear cut.
- Even if the evidence on the impact of COVID-19 this year were clear cut, it is not obvious what assumptions should be made about Victoria's response to COVID-19 in 2021scali

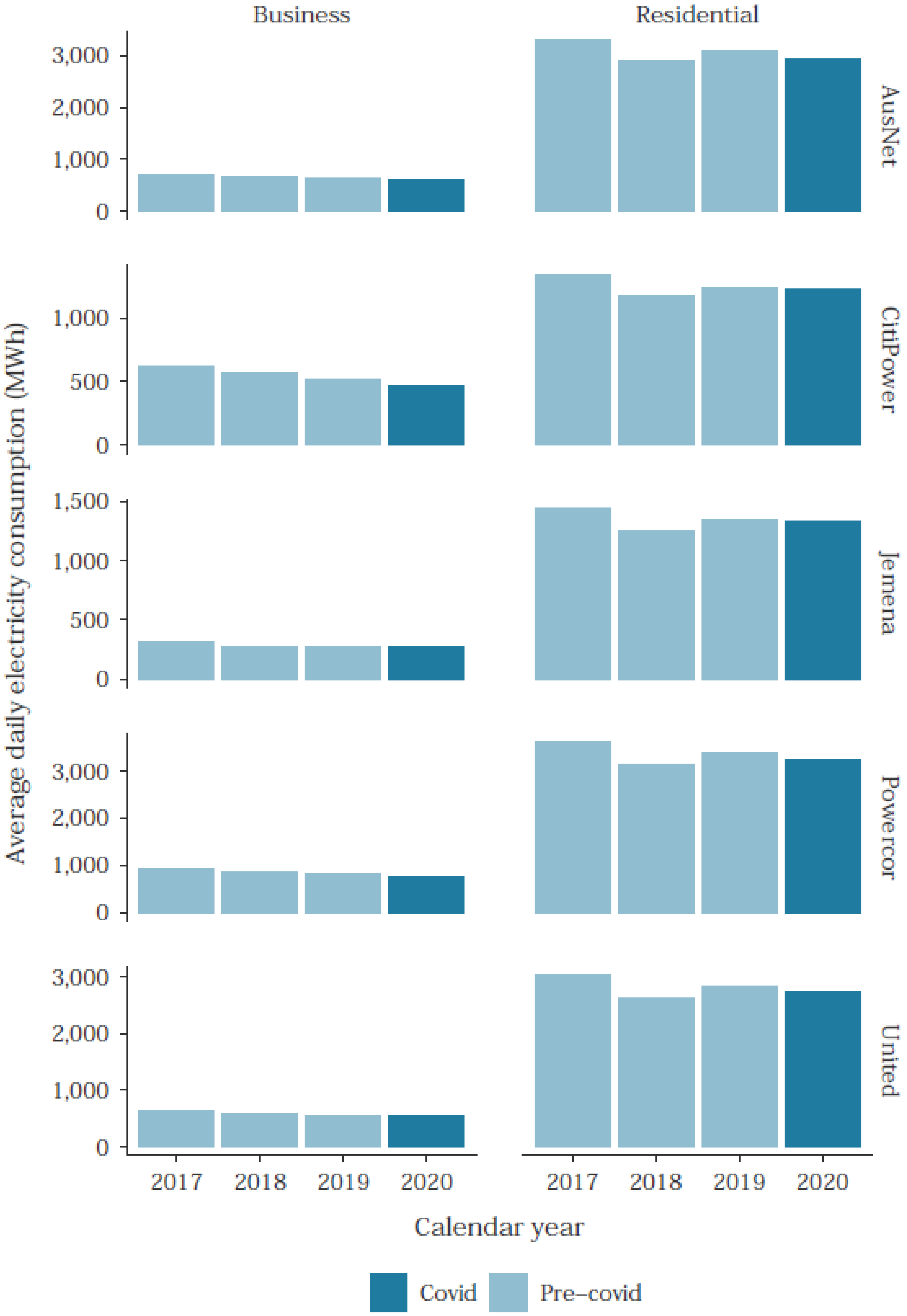
However, we have tested the impact that changes in load profile due the impact of COVID-19 might have on our estimate of WEC. To do this, we used data from the month in which we observed that the impact of COVID-19 has been greatest: August 2020. For this month we calculated the half hourly difference between the normalised load in 2020 and the average normalised load between 2017 and 2019. We then applied that difference to the four years of historical data we use in our analysis, to come up with a rough estimate of what those four years of historical data would have looked like if the effect of COVID-19 that we observed in August 2020 occurred in all those years. Calculating our WEC as normal, but with this adjusted historical data, results in a WEC for residential loads that is slightly higher (less than $1/MWh) and a WEC for business loads that is slightly lower (about $1/MWh). This results are intended just as a *guide* to the potential impact of observed changes in load, if they were to occur throughout 2021. We would emphasis that the adjustments we made are quite blunt, and there are many factors that affect load that this simple analysis has not captured.

Figure 33: Average weekday consumption – February



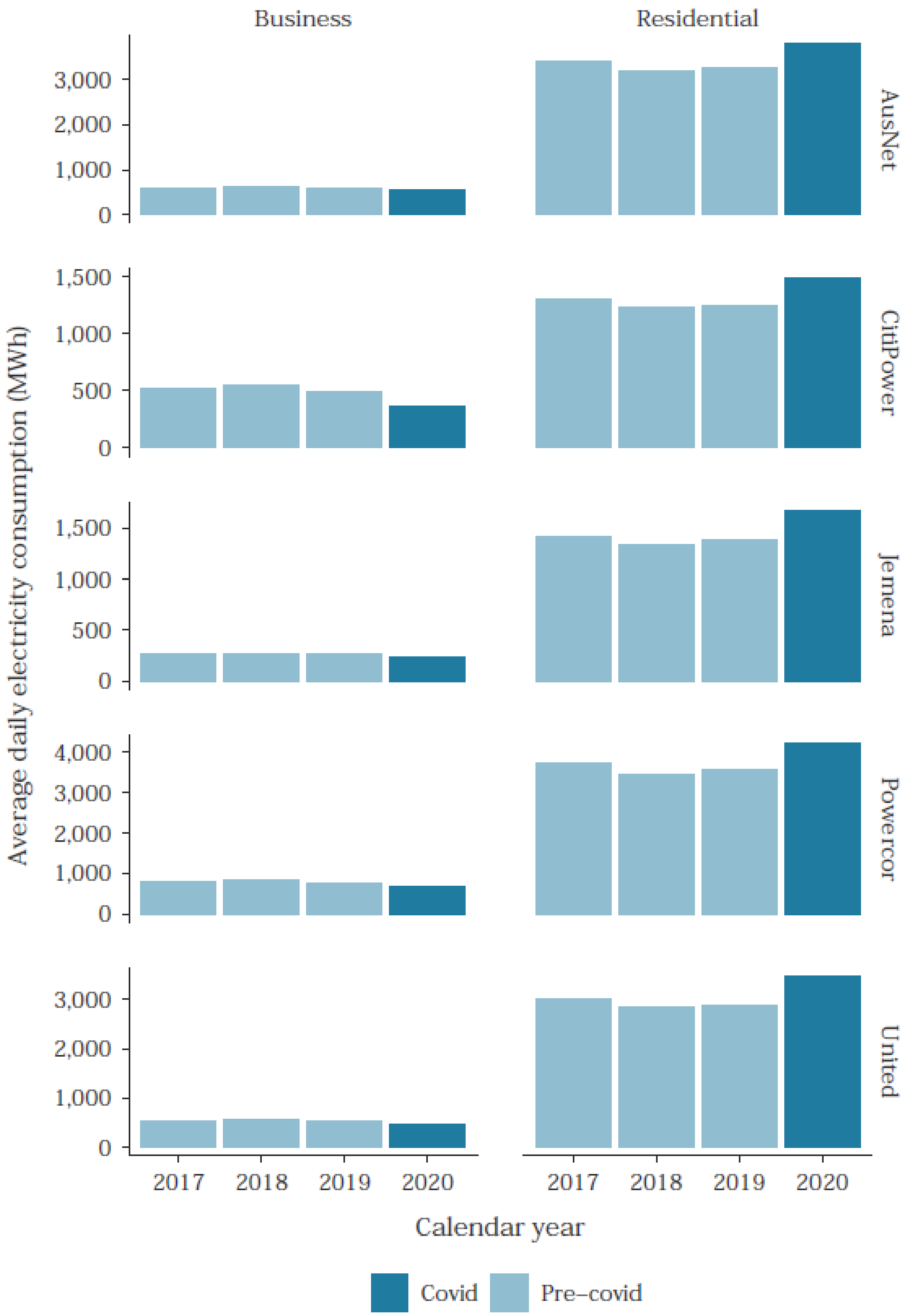
Source: Frontier Economics analysis of AEMO data

Figure 34: Average weekday consumption – March



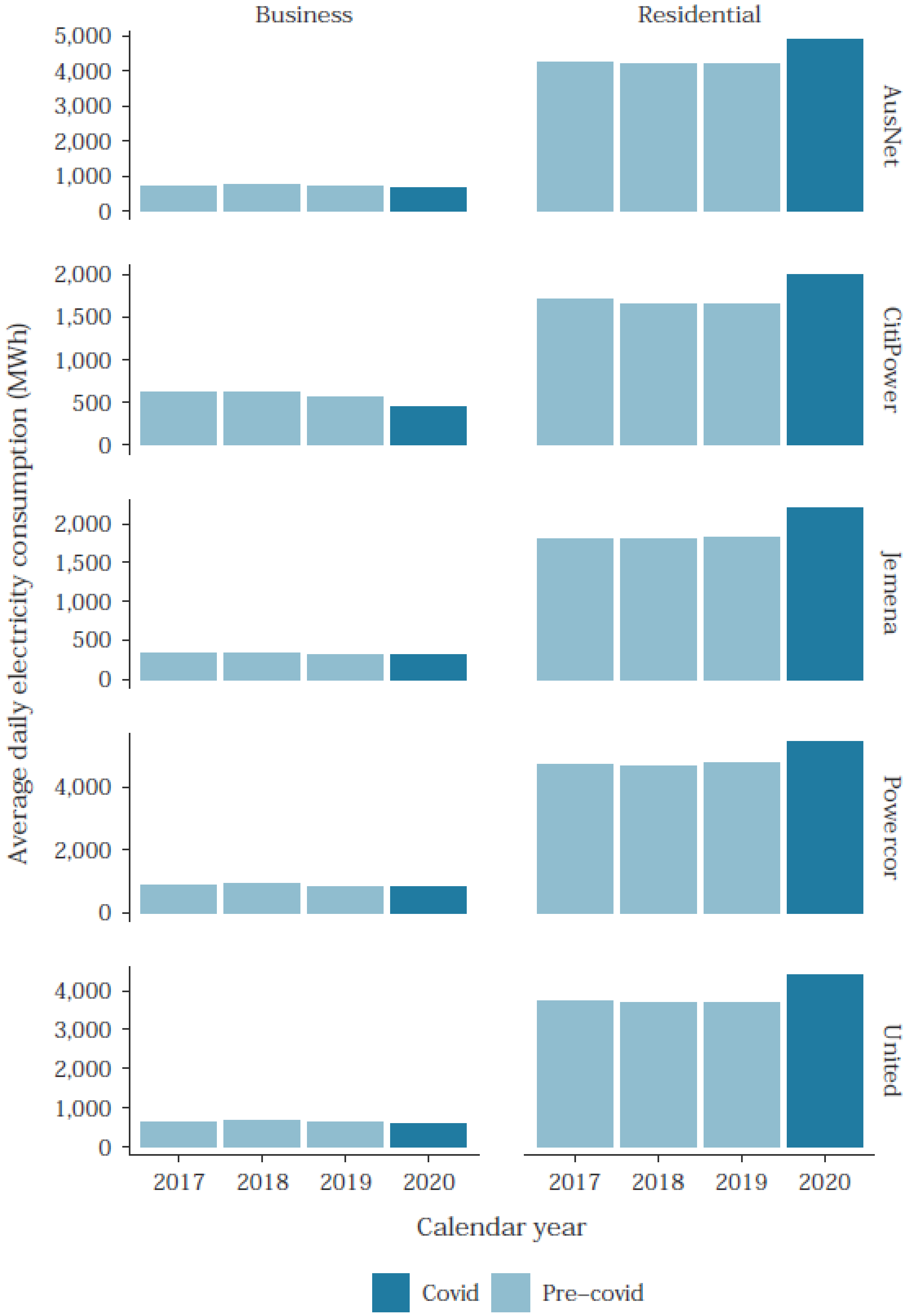
Source: Frontier Economics analysis of AEMO data

Figure 35: Average weekday consumption – April



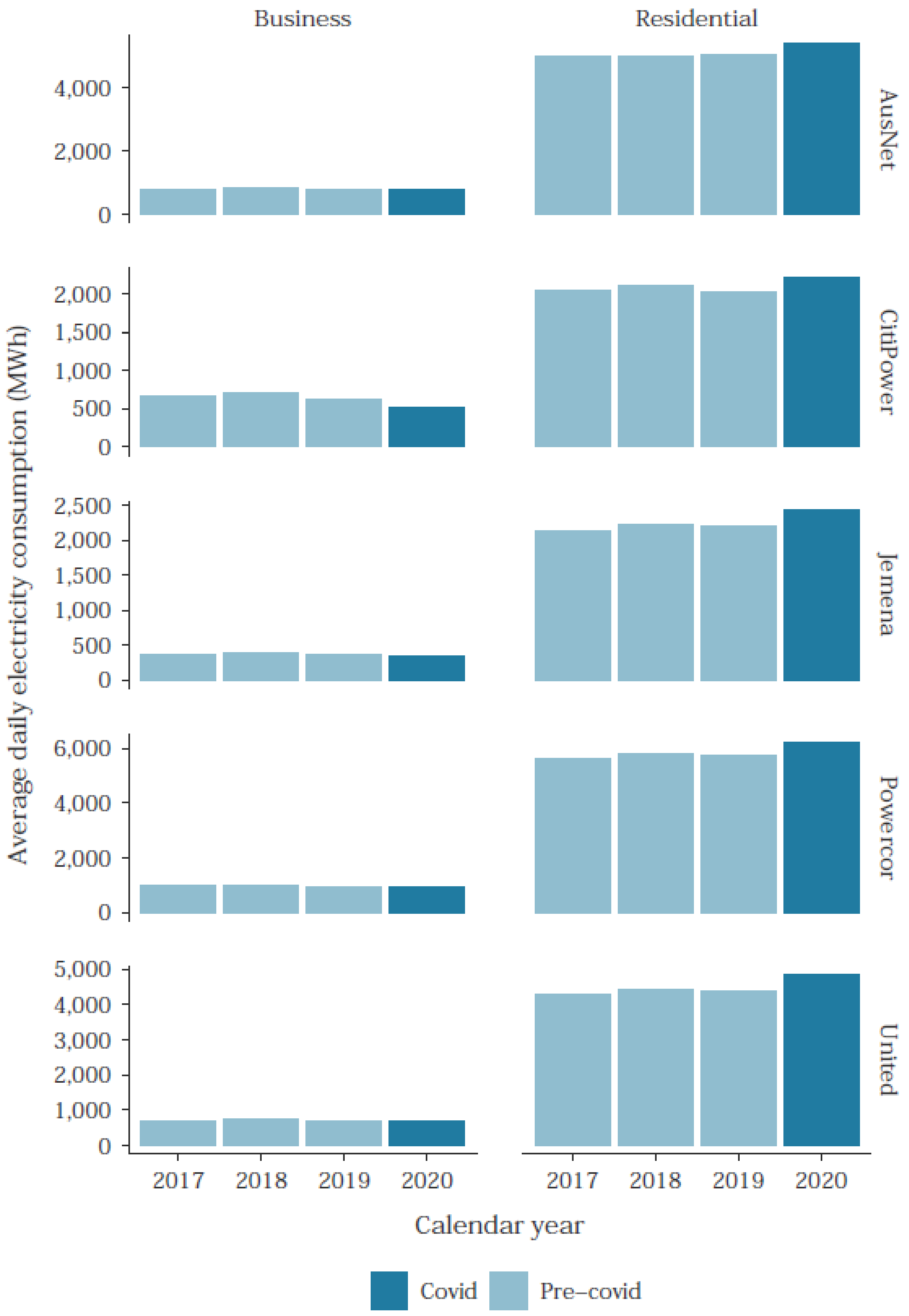
Source: Frontier Economics analysis of AEMO data

Figure 36: Average weekday consumption – May



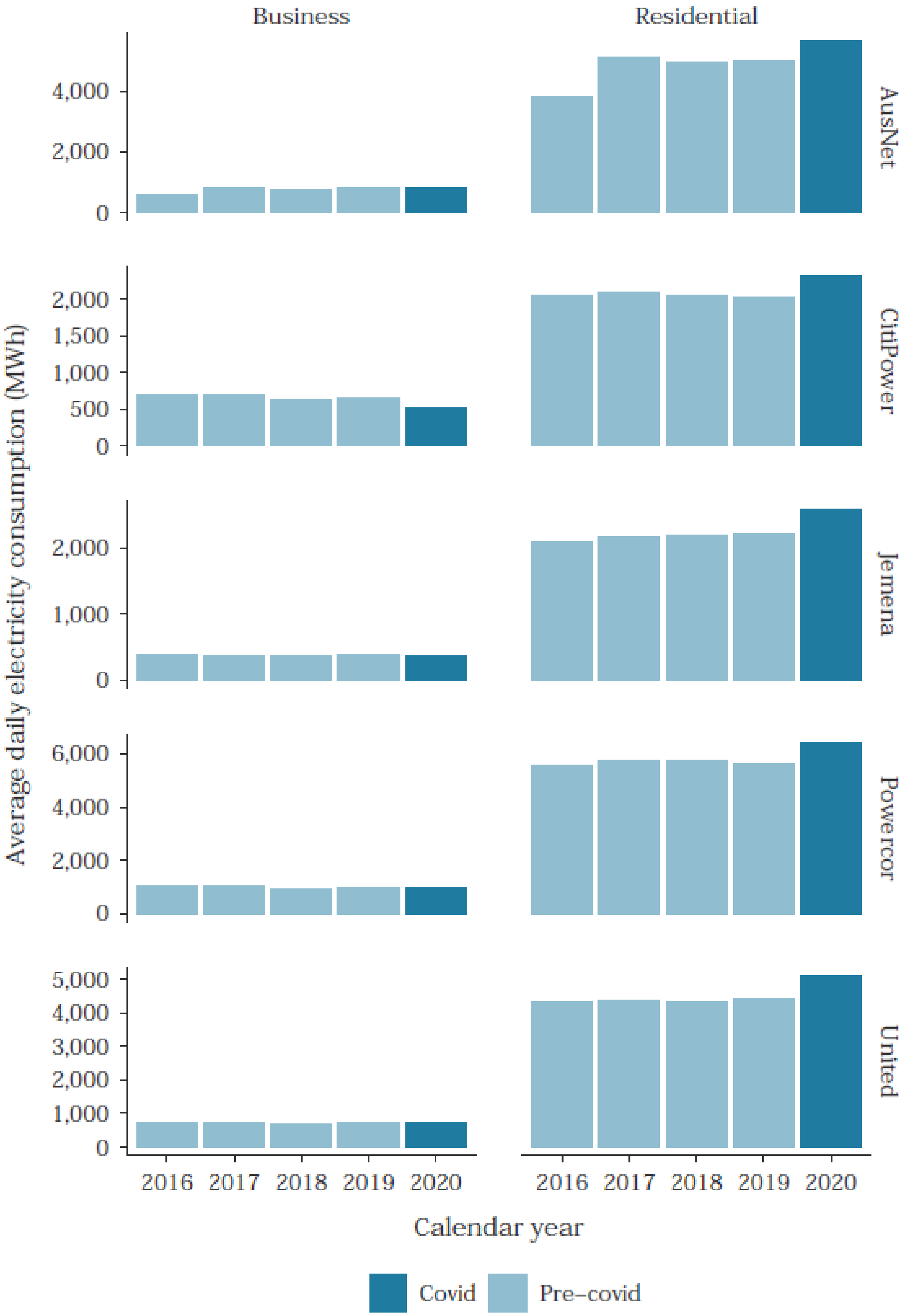
Source: Frontier Economics analysis of AEMO data

Figure 37: Average weekday consumption – June



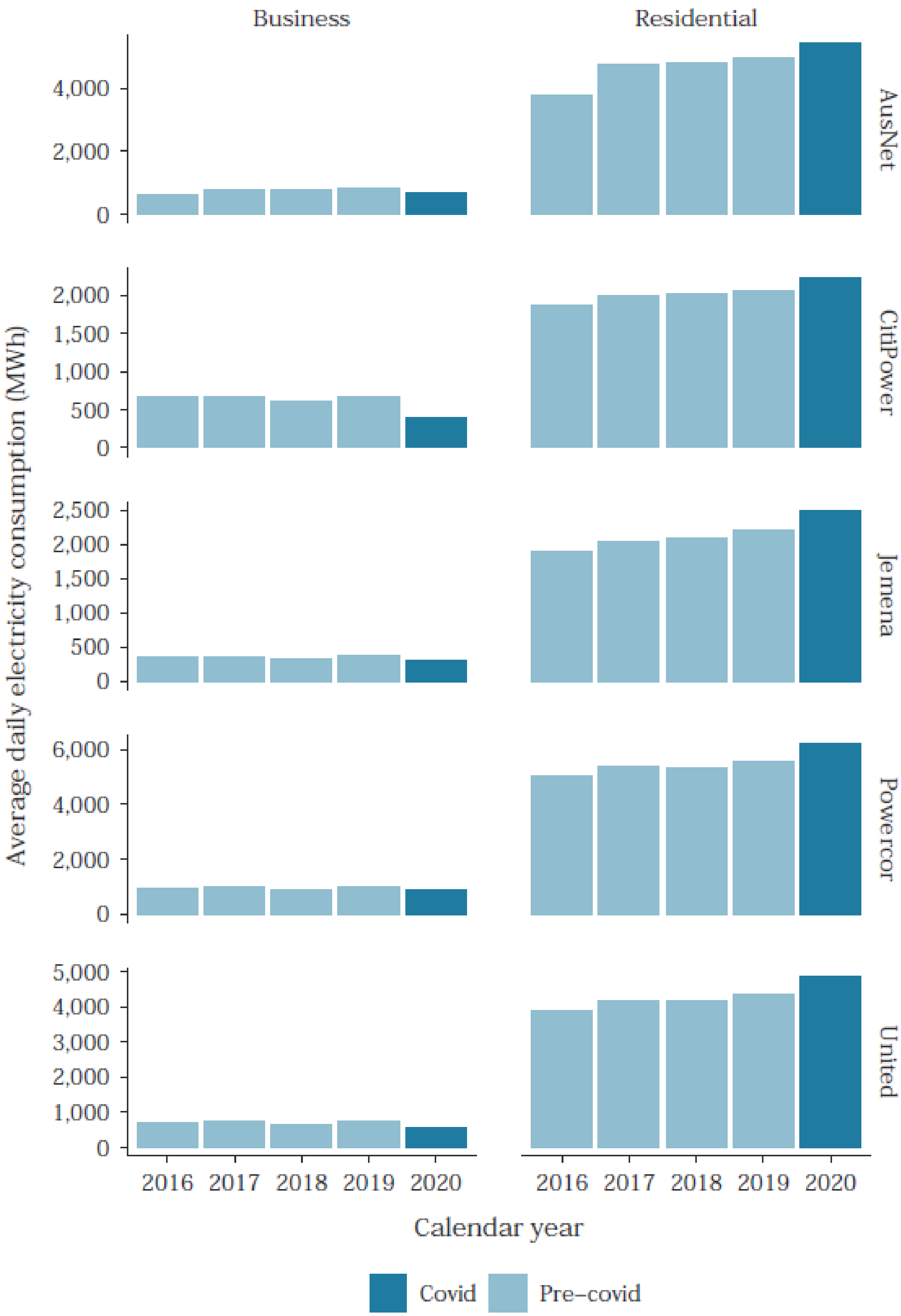
Source: Frontier Economics analysis of AEMO data

Figure 38: Average weekday consumption – July



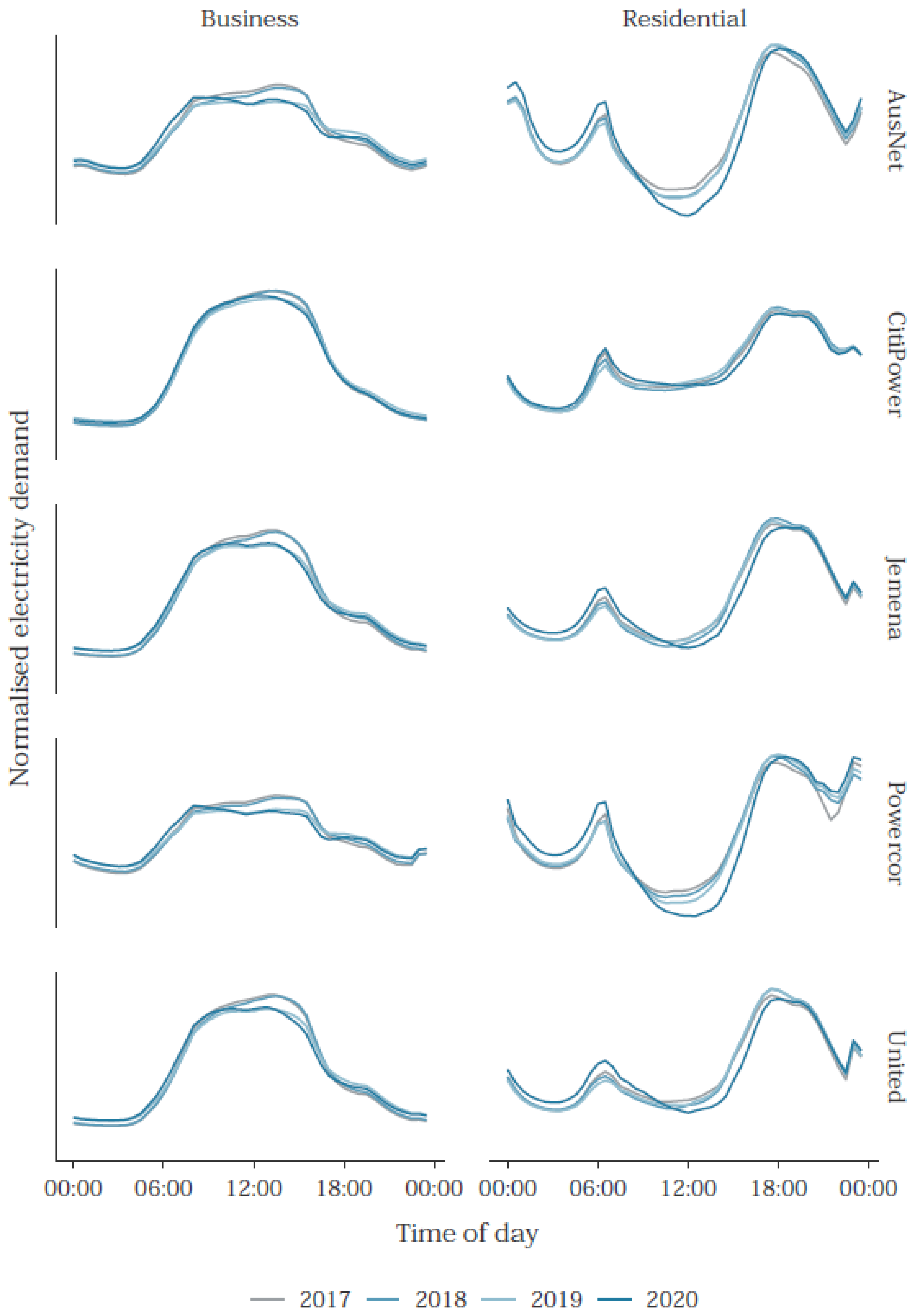
Source: Frontier Economics analysis of AEMO data

Figure 39: Average weekday consumption – August



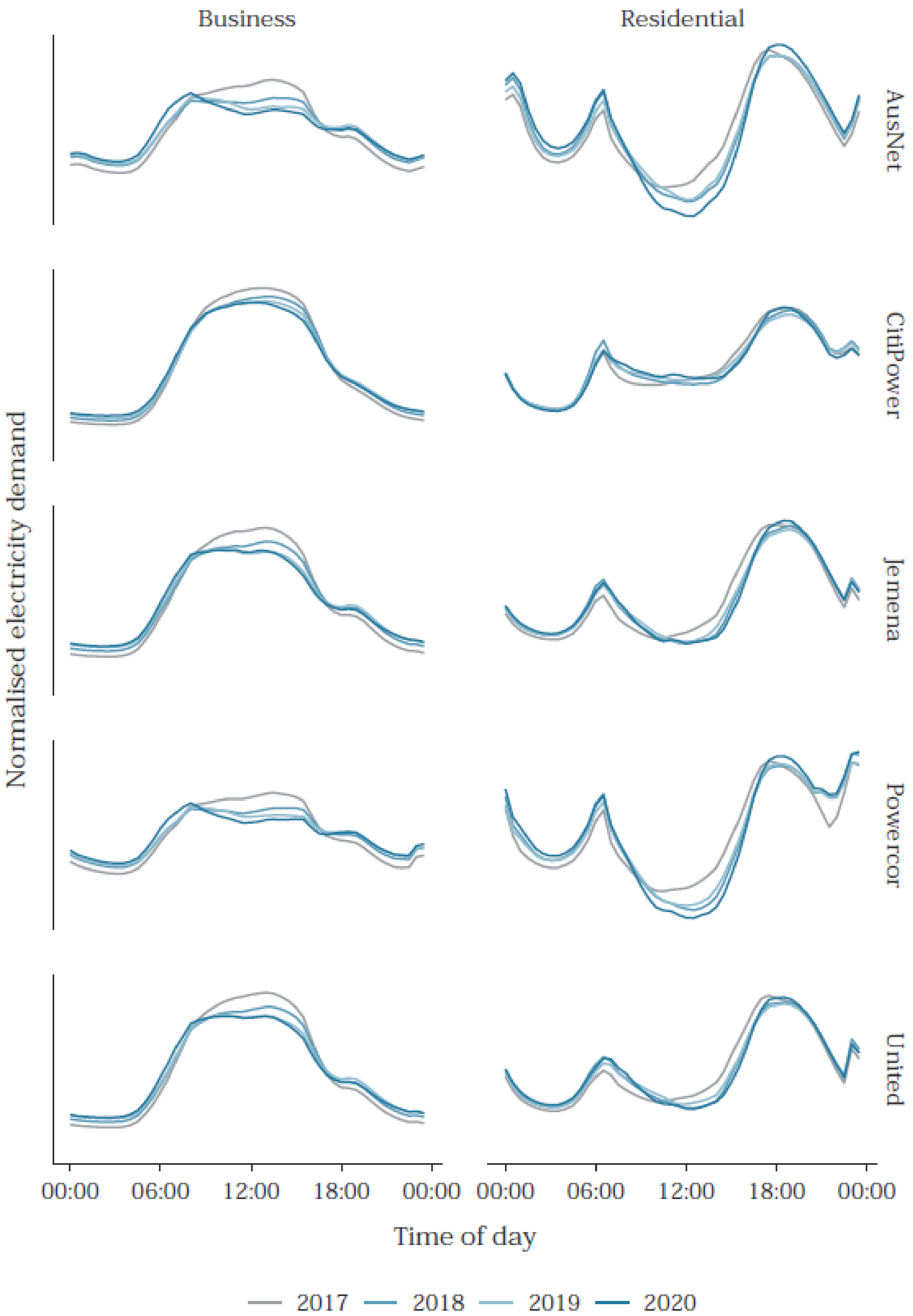
Source: Frontier Economics analysis of AEMO data

Figure 40: Average weekday load shape – February



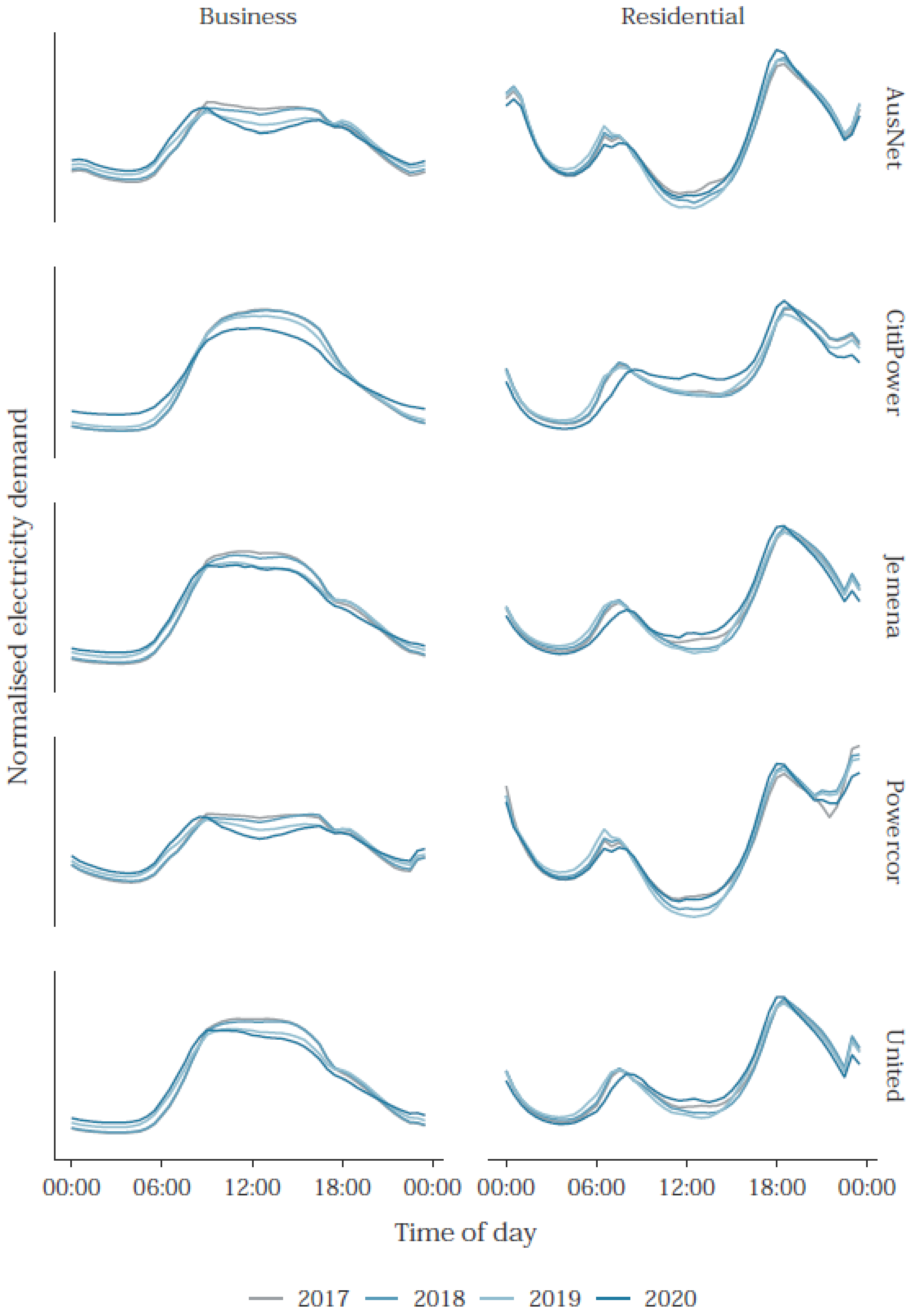
Source: Frontier Economics analysis of AEMO data

Figure 41: Average weekday load shape – March



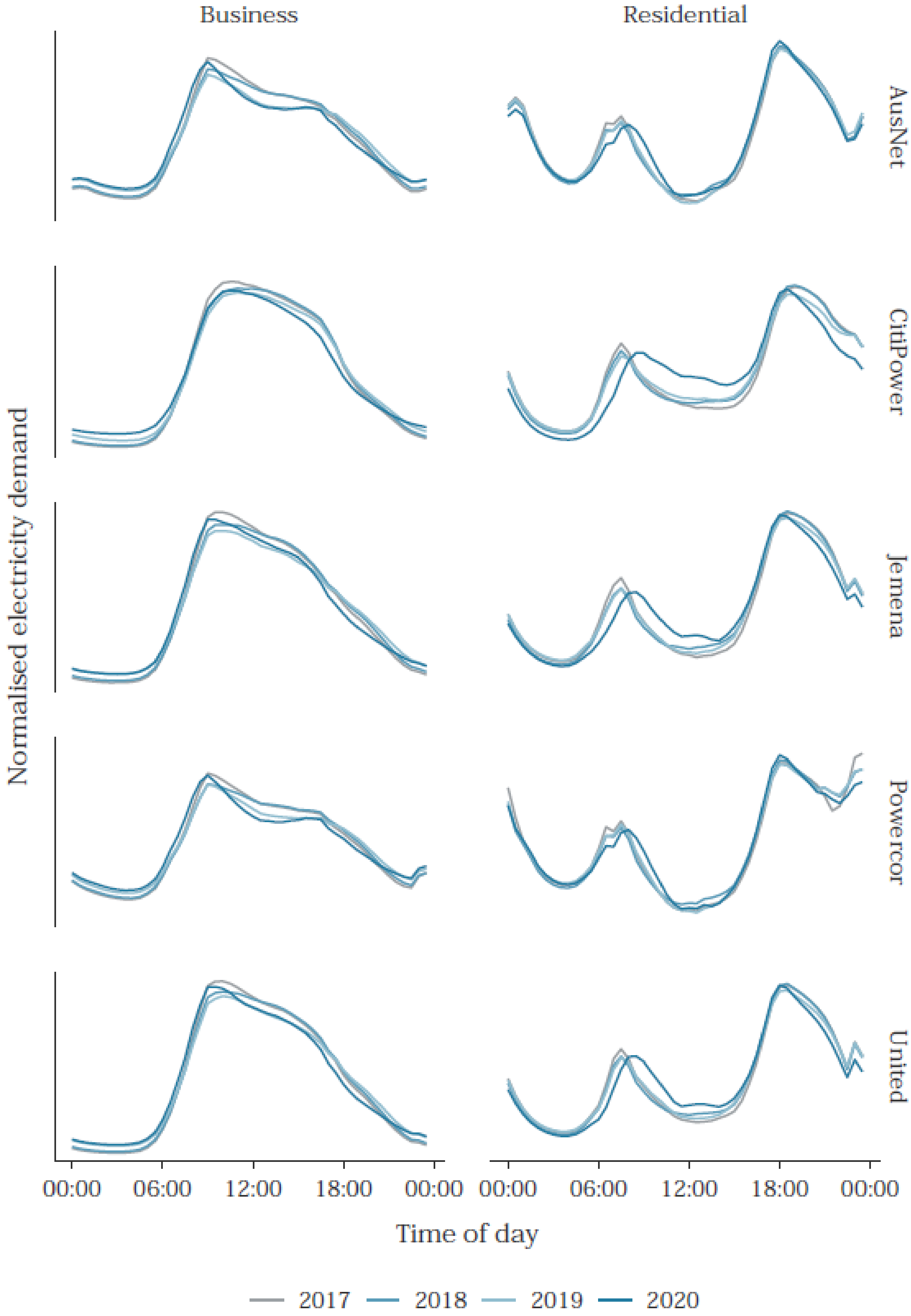
Source: Frontier Economics analysis of AEMO data

Figure 42: Average weekday load shape – April



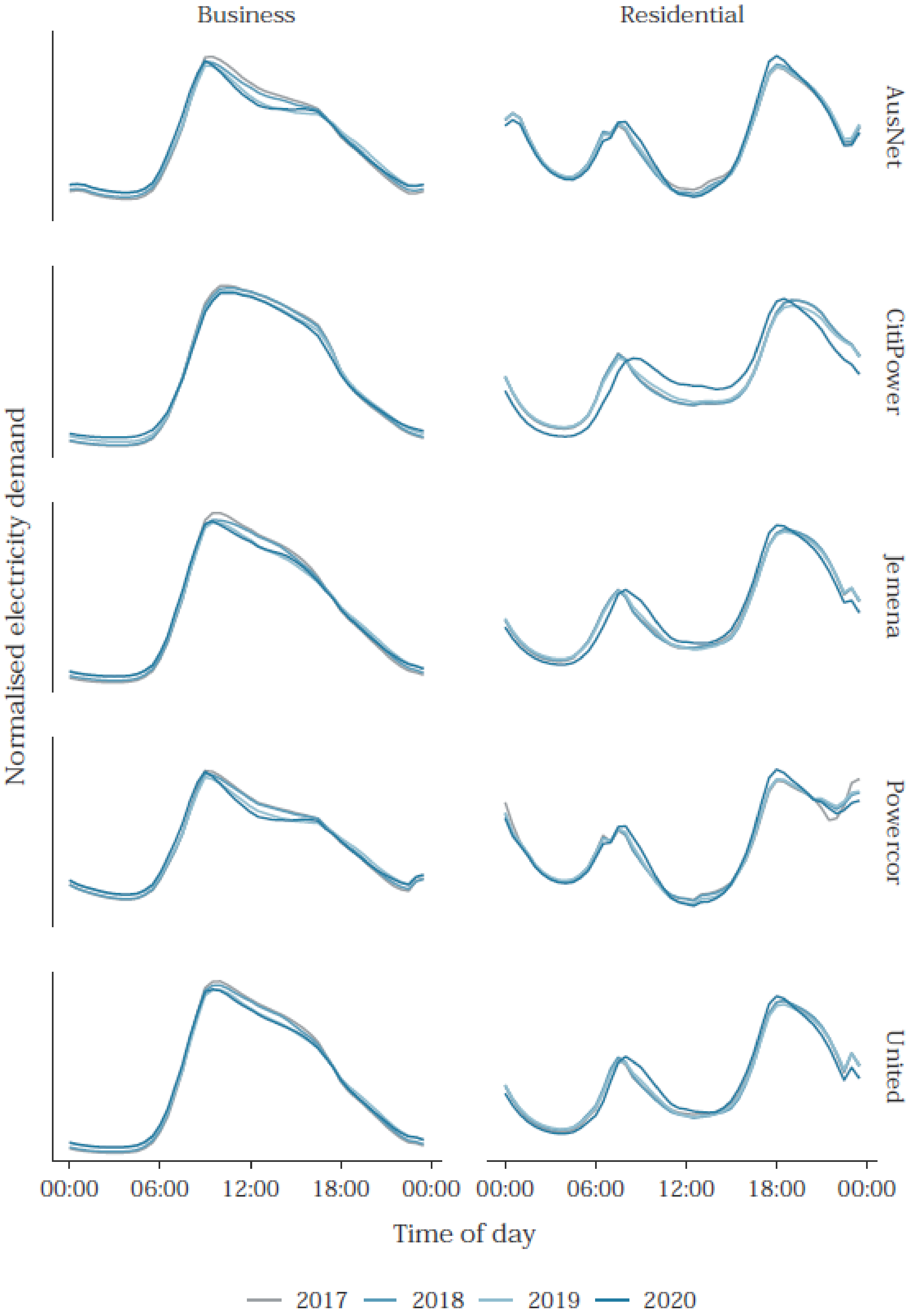
Source: Frontier Economics analysis of AEMO data

Figure 43: Average weekday load shape – May



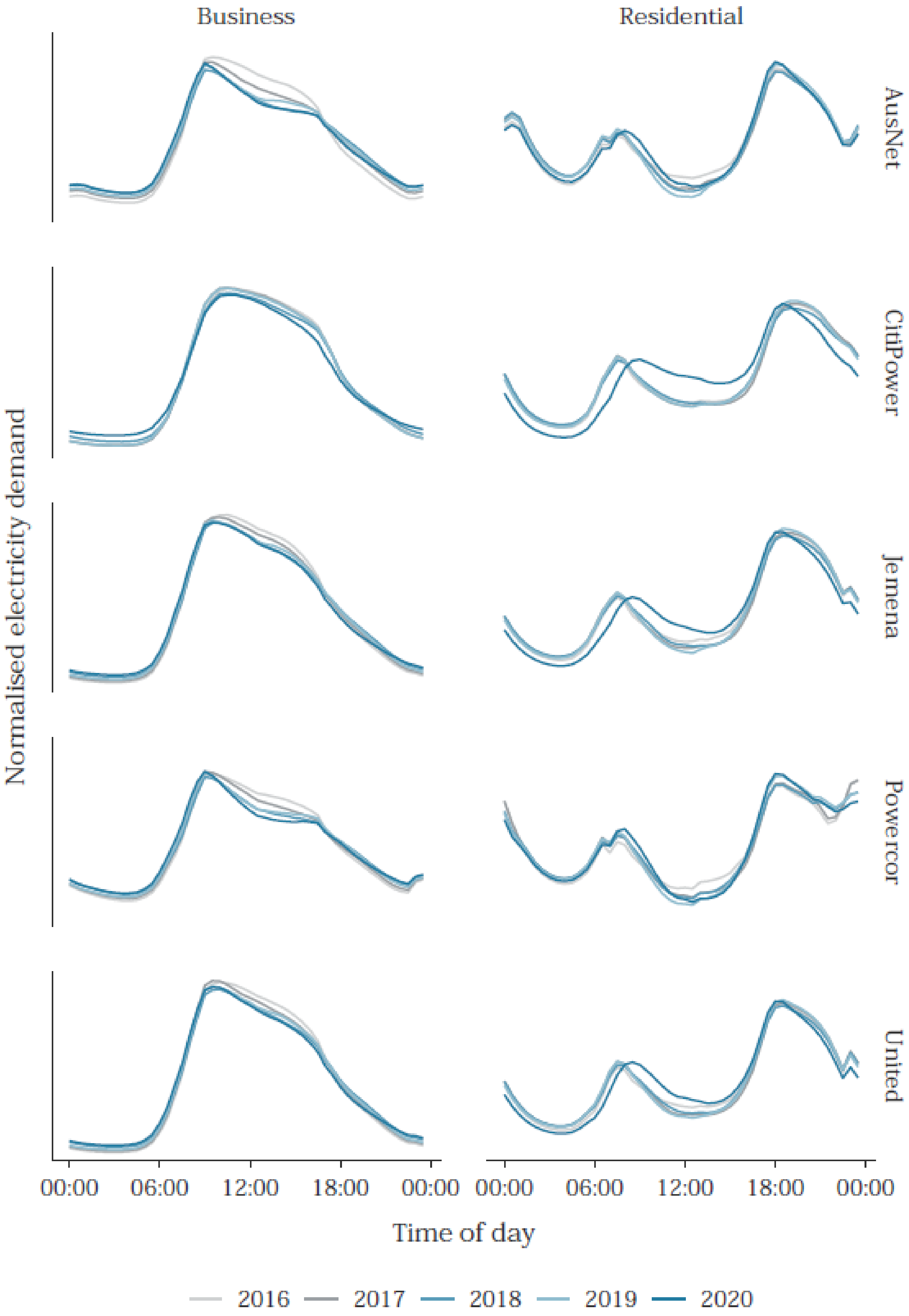
Source: Frontier Economics analysis of AEMO data

Figure 44: Average weekday load shape – June



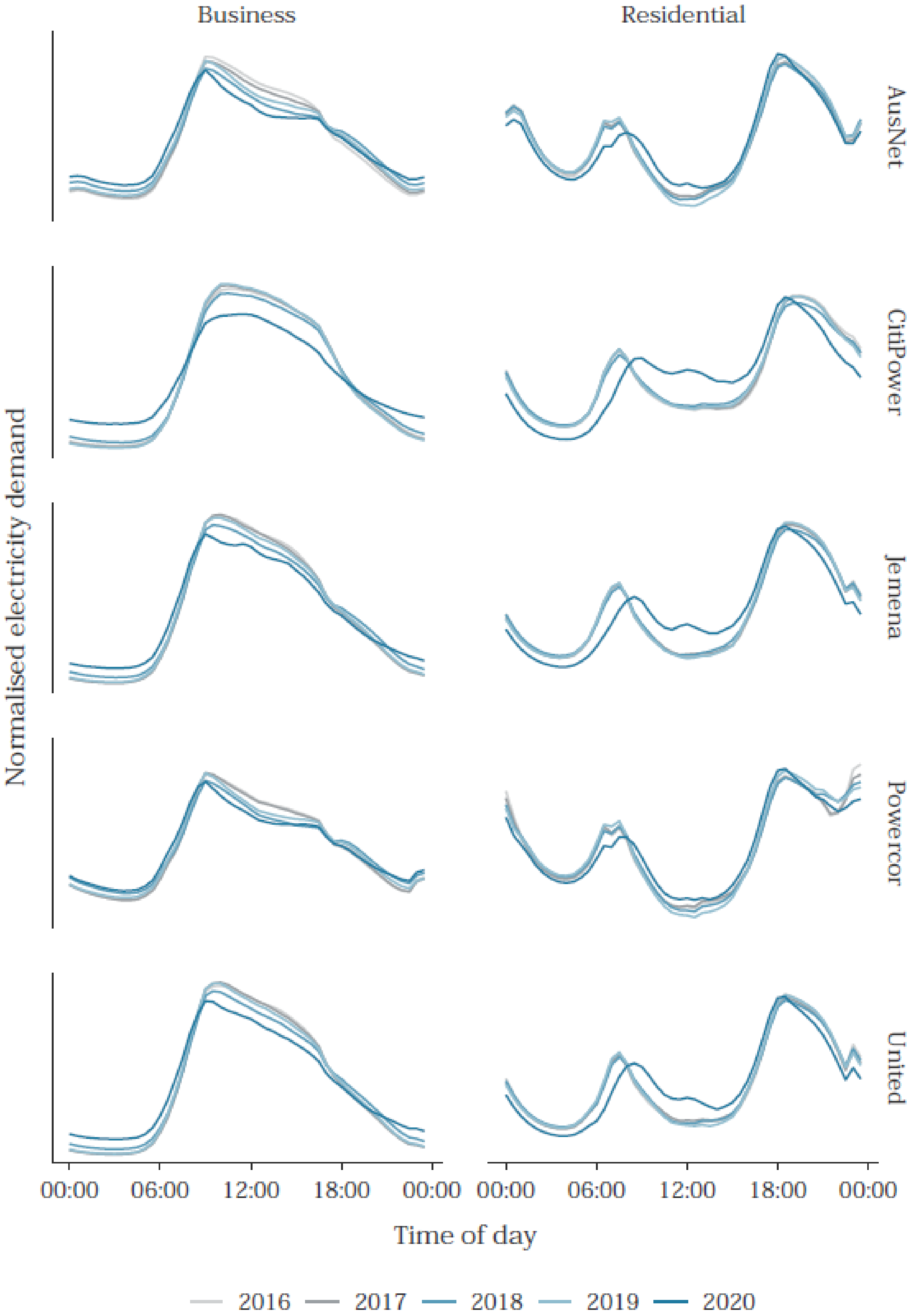
Source: Frontier Economics analysis of AEMO data

Figure 45: Average weekday load shape – July



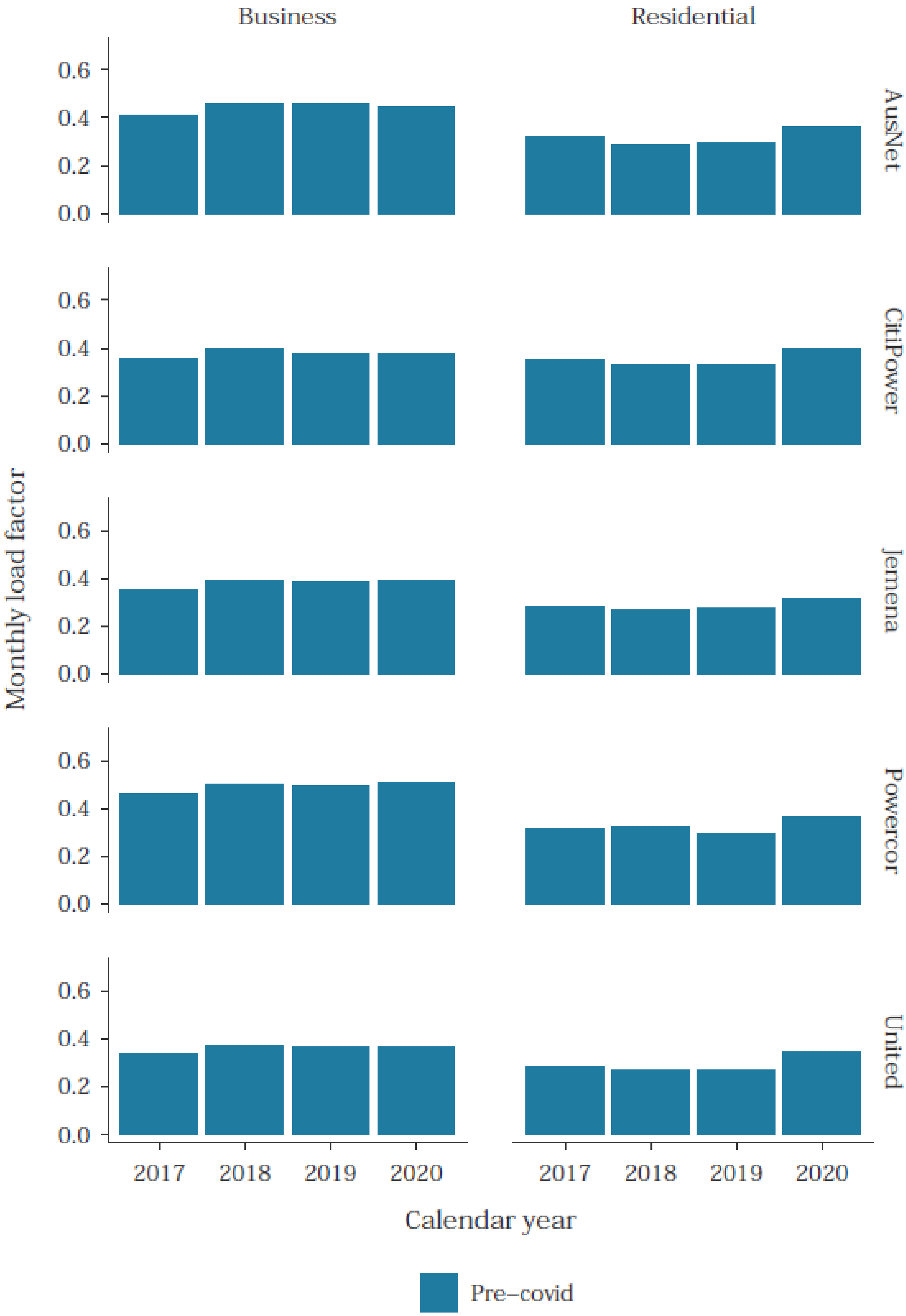
Source: Frontier Economics analysis of AEMO data

Figure 46: Average weekday load shape – August



Source: Frontier Economics analysis of AEMO data

Figure 47: Monthly load factor – February



Source: Frontier Economics analysis of AEMO data

Figure 48: Monthly load factor – March

Source: Frontier Economics analysis of AEMO data

Figure 49: Monthly load factor – April

Source: Frontier Economics analysis of AEMO data

Figure 50: Monthly load factor – May

Source: Frontier Economics analysis of AEMO data

Figure 51: Monthly load factor – June

Source: Frontier Economics analysis of AEMO data

Figure 52: Monthly load factor – July

Source: Frontier Economics analysis of AEMO data

Figure 53: Monthly load factor – August

Source: Frontier Economics analysis of AEMO data

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