Market Performance Quarterly Review

April-June 2022

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1 Purpose of this report

1.1 This document covers a broad range of topics in the electricity market. It is published quarterly to provide visibility of the regular monitoring undertaken by the Electricity Authority (Authority).

1.2 This report also includes a report on peak demand periods, the findings of which are summarised in section 7.

2 Highlights

Demand

2.1 The weekly load was similar to, or less than, the historical average[1] throughout April, May and much of June. From mid-June, however, the weekly load was higher than average. These trends were likely due to unseasonably high late autumn and early winter temperatures associated with La Niña. The increase in demand came as chilly weather gripped all the major centres. This cold weather, resulting large demand, low wind and technical issues at thermal generators led to a grid emergency notice on 23 June.

Retail

2.2 Market share of larger retailers this quarter marginally decreased, while for small-medium sized retailers, it slightly increased. The largest retail gains were made by Vocus and Contact Energy. Trader switches per month decreased compared to last quarter, whilst move-in switches increased.

Wholesale

2.3 Wholesale electricity prices have varied significantly, influenced by swings in hydro storage, periods of high wind generation, and variation in thermal generation. The average spot price for the quarter was $192/MWh, a $27 increase from the March 2022 quarter but a decrease of $79 from the June 2021 quarter. Throughout April and much of May, prices mainly hovered around $200/MWh. During this time, hydro storage was decreasing, and the reliance on thermals was higher. Prices became volatile in late May, as improving hydro storage, the return of TCC and high wind generation reduced the need for other thermal generation.

2.4 Generation from wind was particularly high at some points in the quarter and contributed up to 9 per cent of total generation in some weeks. During these times, the generation need from thermals, particularly coal, reduced significantly.

2.5 Nationally hydro storage continued to decrease throughout April and May, as the country experienced below-average inflows. In late May, however, storage began increasing, particularly at lakes Taupo, Te Anau and Manapouri.

2.6 Gas spot prices mainly hovered around $20/GJ throughout the quarter but increased during the Maui outage, spiking up to $40/GJ.

[1] Averaged over April to June for 2017-2021

Forward Market

2.7 Short-term forward prices decreased, while long-term forward prices increased over the quarter. The change in short-term futures was likely a reaction to an improved gas and hydro storage outlook for winter 2022. High coal prices, high carbon prices, a prolonged trend of low hydro inflows and differences between North and South Island hydro storage all fuelled the higher prices in long-term futures. These rises may have been dampened by the news that the decommissioning of TCC has been pushed back one year to September 2024.

2.8 During the June ETS auction 4.825 million NZUs were sold. After the triggering of the cost containment reserve at $70, an additional 1.2 million NZUs were sold.

3 Demand

3.1 New Zealand spent most of the March 2022 quarter in the “Red traffic light” setting. People were encouraged to work from home, and entry status into businesses, like hospitality, was dependent on having a vaccine pass. In the June quarter, on 13 April, the country entered the “Orange setting”, which lifted indoor gathering limits for those with vaccine passes, and many people returned to work in person.

3.2 Figure 1 shows total daily demand for May and June 2022 against the average daily demand for the averaged 2017-2021. Note that the historical average is based on the date, so the average for any day will likely include weekends (which have different demand profiles). Annotations display the weekly percentage difference between the 2022 load and the 2017-2021 historical average load.

3.3 The weekly load for the quarter peaked during the final week of June at 753 GWh, 5.2 per cent above the historical average.

3.4 Weekly demand was relatively stable throughout April, decreasing slightly during the easter holidays. Variations from the historic demand are likely a feature of when the holidays occurred in previous years. Daily demand began increasing throughout early June, but the total weekly demand remained below average. The week starting 6 June had a weekly demand 4.1 per cent lower than the historical average. Demand began increasing substantially after mid-June as the weather grew colder, and demand in the two weeks from 9-23 June was higher than the historical average.

3.5 Lower load in April and May might have been due to warmer and sunnier conditions, with the country experiencing less the average rainfall in April[2]. Temperatures in April and May were respectively 1.3°C and 1.8°C degrees warmer than the 1981-2010 average[3]. Warmer temperatures could have resulted in less use of heating. Demand in April was also likely impacted by many taking extended Easter holidays. Reduced temperatures and daylight likely drove the rise in demand throughout May.

3.6 The high demand in June was due to a cold snap, which brought frosts to much of the country. This caused high demand, and especially high peak demand each day of the week, see Figure 2.

3.7 On the morning of 23 June, high demand, low wind, and issues with a Stratford peaker and a Rankine unit led to a grid emergency notice being issued at 7:58 am. Due to this, prices spiked at over $2,500 /MWh for two trading periods and ripple control decreased

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[2] Climate Summary for April 2022 | NIWA

[3] Climate Summary for April 2022 | NIWA, Climate Summary for May 2022 | NIWA

load. Demand at 7 am was 3.32 GWh, or 91% of the demand that occurred at 6 pm on 9 August. The impact of the use of ripple control can be seen in Figure 2, the demand profile for 23 June as a dent in the morning peak load curve.

3.8 Reconciled demand for April, May and June 2022 was 3,186 GWh, 3,499 GWh, and 3,619 GWh, respectively.

Figure 1: Daily Load, June 2022 Quarter vs Historic Average.

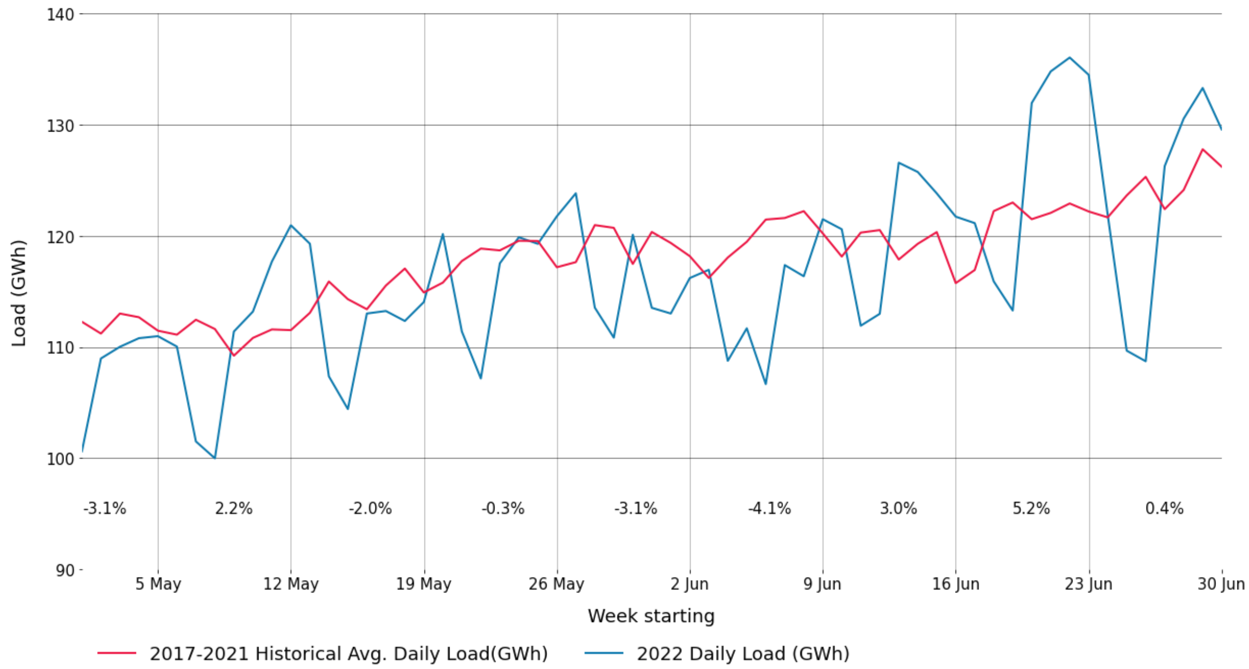
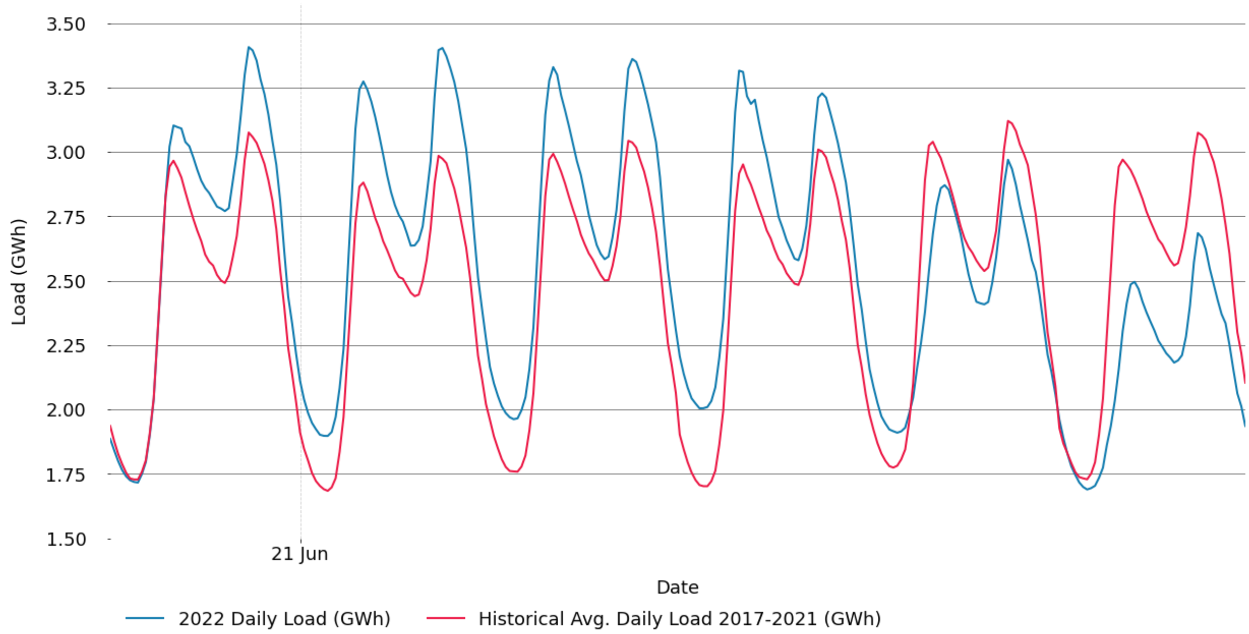


Figure 2: Half hourly load compared to the historical average for 20-25 June



4 Retail

4.1 Over the June 2022 quarter, the collective market share of the four[4] largest retailers, Contact, Genesis, Mercury, and Meridian, decreased by 0.69 percent, to 83.37 percent.

4.2 On 30 June 2022, the five largest retailers held 1,871,060 ICPs between them, losing 8,719 ICPs over the quarter. Small-medium sized retailers held 372,105 ICPs between them, gaining 15,746 ICPs.

4.3 Figure 3 shows the changes in market share of each retailer from 1 April to 30 June 2022. Vocus, Ecotricity and Contact Energy all gaining around 0.1 percent of market share, respectively. Smaller retailers have made gains, with Octopus Energy gaining 0.08 percent of market share, respectively. The retailers with the greatest decline in market share were Nova and Pulse, losing 0.17 and 0.1 per cent respectively.

4.4 The largest regional change in ICPs came from Contact's gains in Auckland, with an increase of 2,010 ICPs over the quarter.

Figure 3: Changes in retailer market share[5]

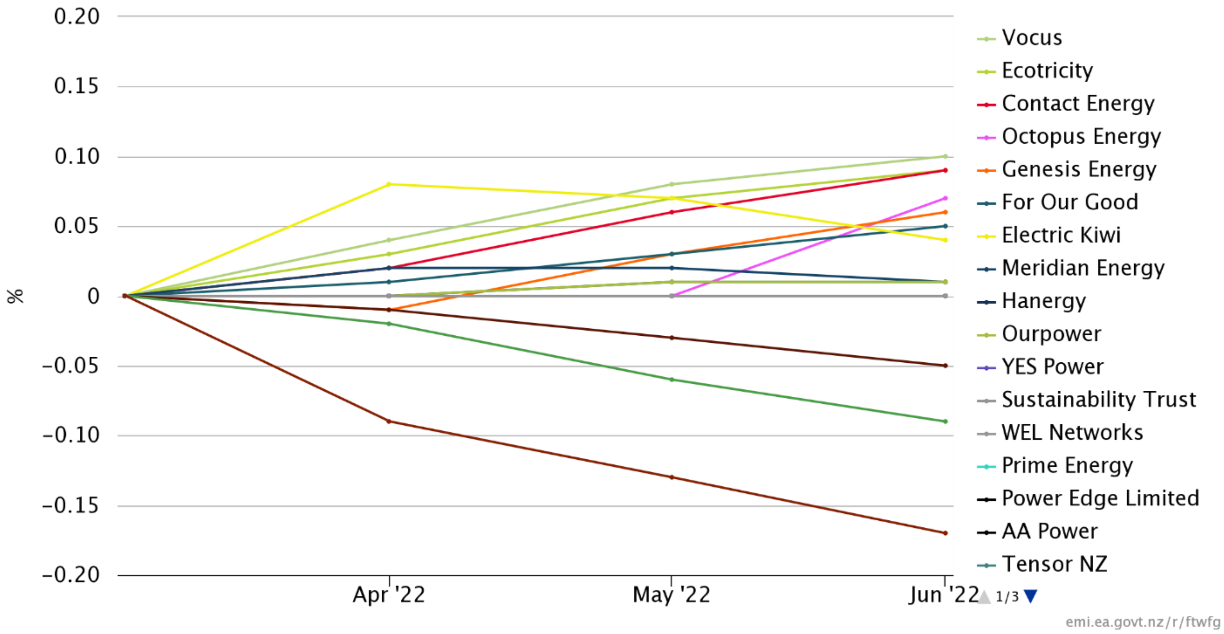


Figure 4 shows the number of electricity connections (ICPs) that have changed electricity suppliers from 1 July 2021 to 30 June 2022 categorised by type 'move in', 'trader' or 'half hour'. Move in switches are switches where the customer does not have an electricity provider contract with a trader. In contrast, trader switches are switches where the customer does have an existing contract with a trader, and the customer obtains a new contract with a different trader.

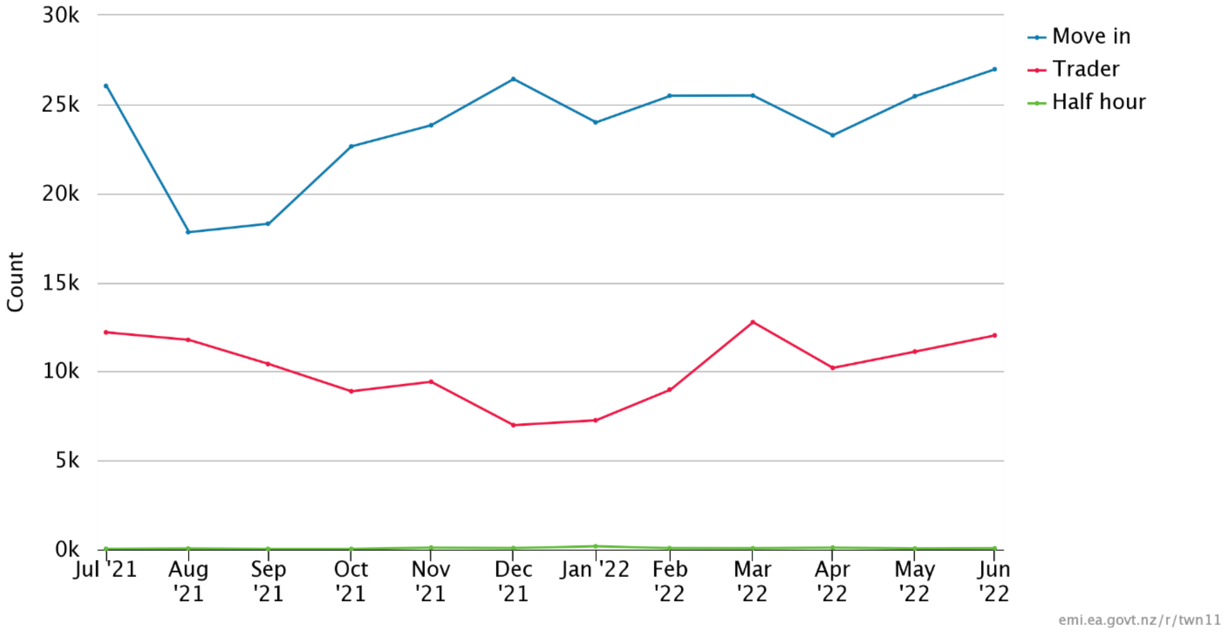
4.5 Over the quarter, trader switches decreased slightly, from 12,767 per month in March 2022 to 11,994 per month in June 2022. Move in switches increased slightly, from 25,488 in March 2022 to 26,948.

4.6 Move in and trader switches are roughly the same as they were a year ago.

[4] As of 1 May 2022, Trustpower sold part of its business to Mercury and changed its name to Manawa Energy. In the future Electricity Authority reports, it will not be bundled with the other large retailers as it has sold its retail assets to Mercury.

[5] Please note that not all traders fit in the key. Please go to emi.govt.nz/r/hcezv to view the key with all traders.

Figure 4: ICP switches by type 2021/22



5 Wholesale

5.1 Wholesale electricity spot prices were relatively stable in April and throughout May. Prices hovered around a daily average of $200/MWh. There were higher-priced periods, often during peak. This price behaviour was similar to the previous quarter. During late May, however, prices became volatile and often swung from close to zero to over $200/MWh. This pattern continued into June. We can see this pattern in Figure 5. The average spot price for the quarter across all nodes was $192/MWh, which despite the volatile prices in June, is $27 higher than last quarter and $79 lower than the June 2021 quarter.

5.2 The quarter’s highest real-time spot price across all key nodes was $4,389/MWh. This occurred at Kikiwa at 8:00 am on 23 June. Here, high demand, low wind, and issues with a Stratford peaker and a Rankine unit led to a grid emergency notice, with ripple control used to decrease load.

5.3 Varying hydro storage have impacted spot prices this quarter. Prices hovered around $200 /MWh as hydro storage continued to fall in April and May. The prices became volatile as hydro storage increased from late May onwards. Figure 6 displays this relationship.

5.4 Prices were also impacted by high wind generation, reducing the need for coal-fired generation, coupled with the return of TCC in late May. Figure 7 shows this relationship, where high winds and the return of TCC eliminate the need for Huntly one and two for much of June.

5.5 Outages of note include TCC and the second Stratford peaker. Earlier in the year,

Contact Energy reported on the issues and a scheduled outage for TCC. A mechanical problem constrained TCC to run for another 2000 hours, after which it would be taken out of service for a repair. To save some of these hours for later in winter, TCC was turned off for several weeks in late April until late May. Contact Energy then updated this outage after engineering advice stated it could run TCC for an extra 750 hours. With this update, TCC was able to run until around mid-August, at which time it would be taken out for repairs. Note that TCC was not offered from 2 August. The outage for the second Stratford peaker was extended until the end of July.

Figure 5: Half hourly wholesale electricity spot prices[6]

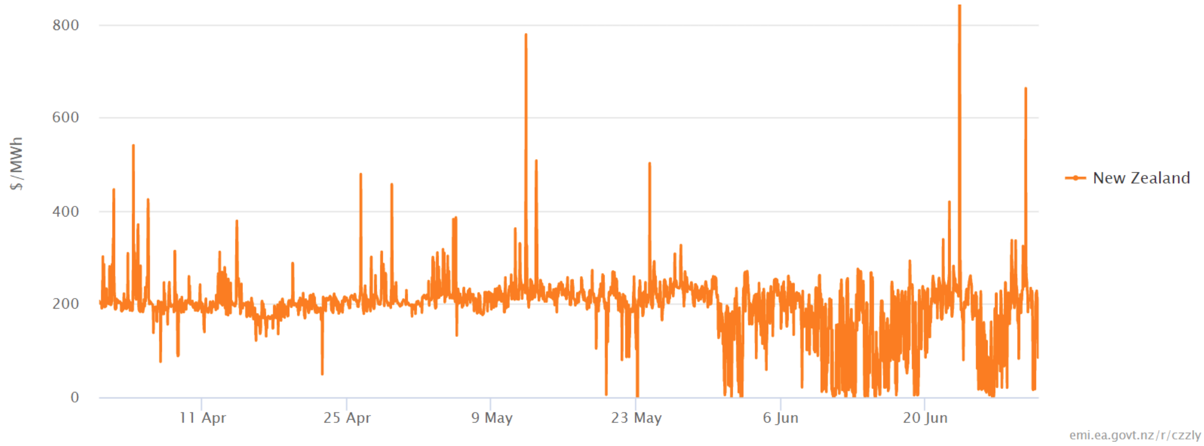
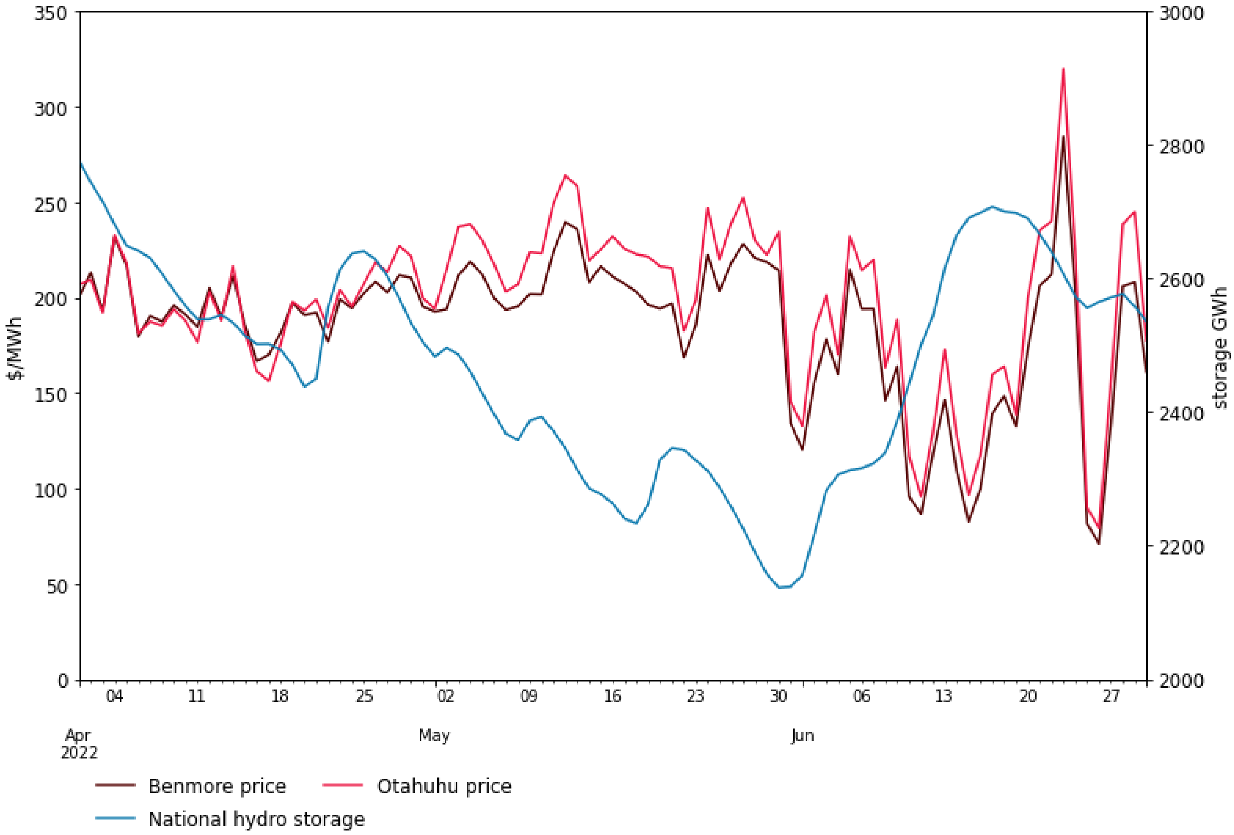
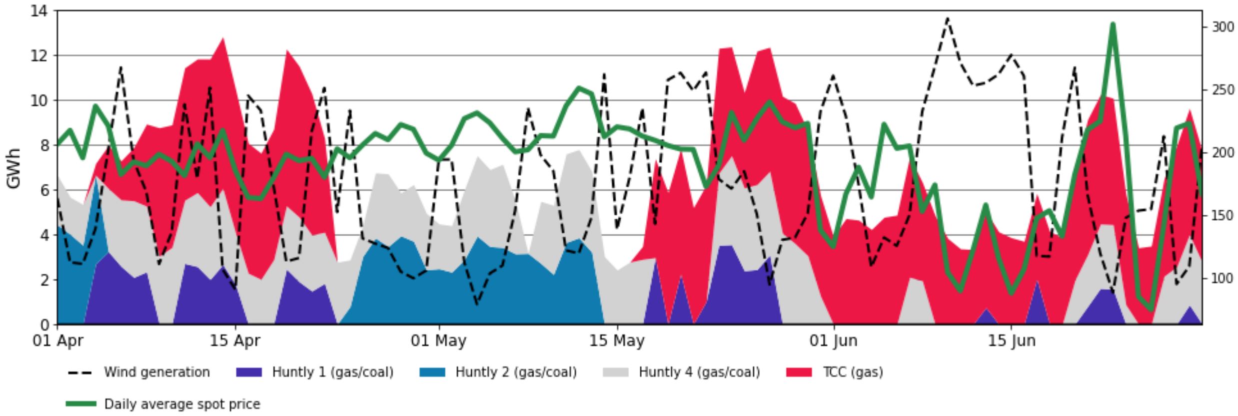


Figure 6: Daily national storage and daily average spot price



[6] Note that the range of the y-axis cuts off the $2,800/MWh price seen on June 24

Figure 7: Daily average spot price and daily total generation, in GWh, at Huntly (coal/gas fired units), TCC and from wind, between 1 April – 30 June 2022



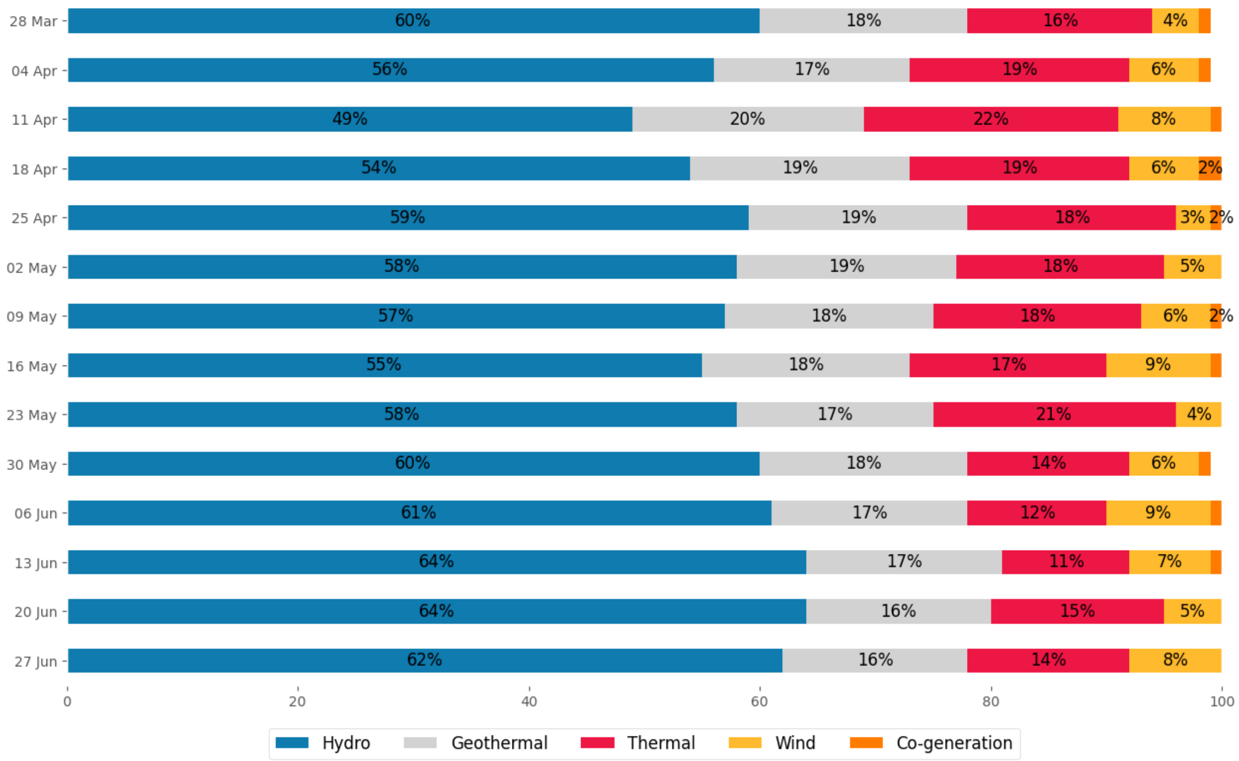
5.6 Generally, outside of unusual circumstances, spot prices increased when grid demand increased, wind generation decreased, and gas and coal powered generation increased. The relationship between wind generation and prices can be seen in Figure 7. Most high prices[7] occurred when wind generation was low. Thermal generation offers set high prices for higher tranche offers due a high SRMC for coal and gas keeping the cost of thermal generation high, see the relationship of high thermal usage often corresponding to high spot prices also Figure 7.

5.7 Decreasing hydro storage throughout the first half of the quarter first kept prices stable at around $200/MWh. Then as storage increased prices became more volatile. Figure 6 shows the daily averaged spot price against the national hydro storage.

5.8 Generation from renewable sources for the quarter averaged 82 per cent of total generation. The slight decrease from last quarter is due to reduced hydro generation early in the quarter, with the shortfall being picked up by extra thermal. Weekly variation can be seen in Figure 8.

[7]Classified as when a price is above the 90th percentile of historical prices from 1997-2021

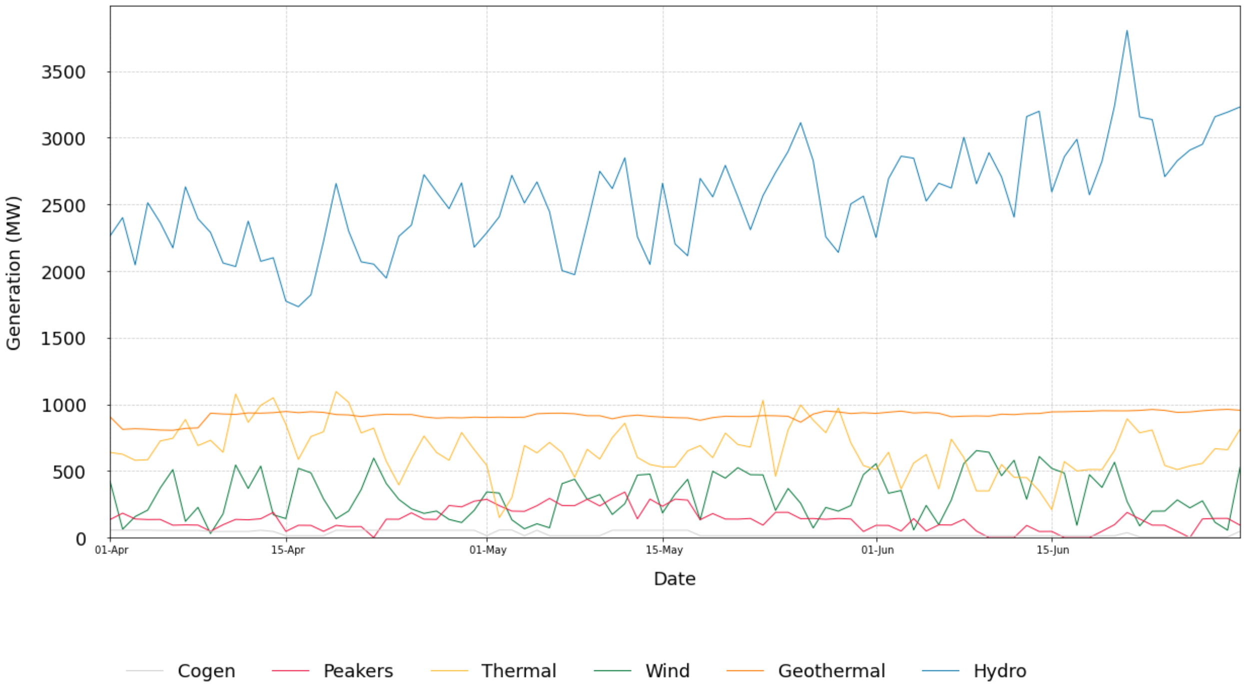
Figure 8: Weekly generation by fuel breakdown



5.9 Figure 9 shows daily generation for the quarter by fuel type. Throughout April, as hydro storage was decreasing, and generation from hydro was subsequently lower, thermal generation supported a higher proportion of baseload - with hydro ramping up and down throughout the day to match load. As hydro storage increased, however, hydro began generating more, and covering more baseload, with thermals turning on and off to match demand.

5.10 Wind generation had a half hourly generation average of 311 MW for the quarter and averaged 7 per cent of total generation. Half hourly hydro generation averaged 2,540 MW and averaged of 55 per cent of total generation. Half hourly thermal generation averaged 790 MW and averaged of 17 per cent of total generation.

Figure 9: Average Daily Generation by Fuel Type



5.11 Figure 10 shows total national controlled hydro storage up to 30 June 2022. Over the June quarter hydro storage decreased by 237 GWh, from 3,083 GWh on 1 April 2022 to 2,846 GWh on 30 June 2022.

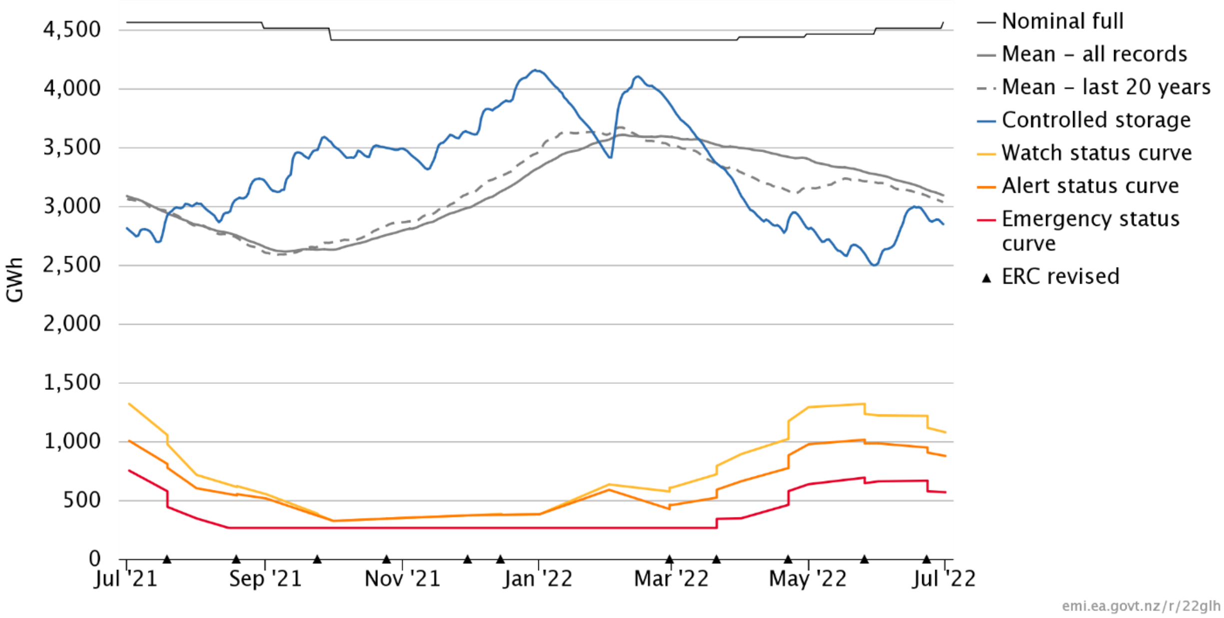
5.12 On 1 April 2022 hydro storage was at its highest point for the quarter, at 88 per cent of historical mean (3,494 GWh) and 70 per cent of nominal full (4,437 GWh). On May 30 storage was at its lowest, at 76 per cent of the historical mean (3,273 GWh) and 55% of nominal full (4,462 GWh)

5.13 Hydro inflows were closer to the historical mean this quarter. Total national inflows[8] were 5,630 GWh, which is 96 per cent of the historical average of 6,837 GWh.

5.14 Inflows at Lake Taupo were high, at 647 GWh, which is 103 per cent of its historical average of 623 GWh.

[8] Between April - June

Figure 10: Controlled National Hydro Storage 2021/2022



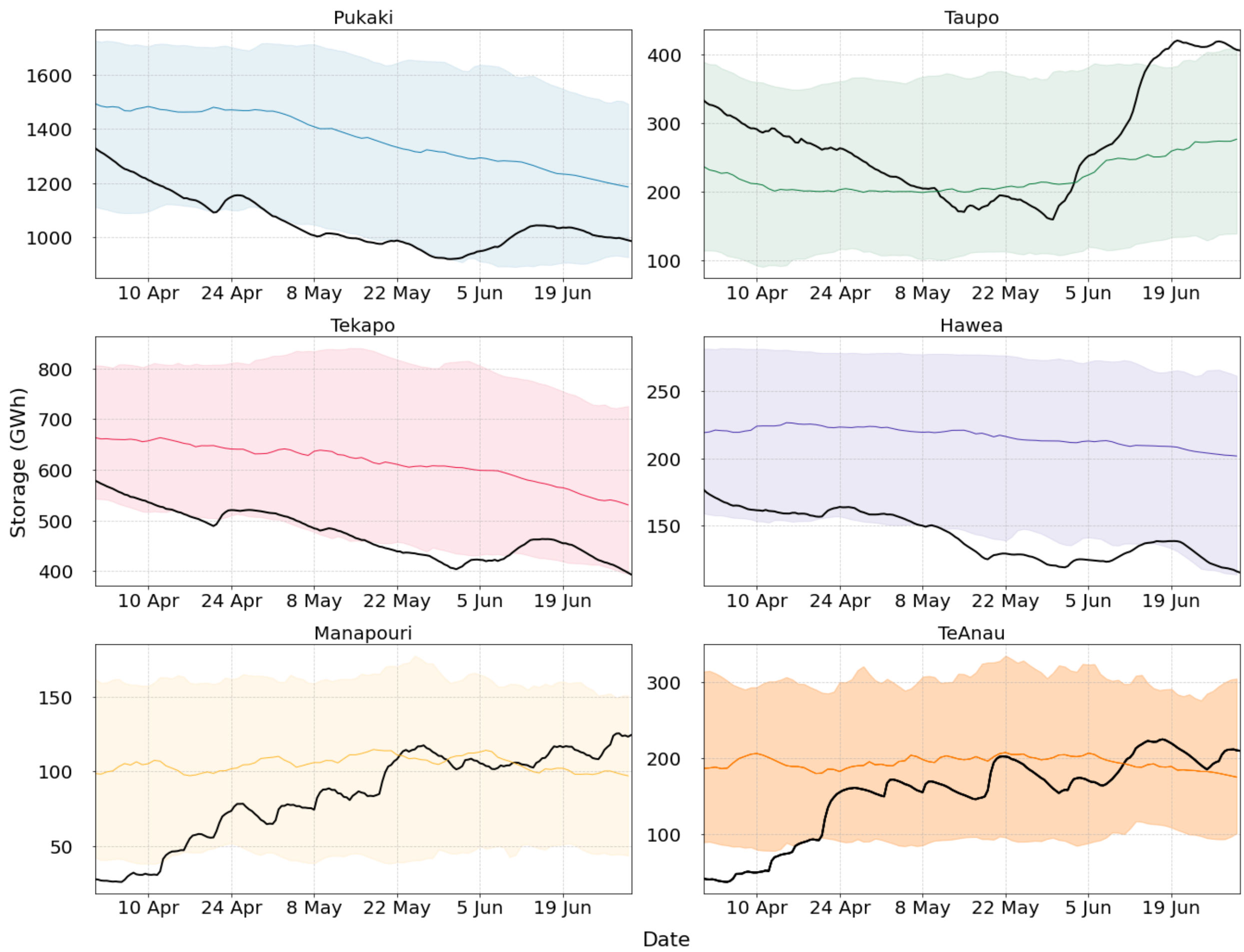
5.15 Figure 11 shows the storage of major catchments Lakes Pukaki, Taupo, Tekapo, Hawea, Manapouri and Te Anau for the quarter against their historical means and 10th-90th percentiles based on data from 1926-2021.

5.16 Storage at Pukaki, Tekapo and Hawea have been below their historic means all quarter, with all spending mostly hovering around their respective 10th percentiles.

5.17 Lakes Manapouri and Te Anau recovered from their extremely low values seen earlier in the year. A combination offering in order to conserve water, meet resource consents, and higher inflows saw both lakes creep up towards their means in May. Both lakes ended the quarter comfortably over their means.

5.18 Storage at Taupo decreased throughout April and dipped below its historic mean for much of May. Large inflows during June, however, increased storage substantially within a few weeks from below mean to above its 90th percentile.

Figure 11: Major Lake Storage v mean, 10th-90th percentile



5.19 Figure 12 shows gas production by major fields and gas consumption by major users from July 2021 – June 2022. Total gas production for the March quarter decreased by 31 TJ/day, from 360 TJ/day on 1 April 2022 to 319 TJ/day on 30 June 2022.

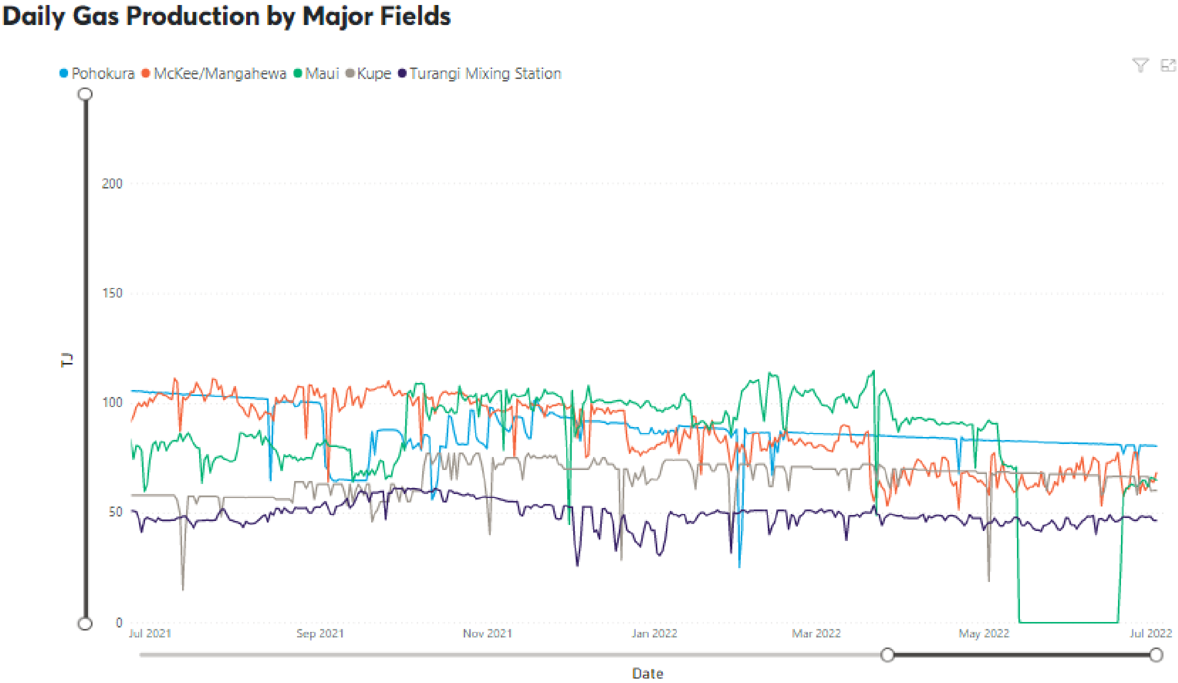
5.20 During the quarter, the largest producing gas field, Maui, went on full outage from 14 May to 19 June. During this time, gas production was reduced by ~90 TJ/day. The outage was initially scheduled to end on 6 June. However, technical issues and bad weather led to a 13-day delay in restarting the field.

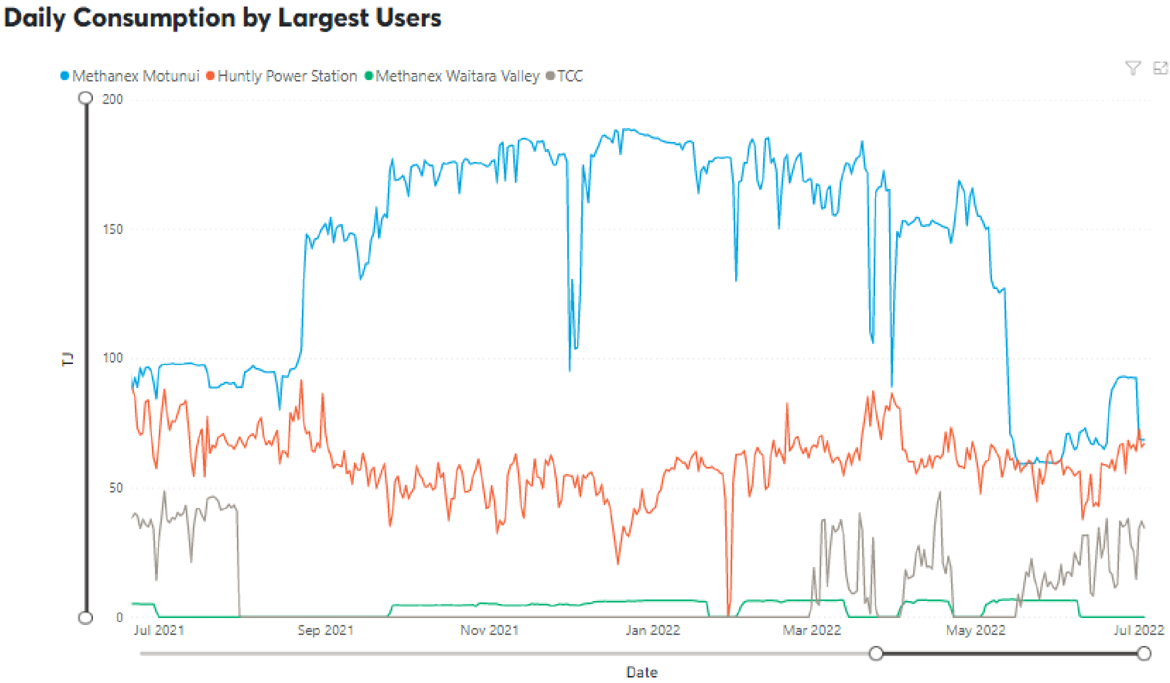
5.21 Output at McKee averaged 67 TJ/ day over the quarter. Kupe appears to have begun declining again after a period of relative plateau. Pohokura continues its long-established decline in output, which has fallen from ~245 TJ/day in 2018 to an average of 82 TJ/day during the June 2022 quarter.

5.22 During the Maui outage, consumption at Methanex reduced, from ~160 TJ/day to ~60TJ/day. On 30 June consumption had returned to ~92 TJ/day. Gas consumption at Huntly remained relatively steady over the quarter as thermal generation met baseload demand. The average consumption over the quarter was 60 TJ/day and peaked on 27 June at 68 TJ/day.

5.23 Once TCC returned in mid-May, its gas consumption steadily increased throughout the rest of the quarter. Consumption averaged 20 TJ/day and peaked on 27 June at 38 TJ/day.

Figure 12: Daily Gas Production and Consumption[9] 2021/2022





5.24 Figure 13 shows the Maui pipeline average marginal price (AMP) for the June quarter. We took pricing data from BGIX[10] (Balancing Gas Information Exchange) which is used here as a proxy for gas spot prices.

[9] https://www.gasindustry.co.nz/about-the-industry/gas-industry-information-portal/gas-production-and-major-consumption-charts/

[10] BGIX - Balancing Gas Information Exchange

5.25 Gas spot prices hovered around $20/GJ for April and much of May. Prices became volatile towards the end of May and peaked at $38/GJ on 29 May. Between 14 – 24 June prices again lingered around $20/GJ before dipping briefly between 25 – 27 June down to $10/GJ.

5.26 Coal prices similarly rose, with Indonesian coal (the coal Genesis imports) reaching over NZ $600/tonne at some points of the quarter, almost four times the price in 2020. Global sanctions on Russian energy resources, including gas, oil, and coal, as a result of the War in Ukraine drove most of the increases in coal prices. This increased the opportunity cost of running the Huntly Rankines to ~$300/MWh.

5.27 The latest coal numbers from Genesis put Huntly's coal stockpile at 877,000 tonnes at the end of the June 2022 quarter, an increase of 50,000 tonnes from March 2022. Note thermal generation offers tend to reflect the opportunity cost of using thermal fuel with offers based on current market prices rather than costs incurred.

5.28 Figure 14 shows coal use at Huntly was high throughout April and May. In early to mid-June, however, coal usage dramatically fell, with some days being coal-free.

Figure 13: Daily Spot Gas Prices

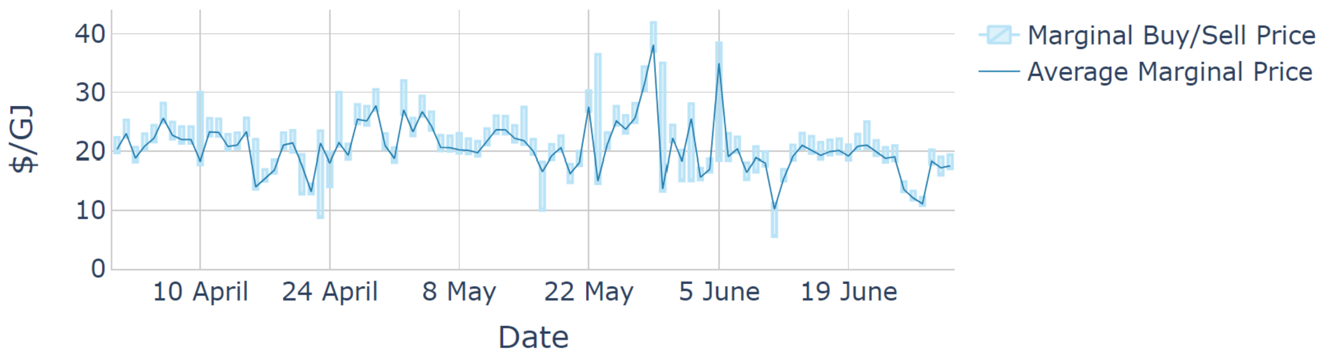
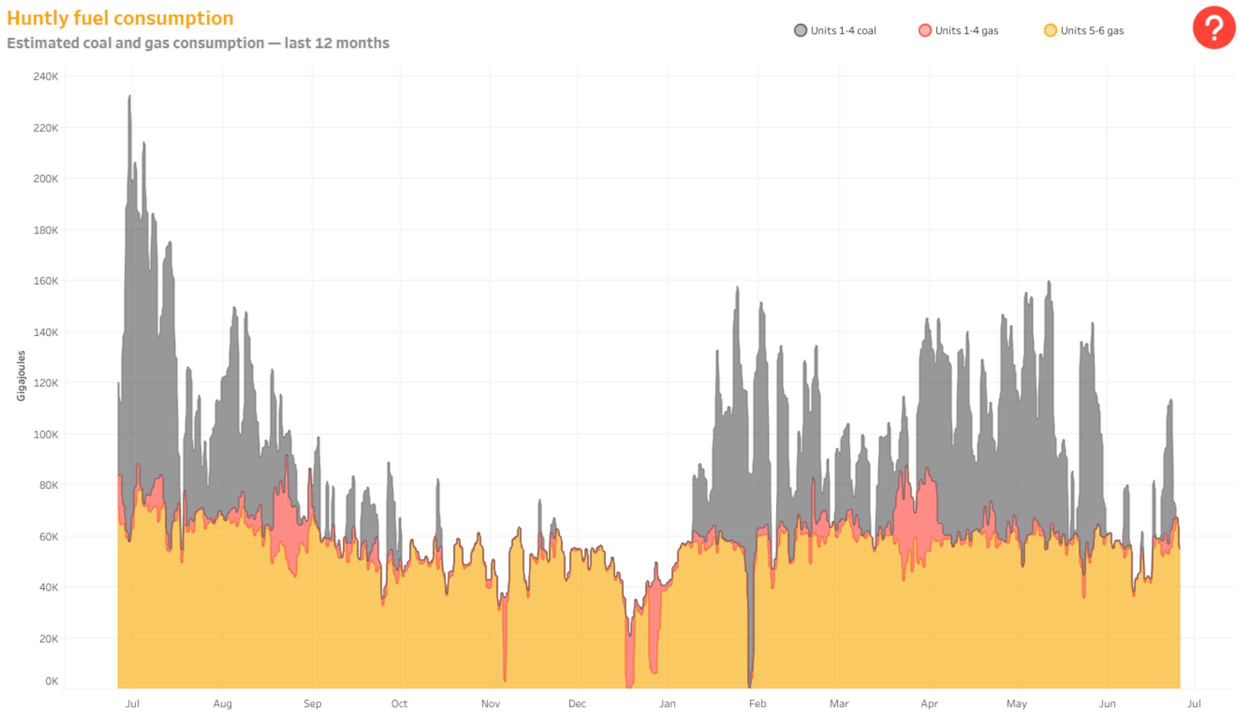


Figure 14: Estimated fuel usage at Huntly 2021/22



6 Forward Market

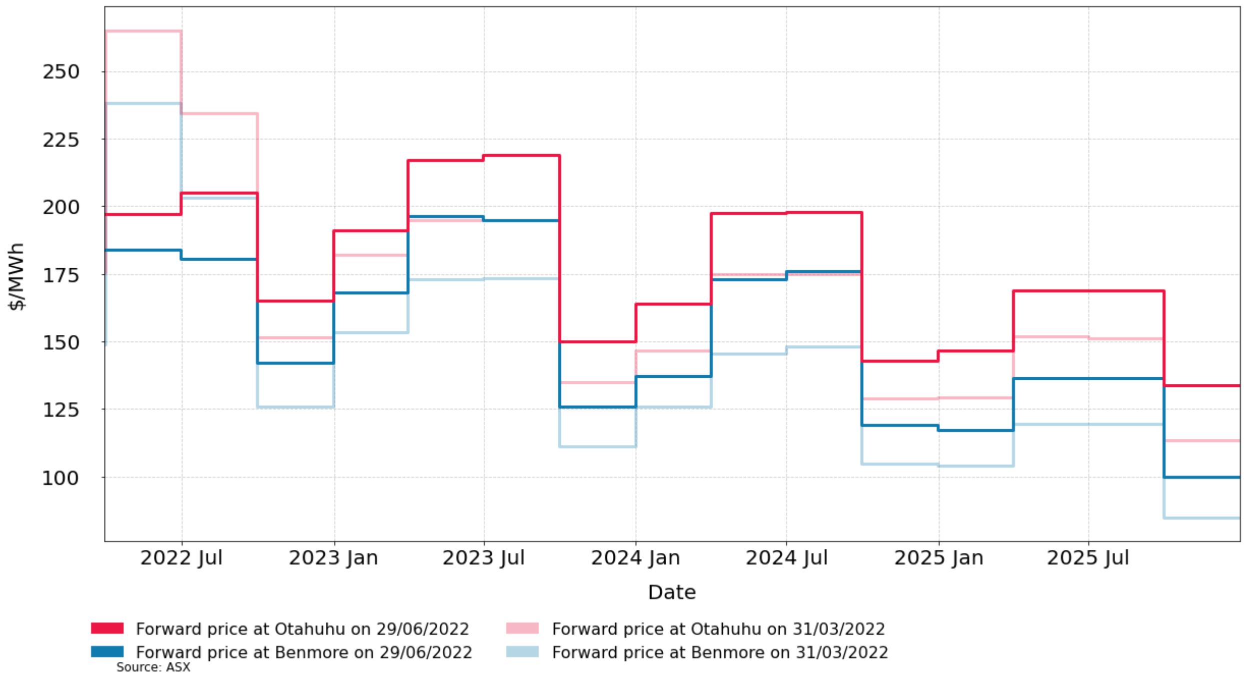
6.1 The ASX forward price curve provides a view of future wholesale spot prices. Figure 15 shows forward prices for Otahuhu and Benmore at the beginning and end of the quarter, to illustrate how forward prices have changed.

6.2 Short-term forward prices (June 2022 and October 2022 quarters) fell by around ~$50/MWh and ~$25/MWh, respectively over the quarter. Long-term forward prices rose by roughly $25/MWh.

6.3 The fall in short-term futures is likely a reaction to an improved short-term gas outlook over winter, as gas consumption from Methanex will reduce as one train at its Motunui site goes on outage for six weeks between July and August. Hydro storage has also increased, especially at Te Anau, Taupo and Manapouri, which has improved the hydro outlook for winter 2022.

6.4 High coal prices, high carbon prices, a prolonged trend of low hydro inflows and differences between the North and South Island hydro storage fueled these rises in long-dated futures prices. North Island storage was around its mean, and storage in three of the five the larger South Island lakes was far below their mean for most of the quarter. Forward prices reflect all these factors as participants factor in cost and risk. The news that the decommissioning of TCC has been pushed back one year to September 2024 may have prevented further increases to long-dated prices. As TCC, which runs on gas, is considerably cheaper to run than Huntly units on coal at current prices.

Figure 15: Future Prices



6.5 The long-term forward prices compared to five years ago are noticeably higher. One factor that appears to play a role in the rise in forward prices is the increasing price of carbon which increases the costs of running thermal generation.

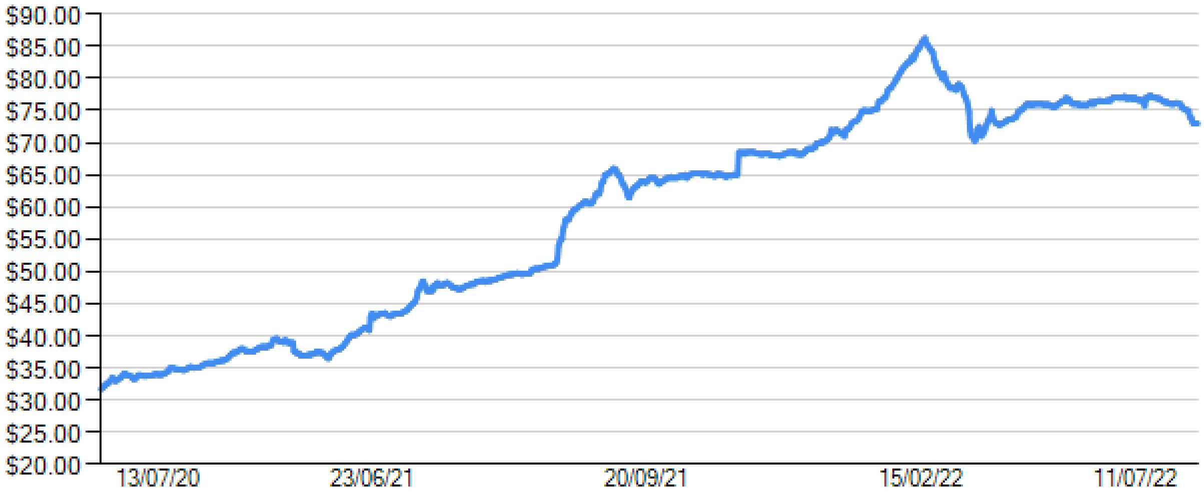
6.6 Figure 16 shows spot NZ carbon unit prices since the first ETS auction began in 2020, taken from CommTrade's (a platform for buying and selling NZ ETS carbon credits owned by Jarden Securities Limited) website.

6.7 Overall carbon prices rose by 81.3 per cent in 2021. During the June quarter, carbon units (NZUs) were cleared at $76 per unit, and 4.825 million NZUs were sold. After the triggering of the cost containment reserve at $70 an additional 1.2 million NZUs were sold.

6.8 The price of carbon feeds into thermal generation costs as approximately ~40 per cent of the price of carbon is added to the final cost of generation for a CCGT (thermal plant) and ~50-60 per cent for OCGTs (peaker plants) when run on gas and ~100 per cent when run on coal. For example, when carbon is at $70/tonne, an additional ~$28/MWh to ~$35/MWh would be added to the running cost of gas-fired generation thermal generation, and ~$70/MWh would be added to coal-fired generation.

6.9 The gas outlook for 2023 should be significantly improved compared to 2022, with gas production increases expected at multiple fields. However, some of the expected drops in gas prices are likely to be offset by continued increases in carbon prices with the cap for ETS auctions in 2023 set to $78.40/tonne and $87.81/tonne in 2024. It is not clear that generators are facing gas supply constraints this winter, so the increased supply may mean more production by Methanex.

Figure 16: New Zealand Carbon Unit Spot Price[11]



[11] https://www.commtrade.co.nz/

7 Deep Dive: Properties of High Demand Trading Periods

Key Findings

7.1 Despite overall consumption each year remaining steady, with around 41-42TWh of total annual demand since 2015, we have seen an increase in peak consumption in recent years.

7.2 57 of the highest 100 consumption trading periods since 2005 have occurred within the last 1.5 years.

7.3 If we instead compare the highest 100 daily maximum consumption trading periods since 2005, 30 of the highest 100 have occurred within the last 2.5 years, still indicating an increase in peak consumption.

7.4 Analysing the highest 100 daily maximum consumption trading periods:

(a) These trading periods had occurred almost exclusively during the winter, with a few occurring in May and September when temperatures across all main city centres were much colder than average.

(b) They have occurred exclusively during weekdays and occurred more often towards the beginning of the week (33 occurring on a Monday and only two occurring on a Friday)

(c) 88 of these trading periods have occurred during the evening peak, with 12 occurring during the morning peak.

(d) Consumption increases somewhat uniformly across all sites when we compare some of the milder trading periods within these 100 (where total consumption is around 3.32GWh) to the highest consumption trading periods (where total consumption is around 3.64GWh)

(e) A Customer Advice Notice (CAN) of low residual generation is indicative that we might be in one of these 100 trading periods, with 4 of the 12 notices we have since 2019 coinciding with one of these trading periods. These notices may also occur because of a low amount of offered generation, which is likely to be the case for notices outside the winter peaks.

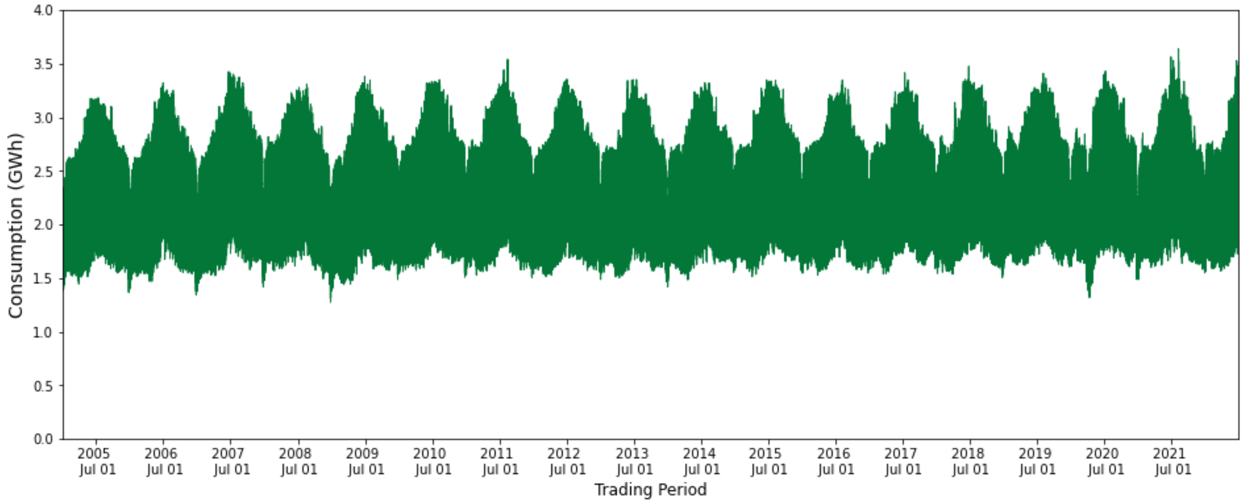
The 100 Highest Consumption Trading Periods

7.5 We have studied the properties of high-demand trading periods focusing on the 100 highest-demand trading periods since 2005.

7.6 Total annual demand has remained steady since 2015, with 41-42TWh consumed per year since 2015 (around 2.35MWh per trading period on average for every year since 2015)

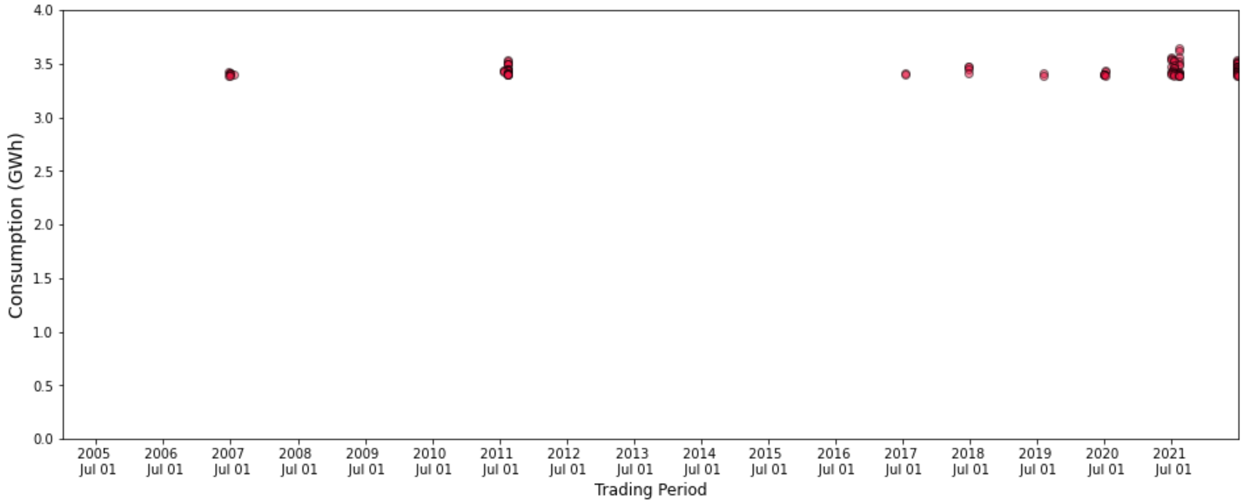
7.7 Figure 17 shows the total national demand for electricity in every trading period since 2005. We see the daily and seasonal oscillations in total demand, and we can see that the total is rarely outside the 1.5-3.3 GWh range. Despite total annual demand remaining steady, we can see a recent trend of growth in the winter peaks over the past six years.

Figure 17: Total demand during each half-hour trading period since 2005



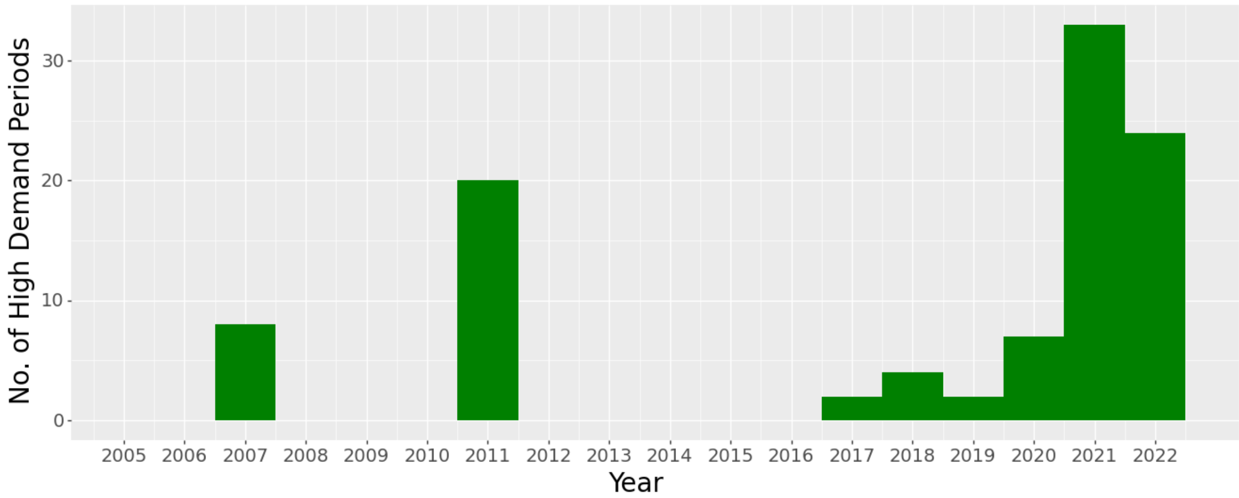
7.8 In Figure 18, we see that the vast majority of the 100 highest trading periods occur during just three years (2011, 2021, and 2022 (even though we are only looking at data up to 30 June 2022)). We also see that these high-demand trading periods are very clumped, often with multiple occurring on the same day. The most extreme example of this was on 9 August 2021, when ten of the 100 highest demand trading periods since 2005 occurred, followed by five more of these high demand trading periods on 10 August 2021.

Figure 18: The 100 trading periods with the highest total demand since 2005



7.9 Figure 19 shows a count of trading periods with the highest demand each year. About 75 of these occurred in just the years 2011, 2021, and 2022.

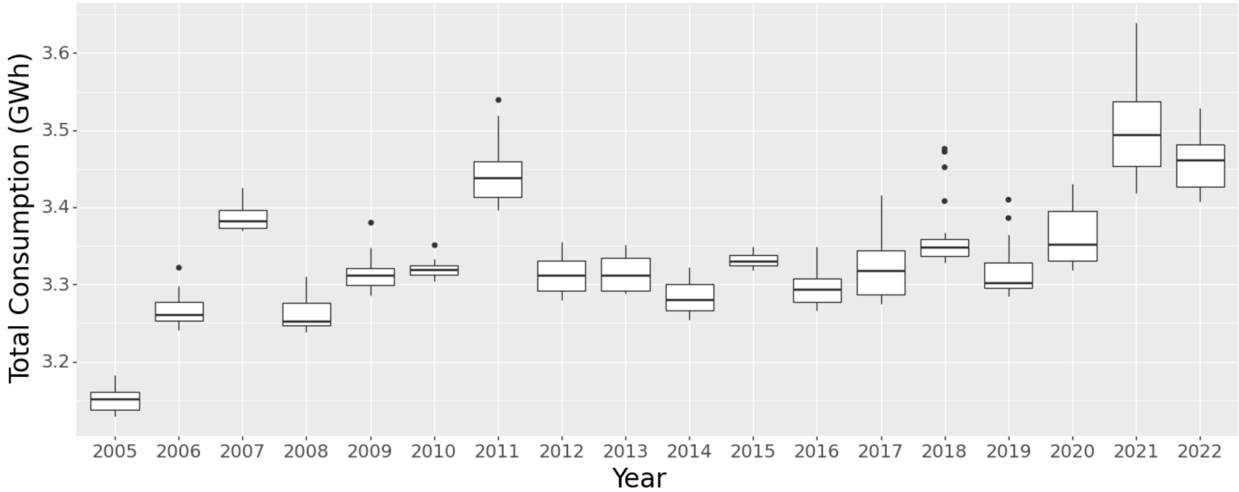
Figure 19: Count of trading periods each year where the total consumption is a part of the highest 100



7.10 In Figure 20, we have a boxplot of each year's 20 highest demand trading periods. There can be large differences in these high-demand trading periods both across years (like 2005, 2006, 2007) or within a year (like 2011 and 2021).

7.11 There has been recent growth in these high-demand trading periods. These high-demand trading periods in 2016 had a median of around 3.3GWh. In 2021 this median was around 3.45GWh.

Figure 20: Boxplot of the total demand during the 20 highest demand trading periods each year



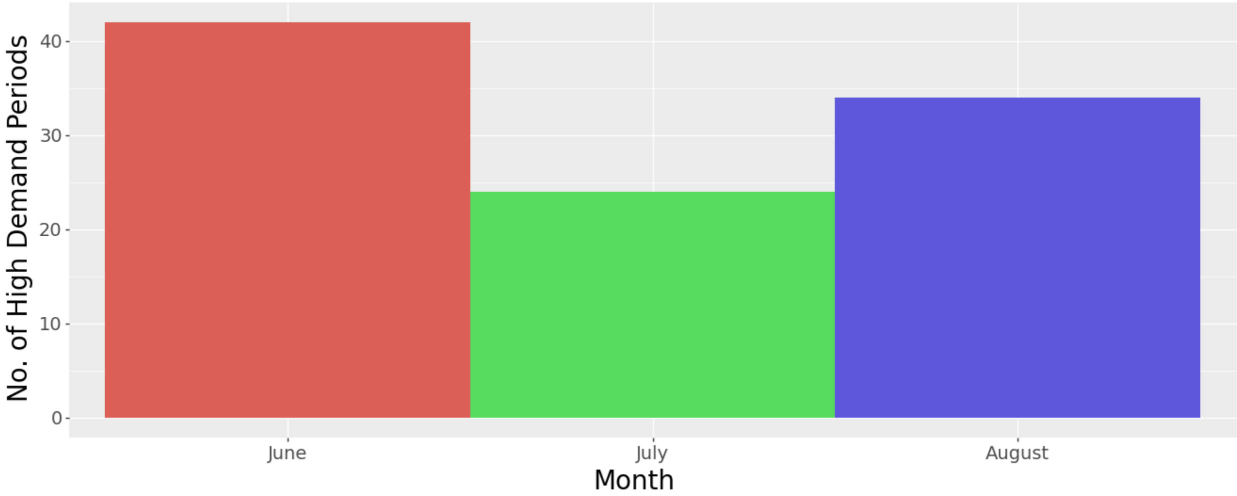
7.12 With the seasonal pattern of total demand shown in Figure 17, it is unsurprising that all the 100 trading periods with the highest demand occurred during the winter months (shown in Figure 21), primarily due to the increased use of electric heaters and lighting throughout New Zealand.

7.13 Fewer public holidays contributing to a more regular work week also increase peak consumption during the winter months.

7.14 Since we have only included demand data up to the end of June 2022, and with the increase in peak demand in recent years, where June 2022 contains 24 of the highest 100 consumption trading periods, the plurality of the high demand periods has occurred in June.

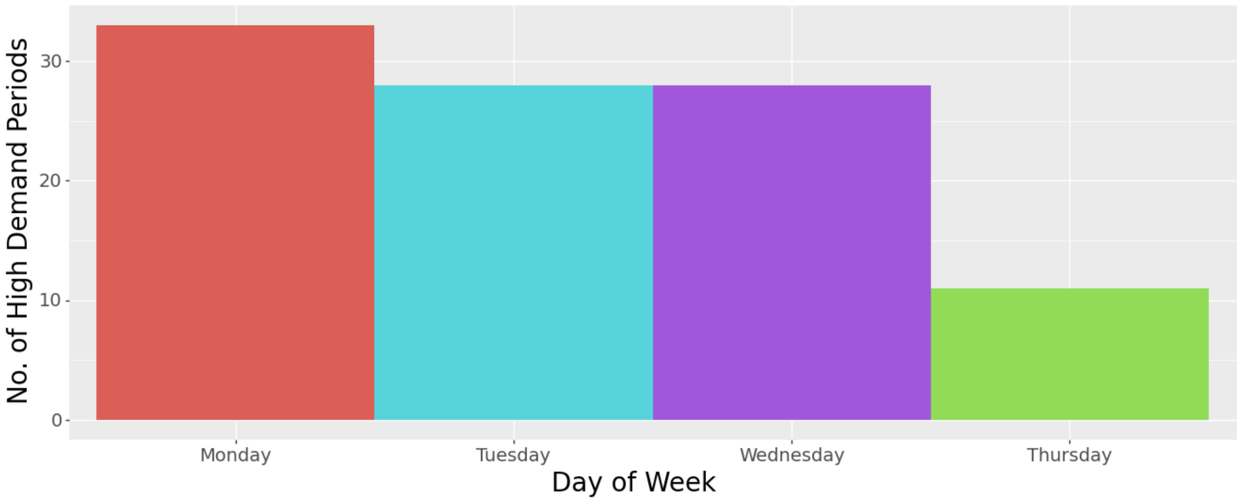
7.15 Also, with those two days in August 2021 contributing to 15 of the highest demand trading periods, there are comparatively fewer high demand trading periods in July.

Figure 21: Count of trading periods each month where the total consumption is a part of the highest 100



7.16 In Figure 22, we see that all the highest consumption trading periods have occurred on a weekday, occurring less often on a Thursday compared to the beginning of the week. None of the 100 highest consumption trading periods since 2005 have happened on a Friday.

Figure 22: Count of trading periods each day of the week where the total consumption is a part of the highest 100



The 100 Highest Daily Maximum Trading Periods

7.17 In the previous section, we saw how a single event could lead to many high-demand trading periods. While it is essential to understand the properties of those types of events, they can distort our analysis with many of those observations occurring in the same day (those 100 highest demand trading periods occurred within 31 days).

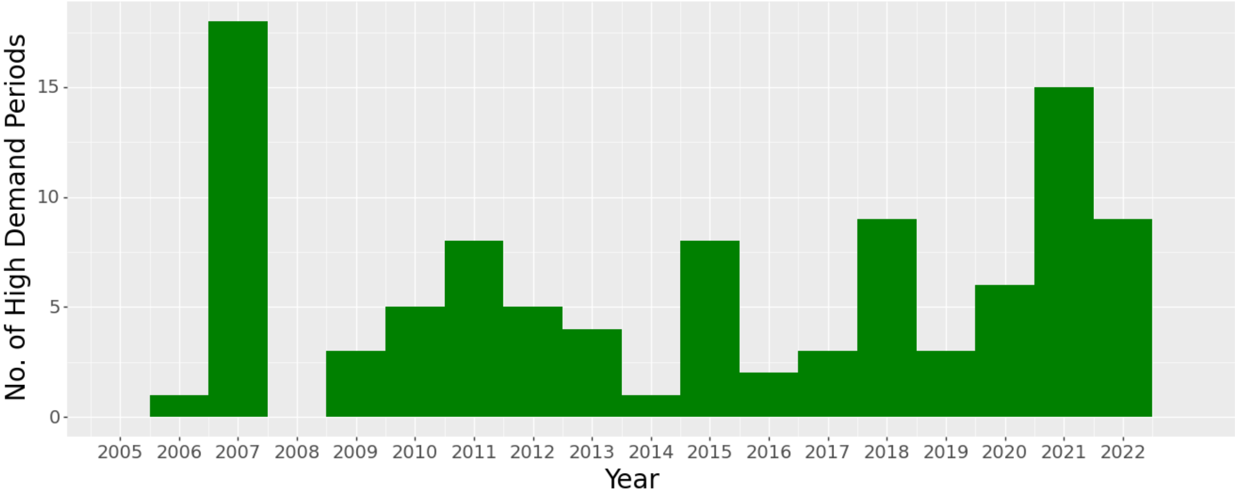
7.18 In this section, we look at the daily maximum demand, limiting each day to one observation in the following plots.

7.19 Figure 23 shows a count of trading periods with the highest maximum daily demand each year. Compared to Figure 19, we see more observations in 2007, which had many days with a high demand trading period (rather than many trading periods in just a few days).

7.20 When we only consider the maximum daily demand, ignoring any additional high-demand trading periods that occur on the same day, there is a reduction in what constitutes a high-demand trading period. The threshold for a high-demand trading period has reduced from 3.39GWh to 3.32GWh because we only look at the maximum daily demand.

7.21 Because of this threshold drop in what is considered a high-demand trading period, there are more high-demand daily maximum trading periods from 2009-2016, all having at least one high-demand trading period.

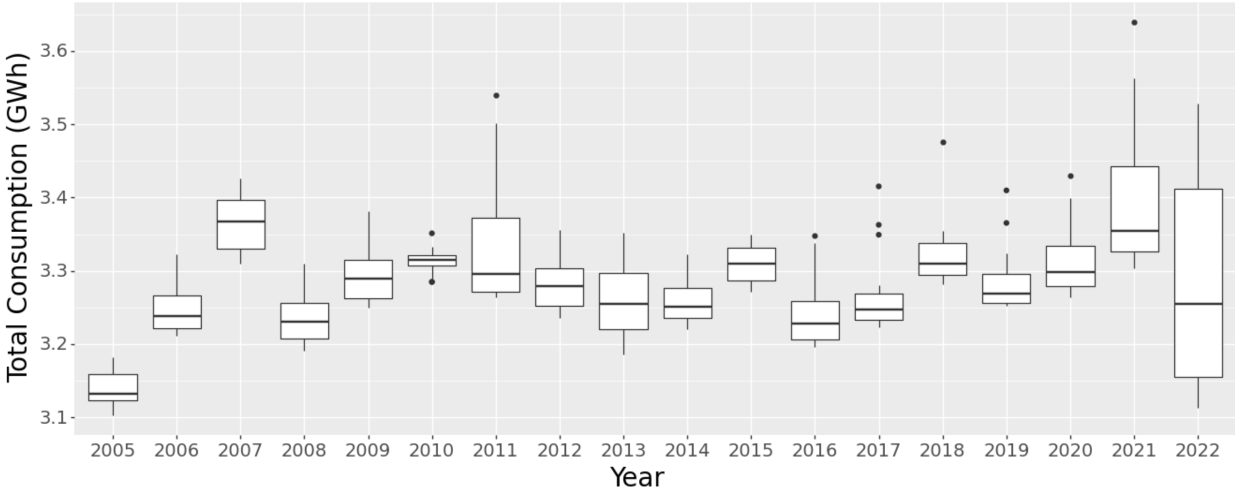
Figure 23: Count of trading periods each year where the maximum daily demand is a part of the highest 100



7.22 Figure 24 shows the recent trend in increasing peak demand from about 2016 that we saw in Figure 20, though with a larger spread between the observations over the years.

7.23 Once we get the July and August observations for 2022, we expect additional high consumption trading periods, likely reducing the spread for 2022 and increasing the median demand of the 20 highest daily maximum demand trading periods.

Figure 24: Boxplot of the highest 20 daily maximum demand trading periods each year

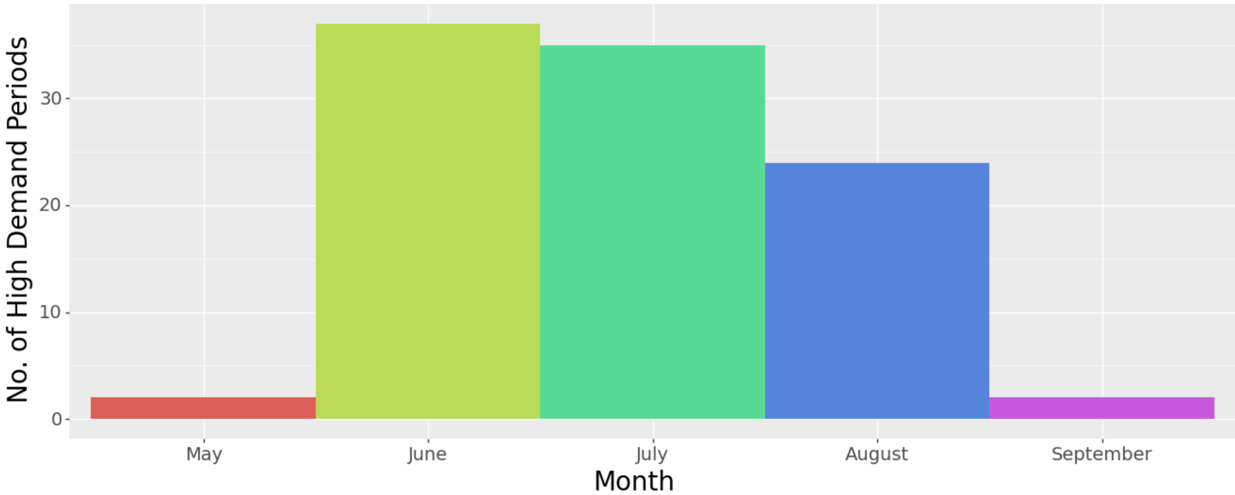


7.24 Figure 25 shows that almost all the high maximum daily demand trading periods occur from June to August, with two observations in May and September.

7.25 There is still a disproportionate number of observations for June, with the additional June 2022 data.

7.26 However, as the extreme scenarios like we saw on 9 August 2021 reduced to a single observation, we have seen a drop in the August high-demand trading periods.

Figure 25: Count of the trading periods each month belonging to the 100 highest daily maximum demand trading periods



7.27 Figure 26 again shows all the highest maximum daily demand trading periods that occur on a weekday. However, now there are also a few that occur on a Friday.

Figure 26: Count of the trading periods each day of the week belonging to the 100 highest daily maximum demand trading periods

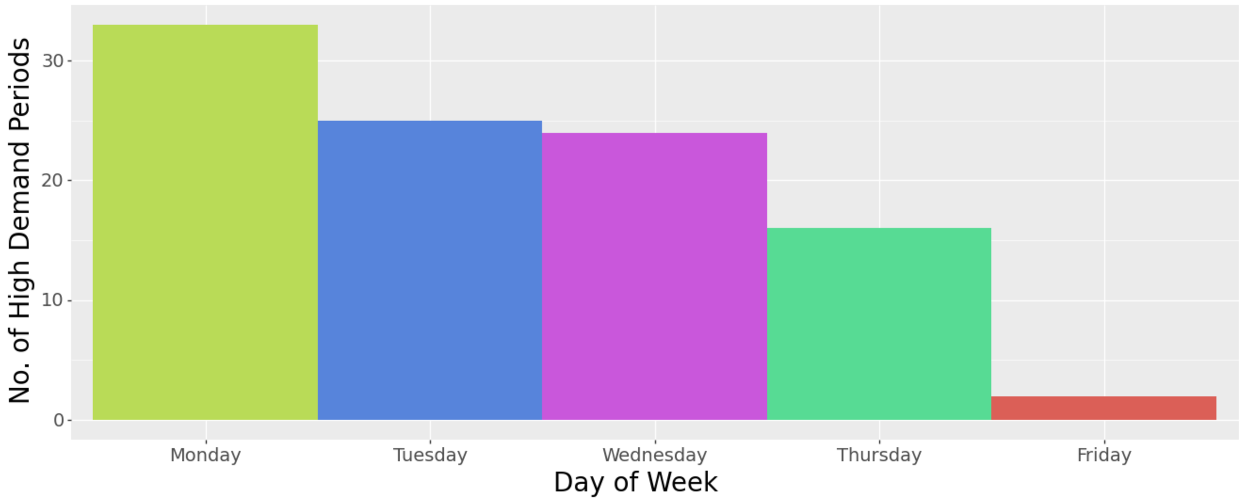
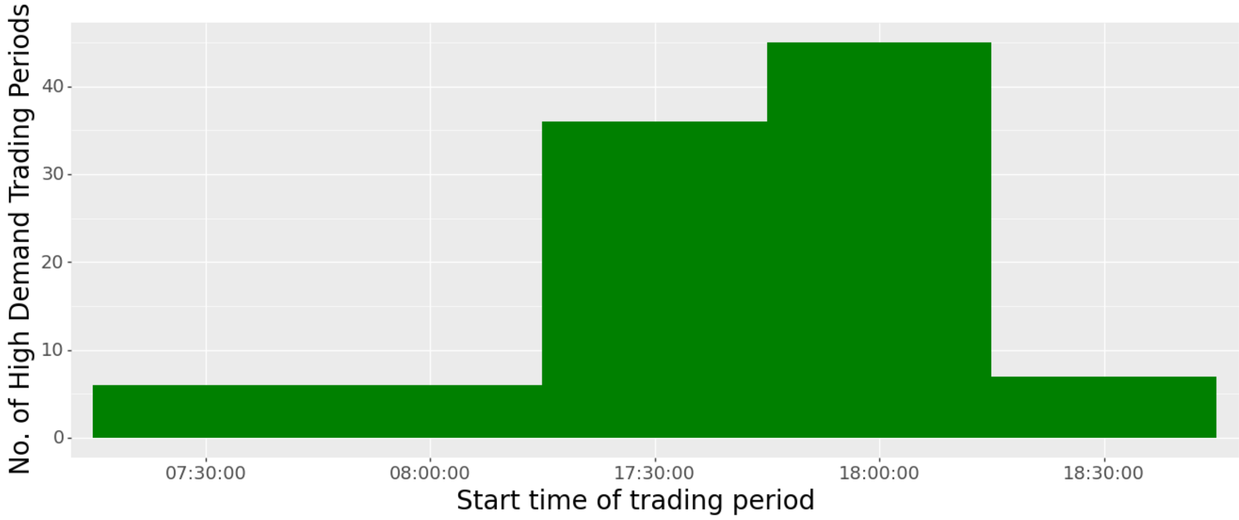


Figure 27 shows that most of the highest daily maximum demand trading periods occur during the evening peak, with the remaining occurring during the morning peak.

Figure 27: Count of the start times of each of the 100 highest daily maximum demand trading periods



7.28 Figure 28 plots the start time and the temperature in Auckland of the high-demand trading periods.

7.29 We can see the temperatures for the four May and September high-demand trading periods occurred during exceptionally low temperatures (below the 10^{th} percentile).

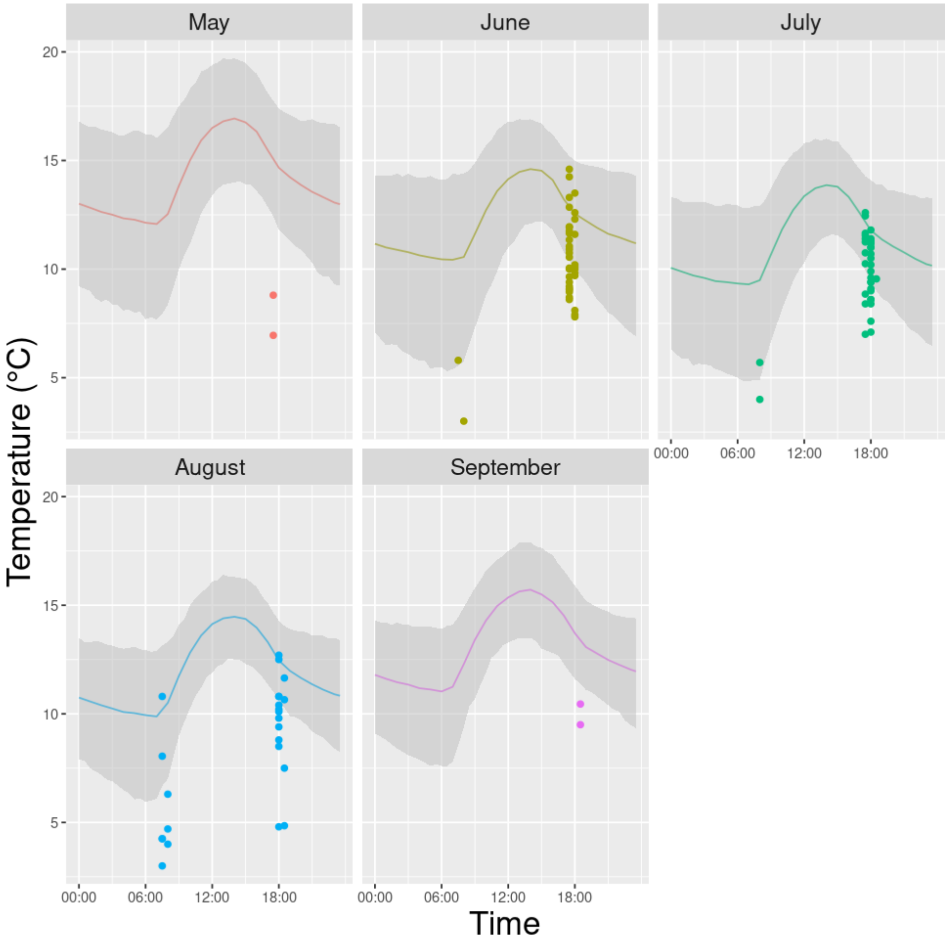
7.30 The average temperature for the high consumption trading periods during the evening peak also appears to be colder than the historic mean temperature.

7.31 All the morning high-demand daily peak trading periods except for two (in August) had occurred when the Auckland temperature was around or below their 10^{th} percentile.

7.32 The average temperature for the high-demand trading periods appears to be higher than the morning peak, with most of the high consumption daily peaks occurring within the 10th-90th historical percentile temperatures.

7.33 We see these same patterns using Wellington and Christchurch temperatures.

Figure 28: Auckland temperature and start time of the 100 highest daily maximum trading periods alongside the mean and 10th -90th percentile temperatures for that time of day in that month



Location impacts of High Demand

7.34 Within the 100 trading periods with the highest daily maximum consumption, the spread from the highest overall (3.64GWh) to the 100th highest (3.32GWh) is 0.318GWh or 318MWh, shown in Figure 29.

7.35 With a reasonably broad range in total consumption across these 100 trading periods, we are interested in finding:

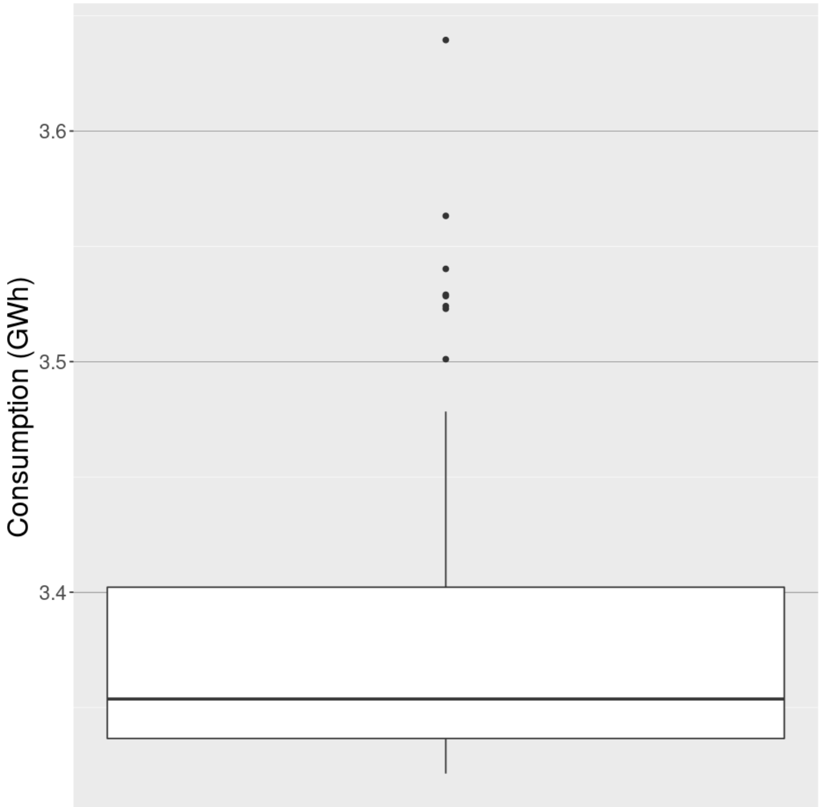
(a) If this difference across the network is uniform.

(b) Where the largest spread in the network if it is not uniform.

(c) For these areas, is this spread caused by growth over time, a change in the allocation of demand to the site, or is it just a very volatile location in terms of electricity consumption within these peaks?

(d) Whether there is a reasonable explanation for the high spread in consumption at those locations.

Figure 29: Boxplot of the national consumption during the 100 highest daily max trading periods

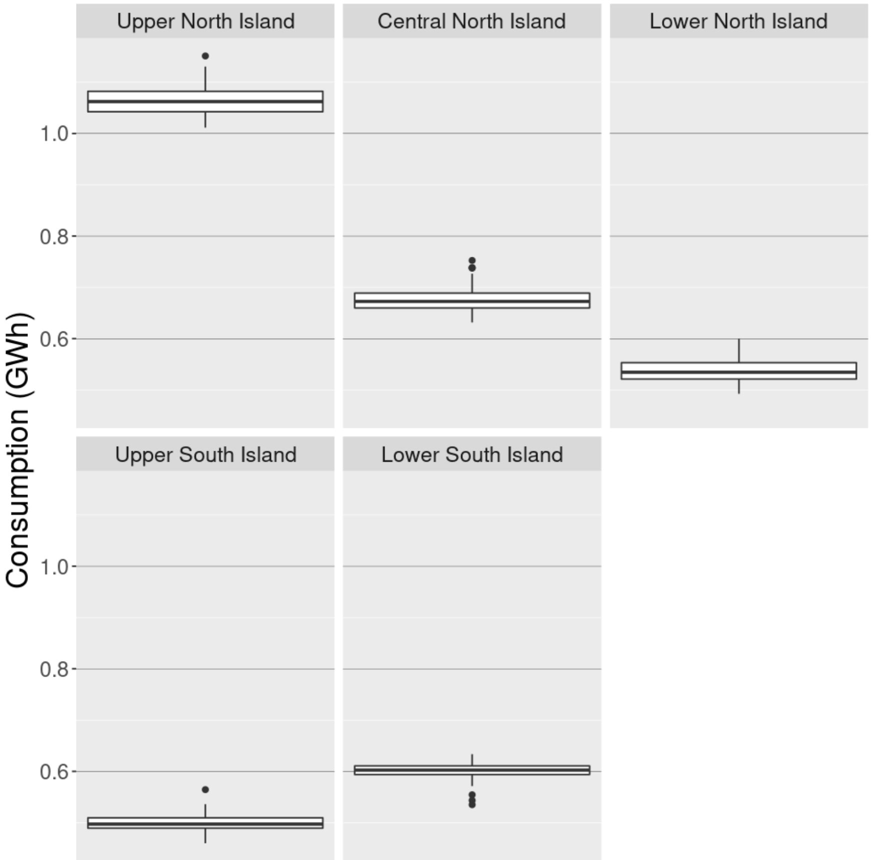


7.36 In Figure 30, we plot the consumption across the five major zones in New Zealand over these 100 trading periods.

7.37 At this level, there does not appear to be a significant difference in consumption across the main islands, with a difference of slightly more than 0.1GWh over the 100 trading periods.

7.38 However, there appears to be slightly higher variability in the consumption on the North Island, especially the Upper North Island.

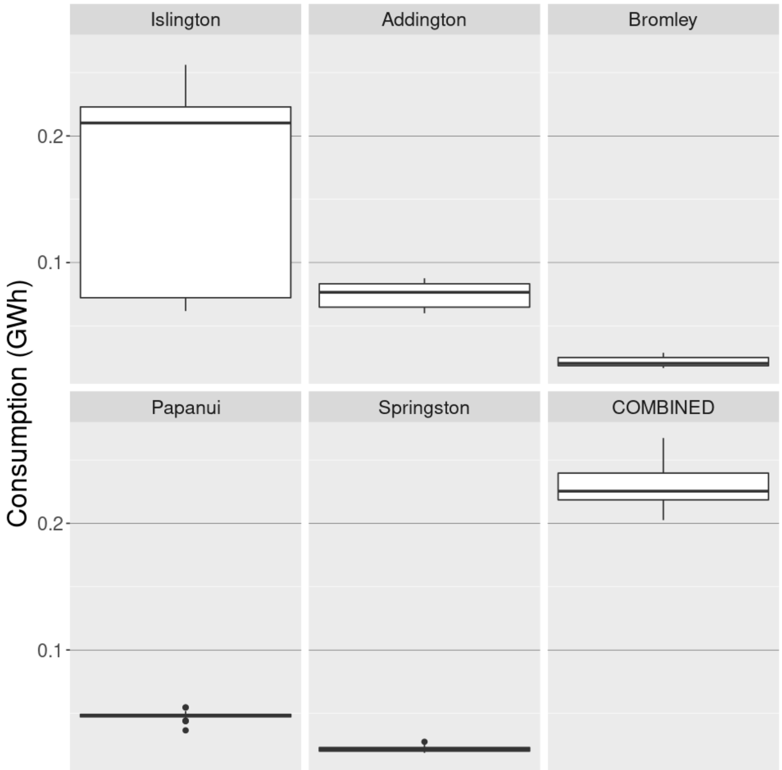
Figure 30: Boxplot of consumption during the 100 highest daily max trading periods in each zone



7.39 As we go down to the site level, we begin to see some sites with a very large spread, some with a spread larger than 0.1 GWh. Large groups of consumers moved to or from a site can explain most of this variability. For example, most of the variability we see at the Islington site in Figure 31 was caused by the Addington, Bromley, Papanui, and Springston sites, all merging with the Islington site between 2013 and 2015.

7.40 In the ‘COMBINED’ boxplot, which adds the consumption at these sites together, we see the overall spread in consumption across those 100 trading periods has reduced dramatically.

Figure 31: Boxplot of each site's consumption during the 100 highest daily max trading periods for sites that now make up the Islington site

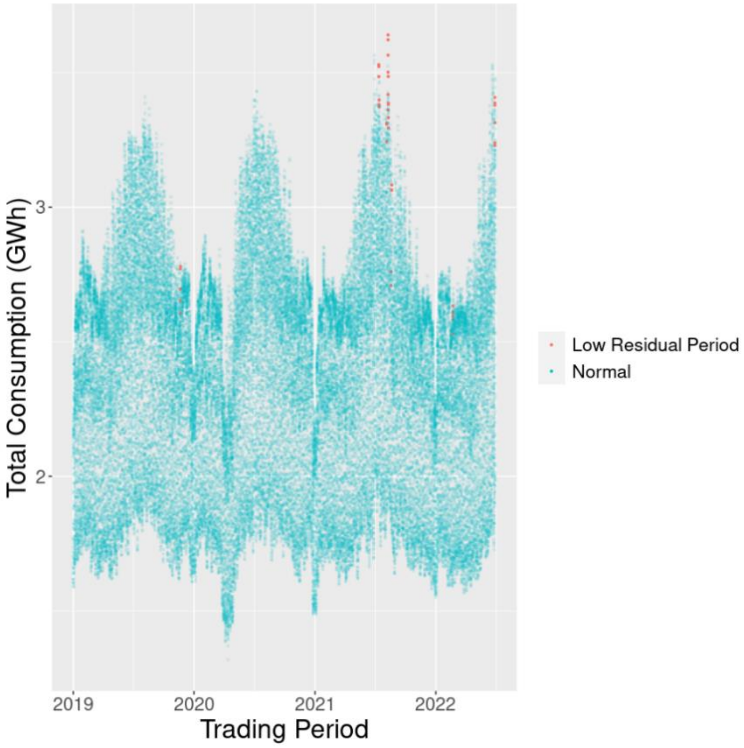


Low Residual Periods

7.41 From 21 November 2019 – 30 June 2022, there have been 12 CAN (Customer Advice Notice) of a low residual situation covering 42 trading periods. Figure 32 shows total demand in each trading period, indicating trading periods that coincided with a low residual situation. Total consumption during a low residual situation is typically around the highest consumption observations for that time of year (within about 0.3GWh).

7.42 There are two trading periods during the morning peak of 18 August 2021 included as part of a low residual situation with total demand of only between 2.71GWh - 2.76GWh. This is far below the demand during other low residual periods occurring around the same time of year (3.0 - 3.6GWh). Low offered generation may be the cause of these low residual notices rather than just high demand.

Figure 32: Consumption in each trading period since 2019, with periods where Transpower has given a Customer Advice Notice (CAN) of a Low Residual Situation is highlighted in red



7.43 Figure 33 shows that eight of the twelve CAN notices have included a trading period that was a part of the daily peak consumption.

7.44 Figure 34 shows that four of the remaining eight trading periods are a part of the 100 highest daily peak consumption trading periods (since 2005).

Figure 33: Daily maximum consumption since 2019, with periods where Transpower has given a Customer Advice Notice (CAN) of a Low Residual Situation is highlighted in red

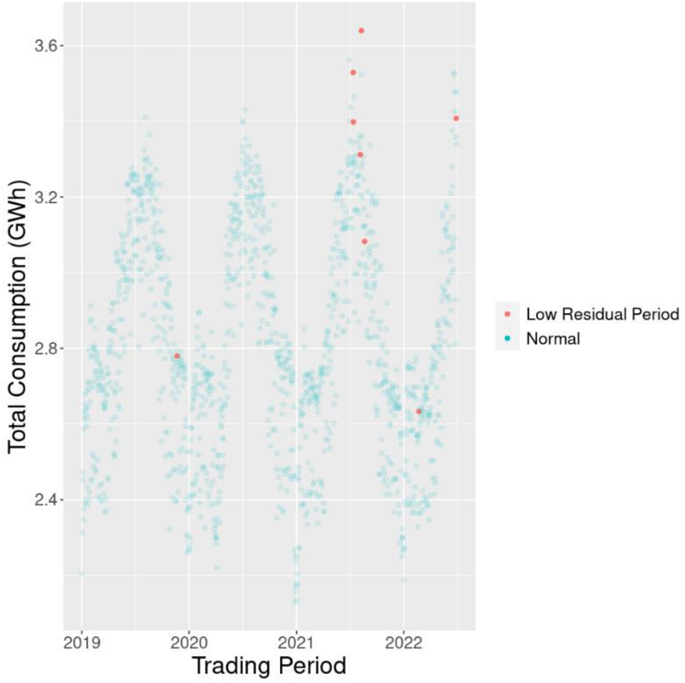


Figure 34: The 100 highest daily maximum total consumption trading periods, with periods where Transpower has given a Customer Advice Notice (CAN) of a Low Residual Situation is highlighted in red