13 November 2023

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for week of 5-11 November

1.1. This was another week of higher than historic average prices with most Benmore and Ōtāhuhu prices sitting close to the 90th percentile bound for much of the week. Constraints on the HVDC saw some price separation during the day on Tuesday. Instances of low and/or under forecast wind saw a few prices reach over $200/MWh during Wednesday and Friday shoulder periods. Generation outages remain high at around 2300-2800MW, with a number of large thermal and hydro unit outages in place. Controlled hydro storage is around 101% of historical mean as of 11 November.

2. Spot prices

2.1. This report monitors underlying wholesale price drivers to assess whether trading periods require further analysis to identify potential non-compliance with the trading conduct rule. In addition to general monitoring, we also single out unusually high-priced individual trading periods for further analysis by identifying when wholesale electricity spot prices are outliers compared to historic prices for the same time of year.

2.2. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10th-90th percentiles adjusted for inflation. The figure also shows graphs of spot prices at Benmore and Ōtāhuhu individually, along with their historic national 10th-90th percentiles and historic median adjusted for inflation. Prices greater than quartile 3 (75th percentile) plus 1.5 times the inter-quartile range[1] of historic prices, are highlighted with a vertical black line. Other notable prices are marked with black dashed lines.

2.3. Between 5-11 November:

(a) The average wholesale spot price across all nodes was $124/MWh.

(b) 95 percent of prices fell between $0.45/MWh and $185/MWh.

2.4. Overall, the majority of spot prices sat above the historic median and close to the historic 90th percentile for most of the week. The weekly average spot price was around $21/MWh lower than the previous week. A few of the highlighted prices were just above the outlier bound but were below $200/MWh and occurred during times of lower wind generation and higher priced thermal or hydro being dispatched.

2.5. Ōtāhuhu prices were usually around $20-$50/MWh higher than at Benmore. However, there was significant price separation on Tuesday from 11.00am-4.00pm caused by binding constraints on the HVDC. Although Ōtāhuhu prices remained below $200/MWh, prices at Benmore dropped as low as $0.03/MWh. Prices at Ōtāhuhu during this time were between ~$50-$160/MWh higher than Benmore.

2.6. A few prices spikes occurred on Wednesday. The first of those was at 7.00am whilst wind generation had dropped below 250MW and two Rankines and two thermal peakers were

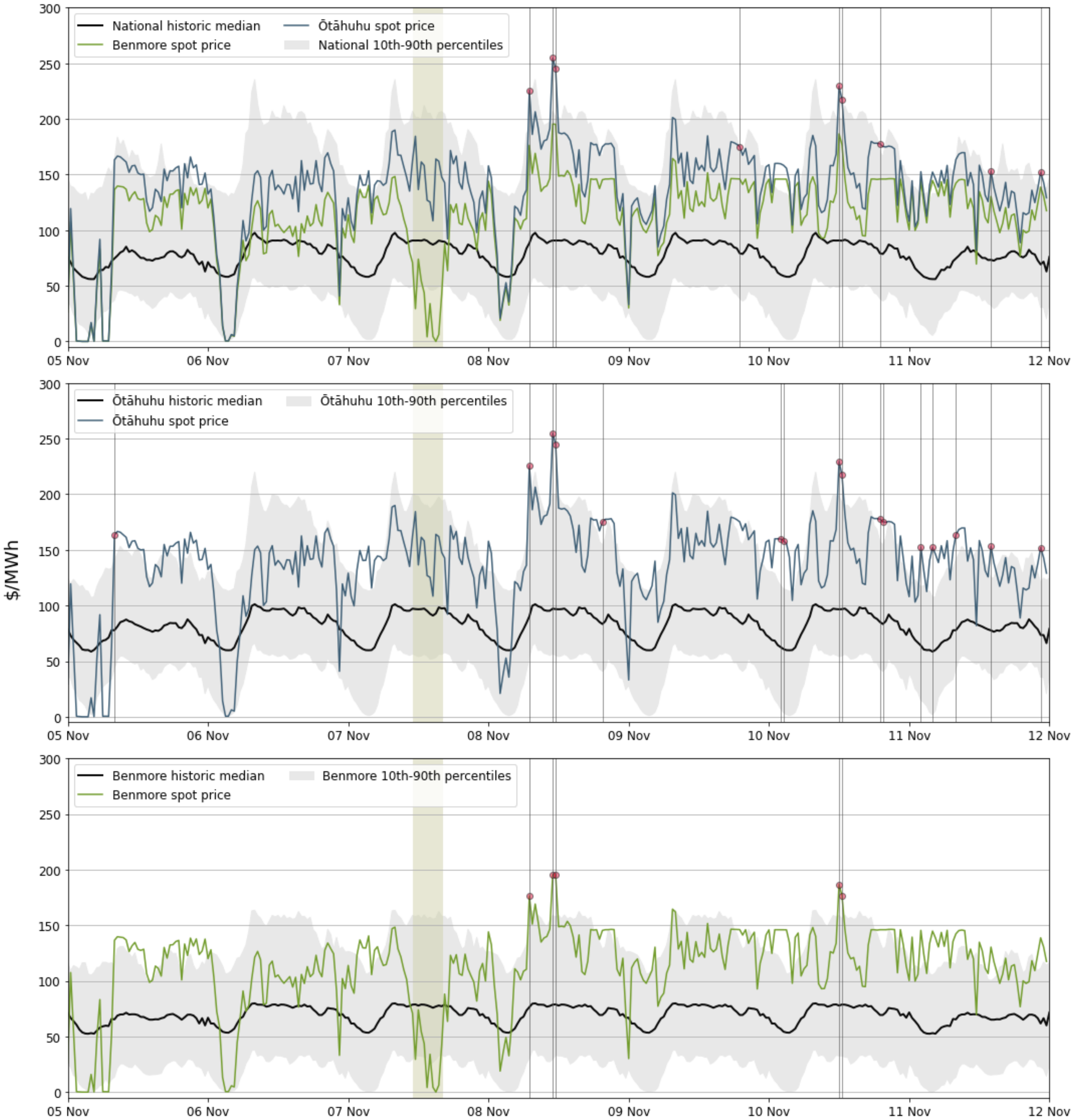
[1] We are identifying any significantly high prices by using the historic distribution of prices depending on whether it is a weekday or weekend day, and looking for prices that lie 1.5 times the interquartile range above the 75th percentile of the distribution. This is using the outlier calculation $Q_3+1.5\times IQR$, where Q_3 is the 75th percentile (or third quartile value) and IQR is your inter-quartile range.

running. Demand was also around 80MW higher than forecast. The price at Ōtāhuhu was $226/MWh and $176/MWh at Benmore. There were also a couple of spikes during the shoulder period, where at 11.00am and 11.30am prices were $255/MWh and $245/MWh at Ōtāhuhu respectively. At Benmore the price was $195/MWh for both trading periods. Wind generation during this period was lower than forecast by between 80-90MW.

2.7. The only other time prices went above $200/MWh was on Friday at 12.00pm and 12.30pm. Prices at Ōtāhuhu were $229/MWh and $217/MWh, with Benmore prices staying under $200/MWh at $187/MWh and $177/MWh respectively. There was lower wind than forecast by around 110-120MW during these two trading periods. The one Rankine that was running ramped up generation during this period with only one thermal peaker running. High priced hydro tranches were also dispatched to meet demand resulting in elevated prices during these trading periods.

2.8. When looking at each node against its historic data, on the second and third graphs at the bottom of Figure 1, it highlights multiple outliers at Ōtāhuhu as well as a large number of prices above its 90th percentile region. Whereas the majority of Benmore prices, although high and close to its 90th percentile bounds, are within $Q_3+1.5\times IQR$[1] and not classed as an outlier based on the historical data. The current conditions and the large number of outages are the main driver for these higher than average prices at the moment.

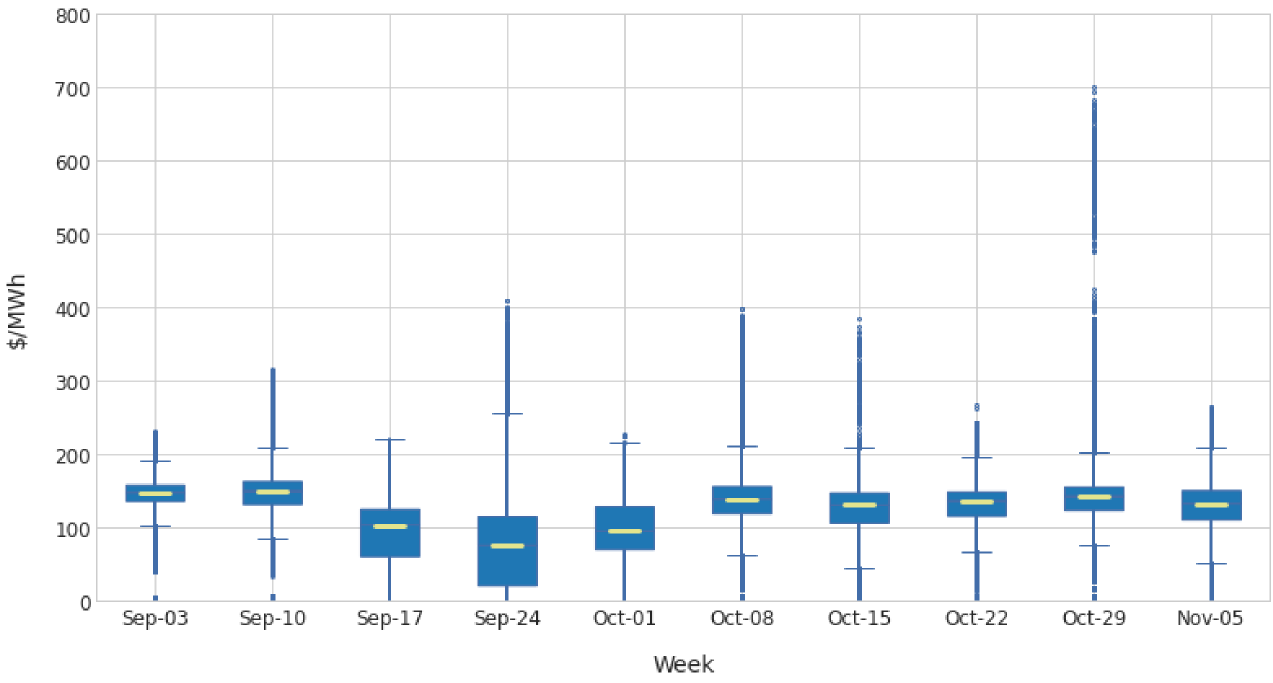
Figure 1: Wholesale spot prices between 5 November (Sunday) and 11 November (Saturday)



2.9. Figure 2 shows a box plot with the distribution of spot prices during this week and the previous nine weeks. The green line shows each week's median price, while the box part shows the lower and upper quartiles (where 50 percent of prices fell). The "whiskers" extend to points that lie within 1.5 times the inter-quartile range (IQR) of the lower and upper quartile, and then observations that fall outside this range are displayed independently.

2.10. The overall distribution of prices was smaller than the previous week due to less outlier prices. The middle 50% of prices was slightly lower than the previous week with most prices sitting between $110-$149/MWh. The median price was $132/MWh.

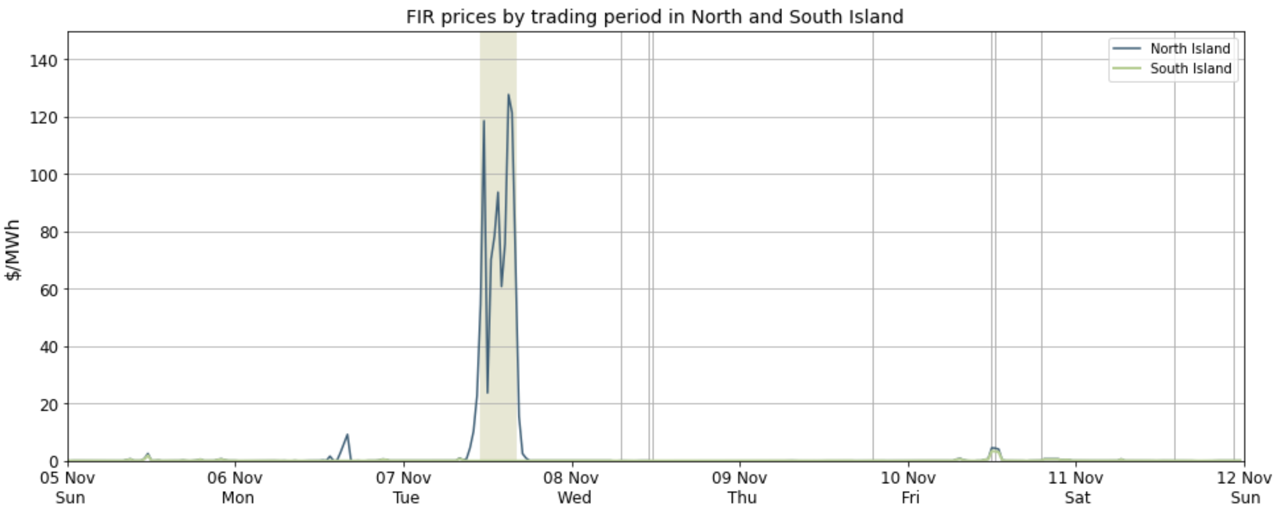
Figure 2: Boxplot showing the distribution of the spot prices this week and the previous nine weeks



3. Reserve prices

3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. This week FIR prices were mainly below $5/MWh. As mentioned in paragraph 2.5 there was a constraint on the HVDC[2], which resulted in North Island FIR spiking during the period of 11.00am and 4.00pm and prices ranged between $55/MWh and $128/MWh.

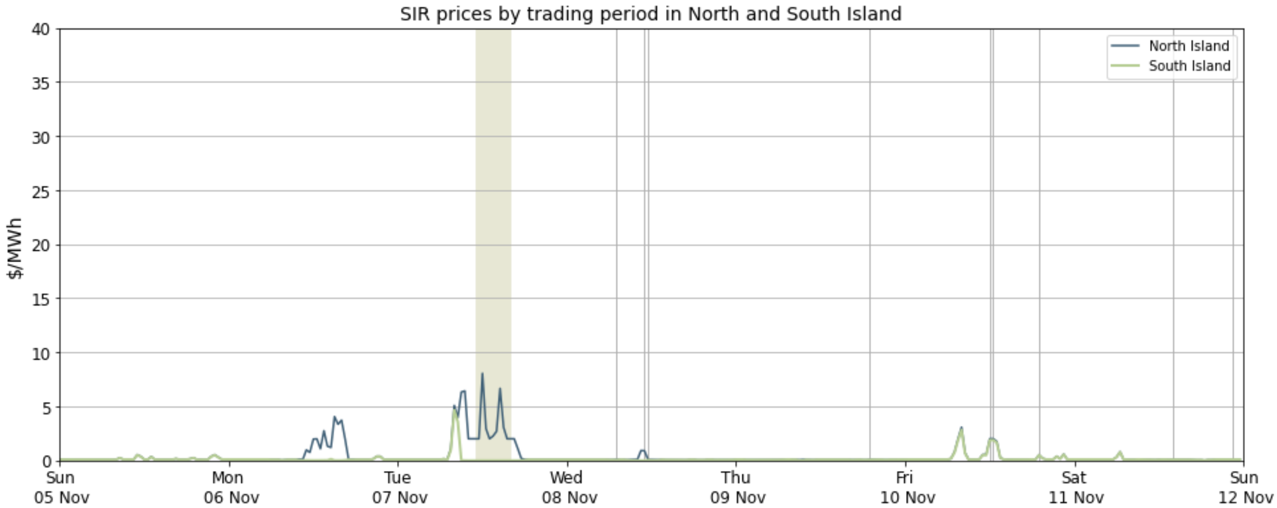
Figure 3: Fast Instantaneous Reserve (FIR) prices by trading period and island



[2] Instantaneous reserve is procured to cover the potential loss of injection from a large generator or one or both poles of the HVDC link, called contingencies or risks. The binding risk is essentially the largest of these—the one that determines the required quantity of instantaneous reserve. Reserve to cover generator risks can be shared between the North and South islands. However, reserve to cover HVDC risks must be located in the receiving island. Because SPD co-optimises energy and reserve, when an HVDC risk binds it can cause both energy and reserve price separation between the islands.

3.2. Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $5/MWh. North Island SIR also increased during the same period as high FIR prices. However, these prices were all under $10/MWh.

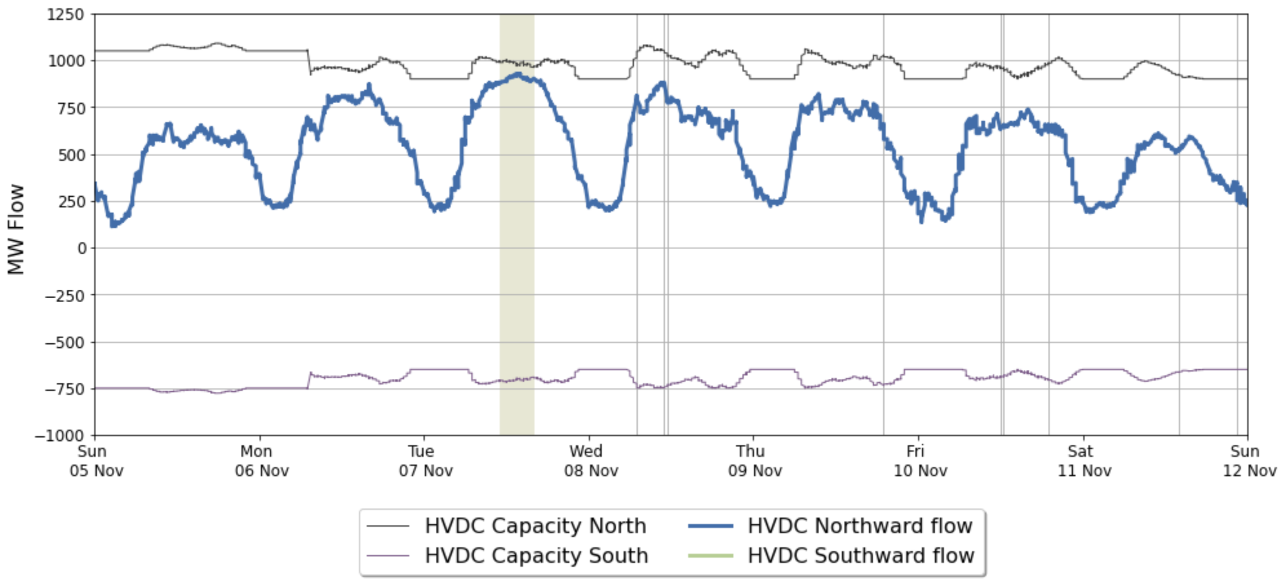
Figure 4: Sustained Instantaneous Reserve (SIR) prices by trading period and island



4. HVDC

4.1. Figure 5 shows HVDC flow between 5-11 November. HVDC flows were northwards all week with the maximum flow north of ~930MW on Tuesday. During the shoulder period on Tuesday the HVDC was very close to capacity, highlighted on the graph below, which lead to the constraints mentioned in paragraph 3.1.

Figure 5: HVDC flow and capacity

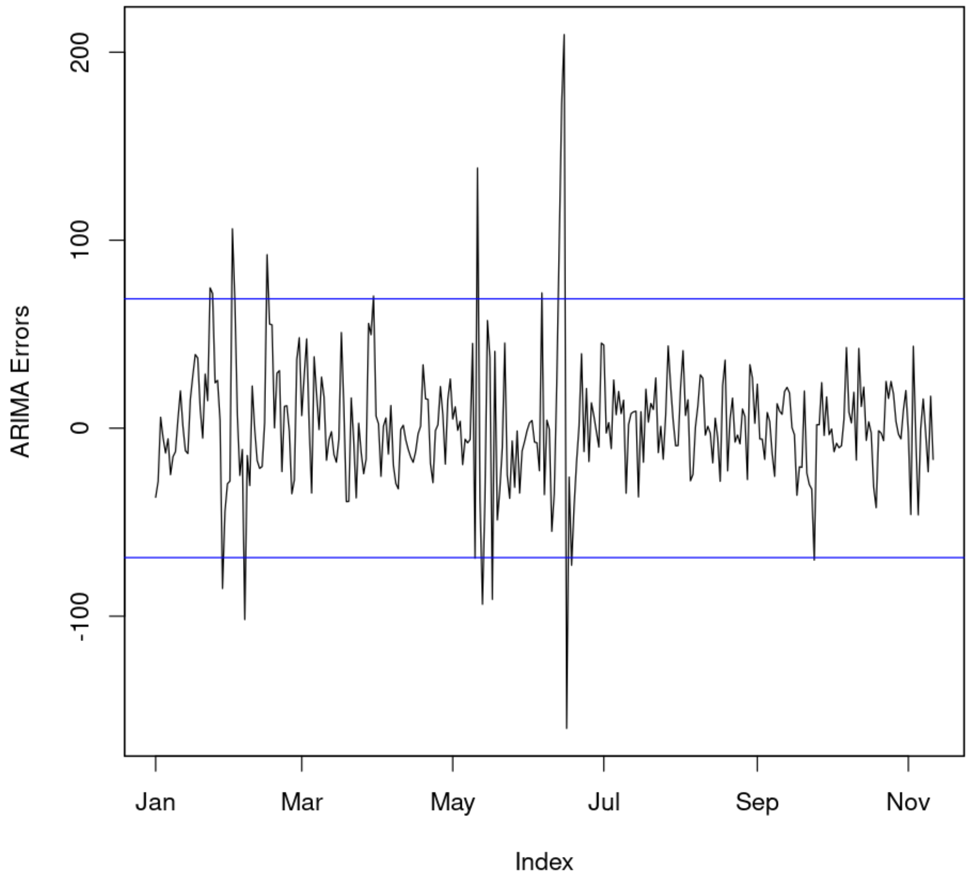


5. Regression residuals

5.1. The Authority's monitoring team uses a regression model to model spot price. The residuals show how close the predicted prices were to actual prices. Large residuals may indicate that prices do not reflect underlying supply and demand conditions. Details on the regression model and residuals can be found in Appendix A on the trading conduct webpage.

5.2. Figure 6 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. Positive residuals indicate that the modelled daily price is lower than actual average daily price and vice versa. When residuals are small this indicates that average daily prices are likely largely aligned with market conditions. These small deviations reflect market variations that may not be controlled for in the regression analysis. This week no residuals were above or below 2 standard deviations, indicating actual and modelled prices were similar.

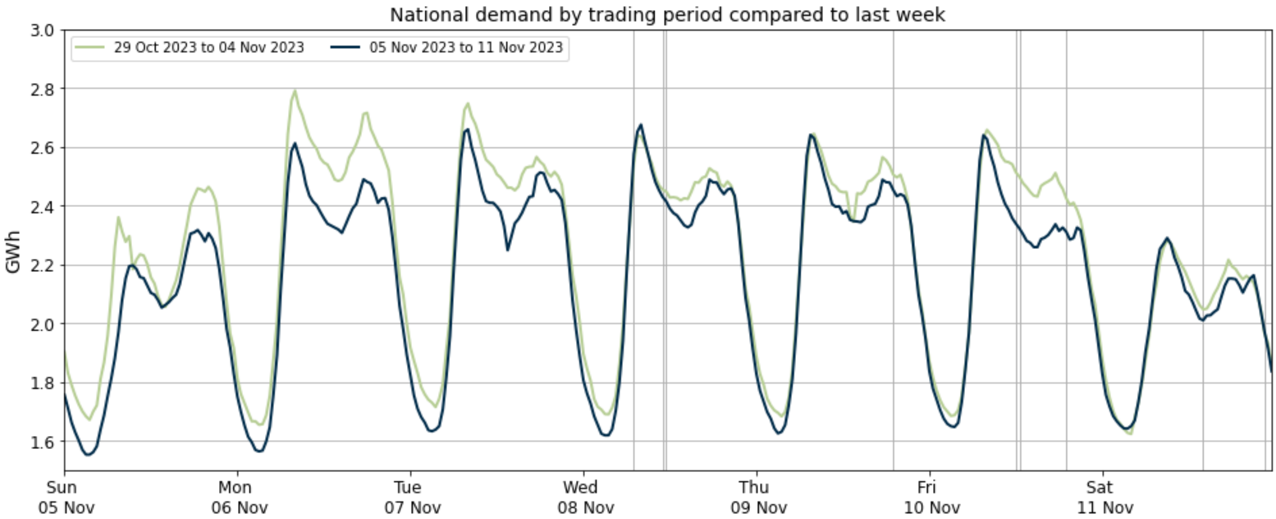
Figure 6: Residual plot of estimated daily average spot prices from 1 January 2023 - 11 November 2023



6. Demand

6.1. Figure 7 shows national demand between 5-11 November, compared to the previous week. Overall, demand was lower than the previous week as milder temperatures were experienced over most of the country.

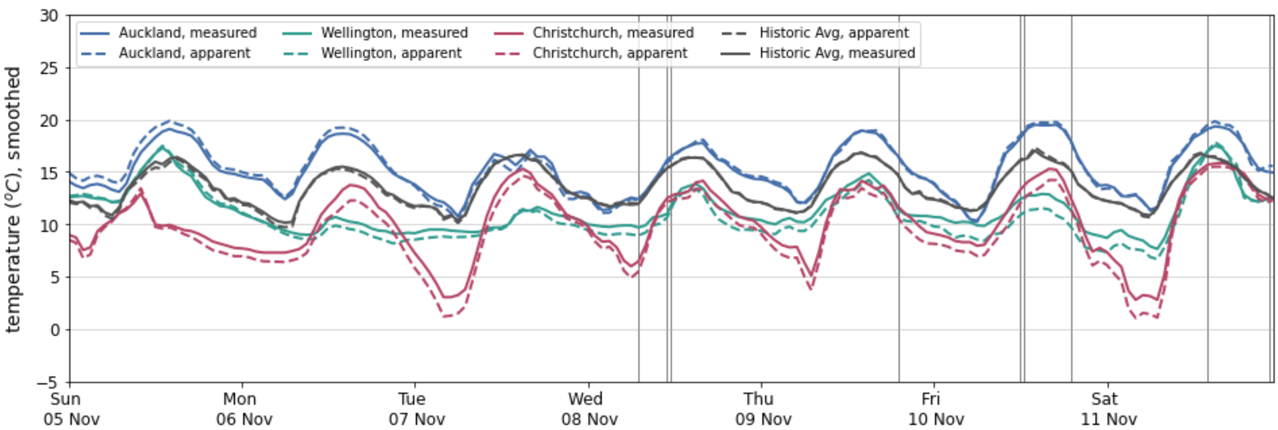
Figure 7: National demand by trading period compared to the previous week



6.2. Figure 8 shows the hourly temperature at main population centres from 5-11 November. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean historical temperature of similar weeks, from previous years, averaged across the three main population centres.

6.3. Auckland temperatures continue to be on or above average. Wellington apparent temperatures ranged from around 7℃ to 18℃ across the week. Christchurch saw more variable apparent temperatures, dropping as low as 1℃ on Tuesday and Saturday mornings, with the highest temperature of the week reaching around 16℃.

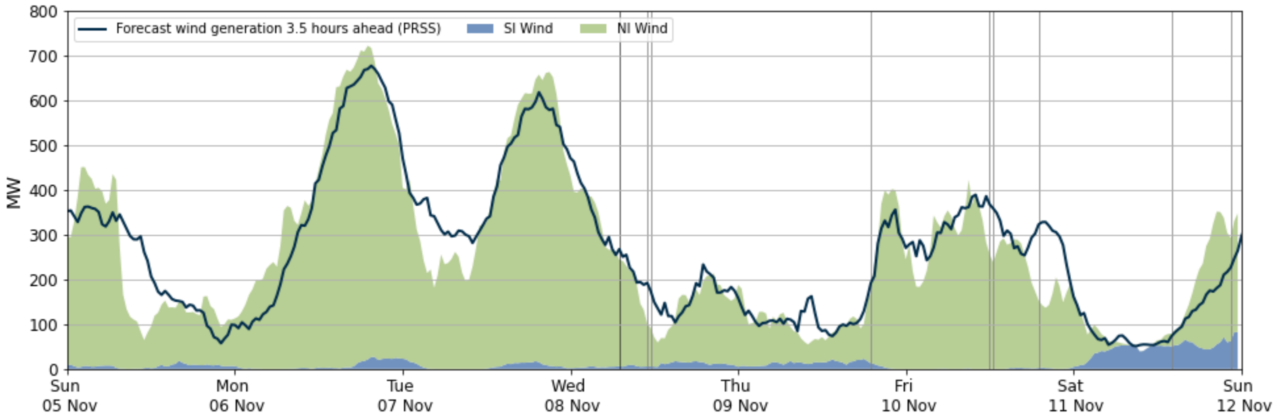
Figure 8: Temperatures across main centres



7. Generation

7.1. Figure 9 shows wind generation, from 5-11 November. Wind generation was generally low across the week compared to some of the recent high generation we have seen. The lowest generation was ~40MW and the highest was 722MW. Monday and Tuesday afternoons were the only times this week wind generation got above 500MW.

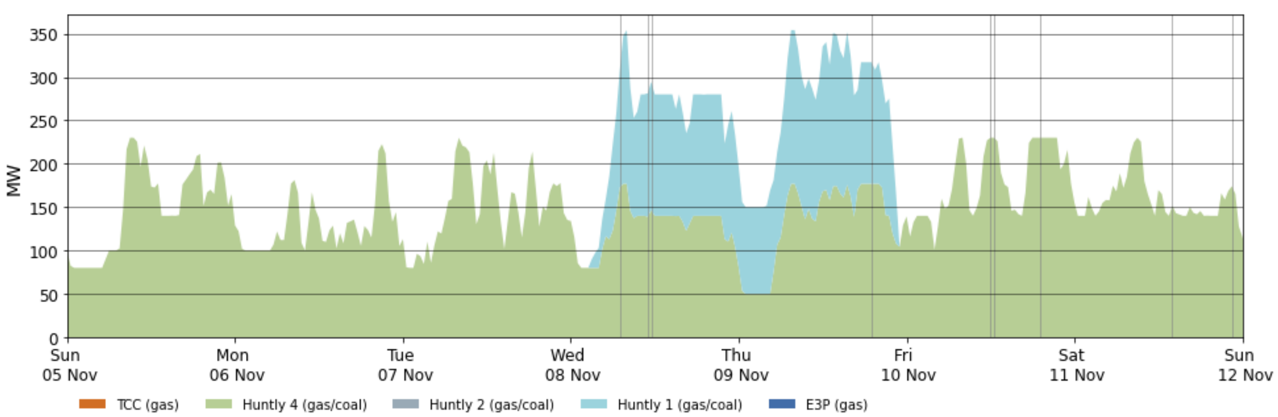
Figure 9: Wind generation and forecast between 5 -11 November

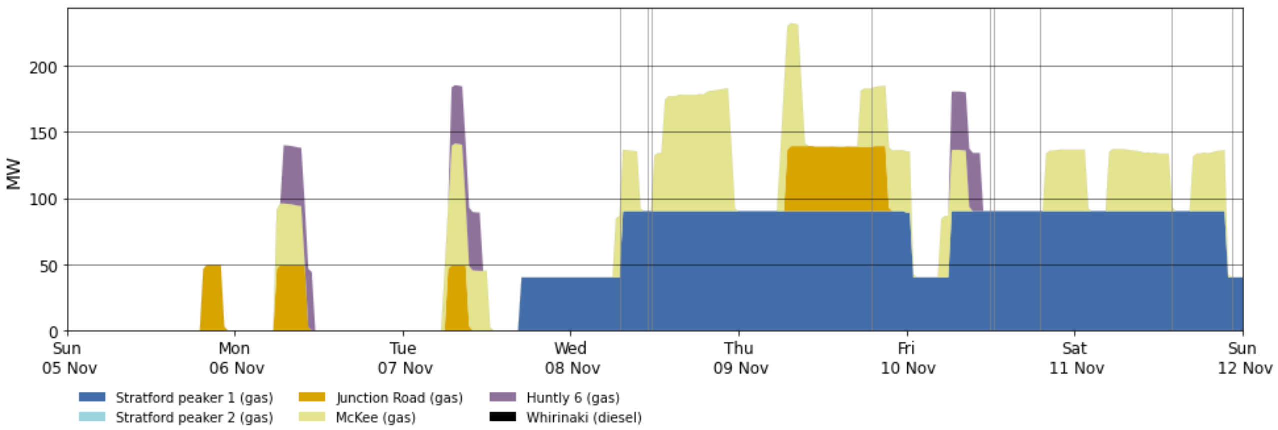


7.2. Figure 10 shows the generation of thermal baseload and thermal peaker plants between 5-11 November. Huntly 4 ran all week as baseload with Huntly 1 supporting over Wednesday and Thursday when wind generation dropped off.

7.3. The early part of the week saw limited thermal peakers running, with Huntly 6, Junction Road and McKee generating for the Monday and Tuesday morning peak periods. After returning from outage on Wednesday, Stratford 1 ran continuously from the Wednesday evening peak through the rest of the week. McKee generated during most of the peak periods from Wednesday to Saturday, with Junction Road running during Thursday shoulder period and Huntly 6 during the Friday morning peak.

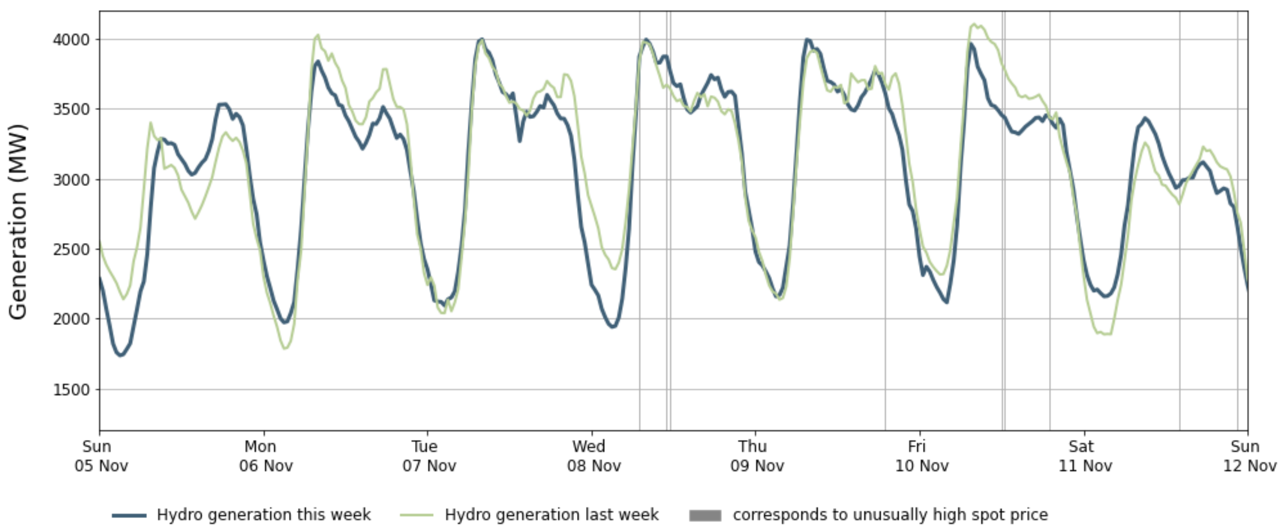
Figure 10: Thermal generation between 5-11 November





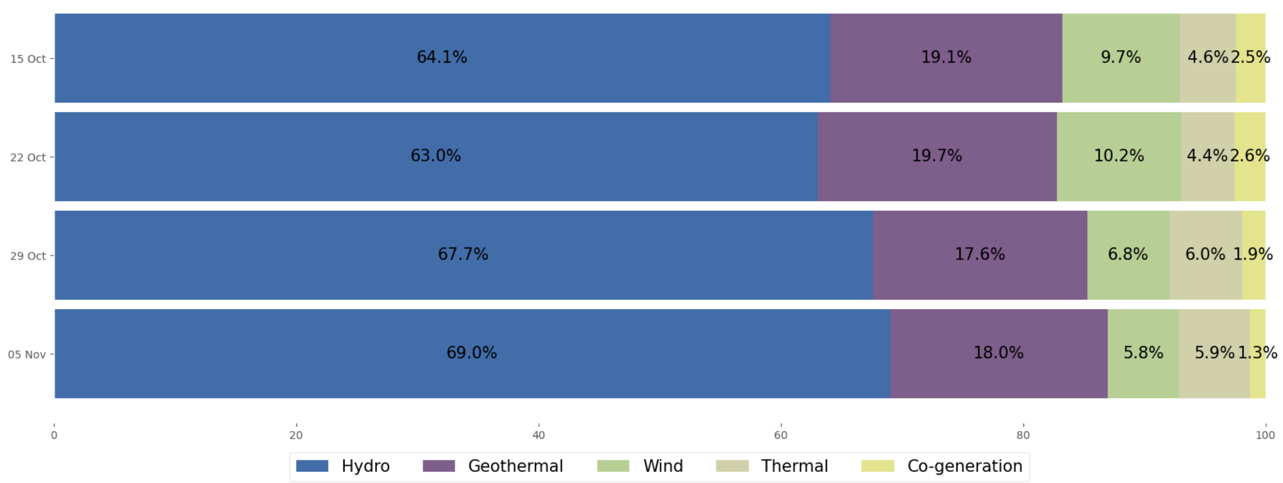
7.4. Figure 11 shows hydro generation between 5-11 November. Overall, hydro generation was similar to the previous week. Monday and Friday saw slightly lower generation than the week before, with the weekend days seeing slightly higher generation.

Figure 11: Hydro generation between 5-11 November compared to the previous week



7.5. As a percentage of total generation, between 5-11 November, total weekly hydro generation was 69%, geothermal 18%, wind 5.8%, thermal 5.9%, and co-generation 1.3%.

Figure 12: Total generation by type as a percentage each week between 15 October and 11 November



8. Outages

8.1. Figure 13 shows generation capacity on outage. Total capacity on outage between 5-11 November ranged between 2300MW and ~2800MW.

8.2. Notable outages include:

(a) Huntly 5 on outage until 22 January 2024

(b) TCC is on outage from 23 October until 22 December 2023

(c) Huntly 2 outage from 27 October to 13 November

(d) Huntly 1 on outage 10 November

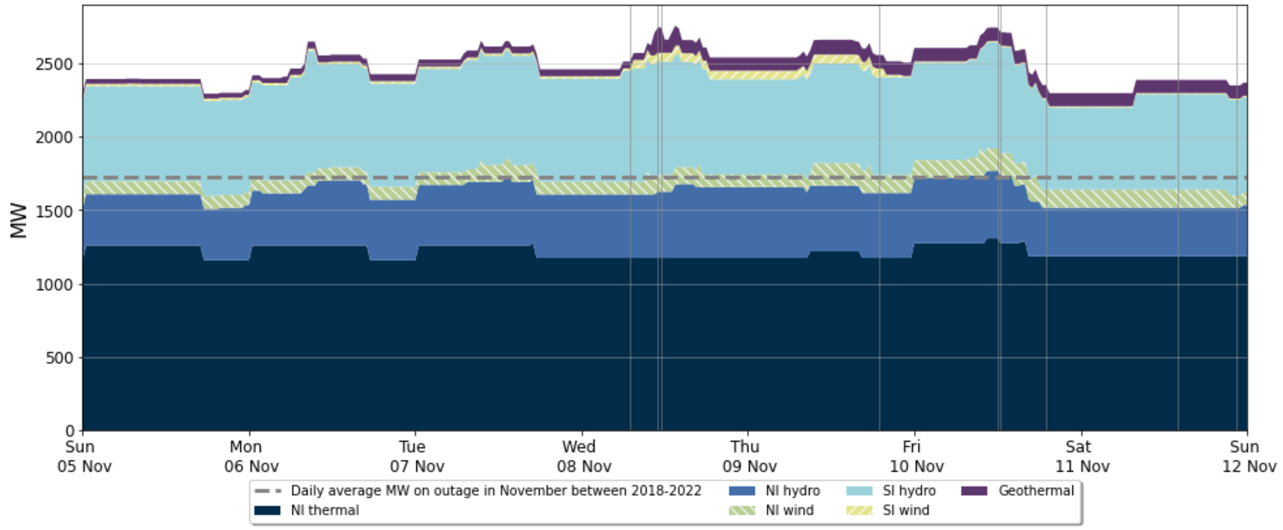
(e) Stratford 1 outage 2 November to 7 November

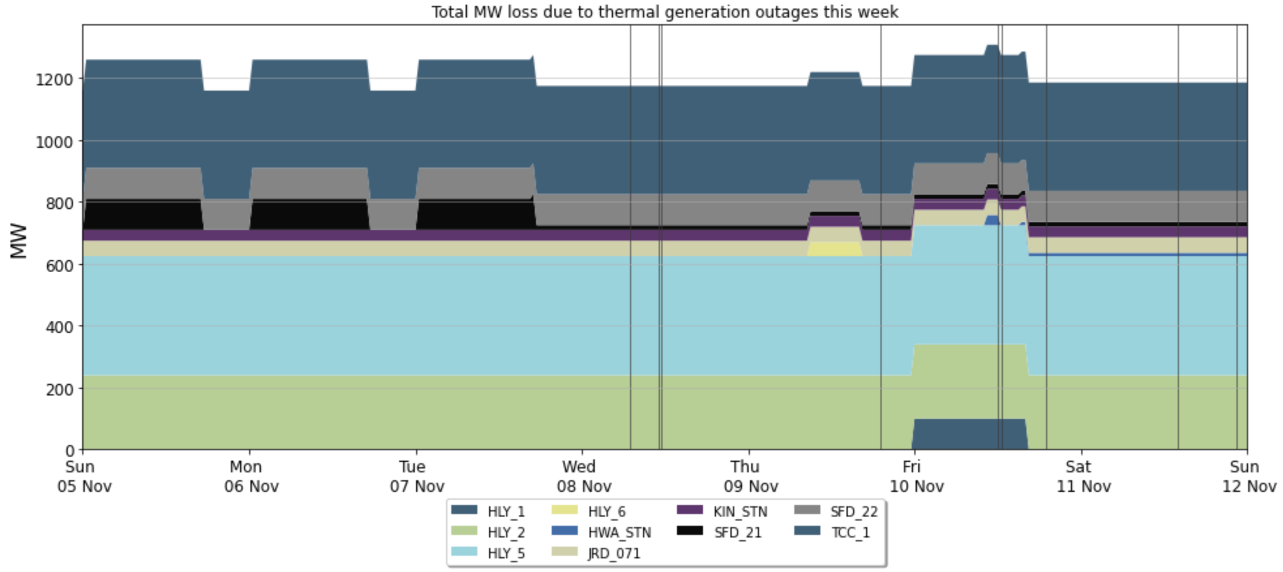
(f) Stratford 2 outage until 28 February 2025

(g) Te Mihi outage on 8 November

(h) Various North and South Island Hydro on outage

Figure 13: Total MW loss due to generation outages





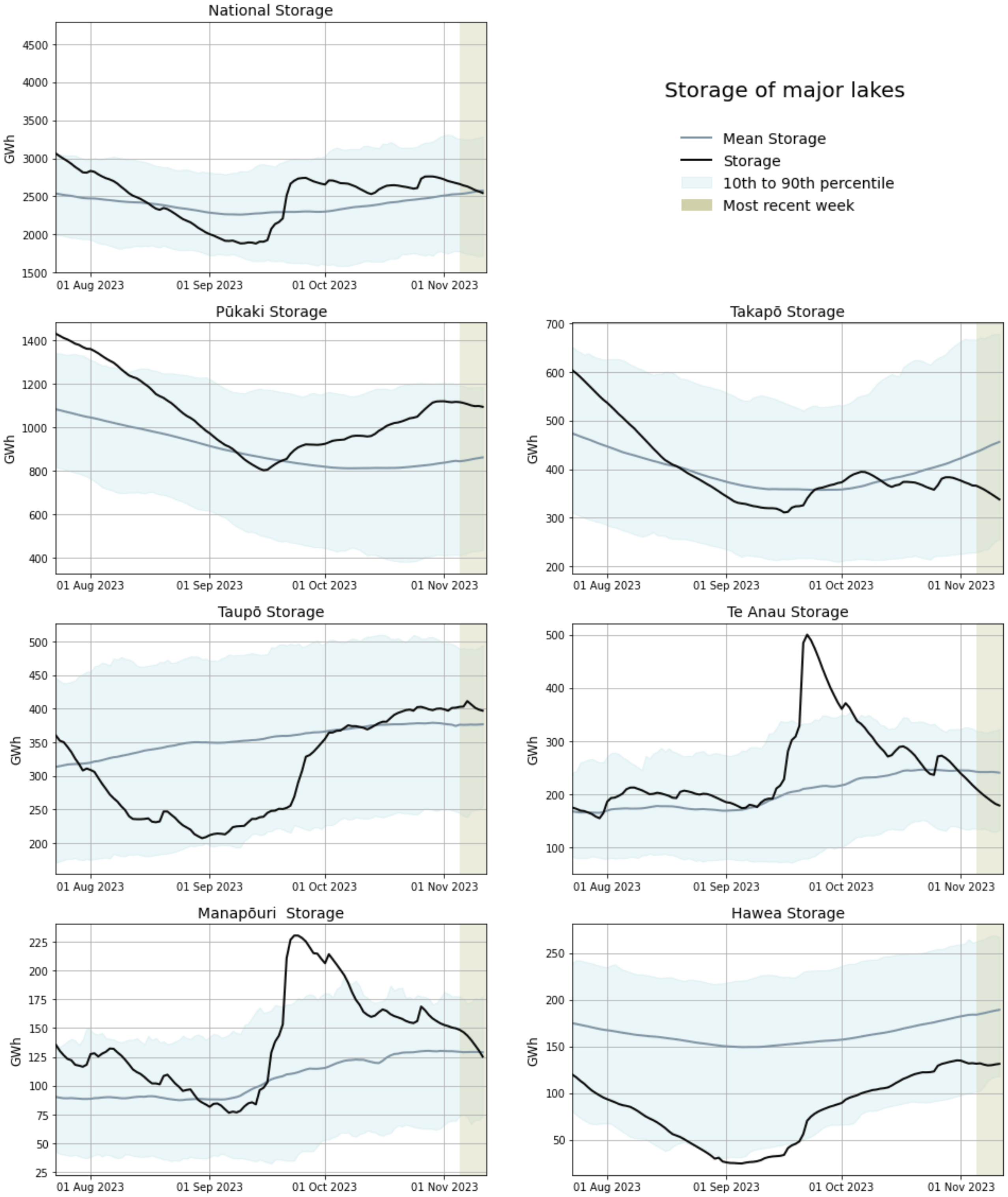
9. Storage/fuel supply

9.1. Figure 14 shows the total controlled national hydro storage as well as the storage of major catchment lakes including their historical mean and 10th to 90th percentiles.

9.2. National hydro storage levels decreased this week with controlled storage at 101% of historic mean and 65% nominally full as of 11 November.

9.3. Taupō storage took a small dip this week but remains above its historic mean and close to 400GWh of storage. Pūkaki storage remains high and close to its 90th percentile, whilst Takapō storage continues to decline below its historic mean. Storage at Te Anau has continued to decrease this week and remains below its historic mean, with Manapōuri storage dipping just below its historic mean at the end of the week. Hawea storage has remained steady over the week.

Figure 14: Hydro storage

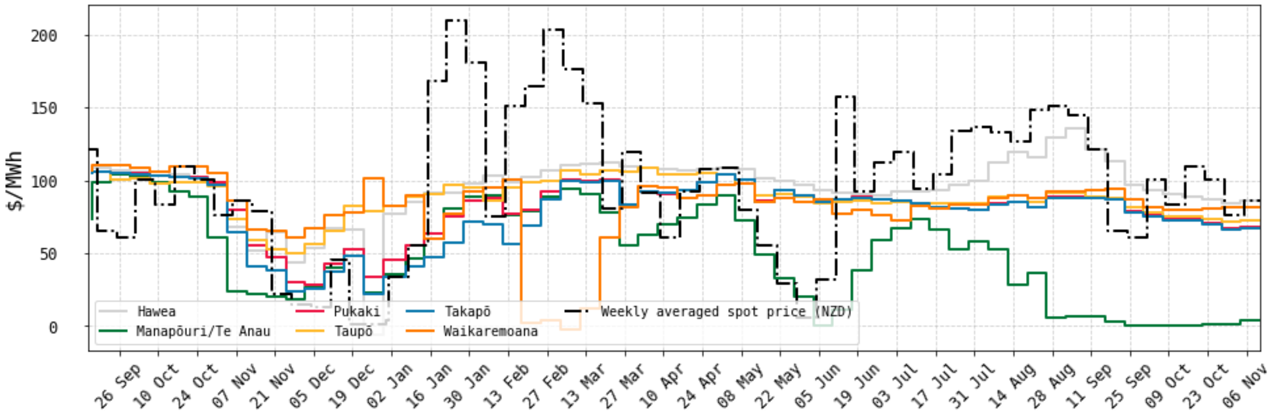


10. JADE water values

10.1. The JADE[3] model gives a consistent measure of the opportunity cost of water, by seeking to minimise the expected fuel cost of thermal generation and the value of lost load and provides an estimate of water values at a range of storage levels. Figure 15 shows the national water values between 15 September 2022 and 11 November 2023 obtained from JADE calculated as at the start of the week. These values are used to estimate the marginal water value at the actual storage level. More details on how water values are calculated can be found in Appendix B.

10.2. Water values at Te Anau/Manapōuri have increases to ~$4/MWh (in line with drops below historical average storage that both lakes have seen over the last week). Most other lake's water values increased by only $1/MWh.

Figure 15: JADE water values across various reservoirs between 15 September 2022 and 11 November 2023



11. Prices versus estimated costs

11.1. In a competitive market, prices should be close to (but not necessarily at) the short run marginal cost (SRMC) of the marginal generator (where SRMC includes opportunity cost).

11.2. The SRMC (excluding opportunity cost of storage) for thermal fuels is estimated using gas and coal prices, and the average heat rates for each thermal unit. Note that the SRMC calculations include the carbon price, an estimate of operational and maintenance costs, and transport for coal.

11.3. Figure 16 shows an estimate of thermal SRMCs as a monthly average up to 1 November 2023. The SRMC of diesel plants has been increasing since May, and the SRMC of coal-fuelled and gas-fuelled plants has started to increase again. The recent increase in the SRMC of gas likely reflects increased production at Methanex, as well as gas production outages.

11.4. The latest SRMC of coal-fuelled Rankine generation is ~$161/MWh. This is now only slightly higher than the cost of running the Rankines on gas at $141/MWh, with Genesis continuing to run the Rankines on a combination of both fuels.

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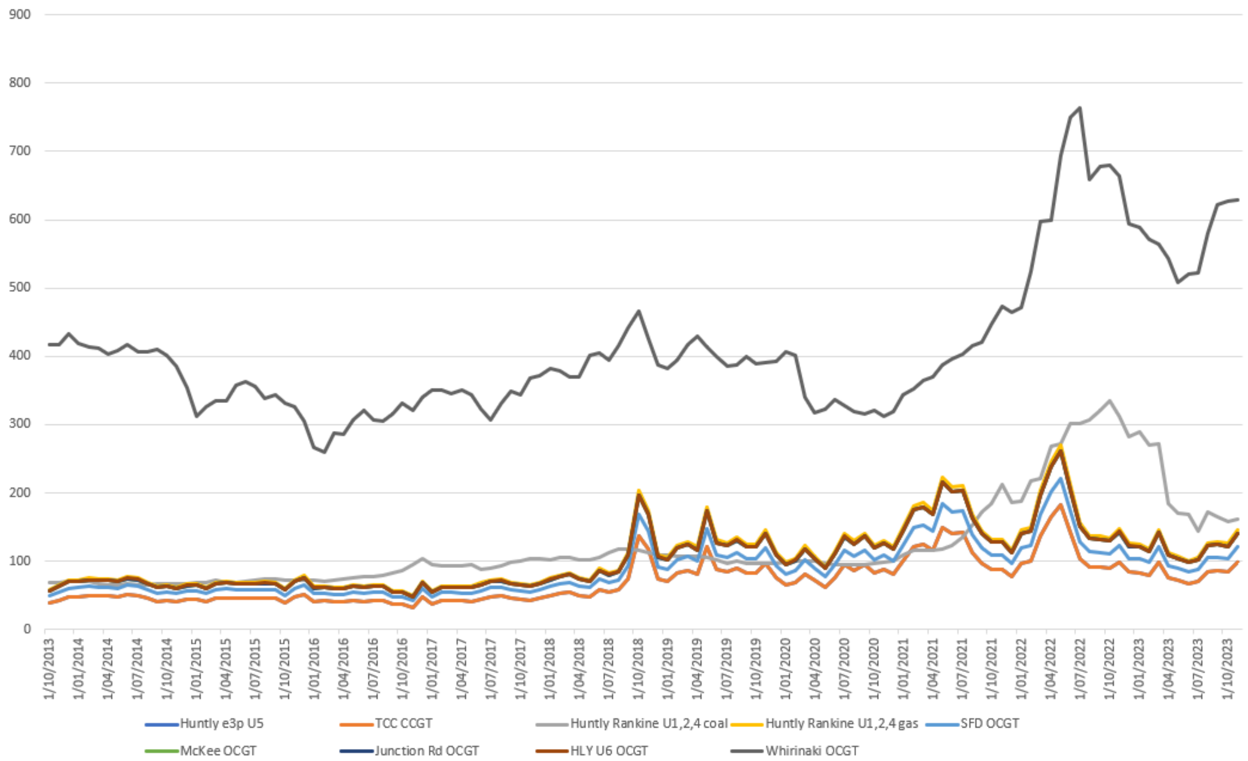
[3] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

11.5. The SRMC of gas fuelled thermal plants is currently between $98/MWh and $141/MWh.

11.6. The SRMC of Whirinaki has increased to ~$629/MWh.

11.7. More information on how the SRMC of thermal plants is calculated can be found in Appendix C on the trading conduct webpage. This appendix was recently updated to reflect the changes made to coal price indices by the Indonesian government. These changes have had the effect of decreasing the coal SRMC from April 2023.

Figure 16: Estimated monthly SRMC for thermal fuels

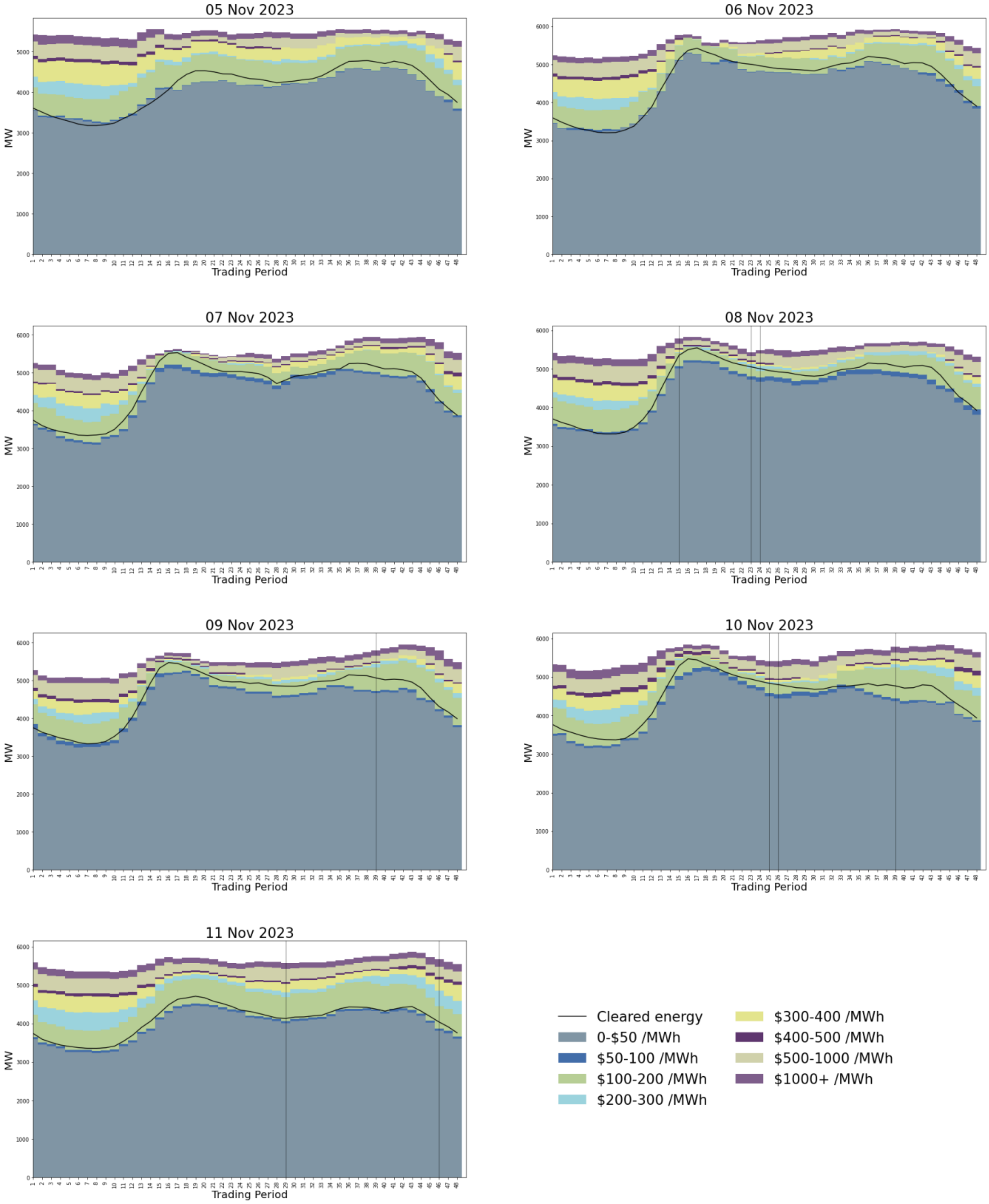


12. Offer behaviour

12.1. Figure 17 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

12.2. Most offers cleared within the $100-$200/MWh band this week. The total effective generation available was lower for the morning peak on 7 November compared to the other mornings this week, due to both generation and transmission outages. As a result, there was very little additional generation available above $200/MWh.

Figure 17: Daily offer stacks



13. Ongoing work in trading conduct

13.1. This week, prices generally appeared to be consistent with supply and demand conditions.

13.2. Further analysis is being done on the trading periods in Table 1 as indicated.

Table 1: Trading periods identified for further analysis

Date	TP	Status	Participant	Location	Enquiry topic
07/10/2022	15-16	Further analysis	Genesis	Huntly 5	Prices change for final energy tranche.
14/06/2023	15-17	Passed to Compliance	Genesis	Multiple	High energy prices associated with high energy offers.
15/06/2023	15-19	Passed to Compliance	Genesis and Contact	Multiple	High energy prices associated with high energy offers.
22/09/2023-30/09/2023	Several	Further analysis	Contact	Multiple	High hydro offers.
11/10/2023	21	Further Analysis	Genesis	Tokaanu	High prices during off-peak time.