2 December 2024

Trading conduct report 24-30 November 2024

Market monitoring weekly report

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1. Overview

1.1. Spot prices increased slightly compared to the previous week, but were mostly below the historical median. National hydro storage decreased, but remained at 129% of mean, resulting in high hydro generation and high northward HVDC flow. This led to price separation between islands, with North Island reserve and spot prices spiking while South Island prices remained low.

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, it also singles 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. Between 24-30 November 2024:

(a) the average wholesale spot price across all nodes was $26/MWh

(b) 95% of prices fell between $0.10/MWh and $128/MWh.

2.3. Overall, the majority of spot prices were within $3-$39/MWh and below the historic median. The weekly average price increased by around $15/MWh compared to the previous week.

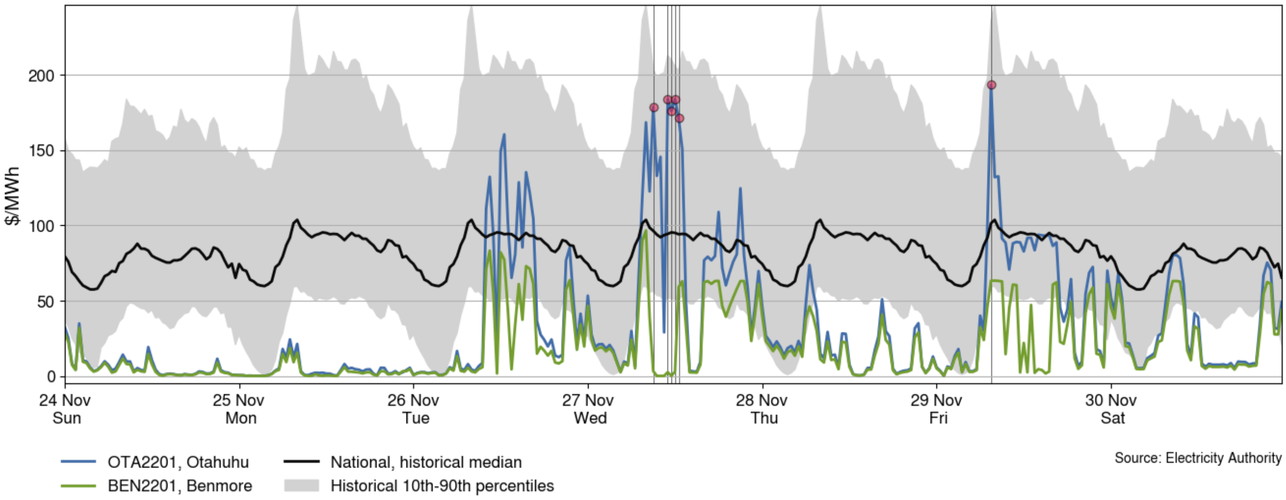
2.4. Periods of price separation of up to $181/MWh, with higher North Island prices, occurred between Tuesday and Friday. This separation mostly occurred during times of low wind generation, during which North Island reserve and energy requirements had to be balanced between the thermal and hydro resource available, which increased both the energy and reserve costs. On Tuesday there were also other line constraints in the North Island, which likely curtailed the export of cheaper energy. Additionally, demand on Tuesday was often under forecasted by over 100MW.

2.5. The Ōtāhuhu spot price reached a maximum of $193/MWh at 7.30am on Friday; the Benmore price at the same time was $63/MWh. Wind was over-forecast by 101MW at the time, and demand was under-forecast by 108MW.

2.6. Forecasting inaccuracies likely contributed to the occasional above-average prices on Tuesday, Wednesday and Friday this week. During many of the relevant trading periods, demand was under-forecast by more than 100MW, and wind was over-forecast by more than 80MW.

2.7. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90th percentiles adjusted for inflation. Prices greater than quartile 3 (75th percentile) plus 1.5 times the inter-quartile range of historic prices, plus the difference between this week's median and the historic median, are highlighted with a vertical black line. Other notable prices are marked with black dashed lines.

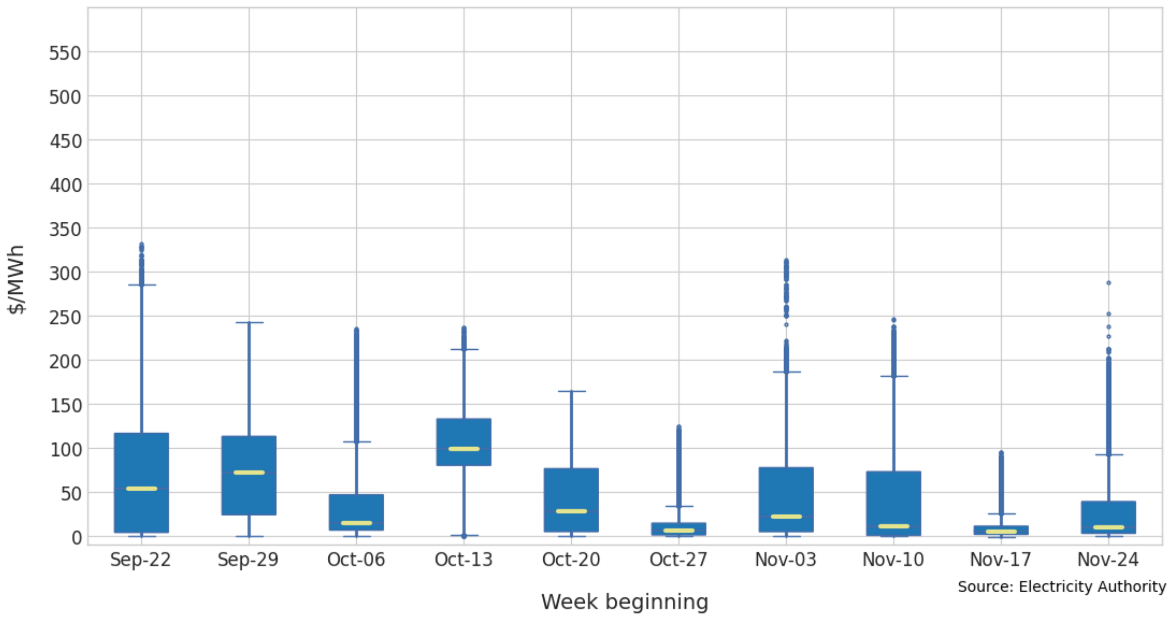
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 24-30 November 2024



2.8. Figure 2 shows a box plot with the distribution of spot prices during this week and the previous nine weeks. The yellow line shows each week's median price, while the blue box shows the lower and upper quartiles (where 50% of prices fell). The 'whiskers' extend to points that lie within 1.5 times of the interquartile range (IQR) of the lower and upper quartile. Observations that fall outside this range are displayed independently.

2.9. The median price increased to $10/MWh this week. The overall range of prices and number of outliers also increased, indicating that prices were less stable.

Figure 2: Box plot showing the distribution of 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. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4.

3.2. Reserve prices were mostly below $1/MWh this week. However, they separated and spiked in the North Island on Wednesday and Friday. On Wednesday, the FIR price reached a weekly maximum of $148/MWh at 11am and the SIR price reached a maximum of $94/MWh at 11.30am. FIR price separation also occurred on Friday, with the North Island price reaching $91/MWh at 7:30am. These separations were due to high northward HVDC flow during low wind generation and the HVDC setting the risk.

Figure 3: Fast instantaneous reserve price by trading period and island, 24-30 November 2024

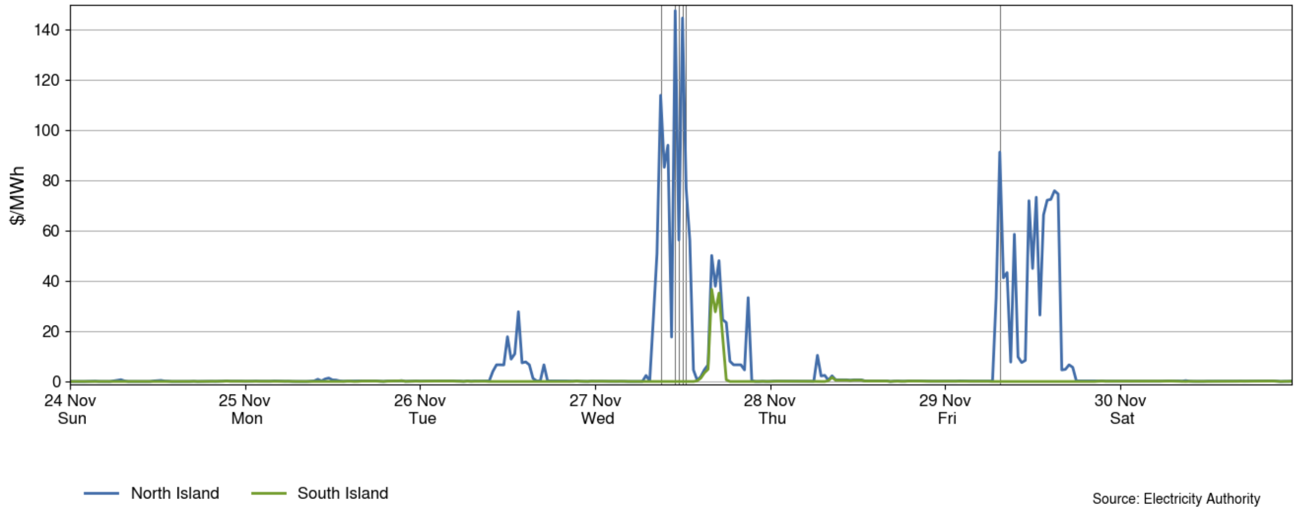
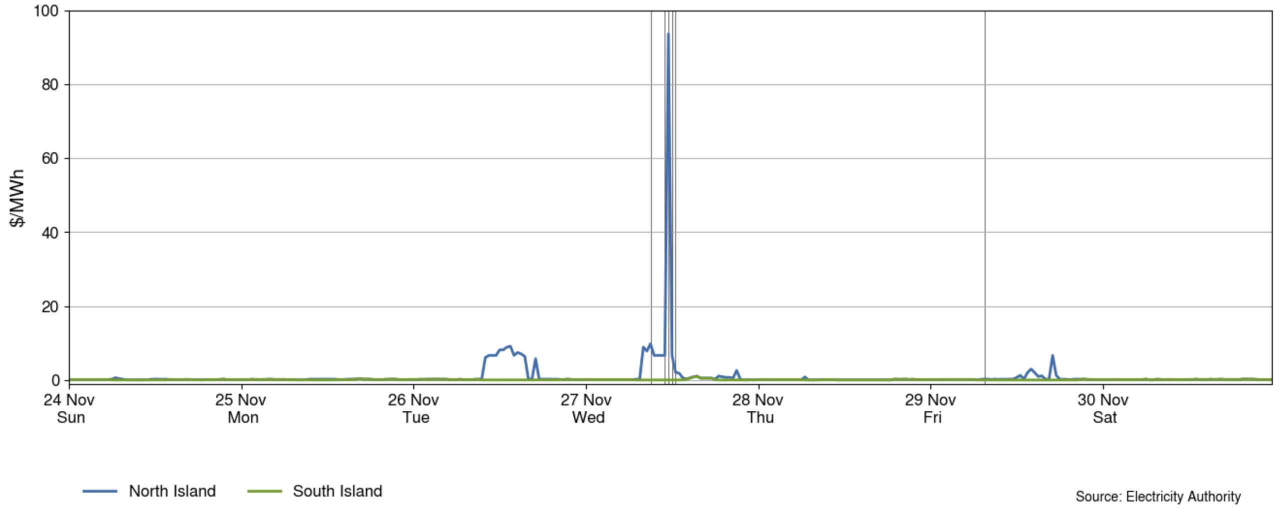


Figure 4: Sustained instantaneous reserve by trading period and island, 24-30 November 2024



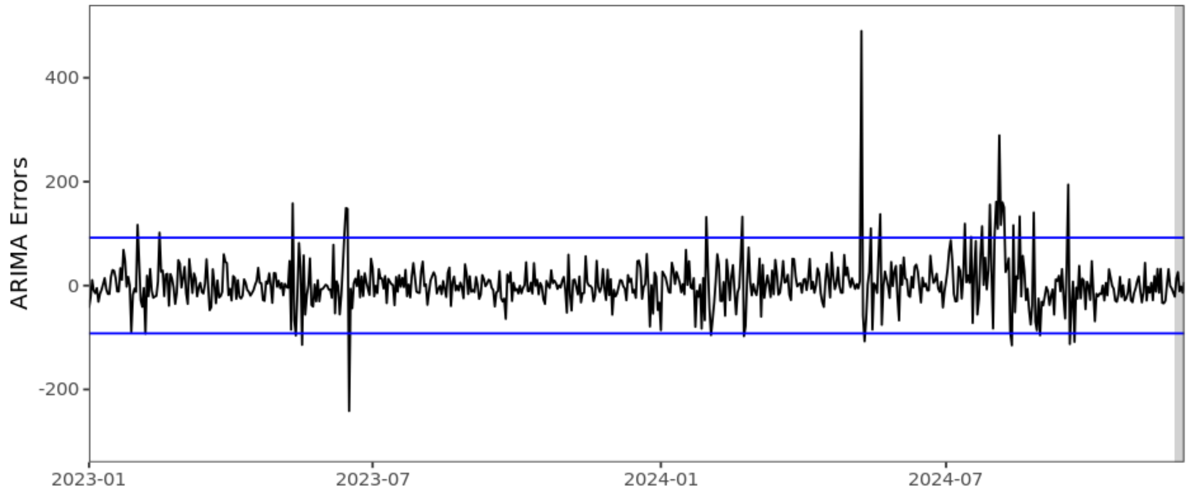
4. Regression residuals

4.1. The Authority's monitoring team uses a regression model to model electricity spot prices. The residuals show how close predicted spot 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.

4.2. Figure 5 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. Positive residuals indicate that the modelled daily price is lower than the 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 in the regression analysis.

4.3. This week, there were no residuals above or below two standard deviations, indicating that prices were similar to those predicted by the model.

Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 - 30 November 2024

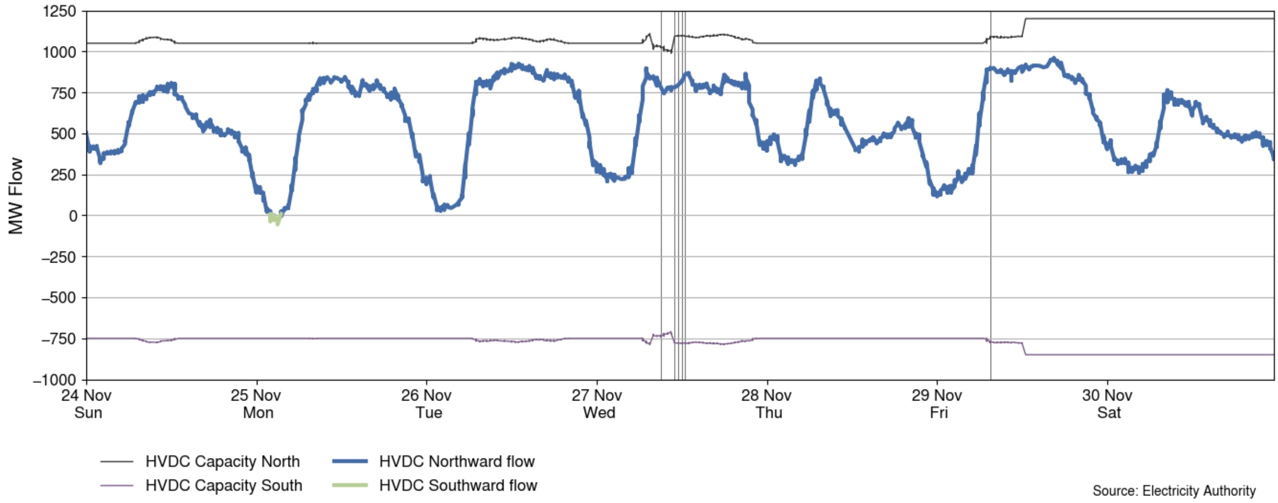


Source: Electricity Authority/Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 24-30 November 2024. HVDC flow was mainly northward and near capacity at times, with some overnight southward flow when wind generation was relatively high early on Monday.

Figure 6: HVDC flow and capacity, 24-30 November 2024

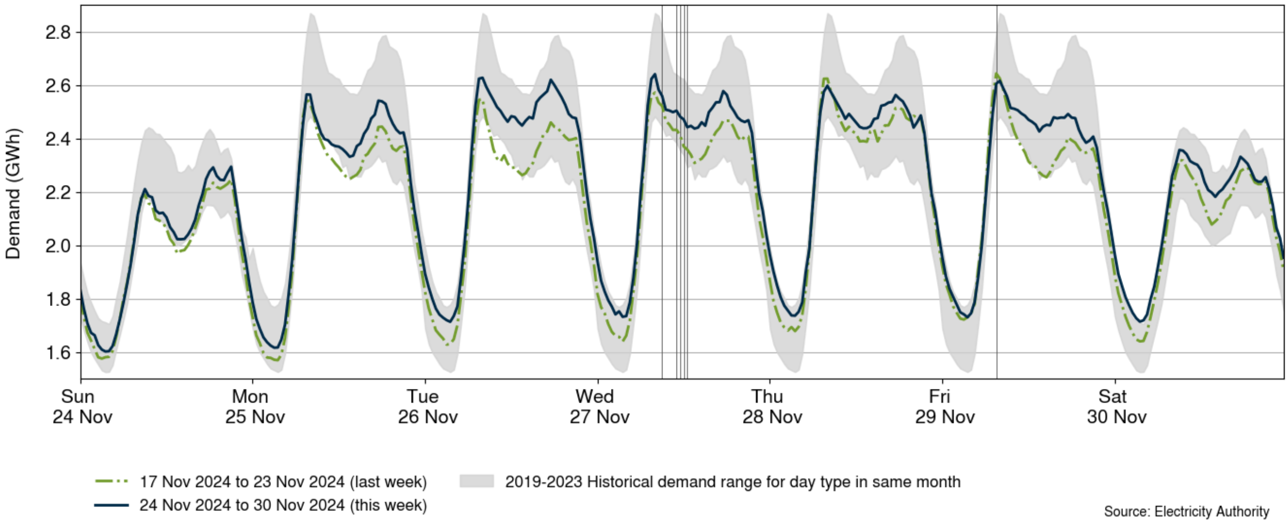


Source: Electricity Authority

6. Demand

6.1. Figure 7 shows national demand between 24-30 November 2024, compared to the historic range and the demand of the previous week. Demand was within or below the maximum historical range this week, but higher than the demand in the previous week. Demand reached a maximum of 2.64GWh at 8.00am on Wednesday.

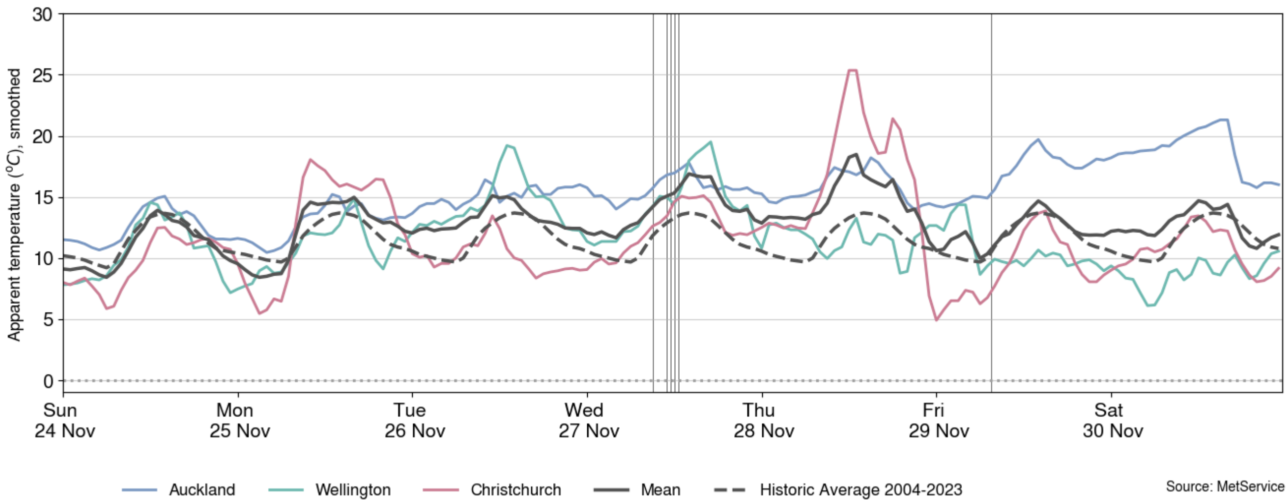
Figure 7: National demand, 24-30 November 2024 compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 24-30 November 2024. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean temperature of the main population centres, and the mean historical apparent temperature of similar weeks, from previous years, averaged across the three main population centres.

6.3. Temperatures were generally close to or above average this week, ranging from 10°C to 22°C in Auckland, 6°C to 20°C in Wellington, and 5°C to 27°C in Christchurch.

Figure 8: Temperatures across main centres, 24-30 November 2024

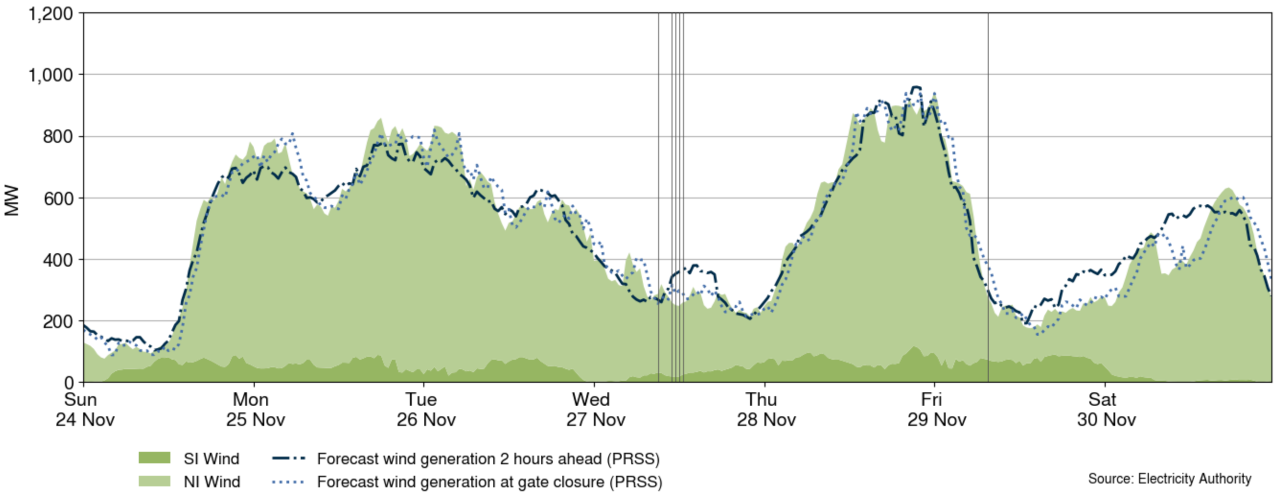


7. Generation

7.1. Figure 9 shows wind generation and forecast from 24-30 November 2024. This week wind generation varied between 76MW and 945MW, with a weekly average of 487MW. Wind generation was highest on Monday when the daily average generation was 709MW.

7.2. The largest gate closure over-forecasting error was at 2.30pm on Friday when wind generation was 145MW lower than the gate closure forecast.

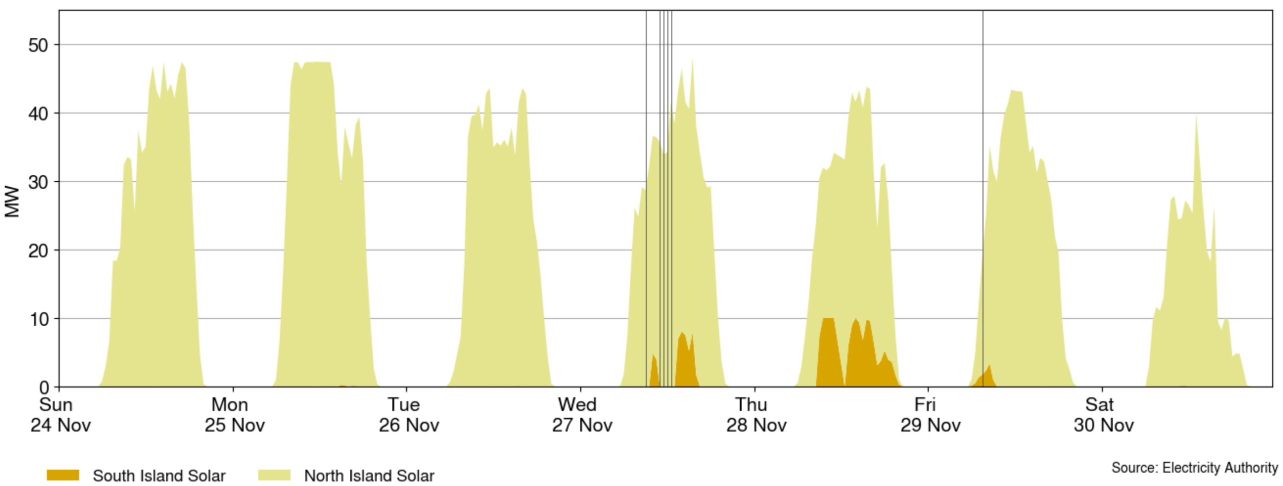
Figure 9: Wind generation and forecast, 24-30 November 2024



7.3. Figure 10 shows solar generation from 24-30 November 2024. Solar generation peaked above 40MW most days this week, with a maximum of 48MW on Wednesday at 3.30pm. The still commissioning solar farm in the South Island, Lauriston, generated up to 10MW this week.

7.4. Increased cloud cover at Edgecumbe may have decreased solar generation on Saturday.

Figure 10: Solar generation, 24-30 November 2024



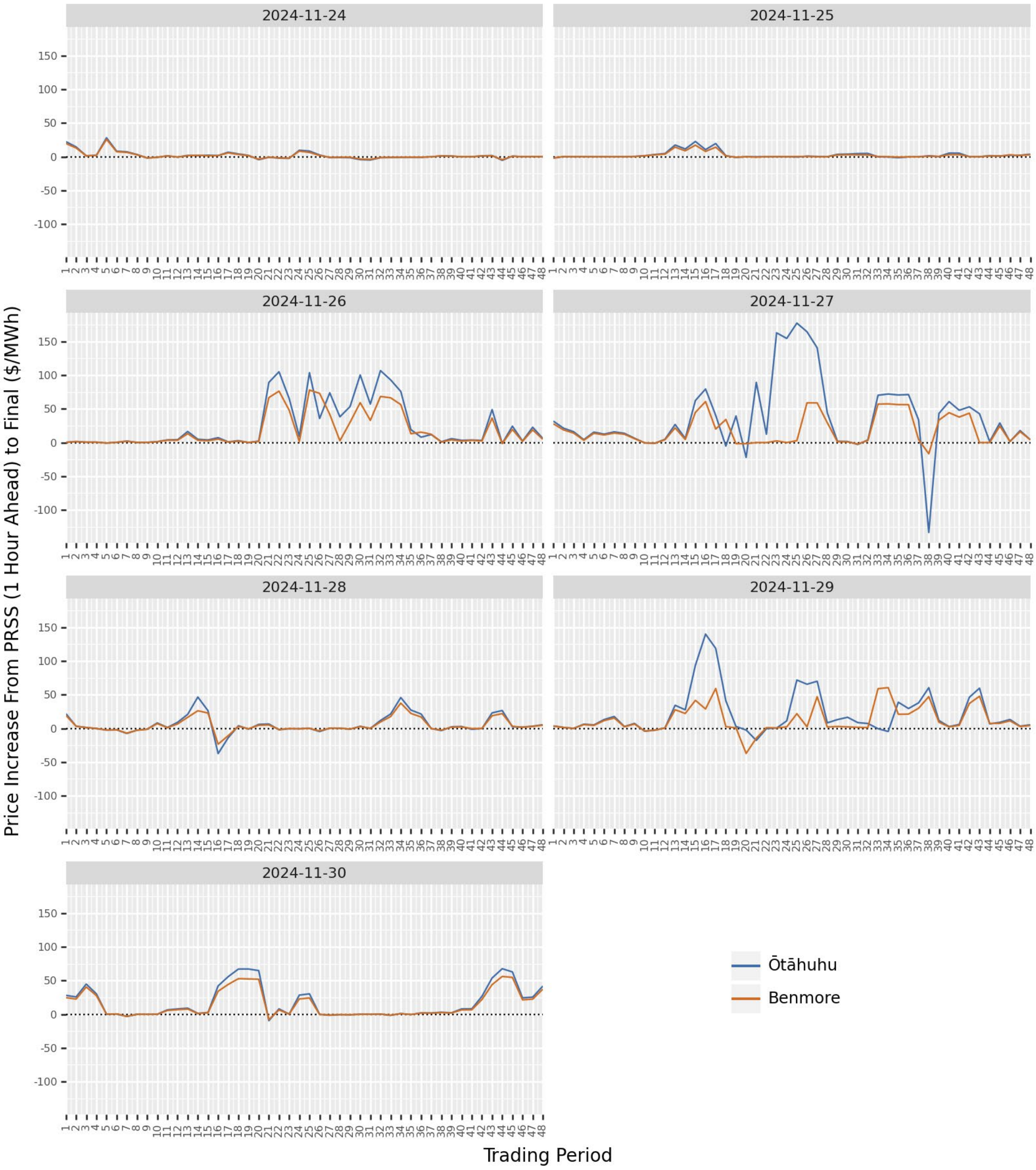
7.5. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-

hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences to final prices. When the difference is positive this means that the 1-hour ahead forecasting inaccuracies resulted in the spot price being higher than anticipated - usually where demand is under forecast and/or wind is over forecast. When the difference is negative, the opposite is true. Because of the nature of demand and wind forecasting, the 1-hour ahead and the RTD wind and demand forecasts will rarely be the same. Trading periods where this difference is exceptionally large can signal that forecasting inaccuracies had a large impact on the final price for that trading period.

7.6. The most significant marginal price difference this week was $177/MWh at 12.00pm on Tuesday at Ōtāhuhu, when demand was under-forecast by 109MW. Differences exceeding $100/MWh also occurred at Ōtāhuhu during other trading periods on Tuesday, Wednesday and Friday, when demand was under-forecast and/or wind was over-forecast. Prices were otherwise generally similar to those simulated.

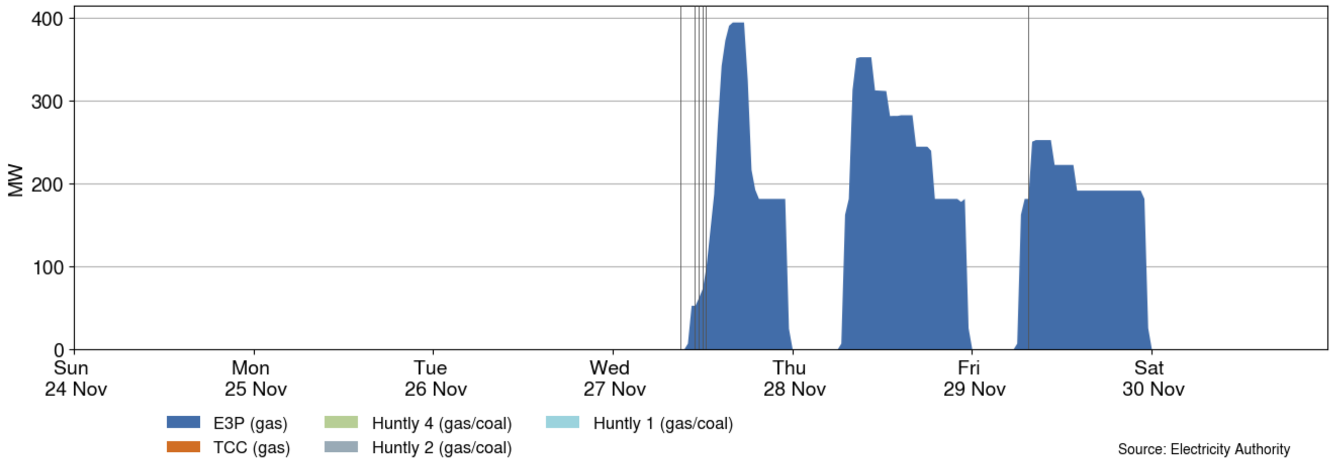
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

Figure 11: Difference between marginal RTD price and simulated RTD price at Benmore and Ōtāhuhu, with the difference due to one-hour ahead wind and demand forecast inaccuracies, 24-30 November 2024



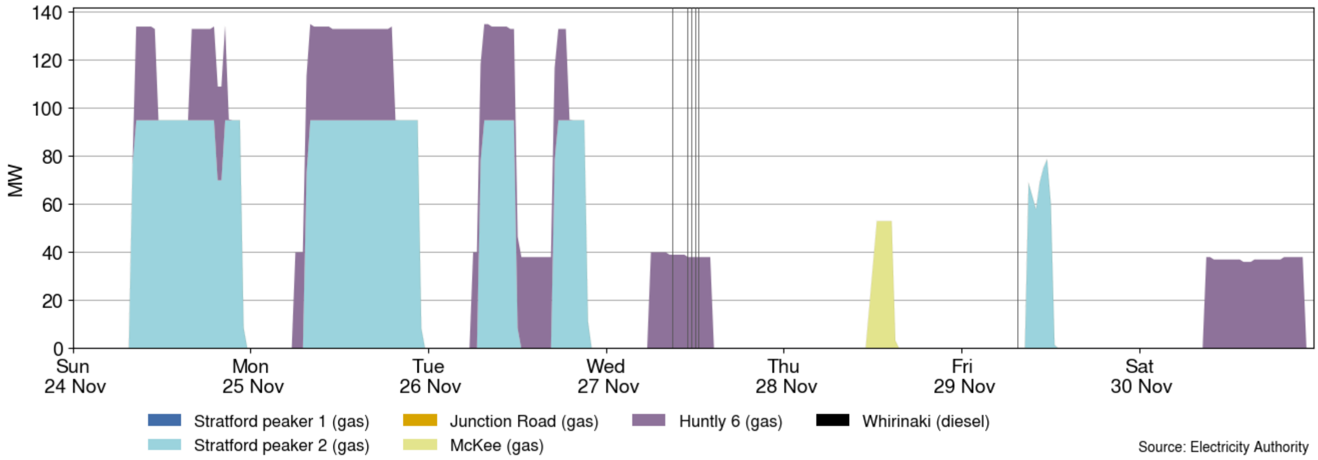
7.7. Figure 12 shows the generation of thermal baseload between 24-30 November 2024. After returning from outage, Huntly 5 generated between Wednesday and Friday.

Figure 12: Thermal baseload generation, 24-30 November 2024



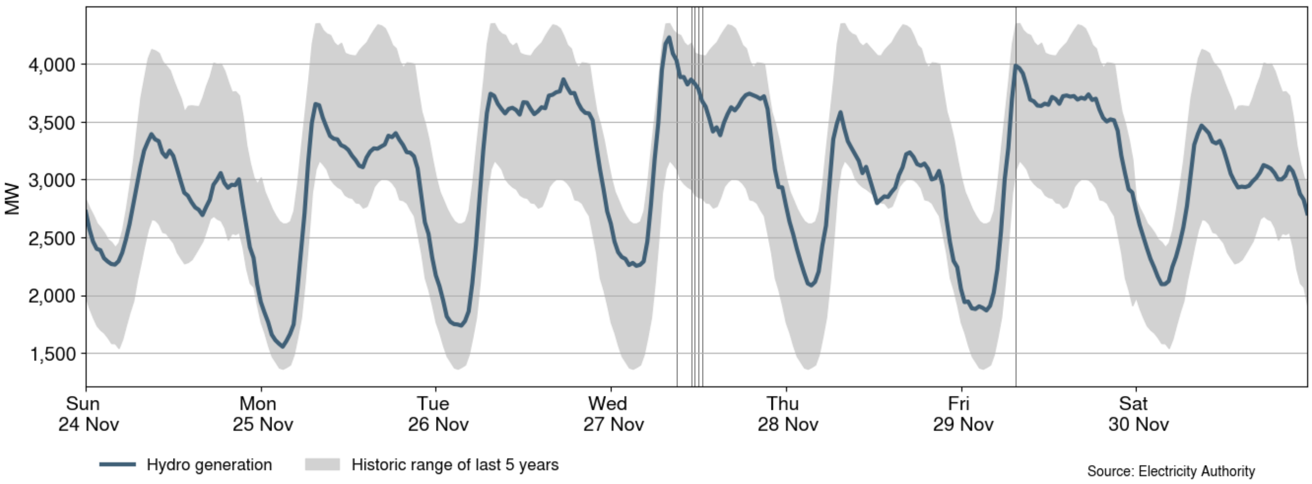
7.8. Figure 13 shows the generation of thermal peaker plants between 24-30 November 2024. Huntly 6 and Stratford 2 were the main peaker units running this week. Huntly 6 ran over peak and/or shoulder periods from Sunday to Wednesday and on Saturday. Stratford 2 also ran from Sunday to Tuesday, as well as on Friday. McKee ran on Thursday afternoon. Less peakers ran once Huntly 5 returned to the market.

Figure 13: Thermal peaker generation, 24-30 November 2024



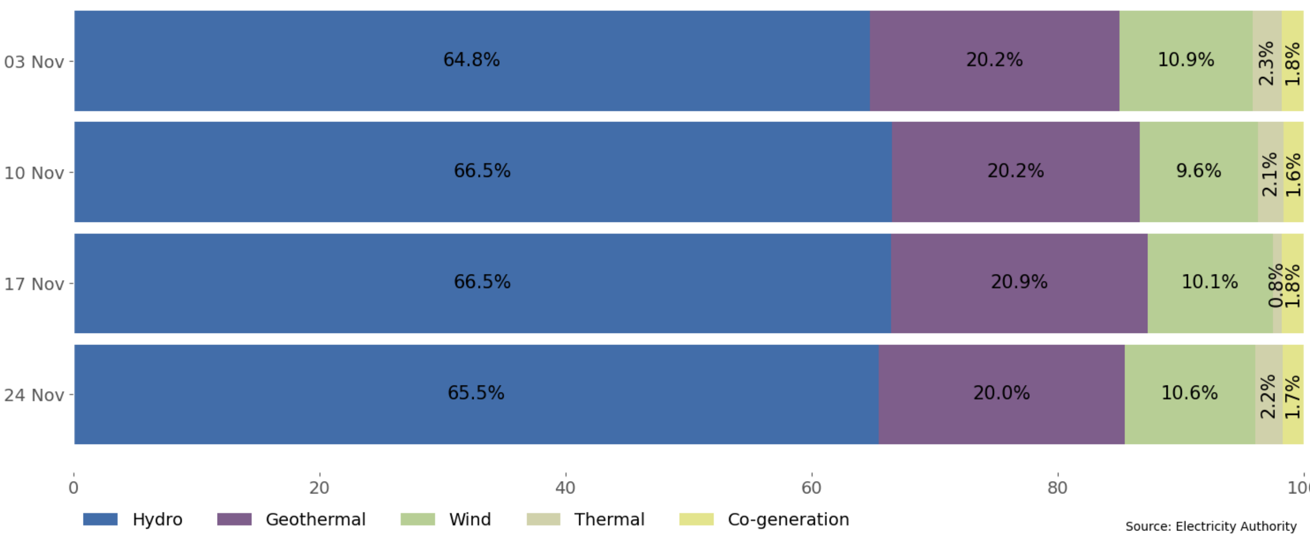
7.9. Figure 14 shows hydro generation between 24-30 November 2024. Hydro generation was around the middle of the historic range with some lower generation. It was highest during the Wednesday and Friday morning peaks periods, when wind generation was low.

Figure 14: Hydro generation, 24-30 November 2024



7.10. As a percentage of total generation, between 24-30 November 2024, total weekly hydro generation was 65.5%, geothermal 20%, wind 10.6%, thermal 2.2%, and co-generation 1.7%, as shown in Figure 15. Thermal generation increased slightly this week, although it remained very low, while hydro and geothermal generation both decreased slightly.

Figure 15: Total generation by type as a percentage each week, 3 November to 30 November



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 24-30 November 2024 ranged between ~1,616MW and ~2,308MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 5 was on outage until 26 November. It went on partial outage again on 30 November-1 December.

(b) Huntly 2 is on outage until 6 December.

(c) Huntly 1 is on outage until 3 December.

(d) Tararua wind farm was on outage from 27-28 November.

(e) The Ngā Awa Pūrua geothermal plant outage end date has been extended from 30 November to 2 December.

(f) Stratford peaker 1 is on outage until 1 December.

(g) Whirinaki unit 3 was on outage on 27 November.

(h) Junction Road has two units on outage from 29 November to 3 December.

(i) Several large hydro units are on outage.

Figure 16: Total MW loss from generation outages, 24-30 November 2024

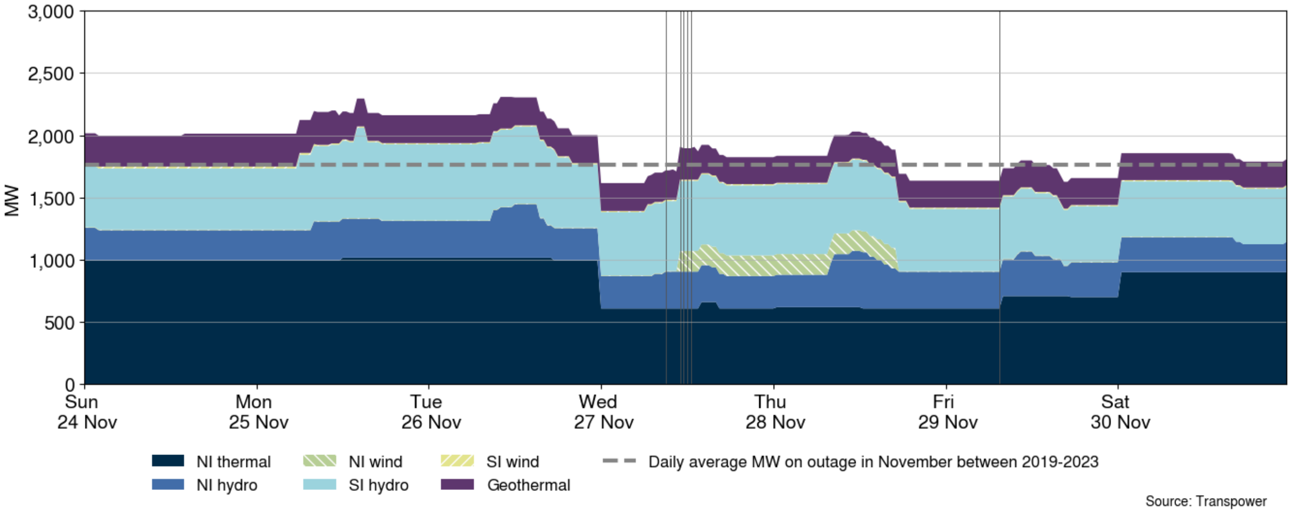
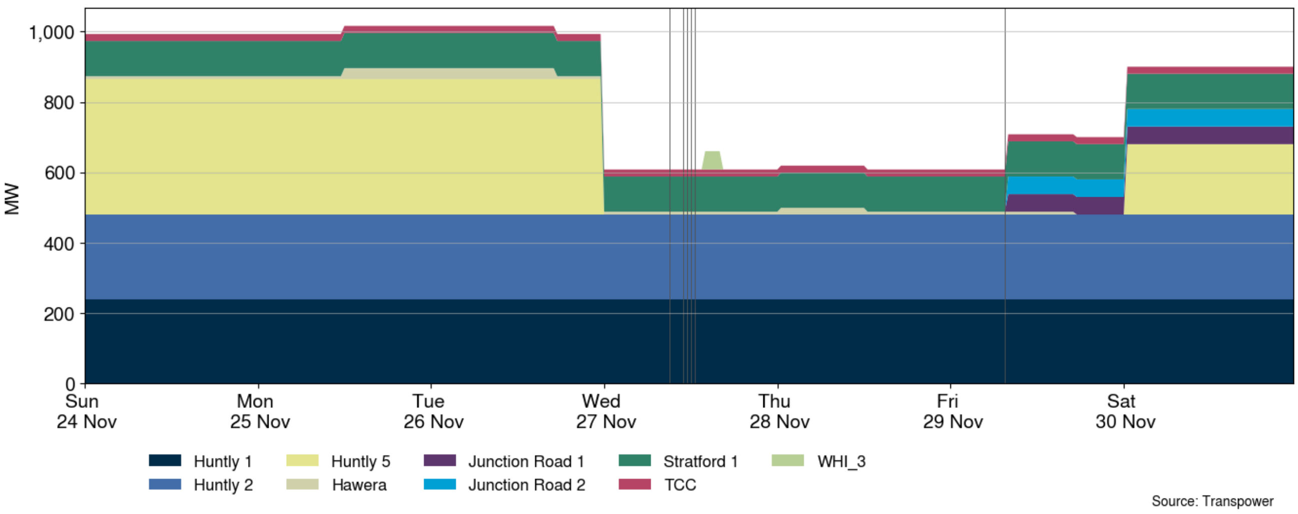


Figure 17: Total MW loss from thermal outages, 24-30 November 2024

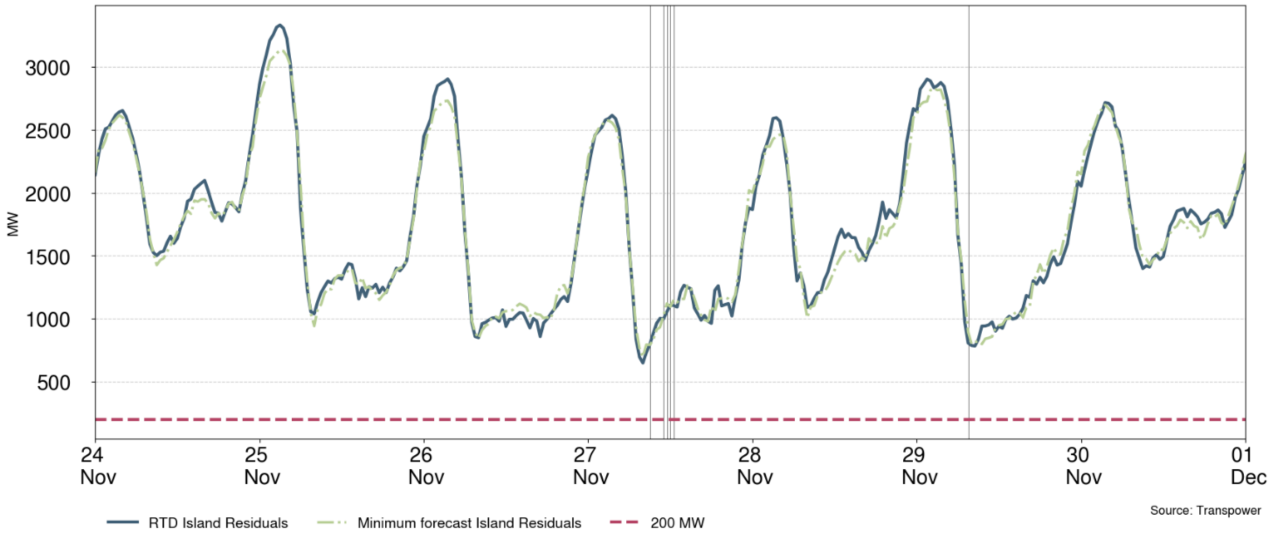


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 24-30 November 2024. A residual is the difference between total energy supply and total energy demand for each trading period. The red dashed line represents the 200MW residual mark which is the threshold at which Transpower issues a customer advice notice (CAN) for a low residual situation. The green dashed line represents the forecast residuals and the blue line represents the real-time dispatch (RTD) residuals.

9.2. The minimum North Island residual this week was ~482MW at 8.30am on Friday.

Figure 18: National generation balance residuals, 24-30 November 2024



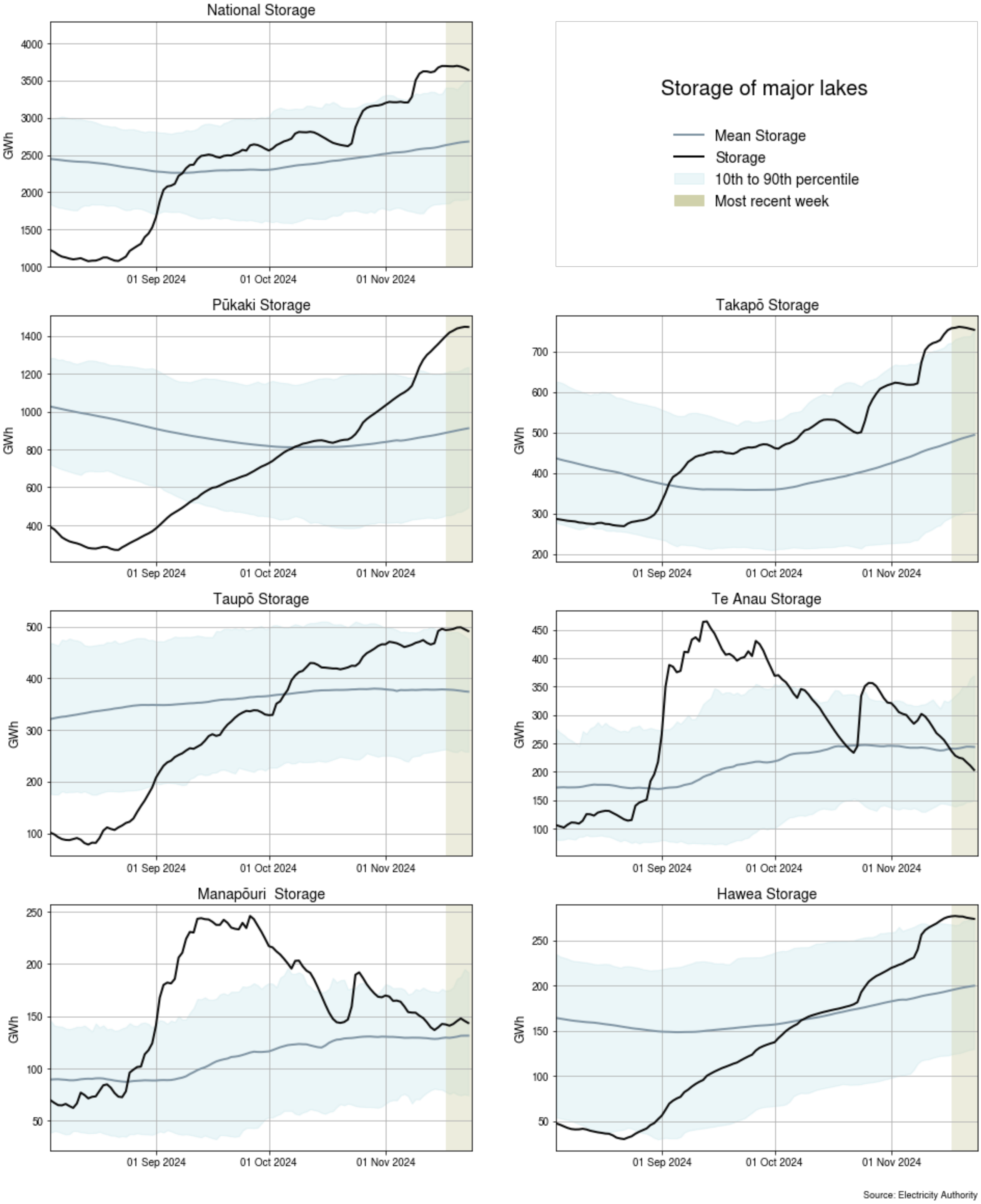
10. Storage/fuel supply

10.1. Figure 19 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.

10.2. National controlled storage decreased slightly this week and was ~88% nominally full and ~129% of the historical average for this time of the year as of 30 November.

10.3. Storage at Te Anau decreased further below mean this week but remained above its 10th percentile. Levels at all other major lakes were above their respective means, with Pūkaki, Takapō, Taupō, and Hawea at or above their 90th percentiles.

Figure 19: Hydro storage



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 21 shows an estimate of thermal SRMCs as a monthly average up to 1 November. The SRMC for gas is similar to the previous month with only a small increase. Coal and diesel SRMC have also increased since the previous month.

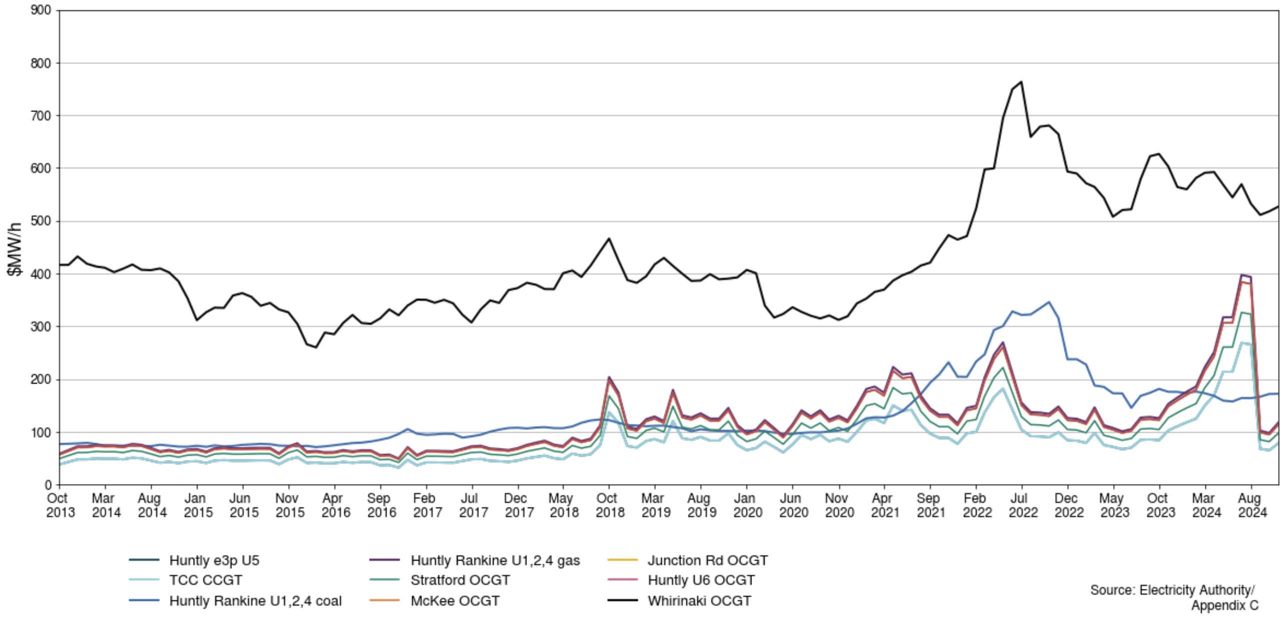
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$172/MWh with the cost of running the Rankines on gas remaining lower at ~$118/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $79/MWh and $118/MWh.

11.6. The SRMC of Whirinaki is ~$527/MWh.

11.7. More information on how the SRMC of thermal plants is calculated can be found in Appendix C.

Figure 20: Estimated monthly SRMC for thermal fuels

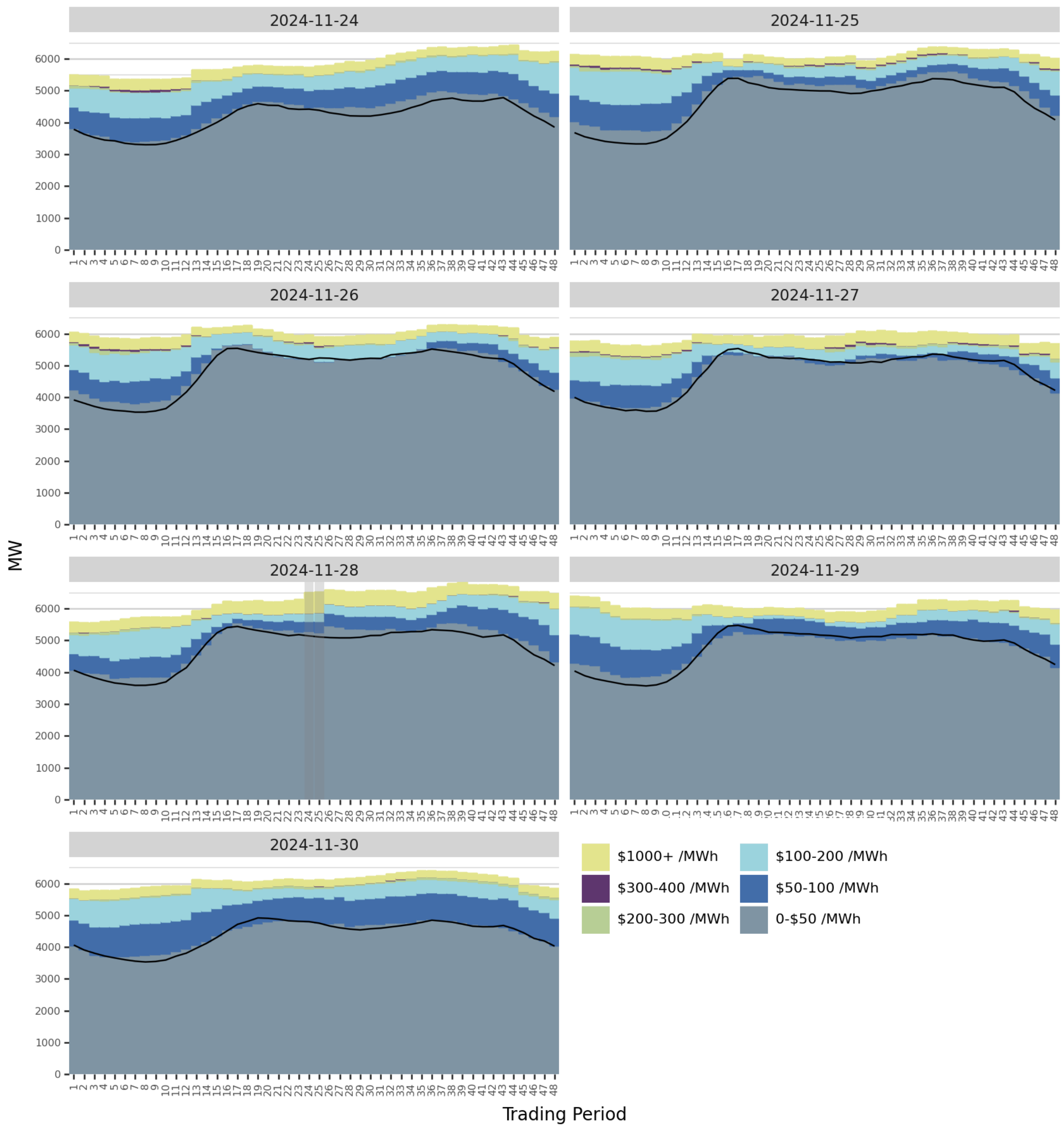


12. Offer behaviour

12.1. Figure 22 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 prices cleared under $100/MWh this week. The $50-$100/MWh offer band was thin on Wednesday, which led to price spikes when forecasting inaccuracies pushed prices up into the next band.

Figure 21: Daily offer stacks[2]



[2] PRSS data has been used for trading periods where RTD data was not available. These stacks will be highlighted within the offer stack and may be slightly higher than the adjusted offers.

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	Trading period	Status	Participant	Location	Enquiry topic
14/06/2023-15/06/2023	15-17/ 15-19	Passed to Compliance for advice	Genesis	Multiple	High energy prices associated with high energy offers
22/09/2023-30/09/2023	Several	Passed to Compliance for advice	Contact	Multiple	High hydro offers
3-4/09/2024 and 13-18/09/2024	Several	Further analysis	Contact Energy	Clutha scheme	Hydro offers