19 March 2025

Trading conduct report 9-15 March

Market monitoring weekly report

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1. Overview

1.1. Spot prices were mostly above $250/MWh due to hydro storage dropping to 64% nominally full, continued low inflows, increased thermal generation and forecasting inaccuracies.

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 9-15 March:

(a) The average spot price for the week was $297/MWh, an increase of around $28/MWh compared to the previous week.

(b) 95% of prices fell between $175/MWh and $410/MWh.

2.3. The average price is still above $250/MWh and prices frequently spiked above $400/MWh. This was due to:

(a) continued declining hydro storage

(b) continued low hydro inflows

(c) increased expensive thermal generation

(d) large wind forecast inaccuracies

(e) and demand forecast inaccuracies.

2.4. The highest price at Ōtāhuhu was $416/MWh at 6:30pm on Monday. Wind was low on Monday. Prices were also above $400/MWh at 8.30-9pm.

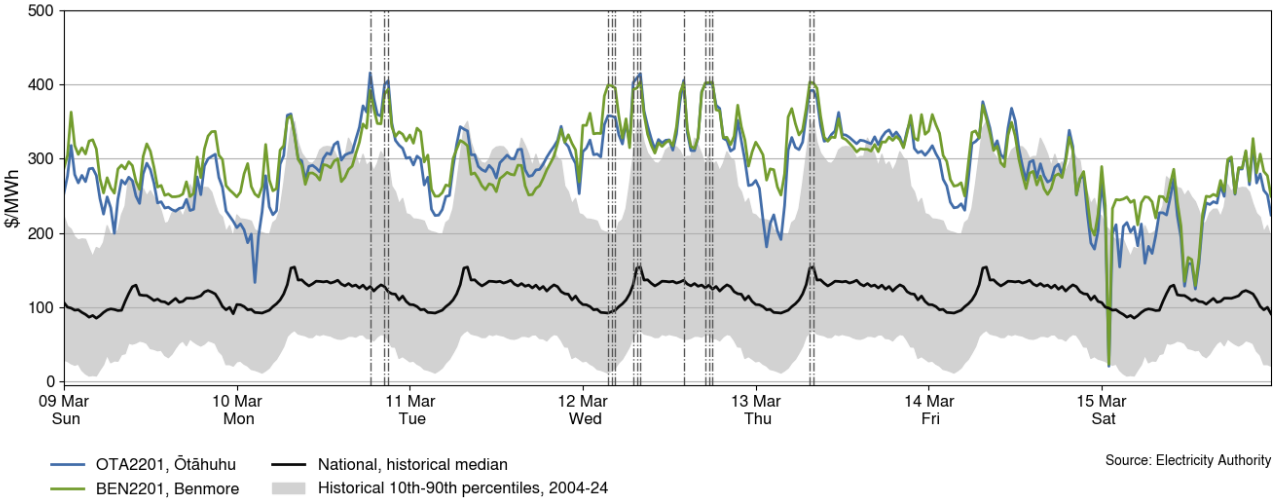
2.5. The highest price at any location was $2,809/MWh at 8pm on Tuesday at Brydone. This was due to line constraints in Southland.

2.6. Prices spiked close to or above $400/MWh often on Wednesday. All these higher prices occurred at times when demand was higher than forecast and/or wind was lower than forecast. The highest combined forecasting inaccuracy occurred at 3.30am when demand was 47MW higher than forecast and wind was 161MW higher than forecast at gate closure. Multiple hydro units also went on unplanned outages on Wednesday.

2.7. Prices were also above $400/MWh on Thursday between 7.30-8am. Demand was ~55MW higher than forecast at these times and wind was more than 30MW lower than forecasts at gate closure.

2.8. 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. Prices close to and above $400/MWh are marked with black dashed lines.

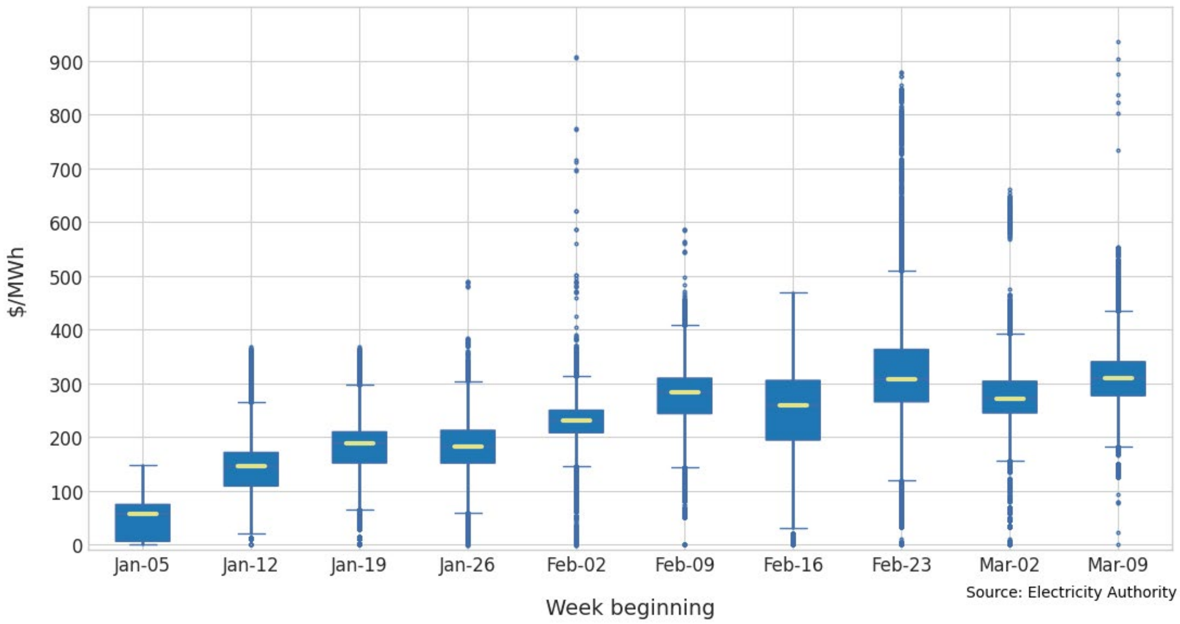
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 9-15 March



2.9. 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.

2.10. The distribution of spot prices this week was skewed slightly higher than last week. The median price was $309/MWh and most prices (middle 50%) fell between $277/MWh and $340/MWh.

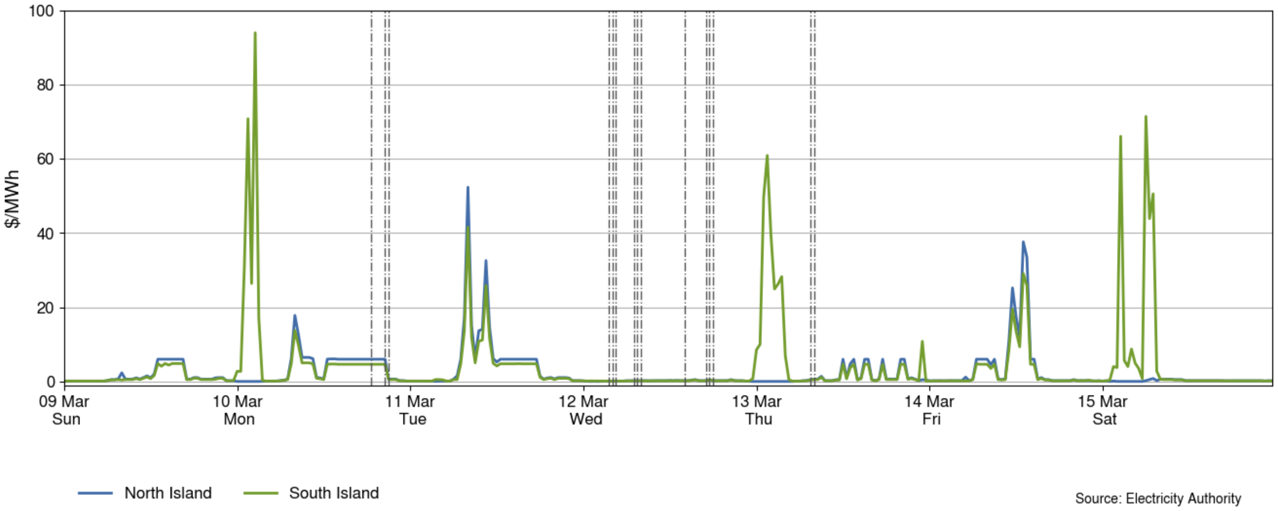
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

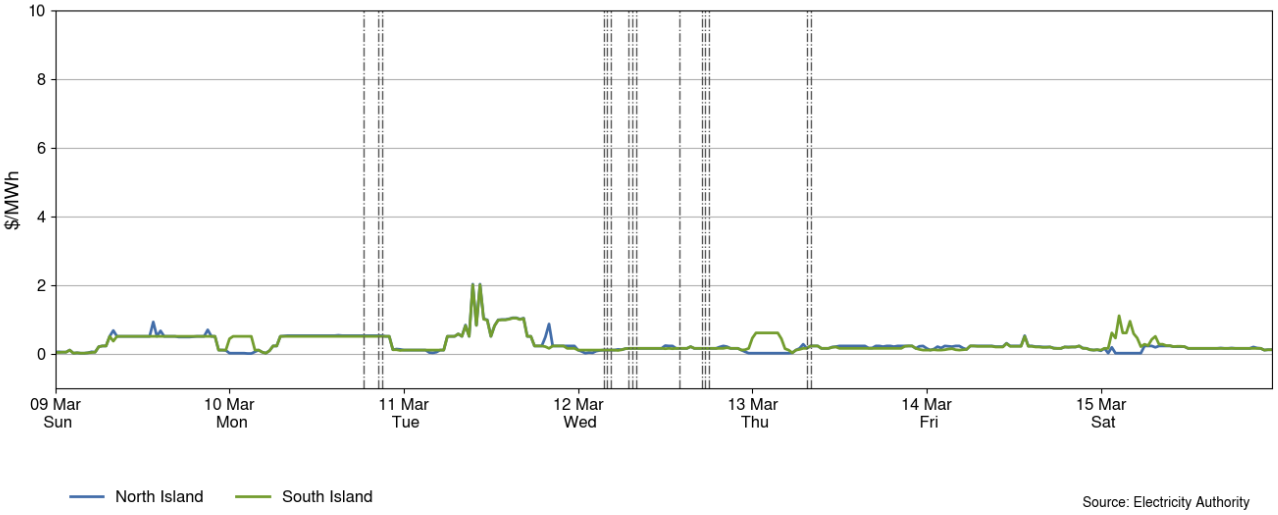
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $1/MWh but spiked to above $40/MWh in the South Island on Monday, Thursday and Saturday morning when the HVDC was flowing South and setting the South Island risk.

Figure 3: Fast instantaneous reserve price by trading period and island, 9-15 March



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $1/MWh and never got above $3/MWh.

Figure 4: Sustained instantaneous reserve by trading period and island, 9-15 March



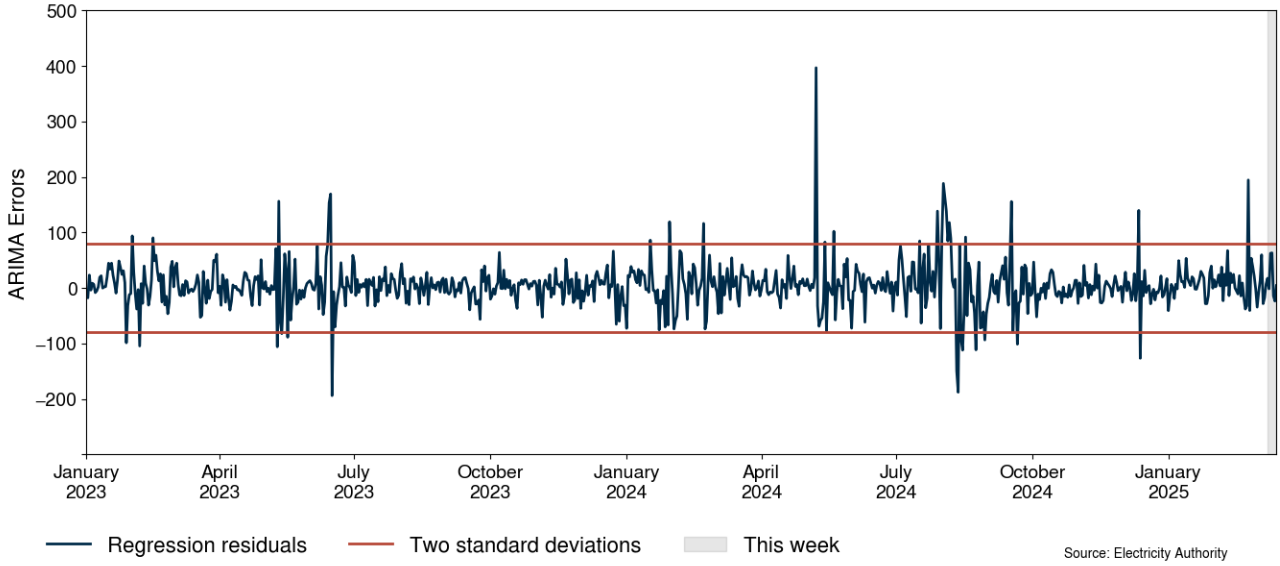
4. Regression residuals

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.

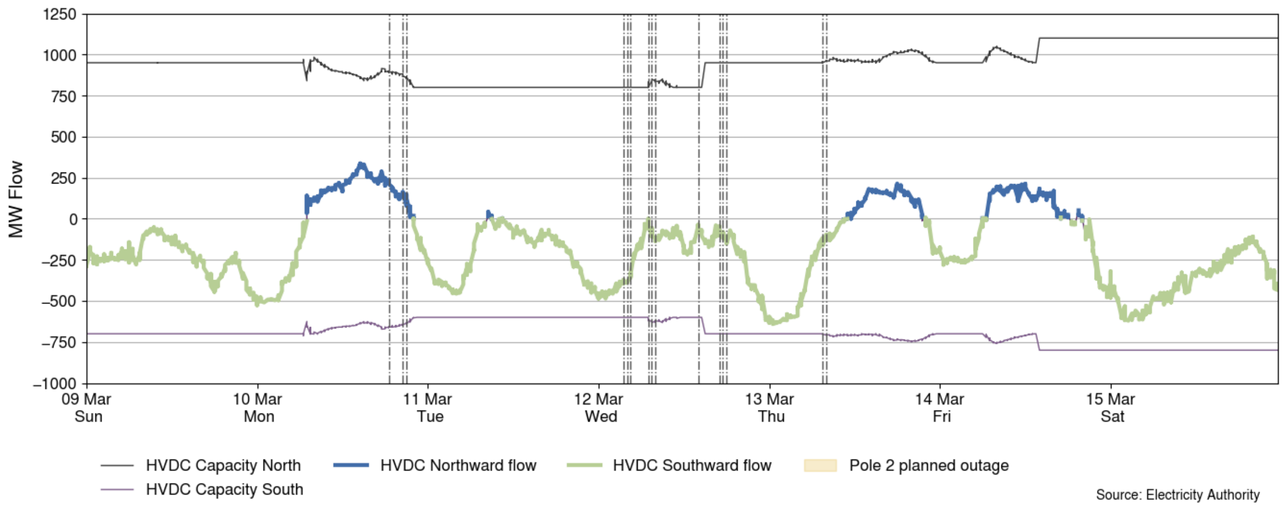
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 15 March 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 9-15 March. HVDC flows were mostly Northward on Monday, Thursday and Friday during days with lower wind, and Southward otherwise.

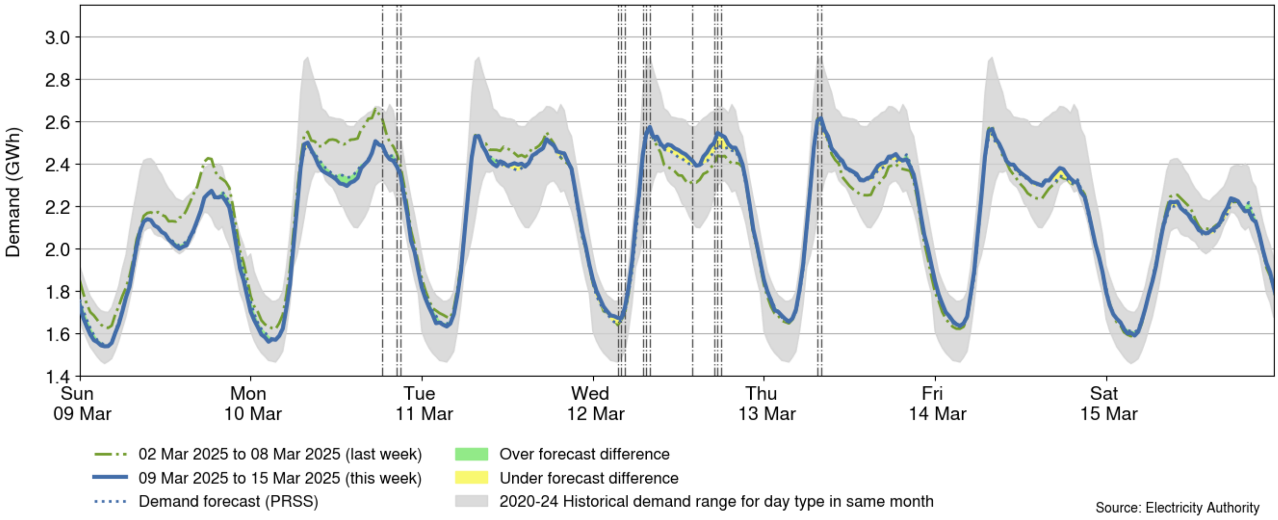
Figure 6: HVDC flow and capacity, 9-15 March



6. Demand

6.1. Figure 7 shows national demand between 9-15 March, compared to the historic range and the demand of the previous week. Demand was near the middle of the historic range this week. Demand was consistently higher than forecast on Wednesday and Friday afternoon.

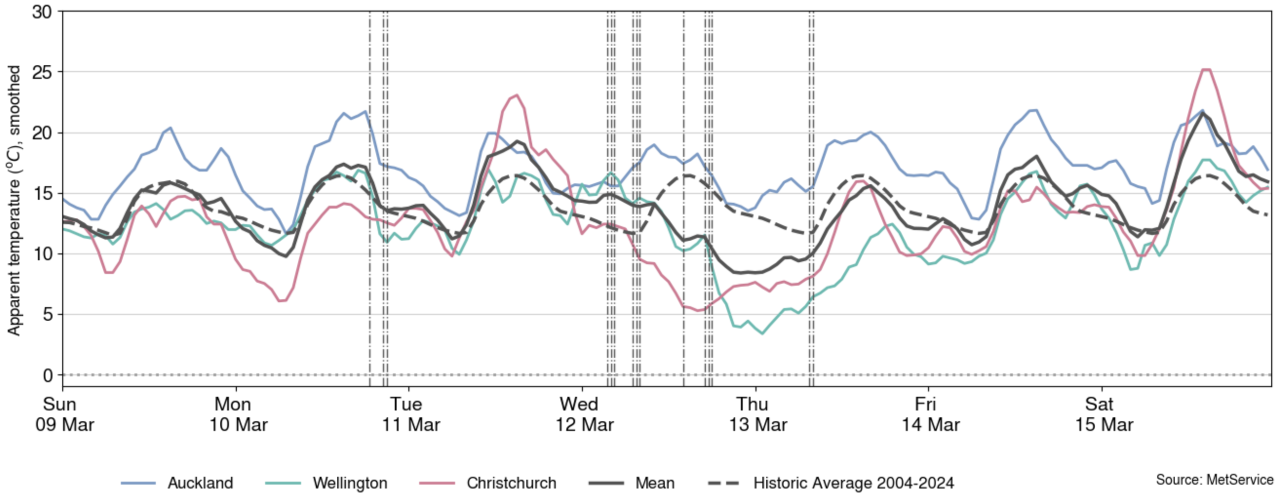
Figure 7: National demand, 9-15 March compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 9-15 March. 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. Apparent temperatures ranged from 11°C to 22°C in Auckland, 3°C to 19°C in Wellington, and 5°C to 26°C in Christchurch. Apparent temperatures were below average on Wednesday.

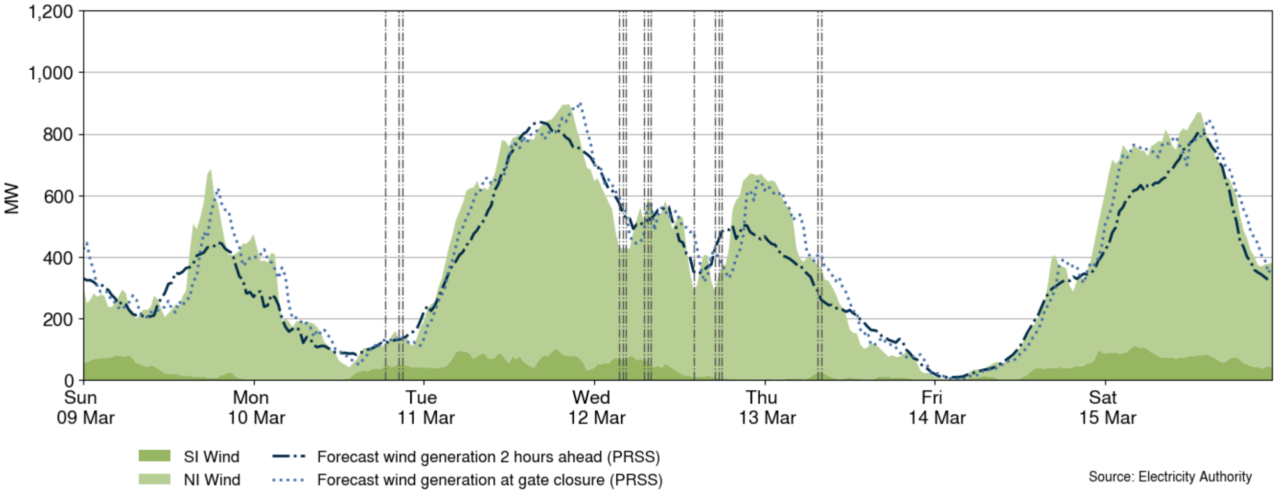
Figure 8: Temperatures across main centres, 9-15 March



7. Generation

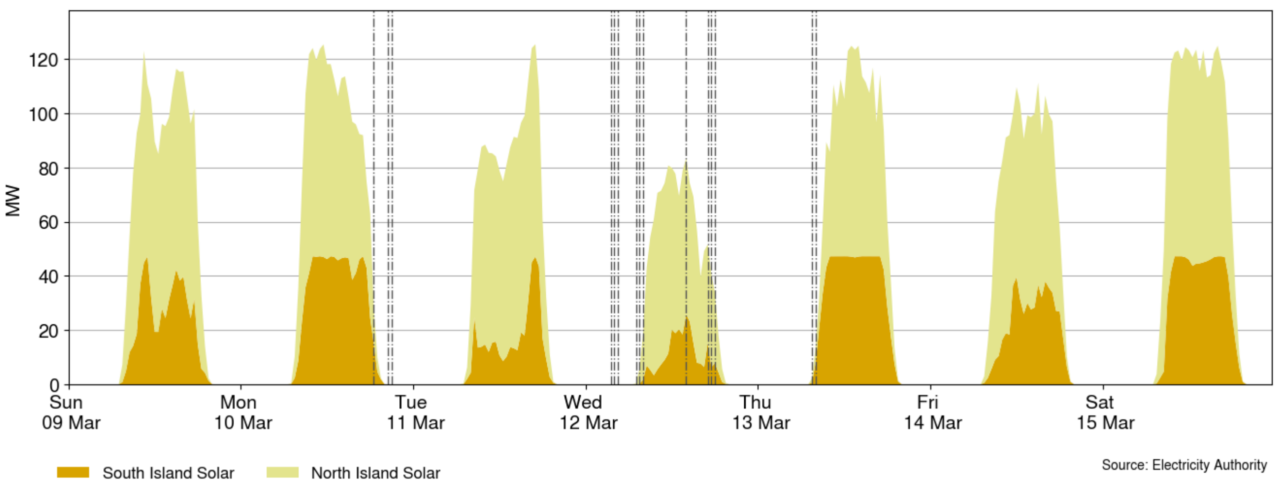
7.1. Figure 9 shows wind generation and forecast from 9-15 March. This week wind generation varied between 2MW and 896MW, with a weekly average of 400MW. Wind generation was low on Monday, Thursday and Friday, but high on Tuesday and Saturday. There were several large wind forecasting errors on Wednesday that contributed to higher prices.

Figure 9: Wind generation and forecast, 9-15 March



7.2. Figure 10 shows grid connected solar generation from 9-15 March. Solar generation was low on Wednesday. Solar reached a maximum of 125MW on Tuesday at 5pm.

Figure 10: Grid connected solar generation, 9-15 March



7.3. 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 here 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

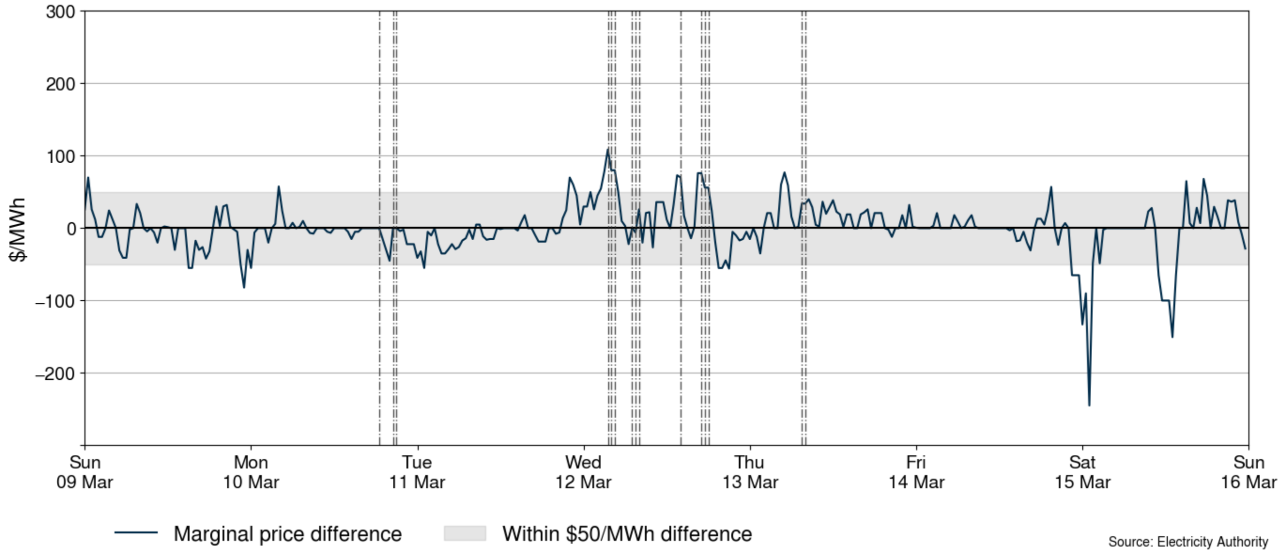
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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.

7.4. The largest positive marginal price difference was +$109/MWh at 3.30am on Wednesday during the highest combined forecast inaccuracy described in paragraph 2.7.

7.5. The largest negative marginal price difference was -$245/MWh at 1am on Saturday. Wind was ~150MW higher than forecast at gate closure at this time.

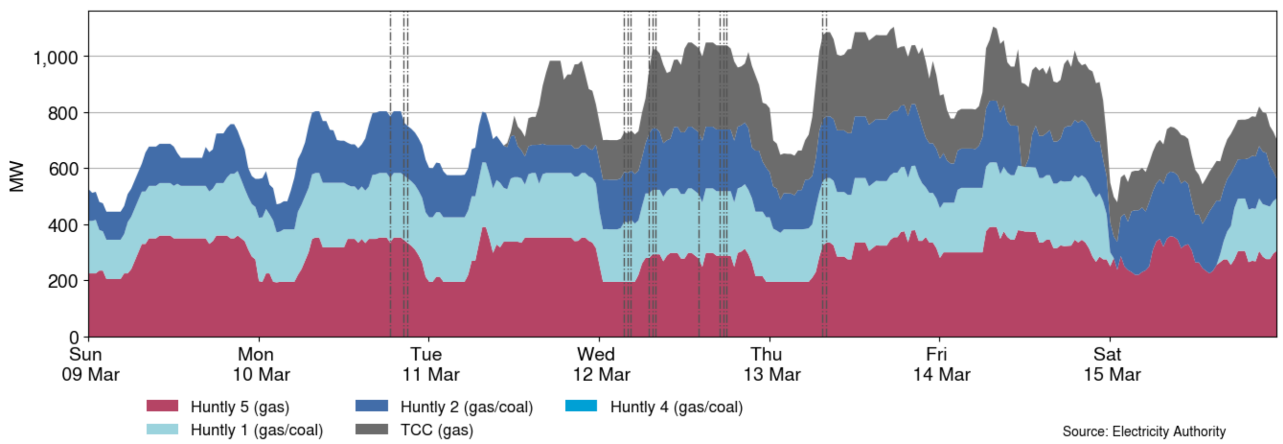
Figure 11: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead wind and demand forecast inaccuracies, 9-15 March



7.6. Figure 12 shows the generation of thermal baseload between 9-15 March. Huntly 5, Huntly 1 and Huntly 2 generated every day. Huntly 1 did not generate on Saturday morning when wind was high. Huntly generation tripped at 11.18am on Friday, causing Huntly 2 generation to cut out until around 12.30pm.

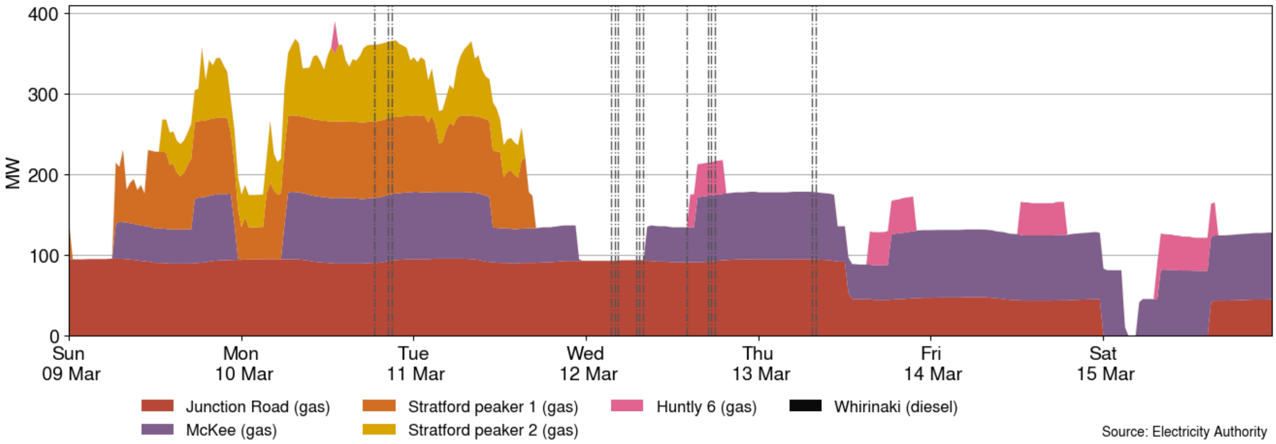
7.7. TCC began generating for the first time this year on Tuesday after coming off outage Monday.

Figure 12: Thermal baseload generation, 9-15 March



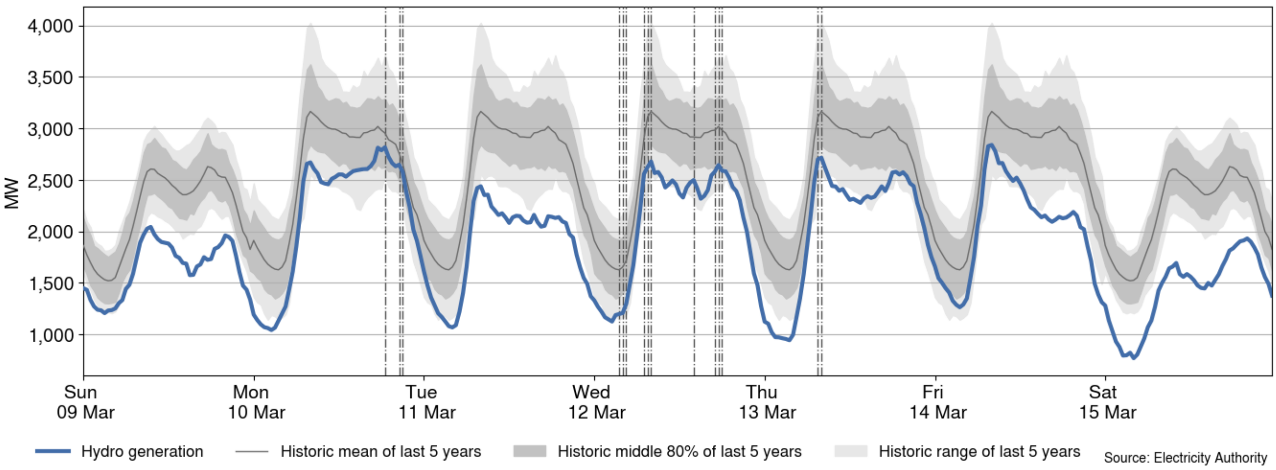
7.8. Figure 13 shows the generation of thermal peaker plants between 9-15 March. Junction Road and McKee generated every day. The Stratford Peakers generated Sunday to Tuesday. Huntly 6 also generated several periods throughout the week.

Figure 13: Thermal peaker generation, 9-15 March



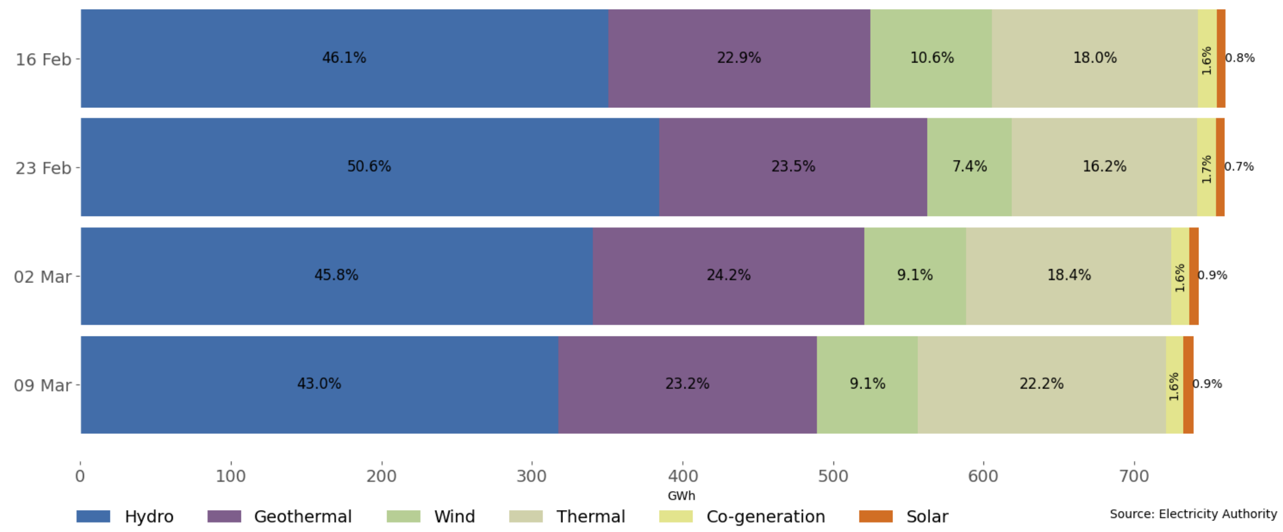
7.9. Figure 14 shows hydro generation between 9-15 March. Hydro generation was very low on Tuesday and Saturday when wind was high. Hydro generation was above its historic 10th percentile during the higher prices on Monday evening.

Figure 14: Hydro generation, 9-15 March



7.10. As a percentage of total generation, between 9-15 March, total weekly hydro generation was 43.0%, geothermal 23.2%, wind 9.1%, thermal 22.2%, co-generation 1.6%, and solar (grid connected) 0.9%, as shown in Figure 15. Thermal generation increased while hydro generation decreased.

Figure 15: Total generation by type as a percentage each week, between 16 February and 15 March



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 9-15 March ranged between ~1,058MW and ~2,118MW. There were increased geothermal outages from Monday to Wednesday that likely increased prices. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) TCC was on outage until 10 March.

(b) Huntly 4 is on outage until 16 March (previously 20 March).

(c) Whirinaki was on outage 11-12 March.

(d) Huntly 5 was on partial outage 10-11 March.

(e) Nga Awa Pūrua was on outage 10-12 March.

(f) Manapōuri unit 4 is on outage until 12 December.

(g) Manapōuri unit 5 is on outage until 18 March (previously 21 March).

(h) Manapōuri unit 2 was on outage until 9 March.

(i) Clyde unit 1 is on outage until 23 May.

(j) Stratford Peaker 2 was on a short notice outage 12-13 March.

Figure 16: Total MW loss from generation outages, 9-15 March

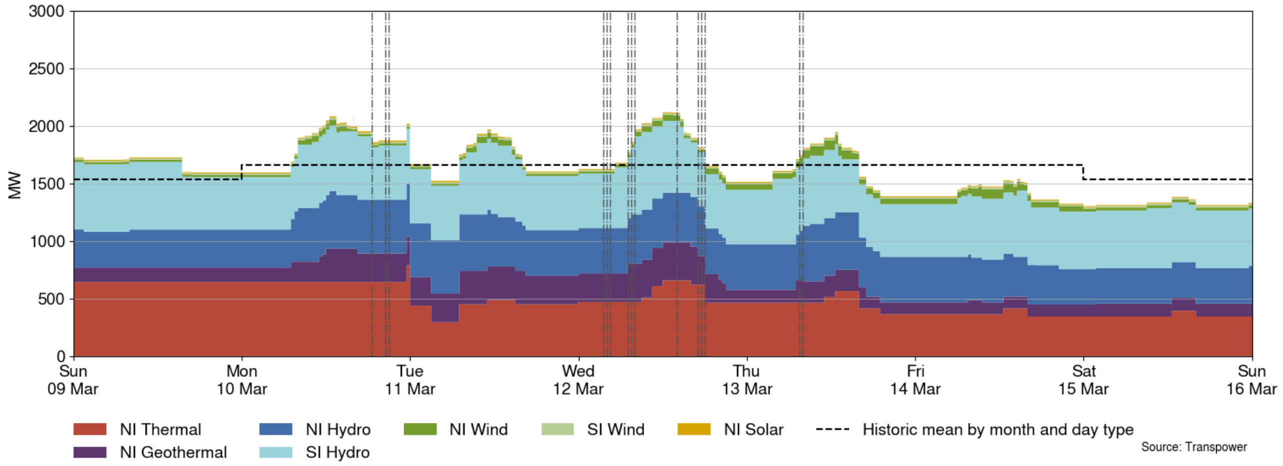
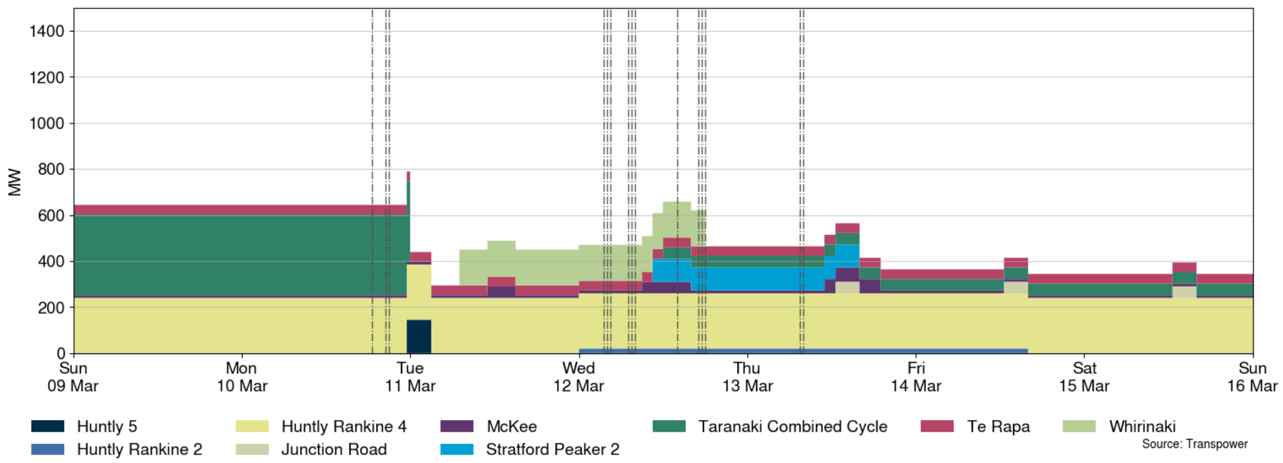


Figure 17: Total MW loss from thermal outages, 9-15 March

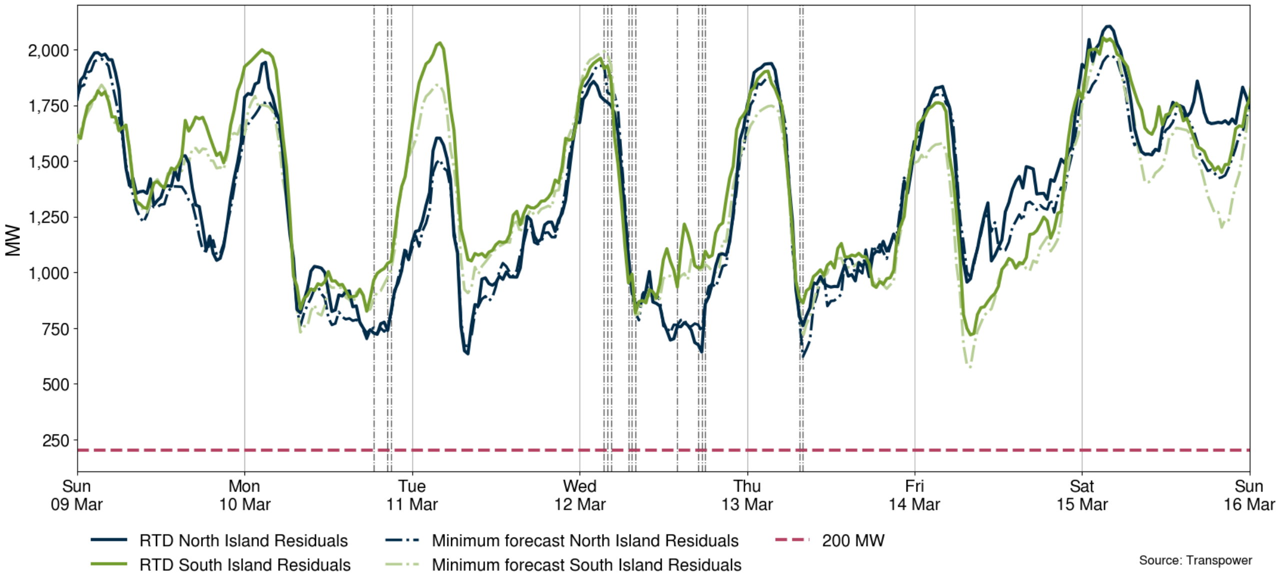


9. Generation balance residuals

9.1. Figure 18 shows the North Island and South Island generation balance residuals between 9-15 March. 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. North Island residuals reached a minimum of 634MW at 8am on Tuesday.

Figure 18: National generation balance residuals, 9-15 March



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 to 64% nominally full and ~79% of the historical average for this time of the year.

10.3. Lake Pūkaki (61% full[2]) has decreased and is still below its historical 10th percentile.

10.4. Lake Takapō (66% full) has decreased and is still around its historic 10th percentile.

10.5. Lake Hawea (72% full) has decreased and is still between its historical mean and 10th percentile.

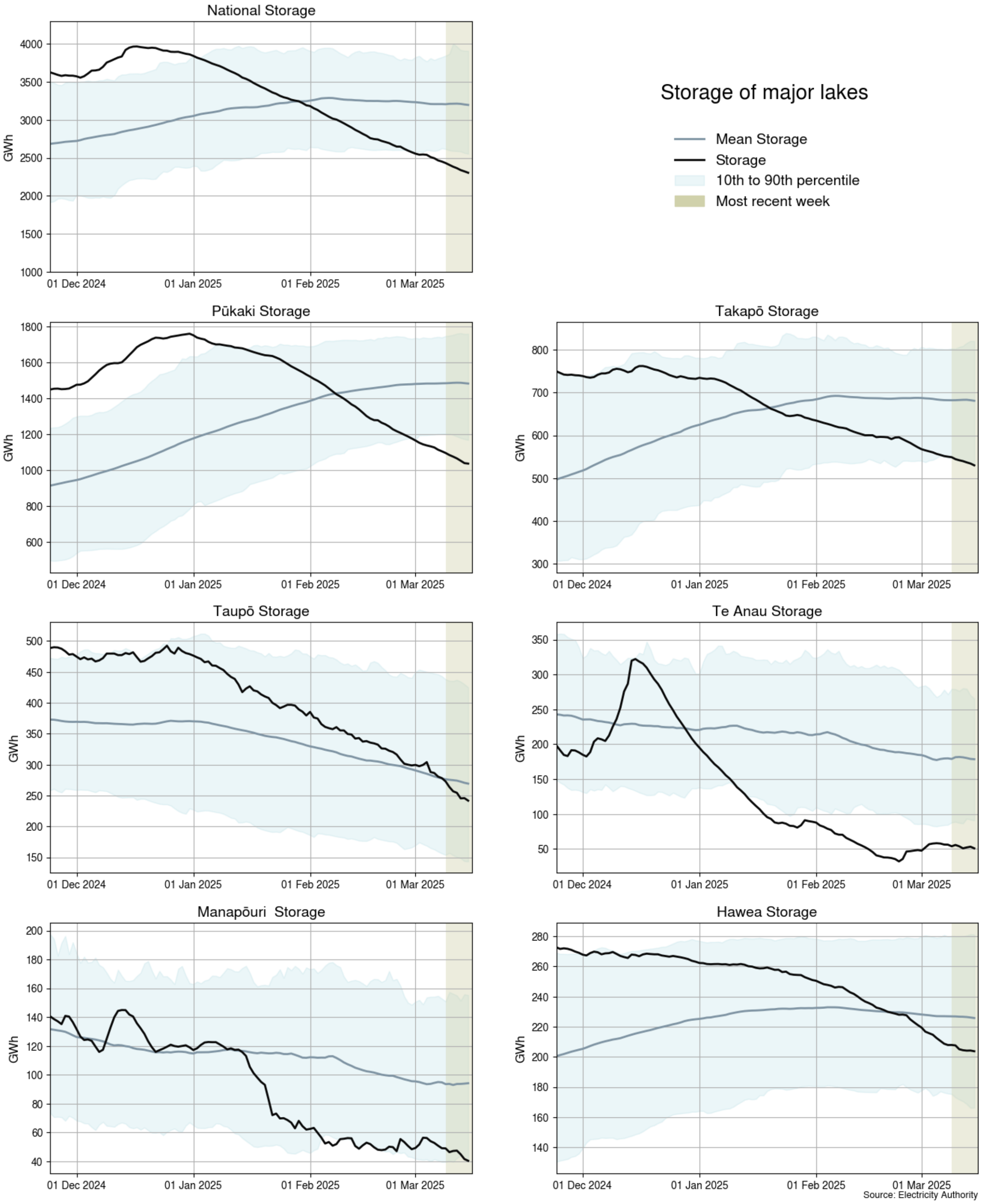
10.6. Lake Taupō (42% full) decreased to between its historical mean and 10th percentile.

10.7. Lake Te Anau has fluctuated below its historical 10th percentile.

10.8. Lake Manapōuri has decreased to around its historical 10th percentile.

[2] Percentage full values sourced from NZX Hydro.

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 20 shows an estimate of thermal SRMCs as a monthly average up to 1 March. The SRMC for gas fuelled generation has increased compared to last month. The SRMC for coal and diesel fuelled generation remains similar.

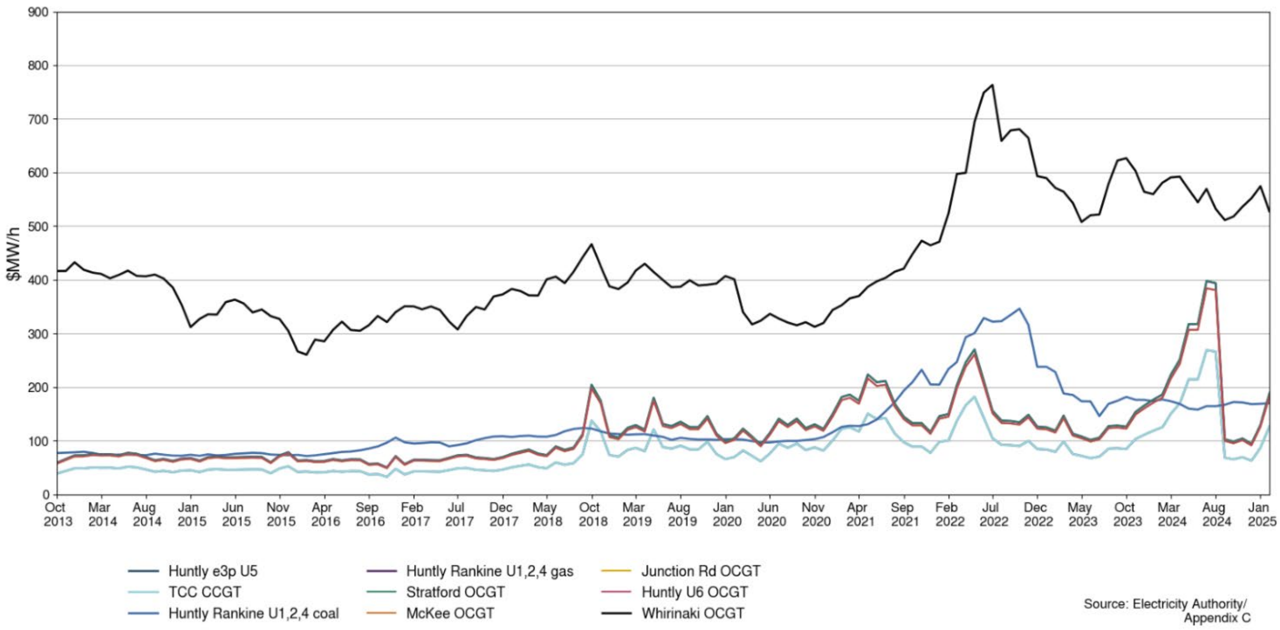
11.4. The latest SRMC of coal-fuelled Rankine generation is still ~$170/MWh, with the cost of running the Rankines on gas now more expensive at ~$224/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $150/MWh and $224/MWh.

11.6. The SRMC of Whirinaki is still ~$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

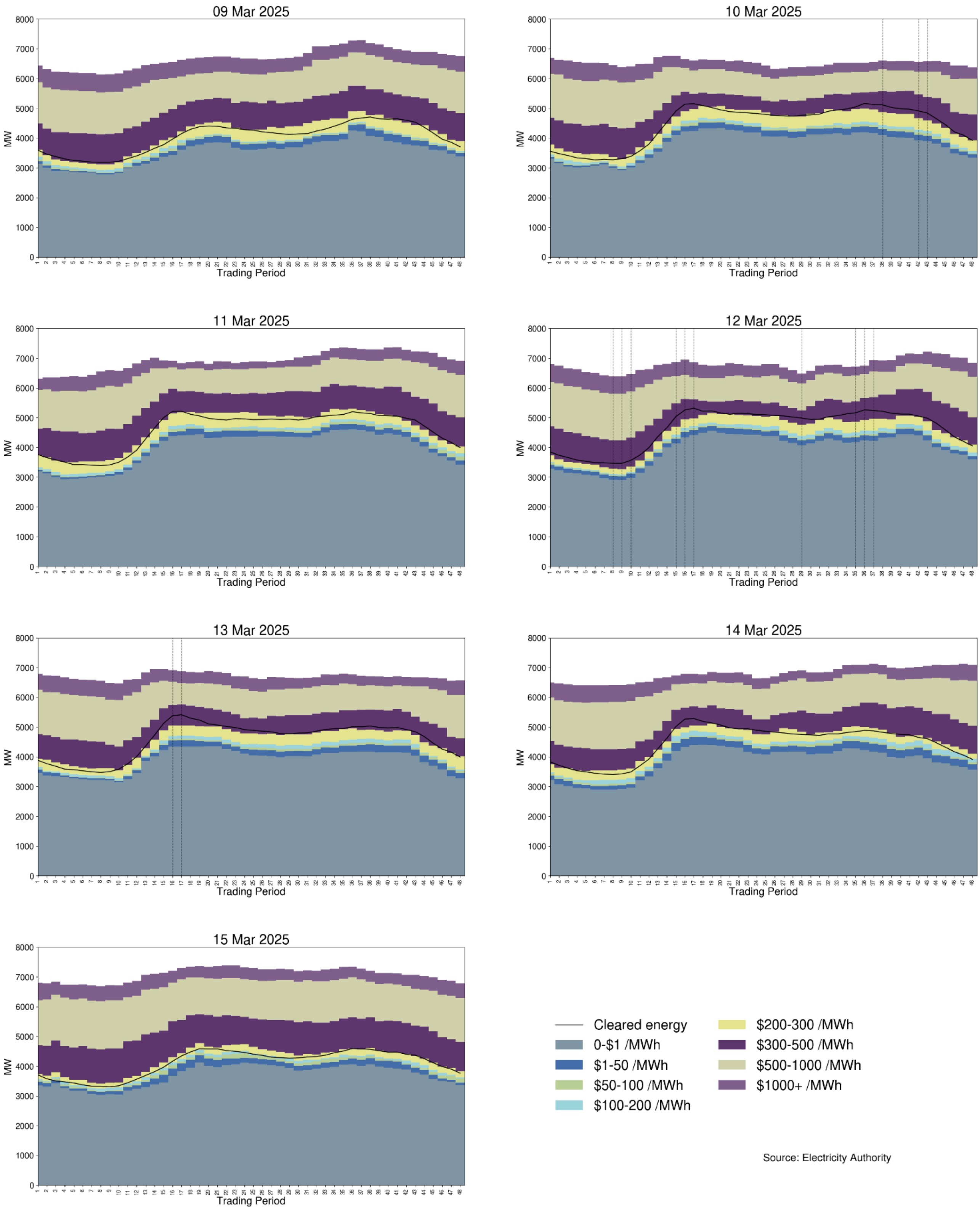


12. Offer behaviour

12.1. Figure 21 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 were clearing in the $200-300/MWh or $300-500/MWh bands this week.

Figure 21: Daily offer stacks



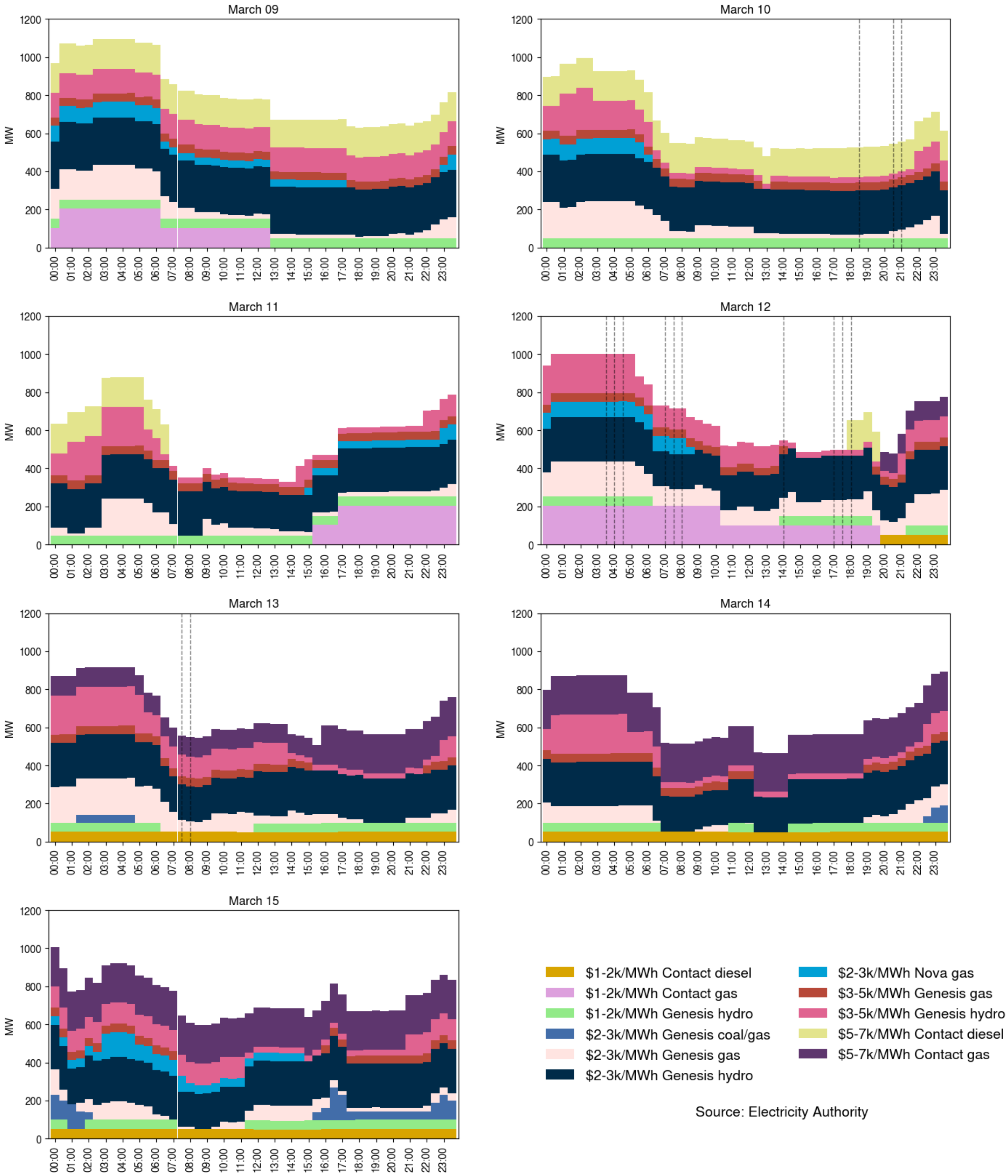
Source: Electricity Authority

12.3. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion these offers are fast start thermal operators.

12.4. If forecast prices are lower than thermal operating costs, this signals some generators may not be needed in that half-hourly trading period. Thermal generators may then price their units high, as they aren't expecting to run. These high prices reflect increased operating costs of running for only a short time. So, if demand is unexpectedly high, wind generation dips, or other generation fails, these high-priced thermal generators may get dispatched, sometimes resulting in a high spot price.

12.5. On average 690MW per trading period was priced above $1,000/MWh this week, which is roughly 12% of the total energy available. The monitoring team will be looking further into Stratford offers priced above $5000/MWh this week.

Figure 22: High priced offers



Source: Electricity Authority

13. Ongoing work in trading conduct

13.1. This week prices generally appeared to be consistent with supply and demand conditions, however, the monitoring team will be enquiring further regarding Contact's offers at Stratford and along the Clutha scheme.

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	Back with monitoring for analysis	Genesis	Multiple	High energy prices associated with high energy offers
22/09/2023-30/09/2023	Several	Back with monitoring for analysis	Contact	Multiple	High hydro offers
3-4/09/2024 and 13-18/09/2024	Several	Further analysis	Contact	Clutha scheme	Hydro offers
21/02/2025	16	Further analysis	Contact	Stratford	Thermal offer
23/02/2025-1/03/2025	Several	Further analysis	Contact	Stratford	Stratford offers
5/03/2024	23-32	Further analysis	Contact	Stratford	Stratford offers
9/03/2025-16/09/2024	Several	Further analysis	Contact	Multiple	Offers