Trading Conduct Report

Market Monitoring Weekly Report

15 September 2021

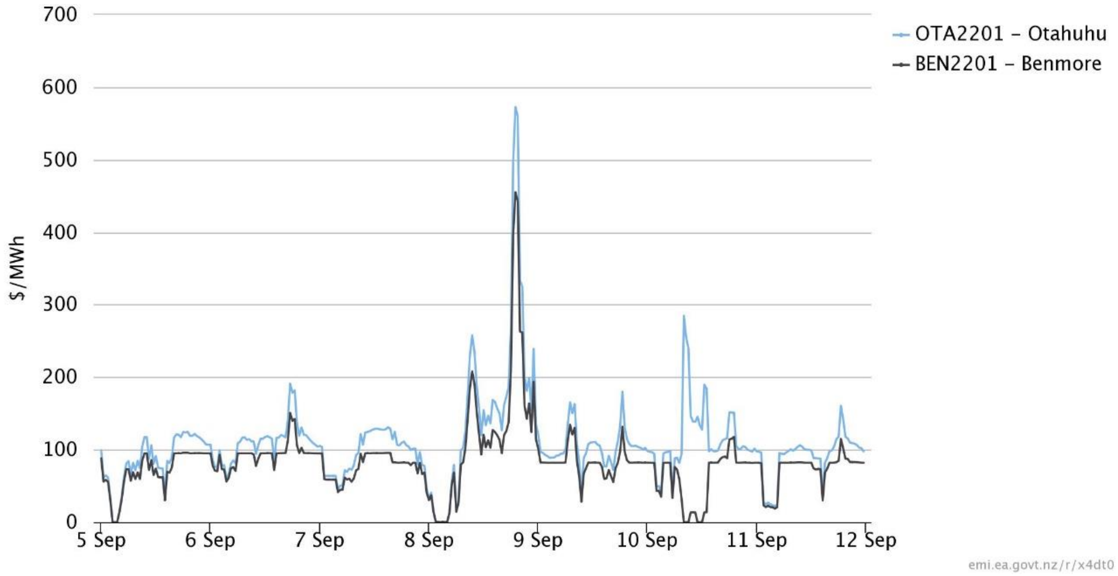
1 Overview for the week of 5 to 11 September

1.1 Prices this week appeared to be consistent with underlying supply and demand conditions. High prices on 8 September were due to high demand.

2 Prices

Energy prices

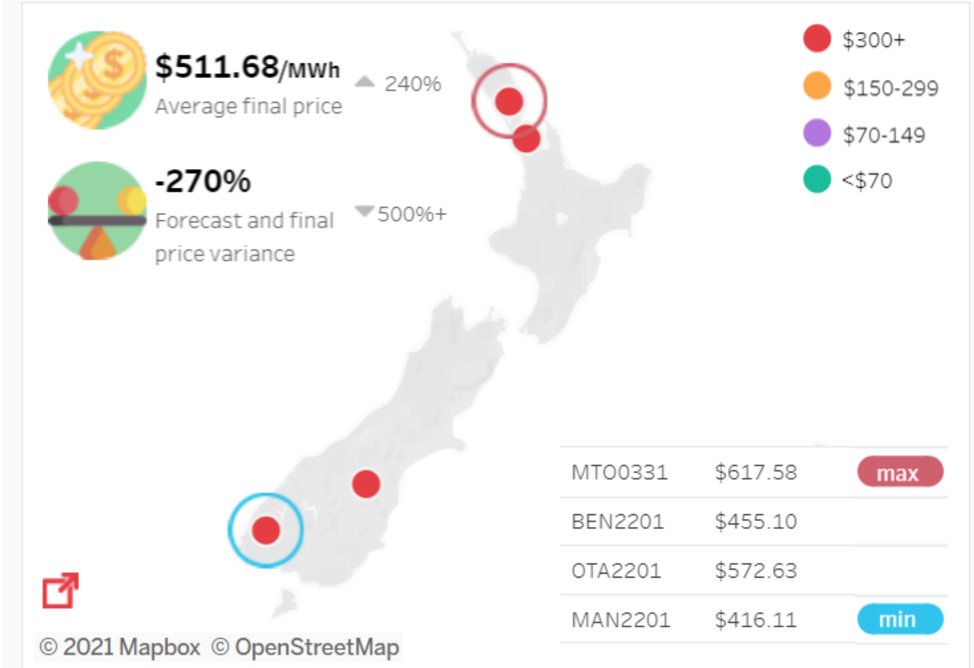
Figure 1: Spot prices by trading period at Otahuhu and Benmore



2.1 Average spot price this week was $96/MWh[1], about 10% higher than the previous week. For most of the week prices were around $100/MWh (see figure 1), with overnight prices sometimes falling to $0/MWh. The highest price occurred on TP 39 on 8 September when prices reached $573/MWh at Otahuhu (see figure 2). There was also price separation on 10 September, due to an HVDC outage.

[1] The simple average of the final price across all nodes, as shown in the trading conduct summary dashboard

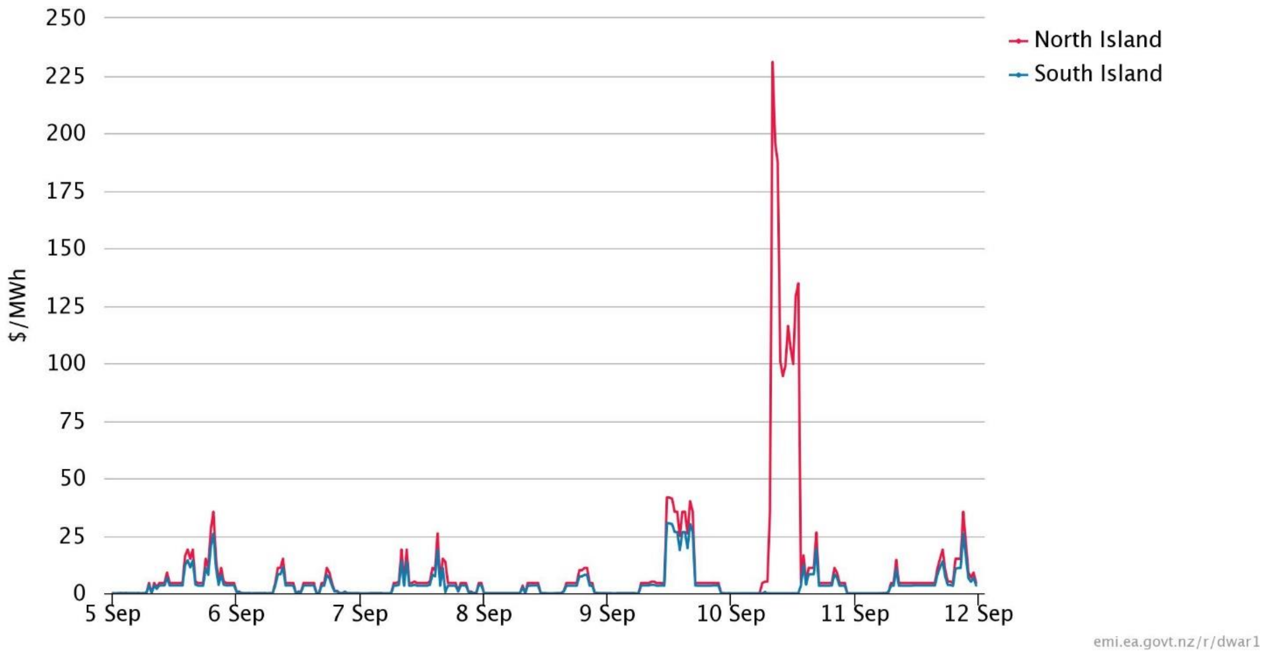
Figure 2: Spot prices for TP 39 on 8 September compared to previous week



Reserve Prices

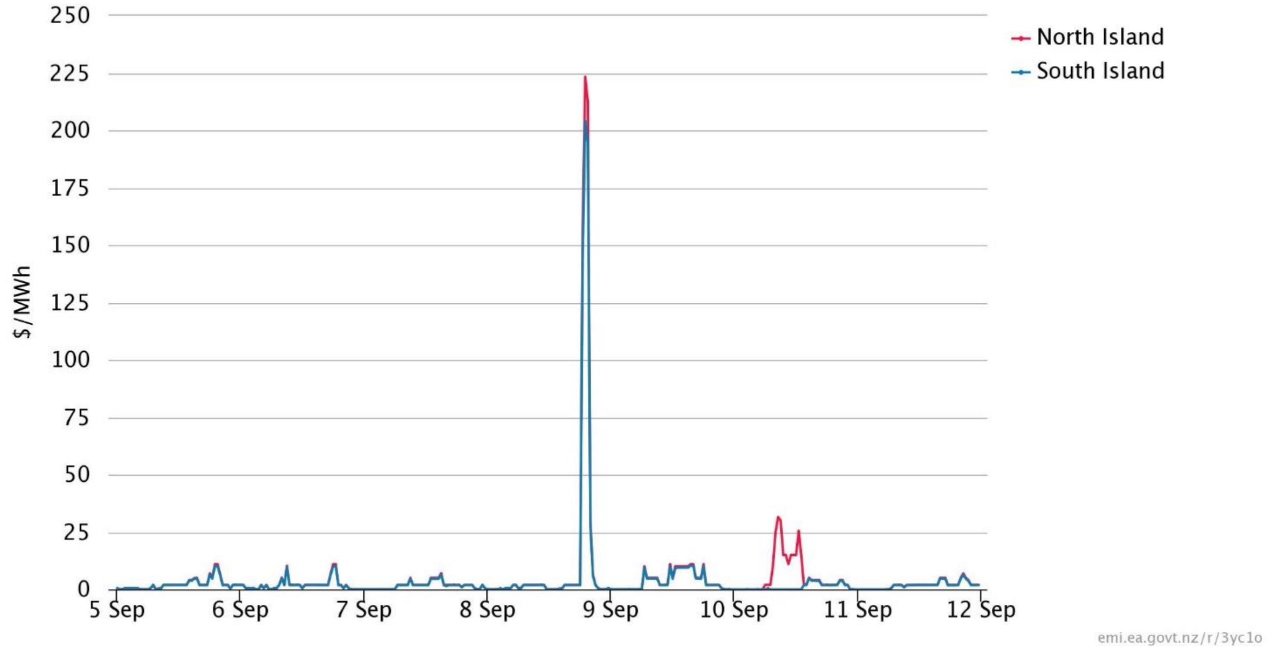
2.2 The prices for fast instantaneous reserves (FIR), shown in Figure 3, were low most of the week, except during the HVDC outage when the North Island price for FIR reached up to $225/MWh. The HVDC outage prevented reserve sharing and increased demand for North Island generation, which both increased demand for North Island FIR resulting in higher prices.

Figure 3: FIR prices by trading period by Island



2.3 The prices for sustained instantaneous reserves (SIR), shown in Figure 4, were below $20/MWh for most of the week. High SIR prices did occur on 8 September, reaching over $200/MWh. This occurred during a period of high demand when generation capacity was tight.

Figure 4: SIR prices by trading period by Island

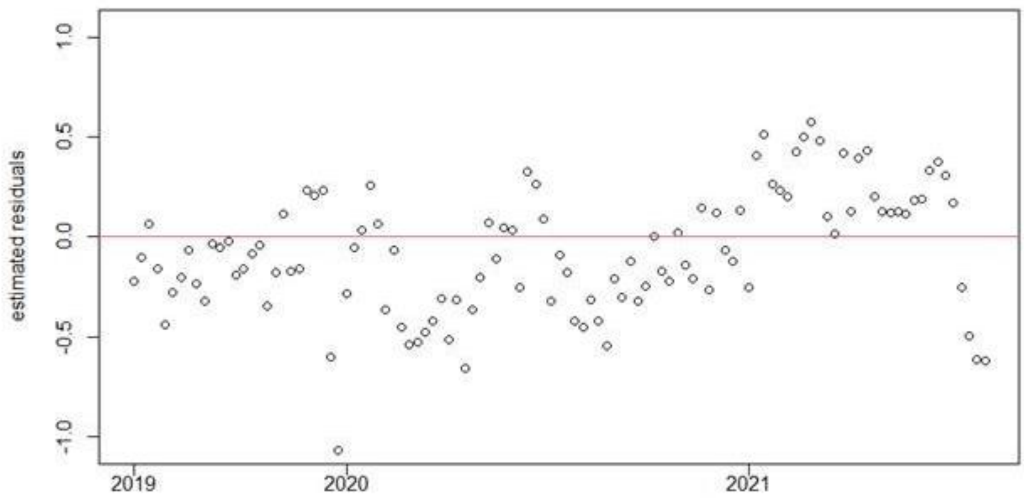


Residuals from regression models

2.4 The Authority's monitoring team has developed two regression models of the 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.

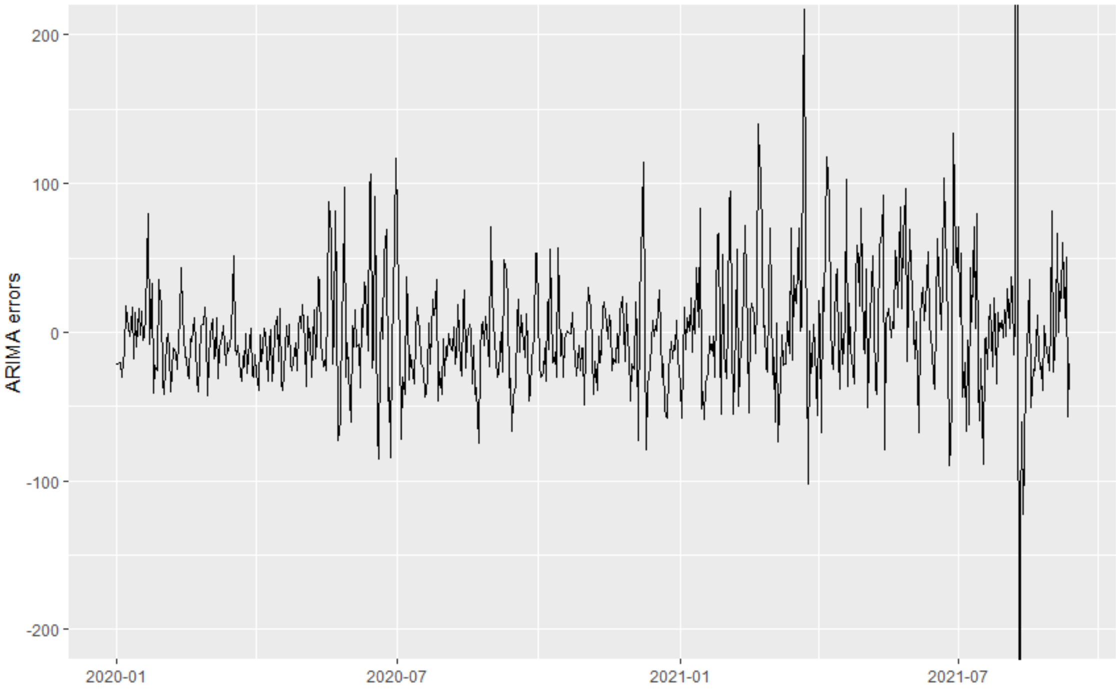
2.5 Figure 5 shows the residuals from the weekly model. During July 2021 the residuals were within the normal range, indicating that weekly prices were close to the model's predictions.

Figure 5: Residual plot of estimated weekly price from 2 July 2019 to 29 July 2021



2.6 Figure 6 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. This week the daily residuals were within the normal range. The residuals for 8 September were quite small, indicating the high prices that day reflected underlying supply and demand conditions.

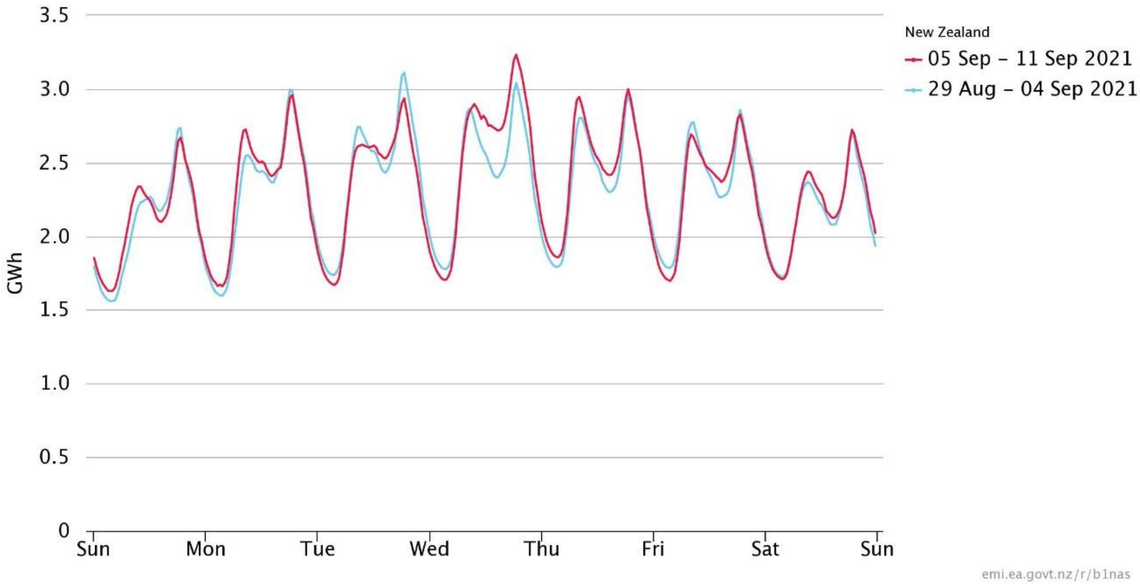
Figure 6: Residual plot of estimated daily average spot price from 1 July 2020 to 21 August 2021



3 Demand Conditions

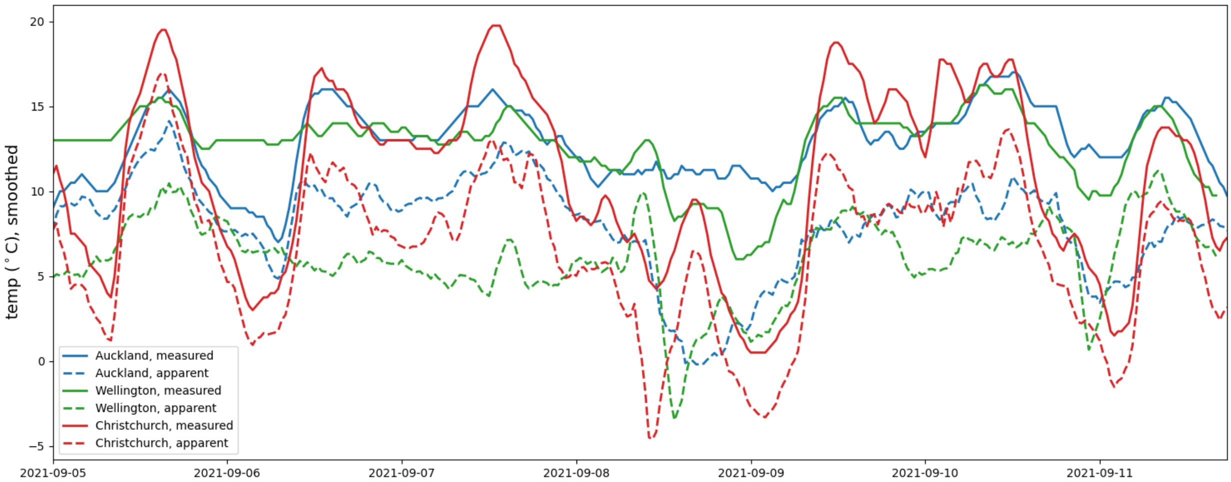
3.1 Demand was 1% higher last week, as the move for most of New Zealand (excluding Auckland) to Covid19 alert level 2 had a smaller impact on demand compared to the move to alert level 3. Demand was particularly high on Wednesday evening when a Southerly front brought cold weather to most of the country. There was an increase in demand on Thursday morning, which may have been due to schools reopening on Thursday as well as cold weather.

Figure 7: National demand compared to previous week



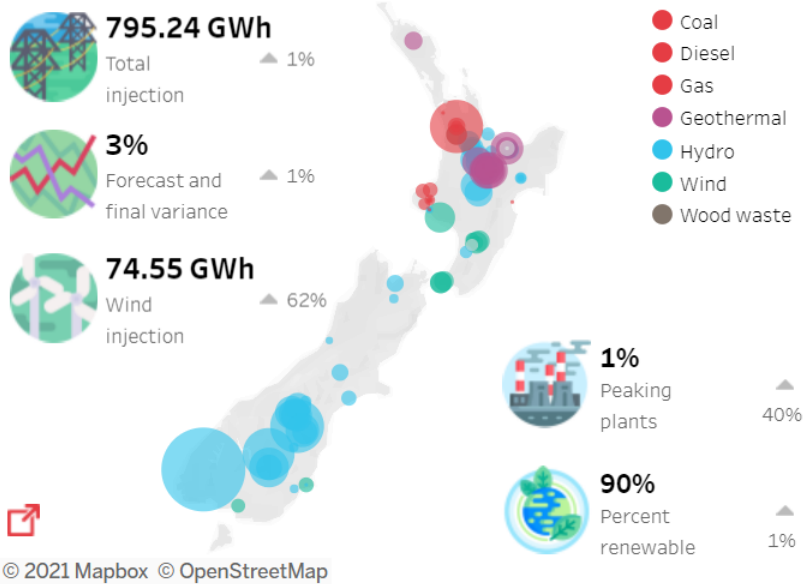
3.2 Figure 8 shows the hourly temperature data at main population centres. The measured temperature is the recorded temperature at each location, while the apparent temperature adjusts for factors, such as wind speed and humidity, to estimate how cold it feels. The apparent temperatures were very cold on 8 September, falling to or below 0°C in all the main centres.

Figure 8: Hourly temperature data at main population centres



4 Supply Conditions

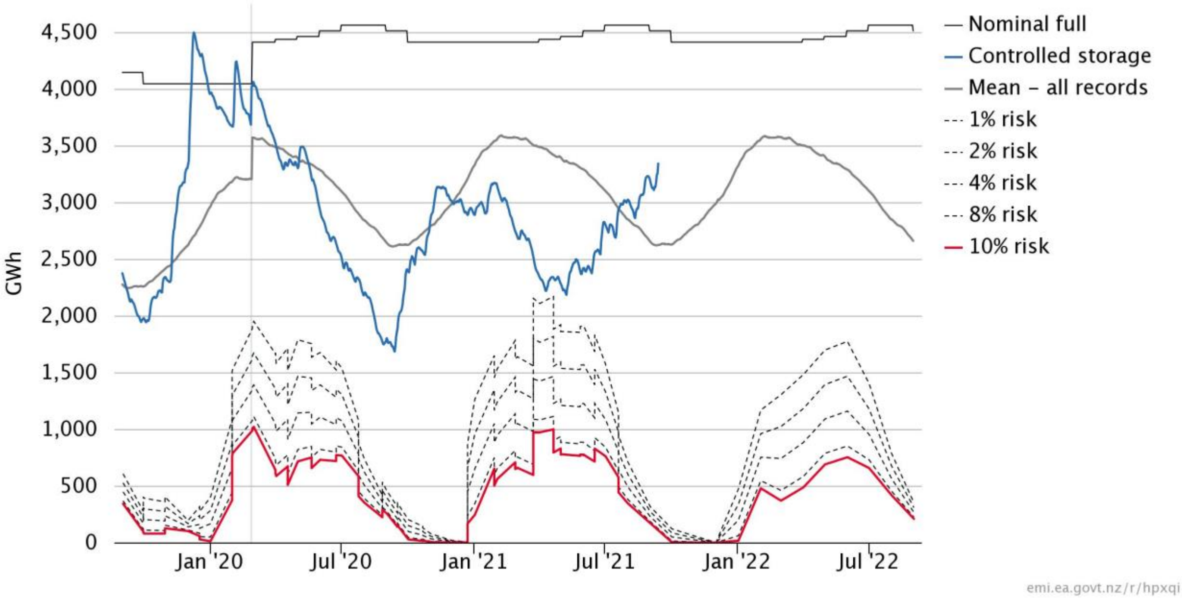
Figure 9: Generation in the last week compared previous week



Hydro conditions

4.1 This week national hydro storage increased to 67% of nominal full.

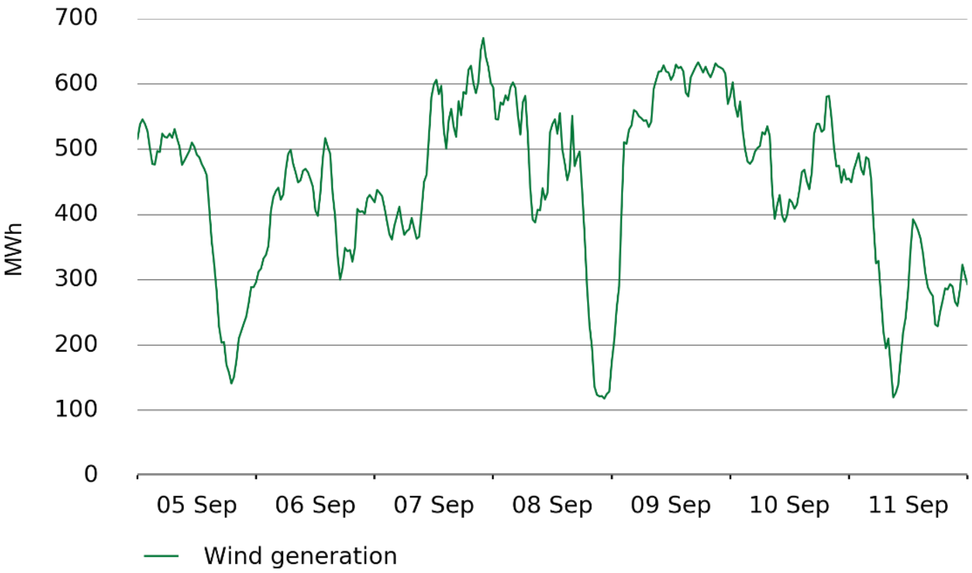
Figure 10: Electricity risk curves and current hydro supply



Wind conditions

4.2 Total wind generation was 75GWh, 62% higher than last week. However, on 8 September when demand was highest there was a steep drop in wind generation from 500MW at 5pm to 120MW by 10pm (see Figure 11). This contributed to the high prices on the evening of 8 September.

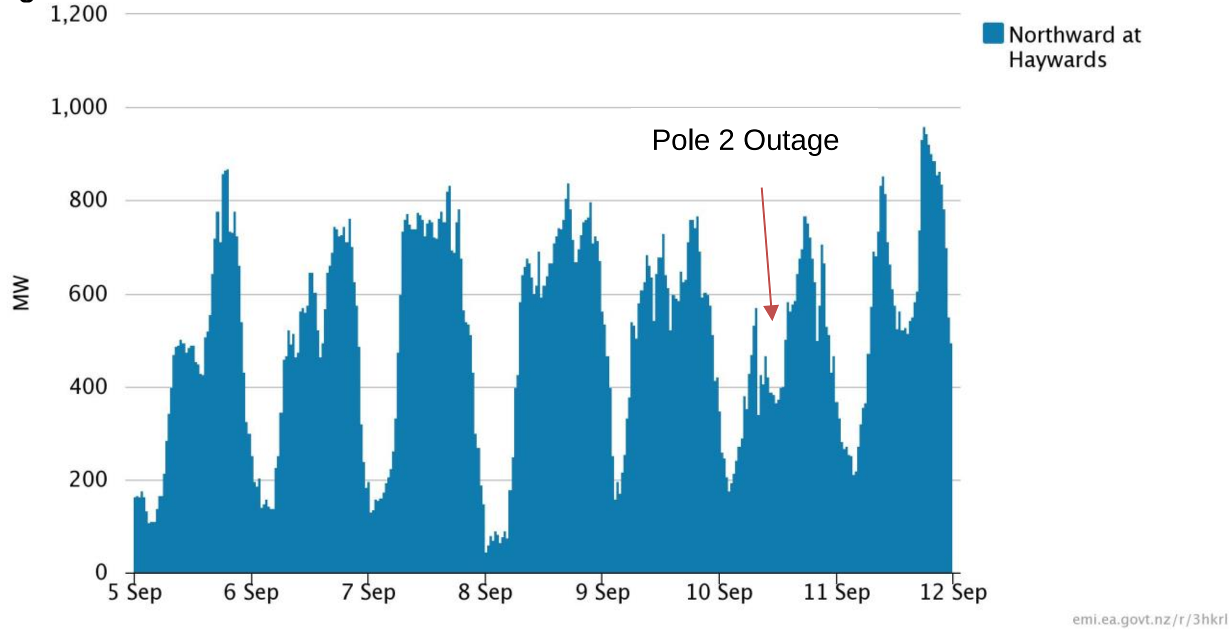
Figure 11: Wind generation for the week



HVDC outage

4.3 This week there was another outage of HVDC pole 2 on 10 September, believed to be caused by high winds driving the conductor too close to a tower. At 6:56am Transpower reduced capacity of pole 2 to 300MW, but from 7:33am until 1pm pole 2 was on full outage, which prevented round power and reserve sharing. The outage caused price separation between the North and South Island, with prices highest at Otahuhu at 8am, shortly after the full outage began.

Figure 12: HVDC transfer

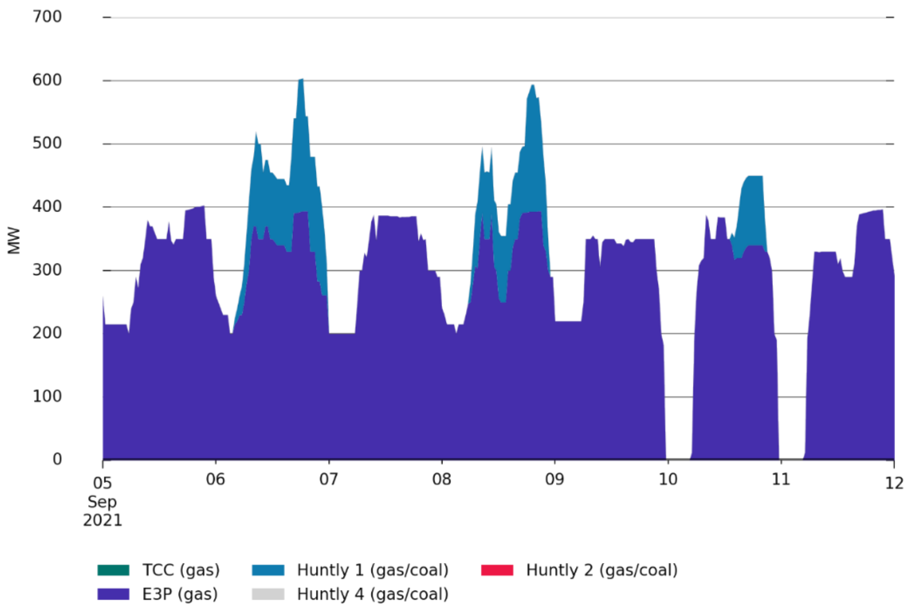


Thermal conditions

4.4 Baseload thermal generation remains low with only Huntly's E3P running as baseload the whole week. This reflects an overall decrease in demand for thermal generation as hydro storage increases and demand drops. However, thermal generation is still needed during cold spells such as seen on 8 September when demand is high and wind generation low.

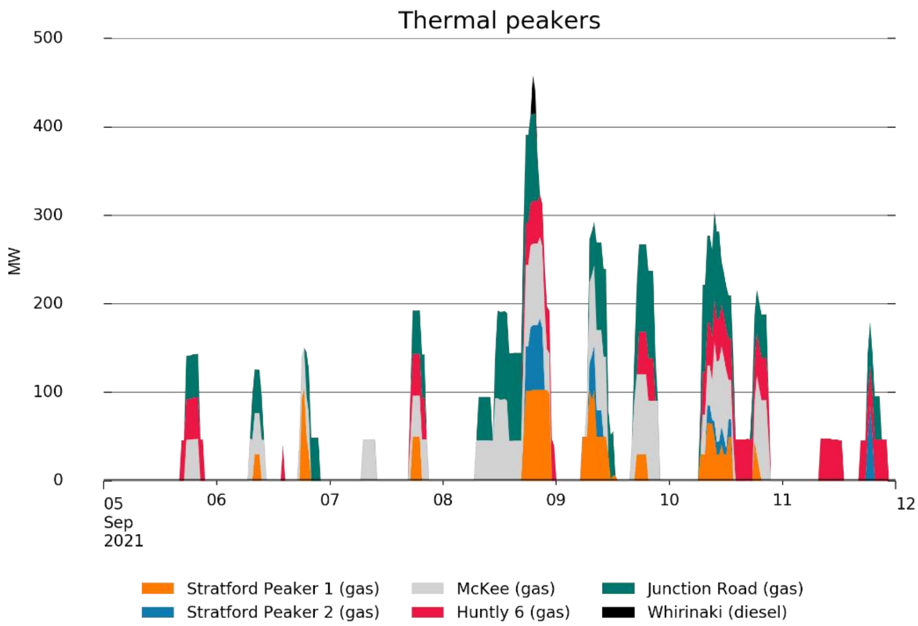
4.5 One of the Rankines, Huntly unit 1 ran most of the day on both 6 and 8 September, both days when weather was expected to be colder. It also ran on 10 September likely in response to the CAN notice issued at 7:42am which stated the unplanned outage would last until 6pm. However, the warmup time for the Rankine unit meant it was not generating until 1:30pm, by which time the outage had finished.

Figure 13: Generation from baseload thermal



4.6 Generation from thermal peakers was low at the start of the week, but during the evening of 8 September, when demand was high and wind generation low, all the thermal peakers were running, including Whirinaki running briefly from 7 to 8pm. All the thermal peakers except Whirinaki also ran on the morning of 10 September while HVDC pole 2 was on outage.

Figure 14: Generation from thermal peakers



Significant outages

4.7 The following outages reduced available generation by at least 90MW:

(a) Clyde,

(i) 116MW (long term outage)

(ii) 116MW (5am-7:30pm 10 September)

(b) Benmore, 90MW (5 July – 19 November)

(c) Manapouri, 125MW (19 July – 25 October)

(d) Huntly

(i) 240MW (27 August – 13 September)

(ii) 240MW (4-5 September)

(e) Ohau

(i) 55MW (2 August – 14 September)

(ii) 50MW (1 September – 14 September)

(iii) 66MW (12pm-4pm 8 September)

(f) Stratford peaker, 100MW (2am-4pm 11 September)

5 Price versus estimated costs

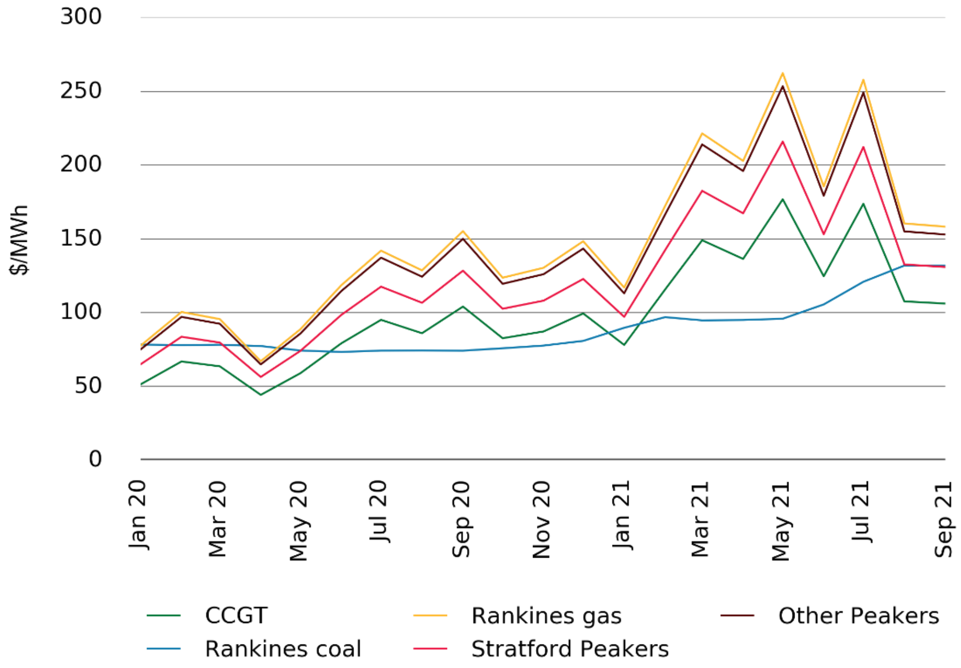
5.1 In a competitive market prices should be close to (but not necessarily at) the short run marginal cost (SRMC) of the marginal generator (where SRMC includes opportunity cost).[2]

5.2 The SRMC (excluding opportunity cost of storage) for thermal fuels can be estimated using gas and coal prices[3] and the average heat rates for each thermal unit. Figure 15 shows estimates of thermal SRMCs as a monthly average. High gas spot prices increased the thermal SRMC for July with prices dropping in August. Prices so far in September (up to 12 September) have been about the same as August, with Methanex increasing production while demand for thermal generation is falling.

[2] For a discussion on these estimates, see our paper 'Approach to monitoring the trading conduct rule' at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-of-spot-market-trading-conduct-provisions/development/trading-conduct-review-decision-published/

[3] The SRMC for thermal fuels includes the carbon price. The gas price already includes the carbon price, but not the coal price, so the carbon price is added to the coal price before estimating the SRMC of coal.

Figure 15: Estimated monthly SRMC for thermal fuels



6 Offer Behaviour

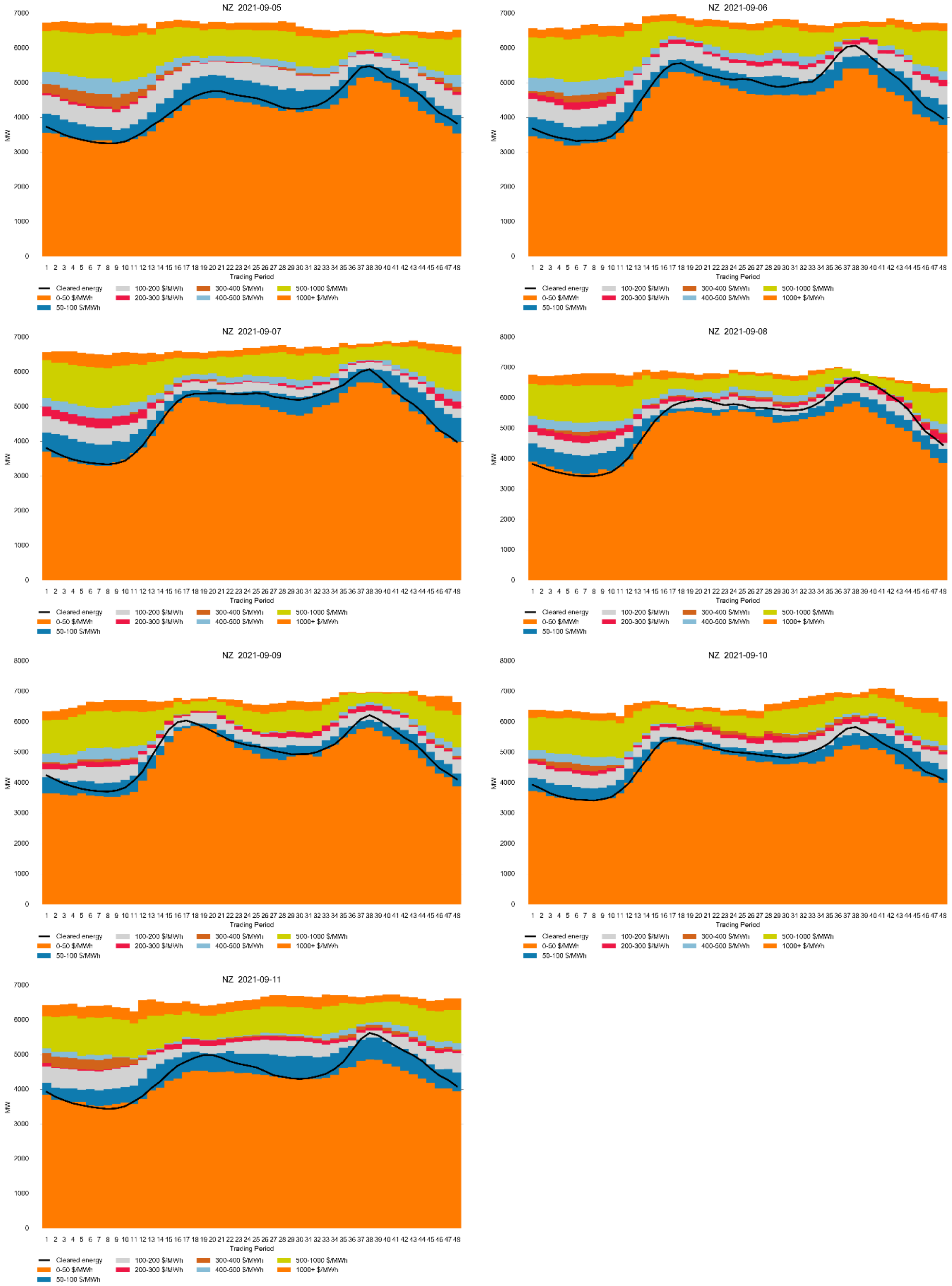
Final daily offer stacks

6.1 Figure 16 shows this week's daily offer stacks, adjusted to take into account wind generation, reserves and frequency keeping.[4] The black line shows the cleared energy, indicating the range of final prices, though this is less reliable for the period of the HVDC outage due to price separation.

6.2 This week there was an increase in offers below $50/MWh, as hydro storage continued to increase, and the quantity weighted offer price dropped 41%. This resulted in lower prices when demand as lower, such as in the South Island during the HVDC outage. However, the offer stacks were also thinner at higher prices.

[4] The offer stacks show all offers bid into the market (where wind offers are truncated at their actual generation and excluding generation capacity cleared for reserves) in price bands and plots the cleared quantity against these.

Figure 16: Daily offer stack



Offers by trading period

6.3 The trading period (TP) with the highest price was TP39 (7pm) on 8 September. Figure 17 shows the offer stack, the generation weighted average price (GWAP) and cleared generation.

6.4 Cleared generation was a lot higher on the 8 September compared to the same TP the day before (figure 18). The market responded by offering more generation below $350/MWh (95% of offers, compared to 92% of offers the day before). The offer stack was steep with not much generation available above $200/MWh besides Whirinaki.

Figure 17: Offer Stack for trading period 39 on 8 September

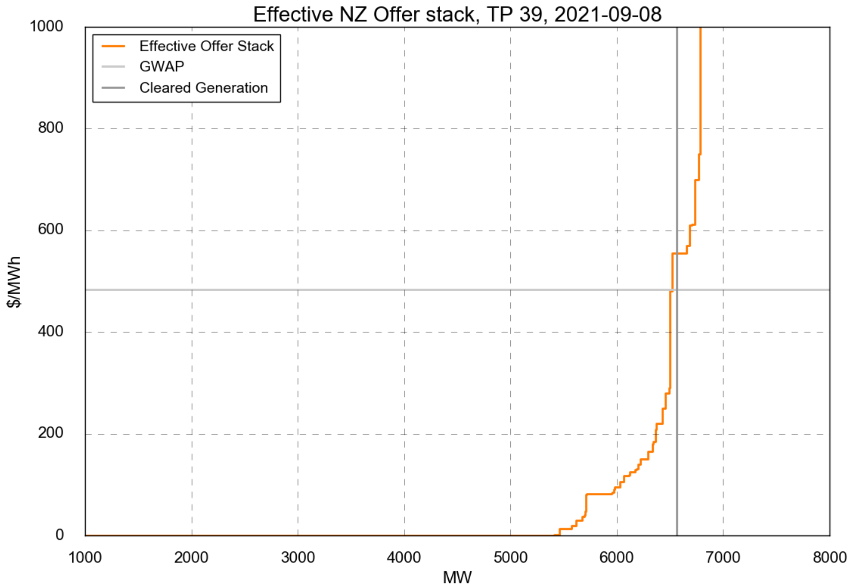
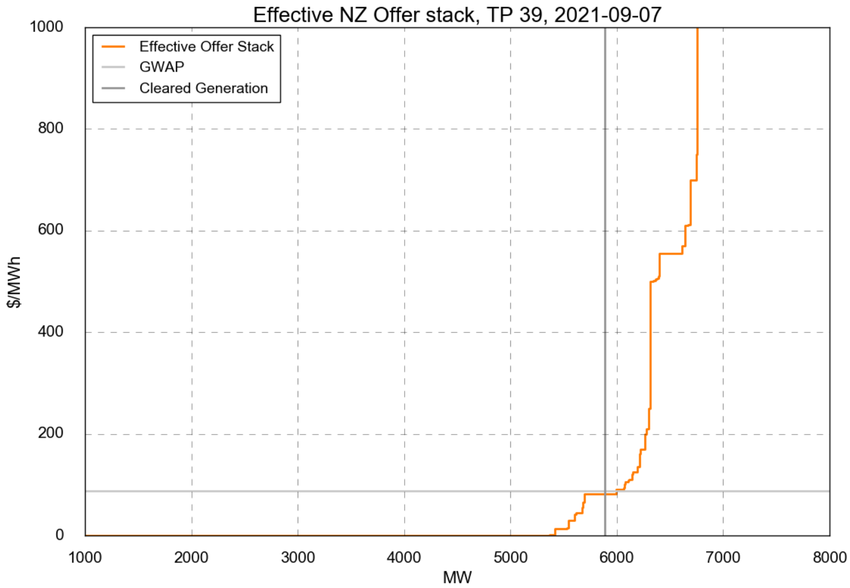


Figure 18: Offer Stack for trading period 39 on 8 September



Ongoing Work in Trading Conduct

6.5 No trading periods have been identified this week as needing further analysis.

6.6 Some of the trading periods identified for further analysis will be grouped in with ongoing work referred to compliance

Table 1: Trading periods identified for further analysis

Date	TP	Status	Notes
21/08/2021	14	Grouped	High South Island SIR price, increase SIR required
30/06-20/08	Several	Compliance: review	High energy prices in shoulder periods
30/06-3/08	Several	Compliance: review	Withdrawn reserve offers

Appendix A Regression Analysis

A.1 The Authority's monitoring team has developed two regression price models. The purpose of these models is to understand the drivers of the wholesale spot price and if outcomes are indicative of effective competition.

Weekly Model

A.2 The weekly model is an updated version of the model published in https://www.ea.govt.nz/assets/dms-assets/27/27142Quarterly-Review-July-2020.pdf, Section 8, pg. 21-25

A.3 The regression equation is

$$\begin{aligned}\log(P_t - \theta_t) = \beta_0 + \beta_1(Storage_t - Seasonal.mean.storage_i) \\ + \beta_2(Demand_t - Ten.year.mean.demand_t) + \beta_3 Wind.generation_t \\ + \beta_4 \log(Gas.price_t) + \beta_5 Generation.HHI_t \\ + \beta_6 Ratio.of.adjusted.offer.to.generation_t + \beta_7 Dummy.gas.supply.risk_t\end{aligned}$$

where P_t is the PPI and trend adjusted weekly average spot prices; $t = week\ 1, \ldots, 52$ for each year; i= spring, summer, autumn and winter

Daily Model

A.4 The daily model estimates the daily average spot price based on daily storage, demand, gas price, wind generation, the HHI for generation (as a measure of competition in generation), the ratio of offers to generation (a measure of excess capacity in the market), a dummy variable for the period since the 2018 unplanned Pohokura outage started, and the weekly carbon price (mapped to daily). The units for the raw data are as following: storage and demand are GWh, spot price is $/MWh, gas price is $/PJ, and wind generation is MW, carbon price is in New Zealand Units traded under NZ ETS, $/tonne.

A.5 We used the Augmented Dicky-Fuller (ADF) to test all variables to see if they are stationary. If not, we tested the first difference and then the second difference using the ADF test until the variable was stationary. The first difference of a time series is the series of changes from one period to the next. For example, if the storage is not stationary, we use $storage_t - storage_{t-1}$.

A.6 We fitted the data using a dynamic regression model with Autoregressive with five lags (AR(5)). Dynamic regression is a method to transform ARIMAX (Autoregressive Integrated Moving Average with covariates model) and make the coefficients of covariates interpretable.

A.7 Once we dropped the insignificant variables; the ratio of offers to generation, the dummy variable for 2018 and carbon price, we got the following model[5], where *diff* is the first difference:

$$y_t = \beta_0 - \beta_1\left(storage_t - 20.year.mean.storage_{dayofyear}\right) + \beta_2 diff(demand_t) - \\ \beta_3\ wind.generation_t + \beta_4\ gas.price_t - \beta_5 diff(generation\ HHI_t) + \ \beta_6 dummy + \eta_t$$

$$\eta_t = \varphi_1\eta_1 - \varphi_2\eta_2 + \varphi_3\eta_3 + \varphi_4\eta_4 + \varphi_5\eta_5 + \varepsilon_t$$

A.8 ε_t, the residuals of ARMA errors (from AR(5)), should not significantly different from white noise. Ideally, we expect the ARIMA errors are purely random, and are not correlated with each other (show no systematic pattern). ARIMA errors equals y_t minus the estimate $\hat{y}$ with their five time lags.

[5] Updated, $diff(storage_t)$ has been replaced with $\left(storage_t - 20.year.mean.storage_{dayofyear}\right)$