1 December 2021

Trading Conduct Report

Market Monitoring Weekly Report

1. Overview for the week of 21 to 27 November

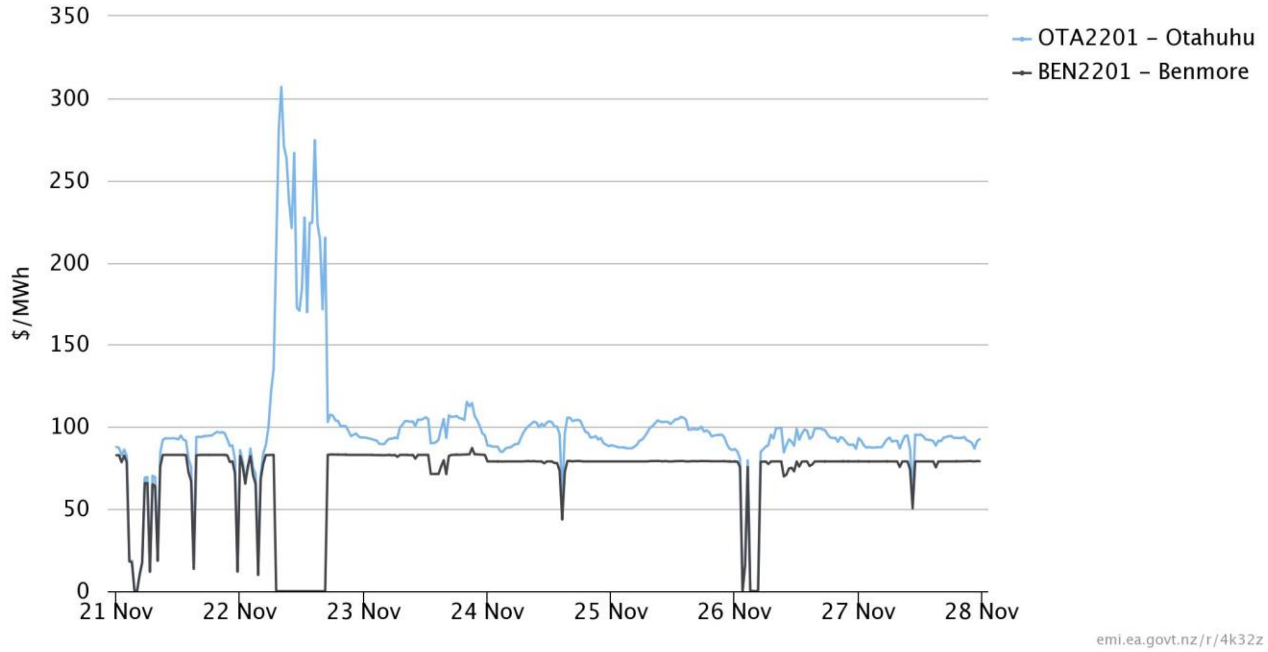
1.1. Energy prices this week appear to be consistent with underlying supply and demand conditions.

2. Prices

Energy prices

2.1. The average spot price this week was $85/MWh[1], 33% higher than last week. Excluding 22 November, prices were relatively stable, usually around $80/MWh at Benmore. There was an outage of HVDC pole 3 on 22 November which caused price separation between the North and South Island. During the outage prices at Benmore were close to $0/MWh while prices at Otahuhu peaked at $307/MWh at TP17.

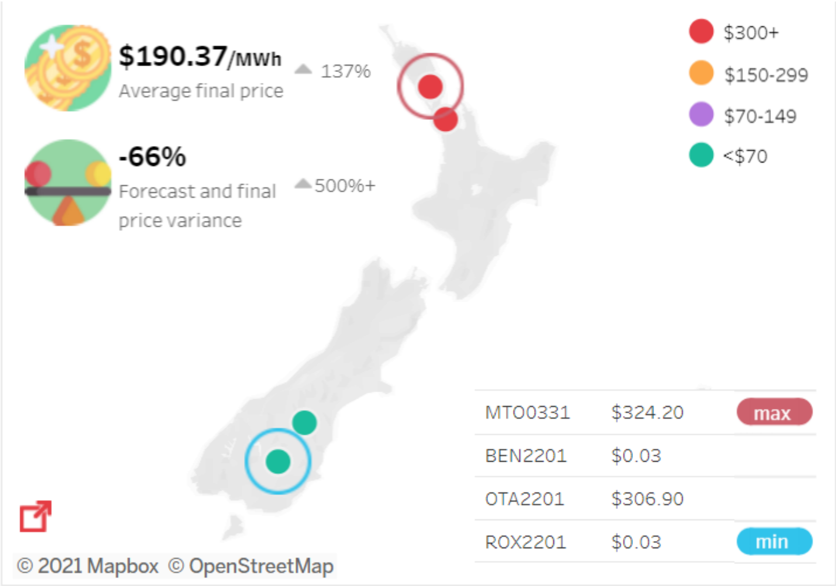
Figure 1: Spot prices by trading period at Otahuhu and Benmore



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

2.2. Figure 2 shows the average nodal price for TP17 on 22 November, the highest and lowest nodal price and the nodal price at Otahuhu and Benmore. This clearly shows price separation-prices in the North Island were above $300/MWh while prices in the South Island were $0.03/MWh.

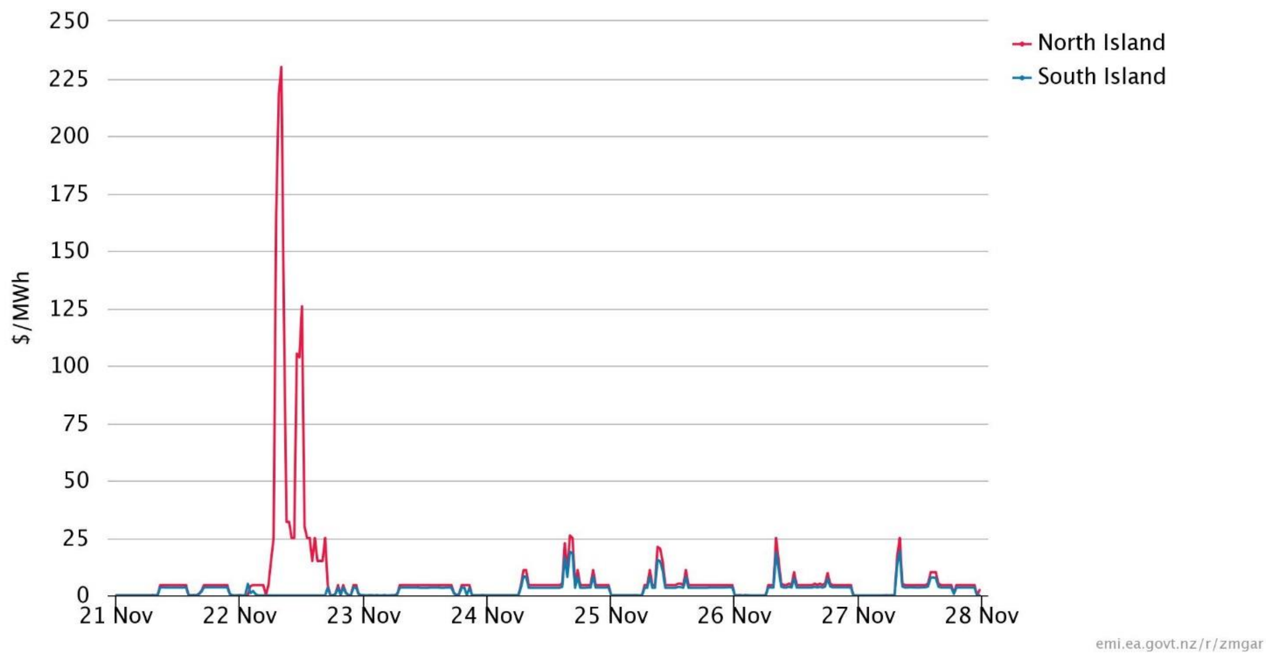
Figure 2: Spot prices for TP17 on 22 November compared to the previous week



Reserve Prices

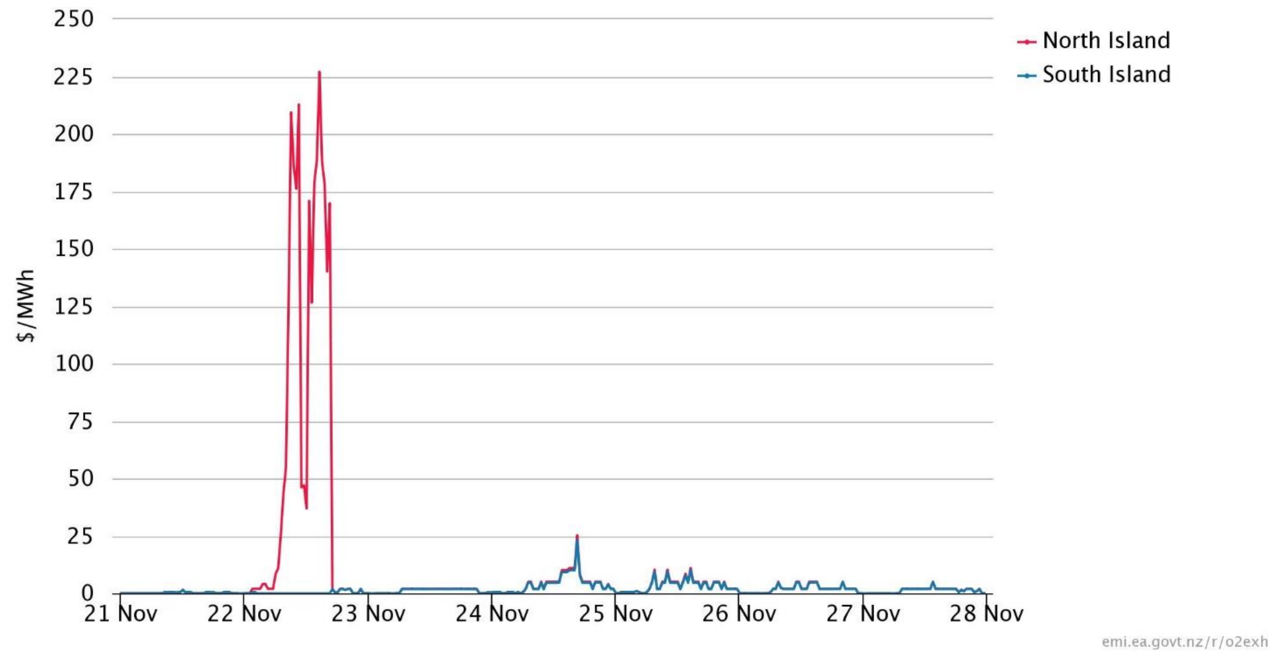
2.3. Fast instantaneous reserves (FIR) prices were usually below $25/MWh. The exception to this occurred on 22 November during the HVDC pole 3 outage which caused North Island prices to increase to $230/MWh during TP17. These high prices were due to the increase in dispatch of both North Island generation and reserves due to the pole 3 outage.

Figure 3: FIR prices by trading period and Island



2.4. Sustained instantaneous reserves (SIR) prices were usually below $25/MWh this week (see Figure 4). Similar to FIR the HVDC pole 3 outage caused price separation on 22 November with North Island SIR prices peaking at $227/MWh at TP30.

Figure 4: SIR prices by trading period and Island

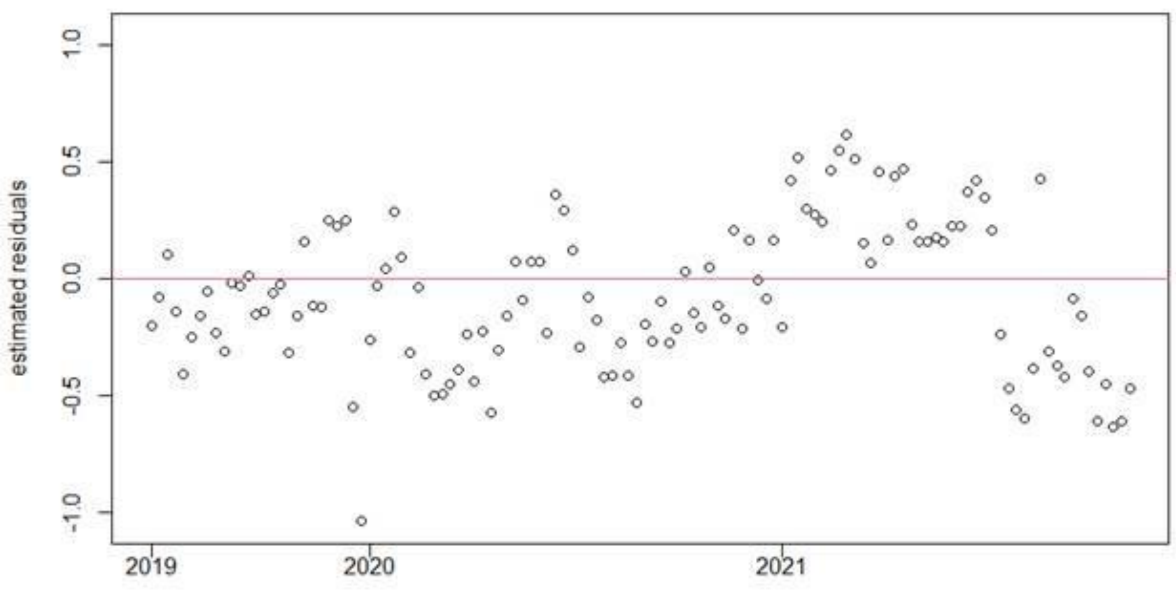


Residuals from regression models

2.5. 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.

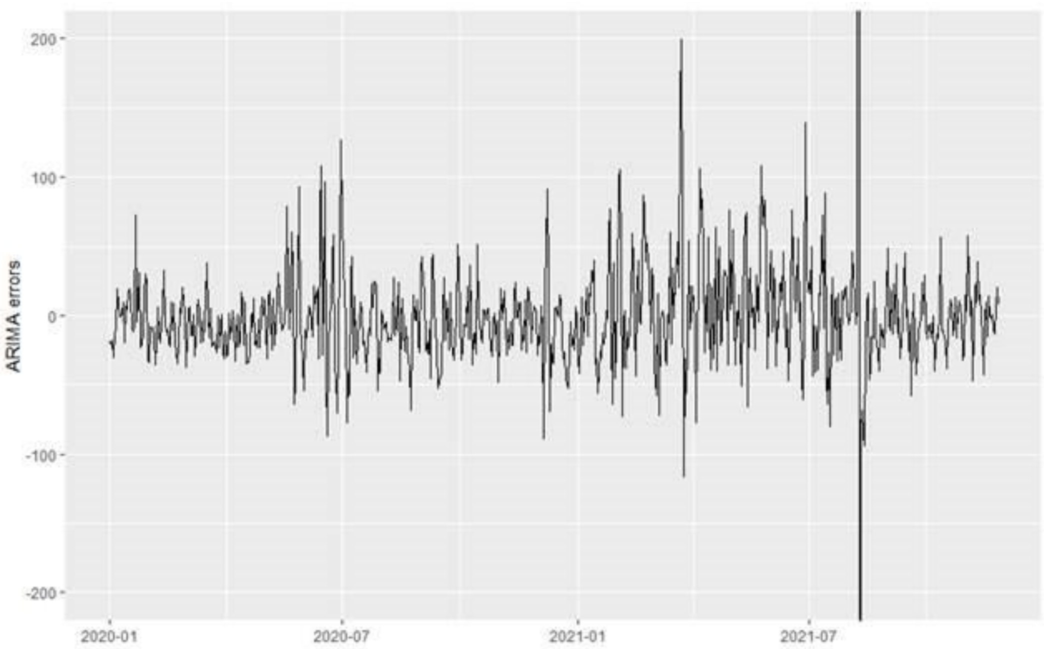
2.6. Figure 5 shows the residuals from the weekly model. During October 2021 the residuals were within the normal range, indicating that weekly prices were close to the model's predictions.

Figure 5: Residual plot of estimated weekly price from 2 July 2019 to 28 October 2021



2.7. 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.

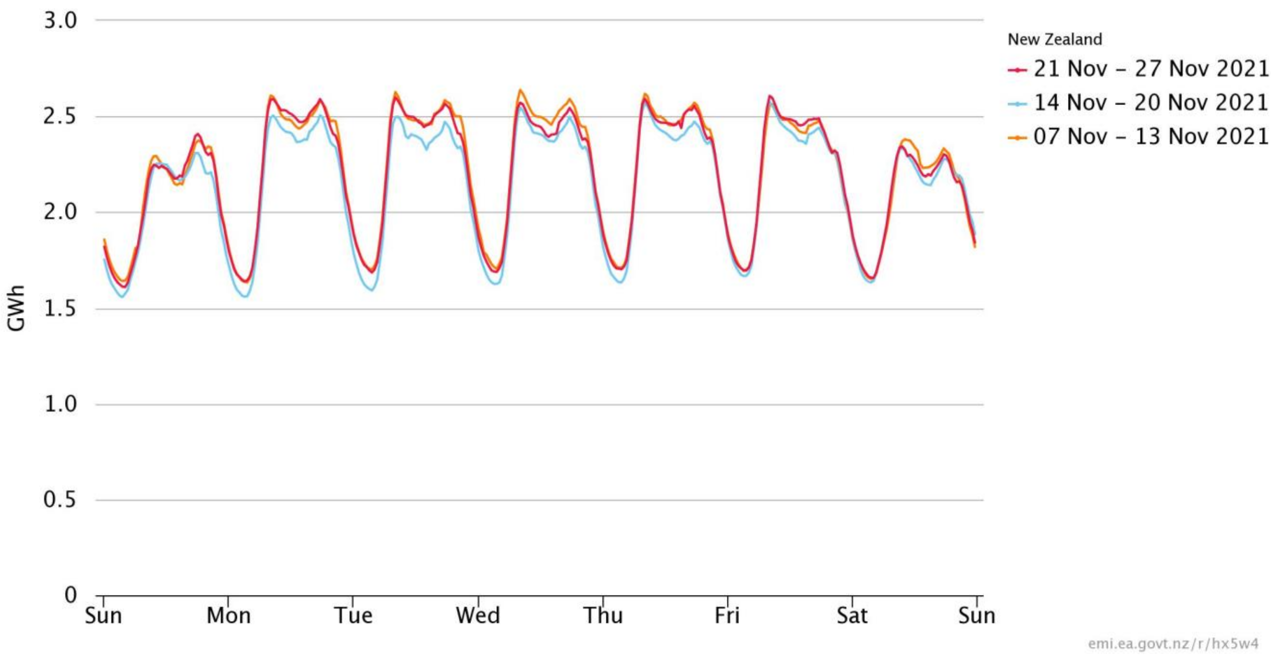
Figure 6: Residual plot of estimated daily average spot price from 1 July 2020 to 27 November 2021



3. Demand Conditions

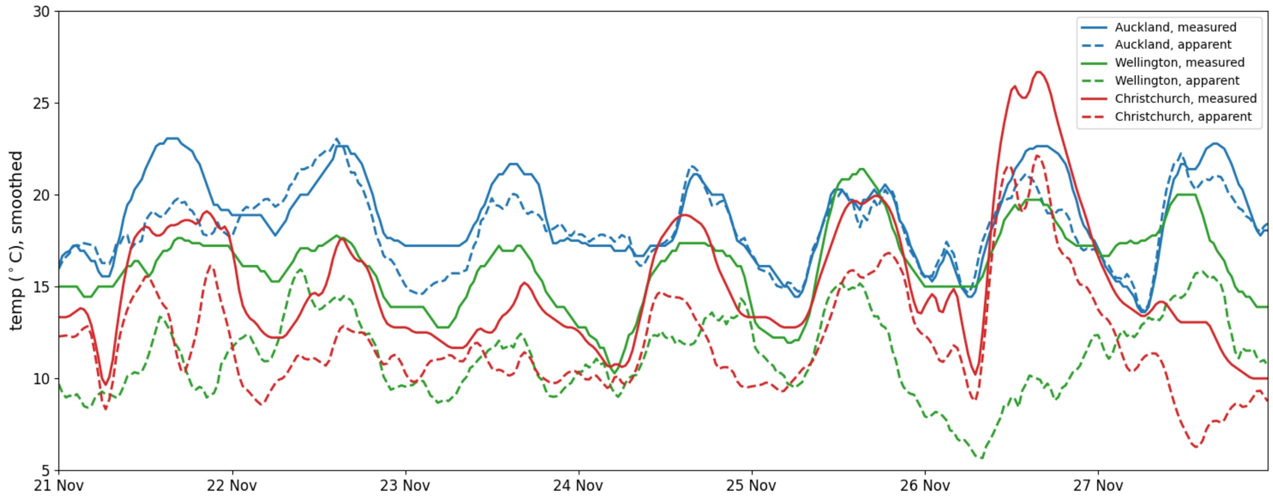
3.1. National demand was 2% higher than the previous week (see Figure 7) and similar to the week before.

Figure 7: National demand compared for current and previous week



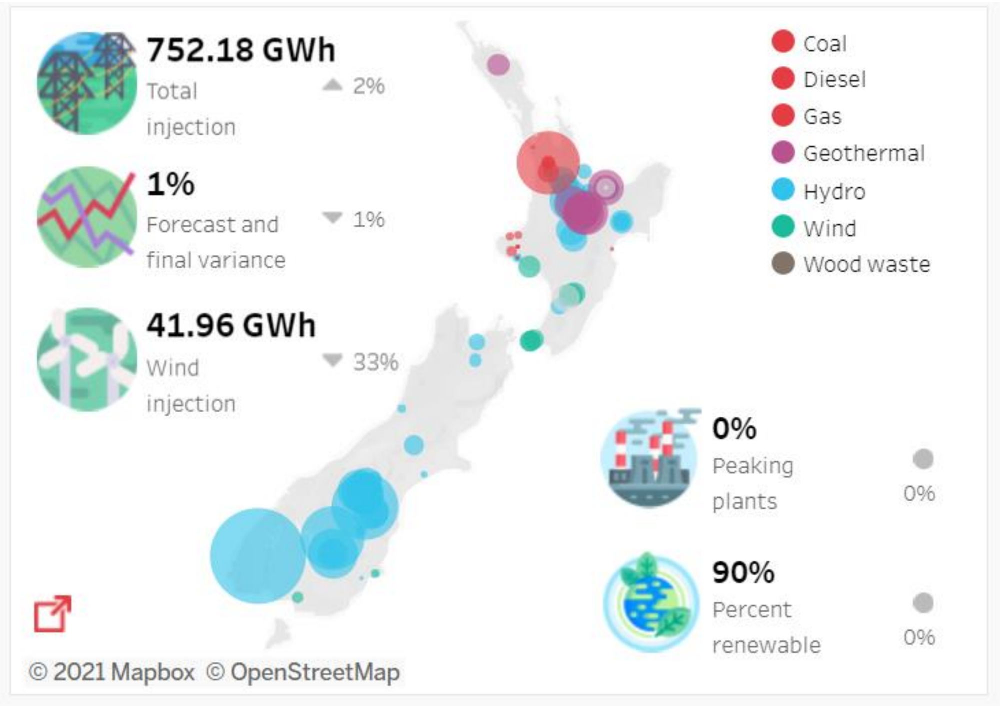
3.2. Figure 8 shows hourly temperature data at main population centres. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Temperatures continue to be warm, with most temperatures ranging from 10° to 25°.

Figure 8: Hourly temperature data (actual and apparent) at main population centres



4. Supply Conditions

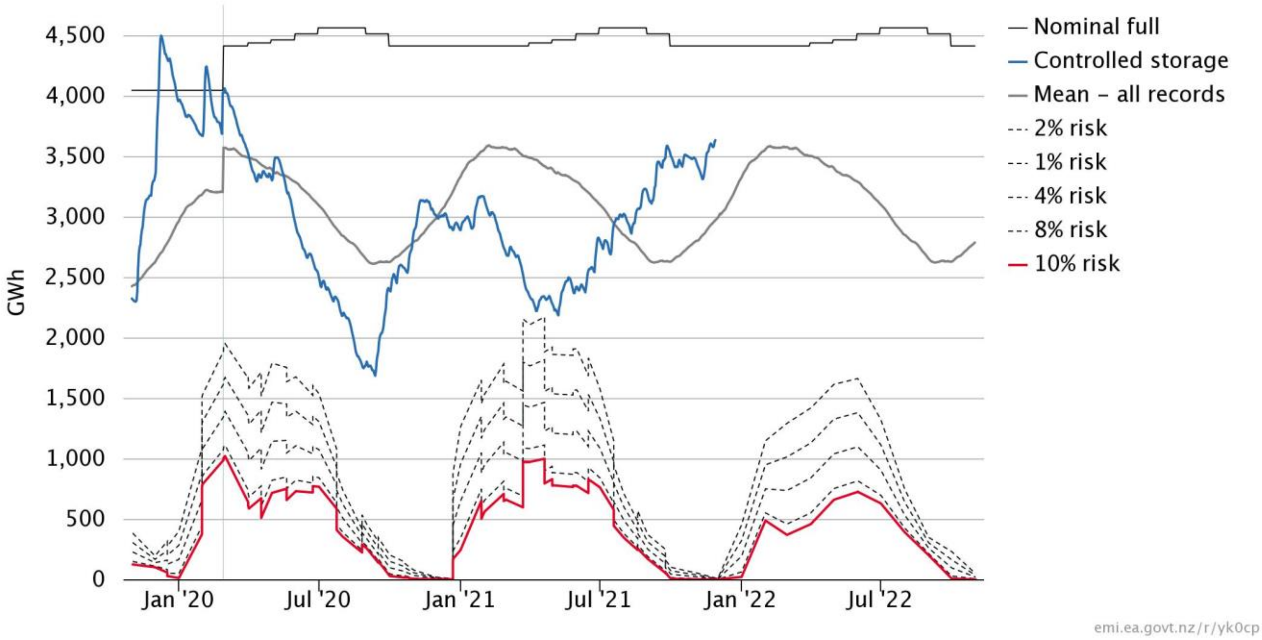
Figure 9: Generation in the last week compared to previous week



Hydro conditions

4.1. National hydro storage increased a small amount this week to 75% of nominal full, shown in Figure 10.

Figure 10: Electricity risk curves and hydro supply

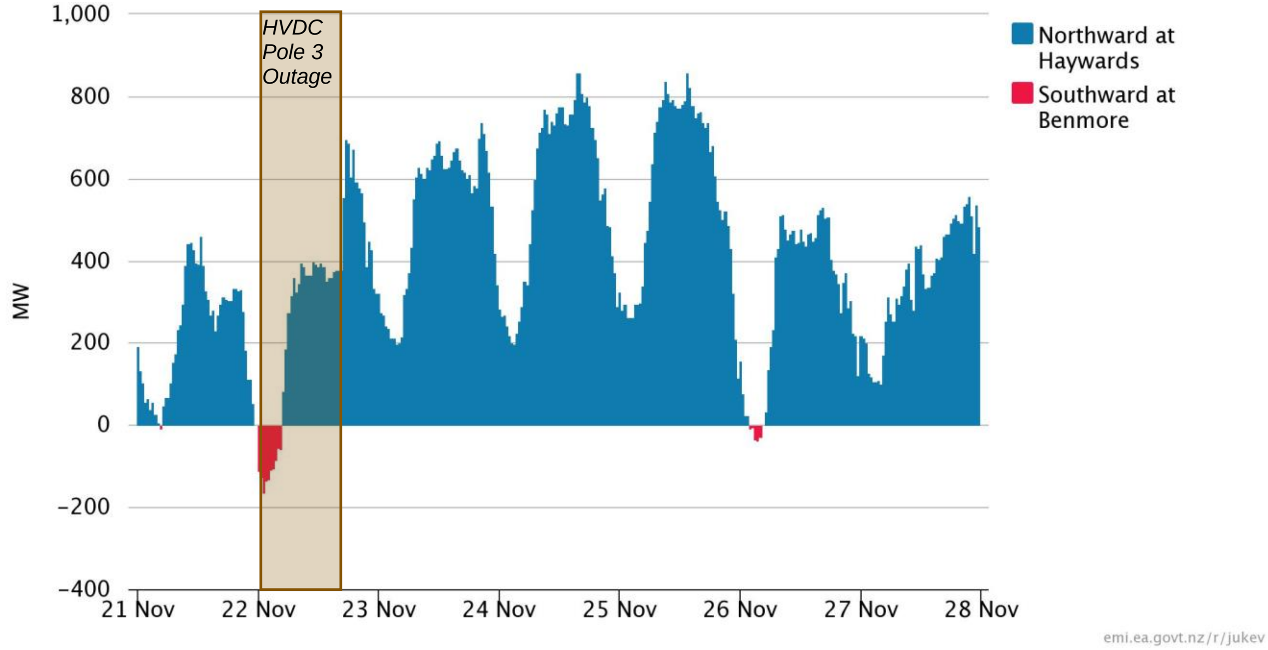


HVDC Pole 3 outage

4.2. At 1:16am on 22 November a mechanical issue caused an outage of HVDC Pole 3. This reduced the HVDC's transfer capacity to around 500MW total and disabled reserve sharing. The initial CAN notices indicated the HVDC would be restored by 8am, but this was pushed back several times until at 9:44am a CAN notice was issued with a restart time of 8pm. HVDC Pole 3 was restored around 5pm.

4.3. At the time the outage started the HVDC was transferring 164MW Southwards, so the outage did not have a large impact. Price separation started around TP14, but which point transmission was Northwards flowing and closer to the limit of pole 2. From TP14 to TP36 the Otahuhu price was between $150-307/MWh while the price at Benmore was $0.03/MWh. Once Pole 3 was restored northwards transfer increased to 697MW and the price at Otahuhu dropped to about $100/MWh for the evening peak.

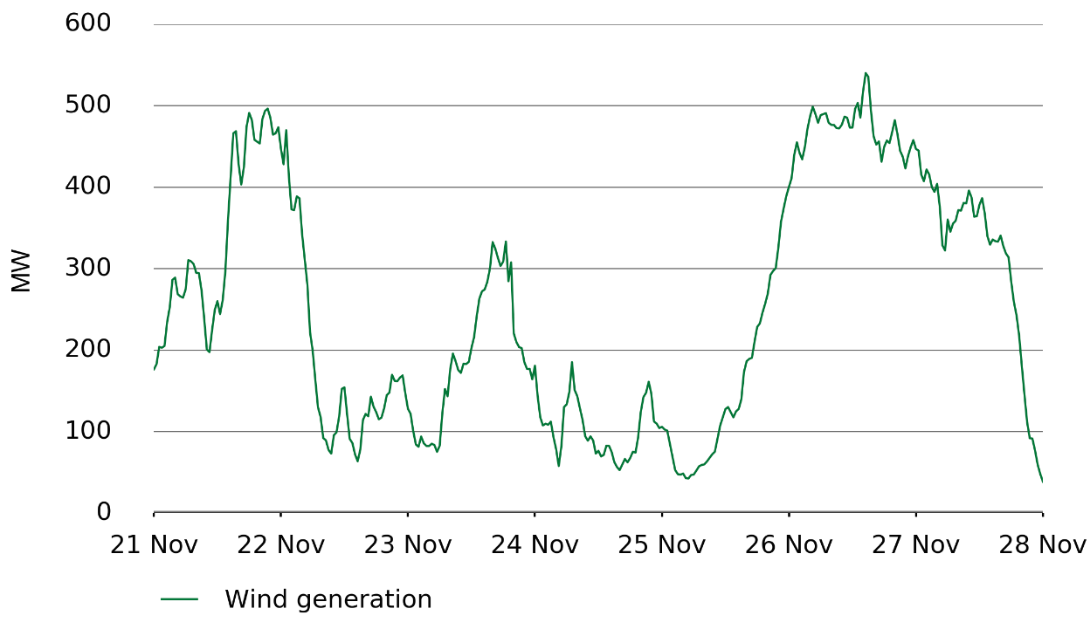
Figure 11: Transfer across HVDC



Wind conditions

4.4. Total wind generation was 42GWh, a third lower than last week. Wind generation was higher on 21 November and 26 November (see Figure 12), which also had the lowest daily price. Low wind on 22 November contributed to high North Island prices during the HVDC pole 3 outage.

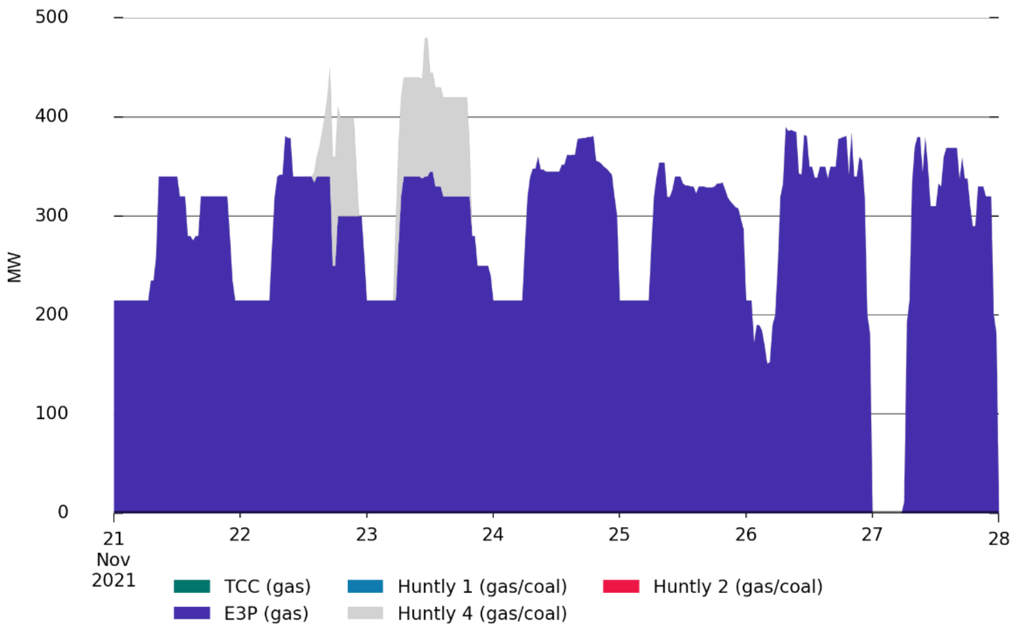
Figure 12: Wind generation by trading period



Thermal conditions

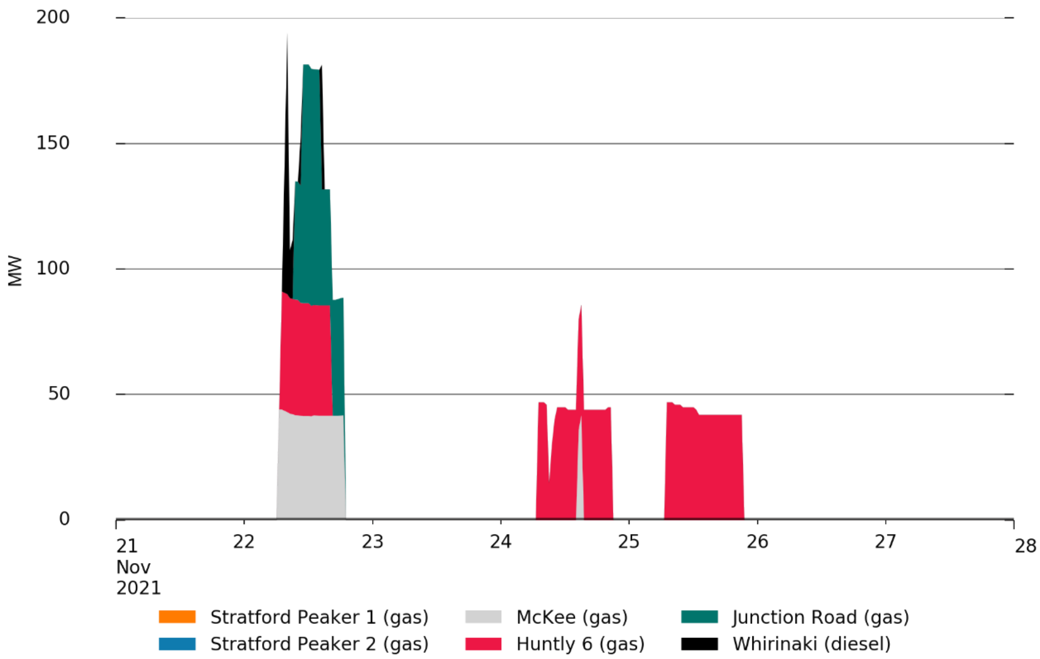
4.5. Huntly's E3P continued to run as thermal baseload this week (Figure 13). Huntly unit 4 started running in the afternoon on 22 November in response to the HVDC outage. At the time it started the HVDC pole 3 outage was expected to continue during the evening peak resulting in high North Island prices. Huntly 4 also ran the following day.

Figure 13: Generation from baseload thermal by trading period



4.6. All available thermal peakers ran on 22 November during the HVDC outage, including Whirinaki, to help cover the shortfall. McKee and Junction Road continued running after outage finished to cover evening peak demand. This week both the Stratford peakers were on outage, as well as one unit at McKee.

Figure 14: Generation from thermal peakers by trading period



4.7. Huntly 6 was also dispatched on 24 and 25 November when wind generation was low, and Huntly 4 was not running. The brief dispatch of McKee on TP30 24 November was likely for testing purposes as one of the units came back from outage. A short time later the other unit at McKee went on outage.

Significant outages

4.8. There continues to be a high number of outages this week, though the long-term outage at Benmore ended on 22 November.

4.9. The following outages reduced available generation by at least 50MW:

(a) Clyde, 116MW (long term outage)

(b) Benmore, 90MW (5 July – 22 November)

(c) Manapouri, 125MW (22-26 November)

(d) Tekapo, 80MW (13 September – 16 January 2022)

(e) Huntly,

(i) Rankine unit; 240MW (4 October-19 December)

(ii) Rankine unit; 240MW (21 November)

(f) McKee,

(i) 50MW (17-24 November)

(ii) 50MW (24-29 November)

(g) Stratford,

(i) 100MW, (31 October-13 December)

(ii) 100MW (7-29 November)

(h) Waipori, 72MW (8 November – 28 January 2022)

(i) Aviemore, 55MW (11-26 November)

(j) Ohau,

(i) 55MW (8:30am-5pm 22 November)

(ii) 55MW (8:30am-5:30pm, 23 November)

(k) Tokaanu, 240MW (11am-1pm 23 November)

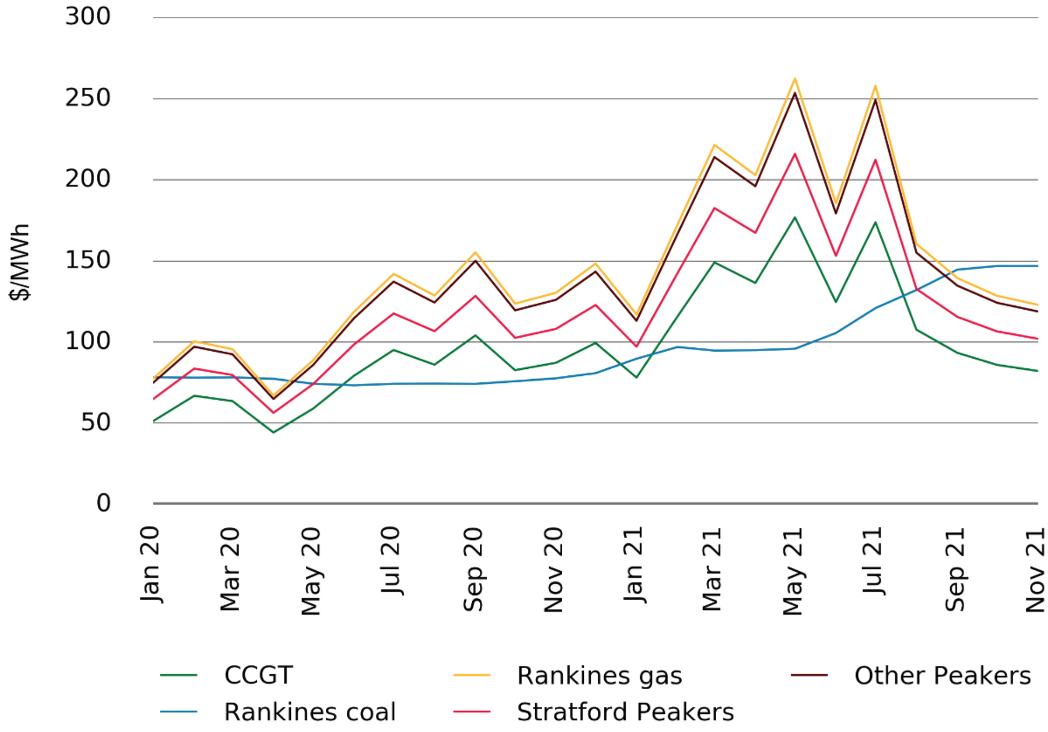
5. Price versus estimated costs

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).

Thermal Fuels

5.2. The SRMC (excluding opportunity cost of storage) for thermal fuels can be estimated using gas and coal prices, and the average heat rates for each thermal unit. Figure 12 shows estimates of thermal SRMCs as a monthly average. The thermal SRMC for both gas and coal fuelled generation in November (to 27 November) is similar to October[2].

Figure 15: Estimated monthly SRMC for thermal fuels

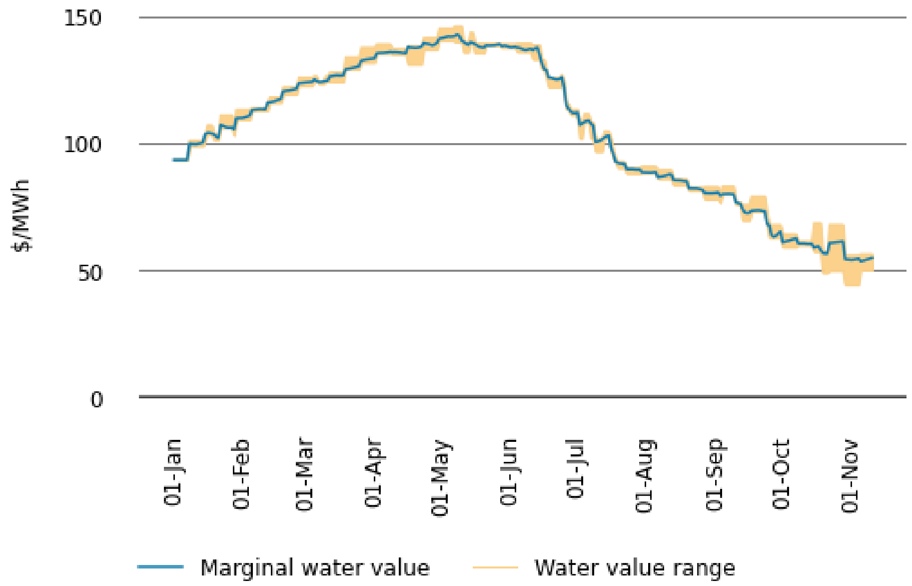


[2] For a discussion on these estimates, see our paper 'Approach to monitoring the trading conduct rule' at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-of-spot-market-trading-conduct-provisions/development/trading-conduct-review-decision-published/

DOASA Water values

5.3. The DOASA[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 16 shows the national water values[4] obtained from DOASA up to end of October 2021. The outputs from DOASA closest to actual storage levels are shown as the yellow water value range. These values are used to estimate marginal water value at the actual storage level, indicated by the blue line[5]. Figure 16 shows that the marginal water value has declined since June as hydro storage levels increased and gas costs decreased.

Figure 16: DOASA water values for January- to November 2021

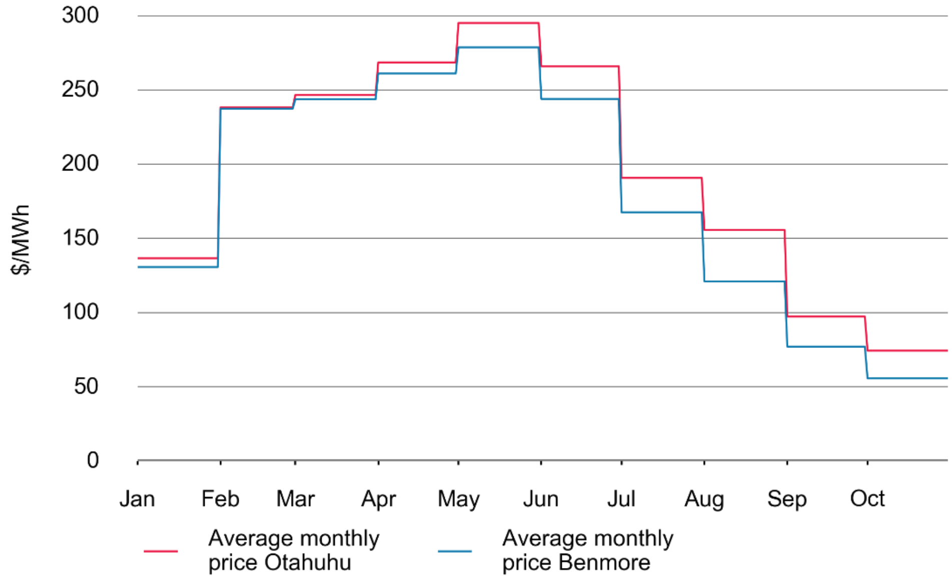


Monthly prices

5.4. Figure 17 shows the average price each month at Otahuhu and Benmore for 2021. It shows that prices have declined since June, similar to the trend for gas costs and water values. The high prices over winter were closer to the SRMC of thermal but as thermal generation decreased average prices have been closer to the marginal water value.

[3] DOASA is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. DOASA was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market. (More details in Appendix B)
[4] The national water values are estimated assuming all hydro storage reservoirs are equally full.
[5] See Appendix B, 2 for more details

Figure 17: Average monthly prices at Otahuhu and Benmore January-October 2021



Offer Behaviour

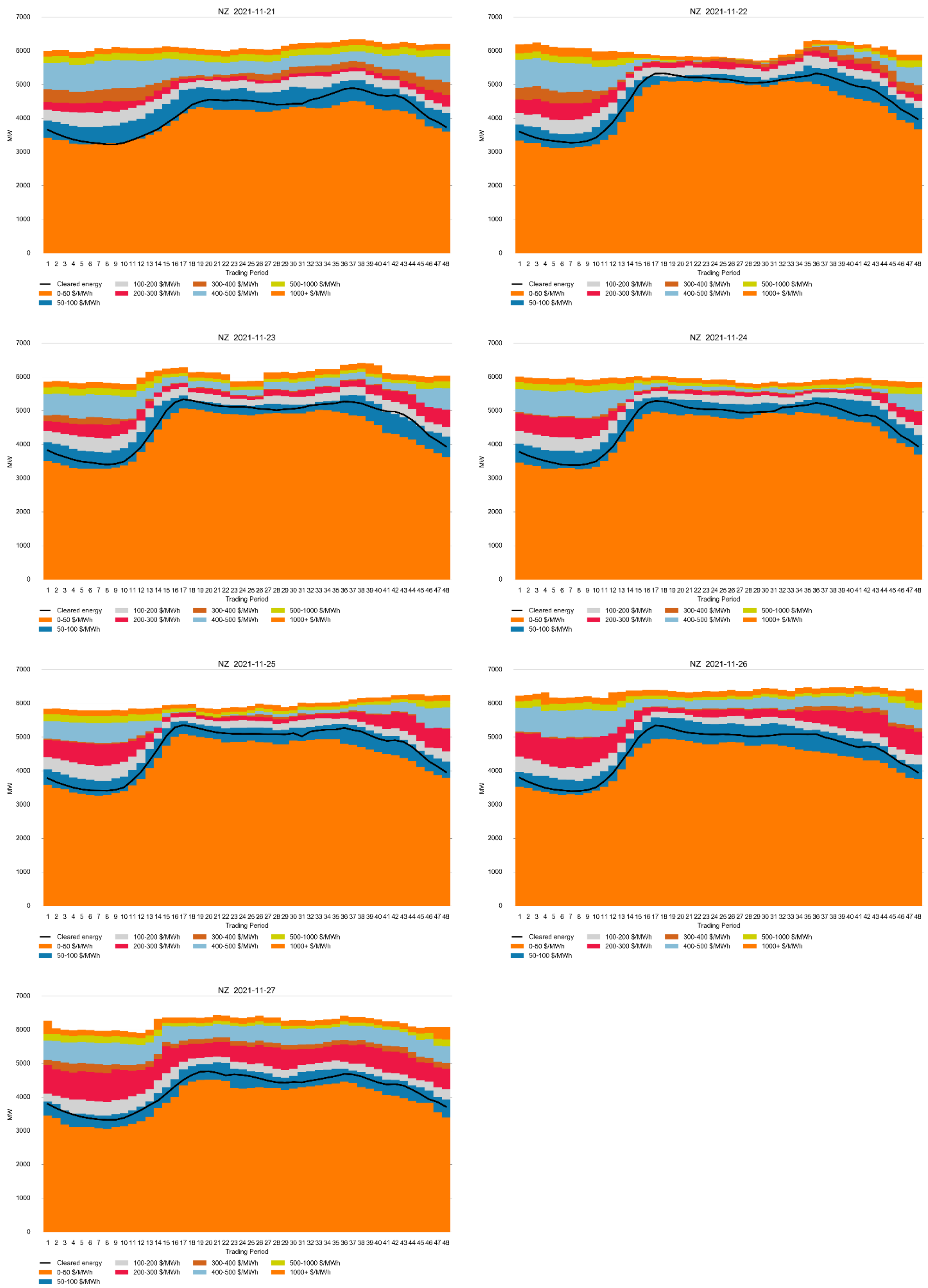
Final daily offer stacks

5.5. Figure 18 shows this week's daily offer stacks, adjusted to take into account wind generation, reserves and frequency keeping.[6] The black line shows the cleared energy, indicating the range of the average final price.

5.6. This week there was an increase in generation offered between $50-$100/MWh. The quantity of offers above $350/MWh was 14% lower than the previous week, likely due to increased hydro storage over the last two weeks. The quantity weighted offer price also fell 7% from last week.

[6] 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.

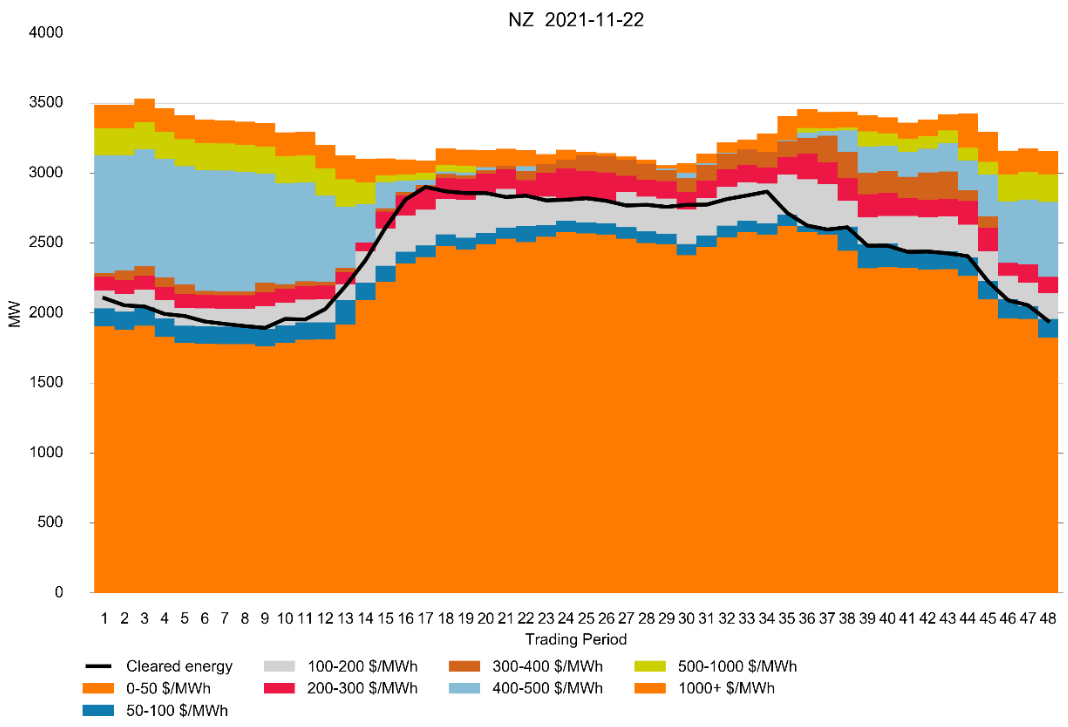
Figure 18: Daily offer stack



5.8. Figure 19 shows the offer stacks for the North Island on 22 November. This gives a more accurate representation of the outcomes in the North Island than figure 18 for the same day, as figure 18 does not account for the HVDC pole 3 outage. Total generation offered dropped in the morning as wind decreased. Cleared generation was also high due to the outage which caused higher priced offers to be dispatched.

5.9. In the afternoon total generation increased as Huntly unit 4 ramped up generation for the evening peak. However, when the outage ended at TP34 there was a decrease in cleared generation in the North Island as the HVDC increased northward transfer. The combined impact was a decrease in the North Island price.

Figure 19: North Island offer stack for 22 November

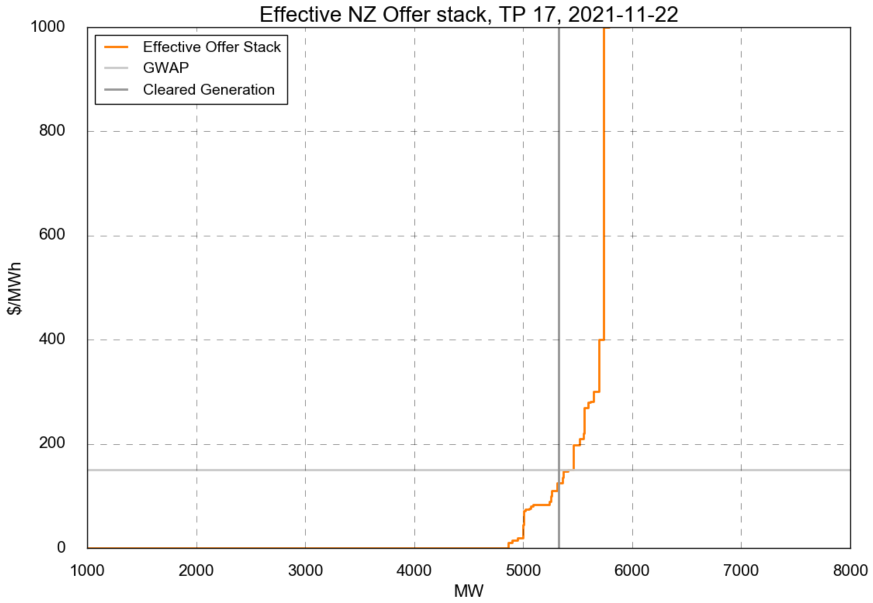


Offers by trading period

5.10. The trading period (TP) with the highest price at Otahuhu was TP17 (8:00am) on November is shown on Figure 20, with the offer stack, the generation weighted average price (GWAP) and cleared generation.

5.11. The GWAP across all nodes was $150/MWh, but price separation meant that prices in the South Island were below $1/MWh while prices in the North Island were around $300/MWh. Cleared generation on 22 November was not particularly high, and the offer stack indicates that if there had not been any outage prices would have been around $100/MWh which is similar to surrounding days.

Figure 20: Offer Stack for trading period 17 on 22 November



Ongoing Work in Trading Conduct

5.12. No trading periods this week were identified for further analysis

Table 1: Trading periods identified for further analysis

Date	TP	Status	Notes
16/11-18/11		Further Analysis	High reserve prices
30/06-20/08	Several	Compliance: review	High energy prices in shoulder periods
30/06-21/08	Several	Compliance: review	Withdrawn reserve offers

Appendix A Regression Analysis

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

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

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,…,52 for each year; i = spring, summer, autumn, and winter

Daily Model

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.

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 $storage_t - storage_{t-1}$.

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.

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[7], where diff is the first difference:

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

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

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.

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

Appendix B DOASA water value model

1. DOASA is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto.[8] DOASA was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.[9] A version of DOASA has been used by EPOC for analysis of the New Zealand electricity market for many years, and SDDP is a well-known and widely accepted modelling tool for hydro-thermal optimisation in electricity systems. DOASA gives a consistent measure of the opportunity cost of water. The DOASA model seeks a policy of electricity generation that meets demand and minimises the expected fuel cost of thermal generation and value of lost load.

2. The DOASA model outputs the marginal water value for a range of storage levels. The marginal water value, y, at the actual storage level, x, is estimated using the outputs closest to actual storage level (x_1, y_1) and (x_2, y_2) using the equation

$$y = y_1 + (\frac{x - x_1}{x_2 - x_1})(y_2 - y_1)$$

3. The following are some of the limitations of the assumptions in the DOASA model:

    a. Load is based on forecasts for future periods and recent periods where reconciled data was not yet available.

    b. Forecast plant and HVDC outages based on current POCP data

    c. The estimated thermal fuel costs used in DOASA may not accurately represent what hydro generators face, in terms of thermal generator offers. Hydro generators must manage their storage levels within the context of volatile thermal fuel prices and availability, and the thermal fuel cost estimates may not perfectly represent these.

    d. Non-dispatchable plant, such as wind, is modelled as having constant power output instead of stochastic power output

    e. Some hydro station head ponds and major reservoirs are governed by complex resource consent rules. The model limits used in DOASA are necessarily somewhat simplified and may not accurately reflect the actual flexibility of these limits.

    f. Inflow probability distributions are based on past inflow sequences.

    g. DOASA does not directly model stagewise dependence (i.e., from week to week) of inflows, e.g. if it was wet last week it's more likely to be wetter this week as well. However, DOASA approximates this effect by an approach called Dependent Inflow Adjustment (DIA), which artificially increases the variance of historical inflows when generating the cutting planes.[9]

4. We use the average water value over all of New Zealand from DOASA rather than the water values for individual reservoirs because the individual reservoir water values are very volatile. This is due to the following.

    a. DOASA does a forward solve (linear programming), so as long as the objective values are the same, it is likely to use all water from one reservoir first until it hits some constraint, before moving to the next reservoir. This leads to the likely extreme usage of small reservoirs (i.e., not using water proportional to total national storage by either holding back or letting it all go).

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[8] M V Pereira and L M Pinto, "Multi-stage stochastic optimization applied to energy planning," Mathematical Programming 52, (1991): 359–375.
[9] Electricity Authority, "Doasa overview," https://www.emi.ea.govt.nz/Wholesale/Tools/Doasa.

b. Therefore, small (constrained) reservoirs in DOASA are expectedly more likely to hit maximum or minimum levels or constraints, and this will be reflected in the water values (high price if likely to hit minimum level and low price if likely to hit maximum level).

c. National water values are calculated based on absolute total national storage, not absolute individual reservoir storage, which tends to make the water values less volatile. That is, if we had two reservoirs with the same capacity and one had storage at 10 percent of capacity and the other at 90 percent, the national water value is based on total storage of 50 percent of total capacity