22 December 2021

Trading Conduct Report

Market Monitoring Weekly Report

1. Overview for the week of 12 to 18 December

1.1. Prices this week appear to be consistent with underlying supply and demand conditions. The average prices were low due to increased hydro storage, but there were some high prices due to transmission outages and low wind.

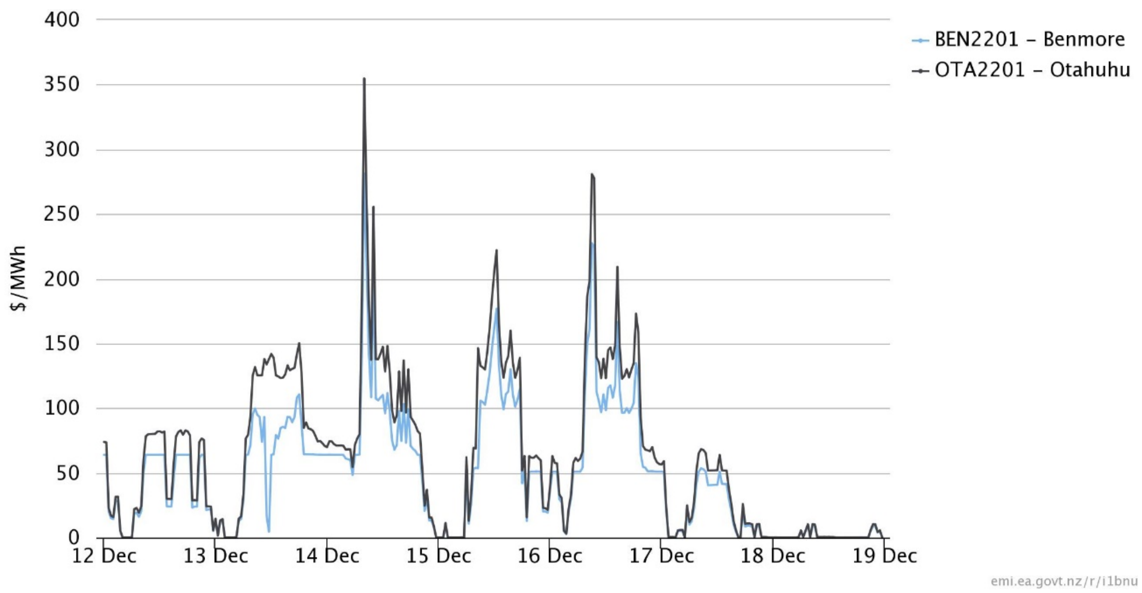
1.2. Note, this report will be the last Trading Conduct Report published in 2021. A trading conduct report covering 19 December to 8 January will be published in mid-January, after which weekly reporting will resume.

2. Prices

Energy prices

2.1. The average spot price this week was $54/MWh[1], 57% lower than last week. Prices were variable this week, ranging between $0-$354/MWh at Otahuhu (see Figure 1). There was some price separation between Benmore and Otahuhu on 13 December, but there was also price separation at times within the South Island (see Figure 2). The highest price of $354/MWh occurred at TP17 on 14 December, but high prices also occurred on 15 and 16 December. Prices were very low on 18 December.

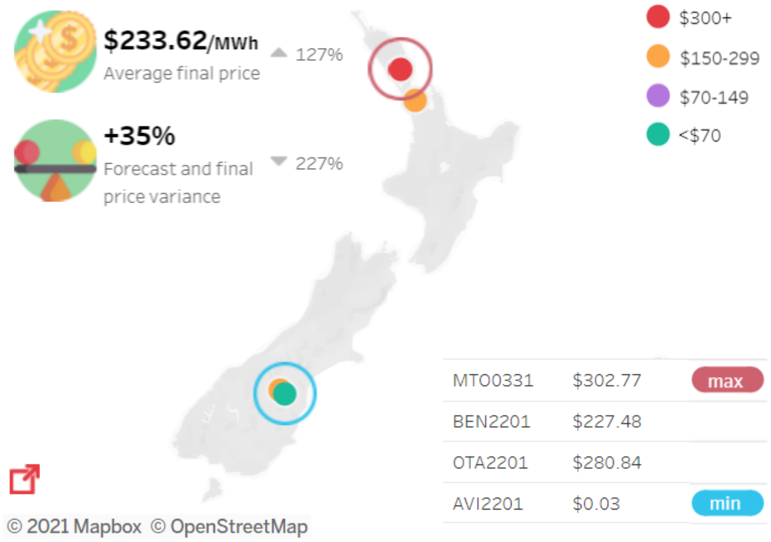
Figure 1: Spot prices by trading period at Otahuhu and Benmore



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

2.2. Figure 2 shows some of the nodal prices for TP19 on 16 December, which was the second highest priced trading period this week, with an average price over all nodes of $234/MWh. The nodal prices show that the price at Benmore was $227/MWh, but the price at Aviemore was $0.03/MWh. This was due to binding transmission constraint between Aviemore and Benmore (see more 4.5).

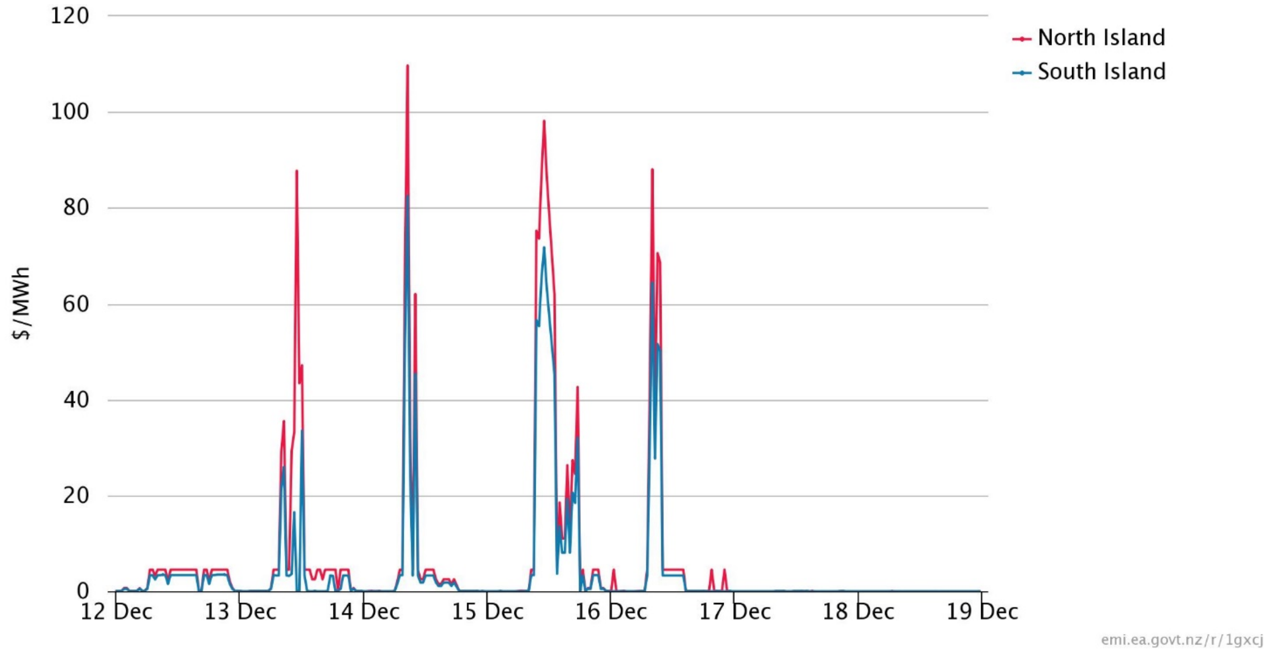
Figure 2: Spot prices for TP19 on 16 December compared to the previous week



Reserve Prices

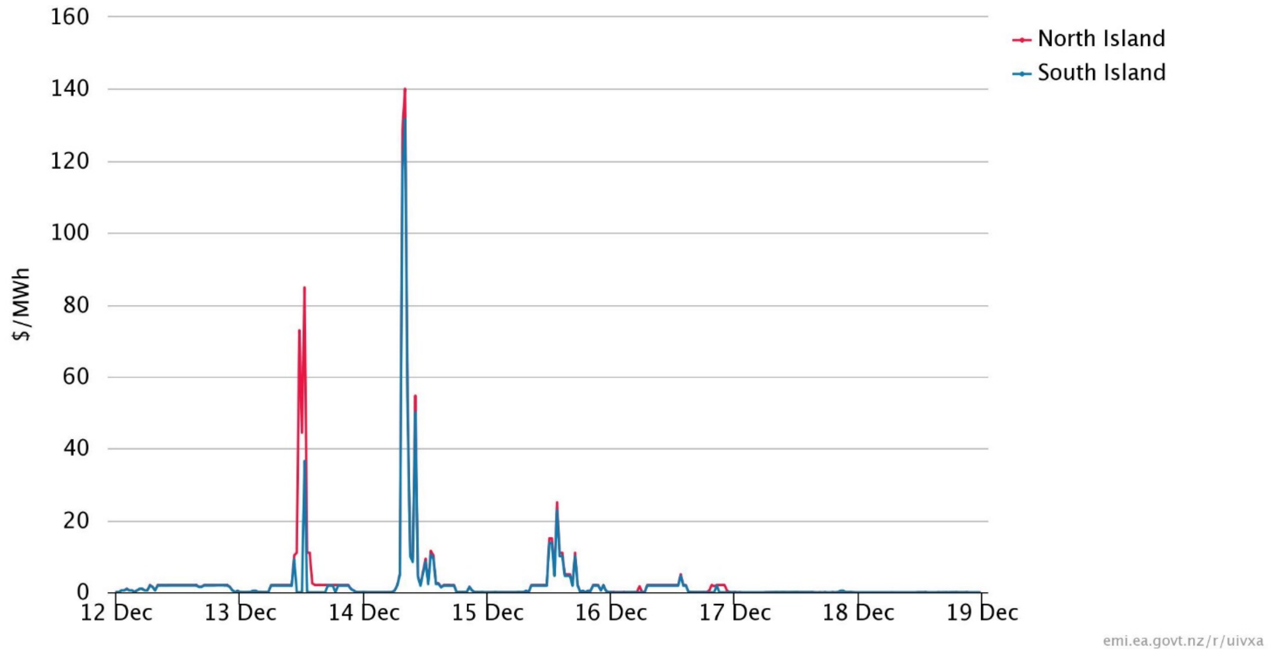
2.3. Fast instantaneous reserves (FIR) prices were usually below $5/MWh this week, but some prices were higher between 13 to 16 December, with the highest price of $110/MWh occurring at TP18 on 14 December. The higher prices on 13 December were mostly due to needing North Island reserves to cover HVDC risk, while from 14 to 16 December high prices were due to tight supply due to transmission constraints in the South Island.

Figure 3: FIR prices by trading period and Island



2.4. Sustained instantaneous reserves (SIR) prices were usually below $5/MWh. Higher prices occurred on 13 and 14 December, with the highest price of $140/MWh coinciding with the highest energy price at TP17 on 14 December. Similar to FIR, high prices on 13 December were due to high HVDC transfer while on 14 December it was due to tight supply.

Figure 4: SIR prices by trading period and Island

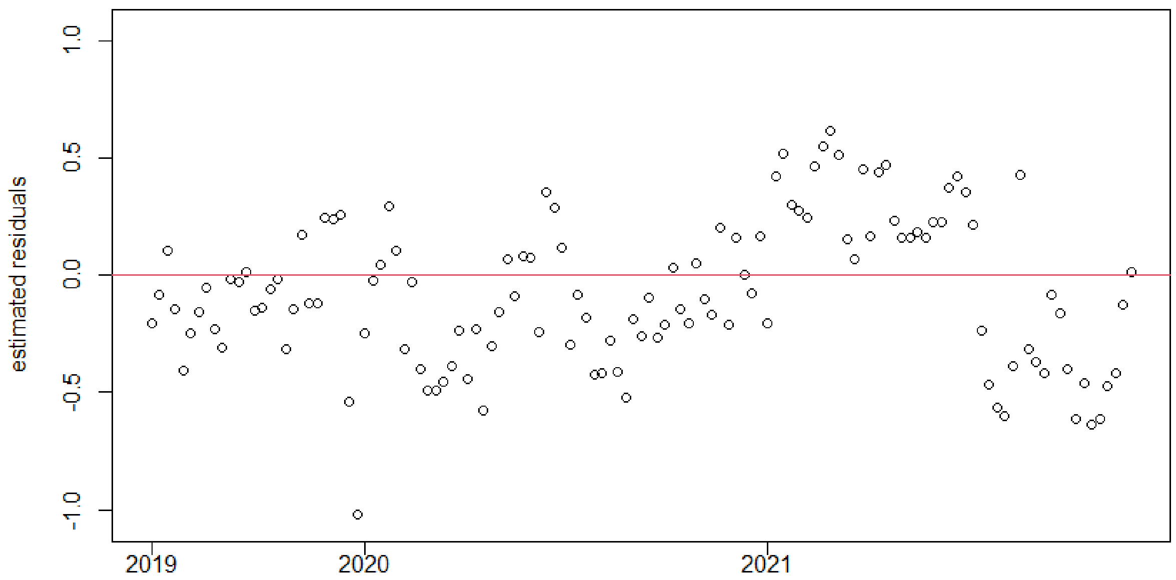


Residuals from regression models

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.

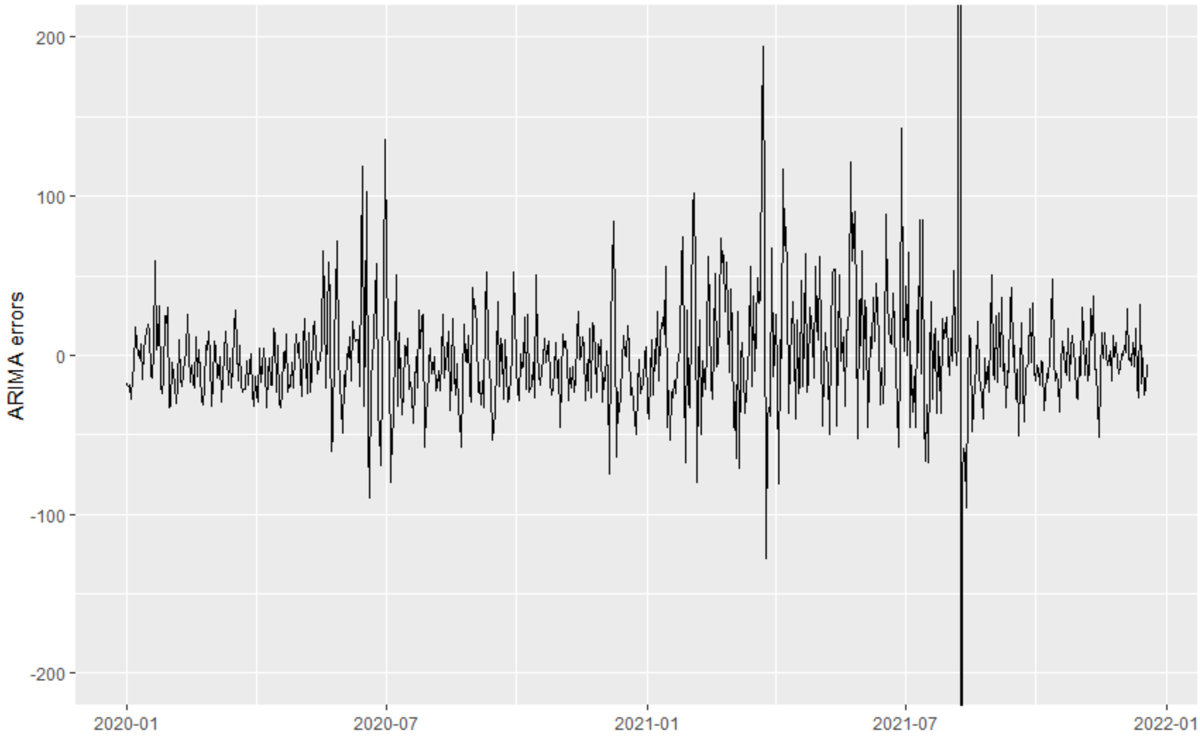
2.6. Figure 5 shows the residuals from the weekly model. During November 2021 the residuals were within the normal range, indicating that weekly prices were close to the model's predictions.

Figure 5: Residual plot of estimated weekly price from 2 July 2019 to 25 November 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.

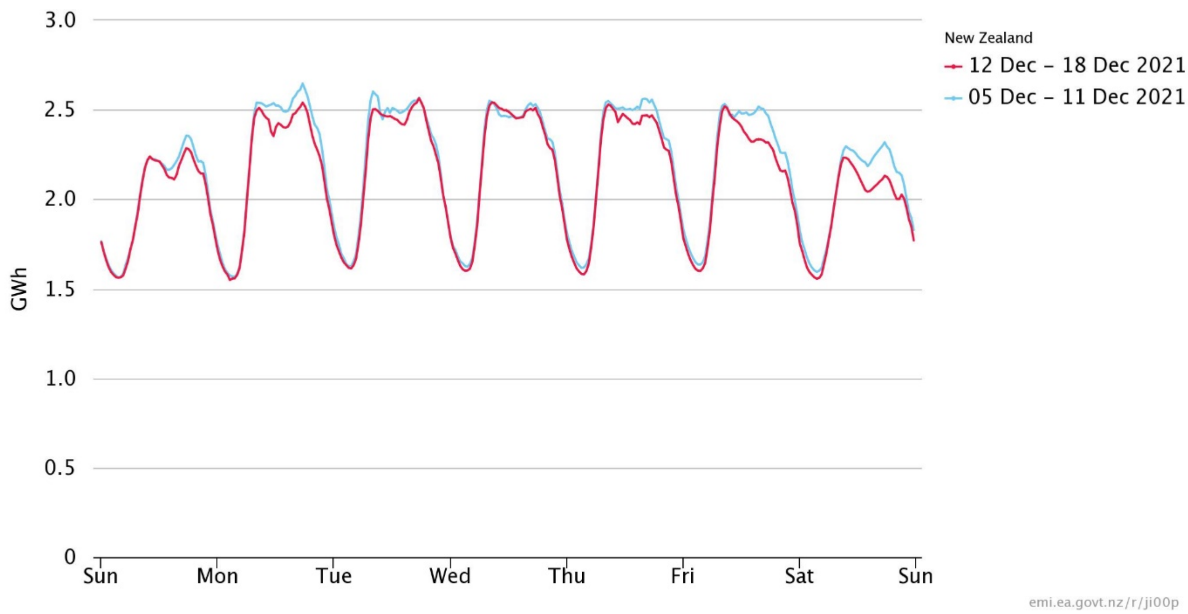
Figure 6: Residual plot of estimated daily average spot price from 1 July 2020 to 18 December 2021



3. Demand Conditions

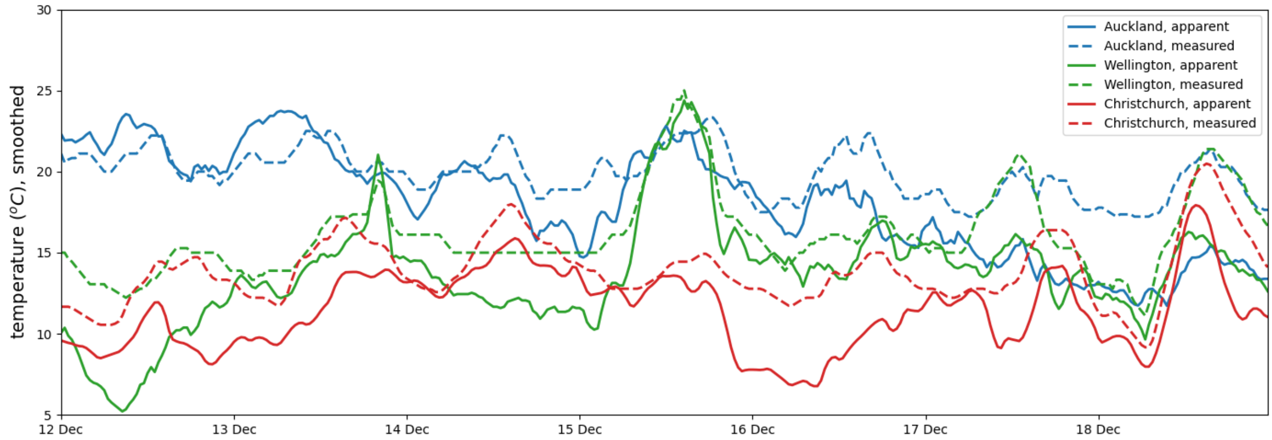
3.1. National demand was 3% lower than the previous week (see Figure 7) with most of New Zealand experiencing mild to warm temperatures.

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



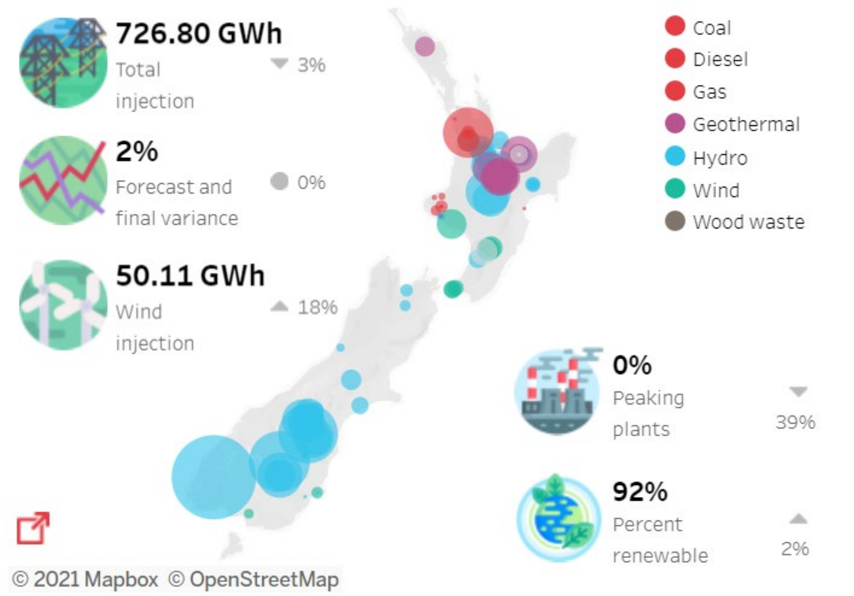
3.2. Figure 8 hourly temperature at main population centres. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Temperatures were relatively mild this week, with the coolest day in Wellington on 12 December, the coolest day in Christchurch on 16 December and Auckland temperatures cooler towards the end of the week.

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



4. Supply Conditions

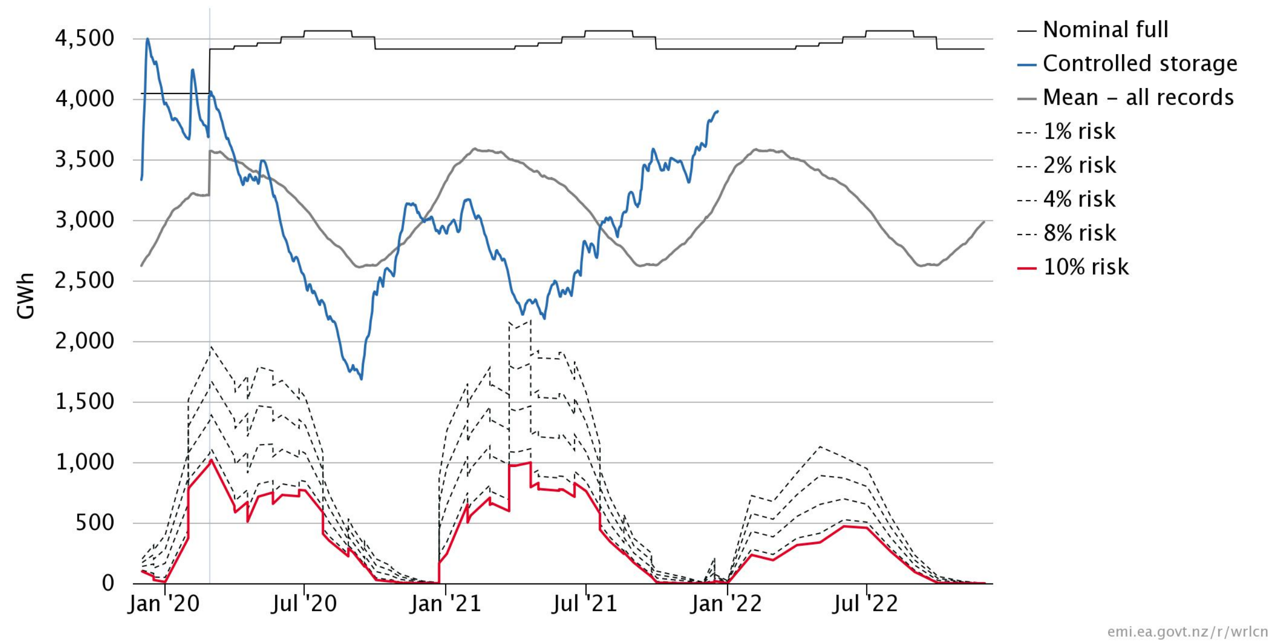
Figure 9: Generation in the last week compared to previous week



Hydro conditions

4.1. National hydro storage increased 2% this week, shown in Figure 10, reaching 82% of nominal full.

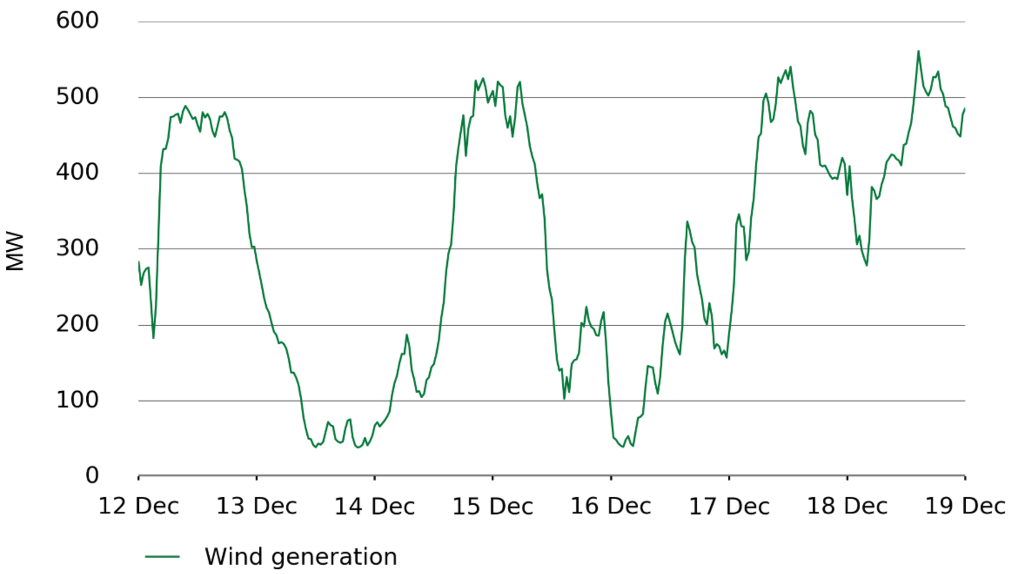
Figure 10: Electricity risk curves and hydro supply



Wind conditions

4.2. Total wind generation was 50GWh, 18% higher than last week. Wind generation was quite variable this week, frequently dropping as low as 50MW and then increasing to over 500MW. Most of the high prices this week occurred when wind generation was dropping or already low. Wind generation was also high when prices were low on 18 December.

Figure 11: Wind generation by trading period



Significant outages

Generation outages

4.3. There continues to be a high number of generation outages this week. Some of the outages were likely coordinated to coincide with nearby transmission outages in the South Island.

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

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

(b) Benmore,

(i) 180MW (29 November – 16 December)

(ii) 90MW (6 December – 16 December)

(c) Manapouri,

(i) 125MW (10-12 December)

(ii) 125MW (12-14 December)

(iii) 250MW (14-17 December)

(d) Tekapo,

(i) 80MW (13 September – 16 January 2022)

(ii) 80MW (9am-4pm 15 December)

(iii) 30MW (9:30am-3:30pm, 15 December)

(e) Waipori, 80MW (8 November – 11 February 2022)

(f) Aviemore, 55MW (9am-3pm, 17 December)

(g) Ohau, 55MW (29 November – 15 December)

(h) Roxburgh,

(i) 40MW, (15 November – 14 December)

(ii) 40MW (14-17 December)

(i) Nga Awa Purua, 136MW (16-17 December)

(j) Huntly,

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

(ii) Peaker, 45MW (10am-5pm 17 December)

(k) McKee, 50MW (13-18 December)

(l) Stratford peakers, 100MW, (31 October – 15 April)

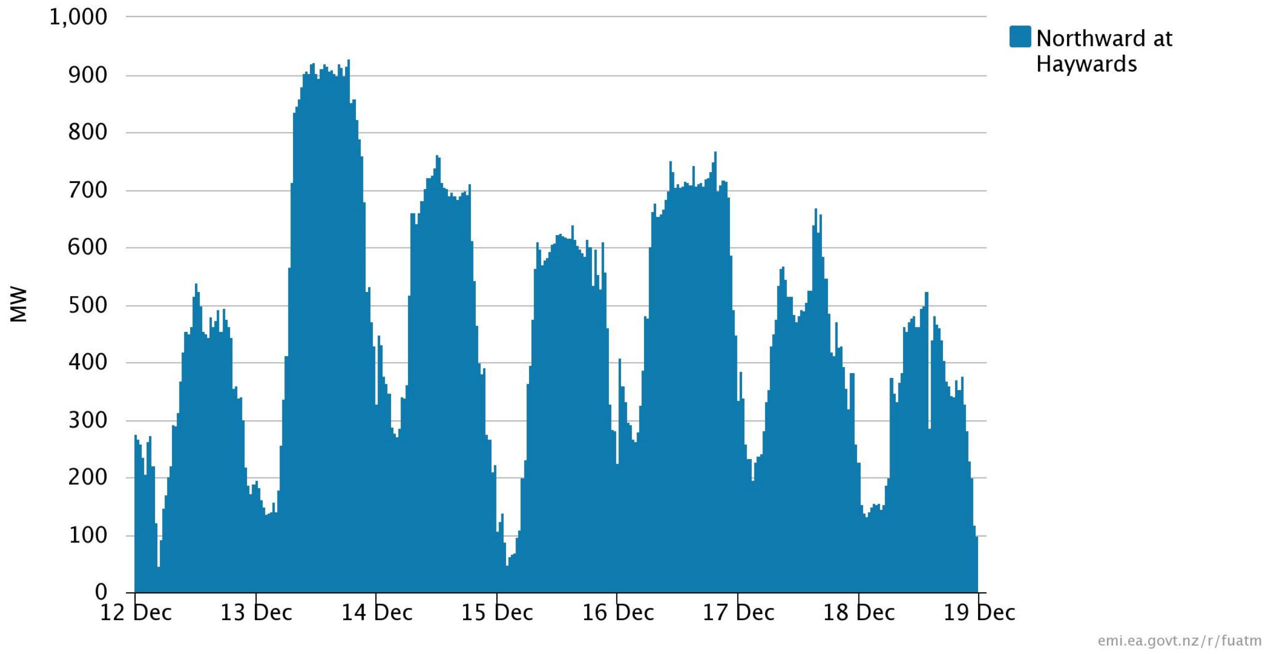
(m) Whirinaki, 52MW (15-16 December)

(n) Junction Road, 50MW (2-21 December)

Transmission outages

4.5. This week there were two major transmission outages in the lower South Island between Naseby and Roxburgh and between Aviemore and Benmore, both running from 14 December 7:30 to 17 December 18:30. As a result transmission of South Island generation was constrained, which reduced Northward transfer across the HVDC by 200-300MW. This increased North Island dispatch and caused higher prices north of the constraints, especially when wind generation was also low.

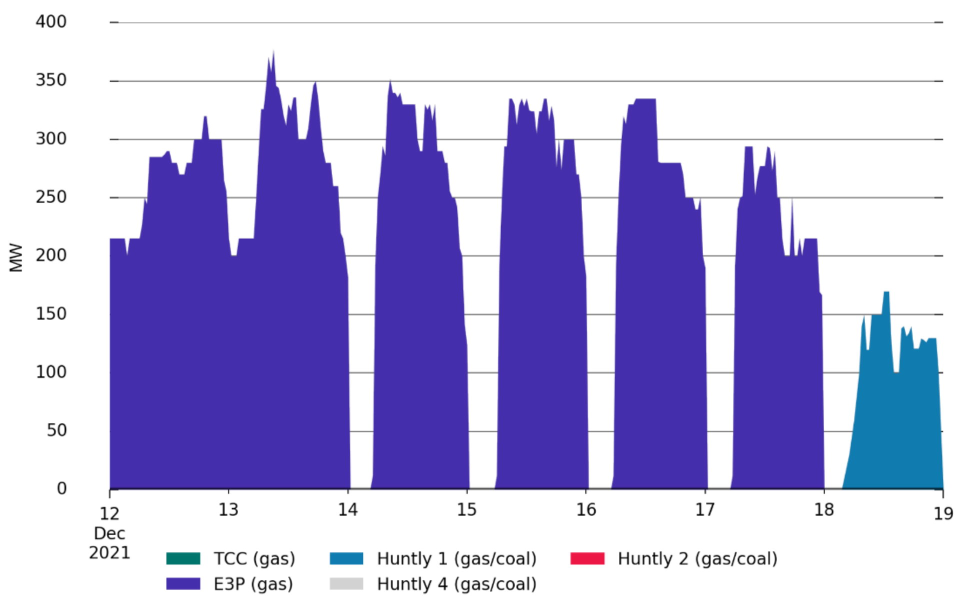
Figure 12: HVDC transfer



Thermal conditions

4.6. Huntly's E3P continued to run as thermal baseload this week, turning off overnight when demand was low. Huntly 1 ran instead of E3P on 18 December.

Figure 13: Generation from baseload thermal by trading period



4.7. The decrease in HVDC transmission from the South Island this week resulted in higher dispatch of North Island generation, especially when wind generation was low. Thermal peakers were dispatched each day between 13 and 16 December (see Figure 14). However, several thermal peakers continued to be on outage, including one Stratford Peaker. As a result, Whirinaki was dispatched for brief periods several times between 14 and 16 December (real time dispatch of Whirinaki is shown on Figure 14, as its intermittent dispatch makes it difficult to see on Figure 13).

Figure 14: Generation from thermal peakers by trading period

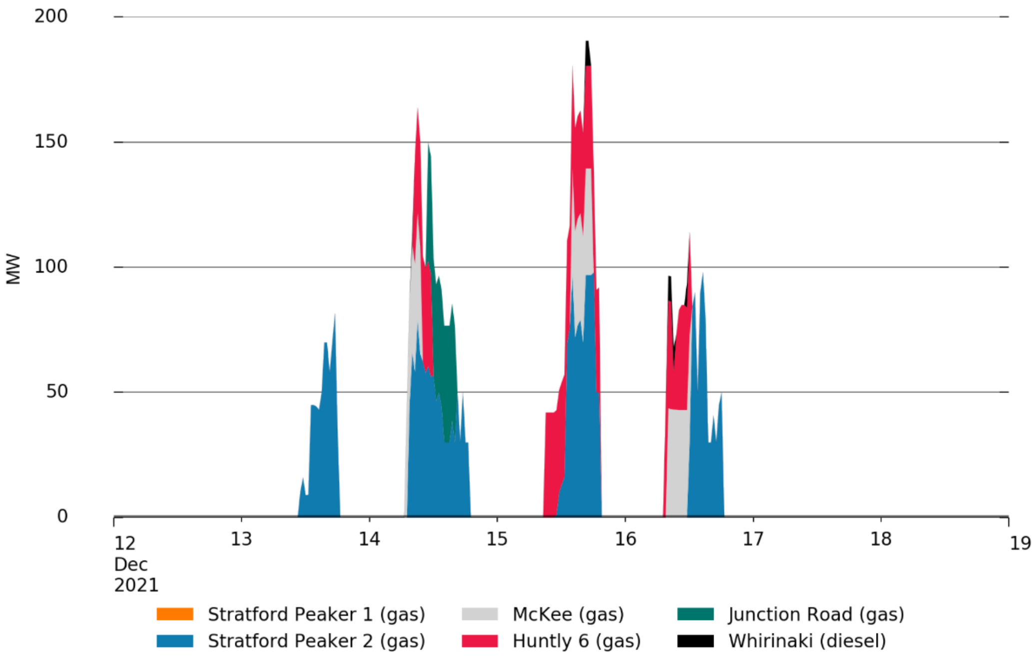


Figure 15: Real Time Dispatch of Whirinaki, 13-17 December

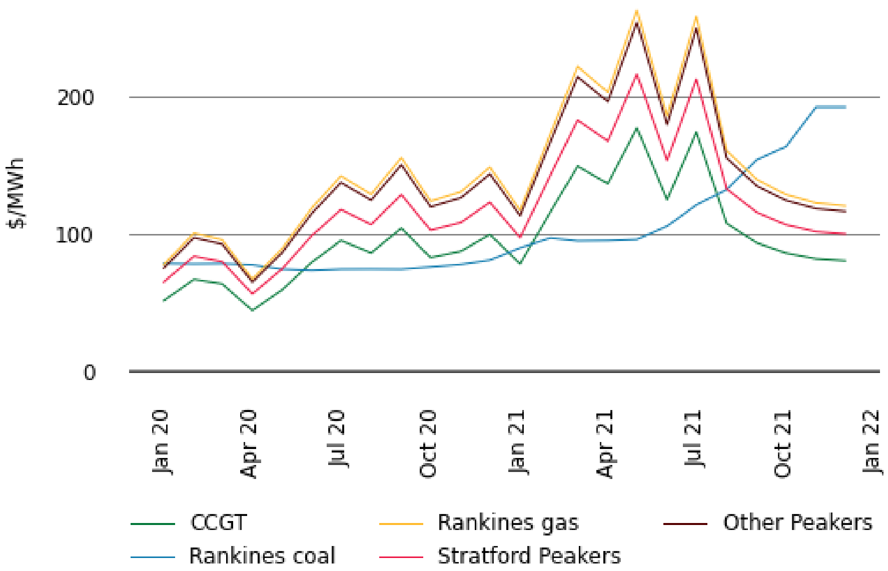
5. Price versus estimated costs

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 of gas (to 18 December) is slightly lower than the previous months and the SRMC of coal has increased over the last few months. Note that the SRMC calculations include the carbon price, an estimate of operational and maintenance costs, and transport for coal.

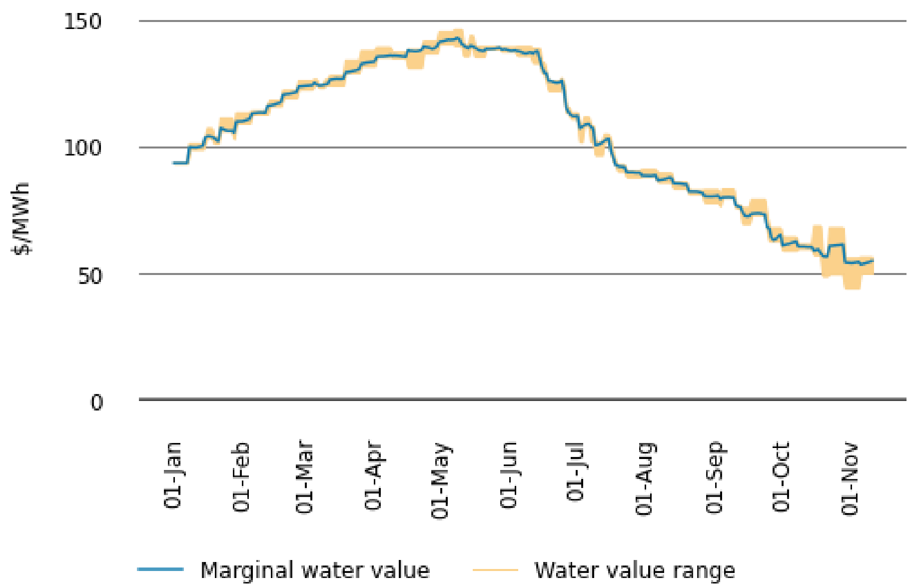
Figure 16: Estimated monthly SRMC for thermal fuels



DOASA Water values

5.3. The DOASA[2] 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 17 shows the national water values[3] 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[4]. Figure 17 shows that the marginal water value has declined since June as hydro storage levels increased and gas costs decreased.

Figure 17: DOASA water values for January- to November 2021



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[2] 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)

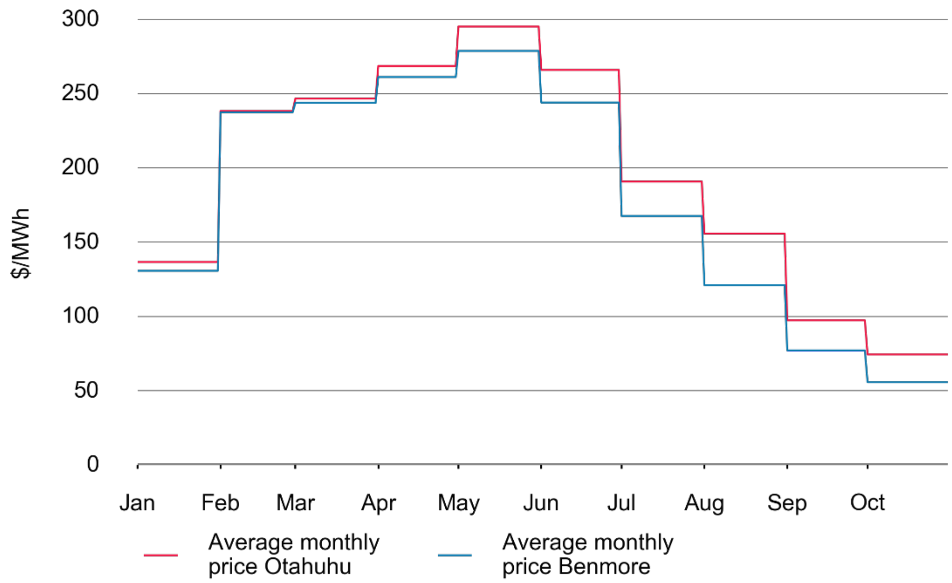
[3] The national water values are estimated assuming all hydro storage reservoirs are equally full.

[4] See Appendix B, 2 for more details

Monthly prices

5.4. Figure 18 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.

Figure 18: Average monthly prices at Otahuhu and Benmore January-October 2021



Offer Behaviour

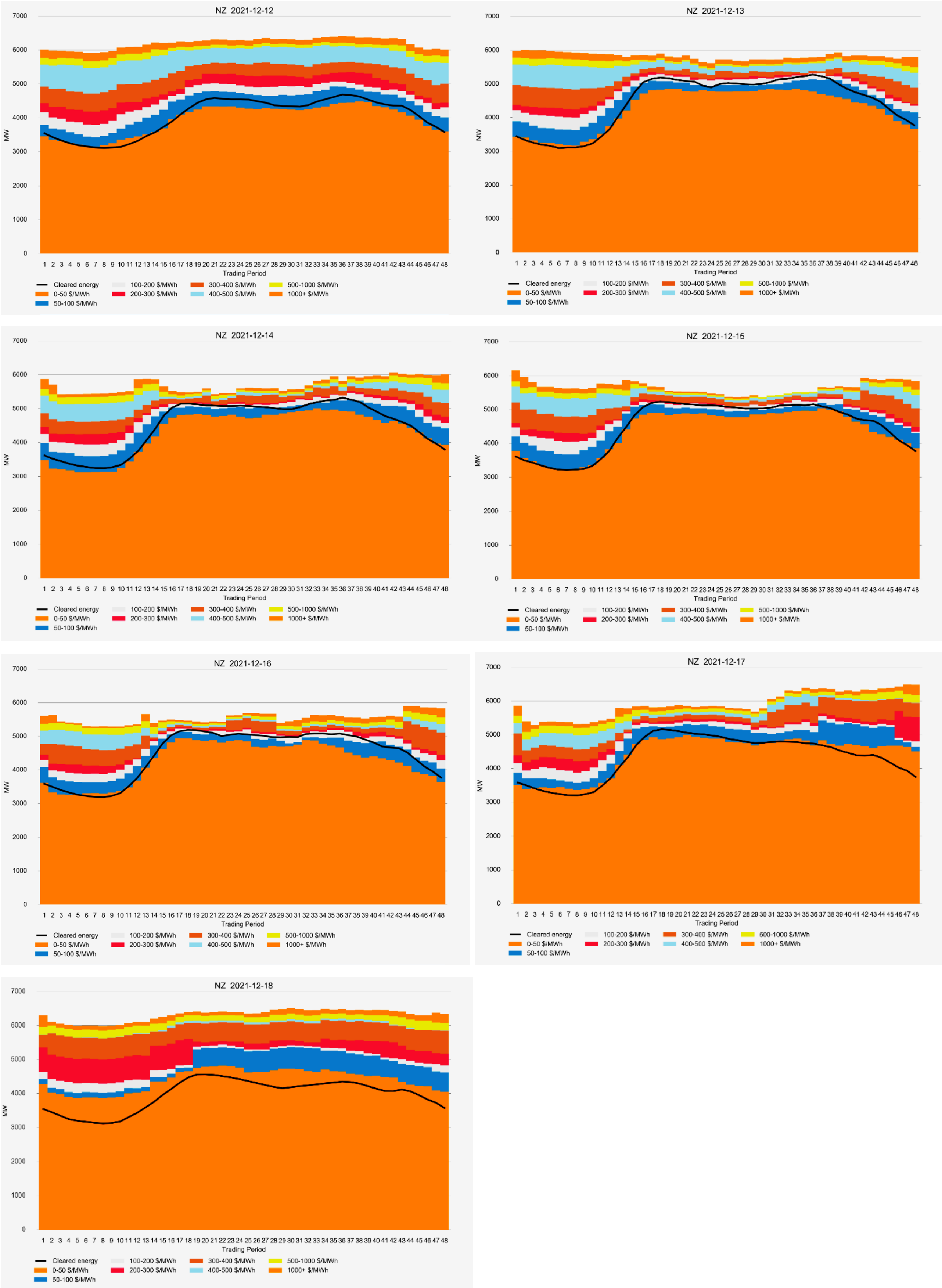
Final daily offer stacks

5.5. Figure 19 shows this week's daily offer stacks, adjusted to take into account wind generation, transmission constraints, reserves and frequency keeping.[5] The black line shows the cleared energy, indicating the range of the average final price.

5.6. This week the quantity weighted offer price increased by 5% from last week, likely due to geothermal and hydro generation outages decreasing offers at close to $0/MWh. However, the quantity total offered generation offered over $350/MWh also decreased. The offer stack was thinner on 14 to 16 December due to transmission constraints and low wind.

[5] 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 19: Daily offer stack



Offers by trading period

5.7. The offer stacks of the trading periods (TP) with the highest prices are TP17 on 14 December shown on Figure 20 along with the generation weighted average price (GWAP) and cleared generation. A similar trading period (which also had low wind) from the week before is shown in Figure 21 for comparison.

5.8. Cleared generation was not particularly high for TP17, the offer curve was steeper than similar trading period the last week, which resulted in higher prices. Whirinaki, which had offers between $354/MWh and $468/MWh, was intermittently dispatched during the trading period. The increased steepness of the offer curve was mostly due to a decrease in South Island offers, either real (some generation units were on outage) or effective (generation offered into market but not able to be cleared due to transmission constraints).

Figure 20: Offer Stack for trading period 17 on 14 December

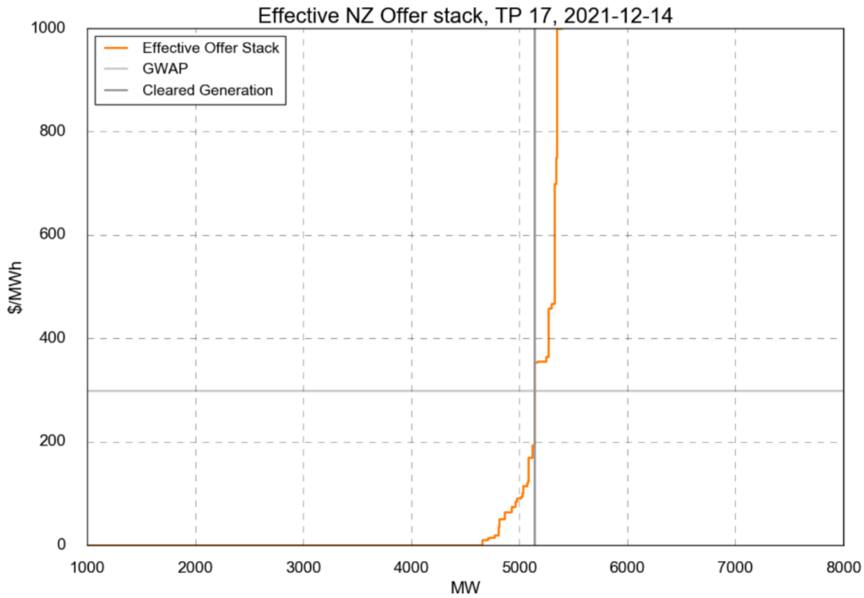
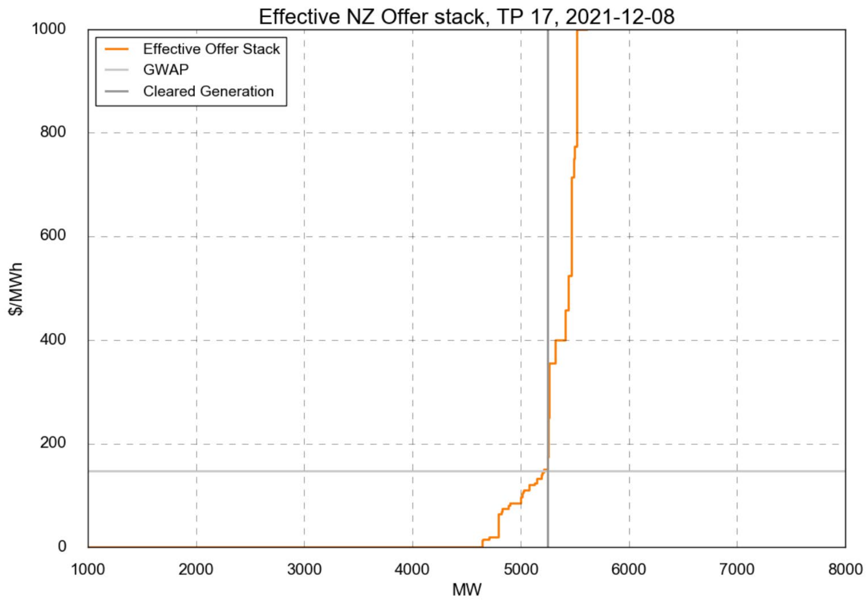


Figure 21: Offer Stack for trading period 17 on 8 December



Ongoing Work in Trading Conduct

5.9. No trading periods have been identified for further analysis.

5.10. Note, this report will be the last Trading Conduct Report published in 2021. A trading conduct report covering 19 December to 8 January will be published early next year, after which weekly reporting will resume.

Table 1: Trading periods identified for further analysis

Date	TP	Status	Notes
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

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

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[6], where diff is the first difference:

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

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

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.

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

Appendix B DOASA water value model

1. DOASA is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto.[7] DOASA was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.[8] 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

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

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.[8]

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).

    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

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[7] M V Pereira and L M Pinto, "Multi-stage stochastic optimization applied to energy planning," Mathematical Programming 52, (1991): 359–375.

[8] Electricity Authority, "Doasa overview," https://www.emi.ea.govt.nz/Wholesale/Tools/Doasa.

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