19 January 2022

Trading Conduct Report

Market Monitoring Weekly Report

1. Overview for the week of 9 to 15 January

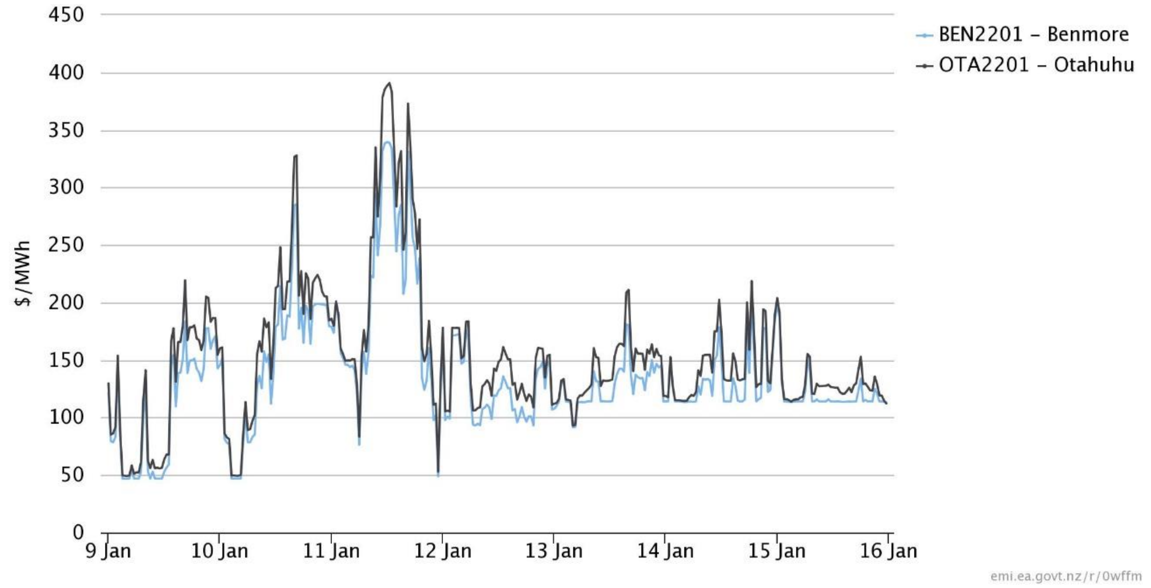
1.1. While supply and demand conditions, such as increased demand and outages, have contributed to higher prices this week, further analysis will be done in relation to recent high prices, especially on 11 January.

2. Prices

Energy prices

2.1. The average spot price this week was $157/MWh[1], 60% higher than last week. Prices were variable at the start of the week, ranging between $50-$400/MWh (see Figure 1). From 12 January onwards, prices were usually between $100-$200/MWh. Prices were highest on 11 January with highest price of $354/MWh occurring at TP26.

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

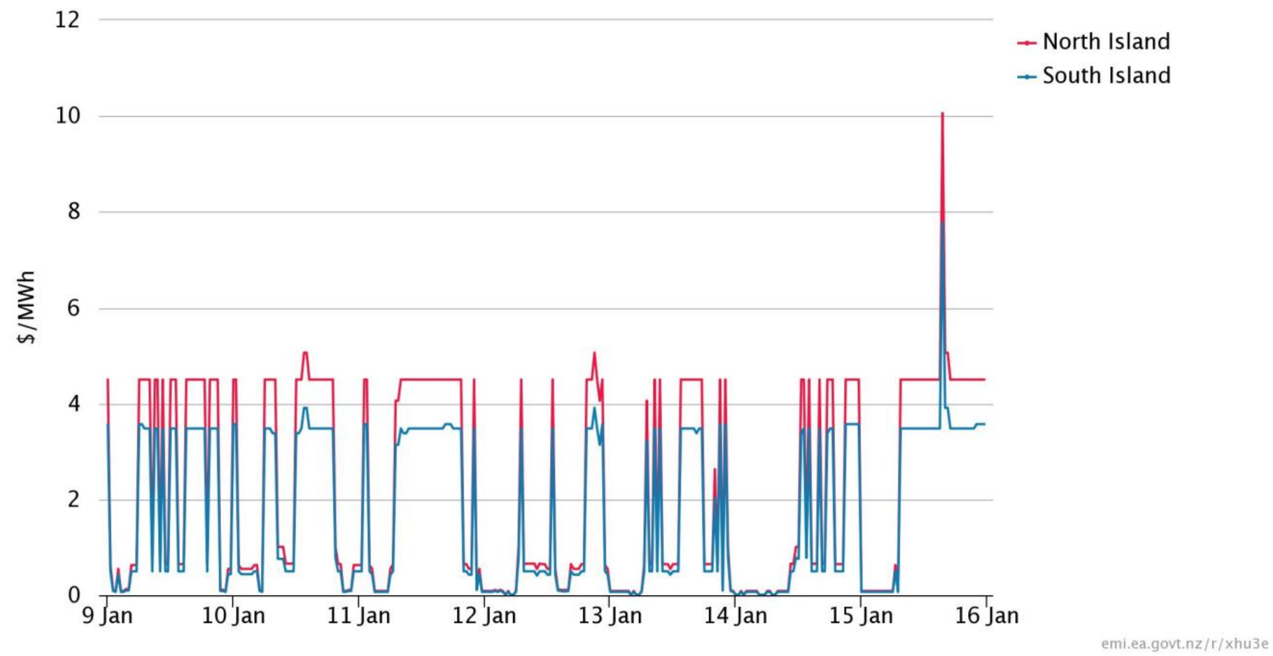


[1] The simple average of the final price across all nodes, as shown in the trading conduct summary dashboard

Reserve Prices

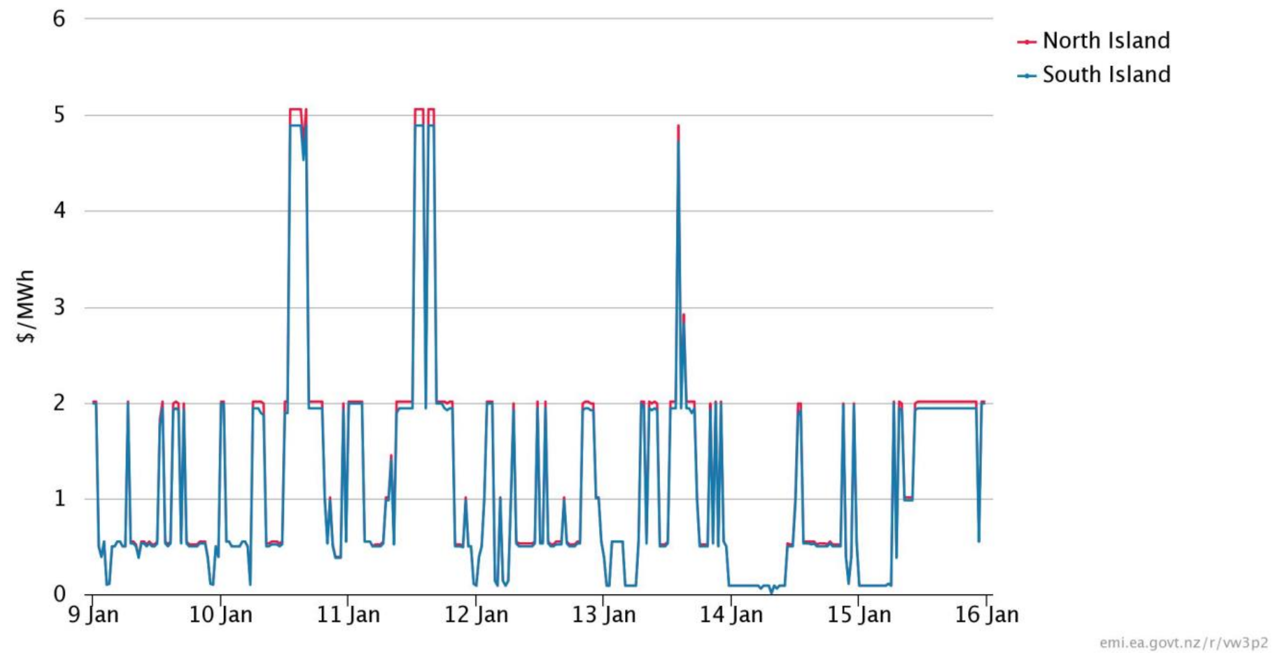
2.2. Fast instantaneous reserves (FIR) prices were usually below $6/MWh this week.

Figure 2: FIR prices by trading period and Island



2.3. Sustained instantaneous reserves (SIR) prices were below $6/MWh for the whole week.

Figure 3: SIR prices by trading period and Island

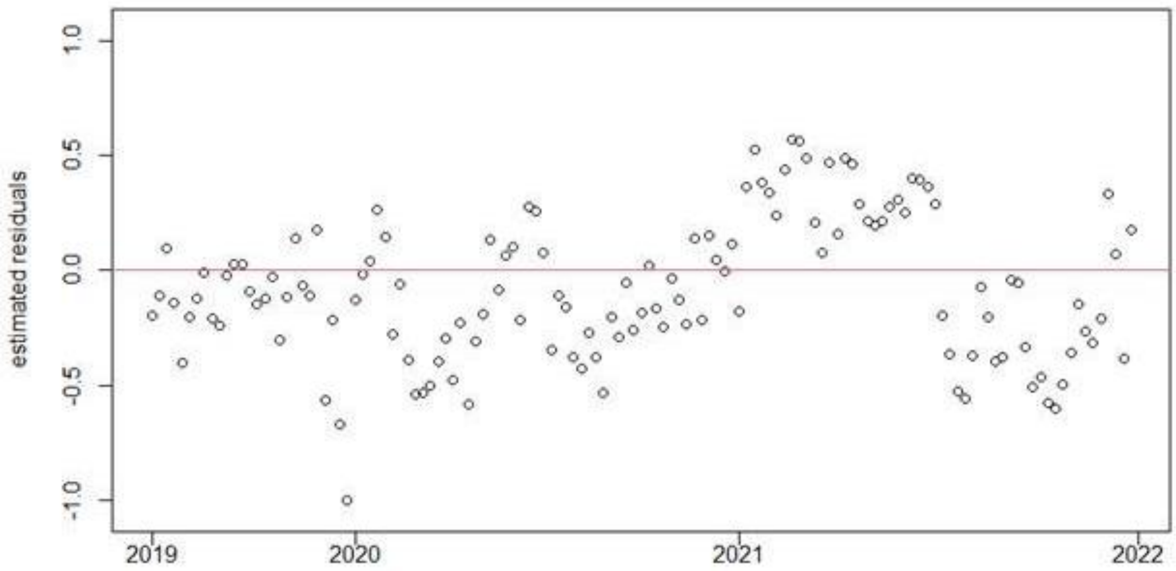


Residuals from regression models

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.

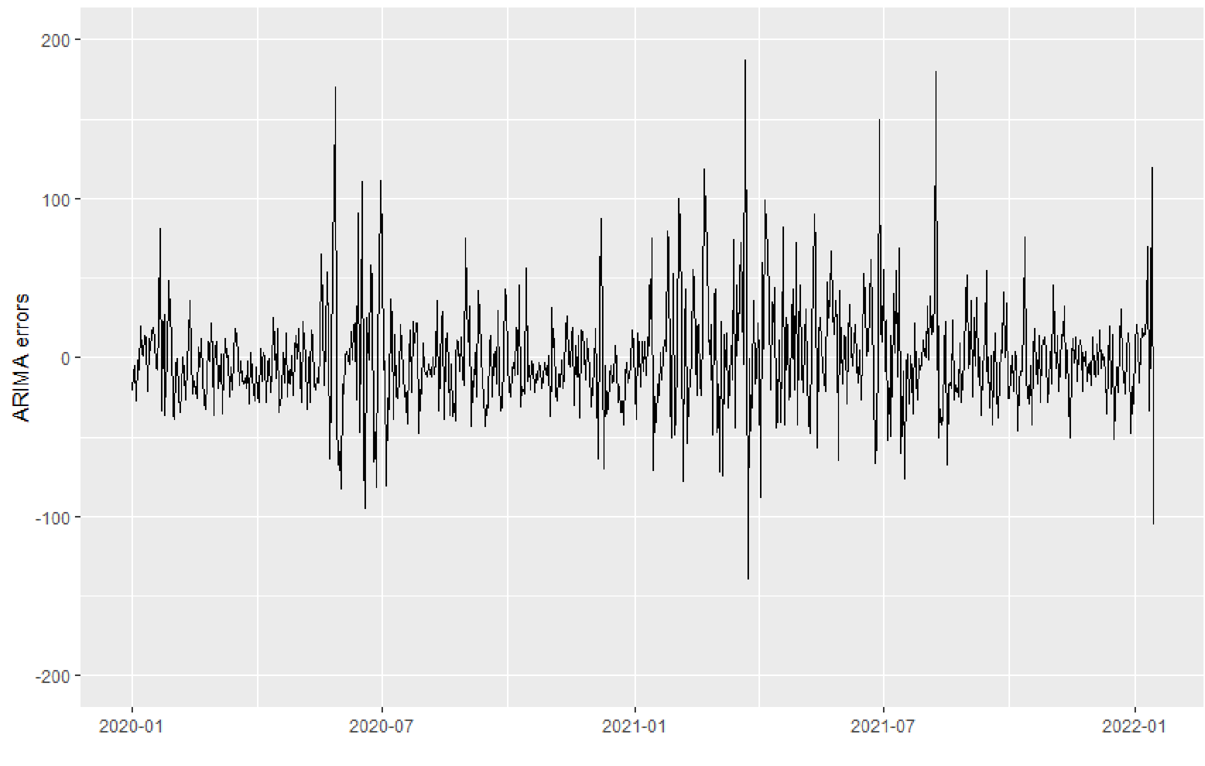
2.5. Figure 4 shows the residuals from the weekly model. During December 2021 the residuals were within the normal range, indicating that weekly prices were close to the model's predictions.

Figure 4: Residual plot of estimated weekly price from 2 July 2019 to 31 December 2021



2.6. Figure 5 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. This week the daily residuals were larger than they have been over the last few months. This indicates that prices over the last week warrant further analysis.

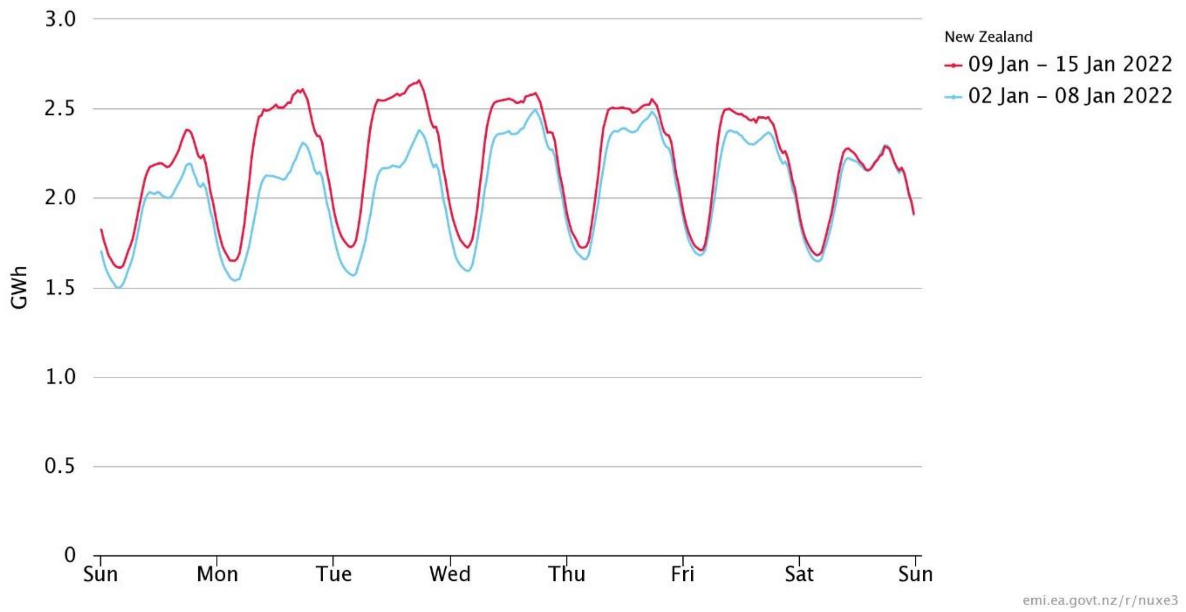
Figure 5: Residual plot of estimated daily average spot price from 1 July 2020 to 18 December 2021



3. Demand Conditions

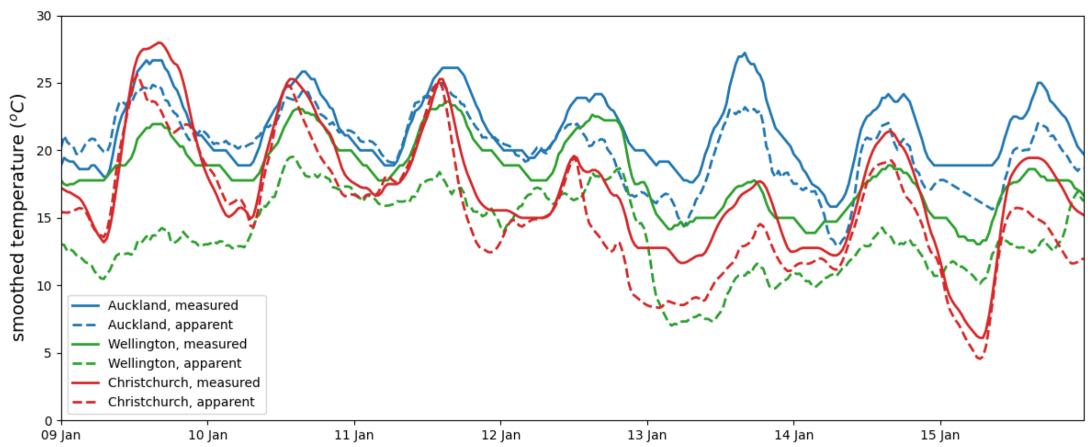
3.1. National demand was higher than the previous week (see Figure 6) due to being the first full working week of the year. Demand was highest on Monday and Tuesday evening, likely due to high temperatures in the main population centres (see Figure 7) and increased irrigation.

Figure 6: National demand by trading period compared to the previous week



3.2. Figure 7 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 warmer during the first half of this week, with measured temperatures above 25°C occurring, especially in Christchurch and Auckland.

Figure 7: Hourly temperature data (actual and apparent) and humidity data at main population centres

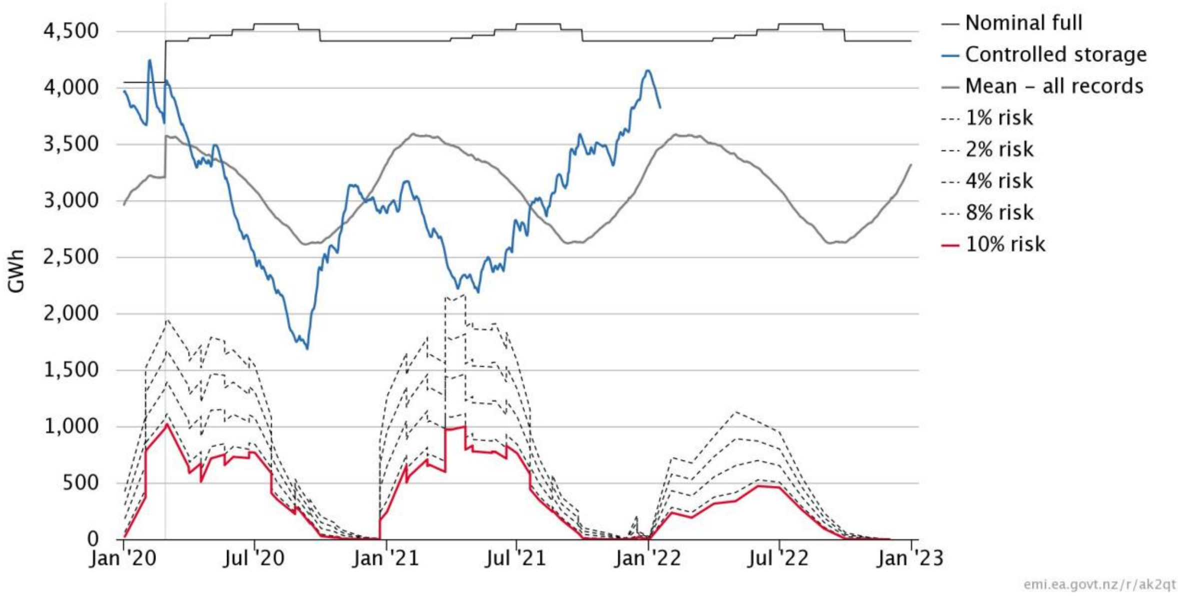


4. Supply Conditions

Hydro conditions

4.1. National hydro storage continued to decrease this week, shown in Figure 8.

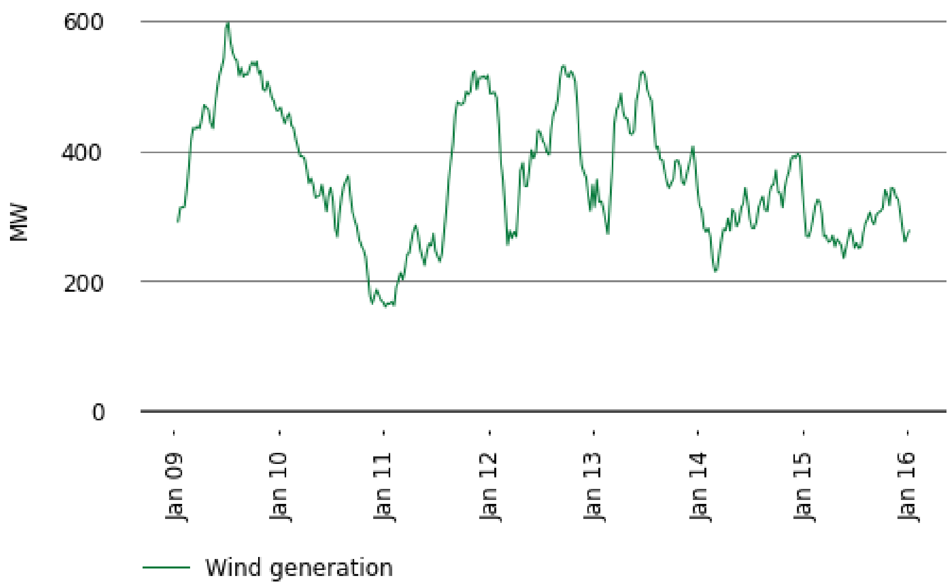
Figure 8: Electricity risk curves and hydro supply



Wind conditions

4.2. Total wind generation was 89GWh, 154% higher than last week. Wind generation was usually between 200 and 500MW this week. Wind generation was between 160 and 300MW on the morning of 11 January, when the highest prices occurred, but increased to over 450MW by TP32, so low wind generation only partially explains high prices on 11 January.

Figure 9: Wind generation by trading period



Significant outages

Generation outages

4.3. There was a high number of generation outages this week, especially in the lower South Island, where up to a quarter of hydro generation capacity was on outage. Some of the outages were likely coordinated to coincide with nearby transmission outages.

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

(a) Clyde,
    (i) 116MW (15 Feb 2021 – 20 May 2022)
    (ii) 116MW (9:30-14:30, 11 January)
(b) Benmore,
    (i) 90MW (10-21 January)
    (ii) 90MW (15-16 January)
(c) Manapouri,
    (i) 125MW (22:22-23:00 9 January)
    (ii) 125MW (9-14 January)
    (iii) 125MW (10-12 January)
    (iv) 125MW (9:34-13:00 10 January)
    (v) 125MW (14:42-18:00 14 January)
(d) Tekapo, 80MW (13 September 2021 – 16 January 2022)
(e) Waipori, 80MW (8 November 2021– 11 February 2022)
(f) Aviemore, 55MW (06:35 – 12:30, 10 January)
(g) Ohau,
    (i) 50MW (06:00-17:00, 11 January)
    (ii) 53MW (06:00-18:00 13 January)
    (iii) 116MW (06:30-19:30 13 January)
(h) Roxburgh,
    (i) 40MW (11-14 January)
    (ii) 40MW (11-18 January)
    (iii) 50MW (11-21 January)
(i) Huntly,
    (i) Rankine, 240MW (20 December 2021 – 26 January 2022)
    (ii) E3P, 145MW (23:30 11 January – 01:00 12 January)
    (iii) E3P, 145MW (00:00-01:30 13 January)
    (iv) Peaker, 45MW (10:00-16:00 13 January)
(j) Stratford peakers,
    (i) 100MW, (31 October 2021 – 30 April 2022)
    (ii) 100MW (02:00-15:00 15 January)

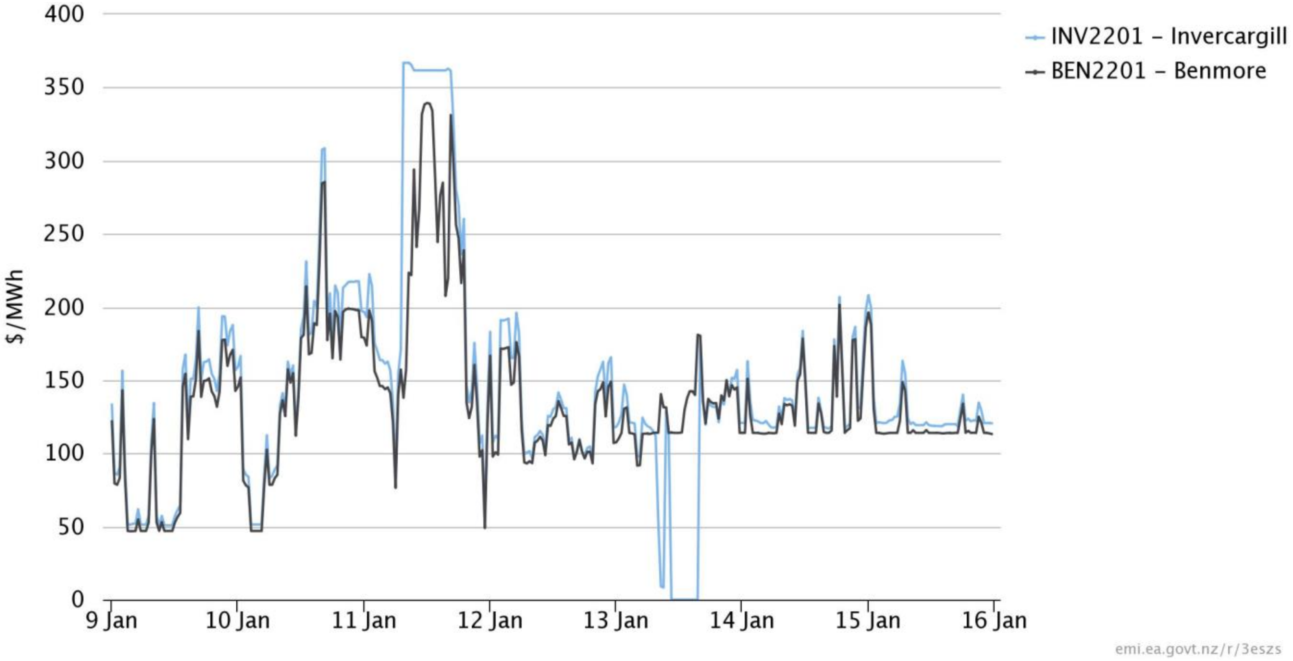
(k) McKee, 50MW (09:00-14:00 13 January)

Transmission outages

4.5. This week there were several transmission outages in the lower South Island. On 11 January there was a transmission outage of one of the lines from Clyde to Roxburgh from 7:30 to 16:30 on 11 January which increased load on the other line from Clyde to Roxburgh and one the line between Livingston and Naseby. Generation south of these lines was also low (primarily due to outages), which caused these transmission lines to bind while flowing south and reduced northward transmission across the HVDC. Demand was also high this day resulting in high prices, especially in Invercargill (see Figure 10).

4.6. On 13 January there was an outage between Ohau and Twizel, constraining generation from Ohau. This resulted in the Livingstone, Naseby, Clyde and Roxburgh transmission line binding while flowing northwards. This resulted in low prices in Invercargill.

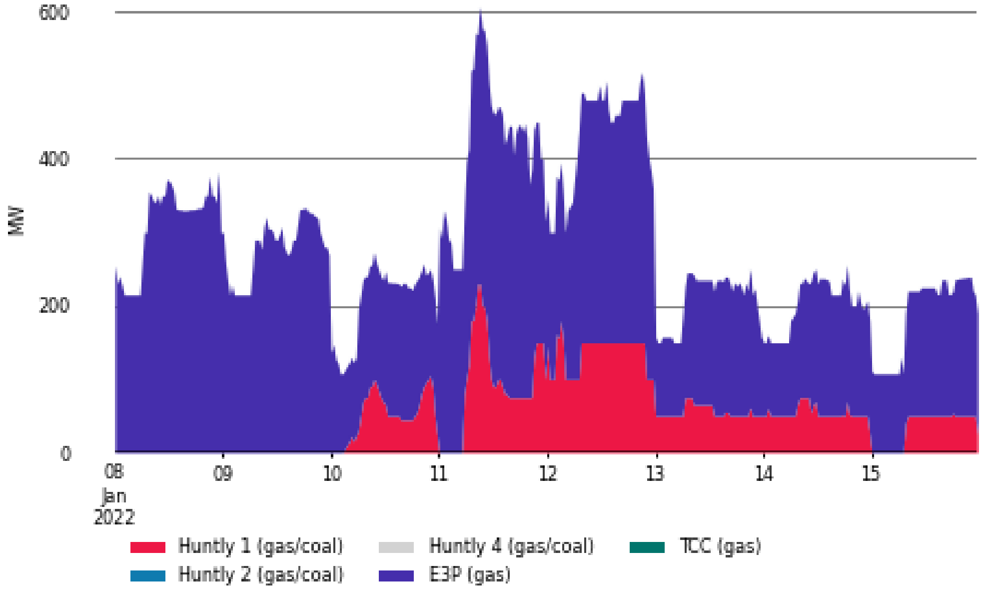
Figure 10: Spot prices by trading period at Invercargill and Benmore



Thermal conditions

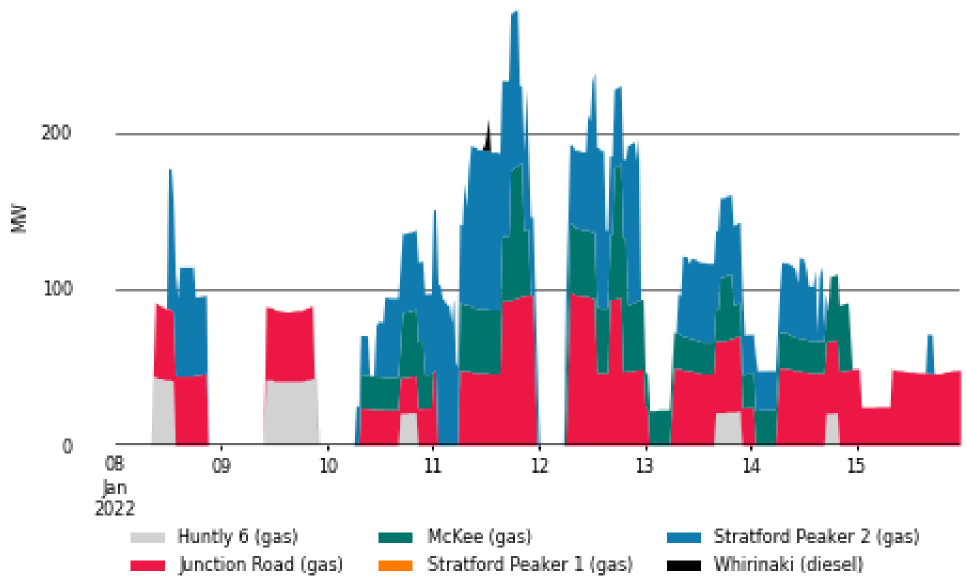
4.7. This week the E3P ran as thermal baseload the whole week, with Huntly 1 running from 10 January. Thermal baseload was highest on 11 January, due to a combination of low wind, high demand and low northward transfer across the HVDC, which all increased demand for North Island generation.

Figure 11: Generation from baseload thermal by trading period



4.8. All the thermal peakers ran this week, except Stratford peaker 1 which is on outage. Huntly 6 was also on outage on 11 January. Whirinaki briefly ran in the middle of the day on 11 January, potentially due to a drop in North Island wind. More peaker units were dispatched as demand increased in the afternoon.

Figure 12: Generation from thermal peakers by trading period



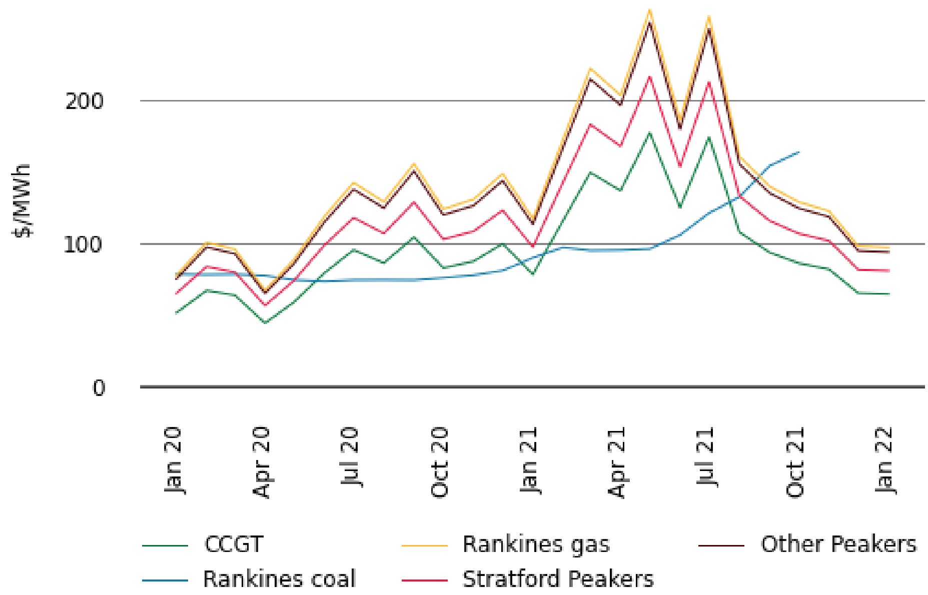
5. Price versus estimated costs

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 15 January) 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 13: Estimated monthly SRMC for thermal fuels

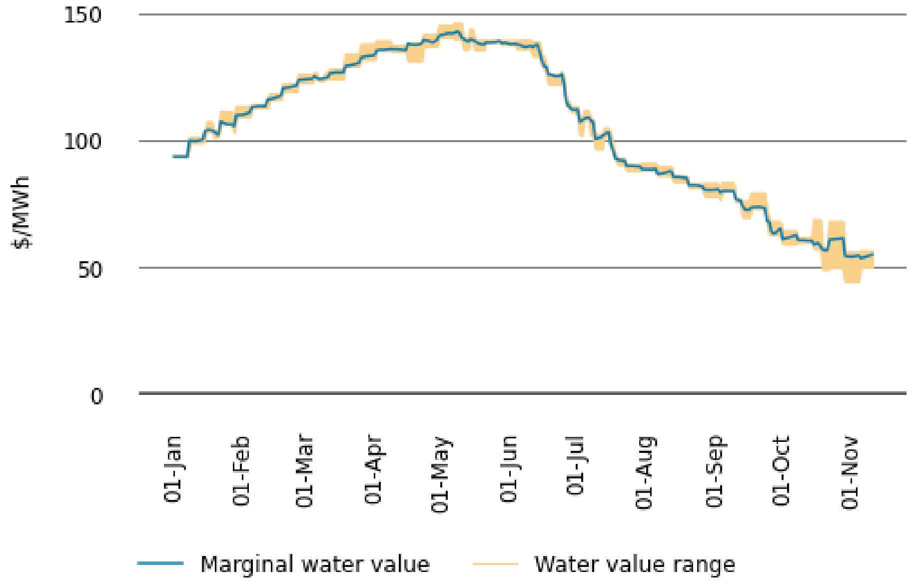


DOASA Water values

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 14 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 14 shows that the marginal water value has declined since June as hydro storage levels increased and gas costs decreased.

[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

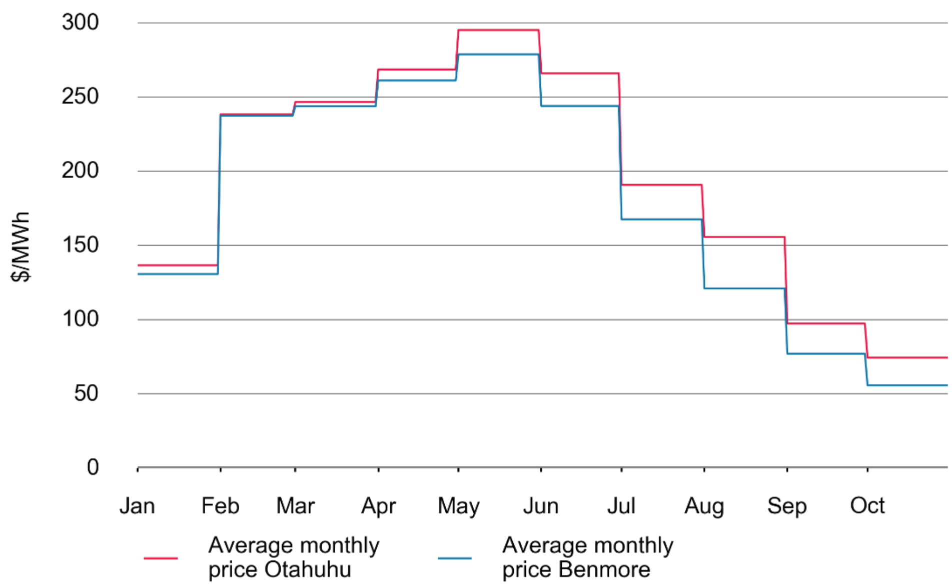
Figure 14: DOASA water values for January- to November 2021



Monthly prices

5.4. Figure 15 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 15: Average monthly prices at Otahuhu and Benmore January-October 2021

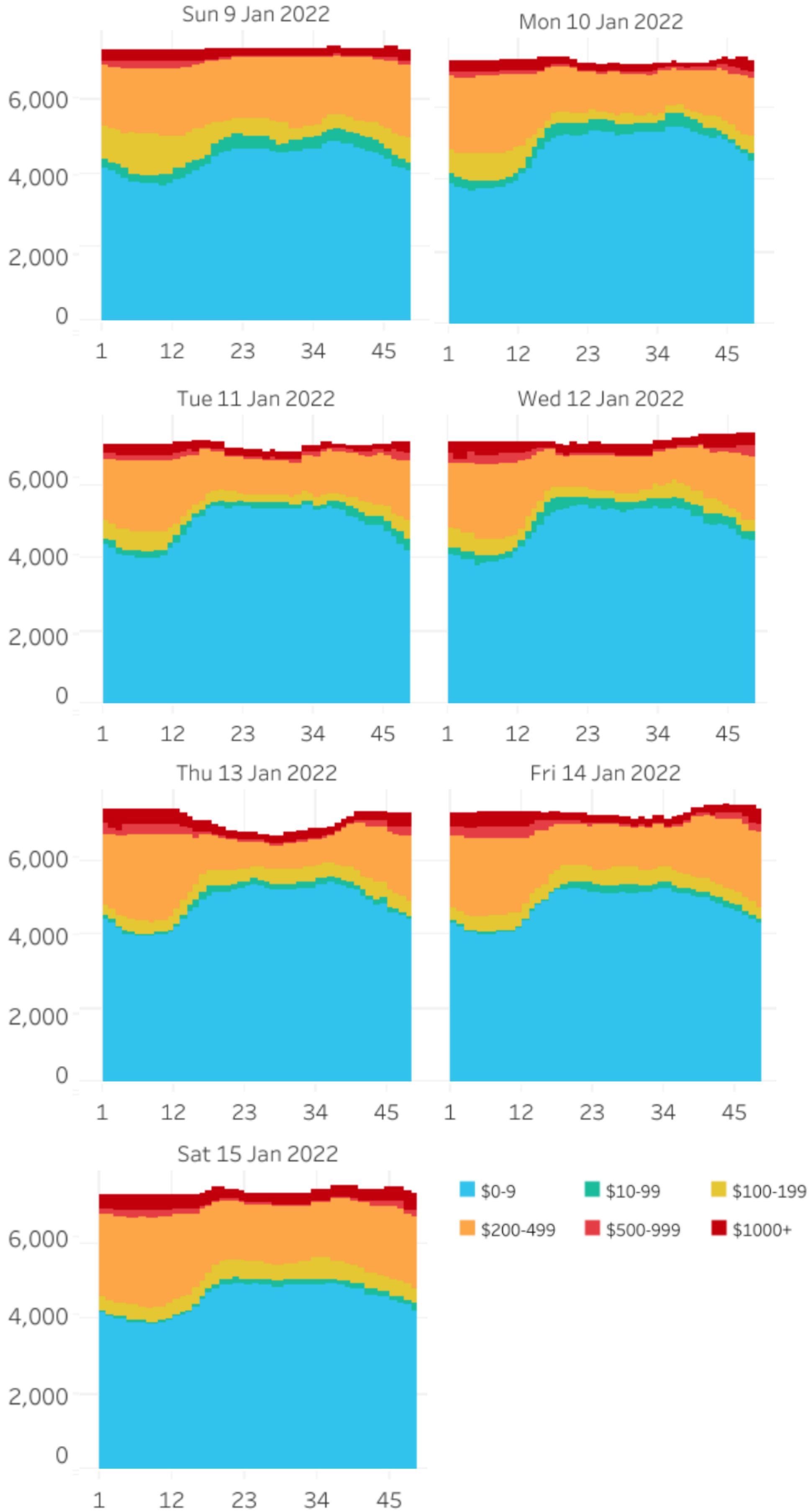


Offer Behaviour

Final daily offer stacks

5.5. Figure 16 shows this week's raw daily final offer stacks. The offer stacks show all offers bid into the market in price bands. Note that these offer stacks have not been adjusted to account for actual wind generation or for capacity dispatched as reserve.

Figure 16: Daily offer stack



5.7. The offer stacks continue to be thin between $10-$199/MWh which means small changes in demand or wind generation can have large impacts on prices. Total generation offered was lower from 11 to 13 January, predominantly due to outages.

Ongoing Work in Trading Conduct

5.8. Some trading periods have been identified for further analysis, particularly on 11 January.

5.9. The Authority's compliance team has obtained information regarding withdrawn reserve offers and high energy prices. Further clarification and analysis is under way to consider compliance with the Code.

Table 1: Trading periods identified for further analysis

Date	TP	Status	Notes
10/01-11/01	Several	Further Analysis	Prices over $300/MWh, increase in outages – further information being sought
02/01-08/01	Several	Further Analysis	High energy prices, low wind, low demand
30/06-20/08	Several	Compliance enquiries in progress	High energy prices in shoulder periods
30/06-21/08	Several	Compliance enquiries in progress	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[5], where diff is the first difference:

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

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

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 $\left(storage_t - 20.year.mean.storage_{dayofyear}\right)$

Appendix B DOASA water value model

1. DOASA is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto.[6] DOASA was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.[7] 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.[7]

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).

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