Market Performance Quarterly Review

April-June 2021

Information paper

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1 Purpose of this report

1.1 This document covers a broad range of topics in the electricity market. It is published quarterly to provide visibility of the regular monitoring undertaken by the Electricity Authority (Authority).

1.2 This report also includes:

(a) A dynamic regression analysis of spot price drivers

2 Highlights

2.1 Over the period, cold weather increased demand week on week, breaking the previous record for peak demand.

2.2 The retail market saw a small increase in the number of new connections while switching numbers maintained their post-Covid levels.

2.3 High wholesale spot prices and high price volatility from the March quarter continued to persist throughout the June quarter. Market conditions were exacerbated by lower than average hydro storage and limited gas production.

2.4 Conservative water management combined with high inflows from above average rainfall increased hydro storage during a time of year when storage historically declines.

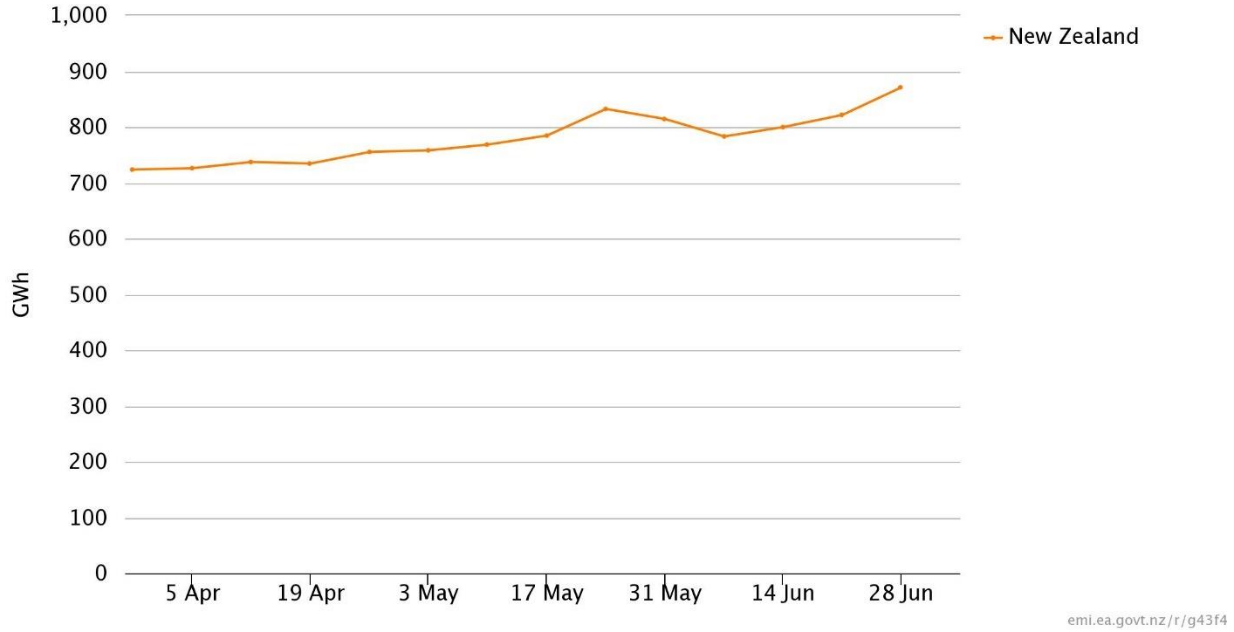
2.5 Low gas production increased coal fuelled thermal generation. Major market participants reached agreements to help ease the tight fuel supply. Tiwai entered an agreement to voluntarily reduce its load and Methanex agreed to a gas swap with Genesis.

2.6 Forward prices continued to remain above historical average levels.

3 Demand

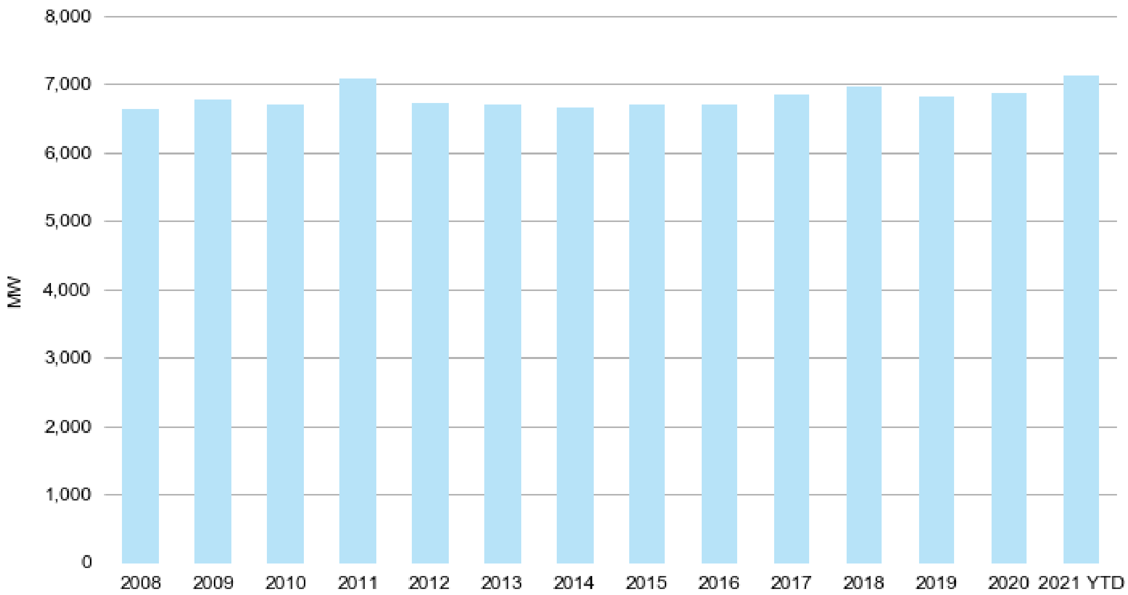
3.1 Electricity demand grew alongside cooling weather over the quarter. With winter approaching weekly demand increased from 723.8 GWh to 821.7 GWh, peaking at 832.5 GWh as shown in Figure 1.

Figure 1: Weekly Grid Demand June Quarter 2021



3.2 Figure 2 shows peak demand for each year from 2011 to 30 Jun 2021. Peak demand in 2021 exceeded peak demand from previous years breaking historical records. On 6pm 29 June 2021 Transpower recorded weekly peak demand at 6,924 MW breaking the previous record of 6,902 MW from 15 August 2011[1]. The spike in demand was due to unusually cold weather caused by an Antarctic cold front.

Figure 2: Peak Demand 2011-2021



3.3 Reconciled demand for each month April, May and June was higher than its equivalent 2011-2020 average by 3 per cent, 2.6 per cent and 0.9 per cent respectively.

3.4 At the end of June Norske Skog closed its Tasman pulp and paper mill in Kawerau citing reasons including decreased demand for product and increased electricity costs. The closure frees up 270 GWh annually.

3.5 To help with security of supply Tiwai agreed to a voluntary electricity swap with Meridian to curb its hourly power usage by up to 30.5MW from 28 April to 31 May.

4 Retail

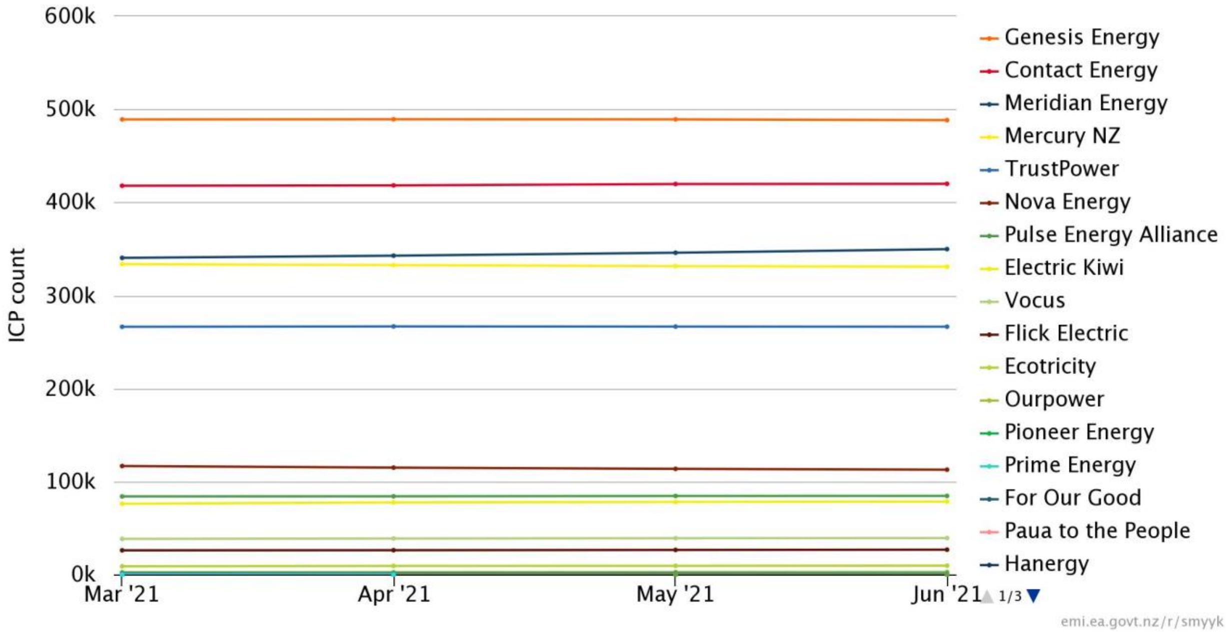
4.1 The retail market is currently composed of five large retailers and over 30 small to medium sized retailers. Collective market share of the five largest retailers Contact, Genesis, Mercury, Meridian and TrustPower was 83.8 per cent at the beginning of the quarter, growing marginally to 83.83 per cent by the end of the quarter. Collective market share of small and medium sized retailers fell by a corresponding 0.03 per cent.

4.2 On 30 June 2021 the five largest retailers held 1,852,570 ICPs between them while the remaining retailers held 357,960 ICPs. Overall, the total number of ICPs grew by 6,543 from 2,203,987 ICPs to 2,210,530 ICPs. Figure 3 shows the total ICP count for each retailer from 31 March 2021 to 30 June 2021. Genesis has remained the largest retailer, gaining 47 ICPs. Contact gained 1,849 ICPs, Meridian gained 5,560 ICPs, Mercury lost

[1] https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/New%20record%20demand%20set%20on%2029%20June%202021.pdf

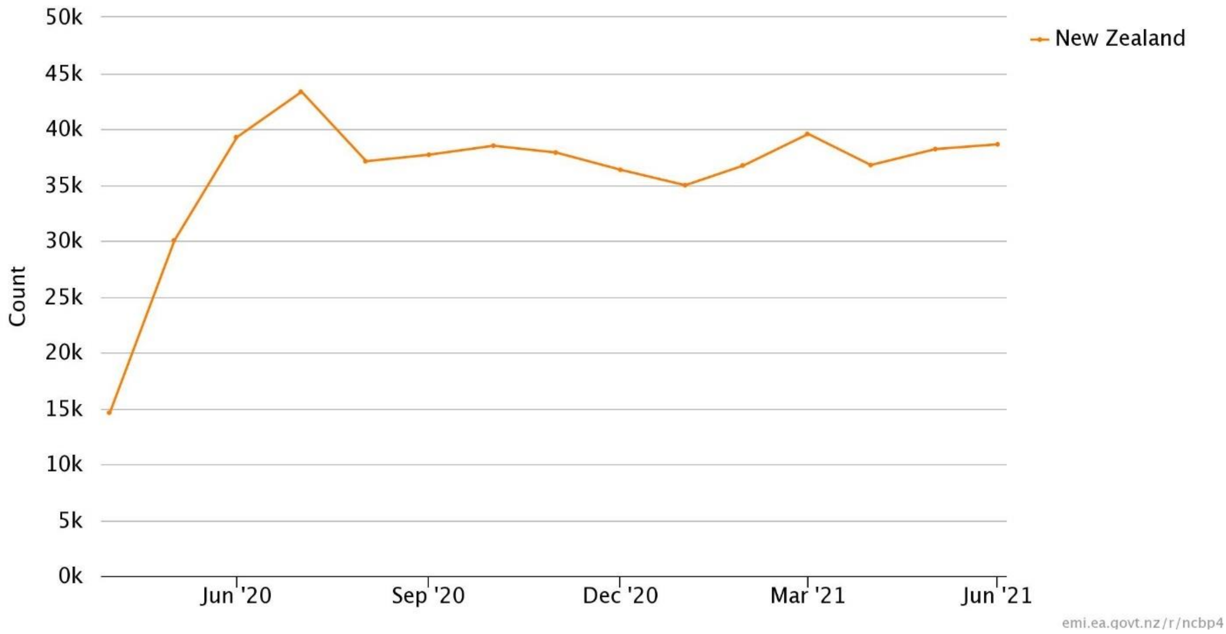
2,152 ICPs and TrustPower gained 204 ICPs. Of the small to medium sized retailers Electric Kiwi grew the most, gaining 2,047 ICPs.

Figure 3: ICP Count by Retailer June Quarter 2021



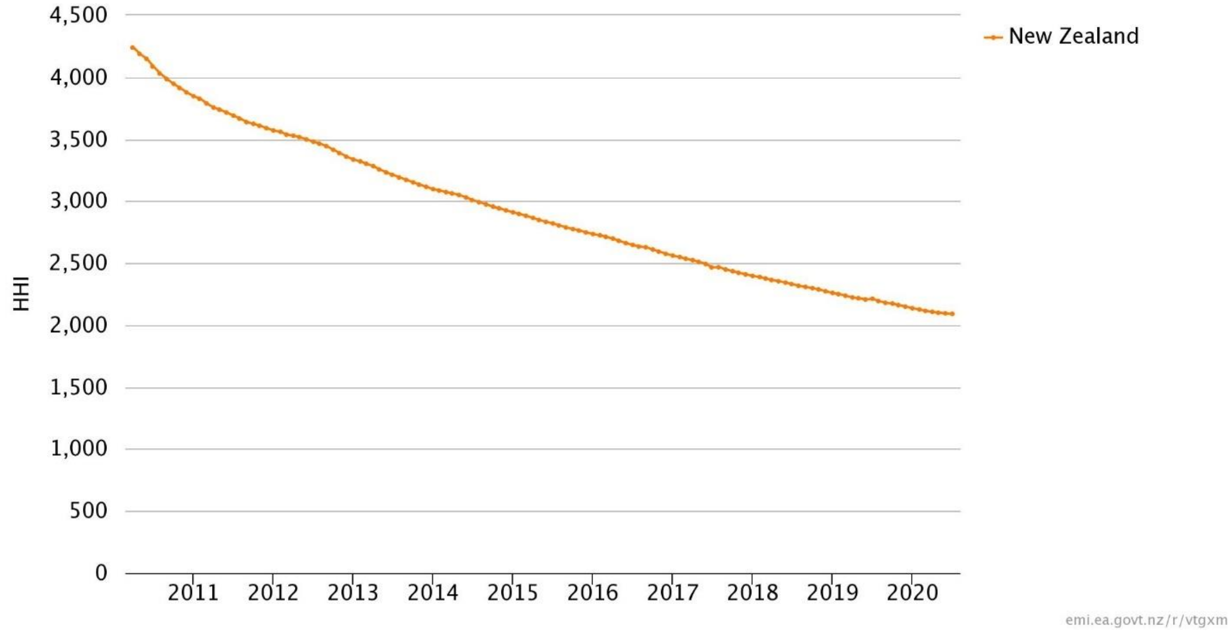
4.3 Figure 4 shows the total number of switches from 1 April 2020 to 30 June 2021. Switching for this quarter continued to remain steady, staying within the 35k to 45k range reached post-Covid.

Figure 4: Switching Past Year



4.4 The Herfindahl-Hirschman Index (HHI) provides a measure of market concentration, a lower number indicates a less concentrated market implying increased competition. The HHI for the electricity retail market as seen in Figure 5 has continued to drop over time and at the end of the June quarter was 2,091, indicating that competition in the retail market continues to improve.

Figure 5: HHI of Retail Market Last 10 Years

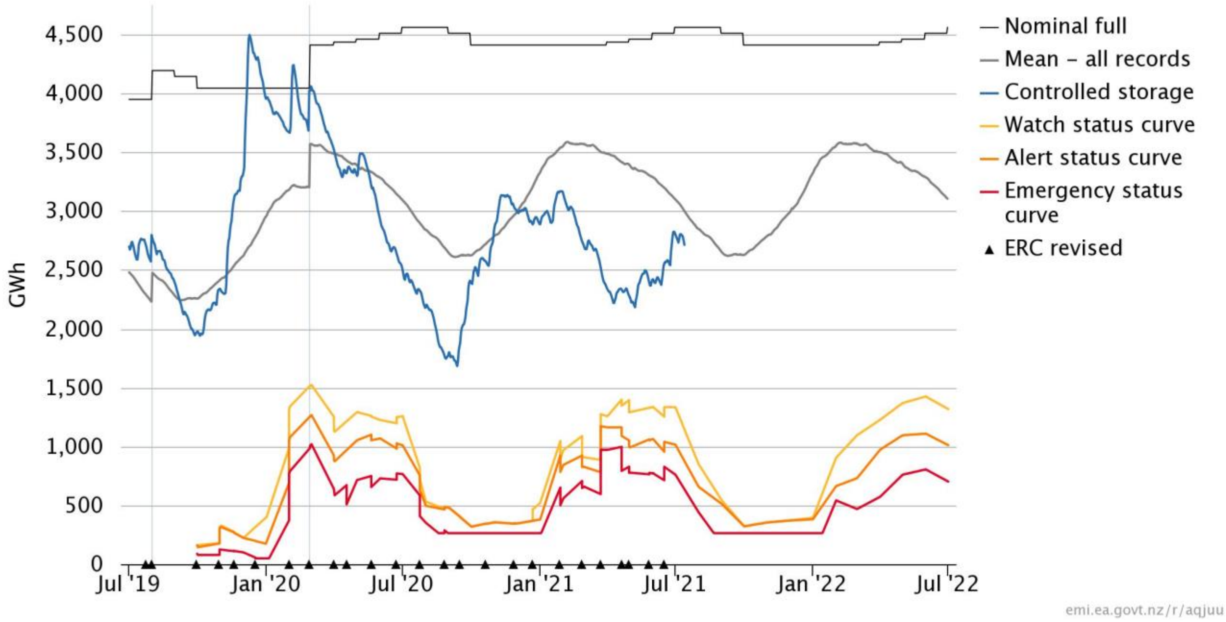


4.5 The fifth largest gentailer, TrustPower, while undergoing a strategic review at the beginning of the year looked at splitting its retail and generation arms into two separate businesses, selling off its retail arm and rebranding to focus on its generation business. On 21 June 2021 TrustPower announced the conditional sale of its retail business (excluding commercial and industrial customers) to Mercury for $441 million, subject to post-completion adjustments. The sale is expected to be completed in late 2021 and TrustPower's remaining generation arm is expected to rename to better distinguish itself as a separate business.

5 Wholesale

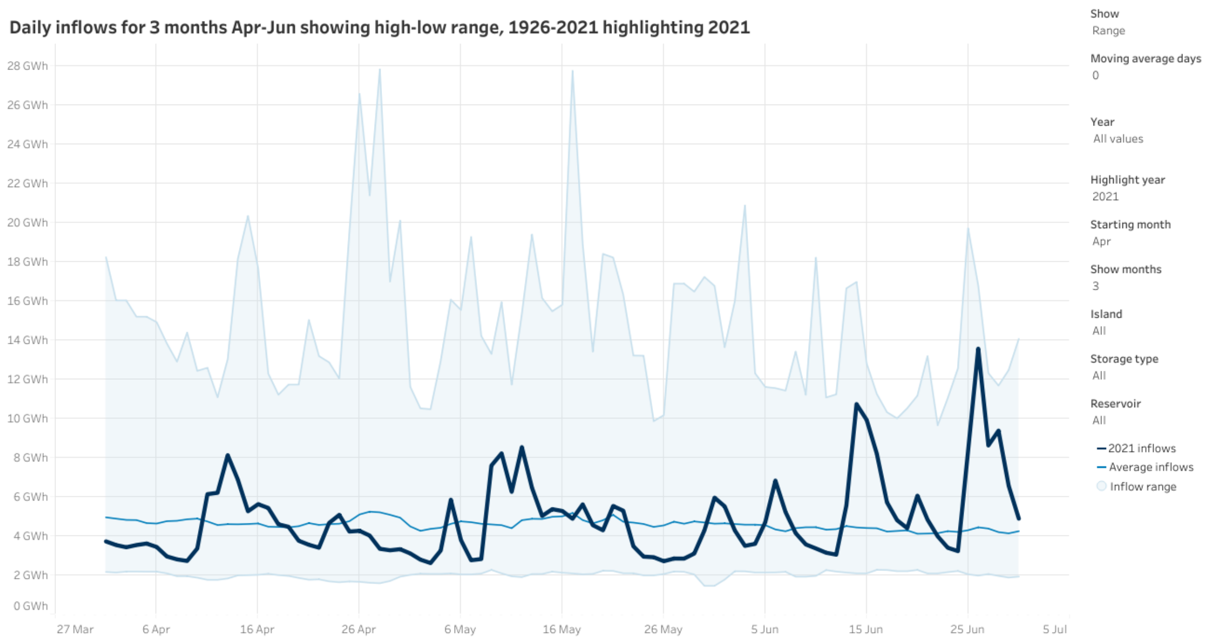
5.1 Figure 6 shows national controlled hydro storage to 30 June 2021. From the beginning of the quarter total controlled hydro storage increased, approaching the historical average by the end of the quarter. On 1 April 2021 hydro storage was 2,337 GWh, 67 per cent of the historical average for that day of year, 3,488 GWh. By 30 June 2021 hydro storage rose by 480 GWh to 2,817 GWh, 90.7 per cent of the historical average for that day of year, 3,106 GWh. As a result national hydro storage is unlikely to reach the alert status curves for the remainder of the year and concern over security of supply has lessened.

Figure 6: Controlled Hydro Storage to 30 June 2021



5.2 The growth in hydro storage which was against historical trends was due to above average inflows and conservative water management. Hydro inflows from 1 April 2021 to 30 June 2021 are mapped in Figure 7 against the historical average and historical range generated from 1926-2020 data. Hydro inflows for this quarter were 5.8 per cent above the historical average for the same period. An improvement on the March 2021 quarter when inflows were 27.7 per cent below the historical average.

Figure 7: Daily Inflows June Quarter 2021



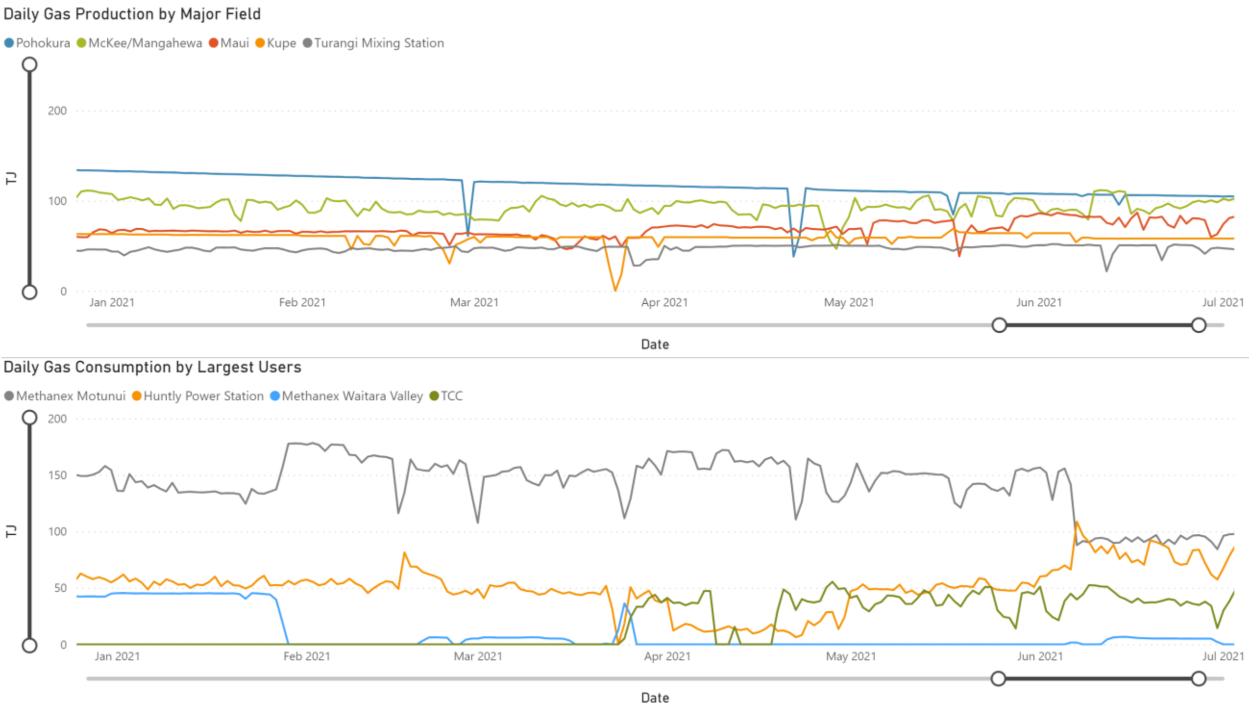
5.3 Total gas production continued to decline over the June quarter with overall production down approximately 20 per cent on last year. Data from GIC shows total daily gas production from major fields in the first chart of Figure 8. Total daily gas production was 391.3 TJ/day on 1 April 2021 dropping to 372.1 TJ/day on 30 June 2021. Daily production at Pohokura was 116.3 TJ/day on 1 April 2021 dropping to 105.1 TJ/day on

30 June 2021. While decay at Pohokura has slowed from a previous 1 per cent drop per week to a 0.5 per cent drop per week Mangahewa is close to replacing Pohokura as the country's largest source of gas production.

5.4 Despite low gas supplies thermal generation over the quarter was above previous year's levels due to an increase in generation from coal offsetting the decline in generation from gas. At Huntly total generation from coal for the quarter was 1175 GWh, a 327 per cent increase over the same quarter last year.

5.5 To help increase the amount of gas available for thermal generation Genesis and Methanex reached an agreement in May which had Methanex decreasing production at its Motonui plant to free up between 3.4 PJ and 4.4 PJ of gas. The results can be seen in the second chart of Figure 8 with a fall in consumption at Methanex Motonui accompanied by a corresponding rise in consumption by Huntly Power Station.

Figure 8: June Quarter Daily Gas Production and Consumption[2]



5.6 Figure 9 shows weekly generation from 5 April 2021 to 27 June 2021 split as a percentage by fuel type. Thermal and wind generation were higher than previous years while hydro and geothermal generation were lower. Thermal generation played a large role in supporting baseload demand in this quarter.

5.7 The average weekly percentage of wind generation was 6.3 per cent. Wind generation averaged 280 MW over the quarter. Total wind generation exceeded 606 GWh, more than total wind generation for each June quarter in the last five years.

5.8 The weekly percentage of geothermal generation reduced from 17 per cent for the week ending 10 May 2021 to 13.6 per cent for the week ending 29 June 2021. Geothermal generation dropping was due to a mechanical fault putting the 104 MW Kawerau geothermal station in an unplanned outage on 7 June 2021, leaving it unable to operate until August 2021.

[2] https://www.gasindustry.co.nz/about-the-industry/gas-industry-information-portal/gas-production-and-major-consumption-charts/

Figure 9: Weekly Generation by Fuel Type June Quarter

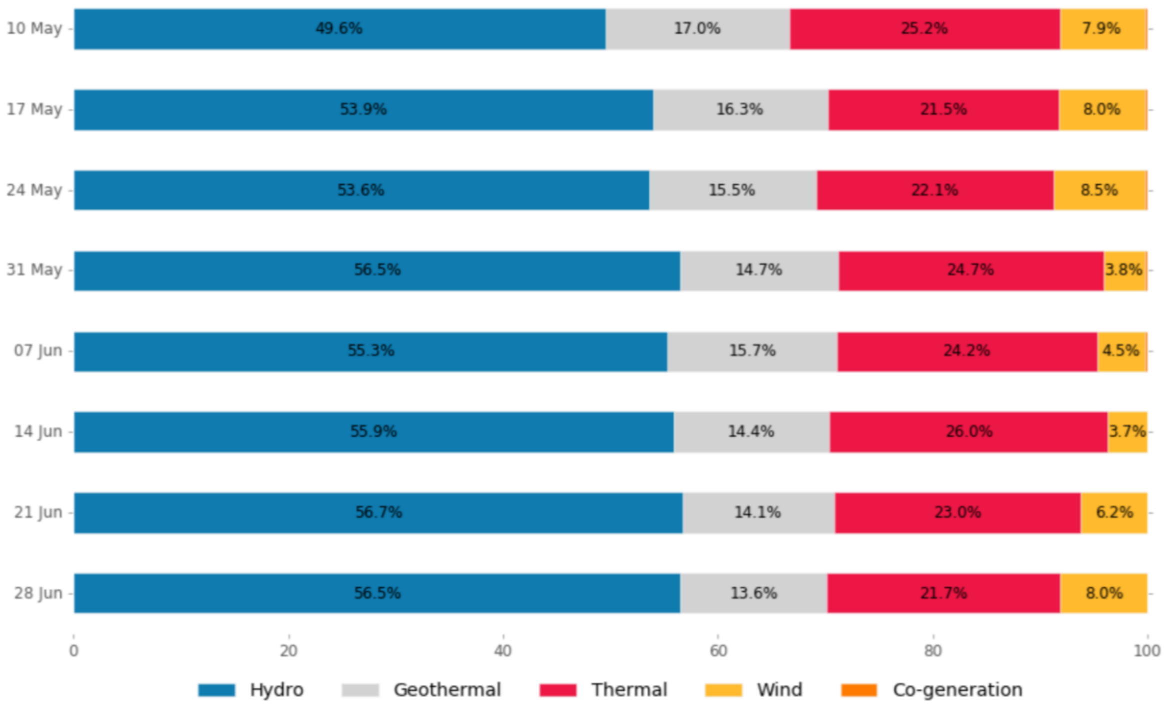
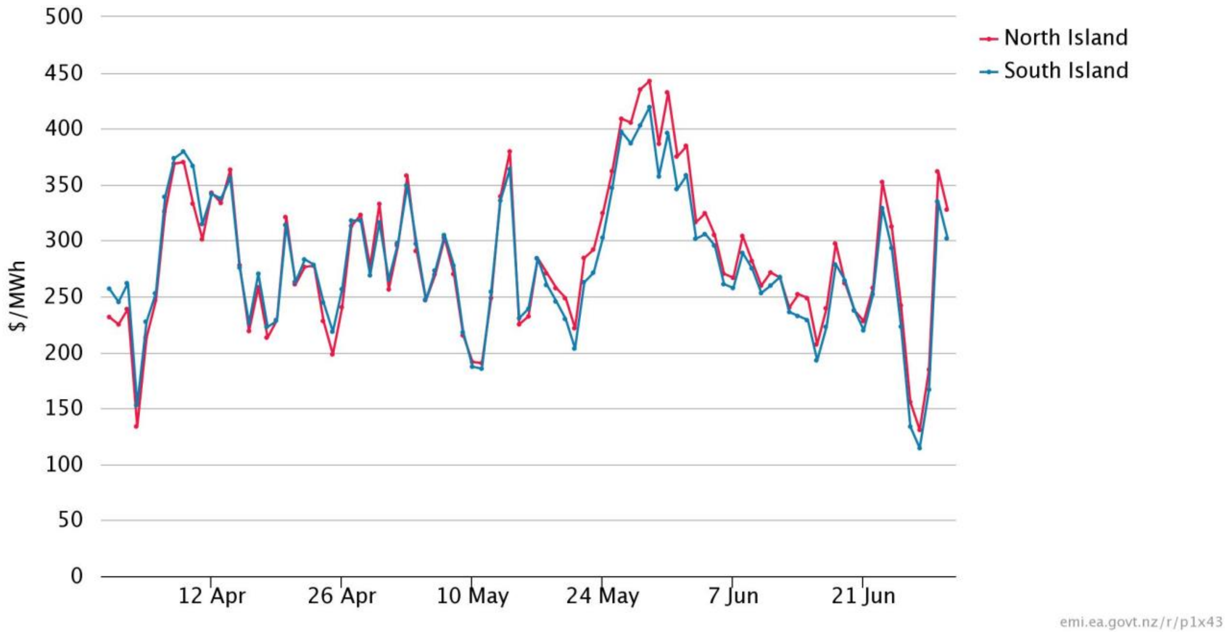


Figure 10 shows the average daily wholesale electricity spot price for each Island over the June quarter. Wholesale prices ranged from $0.01/MWh to $1,750.07/MWh and averaged $271.82/MWh. Prices reflected fuel shortage conditions with below average hydro storage and tight gas supplies exacerbated by periods of low wind generation and high demand causing high prices and price volatility despite higher hydro inflows. A steep offer stack often caused price spikes over $400/MWh after unexpected events such as unplanned outages and above expected demand required generation intended to be priced out of dispatch.

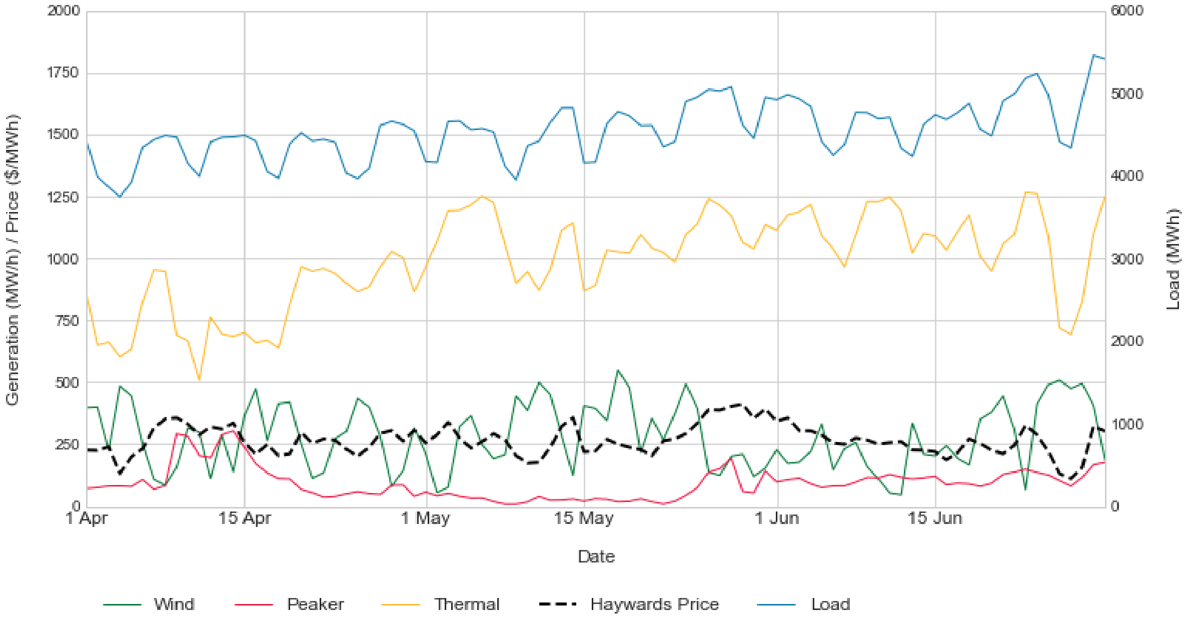
Figure 10: Average Daily Wholesale Spot Price by Island June Quarter



5.9 The highest price peak was $1,750.07/MWh at TUI1101 which was due to a natural constraint in the lines running into the region. With only two 110kV lines running into Hawke's Bay the lines constrained for a brief period forcing generation from the nearby Tuai power station to be dispatched to support local load. Due to low hydro storage the plants offers were priced with the intent to conserve water and the plant just became marginal, only generating 5-7MW, but setting the high price. The next highest peak price was $659.22/MWh.

5.10 Figure 11 shows wind, peaker and thermal generation alongside wholesale prices and load for the June quarter. Peak prices follow peak periods of load. For periods where wind generation was highest wholesale spot prices decreased. High priced periods correlated with periods of high peaker and thermal generation showing how gas scarcity continues to help form the basis of high wholesale prices. No single source of generation explains wholesale price alone with prices derived from a mixture of different factors.

Figure 11: Average Daily Wind, Peaker, Thermal, Price and Load June Quarter



5.11 The installation of distributed generation continues to grow incrementally, increasing by ~13.4 MW to a total of ~1731 MW over the quarter. The growth came primarily from solar generation which increased from ~152 MW across 31,709 ICPs to ~163 MW across 33,083 ICPs from 31 March 2021 to 30 June 2021. New renewable generation commissioned in the quarter was Kapuni Solar Power Plant in South Taranaki commissioned by Todd Energy. The solar farm operating at full capacity exports up to 2.1MW to the national grid.

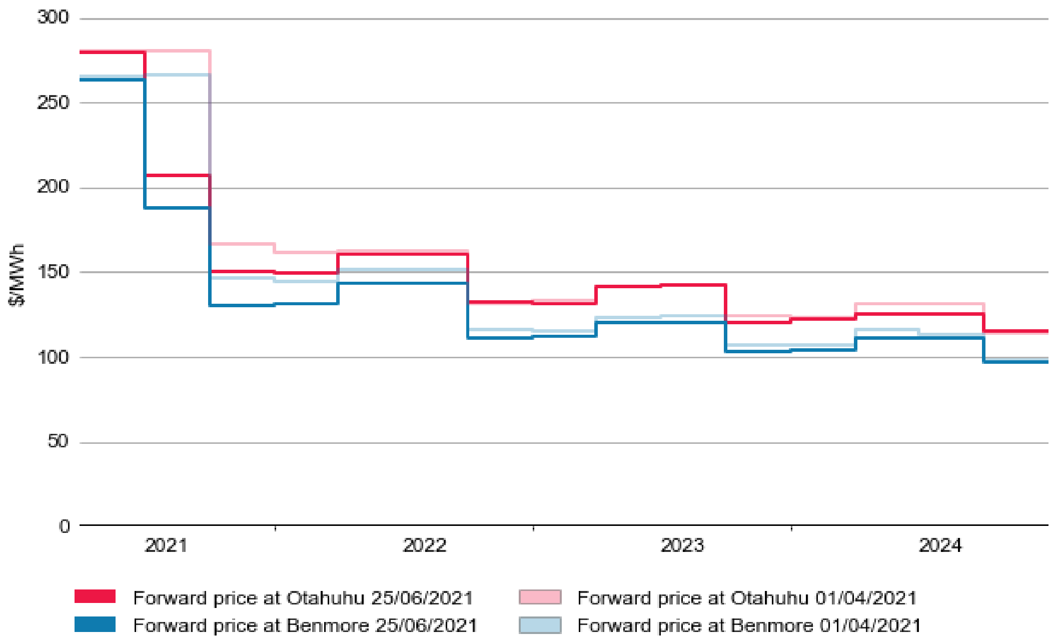
6 Forward Market

6.1 Figure 12 shows the differences between forward prices at Otahuhu and Benmore between 1 April 2021 and 28 June 2021. Until mid-June short term forward prices were consistent, hovering around ~$275/MWh, reflecting expectations that the market's tight fuel conditions were unlikely to be alleviated until spring. Forward prices for the September quarter dropped in mid-June following the injection of Methanex gas into Huntly's E3P unit and the June 18 notification that the Kawerau geothermal plant was to return a month earlier on 1 August. Prices eased from $292/MWh on 11 June 2021 to

$250/MWh on 18 June 2021 before dropping to $209.50/MWh on 21 June 2021. Long term prices over the quarter were largely consistent, increasing slightly in late May/early June before settling back to earlier levels.

6.2 Despite some decline, forward prices at the end of the quarter were still well above historical forward prices. Compared to a similar period in 2020 September forward prices were ~$100/MWh higher and long term forward prices were ~$50/MWh higher.

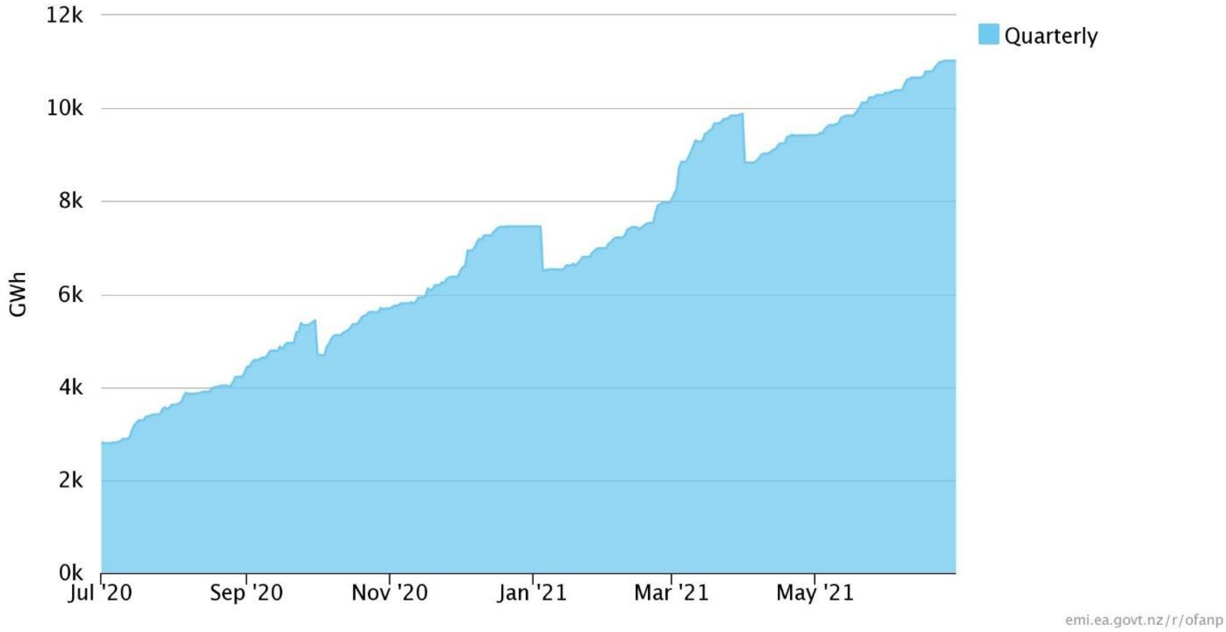
Figure 12: Forward Quarterly ASX Prices at Otahuhu and Benmore



Source: ASX

6.3 Figure 13 shows the amount of unmatched open interest in long dated baseload exchange traded futures for the last four quarters. Open interest continued to grow following the market making changes introduced in February 2020. At the end of the quarter open interest was around ~3.5 times the amount for the same period the previous year. In the face of growing uncertainty around both future generation and demand participants used higher volumes of futures to manage their long term risk.

Figure 13: Unmatched Open interest for Baseload Long Dated Futures Past Year



7 Deep Dive: A Dynamic Regression Analysis of Spot Price Drivers

7.1 We used a linear regression to analyse the drivers of the spot price in the July 2020 quarterly review. We found higher demand and gas prices meant higher spot prices. Increases in storage, wind generation, generation HHI meant lower spot prices. We found autocorrelation in the residuals but we also found evidence of stationarity.

7.2 This study applies a time series model to the same variables using daily data. The model is an extended Autoregressive Integrated Moving Average (ARIMA) model with covariates (known as ARIMAX). This model offers great flexibility in analysing time series data. The details of the model are described below.

7.3 Our research question is the same as the one in the quarterly report: “what is the relationship between the spot price and storage, demand, wind generation, gas price, competition in generation, and gas price risk”.

7.4 We found:

(a) Results consistent with the linear model in the July 2020 quarterly review. This confirms what we qualitatively observe about the spot market: that high spot prices tend to coincide with low wind, low storage, high gas spot prices and other gas sector disruptions, and high demand.

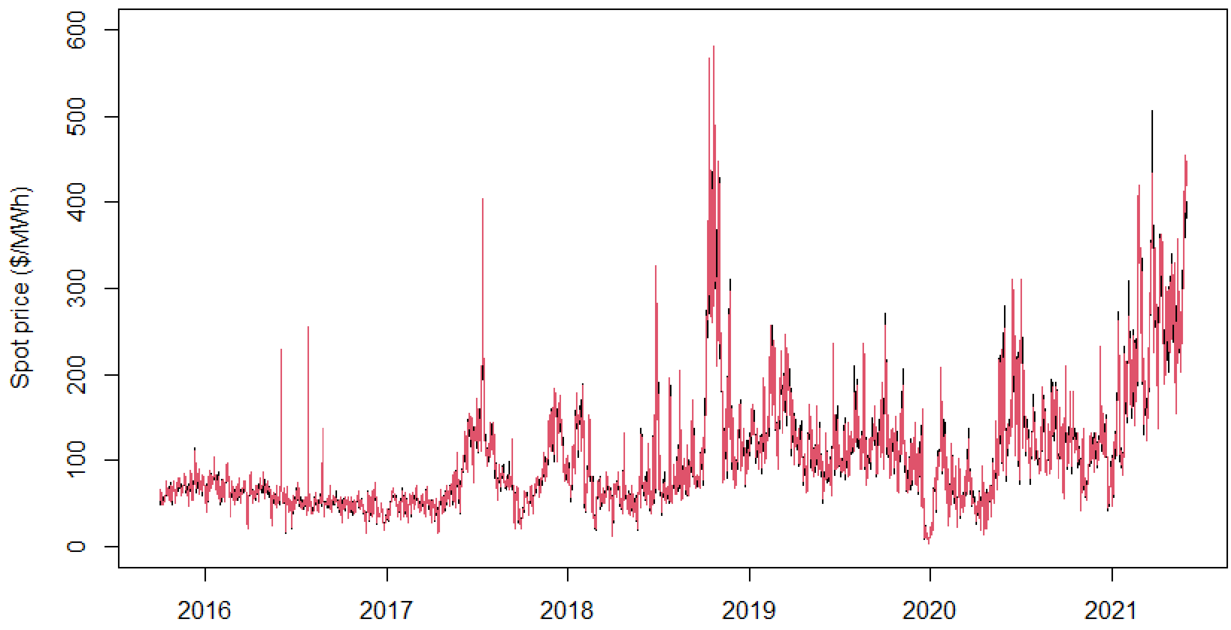
(b) Both the linear model and dynamic regressions provide evidence to support the hypothesis that spot prices are determined by the balance of supply and demand and that these effects dominate any effects due to market concentration.

Data

7.5 We use daily average data from 1 October 2015 to 31 May 2021. The response variable is adjusted daily average spot prices. We adjust the spot price for inflation using the electricity component of the New Zealand Producers Price Index (PPI). Then, we apply trend adjustments for the PPI adjusted prices based on Thomson 2013's paper[3]. Figure 14 shows spot prices in black and adjusted spot prices in red. Augmented Dicky-Fuller test suggests the adjusted spot prices are stationary.

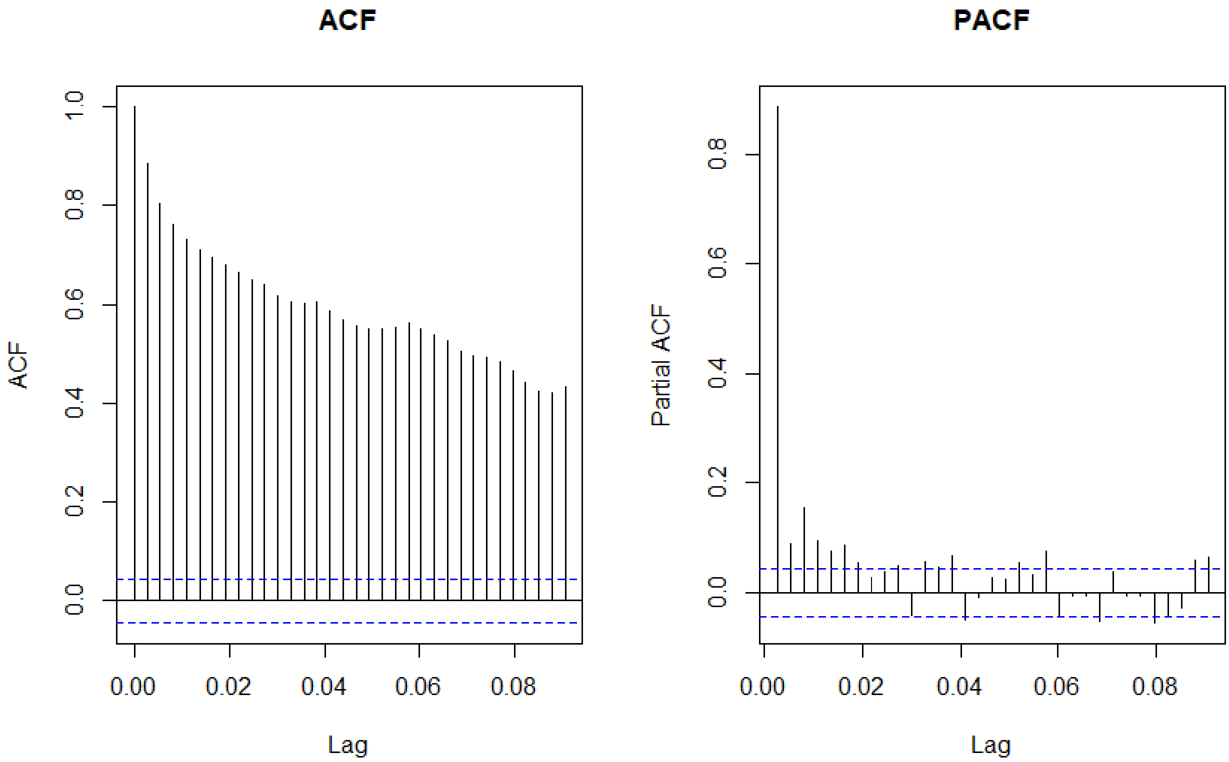
7.6 Figure 15 shows autocorrelation (ACF) and partial autocorrelation (PACF) represent in the adjusted spot prices. The ACF of the adjusted prices is slow-decaying. The PACF plot shows the spike at lag2 and the first cut-off at lag5. This indicates autoregressive model with five lags.

Figure 14: Spot price and PPI adjusted spot price



[3] Thomson, P.J. (2013) An exploratory analysis of the relationship between electricity spot price and hydro storage in New Zealand (2013). Report commissioned by the New Zealand Electricity Authority

Figure 15: ACF and PACF of adjusted spot prices



7.7 The covariates are 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 weekly carbon price mapped to daily. The units for the raw data: storage and demand are GWh, spot price is $/MWh, gas price is $/PJ, and wind generation is MW, carbon is dollars per tonne for New Zealand emission units.

7.8 We used the Augmented Dicky-Fuller (ADF) test all variables to see if they are stationary. If not, we take the first difference to make them stationary. If the ADF test shows the data is still not stationary, then we take second difference. 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 $storage_t - storage_{t-1}$.

7.9 Table 1 shows the ADF test results for stationary. Comparing test-static values with critical values at 1%, 5% and 10%—if the test-static values are less than critical values, the variable is stationary. Storage, demand, and generation HHI are non-stationary, so we take the first difference of these variables. Then we test them with the ADF again. For the ratio of offers to generation, we use the first difference for the total generation and for the total offered, then taking the ratio of them. The test results show the adjusted variables are stationary.

Table 1: Test for stationary

Augmented Dickey Fuller Test Unit Root Test results		
Critical values at 1%	**Critical values at 5%**	**Critical values at 10%**
-2.58	-1.95	-1.62

	test-statistic	Stationary? (Y/N)
adjusted spot price	-5.0857	Y
storage	-0.57	N
demand	-1.22	N
wind generation	-9.6416	Y
gas price	-5.307	Y
generation HHI	-0.5398	N
ratio offer to generation	-1.3672	N
carbon price	3.297	N
Take first difference for non-stationary variables		
diff(storage)	-17.3418	Y
diff(demand)	-46.8247	Y
diff(generation HHI)	-42.1737	Y
ratio diff(offer) to diff(generation)	-31.9005	Y
diff(carbon price)	-30.9048	Y

7.10 For the dummy variable, a value of 0 is given for all time periods before 28 September 2018, and a value of 1 is given for the data from 28 September 2018 onwards. This is to cover the time period since the unplanned Pohokura outage that started in late September 2018. Since this outage, the deliverability of gas from Pohokura has been increasingly uncertain. This uncertainty has persisted. The 2020 outage was partly to determine whether there was further remedial work required on the undersea pipeline, and since this outage ended, output from Pohokura has drifted downwards, creating further uncertainty.

Model

7.11 An ARMA model is an autoregressive model (AR) combined with a moving average model (MA). AR is a regression of the variable against its own lagged values (past values). MA uses lagged errors as a regressor. It captures shock effects (unexpected events) affecting the observation process. So if a time series data denoted by $y_1, \dots, y_n$, ARMA(p,q) model will be $y_t = \varphi_1 y_{t-1} + \cdots + \varphi_p X_{t-p} + Z_t + \theta_1 Z_{t-1} + \cdots + \theta_q Z_{t-q}$ where p and q are order (number of lags) of the autoregressive and moving average components respectively.

7.12 An ARMA model relies on the assumption of that the underlying process is weakly stationary. Weakly stationary means the data has no systematic change in mean and variance and has no periodic fluctuations. If the data is nonstationary, we need to take first differences $(y_t - y_{t-1})$ to transform the data. The differencing process can be performed several times until the data achieve stationary. This model is called an ARIMA model. “I” indicates the differencing process.

7.13 An ARIMAX model is an ARIMA model with added covariates on the right hand side ARIMA equation: $\beta_1 x_{1.t} + \beta_2 x_{2.t} + \cdots + \beta_i x_{i.t}$, where $x_{1.t} \ldots x_{i,t}$ are covariates at time t and $\beta_1, \ldots, \beta_i$ are their coefficients. A disadvantage using an ARIMAX model is that the covariate coefficients are hard to interpret. This is because the covariate coefficients βs are not the marginal effect on y_t when the x_t is increased by one unit. This is because of the lagged response variable on the right hand side of equation. So the coefficient βs can only be interpreted conditional on the value of previous values of the response variable.

7.14 Dynamic regression is a method to transform ARIMAX model and make the coefficients of covariates interpretable. The form of dynamic regression is:

7.15 $y_t = intercept + \beta_1 x_{1,t} + \cdots + \beta_i x_{i,t} + \eta_t$

7.16 $\nabla \eta_t = \varphi_1 \eta_1 + \cdots + \varphi_p \eta_{t-p} + \cdots + \theta_1 Z_{t-1} + \cdots + \theta_q Z_{t-q} + Z_t$

7.17 $where\, x_{1,t}, \ldots, x_{i,t}\ are\ covariates;\ and\, \nabla \eta_t = \eta_t - \eta_{t-1}$.

7.18 The model can be treated as a regression model (first equation) with ARIMA errors with first order differencing (second equation). The errors η_t in the first equation are assumed to be independent and identically distributed with a mean of zero. Note if there is no differencing process, the second equation becomes ARMA errors: $\eta_t = \varphi_1 \eta_1 + \cdots + \varphi_p \eta_{t-p} + \cdots + \theta_1 Z_{t-1} + \cdots + \theta_q Z_{t-q} + Z_t$

7.19 Dynamic regression requires all variables to be weak stationary.

Results

7.20 We fit the data using the Dynamic model and then dropping the insignificant variables: the ratio of offers to generation, the dummy and carbon price. We compared Akaike Information Criterion (AIC) between models with different numbers of lags. The lowest AIC indicates the best fit of the model which is an autoregression model with five lags.

7.21 Table 2 shows the estimated coefficients from the fitted model. All the variables except AR lag 2 are statistically significant. The fitted dynamic regression is:

7.22 $y_t = 109.64 - 0.35 \times\ diff(storage) + 0.79 \times diff(demand) - 7.32 \times wind.generation + 1.67 \times\ gas.price - 0.03 \times\ diff(generation\ HHI) +\ \eta_t$

7.23 $\eta_t = 0.74 \times \eta_1 - 0.05 \times \eta_2 + 0.14 \times \eta_3 + 0.02 \times \eta_4 + 0.09 \times \eta_5 + \varepsilon_t$

Table 2: Results from the regression

	Coefficients	p-values	Significant?
AR1	0.740736	0	Y
AR2	-0.046602	0.09	Y, but very weak
AR3	0.140554	0	Y
AR4	0.015836	0.560674	N
AR5	0.086417	0	Y
intercept	109.639918	0	Y
diff(storage)	-0.345505	0	Y

diff(demand)	0.791798	0	Y
wind generation	-7.318120	0	Y
gas price	1.665229	0	Y
diff(generation HHI)	-0.031056	0.001953	Y

7.24 All estimated coefficients except generation HHI have the expected signs:

- when storage and wind generation increase, the spot price decreases.
- when demand and the gas price increase, the spot price increases.

7.25 The results are consistent with linear regression fitted in the July 2020 quarterly review.

The effect of competition

7.26 The same as we explained in the linear model analysis, we expected a positive sign on HHI as an increase in market concentration (increasing HHI) should suggest a reduction in competitive pressure and therefore higher prices. However, we have a negative sign.

7.27 HHI is the sum of the squared market shares. When storage falls, Meridian becomes a less dominant generator, market shares become more even and the generation HHI falls. But under these circumstances the spot price will be high, as storage is low. This gives the negative sign in our regression suggesting a fall in concentration (increased competitive pressure) leads to higher prices. This negative sign in our regression results suggests that the storage effect dominates any market concentration effect.

Interpretation

7.28 Dynamic regression allows the regression coefficients to be interpreted in a similar way to a linear model.

7.29 **Difference of storage:** a unit increase in difference of daily storage causes on average a $0.35/MWh decrease in the daily adjusted spot price spot price, holding other variables constant.

7.30 **Difference of demand:** a unit increase in difference of daily demand causes on average a $0.79/MWh increase in the daily adjusted spot price, holding other variables constant.

7.31 **Wind generation:** a one MW increase in daily wind generation causes on average a $7.32/MWh decrease in the daily adjusted spot price, holding other variables constant.

7.32 **Gas price:** a dollar per PJ increase in the daily gas price causes on average a $1.67/MWh increase in the daily adjusted spot price, holding other variables constant.

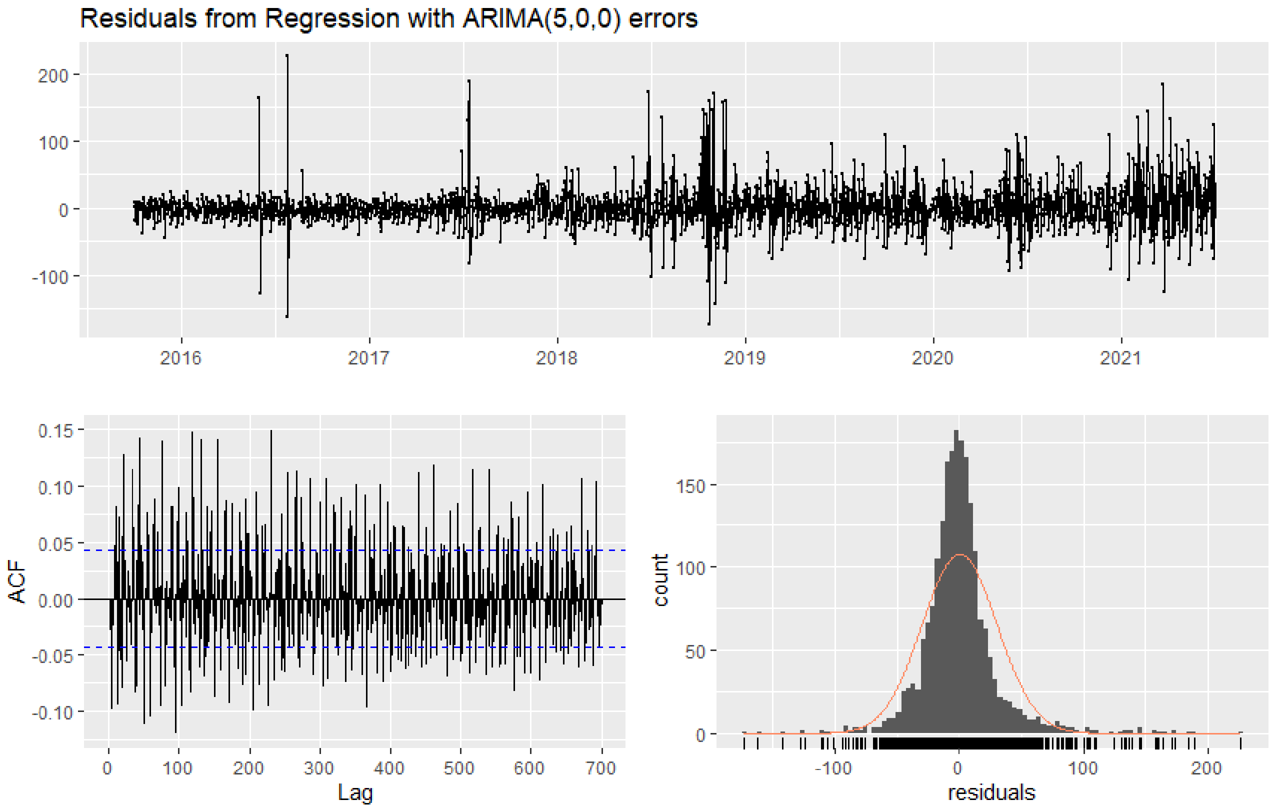
7.33 **Difference of Generation HHI:** a one unit increase in difference of daily generation HHI causes on average a $0.03/MWh decrease in the daily adjusted spot price, holding other variables constant.

Checking residuals

7.34 Figure 16 shows the residuals of ARMA errors are not significantly different from white noise. The bottom left graph, autoregression plot ACF shows no autocorrelation for the residuals. The bottom right graph of histogram for residuals shows the mean of the residuals is zero. All these indicate white noise for the residuals, supporting the assumption that ARMA errors are white noise.

7.35 Box test is a statistical test for if autocorrelation of a time series is different from zero. The p-value for the test is 0.7 suggesting there is no evidence that the residuals are autocorrelated.

Figure 16: Plots for residuals



Conclusion

7.36 The results from dynamic model are consistent with the linear model in the July 2020 quarterly review. Again, the model confirms what we qualitatively observe about the spot market: that high spot prices tend to coincide with low wind, low storage, high gas spot prices and other gas sector disruptions, and high demand.

7.37 Both the linear model and dynamic regressions provide evidence to support the hypothesis that spot prices are determined by the balance of supply and demand and that these effects dominate any effects due to market concentration.