Market Performance Quarterly Review

July-September 2022

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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 detailed analysis of modelling electricity generation and battery capacity expansion, the findings are summarised in section 7.

2 Highlights

2.1 Throughout July to September, weekly load was mostly similar to, or slightly higher than, the historical average[1]. Peak demand often exceeded the historic average, and many of these instances were related to cold snaps. Weekly demand peaked for the week of 22-28 July, while the weeks of 12-18 August, and 2-8 September had also the large positive difference from the historic average. The highest peak demand of the year occurred on the evening of July 25, reaching 7,090 MW, or 97 percent of that seen on 9 August 2021.

2.2 The market share of larger retailers marginally increased in this quarter, while it slightly decreased for small-medium sized retailers. In this quarter, Genesis gained the highest market share, while Contact had the biggest decline. Trader switches and move-in switches per month decreased month on month throughout the quarter.

2.3 Average wholesale electricity prices fell throughout the quarter, influenced by increased hydro storage and periods of high wind generation. The average spot price for the quarter was $66/MWh, a significant decrease compared to the previous quarter. Thermal generation decreased significantly due to increased hydro, and wind generation.

2.4 Nationally hydro storage increased throughout July and August. However, in September storage decreased due to reduced inflows and high hydro generation. This decline was most dramatic at lakes Te Anau and Manapōuri.

2.5 Methanex's second Motanui plant went on its four yearly outage between late July and mid-September - decreasing its gas consumption and causing an excess of gas in the market. At the end of the quarter, gas consumption slightly increased due to Methanex Motunui came back from an outage. Gas spot prices hovered around $10/GJ throughout the quarter declined during the Motunui outage.

2.6 Short-term forward prices decreased, while long-term forward prices increased over the quarter. The change in short-term futures was likely due to an improved hydro storage outlook. Increasing coal and carbon prices likely contributed to the higher long-term futures prices.

[1] Averaged over July to September for 2017-2021

3 Demand

3.1 Figure 1 shows total daily demand between July and September 2022 against the historical average demand from 2017-2021. Note that the historical average is based on the date, so the average for any day will likely include weekends (which have different demand profiles). Annotations display the weekly percentage difference between the 2022 load and the 2017-2021 historical average load.

3.2 Reconciled demand for July, August, and September 2022 was 3,860 GWh, 3,812 GWh, and 3,548 GWh, respectively. This compares to historical average demands for July, August, and September of 3,852 GWh, 3,780 GWh, and 3,517 GWh, respectively. These values show that total demand was higher over the winter months in 2022 compared to the historical average (8 GWh in July, 12 GWh in August, and 31 GWh in September).

3.3 During July to September, total weekly load was generally similar to, or slightly higher than, the historical average. These variations in weekly demand could be from a combination of factors like school holidays decreasing demand, changes in weather throughout the quarter, consumer consumption from relaxing Covid restrictions and general increases in electrification of technologies and industries.

3.4 Peak demand repeatedly exceeded the historic average and were generally related to cold snaps. Despite the school holidays in July, demand peaks were consistently high over those weeks due to a cold snap. This included peak demand of 7,090 MWh on the evening of Monday 25 July. This was 97% of that experienced on 9 August 2021. The highest weekly load for the quarter was also for this week (22-28 July) and totalled 767 GWh.

3.5 Second largest difference from the historical average occurred for 12-18 August, and was 2.9 percent above the historic average. The following week (19-25 August), when temperatures were comparatively higher, weekly load was 4.2 percent lower than the historical average.

3.6 In August and September, daily peak demand often exceeded the historical average. This happened successively between 9-13 August and 5-16 September as the country experienced cold snaps. Demand on the morning of 12 August reached 6,984 MW, or 96% of that experienced on 9 August 2021, as shown in Figure 2.

3.7 High demand between 5-16 September was also due to cold temperatures, which brought frosts to much of the country. This caused high demand, and especially high peak demand each day of the week. Demand on the evening of Monday 5 September reached around 6,900 MW due to a significant decrease in temperature as shown in Figure 3.

Figure 1: Daily load, September 2022 quarter with historic average

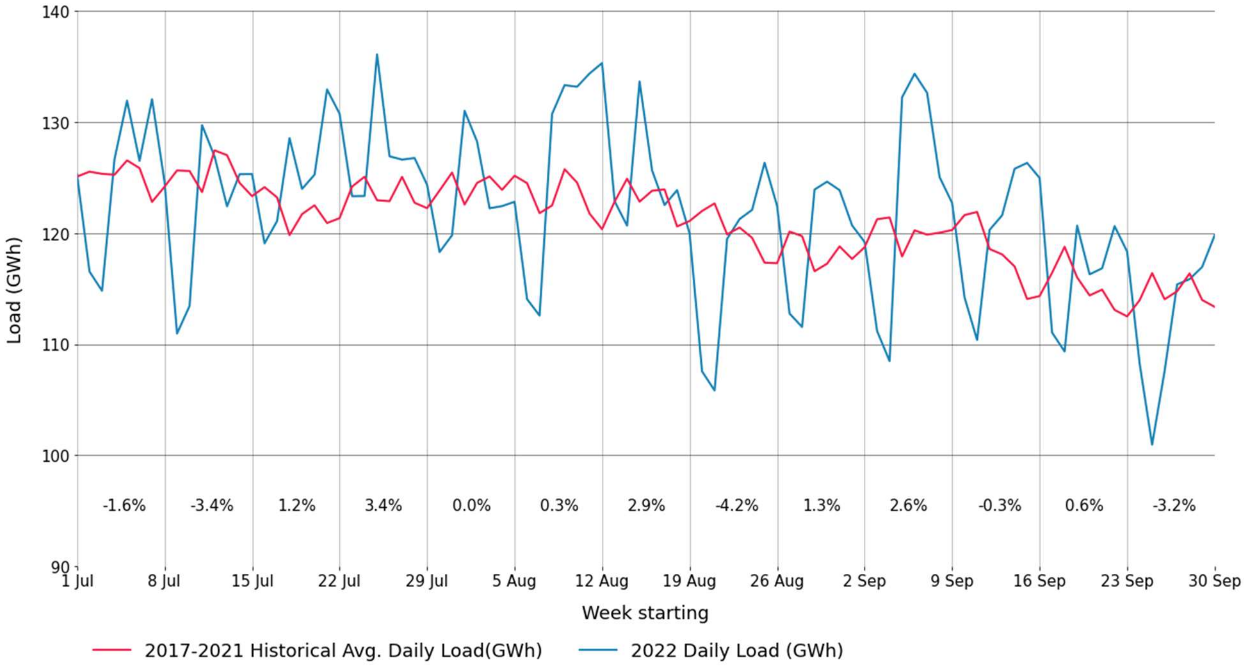


Figure 2 : Half hourly load compared to the historical average for 9-13 August

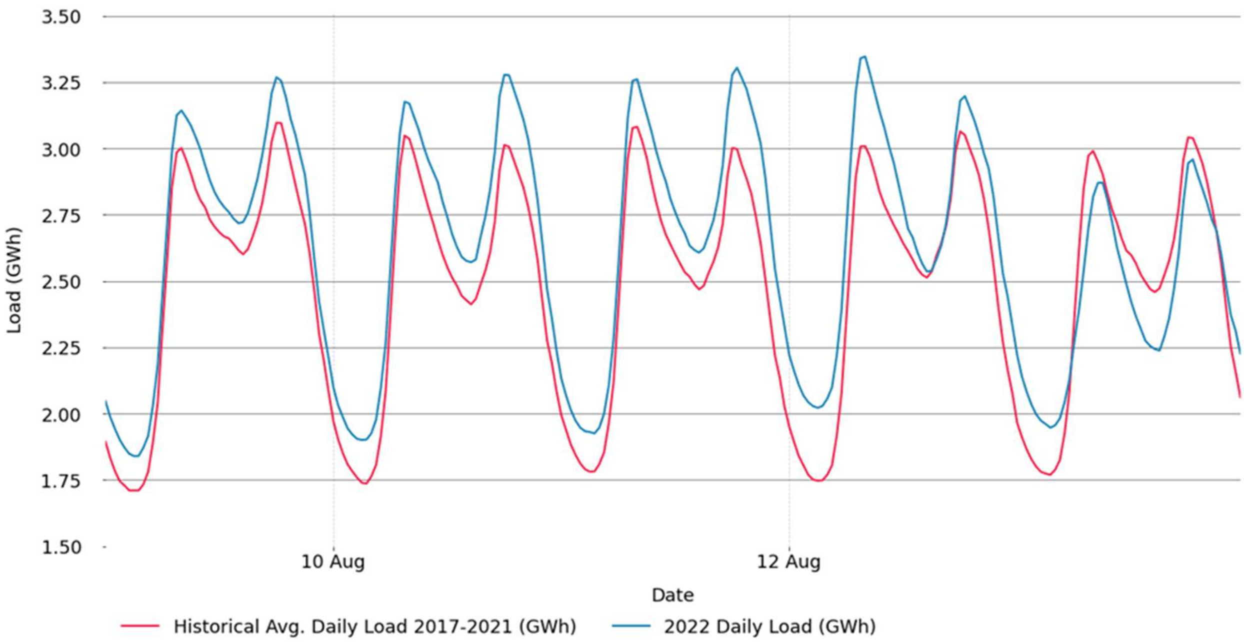
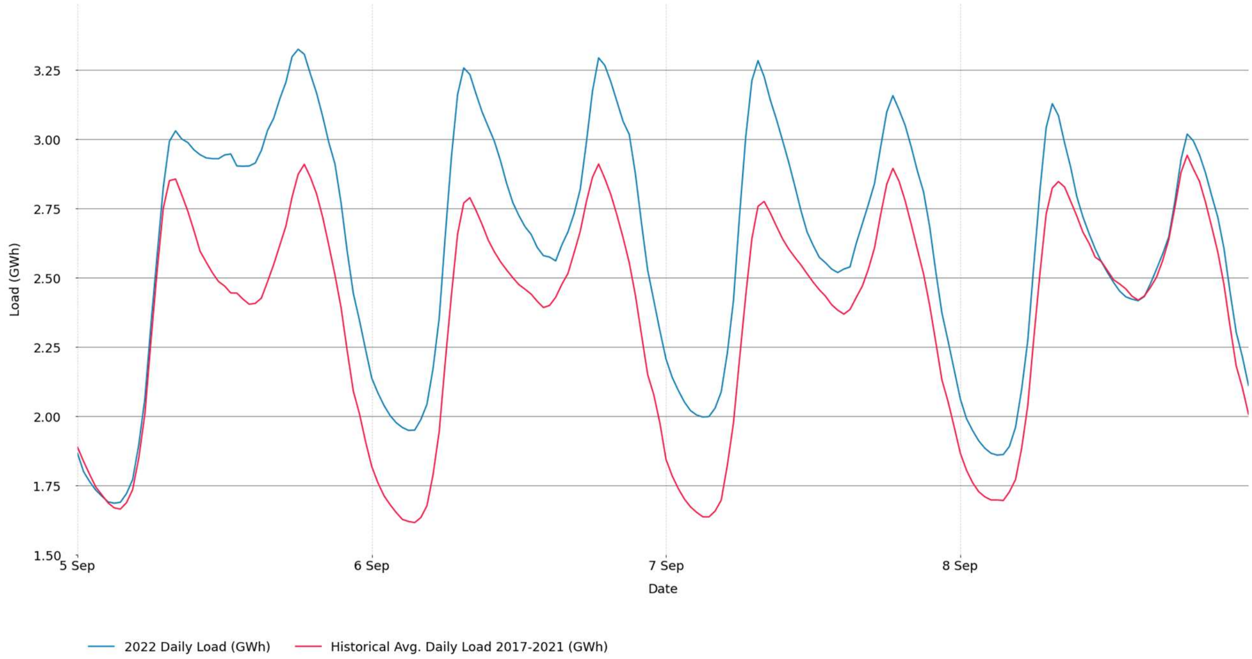


Figure 3: Half hourly load compared to the historical average for 5-8 September



4 Retail

4.1 Over the September 2022 quarter, the collective market share of the four[2] largest retailers, Contact, Genesis, Mercury, and Meridian was 83.37 percent (an increase of 0.30 percent in this quarter).

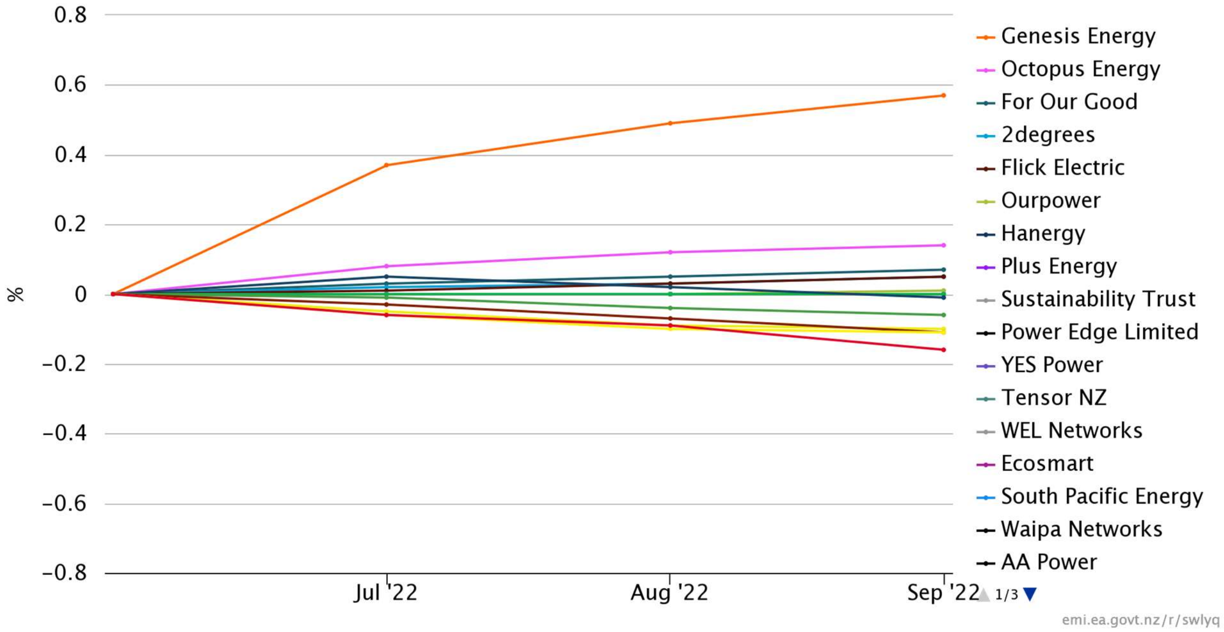
4.2 On 30 September 2022, the four largest retailers collectively held 1,900,136 ICPs between them, by gaining 14,579 ICPs over the quarter. Small-medium sized retailers held 354,064 ICPs between them, losing 4,979 ICPs.

4.3 Figure 4 shows the changes in market share of each retailer from 1 July to 30 September 2022. Genesis Energy had the largest increase in market share of around 0.58 percent. Some smaller retailers also made gains, including Octopus Energy which gained 0.14 percent of market share. However, Contact Energy had the greatest decline in market share by losing 0.16 percent. Mercury, Electric kiwi, and Meridian lost, 0.11, 0.10, and 0.02 percent of market share, respectively.

4.4 The largest regional change in ICPs came from Genesis's gains in Auckland, with an increase of 5,458 ICPs over the quarter.

[2] As of 1 May 2022, Trustpower sold part of its business to Mercury and changed its name to Manawa Energy. In the future Electricity Authority reports, it will not be bundled with the other large retailers as it has sold its retail assets to Mercury.

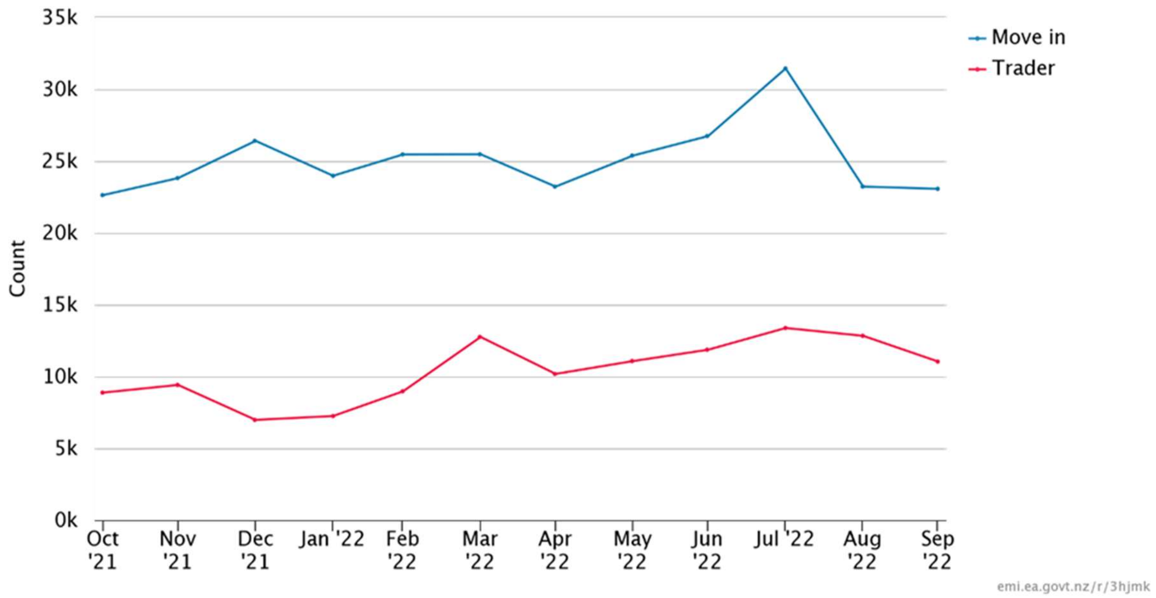
Figure 4: Changes in retailer market share[3]



4.5 Figure 5 shows the number of electricity connections (ICPs) that have changed electricity suppliers from 1 July 2021 to 30 September 2022 categorised by type 'move in', and 'trader'. Move in switches are switches where the customer does not have an electricity provider contract with a trader at a particular ICP, and obtains a contract. In contrast, trader switches are switches where the customer does have an existing contract with a trader, and the customer obtains a new contract with a different trader.

4.6 Over the quarter, trader switches decreased slightly, from 13,383 per month in July to 11,047 per month in September. Move in switches also decreased, from 31,451 in July 2022 to 23,073 in September 2022. Move in and trader switches are slightly higher than they were this quarter last year.

Figure 5: ICP switches by type 2021/22



[3] Please note that not all traders fit in the key. Please go to emi.ea.govt.nz/r/swlyq to view the key with all traders.

5 Wholesale

5.1 Half hourly nationally averaged wholesale electricity spot prices across New Zealand are shown in Figure 6. Average spot prices fell this quarter, with the average spot price being $66/ MWh. However, there were a few notable price spikes.

5.2 As hydro storage increased during July and August, prices fell dramatically to close to $0/MWh during periods of high wind and/or low demand. However, during times of low wind, high thermal usage and/or peak demand, prices rose usually to between $100-$200 /MWh but sometimes much higher.

5.3 On 21 July there was a high price spike during one trading period of the evening peak. Prices rose to above $1500/MWh for this trading period. This corresponded to cold temperatures in both islands and a drop in wind generation resulting in more thermal peaker generation. All available thermal peakers ran including Whirinaki[4], although only one Rankine was running.

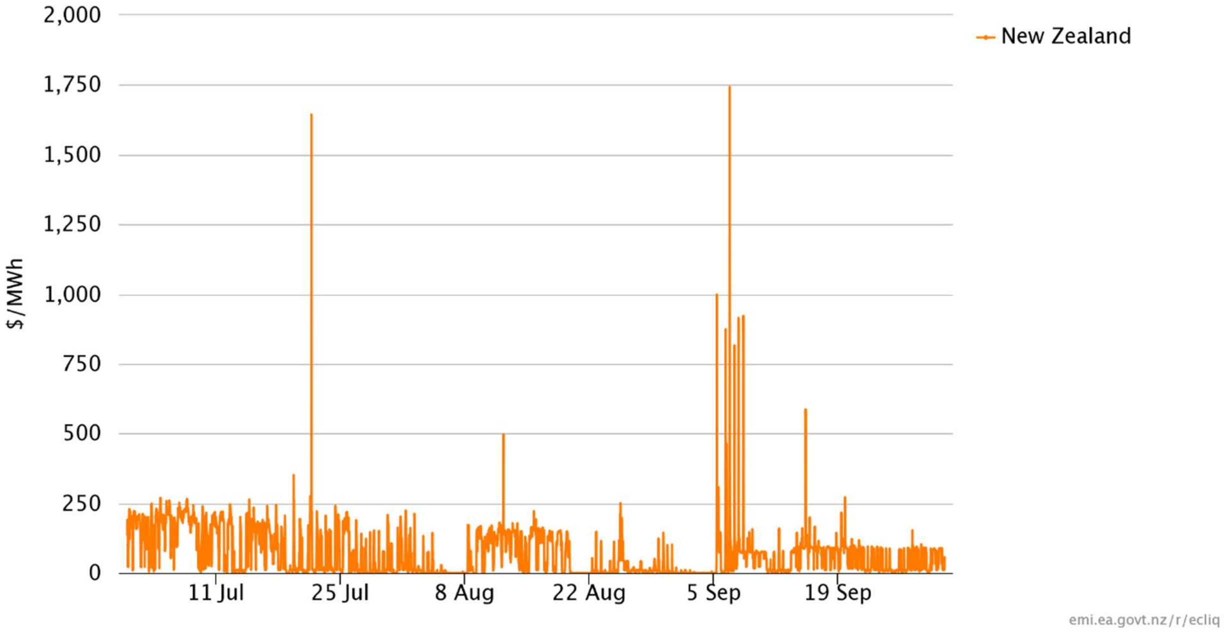
5.4 Prices spiked on August 12 at over $500/MWh during two trading periods, when the country experienced high demand and low wind. The need for more generation was anticipated by the System Operator, who issued a Low Residual Situation customer advice notice (CAN) earlier in the week. This advised of a potential shortfall in generation between 7:30am and 9:00am on Friday 12 August, caused by projected higher demand. The notice was based on the weather forecast of cold weather in the upper North Island (where the bulk of national demand is) and low wind in the lower North Island (where the bulk of wind generation is).

5.5 Several price spikes occurred between 5 - 8 September of up to $1750/MWh, during peak demand periods (Figure 3). The need for increased generation during times on 6 – 7 September was anticipated by the System Operator. A Low Residual Situation CAN was issued earlier in the week which advised of a potential shortfall in generation. Again, based on weather forecasts which predicted low wind generation and cold weather in the upper North Island which was likely to result in above average demand for Tuesday evening and Wednesday morning.

5.6 The System Operator also sent Low Residual Situation CANs notices for the evening of Wednesday 14 September and the morning of Thursday 15 September, for similar reasons as the week prior. Prices did not end up increasing much for the evening peak on Wednesday 14 September, but did spike on Thursday 15 September's morning to around $560/MWh.

[4] Whirinaki is a diesel-powered peaker, which is usually only dispatched when spot prices are high

Figure 6: Half hourly wholesale electricity spot prices



5.7 Figure 7 shows the daily averaged spot price against the national hydro storage. Increasing hydro storage meant hydro generation was offered at lower prices, reducing average spot prices in this quarter. Figure 7 displays this relationship. Decreasing hydro storage throughout the first half of the quarter kept prices comparatively high. Due to an increase in storage from August average prices decreased. However, prices were higher on cold days where more thermal generation was running.

5.8 Prices were also impacted by high wind generation, which reduced the need for coal-fired generation, coupled with TCC running until the start of August. Generally, outside of unusual circumstances, spot prices increased when grid demand increased, wind generation decreased, and thermal powered generation increased. The relationship between wind generation and prices can be seen in Figure 8. Mostly, low prices occurred when wind generation was high and thermal generation was low.

5.9 Outages of note include TCC and the second Stratford peaker. The outage of the second Stratford peaker is ongoing until mid-November, while TCC was on outage from 21 August until 6 September for repairs. However, TCC was switched off on 3 August, which was before its outage, as the abundance of wind and hydro generation made it un-economical to run. Additionally, Contact has indicated that TCC will not be offered into the market until it is economically viable to do so, but it is available to ensure security of supply.

Figure 7: Daily national storage and daily average spot price

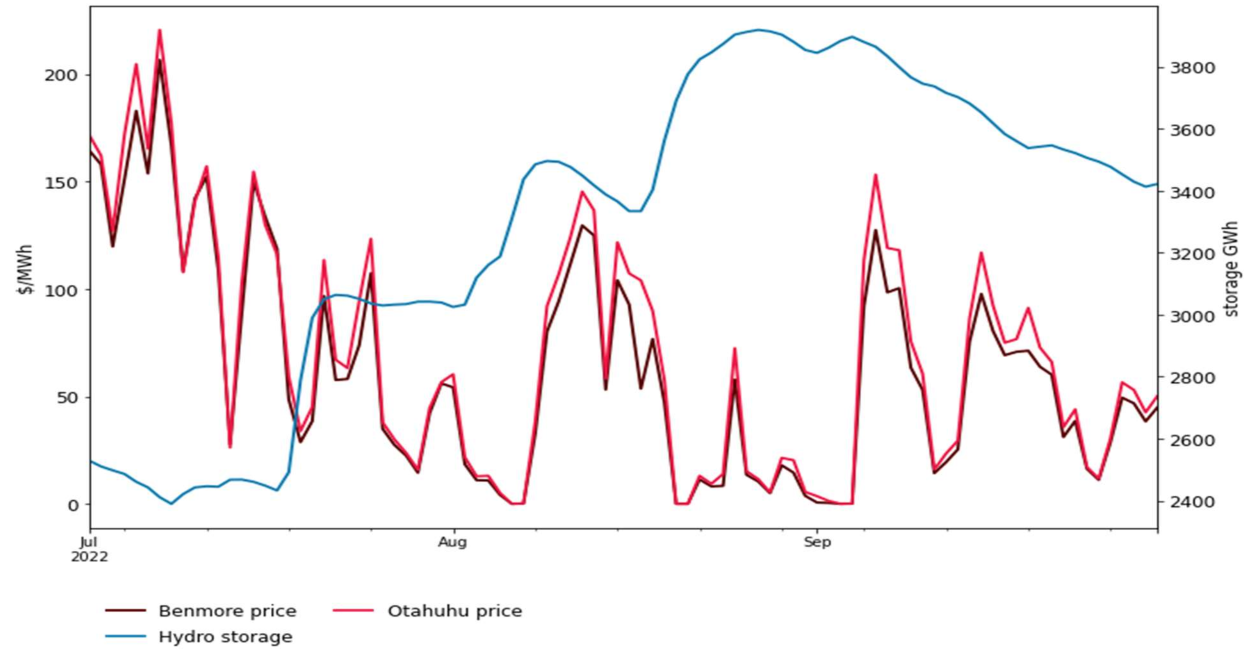
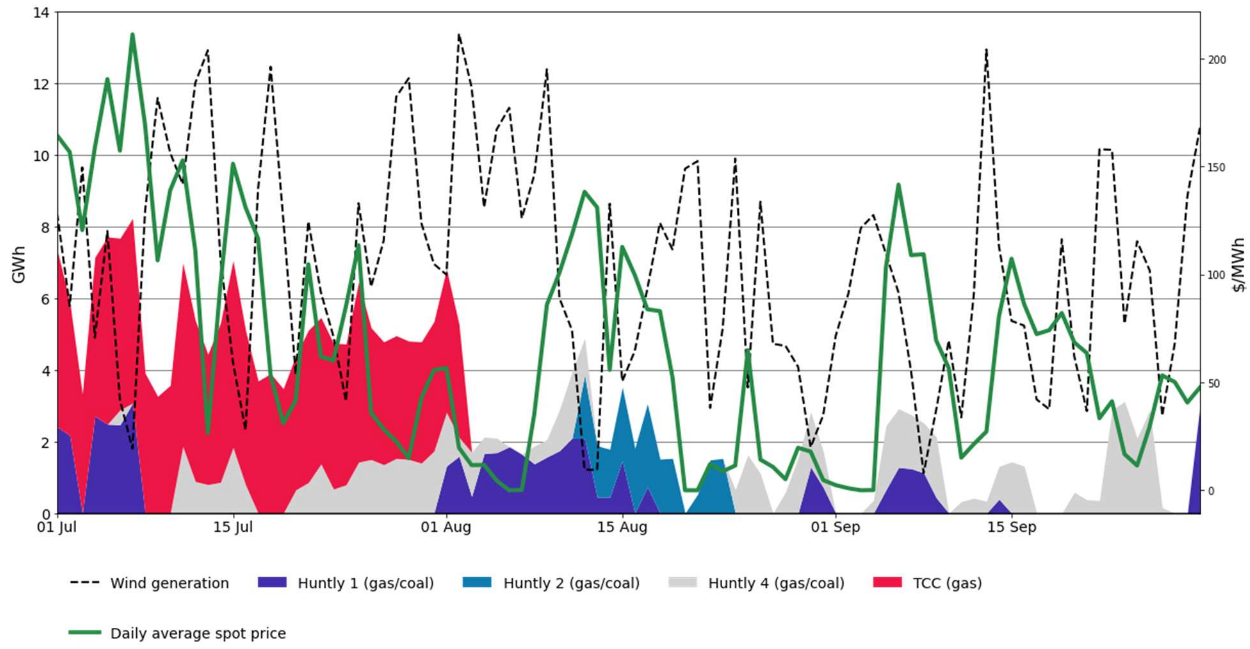
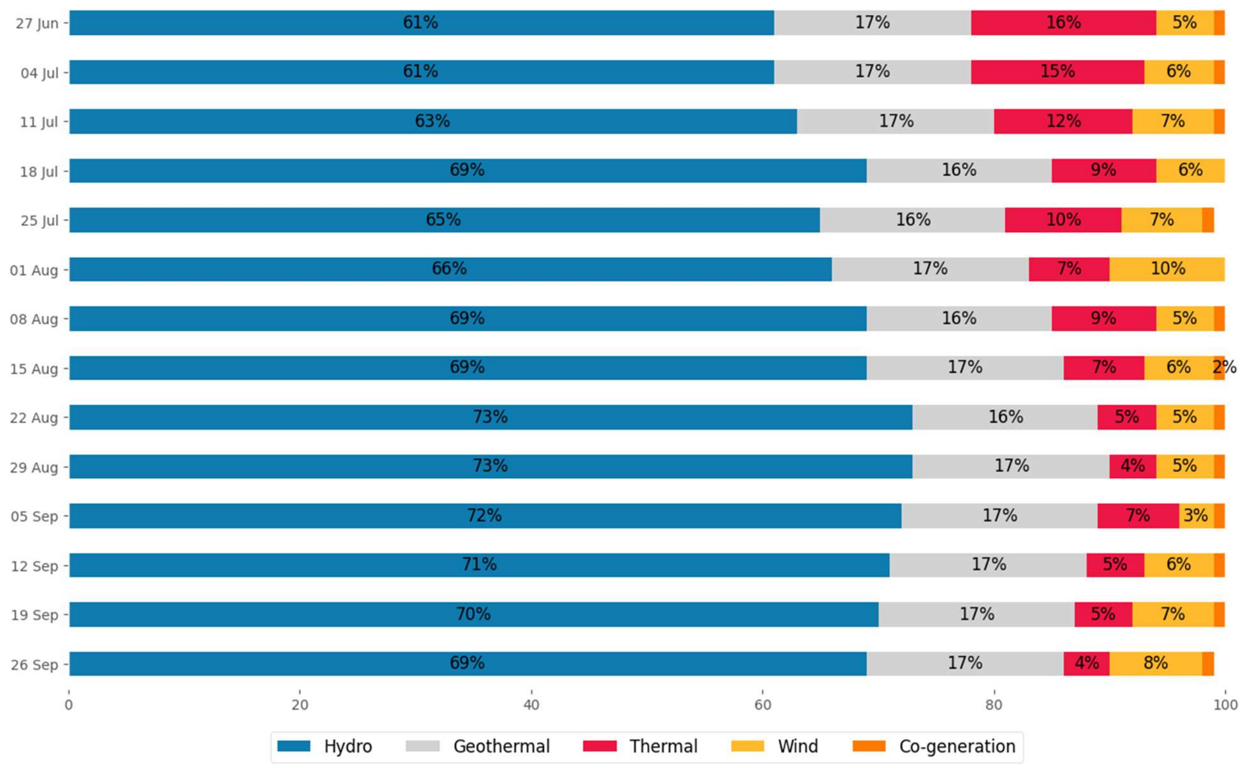


Figure 8: Daily average spot price and daily total generation, in GWh, at Huntly (coal/gas fired units), TCC and from wind, between 1 July – 30 Sep 2022



5.10 Generation from renewable sources for the quarter averaged 91 percent of total generation, increased significantly in this last quarter. Weekly variation can be seen in Figure 9. As hydro generation increased, thermal generation dramatically declined from 16 percent of weekly generation in July to only 4 percent in September. Generation from wind varied between 3 - 10 percent of weekly generation throughout the quarter.

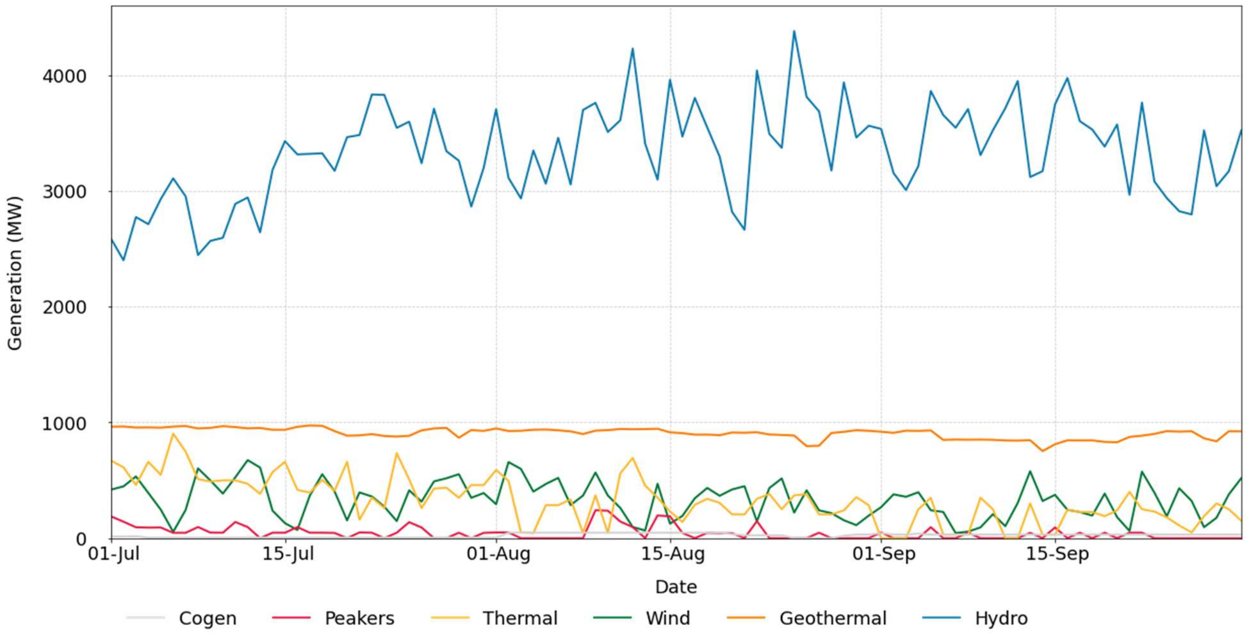
Figure 9: Weekly generation by fuel breakdown



5.11 Figure 10 shows daily generation for the quarter by fuel type. Throughout July and August, as hydro storage increased, generation from hydro was subsequently increased. Large, slow start thermal generation supported a proportion of baseload - with hydro ramping up and down throughout the day to match load. In September, hydro storage slightly decreased, and hydro generation became relatively stable.

5.12 Wind generation had a half hourly generation average of 307 MW for the quarter and averaged 6 percent of total generation. Half hourly hydro generation averaged 3,398 MW and averaged 68 percent of total generation. Half hourly thermal generation averaged 427 MW and averaged 8 percent of total generation. Thermal generation decreased by 9 percent compared to the previous quarter.

Figure 10: Average Daily Generation by Fuel Type

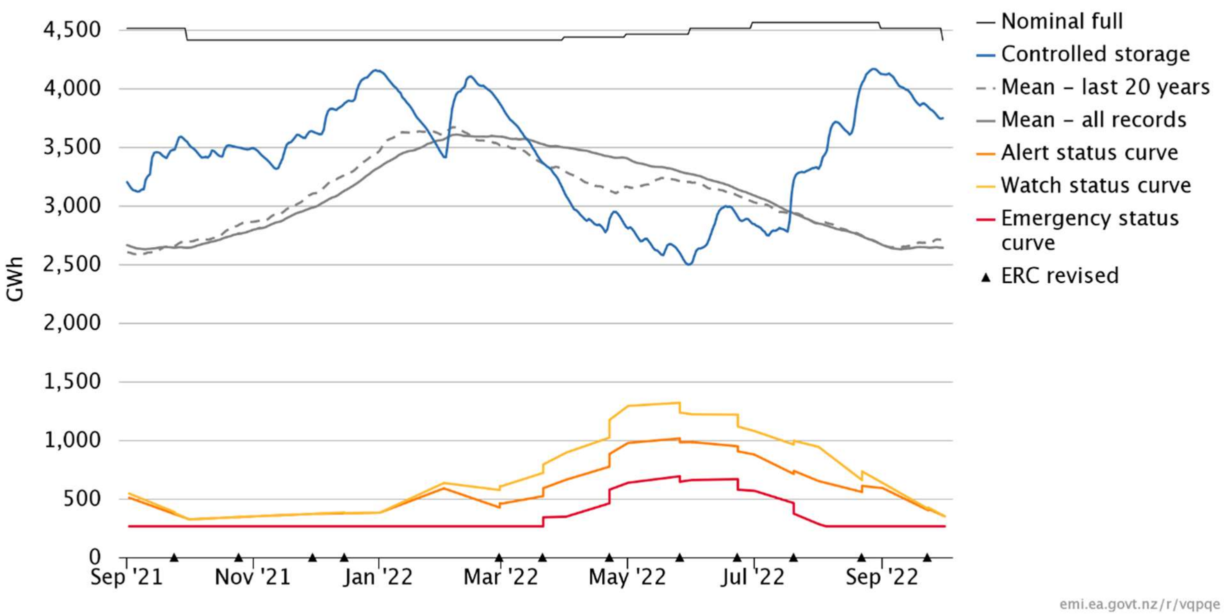


5.13 Figure 11 shows total national controlled hydro storage up to 30 September 2022. Over the September quarter hydro storage increased by 904 GWh, from 2,842 GWh on 1 July 2022 to 3,746 GWh on 30 September 2022.

5.14 On 1 July 2022 hydro storage was at 92 percent of historical mean (3,085 GWh) and 62 percent of nominal full (4,562 GWh). On 30 September 2022 storage was at 142 percent of the historical mean (2,640 GWh) and 85 percent of nominal full (4,412 GWh).

5.15 Hydro inflows were higher than the historical mean for this quarter. Total national inflows between July and September were 8,549 GWh, which is 151 percent of the historical average of 5,643 GWh.

Figure 11: Controlled National Hydro Storage 2021/2022

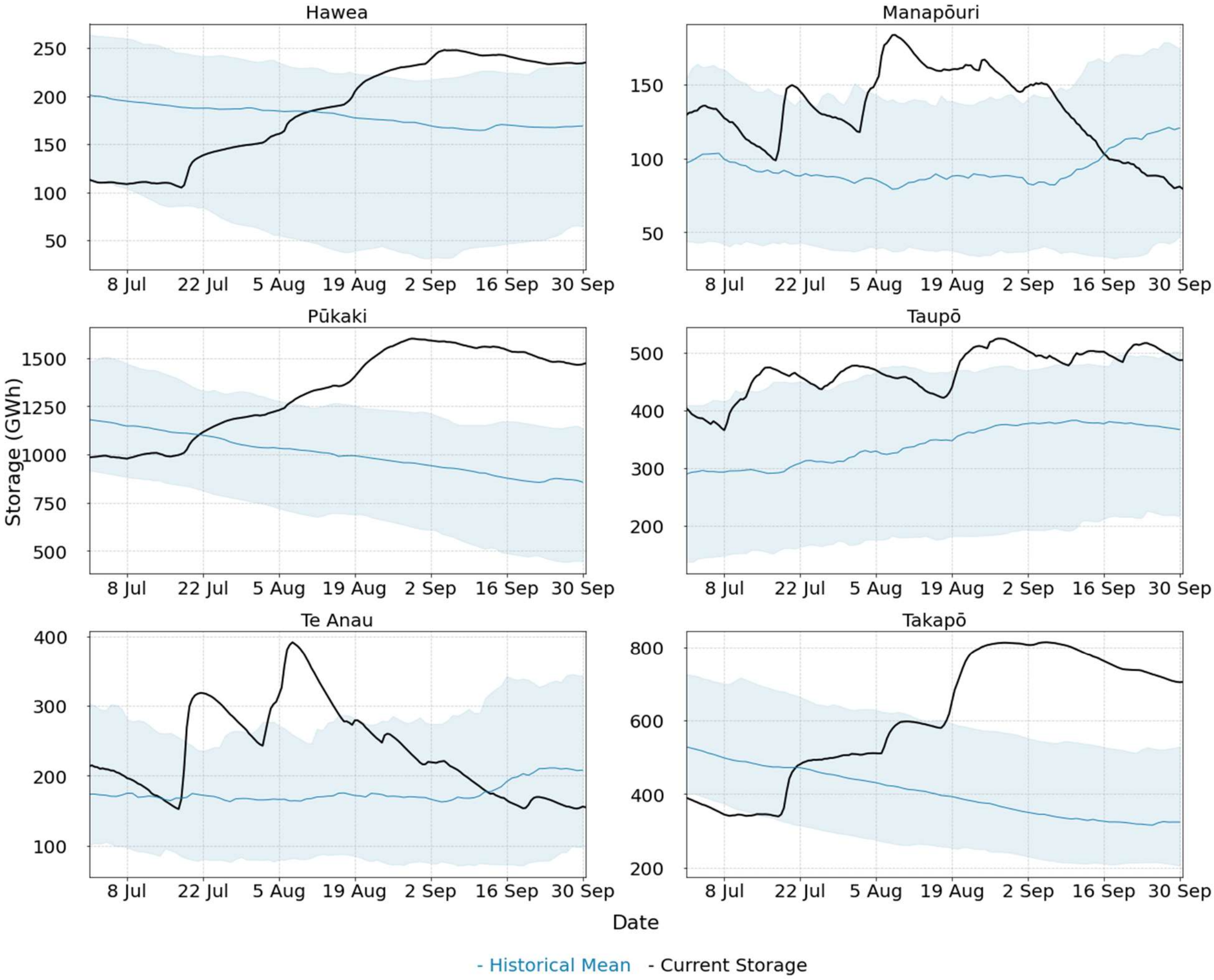


5.16 Figure 12 shows the storage of major catchments lakes Pūkaki, Taupō, Takapō, Hawea, Manapōuri and Te Anau for the quarter against their historical means and 10th -90th percentiles based on data from 1926-2021.

5.17 All lakes received large boosts to their storage in this quarter. At the end of September, storage levels at Hawea, Pūkaki, and Takapō were above their respective 90th percentile, and Taupō just below its 90th percentile. Generally, storage significantly increased in these lakes between July and September.

5.18 Lakes Manapōuri and Te Anau were significantly above their 90th percentile during mid-August but by the end of quarter both were below their historical mean.

Figure 12: Major Lake Storage vs. mean, 10th-90th percentile

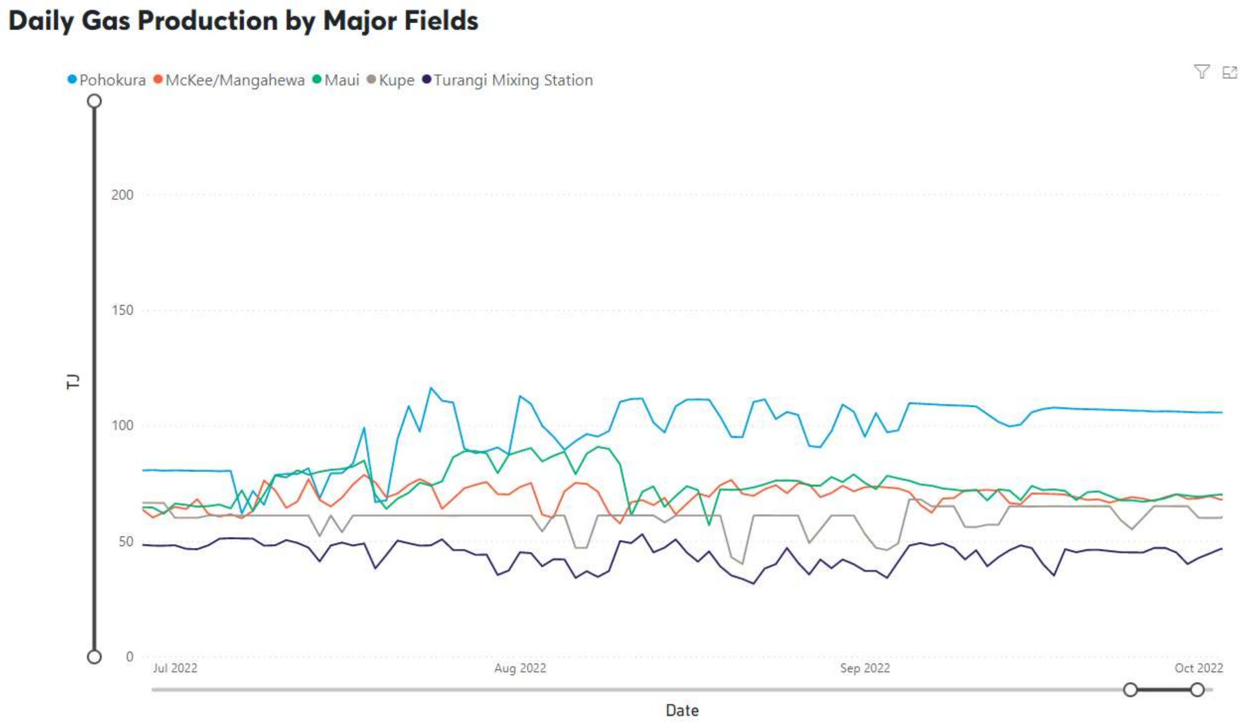


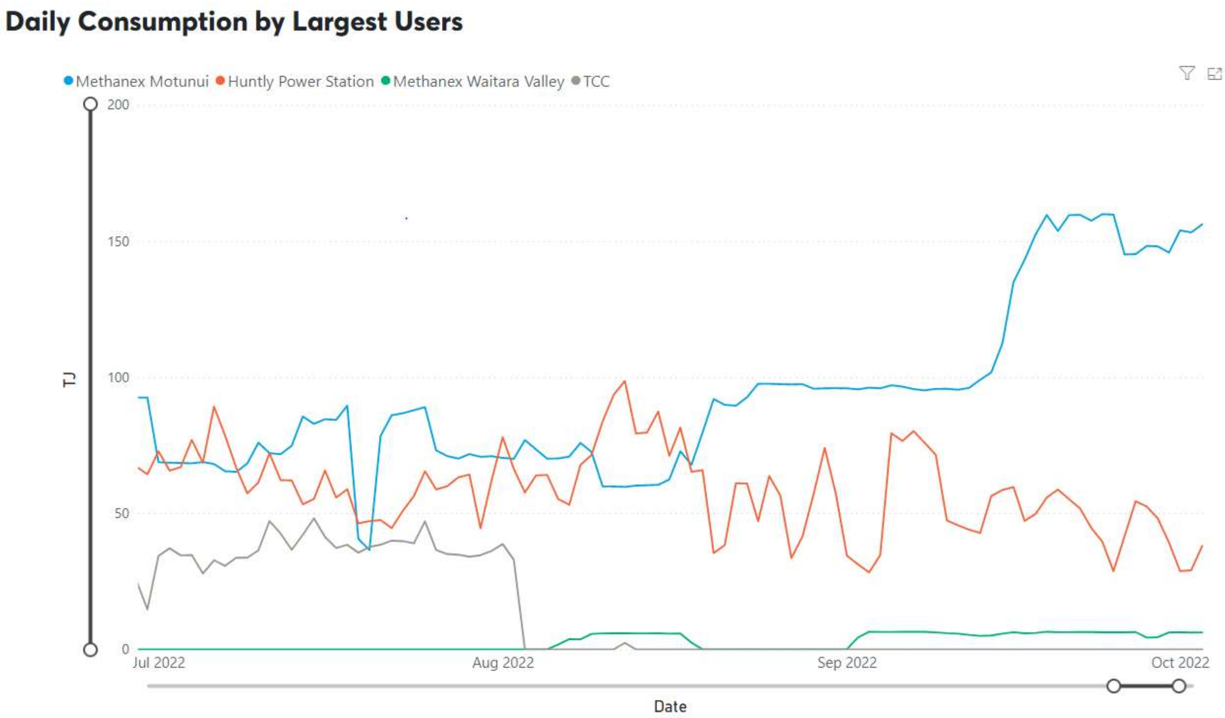
5.19 Figure 13 shows gas production by major fields and gas consumption by major users from July 2022 to September 2022. Total gas production for the September quarter increased by 31 TJ/day, from 319 TJ/day on 1 July 2022 to 349 TJ/day on 30 September 2022 with some volatility.

5.20 Overall, gas consumption increased by 15 TJ/day, from 176 TJ/day on 1 July 2022 to 191 TJ/day on 30 September 2022. In the middle of September, the country's largest energy user Methanex began to ramp up its Motunui-1 plant after its four yearly outage, with total consumption increasing to around 150 TJ/day. TCC was turned off on 3 August 2022.

5.21 During the Motunui shut-down, large volumes were pumped into the Ahuroa underground gas storage (AGS) facility. At the end of September 2022, the total closing balance of AGS was 9,822 TJ, one of the highest of the year so far.

Figure 13: Daily Gas Production and Consumption[5] July – September 2022





[5] Gas production and consumption - Gas Industry

5.22 Figure 14 shows the Māui pipeline average marginal price (AMP) for the September quarter. We took pricing data from BGIX[6] (Balancing Gas Information Exchange) which is used here as a proxy for gas spot prices.

5.23 Gas spot prices decreased around $10/GJ from July to September. Prices generally decreased between July and mid-August, as supply increased due to the Motunui outage. Prices levelled off throughout September as the Motunui plant returned, but gas used by thermal generators was lower.

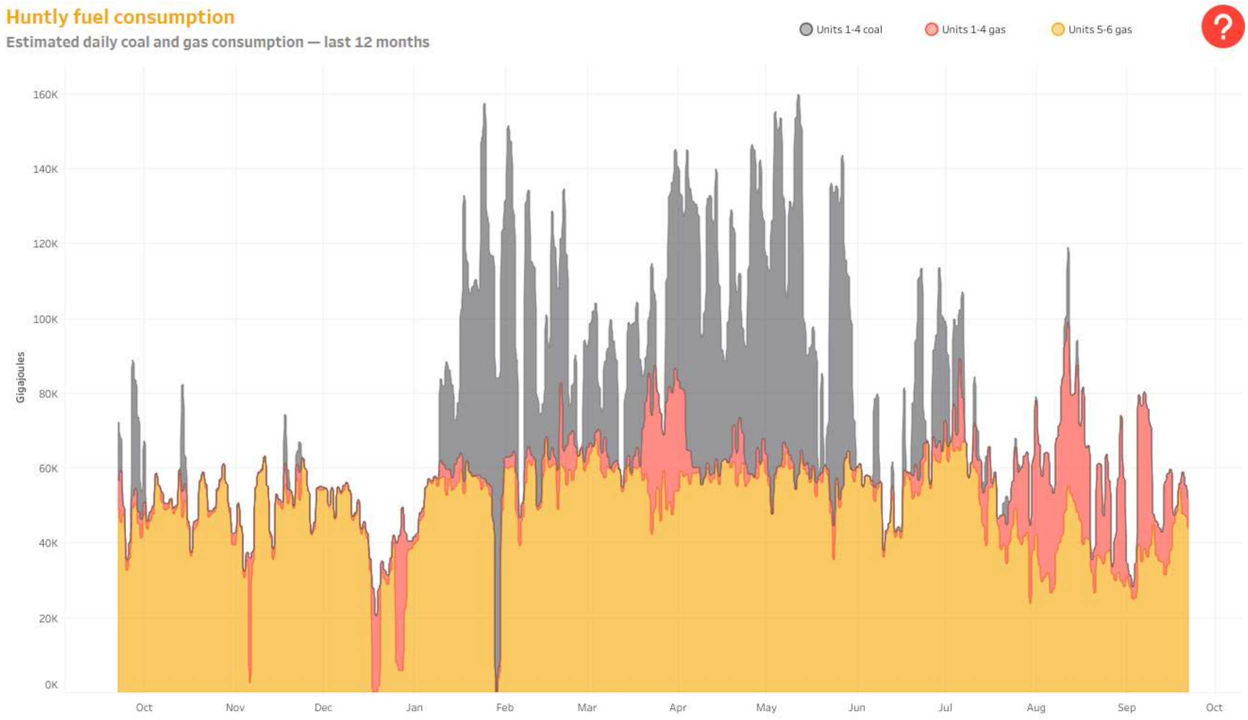
5.24 Figure 15 shows estimated gas and coal usage at Huntly. From mid-July coal use dramatically dropped close to zero. Only a few days in late July and throughout August saw coal burning in the Rankines.

5.25 The latest coal numbers from Genesis put Huntly's coal stockpile at 975,000 tonnes on 30 September 2022 which is the highest stockpile since September 2014. High hydro generation and excess gas in this quarter helped in the growth of coal storage.

Figure 14: Daily Spot Gas Prices

[6] BGIX - Balancing Gas Information Exchange

Figure 15: Estimated fuel usage at Huntly 2021/22



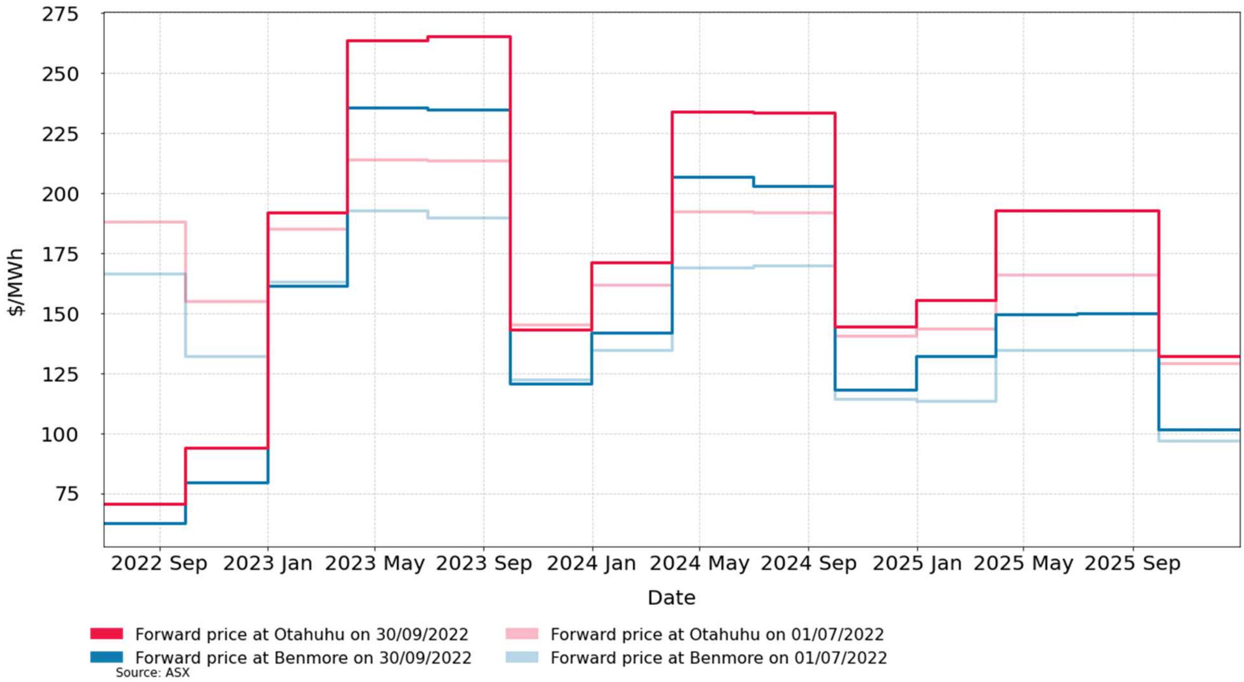
6 Forward Market

6.1 The ASX forward price curve provides a view of future wholesale spot prices. Figure 16 shows forward prices for Ōtāhuhu and Benmore at the beginning and end of the quarter, to illustrate how forward prices have changed.

6.2 Short-term forward prices (September 2022 and December 2022 quarters) fell by up to ~$118/MWh and ~$61/MWh, respectively over the quarter. Long-term forward prices rose between $3/MWh and $51/MWh.

6.3 The fall in short-term futures is likely due to improved hydro storage and short-term gas outlook. However, predicted high coal prices, high carbon prices, and predicted La Niña conditions impacted the long-term futures. Forward prices reflect all these factors as participants factor in cost and risk.

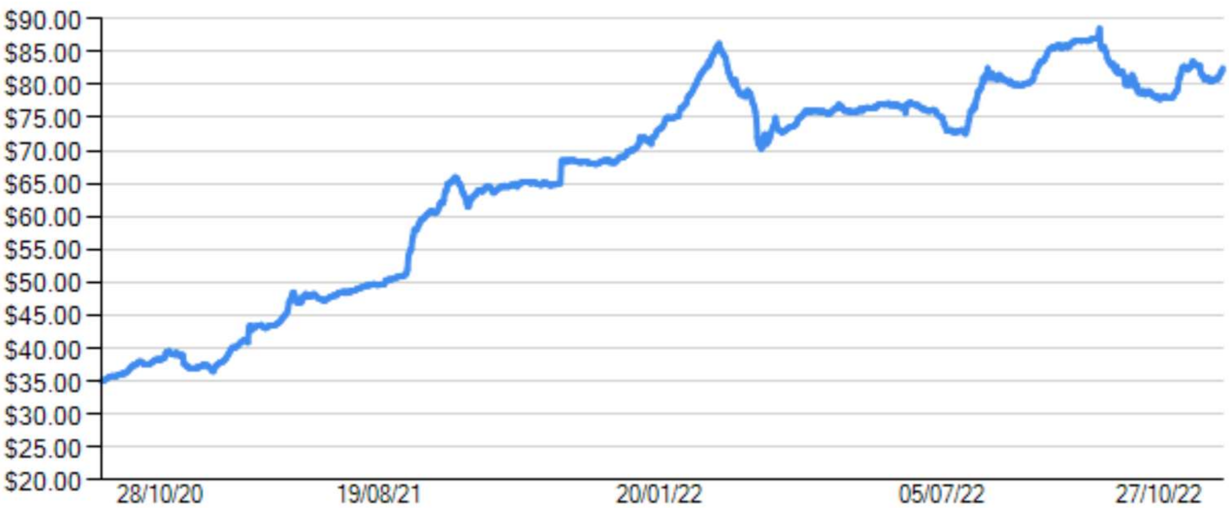
Figure 16: Future Prices



6.4 One factor that contributes to the higher long-term forward prices compared to five years ago is increasing carbon prices, which increases the costs of running thermal generation. Figure 16 shows spot NZ carbon unit prices since the first ETS auction began in 2020, taken from CommTrade's (a platform for buying and selling NZ ETS carbon credits owned by Jarden Securities Limited) website.

6.5 Overall carbon prices rose by 81.3 percent in 2021. During the September 2022 quarter, carbon units (NZUs) were cleared at $85.40 per unit, and 4.825 million NZUs were sold. After the triggering of the cost containment reserve at $70 no additional NZUs were sold.

Figure 17: New Zealand Carbon Unit Spot Price[7]



[7] https://www.commtrade.co.nz/

7 Deep Dive: Modelling electricity generation and battery capacity expansion

This section contains the results of a modelling exercise investigating the market effects of a grid scale battery under various competitive scenarios.

Key Findings

7.1 Our model shows that the benefit of allowing investment into a battery should go to retailers, and ultimately to consumers, if retailers are also perfectly competitive.

7.2 However, in the case of insufficient generation capacity, our model shows that the inclusion of a battery, despite benefitting the system at large, can profit generators while causing retailers to pay even more for energy due to an increase in the average spot price[8].

7.3 Excess generation and battery capacity can lead to significant losses for the generation and battery-owning agents as spot prices don't get high enough to recover their investment costs.

7.4 Thus, a competitive wholesale market, a competitive retail market, and unimpeded generation investment are necessary to ensure consumers benefit from grid-scale battery investments.

Model

7.5 This deep dive aims to develop a simple model that allows us to understand the potential impact of a battery in a perfectly competitive wholesale market. Specifically, how it impacts spot prices and the overall welfare of each participant. This model does not cover other potential benefits of grid scale battery investment, such as reducing transmission investment. This analysis was aimed as being a simple first step with the potential to add complexity in the future.

7.6 The full description of this model and the GAMS implementation can be found at https://github.com/ElectricityAuthority/BatteryDeepDive.

7.7 Electricity demand and supply change with predictable daily, weekly, and annual patterns depending on the type of generator or consumer. In this mathematical model, changing supply and demand loads are represented by discrete blocks, with each 'load block' potentially lasting different lengths of time.

7.8 We begin by defining a set of agents (such as generators and retailers) that exist in the model. We then describe the parameters corresponding to each generation plant (e.g., marginal cost and capacity) and the retail demand. After formulating this competitive wholesale market, we develop an equivalent centrally planned model that attempts to satisfy demand at minimum cost (proving their equivalence through their KKT conditions in the pdf found at https://github.com/ElectricityAuthority/BatteryDeepDive).

[8] Our example extends to when there is a constraint on just one of the generation plants, leading to that generator and the system benefitting from the battery, potentially at the retailer's expense.

7.9 We consider a market with demand and potential supply for electricity at this node. We choose generation and demand curtailment (at a penalty) to meet this demand at a minimum cost.

7.10 Generalising the competitive wholesale market model, agents can be producers (generators), retailers or a combination (gentailers) of electricity. Each agent controls at most one (initially non-existent) generator, are able to build this generator at any size and sell a proportional amount of electricity (based on this size) on the spot market.

7.11 Retailers must purchase generation at the wholesale price to satisfy demand across the different load blocks or curtail them with a penalty. Consumers may have a different load profile compared to one another or a different price they pay for each unit of electricity generation. Our model only has a single retailer, but with multiple retailers, we would expect retail prices to approach the average demand weighted spot price.

7.12 There is also a battery agent with the opportunity of investing in a battery. The agent can use the battery to sell energy in some load blocks by purchasing it in others (with some efficiency losses).

Case Study: Thermal, Wind, and Battery

7.13 In our case study, we assume all electricity generation and demand occurs at a single node and the consumption and production of energy happen in an hour. We have also normalised costs and revenue. The market comprises of:

(a) The Battery agent with the decision to invest capacity into a battery with the opportunity of arbitraging spot prices by charging and discharging this battery across load blocks

(b) The Retail agent who purchases generation on the spot market to sell at a fixed price to consumers whose demand changes over discrete load blocks.

(c) The Thermal generator agent who has the opportunity of constructing a plant with a constant generation capacity but relatively high capacity and running costs.

(d) The Wind generator agent has the opportunity of constructing a plant with variable capacity but lower running costs and investment costs than the thermal plant.

7.14 Table 1 summarises each generation plant, and Table 2 summarises the cost and efficiency of the battery.

7.15 The two sources of variability in our model are demand and wind capacity. This variability is illustrated in Figure 18 and summarised in Table 3 alongside the remaining parameter values used in our model.

Table 1: Generation plant cost and capacity

Description	Capacity expansion cost	Marginal cost of generation	Capacity expansion limit
Parameter	xC	$\mathrm{gC_g}(l)$	$\bar{\mathrm{x}}_g$
$Thermal$	$\$6/MW$	$\$2/MWh$	$10MW$
$Wind$	$\$4/MW$	$\$0/MWh$	$10MW$

Table 2: Battery cost and capacity

Description	Capacity expansion cost	Capacity expansion limit	Battery efficiency
Parameter	xB	$\overline{\mathrm{w}}_b$	b_b^{eff}
	$\$6/MW$	$10MW$	0.8

Figure 18: Diagram illustrating the load blocks that occur. Each load block occurs for 1/8 of the time

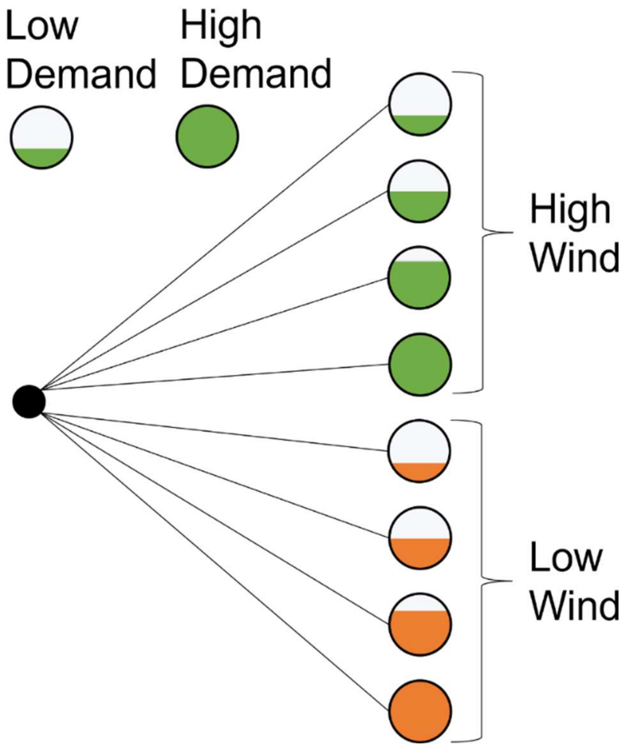


Table 3: Summary of parameters across load blocks

Description	Load block	Time in load block	Capacity factor for Thermal generator	Capacity factor for Wind generator	Retail demand	Retail revenue	Value of lost load
Parameter	l	$\mathbb{T}(l)$	$\mathrm{m}_{Thermal}(l)$	$\mathrm{m}_{Wind}(l)$	$\mathrm{d}_{Retail}(l)$	$\mathrm{r}_{\mathrm{Retail}}$	v
	l_1	$0.125\ s$	1.0	1.0	$1.0\ MW$	$\$20/MWh$	$\$100/MWh$
	l_2	$0.125\ s$	1.0	1.0	$2.0\ MW$	$\$20/MWh$	$\$100/MWh$
	l_3	$0.125\ s$	1.0	1.0	$3.0\ MW$	$\$20/MWh$	$\$100/MWh$
	l_4	$0.125\ s$	1.0	1.0	$4.0\ MW$	$\$20/MWh$	$\$100/MWh$
	l_5	$0.125\ s$	1.0	0.5	$1.0\ MW$	$\$20/MWh$	$\$100/MWh$
	l_6	$0.125\ s$	1.0	0.5	$2.0\ MW$	$\$20/MWh$	$\$100/MWh$
	l_7	$0.125\ s$	1.0	0.5	$3.0\ MW$	$\$20/MWh$	$\$100/MWh$
	l_8	$0.125\ s$	1.0	0.5	$4.0\ MW$	$\$20/MWh$	$\$100/MWh$

Results: Impact of battery in a perfectly competitive environment

7.16 Assuming all decisions are continuous and convex, and all agents are perfectly competitive price takers (maximise their profit for the given spot market prices across the load blocks), the competitive model we have formulated provides the decisions that maximise the benefit to the system.

7.17 In the following tables and figures, we compare the expansion decisions, agent profit and spot prices across load blocks between a model where we constrain the battery capacity to be 0 and a model where we allow investment into a battery.

7.18 Table 4 shows the capacity expansion in both of these models. It illustrates the role we expect large-scale batteries to have on the grid, combined with increased investment into cheaper but intermittent generation to displace more reliable but expensive fossil-fuelled generation.

7.19 Figure 19 shows the profit of all agents in both models. As expected, by relaxing a constraint (allowing investment into a battery), the profit to the system has increased.

7.20 We are modelling the battery owner, the thermal generator, and the wind generator as price takers with constant marginal costs. Accordingly, if spot prices are too low (if price *differences* between load blocks are too low for the battery owner), meaning any revenue would not cover the investment cost, then they will not invest in capacity. If spot prices are high enough (or in the case of the battery if the difference in prices between load blocks are high enough), they will invest up to the maximum capacity. There is a point in the middle where they earn zero profit and construct between zero and the maximum capacity. In our case study, the maximum capacities are intentionally set too high to be binding. Thus, the generation and battery agents will make zero profit from their capacity investment.

7.21 Under the perfect competition model, both with and without the battery agent investment, decisions result in sufficient generation and/or battery load to meet consumers demand in all scenarios. In addition, the increase in profits to the system by allowing investment into a battery is passed on to consumers via the retailer (assuming a perfectly competitive retail market) due to the decrease in average spot prices.

7.22 Figure 20 shows the spot price across all load blocks in both models, showing the benefit a battery has by charging in load block 1 and discharging in load block 8. The demand-weighted average spot price in the ‘No Battery’ model is $28.25/MWh, and the demand-weighted average spot price in the ‘With Battery’ model is $27.56/MWh.

Table 4: Capacity expansion decisions in the perfect competition model

		Model	
		No Battery	**With Battery**
Generation Plant / Battery	**Battery**	–	$2.22MW$
	Thermal	$3.0MW$	0
	Wind	$2.0MW$	$3.56MW$

Figure 19: Profit of each agent in the perfect competition model

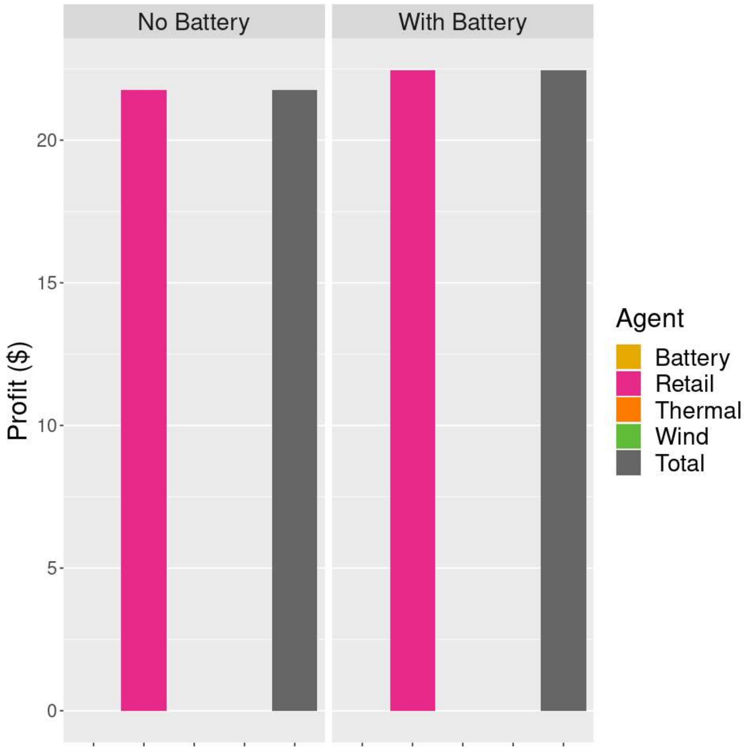
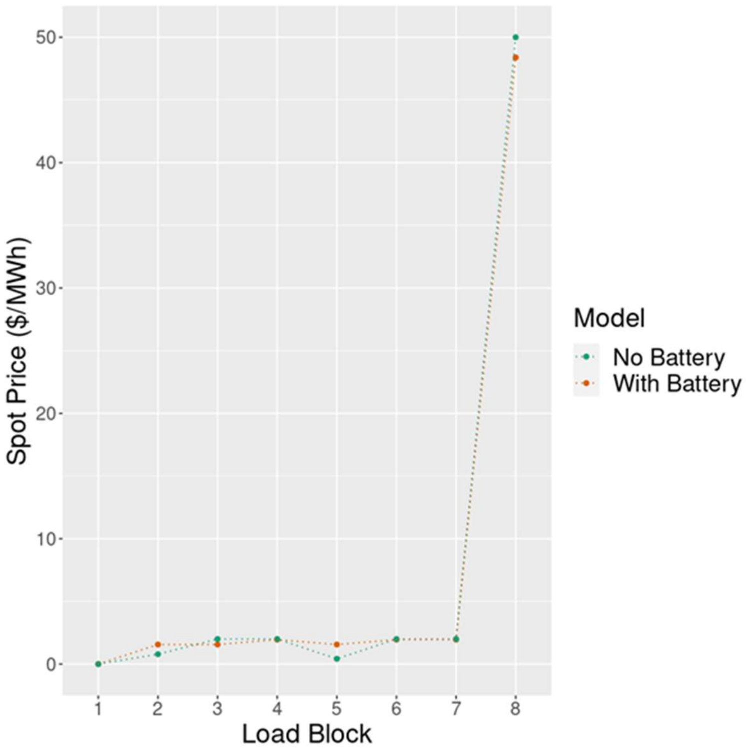


Figure 20: Spot market price in each load block for the perfect competition model



Results: Impact of battery when there is limited generation capacity expansion

7.23 Here, we have fixed capacity expansion decisions for Thermal and Wind to 1MW each. The limited expansion means we have insufficient generation to satisfy the 1MW-4MW demand across all 8 load blocks, leading to the curtailment of some of the demand for most of these load blocks and prices reaching the 'value of lost load' ($100/MWh in our model).

7.24 With the higher prices resulting from the limited generation capacity expansion, both generators benefit and profit on the spot market in the 'No Battery' model. The retail agent suffers from a significant loss in this model as they have to curtail much of their demand, which costs more than the retail revenue they receive.

7.25 By allowing the battery agent to invest, we still see some benefits to the system in Figure 21. The battery enables more demand to be met by shifting some generation from when there is a surplus (load blocks 1 and 5) to the other load blocks.

7.26 However, this time the generators benefit from the presence of the battery as it increases the supply-weighted spot market price (shown in Figure 22). The retail agent makes an even more considerable loss with the battery due to higher spot prices in load blocks 1 and 5 and no change in prices in the remaining load blocks. Given a competitive retail market, the battery would cause an increase in retail prices.

7.27 The interaction between the battery (which is used to arbitrage the low and the high price load blocks) and insufficient spare energy in the low-price load blocks leads to an increase in prices in the low-price load blocks without the high spot price load blocks coming down.

7.28 Limited generation capacity with no battery results in the curtailment of consumer demand in 5 of the 8 load blocks, with the battery reducing the amount of energy curtailed in each load block. However, this increase in reliable supply comes at a cost due to higher retail prices that occur because of higher spot prices in the other 3 load blocks, as the retailer passes higher costs to consumers.

Table 5: Expansion decisions when generation capacity is limited

		Model	
		No Battery	**With Battery**
Generation Plant / Battery	**Battery**	$-$	$1.0MW$
	Thermal	$1.0MW$	$1.0MW$
	Wind	$1.0MW$	$1.0MW$

Figure 21: Profit of each agent when generation capacity is limited

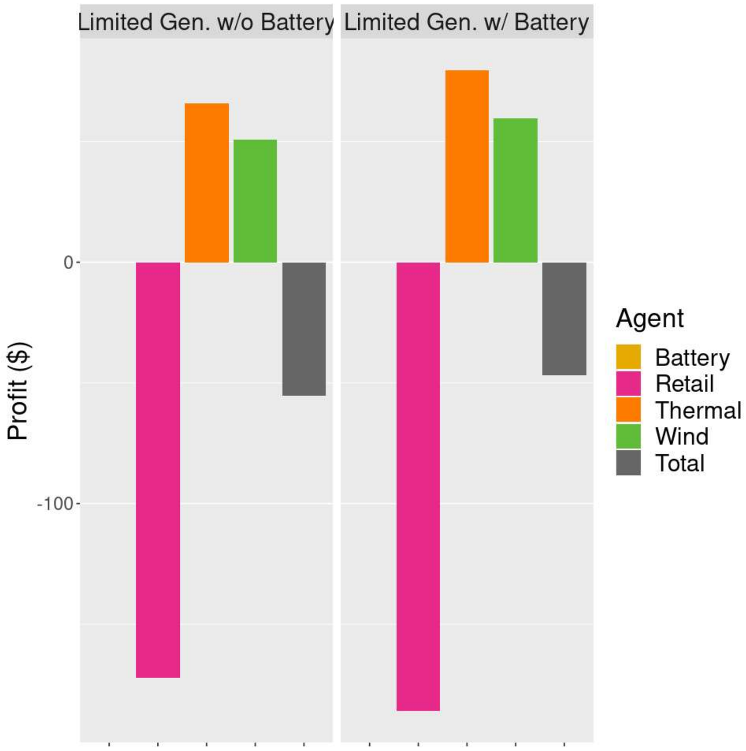
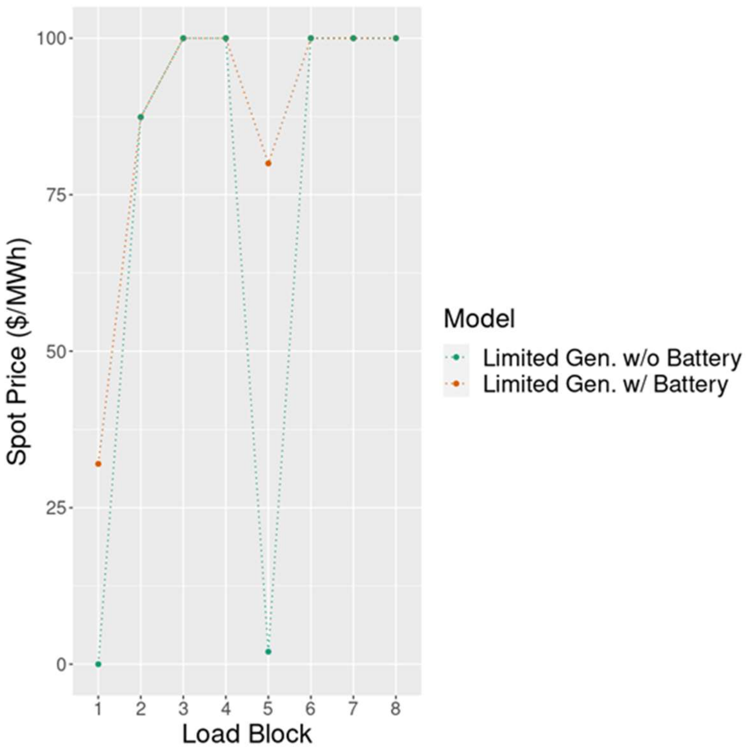


Figure 22: Spot market price in each load block when generation capacity is limited



Results: Impact of battery when there is limited wind capacity expansion

7.29 Here, we have fixed the wind capacity expansion decisions to 1.5MW. We have seen from Table 4 that the optimal mix of generation in this case study uses more than 1.5MW of wind for both the 'with battery' and 'without battery' models.

7.30 The limited capacity expansion means the remaining energy has to come from investment into thermal generation plant (or curtailed at our $100/MWh value of lost load).

7.31 In Figure 23, we see that enforcing an upper bound on wind generation capacity expansion allows the corresponding agent to make a profit due to the resulting higher spot prices.

7.32 Similar to the results we saw in Figure 21, in Figure 23, we again see that the inclusion of the battery benefits the system as a whole (Total profit increases from $21.63 to $21.72). Again, we see the battery helps the wind generator (profit increasing from $0.37 to $0.66) instead of benefitting the retailer (profit reducing from $21.25 to $21.06). With a competitive retail market, consumers would face an increase in retail prices with no additional reliability with the battery.

Table 6: Expansion decisions when there is limited wind generation capacity

		Model	
		No Battery	**With Battery**
Generation Plant / Battery	**Battery**	$-$	$0.5MW$
	Thermal	$3.25MW$	$2.75MW$
	Wind	$1.5MW$	$1.5MW$

Figure 23: Profit of each agent when there is limited wind generation capacity

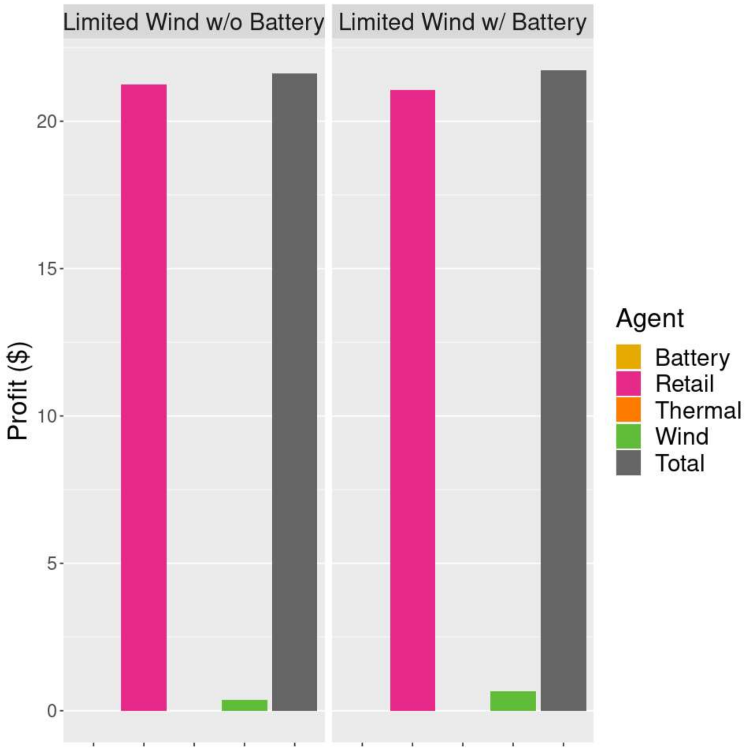
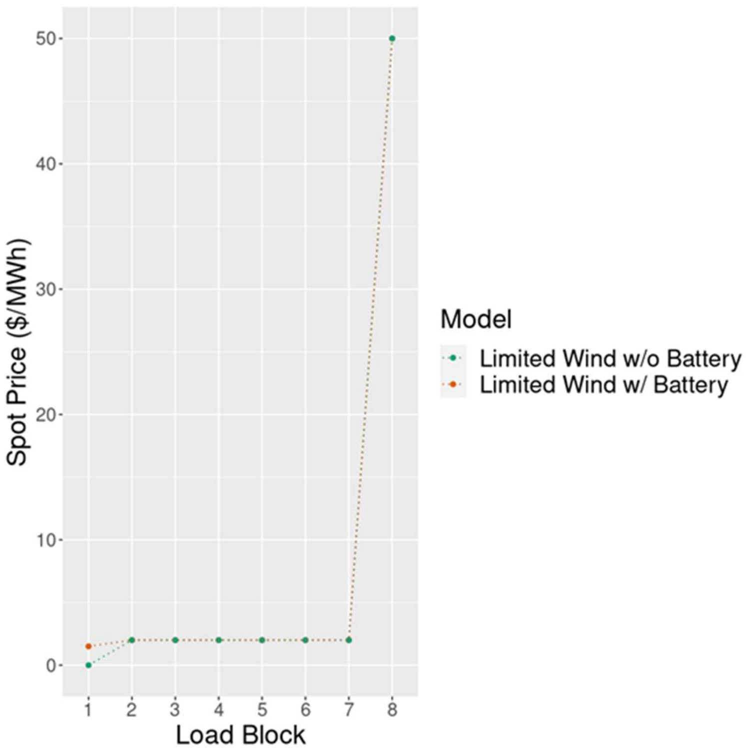


Figure 24: Spot market price in each load block when there is limited wind generation capacity



Results: Impact of battery when there is excess generation capacity expansion

7.33 For this example, we fix wind capacity expansion to 5MW and thermal capacity expansion to 0MW. We have insufficient generation to meet all demand in load blocks 7 and 8. In the 'With Battery' model, we fix battery capacity expansion to 3MW, giving a surplus in capacity (as both wind and battery capacity are larger than the perfectly competitive 'With Battery' model shown in Table 4).

7.34 We see the over-expansion leads to the wind and battery agent making a loss and the retail agent making a significant profit in Figure 25 as they benefit from the $0/MWh spot prices across all load blocks shown in Figure 26, which we expect they would then pass on to consumers.

Table 7: Expansion decisions when there is excess generation capacity

		Model	
		No Battery	**With Battery**
Generation Plant / Battery	**Battery**	–	$3.0MW$
	Thermal	–	–
	Wind	$5.0MW$	$5.0MW$

Figure 25: Profit of each agent when we have an excess in generation capacity

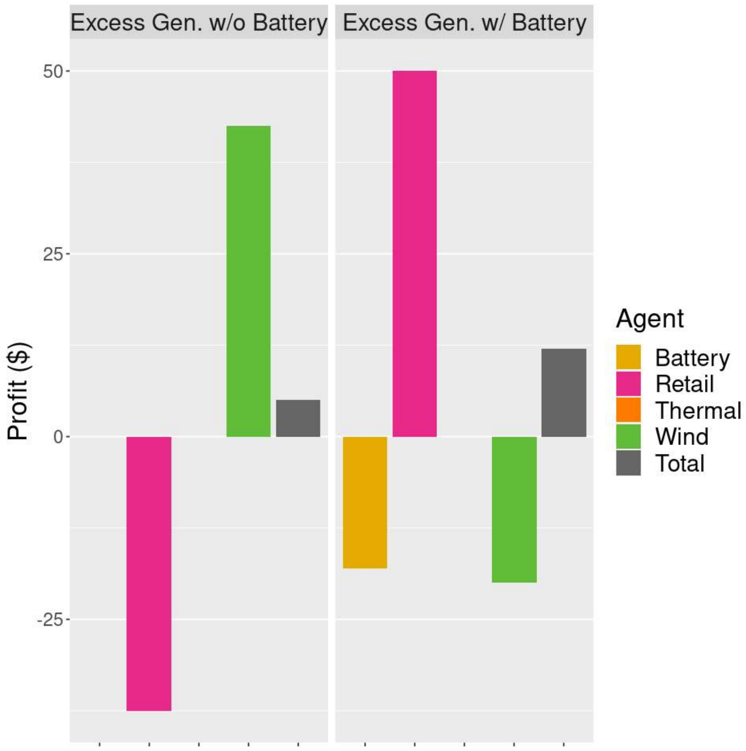
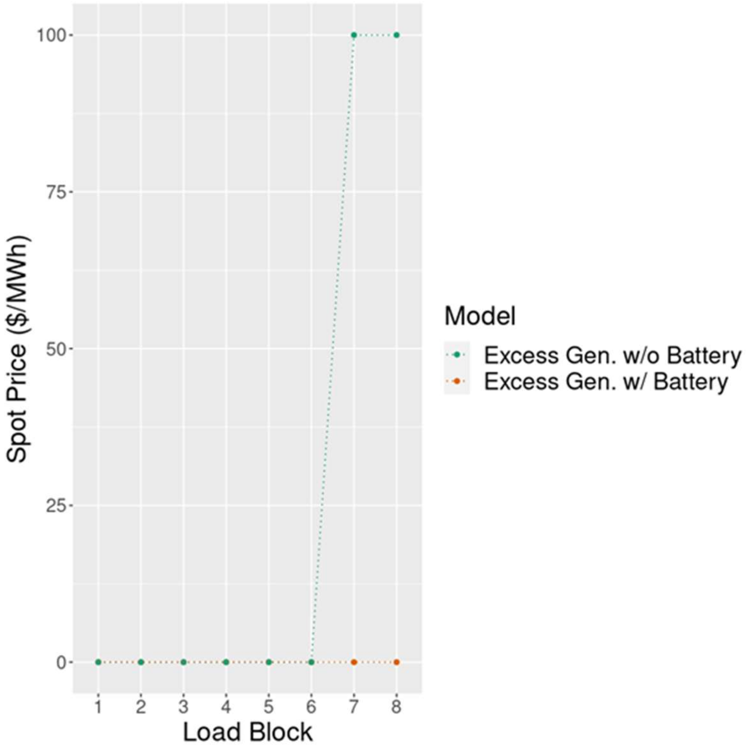


Figure 26: Spot market price in each load block when there is excess generation capacity



Results: Comparing welfare across all models

7.35 In Figure 27, we see the ‘the perfect competition with battery’ model has the highest total system profit due to having all possible investment sources available and not being constrained.

7.36 In Figure 28, we see that the ‘excess generation with battery’ model has the highest retailer profit due to the over-investment leading to $0/MWh spot prices across all load blocks.

7.37 Similarly, in Figure 29, due to the $0/MWh spot prices, the ‘excess generation with battery’ model is also the model with the lowest demand weighted average spot price, which should lead to the lowest consumer prices.

Figure 27: Total system profit across all models

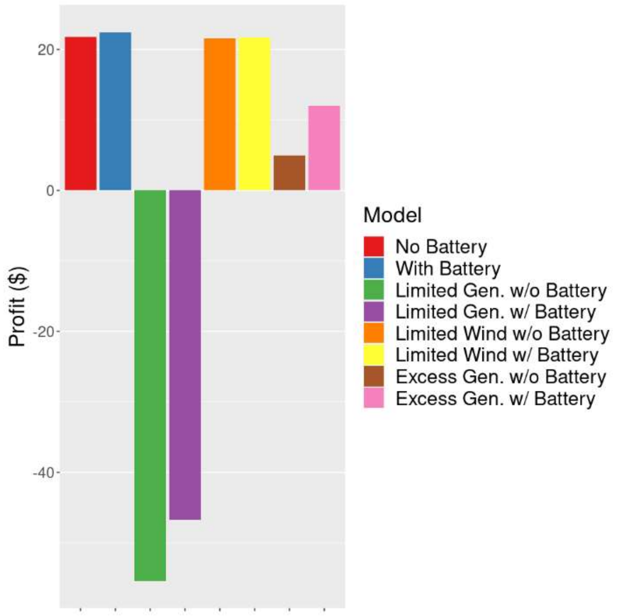


Figure 28: Retailer profit across all models

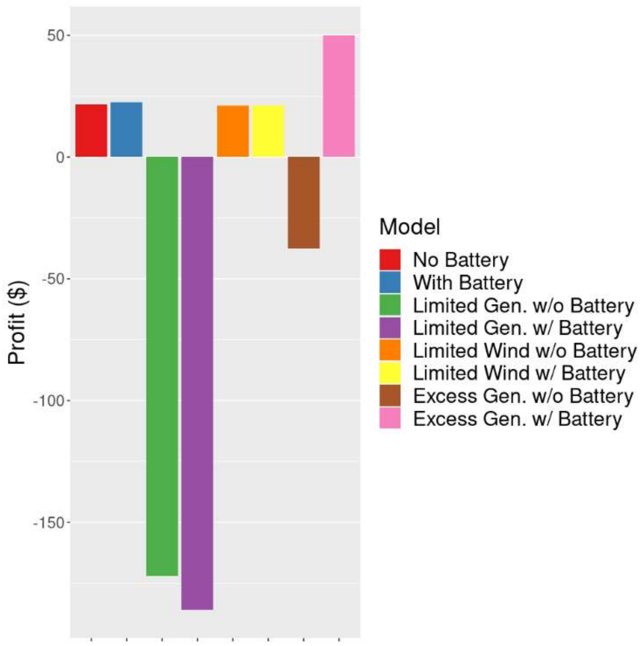


Figure 29: Demand weighted average spot price across all models (curtailed load is assumed to be satisfied at $100/MWh)