MARTIN JENKINS

MODELLING RETAIL ELECTRICITY PRICES UNDER HIGH RENEWABLES, AND LOW-EMISSIONS SCENARIOS

Final Report

An analysis of what the Interim Climate Change Committee's modelling means for retail electricity prices in 2035

28 March 2019

CONTENTS

TABLES

FIGURES

PREFACE

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EXECUTIVE SUMMARY

Background

The Interim Climate Change Committee (ICCC) have engaged MartinJenkins to help it understand what the transition towards a 100% renewable electricity system by 2035 may mean for retail electricity prices in New Zealand.

The ICCC have commissioned modelling scenarios of how New Zealand may transition to a 100% renewable electricity system, and how energy sector greenhouse gas emissions may be minimised through electrification of transport and process heat. This Report explores what the results of its modelling mean for retail electricity prices.

Key questions for this analysis

This Report aims to provide answers to a set of key questions. These include:

- What do the results of the ICCC's modelling mean for retail electricity prices:
  - in different regions of New Zealand?
  - faced by different customer segments (residential, commercial and industrial)?
  - faced by low-income and Māori and Pasifika households?
  - for different times of use?
- What does a potentially higher level of wholesale price volatility (that may result from high levels of intermittent generation) mean for retail electricity prices?

Insights and analysis

The following key insights have been drawn from our analysis in response to the ICCC's key questions.

What do the results of the ICCC's modelling mean for retail electricity prices in different regions of New Zealand?

Currently in NZ, transmission and distribution prices explain much of the differences in retail electricity prices by region. There are currently three electricity price reviews that could impact retail electricity prices in New Zealand: MBIE's Electricity Price Review (EPR); the Electricity Authority's (EA's) transmission pricing methodology (TPM) review; and the EA's distribution pricing methodology (DPM) review. These reviews may result in significant changes to retail electricity prices by 2035, particularly transmission and distribution prices. This uncertainty in transmission and distribution prices make retail electricity prices by region in 2035 extremely difficult to estimate. As a result, these have not been provided.

However, factors that may lead to retail price increases and decreases by region are summarised in the following table.

Table 1: Factors that may lead to retail electricity price increases or decreases

Factor	Increase / decrease
Retail market competition	Decrease
Barriers to market participation for some consumers	Increase
Demand becoming more peaky	Increase
Electricity (energy) demand growth	Increase
Energy efficiency	Decrease
Smart demand management	Decrease
Increased carbon prices	Increase in the short-term, but flat in the long-term

Source: MartinJenkins analysis

What do the results of the ICCC's modelling mean for retail electricity prices faced by different customer segments?

Large increases in retail electricity prices are not expected, unless we achieve 100% renewable electricity generation

Retail electricity prices for residential, commercial and industrial customers in 2035 were modelled for a range of scenarios, and the sensitivity of scenario results were tested against higher emissions prices, higher gas prices, peakier electricity demand and constrained hydro availability. These modelling results showed that for most scenarios, retail electricity prices are expected to be similar to today's levels (specifically average electricity prices for these customer segments for the year ended March 2018).

For all futures modelled (middle of the road; fast tech, high demand; slow tech, low demand), the last 1–2% of fossil fuel generation was very expensive to remove, and this had a large impact on retail prices (11–19% higher, 15–24% higher and 20–31% higher than the middle of the road scenario for residential, commercial and industrial customers respectively). Furthermore, removing that fossil fuel generation resulted in minimal emissions savings.

It should be noted that this result (that large electricity price increases are not expected) was also a finding of the Productivity Commission's low-emissions inquiry.[1]

Electrification of transport and process heat demand is expected to modestly increase retail electricity prices

Retail electricity prices for each customer segment were also modelled for scenarios where large amounts of transport and process heat demand were met from electricity (with a view to minimising energy sector greenhouse gas emissions, rather than maximising the share of renewable electricity generation).

[1] Concept Consulting, Motu, Vivid Economics, 2018. Modelling the transition to a lower net emissions New Zealand: Uncertainty analysis. Retrieved from https://www.productivity.govt.nz/sites/default/files/Modelling%20the%20transition%20to%20a%20lower%20net%20emissions%20New%20Zealand%20-%20Uncertainty%20analysis%20-%20Concept%2C%20Motu%2C%20Vivid.pdf. p. 33 refers.

The central electrification scenario modelled retail electricity prices in 2035 to be 3% higher, 5% higher and 6% higher than the middle of the road scenario for residential, commercial and industrial customers respectively. Sensitivities to the central electrification scenario (slow tech, low demand; peakier demand and elec $150/t emissions price) indicate that retail prices could increase by more than this, especially if emissions prices in 2035 are higher than our central scenario assumptions ($50/t$CO_2$e).

Higher emissions prices and higher gas prices are likely to result in higher retail electricity prices

The sensitivities to higher emissions prices ($150/t$CO_2$e versus $50/t$CO_2$e) and higher gas prices ($19/GJ versus $9.50/GJ) that were modelled imply that if emissions prices or gas prices are higher than we assume in the middle of the road scenario, this will push retail electricity prices higher.

If emissions prices in 2035 are $150/t$CO_2$e, retail electricity prices in 2035 could be 4% higher, 6% higher and 8% higher for residential, commercial and industrial customers respectively compared with the middle of the road scenario.

If gas prices in 2035 are $19/GJ, retail electricity prices in 2035 could be 5% higher, 7% higher and 9% higher for residential, commercial and industrial customers respectively compared with the middle of the road scenario.

Constrained hydro availability is estimated to have little effect on retail prices

The ICCC also modelled the sensitivity of the middle of the road scenario to constrained hydro availability (to reflect competing pressures on freshwater). Under this sensitivity retail electricity prices for all customer segments were about the same as in the middle of the road scenario. Therefore these changes are expected to have little effect on retail prices in 2035.

Peakier electricity demand is estimated to have little effect on retail prices, but this effect may be underestimated

A sensitivity to a peakier electricity demand profile was modelled relative to the electrification scenario (possibly caused by EVs charging at peak times). In this sensitivity retail electricity prices increased 1–2% compared with the electrification scenario for all customer segments.

While these modelling results imply that peakier electricity demand would have little effect on retail prices, we think that this is likely to be an underestimate. In this analysis we assumed that transmission and distribution charges remain as they are today. This is an unrealistic assumption in the case where electricity demand becomes peakier — if electricity demand becomes peakier, network investments for transmission and distribution are likely and this will push up network costs, which will be recovered from the network users. We advise that this result in particular should be interpreted with care.

What do the results of the ICCC's modelling mean for retail electricity prices faced by low-income, Māori and Pasifika households?

Low-income households are disproportionately impacted by increases in retail electricity prices. Māori and Pasifika households are two ethnic groups in New Zealand that are over-represented in statistics on socioeconomic deprivation, and as such are likely to be also disproportionately impacted by increases in retail electricity prices.

Our analysis shows that Māori households comprise a high percentage of rural New Zealand households (especially in the North Island, and those in the two lowest income quintiles). Māori households also comprise a high percentage of large (five or more person) households. Our analysis indicates that Māori households spend more each week on electricity than non-Māori households. If retail electricity prices increase in the future, this could impact Māori whānau harder than non-Māori households. Other research notes that many whānau financially support their local marae — electricity price increases will hit these whānau twice, through increased electricity bills at home, and at the marae. Furthermore, since many Māori whānau live rurally, they are also at higher risk of being impacted by other impacts of the transition to a low-emissions economy (eg rural families have an higher reliance on ICE cars for transport than urban families, and petrol and diesel prices are likely to increase with increasing carbon prices).

Pasifika households face many of the same challenges as Māori households, including being more likely to be on low-incomes, and be living in large households. As a result, Pasifika families are also likely to be disproportionately impacted by increases to retail electricity prices.

What do the results of the ICCC's modelling mean for retail electricity prices for different times of use?

Currently in New Zealand, retail electricity prices do not vary by time of use for most customers; however, the costs of delivering electricity (including generation, transmission and distribution) depend heavily on the time of use. Since most customers do not face electricity prices that signal when the network may be congested (or when there is spare capacity of the system) they have no incentive to move demand away from busy periods. As a result, transmission and distribution companies over-invest in their networks to ensure that peak demand is met, and these costs are recouped from network customers.

The EA is currently reviewing the way costs of electricity transmission and distribution services are shared among customers; the EA and the wider electricity industry recognise that the current transmission and distribution charges are inefficient. The EA's recently released discussion paper on distribution pricing principles notes that:

- electricity distribution is primarily a fixed cost service (which depends on peak demand), but the costs of this service are recouped from customers based on a variable (per kWh) rate
- variable (per kWh) rates do not change by time of day (or by season) so customers have no incentive to move demand away from peak periods
- because some customers can invest in technology that reduces their electricity consumption (eg solar PV) they pay a lower share of distribution network costs. But this does not reduce network costs, so the remaining costs are forced on to other customers on the network.

Overall we would expect that by 2035 time of use distribution pricing would be commonplace in New Zealand, and that retailers would be passing on these price signals to customers in a transparent way. If this occurs, customers would be incentivised to react by shifting demand to off-peak times. While many customers could move to spot-price based pricing plans, many may prefer to remain on a ‘hedged’ price plan. This means that although retail prices would change based on time of use during the day[2], most retail customers will be protected from potential price volatility that may arise from intermittent (and weather dependent) renewable generation by hedge contracts.

What does a potentially higher level of wholesale price volatility (that may result from high levels of intermittent generation) mean for retail electricity prices?

It is possible that wholesale electricity prices may become more volatile in the future if New Zealand moves to very high percentages of renewable generation. This volatility is related to having a large percentage of renewable generation on the system, that is dependent on weather (including hydro, wind and solar), and low levels of energy storage. As a result, it becomes difficult (and extremely costly) for the system to meet demand in dry, calm and / or cloudy periods. This difficulty increases as the percentage of renewables on the system increases.

While wholesale electricity prices may become more volatile with higher percentages of renewable electricity generation, retail electricity prices are likely to continue to be based on wholesale hedge contracts. This assumes a wholesale hedge market is in place that effectively manages this price volatility. If this is that case we would expect that the increased price volatility would have little effect on retail prices, aside from hedge premiums increasing slightly to account for the increased risk of periods of very high prices.

2 This could be different electricity prices for peak, off-peak and shoulder times, or different electricity prices for each trading period (which could be determined statically or dynamically).

INTRODUCTION

Background to this work

The Interim Climate Change Committee (ICCC, "the Committee") is a Ministerial Advisory Committee appointed by the Minister for Climate Change Issues with the agreement of Cabinet (CAB-17-MIN-0547.01 refers). The Committee is a precursor to the Climate Change Commission, which is expected to be established in 2019.

The terms of reference for the Committee outlines the purpose of the Committee, and the deliverables it is expected to produce.[3]

This Report will assist the Committee in their investigation of how New Zealand can transition towards a 100% renewable electricity system. In its work, the Committee must give regard to a number of factors, including the affordability of electricity for consumers.[4]

To this end, the Committee has commissioned modelling of how New Zealand can achieve a 100% renewable electricity system by 2035, and how energy sector emissions could be minimised (through electrification). The focus of this Report is to estimate how retail electricity prices may evolve in 2035, using the Committee's modelling (and other data) as an input.

Key questions for this analysis

This Report aims to provide answers to a set of key questions. These include:

- What do the results of the ICCC's modelling mean for retail electricity prices:
  - in different regions of New Zealand?
  - faced by different customer segments (residential, commercial and industrial)?
  - faced by low-income and Māori and Pasifika households?
  - for different times of use?
- What does a potentially higher level of wholesale price volatility (that may result from high levels of intermittent generation) mean for retail electricity prices?

ICCC's scenarios

The following table describes the ICCC's scenarios (different combinations of 'futures' and 'propositions'). The ICCC also tested the sensitivity of the results for some scenarios to:

- a high emissions price (\$150/tCO_2e by 2035)

3 These terms of reference are available from the ICCC website, https://www.iccc.mfe.govt.nz/who-we-are/terms-of-reference/.

4 Ibid, paragraph 13 refers.

- a high gas price to indicate a low gas supply scenario ($19/GJ by 2035)
- contstrained hydro availability (to reflect competing pressures on freshwater)
- peakier demand (as a result of EV charging at peak times).

Table 2: ICCC's scenarios

	Future		
Proposition	**Middle of the road**	**Fast tech, high demand**	**Slow tech, low demand**
Central	This scenario is a projection of business as usual	In NZ (relative to the base case): Higher economic growth, leading to higher electricity demand growth (although slightly offset by higher end-use efficiency) Tiwai stays open The cost of wind and solar decrease faster (due to technological advancements) Higher uptake of EVs (due to lower cost, greater availability and higher economic growth) More industrial fuel switching (favourable economics and lower tech costs)	In NZ (relative to the base case): Lower economic growth, leading to lower electricity demand growth Tīwai closes before 2035 The cost of wind and solar do not decrease as fast (due to slower technological advancement) Lower uptake of EVs (due to higher purchase price and limited availability) Less industrial fuel switching(due to unfavourable economics)
Pathway to 100% renewable electricity by 2035	These scenarios explore how 100% renewable electricity generation can be achieved. The base case assumptions for technology costs, electricity demand etc will be used.	These scenarios test how 100% renewable electricity generation can be achieved in a world with high economic growth, and electricity demand, and ambitious global climate action and low technology costs	These scenarios test how 100% renewable electricity generation can be achieved in a world with low economic growth, pessimistic global climate action and higher technology costs.
Electrification	This scenario explores how energy sector greenhouse gas emissions can be minimised through electrification of industrial processes and transport. The base case assumptions for technology costs, economic growth etc. but assumes the highest feasible uptake of EVs and fuel switching for process heat and IPPU (excluding Methanex and Tīwai)	Not modelled	This scenario explores how energy sector greenhouse gas emissions can be minimised through electrification of industrial processes and transport. This scenario assumes the cost of wind and solar do not decrease as fast (due to slower technological advancement), and lower overall economic growth.

Source: ICCC

Assumptions for this work, and caveats

These questions will be answered using a range of data and modelling, however there are a wide range of assumptions that must be made to estimate retail electricity prices. These include:

- the assumptions made by EnergyLink in their scenarios span the likely range of variability posed by the range of futures and propositions specified — if New Zealand (or the world) looks different to these futures and propositions in reality, or the market or customers behave differently, the wholesale electricity prices modelled will be different
- the electricity market structure, institutions and rules in 2035 remain materially similar to those of today — if there are material changes to the market structure, this may impact the prices faced by retail electricity customers
- currently there are a number of live regulatory reform processes that may have an impact on retail electricity prices for different regions and customer segments between now and 2035. These include the Electricity Price Review (MBIE) and the reviews of transmission pricing methodology and distribution pricing methodology (Electricity Authority). While these processes are not yet complete, they are likely to result in changes to the way (for example) transmission and distribution charges are passed through to consumers (including the share of these costs paid by different customer segments). However, there is still much ambiguity around how the costs of transmission and distribution will be shared among regions and customer segments in 2035 — as a result we have assumed that the current levels of transmission and distribution charges by customer segment remain as they are today, noting that this is a conservative estimate.[5]
- in 2035, while there is likely to be significant growth in distributed electricity generation (eg solar PV) centralised (and grid connected) electricity generation technologies will continue to provide the bulk of New Zealand's electricity supply.

If New Zealand were to look differently in 2035 than we assume above, the retail electricity prices we model may be significantly different. We stress that estimates of retail electricity prices presented in this Report are projections, and not precise forecasts. These projections have been produced for the purposes of estimating potential impact on retail electricity customers of a move towards a 100% renewable electricity system, and identifying potential policy issues associated with this move.

5 The current level of transmission and distribution charges are a conservative estimate of those in 2035 because: 1) Interest rates are currently low, which lowers the Weighted Average Cost of Capital (WACC) for transmission and distribution businesses, and is the basis for setting the revenue limits for these businesses; 2) Transmission and distribution pricing reform is intended to move pricing for these services to a more efficient and cost reflective regime — in time this should ensure that these services are provided for the minimum cost, given the quality expectations.

HOW WE WILL ANSWER THE KEY QUESTIONS

This section outlines the data sources and approach we have used to answer the key questions listed on page 6 of this Report.

What does a move towards 100% renewable electricity generation mean for retail electricity prices in different regions?

Approach to answering this question

As discussed above (page 8 refers), the current electricity price reforms add a great deal of uncertainty to the future structure and level of electricity prices in New Zealand, particularly for transmission and distribution pricing structures. Transmission and distribution prices are particularly important in determining the current levels of geographical differences in electricity prices in New Zealand — we expect this to continue in the future. Because of this uncertainty we are unable to provide a quantitative answer to this question. Instead we qualitatively discuss factors which may lead to electricity prices in a given region increasing or decreasing.

What does a move towards 100% renewable electricity generation mean for retail electricity prices faced by different customer segments?

Data sources

We used several data sets to inform this analysis. These include:

- Electricity Price Review first report,[6] in particular:
  - Estimated breakdown of charges by customer type (Figure 8, p. 23)
  - Wholesale contract prices versus cost of building new power stations (Figure 14, p. 33)
- Electricity Authority:
  - historical wholesale price data by node[7]

6 MBIE, 2018. Electricity Price Review: First report. Retrieved from https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-consultations-and-reviews/electricity-price/.

7 Electricity Authority's EMI website. https://emi.ea.govt.nz/Wholesale/Datasets/Final_pricing/Final_prices/.

– Residential and business consumption profile data from the Counties Power network area[8]

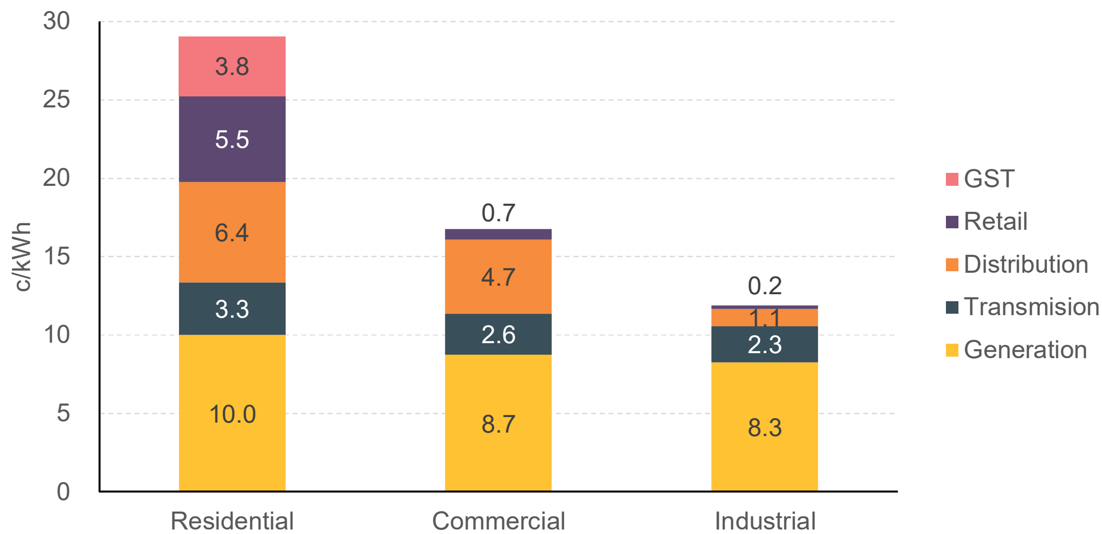
- MBIE:

  – electricity statistics, particularly transmission and distribution line losses.[9]

Description of approach to modelling retail electricity prices

The following figure shows a breakdown of retail electricity prices by customer segment and price component.

Figure 1: Breakdown of electricity prices by customer segment for the year ended March 2018



Source: MBIE, 2018. Electricity Price Review first report. Concept Consulting analysis of data from various sources.

The electricity price reforms that are happening now mean that there is a large degree of uncertainty around transmission and distribution pricing. Until these reforms are concluded, there is no way to predict how these components may change — particularly the how the costs of these charges may be allocated between customer segments. We will therefore assume that in 2035:

- Retail, distribution and transmission price components in absolute terms stay the same as they are today (in the above chart)

8 Electricity Authority's EMI website. Counties Power consumption profiles. https://www.emi.ea.govt.nz/Retail/Datasets/_AdditionalInformation/SupportingInformationAndAnalysis/2017/20170313_CountiesPowerConsumptionProfileExamples/.

9 MBIE, 2018: Electricity webtables. Retrieved from: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/electricity-statistics/. Table 2 refers.

- GST will remain payable by residential consumers at a rate of 15%
- Generation costs for each customer segment will depend on wholesale electricity prices in a similar way as they do today (the following sections provide details of the synthesis of this approach).

Generation costs by customer segment

Generation costs for different customer types (G_s) can be estimated as the product of three factors, multiplied by the time-weighted average wholesale price:

$$G_s = R_s H_s L_s P_{TW}$$

Where:

- P_{TW} is the time-weighted average wholesale electricity price (outputs of the ICCC modelled scenarios)
- R_s is the ratio between demand-weighted average price and time-weighted average price for customer segment s
- H_s is the hedge contract for customer segment s
- L_s is a factor to account for distribution losses for customer segment s.

The following table shows a set of assumed values for the three factors above in each of the customer segments. Notes on these synthesis of these factors follow the table.

Table 3: Assumptions for factors used in modelling generation costs by customer segment

Customer segment	R_s	H_s	L_s	Total scaling factor
Residential	1.03	1.10	1.07	**1.21**
Commercial	1.04	1.10	1.05	**1.20**
Industrial	1.00	1.10	1.04	**1.14**

Source: MartinJenkins analysis

R_s

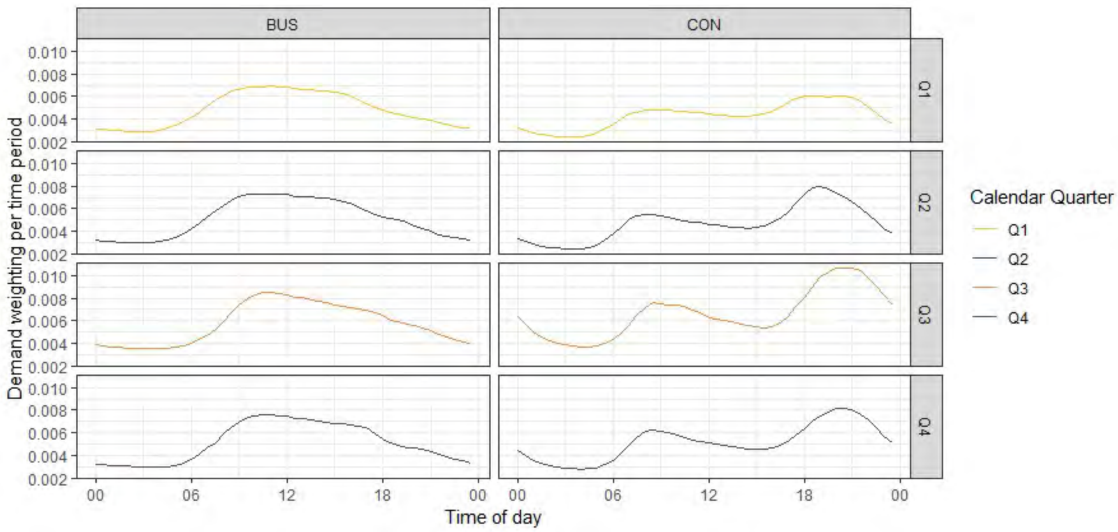
This factor accounts for the costs of serving customers at different times of the day, relative to a flat demand profile. We have assumed that industrial consumers have a roughly flat demand profile, and therefore their R_s is 1.00.

Customers that use electricity at more expensive times will be more costly to serve. The EA have some half hourly consumption profile data from Counties Power network area on their website. These data contain information on the average consumption of business consumers and residential consumers by half-hour for the 2016 calendar year. The following figure shows the demand profile shape for each type of consumer.

Figure 2 shows that business consumers have typically low demand during the periods midnight–0700, and 1800–midnight, and then flat demand during the period 0700–1800 (during work hours). There are some differences in shape between the seasons (calendar quarters), but these are minor.

Residential consumers, on the other hand display the classic “double peak” demand shape, with a morning peak at 0700–0900 and an evening peak at 1800–2100.

Figure 2: Demand profile shapes for business (BUS) and residential (CON) customer types in the Counties Power network area[10]



Source: Electricity Authority. Data are from Counties Power network area for the 2016 calendar year.

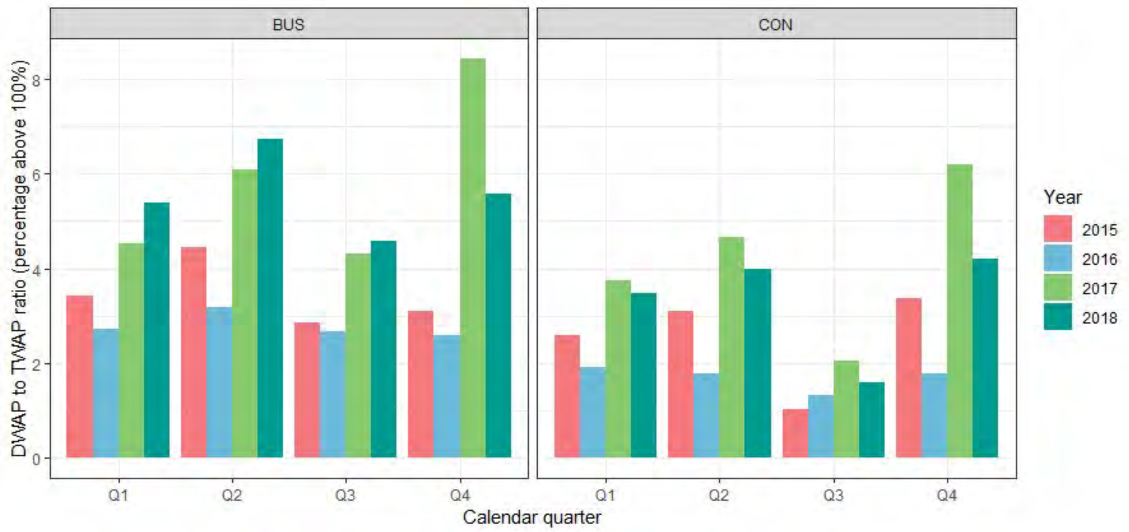
Using these demand shapes to weight half-hourly wholesale electricity prices yields the following results. Note that half-hourly demand data by customer segment is not available from the EA (hence the use of the above 2016 data as a proxy).

Figure 3 below shows the ratio between demand-weighted wholesale prices at the Bombay 110 kV network supply point (NSP) for 2015–17, and time-weighted prices from the same node. Averaging the ratio for each customer type across the quarters and years shown yields that the average ratios are:

- 1.04 for business customers
- 1.03 for residential customers.

[10] Note that data have been normalised so that the area under the curves add to 1 for the whole year.

Figure 3: Ratio between demand-weighted and time-weighted average price for business (BUS) and residential (CON) consumers in the Counties Power network area



Source: MartinJenkins analysis based in Electricity Authority data.

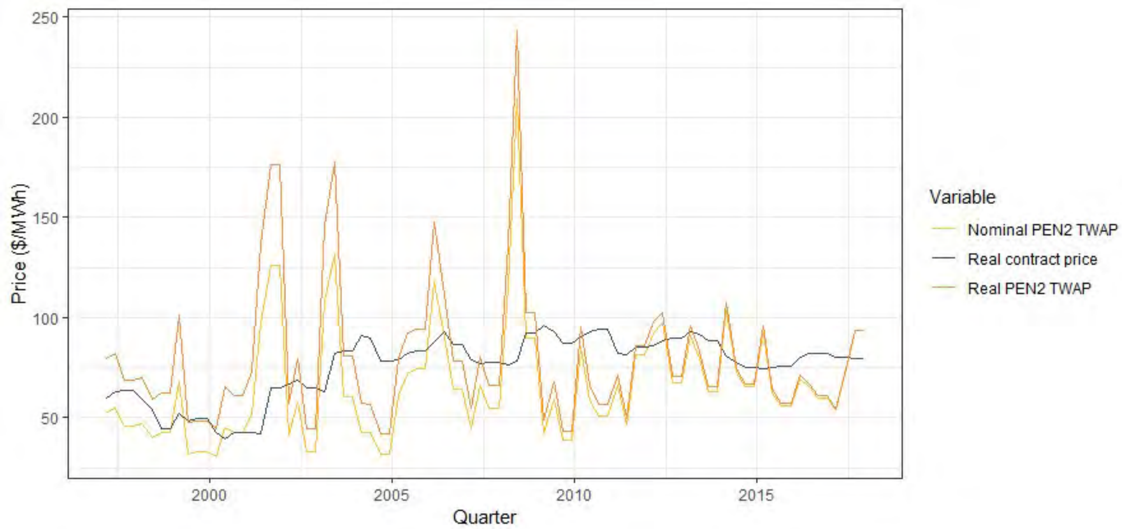
H_s

The hedge contract premium is the average ratio between the wholesale contract price, and the time-weighted average wholesale electricity price. The EPR report includes a wholesale contract price series (1996–2018) — this series was compiled by Concept Consulting from various sources, and it represents the cost of baseload one-year futures contracts referenced to the Otahuhu GXP.[11] We can compare this series with time-weighted average prices sourced from the Electricity Authority to estimate the average hedge premium.

The following figure shows time-weighted average wholesale prices (real and nominal) and the wholesale contract price series mentioned above. Averaging the ratio between the real wholesale contract price (lagged by a year to so that the contract values apply to the correct period) and the real time-weighted average spot price gives an average hedge premium of around 1.085.

[11] MBIE, 2018. Electricity Price Review: Technical Paper to accompany the First Report. p. 4–5 refers.

Figure 4: Wholesale contract prices and time-weighted average spot prices



Source: MartinJenkins analysis based on Electricity Authority and EPR data.

Notes

1 Wholesale contract prices are in real 2018 dollars

2 The EPR report expresses the contract price at the Otahuhu GXP, for the purposes of this analysis we have used average location factors to convert the Otahuhu price to a Penrose price (on average across this period Penrose prices are 0.98% higher than Otahuhu prices).

Given that we expect a higher level of price volatility as New Zealand progresses to having a much higher level of renewable (and intermittent) generation, the historical hedge premium may be an underestimate. Therefore we have assumed the hedge premium is slightly higher, 1.10.

L_s

The average transmission and distribution line losses are published by MBIE each year in their electricity statistics.[12] These data state that average line losses are approximately 2,900 GWh per year, or 7.3% of total demand. Transmission losses account for about 1,400 GWh and Distribution losses account for the balance (1,500 GWh).

The loss factors for different customer segments will vary depending on a range of factors, particularly location and local network conditions.

We assume that most large industrial customers are grid connected, and therefore only transmission losses apply to them. Hence we assume a loss factor of 1.04.

Residential consumers, on the other hand, are connected to distribution networks, so would experience transmission and distribution losses. We therefore assume the residential loss factor to be 1.07.

[12] MBIE, 2018: Electricity webtables. Retrieved from: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/electricity-statistics/. Table 2 refers.

Loss factors for commercial customers are difficult to estimate; however, we assume that most commercial customers would be located in town centres and central business districts (ie not at the end of long, low-voltage lines that would have high losses). As a result of this assumption we think that a reasonable commercial loss factor would be between the industrial and residential value at about 1.05.

What does a move towards 100% renewable electricity generation mean for retail electricity prices faced by low-income, and Māori and Pasifika households?

Data to answer this question

The data to answer this question are primarily from Statistics New Zealand's Household Economic Survey (HES). These data include:

- tables provided for HES surveys 2007–2016:
  - Number of households, by ethnic group (Māori, Pasifika, and all households), by number of people in household (1,2,3,4,5+), by broad region (Auckland, Wellington, Canterbury, Rest of the North Island, Rest of the South Island, All NZ)
  - Number of households, by ethnic group (Māori, Pasifika, and all households), by number of people in household (1,2,3,4,5+), by income quintile (defined for all households, not just Māori households)
  - Average expenditure on electricity (subgroup of household energy), by ethnic group (including Māori, non-Māori, Pasifika, and All ethnic groups), by number of people in household (1,2,3,4,5+)
  - Total household expenditure, by ethnic group (including Māori, non-Māori, Pasifika, and All ethnic groups), by number of people in household (1,2,3,4,5+).
- other data on demographics and socio-economic outcomes for Māori and Pasifika households[13,14]
- research into energy hardship by Statistics New Zealand[15]

13 Ministry of Health website. Māori health statistics: Neighbourhood deprivation. Retrieved from: https://www.health.govt.nz/our-work/populations/maori-health/tatau-kahukura-maori-health-statistics/nga-awe-o-te-hauora-socioeconomic-determinants-health/neighbourhood-deprivation.

14 Pasifika Futures, 2017. Pasikifa People in New Zealand: How are we doing? Retrieved from: http://pasifikafutures.co.nz/wp-content/uploads/2015/06/PF_HowAreWeDoing-RD2-WEB2.pdf.

15 Statistics NZ, 2017. Investigating different measures of energy hardship in New Zealand. Retrieved from http://archive.stats.govt.nz/browse_for_stats/people_and_communities/Households/energy-hardship-report.aspx.

- insights into the impact of electricity prices on low-income households drawn from recent research undertaken as part of MBIE's Electricity Price Review (EPR).[16,17]

Approach

Anecdotally, Māori and Pasifika households are over-represented among low-socioeconomic groups, and are therefore more likely to be disproportionately impacted by increases in retail electricity prices. We have used data from Statistics New Zealand (including the Household Economic Survey, HES) to test this hypothesis, and to see how household expenditure on electricity varies by ethnic group, region and income level.

As there are no data sources that link household ethnic group with energy cost and consumption, this question has been answered qualitatively. A draw-back of this approach is that HES collects expenditure on electricity and not the amount consumed — we therefore do not know if the various household types and spending more on electricity because they are facing higher prices, or if they are consuming more electricity than other households. We have drawn insights from these data, as well as research undertaken by Concept Consulting for the EPR looking at socio-economic differences in electricity prices more generally, and research by Statistics New Zealand into indicators of energy hardship.

What does a move towards 100% renewable electricity generation mean for retail electricity prices for different times of use?

Approach to answer this question

To answer this question, we have talked to a range of key informants. These informants include stakeholders from the Electricity Authority, the Commerce Commission, WEL Networks[18] and the CEO of Flick Electric.

Overall we propose to answer this question using qualitative information that we have captured during our discussions with key informants.

16 MBIE, 2018. Electricity Price Review: First Report. Retrieved from https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-consultations-and-reviews/electricity-price/.

17 Concept Consulting, 2018. *Electricity Price Review: Initial analysis of retail billing data.* Report prepared for the Ministry of Business, Innovation and Employment.

18 WEL Networks have recently brought in a time of use based distribution pricing structure.

What does a potentially higher level of price volatility mean for retail electricity prices?

Approach to answer this question

To answer this question, we interviewed the CEO of Flick Electric. Flick Electric is the largest “spot price” retailer that passes on the wholesale electricity price, plus a margin, to their customers. The feedback captured from Flick’s CEO will allow us to qualitatively answer this question.

INSIGHTS AND ANALYSIS

What does the ICCC's modelling mean for retail electricity prices in different regions of New Zealand?

Insights

Transmission and distribution prices in 2035 are very uncertain

Price reforms (particularly those for transmission and distribution prices) that are happening now in New Zealand could have large impacts on transmission and distribution prices by 2035. As a result, these will impact on retail electricity prices. Because these price reforms are ongoing, we do not know the likely future structure of transmission and distribution charges, particularly how they will be allocated to different customer segments and across different regions.

Distribution prices are a key determining factor in the current level of geographic differences in retail electricity prices in New Zealand (see Figure 5). The focus of the EA's work to review distribution prices is to increase the efficiency of distribution pricing signals. The impact of this work could be that consumers move their electricity demand away from peak times, thereby easing network congestion, and avoiding unnecessary network investment. This could reduce the regional variation in distribution prices, and therefore retail prices, but the extent to which this could happen is uncertain. Because distribution prices comprise on average around a quarter of the residential electricity price (for an 8,000 kWh per year customer) changes to distribution prices could have a material impact on retail prices.

Transmission prices on the other hand comprise a smaller share of residential electricity prices, on average about 10% of the total tariff for an 8,000 kWh per year customer, so have a smaller influence on the level of retail electricity prices. However, the costs of transmission are an important factor in determining the retail price of electricity by region (ie electricity will cost more in regions that are far from generation). The focus of the EA's work to review the transmission pricing methodology is to ensure that the costs of transmission services are allocated to customers in proportion to the benefits received from these services. While the immediate impacts of the TPM (as proposed by the EA in 2016) may be significant, particularly for residential customers in some regions, these impacts will reduce over time as historical investments are depreciated. We note that a more efficient transmission pricing regime (ie that reflects the costs and benefits of transmission services) would keep downward pressure on retail prices overall (but may result in regional pricing differences, since some regions are more costly to deliver electricity to).

Factors that may result in retail price increases or decreases

The following table discusses factors that may result in retail price increases or decreases and the mechanisms by which this may occur. This list is not exhaustive (many other factors could be important).

Table 4: Factors that may increase or decrease retail electricity prices

Factor	Increase / decrease	Mechanism
Retail market competition	Decrease	More electricity retailers operating in a given area will lead to higher levels of competition, and this puts downward pressure on prices. This is because customers are able to switch to a cheaper retailer if they can get a better deal.
Barriers to market participation	Increase	While the EPR notes that higher levels of retail competition has benefitted some (but not all) customers, there remain some customers who do not engage with the market, and are paying higher prices than they could be. The nature of these barriers are complex, that can include: • poor credit histories preventing customers switching (and debt related costs) • barriers to accessing information (which could be related to low digital literacy, or not having access to the internet) or not understanding the information available on switching / electricity prices (such as Consumer NZ's Powerswitch website) • cultural barriers, including language and fear of change • the benefits of switching being viewed as not being worth the bother of switching.
Demand becoming more peaky	Increase	Peak electricity demand puts upwards pressure on wholesale electricity prices (by more expensive generation being used to meet this demand) and on transmission and distribution prices (because the costs of these services are driven by investments to meet peak demand). If peak electricity demand increases over time, retail electricity prices will also increase. Conversely, if demand becomes less peaky, this would put downward pressure on electricity prices.
Electricity (energy) demand growth	Increase	Growth in electricity (energy) demand could result in increasing the general level of electricity prices across the country as this will drive the need for investment in new generation capacity. In the long-term this could be driven by population growth, or new industrial demand (which could be a result of fuel switching to electricity). Concentrated electricity demand growth in particular locations could put upward pressure on electricity prices in that location through the need for investment in network infrastructure.
Energy efficiency	Decrease	Energy efficiency acts to put downward pressure on electricity prices, since this will delay the need for investment in new generation technology
Smart demand management	Decrease	Smart demand management (including home energy management systems, or demand aggregation companies) could allow demand to be shifted to off-peak times, thereby reducing network congestion. This would reduce the need for investment in new network capacity and should put downward pressure on prices

Factor	Increase / decrease	Mechanism
Increased carbon prices	Increase in the short-term, flat in the long-term	If carbon prices increase (as they are expected to do) this will add cost to fossil-fuelled electricity generation. This will make the fossil-fuelled plant more costly to run, which will incentivise investment in low-carbon generation plant. As the percentage of renewables in the electricity system increases, the amount of generation that is subject to carbon prices will decrease. The Productivity Commission's inquiry into NZ's transition to a low-emissions economy found that electricity prices are expected to remain flat under a wide range of transition scenarios.[19]

Source: MartinJenkins analysis

Evidence

Earlier in this report (page 8 refers) we discussed several assumptions made in this analysis. With three separate price reform processes (Electricity Price Review, TPM and DPM) happening at the moment, we have had to assume that current transmission and distribution charge components remain the same as they are today. Together transmission and distribution charges make up 36% of the national average retail tariff for an 8,000 kWh per year residential customer, but this varies geographically — the lines charge (transmission charges plus distribution charges) percentage (relative to the total tariff) ranges from 25% in Ashburton (EA Networks) to 48% in Waipukurau (Centralines).[20]

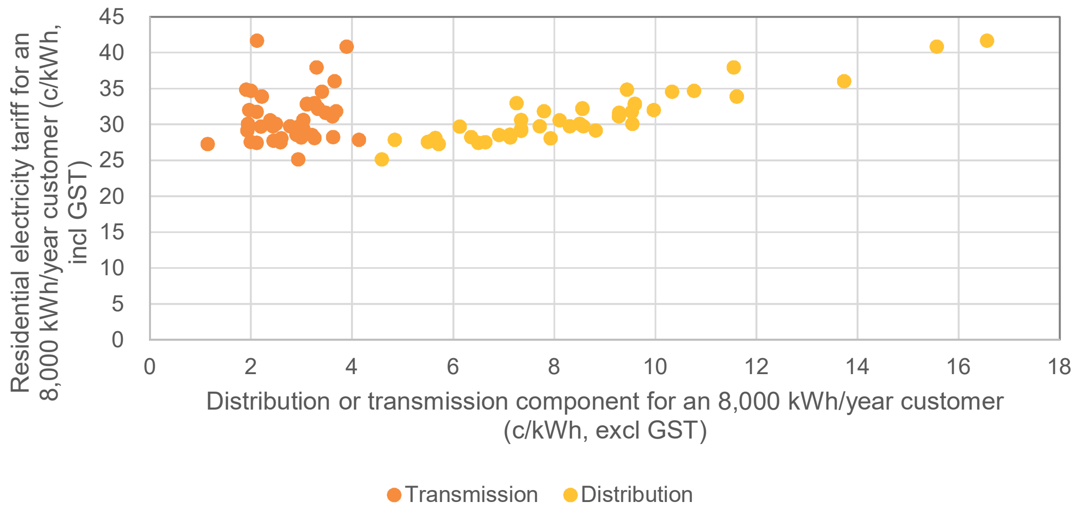
Distribution charges are a key determining factor in retail electricity prices in New Zealand

In New Zealand, areas with high distribution charges also have high electricity tariffs. Figure 5 shows the residential electricity tariff for each lines area plotted against the distribution component and the transmission component. There is a very clear relationship between the level of distribution charges and the level of the total tariff (and a less clear relationship between the transmission component and retail tariffs).

19 Ibid. p. 33 refers.

20 MBIE, November 2018. Quarterly Survey of Domestic Electricity Prices as at 15 November 2018. Retrieved from https://www.mbie.govt.nz/#quarterly-survey-of-domestic-electricity-prices-qsdep.

Figure 5: Residential electricity tariffs for an 8,000 kWh/year customer compared with transmission and distribution charges, by network area



Source: MBIE QSDEP as at 15 November 2018

Changes to the structure and level of transmission and distribution charges that may be a result of the current price reforms will impact retail prices. If the lines component of electricity prices did change, areas where they comprise a large share of the total electricity tariff will be affected more than those where lines charges comprise a small share of the total tariff.

Transmission and distribution price reforms may change the structure of lines charges, including the share of costs paid by customers in different regions

The EPR first report includes information on the likely impacts of the EA's proposed TPM (which was published in December 2016).[21] This indicates that transmission charges for retail consumers (passed on to customers through distribution companies) would increase, and transmission charges for generators and the Tīwai Point NZ Aluminium Smelter would decrease.[22] Furthermore, the report presents estimates of the impacts on annual electricity bills for residential customers as a result of TPM.[23] This information indicated that customers' bills in the Upper North Island would increase, and elsewhere customers' bills would decrease (with many exceptions) — the impacts on customers' bills range from a $43/year decrease in Invercargill to a $54/year increase in Ashburton. In our discussion with the EA on this subject, they stressed that these impacts are instantaneous impacts — ie, if the TPM was to be implemented these would be the impact on customers' bills immediately. Over time

[21] Ibid. Appendix B, p. 82–85 refers.

[22] Ibid. Figure 32 on p. 82 refers.

[23] Ibid. Figure 33, on p. 83 refers.

these impacts would reduce as the residual value of historical transmission investments are depreciated, and as customers and generators adjust their behaviours with regard to the new benefits-based TPM. The EA expect that by 2035 these impacts will be much smaller than those presented in the EPR Report. The EA also expect that a benefits-based TPM would ensure that generation and transmission options are considered together, and that this would maximise benefits for customers.

Although the EA have indicated that they plan to change aspects of the proposed TPM (from the December 2016 proposal), with a new version to be published in 2019, the core of the proposal remains the same. The proposed changes to TPM include:[24]

- Out:
  - the existing interconnection charge (or RCPD charge), and
  - the HVDC charge (under which South Island generators pay the costs of the link between North and South Island).
- In, two charges:
  - a benefit-based charge for new investment and for future charges on selected existing major investments, and
  - a residual charge to cover the costs of the remaining former investments that are not yet fully recovered and other costs.
- Staying (in a similar form to now):
  - connection charge
  - an expanded prudent discount policy.

While distribution charges are a key determining factor in the current regional differences in retail electricity prices around New Zealand, any changes to these differences by region as a result of the EA's review of distribution pricing methodology is harder to determine. The EA published a consultation paper on 11 December 2018 which outlined its proposal for amendments to the Distribution Pricing Principles (clarifying the EA's expectations on efficient distribution prices) and its plan to monitor and report on the efficiency of each Electricity Distribution Business' (EDBs') distribution pricing regime.[25] Submissions on the EA's paper closed on 19 February 2019. In its paper, the EA outline its case for change:[26]

- electricity distribution is primarily a fixed-cost service, but most of these costs are recovered using a variable (per kWh of electricity used) charge that does not change based on whether or not there is spare capacity on the network.
- because the current model of distribution pricing does not signal to customers when the network is congested (nor when it has spare capacity) there is no incentive for customers to avoid using electricity at these peak times. This will become far more important when technologies like

24 https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/progress-update-on-tpm-review/

25 Electricity Authority, 2018. More efficient distribution prices: What do they look like? Retrieved from https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/distribution-pricing-review/consultations/#c17905.

26 Ibid. Section 2, p. 1–5.

Electric Vehicles (EVs) become commonplace. If customers have no incentives to charge their EVs at off-peak times, a much higher level of investment in network capacity will be required (which will cost all network users more)

- because the fixed network costs are recovered on a variable (per kWh) basis, customers are incentivised to invest in technologies that reduce the amount of electricity they draw from the network (eg solar PV). Although these customers may be using less electricity, the EDB's costs may not reduce. This forces the EDB increase its variable charges, this has the effect of shifting a higher share of the network costs on to customers who do not invest in these technologies.
- EDBs costs are largely determined by the peak demand for electricity within the network. If customers are incentivised to shift their demand from peak periods to off-peak periods, the need for additional network investment will be lower.

In response to this case for change, the EA propose that efficient distribution prices:

- reflect the costs of providing electricity distribution services
- allocate costs to customers based on their use of the network (or the benefit they receive from its use)
- recovers sunk costs in a way that least distorts the use of, or investment in, the distribution network
- do not place unreasonable transaction costs on distributors, retailers or consumers (ie these transaction costs should be justified by the benefits they deliver).

In our discussion with the EA on distribution pricing they reiterated the issues highlighted above, and that their next steps were to engage with EDBs and retailers on the proposals. The EA also note that for distribution charges to be cost-reflective they would expect fixed (daily) charges to increase, and variable (per kWh) charges to decrease.

The EA notes that while the focus of their review is on the EDBs, it is the retailers that pass these price signals on to their customers. Therefore to have truly efficient distribution prices the retailers are a key stakeholder.

The EA sees seasonally-based and time of use distribution pricing as key features of a more efficient than pricing model the status quo. They have ranked three pricing models in terms of increasing efficiency, with a model based on recovering fixed costs through a contracted capacity, and a variable charge determined dynamically by congestion on the network as the most efficient model.[27] While individual EDBs vary in terms of their progress on distribution pricing reform, there is widespread recognition that the reform must happen.[28] As a result we would expect that by 2035 more efficient distribution pricing models (that reflect the costs of delivering distribution services, and the benefits of these services for customers) would be commonplace. Should this occur, retail customers will be incentivised to avoid using electricity at peak times. This should minimise unnecessary investment in the distribution networks and put downward pressure on distribution prices.

27 Ibid. Paragraph 4.3, p. 11 refers.

28 Electricity Networks Association, 2016. New pricing options for electricity distributors: a discussion paper for industry feedback. Retrieved from http://www.electricity.org.nz/dmsdocument/38.

The existing regional differences in distribution prices could reduce in 2035 as a result of introducing more efficient pricing models (to the extent that the existing regional differences are driven by inefficient network investment). However, it is impossible to tell at this stage how this may play out by 2035.

Finally, the EA stressed the importance of competition in the retail electricity market as a key factor in minimising electricity prices — it is electricity retailers that set electricity prices (of which transmission and distribution prices are a part) — if there is sufficient competition in the retail market customers can switch retailers to get a better deal.

What does the ICCC's modelling mean for retail electricity prices faced by different customer segments?

Insights

Large increases in retail electricity prices from today's levels are not expected, unless we achieve 100% renewable electricity generation

Retail electricity prices for residential, commercial and industrial customers in 2035 were modelled for a range of scenarios, and the sensitivity of scenario results were tested against higher emissions prices, higher gas prices, peakier electricity demand and constrained hydro availability. These modelling results showed that for most scenarios, retail electricity prices are expected to be similar to today's levels (specifically average electricity prices for these customer segments for the year ended March 2018). The range of retail electricity prices modelled for each customer type was:

- 28.4–33.9 c/kWh for residential customers (compared with 2018 actuals, 29.0 c/kWh)
- 17.4–22.2 c/kWh for commercial customers (compared with 2018 actuals, 16.8 c/kWh)
- 12.5–17.1 c/kWh for industrial customers (compared with 2018 actuals, 11.9 c/kWh).

However, scenarios where New Zealand achieves 100% renewable electricity generation by 2035 did result in material increases from today's levels, including:

- Middle of the road future, step 4 (100% renewable):
  - For residential customers, 14% higher than 2018 actuals (and 17% higher than the middle of the road scenario 2035 price)
  - For commercial customers, 29% higher than 2018 actuals (and 24% higher than the middle of the road scenario 2035 price)
  - For industrial customers, 39% higher than 2018 actuals (and 31% higher than the middle of the road scenario 2035 price)

- Fast tech, high demand[29], step 2 (100% renewable):
  - For residential customers, 17% higher than 2018 actuals (and 18% higher than the fast tech, high demand scenario 2035 price)
  - For commercial customers, 32% higher than 2018 actuals (and 26% higher than the fast tech, high demand scenario 2035 price)
  - For industrial customers, 44% higher than 2018 actuals (and 34% higher than the fast tech, high demand scenario 2035 price)
- Slow tech, low demand[30], step 2 (100% renewable):
  - For residential customers, 8% higher than 2018 actuals (and 11% higher than the slow tech, low demand scenario 2035 price)
  - For commercial customers, 20% higher than 2018 actuals (and 15% higher than the slow tech, low demand scenario 2035 price)
  - For industrial customers, 27% higher than 2018 actuals (and 20% higher than the slow tech, low demand scenario 2035 price)

For all futures modelled (Middle of the road; Fast tech, high demand; Slow tech, low demand), the last 1–2% of fossil fuel generation was very expensive to remove, and this had a large impact on retail prices. Furthermore, removing the last 1–2% of fossil fuel generation results in minimal emissions savings.

It should be noted that this result (that large electricity price increases are not expected) was also a finding of the Productivity Commission’s low-emissions inquiry.[31]

Electrification of transport and process heat demand is expected to increase retail electricity prices modestly

Retail electricity prices for each customer segment were also modelled for scenarios where large amounts of transport and process heat demand were met from electricity (with a view to minimising energy sector greenhouse gas emissions, rather than maximising the share of renewable electricity generation). In all scenarios and sensitivities the electricity price increases modelled were modest. Compared with the middle of the road central scenario, retail prices in 2035 under the electrification scenarios and sensitivities are estimated to be:

- 1.0–2.2 c/kWh (3–8%) higher for residential customers
- 0.8–1.9 c/kWh (5–11%) higher for commercial customers

29 Fast tech, high demand refers to the future that assumes technology costs for wind, solar and batteries reduce at a faster rate than in the Middle of the road future. This future features strong economic growth, and high electricity demand as a result.

30 Slow tech, low demand refers to the future which assumes that technology costs for wind, solar and batteries reduce at a slower rate than in the Middle of the road scenario. A key feature of this future is that the Tīwai Point aluminium smelter closes by 2035, indicating low electricity demand.

31 Ibid. p. 33 refers.

- 0.8–1.8 c/kWh (6–14%) higher for industrial customers.[32]

The ranges above are book-ended by the central electrification scenario at the low end, and the elec $150/t sensitivity ant the high end. The other sensitivities modelled for the electrification scenarios (slow tech, low demand and peakier demand) showed only small increases in retail prices (1–2%) from the central electrification scenario (this result may be an underestimate for the peakier demand sensitivity, see below for more details).

Higher emissions prices and higher gas prices are likely to result in higher retail electricity prices

The sensitivities to higher emissions prices ($150/tCO_2e$ versus $50/tCO_2e$) and higher gas prices ($19/GJ versus $9.50/GJ) that were modelled imply that if emissions prices or gas prices are higher than we assume in the middle of the road scenario, this will push retail electricity prices higher.

The effect of a higher emissions price on retail prices in 2035 for each customer segment is:

- an increase of 4% for residential customers relative to the middle of the road scenario
- an increase of 6% for commercial customers relative to the middle of the road scenario
- an increase of 8% for industrial customers relative to the middle of the road scenario.

The effect of a higher gas price on retail prices in 2035 for each customer segment is:

- an increase of 5% for residential customers relative to the middle of the road scenario
- an increase of 7% for commercial customers relative to the middle of the road scenario
- an increase of 9% for industrial customers relative to the middle of the road scenario.

Constrained hydro availability is estimated to have little effect on retail prices

The ICCC also modelled the sensitivity of the Middle of the road scenario to constrained hydro availability (to reflect competing pressures on freshwater). Under this sensitivity retail electricity prices for all customer segments were about the same as in the middle of the road scenario. Therefore these changes are expected to have little effect on retail prices in 2035.

Peakier electricity demand is estimated to slightly increase retail prices, but this effect may be underestimated

A sensitivity to a peakier electricity demand profile was modelled relative to the electrification scenario (possibly caused by EVs charging at peak times). In this sensitivity retail electricity prices increased slightly compared with the electrification scenario for all customer segments. In 2035 this sensitivity modelled electricity prices for each customer segment to be:

- for residential customers, 1% higher than in the central electrification scenario

32 Commercial and industrial price increases are higher in percentage terms because the level of prices paid by those customers are lower than for residential customers (mainly due to lower transmission, distribution and other retail costs).

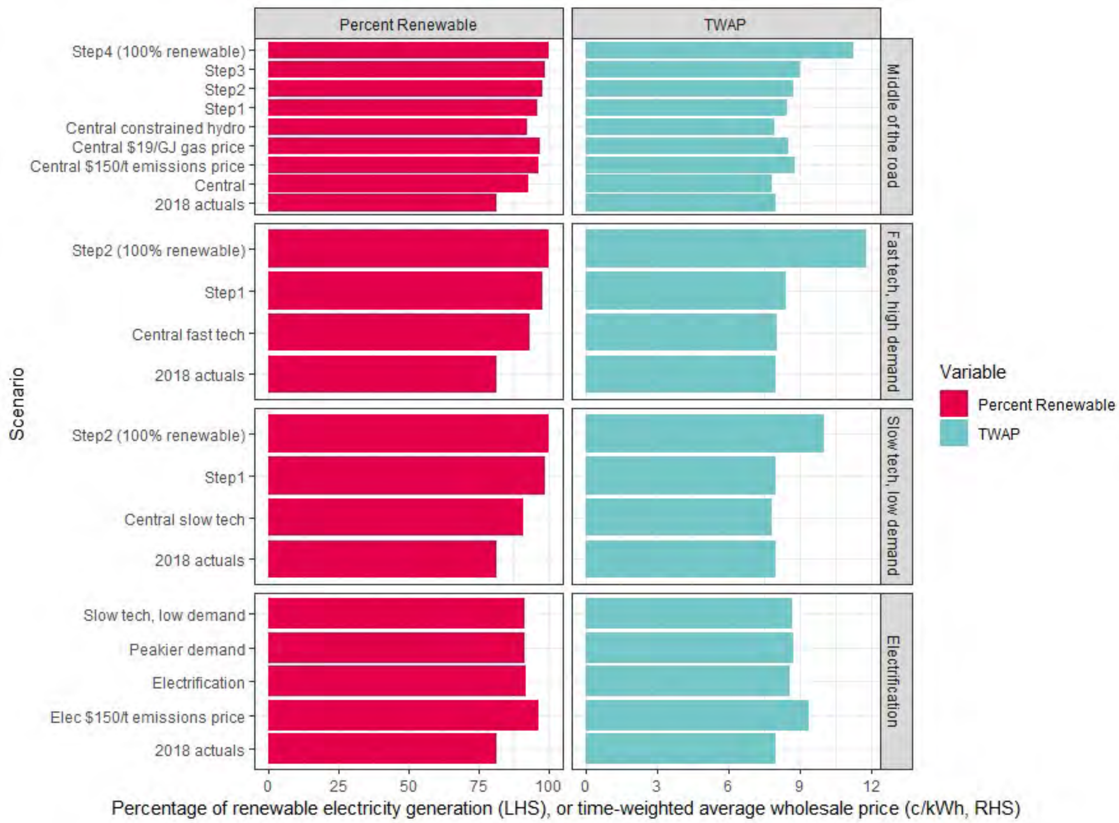
- for commercial customers, 1% higher than in the central electrification scenario
- for industrial customers, 2% higher than in the central electrification scenario.

While these modelling results imply that peakier electricity demand would have little effect on retail prices, we think that this is likely to be an underestimate. In this analysis we assumed that transmission and distribution charges remain as they are today. This is an unrealistic assumption in the case where electricity demand becomes peakier — if electricity demand becomes peakier, network investments for transmission and distribution are likely and this will push up network costs, which will be recovered from the network users. We advise that this result in particular should be interpreted with care.

Evidence

The ICCC has modelled a range of scenarios for the energy sector in 2035 (Table 2 refers). They also tested the sensitivity of some scenario results to a number of factors, including a high emissions price and a high gas price. The following figure shows the ICCC's modelling results for the renewable electricity percentage and time-weighted average electricity price for each scenario and sensitivity run by the ICCC.

Figure 6: Percentage of renewable electricity generation and time-weighted average electricity price by scenario in 2035



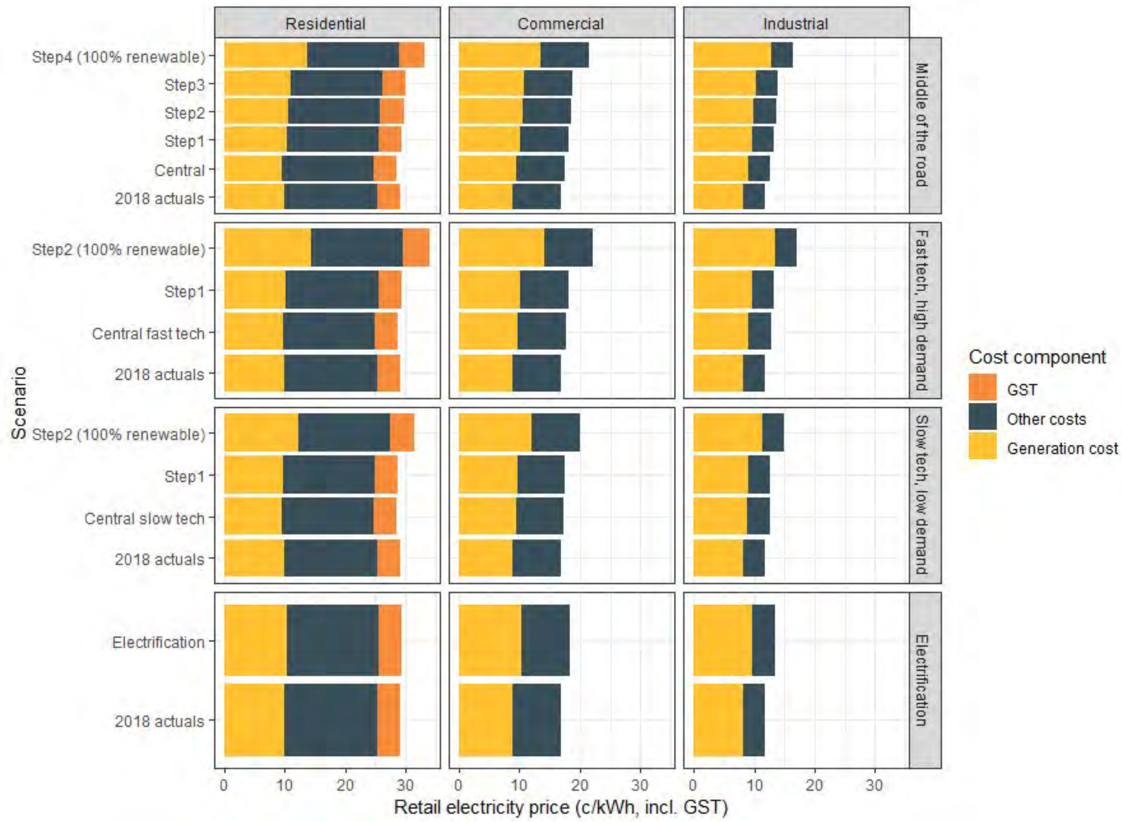
Source: ICCC, based on EnergyLink modelling

The time-weighted average electricity prices (TWAPs) for each scenario were used to estimate the retail electricity prices in 2035 for each customer segment (residential, commercial and industrial) using the method outlined earlier in this report (page 9 refers). The following figures show estimates retail electricity prices for each of the scenarios and sensitivities modelled by the ICCC. Other costs in these figures refers to transmission, distribution and retailing costs, and generation cost refers to the demand shape and loss adjusted wholesale electricity price.

Readers should note that 2018 actuals (historical prices for the year ended March 2018) are included in the figures for context. MBIE's electricity statistics indicate that 81.2% of electricity in the year ended March 2018 was generated from renewables.[33]

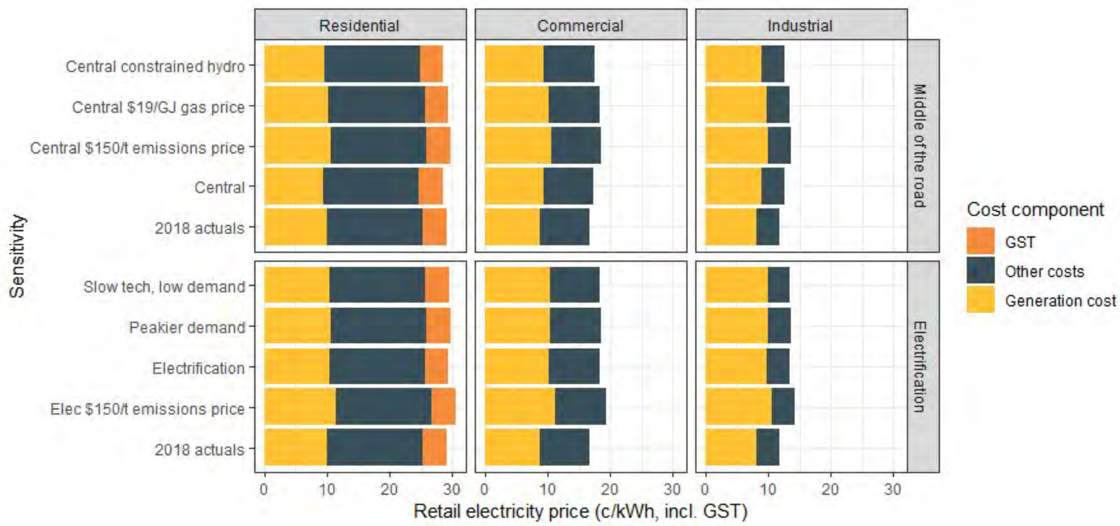
[33] MBIE 2018. Electricity statistics webtable. Retrieved from https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/electricity-statistics/.

Figure 7: Retail electricity prices in 2035 by customer segment and scenario



Source: ICCC, MartinJenkins calculations based on EnergyLink modelling results

Figure 8: Retail electricity prices in 2035 by customer segment and sensitivity



Source: ICCC, MartinJenkins calculations based on Energy Link modelling results

Note

2018 actuals (the historical March year 2018 retail electricity price by customer segment) and the 2035 core scenario (central and electrification) are included in the above chart for comparison purposes.

The above figures show:

- Residential electricity prices in 2035 are estimated to be in the range 28.4–33.9 c/kWh (compared with 2018 actuals, 29.0 c/kWh)
- Commercial electricity prices in 2035 are estimated to be in the range 17.4–22.2 c/kWh (compared with 2018 actuals, 16.8 c/kWh)
- Industrial electricity prices in 2035 are estimated to be in the range 12.5-17.1 c/kWh (compared with 2018 actuals, 11.9 c/kWh)
- Estimated retail electricity prices in 2035 are not expected to increase materially from today's levels for most scenarios and sensitivities except for 100% renewable scenarios.
  - For example, residential electricity prices in 2035 estimated using middle of the road scenario assumptions are between 2% lower to 3% higher than the 2018 actuals, whereas the step 4 (100% renewable) scenario is 14% higher than the 2018 actuals.
  - Similar results were estimated for the fast tech, high demand and slow tech, low demand scenarios (the step 2 fast tech and slow tech scenarios residential prices in 2035 are 17% higher and 8% higher than the 2018 actuals respectively, whereas the fast tech and slow tech step 1 scenarios are just 1% higher, and 1% lower respectively than the 2018 actuals)
- Electrification of transport and process heat demand is expected to modestly increase retail electricity prices in 2035. Retail electricity prices in 2035 under the electrification scenarios and sensitivities are expected to be:

- 3–8% higher than in the middle of the road scenario for residential customers
- 5–11% higher than in the middle of the road scenario for commercial customers
- 6–14% higher than in the middle of the road scenario for industrial customers.

Although electrification of transport and process heat demand may increase retail prices, for residential customers under the electrification scenarios and sensitivities retail prices in 2035 are between 1% and 5% higher than 2018 actuals.

- Estimated retail electricity prices in 2035 for the central fast tech, high demand and central slow tech, low demand scenarios are similar, with the central fast tech retail prices estimated to be slightly higher than the slow tech prices; this is somewhat counterintuitive. In the slow tech scenario the Tīwai Point Aluminium Smelter closes before 2035, whereas in the fast tech scenario it remains open. So while wind and solar technology costs in the slow tech scenario are higher than in the fast tech scenario, Tīwai closing holds prices low by releasing a large quantity of cheap renewable generation into the market. If a longer time horizon were modelled, we expect that retail electricity prices in the slow tech scenario would be higher than in the fast tech scenario.
- A higher emissions price ($150/tCO_2e versus $50/tCO_2e) is likely to mean higher retail electricity prices — residential electricity prices in the central $150/t emissions price and the elec $150/t emissions price scenarios are 5% higher and 8% higher than the middle of the road scenario respectively (a similar trend is seen for commercial and industrial prices, but with slightly higher percentage increases due to lower price levels for commercial and industrial customers)
- A higher gas price ($19/GJ versus $9.5/GJ) is likely to mean higher retail electricity prices — residential electricity prices in the central $19/GJ gas price is 3% higher than middle of the road scenario (a similar trend is seen for commercial and industrial prices, but with slightly higher percentage increases due to lower price levels for commercial and industrial customers)
- Constrained hydro availability is estimated to have little effect on retail electricity prices — the 2035 middle of the road and central constrained hydro scenarios result in similar retail prices (for all customer segments)
- A peakier demand profile is likely to result in slightly higher retail electricity prices for all customer segments — retail electricity prices in 2035 estimated using a peakier EV demand profile for residential, commercial and industrial customers were 1% higher, 1% higher and 2% higher than the central electrification scenario, respectively. However, this analysis assumed that transmission and distribution costs in 2035 remain the same as they are today. Since network costs (transmission and distribution) depend heavily on peak electricity demand, we would expect a scenario with high peak demand to result in higher network costs as well as higher generation costs to meet this demand. As a result the retail prices presented here are likely underestimated for the peakier demand scenario.

What does the ICCC's modelling mean for retail electricity prices faced by low-income, and Māori and Pasifika households?

Insights

Low-income consumers are disproportionately impacted by electricity price increases

Electricity has become an essential household utility in New Zealand, and will become even more so with the increasing levels of electrification expected in the future (particularly for transport and heating). While New Zealand's residential electricity prices are moderate among OECD countries,[34] a growing number of New Zealand households are estimated to be spending a high proportion of their income on energy.[35] A report by Statistics New Zealand estimates that 175,000 households in New Zealand spend more than 10% of their after housing cost income on domestic energy, not all of whom are considered "low income" households.[36] Electricity is by far the most used domestic energy fuel in New Zealand, comprising 69% of total residential energy consumption in 2017.[37] Increases in electricity prices will affect those households in energy hardship disproportionately (ie harder than the average household).

Statistics NZ's energy hardship report estimates the expenditure on energy as a percentage of equivalised household income. The percentages of households within each income decile spending certain percentages of their income on energy are shown in Figure 9 below. This figure shows that the households spending 10% or more of their income on energy (an indicator of energy hardship) are almost all within deciles 1–4 (the lowest income deciles). However, there are households spending between 4.8 and 10% of their income on energy within all decile groups except decile 10 (the highest income decile). While the households in the worst energy hardship are in the lowest income deciles, there are households spending a high proportion of their incomes on energy across the income spectrum. This means that while the worst effects of energy price increases will be felt by those on low incomes, there will be households at almost all income levels that experience hardship as a result of energy prices increases.

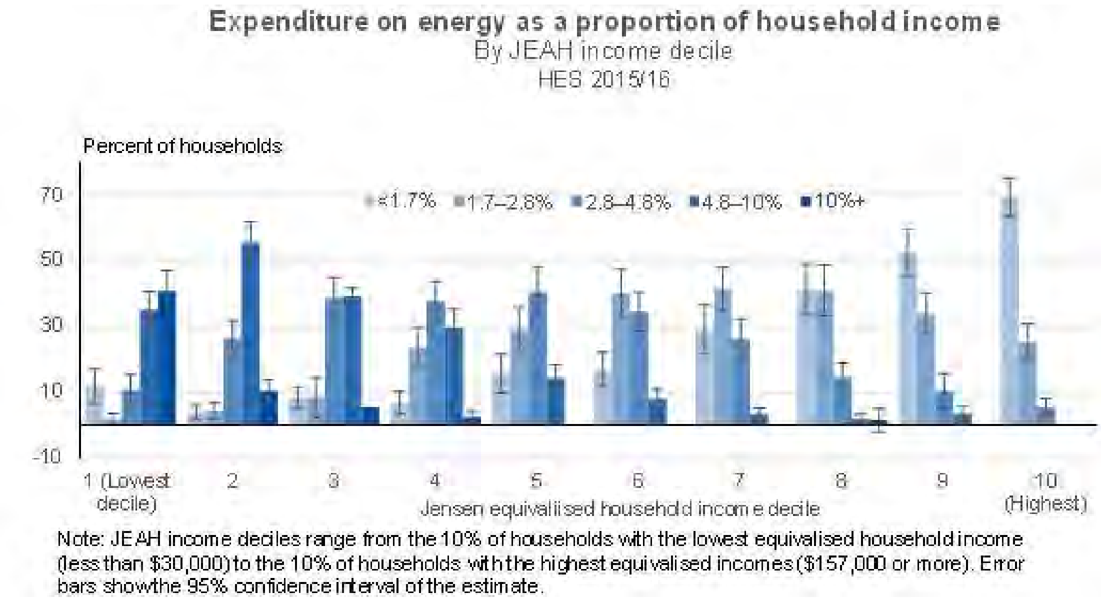
34 MBIE, 2018. Electricity Price Review: First Report. Retrieved from https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-consultations-and-reviews/electricity-price/. Figure 9, p. 23 refers.

35 Ibid. p. 25 refers.

36 Statistics NZ, 2017. Investigating different measures of energy hardship in New Zealand. Retrieved from http://archive.stats.govt.nz/browse_for_stats/people_and_communities/Households/energy-hardship-report.aspx.

37 MBIE, 2018. Energy Balance Tables. Retrieved from https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/energy-balances/.

Figure 9: Percentage of equivalised household income spent on energy by income decile[38]



Source: Stats NZ.

Households can react to this hardship in a number of ways, including cutting back on heating. MBIE's first report on their Electricity Price Review (EPR) presents data from Consumer NZ on the percentage of households "whose home is not as warm as they'd like because the cost of heating means they have to cut back on heating" by income bracket.[39] About 21% of households earning under $50,000 per year face this challenge, compared with around 9% of households earning $100,000 per year or more.

There are a number of factors affecting how much a household spends on electricity, including the number of people in their household, the quality of their housing (including levels of insulation), how they heat their homes (and hot water), and the structure and level of their electricity price. Residential electricity prices within distribution networks in New Zealand subject to retail competition, where customers are able to switch to a lower-priced retailer. The EPR report suggests that although the numbers of electricity retailers operating in each distribution network have increased since the last electricity market reforms (c. 2009), and the percentage of customers switching retailers has also increased (approximately doubling between 2007 and 2012) the average price difference between the highest cost supplier and the lowest cost supplier in each distribution area continues to grow.[40] The EPR first report also notes that 23–42% of residential customers in New Zealand have never switched retailer.[41] This suggests that competition in the retail market may be providing uneven benefits, with

38 Ibid. Figure 6, p. 21 refers.

39 Ibid. Figure 11, p. 27 refers.

40 Ibid. p. 35–39 refers.

41 Ibid. p. 36 refers.

some households switching often to get the best deal, and some customers never switching. There is evidence that customers who do not switch (for whatever reason) end up paying a higher price for their electricity.

Furthermore, the EPR first report notes that customers from highest-deprivation areas are three times more likely than lowest-deprivation households to lose their prompt payment discounts.[42] This has a material effect on their effective electricity price. A more detailed analysis of retail billing data undertaken as part of the EPR notes that customers in the most deprived areas of NZ pay on average $79 per year more for their electricity than customers in the least deprived areas of NZ, most of this difference ($50 per year on average) is accounted for by lost prompt-payment discounts.[43] While these costs are small as a percentage of the average electricity bill (about $2,028 per year) they make a big difference to those least able to pay additional costs.[44]

Given the above mentioned information, ethnic groups that are more likely to experience high levels of socio-economic deprivation are at risk of experiencing energy hardship. Two such groups that are overrepresented in statistics on socio-economic deprivation are Māori and Pasifika households.[45,46]

Key insights on Māori households' expenditure on electricity

Māori households are concentrated in the North Island, and in areas outside the main centres

The percentage of Māori households (relative to households of all ethnic groups) in Auckland, Wellington and Canterbury was lower than the national average percentage of Māori households (16-18%). The percentage of Māori households in the North Island outside Auckland and Wellington was higher (21–28%) than average, indicating that there are higher percentages of Māori households in rural areas of the North Island.

Māori households tend to be larger than average

Māori households comprise a larger proportion of large households (four and five or more person households) than the average for all ethnic groups — this is particularly pronounced for Māori in the rest of the North Island where Māori households comprise around 40% of all four and five or more person households.

Large Māori households are overrepresented in the low income groups

While the percentage of Māori households for all household sizes are distributed fairly evenly among the income quintiles, Māori households have higher than average percentages of five or more person households in quintiles 1 and 2 (the lowest 40% of incomes in New Zealand). Household incomes for this analysis have not been equivalised, so large households on low incomes are further

42 Ibid. Figure 15, p. 37 refers.

43 MBIE, 2018. Initial analysis of retail billing data. p. 3 refers.

44 Ibid. Figure 1, p. 9 refers.

45 Ministry of Health website. Māori health statistics: Neighbourhood deprivation. Retrieved from: https://www.health.govt.nz/our-work/populations/maori-health/tatau-kahukura-maori-health-statistics/nga-awe-o-te-hauora-socioeconomic-determinants-health/neighbourhood-deprivation. Figure 4 refers.

46 Pasifika Futures, 2017. Pasikifa People in New Zealand: How are we doing? Retrieved from: http://pasifikafutures.co.nz/wp-content/uploads/2015/06/PF_HowAreWeDoing-RD2-WEB2.pdf. p. 35–37 refers.

disadvantaged (ie the income for a large household must support more people than for smaller households).

Māori households spend more than Non-Māori on electricity each week (and as a percentage of total expenditure)

In 2016 average weekly expenditure on electricity for Māori households (of all sizes) was $41.2 (±9%) and average weekly expenditure on electricity for non-Māori households (of all sizes) was $36.8 (±4%). This implies that on average, Māori households spend more per week on electricity than non-Māori households.

Furthermore, the percentage of total expenditure on electricity for Māori households (of all sizes) was higher than for non-Māori households (of all sizes) — Māori households spend on average 3.6 ± 0.3% of their total expenditure on electricity, whereas non-Māori households spend 2.9 ± 0.1% of their total expenditure on electricity.

What this may mean for Māori households if electricity prices increase

This analysis has shown that Māori households tend to include more people than average, and that more Māori households are in the two lowest income quintiles. This means that if electricity prices for these households increase (as a result of a transition towards 100% renewable electricity) these ethnic groups may be impacted disproportionately.

This analysis has also shown that there is a higher than average percentage of Māori households in rural areas of the North Island than in the South Island, Auckland or Wellington. If electricity prices rise in rural areas, this may also impact Māori households more than other ethnic groups. Furthermore, MBIE's Quarterly Survey of Domestic Electricity Prices (QSDEP) shows that electricity prices in rural areas are generally higher than the national weighted-average price, due to higher transmission and distribution charges in those areas.[47] We also note that rural households are more exposed to other likely impacts from the transition, such as rising petrol prices in the move towards electrification and are less able to take advantage of the opportunities to mitigate against these other risks. These impacts compound for rural Māori and leave them further exposed.

Furthermore, Whetu Consultancy Group in their report for the ICCC note that some whānau financially support their local marae[48] — if electricity prices increase, this poses an extra hit on whānau as they face an increase in the electricity bill for the marae as well as an increased electricity bill in their own homes.

It is noted that Māori are more likely to be on a lower-income (or unemployed) and are less likely to have completed secondary school and are more likely to be living in a household without telecommunications or internet access.[49] These factors mean that that many whānau may face barriers to actively participating in the retail electricity market and may be paying a higher electricity price as a result — increased electricity prices would hit these customers extra hard.

47 MBIE QSDEP report, 15 November 2018. Retrieved from https://www.mbie.govt.nz/#quarterly-survey-of-domestic-electricity-prices-qsdep.

48 ICCC Electricity slide pack, Whetu Consulting Group, 2018. Slide 22 refers.

49 Ibid. Slide 18.

Key insights on Pasifika households' expenditure on electricity

Pasifika households are concentrated in Auckland

The percentage of households that are Pasifika in Auckland (12–15%) is higher than the national average (6–7%). The percentage of Pasifika households outside Auckland is lower than the national average.

Pasifika households tend to be larger than average and are overrepresented in the low income groups

Pasifika households comprise a larger proportion of large households (four and five or more person households) than the average for all ethnic groups. Pasifika households comprise around 30% of all five or more person households in Auckland.

While the percentage of Pasifika households for all household sizes are distributed fairly evenly among the income quintiles, Pasifika households have higher than average percentages of five or more person households in quintiles 1 and 2 (the lowest 40% of incomes in New Zealand). Household incomes for this analysis have not been equivalised, so large households on low incomes are further disadvantaged (ie the income must support more people than for a smaller household).

What this may mean for Pasifika households if electricity prices increase

Pasifika households in New Zealand face many of the same issues as Māori households. The Pasifika Futures report 2017 states the 56% of Pasifika people live in the most deprived areas of New Zealand.[50] Pasifika are overrepresented in unemployment statistics (approximately double the average unemployment rate)[51] and have lower than average financial net worth.[52] Pasifika also have lower than average rates of leaving school with NCEA level 2 (or higher) qualifications, and lower than average percentages of Pasifika achieve university degrees.[53] Furthermore, data presented in this note states that a higher than average percentage of Pasifika households are large (five or more people) households, and that high percentages of these large households are among the lowest income quintile. If electricity prices rise, this will affect many Pasifika households disproportionately.

Evidence

Data source

Data to inform this analysis is from Statistics New Zealand's Household Economic Survey (HES). HES is a representative survey of around 3,000 households in New Zealand. Expenditure data for HES are collected every three years — for this analysis we requested data from 2007, 2010, 2013 and 2016.

Specifically we requested:

50 Ibid. p. 35 refers.

51 Ibid. p. 34 refers.

52 Ibid. p. 29 refers.

53 Ibid. p. 16–18 refers.

- The estimated number of Māori, Pasifika and total households, by region and by household size
- The estimated number of Māori, Pasifika and total households, by household size and income quintile
- The estimated average expenditure on electricity (and total household expenditure) by ethnic group and by household size.

Caveats

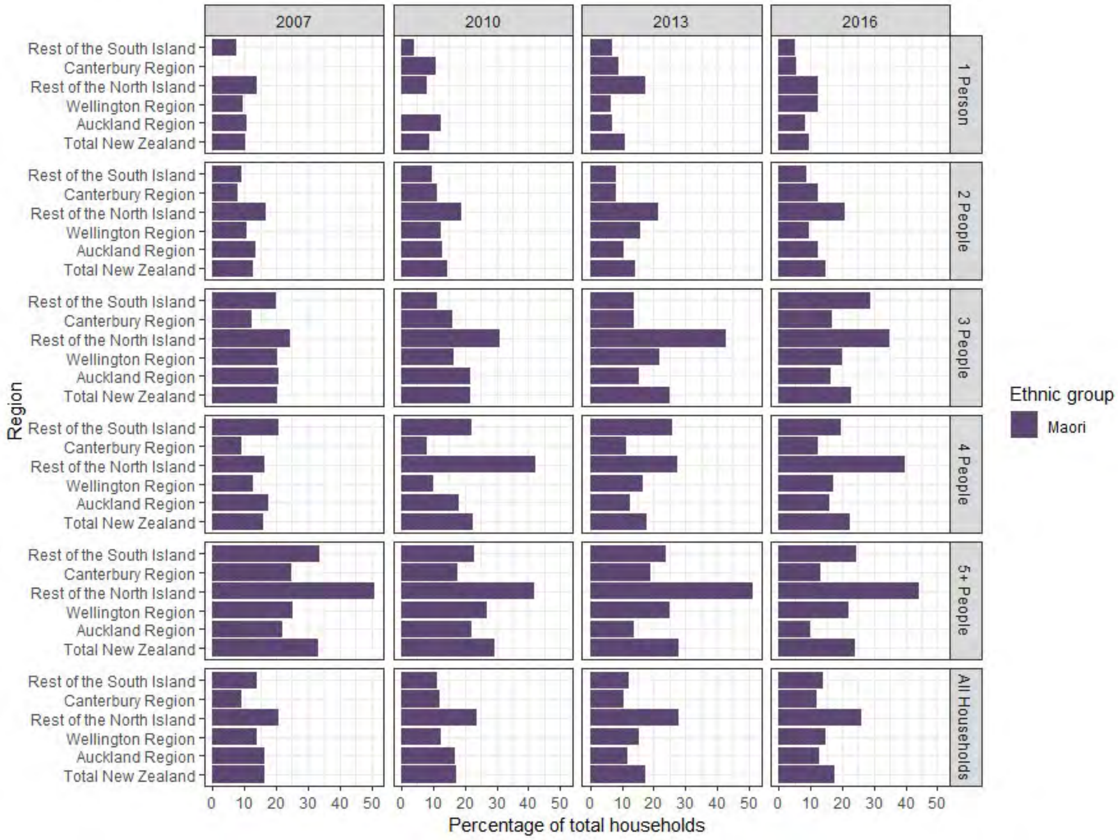
Statistics NZ note that HES is designed to produce national estimates — data slices by sub-populations (eg region, ethnic group and household size) can have large sample errors and should be interpreted with care.

We also note that HES measures expenditure on electricity (among other things) and not the price of electricity. Households' expenditure on electricity could change because they use more or less electricity, or because their electricity prices are higher or lower (or a combination of both). Care should be taken when interpreting these data in the context of price outcomes.

Proportion of Māori households by region and household size

The following figure shows the proportion all households in a region that are Māori households. In the Household Economic Survey (HES) the ethnicity of a household is determined by one or more people in the household selecting that ethnicity (if more than one ethnic group is selected by a particular household, then that household is recorded in two (or more) ethnic groups).

Figure 10: Māori households as a percentage of all households, by region, by HES survey year and by household size



Source: Stats NZ, customised report and licensed by Stats NZ for re-use under the Creative Commons Attribution 4.0 International licence

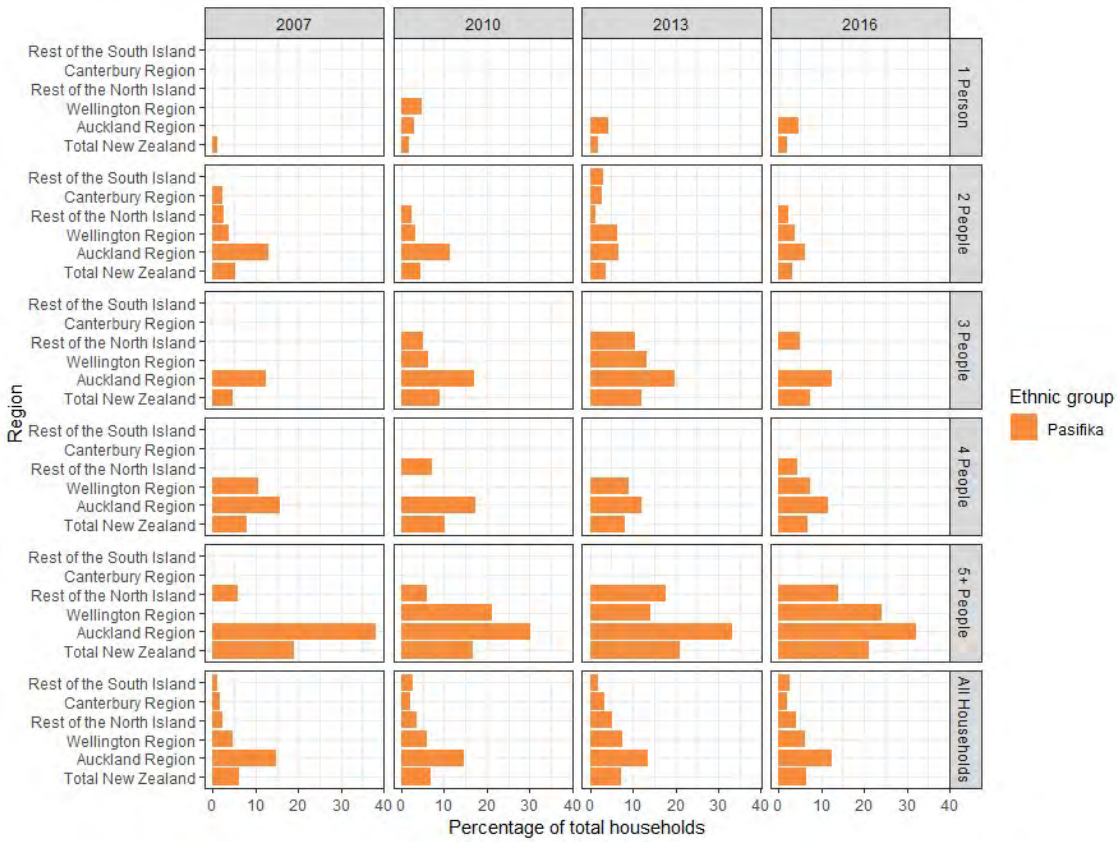
The above chart shows that:

- On average, Māori households comprise around 16-18% of all households in NZ
- There are lower percentages of Māori households in Auckland, Wellington and Canterbury, and higher percentages of Māori households in the Rest of the North Island (21–28% of all households in the rest of the North Island)
- Māori households comprise a larger proportion of large households (four and five or more person households) than the average — this is particularly pronounced for Māori in the rest of the North Island where Māori households comprise over 40% of all four and five or more person households.

Proportion of Pasifika households by region and household size

The following figure shows the proportion all households in a region that are Pasifika households.

Figure 11: Pasifika households as a percentage of all households, by region, by HES survey year and by household size



Source: Stats NZ, customised report and licensed by Stats NZ for re-use under the Creative Commons Attribution 4.0 International licence

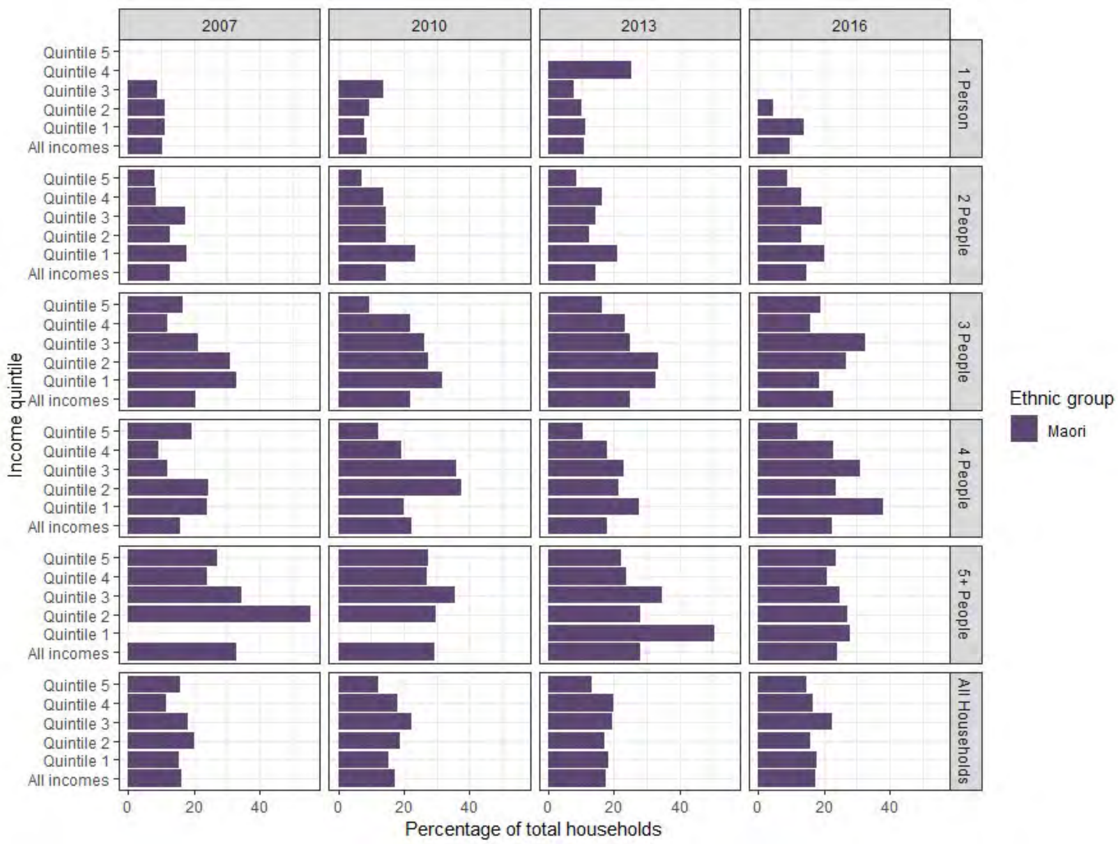
The above figure shows that:

- Pasifika households comprise on average 6-7% of all households in NZ
- The percentage of Pasifika households is highest in Auckland (12–15% of all households in Auckland)
- Pasifika households comprise around 30% of all five or more person households in Auckland
- Pasifika households comprise a larger percentage of five or more person households in New Zealand — this is particularly pronounced in Auckland and Wellington.

Proportion of Māori households by income level

The following figure shows the proportion of Māori households by income quintile (quintile 1 are the group of households with the lowest 20% of incomes, whereas quintile 5 are the group of households with the highest 20% of incomes).[54] Income quintiles are determined for all households in aggregate, and not within groups. Ethnic group of households has been determined the same as the previous section.

Figure 12: Māori households as a percentage of all households by income quintile and household size



Source: Stats NZ, customised report and licensed by Stats NZ for re-use under the Creative Commons Attribution 4.0 International licence

This figure shows that:

- For households of all sizes, quintile 3 has the highest percentage of Māori households (about 23% in 2016), with Māori comprising similar percentages of households in the other quintiles.
- Of the four person, and five or more person households, Māori households are overrepresented in the lower income quintiles (1 and 2) — for example: in 2016, 28% of all five or more person households in quintile 1 were Māori households

54 Note that household incomes have not been equivalised in this analysis.

- A similar trend to the above point is shown for four person households — 39% of all four person households in quintile 1 are Māori households.

Proportion of Pasifika households by income level

The following figure shows the proportion of Pasifika households by income quintile.

Figure 13: Pasifika households as a percentage of all households by income quintile and household size

Source: Stats NZ, customised report and licensed by Stats NZ for re-use under the Creative Commons Attribution 4.0 International licence

This figure shows that:

- Pasifika households of all sizes comprise a similar percentage of households within each income quintile
- A high percentage of large (five or more person) households in income quintile 1 are Pasifika — 41% of all households in this group are Pasifika households. Similarly, 27% of five or more person households in income quintile 2 are Pasifika.

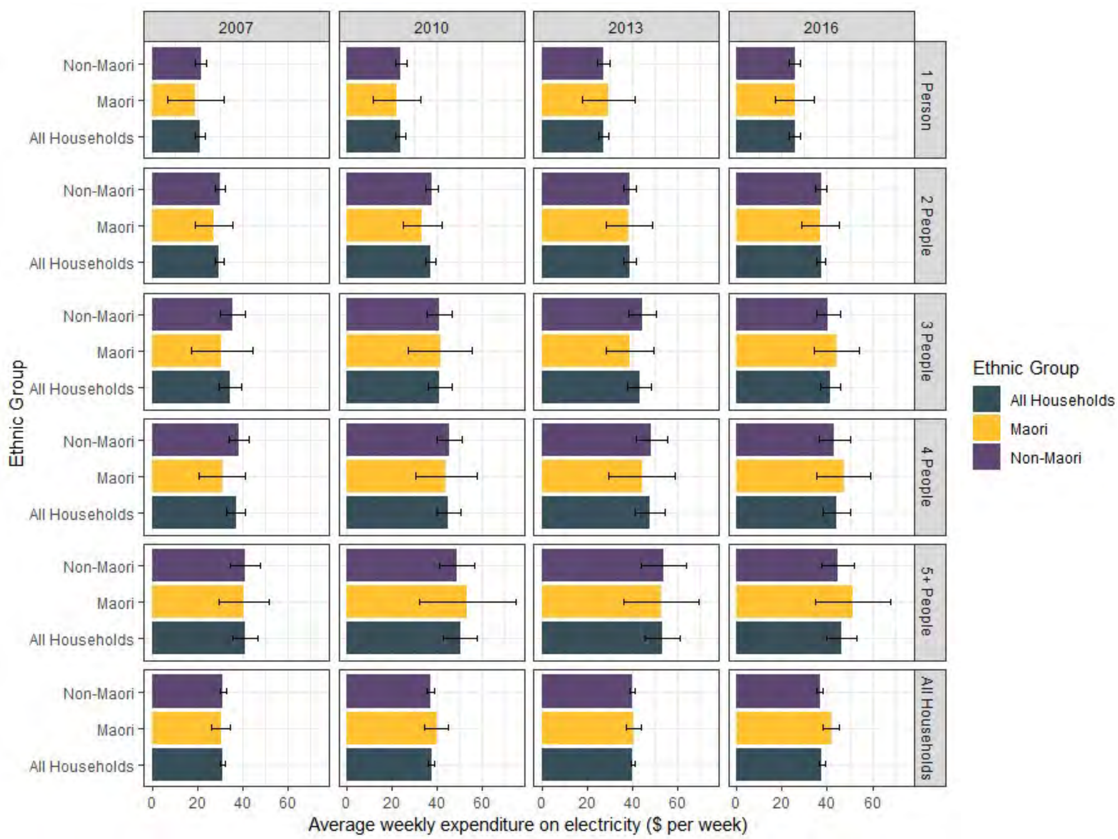
Electricity expenditure

Weekly household expenditure on electricity is collected every three years in Stats NZ's HES. The following figures show how the average household expenditure on electricity varies with household size and ethnic group, and also the percentage of electricity in total weekly household expenditure. Error bars in these figures represent the upper and lower 95% confidence intervals.[55]

Māori households

The following figure shows average weekly expenditure on electricity for Māori, non-Māori and all ethnic groups.

Figure 14: Average weekly expenditure on electricity by household size and for Māori, non-Māori and all ethnic groups



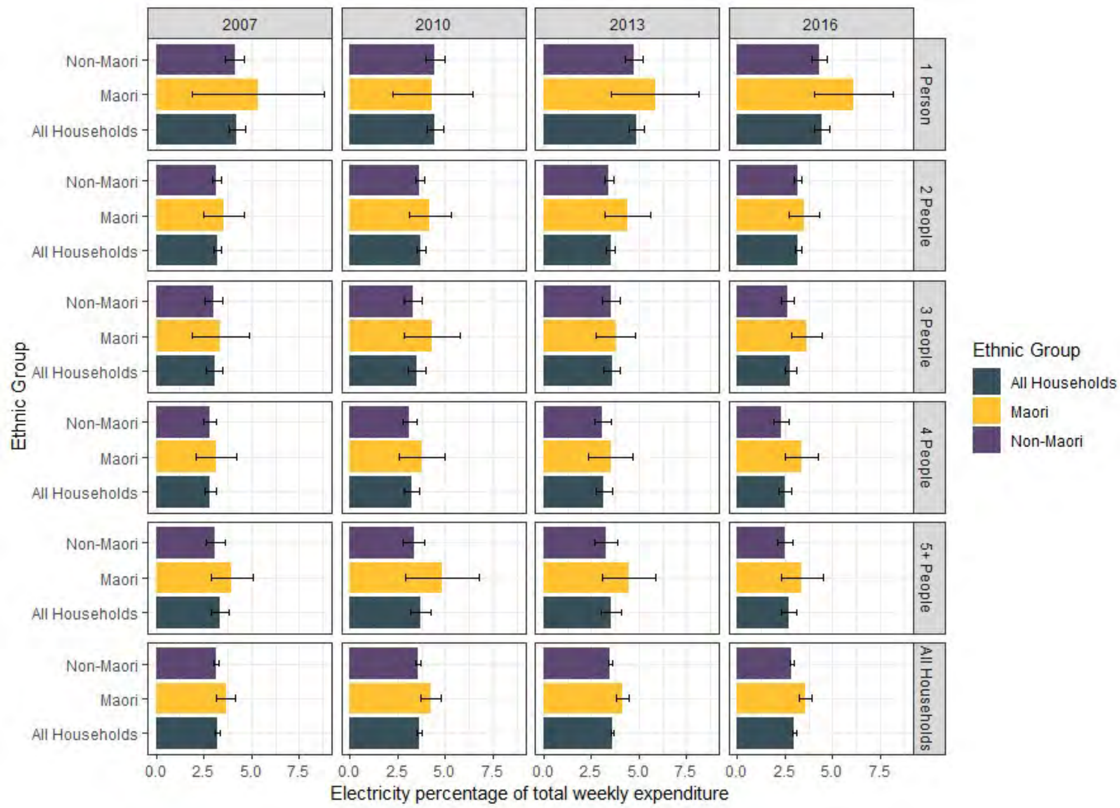
Source: Stats NZ, customised report and licensed by Stats NZ for re-use under the Creative Commons Attribution 4.0 International licence

55 95% confidence intervals are the range of values that we would expect the true estimate of a statistic to lie within with 95% probability (ie the probability that the true estimate is outside this range is 5%).

This figure shows that:

- The average weekly expenditure on electricity for all households is $37.7 (±4%). Māori households' average expenditure on electricity was marginally higher than that of non-Māori, $41.9 (±9%) vs $36.8 (±3%)
- Electricity expenditure seems to increase with increasing household size, although the wide confidence intervals make it difficult to infer a clear trend. For all ethnic groups in 2016 we can say that:
  - Households with five or more people have higher average weekly expenditure on electricity than the average for all household sizes ($46.3 ± 14% vs 37.7 ± 4%)
  - Single person households have lower average weekly expenditure on electricity than the average for all household sizes ($25.6 ± 9%)
  - The confidence intervals for average weekly expenditure on electricity for 2, 3 and 4 person households overlaps with the average for all household sizes (and hence are about average).

Figure 15: Electricity percentage of total weekly expenditure by household size for Māori, non-Māori and all ethnic groups



Source: Stats NZ, customised report and licensed by Stats NZ for re-use under the Creative Commons Attribution 4.0 International licence

The above figure shows that:

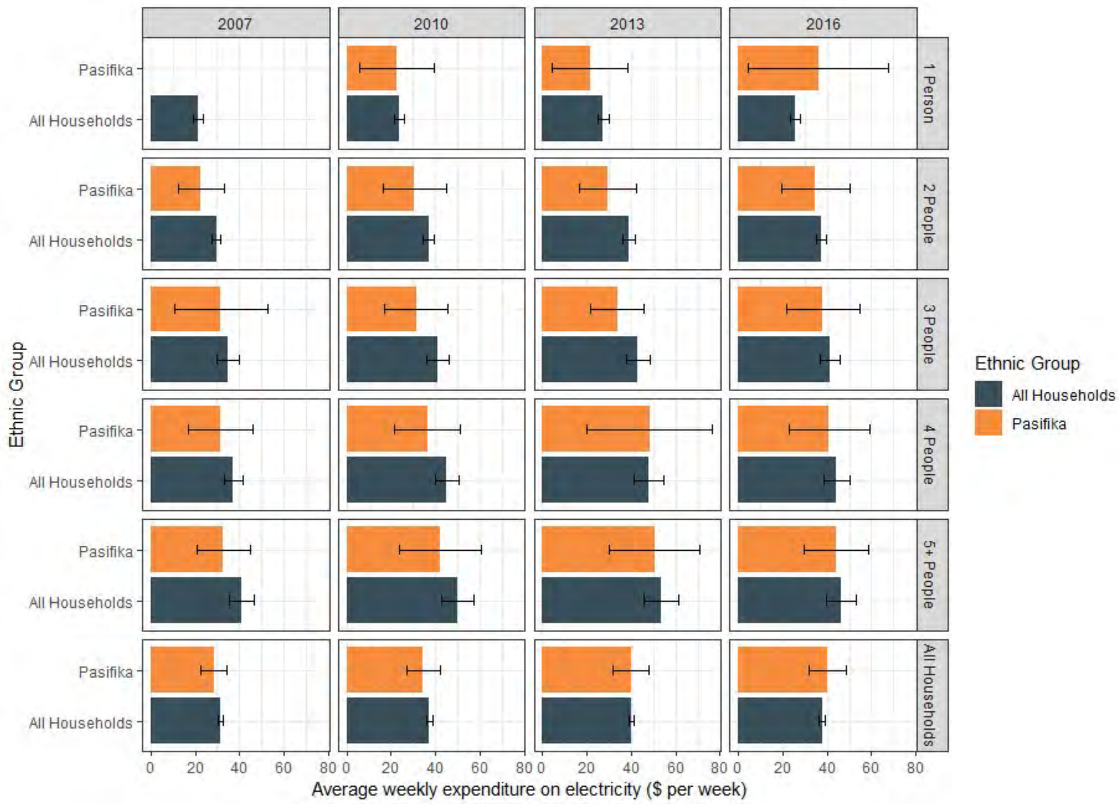
- The average percentage of total expenditure that households of all sizes and ethnic groups spend on electricity in 2016 was 3.0% (±0.1%).
- In 2016, Māori households (of all sizes) spent on average 3.6% (±0.3%) of their total expenditure on electricity (more than average). In comparison, non-Māori households on average spent 2.9% (±0.1%) of their total expenditure on electricity.
- On average:
  - single person households (of all ethnic groups) spend a higher percentage of their total expenditure on electricity than the average for all household sizes (4.4% ± 0.4% vs 3.0 ± 0.1%)
  - four person households (of all ethnic groups) spend a lower percentage of their total expenditure on electricity than the average for all household sizes (2.5% ± 0.3% vs 3.0 ± 0.1%)

- The wide confidence intervals mean that we cannot infer trends in the electricity percentage of total expenditure by household size and ethnic group.

Pasifika households

The following figure shows average expenditure in electricity for Pasifika households.

Figure 16: Average weekly expenditure on electricity by household size, for Pasifika households and all ethnic groups

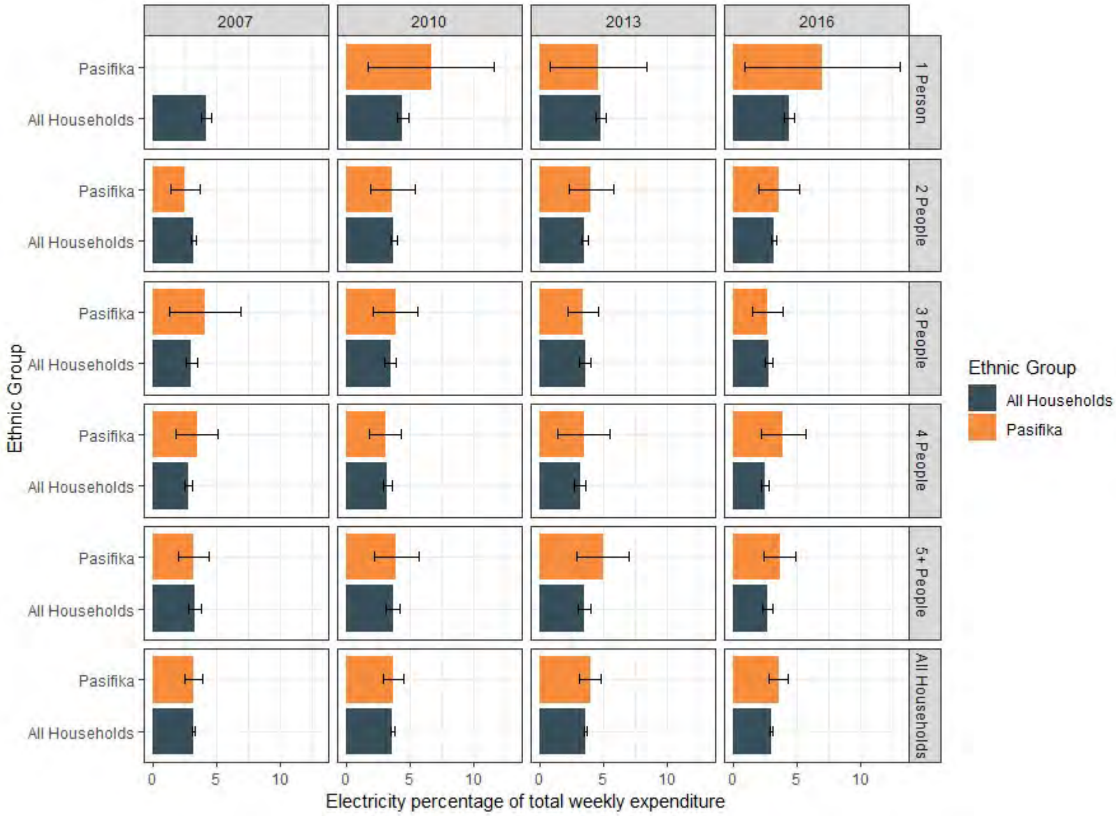


Source: Stats NZ, customised report and licensed by Stats NZ for re-use under the Creative Commons Attribution 4.0 International licence

This figure shows that Pasifika households' average weekly expenditure on electricity was $40.2 (±21%); we are unable to infer if this is higher than the average for all households because of the wide confidence intervals.

The following figure shows the average percentage of total expenditure that Pasifika households, and those of all ethnic groups, spend on electricity.

Figure 17: Electricity percentage of total weekly expenditure by household size for Pasifika households and all ethnic groups



Source: Stats NZ, customised report and licensed by Stats NZ for re-use under the Creative Commons Attribution 4.0 International licence

The above figure shows that Pasifika households of all household sizes spend an average of 3.6±0.7% of their total weekly expenditure on electricity. We cannot infer any clear trends from this figure due to the overlapping confidence intervals.

What does the ICCC's modelling mean for retail electricity prices for different times of use?

Insights

We interviewed a range of key informants in this course of this work, including the EA, Commerce Commission, WEL Networks and Flick Electric. These stakeholders agree that it is likely (and important) that time of use electricity tariffs become more common place in the future. This is especially important as the number of electric vehicles (EVs) increases as it will incentivise charging of EVs at off-peak times.

As discussed earlier in this report (page 21 refers) the EA's work to reform distribution pricing is likely to result in distribution charges moving to a time of use model. This change would provide consumers pricing signals to shift demand to off-peak times. However, retailers pass on these costs to consumers, therefore they are key stakeholders for ensuring that appropriate pricing signals are passed onto consumers.

WEL Networks (the distribution company in Hamilton) have recently brought in time of use pricing. We interviewed WEL's Pricing Manager about their experience of bringing in this new pricing model. WEL's new pricing model charges customers different rates for electricity used at peak periods, shoulder periods and off-peak periods (these rates are statically determined each year, not in real time, based on network congestion). At the moment, these rates are set the same in summer and in winter, but could be tweaked over time if needed.

WEL's Pricing Manager noted that most retailers in their network area were still not passing the time of use pricing signals through to their customers. She thought that many retailers needed to invest in new IT systems to enable them to pass on the pricing signals. She also noted that retailers may be resistant to pass on the time of use distribution prices because the larger retailers prefer national pricing strategies. Furthermore she said that retail customers want retailers to simplify pricing, and that if customers don't understand the prices they won't engage — this could mean that retail customers paying more for their electricity. While there has been some resistance from retailers to pass on the time of use pricing, it is still early days in the implementation.

We also talked to the CEO of Flick Electric (a "spot price plus margin" retailer) about how his customers react to price signals. He said that his customers fall into three groups:

- customers that have invested in technology to manage their demand and price exposure automatically (ie a home energy management system)
- customers that manually manage their demand (ie manually turning off appliances when prices are high)
- passive customers that don't manage their demand, and just pay the bill.

He noted that initially very few of his customers had invested in technology to manage their home's energy demand; however, about 5% of Flick's customers are in this group now.

Overall we would expect that by 2035 time of use distribution pricing would be commonplace in New Zealand, and that retailers would be passing on these price signals to customers in a transparent way. If this occurs, customers would be incentivised to react by shifting demand to off-peak times. They would not necessarily need to invest in their own technology to manage their energy use (although many are likely to do so) because companies that provide this service for them would fill that niche. While many customers could move to spot-price based pricing plans, many may prefer to remain on a 'hedged' price plan. This means that although retail prices would change based on time of use during the day[56], most retail customers will be protected from potential price volatility that may arise from intermittent (and weather dependent) generation by hedge contracts.

56 This could be different electricity prices for peak, off-peak and shoulder times, or different electricity prices for each trading period (which could be determined statically or dynamically).

What does a potentially higher level of wholesale price volatility mean for retail electricity prices?

Insights

We interviewed the CEO of Flick Electric (a “spot price plus margin” electricity retailer) and asked what a higher level of price volatility might mean for retail prices in NZ. He reflected on his experience leading a “spot price” retailer and how his customers manage their exposure to the spot price.

It is possible that wholesale electricity prices may become more volatile in the future if New Zealand moves to very high percentages of renewable generation. This volatility is related to having a large percentage of generation on the system that is dependent on weather (including hydro, wind and solar PV) and low levels of system storage. As a result, it becomes difficult (and extremely costly) for the system to meet demand in dry, calm and / or cloudy periods.

While new technologies like solar PV and batteries may become more prevalent in New Zealand, Flick’s CEO expects that large-scale, centralised, grid-connected electricity generation will still generate most of New Zealand’s electricity in 2035. That said, he expects that higher levels of solar PV and batteries will encourage more innovative models of electricity retailing (including peer to peer models). Furthermore, he thinks that batteries will help customers manage price volatility in the future, and that these should always be installed when solar PV systems are installed — this is because solar does not generate electricity during peak times (morning and evening, and it’s not as sunny in winter when peak demand occurs).

Flick’s CEO offered several insights that would be relevant to this subject. He said that his customers believe in cost-reflective pricing, Flick offers a ‘freestyle’ plan (spot price plus a margin) and a hedged product (a hedge contract price plus a margin) — most of their customers are on the freestyle plan. He mentioned that Flick customers on average pay about 35% less for their electricity than they did with their previous retailers. This is due to the additional costs associated with more traditional retailing models (eg hedge contracts, higher retailing costs to serve etc). The Flick model suits customers who have adequate cash-flow to ride the ups and downs of the electricity market — these customers save money on average. Customers who do not have the cash-flow to manage these ups and downs may be better off paying more on average, with more certainty on what they pay for their electricity. He also mentioned that there are other smart ways for customers to manage price variability, including using a demand aggregation service.

While wholesale electricity prices may be more volatile with higher percentages of renewable electricity generation, retail electricity prices are likely to continue to be based on wholesale hedge contracts. This assumes a wholesale hedge market is in place that effectively manages this price volatility. If this is that case we would expect that the increased price volatility would have little effect on retail prices, aside from hedge premiums increasing slightly to account for the increased risk of periods of very high prices.

ICCC MODELLING:

WIND AND SOLAR PROFILES

FINAL REPORT

APRIL 2019

REPORT TO THE INTERIM CLIMATE CHANGE COMMITTEE

John Culy Consulting

APRIL 2019

CONTENTS

LIST OF TABLES

LIST OF FIGURES

1 INTRODUCTION

This report summarises the construction of synthetic hourly data sets for several wind and solar weather years from a range of locations in New Zealand.

The wind profiles use actual market data where this is available and extrapolate this back in time using data from the Renewable Ninja website.

Wind and solar profiles for new plant in other locations is derived directly from the data available on the Renewable Ninja website. This data is adjusted to reflect generic capacity factors in each region.

The wind and solar profiles used in the modelling do not reflect any particular site or turbine/panel choice, rather they are reflective of a generic new plant in the relevant region. The profiles attempt to capture the likely variation in supply and the correlation with other existing and new wind/solar projects.

The solar profiles are only applied to large scale solar.

2 DATA SOURCES

2.1 HISTORICAL MARKET DATA

Actual generation data is available from the Electricity Authority for several wind farms by half hour from their commissioning dates. These include Tararua, Te Apiti , West Wind, Te Uku, Te Rere Hau and White Hill. This data was downloaded and converted into hourly average capacity factors by dividing average MW by the wind farm capacity. Where necessary the wind farm capacity was adjusted to reflect significant step ups in capacity or for major maintenance periods. The initial construction period was excluded, since no information was available on the commissioning timetable for turbines. As a rule, the historical data includes random short run availability deratings, except for periods where it is clear there have been major sustained outages.

2.2 RENEWABLE NINJA

The renewable Ninja data[1] is available for the period 2000 to 2016[2] by hour. It is derived by taking weather data from global reanalysis models and satellite observations. The 2 main sources are the NASA MERRA reanalysis and the CM-SAF's SARAH dataset. The data used was based on the NASA MERRA(2) global reanalysis.

Data available includes wind speed, solar irradiance data and simulated power output based a virtual wind farm (with a specified turbine type, hub height, etc) and a typical solar farm.

Typically, the wind speed data was used from the renewable Ninja site, then adjusted it to reflect known or expected wind speeds. It was then converted to power output using an empirical or modelled power curve reflecting the actual wind farm (where known) or a typical turbine type for possible future wind farms in other locations.

The Renewable Ninja data is used to extrapolate data from the date of commissioning back to 2000 for existing wind farms, and to estimate expected output from future wind farms for the historical weather years 2000 to 2016.

For existing wind farms the power curve is tuned to calibrate the power curve shape and wind speed scaling to get a good match to the level, volatility and correlation for the actual and simulated synthetic data. An example of the power curve used to convert from wind speed to

[1] https://www.renewables.ninja/.

[2] Data from 2016 to 2018 is now available as at 9 April 2019 , but was not when the data sets were constructed.

generation is given below. This shows capacity factor achieved as a function of wind speed.

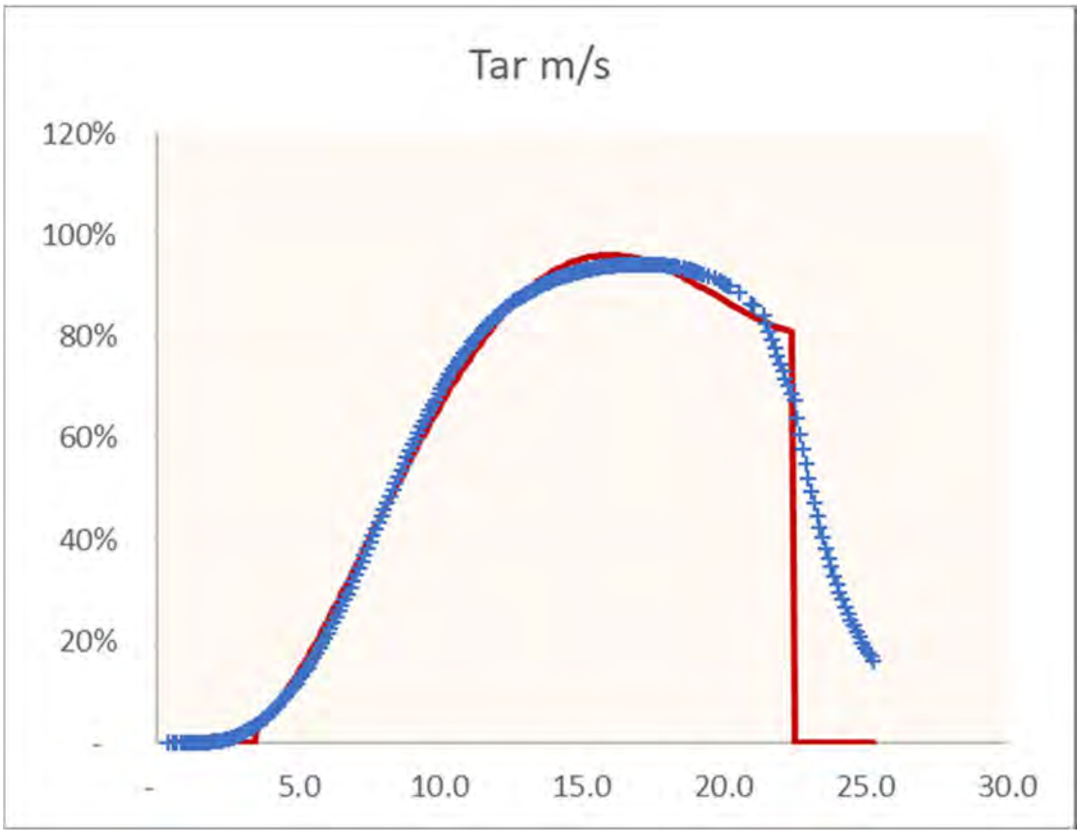


FIGURE 1: AN ILLUSTRATIVE POWER CURVE

2.3 WIND CALIBRATION

The charts below show examples of the calibration of Ninja based synthetic data with actual market generation data on a monthly basis back to 2000.

The second set of charts show the comparison for a sample historical year and month.

As can be seen the Renewable Ninja data is not exactly the same as the actual, but follows it reasonably well and has similar levels of correlation and variation. It's a reasonable proxy to backfill the hourly wind data back to 2000 for existing wind farms. The actual wind generation is slightly more volatile on an hourly time step. This is not considered to be a major limitation since most of the Energy Link modelling uses a 3-hour time step.

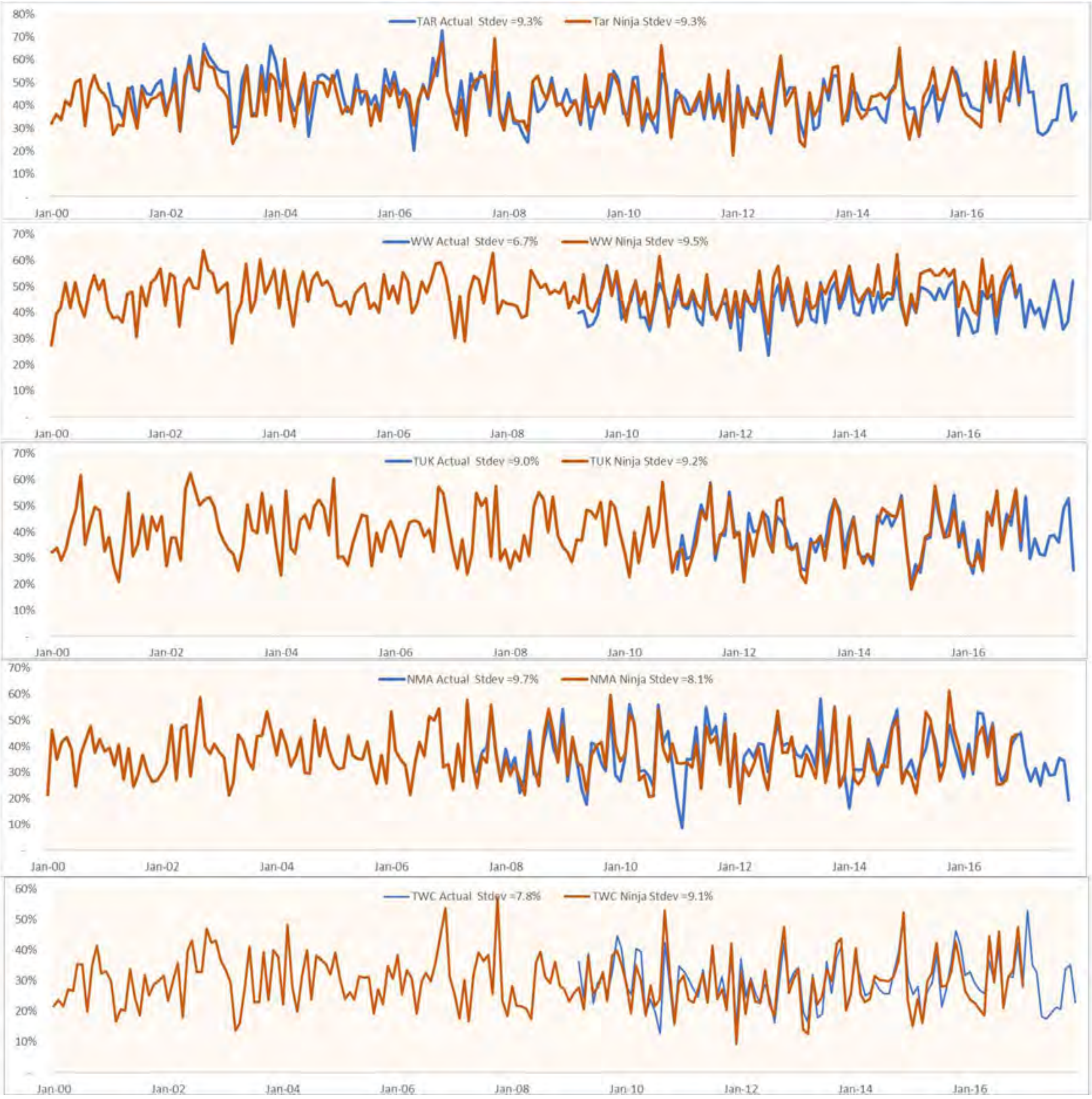


FIGURE 2: COMPARISON OF MONTH RENEWABLE NINJA AND ACTUAL WIND

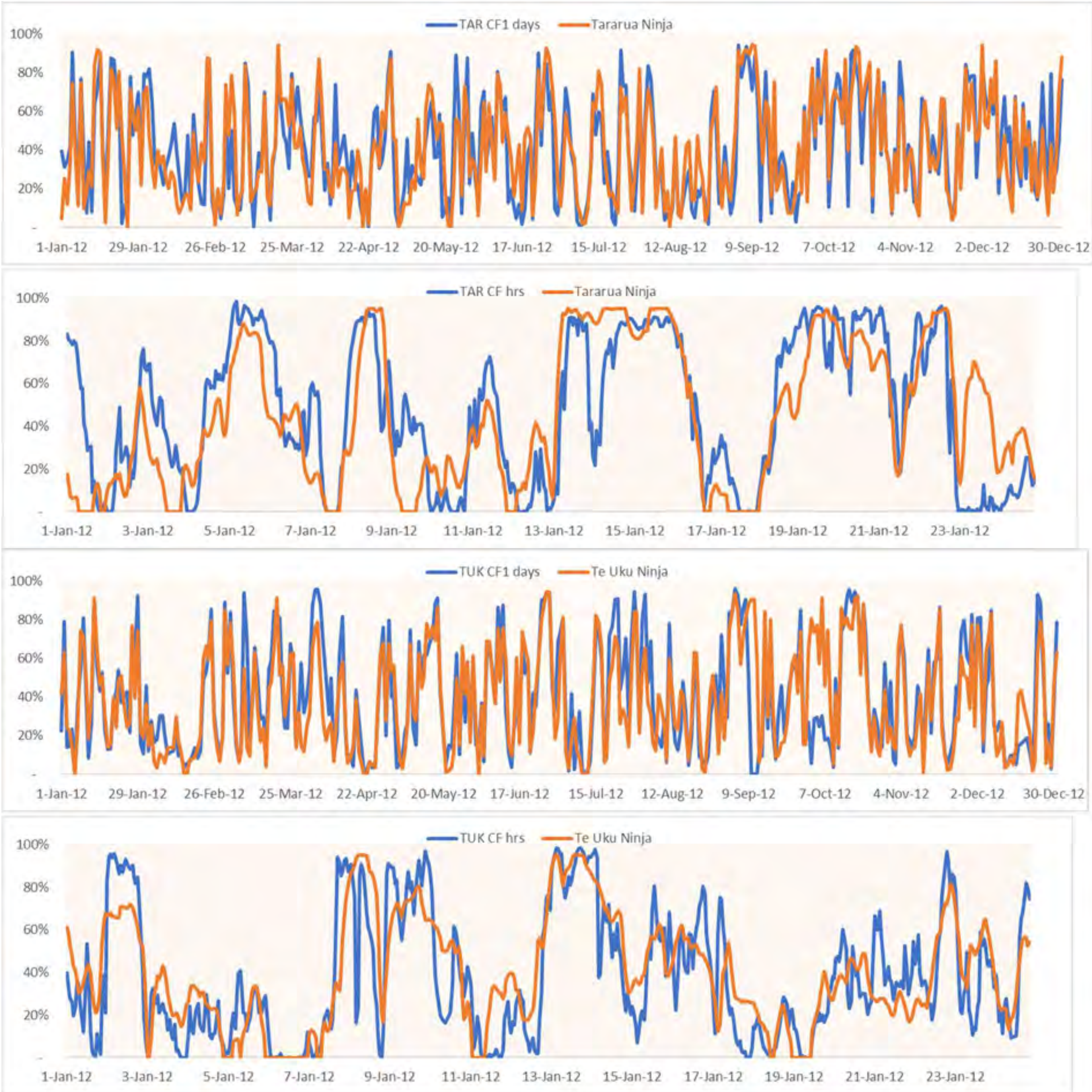


FIGURE 3: COMPARISON OF ACTUAL AND NINJA DATA - 1

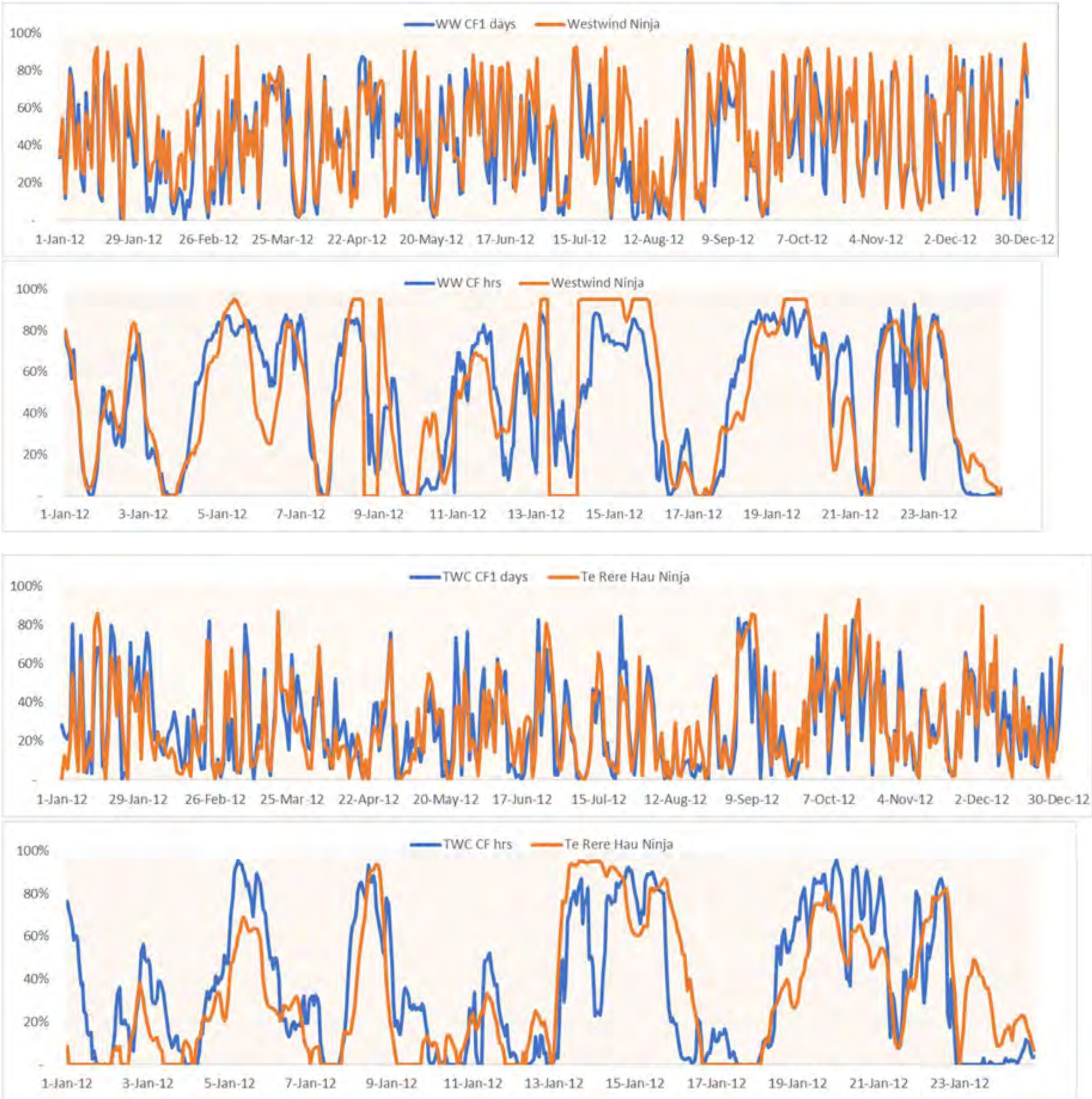


FIGURE 4: COMPARISON OF ACTUAL AND NINJA DATA – 2

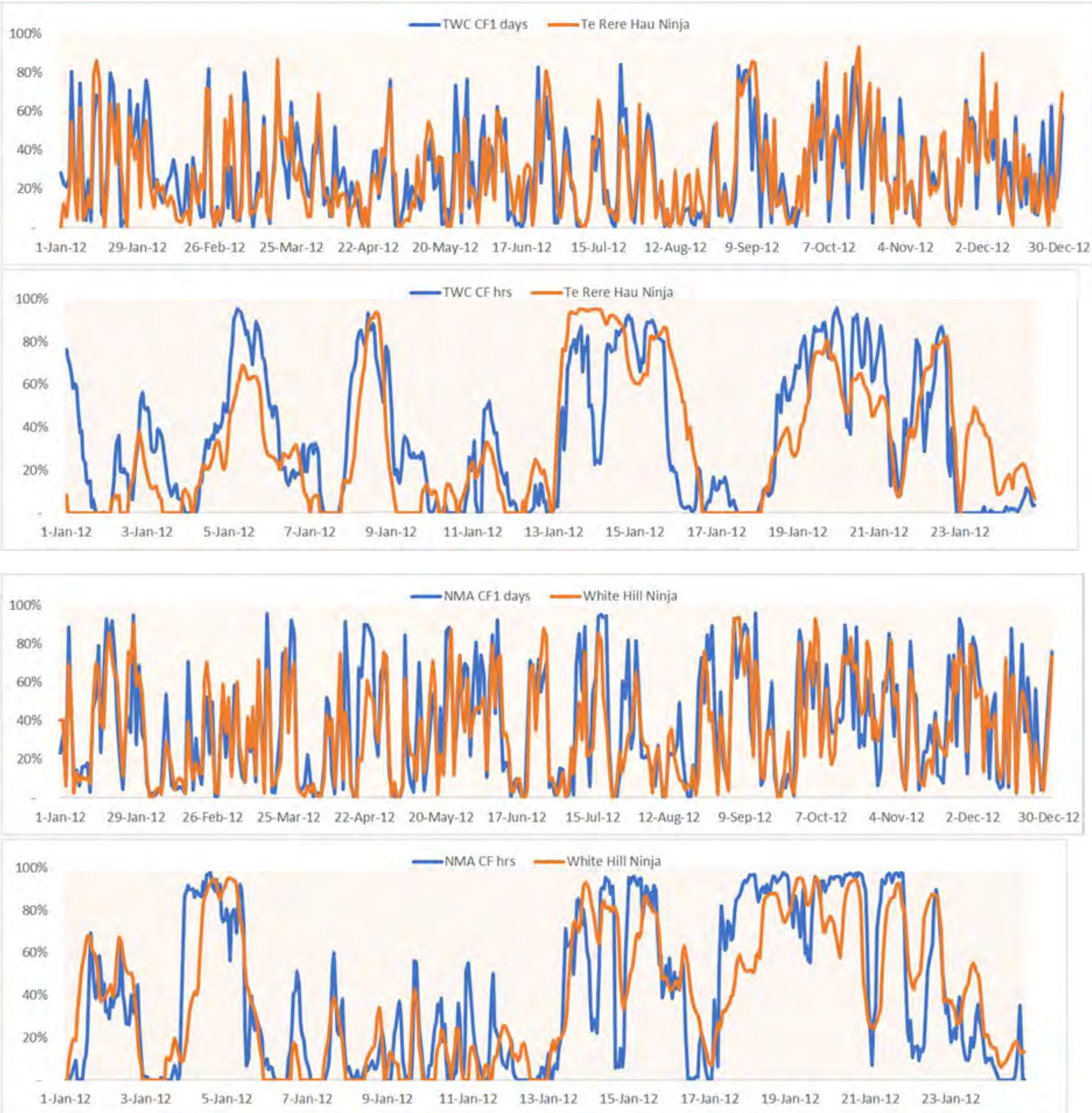


FIGURE 5: COMPARISON OF ACTUAL AND NINJA DATA – 3

As can be seen, it is not possible to get a perfect match, but in general the errors appear to be reasonably small, and the synthetic data retains the expected levels of volatility and correlation as the actual.

3 SYNTHETIC HOURLY DATA

This section provides summary statistics for the full synthetic data set. These statistics are provided separately for monthly, daily and hourly time steps.

3.1 WIND DATA SUMMARY STATISTICS

The summary statistics for the synthetic wind data is summarised in the following tables. These show the mean (unconstrained) capacity factors and the observed % variation on an annual, monthly and daily basis.

TABLE 1: ANNUAL SUMMARY STATISTICS

	Annual Max	Annual P10	Annual P90	Monthly Min	Mean Capacity Factor	Annual Volatility	Annual Cross Correl Tararua
Te Apiti	51%	46%	37%	34%	41%	10%	89%
Tararua	51%	48%	40%	38%	43%	8%	100%
West Wind	51%	49%	42%	42%	45%	6%	78%
Te Uku	46%	43%	37%	36%	40%	6%	54%
Te Rere Hau	35%	33%	27%	26%	30%	8%	64%
White Hill	40%	39%	34%	32%	37%	7%	47%
Northland	48%	45%	39%	38%	42%	6%	47%
Kaimai	49%	46%	40%	39%	43%	6%	56%
Hawkes Bay	49%	47%	41%	39%	43%	7%	68%
Wairarapa	48%	46%	39%	38%	42%	7%	65%
Waverley	49%	46%	40%	39%	43%	6%	56%
Taranaki	49%	47%	41%	39%	43%	6%	68%
Wellington	45%	45%	40%	39%	42%	5%	50%
Canterbury	47%	46%	40%	38%	42%	6%	51%
Southland	48%	46%	41%	40%	43%	5%	62%

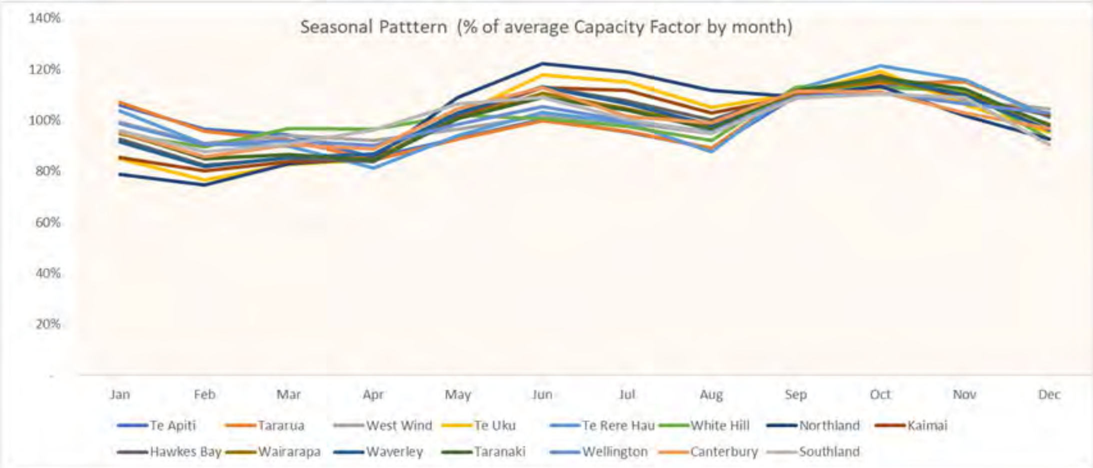
TABLE 2: MONTHLY SUMMARY STATISTICS

	Monthly Max	Monthly P10	Monthly P90	Monthly Min	Mean Capacity Factor	Monthly Stdev	Monthly Volatility	Monthly Cross Correl Tararua	Monthly Serial Correl
Te Apiti	67%	54%	30%	20%	41%	9%	23%	93%	18%
Tararua	73%	55%	32%	20%	43%	9%	22%	100%	18%
West Wind	64%	54%	36%	23%	45%	7%	16%	66%	20%
Te Uku	63%	54%	27%	20%	40%	10%	24%	50%	25%
Te Rere Hau	57%	40%	19%	13%	30%	8%	27%	86%	11%
White Hill	59%	49%	26%	9%	37%	9%	25%	58%	7%
Northland	67%	56%	29%	17%	42%	10%	24%	30%	37%
Kaimai	70%	56%	31%	22%	43%	9%	22%	53%	23%
Hawkes Bay	69%	56%	31%	20%	43%	10%	22%	76%	15%
Wairarapa	67%	54%	31%	21%	42%	9%	21%	78%	11%
Waverley	68%	54%	32%	23%	43%	9%	21%	71%	14%
Taranaki	69%	55%	31%	19%	43%	9%	22%	82%	10%
Wellington	58%	51%	34%	24%	42%	7%	16%	68%	8%
Canterbury	64%	53%	32%	22%	42%	8%	19%	66%	8%
Southland	71%	55%	33%	23%	43%	9%	21%	61%	8%

TABLE 3: DAILY SUMMARY STATISTICS

	Daily P5	Daily P10	Daily P25	Daily P75	Daily P90	Daily P95	Average	Daily Stdev	Daily Cross Correl Tararua	Daily Serial Correl
Te Apiti	87%	80%	64%	17%	6%	3%	41%	27%	96%	45%
Tararua	88%	82%	66%	20%	8%	4%	43%	27%	100%	44%
West Wind	86%	82%	67%	23%	10%	5%	45%	26%	53%	33%
Te Uku	86%	79%	62%	16%	6%	3%	40%	27%	35%	53%
Te Rere Hau	74%	66%	47%	10%	3%	1%	30%	23%	87%	48%
White Hill	86%	79%	60%	11%	3%	1%	37%	28%	32%	50%
Northland	88%	81%	65%	19%	6%	2%	42%	27%	16%	56%
Kaimai	86%	80%	64%	21%	10%	5%	43%	26%	35%	55%
Hawkes Bay	89%	82%	65%	21%	10%	6%	43%	26%	68%	50%
Wairarapa	87%	80%	62%	21%	10%	6%	42%	25%	66%	47%
Waverley	86%	79%	63%	21%	9%	5%	43%	25%	62%	48%
Taranaki	89%	82%	64%	21%	10%	6%	43%	26%	73%	50%
Wellington	81%	76%	62%	22%	11%	6%	42%	24%	48%	35%
Canterbury	86%	80%	63%	21%	10%	6%	42%	25%	46%	46%
Southland	88%	82%	65%	21%	10%	6%	44%	26%	41%	58%

3.1.1 SEASONAL AND DAILY PATTERN BY REGION



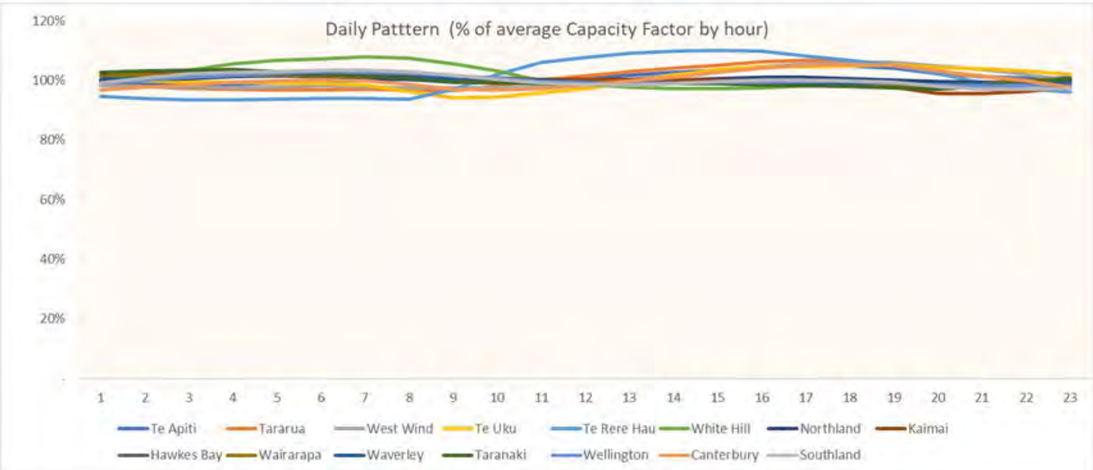


FIGURE 6: MONTHLY AND DAILY WIND PATTERNS

As can be seen there is only a small seasonal variation, with a dip in March to April, and again in July and August. The peak wind is in

October and November. The daily pattern of wind is reasonably uniform.

3.1.2 VARIATION

The following charts show the variation in wind capacity factor on different time frames for each regional wind profile.

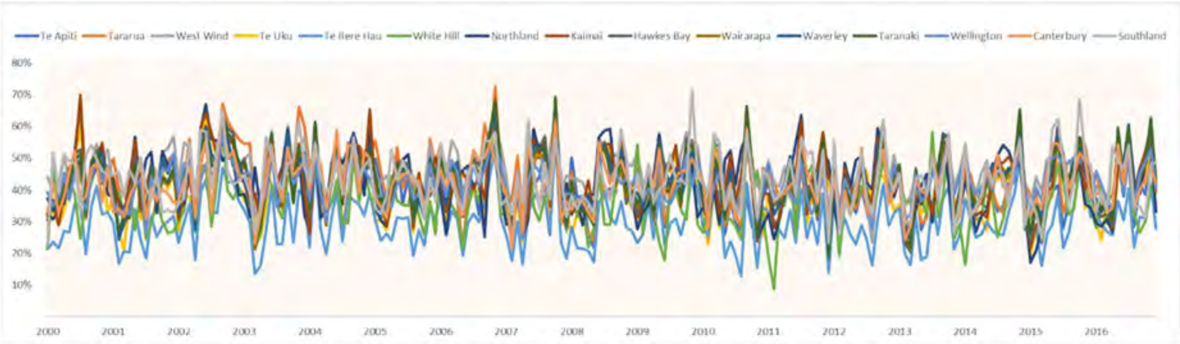


FIGURE 7: MONTHLY VARIATION BY WIND PROFILE

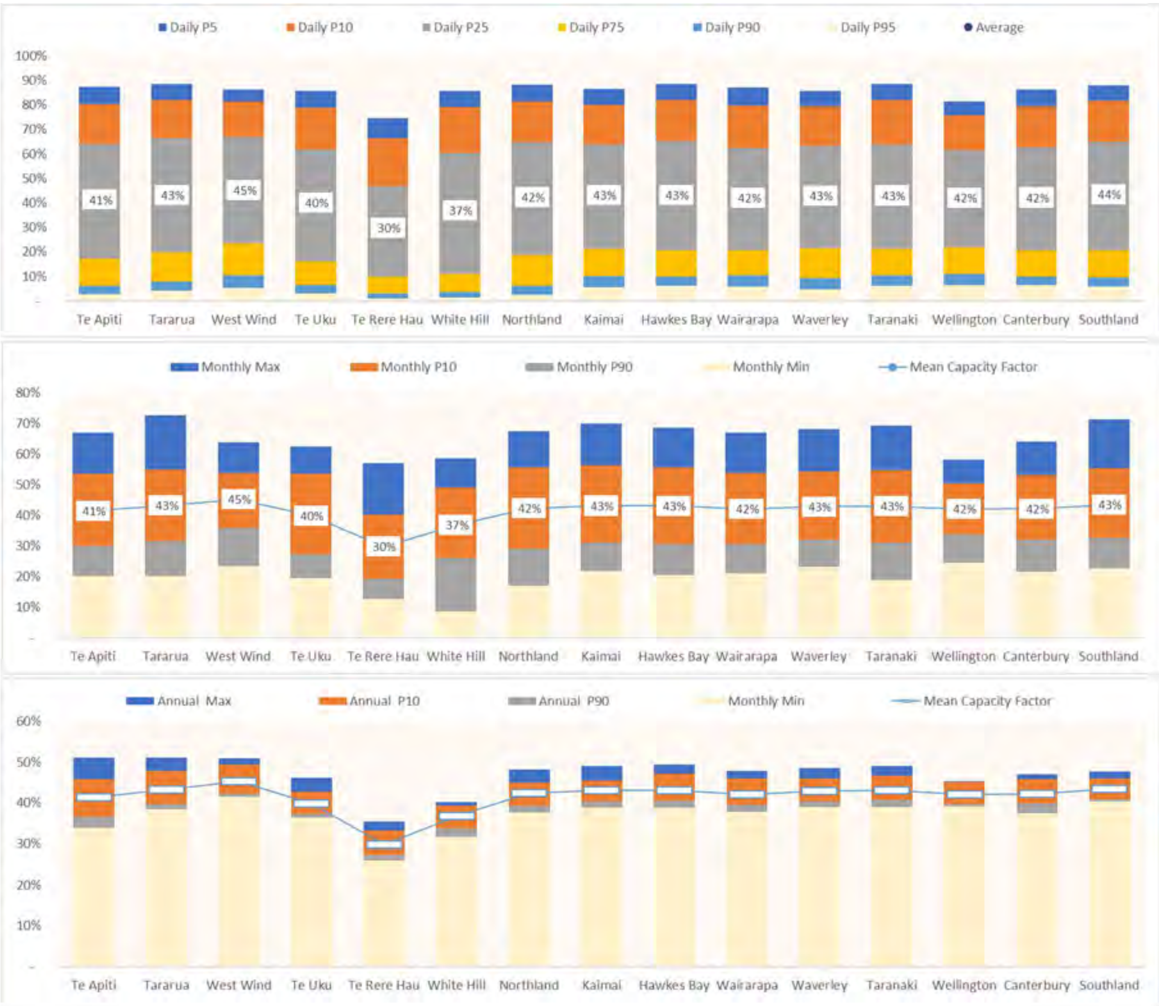


FIGURE 8: DAILY, MONTHLY AND ANNUAL VARIATION BY WIND PROFILE

3.1.3 CROSS CORRELATION

The chart below shows the cross correlation between each regional wind farm profile and Tararua, on the different time scales.

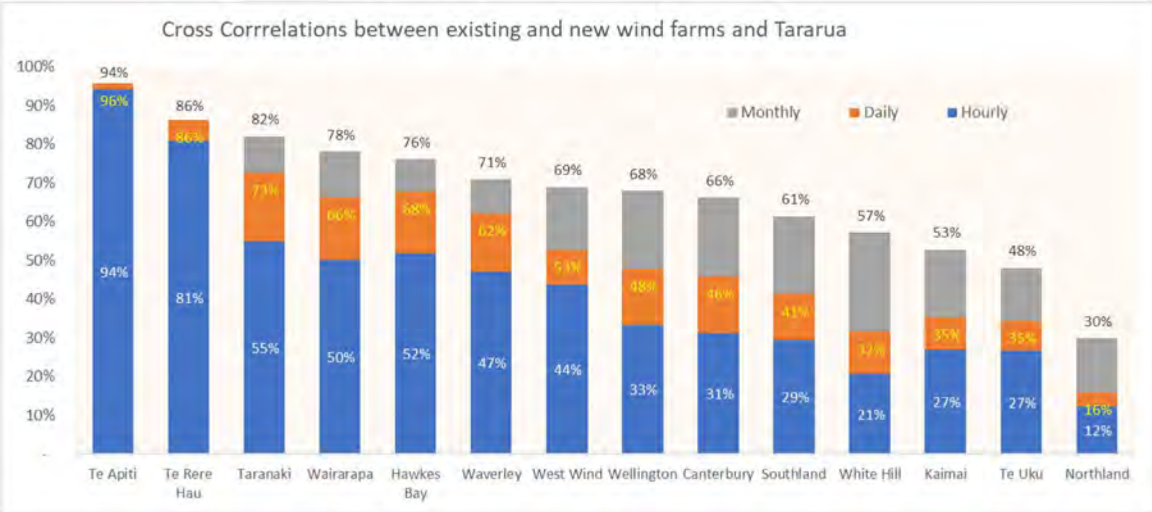


FIGURE 9: CROSS CORRELATIONS BETWEEN WIND FARMS

Note the relatively high cross correlation between wind in different regions. This is most pronounced on a monthly basis but is still significant on a daily basis. As expected, hourly cross correlations are much lower.

The full set of cross correlations between the regional wind profiles is given in the table (4) below.

TABLE 4: CROSS CORRELATION MATRICIES FOR SYSTENTIC WIND DATA

Hourly

	TAP CF1	TAR CF1	WW CF1	TUK CF1	TWC CF1	NMA CF1	Nland CF1	Kai CF1	HB CF1	Wai CF1	Wav CF1	Tar CF1	Wel CF1	Cant CF1	Sland CF1
Te Apiti	100%														
Tararua	94%	100%													
West Wind	40%	44%	100%												
Te Uku	25%	27%	17%	100%											
Te Rere Hau	77%	81%	51%	41%	100%										
White Hill	21%	21%	13%	3%	20%	100%									
Northland	11%	12%	12%	60%	21%	(3%)	100%								
Kaimai	26%	27%	16%	67%	36%	5%	78%	100%							
Hawkes Bay	50%	52%	44%	43%	60%	20%	35%	52%	100%						
Wairarapa	48%	50%	50%	37%	58%	21%	31%	46%	97%	100%					
Waverley	44%	47%	46%	45%	54%	16%	43%	55%	79%	80%	100%				
Taranaki	53%	55%	46%	39%	61%	23%	32%	49%	96%	96%	86%	100%			
Wellington	30%	33%	56%	19%	38%	17%	18%	24%	63%	75%	67%	68%	100%		
Canterbury	30%	31%	36%	23%	36%	37%	19%	26%	54%	60%	47%	56%	57%	100%	
Southland	29%	29%	17%	20%	32%	58%	12%	21%	37%	36%	33%	38%	24%	47%	100%

Daily

	TAP CF1	TAR CF1	WW CF1	TUK CF1	TWC CF1	NMA CF1	Nland CF1	Kai CF1	HB CF1	Wai CF1	Wav CF1	Tar CF12	Wel CF1	Cant CF1	Sland CF1
Te Apiti	100%														
Tararua	96%	100%													
West Wind	49%	53%	100%												
Te Uku	33%	35%	22%	100%											
Te Rere Hau	83%	86%	59%	50%	100%										
White Hill	32%	32%	22%	6%	30%	100%									
Northland	14%	16%	15%	75%	27%	(2%)	100%								
Kaimai	34%	35%	22%	84%	46%	7%	85%	100%							
Hawkes Bay	65%	68%	57%	56%	77%	27%	43%	62%	100%						
Wairarapa	63%	66%	65%	49%	76%	28%	38%	55%	98%	100%					
Waverley	59%	62%	60%	58%	70%	22%	50%	64%	85%	85%	100%				
Taranaki	70%	73%	61%	52%	80%	30%	39%	59%	97%	97%	90%	100%			
Wellington	44%	48%	79%	26%	54%	23%	23%	31%	70%	81%	75%	75%	100%		
Canterbury	45%	46%	54%	33%	53%	49%	25%	36%	67%	72%	59%	67%	69%	100%	
Southland	41%	41%	24%	27%	43%	68%	15%	26%	46%	44%	39%	46%	29%	59%	100%

Monthly

	TAP CF1	TAR CF1	WW CF1	TUK CF1	TWC CF1	NMA CF1	Nland CF1	Kai CF1	HB CF1	Wai CF1	Wav CF1	Tar CF12	Wel CF1	Cant CF1	Sland CF1
Te Apiti	100%														
Tararua	94%	100%													
West Wind	68%	69%	100%												
Te Uku	47%	48%	51%	100%											
Te Rere Hau	82%	86%	73%	66%	100%										
White Hill	56%	57%	42%	27%	53%	100%									
Northland	30%	30%	38%	88%	45%	15%	100%								
Kaimai	51%	53%	51%	95%	68%	28%	90%	100%							
Hawkes Bay	72%	76%	73%	79%	89%	47%	65%	80%	100%						
Wairarapa	74%	78%	78%	75%	90%	48%	60%	76%	99%	100%					
Waverley	67%	71%	73%	84%	86%	46%	71%	84%	93%	93%	100%				
Taranaki	78%	82%	76%	76%	92%	51%	60%	78%	98%	99%	95%	100%			
Wellington	63%	68%	88%	58%	79%	40%	45%	59%	83%	89%	83%	86%	100%		
Canterbury	63%	66%	71%	59%	77%	61%	49%	60%	84%	86%	78%	82%	80%	100%	
Southland	60%	61%	45%	44%	64%	77%	32%	44%	65%	63%	60%	64%	47%	75%	100%

3.2 SOLAR DATA

The statistics for the synthetic solar data is summarised in the following tables. These show the mean (unconstrained) capacity factors and the observed % variation on an annual, monthly and daily basis.

The initial solar capacity factors are scaled to be approximately 25% over the year, on the assumption that single axis tracking is used, and the DC panel capacity is 1.3 oversized relative to the AC inverter capacity. This is typical for utility scale solar farms in Australia and the USA. The initial capacity factor is expected to decline at around 0.5% per annum and so the lifetime average capacity factor will be lower.

The capacity factors for utility scale solar in New Zealand is likely to be around 19% without single axis tracking and without significant oversizing.

Note that statistics are also provided for seasonally/daily adjusted data. This is the difference between the raw capacity factor in each hour and the mean expected in each month and hour over the year.

3.2.1 Summary Statistics

Table 5: Annual, Monthly and Daily Summary Statistics

	Annual Max	Annual P10	Annual P90	Monthly Min	Mean Capacity Factor	Annual Volatility	Annual Cross Correl Akl
Northland	31%	27%	25%	25%	26%	5%	96%
Auckland	29%	26%	25%	24%	25%	4%	100%
Hawkes Bay	27%	26%	25%	24%	26%	3%	81%
Wellington	28%	25%	24%	23%	25%	4%	76%
Nelson	28%	26%	25%	24%	25%	3%	81%
Christchurch	27%	26%	24%	24%	25%	3%	59%

	Monthly Max	Monthly P10	Monthly P90	Monthly Min	Mean Capacity Factor	Monthly Stdev	Monthly Volatility	Monthly Cross Correl Auck	Monthly Serial Correl
Northland	40%	36%	15%	12%	26%	7.9%	30%	99%	81%
Auckland	39%	35%	15%	10%	25%	7.8%	31%	100%	81%
Hawkes Bay	41%	36%	14%	10%	26%	8.3%	32%	97%	80%
Wellington	41%	36%	13%	9%	25%	8.8%	36%	97%	80%
Nelson	42%	37%	13%	10%	25%	9.0%	35%	97%	81%
Christchurch	39%	36%	14%	9%	25%	8.4%	34%	96%	81%
Northland saj	6%	3%	(2%)	(5%)	(0%)	1.9%		20%	6%
Auckland saj	5%	3%	(3%)	(6%)	(0%)	1.9%		22%	11%
Hawkes Bay saj	5%	3%	(3%)	(8%)	(0%)	2.3%		12%	5%
Wellington saj	5%	3%	(3%)	(8%)	(0%)	2.3%		9%	(1%)
Nelson saj	5%	3%	(3%)	(8%)	(0%)	2.2%		10%	4%
Christchurch saj	5%	3%	(3%)	(8%)	(0%)	2.2%		7%	9%

	Daily P5	Daily P10	Daily P25	Daily P75	Daily P90	Daily P95	Average	Daily Stdev	Daily Cross Correl Auck	Daily Serial Correl
Northland	43%	41%	35%	17%	10%	7%	26%	11%	91%	62%
Auckland	43%	40%	34%	17%	10%	7%	25%	11%	100%	61%
Hawkes Bay	44%	42%	35%	16%	9%	6%	26%	12%	74%	65%
Wellington	45%	42%	36%	15%	8%	6%	25%	12%	71%	66%
Nelson	44%	41%	35%	14%	7%	5%	24%	12%	68%	66%
Christchurch	45%	42%	35%	16%	8%	5%	25%	12%	59%	60%
Northland saj	11%	10%	6%	(6%)	(12%)	(15%)		8%	62%	29%
Auckland saj	12%	10%	7%	(6%)	(12%)	(15%)		8%	74%	27%
Hawkes Bay saj	12%	10%	7%	(7%)	(12%)	(16%)		9%	38%	36%
Wellington saj	11%	10%	7%	(6%)	(12%)	(16%)		9%	33%	32%
Nelson saj	13%	11%	7%	(7%)	(12%)	(16%)		9%	30%	35%
Christchurch saj	12%	11%	8%	(7%)	(13%)	(16%)		9%	20%	28%

3.2.2 Solar Seasonal and Daily Patterns

The charts below show the mean monthly and daily profiles for each regional solar profile relative to the average capacity factor in each region. These mean patterns are very similar since they generally reflect the position of the sun in the sky.

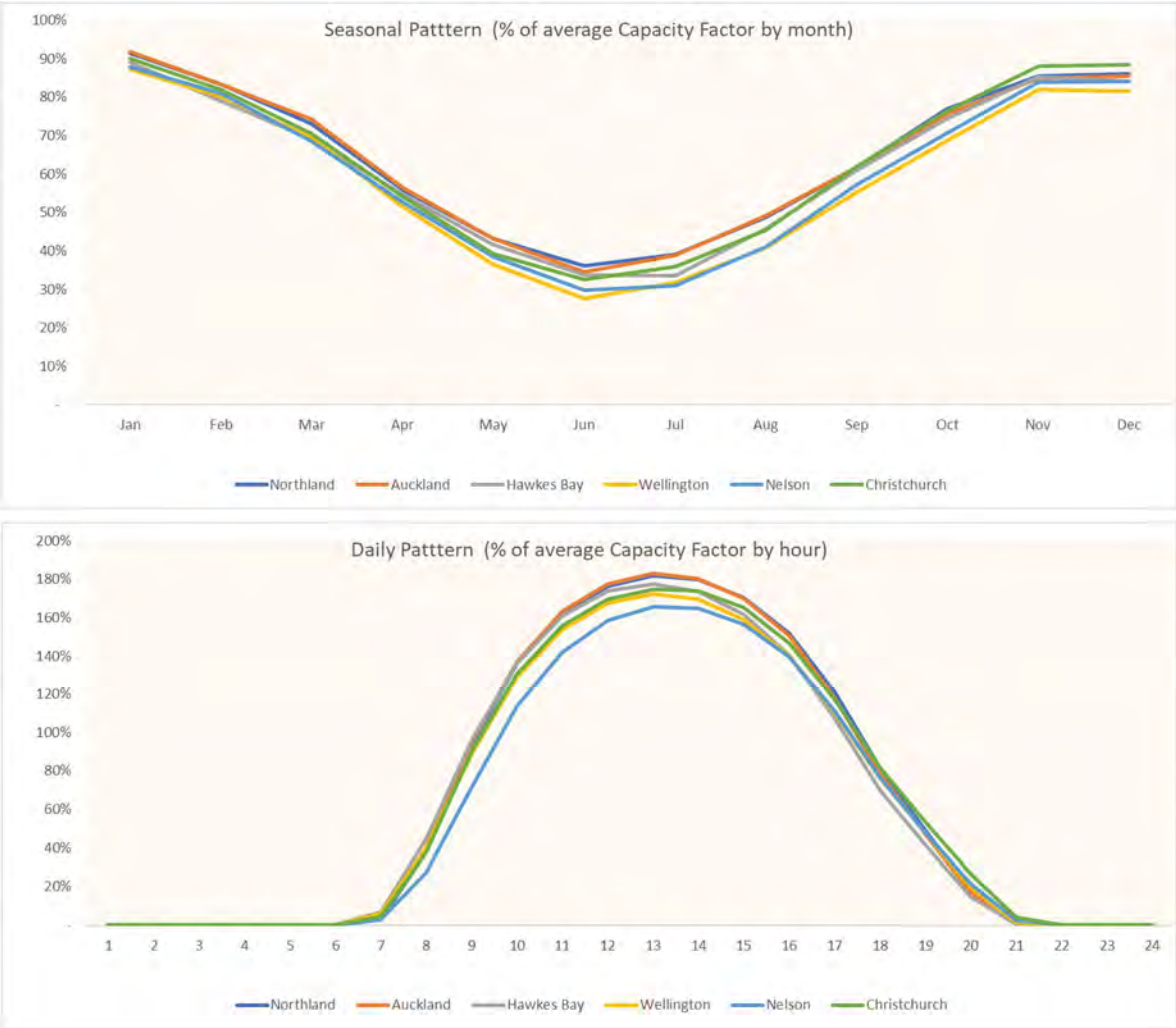


FIGURE 10: SEASONAL AND DAILY PATTERN

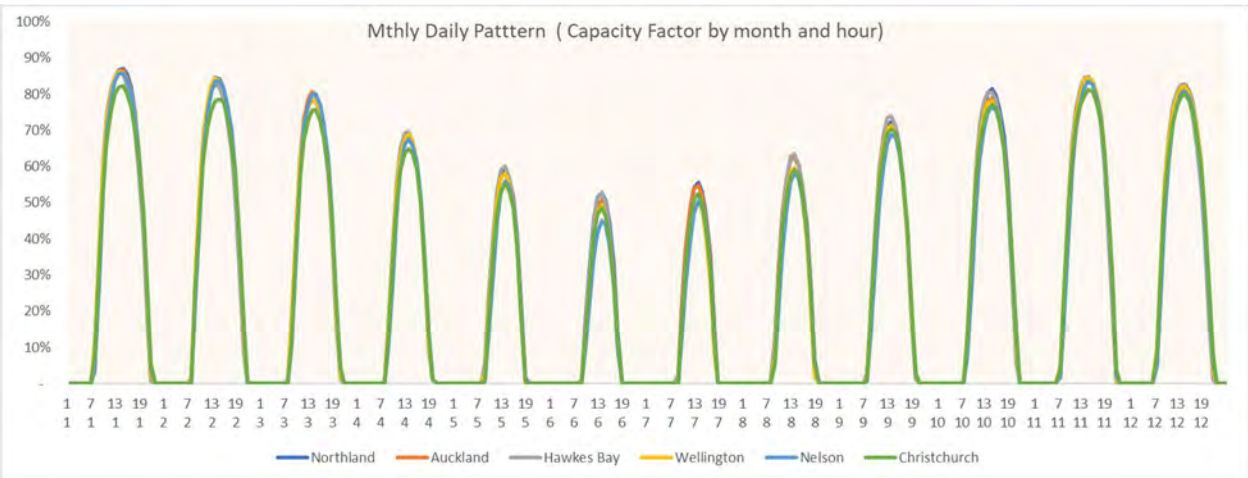


FIGURE 11: SEASONAL AND DAILY PATTERN

There are very strong seasonal and daily patterns for solar. These dominate the random fluctuation resulting from varying weather.

3.2.3 SOLAR VARIATION DAILY, MONTHLY AND ANNUAL

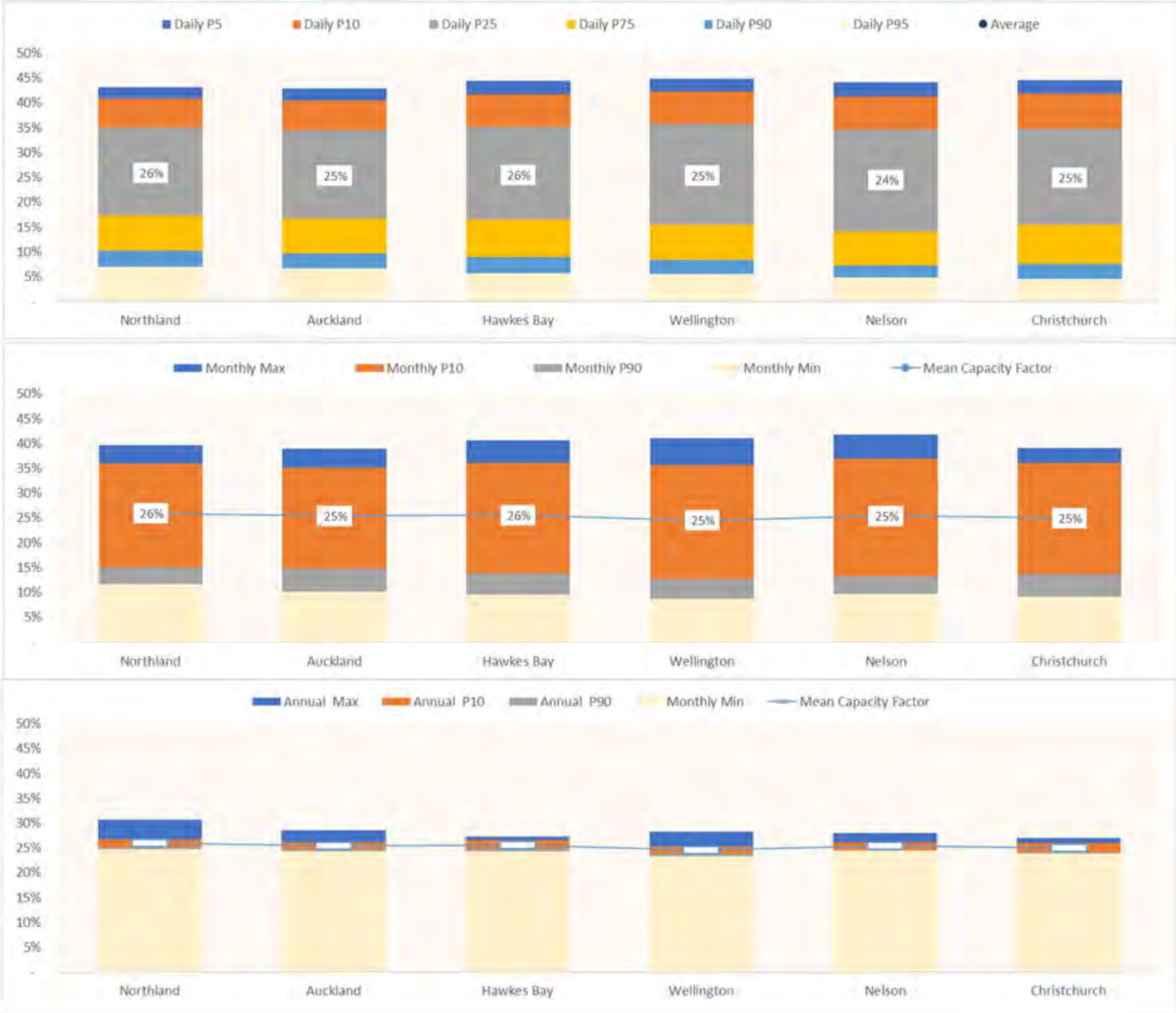


FIGURE 12: VARIATION BY DAY, MONTH AND YEAR

Note that the annual variation is much lower than for wind, around 3 to 5% compared with 6 to 10% for wind.

3.2.4 SOLAR CORRELATIONS

The tables are charts below show the cross correlations between different regions. Note that the correlation measures for the seasonally adjusted outputs are considerably lower than for the raw data. The later include the highly predictable seasonal/daily patterns whereas the former only reflect the random variations due to changing weather.

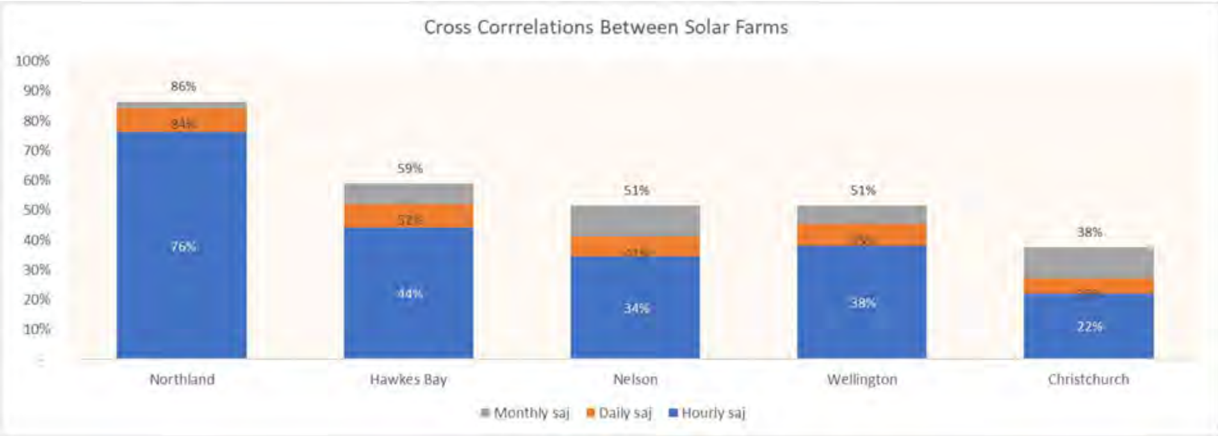


FIGURE 13 CROSS CORRELATION BETWEEN SOLAR FARMS

Hourly

Raw	Northland	Auckland	Hawkes Bay	Wellington	Nelson	Christchurch	Seasonally adjusted	Northland	Auckland	Hawkes Bay	Wellington	Nelson	Christchurch
Northland	100%	96%					Northland saj	100%	76%				
Auckland	96%	100%					Auckland saj	76%	100%				
Hawkes Bay	88%	90%	100%				Hawkes Bay saj	35%	44%	100%			
Wellington	87%	89%	93%	100%			Wellington saj	28%	38%	62%	100%		
Nelson	86%	87%	86%	90%	100%		Nelson saj	25%	34%	29%	52%	100%	
Christchurch	83%	84%	85%	89%	89%	100%	Christchurch saj	16%	22%	28%	47%	50%	100%

Daily

Raw	Northland	Auckland	Hawkes Bay	Wellington	Nelson	Christchurch	Seasonally adjusted	Northland	Auckland	Hawkes Bay	Wellington	Nelson	Christchurch
Northland	100%	91%					Northland saj	100%	84%				
Auckland	91%	100%					Auckland saj	84%	100%				
Hawkes Bay	69%	74%	100%				Hawkes Bay saj	42%	52%	100%			
Wellington	63%	68%	65%	100%			Wellington saj	34%	45%	71%	100%		
Nelson	66%	71%	85%	80%	100%		Nelson saj	30%	41%	35%	61%	100%	
Christchurch	56%	59%	64%	79%	78%	100%	Christchurch saj	19%	27%	35%	59%	62%	100%

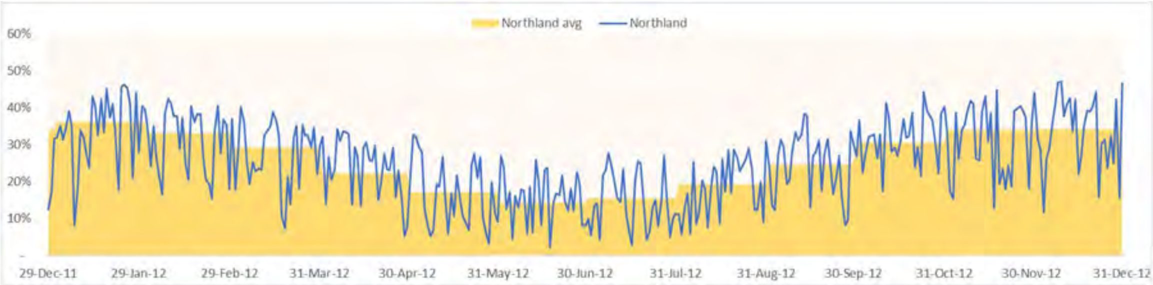
Monthly

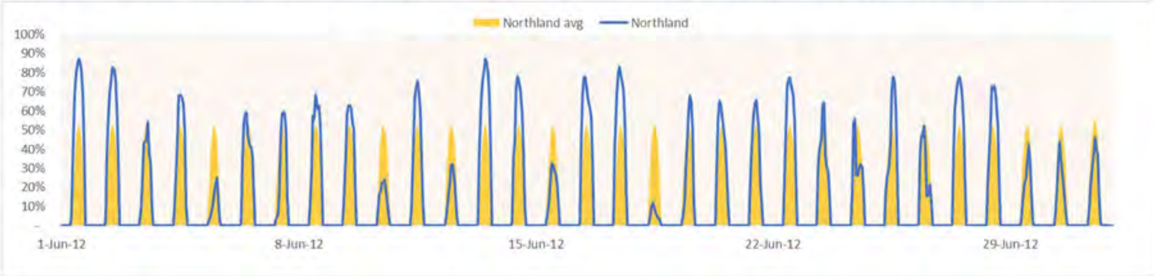
Raw	Northland	Auckland	Hawkes Bay	Wellington	Nelson	Christchurch	Seasonally adjusted	Northland	Auckland	Hawkes Bay	Wellington	Nelson	Christchurch
Northland	100%	99%					Northland saj	100%	86%				
Auckland	99%	100%					Auckland saj	86%	100%				
Hawkes Bay	97%	97%	100%				Hawkes Bay saj	55%	59%	100%			
Wellington	96%	97%	96%	100%			Wellington saj	42%	51%	79%	100%		
Nelson	96%	97%	98%	98%	100%		Nelson saj	37%	51%	47%	65%	100%	
Christchurch	95%	96%	97%	97%	98%	100%	Christchurch saj	31%	38%	58%	71%	68%	100%

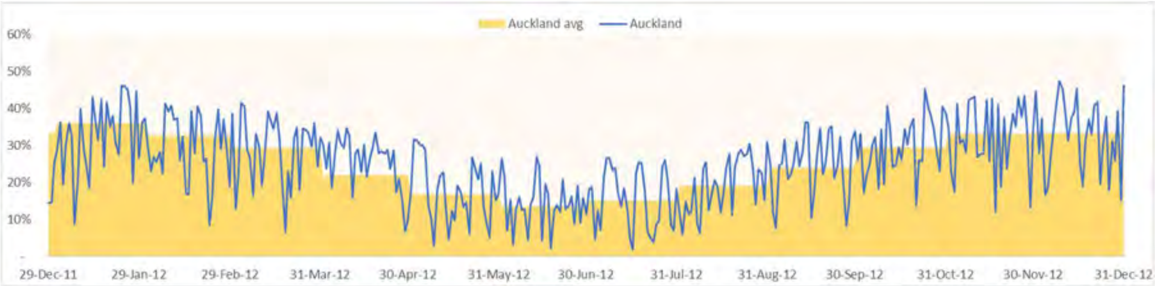
3.2.5 ILLUSTRATIVE SOLAR PROFILES

The following charts show the typical daily and hourly variations for a selected year and month of data.

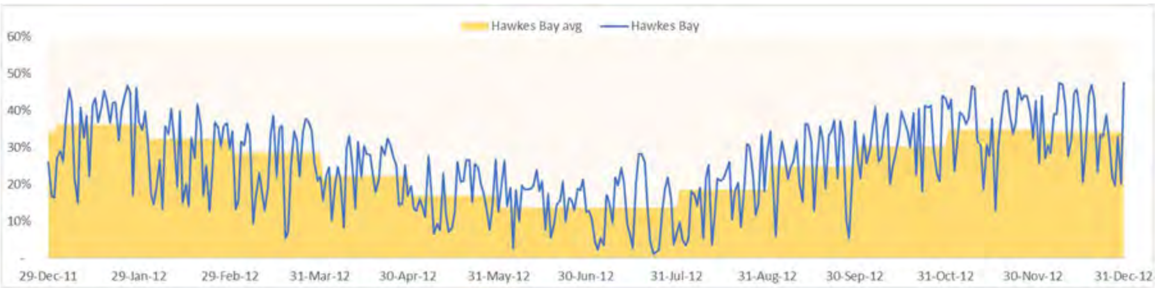
This illustrates the random daily variability due to cloud cover etc.

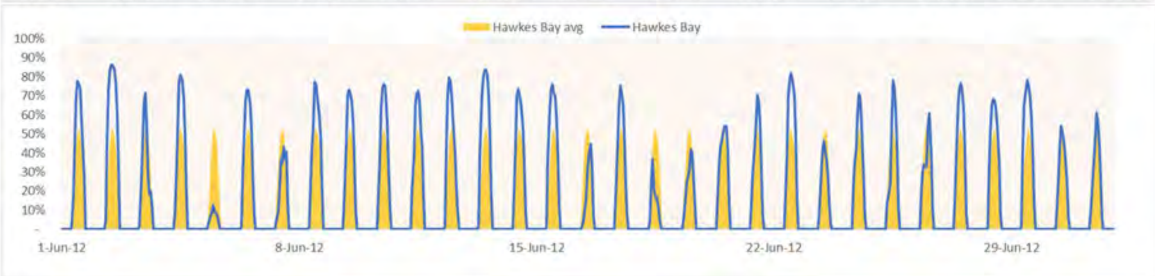

Northland avg
Northland
60%
50%
40%
30%
20%
10%
-
29-Dec-11
29-Jan-12
29-Feb-12
31-Mar-12
30-Apr-12
31-May-12
30-Jun-12
31-Jul-12
31-Aug-12
30-Sep-12
31-Oct-12
30-Nov-12
31-Dec-12


Northland avg
Northland
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
-
1-Jun-12
8-Jun-12
15-Jun-12
22-Jun-12
29-Jun-12


Auckland avg
Auckland
60%
50%
40%
30%
20%
10%
-
29-Dec-11
29-Jan-12
29-Feb-12
31-Mar-12
30-Apr-12
31-May-12
30-Jun-12
31-Jul-12
31-Aug-12
30-Sep-12
31-Oct-12
30-Nov-12
31-Dec-12


Auckland avg
Auckland
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
-
1-Jun-12
8-Jun-12
15-Jun-12
22-Jun-12
29-Jun-12


Hawkes Bay avg
Hawkes Bay
60%
50%
40%
30%
20%
10%
-
29-Dec-11
29-Jan-12
29-Feb-12
31-Mar-12
30-Apr-12
31-May-12
30-Jun-12
31-Jul-12
31-Aug-12
30-Sep-12
31-Oct-12
30-Nov-12
31-Dec-12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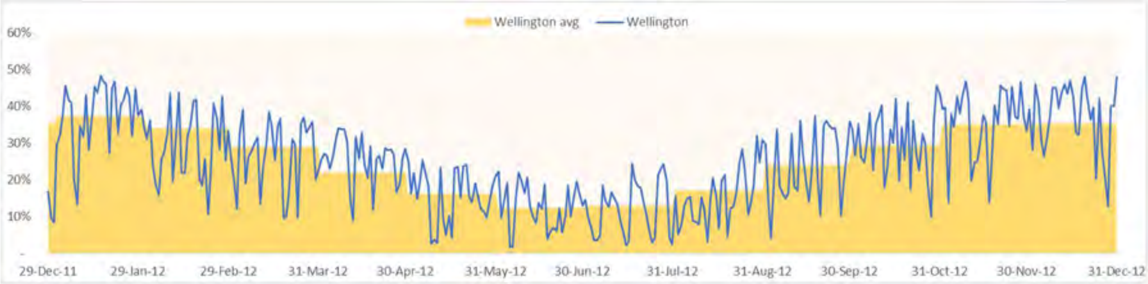
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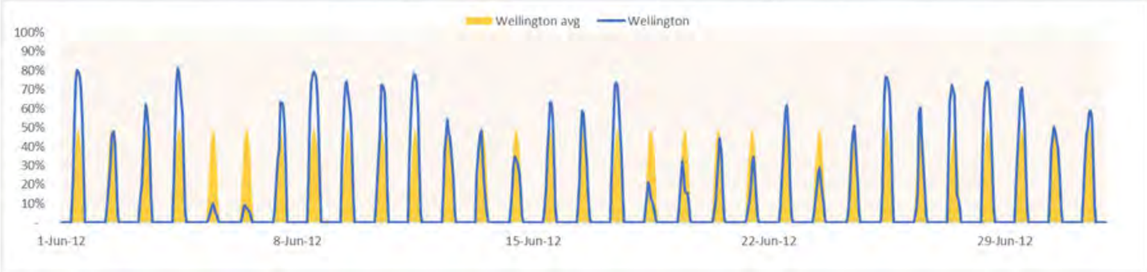
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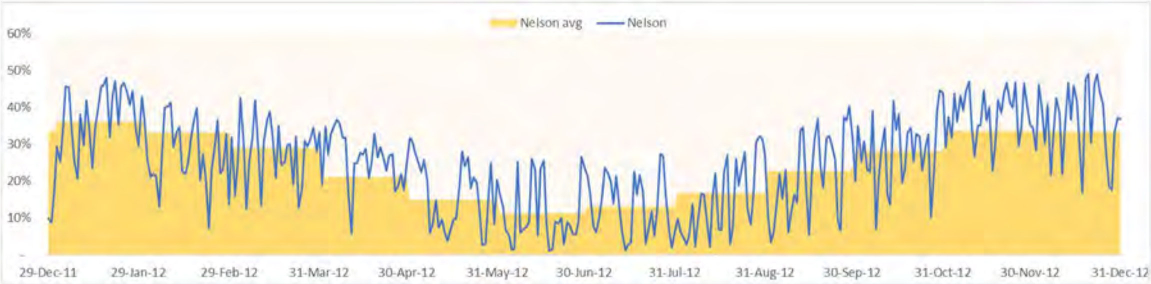
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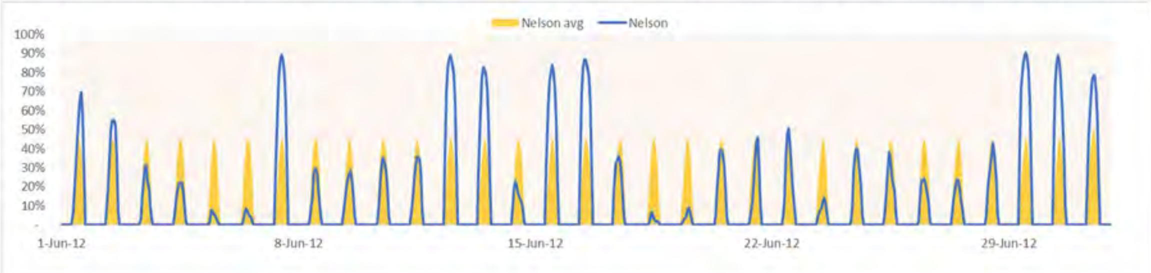
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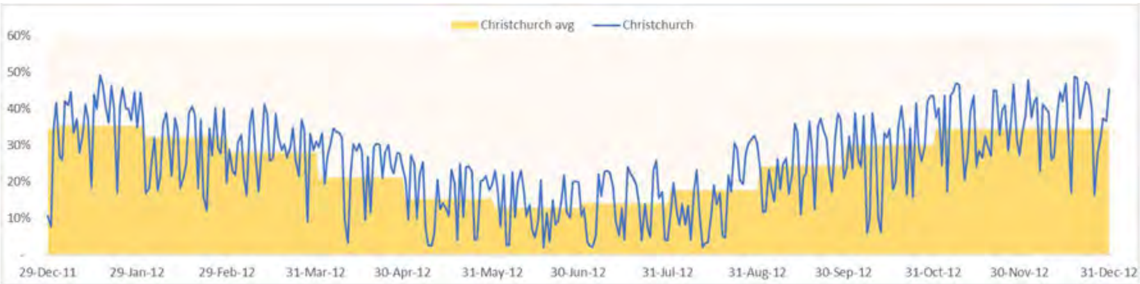
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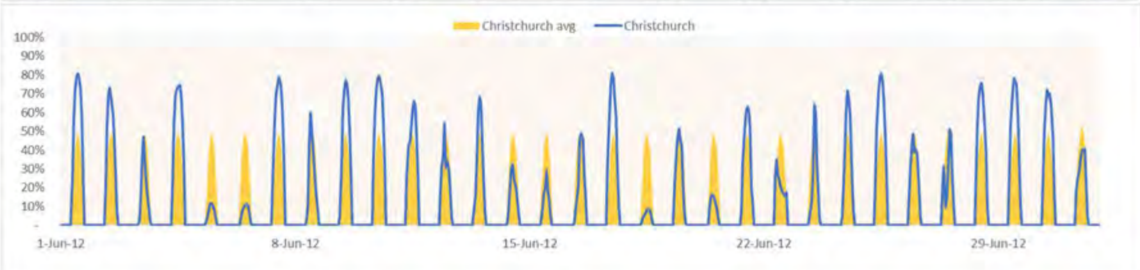
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ICCC MODELLING:

ESTIMATED SYSTEM INCREMENTAL AND MARGINAL COSTS IN 2035

FINAL REPORT

APRIL 2019

REPORT TO THE INTERIM CLIMATE CHANGE COMMITTEE

John Culy Consulting

APRIL 2019

CONTENTS

LIST OF TABLES

LIST OF FIGURES

1 INTRODUCTION

This report details the assessment of total system incremental cost and marginal system cost for the futures and sensitivities as modelled by Energy Link and described in "Electricity Market Modelling 2035" (Energy Link report), April 2019.

The system costs and system marginal costs are derived from the outputs of the Energy Link EMarket model. These include the mean annual outputs (generation, fuel use, operating costs etc) from the various wholesale generation stations averaged over 87 historical based inflow/wind/solar profiles.

Unless otherwise stated, all dollar values in this report are 2018 New Zealand dollars (real prices) exclusive of GST, and all energy prices are in $/MWh.

DISCLAIMER

The information and opinions expressed in this presentation are believed to be accurate and complete at the time of writing.

However, John Culy Consulting does not accept any liability for errors or omissions in this presentation or for any consequences of reliance on its content, conclusions or any material, correspondence of any form or discussions arising out of or associated with its preparation.

2 INPUTS AND DEFINITIONS

2.1 NEW TECHNOLOGY COSTS

The generic costs for new technologies assumed in the modelling are summarised in the following table. Note that capital costs include plant and associated construction costs, permitting, financing and development costs and a development margin. They assume that costs for wind and solar in New Zealand will be at a small premium to the much larger and more competitive Australian, USA and European markets.

TABLE 1: NEW GENERATION TECHNOLOGY COST ASSUMPTIONS

New Technology Generic Costs (Real NZ Dollars 2018)			Generic Geothermal	Generic Wind	OCGT	Generic Solar SAT
Reference Capacity Factor	CF	%	92%	44%	20%	23%
Gross Efficiency (HHV)	Eff	%			40%	-
Gross heat rate (HHV)	HR	GJ/MWh	-	-	9.0	-
Variable Operating Cost	VOM	$/MWh	-	$12	-	$2
Fuel Cost (excl Carbon) in 2035	Fuel	$/GJ	-	-	$14	-
Emission Factor	EF	g/kWh	200	-	477	-
Carbon Price in 2035	Carbon	$/t	$50	$50	$50	$50
Carbon Cost in 2035	Carbon	$/MWh	10	-	24	-
Fixed Operating & Maintenance Cost	FOM	$/kWac/yr	$120	$30	$10	$35
Capital Cost 2018	CAPEX	$/kWac	$5,000	$2,200	$1,200	$2,200
Construction time	Construction	years	2.0	1.6	1.5	1.3
Economic lifetime	Life	years	35	27	20	20
Merchant W ACC	WACC	post tax nominal	8.0%	8.0%	8.0%	8.0%
Capital Recovery Factor	CRF	%	8.4%	8.8%	9.5%	9.3%
Annual Fixed Cost Recovery 2018	**Fixed Cost**	**$/kWac/yr**	**$540**	**$224**	**$124**	**$240**
Variable Cost Component in 2035	**Variable Cost**	**$/MWh**	**$10**	**$12**	**$149**	**$2**
Merchant LCOE (with 2018 capex)	**LCOE (2018)**	**$/MWh**	**$77**	**$70**	**$220**	**$121**
Cost in 2035 relative to 2018						
Middle of Road/Central		%pa	-	-0.5%	-	-3.1%
Fast Tech		%pa	-	-0.9%	-	-4.1%
Slow Tech		%pa	-	-	-	-1.6%
LCOE Fixed Cost Component 2035						
Middle of Road/Central		$/kWac/yr	$540	$210	$124	$159
Fast Tech		$/kWac/yr	$540	$198	$124	$141
Slow Tech		$/kWac/yr	$540	$224	$124	$194
LCOE 2035 (before intermittency costs)						
Middle of Road/Central		$/MWh	$77	$66	$220	$81
Fast Tech		$/MWh	$77	$63	$220	$72
Slow Tech		$/MWh	$77	$70	$220	$99
Notes			Emission factors vary by field from 66 to 460 g/kWh . Capital costs also vary by site.	Capital cost varies by location and connection cost.	The gas cost includes a 45% premium for gas storage and flex.	Single axis tracking with 1.3x Inverter load ratio and 0.5% pa degradation rate.
Comparative Capital Costs and decline rate to 2035						
AEMO Integrated System Plan 2018	Australia (0.9 ER)	NZ $/kWac		$2,156 -0.4%pa		$2,167 -4.5%pa
Typical USA	USA (0.66 ER)	NZ $/kWac		$2,121 -1.0%pa		$2,091 -3.8%pa
NZ Productivity Commission 2018	NZ	NZ $/kWac		-0.6 to -1.8%pa		-1.25 to -3.75%pa
Tilt Waverly Oct18	NZ	NZ $/kWac		$2,500		
Mercury Turitea May19	NZ	NZ $/kWac		$2,151		

The capital recovery factor is derived from the constant real charge required to achieve an 8.0% nominal post tax weighted average return on the capital invested from the start of construction over the economic life.

This accounts for tax and typical tax depreciation rates in New Zealand. A long run 2%pa New Zealand inflation rate is assumed.

This return is indicative of that required for new merchant power plants without long term contracts and without subsidies. Where a plant has a long term (15 to 25yr) fixed price contract with a solid counterparty the required return for the plant owner might be up to 2% lower, as the wholesale merchant price risk is transferred to the buyer of the contract. Care is required when comparing LCOEs with those reported elsewhere as in many cases these use the much lower cost of capital for projects with long term contracts. They can also include subsidies available in other countries including accelerated depreciation.

Note that these costs are representative of the more detailed cost assumptions used for individual projects as described in the Energy Link modelling report section 4.1. Individual project costs can vary according to location, connection and civil costs.

The reference capacity factor is used for the purposes of deriving the LCOE[1]. However, the model calculates the expected capacity factor for each case, and this is considered when the merit order of new supply is assessed and when revenue adequacy is assessed in the detailed modelling.

2.1.1 LARGE SCALE UTILITY SOLAR

There are no recent published estimates for large scale (50 to 100MW) solar farms in New Zealand. Cost estimates used here are based on a translation from recent cost estimates in Australia and the USA to New Zealand conditions.

For the purpose of this modelling it is assumed that utility scale solar farms are built with single axis tracking and 1.3x oversized DC panel capacity relative to the AC inverter capacity. This configuration is typical of new solar farms in Australia and the USA. Its assumed that the life time average capacity factor in New Zealand is around 23% (accounting for 0.5% pa degradation) for this configuration. This can be compared with 18-19% for a fixed panel orientation without oversizing.

Capital costs and capacity factors are reported on a delivered AC basis so that they are comparable with other wholesale supply options. However, many commentators quote capital costs on a DC basis. On this basis, the assumed 2018 solar capital costs would be NZ$1,700/$kW_{dc}$ (US$1,100/$kW_{dc}$).

2.1.2 UTILITY SCALE BATTERY SYSTEMS

The costs for new battery systems assumed in the modelling are summarised in the following table.

TABLE 2: NEW UTILITY BATTERY SYSTEM COST ASSUMPTIONS

New Battery System Costs (Real NZ Dollars 2018)		Li_Battery Pack	Balance of Plant	Total Battery System
Capital Cost for 2 hr storage	$/kWh	260	560	820
Round trip efficiency		80%	80%	80%
Battery Life	yr	15	15	15
Merchant W ACC	post tax nominal	8.0%	8.0%	8.0%
Capital Recovery Factor	%	11%	11%	11%
Capital cost for 6hr storage (2018)	**$/kWh**	**260**	**187**	**447**
Cost in 2035 relative to 2018				
Middle of Road/Central	%pa	-5.0%	-2.3%	-3.7%
Fast Tech	%pa	-7.1%	-4.2%	-5.7%
Slow Tech	%pa	-3.4%	-0.8%	-2.2%
Capital Cost in 2035 6hr system				
Middle of Road/Central	$/kWh	115	129	245
Fast Tech	$/kWh	80	94	175
Slow Tech	$/kWh	148	165	314
Annual Fixed Cost in 2035 for 6hr system				
Middle of Road/Central	$/kW/yr	76	85	162
Fast Tech	$/kW/yr	53	62	115
Slow Tech	$/kW/yr	98	109	207
Notes:				
Comparative Capital Costs and decline rate to 2035				
AEMO Integrated System Plan 2018 - 2hr storage	NZ $/kWac	$256 -4.3%pa	$658 -2.0%pa	$913 -2.6%pa
Typical USA	NZ $/kWac	$303 -7.1%pa	$697 -3.9%pa	$1,000 -4.7%pa
NZ Productivity Commission 2018	NZ $/kWac	-4 to 8%pa		

2.2 DEFINITION OF INCREMENTAL SYSTEM COST

Total annual wholesale incremental system cost of running the electricity system consists of the following components:

- Capital and fixed cost
  - The sum of fixed annual fixed O&M costs and the annuitized capital cost for all new plant. Note that existing plant is assumed to be a sunk cost.
- Variable Cost (excluding carbon)
  - The sum of variable O&M and fuel costs based on the assumed natural gas base price of $9.6/GJ, with a 45% premium for flexible low capacity factor requirements making $14/GJ for gas fired peaking plant.
- Carbon Cost
  - The annual cost of carbon emissions (including geothermal) priced at $50/t.

- Demand response
  - The customer cost of energy reductions during periods of sustained high average prices (e.g. in dry years), priced at $300/MWh, plus a small amount of demand reduction in response to high hourly prices priced at $3000/kWh.
- Tiwai demand response
  - The cost of demand reduction from Tiwai when lake levels fall to critical levels, priced at $500/MWh.
- Shortage
  - The customer cost of demand not met, priced at $10,000/MWh.

In all cases the mean generation, variable cost etc are the averages over the simulated levels over the full set of 87 weather year simulations by 3hour block.

Note that the cost of behind the meter roof-top solar is not included in this measure, nor is transmission or distribution costs. Roof-top solar economics for consumers are driven by retail and buyback tariffs and customer preferences rather than wholesale prices and normal commercial return requirements.

Annual system costs can be used to estimate the cost of moving to 100% renewable, and to estimate the implied carbon abatement cost. The carbon abatement cost is derived from the increase in annual system cost divided by the reduction in annual carbon emissions.

2.3 MEASURES OF SYSTEM MARGINAL COST

As described in section 4.0 of the Energy Link report, the EMarket model dispatches offered generation and calculates spot prices for each node on the system for each 3-hour block and each of 87 historical based weather (inflow/wind/solar) years. This accounts for modelled transmission constraints, marginal transmission losses and variations in demand and weather.

These spot prices can be averaged to derive a measure of expected wholesale electricity price. They can also be used to derive an estimate of wholesale revenue for new generation to ensure that they can achieve an adequate return on capital on average.

Energy Link know from "back-casting" with EMarket against past years, and from its construction, that it models the existing market well, provided the inputs all the key parameters are included.

There are some special issues that arise when the model is applied to the future ICCC futures in the 2035 target year.

- The first issue relates to the fact that a single representative target year is being used. Every effort is made to fine tune the investment build schedule to ensure that the target year is consistent with market participants achieving an adequate return on the lowest cost new plant. However, the actual return in the modelled target year may vary depending on the exact balance of supply and demand and the plant mix.

- The second issue relates to the futures in which most or all thermal plant are closed. In the EMarket model wholesale prices are heavily influenced by water values, which are in turn influenced by historical inflows, the offer prices of remaining thermal generation, the quantities of generation expected from all other sources of generation, and demand. As 100% renewables is approached, there is less, and less plant being offered at prices in the mid-range from $12/MWh up to the price at which demand side response is offered. This means that competitive water values are not well defined over a wide range of storage levels.

To deal with this issue an alternative measure of system marginal price is used to estimate the level of wholesale prices in the different futures. This approach is based on competition in the contracts market and reflects the level of wholesale prices required to support the cost of the lowest cost new generation required in the target year.

In most of the 2035 futures the marginal wholesale supply in 2035 is geothermal, wind or solar. Geothermal is, however, limited in supply and so it not marginal in many cases. Wind and solar are intermittent and hence need to cover the costs of intermittency. These costs are described in section 4.1 in the Energy Link report. These include the GWAP/TWAP[2] ratio and the expected level of wind spill. This level is the difference between the maximum capacity factor and the capacity factor achieved on the assumption that wind offers in at $12/MWh. The estimated level of wind spill and the GWAP/TWAP ratio is a function of the amount of wind investment and the correlation of wind between different wind farms and the level of battery and thermal backup available.

For the futures in which 100% renewables is approached, and thermal peaking plant is removed or restricted, there is a significant level of investment in 6-12hr batteries to meet some of the short run variability of wind (and/or solar) where the hydro storage system is unable to (e.g. when hydro capacity limits, or where minimum generation consent requirements are reached). Some of this battery capacity will deal with demand peaks, but a significant portion can be directly attributed to the meeting the requirements of intermittent supply. As discussed in Energy Link's modelling report section 4.9.4 it is assumed that system battery costs above a minimum level are allocated to wind and solar on in proportion to their installed MW.

The last step to 100% in Energy Link model runs had a higher than normal level of demand shortage. This implies a reduction in the security standard. This might be acceptable considering the increase in the cost of back-up associated with removal of flexible gas peakers but might not be considering the increasing reliance on electricity in the economy.

In the Middle of Road future, the level of supply shortage was approximately 8x the level achieved with gas peakers retained. An examination of the simulation results indicated that the normal level of shortage could have been achieved with around 300-400MW additional wind and a more conservative operation of the batteries to ensure that the additional wind available during the previous day is saved and not dispatched until after short run demand response. This would reduce the shortage considerably but would also result in wind being dispatched off at a price of $12/MWh for an additional 5-6% of the year. Achieving the current level of supply security would imply higher wholesale prices including an allocation of all the incremental battery capacity to wind backup.

The Fast Tech High Demand future had an even higher level of shortage. As above, this might have been reduced with an additional 400-500MW of wind and more conservative battery scheduling. But would also imply higher levels of wind "spill" and a higher allocation of battery operation to wind backup in periods when shortage risk was high.

Conclusion

For the purpose of comparing futures and sensitivities the measure of system marginal cost is the firm flat contract price that would be required in 2035 for the cheapest marginal new source of supply (assumed to be wind in 2035) to cover its annualised capital and operating costs. This includes an allocation of the cost of batteries as described above and the costs of intermittency as reflected in the EMarket modelled GWAP/TWAP and the impact of wind "spill" also derived from the EMarket modelling[3]. A comparison of wind and solar GWAP/TWAP ratios derived from the modelling with other international markets is provided in section 3.4 of this report.

Beyond 2035, depending on rates of costs reductions in solar costs, it is likely that utility scale solar costs will become increasing competitive with new wind and so it is likely that a mix of solar and wind will become lowest cost combination to meet demand increases.

3 RESULTS

This section provides the key results for system incremental cost and system marginal cost for each of 3 possible futures in 2035 with varying realistic combinations of electricity demand growth and rates of technical change in electricity production and consumption technology driven by international developments.

These futures are:

- **Middle of the Road**:
    - 49.2TWh gross demand for generation including moderate demand for EVs and process heat and continuation of recent trends in efficiency of use and middle of the road economic and population growth.
    - 48.1TWh net demand from the grid allowing for 1.1TWh supply from rooftop solar.
- **Fast Tech - High demand**
    - 55.2TWh including higher demand for EVs and process heat, higher economic and population growth, partly offset by increased trends in efficiency of use.
    - 48.1TWh net demand from the grid allowing for 3.1TWh supply from rooftop solar.
- **Slow Tech - Low Demand**
    - 38.5TWh gross demand for generation including lower demand for EVs, no process heat conversions, lower economic and population growth, but also lower trends in efficiency improvements, and (most significantly) closure of a major load in the South Island (around 12% of national demand).
    - 38.0TWh net demand from grid allowing for 0.5TWh supply from rooftop solar.

The results relate to the key questions:

- The incremental and marginal costs of moving from a Business as Usual (BAU) outcome (around 91-93%) up to 100% renewable supply. For the Middle of Road and Fast Tech High Demand futures, and additional step with extra wind and more conservative battery operation is included. This provides an approximate[4] estimate of wind based marginal cost where the normal security standard is maintained.
- The marginal cost of increasing electricity supply by around 8-9 TWh to meet an ambitious target for transport and process heat electrification in the Middle of the Road and Slow Tech Low demand futures.

3.1 PATH TO 100% RENEWABLE

TABLE 3: MIDDLE OF ROAD - SYSTEM INCREMENTAL COSTS AND MARGINAL COST

		Middle of Road					
% renewables		92.6% BAU	95.9% Step1	97.9% Step2	98.6% Step3	100.0% Step4	*No change in security standard*
Estimated Rooftop Solar Capex	$b	$1.4	$1.4	$1.4	$1.4	$1.4	*$1.4*
Estimated Other Incremental Capex	$b	$7.2	$9.1	$9.6	$10.1	$13.6	*$14.3*
New generation capital recovery and FOM	$m/yr	$719	$856	$910	$951	$1,182	*$1,255*
Batteries capital recovery	$m/yr	$33	$60	$60	$60	$168	*$168*
Variable fuel and operating costs	$m/yr	$331	$250	$254	$212	$121	*$121*
Demand response cost	$m/yr	$14	$30	$36	$36	$62	*$27*
Tiwai demand response costs	$m/yr	$1	$1	$2	$2	$0	*$0*
Shortage Costs	$m/yr	$0	$5	$7	$9	$40	*$5*
Total System Costs excluding carbon	**$m/yr**	**$1,099**	**$1,203**	**$1,269**	**$1,269**	**$1,571**	***$1,575***
Carbon Costs	$m/yr	$139	$114	$98	$99	$87	*$87*
Total System Costs including carbon	**$m/yr**	**$1,238**	**$1,317**	**$1,368**	**$1,368**	**$1,658**	***$1,662***
Geothermal Emissions	mt	1.4	1.4	1.5	1.6	1.7	*1.7*
Thermal Emissions	mt	1.4	0.8	0.5	0.3	-	*-*
Total Emissions	**mt**	**2.8**	**2.3**	**2.0**	**2.0**	**1.7**	***1.7***
Marginal Carbon Abatement Cost	**$/t**				**$211**	**$1,277**	
New Wind Marginal Cost							
New Wind potential capacity factor	%	44%	44%	44%	44%	44%	*44%*
Dispatched capacity factor	%	41%	40%	40%	39%	32%	*29%*
Modelled GWAP/TWAP	%	91%	87%	84%	82%	81%	*81%*
Wind % "Spill" dispached off	%	7%	8%	9%	11%	28%	*34%*
Wind merchant LCOE	$/MWh	$66	$66	$66	$66	$66	*$66*
Full GWAP/TWAP	%	86%	82%	79%	77%	65%	*61%*
Wind Required TWAP	$/MWh	$77	$82	$84	$86	$102	*$108*
Battery costs allocated to wind	$/kW/yr	$4	$12	$11	$11	$31	*$42*
Wind required TWAP inc battery cost	**$/MWh**	**$78**	**$85**	**$87**	**$89**	**$113**	***$125***
% of BAU	%	100%	108%	111%	114%	144%	*159%*
Large Solar GWAP/TWAP	%	88%	88%	88%	83%	67%	
Solar merchant LCOE	$/MWh	$79	$79	$79	$79	$79	
Solar Required TWAP	$/MWh	$90	$90	$90	$95	$117	
Solar required TWAP inc 100% battery cost	$/MWh	$92	$95	$95	$101	$132	
Battery Capacity	MW	200	350	350	350	850	850
Battery Storage	hrs	6.0	6.9	6.9	6.9	9.0	9.0
Total Capacity	GW	11.5	11.8	11.8	11.9	12.7	
Total Generation (inc rooftop solar)	TWh	49.2	49.2	49.3	49.3	49.2	
Net Generation (excl rooftop solar)	TWh	48.1	48.1	48.2	48.2	48.1	
Wind generation share	% gen	15%	18%	19%	19%	19%	
Solar generation share	% gen	2%	2%	2%	2%	4%	
Wind capacity share	% MW	19%	23%	24%	24%	28%	
Solar capacity share	% MW	8%	8%	8%	8%	11%	

The Middle of Road BAU achieves around 93% renewables through closure of Huntly and TCC and replacement with new rooftop solar, geothermal, wind, gas peakers and batteries. Wind increases 3x from around 5% to 15% of generation. The marginal cost of achieving 98% renewables is 10% higher than BAU but achieving 100% renewables increases the marginal cost by over 40%. This is mainly a result of increased wind intermittency costs and substantially higher wind spill caused by removal of the flexible gas fired backup peakers.

TABLE 4: FAST TECH HIGH DEMAND - SYSTEM INCREMENTAL AND MARGINAL COST

		Fast Tech High demand			
% renewables		93.2% BAU	97.8% Step1	100.0% Step2	*No change in security standard*
Estimated Rooftop Solar Capex	$b	$2.7	$2.7	$2.7	*$2.7*
Estimated Other Incremental Capex	$b	$10.0	$12.1	$16.5	*$17.2*
New generation capital recovery and FOM	$m/yr	$986	$1,168	$1,474	*$1,553*
Batteries capital recovery	$m/yr	$43	$43	$169	*$169*
Variable fuel and operating costs	$m/yr	$393	$315	$145	*$145*
Demand response cost	$m/yr	$32	$45	$111	*$76*
Tiwai demand response costs	$m/yr	$2	$2	$0	*$0*
Shortage Costs	$m/yr	$9	$16	$75	*$40*
Total System Costs excluding carbon	**$m/yr**	**$1,466**	**$1,589**	**$1,973**	***$1,982***
Carbon Costs	$m/yr	$162	$116	$101	*$101*
Total System Costs including carbon	**$m/yr**	**$1,628**	**$1,704**	**$2,074**	***$2,083***
Geothermal Emissions	mt	1.7	1.7	2.0	*2.0*
Thermal Emissions	mt	1.5	0.6	-	*-*
Total Emissions	**mt**	**3.2**	**2.3**	**2.0**	***2.0***
Marginal Carbon Abatement Cost	**$/t**		**$132**	**$1,335**	
New Wind Marginal Cost					
New Wind potential capacity factor	%	44%	44%	44%	*44%*
Dispatched capacity factor	%	41%	40%	30%	*28%*
Modelled GWAP/TWAP	%	85%	81%	74%	*74%*
Wind % "Spill" dispached off	%	7%	10%	31%	*37%*
Wind merchant LCOE	$/MWh	$63	$63	$63	*$63*
Full GWAP/TWAP	%	80%	76%	57%	*53%*
Wind Required TWAP	$/MWh	$79	$83	$110	*$118*
Battery costs allocated to wind	$/kW/yr	$4	$4	$20	*$32*
Wind required TWAP inc battery cost	**$/MWh**	**$80**	**$84**	**$118**	***$132***
% of BAU	%	100%	105%	147%	*168%*
Large Solar GWAP/TWAP	%	71%	68%	55%	
Solar merchant LCOE	$/MWh	$67	$67	$67	
Solar Required TWAP	$/MWh	$95	$99	$123	
Solar required TWAP inc 100% battery cost	$/MWh	$97	$100	$133	
Battery Capacity	MW	350	350	1,100	1,100
Battery Storage	hrs	6.9	6.9	10.4	10.4
Total Capacity	GW	14.6	15.1	15.8	
Total Generation (inc rooftop solar)	TWh	55.2	55.2	55.0	
Net Generation (excl rooftop solar)	TWh	52.1	52.0	51.9	
		3.1			
Wind generation share	% gen	19%	22%	20%	
Solar generation share	% gen	6%	7%	8%	
Wind capacity share	% MW	21%	24%	29%	
Solar capacity share	% MW	18%	19%	20%	

The Fast Tech High demand BAU achieves around 93% renewables through closure of Huntly and TCC and replacement with new geothermal, wind, gas peakers and batteries. Wind increases 4x from around 5% to 19% of generation. The BAU system marginal cost is around $80/MWh. This is slightly higher than the Middle of Road as the increased intermittency costs of marginal wind more than offsets the reductions in wind cost from faster technology improvements. The increased marginal cost of reaching 98% renewables is 5% but reaching 100% renewable increases marginal costs another 42%.

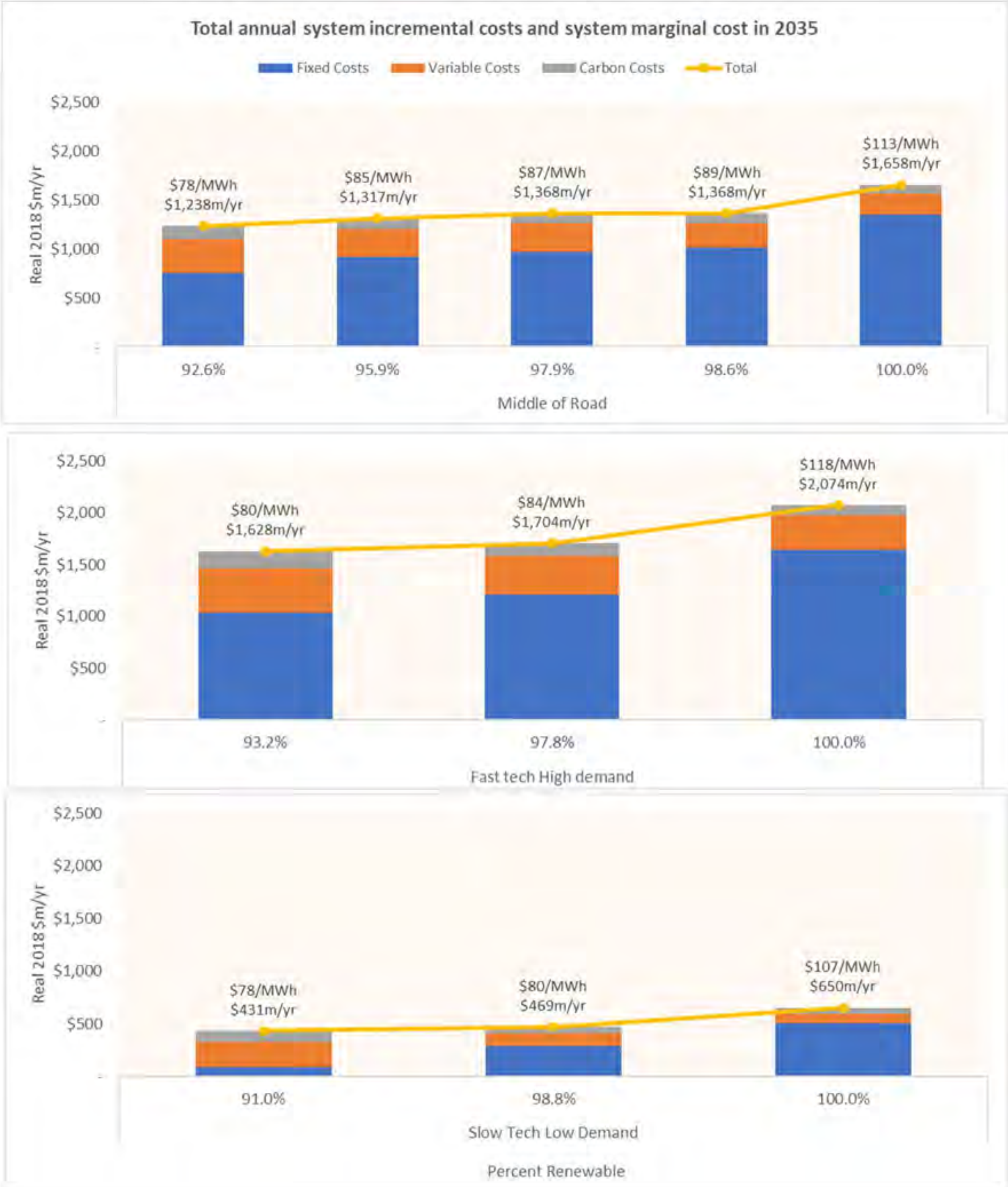
TABLE 5: SLOW TECH LOW DEMAND - SYSTEM INCREMENTAL AND MARGINAL COSTS

		Slow Tech Low Demand		
% renewables		91.0%	98.8%	100.0%
		BAU	Step 1	Step2
Estimated Rooftop Solar Capex	$b	$0.7	$0.7	$0.7
Estimated Other Incremental Capex	$b	$0.5	$2.6	$4.7
New generation capital recovery and FOM	$m/yr	$62	$268	$398
Batteries capital recovery	$m/yr	$21	$21	$102
Variable fuel and operating costs	$m/yr	$237	$105	$42
Demand response cost	$m/yr	$6	$13	$41
Tiwai demand response costs	$m/yr	-	-	-
Shortage Costs	$m/yr	$0	$1	$7
Total System Costs excluding carbon	**$m/yr**	**$325**	**$409**	**$590**
Carbon Costs	$m/yr	$106	$60	$60
Total System Costs including carbon	**$m/yr**	**$431**	**$469**	**$650**
Geothermal Emissions	mt	0.8	1.0	1.2
Thermal Emissions	mt	1.3	0.2	-
Total Emissions	**mt**	**2.1**	**1.2**	**1.2**
Marginal Carbon Abatement Cost	**$/t**		**$91**	**$27,846**
New Wind Marginal Cost				
New Wind potential capacity factor	%	44%	44%	44%
Dispatched capacity factor	%	41%	38%	34%
Modelled GWAP/TWAP	%	97%	101%	98%
Wind % "Spill" dispached off	%	8%	14%	23%
Wind merchant LCOE	$/MWh	$71	$71	$71
Full GWAP/TWAP	%	91%	89%	79%
Wind Required TWAP	$/MWh	$78	$80	$90
Battery costs allocated to wind	$/kW/yr	$1	$0	$51
Wind required TWAP inc battery cost	**$/MWh**	**$78**	**$80**	**$107**
% of BAU	%	100%	102%	137%
Large Solar GWAP/TWAP	%	94%	94%	94%
Solar merchant LCOE	$/MWh	$92	$92	$92
Solar Required TWAP	$/MWh	$97	$97	$97
Solar required TWAP inc 100% battery cost	$/MWh	$98	$98	$122
Battery Capacity	MW	100	100	400
Battery Storage	hrs	6.0	6.0	9.0
Total Capacity	GW	8.5	8.6	8.6
Total Generation (inc rooftop solar)	TWh	38.5	38.5	38.3
Net Generation (excl rooftop solar)	TWh	38.0	37.9	37.8
Wind generation share	% gen	6%	9%	9%
Solar generation share	% gen	1%	1%	1%
Wind capacity share	% MW	9%	13%	15%
Solar capacity share	% MW	5%	5%	5%

The Slow Tech Low demand BAU achieves around 91% renewables through closure of Huntly and TCC. But much less investment in geothermal, wind, gas peakers and batteries is required as demand is around 10TWh lower. Wind increases only slightly from around 5% to 6% of generation. The BAU system marginal cost is around $78/MWh. This is the same as the Middle of Road as the reduced intermittency costs of marginal wind fully offsets the reductions in wind cost from faster technology improvements. The increased marginal cost of reaching 98% renewables is only 2% as this can be achieved with only a small increase in intermittency costs but reaching 100% renewable increases marginal costs by almost 40%.

3.1.1 System incremental Costs

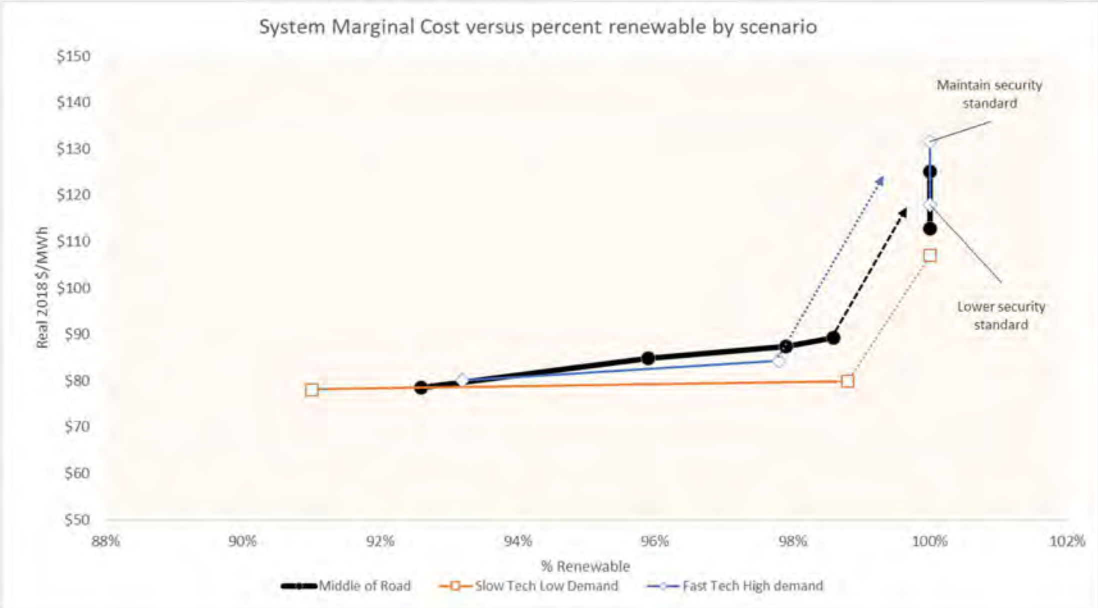
Figure 1 : System Incremental and marginal Costs by Futures



System incremental costs are much lower for the Slow Tech Low Demand future. This mainly driven by the fact that underlying demand is much lower than the other futures as a result of the closure of a major load in the South Island (the Tiwai aluminium smelter). This means that the level of new investment to replace closure of Huntly and TCC is much lower than in the other futures.

3.1.2 SYSTEM MARGINAL COSTS

FIGURE 2: SYSTEM MARGINAL COST BY PCT RENEWABLE



As shown in the chart the BAU system marginal new wind cost is very similar in the 3 realistic futures with different levels of electricity demand and rates of technical change. This is because the lower demand can be supplied with lower levels of new wind supply and the resulting lower levels of wind penetration result in lower wind intermittency costs, which offsets the relatively higher wind technology costs.

In all the alternative futures there is a very significant increase in the marginal cost to go from around 98% to 100% renewables. This ranges between an increase of 30% to over 50% and is caused by the very significant increase in wind "spill" when the flexible backup peakers are retired and replaced with overbuild of wind, solar and batteries.

The steepness of the increase in the system marginal cost to achieve up to 98% renewables depends on the level of levels of intermittent renewables on the system and extent to which the supply curve of new geothermal and wind options is being utilised. The Slow Tech Low Demand future has low levels of new investment and so intermittency costs are low, and the supply curve of options is very flat. The Middle of Road future is steeper as more of the supply curve of options is required and the level of intermittent supply is greater. The Fast Tech High Demand future has greater intermittent supply, but the supply curve has more competitive options as technology improvements have reduced costs.

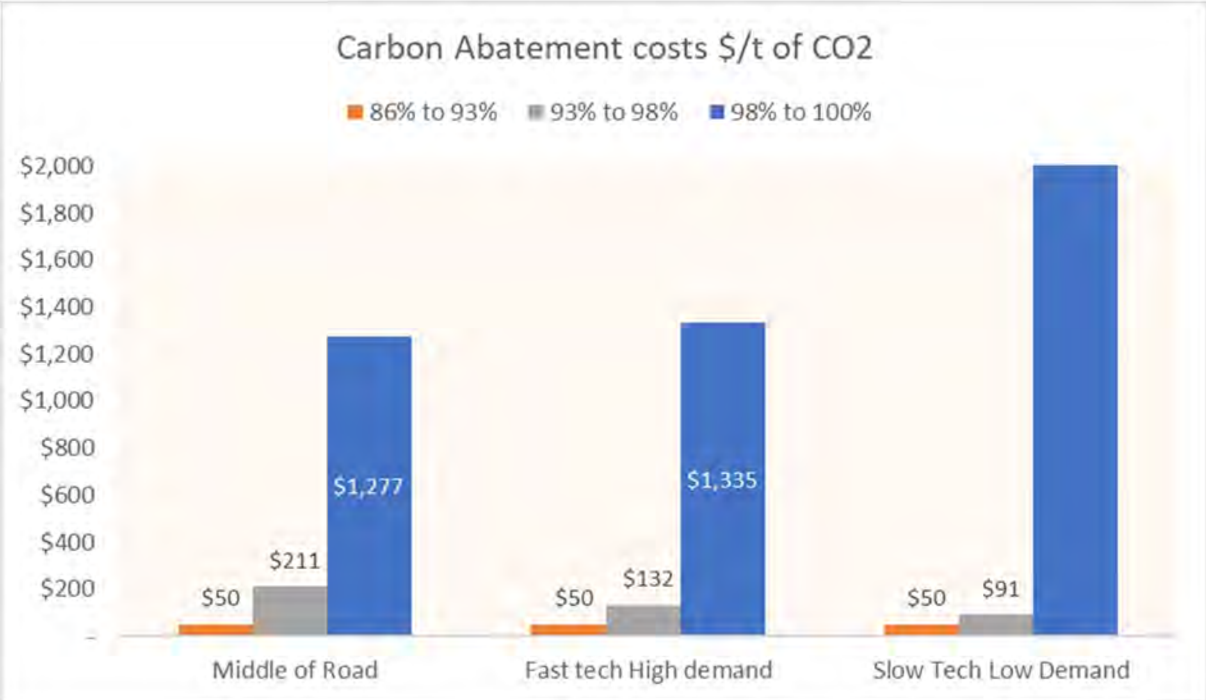
3.1.3 CARBON EMISSION ABATEMENT COSTS

It is possible to derive an estimate of the marginal emission abatement costs that would be implied by different % renewable targets.

This is given by the change in annual system operating costs (in $m/y) excluding the cost of carbon divided by the reduction in Emissions (in mt/yr).

The chart below shows the carbon abatement costs implied from the electricity sector modelling for the path from the BAU to 100% renewables.

FIGURE 3: CARBON ABATEMENT COSTS BY % RENEWABLE BY FUTURE



The carbon abatement measure for the first step to around 93% is not calculated from the modelling runs. It is the carbon price assumed in the Business as Usual plant and is a factor influencing the BAU thermal plant retirement and new investments as well as the operating merit order in the 2035 simulations.

The carbon abatement costs implied by a move to around 98% renewables is of the order of $100 to $200/tonne. This is of the order of abatement costs in other sectors and is probably achievable through a carbon price signal alone.

Pushing from 98% to 100% implies carbon abatement costs above $1000/tonne. This is significantly higher than carbon abatement costs in other sectors and indicates that the most efficient outcome would be promoted by focusing on carbon abatement in other sectors first.

Note that the calculated carbon abatement costs for the Slow Tech Low Demand future for the step from 98% to 100% is off the scale. This is because the new investment to replace the natural gas fired peaking plant is predominantly geothermal (given the assumed carbon price of $50/t and the merit order of new investment options available in 2035) and so the emissions savings from removing the gas fired peakers is almost fully offset by the increased geothermal emissions and so the net emissions savings is almost zero. This illustrates a perverse outcome where reliance of on a policy driving to 100% renewable generation in conjunction with a separate carbon price signal, potentially results in considerable cost being incurred without any benefit in terms of net emissions saving. A policy approach which encouraged reductions in emissions directly would be much less costly and more reliable.

3.2 ELECTRIFICATION

TABLE 6: ELECTRIFICATION FUTURES – SYSTEM INCREMENTAL AND MARGINAL COSTS

		Middle of Road Sensitivities		Slow Tech Low Demand	
		BAU	Electrification	BAU	Electrification
Estimated Rooftop Solar Capex	$b	$1.4	$1.4	$0.7	$0.7
Estimated Other Incremental Capex	$b	$7.2	$13.4	$0.5	$6.8
New generation capital recovery and FOM	$m/yr	$719	$1,255	$62	$672
Batteries capital recovery	$m/yr	$33	$85	$21	$77
Variable fuel and operating costs	$m/yr	$331	$531	$237	$342
Demand response cost	$m/yr	$14	$24	$6	$19
Tiwai demand response costs	$m/yr	$1	$3	-	-
Shortage Costs	$m/yr	$0	$6	$0	$2
Total System Costs excluding carbon	**$m/yr**	**$1,099**	**$1,905**	**$325**	**$1,111**
Carbon Costs	$m/yr	$139	$178	$106	$160
Total System Costs including carbon	**$m/yr**	**$1,238**	**$2,083**	**$431**	**$1,271**
Geothermal Emissions	mt	1.4	1.6	0.8	1.6
Thermal Emissions	mt	1.4	1.9	1.3	1.6
Total Emissions	**mt**	**2.8**	**3.6**	**2.1**	**3.2**
New Wind Marginal Cost					
New Wind potential capacity factor	%	44%	44%	44%	44%
Dispatched capacity factor	%	41%	41%	41%	41%
Modelled GWAP/TWAP	%	91%	87%	97%	96%
Wind % "Spill" dispached off	%	7%	6%	8%	6%
-	-	-		-	
Wind merchant LCOE	$/MWh	$66	$66	$71	$71
Full GWAP/TWAP	%	86%	82%	91%	91%
Wind Required TWAP	$/MWh	$77	$81	$78	$79
Battery costs allocated to wind	$/kW/yr	$4	$15	$1	$30
Wind required TWAP inc battery cost	**$/MWh**	**$78**	**$85**	**$78**	**$87**
	%				
-	-	-		-	
Large Solar GWAP/TWAP	%	88%	90%	94%	94%
Solar merchant LCOE	$/MWh	$79	$79	$92	$92
Solar Required TWAP	$/MWh	$90	$88	$97	$97
Solar required TWAP inc 100% battery cost	$/MWh	$92	$95	$98	$112
Battery Capacity	MW	200	500	100	350
Battery Storage	hrs	6.0	6.6	6.0	6.9
Total Capacity	GW	11.5	14.2	8.5	10.6
Total Generation (inc rooftop solar)	TWh	49.2	57.2	38.5	47.8
Net Generation (excl rooftop solar)	TWh	48.1	56.1	38.0	47.3
-	-				
Wind generation share	% gen	15%	19%	6%	11%
Solar generation share	% gen	2%	3%	1%	1%
Wind capacity share	% MW	19%	23%	9%	15%
Solar capacity share	% MW	8%	9%	5%	4%

Meeting ambitious targets for EVs and process heat conversions would require an additional 8TWh in the Middle of Road future and 9.3TWh in the Slow Tech Low demand future. In both cases this implies an increase of around 9% to 11% in the marginal system costs. This is primarily driven by increased intermittency costs arising from a rise is the % of wind/solar on the system and from the increased costs from accessing less attractive new options in the supply curve. These cost increases are not excessive and may be offset by trends for technology costs for solar/batteries/wind becoming cheaper over time.

3.3 MARKET MODELLING SENSITIVITIES

In addition to uncertainty around the key dimensions of electricity demand and rate of technical change and the level of ambition in electrification in Transport and process heat, there are other uncertainties.

These have been explored through 3 sensitivities on the Middle of Road future including:

- A trebling of the carbon price from $50/t to $150/t.
- A doubling of the baseload cost of natural gas to $19/GJ.
- Restrictions that might arise from tightening of resource consents for existing hydro plant affecting the output and flexibility of hydro supply. See section 3.5 of the Energy Link report for details.

In addition, 2 sensitivities on the Middle of Road future with accelerated electrification has been explored.

- A trebling of the carbon price from $50/t to $150/t.
- Including the impact of a peakier charging pattern for Electric Vehicles. See section 3.5 of the Energy Link Modelling report for details.

TABLE 7: MIDDLE OF ROAD SENSITIVITIES- SYSTEM INCREMENTAL AND MARGINAL COSTS

		Middle of Road Sensitivities			
		BAU	$150/t CO2	$19/GJ gas	Restricted Hydro
Percent renewables		92.6%	96.5%	97.1%	92.5%
Estimated Rooftop Solar Capex	$b	$1.4	$1.4	$1.4	$1.4
Estimated Other Incremental Capex	$b	$7.2	$9.7	$9.6	$7.3
New generation capital recovery and FOM	$m/yr	$719	$907	$948	$719
Batteries capital recovery	$m/yr	$33	$40	$40	$40
Variable fuel and operating costs	$m/yr	$331	$223	$206	$339
Demand response cost	$m/yr	$14	$36	$39	$14
Tiwai demand response costs	$m/yr	$1	$4	$2	$2
Shortage Costs	$m/yr	$0	$4	$4	$0
Total System Costs excluding carbon	**$m/yr**	**$1,099**	**$1,216**	**$1,239**	**$1,116**
Carbon Costs	$m/yr	$139	$264	$116	$141
Total System Costs including carbon	**$m/yr**	**$1,238**	**$1,480**	**$1,355**	**$1,257**
Geothermal Emissions	mt	1.4	1.1	1.8	1.4
Thermal Emissions	mt	1.4	0.7	0.6	1.5
Total Emissions	**mt**	**2.8**	**1.8**	**2.3**	**2.8**
Increase in Emissions	mt		(1.0)	(0.5)	0.0
New Wind Marginal Cost					
New Wind potential capacity factor	%	44%	44%	44%	44%
Dispatched capacity factor	%	41%	39%	39%	41%
Modelled GWAP/TWAP	%	91%	84%	88%	92%
Wind % "Spill" dispached off	%	7%	11%	12%	7%
-	-	-			
Wind merchant LCOE	$/MWh	$66	$66	$66	$66
Full GWAP/TWAP	%	86%	77%	79%	86%
Wind Required TWAP	$/MWh	$77	$86	$84	$77
Battery costs allocated to wind	$/kW/yr	$4	$5	$6	$7
Wind required TWAP inc battery cost	**$/MWh**	**$78**	**$88**	**$85**	**$79**
	%	100%	112%	109%	101%
-	-	-			
Large Solar GWAP/TWAP	%	88%	88%	88%	88%
Solar merchant LCOE	$/MWh	$79	$79	$79	$79
Solar Required TWAP	$/MWh	$90	$90	$90	$90
Solar required TWAP inc 100% battery cost	$/MWh	$92	$92	$93	$93
Battery Capacity	MW	200	250	250	250
Battery Storage	hrs	6.0	6.0	6.0	6.0
Total Capacity	GW	11.5	12.2	11.7	11.6
Total Generation (inc rooftop solar)	TWh	49.2	49.3	49.3	49.2
Net Generation (excl rooftop solar)	TWh	48.1	48.2	48.2	48.1
-	-				
Wind generation share	% gen	15%	21%	16%	15%
Solar generation share	% gen	2%	2%	2%	2%
Wind capacity share	% MW	19%	26%	22%	19%
Solar capacity share	% MW	8%	8%	8%	8%

The key insights from these sensitivities are:

- A trebling of the carbon price is likely to result in the Business as usual % renewables to 97% - mainly driven by the economic closure of the last remaining CCGT plant (E3P).

    - In this case the high carbon price also results the economic switch from new geothermal to wind.
    - The impact of this is to increase the % wind on the system from 15% to 21%. This increases wind spill and wind intermittency costs so that marginal system costs rise 10% or $10/MWh from $78/MWh to $88/MWh.
    - Note that this is a much lower impact than might be expected from the increase in fuel costs due to a $100/t rise in carbon costs (+$40 to $60/MWh).
    - Note also that this case has a significant reduction in emissions of 1 mt/yr from lower geothermal emissions and lower thermal emissions.
- A doubling of the natural gas price to $19/GJ is likely to result in increase in the % renewable to 97%, driven by closure of E3P.
    - However, in this case there is only a 0.5mt reduction in emissions since there is no switching between new wind and new geothermal.
    - The increase in system marginal costs is around 9% in this case, as the there is only a modest increase in wind penetration and wind intermittency costs (since geothermal has not been switched down the merit order).
    - The increase in system marginal costs is much lower than would be expected from the increase in fuel costs (+9.5/GJ = +$70-$85/MWh). The marginal cost of new wind is capping the potential wholesale price rise.
- A more restricted supply from existing hydro in terms of generation and flexibility does not have a significant impact on new investment in 2035, but:
    - Increases system incremental costs by around $19m/yr and reduces the % renewable.
    - It also increases the intermittency costs of wind as reductions in hydro flexibility impact the ability of the hydro system to absorb wind volume fluctuations.
    - The impact of this is to increase system marginal costs by around $1-2/MWh.

TABLE 8: ELECTRIFICATION SENSITIVITIES – SYSTEM INCREMENTAL AND MARGINAL COSTS

		Middle of Road	Electrification Sensitivities	
Percent renewables		Electrification 91.7%	$150/t CO2 96.6%	EV peakier 91.6%
Estimated Rooftop Solar Capex	$b	$1.4	$1.4	$1.4
Estimated Other Incremental Capex	$b	$13.4	$16.4	$13.4
New generation capital recovery and FOM	$m/yr	$1,255	$1,505	$1,255
Batteries capital recovery	$m/yr	$85	$85	$85
Variable fuel and operating costs	$m/yr	$531	$315	$536
Demand response cost	$m/yr	$24	$39	$31
Tiwai demand response costs	$m/yr	$3	$7	$3
Shortage Costs	$m/yr	$6	$16	$10
Total System Costs excluding carbon	**$m/yr**	**$1,905**	**$1,967**	**$1,919**
Carbon Costs	$m/yr	$178	$346	$179
Total System Costs including carbon	**$m/yr**	**$2,083**	**$2,313**	**$2,098**
Geothermal Emissions	mt	1.6	1.5	1.6
Thermal Emissions	mt	1.9	0.8	2.0
Total Emissions	**mt**	**3.6**	**2.3**	**3.6**
Increase in Emissions	mt		(1.3)	0.0
New Wind Marginal Cost				
New Wind potential capacity factor	%	44%	44%	44%
Dispatched capacity factor	%	41%	39%	41%
Modelled GWAP/TWAP	%	87%	81%	85%
Wind % "Spill" dispached off	%	6%	12%	6%
-	-			
Wind merchant LCOE	$/MWh	$66	$66	$66
Full GWAP/TWAP	%	82%	73%	80%
Wind Required TWAP	$/MWh	$81	$91	$83
Battery costs allocated to wind	$/kW/yr	$15	$12	$15
Wind required TWAP inc battery cost	**$/MWh**	**$85**	**$94**	**$87**
	%		110%	102%
-	-			
Large Solar GWAP/TWAP	%	90%	85%	87%
Solar merchant LCOE	$/MWh	$79	$79	$79
Solar Required TWAP	$/MWh	$88	$94	$91
Solar required TWAP inc 100% battery cost	$/MWh	$95	$99	$98
Battery Capacity	MW	500	500	500
Battery Storage	hrs	6.6	8.2	6.6
Total Capacity	GW	14.2	15.0	14.2
Total Generation (inc rooftop solar)	TWh	57.2	57.1	57.2
Net Generation (excl rooftop solar)	TWh	56.1	56.0	56.1
-	-			
Wind generation share	% gen	19%	24%	19%
Solar generation share	% gen	3%	4%	3%
Wind capacity share	% MW	23%	29%	23%
Solar capacity share	% MW	9%	9%	9%

The key insights from these sensitivities on the electrification future are:

- A trebling of the carbon price is likely to result in the Business as usual % renewables to 97% - mainly driven by the economic closure of the last remaining CCGT plant (E3P).

    - In this case the high carbon price also results the economic switch from new geothermal to wind in the investment merit order, although given the higher demand almost all the new geothermal is required and so the impact is not great.
    - The impact of this is to increase the % wind on the system from 19% to 24%. This increases wind spill and wind intermittency costs so that marginal system costs rise 10% or $10/MWh from $85/MWh to $94/MWh.
    - Note that this is a much lower impact than might be expected from the increase in fuel costs due to a $100/t rise in carbon costs (+$40 to $60/MWh).
    - Note also that this case has a significant reduction in emissions of 1.3 mt/yr from lower geothermal emissions and lower thermal emissions.
- A peakier demand as a result of EV charging patterns not being optimised is not particularly great on wholesale supply:
    - System costs are around $16m/yr greater.
    - The intermittency costs of wind are higher, and system marginal costs are around 2% higher.
    - Note that this model only accounts for the impact on the wholesale market, and the greatest costs of peakier demand will arise in the transmission and distribution systems which have not been modelled here.

3.4 GWAP/TWAP AND RENEWABLE PENETRATION

As described in section 2.3 a key factor determining the system marginal cost is the modelled intermittency costs are derived from GWAP/TWAP ratios and the estimate levels of "spill". It is possible to adjust the modelled GWAP/TWAP to derive a Full GWAP/TWAP to account for the additional impact of wind "spill" when prices are lower the marginal wind operating costs. This enables a comparison of the modelling results with historical observed GWAP/TWAP ratios.

The charts below show the Full GWAP/TWAP ratios estimated from the Energy Link modelling as a function of the level od wind and solar penetration (represented by the % of total generation). The charts also include observed annual GWAP/TWAP ratios for New Zealand and several international markets (Australia, USA and Europe) with similar spot market pricing arrangements as New Zealand. Australia, Texas, Germany and New Zealand have energy-only markets. The international comparison is limited to those markets were data is available on an hourly basis to enable the ratio to be calculated. Some markets with high levels of wind and solar are excluded where the regions are small and have large interconnections neighbouring systems (eg Denmark, Belgium). The three eastern regions and Tasmania of the Australian market are included separately. These are interconnected but are included to illustrate the impact of the significant increases in wind generation over the last 10 years. Note that South Australia has very high levels of wind penetration, but this is the result of it being a small region with large interconnection into Victoria. The New Zealand data is based on data from 2006 and is averaged over all the wind farms on the system.

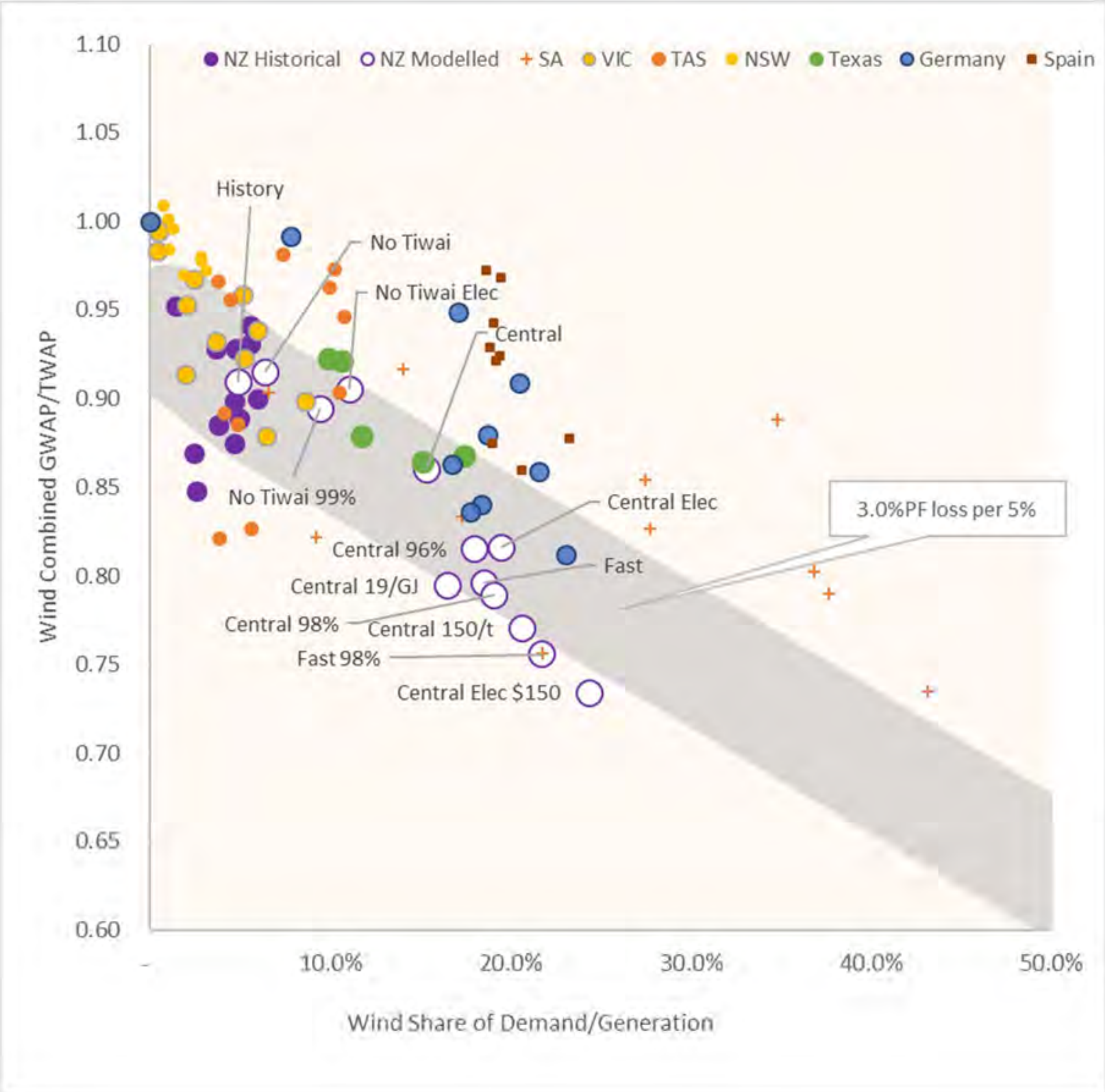


FIGURE 4: WIND GWAP/TWAP VERSUS % WIND GENERATION

There is a significant variation in these historical measures due to annual fluctuations in hydro generation, the supply and demand balance, wind patterns and fuel pricing. However, there is a clear downward trend that can be observed. This is broadly consistent with the trend observed from the EMarket modelling results. As a rule of thumb the wind GWAP/TWAP can be expected to fall 3% for each 5% increase in wind penetration.

The slope of the curve will be influenced by the cost of backup supply and the extent of constraints on the system. Reductions in the cost of batteries and increased demand side flexibility may reduce rate of fall. Also increased costs of backup arising from a ban on gas fired backup peaking capacity, will increase the rate of fall[5].

The solar share of generation is calculated to include both utility scale solar and rooftop solar, as both forms of intermittent supply are highly correlated. Data is more limited for solar, however there are several markets where the solar penetration is now very high, and data is available for a wide range of penetration levels.

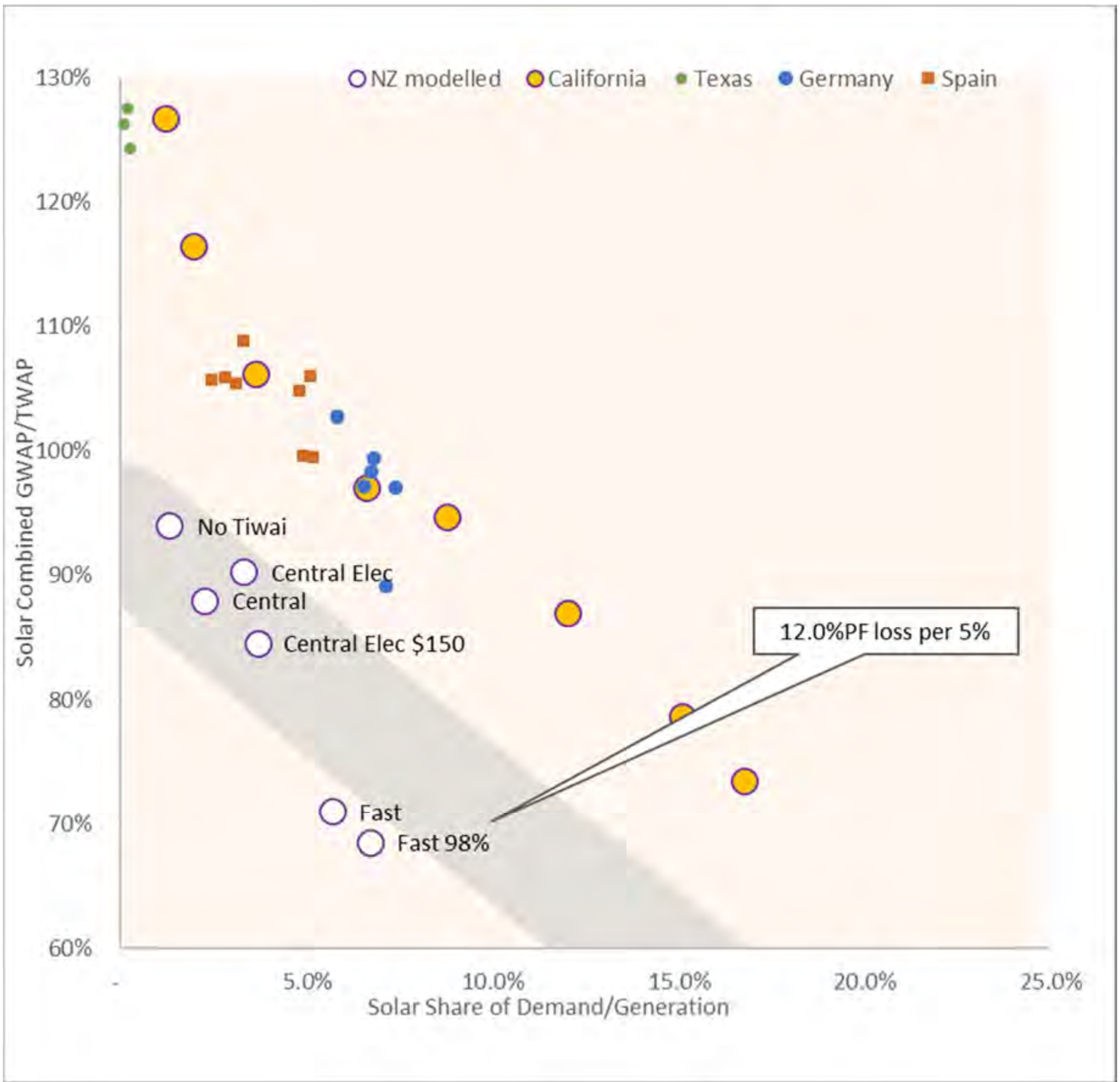


FIGURE 5: SOLAR GWAP/TWAP VERSUS %SOLAR GENERATION

California has the best set of data with solar penetration increasing from 2% to around 18% as a result of state policies and sharply lowering costs for solar. California and Texas are summer peaking systems, and so they originally had a solar GWAP/TWAP which was significantly greater than 100%. This is because solar generation was highly correlated with high summer daytime load/prices.

However, the GWAP/TWAP rapidly fell as the amount of solar generation increased and the residual demand peaks in summer moved from the middle of the day out to when the sun when down. This downward trend is observed in the other international markets.

New Zealand has a winter evening peaking system and so even at very low levels of solar penetration (below 1%), the value of solar is much lower than that observed in summer peaking systems. The EMarket modelling results are shown on the chart. These start from a lower initial level and fall at a similar rate to than observed in California, Germany and Spain. As a rule of thumb the solar GWAP/TWAP can be expected to fall 12% for each 5% increase in solar penetration. The slope is greater than for wind since the capacity factor of solar is lower and the correlation between solar supply is high.

As with wind, the slope of the curve will be influenced by the cost of backup supply and the extent of constraints on the system. Reductions in the cost of batteries and increased demand side flexibility may reduce rate of fall.

3.5 PRICE DURATION CURVES

The chart below illustrates the price duration curves for the range of futures modelled. These are based on the simulated Haywards spot prices for 3-hour blocks including the variation over 87 weather years.

Note the prices at the lower end are often set by the assumed variable cost of wind generation. At this price and below the wind generation is dispatched off since the returns from the market are below the avoidable operating costs.

The chart only shows prices up to $300/MWh. The frequency of prices above $300 are greater for those futures such as Fast Tech High Demand and Middle of Road 97% which have a greater percent of the time with low prices and wind "spill".

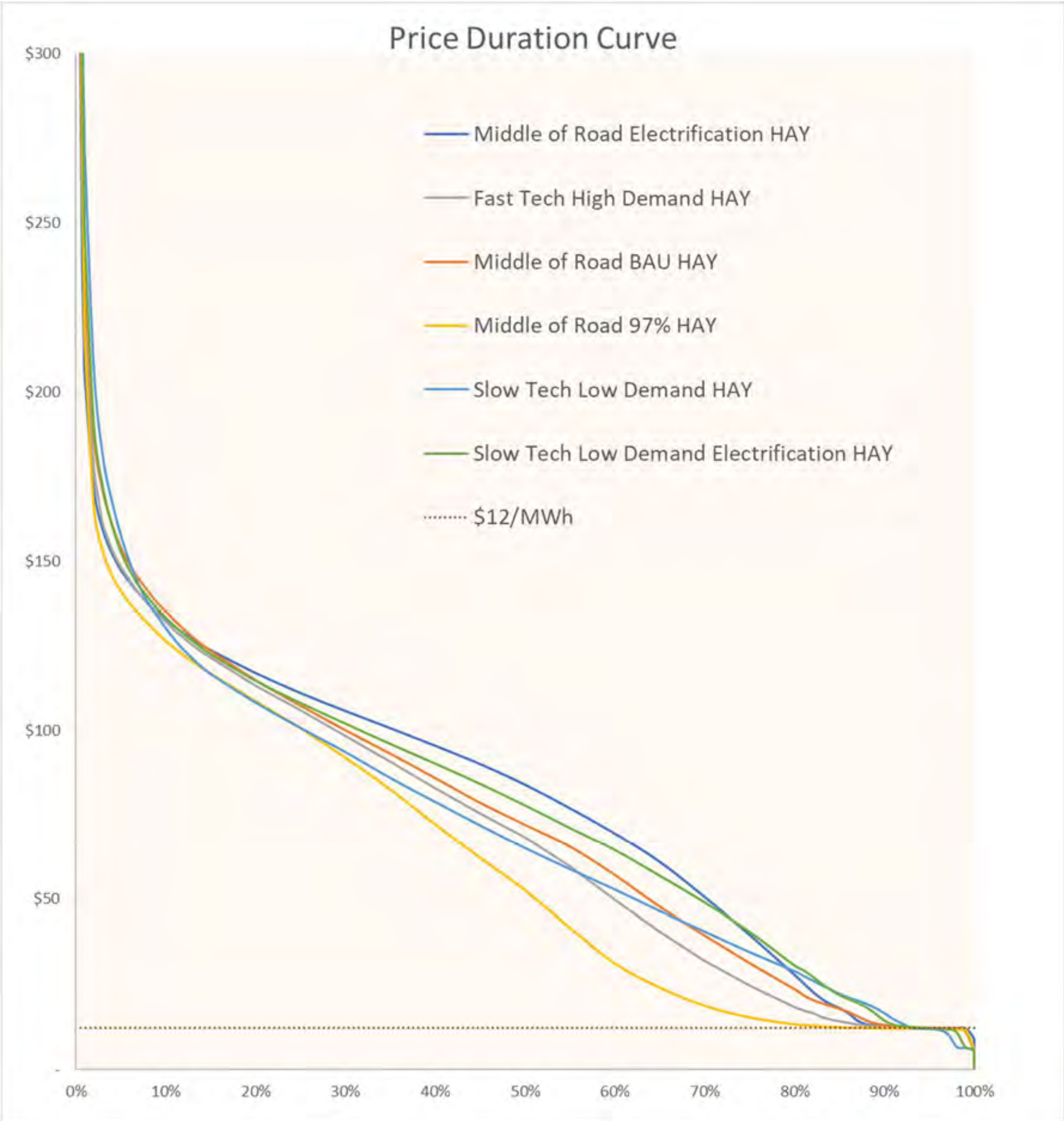


FIGURE 6: PRICE DURATION CURVES

End Notes

[1] LCOE = Long Run Cost of New Entry.

[2] GWAP is the generation weighted average price and TWAP is the time weighted average price. The TWAP is the cost of firm flat electricity supply in the specified year.

[3] It should be noted that there is considerable uncertainty in these estimates of the system marginal cost with 100% renewable generation, as this is pushing the modelling approach to its limits. The availability of flexible gas fired peaking plant as a last resort to cover both short- and long-term wind/hydro supply and demand variability makes it easier to find a long run equilibrium price duration curve, than is the case where gas peaking plant is not available.

[4] This estimate is based on an examination of the EMarket simulation results with 100% and an estimate of the impact of additional wind capacity, wind spill and 100% allocation of incremental battery costs to wind for the step to 100% renewables. It can be argued that this approach is conservatively low since wind "spill" is averaged over all the wind fleet. If the spill was allocated to just the marginal new wind a higher price would be determined. A more robust estimate of the system marginal price might be obtained by carrying out additional 100% renewable EMarket model runs with an increment of load and with enough additional wind and battery capacity (with a suitably conservative operating strategy) to maintain the normal security level. An estimate of the incremental cost of the increment of load could then be derived as the difference in annual system cost divided by the increment in load.

[5] Note that the chart only includes modelling results from the New Zealand runs where gas fired back-up capacity is retained as the last resort. All the comparable international markets have access (either directly or indirectly) to fossil fuel back-up peaking plant.

Electricity Market Modelling 2035

Prepared by Energy Link

for

Interim Climate Change Committee

April 2019

Quality Assurance Information

Name	ICCC modelling by ELL Apr-19 FINAL.docx
File reference	E-ICCC-1221
Issue Status	FINAL
Issue Date	29 April 2019
Client	Interim Climate Change Committee

Definitions

The following terms, abbreviations and acronyms are used in this report.

AC	Alternating current
BAU	Business as usual
CCGT	Combined cycle gas turbine – this type of generator combines a standard open-cycle gas turbine with a heat-recovery steam unit, which then sends steam to a steam turbine generator. CCGTs have the highest efficiency of any type of conventional thermal generator.
Code	Electricity Industry Participation Code
Cogen	Cogeneration – generation associated with an industrial plant which produces heat for an industrial process (typically two thirds of energy production) as well as electricity (the remaining one third of energy production)
DC	Direct current
DSR	Demand-side response
e3p	A combined cycle gas turbine located at Huntly and having nominal capacity of 403 MW (a.k.a. Huntly unit 5)
ETS	Emissions Trading Scheme
EV	Electric vehicle, including battery electric vehicles and plug-in hybrid vehicles
FK	Frequency keeping
GIP	Grid injection point - a location on the grid where power flows from a generator to the grid
GJ	1 million joules, where the joule is the SI unit of energy
GWAP	Generation-weighted average price
GWh	1 million kWh, where a kWh is the energy represented by 1 kW (1,000 joules per second) for 1 hour. 1 kWh is also equal to 3.6 MJ
GXP	Grid exit point - a location on the grid where power flows from the grid to a local network, and hence to consumers
Huntly	Refers to the coal-gas-fired steam turbine units located at Huntly, total nominal capacity 750 MW (a.k.a. Huntly units 1 to 4, though one unit, unit 3, is permanently retired)
HVDC	High voltage DC link which connects the North and South Islands. A.k.a HVDC link.
ICCC	Interim Climate Change Committee
IR	Instantaneous reserves
ILR	Interruptible load reserves
LCOE	Levelised cost of energy
LRMC	Long-run marginal cost
McKee	100 MW McKee gas-fired peaker situated in Taranaki
Node	A point on the grid which is either a GIP, GXP or both, or where two transmission lines join
NZU	New Zealand Unit – a carbon “permit” for one tonne of CO_2 emissions under the ETS
OCC	Official conservation campaign
p40	40 MW gas-fired peaker at Huntly (a.k.a. Huntly unit 6)
PLSR	Partly loaded spinning reserve
RoI	RoI

SRMC	Short-run marginal cost
Stratford	200 MW Stratford gas-fired peaker situated in Taranaki
TCC	Taranaki combined cycle gas turbine thermal generator situated near Stratford and having nominal capacity of 377 MW
TPR	Transmission Planning Report, Transpower, 2018
TWAP	Time-weighted average price
TWD	Tail water depressed
TWh	1 TWh = 1,000 GWh
Whirinaki	155 MW diesel-fired peaker situated at Whirinaki near Napier

Acknowledgemets

The authors are grateful for the assistance provided by John Culy of John Culy Consulting in preparing large quantities of wind and solar data as inputs to the modelling, and for taking the lead in ensuring consistency in approach to the economic interpretation of the model inputs and outputs. Thanks also to the ICCC team and E-CHARGE panel of experts for their constructive comments and responses to questions concerning what may or may not reasonable to expect in 2035.

Contents

1 Introduction

The Interim Climate Change Committee (ICCC) is a Ministerial Advisory Committee established in May 2018 by the Climate Change Minister with the agreement of Cabinet. The Committee's purpose "is to provide independent evidence and analysis on issues in the Terms of Reference that will be passed to a Climate Change Commission to inform its recommendations.[1]" A Climate Change Commission is proposed to be set up under the Zero Carbon Act which will be introduced to Parliament later this year.

The ICCC is to advise on how agriculture could best be brought into the Emissions Trading Scheme (ETS) and on how New Zealand's electricity supply could be generated from 100% renewable generation[2] by 2035, in a normal hydrological year. The ICCC's terms of reference[3] expand on the electricity question by asking it to have regard to opportunities to reduce emissions from the energy sector as a whole, and to emerging technology.

On the face of it, the electricity question appears relatively straightforward to answer: shut down fossil-fueled thermal generating plant and replace it with renewable plant including wind farms, geothermal stations, solar panels, biogas, hydrogen, and so on.

But renewable generation is not controllable to the same extent as thermal generation: a wind farm can't be turned up to maximum if it is calm, solar panels contribute nothing at night and much less than full output when the sun is low in the sky or behind clouds, there is a limited supply of wood and other waste to make biogas, hydrogen is expensive to produce and store, wave and tidal energy only produce when there are waves and when the tide is flowing, and so on.

New Zealand's electricity supply is already 82% renewable[4] and we already have to deal with the complex issue of managing security of supply in the face of volatile inflows into hydro lakes, especially in exceptionally dry periods that last for months[5].

ELECTRICITY PRICES

It is common practice to quote electricity prices in \$/MWh (dollars per megawatt-hour) in the wholesale market and in c/kWh (cents per kilowatt-hour) when referring to prices paid by the customers of electricity retailers.

The conversion is simply \$10/MWh = 1 c/kWh

The ICCC identified the need to comprehensively model the complex interactions between the various sources of generation that might be built between now and 2035, along with management of security of supply, and engaged Energy Link to undertake the detailed modelling tasks.

In this report we cover technical aspects of the modelling, while the results of the scenarios are presented in the main electricity report prepared by the ICCC ("main report"), solar and wind data are described in *ICCC Modelling: Wind And Solar Profiles*, John Culy Consulting, the modelled costs are presented in detail in *ICCC modelling: Estimated system incremental and marginal costs in 2035*, John Culy Consulting ("costs report"), additional information on storage is presented in *ICCC modelling: Dry year storage options analysis,* John

[1] https://www.iccc.mfe.govt.nz/what-we-do/frequently-asked-questions/
[2] Geothermal generation, all located in the north island, is considered to be renewable despite the fact that all geothermal stations emit CO_2.
[3] https://www.iccc.mfe.govt.nz/who-we-are/terms-of-reference/
[4] MBIE data for 2017.
[5] Which we will refer to loosely as 'dry years'. In reality, even what is considered to be a dry year can have long dry and wet periods within it.

Culy Consulting and retail prices are presented in *Modelling Retail Electricity Prices Under High Renewables, And Low-Emissions Scenarios*, Martin Jenkins.

Section 3 summarises the scenarios, variations and sensitivity modelling runs undertaken for the ICCC. Section 4 outlines the modelling methodology and section 5 briefly highlights some key elements of the results of the modelling.

Some aspects of the wholesale electricity market that are much less prominent than the cost of electrical energy based on generation, were not modelled explicitly but are discussed in section 4.8, and we discuss the transmission grid in section 4.12.

Unless otherwise stated, all dollar values in this report are 2018 New Zealand dollars (real prices) exclusive of GST, and all energy prices are in $/MWh.

The outputs and results presented in this report are primarily the result of the modelling, based on inputs provided by us or by others working for the ICCC. In all other cases, where no reference is made to other work, then statements and opinions are based on our experience in and knowledge of the electricity and gas market built up since our establishment in 1996.

2 Summary

Six main scenarios were modelled for 2035, starting with Business as Usual (BAU) and then stepping through three intermediate scenarios before reaching 100% renewables. All of the higher renewables scenarios were based on the same assumptions as the BAU scenario, but were modified by reducing the size of the thermal fleet and replacing thermal generation with renewables generation including geothermal, wind and solar.

The sixth scenario was the Electrification scenario which had the same underlying demand growth as to the BAU scenario, but higher rates of uptake of EVs and conversion of commercial and industrial process heating to electricity.

The carbon price is a key assumption as it can have a significant impact on what new generation is built by 2035: the assumption provided by the ICCC was $50 per tonne of CO_2 (carbon) and it is used in all modelling except for two sensitivities which tested the impact of a carbon price of $150 per tonne.

The scenario results are summarised in Table 1 below and show that the BAU scenario in 2035 reaches 92.6% renewables by shutting down two large thermal stations, and building renewable generation to replace them to meet additional underlying demand plus demand created by rising uptake of EVs and 0.6 TWh of demand from conversion of process heat to electricity.

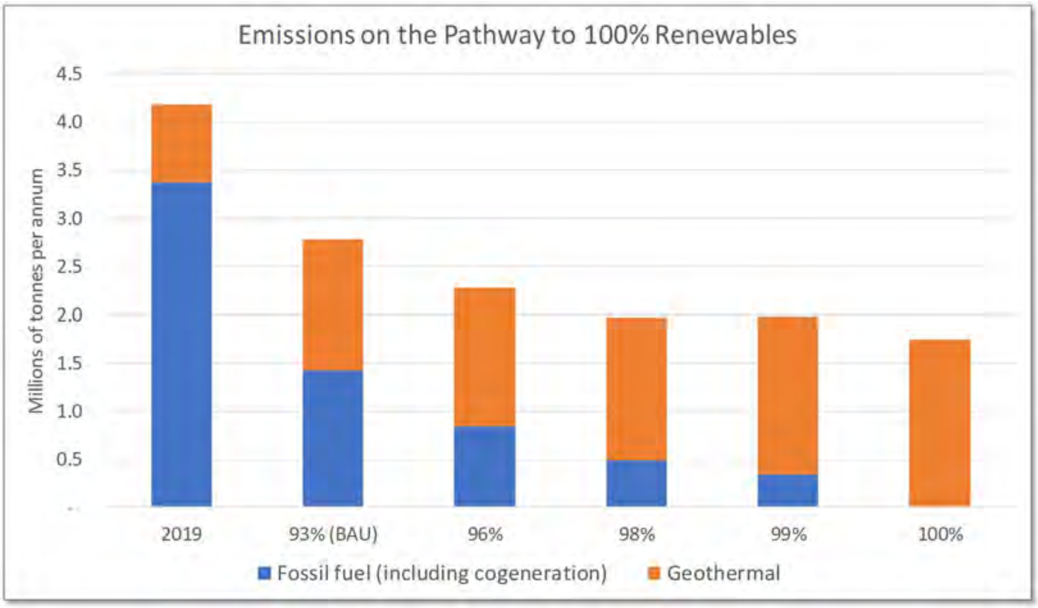
Table 1 – Scenario Result Summary[6]

Annual Results Averaged Over 87 Inflows	BAU	96.0%	98.0%	99.0%	100.0%	Electrification
Renewables	92.6%	95.9%	97.9%	98.6%	100.0%	91.7%
Capital Cost ($Billion)	$8.4	$9.9	$10.5	$11.0	$13.4	$13.3
Total Generation (GWh)	49,196	49,235	49,289	49,278	49,213	57,197
Total Emissions attributed to electricity (g/kWh)	57	46	44	45	35	66
Emissions excl. Co-Gen (g/kWh)	50	39	40	40	35	51
Emissions Geothermal only (g/kWh)	28	29	30	33	35	28
Solar Generation (GWh)	1,108	1,108	1,108	1,222	2,108	1,887
Wind Generation (GWh)	7,528	8,841	9,424	9,244	9,160	11,150
Geothermal Generation (GWh)	11,916	12,555	12,757	13,116	13,562	13,361
Co-Gen Generation (GWh)	1,231	1,231	560	560	560	1,231
Thermal Generation (GWh)	2,620	1,036	1,013	701	0	3,756
Hydro Generation (GWh)	24,793	24,464	24,426	24,435	23,823	25,813

Figure 1 below shows the total emissions per year for the pathway from BAU to 100% renewables, along with an estimate for 2019, split between thermal stations and cogen, and geothermal. The chart shows a steady fall in emissions as plant powered by fossil fuels is retired and replaced by renewable generation including geothermal. The emissions remaining at 100% renewables are fugitive emissions which arrive at the surface along with geothermal steam.

[6] Capital cost of new plant built includes behind-the-meter solar; emissions attributed to electricity exclude cogeneration whose emissions are allocated to industry and not to electricity generation; DSR is demand-side response and represents demand that is foregone due to high prices during times of shortage; non-supply is demand that cannot be supplied at any price. DSR and non-supply are shown in units of MWh (1 MWh = 0.001 GWh): these are used instead of GWh because the amounts of DSR and non-supply are tiny in comparison to total demand.

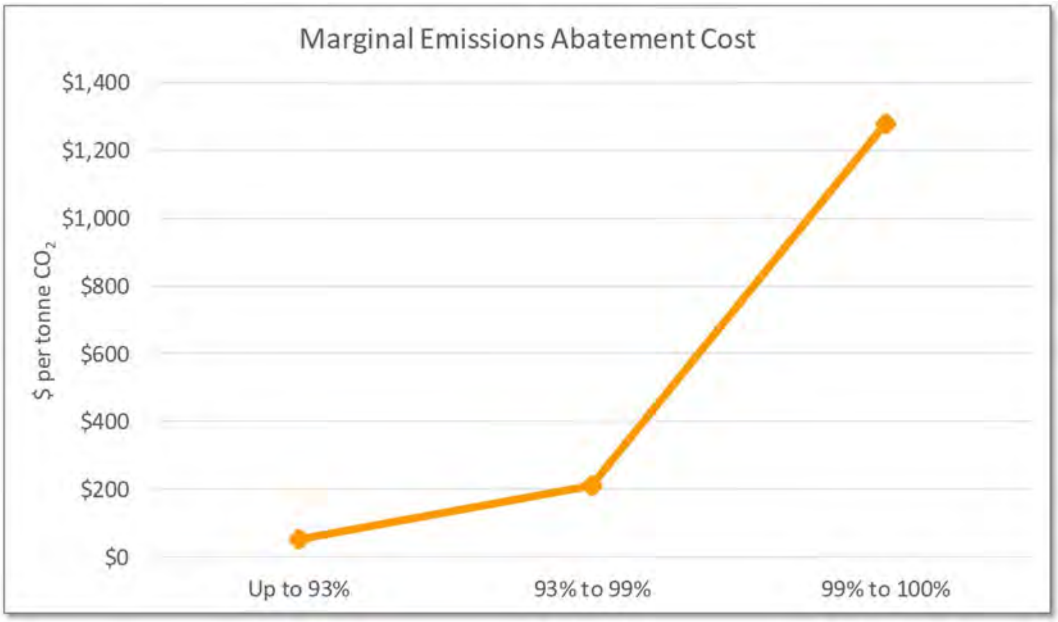
Figure 1 – Emission Pathway to 100% Renewables



The cost of lowering emissions by targeting extremely high renewable generation is illustrated in Figure 2 which shows the marginal cost of abatement[7] per tonne of carbon of achieving emissions reduction by 2035.

The marginal cost in each case is the change in system cost from one scenario to the next, i.e. from present to BAU at 93% renewables, BAU to the mid-ninety percent range, and then for the last step from 99% to 100%. This illustrates how the cost of the last tonne of reduction in emissions increases sharply as the market moves beyond scenarios which have renewable penetration in the mid to high ninety percent range. The key driver of the additional construction cost is the need to over-build wind farms to ensure security of supply in dry years.

Figure 2 – Marginal Abatement Cost per Tonne CO_2



[7] By definition, reduction or removal of a nuisance, in this case greenhouse gases, primarily CO_2.

In addition to the six main scenarios, we also modelled seven variations on the main scenarios, characterized by being either "slow" or "fast". The Slow Tech Low Demand variations have the Tiwai aluminium smelter close as a proxy to represent a significant drop in electricity demand and have otherwise low demand growth, low uptake of EVs and low rates of conversion of process heat to electricity, along with slow or nil reductions in the cost of renewable generation through to 2035.

The Fast Tech High Demand variations continue Tiwai's operation and feature higher demand growth, high uptake of EVs and high rates of conversion of process heat to electricity, along with a higher rate of cost reduction of renewable generation.

The Slow Tech Low Demand and Fast Tech High Demand variations are summarised in Table 2 below. BAU Slow Tech Low Demand has lower renewables than BAU because less renewables are built and the market share of remaining thermal generation is correspondingly higher, with the opposite being the case for BAU Fast.

On other hand, 98% Slow Tech Low Demand has higher renewables than the central 98% scenario because the remaining thermal stations need to operate less due to the lower demand. The 100% variations are both 100% renewable, of course, but their construction costs are markedly different.

Table 2 – Variation Result Summary

Annual Results Averaged Over 87 Inflows	BAU Low Demand Slow Tech	BAU High Demand Fast Tech	98% Low Demand Slow Tech	98% High Demand Fast Tech	100% Low Demand Slow Tech	100% High Demand Fast Tech	Electrification Low Demand Slow Tech
Renewables	91.0%	93.2%	98.8%	97.8%	100.0%	100.0%	91.6%
Capital Cost ($Billion)	$0.3	$12.7	$2.7	$14.4	$3.8	$17.7	$6.2
Total Generation (GWh)	38,491	55,872	39,088	55,148	38,283	55,022	47,837
Total Emissions attributed to electricity (g/kWh)	55.2	58.1	38.0	42.8	31.9	37.0	66.9
Emissions excl. Co-Gen (g/kWh)	46	52	32	39	31	37	60
Emissions Geothermal only (g/kWh)	21	32	27	32	31	37	34
Solar Generation (GWh)	503	3,138	503	3,694	503	4,138	503
Wind Generation (GWh)	2,453	10,241	3,636	12,001	3,428	11,182	5,286
Geothermal Generation (GWh)	7,816	14,211	10,409	13,562	11,512	15,566	13,361
Co-Gen Generation (GWh)	1,231	1,231	560	560	267	560	1,231
Thermal Generation (GWh)	2,453	2,779	466	1,198	0	0	2,994
Hydro Generation (GWh)	24,036	24,273	23,513	24,131	22,573	23,690	24,462

We also modelled five sensitivities, three on the BAU scenario and two on the Electrification scenario, and the results are summarised in Table 3 below.

Increasing the carbon price assumption to $150/tonne increases the renewables percentage significantly relative to the central BAU and Electrification scenarios, respectively, because it causes the last large thermal station still assumed to be in the market in 2035 to become uneconomic, and so it closes in this sensitivity. In addition, wind farms are built ahead of the most carbon-intensive geothermal project that is built in both the BAU and Electricity scenarios.

Table 3 – Sensitivities Result Summary

Annual Results Averaged Over 87 Inflows	BAU Higher Carbon Price ($150/t)	BAU Higher Gas Price ($19/GJ)	BAU Constrained Hydro	Electrification Higher Carbon Price ($150/t)	Electrification Peakier Demand
Renewables	96.5%	97.1%	92.5%	96.3%	91.6%
Capital Cost ($Billion)	$10.7	$10.7	$8.4	$17.0	$13.3
Total Generation (GWh)	49,250	49,250	49,192	57,281	57,194
Total Emissions attributed to electricity (g/kWh)	35.8	47.0	57.3	37.7	57.1
Emissions excl. Co-Gen (g/kWh)	29	40	50	32	51
Emissions Geothermal only (g/kWh)	22	36	28	26	28
Solar Generation (GWh)	1,108	1,108	1,108	2,108	1,887
Wind Generation (GWh)	10,171	8,115	7,496	13,908	11,112
Geothermal Generation (GWh)	11,390	14,044	11,916	13,160	13,361
Co-Gen Generation (GWh)	1,231	1,231	1,231	1,231	1,231
Thermal Generation (GWh)	705	441	2,705	1,097	3,792
Hydro Generation (GWh)	24,645	24,311	24,737	25,778	25,812

Increasing the price of natural gas used to fuel thermal generation in the BAU Higher Gas Price ($19/GJ) sensitivity run also increases the renewables percentage significantly, again because it makes the last large thermal station uneconomic.

Reducing the amount of water available for hydro-electric generation, in the BAU Constrained Hydro sensitivity run, by assuming that some more water in the South Island is extracted for irrigation and increasing minimum river flows, has little impact on the BAU scenario[8], because most of the time flows in the BAU are above minimum anyway, and because the irrigation extraction is a tiny percentage of the water available for generation.

Finally, in the Electrification Peakier Demand sensitivity run it is assumed that EVs are charged at random when people arrive home ('dumb charging' as opposed to 'smart charging'), modifies the daily demand profile to make it "peakier" relative to demand in the central BAU scenario. However, this makes little difference to the results relative to the central Electrification scenario because the increase in peak demand is relatively small. Note, however, distribution networks are not modelled.

In all scenarios, variations and sensitivities it was ensured that dry year security of supply was managed so that Official Conservation Campaigns (OCCs), regulated calls to reduce consumption with the objective of not running the hydro lakes dry, were very unlikely.

[8] The changes to extraction and minimum flows are at the lower end of previous work – refer to section 3.5.

Notwithstanding security of supply in dry years, the possibility of having calm conditions across the country during a cold winter evening meant there were still occasions when spot prices reached levels above $2,000/MWh where consumers exposed to spot prices chose to turn off. Furthermore, there were such periods when demand response to price was insufficient, and non-supply resulted. This occurred in most scenarios[9] as the proportion of generation supplied by wind increased but was most pronounced at the 100% renewables mark, in which it was not economically feasible to build enough plant and batteries to also ensure 100% secure supply.

The modelling produced a great amount of detail on the loading of the transmission grid and showed that there are some transmission lines that would need to be upgraded in some scenarios. However, these were relatively few in number and limited to the HVDC link joining the North and South islands, a handful of known pinch points, along with a small number of lines needing an upgrade where new generation was built in parts of the grid in which existing transmission capacity is limited.

3 Scenario Overview

The ICCC was tasked to study how New Zealand's electricity supply could be generated from 100% renewable generation by 2035, in a normal hydrological year. It is first necessary to define what is meant by a "normal hydrological year". Is it a year of mean inflows into all hydro lakes? Or median inflows? Or a year in which hydro storage, measured in terms of the energy that could be generated from the water in lakes, never drops below a certain value? Or is it a year in which there is no risk of shortage due to low hydro lake levels?

The intent of the normal hydrological year standard seems to be that thermal plant would not run when there is no risk of shortage due to low lake levels. Or in other words, thermal plant is kept available so that it can run during "dry years" so that shortage is avoided.

However, there are a number of problems with this intent. First, we don't know if it is a dry year until the year is over. Many years have dry periods during which hydro lake levels fall quickly, but then it can rain and fill the lakes up: looking back in hindsight, there may never have been a risk of shortage.

Second, many more wind farms will need to be built through to 2035 to meet additional demand and to displace thermal generation, introducing the possibility of dry-calm periods: how are these to be taken account of in the definition of a normal hydrological year?

Third, if we somehow manage to keep thermal generators available in the market, do we then tell them not to run during "wet years" when demand peaks on cold, calm winter nights and wind farms are not producing much? This would result in shortage, unless we add additional capacity to the market in the form of grid-scale batteries, for example, or some other type of generating plant that is currently not economically viable? The effect would be to add cost to electricity supply, even when we have thermal plant sitting around doing nothing when it could be generating.

The ICCC's approach to this complex issue was to model the market in various states between as business as usual (BAU) through to it literally being 100% renewables[10]. This approach avoided the need to arbitrarily define a "normal hydrological year", while providing a consistent series of scenarios to inform policy-making.

[9] BAU had zero non-supply – refer to Table 8 in section 5.3 for details.
[10] Which goes beyond the test of being 100% renewable generation in a normal hydrological year.

The ICCC also modelled versions of the market which achieved high penetration of renewables but lower emissions overall by increasing the uptake of EVs and increasing the conversion of heat production in commerce and industry from fossil fuels to electricity. Five sensitivity variations were also modelled across BAU and Electrification scenarios to test the impact of key variables over a realistic range of settings.

The outputs of the scenarios allow the ICCC to calculate curves for various parameters including the marginal cost of carbon abatement[11], the reduction in emissions at each step from BAU to 100% renewables, and the relative emissions reductions attained by focusing on 100% renewable electricity versus focusing emissions-reduction policy on the wider energy sector emissions including transport and process heat in industry.

The full range of scenarios modelled is shown below in Figure 3 and includes four sensitivity runs, shown as five rectangular boxes related to the scenarios below the scenarios, to give a total of six main scenarios, seven variations on the main scenarios, and five sensitivities.

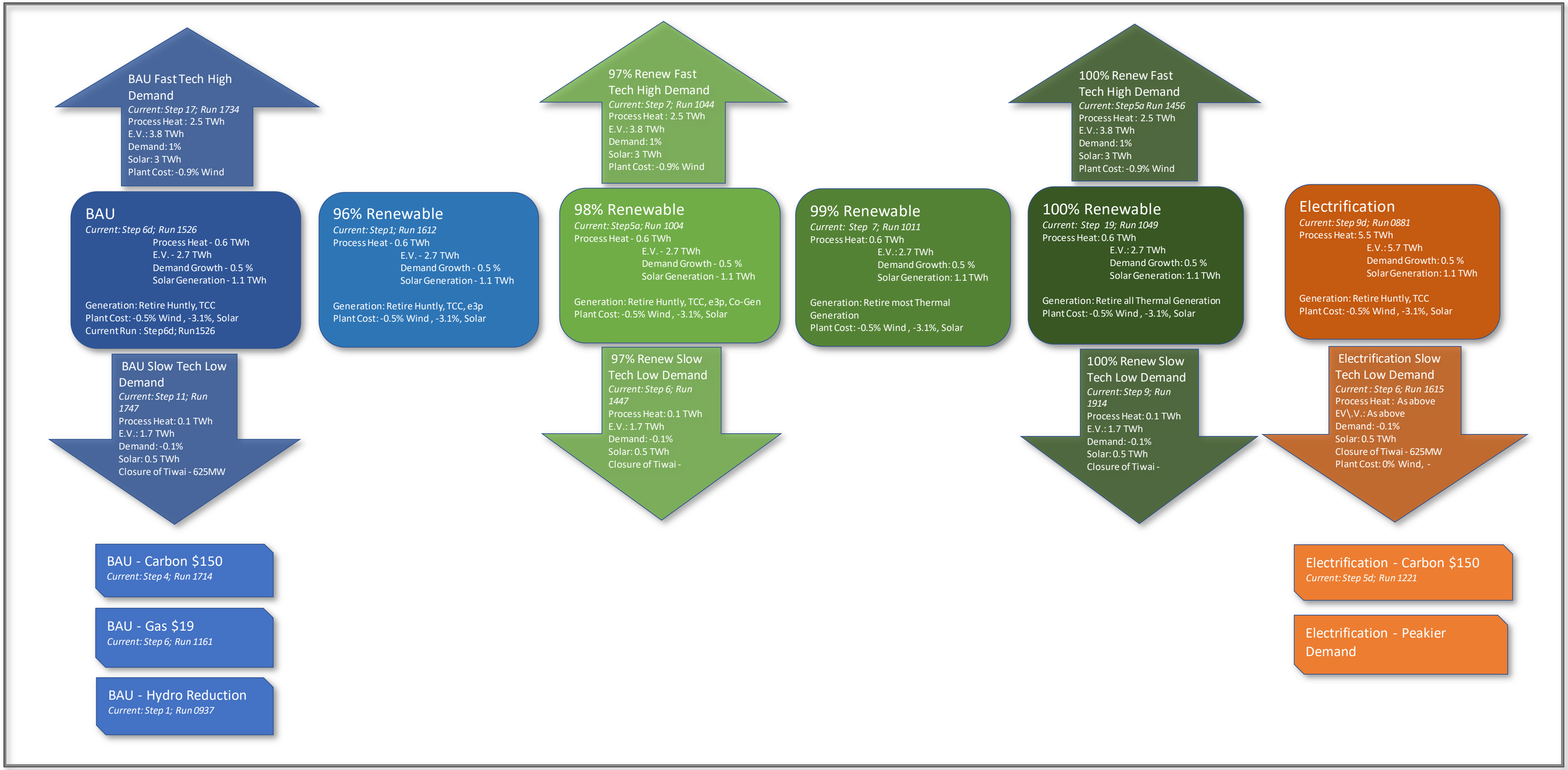
Two variations, called Slow Tech Low Demand and Fast Tech High Demand, were run on some scenarios. The Slow Tech Low Demand variation represents a view of electricity supply in which demand growth is very low by 2035, due to lower than expected growth in GDP and population, and the costs of renewable generation do not fall in real terms. Lower-than-BAU growth in demand is amplified by the closure of the aluminium smelter at Tiwai Point near Bluff (“Tiwai”). Tiwai currently represents 14% of New Zealand’s average annual electricity consumption, so if it were to close it would create a large surplus of supply over demand.

The Fast Tech High Demand variation, on the other hand, assumes higher than expected GDP and population growth, leading to higher-than-BAU demand growth. The cost of renewable generation also falls faster than expected under the relevant central scenarios.

The scenarios are described in more detail in section 6, Appendix A – Scenarios, Variations and Sensitivity Details.

[11] Carbon abatement is a reduction in CO_2 emissions.

Figure 3 – Scenarios and Sensitivities



3.1 BAU

The BAU scenario is based on projecting today's market through to 2035 and of particular note is that it assumes that Huntly and TCC are retired by then. These two generators together represent just over 5% of total generation so if they were to be retired today, assuming that new renewable plant was available to replace their output, renewables would immediately increase to 87% of the market. By 2035, BAU generation increases by 14% and as this is met mostly by renewables generation – wind, geothermal and solar – the percentage of renewables increases more than 5%.

Huntly was commissioned in stages but was fully completed in 1985. One of the four 250 MW units is now permanently retired and there is continuing uncertainty over the future of the remaining three operational units. The plant is relatively inefficient compared to combined cycle turbine plant (TCC and e3p) but is very flexible as it can burn either entirely natural gas or a mix consisting mostly of coal but with gas added. The ability to burn coal has proven useful in dry years and particularly in late 2018 when gas supplies were dramatically reduced due to a problem with supply of gas from the country's largest gas field, Pohokura. Huntly's owner, Genesis Energy, has said that it will not burn coal at the plant after 2030, and in recent years has run the Huntly coal stockpile down below historic levels: as the station burns gas much less efficiently[12] than more modern stations, this implies it will be shut permanently in 2030, if not sooner.

The TCC belongs to Contact Energy and was commissioned in 1998. It is currently due for a major mid-life refurbishment in 2022 but Contact is yet to decide if the $70 million cost of this is justified: if not, the station is likely to close in that year.

If the mid-life refurbishment is completed, the station could continue to operate for many years to come, although by 2035 it would be 37 years old. However, unlike Genesis[13] and Todd Energy[14], the other two owners of thermal generation, Contact does not have an interest in upstream gas, which means that access to cost-effective and flexible gas supplies is becoming more difficult for the company.

E3P OFFERS

As a large CCGT, e3p cannot operate in the same way as a gas-fired peaking station. A true peaking station can reach full output in as little as a few minutes, and it can operate down a few percent of its maximum output.

e3p, on the other hand, can take several hours to reach full output from a cold-start. Furthermore, once it is running, its minimum output is around 200 MW.

Whenever e3p appears in a scenario, variation or sensitivity, it is offered as follows: when the average spot price exceeds $50/MWh for one whole week, e3p is offered into the market primarily as baseload. When the average spot price falls below $50/MWh for one whole week, it is no longer offered into the market.

Another issue for TCC is flexibility: it can operate down to around 160 MW but no lower, and it takes hours to warm up when started from cold. As demand grows and is met by new renewable generation, less flexible thermal plant such as TCC will find it harder to compete with plant that can start faster and operate over a wider range of output. Genesis' e3p has the same problem, but has an advantage in terms of access to gas via ownership in the Kupe gas field, so if one combined cycle

[12] Huntly's efficiency is around 36% but combined cycle plant such as e3p can achieve efficiencies in excess of 50%.
[13] Owns 46% stake in the Kupe gas field.
[14] Owns the McKee, Kapuni and Mangahewa fields.

plant is left in 2035 then it is less likely to be TCC and more likely to be e3p which will only be 28 years old by then.

So in the BAU scenario it is assumed that both Huntly and TCC are retired, and e3p remains. The McKee and Junction Rd[15] gas-fired peakers, each 100 MW, belonging to Todd Energy are assumed to remain, as are Contact's Stratford 200 MW gas-fired peaker and its 155 MW Whirinaki dieseil-fired peaker, and Genesis' 46 MW p40 gas-fired peaker. Todd Energy is also assumed to construct the first stage of its Otorohonga gas-fired peaker and Genesis is assumed to construct a new gas-fired peaker at Huntly.

The BAU scenario is also assumed to have one large grid-scale battery installed in each island[16], which assists the peakers meet peak demand, but otherwise the new plant that provides most of the energy to meet growing demand is either wind farms and new or expanded geothermal stations.

3.2 Pathway to 100% Renewables

Between the BAU scenario and the full 100% scenario are three intermediate steps called 96% Renewables, 98% Renewables and 99% Renewables. The BAU scenario achieves 92.6% renewables but by closing e3p we move to the first intermediate step and 95.9% renewables (96% scenario). To make up for the hole left by e3p, we add more wind farms, more geothermal another battery and the BAU peakers run a little more on average.

97.9% renewables (98% scenario) is achieved by adding more wind farms, a little more geothermal. Cogen that is currently powered by fossil fuels is also assumed to convert to renewable fuels.

98.6% renewables (99% scenario) is achieved by adding more geothermal.

100% renewables is achieved by closing all remaining thermal stations and adding another two large grid-scale batteries.
Getting to 100% renewables, however, is not as simple as removing thermal generation and replacing it with renewable generation. While geothermal plant produces steadily across the day, wind farms only produce when wind is blowing through them.

Consumers place a high value on having a secure and reliable electricity supply, and we assume this will remain the case into the future. The two main concerns around security of supply in New Zealand are:

1. the ability to keep power flowing when the hydro lakes are low: the "dry year problem";
2. the ability to keep power flowing during periods of peak demand, cold winter evenings in particular: the "capacity problem".

The dry year security of supply problem is one of having sufficient energy available to get the nation through a period when the hydro lakes are low or falling rapidly. Generating more energy from hydro stations in these situations could cause lakes to hit empty[17], thus creating prolonged shortages[18], which is to be avoided.

[15] Currently due to be commissioned mid-2020.
[16] The operation of the batteries involves charging up overnight and discharging during peak demand periods during the day.
[17] The hydro lakes don't literally dry up, they reach the lower limit of their consented operating range.
[18] When a hydro lake hits zero storage, its ability to generate is limited to its inflows, which is to say the water that arrives in the lake each hour and each day. This limit is typically well below the total generating capacity installed on the river below the storage lake.

There is currently over 2,300 MW[19] of new wind farms consented to be built in New Zealand and many hundreds more in sites that are not yet consented but that might be in future, totaling almost 3,300 MW of capacity in our list of potential projects, whereas we have only 712 MW of geothermal capacity in our list, primarily expansions of existing projects along with some new projects. In future, based on the ICCC's assumptions for the cost of solar power and other forms of generation, we expect many more wind farms to be built along with the majority of the geothermal projects to meet growing demand, and to make up the gap left by retiring thermal stations.

To ensure that supply is maintained during dry periods, it turns out that we need to build more wind farms than are needed on average, so that in dry periods there is enough spare generating capacity available to keep the lakes from emptying.

The peaking capacity problem becomes more difficult in scenarios with a high reliance on wind farms because there are many mornings and evenings in the depths of winter when demand peaks, but it is calm across the country and hence when wind farms contribute little or nothing to meeting this peak demand.

One factor that becomes important with a high reliance on wind farms is that wind farms in the same region of the country are subject to wind speeds which are highly correlated. Thus, if many wind farms are built relatively close together, it becomes harder to meet peak demand and more likely that some consumers will have to reduce load or, worse still, be turned off completely for a short period. Thus, in scenarios with a high reliance on wind we have had to "move" some wind farm projects to other regions to reduce the degree of correlation between wind farms: this means that we tacitly assume that there are viable sites for wind farms in these other regions. This is a reasonable assumption because wind turbine technology is developing rapidly, especially for turbines in areas of lower wind speeds, i.e. lower than in New Zealand's highest wind speed sites.

3.3 Electrification

This scenario assumes higher uptake of EVs, when compared to the BAU scenario, and a higher rate of conversion to electricity of fossil-fueled heat production in commerce and industry. The latter includes a wide range of applications from gas boilers used for heating in commercial buildings through to production of hot water or steam for use in industrial processes.

The emission reductions obtained by converting the vehicle fleet to EVs are significant because the efficiency of EVs is three times higher[20] than internal combustion engines. Mass conversion to EVs is likely to occur at some point in the future as their purchase cost comes down and their range increases, so the question is how soon the tipping point will be reached. The rate of conversion is ultimately limited by the rate at which vehicles are replaced which is currently around 5% of the fleet per annum.

The efficiency gains for conversion of process heat to electricity are not always as great[21], but when electricity is generated mainly from renewable sources then the reductions in emissions can be large.

[19] Refer to http://www.windenergy.org.nz/consented-wind-farms

[20] For battery EVs.

[21] Converting a gas boiler, for example, takes efficiency from around 85% for gas-fired production of hot water to around 90% for an electrode boiler, or to a coefficient of performance of two to three (which is like saying the efficiency is 200% to 300%) for a high temperature hot water heat pump.

This scenario allows a comparison to be made between policy settings which target 100% renewable electricity, or close to it, for its own sake, and policy settings which target the greatest emission reductions and leave the 100% goal to one side.

The Electrification scenario is the most challenging to model because underlying demand increases the most in this scenario, combined with much higher uptake of EVs and conversion of process heat to electricity, and therefore requiring the largest build of new generation and the highest reliance on wind energy. The reliance on wind energy amplifies the problems created by calm winter days and correlations between wind farms, as outlined in section 3.2 above.

3.4 Slow Tech Low Demand and Fast Tech High Demand

Choosing scenarios is a common approach to modelling the future in many settings and commonly applied in electricity modelling. But by narrowing down the inputs to a scenario, the scenario becomes less and less likely to actually occur. The Slow Tech Low Demand and Fast Tech High Demand scenarios are variations on the three main scenarios - BAU, 100% renewables and Electrification - which have the purpose of exploring the impact of significantly different demand and technology assumptions, and providing an indication of the range of possible futures[22].

The Slow Tech Low Demand variation explores the impact of much lower underlying demand growth in tandem with a slower or zero rate of fall in the cost of wind farms, solar energy and EVs, along with a low rate of conversion of process heat to electricity.

The Fast Tech High Demand variation explores the impact of much higher underlying demand growth in tandem with a higher rate of fall in the cost of wind farms, solar energy and EVs, along with a higher rate of conversion of process heat to electricity. Fast Tech High Demand is not, however, applied to the central Electrification scenario because this scenario is already based on assumptions of high demand growth. It also has a lower probability of actually occurring, along with the highest degree of difficulty in ensuring security of supply during winter peaks, in particular.

3.5 Sensitivities

The five sensitivities have a purpose which is similar to the Slow and Fast Tech High Demand variations, but are limited in scope to testing the impact of just one key input parameter at a time.

A higher carbon price of $150/tonne (against $50/tonne for all other scenarios and variations) is tested for the BAU and Electrification scenarios. The carbon price is the price of New Zealand Units (NZUs) and is subject to supply and demand in the Emissions Trading Scheme (ETS), plus the settings that will apply to the ETS in 2035 including price caps or floors[23]. There is a particularly

[22] Refer to the main report for more information on these variations.
[23] The ETS currently allows emitters to purchase NZUs at $25 per tonne.

high degree of uncertainty in carbon prices because of the uncertainty around these settings, including the possibility of price floors and caps, and the potential for linking the ETS to carbon markets in other countries. A price of $150/tonne would have a very significant impact on the cost of energy in many areas, and this sensitivity tests the response of the electricity industry to high carbon prices.

A higher gas price is tested for the BAU scenario. There is growing uncertainty over the outlook for gas supply in New Zealand through to 2035, primarily because there have been no significant new discoveries since 2005, but amplified by the ban on new offshore exploration for oil and gas. In this sensitivity the gas price is doubled in 2035 to $19/GJ which, to put this in context, is around 2.5 times the current market rate for contracted gas.

The BAU scenario is also tested with a small restriction on major hydro systems in terms of the minimum flows in their respective resource consents, and in terms of extraction for irrigation in the South Island. There is a 5% increase in minimum flows on the South Island major river systems with hydro-electric generation, excluding Manapouri and Te Anau; a 2% increase in extraction of water from the South Island hydro lakes from October to March inclusive but again excluding Manapouri and Te Anau; and a 10% increase in the minimum flows below Karapiro on the Waikato River. These restrictions are at the lower end of earlier work[24] and produced relatively small changes in the results relative to the BAU scenario, but the earlier work showed that the impact of larger changes to the availability of water for hydro generation would be much more significant.

The Electrification scenario is tested for the impact of high penetration of EVs and the assumption that their charging regime is what is sometimes called “dumb charging”, by which we mean that EVs are charged at home, there is no control over when EVs are charged, and there are no new pricing signals which might incent EV owners to charge at particular times of the day. Work by Concept Consulting[25] was referenced to allow us to change the daily demand profile assumed in this sensitivity, adding about 180 MW in total to the daily peak when measured on a half hourly basis.

DISPATCH

Dispatch is the process of matching generation to demand in real-time, a function performed by the System Operator, a division of Transpower.

With the exception of very small generators, most generators have to submit offers to generate in the form of price and quantity. For example, a generator may offer to generate 100 MW for $10/MWh, another 100 MW for $20/MWh, and another 50 MW for $80/MWh.

The System Operator selects offers with the objective of meeting the demand at lowest cost to parties that purchase direct from the spot market (and by extension, lowest cost to consumers).

Dispatch instructions are issued to generators and include the power they are to run at in MW.

Using the generator example above, it might be dispatch to run at 150 MW, in which case it would be paid $20/MWh for all of this output.

Generators make offers every half hour of every day, but dispatch is performed every five minutes. Forecast spot prices are available leading up to and through each half hour, but settlement spot prices are

[24] *Assessment of the Impact of Flow Alterations on Electricity Generation*, Energy M
2015.

[25] *“Driving change” – Issues and options to maximise the opportunities from large-scale electric vehicle uptake in New Zealand*, Concept Consulting, 7 March 2018 (prepared for Orion, Unison, and Powerco lines companies). Refer Appendix B, *What pattern of ‘passive’ EV charging at residential properties is likely to emerge based on current electricity prices?*

4 Methodology

We used our I-Gen and *EMarket* models for the various modelling tasks, with I-Gen working out which generators would be built by 2035 in each scenario modelled, and *EMarket* modelling the electricity market with the new generation added in.

EMarket is a highly detailed model of the electricity market including generation, hydro lakes and river systems, the transmission grid, power flows on the grid, losses on the grid, demand and a range of other aspects relevant to electricity supply. It also models the operation of the wholesale electricity market as it applies to the dispatch of each generator – deciding how much electricity each generator should produce at any particular time – and it produces spot prices around the grid which are consistent with the pricing rules of the real electricity market.

A key aspect of the modelling is that every scenario is run 87 times, each with a different set of inflow data for the years back to 1931. This allows *EMarket* to calculate storage in all of the major hydro lakes and thus to ascertain the impact of each scenario on security of supply during dry periods.

Each inflow year is modelled in steps of 3 hours which means that we could also assess how each scenario performed in terms of meeting peak demand in winter.

4.1 The Elements of a Scenario Run

Given the total demand in a scenario in 2035, the first step is to use the I-Gen model to determine which new generation projects in our list will be built between now and then, based on demand growth and plant retirements: this establishes the "build schedule" for 2035.

Each new generation project has:

- a generator type, be it wind, geothermal, hydro, solar, peaker, and so on;
- a capacity in MW;
- a capacity factor: this is the expected average output MW divided by the total MW installed;
- a capital cost of construction;
- fixed and variable operating costs including fuel;
- an efficiency value;
- an emission factor which determines its emissions when it generates;
- a target after-tax return on investment (RoI);
- a location on the grid;
- time to construct;
- economic lifetime.

I-Gen is designed to simulate the process by which generating companies, and would-be generating companies, decide when to commit to building a new generator. It works across multiple years, from now until 2035 in this case and, in each month along the way, it checks to see if spot price expectations are such that it is feasible to commit to constructing a new plant and, if so, it makes this commitment.

The plant that is built at each step, if any, is the plant which is forecast to achieve at least its target rate of return over the next five years[26]. Only one new plant can be committed in each month.

To perform this evaluation each month, I-Gen calculates a forecast spot price for a number of regions around the country, and compares this with each generator's "trigger price". The trigger price is based on a generator's long run marginal cost (LRMC)[27] which is the spot price it needs to receive over its economic lifetime to just make its target RoI[28].

All the inputs into the modelling were real prices in 2018/19 dollars which means that our generic inflation input parameter is zero. Under the assumption of a target after-tax RoI of 8% nominal, and allowing for an inflation expectation of 2% per annum, this equates to a real after-tax target RoI of 5.88%.

The LRMC of each project is the constant real price which allows the project to achieve a net present value of zero when all of the project's cash flows including tax and return of invested capital, are summed over its economic lifetime and discounted backward at 5.88%. Thus, by definition, 5.88% is the internal rate of return of the project when the average price it receives is its LRMC[29].

So by 2035, there is a list of projects which, in theory, should be the lowest cost mix of plant required to meet demand.

Achieving close to target RoI is important in all the modelling because we aimed to model states of the wholesale market which are stable, and therefore can be directly compared with each other, for example as we progress from BAU to 100% Renewables. If target RoIs are not achieved, or if excess returns are made, then the market is not stable: under-achieving could see exit by one or more generators, whereas over-achieving could see entry of new generation. In all the modelling, there should be no incentive to either enter or exit based on the prices achieved.

In reality, generators do not generate all the time, so the average price they actually achieve in a year is never equal to the simple time-weighted average of the spot prices at its point of location on the grid (known as its grid injection point or GIP). I-Gen only deals with time-weighted average prices, but we can define the generation-weighted average price (GWAP) received by the generator in a year, and the time-weighted average price (TWAP) at its GIP, and then the trigger price used in I-Gen for a generator is its LRMC × TWAP/GWAP.

For example, suppose the LRMC of a wind farm is $70/MWh, which is the average price it needs to earn to achieve its target RoI. But it does not generate all the time and, if it is built in a region that already has a number of wind farms then it will find that the price it earns when it is generating is depressed by all of the generation in the region. It may also not be running during periods when spot prices spike during cold, calm winter nights. The overall effect will be to depress its GWAP below

[26] In reality, a real project would be evaluated over a much longer time scale, but I-Gen is set to work on shorter time frames to avoid over-building. In effect, five years tends to produce price expectations that trigger new builds at a rate which is realistic in terms of matching demand growth and plant retirements. A shorter horizon would lead to longer delays between builds, and vice versa.
[27] Another term often used interchangeable with LRMC is levelised cost of energy or LCOE. By definition, LCOE is the net present value of the all-up unit cost of electricity over the lifetime of a generator; LRMC is the minimum increase in total cost associated with an increase of one unit of output when all inputs are variable.
[28] Or to put it another way, to cover all costs over its economic life time including profit and capital return.
[29] For convenience, the results workbooks show a return on investment (after tax but before depreciation) which does not include an allowance for capital return.

the TWAP at its GIP, and so its TWAP/GWAP ratio is greater than one, and its trigger price in I-Gen is higher than its LRMC.

Expanding on our example, suppose that the wind farm has capacity of 100 MW and expected capacity factor of 40%, so on average it will generate 40 MW or 350.4 GWh per annum. It needs to average $70/MWh to earn its target RoI which equates to annual spot revenues of $24.5 million. If its TWAP/GWAP ratio is 1.1 then it needs a TWAP in I-Gen which is 10% higher than its LRMC to trigger it being built: a price of $77/MWh. The percentage above the LRMC, in this example 10%, is sometimes referred to as the "cost of intermittency".

There is a further complication with wind farms which is based on rule changes for intermittent generators that will be implemented later this year. Currently, wind farms[30] are required under the Code to offer all of their output at a price of $0.01/MWh, but from later this year they will be able to offer their output in the same way as non-intermittent generators do. Wind farms have significant variable costs (short run marginal costs, SRMC) including royalty payments to landowners, and the wear and tear on equipment, for which we have assumed a value of $12/MWh. Offering all output at $0.01/Wh means there would be long periods when a wind farm is running at a loss, but offering at $12/MWh will eliminate these periods and produce an overall higher return, even though the capacity factor will be lowered.

The capacity factors achieved under this assumption vary depending on scenario, but in the BAU scenario, for example, a wind farm that would achieve a capacity factor of 43% (which we'll call the physical capacity factor) offering at $0.01/MWh actually achieves 40% (which we'll call the economic capacity factor) when offered at $12/MWh. When calculating the LRMC of each wind farm we use the economic capacity factor.

4.1.1 Fine-tuning the Build Schedule

In principle, the build from I-Gen is the lowest cost build schedule required to meet demand plus retirements by 2035. However, the actual process by which investors evaluate generation projects is considerably more complex which, when combined with the challenges of moving to very high penetration of wind farms, requires adjustments to be made to the build schedule.

Furthermore, the scenarios required for the ICCC need to be consistent in approach, without allowing the dynamics of the market to overly impact the results required for policy analysis and development. For example, the market may over-build or under-build if expectations of demand growth do not match what actually happens, as has been the case since 2006[31], leading to potentially long periods where new generators either undershoot or overshoot their respective target RoIs.

The basic test for each build schedule, therefore, is that all new generation plant achieves an RoI in 2035 which is close to its target RoI. Existing generators that do not cover their cash costs are shut down, and the build adjusted where necessary by adding the next new project to be triggered.

The Slow Tech Low Demand scenarios also close Tiwai, which creates a particularly difficult issue for I-Gen, which will build new plant to meet forecast demand growth but only up until the date at

[30] This applies to any intermittent generation including solar, but the rule change will impact solar to a much lesser extent because its variable costs of production are more-or-less zero.
[31] Total demand in New Zealand grew at a relatively steady rate from 1974 when records became consistent, through to 2006. The market built new generation in anticipation of this demand growth, but it turned out that after 2006 demand stayed relatively constant (although it has come back recently). It took the market time to adjust to the new demand dynamic, but by then a number of new projects were committed.

which it is apparent to the market, either through announcement or rumour, that Tiwai is to close. If, for example, Tiwai were assumed to announce in 2028 that it will close in 2030, then I-Gen would build plant through to some point close to 2020, then stop building: by 2035 a number of existing stations might need to be retired as a result.

To avoid these problems, it was effectively assumed in the Slow Tech Low Demand variations that Tiwai would close within the next few years and that the closure would be signaled now.

Scenarios with large amounts of new wind generation could suffer from excessively large amounts of non-supply during winter peak demand periods when a "bunch" of new wind farms all built in one region have a calm period. To deal with this issue we moved some wind farms to other regions to reduce the effect of correlations between wind farms: this assumes that there will be other new projects in these regions, that are currently not on our list.

Finally, we made adjustments to the build schedule where new plant was not quite meeting, or was significantly exceeding their respective target RoIs, or where excessive non-supply required the addition of grid-scale batteries: as more wind was added to the grid, the batteries became more and more important. The fine-tuning process typically involved several reruns of the scenario so that RoIs and non-supply could be recalculated after each run, outputs checked, more adjustments made where required, then rerun, and so on. Once the build is finalised, we then know the total capital cost of the build to meet demand and plant retirements in 2035, and we know that this cost is calculated in a manner that is consistent across all modelled scenarios, variations and sensitivities.

4.2 The EMarket Model

Once the build schedule was in place, the 2035 year was run through our EMarket model of the wholesale electricity market[32]. A run for 2035 consists of 87 runs of this year but with a different historical inflow sequence each time, starting with inflows from 1931 and ending with inflows from 2017: 87 inflow years in total. The outputs from the 87 individual runs of 2035 are available if required, but most of the results are averages over all 87 inflows. For example, a new generator might lose money in wet years when prices are low, but the test of meeting target RoI is based on the average return over the 87 inflows years.

To obtain a realistic spread of storage outcomes, the runs were started from 1st January 2034, at a spread of starting storages, thus by the time each inflow run reaches 1st January 2035 we capture the impact of, for example, consecutive dry years or consecutive wet years.

EMarket was run in three-hour mode, giving a total of 2,920 steps in each inflow year and taking about 90 minutes to run all 87 inflows through the two years required for each run[33]. EMarket can run down to the half hourly level, which matches the granularity of the real wholesale market, but this would require run times of nine hours. Three-hour mode achieves a good balance between run times and the need to model the ability of the market to meet peak demand.

The core elements of EMarket are listed below.

1. A grid consisting of 221 GIPs and grid exit points[34] (GXPs) and around 292 transmission lines: this provides enough detail to allow accurate calculation of power flows and losses on the grid including the high voltage DC (HVDC) link that connects the two main islands.

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[32] See http://emk.energylink.co.nz/Main_Page for details.
[33] EMarket is a multi-threaded application which reduces run times on PCs with multiple CPU cores.
[34] A location on the grid where power flows from the grid to a local network, and hence to consumers.

2. Detailed modelling of major hydro systems including large storage reservoirs, head ponds, individual generating stations, minimum flows and water values.
3. Detailed modelled of wind farms including use of historical wind speed data for wind generators.
4. Detailed modelling of geothermal and thermal generation.
5. Full modelling of the process of generators submitting offers to the System Operator.
6. Full modelling of the dispatch process and the process of calculating the final spot price used for settlement.
7. An internal programming language that is used for a variety of purposes including modelling scheduled maintenance of large generating plant.

4.3 Assumptions Common to All Scenarios

The common key assumptions are listed below.

1. The wholesale electricity market remains in place more-or-less as it is today, in line with the requirements of the Code.
2. Historical inflows are representative of future inflows: we know that new records for low inflows are still being set, and there is evidence that inflows may be changing due to climate change, but to the best of our knowledge no one has come up with a set of alternate inflows which we could use with complete confidence.
3. Generators will target an after-tax real RoI of 5.88%[35].
4. $12/MWh is a reasonable value for the SRMC of new wind farms.
5. Hydro-electric generators spill water when their respective reservoirs are full, but offer generation while spilling at a price which if greater than zero but less than the offer price of wind farms: this creates a hierarchy for spill in which wind is 'spilled' before water.
6. Contingent storage can be used in extreme dry years.
7. Storage is managed in a way which makes OCC's, along with the need to reduce demand at Tiwai, very unlikely events.
8. The TPM is modified in a way which removes the current HVDC charge component and removes the bias currently in favour of building new generation in the North Island[36].

4.4 HVDC Assumptions

HVDC capacity is set to be 1,000 MW northward and 550 MW southward in the BAU scenario. These values are 200 MW less than the actual capacity, recognising the fact that at very high levels of transfer the HVDC link is likely to be constrained by IR – refer to section 4.10.2 for more details.

In the 100% Renewables and Electrification scenarios the capacity was increased to 1,200 MW northward and 750 MW southward. The HVDC link is the only transmission line in EMarket that was set to constrain during all runs and, using the current capacity, these two scenarios had a large price difference across the link, indicating long periods of constraint. On closer examination, it was discovered that a combination of the new wind farms built in the South Island, along with the need to meet North Island peak demand by maximising northward transfers, was constraining the link in winter. This pattern is almost the opposite of what happens now: HVDC flows northward reduce in

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[35] Target after-tax RoI of 8% nominal is assumed, and allowing for an inflation expectation of 2% per annum.
[36] The HVDC charge is currently equivalent to $9/MWh for all South Island generators who inject power onto the grid. This is not paid by North Island generators.

winter, and there is normally southward transfer overnight, while thermal and hydro plant in the North Island meet peak winter demand.

4.5 Gas Price Assumption

Energy Link produces a long-term quarterly forecast of electricity spot prices and part of this is the production of six gas price paths, currently through to 2035 and beyond. The medium gas price path was used in the ICCC modelling and it had a price of $9.50/GJ which is used for all gas-fired generators.

Each of the six gas price paths is produced from 1,000 runs of a Monte Carlo model which models gas reserves, the rate of exploration drilling in response to gas price, and the success thereof, the rate of development drilling in response to price, and the success thereof, the distribution of new field sizes as it changes over time, demand response to price, the presence or otherwise of Methanex, and the cost of establishing and operating an LNG import terminal.

The actual success rate of exploration drilling is approximately zero since 2005 and there is growing concern over the supply of gas as the reserves approach the equivalent of ten years of gas consumption at current rates. Although some of the 1,000 runs of our gas model show ample reserves, on average they fall over time and the price rises accordingly.

4.6 The Role of Non-supply, Demand-side Response and Batteries

Non-supply means that "the lights go out" unexpectedly somewhere in the country, and it can occur for a variety of underlying reasons, for example, a large amount of generation could be disconnected from the grid without warning, a transmission line such as the HVDC link could fail, or equipment could fail at a substation at a GXP. In these three examples, the non-supply is due to a sudden, unplanned outage of plant, and not to a lack of enough generating capacity offering into the spot market. Although it is to be avoided, there is always a non-zero chance that unplanned outages can disrupt supply regardless of how much generation is available.

However, our modelling did not consider such instances[37] but instead only considered instances of non-supply due to a lack of generating capacity being available. As we added more wind farms in various scenarios, it became apparent that

WATER VALUES

The water value is a core concept for a hydro-electric generator with storage. Storage gives the generator options: generate now at price X or save the water and generate later at price Y.

The principle of water values is that the generator should release water from a storage lake and generate with it when its water value is equal to or greater than the current spot price.

In this context, the water value can be thought of as the expected future value of water in storage (or strictly, the value of the next cubic metre of water released from storage).

The water value is also the opportunity cost of water in storage, in economic sense, because the next best alternative to generating with the stored water now, is to hold it in storage until some later date.

In EMarket and in the major hydro -electric generators, are algorithms which calculate water values using complex optimisation algorithms. In EMarket, the objective of the optimisation is to maximise the revenue based on uncertainty in inflows, represented by the full range of historical inflows back to 1931.

The process can be conceptualised as follows: storage in a large reservoir is at X GWh at time T. If we project historical inflows forward from here, assuming other participants behave rationally, some storage outcomes will hit the top of the reservoir, resulting in spill with a value of zero (when spilling, additional water arriving in storage has no value), and some will empty the reservoir resulting in shortage and very high prices. The water value is the average across all 87 inflow projections.

If storage falls in a dry period, more inflow projections will hit empty and the shortage prices will add to the water value, and vice versa.

EMarket does not take account of the market power of the large hydro-electric generators, so although it may seem counterintuitive, getting the water values right ensures that water is priced competitively and that it is used for generation in an optimal sense, given expected demand and the other generating assets that are in the market.

[37] Because these will happen anyway, although at very low level of probability.

avoiding non-supply while also ensuring that all new plant achieved close to target RoI, would be difficult if not impossible. As explained in section 3.2, correlations between wind farms means that there are gaps during winter peaks when wind contributes little. But at the same time, wind farms are over-built to ensure security of supply during dry years.

Pricing non-supply was less of an issue, however, because we added four non-supply generators, two in each island, offering to generate at a price of $10,000/MWh[38]. When non-supply occurs, this is indicated by the dispatch of one or more of the four non-supply generators and during these periods spot prices are set at around $10,000/MWh. The Code includes rules[39] for when these situations occur, and they basically set spot prices at between $10,000/MWh and $20,000/MWh. We have chosen the lower limit as we believe it more likely that without these rules, spot prices would otherwise tend to settle at less than $10,000/MWh so would have to be increased to this value under the relevant rules.

The approach taken was to keep non-supply to very low levels, to assume that some short-term demand-side response (DSR) would occur at prices lower than $10,000/MWh (staged from $2,000/MWh up to $7,000/MWh), and to add grid-scale batteries to help to meet peak demand by charging overnight and discharging during peaks.

DSR assumes that consumers exposed to spot prices, assumed to be mainly commercial and industrial, would reduce demand at high prices to minimise their total costs of production.

Depending on scenario, up to 900 MW of grid-scale batteries were included in the modelling. Large grid-scale batteries are slowly starting to be deployed around the world, and the largest under construction is around 200 MW, so it is not unreasonable to expect battery capacity of several hundred MW to be connected to the grid in 2035 if they are required.

The capacity was adjusted alongside DSR to keep non-supply down to low levels. The scenarios requiring the greatest battery capacity were 100% and 100% High Demand Fast Tech (900 MW and 800 MW, respectively), and Electrification scenarios and it variants (500 to 550 MW each): in general, the more wind and solar connected to the grid, the greater the battery capacity required.

The batteries were modelled as being able to discharge at full power for either six or 12 hours and were modelled as charging up overnight at lower prices and then discharging during the day during periods of higher prices.

4.7 Official Conservation Campaigns and Tiwai Triggers

DSR and non-supply generators are included in all scenarios, variations and sensitivities to cover those very unlikely, extreme periods when there is not enough generation to meet demand in the very short term. The frequency of these events is reduced by the addition of batteries which storage energy overnight and release it during the day when demand is higher than at night.

But there are periods when the threat of short-term non-supply is zero, but due to falling levels in hydro storage lakes, the probability of non-supply at some point in the future starts to rise. Although the future in this case is weeks or months away, the historical records show that there are periods of many months when inflows to the hydro lakes can remain much lower than normal.

[38] $10/kWh.
[39] Known as "scarcity pricing".

The Code includes a mechanism for launching an official conservation camp (OCC) when certain criteria are met in terms of how likely it is that storage could reach zero, creating the need for rationing of supply. OCC's are calls for consumers to make voluntary savings with the objective of avoiding forced rationing, i.e. blackouts. These should be very unlikely events, so we have set the modelling up so that they occur between one and four times in each set of 87 inflow years in each scenario, variation or sensitivity.

There is currently a mechanism contained in the agreement between Meridian Energy and Tiwai out to 2030 which allows a pot-line at Tiwai to be turned off in the event that South Island storage falls below specified "trigger levels". In all but the Slow Tech Low Demand variations, in which Tiwai is closed, we have assumed the contract is extended in more-or-less its current form through 2035 and beyond, though the trigger levels are adjusted to work with contingent storage described in section 4.3. Tiwai pot line closures should also be very infrequent events so the trigger levels were also adjusted to ensure this was the case in all modelling runs.

4.8 Wind Farm Modelling

For hydro generation we have 87 years of historical inflows, but for wind farms we have no such record, and this is potentially a problem because it is known that there is a degree of correlation between wind speeds and inflows.

For example, imagine a year in which constant nor'westers top the southern hydro lakes: this is the type of weather that brings wind to Wellington and Palmerston North, and there are already several wind farms close to these cities. In other words, storms tend to bring wind and rain together, and vice versa.

There are some sites around New Zealand where there are longer term records of wind speeds, typically aerodromes near major and provincial cities. However, converting this data to wind speeds at wind farms is a complex process because of the impact that location, altitude and topography have on wind speeds. The approach taken for the ICCC modelling was to use data from a web site called *renewables.ninja* which takes a specified location and details of the wind turbines in a wind farm, and creates a synthetic series of wind farm output data back to the year 2000.

The synthetic data was checked against the output of existing wind farms and correlated well on a daily basis, not quite as well on an hourly basis. A wind farm output dataset was created for 13 regions around the country, and paired with inflows back to 2000. Prior to 2000 the wind speed data was paired randomly with inflows. This approach captured a degree of correlation between wind speeds and inflows, and correlations between wind regions: these turned out to be very important in keeping non-supply down to very low levels.

4.9 Solar Modelling

In all scenarios it was assumed that by 2035 there would be enough solar power installed behind-the-meter to generate just over 1,100 GWh per annum.

In addition, the assumptions for each scenario listed in Appendix A – Scenarios, Variations and Sensitivity Details include a net reduction in cost by 2035. The starting assumption for 2018 was between $110 and $130/MWh, well above wind farms and geothermal, but at the rates of decline in cost shown in the Appendix, eventually it becomes economic in some scenarios to build grid-connected solar farms.

All solar generation was modelled using solar profiles by region from NIWA. Behind-the-meter solar was subtracted from regional demand, but grid-scale solar farms were offered into the market as generation at an offer price of zero to ensure dispatch under all conditions.

4.10 Ancillary Services

Ancillary services support the operation of the electricity market in its primary function of supplying electrical energy to consumers. The three ancillary services of relevance to the modelling are:

- frequency keeping (FK);
- instantaneous reserves (IR);
- voltage support.

4.10.1 Frequency Keeping

FK is the process of maintaining the frequency of the AC grid in both islands at 50 Hz ±0.2 Hz.

When generators connect to the grid and generate, they must first synchronise with the system frequency by rotating at the correct speed to generate at 50 Hz in phase with the rest of the system. As long as generation exactly matches demand, then the frequency will remain constant at 50 Hz but if demand increases then the frequency will start to fall: the FK station senses the fall and responds by increasing its output until generation matches demand again. The process happens in the opposite direction if demand reduces. There is normally one FK station dispatched and it maintains the frequency in its island, and the HVDC link operates in FK control mode to maintain frequency in the other island.

The FK station only needs to be able to modulate its output through 30 MW to be able to maintain frequency, and there is at least one hydro station in each island that can do this. So even in the 100% Renewables scenario there is ample FK capacity available.

If the HVDC link is not operating in FK control mode for some reason, there is still ample capacity for FK. As a result, we have not explicitly allowed for FK in either island.

4.10.2 Instantaneous Reserves

The frequency may fall below 49.8 Hz if a large generator[40] has a sudden outage: instantaneously, demand exceeds generation and the frequency starts to fall, potentially very quickly if the outage is large. IR is dispatched along with generation every five minutes and represents spare generating capacity that is available but not generating: this can be in the form of a generator that is operating at less than its maximum output, called partly loaded spinning reserve (PLSR); or it can be a generating unit at a large hydro station that is spinning in synch with the frequency but not actually generating, called tail water depressed (TWD)[41].

A third form of IR is demand that is connected through a frequency-sensitive relay and which is disconnected if the frequency falls below a preset value, usually 49.2 Hz: this is called interruptible load reserve (ILR).

[40] In fact, any generator operating at 60 MW or more is considered a potential risk.
[41] A TWD unit has its turbine blades spinning in air or compressed air and therefore has no water coming through its penstock, but is ready to generate. But if required, water can be released through the penstock and the unit will start generating.

There is currently no ILR provided in the South Island because there is typically a surplus of IR provided by generators in this island, but in 2035 if more IR is required then load such as a pot line at Tiwai may be able to be provided as ILR, along with other demand such as ripple-controlled hot water and industrial loads.

What determines the dispatch of IR is the reserve risk, assessed separately in each island. The reserve risk is either the largest generator operating in the island or the risk associated with the HVDC link: the island receiving power from the HVDC link is potentially at risk if the HVDC link fails.

The HVDC link is configured in two halves, known as poles: Pole 2 and Pole 3[42], which have total steady-state capacity of 1,200 MW northward and 750 MW southward[43]. If both poles fail at very high power transfer levels then it is likely that non-supply will occur in the receiving island irrespective of the presence of IR, and there is a mechanisms in place to manage this contingency[44].

But the presence of two poles means that the HVDC link can lose one pole and continue to operate without interrupting power flows: the current limits in this respect are 650 MW for northward transfers and 619 MW for southward transfers.

In its FK control mode, the HVDC link is also able to share around 200 MW of IR between the two islands.

Currently, the risk in the North Island is typically set by e3p at up to 400 MW. The HVDC link is typically only a reserve risk in the North Island when it is transferring above 650 MW northward. A description of the dispatch of reserves gets rather complex from this point, but suffice to say that we have not modelled IR explicitly, because to do so in EMarket slows it down, usually by 50% - 100%.

However, not modelling IR in detail does not detract from the validity of the modelling output, because have made allowance for spare capacity to be available to ensure that IR can be provided at adequate levels in all scenarios, variations and sensitivities, except in the small number of dispatches which coincide with DSR or non-supply occurring.

Currently IR is provided by a mix of North and South Island PLSR and TWD and by North Island ILR. Analysis of ILR since 2007 showed that the quantity available has remained in a steady ratio to average demand: about 5.6%. On the assumption that this ratio remains constant, and the supply of ILR grows in proportion to demand, extrapolating the current supply of ILR of around 250 MW to 2035 gives 270 MW of ILR in the BAU scenario.

In addition, all existing hydro will be able to provide PLSR or TWD in 2035. In all but the 100% Renewables scenario there are peaking stations that can also provide PLSR. So, except in short periods of peak demand when non-supply occurs, there will be a mix of ILR, PLSR and TWD available. But even during these peaks, ILR will still be available[45].

In the 100% Renewables scenario, there will be no generators to create risk but there will still be the HVDC link as a risk in the island receiving power. But in this scenario the HVDC link is upgraded

[42] Pole 3 replaced Pole 1 after a major upgrade which completed at the end of 2013.
[43] At high power transfers the losses are high so the power arriving in the island receiving power is less to the tune of 7% for northward transfers and 3% for southward transfers.
[44] Known as Automatic Under-Frequency Load-Shedding (AUFLS).
[45] This does assume that ILR can be provided separately to DSR.

to be able to transfer 1,400 MW northward, which will also enable it to cover its own risk up to 1,000 MW in this direction. There is already 270 MW of ILR assumed to be available in 2035 in the North Island, but at its maximum transfer of 1,400 MW there will be around 1,280 MW received in the North Island, potentially leaving a gap between the risk (280 MW) and the IR available to cover this risk (270 MW) during peak demand periods when all available generation is required to be running, and hence cannot also provide IR. To ensure this risk is covered, and to allow a safety margin, we have limited the upgraded HVDC northward transfers to 1,200 MW northward as measured at the sending end.

4.10.3 Voltage Support

When AC power is transmitted over long distances, the voltage falls in the direction of power flow: power flowing northward into Auckland is a good example. At the far end, of the lines in Auckland, the voltage may fall sufficiently far that voltage corrections[46] in Auckland cannot make up the difference. In this case, either more generation is needed close to Auckland, or additional voltage support equipment must be installed in Auckland to correct the voltage drop.

A related issue is that of voltage stability, which refers to the possibility of voltage collapse after the loss of a key component of the AC grid, for example a large generator or a transmission line carrying large amounts of power. Voltage stability is managed by limiting the amount of power that can flow into a region over long transmission lines, and there are four such limits on the grid: one north into Auckland, one south into Wellington, one north into Christchurch and the top of the South Island, and one south into Tiwai. These four limits are discussed in section 4.11.

Transpower's latest Transmission Planning Report (TPR) discusses the issue of voltage stability in Auckland once the remaining Huntly units are retired, combined with demand growth and hence higher power flows into the region. We have assumed that this work will be required under all scenarios because the Huntly units will be gone in all scenarios and therefore the costs will be more-or-less the same across all scenarios.

It is possible that with the higher demand growth in the Electrification scenario that more voltage support equipment will be needed than in other scenarios, but then Electrification also has more generation built near Auckland in the form of wind farms and large scale solar, which will help to offset some of the voltage issues created by demand growth.

4.10.4 Batteries as an Ancillary Service

As we stepped from BAU to 100% Renewables, and in the Electrification scenario, the amount of wind generation increased substantially, introducing the issues described in section 3.2. Part of the solution to correlations between wind farms was to add grid-scale batteries, and we found that these batteries were essential to avoid excessive non-supply while still achieving close to target RoIs for new generating plant.

The batteries charge up over night when prices are typically lower and then discharge during the day during peaks when prices are typically higher, thus earning net revenue through the difference between night and day prices. However, this revenue was insufficient to justify the cost of these batteries even after allowing for the installed cost to fall to 70% by 2035. It is possible that batteries have other sources of revenue, for example in helping to reduce peak demand on local networks. But

[46] The transformers that reduce voltage from grid-level voltages of hundreds of kilovolts down to the voltages used in local networks, can compensate to a degree for voltage drops.

the other services might conflict with the primary purpose of the batteries in the modelling, which is to support wind generation, and solar to a lesser extent.

This raises the question of whether batteries, or other equipment, should be treated as a new ancillary service and its cost added to the cost of intermittent generation – primarily wind and solar. In other words, at very high levels of wind penetration, a new ancillary service might be required to make up for when it is calm during winter peaks: the service providers would make offers to provide the service; the ancillary market would be cleared[47]; the service providers would be paid the relevant clearing price; and the cost of the service would be paid by intermittent generators.

This approach is entirely consistent with the modelling, in which batteries were required to keep non-supply to very low levels, and it would also put price signals out into the wider market, leading to new solutions, innovation and competitive prices.

This approach was adopted for the calculation of wholesale prices, so all wholesale prices include the impact of adding the cost of the batteries to the LRMC of new wind farms, roof-top solar and grid-scale solar farms.

4.11 Wholesale Pricing

Ignoring IR, EMarket dispatches generation using the rules in the Code, and produces spot prices for energy at all 221 nodes in the modelled grid. The spot prices correctly include the impact of losses, periods when the HVDC link is constrained at its limit, and would also include the impact of transmission constraints on the AC grid if these were enabled.

Due to the continuing importance of large hydro generators and storage, wholesale prices are heavily influenced by water values, which are in turn primarily influenced by historical inflows, the offer prices of remaining thermal generation, the quantities of generation expected from all other sources of generation, and demand.

As we approach 100% renewables, there is less and less plant being offered at prices in the mid-range from $13/MWh up to the price at which DSR is offered, starting at $2,000/MWh. The water values are consistent with a fully competitive market, so the prices produced by EMarket are consistent with the offers from generators. But when offers from real generators are all at very low prices, much lower than their total costs, then the prices produced are not always sufficient to ensure that new generators achieve target RoI[48].

As a result, to ensure consistency, the wholesale prices published as results for all the scenarios were set based on competition in the contracts market to reflects the level of wholesale prices required to support the cost of the lowest cost new generation required in the target year, which in 2035 was wind[49].

In addition, the wholesale price for the 100% Renewables scenario includes an additional allowance for plant that might be built only to eliminate the small but persistent level of non-supply that occurs

[47] As part of the dispatch process.

[48] An underlying assumption of the modelling is that the existing energy-only market structure will be retained, albeit with enhancements along the way to 2035. The low level of wholesale pricing attained with 100% renewables could be an indication that the market structure needs to change, but this issue was not tackled directly. The use of wholesale contract prices includes the implicit assumption that the contract market will sustain a significant price premium relative to spot prices.

[49] For more information refer to the costs report.

in this scenario during winter peaks. In effect, additional battery capacity has to be added to this scenario and this capacity is only used on those infrequent occasions when all DSR is dispatched and non-supply is about to occur.

4.12 Transmission and Distribution

EMarket's grid is capable of modelling local networks, but the information required to do this is not in the public domain, so we only run EMarket with the transmission grid. The full grid has over 850 lines and large transformers, and around 500 nodes, about half of which are GIPs or GXPs. EMarket can work with this level of detail but it slows down the runs. By judicious aggregation of lines, we can achieve a high level of grid detail with 292 lines and 221 nodes. Many lines in the grid run in parallel, so we simply aggregate these into one equivalent line[50].

Many nodes where there is a GXP actually have more than one GXP, e.g. one at 220 kV, one at 66 kV and one at 33 kV. Having all four of these nodes in EMarket adds little if anything to the modelling, as the prices at these nodes are almost always very close. There are key exceptions, particularly where 110 kV and 220 kV lines connect two loops in the grid via a transformer, at Kawerau for example. In these cases, it is important to model both the 110 kV and 220 kV nodes because they can be a "pinch point" in certain circumstances.

Every line in EMarket's modelled grid has a capacity in MW, and in the real market the dispatch will never load a line above its capacity. This can also be enforced in EMarket, but if lines start to reach their limits (we say "constrain") often, then it can slow the run down considerably. In reality, if a line starts to constrain frequently, causing costs to increase significantly for wholesale market participants, then Transpower will put up the case to upgrade the line in some way so as to eliminate the constraint.

The approach we have taken is to enforce the limits on the HVDC link but not on lines in the AC grid. Effectively, this means that we do look at the case to upgrade the HVDC link, but for all AC lines we assume that if they constrain frequently then Transpower will upgrade them and the constraint will disappear by 2035.

There is a second class of potential constraints on the grid known as "equation constraints" and these put a limit on the total power flowing in two or more lines, not just one. These are used either to limit the power flowing from one region of the grid to another, e.g. from the Waikato to Auckland, or to ensure that a line does not exceed a safe power transfer level after a sudden outage in a nearby line (known as "SFT" constraints).

Key examples of regional equation constraints are the four voltage stability constraints mentioned in section 4.10.3 on voltage support. Examples of the SFT constraints appear in the real market from time to time, but there are over 700 that could potentially appear. We have not considered SFT constraints in the modelling due to the large amount of work that would be required, so effectively we have assumed that Transpower would upgrade the grid, or install alternatives to the SFT constraints[51], if they were to constrain frequently.

[50] This raises the question of how one line would be modelled as in outage, and the other not, but this can be done in EMarket.

[51] Examples of alternatives include 'special protection schemes' which use automatic systems to prevent lines from overloading, e.g. by disconnecting nearby generation.

Despite not having enforced the limits on all AC lines, and on the four key voltage stability constraints, we have post-processed the large amount of power flow data produced by EMarket to check for any lines or voltage stability constraints that might constrain.

An implicit assumption in this analysis is that the voltage stability constraints and line limits do not change over time, but this may or may not be the case. For example, when Huntly is retired it is possible that the voltage stability constraint into Auckland might have its limit lowered, if not permanently then at least until new voltage support equipment is installed in Auckland.

The transmission analyses for key scenarios are presented in the following four sections, and scenarios, variations and sensitivities not shown can be inferred from those that are. Overall, our conclusions are that the line constraints that become evident are relatively few in number given the significant increase in demand in 2035 in the BAU scenario: the grid appears to be capable of supporting supply well into the futures. The Electrification scenario has by far the most generation, but it also has the greatest demand which serves to “soak up” much of the new generation that is built to meet demand growth locally, thus reducing the impact on the grid.

Another key factor in the rate of occurrence of constraints is that in the scenarios with the largest number of wind farms, we have to move some of them to reduce correlations between the output of wind farms, thus tending to take pressure off the grid in the regions where there is already a predominance of wind farms.

The lines that do constrain are either already well signaled as needing upgrade at some point in the future, or the result of new generation being built in a small number of areas where there is limited capacity.

It is somewhat of a surprise that the voltage stability constraint southward into Wellington constrains as much as it does, but as demand increases in the South Island and in Wellington, we can expect greater power flows from Bunnythorpe through to Wellington, resulting in an increase in these constraints.

4.12.1 BAU Transmission

In the BAU scenario there are ten lines and one voltage stability constraint that exceed their respective limits, as shown in Table 4 below.

Table 4 – Lines that Exceed Limits in BAU

Line Identifier	Description	Average Exceedance Across All 87 Inflow Years	Average Exceedance (MW)	Maximum Exceedance (MW)	Comment
TWC_TWT	Connects Tarurua wind farm to the substation at BPE (Bunnythorpe) near Palmerston North	8.85%	18.4	60.5	Would need to be upgraded to support BAU wind generation because 8.85% exceedance represents 775 hours per year on average
NSY_ROX	One of the main transmission paths connecting the Clutha and Waitaki valleys	4.42%	21.0	103.1	Upgrading these lines is already approved, but Transpower is waiting until the need arises, which would be the case in the BAU scenario.
LIV_NSY	As for NSY_ROX above[52]	1.10%	19.9	108.0	As for NSY_ROX above
BPE_MTR	Part of the 110 kV link from BPE to the upper North Island	0.42%	3.7	21.5	Already limit transfers to the upper north island and is due for upgrading

[52] ROX_NSY and NSY_LIV connect at Naseby and are in series between Roxburgh and Livingstone on the Waitaki River.

Line Identifier	Description	Average Exceedance Across All 87 Inflow Years	Average Exceedance (MW)	Maximum Exceedance (MW)	Comment
RPO_TNG	Part of a key transmission path from BPE to the geothermal area north of Taupo	0.34%	19.4	118.0	This line is already identified in the TPR as possibly needing an upgrade
BPE_TNG	As for RPO_TNG above	0.25%	12.4	72.1	As for RPO_TNG above
MTR_OKN		0.05%	2.3	11.4	Upgrade may not be justified
BPD_WTK		0.04%	1.1	5.8	Upgrade may not be justified
OKN_RTR		0.01%	1.7	6.5	Upgrade may not be justified
ONG_RTR		0.002%	1.2	3.5	Upgrade may not be justified

For example, OKN_RTR exceeds its limit on average 0.01% of the time over 87 years, which equates to an average of 53 minutes per year, so it might not ever be upgraded as the benefits might exceed the costs.

Ten lines from a total of 221 modelled lines have constraints. Four of them are so infrequent that the impact on generation would be small and so upgrades may not be justified. Five of the other six are already due for an upgrade at some point, leaving only one, TWC_TWT, that is currently not anticipated, but we assume would be undertaken to connect substantially larger amounts of wind generation at the TWC GIP.

Voltage stability south into Wellington constrained 0.06% of the time on average across 87 years, or 5.3 hours per year on average, although this constraint is only likely to constrain during dry periods with a combination of high levels of HVDC transfer southward and medium to high Wellington demand. But at this level an upgrade may or may not be justified.

4.12.2 Slow Tech Low Demand Transmission

Slow Tech Low Demand variations are characterized by the closure of Tiwai, and it is widely known that should this occur then upgrades will be undertaken in the lower South Island to allow power to move northward when the lower South Island hydro lakes are full.

We also upgrade the HVDC link in these variations because northward flows increase substantially. But otherwise, the lack of demand growth means that there would be no additional upgrades contemplated under this variation.

4.12.3 100% Renewables Transmission

In the 100% Renewables scenario there are 13 lines and one voltage stability constraint that exceed their respective limits, three more than in the BAU scenario, as shown in Table 5 below.

Table 5 – Lines that Exceed Limits in 100% Renewables

Line Identifier	Description	Average Exceedance Across All 87 Inflow Years	Average Exceedance (MW)	Maximum Exceedance (MW)	Comment
COL_HOR	Two lines that connect the Coleridge and Hororata power stations	15.3%	6.5	17.0	Would need to be upgraded because Coleridge power station is upgraded. The TPR notes that the capacity could be increased by reconductoring these lines
ATI_WKM	Forms one side of the "Warakei triangle"	7.2%	15.7	90.6	Would need to be upgraded because of the additional geothermal plant built in the Wairakei triangle
RPO_TNG	See Table 4	3.1%	29.0	171.1	See Table 4
NSY_ROX	See Table 4	2.1%	25.0	145.5	See Table 4

Line Identifier	Description	Average Exceedance Across All 87 Inflow Years	Average Exceedance (MW)	Maximum Exceedance (MW)	Comment
FHL_TUI	Connects Tuai generation to the main grid	1.3%	6.8	38.6	Would need to be upgraded because a wind farm and a small hydro generator are built and are connected to the Tuai GIP
LIV_NSY	See Table 4	1.2%	26.3	129.9	See Table 4
BPE_TNG	See Table 4	1.1%	22.4	122.4	See Table 4
RDF_TUI	See FHL_TUI above	1.1%	6.7	42.4	See FHL_TUI above
KOE_MPE	Connects Kaitaia to the grid	0.4%	8.8	36.0	Would need to be upgraded because the Ngawha geothermal station is expanded and a large solar farm connects to Kaikohe
BPE_MTR	See Table 4	0.07%	2.9	15.0	See Table 4
BPD_WTK	See Table 4	0.04%	1.0	3.1	See Table 4
BPE_TKU	Part of a key transmission path from BPE to the geothermal area north of Taupo	0.04%	28.4	102.2	Upgrade may not be justified
RDF_RDF	An interconnection between the 110 kV and 220 kV grids at Redclyffe between Napier & Hastings	0.003%	4.8	7.9	Upgrade may not be justified

Voltage stability south into Wellington constrained 0.07% of the time on average across 87 years, or 6.1 hours per year on average, although this constraint is only likely to constrain during dry periods with a combination of high levels of HVDC transfer southward and medium to high Wellington demand. But at this level an upgrade may or may not be justified.

4.12.4 Electrification Transmission

In the Electrification scenario there are 14 lines and one voltage stability constraint that exceed their respective limits, four more than in the BAU scenario, as shown in Table 5 below.

Table 6 – Lines that Exceed Limits in Electrification

Line Identifier	Description	Average Exceedance Across All 87 Inflow Years	Average Exceedance (MW)	Maximum Exceedance (MW)	Comment
BPE_WDV	Two 110 kV lines connecting the 110 kV grid to the 220 kV grid atBPE	17.1%	17.9	134.0	There is currently a special protection scheme in place to protect these but the addition of new wind farms around BPE would require an upgrade on these lines
NSY_ROX	See Table 4	7.4%	29.8	148.9	See Table 4
BPD_WTK	See Table 4	3.4%	4.1	18.0	See Table 4
LIV_NSY	See Table 4	2.4%	27.5	130.8	See Table 4
BPE_MTR	See Table 4	1.9%	7.2	43.9	See Table 4
RPO_TNG	See Table 4	0.8%	14.2	145.1	See Table 4
STK_STK	An interconnection between the 110 kV and 220 kV grids at Stoke, the main supply point for Nelson and Marlborough	0.8%	3.6	12.6	Would be upgraded due to additional demand in the region
MTR_OKN		0.6%	5.3	28.8	Upgrade may not be justified
BPE_TNG	See Table 4	0.3%	13.5	93.0	See Table 4
OKN_RTR		0.3%	3.8	21.7	Upgrade may not be justified
ATI_WKM	See Table 5	0.2%	8.6	52.2	May need to be upgraded because of the additional geothermal plant built in the Wairakei triangle
ONG_RTR		0.2%	3.1	17.5	Upgrade may not be justified
ONG_RTO		0.08%	2.3	12.2	Upgrade may not be justified
EDG_KAW		0.06%	1.8	7.0	Upgrade may not be justified

Voltage stability south into Wellington constrained 0.95% of the time on average across 87 years, or 83.2 hours per year on average, and at this level we believe an upgrade would be justified.

4.13 Accuracy and Limitations

Modelling has its limitations, which has implications for the validity of the key results, these being:

- the emissions produced in each scenario, variation or sensitivity run;
- the cost of the 2035 build schedule;
- the cost of achieving each increment of carbon abatement;
- the management of dry year security;
- the frequency and size of DSR and non-supply events;
- the amount and frequency of price spikes, demand-side response to price spikes, and non-supply events;
- spot prices.

If the scenarios are well formed, then our ability to model them accurately with I-Gen and EMarket, in particular, is very high: so getting the scenarios 'right' in the first place is important. Our role was to model the scenarios and readers should refer to the main report where the scenario selection process is described in detail.

4.13.1 Emissions

Once the scenario is specified in terms of demand growth and, if relevant, the target renewables percentage, then the 2035 build schedule is constructed from our list of consented and otherwise potential new projects which we keep up to date from publicly available sources including energy-related web sites or publications that we subscribe to.

Not on this list, however, are projects that are not in the public domain, for whatever reason, but that could nevertheless be built between now and 2035. When we create a build schedule, we can only use the information available to us, either specific to a project or generic to a class of projects, for example the expected cost of constructing a wind farm between now and 2035. But it might be that a project is built at a different time or to a different specification because of factors that are peculiar to the project which may be inconsistent with purely economic considerations. For example, householders may install solar power at a rate that is higher than would be expected given its cost.

There may also be projects which are possible, or even consented, but which currently are so expensive or difficult that they are not on our list, the Kaipara harbour tidal project being a case in point.

Furthermore, there may be technologies that are currently far from being mainstream that by 2035 have had major breakthroughs which greatly improve their economic viability and availability.

The exact contents of our project list, however, has a greater impact on the cost of the new build and on the operating costs, than it does on the total emissions from the sector, which are a function of the physical quantity of renewables, not its cost. The only exception to this is the building of new geothermal generation which is considered to be renewable, but which nevertheless has significant emissions: hence the primary uncertainty in emissions is the amount of geothermal that is built in each run.

4.13.2 Dry Years and Inflows

Management of dry year security is a key factor to be considered in the transition to a lower carbon electricity supply, due to our reliance on hydro-electricity, and as the thermal fleet is reduced in size. The total energy available can be adjusted in the build schedule, and then the settings within

EMarket's water valuation module are adjusted to ensure security of supply to any specified standard given the inflow data available, which means that the inflow data is the key area of uncertainty.

It is conventional to use historical inflow data back to around 1930[53] on the assumption that the last 87 years[54] are representative of what will happen in future: is this a reasonable assumption? The answer is that it is probably realistic, but we cannot be totally sure. Most new inflow sequences fall within the envelope of the historical dataset, but there are still new records being set, for example the record low South Island inflows in the summer and autumn of 2012 and then again from February to July 2017[55].

There also appear to be outliers in the historical dataset at both the wet and the dry ends of the inflow spectrum, and we have observed a 20-year trend toward it being drier in the South Island from February to April and wetter in winter.

Finally, can we really be sure that inflows were recorded as accurately in 1931 as they are today? This is a particularly important question because some of the driest inflow years on record were in the 1930s, 1932 and 1937, in particular.

Nevertheless, the historical dataset is the best that we have, and it gives a wide range of possible future outcomes for inflows which is ideal for testing scenarios in 2035. In addition, the way that water values are calculated means that storage is managed to a higher standard than if we assumed that each historical inflow sequence would only ever happen exactly as it happened in the past. In effect, EMarket's water value algorithm allows for the possibility that sequences that are drier than those in the historical record would be 'survivable'.

4.13.3 Wind Farm Output

It is known that there is a degree of correlation between wind speeds and inflows, and strong correlations between the output of wind farms within regions around the country. The use of synthetic wind farm output data back to 2000 obtained from *renewables.ninja*, combined with actual data from existing wind farms, allowed the impact of some of these correlations to be included in the modelling.

Ideally, the synthetic wind farm data would extend right back to 1931 to match the inflow dataset. It would also ideally allow the modelling to test the impact of random fluctuations in wind speed on a sub-day time frame on the ability of the electricity supply system to meet peak winter demand.

Nevertheless, the 87 years of inflow data combined with 20 years of wind speed data provides us with a very large number of combinations of wind farm output and hydro storage down at the three-hour level at which the modelling was done, which provides a high degree of assurance that the modelling of the interactions between wind and wind, and wind and hydro, is robust.

4.13.4 Spot Prices

We know from "back-casting" with EMarket against past years, and from its construction, that it models the market well, provided we can capture in its inputs all of the key parameters. But back-casting shows that there are periods where EMarket diverges from the real market, usually in terms of spot pricing, and these appear to be periods where there is key data that is not in the public

[53] Our inflows are based on the dataset produced by Opus International for the Electricity Authority, which starts April 1931, but there is another dataset produced by NIWA which dates back to 1928.
[54] From April of this year there will be 88 years of data.
[55] See https://www.energylink.co.nz/news/blog/records-fall-dry-period-continues

domain: hedge contracts between the four major players in the market, and large contracts for gas are the likely missing data.

But the spot market underlies everything in the electricity market[56] so in the long run, contracts tend to reflect expectations of spot prices, and if gas prices remain too high for thermal generators to compete with new renewable generation then they will exit the market. So we can conclude that spot prices are the key pricing data for the ICCC modelling[57] and contracts can be ignored that far ahead.

However, one aspect of the market that we are not capturing in the modelling is the impact of unplanned outages. These do occur in the real market and they can and do result in large price spikes which typically have a small impact on average spot prices, but can occasionally be more significant: the recent unplanned outage of the offshore pipeline from the Pohokura gas field is a case in point. Such an outage is a highly unlikely event, but it has nevertheless had a significant impact on the average spot price for the last year. For longer term modelling, however, there are inflow sequences that are drier than any experienced in the 22 years over which the spot market has operated, so the assumption is that these will produce price outcomes that will make up for any loss of detail in modelling unplanned outages.

5 Comparison of Scenarios

The results of the modelling are outlined in the main report, but in this section we briefly compare the results of the various scenarios and highlight some key outputs not covered in earlier sections. Appendix B – Run Details shows the generation output of all generators included in each modelling run.

In the table below, the capital cost is the cost of constructing new plant including solar installed 'behind-the-meter' (at home, for example) but excluding the cost of grid-scale batteries. The emissions attributed to electricity exclude those cogen sites whose emissions are allocated to industry instead of to electricity generation.

COGEN EMISSIONS

A cogeneration plant produces both heat and electricity, and in New Zealand is always associated with an industrial site: the cogen may be on the same site, or heat in the form of water or steam may be piped to a nearby site.

The electricity is used either on the industrial site, or excess electricity is exported into the local network or the grid. About 390 MW of capacity (both grid-connected and non-grid connected) is from cogen.

For the purposes of allocating cogen emissions to sectors, the emissions from cogen plants that produce electricity as their primary purpose are attributed to the electricity sector in New Zealand's emissions inventory. Emissions from other cogen plants are attributed to other sectors.

Glenbrook, Kinleith, Kapuni, Te Rapa and Kiwi Cogen were included in the modelling, while smaller cogen (for which accurate output data is not available) was included implicitly in reduced demand.

Emissions from Kapuni, Te Rapa and Kiwi Cogen are counted in electricity emissions, along with 15% of the emissions from Kinleith.

[56] All electricity generated has to be sold into the spot market and all electricity sold to consumers has to be bought from the spot market. The only exception is on-site generation that never makes it onto the relevant local network.
[57] And in fact for all modelling of the market in future.

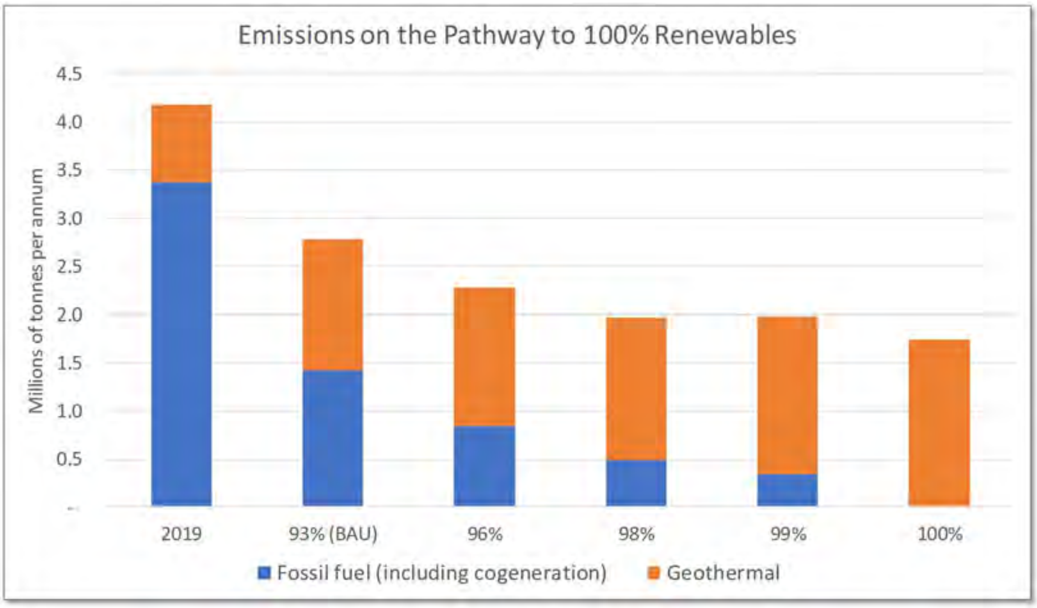
Table 7 – Summary Results

Annual Results Averaged Over 87 Inflows	BAU	96.0%	98.0%	99.0%	100.0%	Electrification	BAU Low Demand Slow Tech	BAU High Demand Fast Tech	98% Low Demand Slow Tech	98% High Demand Fast Tech	100% Low Demand Slow Tech	100% High Demand Fast Tech	Electrification Low Demand Slow Tech	BAU Higher Carbon Price ($150/t)	BAU Higher Gas Price ($19/GJ)	BAU Constrained Hydro	Electrification Higher Carbon Price ($150/t)	Electrification Peakier Demand
Renewables	92.6%	95.9%	97.9%	98.6%	100.0%	91.7%	91.0%	93.2%	98.8%	97.8%	100.0%	100.0%	91.6%	96.5%	97.1%	92.5%	96.3%	91.6%
Capital Cost ($Billion)	$8.4	$9.9	$10.5	$11.0	$13.4	$13.3	$0.3	$12.7	$2.7	$14.4	$3.8	$17.7	$6.2	$10.7	$10.7	$8.4	$17.0	$13.3
Total Generation (GWh)	49,196	49,235	49,289	49,278	49,213	57,197	38,491	55,872	39,088	55,148	38,283	55,022	47,837	49,250	49,250	49,192	57,281	57,194
Total Emissions attributed to electricity (g/kWh)	57	46	44	45	35	66	55	58	38	43	32	37	67	36	47	57	38	57
Emissions excl. Co-Gen (g/kWh)	50	39	40	40	35	51	46	52	32	39	31	37	60	29	40	50	32	51
Emissions Geothermal only (g/kWh)	28	29	30	33	35	28	21	32	27	32	31	37	34	22	36	28	26	28
Solar Generation (GWh)	1,108	1,108	1,108	1,222	2,108	1,887	503	3,138	503	3,694	503	4,138	503	1,108	1,108	1,108	2,108	1,887
Wind Generation (GWh)	7,528	8,841	9,424	9,244	9,160	11,150	2,453	10,241	3,636	12,001	3,428	11,182	5,286	10,171	8,115	7,496	13,908	11,112
Geothermal Generation (GWh)	11,916	12,555	12,757	13,116	13,562	13,361	7,816	14,211	10,409	13,562	11,512	15,566	13,361	11,390	14,044	11,916	13,160	13,361
Co-Gen Generation (GWh)	1,231	1,231	560	560	560	1,231	1,231	1,231	560	560	267	560	1,231	1,231	1,231	1,231	1,231	1,231
Thermal Generation (GWh)	2,620	1,036	1,013	701	0	3,756	2,453	2,779	466	1,198	0	0	2,994	705	441	2,705	1,097	3,792
Hydro Generation (GWh)	24,793	24,464	24,426	24,435	23,823	25,813	24,036	24,273	23,513	24,131	22,573	23,690	24,462	24,645	24,311	24,737	25,778	25,812

The capital cost of new plant in the BAU scenario is $8.4 billion and this achieves 92.6% renewables on the assumption that Huntly and the TCC are closed by 2035, and that the only new thermal plant built is for peaking and hence has a low capacity factor, much lower than it would be today.

The following chart shows the total emissions per year for the pathway from BAU to 100% renewables, along with an estimate for 2019, split between thermal stations and cogen, and geothermal.

Figure 4 – Emission Pathway to 100% Renewables



The chart shows a steady fall in emissions from thermal stations, but an important point to emphasise is that geothermal generation is counted as renewable generation even though it has non-zero emissions[58]: in fact, in the 100% renewables scenario the emissions are totally due to geothermal generation, all of which is built in this scenario.

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[58] Known as "fugitive" emissions: these are not the result of combustion of fossil fuel, but rise to the surface with the geothermal steam.

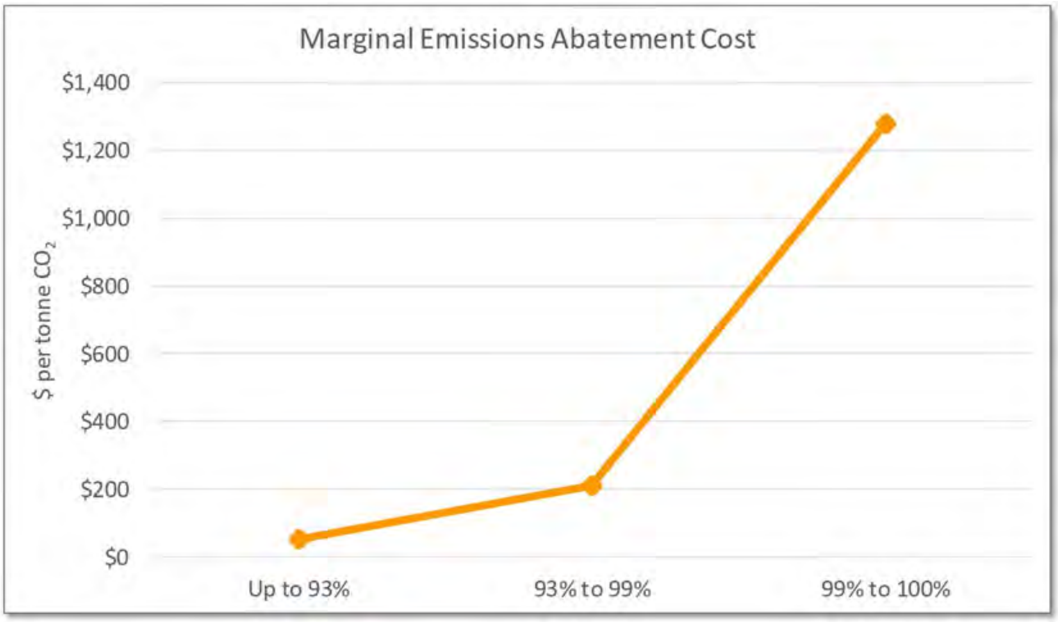
Along the way to 100% renewables, as new geothermal generation is built this serves to increment emissions, while the reduced running hours of thermal plant serves to decrement emissions, so the net increment in emissions between scenarios depends on the geothermal-thermal mix.

Nevertheless, the results highlight the fact that \$8.4 billion capex in the BAU scenario reduces emissions from its current value of around 4.22 million tonnes[59] p.a. to 2.78 million tonnes in 2035, but to get to 100% renewables costs an additional \$5.0 billion in capex.

The marginal cost of carbon abatement is shown in Figure 5 below, where the annual system costs include capex of new plant, variable costs for all plant, and the costs associated with scarcity, i.e. demand response, OCCs, Tiwai response when triggered, and non-supply. The capital costs of plant existing today are not included as these are sunk costs.

The marginal cost in each case is the change in the system cost from one scenario to the next, i.e. from present to BAU at 93% renewables, BAU to the mid-ninety percent range, and then for the last step from 99% to 100%. This illustrates how the cost of the last tonne of reduction in emissions increases sharply as the market moves beyond scenarios which have renewable penetration in the mid to high ninety percent range.

Figure 5 – Marginal Abatement Cost per Tonne CO_2



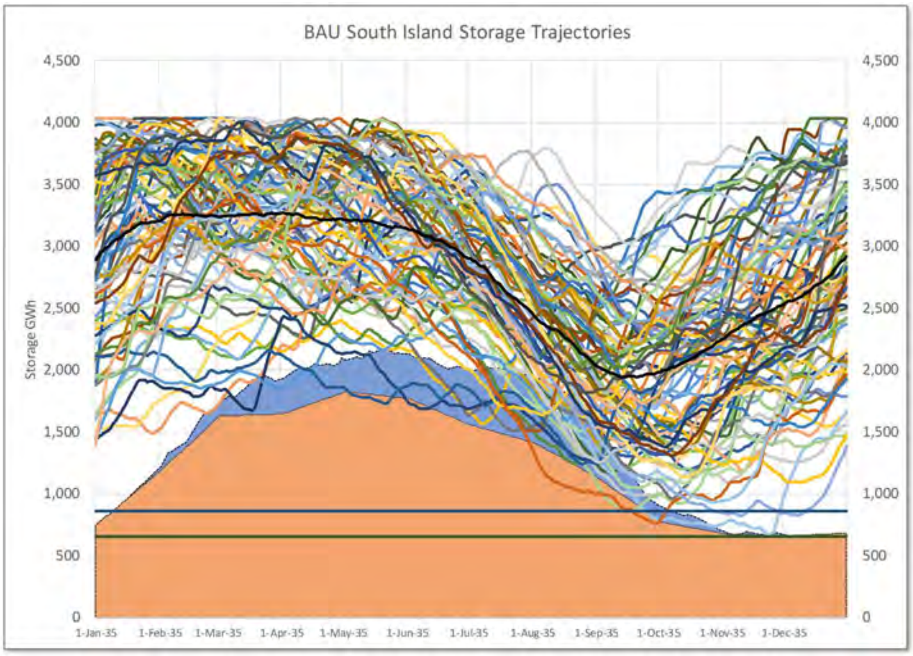
The key driver of the additional construction cost is the need to over-build wind farms to ensure security of supply in dry years. In the BAU scenario, new wind farms achieve capacity factors of around 40% but by the time we reach 100% renewables this falls to just under 32%. In contrast, geothermal generators maintain capacity factors of around 92% through all scenarios and, as a consequence, tend to achieve higher-than-target RoI in the 100% Renewable scenario: the list of potential new geothermal projects and geothermal expansions is limited to 712 MW so no more are built.

[59] MBIE data from the year ending 30 September 2018.

5.1 Hydro Storage

Figure 6 shows the 87 storage trajectories from the BAU scenario for the major South Island hydro lakes, which are typical of the trajectories for all scenarios, variations and sensitivities, with only subtle differences between them.

Figure 6 – South Island Storage Trajectories



The trajectories start at the levels that they ended with on 31 December 2034: this range of starting storage ensures that we correctly account for inflow scenarios which are dry for two years in a row. The trajectories also end in a similar range, which indicates that future dry years will be manageable.

The horizontal green line at 654 GWh is the upper boundary on contingent storage in Lakes Hawea and Pukaki, which can be used in a situation in which an OCC is declared. The horizontal blue line at 854 MW is contingent storage plus storage in Lakes Manapouri and Te Aanu which is typically not used but can be used, for example, in an extremely dry year.

The tops of the orange and blue shaded areas represent the trigger storage values used to determine if a pot-line at Tiwai is to be turned off during a period of extremely low storage. These values are based on the values currently in the contract between Meridian Energy and Tiwai, but moved down by 200 GWh to adjust for the fact that we are allowing storage to go lower in 2035 than it does now, an assumption that is based on the need to use more of the available storage as the percentage of renewables increases.

Tiwai is triggered to take a pot-line out of service if South Island storage falls below the top of the orange shaded region for more than 40 days and then the total energy reduction is 250 GWh spread over a period of 130 days.

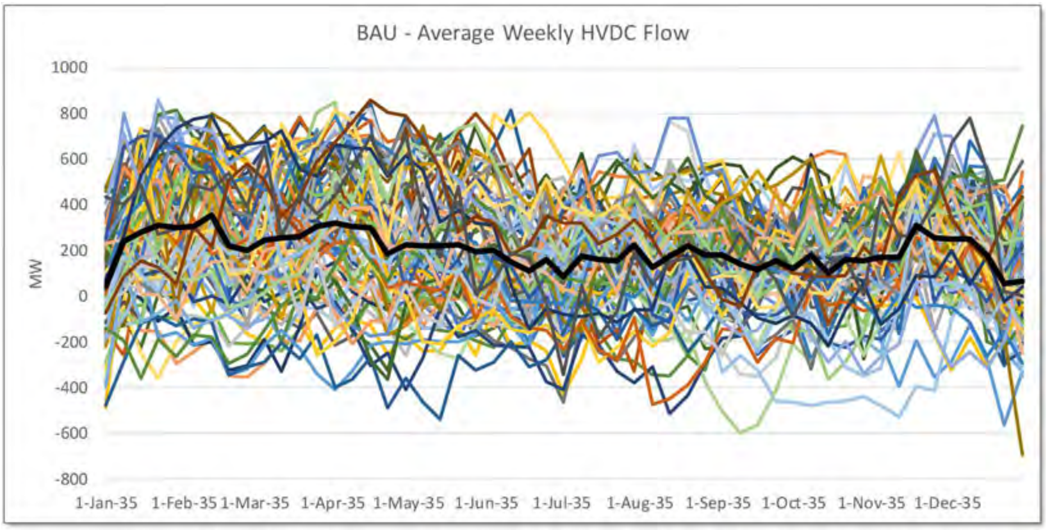
It is important to note that even though the water values for the major South Island reservoirs are based on the contingent storage being available, there are no years in the BAU in which storage actually drops into the contingent zone shown on the chart[60].

Storage outcomes in other scenarios, variations and sensitivities are similar, with minor variations. For example, storage is held higher in the 100% Renewables scenario because the major hydro lakes have to operate more conservatively than in other scenarios.

5.2 HVDC Flows

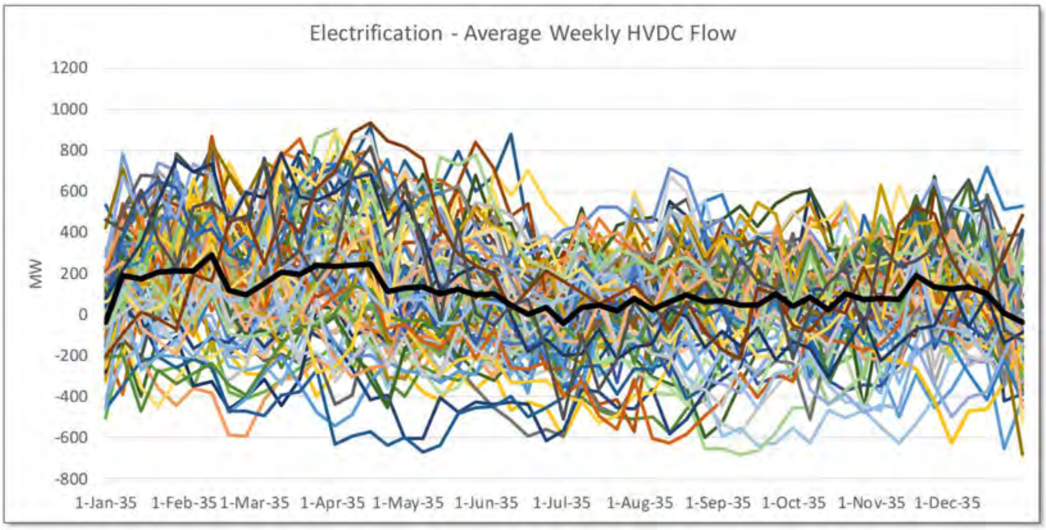
The following three charts illustrate an interesting feature of the 100% Renewables scenario. They show the weekly average HVDC flows by inflow year, plus the average over all inflows in black. In the BAU and Electrification scenarios the HVDC flows peak, on average, in spring or summer when demand is low or falling, and inflows into the major South Island storage lakes are expected to peak due to spring nor'westers and snowmelt.

Figure 7 – BAU Average Weekly HVDC Flow



[60] Although there is nothing to say that, for example, storage in Pukaki could be 10 GWh above its contingent zone while storage in Hawea is 10 GWh into its contingent zone.

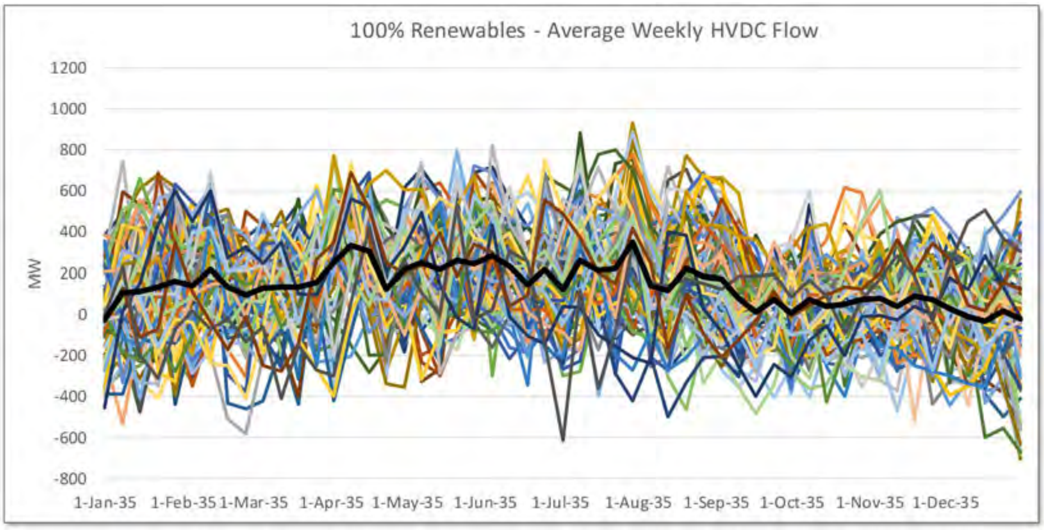
Figure 8 – Electrification Average Weekly HVDC Flow



In contrast, HVDC flows peak in winter in the 100% Renewables scenario, which is caused by a combination of two features of scenarios with renewables at or close to 100%:

1. South Island generation must be exported north to help meet peak demand in the North Island in winter; and
2. we have moved some wind farms from the locations shown our project list to other locations to reduce correlations between wind farms, which is required to keep DSR and non-supply down to levels that are acceptable to consumers.

Figure 9 – 100% Renewables Average Weekly HVDC Flow



5.3 DSR and Non-supply

Table 7 includes DSR and non-supply for all scenarios, variations and sensitivities and these are highlighted in the table below. The units in the table are MWh and represent the average annual amount across all 87 inflows modelled in each run. For example, the BAU scenario has an average of 39 MWh of non-supply per annum in the North Island: this is roughly equivalent to 48,880 houses having no supply for one hour[61], on average in each of the 87 years.

Before non-supply occurs, indicated by dispatch of the four non-supply ‘generators’ modelled, DSR is triggered. DSR is also modelled as generation but it actually represents consumer load that is exposed to spot prices: consumers are assumed to turn this load down or off at prices between $2,000/MWh and $7,000/MWh.

In the BAU scenario, for example, is 1,878 MWh of DSR which is equivalent to 187.8 MW of commercial and industrial demand being turned off for ten hours in each year on average.

Table 8 – DSR and Non-supply Summary

Annual Results Averaged Over 87 Inflows	BAU	96.0%	98.0%	99.0%	100.0%	Electrification	BAU Low Demand Slow Tech	BAU High Demand Fast Tech	98% Low Demand Slow Tech	98% High Demand Fast Tech	100% Low Demand Slow Tech	100% High Demand Fast Tech	Electrification Low Demand Slow Tech	BAU Higher Carbon Price ($150/t)	BAU Higher Gas Price ($19/GJ)	BAU Constrained Hydro	Electrification Higher Carbon Price ($150/t)	Electrification Peakier Demand
DSR (MWh)	39	3,959	4,713	4,952	8,191	3,230	471	4,505	1,448	6,396	3,100	13,996	2,544	4,286	4,175	1,794	5,801	4,248
Non_Supply NI (MWh)	0	536	722	832	3,707	306	14	466	120	1,039	737	6,218	159	425	416	40	1,301	481
Non_Supply_SI (MWh)	0	8	20	19	245	314	0	417	0	577	0	1,295	0	0	0	0	440	469

Non-supply is kept close to zero in the BAU scenario, but it gets increasingly harder to avoid non-supply as the percentage of renewables increases, especially in the North Island on cold winter evenings when the HVDC link reaches its limit northward (even after upgrading it to 1,400 MW and allowing it to reach 1,200 MW northward from the Benmore dam) and it is calm.

In the 100% Renewables run there is a total of 3,952 MWh of non-supply. Non-supply could be eliminated but it would require further over-building of wind farms and solar, or addition of more grid-scale batteries, which is assumed not to occur because none of the additional plant would be economic to build. However, the wholesale price for 100% renewables does include an allowance for additional plant that is built only to provide the “last mile” of supply – refer to section 4.11.

[61] Assuming an average North Island home consumes 7,000 kWh per annum.

6 Appendix A – Scenarios, Variations and Sensitivity Details

The colour shading indicates settings that differ from those used in the BAU scenario.

Scenario, Sensitivity	Demand Growth	Tiwai	EV Demand	Process Heat Demand	Behind-the-meter Solar	Thermal Retirements	Plant Cost Escalation	Gas Price	Carbon Price	Hydro	Peak Demand
BAU	0.5% p.a.	Stays	2.7 TWh p.a.	0.6 TWh p.a.	1.1 TWh p.a.	Huntly, TCC	Wind -0.5% p.a. & solar -3.1% p.a.	$9.50/GJ	$50/tonne	As currently consented	Based on current patterns
BAU - Slow Tech Low Demand	0.1% p.a.	Goes	1.7 TWh p.a.	0.1 TWh p.a.	0.5 TWh p.a.	Huntly, TCC	Wind none & Solar -1.55% p.a.	$9.50/GJ	$50/tonne	As currently consented	Based on current patterns
BAU - Fast Tech High Demand	1.0% p.a.	Stays	3.8 Twh pa.a	2.5 TWh pa.a	3.0 TWh p.a.	Huntly, TCC	Wind -0.9% p.a. & solar -4.05% pa.a	$9.50/GJ	$50/tonne	As currently consented	Based on current patterns
BAU - Carbon $150/tonne	1.0% p.a.	Stays	3.8 Twh pa.a	2.5 TWh pa.a	3.0 TWh p.a.	Huntly, TCC	Wind -0.9% p.a. & solar -4.05% pa.a	$9.50/GJ	$150/tonne	As currently consented	Based on current patterns
BAU - Gas price $19/GJ	1.0% p.a.	Stays	3.8 Twh pa.a	2.5 TWh pa.a	3.0 TWh p.a.	Huntly, TCC	Wind -0.9% p.a. & solar -4.05% pa.a	$19/GJ	$50/tonne	As currently consented	Based on current patterns
BAU - Hydro Reduction	1.0% p.a.	Stays	3.8 Twh pa.a	2.5 TWh pa.a	3.0 TWh p.a.	Huntly, TCC	Wind -0.9% p.a. & solar -4.05% pa.a	$9.50/GJ	$50/tonne	Increased extraction & minimum flows[62]	Based on current patterns
96% Renewables	0.5% p.a.	Stays	2.7 TWh p.a.	0.6 TWh p.a.	1.1 TWh p.a.	Huntly, TCC, e3p	Wind -0.5% p.a. & solar -3.1% p.a.	$9.50/GJ	$50/tonne	As currently consented	Based on current patterns
97% Renewables	0.5% p.a.	Stays	2.7 TWh p.a.	0.6 TWh p.a.	1.1 TWh p.a.	Huntly, TCC, e3p, cogen	Wind -0.5% p.a. & solar -3.1% p.a.	$9.50/GJ	$50/tonne	As currently consented	Based on current patterns
97% Renewables - Slow Tech Low Demand	0.1% p.a.	Goes	1.7 TWh p.a.	0.1 TWh p.a.	0.5 TWh p.a.	Huntly, TCC, e3p, cogen	Wind none & Solar -1.55% p.a.	$9.50/GJ	$50/tonne	As currently consented	Based on current patterns

[62] 5% increase in minimum flows to the South Island major river systems with hydro-electric generation excluding Manapouri and Te Anau; 2% increase in extraction of water from the SI hydro lakes from October to March inclusive to all hydro lakes bar Taupo, Manapouri and Te Anau; 10% increase in minimum flow below Karapiro on the Waikato River.

Scenario, Sensitivity	Demand Growth	Tiwai	EV Demand	Process Heat Demand	Behind-the-meter Solar	Thermal Retirements	Plant Cost Escalation	Gas Price	Carbon Price	Hydro	Peak Demand
97% Renewables - Fast Tech High Demand	1.0% p.a.	Stays	3.8 TWh pa.a	2.5 TWh pa.a	3.0 TWh p.a.	Huntly, TCC, e3p, cogen	Wind -0.9% p.a. & solar -4.05% pa.a	$9.50/GJ	$50/tonne	As currently consented	Based on current patterns
98.5% Renewables	0.5% p.a.	Stays	2.7 TWh p.a.	0.6 TWh p.a.	1.1 TWh p.a.	Huntly, TCC, e3p, McKee, cogen	Wind -0.5% p.a. & solar -3.1% p.a.	$9.50/GJ	$50/tonne	As currently consented	Based on current patterns
100% Renewables	0.5% p.a.	Stays	2.7 TWh p.a.	0.6 TWh p.a.	1.1 TWh p.a.	All thermal	Wind -0.5% p.a. & solar -3.1% p.a.	$9.50/GJ	$50/tonne	As currently consented	Based on current patterns
100% Renewables - Slow Tech Low Demand	0.1% p.a.	Goes	1.7 TWh p.a.	0.1 TWh p.a.	0.5 TWh p.a.	All thermal	Wind none & Solar -1.55% p.a.	$9.50/GJ	$50/tonne	As currently consented	Based on current patterns
100% Renewables – Fast Tech High Demand	1.0% p.a.	Stays	3.8 Twh pa.a	2.5 TWh pa.a	3.0 TWh p.a.	All thermal	Wind -0.9% p.a. & solar -4.05% pa.a	$9.50/GJ	$50/tonne	As currently consented	Based on current patterns
Electrification	0.5% p.a.	Stays	5.7 TWh p.a.	5.5 TWh p.a.	1.1 TWh p.a.	Huntly, TCC	Wind -0.5% p.a. & solar -3.1% p.a.	$9.50/GJ	$50/tonne	As currently consented	Based on current patterns
Electrification - Slow Tech Low Demand	0.1% p.a.	Goes	5.7 TWh p.a.	5.5 TWh p.a.	0.5 TWh p.a.	Huntly, TCC	Wind none & Solar -1.55% p.a.	$9.50/GJ	$50/tonne	As currently consented	Based on current patterns
Electrification - Carbon $150/tonne	0.5% p.a.	Stays	5.7 TWh p.a.	5.5 TWh p.a.	1.1 TWh p.a.	Huntly, TCC	Wind -0.5% p.a. & solar -3.1% p.a.	$9.50/GJ	$150/tonne	As currently consented	Based on current patterns
Electrification - Peakier demand due to EVs	0.5% p.a.	Stays	5.7 TWh p.a.	5.5 TWh p.a.	1.1 TWh p.a.	Huntly, TCC	Wind -0.5% p.a. & solar -3.1% p.a.	$9.50/GJ	$50/tonne	As currently consented	Current patterns plus “dumb EV charging”

7 Appendix B – Run Details

The table below shows the annual output in GWh of all generation across all modelling runs. Generators with an entry in the Node column are new builds and all other generators are existing. The Node include the standard Transpower acronym for the node plus a letter indicating voltage: 2 = 220 kV, 1 = 110kV, 3 = 33 kV, 6 = 66 kV. Some generators are at different nodes in different runs in cases where we have "moved" wind farms to reduce correlations between wind farms across the grid: in this case we have retained the generator name, but obviously they would in fact be completely new projects. The presence of #N/A means that a generator was not included in a run. A number in brackets beside the generator output means that the capacity was different to the value in the Capacity column in that particular run.

Generator Name	Node	Region	Generator Type	Wind Region	Capacity (MW)	BAU	BAU Low Demand Slow Tech	BAU High Demand Fast Tech	Electrification	Electrification Low Demand Slow Tech	96.0%	98.0%	99.0%	100.0%	98% Low Demand Slow Tech	98% High Demand Fast Tech	100% Low Demand Slow Tech	100% High Demand Fast Tech	BAU Higher Carbon Price ($150/t)	BAU Higher Gas Price ($19/GJ)	BAU Constrained Hydro	Electrification Higher Carbon Price ($150/t)	Electrification Peakier Demand
Battery_HAY			Battery		200	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	-12	#N/A	#N/A	#N/A	-11	#N/A	#N/A	#N/A	#N/A	#N/A
Battery_HAY			Battery		200	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	-7	#N/A	#N/A	#N/A	-8	#N/A	#N/A	#N/A	#N/A	#N/A
Battery_HAY			Battery		200	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	-12	#N/A	#N/A	-16	-11	#N/A	#N/A	#N/A	#N/A	#N/A
Battery_HAY			Battery		200	-10	-11	-8	-12	-10	-8	-7	-7	-4	-9	-8	-6	-11	-12	-13	-15	-11	-13
Battery_HAY			Battery		150	#N/A	#N/A	-15	-14	-18	-13	-13	-13	#N/A	#N/A	-13	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	-15
Battery_HAY			Battery		200	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	-21	#N/A
Battery_HAY			Battery		100	#N/A	#N/A	#N/A	-7	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	-7	-7
Battery_HAY			Battery		100	-7	#N/A	-7	-6	-8	-6	-6	-6	-4	#N/A	-6	-6	-5	-7	-7	-7	-6	-7
Glenbrook			Cogen		112	416	416	416	416	416	416	0	0	0	0	0	0	0	416	416	416	416	416
Kapuni			Cogen		25	127	127	127	127	127	127	0	0	0	0	0	0	0	127	127	127	127	127
Kinleith			Cogen		40	267	267	267	267	267	267	267	267	267	267	267	267	267	267	267	267	267	267
Kiwi_CoGen_Hawera			Cogen		40	128	128	128	128	128	128	0	0	0	0	0	0	0	128	128	128	128	128
Te_Rapa			Cogen		44	293	293	293	293	293	293	293	293	293	293	293	0	293	293	293	293	293	293
DSR_BEN			DSR			0	0	1	1	1	1	1	1	2	0	1	0	3	1	1	0	1	1
DSR_HAY			DSR			0	0	1	1	1	1	1	1	2	1	2	1	4	1	1	0	1	1
DSR_ISL			DSR			1	0	1	1	1	1	1	1	2	0	2	0	3	1	1	0	2	1
DSR_OTA			DSR			1	0	1	1	1	1	1	1	2	1	2	2	4	1	1	1	2	1
Kawerau			Geothermal		110	852	852	852	852	852	852	852	852	852	852	852	852	852	852	852	852	852	852
Kawerau_embedded			Geothermal		55	393	393	393	393	393	393	393	393	393	393	393	393	393	393	393	393	393	393
Kawerau_Stage_2	KAW2	Bay of Plenty	Geothermal		100	806	#N/A	806	806	806	806	806	806	806	#N/A	806	604 (75)	806	#N/A	806	806	806	806

Generator Name	Node	Region	Generator Type	Wind Region	Capacity (MW)	BAU	BAU Low Demand Slow Tech	BAU High Demand Fast Tech	Electrification	Electrification Low Demand Slow Tech	96.0%	98.0%	99.0%	100.0%	98% Low Demand Slow Tech	98% High Demand Fast Tech	100% Low Demand Slow Tech	100% High Demand Fast Tech	BAU Higher Carbon Price ($150/t)	BAU Higher Gas Price ($19/GJ)	BAU Constrained Hydro	Electrification Higher Carbon Price ($150/t)	Electrification Peakier Demand
Kawerau_Stage_3	KAW2	Bay of Plenty	Geothermal		100	0	#N/A	806	806	806	#N/A	201	359 (45)	806	#N/A	806	#N/A	1612 (200)	#N/A	806	0	806	806
Mokai			Geothermal		119	876	876	876	876	876	876	876	876	876	876	876	876	876	876	876	876	876	876
Mokai_Expansion	WKM2	Waikato	Geothermal		112	902	#N/A	902	902	902	902	902	902	902	#N/A	902	902	902	902	902	902	902	902
Nga_Awa_Purua			Geothermal		147	1163	1163	1163	1163	1163	1163	1163	1163	1163	1162	1163	1162	1162	1163	1163	1163	1163	1163
Nga_Tamariki			Geothermal		90	711	711	711	711	711	711	711	711	711	711	711	711	711	711	711	711	711	711
Ngatamariki_Stage2	WRK2	Taupo	Geothermal		30	#N/A	#N/A	#N/A	245	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	806 (100)	#N/A	#N/A	#N/A	245	245
Ngatamariki_Stage2	WRK2	Taupo	Geothermal		30	#N/A	#N/A	245	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	245	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Ngatamariki_Stage2	WRK2	Taupo	Geothermal		30	245	#N/A	#N/A	#N/A	245	245	245	245	245	#N/A	#N/A	245	#N/A	245	245	245	#N/A	#N/A
Ngawha_Expansion2	KOE1	Northland	Geothermal		25	201	#N/A	201	201	201	201	201	201	201	#N/A	201	#N/A	201	#N/A	201	201	#N/A	201
Ngawha_Expansion3	KOE1	Northland	Geothermal		25	#N/A	#N/A	201	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	201	#N/A	201	#N/A	#N/A	#N/A	#N/A	#N/A
Ngawha_Expansion3	KOE1	Northland	Geothermal		25	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	201	201	#N/A	#N/A	#N/A	#N/A	#N/A	201	#N/A	#N/A	#N/A
Ohaaki			Geothermal		41	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314
Poihipi_RD			Geothermal		52	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424	424
Rotokawa			Geothermal		36	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254
Rotoma	ROT1	Bay of Plenty	Geothermal		35	#N/A	#N/A	#N/A	280	280	280	280	280	280	#N/A	#N/A	#N/A	280	#N/A	280	#N/A	280	280
Rotoma	TRK2	Bay of Plenty	Geothermal		35	#N/A	#N/A	280	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	280	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Tauhara_Stage_2	WRK2	Taupo	Geothermal		80	648	#N/A	648	648	648	648	648	648	648	648	648	648	648	648	648	648	648	648
Tauhara_Stage_2a	WRK2	Taupo	Geothermal		80	648	#N/A	648	#N/A	648	648	648	648	648	648	648	648	#N/A	648	648	648	#N/A	#N/A
Tauhara_Stage_2a	WRK2	Taupo	Geothermal		80	#N/A	#N/A	#N/A	648	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	648	#N/A	#N/A	#N/A	648	648
Tauhara_Stage_2b	WRK2	Taupo	Geothermal		80	648	#N/A	#N/A	#N/A	648	648	648	648	648	648	#N/A	648	#N/A	648	648	648	#N/A	#N/A
Tauhara_Stage_2b	WRK2	Taupo	Geothermal		80	#N/A	#N/A	648	648	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	648	#N/A	1288 (160)	#N/A	#N/A	#N/A	648	648
Tauhara_Stage1			Geothermal		30	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202	202
Te_Ahi_O_Maui			Geothermal		22	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193
Te_Mihi			Geothermal		165	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388
Tikitere	ROT1	Bay of Plenty	Geothermal		45	#N/A	#N/A	#N/A	359	359	#N/A	#N/A	#N/A	359	#N/A	#N/A	#N/A	359	#N/A	359	#N/A	359	359
Tikitere	TRK2	Bay of Plenty	Geothermal		45	#N/A	#N/A	#N/A	#N/A	#N/A	359	359	359	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Tikitere	TRK2	Bay of Plenty	Geothermal		45	#N/A	#N/A	359	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	359	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A

Generator Name	Node	Region	Generator Type	Wind Region	Capacity (MW)	BAU	BAU Low Demand Slow Tech	BAU High Demand Fast Tech	Electrification	Electrification Low Demand Slow Tech	96.0%	98.0%	99.0%	100.0%	98% Low Demand Slow Tech	98% High Demand Fast Tech	100% Low Demand Slow Tech	100% High Demand Fast Tech	BAU Higher Carbon Price ($150/t)	BAU Higher Gas Price ($19/GJ)	BAU Constrained Hydro	Electrification Higher Carbon Price ($150/t)	Electrification Peakier Demand
Wairakei			Geothermal		130	1045	1045	1045	1045	1045	1045	1045	1045	1045	1045	1045	1045	1045	1045	1045	1045	1045	1045
Wairakei_Binary_Plant	WKM2	Waikato	Geothermal		60	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	482	482	#N/A	#N/A	#N/A
Aniwhenua			Hydro		25	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104
Argyle			Hydro		9	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
Clutha			Hydro		752	3530	3554	3491	3582	3588	3399	3355	3330	2854	3396	3325	3143	2754	3354	3249	3520	3486	3583
Cobb			Hydro		32	194	196	194	195	197	193	193	192	183	194	192	188	185	192	191	194	190	195
Coleridge			Hydro		39	255	256	256	257	256	254	254	254	249	257	255	253	253	255	254	255	256	257
Hawea_Gates	CML2	Otago	Hydro		17	0	#N/A	#N/A	79	#N/A	#N/A	#N/A	79	72	#N/A	#N/A	#N/A	79	72	79	0	79	79
Highbank			Hydro		26	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Kaimai			Hydro		42	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177
Lake_Coleridge	COL6	Canterbury	Hydro		70	#N/A	#N/A	#N/A	342	#N/A	#N/A	#N/A	#N/A	342	#N/A	#N/A	#N/A	342	#N/A	#N/A	#N/A	342	342
Luggate_Clutha	CML2	Otago	Hydro		86	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	335	#N/A
Manapouri			Hydro		0	4995	4850	4986	5034	4987	4937	4939	4896	4742	4728	4920	4558	4749	4908	4877	5005	4917	5032
Mangahao			Hydro		28	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134
Matahina			Hydro		45	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274
Matiri	MCH1	Tasman	Hydro		4.6	#N/A	#N/A	#N/A	26	#N/A	#N/A	#N/A	26	26	#N/A	#N/A	#N/A	26	26	26	#N/A	26	26
Mohaka_River	TUI1	Wairoa	Hydro		44	#N/A	#N/A	#N/A	210	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	210	210
Mohaka_River	TUI1	Wairoa	Hydro		44	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	210	#N/A	#N/A	#N/A	210	#N/A	#N/A	#N/A	#N/A	#N/A
Patea			Hydro		30.7	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106	106
Pukaki_Hydro	TWZ2	Mackenzie	Hydro		35	164	#N/A	#N/A	175	#N/A	164	164	164	#N/A	#N/A	#N/A	#N/A	#N/A	163	164	162	163	175
Pukaki_Hydro	TWZ2	Mackenzie	Hydro		35	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	171	#N/A	175	#N/A	175	#N/A	#N/A	#N/A	#N/A	#N/A
Rangipo			Hydro		120	559	559	559	559	559	559	559	559	559	559	559	559	559	559	559	559	559	559
Rangitata_Diverson_canal_RDR	ASB2	Canterbury	Hydro		6	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	26	#N/A	#N/A	#N/A	#N/A	#N/A
Stockton_Plateau	WMG1	Buller	Hydro		25	131	#N/A	131	131	131	131	131	131	131	#N/A	131	131	131	131	131	131	131	131
Tekapo			Hydro		192	1011	1017	1013	1015	1020	1006	1011	1006	978	1007	1010	974	976	1011	1004	999	1011	1014
Teviot			Hydro		15	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41
Tokaanu			Hydro		240	783	783	783	783	783	783	783	783	783	783	783	783	783	783	783	783	783	783
Waikaremoana			Hydro		138	535	538	538	538	534	521	524	521	507	536	538	509	509	532	524	539	540	538
Waikato			Hydro		959	4345	4339	4336	4351	4347	4322	4328	4323	4313	4335	4338	4318	4286	4338	4322	4348	4333	4348

Generator Name	Node	Region	Generator Type	Wind Region	Capacity (MW)	BAU	BAU Low Demand Slow Tech	BAU High Demand Fast Tech	Electrification	Electrification Low Demand Slow Tech	96.0%	98.0%	99.0%	100.0%	98% Low Demand Slow Tech	98% High Demand Fast Tech	100% Low Demand Slow Tech	100% High Demand Fast Tech	BAU Higher Carbon Price ($150/t)	BAU Higher Gas Price ($19/GJ)	BAU Constrained Hydro	Electrification Higher Carbon Price ($150/t)	Electrification Peakier Demand
Waipa_River	HTI1	Waitomo	Hydro		7	#N/A	#N/A	#N/A	35	#N/A	#N/A	#N/A	#N/A	35	#N/A	#N/A	#N/A	35	#N/A	#N/A	#N/A	#N/A	35
Waipori			Hydro		83.6	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183
Wairau_River_Scheme	BLN1	Marlborough	Hydro		70.5	350	#N/A	#N/A	350	#N/A	350	350	350	350	#N/A	#N/A	#N/A	350	350	350	350	350	350
Waitaha_River	HKK6	SI West Coast	Hydro		20	#N/A	#N/A	#N/A	96	#N/A	#N/A	#N/A	96	96	#N/A	#N/A	#N/A	96	96	96	#N/A	96	96
Waitaki			Hydro		1553	6675	6679	6721	6789	6796	6580	6570	6459	5955	6454	6641	5891	5900	6609	6436	6626	6707	6792
Wheao			Hydro		24	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
NI_Lower_NonSupply			N-S		0	0	0	0	0	0	0	0	0	1	0	0	0	2	0	0	0	0	0
NI_Upper_NonSupply			N-S		0	0	0	0	0	0	1	1	1	3	0	1	1	4	0	0	0	1	0
SI_Lower_NonSupply			N-S		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SI_Upper_NonSupply			N-S		0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0
Large_Solar_1	KOE1	Northland	Solar		50	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	113	#N/A
Large_Solar_1	KOE1	Northland	Solar		50	#N/A	#N/A	#N/A	113	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	113
Large_Solar_1	KOE1	Northland	Solar		50	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	113	113	#N/A	113	#N/A	113	#N/A	#N/A	#N/A	#N/A	#N/A
Large_Solar_2	HEN2	Auckland	Solar		200	#N/A	#N/A	#N/A	665 (300)	#N/A	#N/A	#N/A	#N/A	443	#N/A	443	#N/A	443	#N/A	#N/A	#N/A	443	665 (300)
Large_Solar_2	HEN2	Auckland	Solar		300	#N/A	#N/A	#N/A	665	#N/A	#N/A	#N/A	#N/A	443 (200)	#N/A	443 (200)	#N/A	443 (200)	#N/A	#N/A	#N/A	443 (200)	665
Large_Solar_3	ALB2	Auckland	Solar		200	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	443	#N/A	#N/A	#N/A	443	#N/A	#N/A	#N/A	#N/A	#N/A
Large_Solar_3	DRY2	Auckland	Solar		200	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	443	#N/A
Huntly_e3p			Thermal		395	1884	1982	1764	2091	2058	0	0	0	0	0	0	0	0	0	0	1932	0	2094
Huntly_p40			Thermal		48	46	61	31	30	48	59	58	45	0	61	30	0	0	33	101	48	18	32
Junction_Road			Thermal		100	115	118	99	118	123	130	126	100	0	110	90	0	0	77	56	120	61	120
McKee_II			thermal		100	110	114	95	114	119	128	124	0	0	108	87	0	0	74	55	116	58	115
Stratford_Peaking			Thermal		200	162	175	133	141	167	196	192	156	0	181	118	0	0	110	85	172	76	146
Whirinaki			Thermal		155	3	4	5	3	4	6	6	6	0	7	6	0	0	5	7	3	5	4
Huntly_Peaker	HLY2	Waikato	Thermal		200	212	#N/A	234	278	332	356	348	270	#N/A	#N/A	221	#N/A	#N/A	210	137	221	194	282
Otorohanga_Peaker_Stage 1	TWH2	Waikato	Thermal		120	89	#N/A	97	113	144	162	159	124	#N/A	#N/A	93	#N/A	#N/A	80	#N/A	94	80	116
Otorohanga_Peaker_Stage 2	TWH2	Waikato	Thermal		120	#N/A	#N/A	100	115	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	97	#N/A	#N/A	115	#N/A	#N/A	83	119
Otorohanga_Peaker_Stage 3	TWH2	Waikato	Thermal		120	#N/A	#N/A	92	107	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	89	#N/A	#N/A	#N/A	#N/A	#N/A	76	110
Reserve_Peaker1	OTA2	Auckland	Thermal		300	#N/A	#N/A	129 (100)	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	368	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A

Generator Name	Node	Region	Generator Type	Wind Region	Capacity (MW)	BAU	BAU Low Demand Slow Tech	BAU High Demand Fast Tech	Electrification	Electrification Low Demand Slow Tech	96.0%	98.0%	99.0%	100.0%	98% Low Demand Slow Tech	98% High Demand Fast Tech	100% Low Demand Slow Tech	100% High Demand Fast Tech	BAU Higher Carbon Price ($150/t)	BAU Higher Gas Price ($19/GJ)	BAU Constrained Hydro	Electrification Higher Carbon Price ($150/t)	Electrification Peakier Demand
ReservePeaker1	OTA2	Auckland	Thermal		400	#N/A	#N/A	#N/A	645	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	448	654
Ahipara_Wind_Farm	KOE1	Northland	Wind	Northland	100	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	335	#N/A	304	#N/A	348	#N/A	#N/A	341	#N/A
Ahipara_Wind_Farm	KOE1	Northland	Wind	Northland	100	341	#N/A	#N/A	348	346	337	339	311	202	#N/A	#N/A	#N/A	#N/A	#N/A	303	339	#N/A	346
Ahipara_Wind_Farm	KOE1	Northland	Wind	Northland	100	#N/A	#N/A	315	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	274	#N/A	183	#N/A	#N/A	#N/A	#N/A	#N/A
Awhitu_Wind_Farm	GLN2	Franklin	Wind	Te Uku	18	65	#N/A	59	67	65	65	66	65	58	#N/A	61	#N/A	56	66	62	65	66	66
Castle_Hill_Stage_1	ALB2	Auckland	Wind	Northland	54	#N/A	#N/A	195	#N/A	#N/A	#N/A	#N/A	#N/A	162	#N/A	190	#N/A	155	#N/A	#N/A	#N/A	#N/A	#N/A
Castle_Hill_Stage_1	BPE2	Manawatu	Wind	Te Apiti	54	#N/A	#N/A	#N/A	#N/A	#N/A	190	192	187	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	189	#N/A
Castle_Hill_Stage_1	WDV1	Tararua	Wind	Te Apiti	54	#N/A	#N/A	#N/A	193	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	161	156	#N/A	#N/A	192
Castle_Hill_Stage_2	ALB2	Auckland	Wind	Northland	100	#N/A	#N/A	868 (250)	#N/A	#N/A	#N/A	#N/A	#N/A	299	#N/A	870 (250)	#N/A	290	#N/A	#N/A	#N/A	#N/A	#N/A
Castle_Hill_Stage_2	BPE2	Manawatu	Wind	Te Apiti	100	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	347	#N/A
Castle_Hill_Stage_2	WDV1	Tararua	Wind	Te Apiti	100	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	287	#N/A	#N/A	#N/A	#N/A
Castle_Hill_Stage_2	WDV1	Tararua	Wind	Te Apiti	100	#N/A	#N/A	#N/A	351	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	349
Castle_Hill_Stage_3	ALB2	Auckland	Wind	Northland	200	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	559	#N/A	809 (250)	#N/A	544	#N/A	#N/A	#N/A	#N/A	#N/A
Castle_Hill_Stage_3	BPE2	Manawatu	Wind	Te Apiti	200	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	672	#N/A
Castle_Hill_Stage_4	ALB2	Auckland	Wind	Northland	350	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	483 (200)	#N/A	452 (150)	#N/A	787	#N/A	#N/A	#N/A	#N/A	#N/A
Castle_Hill_Stage_4	BPE2	Manawatu	Wind	Te Apiti	200	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	632	#N/A
Central_Wind_Moawhango	NPL2	Taranaki	Wind	Waverly	120	#N/A	#N/A	428	#N/A	#N/A	#N/A	#N/A	#N/A	373	#N/A	426	#N/A	363	#N/A	#N/A	#N/A	#N/A	#N/A
Central_Wind_Moawhango	TNG2	Ruapehu	Wind	Te Apiti	120	394	#N/A	#N/A	385	407	369	370	351	#N/A	#N/A	#N/A	#N/A	#N/A	360	336	390	328	382
Hauauru_ma_raki_Wind_Stage_1	HLY2	Waikato	Wind	Te Uku	154	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	327	#N/A	#N/A	#N/A	#N/A	#N/A
Hauauru_ma_raki_Wind_Stage_1	HLY2	Waikato	Wind	Te Uku	154	#N/A	#N/A	#N/A	550	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	540	#N/A	#N/A	521	547
Hurunui_Wind	WPR2	Hurunui	Wind	Canterbury	71.3	259	#N/A	260	262	254	257	258	256	239	#N/A	260	#N/A	240	258	254	259	259	262
Kaimai_Wind_Farm	KPU1	Coromandel	Wind	Kaimai	100	359	#N/A	352	366	361	355	357	351	294	#N/A	343	#N/A	288	354	339	357	359	365
Kaiwera_Downs_Stage_1	GOR2	Southland	Wind	Southland	36	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	105	125	122	#N/A	124	#N/A
Kaiwera_Downs_Stage_1	GOR2	Southland	Wind	Southland	36	130	#N/A	128	131	#N/A	126	126	123	105	#N/A	122	#N/A	#N/A	#N/A	#N/A	130	#N/A	131
Kaiwera_Downs_Stage_2	GOR2	Southland	Wind	Southland	84	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	243	#N/A	#N/A	#N/A	293	#N/A
Kaiwera_Downs_Stage_2	GOR2	Southland	Wind	Southland	84	302	#N/A	296	303	#N/A	288	289	280	235	#N/A	278	#N/A	#N/A	284	278	301	#N/A	303

Generator Name	Node	Region	Generator Type	Wind Region	Capacity (MW)	BAU	BAU Low Demand Slow Tech	BAU High Demand Fast Tech	Electrification	Electrification Low Demand Slow Tech	96.0%	98.0%	99.0%	100.0%	98% Low Demand Slow Tech	98% High Demand Fast Tech	100% Low Demand Slow Tech	100% High Demand Fast Tech	BAU Higher Carbon Price ($150/t)	BAU Higher Gas Price ($19/GJ)	BAU Constrained Hydro	Electrification Higher Carbon Price ($150/t)	Electrification Peakier Demand
Kaiwera_Downs_Stage_3	GOR2	Southland	Wind	Southland	120	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	319	#N/A	#N/A	#N/A	406	#N/A
Kaiwera_Downs_Stage_3	GOR2	Southland	Wind	Southland	120	422	#N/A	410	554	#N/A	395	395	379	304	#N/A	377	#N/A	#N/A	385	376	419	#N/A	553
Long_Gully_Wind_farm	CPK1	Wellington	Wind	West Winf	12.5	#N/A	#N/A	50	51	#N/A	50	50	50	#N/A	#N/A	50	#N/A	45	50	49	#N/A	50	51
Mahinerangi_Wind			Wind	Southland	36	114	109	112	114	110	108	108	105	88	93	105	81	82	106	104	114	107	113
Mahinerangi_WindFarm_Stage_2	TMH2	Dunedin	Wind	Southland	160	#N/A	#N/A	#N/A	576	#N/A	553	555	538	445	#N/A	331 (100)	#N/A	639 (260)	546	535	#N/A	540	576
Maungaharuru	WHI2	Hawkes Bay	Wind	Hawkes Bay	94	312	#N/A	292	310	321	298	300	287	184	302	261	256	156	293	270	308	281	307
Mill_Creek			Wind	West Wind	60	232	224	230	235	227	228	230	226	202	202	224	181	189	229	223	232	230	235
Mount_Cass_Wind_Farm	WPR2	Hurunui	Wind	Canterbury	69	251	#N/A	253	254	#N/A	249	251	248	231	#N/A	252	#N/A	601 (200)	250	246	251	614 (169)	254
Mt_Munro	MST1	Tararua	Wind	Wairapa	60	#N/A	#N/A	208	216	#N/A	210	211	208	180	#N/A	202	#N/A	175	210	206	#N/A	213	216
Pouto_Stage1	HEN2	Auckland	Wind	Northland	100	362	#N/A	360	367	359	360	362	358	310	342	352	309	303	362	349	361	727 (200)	367
Pouto_Stage2	HEN2	Auckland	Wind	Northland	100	359	#N/A	354	366	358	359	361	357	302	456	347	311	297	362	345	358	725 (200)	365
Pouto_Stage3	HEN2	Auckland	Wind	Northland	100	355	#N/A	341	363	355	354	357	351	272	#N/A	331	301	263	358	337	353	700 (200)	362
Puketoi_Stage_1	ISL2	Christchurch	Wind	Canterbury	60	#N/A	#N/A	219	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	216	#N/A	193	#N/A	#N/A	#N/A	#N/A	#N/A
Puketoi_Stage_1	TWC2	Manawatu	Wind	Tararua	60	#N/A	#N/A	#N/A	222	#N/A	196	198	190	#N/A	#N/A	#N/A	#N/A	#N/A	199	186	#N/A	172	222
Puketoi_Stage_2	ISL2	Christchurch	Wind	Canterbury	130	#N/A	#N/A	364 (100)	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	471	#N/A	432	#N/A	#N/A	#N/A	#N/A	#N/A
Puketoi_Stage_2	TWC2	Manawatu	Wind	Tararua	130	#N/A	#N/A	#N/A	476	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	413	#N/A	#N/A	361	475
Puketoi_Stage_3	ISL2	Christchurch	Wind	Canterbury	205	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	464 (130)	#N/A	645	#N/A	#N/A	#N/A	#N/A	#N/A
Puketoi_Stage_3	TWC2	Manawatu	Wind	Tararua	130	#N/A	#N/A	#N/A	460	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	342	458
Slopedown_Wind_farm	GOR2	Southland	Wind	Southland	100	362	#N/A	358	364	#N/A	351	353	343	296	#N/A	346	#N/A	#N/A	#N/A	#N/A	362	#N/A	364
Slopedown_Wind_farm	GOR2	Southland	Wind	Southland	100	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	348	340	#N/A	#N/A	#N/A
Slopedown_Wind_farm	GOR2	Southland	Wind	Southland	250	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	232 (100)	#N/A	#N/A	#N/A	770	#N/A
Taharoa_C	HAM2	Waikato	Wind	Te Uku	54	122	#N/A	165	188	#N/A	185	187	183	121	#N/A	151	#N/A	105	181	172	121	175	186
Tararua_Stage_3			Wind	Tararua	91	329	327	317	320	325	316	319	309	247	295	301	260	221	317	303	328	298	318
Taumatatotara	HTI1	Waitomo	Wind	Te Uku	44	#N/A	#N/A	142	158	#N/A	153	154	150	113	#N/A	138	#N/A	110	151	144	#N/A	155	157
Te_Apiti			Wind	Te Apiti	90	309	307	298	301	308	291	293	283	233	276	284	245	217	287	280	308	276	300
Te_Rere_Hau			Wind	Te Rere Hau	49	124	122	120	125	122	121	122	120	96	110	114	97	85	123	118	124	122	124

Generator Name	Node	Region	Generator Type	Wind Region	Capacity (MW)	BAU	BAU Low Demand Slow Tech	BAU High Demand Fast Tech	Electrification	Electrification Low Demand Slow Tech	96.0%	98.0%	99.0%	100.0%	98% Low Demand Slow Tech	98% High Demand Fast Tech	100% Low Demand Slow Tech	100% High Demand Fast Tech	BAU Higher Carbon Price ($150/t)	BAU Higher Gas Price ($19/GJ)	BAU Constrained Hydro	Electrification Higher Carbon Price ($150/t)	Electrification Peakier Demand
Te_Rere_Hau_Stage_5	GYT1	Manawatu	Wind	Wairapa	28	#N/A	#N/A	98	#N/A	#N/A	#N/A	#N/A	#N/A	85	#N/A	95	#N/A	78	#N/A	#N/A	#N/A	#N/A	#N/A
Te_Rere_Hau_Stage_5	LTN2	Manawatu	Wind	Te Apiti	28	#N/A	#N/A	#N/A	101	#N/A	#N/A	#N/A	98	#N/A	#N/A	#N/A	#N/A	#N/A	100	96	#N/A	99	101
Te_Uku		Te Uku	Wind	Te Uku	64	211	217	201	216	212	210	212	208	155	201	195	179	147	211	199	210	210	215
Turitea_Stage_1	TWC2	Manawatu	Wind	Tararua	60	215	#N/A	#N/A	#N/A	#N/A	207	209	202	#N/A	#N/A	#N/A	#N/A	#N/A	208	198	214	184	#N/A
Turitea_Stage_1	TWZ2	Mackenzie	Wind	Southland	60	#N/A	#N/A	217	#N/A	#N/A	#N/A	#N/A	#N/A	178	#N/A	206	#N/A	151	#N/A	#N/A	#N/A	#N/A	#N/A
Turitea_Stage_2	TWC2	Manawatu	Wind	Tararua	120	422	#N/A	#N/A	#N/A	#N/A	404	409	394	#N/A	#N/A	#N/A	#N/A	#N/A	407	387	419	355	#N/A
Turitea_Stage_2	TWZ2	Mackenzie	Wind	Southland	120	#N/A	#N/A	429	#N/A	#N/A	#N/A	#N/A	#N/A	348	#N/A	403	#N/A	291	#N/A	#N/A	#N/A	#N/A	#N/A
Wainui_Hills_Wind_Farm	GFD1	Wellington	Wind	West Wind	30	#N/A	#N/A	115	117	#N/A	114	114	113	101	#N/A	112	#N/A	95	114	111	#N/A	114	117
Waitahora_Wind	TUI1	Wairoa	Wind	Hawkes Bay	177	#N/A	#N/A	535	#N/A	#N/A	#N/A	#N/A	#N/A	307	#N/A	476	#N/A	262	#N/A	#N/A	#N/A	#N/A	#N/A
Waitahora_Wind	WDV1	Tararua	Wind	Te Apiti	177	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	527	497	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	430	#N/A
Waitahora_Wind	WDV1	Tararua	Wind	Te Apiti	177	#N/A	#N/A	#N/A	556	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	553
Waitahora_Wind	WDV1	Tararua	Wind	Te Apiti	177	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	472	#N/A	#N/A	#N/A	#N/A
Waverley	WGN1	Whanganui	Wind	Waverly	130	450	457	436	448	454	431	438	426	338	411	419	362	321	#N/A	#N/A	447	407	446
Waverley_Stage2	BRK2	South Taranaki	Wind	Waverly	150	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	393	#N/A	#N/A	#N/A	356	#N/A	#N/A	#N/A	#N/A	#N/A
Westwind		Wet Wind	Wind	West Wind	142	545	524	537	550	533	533	536	526	468	470	520	421	436	533	519	545	536	549
White_Hills		White Hills	Wind	White Hills	58	180	166	179	183	168	177	177	173	153	142	175	122	153	176	173	180	177	183

JC2

ICCC MODELLING:

DRY YEAR STORAGE OPTIONS ANALYSIS

Final Report

April 2019

Report to the Interim Climate Change Committee

John Culy Consulting

JC²

ICCC Modelling: Comparative analysis of dry year backup options

Final Slides : John Culy

25 Apr 2019

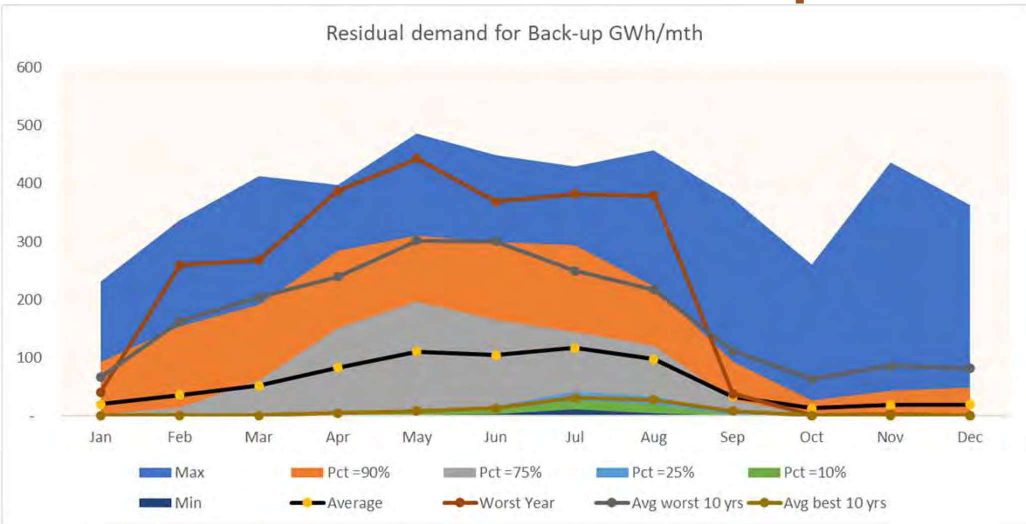
Introduction

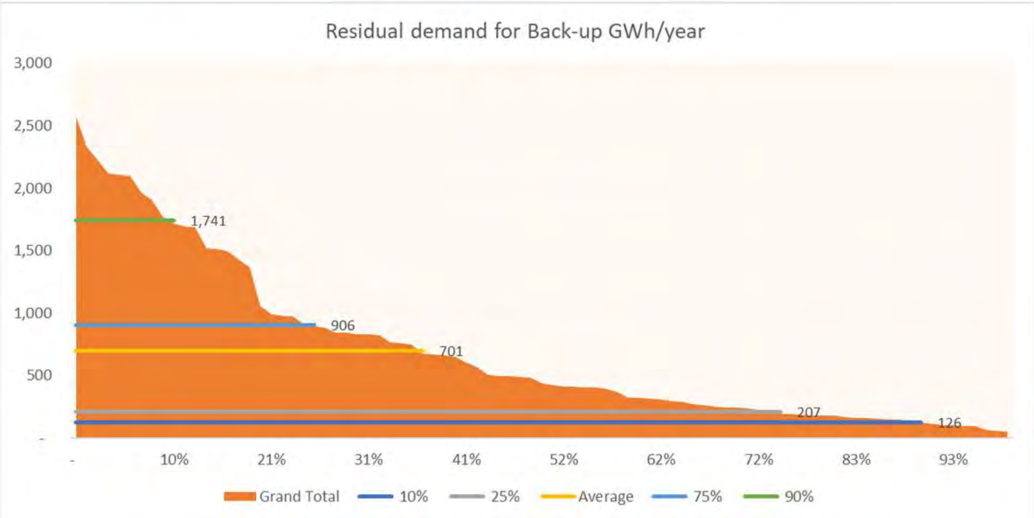
JC²

- Currently natural gas and oil flexible peaking generation provides an effective, low cost, back-up to cover wind and solar intermittency and dry years with low hydro generation.
  - **The modelling shows that once base load thermal is retired and replaced with geothermal, wind/solar and batteries around 98% renewable (on average) can be achieved by 2035 at relatively low cost.**
  - **The last 2% of generation in 2035 is around 0.7TWh/yr on average but varies between 0.1 and 2.6TWh/yr depending on the weather (mainly hydro inflows and wind). This requires flexible fuel supply of up to 25PJ with a mean of around 7PJ/yr. The peaker capacity is 820MW and the average capacity factor is around 10%.**
    - It is assumed that natural gas supply flexibility is met from 17PJ of gas storage at Ahuroa plus an additional 8PJ/yr flex in gas supply
    - It is assumed there is a capital cost of $200m for upgrades to Ahuroa (to increase withdrawal capacity to 150TJ/d) and working capital costs of $10m/y and fixed option fees of $22m/yr to secure access to 8PJ/y of flexible gas priced at a variable cost of $9.6/GJ. This implies an average gas cost of around $17/GJ including flex and storage.
- These slides compare a number of options for eliminating this residual fossil fuel required for long term back-up.
  - **The options explicitly compared in this report include:**
    1. <u>Overbuilding renewables</u> – assumes additional wind/solar and batteries to replace the gas peakers
       - this is based on the Energy Link modelling runs described in "*ICCC modelling: Estimated system incremental and marginal costs in 2035", John Culy, 25 April 2019*
    2. <u>Hydrogen and Ammonia</u> – assumes new hydrogen production and conversion of Ahuroa to hydrogen storage and additional ammonia storage to meet demand.
       - this is based on a standalone modelling described in a set of slides "*ICCC Modelling : Hydrogen Storage Options Analysis", John Culy, 25 April 2019*
    3. <u>Pumped hydropower</u> – assumes a 1000MW pumped storage facility with 5TWh of storage in the South Island above the Clutha scheme.
       - this is based on a standalone modelling described in a set of slides "*ICCC Modelling: Pumped hydro storage - Lake Onslow option analysis", John Culy, 25 April 2019*
    4. <u>Biomass</u> – assumes new wood pellet fired peaking plant with associated covered wood pellet storage.
       - This is based on assumptions from *Concept (2019)* and additional assumptions for pellet storage costs
    5. <u>Indicative large-scale demand interruption</u> –
       - This is an assessment of a hypothetical very large customer who is prepared to be completely shut down for up to 6-8 months with a frequency of around (1 in 5 year) in return for a fee.
    6. <u>Long-term battery storage</u>
       - This is based on a very large battery with a capacity of around 2,700 GWh operated in "peaker" mode.

Concept(2019) : "Analysis on economics of alternative options to provide dry-year electricity", Concept Consulting, 21 Feb 2019

Residual Demand for Gas peakers





The monthly and annual distributions for the residual demand for gas/oil peaker back-up is illustrated in the charts.

This shows that the demand is most often in winter, but there are occasions (when hydro lakes are low at the start of a year as a result of a previous dry year) and current inflows are low as well, when the demand for gas peakers is sustained for periods of up to 6 months.

Summary of Back-up Cost estimates

JC[2]

Counterfactual: Gas Peaker Back-up

- This is the demand for gas/oil peakers in the 98.6% renewable Middle of Road electricity future.
- This has a average demand of 0.7TWh from gas/oil peakers or 7PJ/yr (0.33mt emissions).
- Annual cost = $118m/yr consisting of:
  - $66m/yr = variable fuel cost at an average $9.6/GJ
  - $24m/yr = fixed option fees for right to take up to 8PJ/yr at $10/GJ
  - $10m/yr = fixed working capital costs for Ahuroa gas storage
  - $18m/yr = fixed cost of upgrading Ahuroa to 150TJ/day extraction rate ($0.2b capex)
- Average cost = $18/GJ for flexible gas at 10% capacity factor from storage and supply flex.
- Notes:
  - The key risk for this option is continued availability for around 7PJ of gas supply and storage or supply flex up to 25PJ.
  - Extra costs have been allowed for to enable this flexibility in the future given that current sources of gas supply flexibility for electricity use are likely to reduce if Methanol production shuts down and off-shore gas supply flexibility is phased out.
  - Any increase in the cost of providing gas flexibility will reduce the estimated abatement costs for the other back-up options.

1: Overbuilding Renewables

- This replaces 0.7TWh of gas/oil peakers with 1174 MW of new renewables and 500MW (5.25 GWh) of batteries and extra demand response and shortage.
- Annual cost = $412m/yr consisting of:
  - $55m/yr shortage and demand response
  - $107m/yr battery fixed cost ($1.0b capex)
  - $250m/yr new renewable fixed and variable cost ($2.7b capex)
- Total capex = $3.7b
- Emission saving = 0.232
  - 0.334mt (fossil fuels) - 0.102mt (extra emissions from extra geothermal)
- The extra costs of over building with renewables relative to gas peakers is $294m/yr or $1,270/t emission abatement cost.
- Notes:
  - This is slightly lower than the estimates given in the system costs report as the counterfactual now includes a more explicit modelling of the fixed and variable costs of gas supply.
  - The abatement cost with additional investment in wind to reduce storage and demand response costs back to normal levels is similar considering that the additional capital costs are mostly offset by reductions in shortage and demand costs.

Dry year back-up Options 2 and 3

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2: Hydrogen storage at Ahuroa and Ammonia

- This involves conversion of Ahuroa to hydrogen storage (5PJ), a 1.6GW Hydrogen plant, a 12PJ/yr Ammonia plant, 20PJ of ammonia storage and 0.82GW of hydrogen peakers.
    - This generates 0.7TWh, but has an electricity demand of 5.1TWh since the combined efficiency is 13.6%.
- The annual cost of this is $625m/yr, consisting of
    - **$171m/y electricity purchase costs 5.1TWh at $33.5/MWh**
    - **$14m/yr variable operating costs for H2 peakers**
    - **$31m/y variable operating and network cost for electrolyser**
    - **$28m/yr working capital for H2 and ammonia in storage**
    - **$381m/yr capital recovery on $3.7b capex and fixed operating cost**
        - 1.6GW Electrolyser (capex $1.1b), 12PJ/yr ammonia plant (capex $0.6b), 20PJ ammonia tanks (capex $1.0b), 0.82GW new H2 peakers (capex $0.8b), 5PJ Ahuroa conversion to hydrogen (capex $0.2b)
- Total capex $3.7b
- Emission saving = 0.334 mt
- The extra costs of hydrogen/ammonia option is $507/yr or $1,520/t implied emission abatement cost.
- Notes
    - **This is slightly higher than the $1440/t in the hydrogen storage option report since the project is scaled up to fully replace the gas peakers. The risks and uncertainties are summarised in that report.**

3: Pumped hydro storage

- This involves the creation of 5TWh storage reservoir in the Onslow basin by building a dam and a 15-24km tunnel down to an under ground 1GW pumping/generation station which discharges into the Clutha river. This would operate as a generator when required and a pump during wet periods when power was not required.
    - By virtue of the large storage and greater capacity, this option would be able to provide more than the dry year backup required to replace the gas peakers. Separate modelling indicates that it can provide up to 5TWh of dry year backup and save around 1.5TWh of backup thermal plant, and 0.61mt of emissions. The full capital cost is estimated to be $3.2b.
    - For the purpose of this comparison the value of generation to replace the same 0.7TWh of gas peakers is counted and the full capital cost recovery is offset by the additional benefits from the full scheme.
- The net annual cost of this option is $268m consisting of:
    - **$290m/yr recovery for the full capital cost and fixed operating cost**
    - **$29m/yr electricity purchase cost for pumping to meet the 0.7TWh/yr required to replace the counterfactual dry year backup demand.**
    - **-$50m/y as a credit for the benefits from the extra gross margin from the additional 0.8TWh/yr of dry-year backup available from the full project.**
- This extra net annual cost is $150m/yr and the overall carbon savings are 0.334 mt + 0.276mt = 0.61mt , so the carbon abatement cost is $250/t.
- Notes:
    - **This is the same as that derived in the Pumped Storage report. The risks associated with this option are summarised in that report.**

Dry year back-up Options 4 and 5

JC2

4: Biomass fired back-up plant

- This involves the construction of around 16 new 50MW biomass backup plant located near wood supply sources with 20PJ of covered wood pellet storage facilities (possibly silos).
    - It is assumed that biomass back-up plant have a cost of $2,600/kW, and wood pellets cost $20/GJ and wood pellet storage has a capital cost of $15/GJ of storage (based on reported costs of $10/GJ for grain silos and $20/GJ wood pellet storage and handling facilities at ports).
- The annual costs of this option would be $384m/yr:
    - $129m/yr wood pellet fuel costs
    - $30m/yr working capital for the cost of wood pellets in storage
    - $226/yr fixed capital recovery and operating costs - from
        - Pellet storage facilities (capex $0.4b)
        - New biomass backup plant (capex $2.1b)
- The extra annual costs above gas peakers is $266m/yr, and the emissions savings would be 0.334mt implying a carbon abatement cost of $800/t.
- Notes:
    - There is little experience of biomass being used to provide long term backup with a low capacity factor operation. The costs to maintain long term storage in the form of wood pellets without deterioration or risk of fire may be greater. Also there may be competition from other uses of wood which could push up the cost of pellets.

5: Indicative large scale demand interruption

- This is theoretical option which is provided as benchmark, rather than a realistic commercial option.
    - It would require a major load (such as Tiwai) being prepared to contract to be completely shut down for up to 6-8 months with a frequency of around (1 in 5 year) in return for a fee (assumed to be $500/MWh).
- This would not involve a significant capital expenditure but would involve substantial costs (assumed to be $500/MWh or $1.7b per event) when called (1 in 5 years).
- The annual costs of this option would be $384/yr.
    - Just the expected cost of calling for and outage at $500/MWh.
- The extra costs is $229m/yr and the average emission saving is 0.334 mt , so the implied abatement cost is $690/t.
- Notes:
    - This option is very unlikely to available.

Dry year back-up Option 6

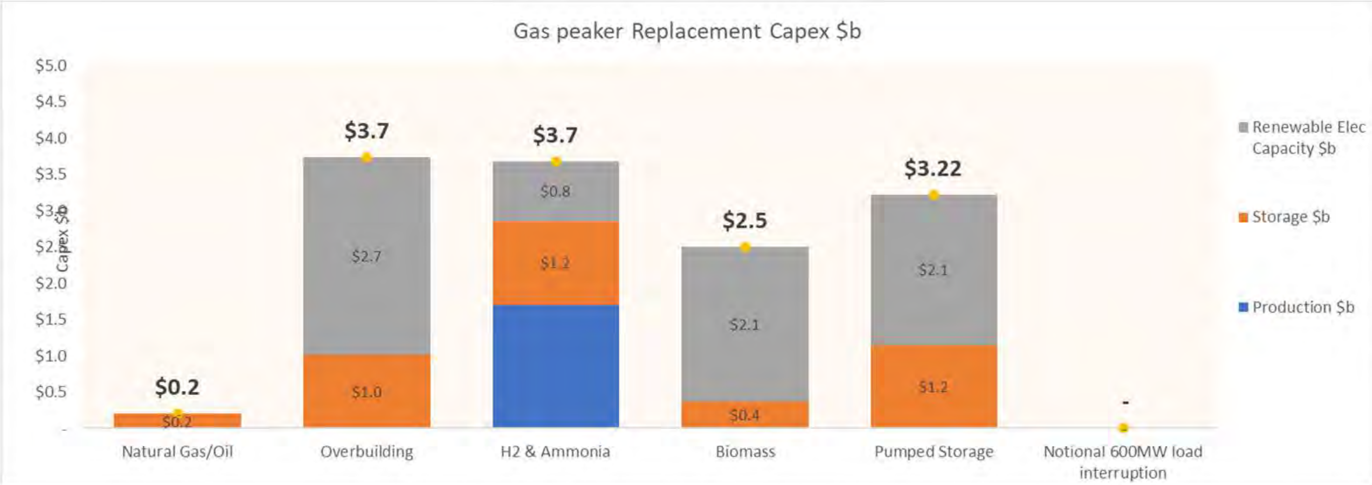
JC²

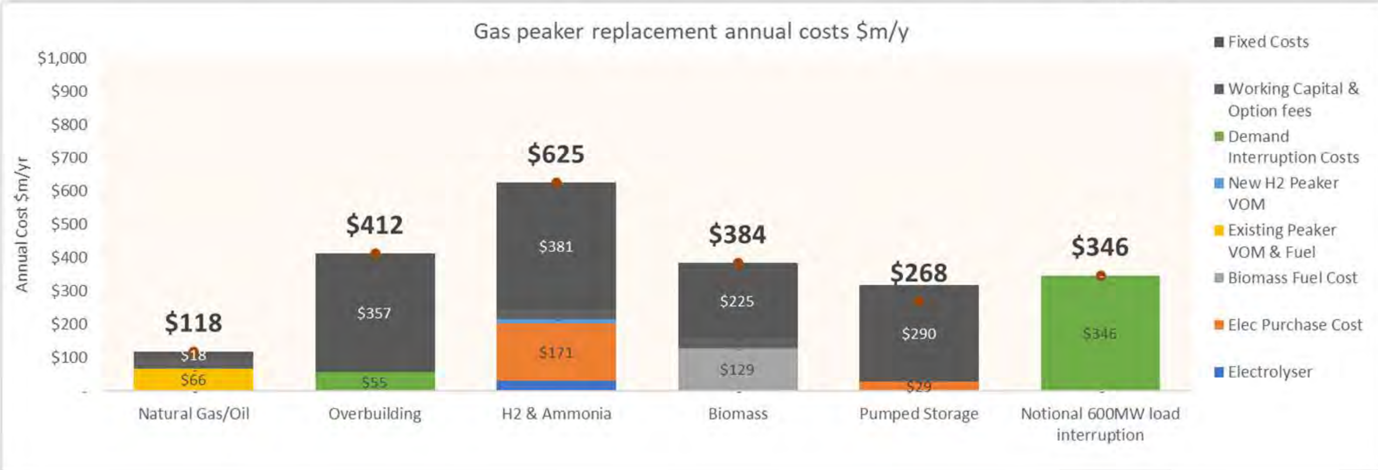
6: Indicative batteries to provide long term storage

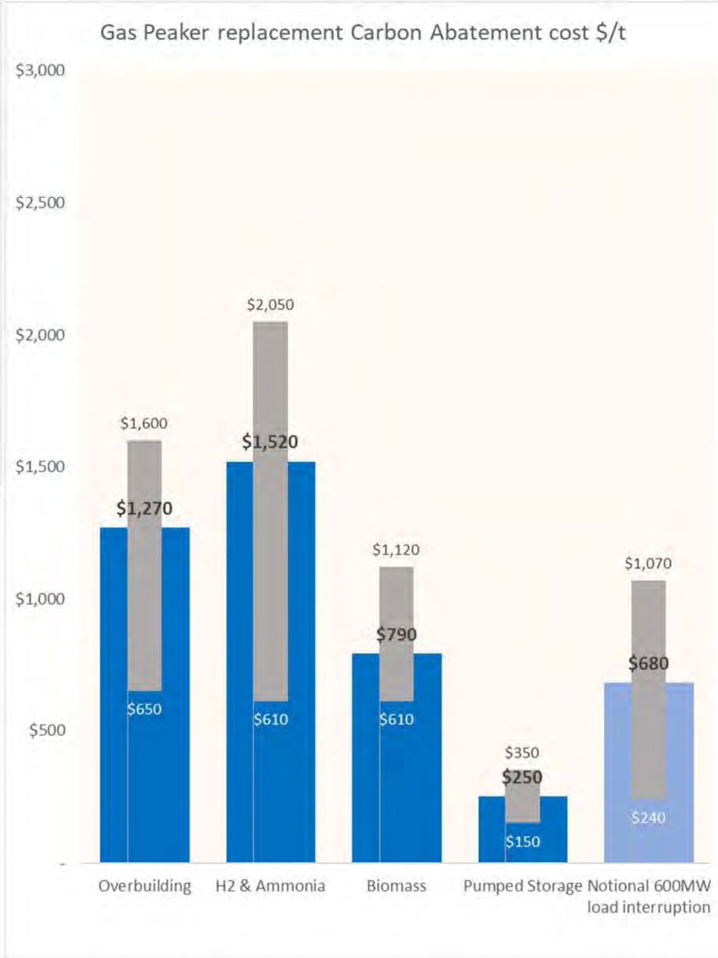
- This involves at least 2,700 GWh of battery storage (and around 1000MW of charge/discharge capacity) which could be operated in peaker mode (i.e. charged when electricity prices were low and discharged when backup was required).
- This would incur a capital cost of $270b (assuming battery storage capital costs fall to $100/kWh).
- The annual costs would be at least $28b/y. This would imply a carbon abatement cost of $83,000/t.
- While technically feasible this option this option is clearly not an economically sensible option to provide long term dry year back-up.
  - Batteries do however have an important (economically viable) role in providing short term (within day) backup for wind and solar. Batteries operating in this mode are an important component in the renewable over build option 1.

Comparison of options to replace gas peakers

JC2







Note that Batteries have been excluded from the chart as they are off the scale. The uncertainty ranges reflect reasonable variations in some of the key cost assumptions.

Conclusions

- All of the options considered in this report are technically feasible, but vary substantially in cost.
- The lowest cost option would be to continue to use gas/oil in existing or new peakers and to offset the 0.33mt of emissions with saving in emissions in other sectors.
- The most promising alternative option appears to be a large pumped storage facility in the South Island.
  - Additional analysis is required to assess the interactions of this option with the operation of other hydro storages and with transmission constraints including on the HVDC. Also more work is required on the cost estimates, including the costs of additional transmission.
  - It is noted that there are very significant consenting and commercial risks associated with a project of this nature and large size, but the project would enable higher electricity demand to support accelerated electrification without increasing emissions.
- Dry year back-up supply from biomass in the form or wood pellets appears to be expensive
- Although its cost might be similar, its very unlikely that a large customer would be prepared to offer sufficient demand response to completely replace gas peakers.
  - Although, demand response can provide an important supplementary role in other options, such as overbuilding renewables.
- Dry year back up from over-building renewables or from a dedicated hydrogen / ammonia production and storage facility are very expensive, and almost certainly have a higher implied carbon abatement cost than is available from other parts of the economy.
- The very large scale battery solution is far too expensive even with significant cost reductions in batteries.
  - However short term batteries can provide an important supplementary role in some other options, such as overbuilding renewables.

Caveats and Disclaimer

JC2

Limitations and Caveats

- This report only covers a small number of illustrative options to replace gas peakers in its role of providing dry year back-up. Other optins and combination of options are possible , but are beyond the scope of this report.
- There are limitations in the analysis of the hydrogen and pumped storage options which are described in the referenced reports.
- The remaining analysis is very simplified and is highly dependent on the cost assumptions made. This is illustrated by the wide uncertainty ranges shown in the chart on page 8.

Disclaimer

- The information and opinions expressed in this presentation are believed to be accurate and complete at the time of writing.
- However, John Culy does not accept any liability for errors or omissions in this presentation or for any consequences of reliance on its content, conclusions or any material, correspondence of any form or discussions arising out of or associated with its preparation.

JC²

ICCC Modelling : Hydrogen Storage Options Analysis

Final Slides : John Culy

Introduction

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- These slides examine the likely costs in 2035 of meeting all or part of the dry year back-up demand for electricity using hydrogen producemarketelectricity (at times of low prices) and stored directly in an underground storage or indirectly in the form of ammonia.
- The modelling focuses on a specific stand-alone option using well developed technology (albeit with uncertain costs and some residual risk).
  - This involves the conversion of the Ahuroa gas storage facility to store hydrogen, the construction of an on-site hydrogen electrolysis plant and ammonia production/storage facility. For the base case it is assumed that ammonia needs to be converted back to hydrogen before burning in new 100% hydrogen compatible open cycle peakers. It is not assumed that conversion of existing gas peakers to 100% hydrogen burning is much cheaper than new hydrogen peakers.
- Four options are considered
  - These range from a 5PJ storage option from Ahuroa only and 200MW H_2 production facility, which only substitutes for a small portion of the demand for dry year back-up to a 25PJ storage option with an additional 20PJ of ammonia storage and a 1600MW H_2 production facility.
- The operation of the H_2 production and storage use is modelled using electricity prices from an EMarket simulation
  - The operational modelling is based on simulation using tuned Ahuroa and NH_3 storage operating rules and 3hr prices from the 87 weather years of the EMarket simulation with building of renewables to achieve 98.6% renewables. This has a potential.
  - This modelling determines the cost of electricity for H_2 production and the value of generation from the H_2 peakers as well as the level of H_2 and NH_3 storage over the 87 simulated weather years.
- Assumptions and sensitivities
  - The assumptions concerning costs and efficiencies in 2035 draw heavily on work carried out by Concept Consulting in 2018.
  - The very high uncertainty in the costs is addressed through extensive sensitivity analysis.
- The key results derived from the analysis are the implied carbon abatement costs for each option
  - The carbon abatement cost for the small option is $560/t, but this only saves 0.08mt. The carbon abatement costs for the large options are > 1400/t and these save 0.27 to 0.29mt.
- Key technical risks include:
  - Ahuroa not having a significant hydrogen leakage issue and there not being significant NH_3 transport costs.

Generic and modelled options for long term hydrogen storage

JC²

Generic Options

Options for long term storage of Hydrogen

- **Man made salt caverns**
  - Not available in New Zealand
- **Depleted oil/gas reservoirs**
  - Possible onshore options include Ahuroa, Mkee And Kapuni
    - Ahuroa is already operating as a natural gas storage and could be converted provided hydrogen leakage is not an issue.
- **Underground Aquifers**
- **Hard rock caverns**
- **Storage of hydrogen as Ammonia**

General Issues

- **Hydrogen leakage (hydrogen is a smaller molecule than methane)**
- **Hydrogen Embrittlement (exposure of steel to hydrogen makes it brittle)**
- **Low energy density of hydrogen compared to methane**
- **Hydrogen contamination**
- **Technical and economic issues related to burning hydrogen or ammonia in OCGT peaking plant (need for dilution with nitrogen or steam, flame temperature control, meeting NOx emissions limits, safety issues, managing embrittlement issues).**

Modelled Options considered in this study

Ahuroa hydrogen storage facility

- Conversion of the existing Ahuroa natural gas storage facility (depleted oil/gas reservoir) to hydrogen storage.
- Construction of a local electrolysis plant to produce hydrogen from electricity at times of low electricity price and inject into the Ahuroa storage.
- Conversion of the existing 200MW Stratford OCGT to run on hydrogen (or replacement with a new hydrogen fired peaking plant up to 300MW) running on hydrogen.
- Investment in additional wells and compression equipment to handle hydrogen injection rates (determined by capacity of the electrolyser plant) and to handle withdrawal rates (determined by the size of the hydrogen fired peaking plant).

Additional ammonia storage

- Construction of additional electrolysis capacity to produce hydrogen from electricity at times of low electricity price.
- Construction of a hydrogen to ammonia conversion facility.
- Construction of ammonia storage tanks.
- Construction of additional hydrogen or ammonia fired OCGT peaking capacity.
  - If ammonia fired OCGT is not technically or economically feasible then it would be necessary to construct an ammonia to hydrogen conversion facility.

Hydrogen Storage at Ahuroa

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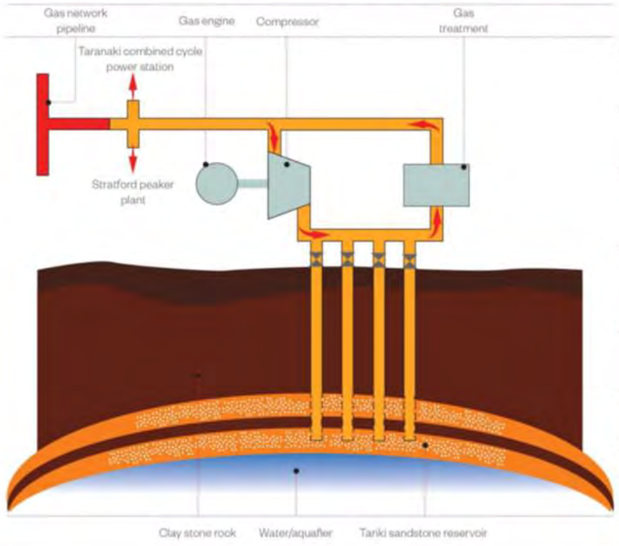
H2 Power-Power via depleted gas reservoirs

- Ahuroa is a depleted natural gas reservoir currently being used for natural storage. It was developed by Contact Energy and sold to First gas for $200m in 2017.
  - **It currently has a maximum working storage of approximately 17PJ of natural gas, with cushion gas of around 6PJ. Ahuroa has wells and compressors to inject approx. 32TJ/day and withdraw 45TJ/day of natural gas. The operating pressure has a maximum of 3,450 psi or (26MPa or 260 bar).**
    - First Gas have plans to increase the injection and withdrawal capacity to 65TJ/day, and Contact indicated that the cost of an additional increments of 50TJ/day would be around $70m. These additional increments are likely to require additional compressors, gas treatment capacity and possibly wells.
  - **If Ahuroa was converted to hydrogen storage it would provide around 4.9PJ[1] of hydrogen it would also require around 2.4PJ of cushion storage.**
    - It is not known exactly how much injection and withdrawal capacity would be provided by the existing wells and compressors, but it is likely to be also around 1/3 of the existing TJ/day when operating on hydrogen given the lower energy density and assuming capacity relates to flow volume.
  - This implies a maximum electrolyser capacity of 12TJ/day of hydrogen production (or 200MW of electricity input assuming a 70% conversion rate).
    - The current withdrawal capacity would convert to only 15TJ/day of hydrogen (enough for around 63MW of peaker capacity).
    - An additional <u>$150m </u>would be required to increase the withdrawal rate to 55TJ/day of hydrogen (225MW of peaker capacity).
    - An additional $220m would be required to support 72TJ/day of hydrogen (300MW peaker capacity).
  - **Other assumptions**
    - For this analysis it is assumed that hydrogen leakage from Ahuroa is not an issue. If it was an issue, it would not be feasible to cap or seal the reservoir and so viability would depend on the extent of the leakage and safety or environmental issues arising. The process of transferring Ahuroa from natural gas to H_2 is not assumed to be a significant additional cost. This would require a phased shift from 100% natural gas to 100% hydrogen over a period.

Contact Energy Cost estimates

AGS provides Contact with up to 17 PJ of gas storage capacity



- ~17 PJ max working volume
- 11.3 PJ working volume as at 30 June 2015
- Connected to Stratford power stations by 2 pipelines
- Operated by NZEC (from Waihapa Production Station)
- Max reservoir pressure 3,450 psi
- 45TJ/day extraction rate (single train)
- 27 TJ/day injection rate (via Waihapa Production Station) (single train)

16 Taranaki site tour 28 July 2015

- Initial investment (excl Cap interest) $197m
  - Assets $111m
  - Gas rights $35m
  - Cushion gas $51m
- Ahuroa
  - 2 stage options to expand injection and extraction capacity at 50 TJ/day increments ($60 - $80m)

1) The volumetric HHV energy density of hydrogen is 12.8MJ/m3 compared with 40.3MJ/m3 for natural gas at atmospheric pressure. This implies a 1:3 ratio at atmospheric pressure which could fall at higher pressure. I have assumed the ratio is between 1:3 and 1:4 for gas in the reservoir at a pressure up to 26MPa.

Ammonia Conversion and Storage

Technology

- **Conversion of Ahuroa would only deal with a portion of the need for medium and long term storage.**
- **An alternative mid/long term storage option is to convert the H_2 to ammonia for storage and transport.**
  - **This involves the use of the Haber-Bosch process to convert hydrogen to ammonia.**

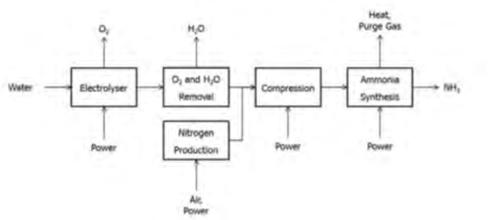


Figure 2.2: Block Diagram of Power to Ammonia

  - **The ammonia conversion process is relatively inflexible and so it is assumed that the conversion operates at baseload using the Ahuroa storage as a buffer to smooth fluctuations in H_2 production from the electrolysis plant.**
  - **Bulk storage of ammonia can be:**
    - at atmospheric temperature in large scale double-walled and vacuum-insulated to maintain a temperature close to -33ºC, or
    - as liquid at around 7 bar pressure at 20ºC in tanks similar to LNG

Cost assumptions

- **Incremental Ammonia production costs = \$5.0/GJ H_2**
  - Concept (2018) reports that a conventional ammonia plant (1,400 tonne/day capacity, or 35,000 GJ/day worth of H_2) with some storage capacity costs approximately NZ\$490M (based on 2012 costs from the USA) – this implies a <u>\$38m</u> for a each 1PJ/yr production capacity.
  - This implies that estimated that the incremental charge for an ammonia plant would be NZ\$5.0/GJ – on the basis of the HHV energy content of the hydrogen (assuming a 10% CRF and 3% of capex operating cost).
    - The estimated conversion efficiency from hydrogen to ammonia is 75%, and 80% for ammonia back to hydrogen for use in a hydrogen gas turbine peaker (overall 60% efficiency).
- **Storage capital costs = NZ\$50/GJ H_2 stored**
  - Bartel (2008)[1] – Estimates costs for a low-temperature ammonia storage facility, including a 25,000 t storage vessel, refrigeration system, and all ammonia handling and plant facilities, was estimated to cost US\$20.2m in 2007 dollars. This can hold the hydrogen energy equivalent of 564 GJ (HHV).
    - This is US\$36/GJ capital cost , or NZ\$62/GJ (accounting for US inflation and 0.68 exchange rate) for 0.6PJ sized storage facilities.
    - Storage efficiency is estimated to be 94% (6% losses).
  - Concept (2018) reports that 30 kt capacity refrigerated storage terminal costs in the region of NZ\$30M to build (NZ\$45/GJ H_2 capacity), and that constructing bulk pressurised ammonia storage costs around NZ\$2.00 per litre (\$117/GJ H_2 capacity).
  - Leighty (2012) reports the cost of 30kt storage as is typical in the USA corn belt is US\$15m – or NZ\$25m (NZ\$41/GJ). It is likely to cost more in NZ.
  - For this study I have assumed a capital cost of NZ\$50/GJ H_2 stored.
    - This can be compared with the minimum capital cost of over \$400/GJ for bulk liquid H_2 at -253 degrees C in insulated tanks
- This implies a capital cost of approx. for <u>\$250m</u> for tanks to hold 5 PJ of Hydrogen in the form of ammonia.
  - This would require around 8-9 large scale (30,000 t) tanks typical of those used in the USA corn belt.

[1] "*Implementing the Ammonia Economy*", Iowa State University Jeffrey R. Bartels Michael B. Pate, PhD December 2008
[2] Concept (2018) - "H2_Report_3_Research" Concept Consulting , December 2018
[3] "Alternatives to Electricity for Transmission, Firming Storage, and Supply Integration for Diverse, Stranded, Renewable Energy Resources", William C. Leighty a , John H. Holbrook, World Hydrogen Energy Conference 2012.

Peaking Generation on Hydrogen or Ammonia

JC[2]

Conversion of Taranaki peaking plant to run on hydrogen

- **The issues with running open cycle peakers on hydrogen include:**
  - The need to dilute hydrogen with nitrogen or steam.
  - Flame stability and high combustion temperatures
  - Control of NOx emissions
  - Hydrogen embrittlement issues
- **It has been demonstrated that existing gas turbines can be converted to take up to 30% hydrogen / 70% natural gas mixtures.**
  - Stratford comprises 4 * 50MW , each a Pratt and Witney TwinPack of two FT4 gas turbines.
    - While it may be theoretically possible to convert Stratford to 100% H_2 operation, it is not known if this is technically or economically feasible.
  - Assume that Stratford is almost entirely replaced with a new open cycle gas turbine designed to operate 100% on hydrogen. It is not known what the cost of a new hydrogen peaking plant (still in RD&D).
    - Assumed Costs :
      - Capex = $1000±50%/kW for a largely new H_2 capable peaking plant on Stratford site
      - FOM = $15±5 /kW/yr accounting for low capacity operation and safety
      - VOM = $20±10/MWh accounting for low CF operation, H_2 handling and dilution, NOx control/scrubbing and hydrogen embrittlement issues
      - Efficiency = 36% HHV - consistent with low capacity factor operation
  - It is assumed that it is not economically feasible to convert TCC to 100% H_2 operation given its age and operational limits.
  - For this study it is assumed that Stratford is replaced or converted to H_2 firing with a capacity of 220MW at a total capital cost of $220m.

Ammonia fired peaking plant

- **Direct burning of ammonia in gas turbines is in R&D stage.**
  - The 2017 ISPT report[1] concludes that ammonia-burning gas turbines are a technology for the medium-to-long term at the earliest.
- **For this analysis it is assumed that ammonia is converted back to hydrogen and used in a hydrogen capable OCGT.**
  - This involves around an 80% conversion efficiency.
  - It may be possible to convert other existing peakers to operate on H_2, but this is not known and would involve the transport of ammonia from Ahuroa.
  - It may also be possible to use ammonia directly in a modified reciprocating diesel engine. This is likely to be a higher capital cost than in this study, and probably would involve additional NOx control costs.
  - So for this study it is assumed a generic cost for new peakers (located near to Ahuroa without a significant ammonia transport cost) as assumed for Stratford.
- **For example if we assumed 500MW of peaking capacity supplied from the ammonia storage this would require $500m capital cost.**

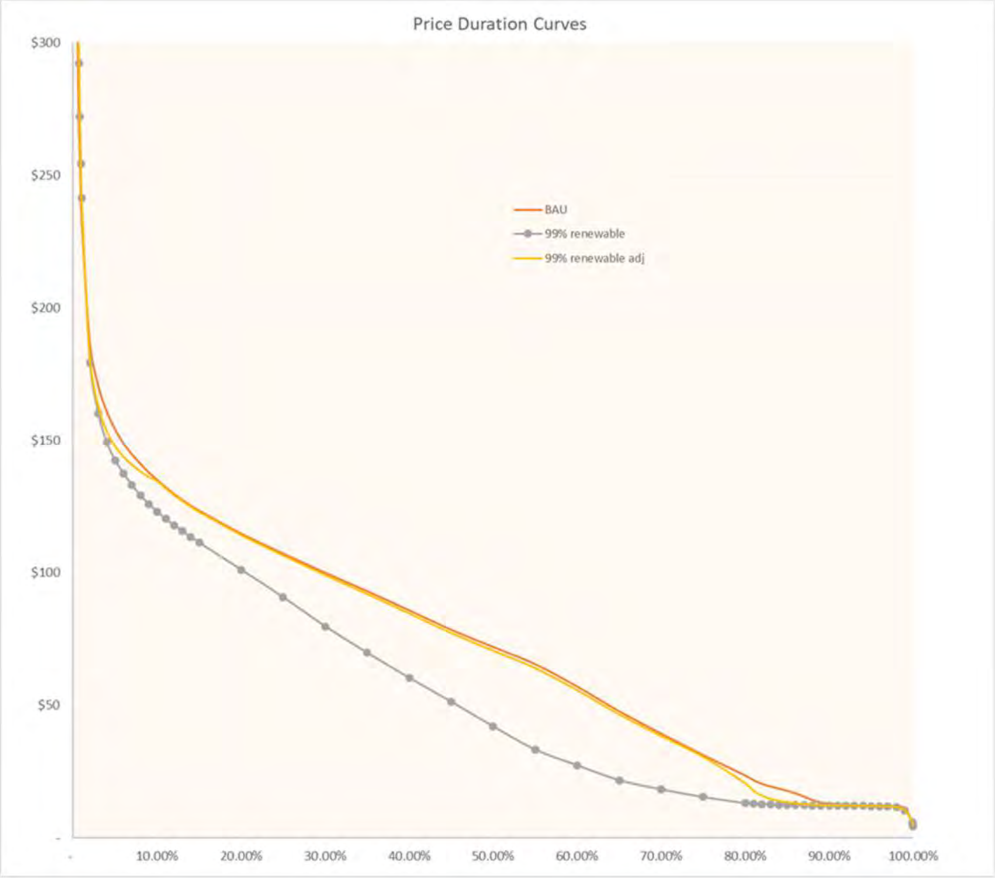
1) http://www.ispt.eu/media/ISPT-P2A-Final-Report.pdf.

Electricity market prices

Wholesale prices

- The operation of a combined electrolyser, H_2 storage and H_2 peaking facility is modelled using prices derived from EMarket runs.
- Used an E-market run to simulate electricity spot price outcomes.
  - **The 98.6% renewable base case with closure of E3P and all cogen (except of one assumed to be converted to biomass) and some new renewables, but with around 830MW gas/oil peakers still operating to provide peak, seasonal and dry/calm year back up.**
- The price duration curves for each is shown in the chart.
  - **Used 2 curves for the analysis:**
    1. An adjusted PDC scaled to an average HAY price of $88/MWh. This is approx. revenue adequate and has prices falling below $12/MWh around 15-20% of the time.
    2. The raw PDC from the model run which has an average HAY price of $76/MWh which is not revenue adequate and has significantly lower prices at the bottom end of the price duration curve. This is an optimistic case since the cost of electricity for H_2 production is lower.
  - **In each case the mean residual demand for peaker generation is approx. 0.7 TWh (1.4% of total generation). The potential emission saving is 0.33mt.**

Price Duration Curves



Note: the PDC is derived from 3hrly average prices from the Emarket market simulation over 87 historical weather years , run PP_98.5_Renewable_Step7_A_MGMD_SC_1011.

Assumptions Ahuroa H_2 and NH_3 Storage – for 2035

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		Low	Base	High	Notes
Electrolyser Costs					
Electrolyser Capex	$/kW (input)	$525	$700	$875	Concept (2018) Future cost +30% and -20% - flexible PEM
Annual cost	$/kW/yr (input)	$54	$72	$90	Capex * CRF (15 years - now - assume 20 yr life by 2035)
Electrolyser Fixed Operating Cost	$/kW/yr (input)	$5	$10	$15	Assumption ±50%
Electrolyser Variable Operating Cost	% Capex	4.0%	5.0%	6.0%	Concept (2018) ±1%
Variable operating Cost	$/MWh (input)	$2.4	$4.0	$6.0	Calculated from %capex
Variable transmission Cost	$/MWh (input)	$2.8	$3.5	$4.7	Concept (2018) 10% of Average transmission charge $35/MWh ± 20%
Electrolyser Efficiency	%	75.0%	70%	65.0%	Concept (2018) Future efficiency ±5%
Incremental Storage Costs					
Ahuroa H2 working storage	PJ	4.3	4.9	5.7	Assumes between 1/4 and 1/3 of natural gas storage capacity
Ahuroa H2 cushion gas storage	PJ	2.1	2.4	2.8	50% of working storage
Value of cushion natural gas	$/GJ H2 HHV	8.0	7.0	6.0	Assumption ± $1/GJ
Ahuroa Conversion Cost 1	$m	$124	$155	$186	Contact (2015) to enable up to 220MW peaker ±20%
Ahuroa Conversion Cost 2	$m	$180	$225	$270	Contact (2015) to enable up to 300MW peaker
Implied Storage capital Cost	$/GJ H2 HHV	$42	$46	$48	Conversion cost / max working storage
Cushion gas Net Cost	$m	$11	$17	$26	Replace 6PJ of cushion natural gas @$7/GJ with H2 @$21/GJ
Avg Storage Cost (2TJ)	$m	$34	$42	$50	Cost at $21/GJ hydrogen production cost ±5%
H2 Compressor Efficiency	%	95.0%	90%	85.0%	Concept (2018) ±5%
H2 Peaker Cost					
Stratford Peaker Conversion	$/kW	$500	$1,000	$1,500	Assumption: replacement of Stratford with new H2 capable gas turbine ±50%
Annual cost	$/kW/yr	$52	$103	$155	Capex * CRF
Peaker Efficiency on H2	%	38%	36%	34%	Assumption: Low capacity factor operation on H2
FOM (on H2)	$/kW/yr	$10	$15	$20	Assumption ±5/kW/yr
VOM (on H2)	$/MWh	$10	$20	$30	High variable cost, for low capacity factor operation, NOx scrubbing, more inspections etc ±50%
Electricity Market Prices	Scenario	BAU	98% renew	98% renew	From Elink model hourly model runs - 87 weather sequences
Additional Ammonia Production Costs					
NH4 Production Capital Cost	$m	$11	$13	$15	For plant with 0.5 PJ/yr H2 input (assumes 0.1 CRF and 4% operating costs)
H2 to Ammonia efficiency	pct HHV	80%	75%	70%	Concept (2018)
Incremental production cost	$/GJ HHV H2 output	$4.0	$5.0	$6.0	Concept (2018) Assumes 95% CF operation
Incremental operating costs	%	2.0%	3.0%	4.0%	Bartel (2018) % of capital cost per annum
Ammonia to H2 conversion	%	85%	80%	75%	Concept (2018)
Storage Capital Cost	$m	$188	$250	$313	for 5 PJ of bulk storage in insulated vessels at -33 deg C
Annual Storage Cost	$/GJ HHV H2	$5.0	$5.2	$6.5	Annualised cost of storage facilities
Ammonia storage efficiency	%	96%	94%	92%	Boil off losses
Notes:					
Capital Recovery Factor	CRF	10.3%			Capital recovery factor (20yr life and 8% nominal post tax unlevered WACC)
Concept (2018)					"Hydrogen in New Zealand Report 2 – Analysis", Concept Consulting Nov 2018
Contact (2015)					"Taranaki site tour", Investor presentation, Contact Energy July 2015
Bartels (2008)					"A feasibility study of implementing an Ammonia Economy", Jeffrey R. Bartels Michael B. Pate, December 2008

Notes: all prices are in 2018 NZ dollar terms unless otherwise indicated .
1) It is possible that additional compression on the pipeline from Ahuroa to Stratford may be required (given the lower volumetric density of hydrogen). This is not accounted for in the analysis.

Results

JC[2]

Results

		Small (5PJ)	Medium (12PJ)	Large (20PJ)	Very Large (25PJ)
Capacities	Units	Ahuroa Only	Ahuroa & Small NH3	Ahuroa & Medium NH4	Ahuroa & Large NH3
% Renewable GWh	%	98.9%	99.4%	99.8%	100%
% Peakers Converted to H2	%	27%	63%	100%	100%
Electrolyser Capacity	MW	200	800	1,400	1,600
H2 Peaker MW at Stratford	MW	220	220	220	220
NH3 Peaker MW	MW	-	305	610	610
Ammonia Conversion Capacity	TJ/yr	-	5,500	11,000	12,000
Ahuroa H2 Storage Capacity	TJ	4,857	4,857	4,857	4,857
Ammonia Storage Capacity	TJ	-	7,500	15,000	20,000
Price Set		98.6% renewable Adj	98.6% renewable Adj	98.6% renewable Adj	98.6% renewable Adj
Time weighted Average Wholesale price	$/MWh	$88	$88	$88	$88
	-	-	-	-	-
Results					
Total H2 Produced	TJ/yr	1,807	6,339	10,298	11,317
H2 Used by H2 Peaker	TJ/yr	1,619	1,252	969	971
H2 converted to NH3	TJ/yr	-	4,434	8,272	9,186
NH3 converted to H2	TJ/yr	-	3,102	5,787	6,413
H2 Average Level	TJ	2,092	2,081	2,079	2,165
NH3 Average Level	TJ	-	4,490	9,239	12,892
Elec Demand for H2 production	GWh/yr	717	2,515	4,086	4,491
Total H2/NH3 Peaker Generation	GWh/yr	162	373	560	610
H2 Peaker output Value	$m/yr	$48	$116	$180	$193
H2 Elec Wholesale Costs	$m/yr	$23	$86	$143	$157
Electrolyser Network & VOM Costs	$m/yr	$5	$19	$31	$34
Peaker VOM Costs	$m/yr	$3	$7	$11	$12
Gross Margin	**$m/yr**	**$17**	**$4**	**-$5**	**-$10**
Fixed Costs Electrolyser	$m/yr	$16	$66	$115	$131
Fixed Costs H2 Peakers	$m/yr	$26	$62	$98	$98
Fixed Costs Ahuroa storage	$m/yr	$18	$18	$18	$18
Fixed Cost NH3 Production	$m/yr	-	$28	$55	$60
Fixed Costs NH3 Storage	$m/yr	-	$39	$77	$103
Incremental Cost	**$m/yr**	**$44**	**$207**	**$367**	**$420**
Incremental carbon abatement cost	$/t	$560	$1,157	$1,367	$1,436
Electrolyser capacity Factor	factor	41%	36%	33%	32%
Peaker Capacity Factor	factor	8.4%	8.1%	7.7%	8.4%
Avg Electrolyser Elec Costs	$/MWh	$32	$34	$35	$35
Avg Peaker Revenue	$/MWh	$299	$311	$322	$316
Combined Efficiency	factor	23%	15%	14%	14%
Cost of H2 produced	$/GJ	$25	$27	$28	$28
Cost of NH3 Produced	$/GJ	-	$55	$58	$58
Ahuroa storage capital cost	$/GJ/y	$3.6	$3.6	$3.6	$3.6
Ammonia storage capital cost	$/GJ/y	-	$5.2	$5.2	$5.2
Carbon Emissions saved	mt/y	0.08	0.18	0.27	0.29
Total Capex	$m	$515	$1,882	$3,249	$3,688
Electrolyser	$m	$140	$560	$980	$1,120
NH3 Production	$m	-	$267	$534	$583
Ahuroa Capex	$m	$155	$155	$155	$155
NH3 Storage	$m	-	$375	$750	$1,000
H2 Peaker Capex	$m	$220	$525	$830	$830

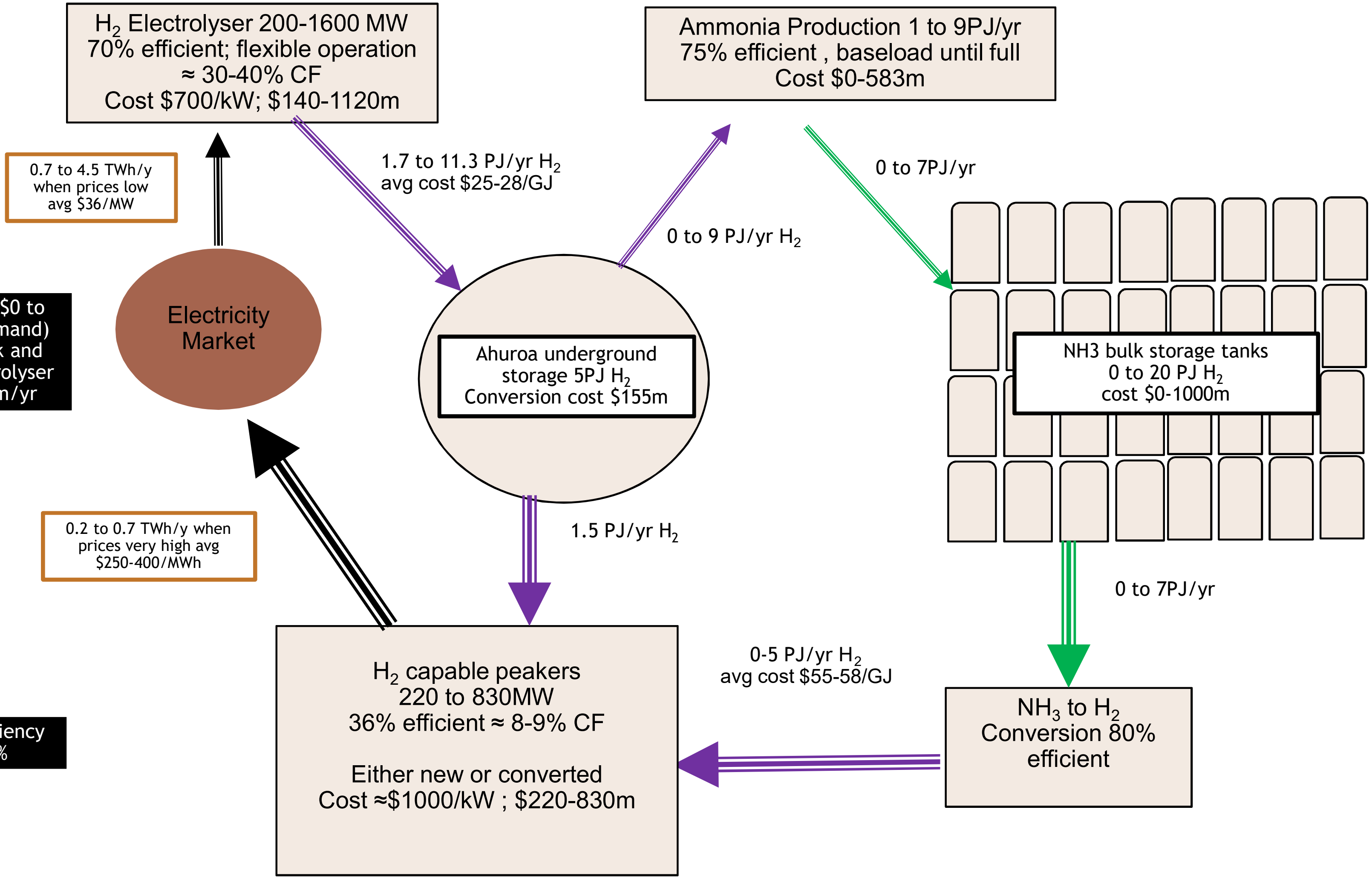
Commentary

- **The modelling is based on simulation using tuned Ahuroa and NH_3 storage operating rules and 3hr prices from Energy Link's market simulation with building of renewables to achieve 98.6% renewables.**
  - The modelling assumes H_2 fired peakers is quite flexible and can meet within day, week, month and year demands for backup subject to modelled limits to storage of H_2 in Ahuroa and in the Ammonia tanks.
- **Three configurations are considered**
  - Small : 200MW H_2 plant, Ahuroa with 4.9PJ and no NH_3 tanks, 220 MW peakers
  - Medium: 800MW H_2 plant, 4.9PJ Ahuroa + 7.5PJ NH_3 storage, 525MW peakers
  - Large: 1400MW H_2 plant, 4.9PJ Ahuroa + 15PJ NH_3 storage, 830 MW peakers
  - Very Large: 1600MW H_2 plant, 4.9PJ Ahuroa + 20PJ NH_3 storage, 830 MW peakers
- **In these cases the reduction in the % renewable is <0.3-1.3% as there is assumed to be overbuilding of renewables and so peaker capacity factors are low.**
- **The modelling indicates that the gross margin available from using low priced electricity to produce hydrogen which is used as a peaker fuel at times of very high price is generally enough to cover the variable costs and make a surplus, unless the hydrogen production is large.**
  - This is achieved by buying at $35/MWh to produce H_2 by electrolysis and earning around $300-400/MWh in back up peakers operating at 8-10% average capacity factor.
  - This is despite an overall efficiency of only 14% to 23%.
  - The gross margin is adequate to cover the fixed electrolyser and NH_3 production costs, but does not cover the fixed costs of incremental storage facilities and new H_2 capable peakers.
- **There is a net cost of replacing existing and new gas peakers with H_2 and NH_3 storage of the order of $44 to $441m/yr depending on the % reduction in % renewable required.**
  - This implies an incremental carbon abatement cost of $560 to $1500/t.
    - Note the modelling of electricity prices assumes a $50/t carbon price.

Overview - A dedicated H_2 backup facility

JC[2]

Total Capex \$0.5 to \$3.7b



Gross margin \$0 to \$23/MWh (demand) after network and variable electrolyser costs; \$0-17m/yr

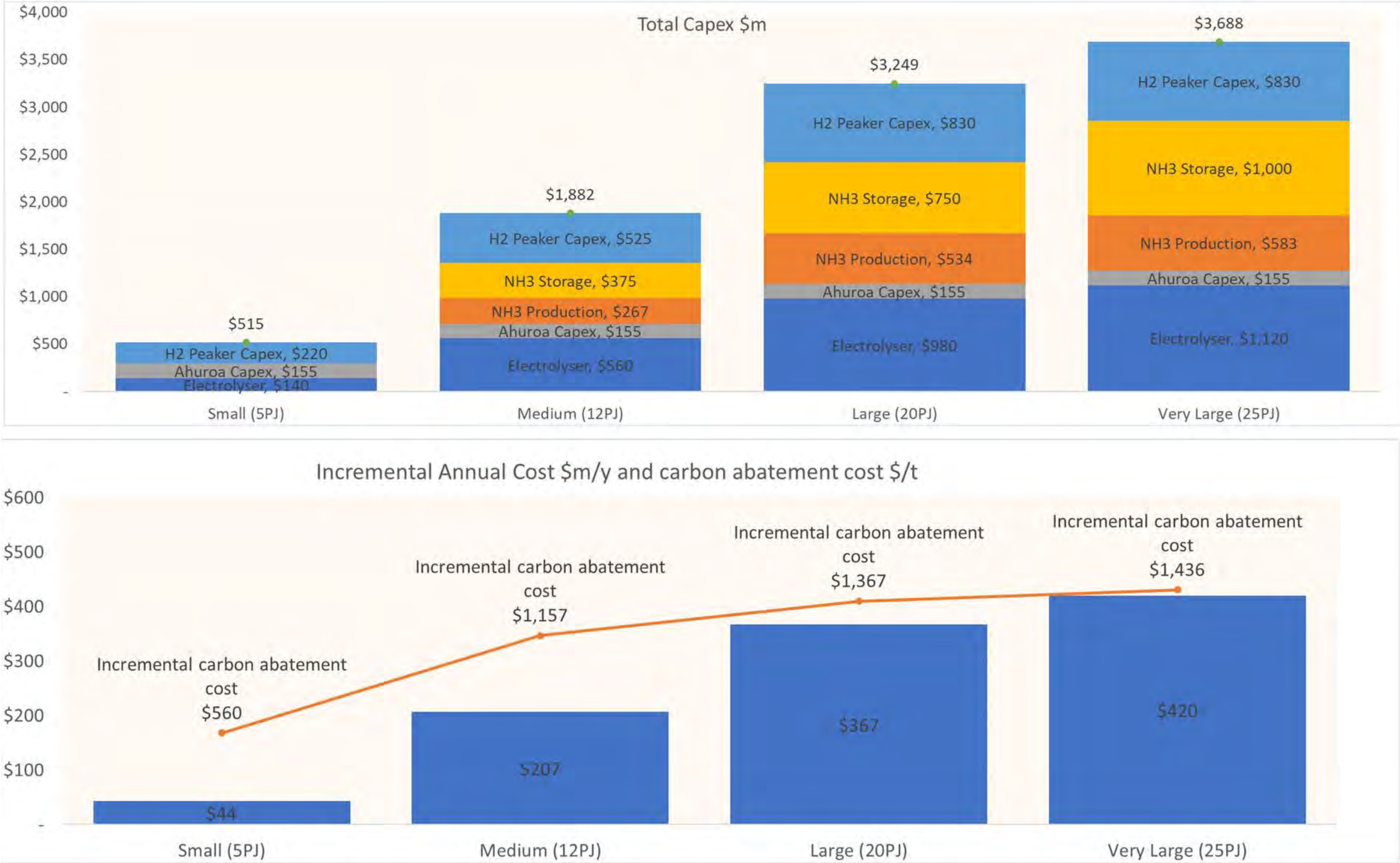
Annual fixed costs \$60-410m/yr

Emission savings 0.10 - 0.31 mt/yr

Overall efficiency 23 to 14%

Costs and incremental abatement costs

JC2



Annual incremental costs include:

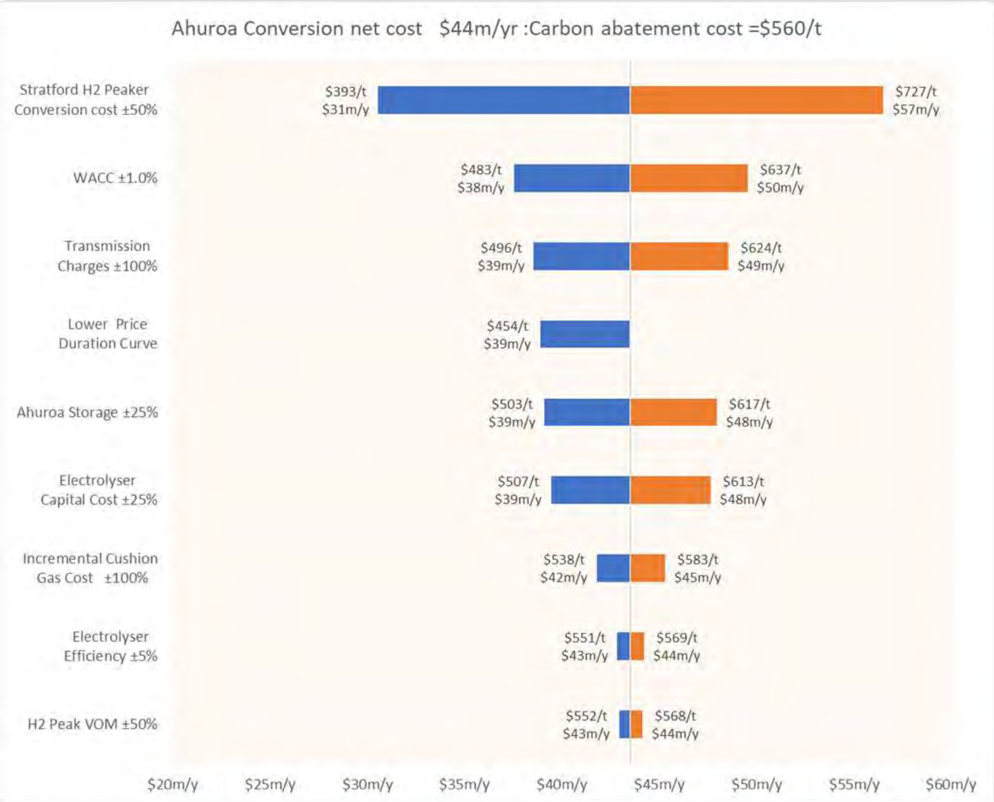
- The fixed operating costs for facilities, plus
- the annualised capital costs (assuming 20yr life)
- minus the net gross margin from the electricity market (gains from selling high and buying low, net of variable operating costs).

The marginal carbon abatement cost for incremental ammonia production and storage is around $1750/t.

Sensitivity on costs to achieve first 0.3% renewable

JC²

Sensitivity Tornado Chart -



Note : each $1m/yr corresponds to approx. $12.9/t change in the carbon abatement cost.

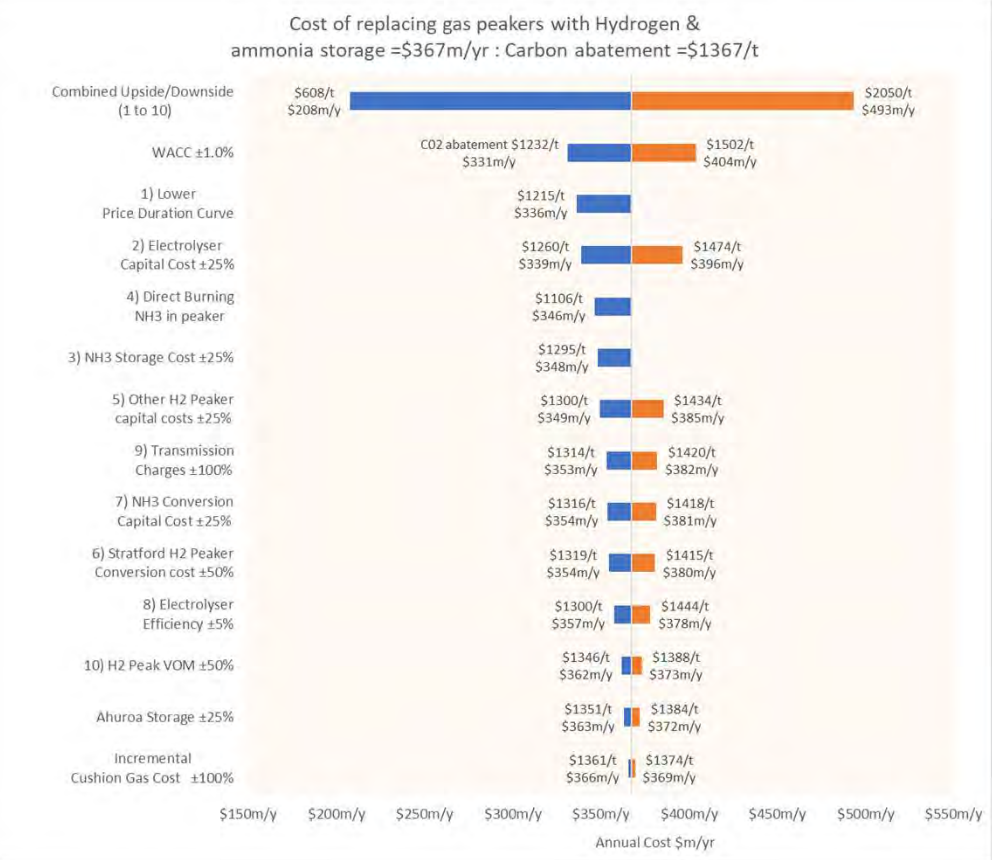
Commentary

- **The base case has a calculated net cost of $44m/yr and an implied carbon abatement cost of $560/t.**
- **The key factors affecting the cost are:**
  - **The cost of converting Stratford to H_2 operation.**
    - If this could be achieved at $500/kW then the implied incremental carbon abatement cost would be reduced to $393/t.
  - **A reduction in the cost of capital by 1% would also have a big impact.**
    - As would a reduction in transmission charges and a lower price duration curve.
  - **The cost of conversion of Ahuroa gas storage to H_2 would also have a big impact.**
    - The base assumption is that a capital cost of $155m would be required to enable the extraction rates to be sufficient to operate Stratford fully on Hydrogen.
      - Also the base assumption assumes that there is a low cost transition from Ahuroa operating on gas to hydrogen. This would require a careful process of operating on gradually increasing the blend from 10 to 100% hydrogen over time, and dealing with this changing blend at the power station. It may not be possible to do this, if so then Ahuroa may need to be closed while it is converted. This may involve a considerable cost.
  - **Electrolyser efficiency and peaker variable operating costs (to control NOx) have a smaller impact.**

Sensitivity on costs to achieve +1.2% renewable

JC2

Sensitivity Tornado Chart



Commentary

- **The base case net cost of completely replacing natural gas peakers with a combination of H_2 and Ammonia storage is $367m/y, with an implied abatement cost of $1367/t.**
- **The key factors affecting the cost are:**
  - **The cost of capital**
    - 1% reduction gives a $36m/yr reduction and a $1232 abatement cost.
  - **A lower price duration curve and lower electrolyser capital costs would reduce annual costs by around $30m/yr and reduce carbon abatement costs to around 340/t**
  - **If it is possible to burn NH_3 in a new peaker, rather than converting NH_3 to H_2 and then burning in a peaker:**
    - The cost would fall by $21m/yr and abatement costs would fall to $1100/t.
  - **The net largest sensitivities relates to the cost of NH_3 storage.**
    - A 25% reduction would save $19m/yr.
  - **The cost of converting existing peakers to run on H_2, or building new H_2 capable peakers**
    - The base assumption is that this will cost $1000/kW.
    - A 25% reduction in this cost would save $18m/yr and reduce the carbon abatement cost to around $1300/t.
  - **Other factors have a relatively small impact on costs.**
- **If all the uncertainties were favourable then implied abatement costs :**
  - could fall to $608/t, but if they were unfavourable abatement costs could exceed $2000/t.

Conclusion

JC²

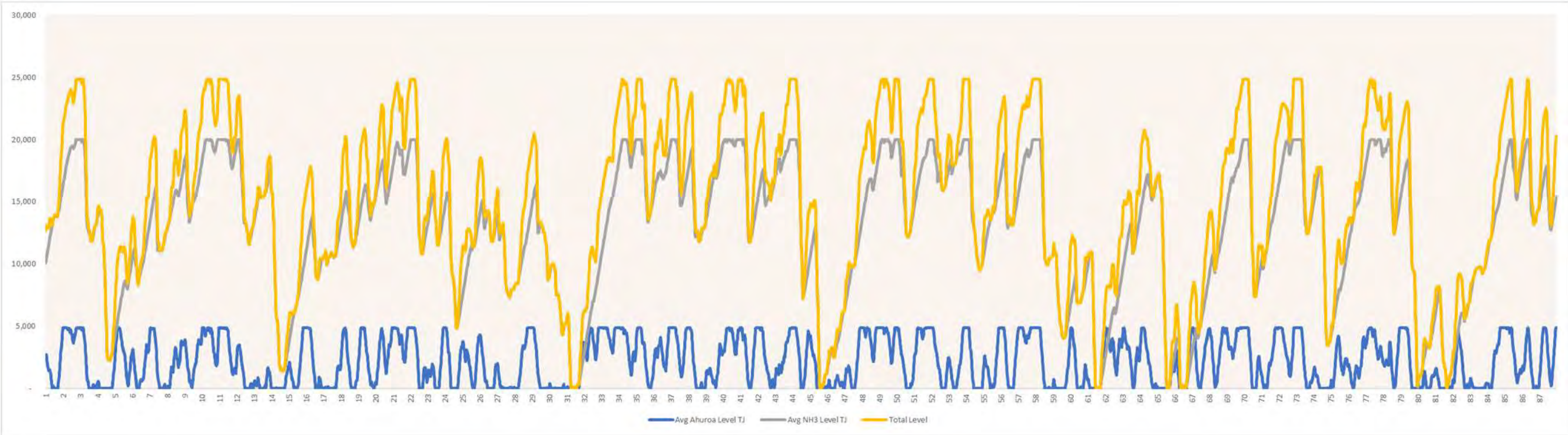
- There are significant costs in using hydrogen as a replacement for gas as a backup fuel.
- Conversion of Ahuroa gas storage to hydrogen from a electrolysis plant for use in a 220MW hydrogen fired peaker appears to be the lowest cost.
  - The technical feasibility would need to be confirmed (ie confirm leakage is not too great an issue).
- But
  - This only achieves a reduction of around 0.3% renewable, around 0.1mt of emissions and provides around 5PJ storage capacity.
  - The capital cost could be around $515m (electrolyser, new/conversion peaker cost, Ahuroa capex to enable adequate withdrawal rates, replacement of natural gas cushion gas with hydrogen).
  - H_2 fired peakers are feasible, but are in early development and costs are highly uncertain. There are potential issues with NO_x emissions which could increase costs.
  - The conversion efficiency is around 22% (electricity out / electricity in)
  - The implied carbon abatement cost is in the order of $560/t.
- Addition of an Ammonia conversion plant and storage would be technically feasible at a high cost:
  - This could achieve 100% renewable and save around 0.3 mt/y of emissions and provide around 25PJ of storage sufficient to cover hydro and other fluctuations.
  - The capital cost could be up to $3.7 billion (a larger electrolyser, additional H_2 peaking plant, ammonia production facility and ammonia storage tanks).
  - The conversion efficiency is around 14% for the combined facility (lower as a result of ammonia conversion and reconversion losses).
  - The implied carbon abatement cost is of the order of $1400/t (for the combined facility).
    - The marginal abatement cost for the additional ammonia facilities and storage is around $1750/t.
- There might be gains from integrating this into a wider hydrogen business, however the storage and capacity requirements for H_2 use as a back up in electricity are different from other hydrogen uses and so synergies may be minimal.

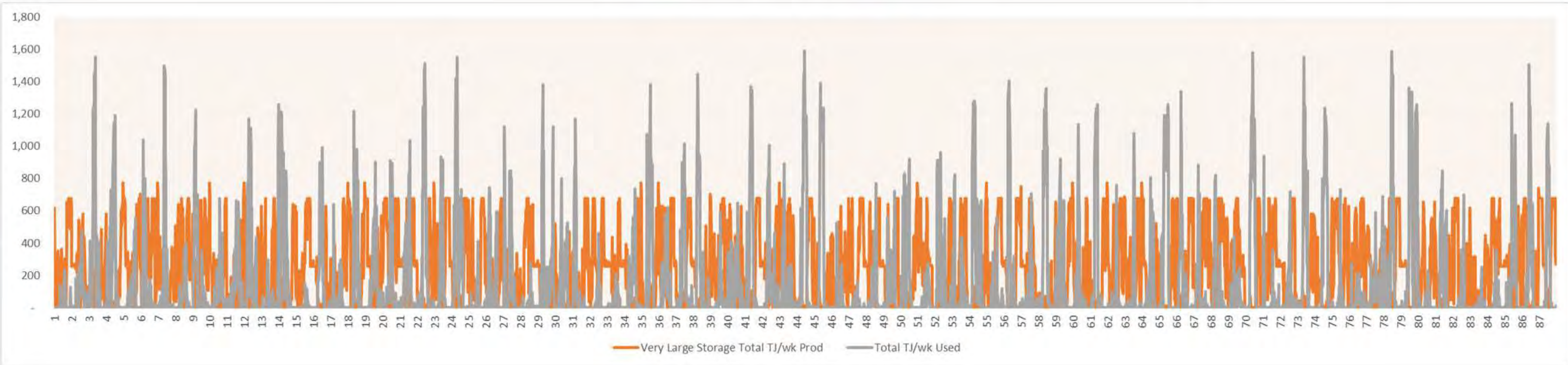
Appendix

Background Charts

Max case : 25PJ storage (20PJ of NH_3 and 5PJ of H2)

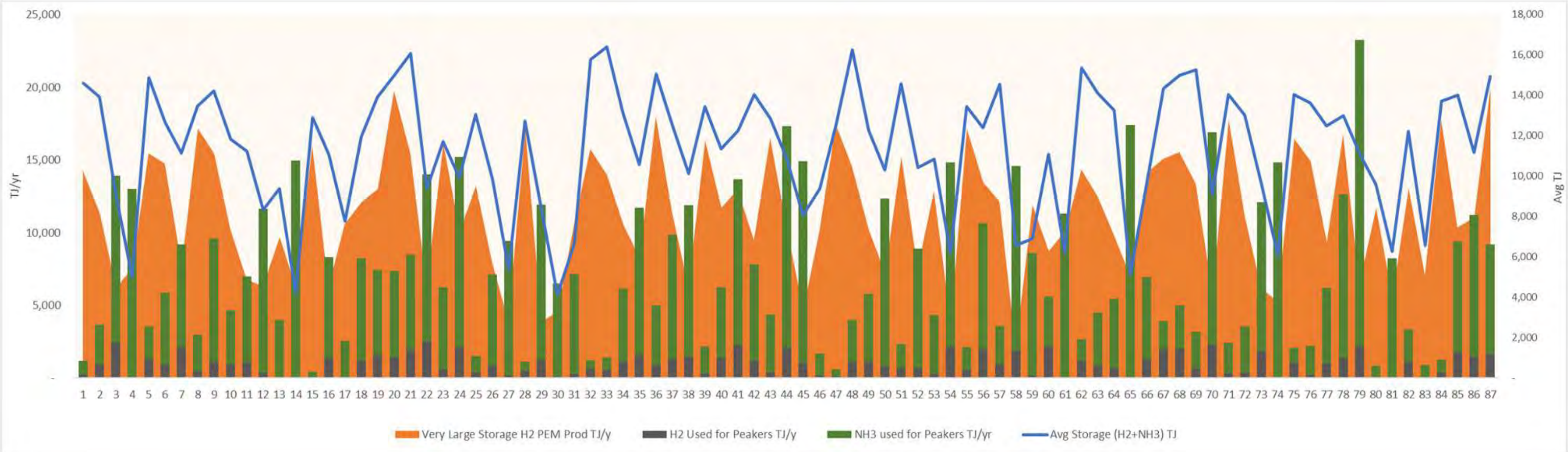
JC²

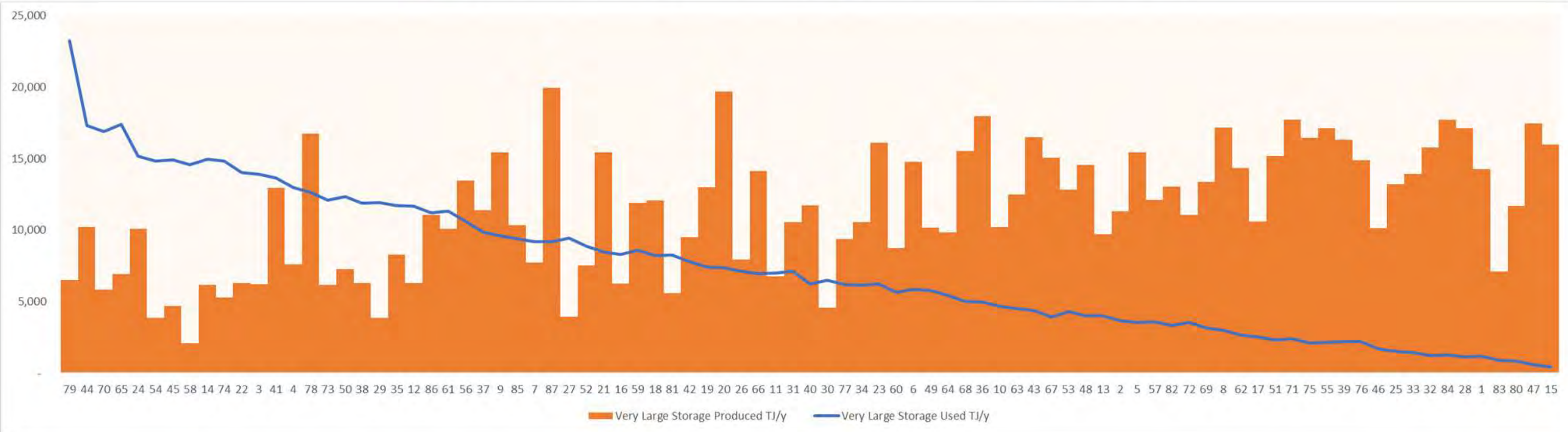




Annual Distributions: Max Case 25PJ storage

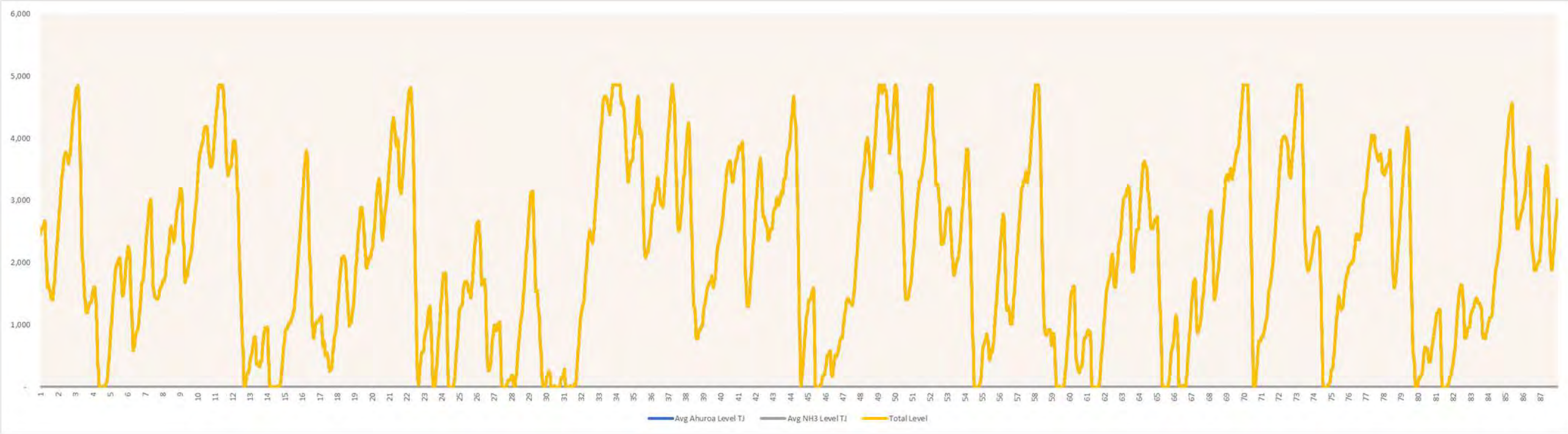
JC2

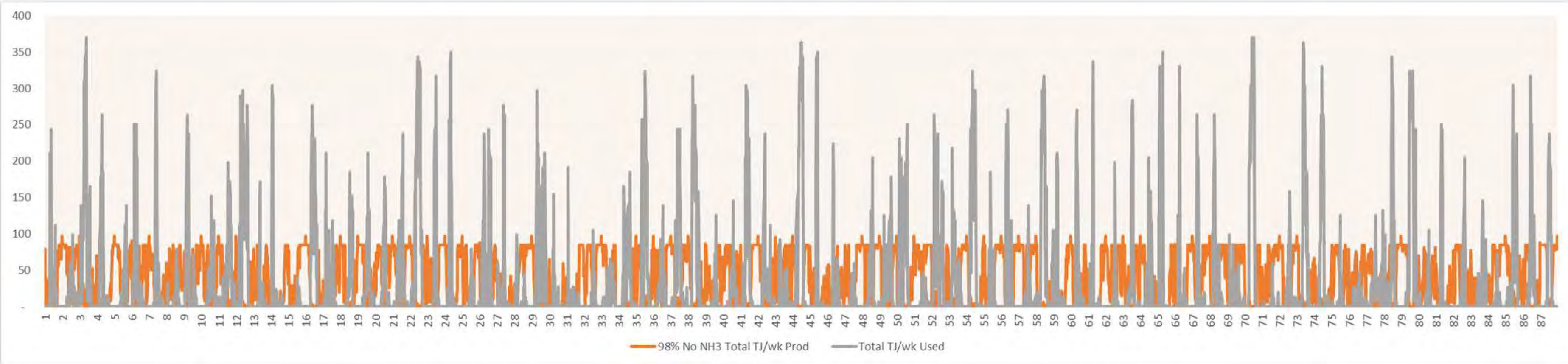




Ahuroa Only – Stratford power station

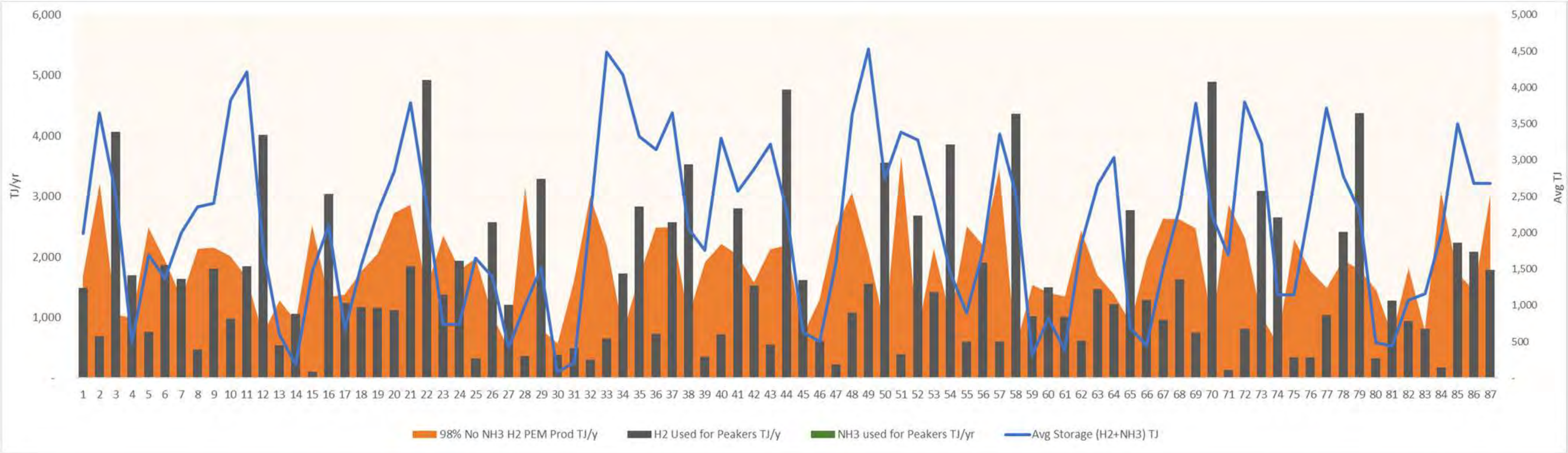
JC2

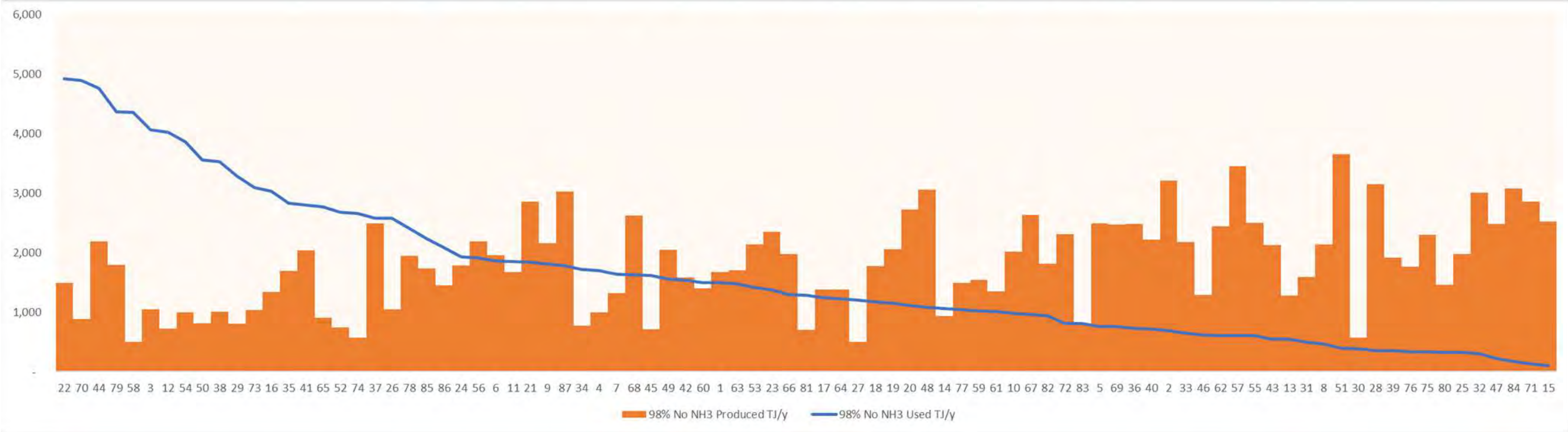




Annual Distributions : Ahuroa only

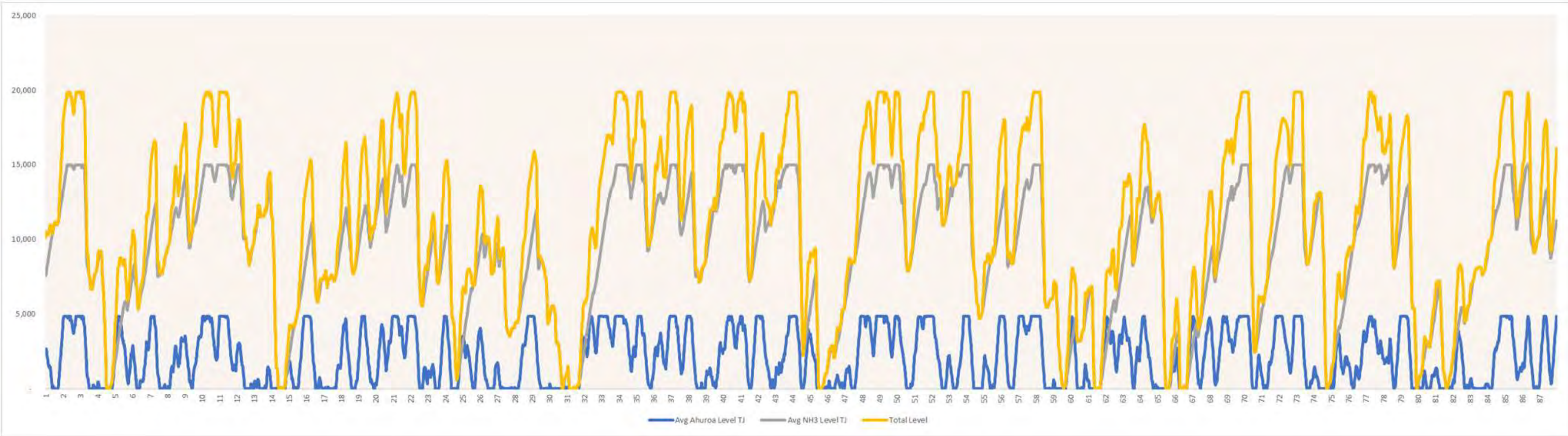
JC2

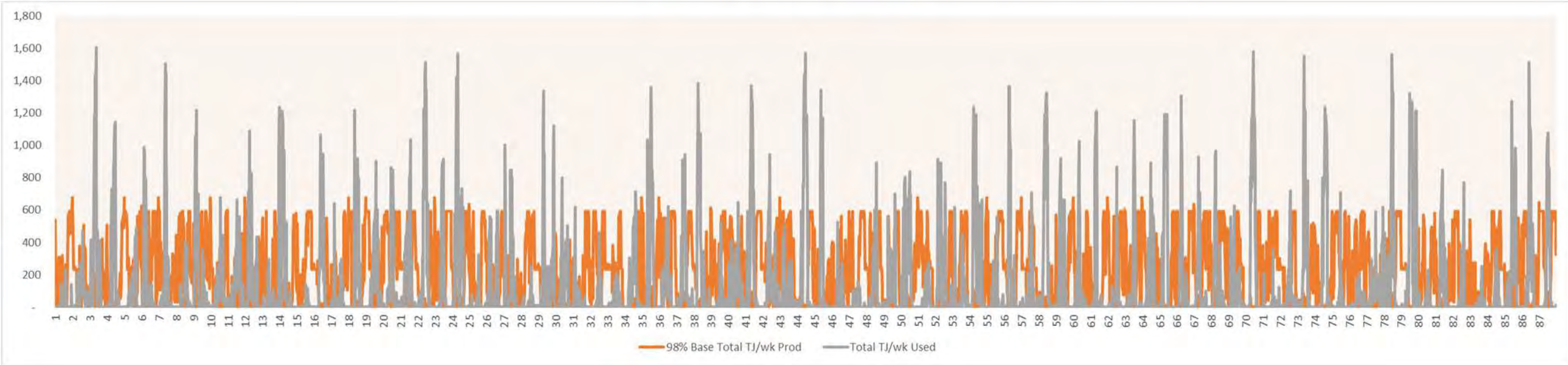




Base case : 20PJ storage (15PJ of NH3 and 5PJ of H_2)

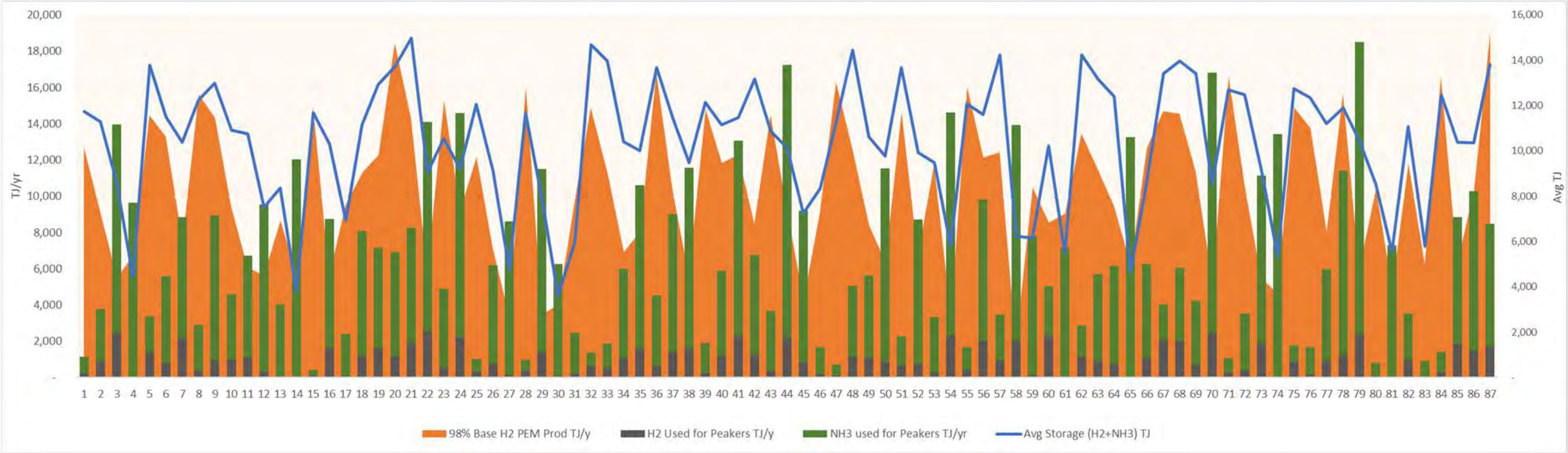
JC²

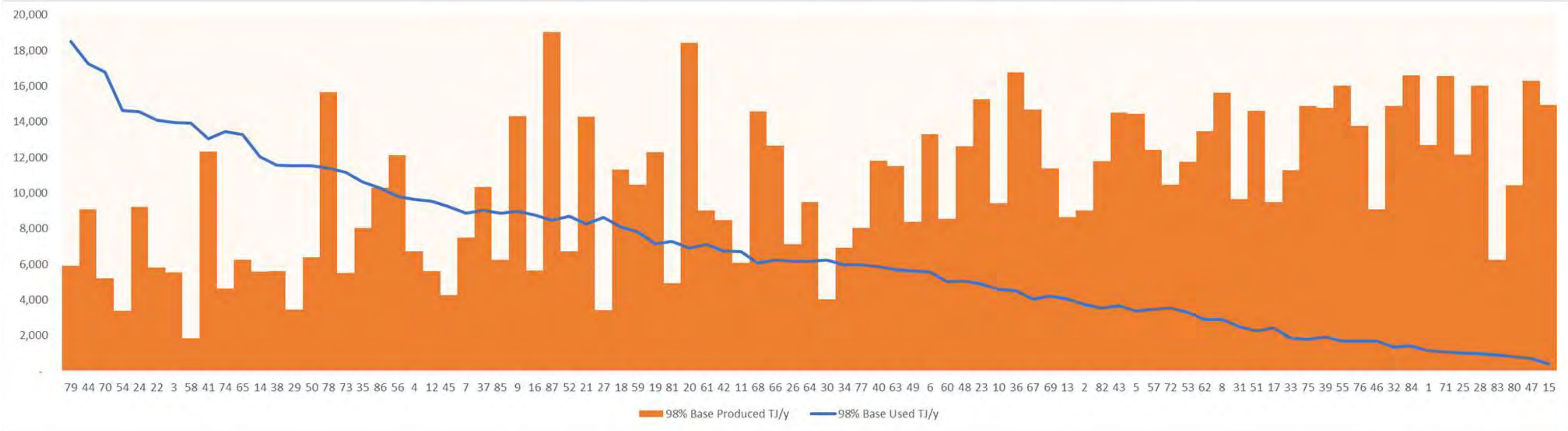




Annual Distributions: Base Case 20PJ storage

JC2

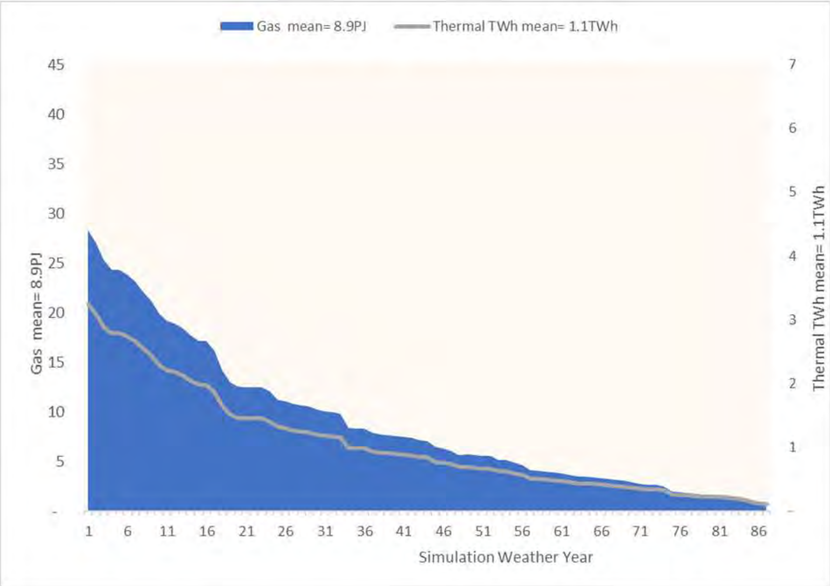




Annual thermal demand curves PJ and TWh per weather year

JC2

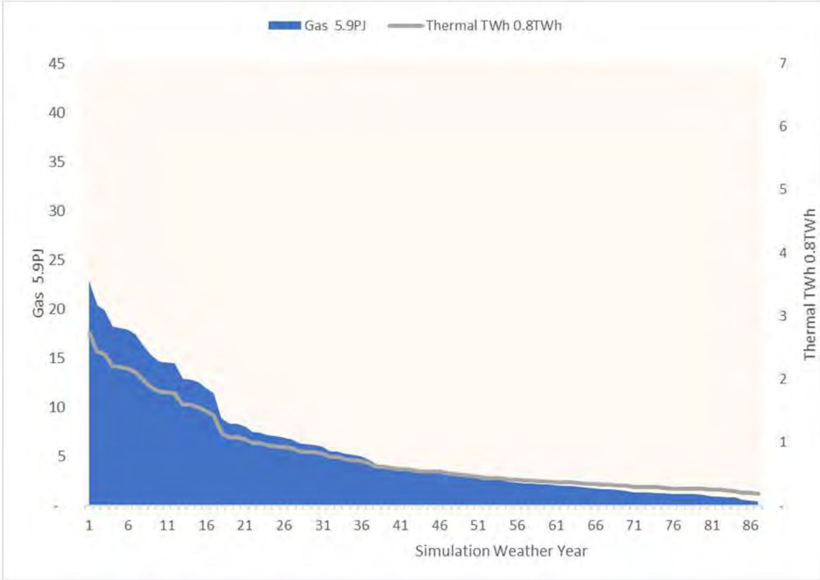
97.9% renewable - no E3P and Cogen - 920MW of peakers



Includes :

- E3P and Cogen retirement
- 920MW of gas/oil peakers

98.6% renewable - Wind and solar overbuild - 820 MW peakers



Includes extra:

- 820 MW gas/oil peakers.
- 150MW batteries (12 hour)
- 250 MW large scale solar
- 126MW wind
- 30MW geothermal
- Wind spill approx. 1200GWh

Caveats and Disclaimer

Limitations and Caveats

- The indicative analysis is based on a stand-alone simulation of the operation of the Ahuroa and ammonia storage facilities based on relatively simple operating rules with generation trigger prices tuned to ensure most long run (dry year) backup requirements are met, and hydrogen production trigger prices to give low production costs.
- There are limitations:
  - It is not guaranteed that all the demand for dry year back-up is met as the simulated results have some sequences which reach zero combined storage even with 20 or 25PJ storage. In these situations there may need to be additional demand response.
  - The impact of these projects on the EMarket simulated prices are ignored. There may be an increase in prices when there is extra demand for H_2 production , particularly if this extra demand exceeds wind “spill”.
  - The hydrogen production and storage use operating rules are reasonable heuristics but are not fully optimised.
  - There are uncertainties concerning the technology efficiencies, costs assumed as significant improvements above current levels are built into the analysis.

Disclaimer

- The information and opinions expressed in this presentation are believed to be accurate and complete at the time of writing.
- However, John Culy does not accept any liability for errors or omissions in this presentation or for any consequences of reliance on its content, conclusions or any material, correspondence of any form or discussions arising out of or associated with its preparation.

ICCC Modelling:
Pumped hydro storage -
Lake Onslow option analysis

Final Slides: John Culy

Introduction and Summary

JC²

- This report examines the likely costs and benefits of a hydro pumped storage scheme in the South Island of New Zealand.
    - This involves a 15-24km tunnel, underground power/pumping station and new dam/s to create a storage reservoir in the Onslow/Manabourn basins at an elevation of 700-800m. This can provide 1000 to 1500MW capacity with 4 to 12 TWh of storage capacity.
- **The possible design and cost estimates are based on a variety of sources including:**
    - Various notes by Bardsley et al and a 2019 PHD thesis Majeed (2019) supervised by Bardsley.
    - Preliminary cost estimates for the full Lake Onslow/Manabourn scheme prepared by PB Power in 2006 for the Electricity Commission.
    - A 2018 review of the potential by Sapere Research Group for the Productivity Commission.
- **This assessment assumes a small scheme with 1000MW capacity and 5TWh storage.**
- **The estimated costs for an underground power station and tunnel are benchmarked against the costs estimates for the 2000MW Snowy 2.0 pumped storage project in Australia and a 1985 completed 640MW pumped storage project in Norway with around 7-8TWh storage capacity.**
    - Snowy 2.0 is a project with a tunnel and underground power/pumping station, but does not include a new hydro storage dam as it utilises an existing (but much smaller) reservoir with a similar relative elevation. The project is around twice the capacity and hence requires a larger tunnel diameter and underground power station cavern. It has gone to tender and the EPC contracts are close to being finalised.
    - The Norway project has a larger storage capacity, but a lower MW capacity, lower hydraulic head and a shorter 10km tunnel.
- **A capital cost range based on the modified original costing and external benchmarks is around $NZ3.2 ± 1.0 billion including transmission upgrades.**
- **An indicative stand-alone evaluation of this project is based on the Middle of Road, Business as Usual, EMarket market simulation results and prices:**
    - This suggests that a generation capacity factor of around 17% and a pumping capacity factor of 22% might be achieved and this could displace around 0.6mt of emissions per year at a carbon abatement cost of around $250 ± 100/t.
    - This simplified evaluation ignores some additional benefits from reduced spill at other hydro reservoirs and provision of ancillary services, but also some negative impacts on the operation of the existing Clutha hydro stations and on possible impacts arising from transmission constraints and losses.
    - It is noted that there are very significant consenting and commercial risks associated with a project of this nature and large size.

Earl Bardsley (University of Waikato), Bryan Leyland (LCL Ltd), Sarah Bear (URS Ltd) *A large pumped storage scheme for seasonally reliability of national power supply* Presentation to the EEA Conference.

Majeed, M., 2019. Evaluating the potential for a multi-use seasonal pumped storage scheme in New Zealand's South Island. PhD thesis, University of Waikato

New Zealand - Lake Onslow Pumped Storage

JC²

Illustrative Design (Majeed 2019)

- **Lake Onslow**
  - **A new 3.8km 80m earth dam would provide around 7 TWh of storage in the Onslow Basin, lake area 74km².**
  - **24km kilometre tunnel linking the new reservoir with the Clutha River at lake Roxburgh.**
    - Pre-cast concrete lined low pressure 7.5-8.0m internal diameter through schist rock
  - **1.3GW pump-generators located at 80 metres above sea level underground so as to avoid steel linings for lower portion of tunnel.**
    - Operating head approx. 600-700m
    - Full pumping to generation with minutes

Options

- **Storage could be:**
  - 12 TWh if the Manorburn basin used and 800m dam with 124 km² area
  - 4 TWh if only Onslow basin and 60m dam
- **Outlet**
  - 24 km into lake Roxburgh (provides flow regulation but impacts Contact's resource consents)
  - 15km into Clutha below Teviot
- **Capacity could be 1.0 to 1.3GW**
  - 1GW would reduce tunnel diameter to 7m approx.

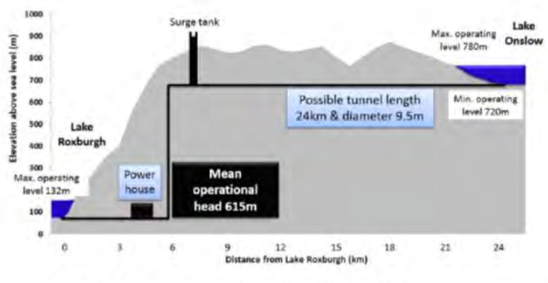


Figure 3.12 Cross section of the simulated Onslow PHES.

Clutha river operating range 300-900 cumec

185 cumec pumping, 240 cumec discharge

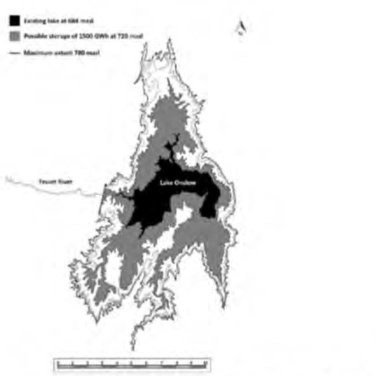


Figure 3.10 The hypothetical Onslow basin at 780 masl as the maximum extent of development and 720 masl as the minimum operational level.

Figure 1 – The Onslow-Manorburn depression, showing maximum pumped storage reservoir development to 800 metre elevation in both Upper Manorburn and Lake Onslow basins.

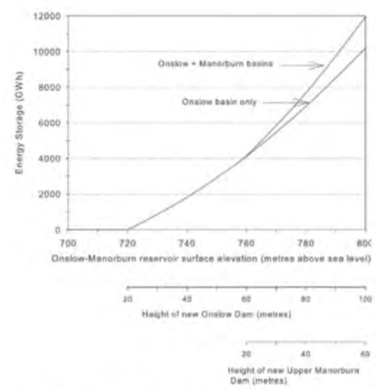


Figure 2 – Gravitational potential energy of a pumped storage reservoir in the Onslow-Manorburn depression. For both dams, the energy storage contribution is measured from zero at a 20-metre dam height on the basis of maintaining a permanent minimum lake area for environmental reasons.

Source: Majeed, M., 2019. Evaluating the potential for a multi-use seasonal pumped storage scheme in New Zealand's South Island. PhD thesis, University of Waikato

Lake Onslow - Additional Costs and Issues

JC²

Transmission Upgrade costs

- Evaporative losses
  - Majeed (2019) concluded that natural inflows into Lake Onslow would exceed evaporative losses, but maybe some reduction in Teviot river flow.
- Transmission
  - **To get full value from pumped storage you need to get power at times of shortage to North Island**
  - **Upgrade lines from Clutha to BEN**
    - Approx. $90-100m for thermal upgrade of Cromwell to Twizel, and duplexing of other lines (Transpower 2018 Transmission Planning report).
  - **Upgrade HVDC capacity to 1400MW (north)**
    - Additional cost $150m
      - Adding 4th cable and associated filters etc
      - Assuming done at same time as $300m cable replacement project.
- Total costs
  - **Capex NZ$2.3b to $4.0b ($1.8 - 3.1/W) + transmission ($0.25b)**
    - Operating cost NZ$12 to $50m/yr
  - **Sapere suggested NZ$1.8 to $5.2b capex range.**

Location and Geology

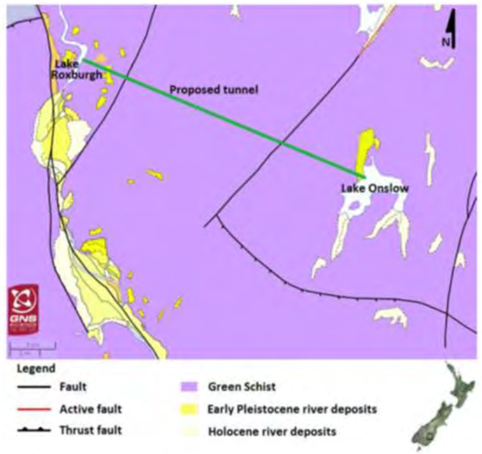


Figure 3.7 Geology surrounding the proposed scheme (based on Geology data GNS Science 2014) [91].

Figure 3.8 Location and layout of the hypothetical Onslow PHES at the maximum extent of development of the upper reservoir 1:250,000 scale map.

Circuit	Summer/Winter rating
Aviemore–Benmore–1 and 2	609/671 MVA[1]
Aviemore–Waitaki–1	609/671 MVA
Livingstone–Waitaki–1	609/671 MVA
Livingstone–Naseby–1	609/671 MVA[1]
Naseby–Roxburgh–1	609/671 MVA[1]
Clyde–Cromwell–Twizel–1 and 2	561/617 MVA[1]
Clyde–Roxburgh–1 and 2	709/781 MVA
Benmore–Twizel–1	404/493 MVA
Benmore–Ohau B–1	558/614 MVA
Ohau B–Twizel–3	694/764 MVA
Benmore–Ohau C–2	558/614 MVA
Ohau C–Twizel–4	694/764 MVA

[1] The timing to upgrade these circuits will periodically be reviewed. The summer/winter rating for these circuits prior to upgrade is:
- 202/246 MVA for Aviemore–Benmore–1 and 2, Roxburgh–Naseby–Livingstone–1, and
- 385/470 MVA for Cromwell–Twizel–1 and 2.

Source: Sapere Research Group, "Memorandum on a Pumped Storage scheme at Lake Onslow" July 2018

Australia - Snowy 2.0 Pumped Storage

Summary

- Physical
  - 2000MW and 80-176 hours of storage (360 GWh) operating head = 700m
  - 27 km of 10m diameter concrete lined underground tunnels and underground power station
  - 6 reversible Francis pump-turbine and motor-generator units (3 synchronous and 3 variable) - can swap from full pump to generate within minutes
  - 76% round trip efficiency
  - Simulated capacity factor ≈17% output, ≈24% pumping
- Capital Cost
  - A$3.8-4.5b + $1-2b (Transgrid for transmission) - Dec 2017 $ terms
    - Spread over 7 years, 50 year economic life

  Operating Cost
    - FOM A$5m/yr = A$2.5/kW/yr and VOM = 1/MWh (brush gear replacement)
- Stated Value - NPV @ 4.55% discount rate
  - Conventional capacity value = A$2.7b (or A$1.36/W) (i.e. back a $300/MWh cap)
  - Renewable firming = A$0.72b
  - Retail diversification = A$0.47b
  - Storage value = A$3.6b
  - Ancillary services = A$0.25b
  - O&M & Tax = -A$0.15b
  - 8% equity IRR when funded by debt at average cost of 5.66%.

Charts

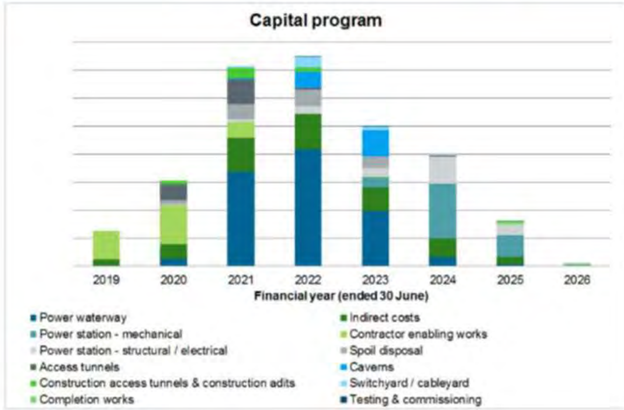


Figure 8: Capital program

Power Station Mechanical & Elec & structural & cavern ≈ 25%
Tunnels & Enabling & Spoil ≈ 62%
Other Indirect ≈ 13%

Source: Snowy 2.0 Final Investment Decision Information https://www.snowyhydro.com.au/our-scheme/snowy20/fid/

Comparison of Snowy 2.0 and Lake Onslow pumped storage

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Comparison

	Units	Norway Saurdal	Australia Snowy 2	NZ Onslow	NZ Onslow small
Capacity	GW	0.64	2.00	1.30	1.00
Energy	TWh	7.76	0.35	7.00	5.00
Upper Reservoir level range	m	125		80	70
Lake Area	km^2	82		74	70
Tunnel Length	km	10.5	27	20	20
Tunnel internal diameter	m		9.0	8.0	6.8
Hydraulic Head (Avg)	m	465	650	615	650
Capital Cost Hist/Mid	**NZ $b 2018**	**$1.80**	**$4.46**	**$3.15**	**$2.80**
Low	NZ $b 2018		$4.08	$2.30	$2.00
High	NZ $b 2018		$4.83	$4.00	$3.50
Transmission	NZ $b 2018		$1.6	$0.3	$0.3
Initial Filling	NZ $b 2018			$0.2	$0.1
Capital Cost Hist/Mid	**NZ $/W 2018**	**$2.8**	**$2.2**	**$2.4**	**$2.8**
Low	NZ $/W 2018		$2.0	$1.8	$2.0
High	NZ $/W 2018		$2.4	$3.1	$3.5
Transmission	NZ $/W 2018		$0.8	$0.2	$0.2
Capital Cost Hist/Mid	**NZ $/kWh 2018**	**$0.4**	**$6.4**	**$0.3**	**$0.6**
Low	NZ $/kWh 2018		$5.8	$0.3	$0.4
High	NZ $/kWh 2018		$6.9	$0.4	$0.7
Total	**NZ $b 2018**		**$4.5**		**$2.8**
Water way & Tunnels	NZ $b 2018		$2.8		$1.3
Power House & Cavern	NZ $b 2018		$1.1		$0.6
Dam & Land purchase	NZ $b 2018				$0.7
Other	NZ $b 2018		$0.6		$0.3

Commentary

- Snowy 2.0
  - **Has 2x capacity 2000MW compared with 1000MW**
  - **Has similar head to Onslow at around 700m**
  - **Has slightly longer tunnel 27km with 9m versus 15-24km with 7m internal diameter for Onslow.**
  - **Has pre-cast concrete lined tunnels like Onslow**
  - **Does not have the extra cost of a 3.8km, 70m high dam**
- Onslow (small) estimated cost based on Snowy costs
    - Assumes tunnel cost is scaled by volume and power house by MW
    - plus cost of 70m concrete faced rock dam and land purchase NZ$0.7b
  - **Total of NZ$2.8b (i.e. same $/W as large pumped storage in Norway)**
    - plus incremental transmission say NZ $0.3b - for Clutha to BEN capacity and increase of HVDC to 1400 MW, plus NZ $0.1b cost to fill to 3TWh
  - **Grand total NZ$3.2b ± 30% (± $1.0b)**
- Risks:
  - **Large consenting risks, potential conflict with other consents on Clutha**
  - **Large single project compared to many small overbuild projects in North Island**
  - **Could face significant transmission costs/constraints compared to North Island option**
  - **Uncertain impact of Onslow on other hydro and on pricing outcomes**
  - **Earthquake risks**
  - **Difficult for any single party in the market given size and risks**

Indicative Evaluation

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Base Valuation

- Base Valuation
  - **Assume:**
    - $3.2b capital cost including incremental cost of transmission to enable 1400 MW transfer capacity to the North Island and cost to fill
      - 50 year life capital recovery factor 8.5% (to give 8.0% post tax nominal merchant WACC)
    - $16m/yr operating cost (0.5% of capital)
    - $3.5/MWh variable transmission costs for pumping
    - 5 TWh storage (Onslow basin only)
    - 1GW capacity (pumping and generating)
    - 78% round trip efficiency (75% for dry year and 80% for cycling)
    - Middle of Road Business as Usual South Island price duration curve in 2035 and limits from HVDC operating to 1400MW max
      - This has gas peaker and CCGT capacity of 1GW and average generation of 1.5TWh/yr that could be replaced by Onslow Pumped Storage
      - Pumped storage is operated to pump trigger prices around $45-70/MWh and generate trigger prices around $80-180/MWh depending on storage.
  - **Ignore:**
    - The impact of Onslow pumped storage on the BAU price duration curve
      - i.e. use of stand alone model of pumped storage operation based on price triggers and HVDC constraints
    - Impact of constraints in Clutha river downstream at Roxburgh
    - Impact of marginal losses and transmission constraints other than HVDC.
    - Potential benefits from reduced spill etc from impact of Onslow storage on the operation of other South Island storages
    - Potential benefits from ancillary services (possibly $10m/yr)

Results

- **Pumping CF = 21.5% - 1.9TWh - avg cost $30/MWh**
- **Generation CF = 16.6% - 1.5TWh avg value $158/MWh**
- **Annual gross margin = $167m/yr or $167/kW/yr**
- **The annual capital cost = $290m/yr or $290/kW/yr**
- **The cost of delivered electricity is approx. $243/MWh for 16.6% capacity factor operation (capital cost recovery and power purchase).**
- **There is an operating loss of $123m/yr but can save 0.61mt of emissions/yr (E3P & gas peakers)**
  - **The implied incremental abatement cost is $200/t (note that the BAU already includes a $50/t carbon price) so the total is $250/t.**
  - **The range of abatement costs for a variation of 30% ±S1.0b is approx. ±S100/t.**

Results Charts

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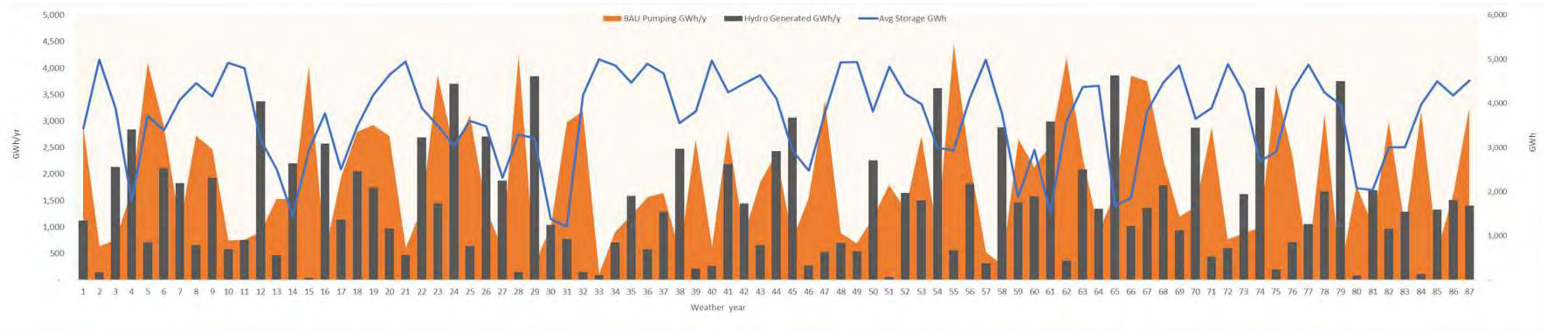

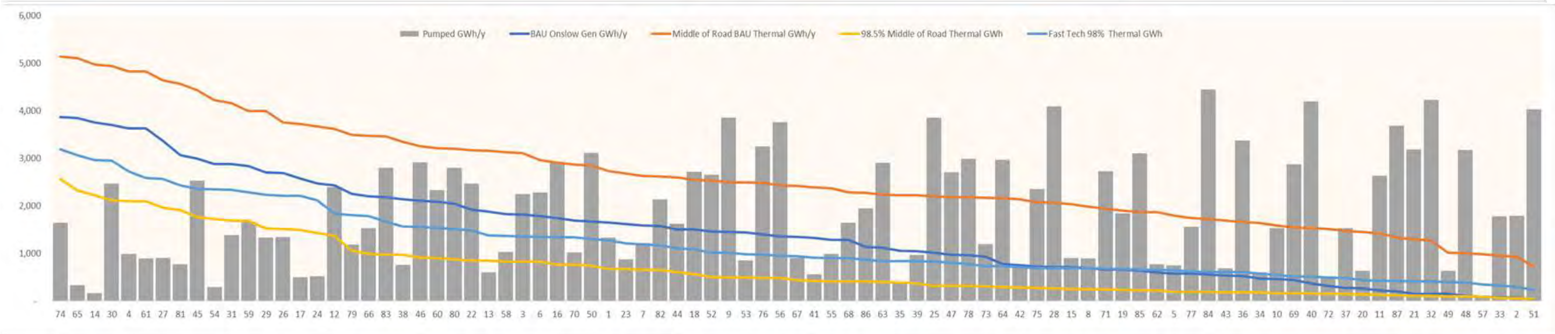

Pumped storage weekly levels stay above zero and average 3.8TWh

Onslow meets around 2/3 of Middle of road BAU peaking and E3P thermal demand.

Note that Onslow can meet >60% above the 2035 Middle of Road 98.5% renewable, residual thermal demand.

It can also meet 20% more than the residual thermal demand from the Fast Tech High Demand 98% renewable, residual thermal demand.

Pumped Storage Operation and HVDC constraints

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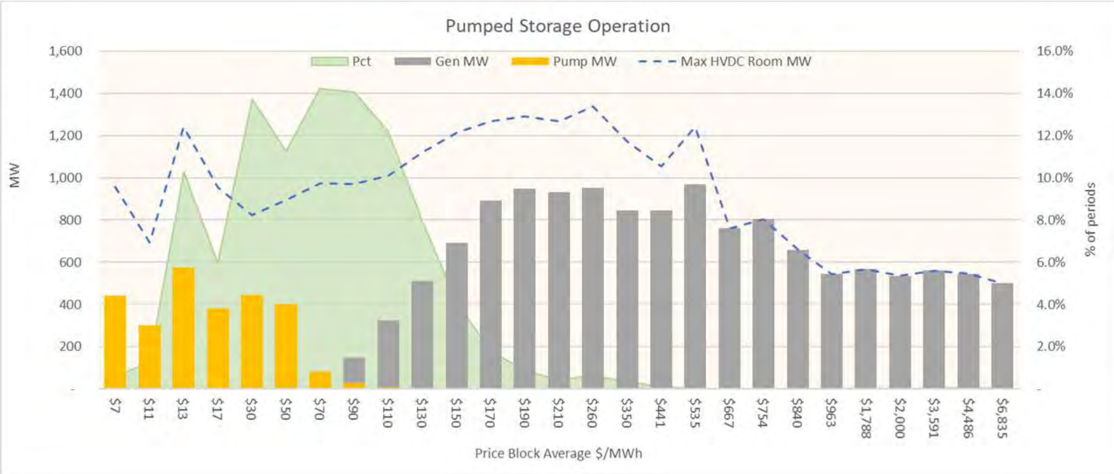

- The chart shows pumping and generation profile of Onslow by Benmore Price block.
  - The Benmore prices are those for the Middle of Road BAU scenario
  - This does not account for impact of Onslow on dispatch of other hydro in the SI. Ideally Onslow should be modelled as a part of the system.
- Note: pumping for prices below $70-80/MWh and generation for prices above $80-100/MWh
- The impact of northward constraints on the HVDC is shown by dotted line
  - Note that this is after expansion of capacity to 1400MW (with 4th cable).
  - At very high prices (when most other SI hydro is operating to capacity) the HVDC will limit incremental generation at Onslow to around 600MW.
  - The extend of this HVDC limit will depend on SI demand and generation - this is approximated by modelled HVDC operation before the expansion of HVDC
    - It is possible that at very high prices Onslow generation may simply displace other SI hydro when the HVDC is expanded. This needs to be investigated with additional integrated modelling.

Caveats and Disclaimer

JC[2]

Limitations and Caveats

- The indicative analysis is based on a stand-alone simulation of the operation of the pumped storage facility based on relatively simple operating rules with pumping and generation trigger rules, tuned ensure the storage is fully used to cover both short run and long run (dry year) backup requirements.
- There are limitations:
  - Only the HVDC limits and losses are accounted for. Other potential transmission constraints are ignored.
  - The potential downstream constraints at Roxburgh are ignored.
  - The impact of this project on the E-market simulated prices are ignored.
  - The interactions between the operation of the pumped storage and other storage are ignored. There may be potential spill savings at other reservoirs in the South Island.
  - Ancillary service revenues are ignored.
  - The pumped storage operating rules are reasonable tuned heuristics but are not fully optimised.
  - It is difficult to determine the net impact of these limitations on the conclusions as some are negative and some are positive.

Disclaimer

- The information and opinions expressed in this presentation are believed to be accurate and complete at the time of writing.
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