

# 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 <sub>2</sub> 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
Rol	Rol

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

## Acknowledgements

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 be reasonable to expect in 2035.

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# 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.<sup>1</sup>" 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<sup>2</sup> by 2035, in a normal hydrological year. The ICCC's terms of reference<sup>3</sup> 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<sup>4</sup> 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<sup>5</sup>.

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

## 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

<sup>1</sup> <https://www.iccc.mfe.govt.nz/what-we-do/frequently-asked-questions/>

<sup>2</sup> Geothermal generation, all located in the north island, is considered to be renewable despite the fact that all geothermal stations emit CO<sub>2</sub>.

<sup>3</sup> <https://www.iccc.mfe.govt.nz/who-we-are/terms-of-reference/>

<sup>4</sup> MBIE data for 2017.

<sup>5</sup> 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<sub>2</sub> (carbon) and it is used in all modelling except for two sensitivities which tested the impact of a carbon price of \$150 per tonne.

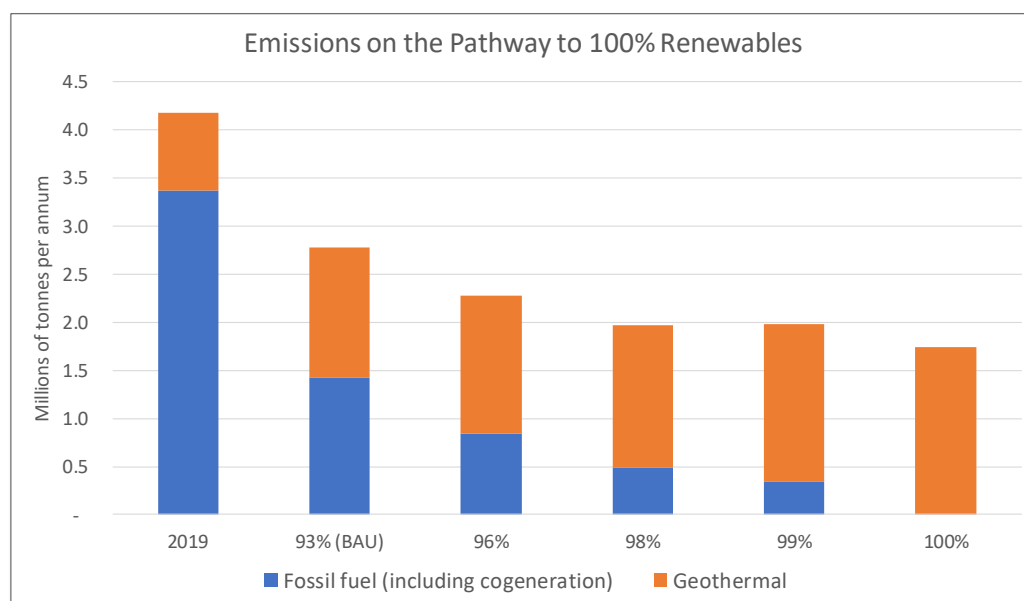
The scenario results are summarised in Table 1 below and show that the BAU scenario in 2035 reaches 92.6% renewables by shutting down two large thermal stations, and building renewable generation to replace them to meet additional underlying demand plus demand created by rising uptake of EVs and 0.6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

**Table 1 – Scenario Result Summary<sup>6</sup>**

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

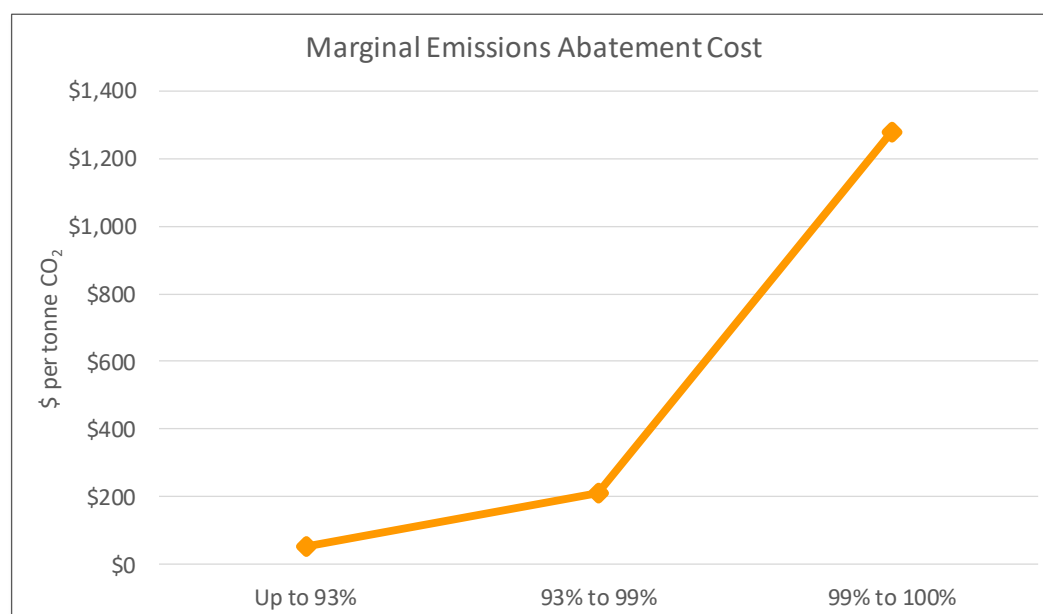
Figure 1 below shows the total emissions per year for the pathway from BAU to 100% renewables, along with an estimate for 2019, split between thermal stations and cogen, and geothermal. The chart shows a steady fall in emissions as plant powered by fossil fuels is retired and replaced by renewable generation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

<sup>6</sup> 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<sup>7</sup> 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<sub>2</sub>**

<sup>7</sup> By definition, reduction or removal of a nuisance, in this case greenhouse gases, primarily CO<sub>2</sub>.



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
<b>Renewables</b>	91.0%	93.2%	98.8%	97.8%	100.0%	100.0%	91.6%
<b>Capital Cost (\$Billion)</b>	\$0.3	\$12.7	\$2.7	\$14.4	\$3.8	\$17.7	\$6.2
<b>Total Generation (GWh)</b>	38,491	55,872	39,088	55,148	38,283	55,022	47,837
<b>Total Emissions attributed to electricity (g/kWh)</b>	55.2	58.1	38.0	42.8	31.9	37.0	66.9
<b>Emissions excl. Co-Gen (g/kWh)</b>	46	52	32	39	31	37	60
<b>Emissions Geothermal only (g/kWh)</b>	21	32	27	32	31	37	34
<b>Solar Generation (GWh)</b>	503	3,138	503	3,694	503	4,138	503
<b>Wind Generation (GWh)</b>	2,453	10,241	3,636	12,001	3,428	11,182	5,286
<b>Geothermal Generation (GWh)</b>	7,816	14,211	10,409	13,562	11,512	15,566	13,361
<b>Co-Gen Generation (GWh)</b>	1,231	1,231	560	560	267	560	1,231
<b>Thermal Generation (GWh)</b>	2,453	2,779	466	1,198	0	0	2,994
<b>Hydro Generation (GWh)</b>	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
<b>Renewables</b>	96.5%	97.1%	92.5%	96.3%	91.6%
<b>Capital Cost (\$Billion)</b>	\$10.7	\$10.7	\$8.4	\$17.0	\$13.3
<b>Total Generation (GWh)</b>	49,250	49,250	49,192	57,281	57,194
<b>Total Emissions attributed to electricity (g/kWh)</b>	35.8	47.0	57.3	37.7	57.1
<b>Emissions excl. Co-Gen (g/kWh)</b>	29	40	50	32	51
<b>Emissions Geothermal only (g/kWh)</b>	22	36	28	26	28
<b>Solar Generation (GWh)</b>	1,108	1,108	1,108	2,108	1,887
<b>Wind Generation (GWh)</b>	10,171	8,115	7,496	13,908	11,112
<b>Geothermal Generation (GWh)</b>	11,390	14,044	11,916	13,160	13,361
<b>Co-Gen Generation (GWh)</b>	1,231	1,231	1,231	1,231	1,231
<b>Thermal Generation (GWh)</b>	705	441	2,705	1,097	3,792
<b>Hydro Generation (GWh)</b>	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<sup>8</sup>, 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.

<sup>8</sup> 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<sup>9</sup> 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<sup>10</sup>. This approach avoided the need to arbitrarily define a "normal hydrological year", while providing a consistent series of scenarios to inform policy-making.

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<sup>9</sup> BAU had zero non-supply – refer to Table 8 in section 5.3 for details.

<sup>10</sup> 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<sup>11</sup>, 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.

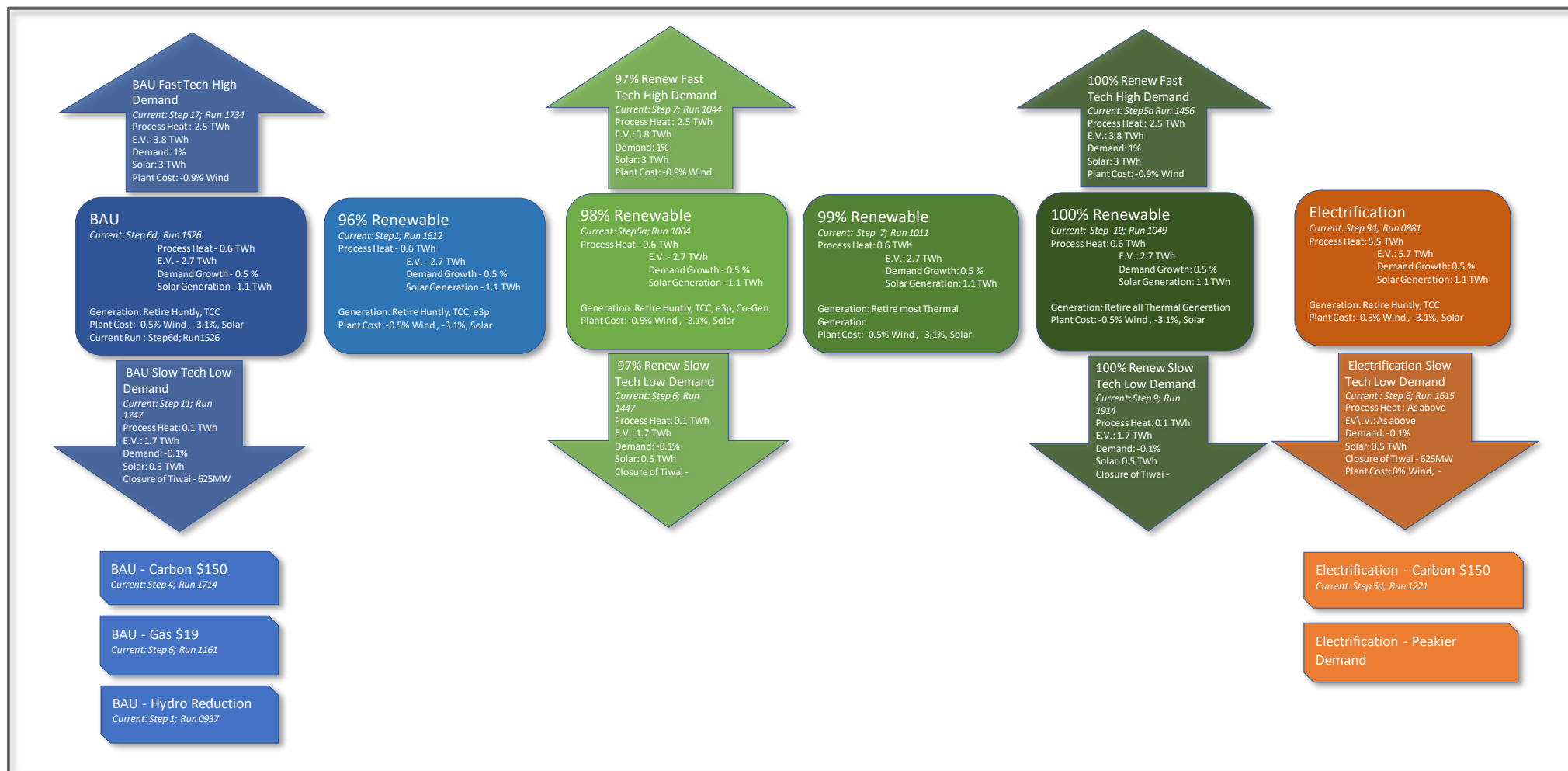
The Fast Tech High Demand variation, on the other hand, assumes higher than expected GDP and population growth, leading to higher-than-BAU demand growth. The cost of renewable generation also falls faster than expected under the relevant central scenarios.

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

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<sup>11</sup> Carbon abatement is a reduction in CO<sub>2</sub> 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<sup>12</sup> 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<sup>13</sup> and Todd Energy<sup>14</sup>, 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.

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

#### 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.

<sup>12</sup> Huntly's efficiency is around 36% but combined cycle plant such as e3p can achieve efficiencies in excess of 50%.

<sup>13</sup> Owns 46% stake in the Kupe gas field.

<sup>14</sup> 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<sup>15</sup> 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 diesel-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<sup>16</sup>, 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<sup>17</sup>, thus creating prolonged shortages<sup>18</sup>, which is to be avoided.

<sup>15</sup> Currently due to be commissioned mid-2020.

<sup>16</sup> The operation of the batteries involves charging up overnight and discharging during peak demand periods during the day.

<sup>17</sup> The hydro lakes don't literally dry up, they reach the lower limit of their consented operating range.

<sup>18</sup> 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<sup>19</sup> 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<sup>20</sup> 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<sup>21</sup>, but when electricity is generated mainly from renewable sources then the reductions in emissions can be large.

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<sup>19</sup> Refer to <http://www.windenergy.org.nz/consented-wind-farms>

<sup>20</sup> For battery EVs.

<sup>21</sup> 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<sup>22</sup>.

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<sup>23</sup>. There is a particularly

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<sup>22</sup> Refer to the main report for more information on these variations.

<sup>23</sup> 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<sup>24</sup> 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<sup>25</sup> 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

<sup>24</sup> *Assessment of the Impact of Flow Alterations on Electricity Generation*, Energy Market Authority, 2015.

<sup>25</sup> “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<sup>26</sup>. 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)<sup>27</sup> which is the spot price it needs to receive over its economic lifetime to just make its target RoI<sup>28</sup>.

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<sup>29</sup>.

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  $\text{LRMC} \times \text{TWAP}/\text{GWAP}$ .

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

<sup>26</sup> 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.

<sup>27</sup> 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.

<sup>28</sup> Or to put it another way, to cover all costs over its economic life time including profit and capital return.

<sup>29</sup> 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<sup>30</sup> 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<sup>31</sup>, 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

<sup>30</sup> 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.

<sup>31</sup> 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<sup>32</sup>. 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 1<sup>st</sup> January 2034, at a spread of starting storages, thus by the time each inflow run reaches 1<sup>st</sup> 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<sup>33</sup>. 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<sup>34</sup> (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.

<sup>32</sup> See [http://emk.energylink.co.nz/Main\\_Page](http://emk.energylink.co.nz/Main_Page) for details.

<sup>33</sup> EMarket is a multi-threaded application which reduces run times on PCs with multiple CPU cores.

<sup>34</sup> 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%<sup>35</sup>.
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 is 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<sup>36</sup>.

### 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

<sup>35</sup> Target after-tax RoI of 8% nominal is assumed, and allowing for an inflation expectation of 2% per annum.

<sup>36</sup> 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<sup>37</sup> 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.

<sup>37</sup> 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<sup>38</sup>. 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<sup>39</sup> 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 its 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 store 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.

<sup>38</sup> \$10/kWh.

<sup>39</sup> 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  $\pm 0.2$  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<sup>40</sup> 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)<sup>41</sup>.

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).

<sup>40</sup> In fact, any generator operating at 60 MW or more is considered a potential risk.

<sup>41</sup> 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<sup>42</sup>, which have total steady-state capacity of 1,200 MW northward and 750 MW southward<sup>43</sup>. 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<sup>44</sup>.

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<sup>45</sup>.

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

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<sup>42</sup> Pole 3 replaced Pole 1 after a major upgrade which completed at the end of 2013.

<sup>43</sup> 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.

<sup>44</sup> Known as Automatic Under-Frequency Load-Shedding (AUFLS).

<sup>45</sup> 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<sup>46</sup> 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

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<sup>46</sup> 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<sup>47</sup>; 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<sup>48</sup>.

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 reflect 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<sup>49</sup>.

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

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<sup>47</sup> As part of the dispatch process.

<sup>48</sup> 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.

<sup>49</sup> 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<sup>50</sup>.

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<sup>51</sup>, if they were to constrain frequently.

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<sup>50</sup> 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.

<sup>51</sup> 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 <sup>52</sup>	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

<sup>52</sup> 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 at BPE	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<sup>53</sup> on the assumption that the last 87 years<sup>54</sup> 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<sup>55</sup>.

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

<sup>53</sup> 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.

<sup>54</sup> From April of this year there will be 88 years of data.

<sup>55</sup> 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<sup>56</sup> 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<sup>57</sup> 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.

<sup>56</sup> 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.

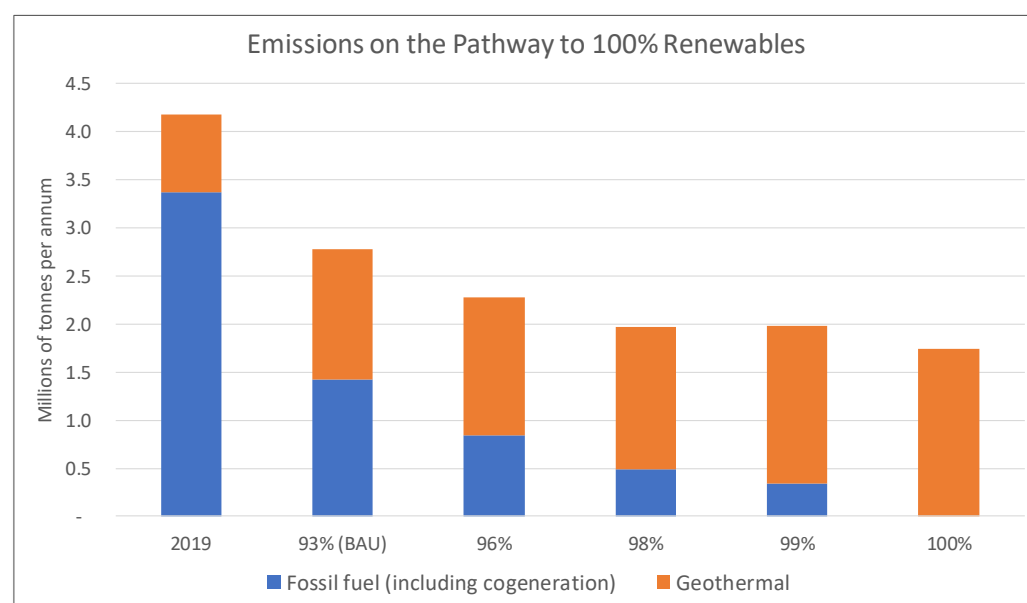
<sup>57</sup> And in fact for all modelling of the market in future.

**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 (\$150t)	BAU Higher Gas Price (\$19/GJ)	BAU Constrained Hydro	Electrification Higher Carbon Price (\$150t)	Electrification Peaker 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<sup>58</sup>: in fact, in the 100% renewables scenario the emissions are totally due to geothermal generation, all of which is built in this scenario.

<sup>58</sup> Known as “fugitive” emissions: these are not the result of combustion of fossil fuel, but rise to the surface with the geothermal steam.

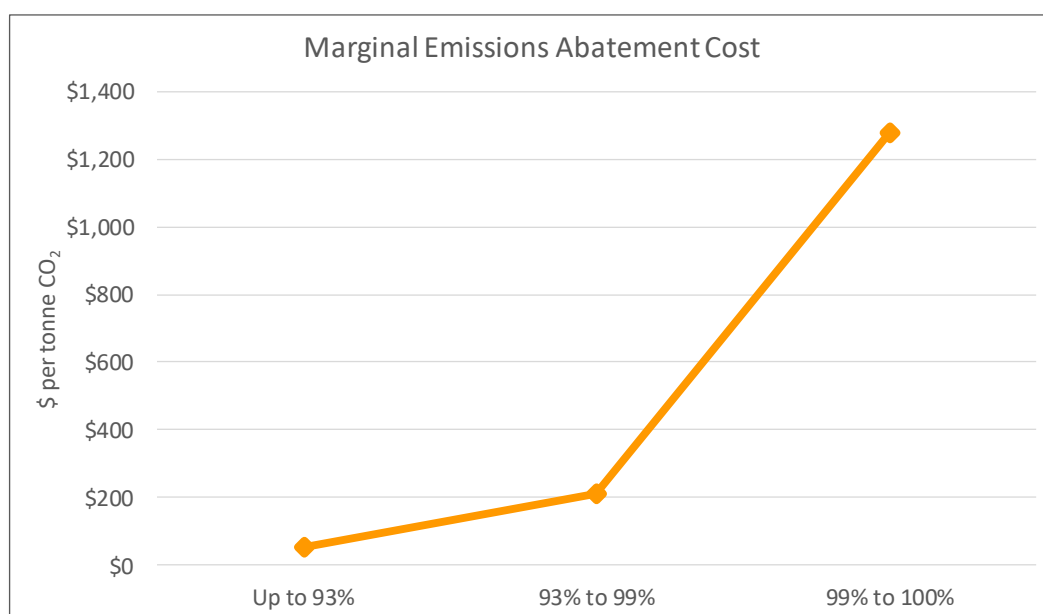
Along the way to 100% renewables, as new geothermal generation is built this serves to increment emissions, while the reduced running hours of thermal plant serves to decrement emissions, so the net increment in emissions between scenarios depends on the geothermal-thermal mix.

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<sup>59</sup> 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<sub>2</sub>**



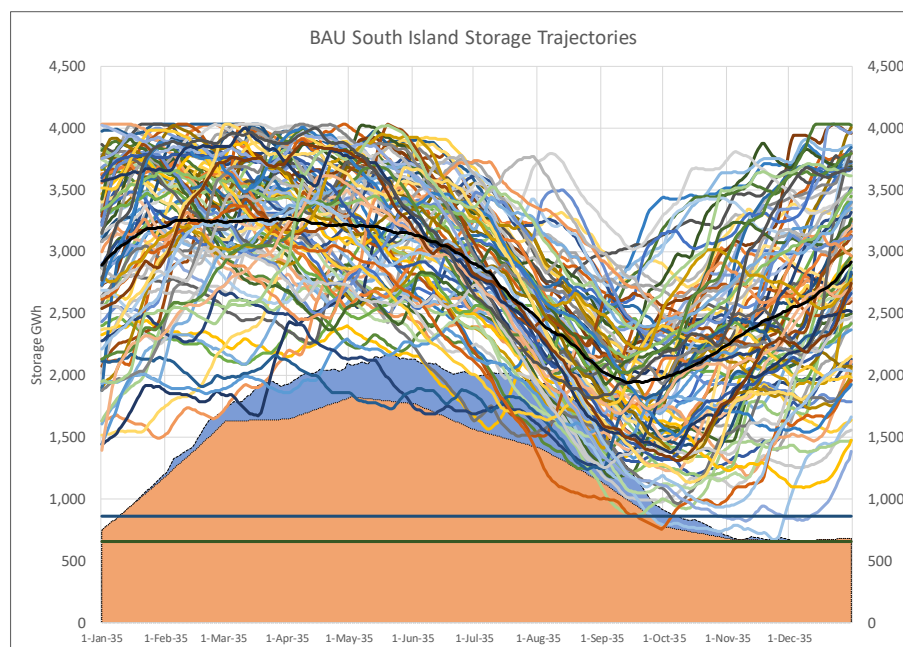
The key driver of the additional construction cost is the need to over-build wind farms to ensure security of supply in dry years. In the BAU scenario, new wind farms achieve capacity factors of around 40% but by the time we reach 100% renewables this falls to just under 32%. In contrast, geothermal 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.

<sup>59</sup> 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 GWh is contingent storage plus storage in Lakes Manapouri and Te Anu 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.



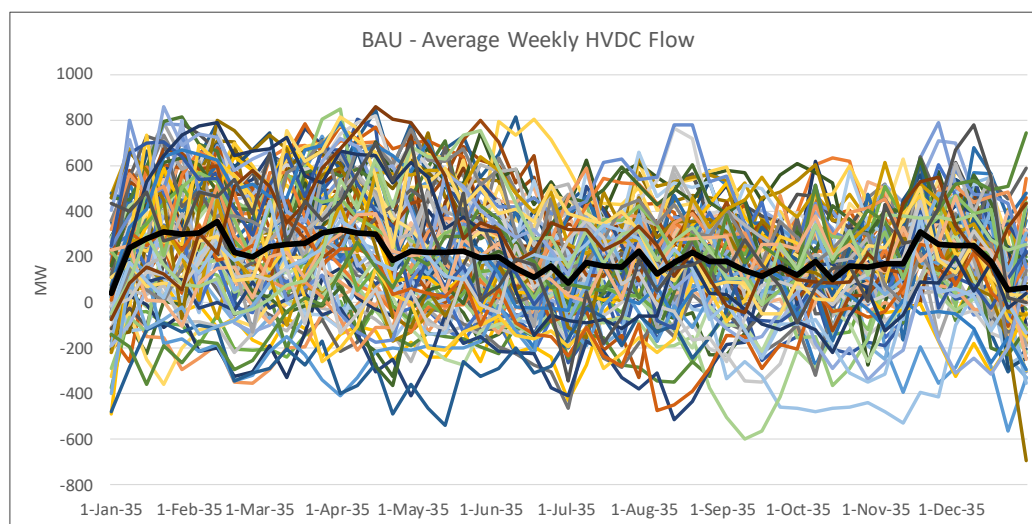
It is important to note that even though the water values for the major South Island reservoirs are based on the contingent storage being available, there are no years in the BAU in which storage actually drops into the contingent zone shown on the chart<sup>60</sup>.

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.

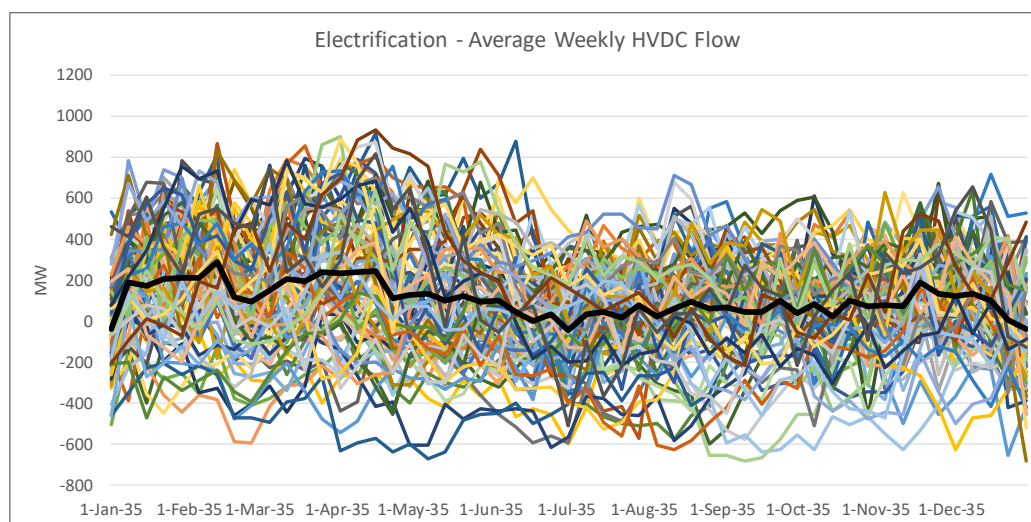
## 5.2 HVDC Flows

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**

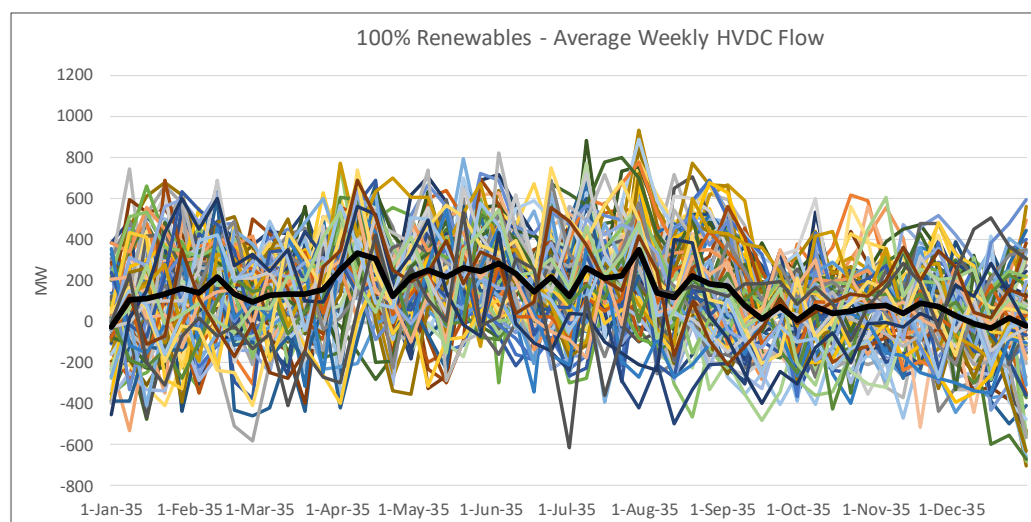


<sup>60</sup> Although there is nothing to say that, for example, storage in Pukaki could be 10 GWh above its contingent zone while storage in Hawea is 10 GWh into its contingent zone.

**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<sup>61</sup>, 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.

<sup>61</sup> 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 <sup>62</sup>	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

<sup>62</sup> 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 p.a.	2.5 TWh p.a.	3.0 TWh p.a.	Huntly, TCC, e3p, cogen	Wind -0.9% p.a. & solar -4.05% p.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 p.a.	2.5 TWh p.a.	3.0 TWh p.a.	All thermal	Wind -0.9% p.a. & solar -4.05% p.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	0	0	0	0	0	0	0	0	416	416	416	416	416
Kapuni			Cogen		25	127	127	127	127	127	0	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	0	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	116 3	116 3	1163	1163	116 3	116 3	116 3	1163	1163	116 2	1163	1162	1162	116 3	116 3	116 3	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	#N/A	#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	138 8	138 8	1388	1388	138 8	138 8	138 8	1388	1388	138 8	1388	1388	1388	138 8	138 8	138 8	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	#N/A	#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	432	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	2	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	HLV2	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	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	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	A	189	#N/A
Castle_Hill_Stage_1	WDV1	Taranua	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	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	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	A	347	#N/A
Castle_Hill_Stage_2	WDV1	Taranua	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	A	#N/A	#N/A
Castle_Hill_Stage_2	WDV1	Taranua	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	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	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	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	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	A	632	#N/A
Central_Wind_Moawhang o	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	A	#N/A	#N/A
Central_Wind_Moawhang o	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_S tage_1	HLV2	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	A	#N/A	#N/A
Hauauru_ma_raki_Wind_S tage_1	HLV2	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	Canterbur y	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	A	130	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	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
Taumatotara	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