

**ICCC MODELLING:
ESTIMATED SYSTEM
INCREMENTAL AND
MARGINAL COSTS IN 2035**

**FINAL REPORT
APRIL 2019**

REPORT TO THE INTERIM CLIMATE CHANGE COMMITTEE

CONTENTS

1	INTRODUCTION	4
2	INPUTS AND DEFINITIONS	5
2.1	NEW TECHNOLOGY COSTS	5
2.1.1	LARGE SCALE UTILITY SOLAR.....	6
2.1.2	UTILITY SCALE BATTERY SYSTEMS.....	6
2.2	DEFINITION OF INCREMENTAL SYSTEM COST	7
2.3	MEASURES OF SYSTEM MARGINAL COST	8
3	RESULTS.....	11
3.1	PATH TO 100% RENEWABLE	12
3.1.1	SYSTEM INCREMENTAL COSTS.....	15
3.1.2	SYSTEM MARGINAL COSTS.....	16
3.1.3	CARBON EMISSION ABATEMENT COSTS	16
3.2	ELECTRIFICATION	19
3.3	MARKET MODELLING SENSITIVITIES.....	20
3.4	GWAP/TWAP AND RENEWABLE PENETRATION.....	24
3.5	PRICE DURATION CURVES.....	27

LIST OF TABLES

TABLE 1: NEW GENERATION TECHNOLOGY COST ASSUMPTIONS	5
TABLE 2: NEW UTILITY BATTERY SYSTEM COST ASSUMPTIONS.....	7
TABLE 3: MIDDLE OF ROAD - SYSTEM INCREMENTAL COSTS AND MARGINAL COST	12
TABLE 4: FAST TECH HIGH DEMAND - SYSTEM INCREMENTAL AND MARGINAL COST	13
TABLE 5: SLOW TECH LOW DEMAND - SYSTEM INCREMENTAL AND MARGINAL COSTS	14
TABLE 6: ELECTRIFICATION FUTURES – SYSTEM INCREMENTAL AND MARGINAL COSTS	19
TABLE 7: MIDDLE OF ROAD SENSITIVITIES- SYSTEM INCREMENTAL AND MARGINAL COSTS	21
TABLE 8: ELECTRIFICATION SENSITIVITIES – SYSTEM INCREMENTAL AND MARGINAL COSTS	23

LIST OF FIGURES

FIGURE 1 : SYSTEM INCREMENTAL AND MARGINAL COSTS BY FUTURES	15
FIGURE 2: SYSTEM MARGINAL COST BY PCT RENEWABLE	16
FIGURE 3: CARBON ABATEMENT COSTS BY % RENEWABLE BY FUTURE.....	17
FIGURE 4: WIND GWAP/TWAP VERSUS % WIND GENERATION	25
FIGURE 5: SOLAR GWAP/TWAP VERSUS %SOLAR GENERATION	26
FIGURE 6: PRICE DURATION CURVES	28

1 INTRODUCTION

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

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

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

DISCLAIMER

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

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

2 INPUTS AND DEFINITIONS

2.1 NEW TECHNOLOGY COSTS

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

TABLE 1: NEW GENERATION TECHNOLOGY COST ASSUMPTIONS

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

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

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

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

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

The reference capacity factor is used for the purposes of deriving the LCOE¹. However, the model calculates the expected capacity factor for each case, and this is considered when the merit order of new supply is assessed and when revenue adequacy is assessed in the detailed modelling.

2.1.1 LARGE SCALE UTILITY SOLAR

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

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

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

2.1.2 UTILITY SCALE BATTERY SYSTEMS

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

TABLE 2: NEW UTILITY BATTERY SYSTEM COST ASSUMPTIONS

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

2.2 DEFINITION OF INCREMENTAL SYSTEM COST

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

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

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

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

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

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

2.3 MEASURES OF SYSTEM MARGINAL COST

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

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

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

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

- The first issue relates to the fact that a single representative target year is being used. Every effort is made to fine tune the investment build schedule to ensure that the target year is

consistent with market participants achieving an adequate return on the lowest cost new plant. However, the actual return in the modelled target year may vary depending on the exact balance of supply and demand and the plant mix.

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

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

In most of the 2035 futures the marginal wholesale supply in 2035 is geothermal, wind or solar. Geothermal is, however, limited in supply and so it not marginal in many cases. Wind and solar are intermittent and hence need to cover the costs of intermittency. These costs are described in section 4.1 in the Energy Link report. These include the GWAP/TWAP² ratio and the expected level of wind spill. This level is the difference between the maximum capacity factor and the capacity factor achieved on the assumption that wind offers in at \$12/MWh. The estimated level of wind spill and the GWAP/TWAP ratio is a function of the amount of wind investment and the correlation of wind between different wind farms and the level of battery and thermal backup available.

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

The last step to 100% in Energy Link model runs had a higher than normal level of demand shortage. This implies a reduction in the security standard. This might be acceptable considering the increase in the cost of

back-up associated with removal of flexible gas peakers but might not be considering the increasing reliance on electricity in the economy.

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

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

Conclusion

For the purpose of comparing futures and sensitivities the measure of system marginal cost is the firm flat contract price that would be required in 2035 for the cheapest marginal new source of supply (assumed to be wind in 2035) to cover its annualised capital and operating costs. This includes an allocation of the cost of batteries as described above and the costs of intermittency as reflected in the EMarket modelled GWAP/TWAP and the impact of wind “spill” also derived from the EMarket modelling³. A comparison of wind and solar GWAP/TWAP ratios derived from the modelling with other international markets is provided in section 3.4 of this report.

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

3 RESULTS

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

These futures are:

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

The results relate to the key questions:

- The incremental and marginal costs of moving from a Business as Usual (BAU) outcome (around 91-93%) up to 100% renewable supply. For the Middle of Road and Fast Tech High Demand futures, and additional step with extra wind and more conservative battery operation is included. This provides an approximate⁴ estimate of wind based marginal cost where the normal security standard is maintained.
- The marginal cost of increasing electricity supply by around 8-9 TWh to meet an ambitious target for transport and process heat electrification in the Middle of the Road and Slow Tech Low demand futures.

3.1 PATH TO 100% RENEWABLE

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

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

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

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

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

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

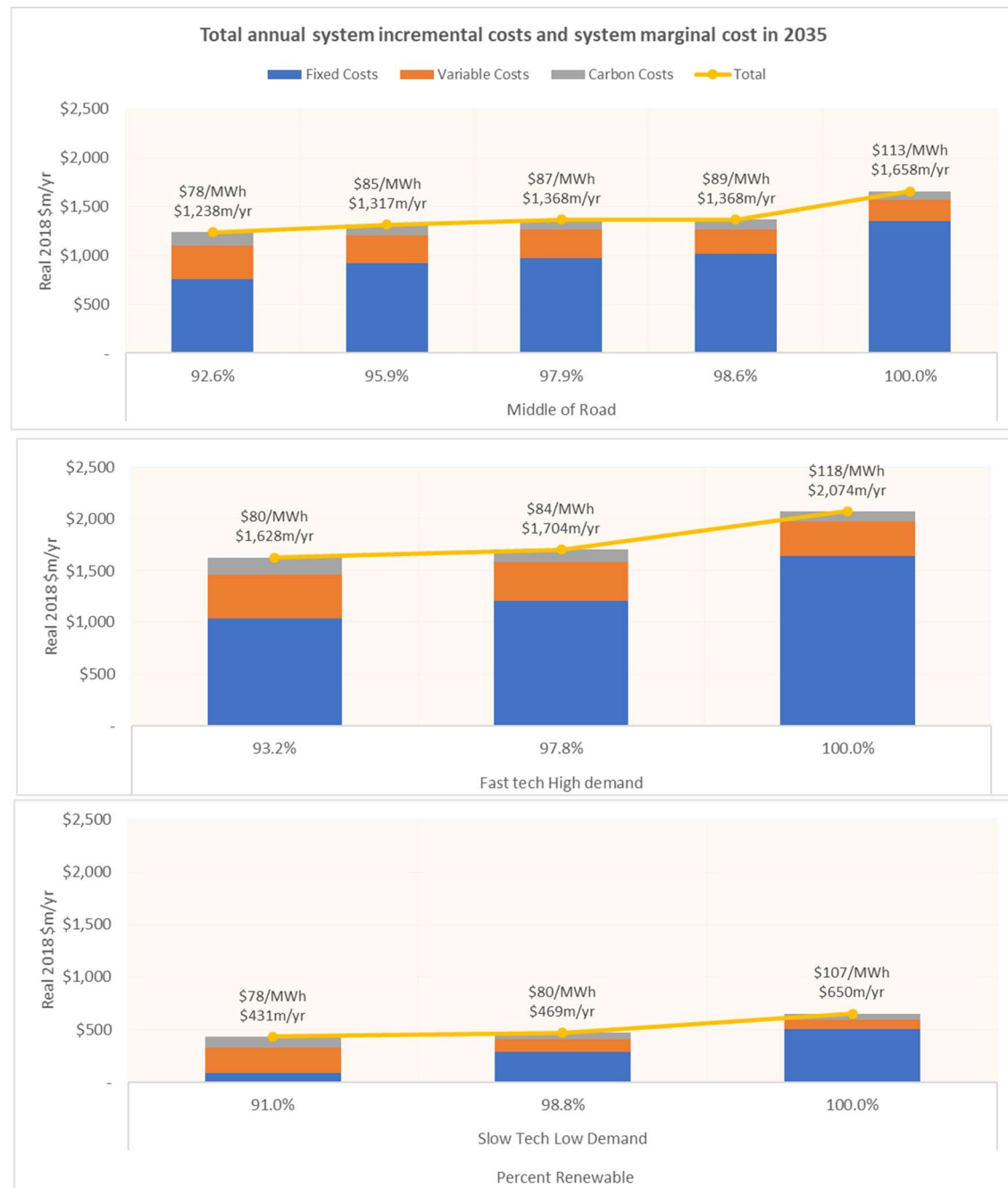
TABLE 5: SLOW TECH LOW DEMAND - SYSTEM INCREMENTAL AND MARGINAL COSTS

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

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

3.1.1 SYSTEM INCREMENTAL COSTS

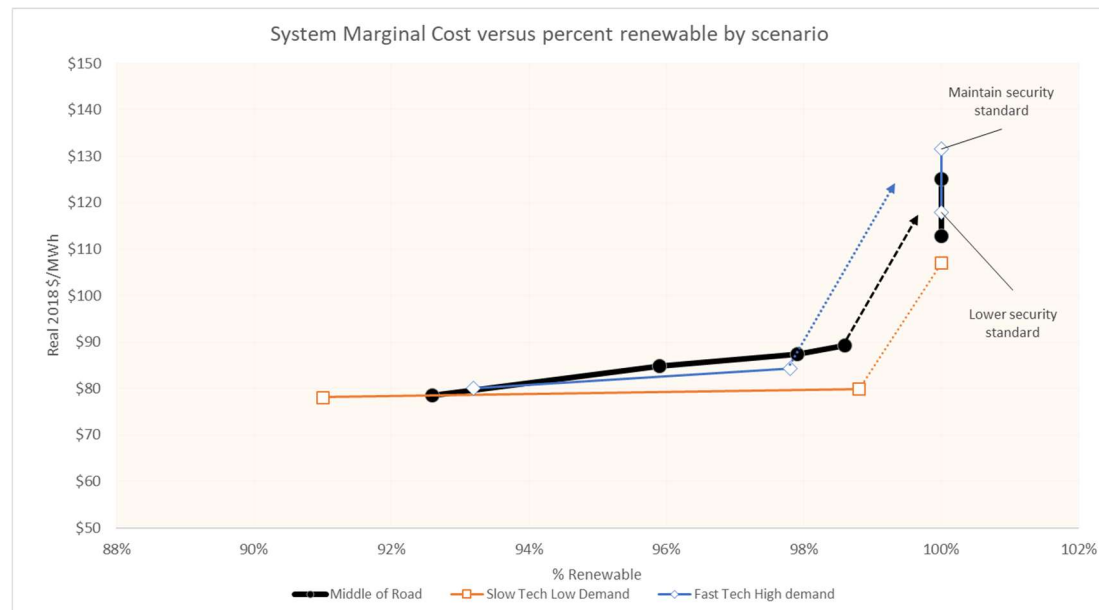
FIGURE 1 : SYSTEM INCREMENTAL AND MARGINAL COSTS BY FUTURES



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

3.1.2 SYSTEM MARGINAL COSTS

FIGURE 2: SYSTEM MARGINAL COST BY PCT RENEWABLE



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

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

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

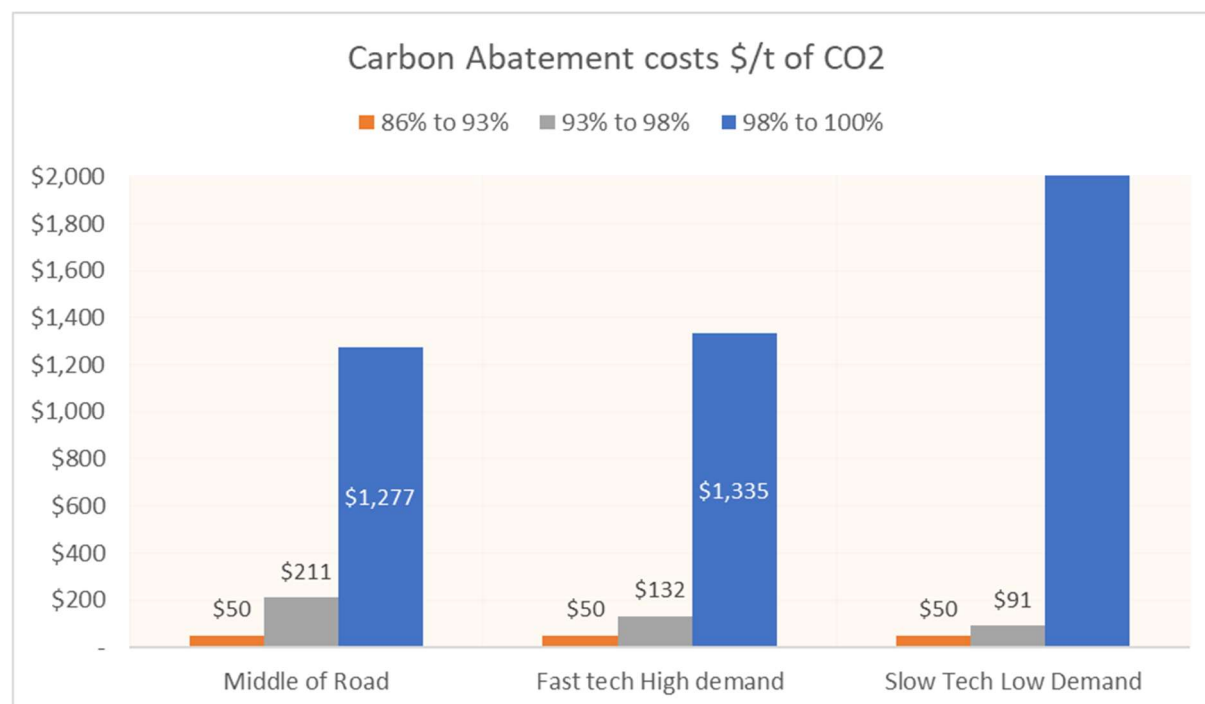
3.1.3 CARBON EMISSION ABATEMENT COSTS

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

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

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

FIGURE 3: CARBON ABATEMENT COSTS BY % RENEWABLE BY FUTURE



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

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

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

Note that the calculated carbon abatement costs for the Slow Tech Low Demand future for the step from 98% to 100% is off the scale. This is because the new investment to replace the natural gas fired peaking plant is predominantly geothermal (given the assumed carbon price of \$50/t and the merit order of new investment options available in 2035) and so

the emissions savings from removing the gas fired peakers is almost fully offset by the increased geothermal emissions and so the net emissions savings is almost zero. This illustrates a perverse outcome where reliance of on a policy driving to 100% renewable generation in conjunction with a separate carbon price signal, potentially results in considerable cost being incurred without any benefit in terms of net emissions saving. A policy approach which encouraged reductions in emissions directly would be much less costly and more reliable.

3.2 ELECTRIFICATION

TABLE 6: ELECTRIFICATION FUTURES – SYSTEM INCREMENTAL AND MARGINAL COSTS

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

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

3.3 MARKET MODELLING SENSITIVITIES

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

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

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

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

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

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

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

The key insights from these sensitivities are:

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

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

TABLE 8: ELECTRIFICATION SENSITIVITIES – SYSTEM INCREMENTAL AND MARGINAL COSTS

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

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

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

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

3.4 GWAP/TWAP AND RENEWABLE PENETRATION

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

The charts below show the Full GWAP/TWAP ratios estimated from the Energy Link modelling as a function of the level of wind and solar penetration (represented by the % of total generation). The charts also include observed annual GWAP/TWAP ratios for New Zealand and several international markets (Australia, USA and Europe) with similar spot market pricing arrangements as New Zealand. Australia, Texas, Germany and New Zealand have energy-only markets. The international comparison is limited to those markets where data is available on an hourly basis to enable the ratio to be calculated. Some markets with high levels of wind and solar are excluded where the regions are small and have large interconnections neighbouring systems (eg Denmark, Belgium). The three eastern regions and Tasmania of the Australian

market are included separately. These are interconnected but are included to illustrate the impact of the significant increases in wind generation over the last 10 years. Note that South Australia has very high levels of wind penetration, but this is the result of it being a small region with large interconnection into Victoria. The New Zealand data is based on data from 2006 and is averaged over all the wind farms on the system.

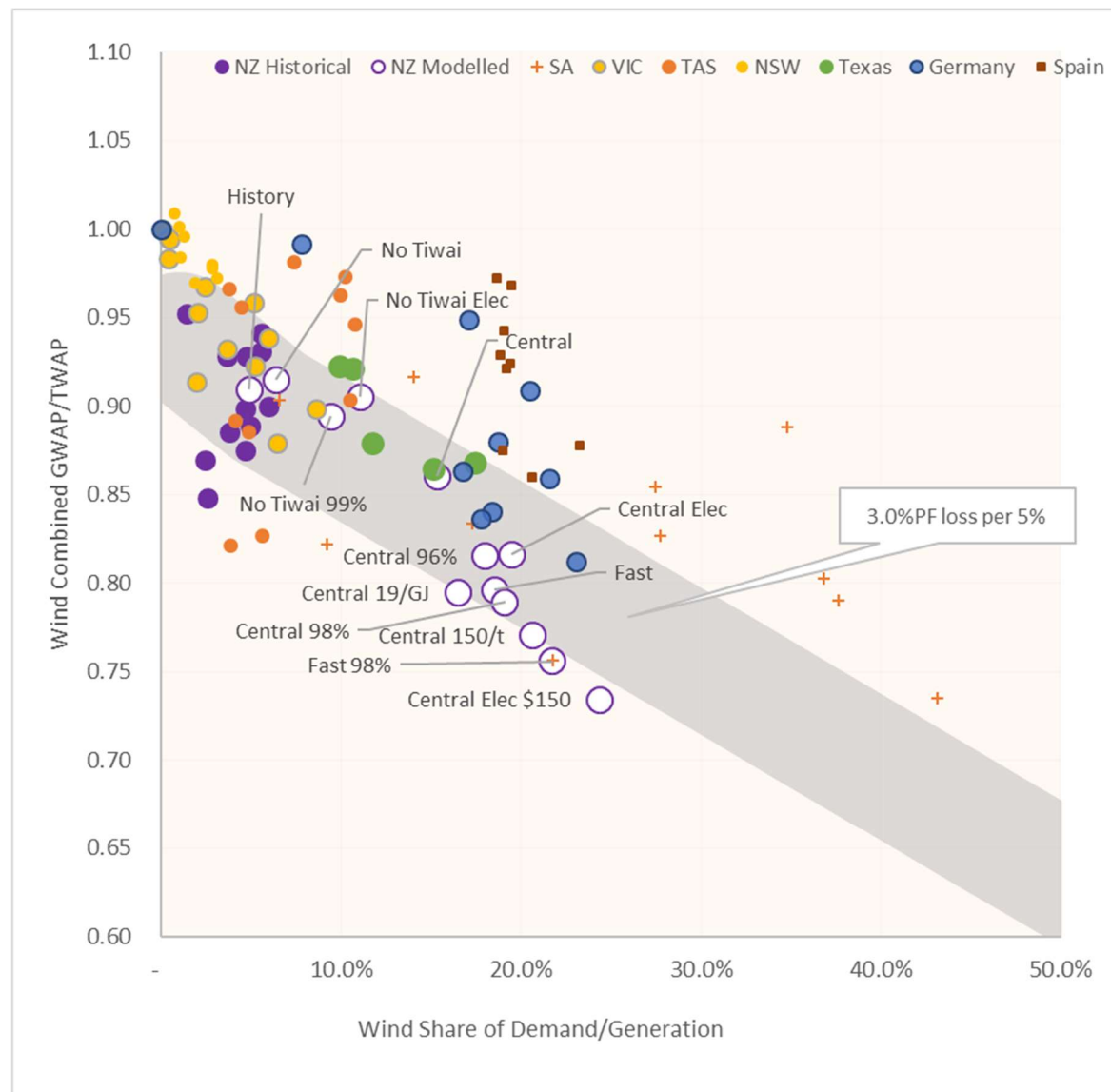


FIGURE 4: WIND GWAP/TWAP VERSUS % WIND GENERATION

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

The slope of the curve will be influenced by the cost of backup supply and the extent of constraints on the system. Reductions in the cost of batteries and increased demand side flexibility may reduce rate of fall. Also increased costs of backup arising from a ban on gas fired backup peaking capacity, will increase the rate of fall⁵.

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

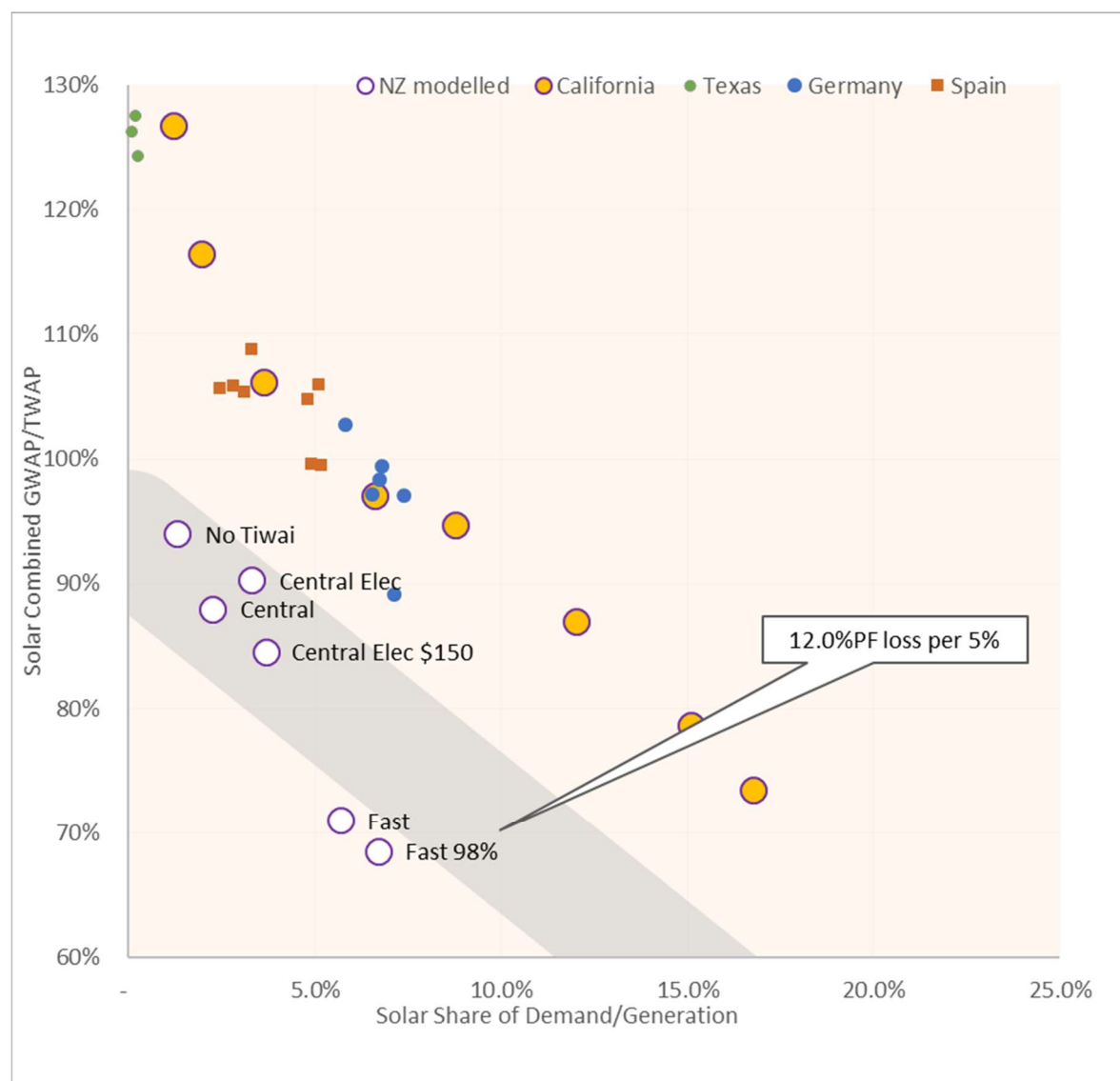


FIGURE 5: SOLAR GWAP/TWAP VERSUS %SOLAR GENERATION

California has the best set of data with solar penetration increasing from 2% to around 18% as a result of state policies and sharply lowering costs for solar. California and Texas are summer peaking systems, and so they

originally had a solar GWAP/TWAP which was significantly greater than 100%. This is because solar generation was highly correlated with high summer daytime load/prices.

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

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

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

3.5 PRICE DURATION CURVES

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

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

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

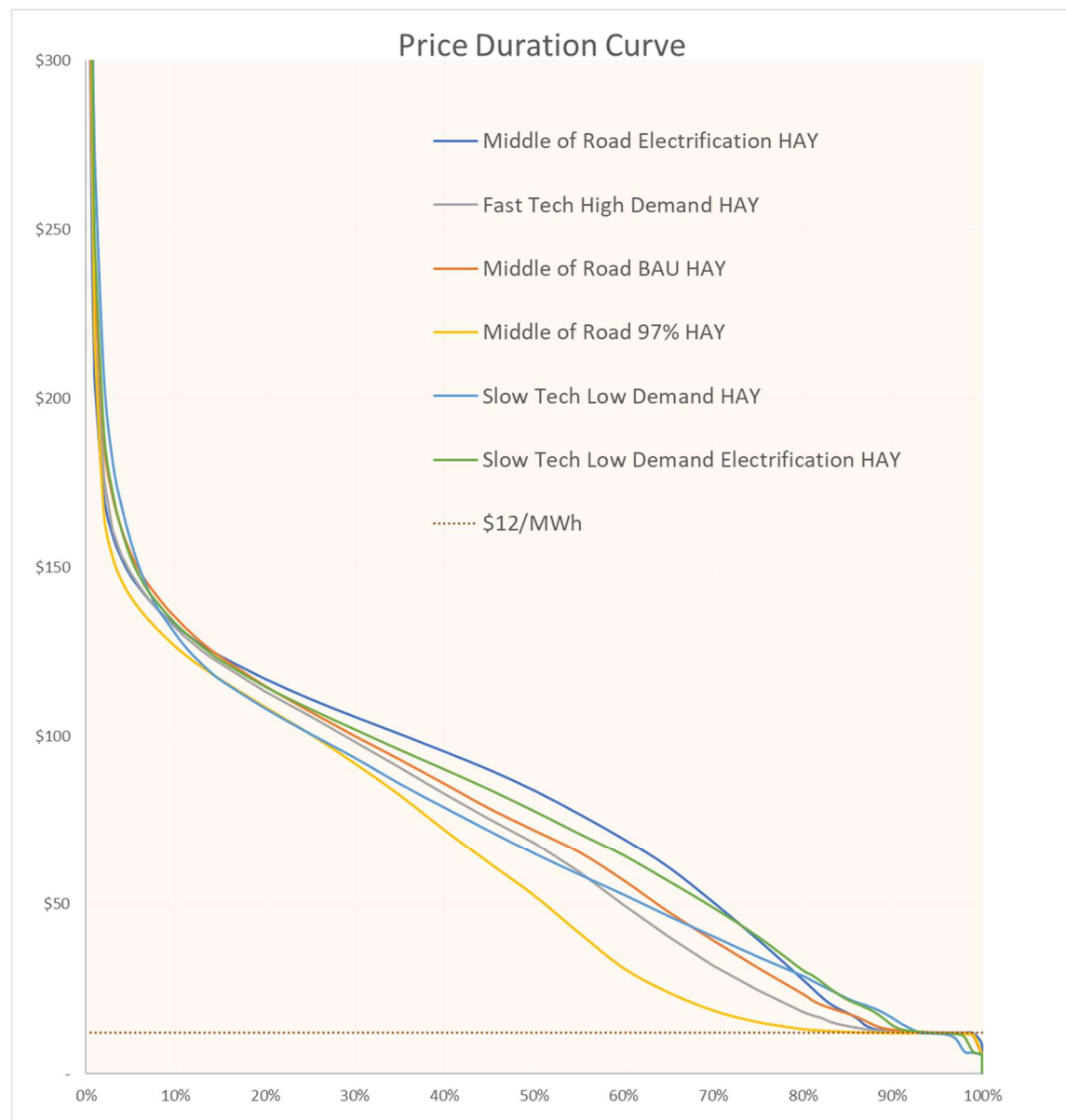


FIGURE 6: PRICE DURATION CURVES

End Notes

¹ LCOE = Long Run Cost of New Entry.

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

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

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

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