Estimated gross benefits of NZ Battery options: Modelling Appendix.

Report prepared for The NZ Battery Team MBIE.

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30 November 2022

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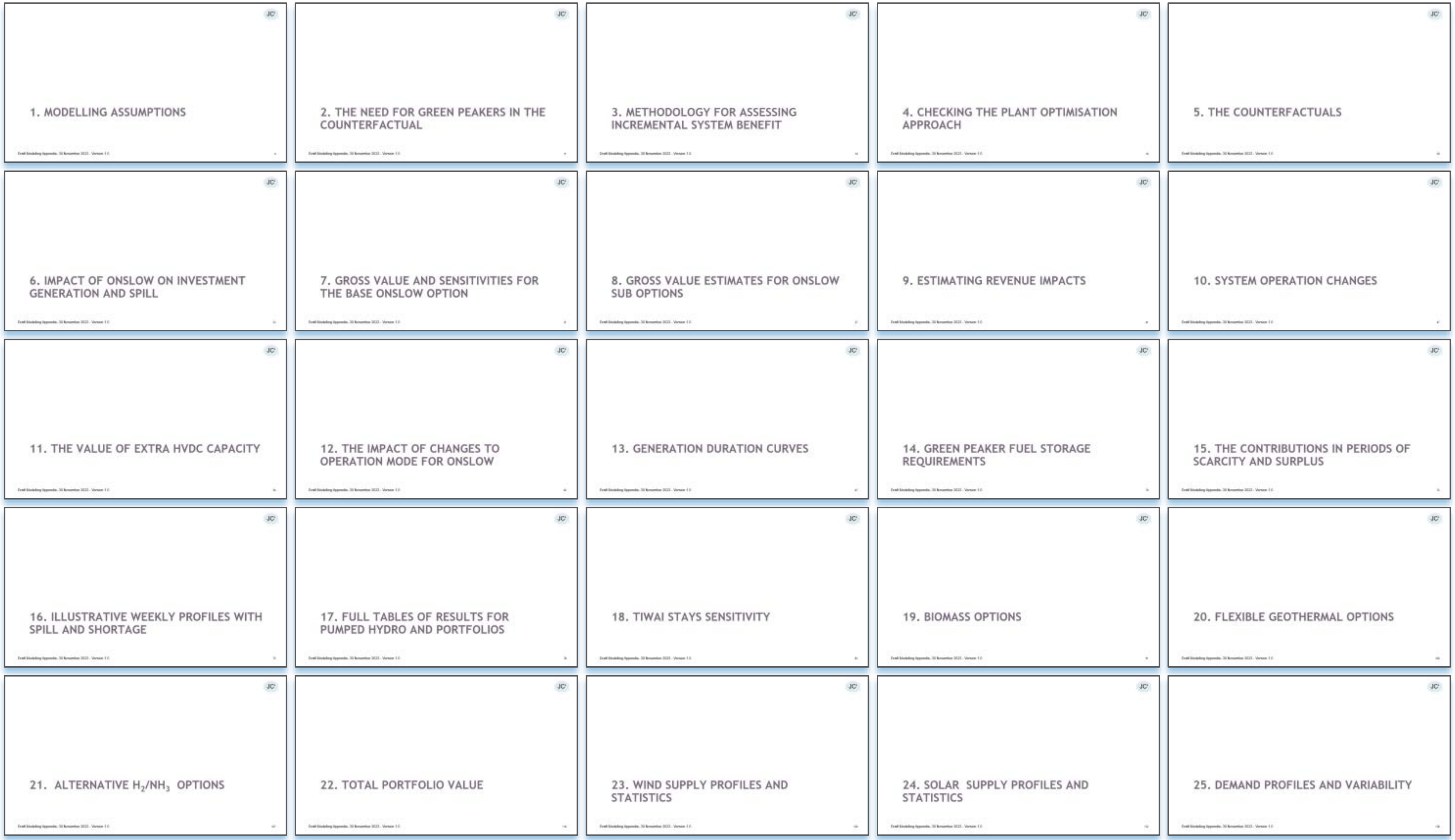
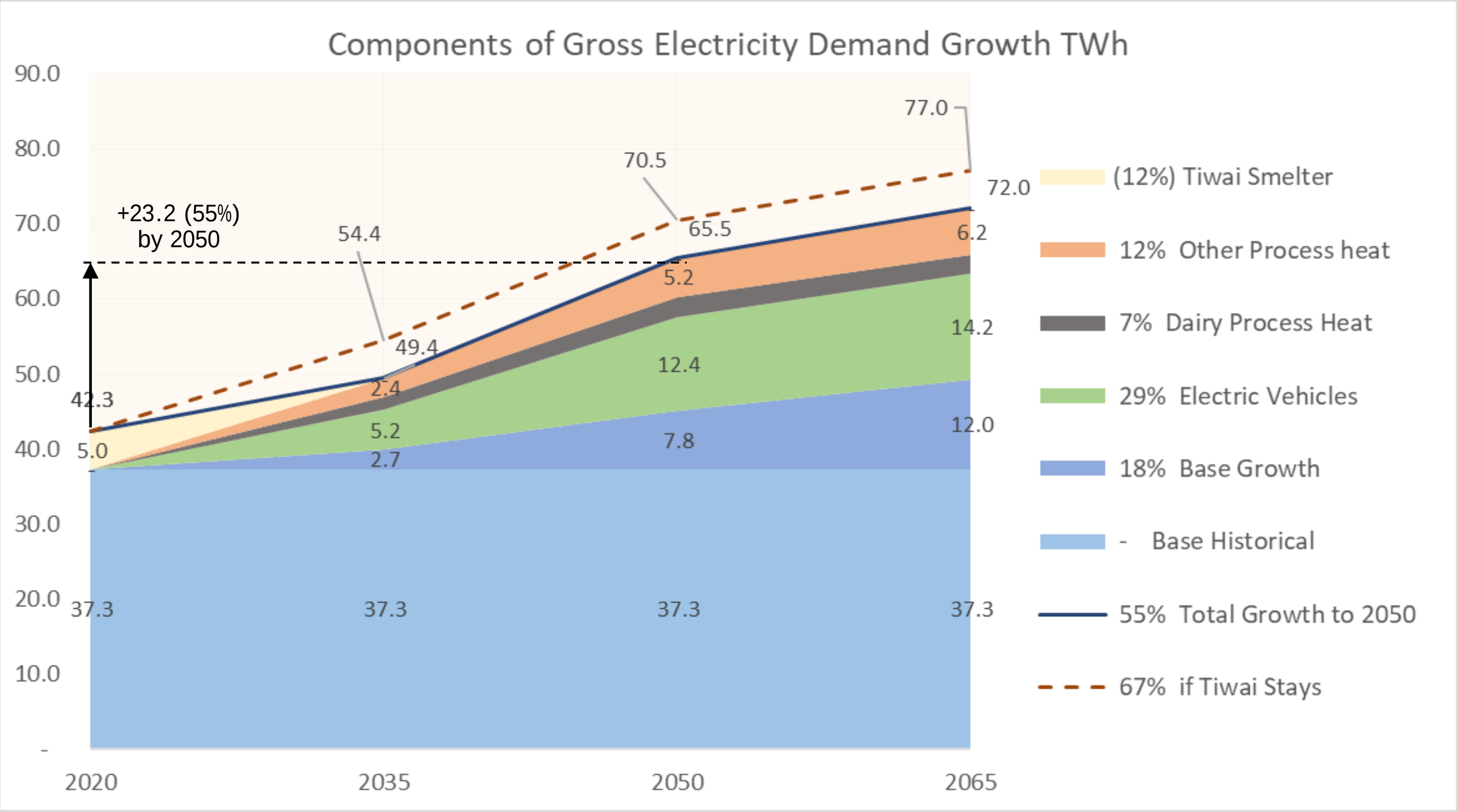
Appendix



1. MODELLING ASSUMPTIONS

The base case assumes that electric vehicles and process heat drive the growth in gross energy demand

Total gross demand is assumed to increase 55% by 2050 and 70% by 2065 even though the Tiwai aluminium smelter exits by 2035. If Tiwai stays, the increase is 67% by 2050 and 80% by 2065 .



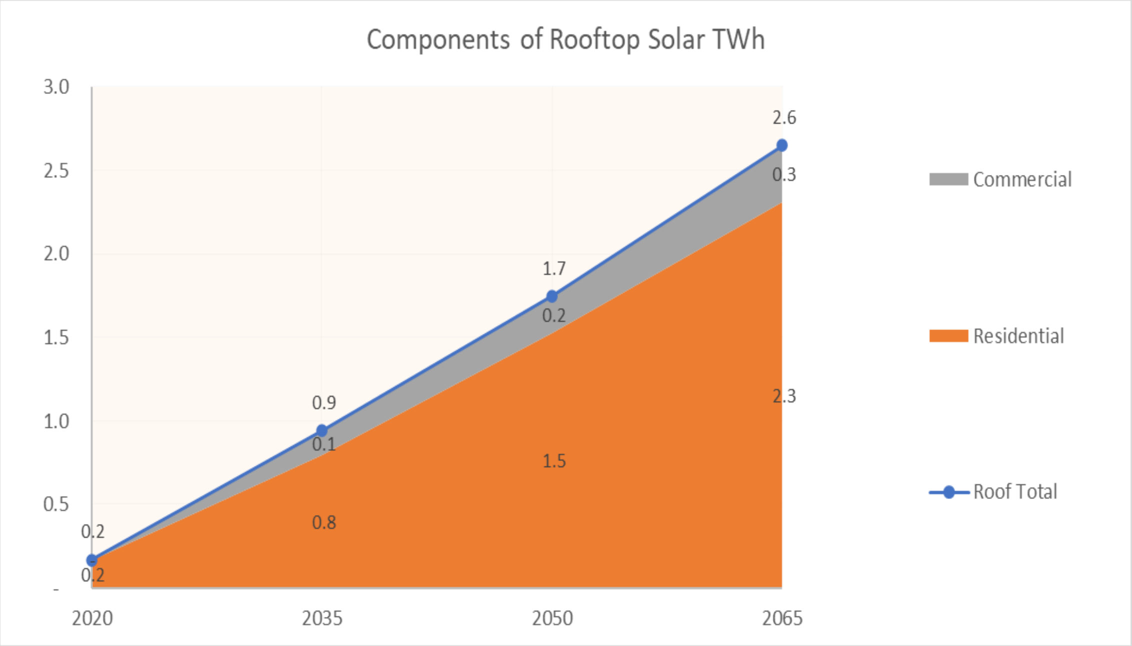
Demand growth is dominated by Tiwai closure (or not) and transport and process heat decarbonisation.

- Historical and base demand is driven by 0.7% population and 2% GDP growth and allows for residential and commercial efficiency improvements of 26% by 2050.
- Electric vehicle demand assumes a growth to 12.4TWh by 2050:
  - 8.4TWh -95% of the light vehicle fleet
  - 2.6TWh - 60% of the heavy vehicle fleet
  - 1.6TWh - offroad transport
  - 4.1m light electric vehicles by 2050 each using 5-6kWh/day or around 2 MWh/yr.
- Process heat electrification amounts to 8.0 TWh by 2050
  - Assumes the bulk of high temperature process heat decarbonization is via biomass, with only a modest level via electricity.
  - Assumes electric heat pumps provide a much greater role in decarbonization of medium and low temperature process heat.
- Of the 23.2TWh (55%) net growth to 2050, EVs and process heat account for 48%.

Note: Dairy process heat is assumed to be mostly met by biomass, so the bulk of process heat relates to low and medium temperature process heat electrification. The shape of low/mid temperature demand assumed to follow underlying demand. A specific summer oriented seasonal shape is assumed for food processing process heat. The EV profile is based on a 60% - 40% mix of optimised overnight charging and observed charging patterns as used by Transpower in their 2020 modelling. It is possible that there may be slight summer seasonal shape for EV demand which is assumed to follow the seasonal shape of existing petrol demand, but this is offset by increased EV efficiency in the summer (+5%).

Roof top solar is assumed to grow steadily to reach around 20% of households by 2065

It is assumed that there is steady growth in roof top solar installations to reach 20% of households by 2065.

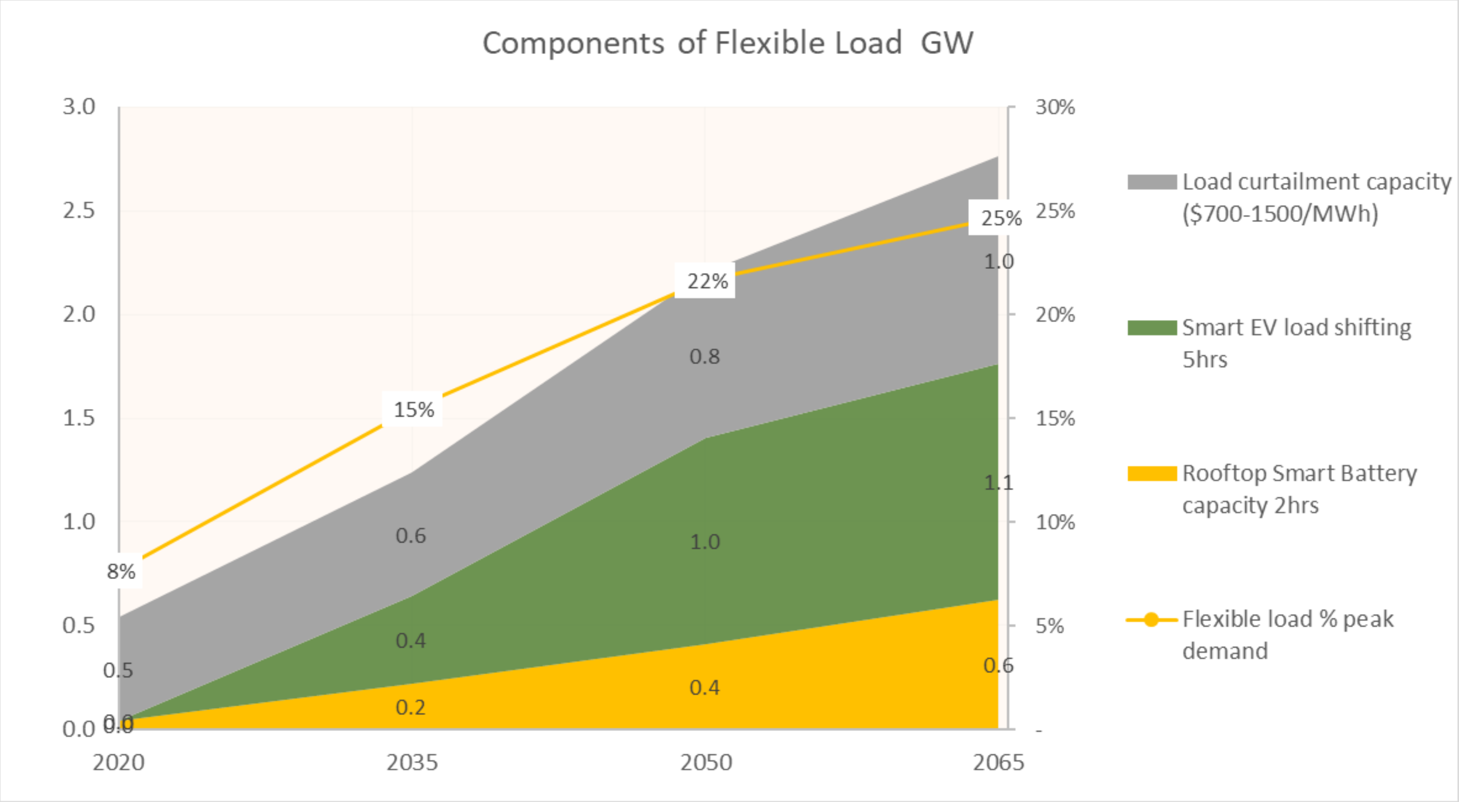


Commentary

- Rooftop solar is modelled at a fixed build rate, increasing to 20% of households and 10% of commercial equaling 0.5 million installations or 2.1GW (2.6TWh) by 2065.
- This assumes :
  - Average residential and commercial installations are is 4kW and 7kW and the capacity factor is approximately 14%.
  - The capacity typically includes behind the meter batteries with a 2-hour duration. It is assumed 30% of this capacity can be used to shift solar generation to times of system need.
- This investment in rooftop solar is an exogenous assumption and not optimised alongside wind, utility solar and other generation.

There is a significant increase in flexible within the day load shifting capacity that comes with EVs and rooftop solar

Sources of flexible load include load shifting from smart EV charging and behind the meter solar batteries and voluntary load curtailment in response to high spot prices.



Commentary

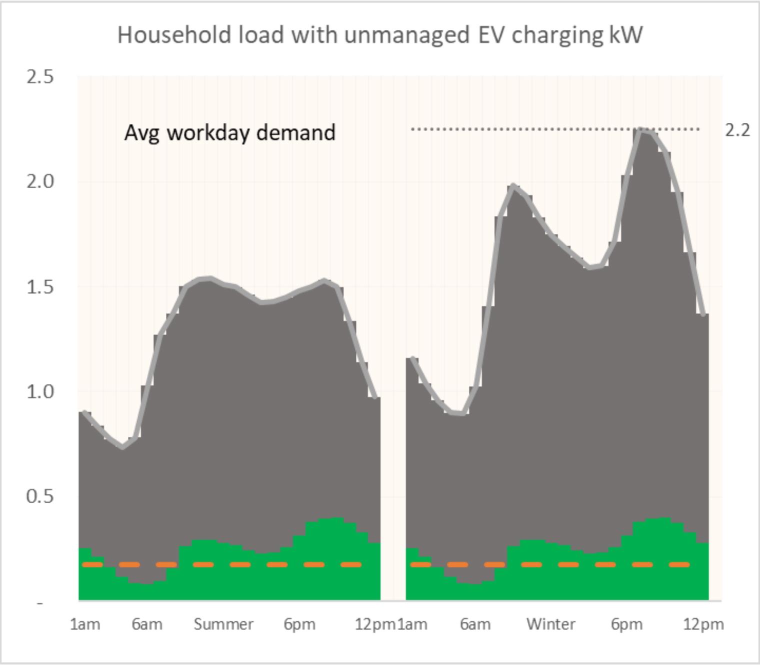
- Rooftop batteries and smart EV load charging result in demand shifting within the day.
- Short run load reduction is discretionary load which customers curtail when spot prices exceed $700/MWh.
  - The total load curtailment is assumed to be 8% of peak system load excluding Tiwai, rising to 9% by 2065.
  - We assume three tranches (40%, 30% and 30%) triggered at $700/MWh, $1000/MWh, and $1500/MWh. Each tranche is around 2-3% of peak load.
- The modelling also accounts for involuntary shortage not shown in the chart. This consists of:

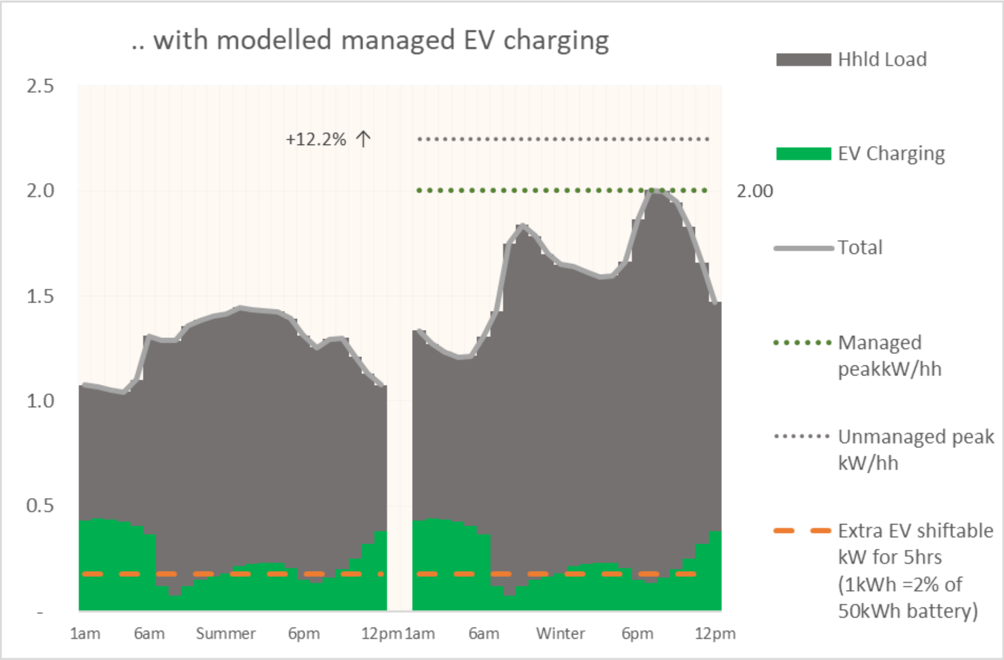
Conservation campaigns	$800 /MWh
Shallow rolling outages	$3,000 /MWh
Deep rolling outages	$10,000 /MWh

- Note:
  - the very significant increase in price responsive flexible demand from 8% to almost 25% of peak demand by 2065.

Modelling electric vehicle charging

The modelling assumes 65% of EV charging load is managed into overnight off peak periods through time of use tariffs etc. This avoids EV charging from increasing residential peak demand by over 12%. In addition it is assumed that 70% of the average EV charging load is able to be dynamically shifted for around 5 hours in response to system needs.



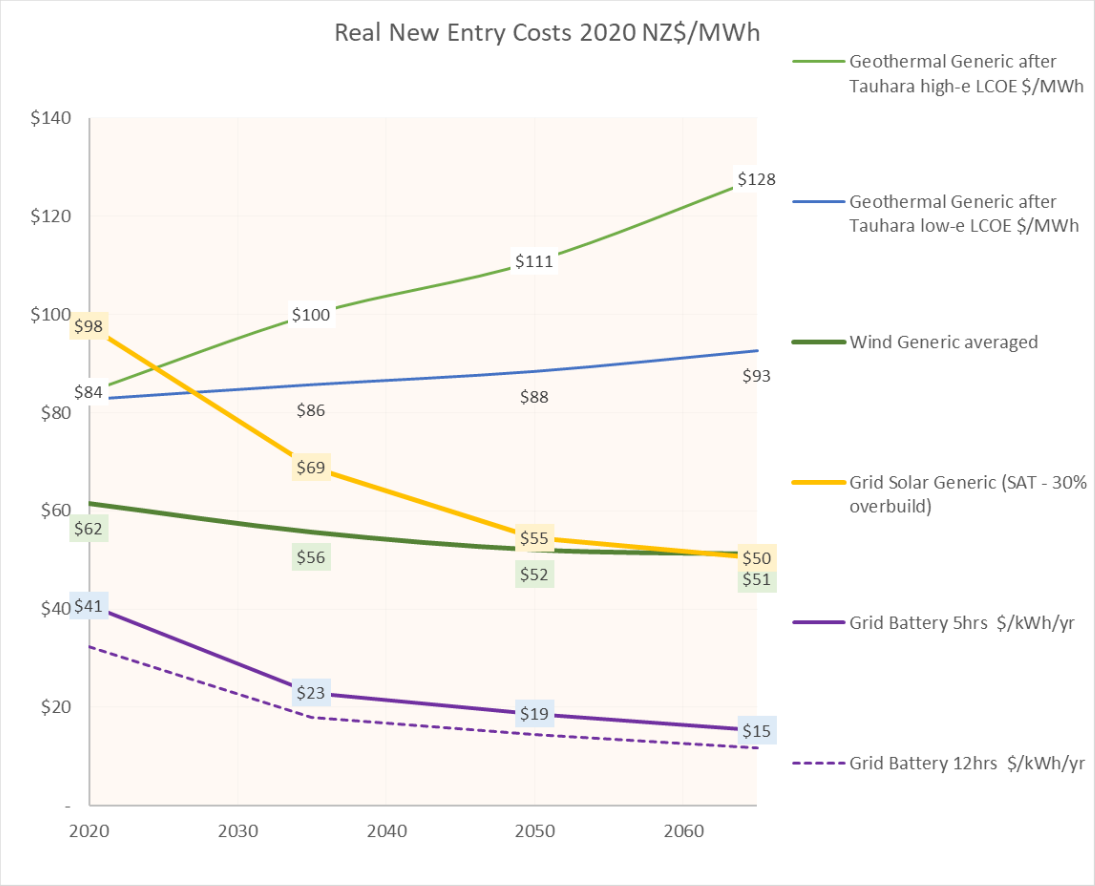


Commentary

- The modelling assumes that at least 65% of EV charging is shifted out of the winter peak period into off-peak overnight periods.
  - It is not clear how this will be achieved, but it could be by having smart charging set to night time periods by default or regulation, or through time of use pricing.
- It is also assumed that there is some level of dynamic control of charging which allows around 70% of the average charging load to be moved by 5 hours in response to short term system requirements (ie changes in wind or solar fluctuations or security).
  - This only represents 1-2% of the total battery storage in the fleet, and might be achieved through active smart charging management by retailers or customers, and/or through automatic control similar to ripple control of water heaters today.
  - On average only around 10% of the EV battery capacity is charged each day so shifting of 1-2% within each day should have little impact on users.

Wind and solar costs are assumed to decline over time in real terms

New Entry costs are influenced by learning curves



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Commentary

- The costs have been developed by NZ Battery team accounting for typical NZ project size, cost structures, learning curves etc.
- The short-term increases in costs associated with the recent issues post pandemic and war supply chain issues, materials, transport and other costs is not shown on the chart.
    - It is assumed that by 2035 these short-term issues are no longer relevant.
- These new entry costs assume a 7.0% post tax nominal weighted average cost of capital.
    - They account for tax depreciation and 2.0% pa inflation.
    - Construction periods are 1 year for wind, solar and batteries and 3 years for geothermal.
- Economic lives are assumed to be 20 yrs for battery systems, 27yr for wind, 25yr for and solar and 30 yrs for geothermal.
- Potential generic life-time average capacity factors are assumed to be 41% for wind and 22% for grid solar (with single axis tracking and oversizing panels relative to other infrastructure).
- Solar costs assume 0.6% pa panel degradation.
- Geothermal costs include carbon for 50% of projects which do not employ carbon capture and reinjection.
- For the chart.
    - Low emission = 30kg/KWh
    - High emission = 120 kg/kWh
- Note: The capital cost recovery assumptions are close to those that would result from use of a 6% pre-tax real WACC .

The modelling uses 87 years of synthetic hourly data for simulations

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Hourly inflows over 87 years are taken to include hydro, wind and solar. Of these the last 40 years use full matching hourly data, and first 47 years map solar/wind years to the closest matching hydro year.

- These include:
  - The years 87-year period 2033-2019 inflow data from the Hydrological Modelling Dataset from the Electricity Authority.
    - This includes synthetic daily inflows for all the major hydro schemes in NZ.
- For the 40-year period 1980-2019 wind, solar and demand data is based on history.
  - The wind potential generation is based on a combination of historical generation and NASA MERRA-2 satellite reanalysis wind speed data converted to potential generation and calibrated to reflect historical NZ wind generation where possible.
    - This includes data for 8 regions, with correlations between regions preserved.
  - The solar potential generation data is based on hourly meteorological records provided by ANSA.
    - This includes data for 9 regions for grid connected solar and 3 regions for rooftop solar, with correlations between regions preserved.
  - Synthetic demand shape data is based on:
    - Actual demand shapes (base actual demand excluding Tiwai) from 2000-2020.
    - Simulated demand shapes for 1980 to 1999 derived from MERRA-2 weather data adjustment to the seasonal/hourly profile plus random adjustments to reflect annual observed annual and weekly random demand variability (1.2% and 2.5% std deviations for annual and weekly loads).
    - This includes matching demand shapes for the NI and SI regions to ensure correlations between demand regions are preserved.

Some adjustments are made to the data

- Wind/solar/demand synthetic data for 2033-1979 is back-cast:
  - For the 47-year period 1933-1979, wind and solar data for the closest matching hydro year from 1980-2019 is used.
    - This helps ensure that correlations between wind and hydro inflows (around 30-40%) are preserved.
    - All the within-year regional and cross correlations between wind, solar and demand are fully preserved.
- Climate change adjustments are applied.
  - These are based on estimates by Dr Jen Purdie of ClimateWorks.
  - These take the form of adjustments to the average weekly profile of wind and hydro inflows by region by 2050.
    - These are phased in over time:
      - 50% in 2035 and 100% for 2050 and 2065
- Hourly data is combined as required to match the time zones used in the modelling.
  - To mitigate the excessive smoothing effect of taking averages over all workdays within each week:
    - The wind and solar profiles used a 25% weighting of the average wind and solar over all days in the week and a 75% weighting of a randomly sampled day within each week.

2. THE NEED FOR GREEN PEAKERS IN THE COUNTERFACTUAL

Choice of counterfactual

It is important to have a robust and consistent counterfactual for analysing the NZ Battery Options.

We have chosen to focus on the “Green peaker” counterfactual - this covers capacity shortfalls of the order of days to weeks **-** it is does not cover longer term dry year shortfalls.

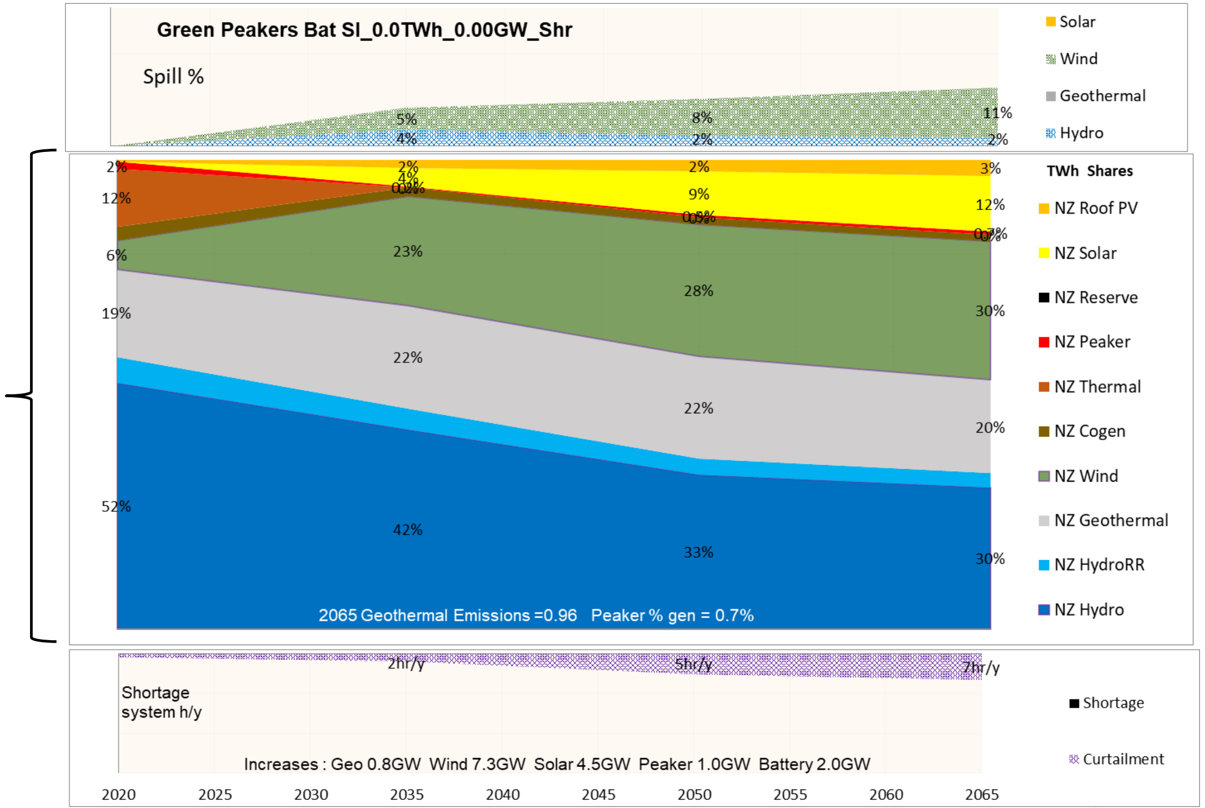
- Use of green peakers is a modelling device to ensure that NZ Battery options are measured on a consistent basis against a common generic capacity backup technology which can be modelled simply and robustly:
  - The aim is to represent one of several possible forms generic capacity backup reserve in a standard fashion to provide a robust counterfactual for the with and without analysis for the various NZ Battery options.
  - This technology is a low capital cost, high running cost form of backup to cover shortfalls greater than a day (within day can be handled with batteries), and that could last for several days or weeks.
    - The peaker is a standard open cycle gas turbine running on high priced “green” fuel costing $45/GJ.
    - The fixed cost of green peakers includes around $15/kW/yr as the holding costs for several weeks' storage of fuel
  - **While it is described a “Green peaker” it can also represent a whole range of possible technologies some of which are widely** used today in the industry, and others for which the technology is technically proven but are not yet widely adopted and the costs are more uncertain:
    - These possible technologies include OCGTs (suitably modified):
      - Using local or imported drop-in biodiesel produced from woody or another biomass
      - Using local or imported ethanol - at a price of the order of $40-$50/GJ
      - Using local biogas produced from a products
      - Using local or imported green hydrogen or ammonia
      - Continued use of existing gas peakers (open cycle gas turbines) with a gas price and high shadow price on carbon emissions (around $500/t)
      - Use of existing gas peakers combined with some form of carbon capture utilization and/or storage (CCUS) activity (possibly at existing or new geothermal) as an explicit offset.
      - It could also represent flexible demand prepared to shut off when prices exceed $500/MWh in return for an option payment.
  - The advantage of using this generic green peaker assumption is that it means that the value of the NZ battery options is not overly dependent on assumptions concerning the exact patterns of future wind/solar volatility and the assumed costs of non-supply, all of which are inherently uncertain.
      - Note: results are also presented using a no green peaker counterfactual, and for continued use of gas peaking plant with a carbon price.

Discussion

- A counterfactual which did not allow for generic green peakers was considered to be unrealistic and problematic for this work.
- The charts in the following slides show that the level of spill and demand response arising from capacity (not dry year energy) shortfalls is excessive and unrealistic.

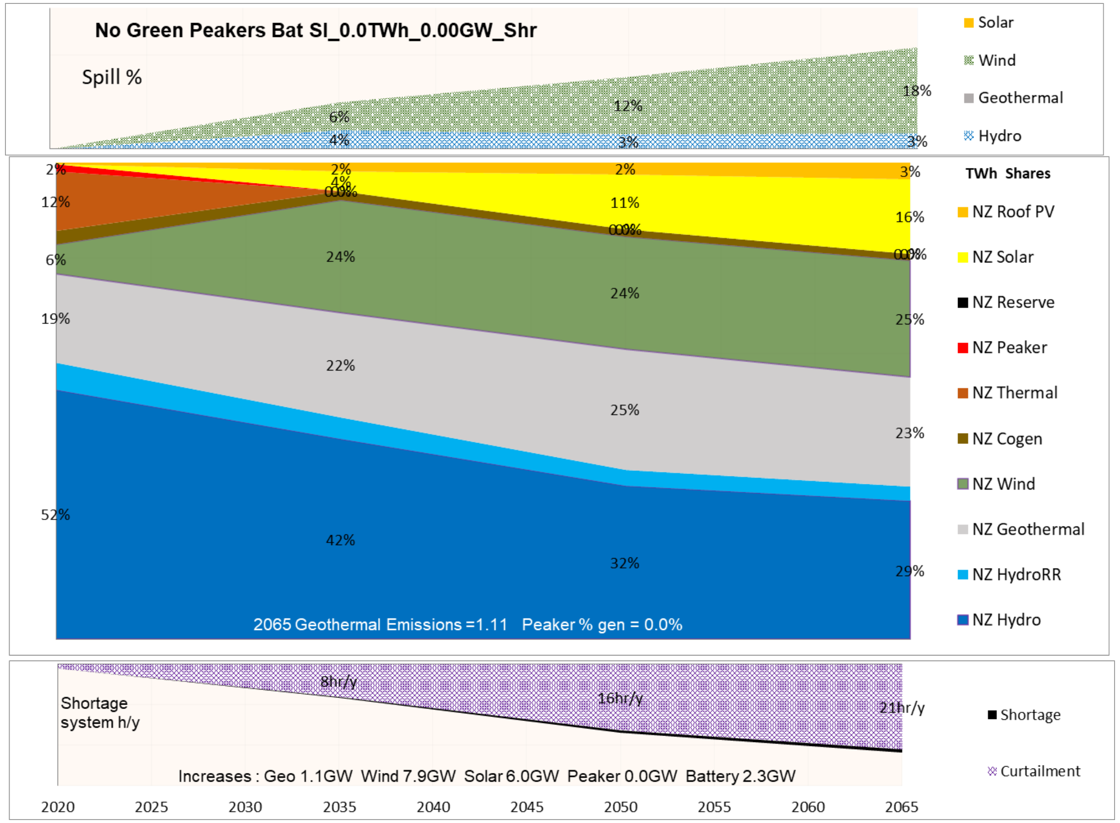
Green peakers (or similar firm capacity backup options) are required if 100% renewables is to be achieved

Where green peakers are allowed to cover capacity shortfalls caused by low wind weeks, overbuilding wind/solar covers dry years with significant but not excessive spill or market curtailment.



Green Peakers counterfactual		No NZ Battery		
		2035	2050	2065
Wind/Solar	GW	1.2	4.6	6.6
Green peaker	GW	0.4	0.8	1.1
Green peaker	TWh %gen	0.2%	0.5%	0.7%
Total Emissions CO2-e	mt/y	0.8	0.8	0.8
" Spill "	TWh/y	4.3	6.6	8.9
Curtailment	SysHr/y	3.0	6.3	6.3
Wind/Solar GW investment	x 2020GW	0.7	5.5	8.3

Where green peakers are not allowed to cover correlated low wind weeks, overbuilding wind/solar creates excessive levels of spill and market curtailment. Some technology which can provide firm capacity for at least a few weeks will be required.



No Green Peakers counterfactual		No NZ Battery		
		2035	2050	2065
Wind/Solar	GW	1.9	5.8	8.4
Green peaker	GW	0.0	0.0	0.0
Green peaker	TWh %gen	0.0%	0.0%	0.0%
Total Emissions CO2-e	mt/y	0.8	1.1	1.1
" Spill "	TWh/y	4.7	9.1	14.8
Curtailment	SysHr/y	9.2	18.1	21.9
Wind/Solar GW investment	x 2020GW	1.6	7.1	10.8

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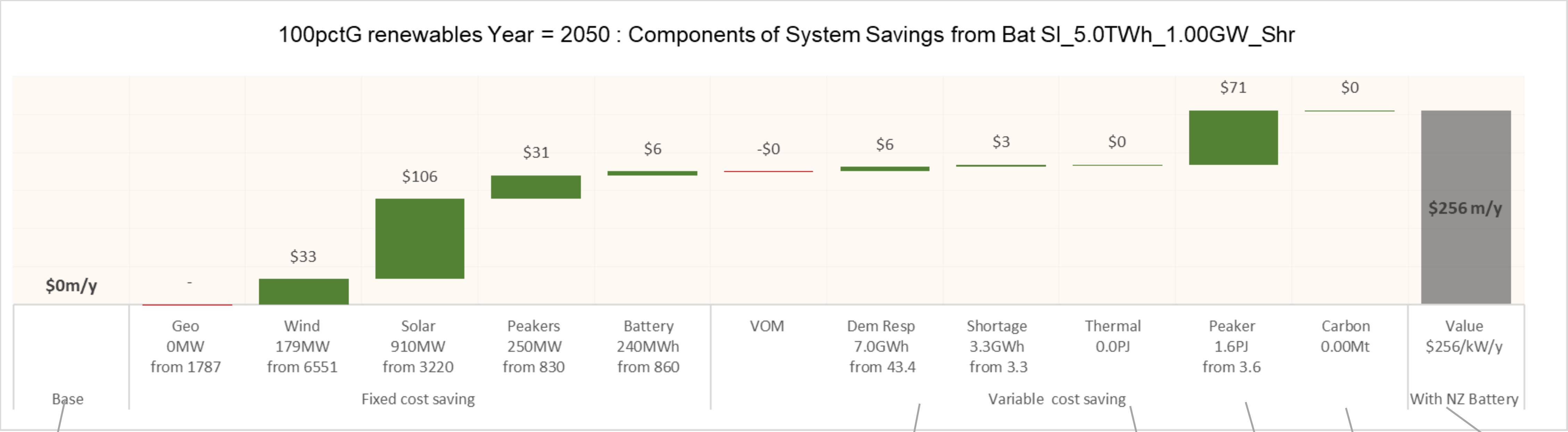
3. METHODOLOGY FOR ASSESSING INCREMENTAL SYSTEM BENEFIT

The chart shows the way we decompose system benefits ($m/y) for a 5TWh/1GW pumped hydro in the South Island in 2050



Treat cost of a 100% renewables system with green peakers but without NZ Battery as the base line - and measure deviations from this base line if NZ Battery is available

Capex savings from geothermal, wind, solar & peaker plant which is not needed

Capex savings from smaller scale storage batteries which are not built

Extra variable operating costs (wind spill)

Avoided demand response costs

Change in other fuel costs

Change in green peaker fuel costs

Savings in geothermal CO2 emissions

Sum of parts = gross benefit of NZ Battery

4. CHECKING THE PLANT OPTIMISATION APPROACH

Illustrative price margin based manual optimisation

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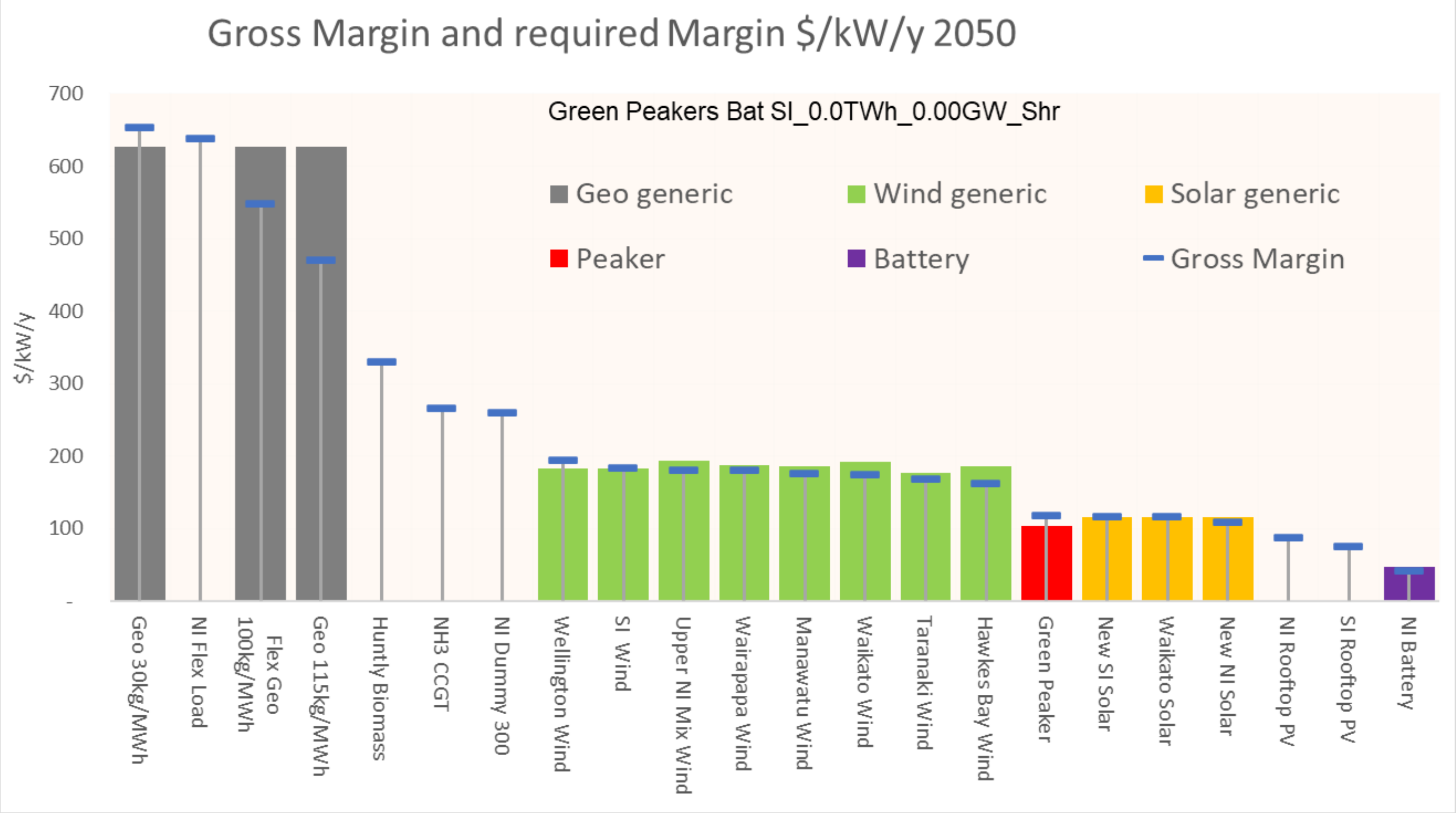
Gross margin charts



Geothermal operates base load but faces a carbon cost , so gross margin is reduced. The chart shows an example with marginal geothermal with an emission rate of 115kg / MWh and a carbon price of $250/t in 2050.

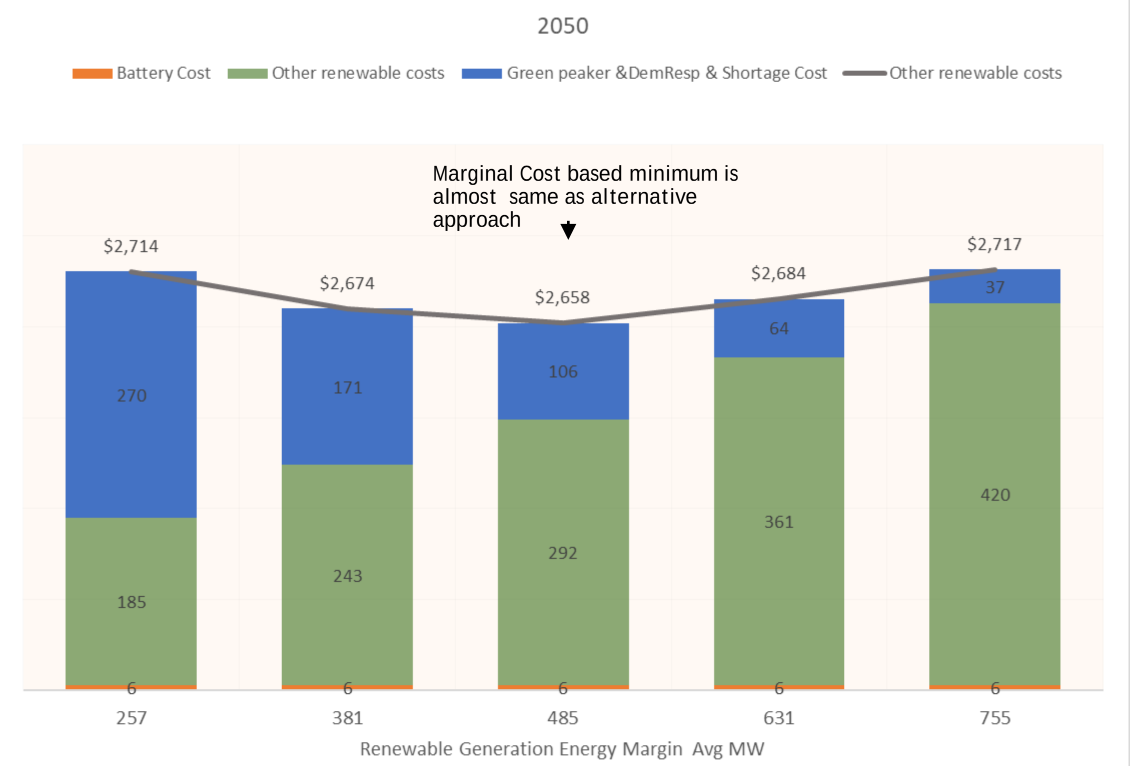
Notes

- The chart shows the gross margin in $/kW/yr earned in the spot market by each type of plant ranked from highest to lowest on the x axis.
  - This is derived from the full simulation model by week and time zone averaged over 87 weather scenarios.
  - Gross margin = spot revenue minus assumed SRMC.
  - This is calculated for actual new plant and for a notional very small new plant where none is built yet.
- The columns show the gross margin required to cover fixed operating costs and to provide a 7% nominal post tax return on capital.
- The generic new build of each technology is adjusted until they are all close to being just revenue adequate.
  - To achieve this it is necessary to adjust the mix of wind/solar between regions to take advantage of supply diversity.

  - Note that in the base case the first tranche of geothermal with emissions from 0 to 60kg/MWh are revenue adequate, but the last tranche with emissions greater than 115kg/MWh is not, hence it is not build.

We have confirmed that the ‘planting optimisation’ part of the modelling process is robust

Without NZ Battery the minimum system cost is $2658m

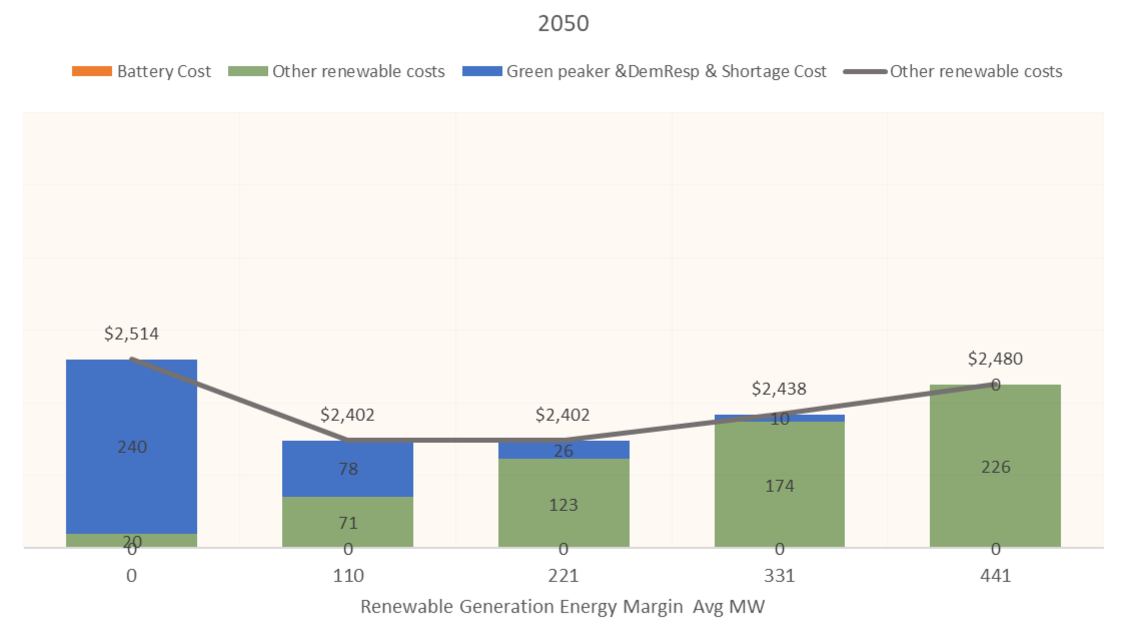


Marginal Cost based minimum is almost same as alternative approach

The marginal cost based minimum is consistent with minimum from curve with increments from minus 10% to plus 10% increase in average MW from new renewables (using shares from the revenue adequate base case) but no changes to small batteries.

Marginal cost based - adds a mix of new batteries, geothermal, wind and solar until they are just revenue adequate with “water value” and shortage based marginal pricing.

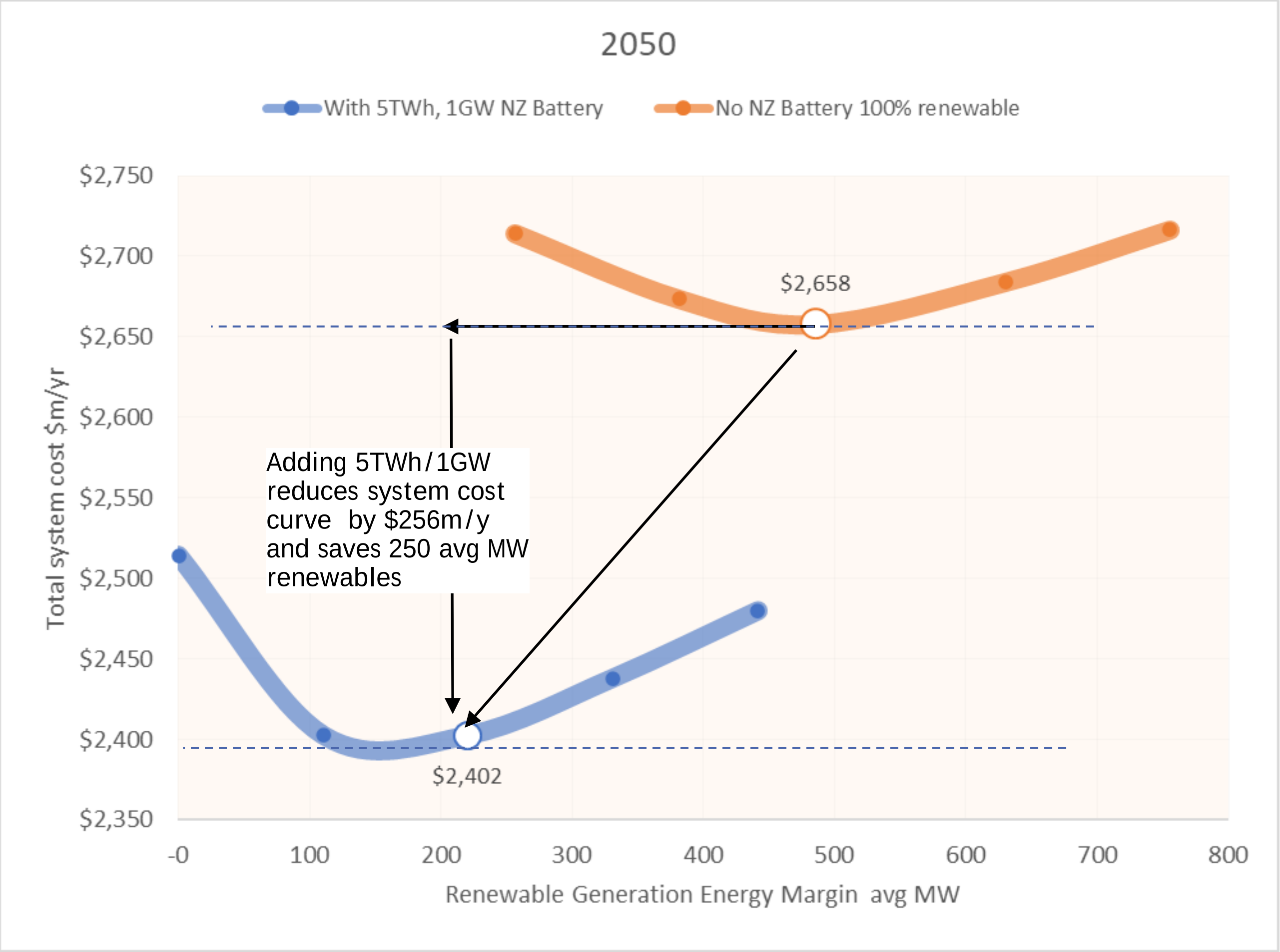
With NZ Battery 5.0TWh/1.0GW - the minimum drops $256m to $2404m



The marginal cost based minimum is consistent with the cost from total system cost approach for the cases with NZ Battery as well.

The system cost curves as a function of renewable energy margin can be assessed with and without NZ battery

The chart shows curves fitted to each of the system cost curves in the counterfactual (no NZ battery) and factual cases.



Adding 5TWh/1GW reduces system cost curve by $256m/y and saves 250 avg MW renewables

Base load equivalent average MW relative to a reference level.

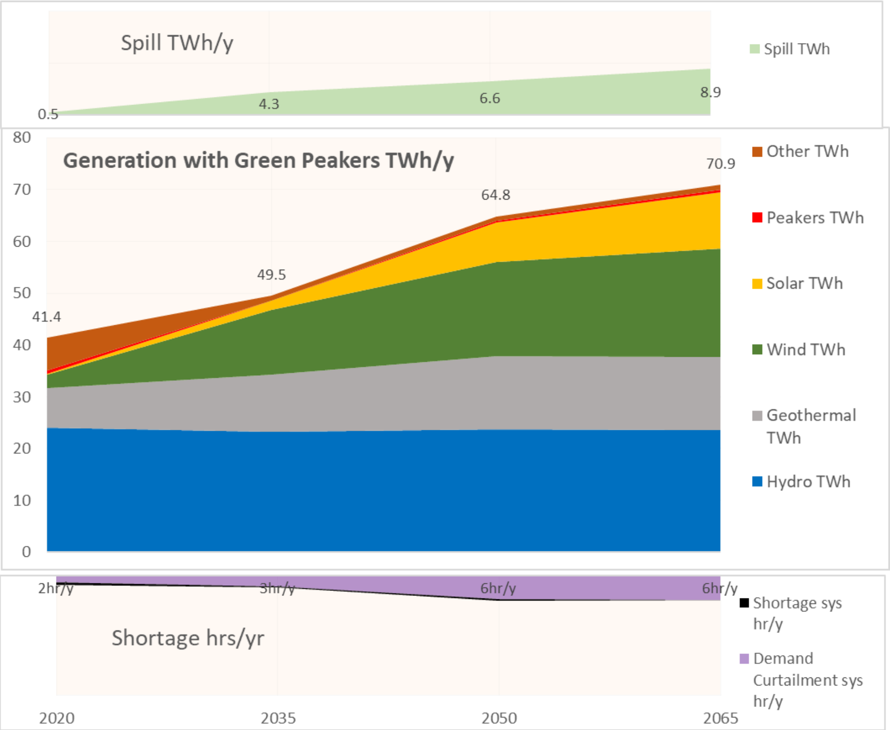
Comments

- The cost functions in each case are relatively flat over 100MW changes in renewable margin.
- To be able to assess the benefit are trying to compare the minimums from each curve.
- It can be seen that the manual plant optimisation appears to be within the flat part of a fitted curve, but slightly to the right (i.e. more conservative).
- The benefit is measured as the difference between the minimum system costs -
  - The measured benefit is around 10% of total system costs.
  - This estimated benefit is not particularly sensitive to the exact position on the curves, provided they are both in the flat portion , or if they are consistently biased in each case.
  - As can be seen the modelling estimates used (shown by open circles) are both on the flat part of the curve and to the extent they are biased the effect is similar in both cases.
  - This means the cost change is likely to be reliable and **not to subject to "modelling noise".**

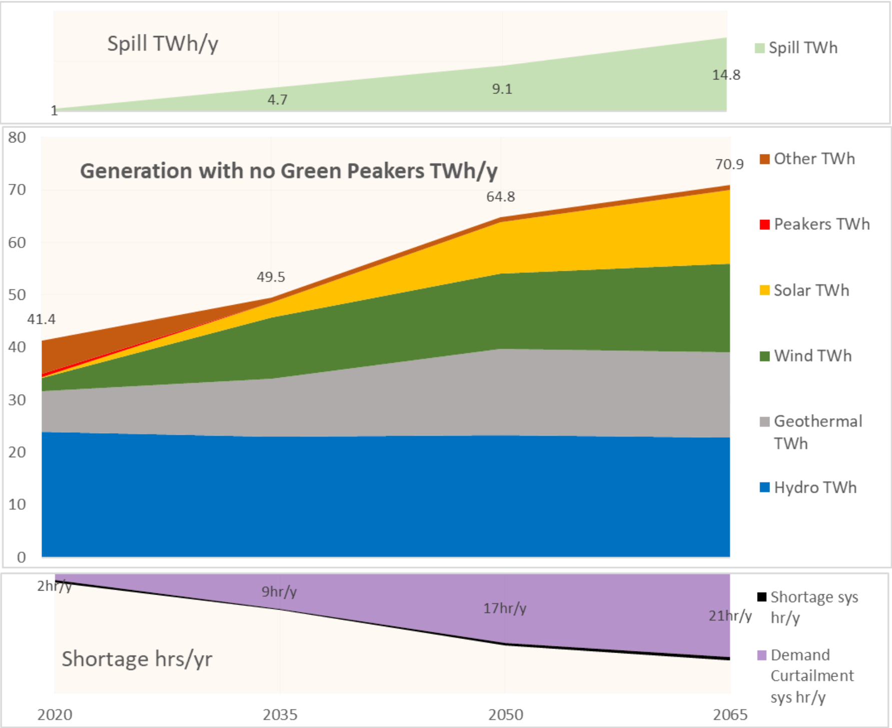
5. THE COUNTERFACTUALS

Generation by fuel for “green peaker” and “no green peaker” counterfactuals

Charts show the mean levels of generation by fuel type as well as spill and load curtailment for the green peaker and no green peaker counterfactuals.



0.8	5.5	11.1	14.7	<-Wind & solar GW
1.0	1.4	1.8	1.8	<-Geothermal GW
0.5	0.4	0.8	1.1	<-Peakers GW
0.0	0.5	1.1	1.3	<-Load Shift & Bat GW
4.1	0.8	0.8	0.8	<-Emissions mt
1.5%	0.2%	0.5%	0.7%	<-Pct Peaker TWh
7%	29%	40%	45%	<-Pct intermittent



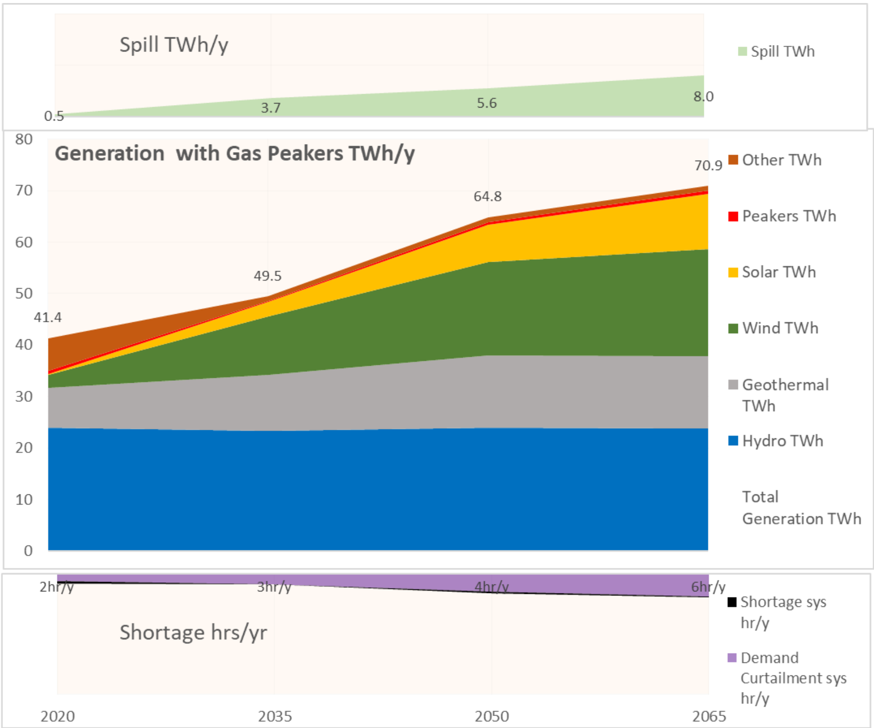
0.8	5.9	11.9	16.7	<-Wind & solar GW
1.0	1.4	2.1	2.1	<-Geothermal GW
0.5	0.0	0.0	0.0	<-Peakers GW
0.0	0.7	1.4	1.8	<-Load Shift & Bat GW
4.1	0.8	1.1	1.1	<-Emissions mt
1.5%	0.0%	0.0%	0.0%	<-Pct Peaker TWh
7%	30%	37%	44%	<-Pct intermittent

Comments

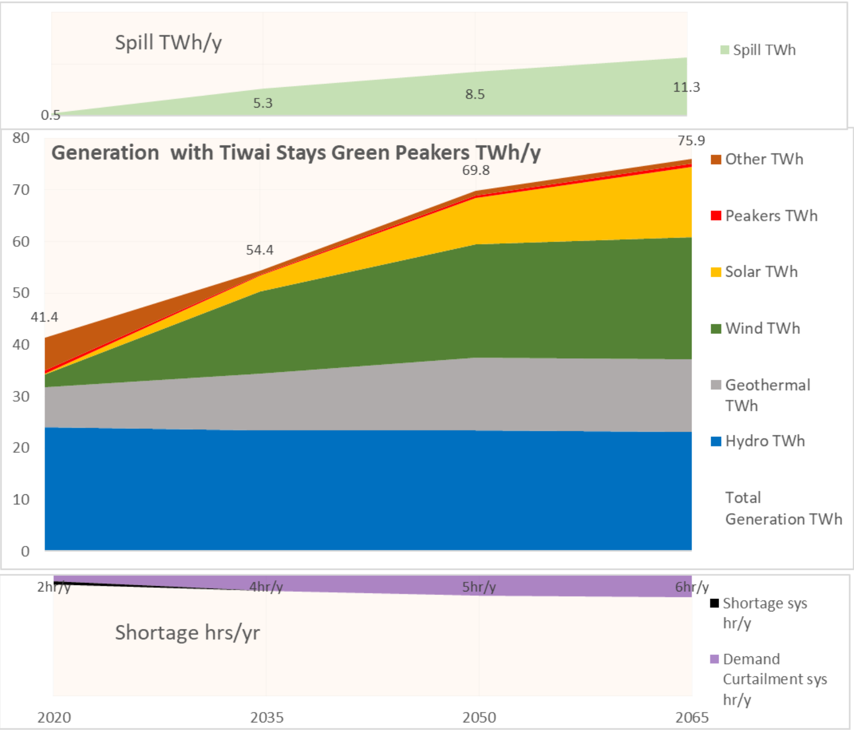
- Note:
  - Emissions are increased in the no Green Peaker world as more firm geothermal without carbon capture becomes economic.
  - Involuntary load curtailment is only increased slightly but market based curtailment which is triggered when prices rise above $700-1500/MWh is increased substantially.
  - Where green peakers are allowed excessive spill can be avoided as these cover capacity shortfalls caused by low wind.

Generation by fuel for “Gas Peaker” and “Tiwai stays” counterfactuals

Charts show the mean levels of generation by fuel type as well as spill and load curtailment for the gas peaker and Tiwai stays counterfactuals.



0.8	5.5	10.8	14.3	<-Wind & solar GW
1.0	1.4	1.8	1.8	<-Geothermal GW
0.5	0.4	1.0	1.2	<-Peakers GW
0.0	0.5	1.1	1.3	<-Load Shift & Bat GW
4.1	0.9	1.1	1.2	<-Emissions mt
1.5%	0.4%	0.8%	0.9%	<-Pct Peaker TWh
7%	29%	39%	44%	<-Pct intermittent



0.8	7.5	13.4	17.4	<-Wind & solar GW
1.0	1.4	1.8	1.8	<-Geothermal GW
0.5	0.4	1.0	1.2	<-Peakers GW
0.0	0.6	1.2	1.8	<-Load Shift & Bat GW
4.1	0.8	0.8	0.8	<-Emissions mt
1.5%	0.3%	0.6%	0.8%	<-Pct Peaker TWh
7%	35%	44%	49%	<-Pct intermittent

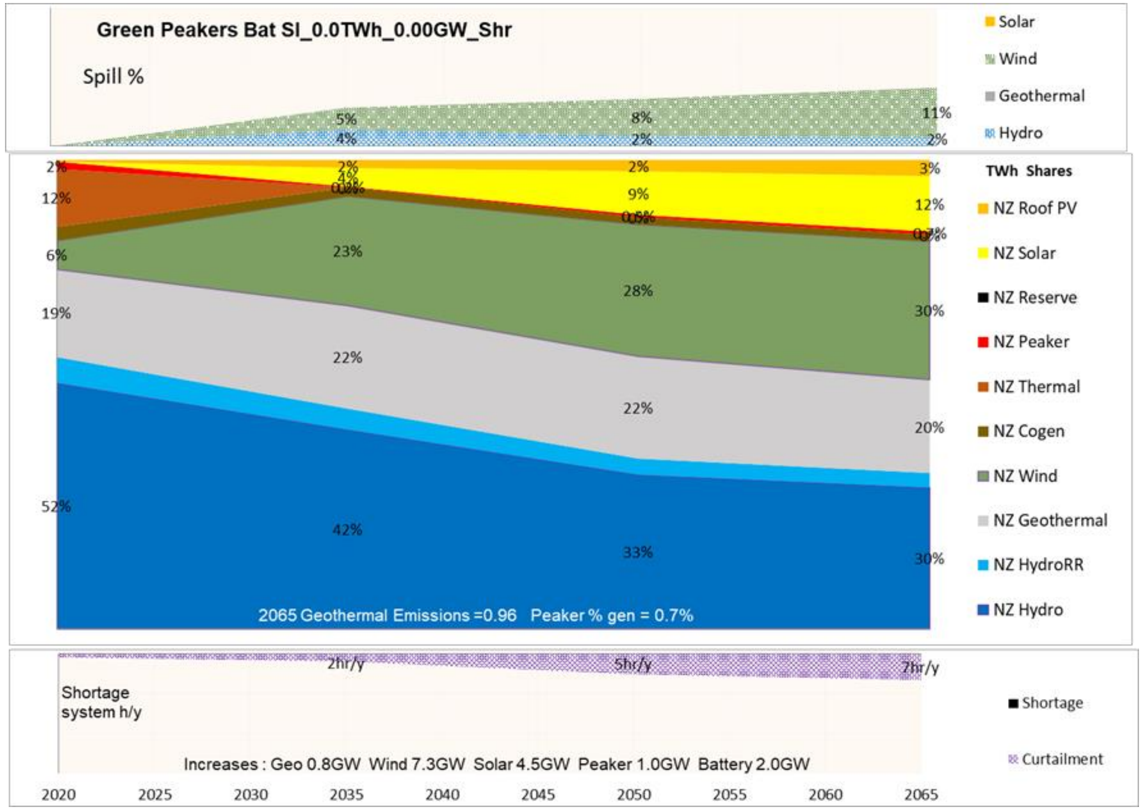
Comments

- With gas peakers, by 2065:
  - Emissions are higher, but are almost exactly the same as in the No green peaker world due to increased geothermal build.
  - Spill is reduced by around 1TWh since the cost of back-up for wind is reduced
  - Shortage and demand curtailment remains the same.
- If Tiwai remains, by 2065:
  - 2.9GW more wind and solar is required
  - The % intermittent increases from 45% to 49%
  - Spill is increased by around 1.5 TWh

6. IMPACT OF ONSLOW ON INVESTMENT GENERATION AND SPILL

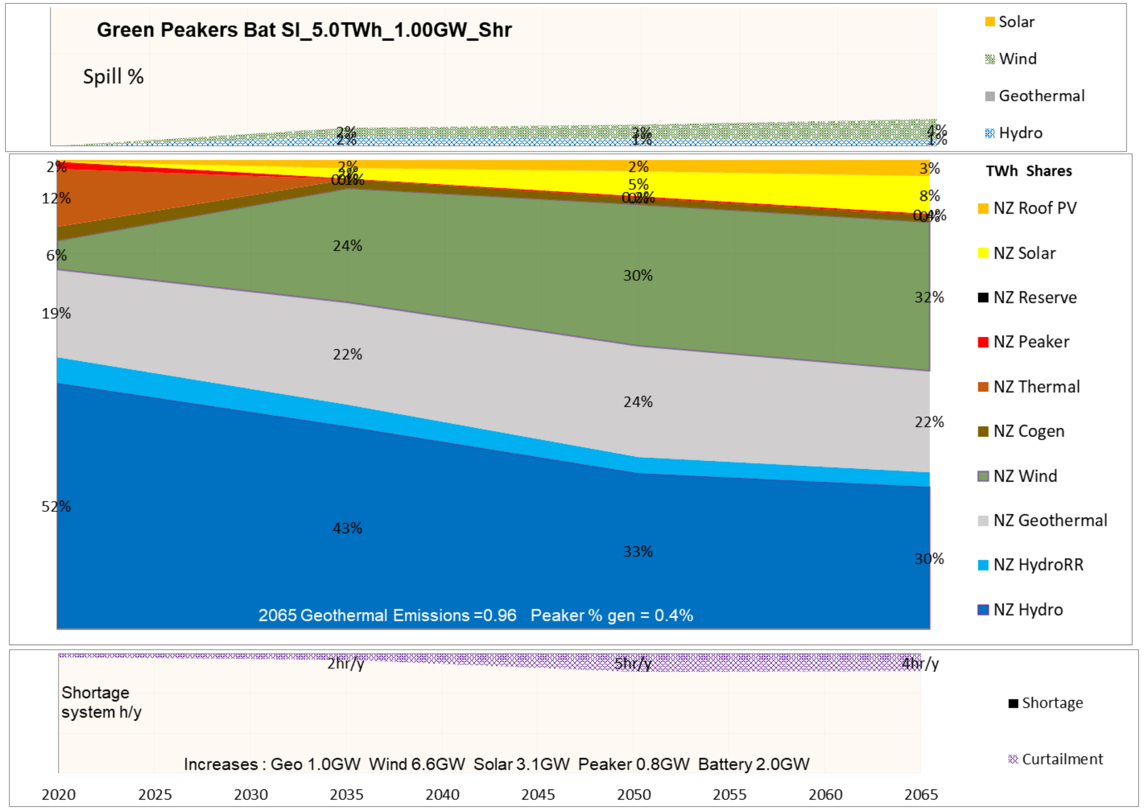
Where green peakers are allowed Onslow enables wind “spill” to be reduced and wind/solar and peaker capacity to be saved - wind generation shares increase slightly

Without NZ Battery - where green peakers are allowed



Green Peakers counterfactual		No NZ Battery		
		2035	2050	2065
Wind/Solar	GW	1.2	4.6	6.6
Green peaker	GW	0.4	0.8	1.1
Green peaker	TWh %gen	0.2%	0.5%	0.7%
Total Emissions CO2-e	mt/y	0.8	0.8	0.8
" Spill "	TWh/y	4.3	6.6	8.9
Curtailment	SysHr/y	3.0	6.3	6.3
Wind/Solar GW investment	x 2020GW	0.7	5.5	8.3

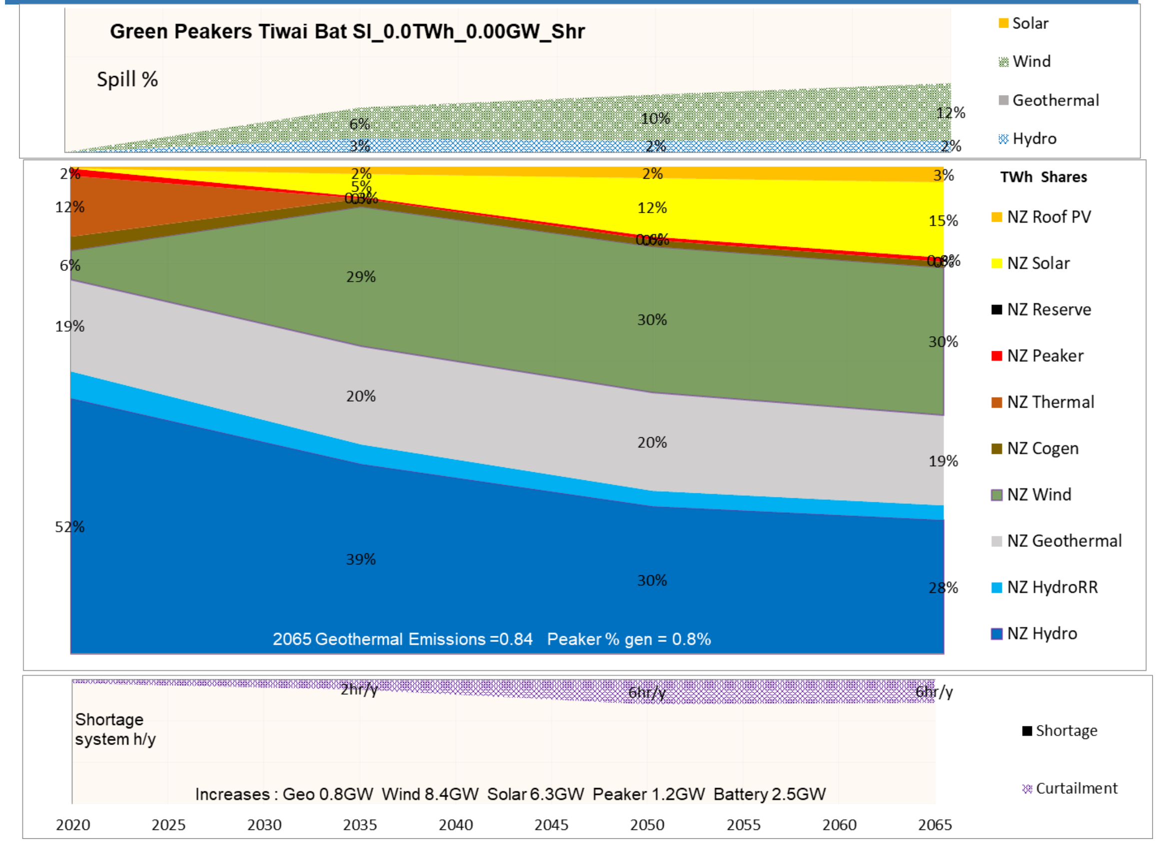
With NZ Battery = South Island 5TWh/1GW - new investment in wind and solar can be **reduced and “spill” can be reduced.**



Green Peakers counterfactual		Saving from Pumped storage		
		2035	2050	2065
Wind/Solar	GW	0.4	1.1	1.2
Green peaker	GW	0.1	0.3	0.2
Green peaker	TWh %gen	0.1%	0.2%	0.3%
Total Emissions CO2-e	mt/y	0.0	0.0	(0.0)
" Spill "	TWh/y	2.0	3.2	4.3
Curtailment	SysHr/y	0.2	1.4	1.6

Where Tiwai remains Onslow enables wind "spill" to be reduced and wind/solar and peaker capacity to be saved - wind generation shares increase slightly

Without NZ Battery - where green peakers are allowed

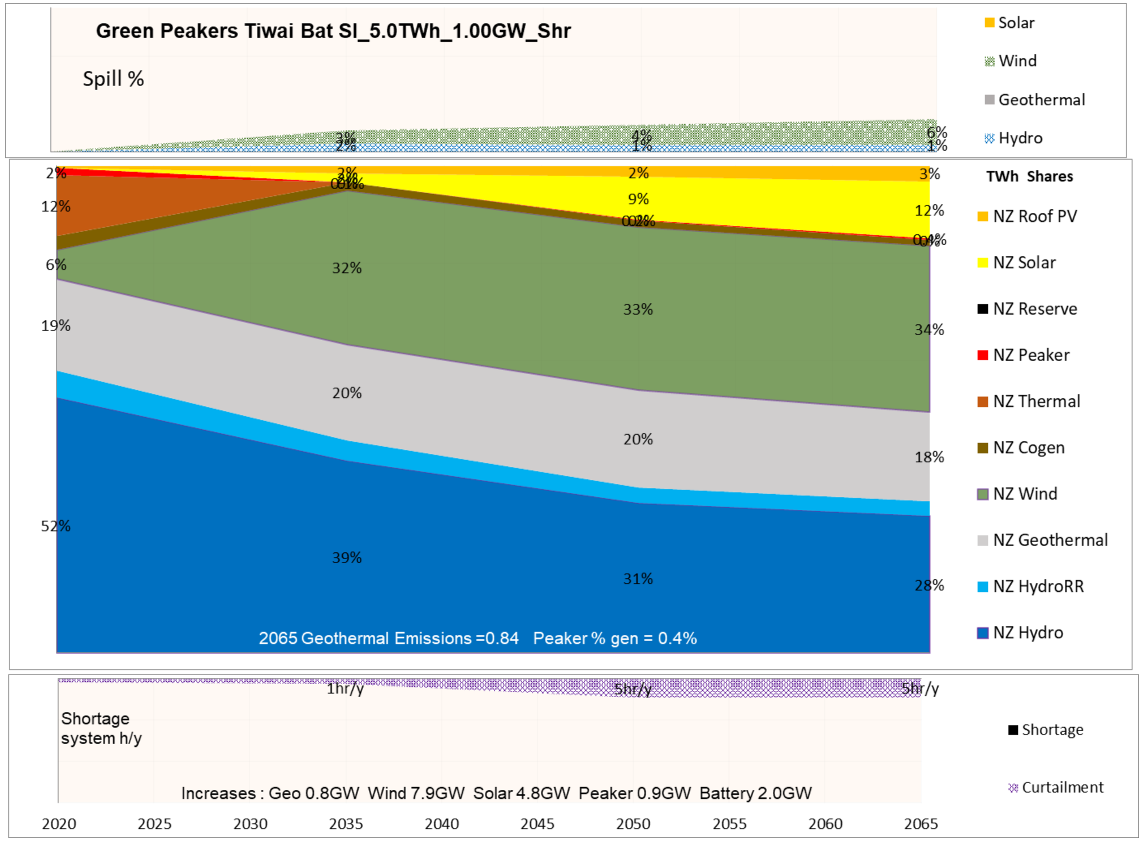


2065 Geothermal Emissions =0.84 Peaker % gen = 0.8%

Increases : Geo 0.8GW Wind 8.4GW Solar 6.3GW Peaker 1.2GW Battery 2.5GW

Green Peakers Tiwai counterfactual		No NZ Battery		
		2035	2050	2065
Wind/Solar	GW	2.1	5.9	8.4
Green peaker	GW	0.5	0.9	1.2
Green peaker	TWh %gen	0.3%	0.6%	0.8%
Total Emissions CO2-e	mt/y	0.8	0.8	0.8
" Spill "	TWh/y	5.1	8.4	11.2
Curtailment	SysHr/y	2.4	6.0	5.5
Wind/Solar GW investment	x 2020GW	2.0	7.3	10.9

With NZ Battery = South Island 5TWh/1GW - new investment in wind and solar can be **reduced by 1.5GW and "spill" can be reduced by 5.0TWh.**



2065 Geothermal Emissions =0.84 Peaker % gen = 0.4%

Increases : Geo 0.8GW Wind 7.9GW Solar 4.8GW Peaker 0.9GW Battery 2.0GW

Green Peakers Tiwai counterfactual		Saving from Pumped storage		
		2035	2050	2065
Wind/Solar	GW	0.9	1.4	1.9
Green peaker	GW	0.3	0.5	0.3
Green peaker	TWh %gen	0.2%	0.4%	0.4%
Total Emissions CO2-e	mt/y	0.0	(0.0)	(0.0)
" Spill "	TWh/y	2.8	4.2	6.1
Curtailment	SysHr/y	0.9	0.1	1.5

Physical impact of the base case Onslow pumped storage with and without green peakers

By 2065 pumped hydro saves 4.3TWh spill, 1.2GW of wind/solar, and 0.2GWof gas peakers and batteries, $1.7b capex, 1.5 hr/yr curtailment.

But increases load by 0.9TWh/yr for pumping

Green Peakers counterfactual		No NZ Battery Bat SI_0.0TWh_0.00GW_Shr			Onslow 5TWh/1GW Bat SI_5.0TWh_1.00GW_Shr			Difference Saving from Pumped storage		
		2035	2050	2065	2035	2050	2065	2035	2050	2065
Total Capacity	GW	14	21	26	14	21	25	0.5	1.6	1.4
Hydro	GW	5.1	5.1	5.1	5.1	5.1	5.1	-	-	-
Geothermal	GW	1.4	1.8	1.8	1.4	1.8	1.8	-	-	-
Wind	GW	4.3	6.6	8.0	3.9	6.4	7.4	0.37	0.18	0.62
Solar	GW	1.2	4.6	6.6	1.2	3.7	6.1	0.01	0.91	0.55
Gas Peakers	GW	0.4	0.8	1.1	0.3	0.6	0.9	0.10	0.25	0.23
Load Shift & Batteries	GWh	0.3	0.9	2.2	0.3	0.6	2.2	-	0.24	-
Capex Saving	$b							$0.8	$1.5	$1.7
Total Generation	TWh	49.5	64.8	70.9	50.1	65.6	71.8	(0.5)	(0.8)	(0.9)
Hydro	TWh	21.0	21.5	21.4	21.6	21.7	21.7	(0.5)	(0.2)	(0.3)
Geothermal	TWh	10.9	14.1	14.1	10.9	14.1	14.1	0.0	0.0	(0.0)
Wind	TWh	12.6	18.1	20.9	12.7	20.4	22.7	(0.1)	(2.3)	(1.7)
Solar	TWh	1.7	7.6	10.8	1.7	5.9	9.8	0.0	1.7	1.0
Spill	TWh	4.3	6.6	8.9	2.4	3.3	4.6	2.0	3.2	4.3
Pct intermittent	%	29%	40%	45%	29%	40%	45%	0%	(1%)	(0%)
Pct spill	%	9%	10%	13%	5%	5%	6%	4%	5%	6%
Green peaker	TWh	0.09	0.34	0.51	0.05	0.19	0.32	0.05	0.15	0.19
Green peaker	Max TWh	0.97	1.33	1.40	0.18	0.60	0.81	0.79	0.73	0.59
% generation	%	0.2%	0.5%	0.7%	0.1%	0.3%	0.4%	0.1%	0.2%	0.3%
Total Emissions CO2-e	mt/yr	0.8	0.8	0.8	0.8	0.8	0.8	0.0	0.0	(0.0)
Geothermal	mt/yr	0.8	0.8	0.8	0.8	0.8	0.8	0.0	0.0	(0.0)
Peakers	mt/yr	-	-	-	-	-	-	-	-	-
gas emissions as % geo	%	-	-	-	-	-	-	-	-	-
Total Market Curtailment	SysHr/y	2.9	5.9	6.2	2.7	4.9	4.7	0.2	1.0	1.5
Forced Shortage	SysHr/y	0.1	0.5	0.1	0.0	0.0	0.0	0.0	0.4	0.0
								-	-	-
Total Capex (ex NZ Battery)	$b	$16.4	$25.4	$28.2	$15.6	$23.9	$26.5	$0.8	$1.5	$1.7
Geothermal	$b	$7.6	$9.8	$9.8	$7.6	$9.8	$9.8	-	-	-
Wind	$b	$7.9	$11.3	$13.0	$7.2	$11.0	$12.0	$0.7	$0.3	$1.0
Solar	$b	$0.5	$3.3	$4.1	$0.5	$2.4	$3.6	$0.0	$0.9	$0.5
Peakers	$b	$0.4	$0.8	$1.1	$0.3	$0.6	$0.9	$0.1	$0.3	$0.2
Batteries	$b	$0.1	$0.1	$0.3	$0.1	$0.1	$0.3	-	$0.0	-

In the no green peaker world - the pumped hydro saves 6.5TWh spill, 1.9GW of wind/solar, and 1.7GWh of batteries, $2.8b capex, 3.1 hrs/yr curtailment .

But increases load by 0.7TWh/yr for pumping

No Green Peakers counterfactual		No NZ Battery Bat SI_0.0TWh_0.00GW_Shr			Onslow 5TWh/1GW Bat SI_5.0TWh_1.00GW_Shr			Difference Saving from Pumped storage		
		2035	2050	2065	2035	2050	2065	2035	2050	2065
Capacity		14	22	28	14	22	27	(0.3)	0.2	0.7
Hydro	GW	5.1	5.1	5.1	5.1	5.1	5.1	-	-	-
Geothermal	GW	1.4	2.1	2.1	1.4	2.1	2.1	-	-	-
Wind	GW	4.1	6.1	8.3	3.7	5.3	7.0	0.4	0.9	1.4
Solar	GW	1.9	5.8	8.4	1.5	5.3	7.9	0.4	0.4	0.5
Gas Peakers	GW	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-
Load Shift & Batteries	GWh	2.0	3.8	6.8	1.7	2.7	5.1	0.2	1.0	1.7
Capex Saving	$b							$1.1	$2.0	$2.8
Total Generation	TWh	49.5	64.8	70.9	50.1	65.5	71.6	(0.6)	(0.7)	(0.7)
Hydro	TWh	20.8	21.1	20.7	22.0	22.0	21.9	(1.2)	(0.9)	(1.2)
Geothermal	TWh	10.9	16.4	16.3	10.9	16.4	16.3	(0.0)	0.0	(0.0)
Wind	TWh	11.7	14.5	16.8	11.7	15.0	17.2	(0.0)	(0.6)	(0.4)
Solar	TWh	2.9	9.8	14.0	2.3	8.9	13.0	0.7	0.9	1.1
Spill	TWh	4.7	9.1	14.8	2.1	4.4	8.3	2.6	4.7	6.5
Pct intermittent	%	30%	37%	44%	28%	36%	42%	2%	1%	1%
Pct spill	%	10%	14%	21%	4%	7%	12%	5%	7%	9%
Green peaker	TWh	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)
Green peaker	Max TWh	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)
% generation	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.0%	-0.0%	-0.0%
Total Emissions CO2-e	mt/yr	0.8	1.1	1.1	0.8	1.1	1.1	(0.0)	0.0	(0.0)
Geothermal	mt/yr	0.8	1.1	1.1	0.8	1.1	1.1	(0.0)	0.0	(0.0)
Peakers	mt/yr	-	-	-	-	-	-	-	-	-
gas emissions as % geo	%	-	-	-	-	-	-	-	-	-
Total Market Curtailment	SysHr/y	9.0	17.5	21.1	9.0	13.4	18.0	0.1	4.1	3.1
Forced Shortage	SysHr/y	0.2	0.6	0.8	0.9	0.5	0.8	(0.8)	0.1	(0.0)
								-	-	-
Total Capex (ex NZ Battery)	$b	$16.8	$27.0	$31.2	$15.7	$25.0	$28.4	$1.1	$2.0	$2.8
Geothermal	$b	$7.6	$11.4	$11.4	$7.6	$11.4	$11.4	-	-	-
Wind	$b	$7.5	$10.6	$13.4	$6.8	$9.1	$11.2	$0.7	$1.5	$2.2
Solar	$b	$1.3	$4.5	$5.6	$0.9	$4.1	$5.2	$0.4	$0.5	$0.5
Peakers	$b	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-	-	-
Batteries	$b	$0.4	$0.6	$0.8	$0.4	$0.5	$0.7	$0.0	$0.1	$0.1

Physical impact of Onslow pumped storage with Gas peaker and Tiwai stays counterfactuals

Where gas peakers remain - Onslow saves 4.3TWh spill, 1.1GW of wind/solar, and 0.2GWof gas peakers and batteries, $1.7b capex, 2.3 hr/yr curtailment.

But increases load by 0.9TWh/yr for pumping

		No NZ Battery			Onslow 5TWh/1GW			Difference		
Gas Peakers counterfactual		**Bat SI_0.0TWh_0.00GW_Shr**			**Bat SI_5.0TWh_1.00GW_Shr**			**Saving from Pumped storage**		
		2035	**2050**	**2065**	**2035**	**2050**	**2065**	**2035**	**2050**	**2065**
Total Capacity		14	21	26	14	21	25	(0.4)	0.2	0.3
Hydro	GW	5.1	5.1	5.1	5.1	5.1	5.1	-	-	-
Geothermal	GW	1.4	1.8	1.8	1.4	1.8	1.8	-	-	-
Wind	GW	3.8	6.3	7.8	3.7	6.2	7.2	0.1	0.1	0.6
Solar	GW	1.8	4.5	6.5	1.4	3.6	6.0	0.4	0.8	0.5
Gas Peakers	GW	0.4	1.0	1.2	0.3	0.7	1.0	0.1	0.3	0.2
Load Shift & Batteries	GWh	0.3	0.5	1.4	0.3	0.5	1.4	-	-	-
Capex Saving	$b							$0.7	$1.3	$1.7
Total Generation	TWh	49.5	64.8	70.9	50.1	65.7	71.8	(0.6)	(0.8)	(0.9)
Hydro	TWh	21.1	21.6	21.5	21.7	21.9	21.8	(0.5)	(0.2)	(0.3)
Geothermal	TWh	10.9	14.1	14.1	10.9	14.1	14.1	0.0	0.0	(0.0)
Wind	GW	11.4	18.1	20.9	12.2	20.4	22.7	(0.9)	(2.3)	(1.8)
Solar	GW	2.8	7.4	10.6	2.0	5.8	9.6	0.7	1.5	1.0
Spill	TWh	3.7	5.6	8.0	2.0	2.7	3.7	1.7	2.9	4.3
Pct intermittent	%	29%	39%	44%	28%	40%	45%	0%	(1%)	(1%)
Pct spill	%	7%	9%	11%	4%	4%	5%	3%	5%	6%
Gas Peakers	TWh	0.18	0.49	0.64	0.08	0.28	0.40	0.09	0.21	0.23
Gas Peakers	Max TWh	1.48	2.35	1.73	1.09	1.46	1.56	0.38	0.89	0.16
% generation	%	0.4%	0.8%	0.9%	0.2%	0.4%	0.6%	0.2%	0.3%	0.3%
Total Emissions CO2-e	mt/yr	0.9	1.1	1.2	0.8	1.0	1.1	0.0	0.1	0.1
Geothermal	mt/yr	0.8	0.8	0.8	0.8	0.8	0.8	0.0	0.0	(0.0)
Gas Peakers	mt/yr	0.1	0.3	0.3	0.0	0.2	0.2	0.0	0.1	0.1
gas emissions as % geo	%	12%	31%	40%	6%	18%	25%	6%	13%	15%
Total Market Curtailment	SysHr/y	2.5	4.5	5.7	2.1	3.0	3.4	0.4	1.4	2.3
Forced Shortage	SysHr/y	0.1	0.4	0.1	0.0	0.0	0.0	0.1	0.4	0.1
Total Capex (ex NZ Battery)	$b	$16.3	$25.0	$27.8	$15.6	$23.7	$26.1	$0.7	$1.3	$1.7
Geothermal	$b	$7.6	$9.8	$9.8	$7.6	$9.8	$9.8	-	-	-
Wind	$b	$7.0	$10.9	$12.6	$6.8	$10.7	$11.6	$0.1	$0.2	$1.0
Solar	$b	$1.2	$3.2	$3.9	$0.7	$2.3	$3.5	$0.5	$0.9	$0.5
Peakers	$b	$0.4	$1.0	$1.2	$0.3	$0.7	$1.0	$0.1	$0.3	$0.2
Batteries	$b	$0.1	$0.1	$0.2	$0.1	$0.1	$0.2	-	-	-

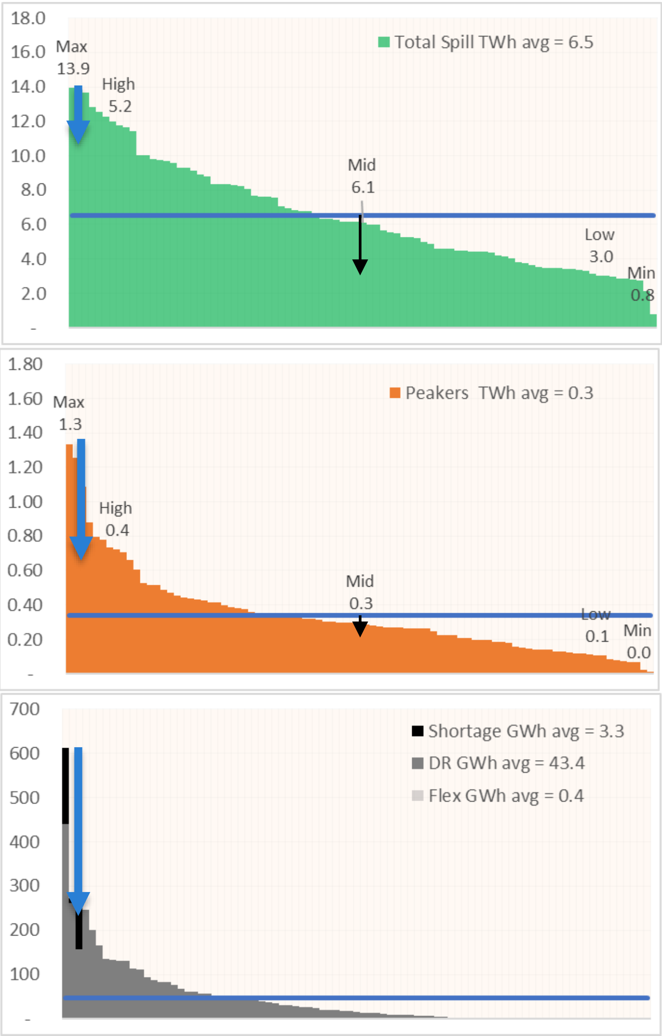
Where Tiwa stays - Onslow saves 6.1TWh spill, 1.9GW of wind/solar, and 0.3GW of peakers and 3.2GWh batteries, $3.0b capex.

But increases load by 0.9TWh/yr for pumping

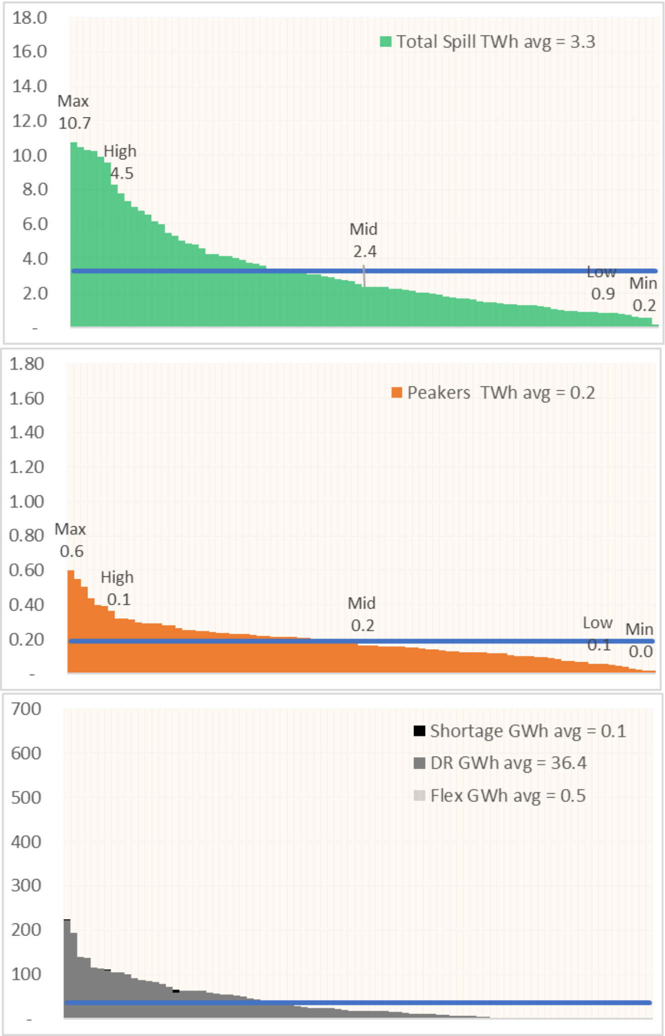
		No NZ Battery			Onslow 5TWh/1GW			Difference		
Green Peakers Tiwai counterfactual		**Bat SI_0.0TWh_0.00GW_Shr**			**Bat SI_5.0TWh_1.00GW_Shr**			**Saving from Pumped storage**		
		2035	**2050**	**2065**	**2035**	**2050**	**2065**	**2035**	**2050**	**2065**
Total Capacity		16	24	29	16	23	28	0.3	1.0	1.6
Hydro	GW	5.1	5.1	5.1	5.1	5.1	5.1	-	-	-
Geothermal	GW	1.4	1.8	1.8	1.4	1.8	1.8	-	-	-
Wind	GW	5.6	8.1	9.4	5.4	7.9	8.6	0.2	0.2	0.7
Solar	GW	1.9	5.3	8.1	1.2	4.2	6.9	0.7	1.2	1.2
Peakers	GW	0.4	1.0	1.2	0.2	0.5	0.9	0.3	0.5	0.3
Load Shift & Batteries	GWh	1.4	1.5	5.6	0.5	0.6	2.5	0.9	0.8	3.2
Capex Saving	$b							$1.6	$2.2	$3.0
Total Generation	TWh	54.4	69.8	75.9	55.1	70.7	76.9	(0.7)	(0.8)	(0.9)
Hydro	TWh	21.2	21.2	20.9	21.7	21.8	21.7	(0.5)	(0.6)	(0.8)
Geothermal	TWh	10.9	14.1	14.1	10.9	14.1	14.1	0.0	(0.0)	(0.0)
Wind	GW	16.0	21.9	23.6	17.5	24.5	26.2	(1.5)	(2.6)	(2.6)
Solar	GW	3.0	9.0	13.6	1.7	6.9	11.4	1.3	2.2	2.2
Spill	TWh	5.3	8.5	11.3	2.5	4.4	5.3	2.8	4.2	6.1
Pct intermittent	%	35%	44%	49%	35%	44%	49%	0%	(0%)	0%
Pct spill	%	10%	12%	15%	5%	6%	7%	5%	6%	8%
Green peaker	TWh	0.14	0.44	0.60	0.03	0.17	0.34	0.11	0.27	0.26
Green peaker	Max TWh	0.89	1.32	1.23	0.49	0.54	0.79	0.41	0.79	0.45
% generation	%	0.3%	0.6%	0.8%	0.1%	0.2%	0.4%	0.2%	0.4%	0.4%
Total Emissions CO2-e	mt/yr	0.8	0.8	0.8	0.8	0.8	0.8	0.0	(0.0)	(0.0)
Geothermal	mt/yr	0.8	0.8	0.8	0.8	0.8	0.8	0.0	(0.0)	(0.0)
Peakers	mt/yr	-	-	-	-	-	-	-	-	-
gas emissions as % geo	%	-	-	-	-	-	-	-	-	-
Total Market Curtailment	SysHr/y	3.9	5.1	5.6	3.1	5.1	4.1	0.8	0.0	1.5
Forced Shortage	SysHr/y	0.1	0.1	0.1	0.0	0.0	0.0	0.1	0.1	0.0
Total Capex (ex NZ Battery)	$b	$20.0	$29.1	$32.2	$18.4	$26.9	$29.2	$1.6	$2.2	$3.0
Geothermal	$b	$7.6	$9.8	$9.8	$7.6	$9.8	$9.8	-	-	-
Wind	$b	$10.3	$14.0	$15.1	$10.0	$13.5	$13.9	$0.3	$0.4	$1.2
Solar	$b	$1.4	$4.1	$5.4	$0.6	$2.9	$4.3	$0.8	$1.2	$1.1
Peakers	$b	$0.4	$1.0	$1.2	$0.2	$0.5	$0.9	$0.3	$0.5	$0.3
Batteries	$b	$0.3	$0.2	$0.7	$0.1	$0.1	$0.3	$0.2	$0.1	$0.4

Impact of Onslow on spill, green peaker and demand response distributions

Green Peaker Counterfactual 2050



.. with Onslow 5TWh/1.00GW



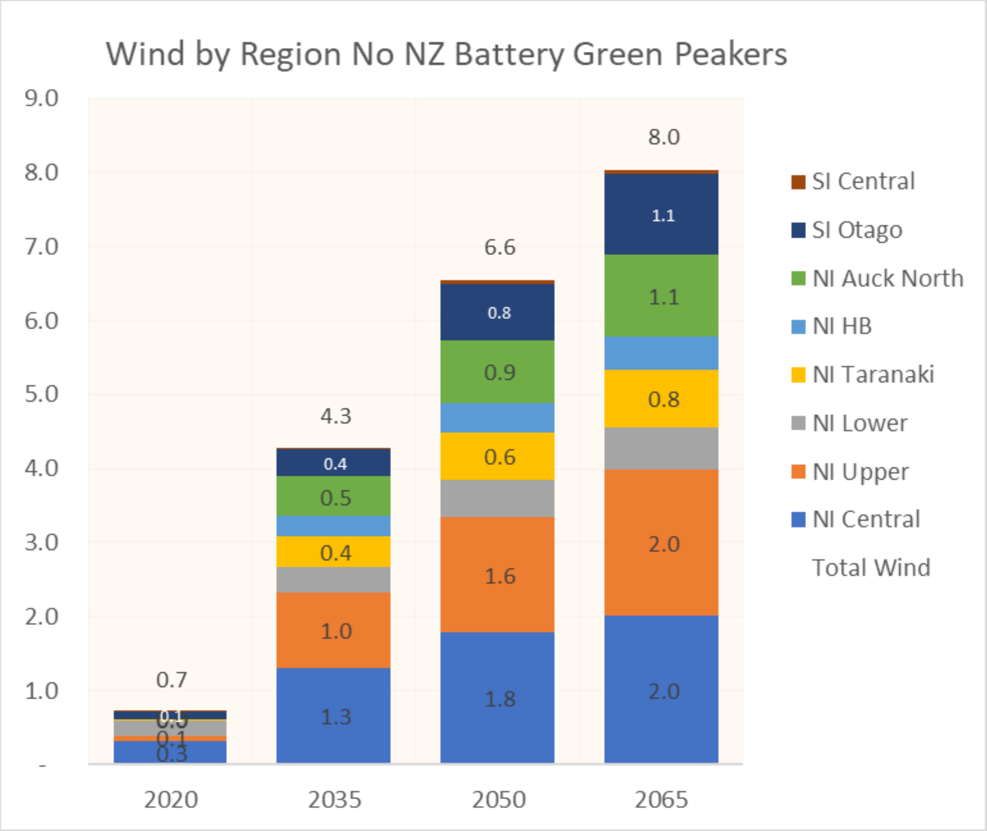
Comments

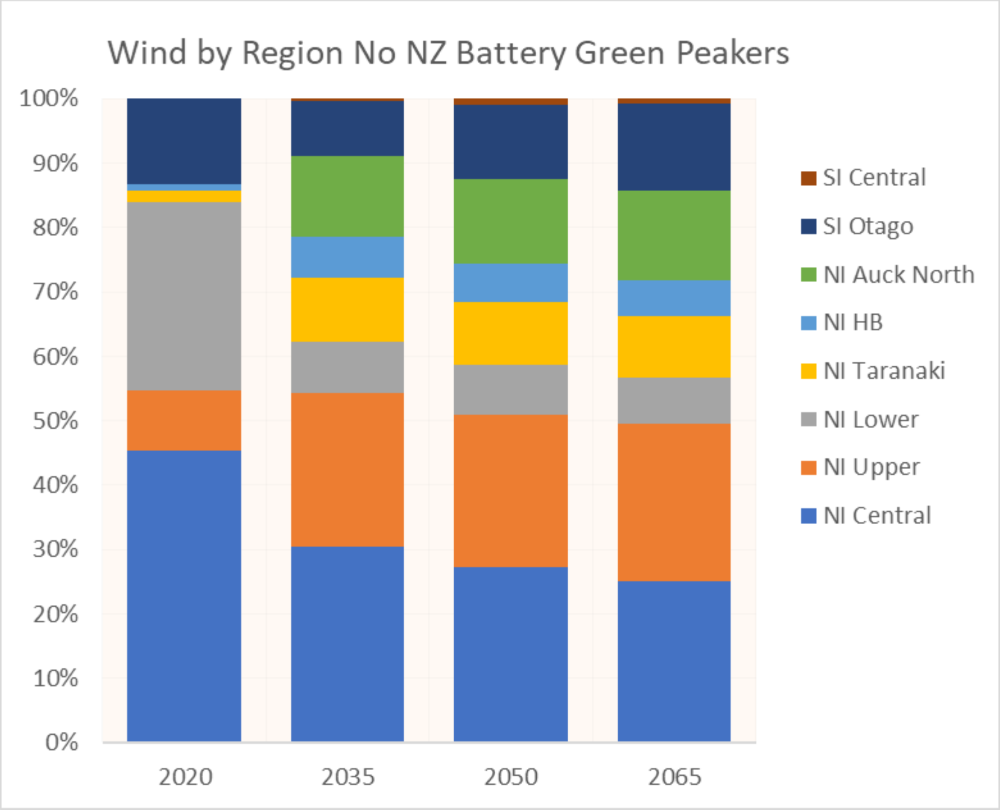
- Onslow shifts the level of spill down significantly, but does not change the range substantially.
- Onslow reduces mean green peaker use by 0.1 TWh and the worst year by 0.7 TWh.
- Onslow reduces the level of shortage and load curtailment down by around 7GWh on average but the worst year by around 400GWh.

The changing regional mix of wind supply - 100% renewable worlds with no NZ Battery

It is assumed that there is a significant increase in new wind in the upper North Island to take advantage of wind diversity and better locational prices. South Island development occurs from 2035 onwards. This has a diversity benefit but a locational price disadvantage.

On a percentage basis Central NI wind falls from the current 45% to around 30% of supply, other NI to 40% and 25% in the South Island.





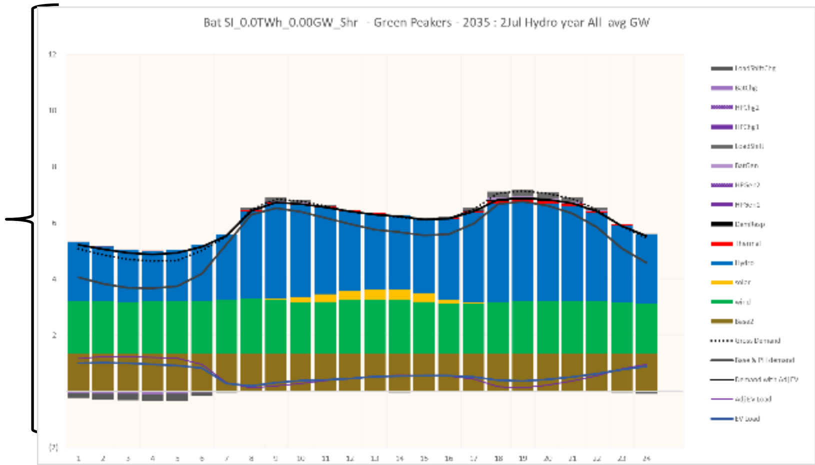
Averaged daily patterns of supply in 2035 and 2050 with green peakers and NZ Battery

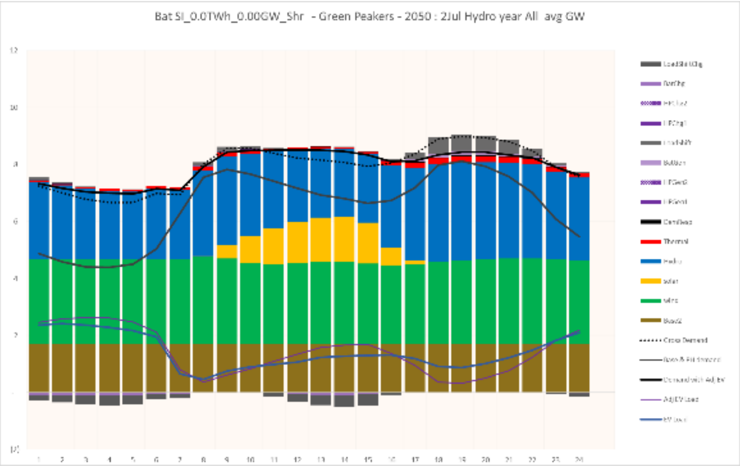
100% Renewable without NZ Battery in 2035

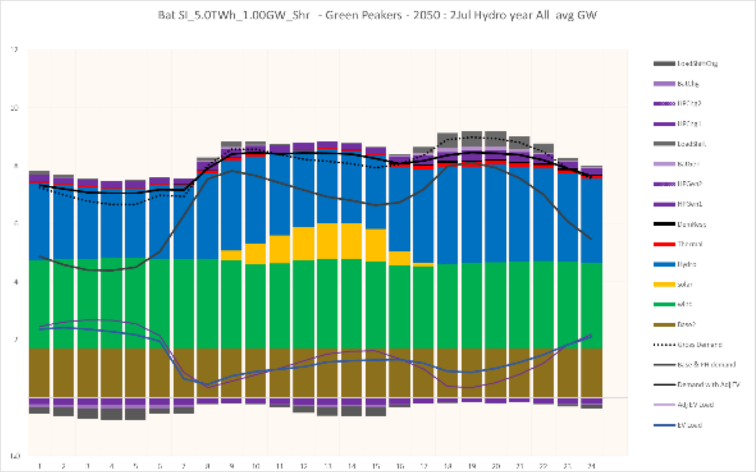
100% Renewable without NZ Battery in 2050

100% Renewable with Onslow in 2050

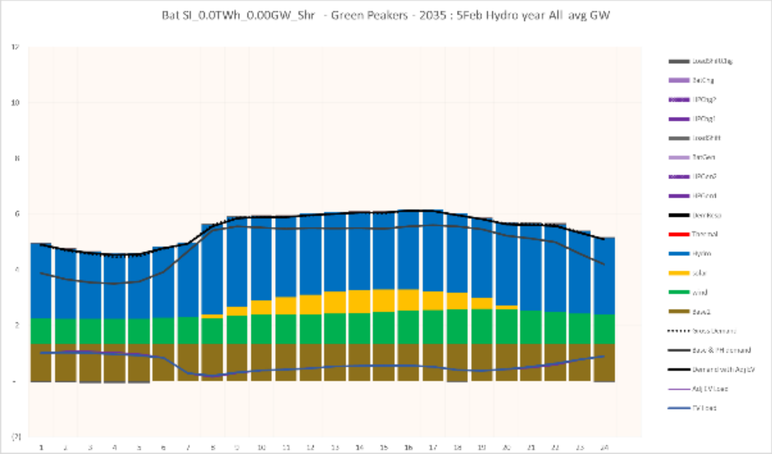
A typical winter week

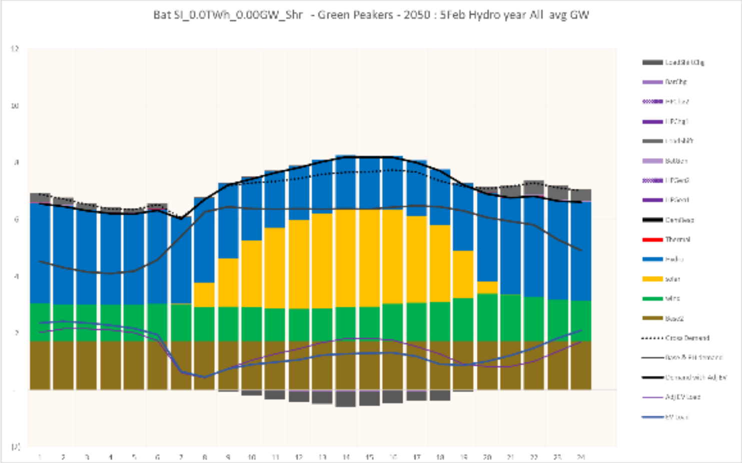


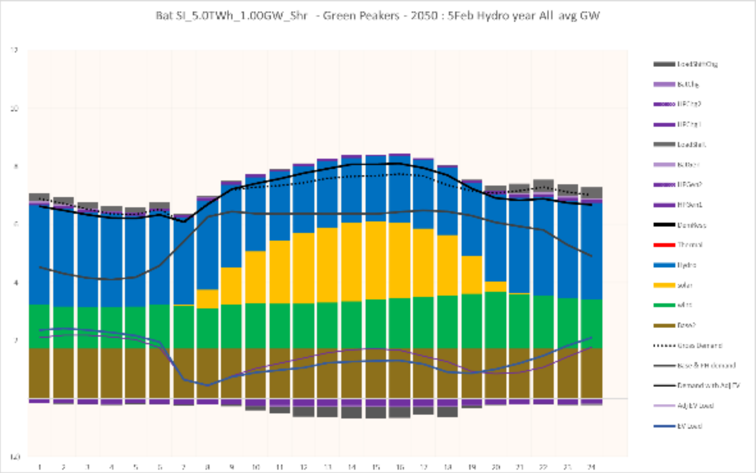




A typical Summer week







The charts show the contribution of each source of supply and flexibility in GW in each hour of a typical working day in winter and in summer. The results are averaged over all 87 weather years.

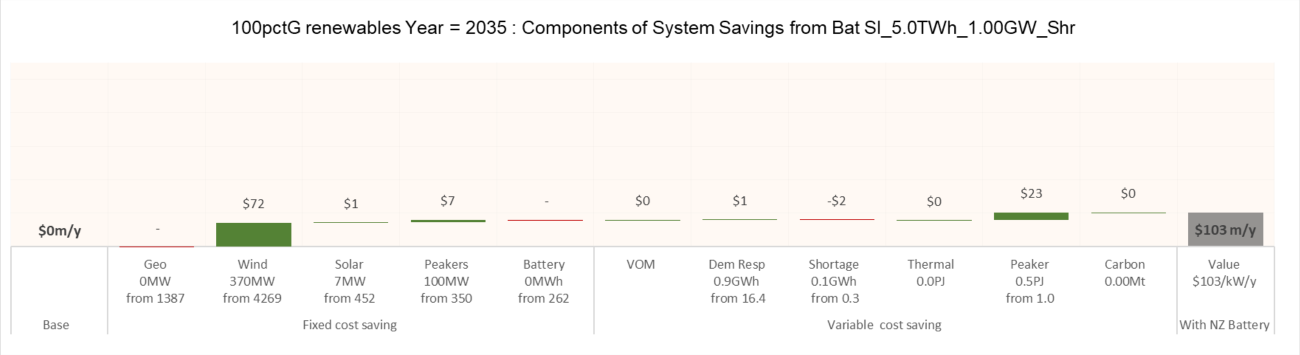
7. GROSS VALUE AND SENSITIVITIES FOR THE BASE ONSLOW OPTION

Charts show how the sources of benefit for Onslow 5TWh/1GW change over time

Green peakers available

- Analysis shows how sources and level of benefit change over time
- Where green peakers are available, NZ Battery mainly saves capex and fuel costs

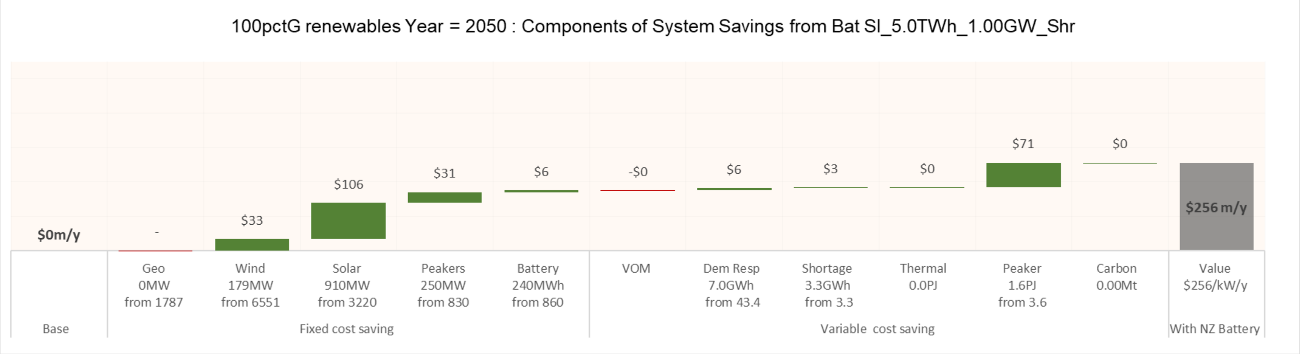
2035


100pctG renewables Year = 2035 : Components of System Savings from Bat SI_5.0TWh_1.00GW_Shr

Base case benefit

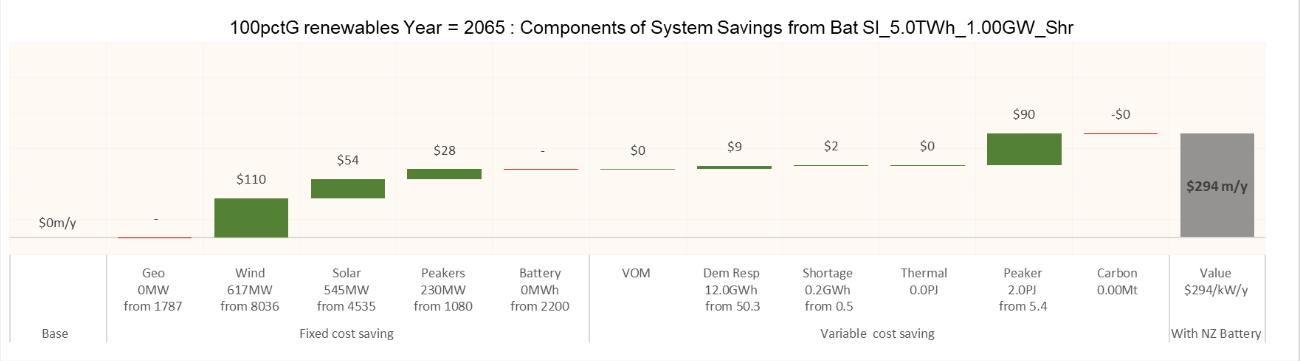
$103m/y

2050


100pctG renewables Year = 2050 : Components of System Savings from Bat SI_5.0TWh_1.00GW_Shr

$256m/y

2065


100pctG renewables Year = 2065 : Components of System Savings from Bat SI_5.0TWh_1.00GW_Shr

$294m/y

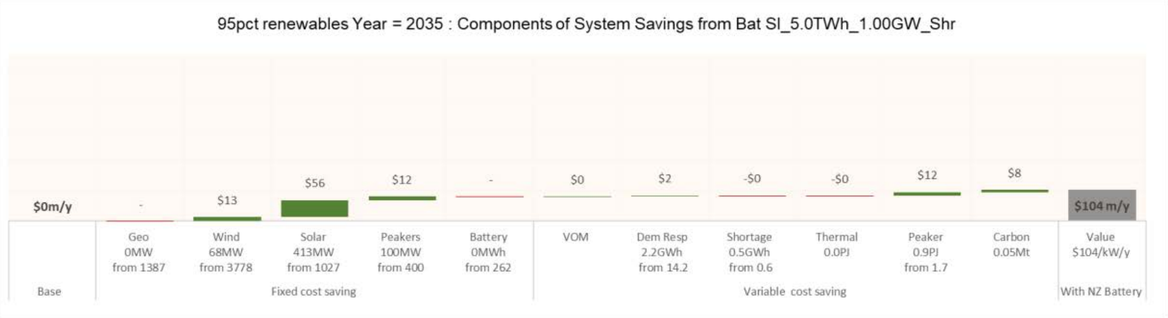
Note: The vertical scales on the charts are the same in each chart and the MW investment saving is

Incremental system benefit of Onslow is reduced relative to the Gas counterfactual

The chart shows the components of the gross incremental system value for a 5TWh/1GW Onslow in a world where gas peakers (paying carbon costs) are allowed.

Base case benefit

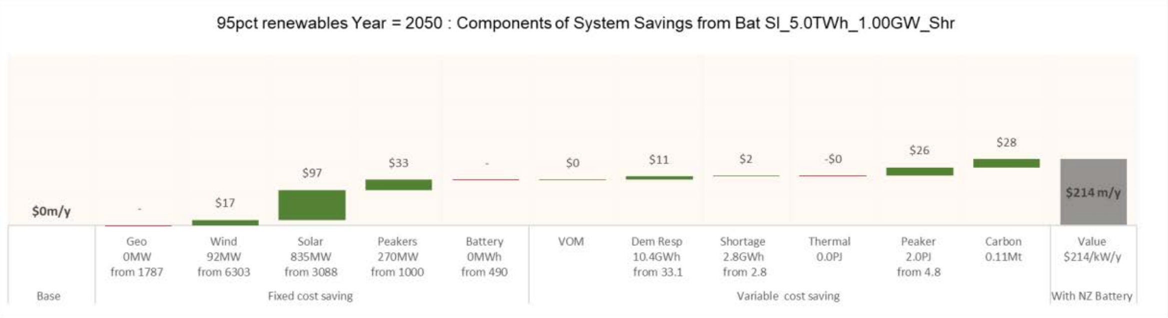
$103m/y


95pct renewables Year = 2035 : Components of System Savings from Bat SI_5.0TWh_1.00GW_Shr

Difference

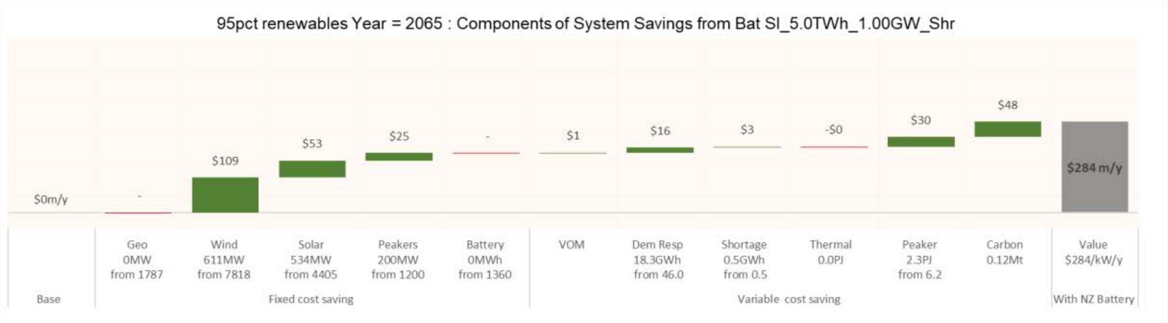
$1m/y

$256m/y


95pct renewables Year = 2050 : Components of System Savings from Bat SI_5.0TWh_1.00GW_Shr

$-42m/y
-16%

$294m/y


95pct renewables Year = 2065 : Components of System Savings from Bat SI_5.0TWh_1.00GW_Shr

$-13m/y
-4%

Commentary

- The Onslow benefit in 2035 is virtually the same in 2035
  - Capacity constraints are not as significant in 2035 as the % intermittent supply is only 30% and this can be met mostly from flexible hydro and batteries.
  - The difference is within modelling error.
- By 2050 the Onslow benefit is 16% lower in the gas counterfactual
  - The percent intermittent increases to 40% and the balance of risk shifts from dry years to dunkleflautes.
  - The SRMC cost of gas peakers including carbon is only 43% of the cost of green peakers, and the extra MW of peaking plant is reduced.
  - The reduction in Onslow benefit is roughly $20m/y for lower peaker capital cost and $20m/y for lower gas peaker running costs.
- By 2065 the Onslow benefit is 4% lower in the gas counterfactual
  - By this stage the difference in running cost of gas peakers including carbon has increased to 70% of the green peaker cost, and so the benefits of gas peakers over green peakers is now much lower.

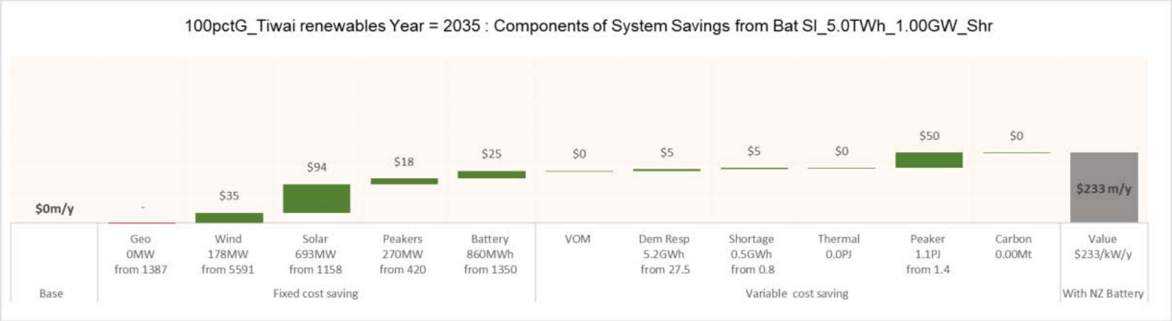
Incremental system benefit results with Tiwai stays counterfactual

The chart shows the components of the gross incremental system value for a 5TWh/1GW Onslow in a world where Tiwai stays with the existing 80MW load response triggered at very low lake levels.

Base case benefit

Difference

$103m/y

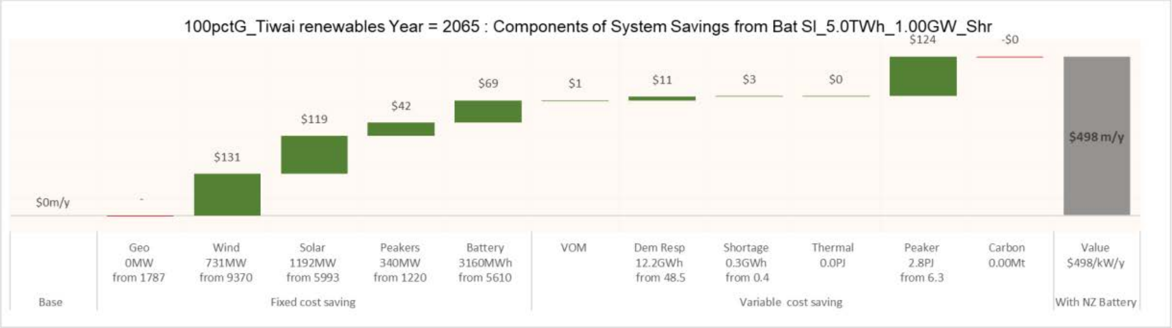


$130m/y
+ 130%

$256m/y

$135m/y
+52%

$294m/y



$204m/y
+70%

Commentary

- The value of Onslow with Tiwai is higher, partly because the demand and intermittency has increased the value of backup, and partly because there is a more balanced NI/SI system which increases the value of SI based reserves.
- The Onslow benefit in 2035 with Tiwai is 130% greater than the base case.
  - This is caused by the 5TWh higher demand increasing the pct intermittency 6% from 29% to 35%.
    - Extra backup beyond the existing hydro system and batteries is required for everything beyond 29% intermittent supply.
    - The extra Tiwai load effectively takes the situation from 2035 towards 2050 without Tiwai, and the benefit moves towards 2050 benefit without Tiwai ($256m)
- The Onslow benefit in 2050 is 62% higher than the base case in 2050
  - The higher demand increases the intermittency by 4% rather than 6%.
- The Onslow benefit in 2065 is 70% higher than the base case in 2065.
  - The value of capacity firming increases as the intermittency increases from 45% in the base case to almost 50% with Tiwai

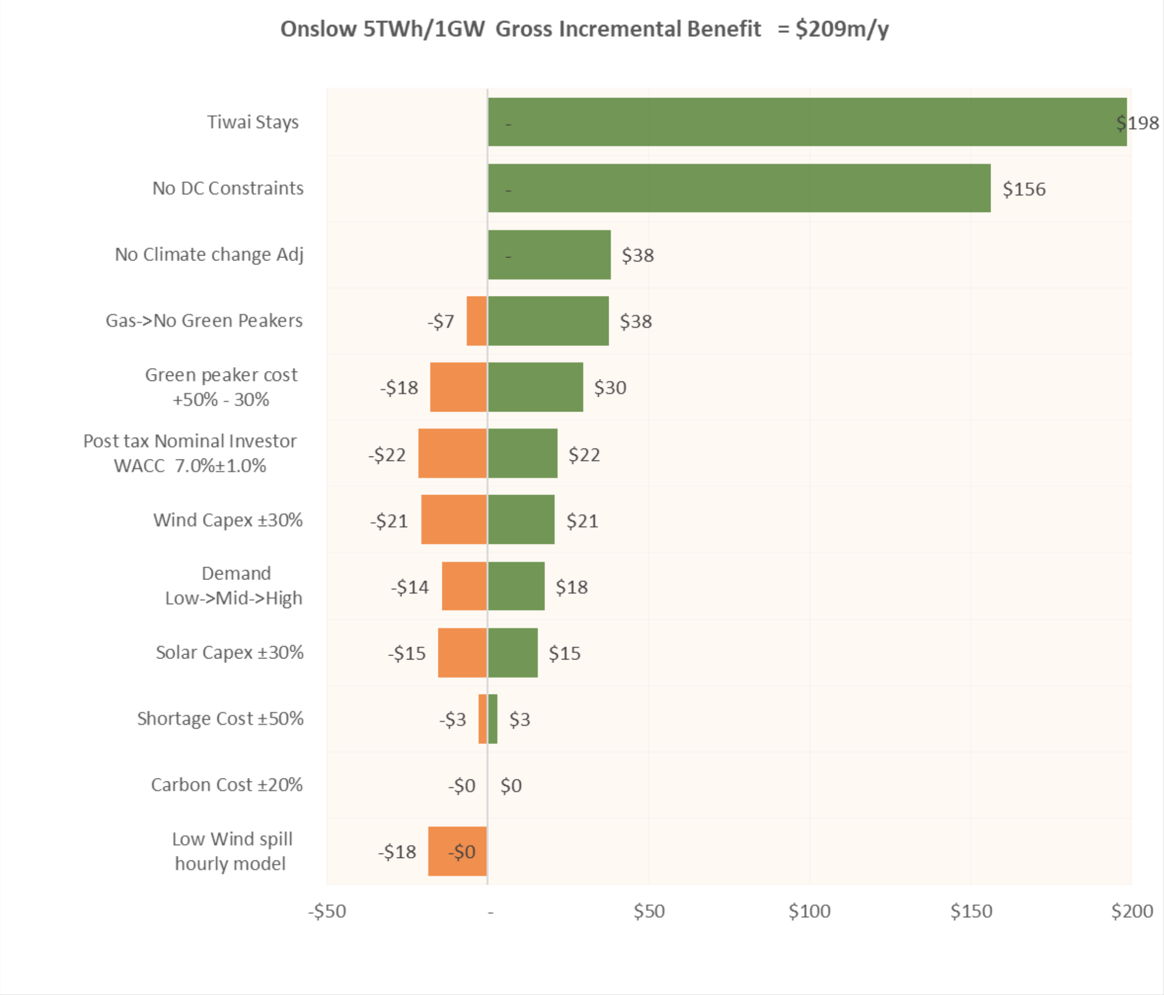
Tiwai exit assumption, HVDC constraints and climate change inflow assumptions have the greatest impact on Onslow gross system value

Onslow' s estimated gross system benefit is sensitive to variations in the assumptions used in the modelling

- If Tiwai is assumed to stay, then Onslow would have a $198m/y higher gross benefit:
  - But Tiwai staying would result in higher electricity prices/costs ..
- If the constraints imposed by the current HVDC link were to be substantially removed (or if Onslow was in the NI) the benefit would be $156/yr higher
  - But capital costs would be increased by the cost of a new HVDC ..
- If the climate change assumptions were not factored in, then the benefit would be $38m/y higher
- A 50% increase in green peaker running costs would increase benefit by $30m/y, and a 30% reduction would reduce benefit by $18m/y .
- If green peakers were not assumed in the counterfactual then the Onslow benefit would increase $38m/y, and if existing gas peakers were retained then benefit would reduce $7m/y
  - But retaining gas peakers would result in lower electricity prices/costs and not allowing green peakers would increase electricity prices/costs …
- Gross benefit increases by ±$21m/yr for each ±1% increase in the required post tax nominal WACC.
  - But increasing the WACC would increase Onslow annual capital cost ..
- Higher/Lower rates of growth in electricity demand for decarbonization will increase/decrease Onslow benefits by $14-18m/y
- Variations in the capital cost of wind and solar each have a $15m/y impact.
- Gross benefit estimates are also sensitive to demand response costs, and carbon charges
  - But these have less effect on overall gross value than the variables noted above
- Reducing the wind offers from $10 to$1/MWh, using flat Onslow offers and simulation based on 168hrs/week, reduced Onslow value by $18m/y

Notes: Gross benefit figures are in real terms and dollars of the day (i.e. not discounted to 2021 and not adjusted for inflation). Central estimate is a 60 year 6% real discounted average gross benefit for Onslow with 5 TWh of storage and 1 GW of capacity in the Green Peakers world starting from 2035.

The largest upsides in gross value relate to the assumption Tiwai exits by 2035 and the constraints from the HVDC. Most other sensitivities are of the order of ± $20m/y



Qualitative discussion on effect of modelling assumptions

Modelling Limitation	Impact and mitigation
The model only considers HVDC constraints and losses, but properly modelling the full AC network will probably reduce the benefit of South (and possibly North) Island options.	This is a limitation but is partly accounted for by ensuring that the cost of AC network upgrades to enable constraint free operation is included as a component of the capital cost for each generation option.
Within each week, the model assumes a cost minimising approach with limited storage resources being dispatched with foresight subject to energy and other heuristic constraints which approximate the impact of chronological issues such as plant ramping, detailed river chain scheduling and ancillary services. Batteries operate within each model day, and varying portions of hydro tributaries are assumed to be baseload.	The risk is that required levels of 5-12hr batteries or load control is underestimated. This is not considered to be a serious problem for the estimation of gross benefits from NZ Battery options since the investment in Li-ion batteries and green peakers caps the within-week price variability to reflect the cost of those options so that the incremental value of pumped hydro is not significantly impacted.
The model assumes an SRMC based dispatch order (where relevant) and heuristic offer curves - including for NZ Battery. The heuristics are based on achieving full use of the storage without running empty too often while avoiding spill if possible. Onslow's offers assume a buy/sell spread consistent with the round-trip efficiency.	A wide range different offer curve shapes (flat->seasonal) and levels (higher->lower) were tested. While these changed the allocation of water use between reservoirs, the impact on estimated Onslow value was of the order of $10m/y. The impact of offering Onslow with a buy/sell spread much greater than the round-trip efficiency was significantly higher.
The model assumes that investments of each generic technology will occur when commercially economic to do so. I believe this to be a reasonable assumption on average, but in practice, investments will be lumpy and not perfectly timed.	There is significant uncertainty concerning the costs and details of new investment options out 15-30 years. Detailed optimisation of new investment issue beyond this approach does not seem to be warranted. I have tested the impact of changes to the mix of wind and solar on Onslow value and this was around $3-7m out of ≅$250m/yr. Also, I compared this approach with one based on scaling up/down a mix of new investments to find a minimum national system cost. This was within ±$10m.
It was assumed that historical weather conditions provide a good basis of future weather conditions.	The historical inflow have now been reshaped to reflect the likely impact of climate change to result in more rain/less snow in winter. This had reduced Onslow value by around $30-40m/y.
The model assumes that wind generators offer at $5-10/MWh to reflect the potential variable costs associated with risk sharing arrangements with suppliers (e.g. O&M providers offing variable maintenance contracts, and royalty payments to landowners). These are not treated as national costs in the gross benefit calculations as all wind O&M is assumed to be a fixed cost.	This results in the model having higher levels of spill overall and higher shares of wind spill compared to hydro. A strict cost minimising model would have lower levels of spill overall and much lower levels of wind spill. I tested the impact of reducing the wind offer prices and this resulted in a 15-20% reduction in spill overall but only had a $5-10m impact on Onslow value.
The model uses 36 blocks each week: hourly for a typical working day and 2 hourly for a typical weekend/holiday. This enables simulations to be done quickly, but can lead to issues for chronological constraints (e.g. battery and river chain operation within each day) and weather volatility. Batteries are assumed to be used and refilled within each modelled day.	The wind/solar contribution in each 36 block is 25:75 mix of the average for each time zone in the week and a randomly sampled work or non-work day. This ensures a realistic level of within week variability. I have tested the impact of going to full hourly modelling. This resulted in slightly greater investment in batteries and less solar/more wind, but the impact on Onslow value was of the order of $10-20m out of ≅$250m/yr.

8. GROSS VALUE ESTIMATES FOR ONSLOW SUB OPTIONS

The estimated gross benefit of NZ battery (5TWh/1GW) increases as NZ progresses to full decarbonisation

The value in 2035 is relatively low in the order of $100m per annum. This progressively increases to around $295m/yr by 2050 as the penetration of wind/solar increases and the balance of system risk moves from dry year energy towards low wind/solar weeks.

The value is higher without climate change, as this reduces the need for seasonal storage

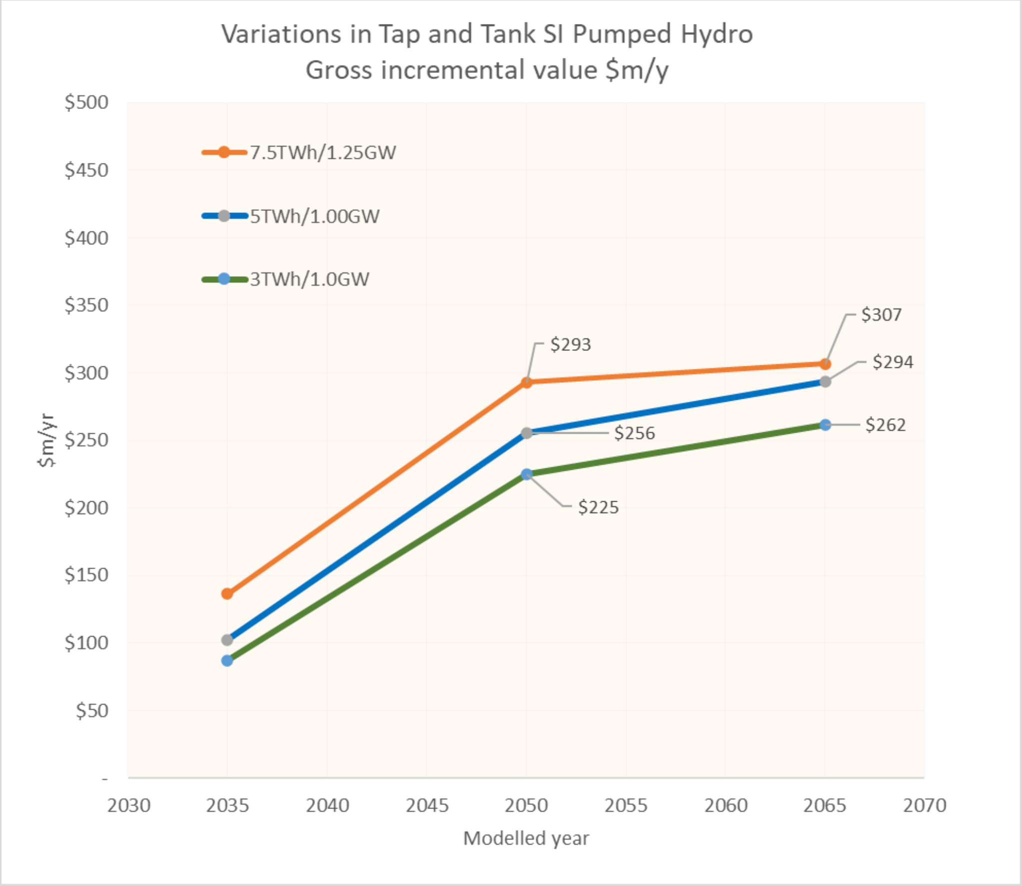
The value is lower if existing contingent hydro storage can be used without an additional penalty

Comments

- The results show a significant increase over time.
  - This reflects the increasing percentage of intermittent supply, and the resulting increased capacity value.
- There is a favourable impact of climate change on existing hydro inflows being shifted from spring to winter.
  - This reduces the value of pumped hydro by around $20-$60m/yr.
- There is also a favourable impact if less restricted use of existing hydro contingent storage zones was allowed.
  - This is not assumed in the base case but would reduce the value of pumped storage by $10-15m/yr.

Impact of tank variations for SI pumped hydro on annual value

The chart shows the impact on gross system value of a change in storage from 7TWh to 3TWh



Commentary

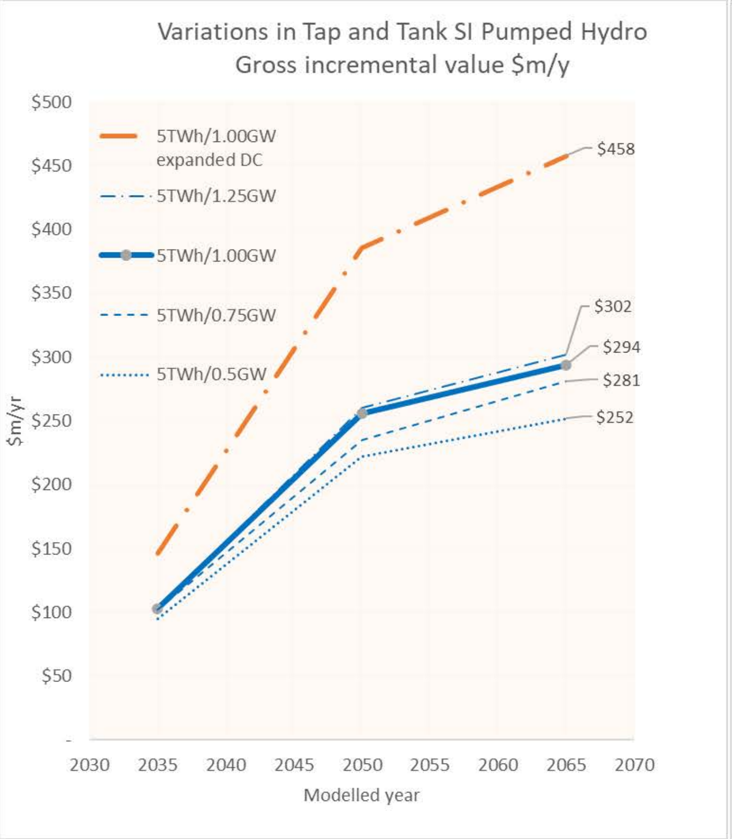
- There is a small $13-$38m/yr (4-33%) increase in gross value from increasing storage 50% from 5TWh to 7.5TWh and increasing capacity 25% from 1GW to 1.25 GW. The increased benefit falls over time.
  - The net benefit will depend on the incremental cost of raising the upper dam and increasing the capacity of the pumping/generation station.
- There is a modest reduction in the gross value of around $15-30m/yr from a 40% reduction in the size of the storage from 5TWh to 3TWh.
  - The net benefit will depend on the incremental cost savings from a lower dam.
- The deviations from the base 5TWh/1.00GW configuration are shown in the table below.

			Onslow Green Peaker Counterfactual							
	Unit	Base	Small Tank	Large Tank	Large Tap	Small Tap	Vsmall Tap	Large DC	Small Tank/Tap	Vsmall Tank/Tap
		5TWh 1GW	3TWh 1GW	7.5GW 1.25GW	5TWh 1.25GW	5TWh 0.75GW	5TWh 0.5GW	1GW Large DC	3TWh 0.75GW	3TWh 0.50GW
Tank	TWh	5.00	3.00	7.50	5.00	5.00	5.00	5.00	3.00	3.00
Tap	GW	1.00	1.00	1.25	1.25	0.75	0.50	1.00	0.75	0.50
2035	$m/y	$102	$87	$136	$103	$102	$95	$146	$89	$84
2050	$m/y	$256	$225	$293	$260	$235	$222	$385	$211	$200
2065	$m/y	$294	$262	$307	$302	$281	$252	$458	$250	$218
Tank	ΔTWh		-2.0	2.5	0.0	0.0	0.0	0.0	0.0	0.0
Tap	ΔGW		0.00	0.25	0.25	-0.25	-0.50	0.00	-0.25	-0.50
2035	Δ$m/y		-$16	$34	$0	-$1	-$8	$44	$2	-$3
2050	Δ$m/y		-$31	$38	$4	-$21	-$33	$130	-$13	-$25
2065	Δ$m/y		-$32	$13	$8	-$13	-$42	$164	-$11	-$43
Tank	Δ%		(40%)	50%	-	-	-	-	-	-
Tap	Δ%		-	25%	25%	(25%)	(50%)	-	(25%)	(50%)
2035	Δ%		(15%)	33%	0%	(1%)	(7%)	43%	3%	(4%)
2050	Δ%		(12%)	15%	2%	(8%)	(13%)	51%	(6%)	(11%)
2065	Δ%		(11%)	4%	3%	(4%)	(14%)	56%	(4%)	(17%)

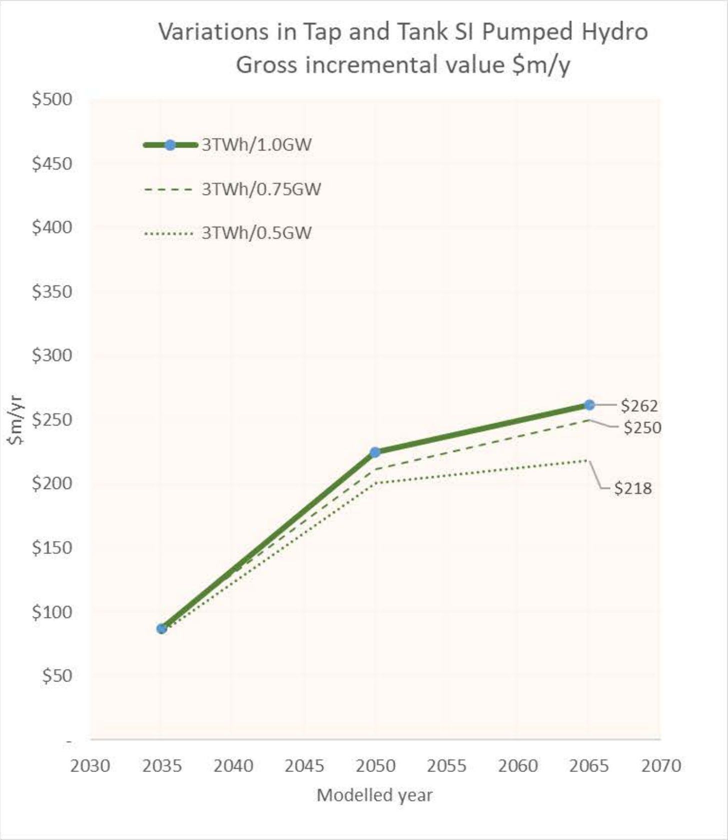
Impact of tap variations for SI pumped hydro on annual value

The chart shows the impact on gross system value of 0.25GW increments and decrements for 5TWh and 3TWh reservoirs. The impact is asymmetric : increases in capacity have a much lower impact than decreases. The impact of location in the SI is illustrated by the large increase in value of 1GW from an expanded HVDC link.

Variations in Tap for 5TWh scheme



Variations in Tap for 3TWh scheme



There is little additional value from increases in the capacity beyond 1.0GW. Cost reductions from a 0.5GW scheme may well exceed the loss on system benefit.

- There appears to be limited value of <$8m/y (3%) from increasing the capacity of a 5 TWh scheme 25% to 1.25GW.
  - This is because the HVDC is already constrained in the 1.0GW case.
- Relieving the HVDC limits (or locating in NI) would make a much larger impact of $40 to $160m/y (43-60%).
  - HVDC limits significantly affect the value that can be achieved from a 1GW scheme located in the SI.
- Reducing the capacity 50% to 0.5GW has a more significant loss of $8-42m/y (7-14%). The loss increases beyond 2050.
  - This would be justified if the incremental cost savings was greater than $8/42m/y.
- Reducing the capacity of a 3TWh scheme 25% from 1.0GW to 0.75GW has a small <6% impact on value, whereas a reduction to 0.5GW has a greater $3-43m/y (4-17%) impact, particularly beyond 2040.
  - A 0.75 GW option is still occasionally limited by HVDC capacity, whereas a 0.5GW option is not significantly impacted by HVDC constraints.
  - A reduction in the capacity to 0.5GW might be justified if the incremental cost saving from a smaller scheme was greater than $3-43m/y.

9. ESTIMATING REVENUE IMPACTS

Exploring the impact of NZ Battery on prices and costs

To date we have focused on cost based measures, but there is an interest in price based measures as well. These provide some useful information - but there are issues.

- Although the model is focussed on the cost impacts of NZ battery it is possible to also provide some estimates of impacts on prices:
  - For the main modelling results, we have focused on total system cost as the primary measure of benefit for NZ Battery options.
    - This measure includes the benefits/costs of new investments saved or incurred plus the benefits/costs from changes in variable operating costs, carbon costs, fuel costs and variable shortage/demand response costs.
    - It is found from experience that focussing on price outcomes is problematic in that these can be volatile and highly dependent on relatively subjective assumptions, such as the assumed hydro and pumped hydro offer strategies as implemented in the model. The cost
  - If we assume that new entrant wind/solar are just revenue adequate, then we can derive a cost-based measure of prices = generic new entry costs for wind and solar adjusted for a weighted average wind and solar capture rates estimated from the model.
    - This measure is reasonably consistent and robust and not too sensitive to the exact average balance of supply and demand in the factual and counterfactual.
  - The table to the right shows several of the measures derived from the modelling.
    - There estimates need to treated with caution:
      - Simulated prices are “marginal” and are particularly sensitive to the exact assumed level, mix and location of new entry.
      - They can also be significantly influenced by the assumed water values or offering behaviour of generators. While these effects are mitigated by the modelling approach to new entry, they can still be significant and result in “modelling noise”. The revenue impact of this noise can swamp the much more reliable estimates of system cost estimates.
    - If market revenues and system incremental values are approximately equal to the incremental cost of Onslow then, the estimated price impacts might be interpreted as a being reflective of genuine electricity market efficiency gain.
      - However, if the incremental cost is significantly greater than the incremental benefits then the price effect simply reflects the implicit subsidy in the cost of backup being provided by Onslow. This implicit subsidy is likely to result in additional dead-weight losses in dynamic efficiency.

Examples of price and cost based measures from simulations

		Without NZ Battery			Without NZ Battery					
		Gas Peakers			Green Peakers			Green Peakers Tiwai Stays		
		2035	2050	2065	2035	2050	2065	2035	2050	2065
Generic LCOE										
Wind	$/MWh	$55	$53	$51	$55	$53	$51	$55	$53	$51
Solar	$/MWh	$71	$61	$52	$71	$61	$52	$71	$61	$52
Avg Capture rates										
Wind	%	77%	64%	57%	70%	59%	54%	61%	57%	55%
Solar	%	84%	71%	61%	86%	68%	60%	81%	64%	55%
NI Flex Hydro	%	130%	148%	163%	136%	159%	171%	140%	158%	165%
SI Flex Hydro	%	106%	115%	127%	111%	123%	131%	123%	134%	141%
Required baseload price										
Wind	$/MWh	$71	$82	$89	$79	$89	$94	$91	$93	$93
Solar	$/MWh	$85	$85	$85	$83	$89	$87	$88	$95	$94
Weighted avg required price		**$73**	**$83**	**$89**	**$79**	**$89**	**$93**	**$91**	**$93**	**$93**
Simulated HAY TWAP	$/MWh	*$73*	*$81*	*$86*	*$79*	*$89*	*$92*	*$92*	*$95*	*$99*
Simulated BEN TWAP	$/MWh	*$67*	*$75*	*$79*	*$71*	*$81*	*$83*	*$87*	*$89*	*$91*
Simulated NZ TWAP	*$/MWh*	**$72**	**$79**	**$84**	**$77**	**$87**	**$90**	**$91**	**$94**	**$97**

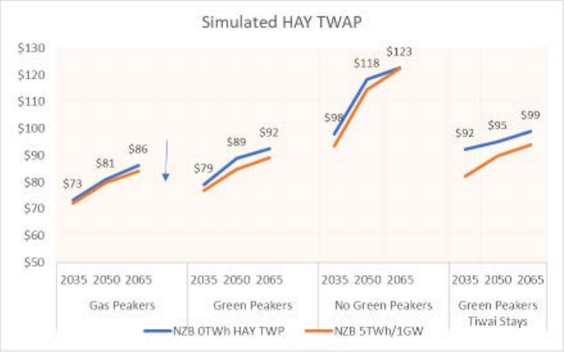
		With NZ Battery 5TWh/1GW			With NZ Battery 5TWh/1GW					
		Gas Peakers			Green Peakers			Green Peakers Tiwai Stays		
		2035	2050	2065	2035	2050	2065	2035	2050	2065
Avg Capture rates(GWAP/TWAP)										
Wind	%	80%	71%	64%	73%	63%	58%	72%	62%	60%
Solar	%	85%	77%	65%	82%	72%	62%	80%	69%	60%
NI Flex Hydro	%	129%	139%	153%	139%	152%	166%	133%	155%	161%
SI Flex Hydro	%	98%	103%	108%	100%	108%	113%	103%	114%	119%
Required baseload price										
Wind	$/MWh	$69	$75	$79	$75	$84	$87	$77	$85	$84
Solar	$/MWh	$83	$79	$80	$87	$84	$85	$89	$88	$87
Required price for mix		**$71**	**$75**	**$79**	**$77**	**$84**	**$87**	**$79**	**$86**	**$84**
Simulated HAY $/MWh	$/MWh	*$72*	*$80*	*$84*	*$77*	*$85*	*$89*	*$82*	*$90*	*$94*
Simulated BEN $/MWh	$/MWh	*$62*	*$68*	*$68*	*$63*	*$68*	*$67*	*$72*	*$74*	*$74*
Simulated NZ Mix $/MWh	*$/MWh*	**$70**	**$77**	**$80**	**$74**	**$81**	**$84**	**$80**	**$86**	**$89**
NZ Battery value $m/y										
Incremental system benefit	$m/yr	$104	$214	$284	$102	$256	$294	$233	$391	$498
Simulated market rev	$m/yr	$54	$132	$183	$81	$177	$232	$116	$236	$299
HAY $300 Cap	% TWAP	11%	16%	22%	20%	30%	33%	30%	30%	33%
-- with NZ Battery	% TWAP	12%	11%	16%	21%	25%	31%	22%	29%	29%

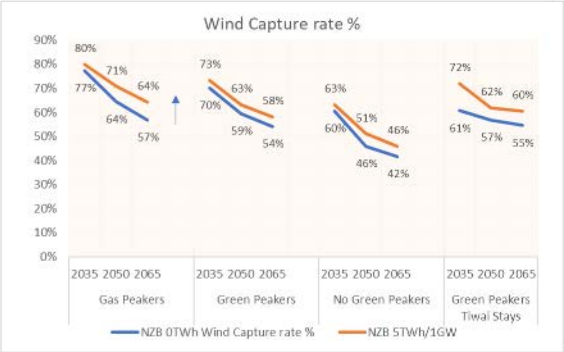
Impact of NZ Battery on measures of system cost and simulated market prices

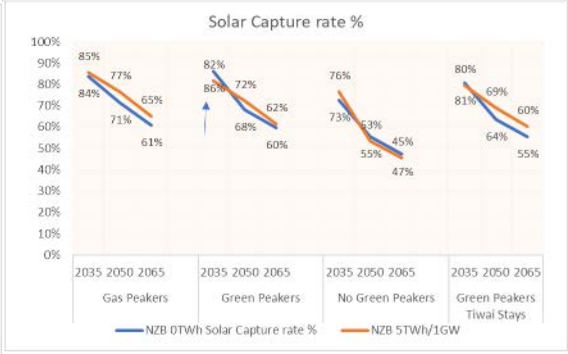
Measures of system incremental/marginal cost and renewable capture rates

Simulated prices are lower with NZ Battery

Baseload new entry costs are slightly lower with NZ Battery because capture rates are higher.



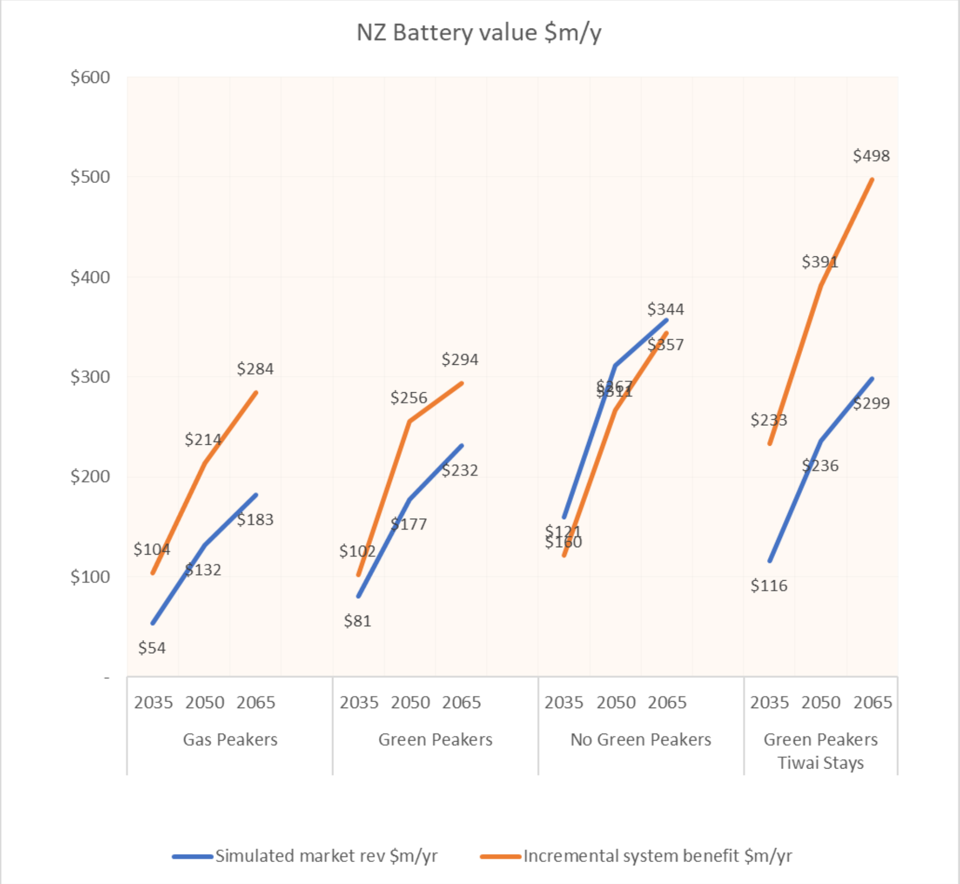




Wind capture rates are slightly higher with NZ Battery

Solar capture rates are slightly higher with NZ Battery with green peakers.

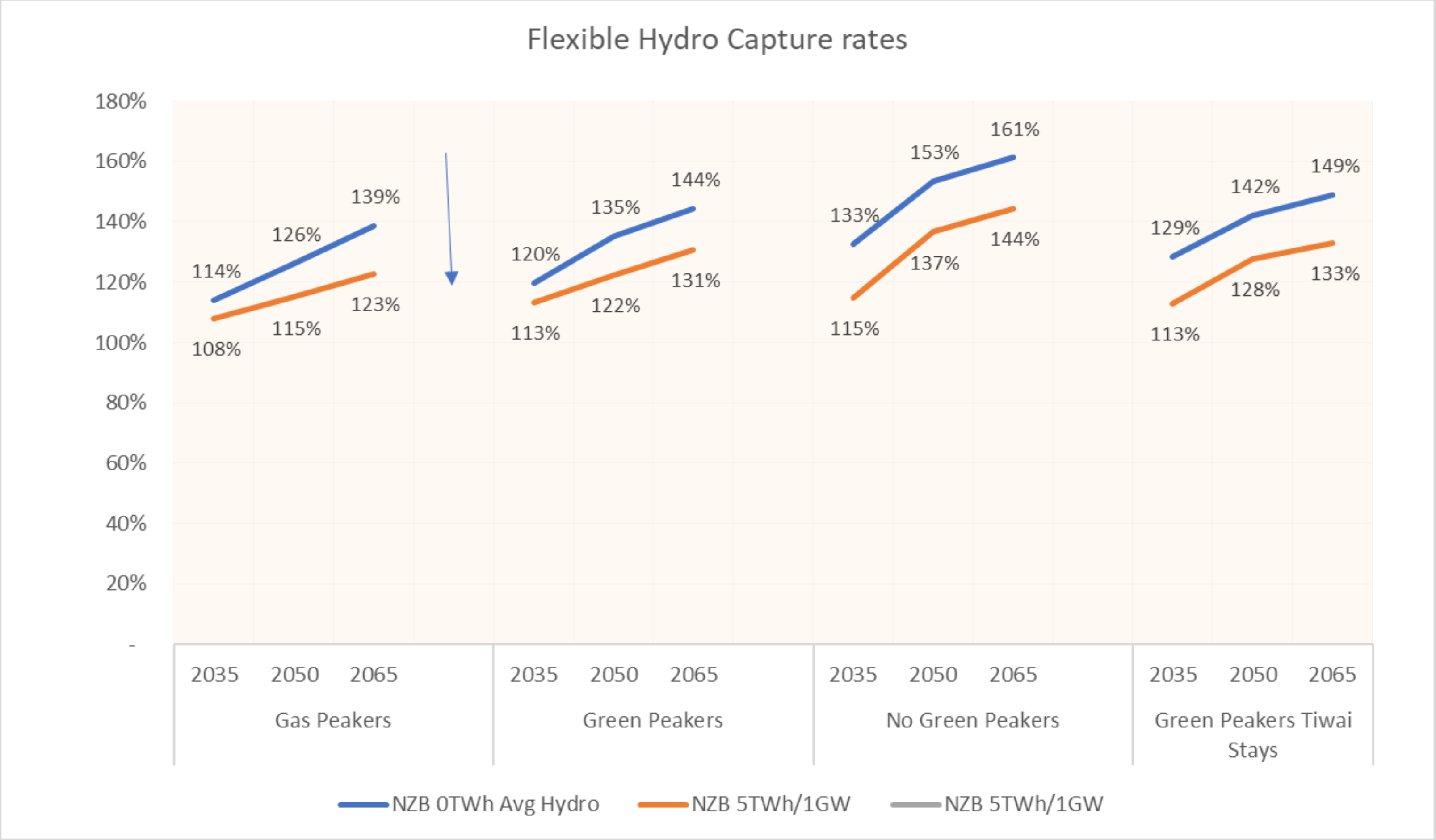
Impact on simulated NZ Battery net market value - this is simulated value of spot sales minus costs of pumping



Simulated Pumped hydro revenue is lower than the estimated incremental system benefits where green peakers are available. This is to be expected as the marginal value typically falls as the market for a new technology is progressively exploited. The first MW for a large scale long term seasonal storage is worth more than the last MW.

Impact on other hydro and wind generators

Existing flexible hydro generators will get significant gains in GWAP/TWAP as the system is decarbonised over time. But these revenue gains will be reduced by around 10 to 15% if a 5TWh/1.0GW pumped hydro is built.

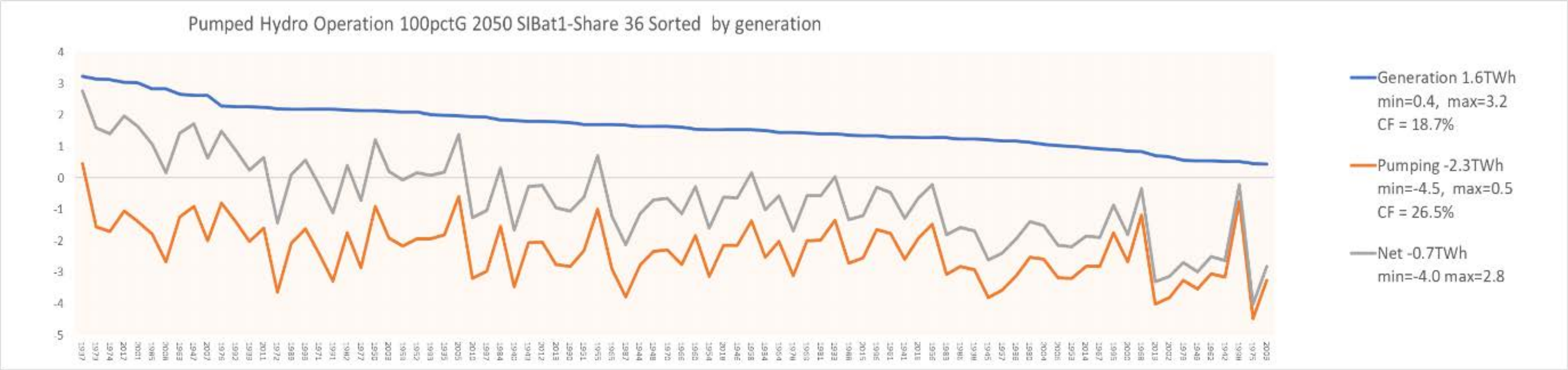


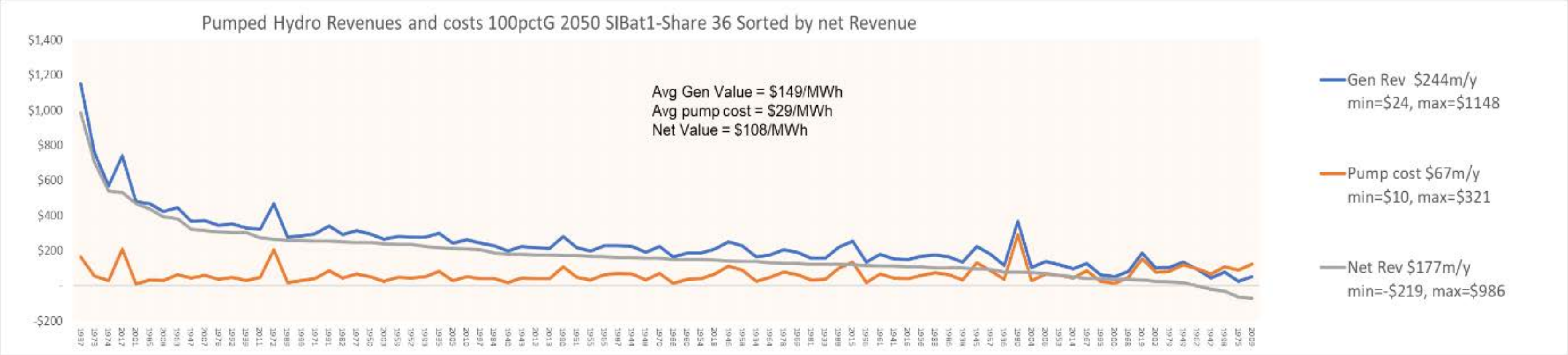
Comments

- These typical hydro GWAP/TWAP factors assume highly flexible operation and medium to mid term storage.
- The impact will vary significantly depending on the particular hydro scheme and its relative storage size, flexibility, pct tributary and inflow correlation.
- Never the less they can be used to derive the approximate impact of a NZ Battery option on other existing hydro generators.
- The generic wind capture rates (GWAP/TWAP) can also be used to assess the approximate impact on existing wind generation.

NZ Battery operation and market revenue - green peakers available

Pumped hydro operation and simulated market revenues in 2050


Pumped Hydro Operation 100pctG 2050 SIBat1-Share 36 Sorted by generation


Pumped Hydro Revenues and costs 100pctG 2050 SIBat1-Share 36 Sorted by net Revenue

Comments

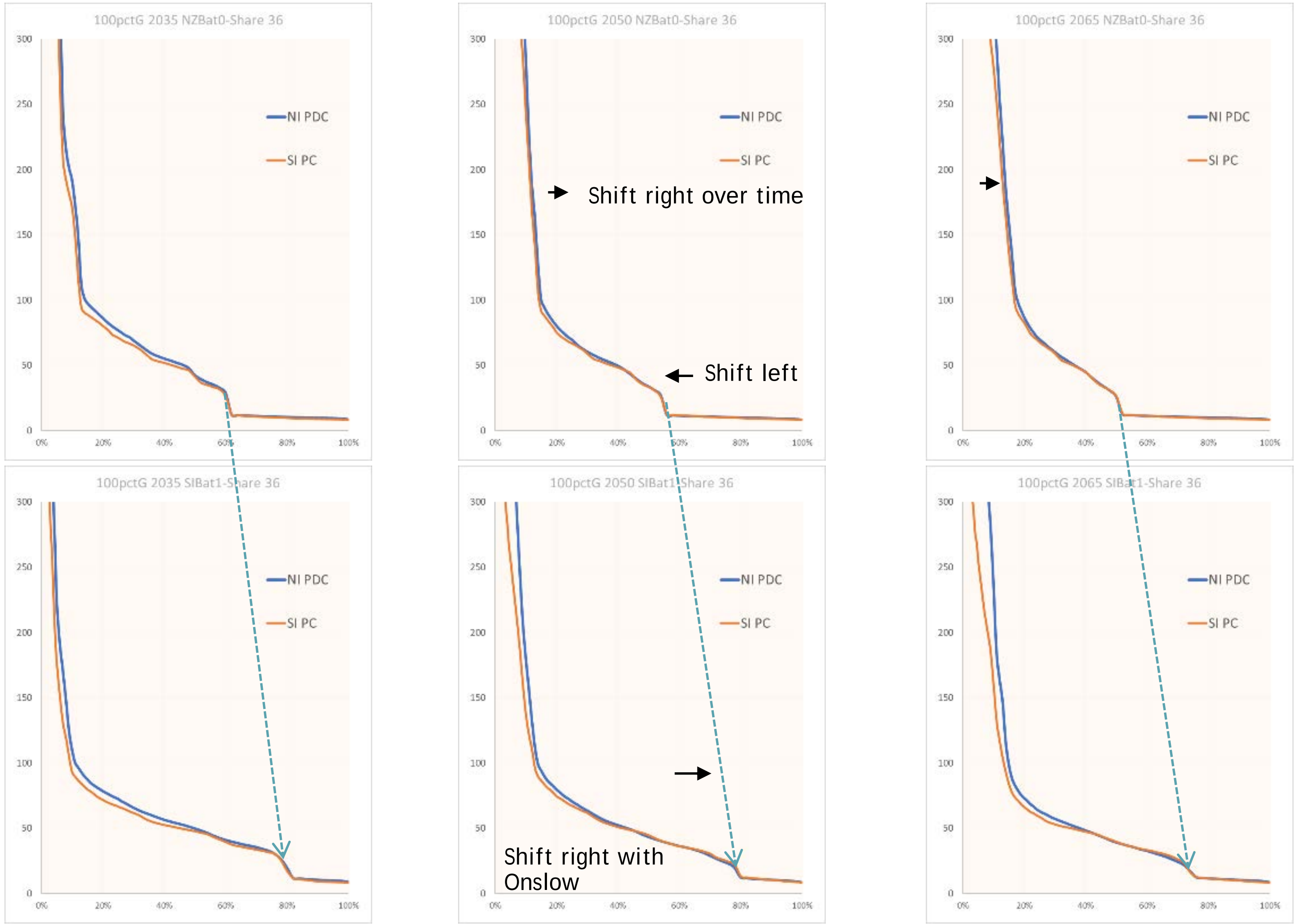
- The average annual generation from Onslow is 1.6TWh/y, but can vary from 0.4 to 3.0TWh.
  - This implies a generation capacity factor of 18.7%
    - and a pumping capacity factor of 26.5%
  - The average net revenue is $177m, but this can vary from $-90m up to $1000m.
    - The simulated average generation value is $149/MWh and pumping cost is $29/MWh.

Impact of Onslow on weekly price duration curves (PDC)

Case	In 2035	In 2050	In 2065

- Green peaker counterfactual
  - As the % intermittent supply increases the PDC moves to the right and the duration of very low prices increases.
  - This implies an increase in price volatility as the frequency of both high (>100/MWh) and low (<$25/MWh) prices increases.
  - The risks of very high price (>300/MWh) prices increases only slightly as this is capped by building new green peakers as they are required and economic.

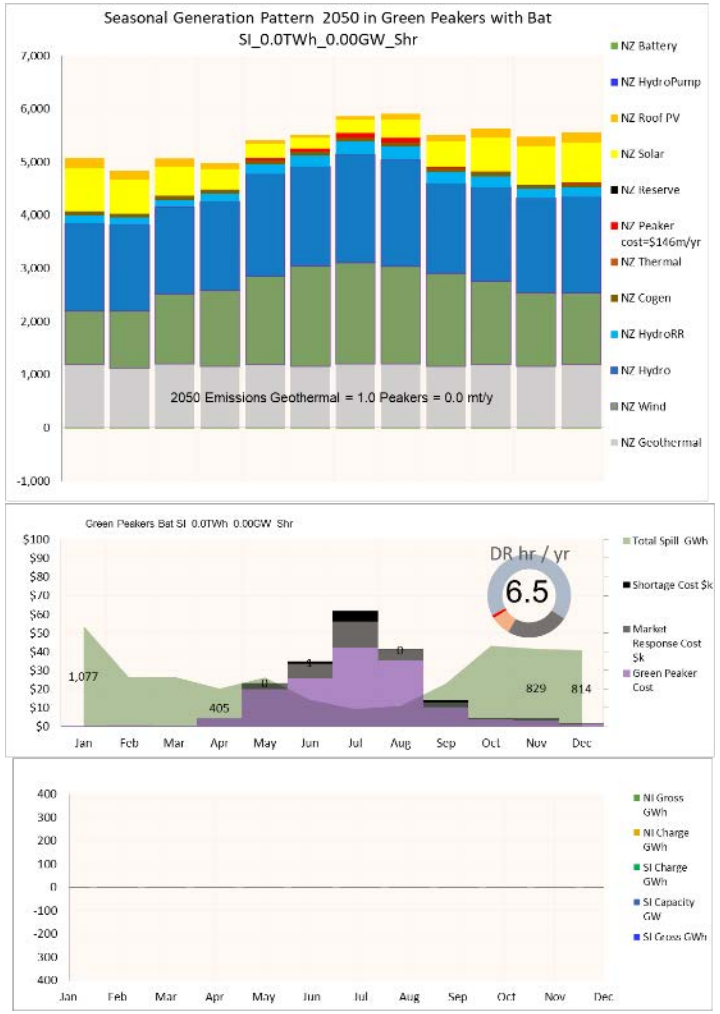
- Onslow 5TWh/1.0GW scheme
- The impact of Onslow is to significantly reduce the duration of very low prices in both islands, as it can absorb spill.
- It has a bigger impact on the frequency of high prices in the South compared to the north, as HVDC constraints are often binding during periods of capacity shortfall in the North .
- Weekly price volatility is reduced but still remains significant.



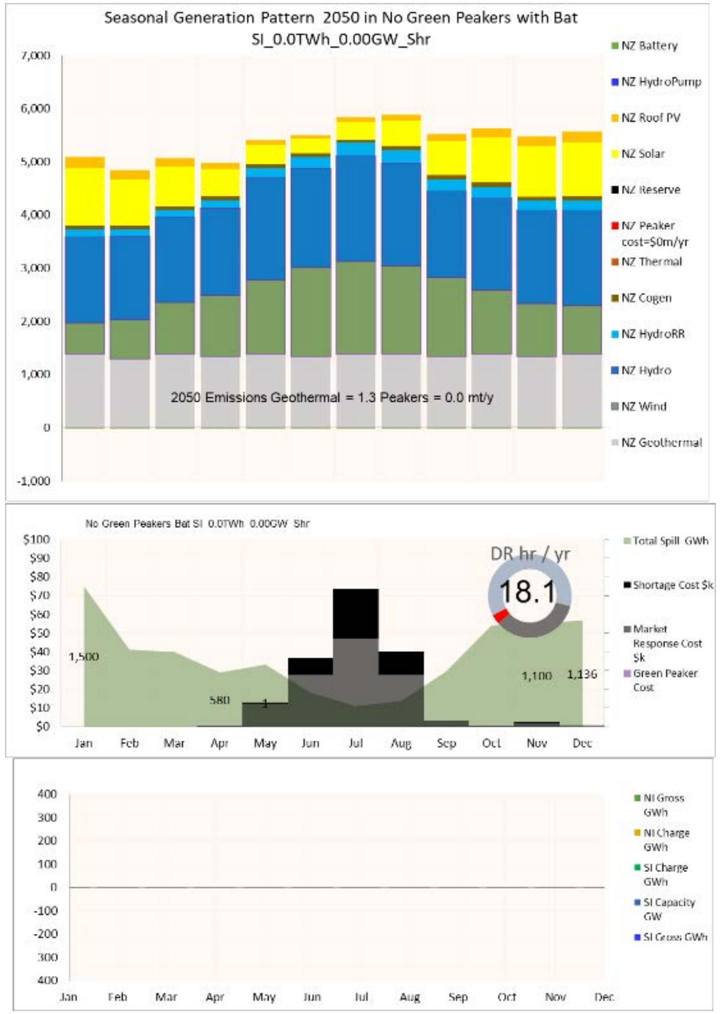
10. SYSTEM OPERATION CHANGES

Seasonal patterns of operation in 2050 without NZ Battery

100% renewable with green peakers



100% renewable without green peakers



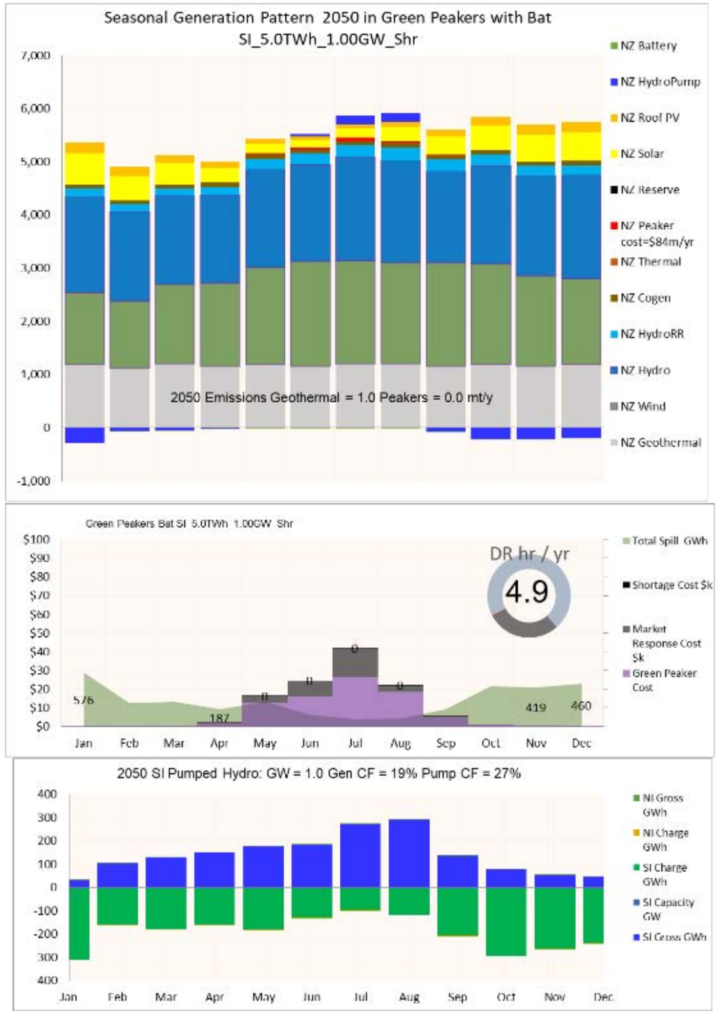
Comments

- The chart shows the seasonal operation in each world in 2050 without a pumped hydro.
  - Note that the spill is greatest in the spring summer when demand is low, solar is greatest, and lakes are getting filled ready the coming winter.
  - In the winter “spill” is lowest as demand is higher, solar is lower, and lakes are being drawn down.
  - In the 100% renewable world there is some shortage, mostly relating to periods of low wind, low hydro and high winter demand.
  - Where available green peakers operate mainly in the winter months to meet peak demands in low wind periods and also to help maintain hydro storages as lakes run down.
  - The shortages in 2050 mainly relate to low wind weeks in the winter.

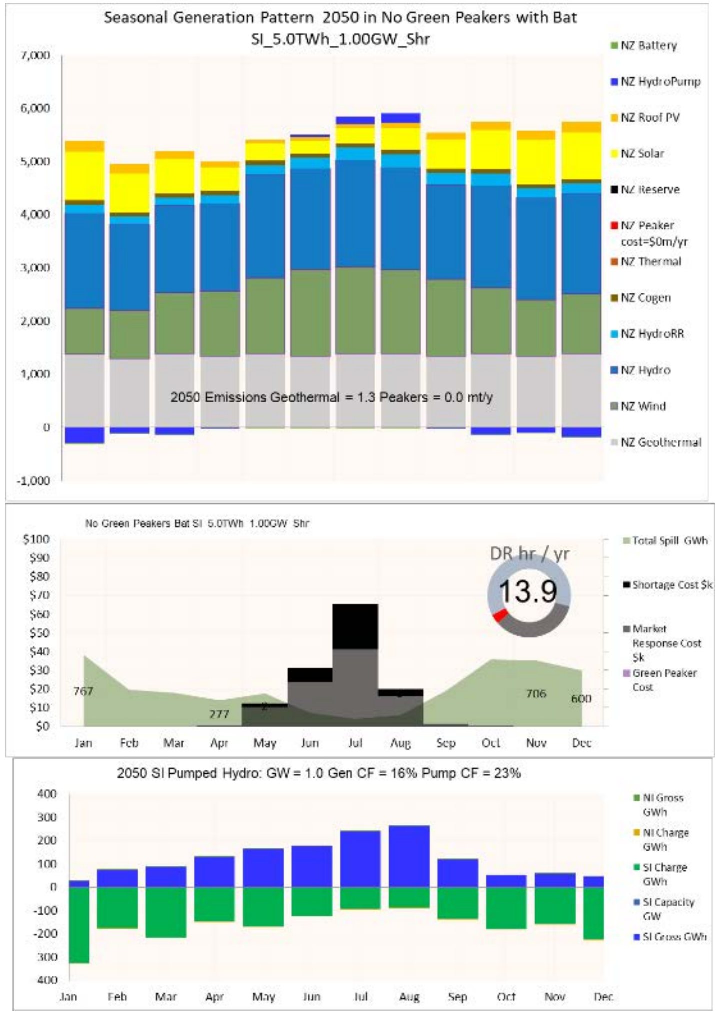
Notes: Shortage cost in the middle chart includes conservation campaigns, rolling cuts and shortage.

Seasonal patterns of operation with Onslow pumped hydro (5TWh/1GW)

100% renewable with green peakers



100% renewable no green peakers



Comments

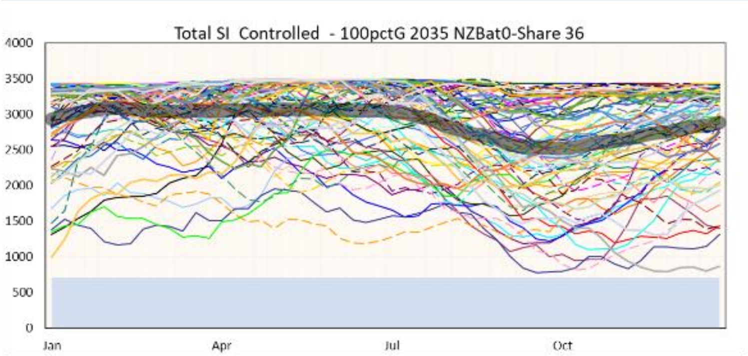
- A 5TWh/1.0GW SI pumped hydro enables part of the winter peak demand to be met from low cost 'spill' energy which is stored from the summer.
- Where green peakers are available, peak fuel use can be significantly reduced, and there is minimal shortage.
- In the 100% renewable world winter shortages are substantially reduced but not eliminated.
- In both cases there are savings from a reduced level of investment in wind/solar/geothermal.
- The pumped storage plant operates in generation mode for most of the winter, and in pumping mode from Nov to Feb when the risk of 'spill' is greatest.
- There are some months (Sep-Oct and Mar-May) where there a mix of pumping (eg high wind) and generation (low wind) depending on the state of lakes and residual demand.
- However, the charts show average seasonal etc patterns over many modelled years and the pattern for an individual year can differ from the average
- Note that there is still a significant level of load curtailment and shortage in 2050 with a 1GW SI pumped storage, this is largely due to HVDC constraints which restrict the additional MWs available to cover NI low wind periods.

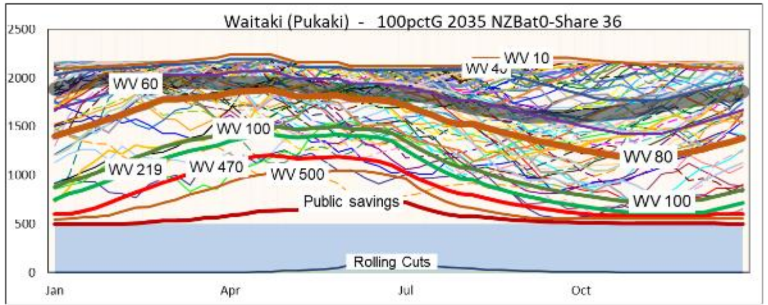
Notes: Shortage cost in the middle chart includes conservation campaigns, rolling cuts and shortage.

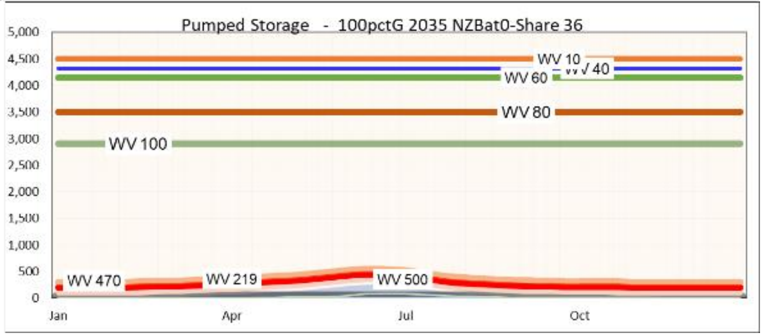
The model produces sensible looking lake management in the case where NZ Battery is not available

JC²

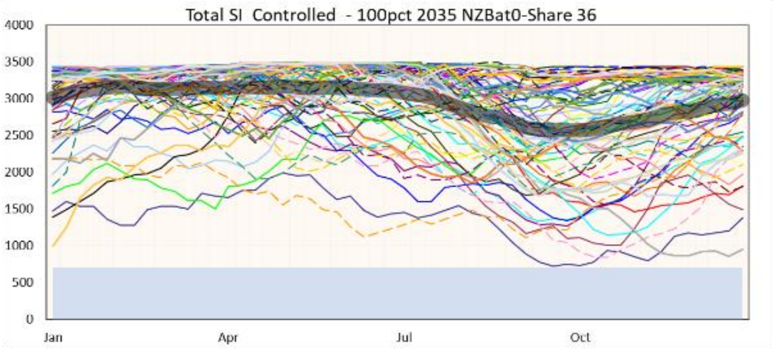
100% renewable with green peakers 2035

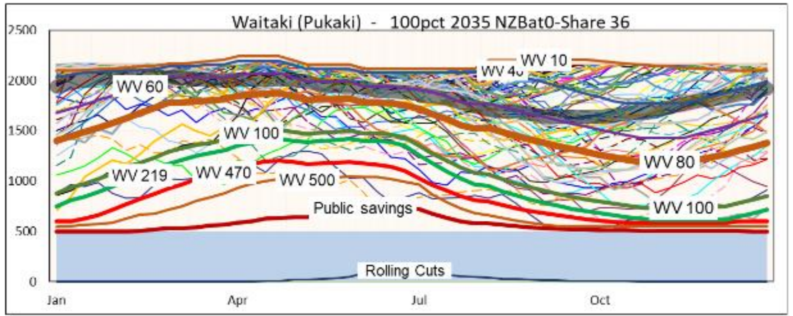

Total SI Controlled - 100pctG 2035 NZBat0-Share 36

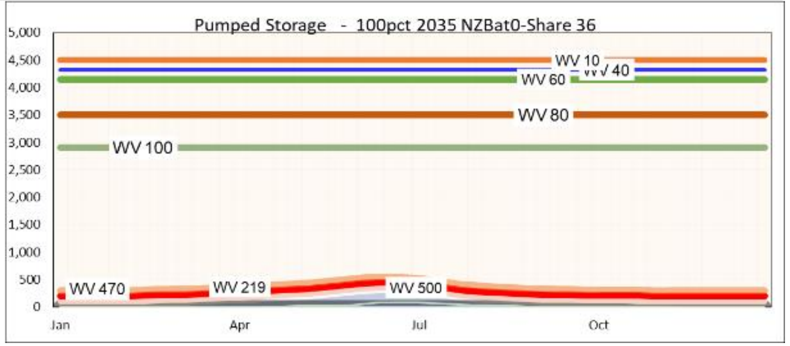

Waitaki (Pukaki) - 100pctG 2035 NZBat0-Share 36


Pumped Storage - 100pctG 2035 NZBat0-Share 36

100% renewable without green peakers


Total SI Controlled - 100pct 2035 NZBat0-Share 36


Waitaki (Pukaki) - 100pct 2035 NZBat0-Share 36


Pumped Storage - 100pct 2035 NZBat0-Share 36

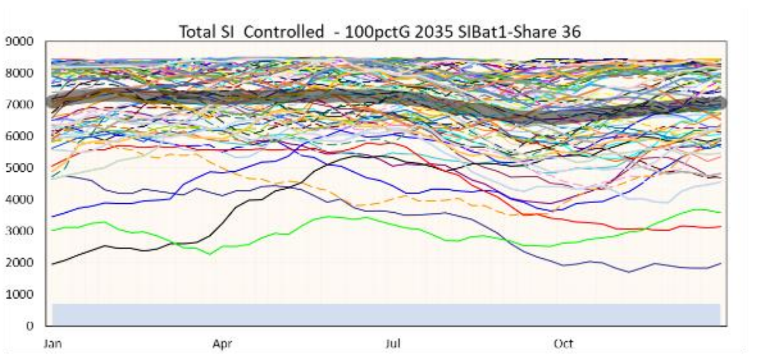
Comments:

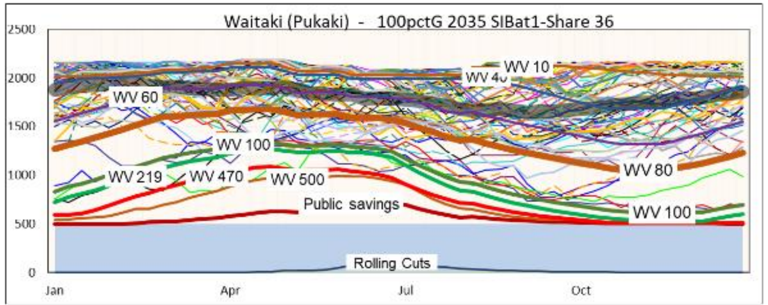
- Lake level (GWh) spaghetti charts are shown for a major storage reservoir (Waitaki) and the sum of the controlled lakes in the SI (Waitaki, Tekapo, Clutha) and for NZ Battery.
- As before, the level includes contingent storage - indicated by the blue zone. The charts shows the result of sequential simulation, so that the end level for each hydro inflow year is used as a starting level for the next hydro inflow year.
- Note:
  - With high levels of renewable build and no thermal buffer in the 100% Renewable world there is a tendency for the lakes to fill rapidly in Dec to Feb, this has to be countered by reducing the guidelines somewhat otherwise the fuller storage range would not be used even in the worst hydro sequence.
- Note also:
  - It is assumed that public savings are triggered when the major reservoirs get very close to the contingent zone and rolling cuts are only required when the contingent zone is fully utilised.

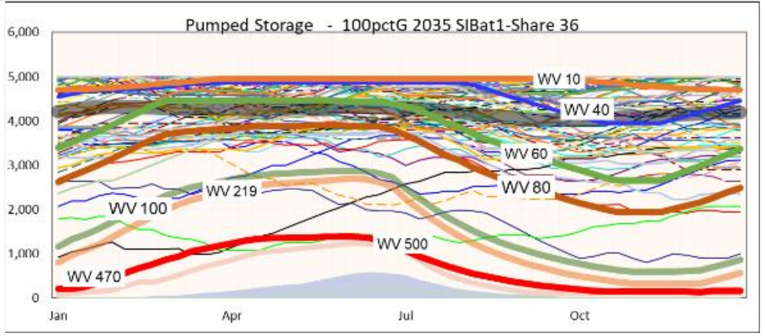
Likewise the model produces sensible looking lake management in the case where NZ Battery is available

JC²

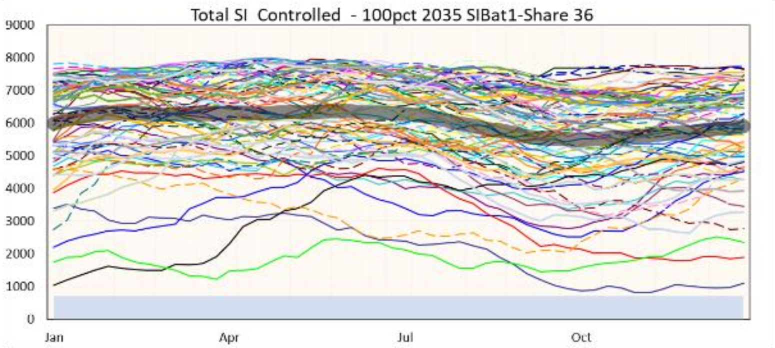
100% renewable - Green peakers available

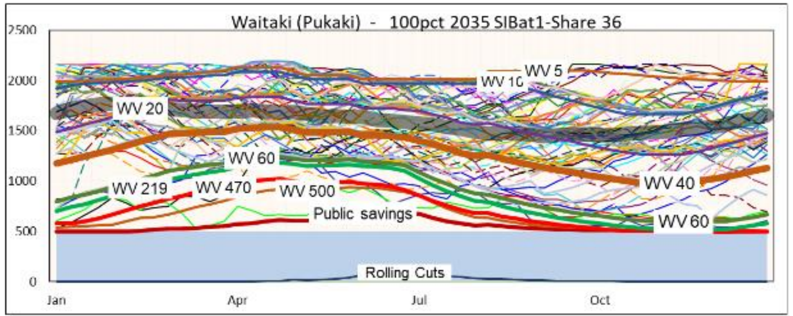


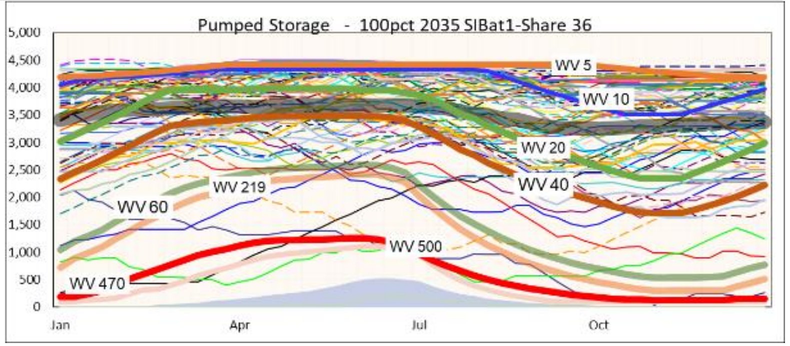




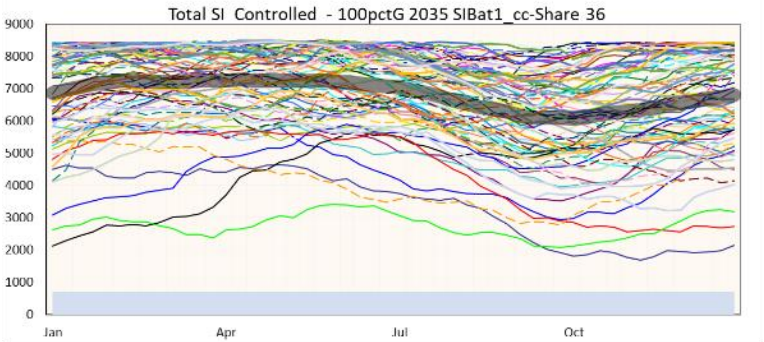
100% Renewable - no green peakers

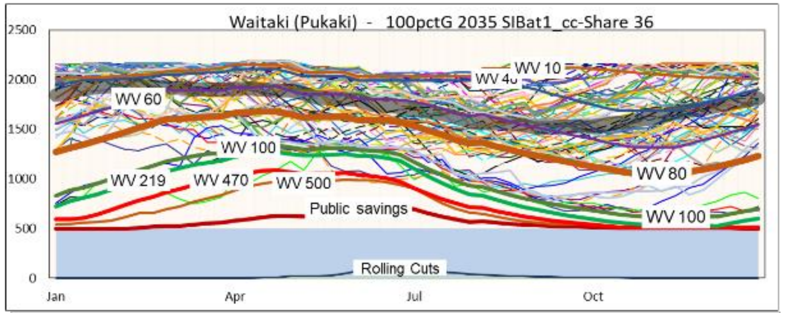


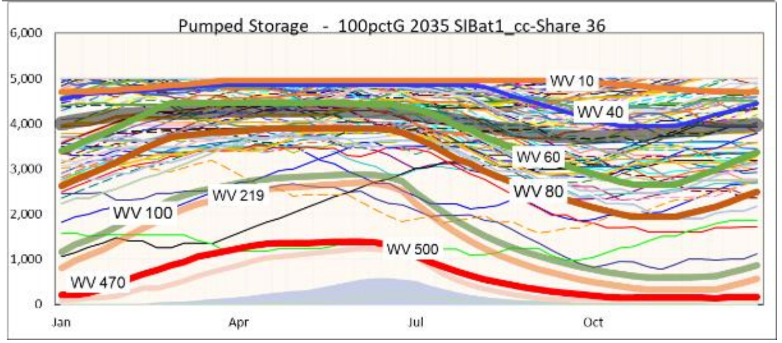




100% Renewable - green peakers available - no climate change

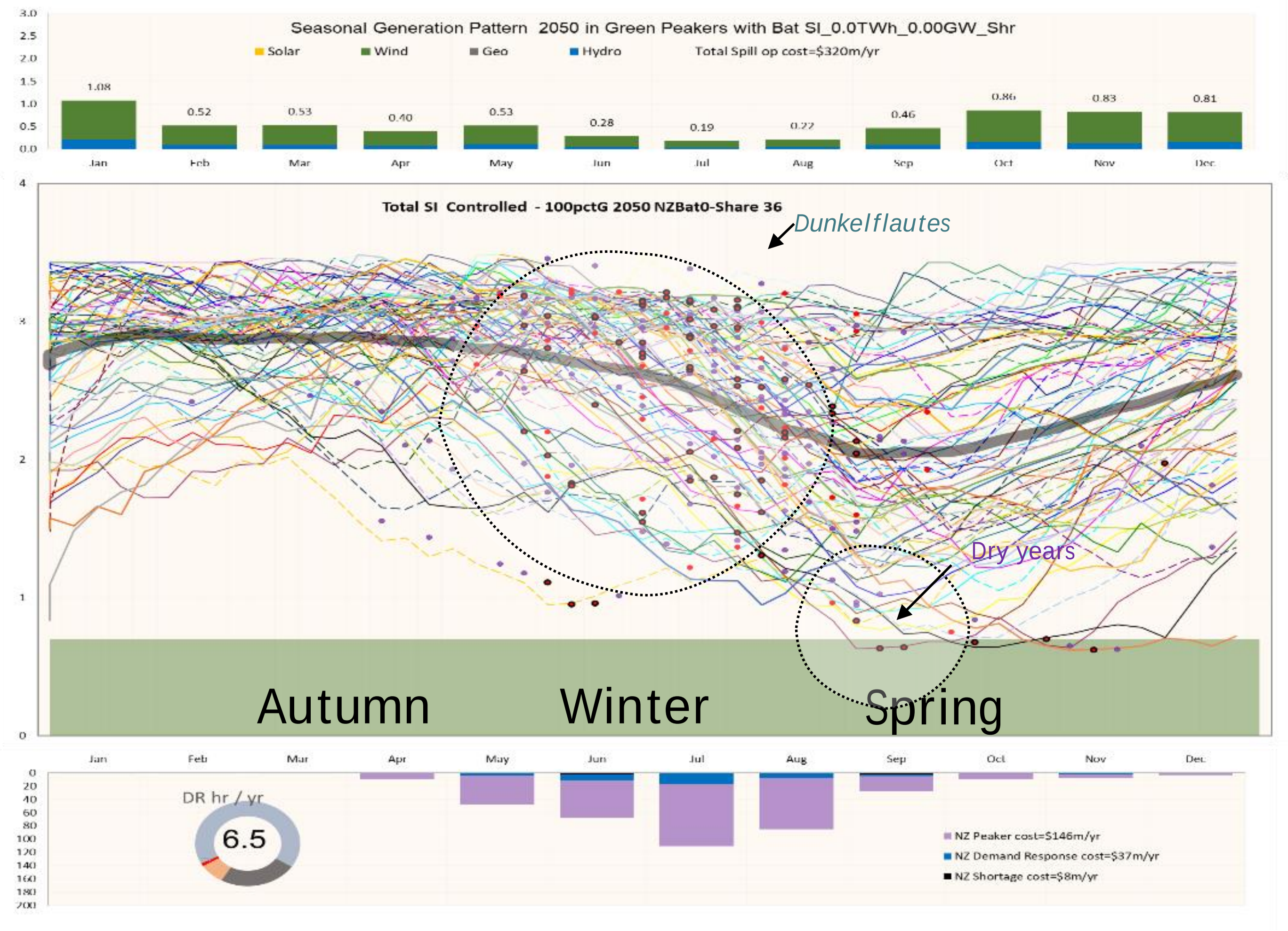






The model is producing sensible looking lake operation and dry year security under the **100% renewable reference case, but with higher “spill” than now**

2050 - 100% renewable reference case - showing the trade-off between spill and use of flexible resources over the year



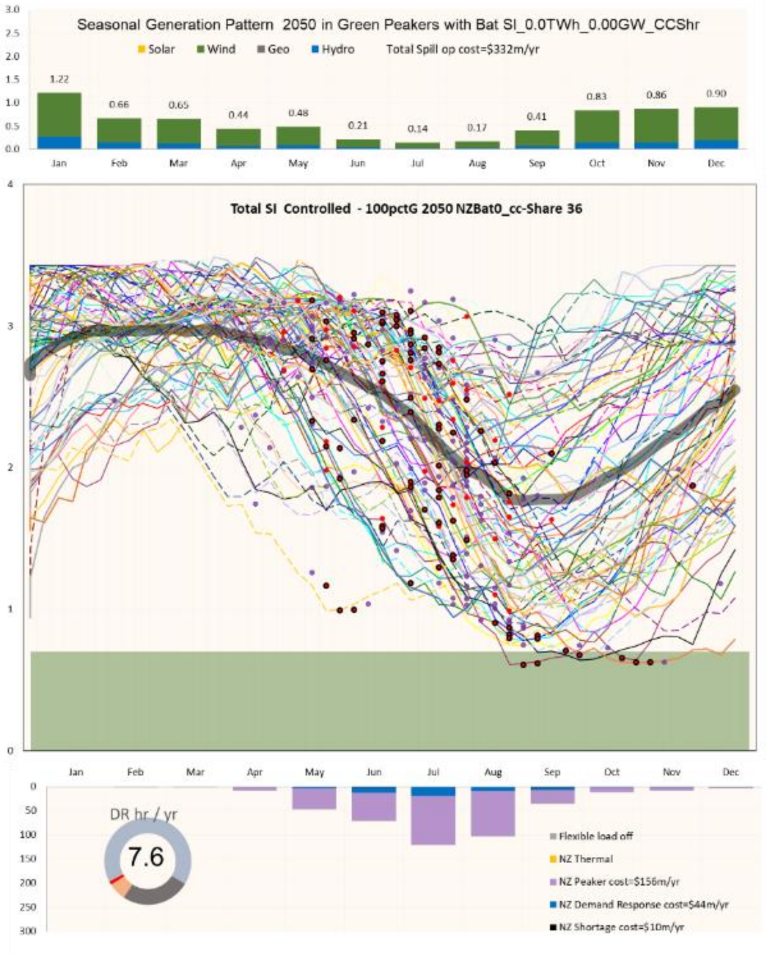
Note: 1) purple = green peaker required in week, Black circle = green peaker > 50GWh in week, Red dot = demand response required.

Chart explanation

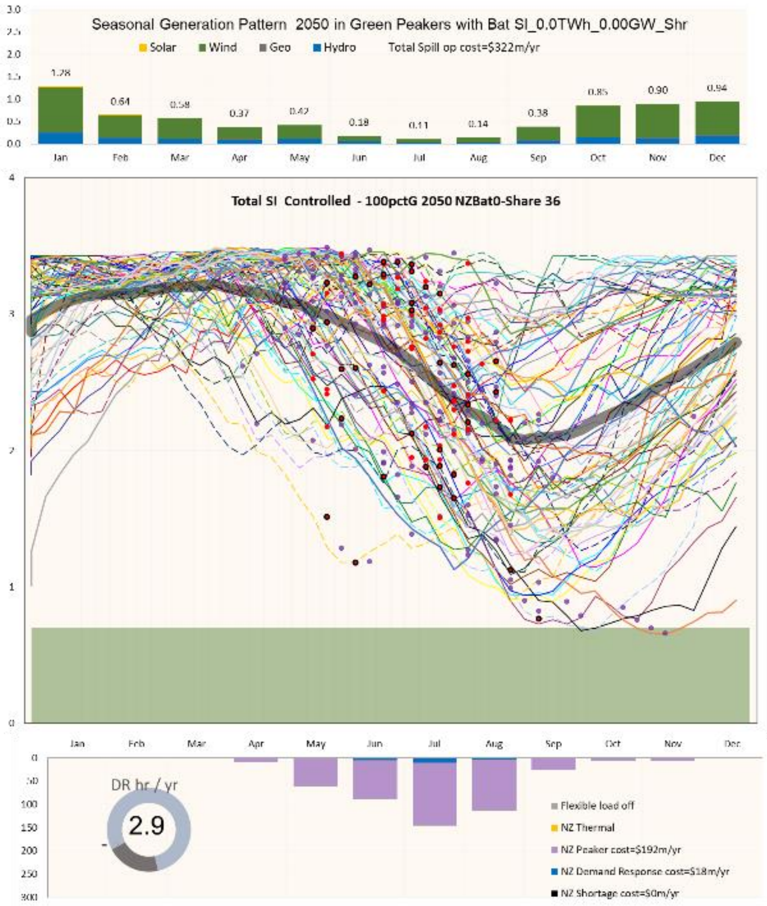
- The offer price contours reflect the cost of spill when lake levels are full, and the risk of spill is high. They reflect the cost of green peakers, demand response and shortages when lake levels are low, and the risk of supply is higher.
- The guidelines are shaped to ensure that, with the level of new renewable investment, the risks of running into the contingent zone in the worst simulated sequence is very low.
- For intermediate lake levels the offer prices are set to achieve a new entry equilibrium whereby new geothermal/wind/solar are able to achieve revenue adequacy and hydro storage levels are able to be maintained at a sufficiently high level prior to winter to manage dry year risks, without a major new pumped hydro investment.
- Dry year security can be maintained with existing levels of storage capability under 100% renewables via additional renewable build to ensure that lake levels are adequate in all but the worst sequence.
- Renewable build is also driven by the need to avoid **“capacity” and green peaker costs in winter days with** low wind.
- Spill occurs when lakes are filled prior to winter and there is high inflow and or wind/solar.
- The red and black circles[1] and black dots show weeks in which either green peakers or demand response are required. Most of these are winter weeks with low wind. Only a few are related to low hydro periods in 2050.

Impact of NZ Battery - with green peakers - in 2050

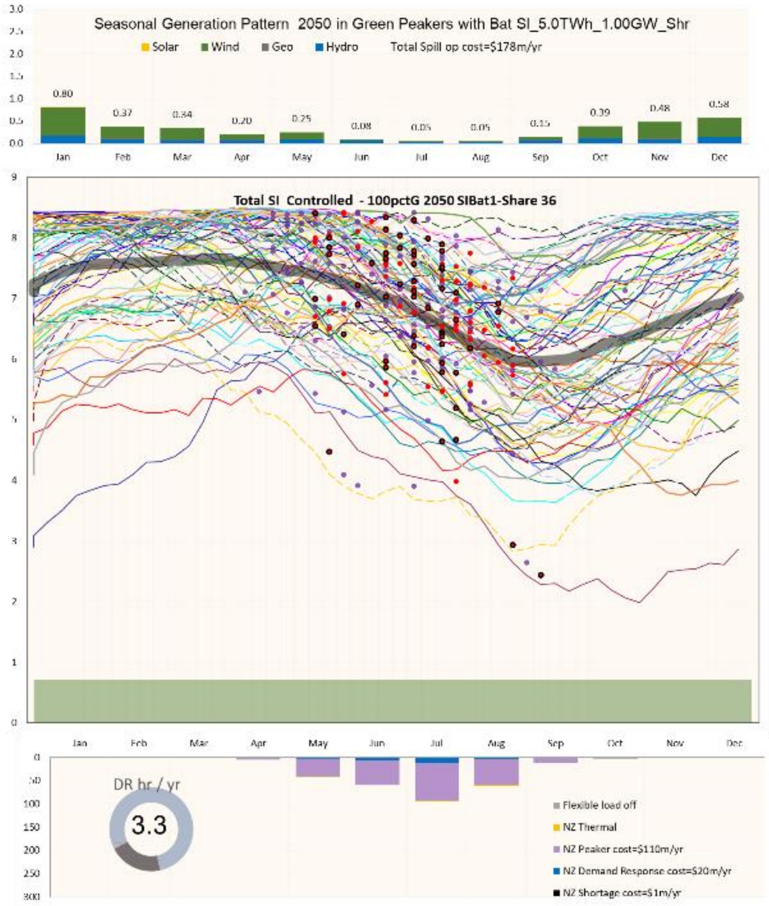
Without NZ Battery and without climate change - less inflows in winter more in spring - greater need for seasonal storage.



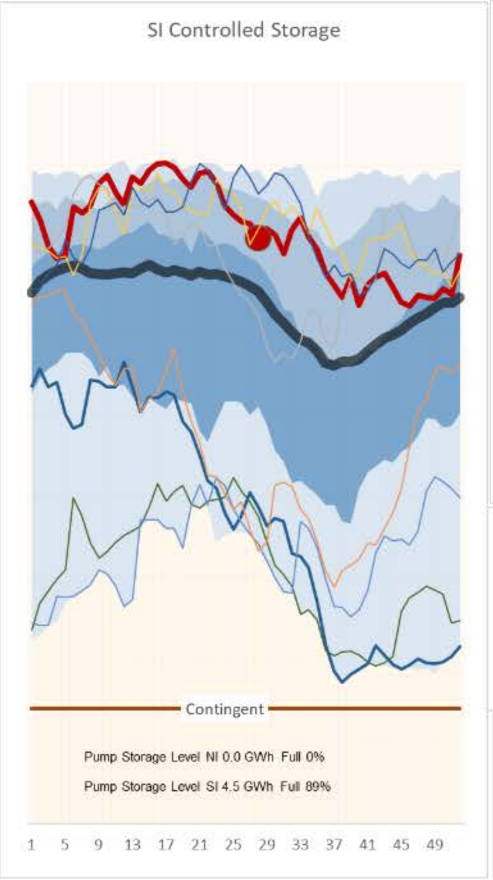
With Climate change the existing lakes are held higher going into winter by building extra renewables. This causes spill, but avoids lakes running into shortage.



With NZ battery the total controlled storage is increased and there is greater head-room to avoid spill as well as a larger buffer to cover dry years

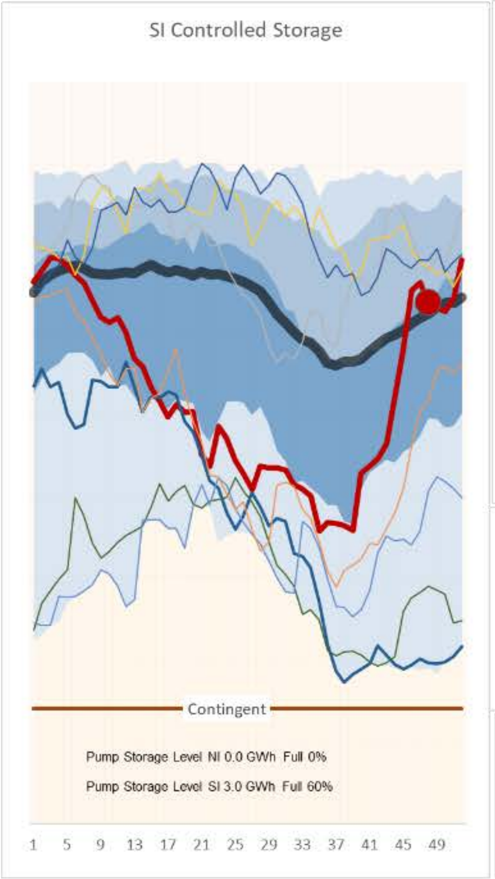


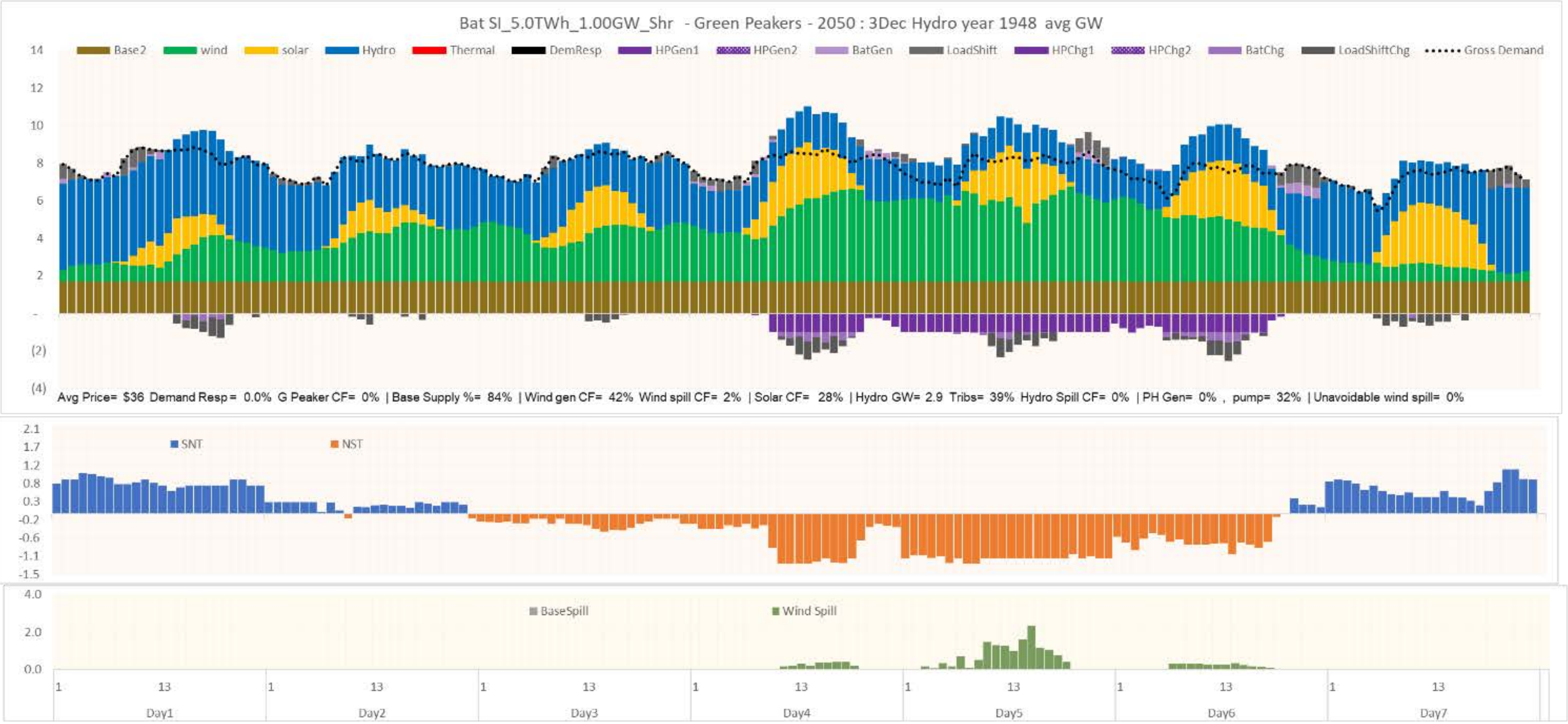
Example of one of the worst deficit weeks - with green peakers and SI Pumped storage - demand response is required when south to north capacity is limited - pumped storage is max but other hydro is backed off



Example of week where SI Battery is pumping in summer - high wind - spill occurs when HVDC southward flow hits max limit or pumping is at max capacity

JC2





11. THE VALUE OF EXTRA HVDC CAPACITY

The value of a 5TWh/1.0GW SI scheme would be increased by around $43 - 163m/yr if the HVDC was significantly larger

JC²

Extra HVDC capacity adds around $130m/yr to gross value in 2050

Base case benefit

Gain

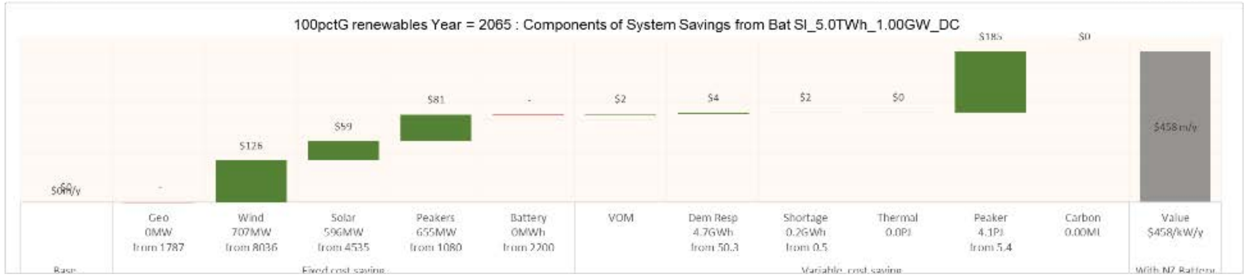
$103m/y

$43m/y

$256m/y

$129m/y

$294m/y



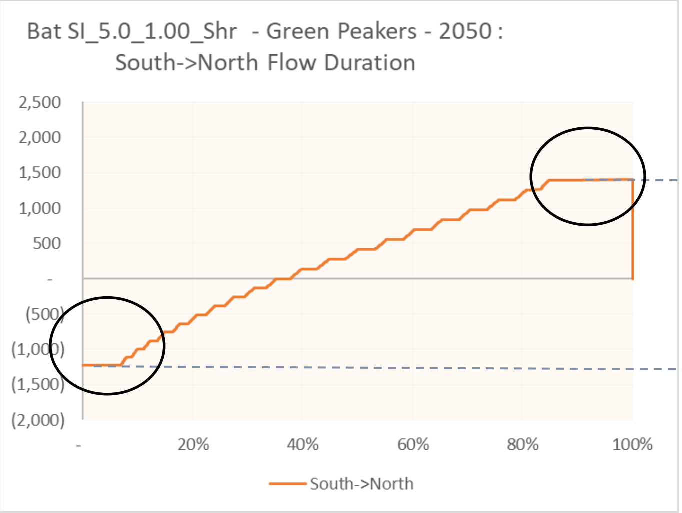
$164m/y

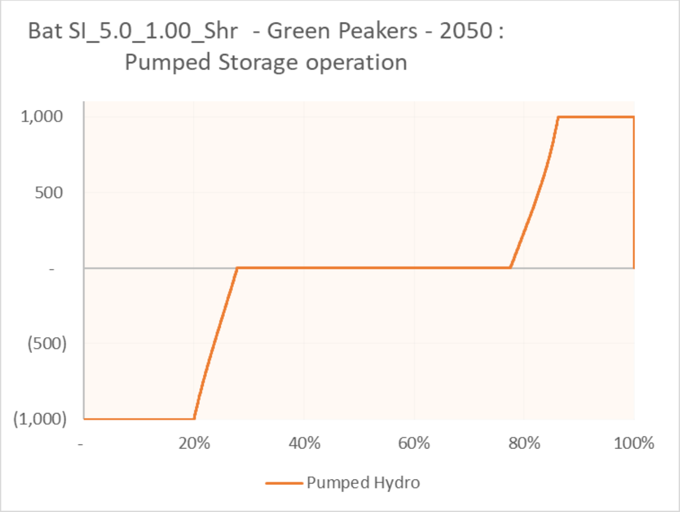
Sensitivity

- HVDC S->N increases from 1400MW to 2100MW
- HVDC S->S increases from 1300MW to 1500MW
- Loss function unchanged

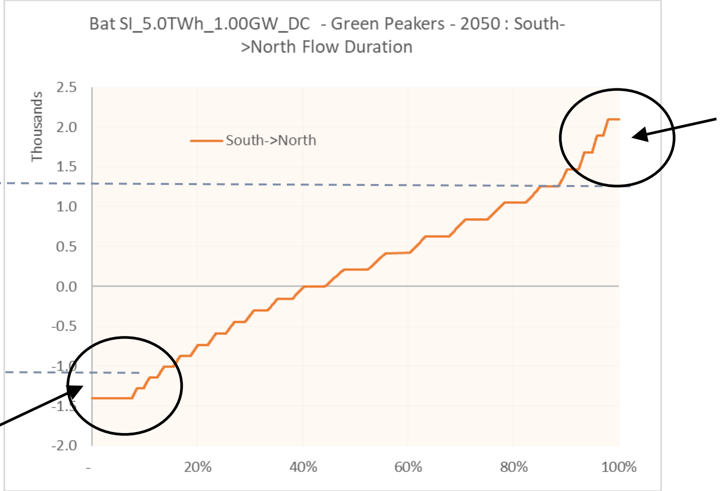
Pumped storge is much less constrained if the HVDC is significantly expanded

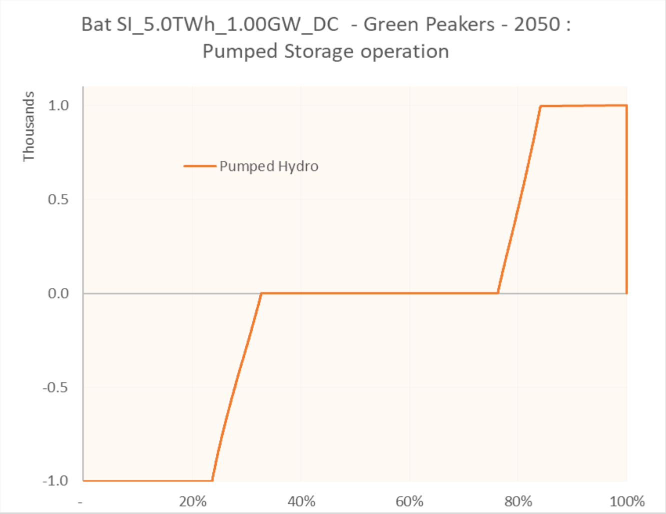
HVDC duration curve with constrained HVDC





HVDC duration Curve - with expanded HVDC



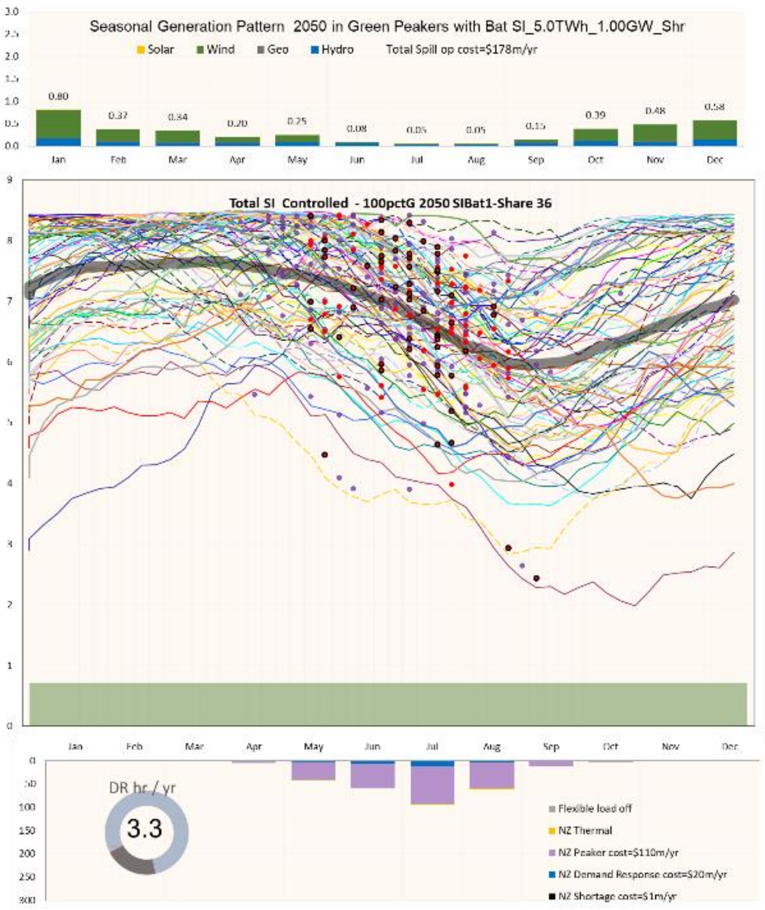


Still some periods where HVDC North->South flow is constraining

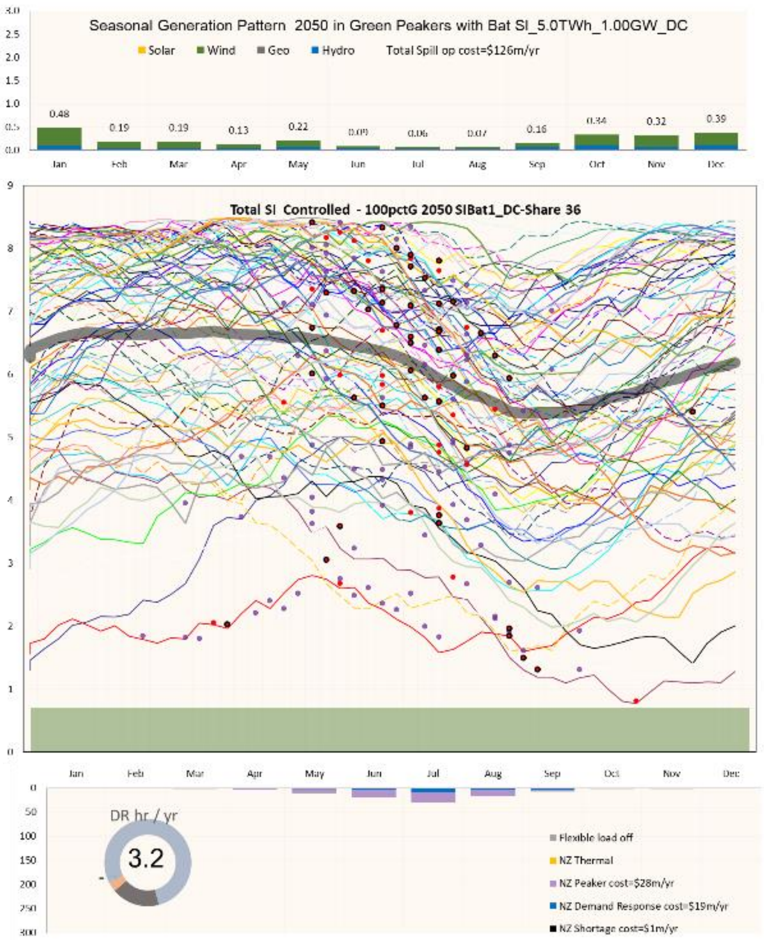
Large extra value of SI pumped storage when there is NI scarcity - DC is not binding.

Impact of HVDC constraints on operation of a 5TWh/1GW SI pumped hydro

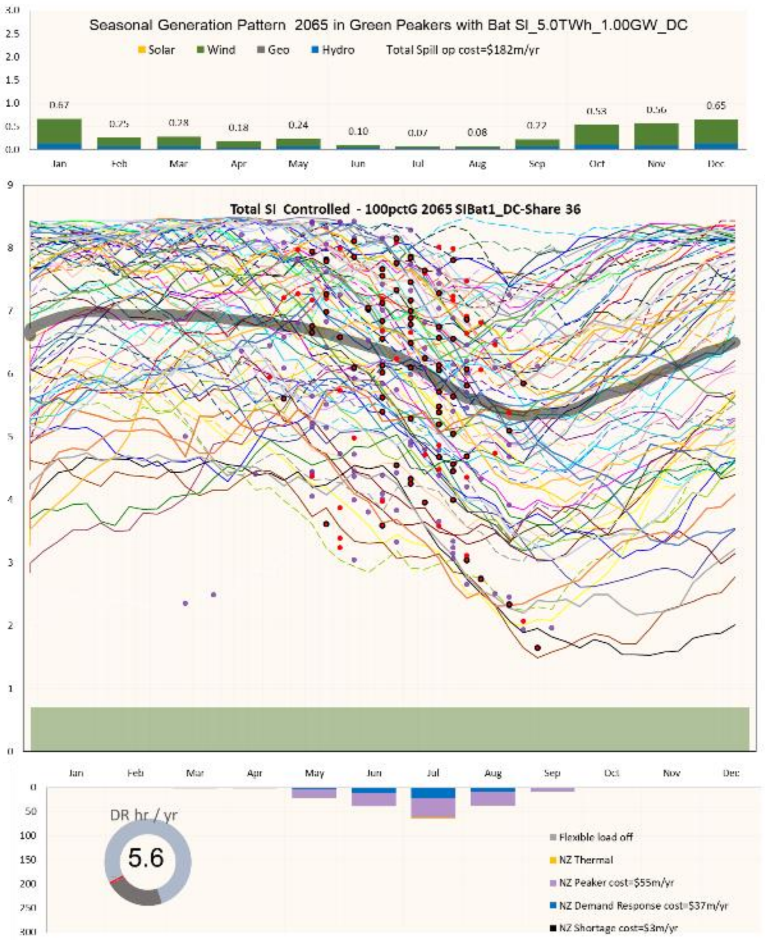
Base case in 2050 with green peakers capacity issues **arising from dunkleflaute events can't always be covered** by a SI 1GW scheme because of HVDC limits



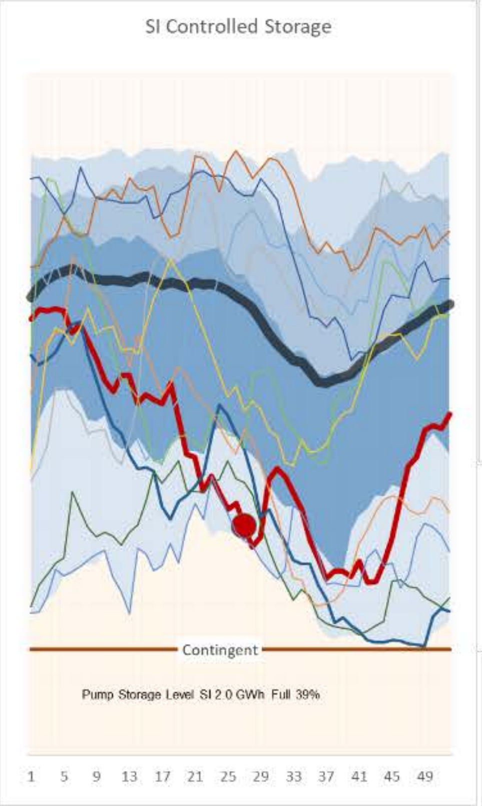
With expanded HVDC in 2050 - many more dunkleflaute events can be covered by SI scheme and hence save green peaker running .

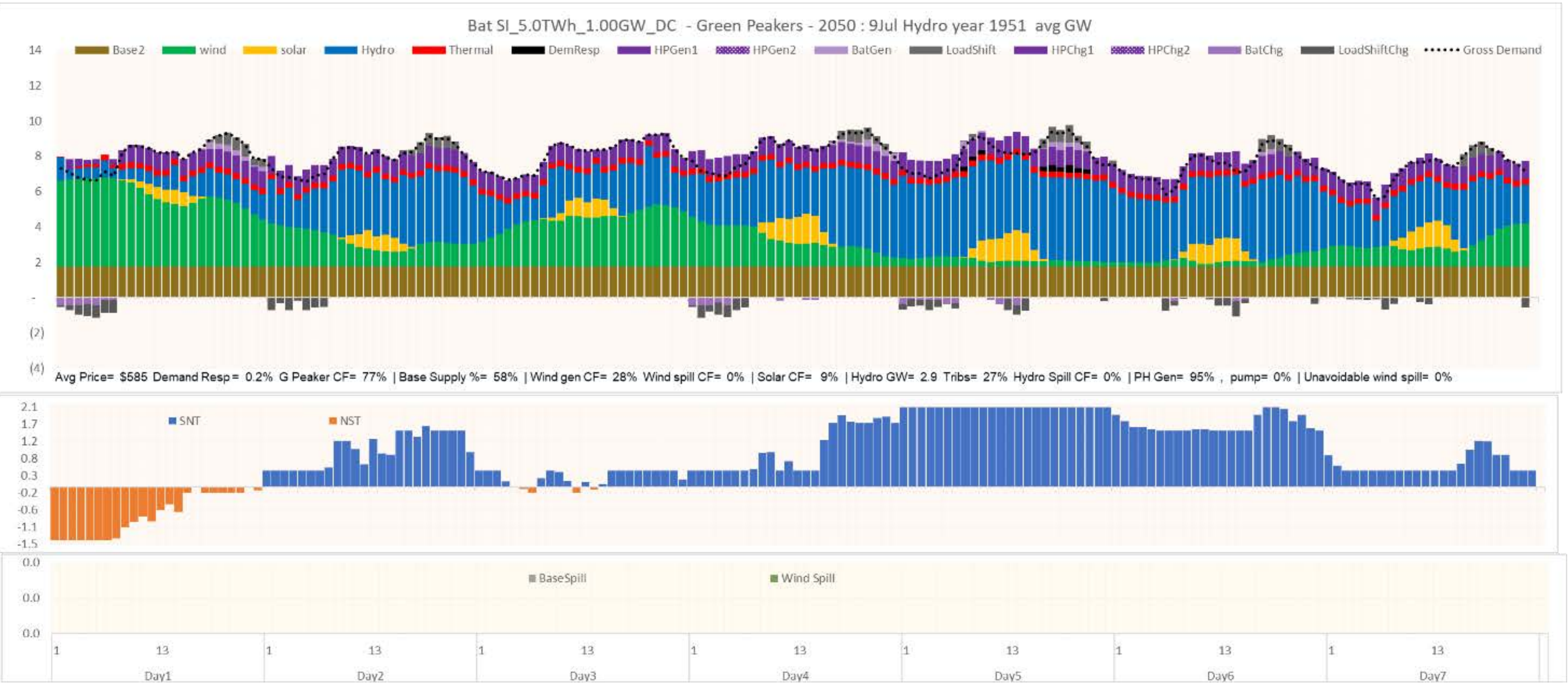


By 2065, even with an expanded HVDC, capacity issues arising from dunkleflautes become more frequent as the **MW from a SI scheme can't fully cover loss of wind.**

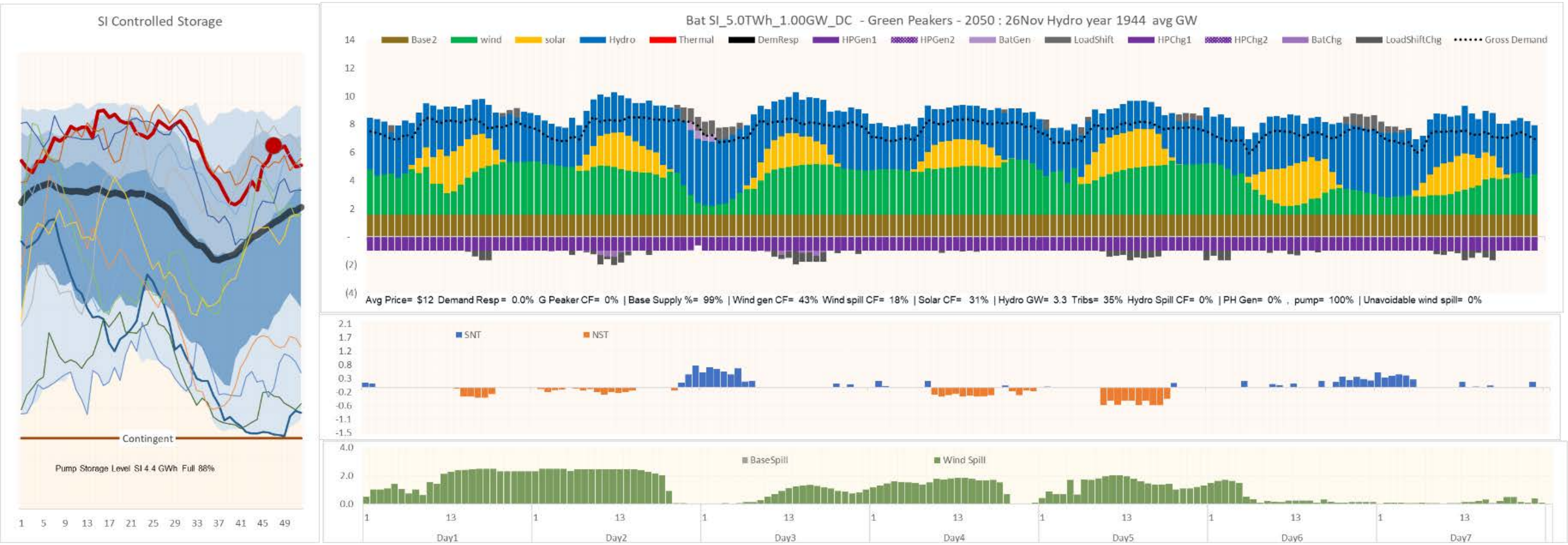


One of worst weeks with expanded HVDC - shortage arises when expanded HVDC limit is reached





Spill can still occur with expanded HVDC when pumping limits are hit or when the pumped storage is full



12. THE IMPACT OF CHANGES TO OPERATION MODE FOR ONSLOW

Estimating the impact of alternative SI pumped hydro operating guidelines

The heuristic pumped storage operating offer rules ensure that pumped hydro is use as a backup to avoid conventional hydro dipping into the contingent zone. Buffers are included to ensure capacity is available for generation when total storage is low and pumping when otherwise spill would occur.

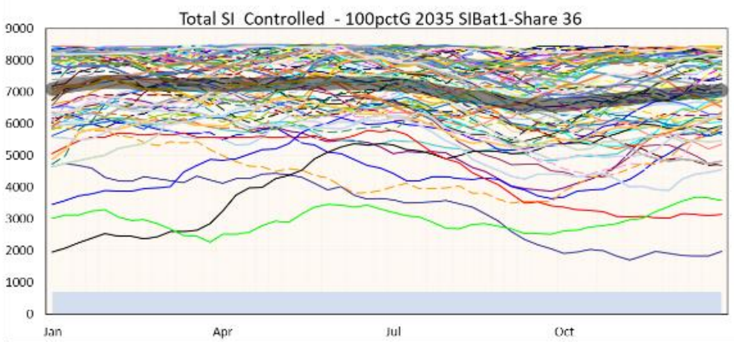
- The base case assumes that offer curves for the SI pumped hydro are based a similar seasonal shape to those for the main hydro storages. This base offer price provides a **"water value" which used to determine priority of conventional and pumped hydro.**
- From this base price a pair of prices are constructed:
  - **A buy price = "water value" * 71%** - at which the pumped hydro will be prepared to start pumping
  - **A sell price = "water value" at which the pumped storage will be prepared to** generate.
  - These prices then determine the merit order of generation from existing hydro and pumped storage;
    - The pumped storage curves are priced so that once the storages in conventional hydro get down to the "risk" curves (i.e. when risk of running to contingent storage becomes significant and green peakers might otherwise be run) then the pumped storage will be run in preference to conventional storage, right down until the pumped storage itself reaches a risk of running out level.
      - A buffer zone at the bottom is useful to ensure there is sufficient water available to enable the pumped storage capacity to be used in DF events
    - When the storages in conventional hydro get up towards full then conventional water offer curves will fall below the pumped hydro buy price and the pumped hydro will start to be filled until the pumped storage level gets into the upper buffer zone.
      - Although the pumped hydro can't actually spill, it is useful to maintain some headroom for additional pumping in situations where spill of wind/solar or hydro occurs because of capacity limitations.
    - When both the pumped storage and conventional hydro are in the middle zone, the offers curves for pumped hydro are likely to be similar and so pumping or generation will oscillate - thus seasonal shifting will be shared.
  - The level of the offer curves is adjusted for each target year so that, where possible, the full range of storage is used and excessive spill and shortage is avoided.

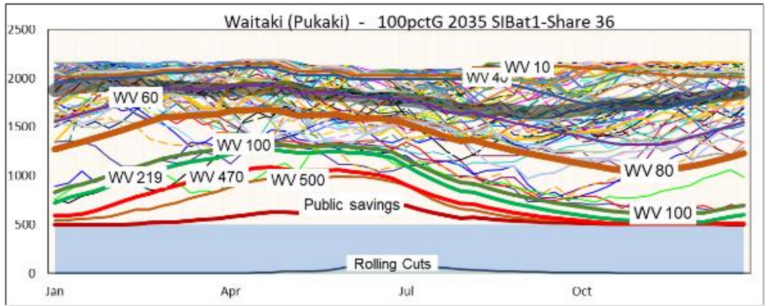
An alternative view is that generation from Onslow should be dispatched on the basis of an operating rule designed to minimise the risk

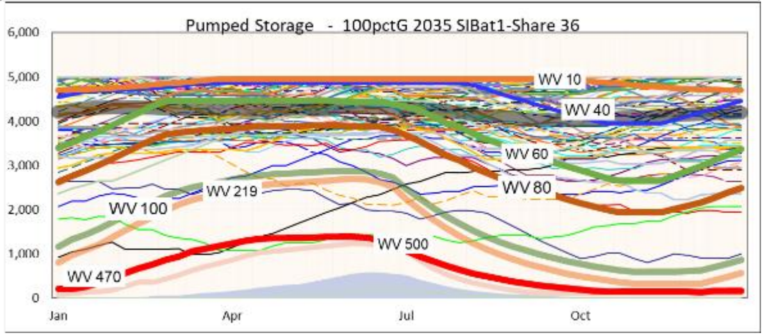
- Flat with Large spread:
  - It is possible to simulate the impact of a much more restrictive operating mode which limits the use of pumped storage by increasing the spread between buy and sell prices significantly (around $50/MWh).
  - This assumes that the pumped hydro would not generate until the water values in conventional storage was at least $85/MWh , and would only fill when prices were very low (less than $30/MWh).
    - This reduces the capacity factor (and pumping losses) substantially from 18% to around 8%. Although this achieves a higher arbitrage margin, this is offset by the lower volume, and so net revenues and gross system benefit falls by around $20 to $50m/yr.
- Energy security operation only:
  - This assumes that the pumped hydro will only offer to generate when there is an **"energy" security risk , based on crossing a specified hydro storage guideline in** the major SI hydro lakes.

Rule based operating modes for Onslow can have a significant impact on operating capacity value and system benefit

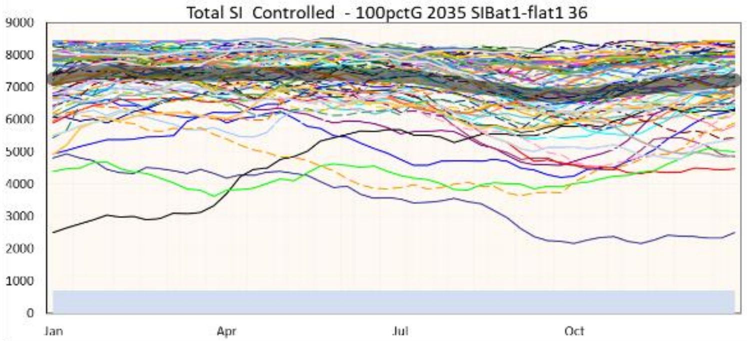
The base case assumes "water value" based offers to generate and bids to pump at a 72% round trip efficiency differential

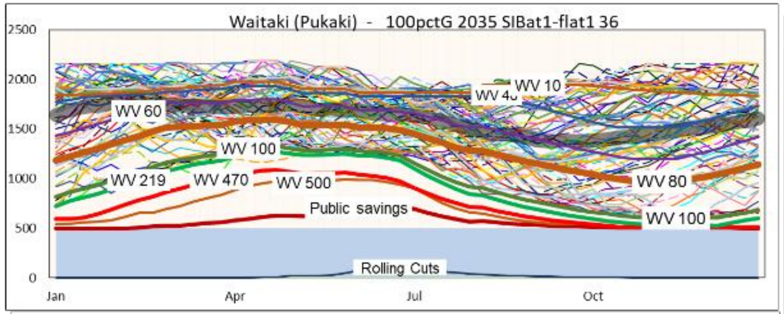


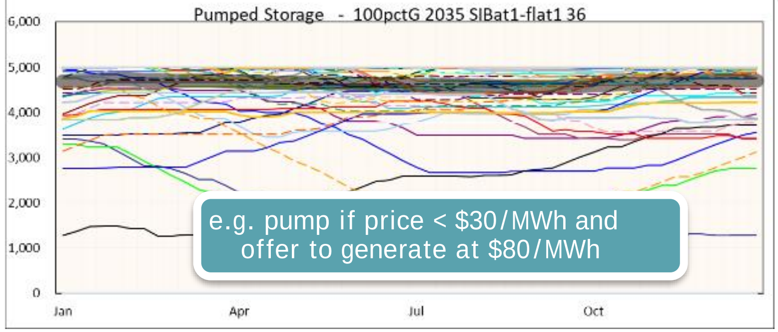




Onslow offers with a $50/MWh spread - e.g. pump if prices < $30/MWh and generate only when prices are greater than $80/MWh

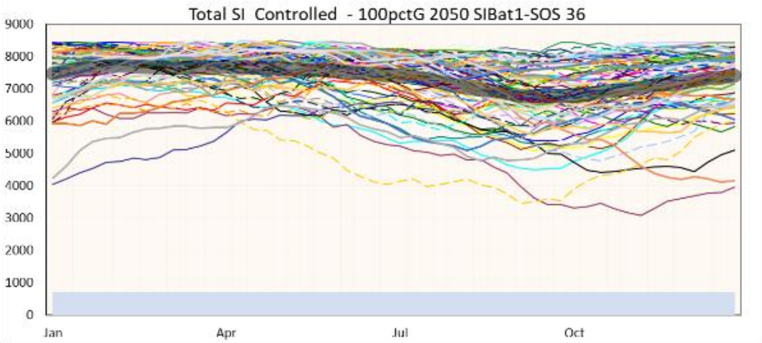


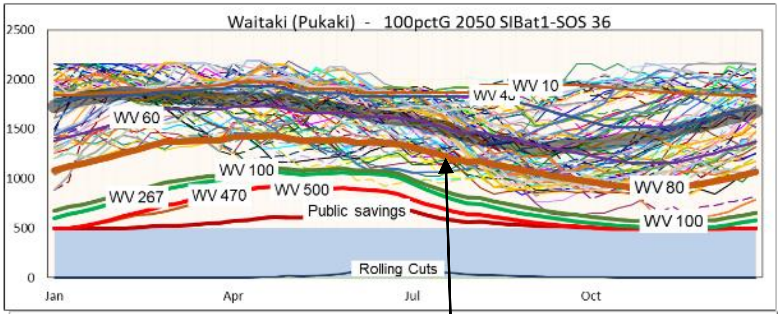


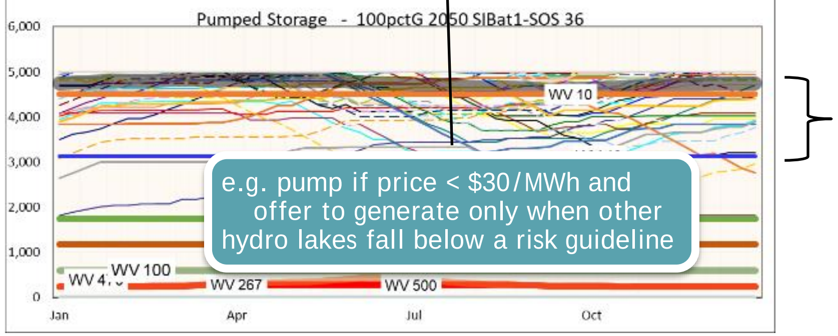


e.g. pump if price < $30/MWh and offer to generate at $80/MWh

Onslow operates to a storage based risk in other hydro storages (eg when Pukaki storage falls below the brown $80/MWh storage guideline below).



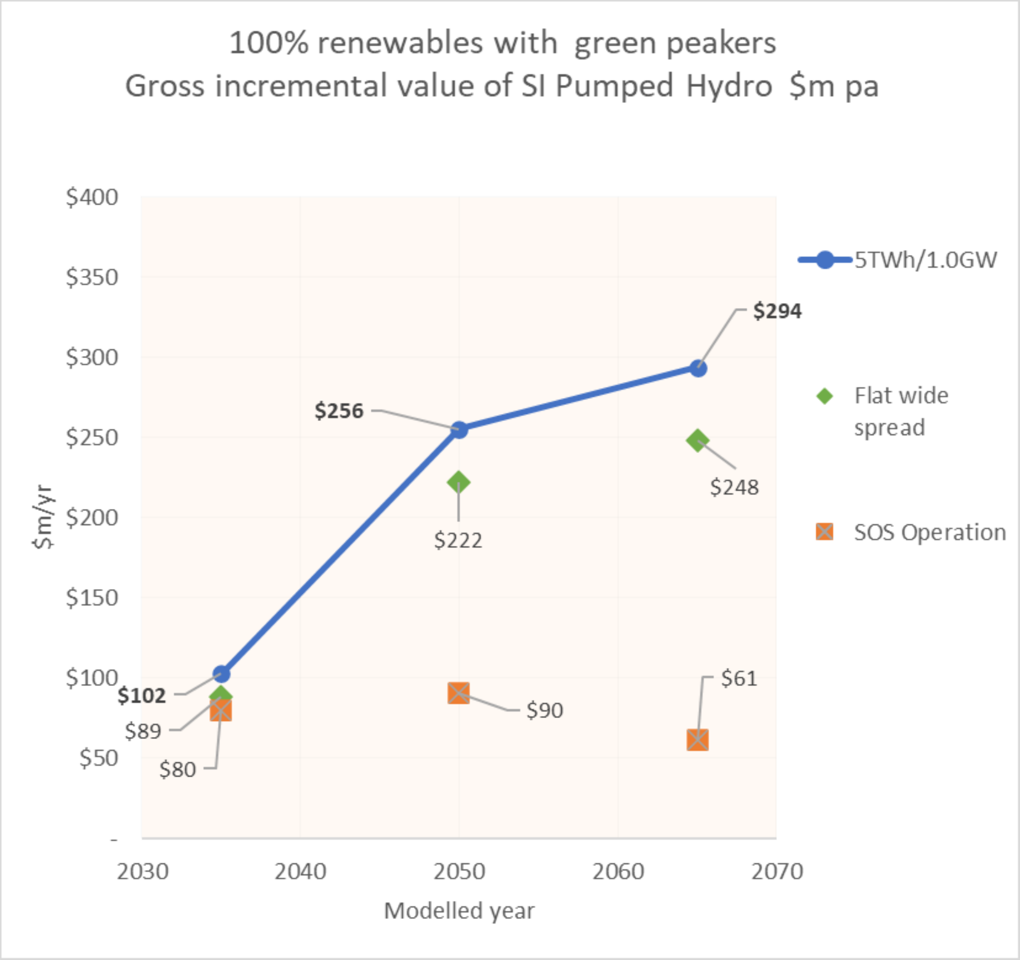




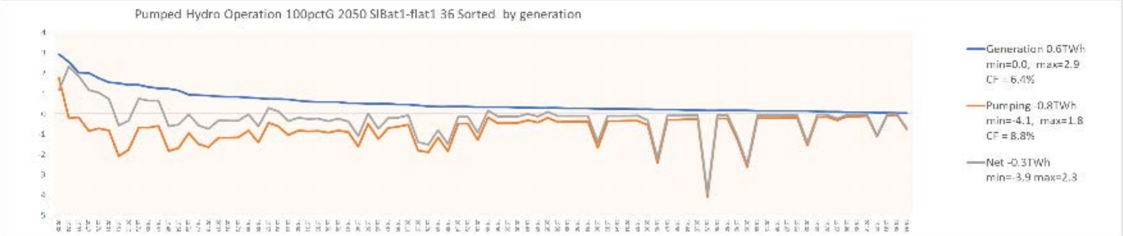
e.g. pump if price < $30/MWh and offer to generate only when other hydro lakes fall below a risk guideline

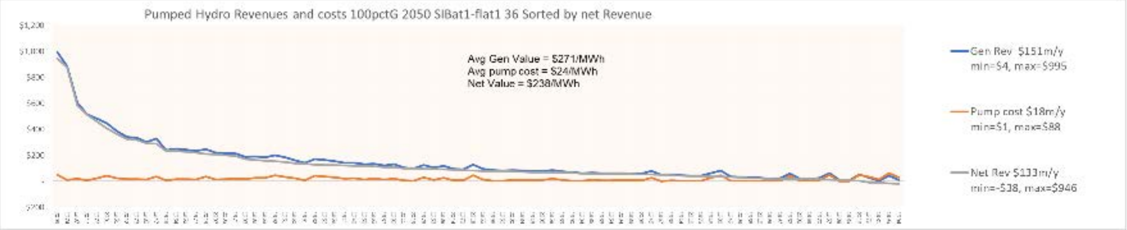
Limited pumped hydro operational mode reduces value and net revenue significantly

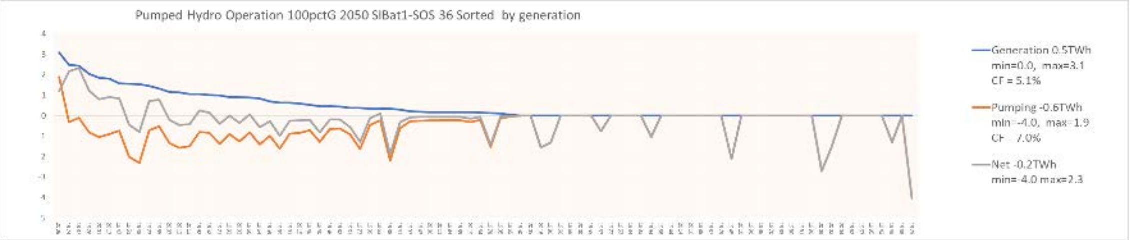
A flat profile with a low spread has a very similar out come to the shared operating rules, but flat profile with a large spread reduces gross value by around $50-20m/yr in 2050 to 2065

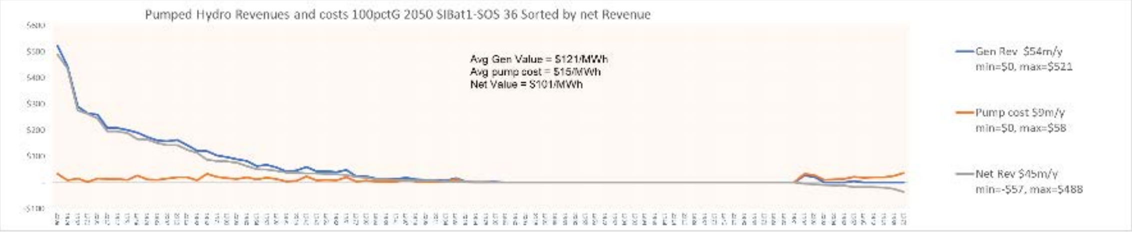

100% renewables with green peakers
Gross incremental value of SI Pumped Hydro $m pa

The flat profile with large spread - reduces pumping substantial from 18.5% to 6.4%. The loss of volume is not compensated by the margin gain and reduction in pumping losses so net revenues fall $33m/yr


Pumped Hydro Operation 100pctG 2050 SIBat1-flat1 36 Sorted by generation


Pumped Hydro Revenues and costs 100pctG 2050 SIBat1-flat1 36 Sorted by net Revenue


Pumped Hydro Operation 100pctG 2050 SIBat1-SOS 36 Sorted by generation

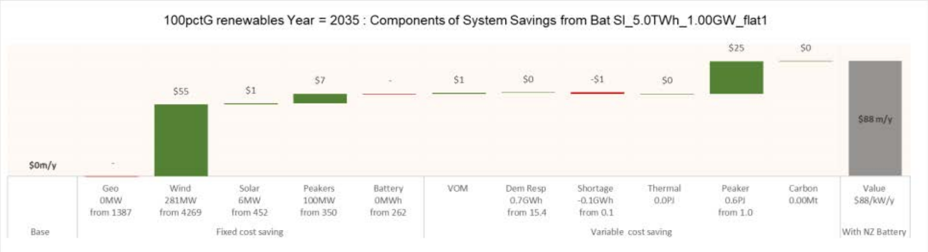

Pumped Hydro Revenues and costs 100pctG 2050 SIBat1-SOS 36 Sorted by net Revenue

Restricting Onslow offers to be based on a fixed pump/generate spread or based on a **“hydro” energy risk criterion can drastically reduce system benefits.**

Gross system benefits for operating rules based on a $50/MWh spread between a pumping price and generation price (e.g. >$30/MWh to pump and >$80/MWh to generate reduce system benefits by $14 to $46m/).

Base case benefit

$103m/y

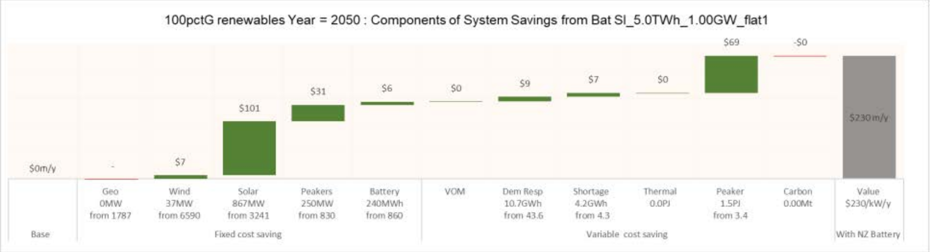


100pctG renewables Year = 2035 : Components of System Savings from Bat SI_5.0TWh_1.00GW_flat1

Loss

$15m/y

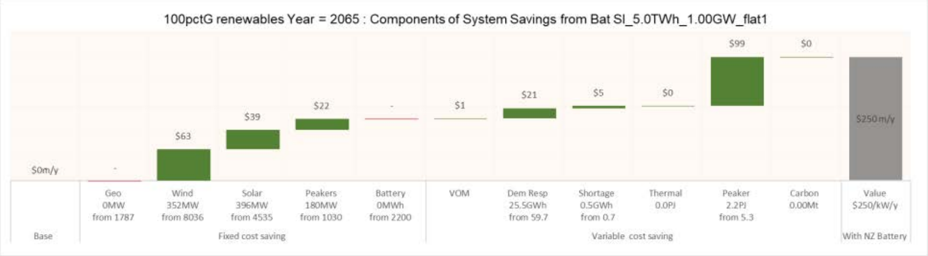
$256m/y



100pctG renewables Year = 2050 : Components of System Savings from Bat SI_5.0TWh_1.00GW_flat1

$26m/y

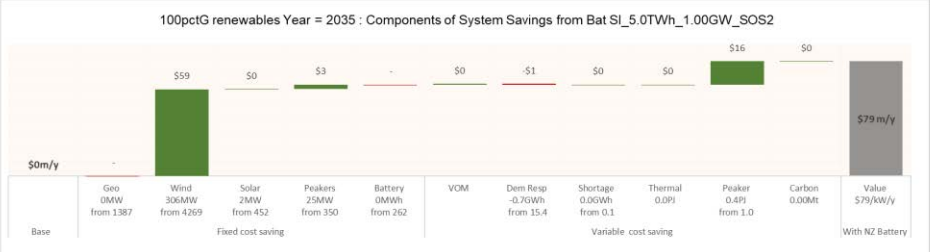
$294m/y



100pctG renewables Year = 2065 : Components of System Savings from Bat SI_5.0TWh_1.00GW_flat1

$44m/y

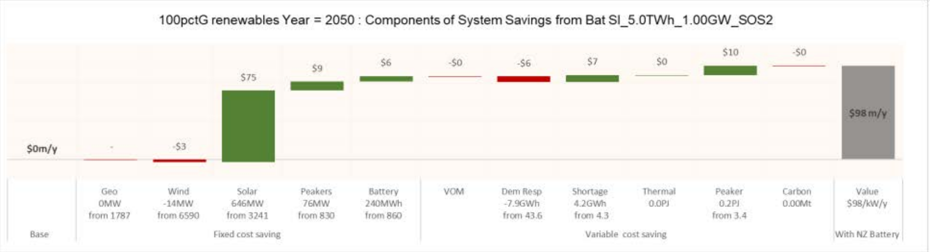
If Onslow is restricted from offering to generating until the market lakes get down to a storage based trigger then potential system value is reduced very substantially since it will not be dispatched to cover dunkleflautes. The loss in potential value is particularly severe beyond 2050 when low wind events become the primary risk.



100pctG renewables Year = 2035 : Components of System Savings from Bat SI_5.0TWh_1.00GW_SOS2

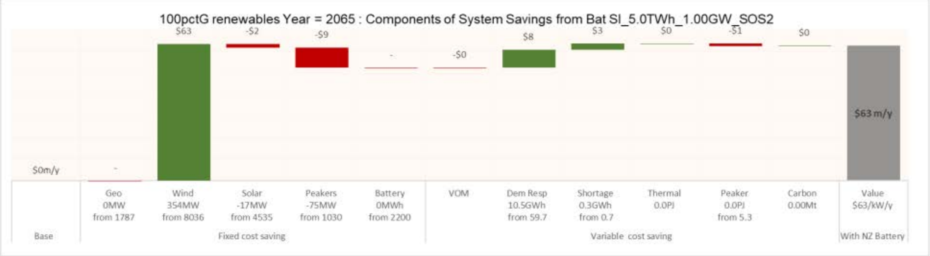
Loss

$24m/y



100pctG renewables Year = 2050 : Components of System Savings from Bat SI_5.0TWh_1.00GW_SOS2

$158m/y



100pctG renewables Year = 2065 : Components of System Savings from Bat SI_5.0TWh_1.00GW_SOS2

$231m/y

Note that in this case we look at the full impact of the change in operating mode, including the impact on new investment as a result of this change in operating mode.

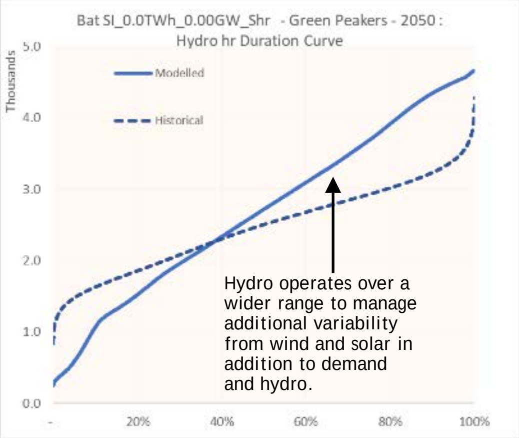
13. GENERATION DURATION CURVES

JC²

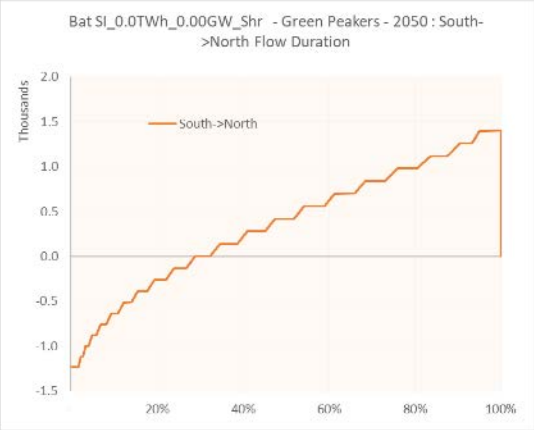
Generation duration curves in 2050

No NZ Battery 100%

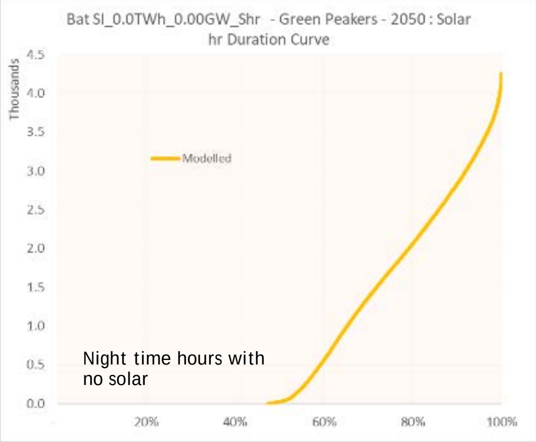
GW



Hydro operates over a wider range to manage additional variability from wind and solar in addition to demand and hydro.

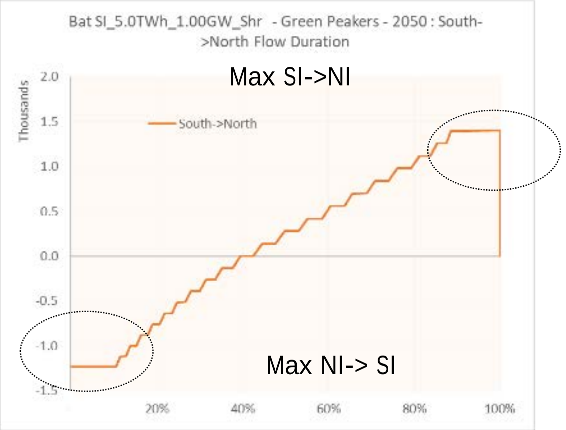


GW



Night time hours with no solar

With 5TWh/1.0 GW Battery in South Island



Max SI->NI

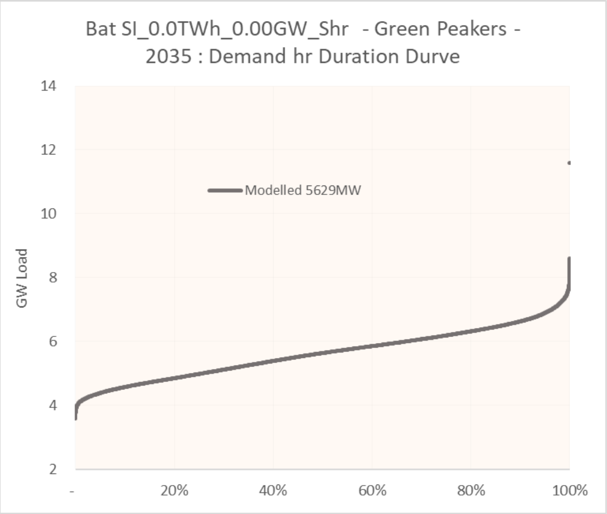
Max NI-> SI

Cumulative % of hours ranked from low to high generation.

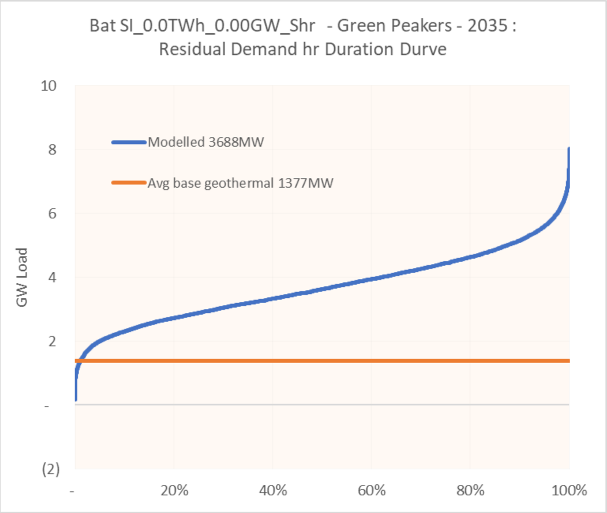
Modelled generation patterns for wind, and solar are similar for the NZ Battery ‘in’ and ‘out’ cases and this appears reasonable given underlying physics. However, modelled operation of existing hydro generation changes to be more flexible than historical patterns in both the NZ Battery ‘in’ and ‘out’ cases. This change reflects the growing need for hydro to offset short term intermittency. It is unclear whether the existing hydro system will be physically able to fully alter its operation. To the extent it encounters physical constraints, we expect that would bring forward in time the gross benefits provided by the different NZ Battery options – but we don’t expect any material change to relative benefits of different tank/tap options.

Load and Residual Load Duration Curves in 2050 - 100% renewables (no peakers)

No Battery - 2035

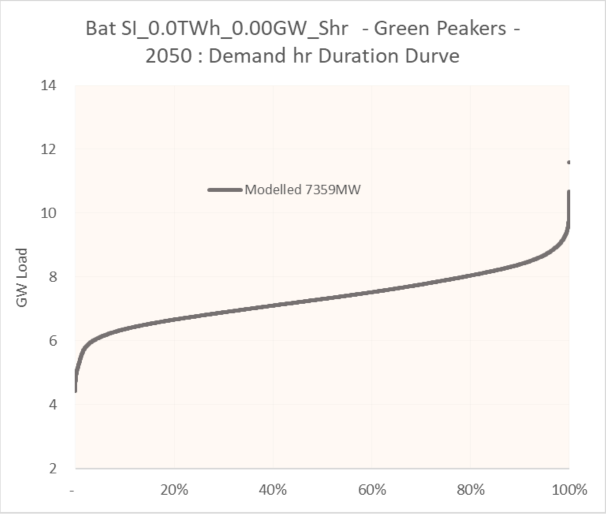

Bat SI_0.0TWh_0.00GW_Shr - Green Peakers - 2035 : Demand hr Duration Durve

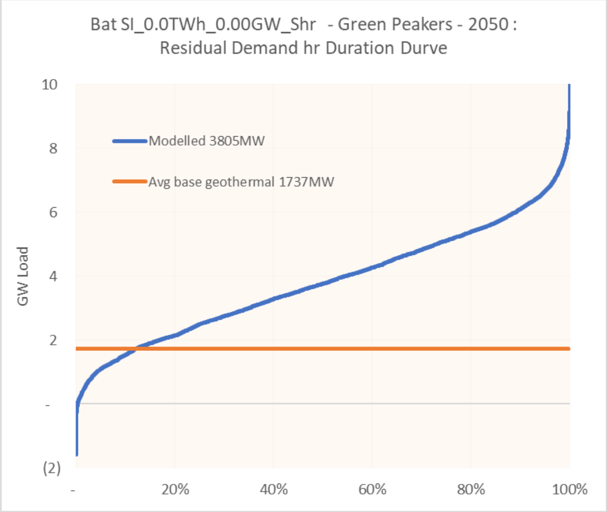
Between 2035 and 2065 the demand duration curve rises and flattens as EV & PH load is added…


Bat SI_0.0TWh_0.00GW_Shr - Green Peakers - 2035 : Residual Demand hr Duration Durve

and the residual demand curve steepens as more wind and solar is built. The peak residual demand remains high & risk of spill increases as RLDC falls below base geothermal generation

No Battery - 2050

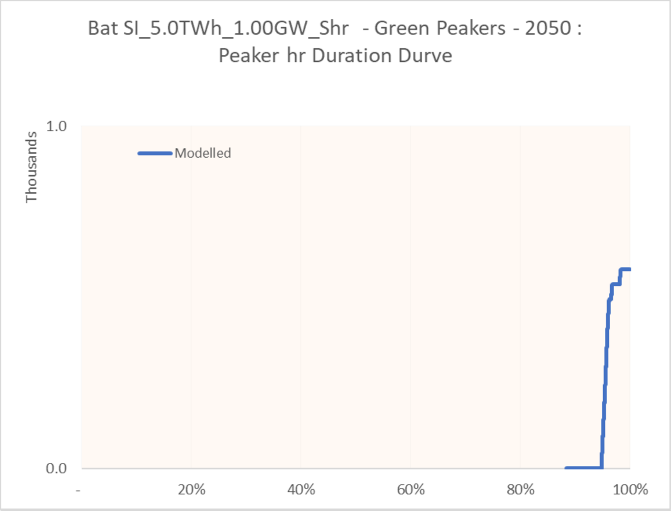

Bat SI_0.0TWh_0.00GW_Shr - Green Peakers - 2050 : Demand hr Duration Durve

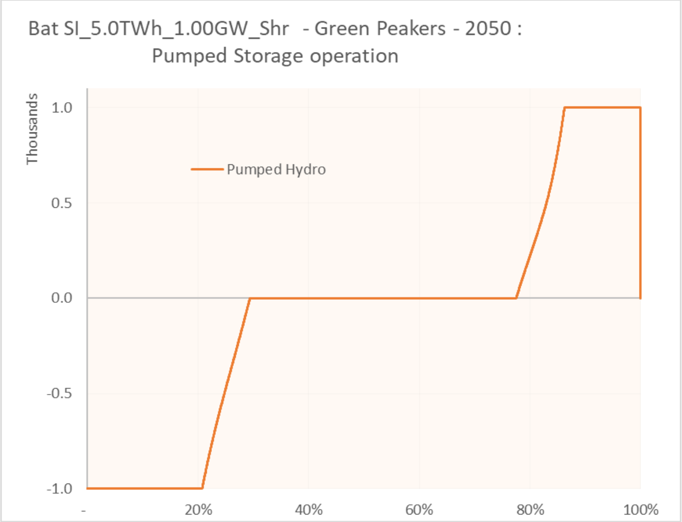

Bat SI_0.0TWh_0.00GW_Shr - Green Peakers - 2050 : Residual Demand hr Duration Durve

Adding NZ Battery lifts the residual demand curve rises as some wind and solar build can be avoided when pumped storage is added. The risk of spill reduces.

NZ Battery operates with a generation capacity factor of around 18-19% and does not operate at all for around 50% of the time

South Island Battery 5TWh/1.0 - 2050


Bat SI_5.0TWh_1.00GW_Shr - Green Peakers - 2050 : Peaker hr Duration Durve

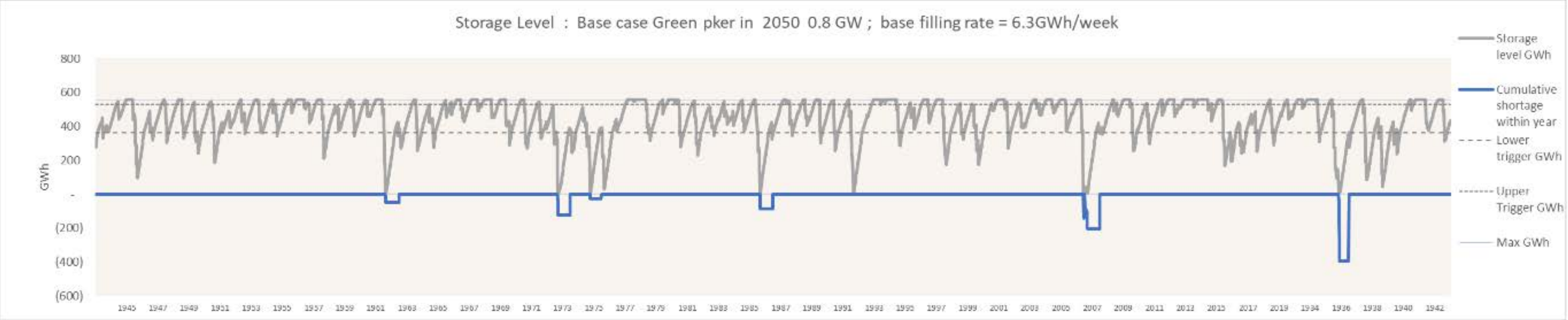

Bat SI_5.0TWh_1.00GW_Shr - Green Peakers - 2050 : Pumped Storage operation

Notes: Residual Demand is demand minus potential generation from solar and wind generation. This measure highlights the risk of "spill" as the RLDC falls below minimum levels of other generation. The chart shows baseload geothermal, but there is also minimum hydro generation from resource constraints and hydro tributaries which will also contribute to the risk of "spill".

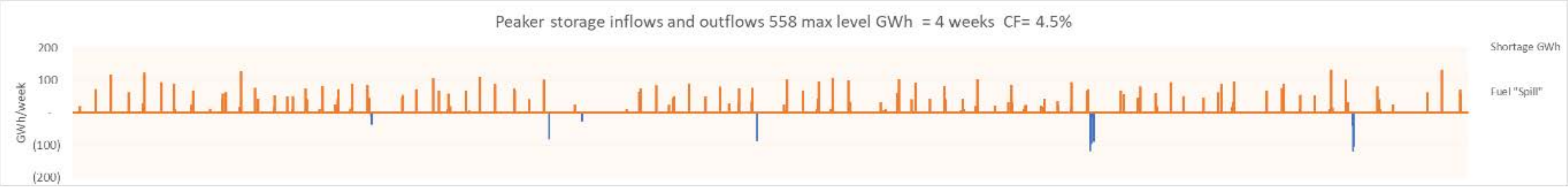
14. GREEN PEAKER FUEL STORAGE REQUIREMENTS

Storage and supply chain requirements for last resort green peaker operation in the 100% renewable reference case in 2050

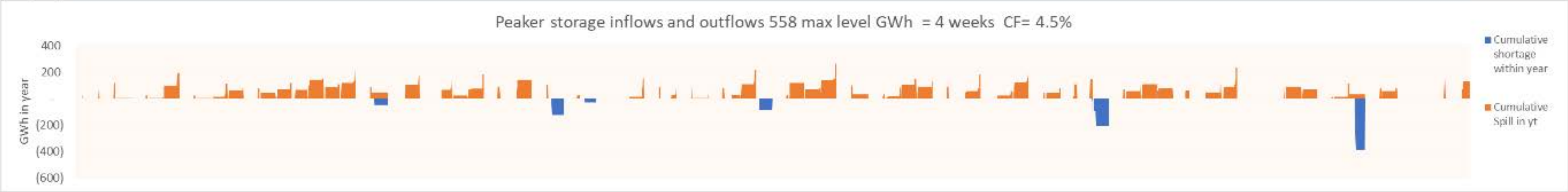
Green peakers will need around 4 weeks of fuel storage to meet the low wind firming requirements in the reference case. There are a few periods where the 4 weeks is insufficient, however these can be met all the modelled requirements. Other longer-term options will be required, such as use of use of contingent storage, or modest use of official conservation campaigns if necessary.



Storage Level : Base case Green pker in 2050 0.8 GW ; base filling rate = 6.3GWh/week



Peaker storage inflows and outflows 558 max level GWh = 4 weeks CF= 4.5%



Peaker storage inflows and outflows 558 max level GWh = 4 weeks CF= 4.5%

Commentary

- This chart shows the operation of a fuel stockpile for a green peaker.
- The base assumption is a storage of 4 weeks at full capacity.
- It is assumed that the fuel purchases are at the average level when the stockpile is between 20 and 80% full but can be boosted to 2x the average when storage levels fall low.
  - This is an approximation. Top-up supply might involve special arrangements for larger quantities with a time delay.
- The stockpile is used to supply the green peakers as the system requires to meet periods of low wind/solar/hydro. These occur on a regular basis most years, but occasional are bunched when lakes fall low.
- There are 3 to 5 periods out of 87 years when fuel storage reaches zero and green **peakers can't meet the entire demand.**
- In these cases, there will be a shortfall which would have to be met from other sources, such as drawing down into the contingent zone at Waitaki, or by low levels of demand control.

Note: the storage is measured in terms of the GWh of peaker operation. This can be roughly converted into PJ by dividing by 100. The one-off cost of filling the stockpile is approximately $200m (assuming 80% full @ $45/GJ), and there will be additional costs for biodiesel tanks or biogas storage facilities. This adds around $15-20/kW/yr to the fixed operating costs for green peakers.

15. THE CONTRIBUTIONS IN PERIODS OF SCARCITY AND SURPLUS

Contribution of renewables to periods of surplus and scarcity - chart explanation

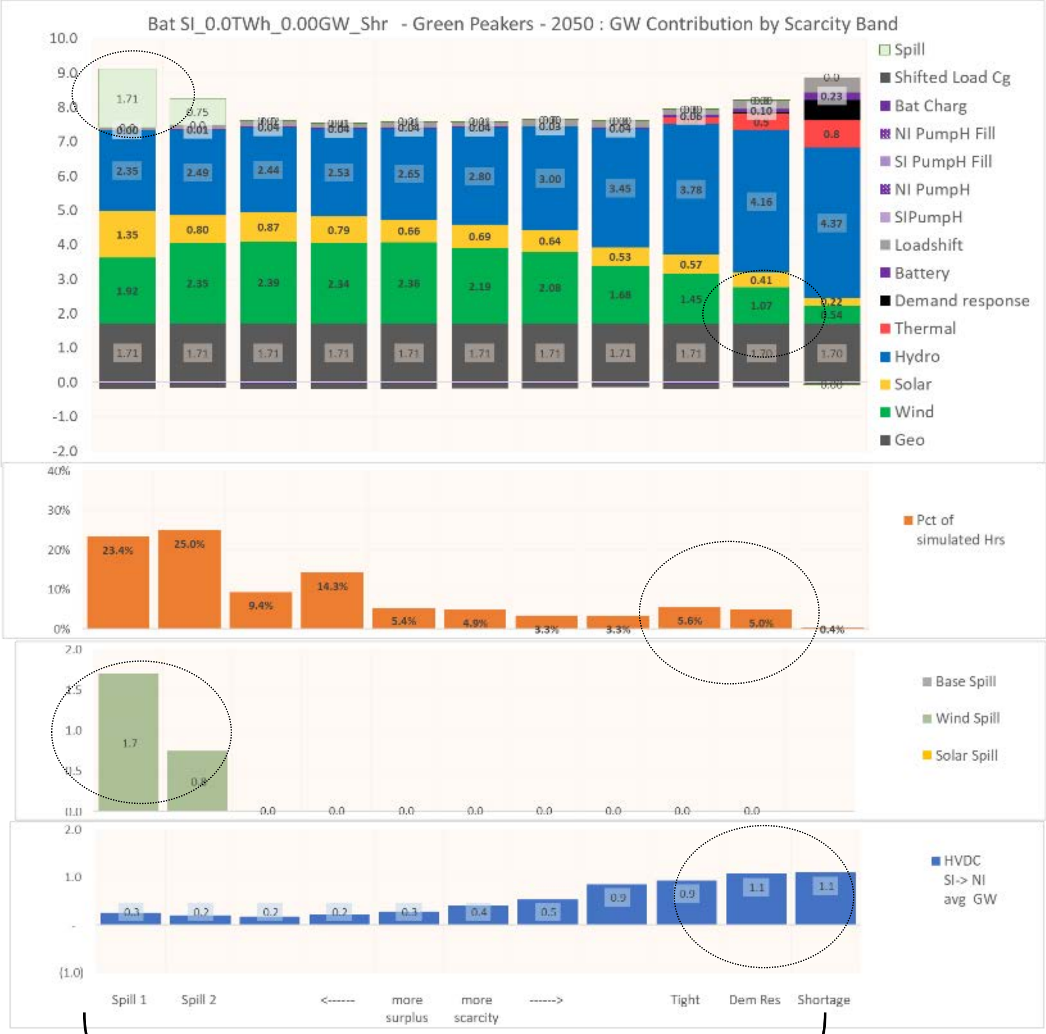
Illustrative Chart - 100% renewable in 2050

Average GW contribution of supply to meet demand in each “bin”

% of simulated periods in each “bin”

Average GW of “spill” by type in each bin

Average GW of HVDC Transfer



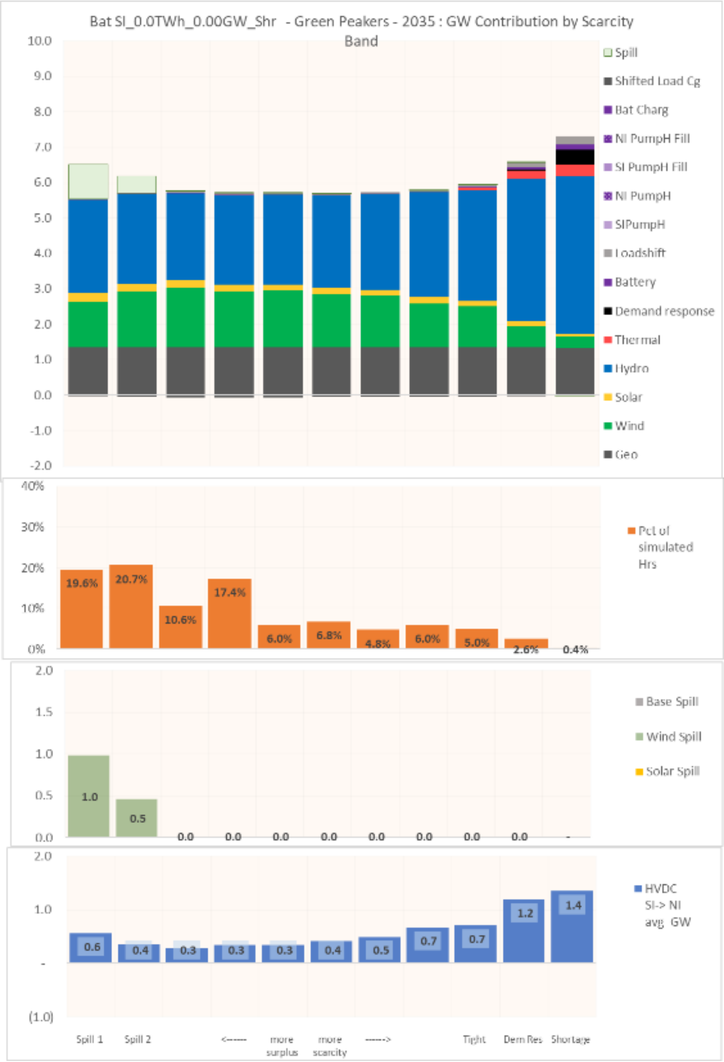
Individual “bins” ranked from low to high risk of scarcity

Chart explanation

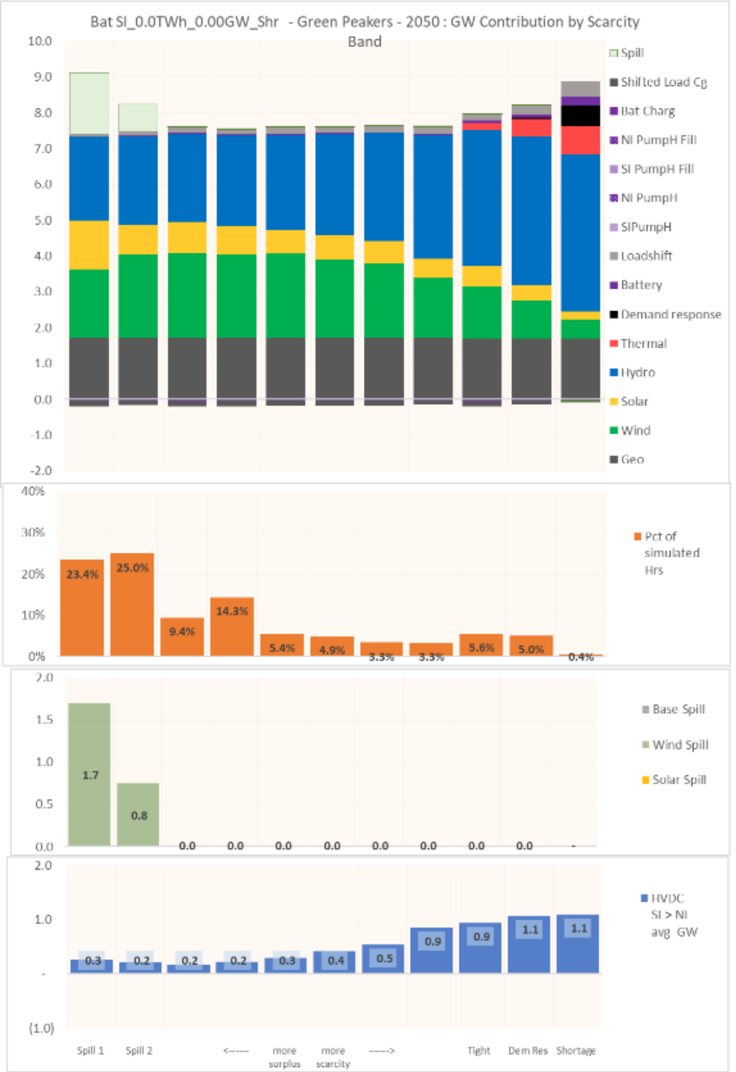
- These charts show the average MW contribution of different generation types in blocks of relative scarcity and shortage.
- **The charts are made by putting each simulated period in to number of “bins” which** are reflect the balance of supply and demand.
- **Bins with excess supply and high risk of “spill” are show on the left and bins with** relative shortage and high risk of demand response being required are shown to the right.
- The charts are useful to assess the value contribution of the different types of supply including intermitted supply (solar and wind), dispatchable hydro and thermal, and batteries of different sizes and duration.
  - **Note that “Demand response” includes both voluntary curtailed load and shoratges. “Load shifting” is smart shifting of EV charging load within the day.**
  - Batteries include different hours of storage (from 3 to 12 hours) and include that portion of behind the meter batteries that are scheduled according to system need.
- The percentage of periods in each indicated by the probability histogram.
  - The bins to the far right that correspond to demand response and shortage have low probability (typically < 1%) but a very high impact on cost.
- **The expected level of “spill” in each band is shown below. This is wind, solar and** geothermal being dispatched off when there is excess supply to meet demand.
  - **The bins to the left include a high risk of “spill” when prices fall below the** minimum offer prices for wind and solar.
- The final chart shows the expected level of South to North transfer on the HVDC link and illustrates the frequency of link limits being hit.
  - When the average HVDC S->N gets close to 1.4GW there is a high risk the HVDC **limit becomes binding, and SI flexible resources can’t be fully utilised to meet NI** shortages.

Contribution of renewables to periods of surplus and scarcity in 2035 and 2050 with and without NZ Battery

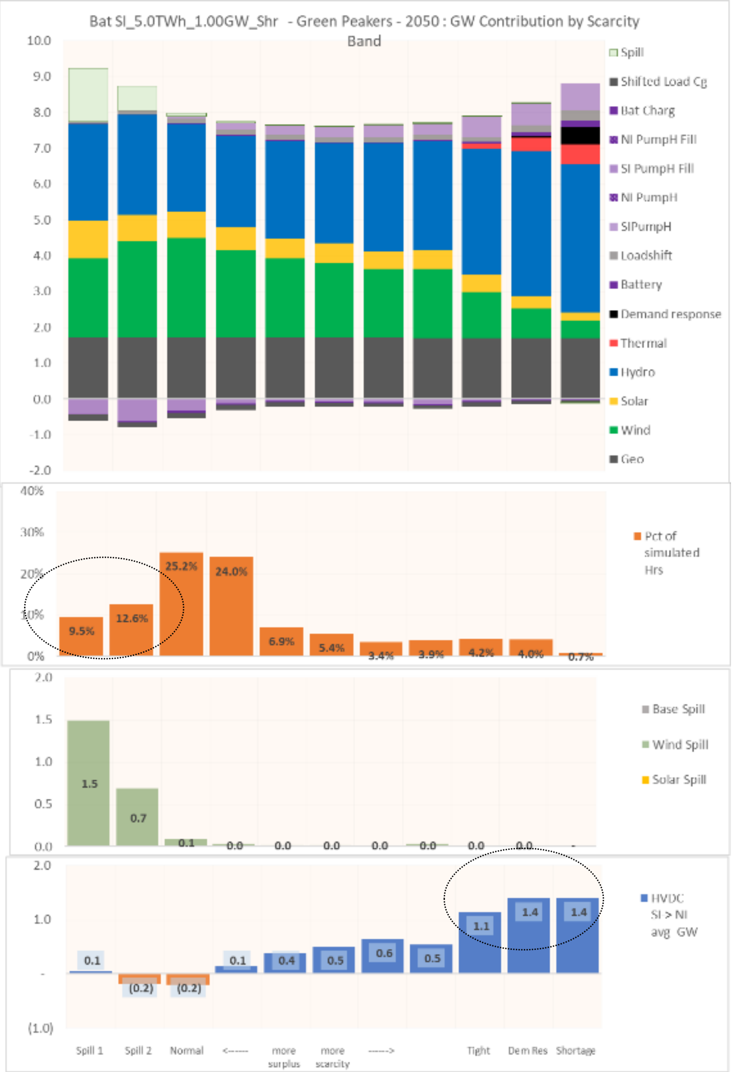
100% renewable with green peakers - 2035



100% renewable with green peakers -2050



100% renewable with peakers and NZ Battery in 2050



Notes: The horizontal axis is a set of "bins" of modelled periods ranked from periods of highest "spill" risk to highest scarcity/shortage risk. The vertical axis is average GW contribution to meeting demand in each "bin".

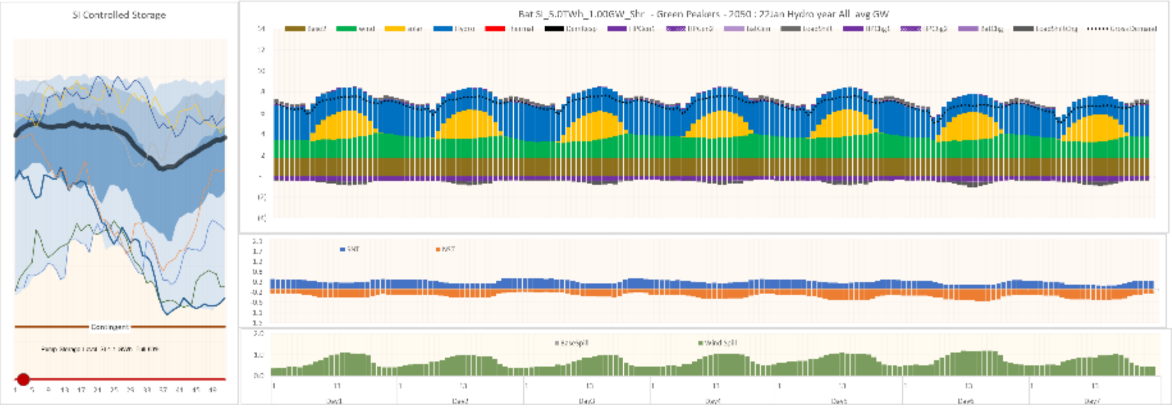
16. ILLUSTRATIVE WEEKLY PROFILES WITH SPILL AND SHORTAGE

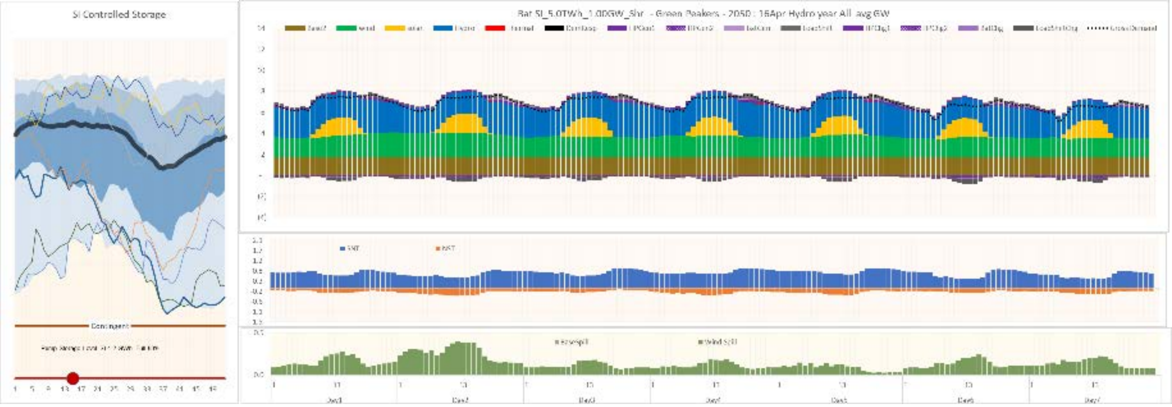
The average pattern of supply by season - 2050

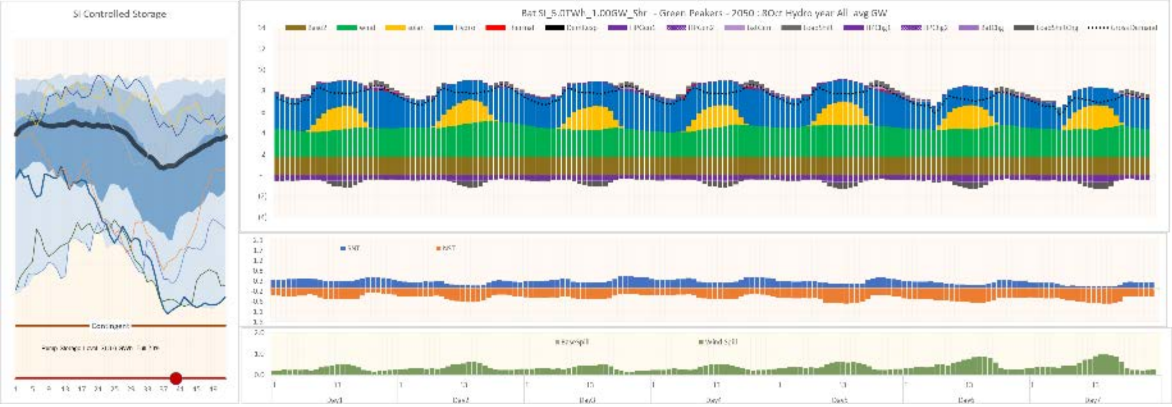
JC²

Average pattern - Upper) summer
Lower) autumn

Average pattern - Upper) winter
Lower) spring





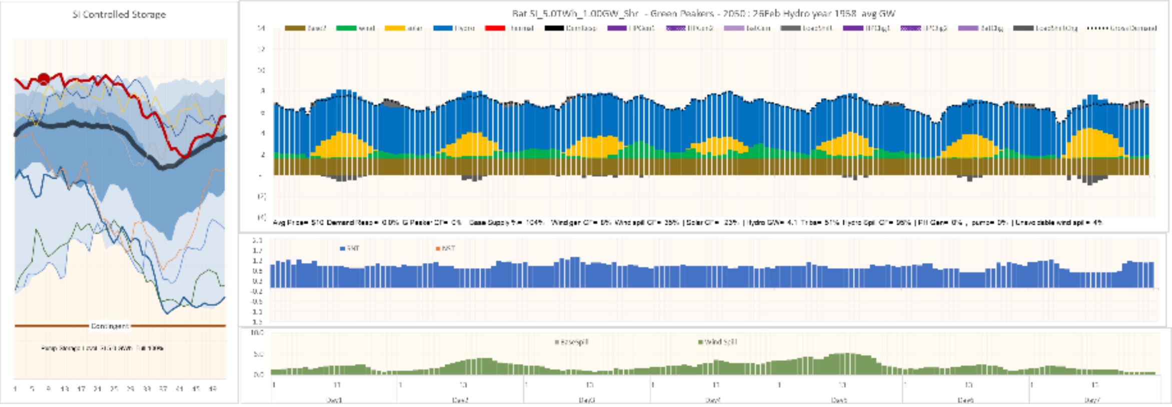


The average pattern of supply hides a multiplicity of within week variations and system conditions

JC²

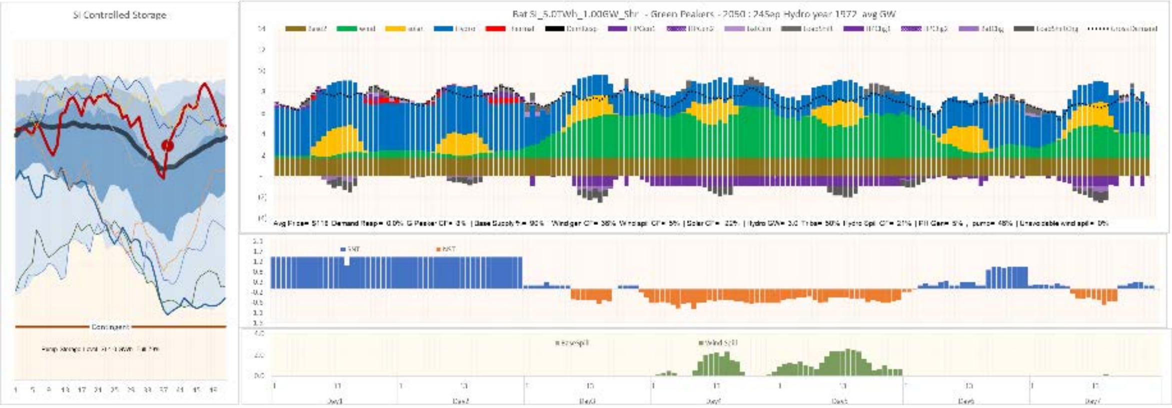
Upper) High wind spill in May - Pumping maximum

Lower) Wind spill in Feb - Pumped storage full- no head room



Upper) Peakers & Load curtailment - very low wind for a day in July - S->N link at limit

Lower) Peakers & load curtailment for few days - low wind in Sep S->N at limit



17. FULL TABLES OF RESULTS FOR PUMPED HYDRO AND PORTFOLIOS

Table of key results in the 3 worlds without and with a SI 5TWh/1GW pumped hydro

JC2

			No NZ Battery									With 5TWh/1.0GW Pumped Hydro								
			Gas Peakers			Green Peakers			Green Peakers Tiwai			Gas Peakers			Green Peakers			Green Peakers Tiwai		
		2020	2035	2050	2065	2035	2050	2065	2035	2050	2065	2035	2050	2065	2035	2050	2065	2035	2050	2065
Total Generation																				
Geo	TWh	7.7	10.9	14.1	14.1	10.9	14.1	14.1	10.9	14.1	14.1	10.9	14.1	14.1	10.9	14.1	14.1	10.9	14.1	14.1
Wind	TWh	2.5	11.4	18.1	20.9	12.6	18.1	20.9	16.0	21.9	23.6	12.2	20.4	22.7	12.7	20.4	22.7	17.5	24.5	26.2
Hydro	TWh	21.7	21.1	21.6	21.5	21.0	21.5	21.4	21.2	21.2	20.9	21.7	21.9	21.8	21.6	21.7	21.7	21.7	21.8	21.7
HydroRR	TWh	2.3	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Cogen	TWh	1.2	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Thermal	TWh	5.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Peaker	TWh	0.6	0.2	0.5	0.6	0.1	0.3	0.5	0.1	0.4	0.6	0.1	0.3	0.4	0.0	0.2	0.3	0.0	0.2	0.3
Reserve	TWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar	TWh	0.0	1.9	5.7	8.2	0.9	6.0	8.4	2.2	7.4	11.2	1.2	4.2	7.2	0.8	4.3	7.4	0.9	5.3	9.0
Roof PV	TWh	0.2	0.9	1.6	2.4	0.9	1.6	2.4	0.9	1.6	2.4	0.9	1.6	2.4	0.9	1.6	2.4	0.9	1.6	2.4
Total Generation excl flex	**TWh**	**41.4**	**49.5**	**64.8**	**70.9**	**49.5**	**64.8**	**70.9**	**54.4**	**69.8**	**75.9**	**50.1**	**65.7**	**71.8**	**50.1**	**65.6**	**71.8**	**55.1**	**70.7**	**76.9**
Pumped hydro gen	TWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3	1.7	1.9	1.2	1.6	1.8	1.5	1.7	2.0
Load shift Gen	TWh	-	0.2	1.0	1.4	0.2	1.0	1.4	0.3	1.1	1.5	0.2	0.9	1.3	0.2	0.9	1.3	0.3	1.0	1.4
Batteries Gen	TWh	0.0	0.0	0.0	0.2	0.0	0.1	0.3	0.1	0.1	0.7	0.0	0.0	0.2	0.0	0.0	0.3	0.0	0.1	0.4
Flex load backed off	TWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Flexible Supply	**TWh**	**0.0**	**0.3**	**1.1**	**1.6**	**0.2**	**1.1**	**1.6**	**0.3**	**1.3**	**2.2**	**1.5**	**2.7**	**3.4**	**1.5**	**2.6**	**3.4**	**1.8**	**2.8**	**3.8**
Pumped hydro load	TWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.8	2.4	2.7	1.7	2.3	2.5	2.1	2.5	2.8
Load shift Load	TWh	-	0.2	1.0	1.4	0.2	1.0	1.4	0.3	1.1	1.5	0.2	0.9	1.3	0.2	0.9	1.3	0.3	1.0	1.4
Batteries Load	TWh	0.0	0.0	0.0	0.2	0.0	0.1	0.3	0.1	0.2	0.8	0.0	0.0	0.3	0.0	0.1	0.3	0.0	0.1	0.4
Flex load	TWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Flexible Load	**TWh**	**0.0**	**0.3**	**1.1**	**1.6**	**0.3**	**1.1**	**1.7**	**0.3**	**1.3**	**2.3**	**2.1**	**3.4**	**4.2**	**2.0**	**3.3**	**4.2**	**2.4**	**3.5**	**4.7**
Demand excl Flexible	**TWh**	**41.4**	**49.5**	**64.8**	**70.9**	**49.5**	**64.8**	**70.9**	**54.4**	**69.8**	**75.8**	**49.5**	**64.9**	**71.0**	**49.5**	**64.9**	**71.0**	**54.5**	**69.9**	**76.0**
Total Spill	TWh	0.5	3.7	5.6	8.0	4.3	6.6	8.9	5.3	8.5	11.3	2.0	2.7	3.7	2.4	3.3	4.6	2.5	4.4	5.3
Total Shortage	TWh	0.01	0.01	0.04	0.05	0.02	0.05	0.05	0.03	0.04	0.05	0.01	0.02	0.03	0.02	0.04	0.04	0.02	0.04	0.04
Pct renewable & green peaker	**%**	**86%**	**100%**	**99%**	**99%**	**100%**	**99%**	**99%**	**100%**	**99%**	**99%**	**100%**	**100%**	**99%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Pct Wind	%	6%	23%	28%	30%	25%	28%	30%	29%	31%	31%	24%	31%	32%	25%	31%	32%	32%	35%	34%
Pct Solar	%	0%	6%	11%	15%	3%	12%	15%	6%	13%	18%	4%	9%	13%	3%	9%	14%	3%	10%	15%
Pct Intermittent	**%**	**7%**	**29%**	**39%**	**44%**	**29%**	**40%**	**45%**	**35%**	**44%**	**49%**	**28%**	**40%**	**45%**	**29%**	**40%**	**45%**	**35%**	**44%**	**49%**
CO2 Emissons	**mt**	**4.1**	**0.9**	**1.1**	**1.2**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**1.0**	**1.1**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**
Geothermal Emissions	mt	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Thermal Emissions	mt	3.3	0.1	0.3	0.3	-	-	-	-	-	-	0.0	0.2	0.2	-	-	-	-	-	-
Fuel Use	PJ	60.3	1.7	4.8	6.3	1.0	3.6	5.4	1.5	4.7	6.4	0.8	2.8	4.0	0.5	2.0	3.4	0.3	1.8	3.6
Wind	CF after spill	41%	34%	33%	31%	34%	32%	30%	33%	31%	29%	38%	37%	36%	37%	37%	35%	37%	36%	35%
Grid Solar	CF after spill	21%	21%	21%	21%	22%	21%	21%	21%	21%	21%	22%	21%	21%	22%	21%	21%	22%	21%	21%
Rooftop Solar	CF after spill	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
Wind Spill	% of Supply	1%	15%	20%	24%	17%	22%	27%	19%	24%	29%	7%	8%	11%	9%	10%	14%	8%	12%	14%
Pumped Hydro Gross CF	CF	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	14%	19%	21%	14%	19%	20%	17%	20%	22%
Pumped Hydro Pumping CF	CF	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	20%	28%	30%	20%	27%	29%	24%	28%	32%
Flexible Load CF	CF	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Table of key results in the 3 worlds without and with a SI 5TWh/1GW pumped hydro

			No NZ Battery									With 5TWh/1.0GW Pumped Hydro								
			Gas Peakers			Green Peakers			Green Peakers Tiwai			Gas Peakers			Green Peakers			Green Peakers Tiwai		
		2020	2035	2050	2065	2035	2050	2065	2035	2050	2065	2035	2050	2065	2035	2050	2065	2035	2050	2065
Flexible Load CF	CF	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total Capacity																				
Geo	GW	1.0	1.4	1.8	1.8	1.4	1.8	1.8	1.4	1.8	1.8	1.4	1.8	1.8	1.4	1.8	1.8	1.4	1.8	1.8
Wind	GW	0.7	3.8	6.3	7.8	4.3	6.6	8.0	5.6	8.1	9.4	3.7	6.2	7.2	3.9	6.4	7.4	5.4	7.9	8.6
Hydro	GW	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
HydroRR	GW	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Cogen	GW	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Thermal	GW	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Peaker	GW	0.5	0.4	1.0	1.2	0.4	0.8	1.1	0.4	1.0	1.2	0.3	0.7	1.0	0.3	0.6	0.9	0.2	0.5	0.9
Reserve	GW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar	GW	0.0	1.0	3.1	4.4	0.5	3.2	4.5	1.2	4.0	6.0	0.6	2.3	3.9	0.4	2.3	4.0	0.5	2.8	4.8
Roof PV	GW	0.1	0.7	1.4	2.1	0.7	1.4	2.1	0.7	1.4	2.1	0.7	1.4	2.1	0.7	1.4	2.1	0.7	1.4	2.1
HydroPump	GW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Grid Battery 4-12hr	GW	0.0	0.1	0.1	0.2	0.1	0.1	0.3	0.2	0.2	0.7	0.1	0.1	0.2	0.1	0.1	0.3	0.1	0.1	0.4
EV Load Shifting	GW	-	0.4	1.0	1.0	0.4	1.0	1.0	0.4	1.0	1.0	0.4	1.0	1.0	0.4	1.0	1.0	0.4	1.0	1.0
Roof Top Battery	GW	-	0.2	0.4	0.6	0.2	0.4	0.6	0.2	0.4	0.6	0.2	0.4	0.6	0.2	0.4	0.6	0.2	0.4	0.6
Demand Response	GW	0.4	0.6	0.8	1.0	0.6	0.8	1.0	0.7	0.9	1.1	0.6	0.8	1.0	0.6	0.8	1.0	0.7	0.9	1.1
Total Capacity	**GW**	**9.1**	**14.0**	**21.2**	**25.5**	**13.8**	**21.4**	**25.8**	**16.2**	**24.1**	**29.3**	**14.4**	**21.0**	**25.2**	**14.4**	**21.1**	**25.4**	**15.9**	**23.1**	**27.6**
Demand management & Batteries	GW	0.4	1.2	2.2	2.7	1.2	2.2	2.7	1.3	2.3	2.8	1.2	2.2	2.7	1.2	2.2	2.7	1.3	2.3	2.8
as % total capacity	%	4%	9%	10%	10%	9%	10%	10%	8%	10%	9%	9%	11%	11%	9%	10%	11%	8%	10%	10%
Load shifting % demand TWh	%	-	0.5%	1.6%	1.9%	0.5%	1.6%	1.9%	0.5%	1.6%	2.0%	0.5%	1.4%	1.8%	0.5%	1.4%	1.8%	0.5%	1.4%	1.9%
Battery shifting % demand TWh	%	0%	0.0%	0.1%	0.3%	0.0%	0.1%	0.4%	0.1%	0.2%	0.9%	0.0%	0.1%	0.3%	0.0%	0.1%	0.4%	0.0%	0.1%	0.5%
Pumped hydro % demand TWh	%	0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.5%	2.6%	2.6%	2.4%	2.5%	2.5%	2.6%	2.4%	2.6%
Geothermal Investment	GW	-	0.4	0.8	0.8	0.4	0.8	0.8	0.4	0.8	0.8	0.4	0.8	0.8	0.4	0.8	0.8	0.4	0.8	0.8
Wind Investment	GW	-	3.1	5.6	7.1	3.6	5.8	7.3	4.9	7.4	8.7	3.0	5.5	6.5	3.2	5.7	6.7	4.7	7.1	7.9
Grid Solar Investment	GW	-	1.0	3.1	4.4	0.5	3.2	4.5	1.2	4.0	6.0	0.6	2.3	3.9	0.4	2.3	4.0	0.5	2.8	4.8
Rooftop Solar Investment	GW	-	0.6	1.2	2.0	0.6	1.2	2.0	0.6	1.2	2.0	0.6	1.2	2.0	0.6	1.2	2.0	0.6	1.2	2.0
Total renewable investment	**GW**	**-**	**5.1**	**10.7**	**14.3**	**5.0**	**11.1**	**14.6**	**7.1**	**13.4**	**17.4**	**4.6**	**9.8**	**13.1**	**4.7**	**10.0**	**13.5**	**6.2**	**12.0**	**15.5**
SI Renewable Investment	GW	-	0.6	1.8	2.5	0.5	1.7	2.5	1.4	3.6	4.9	0.4	1.4	2.1	0.4	1.3	2.2	1.2	3.0	4.2
Total Capex Value (ex NZ Battery)	**$b**		**16.3**	**25.0**	**27.8**	**16.4**	**25.4**	**28.2**	**20.0**	**29.1**	**32.2**	**15.6**	**23.7**	**26.1**	**15.6**	**23.9**	**26.5**	**18.4**	**26.9**	**29.2**
Geothermal	$b		7.6	9.8	9.8	7.6	9.8	9.8	7.6	9.8	9.8	7.6	9.8	9.8	7.6	9.8	9.8	7.6	9.8	9.8
Wind	$b		7.0	10.9	12.6	7.9	11.3	13.0	10.3	14.0	15.1	6.8	10.7	11.6	7.2	11.0	12.0	10.0	13.5	13.9
Grid Solar	$b		1.2	3.2	3.9	0.5	3.3	4.1	1.4	4.1	5.4	0.7	2.3	3.5	0.5	2.4	3.6	0.6	2.9	4.3
Peakers	$b		0.4	1.0	1.2	0.4	0.8	1.1	0.4	1.0	1.2	0.3	0.7	1.0	0.3	0.6	0.9	0.2	0.5	0.9
Batteries	$b		0.1	0.1	0.2	0.1	0.1	0.3	0.3	0.2	0.7	0.1	0.1	0.2	0.1	0.1	0.3	0.1	0.1	0.3

Table of key results in the 3 worlds without and with a portfolio of other technologies

			No NZ Battery						With Portfolio					
			Green Peakers			Green Peakers Tiwai			Green Peakers			Green Peakers Tiwai		
		2020	2035	2050	2065	2035	2050	2065	2035	2050	2065	2035	2050	2065
Total Generation														
Geo	TWh	7.7	10.9	14.1	14.1	10.9	14.1	14.1	12.5	15.3	15.2	12.5	15.4	15.2
Wind	TWh	2.5	12.6	18.1	20.9	16.0	21.9	23.6	12.3	18.2	21.1	16.5	22.1	23.7
Hydro	TWh	21.7	21.0	21.5	21.4	21.2	21.2	20.9	21.7	21.9	21.8	21.7	21.6	21.3
HydroRR	TWh	2.3	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.2
Cogen	TWh	1.2	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Thermal	TWh	5.2	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.4	0.5	0.3	0.5	0.6
Peaker	TWh	0.6	0.1	0.3	0.5	0.1	0.4	0.6	0.0	0.0	0.1	0.0	0.1	0.2
Reserve	TWh	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar	TWh	0.0	0.9	6.0	8.4	2.2	7.4	11.2	0.8	6.3	8.2	1.4	7.5	10.9
Roof PV	TWh	0.2	0.9	1.6	2.4	0.9	1.6	2.4	0.9	1.6	2.4	0.9	1.6	2.4
Total Generation excl flex	**TWh**	**41.4**	**49.5**	**64.8**	**70.9**	**54.4**	**69.8**	**75.9**	**51.7**	**66.9**	**72.4**	**56.5**	**71.9**	**77.5**
Pumped hydro gen	TWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Load shift Gen	TWh	-	0.2	1.0	1.4	0.3	1.1	1.5	0.2	1.1	1.4	0.3	1.2	1.6
Batteries Gen	TWh	0.0	0.0	0.1	0.3	0.1	0.1	0.7	0.0	0.1	0.2	0.0	0.1	0.7
Flex load backed off	TWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	1.2	1.3	0.7	1.2	1.3
Flexible Supply	**TWh**	**0.0**	**0.2**	**1.1**	**1.6**	**0.3**	**1.3**	**2.2**	**1.0**	**2.4**	**3.0**	**1.0**	**2.5**	**3.5**
Pumped hydro load	TWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Load shift Load	TWh	-	0.2	1.0	1.4	0.3	1.1	1.5	0.2	1.1	1.4	0.3	1.2	1.6
Batteries Load	TWh	0.0	0.0	0.1	0.3	0.1	0.2	0.8	0.0	0.1	0.2	0.0	0.1	0.7
Flex load	TWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.2	3.3	3.2	3.2	3.3	3.2
Flexible Load	**TWh**	**0.0**	**0.3**	**1.1**	**1.7**	**0.3**	**1.3**	**2.3**	**3.5**	**4.5**	**4.9**	**3.5**	**4.6**	**5.6**
Demand excl Flexible	**TWh**	**41.4**	**49.5**	**64.8**	**70.9**	**54.4**	**69.8**	**75.8**	**49.2**	**64.8**	**70.4**	**54.0**	**69.8**	**75.4**
Total Spill	TWh	0.5	4.3	6.6	8.9	5.3	8.5	11.3	3.0	5.1	7.0	3.7	6.5	8.9
Total Shortage	TWh	0.01	0.02	0.05	0.05	0.03	0.04	0.05	0.00	0.05	0.06	0.01	0.04	0.05
Pct renewable & green peaker	**%**	**86%**	**100%**	**99%**	**99%**	**100%**	**99%**	**99%**	**100%**	**99%**	**99%**	**99%**	**99%**	**99%**
Pct Wind	%	6%	25%	28%	30%	29%	31%	31%	24%	27%	29%	29%	31%	31%
Pct Solar	%	0%	3%	12%	15%	6%	13%	18%	3%	12%	15%	4%	13%	17%
Pct Intermittent	**%**	**7%**	**29%**	**40%**	**45%**	**35%**	**44%**	**49%**	**27%**	**39%**	**44%**	**33%**	**43%**	**48%**
CO2 Emissons	**mt**	**4.1**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**1.3**	**1.2**	**1.2**	**1.3**	**1.2**	**1.2**
Geothermal Emissions	mt	0.8	0.8	0.8	0.8	0.8	0.8	0.8	1.3	1.2	1.2	1.3	1.2	1.2
Thermal Emissions	mt	3.3	-	-	-	-	-	-	-	-	-	-	-	-
Fuel Use	PJ	60.3	1.0	3.6	5.4	1.5	4.7	6.4	2.6	4.0	6.0	3.4	5.6	7.9
Wind	CF after spill	41%	34%	32%	30%	33%	31%	29%	38%	35%	33%	37%	35%	32%
Grid Solar	CF after spill	21%	22%	21%	21%	21%	21%	21%	22%	21%	21%	22%	21%	21%
Rooftop Solar	CF after spill	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
Wind Spill	% of Supply	1%	17%	22%	27%	19%	24%	29%	8%	13%	18%	9%	15%	20%
Pumped Hydro Gross CF	CF	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Pumped Hydro Pumping CF	CF	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Flexible Load CF	CF	0%	0%	0%	0%	0%			78%	62%	59%	78%	63%	61%

Table of key results in the 3 worlds without and with a portfolio of other technologies

			No NZ Battery						With Portfolio					
			Green Peakers			Green Peakers Tiwai			Green Peakers			Green Peakers Tiwai		
		2020	2035	2050	2065	2035	2050	2065	2035	2050	2065	2035	2050	2065
Total Capacity														
Geo	GW	1.0	1.4	1.8	1.8	1.4	1.8	1.8	1.7	2.1	2.1	1.7	2.1	2.1
Wind	GW	0.7	4.3	6.6	8.0	5.6	8.1	9.4	3.7	5.9	7.2	5.1	7.3	8.4
Hydro	GW	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
HydroRR	GW	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Cogen	GW	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Thermal	GW	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.6	0.6	0.6	0.6
Peaker	GW	0.5	0.4	0.8	1.1	0.4	1.0	1.2	0.0	0.1	0.4	0.0	0.3	0.6
Reserve	GW	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar	GW	0.0	0.5	3.2	4.5	1.2	4.0	6.0	0.4	3.4	4.4	0.8	4.0	5.9
Roof PV	GW	0.1	0.7	1.4	2.1	0.7	1.4	2.1	0.7	1.4	2.1	0.7	1.4	2.1
HydroPump	GW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grid Battery 4-12hr	GW	0.0	0.1	0.1	0.3	0.2	0.2	0.7	0.1	0.1	0.2	0.1	0.1	0.6
EV Load Shifting	GW	-	0.4	1.0	1.0	0.4	1.0	1.0	0.4	1.0	1.0	0.4	1.0	1.0
Roof Top Battery	GW	-	0.2	0.4	0.6	0.2	0.4	0.6	0.2	0.4	0.6	0.2	0.4	0.6
Demand Response	GW	0.4	0.6	0.8	1.0	0.7	0.9	1.1	1.0	1.2	1.4	1.1	1.3	1.5
Total Capacity	**GW**	**9.1**	**13.8**	**21.4**	**25.8**	**16.2**	**24.1**	**29.3**	**14.2**	**21.5**	**25.3**	**16.0**	**23.8**	**28.6**
Demand management & Batteries	GW	0.4	1.2	2.2	2.7	1.3	2.3	2.8	1.6	2.6	3.0	1.7	2.7	3.1
as % total capacity	%	4%	9%	10%	10%	8%	10%	9%	11%	12%	12%	11%	11%	11%
Load shifting % demand TWh	%	-	0.5%	1.6%	1.9%	0.5%	1.6%	2.0%	0.4%	1.7%	2.0%	0.5%	1.7%	2.0%
Battery shifting % demand TWh	%	0%	0.0%	0.1%	0.4%	0.1%	0.2%	0.9%	0.0%	0.1%	0.3%	0.0%	0.2%	0.8%
Pumped hydro % demand TWh	%	0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Geothermal Investment	GW	-	0.4	0.8	0.8	0.4	0.8	0.8	0.7	1.1	1.1	0.7	1.1	1.1
Wind Investment	GW	-	3.6	5.8	7.3	4.9	7.4	8.7	3.0	5.1	6.5	4.4	6.6	7.7
Grid Solar Investment	GW	-	0.5	3.2	4.5	1.2	4.0	6.0	0.4	3.4	4.4	0.8	4.0	5.9
Rooftop Solar Investment	GW	-	0.6	1.2	2.0	0.6	1.2	2.0	0.6	1.2	2.0	0.6	1.2	2.0
Total renewable investment	**GW**	**-**	**5.0**	**11.1**	**14.6**	**7.1**	**13.4**	**17.4**	**4.8**	**10.9**	**14.0**	**6.5**	**12.9**	**16.6**
SI Renewable Investment	GW	-	0.5	1.7	2.5	1.4	3.6	4.9	0.4	1.7	2.5	1.0	3.3	4.5
Total Capex Value (ex NZ Battery)	**$b**		**16.4**	**25.4**	**28.2**	**20.0**	**29.1**	**32.2**	**16.7**	**25.3**	**27.5**	**19.7**	**28.6**	**31.3**
Geothermal	$b		7.6	9.8	9.8	7.6	9.8	9.8	9.3	11.5	11.5	9.3	11.5	11.5
Wind	$b		7.9	11.3	13.0	10.3	14.0	15.1	6.9	10.1	11.6	9.4	12.6	13.5
Grid Solar	$b		0.5	3.3	4.1	1.4	4.1	5.4	0.5	3.5	3.9	0.9	4.1	5.2
Peakers	$b		0.4	0.8	1.1	0.4	1.0	1.2	0.0	0.1	0.4	0.0	0.3	0.6
Batteries	$b		0.1	0.1	0.3	0.3	0.2	0.7	0.1	0.1	0.1	0.1	0.1	0.5

18. TIWAI STAYS SENSITIVITY

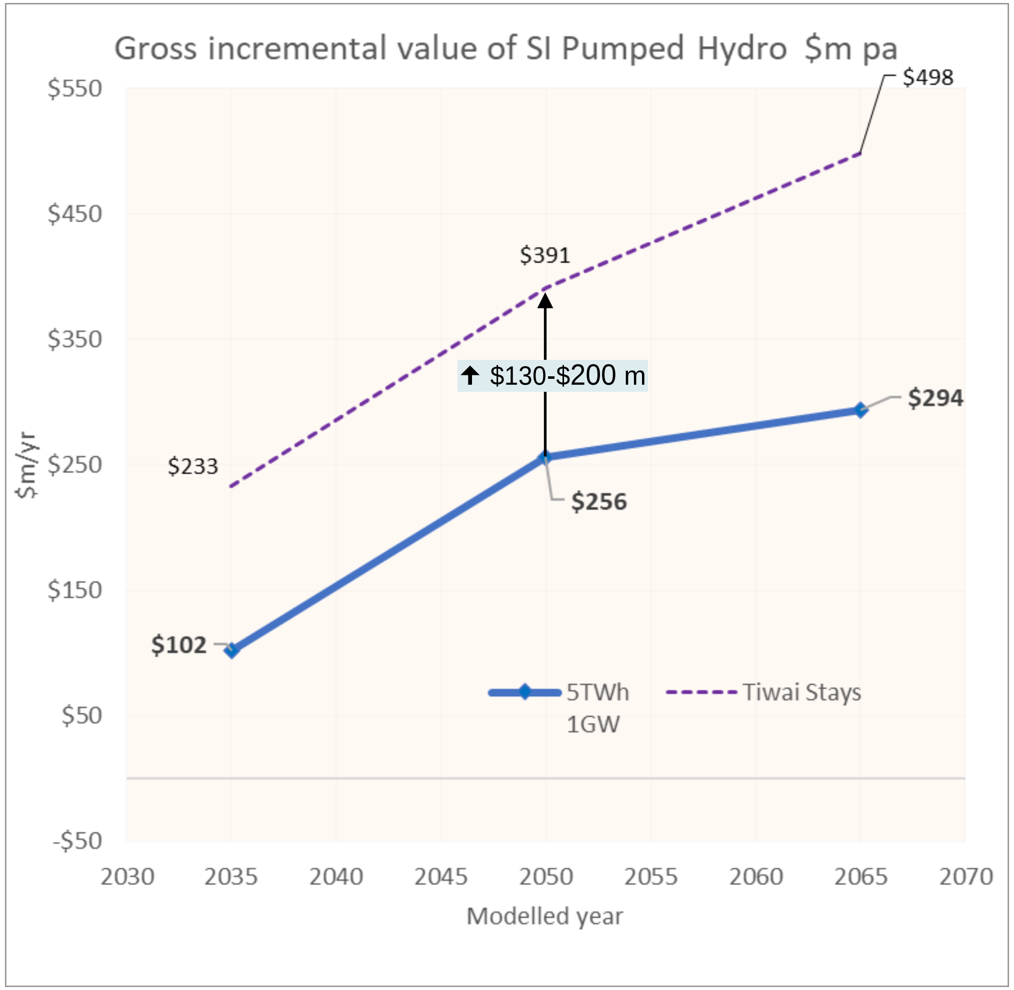
Tiwai Stays sensitivity - green peakers counterfactual

JC2

There is a possibility that Tiwai continues to operate beyond 2035

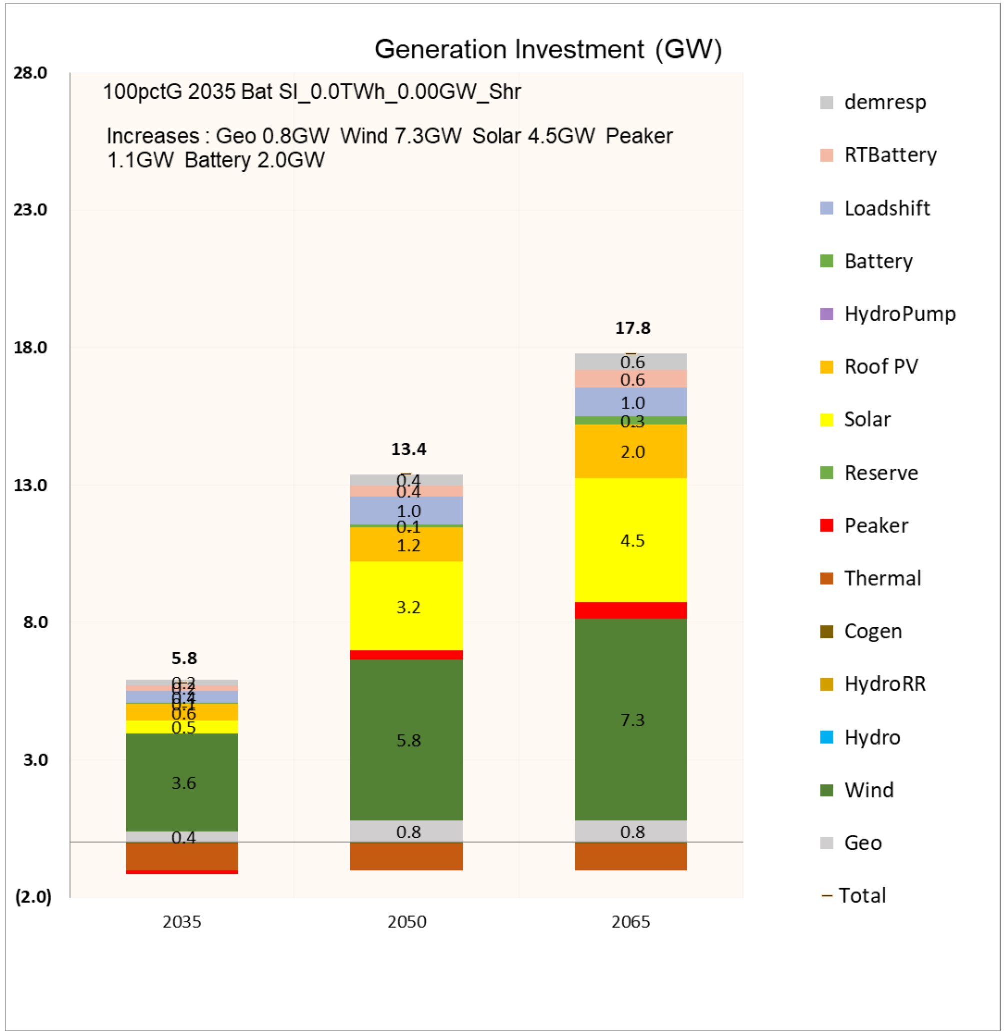
- This sensitivity explores the implications of Tiwai continuing to operate over the period 2035 to 2065.
  - For this sensitivity it is assumed that Tiwai operates in an baseload mode with an average load of 572MW, with the existing arrangement which allows a 80MW reduction when hydro storages in the SI lakes are very low (we use the $500/MWh storage offer curve as a proxy).
  - Firm baseload electricity prices are greater if Tiwai stays, and it is not clear if Tiwai would be able to sustain baseload operation at this level of demand at these prices.
    - Firm baseload SI prices are expected to increase to around $90/MWh by 2050 if Tiwai stays.
  - Note that by 2035 the Tiwai smelter will be over 60 years old by 2035 and would be over 90 years old by 2065.
    - Even the third pot line will be around 50yrs old by 2035.
  - It is likely that significant capital investment would be required for the smelter to continue to operate over the 2035-2065 period.
    - It is possible that Tiwai might invest to enable more flexible operation. If this was the case, and if Tiwai was able to reduce operations significantly when spot prices were high then its electricity costs could be reduced significantly.
  - It is not known if Tiwai would invest, and so we consider a more likely scenario which involves the same 80MW reduction, but triggered at a higher storage (proxied by the $250/MWh offer curve).

The incremental gross value of Onslow pumped storage increases if Tiwai stays as an inflexible demand.

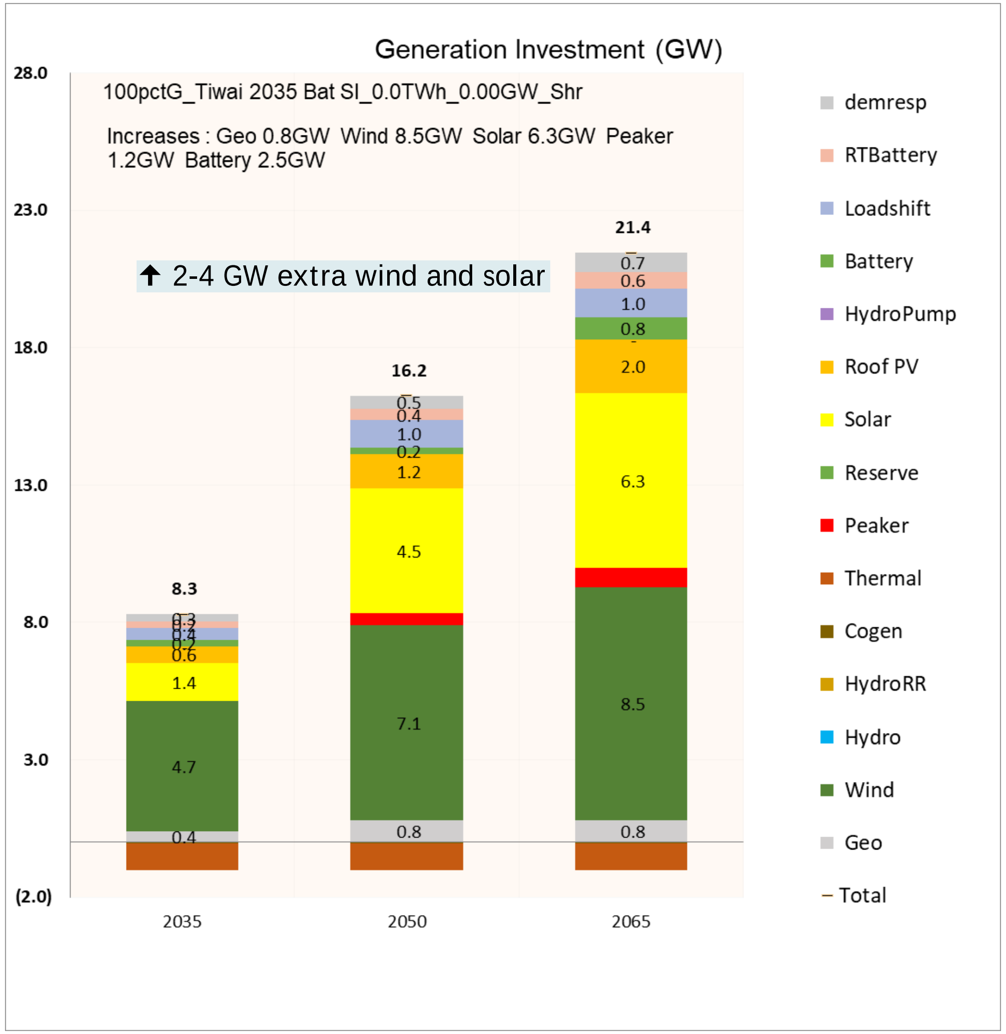


Around 3-4GW additional renewable and firming investment is required if Tiwai stays

Base Case - Tiwai exits by 2035



Tiwai stays to 2065 sensitivity

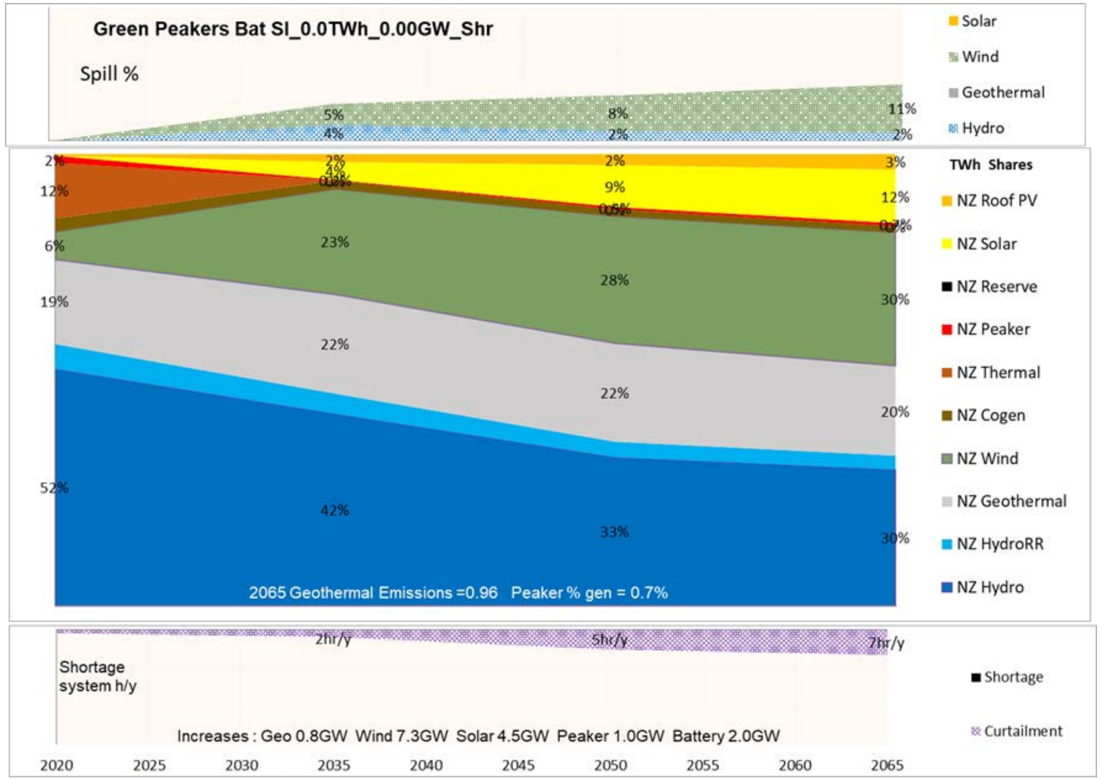


↑ 2-4 GW extra wind and solar

A greater % of wind and solar is required in Tiwai stays

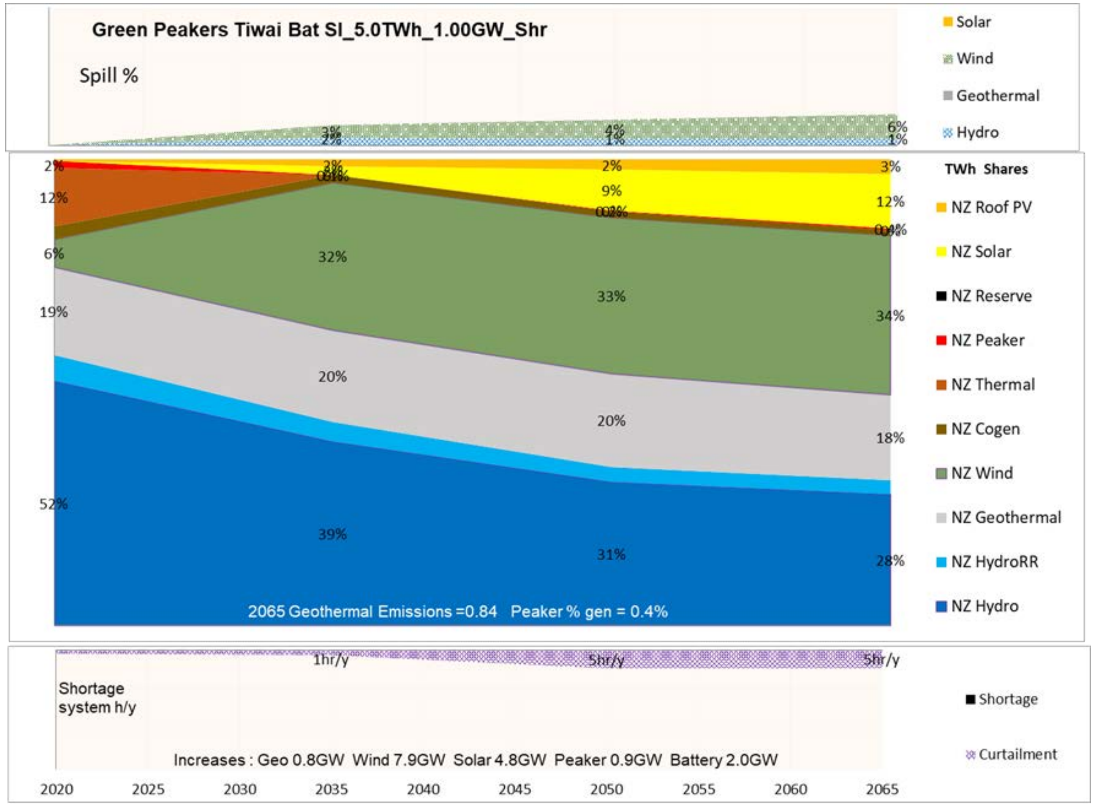
JC2

Base Case generation shares



Green Peakers counterfactual		No NZ Battery 2035	2050	2065
Wind/Solar	GW	1.2	4.6	6.6
Green peaker	GW	0.4	0.8	1.1
Green peaker	TWh %gen	0.2%	0.5%	0.7%
Total Emissions CO2-e	mt/y	0.8	0.8	0.8
" Spill "	TWh/y	4.3	6.6	8.9
Curtailment	SysHr/y	3.0	6.3	6.3
Wind/Solar GW investment	x 2020GW	0.7	5.5	8.3

There is an increase in the % intermittent supply if Tiwai demand stays

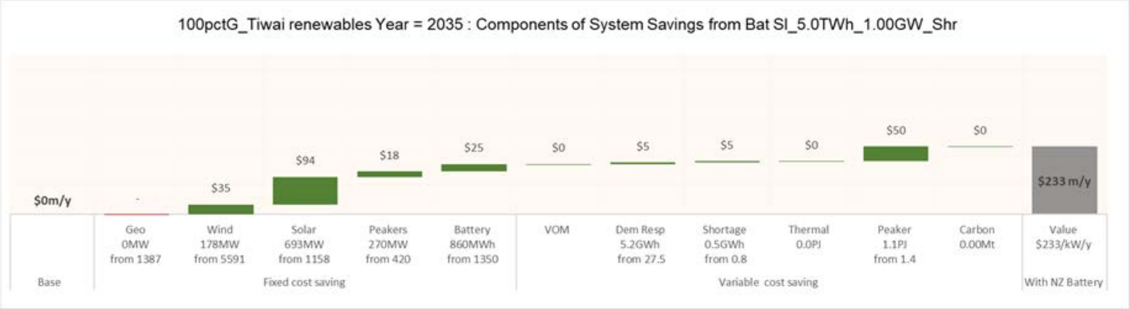


Green Peakers Tiwai counterfactual		Saving from Pumped storage 2035	2050	2065
Wind/Solar	GW	0.9	1.4	1.9
Green peaker	GW	0.3	0.5	0.3
Green peaker	TWh %gen	0.2%	0.4%	0.4%
Total Emissions CO2-e	mt/y	0.0	(0.0)	(0.0)
" Spill "	TWh/y	2.8	4.2	6.1
Curtailment	SysHr/y	0.9	0.1	1.5

The gross incremental benefit of Onslow 5.0TWh/1.0GW is increased if Tiwai stays

JC²

The chart shows the breakdown of the benefit of a 5TWh/1GW pumped hydro relative to a Tiwai Stays counterfactual is between $234 and $514m/yr

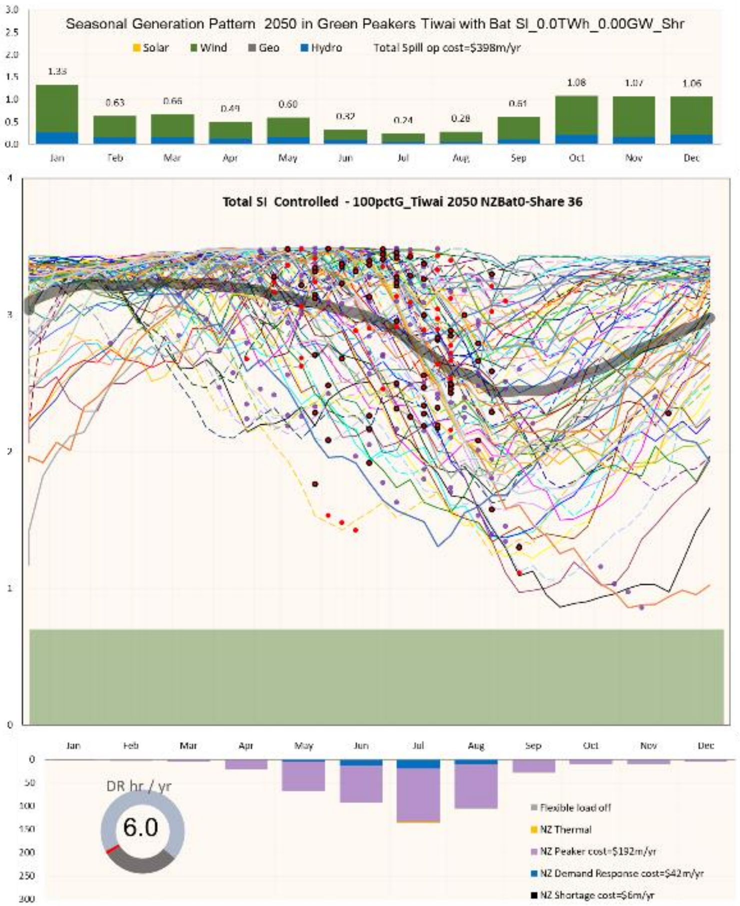


Comments

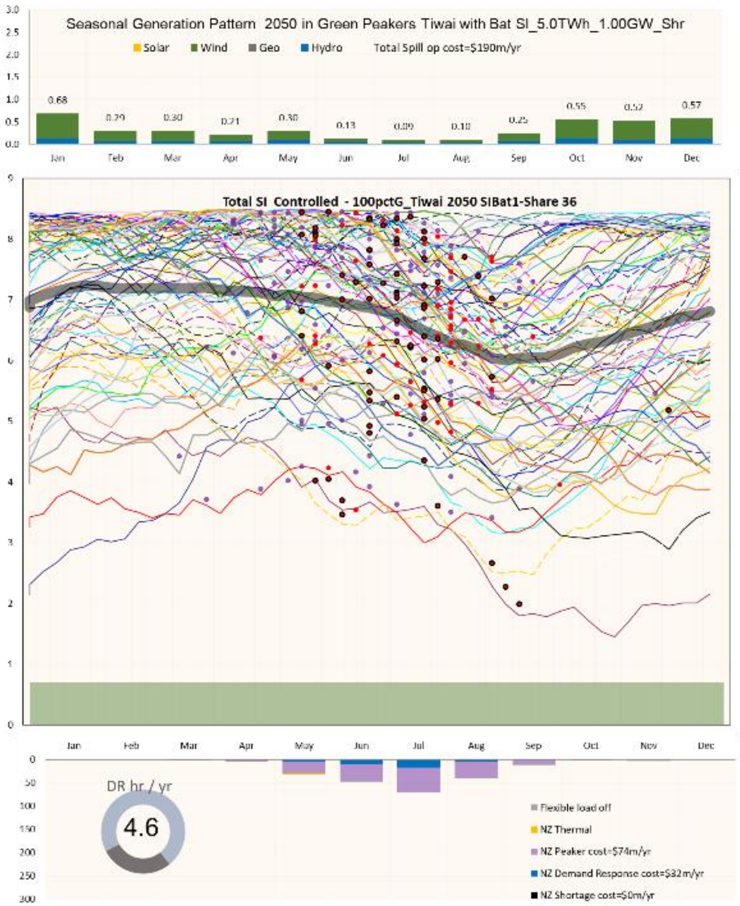
- The chart shows the benefit of a 5TWh/1.0GW pumped storage where the 600MW Tiwai stays.
    - This assumes that the existing 80MW of demand response is available when lake levels fell to very low levels (modelled as a the $500/MWh storage curve).
  - This benefit increases from $233m/y in 2035 to almost $500m/y in 2065
    - The benefit of pumped storage is greater as total demand is higher, and so more renewables with lower capture rates and greater spill are required.
  - There is also a greater benefit since the HVDC is less of a constraint.
    - The extra load in the South Island means that the average level of power flow from South to North is closer to zero and the frequency of HVDC limits being binding is lower.
  - The Onslow pumped storage enables greater savings in renewable investments and greater savings in green peaker fuel costs.

Hydro operation in 2050 if Tiwai stays ..

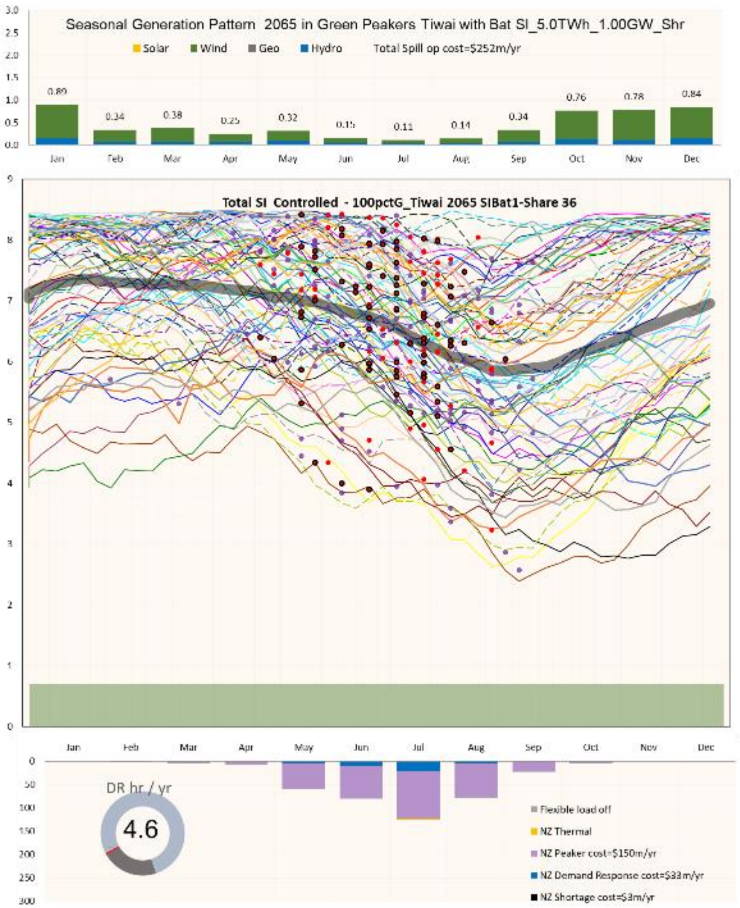
No NZ Battery



With NZ Battery - 2050



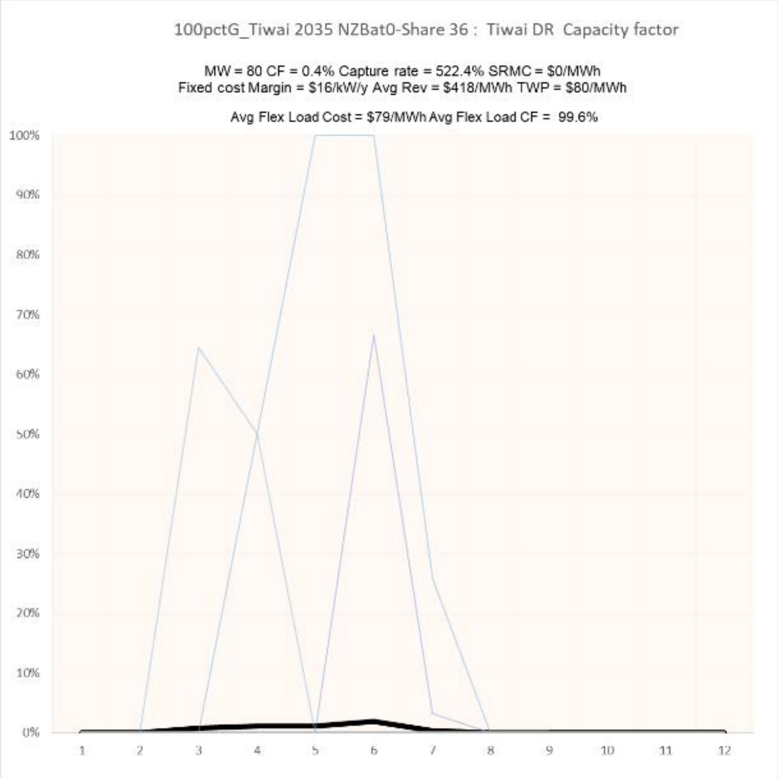
With NZ Battery - 2065



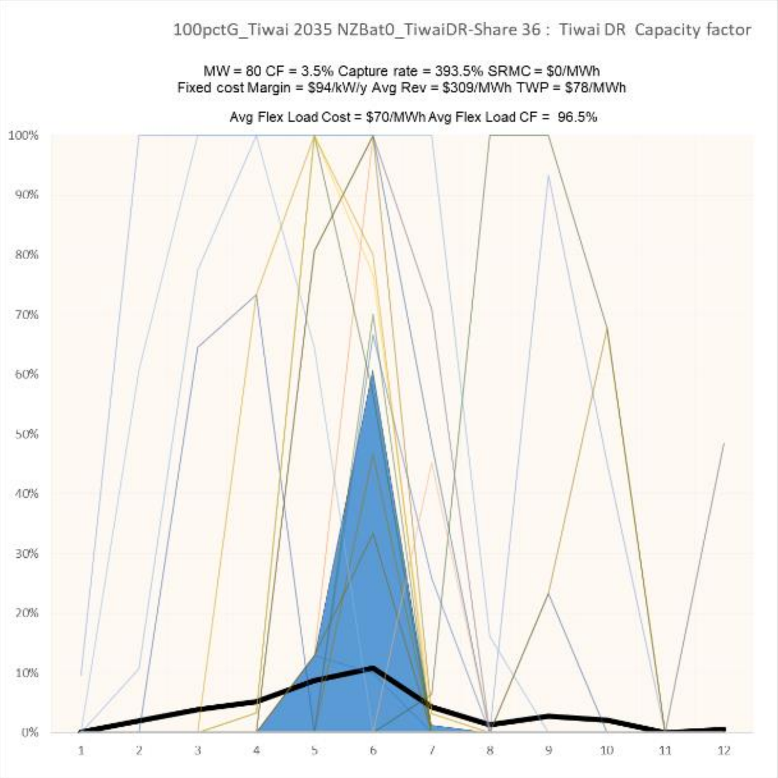
Tiwai demand reduction would only be triggered a couple of years out of 87 using the $500/MWh storage trigger. This would be increased 10% of years in 2035 with using a $250/MWh trigger, but then would reduce as the balance of risk moves from dry years to dunkleflautes.

JC²

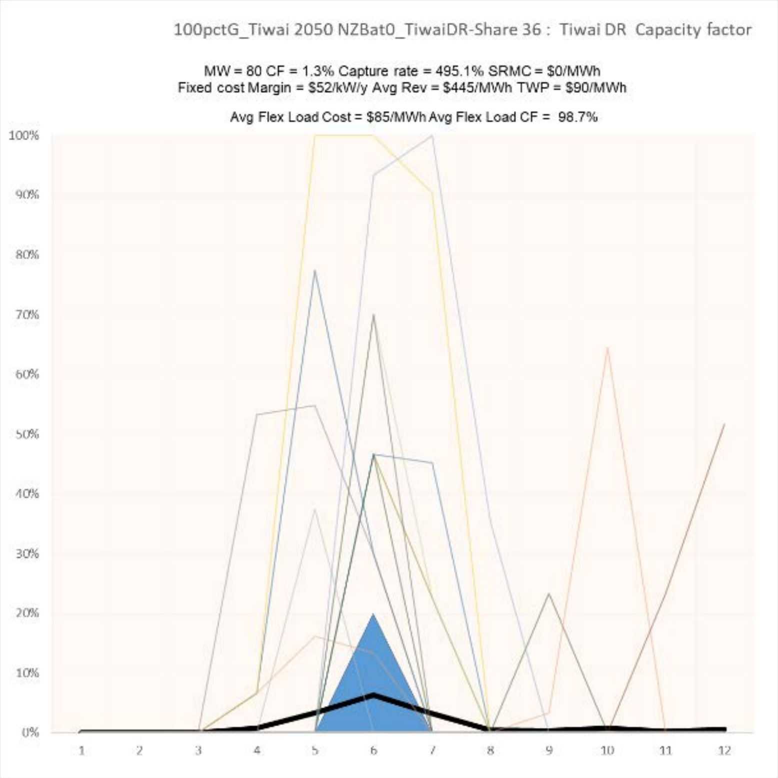
Use of 80MW Tiwai demand response triggered at $500/MWh storage guideline - 2035



Use of 80MW Tiwai demand response triggered at $250/MWh storage guideline 2035



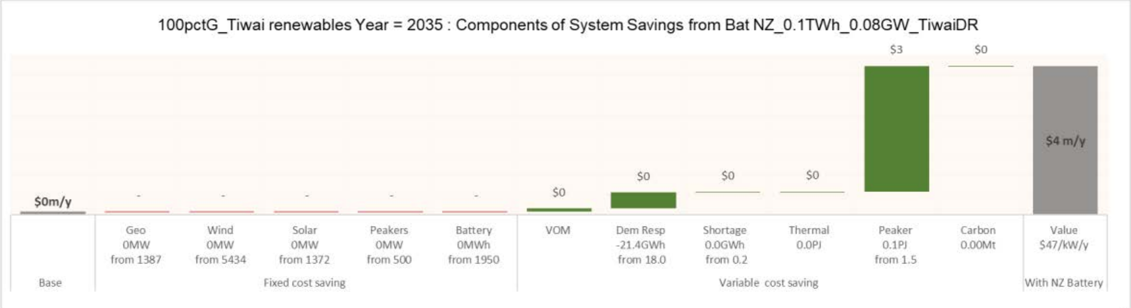
.. In 2050 the value declines as balance of risk moves from dry years to dunkleflautes

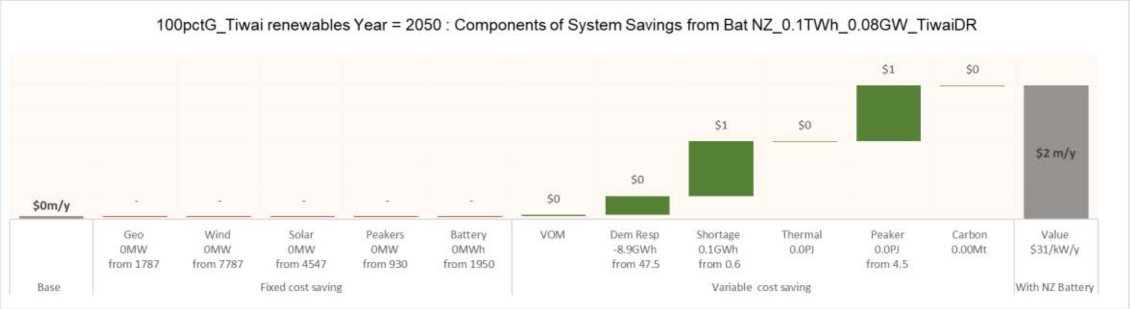


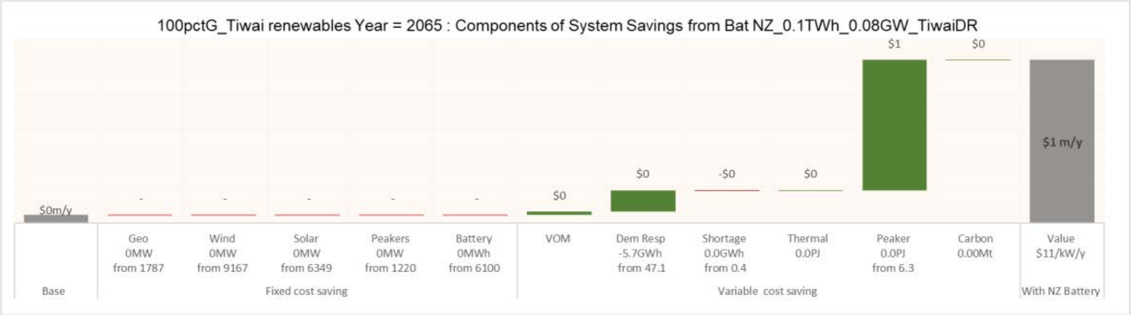
The gross incremental benefit of extra use of 80MW Tiwai response is only $1-4m/yr

JC²

The chart shows the benefit of increased use of 80MW of demand response from Tiwai achieved by lowering the trigger from $500/MWh to $250/MWh.







Comments

- Modelled extra demand response:
  - Lowering the Tiwai trigger lake storage level from $500/MWh to $250/MWh increases the use of 80MW Tiwai demand reduction from 1 year in 87 to around 8 years in 87.
  - This provides around $4m/yr of gross benefit in 2035, falling to $1m/yr as the balance of risks moves from dry years towards dunkleflautes.
  - This extra Tiwai demand response is included in Portfolio 3.
- Potential additional demand response (not modelled):
  - Much greater flexibility might be achieved by investing in NPOT technology or equivalent.
  - This would enable Tiwai to reduce demand at times of high prices as well as times of low lake levels.
    - It is not certain how much flexibility could be provided.
      - However, as an indication, Concept Consulting[1] in their modelling for the Boston Consulting Group study[2] assumed that 400MW of demand response could be provided in 100MW blocks when prices were between $100-$400/MWh, while the last 200MW would only be curtailed when prices reached $4,000/MWh.
      - Boston Consulting report[2] (page 91) suggests that technology to enable 25% of Tiwai load to be controlled would cost $50-60m.
  - This level of demand reduction would be much more valuable and could targeted during periods of both capacity and energy shortage risk.

(1) Concept consulting: “Which way is forward? Analysis of key choices for New Zealand’s energy sector”, 21 October 2022
(2) Boston Consulting Group study – “The Future is Electric “ October 2022.

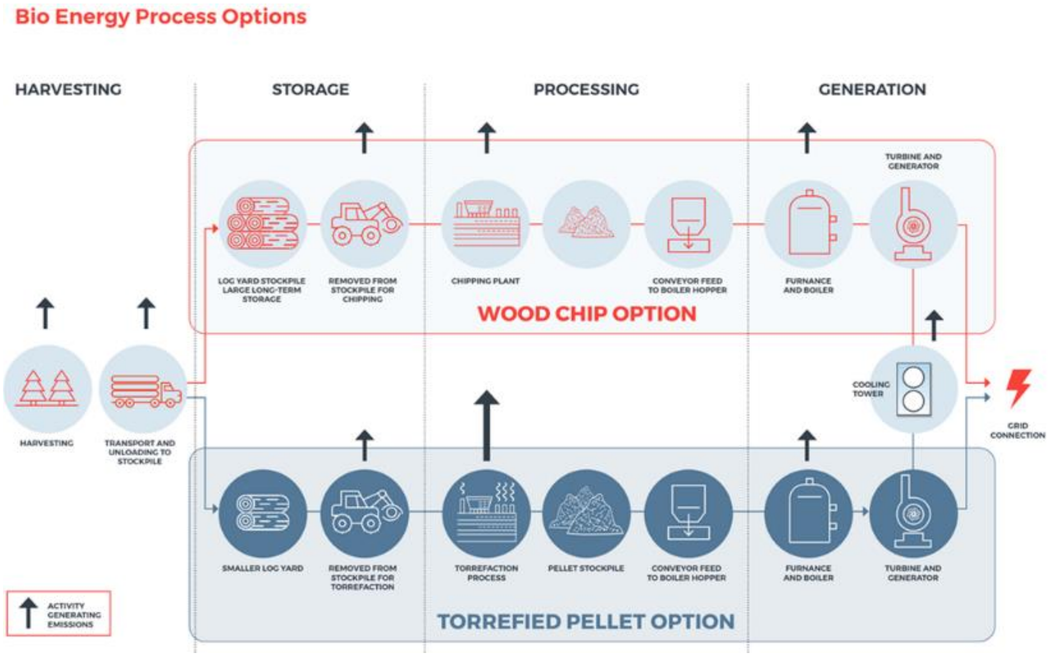
19. BIOMASS OPTIONS

Biomass Options

Flexible Geothermal

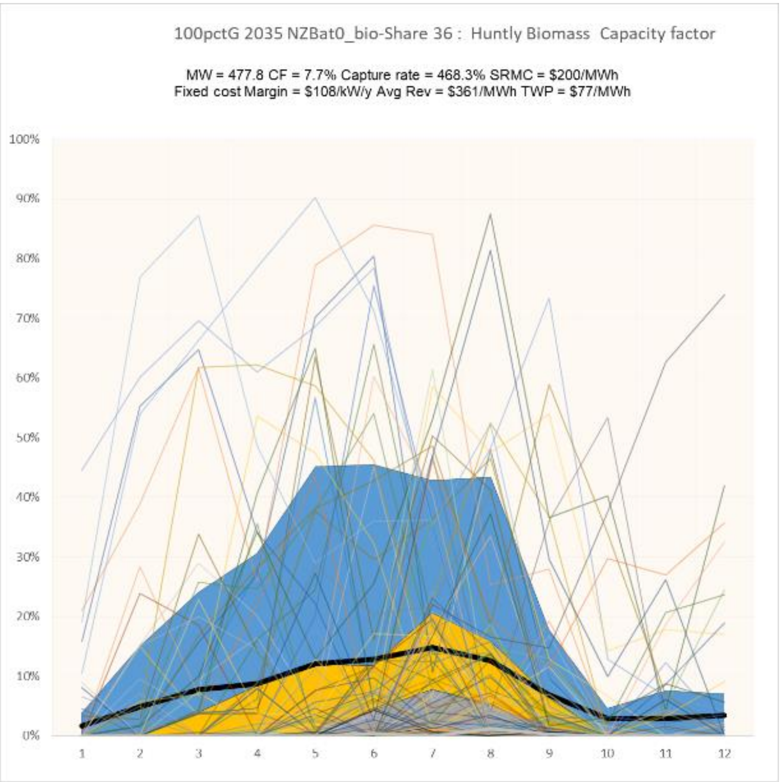
- Modelling assumptions and approximations:
  - Assumes:
    - 2 x 250 MW Rankine cycle generators operating on chipped wood or torrefied pellets
    - biomass generation is offered at $200/MWh to achieve a target capacity factor of approx. 8-10%.
      - 2.85 t/MWh for 40% moisture.
      - a 1 TWh (generation equivalent) stockpile of logs at the generation site, which is close to the forest to minimise transport distances
    - logs are harvested and supplied to the stockpile at a steady rate of equal to the expected generation from generators, supply rate can be increased1.5x when stock run low
    - logs are retained for 3 years and then burnt in generator or go to an alternative use when the stockpile is full
    - The modelling now accounts for the cost of a base take or pay supply, with supplementary top-up supply at a premium and sales of surplus logs to third parties at a 40% discount.
    - The
      - Take or pay cost (TOP) = $112/t = $123/MWh
      - Top-up cost = $136/t = $149/MWh
      - Resale price = $ 67/t = $ 74/MWh

Configuration

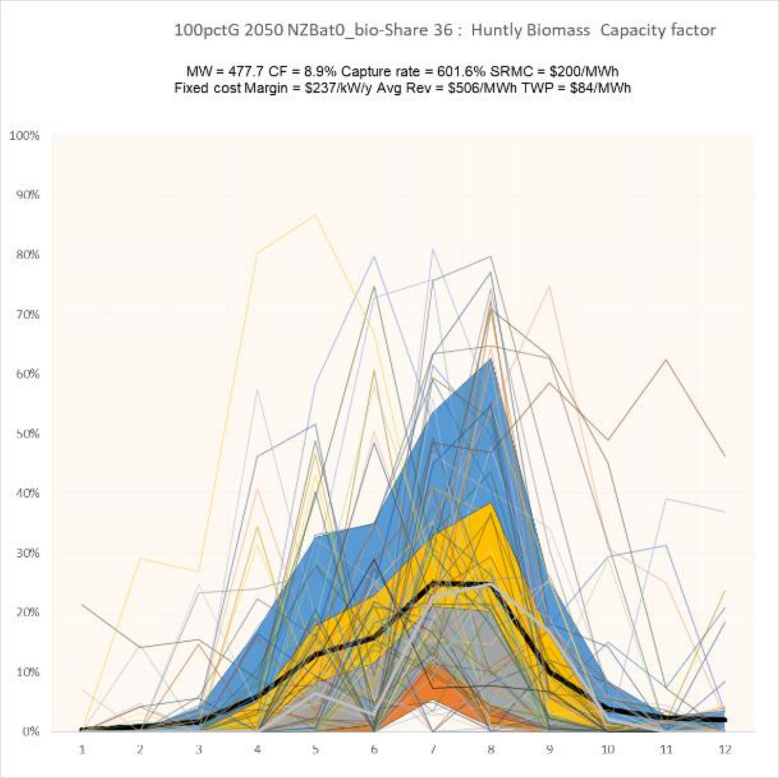


Monthly operation of biomass Plant achieves 8-10% capacity factor

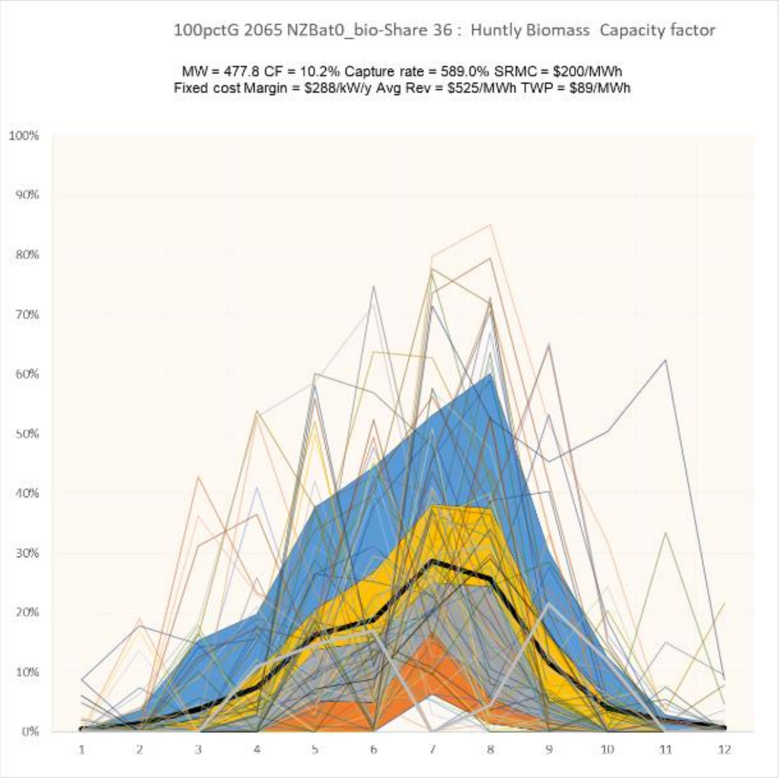
2035 - Operating biomass plant at $200/MWh



2050 -

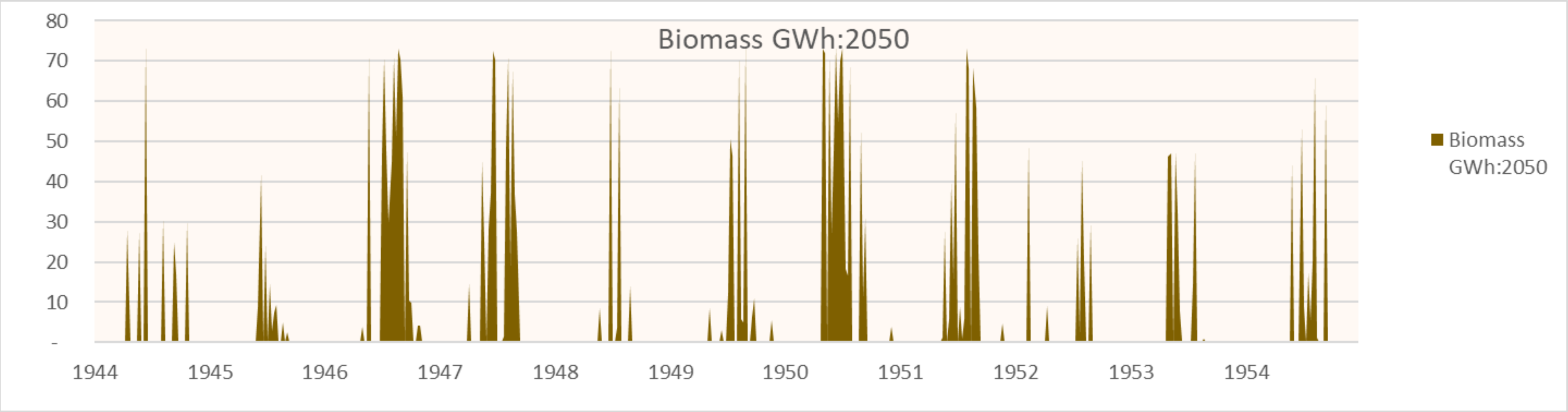


2065 -



The charts show the mean capacity factor as a solid black line, the lower 25% ile as grey area, the 25-75% as Orange and the 75%-90% ile as blue.

Weekly operation of Biomass Rankine plant - offered at $200/MWh



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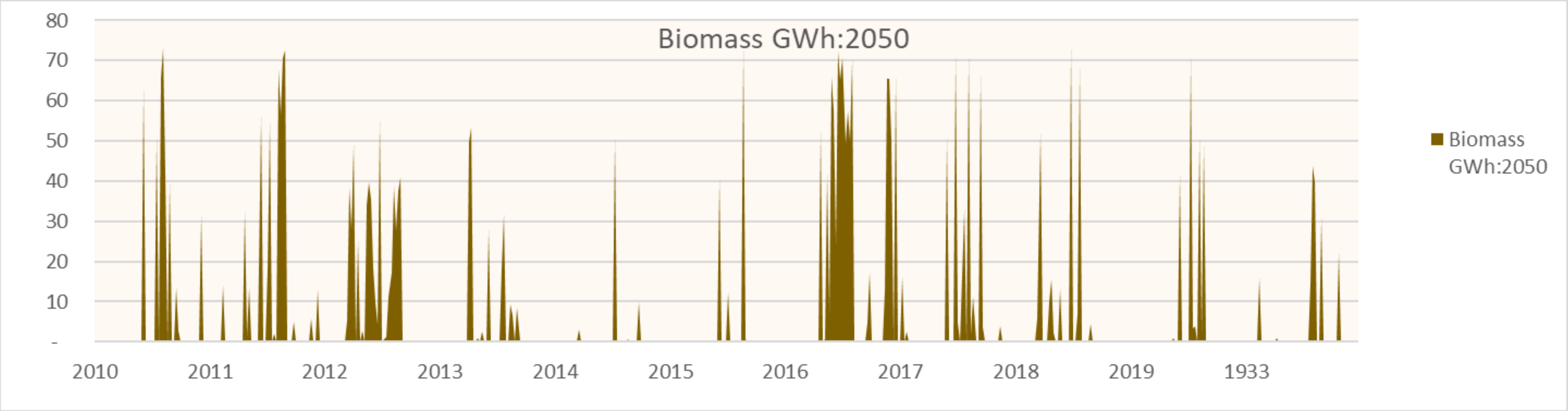
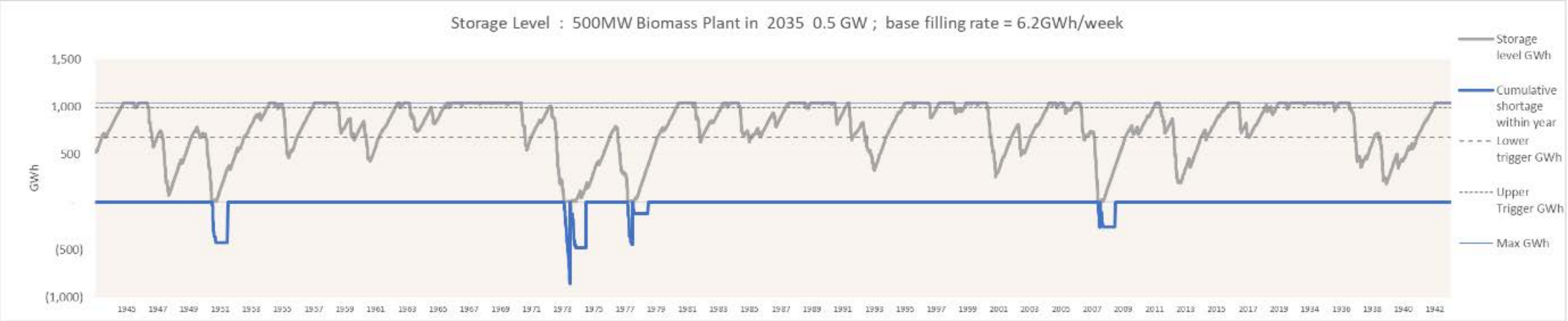
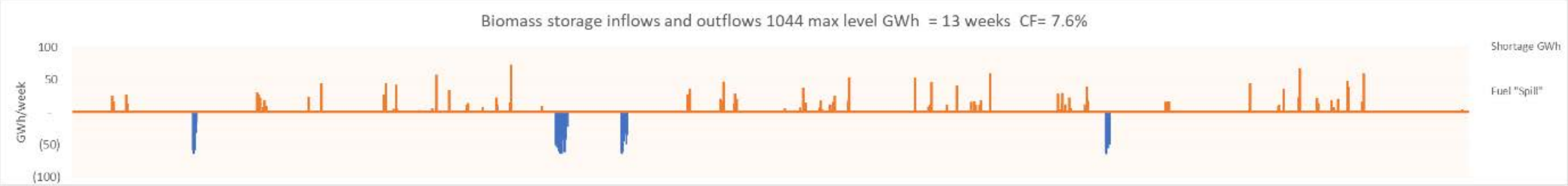


Operation of log stockpile

A storage of 1 TWh with moderately flexible supply appears to be adequate to enable Biomass supply to Rankine if offered at $200/MWh. There may be 1 or 2 occasions where contingent hydro storage may be needed. There will be excess supply from time to time which will have to be off-loaded to another storage area or sold to alternative uses in NZ.


Storage Level : 500MW Biomass Plant in 2035 0.5 GW ; base filling rate = 6.2GWh/week


Biomass storage inflows and outflows 1044 max level GWh = 13 weeks CF= 7.6%

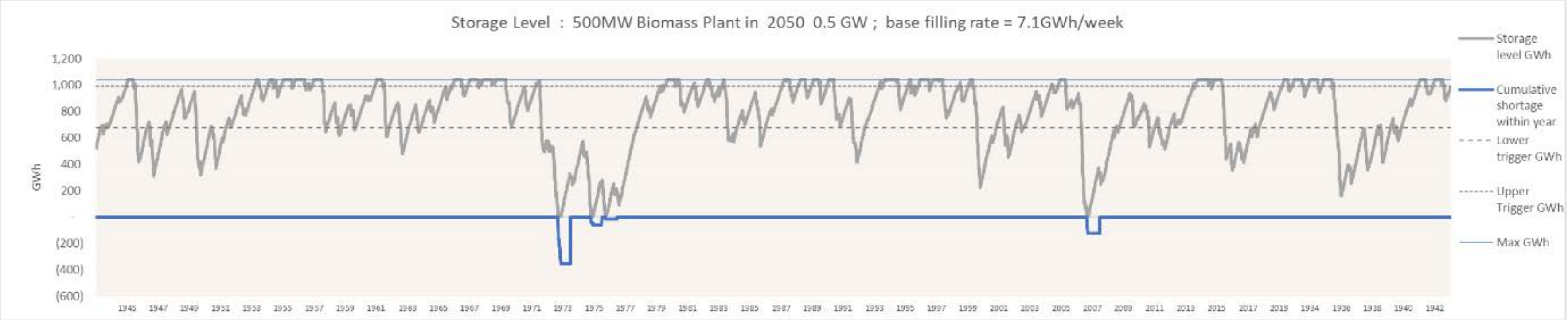

Biomass storage inflows and outflows 1044 max level GWh = 13 weeks CF= 7.6%

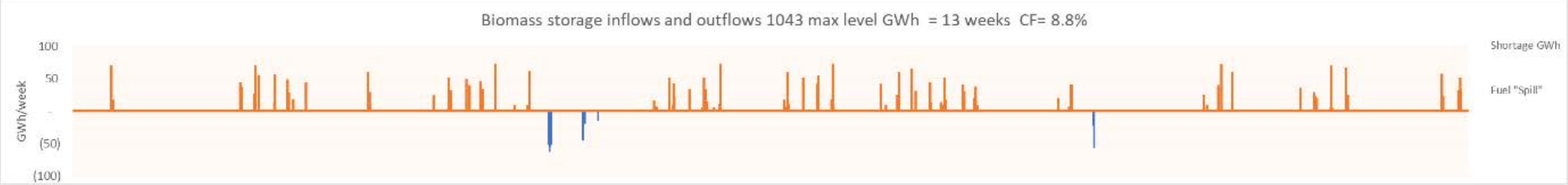
Comments

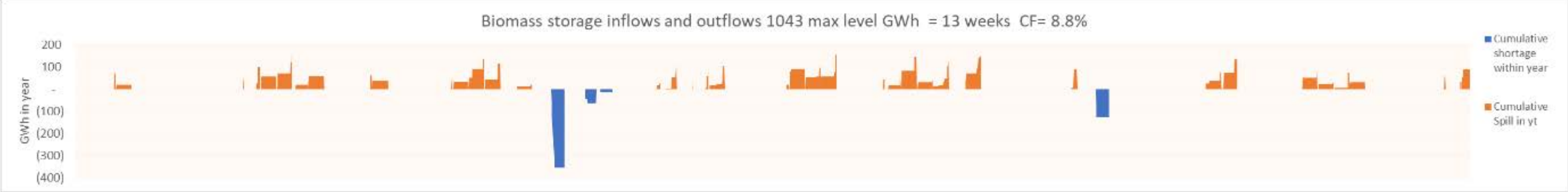
- The chart shows the operation of a stockpile with a base filling rate equal to the expected long run usage (6.2GWh/week).
  - With a possible increase of 1.5x when in lower zone, and 1.0x when in upper zone.
  - In 2035 the expected cost of meeting supply is based on
    - 148% purchase @ TOP $123/MWh
    - 18% purchase @ Top up rates $149/MWh
    - 68% sales to others @ $74/MWh
  - Sales to others occurs when the stockpile gets full or when there is insufficient use to cover approximately 1/3 of the average stockpile level.
  - The weighted average cost of supply is $161/MWh in 2035

Operation of log stockpile 2050

Chart





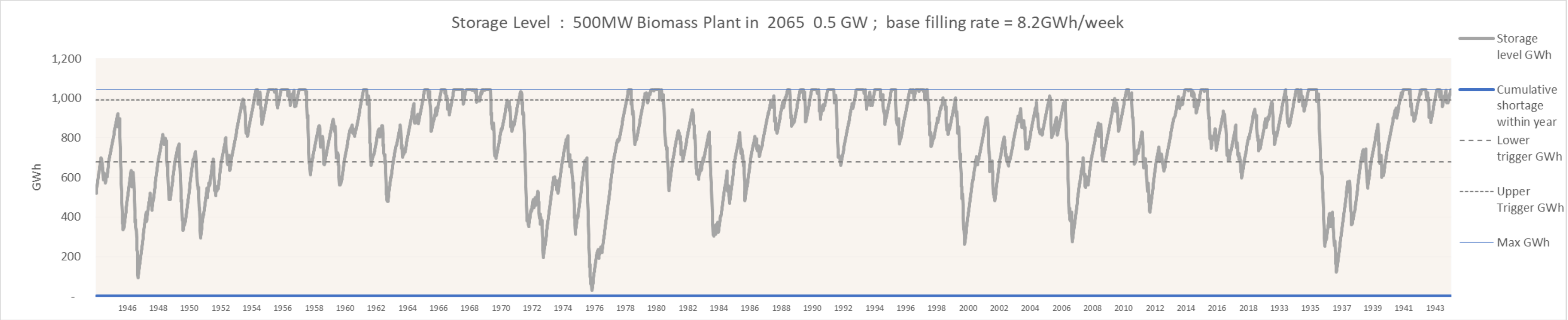


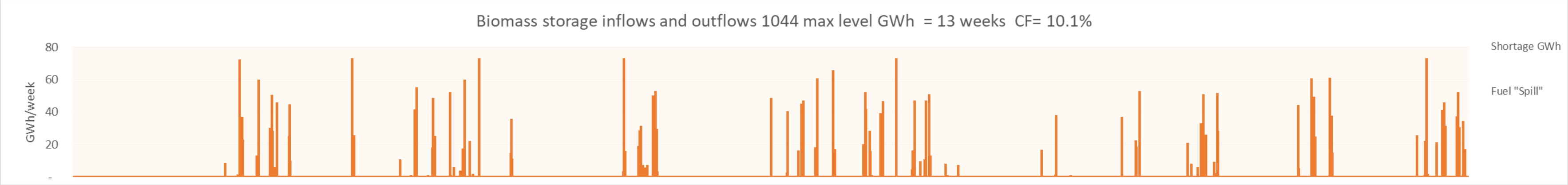
Comments

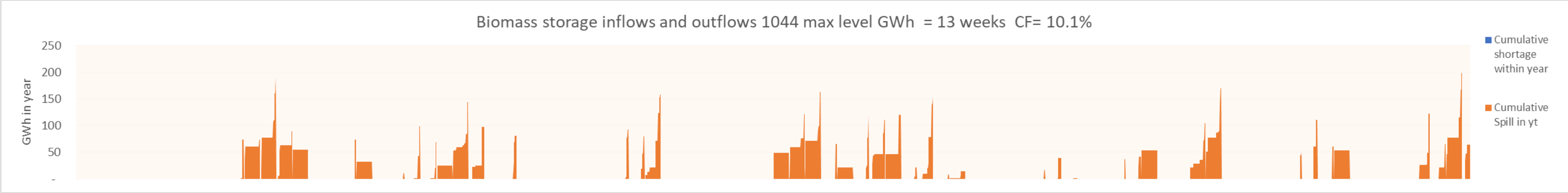
- In 2035 the expected cost of meeting supply is based on
  - 107% purchase @ TOP $123/MWh
  - 15% purchase @ Top up rates $149/MWh
  - 22% sales to others @ $74/MWh
- Sales to others occurs when the stockpile gets full or when there is insufficient use to cover approximately 1/3 of stockpile level
- The weighted average cost of supply is $137/MWh in 2035
- This is lower average cost since capacity factor is a bit higher

Operation of log stockpile 2065

Chart





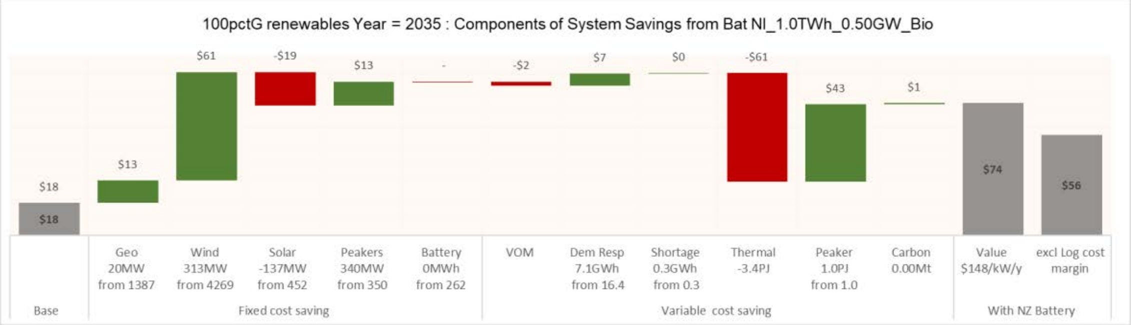


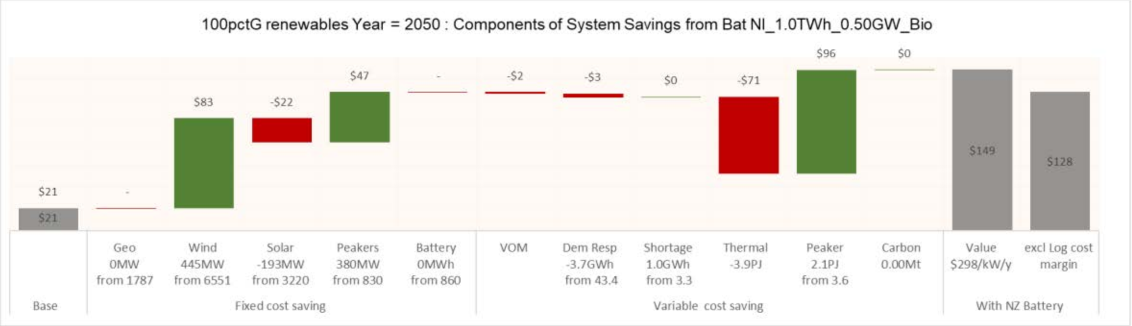
Comments

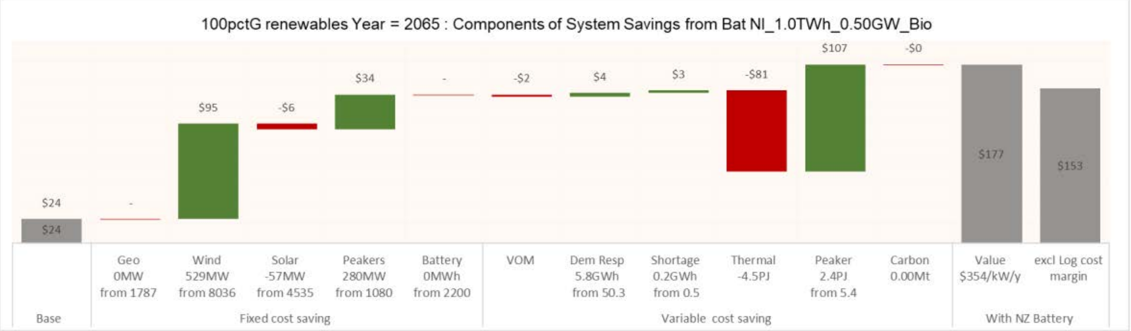
- In 2035 the expected cost of meeting supply is based on :
  - 101% purchase @ TOP $123/MWh
  - 13% purchase @ Top up rates $149/MWh
  - 14% sales to others @ $74/MWh
- Sales to others occurs when the stockpile gets full or when there is insufficient use to cover approximately 1/3 of average stockpile level (resell or use 1/3 of stockpile each year)
- The weighted average cost of supply is $133/MWh in 2035
- This is lower average cost since capacity factor is a bit higher

Incremental system benefits rise from $74m/y in 2035 to $177m/y in 2065

The chart shows the components of incremental system benefit for a 500MW biomass plant - these include the log cost margin


100pctG renewables Year = 2035 : Components of System Savings from Bat NI_1.0TWh_0.50GW_Bio


100pctG renewables Year = 2050 : Components of System Savings from Bat NI_1.0TWh_0.50GW_Bio


100pctG renewables Year = 2065 : Components of System Savings from Bat NI_1.0TWh_0.50GW_Bio

Commentary

- A 500MW biomass plant with an offer of $200/MWh enables around 230-380MW of green peakers to be avoided, and also reduces investment in batteries, wind solar and geothermal (in 2035).
- Measured benefits from green peaker fuel use is offset by the $200/MWh offer price of the biomass to achieve approx. 8-10% capacity factor.
- The average cost of purchasing logs (take or pay + top up - sales to 3rd parties) is taken to be $144/MWh - average for 2035,2050 and 2065. Thus there is a log sales margin of $56/MWh.
-

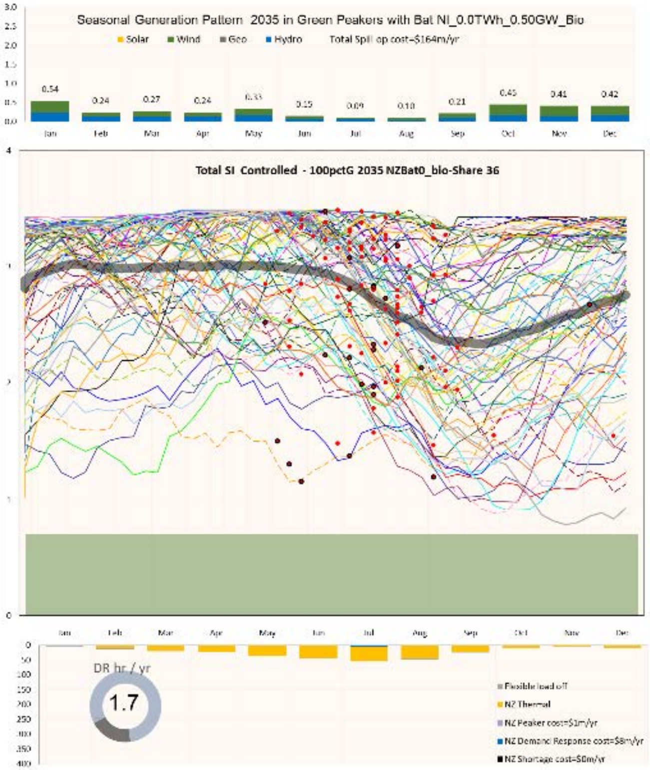
Biomass - $200/MWh offer price

Component	Units	MW	2035	2050	2065
Biomass	GWh/yr	478	320	370	424
Capacity factor	CF		7.6%	8.8%	10.1%
Market Value @ 200/MWh	NZ$m		$52	$113	$138
Log cost Margin	NZ$m		$18	$21	$24
Market Gross Margin	NZ $m		$69	$134	$161
Incremental System Value	**NZ $m**		**$74**	**$149**	**$177**
Indicative fixed cost (low)	*NZ $m/y*		*$300*	*$300*	*$300*
TWAP	NZ$/MWh		$77	$84	$90
Avg Value of generation	NZ$/MWh		$361	$506	$525
	Ratio		468%	600%	586%
Market Gross Margin	NZ$/kW/yr		$174	$335	$403
Incremental System Value	***NZ$/kW/yr***		**$185**	**$372**	**$443**
Indicative fixed cost (low)	*NZ $m/y*		*$629*	*$629*	*$629*

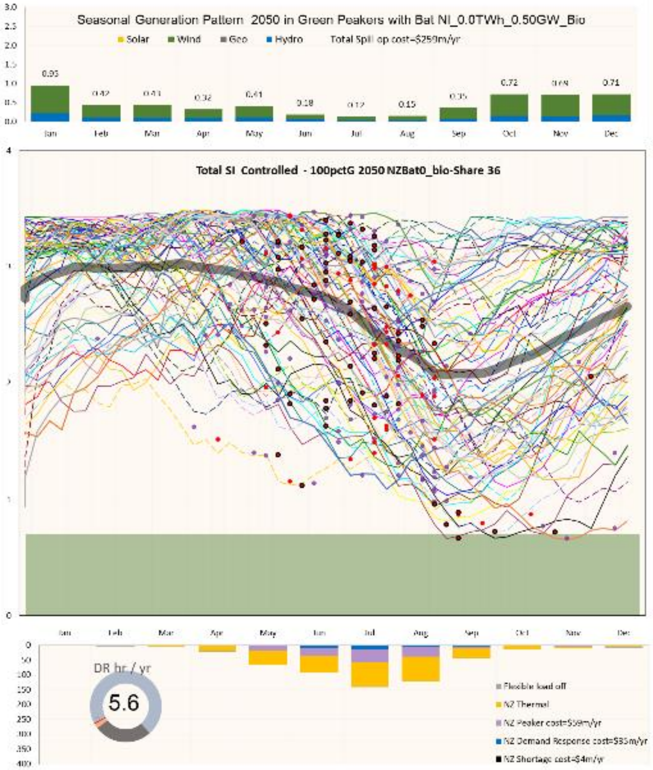
Hydro operation including spill and green peaker / biomass generation by month

JC²

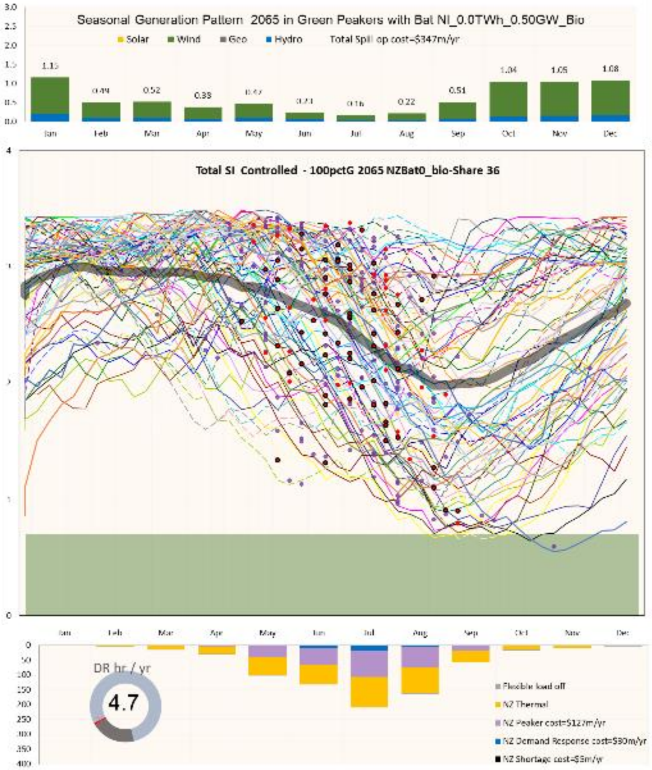
Base Case - Green Peaker counterfactual in 2035



Biomass in 2035



Biomass in 2050



20. FLEXIBLE GEOTHERMAL OPTIONS

Flexible geothermal options

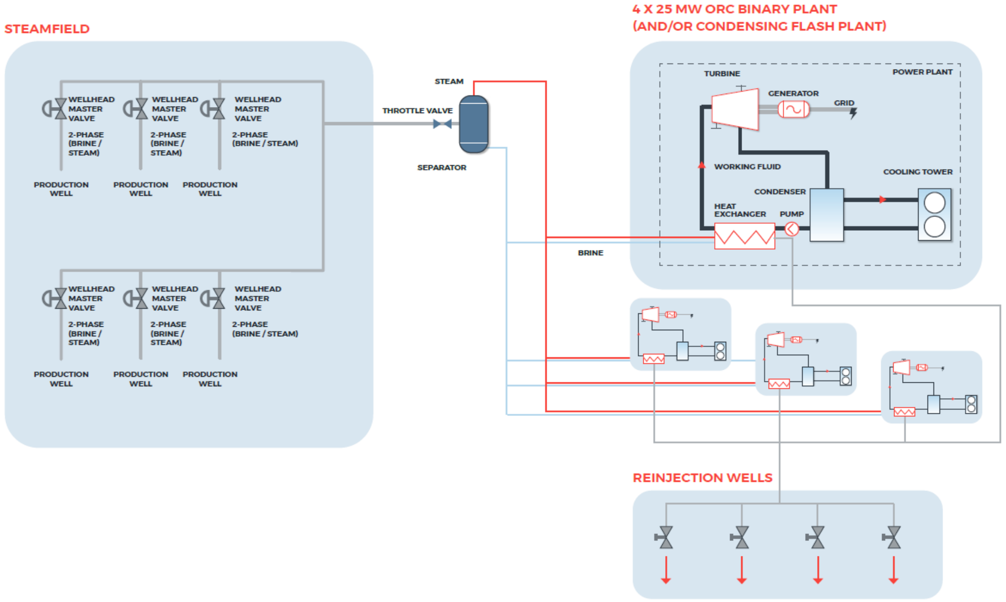
Flexible geothermal is an option which can be operated to provide both firm energy and capacity supply while operating a lower capacity factor so as to minimise carbon emissions for fields where capture and reinjection is not technically feasible.

- Flexible geothermal:
  - This assumes that 400MW of flexible mainly ORC binary geothermal plant is built by 2035.
    - The 400MW includes the fields where carbon capture and reinjection is not feasible. This includes 100MW with 60kg/MWh and 300MW with 120kg/MWh emissions.
    - It is assumed that the 100MW with 60kg/MWh is supplied by the market in the base case counterfactual, but the 300MW with 120kg/MWh is not developed by the market as the carbon cost would be too great if it was baseload.
    - Of the 400MW, 100MW is run base load and 300MW is dispatched during the winter weeks and when storage levels in Waitaki fall below a specified risk level.
    - Production can be phased up from 25% running to 100% over a period of weeks.
      - (modelling currently assumes 1 week)
  - For modelling we assume that flexible geothermal operates in energy security of supply mode:
    - This means operating when hydro lake levels fall below a hydro risk level at any time of the year.
  - We also model running flexible geothermal in energy and capacity security dispatch mode
    - This means operating at all times during the peak winter months when the risk of low wind causing capacity shortage and green peaker running is very high, and
    - Operating when hydro lake levels fall below a hydro risk level at other times of the year.

Configuration

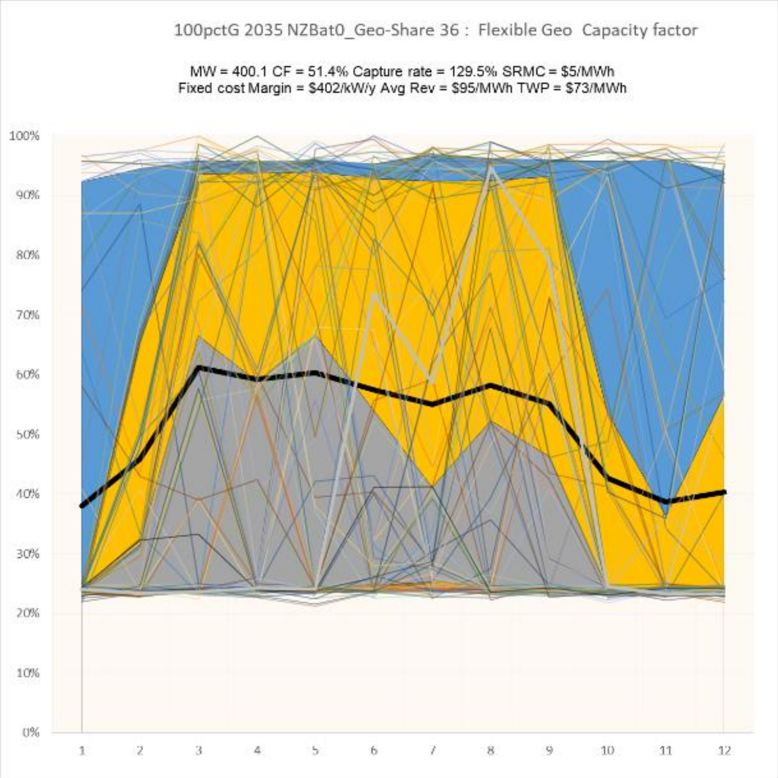
Typical Geothermal NZ Battery Site (Integrated Steamfield and Plant)

- **Normal year turned down state**: all steamfield wellhead and reinjection master valves turned down and 25MW of 100MW available generation plant normally running
- **Dry year preparation and ramp up** gradually open steamfield wellhead master valves and bring wells to 100% flow (in parallel with power plant warm up and preparation to run plant at full capacity)
- **Dry year state**: run plant at 100% (or a chosen mid-range point to suit the dry year requirement)



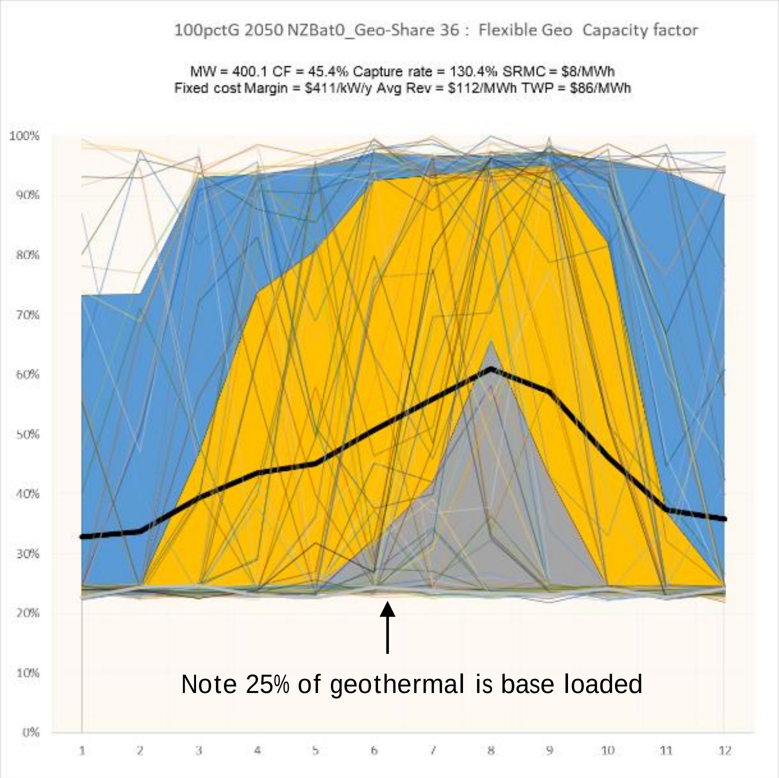
Monthly operation of flexible geothermal in security of supply mode.

2035 - Operating flexible geothermal in security mode


100pctG 2035 NZBat0_Geo-Share 36 : Flexible Geo Capacity factor

MW = 400.1 CF = 51.4% Capture rate = 129.5% SRMC = $5/MWh
Fixed cost Margin = $402/kW/y Avg Rev = $95/MWh TWP = $73/MWh

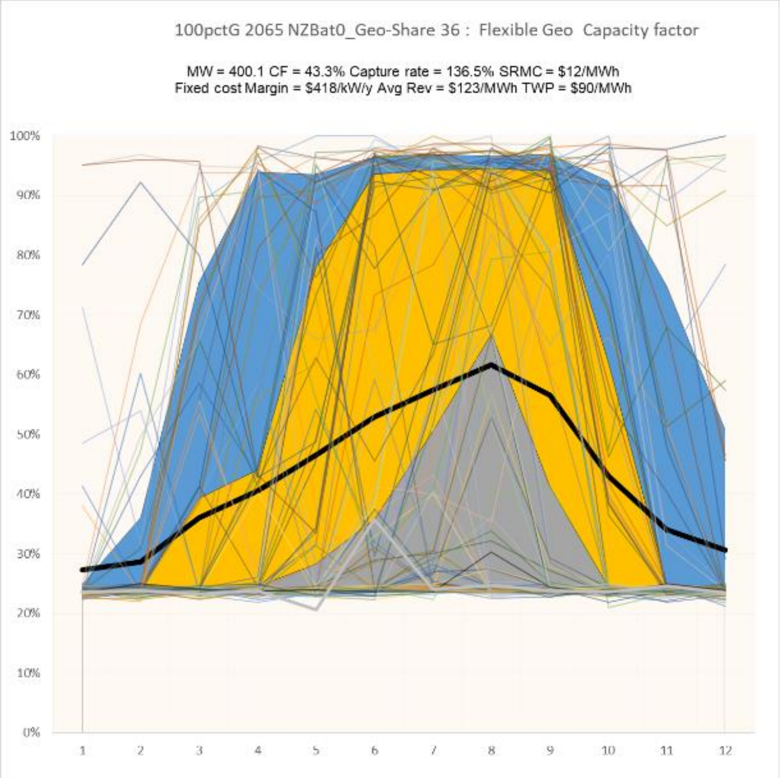
2050 -


100pctG 2050 NZBat0_Geo-Share 36 : Flexible Geo Capacity factor

MW = 400.1 CF = 45.4% Capture rate = 130.4% SRMC = $8/MWh
Fixed cost Margin = $411/kW/y Avg Rev = $112/MWh TWP = $86/MWh

Note 25% of geothermal is base loaded

2065 -


100pctG 2065 NZBat0_Geo-Share 36 : Flexible Geo Capacity factor

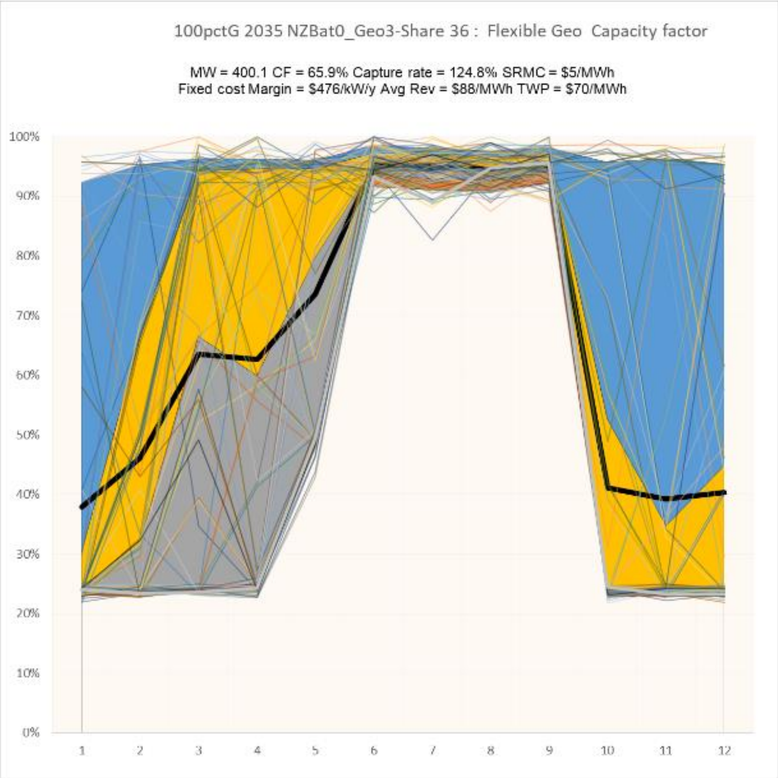
MW = 400.1 CF = 43.3% Capture rate = 136.5% SRMC = $12/MWh
Fixed cost Margin = $418/kW/y Avg Rev = $123/MWh TWP = $90/MWh

Operating in a dry year energy mode only sometimes enables the flexible geothermal to cover winter capacity risks as well, but there are many winter capacity shortfall events during which time the flexible geothermal is not operating.

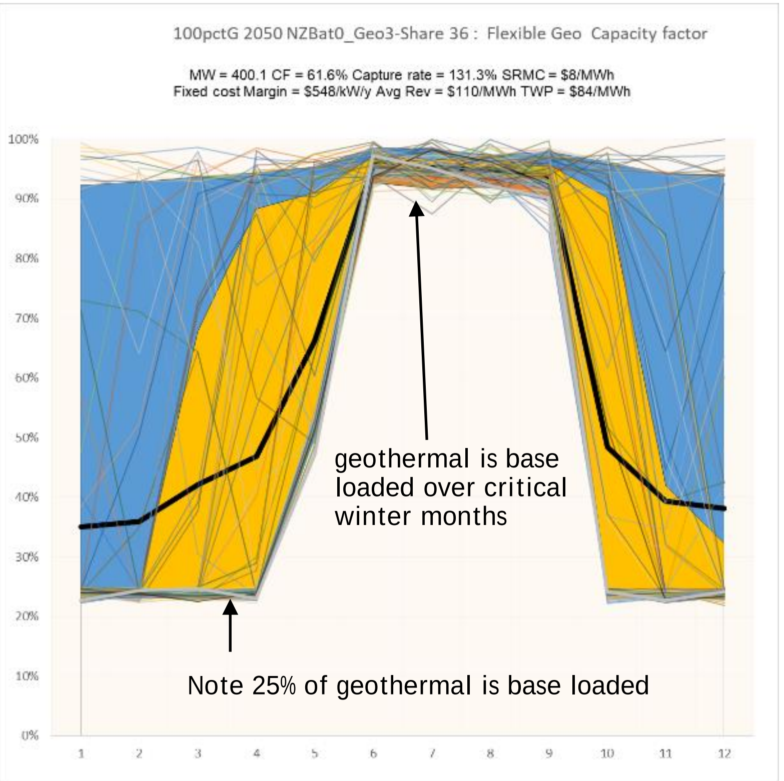
The charts show the mean capacity factor as a solid black line, the lower 25% ile as grey area, the 25-75% as Orange and the 75%-90% ile as blue.

Monthly operation of flexible geothermal in energy and capacity security of supply mode.

2035 - Operating flexible geothermal in security mode



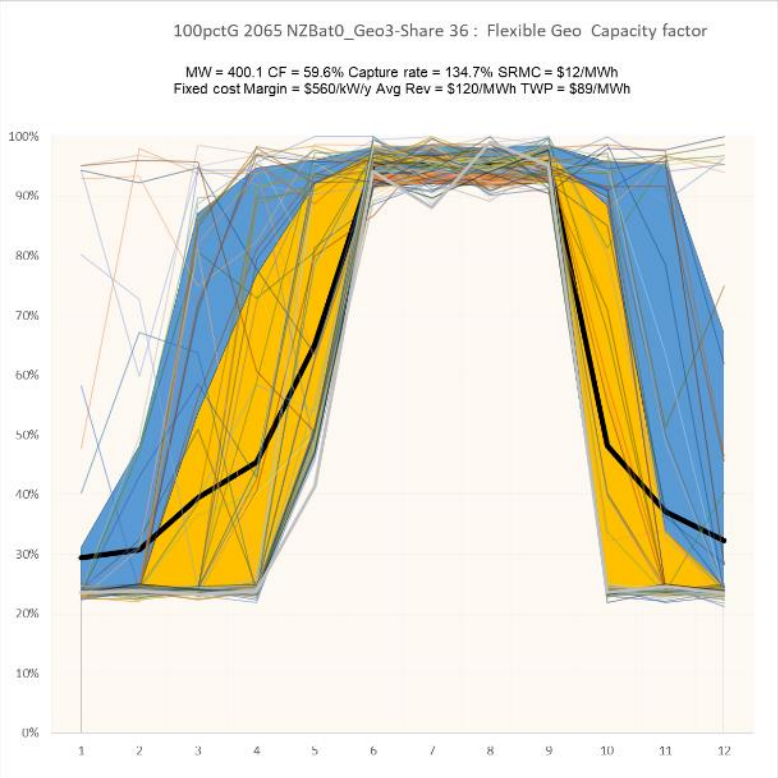
2050 -



geothermal is base loaded over critical winter months

Note 25% of geothermal is base loaded

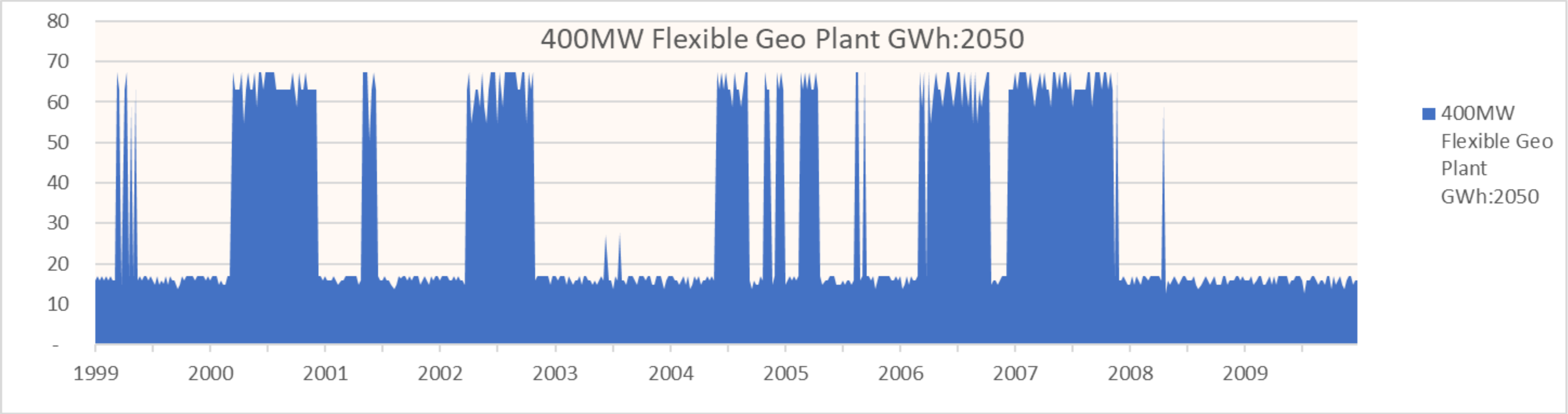
2065 -



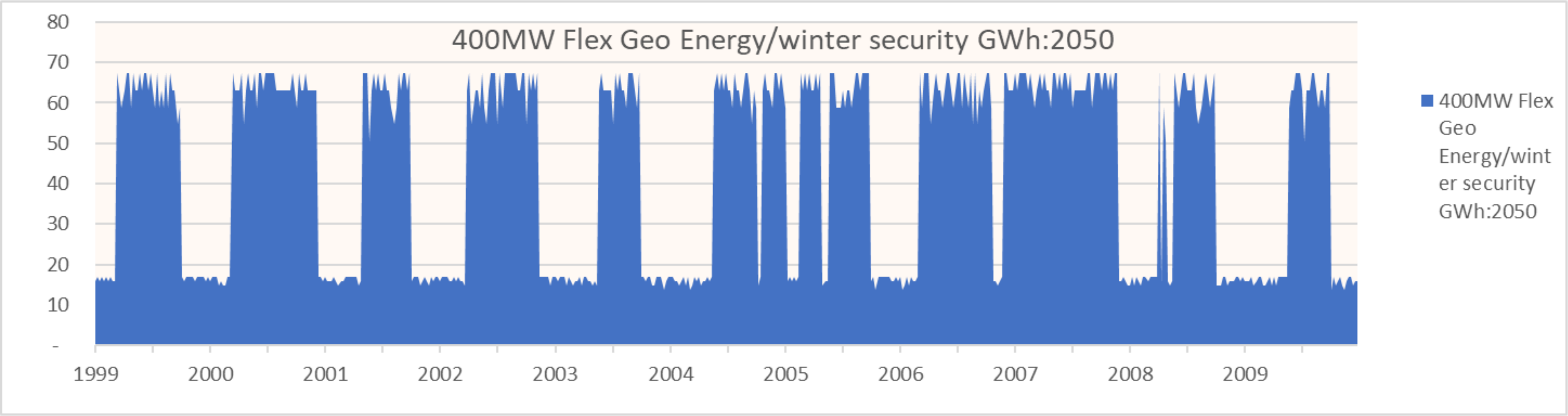
This shows the impact of baseload running for the 3-4 months in winter when the risk of capacity shortfalls is greatest.

The charts show the mean capacity factor as a solid black line, the lower 25% ile as grey area, the 25-75% as Orange and the 75%-90% ile as blue.

Weekly operation of geothermal - under energy security mode or energy and capacity security mode



The weekly operation of the flexible geothermal plant is shown in the chart. This has 100MW base loaded, and 300MW dispatched for security when lake levels in Waitaki fall below a selected risk guideline.

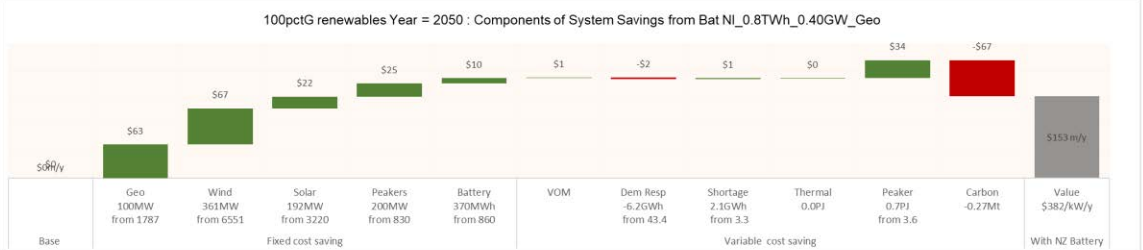


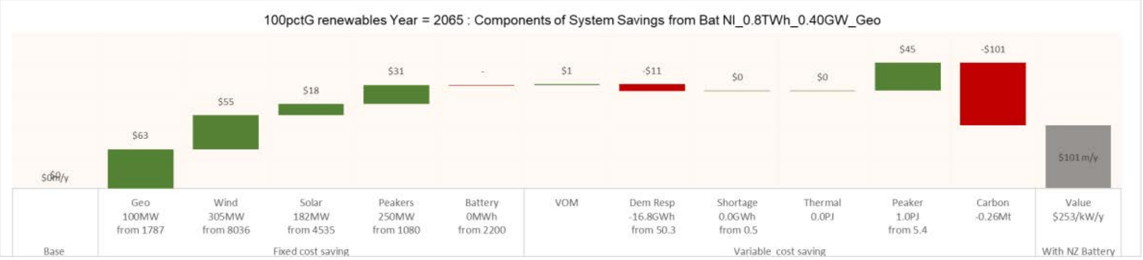
This has 100MW base loaded, and 300MW dispatched for security during either the 20 winter months or when lake levels in Waitaki fall below a selected risk guideline.

This increases the capacity factor from around 50% to 65% in 2035.

Operating flexible geothermal using energy security based dispatch rules - can reduce spill and provide around $380/kW/y benefit to 2050, falling to $250/kW/y by 2065

The chart shows the components of gross value for flexible geothermal dispatched for energy security only. This ranges from $101 to $154m/yr.





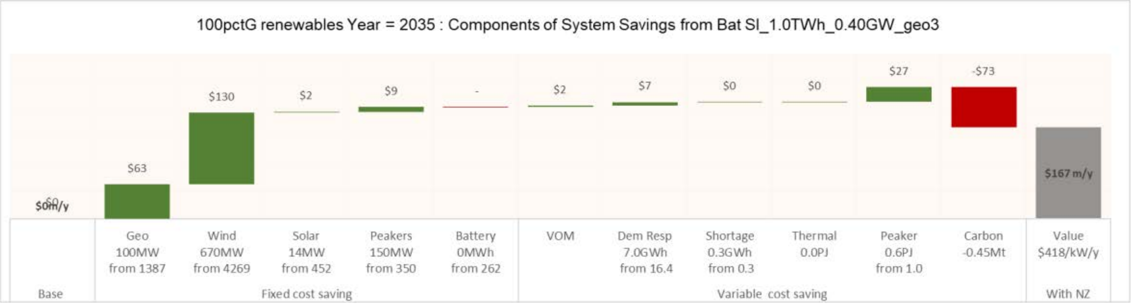
Commentary

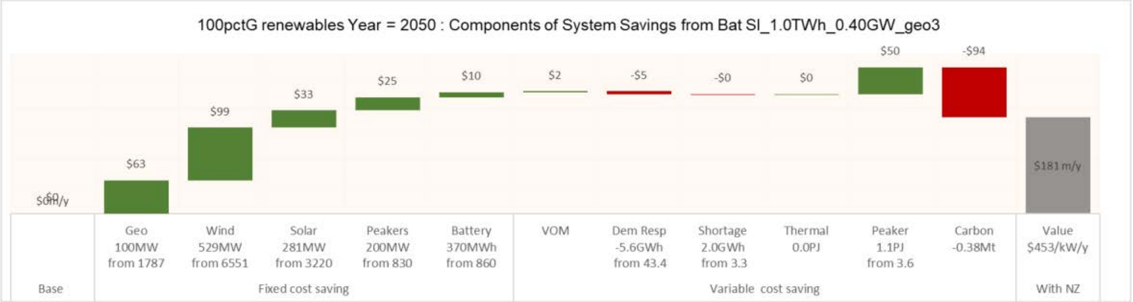
- The key benefits are from reductions in renewable geothermal, wind and solar investment and reductions in peaker costs , offset by carbon costs.
  - It is also assumed flexible geothermal has a forced outage rate of approx. 5%.
- The flexible geothermal has a capacity factor of 51% falling to 43% by 2065.
- The incremental system benefit falls in 2065 mainly due to the offsetting cost of emissions rising to $390/t.

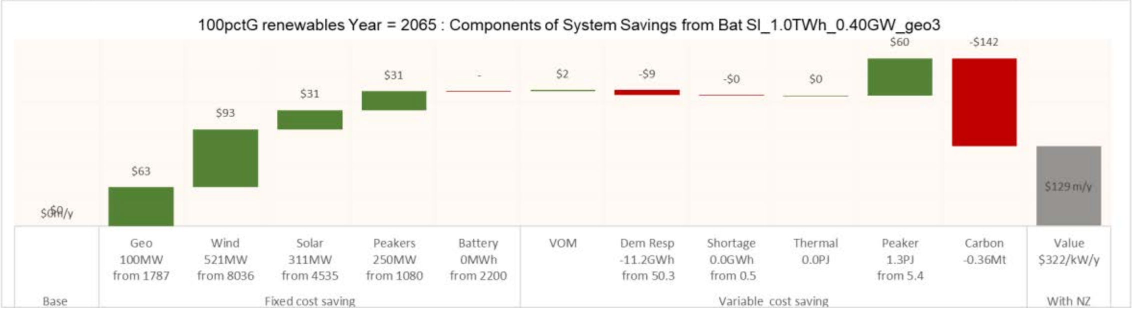
Flexible Geothermal - Dispatched for energy security					
Component	Units	MW	2035	2050	2065
Generation	GWh/yr	400	1,789	1,579	1,508
Capacity factor	CF		51.0%	45.0%	43.0%
Value of Gen	*NZ $m*		$169	$176	$185
Cost of Carbon	*NZ $m*		-$29	-$39	-$59
Market Gross Margin	NZ $m		$141	$137	$126
Incremental System Value	***NZ $m***		**$154**	**$153**	**$101**
TWP	NZ$/MWh		$73	$86	$90
Avg Value of generation	NZ$/MWh		$95	$112	$123
GWAP/TWAP	Ratio		129%	130%	136%
Carbon Cost	NZ$/MWh		$16	$25	$39
Market Gross Margin SOS	NZ$/kW/yr		$352	$342	$316
Incremental System Value SOS	***NZ$/kW/yr***		**$385**	**$382**	**$253**

Operating flexible geothermal to cover winter capacity and hydro risks achieves a $13-30m/yr higher system incremental benefit

If flexible geothermal dispatched for energy and capacity security the benefit is increased by $13 to $30m/yr.


100pctG renewables Year = 2035 : Components of System Savings from Bat SI_1.0TWh_0.40GW_geo3


100pctG renewables Year = 2050 : Components of System Savings from Bat SI_1.0TWh_0.40GW_geo3


100pctG renewables Year = 2065 : Components of System Savings from Bat SI_1.0TWh_0.40GW_geo3

Dispatching for capacity security during the winter increases the value of output more than it increases the carbon cost.

- The benefit of flexible geothermal is significantly enhanced if it is dispatched for both energy and capacity security.
- This increases the capacity factor to 65% falling to 60% by 2065.
- Operating flexible geothermal in the winter/energy security mode would achieve around $30-70/kW higher returns than in energy security mode alone.
- This is despite the higher carbon cost of operating at a higher capacity factor.

Flexible Geothermal - Dispatched for energy and capacity security

Component	Units	MW	2035	2050	2065
Generation	GWh/yr	400	2,291	2,148	2,075
Capacity factor	CF		65.4%	61.3%	59.2%
Value of Gen	*NZ $m*		$200	$255	$261
Cost of Carbon	*NZ $m*		-$37	-$54	-$81
Market Gross Margin	NZ $m		$164	$201	$180
Incremental System Value	***NZ $m***		**$167**	**$181**	**$129**
TWAP	NZ$/MWh		$70	$90	$94
Avg Value of generation	NZ$/MWh		$87	$119	$126
GWAP/TWAP	Ratio		124%	132%	134%
Carbon Cost	NZ$/MWh		$16	$25	$39
Market Gross Margin - energy and sec	NZ$/kW/yr		$409	$503	$451
Incremental System Value - energy	***NZ$/kW/yr***		**$417**	**$453**	**$322**

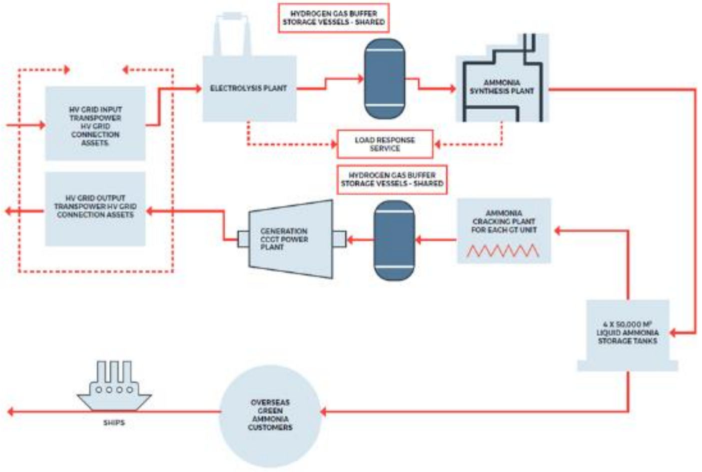
21. ALTERNATIVE H_2/NH_3 OPTIONS

Hydrogen/Ammonia Options

JC^2

Base configuration

Hydrogen Stream – Base Case envelope process flow diagram



- Electrolysis of water into hydrogen using a fully flexible electrolyser, with buffer storage of hydrogen equivalent to about twelve hours of production at full electrolyser output
- Ammonia synthesis plant, sized to match the electrolyser plant hydrogen output. Ammonia production which can drop to part-load rapidly, or turn off with a two-day re-start time
- Bulk ammonia storage using above ground containment tanks, plus supplementary storage to support an export terminal
- Cracking of ammonia back into hydrogen to feed electricity generation through two 75 MW CCGT plants
- Most of the response is provided by turning off the electrolyser, but significant response is also from the hydrogen-fuelled generation.

Technology and International Price Scenarios

- There is significant uncertainty around green ammonia prices into the future.
- The numbers below are far from definitive, but provide a reasoned estimate for modelling purposes, with the IEA references providing a touchstone.

Flexible NH_3 production facility & CCGT @ international NH_3 prices

Component	Units	2035	2050	2065
International H2 Cost	US$/kg	$3.0	$2.0	$1.2
NH_3 Price	US$/t	$750	$500	$400
	NZ $/t	$1,154	$769	$615
CCGT Offer Price	NZ $/MWh	$400	$266	$213
Max Price to H2 Plant	NZ $/MWh	$92	$61	$49

Open Loop Modelling

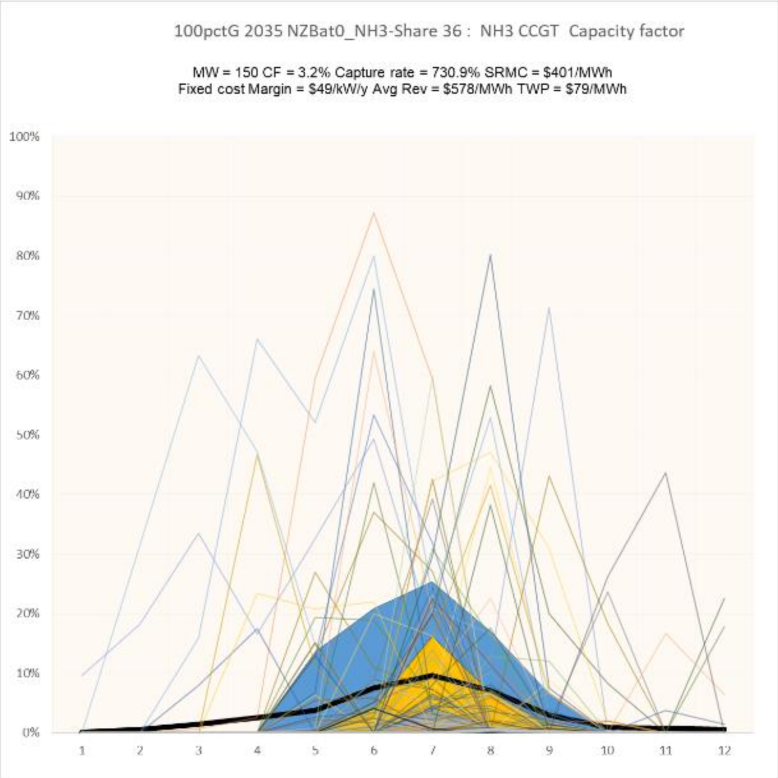
Open Loop Modelling - a NH_3 production plant and CCGT both exposed to international NH_3 pricing.

- Modelling assumptions:
  - The combined electricity demand for the H_2/NH_3 plant is 370MW.
    - This is treated as a flexible load which is backed off to a standby level of 8% when prices exceed an export parity netback value of $90/MWh , $60/MWh and $50/MWh in 2035, 2050 and 2065 respectively.
  - There is sufficient H_2 storage (1 day assumed) to enable NH_3 slower ramping rates to be accommodated.
    - This may be a slightly optimistic assumption.
  - The NH_3 is used to fire flexible CCGT plant operating on H_2 which is cracked from NH_3.
    - It is assumed that the CCGT can be operated flexibly. This is a necessary approximation given that the model can't explicitly model unit commitment.
  - The CCGT offer price to the market reflects the export parity prices for ammonia and the efficiency of cracking ammonia and CCGT generation.
    - These are modelled as being $400, $260 and $ 210/MWh in 2035, 2050 and 2065 respectively.

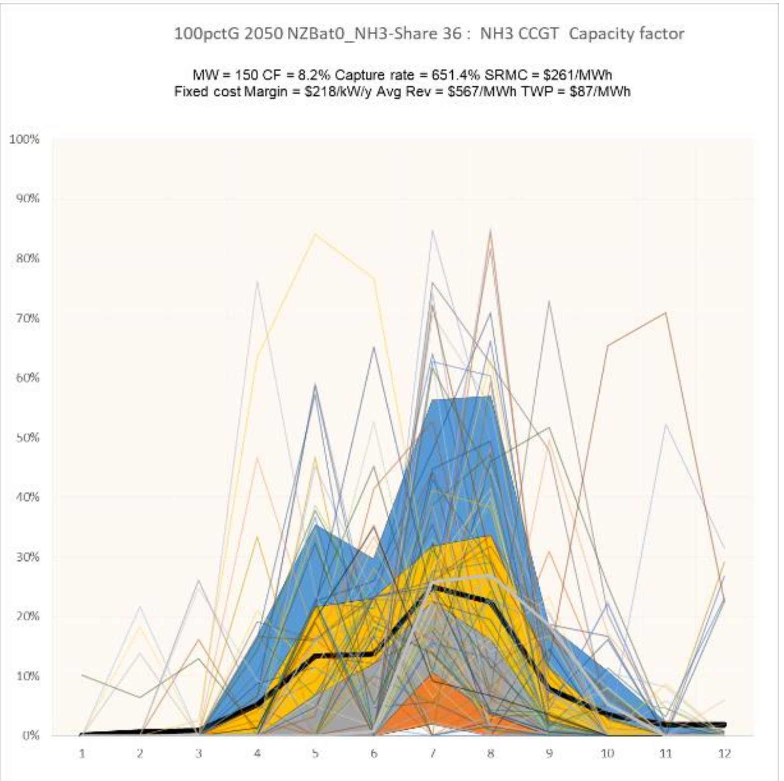
Commentary

NH_3 CCGT generation operation has capacity factors < 10% given the assumed international NH_3 price

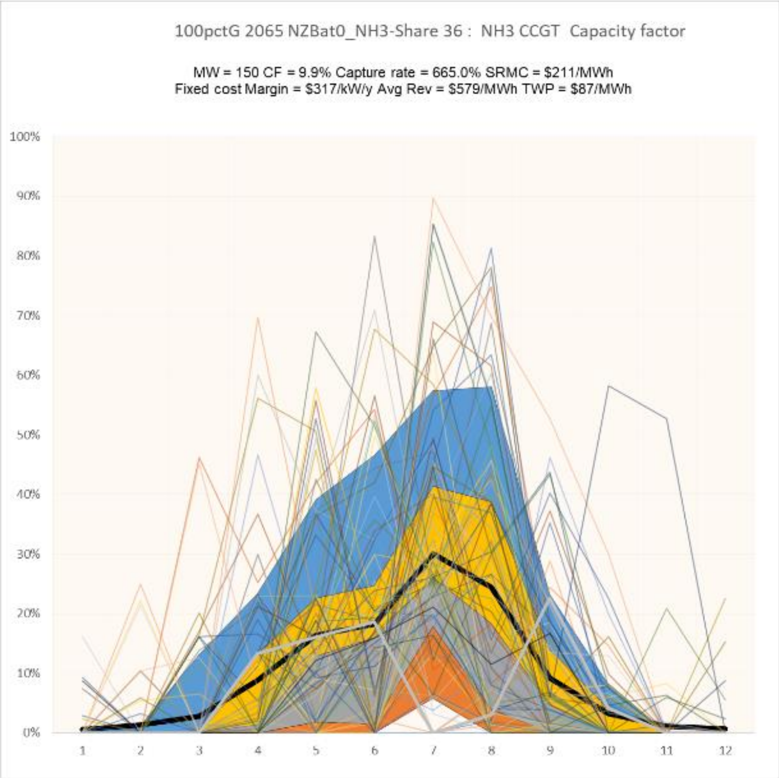
2035 - with an international NH_3 cost of US$750/t, implying a $400/MWh SRMC.



2050 - with an international NH_3 cost of US$500/t, implying a $260/MWh SRMC.



2065 - with an international NH_3 cost of US$400/t, implying a $210/MWh SRMC.



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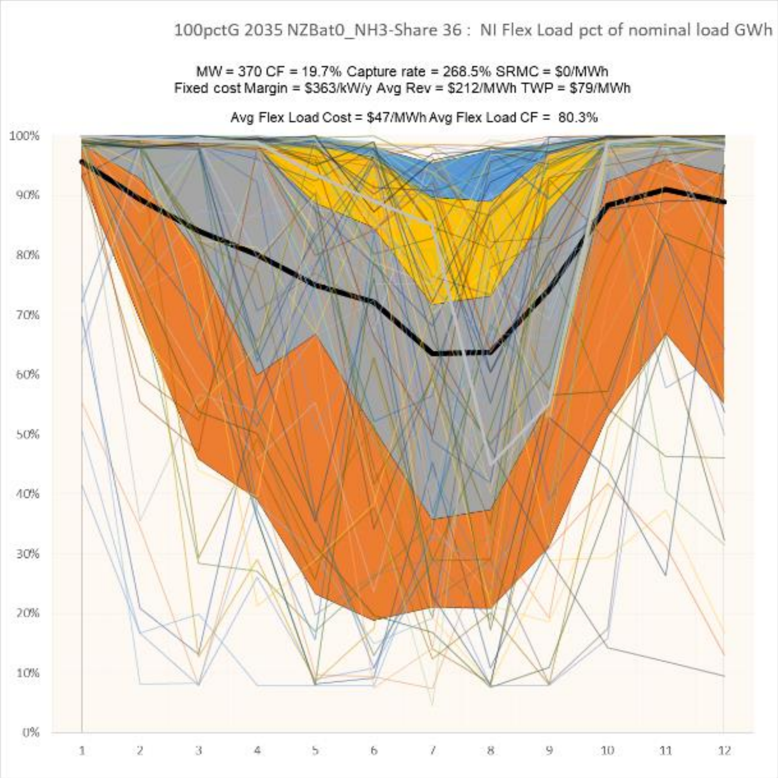
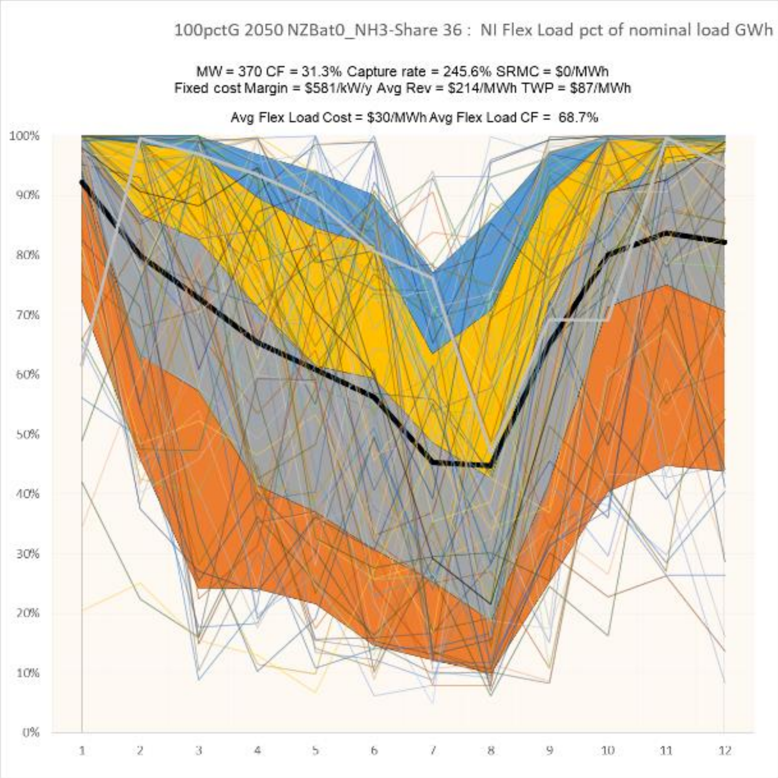
The charts show the mean capacity factor as a solid black line, the lower 25% ile as grey area, the 25-75% as Orange and the 75%-90% ile as blue.

H_2/NH_3 flexible load operation and cost - capacity factor around 80-66% with average wholesale cost of flexible load falling from $47/MWh to $24/MWh

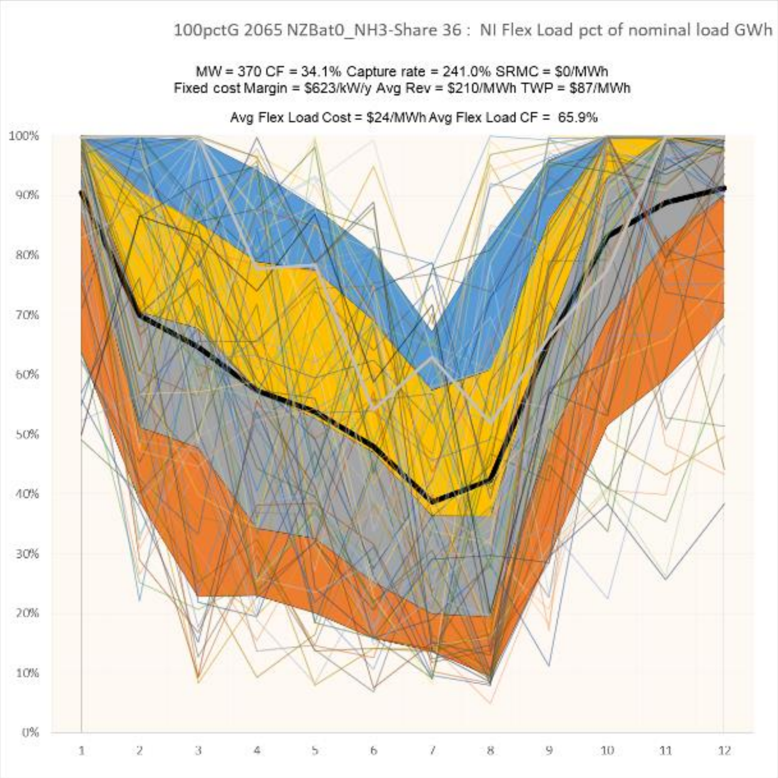
2035



2050

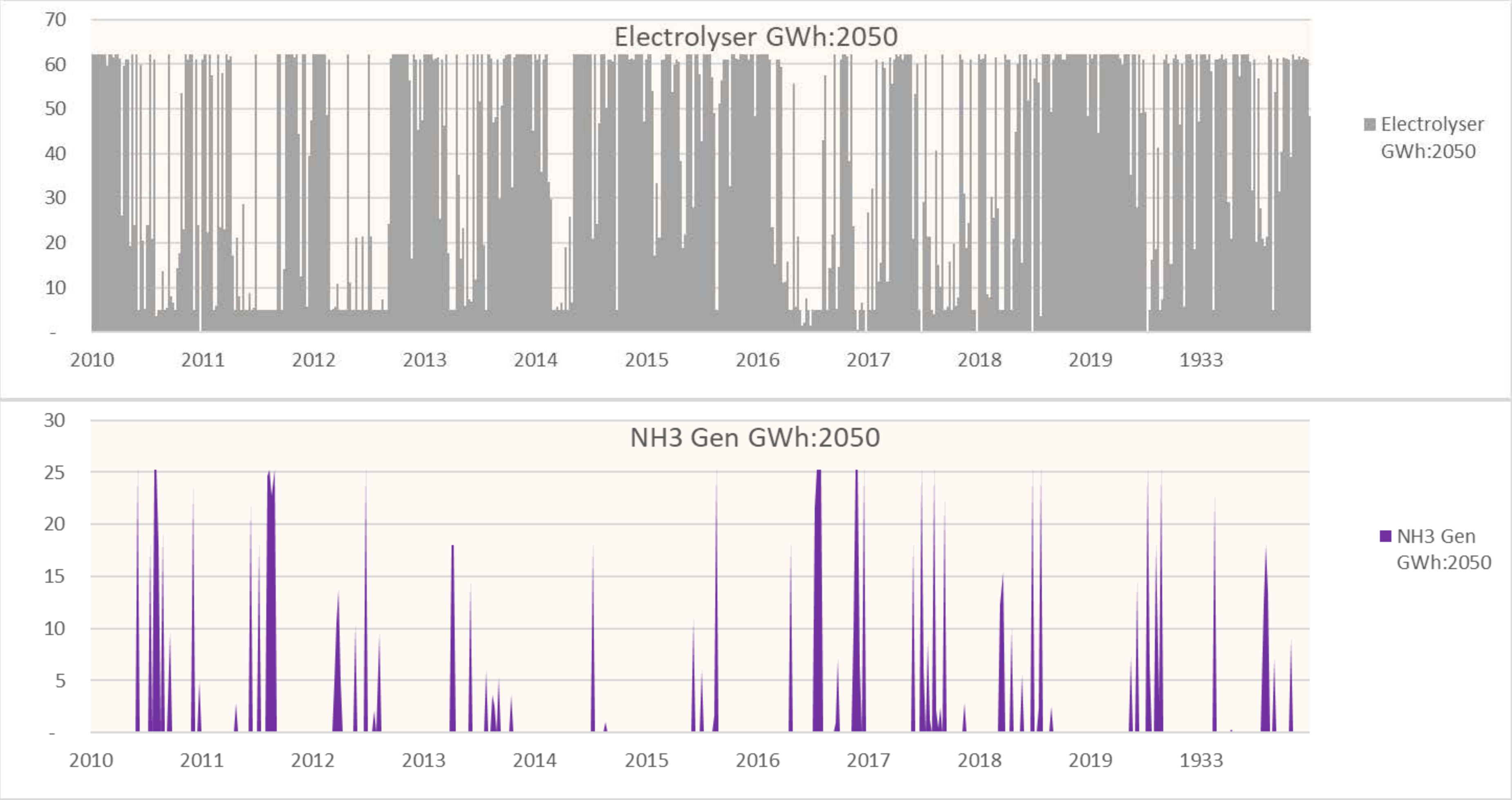


2065



The charts show the mean capacity factor as a solid black line, the lower 25% ile as grey area, the 25-75% as Orange and the 75%-90% ile as blue.

Weekly operation of electrolyser and NH_3 CCGT plant with open configuration



The weekly operation of the electrolyser in 2050 over a sample of weather years is illustrated in the chart. This shows many weeks with full load operation, and occasional periods in the winter with minimum standby load.

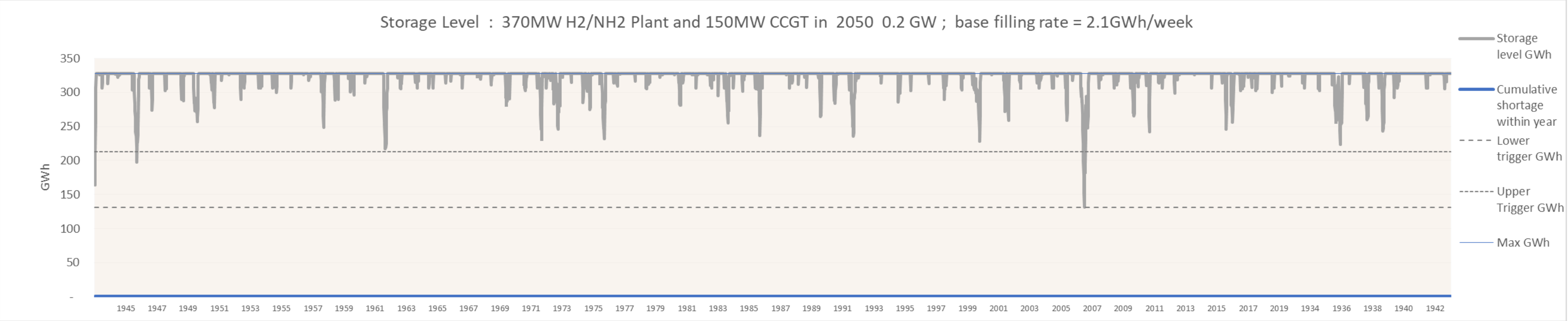
There are occasions where the electrolyser ramps up to full for a single or several weeks and then shutdowns. The costs of this mode of operation will be assessed in the final runs.

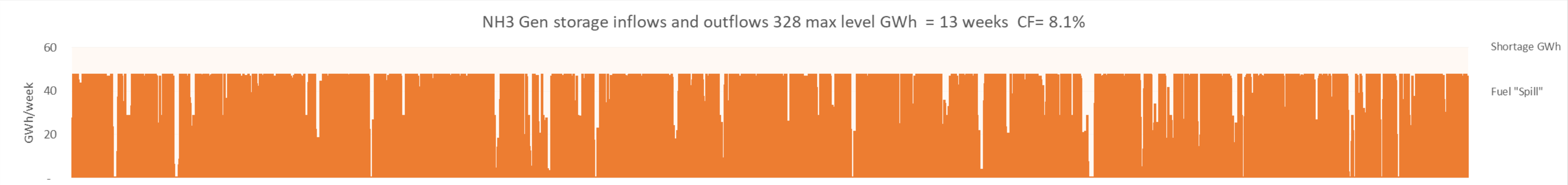
The weekly operation of the NH_3 CCGT plant is illustrated in the chart. This shows a few periods of full running for several weeks on end, and many cases where it is operated for only a part of a week to cover capacity shortfalls when wind/solar is low and demand is high.

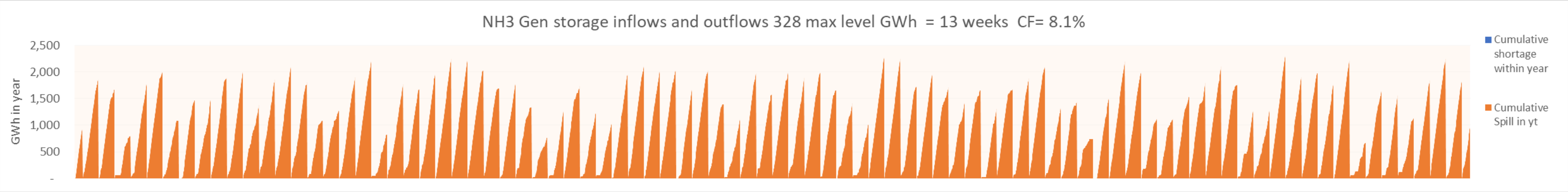
For the final runs the implication of these patterns of NH_3 production and use on the residual supply for export/local use will be explored in light of likely ship sizes and port stock limits.

Operation of Ammonia Stockpile

A storage of 0.33TWh enables electricity use of ammonia to be met while surplus is exported to the international market on a reasonably regular basis


Storage Level : 370MW H2/NH2 Plant and 150MW CCGT in 2050 0.2 GW ; base filling rate = 2.1GWh/week


NH3 Gen storage inflows and outflows 328 max level GWh = 13 weeks CF= 8.1%

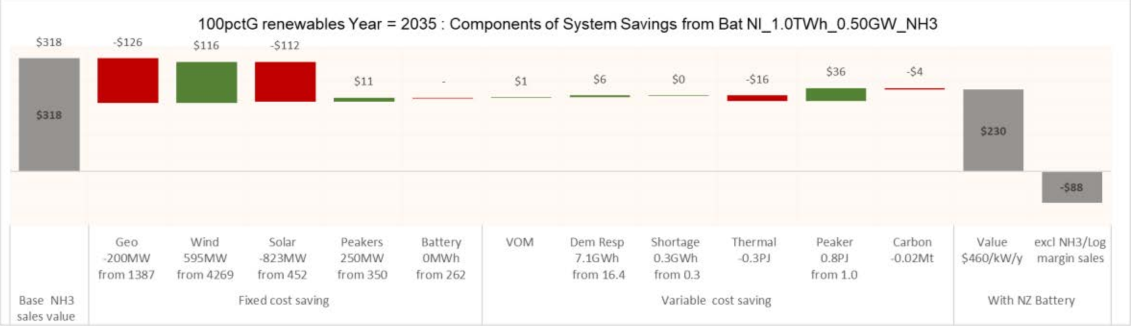

NH3 Gen storage inflows and outflows 328 max level GWh = 13 weeks CF= 8.1%

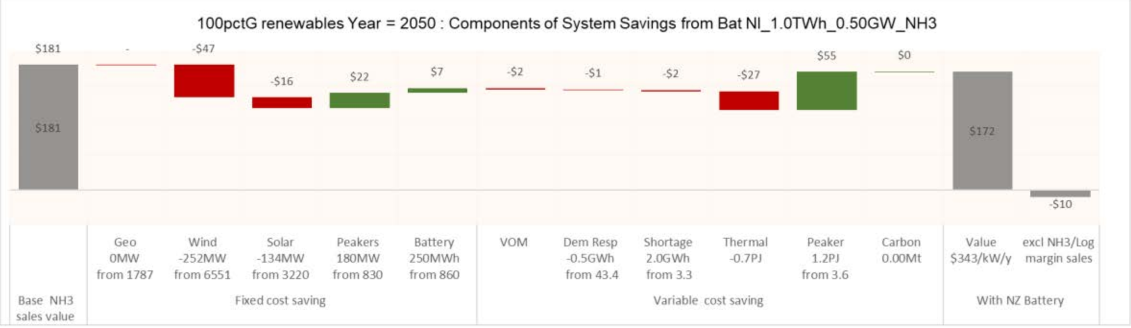
Comments

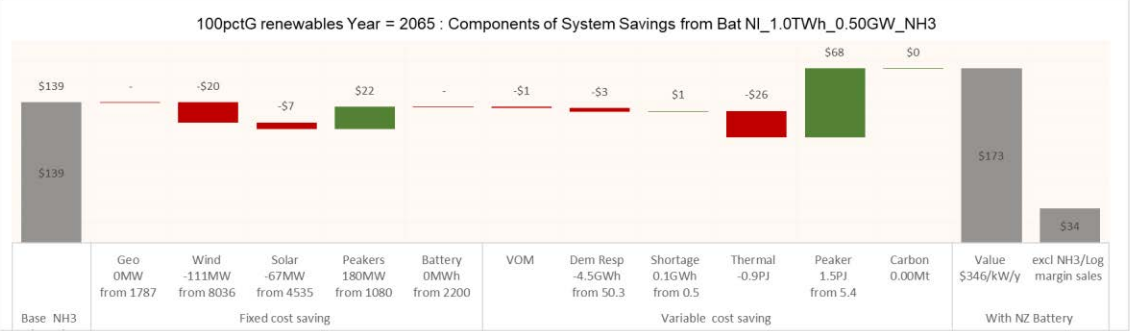
- The chart shows the operation of a stockpile with a filling rate determined by the flexible use of an electrolyser/NH_3 plant. This plant operates when electricity prices are low .
- The CCGT plant takes ammonia from the stock pile as required to cover both dry years and periods when there is a risk of capacity shortfall.
- Operation of the CCGT is triggered by an offer price linked to international ammonia export prices.

The flexible load and CCGT option is estimated to have an incremental gross margin in the range of $172m to $230m/y.

The gross incremental value $m/yr - for both 370MW of flexible load and 150MW of green NH_3 fired CCGT is estimated to be in the range of $172-230m/y.







A flexible electrolyser might be able to operate at around 77% to 63% capacity factor with a base electricity cost (ex transmission) of $30-$20/MWh and be almost competitive in the international market.

- Note that the sales value for NH_3 production is included in the gross margin. The net benefit reflects a mix of low cost of supply for the electrolyser and the benefits of reduced green peaker capital and operating costs, offset by the somewhat lower cost of CCGT variable cost at the international cost of NH_3.

Flexible NH_3 production facility & CCGT @ international NH_3 prices

Component	Units	MW	2035	2050	2065
Electrolyser demand	GWh/y	370	2,607	2,243	2,143
Capacity factor	CF		80%	69%	66%
Avg Cost Electricity	NZ $/MWh		$28	$24	$21
NH_3 Production	GWh/y LHV		1,446	1,244	1,188
NH_3 Production	Mt/yr		275	237	226
NH_3 Price	US$/t		$750	$500	$400
NH_3 Production value	NZ$m		$318	$182	$139
Elec Cost	NZ$m		$73	$53	$45
NH3 Market Gross Margin	NZ$m/y		$245	$129	$94
NH_3 SRMC	$/MWh LHV		$400	$266	$213
CCGT NH_3 Fuel Use	GWh/y LHV		77	198	239
CCGT Generation	GWh/y	150	42	107	129
Capacity factor	CF		3.2%	8.1%	9.8%
CCGT Market Gross Margin	NZ $m		$8	$34	$49
Avg Value of CCGT gen	NZ$/MWh		$578	$567	$579
Avg Cost of generation	NZ$/MWh		$378	$252	$202
Gross Margin	NZ$/kW/yr		$49	$218	$317
Total Gross Margin	NZ $m/y		$253	$163	$143
Incremental System Value	***NZ$m/y***		**$230**	**$173**	**$173**

Note: ...

Conclusions

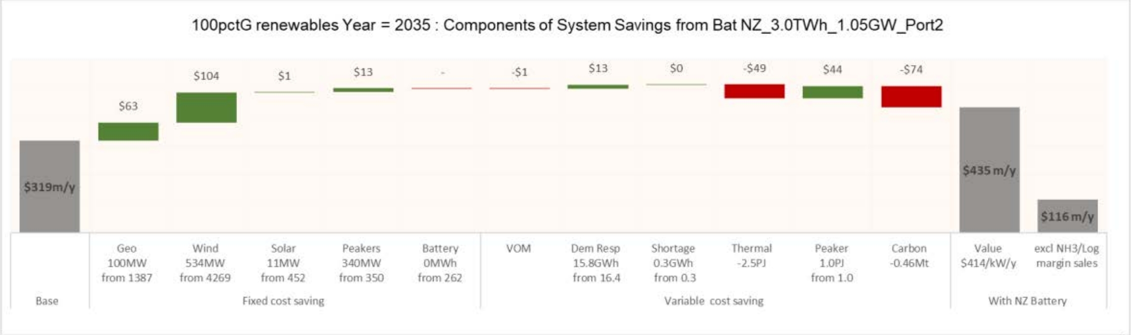
The analysis suggests that a very flexible hydrogen plant could be supplied from the NZ electricity system at low $30/MWh wholesale price which may to be competitive with supply from very good international renewable resources with a 35-60% capacity factor .

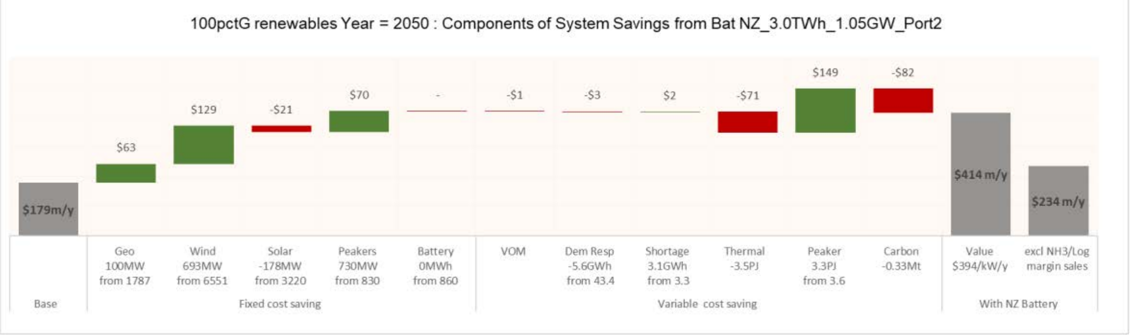
- If the electrolyser can be fully flexible and the cost of ramping the ammonia plant up and done over a period of days is relatively low, then the market cost of electricity supply for hydrogen/ammonia can be reduced below $30/MWh while still achieving 80-66% capacity factor.
  - This may well be competitive with the production of hydrogen and ammonia from good international renewable wind and solar resources with capacity factors in the range of 35-55%.
  - This means that there is a reasonable likelihood that some hydrogen production facilities could be commercially profitable in the NZ market, particularly if they can serve local demand in hard-to-decarbonise uses such as fertilizers, aviation, heavy transport, steel, and cement production.
    - There will be limits to the total MWs of this flexible supply available at this cost, but modelling suggests that 300-500MW is possible.
- A local hydrogen and ammonia industry based on these uses might then provide sufficient supply chain flexibility for new small scale, low capital cost hydrogen or ammonia supplied flexible peaking plant with a low expected annual use.
  - This may be a more economical approach than the much higher capital costs of CCGTs assumed in this option.

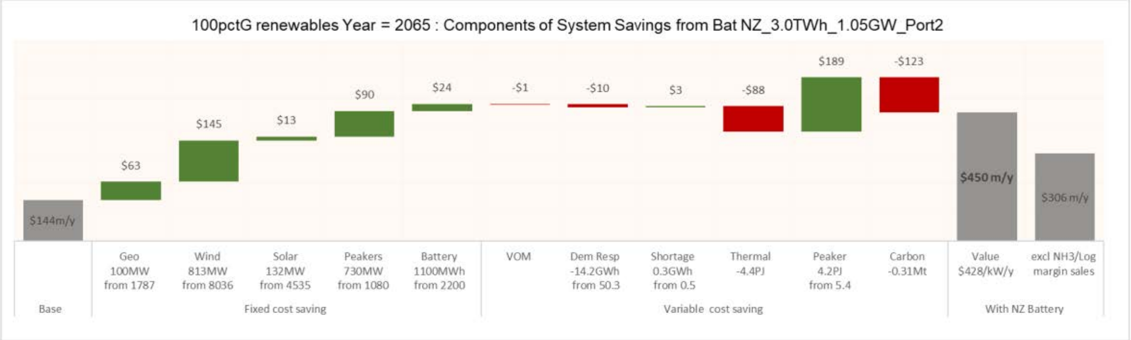
22. TOTAL PORTFOLIO VALUE

Portfolio 2 includes 400MW flexible geothermal, 500MW biomass and 370MW H_2/NH_3 flexible load and 150MW CCGT H_2 peaker

The total system benefit for a portfolio of flexible geothermal, biomass and flexible load and a small CCGT is between $410 and $450m/yr relative to the base green peaker counterfactual in which Tiwai exits NZ


100pctG renewables Year = 2035 : Components of System Savings from Bat NZ_3.0TWh_1.05GW_Port2


100pctG renewables Year = 2050 : Components of System Savings from Bat NZ_3.0TWh_1.05GW_Port2


100pctG renewables Year = 2065 : Components of System Savings from Bat NZ_3.0TWh_1.05GW_Port2

The total portfolio value is slightly lower than the sum of the standalone options

- This is value of a portfolio consisting of :
  - A 370 flexibly operated H_2/NH_3 plant with a 370GWh stockpile of NH_3 which serves a 150 MW CCGT fired on H_2 cracked from ammonia.
  - A 500MW biomass plant with a 1 TWh stockpile of logs supplying a Rankine generator using chipped logs as fuel.
  - 400MW of flexible geothermal operating according to an energy security dispatch rule.
  - The portfolio value is slightly lower than the sum of the standalone options.

Portfolio - Tiwai Exits - Green Peaker

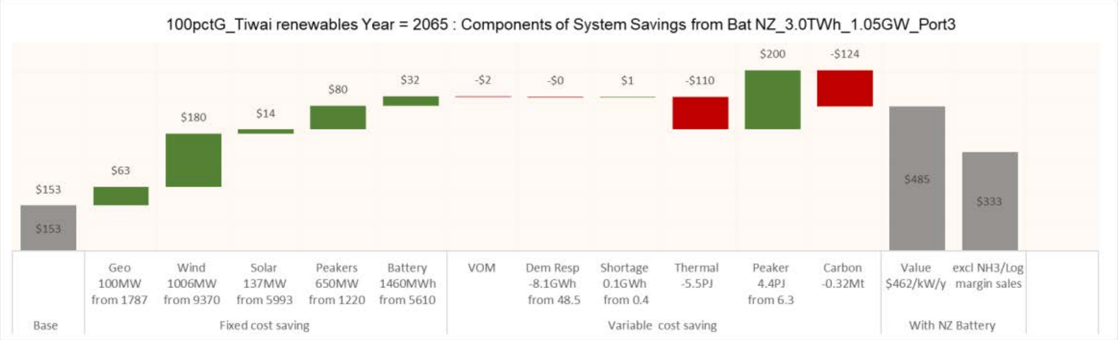
Component	Units	MW	2035	2050	2065
Biomass Generation	GWh/yr	478	230	301	355
	CF		5.5%	7.2%	8.5%
Geo Generation energy security	GWh/yr	400	2,313	1,899	1,817
	CF		66.0%	54.2%	51.9%
CCGT Generation	GWh/yr	150	12	54	100
	CF		0.9%	4.1%	7.6%
Electrolyser demand	GWh/y	370	2,514	2,010	1,907
	CF		77.6%	62.0%	58.8%
NH_3 Production	kT/y		265	212	201
NH_3 Price	US $/t		$750	$500	$400
NH_3 Production value	NZ $m/y		$306	$163	$124
Log cost Margin	NZ $m/y		$13	$17	$20
Market Gross Margin					
Biomass	NZ $m/y		$31	$118	$156
Geothermal	NZ $m/y		$170	$153	$145
NH3	NZ $m/y		$227	$109	$77
CCGT	NZ $m/y		$1	$21	$38
Total Market Gross Margin	NZ $m/y		$429	$401	$416
Incremental System Value	**NZ $m/y**		**$435**	**$415**	**$450**
Sum of stand alone	NZ $m/y		**$458**	**$474**	**$451**
Portfolio/Sum stand alone	%		*95%*	*87%*	*100%*

Portfolio3a includes 400MW flexible geothermal, 500MW biomass and 80MW Tiwai flexible load and 370MW H_2/NH_3 flexible load and 150MW CCGT H_2 peaker - relative to Tiwai stays counterfactual

The total system benefit for a portfolio of flexible geothermal, biomass and increased Tiwai demand response is between $490 and $550m/y relative to Tiwai stays counterfactual


100pctG_Tiwai renewables Year = 2035 : Components of System Savings from Bat NZ_3.0TWh_1.05GW_Port3


100pctG_Tiwai renewables Year = 2050 : Components of System Savings from Bat NZ_3.0TWh_1.05GW_Port3


100pctG_Tiwai renewables Year = 2065 : Components of System Savings from Bat NZ_3.0TWh_1.05GW_Port3

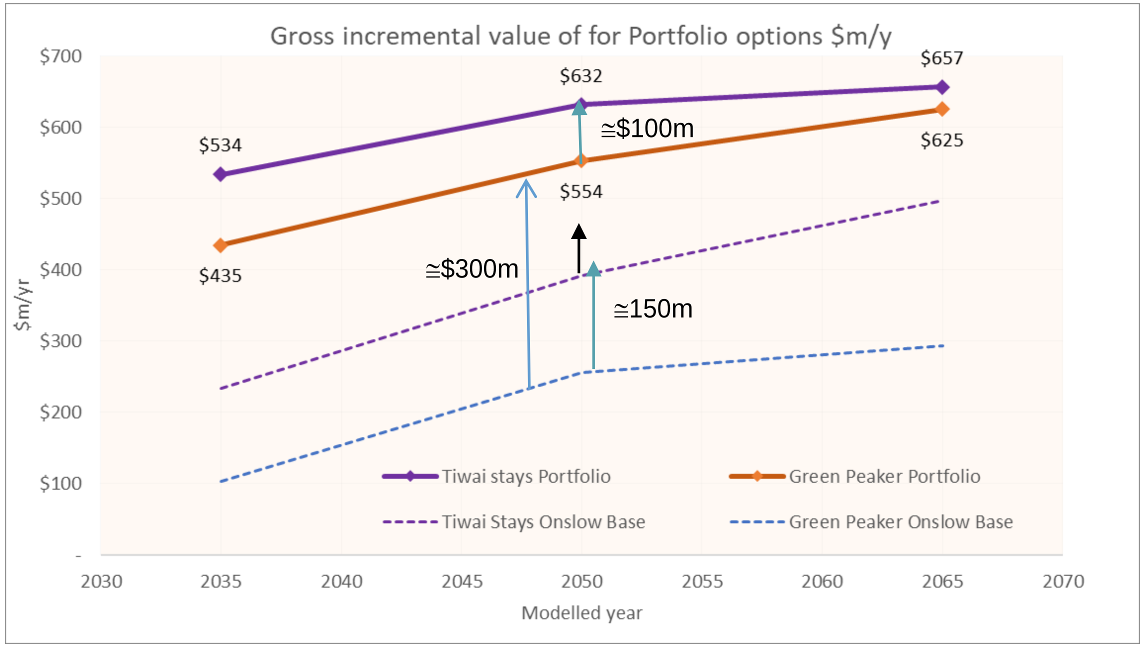
Table

- The value of the portfolio increases by $80-100m/y if Tiwai Stays.
- There is only a small additional value from more frequent use of the existing 80MW Tiwai demand reduction in extreme dry years.

Portfolio - Tiwai Stays - Green Peaker					
Component	Units	MW	2035	2050	2065
Biomass Generation	GWh/yr	478	293	384	440
	CF		7.0%	9.2%	10.5%
Geo Generation energy security	GWh/yr	400	2,326	1,981	1,833
	CF		66.4%	56.5%	52.3%
CCGT Generation	GWh/yr	150	25	72	130
	CF		1.9%	5.5%	9.9%
Electrolyser demand	GWh/y	370	2,525	2,034	1,969
	CF		77.9%	62.7%	60.8%
Tiwai Extra DR	GWh/yr	80	22	7	6
	CF		3.1%	1.0%	0.8%
NH_3 Production	kT/y		267	215	208
NH_3 Price	US $/t		$750	$500	$400
NH_3 Production value	NZ $m/y		$308	$165	$128
Log cost Margin	NZ $m/y		$16	$21	$25
Market Gross Margin					
Biomass	NZ $m/y		$54	$137	$156
Geothermal	NZ $m/y		$177	$172	$148
NH3	NZ $m/y		$234	$114	$82
CCGT	NZ $m/y		$3	$25	$37
Total Market Gross Margin	NZ $m/y		$468	$448	$422
Incremental System Value	**NZ $m/y**		**$534**	**$494**	**$485**

The portfolio options provide higher value, but also higher capital costs

The portfolio benefits are around $150 to $330m/yr higher than for Onslow

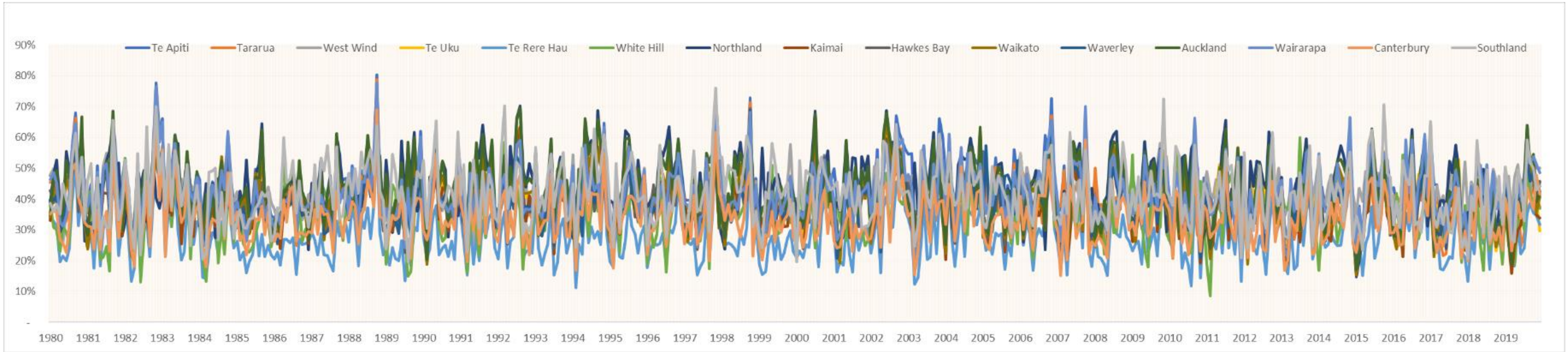


Commentary

- The portfolio options provide $300-$330m/y higher system benefits than the base case Onslow pumped hydro option, but have higher capital costs.
  - **We can't determine the net benefit since we do not have the full costs of these** options.
- The extra benefits in the Tiwai stays case or a bit lower at $150 to $310m.
- The impact of Tiwai staying on Onslow is around $130-220m/y.
  - This is greater than the impact of Tiwai staying on the Portfolio which is $40-110m/y.
  - Note that a large component of the portfolio value is the sales value of the green ammonia produced (around $300 falling to $150m/yr).
    - This is highly uncertain - the modelling assume a declining curve from $US750 in 2035 to $US400/tonne in 2065.

23. WIND SUPPLY PROFILES AND STATISTICS

Updated MERRA-2 satellite based wind data - monthly - 1980 to 2019



Monthly Statistics

	Monthly Max	Monthly P10	Monthly P90	Monthly Min	Mean Capacity Factor	Monthly Stdev	Monthly Volatility	Monthly Cross Correl Tararua	Monthly Serial Correl
Te Apiti	80%	56%	32%	20%	42%	9.5%	22%	94%	17%
Tararua	79%	54%	29%	18%	40%	9.5%	24%	100%	17%
West Wind	71%	50%	32%	20%	42%	7.6%	18%	72%	13%
Te Uku	67%	54%	30%	20%	40%	9.6%	24%	64%	17%
Te Rere Hau	63%	39%	18%	11%	28%	8.3%	30%	93%	18%
White Hill	70%	48%	23%	9%	36%	10.0%	28%	63%	11%
Northland	70%	57%	31%	15%	43%	10.3%	24%	34%	29%
Kaimai	66%	53%	29%	16%	39%	9.3%	24%	66%	14%
Hawkes Bay	72%	51%	30%	16%	39%	9.3%	24%	77%	9%
Waikato	68%	54%	30%	15%	40%	9.8%	25%	62%	18%
Waverley	71%	50%	29%	19%	39%	8.7%	23%	82%	18%
Auckland	70%	58%	32%	17%	43%	10.2%	24%	57%	22%
Wairarapa	78%	54%	31%	19%	42%	9.5%	22%	89%	17%
Canterbury	69%	46%	25%	15%	34%	8.3%	24%	78%	3%
Southland	76%	55%	30%	20%	42%	10.0%	24%	64%	12%

Annual Statistics

	Annual Max	Annual P10	Annual P90	Monthly Min	Mean Capacity Factor	Annual Volatility	Annual Cross Correl Tararua
Te Apiti	51%	48%	38%	37%	42%	8%	85%
Tararua	47%	44%	36%	34%	40%	8%	100%
West Wind	47%	45%	38%	37%	42%	7%	48%
Te Uku	46%	44%	37%	33%	40%	7%	63%
Te Rere Hau	34%	32%	25%	23%	28%	9%	85%
White Hill	44%	40%	32%	29%	36%	10%	62%
Northland	49%	47%	39%	37%	43%	7%	39%
Kaimai	45%	42%	35%	33%	39%	8%	68%
Hawkes Bay	46%	42%	36%	34%	39%	7%	83%
Waikato	46%	44%	37%	35%	40%	7%	69%
Waverley	45%	42%	36%	35%	39%	6%	88%
Auckland	49%	47%	39%	37%	43%	7%	61%
Wairarapa	49%	46%	39%	36%	42%	7%	85%
Canterbury	39%	38%	31%	29%	34%	8%	72%
Southland	49%	46%	39%	35%	42%	8%	61%

Daily Statistics

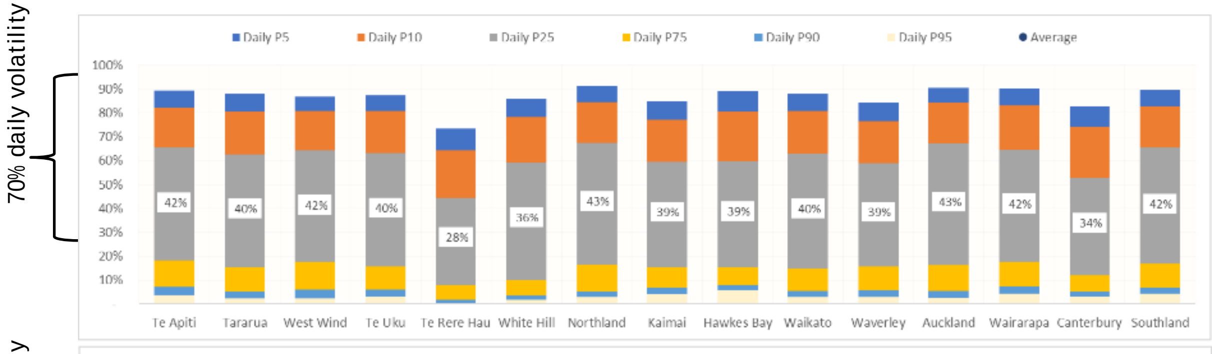
	Daily P5	Daily P10	Daily P25	Daily P75	Daily P90	Daily P95	Average	Daily Stdev	Daily Cross Correl Tararua	Daily Serial Correl
Te Apiti	89%	82%	65%	18%	7%	4%	42%	27%	96%	47%
Tararua	88%	81%	63%	15%	5%	2%	40%	28%	100%	48%
West Wind	87%	81%	64%	18%	6%	2%	42%	27%	65%	37%
Te Uku	87%	81%	63%	16%	6%	3%	40%	27%	50%	52%
Te Rere Hau	73%	64%	44%	8%	2%	0%	28%	23%	94%	49%
White Hill	86%	78%	59%	10%	4%	2%	36%	28%	38%	53%
Northland	91%	85%	67%	17%	5%	3%	43%	29%	23%	54%
Kaimai	85%	77%	60%	15%	7%	4%	39%	26%	49%	54%
Hawkes Bay	89%	80%	60%	15%	8%	6%	39%	27%	68%	52%
Waikato	88%	81%	63%	15%	5%	3%	40%	28%	50%	52%
Waverley	84%	77%	59%	16%	6%	3%	39%	26%	78%	48%
Auckland	90%	84%	67%	16%	5%	3%	43%	29%	42%	54%
Wairarapa	90%	83%	65%	18%	7%	4%	42%	27%	86%	47%
Canterbury	83%	74%	53%	12%	5%	3%	34%	26%	64%	45%
Southland	90%	83%	65%	17%	7%	4%	42%	28%	44%	57%

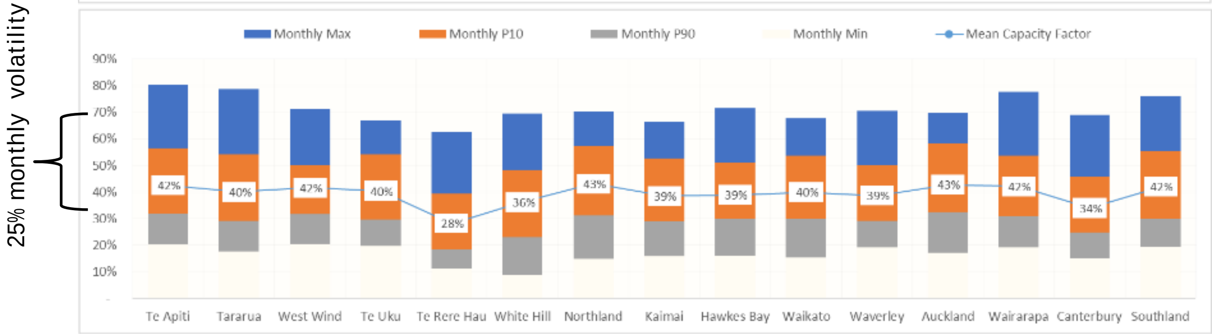
There is a modest winter and spring bias in the seasonal pattern and a small time-time bias in the daily pattern on average

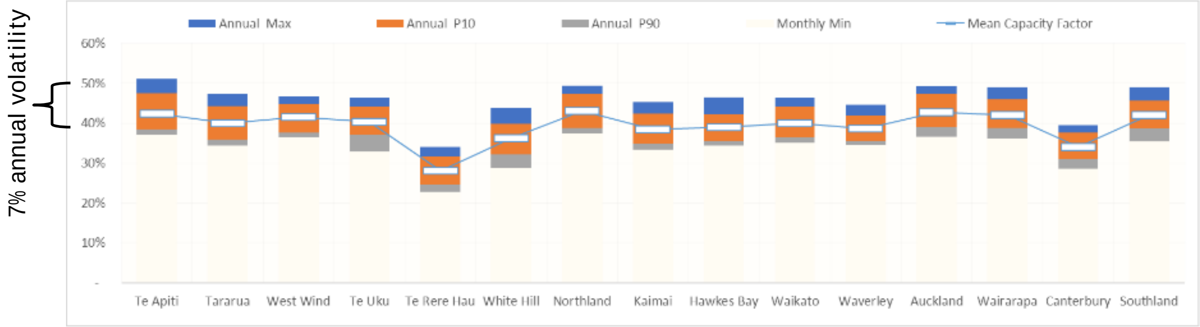
JC²

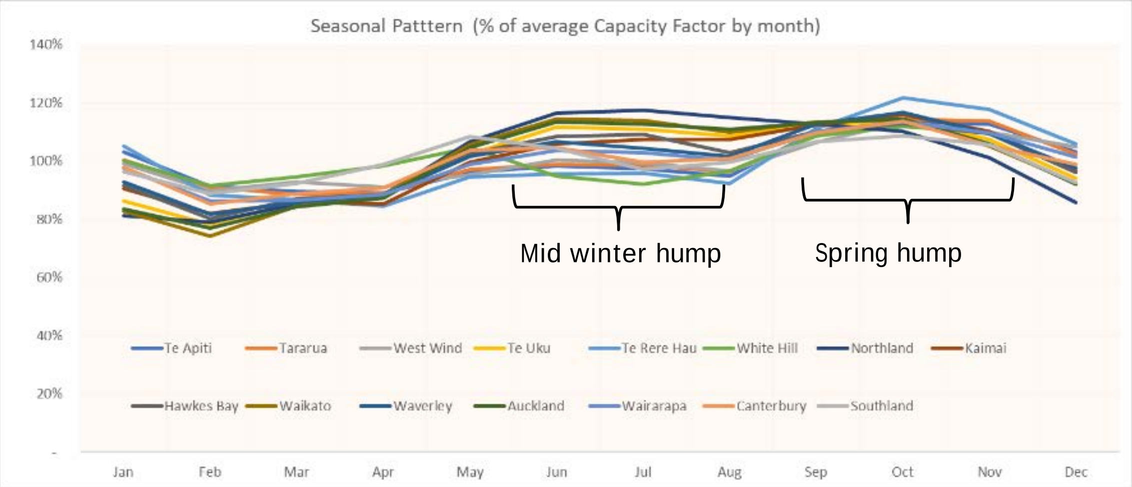
There is a very high daily variation in the wind profiles. The greatest volatility is around is between days. This falls to 25% between months and 7% between years.

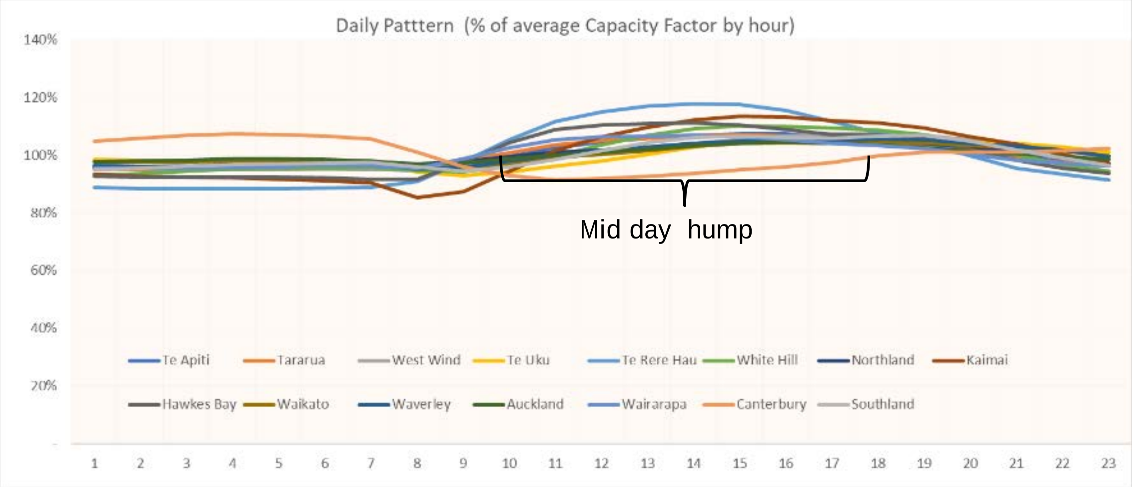
The average seasonal and daily patterns of supply show slight mid-winter, spring and mid-day humps.











There is a high correlation between wind profiles within the Manawatu. This falls off with distance but is still is reasonably high at 30-40% in the South Island and Northland.

The cross corelation matrix shows the relationship between variation between all pairs of wind profiles. The highest cross correlations are shown in green and the lowest in red.

The correlations are greatest on a monthly basis, lower on a daily basis and also lower again on an hourly basis.

There is a 90% + corelation between profiles within the Manawatu, this falls towards 50% for other NI regions, and down to 30% for South Island sites and Northland.

The benefits from regional diversification of wind are significant, but not overwhelming.

Hourly

	TAP CF1	TAR CF1	WW CF1	TUK CF1	TWC CF1	NMA CF1	Nland CF1	Kai CF1	HB CF1	Wai CF1	Wav CF1	Tar CF1	Wel CF1	Cant CF1	Sland CF1
TAP CF1	100%														
TAR CF1	94%	100%													
WW CF1	57%	57%	100%												
TUK CF1	39%	41%	24%	100%											
TWC CF1	89%	90%	62%	45%	100%										
NMA CF1	29%	29%	20%	10%	29%	100%									
Nland CF1	16%	18%	16%	69%	21%	(2%)	100%								
Kai CF1	38%	40%	21%	89%	44%	11%	70%	100%							
HB CF1	59%	62%	48%	65%	67%	14%	49%	65%	100%						
Wai CF1	40%	42%	31%	93%	46%	9%	72%	87%	72%	100%					
Wav CF1	71%	72%	62%	58%	76%	20%	39%	55%	74%	67%	100%				
Tar CF1	32%	34%	23%	91%	37%	7%	83%	89%	64%	93%	55%	100%			
Wel CF1	81%	82%	72%	46%	87%	25%	27%	46%	75%	51%	77%	42%	100%		
Cant CF1	51%	52%	57%	29%	56%	43%	17%	28%	43%	32%	49%	27%	62%	100%	
Sland CF1	35%	36%	21%	23%	37%	71%	9%	23%	26%	23%	31%	21%	35%	48%	100%

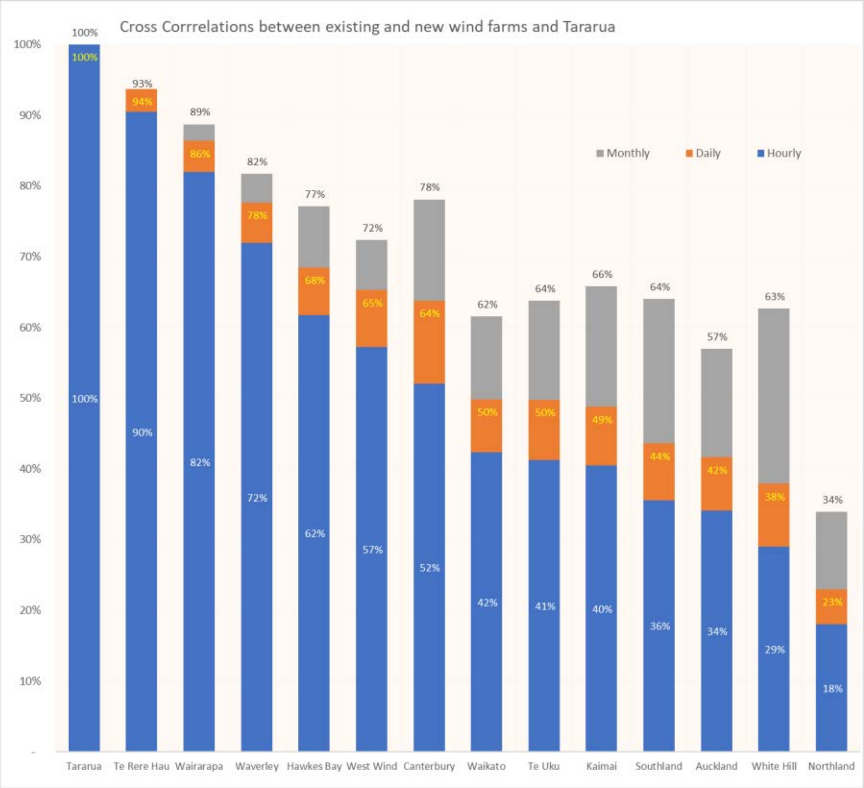
Daily

	TAP CF1	TAR CF1	WW CF1	TUK CF1	TWC CF1	NMA CF1	Nland CF1	Kai CF1	HB CF1	Wai CF1	Wav CF1	Tar CF12	Wel CF1	Cant CF1	Sland CF1
TAP CF1	100%														
TAR CF1	96%	100%													
WW CF1	66%	65%	100%												
TUK CF1	47%	50%	30%	100%											
TWC CF1	93%	94%	70%	53%	100%										
NMA CF1	38%	38%	27%	14%	37%	100%									
Nland CF1	21%	23%	20%	77%	25%	(1%)	100%								
Kai CF1	46%	49%	27%	93%	51%	14%	77%	100%							
HB CF1	66%	68%	58%	74%	74%	18%	56%	73%	100%						
Wai CF1	47%	50%	37%	95%	53%	12%	78%	91%	80%	100%					
Wav CF1	77%	78%	70%	66%	81%	26%	45%	62%	82%	73%	100%				
Tar CF12	39%	42%	28%	95%	44%	10%	87%	94%	72%	96%	62%	100%			
Wel CF1	86%	86%	78%	54%	91%	33%	32%	54%	82%	59%	83%	50%	100%		
Cant CF1	63%	64%	68%	38%	68%	55%	21%	38%	54%	41%	61%	36%	74%	100%	
Sland CF1	43%	44%	25%	29%	45%	77%	11%	28%	32%	28%	37%	26%	42%	59%	100%

Monthly

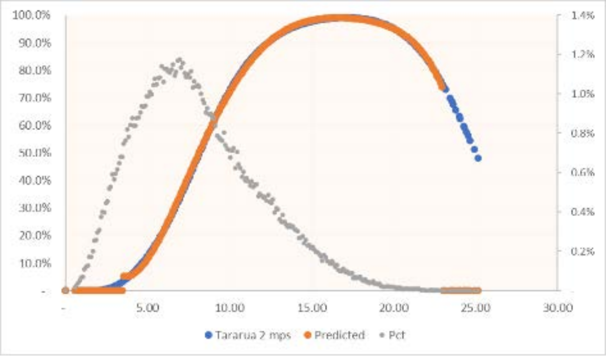
	Te Apiti	Tararua	West Wind	Te Uku	Te Rere Hau	White Hill	Northland	Kaimai	Hawkes Bay	Waikato	Waverley	Auckland	Wairarapa	Canterbury	Southland
Te Apiti	100%														
Tararua	94%	100%													
West Wind	71%	72%	100%												
Te Uku	61%	64%	48%	100%											
Te Rere Hau	93%	93%	77%	65%	100%										
White Hill	63%	63%	43%	35%	62%	100%									
Northland	31%	34%	26%	81%	32%	11%	100%								
Kaimai	64%	66%	45%	95%	67%	38%	81%	100%							
Hawkes Bay	75%	77%	70%	85%	81%	46%	68%	85%	100%						
Waikato	58%	62%	50%	97%	62%	33%	84%	93%	89%	100%					
Waverley	80%	82%	74%	80%	85%	51%	58%	79%	91%	83%	100%				
Auckland	54%	57%	43%	96%	57%	30%	90%	95%	84%	98%	77%	100%			
Wairarapa	88%	89%	82%	72%	93%	57%	45%	73%	90%	73%	90%	68%	100%		
Canterbury	78%	78%	74%	62%	82%	71%	36%	61%	78%	63%	78%	58%	87%	100%	
Southland	65%	64%	40%	47%	65%	85%	23%	48%	56%	47%	58%	44%	64%	77%	100%

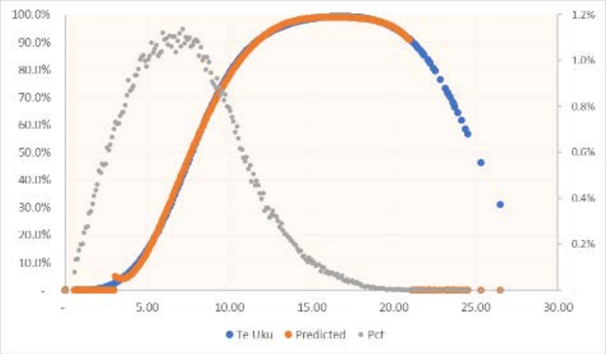
Note: the correlation is measured using the Pearson Product-Moment Correlation.

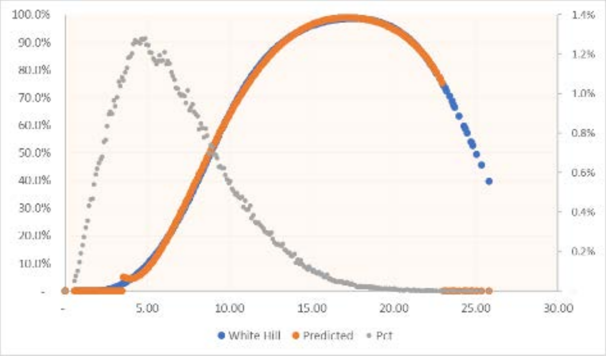


Power curves assumed for existing wind farms - cross checks with actual where possible and calibrated to get averages

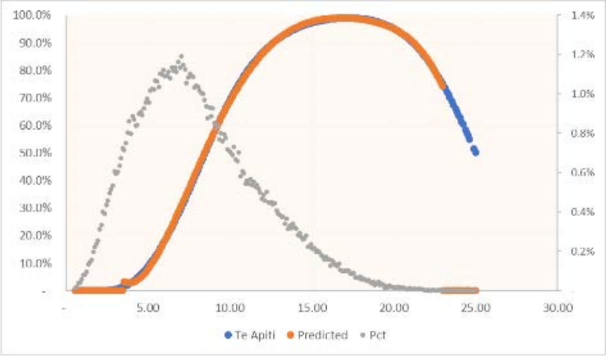
Tararua, Te Uku and White Hill

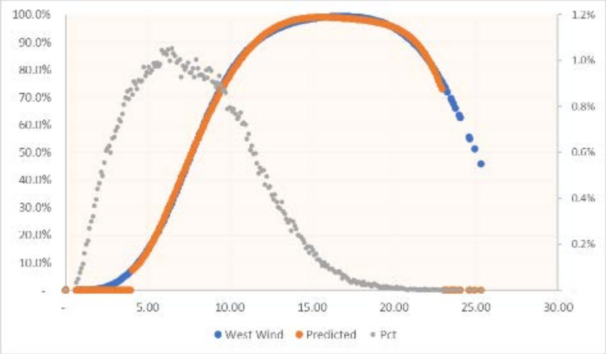


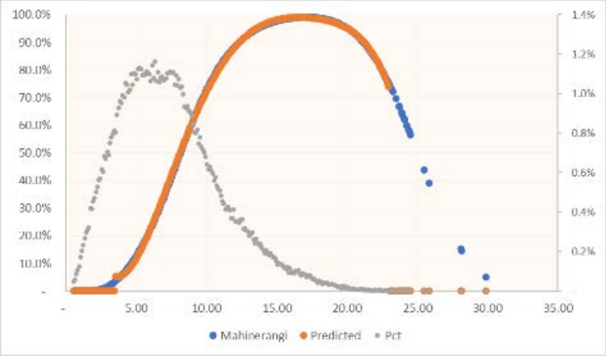




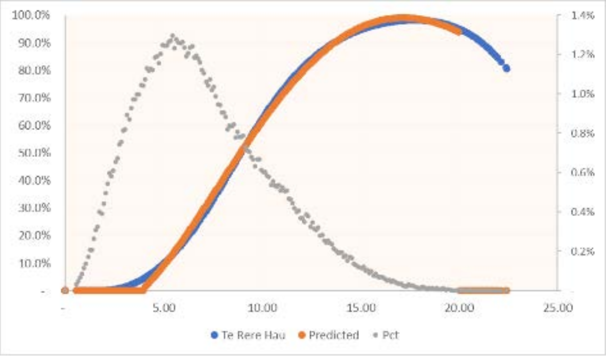
Te Apiti, West wind and Mahineragi

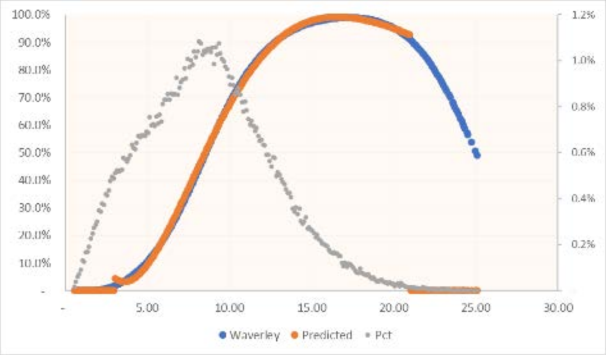






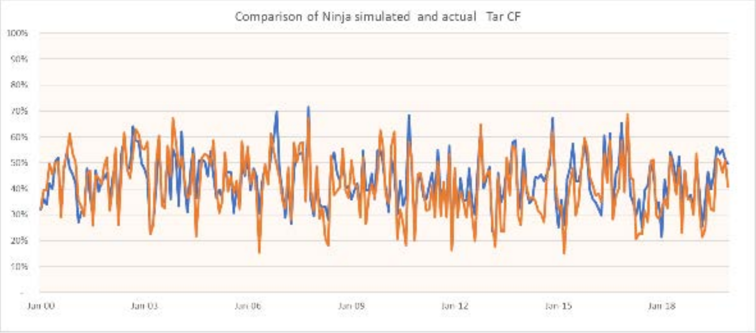
Te Rere Hau , Waverly (estimated to align with CF)

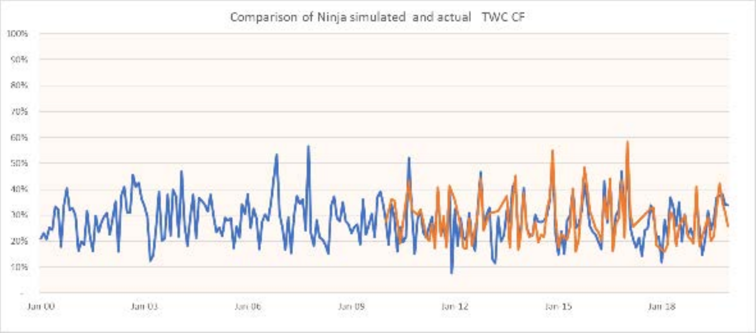


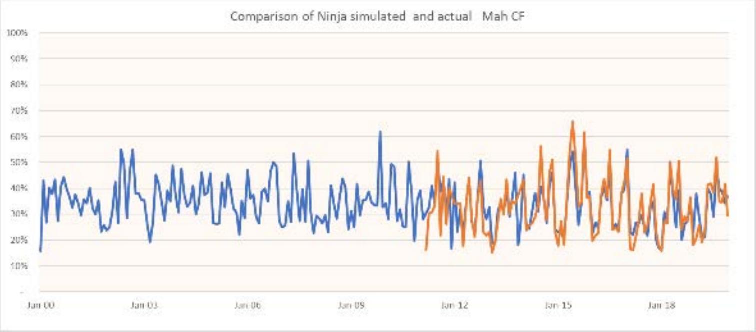


The satellite wind based synthetic data matches pattern and volatility of actual quite closely

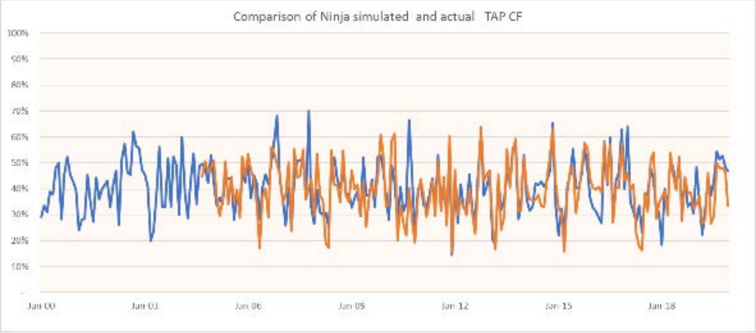
Set 1

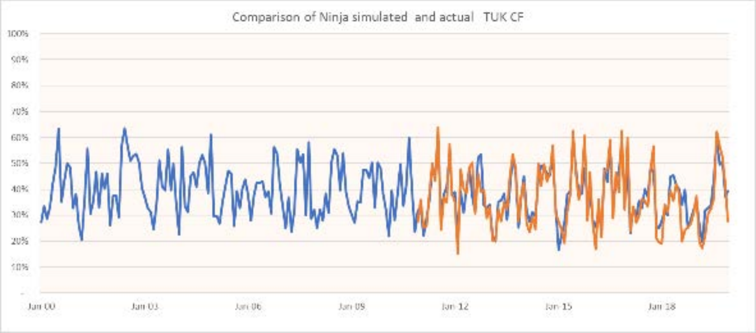




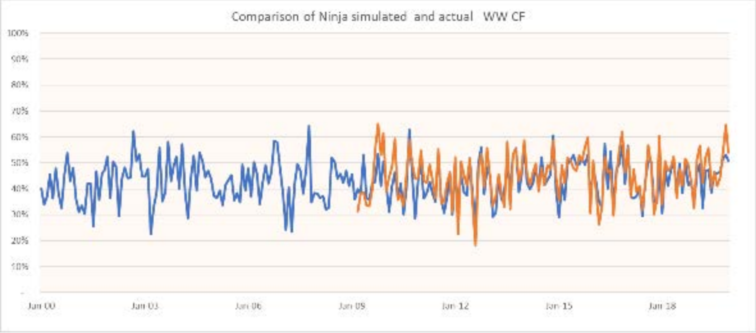


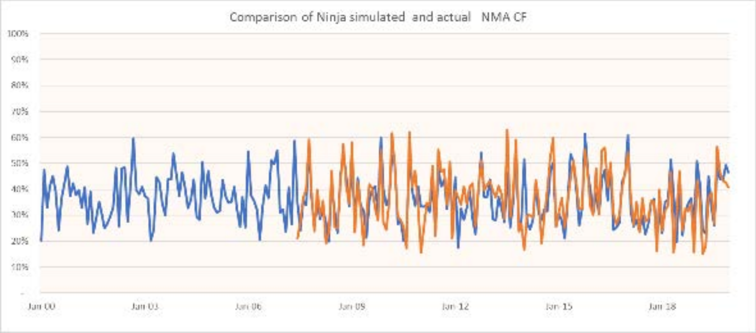
Set 2





Set 3

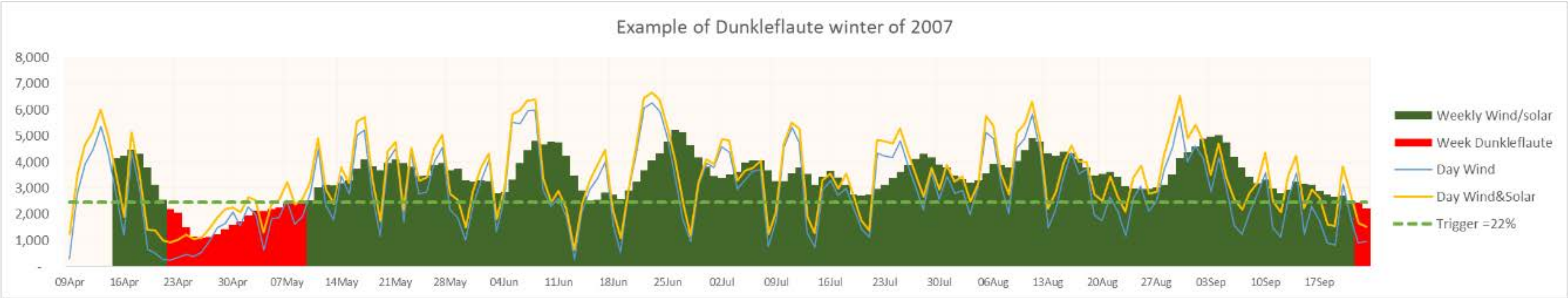


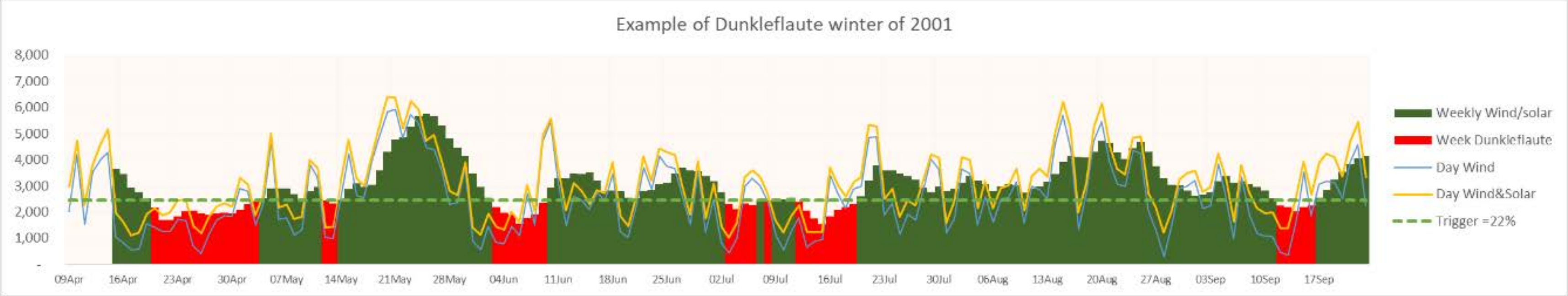


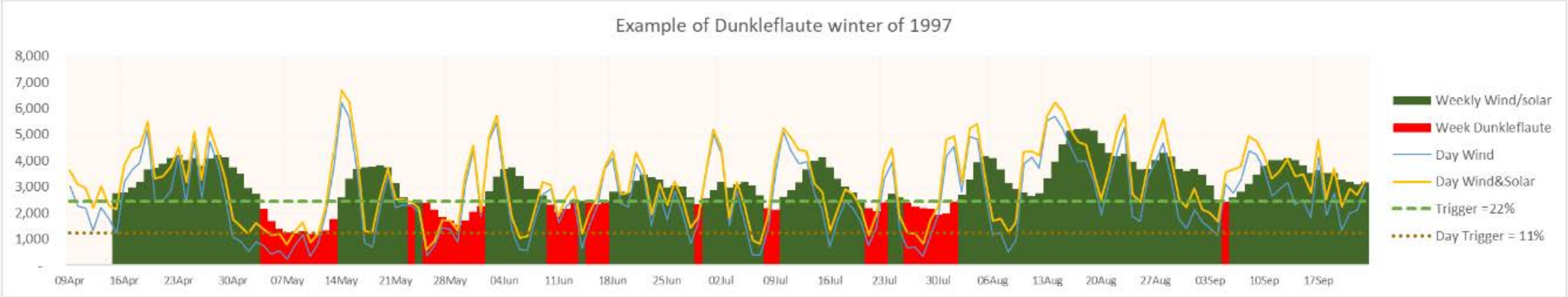
Historical/Synthetic						
	Te Apiti	Tararua	West Wind	Te Uku	Te Rere Hau	White Hill
Start date	1-Aug-04	1-Jan-01	1-Apr-09	1-Dec-10	1-Jan-10	1-Jul-07
Actual Average Hist	41%	40%	43%	39%	28%	36%
Actual Stdev	32%	33%	32%	33%	28%	35%
Actual Cross Correl Tar	92%	100%	34%	22%	85%	18%
Full Average 1980-2019	42%	40%	42%	40%	28%	36%
Full Stdev	33%	33%	33%	32%	28%	33%
Full Cross Correl Tar	94%	100%	57%	41%	90%	29%

What is a Dunkleflaute ?

The chart shows 3 years of illustrative weather history which contain weekly dunkleflautes - defined here when there is a rolling 7 day average supply from wind and solar with a combined capacity factor of less than 20%. As can be seen there around 4-5 such events each year, 1-3 of which last for 1 or more weeks.


Example of Dunkleflaute winter of 2007


Example of Dunkleflaute winter of 2001


Example of Dunkleflaute winter of 1997

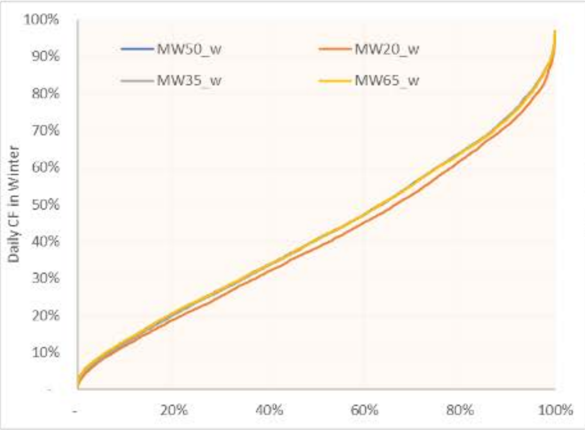
Comments

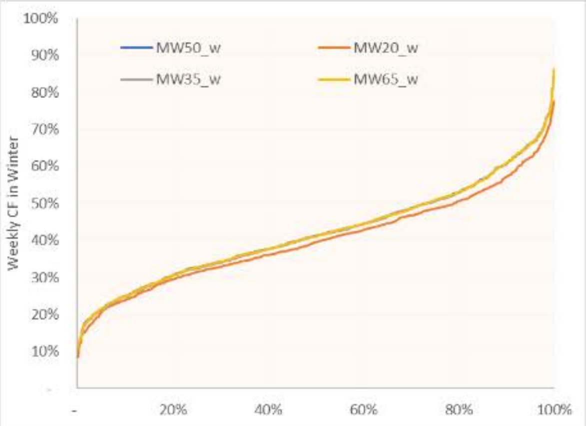
- The chart also show the daily average potential generation from solar and wind .
  - This falls below a 10% capacity factor threshold but this is generally only for a few days at a time.

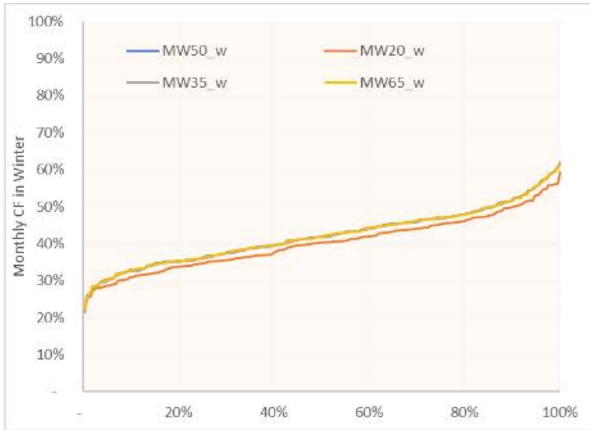
Wind duration curves in winter - from daily to monthly

It is useful to look at the issues from low wind periods in winter (Dunkelflaute events). The charts show wind capacity factors as a function of the % of periods each winter (based on 1980-2020 data)

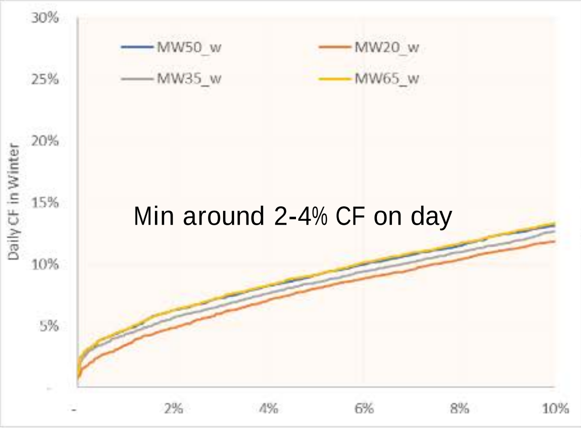
Full winter period



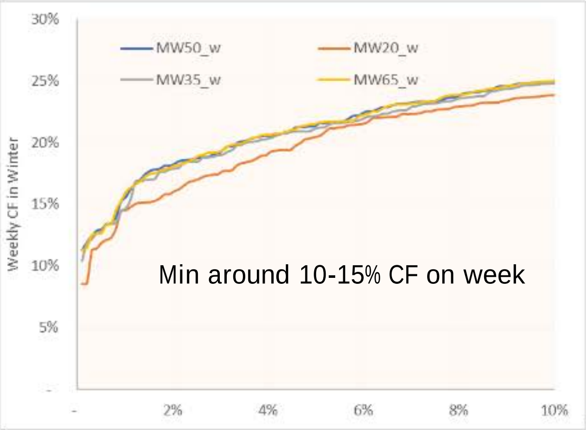




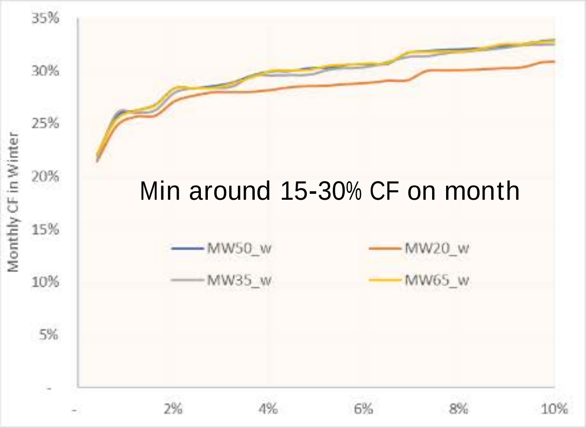
Worst 10% of winter



Min around 2-4% CF on day



Min around 10-15% CF on week



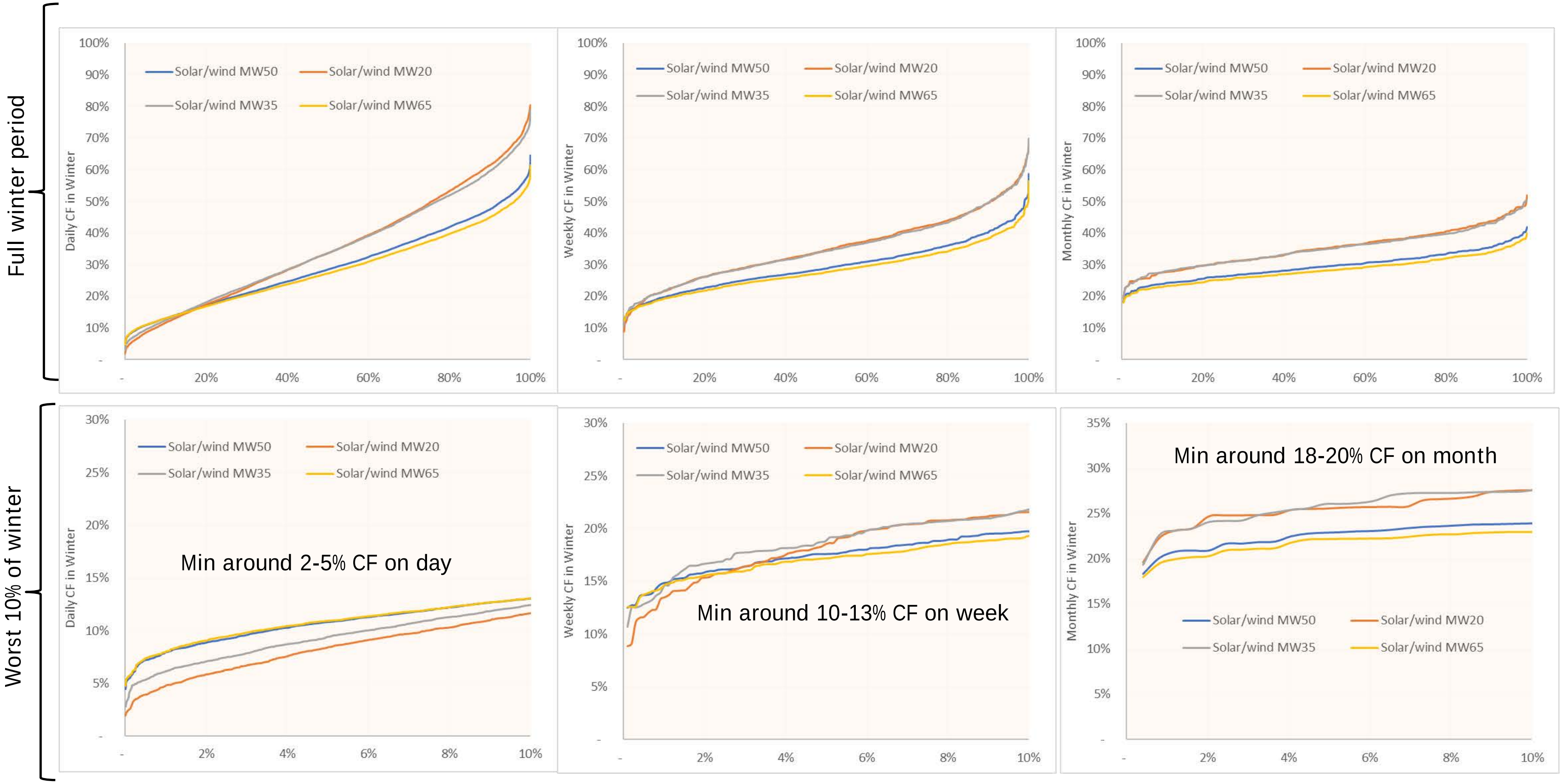
Min around 15-30% CF on month

Notes

- Although the portfolio of wind can fall to 2-4% on the worst day in winter, the worst week and month are much higher.
- There is a modest benefit from diversification as wind in different regions is added to the mix.

Solar/Wind duration curves in winter - from daily to monthly

It is useful to look at the issues from low wind/solar periods in winter (Dunkelflaute events). The charts show wind capacity factors as a function of the % of periods each winter (based on 1980-2020 data)



Notes

- Although the portfolio of solar & wind can fall to 5% on the worst day in winter, the worst week and month are much higher.
- There is a modest benefit from diversification as wind and solar in different regions is added to the mix.

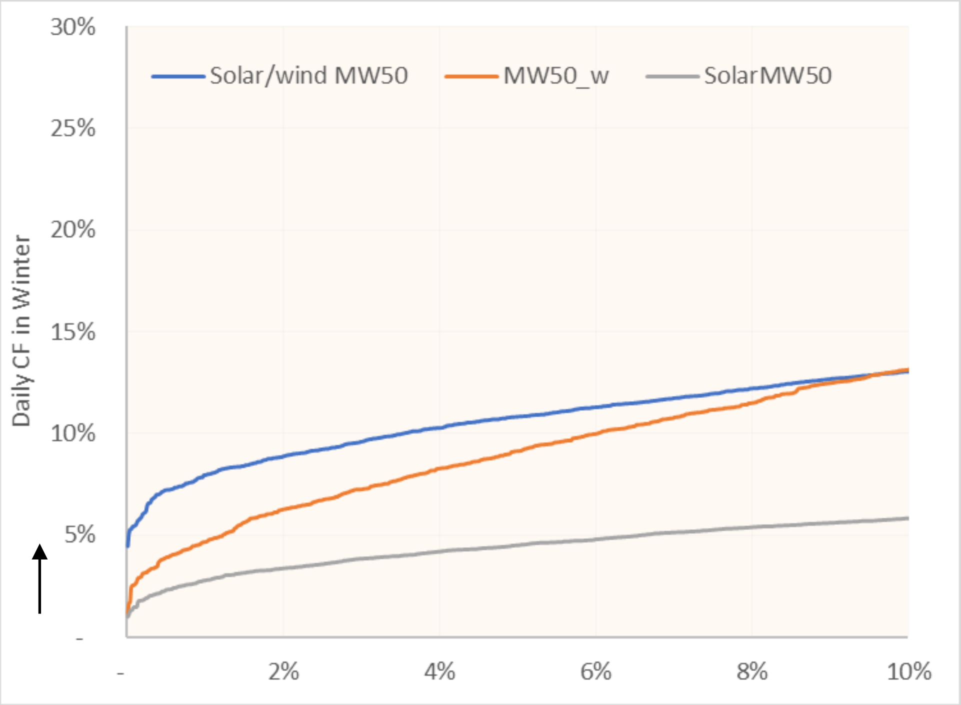
There is benefit from a mix of wind/solar in terms of extra firm MW in winter on a daily average basis

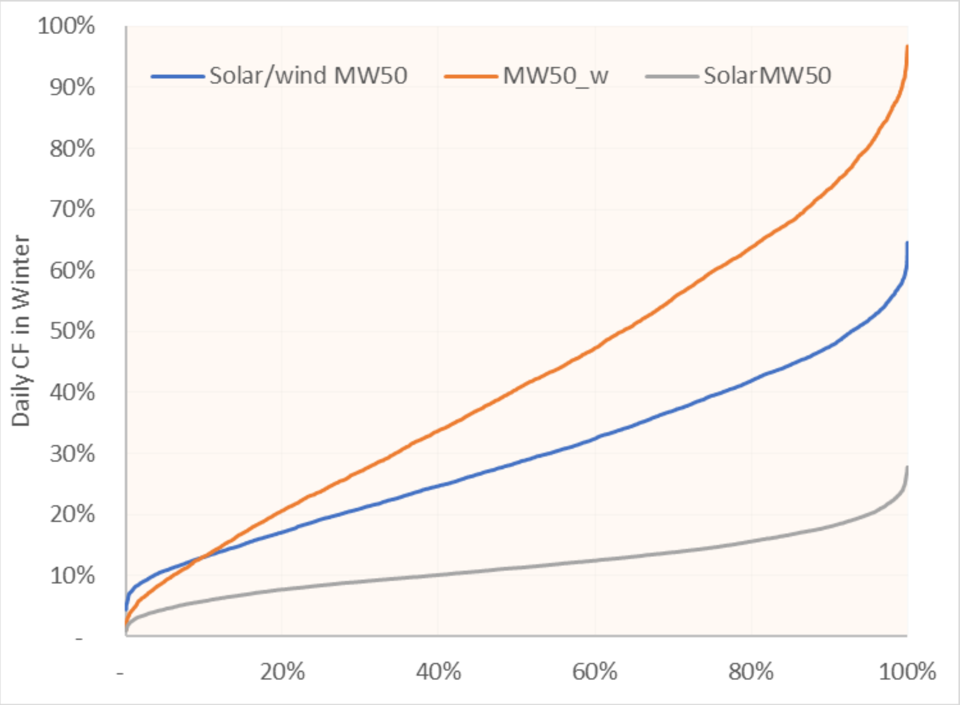
JC²

Daily generation duration curve over worst 10% of days in winter - this is for modelled mix of wind solar and rooftop solar in 2050.

Solar increases the minimum capacity factor for 1-2% for wind alone to around 5%.

Daily generation duration curve over full winter - note that solar capacity factor over winter is only 12% for mix of grid and rooftop , wind is around 42% and the combined solar/wind is around 30%



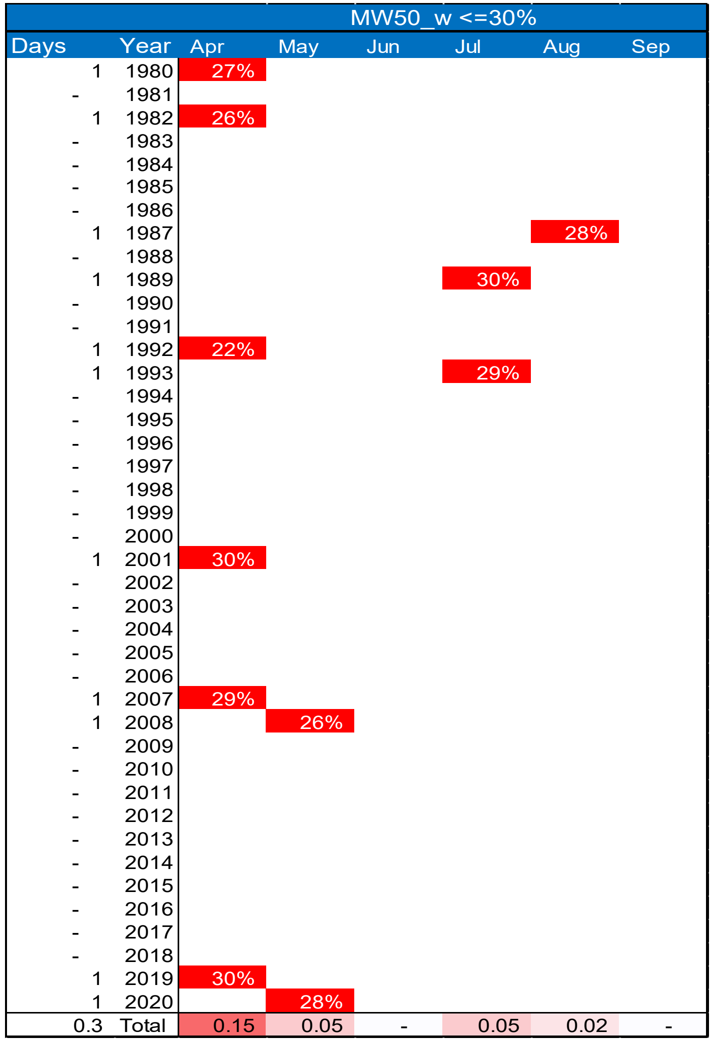


Heat maps for low wind periods - show

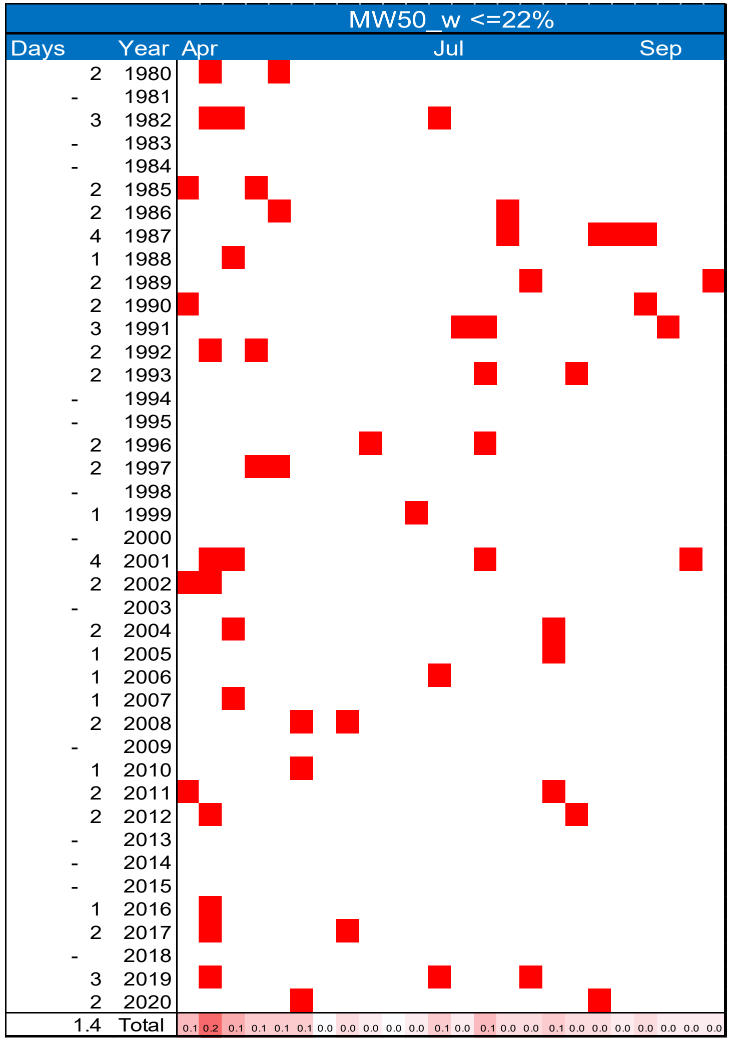
Monthly CF <=30% - up to 1 month per year - highest dunkleflaute risk is early in winter

Weekly <= 22% CF up to 2-4 weeks per year. Most dunkleflautes are 1 week, but can be up to 3 weeks long

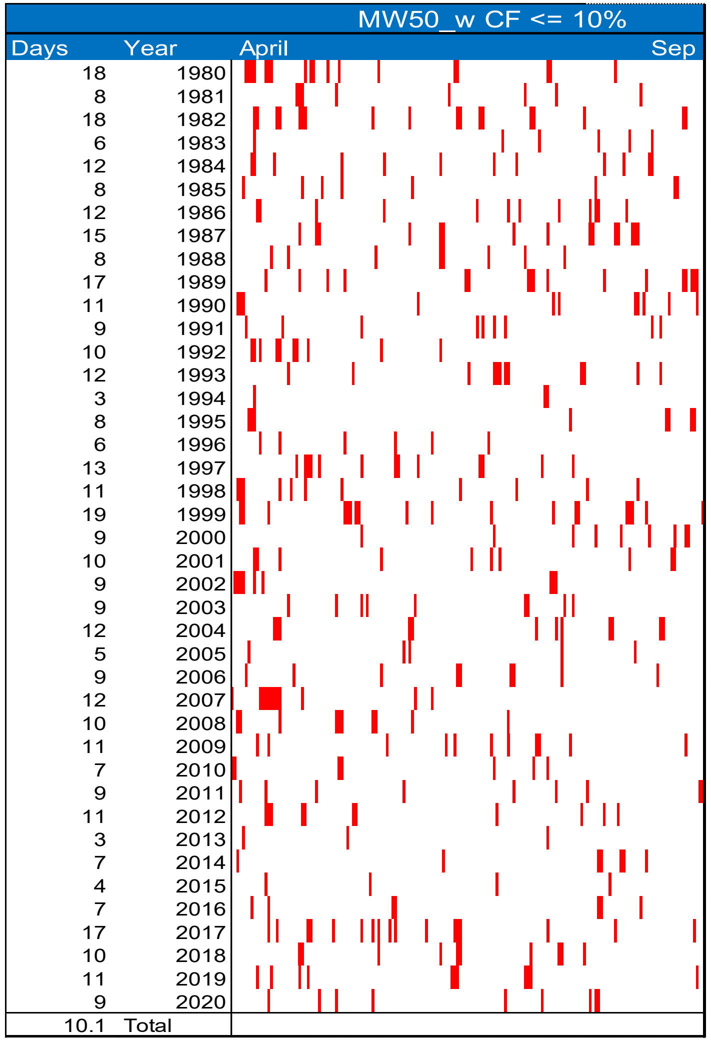
Daily CF <= 10% 10-20days per year. Most daily dunkleflautes are 1 day but there are some which are over 7 days


MW50_w <=30%

Days	Year	Apr	May	Jun	Jul	Aug	Sep
1	1980	27%					
-	1981						
1	1982	26%					
-	1983						
-	1984						
-	1985						
-	1986						
1	1987					28%	
-	1988						
1	1989				30%		
-	1990						
-	1991						
1	1992	22%					
1	1993				29%		
-	1994						
-	1995						
-	1996						
-	1997						
-	1998						
-	1999						
-	2000						
1	2001	30%					
-	2002						
-	2003						
-	2004						
-	2005						
-	2006						
1	2007	29%					
1	2008		26%				
-	2009						
-	2010						
-	2011						
-	2012						
-	2013						
-	2014						
-	2015						
-	2016						
-	2017						
-	2018						
1	2019	30%					
1	2020		28%				
0.3	Total	0.15	0.05	-	0.05	0.02	-



Days	Year
2	1980
-	1981
3	1982
-	1983
-	1984
2	1985
2	1986
4	1987
1	1988
2	1989
2	1990
3	1991
2	1992
2	1993
-	1994
-	1995
2	1996
2	1997
-	1998
1	1999
-	2000
4	2001
2	2002
-	2003
2	2004
1	2005
1	2006
1	2007
2	2008
-	2009
1	2010
2	2011
2	2012
-	2013
-	2014
-	2015
1	2016
2	2017
-	2018
3	2019
2	2020
1.4	Total



Days	Year
18	1980
8	1981
18	1982
6	1983
12	1984
8	1985
12	1986
15	1987
8	1988
17	1989
11	1990
9	1991
10	1992
12	1993
3	1994
8	1995
6	1996
13	1997
11	1998
19	1999
9	2000
10	2001
9	2002
9	2003
12	2004
5	2005
9	2006
12	2007
10	2008
11	2009
7	2010
9	2011
11	2012
3	2013
7	2014
4	2015
7	2016
17	2017
10	2018
11	2019
9	2020
10.1	Total

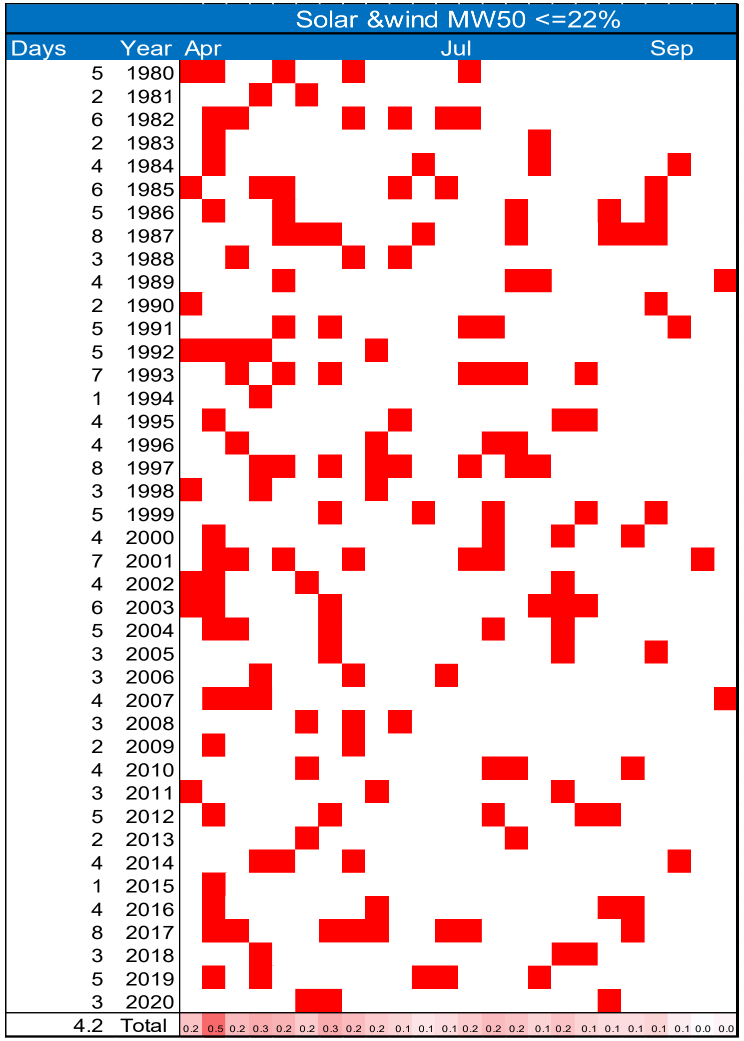
Heat maps for low wind/solar periods

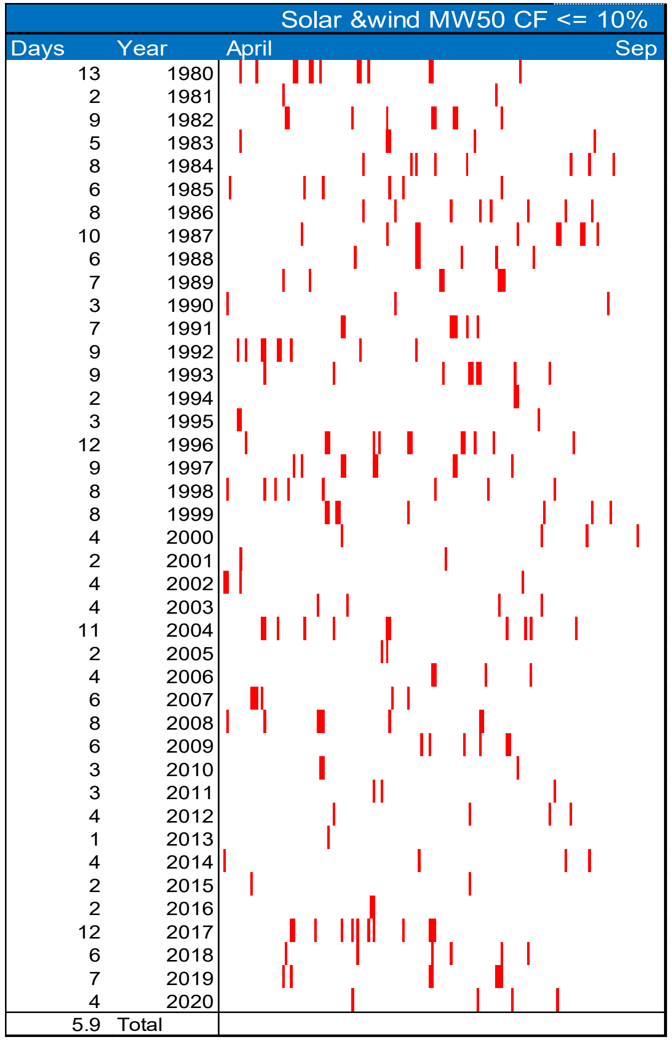
Monthly CF <=30% - up to 1-5 month per year - when looking at solar and wind together the monthly dunkleflaute risk is spread evenly Apr-Jul

Weekly <= 22% CF up to 2-8 weeks per year

Daily CF <= 10% 3-13 days per year. On a daily basis the combined solar/wind dunkleflaute risk is reduced.

		Solar &wind MW50 <=30%					
Days	Year	Apr	May	Jun	Jul	Aug	Sep
4	1980	22%	25%	28%	29%		
2	1981		26%	29%			
4	1982	21%		22%	30%		26%
1	1983				25%		
5	1984	28%	27%	27%	26%		27%
4	1985	25%	25%	24%	30%		
4	1986		25%	30%	29%	26%	
4	1987		23%	24%	27%	22%	
1	1988	25%					
6	1989	28%	26%	30%	22%	29%	27%
3	1990			28%	28%		27%
3	1991		27%		24%		29%
3	1992	18%		28%			29%
4	1993	27%	29%		21%	27%	
2	1994	27%				29%	
3	1995	25%	28%	30%			
3	1996	24%		29%	24%		
4	1997	28%	24%	24%	24%		
3	1998	23%		25%	29%		
5	1999		27%	24%	28%	29%	27%
3	2000	26%	29%			26%	
4	2001	23%		27%	24%		27%
1	2002	25%					
4	2003	25%	27%		26%	28%	
3	2004	26%	29%		27%		
4	2005	29%		29%		26%	28%
4	2006	28%	25%		30%	29%	
1	2007	22%					
3	2008	28%	20%				28%
3	2009	26%		29%	27%		
3	2010		23%		24%	26%	
3	2011	27%		26%		27%	
4	2012	25%	28%		24%	23%	
4	2013		25%	26%	29%	27%	
3	2014	28%	26%				30%
2	2015	30%				30%	
3	2016	25%		30%		27%	
5	2017	24%	23%	23%	26%	28%	
3	2018			28%		25%	29%
3	2019	24%		24%	28%		
4	2020		21%	29%	30%	26%	
3.3	Total	0.73	0.56	0.61	0.63	0.46	0.29





24. SOLAR SUPPLY PROFILES AND STATISTICS

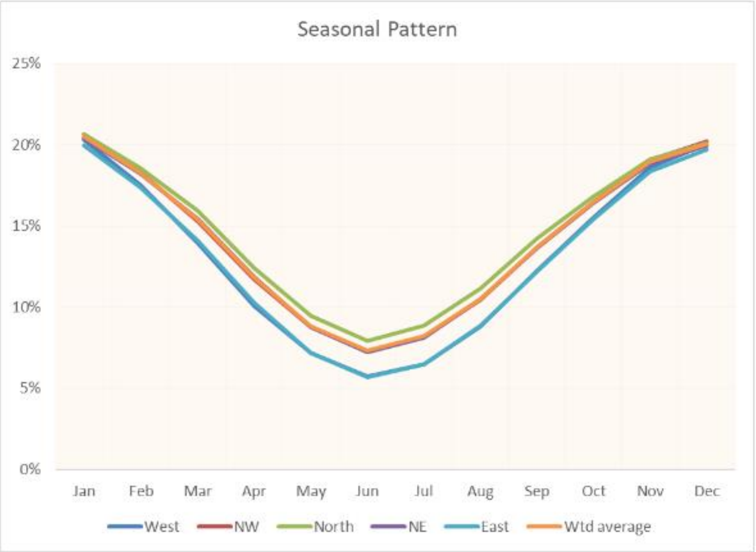
Solar profile adjustments

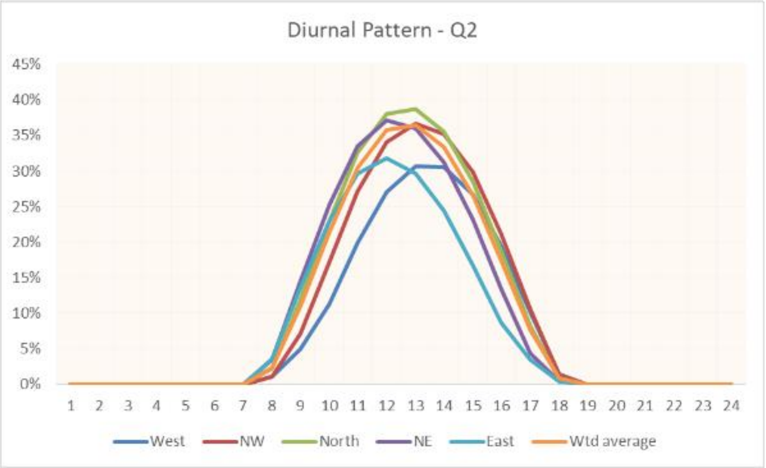
Rooftop Solar uses a fixed of fixed tilt solar panels with different orientations.

Utility solar is based on single axis tracking with panel overbuild.

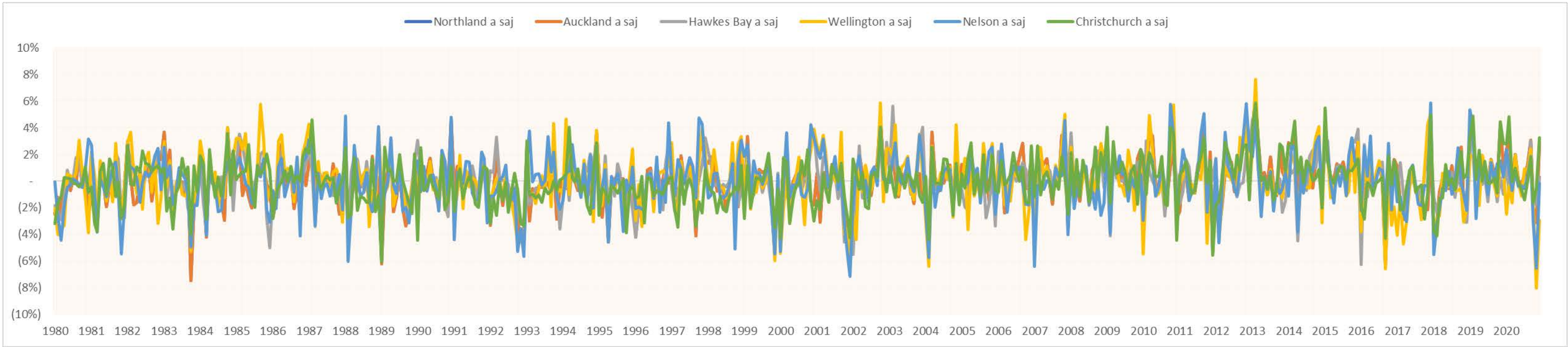
- For Rooftop solar I have taken a weighted average of profiles for fixed axis 20deg tilt with orientations North, NW, NE, West and East (30%,30%,30%, 5%, 5%) to represent a typical mix in each region. This is a reasonable approximation for our target year model even though the actual weights are not known and will vary region by region and over time.
- For utility solar I have assumed a standard single axis tracking configuration with mono facial panels and a 1.3 ILR. In reality there will be a mix of technologies etc , but this single profile is a reasonable approximation for generic solar supply in our target years.
- I have also taken weighted average from the regional profiles provided by ANSA to match the generic solar options that I am modelling.
- In each case my modelling is for a target year which will have a range of different panel ages. To handle this I have scaled back the year 1 generation to reflect the average degradation over a 10 year period.

Impact on seasonal and diurnal patterns for Roof top solar as a result of taking a weighted average.





Updated ANSA solar data - monthly de-seasonalised - 1980 to 2020



Monthly Statistics

	Monthly Max	Monthly P10	Monthly P90	Monthly Min	Mean Capacity Factor	Monthly Stdev	Monthly Volatility	Monthly Cross Correl Auck	Monthly Serial Correl
Northland a	37%	31%	11%	8%	21%	7.6%	36%	98%	81%
Auckland a	36%	29%	9%	7%	20%	7.6%	38%	100%	83%
Hawkes Bay a	36%	32%	10%	7%	21%	8.5%	41%	98%	83%
Wellington a	37%	32%	8%	5%	20%	9.3%	46%	97%	82%
Nelson a	40%	35%	10%	8%	23%	9.4%	42%	97%	83%
Christchurch a	36%	32%	8%	6%	20%	9.2%	46%	97%	84%
Auck RT	22%	19%	7%	5%	14%	4.5%	33%	100%	83%
Wellington RT	23%	20%	7%	5%	14%	5.1%	37%	98%	83%
Chch RT	22%	20%	6%	4%	13%	5.1%	39%	96%	82%
Northland a saj	*6%*	*2%*	*(3%)*	*(7%)*	*0%*	*1.8%*	-	*16%*	*(7%)*
Auckland a saj	*6%*	*2%*	*(2%)*	*(6%)*	*0%*	*1.8%*	-	*23%*	*3%*
Hawkes Bay a sa	*6%*	*2%*	*(3%)*	*(7%)*	*0%*	*1.9%*	-	*17%*	*1%*
Wellington a saj	*8%*	*3%*	*(3%)*	*(8%)*	*0%*	*2.2%*	-	*11%*	*8%*
Nelson a saj	*6%*	*2%*	*(2%)*	*(7%)*	*0%*	*2.1%*	-	*12%*	*2%*
Christchurch a sa	*6%*	*2%*	*(2%)*	*(6%)*	*0%*	*1.7%*	-	*8%*	*16%*
Auck RT saj	*3%*	*1%*	*(1%)*	*(3%)*	*0%*	*1.0%*	-	*23%*	*5%*
Wellington RT sa	*4%*	*1%*	*(1%)*	*(3%)*	*0%*	*1.0%*	-	*14%*	*(0%)*
Chch RT saj	*3%*	*1%*	*(2%)*	*(4%)*	*0%*	*1.2%*	-	*8%*	*19%*

Annual Statistics

	Annual Max	Annual P10	Annual P90	Monthly Min	Mean Capacity Factor	Annual Volatility	Annual Cross Correl Akl
Northland a	23%	22%	21%	20%	21%	3.2%	53%
Auckland a	21%	21%	19%	19%	20%	3.5%	100%
Hawkes Bay a	23%	22%	20%	20%	21%	3.5%	93%
Wellington a	21%	21%	19%	19%	20%	3.4%	49%
Nelson a	24%	24%	22%	21%	23%	2.9%	52%
Christchurch a	22%	21%	19%	19%	20%	3.0%	48%
Auck RT	14%	14%	13%	13%	14%	2.9%	96%
Wellington RT	14%	14%	13%	13%	14%	2.4%	80%
Chch RT	14%	14%	13%	13%	13%	2.8%	47%

Daily Statistics

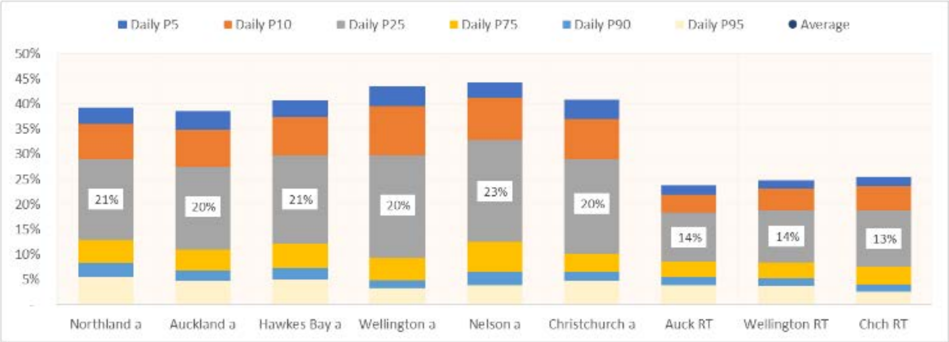
	Daily P5	Daily P10	Daily P25	Daily P75	Daily P90	Daily P95	Average	Daily Stdev	Daily Cross Correl Auck	Daily Serial Correl
Northland a	39%	36%	29%	13%	8%	6%	21%	10%	82%	66%
Auckland a	39%	35%	27%	11%	7%	5%	20%	10%	100%	65%
Hawkes Bay a	41%	37%	30%	12%	7%	5%	21%	11%	85%	72%
Wellington a	44%	40%	30%	9%	5%	3%	20%	13%	72%	65%
Nelson a	44%	41%	33%	13%	7%	4%	23%	13%	73%	68%
Christchurch a	41%	37%	29%	10%	7%	5%	20%	11%	68%	75%
Auck RT	24%	22%	18%	9%	6%	4%	14%	6%	92%	65%
Wellington RT	25%	23%	19%	8%	5%	4%	14%	7%	77%	73%
Chch RT	26%	24%	19%	8%	4%	3%	13%	7%	62%	62%
Northland a saj	*11%*	*8%*	*5%*	*(4%)*	*(10%)*	*(14%)*	*0%*	*7%*	*46%*	*31%*
Auckland a saj	*12%*	*9%*	*5%*	*(4%)*	*(10%)*	*(14%)*	*0%*	*7%*	*71%*	*31%*
Hawkes Bay a saj	*11%*	*9%*	*5%*	*(4%)*	*(10%)*	*(14%)*	*0%*	*7%*	*49%*	*37%*
Wellington a saj	*14%*	*12%*	*6%*	*(5%)*	*(12%)*	*(17%)*	*0%*	*9%*	*31%*	*30%*
Nelson a saj	*12%*	*10%*	*6%*	*(5%)*	*(12%)*	*(17%)*	*0%*	*9%*	*32%*	*31%*
Christchurch a saj	*11%*	*9%*	*4%*	*(4%)*	*(9%)*	*(13%)*	*0%*	*7%*	*21%*	*31%*
Auck RT saj	*6%*	*5%*	*3%*	*(2%)*	*(6%)*	*(8%)*	*(0%)*	*4%*	*59%*	*29%*
Wellington RT saj	*6%*	*5%*	*3%*	*(3%)*	*(6%)*	*(8%)*	*(0%)*	*4%*	*36%*	*36%*
Chch RT saj	*7%*	*6%*	*4%*	*(4%)*	*(7%)*	*(9%)*	*(0%)*	*5%*	*18%*	*26%*

There is a strong summer bias in the seasonal and diurnal solar supply patterns

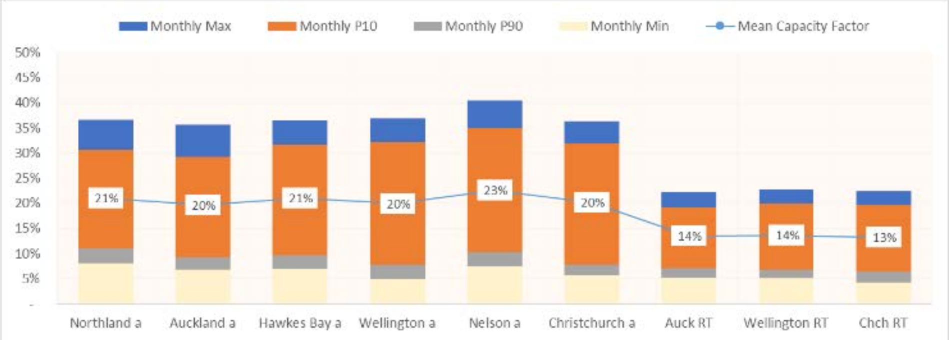
There is a very high volatility in daily solar capacity factor, but this reduces significantly for months and is only 4% for years

The average seasonal and daily patterns of supply show a strong summer peak and a strong diurnal pattern with a peak around 1pm for rooftop and 3pm for utility solar.

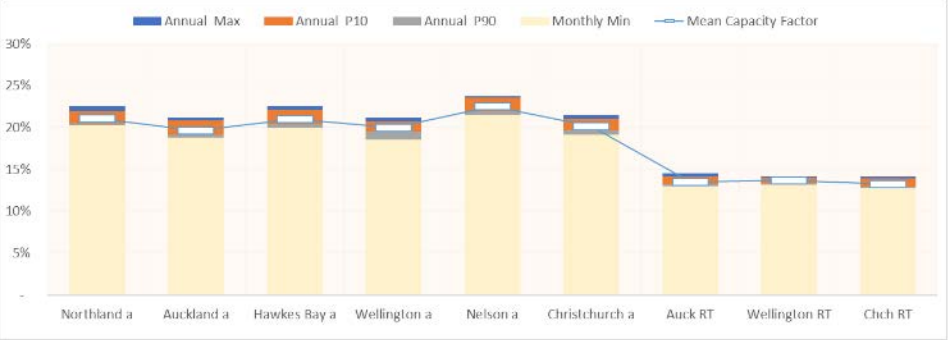
250% daily volatility

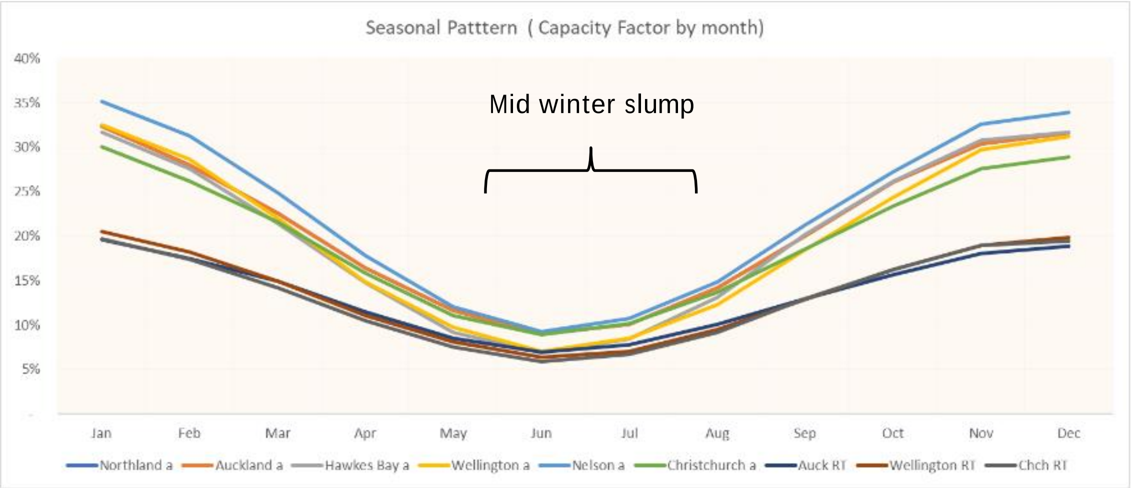


40% monthly volatility

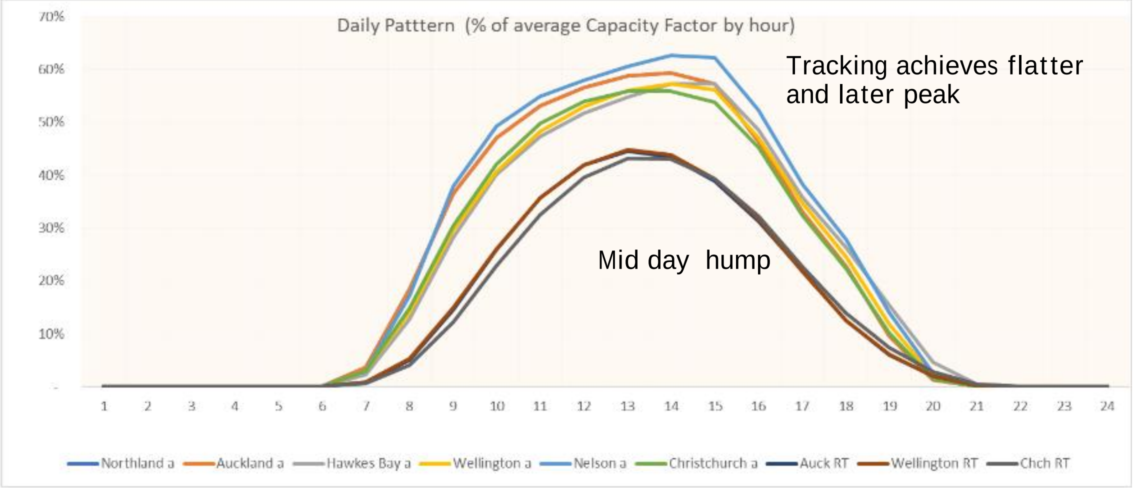


4% annual volatility





Mid winter slump



Tracking achieves flatter and later peak

Mid day hump

There is a high correlation between solar supply in each region as a result of their similar seasonal and diurnal patterns. The random component is less correlated.

JC²

The cross corelation matrix shows the relationship between variation between all pairs of solar profiles. The highest cross correlations are shown in green and the lowest in red.

The correlations are greatest on a monthly basis, lower on a daily basis and also lower again on an hourly basis.

There is a declining cross correlation in seasonally adjusted solar output between Northland and each region from north to south.

This is the case for all time frames. The cross corelation falls off fastest for hourly, then daily and monthly.

Hourly

	North1	Auckland1	HB1	Wellington1	Nelson1	ChCh1	Pukekoe Roof PV	Wellington Roof PV	Chch Roof PV
North1	100%								
Auckland1	90%	100%							
HB1	88%	92%	100%						
Wellington1	81%	84%	91%	100%					
Nelson1	83%	86%	89%	89%	100%				
ChCh1	83%	84%	86%	87%	89%	100%			
Pukekoe Roof PV	88%	94%	89%	83%	84%	84%	100%		
Wellington Roof P	86%	88%	93%	92%	88%	87%	93%	100%	
Chch Roof PV	81%	82%	85%	85%	85%	91%	86%	91%	100%

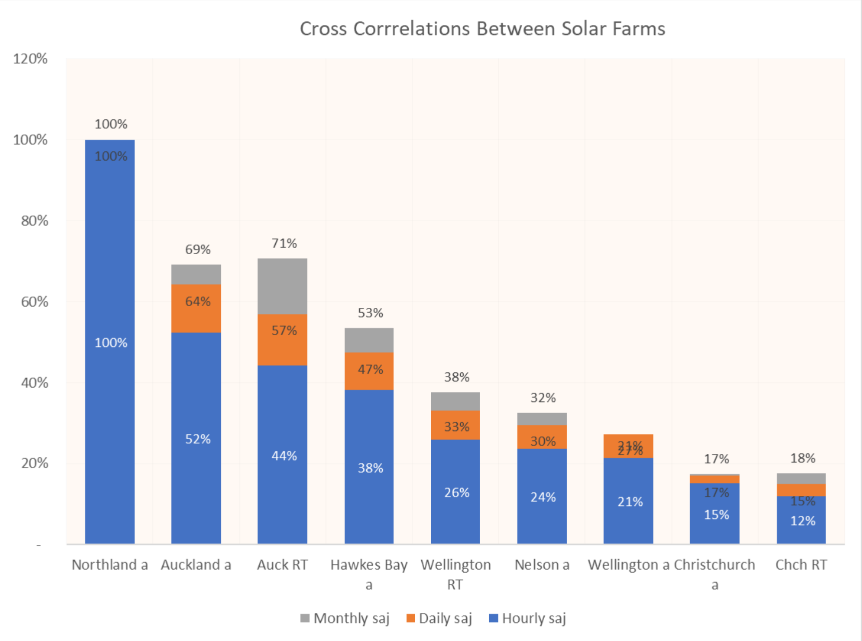
Daily

	Northland a	Auckland a	Hawkes Bay a	Wellington a	Nelson a	Christchurch a	Auck RT	Wellington RT	Chch RT
Northland a	100%								
Auckland a	82%	100%							
Hawkes Bay a	75%	85%	100%						
Wellington a	64%	72%	85%	100%					
Nelson a	66%	73%	79%	86%	100%				
Christchurch a	64%	68%	73%	79%	81%	100%			
Auck RT	79%	92%	81%	68%	69%	66%	100%		
Wellington RT	69%	77%	91%	90%	81%	76%	81%	100%	
Chch RT	57%	62%	71%	77%	75%	87%	64%	80%	100%

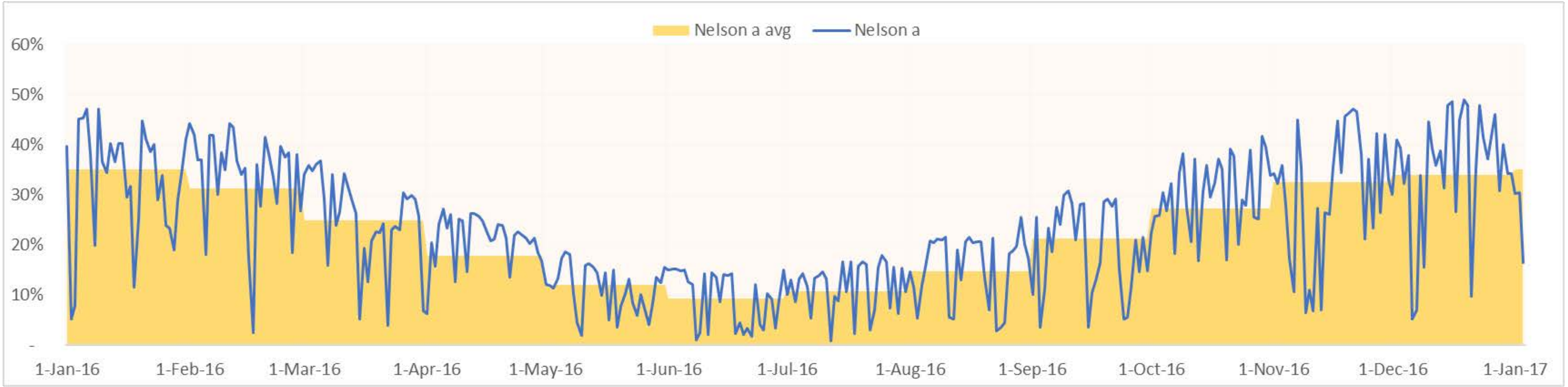
Monthly

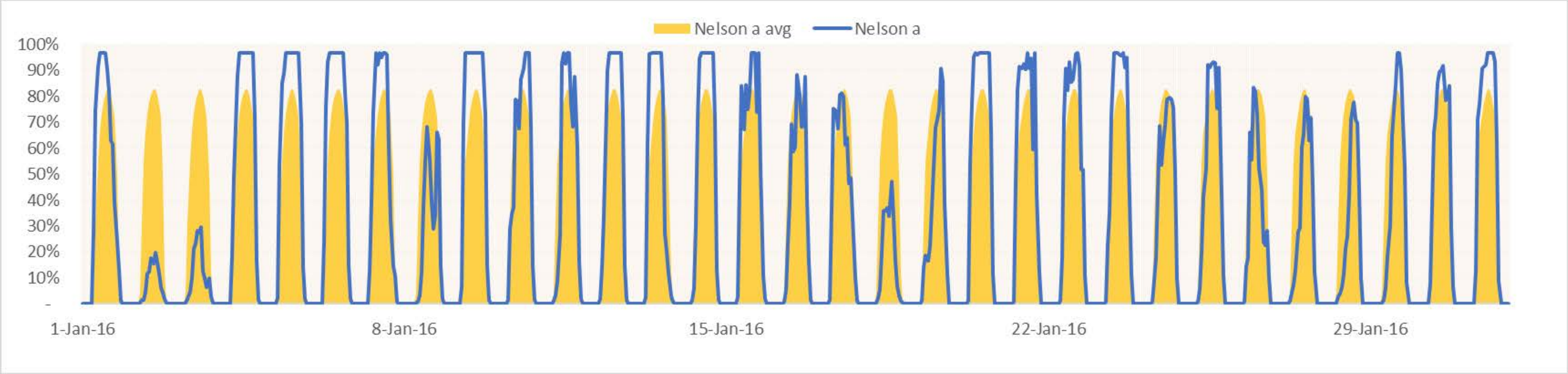
	Northland a	Auckland a	Hawkes Bay a	Wellington a	Nelson a	Christchurch a	Auck RT	Wellington RT	Chch RT
Northland a	100%								
Auckland a	98%	100%							
Hawkes Bay a	97%	98%	100%						
Wellington a	95%	97%	98%	100%					
Nelson a	96%	97%	98%	99%	100%				
Christchurch a	96%	97%	98%	98%	98%	100%			
Auck RT	98%	100%	98%	97%	97%	96%	100%		
Wellington RT	97%	98%	99%	100%	99%	98%	98%	100%	
Chch RT	95%	96%	98%	98%	98%	99%	96%	98%	100%

Note: the correlation is measured using the Pearson Product-Moment Correlation.



Illustrative annual and monthly profiles for utility scale (with single axis tracking) in a selected year



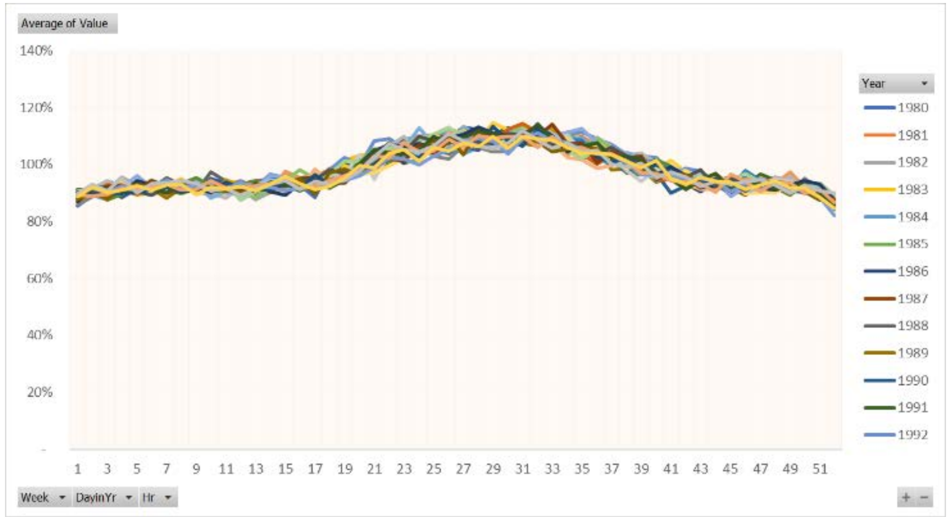


25. DEMAND PROFILES AND VARIABILITY

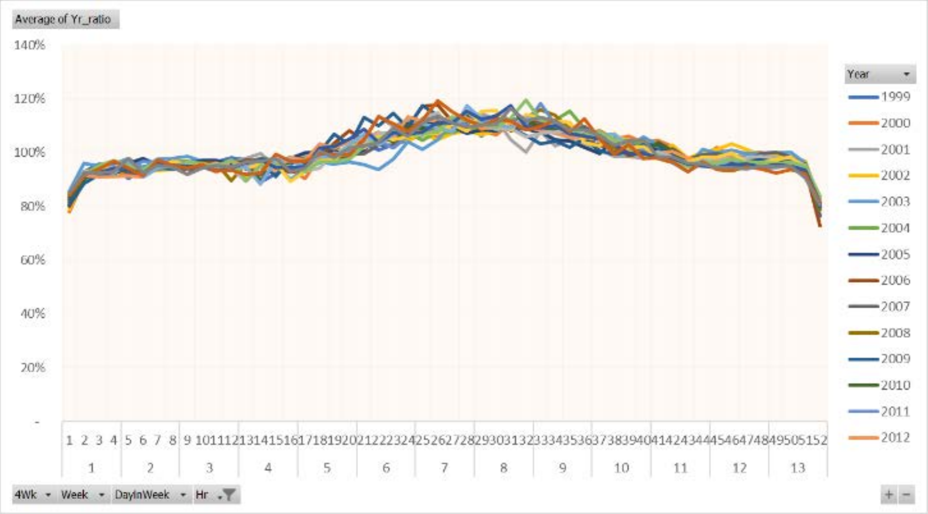
Comparison between synthetic demand profiles and actuals from 1999

North Island Weekly

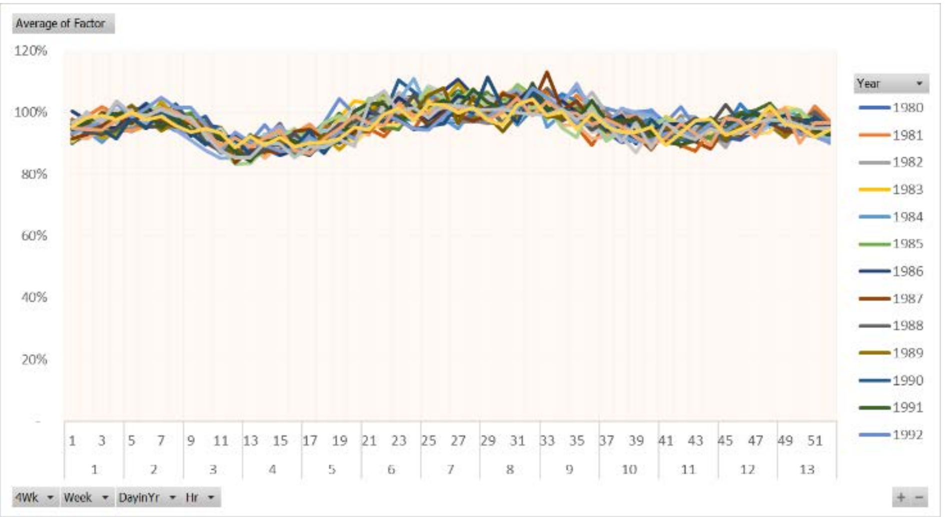
Synthetic demand over 40yrs

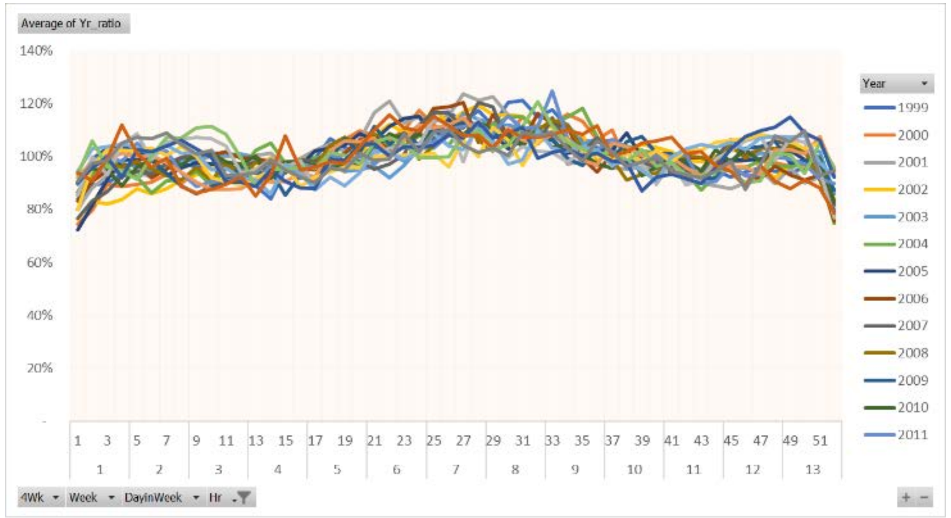


Actual demand from 1999 to 2019



South Island Weekly

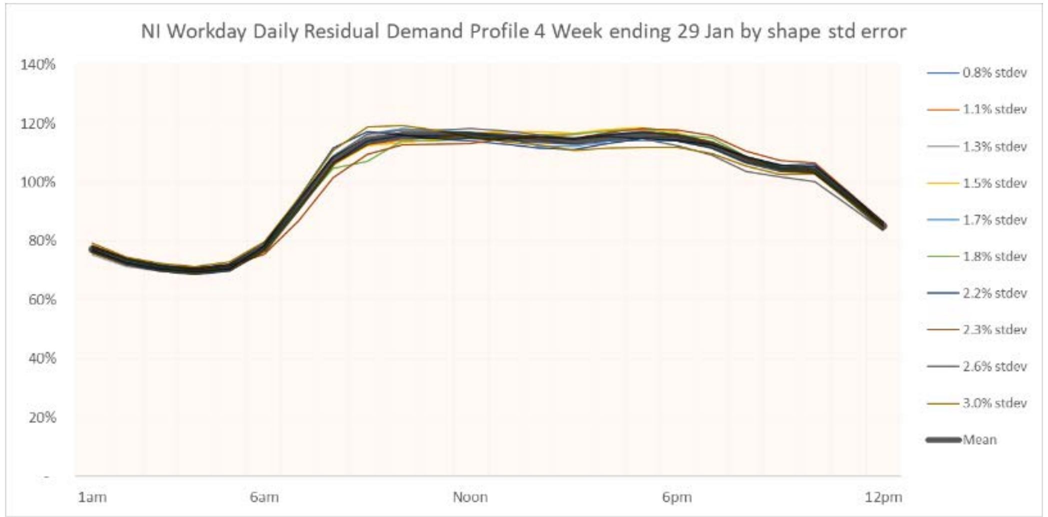


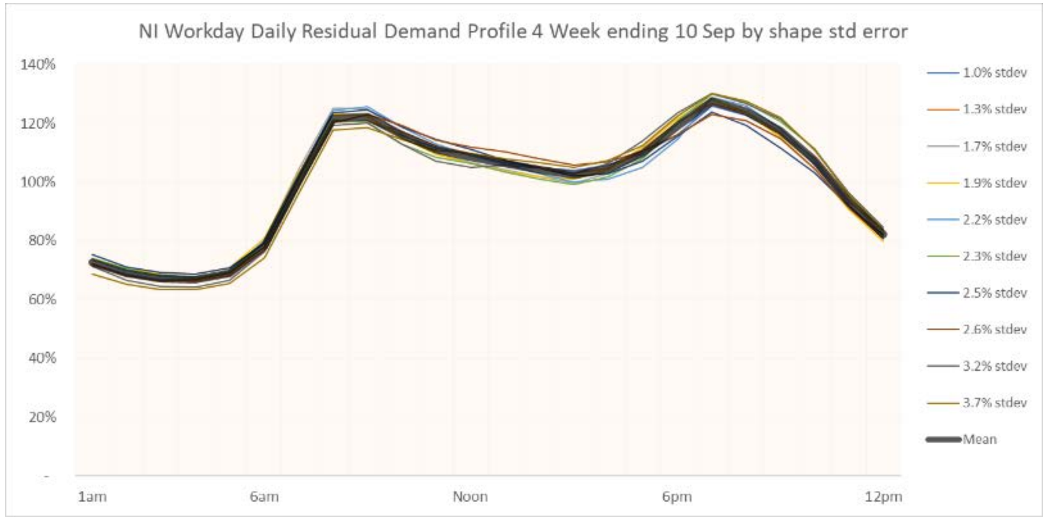


Note: synthetic data is for a standard holiday pattern - day 6 and day 7 every week, whereas history has a rolling pattern of holidays that shift each year

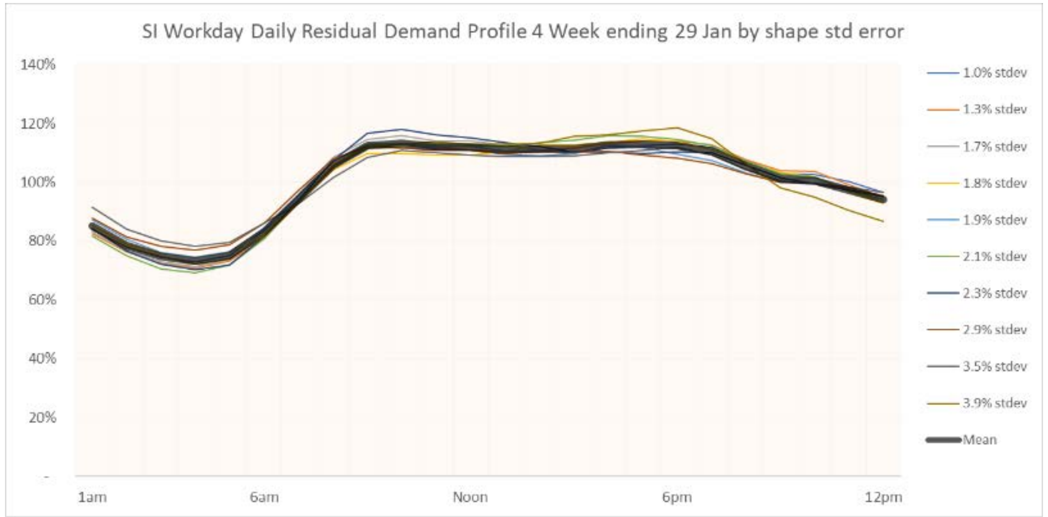
Workday Profiles: Summer Winter - these are derived from 2017, 2018 and 2019 years

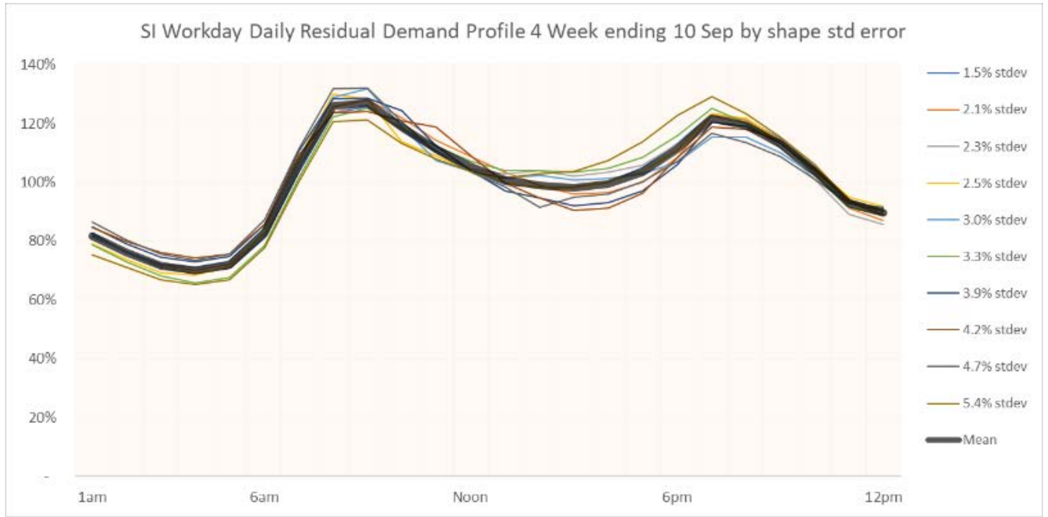
North Island


NI Workday Daily Residual Demand Profile 4 Week ending 29 Jan by shape std error


NI Workday Daily Residual Demand Profile 4 Week ending 10 Sep by shape std error

South Island

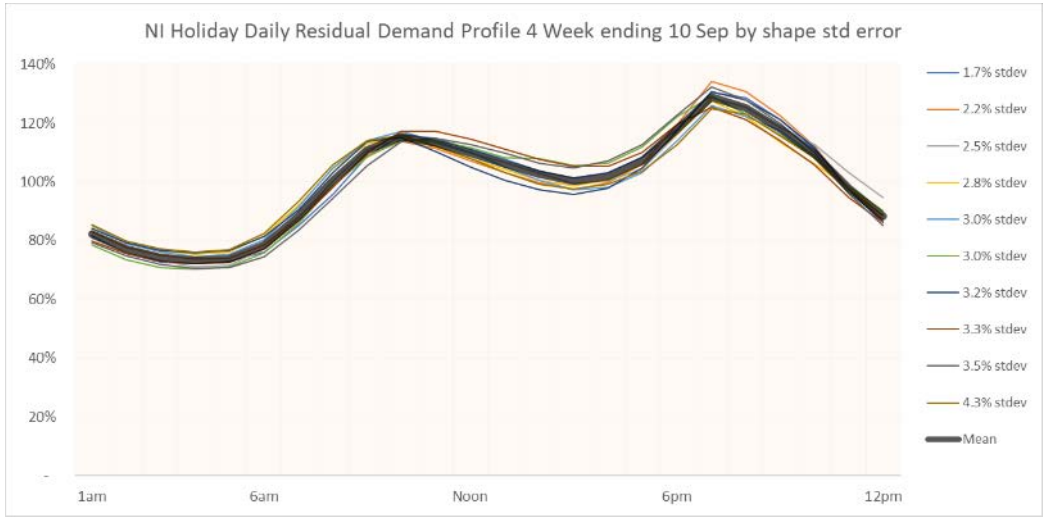

SI Workday Daily Residual Demand Profile 4 Week ending 29 Jan by shape std error


SI Workday Daily Residual Demand Profile 4 Week ending 10 Sep by shape std error

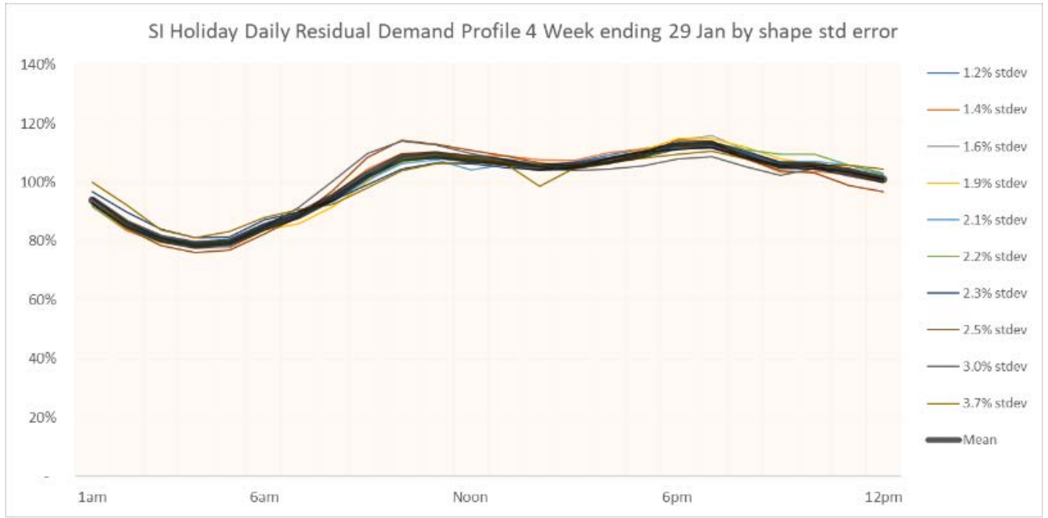
Holiday Profiles : Summer Winter

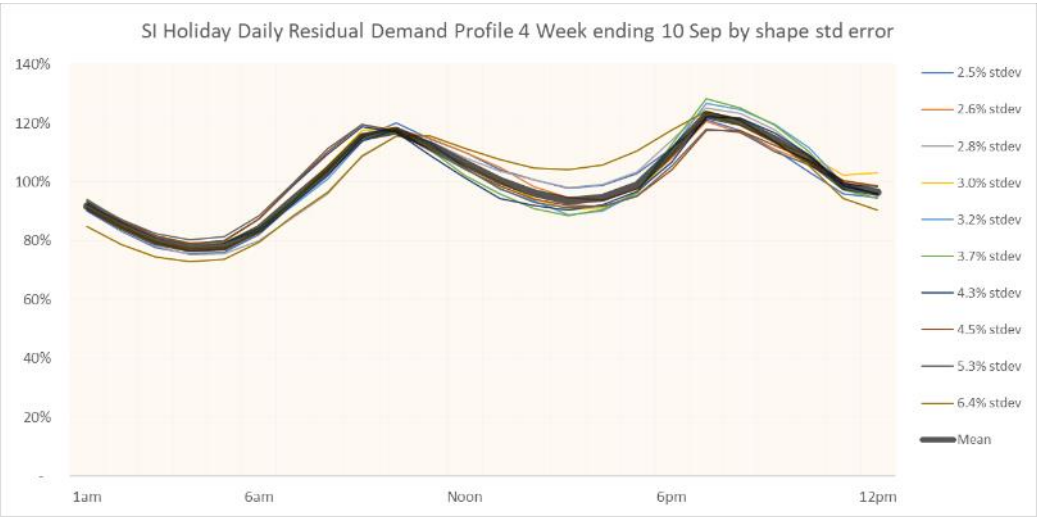
North Island


NI Holiday Daily Residual Demand Profile 4 Week ending 29 Jan by shape std error


NI Holiday Daily Residual Demand Profile 4 Week ending 10 Sep by shape std error

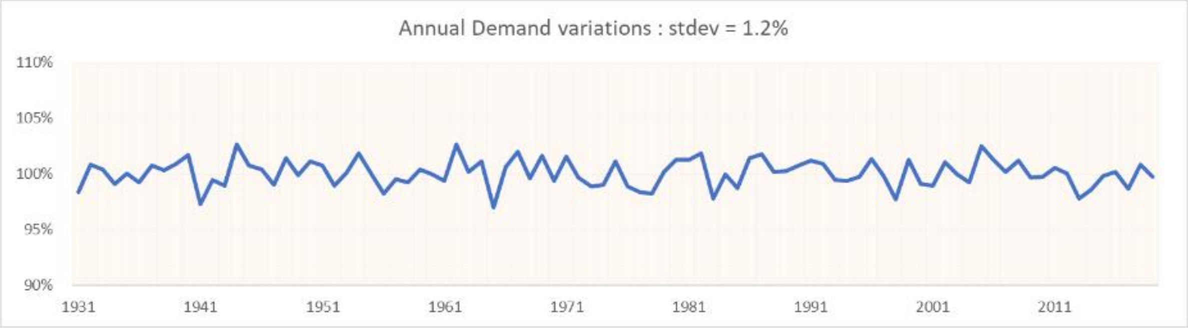
South Island

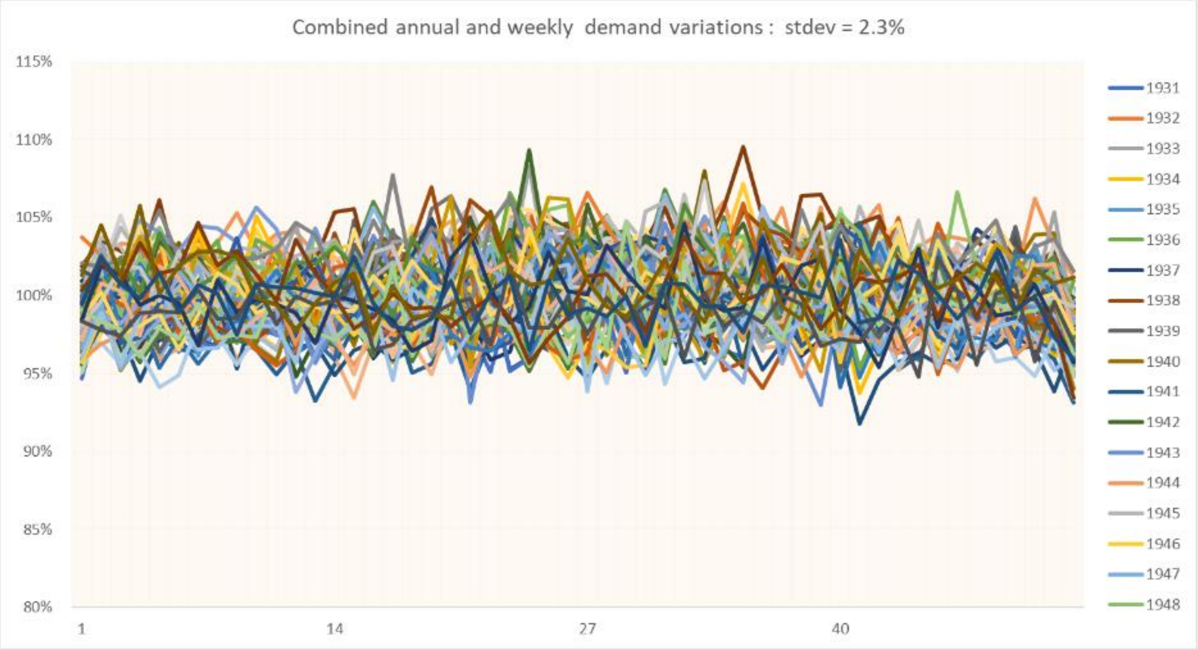

SI Holiday Daily Residual Demand Profile 4 Week ending 29 Jan by shape std error


SI Holiday Daily Residual Demand Profile 4 Week ending 10 Sep by shape std error

Full modelling includes both weather driven and random demand variability

For modelling I assume variations within each year reflective of matched weather variability and also allow for random annual variation with a standard deviation of 1.2% - the combined impact is a weekly standard deviation of 2.3%.





Comments

- For modelling over the whole period I use:
  - simulated weather-driven and random variations within each year each year
    - this follows the matched weather years to period 1980 to 2019
    - this ensures that the short run weather-driven correlations between demand, wind, solar are preserved
  - plus
    - annual variations with a std variation of 1.2% (consistent with random annual demand variation over the period 1999 to 2019)
    - the annual variations are sampled from an independent normal distribution for each modelled year.