ESTIMATING THE GROSS BENEFIT OF NZ BATTERY OPTIONS

FINAL REPORT

30 NOVEMBER 2022

REPORT TO THE NZ BATTERY TEAM:

MINISTRY OF BUSINESS, INNOVATION & EMPLOYMENT.

John Culy Consulting

30 NOVEMBER 2022

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Disclaimer

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2 INTRODUCTION

2.1 Purpose

This report sets out estimates of gross national benefits for generic pumped hydro storage schemes (referred to as 'NZ Battery' options) defined in terms of their storage size ('tank'), maximum output ('tap'), location in the North or South Island, and round-trip efficiency (% of input energy which is returned to the grid).

It also sets out estimates of gross national benefits for 3 selected storage options using other technologies including biomass, flexible geothermal and hydrogen/ammonia production, and use.

The assumptions used are fully documented in "NZ Battery economic modelling assumptions.docx". These are based on the Climate Change Commission's demonstration pathway modelling analysis, and its own assessments based on advice from Aurecon, Transpower and others.

Additional information and charts are provided in a separate set of slides "NZ_Battery_Gross_Benefit_Appendix.pdf."

All prices are in real NZ 2021-dollar terms unless indicated otherwise.

3 EXECUTIVE SUMMARY

3.1 Approach

Gross benefits are measured at the national level based on the change in total electricity system cost enabled by each NZ Battery option. System costs include the capital costs for new generation and smaller-scale batteries, fuel and carbon costs, and the costs of demand response. Gross benefits are formally estimated for three representative years: '2035' (early in project life but after any 'fill' period), '2050' (when decarbonisation has lifted non-Tiwai electricity demand by around 50%) and '2065' (when electricity demand has almost doubled).

These representative years can be used to estimate gross benefits for the NZ Battery schemes with their own assumed economic lives. Gross benefit estimates for years between 2035, 2050 and 2065 are based on interpolations. Gross benefits beyond 2065 are assumed to be constant in real terms (2021 dollars).

Gross benefits are estimated under two futures:

1. 100% Renewable with green peakers
    - allowing for use of a net zero emission fuel peaking plant (e.g., biodiesel, biogas or similar) at a variable cost of $480/MWh for last resort backup.
2. 100% Renewables without green peakers,

I also consider two other "worlds" for selected NZ Battery options.

3. Mostly renewable with continued use of gas fired peaking plant accounting for a carbon cost of emissions.
    - Gas variable costs rise from $220/MWh in 2035, to $270/MWh in 2050 and $350/MWh in 2065 including carbon.
4. 100% renewable with green peakers with Tiwai smelter continuing operation from 2035, adding 5TWh of firm inflexible load.

I do not calculate estimates of net benefits because I do not have information on the costs of different NZ Battery options.

The forecast demand and assumptions used in the modelling were developed by MBIE NZ Battery Project team and are fully documented in "NZ Battery economic modelling assumptions.docx"[1]. MBIE has endeavoured to take an orthodox, mainstream view on assumptions, to focus the modelling on the issue at hand, being how futures vary with and without different NZ Battery options.

3.2 NZ Battery options assessed

A range of NZ Battery options are assessed including 6 SI pumped hydro options ranging from 3 to 7.5TWh tanks size and 0.5 to 1.25GW tap size.

1. SI 7.5TWh / 1.25GW
2. SI 5.0TWh / 1.25GW
3. **SI 5.0TWh / 1.00GW <<< base Lake Onslow option**
4. SI 5.0TWh / 0.75GW
5. SI 5.0TWh / 0.50GW

[1] NZ Battery Project, NZ Battery economic modelling assumptions, 14 November 2022.

6. SI 3.0TWh / 1.00GW
7. SI 3.0TWh / 0.75GW
8. SI 3.0TWh / 0.50GW

Three other technologies have also been assessed including:

1. Portfolio 1 – where Tiwai exits before 2035 consisting of:
    a. 0.40 GW of flexible geothermal,
    b. 0.50 GW of Rankine plant fired with biomass (chipped logs),
    c. 0.37 GW flexible hydrogen/ammonia plant with green ammonia available to fire a 0.15 GW CCGT plant.
2. Portfolio 2 - where Tiwai remains consisting of:
    a. 0.40 GW of flexible geothermal,
    b. 0.50 GW of Rankine plant fired with biomass (chipped logs),
    c. 0.37 GW flexible hydrogen/ammonia plant with green ammonia available to fire a 0.15 GW CCGT plant.
    d. The existing 80 MW demand reduction currently made available by Tiwai in extreme dry years but allowed to be used more frequently.

3.3 Future "worlds" without NZ Battery

3.3.1 Demand

The chart below shows the base case gross demand for generation (i.e., including transmission losses) to be met from grid generation and rooftop solar[2].

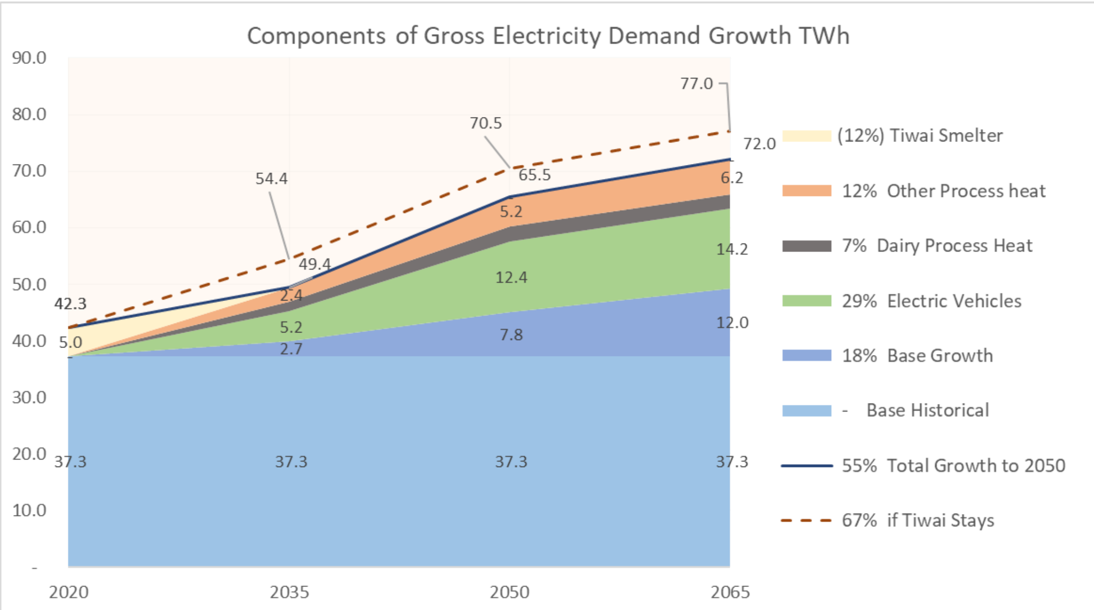

Figure 1: Components of gross electricity demand

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 reaches 12.4TWh by 2050:

[2] It should be noted that the demands and other assumptions described in this section are exogenous inputs and not an output from the modelling.

- 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 55% net growth to 2050, EVs and process heat account for 48%.

Rooftop solar is modelled at a fixed build rate, increasing to 20% of households equalling 0.5 million installations or 2.1GW (2.6TWh) by 2065. 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.

It is assumed that there a degree of management of EV charging as illustrated in the chart below.

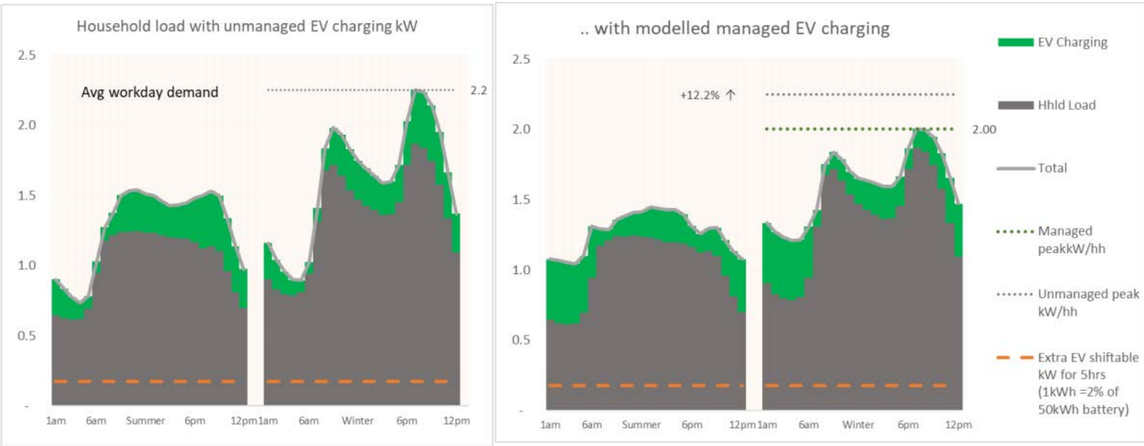

Figure 2: Assumed EV charging management

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 aggregators, 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.

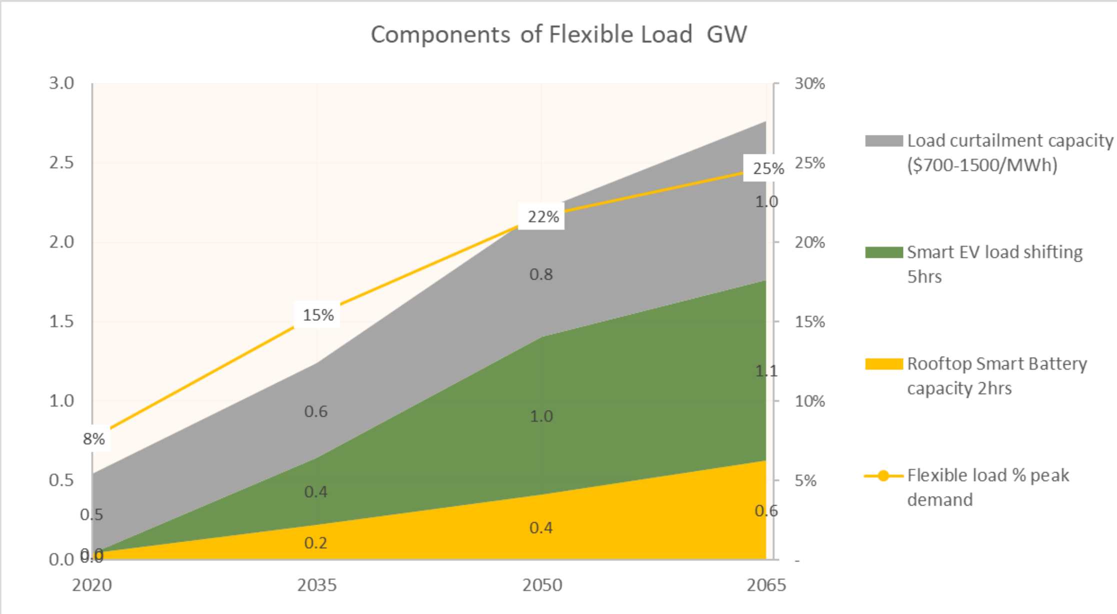

Figure 3: Components of flexible load

Rooftop batteries and smart EV load charging result in demand shifting within the day, whereas short run load reduction is discretionary load which customers curtail when spot prices exceed $700/MWh. Three tranches (40%, 30% and 30%) triggered at $700/MWh, $1000/MWh, and $1500/MWh are assumed. Each tranche is approx. 2-3% of system peak demand, with the total reaching 9% by 2065.

Supply

In addition to this assumed level of within-day load shifting associated with EVs and rooftop solar with batteries the only additional technology options being considered include:

- Wind and Solar (unlimited)
- Geothermal
  - It is assumed that 50% of the 0.68GW of new geothermal beyond Tauhara have carbon capture and reinjection and that the other 50% have either low (<60kg/MWh) or high (>115kg/MWh) emissions.
- Grid connected 5 and 12-hour battery (e.g. Li-ion) systems (unlimited)
- Green peakers (unlimited)

The costs[3] of these technologies are based on the NZ Battery team assessment as indicated by the chart below. This accounts for the typical size of projects in NZ, the structure of costs, learning curve adjustments to components, average transmission costs, and potential supply limitations.

The chart shows geothermal costs for illustrative low and high emission rates of 30 kg/kWh and 120kg/kWh.

[3] These costs assume a 7% post tax nominal weighted average cost of capital. They account for tax depreciation and 2% 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.

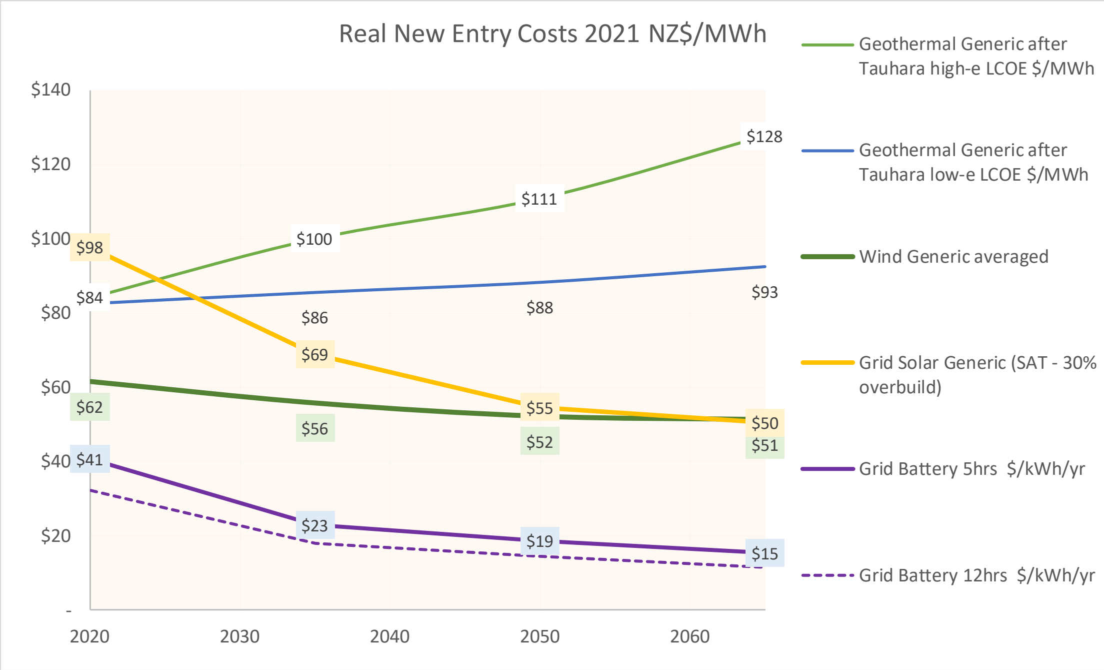

Figure 4: Assumed technology cost profiles

It is assumed no new hydro is available.

HVDC losses/constraints are modelled explicitly. HVDC capacity is assumed to be 1400 MW (north) and 950 MW (south) and I assume no reserve-related transfer limits on basis that NI batteries should be able to support full reserves requirements.

Where Onslow is built, I assume that the south transfer limit is increased to 1300MW with investment in additional grid upgrades in the lower North Island. Average HVAC losses are included in demand and AC grid is assumed to be unconstrained.

As discussed later, new zero-carbon thermal generation 'green' peaking options are available with fuel cost of $45/GJ (real $2021) – to reflect future possible biofuel or hydrogen options.

Carbon prices in 2021 $ terms follow the CCC assumptions of $160/t, $250/t and $390/t in 2035, 2050 and 2065.

Inflow profiles – hydro/wind/solar/demand

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.

- The years 87-year period 2033-2019 inflow data from the Hydrological Modelling Dataset from the Electricity Authority and 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 for each island is based on actual demand shapes from 2000-2020. and 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).

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 mostly preserved, and all the within-year regional and cross correlations between wind, solar and demand are fully preserved.

3.3.2 Climate change

The likely impacts of climate change are accounted for. Although there is great uncertainty about the level of these changes there is a broad consensus of the direction:

- For our major reservoirs, it is generally agreed that there will more rain in the winter and lower inflows from snow melt in the spring.
- Wind is likely to be lower in the north and higher in the south.
- There is no consensus about the impact on solar.

These changes are accounted for by adjusting the historical inflow and wind data by factors by week in the year and region. The chart below shows the aggregate impact on inflows and the patterns of wind and solar of climate change[4], which I assume to occur with linear change to 2050 and remain the same thereafter.

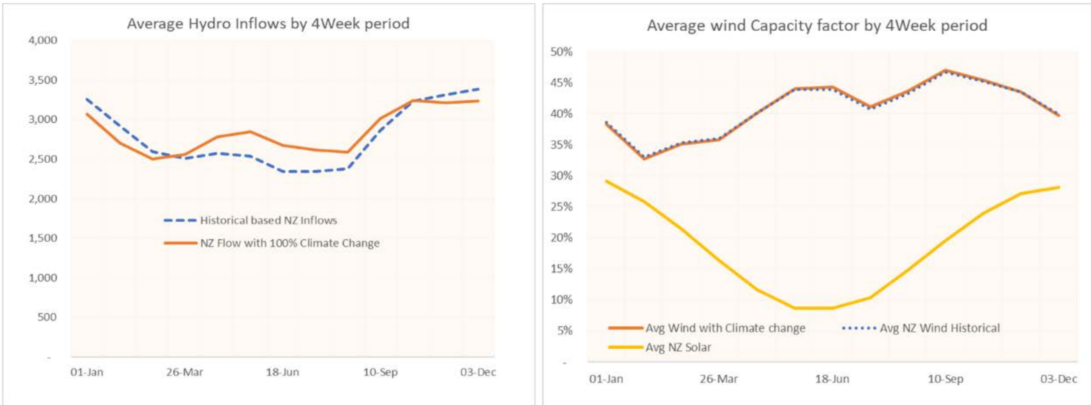

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Figure 5: Impact of climate change on hydro wind and solar

The net effect of climate change on the total NZ wind capacity factor is modest, but this hides significant seasonal variations (lower in north, higher south). Solar is not impacted.

[4] Estimates provided by Dr Jen Purdie of ClimateWorks.

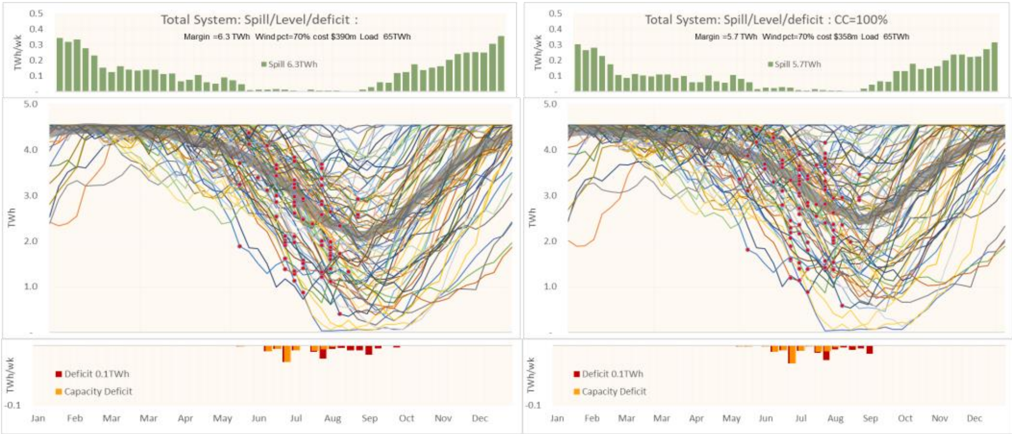

Figure 6: Impact of climate change on the need for storage

A measure of the seasonal energy balance required can be estimated by a simple weekly energy balance model[5] which estimates the additional wind/solar required to achieve a target energy deficit over 87 sequences.

The results are shown above. With 100% climate change, the seasonal energy imbalance reduces from 6.3TWh to 5.7TWh because of higher inflows being shifted into the winter.

3.3.3 NZ's storage needs change over time

NZ's storage requirements will progressively change as the nation decarbonises: shorter term flex will become increasingly important and the need for longer cycle 'dry year' flex will decline in relative (and absolute) terms.

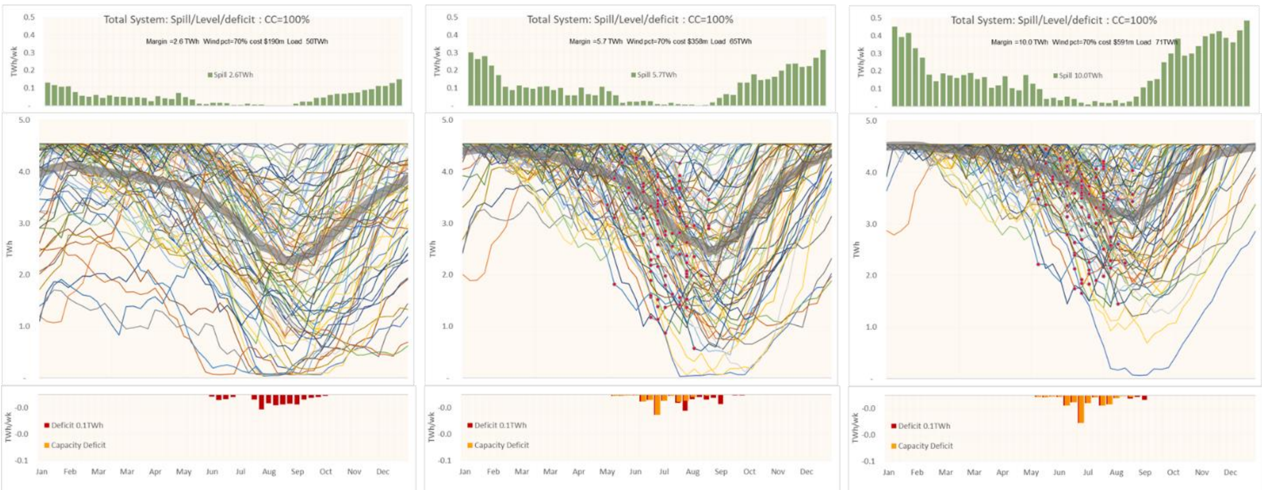

Figure 7: The changing nature of storage requirements over time

By 2065, most of the total electricity production is projected to come from wind and solar generation. This means NZ's system will become more like that of Germany – in which the challenge is dunkelflaute events – calm/dark periods with low wind/solar generation. To achieve capacity adequacy in this type of system, it will be economic (i.e. necessary) to build sufficient levels of renewable generation that results in significant spill at times.

[5] This seasonal imbalance measure is derived from a very simple one region weekly energy balance model with weekly constraints on hydro releases from storage. This was adapted from a demonstration model developed by Conrad Edwards. The imbalance measure is the extra wind/solar required to meet a target deficit level. The wind/solar pct is based on energy shares.

Indeed, this level of generation build is expected to become sufficiently large to start to shrink the dry year challenge – basically dry years will cause wind/solar spill to decline rather than manifesting as energy shortages

This dynamic also explains why long-term benefits are driven more by tap size than tank size – since big taps are more useful than big tanks for getting through 'dunkelflaute' events.

3.4 Simulation Modelling

3.4.1 High level approach

The modelling methodology is summarised in the figure below.

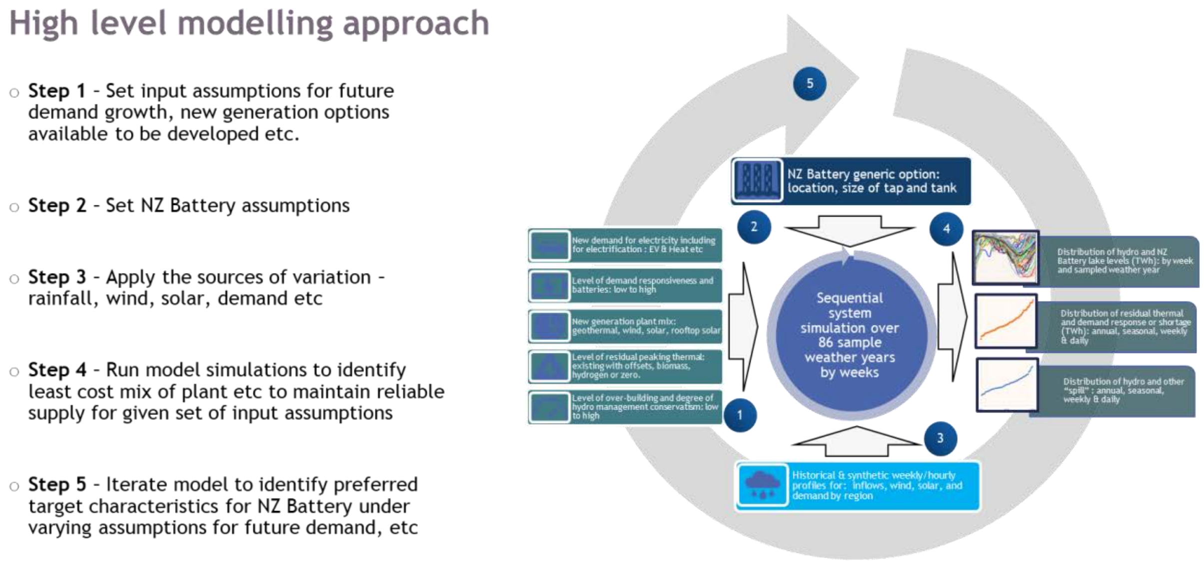

Figure 8: High level description of modelling approach.

3.4.2 Simulation methodology

The simulation is carried out week by week over 87 historical weather years. The lake levels at the end of each simulated year are used as the starting levels for the next simulated weather year.

Stored hydro is assumed to be offered based on heuristic hydro "offer" functions of storage level and time of year. These have not been fully optimised but are manually adjusted over time to ensure that dry year security is maintained (i.e., contingent storage is used rarely) and that the full range storage is used as much as possible[6] to minimise spill.

Within each simulated week the available supply resources (including demand response, batteries, green peakers, intermittent supply and offered hydro) are dispatched to meet the time profile of demand in each island at minimum cost (see below).

[6] It is found that the results are not too sensitive to these heuristic offer functions if they are broadly "sensible" and approximately reflect the rising risks and cost of shortage as lakes get close to empty and the increasing risks of spill as lakes get close to full. In a 100% renewable world the national aggregate levels of spill and hydro shortage are largely determined by the level of investment in renewables, rather than by the exact shape of these offer functions. Offer functions are important for the allocation of spill between individual hydro schemes and can affect the allocation of hydro and wind/solar/geothermal being constrained off. These allocations are not particularly important for this exercise which is focusing on national economic benefits.

Energy and capacity constraints and round-trip efficiencies are accounted for as well as inter-island transmission constraints and losses.

Within-week modelling

Most simulations use 36-time blocks within each week corresponding to a typical sampled workday by hours and a typical sampled non-workday by 2-hour blocks[7].

The model used here focuses on the simulated weekly variations of weather conditions by time zone and does not attempt to fully model the fine detail the chronological supply and demand or issues relating to AC network constraints, plant ramping, detailed river chain modelling and ancillary services[8].

The model assumes a cost minimising approach with limited storage resources being dispatched with foresight subject to energy and other heuristic constraints which reflect the other chronological issues. While this is not entirely realistic in practice, it does provide a reasonable approximation to physical outcomes[9] and is suitable for a with and without analysis.

3.4.3 The new investment methodology

In essence, for a given level of future demand and assumed existing supply the model calculates the "revenue[10]" available from incremental investments in different new supply resources (wind, geothermal, Li-ion batteries etc).

These revenue sums are compared to the annualised costs of the different options (noting that I assume that wind, solar and battery costs decline over time). When revenue for a resource type exceeds its cost, I add more of a resource. A manual iterative process of adding resource is followed until the point where further investment is no longer revenue adequate.

North/South investments

The model tends to build new generation/small batteries mainly in the North Island – especially in the earlier years. This reflects the effect of HVDC capacity constraints, Tiwai shutdown, thermal plant closures and the preponderance of demand.

Regional wind/solar investments

The model places wind/solar investments in different locations to reflect effect of correlation issues and GWAP/TWAP[11] factors as more plant of each type are added in each region.

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[7] The model can be run using a full 168 hourly time steps It has been found that the 36-load block approach provides very similar results, provided that the sampling approach for typical workdays and non-workdays is suitably adjusted.

[8] These issues are more fully addressed by the parallel SDDP modelling work stream.

[9] The potential bias that this introduces here is that the level of ancillary services and Li-ion batteries or load control is underestimated, however I am interested in the value of pumped hydro rather than these quantities. If the simulation modelling did not have this bias, then investment approach would increase the quantities of Li-ion batteries and green peakers to achieve a similar new entry equilibrium price distribution. Thus, the modelled incremental value of pumped hydro is not significantly impacted.

[10] The "revenue" measure is derived from prices which depend on assumed water value curves, the SRMC of plant, and demand response and shortage cost tranches.

[11] Generation weighted average price / time weighted average price. This provides a measure of how much of the average market price that a particular project can 'capture'.

3.4.4 Illustrative results in 2050 with green peakers without NZ Battery

The chart below shows the revenue and cost results for each technology type and location after this manual iteration. Note that the chart focuses on "marginal plant" rather than existing plant whose capital has already been sunk. There is an attempt to make all the marginal plant just revenue adequate, but this can't be exactly achieved with a manual process. Fortunately, the overall results are not particularly sensitive to the exact mix[12] as they have very similar costs relative to the forecast cost uncertainties.

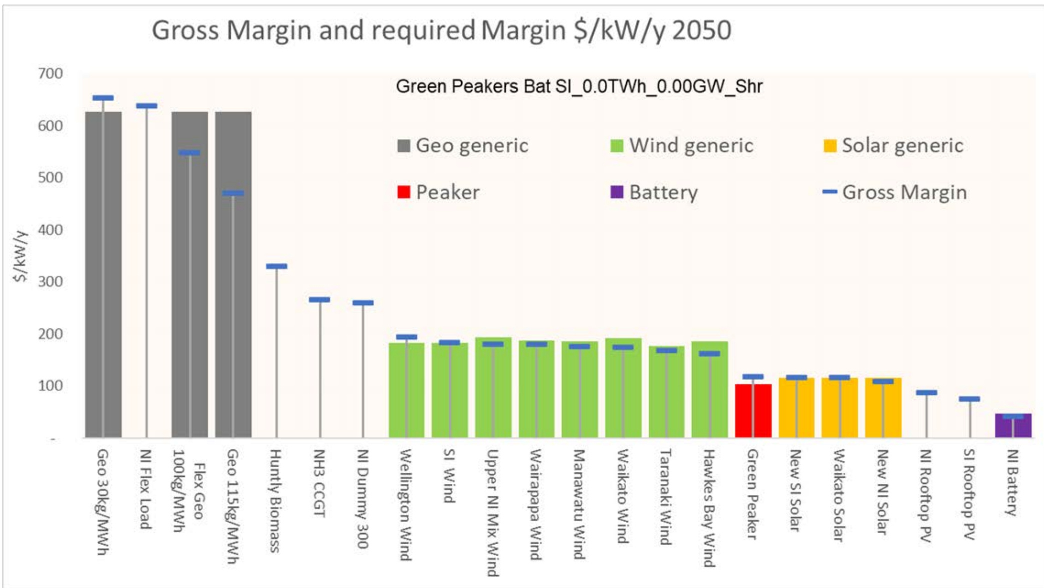


Figure 9: Simulated annual gross revenues and costs for technologies in 2050

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 is equal to spot revenue minus assumed SRMC and 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 7.0% nominal post tax return on capital[13].

In the example, all available geothermal with emission rate up to 60kg/MWh have been built, but the next tranche at 115kg/MWh is not built as it would not cover its cost.

New green peakers are required to recover all fixed costs and an allowance for the cost of holding several weeks of fuel.

It is assumed that batteries receive revenues for ancillary services, distribution and transmission support etc. and so only require 50-60% recovery of fixed costs from wholesale market price arbitrage. Investment in rooftop solar is an assumption and so is not adjusted in the manual optimisation.

[12] I have tested the impact of changes to the mix of wind and solar on incremental value and this was around $3-7m out of 230m/yr.

[13] approximately the same as a 6% pre-tax real return.

3.4.5 Interpretation of plant optimisation

I have checked that the manual approach to plant investment described above is broadly consistent with a national cost benefit approach. The chart below shows the simulated system costs as the level of new renewable investment is varied up and down[14].

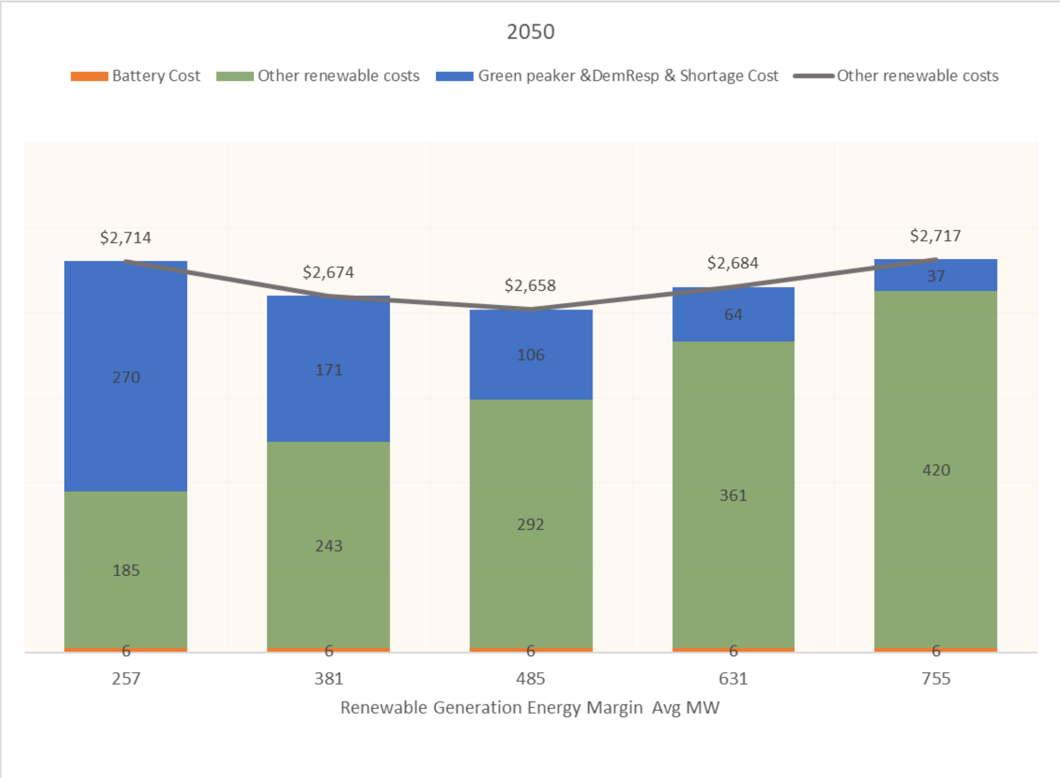


Figure 10: The trade off between the cost of renewables and the cost of green peaker fuel, demand response and shortage

As total renewable investment is decreased, there is a linear reduction in investment in investment costs, offset by an approximately exponential increase in green peaker and demand response costs. As a result, the total cost has an approximate quadratic shape with a minimum, which is very close to the manually optimised cost. This is the familiar economic trade-off curve between the cost of new supply and the cost of fuel and demand curtailment, but with a 100% renewable system[15].

The chart below shows the curve above, and the corresponding curve with a SI 5TWh/1.0GW pumped hydro. Note that the curve is relatively flat over 100MW changes in renewable margin. The manual plant optimisation – shown with open circles – appears to be within the flat part of a fitted curve, but slightly to the right (i.e., more conservative).

[14] In this case the mix of wind and solar investment is increased or decreased.

[15] Note that our approach here is to use an implicit security standard that represents an economic trade-off between supply and non-supply. In other modelling exercises and exogenous security standard (such as a capacity or energy margin) is applied. This can't be applied here because it is not practical to develop appropriate physical standards for a 100% renewable system out 30 years. This is because the nature of supply reliability will change substantially as the relative mix of hydro, wind, solar, geothermal, batteries etc. evolves in the factual and counterfactual.

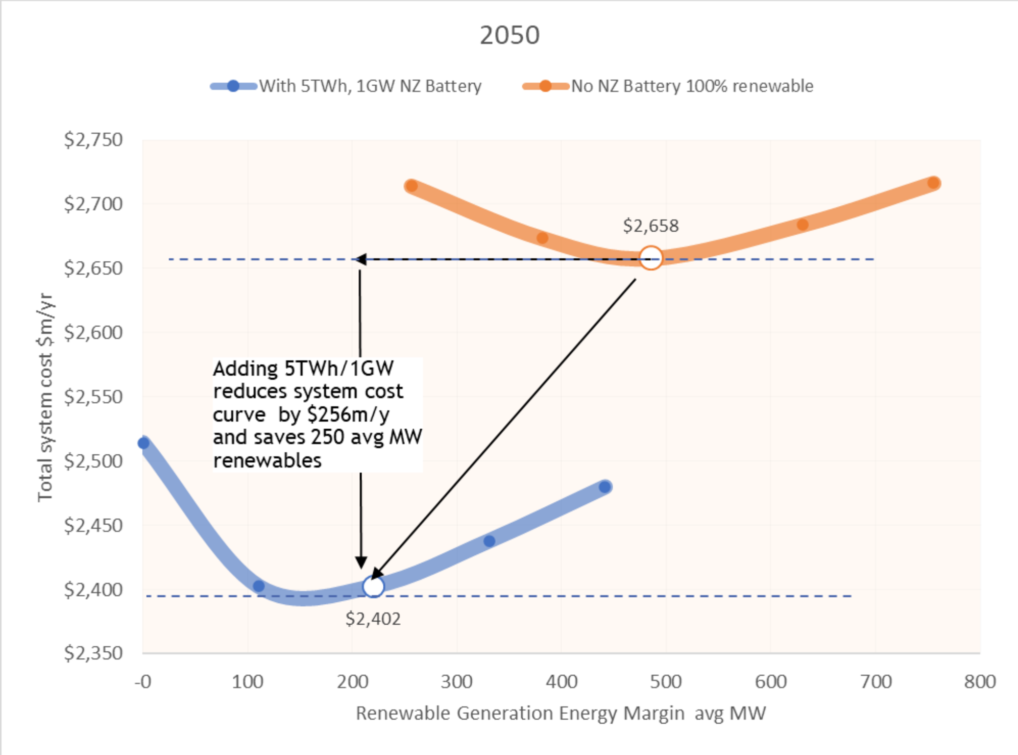


Figure 11: The national cost of supply curves with and without Onslow

The estimated incremental value of pumped hydro is determined by the difference in total system value at the minimum point of each curve (around 10% or $256m/yr in this example).

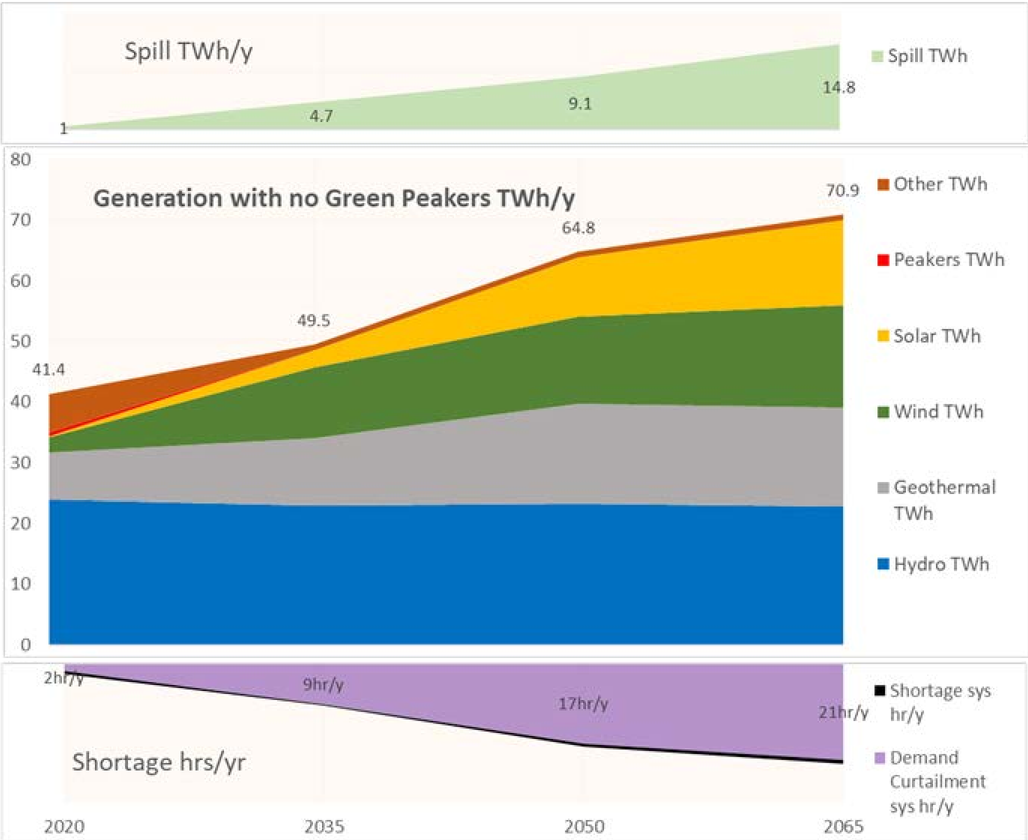
This estimated benefit is not particularly sensitive to the exact position on the curves, provided they are both in the flat portion, or if they are consistently biased in each case. This means the estimated cost change is likely to be reliable and not subject to excessive "modelling noise".

3.5 Summary Results

3.5.1 Results in 100% renewable world without "green peakers"

The chart below shows the simulated results for a world without NZ battery and without green peakers.

This scenario requires 16.7GW of wind and solar by 2065 and very significant spill



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

Figure 12: Annual generation, spill and curtailment without green peakers

As can be seen there is very high levels of market demand curtailments and spill. However, this is not driven by the need for dry year energy security, but rather by the increasing risks associated with capacity shortfalls associated with low wind weeks during winter. Note that carbon emissions from geothermal increase to 1.1mt/yr in this case.

There are many technological solutions to this problem, and it seems unrealistic to assume that no technology will become available other than demand curtailment at very high cost and overbuilding of correlated intermittent wind and solar[16].

3.5.2 Results in 100% renewable with green peakers

Ideally the counterfactual used to compare NZ Battery options should include a realistic capacity backup technology which is consistent and can be modelled simply and robustly.

As described above, the no green peaker counterfactual implies unrealistic levels of load curtailment and spill and is highly sensitive to assumptions concerning the exact patterns of future wind/solar volatility and the assumed costs of non-supply, all of which are inherently uncertain. This scenario is not considered to be a realistic counterfactual. I prefer a green peaker counterfactual that allows for 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

[16] Note that, in this counterfactual, I also assume that no further geothermal is built because it does not employ carbon capture and utilisation or reinjection and is hence uneconomic. This assumption makes the capacity issues even greater.

several days or weeks. This is simply and consistently modelled as a standard open cycle gas turbine (OCGT) running on high priced "green" fuel costing $45/GJ. In addition to the high variable cost it is assumed these peakers incur around $15/kW/yr as the holding costs for several weeks' storage of fuel.

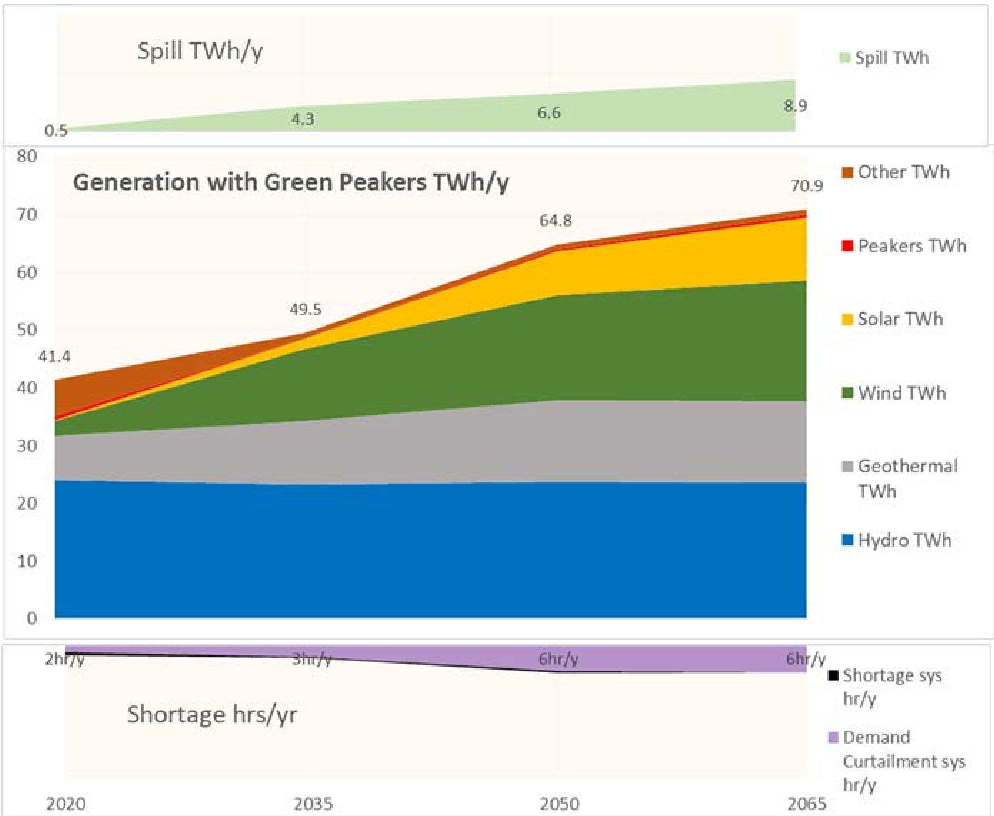
While it is described as a "green peaker" it can also approximately represent a whole range of possible technologies some of which are widely used today in the industry, and others for which the technology is technically proven but are not yet widely adopted and the costs are more uncertain:

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 range of products
- 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.

Note also that the results are also very similar to continued use of existing gas peakers (open cycle gas turbines) with a gas price and high shadow price on carbon emissions (around $500/t).

The simulated results for the green peaker world are shown below.



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

Figure 13: Annual generation, spill and curtailment with green peakers

The green peakers account for less than 1% of generation on average and produce reasonable levels of market-based demand curtailment. There is still a degree of increase in "spill" but this is much lower and reflects the cost of a modest level of over-building renewable to ensure dry year security.

Geothermal emissions reach around 0.8 mt/yr by 2065. This is 0.3mt/y less than in the no green peaker counterfactual but is still almost 2x the average emissions from peakers if they were to be running on natural gas.

The middle of the chart below shows the simulated operation of the SI hydro reservoirs in the green peaker world. Each line represents the storage trajectory for the combined SI controlled hydro schemes in a different weather year with matching hydro inflows, wind, solar and demand. The modelling proceeds from a 1931 weather year and simulates a full sequence from 1931 to 2019, with the starting lake levels reflecting the ending levels from the earlier weather year.

The top of the chart shows the "spill[17]" in each month averaged over all weather years. The bottom of the chart shows the running of peakers and resulting market demand response (curtailment not load shifting within the day) and shortage.

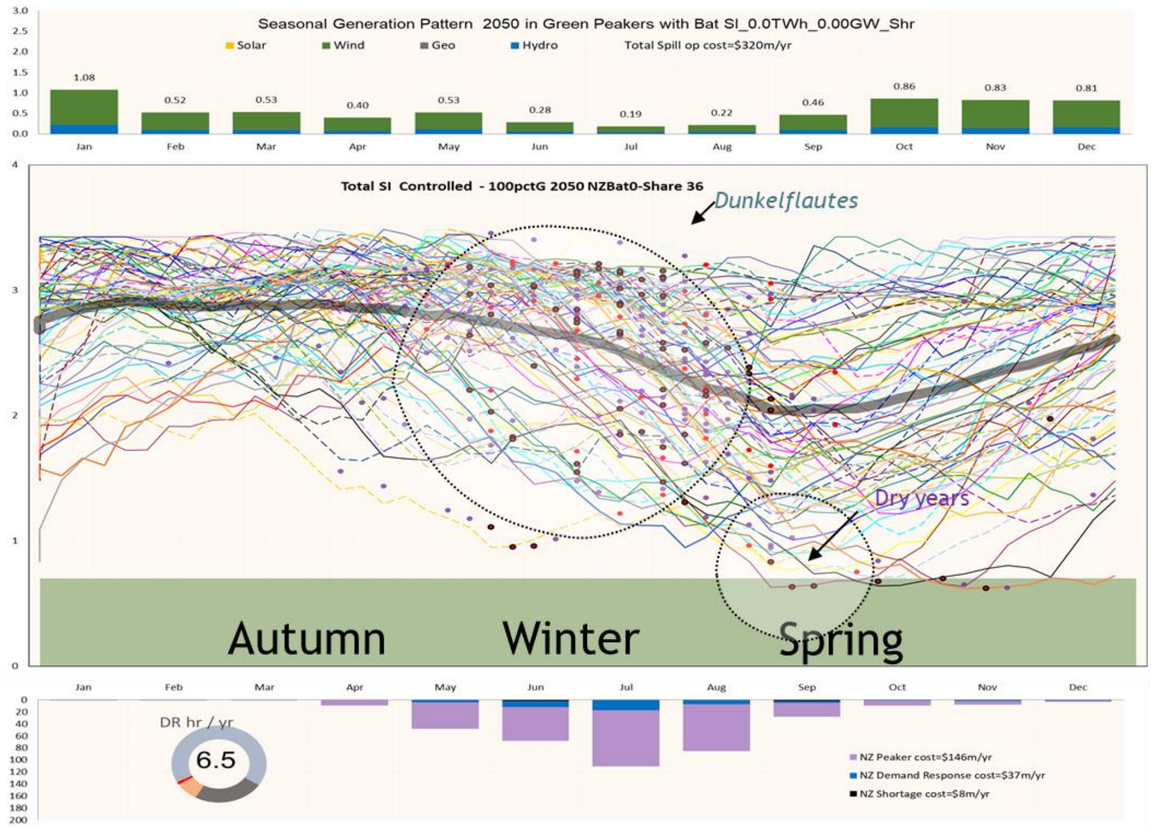


Figure 14: Weekly generation, spill and curtailment with green peakers

The simulation modelling assumes existing hydro offers are low when lake levels are full, and the risk of spill is high, and they rise to reflect the cost of green peakers, demand response and shortages when lake levels are low, and the risk of supply is higher.

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[17] "Spill" is a combination of actual hydro spill and market curtailment of wind /solar & geothermal. In practice the allocation of this "spill" will depend on the avoided costs from not dispatching plant which is potentially available. The modelling assumes some O&M costs can be saved for wind. Spill should be seen as unutilised capacity. This has an economic cost to be traded off against the cost of other forms of underutilised capacity (e.g. green peakers).

The offers are a function of storage and time of year and 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 can 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.

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 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.

What are Dunkleflautes?

The chart below shows an illustrative weather year with periods of low wind and solar with the system as it might be in 2050. The days in red have the rolling weekly average contribution from wind and solar falling below a 22% capacity factor trigger. Where the red days extend for over 5-7days then we have a dunkleflaute week. This is a German term meaning 'dark wind lull'. These are likely to occur in NZ with a frequency of 2 to 4 weeks per year on average and require sustainable capacity backup from green peakers, pumped hydro, or sustained demand reductions.

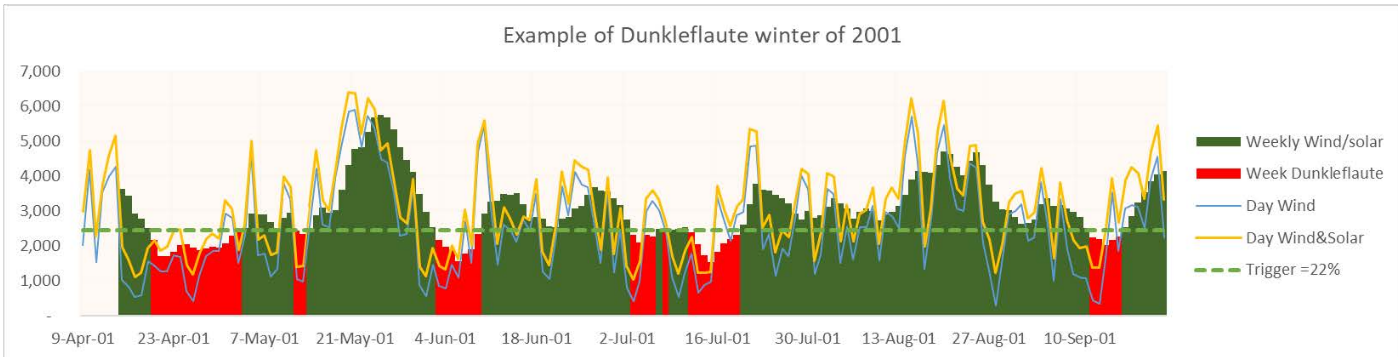

Figure 15: An illustrative year with Dunkleflautes

Challenges with green peakers

Green peakers are modelled as a very high operating cost, but low fixed cost, method for ensuring system reliability during dunkleflaute (low wind) events. They are effective, however face issues associated with supply chain flexibility, as they need to be able to operate for extended periods (weeks or possibly a month) at full capacity with little warning. To handle this, it would be necessary to hold stocks of biodiesel or other green fuel and to purchase top up supplies when stocks are drawn down. The chart below shows how a stocking policy might work given the simulated need for biofuel to run green peakers in the counterfactual.

This policy assumes that an operator has 5 weeks of fuel storage, a base load steady supply at the average annual green peaker use, and this supply can be increased 2x when storages get low and turned off (or on-sold) when storages are full.

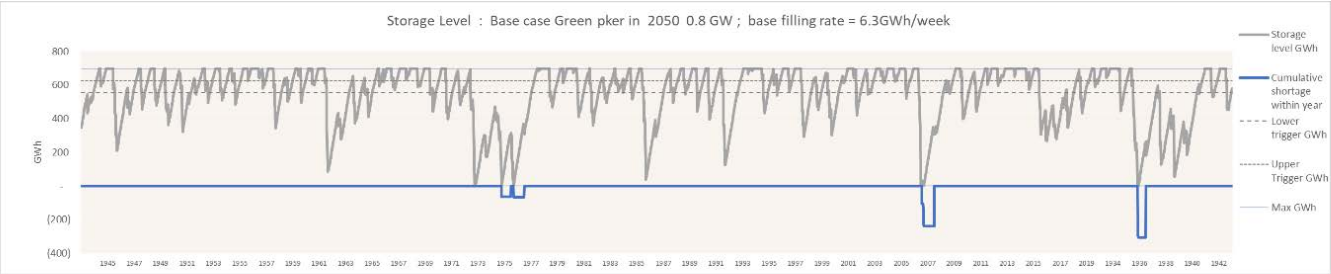

Figure 16: Simulated fuel stockpile for green peakers in counterfactual

With this degree of flexibility in the supply chain a green peaker would be able to meet the unconstrained system demand in all but 3 out of 87 weather years. In those years it would be necessary to constrain green peaker use somewhat. This can be handled by extra hydro generation at the cost of going into the contingent zone.

3.5.3 Impact of a SI pumped hydro scheme

The table below shows the simulated impact of a 5.0TWh / 1.00GW pumped hydro scheme in the South Island on investment in renewable energy capacity, generation, spill, green peaker operation and market demand curtailment in each of our target years.

Table 1: The physical impact of SI pumped hydro

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 summary the Onslow pumped hydro scheme, by 2065, can save:

- 4.3TWh spill,
- 1.2GW of wind/solar,
- 0.3GWof gas peakers and batteries,
- 2.7 hr/yr curtailment, and
- approx. $1.7b capex over the period to 2065

but increases load by 0.9TWh/yr for pumping.

The chart shows the impact of Onslow on the annual distributions of total spill, and on peaker use and demand response as modelled for 2050. These are the distributions of annual use in each weather year ranked from the highest to the lowest. As can be seen the Onslow has a much larger impact on the worst years than on the average over all years.

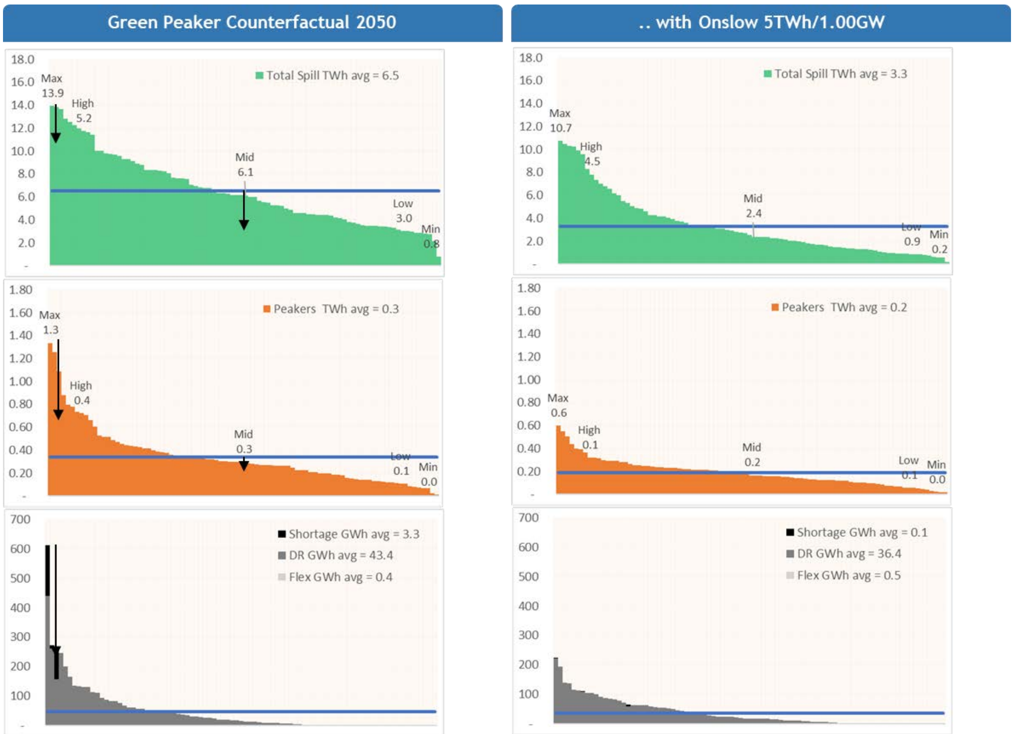

Figure 17: The impact of Onslow on annual distributions of spill and peaker use

The average seasonal operation of the pumped hydro scheme in 2050 is show below. This indicates that the pumped hydro is pumping hard during the spring/summer and generating hard during the autumn/winter. There is also a mix of both pumping and generation in some months as required by fluctuations in hydro and wind/solar inflows.

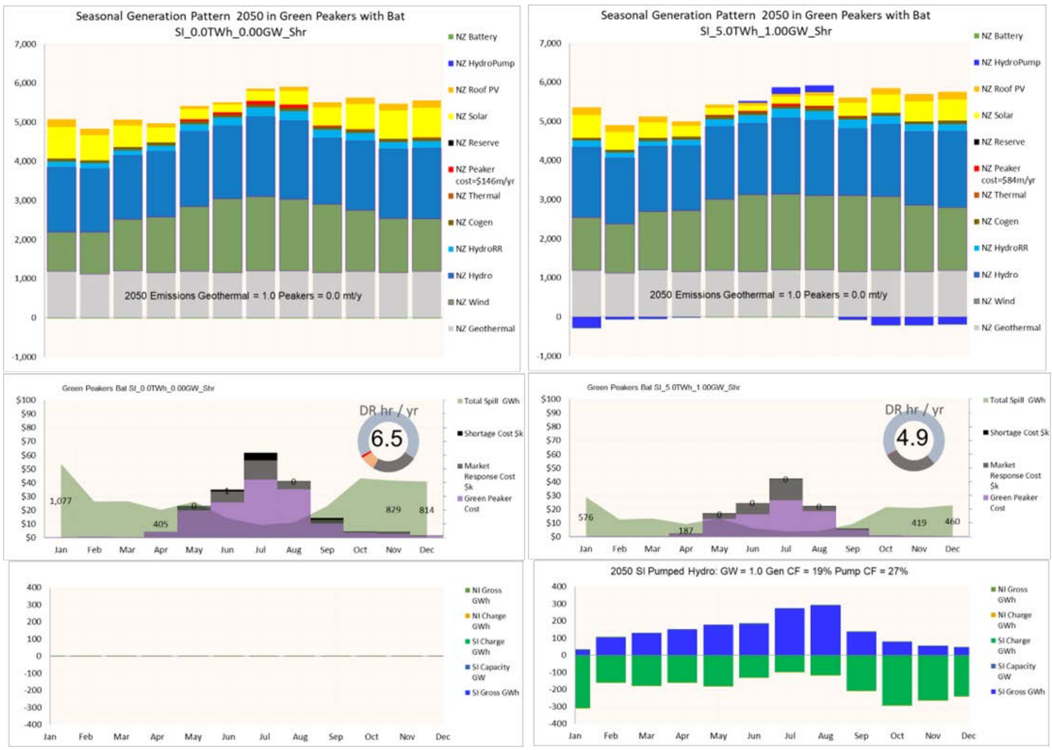

Figure 18: The seasonal operating of Onslow pumped hydro

3.5.4 What do I mean by gross benefits from pumped hydro?

Gross benefits are defined as the savings in total electricity system costs arising from a given NZ Battery option in a future study year.

These savings are estimated by considering the difference in total electricity system costs between two scenarios:

- NZ Battery is already built, filled and available
- NZ Battery is not built.

In both scenarios I identify the least cost mix of generation and demand response – i.e. I take the role of a cost minimising system planner

My total system cost estimates:

- include capital costs for construction of new generation and small-scale batteries (i.e. not NZ Battery)
- include cash operating costs for new generation and smaller scale batteries and carbon charges (e.g. for geothermal)
- include demand response[18] and shortage costs – both voluntary and involuntary
- exclude capital costs for existing generation which is likely to continue in operation (since capex for these is already sunk)

[18] I use demand response as a generic term for voluntary load curtailment. Voluntary load curtailment occurs when customers reduce consumption in response to spot prices exceeding pre specified levels (e.g. $700/MWh, $1000/MWh, $1500/MWh). Shortage occurs when load is involuntarily curtailed when there is insufficient generation capacity to meet total load after all the voluntary load curtailment has been exhausted. This is assumed to have a cost of $10,000/MWh. Shortage also includes the costs of public conservation campaigns if these are required in a very dry period.

- exclude transmission costs because the grid is assumed to be the same in the scenarios with and without NZ Battery (noting that I only explicitly model the HVDC link)
- exclude the cost of building and initially filling ('charging') NZ Battery as both are currently unknown
- include the cost of refilling NZ Battery once it is operating – noting this cost is embedded in the capital cost for new generation (some of whose energy is used to fill NZ Battery and cover its recharge/transfer losses)

The resulting differences in estimates represent the national economic benefits of NZ Battery. This is illustrated in the chart below as the components of net benefit from a 5TWh/1.0GW SI pumped hydro operating in 2050.

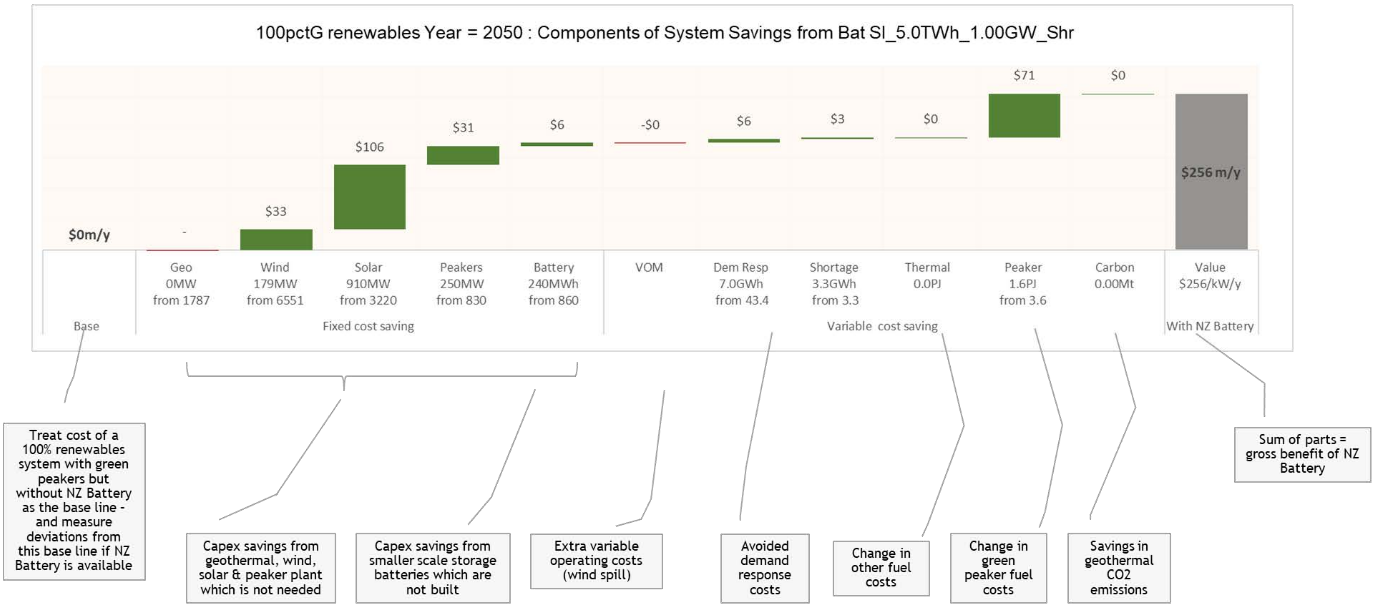

Figure 19: Components of Gross Benefit in 2050

3.5.5 Base Case Results for Onslow (5.0TWh/1.00GW)

Green peaker counterfactual

The chart below shows the estimated benefits from the base case pumped storage configuration with the green peaker counterfactual. Beyond 2065 the growth in electricity demand is expected to be much lower, as the transport sector is fully decarbonised, and population and income growth are offset by efficiency improvements.

The key observations on these results are:

- 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.

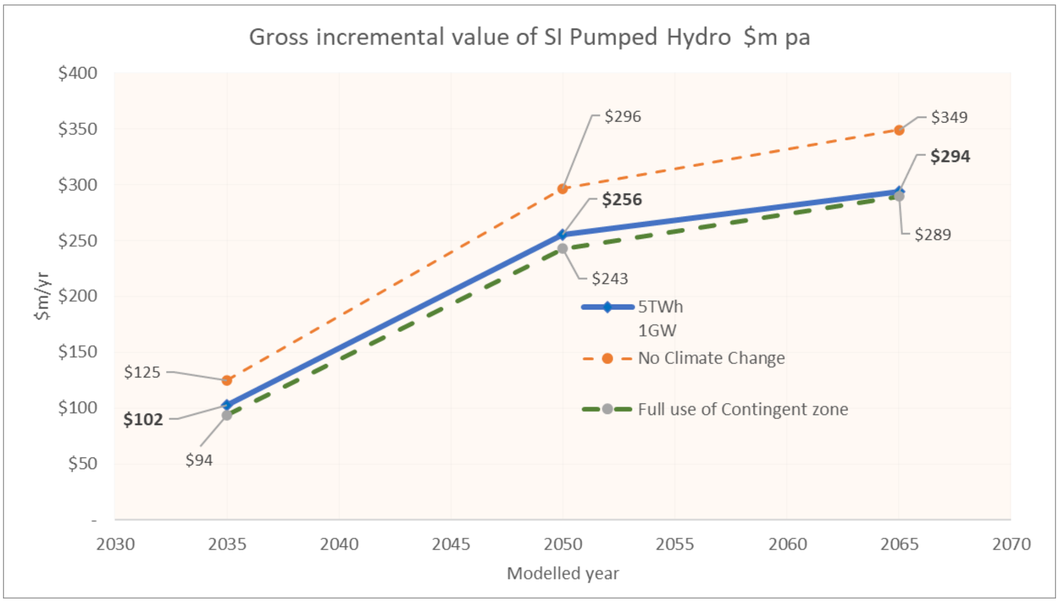

Figure 20: Gross benefit of SI 5.0TWh/1.0GW pumped hydro with green peakers[19]

Continued gas peaker use and Tiwai-stays counterfactuals

I have also explored the base case configuration under the 2 other counterfactuals; continued use of existing gas peakers and continued operation of an inflexible Tiwai aluminium smelting load.

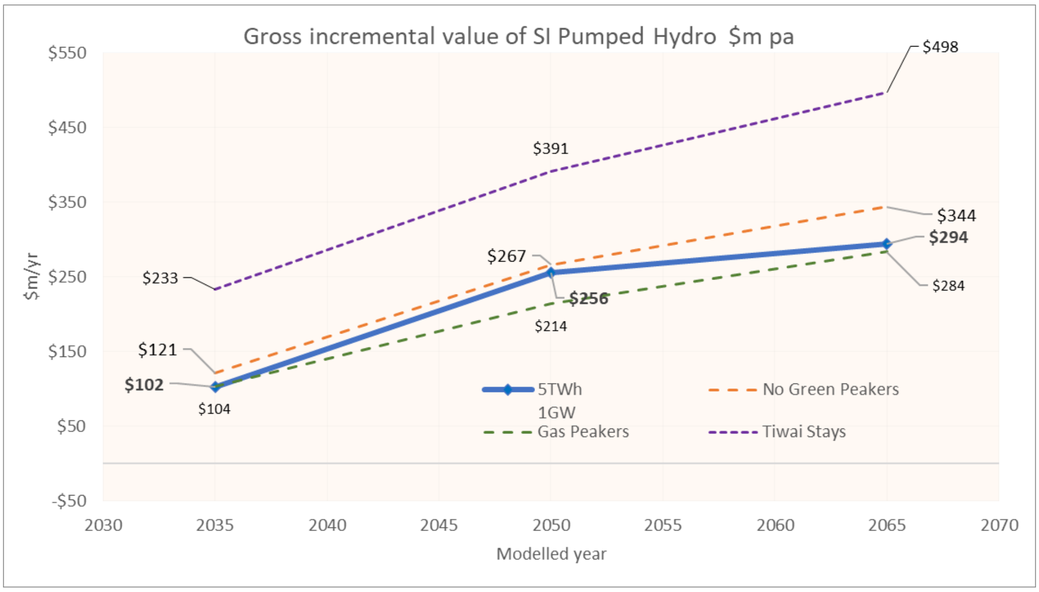

Figure 21: Gross benefit of SI 5.0TWh/1.0GW pumped hydro in continued gas peaker and Tiwai stays worlds

In the case where it is assumed that gas peakers paying a carbon price ($200/MWh SRMC in 2035, $270/MWh in 2050 and $350/MWh in 2065) are retained for last resort firming capacity, and some additional green peakers are built to replace slow start thermals where economic:

- The gross value is very similar in 2035 because capacity issues have not yet become significant.

.

- The value is lower in 2050, but only slightly lower in 2065.
    - This is because the gas SRMC is 60% lower than green peakers in 2050, but only 30% lower in 2065.

The case where Tiwai remains requires an extra 5TWh of largely inflexible demand:

- The gross value of the pumped hydro in 2035 is increased significantly (by $130 to $233m/yr).
- This can be attributed to the higher percentage intermittent supply required to meet the higher demand, and the lower percentage of flexibility in demand from EVs.
- Most of this increased value for pumped hydro is from the higher capacity value, rather than "dry-year" value.
- There is also an increase in the capacity value resulting from a more balanced use of the HVDC and less time in constraint.

3.5.6 Onslow pumped hydro tank and tap size options

The chart below shows the gross benefit of SI pumped hydro schemes with a range of different tank and tap sizes, in all cases with green peakers

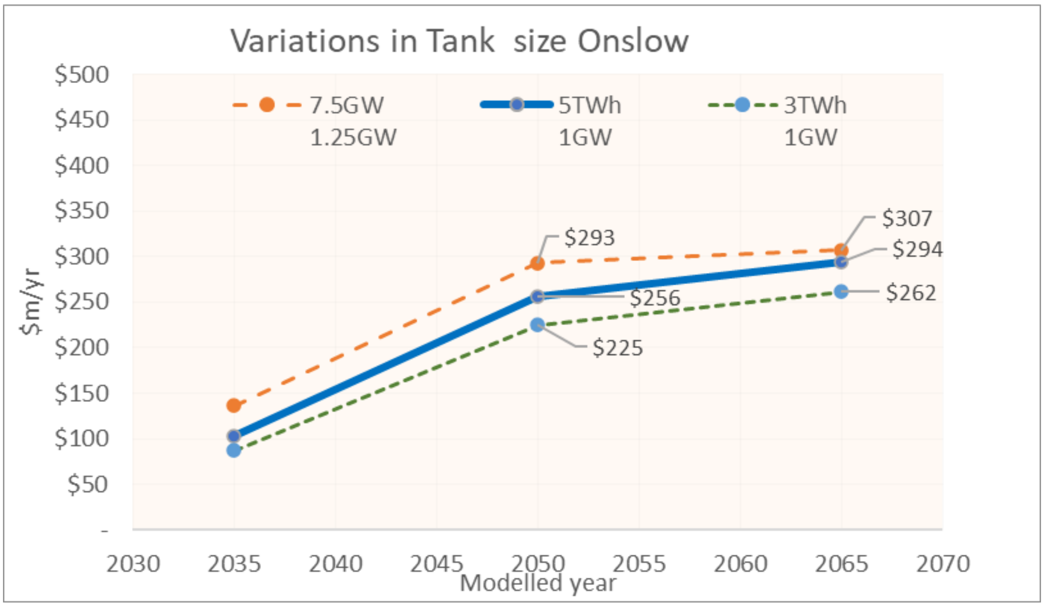

Figure 22: Variation of gross benefit with Tank size

The key conclusions are:

- There appears to be only a $30 to $13m/yr (14%-5%) gain from an extra 0.25GW (25%) capacity and a 2.5TWh (50%) increase in tank size. This gain declines over time as balance of risks shifts from dry years to capacity constraints.
- There is a low $20-35m/yr (12%-10%) loss from reducing storage (40%) from 5TWh to 3TWh.

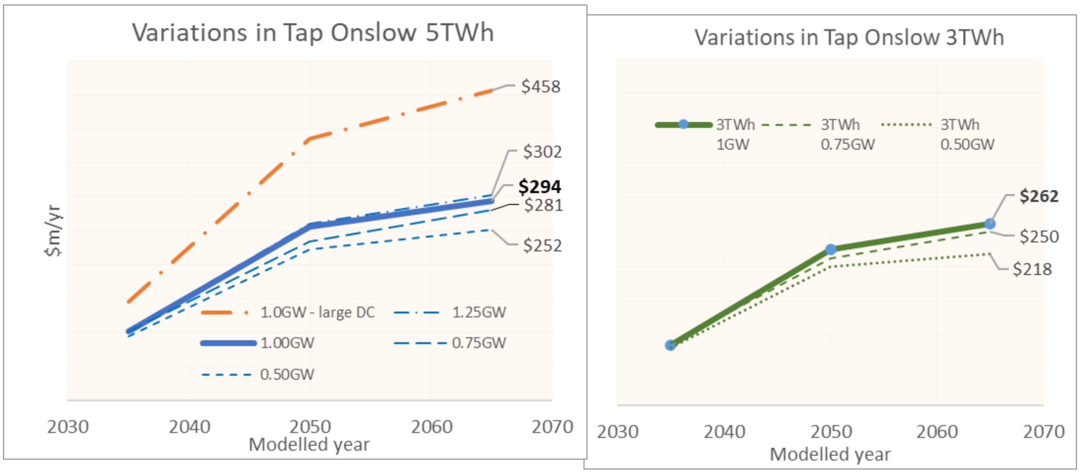

Figure 23: Variation of gross benefit with Tap size

The key conclusions are:

- There appears to be limited value of <$8m/y (3%) in increasing the capacity of a 5TWh scheme from 1GW to 1.25GW without HVDC expansion.
  - This is because the HVDC is already constrained in the 1.0GW case.
- Reducing the capacity of a 5TWh scheme 25% to 0.75GW has only a minor $1-20m/y (1-4%) loss in value, whereas reducing the capacity 50% to 0.5GW has a more significant loss of $8-42m/y (7-14%). The loss increases beyond 2050.
- Reducing the capacity of a <u>3TWh</u> 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.
- The preceding observations assume the HVDC upgrades to its maximum of 1400 MW S->N and 1300MW N_S .
- The chart also shows the impact of an expansion of the HVDC to 2100MW S->N and 1500 N->S (or the addition of a second HVDC link.)
  - This results in a substantial $44 to 164m/y (43-56%) increase in gross value.

3.5.7 Sensitivity Analysis

The chart below shows the impact on the estimated benefits of changes in the modelling assumptions.

The gross benefit figures are discounted averages from 2035 over 60 years at a 6% real rate, assuming values are interpolated from the 3 target years to 2065 then held constant in real terms.

The chart shows differences from the base case Onslow option (5TWh/1GW) with the green peaker counterfactual.

This shows that the Tiwai exit assumption and the HVDC constraints have the greatest impact on Onslow gross system benefit.

The assumed availability and cost of green peakers and assumptions around climate change adjustments have up to a $40m (20%) impact. Other assumption relating to new investment capital costs and the required return to capital have around a ±$20m (±10%) impact.

Shortage costs do not make a big difference as these are mostly assumed to be equalised by adjusting the investment in green peakers and batteries in both the factual and counterfactual. The impact of carbon prices is negligible since it only affects geothermal and the supply is normally at its same limit in factual and counterfactual.

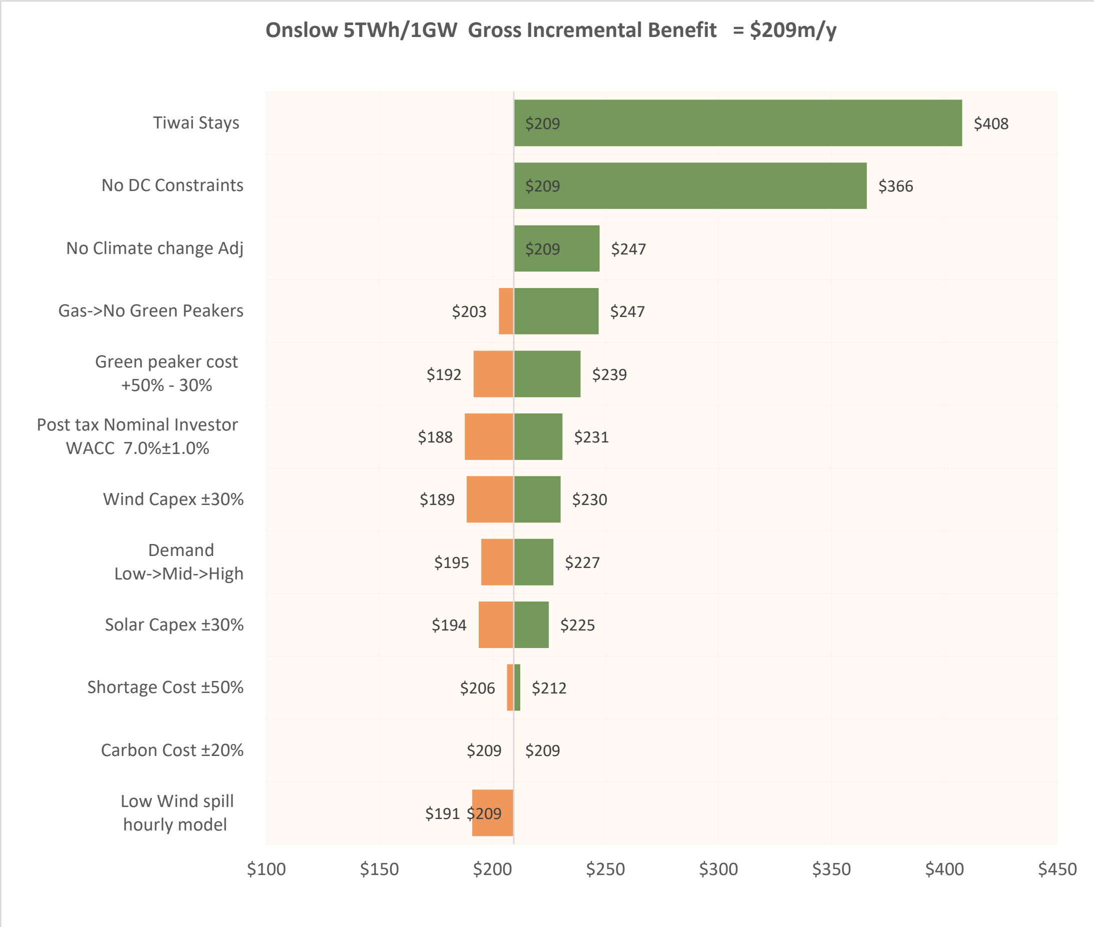

Figure 24: Sensitivity of Onslow 5TWh gross benefits to key assumptions

The key observations are:

- 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 could 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

3.6 Summary of other technology options

The NZ Battery team and WSP[20] have developed 3 potential alternative technologies including:

1. 400MW of flexible geothermal,
2. a 500MW biomass thermal back up plant fired from wood, and
3. a flexible hydrogen/ammonia plant which mostly supplies a local or international market for green ammonia but also supplies a 150MW CCGT plant.

I have attempted to model the key features of these options and assess the potential system benefits from each. As with the pumped hydro, I have not attempted to assess the costs of each, just the system benefits.

3.6.1 Flexible Geothermal

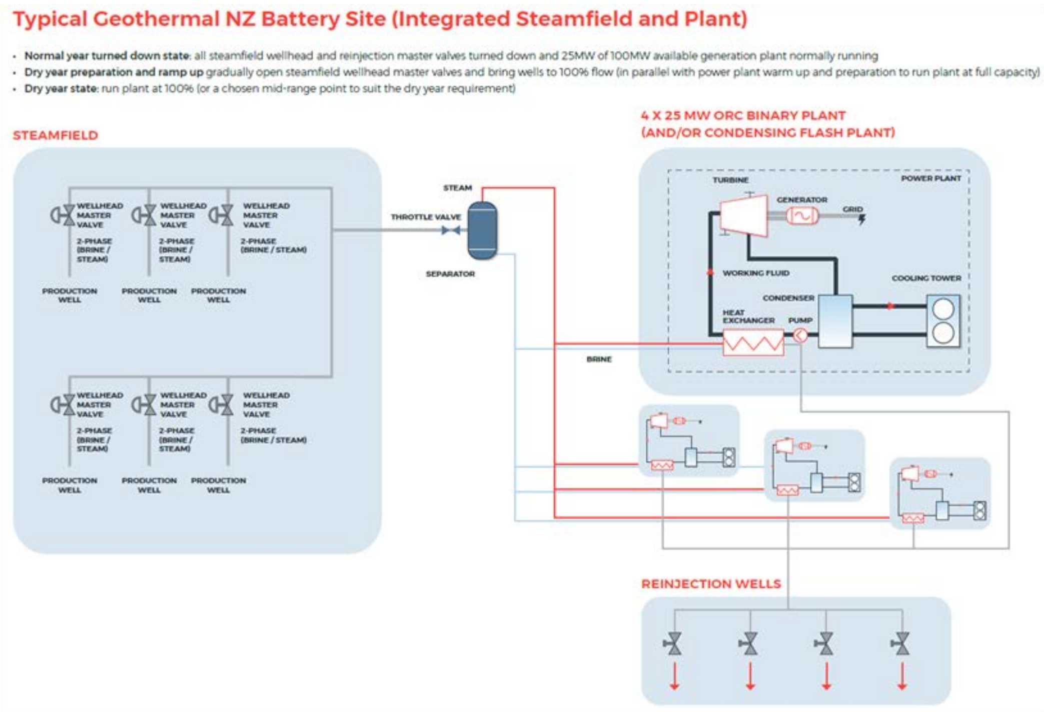

Figure 25: Flexible Geothermal Configuration

Typically, geothermal generators are very inflexible and tend to operate in base load mode. However, it is possible to operate them somewhat flexibly. This can enable them to provide firm MW supply when needed for capacity or energy security of supply while limiting their generation to less than full load. This only makes economic sense when there is a variable cost that can be avoided when not running. This is the case for the assumed 50% of geothermal fields which have moderate or high emissions, and which can't practically have carbon capture and reinjection.

The option developed by WSP includes 400MW (4x 100MW with 4 25MW units) spread across several greenfield geothermal sites in the Taupo volcanic zone:

1. MBIE assume that this option includes the fields where carbon capture and reinjection are not feasible. This includes 100MW with 60kg/MWh and 300MW with 120kg/MWh emissions.

[20] WSP, NZ Battery Project - Other Technologies Feasibility Study – Feasibility Assessment Report, November 2022.

2. 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.
3. Of the 400MW, 100MW is run base load and 300MW is dispatched when storage levels in Waitaki fall below a moderate risk level.
4. Production can be phased up from 25% running to 100% over a period of a week[21].

The typical pattern of the simulated weekly operation is shown in the chart below. This implies a 40-50% capacity factor on average. Note that some random outage of the geothermal is modelled and so weekly generation also has a random variation.

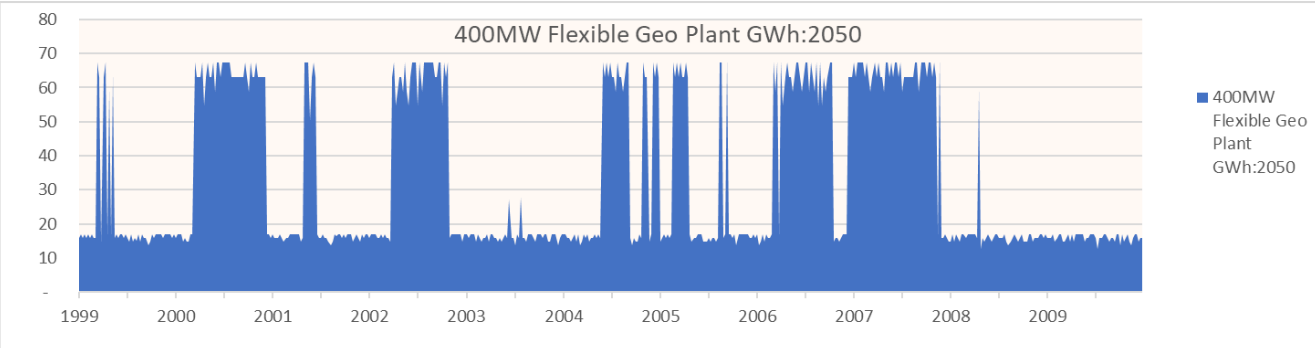

Figure 26: Typical Flexible Geothermal Operation over 10 weather years

The system benefit of this is estimated in the same way as for pumped hydro from the savings in avoided renewable and peaker build and use. These benefits are offset by increased carbon emissions cost, as shown below.

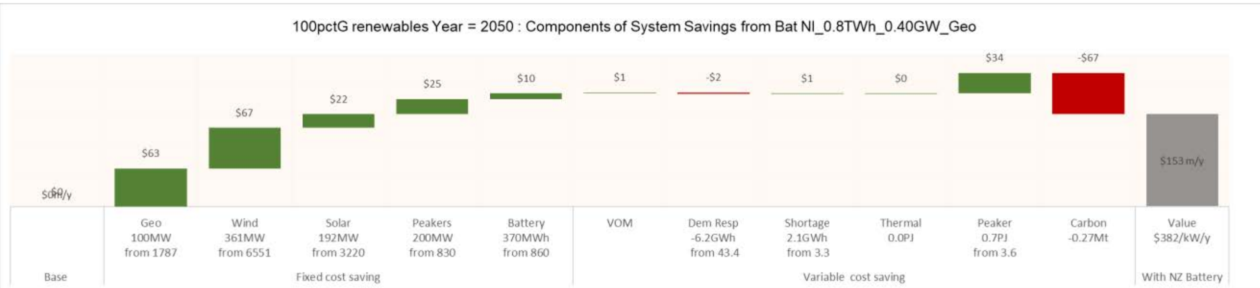

Figure 27: System benefit from flexible geothermal.

The table below summarizes the key physical and market-based results from the simulation and compares these with the incremental system cost savings.

[21] This is an approximation due to modelling limitation. It may be that up to 2 weeks is required.

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**

Table 2: Estimated market and system value for flexible geothermal

Conclusions:

- As with the estimates of pumped hydro the market-based measure of value is slightly different from the incremental system value. I consider the estimated system value to be more reliable.
- The value of this flexible option could be enhanced if flexible geothermal was dispatched each winter to be always available to meet capacity shortfalls during the highest capacity risk period over winter. This would increase the capacity factor to 65-60% and would increase the system value by around $13-$30m/yr or $30-70/kW/y.

3.6.2 Biomass Generation

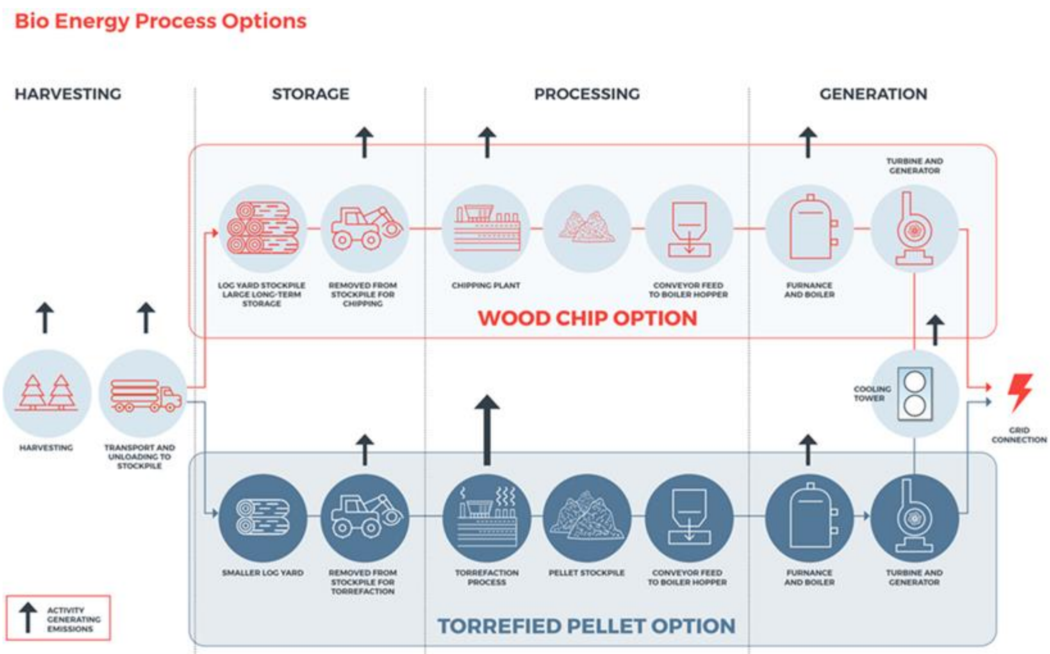

Figure 28: Illustrative Biomass Option

This option developed by WSP involves a new biomass generator consisting of 2 x 250 MW Rankine cycle generator units operating on chipped wood or torrefied pellets and holding a stockpile of 1 TWh (generation equivalent) stockpile of logs at the generation site, which is close to the forest to minimise transport distances.

For initial modelling it is assumed that:

- biomass generation is offered at $200/MWh to the market to achieve a target capacity factor of approx. 8-10%.
- logs are harvested and supplied to the stockpile at a steady rate equal to the expected use for generation.
- The supply rate can be increased 1.5x 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 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.
    - Take or Pay (TOP) cost $112/t = $123/MWh
    - Top-up cost $136/t = $149/MWh
    - Resale discount 40% down on TOP cost = $74/MWh

The simulated weekly operation of the biomass plant is illustrated below for 10 different weather years. As can be seen, the plant operates to cover both dry years and capacity shortfalls during dunkleflautes.

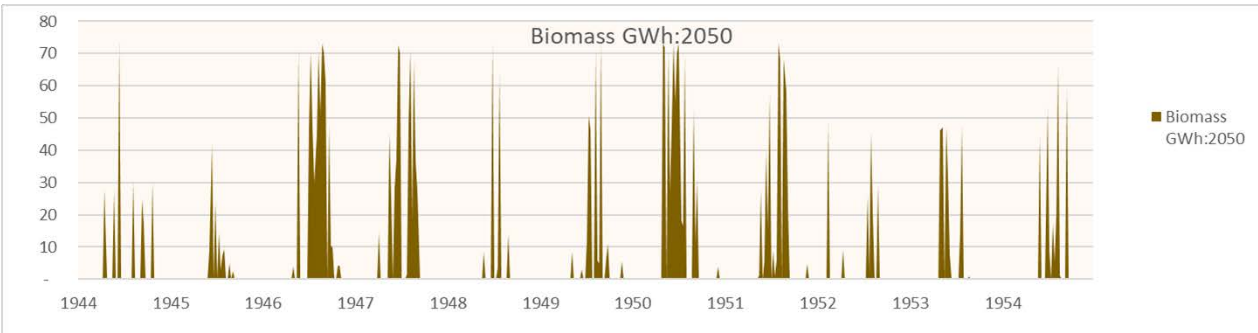

Figure 29: Typical Biomass Operation over 10 weather years

The benefit of this is estimated in the same as for pumped hydro from the savings in avoided renewable and peaker build and use. These benefits are offset by the variable running cost for the Rankine units. For this calculation I use the simulated offer price of $200/MWh. This offer price is set so as achieve the desired capacity factor of 8-10%.

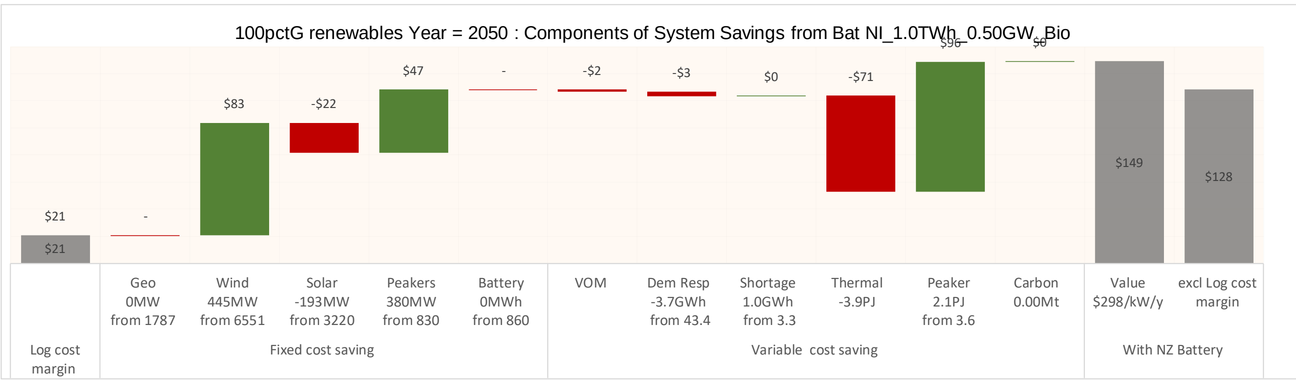

Figure 30: Benefit components of a 500MW biomass plant in 2050

In reality the actual variable cost of logs is not a simple SRMC, but depends on the cost of take or pay log purchases and the extra costs associated with supply including the base take or pay supply of logs, the additional costs to extra top up supply to enable the stockpile to be maintained and the net costs of re-sale of purchased logs should the stockpile be full or if the 3 year retention period is exceeded. The electricity model does not explicitly account for these complexities. I start with the unconstrained demand for biomass generation (based on the $200/MWh offer price). This gives a profile of demand for generation which enables a stockpile strategy to be simulated. The output from this for 2050 is shown in the chart below which shows that a stockpile of around 1TWh is sufficient to meet the unconstrained demand from the Rankine units in all be 2-3 years out of 87. The shortfall in those years can be readily accommodated through extra hydro generation at the cost of a short excursion into the contingent zone.

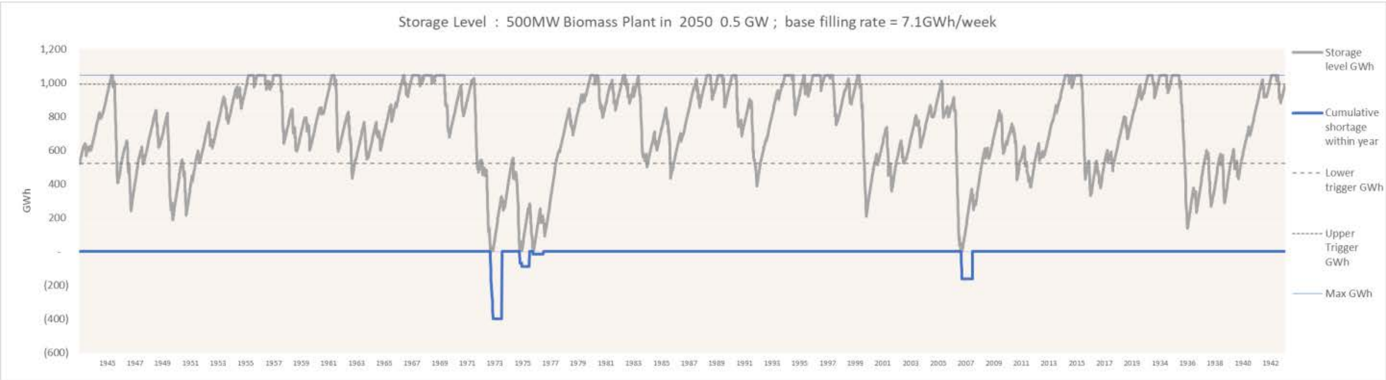

Figure 31: Simulated operation of the biomass log stockpile

This shows the level of stocks derived from a simple stocking rule which assumes the unconstrained demand for biomass fuel is met, and 50% extra top up supply is triggered when the stockpile falls below 50%. 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 following this policy is estimated to be approximately $144/MWh. This means that the actual cost of supply is $56/MWh lower than the offer price.

To derive the total system benefits I add the log cost margin equal to $56/MWh multiplied by the expected Rankine generation level.

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**	**$177**
TWAP	NZ$/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**

Table 3: Estimated System Value for a Biomass Rankine

Conclusions:

- The biomass option has an incremental system value of $185 to $443/kW/y. This would be good value if the capital cost of Rankine generators can be reduced, and if the cost of logs supply could be kept below $100/t.
- This might be a good transitional option if existing generators such as Huntly have their life extended and be converted to run on chipped logs.

3.6.3 H2/NH3

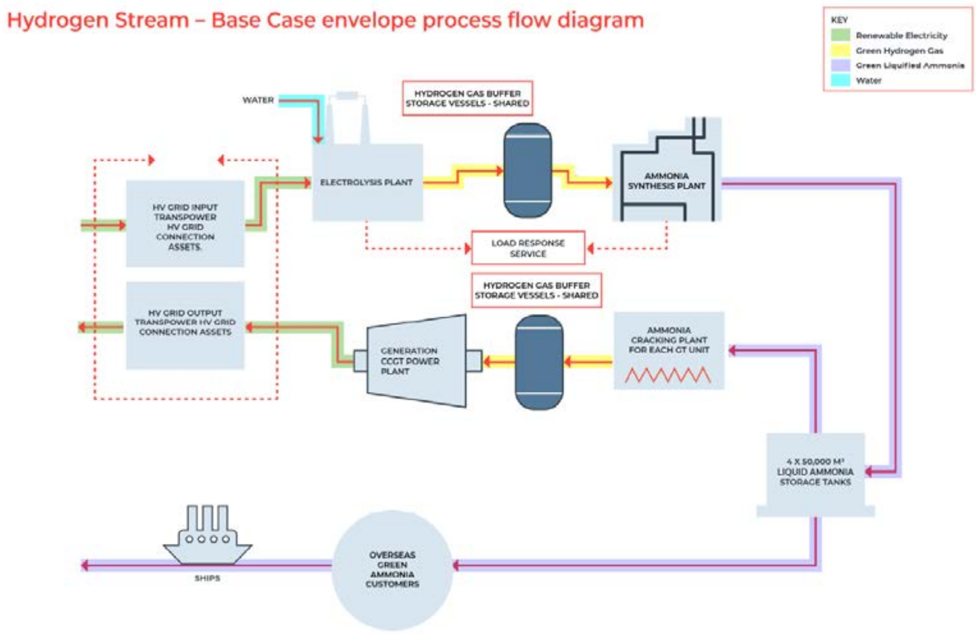

Figure 32: Modelled H_2/NH_3 plant and CCGT peaker

This option developed by WSP involves building an electrolyser to create H_2 (when electricity prices are low) to supply an Ammonia (NH_3) plant via a 1-day buffer storage (compressed hydrogen tanks). The ammonia is stored in liquid ammonia tanks (200k m3 or 380MWh of generation) which supplies a small 150MW (2x75MWunits) CCGT generator and export markets for green ammonia.

To evaluate this option, it is assumed:

- 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 $80/MWh, $50/MWh, and $40/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. I don't model any specific limitation or cost of ramping the ammonia plant up and down over the space of several days[22].
- The NH_3 is used to fire flexible CCGT plant operating on H_2 which is cracked from NH_3.
- 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.

The chart below shows the simulated demand from the electrolyser and generation from the CCGT plant by week over 20 weather years. As can be seen the electrolyser is often backed off when prices are high. On average it achieves an 80% capacity factor falling to 66% by 2065. The CCGT generator only operates occasionally when prices are very high. This achieves a 3-10% capacity factor on average. The total quantity of NH_3 produced is around 270-230kt/yr. Of this around 10-20% is used by the CCGT, with the remaining going to export or other green ammonia markets.

[22] This may be a bit optimistic.

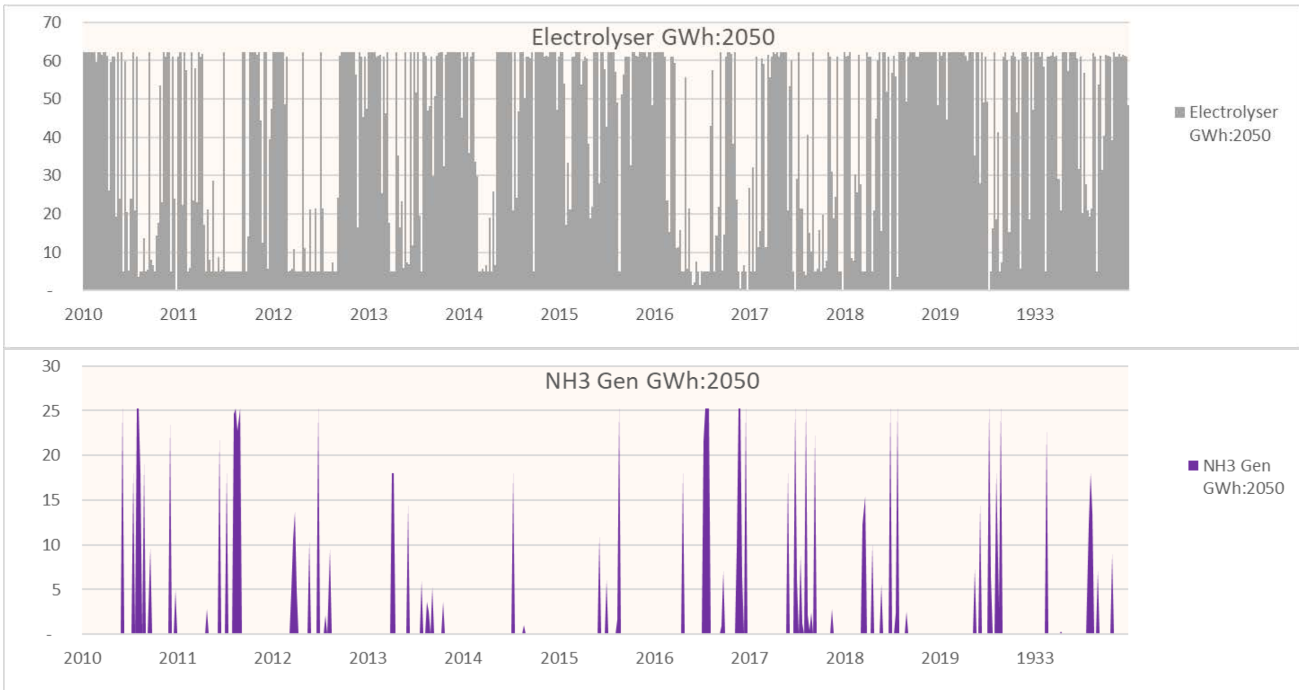

Figure 33: Typical Electrolyer demand and CCGT generation over 20 weather years

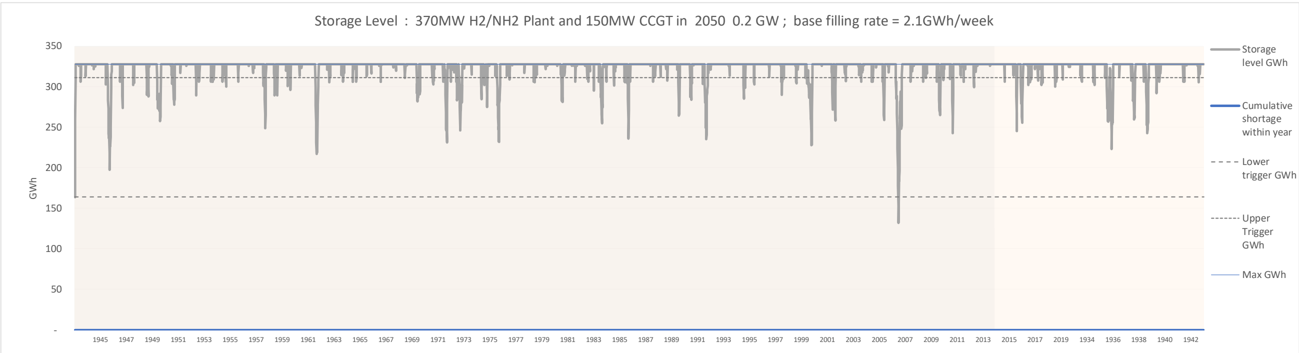

Figure 34: Simulated operation of the ammonia storage tanks over full 87 years

The bulk of the ammonia production goes to export rather than for use in the electricity system. To derive a national benefit, it is necessary to include the value of this production in the total system benefit. In this case I value the ammonia produced at the assumed export parity price of $US750, 500 and 400/t converted to NZ dollars. From this I then account for the additional investment cost to meet the net cost to the electricity system of supplying the load for the electrolyser, net of the system benefits from the CCGT peaker plant, on the assumption that it pays for its ammonia use at the export parity price.

The components of this value in 2050 are shown below. There is a base sales value for the ammonia produced of $181m, this is then offset by the net cost of supplying the power for the 370MW flexible demand from the electrolyser net of the benefit of the 150MW CCGT peaker. In this year there was only a net $10m/yr system to supply this load. The bulk of the value is from export or local sales of ammonia.

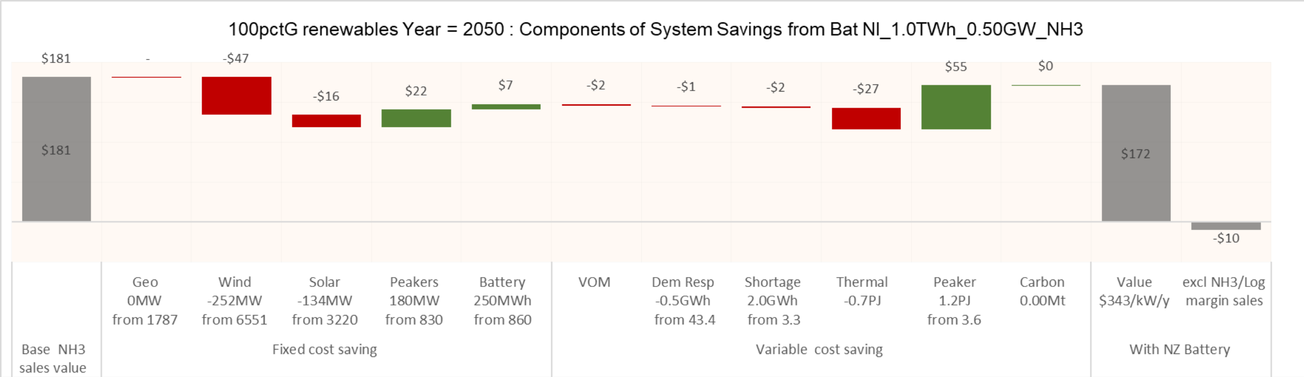

Figure 35: Benefit components of an Ammonia plant in 2050

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**

Table 4: Estimated System Value for an Ammonia Plant

Conclusions:

- 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.

3.6.4 Portfolio value

Two separate portfolios of the alternative technology options have been modelled for comparison with the lake Onslow option.

These consist of the 0.4GW of flexible geothermal, 0.5GW of biomass plus the 0.37/0.15GW electrolyser/ CCGT options as a package. The value of these portfolios is assessed relative to the green peaker counterfactuals with and without Tiwai.

The incremental value for a combination of these technologies has been simulated as it differs somewhat from the sum of the standalone options due to interactions. The results are summarised below.

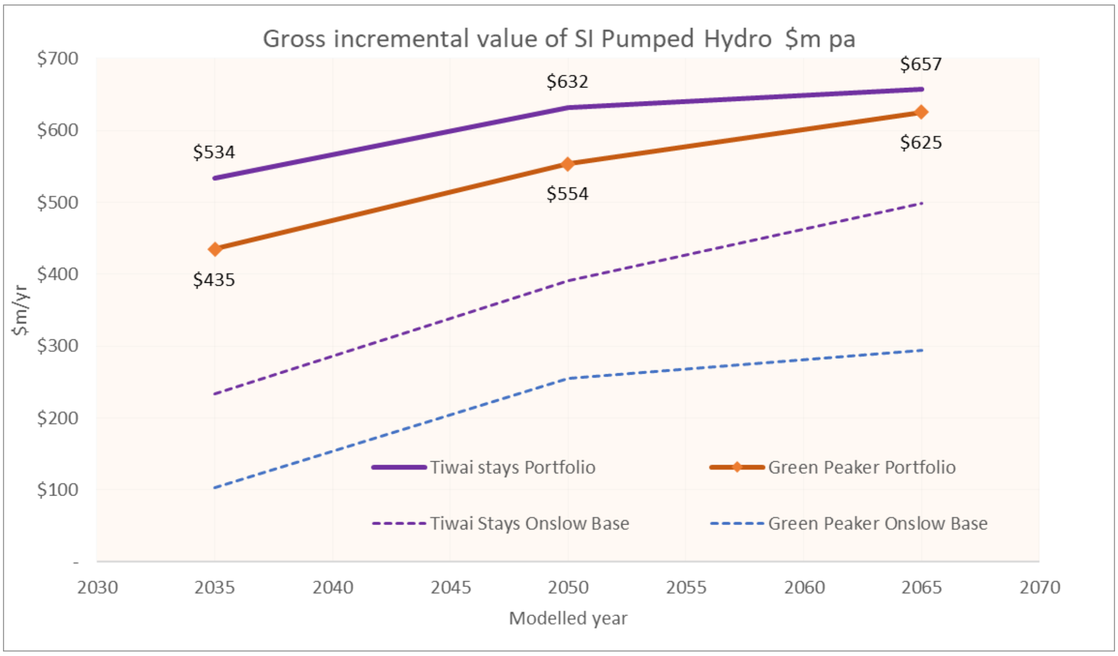

Figure 36: The national benefit of a portfolio of other technologies compared with Onslow pumped hydro

This shows:

- The portfolio options provide $300-$330m/y higher system benefits than the base case Onslow pumped hydro option but may have higher capital costs. I can't comment on the overall net benefit without knowing the difference in cost.
- The extra benefits in the Tiwai stays case is 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.

3.7 Price impacts

The modelling setup and focus was to estimate the national cost impacts of NZ battery options rather than price impacts. However, MBIE is also interested in price outcomes as well as national cost benefits.

Our experience is that estimating price outcomes is problematic in that they 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.

Nevertheless, our approach which includes modelling a new entry equilibrium, can provide some potentially useful information on price outcomes, especially when considering price impacts between different options.

3.7.1 Wholesale price levels

The following chart provides a range of price-based results from our modelling. These should be used carefully and a subject to several qualifications:

- Cost based measures are "incremental", whereas simulated prices are "marginal".
- The price-based measures are particularly sensitive to the exact assumed level, mix and location of new entry.
- Market based measures of baseload assume a particular location, whereas the cost-based measures are for a mix of new investments in different locations.
- Market based measures are influenced by the assumed offer curves for the major hydro reservoirs and for NZ Battery[23].
  - These flow through to simulated market prices and have an impact on price volatility and hence on market simulated capture rates. These can be significant when HVDC transmission constraints are binding.
- 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.

[23] The modelling here focuses on national economics of new investment within the electricity sector. It does not attempt to explore all the issues related to price formation in the market. The simulated prices presented here are based on specific assumptions. These specific assumptions do not appear to have a major impact on the national economics but can have an impact on simulated price levels and volatility. This means that relative changes in results are more reliable than the absolute results.

Figure 37: Estimated impact on simulated prices and capture rates

The key observations:

- Simulated time weighted prices increase over time despite falling wind and solar LCOEs, as greater load requires greater levels of intermittent supply and greater price volatility, and this implies falling capture rates (GWAP/TWAP ratios).
- Compared with the green peaker world; simulated prices are slightly lower with continues gas peaker use and are significantly higher in a no green peaker world.
- Flexible hydro[24] capture rates rise significantly over time as price volatility increases.

- With 5TWh/1.0GW Onslow:
  - o simulated prices are somewhat lower because wind and solar rates are higher.
  - o flexible hydro capture rates are significantly lower

The impact of Onslow on new renewable development is:

- it reduces the need for new renewable supply as it enables the system to be renewable with a lower level of renewable overbuild and spill. The total market need for new renewables is reduced by around 1.2GW by 2065.
- it does not impact the mean profitability of <u>new</u> entry wind and solar since these modelled as being just revenue adequate with and without Onslow.
- it will tend to increase capture rates for both wind and solar, but this effect is offset by a reduction in time weighted prices.
- it is expected to reduce price volatility to some degree, and this might make financing and funding for new independent renewable generators easier. However, this impact might be partly offset by changes in hedging arrangements between new

[24] These hydros have highly flexible operation and significant short to midterm storage. Other hydro capture rates will vary significantly depending on the particular hydro scheme and its relative storage size, flexibility, pct tributary and inflow correlation.

generators and customers since both parties are affected by an increase or decrease in price volatility.

- it may have a significant impact on revenues earned by existing generators, as the new entry equilibrium does not ensure revenue adequacy for past sunk investments that were built based on different technology and market conditions.

3.7.2 Expected annual pumped hydro revenue

The chart below shows the estimated system incremental value and the simulated average annual net market earnings for a SI 5.0TWh/1.0GW pumped hydro.

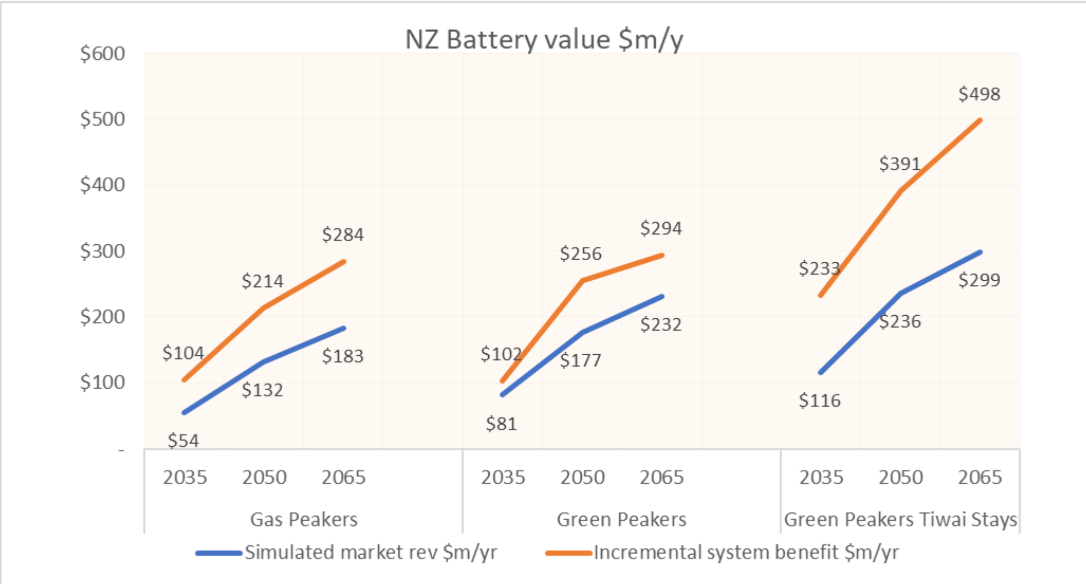

Figure 38: Estimated pumped hydro revenues and costs

Note:

- 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.
- The situation without green peakers is more complex as the capacity issues of meeting weekly shortfalls in intermittent supply dominate the seasonal issues.
- Note that the estimated market revenues for pumped hydro are particularly sensitive to the assumed offer behaviour, so great care is required when using these.

3.7.3 Distribution of pumped hydro net revenues

The chart below shows the simulated pumped hydro operation and market revenues in 2050 in the green peaker counterfactual.

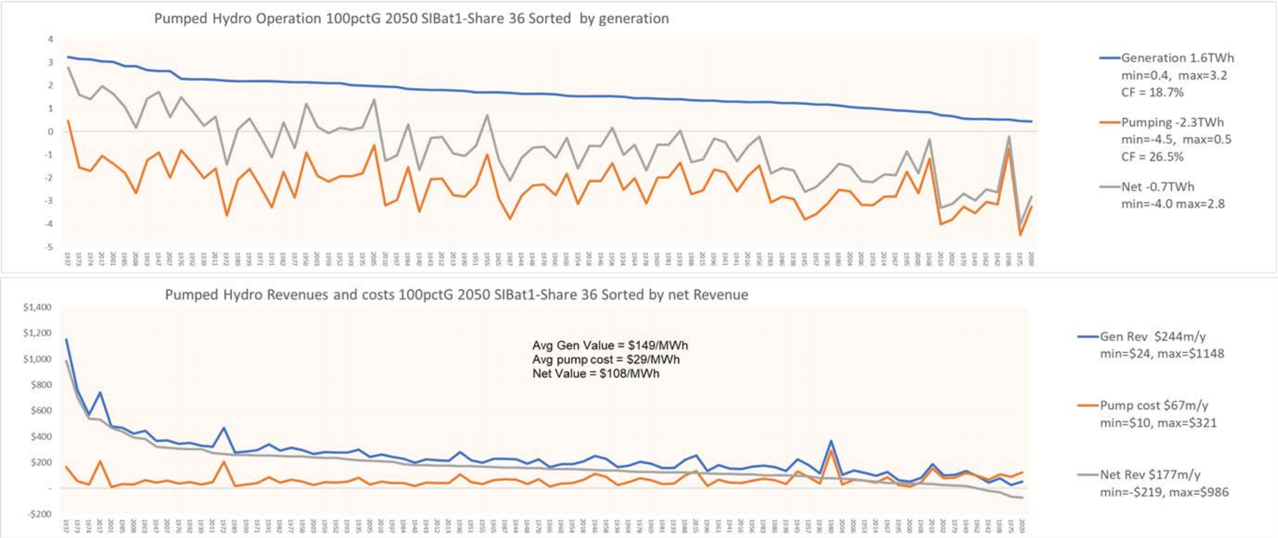

Figure 39: Simulated distribution of pumped hydro operation, revenues and costs

The upper chart shows the physical operation of the pumped storage in 2050 over 87 weather years, ranked from the year with the highest generation to the lowest. This implies a generation capacity factor of around 18-19% (and a pumping capacity of 24-25% accounting for pumping efficiency).

The lower chart shows the pumped hydro revenues (generation at spot price) and costs (pumping load at spot price) ranked from highest net revenue to lowest. The simulated cost of pumping is quite low ($25/MWh) as most pumping occurs at times when there would otherwise be "spill" of hydro or wind. The value of generation is very high ($154/MWh) as this occurs when there are capacity supply issues in the North Island during low wind periods or when storage in other hydro lakes is low.

As discussed above, the generation value can significantly be affected by the pumped storage offering approach, particularly when the HVDC is constraining, and NI is facing market demand curtailment.

3.8 Conclusions and insights

- Additional long-term storage could be beneficial for NZ but may not necessarily be essential.
  - There is an economic trade-off between the capital cost of "overbuilding" and "spilling" renewables and the capital cost of storage options.
- As the cost of backup (either fuel burn or storage capital) increases and the cost of renewables falls, the economically ideal level of renewable "overbuild" and "spill" will rise.
- The need for storage has several distinct time frames:
  - **Dry-years**: the long-term risk of sustained low hydro inflows lasting for months.
  - **Dunkelflautes:** the medium-term risk of sustained low wind/solar (typically weeks of low wind during winter)
  - **Intermittency**: the short-term risks of low solar and wind supply within each week and day)
- The importance of these different storage needs will change as NZ decarbonises by retiring thermal plant and electrifying transport and bulk heat demands.
- Phase 1: Status quo
  - Currently the dry year risks dominate but can be managed by thermal plant. But these are to be retired under 100% renewables.

- Phase 2:
  - Once the thermal plants are retired, and Tiwai is closed, the energy supply from thermal needs to be replaced with intermittent wind/solar and firm geothermal supplemented with batteries.
    - This means that intermittent supply increases from around 7% towards 30% of total supply.
    - As this occurs the importance of Dunkelflautes and intermittency increases. Dry years still occur, but their relative importance declines.
    - During this phase the cost of batteries is expected to fall rapidly during this period, and the quantity of potentially shifted load (such as EV charging and process heat) increases.
- Phase 3:
  - Beyond 2035, electricity demand grows, and the level of intermittent supply rises to almost 50% of total supply. By this phase dunkleflaute and intermittency risks become the dominate risk. Dry year risk still occurs, but it continues to fall in relative importance.
  - In addition, longer duration batteries up to 12 hours are expected to get cheaper and potentially shiftable EV charging load continues to grow.

The options to address these different storage demands include "overbuilding" renewables or specific investment in medium term green storage or backup technologies (pumped hydro, green peaking plant, biomass, hydrogen/ammonia, flexible geothermal, medium term flexible load etc).

Overbuilding renewables

- The effectiveness of overbuilding renewables in meeting reliability issues changes as we go from phase 2 to phase 3.
  - In phase 2 the system still has a relatively high percentage of flexible hydro, and intermittent supply from wind and solar is still below 30%.
  - During this phase it would be possible to delay the increases in intermittent supply if more new geothermal supply was available at $5.5/W capital cost particularly if carbon capture and reinjection was practical at a cost of less than $200/t CO_2.
  - A combination of existing flexible hydro[25], batteries and within-day load shifting can address short run intermittency.
  - Modest levels of overbuilding wind and solar can firm up winter supply to cover dry years at the expense of increased hydro and other renewable spill.
  - The dunkleflaute risks are growing throughout this phase but can be covered by occasional use of green peaking plant if this available. Without this, the system would require occasional voluntary or involuntary demand response.
- When we get to phase 3 the system is much more reliant on solar and wind (which now approaches 50% of total supply), and dunkelflaute risks dominate.
  - Dry year energy risks can still be met by overbuilding at the expense of spill, and short run intermittency can be covered with batteries and load shifting.
  - The spill from overbuilding might result increased demand, but that would only occur during occasional very low spot price periods, and would not result in extra capacity being required.
  - By now, covering capacity shortfalls of wind and solar during dunkleflautes by building wind and solar becomes more and more difficult.

[25] Note that there would need to be a change in the offering and operation of existing flexible operation. Currently the flexible hydro is used to cover relatively predictable demand variations, whereas in the future it would also need to respond to more unpredictable variations in wind and solar supply.

  - Overbuilding wind and solar provides extra energy but provides very little firm capacity value as intermittent supply is very high and positively correlated.
  - Green peakers or medium-term storage options are necessary to avoid excessive load curtailment.

Pumped Hydro Options

- Weekly to monthly dunkelflaute variation can be met by either low capital/high operating cost options such as green thermals or from medium term (week/month) electrically charged storage options.
  - Moderately flexible supply and several weeks storage should be sufficient to meet the periods of low wind.
  - This might also be met by increasing the MW capacity of the existing hydro system.
- Pumped hydro can provide both dry-year backup value and capacity value[26] during dunkelflaute events, the latter particularly if it is in the North Island, or if the HVDC is expanded.
  - Increases in pumped hydro storage value beyond 2040 are likely to be driven mainly by the rising risks and costs of dunkelflautes as more wind and solar is required to meet rising demand.
    - Peak capacity issues are of a medium term (hourly-monthly) nature.
    - Within-day variation is likely to be best met through hydro flex, EV charging load shifting and Li-ion batteries.
- The incremental value from SI pumped hydro beyond 3.0-5.0TWh and 0.75GW – 1.0GW appears to be relatively modest, unless the HVDC is expanded significantly.
- If technically feasible, a NI pumped hydro could provide proportionately higher benefits beyond 2035, even for low tank sizes relative to the 5.0TWh SI option.

Other Technologies

- There are a range of other technologies that can provide back up for intermittent wind and solar and dry years. Some of these can be effective for both purposes. The NZ battery team has identified 3 options including a 500MW biomass Rankine plant, 400MW of flexible geothermal, and a 370MW flexible electrolyser and ammonia plant for export, local use and a 150MW hydrogen-fired CCGT plant. These have been assessed individually and as a portfolio.
- Compared to pumped hydro these options are generally smaller in scale, less lumpy, better located and more diversified. However, some involve technologies which are not yet mature.
- I have estimated the gross benefit for each option and for portfolios relative to the green peaker and Tiwai stays counterfactual. The gross benefits for the portfolio are estimated to be greater than those for pumped hydro, but these include a highly uncertain value for Ammonia sales that are not used in the electricity sector.

Other

- More generally, the analysis shows NZ's storage needs are influenced by a complex interplay of factors and the past will not necessarily be a good guide to the future.
- Lastly, transition issues could well be quite important for legacy generators, particularly given the dynamic environment NZ finds itself in, with changing risks (dry year -> dunkelflaute) and technology options (falling Li-ion battery/wind/solar costs).

[26] Pumped hydro can reduce the need for green peaker backup and can also reduce the risk of involuntary load curtailment during these events.