# NZ Battery - OptGen/SDDP Market Modelling Report

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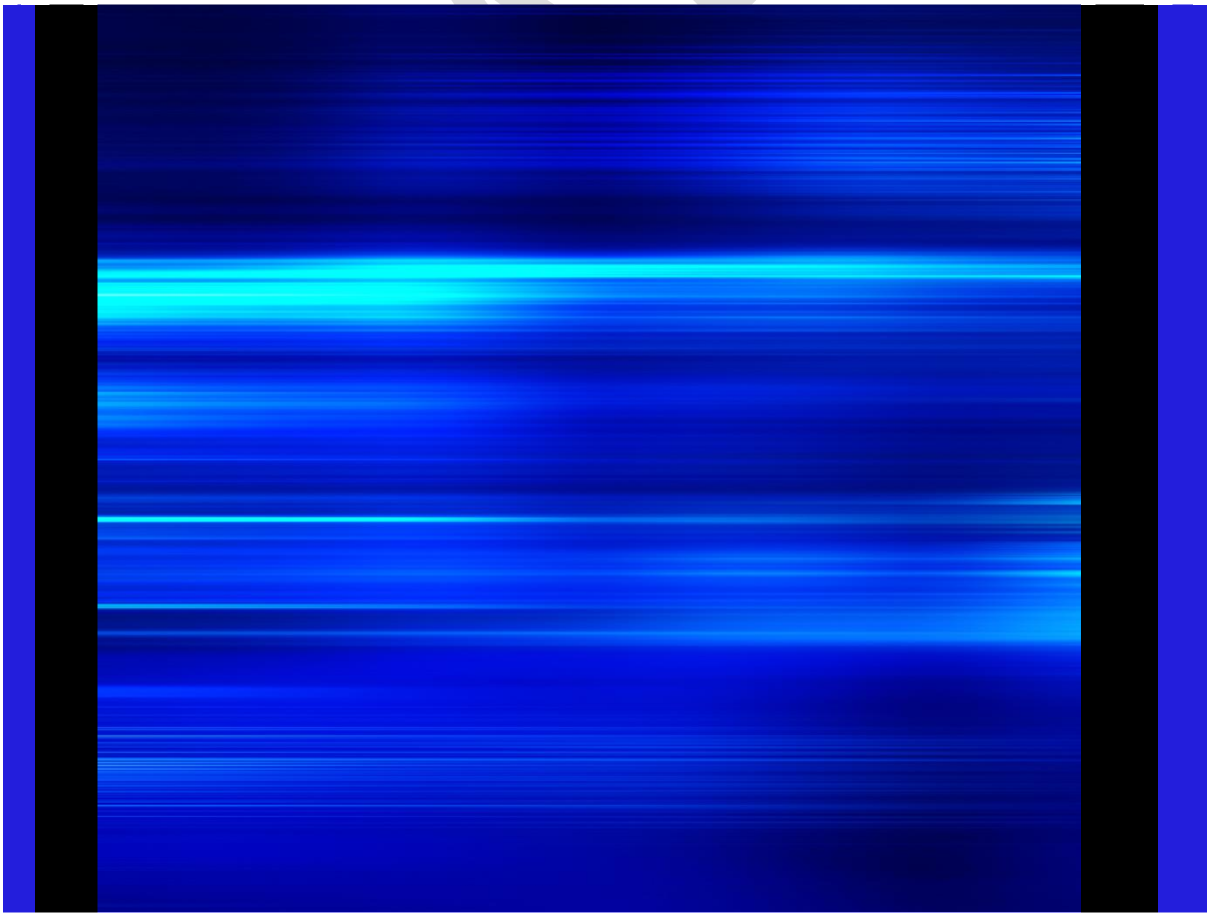
NZ BATTERY SDDP MODELLING
20 January 2023



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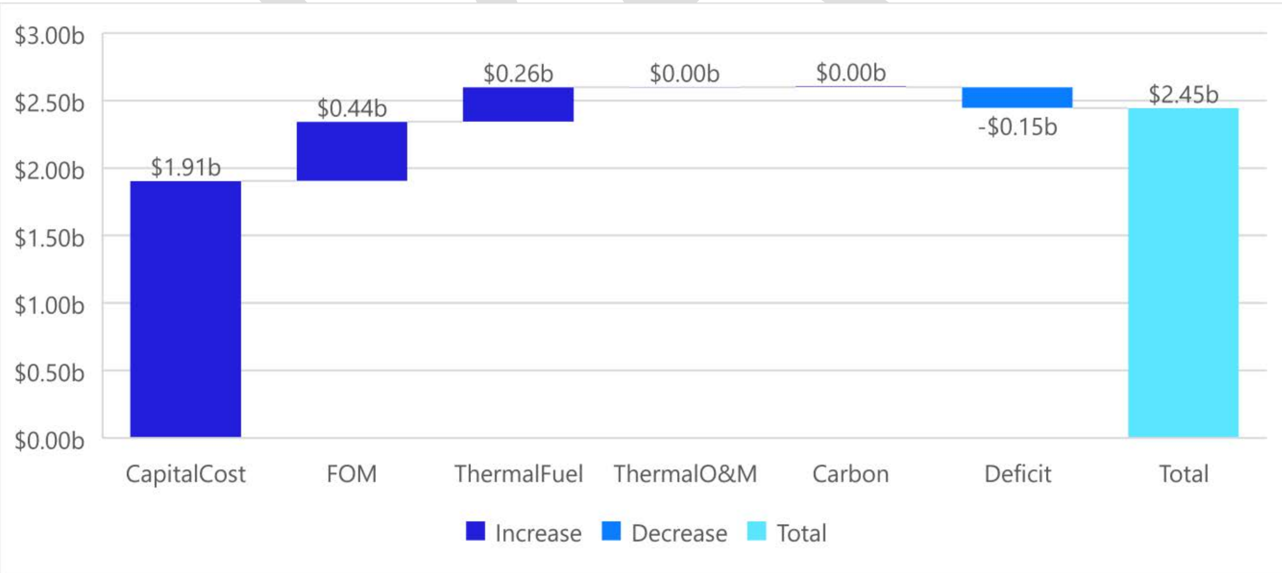
# Executive summary

Jacobs was engaged by the Ministry of Business, Innovation and Employment (MBIE), to perform electricity market modelling of options under consideration for the NZ Battery Project The focus of the study was to evaluate the gross benefit of approaches to 100% renewable electricity supply in New Zealand, and to investigate the impacts on electricity market operation and transmission implications. This executive summary presents a concise overview of our findings and recommendations.

The investigation of a hydro-dominated electricity market over long modeling horizons requires balancing accuracy, precision, and computational feasibility. The problem is further complicated by the presence of variable renewable energy sources, which tends to increase the importance of high time-resolution modelling. A Stochastic Dual Dynamic Programming (SDDP[1]) approach was taken for this investigation to simulate water dispatch policy in hydro-thermal electricity systems. The primary motivation behind SDDP is to estimate the value of storing water at a particular point in time as a function of reservoir levels in the system, considering trade-offs between immediate and future costs. The water value functions derived from SDDP were used in dispatch simulations to gain insights into least-cost electricity system dispatch. The OptGen model was used to derive a least-cost generation expansion plan considering hydrological uncertainty. By using a fundamental water value model – rather than a set of heuristics developed by observation of historical behaviour – we increase our confidence that the outcomes are robust to fundamental changes in the structure of supply and demand in the electricity market.

The impact of Lake Onslow on the market was simulated through two cases: the Factual scenario with Lake Onslow and the Counterfactual scenario without. The gross benefit[2] of Lake Onslow is calculated as the difference between the sum of all the fixed and operating costs of the Factual and the Counterfactual scenario. The total gross benefit over the calculation period (2035-2065) is estimated to be $2.45 billion in 2035 terms. Much of the benefit is due to reduced capital and fixed operating costs, with smaller impacts seen in thermal fuel cost and load curtailment cost. Representative years – 2040, 2050, and 2065 – were selected to showcase the expected gross benefit of Lake Onslow, showing that once Lake Onslow overcomes the initial 'filling of the reservoir' stage, the project will provide a consistent benefit to the system.

**Figure 1. Gross benefits of 5 TWh/1000 MW Lake Onslow pumped hydro energy storage (2035-2065)**




The transmission implications of Lake Onslow (LOPHES) were investigated and fed back to Transpower through an iterative process. Lake Onslow can best be thought of as a potential 1000 MW increase in South Island generation and a 1000 MW increase in South Island load. SDDP will attempt to operate LOPHES along

[1] In this report "SDDP" refers to the commercial implementation developed by PSR of the SDDP algorithm

[2] Net benefit of NZ Battery options is outside the scope of this report as the capital and operating costs of NZ Battery options was not available. Therefore, all benefits are present in 'gross' terms.

with other hydro storages to minimize total system costs. The operational mode of LOPHES in SDDP is different from a pure dry-year cover mode, as it often uses South Island capacity – including Onslow – to firm the largely North Island variable renewable energy (VRE). Initial results indicated several AC capacity upgrades that may be required to access the full benefit of LOPHES, including upgrades to the Roxburgh to Benmore, Bunnythorpe to Haywards, and Bunnythorpe to Wairakei corridors. In addition, the increase in the level and frequency of high northward and southward transfer on the HVDC link due to LOPHES increases the benefit of additional HVDC capacity. HVDC flow duration curves for 2035 and 2050 show that the utilization of the HVDC link in the Factual case reaching the northward and southward transfer limits more frequently than in the Counterfactual case.

The generation expansion plans produced by OptGen for the Factual and Counterfactual scenarios extend for the entirety of the modelling horizon (2022 – 2065). The plans are identical up until 2030, where Onslow is 'forced in' in the Factual scenario and 'forced out' in the Counterfactual. This divergence in the build schedule causes a multitude of difference between the two scenarios. Results show that the North Island wind capacity plateaus around the mid-2040s and slows down after reaching 5500 MW for both scenarios, while the South Island wind capacity is lower in the factual scenario due to LOPHES and increased HVDC southward flow capacity. Grid-scale solar becomes the primary new supply technology in the early 2040s and grows linearly until the end of the modeling period. The North Island shows almost identical grid-scale solar capacities in both scenarios, but the South Island has very little solar capacity built in the factual case for the same reasons as for wind. Overall, the total wind and grid-scale solar capacity is greater in the counterfactual case as expected.

The Factual case has significantly less battery capacity built than the Counterfactual, suggesting some cross-over in the roles of Onslow and grid-scale chemical batteries. This effect made up a significant share of the capital cost savings making up the gross benefits and is higher than expected.

The operation of the Lake Onslow was analyzed in terms of weekly available stored energy in each of the 89 historical inflows sequences that were modelled. The operation of Lake Onslow can be split into three phases: fill-up (2030 to 2035/2036), heavy cycling (2036 to 2050), and lighter cycling (2051-2065). The fill-up phase is driven by the fact that Lake Onslow starts the modelling horizon empty and must be 'filled-up' to be utilized later in the study. Interestingly, during the heavy cycling phase Onslow regularly reaches max capacity indicating that Onslow can and is utilizing the VRE in the system. During the preceding phase capacity utilization decreases, but prices remain the same indicating that system is stabilizing. An alert level of 250 GWh on Lake Onslow was imposed from 2035, which is a soft constraint meaning that SDDP will draw Lake Onslow below the alert level with a penalty. The operation of existing hydro storages like Lake Pukaki, Lake Taupo, and Manapouri were also analyzed and compared between the Factual and Counterfactual scenarios. The results show that the Counterfactual scenario tends to hold storage levels higher, especially in the autumn and winter, compared to the Factual scenario.

Lake Onslow reduces energy prices in the South Island and reduces price volatility in both Islands. It is noted that the price results from SDDP and other market models should be treated with caution as it assumes perfect competition and ignores real market dynamics such as contracts, portfolios, outages, and other factors that influence prices. Despite this, the SDDP price outcomes are still useful in illustrating the stress on the system, relative merit of supply options, and feasibility of build schedules. The North Island results show that relationship between prices in the two cases is not consistent over time and that the impact of Onslow on prices is not significant. By 2050, Lake Onslow stabilizes and reduces price volatility compared to the Factual. The South Island results show a marked difference with the Onslow case returning prices consistently $10 or more lower than the No Onslow case. This is due to Onslow effectively removing the risk of load curtailment, leading to lower average prices and decreased volatility.

Lake Onslow has an impact on load curtailment, but it is not necessarily expected to always result in less load curtailment compared to the Counterfactual due to different supply expansion. The Factual has less energy supply and peaking capacity, which could sometimes result in more load curtailment. The impact of Lake Onslow on load curtailment changes over time, with the highest difference in 2035 where the Factual has close to twice the load curtailment as the Counterfactual. By 2050-2065, average load curtailment is similar across both cases, but there are more sequences where the Counterfactual has higher levels of load curtailment.

Simulations undertaken with hourly resolution allowed for the analysis of "Dunkelfaute" events. These are periods where little to no energy can be generated from either wind or solar generators for up to several days. Due to the nature of these events, we must look at specific times in the modelling horizon for a specific hydro sequence. Several “Dunkelfaute” events were analyzed showing that the Factual had lower load curtailment in most cases as Lake Onslow acted as additional storage. However, if SDDP ran the Onslow reservoir to empty, the Factual case could result in high load curtailment than the Counterfactual due to the lower supply capacity built. While the Counterfactual had to use the next tranche of load curtailment as soon as the event begins.

This report summarizes the progress made so far and serves as an interim report. The final report will be produced at the conclusion of the investigation. In the next phase of work, the team will review the results of the "dunkelflaute" with adjustments OptGen configuration and investigate additional NZ Battery options and sensitivities. The team has collaborated with the developers of OptGen and SDDP to enhance the implementation and understanding of the interactions between OptGen and SDDP, especially with regards to hourly simulations. Before finalizing the outcomes of the Factual and Counterfactual, the team wants to verify that any changes to the OptGen and/or SDDP configuration, based on recent developments and advice, will not affect the outcomes. Additionally, the team will model the sensitivities for varied sizes for Lake Onslow, develop a method for modeling long-term commitments in SDDP for use with flexible geothermal plants in the portfolio option, model the portfolio option, and model a sensitivity case where Tiwai stays.

# Contents

## Appendices



## Tables



## Figures

# Acronyms and abbreviations

*Delete section if not required. Delete by going to Jacobs Tab and select Sections > Delete Section from the Insert group.*

| | |
|---|---|
| SDDP | Stochastic Dual Dynamic Programming |
| VRE | Variable Renewable Energy |
| NZGP | Net-Zero Grid Pathways |
| LOPHES | Lake Onslow Pumped Hydro Energy Storage |

# 1. Introduction

Jacobs was engaged by the Ministry of Business, Innovation and Employment (MBIE), to perform electricity market modelling of options under consideration for the NZ Battery Project The focus of the study was to evaluate the gross benefit of approaches to 100% renewable electricity supply in New Zealand, and to investigate impacts on electricity market operation and transmission implications. This executive summary presents a concise overview of our findings and recommendations.

## 1.1 NZ Battery Project

The NZ Battery Project is investigating approaches to enable a 100% renewable electricity system in New Zealand. The project is considering several centralized approaches to providing 'dry-year' security in a world without a large stockpile of fossil thermal fuel, including large pumped hydro energy storage, green peaking plant, large-scale flexible load, and overbuilding renewables.

## 1.2 Motivation for this analysis

The modelling undertaken for this report sits alongside the primary modelling developed by John Culy. The motivations for operating parallel models were:

- Corroborate John Culy's modelling results with a model that develops water dispatch policies from first principles rather than based upon observation of past behaviour
- Investigate the transmission system implications of commissioning a large pumped hydro energy storage scheme at Lake Onslow
- Provide insights on other operational or market issues that might not be highlighted by the Culy model

## 1.3 Key contributors

We would like to thank the important contributions of Tom Halliburton for expert support with SDDP and Jen Purdie for providing advice on the impact of climate change on hydro and wind energy inflows.

# 2. Factual and Counterfactual

This section describes the cases treated as the Factual and the Counterfactual for the purposes of this investigation.

Unless otherwise stated, starting assumptions in the Factual and Counterfactual cases are identical.

## 2.1 Factual

The Factual case presented in this report assumes that a 1000 MW, 5 TWh pumped hydro energy storage scheme is commissioned at Lake Onslow in 2030. The scheme is commissioned empty and must pump water from the Clutha River in order to store energy for generation at a later time.

## 2.2 Counterfactual

The Counterfactual case presented in this report does not include the pumped hydro energy storage scheme at Lake Onslow or any other NZ Battery approach. The generation expansion model is allowed to find a least cost expansion plan through a combination of VRE 'overbuild', green peaking plant and batteries.

# 3. Modelling Approach

This section details the modelling approach taken for this investigation and the motivation for those choices. The section is separated into three sub-sections based on the structure of the problem decomposition chosen:

- Generation expansion
- Water policy simulation
- Dispatch simulation

Simulating an electricity market over long modelling horizons requires many trade-offs between accuracy, precision, and computational tractability.

This complexity increases further when variable renewable energy (VRE) sources and hydrological uncertainty play a significant role in the problem.

We have therefore taken the highest resolution approach available to us unless it seemed computational unreasonable to do so. The details of those choices are outlined in the following subsections

## 3.1 Stochastic Dual Dynamic Programming (SDDP)

SDDP is a family of algorithms often used for creating water dispatch policy in hydro-thermal electricity systems. [3]

The primary motivation of SDDP is to develop a set of "water value functions" that can be used to estimate the value of storing water at a particular point in time as a function only of the reservoir levels in the system. In doing so, SDDP considers optimal trade-offs between minimizing the immediate costs (by reducing thermal fuel consumption and deficit) and minimizing the future costs (by keeping lake-levels high to reduce future fuel costs and deficit costs). These water value functions can then be used in dispatch simulations to glean a broad arrange of insights related to least-cost electricity system dispatch.

The benefit of using a model, such as SDDP, that dynamically models the dispatch policy of hydro generators is that it considers a significant complicating feature of electricity systems with a material amount of storage available; that the value of that storage increases as the storage decreases in a way that depends on the:

- **Expected future loads:** expected higher load periods will tend to increase water values as the benefit of conserving water to avoid dispatch of more expensive generation or deficit increases
- **Expected future inflows:** if upcoming inflows are expected to be low due to seasonal variation, water values will tend to increase as the opportunity to re-fill the reservoirs is expected to be limited
- **Other plant available on the system:** water values increase as the risk of needing to dispatch expensive generation and/or shed load increase. So, if there is insufficient energy margin to cover low inflows or extended periods with limit wind or solar generation, water values will increase.
- **Cost of load curtailment**

Given the number of dimensions that influence hydro dispatch decisions, it is difficult to be confident that approaches that model hydro dispatch behaviour with fixed exogenous factors are producing robust results – particularly if the future electricity system being modelling is materially different to the current system. Alternative approaches range from treating hydro as free and allowing it to be dispatched at least cost with regular reservoir levels targets to dispatch hydro with a fixed offer stack similar to how a thermal might be offered, to deriving water value functions as an input to the model based on observations of historical hydro dispatch behaviour.

These alternative approaches all have potential shortcomings that might be considered reasonable trade-off between robustness and computational complexity, depending on the nature of the analysis. In the case of the NZ Battery work, the primary market modelling approach includes a set of water value functions that were developed based on observations of historical hydro dispatch behaviour. This approach allows the model to short-cut the most computationally intensive element of SDDP, developing waster value functions, and focus

[3] "SDDP" is the commonly used abbreviation for the family of algorithms known as "stochastic dual dynamic programming" and a commercial software package developed by PSR in Brazil that uses the algorithm for hydro-thermal dispatch optimisation. Other than in section 3.1, reference to "SDDP" in this report refer to the commercial package.

on simulation dispatch and reaching a market equilibrium of new capacity on the assumption that the water value functions are robust.

## 3.2 Generation expansion

We have used PSR's OptGen[4] model to derive a least-cost generation expansion plan given hydrological uncertainty. OptGen, as configured for this investigation, decomposes the investment problem and the operational problem in separate components and uses SDDP to iteratively develop an accurate estimate of operating costs for the investment problem. In taking this approach, OptGen builds a least cost generation expansion plan that is robust to hydrological uncertainty.

An alternative configuration of OptGen was tested in the early stages of this investigation but was found to be unfit for our purposes. The alternative approach integrates the investment and operational optimization into one problem, removing SDDP from the approach. In integrate the investment and operational problems and removing SDDP, this alternative approach reduced the hydro uncertainty and the uncertainty of variable renewable generation considered in the build schedule. The resulting generation expansion plans result in unrealistically high time-weighted and generation-weighted average prices in the simulation phase.

OptGen was configured to build generation expansion plans from 2022 to 2065 using rolling horizons of 2-3- years to improve solution quality and reduce the impact of perfect foresight. For the purposes of OptGen, SDDP was configured using 25 synthetic hydro sequences[5] in order improve solution time.

## 3.3 Water policy estimation

The 'optimisation' step of SDDP develops an estimation of an optimal set of water value policies. We configured the optimization step as follows:

- 89 historical inflow sequences
- 3 year rolling horizons with 2 additional years modelled for each horizon to reduce end-effects
- 6 % p.a. real post-tax discount rate
- 52 weekly stages per year with aggregated load-blocks
- Two node model (HVDC only network element modelled)

## 3.4 Dispatch simulation

The simulation step in SDDP uses the policy developed in the optimisation stage to inform a higher resolution simulation. The simulation step was configured as follows:

- 89 historical inflows sequences
- 52 weekly stages per year with 21 chronological load blocks for load block cases and 168 hours per week for hourly cases
- Lossy HVDC and lossless AC network with security-constrained dispatch for network investigations
- Two-node model only for other investigations

[4] https://www.psr-inc.com/softwares-en/?current=p4040

[5] We are investigating the impact of this approach in the next round of modelling.

# 4. Assumptions

All assumptions about the future state of the New Zealand energy system are derived from the NZ Battery assumptions book. This section outlines those assumptions.

## 4.1 Demand

**Figure 2 New Zealand annual electricity demand per island**

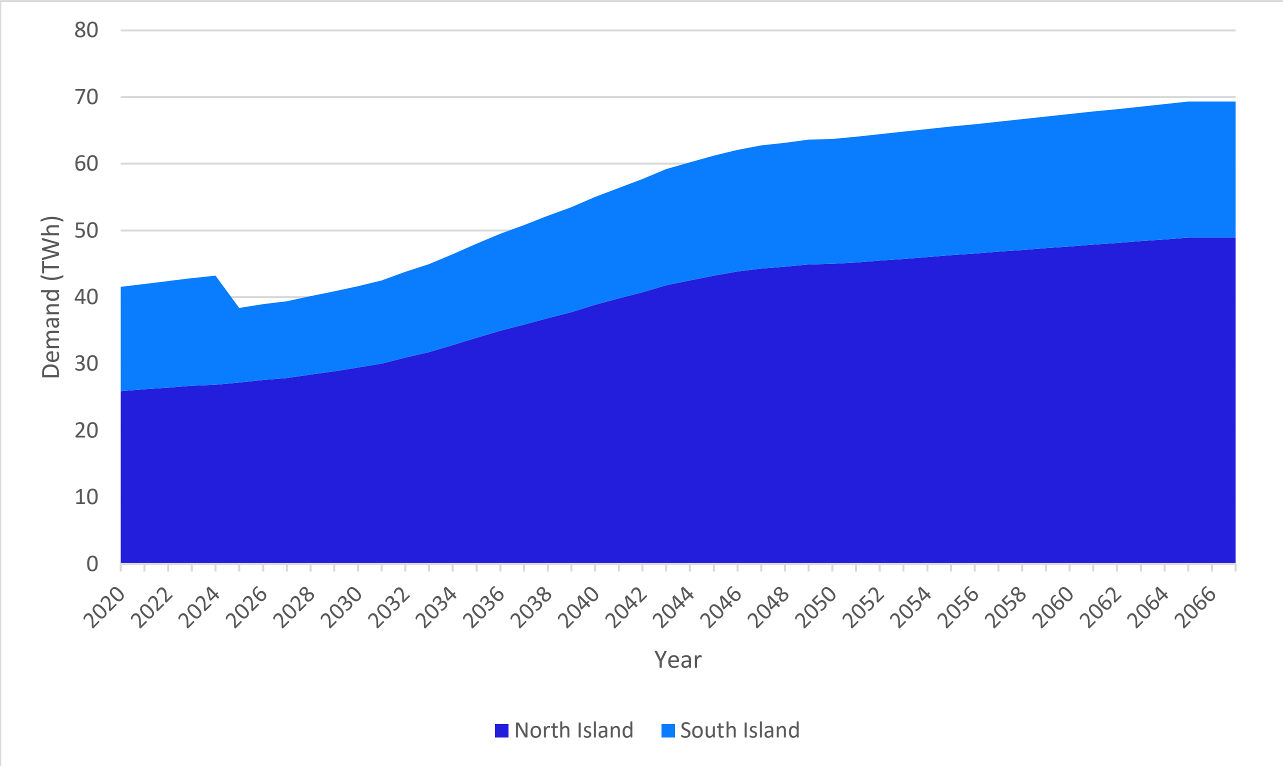
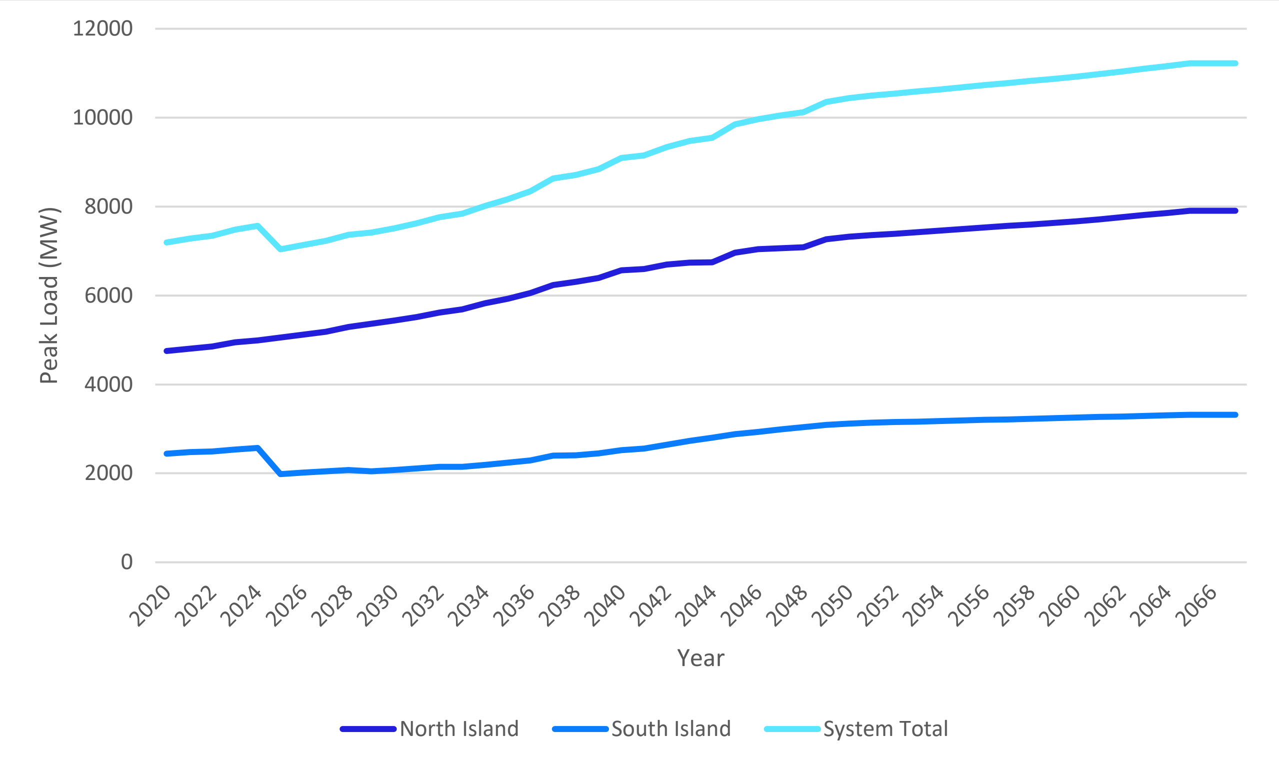


**Figure 3 Annual peak electrical load per island & system wide**




### 4.1.1 Tiwai Point aluminium smelter

We assume that the Tiwai Point aluminium smelter retires at the end of 2024, resulting in a reduction in baseload South Island demand of approximately 600 MW.

## 4.2 Generation build stack & Fixed and variable operating costs

**Table 1. Available capacity, FOM, and VOM for build by technology and island**

| Technology | North Island Capacity | South Island Capacity | Total Per Technology | FOM ($/kW) | VOM ($/kW) |
|---|---|---|---|---|---|
| Battery | 3120 | 1200 | 4320 | 10 | 0 |
| Green Peaker | 2560 | - | 2560 | 4.6 | 11.4 |
| Geothermal | 1010 | - | 1010 | 189 | 2 |
| Solar | 4120.8 | 3860 | 7980.8 | 29 | 0 |
| Wind | 9618.5 | 3127.4 | 12745.9 | 46 | 0 |
| Grand Total | 20829.3 | 8187.4 | 29016.7 | - | - |

## 4.3 Retirements of Plants and repowering of existing wind farms

Table 2 below shows the thermal retirement assumptions used in the Factual and the Counterfactual cases.

**Table 2. Retirement of exiting plant**

| Generator | PoC | Technology | Capacity | Retirement Date |
|---|---|---|---|---|
| TeRapa | TWH220 | Gas | 44 | 1/1/2024 |
| TaranCC | SFD220 | Gas | 380 | 1/1/2025 |
| HuntC1 | HLY220 | Coal | 250 | 1/1/2025 |
| HuntC2 | HLY220 | Coal | 250 | 1/1/2025 |
| HuntC4 | HLY220 | Coal | 211 | 1/1/2025 |
| Whirina | WHI220 | Diesel | 155 | 1/1/2029 |
| McKee | MKE110 | Gas | 100 | 1/1/2033 |
| Edgcmb | EDG220 | Gas | 10 | 1/1/2033 |
| P40 | HLY220 | Gas | 50 | 1/1/2035 |
| E3p | HLY220 | Gas | 403 | 1/1/2035 |
| SFDOCGT | SFD220 | Gas | 200 | 1/1/2035 |
| JnctnRd | JRD110 | Gas | 100 | 1/1/2035 |
| BRBPkr | BRB220 | Diesel | 9 | 1/1/2035 |

Table 3, below, shows the assumptions used in the Factual and the Counterfactual regarding the repowering of existing wind farms.

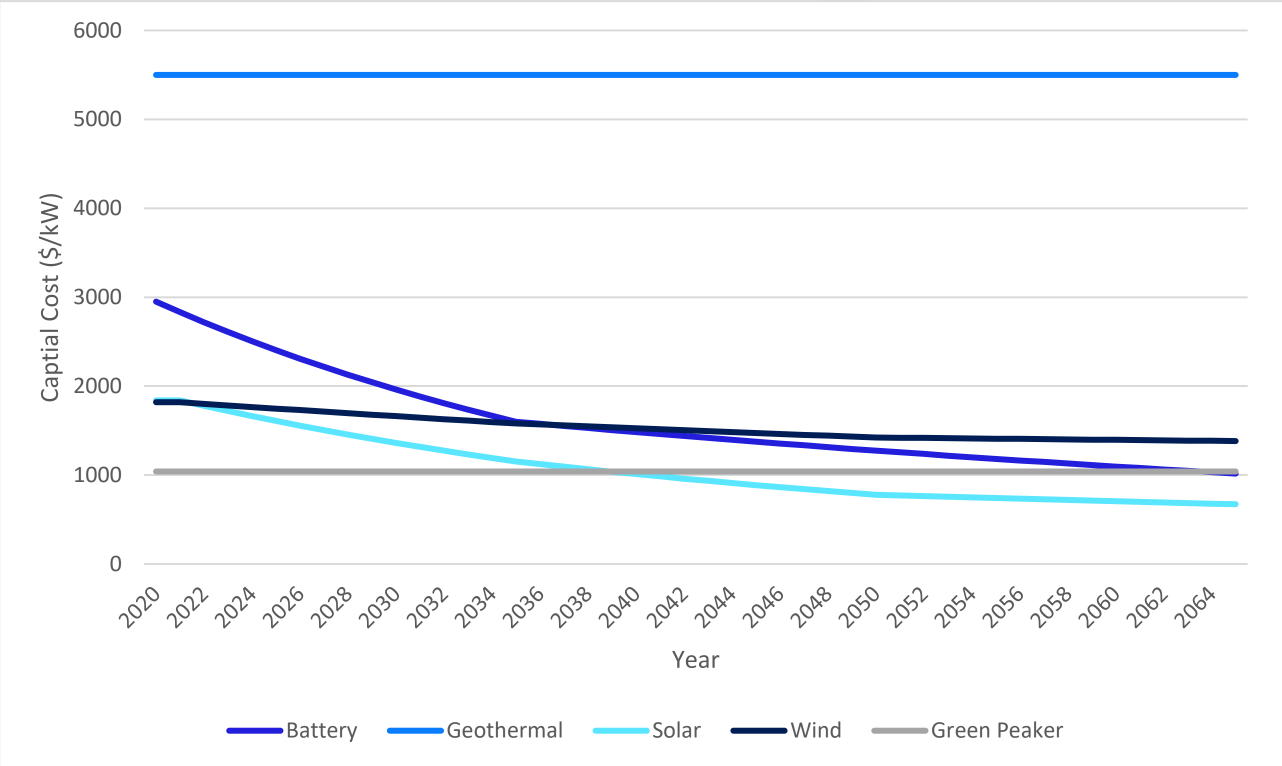
**Table 3. Repowering of existing wind farms**

| Generator | PoC | Technology | Old Capacity | New Capacity | Repowering Date |
|---|---|---|---|---|---|
| Mahiner_s1 | HWB220 | Wind | 36 | 50 | 1/1/2041 |
| WhiteHill | NMA220 | Wind | 58 | 115 | 1/1/2037 |
| MillCreek | WIL220 | Wind | 60 | 105 | 1/1/2044 |
| TaraW1 | BPE220 | Wind | 34.3 | 100.8 | 1/1/2029 |
| TaraW2 | LTN220 | Wind | 33.7 | 140 | 1/1/2034 |
| TaraWd3 | TWC220 | Wind | 93 | 125 | 1/1/2037 |
| TeApiti | WDV110 | Wind | 90.8 | 220 | 1/1/2034 |
| TeRereHau | TWC220 | Wind | 16.5 | 82 | 1/1/2041 |
| TeRereHau3 | TWC220 | Wind | 16 | 82 | 1/1/2041 |
| TeRereHau4 | TWC220 | Wind | 16 | 81 | 1/1/2041 |

| Generator | PoC | Technology | Old Capacity | New Capacity | Repowering Date |
|---|---|---|---|---|---|
| TeUku | TWH220 | Wind | 64.4 | 110 | 1/1/2041 |
| WestWind | WIL220 | Wind | 142.6 | 250 | 1/1/2039 |

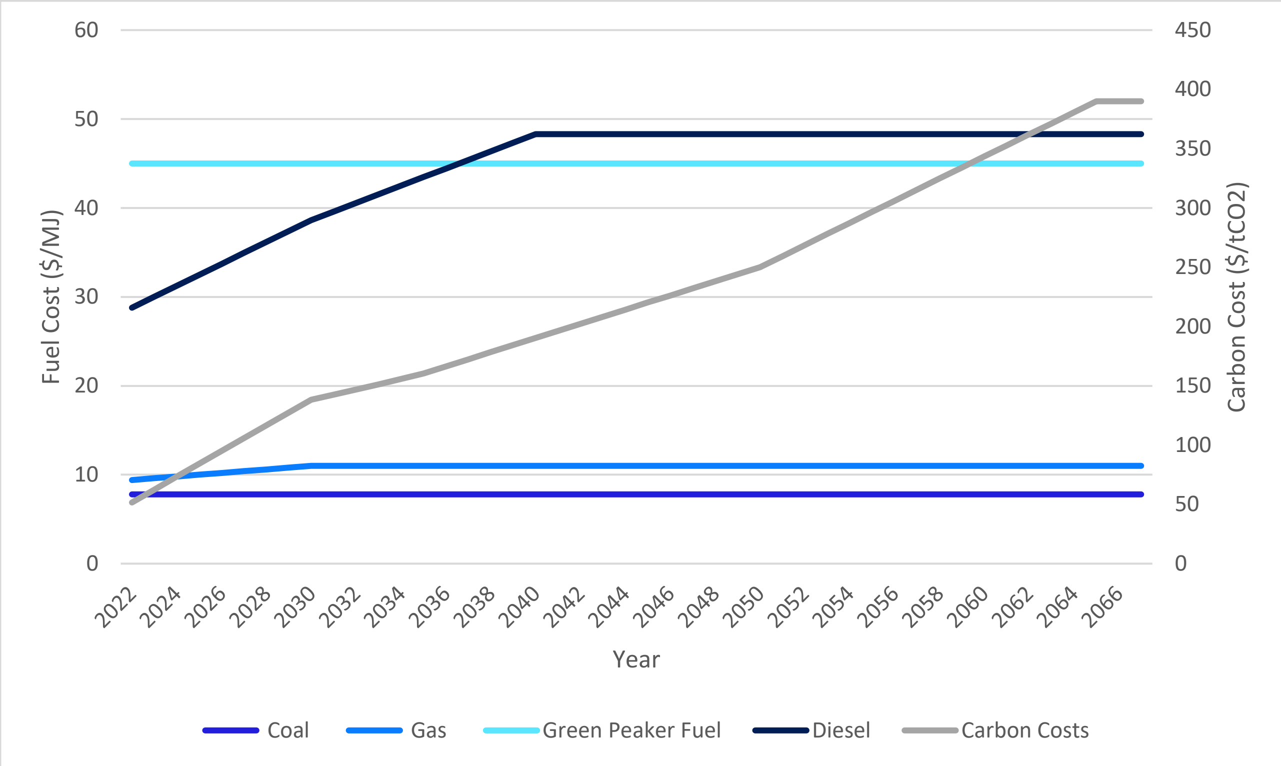
## 4.4 Capital costs

**Figure 4. Capital costs per technology**



## 4.5 Fuel and carbon costs

**Figure 5. Fuel costs per technology and carbon costs**





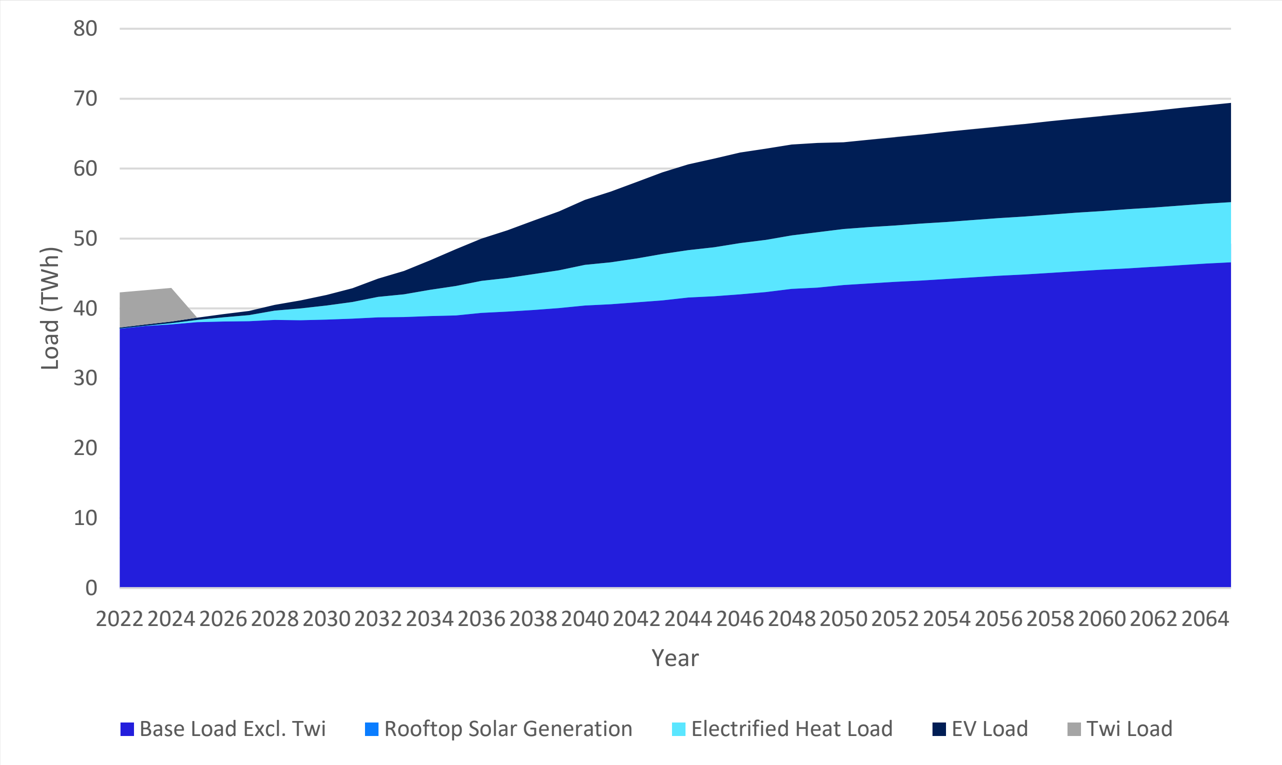

## 4.6 Carbon capture of geothermal emissions

We have assumed that 50% of the geothermal build stack is able to capture 100% of their emissions, i.e., that half of the capacity of new geothermal plant in each tranche of emissions intensity can be built with a zero emissions factor at no additional capital cost premium.

## 4.7 Rooftop solar & Distributed storage

The NZ battery needed a long-term demand forecast for the purposes of our study. The team started with Transpower's 'Accelerated Electrification' forecast which ran from 2019 – 2050 and was split into Base Load including Twi, Rooftop Solar Generation, Electrified Heat Load, and EV Load. Since Twi is included in the base load throughout the horizon and we assume that Twi retires at the end of 2024 the team started by extracting Twi load from the baseline load and separating it into its own category. Enabling the team to retire it at the end of 2024. Following that the team matched the distinct types of load to John Culy's load forecast, but due to the nature of Culy's modelling we only have three values for the years of 2035, 2050, and 2065. To organically align these forecasts, the team decided to compute a linear 'application factor' for the scaling necessary in-between the yearly values e.g., 2022 – 2034. This method of scaling individual load types in a linear fashion ensured that we captured both the correct trends from the Transpower forecast and the correct magnitude from John Culy's forecast. And the summation of these load element allows us to compute net system wide load.

**Figure 6. New Zealand demand forecast split by load components**




## 4.8 Transmission network

Our starting point for the future state of the AC and DC networks was the post-2030 state indicated by Transpower's NZGP phase one investigations. At this stage of the investigation, stage one NZGP is expected to include:

- Clutha and Upper Waitaki Lines Project (CUWLP): This work is now complete but include for completeness
- Brownhill-Whakamaru: 45% series compensation
- Brownhill-Pakuranga cable operating unconstrained
- Tokaanu-Whakamaru line duplexed with Goat at 120 C
- Bunnythorpe-Tokaanu line duplexed with Goat at 120 C
- Huntly Stratford circuit protection upgrade to increase capacity
- Tokaanu intertrip Special Protection Scheme Disabled
- Ongarue circuit breaker #92 open to create 110 kV system split in the Central North Island
- Te Mihi-Wairakei thermal upgrade to 100 C
- Te Mihi-Whakamaru thermal upgrade to 100 C
- Whakamaru-Wairakei thermal upgrade to 100 C
- Ohakuri-Wairakei thermal upgrade to 120 C
- Atiamuri-Ohakuri thermal upgrade to 120 C
- Atiamuri-Whakamaru thermal upgrade to 120
- New 62.5 MVA Edgecumbe interconnector
- New Bombay 220 kV bus between Drury and Huntly
- Arapuni-Bombay 110 kV circuits removed
- Additional 110 kV splits: Ongarue-Rangitoto, Mangamaire-Masterton, Edgecumbe-Kawerau 1&2. Glenavy-Studholme-2

## 4.9 Impact of climate change

Given the long-term nature of the NZ Battery team's modelling horizon, we must take into account both short-term and long-term effects that may arise. One crucial factor to consider is climate change, which may impact the availability of variable renewable energy (VRE) sources such as wind and hydro energy. To better understand the potential effects of climate change, we consulted Jen Purdie, a climate expert from Otago University. Her insights informed our assessment of the potential changes in VRE availability that we expect to see by 2050.

To apply these projections across our entire modelling horizon (spanning 2022-2065), we have introduced an "application factor." This factor starts at 0 in 2022 and increases linearly to 1 in 2050, after which it remains constant for the remainder of the horizon. The application factor is used to scale the projected changes in VRE availability, recognizing that the impact of climate change on these sources will likely occur gradually over time rather than instantaneously.

**Figure 7. Change Factors for Wind Traces per Region**

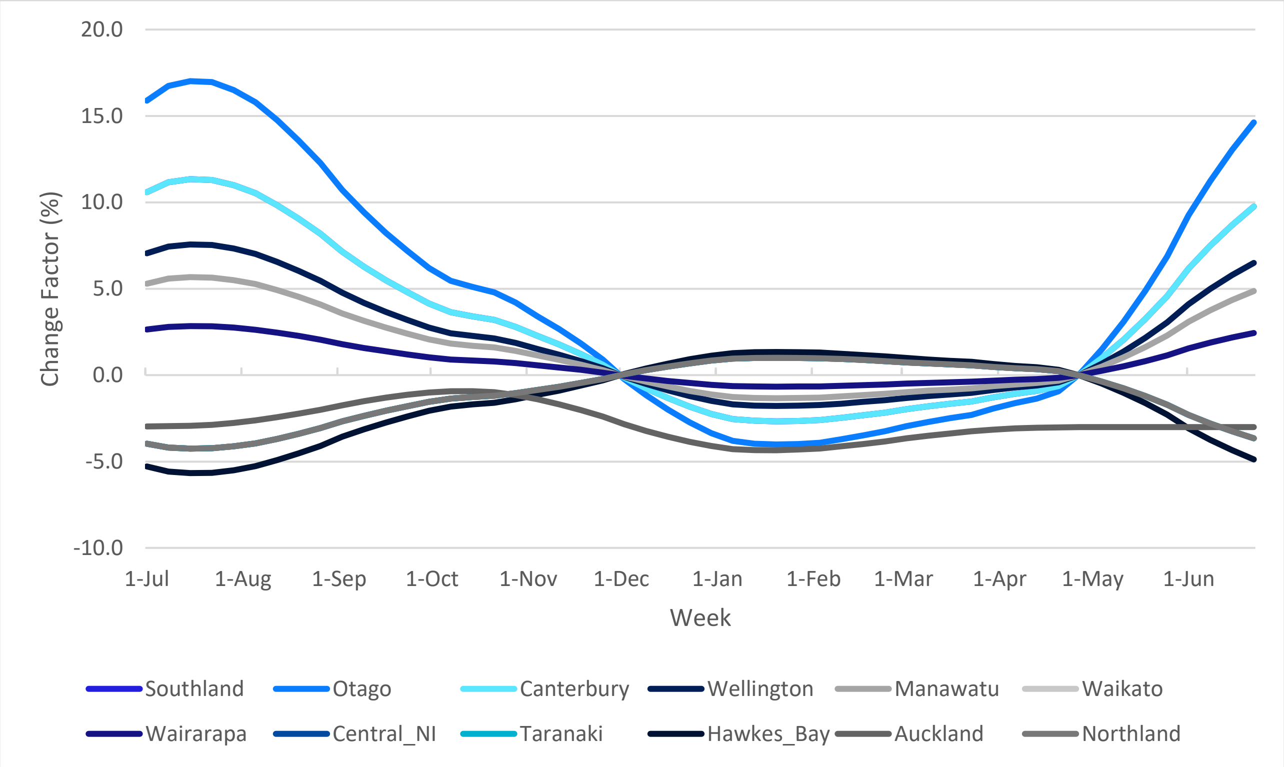
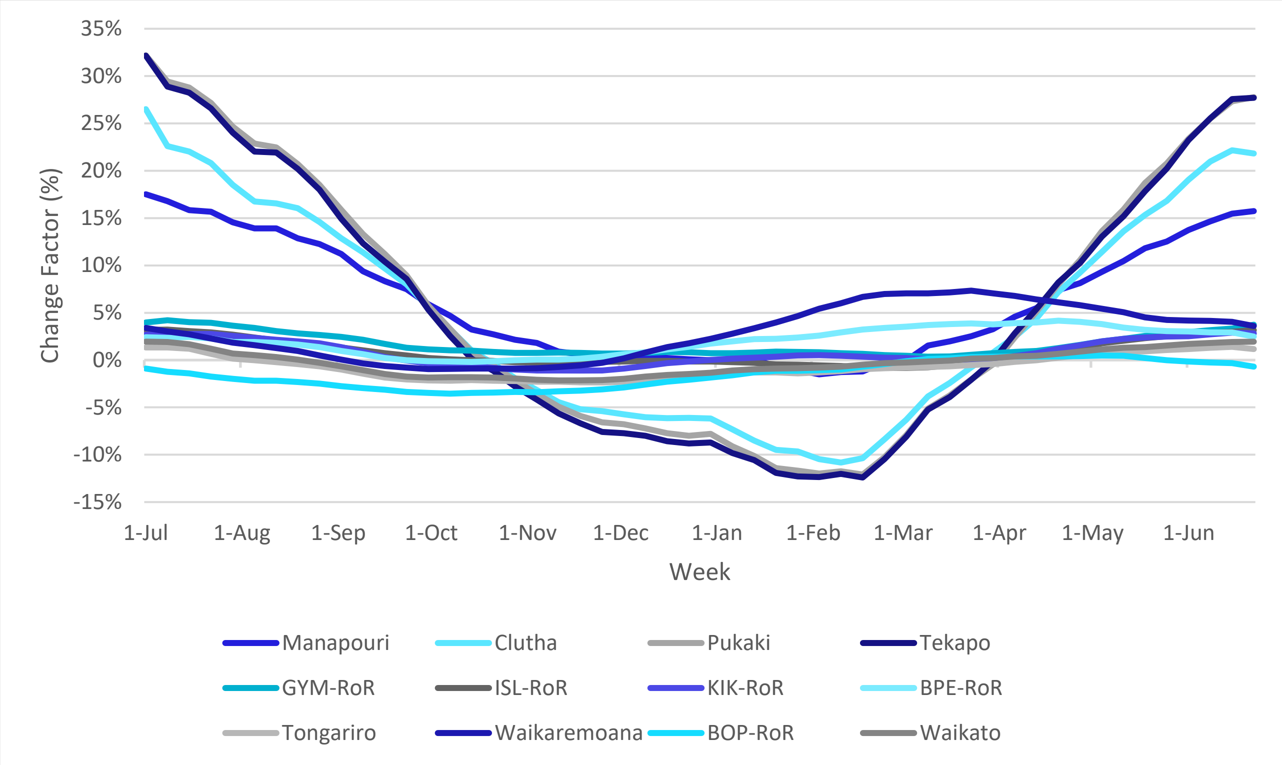


**Figure 8. Change Factors for Hydro Inflow Traces per Region**



# 5. Observations

This section presents the outcomes observed in the modelling results. Unless stated others, all results are presented as averaged across 89 simulations beginning in 2028 and ending in 2065, with each simulation using a different historical inflow sequence.

## 5.1 Gross benefit of Lake Onslow Pumped Hydro

Gross benefit is the key market modelling measure of the value that pumped hydro energy storage (PHES) provides to the system. Gross benefit is calculated as the difference between the sum of all the fixed and operating costs of the Factual and the Counterfactual. All values are presented in real 2022 terms. Note that gross benefit does not include any capital cost associated with the Lake Onslow scheme itself, which will be captured in the NZ Battery Project's *net* benefit calculation.

Figure 9 shows the present value – in 2035 – for the gross benefit. Gross benefits are broken into several categories, with approximately 90% of the benefit being the result of reduced capital and fixed operating costs in the Factual case. Smaller impacts are seen in the thermal fuel cost and load curtailment cost (deficit). The total gross benefit of the calculation period is 2.45 billion dollars.

We observe that the Factual doesn't necessary reduce the cost of load curtailment, which could be unexpected. Load curtailment costs are relatively volatile of the modelling period – with some years favouring the Factual and other years the Counterfactual. This suggests that there is a fine balance between the cost of last unit of supply built and the level of load curtailment. For example, a small amount of additional supply in the Factual would reduce load curtailment but come at a capital cost very similar to the cost of load curtailment avoided. In particular, the Factual builds less peaking capacity – green peakers and batteries – in the North Island, meaning that during extreme dry, calm, cloudy periods there is less reserve generation available that is local to North Island load.

**Figure 9. Present value gross benefit (2035-2065) – 2035 dollars**

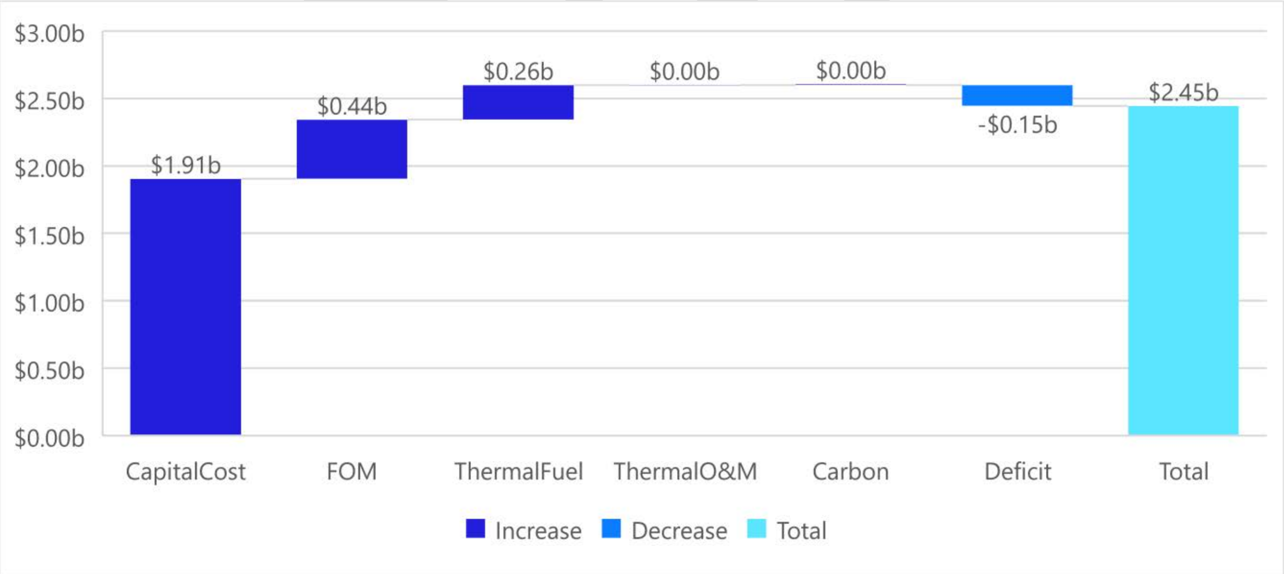



Figure 10 shows the gross benefit for the modelled year 2040 averaged over all hydro sequences. The capital costs include the annualized capital costs of all new supply – other than the Onslow scheme itself between the beginning of the modelling horizon and 2040. All other costs are the costs incurred during the 2040 modelled year.

We have chosen 2040 as a representative year rather than 2035 to aid comparisons with John Culy's results. The chronological modelling capability afforded by OptGen and SDDP, allowed us to model the 'filling up' phase of Lake Onslow as we are modelling the evolution of the electricity system over time. As a result, it takes some time for the SDDP results to reach a stable 'system normal' operation pattern. This provides additional insight into the impact that Lake Onslow will have on the system early on in the modelling horizon.

This aspect of project was out of scope John Culy's model, instead focusing on the stability of the market. Meaning that we had to offset the comparison years to best align our results.

The shape of the of 2040 waterfall graph is similar to the 2035-2065 graph above, with the exception of there being a positive benefit in the deficit category.

**Figure 10. Annual gross benefit 2040**

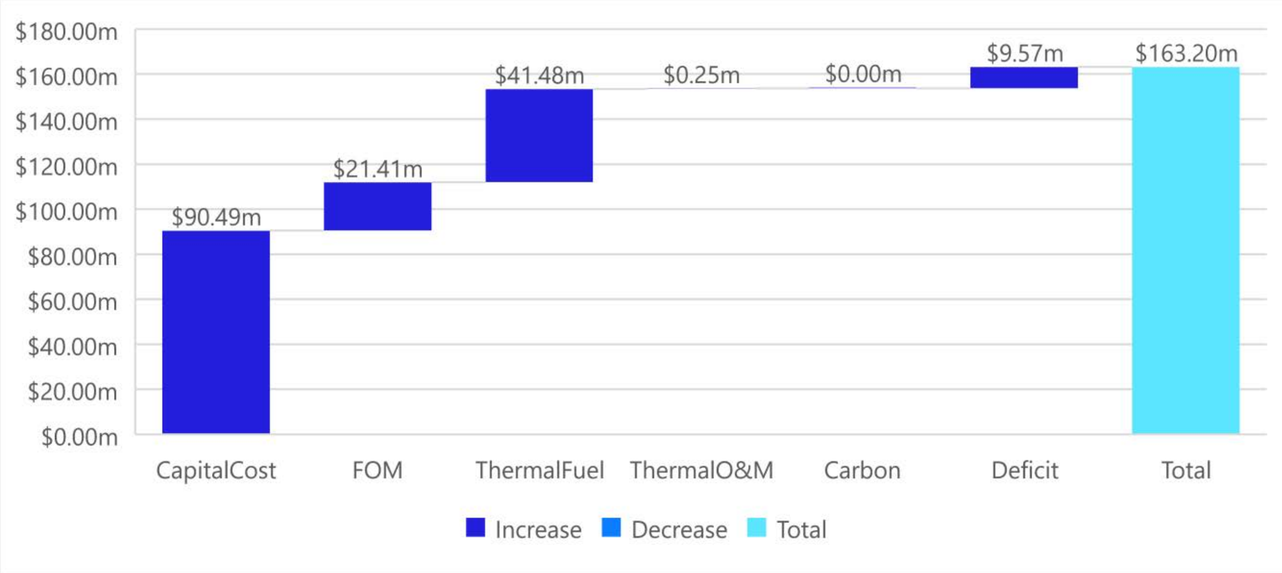


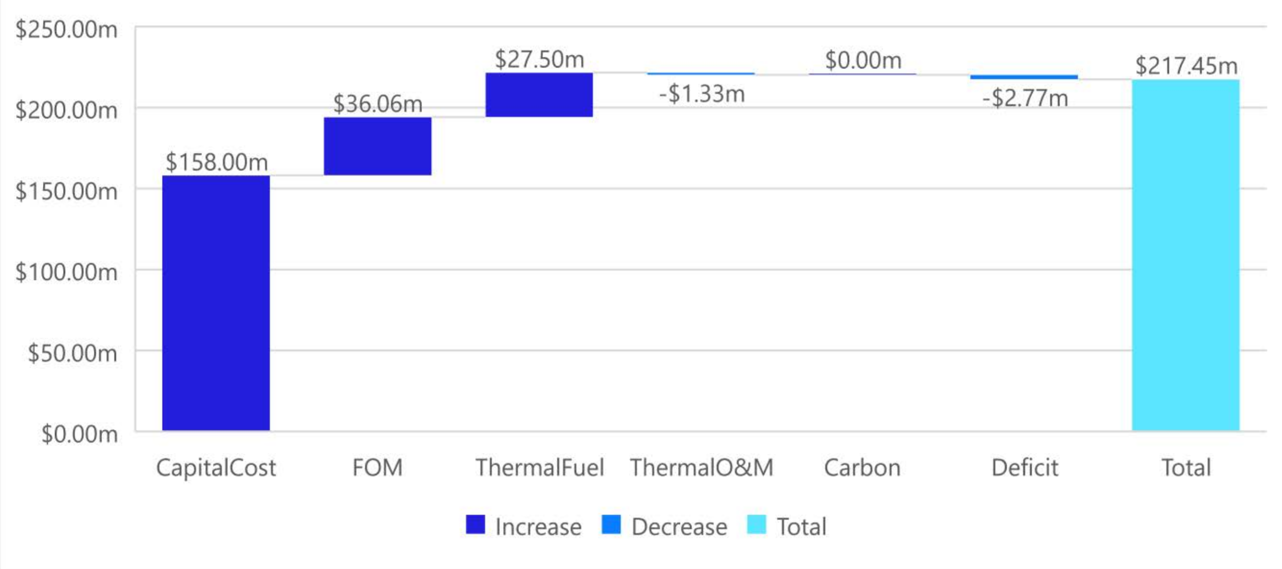

Figure 11 shows the gross benefit for the modelled year 2050 averaged over all hydro sequences. The capital costs include the annualized capital costs of all new supply – other than the Onslow scheme itself between the beginning of the modelling horizon and 2040. All other costs are the costs incurred during the 2040 modelled year.

Again, the shape of the gross benefit. in 2050 is similar to the 2035-2065 gross benefit.

**Figure 11. Annual gross benefit 2050**


Figure 12 shows the gross benefit for the modelled year 2060 averaged over all hydro sequences. The capital costs include the annualized capital costs of all new supply – other than the Onslow scheme itself between the beginning of the modelling horizon and 2060. All other costs are the costs incurred during the 2040 modelled year.

**Figure 12. Annual gross benefit - 2065**




## 5.2 Transmission implications

This section discusses the transmission implications of a 1000 MW generator and pump in injecting into a new connection point near Roxburgh.

LOPHES presents a potential 1000 MW increase in South Island generation and a 1000 MW increase in South Island load. SDDP will attempt to operate LOPHES – in combination with other hydro storages – to minimize total system costs. Therefore, it will use LOPHES for 'dry-year' cover as well as firming VRE in the North Island and the South Island. As a result, SDDP is not simply stepping in to replace existing hydro capacity when lake levels are low but can operate simultaneously with them to firm VRE. This operation mode presents a very different transmission need – using South Island capacity to firm largely North Island VRE – than a pure dry-year cover mode – using South Island hydro to firm other South Island hydro.

We have found that the Factual utilizes the AC and DC networks much more than the Counterfactual and is constrained from optimal operation by network capacity – even after Transpower's proposed Net-Zero Grid Pathways (NZGP) investments are completed.

### 5.2.1 Thermal overloads in AC interconnected network with LOPHES in service

Our initial results indicated several AC interconnection upgrades that are likely to be required in addition to the enhancements assumed as a result of Transpower's NZGP investigations (see section 4.8) if LOPHES is commissioned. LOPHES presents a potential 1000 MW generator and a 1000 MW load.

The three corridors requiring additional thermal capacity were:

- Roxburgh to Benmore:
  - Issue: we found that that Northward transfer was constrained by thermal security constraints even after the CUWLP upgrades were included.
  - Assumed solution: New Onslow to Benmore 220 kV double-circuit line plus duplexing Aviemore-Benmore
- Bunnythorpe to Haywards:
  - Issue: one Bunnythorpe to Haywards circuit would thermally overload following an outage on the other Bunnythrope to Haywards circuit during high northward or southward flow
  - Assumed solution: duplex Bunnythorpe-Haywards 1&2
- Bunnythorpe to Wairakei:
  - Issue: Bunnythorpe to Tangiwai would thermally overload following an outage on another central North Island circuit (for example Tokaanu-Whakamaru) for high northward flow
  - Assumed solution: duplex Bunnythorpe-Tangiwai, Tangiwai-Rangipo and Rangipo-Wairakei.

### 5.2.2 Thermal limits of HVDC link with LOPHES in service

LOPHES increases extremes of northward and southward flows on the HVDC link and – as a result – increases the value of additional HVDC capacity. By providing 1000 MW of South Island generation capacity and 1000 MW load sink for VRE, LOPHES increases transmission loading between the Otago and load centres (when generating) and VRE resources (when pumping). LOPHES is able to absorb excess North Island VRE when North Island local load is low to the extent that the transmission network can transport the energy.

Southward flow on the HVDC link is limited by AC network constraints rather than the limits to the HVDC equipment or the cables themselves. Early results showed significant benefit in relatively small increases to southward capacity.

The NZ Battery team assumes that the combination of duplexing Bunnythorpe-Haywards and additional dynamic reactive plant at Haywards could increase southward flow limit to 1300 MW. Therefore, subsequent modelling for the Factual case used 1300 MW as the southward flow limit rather than 950 MW as assumed in the Counterfactual.

### 5.2.3 HVDC cable

This section presents three HVDC flow duration curves for one year in the Factual and Counterfactual cases. Each graph shows the likelihood – over all 89 historical inflow sequences – that HVDC flow exceeds the value on the vertical axis during the given year.

Figure 13 shows the HVDC flow duration curve the 2035 and relatively small differences in the use of the HVDC link between the two cases. The additional southward capacity in the Factual is clear by the light blue line extending below 950 MW for approximately 4% of the time. It is also clear that southward flow in general is more common as LOPHES uses excess VRE to pump water into the upper reservoir. Differences in northward flow are less market at this point until the higher transfers as LOPHES is still seldom playing a role of firming large-scale North Island VRE. However, the impact on HVDC flow of that firming is visible in the divergence of the two cases at the upper end and the horizontal line at 1400 MW indicating the northward thermal limit is reached approximately 6% of the time in the Factual compared to 3% of the time in the Counterfactual.

**Figure 13. HVDC flows - 2035**

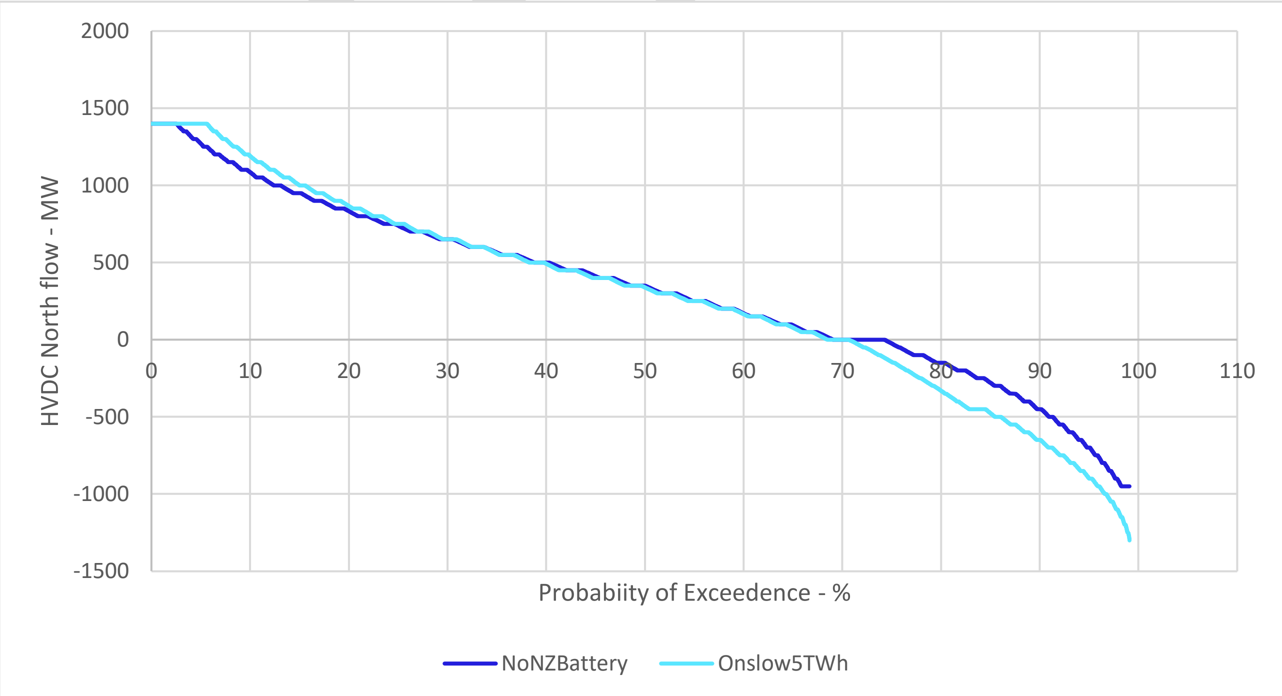



Figure 14 presents the same information for the 2050 modelled year and show the distinction in HVDC utilization becoming more marked. The Factual case is now reaching the northward and the southward transfer limits for regularly, at 8% and 10% of the time, respectively. Simultaneously, the Counterfactual case is starting to show a pattern of supply and demand being balanced in each island individually leading to increasing periods of time with zero HVDC flow. However, the northward and southward transfer limits are reached a similar amount of time as in 2035, suggesting that the HVDC link capacity is still required to allow existing South Island hydros to firm North Island VRE and North VRE to meet South Island load and allow hydros to be held back for higher value operation.

**Figure 14. HVDC flows - 2050**

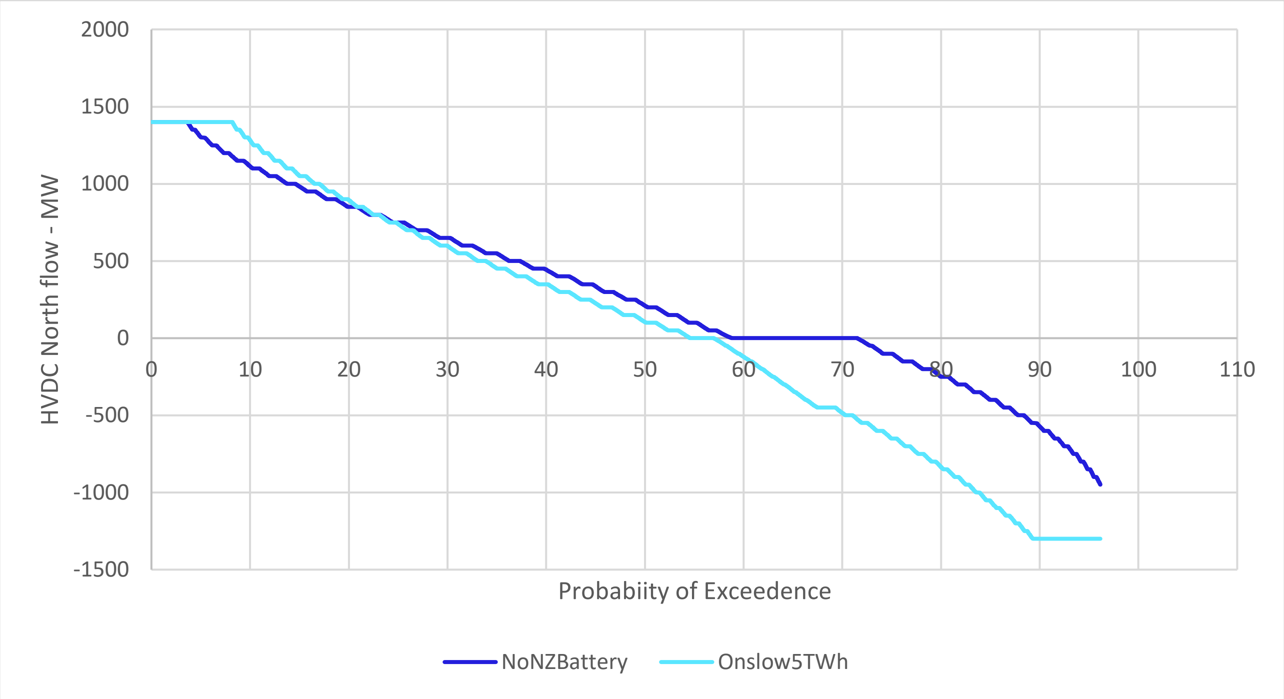
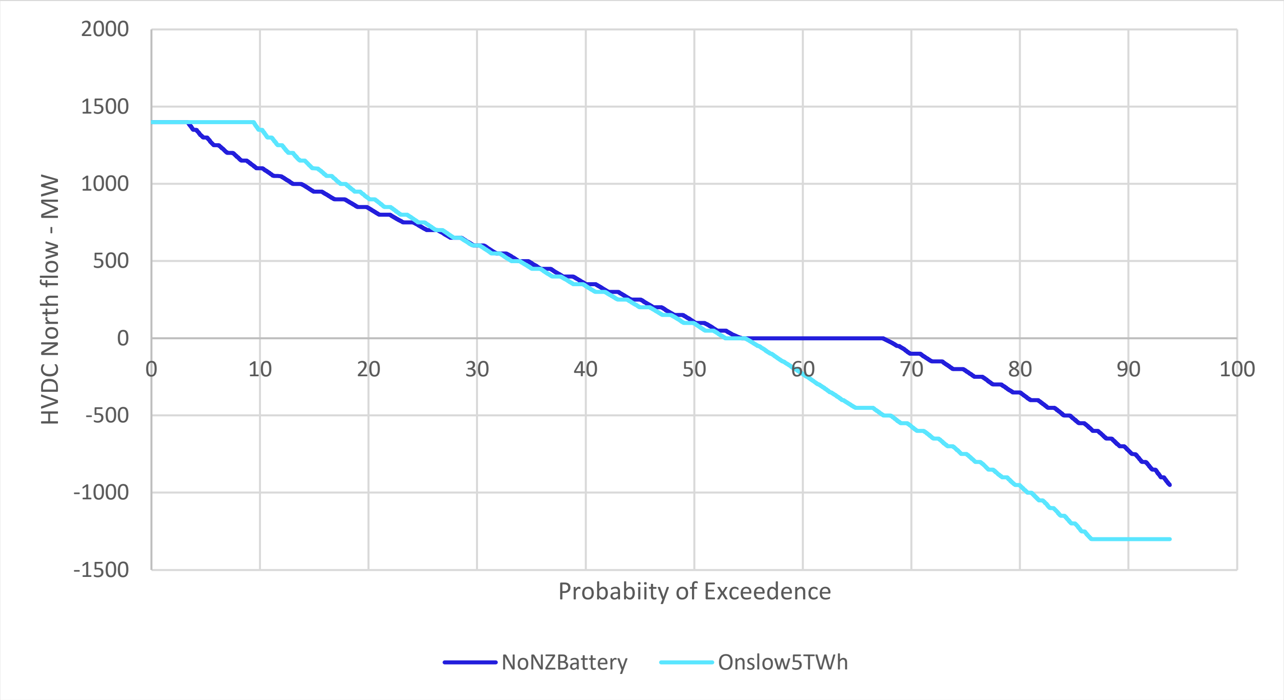


Figure 15 shows the same information again for the 2065 modelled year and presents a similar story to 2050 only more so. Northward and Southward transfer limits are now reached almost 9% and 14% percent of the time respectively in the Factual case as LOPHES is called on to firm increasing levels of North Island VRE and increasing levels of North Island VRE is available to use for pumping.

**Figure 15. HVDC flows - 2065**




## 5.3 Generation expansion

This section details the generation expansion outcomes in the Factual and the Counterfactual cases. All generation expansion from 2022 to 2065 was modelled in OptGen with LOPHES 'forced in' in the Factual and not 'forced out' in the Counterfactual. Other than the transmission upgrades discussed in section 5.2, all input assumptions are the same in both cases.

In this section, outcomes are presented from 2030 to 2065 to reflect the period when the Factual and the Counterfactual produce different outcomes

### 5.3.1 Wind

Figure 16 and Figure 17 show North Island and South Island wind capacity expansion, respectively, from 2030 to 2065.

In the North Island, there is a clear plateau in both cases from the late 2030s as installed capacity of North Island wind approaches 5000 MW and the correlation between the intermittent resources begins to impact the incremental benefit of new capacity. This effect is delayed slightly in the Factual by LOPHES and the higher HVDC southward capacity allowing more excess supply to be stored and used at a time of greater value to the system. However, by the mid-2040s, with North Island wind capacity at approximately 5500 MW, investment in North Island wind slows to less than 50 MW per year.

Wind capacity expansion in the South Island diverges more materially as the combination of higher HVDC southward capacity and LOPHES tends to reduce the benefit of additional South Island capacity. Non-hydro South Island generation provides a lot of system benefit during dry years by providing diversity of inflows with respect to the hydro resource. By addressing the dry year problem and increasing the HVDC southward flow capacity, the Factual case provides additional cover that effectively reduces the benefit of new South Island supply capacity. As a result, wind capacity in the South Island is much lower in the Factual than the Counterfactual as shown in Figure 17.

**Figure 16. North Island wind capacity expansion**

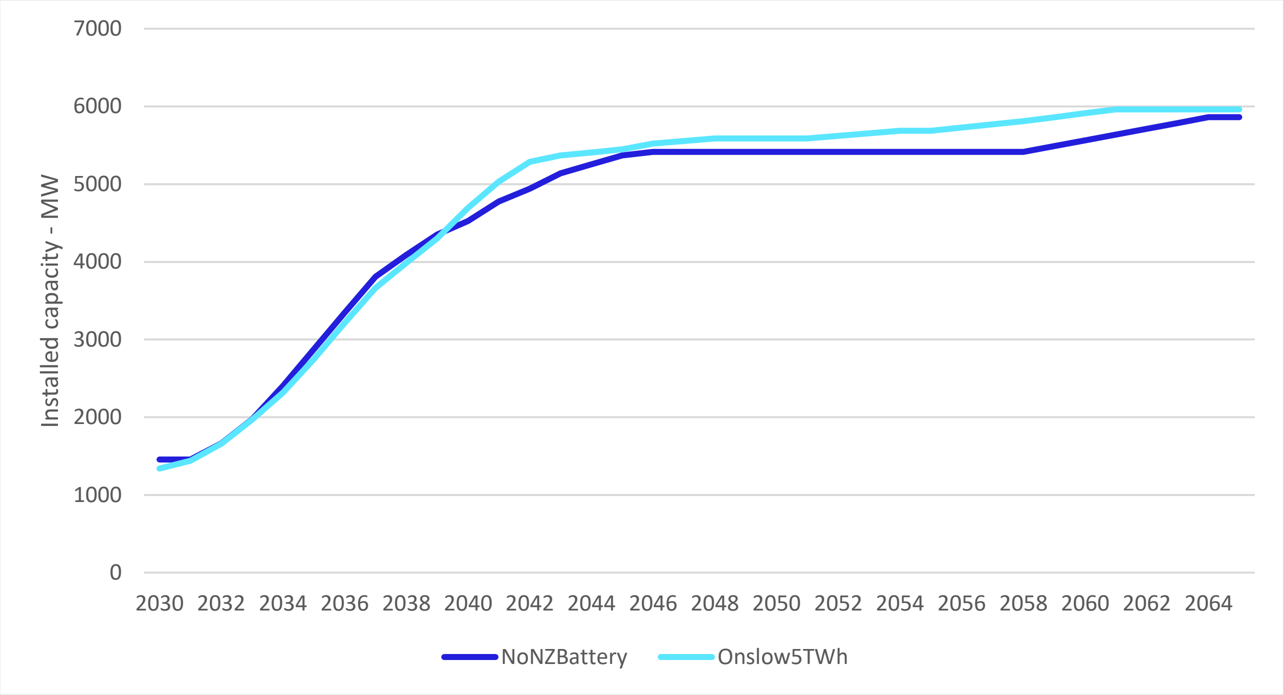
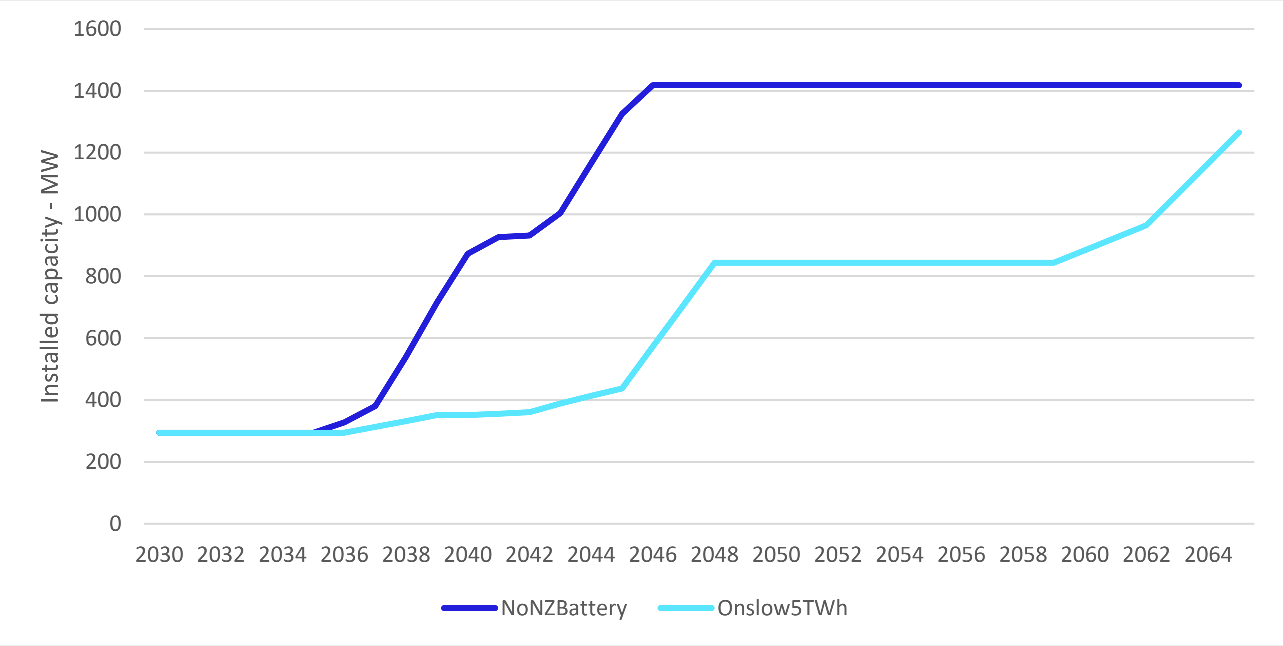



**Figure 17. South Island wind capacity expansion**




Note that the total wind capacity installed across New Zealand is greater in the Counterfactual than the Factual as the Counterfactual is forced to 'overbuild' VRE supply to cover dry years.

### 5.3.2 Grid-scale solar

Figure 18 and Figure 19 show the expansion of grid-scale solar capacity in the North and South Islands, respectively.

In the Factual and the Counterfactual, capacity expansion tends to switch from wind build to grid-scale solar build in the early 2040s and wind supply starts to saturate the market and solar costs continue to decline.

From that point on, grid-scale solar becomes the primary new supply technology, growing closely linearly for the remainder of the modelling period.

There are strong parallels between solar and wind capacity expansion when comparing the Factual and Counterfactual results across the North and South Island. The Factual tends to build more grid-scale solar capacity in the North Island and uses the HVDC capacity and LOPHES for firming and as a load sink. By the end of the modelling horizon, the two cases have almost identical North Island grid-scale solar capacities.

In the South Island, we see that same impact of LOPHES on grid-scale solar build as we did for South Island wind, but more marked. The Factual case as very little South Island solar capacity built until the late 2050s, as a result of LOPHES and the higher HVDC capacity substantially reducing the system benefit of new South Island supply.

**Figure 18. North Island grid-scale solar capacity expansion**

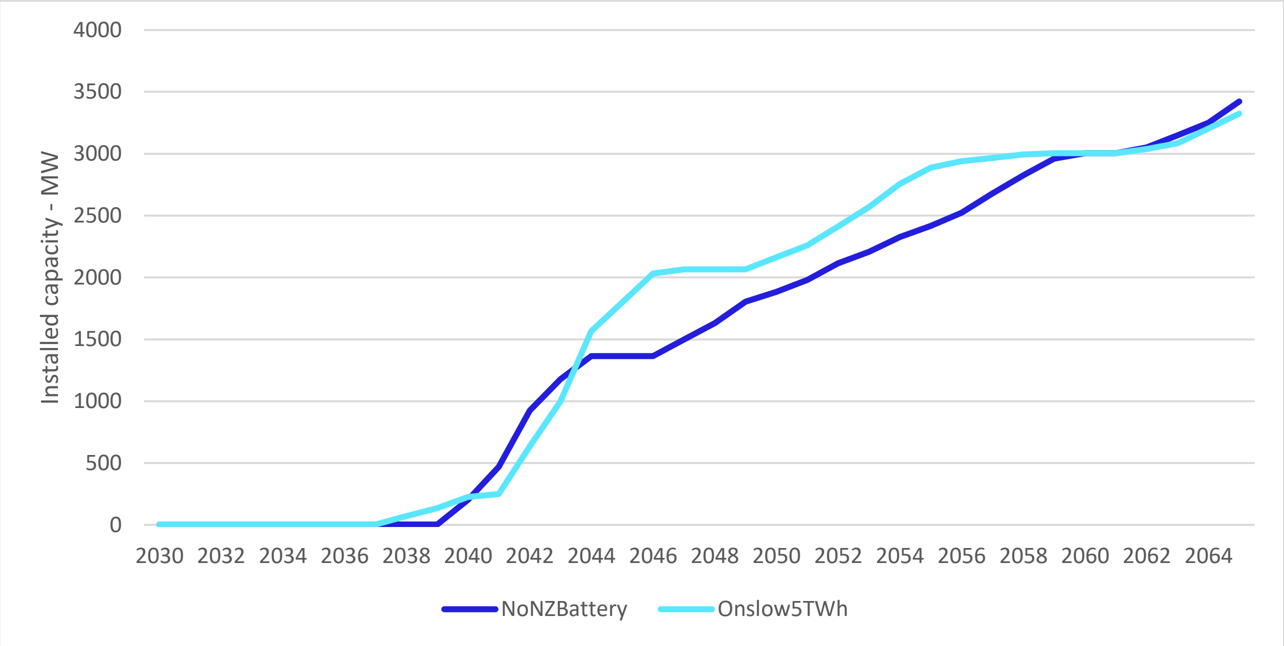
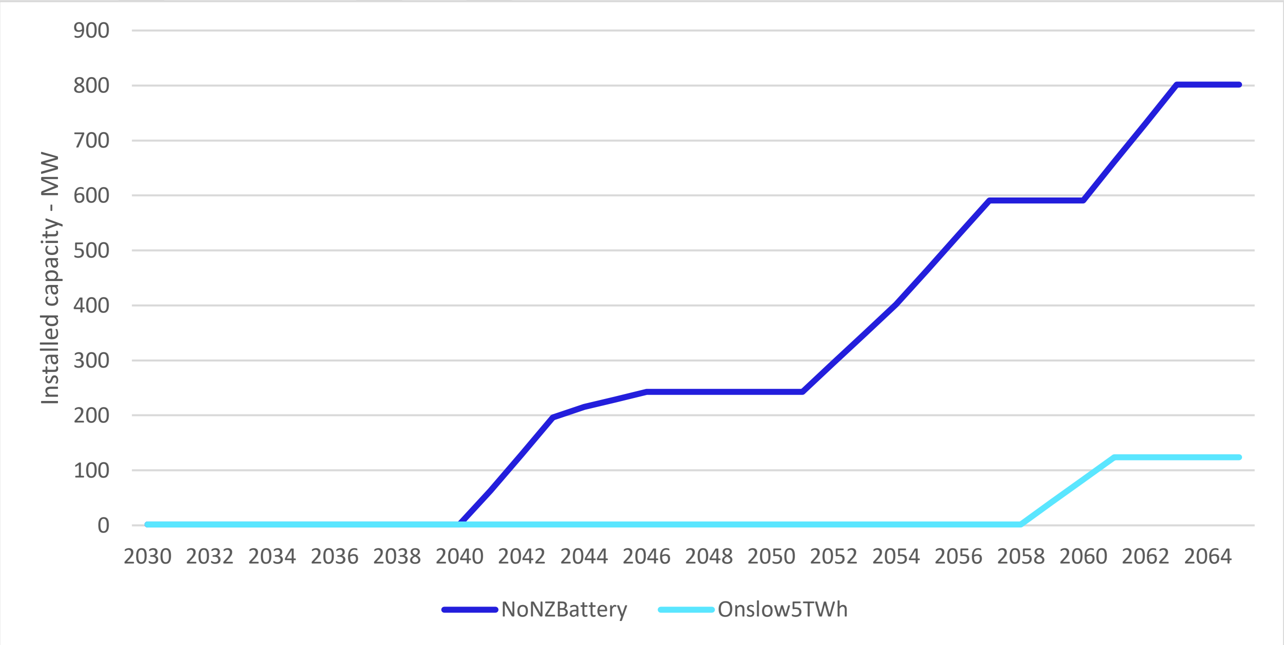



**Figure 19. South Island grid-scale solar capacity expansion**



As with wind capacity, note that the total grid-scale solar capacity is greater in the Counterfactual case than the Factual case.

### 5.3.3 Grid-scale batteries

Figure 20 and Figure 21 show the grid-scale battery capacity growth in the North Island and the South Island, respectively.

OptGen will build batteries if there is a system benefit to arbitrage energy prices that exceeds the cost of the battery

**Figure 20. North Island grid-scale battery capacity expansion**

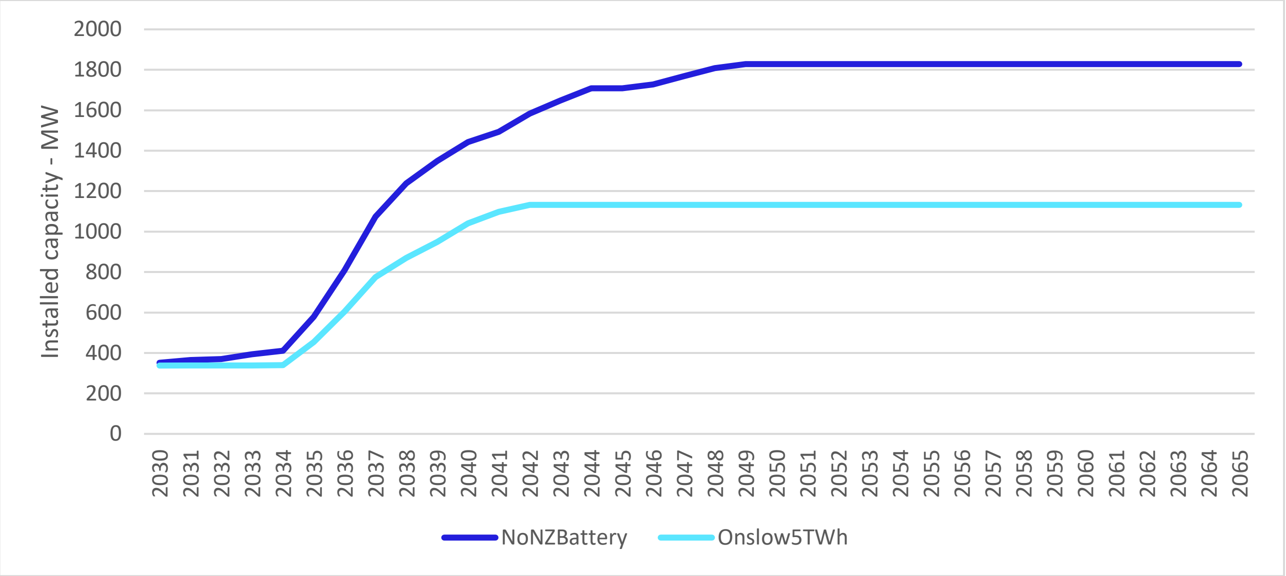



**Figure 21. South Island grid-scale battery capacity expansion**

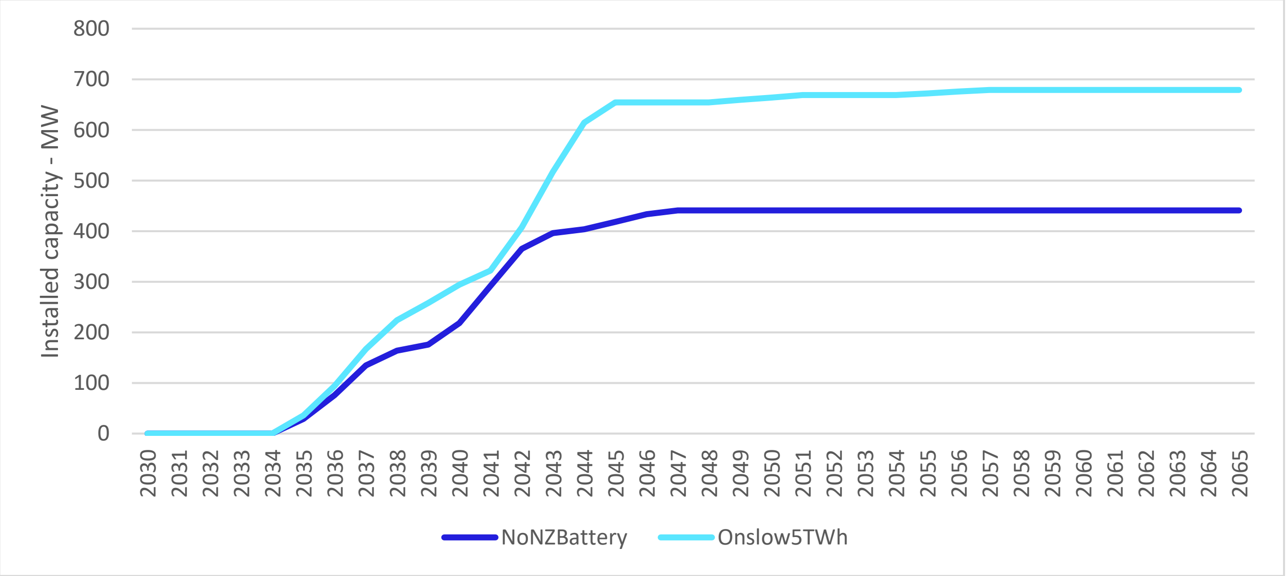


**Figure 22. Geothermal capacity expansion**

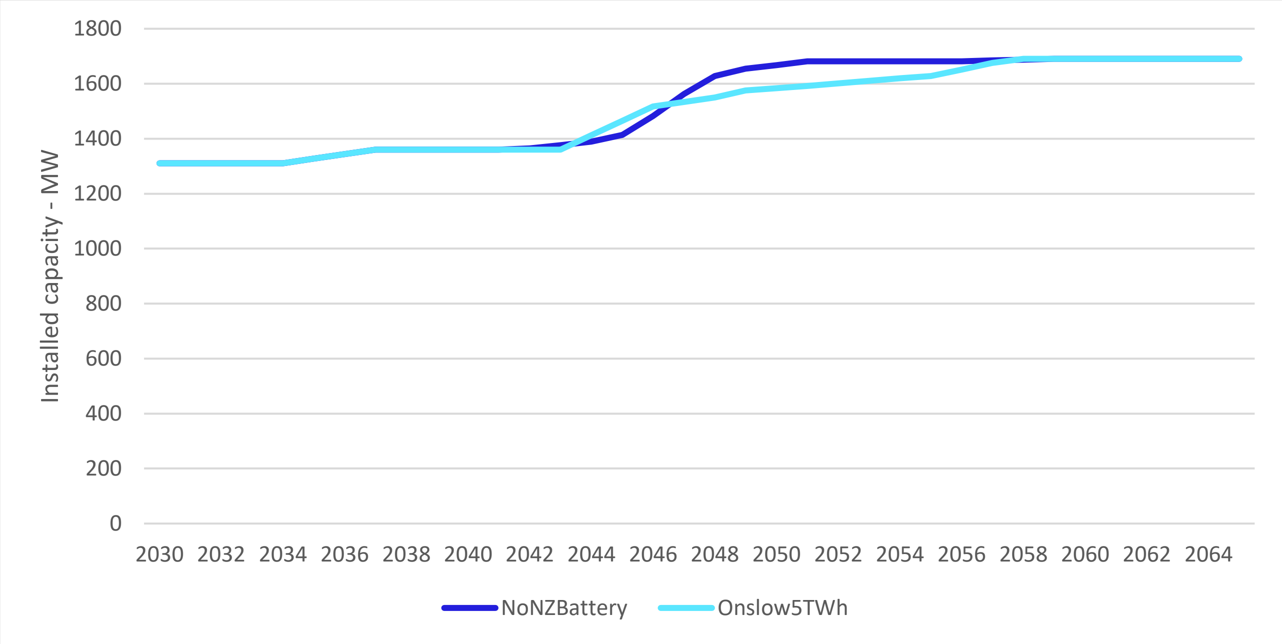
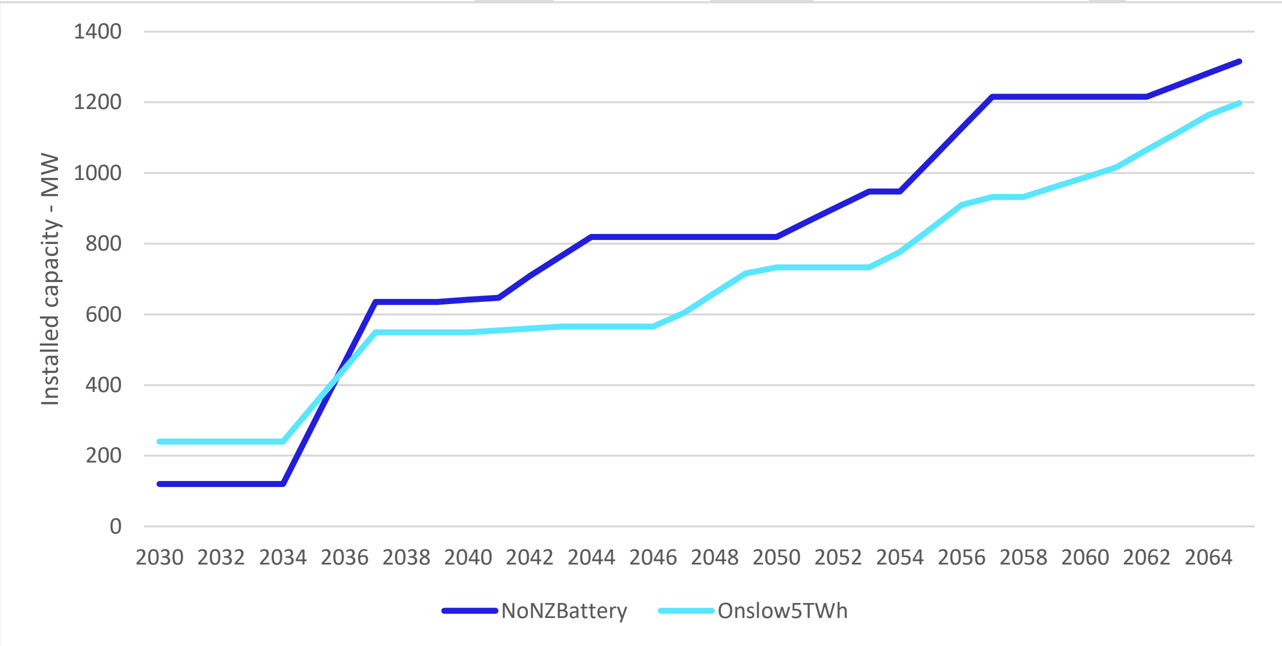



**Figure 23. Green peaker capacity expansion**




## 5.4 System operation

This section presents modelled outcomes related to how the system built (as covered in the previous section) is operated in SDDP.

### 5.4.1 Onslow operation

Figure 24 shows the weekly available stored energy in Lake Onslow in each of the 89 historical inflows sequences that were modelled. The heavy blue line is the mean across all hydro sequences modelled.

Note that Onslow operation could be split into three phases: fill-up (2030 to 2035/2036), heavy cycling (2036 to 2050) and lighter cycling (2051-2065). The driver for the filling phase is clear as Lake Onslow is empty at the beginning of the modelling horizon and needs to fill in order to provide benefit to the system. During the heavy cycling phase from the end of the fill phase until about 2050, Onslow regularly reaches its maximum storage capacity indicating that SDDP sees value in having large amounts of storage on-hand and there being enough times of excess energy to fill the reservoir. After 2050, the reservoir seldom reaches its capacity, but prices remain stable (see section 5.5), indicated that the value the SDDP is attributed to large amounts of storage at Onslow is changing, possibly due to the relative increase in the importance of firming VRE rather than dry year cover.

We have imposed an alert level of 250 GWh on Lake Onslow from 2035. The alert is to reflect that the market is likely to be averse to drawing Onslow entirely empty. The alert level is modelled as a soft constraint, meaning that SDDP will draw Lake Onslow below the alert level at a penalty of 1.1 times the cost of the most expensive thermal generation that is available. The effect of the alert level is clear in the graph below as the level that few hydro sequences drop below from 2035 onwards.

**Figure 24. Lake Onslow available storage**

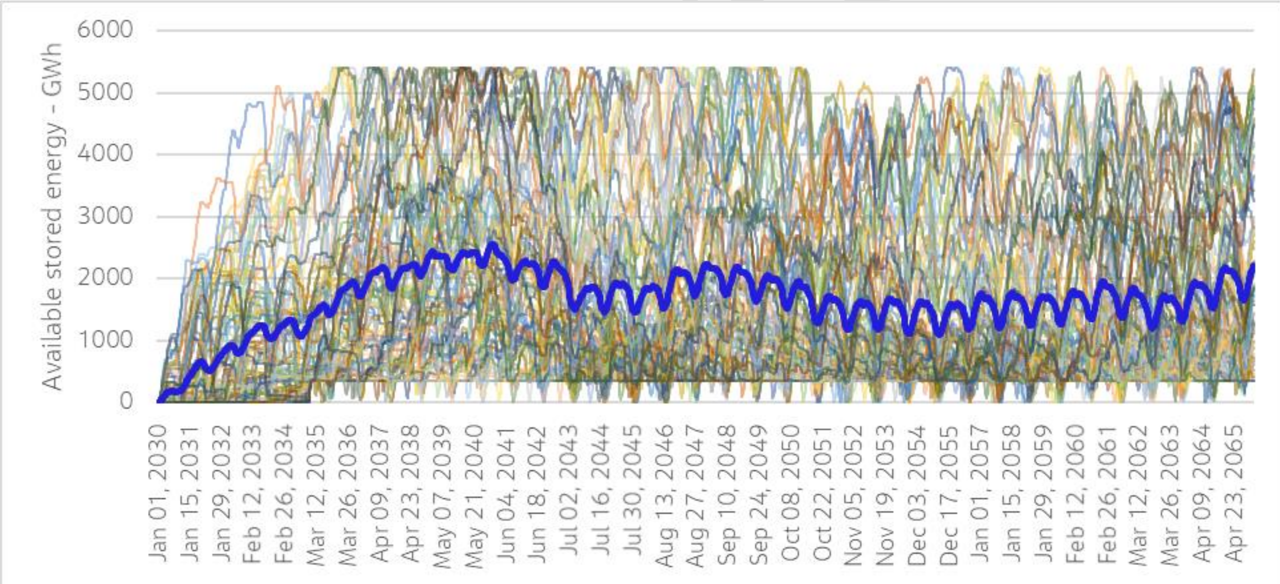
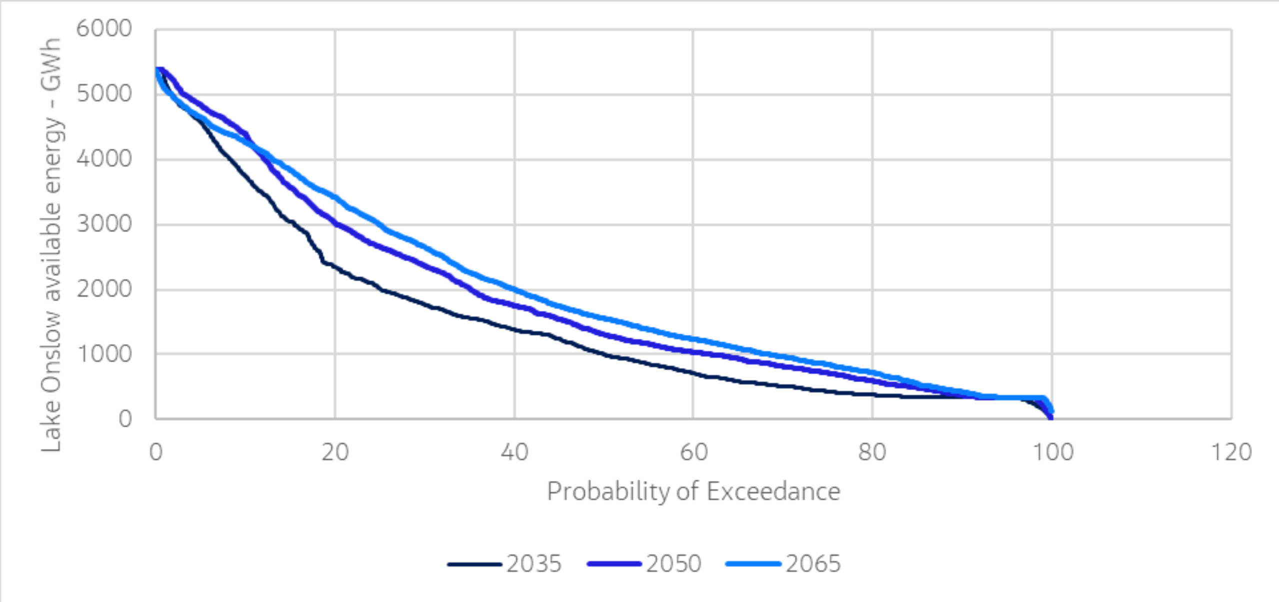


Figure 25 show the likelihood – over all 89 modelled inflow sequences – that the available stored energy in Lake Onslow will exceed a given value in 2035, 2050, and 2065. Note the markedly different shape of the curve in 2035 as the reservoir is still filling in some sequences. Also note that the 2050 and 2065 curves cross; median storage levels are higher in 2065 than in 2050, but the higher and lower percentiles are higher in 2050 than in 2065. This suggests that Onslow is providing good value to the system – otherwise SDDP would see little value in keeping average levels high – but that the benefit of the upper levels of the reservoir could reduce over time as firming VRE starts to become as important as dry year firming and some amount of renewable 'overbuild' occurs.

**Figure 25. Lake Onslow storage duration curves**




## 5.4.2 Existing hydro scheme operation

This section discusses the difference in the operation of some existing hydro storages in the Factual and Counterfactual cases.

Figure 26 shows the weekly available energy storage at Lake Pukaki in the Onslow and No NZ Battery cases. Note that SDDP holds storage levels higher across the year from 2035 to 2040, a period of time just after the last fossil-fuel thermal plant retire when the Onslow case holds Onslow reservoir levels high (see Figure 18). From 2040, the difference becomes more muted but there remains a general tendency for the No NZ Battery case to hold reservoir levels higher – particularly in autumn and winter. This is likely driven by the existing hydro schemes being forced to manage a substantial amount of the dry year risk and play a VRE firming role in the No NZ Battery case and taking advantage of additional renewable supply to hold back water until it is more valuable to the system, e.g. when inflows and/or renewable supply is low.

**Figure 26. Lake Pukaki weekly available storage**

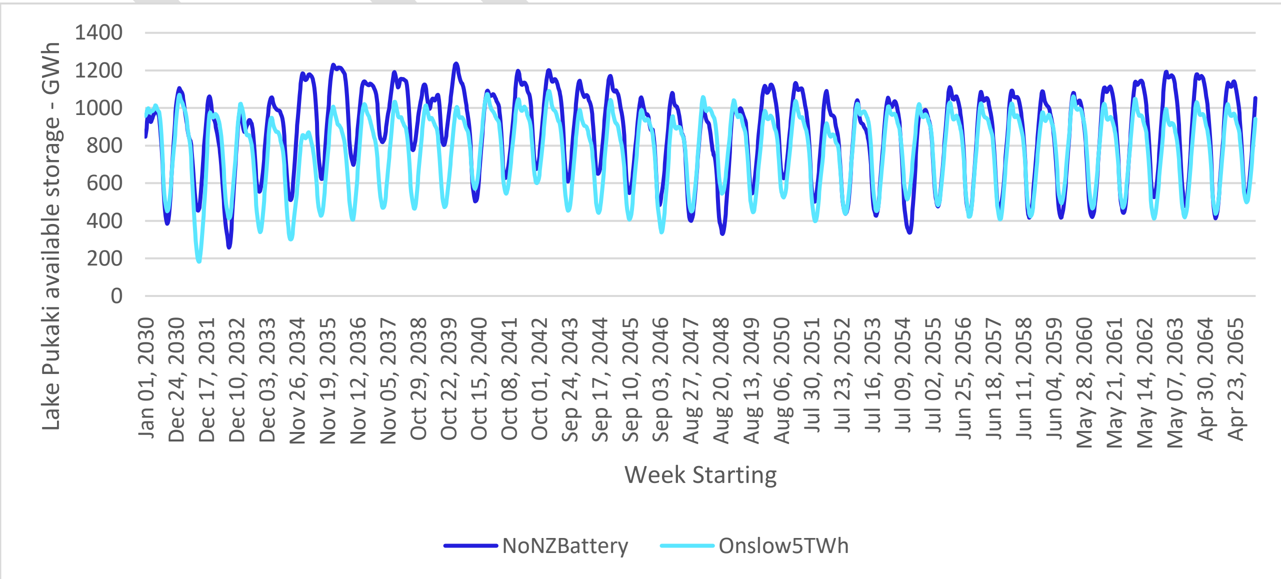


Figure 27 shows the energy storage comparison for Lake Taupo and follows a similar patten to Lake Pukaki from 2035 to 2040 but by the end of the modelling horizon the two cases are very similar. Prior to 2048 the No NZ Battery case tends to keep Lake Taupo levels higher than the Onslow case – particularly in autumn. But by 2048, the Onslow case tends to keep Taupo levels higher as well, possibly as a result of increased VRE supply and the limited firming that Onslow can provide in the North Island due to generation capacity and HVDC transfer limits.

**Figure 27. Lake Taupo weekly available storage**

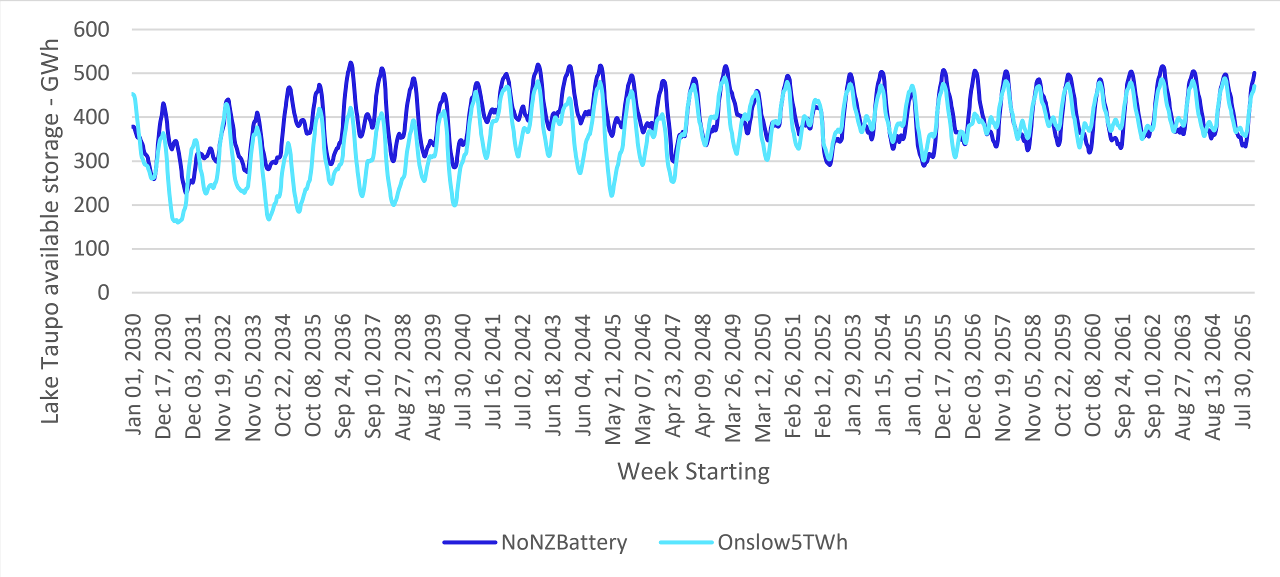
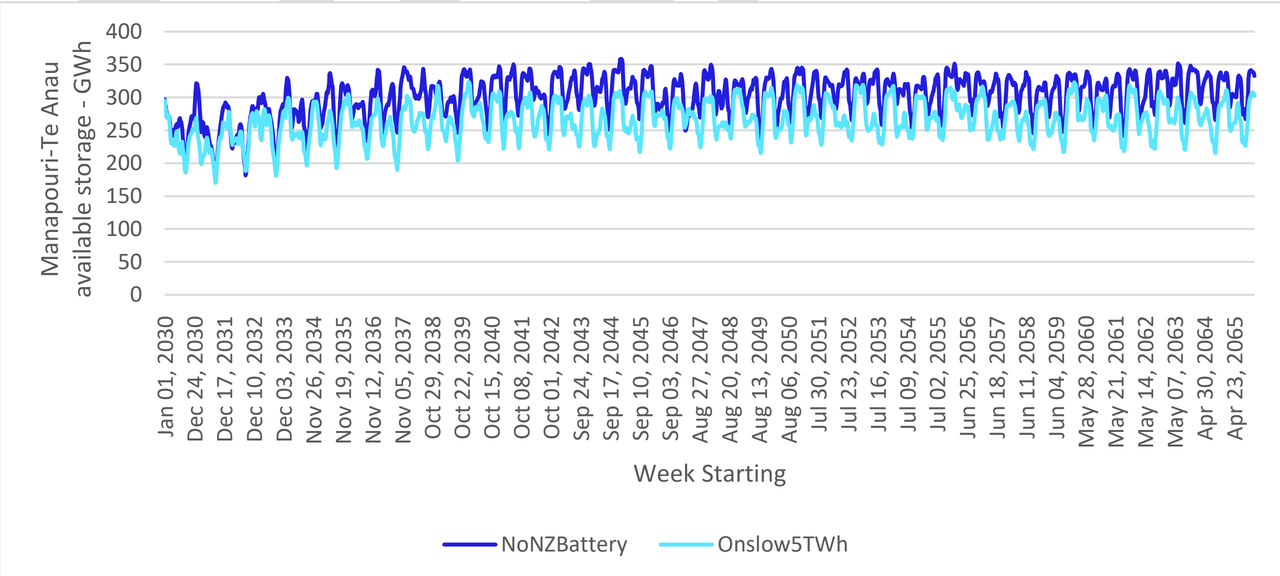



**Figure 28. Manapouri-Te Anau weekly available storage**

Figure 28 show a significant impact on Manapouri storage levels. From 2035 onwards, Manapouri storage levels are consistently higher in the No NZ Battery case than in the Onslow case across the year. Unlike the Pukaki and Taupo results, the Manapouri results are consistent across the horizon, indicating that Manapouri could be playing an important firming role in the No NZ Battery case that is not required in the Onslow case – possibly as a result of the additional South Island VRE and Manapouri's high capacity in a single station.

**Figure 28. Manapouri-Te Anau weekly available storage**




## 5.4.3 Impact on spilled energy

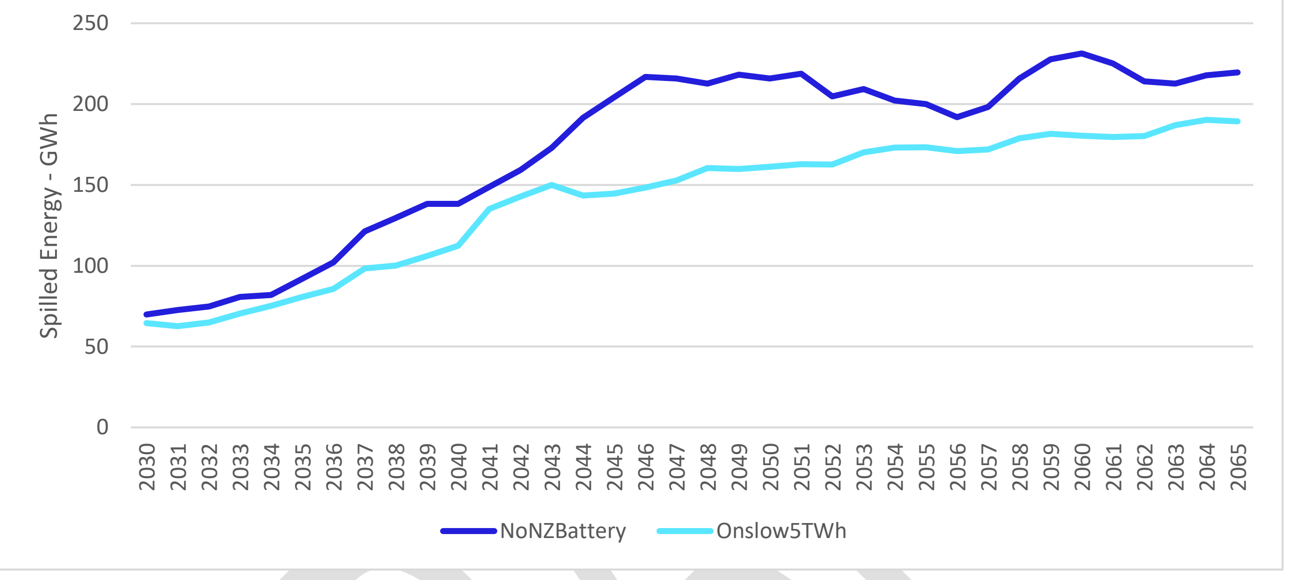
This section presents the differences between the Factual and Counterfactual with respect to spilled energy.

#### 5.4.3.1 Hydro

Spilled hydro energy refers to water that is spilled with generation and the energy potential of that spilled water. SDDP is given a small penalty for spilling water to avoid arbitrary spillage without materially impacting the system cost.

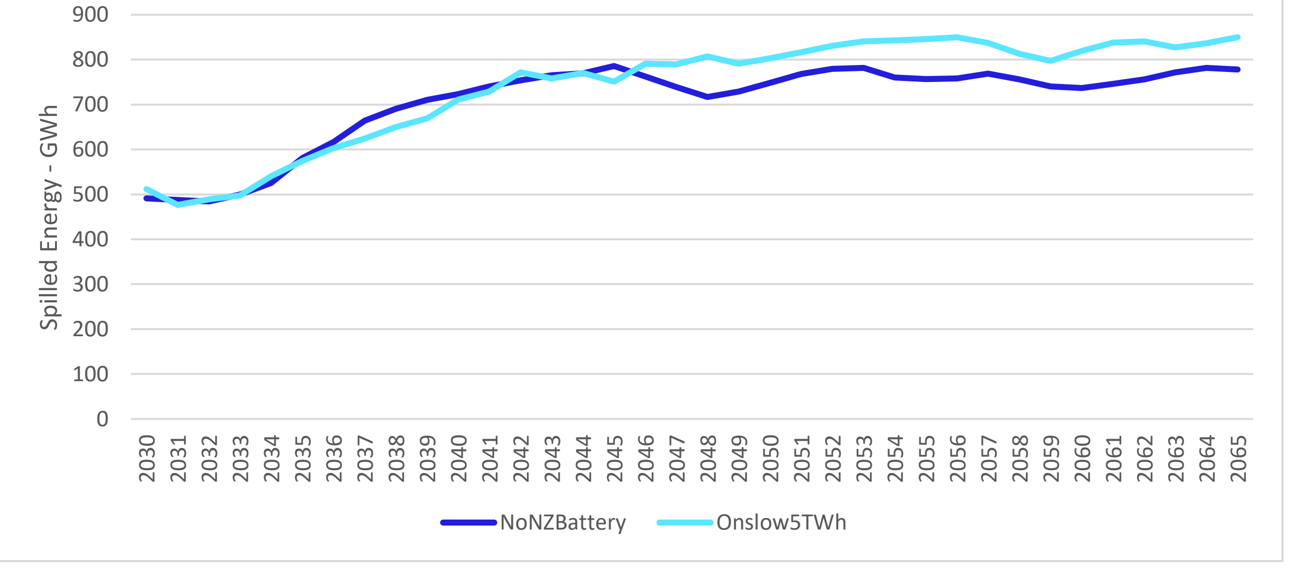
North Island spilled hydro is consistently higher in the No NZ Battery case across the modelling horizon, peaking in late 2040s. This is likely driven by the tendency for the No NZ Battery case to hold Lake Taupo and higher levels to reduce the risk of shortage.

**Figure 29. North Island hydro annual spilled energy**




South Island hydro spill is very similar in the two cases until the late 2040s when the Onslow case starts to exceed the No NZ Battery case. This is an interesting result given that reservoirs levels in the South Island tend to be higher in the No NZ Battery case (see section 5.4.2) which would reduce the likelihood of spill and could be a result of interactions on the Clutha with Onslow in play. Closer investigation of this effect could be undertaken in the next stage of our investigation.

**Figure 30. South Island hydro annual spilled energy**



#### 5.4.3.2 Wind

Spilled wind energy is any wind supply that is not used to meet immediate consumer demand or for charging batteries. We have assumed zero cost for spilling wind or solar generation, but any energy spilled will reduce the system benefit of the technology and therefore reduce the likelihood that OptGen will build it.

Spilled wind energy is driven by:

1. the installed capacity of wind supply relative to demand
2. correlation between wind farms
3. correlation between wind supply and demand
4. transmission constraints
5. the capacity (MW and MWh) of flexible load sinks such as batteries and pumped hydro

As such, the No NZ Battery case is expected to have greater levels of wind spill due to points 1, 4 and 5: there is more wind capacity installed, the south-flow limit on the HVDC is lower and the there is less storage capacity.

Figure 31 and

Figure 32 show the North Island and South Island spilled wind energy respectively in each case and agree with expectations. The No NZ Battery case has three to four times the North Island wind spill as the Onslow case, despite having very similar installed capacity (see

Figure 16). In the South Island, the Onslow case has close to zero spill – due partly to less installed capacity – while the No NZ Battery case peaks at almost 600 GWh in the year.

**Figure 31. North Island wind annual spilled energy**

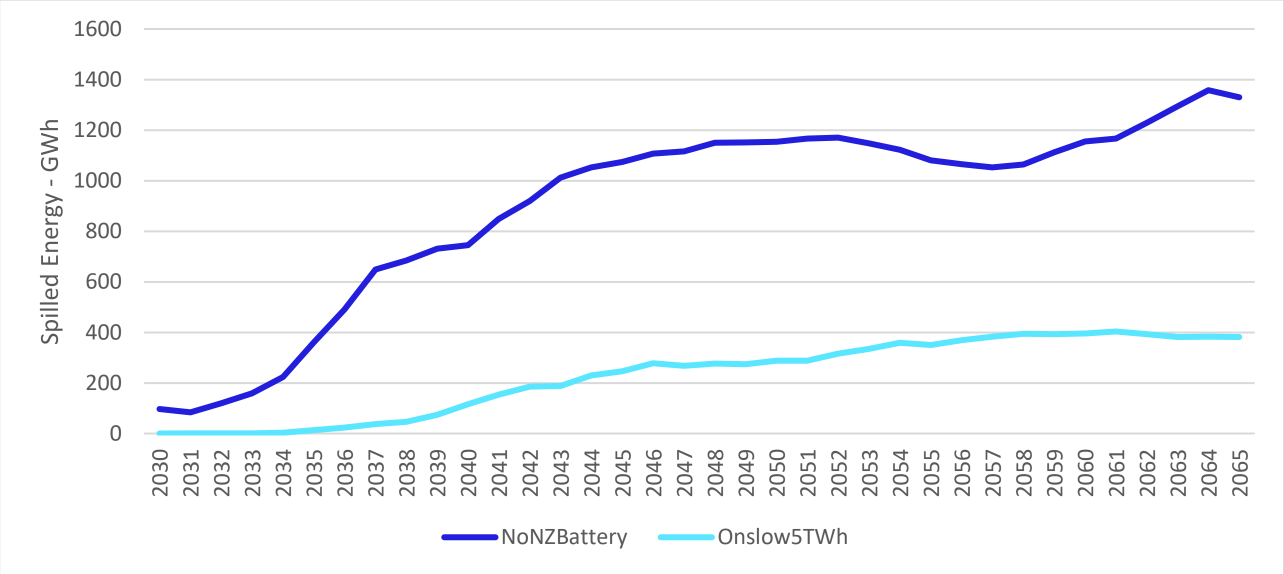
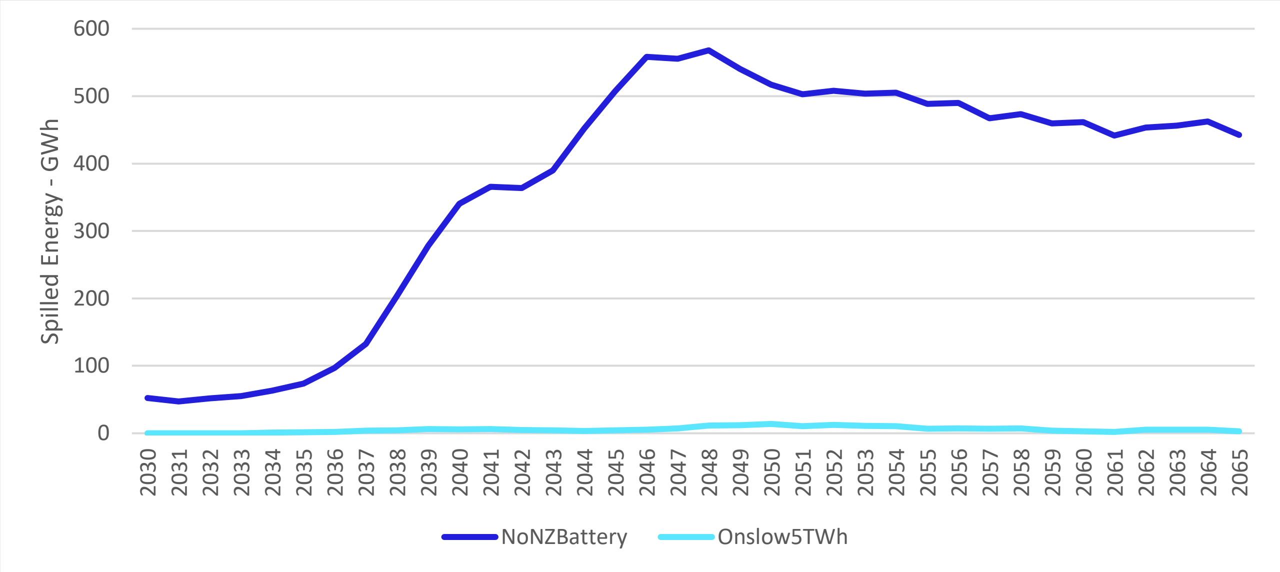


**Figure 32. South Island wind annual spilled energy**




### 5.4.3.3 Grid-scale solar

The drivers for solar spill are similar to the drivers for spilled wind energy:

1. the installed capacity of solar supply relative to demand
2. correlation between solar farms
3. correlation between solar supply and demand
4. transmission constraints
5. the capacity (MW and MWh) of flexible load sinks such as batteries and pumped hydro

Figure 33 and Figure 34 show the annual spilled energy of North Island and South Island solar, respectively. As with wind spill, solar spill is substantially more in the No NZ Battery case than in the Onslow case, partly due to higher installed capacity (in the South Island), but also due to transmission constraints and reduced storage.

**Figure 33. North Island grid-scale solar annual spilled energy**

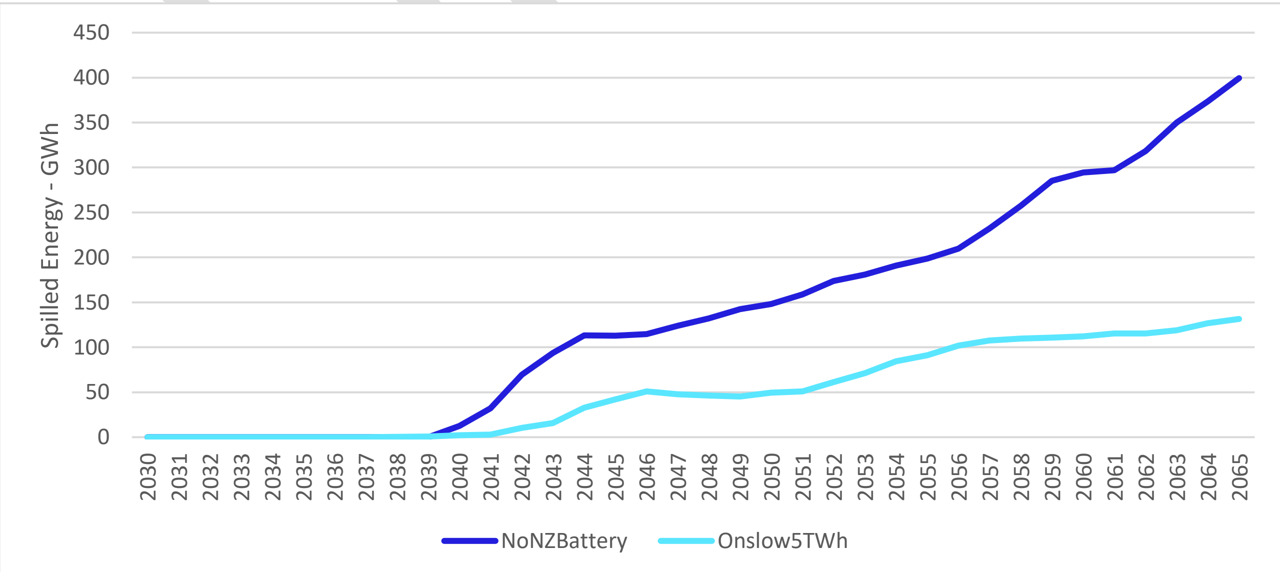
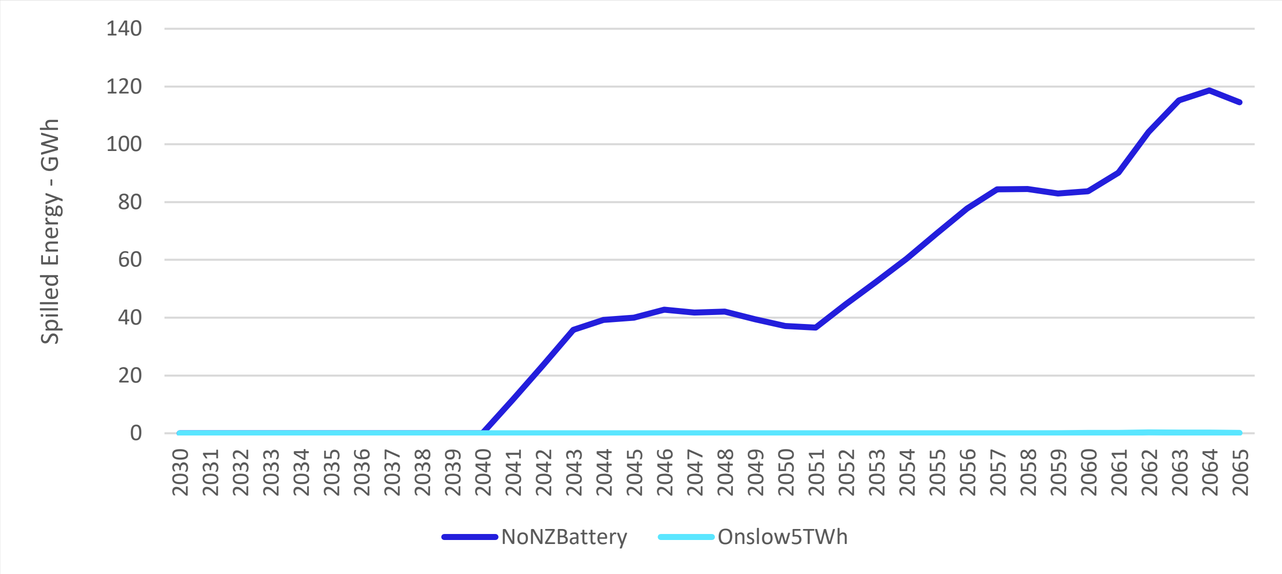


**Figure 34. South Island grid-scale solar annual spilled energy**




## 5.5 Impact on prices

This section discusses the differences in pricing metrics between the Factual and Counterfactual modelling results.

Price results from SDDP – and other market models – should be treated with some caution. SDDP is a perfect competition model, meaning that they will ignore any market power or portfolio effects that are present in a real market. The objective of the optimization is to minimize total system costs rather than find a solution where all participants in the market are maximizing revenue. Prices outcomes in SDDP are therefore more representative of the marginal cost to the system of an additional megawatt-hour of load rather than a prediction of the price at which a real market would settle, which would be influenced by contracts, portfolios, planned and unplanned outages and other market dynamics.

That said, SDDP price outcomes are still useful illustrations of the stress the system might be under, relative merit of supply options in different case, and as a sense-check on whether a build-schedule is economically feasible.

### 5.5.1 North Island

**Error! Reference source not found.** shows the annual time-weighted average price (TWAP) in the North Island and South Island. Note that the relationship between prices in the two cases is not consistent over time, with the Onslow case having higher prices in some years and the No NZ Battery case having higher prices in others. Except for the first few years of the modelling horizon – when Onslow likely increases prices by providing additional pumping load – there isn't a strong case for assuming that Onslow would significantly increase or decrease prices.

This result might be unexpected for some but is consistent with the dynamics of allowing the build schedules to change between the two cases. If the build schedules we held constant, we would expect that Onslow would reduce prices by providing a large flexible supply to the system. However, Onslow also reduces the need for 'overbuild' of VRE, i.e., it reduces the installed capacity at which the system benefit of new renewable supply falls below that cost of installing and operating it. This new equilibrium is likely to have a very similar marginal cost in both cases as it is driven by the long-run marginal cost of installing new firm capacity, which is the cost of new solar/wind plus battery or green peaking plant in both cases.

Figure 35. Time-weighted average annual marginal cost of load – North Island

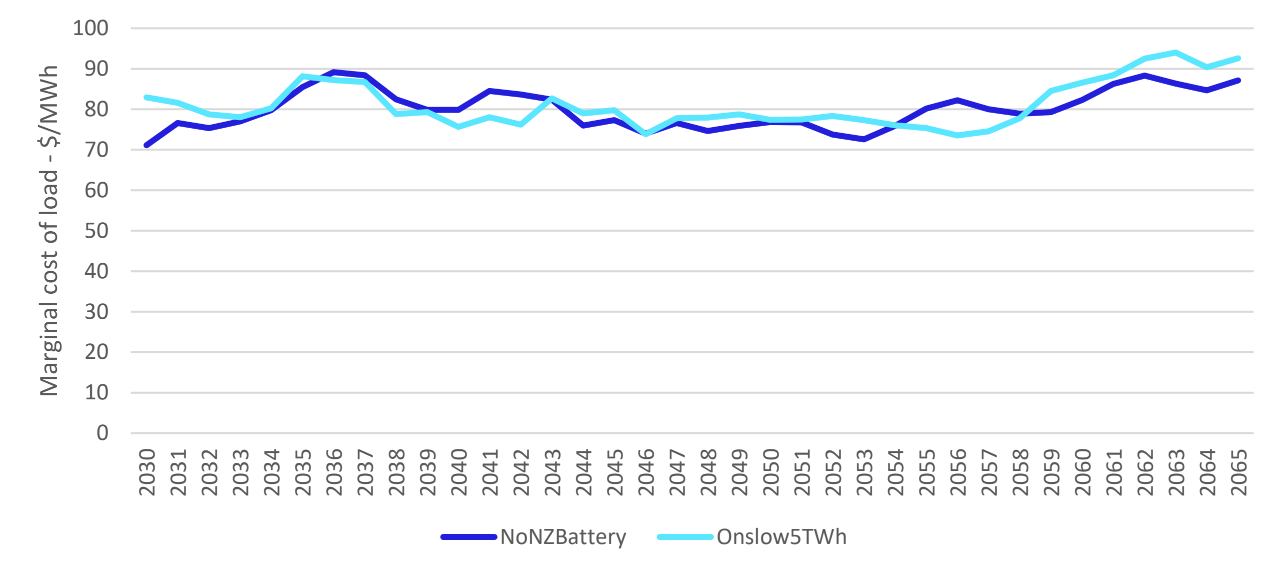


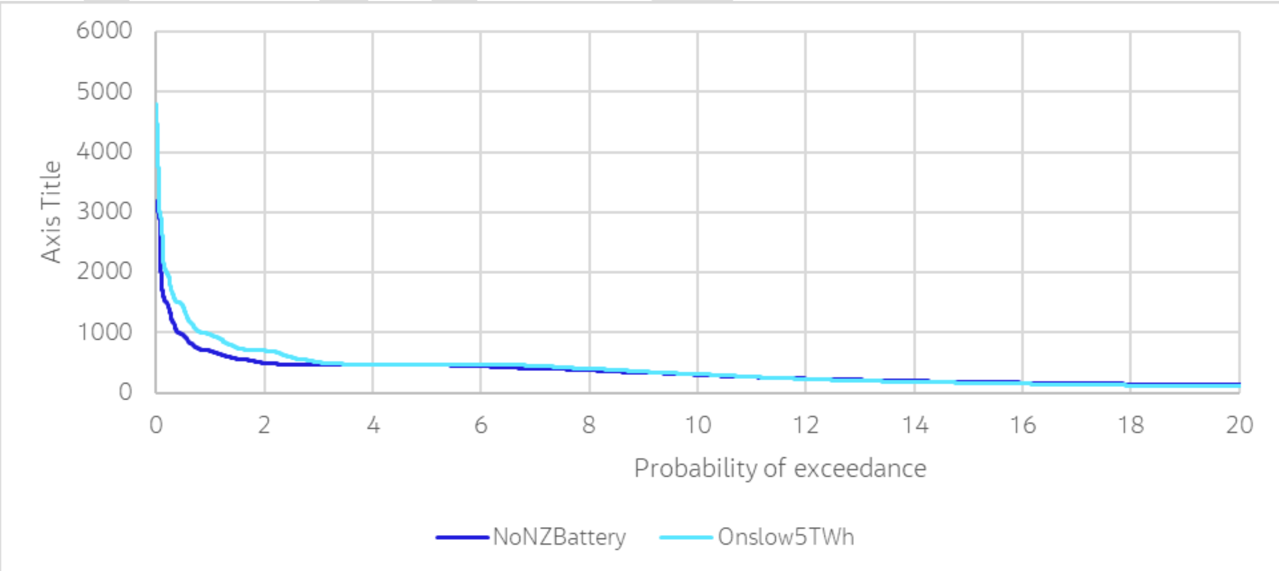

**Figure 38. Price duration curve – North Island 2065**

By 2050, Lake Onslow has reached stable operation and we start to see Onslow reduce price volatility relative to the Counterfactual. Note that TWAP (see Figure 29) is similar in the that the Counterfactual has instances of prices above $3000/MWh that are not present in the Factual.

Figure 36, Figure 37, and Figure 38 are price duration curves for 2035, 2050, and 2065 respectively; show the likelihood – over all inflow sequences – that prices exceed the level given on the vertical axes. All the graphs are restricted to the top 20% of prices for ease of reading. In general, Onslow slightly increasing prices in the off-peak periods and reduces the frequency of zero prices, but the impact on high prices is more variable in the results.

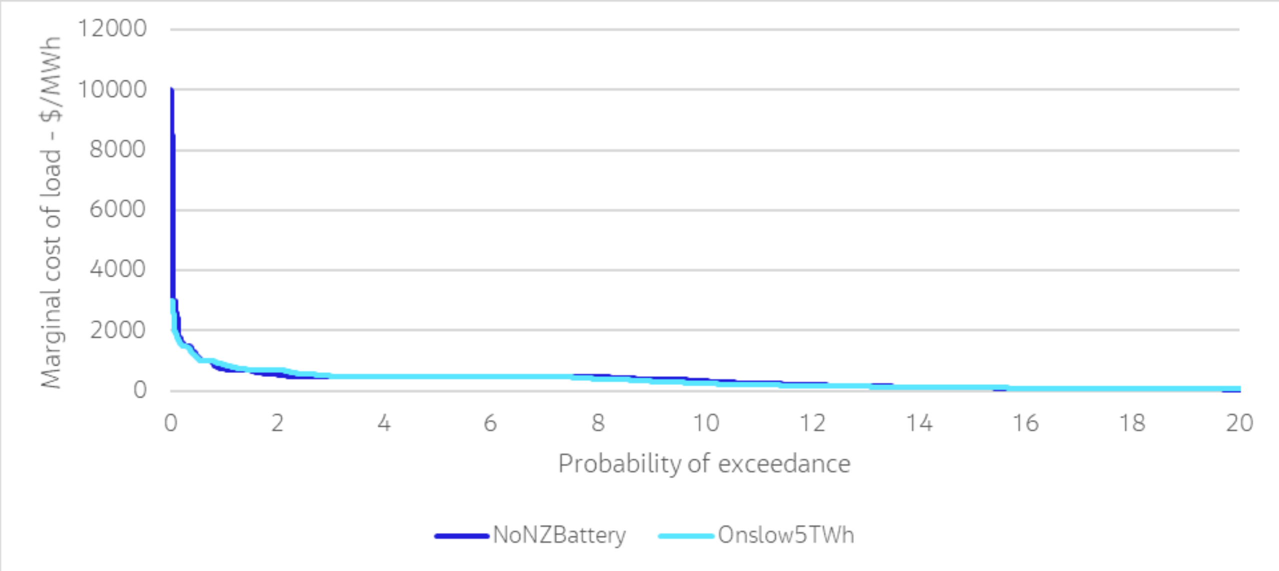
In 2035, Lake Onslow is still filling in several inflow sequences, which is evident in some increased prices in peak periods relative to the No NZ Battery case. The top 3 % of prices in the Onslow case are consistently higher than those in the No NZ Battery case, showing that prices are not only higher on average as show in the graph above, but also more volatile.

**Figure 36. Price duration curve – North Island 2035**



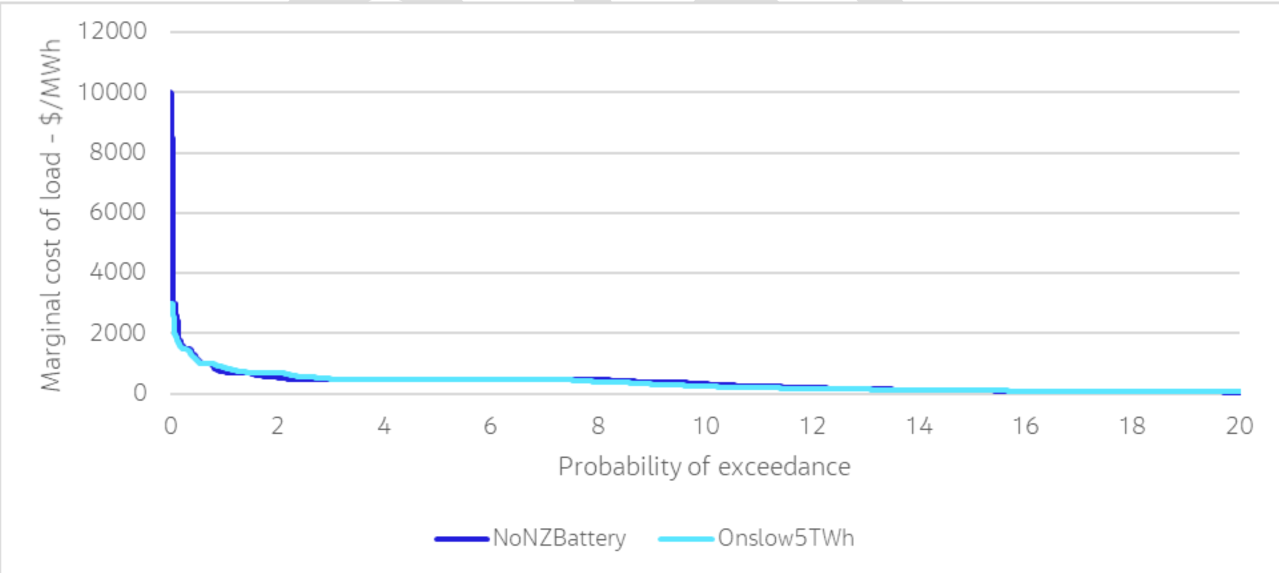

By 2050, Lake Onslow has reach stable operation and we start to see Onslow reduce price volatility relative to the No Onslow case. Note that TWAP (see **Error! Reference source not found.**) in 2050 is close to equal in the two cases but that the No NZ Battery case has instances of prices above $3000/MWh that are not present in in the Onslow case.

**Figure 37. Price duration curve – North Island 2050**




The 2065 curve is very similar to the 2050 curve, with Onslow avoiding some of the very high prices experienced in the No NZ Battery case.

**Figure 38. Price duration curve – North Island 2065**

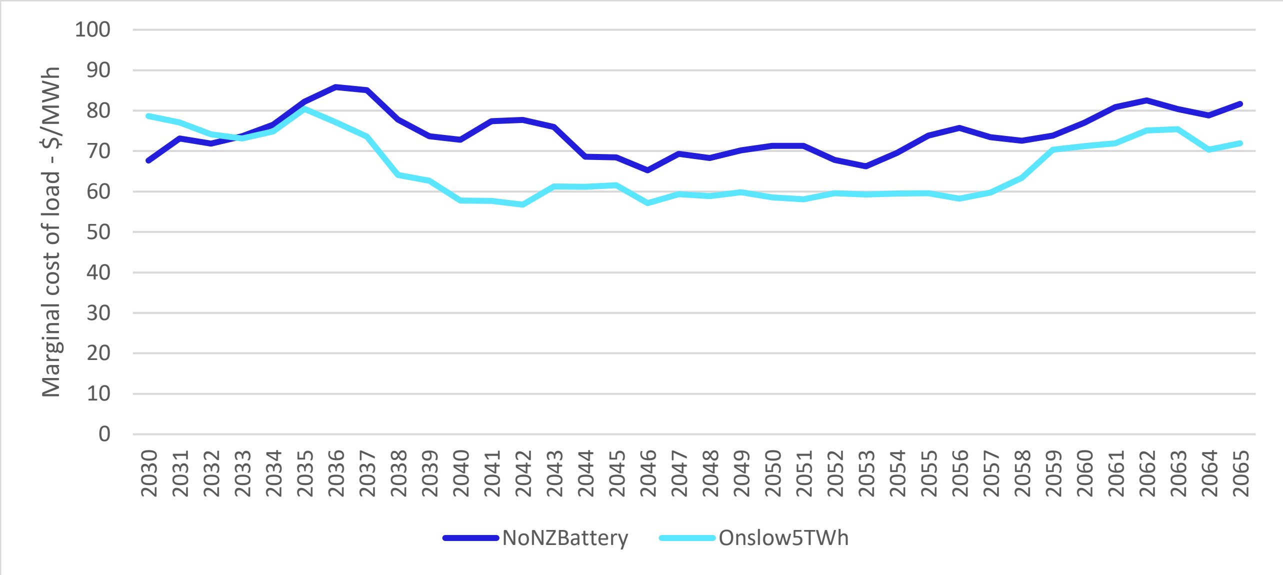



### 5.5.2 South Island

South Island price results have a more marked difference than the North Island – particularly after 2035.

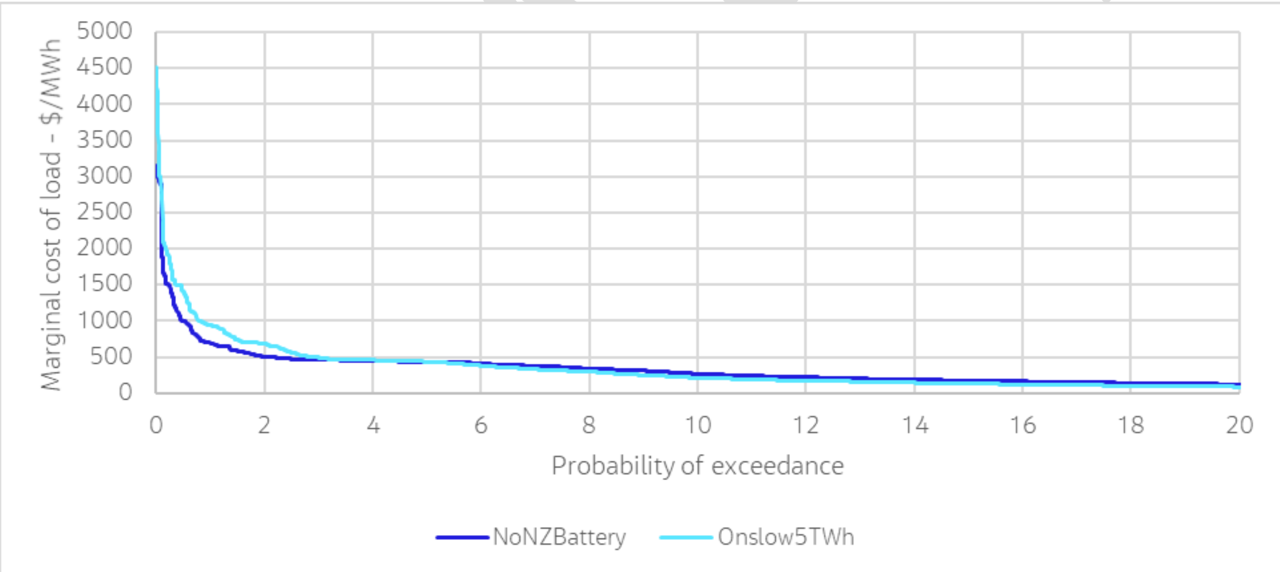
The downward pressure that Onslow exerts on South Island prices is quite evident in the results with Onslow case returning prices consistently $10 or more less than the no NZ Battery case. From 2035 onwards, the Onslow effectively removes the risk of load curtailment from the South Island through a combination of increased HVDC south-flow capacity and the Onslow scheme itself. As result, instances of high South Island prices are very rare, leading to lower average prices.

**Figure 39. Time-weighted average annual marginal cost of load – South Island**




In 2035, the results are similar to the North Island results as Onslow is still filling in several inflow sequences. The higher installed capacity in the No NZ Battery case results in less price volatility.

**Figure 40. Price duration curve – South Island 2035**




By 2050 and 2065, however, the Onslow case has lower prices across most of the probability of exceedance curve, showing that the Onslow case is decreasing the average price and decreasing volatility.

**Figure 41. Price duration curve – South Island 2050**

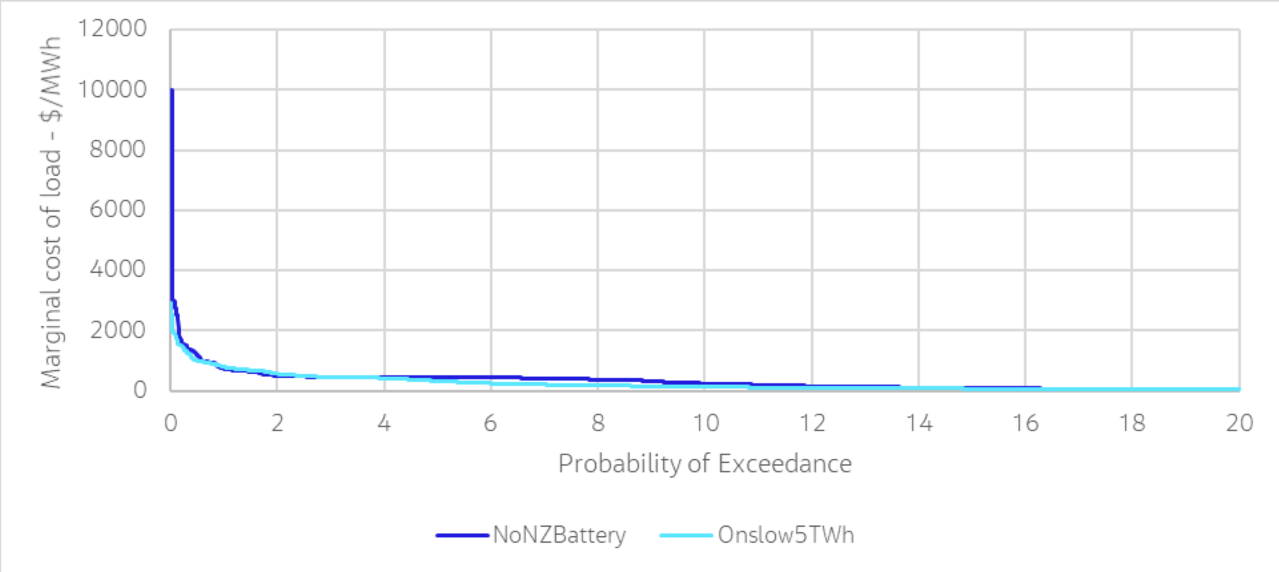
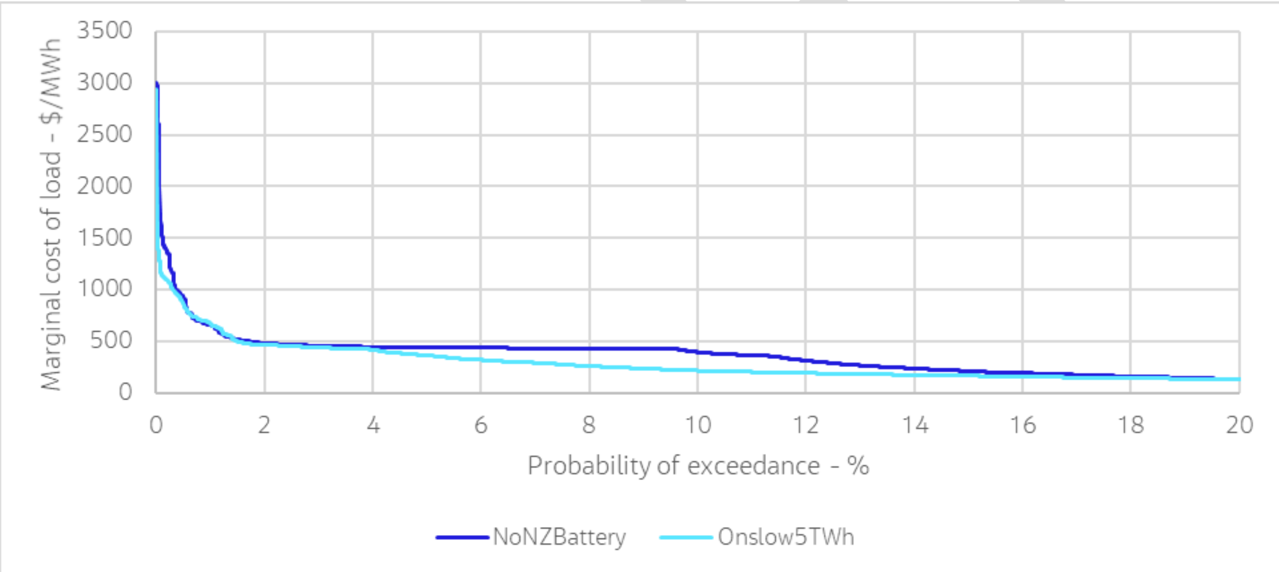



**Figure 42. Price duration curve – South Island 2060**




### 5.5.3 Generation-weighted average prices

This section details the expected generation-weighted average prices (GWAPs) for different generation types in the system. Annual GWAP is calculated as the sum of generator revenue over the year divided by the sum of all the generation and spilled energy over the year.

GWAPs are impacted by:

1. TWAP
2. dispatchability of the generation
3. correlation between availability and periods of high prices.

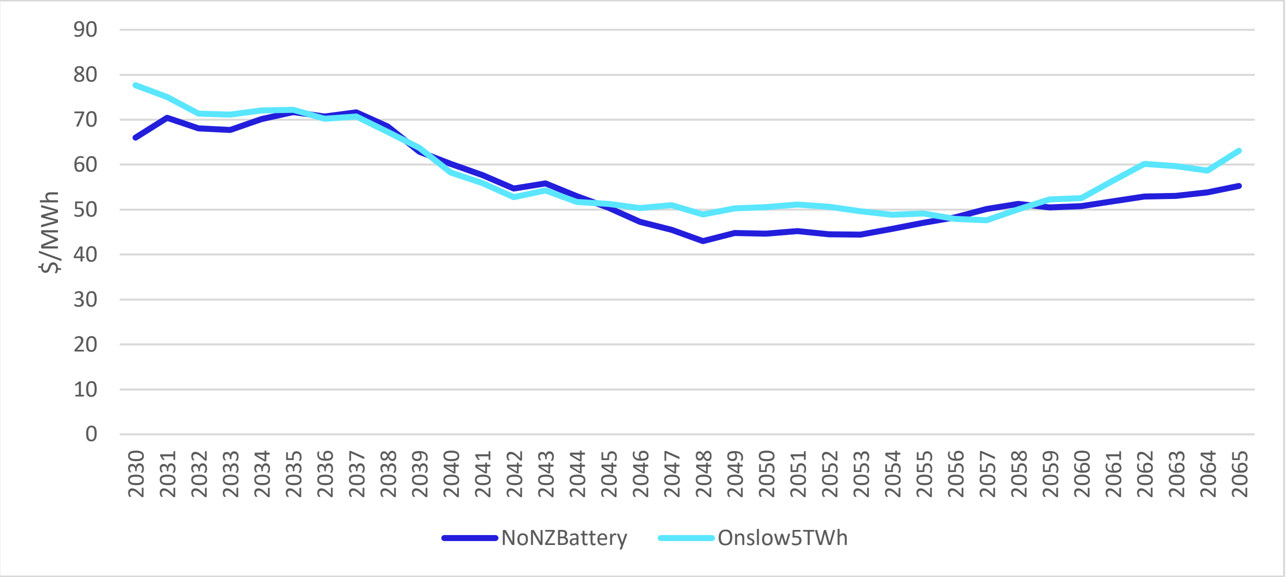
Cases with higher TWAP will tend to have high GWAPs across all generation types and technologies that are highly dispatchable and/or whose availability is positively correlated with high prices will have high GWAPs than technologies that are inflexible or poorly correlated with prices. Note that correlation with other VRE can result in being anti-correlated with price.

#### 5.5.3.1 Wind

Wind is not dispatchable or clearly correlated with prices in SDDP, so has a GWAP similar to TWAP at the beginning of the modelling horizon. However, as more wind capacity is installed on the system, wind becomes counter-correlated with prices and more likely to be curtailed. This causes GWAP to drop to $45/MWh-$50/MWh.

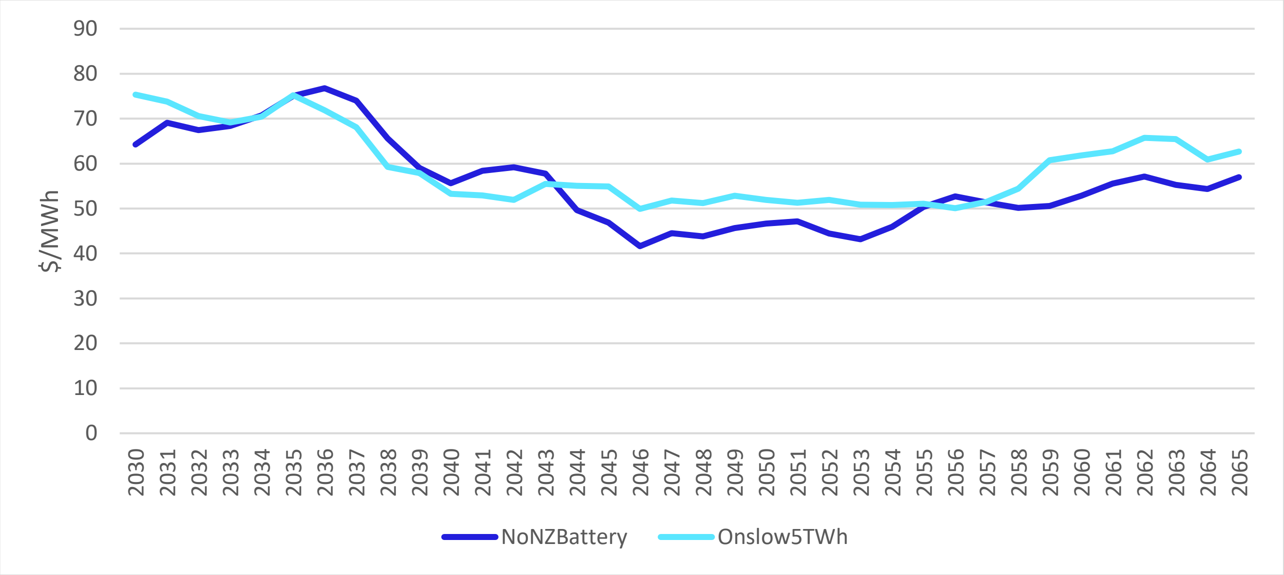
There is some indication that the GWAP od wind is higher in the Onslow case than the No NZ Battery case, but it is not particularly strong or consistent across the modelling horizon. As discussed with respect to TWAP, the market equilibrium is reached at a lower installed capacity in the Onslow case but at a similar price point as the price point is driven by the same capital cost assumptions in both cases.

**Figure 43. Generation-weighted average price – North Island wind**




However, the GWAP:TWAP ratio of wind does appear to be improved in the Onslow case – particularly in the South Island where TWAP is significantly lower in the Onslow case by the GWAP of wind is higher for most of the modelling horizon. This is likely the result of higher prices during low-price periods, which will be well correlated with high wind generation.

**Figure 44. Generation-weighted average price – South Island wind**



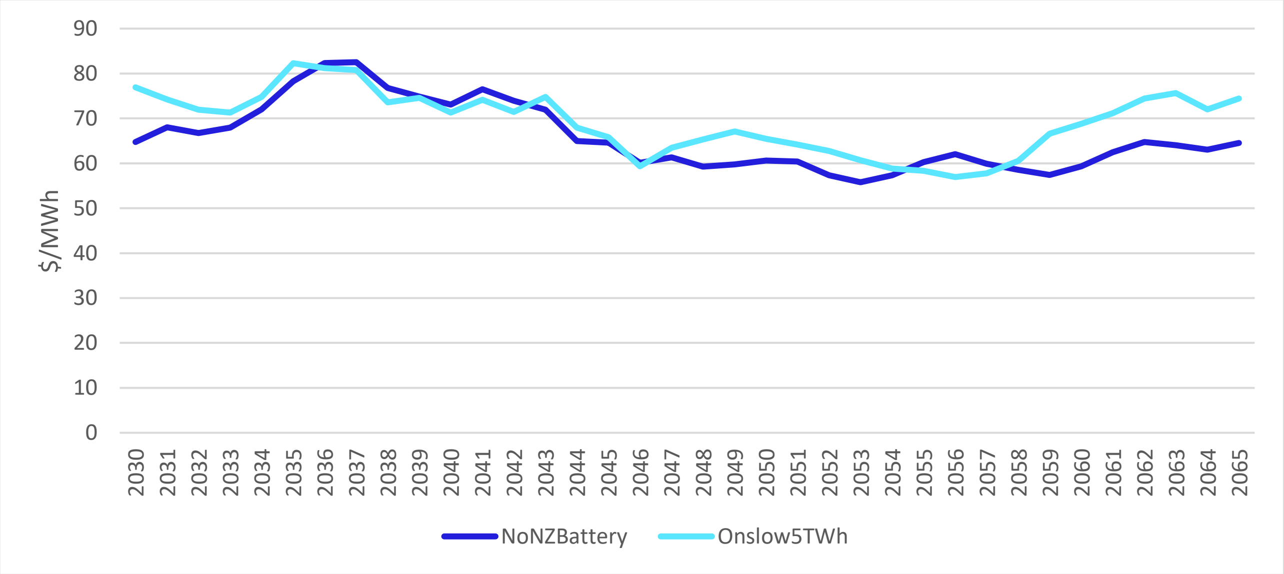

#### 5.5.3.2 Solar

Similar to wind generation, solar is not dispatchable, but it is also quite poorly correlated with SDDP prices due to the generation profile relative to national load profile.

As a result, solar GWAP is slightly below TWAP at the beginning of the modelling horizon and stays that way until solar installed capacity increases in the 2040s, when it begins to fall.

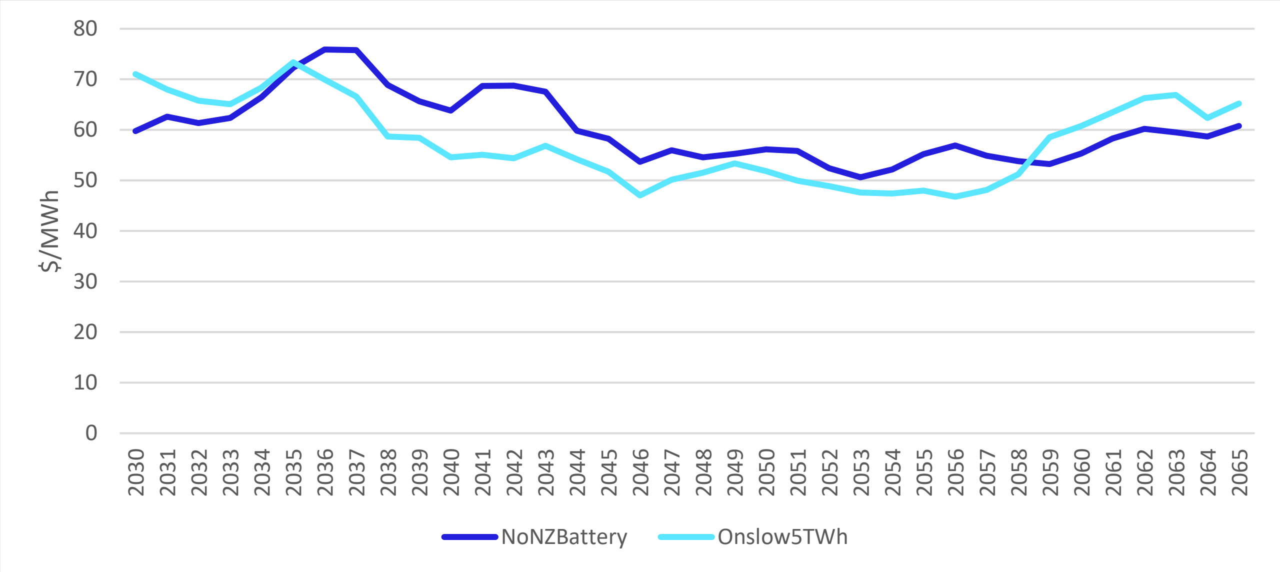
Also similar to wind, there is some sign that GWAPs are higher (at least in the North Island) in the Onslow case than the No NZ Battery case, but the impact is not consistent across the horizon.

**Figure 45. Generation-weighted average price – North Island grid-scale solar**




The GWAP impact of Onslow in the South Island is quite different for solar than seen for wind as solar is less well-correlated with the low-price periods so does not benefit as much from the price floor that Onslow tends to put on South Island prices. As result, the lower South Island TWAP in the Onslow case is largely carried through to the solar GWAP until the early 2060s when national TWAPs increase to the point where building South Island solar is justified in the Onslow case but here is not enough South Island solar capacity to saturate the market yet in that case.

Figure 46. Generation-weighted average price – South Island grid-scale solar




#### 5.5.3.3 Onslow pumping and generation

**Error! Reference source not found.** presents the generation-weighted and pump-weighted average prices for Onslow. GWAP is defined for Onslow in the same manner as described above and pump-weighted average price is analogously defined for pumping as the total cost of pumping in the year divided by the total energy consumed by the pump.

The pump-weighted average price sits relatively consistently at $25-$35/MWh across the modelling horizon, increasingly slightly over time. It is expected that the average pumping price would be quite stable as it is driven by the low end of prices which tend to gather around the same point – assuming that the market does not allow negative prices.

Onslow GWAP results show a distinct peak in the mid-to-late 2030s before stabilizing at $110/MWh-$150/MWh for the rest of the modelling horizon. The 2030s peak is driven partly by a TWAP increase and price volatility but also by SDDP's water values. In the late 2035 and 2036, when Onslow levels are still low in several inflow sequences, it will only generate when the system need is high. Whereas stable operation is reached, there will more cases when Onslow is dispatched at lower prices as storage levels are high and the risk of shortage is low.

Figure 47. Onslow Generation and Pump-weighted average price

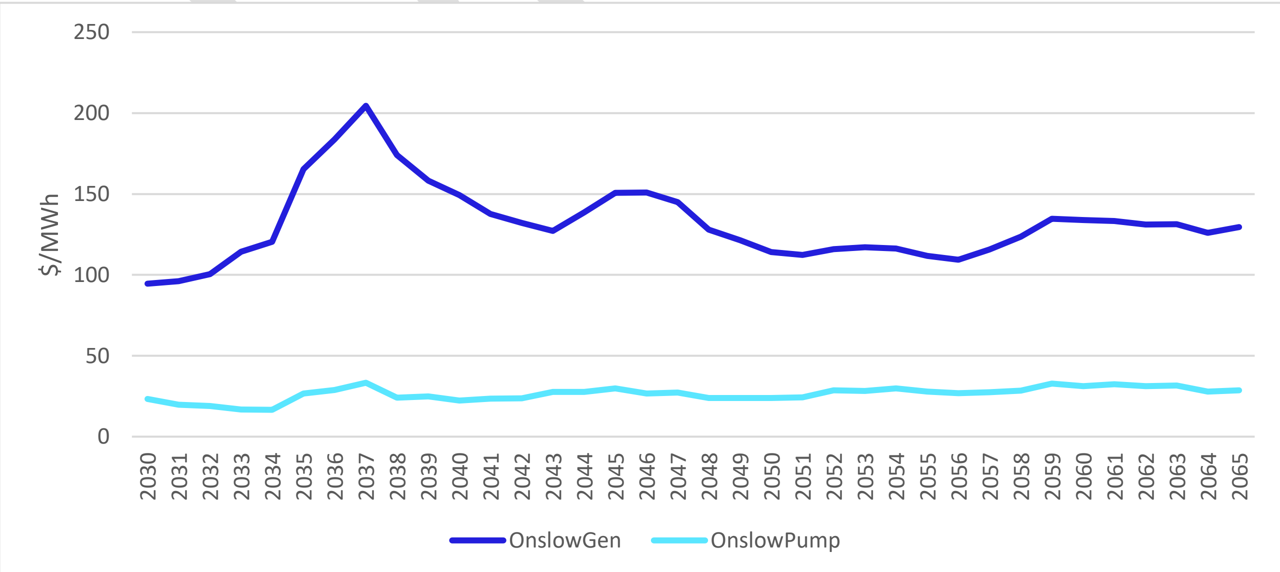


**Figure 48. Onslow net revenue distribution – 2030-2065**

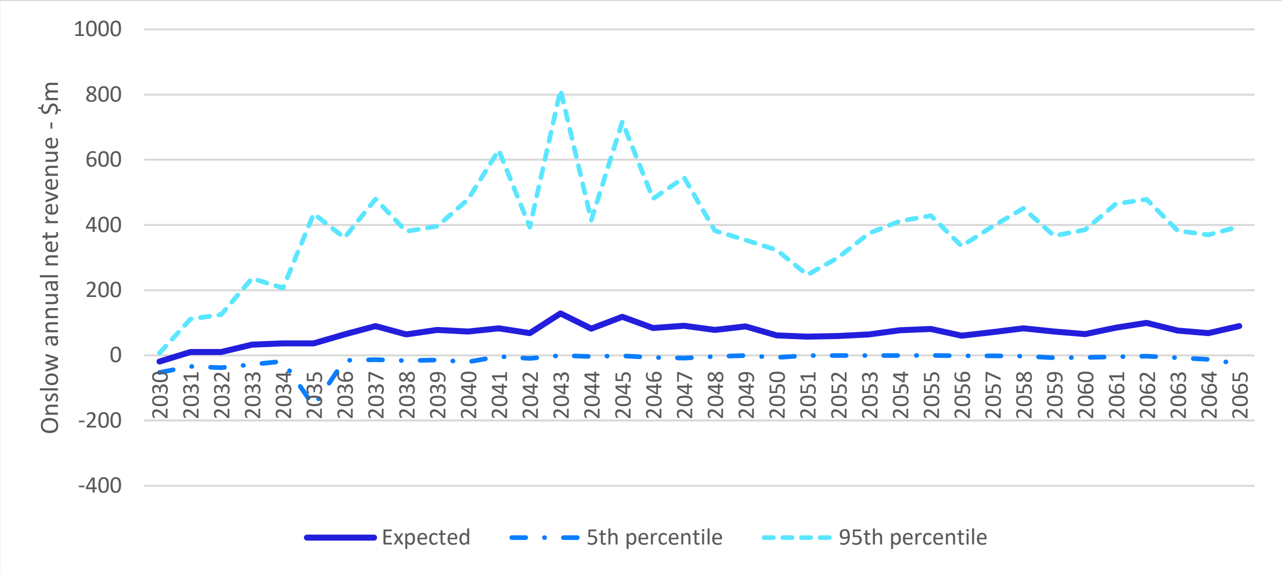



Figure 49 and Figure 50 are snapshots of Onslow net revenue by inflow sequence for 2040 and 2065, respectively and indicated that Onslow net revenue could increase and become more stable over time.

In 2040, the maximum modelled net revenue was almost one billion dollars with a mean across all inflow sequences of $73 million. Note that less than half of the inflow sequences modelled have a positive net revenue, suggesting that Onslow generation is being reserved for relatively unusual events. As result Onslow is losing a small amount of money in about 25% of annual inflow sequences, braking even or making a small amount of profit in a similar number of years and making almost all its net revenue in a handful of inflow sequences.

By 2065 however, Onslow is averaging a higher net revenue across inflow sequences ($90 million) but the distribution across inflow sequences is more even. The maximum net revenue is $600 million and approximately 85% of inflow sequences at least break even and only rarely losing money. This is the result of Onslow being held in reserve for high risk dry years but being more regularly cycled as a general firming service for VRE, meaning more regular income.

**Figure 49. Onslow net revenue by inflow sequence - 2040**

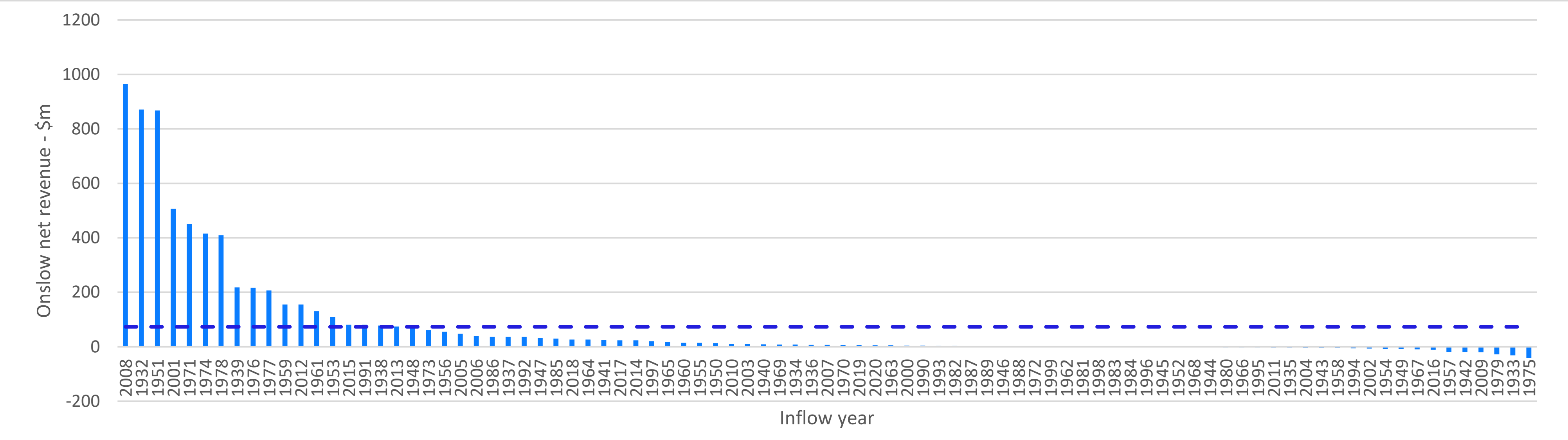
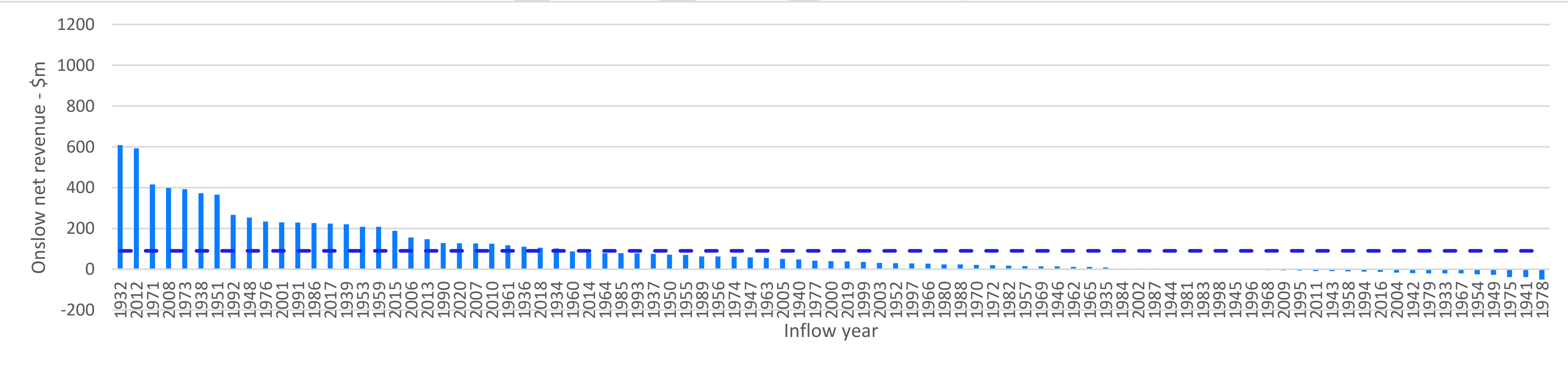



**Figure 50. Onslow net revenue by inflow sequence - 2065**



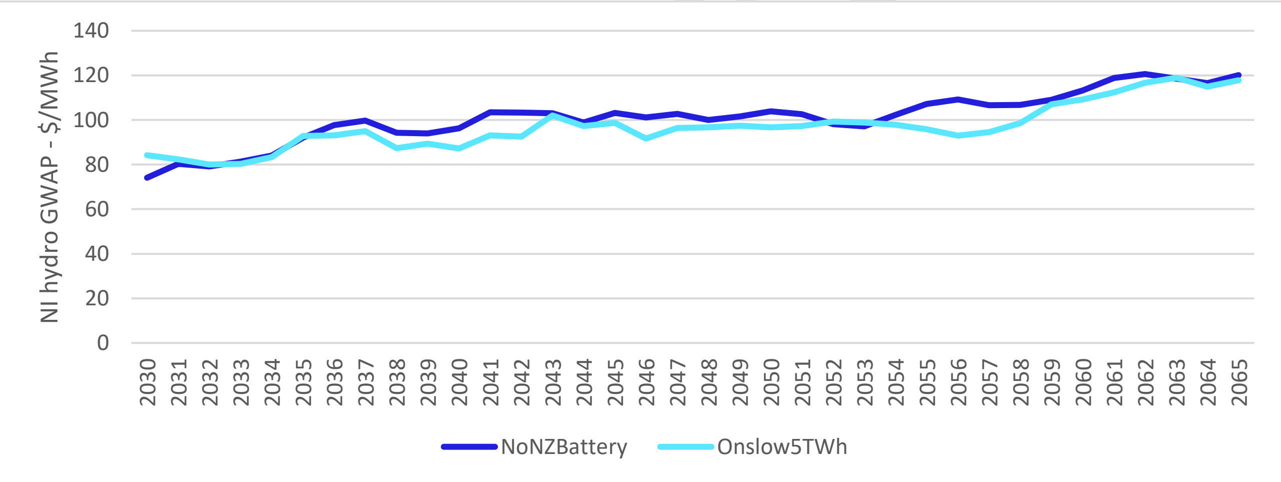
#### 5.5.3.4 Existing hydro

The GWAP impact on existing hydro is a slightly different story than that of other technologies present in this section as they are all existing and they are not affected by building more of the same technology as the only hydro available in the build-stack is Onslow.

As shown in **Error! Reference source not found.**, the expected GWAP of North Island hydro is likely to increase in both the Onslow case and the No NZ Battery case. This increase is driven by increasing the value of flexible generation in a 100% renewable future. North Island hydro is likely to be reserved – as much as chain flexibility allows – for higher-value periods such as low wind/solar and high demand.

This effect is slightly more marked in the in No NZ Battery case as North Island hydro, with GWAPs generally being $5/MWh-$10/MWh higher in that case than in the Onslow case – although that is not consistent across the modelling horizon. The difference is likely driven by the increased flexibility that Onslow provides to the system, albeit limited by generation capacity and HVDC transfer limits.

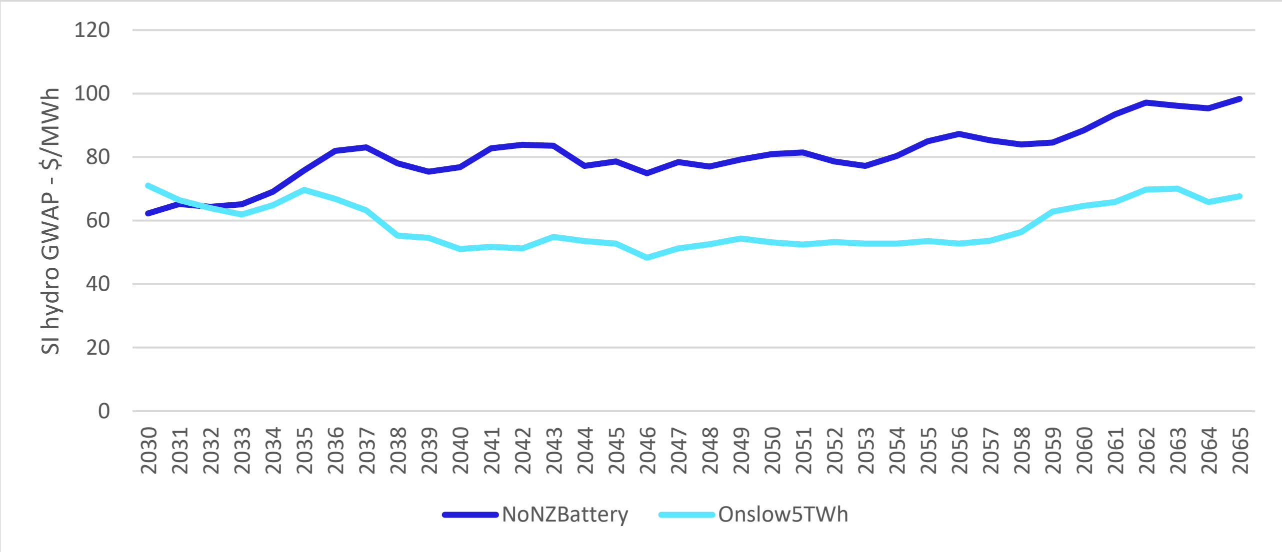
**Figure 51. Existing North Island hydro generation-weighted average price**




The existing South Island hydro plant, however, have significantly ($20/MWh-$25/MWh) and consistently lower GWAPs in the Onslow case than in the No NZ Battery case. The modelled GWAPs suggest a branch in South Island hydro policy from 2035. In the No NZ Battery case, South Island hydro starts to be increasingly reserved for risk management resulting in higher GWAPs and higher reservoir levels. (see section 5.4.2). By contrast, in the Onslow case, Onslow dominates the risk management role leaving the existing South Island hydro plant with less opportunity to capture shortage prices. In addition, the higher HVDC south-flow limit results in more north to south transfer of excess North Island generation.

The difference in South Island GWAPs for existing hydro between the two cases is almost double the difference in TWAP. The reasoning for this is the inverse of that of wind, where the GWAP relationship was counter to the TWAP relationship. While South Island wind GWAP had an outweighed benefit from a lift in in low prices, South Island hydro suffers an outweighed detriment due to the reduction in high price events.

**Figure 52. Existing South Island hydro generation-weighted average price**




## 5.6 Impact on load curtailment

This section presents three snapshots of load curtailment by inflow sequence in the Factual and Counterfactual.

For the same reasons discussed earlier with respect to prices, it is not necessarily expected that the Onslow case will always have less load curtailment than the No NZ Battery case. The Onslow case builds less energy supply and less additional peaking capacity (green peaker and batteries), so in some circumstances, it could result in more load curtailment than the No NZ Battery case even if the total system cost of build plus operation is less.

**Error! Reference source not found.**By 2050, average load curtailment is very similar across the two cases and there are more sequences where the No NZ Battery case has higher levels of load curtailment than the Onslow case. It appears that the drivers of load curtailment are different in the two cases as the Onslow case appears to have more load curtailment in the sequence where it curtails load, but there are several sequences where there is zero load curtailment in the Onslow case but relatively large amounts of load curtailment in the No NZ Battery case.

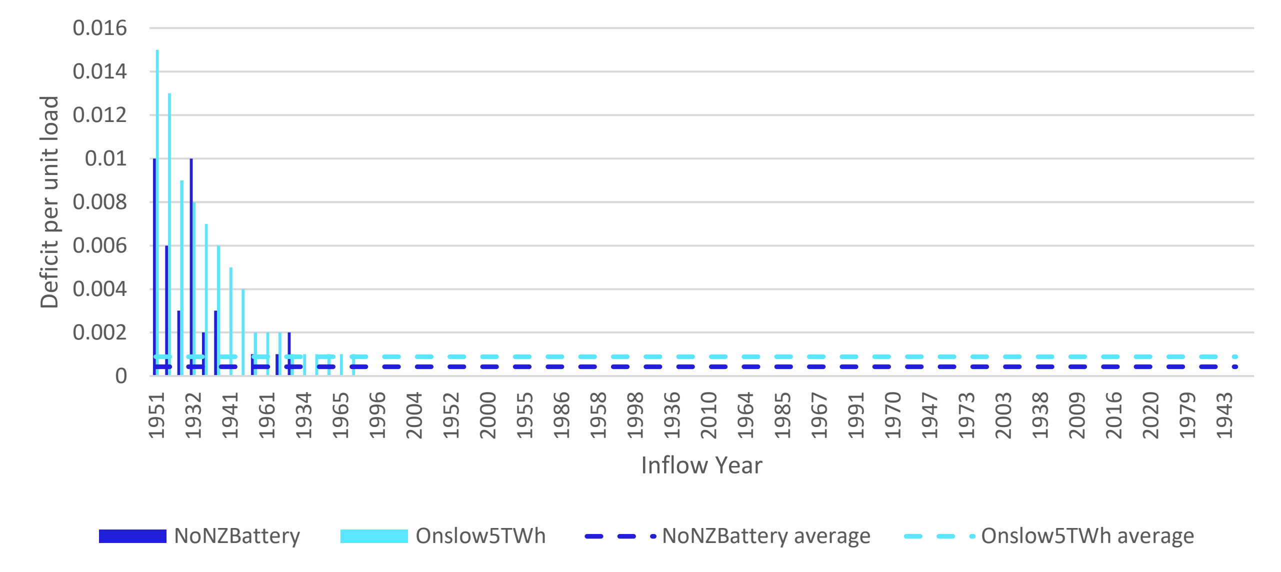
**Figure 54. Impact on load curtailment by hydro sequence - 2050**

Figure 53, Figure 54, and

Figure 55 show the annual proportion of load that was curtailed in each inflow sequence in the columns and the average across all inflow sequence in the dashed lines. The load curtailment included in these graphs includes all load that SDDP has chosen not to supply, from the economic load shedding at $700/MWh to involuntary load-shedding at $10,000/MWh. Each graph is sorted with sequence with the highest load curtailment in the Onslow case on the left and the lowest curtailment in the Onslow case on the right.

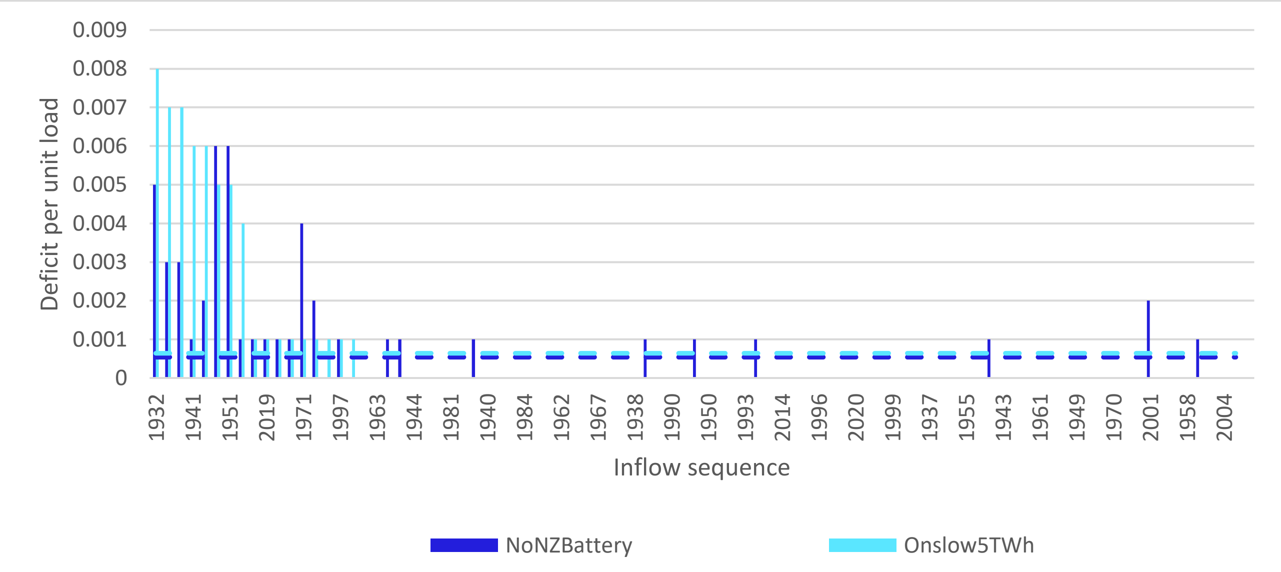
In 2035, the Onslow case has close to twice the load curtailment as the No NZ Battery case, on average more load curtailment in almost all sequences where load curtailment occurs. This outcome is consistent with those seen in prices and reservoir levels in 2035 as the system is yet to reach a stable state with Onslow at economic levels.

**Figure 53. Impact on load curtailment by hydro sequence - 2035**



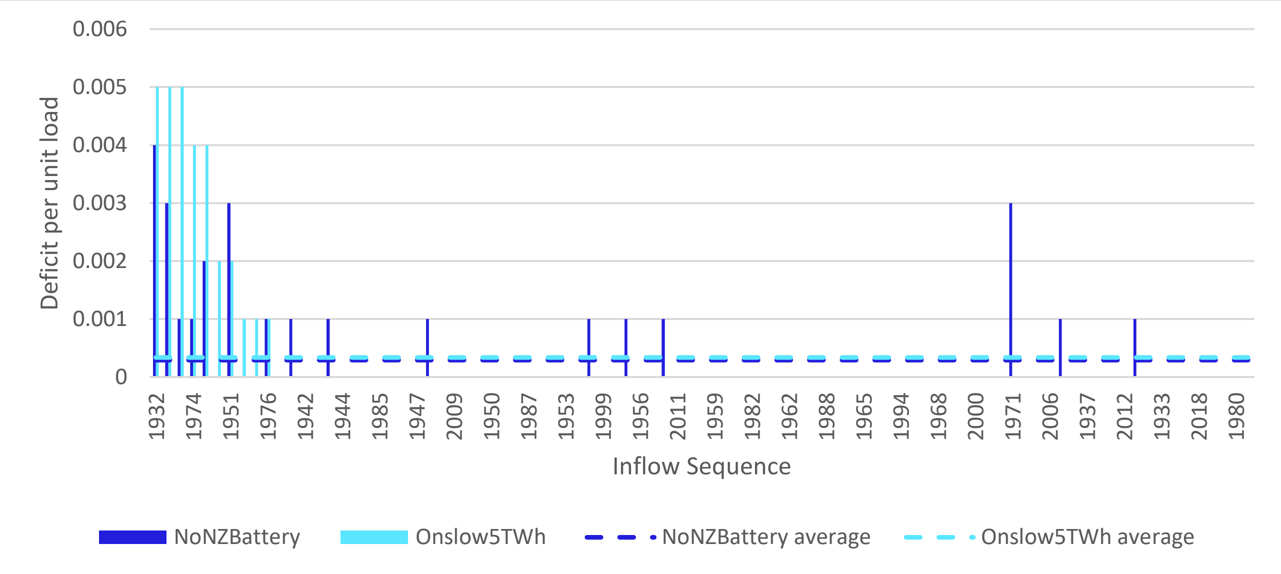

By 2050, average load curtailment is very similar across the two cases and there are more sequences where the No NZ Battery case has higher levels of load curtailment than the Onslow case. It appears that the drivers of load curtailment are different in the two cases as the Onslow case appears to have more load curtailment in the sequence where it curtails load, but there are several sequences where there is zero load curtailment in the Onslow case but relatively large amounts of load curtailment in the No NZ Battery case.

**Figure 54. Impact on load curtailment by hydro sequence - 2050**




Modelled load curtailment in 2065 follows a similar pattern to that in 2050, with average curtailment similar in both cases, but the sequences which show curtailment shifting across the cases.

**Figure 55. Impact on load curtailment by hydro sequence - 2065**




## 5.7 Impact on Dunkelflaute events

This section presents three 'dunkelflaute' events observed in the hourly results and compared between the Onslow case and the No NZ Battery case. The events were selected by filtering for very high price events in the Onslow case and drawing the pricing, inflow, dispatch and curtailment data for both cases. All events presented in this section occur in the 2050 modelled year.

It became clear during this analysis that these high prices events were usually the product of the initial reservoir levels in 2050 as well as the inflows during 2050. To provide greater context, we have therefore presented weekly inflows in 2049 and 2050 for each case with an hourly breakdown of the week of the event.

Three high price events are presented to demonstrate a range and we find that – while the Onslow cases tend to have lower load curtailment during these event – a system that has reduced its capacity due to the presence of Onslow could be vulnerable to a protracted drought that empties Lake Onslow leaving it without the intended risk mitigation or additional supply.

### 5.7.1 DunkelFlaute One – 1970-71 inflows

The first event occurred in the simulation using 1970 and 1971 historical inflows for 2049 and 2050 modelled years. The 1970 sequence was characterized by below average hydro inflows over winter and very high inflows over spring and the 1970-71 summer as shown in **Error! Reference source not found.**. VRE inflows (solar and wind energy inflows are combined in the graph below) were also above average over the 1970-71 summer but VRE and hydro inflows dropped to well below average in autumn and winter 1970.

**Figure 56. DF One – Weekly energy inflows**

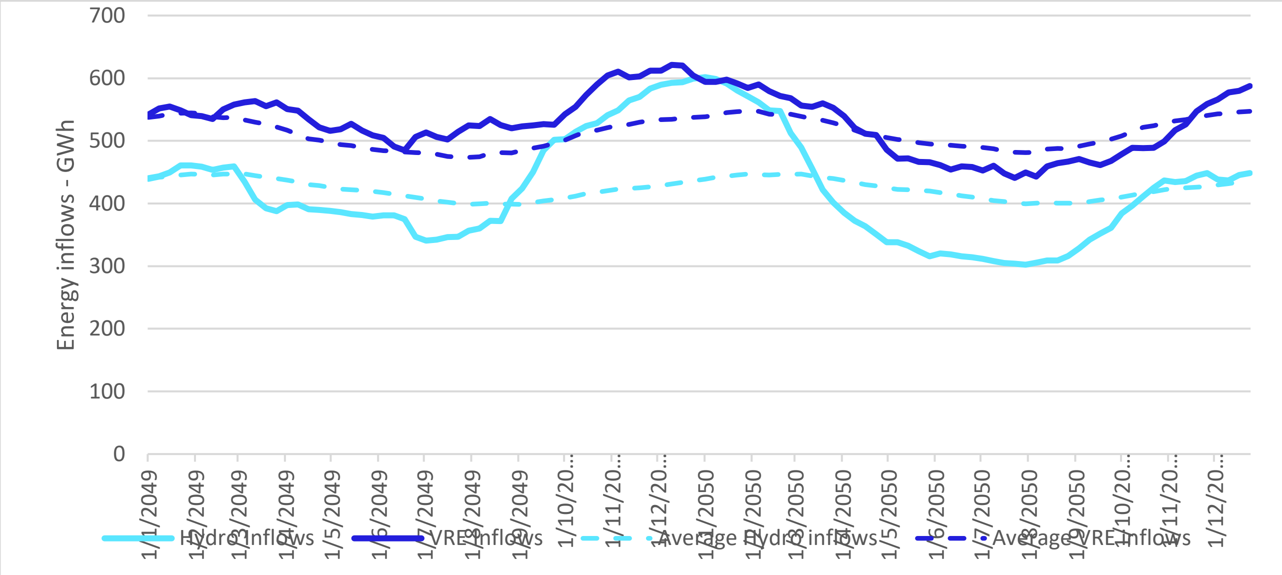
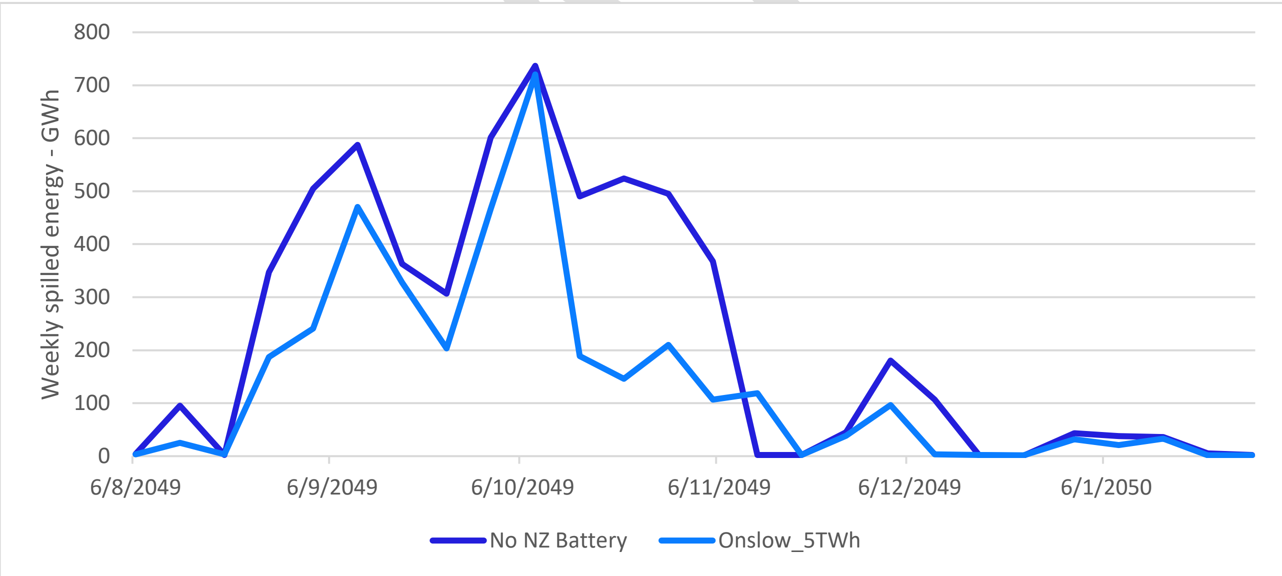



Figure 57 shows the impact of the 1970-71 inflow sequence on energy spillage in the Onslow and No NZ Battery cases. The No NZ Battery case is forced to spill significantly more energy at the end of 2049 due to limited flexibility and high lake levels.

**Figure 57. DF One – Energy Spillage**




The net result of the inflows during 2049 is that reservoirs levels are generally high at the beginning of 2050.

Figure 52Figure 59 show the weekly reservoir levels across 2050 for this inflow sequence simulation. For context, average January reservoir levels across all inflow sequences in the Onslow case were:

- Taupo: 470 GWh
- Pukaki: 834 GWh
- Tekapo: 512 GWh
- Manapouri: 313 GWh
- Onslow: 1628 GWh

**Figure 58. DF One – Reservoir levels in the Onslow case**

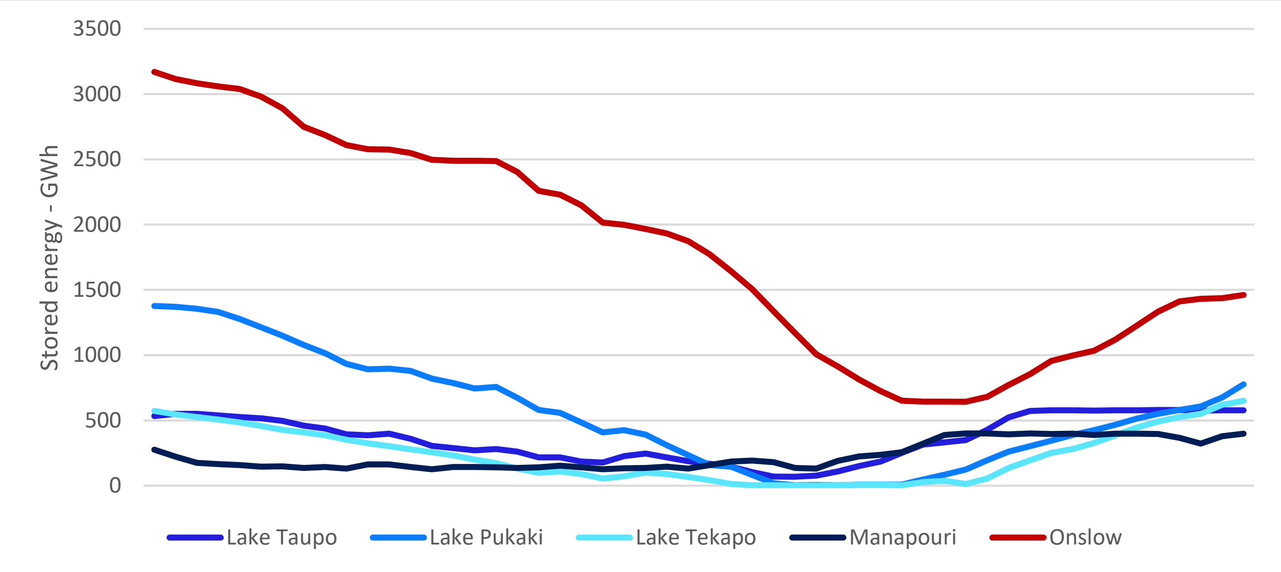
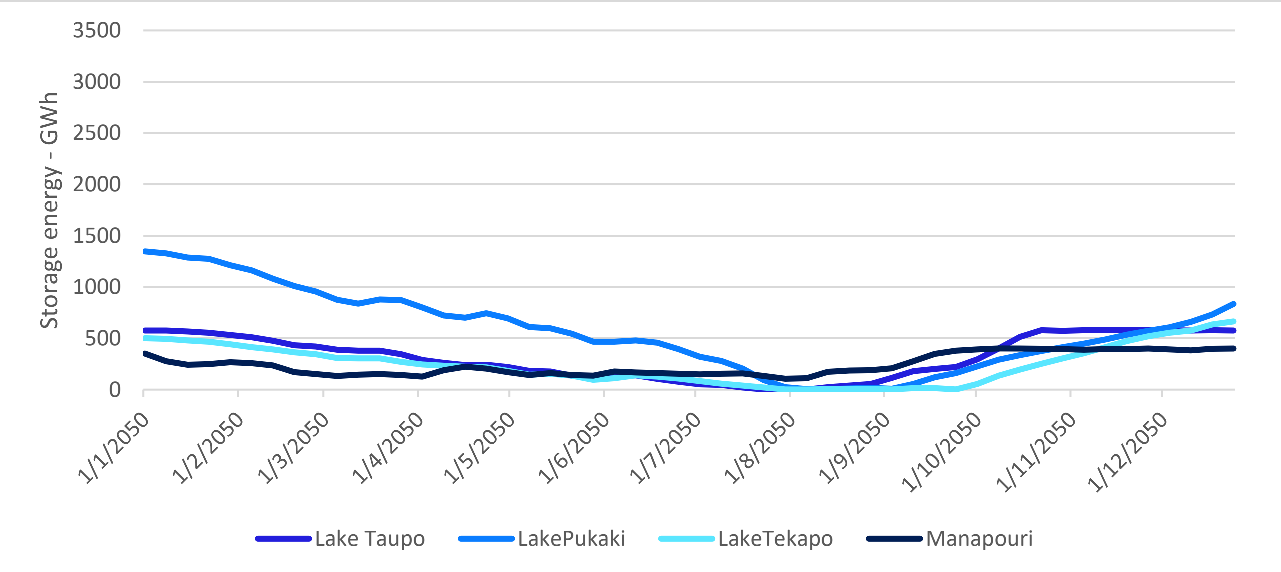



**Figure 59. DF One – Reservoir levels in the NoNZBattery case**




Average January 2050 reservoir levels across all inflow sequences in the No NZ Battery case were:

- Taupo: 508 GWh
- Pukaki: 1030 GWh
- Tekapo: 565 GWh
- Manapouri: 326 GWh

Note firstly, that both cases start 2050 with similar reservoir levels in the existing storage lakes but the Onslow case has an additional 3170 GWh stored in Lake Onslow. This sequence is using Lake Onslow as additional storage rather than as replacement for storing energy in one of the existing lakes.

Secondly, note that all reservoirs other than Manapouri empty by the end of July 2050 in the No NZ Battery case, which is when this event occurs. By contrast, the Onslow still has a lot of energy stored in Lake Onslow throughout the year.**Error! Reference source not found.**

**Figure 61. DF One – Hourly dispatch by technology – NoNZBattery case**

Figure 54 and Figure 61 show the hourly dispatch by technology, price and load curtailment in the Onslow and No NZ Battery cases, respectively.

Note the dunkelflaute event start as the wind production drops from ~4 GW at 6pm on July 24th to less than 500 MW for 72 hours from the beginning of July 26th.

In the Onslow case, existing hydro production is increased to cover the shortfall, but Onslow is also contributing due to the relatively high reservoir levels. Prices increase – particularly in the North Island as an additional tranche of load curtailment is used, but they soon return to the prices seen at the beginning of the week. Importantly, the combination of geothermal, green peakers, Onslow, and existing hydro plant maintain a peak daily contribution of approximately 7000 MW across the dunkelflaute event.

By contrast, the No NZ Battery case is forced to use the next tranche of load curtailment as soon as the dunkelflaute event begins. Geothermal, green peakers and the existing hydro plant combined contribute a daily peak of just 6,500 MW, leaving the rest to be covered by batteries, solar and load curtailment. As a result, more load is curtailed more often throughout the week, as shown in Figure 56. DF One – Load curtailment during event

**Figure 60. DF One – Hourly dispatch by technology – Onslow case**

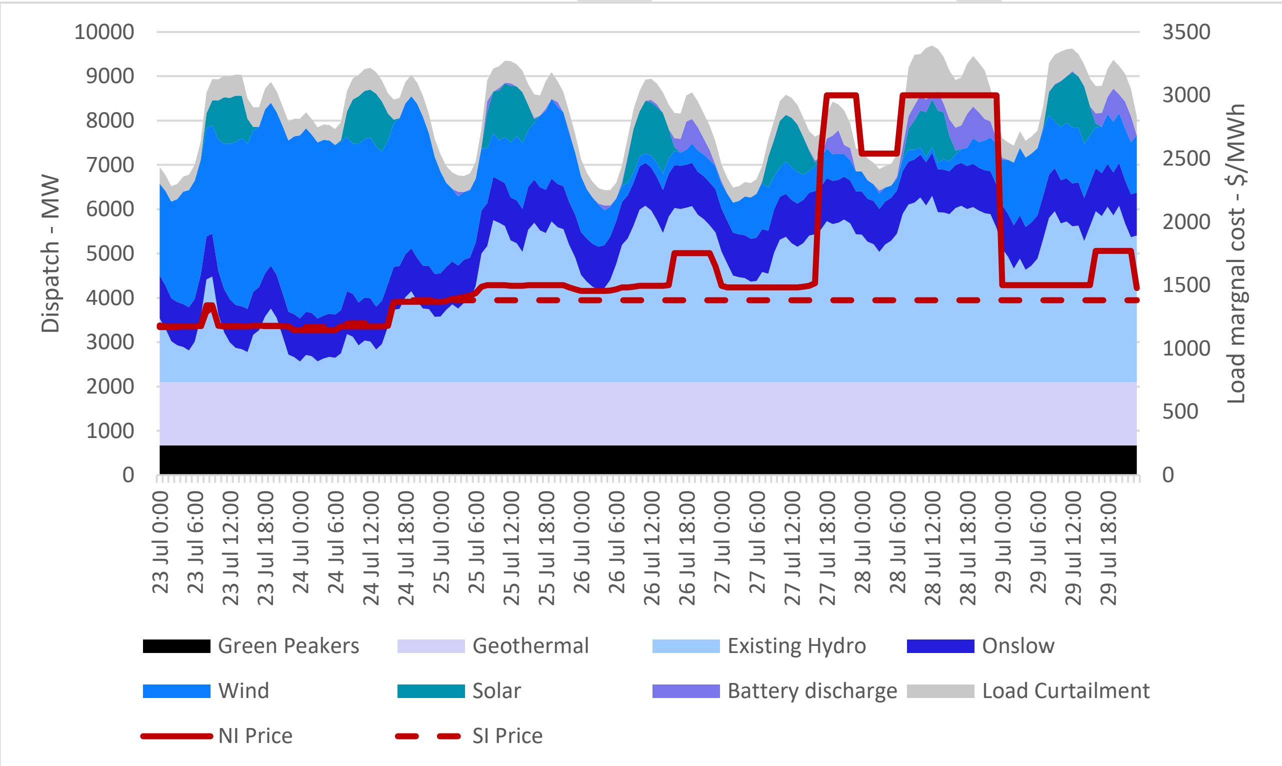


**Figure 61. DF One – Hourly dispatch by technology – NoNZBattery case**

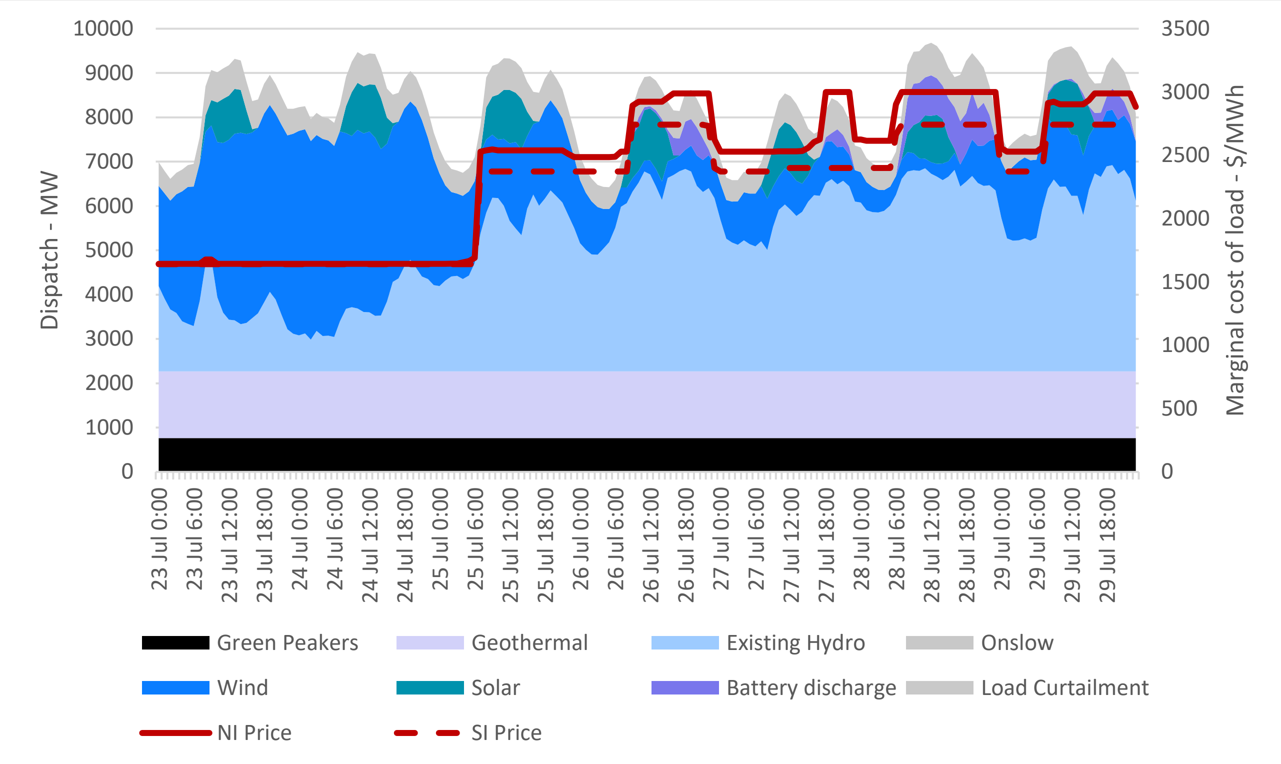
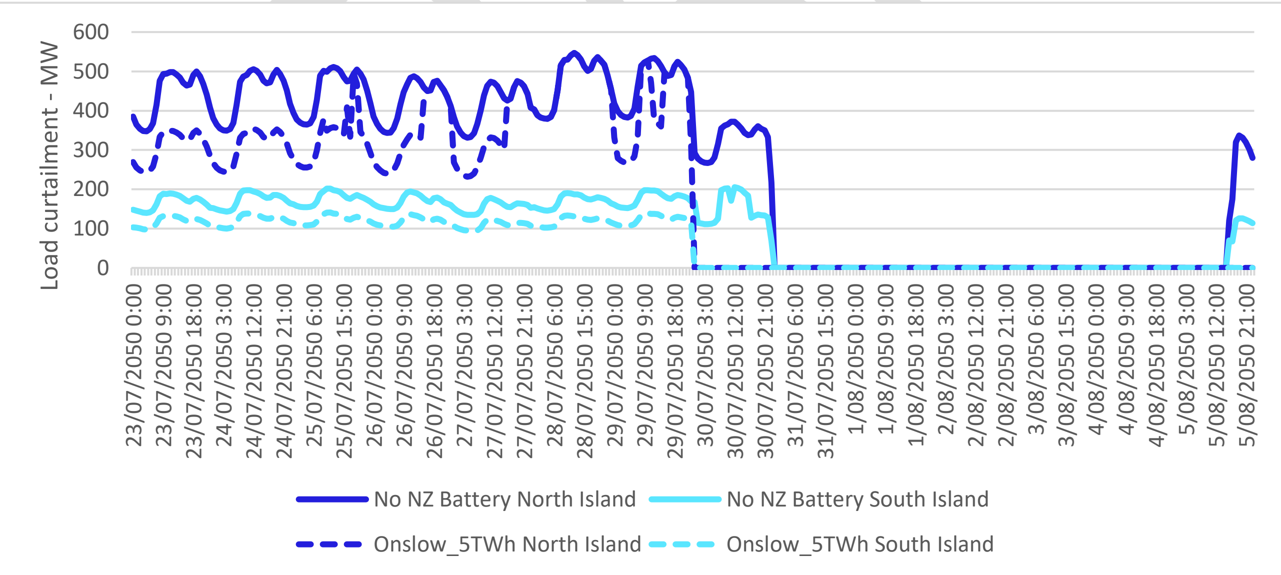



**Figure 62. DF One – Load curtailment during event**

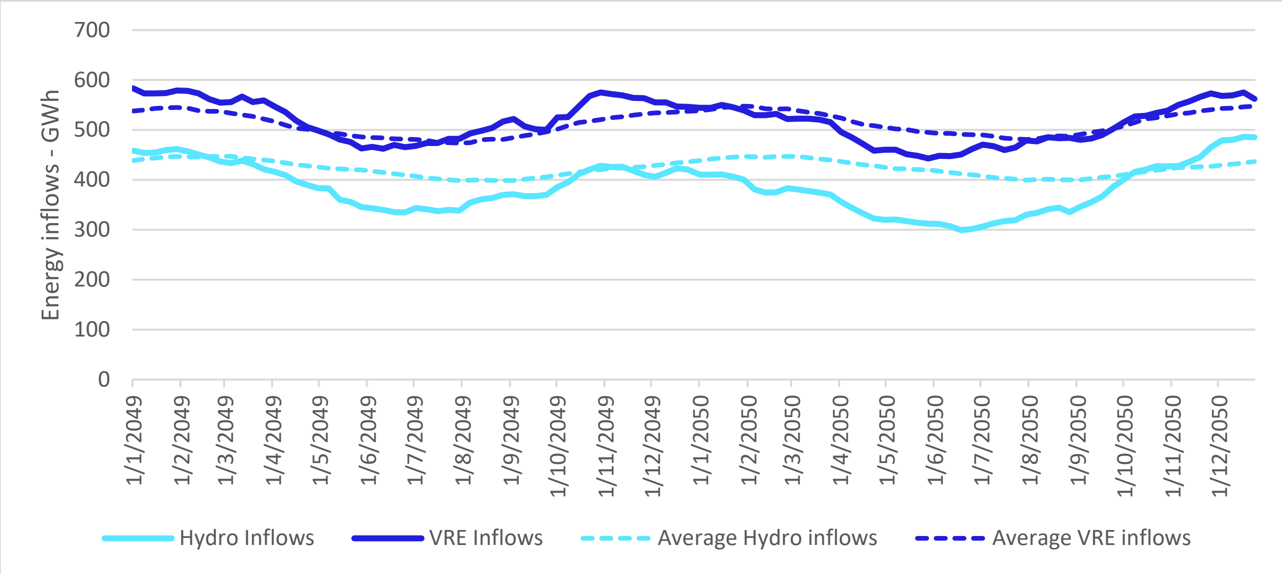



## DunkelFlaute Two – 2007-08 inflows

The second event occurred in the simulation using 2008 and 2009 historical inflows for 2049 and 2050 modelled years. The 2008 sequence was characterized by below average hydro inflows over winter and average inflows over spring as shown in

Figure 63. VRE inflows (solar and wind energy inflows are combined in the graph below) were average over 2008 and early 2009. From early 2009, hydro inflows dropped to well below average and in autumn, VRE inflows dropped similarly, triggering the high-price event.

**Figure 63. DF Two – Weekly energy inflows**




The net result of the inflows during 2049 is that reservoirs levels are generally low at the beginning of 2050. Figure 58 and

Figure 65 show the weekly reservoir levels across 2050 for this inflow sequence simulation. For context, average January reservoir levels across all inflow sequences in the Onslow case were:

- Taupo: 470 GWh
- Pukaki: 834 GWh
- Tekapo: 512 GWh
- Manapouri: 313 GWh
- Onslow: 1628 GWh

**Figure 64. DF Two – Reservoir levels in the Onslow case**

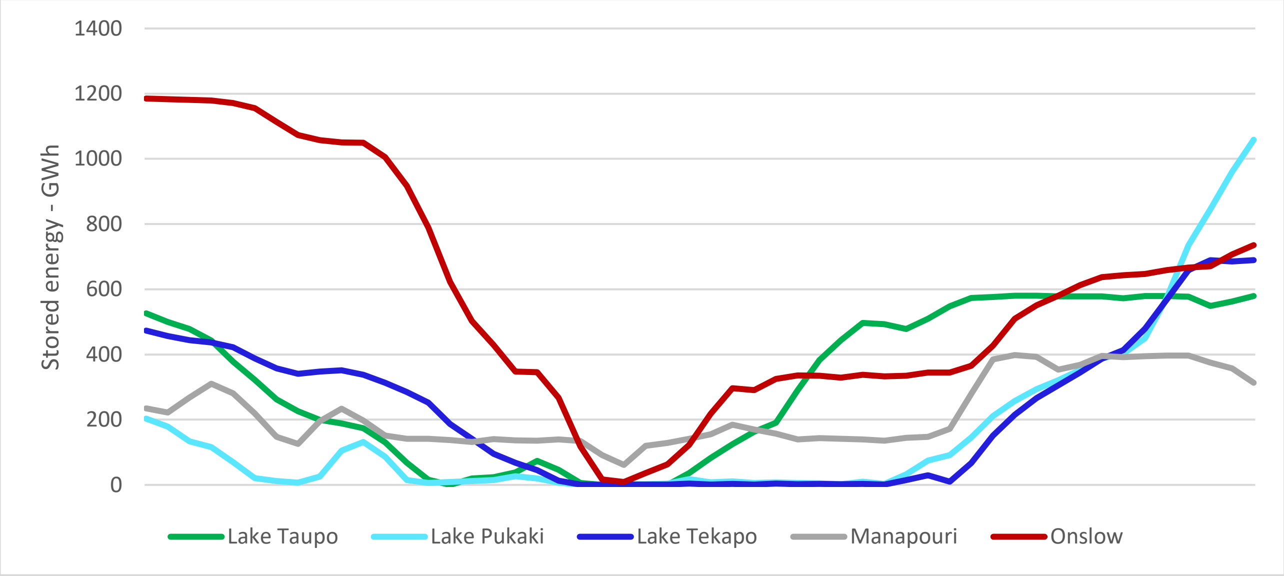
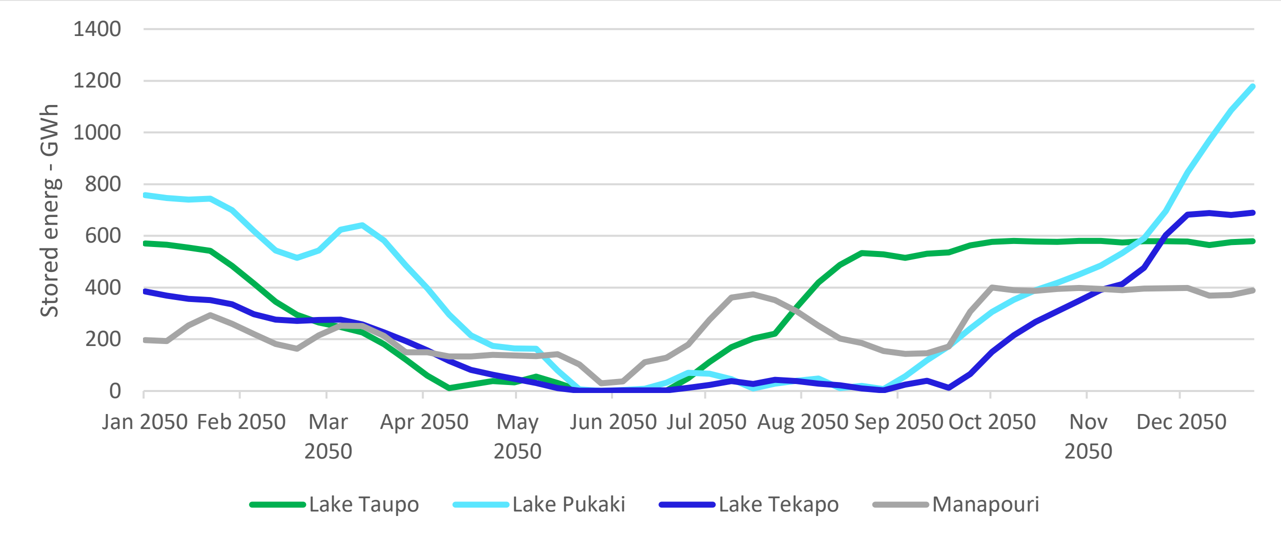


**Figure 65. DF Two – Reservoir levels in NoNZBattery case**




Average January 2050 reservoir levels across all inflow sequences in the No NZ Battery case were:

- Taupo: 508 GWh
- Pukaki: 1030 GWh
- Tekapo: 565 GWh
- Manapouri: 326 GWh

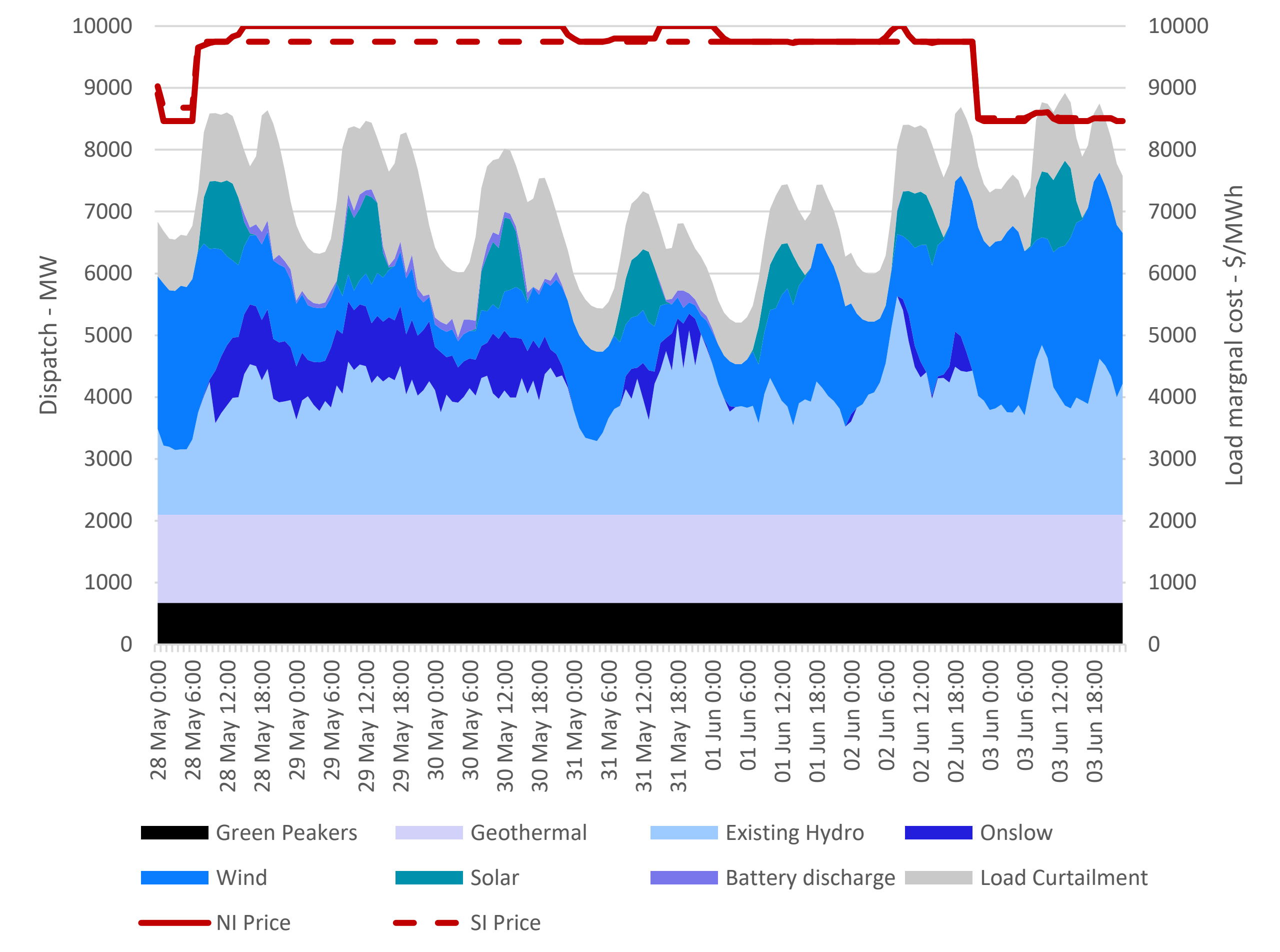
Both cases are reaching very low storage levels by winter. The No NZ Battery case has emptied all the reservoirs by the beginning of June 2050, while the Onslow case retains some storage in Manapouri.

Figure 66 and Figure 67 show the hourly dispatch by technology, price and load curtailment in the Onslow and No NZ Battery cases, respectively.

Note the dunkelflaute event start as the wind production drops from ~3 GW at 6am on May 28th to less than 1,000 MW for almost four days from the evening of May 28th.

In the Onslow case, Onslow generation is already being rationed due to low reservoir levels, but the capacity contribution from Onslow there remains enough water to allow Onslow to contribute to meeting peak demand. Prices quickly increase to the involuntary load-shedding level and stay there for most of the week before dropping slightly when wind production increase at the end of the week. This price differential allows the batteries to make a contribution as arbitrage opportunity arises.

**Figure 66. DF Two – Hourly dispatch by technology – Onslow case**




In the No NZ Battery case, there is very little flexibility left in the existing hydros, so they are restricting to using the inflows in the week. Without the additional capacity provided by Onslow, this results in SDDP being forced to empty the exiting lakes completely meaning that prices do not drop when wind production increases at the end of the week and batteries have little opportunity to arbitrage.

**Figure 67. DF Two – Hourly dispatch by technology – NoNZBattery case**

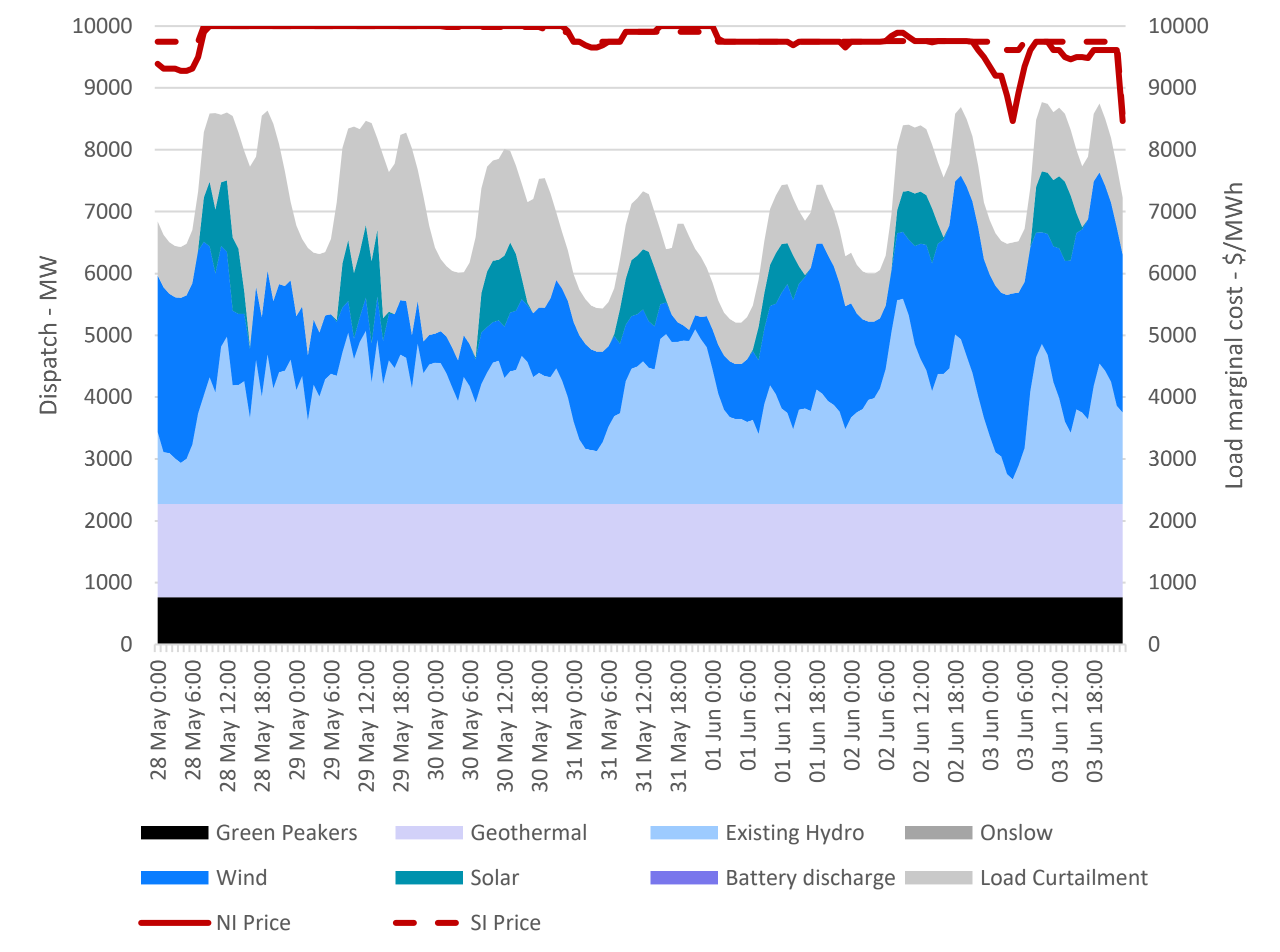
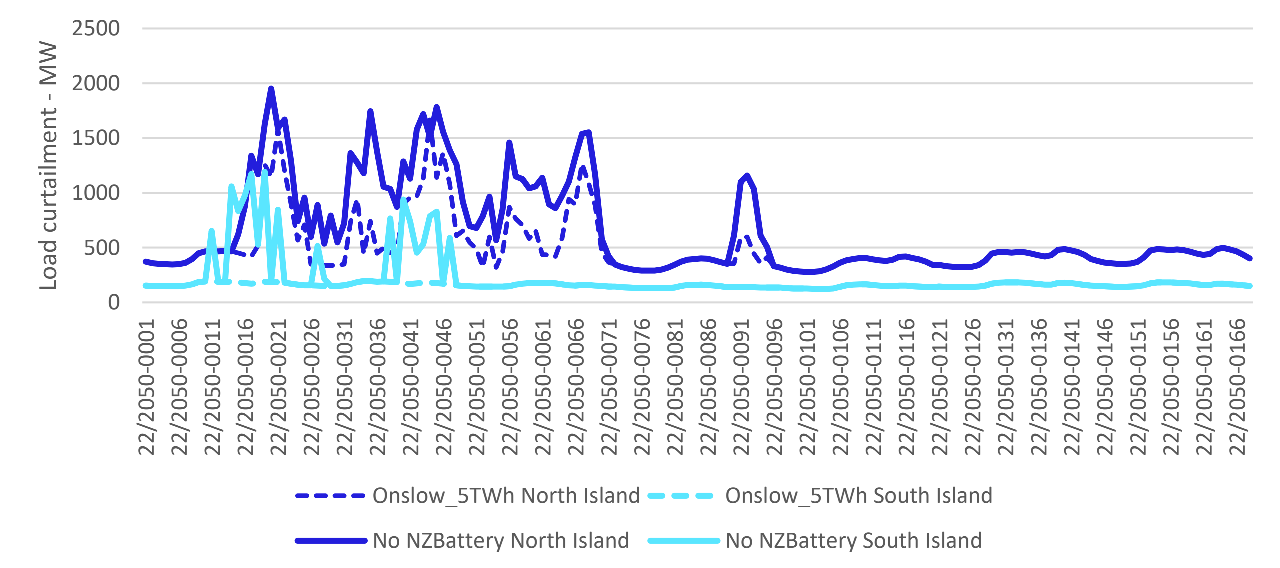



Figure 68 shows that load curtailment in during the event is greater in the No NZ Battery case than in the Onslow case in the North Island and the South Island.

**Figure 68. DF Two – Load curtailment during event**

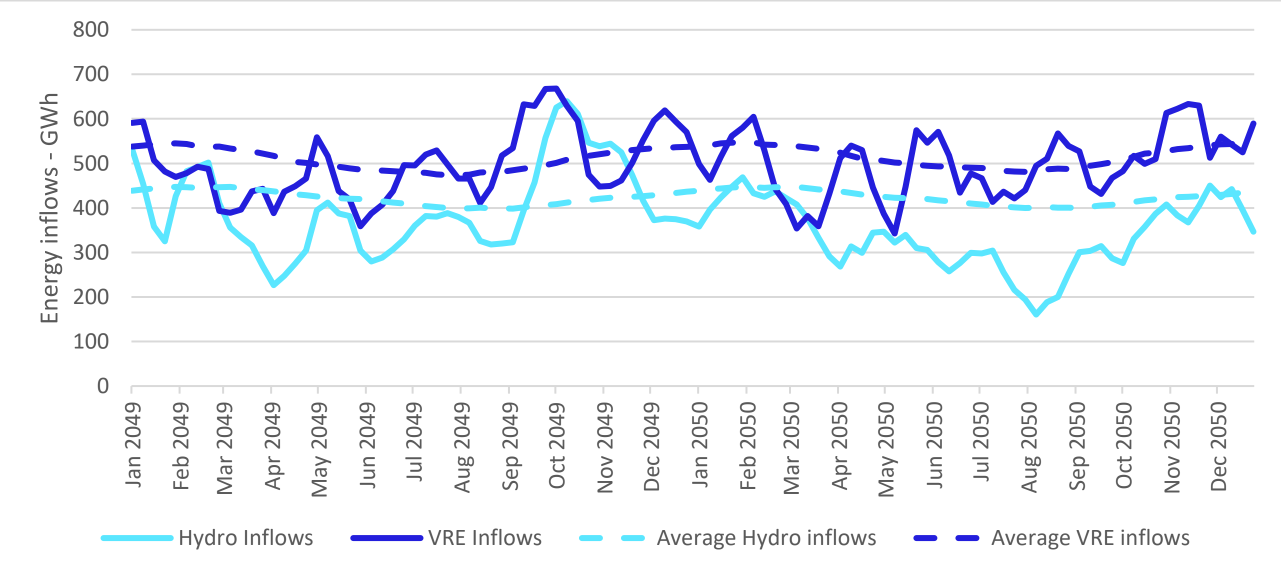


## DunkelFlaute Three – 2020-1932 inflows

The second event occurred in the simulation using 2020 followed by 1932 historical inflows for 2049 and 2050 modelled years. Note that this sequence obviously did not occur but is simulated as a consequence of the way that SDDP simulation carousel to the beginning of the historical inflow sequence when the reach the end of the historical data.

The 2020 sequence was characterized by below average hydro inflows for much of the year but high inflows over spring as shown in **Error! Reference source not found.**. VRE inflows (solar and wind energy inflows are combined in the graph below) were volatile but trending below average in 2020 and 1932. From early 1932, hydro inflows dropped to well below average and continued to decrease, resulting in one of the worst droughts on record. VRE inflows oscillated around average, but a relatively moderate dunkelflaute event in September while system storage was very low resulted in a high price event in which the Onslow case performed more poorly than the No NZ Battery case.

**Figure 69. DF Three – Weekly energy inflows**




The net result of the inflows during 2049 is that reservoirs levels are generally low in the largest storage lake (Pukaki and Onslow) but average across the rest of the system.

Figure 64 and Figure 71 show the weekly reservoir levels across 2050 for this inflow sequence simulation. For context, average January reservoir levels across all inflow sequences in the Onslow case were:

- Taupo: 470 GWh
- Pukaki: 834 GWh
- Tekapo: 512 GWh
- Manapouri: 313 GWh
- Onslow: 1628 GWh

**Figure 70. DF Three – Reservoir levels in the Onslow case**

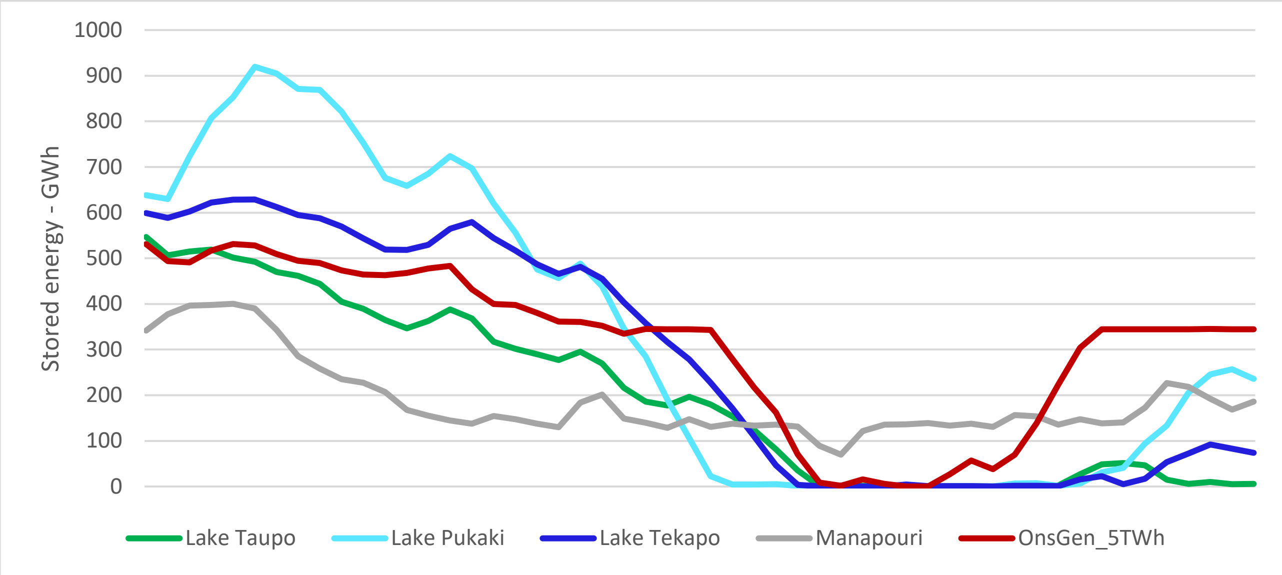
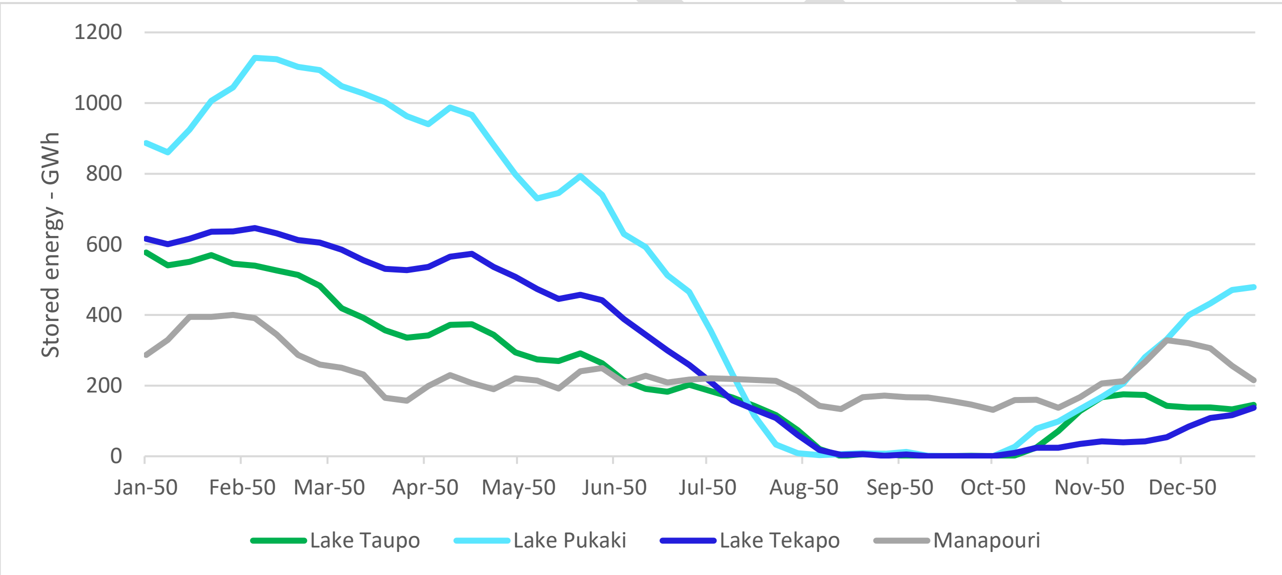



**Figure 71. DF Three – Reservoir levels in the NoNZBattery case**




Average January 2050 reservoir levels across all inflow sequences in the No NZ Battery case were:

- Taupo: 508 GWh
- Pukaki: 1030 GWh
- Tekapo: 565 GWh
- Manapouri: 326 GWh

Both cases empty all reservoirs other than Manapouri by the end of August 2050 and remain extremely low for several months.

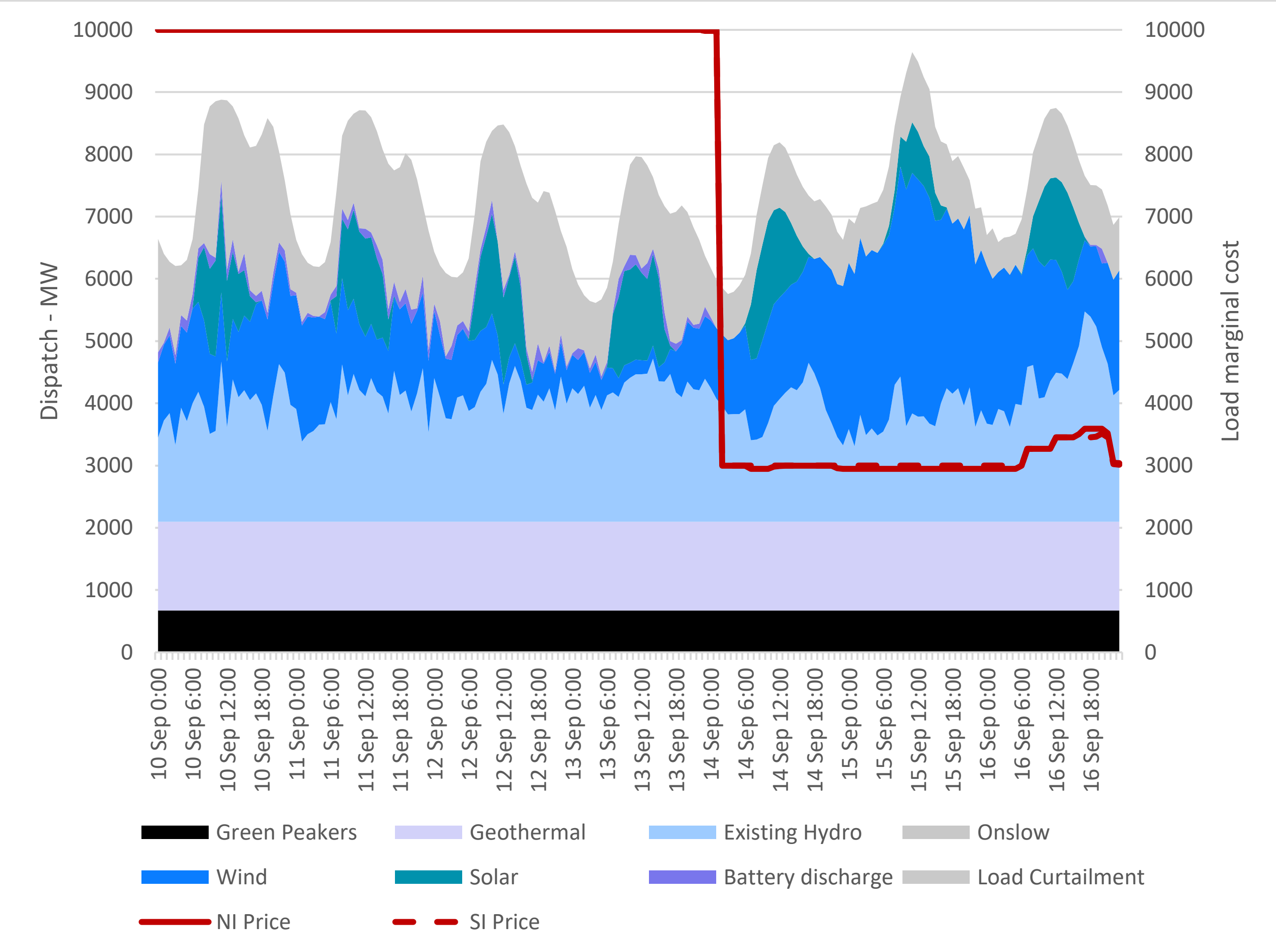
Figure 72 and

Figure 73 show the hourly dispatch by technology, price and load curtailment in the Onslow and No NZ Battery cases, respectively.

The high price event is already underway when the week starts due to the very low storage levels and low inflows limiting the contribution of the hydro plant. Renewable contribution is also low, but a genuine dunkeflaute event begins in on September 12th and lasts less than 48 hours. The primary focus of this comparison is the contribution of Onslow during the week and the different results after the dunkelflaute event finishes and wind production increases.

In the Onslow case, Lake Onslow is empty, so no Onslow capacity is available. Low lake levels in the existing reservoirs mean and low inflows during the week mean that all hydro generation is limited result in continued involuntary load-shedding until wind production increases on September 14th. This price differential allows the batteries to make a contribution as arbitrage opportunity arises.

**Figure 72. DF Three – Hourly dispatch by technology – Onslow case**




The No NZ Battery case look very similar to the Onslow case: limited hydro dispatch, high prices until wind production increases but the load curtailment numbers are higher in the Onslow case than the No NZ Battery case.

**Figure 73. DF Three – Hourly dispatch by technology – NoNZBattery case**

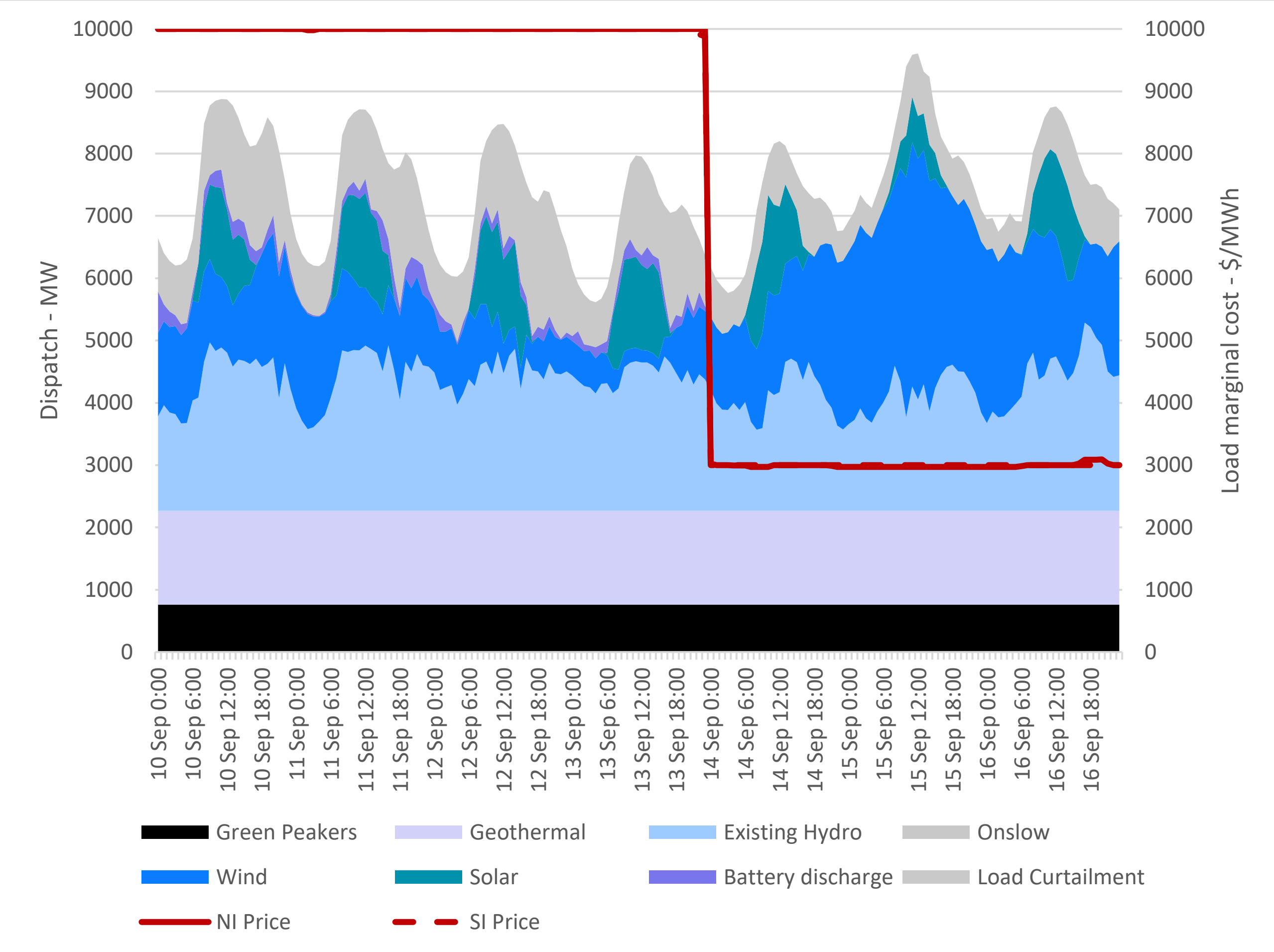
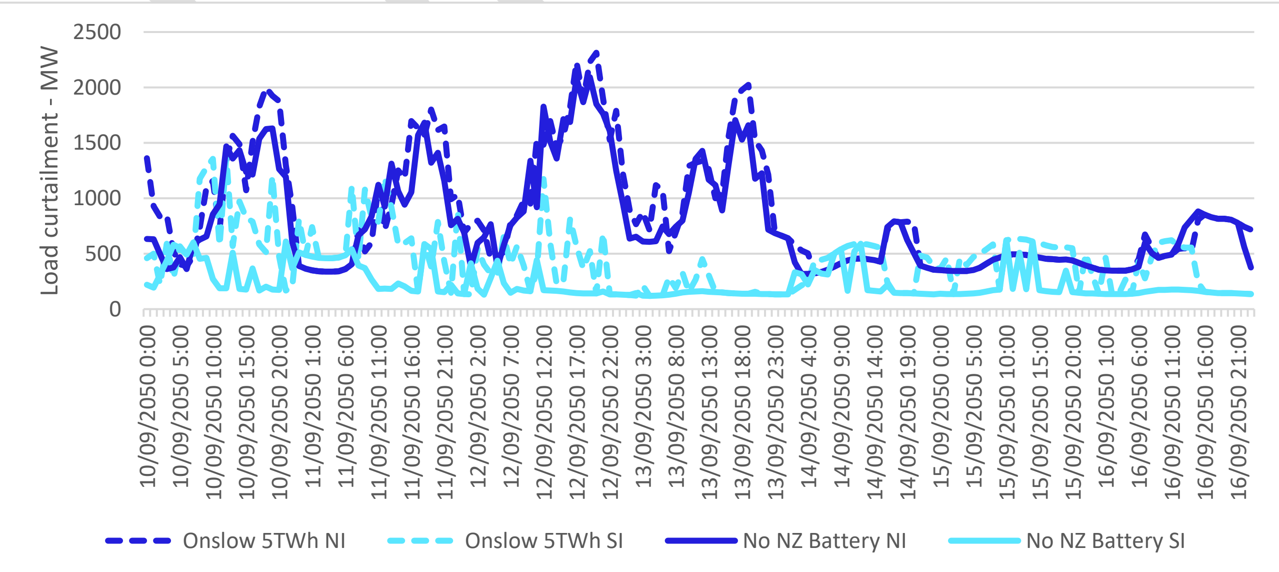



Figure 74**Error! Reference source not found.** shows the additional load curtailment in the Onslow case relative to the No NZ Battery case in the North Island and the South Island. In this sequence, the lower installed capacity of geothermal, green peakers in the Onslow case results in higher load curtailment because Lake Onslow has already been emptied by a protracted drought.

**Figure 74. DF Three – Load curtailment during event**



# 6. Next steps

This report presents the outcomes of work completed to the end of 2022 and is intended to be an interim report to be replaced by a final report issued at the conclusion of our investigation.

The next phase of work will include:

- Review of dunkelflaute results with adjusted OptGen configuration: we have spent a lot of time with the developers of OptGen and SDDP improving the implementation and our understanding of the interactions between OptGen and SDDP, particularly with respect hourly simulations. Before locking down our current No NZ Battery and Onslow 5 TWh outcomes as the reference point for further cases, we would like to confirm that adjustments to OptGen and/or SDDP configuration based on recent model developments and advice would not impact the outcomes.
- Model Onslow 3 TWh and 7.5 TWh sensitivities
- Develop approach for modelling long-term commitment in SDDP to be used with flexible geothermal plant in the portfolio option
- Model Portfolio Option
- Model a Tiwai stays sensitivity

# Appendix A. Demand forecast

**Table 4. Demand forecast**

| Years | Base Load Excl. Twi | Rooftop Solar Generation | Electrified Heat Load | EV Load | Twi Load | System Net Load |
|---|---|---|---|---|---|---|
| 2022 | 37.25583749 | -0.168298101 | 0.046810541 | 0.127766454 | 5.028309963 | 42.29042635 |
| 2023 | 37.65736016 | -0.193280495 | 0.080991298 | 0.165174487 | 4.9029251 | 42.61317055 |
| 2024 | 37.96634908 | -0.231386038 | 0.184659005 | 0.223079182 | 4.778090743 | 42.92079197 |
| 2025 | 38.29992649 | -0.287021054 | 0.334478873 | 0.30619776 | 0 | 38.65358207 |
| 2026 | 38.48519364 | -0.363671448 | 0.613445556 | 0.426456436 | 0 | 39.16142418 |
| 2027 | 38.64984261 | -0.460289291 | 0.851857 | 0.594368138 | 0 | 39.63577846 |
| 2028 | 38.92090967 | -0.565720122 | 1.329520017 | 0.825231653 | 0 | 40.50994121 |
| 2029 | 38.99318041 | -0.664253043 | 1.685333819 | 1.122758454 | 0 | 41.13701964 |
| 2030 | 39.15568206 | -0.748886457 | 2.025496143 | 1.500029879 | 0 | 41.93232163 |
| 2031 | 39.33264027 | -0.812474007 | 2.391320643 | 1.975847501 | 0 | 42.8873344 |
| 2032 | 39.58637304 | -0.859506278 | 2.925650629 | 2.592505852 | 0 | 44.24502324 |
| 2033 | 39.64840886 | -0.888265762 | 3.246996111 | 3.331822054 | 0 | 45.33896126 |
| 2034 | 39.80276694 | -0.917200253 | 3.764104621 | 4.216116034 | 0 | 46.86578734 |
| 2035 | 39.95825 | -0.94121 | 4.2 | 5.23412 | 0 | 48.45116 |
| 2036 | 40.3834953 | -1.024418302 | 4.589111763 | 6.052616376 | 0 | 50.00080514 |
| 2037 | 40.62537928 | -1.10110507 | 4.815111563 | 6.837346353 | 0 | 51.17673212 |
| 2038 | 40.96073667 | -1.167829852 | 5.115678965 | 7.629750469 | 0 | 52.53833625 |
| 2039 | 41.29993579 | -1.236742745 | 5.387478197 | 8.43683481 | 0 | 53.88750605 |
| 2040 | 41.73109537 | -1.304966625 | 5.796520239 | 9.287133652 | 0 | 55.50978263 |
| 2041 | 41.97705169 | -1.369805153 | 6.00720867 | 10.1017009 | 0 | 56.71615611 |
| 2042 | 42.32056446 | -1.43931284 | 6.27605704 | 10.90803247 | 0 | 58.06534112 |
| 2043 | 42.65913337 | -1.499595774 | 6.635025333 | 11.64541656 | 0 | 59.43997949 |
| 2044 | 43.12374231 | -1.556904217 | 6.762756523 | 12.28918604 | 0 | 60.61878065 |
| 2045 | 43.35177947 | -1.606577073 | 6.988989664 | 12.69796148 | 0 | 61.43215354 |
| 2046 | 43.69880195 | -1.659525848 | 7.278793004 | 12.95905478 | 0 | 62.27712388 |
| 2047 | 44.04488293 | -1.703718531 | 7.475903246 | 13.04322864 | 0 | 62.86029629 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 2048 | 44.52038878 | -1.736435671 | 7.642402446 | 12.99466358 | 0 | 63.42101913 |
| 2049 | 44.74319889 | -1.743382108 | 7.918130027 | 12.731607 | 0 | 63.6495538 |
| 2050 | 45.09835 | -1.74619 | 8 | 12.38848 | 0 | 63.74064 |
| 2051 | 45.37570533 | -1.806344 | 8.04 | 12.50844133 | 0 | 64.11780267 |
| 2052 | 45.65306067 | -1.866498 | 8.08 | 12.62840267 | 0 | 64.49496533 |
| 2053 | 45.930416 | -1.926652 | 8.12 | 12.748364 | 0 | 64.872128 |
| 2054 | 46.20777133 | -1.986806 | 8.16 | 12.86832533 | 0 | 65.24929067 |
| 2055 | 46.48512667 | -2.04696 | 8.2 | 12.98828667 | 0 | 65.62645333 |
| 2056 | 46.762482 | -2.107114 | 8.24 | 13.108248 | 0 | 66.003616 |
| 2057 | 47.03983733 | -2.167268 | 8.28 | 13.22820933 | 0 | 66.38077867 |
| 2058 | 47.31719267 | -2.227422 | 8.32 | 13.34817067 | 0 | 66.75794133 |
| 2059 | 47.594548 | -2.287576 | 8.36 | 13.468132 | 0 | 67.135104 |
| 2060 | 47.87190333 | -2.34773 | 8.4 | 13.58809333 | 0 | 67.51226667 |
| 2061 | 48.14925867 | -2.407884 | 8.44 | 13.70805467 | 0 | 67.88942933 |
| 2062 | 48.426614 | -2.468038 | 8.48 | 13.828016 | 0 | 68.266592 |
| 2063 | 48.70396933 | -2.528192 | 8.52 | 13.94797733 | 0 | 68.64375467 |
| 2064 | 48.98132467 | -2.588346 | 8.56 | 14.06793867 | 0 | 69.02091733 |
| 2065 | 49.25868 | -2.6485 | 8.6 | 14.1879 | 0 | 69.39808 |

# Appendix B. New capacity capital costs

**Table 5. New build capital cost**

| Year | Battery | Geothermal | Solar | Wind | Green Peaker |
|---|---|---|---|---|---|
| 2020 | 2950.056792 | 5499.7932 | 1839.155364 | 1819.105228 | 1040 |
| 2021 | 2832.05452 | 5499.7932 | 1839.155364 | 1819.105228 | 1040 |
| 2022 | 2718.772339 | 5499.7932 | 1778.647152 | 1800.914176 | 1040 |
| 2023 | 2610.021446 | 5499.7932 | 1720.129661 | 1782.905034 | 1040 |
| 2024 | 2505.620588 | 5499.7932 | 1663.537395 | 1765.075984 | 1040 |
| 2025 | 2405.395764 | 5499.7932 | 1608.807015 | 1747.425224 | 1040 |
| 2026 | 2309.179934 | 5499.7932 | 1555.877264 | 1729.950972 | 1040 |
| 2027 | 2216.812736 | 5499.7932 | 1504.688902 | 1712.651462 | 1040 |
| 2028 | 2128.140227 | 5499.7932 | 1455.184637 | 1695.524947 | 1040 |
| 2029 | 2043.014618 | 5499.7932 | 1407.309063 | 1678.569698 | 1040 |
| 2030 | 1961.294033 | 5499.7932 | 1361.008594 | 1661.784001 | 1040 |
| 2031 | 1882.842272 | 5499.7932 | 1316.231412 | 1645.166161 | 1040 |
| 2032 | 1807.528581 | 5499.7932 | 1272.927398 | 1628.714499 | 1040 |
| 2033 | 1735.227438 | 5499.7932 | 1231.048087 | 1612.427354 | 1040 |
| 2034 | 1665.81834 | 5499.7932 | 1190.546605 | 1596.303081 | 1040 |
| 2035 | 1599.185607 | 5499.7932 | 1151.377622 | 1580.34005 | 1040 |
| 2036 | 1575.197822 | 5499.7932 | 1121.787217 | 1569.27767 | 1040 |
| 2037 | 1551.569855 | 5499.7932 | 1092.957285 | 1558.292726 | 1040 |
| 2038 | 1528.296307 | 5499.7932 | 1064.868283 | 1547.384677 | 1040 |
| 2039 | 1505.371863 | 5499.7932 | 1037.501168 | 1536.552984 | 1040 |

| Year | Battery | Geothermal | Solar | Wind | Green Peaker |
|---|---|---|---|---|---|
| 2040 | 1482.791285 | 5499.7932 | 1010.837388 | 1525.797113 | 1040 |
| 2041 | 1460.549415 | 5499.7932 | 984.8588672 | 1515.116533 | 1040 |
| 2042 | 1438.641174 | 5499.7932 | 959.5479943 | 1504.510718 | 1040 |
| 2043 | 1417.061557 | 5499.7932 | 934.8876108 | 1493.979143 | 1040 |
| 2044 | 1395.805633 | 5499.7932 | 910.8609992 | 1483.521289 | 1040 |
| 2045 | 1374.868549 | 5499.7932 | 887.4518716 | 1473.13664 | 1040 |
| 2046 | 1354.245521 | 5499.7932 | 864.6443585 | 1462.824683 | 1040 |
| 2047 | 1333.931838 | 5499.7932 | 842.4229985 | 1452.58491 | 1040 |
| 2048 | 1313.92286 | 5499.7932 | 820.7727274 | 1442.416816 | 1040 |
| 2049 | 1294.214017 | 5499.7932 | 799.6788683 | 1432.319898 | 1040 |
| 2050 | 1274.800807 | 5499.7932 | 779.1271214 | 1422.293659 | 1040 |
| 2051 | 1255.678795 | 5499.7932 | 771.4916756 | 1419.591301 | 1040 |
| 2052 | 1236.843613 | 5499.7932 | 763.9310572 | 1416.894078 | 1040 |
| 2053 | 1218.290959 | 5499.7932 | 756.4445328 | 1414.201979 | 1040 |
| 2054 | 1200.016594 | 5499.7932 | 749.0313764 | 1411.514995 | 1040 |
| 2055 | 1182.016346 | 5499.7932 | 741.6908689 | 1408.833117 | 1040 |
| 2056 | 1164.2861 | 5499.7932 | 734.4222984 | 1406.156334 | 1040 |
| 2057 | 1146.821809 | 5499.7932 | 727.2249599 | 1403.484637 | 1040 |
| 2058 | 1129.619482 | 5499.7932 | 720.0981553 | 1400.818016 | 1040 |
| 2059 | 1112.675189 | 5499.7932 | 713.0411933 | 1398.156462 | 1040 |
| 2060 | 1095.985062 | 5499.7932 | 706.0533896 | 1395.499964 | 1040 |
| 2061 | 1079.545286 | 5499.7932 | 699.1340664 | 1392.848514 | 1040 |

| Year | Battery | Geothermal | Solar | Wind | Green Peaker |
|---|---|---|---|---|---|
| 2062 | 1063.352106 | 5499.7932 | 692.2825526 | 1390.202102 | 1040 |
| 2063 | 1047.401825 | 5499.7932 | 685.4981836 | 1387.560718 | 1040 |
| 2064 | 1031.690797 | 5499.7932 | 678.7803014 | 1384.924353 | 1040 |
| 2065 | 1016.215435 | 5499.7932 | 672.1282544 | 1382.292997 | 1040 |

# Appendix C. Carbon and fuel costs

**Table 6. Carbon and fuel costs**

| Year | Coal | Gas | Green Peaker Fuel | Diesel | Carbon Costs |
|---|---|---|---|---|---|
| 2022 | 7.79 | 9.4 | 45 | 28.78 | 51.6 |
| 2023 | 7.79 | 9.6 | 45 | 30.01 | 62.5 |
| 2024 | 7.79 | 9.8 | 45 | 31.24 | 73.4 |
| 2025 | 7.79 | 10 | 45 | 32.48 | 84.2 |
| 2026 | 7.79 | 10.2 | 45 | 33.71 | 95 |
| 2027 | 7.79 | 10.4 | 45 | 34.94 | 105.9 |
| 2028 | 7.79 | 10.6 | 45 | 36.18 | 116.7 |
| 2029 | 7.79 | 10.8 | 45 | 37.41 | 127.6 |
| 2030 | 7.79 | 11 | 45 | 38.64 | 138.4 |
| 2031 | 7.79 | 11 | 45 | 39.61 | 142.6 |
| 2032 | 7.79 | 11 | 45 | 40.57 | 146.8 |
| 2033 | 7.79 | 11 | 45 | 41.54 | 151.2 |
| 2034 | 7.79 | 11 | 45 | 42.51 | 155.8 |
| 2035 | 7.79 | 11 | 45 | 43.47 | 160.5 |
| 2036 | 7.79 | 11 | 45 | 44.44 | 166.4 |
| 2037 | 7.79 | 11 | 45 | 45.4 | 172.4 |
| 2038 | 7.79 | 11 | 45 | 46.37 | 178.4 |
| 2039 | 7.79 | 11 | 45 | 47.34 | 184.3 |
| 2040 | 7.79 | 11 | 45 | 48.3 | 190.3 |
| 2041 | 7.79 | 11 | 45 | 48.3 | 196.3 |
| 2042 | 7.79 | 11 | 45 | 48.3 | 202.3 |
| 2043 | 7.79 | 11 | 45 | 48.3 | 208.2 |
| 2044 | 7.79 | 11 | 45 | 48.3 | 214.2 |
| 2045 | 7.79 | 11 | 45 | 48.3 | 220.2 |
| 2046 | 7.79 | 11 | 45 | 48.3 | 226.1 |
| 2047 | 7.79 | 11 | 45 | 48.3 | 232.1 |
| 2048 | 7.79 | 11 | 45 | 48.3 | 238.1 |

| Year | Coal | Gas | Green Peaker Fuel | Diesel | Carbon Costs |
|---|---|---|---|---|---|
| 2049 | 7.79 | 11 | 45 | 48.3 | 244 |
| 2050 | 7.79 | 11 | 45 | 48.3 | 250 |
| 2051 | 7.79 | 11 | 45 | 48.3 | 259.3 |
| 2052 | 7.79 | 11 | 45 | 48.3 | 268.7 |
| 2053 | 7.79 | 11 | 45 | 48.3 | 278 |
| 2054 | 7.79 | 11 | 45 | 48.3 | 287.3 |
| 2055 | 7.79 | 11 | 45 | 48.3 | 296.7 |
| 2056 | 7.79 | 11 | 45 | 48.3 | 306 |
| 2057 | 7.79 | 11 | 45 | 48.3 | 315.3 |
| 2058 | 7.79 | 11 | 45 | 48.3 | 324.7 |
| 2059 | 7.79 | 11 | 45 | 48.3 | 334 |
| 2060 | 7.79 | 11 | 45 | 48.3 | 343.3 |
| 2061 | 7.79 | 11 | 45 | 48.3 | 352.7 |
| 2062 | 7.79 | 11 | 45 | 48.3 | 362 |
| 2063 | 7.79 | 11 | 45 | 48.3 | 371.3 |
| 2064 | 7.79 | 11 | 45 | 48.3 | 380.7 |
| 2065 | 7.79 | 11 | 45 | 48.3 | 390 |
| 2066 | 7.79 | 11 | 45 | 48.3 | 390 |
| 2067 | 7.79 | 11 | 45 | 48.3 | 390 |

# Appendix D. Impact of climate change on inflows

## D.1 Wind

**Table 7. Impact of climate change on wind resource**

| Week | Southland | Otago | Canterbury | Wellington | Manawatu | Waikato | Wairarapa | Central_NI | Taranaki | Hawkes_Bay | Auckland | Northland |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1-Jul | 10.6 | 15.9 | 10.6 | 7.1 | 5.3 | -4.0 | 2.6 | -4.0 | -4.0 | -5.3 | -3.0 | -4.0 |
| 8-Jul | 11.2 | 16.7 | 11.2 | 7.4 | 5.6 | -4.2 | 2.8 | -4.2 | -4.2 | -5.6 | -3.0 | -4.2 |
| 15-Jul | 11.3 | 17.0 | 11.3 | 7.6 | 5.7 | -4.3 | 2.8 | -4.3 | -4.3 | -5.7 | -2.9 | -4.3 |
| 22-Jul | 11.3 | 17.0 | 11.3 | 7.5 | 5.7 | -4.2 | 2.8 | -4.2 | -4.2 | -5.7 | -2.9 | -4.2 |
| 29-Jul | 11.0 | 16.5 | 11.0 | 7.3 | 5.5 | -4.1 | 2.8 | -4.1 | -4.1 | -5.5 | -2.8 | -4.1 |
| 5-Aug | 10.5 | 15.8 | 10.5 | 7.0 | 5.3 | -3.9 | 2.6 | -3.9 | -3.9 | -5.3 | -2.6 | -3.9 |
| 12-Aug | 9.8 | 14.7 | 9.8 | 6.6 | 4.9 | -3.7 | 2.5 | -3.7 | -3.7 | -4.9 | -2.4 | -3.7 |
| 19-Aug | 9.1 | 13.6 | 9.1 | 6.0 | 4.5 | -3.4 | 2.3 | -3.4 | -3.4 | -4.5 | -2.2 | -3.4 |
| 26-Aug | 8.2 | 12.3 | 8.2 | 5.5 | 4.1 | -3.1 | 2.0 | -3.1 | -3.1 | -4.1 | -2.0 | -3.1 |
| 2-Sep | 7.1 | 10.7 | 7.1 | 4.8 | 3.6 | -2.7 | 1.8 | -2.7 | -2.7 | -3.6 | -1.7 | -2.7 |
| 9-Sep | 6.3 | 9.4 | 6.3 | 4.2 | 3.1 | -2.4 | 1.6 | -2.4 | -2.4 | -3.1 | -1.5 | -2.4 |
| 16-Sep | 5.5 | 8.2 | 5.5 | 3.7 | 2.7 | -2.1 | 1.4 | -2.1 | -2.1 | -2.7 | -1.3 | -2.1 |
| 23-Sep | 4.8 | 7.2 | 4.8 | 3.2 | 2.4 | -1.8 | 1.2 | -1.8 | -1.8 | -2.4 | -1.1 | -1.8 |
| 30-Sep | 4.1 | 6.2 | 4.1 | 2.8 | 2.1 | -1.6 | 1.0 | -1.6 | -1.6 | -2.1 | -1.0 | -1.6 |

| Week | Southland | Otago | Canterbury | Wellington | Manawatu | Waikato | Wairarapa | Central_NI | Taranaki | Hawkes_Bay | Auckland | Northland |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7-Oct | 3.6 | 5.5 | 3.6 | 2.4 | 1.8 | -1.4 | 0.9 | -1.4 | -1.4 | -1.8 | -0.9 | -1.4 |
| 14-Oct | 3.4 | 5.1 | 3.4 | 2.3 | 1.7 | -1.3 | 0.9 | -1.3 | -1.3 | -1.7 | -0.9 | -1.3 |
| 21-Oct | 3.2 | 4.8 | 3.2 | 2.1 | 1.6 | -1.2 | 0.8 | -1.2 | -1.2 | -1.6 | -1.0 | -1.2 |
| 28-Oct | 2.8 | 4.2 | 2.8 | 1.9 | 1.4 | -1.0 | 0.7 | -1.0 | -1.0 | -1.4 | -1.1 | -1.0 |
| 4-Nov | 2.3 | 3.4 | 2.3 | 1.5 | 1.1 | -0.9 | 0.6 | -0.9 | -0.9 | -1.1 | -1.4 | -0.9 |
| 11-Nov | 1.8 | 2.7 | 1.8 | 1.2 | 0.9 | -0.7 | 0.4 | -0.7 | -0.7 | -0.9 | -1.7 | -0.7 |
| 18-Nov | 1.2 | 1.8 | 1.2 | 0.8 | 0.6 | -0.5 | 0.3 | -0.5 | -0.5 | -0.6 | -2.0 | -0.5 |
| 25-Nov | 0.6 | 0.9 | 0.6 | 0.4 | 0.3 | -0.2 | 0.1 | -0.2 | -0.2 | -0.3 | -2.4 | -0.2 |
| 2-Dec | -0.1 | -0.2 | -0.1 | -0.1 | -0.1 | 0.1 | 0.0 | 0.1 | 0.1 | 0.1 | -2.9 | 0.1 |
| 9-Dec | -0.8 | -1.2 | -0.8 | -0.5 | -0.4 | 0.3 | -0.2 | 0.3 | 0.3 | 0.4 | -3.2 | 0.3 |
| 16-Dec | -1.3 | -2.0 | -1.3 | -0.9 | -0.7 | 0.5 | -0.3 | 0.5 | 0.5 | 0.7 | -3.6 | 0.5 |
| 23-Dec | -1.8 | -2.7 | -1.8 | -1.2 | -0.9 | 0.7 | -0.5 | 0.7 | 0.7 | 0.9 | -3.9 | 0.7 |
| 30-Dec | -2.2 | -3.4 | -2.2 | -1.5 | -1.1 | 0.8 | -0.6 | 0.8 | 0.8 | 1.1 | -4.1 | 0.8 |
| 6-Jan | -2.5 | -3.8 | -2.5 | -1.7 | -1.3 | 1.0 | -0.6 | 1.0 | 1.0 | 1.3 | -4.3 | 1.0 |
| 13-Jan | -2.6 | -4.0 | -2.6 | -1.8 | -1.3 | 1.0 | -0.7 | 1.0 | 1.0 | 1.3 | -4.3 | 1.0 |
| 20-Jan | -2.7 | -4.0 | -2.7 | -1.8 | -1.3 | 1.0 | -0.7 | 1.0 | 1.0 | 1.3 | -4.4 | 1.0 |
| 27-Jan | -2.7 | -4.0 | -2.7 | -1.8 | -1.3 | 1.0 | -0.7 | 1.0 | 1.0 | 1.3 | -4.3 | 1.0 |

| Week | Southland | Otago | Canterbury | Wellington | Manawatu | Waikato | Wairarapa | Central_NI | Taranaki | Hawkes_Bay | Auckland | Northland |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3-Feb | -2.6 | -3.9 | -2.6 | -1.7 | -1.3 | 1.0 | -0.7 | 1.0 | 1.0 | 1.3 | -4.2 | 1.0 |
| 10-Feb | -2.5 | -3.7 | -2.5 | -1.7 | -1.2 | 0.9 | -0.6 | 0.9 | 0.9 | 1.2 | -4.1 | 0.9 |
| 17-Feb | -2.3 | -3.5 | -2.3 | -1.6 | -1.2 | 0.9 | -0.6 | 0.9 | 0.9 | 1.2 | -4.0 | 0.9 |
| 24-Feb | -2.2 | -3.3 | -2.2 | -1.4 | -1.1 | 0.8 | -0.5 | 0.8 | 0.8 | 1.1 | -3.8 | 0.8 |
| 2-Mar | -2.0 | -3.0 | -2.0 | -1.3 | -1.0 | 0.7 | -0.5 | 0.7 | 0.7 | 1.0 | -3.7 | 0.7 |
| 9-Mar | -1.8 | -2.7 | -1.8 | -1.2 | -0.9 | 0.7 | -0.5 | 0.7 | 0.7 | 0.9 | -3.5 | 0.7 |
| 16-Mar | -1.7 | -2.5 | -1.7 | -1.1 | -0.8 | 0.6 | -0.4 | 0.6 | 0.6 | 0.8 | -3.4 | 0.6 |
| 23-Mar | -1.5 | -2.3 | -1.5 | -1.0 | -0.8 | 0.6 | -0.4 | 0.6 | 0.6 | 0.8 | -3.3 | 0.6 |
| 30-Mar | -1.3 | -1.9 | -1.3 | -0.9 | -0.6 | 0.5 | -0.3 | 0.5 | 0.5 | 0.6 | -3.2 | 0.5 |
| 6-Apr | -1.1 | -1.6 | -1.1 | -0.7 | -0.5 | 0.4 | -0.3 | 0.4 | 0.4 | 0.5 | -3.1 | 0.4 |
| 13-Apr | -0.9 | -1.4 | -0.9 | -0.6 | -0.5 | 0.3 | -0.2 | 0.3 | 0.3 | 0.5 | -3.0 | 0.3 |
| 20-Apr | -0.6 | -0.9 | -0.6 | -0.4 | -0.3 | 0.2 | -0.2 | 0.2 | 0.2 | 0.3 | -3.0 | 0.2 |
| 27-Apr | 0.1 | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -3.0 | 0.0 |
| 4-May | 1.0 | 1.5 | 1.0 | 0.7 | 0.5 | -0.4 | 0.2 | -0.4 | -0.4 | -0.5 | -3.0 | -0.4 |
| 11-May | 2.1 | 3.1 | 2.1 | 1.4 | 1.0 | -0.8 | 0.5 | -0.8 | -0.8 | -1.0 | -3.0 | -0.8 |
| 18-May | 3.2 | 4.9 | 3.2 | 2.2 | 1.6 | -1.2 | 0.8 | -1.2 | -1.2 | -1.6 | -3.0 | -1.2 |
| 25-May | 4.6 | 6.9 | 4.6 | 3.1 | 2.3 | -1.7 | 1.1 | -1.7 | -1.7 | -2.3 | -3.0 | -1.7 |

| Week | Southland | Otago | Canterbury | Wellington | Manawatu | Waikato | Wairarapa | Central_NI | Taranaki | Hawkes_Bay | Auckland | Northland |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1-Jun | 6.2 | 9.2 | 6.2 | 4.1 | 3.1 | -2.3 | 1.5 | -2.3 | -2.3 | -3.1 | -3.0 | -2.3 |
| 8-Jun | 7.5 | 11.2 | 7.5 | 5.0 | 3.7 | -2.8 | 1.9 | -2.8 | -2.8 | -3.7 | -3.0 | -2.8 |
| 15-Jun | 8.7 | 13.0 | 8.7 | 5.8 | 4.3 | -3.3 | 2.2 | -3.3 | -3.3 | -4.3 | -3.0 | -3.3 |
| 22-Jun | 9.7 | 14.6 | 9.7 | 6.5 | 4.9 | -3.7 | 2.4 | -3.7 | -3.7 | -4.9 | -3.0 | -3.7 |

## D.2 Hydro

**Table 8. Impact of climate change on hydro inflows**

| Week | Manapouri | Clutha | Pukaki | Tekapo | GYM-RoR | ISL-RoR | KIK-RoR | BPE-RoR | Tongariro | Waikaremoana | BOP-RoR | Waikato |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1-Jul | 18% | 27% | 32% | 32% | 4% | 3% | 3% | 2% | 1% | 3% | -1% | 2% |
| 8-Jul | 17% | 23% | 29% | 29% | 4% | 3% | 3% | 2% | 1% | 3% | -1% | 2% |
| 15-Jul | 16% | 22% | 29% | 28% | 4% | 3% | 3% | 2% | 1% | 3% | -1% | 2% |
| 22-Jul | 16% | 21% | 27% | 27% | 4% | 3% | 3% | 2% | 1% | 2% | -2% | 1% |
| 29-Jul | 15% | 19% | 25% | 24% | 4% | 3% | 3% | 2% | 0% | 2% | -2% | 1% |
| 5-Aug | 14% | 17% | 23% | 22% | 3% | 2% | 2% | 2% | 0% | 2% | -2% | 1% |
| 12-Aug | 14% | 17% | 22% | 22% | 3% | 2% | 2% | 2% | 0% | 1% | -2% | 0% |
| 19-Aug | 13% | 16% | 21% | 20% | 3% | 2% | 2% | 2% | 0% | 1% | -2% | 0% |
| 26-Aug | 12% | 15% | 19% | 18% | 3% | 2% | 2% | 1% | -1% | 0% | -2% | 0% |

| Week | Manapouri | Clutha | Pukaki | Tekapo | GYM-RoR | ISL-RoR | KIK-RoR | BPE-RoR | Tongariro | Waikaremoana | BOP-RoR | Waikato |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2-Sep | 11% | 13% | 16% | 15% | 2% | 1% | 1% | 1% | -1% | 0% | -3% | -1% |
| 9-Sep | 9% | 11% | 13% | 12% | 2% | 1% | 1% | 1% | -1% | 0% | -3% | -1% |
| 16-Sep | 8% | 10% | 11% | 10% | 2% | 1% | 0% | 0% | -2% | -1% | -3% | -1% |
| 23-Sep | 7% | 8% | 9% | 9% | 1% | 1% | 0% | 0% | -2% | -1% | -3% | -2% |
| 30-Sep | 6% | 6% | 6% | 5% | 1% | 0% | 0% | 0% | -2% | -1% | -3% | -2% |
| 7-Oct | 5% | 3% | 3% | 3% | 1% | 0% | -1% | 0% | -2% | -1% | -4% | -2% |
| 14-Oct | 3% | 1% | 1% | 0% | 1% | 0% | -1% | 0% | -2% | -1% | -3% | -2% |
| 21-Oct | 3% | 0% | -1% | -1% | 1% | 0% | -1% | 0% | -2% | -1% | -3% | -2% |
| 28-Oct | 2% | -2% | -2% | -3% | 1% | 0% | -1% | 0% | -2% | -1% | -3% | -2% |
| 4-Nov | 2% | -3% | -4% | -4% | 1% | 0% | -1% | 0% | -2% | -1% | -3% | -2% |
| 11-Nov | 1% | -4% | -5% | -6% | 1% | 0% | -1% | 0% | -2% | -1% | -3% | -2% |
| 18-Nov | 1% | -5% | -6% | -7% | 1% | 0% | -1% | 0% | -2% | -1% | -3% | -2% |
| 25-Nov | 0% | -5% | -7% | -8% | 1% | 0% | -1% | 0% | -2% | 0% | -3% | -2% |
| 2-Dec | 1% | -6% | -7% | -8% | 1% | 0% | -1% | 1% | -2% | 0% | -3% | -2% |
| 9-Dec | 0% | -6% | -7% | -8% | 1% | 0% | -1% | 1% | -2% | 1% | -3% | -2% |
| 16-Dec | 0% | -6% | -8% | -9% | 1% | 0% | 0% | 1% | -2% | 1% | -2% | -2% |
| 23-Dec | 0% | -6% | -8% | -9% | 1% | 0% | 0% | 1% | -2% | 2% | -2% | -1% |
| 30-Dec | 0% | -6% | -8% | -9% | 1% | 0% | 0% | 2% | -2% | 2% | -2% | -1% |
| 6-Jan | 0% | -7% | -9% | -10% | 1% | 0% | 0% | 2% | -1% | 3% | -2% | -1% |

| Week | Manapouri | Clutha | Pukaki | Tekapo | GYM-RoR | ISL-RoR | KIK-RoR | BPE-RoR | Tongariro | Waikaremoana | BOP-RoR | Waikato |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 13-Jan | 0% | -8% | -10% | -11% | 1% | 0% | 0% | 2% | -1% | 3% | -1% | -1% |
| 20-Jan | -1% | -9% | -11% | -12% | 1% | 0% | 0% | 2% | -1% | 4% | -1% | -1% |
| 27-Jan | -1% | -10% | -12% | -12% | 1% | -1% | 0% | 2% | -1% | 5% | -1% | -1% |
| 3-Feb | -2% | -10% | -12% | -12% | 1% | -1% | 1% | 3% | -1% | 5% | -1% | -1% |
| 10-Feb | -1% | -11% | -12% | -12% | 1% | -1% | 0% | 3% | -1% | 6% | -1% | -1% |
| 17-Feb | -1% | -10% | -12% | -12% | 1% | -1% | 0% | 3% | -1% | 7% | -1% | 0% |
| 24-Feb | 0% | -8% | -10% | -10% | 1% | -1% | 0% | 3% | -1% | 7% | 0% | 0% |
| 2-Mar | 0% | -6% | -8% | -8% | 0% | -1% | 0% | 4% | -1% | 7% | 0% | 0% |
| 9-Mar | 2% | -4% | -5% | -5% | 0% | -1% | 0% | 4% | -1% | 7% | 0% | 0% |
| 16-Mar | 2% | -2% | -4% | -4% | 0% | -1% | 0% | 4% | -1% | 7% | 0% | 0% |
| 23-Mar | 3% | -1% | -2% | -2% | 1% | 0% | 0% | 4% | -1% | 7% | 0% | 0% |
| 30-Mar | 3% | 1% | 0% | 0% | 1% | 0% | 0% | 4% | 0% | 7% | 0% | 0% |
| 6-Apr | 5% | 2% | 2% | 3% | 1% | 0% | 0% | 4% | 0% | 7% | 0% | 0% |
| 13-Apr | 5% | 4% | 5% | 5% | 1% | 0% | 1% | 4% | 0% | 6% | 0% | 0% |
| 20-Apr | 7% | 7% | 8% | 8% | 1% | 1% | 1% | 4% | 0% | 6% | 0% | 1% |
| 27-Apr | 8% | 9% | 11% | 10% | 2% | 1% | 2% | 4% | 1% | 6% | 0% | 1% |
| 4-May | 9% | 11% | 14% | 13% | 2% | 2% | 2% | 4% | 1% | 5% | 0% | 1% |
| 11-May | 10% | 14% | 16% | 15% | 2% | 2% | 2% | 3% | 1% | 5% | 0% | 1% |
| 18-May | 12% | 15% | 19% | 18% | 3% | 2% | 2% | 3% | 1% | 5% | 0% | 1% |

| Week | Manapouri | Clutha | Pukaki | Tekapo | GYM-RoR | ISL-RoR | KIK-RoR | BPE-RoR | Tongariro | Waikaremoana | BOP-RoR | Waikato |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 25-May | 13% | 17% | 21% | 20% | 3% | 3% | 2% | 3% | 1% | 4% | 0% | 2% |
| 1-Jun | 14% | 19% | 23% | 23% | 3% | 3% | 3% | 3% | 1% | 4% | 0% | 2% |
| 8-Jun | 15% | 21% | 26% | 26% | 3% | 3% | 3% | 3% | 1% | 4% | 0% | 2% |
| 15-Jun | 15% | 22% | 27% | 28% | 3% | 3% | 3% | 3% | 1% | 4% | 0% | 2% |
| 22-Jun | 16% | 22% | 28% | 28% | 4% | 3% | 3% | 2% | 1% | 4% | -1% | 2% |