TRANSPOWER

Upper South Island Upgrade Stage 1: Major Capex Proposal

Attachment 6: Benefits modelling

August 2025

Purpose

This attachment describes how we have calculated benefits of the short-list investment options for our Upper South Island (**USI**) Upgrade Stage 1 project. We used models of the New Zealand electricity system to estimate the benefits of alternative investment options to meet the investment needs of the USI region, to inform our decision-making for this major capex proposal.

Contents

1 Benefits modelling approach

This section describes our approach to modelling the benefits used in our analysis.

1.1 Overview

We use models of the New Zealand electricity system to estimate the benefits of alternative investment options for transmission into the USI region.

The main building blocks of our approach for this project include:

- **Power system analysis**. Conducted by our system planning team using DigSILENT's Power Factory software. This analysis helps determine the investment need, investment options and the timing of each investment option. It also provides inputs into our generation dispatch simulation modelling, such as upgraded circuit capacities for each investment option. Further details on power system analysis can be found in Attachment 10.
- **Generation expansion planning**. Our model finds the lowest cost combination of new generation projects required to meet forecast demand. For this analysis we use PSR Inc's OptGen software. Generation expansion plans are developed for each of the 2019 Electricity Demand and Generation Scenario (**EDGS**) variations[1].
- **Generation dispatch simulations.** These simulations estimate electricity system operating costs for our counterfactual (or do-nothing) and each investment option. For this we use PSR Inc's SDDP software with generation dispatch simulations developed for each EDGS scenario.

Our modelling provides estimates of electricity system costs for the counterfactual and each investment option. The relative benefits of a transmission option are determined by the difference between the system costs of the investment option (factual) and the counterfactual.

1.2 Power system analysis

Power system analysis, using DigSILENT's Power Factory software, provides key inputs to the transmission network models used for our generation dispatch simulations. An overview of these inputs follows.

1.2.1 Timing of transmission network changes

Power system analysis is used to determine the timing of each investment option's transmission upgrades. The load on existing transmission assets is calculated assuming Environmental prudent peak demand. This timing is held constant in the calculation of benefits for other modelled

[1] See Attachment 1 for further information about the scenarios we have used.

scenarios. Investment is timed so that loads on existing transmission assets do not exceed their current capabilities prior to being replaced or upgraded.

1.2.2 Specifications of transmission network changes

Power system analysis is also used to help determine new and upgraded circuit capacities, resistances, and reactances for each investment option's transmission upgrades.

Transmission development plans are modelled in Power Factory to resolve the identified Investment Need using combinations of:

- upgrading existing assets,
- reconfiguring existing assets,
- adding new assets, and/or
- adding an operational procedure, such as a Special Protection Scheme (**SPS**), to address part or all the system need.

1.2.3 Transmission network constraints

Transmission network constraints are also derived from power system analysis and defined for all our investment options. These constraints ensure flows from the lower South Island (**LSI**) to the USI mimic actual market conditions. Constraints are applied to limit circuit flows to ensure that transmission equipment is not damaged.[2] These constraints may limit flows substantially below the thermal rating of a circuit.

Only network constraints that cannot be modelled in our generation dispatch simulation software need to be produced through power systems analysis. Our generation dispatch simulations use a simplified, linear, DC load flow model. Thermal N, and N-1, limits can be captured within the simulation model dynamically, resulting in security constrained dispatch outcomes. However, some constraints, such as voltage stability, cannot be modelled explicitly in the generation dispatch simulation. Therefore, these limits must by produced by power systems analysis in the form of a "circuit sum constraint".

Low levels of generation in the Waitaki Valley would reduce maximum flow possible from the LSI to the USI without exceeding the voltage stability limit. Recent functionality added to SDDP has allowed us to more accurately model the interaction between the voltage constraint and lower Waitaki Valley generation. This is described further in Appendix A5.

1.3 Generation expansion planning

Generation expansion planning is the process of forecasting future grid connected generation for a given demand forecast. Generation expansion plans are an input to our generation dispatch simulations.

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2 More technically, circuit flows are limited so as to ensure circuit thermal ratings are respected in the event of a contingency (failure of a line or transformer) or to avoid voltage stability issues.

1.3.1 Least cost generation plans

Our generation expansion modelling focuses on the cost of new generation. Our modelling effectively steps through time (out to 2050 in this case), building new generation as required to meet forecast demand. It chooses new generation from the generation stack with the overall objective of minimising the cost of electricity over the period being considered. We recognise that there are other factors that play a role in generation investment decisions such as the availability of capital, future views on wholesale electricity prices, project consentability, power purchase agreements, retail positions relative to generation, etc. However, our view is that it is reasonable to focus on generation costs on the premise that, although our model may deliver new generation in a different order to the actual electricity market, in the long-run, costs will be the major deciding factor.

1.3.2 Using OptGen

PSR Inc's OptGen modelling software has been used to develop our generation expansion plans. We use their 'Optgen1' algorithm.

Optgen1 finds the lowest cost combination of capital costs (due to investments in new generation) and operating costs (due to operating existing and new generation plant) over the modelling horizon. This is done in two separate stages:

- Operating costs are estimated using the same SDDP algorithm as used for our generation dispatch simulations, with some simplifications to ensure that the model can provide a solution in a reasonable time. Operating costs do account for hydro energy variability, hydro uncertainty, and renewable energy variability.
- Operating costs are fed into a separate algorithm to determine the least cost combination of capital and operating costs.

Optgen1 can be configured with several different generation energy or capacity constraints. We have applied a maximum wind and solar installed capacity constraint such that only 1,000 MW of wind or solar can be built within a given year.

1.3.3 Ensuring revenue adequacy

As an additional step, the generation expansion plans from OptGen were adjusted to improve the modelled revenue adequacy of future generation projects. Revenue adequacy is the ratio of expected revenues over expected capital costs. While it can be difficult to model revenue adequacy, particularly in a future dominated by intermittent renewable generation, future generation plants should in general be revenue adequate. These adjustments were made as a 'post processing' step, after the OptGen modelling process. The results of this adjustment are shown in Appendix B.

1.3.4 How many generation expansion plans?

We produced generation expansion plans for three of our 2019 EDGS variations, as supported through our long-list consultation. The scenarios were Environmental, Disruptive and Reference. We assumed that:

- future generation would be unaffected by USI regional constraints. Initial testing of this assumption produced generation expansion plans that were not materially different with different transmission development plans, and

- that the AC grid is unconstrained.

For these reasons, we applied the same generation expansion plan for a given EDGS scenario across the counterfactual and all short-listed investment options.

1.4 Generation dispatch simulation

PSR Inc's SDDP modelling software has been used for generation dispatch simulations. SDDP minimises system operating costs accounting for:

- future changes in generation and grid scale batteries – as provided by our generation expansion plans.
- future changes to the transmission network for each investment option.
- changes in demand – arising from daily and weekly demand variations through to long term forecast demand growth.
- hydro inflow variability and uncertainty.
- renewable energy variability.
- grid scale battery operation.
- plant operational constraints – including thermal plant unit commitment and hydro plant minimum flow constraints.

SDDP is a well-established model that is widely used in many jurisdictions around the world.

1.4.1 SDDP policies and water values

SDDP generation dispatch simulations are produced in two steps:

1. *Policy evaluation.* In this step SDDP derives a policy, effectively a set of water values for each of New Zealand's major hydro reservoirs. Water values provide the opportunity cost of using or storing water in each hydro reservoir, accounting for risks of both dry year energy shortages and wet year hydro spillage.
2. Simulation*.* Using the water values from the policy, the operation of the electricity system is simulated for a given set of hydro inflow sequences.

SDDP policies need only be produced where changes are made to SDDP inputs that could materially alter hydro generation operating decisions and associated water storage values. For the USI project, consistent with our generation expansion plan approach, we only ran policies for the three selected 2019 EDGS variations. For a given scenario we applied the same policy to the counterfactual and each investment option. USI investment options are unlikely to affect water values for our major hydro reservoirs.

1.4.2 Resolution

The process of choosing the best resolution for a model is a compromise between model accuracy and computational tractability. For SDDP, resolution relates to the size of the time step considered by the model. Resolution is improved by reducing the size of the time step. A model with a high resolution will better capture real world variations in demand and renewable generation. However, this will be at the expense of increasing model solve time and model result data storage requirements.

For our USI generation dispatch simulations, we use an hourly resolution over the full modelling horizon.

1.4.3 Hydro inflow sequences

SDDP simulates the dispatch of generation and batteries in the electricity system for a defined set of yearly hydro inflow sequences covering our modelled hydro generators. In New Zealand electricity system costs vary significantly with hydro inflows, so capturing this behaviour is a critical part of our generation dispatch simulations.

We use 'synthetic' hydro inflow sequences that are derived from actual inflows. Synthetic inflows reduce the level of fluctuations, help the model converge, and reduce model solve time. They are produced by SDDP by analysing the relationship between an inflow sequence and time of year as well as the interdependence among inflows to different hydro plants.

For the USI project, we used:

- Policy step: 15 and 50 equally-weighted synthetic inflow sequences, respectively, for the 'backward' and 'forward' phases of the SDDP algorithm
- Simulation step: 50 equally-weighted synthetic inflow sequences.

1.4.4 Modelling the transmission network with SDDP

SDDP uses a simplified, linear, DC load flow model. For our USI modelling, we also make the following further simplifications:

- Circuit flows are constrained to respect both thermal ratings and other circuit constraints only for the interface between the Lower South Island and the USI. Where appropriate, different thermal ratings and constraints are applied for the counterfactual and each investment option. For the rest of the AC grid circuit flows are unconstrained.
- Only circuits above 66 kV are included in our grid model.
- AC network losses are ignored during the SDDP generation dispatch simulation. Losses are estimated as a post processing step (after the model has been run), based on dispatch circuit flows, when estimating benefits. All loads are escalated by an island loss factor (2.8% in the North Island and 3.85% in the South Island[3]) to account for AC losses that must be supplied by generators over and above grid offtake at the GXP.
- Losses on the HVDC are modelled within SDDP using a linearized approximation of observed HVDC losses.

[3] See section 2.2 for additional information of AC network loss modelling for this investigation.

2 Modelling assumptions

Demand and generation assumptions for each 2019 EDGS variation are described in Attachment 2. These assumptions form the core of our modelling inputs. Assumptions specific to either the counterfactual or each investment option are discussed in this section.

2.1 Transmission network

Transmission network assumptions for the counterfactual and each investment option are defined in Appendix A.

2.2 AC Losses

As outlined in section 1.4.4, Transpower typically runs SDDP with a lossless AC network to reduce computational complexity. To account for AC system losses, escalation factors are applied to North Island and South Island loads to reflect the expected losses in the AC network in each island. These loss factors are included in the TPM Assumptions Book and are based on analysis of historical system losses.

This simplifying assumption is generally fit for purpose for the Investment Test as losses typically do not change the merit order of dispatch, and explicitly modelling losses in the market model does not materially influence the preferred option.

However, our review of SDDP network flows against network flows from a power-flow model that explicitly modelled losses found that assuming a constant loss factor across the South Island reduced transfer requirements between the LSI and USI. Per unit losses in the USI are higher than those in the LSI due to the stringy network and low levels of local generation. USI loads generally require more power to travel longer distances along less efficient transmission lines compared to LSI loads.

Therefore, the constant island-wide loss factor was reducing the need for transmission capacity between the USI and LSI and therefore the benefit of augmenting it.

To ensure that losses in SDDP were consistent with observed losses, we calibrated the sharing of South Island losses across the LSI and USI regions to be consistent with the loss outcomes in the power systems modelling. To do this we increased load (to account for losses) in the USI by 3.4% of gross USI load – equivalent to the underestimate of losses using our standard approach – and decreased LSI load by 3.4% of USI load. These equal and opposite adjustments meant that total South Island was unchanged but more of the South Island losses were supplied in the USI.

The calibration results in system states – the combination of circuit flows, bus demand, losses, and generation – that are more consistent with power systems modelling and therefore provide a more accurate estimation of system benefits.

2.3 Deficit cost

The cost of deficit (the value of expected unserved energy under the Capex IM) (on a $ per MWh basis) is an important input to our generation expansion plan and generation dispatch simulation. Deficit can be thought of as the cost of energy that cannot be supplied by either generation or the transmission network.

The cost of deficit influences how much generation will be built by our OptGen model. A higher deficit cost results in generation being built sooner as the consequence of running out of generation is greater than would otherwise be the case.

Our investment options are designed to ensure that the USI continues to be served by the transmission network into the future. As a result, deficit in the region is expected to be infrequent and for short periods of time. For this reason, we assume the cost of deficit is as shown in Table 1.

For our SDDP model the cost of deficit influences how stored water is used in SDDP, with higher deficit costs resulting in higher water values (as water availability is of more value to the system to avoid deficit costs), and therefore a tendency for water to be held back in reserve for dry periods. In addition, the cost of deficit is used to value demand that is unable to be served by the transmission grid. This is important for the USI project.

In our generation expansion plan modelling, deficit will typically occur during peak demand periods where there is not enough generation to meet peak demand, and during dry inflow periods where there is not enough energy to meet winter demand. The total amount of deficit is a very small proportion of the total amount of demand served to consumers. It occurs infrequently and for short periods of time.

To account for these characteristics, we assume that the cost of deficit is defined by four incrementally increasing 'tranches' as described in Table 1. Each tranche is for a given amount of deficit, expressed as a percentage of hourly[4] Island demand. The first three tranches are intended to represent voluntary 'demand response' measures, such as retailers controlling hot water cylinder demand. The last high value tranche is intended to represent forced curtailment of load (i.e., not supplying electricity), as could occur in a grid emergency. For our generation expansion plan modelling almost all deficit falls within the first three tranches in Table 1.

Table 1: Generation expansion plan modelling deficit cost tranches

Deficit as a proportion of Island hourly demand	Cost
First 5% of demand	$600 per MWh
Between 5% and 10% of demand	$800 per MWh
Between 10% and 15% of demand	$2,000 per MWh
Greater than 15% of demand	$10,000 per MWh

4 For Optgen1, deficit tranches are specified for the quantity of deficit expressed as a percentage of 'load block' Island demand. Load blocks are groups of similar periods of demand within a given week.

3 Generation expansion plans

This section describes the generation expansion plans derived for this investigation. These plans use the 2019 EDGS variations described in Attachment 2 and are an input to the generation dispatch simulations.

Figure 1 shows cumulative new generation capacity additions and deletions, out to 2050, for the Environmental, Disruptive, and Reference scenarios[5]. New generation build is dominated by wind and solar for all scenarios. Fossil fuel retirements are covered by new fossil fuel generation, grid scale batteries, geothermal or biofuels.

Our assumptions, intended to provide diversity across our generation expansion plans, drive the relatively strong growth in grid scale batteries in the Disruptive scenario.

For our base modelling runs we have assumed only committed generation is built in the USI.

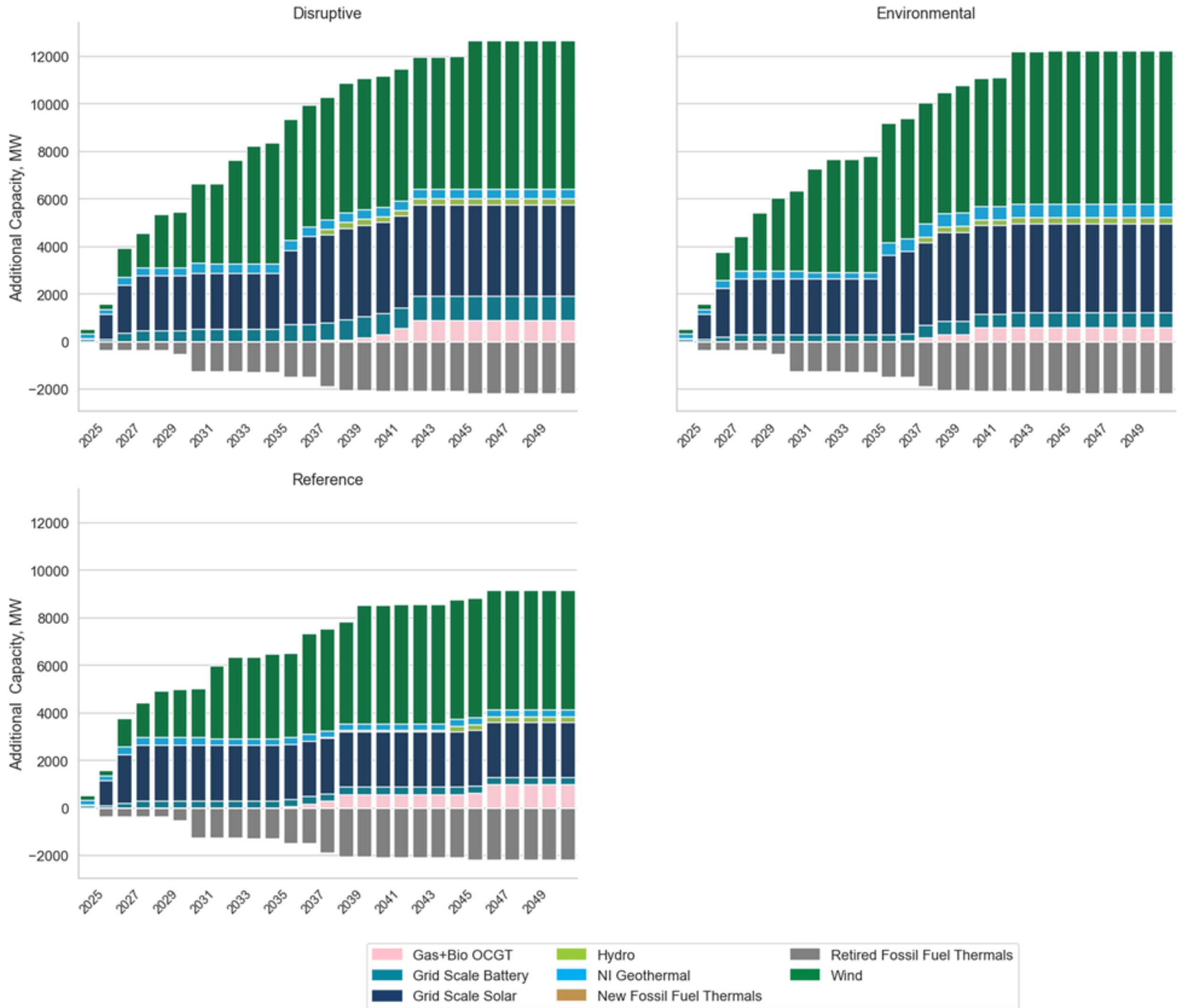

Figure 1: Generation expansion plans, capacity additions and deletions

[5] These are the scenarios used in the base investment test. For our base investment test the Global and Growth scenarios have zero weighting and for this reason are not shown.

Note that, as described in Attachment 2, in the base expansion plans, we have assumed that the new supply built – other than that already well-advanced – is built outside the USI to avoid relying on new supply where the timing and location are subject to many more unknowns than can be captured in our generation expansion model.

However, we have undertaken four generation expansion sensitivities that assume more USI generation is built. The outcomes from these sensitivities in included in section 4.1.2.

4 Generation dispatch simulation results

This section provides an overview of our generation dispatch simulation results. Benefits derived from our generation dispatch simulations are combined with all other investment option benefits and costs in Attachment 4.

4.1 Generation dispatch simulation benefits

Generation dispatch simulation benefits ('dispatch benefits') are calculated for each investment option by finding the difference between simulated electricity system costs for that investment and the counterfactual of no transmission investment. These benefits are gross in that they exclude the cost of the transmission investment upgrade. Dispatch benefits are calculated for these benefit categories:

- *Thermal operating benefits:* Including savings on fuel costs, variable operating costs and emission costs relative to the Counterfactual.
- *Deficit benefits:* Savings on unserved energy costs, explained above relative to the Counterfactual.
- *AC loss benefits:* Savings on AC grid energy loss costs relative to the Counterfactual. AC line energy losses are not explicitly included in either the generation or dispatch simulation modelling. They are calculated in a post processing step using modelled circuit flows. Loss costs are then estimated using Island short run marginal costs.

There are no generation investment benefits as we are using the same set of generation plans for the counterfactual and each investment option.

All costs are sourced from dispatch simulation modelling and are averaged over 50 equally-weighted simulated historical hydro inflow sequences.

Dispatch benefits broken down by cost category are shown in the tables below for the Environmental, Disruptive, and Reference scenarios. Dispatch benefits are net present values over 2025-2050, using a 5% real discount rate, and they are in 2021[6] dollars.

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6 The Investment Test analysis uses a shorter period of 2031-2050 as per the Capex IM requirement and also uses 2024 dollars.

Deficit benefits are due to reductions in deficit relative to the counterfactual. Thermal operating costs are disbenefits (i.e., negative benefits, where costs increase following the investment option). Investment options reduce deficit in the USI region, increasing the quantity of energy that must be served by grid connected generation and the transmission network. This in turn leads to small increases in generation costs.

Dispatch benefits vary substantially by scenario. These variations are primarily due to the differences in the rate of demand growth – including electrification demand at Clandeboye.

As discussed in Attachment 4, Option 2 is our proposed stage 1 investment.

Table 2: Environmental scenario, gross benefits by cost category. Benefits are NPV, 5% real discount rate

Option	Thermal operating benefits ($m)	AC loss benefits, ($m)	Deficit benefits, ($m)	Total benefits, ($m)
Option 1: Single switching station path	(1)	100	159	258
Option 2: Dual switching station path	(0)	15	158	173
Option 3: STATCOM path	(1)	110	159	268

Table 3: Disruptive scenario, gross benefits by cost category. Benefits are NPV, 5% real discount rate

Option	Thermal operating benefits ($m)	AC loss benefits, ($m)	Deficit benefits, ($m)	Total benefits, ($m)
Option 1: Single switching station path	(1)	113	276	388
Option 2: Dual switching station path	(2)	43	276	317
Option 3: STATCOM path	(3)	125	274	396

Table 4: Reference scenario, gross benefits by cost category. Benefits are NPV, 5% real discount rate

Option	Thermal operating benefits ($m)	AC loss benefits, ($m)	Deficit benefits, ($m)	Total benefits, ($m)
Option 1: Single switching station path	0	53	4	57

Option 2: Dual switching station path	0	(0)	4	4
Option 3: STATCOM path	1	62	2	64

4.1.1 Benefits over time

Dispatch benefits over time are shown for the Environmental scenario and Option 2, in Figure 2. Deficit benefits ramp up with USI net demand growth exceeding the import capacity from the early 2030s. As can be seen, deficit benefits are substantial, persistent, and growing over the period of analysis.

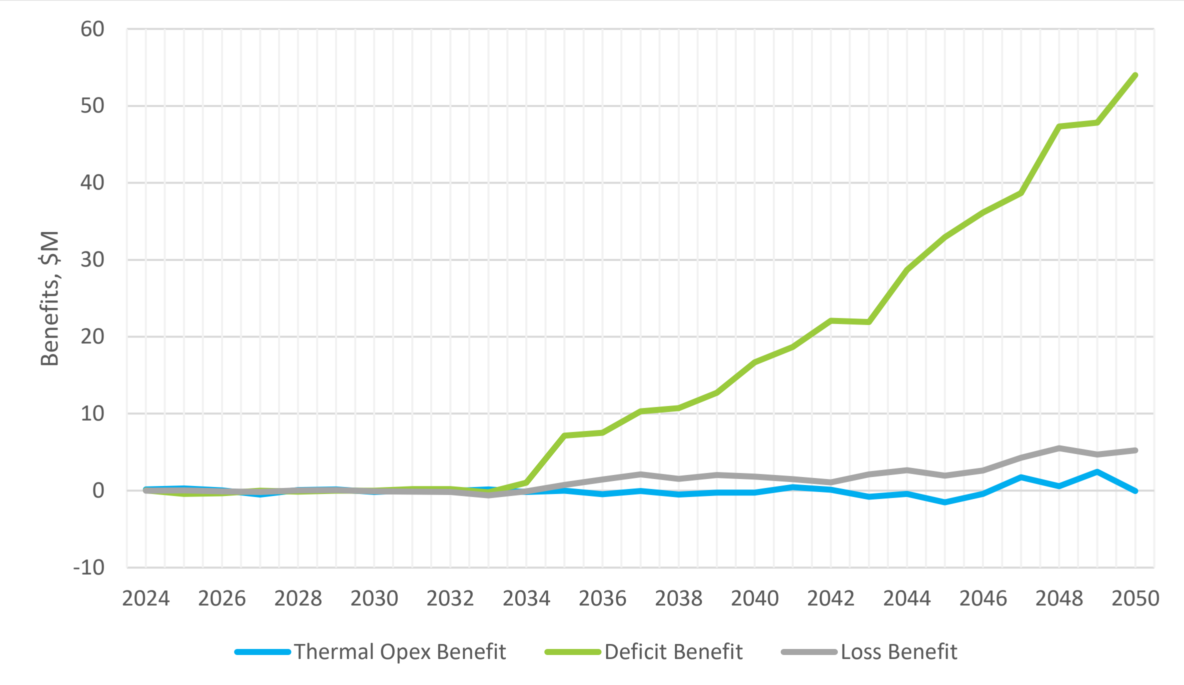


Figure 2: Dispatch benefits over time. Benefits are gross, real 2021 dollars

4.1.2 Impact of USI supply capacity expansion on dispatch benefits

We undertook four generation expansion sensitivities based on information provided following our previous consultation. The sensitivities include the following additional generation capacity in the USI (over our base assumptions).

- Sensitivity 1: Around 200 MW solar and 100 MW BESS.
- Sensitivity 2: Around 300 MW solar and 150 MW BESS.
- Sensitivity 3: Around 300 MW solar.
- Sensitivity 4: Around 300 MW solar, 150 MW BESS and 300 MW wind.

We have applied these assumptions to the Environmental scenario only to test whether additional USI supply capacity was likely to impact the preference order of the investment options. As the investment need is to ensure N-1 security, the essential metric is the preference order of the investment options that provide N-1 security. The Environmental scenario was chosen as it is the highest weighted scenario and the scenario with the moderate dispatch benefits (Reference has lower and Disruptive is higher).

The figures below summarise the impact of the generation sensitivities on dispatch benefits. Dispatch benefits in the Environmental scenario without the additional USI supply capacity is include on the right side of the graph for reference.

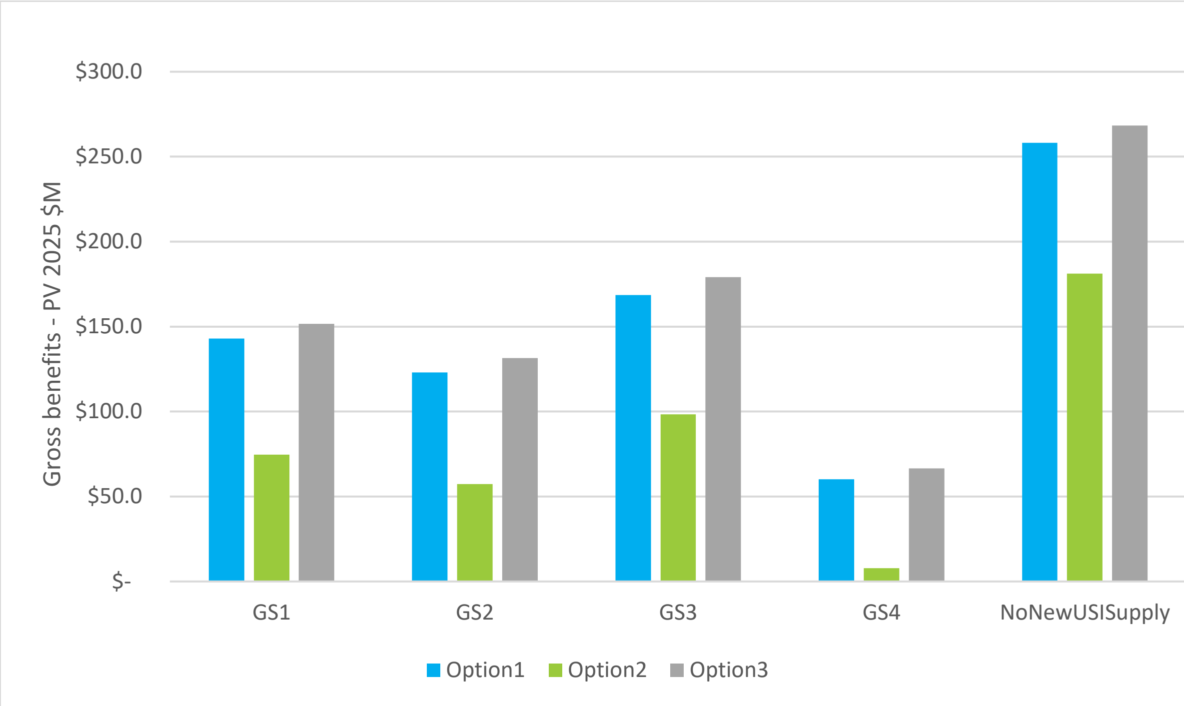


Figure 3: Dispatch benefits, Environmental scenario, four generation cases

Figure 3 shows that additional USI supply capacity, particularly wind (**GS4**), materially reduces the dispatch benefits of all the investment options. Additional solar with BESS (**GS2**) reduces dispatch benefits by approximately $120m to $140m across the investment options, which is reduced to about $80m to $90m if BESS is not included (**GS3**). The additional USI wind in GS4 results in a benefit reduction of approximately $170m to $200m across the options.

However, the additional USI supply capacity in the generation sensitivities does not materially impact the *difference* between options relative to the expected difference in capital costs between the options as shown in Attachment 4.

The following three charts show the composition of dispatch benefits for each generation sensitivity and investment option. Note that Option 2 has little loss benefit in any case and thermal benefits are also very small in all cases, so the primary movement in benefits across the cases is in deficit benefits.

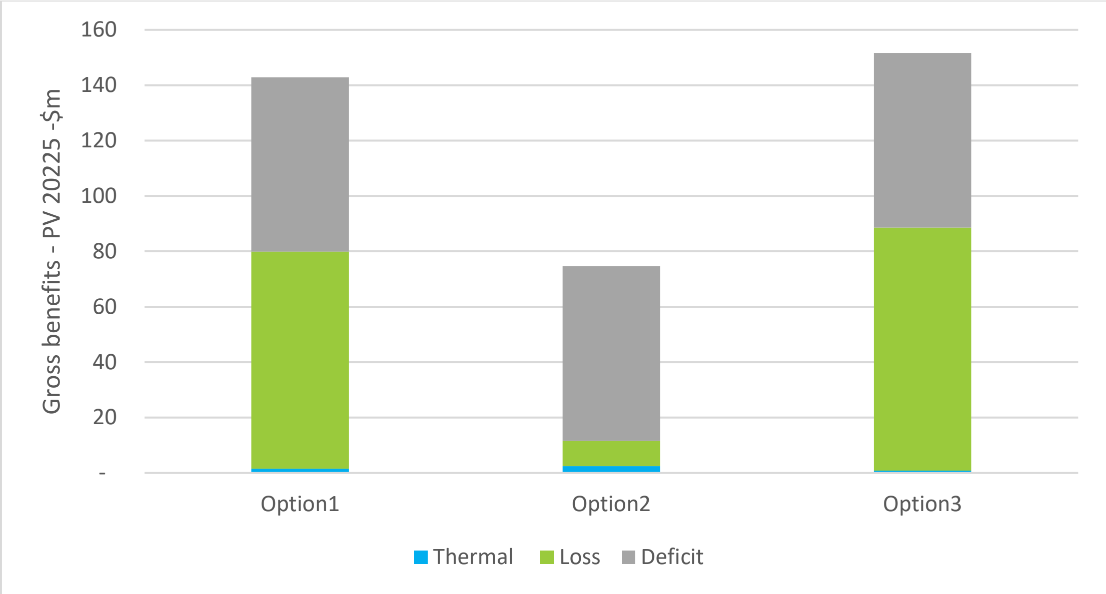


Figure 4: Composition of dispatch benefits – Generation sensitivity 1

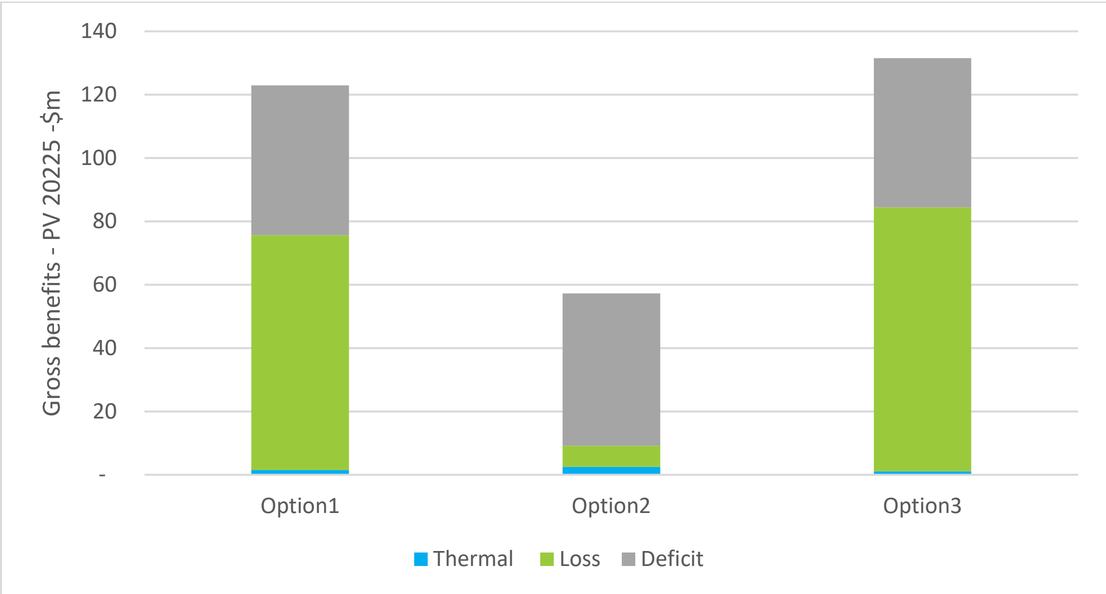


Figure 5: Composition of dispatch benefits – Generation sensitivity 2

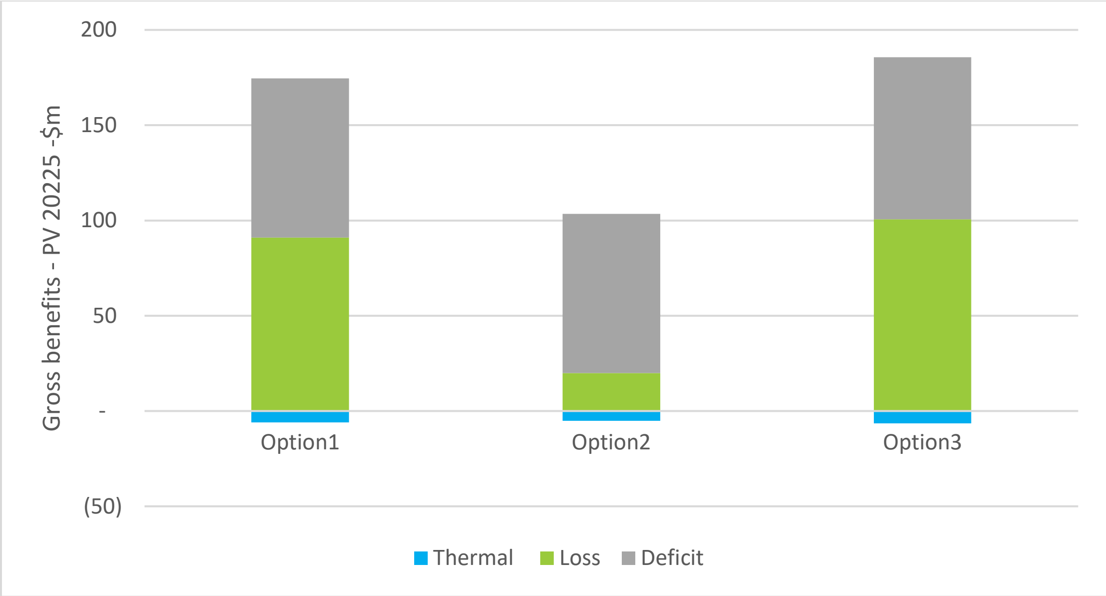


Figure 6: Composition of dispatch benefits – Generation sensitivity 3

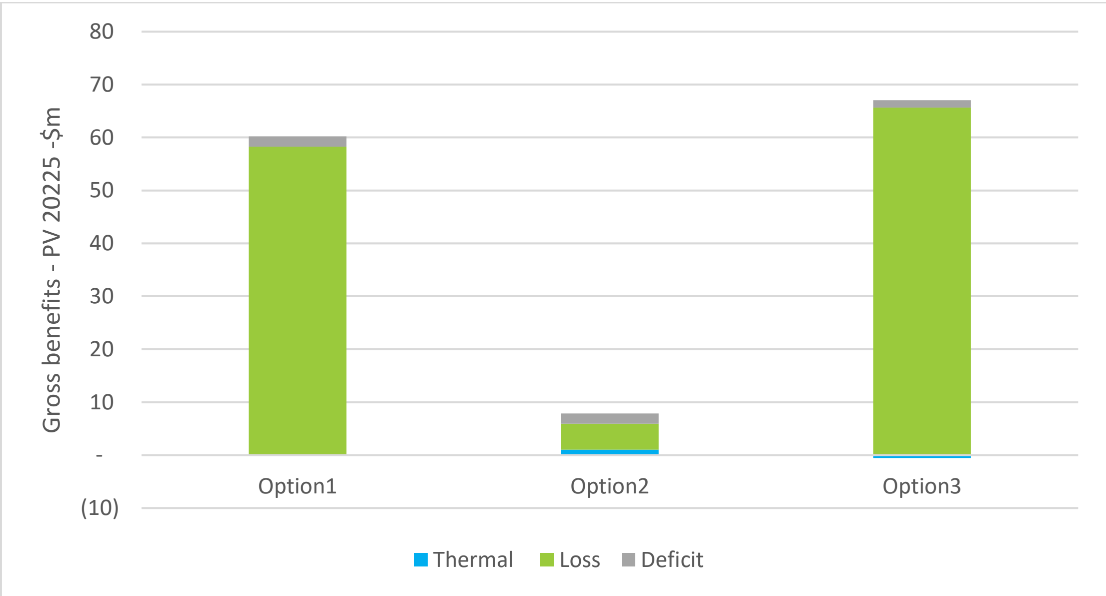


Figure 7: Composition of dispatch benefits – Generation sensitivity 4

Note that in all cases other than generation sensitivity 3, most of the dispatch benefits in Option 2 – the proposed stage 1 investment– result from reduction in deficit.

4.2 Circuit flows

Figure 8 shows the sum of Environmental Scenario circuit flows into the USI for the counterfactual and the shortlist of options. Circuit flows are averaged over each week and for all hydro scenarios.

As can be seen, in the counterfactual, flows are constrained leading to the non-supply of electricity to the USI region and the large deficit costs shown above. Constrained flows into the USI occur from the early 2030s in the counterfactual. All the investment options result in very similar flows across the LSI-USI interface as they all result in a relatively unconstrained network.

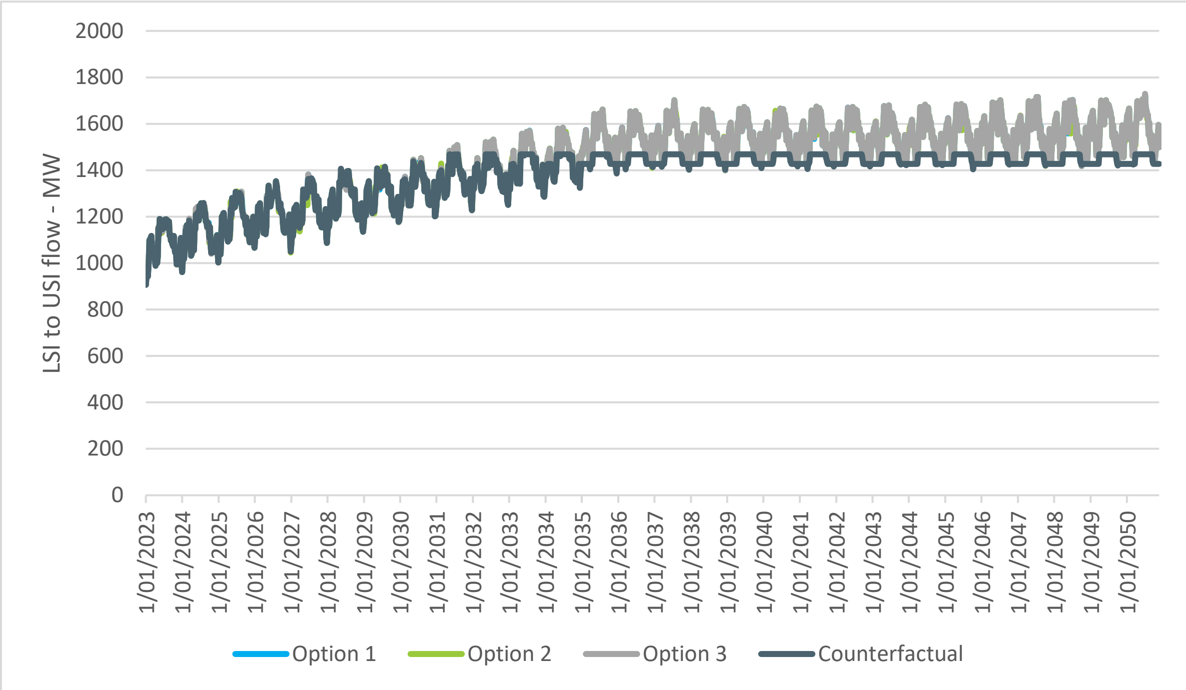


Figure 8: Sum of circuit flows into USI. Peak flows over each week and all hydro scenarios

Figure 9 shows flow duration curves for the Environmental Scenario circuit flows in 2045, into the USI, for the counterfactual and Options 1, 2 and 3. Our generation dispatch simulations provide results over 50 hydro sequences. The flow duration curves shown are for each hour in the year, across all hydro sequences. The investment options shown provide largely unconstrained flows, leading to the relatively small differences in dispatch benefits across options, meaning that they are indistinguishable in the graphs below. In contrast, the counterfactual demonstrates heavily constrained flows for approximately 7% of the year – equivalent to 600 hours – and modestly constrained flows for about 70% of the year.

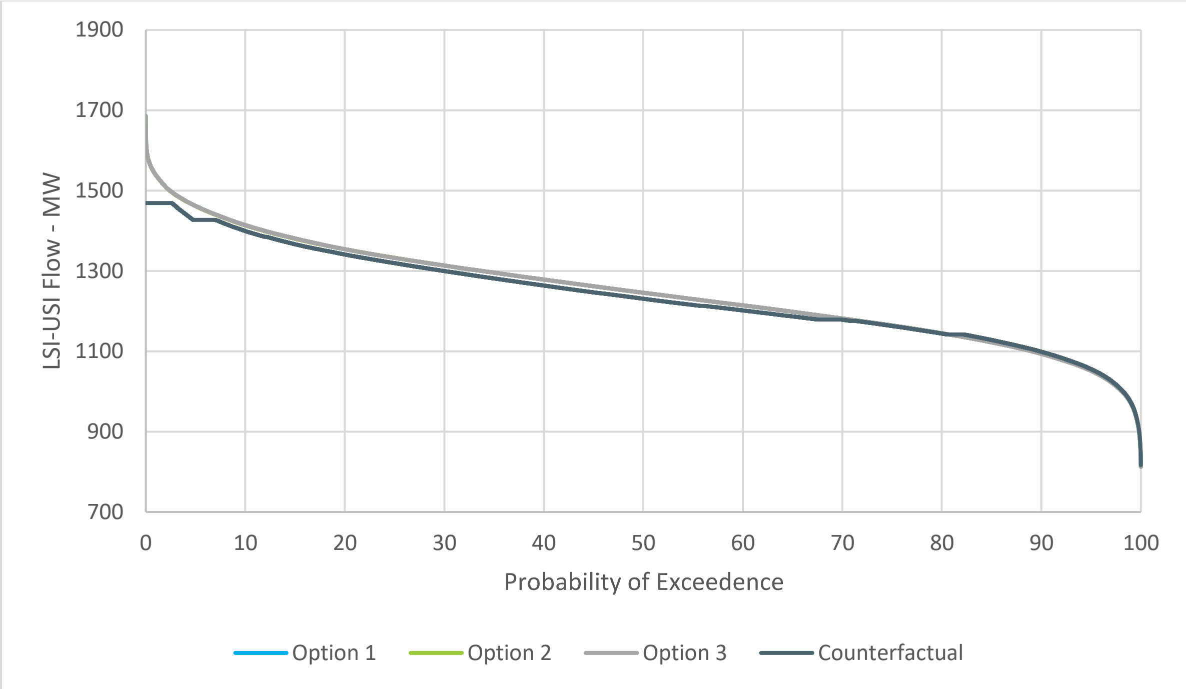


Figure 9: Flow duration curve, 2045, for sum of circuit flows into the USI.

4.3 Deficit

Figure 12 shows deficit for the Environmental Scenario in the USI for the counterfactual and the investment options. Deficit is averaged over all hydro scenarios. Note that the three investment options have very similar deficit results the so are not distinguishable in the graph.

The investment options reduce USI deficit by modest amounts beginning from the early 2030s, growing to 39% by 2035 and 78% by 2050. For all our investment options there will always be some residual deficit across the country associated with either dry years or generation capacity shortages. For these types of events SDDP spreads deficit across the Island in proportion to demand.

Other investment options show similar trends.

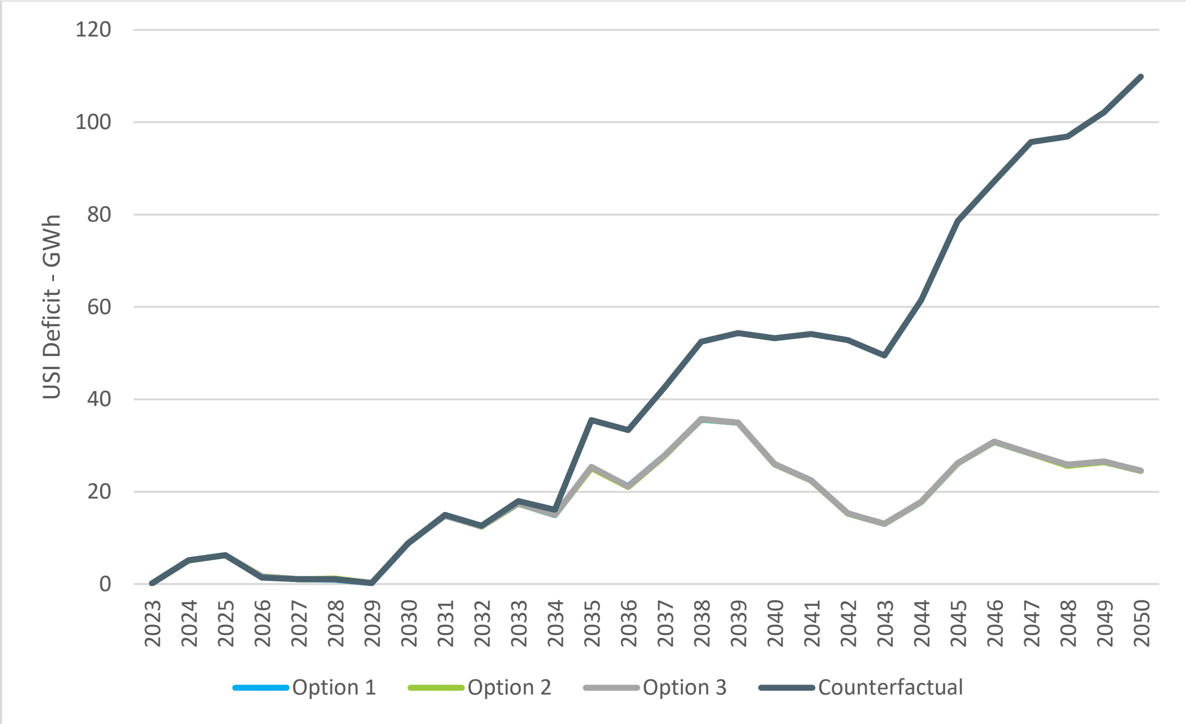


Figure 10: Deficit in the Upper South Island, averaged over all hydro scenarios

Appendix A – Transmission Network Assumptions

A1 Existing transmission grid

Transmission network properties, including the bus voltage, line resistance, line reactance, and line ratings are from Transpower's asset capability information system. This is the same system used to provide network information from the grid owner to the system operator.

A2 Changes to lines

This section sets out changes to lines, with the existing transmission network as a base. Changes for the counterfactual are confined to committed transmission projects within the interface between the Lower South Island and USI regions.

A2.1 Changes to existing lines

All cases

All cases – including the counterfactual – include new Timaru 220/33 kV supply transformers.

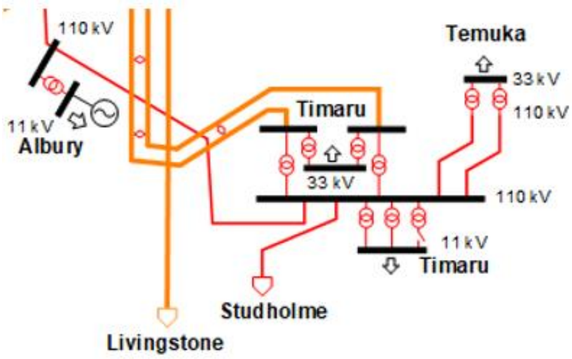


Figure 11: Future Timaru 33 kV supply

Table 5: Future Timaru supply transformers

Transformer Name	Primary node	Secondary node	Ratings (MVA)		Base MVA	R(%)	X (%)
			Winter	Summer / Shoulder			
TIM–T9 and T10	TIM220	TIM33	80	80	80	0.517	10

Counterfactual

The 220 kV Ashburton–Timaru–Twizel–1 circuit was modified to supply Clandeboye load from Orari (**ORI**) in the counterfactual.

Table 6: Counterfactual Network reconfigurations

Existing circuit	Change	R (ohms)	X (ohms)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
ASB–OPI–1	ASB–ORI–1 OPI–ORI–1	1.4901 0.8464	12.7373 7.2419	694.33	764.34	730.31	2028	220

Option 1

In this option, the Orari switching station is built. The line:

- ASB–OPI will be reconfigured to ASB–ORI–OPI
- LIV–NWD will be reconfigured to LIV–ORI–NWD.

Table 7: Option 1 Network reconfigurations

Existing circuit	Change	R (ohms)	X (ohms)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
LIV–NWD–1	NWD–ORI–1 LIV–ORI–1	4.2029 4.390	29.3875 31.750	403.98 609.53	492.85 671.11	450.78 641.18	2028	220
ASB–OPI–1	ASB–ORI–1 OPI–ORI–1	1.4901 0.8464	12.7373 7.2419	694.33	764.34	730.31	2028	220
ASB–OPI–2	ASB–ORI–2 OPI–ORI–2	1.4901 0.8464	12.7373 7.2419	694.33	762.1	730.31	2028	220

Option 2

In this option, both ORI and RTA switching stations are built. The line:

- ASB–OPI will be reconfigured to ASB–ORI–OPI
- LIV–NWD will be reconfigured to LIV–ORI–RTA–NWD.

Table 8: Option 2 Network reconfigurations

Existing circuit	Change	R (ohms)	X (ohms)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
LIV–NWD–1	NWD–RTA–1 ORI–RTA–1 LIV–ORI–1	3.9162 0.2867 4.390	27.2356 2.1519 31.750	403.98 609.53 609.53	492.85 671.11 671.11	450.77 641.18 641.18	2028	220
ASB–OPI–1	ASB–ORI–1 OPI–ORI–1	1.4901 0.8464	12.7373 7.2419	694.33	764.34	730.31	2028	220
ASB–OPI–2	ASB–ORI–2 OPI–ORI–2	1.4901 0.8464	12.7373 7.2419	694.33	762.1	730.31	2028	220
ISL–TKB–1	RTA–TKB–1 RTA–ISL–1	4.311 5.1843	29.4066 35.3974	556.65	609.68	589.22	2028	220

Option 3

The 220 kV Ashburton–Timaru–Twizel–1 circuit was modified to supply Clandeboye load from Orari (**ORI**).

Table 9: Option 3 Network reconfigurations

Existing circuit	Change	R (ohms)	X (ohms)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
ASB–OPI–1	ASB–ORI–1 OPI–ORI–1	1.4901 0.8464	12.7373 7.2419	694.33	764.34	730.31	2028	220

A2.2 New lines and buses

New lines and associated new buses are detailed below. SDDP cannot model tee connections so tee connections have been approximated in SDDP by modelling each tee as a bus.

Table 10: New buses

Options	Bus Name	Bus Voltage	Purpose
All Options	ORI220	220	New Switching Station/Load
Option 2	RTA220	220	New Switching Station

Table 11: New lines and upgrades Option 1

Line Name	R (ohms)	X (ohms)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date
TTU NWD–ORI–1 (NWD–RTA–1 circuit section: duplex GoatGZ 75°C)	4.2029	29.3875	691.98	744.29	718.71	2028
TTU OPI–TWZ–1 and 2 (duplex ZebraGZ 90°C)	2.525	21.5851	788.51	847.96	818.89	2031
New single circuit line from ISL–TWZ (duplex Sulfur AAAC 75°C)	5.3115	70.8927	902.91	993.6	949.53	2034

Table 12: New lines and upgrades Option 2

Line Name	R (ohms)	X (ohms)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date
TTU NWD–ORI–1 (NWD–RTA–1 circuit section: duplex GoatGZ 75°C)	3.9162	27.2356	691.98	744.71	718.71	2028
TTU ORI–RTA–1 (duplex GoatAC 90°C)	0.2867	2.1519	691.98	744.29	718.71	2030
TTU OPI–TWZ–1 and 2 (duplex ZebraGZ 90°C)	2.525	21.5851	788.51	847.96	818.89	2033
TTU RTA–TKB–1 (duplex GoatGZ 90°C)	4.311	29.4066	666.27	716.64	692.01	2035
Reconductor ORI–RTA–1: (duplex ZebraGZ 90°C)	0.248757	2.264998	788.51	847.96	818.89	2035
TTU ASB–ORI–1 and 2 (duplex ZebraGZ 90°C)	1.4901	12.7373	788.51	847.96	818.89	2035

Table 13: New lines and upgrades Option 3

Line Name	R (ohms)	X (ohms)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date
TTU OPI–TWZ–1 and 2 (duplex ZebraGZ 90°C)	2.525	21.5851	788.51	847.96	818.89	2028
TTU LIV–NWD–1 (duplex GoatAC 90°C)	8.7996	63.955	691.98	744.29	718.71	2029
New single circuit line from ISL–TWZ: (duplex Sulfur AAAC 75°C)	5.312	70.893	902.91	993.6	949.53	2031

A3 Line security constraints

SDDP models contingencies on the following lines. SDDP constrains circuit flows, ensuring security constrained dispatch, so that if a contingency does occur, the load on neighbouring circuits does not exceed their rating line capacities.

Table 14: Line security constraints

Contingency- Options Counter factual, Option 1	Contingency, Options 2	Contingency, Options 3
ASB–OPI–1	ASB–OPI–1	ASB–OPI–1
ASB–OPI–2	ASB–OPI–2	ASB–OPI–2
LIV–NWD–1	LIV–NWD–1	ISL–TKB–1
ISL–TKB–1	OPI–TWZ–1	OPI–TWZ–1
NWD–RTA–1	OPI–TWZ–2	OPI–TWZ–2
OPI–TWZ–1	ASB–ORI–1	ASB–ORI–1
OPI–TWZ–2	OPI–ORI–1	OPI–ORI–1
ASB–ORI–1	OPI–ORI–2	OPI–ORI–2
OPI–ORI–1	OPI–TIM–1	OPI–TIM–2
OPI–ORI–2	OPI–TIM–2	RTA–ISL–1
OPI–TIM–1	RTA–TKB–1	OPI–TIM–1
OPI–TIM–2	RTA–ISL–1	LIV–NWD–1
ASB–ISL–1	ORI–RTA–1	
	ISL–TKB–1	

A4 Group constraints

The following group constraints were also modelled in SDDP. These are required to prevent under voltage in the USI region and ensure that thermal N-1 security limits are respected in the counterfactual.

No group constraints were necessary in any of the investment options as power system analysis showed that the development plans satisfied N-1 thermal and voltage stability limits under prudent demand assumptions.

Table 15: Counterfactual group constraints

Group Constraint	(MW) Summer|Shoulder|Winter
(-1) * ISL–TKB–1 + (-1) * OPI–TWZ–1 + (-1) * OPI–TWZ–2 + (1) * LIV–NWD–1	1427 | 1427 | 1469
(-1) * OPI–TWZ–1 + (-0.61) * OPI–TWZ–2	694.33 | 694.33 | 763.65

A5 Generic constraints

To better capture the interaction between Waitaki Valley generation and the USI voltage stability constraint, this iteration of modelling included a “generic” constraint that included circuit flows and Waitaki Valley generation in both Option 0 and Option 2.

The impact of these generic constraints is to force SDDP to increase generation in the Waitaki Valley to maximise the power transfer from the LSI to the USI without unacceptable risk of voltage collapse should a contingency occur.

The motivation for including these constraints was derived from a set of system state analyses based on the previous iteration of the modelling that found that using a circuit sum constraint alone to model the USI stability constraint resulted in regular cases where SDDP would transfer the maximum allowable power across the LSI to USI interface but have very low or zero generation in the Waitaki Valley due to high wind and solar generation at the time. This behaviour was inconsistent with AC power system modelling indicating that a minimum level of Waitaki Valley generation is required to maximise flow into the USI.

Option 0

Generic Constraint	(MW)
(-1) * ISL-TKB-1 + (-1) * OPI-TWZ-1 + (-1) * OPI-TWZ-2 + (1) * LIV-NWD-1 + (-0.214) WTK Valley Gen ≤	1142 | 1142 (summer / shoulder)
(-1) * ISL-TKB-1 + (-1) * OPI-TWZ-1 + (-1) * OPI-TWZ-2 + (1) * LIV-NWD-1 + (-0.217) WTK Valley Gen	1179 (winter)

Option 2

Stage 1:

Orari and Rangitata switching stations (2028)

Generic Constraint	(MW)
(-1) * ISL-TKB-1 + (-1) * OPI-TWZ-1 + (-1) * OPI-TWZ-2 + (1) * LIV-ORI-1 + (-0.309) WTK Valley Gen	1132 | 1132 (summer / shoulder)
(-1) * ISL-TKB-1 + (-1) * OPI-TWZ-1 + (-1) * OPI-TWZ-2 + (1) * LIV-ORI-1 + (-0.288) WTK Valley Gen	1194 (winter)

Orari and Rangitata switching stations (2028) plus 2x75 Mvar capacitor at Orari (2030)

Generic Constraint	(MW)
(-1) * ISL-TKB-1 + (-1) * OPI-TWZ-1 + (-1) * OPI-TWZ-2 + (1) * LIV-ORI-1 + (-0.403) WTK Valley Gen	1191 | 1191 (summer / shoulder)
(-1) * ISL-TKB-1 + (-1) * OPI-TWZ-1 + (-1) * OPI-TWZ-2 + (1) * LIV-ORI-1 + (-0.351) WTK Valley Gen	1282 (winter)

Stage 2:

Orari and Rangitata switching stations (2028) plus 2x75 Mvar capacitor at Orari plus 150 Mvar STC at Ashburton (2033)

Generic Constraint	(MW)
(-1) * ISL-TKB-1 + (-1) * OPI-TWZ-1 + (-1) * OPI-TWZ-2 + (1) * LIV-ORI-1 + (-0.497) WTK Valley Gen	1141 | 1141 (summer / shoulder)
(-1) * ISL-TKB-1 + (-1) * OPI-TWZ-1 + (-1) * OPI-TWZ-2 + (1) * LIV-ORI-1 + (-0.420) WTK Valley Gen	1274 (winter)

Orari and Rangitata switching stations (2028) plus 2x75 Mvar capacitor at Orari plus 150 Mvar capacitor at Ashburton plus 100 Mvar capacitor at Ashburton (2035)

Generic Constraint	(MW)
(-1) * ISL-TKB-1 + (-1) * OPI-TWZ-1 + (-1) * OPI-TWZ-2 + (1) * LIV-ORI-1 + (-0.592) WTK Valley Gen	1065 | 1065 (summer / shoulder)
(-1) * ISL-TKB-1 + (-1) * OPI-TWZ-1 + (-1) * OPI-TWZ-2 + (1) * LIV-ORI-1 + (-0.487) WTK Valley Gen	1208 (winter)

Appendix B – OptGen Adjustments

Adjustments to OptGen expansion plans for the Environmental, Disruptive and Reference scenarios have been made to improve revenue adequacy. Revenue adequacy is the ratio of expected revenues over expected capital costs.

While it can be difficult to model revenue adequacy, particularly in a future dominated by intermittent renewable generation, future generation plants should in general be revenue adequate and have a ratio close to 1. Revenue adequacy that is materially less than 1 indicates that the plant is unlikely to cover its costs and is unlikely to be built. Conversely, revenue adequacy that is materially greater than 1 indicates that, if possible, more generation of a similar type would be added to the system to capture some of those strong returns.

We have used an iterative process to better match the underlying short-run marginal costs (e.g. prices) of the modelling with the revenue required to pay for new plant to help ensure ratios are close to 1 – focusing particularly on wind and solar plants.

The figures below illustrate the adjustments made for solar and wind built in each of the modelled scenarios throughout the iterative process. “Iter0” indicates the expansion plan from the initial Optgen run. The remaining iterations show the expansion plan after subsequent iterations of the process outlined above. In each scenario, all plants were within the revenue adequacy thresholds after four iterations (“iter4”), which is the generation expansion plan used in the final simulations.

The impact of the revenue adequacy adjustments, as shown in the figures below, is that the timing of both solar and wind plants has generally been deferred in each iteration of our process to improve revenue adequacy. Deferring generation reduces supply and therefore increases the short-run marginal cost of load (i.e. spot prices) which, in turn, increases generation revenues and improves revenue adequacy. In some cases, generation is deferred beyond the end of the modelling horizon, meaning the total installed capacity at the end of the period is lower than in the initial OptGen expansion plans.

Figure 12: Optgen Adjustments – Environmental

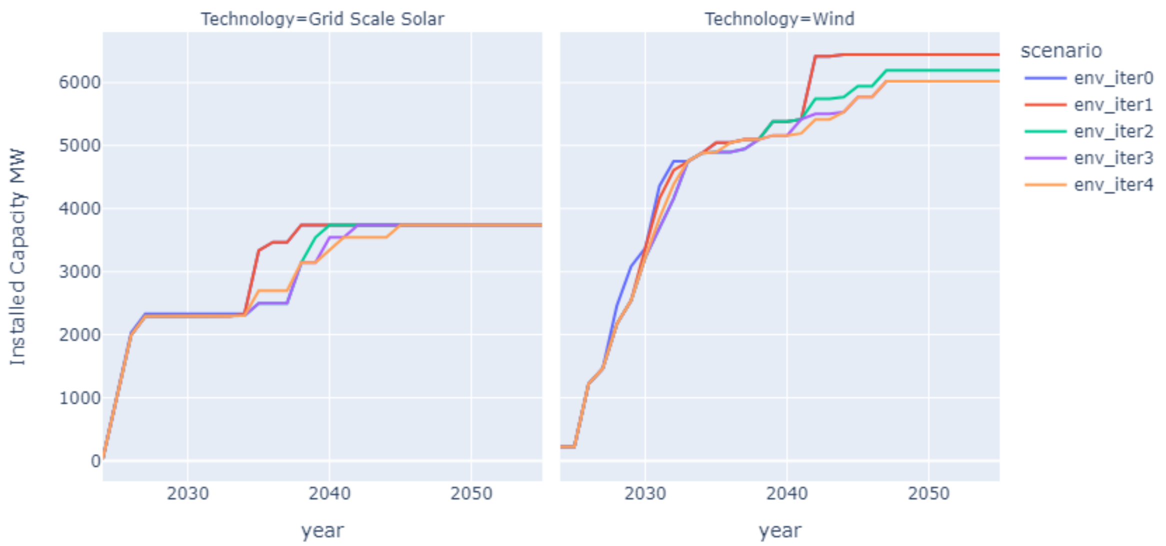


Figure 13: Optgen Adjustments – Disruptive

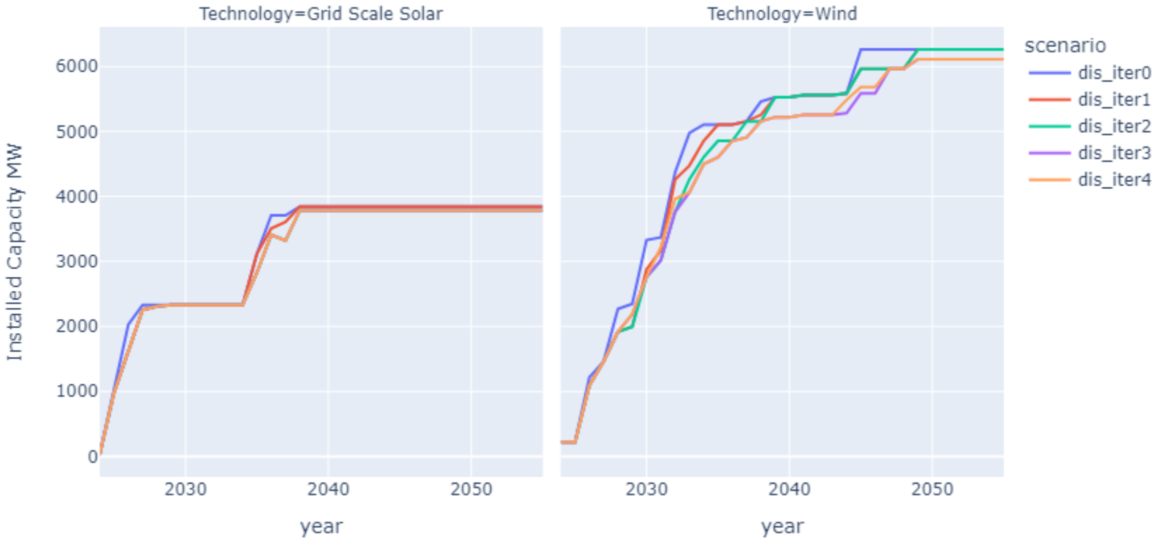
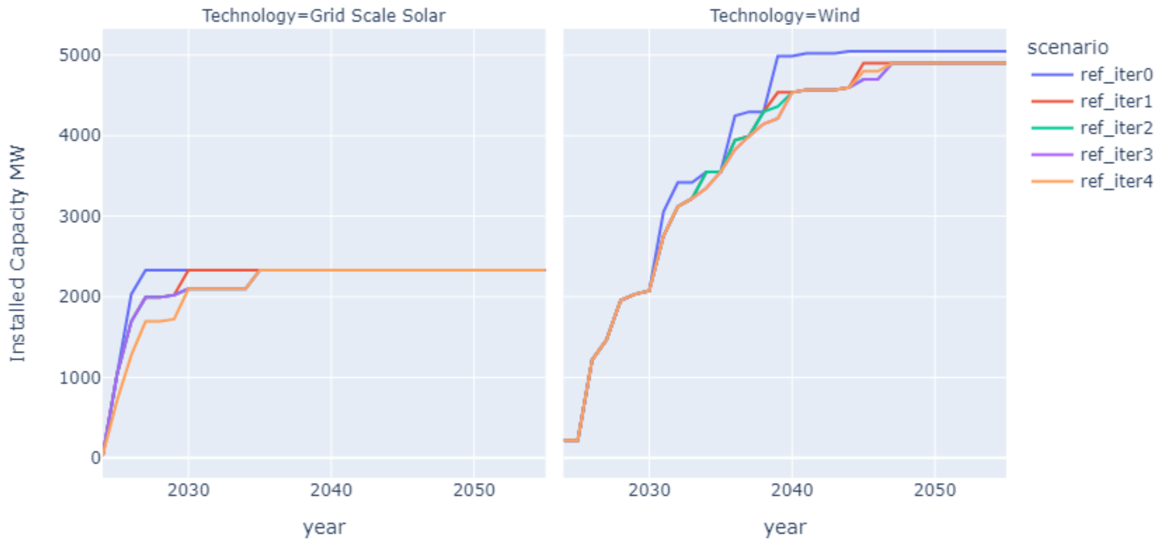


Figure 14: Optgen Adjustments – Reference



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