TRANSPOWER

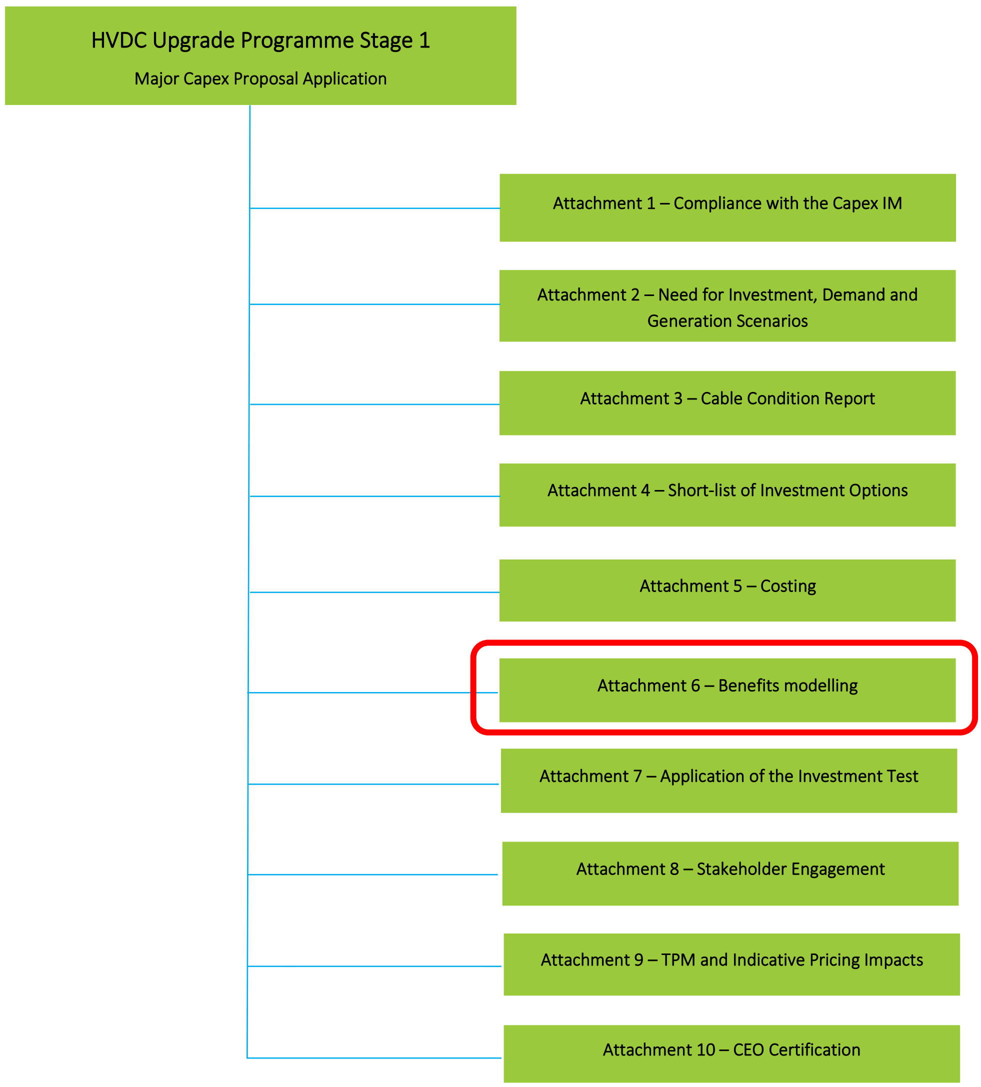
HVDC Link Upgrade Programme
Major Capex Proposal (Stage 1)

Attachment 6: Benefits modelling

September 2025

Purpose

This document is part of our HVDC Link Upgrade Programme Stage 1 Major Capex Proposal (**MCP**). The purpose of this attachment is to describe how we have calculated benefits of the short-listed investment options for use in the Capex IM investment test. We used models of the New Zealand electricity system to estimate the benefits of the investment options.



Contents

1 Benefits modelling approach

This section describes our approach to modelling the electricity market benefits[1] used in our analysis.

1.1 Overview

Our modelling has focused on deriving the market benefits relating to investment in the HVDC link. We use models of the New Zealand electricity system to estimate the benefits of alternative investment options for the HVDC link. These benefits are measured as electricity market savings relative to a no-investment 'Base Case' option. These benefits could be from the avoided cost of building new generation or reducing the operational costs of the generation dispatched.

The main building blocks of our approach to estimating these benefits are:

- **Generation expansion planning**. We identify the lowest-cost combination of new generation projects required to supply future demand under different scenarios. Where an investment option influences generation build, we determine multiple generation expansion plans for each demand and generation scenario we have used in our analysis;[2]
- **Generation dispatch simulations.** These simulations estimate the electricity system's operating costs for each generation expansion plan.

1.2 Generation expansion planning

Generation expansion planning is the process of determining future grid connected generation for a given demand scenario. Generation expansion plans are an input to our generation dispatch simulations[3].

1.2.1 Least cost generation plans

Our generation expansion modelling focuses on new generation costs compared with operating existing generation. Our modelling effectively steps through time (out to 2060 in this case), building new generation as required to meet forecast demand while minimising generation expansion and dispatch costs. It chooses new generation from a generation stack

1 In the language of the Capex IM, these are electricity market benefit or cost elements. We have also modelled the capital costs of modelled projects for the investment options, which are also electricity market benefit or cost elements. See Attachment 7 for more information about the modelled project capital costs.

2 In the language of the Capex IM, we have used demand and generation scenario variations in our analysis because the scenarios differ from the EDGS most recently published by MBIE. See Attachment 2 for further information about the scenarios.

3 Note that generation embedded within the distribution network is included in the demand forecast.

of potential projects with the overall objective of minimising the cost of electricity over the period being considered.

We consider that these least-cost generation plans are representative of what the market would deliver in these future scenarios. However, we recognise that there are many factors that play a role in generation investment decisions such as:

- availability of capital;
- future views on wholesale electricity prices;
- project consentability;
- power purchase agreements and retail positions relative to generation.

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, generation cost will be the major deciding factor of investment decisions.

1.2.2 Using OptGen

We use PSR's OptGen modelling software[4] to develop generation expansion plans. We use their 'Optgen1' algorithm.

Optgen1 determines the lowest-cost combination of capital costs (from new generation investments) and operating costs (from existing and new generation plant) over the modelling horizon. It performs an iterative calculation with repetition of the following stages until the algorithm converges on a solution:

1. Operating costs are estimated for an assumed generation expansion plan using the same SDDP algorithm as used for our generation dispatch simulations (see section 1.3). The SDDP formulation has some simplifications to ensure that the model can provide a solution in a reasonable time. Operating costs account for hydro energy variability, future inflow uncertainty, and renewable energy variability;
2. Operating costs are fed into a separate algorithm that determines an updated generation expansion plan. Based on the operating costs, the expansion plan may feature more generation build than the previous assumed expansion plan if this leads to a lower combination of capital and operating costs.

To align the expansion plans with our expectations of what the market will deliver in the short term, we initially constrain the build to generation projects to which developers have committed, and to those projects which are in the advanced stages of Transpower's connection pipeline.

We examine key output metrics to ensure the modelled expansion plan is suitable for investment testing. The expansion plans for this proposal have been adjusted to ensure that new generation build is revenue adequate. This adjustment is made with an iterative process

4 https://www.psr-inc.com/software/optgen.html

which adjusts the timing of new generation build to ensure that its modelled revenue covers its operating cost and capital repayments[5].

1.2.3 Generation expansion plans to match investment options

Our expectation is that a significant transmission investment may influence where generation is built. However, it is not always practical to determine unique generation expansion plans for multiple investment options within our modelling. Our experience is that the differences in generation expansion plans between similar investment options cannot always be resolved with sufficient accuracy.

We expect that HVDC link investment will influence both the location and type of new generation. Because of this we determine unique expansion plans for Option 1 (the decommissioning of the HVDC), and the cable replacement Options 3, for each scenario.

The generation expansion plan for Option 1 assumes that the HVDC is decommissioned in 2038[6], which results in a dramatically different generation expansion plan compared with the HVDC remaining in operation (Options 2 and 3).

However, the differences between Option 2 (like-for-like replacement, 1200 MW) and Option 3 (capacity increase, 1400 MW) are more subtle and differences in generation expansions plans are not practical to resolve. For this reason, we use a single generation expansion plan for both Option 2 and Option 3 for each scenario.

1.3 Generation dispatch simulation

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

- Future changes in grid connected generation and batteries - as provided by our generation expansion plans;
- Future changes to the HVDC for each investment option;
- Changes in demand - arising from daily and weekly demand variations through to long term 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.

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5 Improving revenue adequacy typically involves delaying the build of new renewable generation and bringing thermal peaking generation forward in time. We apply an algorithm which preserves the sequence of renewable generation build from the Optgen model but spreads the capacity additions out in time. The total costs of the revenue adequate expansion plans (capital and operating costs) are typically within ~1% of the unadjusted expansion plans. The adjustments are necessary due to approximations that Optgen applies when estimating operational costs.

6 While cables progressively fail, the 2038 decommissioning date is driven by a failure of the Control Systems which is a key component for the HVDC link to be able to operate.

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

1.3.1 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. We determine unique SDDP policies for every investment option and scenario.

1.3.2 Temporal 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. This will, though, be at the expense of increasing model solve time and model result data storage requirements.

For our HVDC generation dispatch simulations we use an hourly resolution over the full modelling period, 2023 to 2060[7].

1.3.3 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 the New Zealand electricity system costs vary significantly with hydro inflows; 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 this analysis we used:

- policy step: 15 and 50 synthetic inflow sequences, respectively, for the 'backward' and 'forward' phase of the SDDP algorithm;
- simulation step: 50 synthetic inflow sequences.

[7] The modelling begins before the cable installation year to establish a generation expansion plan which transitions from the existing electricity system.

1.3.4 Modelling the transmission network with SDDP

Our SDDP model incorporates a detailed representation of the transmission network. [8] However, for each analysis we tailor the set of transmission constraints to emphasize the aspects most pertinent to the study. In this case, we focus on the following elements:

- *HVDC Losses and Transfer Limits*: We model HVDC losses and transfer limits, accounting for variations across different investment options;
- *HVDC Overload Ratings:* We include overload ratings for each HVDC pole, with these ratings varying between investment options. This factor plays a role in determining the HVDC's contribution to the instantaneous reserves requirement;[9]
- *AC Network Constraints:* We do not impose transmission constraints on the AC network;
- *AC Network Losses:* Instead of explicitly modelling AC network losses, we incorporate them directly into the demand.

1.3.5 Modelling reserves in SDDP

The HVDC link plays an important role by facilitating the sharing of instantaneous reserves (hereafter, simply reserves) between the North and South Islands, and setting the risk and need for reserves when transferring at high capacities.

For this analysis we have modelled – in Optgen and SDDP – how the HVDC can set the requirement for reserves in the island receiving power[10]. The reserve requirement in each island needs to cover a contingent event, which is the failure of an HVDC pole or a large generation unit (whichever is larger). The reserve requirement is a constraint that the model optimisation must satisfy with standby generation, grid scale batteries, or interruptible load.

The implementation detail is as follows:

- For the North and South Island, a set of backed and backing plant and connections are defined;
- The backed set includes large thermal generators and each pole of the HVDC;
- Backing generators are plants which can provide reserves. Included are some hydro generation, existing levels of interruptible load, some existing and future thermal plants, and all existing or future grid scale batteries;
- Minimum generation requirements are set for backing thermal plants to ensure that they are 'spinning' if providing reserves;
- A representative offer stack for reserves (e.g., the price at which reserves are offered into the market) has been defined based on analysis of historical market bids;

Further detail on the configuration of reserves is provided in Appendix A.

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8 All circuits 66 kV and above are included in our grid model.

9 See Appendix A Reserve modelling implementation for a description of how the reserve requirement has been determined for this analysis.

10 Note that is not possible to model reserve sharing between Islands with our implementation of SDDP.

2 Modelling assumptions

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

2.1 Transmission network

2.1.1 HVDC transfer capacity

The northward and southward transfer capacity of the HVDC is the key input into our modelling which varies between investment options.

Initially, the HVDC has a transfer capacity of 1071 MW North and 762 MW South. This derated capacity is consistent with our modelling for our NZGP1.1 major capex project and reflects that transfers are currently constrained by the availability of reactive support plant at Haywards. This is to be resolved by the installation a STATCOM at Haywards in May 2027. From that point onward, we assume transfer capacity of 1200 MW North and 950 MW South.

The transfer capacities available under each of the investment options differ from 2031:

- In the Base Case (Option 1), which assumes no additional investment, we assume that one submarine cable fails in July 2031, after which the HVDC is reconfigured to operate with a single 500 MW cable on each pole, resulting in a transfer capacity of 1000 MW North. The HVDC is then assumed to be decommissioned in July 2038 after failure of the Control System;
- Option 2 assumes a like-for-like replacement of the existing cables in April 2031[11], with no change to the HVDC transfer capacity;
- Option 3 assumes a 1400 MW capacity upgrade replacement in April 2031, by increasing the Northwards transfer capacity only.[12]

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[11] April 2031 is assumed to coincide with the completion of the cable installation. However, we note that the commissioning of the new cables will coincide with the commissioning of the replacement control system which may now be towards the end of 2031.

[12] We note that the enhancement to the north transfer capacity and pole 2 overload will also not be realised until the replacement control systems are commissioned towards the end of 2031.

Table 1: Assumed HVDC transfer capacities for each investment option

	Beginning	North transfer (MW)	South transfer (MW)
Base Case Option 1	May 2027	1200	950
	July 2031	1000	950
	July 2038	0	0
Option 2	May 2027	1200	950
	April 2031	1200	950
Option 3	May 2027	1200	950
	April 2031	1400	950

We assume that changes to the HVDC transfer capacity occur on the 1st day of the specified month. HVDC outages during the installation and commissioning of replacement HVDC cables are not considered in our modelling. This is because such outages are expected to be common to Option 2 and Option 3, and the associated costs of these outages will be small compared to the difference in benefits between Options 1 and 2.

Note that the southward transfer capacity is assumed to remain at 950 MW for both option 2 and option 3. This transfer limit reflects AC network constraints in the lower North Island. This constraint could potentially be alleviated through other investments in the AC network, however this is not considered as part of this analysis.

2.1.1.1 The basis for the decommissioning scenario

For the Base Case (Option 1), the decommissioning date is primarily driven by the obsolescence of the existing control systems, which are expected to be the first HVDC system components to become non-operational. The timing of the control system obsolescence also closely aligns with the projected end of life of the cables.

Under our decommissioning option, it is assumed that all HVDC system components, including control systems (scheduled for replacement in the early 2030s, after 20 years in operation), will remain in operation until decommissioning in 2038, with no further investment. This relies on optimistic assumptions regarding system performance beyond their nominal lifespans, however we consider it a suitable Base Case for comparison.

The existing submarine cables are assumed to deteriorate progressively over that period, and with an increasing probability of failure. We have used the asset health model forecasts described in Attachment 3 to generate a cable failure scenario. We assume discrete cable failures when the combined failure probability reaches 50%[13], and in this way construct a central failure scenario. We assume the first cable fails in the year when the probability that at least one cable has failed reaches 50%. We assume the second cable fails in the year when the probability that at least 2 cables has failed reaches 50%. This approach resulted in modelling a cable failure in 2031, and a second cable failure in 2039 (shortly after the assumed decommissioning due to the control system failure).

2.1.2 HVDC losses

The transfer capacities outlined above are specified in terms of power sent (e.g., a 1200 MW North transfer at Benmore). The received power ratings of the HVDC are lower due to DC transmission losses. HVDC losses are complex, depending on:

- the operating mode (e.g. round power, balanced, unbalanced);
- the temperature of the HVDC components, including the converter plant.

To approximate HVDC losses we use a simple DC circuit model which includes Pole 2, Pole 3 and an earth return. We assume balanced loading of the poles up to the nominal operating limit of Pole 2, and unbalanced loading beyond this.

We assume the circuit parameters listed in Table 2 for the existing HVDC and 1200 MW configuration. The circuit resistances are midpoint estimates across a cold/hot operating range.

Table 2: HVDC simple DC circuit model parameters

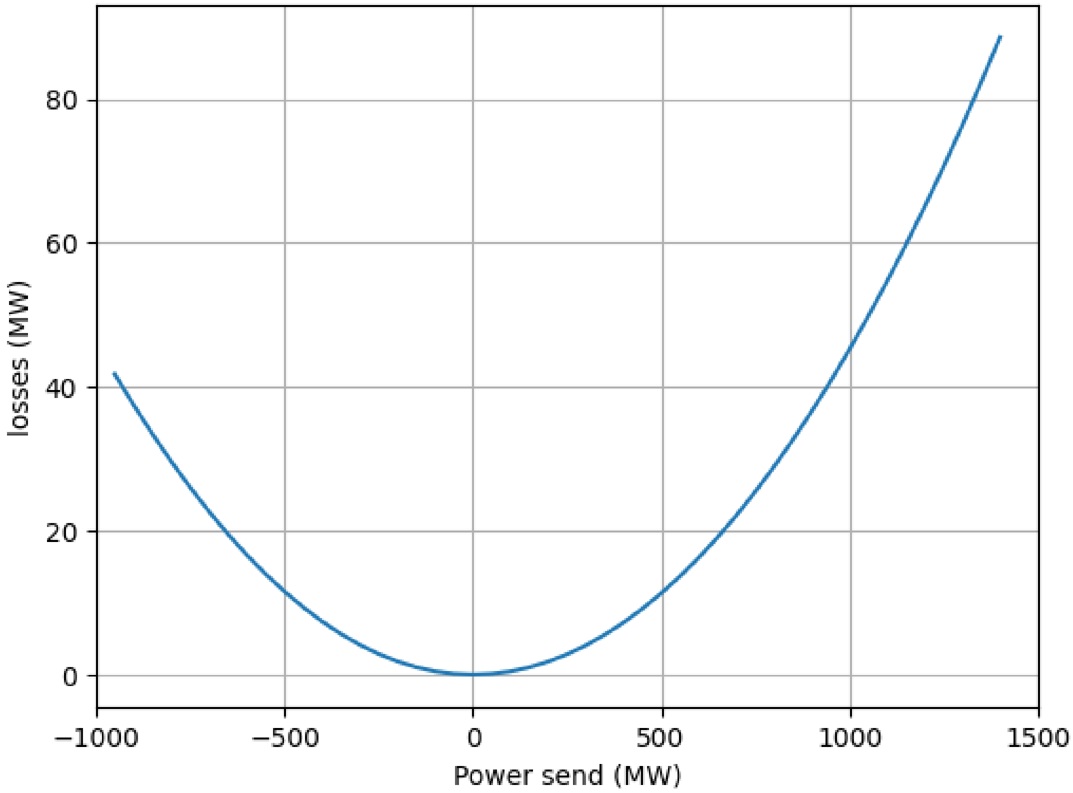
	Resistance (ohms)	Voltage for north transfers (kV)	Voltage for south transfers (kV)
Pole 2	11.3255	350	342
Pole 3	11.0755	350	350
Earth return	1.1	NA	NA

We assume that for Option 3 the resistance of both poles is equal to the existing resistance of Pole 3 (for the existing HVDC the cable configuration is the cause of resistance variance between poles).

To illustrate, the transfer losses for the 1400 MW HVDC configuration are shown Figure 1. Note that in SDDP and Optgen we approximate this loss curve in tranches with linear losses. We use the incremental (i.e., marginal) losses in each tranche.

13 Note that the relationship between asset health and failure probability is highly uncertain. For this failure scenario the cable failure probabilities are calibrated to the CIGRE 2020 submarine cable failure statistics.

Figure 1: Assumed HVDC transfer losses (Option 3)



2.1.3 HVDC reserve self-cover

Each pole of the HVDC has an overload capacity at which it can operate for short periods of time. This allows the HVDC to self-cover its own reserve requirement to an extent. For example, if Pole 3 were to trip then Pole 2 could compensate by operating at a higher capacity for 15 minutes until the market can be re-dispatched.

The HVDC's ability to self-cover for a contingent event (CE)[14] , the loss of one pole, is reflected in the System Operator's tools by the HVDC risk subtractor variable. The risk subtractor quantifies the extent to which the HVDC can self-cover the receiving island reserve requirements. It is determined by the lower of the overload ratings of each pole. Currently the North Island risk subtractor is 650 MW, which is the maximum power received at Haywards when Pole 2 is operating on overload. This means that reserves are only required to cover the HVDC transfers with received power above 650 MW. Worked examples of reserve requirements are given in Table 4[15].

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14 Event categorisation | Transpower

15 Note that these examples only consider the requirement for sustained instantaneous reserves which is the extent of our reserve modelling. There is an additional requirement for fast instantaneous reserves to cover the same contingent risk. We ignore this reserve requirement in our modelling as there is considerable overlap between the providers of fast and slow instantaneous reserves.

Through investment in the HVDC we can increase the overload capacity of Pole 2 and enhance the ability of the HVDC to self-cover its reserve requirement. This requires an increase in the capacity of the cables connected across Pole 2 (consistent with Option 3) and enhancements to the converter equipment at Benmore and Haywards.

The enhancements to the converter equipment are assumed to happen in stages. Coinciding with the installation of the cables we assume the completion of the Pole 2 overload project which increases the overload capacity to 840 MW in terms of power sent at Benmore. We are planning to replace Pole 2 (and its converter transformers) in 2042 at the end of its life.[16] At that time we assume that the transformers in the replacement pole will support 1000 MW overload.

Table 3 summarises the overload capabilities of the cable replacement investment options (Options 2 and 3) at various stages. Note that the overload capacity can be specified in terms of both the power sent at Benmore and received at Haywards, with the difference due to losses.

For south transfers we assume a risk subtractor of 619 MW for both Option 2 and Option 3.

Table 3: Pole overload capabilities for north transfers and risk subtractors for Options 2 and 3

	Option 2 (1200 MW HVDC)		Option 3 (1400 MW HVDC) before 2042		Option 3 (1400 MW HVDC) from 2042	
	Pole 2	Pole 3	Pole 2	Pole 3	Pole 2	Pole 3
Overload capacity (MW send at Benmore)	700	1000	840	1000	1000	1000
Overload capacity (MW received at Haywards)	650	900	770	900	900	900
North Island risk subtractor (MW)	650		770		900	

16 The Pole 2 replacement project is a modelled project for Options 2 and 3.

Table 4: Example of modelled North Island reserve requirements for Option 2 (1200 MW) and Option 3 (1400 MW)

		Option 2 (1200MW HVDC)	Option 3 (1400MW HVDC) before 2042	Option 3 (1400MW HVDC) from 2042
Example 1	Power received at Haywards (MW)		700	
	HVDC North Island reserve requirement (MW)	50	0	0
Example 2	Power received at Haywards (MW)		1000	
	HVDC North Island reserve requirement (MW)	350	230	100

Further information on the benefits of upgrading the Pole 2 overload can be found in Appendix B.

2.1.4 AC network

Constraints on the AC network are not modelled for this analysis. We implicitly assume that these are resolved as necessary through other investments (which are not modelled projects for any of the investment options).

2.2 Deficit cost

The cost of deficit (on a $ per MWh basis) is an important input to our generation expansion plan and generation dispatch simulation modelling. Deficit can be thought of as the cost of energy that cannot be supplied by either generation or the transmission network with all assets in service.

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.

For our SDDP model the cost of deficit influences how stored water is used, 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.

2.2.1 Value of expected unserved energy

The value of expected unserved energy is the assumed value to consumers of losing electricity supply because of an unplanned outage. As opposed to deficit costs, the value of unserved energy relates to the unexpected loss of supply of electricity. We use this value to assess reliability benefits, in situations where different options deliver differing levels of reliability of supply. As we are not assessing reliability benefits, we have not used values of expected unserved energy in our benefit analysis, only deficit costs.

2.2.2 Generation expansion planning deficit cost tranches

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 5. Each tranche is for a given amount of deficit, expressed as a percentage of hourly[17] 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 5.

Table 5: 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

2.2.3 Generation dispatch simulations

For generation dispatch simulations, we assume the cost of deficit is as shown in Table 5.

17 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 analysis. These plans use the demand and generation assumptions for each scenario described in Attachment 2 and are an input to the generation dispatch simulations.

Our assumptions, intended to provide diversity across our generation expansion plans, drive the relatively strong growth in:

- geothermal generation in the Growth scenario;
- solar generation in the Environmental and Disruptive scenarios.

3.1 Base Case (Option 1. Decommissioning the HVDC)

Figure 2 illustrates cumulative new generation capacity additions and deletions, out to 2060, for the Environmental, Disruptive, Growth and Reference scenarios[18] under the Base Case (Option 1). This Base Case assumes that the northward capacity of the HVDC is reduced in 2031, and the link is fully decommissioned in 2038.

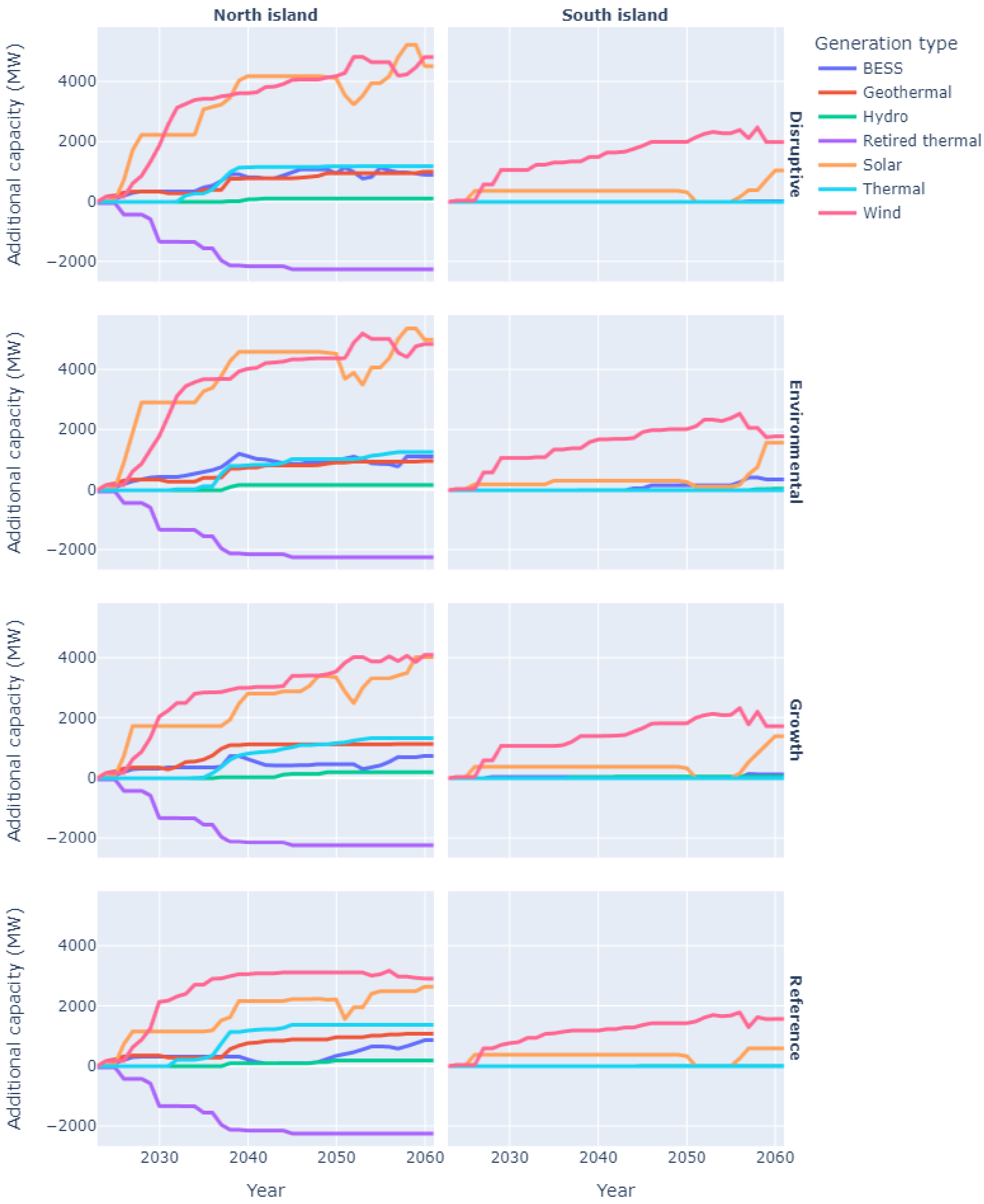
For these scenarios we see new generation build is dominated by wind and solar, with the largest additions occurring in the Disruptive and Environmental scenarios. For all scenarios there are large additions of this generation capacity through to 2030 to meet increases in demand and to displace existing thermal generation. Beyond 2030, we see more gradual increases in wind and solar generation, and some rationalisation of the installed base when projects reach the end of their operational life[19]. New wind and solar generation are concentrated in the North Island which is proximate to demand and has good renewable resource.

Firm capacity additions are largely thermal generation, geothermal generation, and grid scale batteries located in the North Island. These additions are both to compensate for the assumed retirements of existing thermal generation and in response to the decommissioning of the HVDC. Notably, the expansion plans feature large additions of geothermal generation coinciding with the assumed decommissioning, demonstrating that this is the most cost-effective way of ensuring both energy supply and capacity adequacy in the North Island without the HVDC.

18 These are the scenarios used in the base investment test. For our investment test the Global scenario has zero weighting and for this reason is not shown.

19 In Figure 2 and Figure 3 below this rationalisation is seen as reductions in additional capacity. This occurs when generation reaches the end of its operational life and closes and is not immediately replaced by new build.

Figure 2: Generation expansion plans, capacity additions and deletions for Base Case (Option 1)

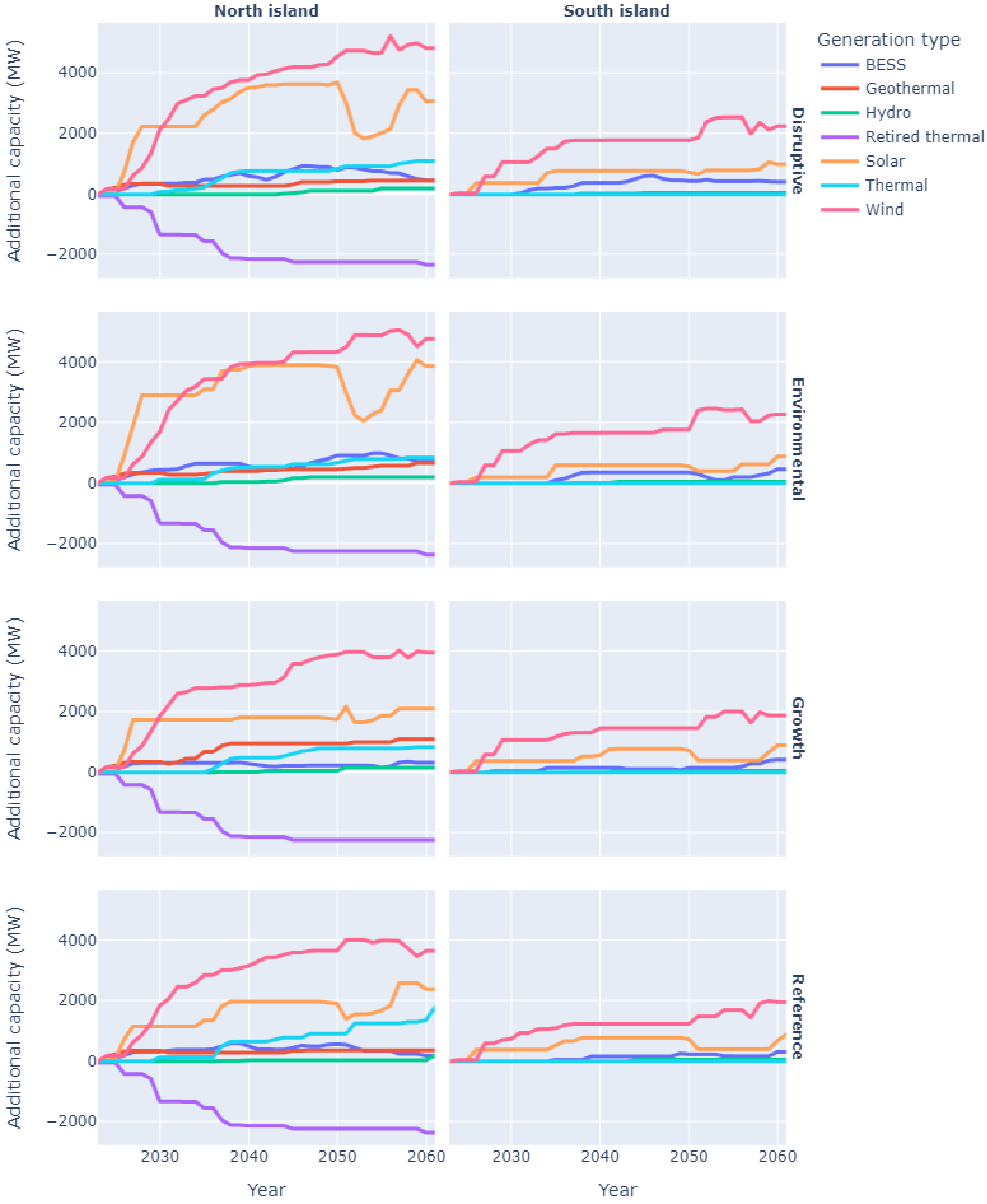


3.2 Replacing the HVDC cables (Options 2 and 3)

We assume the same generation expansion plans for Option 2 and Option 3, as both involve the replacement of the HVDC cables and continued transfers through to 2060. The expansion plans for each scenario are shown in Figure 3 below.

The capacity additions for each scenario are broadly consistent with those for the corresponding scenario in the Base Case (Option 1), with large additions of wind and solar in all scenarios, with an enduring role for thermal generation.

Figure 3: Generation expansion plans, capacity additions and deletions for Options 2 and 3



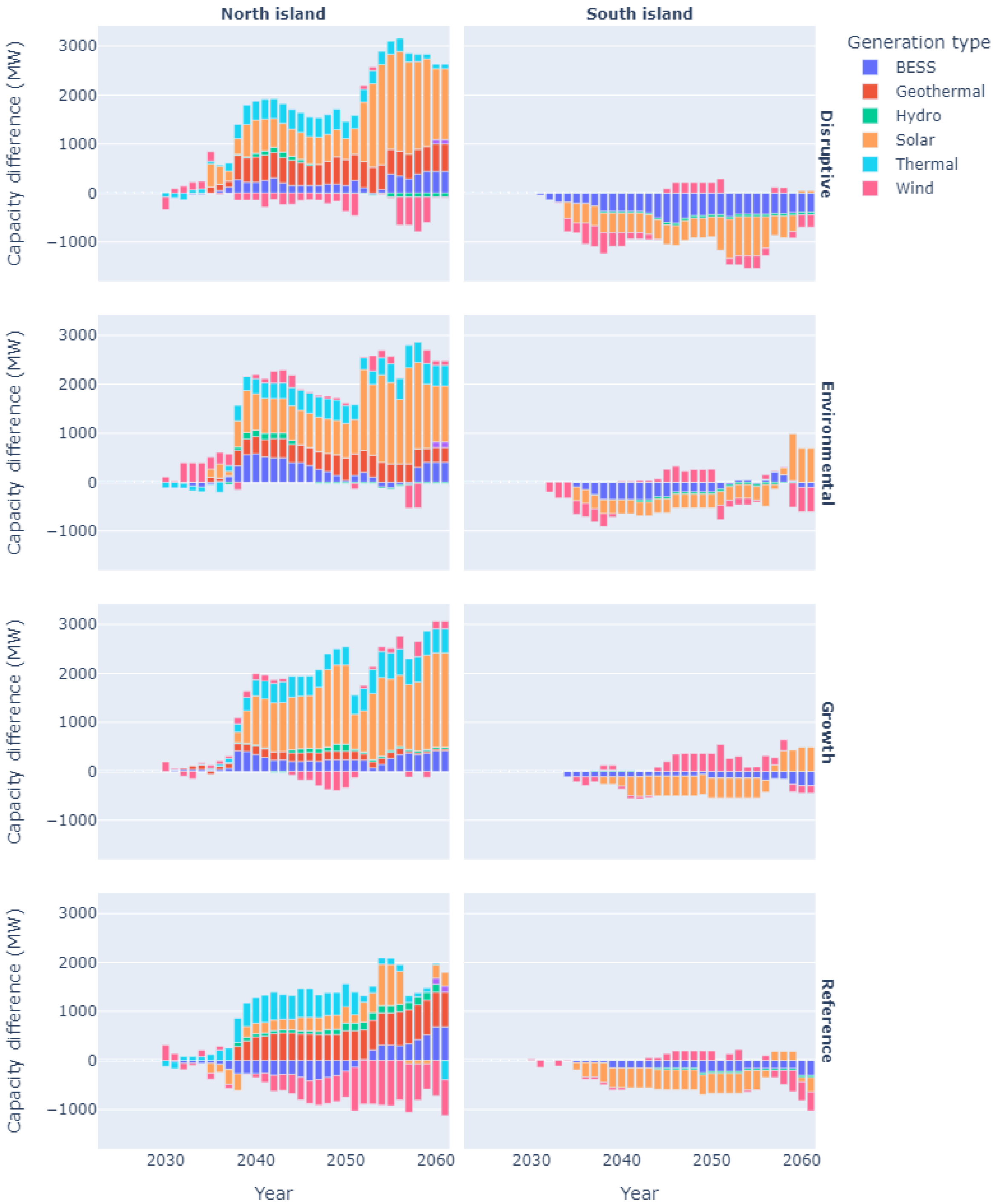
3.2.1 Comparison of expansion plans

Figure 4 below shows the annual difference between the Base Case (Option 1) and the cable replacement options (Option 2 and Option 3) expansion plans. These demonstrate the key impacts on generation build from decommissioning the HVDC. A positive capacity difference implies that the decommissioning scenario has more installed generation capacity.

The key differences between the expansion plans are that:

- The Base Case (Decommissioning of the HVDC) results in more geothermal generation being developed. By 2050 we see up to 600 MW of additional geothermal capacity (Reference scenario). For context, this can generate approximately 5 TWh p.a. of electricity supply, whereas the net northward transfer of the HVDC is currently expected to be around 4TWh;
- For the Growth scenario large increases in geothermal generation are not possible, as most of this resource has already been developed. Instead, this scenario compensates for the loss of the HVDC by building comparatively more solar and thermal generation;
- In all scenarios, either additional thermal generation is required in the Base Case, or thermal generation is needed earlier than under Option 3;
- The scenarios in the Base Case also generally build more grid scale batteries in the North Island and less in the South Island;
- In all scenarios in the Base Case, more solar generation is bult in the North Island and less in the South Island.

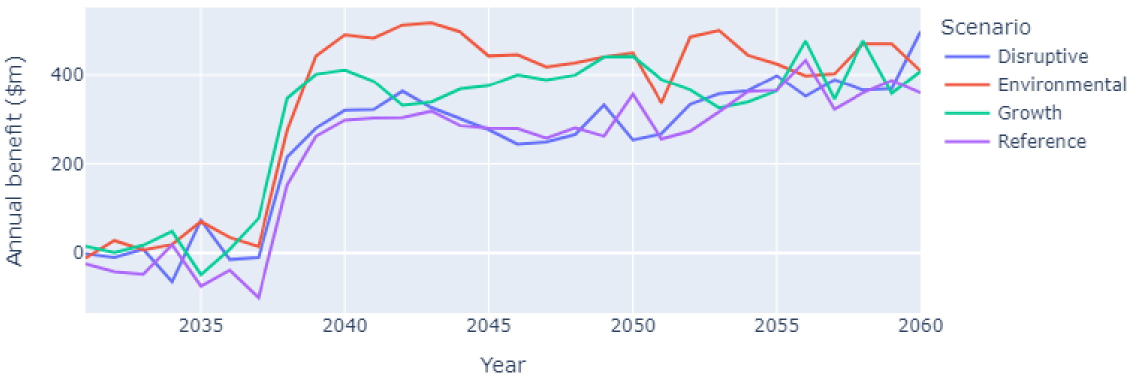
Figure 4: Difference in cumulative capacity between Base Case (Option 1) expansion plan and cable replacement options (Options 2 and 3) expansion plans



3.2.2 Electricity market capital benefits

The avoided cost of generation build is an economic benefit that is considered in our analysis. Continued investment in the HVDC (Option 2 and Option 3) results in a reduction in overall need for new generation capacity to be developed (compared with Base Case/Option 1), resulting in a capital cost benefit to the electricity market. Figure 5 illustrates this capital benefit, while Table 7 provides a comparison of the net present value of this capital benefit for each investment option.

Figure 5: Electricity market capital cost benefits over time (undiscounted) for Options 2 and 3 versus the Base Case (Option 1)



The capital benefit is significant and ranges from $2.0b to $3.3b. Note, operational benefits are set out in Section 4.5.

Table 6: Electricity market capital cost benefits present value ($m 2025, 5% discount rate) relative to the Base Case (Option 1)

Scenario	Disruptive	Environmental	Growth	Reference
Base Case / Option 1	0	0	0	0
Option 2	2269	3341	2880	1973
Option 3	2269	3341	2880	1973

3.3 Thermal retirements and the Huntly power station

As noted in Attachment 2, there is an inconsistency between our modelled expansion plan, and recent market announcements around the future of the Rankine generation units at the Huntly power station. Our expansion plans assume that the three 250 MW Rankine units are retired in 2030 – these are included in the retired thermal traces in Figure 2 and Figure 3.

However, a recent agreement between Genesis, Contact, Mercury and Meridian aims to establish Huntly as a strategic energy reserve, and if approved by the Commerce Commission, is likely to underpin the operation of the Rankine units until 2035.

We note this inconsistency; however, we are of the view that the assumption around the Rankine units does not materially alter the outcomes of our analysis and could even strengthen the electricity market benefits for Options 2 and Options 3. This is because:

- The extension of the operation of the Rankine units is likely to compensate for an earlier retirement of gas generation. Our expansion plans assume that the large, combined cycle gas generator E3p (~400 MW) continues to operate until 2037, however the availability of natural gas fuel supply may not support this. Because the Rankine units can operate using coal, they are likely to operate instead of the gas generation. This suggests that our analysis is not underestimating available capacity;
- Coal fired generation at Huntly is likely to be more expensive than the gas fired generation we assume in the Reference, Growth and Disruptive scenarios. This means the avoided thermal fuel costs (e.g. operational benefits) will be larger in a future where Huntly continues to operate;
- The extension of the operation of the Rankine units is only until 2035 and there is considerable uncertainty around what generation will provide firming beyond this time. Therefore the inconsistency only persists for a short period of the horizon over which benefits are considered.

4 Generation dispatch simulation results

This section provides an overview of our generation dispatch simulation results and the operational benefits of each investment option.

The dispatch simulations are consistent with the generation expansion plans described in section 3. Using these expansion plans electricity system operations are simulated out to 2060 with hourly temporal resolution. These simulations test how the system operates with renewable intermittency and moments of peak demand. It also allows us to analyse the deficiencies and strengths of the electricity system for each of the investment options.

As described in Attachment 2, each of the scenarios have different assumptions around thermal fuel and emission costs, and different levels of demand. We simulated each of these scenarios for each investment option, giving a total of 12 modelled scenarios.

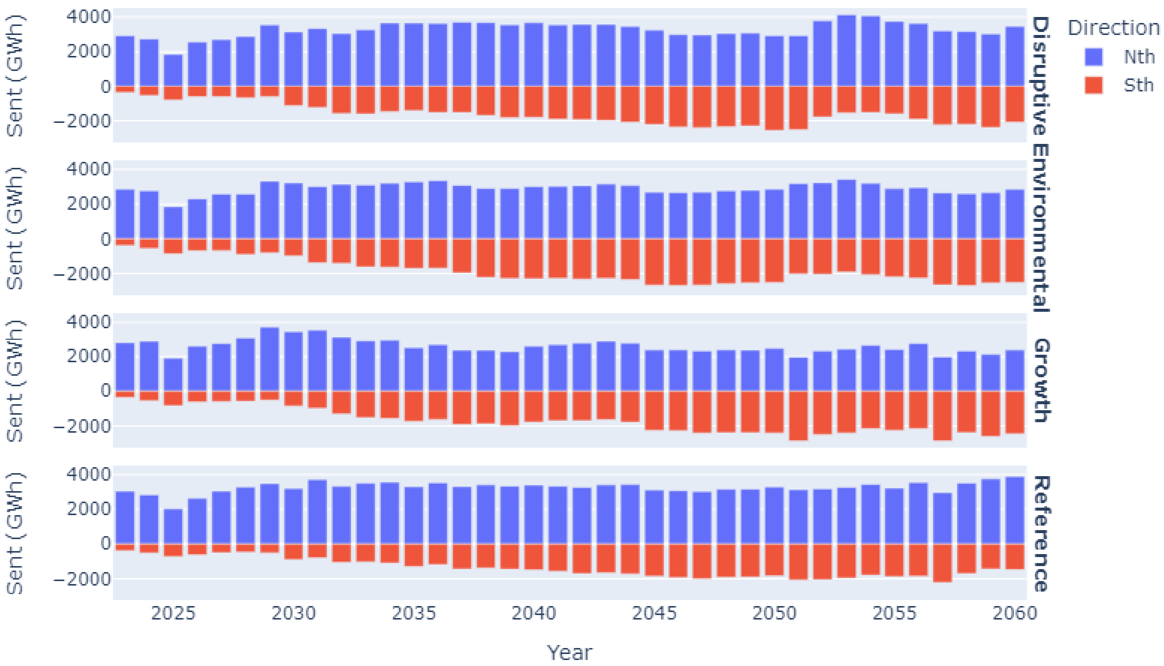
4.1 HVDC transfers

4.1.1 Changing role of the HVDC

Our scenarios show an evolution of the role of the HVDC in the electricity system. Historically the HVDC has primarily been used to facilitate a bulk energy transfer from the South to the North Island. Our modelling shows that over time transfers on the HVDC become more balanced with significant transfers southwards. This trend is observed in all modelled scenarios as shown in Figure 6. The northward transfers are least significant in the Growth scenario as this has high levels of geothermal generation in the Central North Island and so achieves the highest self-sufficiency for the North Island.

Figure 6 shows only Option 3 for brevity, but the transfers for Option 2 are indistinguishable on this scale. For the Base Case (Option 1), transfers go to zero in 2038/2039 when the HVDC is assumed to be decommissioned.

Figure 6: HVDC transferred annual energy (GWh) for Option 3, averaged across all hydrology



4.1.2 1200 MW versus 1400 MW capacity

The flow duration curves in Figure 7 illustrate the variation in HVDC transfers over the years. These show the proportion of time that hourly transfers are at a particular level, considering all simulated hydrology.

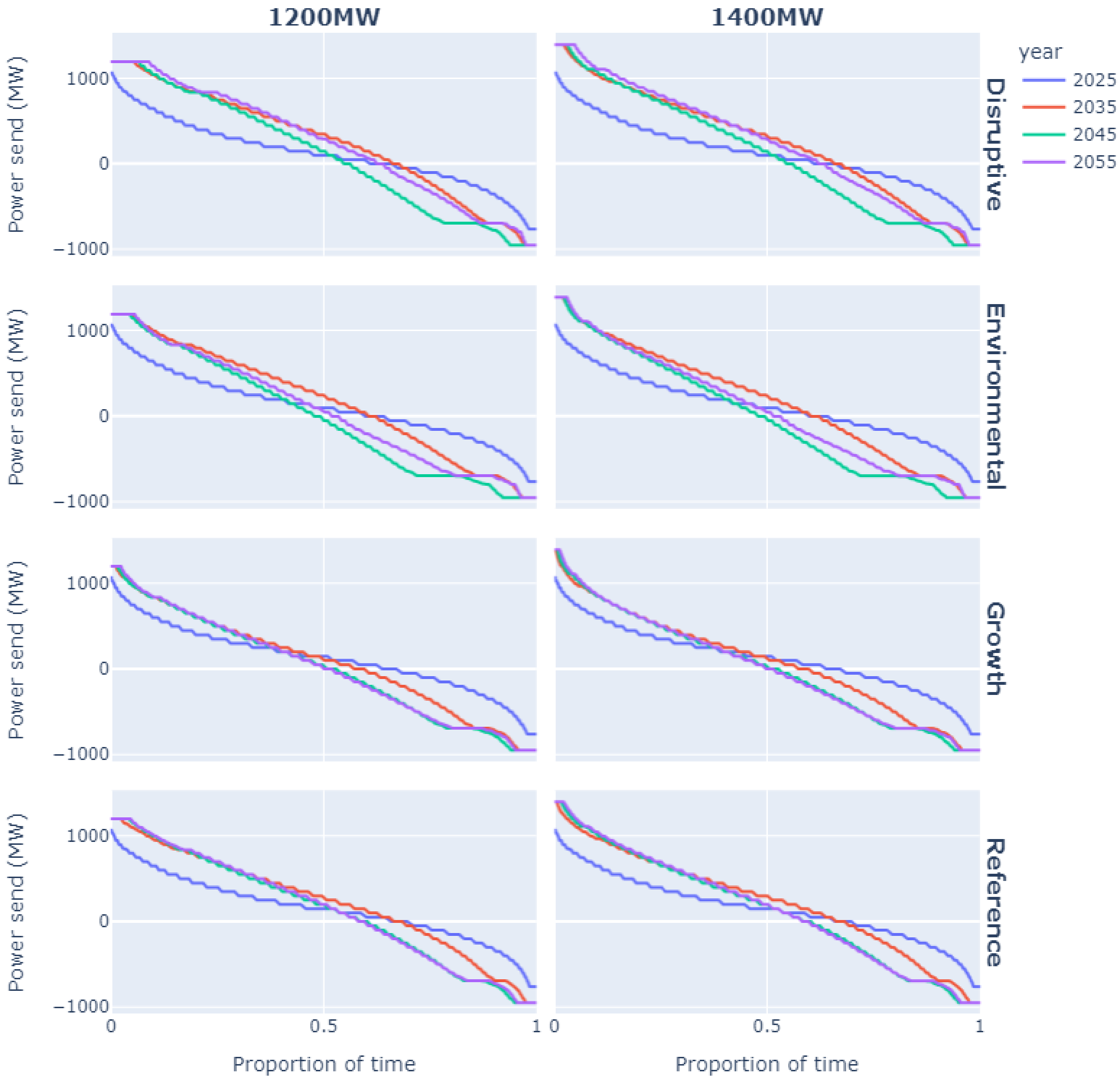
The curves indicate that the HVDC operates at increasingly high transfer levels for both North and South flows. From around 2030 we start to see Northward transfers being constrained at 1200 MW for Option 2 for some hydro inflow and renewable sequences. However, Option 3, which increases northward capacity to 1400 MW, significantly reduces these Northward transfer constraints.

Constrained Northward transfers occur in all scenarios but are least significant in the Growth scenario due to the high level of geothermal generation and relative self-sufficiency of the North Island.

Note that Southward flows are also quite significant[20] and there are periods when these transfers are constrained[21]. However, neither Option 2 nor Option 3 increases the South transfer capacity.

As discussed, the HVDC south transfer capability is limited to 950MW in Option 2 and 3 to reflect constraints in the AC transmission grid. While additional investment could remove the southward constraint, we have assumed the 950 MW limit remains in place in our modelling.

Figure 7: Flow duration curves for investment Options 2 and 3



The simulation results reveal that the periods when northward transfers are highest typically coincide with low North Island wind generation. Transfers on the HVDC are increasingly to firm intermittent North Island renewable generation. The periods of low wind can last for

20 Some Southward transfers occur during periods of negative marginal costs which signal that renewable spillage is occurring. HVDC transfers are potentially overstated during these periods.

21 South transfers first limit below the 950 MW nominal capacity of the HVDC. This level corresponds to the threshold at which the HVDC can self-cover its reserve requirement for Southward transfers.

multiple days and the HVDC enables South Island generation to providing firming. Note that this duration of firming would be difficult for North Island connected grid scale batteries to provide.

4.2 System operation

The operation of the electricity system will change as intermittent renewables make up a larger share of the generation mix. In our generation dispatch simulations, we observe:

- An increase in spill over time which occurs during periods of renewable surplus;
- Thermal generation operating less on average and flexibly within the year to firm intermittent renewables, providing capacity during times of peak demand, and delivering energy during dryer years;
- Dispatchable hydro generation provides capacity during periods of low renewables and peaks in demand.

4.3 Market reserves

In our dispatch modelling we observe that reserve requirements are increasingly set by the HVDC. This is due to a combination of:

- Large thermal retirements and more occasional thermal operation in the North Island. Our modelling assumes the closed cycle gas turbines TCC and E3p close in 2026 and 2037, respectively. When these large generators are operating near their nameplate capacity, they typically set the North Island CE risk; if they are not operating then the reserve requirement is reduced;
- Increasing transfers on the HVDC at high capacities in both Islands. When the received DC power exceeds the capability of the link to self-cover, the HVDC can set the Island risk and reserve requirement.

For the North Island the first of these factors is more dominant and there is a net reduction in the total reserve requirement for all investment options as shown in Figure 8. From the early 2030s the North Island reserve requirement is most often set by geothermal generation, with the recently completed Tauhara power station assumed to be the largest single point of failure and setting a floor for the North Island CE risk.

As discussed in Section 2.1.3, Option 3 includes an increase in the overload capacity of Pole 2 which allows the HVDC to self-cover to a greater extent when transferring power from the South Island to the North Island. A key impact of this change is that the risk subtractor increases from 650 MW to 770 MW in 2031, and then to 900 MW in 2042.

Once the initial overload upgrade is completed for Option 3 there is a reduction in the total reserve requirement for the North Island. This is due to the increase to the North Island risk subtractor for Option 3 which means the reserve requirement from the HVDC will be 120 MW less than for Option 2 for equivalent transfers. However, because Option 3 enables higher northward transfers, the North Island reserve requirement can exceed Option 2 for transfers above approximately 1330 MW.

We assume that for Option 3 in 2042 Pole 2 is replaced (a modelled project for Option 3) and the new converters can support 1000 MW overload which gives a 900 MW risk subtractor.

From this time, for equivalent northward transfers the HVDC reserve requirement will be 250MW less for Option 3 than for Option 2. Even when operating at a maximum capacity of 1400 MW the reserve requirement for Option 3 is less than it is for Option 2 operating at 1200 MW.

To illustrate, the evolution of the annual total reserve requirement between the investment options for the Disruptive scenario is shown in Figure 8. The total reserve requirement is decomposed into the requirement to cover the HVDC, thermal and geothermal generation. As discussed, from the early 2030s geothermal generation most often sets the reserve requirement and is the largest contributor to the total reserve requirement. The HVDC reserve requirement and total annual reserve requirement in Option 3 is less than in Option 2 due to the increase in the Pole 2 overload capacity.

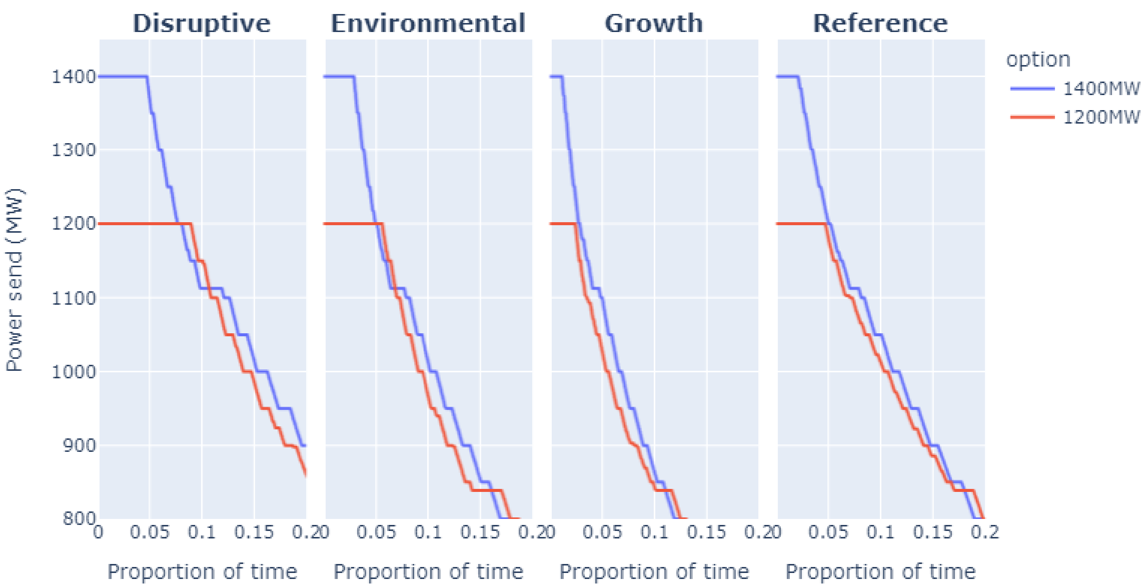
Figure 8: North Island total annual reserve requirement for each investment option for the Disruptive scenario (averaged across simulated hydrology)

To illustrate, the changes to the maximum reserve requirement between the investment options for the Disruptive scenario are shown in Figure 9. For Options 2 and 3 the maximum reserve requirement is set by the HVDC but is smaller for Option 3 once the 1000 MW overload for pole 2 is completed in 2042.

Figure 9 North Island maximum reserve requirement for each investment option for the Disruptive scenario

The reduction in total and maximum reserve requirements is beneficial to the electricity system as we expect instances where the reserve availability is constrained which would limit HVDC transfers. For Option 3 we observe transfers at high capacity more frequently as shown in Figure 10.

Figure 10: Flow duration curve for HVDC transfers in 2055 comparing Option 2 (1200MW) and Option 3 (1400MW)

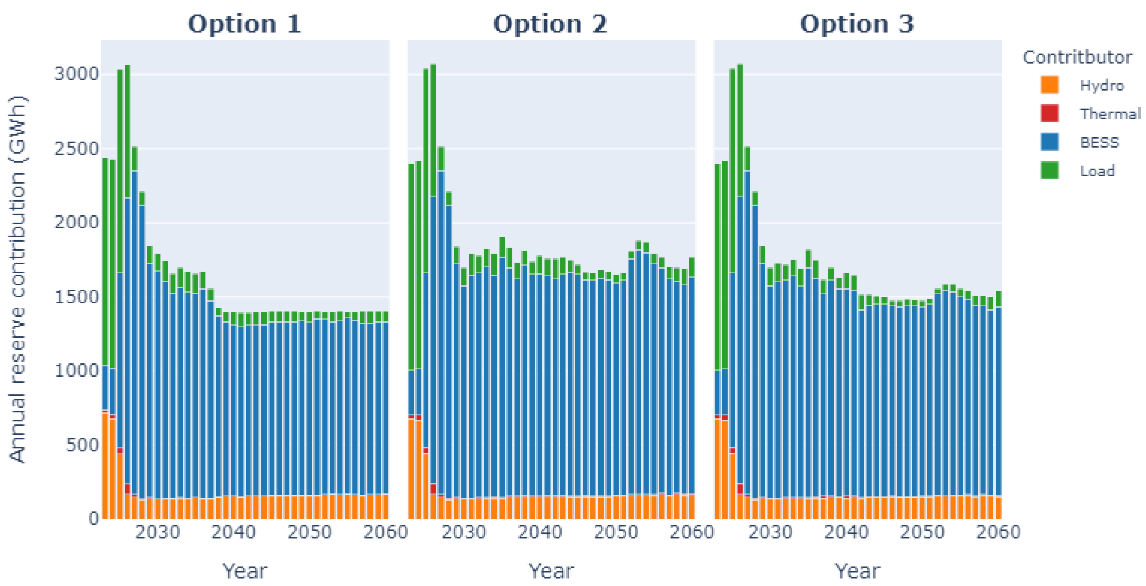


The reserve requirement set by the HVDC or large generators is always satisfied in our generation dispatch simulations. Reserve providers (backing plants) include hydro generation and grid scale batteries and – in the North Island – thermal peakers and interruptible load. The SDDP model ensures that these backing plants have sufficient capacity available while optimising system costs. The model considers the value to the system of the backing plants in providing generation and the payment they require for providing reserves and ensures that the combination of plants dispatched for generation and reserves minimise total system costs.

Our modelling shows that before 2030 much of the North Island reserve capacity provided by hydro generation, gas peakers and interruptible load is increasingly displaced by grid connected batteries. To illustrate, this shift is shown in Figure 11 for the Disruptive scenario. This trend is similarly observed across all scenarios and investment options.

Grid scale batteries are well suited for providing reserves as doing so does not necessarily consume their stored energy and they can be paid for this service[22]. We assume that battery reserve offer costs are less than those from most other providers as is outlined in Appendix A. By comparison, thermal peakers have high running costs and need to be generating to offer reserves, and much hydro reserve capacity is offered at high prices. We assume that reserves from grid scale batteries are offered at less than interruptible load, however we note that there is uncertainty around the relative position in a merit order for these providers.

Figure 11: Average contribution to North Island reserves for Disruptive scenario Option 1-3



4.4 Operational costs

The simulated system costs are evaluated to understand how the system operates, and to consider the benefits between different investment options. The following cost categories are considered for this analysis:

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22 For clarity, a grid scale battery providing reserves means that that it has stored energy which can be discharged in response to a contingent event.

- *Thermal fuel and thermal operating and maintenance costs.* Fuel costs apply only to gas, biofuel, diesel and coal generators, whereas operating and maintenance costs include geothermal generation as well;
- *Emission costs*. These apply to both thermal and geothermal generation;
- *Deficit costs:* These are costs that apply to load which cannot be met by grid supply. This can be either due to capacity or energy shortages;
- *Reserve costs:* These are the payments to market participants that are providing reserves.

On average, electricity system operational costs reduce in all scenarios over time as thermal generation is operated less frequently. This is because existing thermal generation is displaced by renewables, and renewable build provides most of the energy to meet new demand. Compared with thermal generation which has high fuel and emissions costs, wind and solar generation are assumed to have zero variable operational costs[23], and emissions are the only operational cost component for geothermal.

There is considerable variance in operational costs within the year. They are very low over summer months when there is an excess of renewable supply, and peak during winter months when thermal generation is running. There are also periods of deficit, generally over winter due to capacity or energy shortages which can occur during peak demand and/or dry years. As discussed in section 2.2, we model four tranches of deficit ranging in cost from $600/MWh to $10,000/MWh. The vast majority of the modelled deficit occurs in the lowest three tranches which represent voluntary load reduction.

4.5 Generation dispatch simulation benefits

Generation dispatch simulation benefits ('dispatch benefits') are calculated for Option 2 and Option 3 as the relative difference in simulated electricity system costs. Dispatch benefits are calculated for the cost categories outlined in section 4.4 and are presented in section 4.5.1 relative to the Base Case (Option 1). Then in section 4.5.2 the benefits of Option 3 relative to Option 2 are considered.

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

4.5.1 Cable replacement operational benefits

The cable replacement operational benefits compare the saving in operational costs for Option 2 (1200 MW replacement) relative to the Base Case/Option 1 (decommissioning the HVDC). These benefits are significant and are primarily due to savings in thermal fuel and emissions costs as is shown in Figure 12.

Without the HVDC, more geothermal and/or thermal generation is required to supply North Island demand. The geothermal generation runs year-round as baseload and the thermal generation is flexible and ramps up over winter months. Both generation types have

23 We model fixed operating and maintenance costs for all generation types as an annual payment proportional to the plant capacity. These fixed costs are included with capital costs. We assume the variable operating cost component for wind, solar and hydro is zero.

operational costs: for geothermal these are emissions costs, and for thermal there are fuel, operating and maintenance and emission costs.

Figure 12 shows that benefits from avoided operational costs begin to occur from 2031 when we assume the failure of a submarine cable and reduced Northwards transfer in the Base Case/Option 1. Significant benefits begin to accrue in 2038 when the HVDC is assumed to be decommissioned in the Base Case/Option 1.

There is some variance across the modelled scenarios which we attribute to combinations of scenario assumptions (e.g., carbon and fuel costs) and differences in generation mix. Summary explanations are as follows:

- **Disruptive** scenario has relatively high benefits as the thermal and geothermal generation which is avoided in Option 2 has high emissions costs;
- **Environmental** scenario has similarly high benefits, however these are largely from avoided thermal fuel costs as this scenario assumes peaking generation transitions from gas to more expensive biofuels;
- **Growth** scenario benefits are primarily due to avoided thermal operation costs as the geothermal operation is similar in the Base Case/Option 1 and Option 2. The benefits increase over time due to an increase in assumed carbon price;
- **Reference** scenario has comparatively low benefits despite high levels of geothermal generation for the Base Case/Option 1. This is due to the assumed flat carbon price which reduces the emissions costs for both thermal and geothermal generation. Additionally, because the level of demand is less for this scenario, less thermal generation is required.

Figure 12: Operational benefits (undiscounted) for Option 2 relative to the Base Case/Option 1

Note that there is also variance in deficit benefits from year to year. The level of deficit is highly sensitive to the timing of generation build and small differences between the expansion plans for Base Case/Option 1 and Option 2 manifest as variance in deficit costs.

The present values of the operational cost benefits are shown in Table 7. This also includes benefits for Option 3 relative to the Base Case/Option 1. The difference between operational benefits for Option 2 and Option 3 is explored in section 4.5.2

Table 7: Operational benefits (2025 $m) present value (5% discount rate)

Scenario	Disruptive	Environmental	Growth	Reference
Base Case Option 1	-	-	-	-
Option 2	2,462	2,467	1,975	1,623
Option 3	2,668	2,702	2,104	1,765

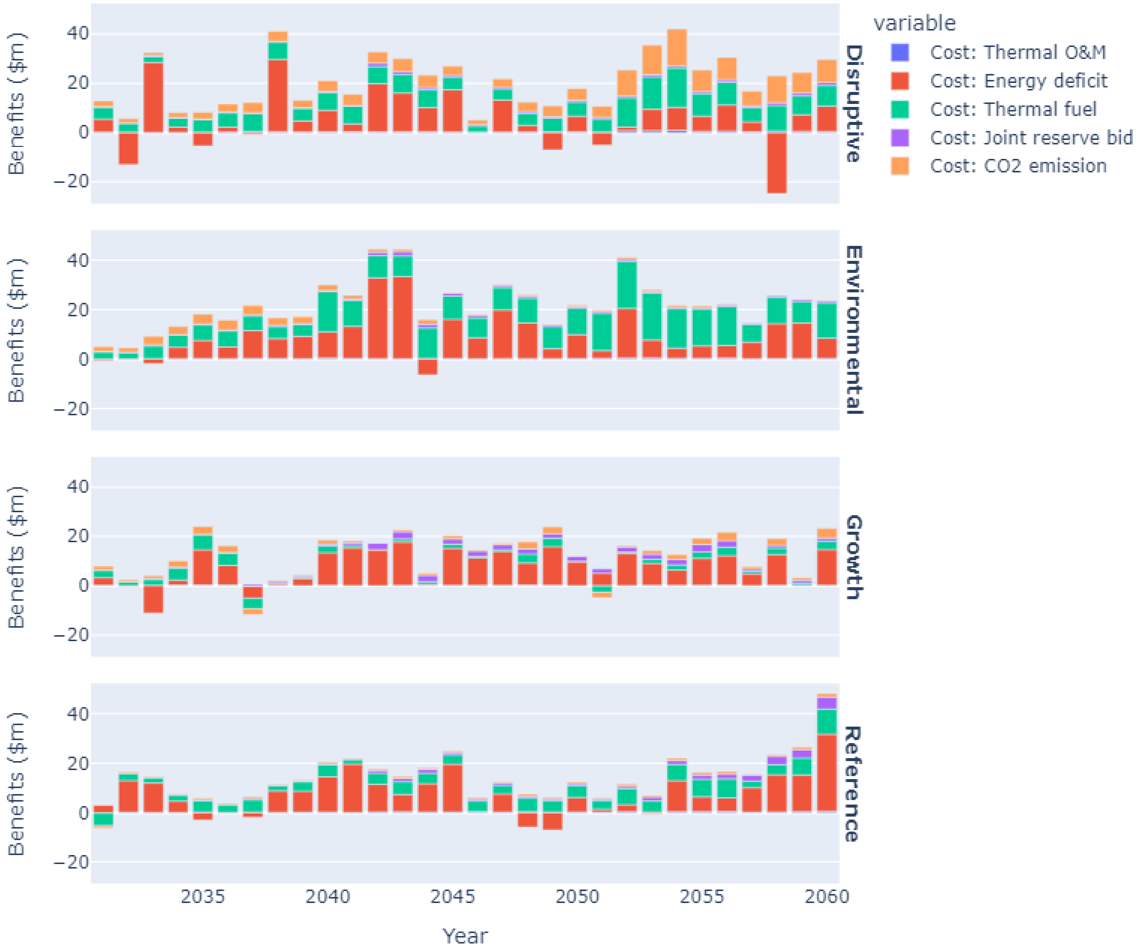
4.5.2 Incremental operational benefit of 1400MW Northwards capacity

The additional operational benefits from Option 3 over Option 2 are due primarily to avoided deficit and savings in thermal running costs and emissions as shown in Figure 13. These benefits begin to accrue around 2031 at the time when the Northwards capacity of the HVDC is assumed to increase to 1400MW for Option 3.

The benefits are realised primarily during periods of high demand and low North Island wind generation. During these periods Option 3 can provide 200 MW of additional firming to the North Island from South Island hydro. Without this, more expensive thermal generation would be dispatched, and in instances where there is insufficient generation capacity, deficit is incurred.

The variance between the scenarios reflects the different levels of North Island firm capacity available (including grid scale batteries) and differences in running costs for thermal firming generation. Note that the firm capacity available also varies with time due to the assumed retirement of existing thermal generation and the lumpy build of new generation and grid scale batteries in our expansion plans.

Figure 13: Difference in operational benefits (undiscounted) for Option 3 over Option 2



The present value of these incremental operational benefits for each scenario are given in Table 8. The level of deficit ranges from 30% to 60% of the total discounted incremental operational benefits. We note that other non-modelled generation could occur instead of deficit.

Table 8: Incremental operational benefits present value ($m 2025, 5% discount rate) of Option 3 over Option 2

	Disruptive	Environmental	Growth	Reference
Total operational benefits	206	235	130	142

We interpret the major factors which drive variance in operational benefits between the scenarios as:

- **Disruptive** scenario has high benefits as transfers on the HVDC displace expensive thermal generation and avoid deficit. Firm capacity is particularly tight during the period of 2040-2045 and the higher deficit benefits during this period are consistent with this;
- **Environmental** scenario has slightly higher benefits as HVDC transfers displace comparatively more expensive thermal generation as this scenario assumes exclusive biofuel use from 2040. Again, there is a period before 2045 where firm capacity is tight and high deficit benefits occur;
- **Growth** scenario has the lowest benefits as there is less requirement to firm the North Island due to the larger installed base of geothermal generation. A large proportion of the benefits which occur are due to avoided deficit, indicating a shortage in flexible capacity;
- **Reference** scenario has low benefits in part because there is less demand to serve, and also because the fuel and emissions costs are lower in this scenario.

5 Gross market benefits

The gross market benefits that are considered in the Investment Test are a combination of generation capital benefits (as outlined in section 3.2.20) and operational cost benefits (as outlined in section 4.5.1). It is important that these are considered in total as it can be possible to substitute operational and capital costs (e.g. investing in renewable generation avoids operational costs but requires capital expenditure).

We see that for this analysis both Option 2 and Option 3 have both strong electricity market capital and operational benefits compared with the Base Case (Option 1). The capital cost benefits are due to avoided generation build and the operational cost benefits are from avoided running costs.

The gross market benefits for each scenario and investment option are summarised in Table 9. There is some variation in the share of operational vs capital cost benefits across the scenarios due to the spread of scenario assumptions and how generation is built in response to the decommissioning of the HVDC. The present value of the gross benefits ranges from $3.6 – $6.0 billion across the scenarios.

Table 9 Gross market benefits present value relative to Base Case (option 1) (2025 $m, 5% discount rate)

		Disruptive	Environmental	Growth	Reference
Base Case Option 1	Capital cost benefits	-	-	-	-
	Operating costs benefits	-	-	-	-
	Total benefits	-	-	-	-
Option 2	Capital cost benefits	2,269	3,341	2,880	1,973
	Operating costs benefits	2,462	2,467	1,975	1,623
	Total benefits	4,730	5,808	4,854	3,596
Option 3	Capital cost benefits	2,269	3,341	2,880	1,973
	Operating costs benefits	2,668	2,702	2,104	1,765
	Total	4,936	6,043	4,984	3,737

Option 3 has the highest gross market benefit, as (compared with Option 2) 1400 MW provides additional firm capacity to the North Island which benefits the system during periods of high demand and low North Island wind generation.

These benefits are gross in that they do not include the capital cost of the investment options. Expected net electricity market benefits are calculated as part of the investment test (see Attachment 7).

Appendix A: Reserve modelling implementation

In the electricity market instantaneous reserves are provided by standby generation, grid scale batteries or interruptible load which can compensate for an unexpected event to arrest the fall in system frequency and return it to 50Hz promptly. The amount of reserves required is determined in accordance with the System Operator's Credible Event Review process.[24] In short, this is the largest source of MW in each island which is at risk of a single point of failure – in the New Zealand electricity market this is typically a large thermal generator or one Pole of the HVDC.

The requirement for reserves and providers of reserves is modelled in SDDP and Optgen and included in the generation dispatch optimisation. The reserve requirement is set by the need to compensate for the individual outage of nominated backed plants, and specified backing plants can contribute to meeting this requirement. The model then co-optimises the dispatch of generation to provide energy to meet demand ensuring that standby generation, grid scale batteries and interruptible load is available to provide reserves for generating units.

In SDDP we model sustained instantaneous reserves (SIR), which comprise only half of the instantaneous reserve market. Fast instantaneous reserves (FIR) are also procured in the market to provide faster response cover for the same failure event as SIR. We note that there is considerable overlap between standby generation and grid scale batteries that provide FIR and SIR and so consider it appropriate to consider only SIR in our modelling.

It is not possible to model the sharing of reserves between the North and South Island with our implementation of SDDP. In the NZ electricity market reserve providers can cover the reserve requirement in both islands provided it is not the HVDC setting the risk. In SDDP we model reserves distinctly in each island.

5.1 Reserve requirement

The backed units for the North and South Island which set the reserve requirements are summarised in Table 10. Of the existing generators, Tauhara 2a operates at 157 MW as baseload[25] and is assumed to provide a floor for North Island reserve requirements through the study horizon[26]. It is not necessary to consider the reserve requirements to cover the unplanned outage of any smaller generating units as this reserve requirement is less than that represented by Tauhara 2a.

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24 Event categorisation | Transpower

25 We derate Tauhara by 10% below its nameplate capacity of 174MW to reflect the average unavailability due to outages.

26 Note that we do not model the reserve requirement to cover for the risk from large wind and solar generation plants. For example, the Turitea windfarm can generate at up to 220MW and so could present a larger single point of failure larger than Tauhara. It is reasonable to ignore this detail because we expect that these occasions are infrequent, there is uncertainty on the connection size for future wind and solar generation, and we expect that periods of high North Island renewable generation do not coincide with high northward transfers on the HVDC.

Similarly for the South Island, we assume the generation from a single Manapouri generation unit (e.g. one turbine) sets the floor for reserve requirements in the South Island. We do not model reserve requirements to back any other South Island generation.

Table 10: Reserve backed plants. Single unit installed capacity determines the reserve requirement (shown in brackets)

	North Island	South Island
Existing generation	TCC (377MW) E3p (403MW) Tauhara2a (174MW)	Manapouri (single turbine)
Future generation	NewHLYOCGT (250MW) NewHLYOCGT2 (250MW) NewSFTOCGT2 (200MW)	
HVDC	Pole 2 and Pole 3	Pole 2 and Pole 3

5.2 Reserve providers

A set of backing generators which can provide reserves has been defined in SDDP. This set comprises of applicable thermal and hydro generation, interruptible load and grid scale batteries, considering existing and future plant. The configuration in SDDP requires the specification of an offer price and maximum capacity for every reserve provider.

For existing generation, reserve offers are based on analysis of reserve offers in the New Zealand electricity market over the period Jan 2023 to June 2024. For every reserve provider we determined an:

- offer-weighted-average-price across the historical period;
- average offer across the 100 trading periods where reserve offers are highest in each island

These values are then set to the offer price and maximum capacity for backing plants in SDDP. We model all reserve providers in SDDP with an average offer greater than 2 MW. The assumed maximum reserve capacities and offer prices for existing providers are shown in Table 11.

Note that thermal peaking generators need to be spinning to provide reserves. To accommodate this in SDDP, for thermal reserve providers, a minimum generation of 5 MW and block commitment is specified. This ensures that gas or diesel peaking is partially dispatched for generation if providing reserves.

Table 11: Existing reserve backing plants and reserve offers

Type	Island	Name	Capacity (MW)	Offer price ($/MWh)
Battery Energy Storage Systems (BESS)	North Island	Southdown	1	0.1
		WEL_HLY	35	0.1
Hydro	North Island	Arapuni1-5	12	84.4
		Aratiatia	7	139.6
		Atiamuri	6	63.0
		Karapiro	5	2.1
		Maraetai	123	277.0
		Matahina	55	10.1
		Ohakuri	10	41.6
		Patea	22	3.9
		Piripaua	2	0.1
		Rangipo	19	0.1
		Tokaanu1-2	107	6.2
		Waipapa	4	46.8
		Wheao	3	2.0
	South Island	Aviemore	41	0.2
		Benmore	108	0.2
		Clyde	145	58.7
		Manapouri	71	0.3
		OhauA	48	0.2

Type	Island	Name	Capacity (MW)	Offer price ($/MWh)
		OhauB	39	0.2
		OhauC	39	0.2
		Roxburgh1_5	126	73.3
Thermal	North Island	HuntC1	29	0.4
		HuntC2	31	1.7
		HuntC4	34	0.5
		SFDOCGT	100	28.7
		SFDOCGT2	100	21.5
		Whiri2	45	57.2
		Whiri3	45	66.7
		Whirina	50	41.5
Load	North Island	Aggregated	172	1.3

The set of existing reserve providers can be formed into a price offer stack for reserves as shown in Figure 14 and Figure 15.

Figure 14: Assumed reserve offer stack for existing North Island generation reserve providers

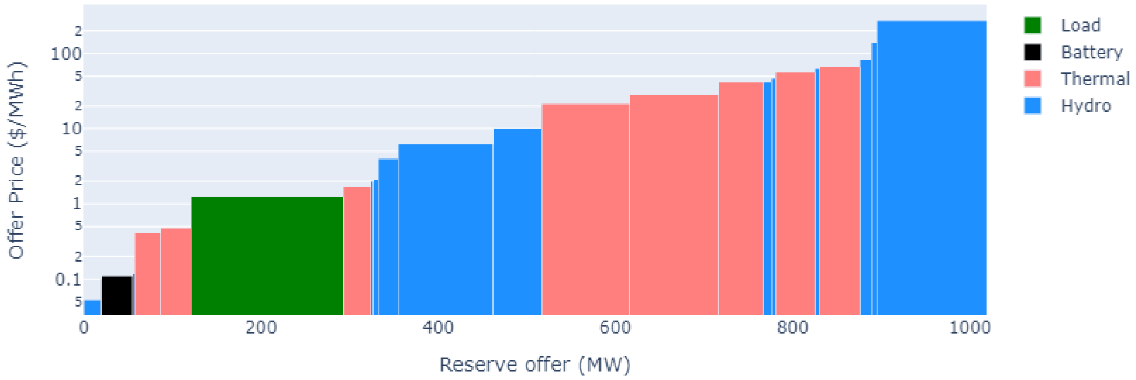
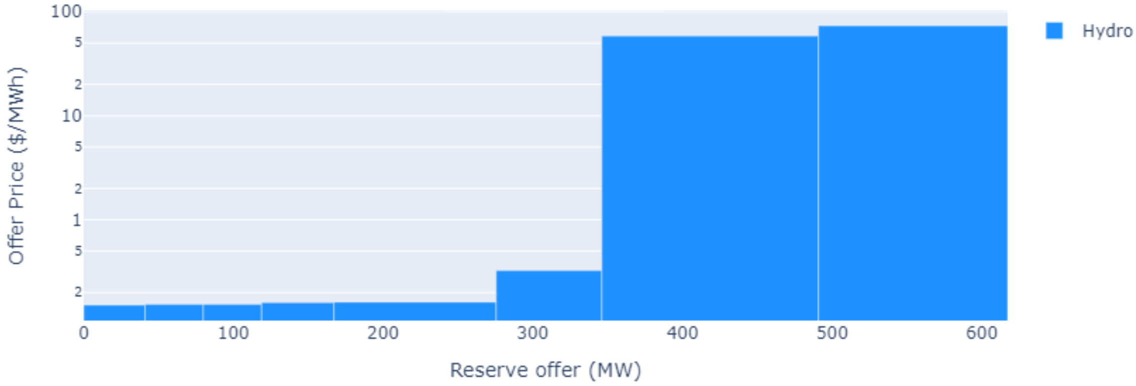


Figure 15: Assumed reserve offer stack for existing South Island generation reserve providers



For existing and future grid scale batteries that can provide reserves we assume the full installed capacity is available and near-zero offer prices. This is reasonable as we assume that grid scale batteries will participate fully in the reserve market. The model optimisation considers the relative value of using batteries for energy or providing reserves. Grid scale batteries are also able to displace existing generation which provides reserves at a higher cost.

Note that only a subset of grid scale batteries in Optgen are able to provide reserves. This is to reduce the complexity of the optimisation problem that Optgen considers and to improve model solve times. However, we find that only the reserve backing batteries feature in our generation expansion plans, as reserve payments provide an additional revenue stream for these projects which differentiates them from other candidate batteries. As we are not modelling AC network constraints the node where the battery is connected is not relevant.

The complete list of future projects that can provide reserves is given in Table 12. Note that not all these projects will be included in a scenario’s generation expansion plan.

Table 12: Future reserve backing plants and reserve offers

Type	Island	Name	Capacity (MW)	Offer price ($/MWh)
Thermal	North Island	OTOpeaker_s1	115	21.5
		OTOpeaker_s2	115	21.6
		OTOpeaker_s3	115	21.7
BESS	North Island	Ruakaka	100	0.1
		HLY_PS2h	100	0.1
		Glenbrook_2h	100	0.1
		LIBES2hOTA	100	0.1
		LIBES2hSFD	100	0.1
		LIBES2hHAY	100	0.1
		LIBES2hWIL	100	0.1
		LIBES2hBHL	100	0.1
		LIBES2hPAK	100	0.2
		LIBES2hBPE	100	0.2
		LIBES2hTKU	100	0.2
		LIBES4hOTA	60	0.2
		LIBES4hHLY	60	0.2
		LIBES4hSFD	60	0.2
		LIBES4hHAY	60	0.2
		LIBES4hWIL	60	0.2
		LIBES4hBHL	60	0.2
		LIBES4hPAK	60	0.2

Type	Island	Name	Capacity (MW)	Offer price ($/MWh)
		LIBES4hBPE	100	0.2
		LIBES4hTKU	60	0.2
		LIBES8hOTA	60	0.2
		LIBES8hHLY	60	0.2
		LIBES8hSFD	60	0.2
		LIBES8hHAY	60	0.2
		LIBES8hWIL	60	0.2
		LIBES8hBHL	60	0.2
		LIBES8hPAK	60	0.2
		LIBES8hBPE	60	0.2
		LIBES8hTKU	60	0.3
	South Island	LIBES4hISL	100	0.1
		LIBES4hBEN	60	0.1
		LIBES4hCYD	60	0.1
		LIBES4hKIK	60	0.1
		LIBES4hAVI	60	0.1
		LIBES4hROX	100	0.1
		LIBES2hISL	100	0.1
		LIBES2hBEN	100	0.1
		LIBES2hCYD	100	0.1
		LIBES2hKIK	100	0.1

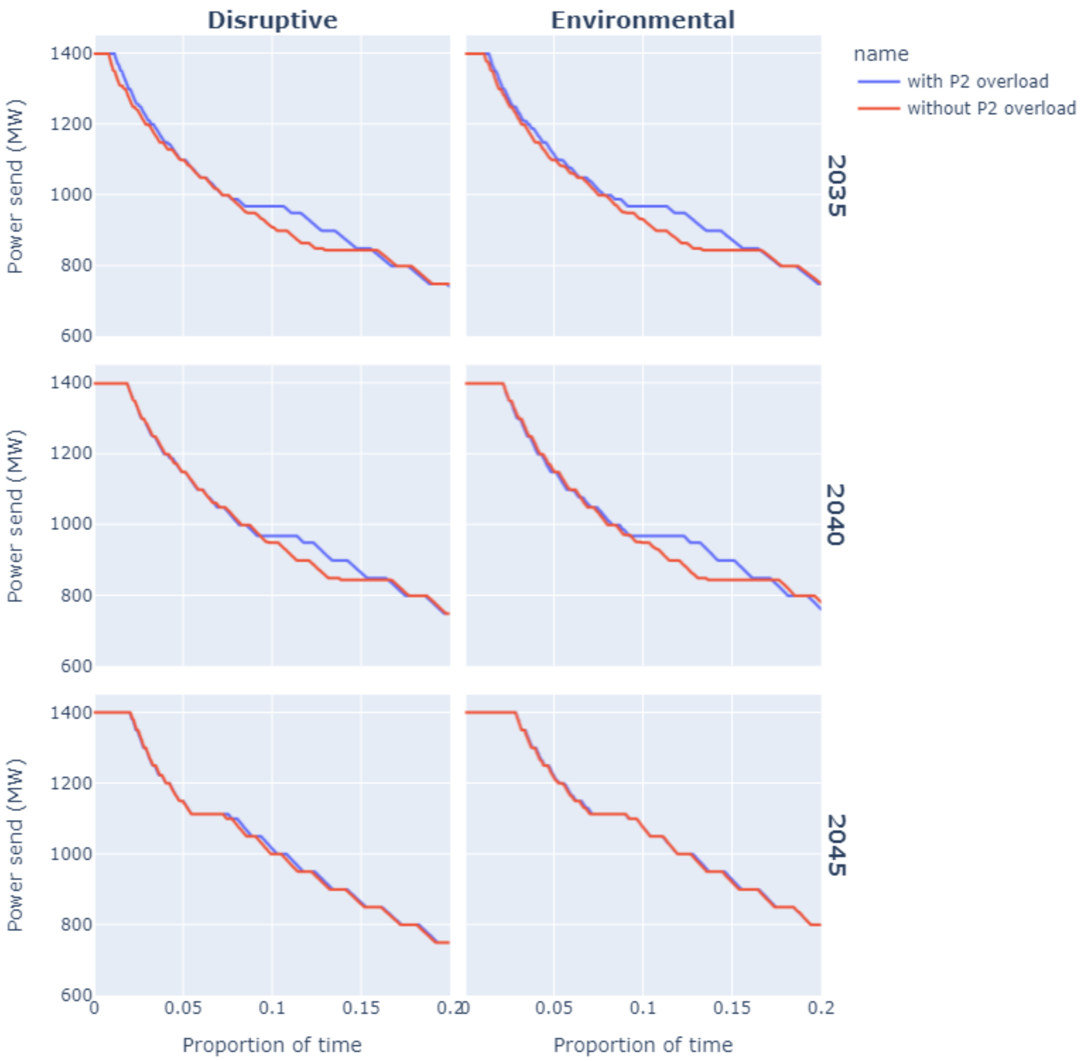
Type	Island	Name	Capacity (MW)	Offer price ($/MWh)
		LIBES2hAVI	100	0.2
		LIBES2hROX	100	0.2
		LIBES8hISL	60	0.2
		LIBES8hBEN	60	0.2
		LIBES8hCYD	60	0.2
		LIBES8hKIK	60	0.2
		LIBES8hAVI	60	0.2
		LIBES8hROX	60	0.2

Appendix B: Economic benefits of Pole 2 overload

The quantified benefits for the proposed investment (option 3 – 1400 MW) assume that the Pole 2 overload project is completed. Implementing the Pole 2 overload upgrade alongside the fourth cable will increase the utilisation of the HVDC at high transfers, directly supporting the additional capacity of the 1400 MW option.

Flow duration curves for HVDC transfers are shown below to compare scenarios with and without the Pole 2 overload[27]. Transfers are consistently higher in the case where the Pole 2 overload upgrade is in place. By 2045, transfers converge as the modelling assumes Pole 2 replacement occurs by this date (and the new Pole 2 will then match the overload of Pole 3).

Figure 16: HVDC transfers with and without pole 2 overload



27 Note that duration curves are based on modelling performed for the Short-list consultation.

If the Pole 2 overload upgrade is not implemented, the benefits of the 1,400 MW option are reduced. Sensitivity analysis was undertaken for the Environmental and Disruptive scenarios, assuming the overload capacity of Pole 2 remains at ~650 MW until 2042. All other modelling inputs, including generation expansion plans, remained unchanged.

Without the overload upgrade, system operational costs increase – particularly due to higher energy deficit costs – indicating that there are periods when the system is short on dispatchable capacity. The table below quantifies the reduction in benefits if the Pole 2 overload upgrade is removed from Option 3.

Table 13: Change in benefits for Option 3 without pole 2 overload project. (Present value, $m 2024, 5% discount rate)

Scenario	Cost: Thermal O&M	Cost: Energy deficit	Cost: Thermal fuel	Cost: Joint reserve bid	Cost: CO_2 emissions	Total
Environmental	0	-28	-6	-6	-3	**-42**
Disruptive	-1	-28	-10	-5	-6	**-48**

On average, not completing the Pole 2 overload upgrade results in a benefit reduction of approximately **$45 million**. Given that the Pole 2 overload project cost is approximately **$13 million**[28], the Pole 2 overload upgrade will deliver a net benefit of approximately **$32 million**.

The majority of the lost benefits stem from increased energy deficit costs. These deficits were modelled using tranches from $600/MWh up to $10,000/MWh, with some tranches representing demand response. The results show that without the Pole 2 overload upgrade, the system experiences more frequent and costly shortfalls in dispatchable capacity.

28 Note the additional cost of the Pole 2 overload is included in the Investment Test for Option 3.

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