Assessment of the Impact of Flow Alterations on Electricity Generation

For

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Preface

This study models possible outcomes for hydro-electricity generation in eight scenarios. The outcomes are possible consequences of setting freshwater objectives under the National Policy Statement for Freshwater Management (Freshwater NPS). The results are generated from a simulation of the New Zealand electricity system, are subject to limitations and need to be interpreted with care.

The purpose of this study is to integrate environmental and economic information at a national level to inform national policy decisions on possible changes to the Freshwater NPS. The results are not intended to dictate or influence the choices that communities will make in managing water quality at the local level. This study should not be used for any other purposes.

Authors

This study has been carried out by carried out by Tom Haliburton (Energy Modelling Consultants Ltd). It was commissioned by Ministry for the Environment and Ministry for Primary Industries. Officials have prepared this preface. The report was reviewed by Ministry of Business, Innovation and Employment and the Electricity Authority.

Background

This report is one of a series of reports commissioned by central government that consider the potential environmental, economic, social and cultural impacts of choices for setting freshwater objectives and limits. The impact studies assess a range of scenarios for managing water quality. The studies inform national policy development on the potential impacts of setting freshwater objectives and limits, including proposals for national bottom lines, introduced into the Freshwater NPS via amendments in 2014. This study will inform further national policy development.

National Policy Statement for Freshwater Management

The Freshwater NPS was first introduced in 2011 it was subsequently amended in 2014. It requires regional councils to recognise the national significance of fresh water for all New Zealanders and Te Mana o te Wai (the mana of the water). Amongst other things it directs regional councils to:

- set freshwater objectives according to a specified process (the national objectives framework) to meet community and tāngata whenua values which include the compulsory values of ecosystem health and human health for recreation
- use a specified set of water quality measures (attributes) to set the freshwater objectives
- set limits which allow freshwater objectives to be met (e.g. a total catchment contaminant-load or a total rate of water take)
- fully implement the Freshwater NPS by 2025

Councils must consider the values of freshwater to determine those that are relevant

- the compulsory values apply everywhere,
- the additional values that are listed in the Freshwater NPS must be considered,

- any other locally specific values or uses of fresh water that are considered appropriate will be identified.

The Freshwater NPS includes a set of national bottom lines to achieve the two compulsory values. The bottom lines describe minimum acceptable water quality. If water bodies are below this quality then freshwater objectives must be set at or above the bottom lines. Councils must put in place plans to work towards these objectives over time.

Councils can choose to set a freshwater objective below a national bottom line in limited and specified circumstance, as follows:

- water quality is already below the national bottom line and
- the water quality is caused by naturally occurring processes or
- any of the existing infrastructure listed in an Appendix to the Freshwater NPS contributes to the water quality.

There is also a provision for setting a freshwater objective below a national bottom line for a transitional period if this is specified in an Appendix to the Freshwater NPS.

The freshwater environment must be managed to meet the objectives set and so provide for the values identified. The Freshwater NPS lists water quality attributes that represent some of the aspects of the freshwater environment that may need to be managed. Objectives have to be set for those attributes.

It is up to regional councils and their communities to determine the appropriate local freshwater objectives that provide for the identified values. This includes identifying the resource use limits, methods, rules and management options needed to meet the objectives.

Assessment Approach

This study models the impact of meeting 'theoretical' freshwater objectives in water bodies that contain hydro-electricity generation schemes. It is assumed that to meet those objectives alteration to the flow regime will be required. Where possible the impacts on the electricity system are quantified. The freshwater objectives considered relate to a number of values of freshwater environment including the compulsory value for ecosystem health.

In reality the resource use limits and management measures used to meet freshwater objectives will be more targeted than those in the scenarios modelled. Evidence suggests councils and communities are more likely to choose an integrated package of management measures that would be put in place over time and across different resource uses. It is reasonable to expect that improving environmental outcomes will almost certainly require managing costs and responses over many years, perhaps over generations.

The results are generated from a simulation of the New Zealand electricity system, are subject to limitations and need to be interpreted with care.

This study uses Stochastic Dual Dynamic Programming software (SDDP) which simulates the electricity generation system operation for the whole of New Zealand – determining the lowest cost means of meeting the specified electricity demand.

The period 1 January 2020 through to 31 December 2025 has been studied. This was chosen as a representative period when electricity generation supply and demand balance has been achieved. The "mixed renewables" scenario devised by Ministry of Business Innovation and Employment was used. This scenario resembles business as usual and assumes that up till 2040

- there are no significant reductions in the cost of existing generation technologies, and
- international carbon trading remains limited to those countries which have already committed to carbon markets.
- domestically, our available energy supply remains much as it is today[1].

The eight scenarios cover a range of policies and possible outcomes. Some of the scenarios evaluated are considered to be extreme and would therefore not be realistically used as approaches to manage the water environment. The scenarios were chosen to show the scale of the possible outcomes.

The scenarios do not represent current policy proposals or intentions. The evaluations do not reflect current or expected water quality conditions in the water bodies modelled and do not take into account ongoing community discussions on values for water environment. The whole of New Zealand generation system has been modelled as changes at one power station can result in compensating changes in operations at a number of other power stations.

Since this study was completed, the electricity generation system has changed as a result of thermal generation closures.

Flow alteration scenarios

The scenarios represent situations where the resource use of a hydro-electricity scheme is limited to meet theoretical freshwater objectives. The limits evaluated require the alteration of the river flow (the flow regime). Councils and communities are assumed to have made the decision that this is the most effective and efficient way to provide for the values of freshwater.

Scenarios are tailored to the particular catchment but do not reflect any expected outcomes from the freshwater planning process. The scenarios were not developed by councils or electricity generators.

Flow regime

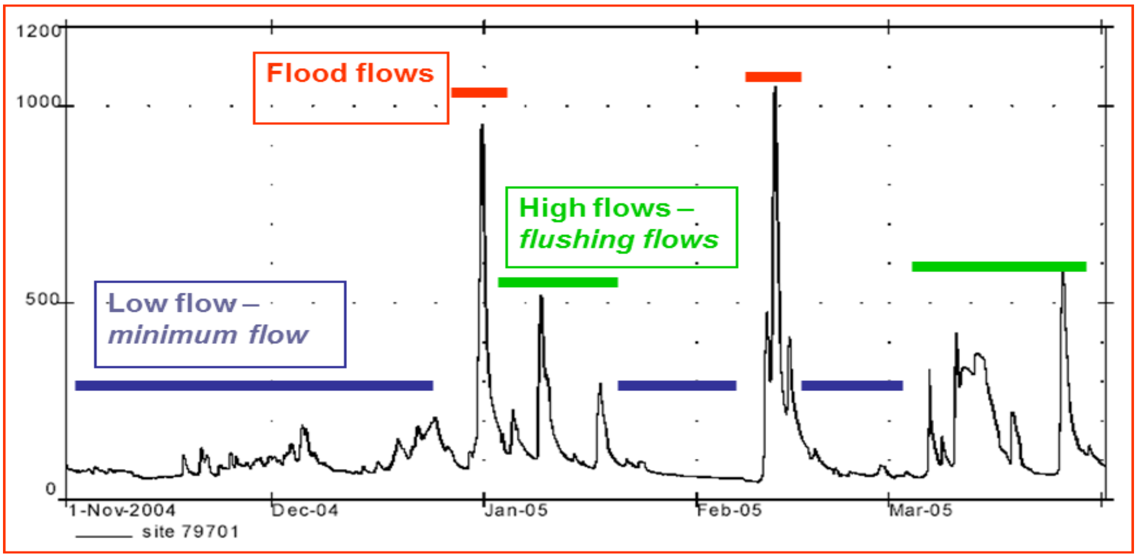
Healthy river ecology relies on a flow regime that is variable. The important components of a flow regime are shown in Figure i. and are

- magnitude and duration of low flow
- magnitude, frequency, and duration of high flows
- magnitude, frequency and duration of flood flows

Flow regime is important to provide for ecosystem health but also support other values of freshwater. Dams and diversions can change the flow regime downstream and upstream. Dams can heavily modify the volume of water flowing downstream, change the timing, frequency, and duration of high and low flows, and alter the natural rates at which rivers rise and fall.

1 http://www.med.govt.nz/sectors-industries/energy/energy-modelling/modelling/new-zealands-energy-outlook-electricity-insight

Figure i. Different components of the flow regime in the Waiau River[2]



The scenarios consider the following aspects of the flow regime.

Flushing flows

These are high flows that occur moderately frequently after periods of rain. Where a river flow is controlled (by a dam or a large diversion) there can be a lack of flushing flows. This can lead to a build-up of silt that becomes compacted and hardened and reduces the habitat for macroinvertebrates and consequently food for fish.

A steady flow (without flushes) will also allow a build-up of periphyton to occur. While this is a normal function of a river ecosystem, periodic flushing flows maintain a balance of cycles between build-up and removal. Too much periphyton can consume all the oxygen in the river, effectively suffocating all other life. In some circumstances dams can release water creating a flush.

Low flows

Natural periods of low flows are important to ensure a healthy ecosystem but when the low flow persists ecology can be negatively impacted. Ensuring that there is always a minimum of flow of water in a river provides for ecosystem health and supports other values of freshwater.

Where a river flow is controlled (by a dam or a large diversion) very low water releases may result in downstream flows well below natural levels[3]. 'Minimum flow' consent conditions are often used to ensure that the problems of low flow conditions are avoided. A 'minimum flow' limits the amount of abstraction during low river flows.

Ensuring a minimum amount of water (discharge) is released from a lake can serve to support the values provided for by both flushing and low flows.

2 Beca. 2008. Draft Guidelines for the Selection of Methods to Determine Ecological Flows and Water Levels. Report prepared by Beca Infrastructure Ltd for MfE. Wellington: Ministry for the Environment.

3 Richter, B. D., and G. A. Thomas. 2007. Restoring environmental flows by modifying dam operations. *Ecology and Society* 12(1): 12.

Table i. Modelled Scenarios

Hydro-electricity generation scheme(s)	Scenario	
Waitaki power scheme Waitaki catchment	Diversion from Lake Tekapo	Diversion of a constant 7 cumecs during weeks 1 to 14 and 39 to 52 each year, with the abstracted water used for generation along the irrigation canal.
	Minimum flows in the Tekapo and Pukaki rivers	Diversion of a constant 10 cumecs down the Tekapo River and 20 cumecs into the Pukaki River from Lakes Tekapo and Pukaki respectively.
	Increased minimum flow at Waitaki Power Station	An increased minimum flow at Waitaki Power Station of 200 cumecs.
Clutha Power Scheme	Flushing flows in the Clutha River	A continuous minimum discharge from Lake Roxburgh of 300 cumecs.
Tongariro and Waikato Power schemes	Reduction of flows into Lake Rotoaira	Reduction of flows into Lake Rotoaira, and consequently Tokaanu power station and Lake Taupo, of 20 cumecs.
Waikaremoana power scheme	Minimum discharge from Lake Waikaremoana	5 cumec minimum discharge from Lake Waikaremoana.
	Flushing flows from Lake Waikaremoana	Provide a flushing flow of three times mean flow for one week each month over summer from Lake Waikaremoana.
Combined scenarios	The flow regime scenarios described above are studied, individually and all flow modifications together in a single (national) scenario.	
Baseline	This represents the status quo. Hydro schemes operate under current conditions. No alteration of flow regime. For the Waitaki Scheme this includes no minimum flows in the Tekapo, Pukaki and Ohau rivers.	

Additional studies

Concept Consulting- ***Evaluation of potential electricity sector outcomes from revised minimum flow regimes on selected rivers*** (2013) - looked at the impacts of increasing minimum flows on hydro-electricity generation[4]. The same altered minimum flow scenarios applied to each scheme[5].

The Concept Consulting exercise highlighted the potential nature and scale of economic impacts on electricity generation *if* some rivers were to have increased minimum flow requirements. The study assumed that regional councils would increase or implement minimum flow limits to achieve freshwater objectives and found that[6]:

[4] Concept Consulting (2013). Evaluation of potential electricity sector outcomes from revised minimum flow regimes on selected rivers. http://www.mfe.govt.nz/publications/fresh-water/evaluation-potential-electricity-sector-outcomes-revised-minimum-flow

[5] Increasing minimum flows above existing consented levels by a set percentage (10% or 40%). Setting minimum flows at a fixed % of natural minimum flows (40% or 80%).

[6] http://www.mfe.govt.nz/sites/default/files/overview-of-studies-assessing-potential-impacts-setting-water-quality-scenarios.pdf

- There will be an economic cost on the electricity system. This will have flow-on effects for national consumers, regardless of where the minimum flow limit is implemented or increased.
- The unique nature of each scheme – size, amount of storage, hydrological inflows and position in a chain for example – ensures that:
  - the scale and nature of the economic cost varies significantly from river to river and from scheme to scheme.
  - there is no linear relationship between minimum flow rates and costs of electricity generation.

The analysis described in this report and that carried out by Concept Consulting are designed to give an indication of the scale and nature of impacts from scenarios of altered flow. In reality, considerably more analysis involving interrelated models would be required to give a more accurate reflection of the impacts. These analyses are therefore useful for understanding the scale and nature of potential economic costs, but do not profess to be a view of the expected quantitative costs. A case by case approach will be needed when regional councils assess potential impacts of freshwater objectives rates on electricity generators.

Summary

The effects on the electricity generation system of a number of possible changes to minimum flows required at hydro power schemes are evaluated. Eight scenarios for these changes have been devised, representing a range of credible options, rather than any specific proposed changes. The intention is to determine the feasibility of the scenarios, and the scale of their impact on the electricity generation system.

Modelling has been carried out using the Stochastic Dual Dynamic Programming (SDDP) model, which is a least cost mid-term optimal dispatch planning model. The whole New Zealand generation system has been modelled as changes at one power station can result in compensating changes in operations at a number of other projects. Because the SDDP model finds an overall least cost solution, it gives different results to those that would apply in the electricity market. In a market situation participants need to manage market risk and are concerned about the volatility of their earnings, not just the average value of their earnings. Hence SDDP is likely to find a lower bound on the effects of the changes investigated.

The period 1 January 2020 through to 31 December 2025 has been studied as representative of a period when generation and supply balance has been achieved.

In addition to a base case representing the status quo, the following scenarios have been examined:

1. Diversion from Lake Tekapo of a constant 7 cumecs during weeks 1 to 14 and 39 to 52 each year, with the abstracted water used for generation along the irrigation canal. (This scenario is similar to a study carried out by eCan.)
2. Diversion of a constant 10 cumecs down the Tekapo River and 20 cumecs into the Pukaki River from Lakes Tekapo and Pukaki respectively.
3. An increased minimum flow at Waitaki Power Station of 200 cumecs (currently 150 cumecs).
4. Flushing flows in the Clutha River, resulting in a continuous minimum discharge from Lake Roxburgh of 300 cumecs.
5. Reduction of flows into Lake Rotoaira, and consequently Tokaanu power station and Lake Taupo, of 20 cumecs.
6. 5 cumec minimum discharge from Lake Waikaremoana.
7. For Lake Waikaremoana, over the summer period, a total discharge requirement to provide a flushing flow of three times mean flow for one week each month.
8. A combination of all the above.

Short run marginal cost[7] (SRMC) is affected only in scenarios 2, 5 and 8. These are the cases where hydro energy is significantly reduced – the other cases where increased minimum flows are required do not have a significant impact on total hydro generation energy. Only scenarios 5 and 8 show significant increases in deficit[8] (Figure 2) – these are the two scenarios with reduced flows at Tokaanu and into Lake Taupo.

[7] Short run marginal cost represents the cost of supplying an extra MWh of electricity from the existing generation system. SRMC is determined by the most expensive plant currently operating, which is able to increase its output by one MW. SRMC consists of the sum of fuel purchase and transport costs, variable operation and maintenance costs and carbon emission costs for a thermal plant, or for a hydro plant it consists of water value plus variable operating and maintenance cost.

[8] Deficit in this case refers to demand that is not supplied for any reason, including due to the price response of load, voluntary load reductions and forced load reductions.

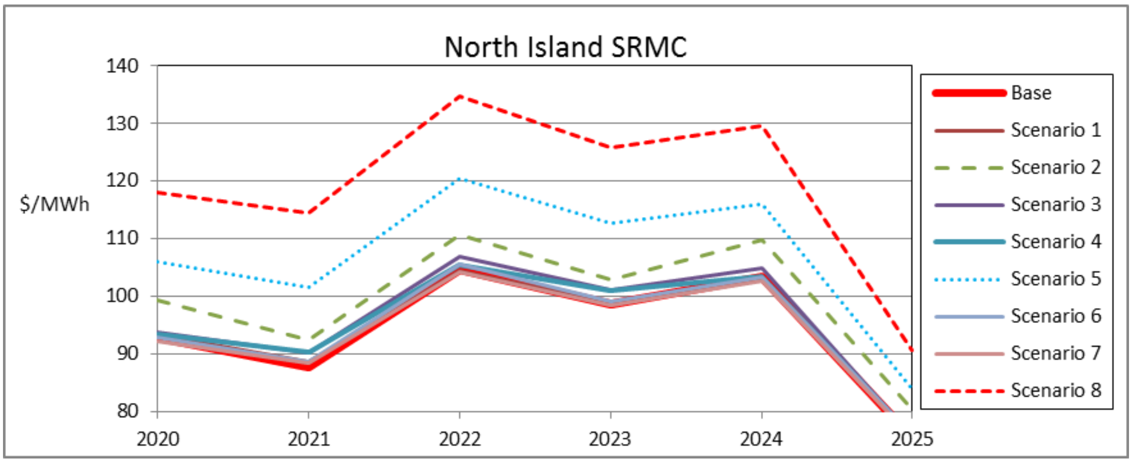


Figure 1: North Island annual average short run marginal cost

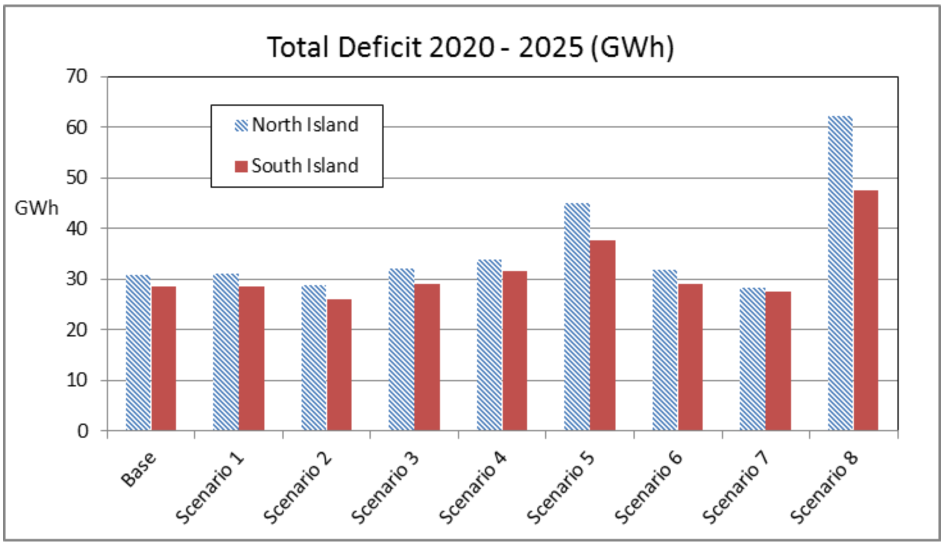


Figure 2: Total average deficits for entire study period

SDDP modelling indicates that the changes to hydro system flow requirements that were investigated have a significant impact only when total available energy generation is affected. The relatively modest changes to minimum flow requirements that were studied do not have significant impacts. This conclusion can be drawn from the effects on short run marginal cost (SRMC) in Figure 1 and deficits in Figure 2.

Similarly the effects on CO_2 emissions are relatively small for scenarios 3, 4, 6 and 7 which do not result in a total loss of inflows to the hydro generation system, as in Table 1. Effects on scenario 1 are also small as much of the energy lost from Waitaki system generation is recovered by new generation plant located along irrigation canals.

Table 1: Average annual increase in CO_2 emissions above base case, over analysis period of 1 Jan 2020 to 31 Dec 2025 (tonnes)

Scenario	1	2	3	4	5	6	7	8
Average	10,572	146,382	7,313	7,131	282,061	3,922	2,032	465,481

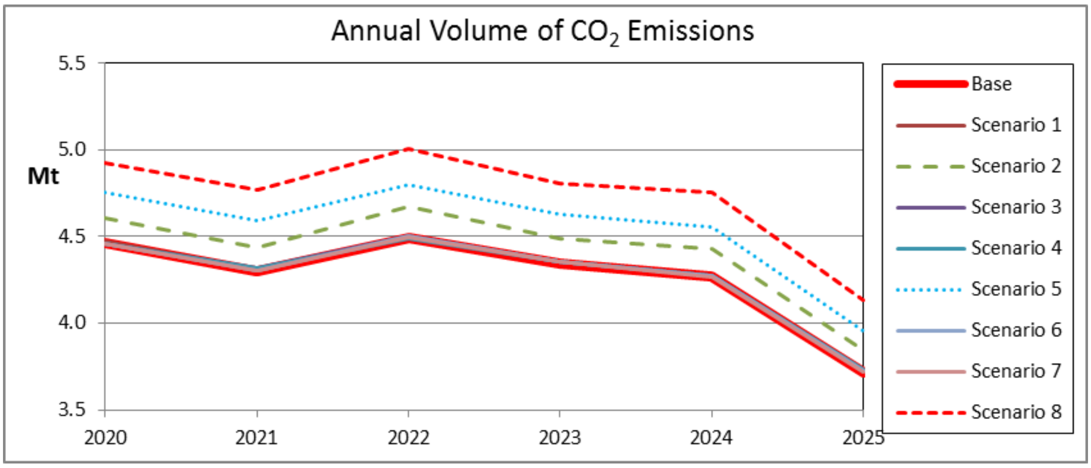


Figure 3: Annual average volume of CO_2 emissions

Constraints on flows at a hydro station can be expected to reduce the revenue of that plant because more generation is forced to occur at lower value times rather than higher value times. However, analysis of revenue calculated at SRMC value shows that additional constraints on hydro plant operation often do not reduce the revenue of the owner, if a number of other generation plants have the same owner. The reduction in flexibility at one station may be more than offset by increased prices at other stations. A similar situation may apply in the electricity market, which does not clear at SRMC[9].

Table 2: Increase in total hydro revenue[10] relative to base case for 2020 - 2025 (%)

Scenario	Waikato	Tekapo	Ohau	MidWaitaki	Clutha	Waikaremoana	Tongariro
1. Diversion from Lake Tekapo	0.2	-3.9	-0.5	-1.0	0.4	0.6	0.4
2. Minimum flows in Tekapo & Pukaki Rivers.	5.9	-6.6	-1.8	6.1	7.4	4.6	6.6
3. Increased minimum flow at Waitaki Power Station	2.7	3.2	1.8	0.9	1.9	3.3	2.1
4. Flushing flows in the Clutha River	1.9	1.4	1.4	0.7	1.8	2.2	1.4
5. Reduction of flows into Lake Rotoaira	3.0	14.3	14.3	14.2	14.3	14.7	-11.1
6. Minimum discharge from Lake Waikaremoana.	0.4	0.4	0.4	0.3	0.6	0.0	0.4
7. Flushing flows from Lake Waikaremoana	-0.1	0.0	-0.1	-0.3	-0.2	-0.7	-0.1
8. A combination of all the above	16.5	13.1	18.8	25.0	28.7	27.1	-0.3

Actual data shows that Waitaki power station is at its minimum output level for a much smaller proportion of time than the SDDP modelling would predict. Factors leading to this difference include

- Waitaki power station has a rate of change of flow constraint, which cannot be modelled in SDDP as it not a chronological time model.

[9] The New Zealand electricity market price is determined for each half hour by the highest price bid from a generator which is actually dispatched. This is known as the clearing price – the price at which demand equals generations. The clearing price is dependent only on generator market bids, which are usually different to SRMC.

[10] "Hydro revenue" is calculated as generation multiplied by SRMC. This is the revenue that the hydro plant would earn if its generation was sold at SRMC.

- A desire by power station operations staff to maintain a safety margin above their legally required minimum flow.

Modelling using a more detailed companion model of SDDP (the NCP model) would enable the modelling of ramp rate restrictions on both hydro and thermal power stations. This would give a better representation of the effect of the operational restrictions created by the proposed flow constraints.

Objective

The objective of this study is to quantify possible effects on the electricity generation system of a number of possible changes to minimum flows required at hydro power projects. Eight scenarios for these changes have been devised. These scenarios represent a broad range of credible options, rather than specific proposed changes to flow requirements. The intention is to determine the feasibility of the scenarios, and the scale of their impact on the electricity generation system.

The period 1 January 2020 through to 31 December 2025 has been studied. Modelling is carried out using a weekly time step with five load categories within each week. Hence the current work should be viewed as a "first cut" only – more detailed modelling using an hourly or half hourly time step could be carried out to assess possible impacts in greater detail.

Scenarios Studied

In addition to a base case representing the status quo, the following scenarios have been examined:

1. Diversion from Lake Tekapo of a constant 7 cumecs during weeks 1 to 14 and 39 to 52 each year, with the abstracted water used for generation along the irrigation canal. (This is similar to a study carried out by eCan.)
2. Diversion of a constant 10 cumecs down the Tekapo River and 20 cumecs into the Pukaki River.
3. An increased minimum flow at Waitaki Power Station of 200 cumecs (currently 150 cumecs).
4. Flushing flows in the Clutha River, resulting in a continuous minimum discharge from Lake Roxburgh of 300 cumecs.
5. Reduction of flows into Lake Rotoaira, and consequently Lake Taupo, of 20 cumecs, i.e. additional water is diverted into the Wanganui River.
6. 5 cumec minimum discharge from Lake Waikaremoana.
7. For Lake Waikaremoana, over the summer period, a total discharge requirement to provide a flushing flow of three times mean flow for one week each month.
8. A combination of all the above.

For scenarios 6, 7 and 8, minimum flows from Lake Waikaremoana have been modelled as discharges for generation, rather than as a requirement to divert water down the course of the Waikaretaheke River, by-passing the three hydro stations. Consequently this minimum flow requirement does not necessarily reduce the total energy generated by the Waikaremoana scheme.

Modelling Approach

A least cost optimal dispatch model has been used to study the selected scenarios – the Stochastic Dual Dynamic Programming (SDDP) software. This software simulates generation system operation for the whole of New Zealand, determining the lowest cost means of meeting the specified demand for electricity. It is a stochastic model in that it assumes only that the statistics of inflows to the hydro system are known, not the actual values for those inflows, i.e. the simulation process does not assume foresight of future hydro system inflows. The model has available similar information about inflows as a real decision maker would have. All other quantities are assumed known, including electricity demand.

Modelling of the complete generation system is essential as changes to operating requirements at any one project may require changes throughout the power system to obtain a new least cost strategy. The effects of each scenario on the entire system can then be compared with a base case representing the status quo to determine the effect of the change.

SDDP calculates a least cost dispatch, so it does not attempt to represent the marketing strategies of generation companies. A risk neutral optimum is found by SDDP. This means that the model finds the solution with the lowest expected cost. It does not attempt to limit the variability of costs across simulations for different inflow outcomes. In contrast, in the electricity market situation some market participants are likely to be willing to accept lower average returns in an effort to reduce the volatility of those returns. One consequence of this feature is that SDDP is more likely to completely empty a particular hydro reservoir than an electricity market participant. Market power has a significant effect on generation scheduling within the electricity market. Generation companies are likely to be reluctant to allow their company to be put in a situation where they need to purchase on the spot market to meet contractual requirements – this situation could leave them exposed to another company using its temporary market power to raise prices.

As a result of the above considerations, it is likely that the costs determined by this study for various restrictive scenarios for hydro operations form a lower bound on the market costs. However, some market costs may be transfer payments, rather than actual resource costs.

SDDP is developed by Power Systems Research Inc. of Rio de Janeiro, Brazil. It was initially developed in the late 1980s, but has been developed continuously since then. Each large hydro storage reservoir is modelled explicitly within SDDP and each hydro station and all thermal plants are modelled individually. Hydrological flow paths are modelled in detail. For example, Lake Tekapo is modelled as being able to spill water directly to Lake Benmore, as an alternative to passing through the Tekapo A power station. The small headponds located at each hydro project are not modelled – only those that have month to month storage are included. Generation units at hydro stations are aggregated – modelling is at the station level for hydro plants. The AC transmission system has not been modelled in the current study - the HVDC link is the only part of the transmission system represented. It is most unlikely that modelling the AC transmission system would affect this analysis.

Generation System Data

Economic Parameters

An 8% discount rate is used.[11]

Supply shortfalls are costed at $1500 per MWh for the first 10% of load not supplied and at $3000 per MWh for further shortfalls. Shortfalls, or deficit, in this context refers to demand that is not supplied for any reason, including due to the price response of load, voluntary load reductions and forced load reductions. The cost of $1500 per MWh does not represent an actual payment, but rather captures the economic impact of these load reductions.

The value of shortfall has some impact on hydro reservoir operating strategies. The values selected are typical for this type of model study where shortfalls are largely due to low inflows to the hydro

[11] 8% is a typical discount rate for this type of study. The SDDP solution is not especially sensitive to the value of the discount rate, but a non-zero discount rate can assist model convergence.

system. In these situations the risk of shortfall can be predicted some time ahead, allowing management of loads to lessen impacts. Much higher values would be used in an analysis of sudden short duration outages of which there would be no warning.

Generation Development Scenario

The "Mixed Renewables" scenario developed by the Ministry for Business, Innovation and Employment (MBIE) has been used. Data for this was obtained from their web site in December 2014. Commissioning dates for new plant are given in Table 3 and decommissioning dates in Table 4. All changes are modelled as occurring on 1 January of the specified year. Two units have already been decommissioned at Huntly, with the remaining 2 coming out of service on 1 January 2020 in the modelled scenario.

Table 3: New plant commissioned, Mixed Renewables scenario

Plant	Installed Capacity (MW)	Type	Commissioning Date
CCGT Cogen 1	40	Gas, Cogeneration	2019
Recip Diesel 7	10	Diesel	2019
Pukaki	35	Hydro	2020
Recip Diesel 1	10	Diesel	2020
Recip Diesel 2	10	Diesel	2020
Recip Diesel 5	10	Diesel	2020
Tauhara 2	250	Geothermal	2020
Turitea	183	Wind	2021
Wairau	70	Hydro	2022
Rotokawa	130	Geothermal	2023
Hawea CG	17	Hydro	2024
OCGT 1	200	Gas	2024
Otahuhu C		Gas	2024
Tauhara 1	80	Geothermal	2024
Arnold	46	Hydro	2025
Coleridge 2	70	Hydro	2025
Maungaharuru	225	Wind	2025
OCGT 5	200	Gas	2025
OCGT 8	200	Gas	2025
Stockton M	35	Hydro	2025
Stockton P	25	Hydro	2025
Tikitere	45	Geothermal	2025

Note: All plant commissions on 1 January of specified year

Table 4: Plant Decommissioning (1 January)

Plant	Year
Southdown	2024
Taranaki Combined Cycle	2024
Remaining two Huntly units	2020

Electricity Demand

Grid Exit Point (GXP) load from MBIE's Mixed Renewables scenario has been used. Only total New Zealand loads are published, so this has been allocated to each island using the same proportions as applied in some earlier work carried out for MBIE for their EDGS (Energy Demand and Generation) project.

Because losses in the AC transmission system are not modelled in SDDP, these must be added to the GXP demand for use within SDDP. 3.68% has been added to North Island data and 5.34% to South Island data. These are the values embedded in the Electricity Authority's Generation Expansion Model (GEM). HVDC transmission losses are calculated explicitly within SDDP, and so do not need to be added to demand data.

Table 5: Annual total load modelled (GWh)

	NZ Total	North Island	South Island
2020	41,350	26,911	16,216
2021	41,715	27,198	16,309
2022	42,243	27,527	16,531
2023	42,776	27,960	16,653
2024	43,303	28,393	16,768
2025	43,860	28,821	16,919

Load within each week is represented by five blocks, each consisting of a fraction of the week as in Table 6. Load block 1 consists of the 5% of each week containing the highest loads, with decreasing load in each block through to block 5 consisting of the 20% of the week with lowest loads.

Table 6: Load block sizes, percentage of each week

Load block number	1	2	3	4	5
Percentage of week	5	15	30	30	20

Load has been allocated to each block using the following process:

1. Obtain half hourly total demand for each island for 2013, from the Electricity Authority's Centralised Data Set (CDS). This demand data excludes embedded generation.
2. Calculate total New Zealand demand for each half hour
3. From the total New Zealand demand, determine the mapping of half hourly periods to load blocks, for each week.
4. Allocate North and South Island demand into the load block format, with separate sets of data for each island, using this mapping.
5. Apply the required load growth factors to obtain the total load in each island as in Table 5.

Inflows

Weekly inflow data was obtained from the Opus Consultants 2010 "Spectra Update", with some manipulation to obtain flows for the specific sites required. 78 complete years of data are available, spanning the period from 1 January 1932 to 31 December 2009. More recent data has not yet been published by the Electricity Authority. To provide some context for the scale of the flow modification scenarios, mean inflows for a number of projects are given in Table 7. In the table, Waikato Tributaries consists of all additional flows occurring between the Lake Taupo outlet and Karapiro. Lake Taupo inflow includes the Tongariro scheme diversions. Tokaanu and Rangipo flows refer to the total flows available at each of those two projects. Benmore flows represent the additional inflow from the Ahuriri River and other minor inflows that occur below the main Waitaki storage lakes.

Clyde inflow consists of all inflows at that hydro station less flows from lakes Wanaka and Hawea. Manapouri inflow refers to the total inflow to Lakes Manapouri and Te Anau.

Table 7: Mean inflows 1 Jan 1932 to 31 December 2009, m^3/sec

Benmore	44.8
Clyde	239.5
Cobb	5.4
Coleridge	24.5
Lake Hawea	65.0
Lake Ohau	80.6
Lake Pukaki	126.6
Lake Taupo	152.9
Lake Tekapo	81.2
Lake Waikaremoana	17.7
Lake Wanaka	196.6
Manapouri	403.7
Mangahao	8.6
Matahina	64.7
Patea	18.6
Rangipo	35.8
Tokaanu	53.9
Waikato Tributaries	95.5

Existing Generation Plant

Using information from the Electricity Authority's Centralised Dataset (CDS), total generation has been compared with total load plus estimated transmission losses. By determining the load and generation balance, generation plants to include in the model were confirmed. The purpose of the comparison is to ensure that embedded generation plants are not included in the model. This is necessary because the load data used excludes embedded generation – i.e. generation which injects into local distribution networks, and is therefore not included in grid off-take load measurements.

Some hydro plant production factors (MW per cumec flow) have been revised after comparison of modelled generation for a specific flow year with the actual generation for that calendar year, as reported in the Centralised Data Set. This analysis ensures that the production factors used in the model represent the average values occurring in practice, rather than that applying at some arbitrary efficiency point.

Table 8: Existing Hydro Plant Installed Capacities (MW)

North Island		South Island	
Rangipo	120	Cobb	32
Tokaanu	240	Coleridge	40
Kaitawa	37	Tekapo A	25
Tuai	58	Tekapo B	160
Piripaua	45	Ohau A	264
Aratiatia	78	Ohau B	212
Ohakuri	106	Ohau C	212
Atiamuri	84	Benmore	540
Whakamaru	100	Aviemore	220
Maraetai	352	Waitaki	90
Waipapa	51	Clyde	420
Arapuni	182	Roxburgh	320
Karapiro	96	Manapouri	730
Matahina	80	Branch River	12
Mangahao	28		
Wheao/Flaxy	26		
Patea	32		

Table 9: Existing Thermal and Wind Plants

	Installed Capacity (MW)	Fuel Type
Otahuhu B	400	Gas
Southdown	175	Gas
Taranaki CC	377	Gas
Huntly U3	243	Coal
Huntly U4	243	Coal
Huntly U5	385	Gas
Huntly U6	48	Gas
Whirinaki	155	Diesel
Stratford Peaker	200	Gas
Todd Peaker	100	Gas
Mokai	112	Geothermal
Ohaaki	40	Geothermal
Poihipi	55	Geothermal
Wairakei	156	Geothermal
Wairakei Binary	16	Geothermal
Te Mihi	114	Geothermal
Kawerau	100	Geothermal
Ngawha	26	Geothermal
Te Huka	23.4	Geothermal
Nga Awa Purua	138	Geothermal
Ngatamariki	82	Geothermal
Kaponga	24	Cogeneration
Kinleith	40	Cogeneration
Whareroa	64	Cogeneration
Te Rapa	44	Cogeneration
Tararua Wind	161	Wind
Te Apiti	88	Wind
West Wind	143	Wind
Te Uku	64	Wind
Mill Creek	60	Wind
Te Rere Hau	48.5	Wind

Existing Minimum Flow Constraints

A number of currently existing minimum flow constraints are modelled in the base case. These are shown in Table 10.

The complex network of flow paths in the Waitaki system are modelled as shown in Figure 4. The base case scenario requires no minimum flows in the Tekapo, Pukaki and Lower Ohau Rivers.

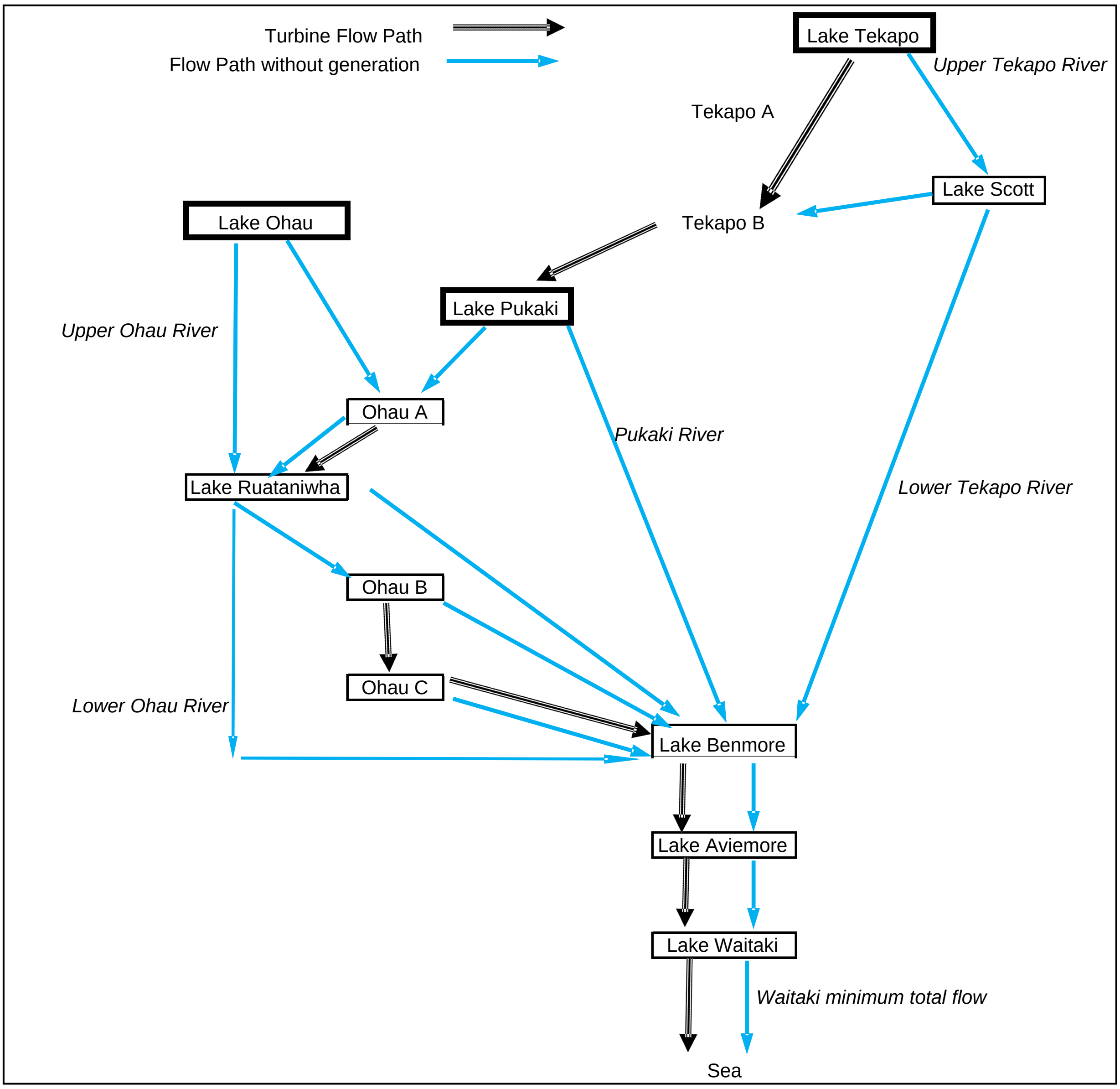


Figure 4: Waitaki system schematic

Table 10: Existing minimum flow constraints	
Location	Minimum Flow (m^3/sec)
Karapiro	148
Taupo Outflow	50
Upper Ohau River	8/12
Waitaki	150
Roxburgh	200
Manapouri	100

Note: Upper Ohau River constraint varies with time of year.

Fuel and Carbon Costs

Fuel and carbon costs were taken from MBIE published data. No series of prices are given by MBIE for diesel fuel, so the constant value used in their Long Run Marginal Cost (LRMC) calculations has been used. Emissions factors giving the CO_2 emitted per GJ of fuel used have been taken from MBIE data. Note that geothermal plants have an associated emission, which is an average value as it is likely to vary from one field to another. See Table 11 for details of fuel costs and CO_2 emission factors.

Take or pay fuel supply contracts affect scheduling as these fuels have zero variable cost – only the plant variable operation and maintenance costs and CO_2 emission costs are considered when calculating the optimal schedule. Table 12 shows the weekly take or pay fuel quantities assumed for each company, and the percentage load factors that these quantities imply. Contact's gas volumes are optimally allocated by the model to the Taranaki or Otahuhu combined cycle plants as required.

Table 11: Fuel and carbon Costs

	Excluding CO_2 cost				Including CO_2 cost			
	Gas $/GJ	Coal $/GJ	Diesel $/GJ	CO_2 $/T	Gas $/GJ	Coal $/GJ	Diesel $/GJ	Geothermal $/MWh
2020	7.13	6.24	40	25.00	8.88	7.99	41.75	2.50
2021	7.13	6.24	40	31.00	9.30	8.41	42.17	3.10
2022	7.13	6.24	40	37.22	9.74	8.85	42.61	3.72
2023	7.13	6.24	40	43.61	10.18	9.29	43.05	4.36
2024	7.13	6.24	40	50.16	10.64	9.75	43.51	5.02
2025	8.00	6.24	40	56.83	11.98	10.22	43.98	5.68

Table 12: Take or pay fuel quantities and assumed plant load factors

	Take or pay fuel GJ / week	% load factor
Mighty River Power	125	40
Genesis Gas	330	70
Contact	493	50

Hydro Reservoirs

Hydro reservoir volumes have been obtained from the ECNZ Reservoir Operating and Data Sheets. The extra emergency storage capacity in Lake Pukaki due to a change in resource consents is not modelled.

Table 13: Hydro reservoirs	
	Working storage (Hm^3)
Lake Taupo	760
L Waikaremoana	160
Cobb	24
Coleridge	137.6
Lake Tekapo	788.22
Lake Pukaki	2394.5
Lake Ohau	40
Lake Hawea	1141.9
Manapouri & Te Anau	1029.2

(Hm^3 = millions of cubic metres)

To obtain reservoir operating patterns for South Island storage that are more representative of the risk averse reservoir management that occurs in practice, two levels of reservoir risk curves have been modelled. These were obtained from the data published by the System Operator in their security of supply assumptions. A first level of risk aversion in SDDP is represented by the System Operator's 4% risk curve. At this level a penalty is applied to ensure that the level is violated only when all thermal plants are operating. The 10% or emergency level is used as a second level of risk aversion with a penalty ensuring that it is breached only when deficit is occurring.

HVDC Link

HVDC link capacity and loss data has been obtained from the earlier study carried out for MBIE's EDGS project, as in Table 14.

Table 14: HVDC capacity and loss parameters				
	South to North		North to South	
	Capacity (MW)	Loss (%)	Capacity (MW)	Loss (%)
Step 1	323.4	1.42	208.7	1.42
Step 2	753.3	3.30	582.7	3.30
Step 3	323.3	7.11	208.6	4.59
Total	1400.0		1000.0	

Results

Hydro Generation

Only scenarios 2, 5 and 8 result in a significant loss of hydro generation energy. Scenarios involving increased minimum flows only do not, because re-scheduling of flows is possible within the approximations of the SDDP modelling system. Total annual average hydro generation results are shown in Figure 5. Total hydro generation volumes for all scenarios except 2, 5 and 8 are close to those obtained for the base case, as can be seen in Table 15.

Scenario 2 involves the bypassing of various Upper Waitaki projects to enable residual flows in the Tekapo and Pukaki Rivers. Scenario 5 models a loss of water diversion to Tokaanu and consequent loss at all the Waikato River stations. Scenario 8 includes both these cases for the loss of water, as well as the other minimum flow requirements.

Scenario 1 models a diversion of water from Lake Tekapo for irrigation purposes, causing a loss of generation the Waitaki system of 117 GWh per year on average over the study period, but this is partly offset by the generation of 89 GWh from plant located on the irrigation canals.

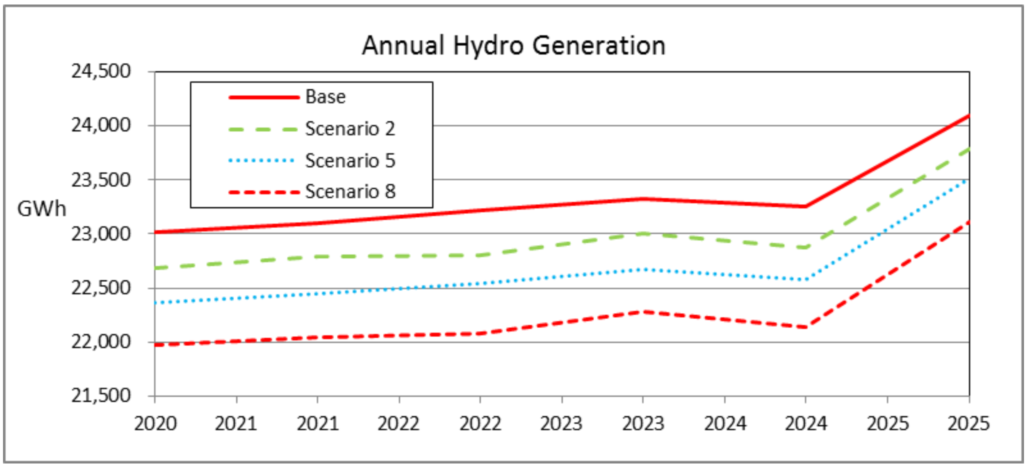


Figure 5: Total annual hydro generation

Table 15: Annual Average Hydro Generation (GWh)

Scenario:	Base	1	2	3	4	5	6	7	8
2020	23,019	22,999	22,682	23,032	23,042	22,361	23,026	23,023	21,969
2021	23,102	23,067	22,788	23,066	23,055	22,448	23,094	23,093	22,051
2022	23,224	23,192	22,801	23,209	23,231	22,543	23,209	23,219	22,077
2023	23,320	23,301	23,006	23,306	23,304	22,674	23,317	23,315	22,287
2024	23,249	23,228	22,872	23,234	23,244	22,582	23,243	23,255	22,144
2025	24,099	24,074	23,782	24,093	24,068	23,515	24,091	24,100	23,114
Total	140,013	139,860	137,931	139,939	139,943	136,123	139,980	140,005	133,642
Total Decrease		152	2,082	73	69	3,890	32	8	6,370

Waitaki Power Station Operation

Operation of the Waitaki power station is discussed in more detail as some of the issues are relevant to other sites. Figure 6 shows the cumulative distribution of modelled turbine flows at Waitaki power station. For the base case, flows are at the minimum level of 150 cumecs 23% of the time. For scenario 8, flow is at the minimum of 200 cumecs for 32% of the time. From actual data for the period 1 January 2000 to 31 December 2013, turbine flows were at or below 150 cumecs for approximately 1% of the time, and below 200 cumecs for only 6.5% of the period.

This marked difference in operations is likely to be due in part to the following:

- Waitaki power station has a rate of change of flow constraint, which cannot be modelled in SDDP as it not a chronological time model. (See an appendix for a discussion on chronological and load duration curve modelling.)
- While SDDP includes unit commitment modelling for thermal plants, it does not model ramp rate constraints at thermal stations. This may permit larger changes in hydro generation as in the model the hydros do not have to compensate for the restricted operations of the thermal plants.
- Market operations, which often result in a generation company wishing to generate an amount equal to their contract and retail commitments, to avoid being exposed to spot market prices.
- A desire by power station operations staff to maintain a safety margin above their legally required minimum flow.

Modelling using the more detailed companion model to SDDP (NCP) would enable modelling of ramp rate restrictions on both hydro and thermal power stations.

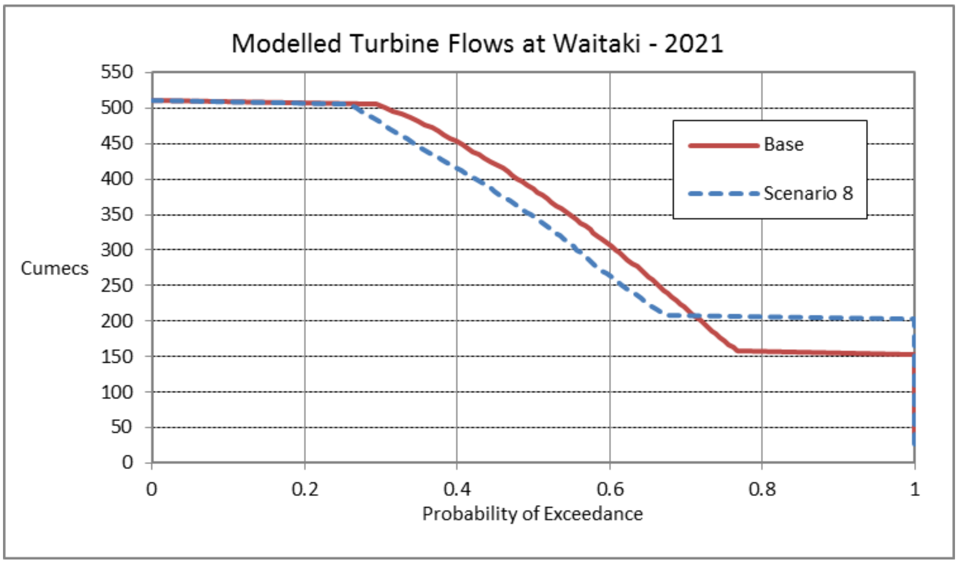


Figure 6: Cumulative distribution plot of Waitaki power station turbine flows (minimum 150 cumecs for base case, 200 cumecs for Scenario 8).

Short Run Marginal Costs

Short run marginal cost (SRMC) represents the cost of supplying an extra MWh of electricity from the existing generation system. SRMC is determined by the most expensive plant currently operating, which is able to increase its output by one MW. SRMC consists of the sum of fuel purchase and transport costs, variable operation and maintenance costs and carbon emission costs for a thermal plant, or for a hydro plant it consists of water value plus variable operating and maintenance cost. Note that capital and fixed costs do not contribute to short run marginal cost.

In Figure 7 it can be seen that effects on the annual average short run marginal costs are minor for the scenarios which do not involve significant loss of hydro energy. Noticeably higher SRMC is seen in

Figure 7 only for scenarios 2, 5 and 8. South Island SRMC is not shown in the graph as it is close to that for the North Island, as can be seen in Table 17. SRMC in the two islands diverge widely only when the HVDC link is fully loaded, in either direction. Smaller differences in SRMC occur due to the losses on the link – SRMC is lower at the sending end than at the receiving end by an amount dependent on the transmission losses. Consequently the results obtained indicate that the HVDC link is not often constrained.

SRMC drops in 2025. This is because 846 MW of new plant is commissioned in that year, consisting of the following types of plant:

Hydro	176 MW
Wind	225 MW
Gas	400 MW
Geothermal	45 MW

The increase in SRMC for scenario 8 over the base case would probably be sufficient to justify the construction of new plant, which would reduce SRMC for that scenario.

Figure 8 shows the cumulative distribution of SRMC for three scenarios for 2021. The increases in cost appear to occur over the full range of SRMC values – for most of the range, the entire distribution is moved up from the base case for scenarios 5 and 8.

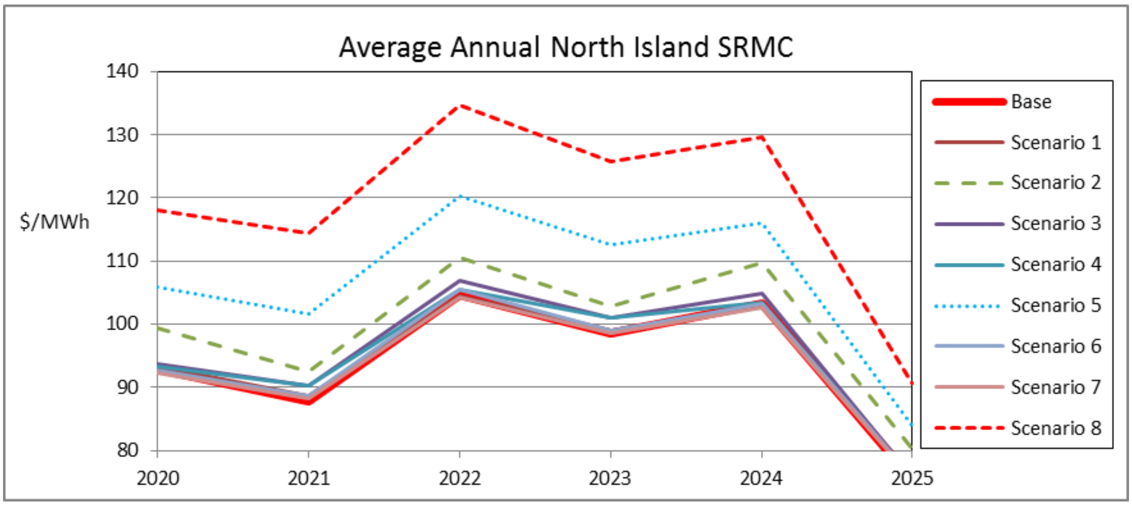


Figure 7: North Island annual average short run marginal cost

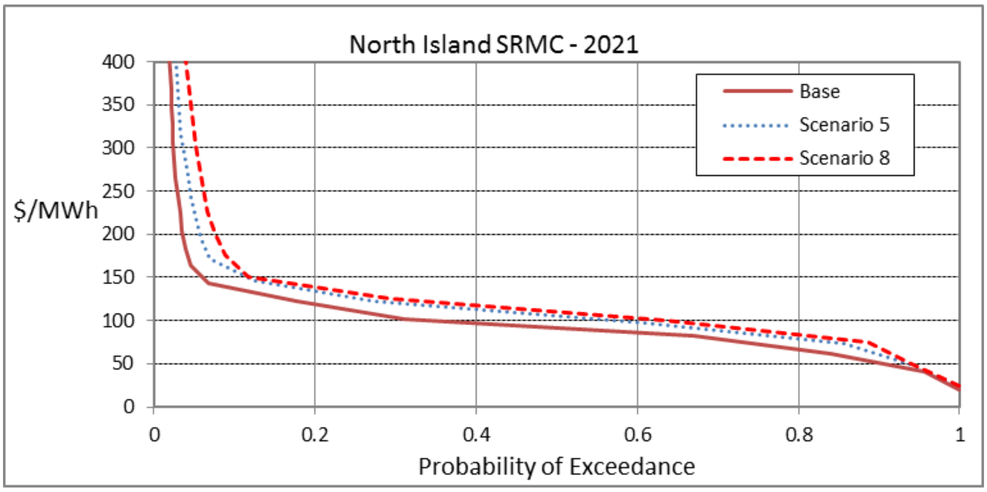


Figure 8: Cumulative plot of North Island short run marginal cost for 2021

Table 16: Annual Average SRMC ($/MWh)

Scenario	Base	1	2	3	4	5	6	7	8
North Island									
2020	92.9	93.4	99.4	93.8	93.3	106.0	92.8	92.3	118.1
2021	87.8	88.7	92.4	90.3	90.3	101.6	88.6	88.3	114.5
2022	104.6	104.4	110.6	107.0	105.5	120.4	105.5	104.2	134.8
2023	98.6	98.9	102.9	101.1	101.1	112.6	99.0	98.5	125.8
2024	103.2	103.1	109.7	104.9	103.5	116.1	103.3	102.6	129.7
2025	75.4	75.7	80.4	75.8	75.6	83.9	75.9	75.6	90.7
Average	93.8	94.0	99.2	95.5	94.9	106.8	94.2	93.6	118.9
South Island									
2020	95.5	95.7	102.7	95.3	95.7	108.6	95.1	94.5	121.3
2021	90.9	91.7	95.8	92.6	93.3	104.9	91.6	91.2	117.9
2022	108.8	109.0	116.1	110.5	109.8	125.4	110.5	108.5	139.7
2023	103.8	103.7	108.4	104.8	106.0	118.0	104.0	103.4	131.0
2024	108.0	108.0	115.7	108.6	108.0	121.9	108.2	107.4	135.4
2025	77.2	77.5	83.0	77.0	77.4	86.0	78.3	77.5	93.0
Average	97.4	97.6	103.6	98.1	98.4	110.8	98.0	97.1	123.1

Table 17: Annual Average Change in SRMC relative to base case ($/MWh)

Scenario	1	2	3	4	5	6	7	8
North Island								
2020	0.5	6.4	0.8	0.4	13.0	-0.2	-0.7	25.2
2021	0.9	4.6	2.5	2.6	13.9	0.8	0.5	26.7
2022	-0.2	6.0	2.4	0.9	15.8	0.9	-0.4	30.2
2023	0.3	4.3	2.4	2.4	13.9	0.4	-0.1	27.2
2024	-0.1	6.5	1.7	0.3	12.9	0.1	-0.7	26.5
2025	0.4	5.1	0.4	0.3	8.5	0.5	0.2	15.3
Average	0.3	5.5	1.7	1.1	13.0	0.4	-0.2	25.2
South Island								
2020	0.2	7.1	-0.3	0.2	13.1	-0.4	-1.0	25.7
2021	0.8	4.9	1.8	2.4	14.1	0.7	0.3	27.0
2022	0.1	7.3	1.7	1.0	16.5	1.7	-0.3	30.9
2023	-0.1	4.6	1.0	2.3	14.2	0.2	-0.4	27.2
2024	0.0	7.7	0.5	0.0	13.9	0.1	-0.6	27.4
2025	0.3	5.8	-0.3	0.1	8.8	1.0	0.2	15.8
Average	0.2	6.2	0.7	1.0	13.4	0.6	-0.3	25.7

Volatility of SRMC due to hydro inflow variability increases only a little in Figure 9 when the base case is compared to Scenario 8. (Scenario 8 has all modifications included.) For 2021, the standard deviation of weekly SRMC increases from 76.8 $/MWh for the base case up to 106.0 $/MWh for scenario 8. The hydro inflow sequences simulated, using the optimised strategy, are the actual historical inflows from 1932 to 2009.

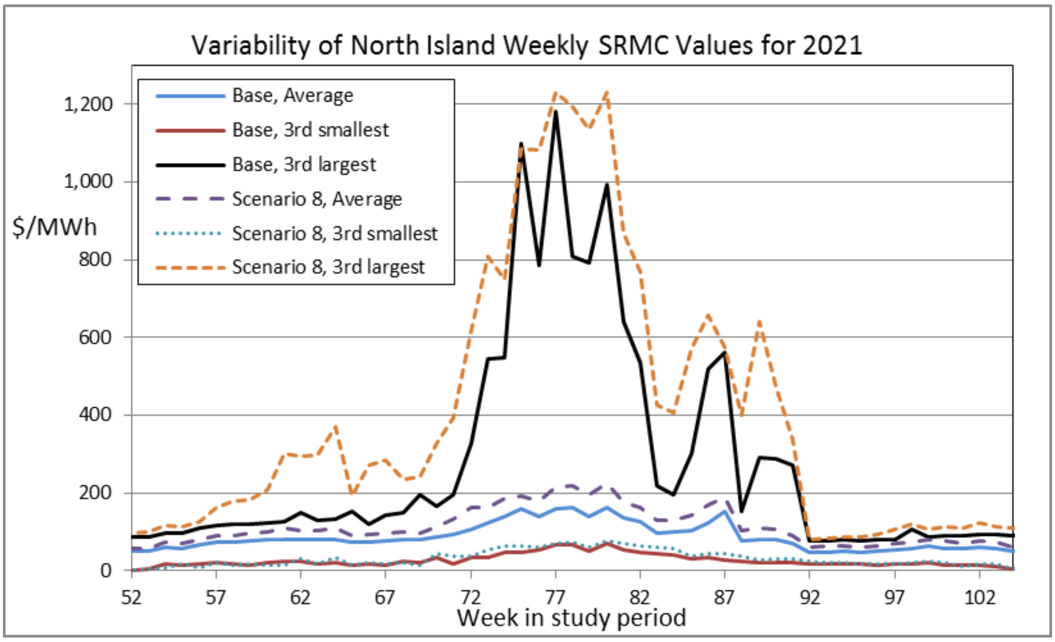


Figure 9: Plot illustrating small increase in SRMC volatility with hydro inflows, North Island SRMC, 2021

Variable operating costs for three plants with a range of costs are shown in Table 18. This cost consists of:

- Variable operation and maintenance cost
- Fuel cost, both purchase and transport costs
- Carbon emission costs

The cumulative plot of SRMC (Figure 8) indicates that the Otahuhu C gas fired combined cycle plant is likely to be base loaded because average SRMC exceeds the variable cost of this plant for much of the time. The open cycle gas turbine plant is likely to operate at shoulder periods and when hydro storage is low, while the high cost reciprocating diesel plant is used only rarely (less than 5% of the time).

Table 18: Variable costs of thermal plant ($/MWh)

	Otahuhu C	OCGT 5	Recip Diesel 2
2020	70.53	113.74	430.10
2021	72.67	115.88	446.90
2022	74.88	118.10	464.31
2023	77.16	120.38	482.22
2024	79.50	122.71	500.54
2025	88.01	132.66	519.21

Supply Shortfalls

The incidence of shortfalls in generation supply remains largely unchanged for all scenarios except 5 and 8, both of which involve the loss of generation at Tokaanu and along the Waikato River.

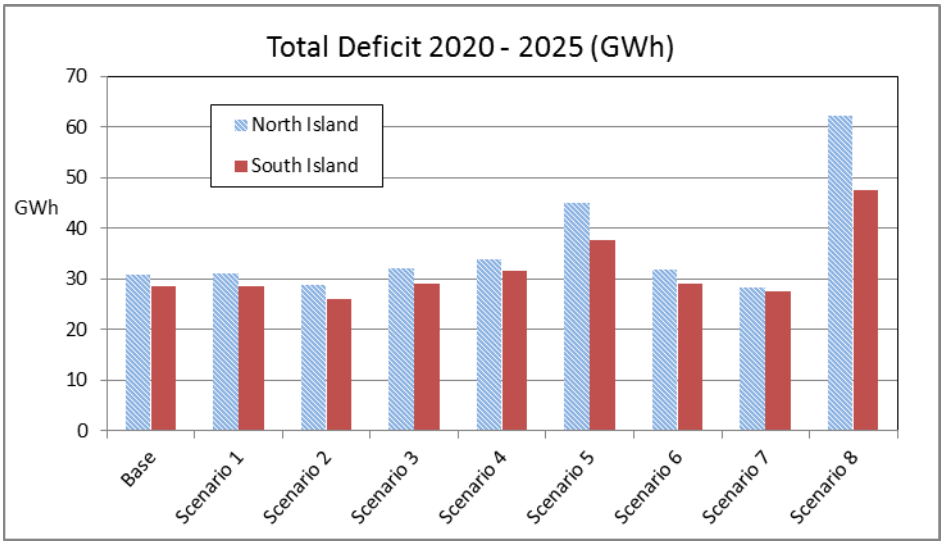


Figure 10: Total average deficits for entire study period

Table 19: Total Demand and Annual Average Deficit, NZ Total (GWh)

	Total Demand	Annual Average Deficits for various scenarios								
		Base	1	2	3	4	5	6	7	8
2020	43,127	8.2	10.2	7.9	9.9	10.8	12.1	7.4	8.4	17.7
2021	43,508	16.8	16.1	16.1	18.2	18.9	22.8	18.5	15.2	30.2
2022	44,058	19.5	18.1	16.8	17.8	19.2	25.8	19.1	17.9	31.5
2023	44,613	14.8	15.1	13.9	14.9	16.6	22.1	15.1	13.6	28.0
2024	45,161	0.1	0.0	0.0	0.3	0.0	0.1	0.7	0.5	2.2
2025	45,742	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Deficit		59.3	59.5	54.7	61.1	65.4	82.8	60.8	55.6	109.6
Increase in Deficit relative to base case			0.2	-4.6	1.8	6.1	23.5	1.5	-3.7	50.3

Fuel Consumption and CO_2 emissions

Gas and diesel consumption and CO_2 emissions increase markedly only for the three scenarios with significantly reduced hydro generation – scenarios 2, 5 and 8. Note that no coal fired plant is operational during the study period of 1 January 2020 to 31 December 2025.

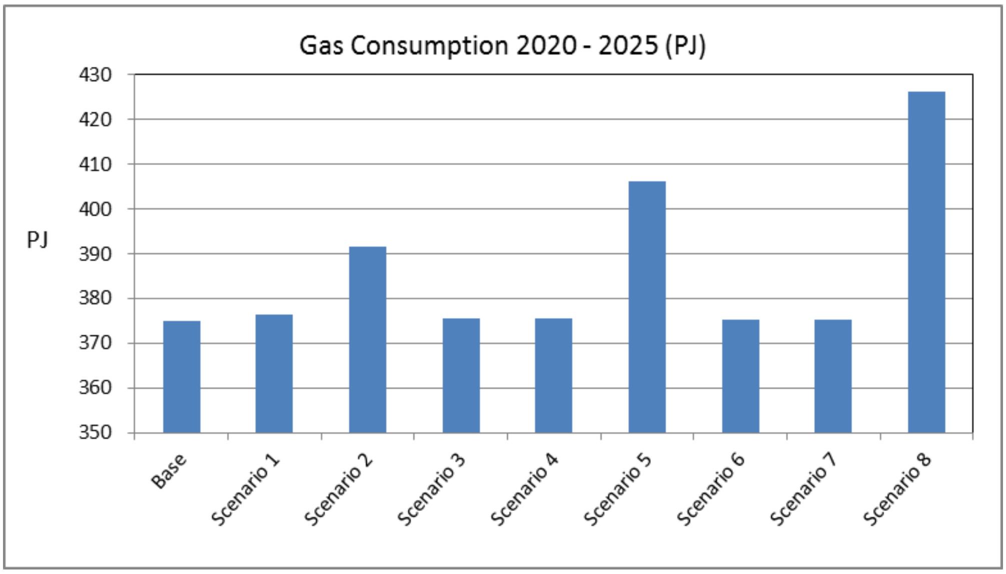


Figure 11: Total gas consumption for entire study period

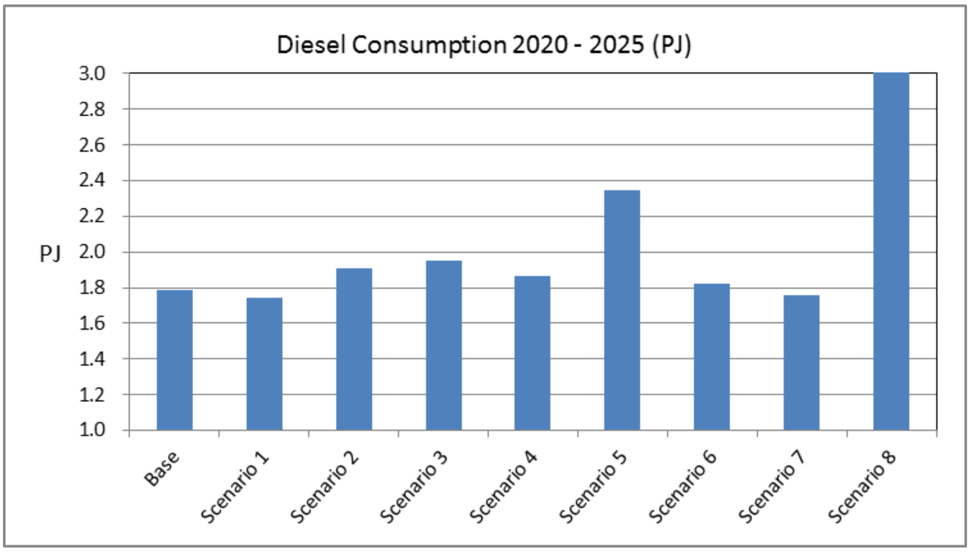


Figure 12: Total diesel consumption for entire study period

Table 20: Annual average fuel consumption (TJ)

Scenario:	Base	1	2	3	4	5	6	7	8
Gas									
2020	67,697	67,888	70,292	67,580	67,539	73,031	67,616	67,708	76,050
2021	64,645	64,932	67,269	64,931	65,013	70,016	64,749	64,734	73,256
2022	68,113	68,398	71,472	68,211	68,112	73,661	68,273	68,217	77,403
2023	63,479	63,682	66,109	63,627	63,611	68,702	63,554	63,594	71,807
2024	60,842	61,011	63,772	60,969	60,900	66,139	60,899	60,801	69,615
2025	50,196	50,369	52,574	50,294	50,503	54,686	50,276	50,217	58,038
Diesel									
2020	314.4	310.0	371.6	341.3	335.5	410.9	312.0	294.9	566.7
2021	275.9	272.2	253.6	313.1	300.2	372.5	285.2	281.6	509.2
2022	412.1	397.0	438.2	457.9	399.9	569.2	413.4	409.9	715.9
2023	378.7	371.2	400.3	418.0	420.2	480.5	388.8	382.2	654.4
2024	356.2	340.7	378.7	371.0	354.1	436.1	355.8	340.0	605.7
2025	51.1	53.7	64.2	49.5	52.9	79.0	64.0	49.1	96.0

Table 21 shows the average annual increase in CO_2 emissions for each scenario, averaged over inflow sequences and the 6 years of the study period. As expected, scenarios 2, 5 and 8 give the largest increase in emissions as these scenarios result in lost hydro generation. Emissions drop in 2025 due to the commissioning of 846 MW of new plant – 401 MW being zero emissions hydro and wind, with a further 45 MW of geothermal which has low emissions. Carbon emission costs per tonne rise steadily over the study period, so only a slight fall in emissions costs occurs in 2025 (Figure 14).

Table 21: Average annual CO_2 emissions, over analysis period 2020 to 2025 (kilo-tonnes)

	Base	1	2	3	4	5	6	7	8
2020	4463	4472	4603	4458	4456	4752	4459	4461	4921
2021	4298	4313	4434	4316	4320	4589	4305	4305	4769
2022	4493	4506	4673	4500	4491	4795	4501	4497	5002
2023	4346	4356	4486	4358	4357	4630	4351	4353	4805
2024	4269	4276	4425	4276	4271	4556	4271	4266	4750
2025	3718	3728	3845	3723	3734	3957	3723	3718	4132
Average annual increase over base		10.6	146.4	7.3	7.1	282.1	3.9	2.0	465.5

Table 22: Carbon Costs

	$/Tonne
2020	25.00
2021	31.00
2022	37.22
2023	43.61
2024	50.16
2025	56.83

Table 23: Average annual cost of CO_2 emissions, over analysis period 2020 to 2025 ($m)

	Base	1	2	3	4	5	6	7	8
2020	111.6	111.8	115.1	111.4	111.4	118.8	111.4	111.5	123.0
2021	133.3	133.7	137.5	133.8	133.9	142.3	133.4	133.4	147.8
2022	167.2	167.7	173.8	167.5	167.2	178.5	167.5	167.4	186.2
2023	189.5	190.0	195.6	190.0	190.0	201.9	189.7	189.8	209.5
2024	214.1	214.5	221.9	214.5	214.3	228.4	214.2	213.9	238.2
2025	211.2	211.7	218.4	211.5	212.1	224.8	211.5	211.2	234.8

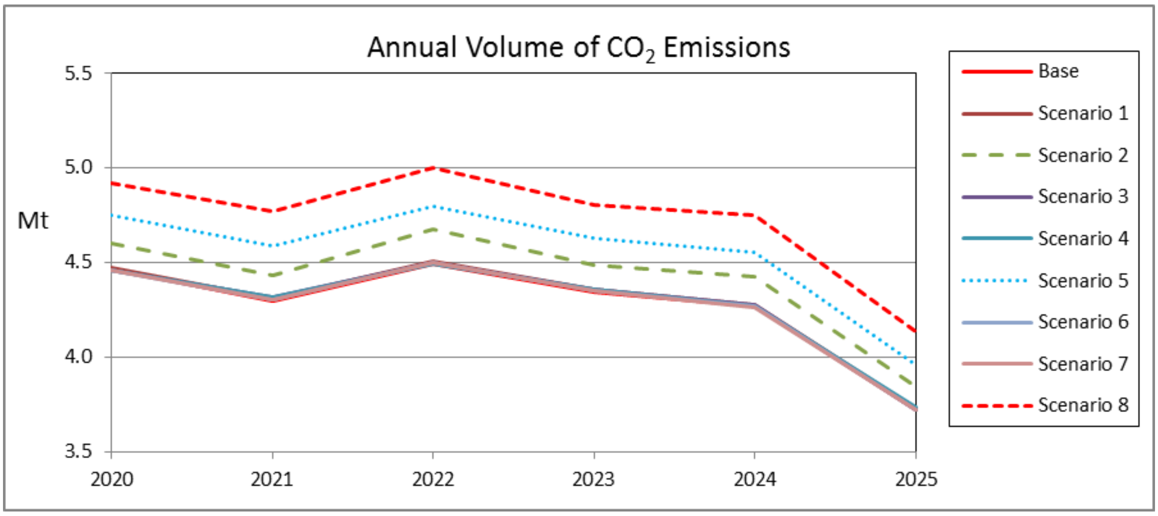


Figure 13: Annual average volume of CO_2 emissions

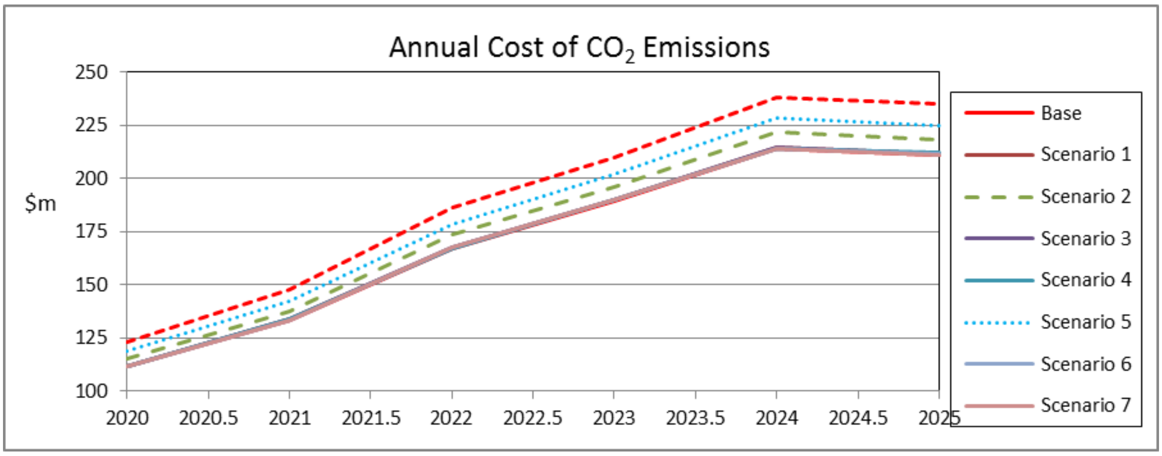


Figure 14: Annual average cost of CO_2 emissions

Hydro System Spill

Major reductions in hydro system spill occur only for the two scenarios in which water is diverted down the Tekapo and Pukaki rivers - scenarios 2 and 8. A smaller reduction in spill also occurs for Scenario 1, with diversion of water from Lake Tekapo for irrigation. Changes in spill do not necessarily indicate increased or decreased system operating costs. For example, it may be optimal to accept a high risk of spill at the beginning of winter due to full storage lakes to increase the probability of being able to meet winter demand with the minimum use of expensive diesel fired plant.

Table 24: Average annual energy spilled from hydro system (GWh)

Scenario	Base	1	2	3	4	5	6	7	8
2020	898	813	739	901	912	897	898	890	741
2021	910	858	747	935	918	911	918	915	742
2022	892	818	762	903	893	874	879	898	762
2023	929	859	776	938	942	926	946	931	771
2024	886	818	749	899	894	866	884	877	764
2025	1013	943	845	1020	1012	959	1011	1011	819
Total	5528	5110	4618	5595	5572	5432	5537	5522	4598

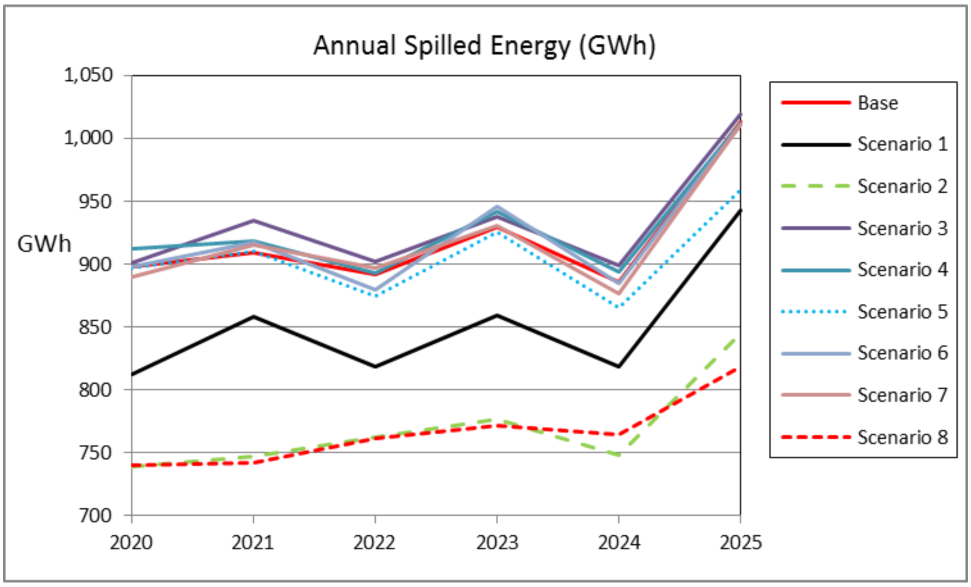


Figure 15: Annual average spilled energy

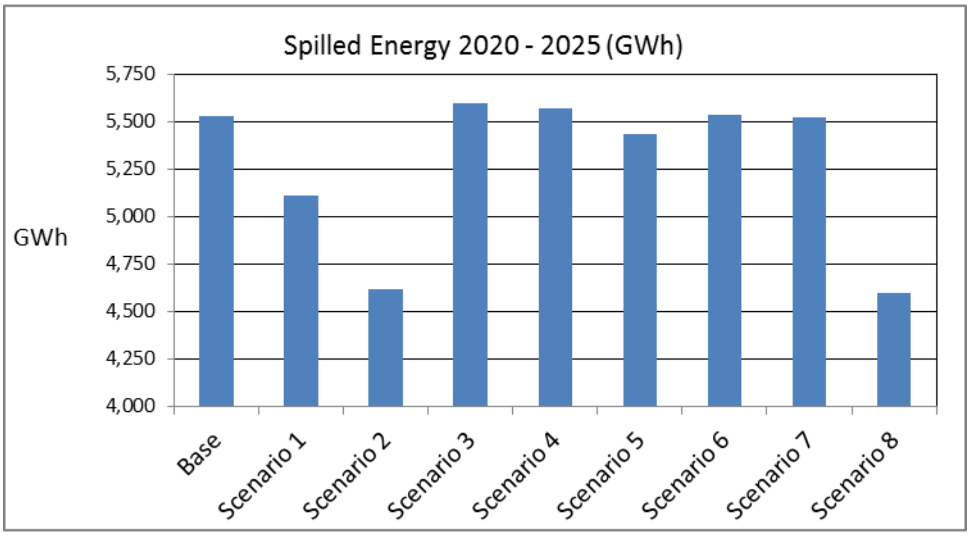


Figure 16: Total average spilled energy for entire study period

Effects on Revenue

Revenue is defined in this context as generation times SRMC. If the electricity market was perfectly efficient, then SRMC would be the market clearing price and the revenue calculated by SDDP would represent the actual market revenues. SRMC is not generally the price at which the New Zealand market clears as most companies have some market power, enabling them to increase prices above SRMC. "Market clearing price" refers to the price at which the quantity of generation that power companies wish to sell equals the power that consumers wish to purchase – supply and demand are in balance at this price.

Revenue calculation is done for each load block separately, and for each inflow sequence as both generation and SRMC vary with load block and flow sequence.

Increasing minimum flows at a hydro station, as for scenario 3 where Waitaki minimum flow increases from 150 to 200 cumecs, might be expected to reduce revenue to the plant owner. This is because the owner is forced to move generation from higher value periods into lower value periods to meet the minimum flow. The situation is different when the company owns a number of hydro plants, as the results in Table 25 show. Considering scenario 3, generation in the mid-Waitaki group of stations has an additional constraint applied through the increased minimum at Waitaki, but the total revenue of the three stations increases slightly. This is due to the increase in SRMC. The increase is small, and is likely to be within the margin of error of the model. The owners of other groups of stations achieve higher increases in revenue, which are likely to be significant. For scenario 2, a reduction in revenue occurs for the Tekapo and Ohau groups as these have less water available, but the mid Waitaki stations sees a large increase in their revenue as it has no reduction of inflows, but benefits from higher SRMC.

It is possible that a similar effect might occur in the electricity market – the additional constraints might not result in lower income for plant owners.

Table 25: Increase in total hydro revenue relative to base case for 2020 - 2025 (%)

Scenario	Waikato	Tekapo	Ohau	MidWaitaki	Clutha	Waikaremoana	Tongariro
1. Diversion from Lake Tekapo	0.2	-3.9	-0.5	-1.0	0.4	0.6	0.4
2. Minimum flows in Tekapo & Pukaki Rivers	5.9	-6.6	-1.8	6.1	7.4	4.6	6.6
3. Increased minimum flow at Waitaki Power Station	2.7	3.2	1.8	0.9	1.9	3.3	2.1
4. Flushing flows in the Clutha River	1.9	1.4	1.4	0.7	1.8	2.2	1.4
5. Reduction of flows into Lake Rotoaira	3.0	14.3	14.3	14.2	14.3	14.7	-11.1
6. Minimum discharge from Lake Waikaremoana	0.4	0.4	0.4	0.3	0.6	0.0	0.4
7. Flushing flows from Lake Waikaremoana	-0.1	0.0	-0.1	-0.3	-0.2	-0.7	-0.1
8. Combination of all of the above	16.5	13.1	18.8	25.0	28.7	27.1	-0.3

Conclusions

Changes to inflow constraints that result in less water being available for hydro generation have significant impacts on thermal generation fuel consumption and CO_2 emissions. The combined impact of all the changes examined might be sufficient to bring forward the construction of new plant.

Raising minimum flows, or requiring flushing flows, does not have a significant impact on generation system operations, as modelled by SDDP. It appears that the model uses the flexibility available elsewhere in the generation system to compensate for the additional restrictions on hydro operations.

Additional constraints on hydro plant operation might not reduce the revenue of the owner, if they own a number of other generation plants. The reduction in flexibility at one station may be more than offset by increased prices resulting in additional revenue at other stations.

Analysis using a more detailed model with hourly or half hourly time steps would enable modelling of ramp rate restrictions on both hydro and thermal power stations. This would enable better representation of the effect of the operational restrictions created by the proposed flow constraints. Software such as NCP, the short term companion model to SDDP, would be likely to show greater effects on system operations than are evident from the current study.

Appendix: Load Duration Curve Modelling

SDDP has been solved with a one week time step for this study. This means that many quantities are averaged over the one week time step. Water balance for hydro reservoirs, for example, is enforced only at the end of each week, so inflows are effectively averaged over the week. This is the usual approach to modelling generation system operation over a period of several years. To capture some of the effects of load variability within each week, a load duration curve is used.

For SDDP, the load duration curve consists of 5 load categories, with a constant load within each category. Each category represents the load over some proportion of the week, with the percentages of the week represented by each block used in this study being 5, 15, 30, 30 and 20. The first load block represents the 5% of hours with the highest loads. Each block represents successively lower loads, through to the final block representing the 20% of hours within the week with lowest loads.

The peak load block of 5% represents 8.4 hours. It might consist of the average of 1.5 hours from each day Monday through to Thursday and 2.4 hours from Friday, for a particular week. The composition of hours from the various days will vary from week to week, as the load block just contains the 8.4 hours of highest loads, irrespective of when they occur within the week.

By representing the load variation within each week in this way, the scheduling of generation plant is more realistic. For example, the load duration curve requires additional generation plant to be operated to meet peak loads. Some thermal plants are modelled as requiring commitment. This means that if they are to operate at all during a given week, they must run for the entire week, and at some minimum output or above. The load duration curve modelling might require extra plant to be committed just to meet the peaks, in some cases, but the plant is then forced to operate for the entire week.

The load duration curve approach reduces the computational effort required to solve SDDP, compared to modelling each hour in sequence. Solving for all 168 hours each week would increase the size of the already very large problem to unmanageable proportions without the use of exceptionally large computer resources. The massively parallel version of SDDP is required to do this.

The disadvantage of the load duration curve representation is that it is not possible to model the hour to hour operation of generation plant. For example, some hydro plants are limited in the rate at which flows in the river can be changed, to avoid drowning stock grazing in the river bed, and to reduce damage to river banks. These rate of change constraints cannot be modelled by a load duration curve model. A chronological model is required – one that represents each hour or half hour separately, and in the correct sequence. The usual approach is to use a separate, more detailed model for this stage of the analysis, if required. The NCP model has been developed by PSR to carry out chronological analysis. NCP can be used to further analyse a solution obtained with SDDP, solving for one year, for a given flow sequence.

Because SDDP enforces flow balance in the hydro system at the end of each week only, it is not able to model the operation of the small headponds behind each dam. These headponds might cycle several times over the course of a day, so an end of week flow balance is not meaningful. Instead, SDDP assumes no week to week storage carry over for these small headponds, and also restricts the amount of regulation that they can carry out. (Regulation refers to the process of storing water at off-peak times for use at peaks, etc.) A chronological model such as NCP is also needed to represent this level of detail.