Climate change impact on cost of decarbonisation in a hydro-based power system

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Abstract

Understanding the impact of climate change on renewable energy resources is increasingly vital as our energy systems transition towards higher levels of renewable generation. This paper explores power system transition under climate change impacts on hydro resources, as well as the impact of climate change on the cost of decarbonisation. We use an integrated energy systems assessment tool to investigate the impact of altered seasonal availability factors on the optimal energy investment pathways. We assess the cost of decarbonisation under climate change impact on the hydro resources, as well as the impact of discount rate assumptions on total cost of decarbonisation. We find that in the case of New Zealand, more hydro will be available in winter due to climate change, but less in summer, which is compensated for with increased solar capacity. We also find that decarbonisation in New Zealand sees a major transformation in the transport sector, supported by a relatively moderate increase in overall demand in the electricity sector. While climate change impact on the hydro resource may reduce the total cost of decarbonisation in New Zealand, the choice of discount rate has a significant impact on the cost of climate change mitigation.

Keywords: energy systems modelling, climate change impact on hydro, decarbonisation, cost of mitigation

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1. Introduction

Hydro power has several technical benefits in an electricity system; it can provide low-cost baseload power, it can ramp up quickly to respond to variable renewables on the grid, such as solar and wind, and, in the case of dammed hydro, it can be used to store energy for later use [1]. However, hydrological flows are often seasonal, and climate change is likely to further have an impact on the natural variability of hydro. In fact, the impact of climate change on renewable energy sources and thereby on the energy system has been studied extensively over the past decade, in particular for hydro [2–13], wind [12, 14–22], solar [12, 23–26], biomass [27], and even waves [28, 29]. This poses additional challenges for system planners and government agencies, particularly when increased deployment of renewables is part of their energy system decarbonisation plan [30–35].

Decarbonisation of energy has also been studied extensively both at country [36–41], regional [42–46], and global [47–49] levels. Studies find that electrification of demand sectors, together with transitioning to a low carbon power sector, are key enablers to deep decarbonisation of the energy sector [43, 46, 47, 50, 51]. However, few studies have gone further to investigate the impact of climate change on the cost of mitigating climate change, or, decarbonising the energy sector, through bottom-up modelling – the key contribution of this paper.

New Zealand's electricity system typically has a 55% to 60% annual contribution from hydro, varying by annual rainfall and snowmelt patterns [52]. These patterns are susceptible to climate change, which in turn will impact the annual and seasonal availability of hydro power, and thereby have an impact on the operation of the electricity system. The key question here is: How will these changes in hydrological patterns impact long-term energy system planning, both from a cost and energy supply perspective?

To classify the stringency of different global warming mitigation scenarios, the concept of Representative Concentration Pathways (RCPs) was introduced to climate change research. These RCPs include a stringent mitigation scenario (RCP2.6), two intermediate scenarios (RCP4.5 and RCP6.0) and one scenario with very high GHG emissions (RCP8.5). According to the 5th Assessment Report of the IPPC (2014) [53], the increase in greenhouse gases (GHG) emissions under current policies would lead to a future somewhere between the RCP6.0 and the RCP8.5 scenarios. In this paper, therefore, we investigate the RCP8.5 scenario's impact on New Zealand's hydro generation, including a sensitivity analysis on seasonal hydro availability, using an integrated energy systems modelling tool.

The model is based on the TIMES (The Integrated Markal-EFOM System) platform, which provides a technology rich, bottom-up model using linear-programming to produce a least-cost energy system, optimised under a number of user constraints, over a long-term time horizon[54]. The TIMES model developed for New Zealand, TIMES-NZ, includes a characterisation of the main energy demand sectors of the economy: residential, services, industry, agriculture and transport. The supply side is characterised in terms of energy resources and transformation technologies, including techno-economic data for all processes involved.

This tool goes beyond existing energy and climate change tools currently used in New Zealand as it covers the entire energy system, rather than focusing on one particular subsector of the system, for example, the electricity sector [55]. This is crucial for modelling decarbonisation of the energy sector, as transitions are bound to occur across sectors, with indirect impacts within the entire energy sector.

This paper presents a study on how the impact of climate change on hydro resources may affect optimal long-term energy systems planning and the cost of decarbonisation of the energy sector. This includes a sensitivity analysis on the currently most likely climate change scenario and a discussion on the shifts in optimal technology and fuel choices under increasing climate change effects. The paper also presents results on the cost of decarbonisation at increasingly stringent emissions reduction targets, and shows how the marginal cost of decarbonisation increases as more expensive technological shifts take place as the target is increased.

2. Model description

The model used in this study is an integrated energy systems assessment model recently developed for New Zealand using the TIMES modelling framework [54]. TIMES is part of a family of MARKAL-TIMES optimization energy models developed by ETSAP (Energy Technology Systems Analysis Program) from the International Energy Agency, which are widely used for the analysis of climate and energy scenarios and policies. It can be used to characterise the energy resources and transformation technologies in detail. The energy system thus includes primary energy forms, secondary energy forms and energy services. Transformation technologies include power generation technologies, fuel refining and alternative fuel production technologies (such as hydrogen or biofuels) and demand side technologies such as heat pumps, boilers or different types of vehicles.

The model computes a partial equilibrium; i.e. it computes the flows and prices of all energy carriers for each time period and in each part of the energy system. More information about the TIMES model, including all equations, can be found in the documentation [54, 56, 57]. Hence, it covers the economy-wide energy demands, but, being an energy systems model, includes only energy related GHG emissions. In summary, the model minimises the net present value (NPV), i.e. total discounted cost of the energy system over the entire modelling period. The NPV is given by Equation 1.

$$NPV = \sum_{r=1}^{R} \sum_{t \in YEARS} (1 + d_{r,t})^{REFyr} \cdot ANNCOST_{r,t} \qquad (1)$$

where NPV is the net present value of total costs; d is the discount rate; r is the region (r_1 = North Island, r_2 = South Island), t is the year, while $YEARS$ is the set of years included in the model; $REFyr$ is the reference year to which all costs are discounted to ($REFyr = 2018$); and $ANNCOST$ is the total net annual cost per region, which includes investment, decommissioning, fixed and variable operation and maintenance, and carbon costs (where applicable), costs of fuel imports, revenues from fuel exports and salvage value of investments at the end of the time horizon.

The time-horizon goes from 2018 to 2060, with 2018 and 2019 used as reference years for calibration and results calculated for one average year in five year time periods thereafter starting in 2020. Each year is modelled in 24 time-slices that represent three periods of an average day (day, night and peak hours), weekdays and weekend days, and four seasons: Summer, Fall, Winter, and Spring (e.g. winter weekday peak, or summer weekend night).

In New Zealand over 50% of primary energy comes from oil and gas (33% and 21% respectively in 2019). Geothermal accounts for 22%, hydro for 10%, other renewables for 8% and coal for 7% (2019) [52]. The electricity mix is hydro-dominated, with a 15-year average (2005-2019) of 56% of annual supply coming from hydro, 18% from natural gas, 14% from geothermal (capacity growth has increased this to 17-18% over the last 5 years, while decreasing natural gas to 12-15% over the same period), 6% from coal, 4% from wind and less than 1% from wood, biogas, solar, and waste heat.

In this model the existing energy resources and conversion technologies are based on public data released annually by the Ministry of Business, Employment and Innovation (MBIE) [52]. This includes existing reserves of fossil fuels, and installed capacities of hydro (5389 MW), geothermal (957 MW), thermal (2241 MW), wind (689 MW), and solar (117 MW). Also reference year energy demands per sector are included from this report. New capacity by source is constrained by techno-economic and regulatory feasibility, as presented in the future generation stack published by the MBIE [58]. This allows a limited addition of hydro capacity (452 MW), roughly a doubling of geothermal (1035 MW), essentially leaving the model to choose from thermal, wind and/or solar capacity expansion.

To characterise the conversion technologies in the demand sectors, the 'Energy End Use Database' published by the Energy Efficiency and Conservation Authority (EECA) was used [59]. This provides techno-economic data of the existing demand side technologies (such as different types of boilers, heat-pumps or lighting technologies), giving the model options to choose from, based on costs, efficiencies and possible constraints. The five demand sectors (residential, commercial, transport, industrial and agricultural) combined contain 36 end-use energy demand categories (e.g. residential space heating, or light duty vehicle kilometers), and a total of 25, 27 and 34 end-use technologies to choose from in the residential, commercial and transport sectors respectively (e.g. electric heatpump or wood burner to supply space heating; petrol car or electric vehicle to supply light duty vehicle kilometers). The industrial sector consists of six subsectors: food processing; wood, pulp, paper and printing; chemicals, basic metals, methanol production; and other industrial sectors. These subsectors, as well as the agricultural sector, are modelled at an aggregated level by fuel demands, with limited allowance for fuel switching.

All scenarios modelled in this paper adopt the same socio-economic trends. Future demands for energy services are modelled based on GDP projections for each sector (commercial, industry, transport and agriculture) provided by the New Zealand Institute for Economic Research [60]. The residential sector's energy service demand growth is assumed to be driven by population growth projections per region from Statistics New Zealand were used [61]. No demand elasticities were used in this model, however, the total delivered energy may decrease through more energy efficient technologies.

3. Methodology

In this paper we investigate the impact of climate change on seasonal availability of the hydro resources, and thereby on the optimal long-term investments and dynamics of the electricity mix. We also investigate the impact of climate change on the cost of emissions reductions in the energy sector. Our research provides the following two key contributions:

1. Climate change impact on hydro resources: a sensitivity analysis of RCP8.5 in 2035 for New Zealand.
2. Climate change impact on cost of decarbonisation: a study of CO_2 emissions reduction targets in the energy sector.

3.1. Climate change impact on hydro resources

New Zealand consists of two main islands, the North Island and the South Island, each with specific seasonal hydrological characteristics. An availability factor (AF) gives the average generation level of a power generator. For example, an AF of 0.5 indicates that a generator generated the equivalent of running at full capacity for half the time.

For our first contribution, to calculate the impact of the RCP8.5 climate change scenario on the seasonal availability factors for hydro generation for the two main islands, we use the results from modelling work on hydro generation availability [62, 63] based on a climate change impact assessment on New Zealand's water resources conducted by the National Institute of Water and Atmospheric Research (NIWA) [64].

Figure 1 gives the relative change in seasonal availability factors of hydro generation on the North Island and South Island under the RCP8.5 scenario in 2035, relative to the baseline scenario, where no impact of climate change is considered. Thus, to apply this climate change scenario, the historical seasonal availability factors are increased or decreased by the corresponding factors. The results for the RCP8.5 scenario from Moniotte [62] show a 12 to 17 percent increase in hydro availability in winter, when electricity demand is highest, and a 5 percent increase and an approximately 12 percent decrease in the North Island and South Island, respectively, in summer.

We then run sensitivity scenarios on hydro availability under the RCP8.5 climate scenario for 2035. We incrementally apply the impact of climate change to the historical seasonal hydro availability factors by multiplying the climate change impact factor by a factor ranging from 0.1 (a slight climate change impact) to 1.5 (a 50% higher factor than the RCP8.5 scenario

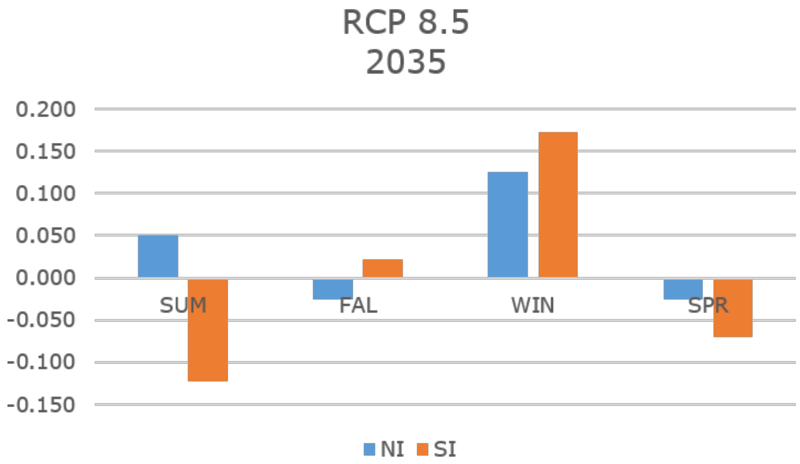

Figure 1: Relative change in seasonal availability factors of hydro generation on the North Island (NI) and South Island (SI) of New Zealand for the RCP 8.5 scenario for 2035.

indicates), at increments of 0.1. The factor 1.0 corresponds to the scenario shown in Figure 1, i.e. the expected result of the RCP8.5 climate change scenario.

Table 1 gives a key to scenario names for the sensitivity analysis. The factor x (ranging from 0.1 to 1.5) following the RCP scenario gives the scaling factor used to multiply the RCP 8.5 2035 availability factors to give a range of potential availability factors under climate change in 2035. All availability factors are interpolated between the historical values calculated for 2015 and the climate change impacted values in 2035. After inspecting all scenario results in detail, due to the large number of scenarios, only a subset is presented in figures for a more clear representation. This does not affect the overall conclusions.

3.2. Cost of decarbonisation

For our second contribution, we explore the impact of climate change on the cost of energy sector decarbonisation, in the case of a hydro-based electricity system. In line with the government's target to achieve net zero carbon emissions by 2050, we impose an increasingly stringent energy sector wide carbon cap, as a percentage reduction in annual emissions from 1990 levels. The scenarios investigated are given in Table 2.

While all the above scenarios were investigated, some results are presented

Table 1: Sensitivity analysis scenario names and descriptions.

Scenario name	Description
RCP8.5 0.1	RCP8.5 scenario, seasonal AFs scaled by factor 0.1
$\vdots$	
RCP8.5 x	RCP8.5 scenario, seasonal AFs scaled by factor x
$\vdots$	
RCP8.5 1.5	RCP8.5 scenario, seasonal AFs scaled by factor 1.5

Table 2: Decarbonisation scenarios.

Scenario name	Description
CO2Cap -0%	No reduction target, but also not permitted to increase emissions
CO2Cap -50%	50% emissions reduction
CO2Cap -55%	55% emissions reduction
CO2Cap -60%	60% emissions reduction
CO2Cap -65%	65% emissions reduction
CO2Cap -70%	70% emissions reduction
CO2Cap -75%	75% emissions reduction
CO2Cap -80%	80% emissions reduction

only for a subset of these scenarios, simply for the sake of visual clarity in graphs.

4. Results and discussion

The results are presented first for the climate change sensitivity analysis, followed by the cost of decarbonisation scenarios.

4.1. Climate change impact on hydro resource: Sensitivity analysis

This section presents the first key contribution. We first explore the results in regard to the impact of climate change on optimal generation capacity investment and resulting generation mix. Figure 2 shows the installed capacity trends for the climate sensitivity scenarios for the main sources of electricity generation. Omitted sources are either invariable between scenarios (e.g. geothermal), negligible in scale (e.g. oil), or are phased out equally in all scenarios (e.g. biomass).

The main impact from the RCP sensitivity is in the installed capacities of solar and wind power. The more severe the climate change impact, the more the system relies on solar. This is due to the seasonal impact of climate change on the hydro resource in New Zealand; hydro becomes more available in winter, when the solar resource is at its minimum, and less available in summer – particularly in the South Island region, which holds the majority of installed hydro capacity – when the solar resource is at its maximum. Hence solar is balancing the increased seasonal deviation of the hydro resource.

The opposite is true for wind. An increased climate change effect results in a lower installed capacity of wind power. This indicates a trade-off between resource availability and costs. In a scenario without climate change effects, wind would be the preferred technology. However, due to the better seasonal fit of solar with increased climate change effects, solar becomes the preferred technology as the effects of climate change on the hydro resource become more severe in magnitude.

A certain amount of natural gas is kept in the energy system to balance the variability of renewables.

Figure 3 gives the seasonal generation mix by source for the RCP8.5 sensitivity scenarios. The impact on the hydro resource (based on Figure 1), particularly in the South Island region, is very clear, with increased generation in winter, and decreased generation in summer, as the climate scenarios become more severe. Note, the installed capacity of hydro remains the

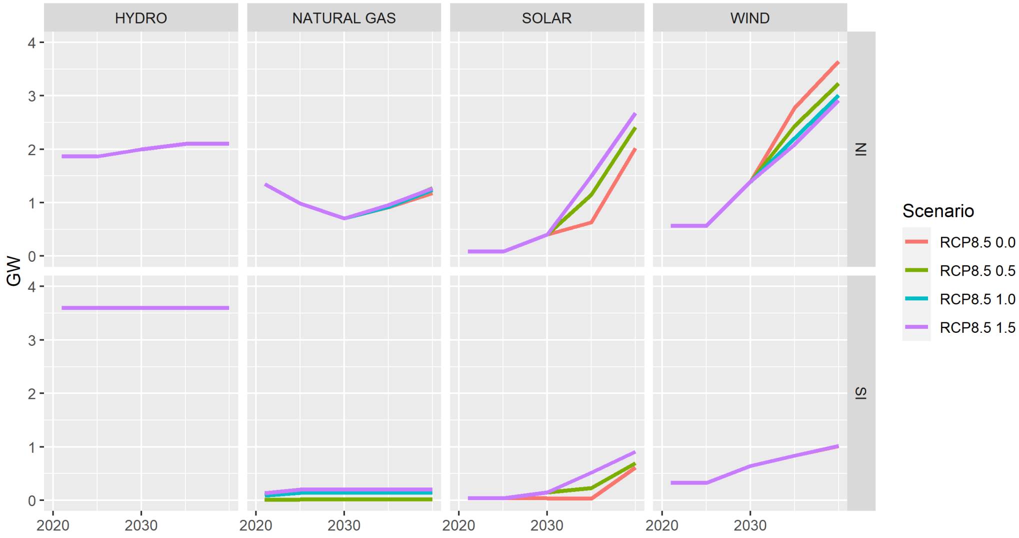

Figure 2: Installed capacity by source and region (North Island (NI) and South Island (SI)), given per climate change sensitivity scenario.

same in all scenarios. One can also observe the increased solar generation in summer in the North Island, roughly corresponding to the decreased hydro generation in the South Island.

4.2. Decarbonisation through emission reduction targets

This section presents the second contribution. This covers the emissions reduction scenarios, going from 'CO2Cap -0%' (no reduction required, but no increase permitted either) to 'CO2Cap -80%' (80% reduction in annual emissions from the reference year 1990). Scenarios between 0 and 50% emissions reduction targets are redundant, while targets above 80% are infeasible with the costs and technology options currently available in the model.

4.2.1. Emissions

Figure 4 shows the emissions reductions to the target year 2050. Note that even scenario 'CO2Cap: -0%', which requires no reduction of emissions beyond the 1990 reference year emissions level, sees significant emissions reductions. This is largely due to the transport sector transformation, as electric vehicles quickly become the most cost-effective solution in terms of cost per vehicle-kilometer. This is largely due to the transport sector transformation by 2050, as electric vehicles quickly become the most cost-effective

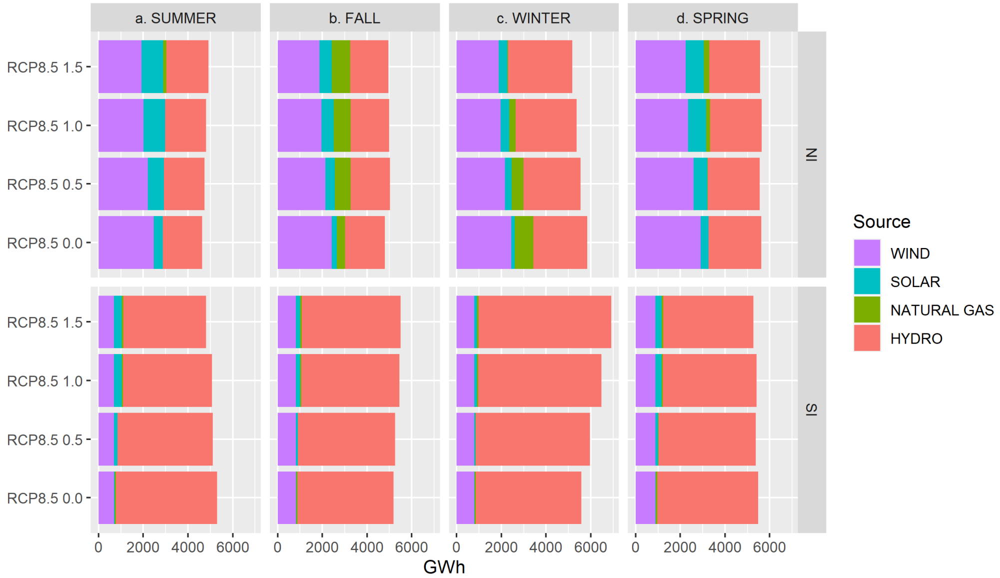

Figure 3: Generation output by season and source for select RCP 8.5 sensitivity scenarios in 2035.

solution in terms of cost per vehicle-kilometer, given a fully equipped, large-scale charging infrastructure network and a clean electricity mix are ready in place.

Figure 5 shows the per sector emissions reductions for the 'CO2Cap: 80%' scenario. The transport sector sees the steepest emissions reductions, where shifting from petroleum products to electric drive trains occur. Other sectors experience more moderate emissions reductions, as switching to electricity occurs.

4.2.2. Fuel switching

Figure 6 shows how the economy-wide total demand for different fuels over the modelled time horizon shifts as more stringent carbon reduction targets are set. Results are similar both for the scenarios with no climate change impact included and scenarios with climate change, hence for visual clarity only the scenario results with no climate change impact are presented in these results. The main shifts can be seen in increased electrification and reduced oil demand. Note that coal is phased out in all scenarios, and hence there are no significant changes between the scenarios. To investigate these shifts further, we look at the fuel demands in the demand sectors, and find

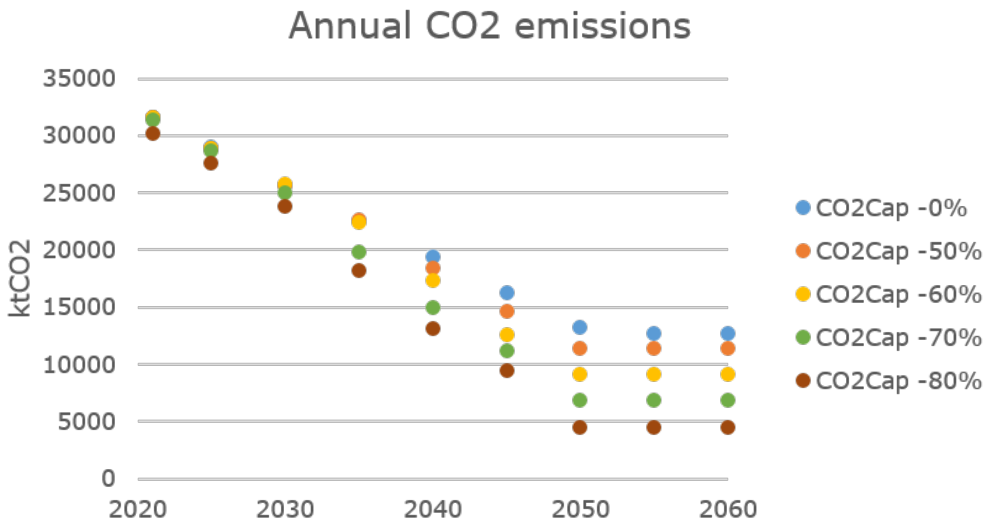

Figure 4: Carbon dioxide emissions from the energy sector under emissions reduction targets for 2050.

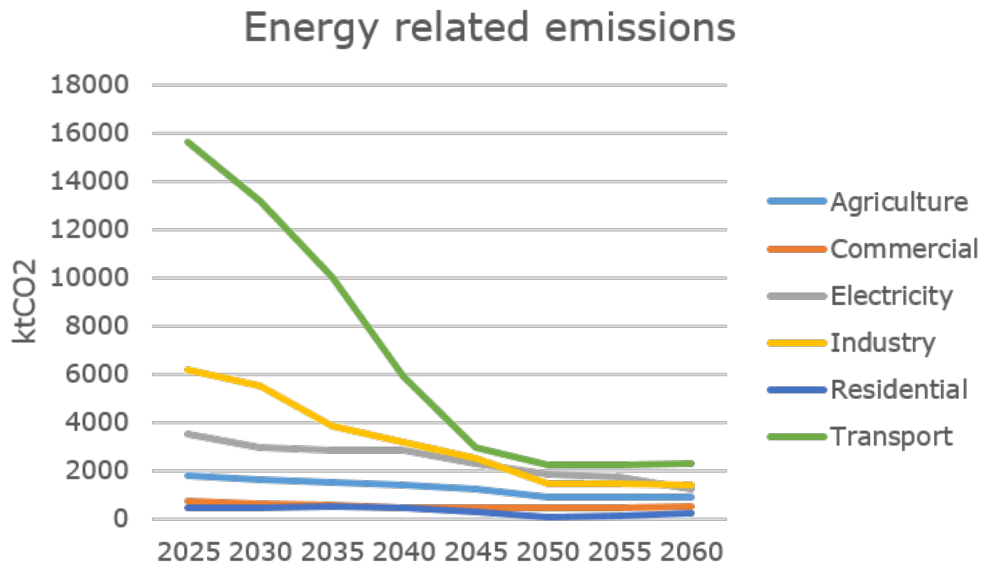

Figure 5: Energy-related carbon dioxide emissions by sector under the 80% emissions reduction targets for 2050, without climate change impact.

that the significant shifts occur in the transport and industrial sectors.

Figure 7 shows the demands for the transport sector fuels mostly affected by the carbon cap targets, for 2018, 2030 and 2050. Petrol is phased out before 2050 even without a carbon reduction target. The shift as the carbon target becomes more stringent occurs in the use of diesel and electricity, with parts of the heavy duty vehicle fleet, namely buses and medium size trucks, transitioning to electric drive trains.

Figure 8 shows the demands for the industrial fuels mostly affected by the carbon cap targets, for 2018, 2030 and 2050. There are two drivers for the shifts here: (1) overall reduction in energy demand as a downward trend is expected in this sector over the next decades, and (2) a shift from the use of coal and natural gas to electricity as the carbon target becomes more stringent, particularly at a target above 70% carbon emissions reduction. However, we note that industrial sectors are modelled through aggregated fuel demands, rather than technologies; hence, the opportunity to decarbonise comes simply from limited fuel switching, rather than technological transformation. More detailed modelling of industrial subsectors remains for future research.

4.2.3. Cost of decarbonisation

The cost of decarbonisation is calculated from the difference in total system costs and total emissions reductions between scenarios. Figure 9 gives the average cost of decarbonisation to reach different emissions reduction targets (x-axis) at different discount rates. This shows how the cost varies significantly depending on the choice of discount rate. The dispersed average cost of decarbonisation subject to different discount rates is evident when emissions reduction targets are higher, specifically exceeding 140 MtCO2.

For further examination, we select scenarios for a discount rate of 5%, the discount rate recommended for renewable energy projects by New Zealand Treasury. Figure 10 gives the average and marginal costs of decarbonisation per tonne carbon dioxide (tCO_2) for different levels of decarbonisation from 1990 emissions levels, and with (RCP8.5) and without (no RCP) the impact of climate change on the hydro resources. The costs of decarbonisation are also presented numerically in Table 3. While the average cost increases to just under 30 NZD/tCO_2, over the increasing emissions reduction targets, the marginal cost increases more steeply to over 85 NZD/tCO_2 as the target increases. The first visible leap in marginal costs, going from 65% to 70% emissions' reduction, comes from a shift from diesel to battery-electric drive-

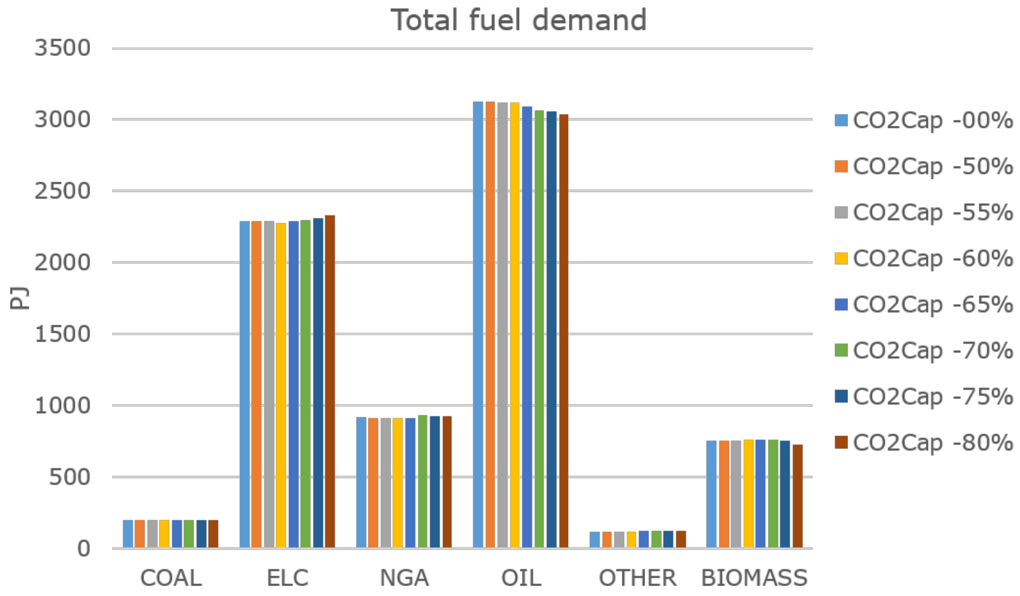

Figure 6: Shift in total fuel demand as carbon emissions reduction target is increased. The results are very similar with and without the climate change impact (RCP8.5). ELC stands for electricity and NGA for natural gas.

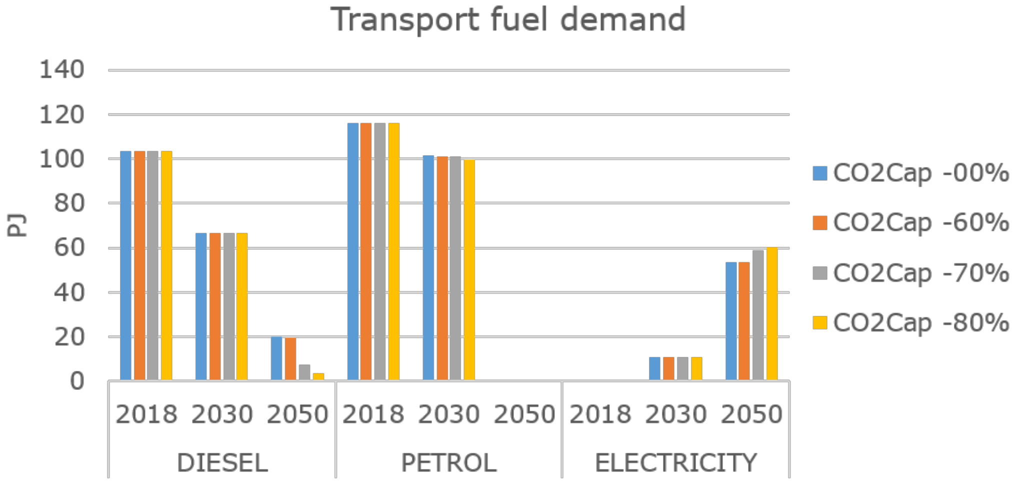

Figure 7: Transport sector annual fuel demands for different carbon emission reduction targets over time.

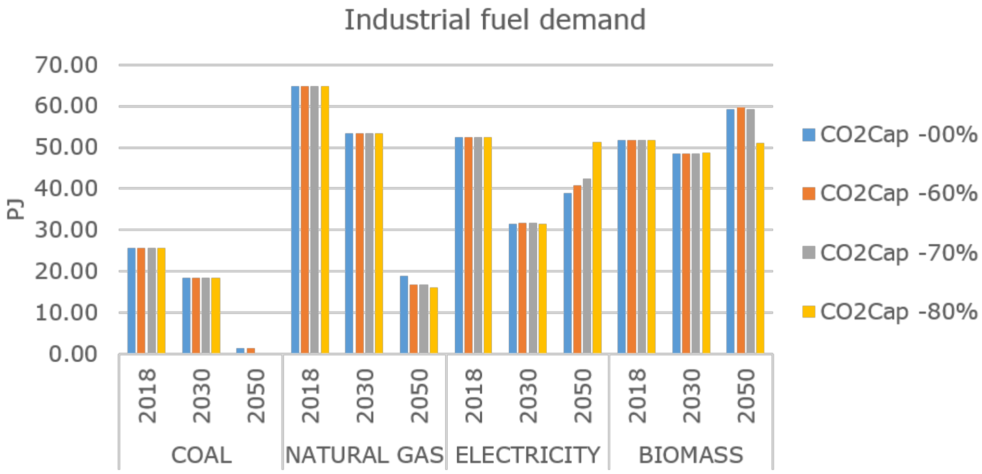

Figure 8: Industry sector annual fuel demands for different carbon emission reduction targets over time.

trains in buses and medium sized trucks. The second visible leap, going from 75% to 80%, comes from a shift from biomass to electricity in the industrial sector. Due to the fuel-based modelling of the industrial sector, we recognise that the step from 75% to 80% may be under-estimated, as the capital costs permitting those fuel switches are not included. However, we note that decarbonisation at this level is becoming increasingly costly as we have exhausted the most cost-effective options, and the need for more detailed modelling of technological solutions to take us beyond the 80% target becomes evident.

5. Discussion and conclusions

Climate change will not only have a direct impact on renewable energy resources, but these changes will in turn also have an impact on the optimal decarbonisation strategies. This paper explored the impact of climate change on the hydro resource in a hydro based energy system. In this case seasonal variability is amplified, leading to an increase in hydro availability in winter, when demand is high, and a decrease in hydro availability in summer, when demand is relatively low. The increase in winter leads to a decrease on fossil fuel reliance in winter, while the decreased availability in summer leads to an increase in solar capacity. We also observed a shift from wind generation capacity to solar capacity as the impact of climate change increased.

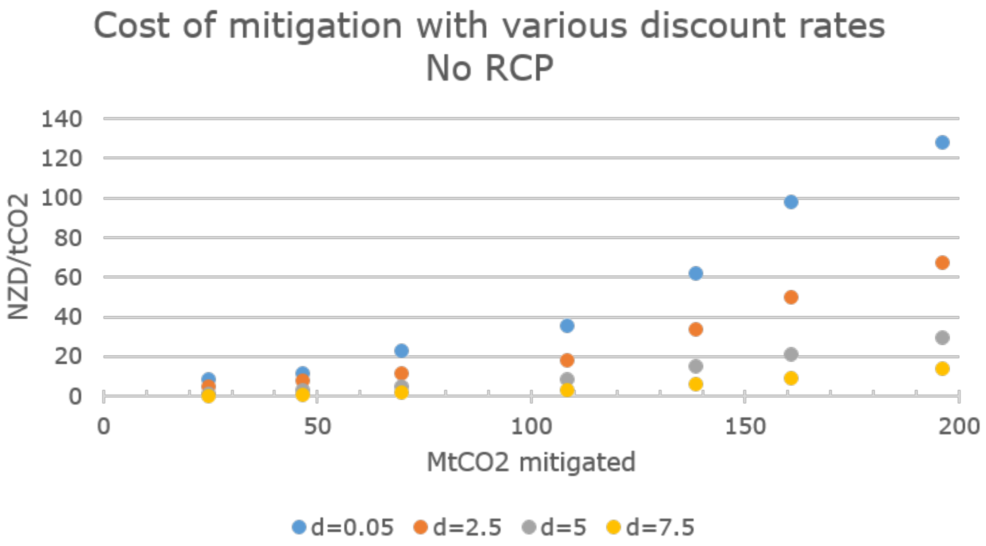

Figure 9: Cost of decarbonisation at different levels of emission targets and discount rates (d): d=0.05%, d=2.5%, d=5% and d=7.5%. No climate change impact has been included in these scenarios.

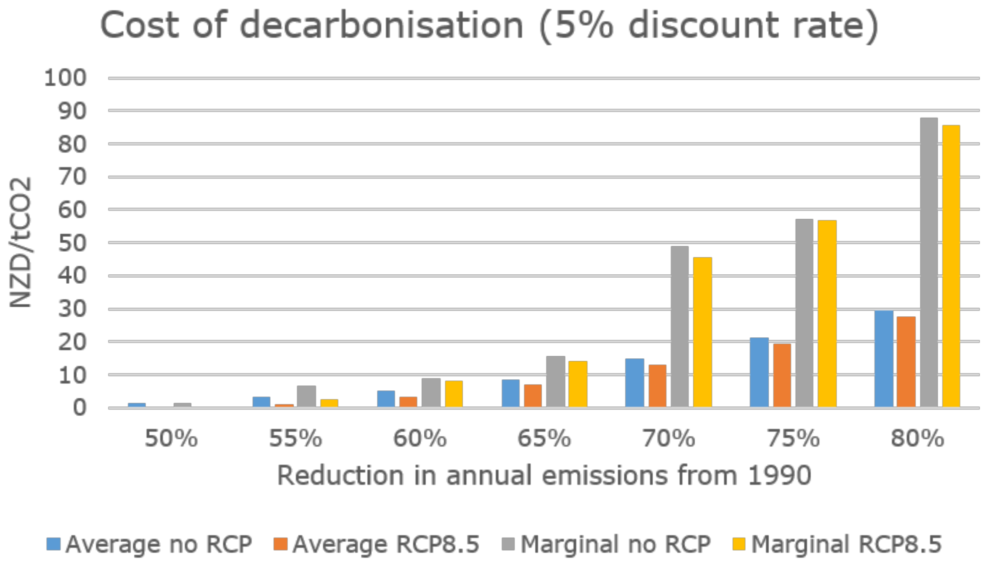

Figure 10: Average and marginal cost of decarbonisation with and without a RCP8.5 climate change impact on the hydro resource, at different levels of decarbonisation from 1990 emissions level.

Table 3: Average and marginal cost of decarbonisation (NZD/tCO_2).

	Average no RCP	Average RCP8.5	Marginal no RCP	Marginal RCP8.5
50%	1.46	0.31	1.46	0.31
55%	3.36	1.10	6.51	2.40
60%	5.14	3.42	8.79	8.16
65%	8.64	7.11	15.46	14.28
70%	15.01	13.15	49.05	45.42
75%	21.14	19.49	57.24	56.80
80%	29.45	27.74	87.87	85.75

There is no obvious contradiction between the shift in optimal generation capacity due to the seasonal climate change impact in the regions of New Zealand, as we could e.g. expect a decrease in precipitation to imply an increase in sunny days. However, the impact of climate change on other renewable resources, would need to be taken into account for further accuracy in future studies, particularly for resources that are set to play a major role in the energy system.

In addition, this paper investgated the impact of climate change on the cost of decarbonisation. This was explored through a range of decarbonisation scenarios, applied through an increasingly stringent carbon cap on annual emissions in 2050, with a reference year of 1990. The carbon price in the New Zealand Emissions Trading Scheme climbed to just under 40 NZD/tCO_2 in 2020. While the cost of decarbonisation is comparatively low on average, to reach an 80% emissions reduction target for the energy sector, the price would need to more than double to approximately 85-90 NZD/tCO_2.

The New Zealand government has set a net-zero energy emissions target by 2050. While our scenarios show feasible reductions all the way to an 80% reduction from 1990 emissions levels, we acknowledge that both technological improvements as well as carbon off-setting projects will be needed to reach the net-zero target. Decarbonising the last 20% of the energy emissions will require a more detailed study on future technologies; their performance characteristics as well as cost curves, which will remain a topic for future research.

It is also important to note that the energy sector typically consists of long-term, capital intensive investments, particularly on the supply side. This means that a transition will in reality take much longer than a model might imply. To avoid locking in the major part of investments over the short-to-medium term into an infrastructure choice that is not optimal for the long run welfare, governments could, for example, consider deploying large-scale infrastructure through public-private partnerships [65]. Hence, in addition to a strong carbon price, clear long-term policy is recommended to promote an effective transition towards a net zero energy future.

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