Potential benefits from large-scale flexible hydrogen production in New Zealand

Prepared for Meridian Energy and Contact Energy

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Executive Summary

Contact and Meridian are investigating the prospects for a green hydrogen production and export facility at Tiwai in Southland. As part of that investigation, Concept has been asked whether 'flexible' operation of such a facility (i.e. decreasing output at times of low hydro, wind, or solar generation and increasing it at times of surplus) could enable New Zealand to decarbonise more cost-effectively than alternative options.

To assess this, we have used our proprietary models of New Zealand's electricity system to examine likely outcomes from different decarbonisation options in two future years: 2030 and 2050.

In a nutshell: A flexible hydrogen production facility could be one of several lower-cost options for achieving broader economy-wide decarbonisation

The results indicate that a flexible hydrogen production facility could enable New Zealand to reach 100% renewable generation for those years. Further, depending on the cost of curtailing such demand at times of scarcity, it could potentially be one of the lower cost options for achieving this goal.

Other similarly lower cost options include:

- Continuing with the Tiwai aluminium smelter but investing in technology to enable it to operate in a similarly flexible manner. Whether continuing with aluminium production or developing hydrogen production would deliver greatest overall benefit for New Zealand will principally depend on non-electricity sector dynamics, particularly future world prices for aluminium and hydrogen and the extent of any price discount due to a varying production profile to provide electricity flexibility, and the extent of capital investment and non-fuel operating costs required. Such broader considerations are outside the scope of this study.
- Continuing with some limited amount of thermal peaking generation, either fuelled by fossil gas (resulting in a 99% renewable system) or by liquid biofuel. The extent to which these options are higher or lower cost than flexible hydrogen or aluminium production is driven by factors such as future fossil gas, biofuel, and carbon prices, and the opportunity cost of curtailing hydrogen or aluminium production to provide flexibility.

Higher cost options include:

- Solely relying on 'over-building' renewables – i.e. building wind and solar to the extent that there is significant spill at times of surplus in order to have just enough generation at times of scarcity. There is over-build in all the options as it is a low cost option to deliver much of New Zealand's flexibility requirements, but in this option the amount of over-build would need to be much greater.
- Maintaining the Huntly Rankine coal-fired station as strategic reserve to only operate during dry-year events.

The highest-cost option we examined is investing in a large South Island pumped storage facility.

In terms of emissions, there is relatively little difference between the options with regards to power generation emissions, but potentially some greater differences in whole-of-economy emissions:

- Power-generation emissions in 2030 are projected to fall to between 15% and 18% of 2020 levels. The 15% is due to geothermal generation which is the largest source of emissions in all future scenarios, with the extra 3% being the option with fossil gas peakers. In 2050 geothermal emissions are projected to rise by 1/3 compared to 2030 levels, while the option with fossil gas peakers projects emissions from such plant will almost halve.

- Differences in electricity price outcomes will drive potentially greater differences in whole-of-economy emissions, as options with lower consumer electricity prices will facilitate greater levels of fossil→electric fuel switching for transport, process heat, and space & water heating.

  Although not the principal focus of this analysis, our modelling indicates that those options which are best at balancing the increasingly variable renewable generation from wind & solar will deliver the lowest average wholesale electricity prices. These options include the most flexible hydrogen or aluminium operation, having some limited amount of peaking generation (either fossil gas or biofueled), or a large South Island pumped storage scheme.

  However, despite delivering relatively low wholesale prices, recovering the estimated $4bn cost of the pumped storage scheme means that this option is likely to deliver higher consumer electricity prices than many of the other options.

Digging deeper, we explain the key drivers behind these results

This analysis has helped shed light on some key issues and opportunities for New Zealand's power sector de-carbonisation challenge, and the extent to which the different options we have considered may help deliver cost-effective whole-of-economy decarbonisation.

New Zealand's changing flexibility challenge

The key insights into New Zealand's general power-sector decarbonisation challenge are:

- Reductions in wind & solar costs, combined with increases in carbon prices, mean that it is becoming economic to 'over-build' renewables to the extent that there is systemic spill during periods of renewable surplus in order to have 'just enough' during periods of renewable scarcity. This significantly reduces the need to call upon other flexibility resources to perform the flexibility duty that is currently performed by fossil generation.
- Projected significant increases in wind & solar generation to meet growing demand, combined with this renewable over-build, will radically change the nature of New Zealand's flexibility challenge:
  - Over-build will increasingly reduce the amount of resource required to meet year-to-year variations in hydro generation. i.e. we will still have a dry-year problem, but the size of the dry-year problem will become progressively less over time.
  - The significant increase in wind & solar generation with their much greater short-term volatility will give rise to greater need for flexibility resources that can operate over shorter durations: within-day and within-week. The ability to meet periods of low wind and solar generation that could last days or even weeks – so-called 'dunkelflaute' events[1] – will become steadily more and more a key driver of our flexibility requirements.

    Appendix A sets out the dynamics behind these changes in more detail.
- This reduction in dry-year requirements and increase in dunkelflaute requirements will change the type of response that will most cost-effectively meet our flexibility needs.
  - Our existing hydro fleet will be able to meet much of this challenge with altered within-day and within-week operations, but physical limitations (finite MW capacity, river chain dynamics, finite capacity to transfer South Island generation across the HVDC, and the requirement to maintain minimum river flows) will mean that hydro stations can't meet all this additional demand for short-term flex.

[1] "Dunkelflaute" is a German word which literally means "dark doldrums".

– Batteries (both static batteries and within electric vehicles) combined with demand-side response will also be able to meet much of the challenge for very short-term duration response. In doing so, they will radically reduce the need for very-infrequently used MW generating capacity, delivering significant economic savings (although not much GWh and associated carbon savings).

– Flexibility resources located in the North Island will deliver significantly greater benefit than equivalent resources located in the South Island. This is because:

  ◦ there is limited transmission capacity between the North and the South islands, and

  ◦ most of the wind & solar development will be in the North Island due to most of the demand growth occurring in the North Island and the fact that the fossil thermal generation that is due to exit is all located in the North Island.

Relative merits of the options to meet this flexibility challenge

These dynamics explain the relative merits of the different options our modelling has explored:

- Despite being located in the South Island (and thereby having its flexibility contribution to meet North Island dunkelflaute events constrained at times)[2], large-scale flexible demand from a hydrogen production facility or the aluminium smelter could be low-cost options because

  – they don't have any significant capital cost requirements that must be recovered from the electricity market – the cost of the hydrogen production facility or the smelter should be recovered by the sales of hydrogen or aluminium; and

  – the size of their potential response is large relative to the NZ system.

  However, the extent to which these could be lower cost solutions is heavily dependent on their ability to flexibly reduce production without incurring significant costs, including for sustained periods of time. If the opportunity cost of curtailing production of hydrogen or aluminium to deliver electricity flexibility is greater than the assumptions we have used, the scale of benefit we have modelled would be less (and vice versa). We note there is significant uncertainty over this issue of curtailment opportunity costs, and consider this to be a key issue for further analysis.

- North Island peaking thermal generation run infrequently at times of significant scarcity can be a very cost-effective means of meeting the relatively small residual demand for flexibility that isn't provided by renewable over-build.

  – The very high running costs of thermal peakers (either due to fossil gas facing a high carbon price, or biofuel being inherently high cost) is more than outweighed by the benefit of the low capital costs of such options. This is particularly true given that in most cases the peaking plant already exist, so their capital costs have been sunk (at least for the next few decades).

  – Further, the North Island location of such peakers will reduce the extent to which high-cost batteries will be needed for periods of extreme scarcity.

  However, we note that the green peaker option faces material uncertainty regarding the cost and practicality of producing and storing sufficient biofuel to provide flexibility.

[2] Our modelling has been potentially optimistic to South Island options as it assumes the HVDC interconnector between the islands can operate at 1,400 MW in all scenarios. This is materially greater than the currently observed maximum north-flow of about 1,000 MW, and effectively assumes a cable upgrade plus a change to the arrangements for the procurement of instantaneous reserves to cover the risk of the failure of one of the two HVDC 'poles'.

The fossil gas peaker option faces far less technical uncertainty. For example, the carbon price required for the cost of electricity to be the same as that assumed for the green peaker is approximately $550/t$CO_2$. This price is substantially higher than most projections, and yet it would deliver an equivalent level of benefit to the green peaker option – which itself is lower cost than the Coal reserve, Overbuild, and SI Pumped Hydro options.

Another key advantage of the thermal peaking options is that they are more readily deployed incrementally, and thus would not result in the adverse outcomes associated with 'mega projects' detailed below.

- While a large pumped-storage scheme in the South Island would provide a lot of flexibility for the system, it appears likely that it would come with a significant additional cost. If these costs are recovered from electricity consumers (via a levy or market-mechanism) that could result in higher whole-of-economy emissions, even though this is a 100% renewable option. As noted by the Climate Change Commission, this is because higher electricity prices could frustrate electric vehicle uptake and electrification of space & water heating and industrial process heat.

  As with flexible hydrogen/aluminium production, its South Island location will make it less effective at meeting North Island dunkelflaute events.

  The 25% round-trip efficiency losses associated with pumping will tend to reduce the benefit of its renewable balancing effectiveness.

  Lastly, it is likely that this option would take the longest to develop (most of the other options already exist or, in the case of the hydrogen production facility, could be developed several years earlier than a large-scale South Island pumped hydro scheme), and give rise to the greatest adverse outcomes associated with 'mega projects'.

Potential issues with 'mega projects'

Options which are large relative to the size of the system and cannot be readily broken into smaller components create special challenges in the years leading up to their commissioning. This is because, upon commissioning, the system will suddenly switch into being in a situation of major surplus relative to the period prior to commissioning.

This may tend to suppress investment in renewable generation in the years immediately prior to the mega project's commissioning, as such renewable generation will be less able to cover its costs in a market which is in surplus after the mega project's commissioning.

In the years immediately prior to the mega project's commissioning, the consequences are likely to be:

- Higher prices; and
- Higher levels of fossil generation.

An example of this dynamic is the uncertainty experienced over the last few years as to whether the Tiwai aluminium smelter would exit and cause the system to switch to a situation of major surplus with the loss of 13% of New Zealand's demand. This uncertainty has caused lower investment in new renewable generation over the past few years, resulting in the system being short of generation once the aluminium smelter's contract was extended – albeit for four years and creating a new "will it stay or go?" uncertainty horizon.

The larger and lumpier the project, the more significant the effect is likely to be on outcomes. Of the options we have considered, the pumped-storage scheme is likely to be most challenging. This is because it is largest in size and because it has the additional challenge of significantly increasing demand in the year or two prior to its commissioning when it is being filled. This filling dynamic will further exacerbate the relative change in the supply/demand balance upon its commissioning.

These adverse effects will vary according to underlying levels of demand growth and associated generation build. If demand growth is high the change in supply/demand balance (and associated adverse outcomes) upon the mega-project's commissioning will not be as great or sustained compared to if demand growth is low. Similarly, if a mega project can be broken into components and staged over time that would reduce the transition challenge.

It was beyond the scope of this study to try and quantify these potential mega-project effects for the different scenarios.

1 Introduction

Contact and Meridian are jointly investigating the potential for a green hydrogen production and export facility at Tiwai - a key purpose being to make use of the surplus electricity generation and transmission capability if / when the Tiwai aluminium smelter exits at the end of 2024.

In evaluating the facility's potential costs and benefits, one significant point of focus is the extent to which flexible production of hydrogen may materially lower the electricity input costs of hydrogen production and, in doing so, enable the New Zealand electricity system to more easily move towards 100% renewable generation.

To help evaluate this, Contact and Meridian have asked Concept to use its electricity system models to determine the extent to which such a facility could enable the New Zealand electricity system to move towards 100% renewable generation, and how the economic and emissions outcomes are likely to compare to alternative options.

This comparison with alternatives is because a range of options are being considered by government for decarbonising our energy system, and some are likely to be mutually exclusive to each other. For example, if electricity decarbonisation is largely achieved through development of a major pumped storage facility there would be little or no benefit from flexible operation of a hydrogen facility. Similarly, if the Tiwai smelter doesn't close in 2024 but instead had investment to enable much more flexible operation, there would be limited opportunity to develop a hydrogen facility.

Accordingly, our analysis has considered the costs and benefits of a flexible hydrogen facility relative to the key alternatives being considered for energy sector decarbonisation.

As well as helping consideration of the prospects for a hydrogen production facility specifically, this analysis of a range of alternatives is also intended to contribute to the broader public and policy debate about which options which are likely to be best at helping meet New Zealand's decarbonisation challenge.

2 Methodology and assumptions

2.1 Modelling methodology

We have used our proprietary electricity system models to evaluate the extent to which a large-scale hydrogen production facility which is operated flexibly – i.e. reducing demand at times of system scarcity and increasing demand at times of surplus – could help New Zealand achieve 100% renewables by 2030.

To do this, we have compared the total electricity system costs for a range of scenarios:

- ***Continuing with some fossil generation*** to help meet New Zealand's flexibility requirements, but with the level of fossil generation being much smaller than today. i.e. achieving close to 99% renewable generation (depending on the scenario), compared to the approximately 83% achieved today.[3] Two sub-options have been assessed:
  - *Fossil-gas-fired peakers*, using open-cycle gas turbines (OCGTs)
  - *Coal-fired generation at Huntly*, using three of the Rankine units
- Development of a large ***South Island pumped storage*** scheme. We have evaluated a potential scheme with 5 TWh of storage and 800 MW of generating capacity.
- Using '***green peakers***' to meet New Zealand's flexibility needs. This option involves building or re-configuring existing OCGTs to burn biofuel
- ***Flexible operation of the Tiwai aluminium smelter*** – i.e. in fundamentally the same way as the proposed hydrogen production facility.
- Solely relying on ***overbuilding renewables***. All the above options will have some over-build of renewables, with the extent of such overbuild being driven by the relative economics of the different options. In this option the extent of renewable overbuild will be much greater.

In all our scenarios we assume that the 2% of existing generation from fossil cogeneration will have been retired due to the 100% renewable generation policy.[4]

For each scenario option our modelling determines the least-cost mix of additional renewable generation plant and shorter-term storage batteries to meet projected demand. Electricity supply costs are assessed from a national economic perspective – i.e. we look for the mix that is lowest cost for society as a whole. This least-cost evaluation effectively trades-off:

- the increasing costs of building progressively more renewable generation and batteries; versus
- the progressive reduction in fossil generation costs (fuel, carbon, and station costs) and demand curtailment costs

This trade-off results in the classic 'bathtub' representation of total system costs as represented in Figure 1 below. As the amount of new renewable generation and batteries increases, the cost of supply rises (shown in blue). Conversely, with more supply resources on the system the cost of demand curtailment and any fossil generation decreases (shown in red). Adding the two curves together gives the total system cost which has the bathtub shape (shown in green).

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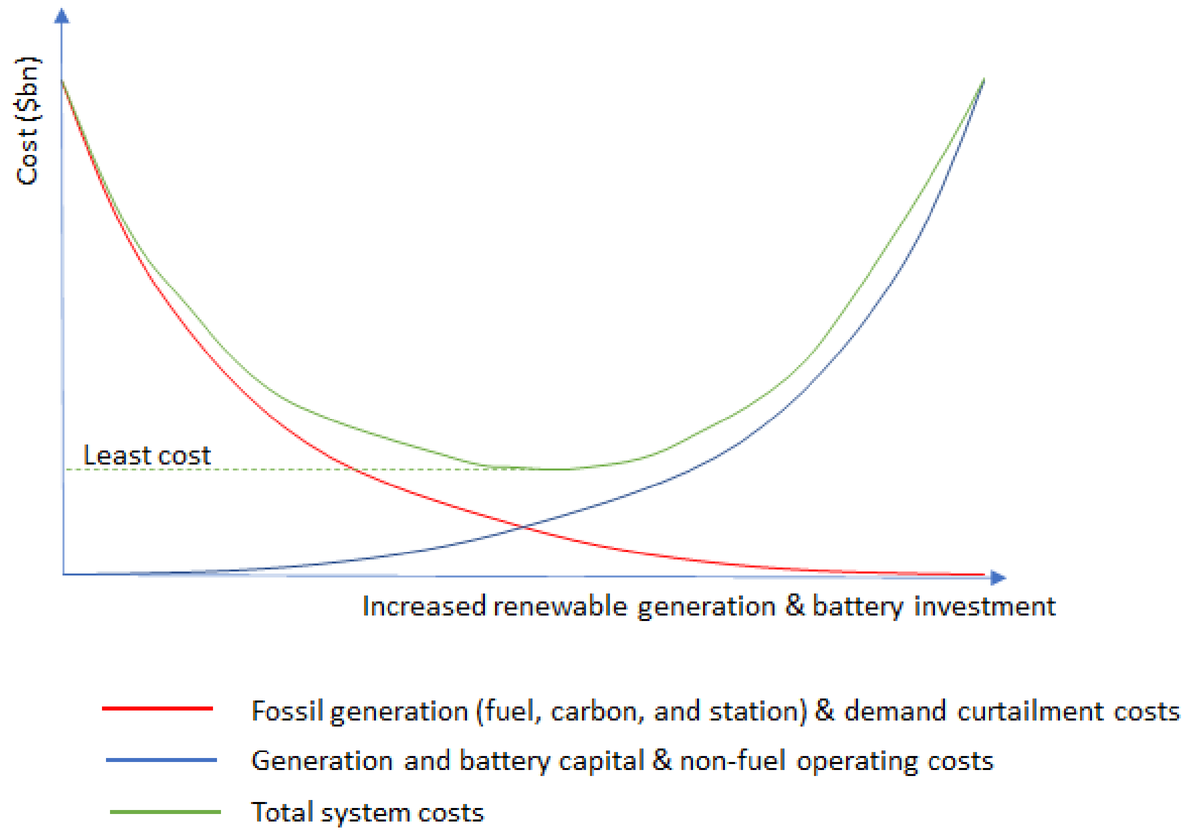
[3] We have excluded the 2% of current generation from fossil cogeneration from these % renewable numbers.

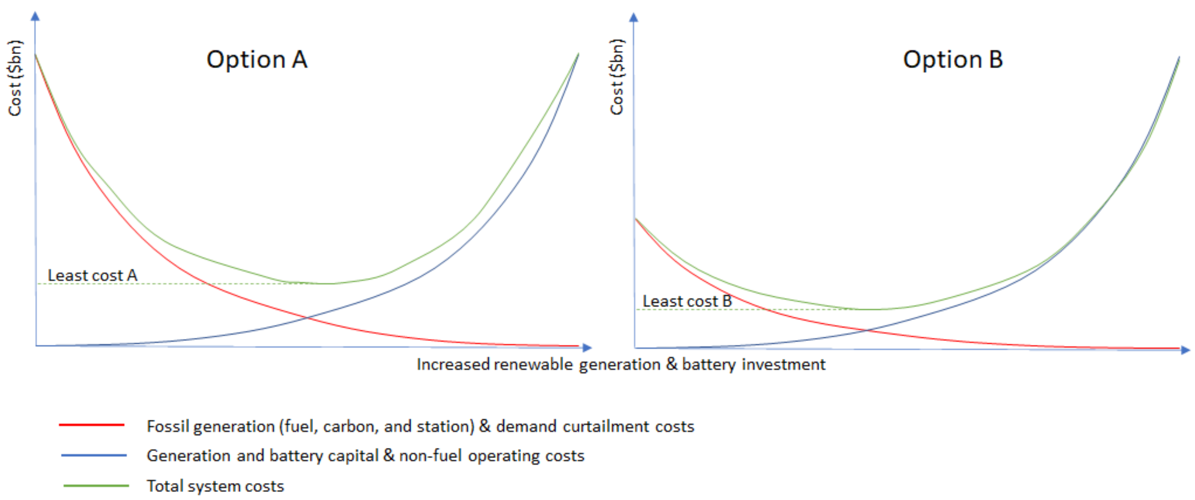
[4] We retire fossil cogen in the two scenarios with fossil generation in order to make like-for-like comparisons of system costs and emissions between the different options.

Figure 1: Illustration of electricity system costs trade-off[5]



The least-cost mix of energy resources will vary between scenarios. For example, Figure 2 below illustrates two different scenario options, A and B, with option B having access to a significant amount of lower-cost demand curtailment. As can be seen, the lowest system cost is different between the two scenarios, with option B also requiring less renewable generation and battery investment.

Figure 2: Illustration of different generation cost trade-offs between two scenarios



[5] The single "increased renewable generation and battery investment" axis is a simplification. The model optimizes across many different investment dimensions, leading to a multi-dimensional surface. The optimal system is the low point on this surface.

Our analysis performs this least-cost evaluation for all the scenario options, enabling the total system costs for the different options to be compared. Crucially, in performing this analysis we take account of the dynamics of the New Zealand electricity system.

Thus, our approach is as follows:

1) For a given scenario option for a given future year, we 'plant' the system with a trial mix of renewable generation and batteries
2) We model how that system would operate over that future year in terms of generation called upon and demand curtailment required, and subsequent system costs.
   - We use a hydro-thermal dispatch model which simulates the storage and release decisions of the various hydro reservoirs in the New Zealand system progressively over the course of the year.
   - We model numerous different "environmental years" to account for different possible outcomes during the modelled year:
     - To account for potential variation in hydro inflows, we include 1990-2017 hydro inflow sequences for New Zealand's hydro schemes. This historical inflow data is at a daily level of resolution.
     - To account for the variability of wind and solar, we include historical wind speed and insolation "inflows" for 1990-2017 and 1990-2014 respectively for 6 different locations around the country. This historical data is at an hourly level of resolution.
     - The GWh total amount of demand is held constant between environmental years, but the *shape* within the year varies for each hour based on the demand shape observed during 1990-2017.
     - Where possible, historical years for each input are matched to the corresponding historical year for other inputs. This captures any correlation between the different effects. When this is not possible, the input series is repeated from an alternative year.
   - The model accounts for the key transmission constraint between the North and the South islands, as well as accounting for transmission losses and the need to maintain reserves.
   - The model solves at an hourly resolution, in daily steps. For each day it operates a two stage solve process to account for on-the-day errors in forecasting. The system is first dispatched based on an inaccurate forecast, then the level for some less responsive or storage constrained resources are fixed (batteries, some hydro releases and, although not relevant for this modelling, baseload thermal). The model then re-dispatches more flexible resources on the system based on an accurate forecast. This approach rewards more flexible resources and accounts for the costs of forecast uncertainty as increasing quantities of wind and solar are developed.
3) We progressively repeat the modelling for a given scenario option with different 'planting' mixes of generation and batteries in order to plot out points along the total system cost bathtub curve
4) We identify the least-cost mix of generation and batteries for the scenario option
5) We repeat the above process for all the different scenario options.

Due to the significant computational effort associated with this analysis, it is not practicable to do this analysis for every year in the future. Instead, we have performed this analysis for two future years: 2030 and 2050.

This allows computational effort to be focussed on analysing a greater number of scenarios, whilst also exploring the implications of the significant changes that are likely to occur over the space of a couple of decades.

In particular, electricity demand in 2050 is projected to be significantly greater than in 2030 driven by the electrification of transport and some fossil-fuelled heating for homes and businesses. This increased electricity demand will need to be met by increased renewable generation development, particularly geothermal, wind, and solar.

We have chosen 2030 for the earlier sample year for this analysis as:

- It is the year which has currently been chosen by the government for its target to achieve 100% renewable electricity generation; and
- It is the earliest practicable year for development of a major South Island pumped storage scheme.

2.2 Common assumptions across scenarios

In order to compare outcomes for the scenario options on a like-for-like basis, we use a core set of assumptions that are common across all scenarios:

- ***The level and composition of demand in 2030 and 2050***. The projections have significant demand growth due to a combination of:
  - progressive electrification of transport, space & water heating, and some industrial process heat
  - general population and GDP growth.

  Overall, the demand for generation (which takes account of transmission and distribution losses) rises from just under 43 TWh in 2020 to 49 TWh in 2030 and 65 TWh in 2050.

  The modelling of the within-year and within-day shape varies between four main types of demand:

  1. General demand. This has the current non-Tiwai demand shape.
  2. Electric vehicles. This has a flat within-year demand profile, but is dispatched within-day by the model (to a limited degree) to account for smart charging. 2.5 TWh of EV demand was assumed by 2030, rising to 8 TWh in 2050.
  3. Baseload. This is a completely flat demand profile. It represents industrial processes (other than Dairy) or similar.
  4. Dairy. This is a seasonal load profile that is higher in spring to account for dairy processing, but which has a flat within-day profile.

  Although demand assumptions are common to all scenarios, the exception is with regards to the scenarios with the flexible hydrogen production / aluminium smelter operation. In these scenarios the demand from such facilities is flexible, responding to market price as set out below in section 2.3.1, but in the other scenarios there is an equivalent level of demand (572 MW – corresponding to the main three aluminium smelter potlines) which is held constant.

- ***The level of future geothermal development***. This reflects the fact that the extent of future geothermal development is likely to be limited by resource limitations rather than uncertainty over demand growth. This is based on the quantity of geothermal available by 2030 and 2050 in "Future geothermal generation stack" report prepared for MBIE. We assume that geothermal will be built up to the amount available in all scenarios.

- ***The level of rooftop solar development***. We project significant uptake of rooftop solar driven by non-price factors and artificial incentives caused by (currently) non-cost-reflective consumer electricity prices.
- ***The carbon prices faced by the sector***. The carbon prices are consistent with the Climate Change Commission estimates projected to be required to achieve New Zealand's net-zero target in its Demonstration Path scenario. These prices are:
  - $138/t$CO_2$ in 2030; and
  - $250/t$CO_2$ in 2050.
- ***The extent of future cost reductions for wind, solar, and batteries***. We assume the levelised cost of energy (LCOE) for wind drops from today's value of approximately $70/MWh to 55 $/MWh in 2030 and then 52.3 $/MWh in 2050. For solar we assume 62 $/MWh in 2030 dropping to 55 $/MWh in 2050. Batteries are assumed to have four hours of storage, and drop from 1,000 $/kW in 2030 to 800 $/kW in 2050. (all $ are real 2021 values).
- ***The cost and quantity available of various forms of general demand response*** – i.e. not from a flexible hydrogen production facility or flexible aluminium smelter. This varies with level of demand and has numerous tranches priced from 700 $/MWh to 20,000 $/MWh.

  However, while the quantity of general demand response which is *available* is common across all scenarios, the amount of demand response that is called upon varies between scenario based on the least-cost optimisation process. For example, an option which has greater availability of low-cost flexibility resources will have less need to call upon demand response.
- ***The amount of hydro generation available***. There are no significant additions to New Zealand's hydro fleet in all scenarios. However, while the fleet is common across all scenarios, the operation of the fleet in each scenario can vary as variations in the extent to which wind and solar is developed, or additional flexibility resources are available (e.g. pumped storage or large-scale flexible demand) will affect the optimal pattern of hydro reservoir storage and release.

2.3 Scenario-specific assumptions

In addition to these common assumptions, there are assumptions specific to each of the scenario options.

2.3.1 Large scale demand response from a hydrogen production facility or the Tiwai aluminium smelter

The key assumptions for these demand-response options relate to how demand will progressively curtail during periods of tight supply. This will be driven by the opportunity cost of curtailing demand, i.e. the cost of foregone hydrogen or aluminium sales. These costs will be driven by factors such as the market price of such commodities. There may also be some physical constraints on how quickly such plant can turn on or off.

There is material uncertainty over both the opportunity-cost-driven prices at which it would be economic to curtail demand from such facilities, and the extent to which physical constraints may affect plant operations. Given such uncertainties, we have modelled three different scenarios for how demand would be curtailed for such a large-scale plant using demand-response prices provided by Meridian.

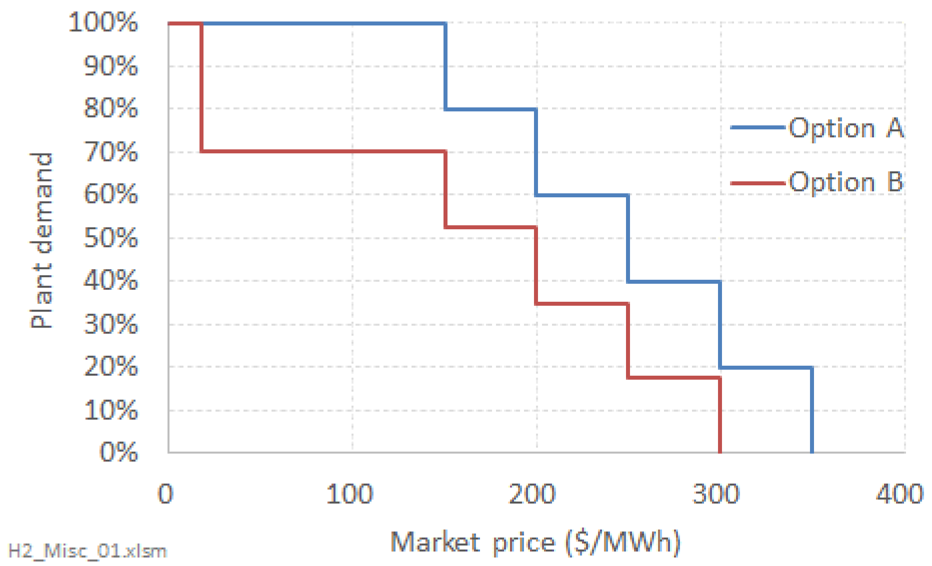
Firstly, we model two different pricing options:

- Option A reflects a pattern of operation where the plant will be operational for most of the time, but only start to curtail demand at times of tight supply. Demand is progressively curtailed in five tranches of 20% of plant output, with the first tranche curtailing when prices rise above $150/MWh, with the threshold price for each subsequent tranche increasing by $50/MWh.

- Option B reflects a pattern of operation where 70% of the plant operates in a fashion similar to option A, with curtailment above $150/MWh happening in four tranches of 17.5% of capacity. However, the remaining 30% of the plant's capacity only operates at times of significant system surplus, once market prices fall below $17.5/MWh.

This pattern of operation is illustrated in Figure 3 below.

Figure 3: Demand curtailment offer curves for large-scale flexible hydrogen or aluminium production



Both pricing options are modelled for plants which are assumed to have the flexibility to turn on or off on an hour-by-hour basis.

In addition, we run a third scenario which uses Option A pricing, but assumes that the plants can only turn on or off on a daily basis – with the scheduling decision made at midnight.

From an electricity system costs perspective, there is no difference as to whether this flexibility is delivered by a 572 MW aluminium smelter at Tiwai, or a 572 MW hydrogen production facility at Tiwai.

Further, while we treat the costs of demand curtailment as represented by Figure 3 as economic costs for delivering flexibility, the capital and fixed operating costs of the aluminium or hydrogen plants are not relevant considerations for the whole-of-New Zealand cost perspective as such costs are constant and are assumed to be recovered from the sale of hydrogen or aluminium (otherwise, the plants would not exist).

Having said that, there may be some incremental costs in addition to the demand response costs assumed above. In particular for the aluminium smelter option there may be some additional capital costs for investing in the technology to enable flexible operation. One option for this could be the 'EnPot' technology developed by Energia Potior.[6] Based on information provided by Meridian, we understand the scale of this investment could be of the order of $100m giving rise to roughly $15m/yr capital recovery requirement.

[6] For more details see https://www.energiapotior.com/

Lastly, while we note there is significant uncertainty about the cost of demand curtailment for aluminium and hydrogen production, we believe the above values are potentially conservative estimates – ie, the curtailment cost is likely to be lower. This is based on:

- Analysis of the netback for aluminium smelting for different historical aluminium prices, alumina prices and exchange rates, which indicates break-even electricity prices in the range $25-125/MWh
- The recent McKinsey analysis of the potential for hydrogen export which indicates that it would not be competitive to produce hydrogen at the prices indicated in the curtailment offer curves shown in Figure 3.[7]

2.3.2 Fossil gas-fired peakers

In this scenario, existing open-cycle gas turbine (OCGT) peakers are retained, and new ones developed as required, and fuelled from fossil gas.

The extent of OCGTs retained / developed is determined from the least-cost optimisation process of our modelling which is driven by the relative economics of using OCGTs to provide flexibility versus:

- Overbuilding renewables;
- Building batteries; and
- Using voluntary demand curtailment.

The costs of such plant include:

- Any capital costs for OCGTs that need to be built. We assume that almost half the existing OCGTs will have been retired due to old age by 2050, meaning that some of the OCGT capacity in 2050 will have come from new-build.
- Gas costs of $12.6/GJ in 2030 and $13.0/GJ in 2050, factored by the assumed heat rate (the efficiency of the stations) of 9.5 GJ/MWh. The relatively high gas prices compared to long-run average wholesale gas prices is due to the flexibility premium (referred to as ‘swing’ premium in the gas industry) of providing such gas very infrequently.
- Carbon costs based on the carbon price, factored by the emissions intensity of gas (0.053 tCO2/GJ) and the heat rate
- Fixed operating & maintenance (FOM) costs of $35/kW/yr.
- Non-fuel variable operating & maintenance (VOM) costs of $10/MWh.

2.3.3 Coal reserve

In this option, three coal-fired Rankine units at the Huntly power station, comprising 750 MW of total capacity, are retained and are only operated when South Island lake levels fall below a trigger threshold (corresponding to the $300/MWh water value curve).

The costs of this option include:

- Coal fuel costs of $8.3/GJ in 2030 and $8.6/GJ in 2050, factored by the heat rate of 10.5 GJ/MWh. As with gas prices, a material element of the coal price is associated with providing coal for low capacity-factor duties.
- Carbon costs based on the carbon price, factored by the coal emissions factor of 0.095 tCO2/GJ and the plant heat rate

[7] See: https://www.datocms-assets.com/49051/1626295071-the-nz-hydrogen-opportunity.pdf

- Fixed operating & maintenance costs of $85/kW/yr. This higher fixed O&M requirement compared to OCGTs reflects the higher stay-in-business capex associated with this aging plant.
- Non-fuel variable operating & maintenance of $20/MWh.

2.3.4 Development of a South Island pumped-storage facility

This is one of the options that the government is exploring for helping move to 100% renewable generation.

While there are a variety of possible configurations in terms of storage reservoir size and generating capacity, we have chosen a single option for consideration, being:

- 5 TWh of storage; and
- 800 MW of generating capacity.

The scheme operates like a giant battery pumping water up into the storage reservoir at times of system surplus, in order for it to be released for generation at times of tight supply.

The model optimises the decisions for how much to pump and generate using a similar water value approach to that used for the storage and release decisions for the conventional hydro reservoirs.

The costs of this scheme include:

- Efficiency losses from the energy used in pumping the water up to the storage reservoir. Total round-trip efficiency is assumed to be 75%.
- The capital and non-fuel fixed operating & maintenance costs of the scheme. There is some uncertainty over this. We have assumed the construction cost is $4bn for the analysis, being the current estimate from MBIE for the Onslow pumped storage project.[8] We have assumed it will take five years to construct, a further two years to fill to an operational level (at a cost of $200m), with the capital costs recovered over a 60-year period using a 6% pre-tax, real cost of capital, and that the ongoing non-fuel operating & maintenance costs of the scheme will be equivalent to 0.35% of the original capital cost. This gives an overall annual capital + fixed cost recovery requirement of approximately $335m.

2.3.5 Green peakers

This option is similar to the fossil peakers option, except that instead of fossil gas costing $10/GJ, the fuel is a biofuel costing $42/GJ but which has a zero emissions factor.

The $42/GJ is based on analysis undertaken by Scion in its Biofuels roadmap, and assumes the feedstock for the biofuel are pulp logs priced at $115/t.

However, if there would be a need for significant on-site storage of bio-diesel (as discussed later in section 3.5), the biodiesel costs for a green peaker could be 60% greater than the cost of production from a bio-refinery. If this were the case, the $42/GJ price implies a pulp log price of approximately $70/t.

For reference, the price of pulp logs consumed in the domestic market is about $50/t, whereas export pulp logs have averaged around $120/t over recent years.

The other station costs (capital and O&M) are the same as in the fossil peakers option, but the quantity of green peakers is different to that of the fossil peakers option, as they are each determined by the least-cost planting optimisation process.

[8] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/low-emissions-economy/nz-battery/lake-onslow-option/

2.3.6 Summary of options

Table 1: Flexibility options modelled

Name	Description	100% renewables?
Fossil gas peaker	Fossil-gas fired OCGTs	N
Green peaker	Biofuel-fired OCGTs	Y
Coal reserve	Huntly Rankine coal stations operating only when lakes are low	N
Overbuild	Flexibility solely met by overbuilding renewables and batteries	Y
H2/Al Flex - Daily A	Flexible large-scale demand, turning down when prices are high on a day-to-day basis	Y
H2/Al Flex - Hrly A	Flexible large-scale demand, turning down when prices are high on an hour-by-hour basis	Y
H2/Al Flex - Hrly B	Flexible large-scale demand. 70% turning down when prices are high on an hour-by-hour basis, but 30% only turning on when prices are very low	Y
SI Pumped hydro	5 TWh / 800 MW South Island pumped storage scheme	Y

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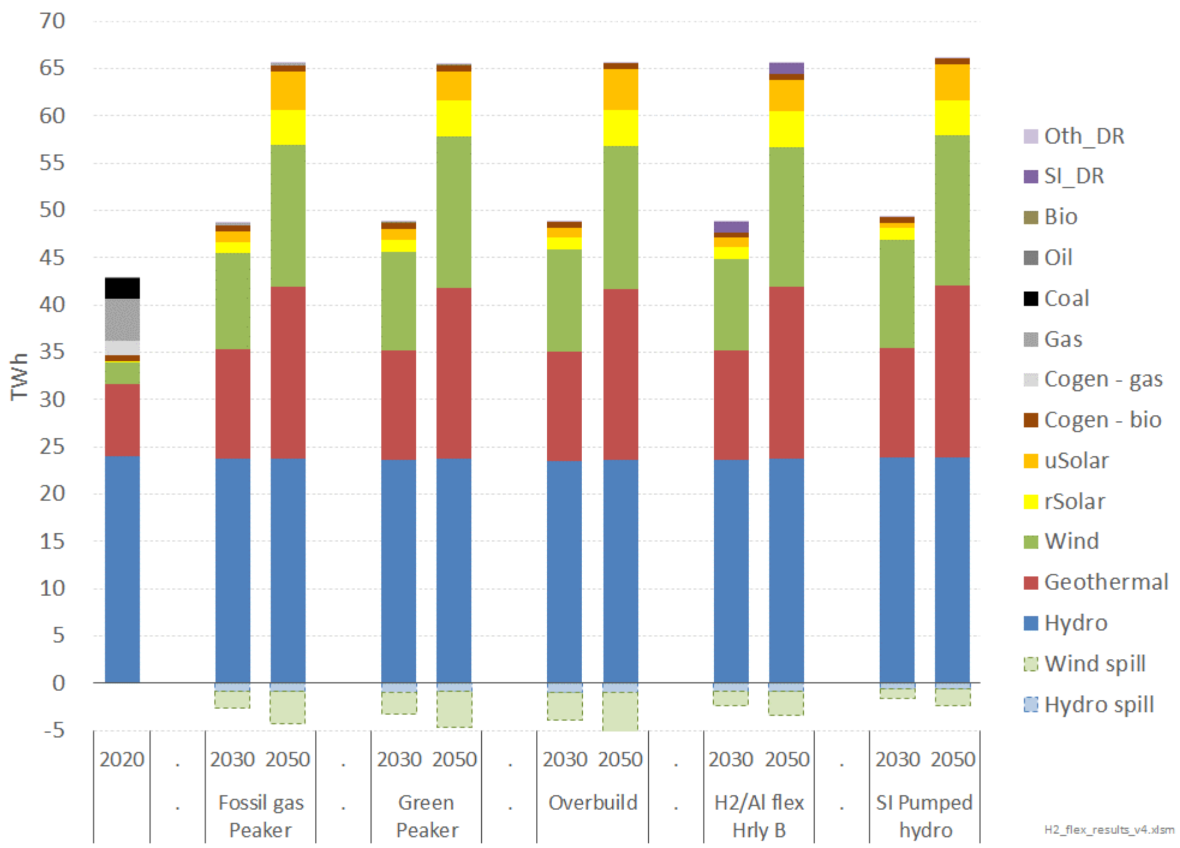
3 Results

3.1 Projected generation

In terms of general TWh levels of generation, there are similar outcomes between the scenarios. Figure 4 shows the projected TWh of generation and spill by plant type for four of the scenarios for 2030 and 2050, and also actual values for 2020.

Figure 4: Projected system generation and spill[9]



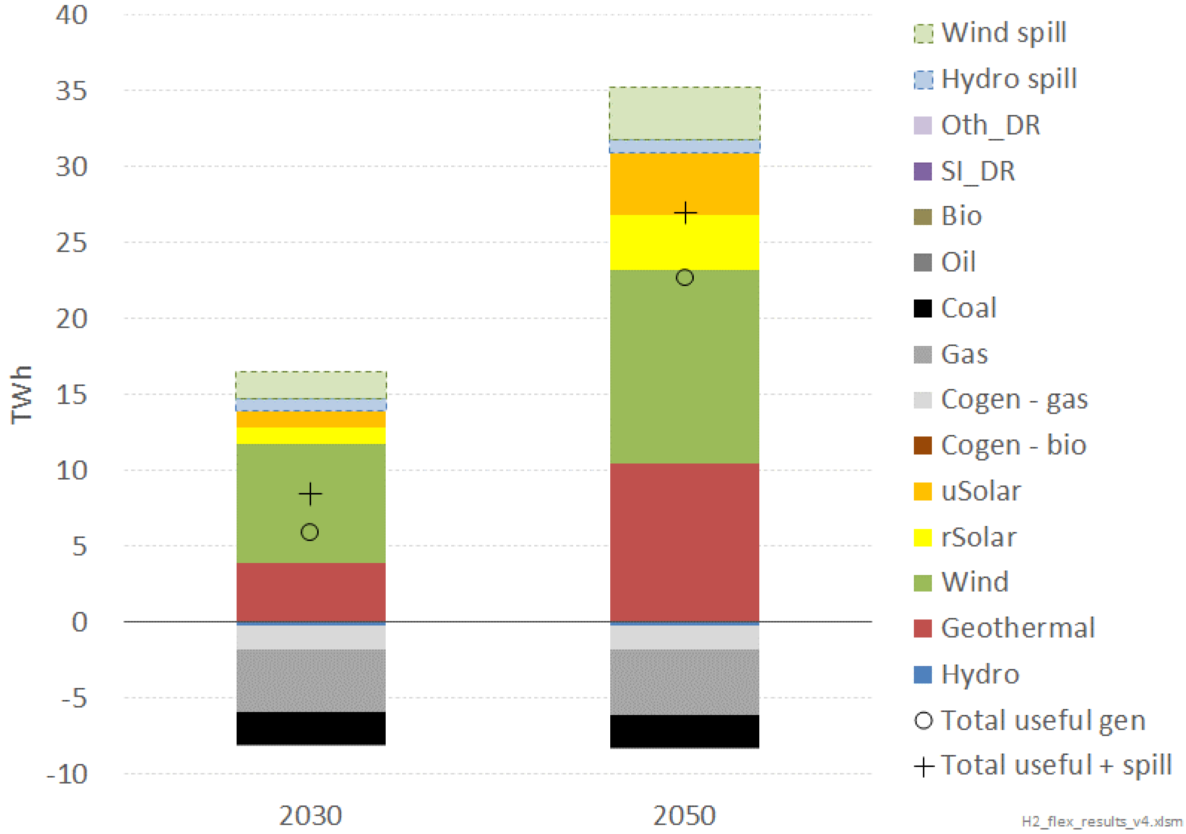
Relative to the outcomes for 2020, all scenarios have:

- a significant reduction in generation from fossil fuel sources (Oil, Coal, Gas, and Cogen – gas), even in the fossil gas peaker scenario;
- a significant increase in geothermal, wind, and solar generation. This increase is both to meet the increase in demand and to displace current fossil generation; and
- an increasing amount of spill from wind and hydro plant.[10]

Figure 5 below illustrates these above outcomes by showing the differences compared to 2020 for the Fossil gas peaker scenario.

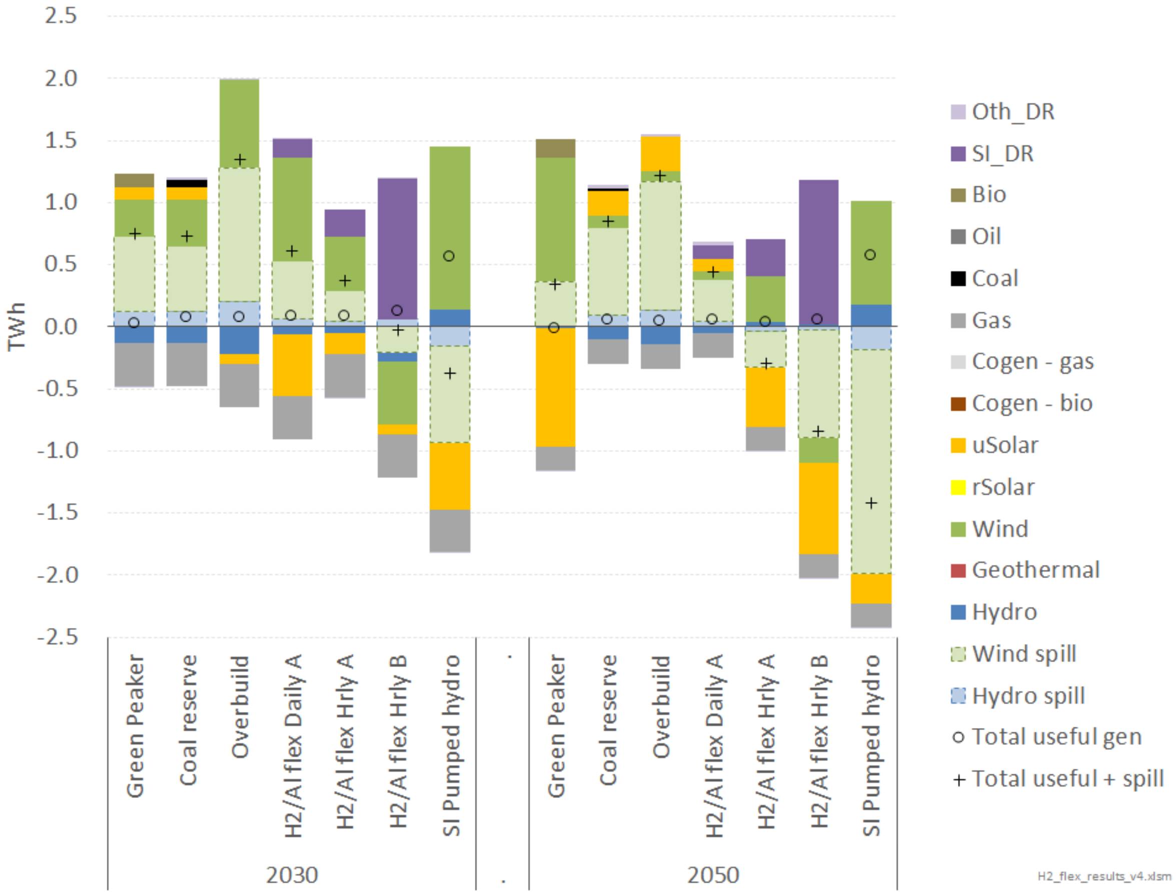
[9] SI_DR = demand response from the South Island hydrogen or aluminium plant. Oth_DR = Demand response from other consumers. Bio = biofueled peaker generation. rSolar = rooftop solar. uSolar = utility solar.
[10] Spill is shown as zero for "2020" but water is currently spilled from hydro storage lakes from time to time. However, most of the current hydro spill is due to physical factors at the reservoirs, rather than reflecting oversupply in the market, so is not directly comparable.

Figure 5: Differences to 2020 for projected generation outcomes for Fossil gas peaker scenario



While Figure 5 above helps illustrate the broad changes between 2020 and future years that will be common to all scenarios, Figure 6 below helps illustrate differences in future outcomes between these scenarios. It shows the differences for the two future years between projected generation under the Fossil gas peaker scenario, and the other scenarios.

Figure 6: Differences in generation outcomes compared to the Fossil gas peaker scenario



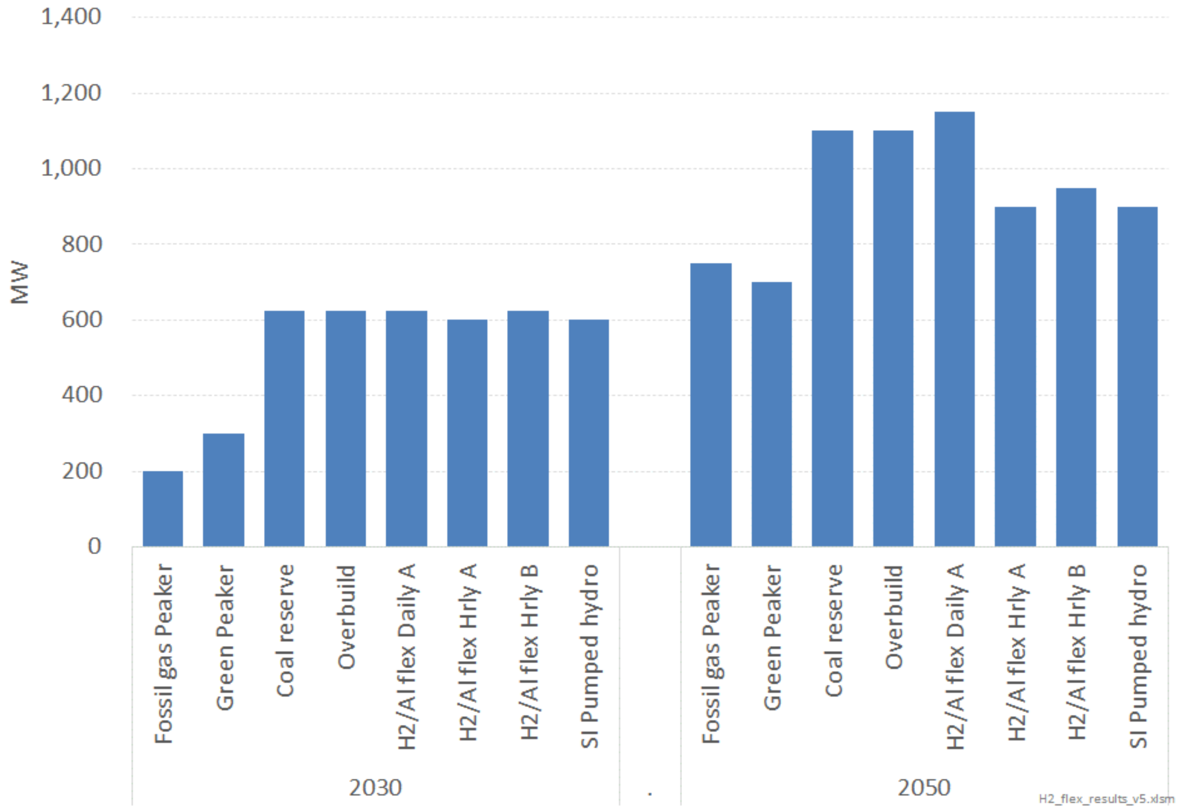
The differences between the different scenarios are fundamentally driven by differences in how the flexibility to manage demand and renewable variability is provided.

The key take-aways from Figure 6 are:

- If fossil gas peaker generation is not allowed, the replacement flexibility needs to come from the alternative resource (e.g. coal reserve, H2/Al flex, SI pumped hydro) plus, generally, spill resulting from additional renewable over-build.
- The two exceptions to this requirement for additional renewable overbuild are SI pumped hydro and very flexible H2/Al production scenario ('Hrly B'), both of which have less renewable overbuild than the fossil gas peaker scenario.
- The requirement for total useful generation is approximately 0.5 TWh (approximately 1%) a year greater in the SI Pumped hydro scenario due to the efficiency losses associated with pumping – noting that the round-trip efficiency for the storage is 75%. However, this requirement for increased generation is more than offset by the reduction in spill, resulting in total renewable build requirements being least in this scenario – as indicated by the lowest value for 'Total useful + spill'.
- The increases in useful generation requirements relative to the fossil gas peaker scenario for all the other scenarios is due to the greater transmission losses associated with the replacement generation – noting that the fossil gas peaker location is generally closer to the main load centres than the generation that would need to replace it.

The other key difference between the scenarios relates to the amount of batteries that are developed. The optimal level of batteries is determined by the least-cost optimisation process. Figure 7 shows the results of the battery projections.

Figure 7: Battery capacity projections



The key take away is that the peaker options require the least amount of batteries to be developed. This is because of their North Island location and their consequent ability to contribute peaking capacity at all times. In contrast:

- The H2/Al flex and SI Pumped hydro options are limited by the capacity of the HVDC link to supply capacity at some peak times.
- The coal reserve option is limited in its ability to supply capacity because of the constraint that it can only run when lakes are low. However, going forward, some peak capacity requirements will be at times when lakes are not too low but wind and solar output is low at times when demand is high.

3.2 Projected system costs

Figure 8 shows the projected total system costs for the different options for 2030 and 2050. These costs have been split into the following main categories:

- ***Plant costs.*** The non-fuel and non-CO_2 costs of building and maintaining capital assets such as power stations and batteries. These have been split between
  - *renewable power plant* (hydro, geothermal, wind, and solar)
  - *thermal power plant* (the OCGT Peakers or the Huntly Rankine)
  - *pumped storage plant*
  - *batteries*

- ***Fuel costs***. This is split between fossil fuel (coal or gas) and biofuel (for the Green Peaker scenario)
- ***CO_2 costs.*** This is split between geothermal emissions and fossil emissions, with emissions being costed at the modelled carbon price for each year (\$138/tCO_2 for 2030, and \$250/tCO_2 for 2050).
- ***Demand response ('DR') costs.*** This is split between the costs of curtailing production at the hydrogen facility or aluminium smelter ('H2/Al'), and other demand response from mass-market and industrial consumers.

Figure 8: Projected wholesale electricity system costs[11]

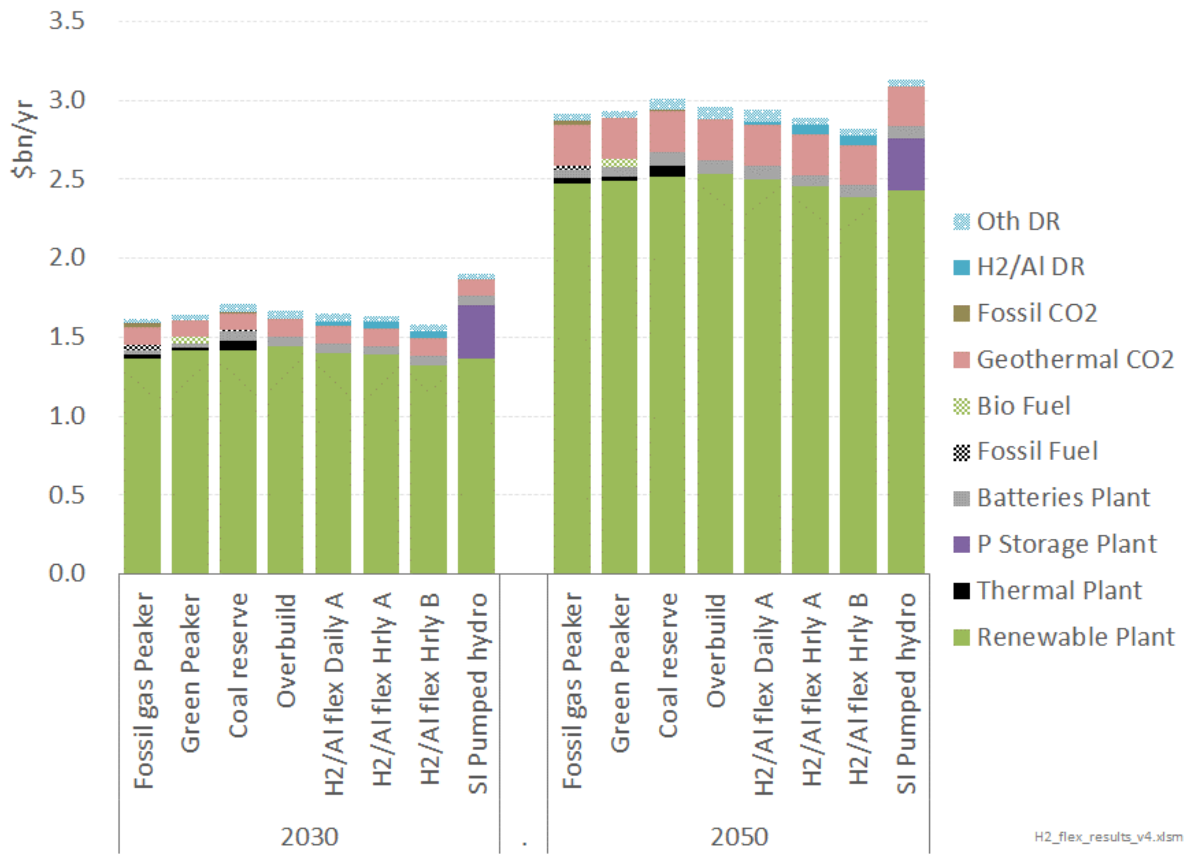
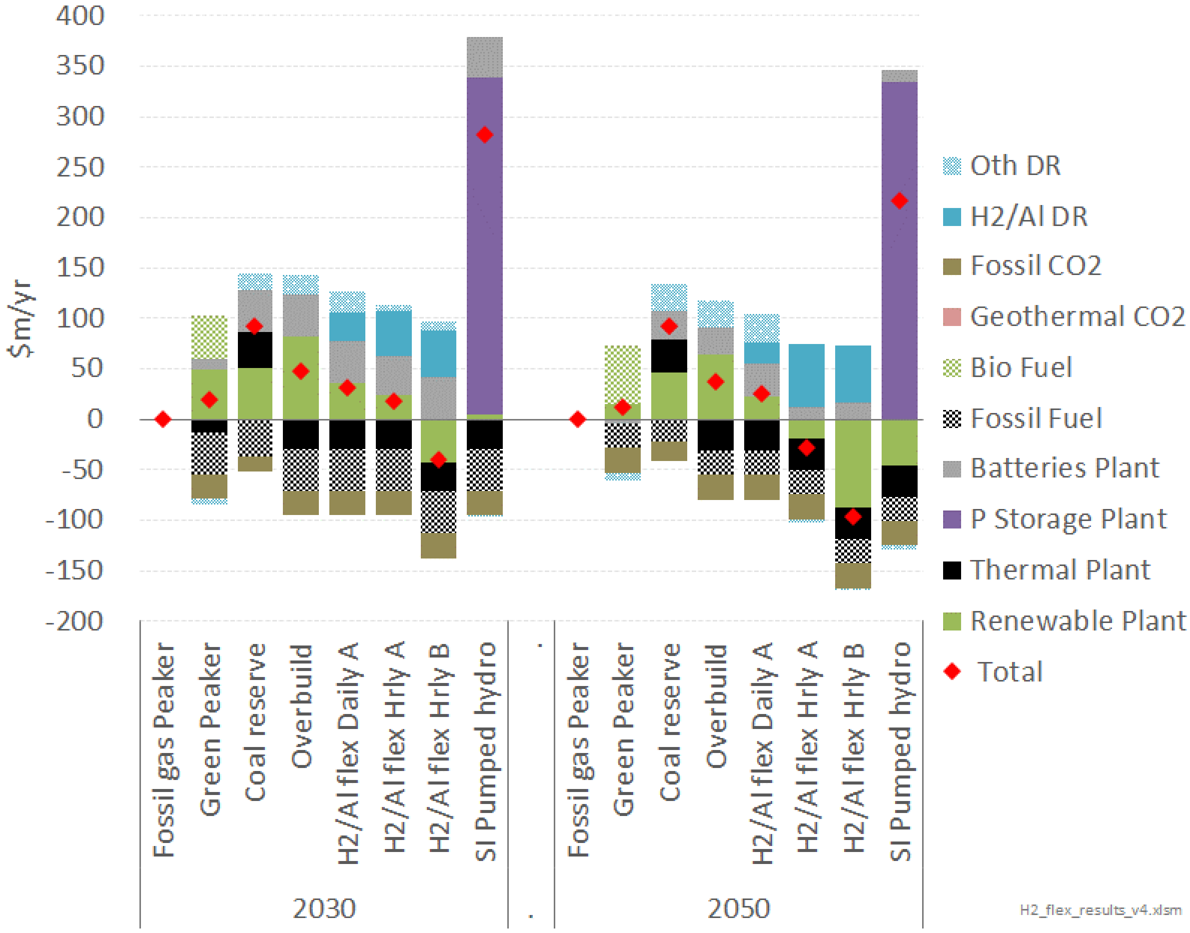


Figure 9 below is based on the same information as in Figure 8, but shows the differences in costs relative to the Fossil gas peaker scenario. This has been chosen as the counterfactual for comparison as it is the option which the Climate Change Commission recommended was most appropriate for New Zealand achieving its broader decarbonisation goals.

[11] The potential capital cost recovery for investing in flexibility-enabling technology for the aluminium smelter is not shown. However, as detailed in section 2.3.1 previously, this is likely to be relatively low – adding approximately \$0.015bn to the H2/Al flex columns in Figure 8.

Figure 9: Difference in wholesale electricity system costs relative to the fossil gas peaker scenario



The key results from this analysis are:

- The lowest cost option is the most flexible hydrogen or aluminium production option: "Hrly B". i.e. 30% of the plant only operating at times of significant renewable surplus with the rest of the plant only progressively curtailing production at times of increasing renewable scarcity.
- Options with higher priced hydrogen / aluminium production flexibility (i.e. only curtailing at times of scarcity) are similar cost to the fossil gas peaker and green peaker scenarios.
- Hydrogen/aluminium production that is only able to respond on a daily basis has higher costs than if it can respond hour-to-hour, particularly in 2050. This reflects that short term supply constraints increasingly become the main challenge for the system to meet.
- Higher cost options include relying solely on renewable over-build (due to materially higher costs of renewables) and the coal reserve scheme (due to the significant carrying costs for the Rankine units)
- The highest cost option is building a large South Island pumped storage scheme due to having to recover the costs associated with building such a scheme. (Which, as set out in section 2.3.4, is assumed to be $4bn for construction plus a further $200m to fill the lake to an operational level).

Table 2 below shows the demand-weighted average cost of the flexible hydrogen or aluminium demand curtailment behind the blue 'H2/Al DR' bars in Figure 8 and Figure 9. These represent the extent to which the different tranches of curtailment represented by Figure 3 on page 14 previously were called upon.

Table 2: Demand-weighted average cost of assumed hydrogen / aluminium curtailment ($/MWh)

	2030	2050
Daily A	190	185
Hrly A	199	205
Hrly B	41	49

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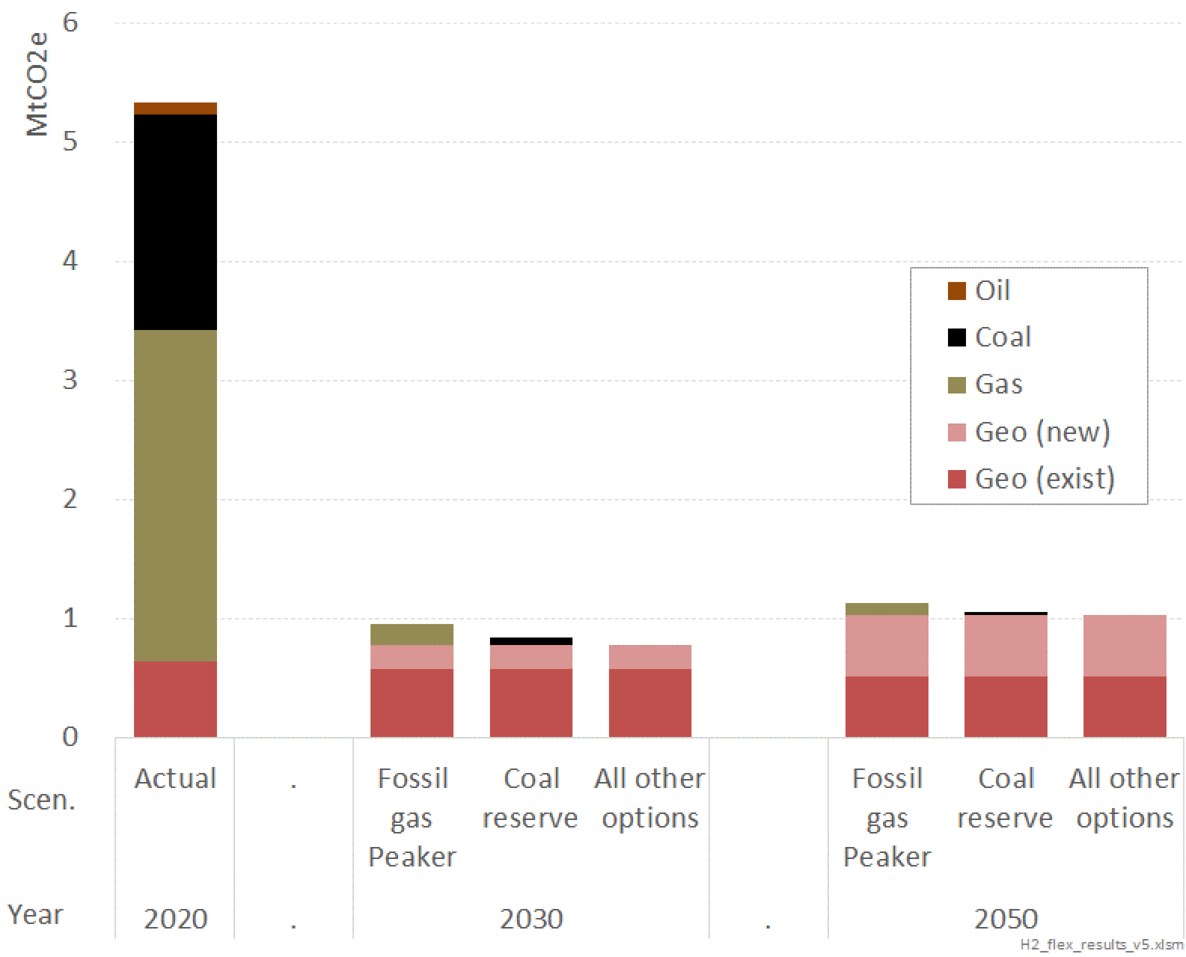
As can be seen, the Hrly B option has a very low average curtailment cost. This is consistent with the operating pattern assumed by this scenario whereby 70% of the plant operates for most of the time and only curtails at times of high market price, whereas 30% of the plant only operates opportunistically at times of very low market prices. Such a pattern of operation would be consistent with the capital and fixed costs of the plant being recovered by sales of hydrogen / aluminium from the 70% of consistent production, and the 30% of opportunistic production only seeking to recover the variable costs of production.

3.3 Projected emissions

3.3.1 Power-sector specific emissions

Figure 10 below shows actual power sector emissions for 2020, and the projected emissions from different power generation sources for 2030 and 2050 for the different scenarios modelled.

Figure 10: Historical and projected electricity generation emissions



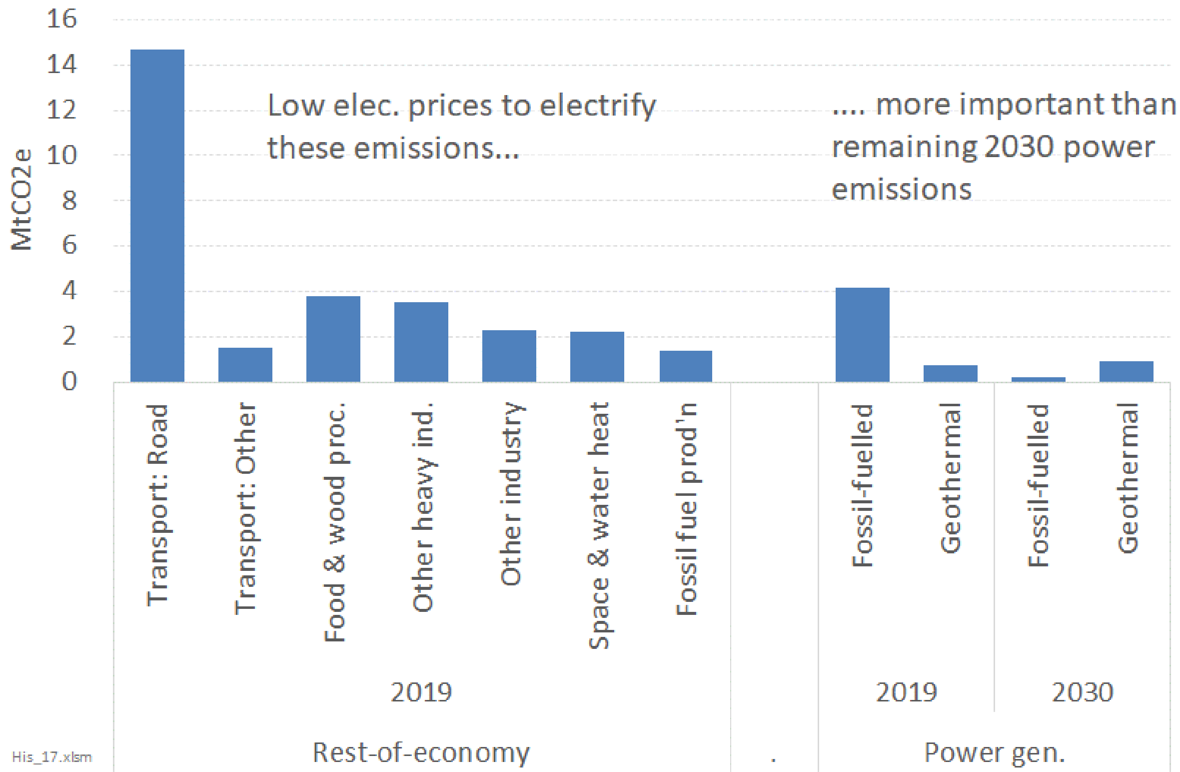
The results show that future direct emissions from power generation are relatively similar between the scenarios. In all cases they are dominated by emissions from geothermal power stations, with the scenarios that have some fossil generation (the fossil gas peaker and coal reserve scenarios) only contributing comparatively few emissions, due to the small amounts of generation from these sources.

The comparison with actual 2020 emissions shows just how significant the reduction in fossil generation is for all scenarios, including those which retain a small amount of fossil generation to balance variable renewables.

3.3.2 Whole-of-economy emissions

From a whole-of-economy decarbonisation perspective, the different scenarios are likely to have greater variations in emissions outcomes. This will be due to differences in consumer electricity prices emerging from each scenario, and consequent differences in the degree of fuel switching from fossil to electric options in sectors such as transport, space & water heating, and industrial process heat. As Figure 11 below illustrates, emissions from these sectors will far outstrip remaining power sector emissions even in the fossil peaker scenario.

Figure 11: Whole-of-NZ Energy emissions for 2019, plus projected power gen. emissions under fossil peaker scenario for 2030[12]



All scenarios will face a common key driver for electricity price outcomes, namely the cost of building new generation (predominantly wind & solar) to meet demand. In the long run, wholesale electricity prices over the longer term should broadly reflect the cost of such new electricity supply.

[12] Emissions from those activities classed as 'Energy' under international reporting requirements. Accounts for 41% of NZ's 2019 gross emissions. Other NZ gross emissions in 2019 were from: Agriculture (48%), Industrial processes & product use (6%), and Waste (4%).

However, despite this common key driver, there will likely be differences in consumer electricity prices between the scenarios due to two key factors:

1. ***The extent to which the different flexibility resources help balance the variable output from wind & solar, leading to lower wholesale prices***

   In general, average wholesale market prices will tend to be higher than the levelised-cost of energy (LCOE) from new wind & solar. This is because prices throughout the year will tend to be anti-correlated with the output from such variable renewables. E.g., at times of high wind output the increase in generation supply will tend to reduce wholesale prices, and vice versa at times of low wind output. This will result in the generation-weighted average price (GWAP) the wind plant earns (which should equal the LCOE of the marginal new wind plant) being a discount to the time-weighted average price (TWAP) for the market as a whole. This GWAP/TWAP discount will get progressively worse as the proportion of variable renewables on the system grows. So, for example, if the LCOE of new wind generation were $65/MWh, but wind achieved a GWAP/TWAP ratio of 90%, the time-weighted market price would be 65÷0.9 = $72.2/MWh.

   However, if significant flexibility resources are available which can balance the variable output, these will tend to improve the GWAP/TWAP ratio for variable renewables, with consequent improvements in the average market price. Thus, if wind were to face a GWAP/TWAP ratio of 92% in the above example, the time-weighted market price would be 65÷0.92 = $70.6/MWh.

   In this respect, the overbuild and coal reserve scenarios are relatively poor at renewable balancing, whereas the very flexible SI hydrogen/aluminium production, fossil gas peaker, green peaker, and SI pumped storage options are relatively better. As such these latter options will tend to result in lower market prices than the former options.

2. ***The extent to which an option has material additional costs which will need to be recovered from consumer prices***

   This principally applies to the large South Island pumped storage scheme (and, to a much lesser extent, to the coal reserve scheme). Using the cost estimates set out in section 2.3.4 earlier, we estimate that recovering the costs of such a scheme would add an additional $6.8/MWh to consumer prices in 2030 and $5.1/MWh in 2050 (due to 2050 having higher GWh sales over which to spread the cost recovery).

   Although our study has principally focussed on total costs rather than market prices, our provisional estimate is that this adder to consumer prices would outweigh any potential GWAP/TWAP-driven wholesale market price benefit from the renewable balancing the pumped storage provides. As such this option is likely to have higher consumer prices than some of the other options which also deliver good renewable balancing.

It is out of scope for this report to consider the extent to which whole-of-economy emissions are likely to be greater in those scenarios which result in relatively higher consumer electricity prices.

3.4 Flexibility benefits to producers of hydrogen / aluminium

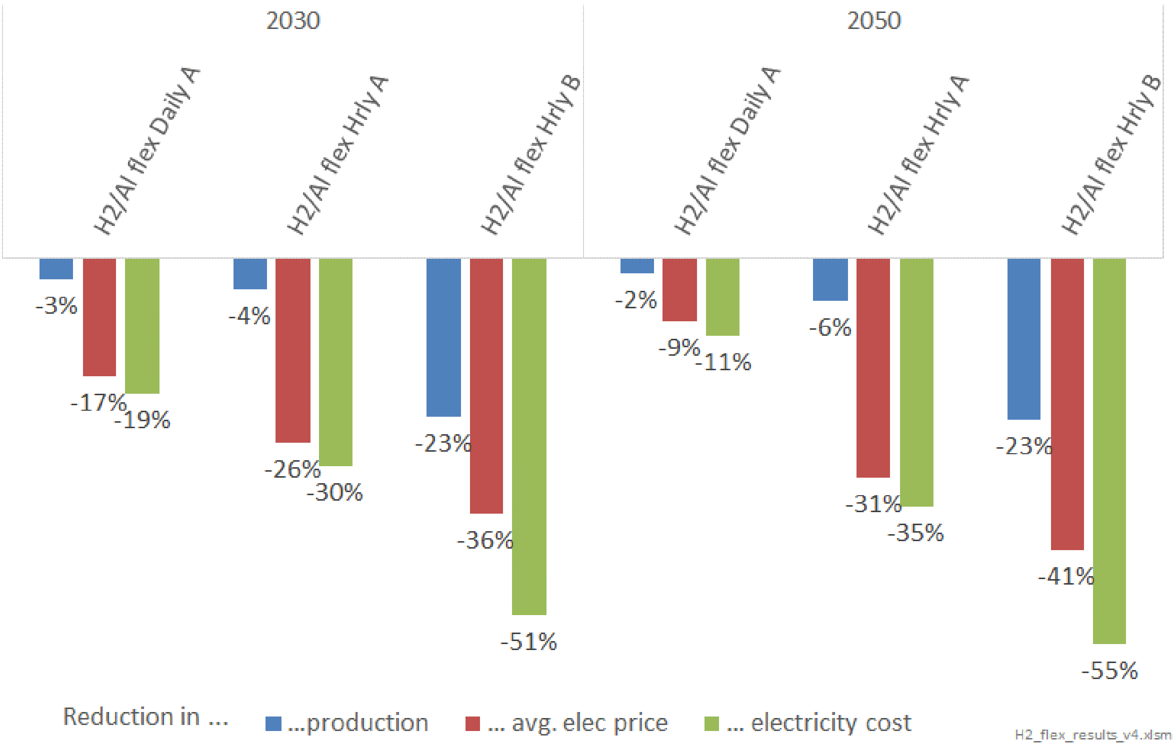
Operating a hydrogen production or aluminium smelter facility flexibly should deliver benefits to the owners of such a facility in terms of achieving a lower demand-weighted average price of electricity consumed.

Figure 12 below shows the extent to which operating a hydrogen/aluminium production facility in a flexible fashion will result in the facility

- paying a lower average price for wholesale electricity
- paying less in total for wholesale electricity costs (because consumption is lower *and* the average price paid for electricity is less)

It also shows the average reduction in hydrogen/aluminium production that this flexible operation would require. The reduction in electricity costs is more relevant when comparing to a drop in production.

Figure 12: Reductions in production and average electricity price & cost relative to baseload operation for different hydrogen/aluminium flexibility operating patterns



As can be seen, in all cases being able to operate flexibly reduces electricity costs significantly more than the reduction in production.

Further, as evidenced by comparing the 'Daily A' and 'Hrly A' results, being able to operate flexibly on an hourly basis rather than daily, will deliver significant extra reductions in electricity purchase price, with relatively little extra curtailment in production.

Having some operation which only occurs at times of renewable surplus in addition to having some which only curtails at times of high price (as in 'Hrly B') will deliver additional reductions in electricity purchase price compared to operation which only curtails at high prices (as in 'Hrly A'), but requires materially more reductions in production.

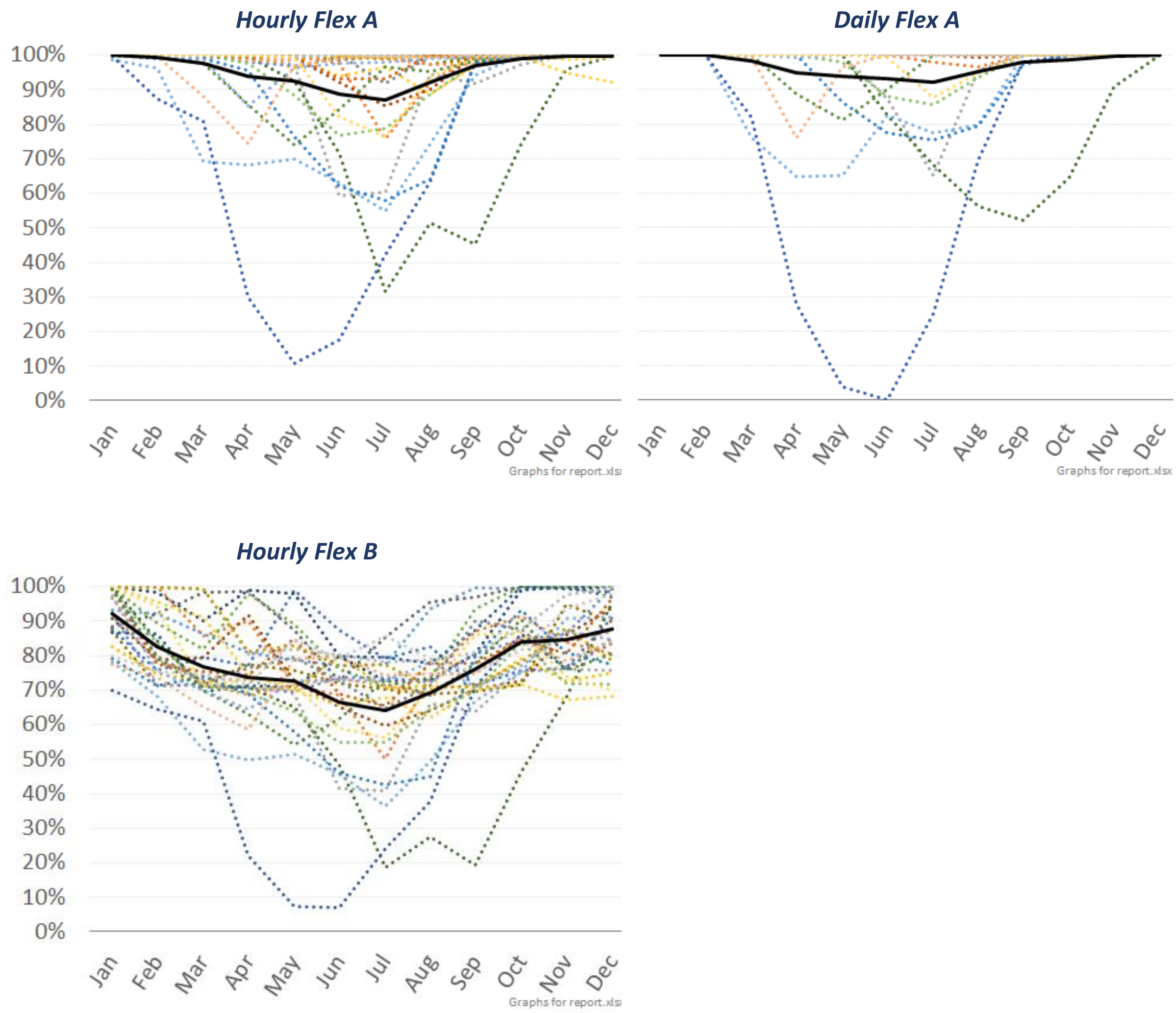
What this analysis doesn't show is the lost revenue associated with this lost production. This has been set by assumption through the curtailment offer curves shown in Figure 3 on page 14 above.

By definition, if these curves are true reflections of the opportunity cost of foregone hydrogen/aluminium production, then the demand response that has been modelled will be value-enhancing for the owners of the hydrogen/aluminium production facility (i.e. the savings in lower electricity costs will match or exceed the profit on foregone sales).

However, such offer curves don't take account of potential real-world constraints on the ability of such plants to curtail production for sustained periods of time. To get a feel for the potential nature and scale of this dynamic, Figure 13 below shows, for the three different flexible hydrogen/aluminium operating regimes, monthly average electricity demand (a proxy for production of hydrogen/aluminium) for 2030:

- For the 28 different 'environmental years'[13]; and
- Averaged across all environmental years (the solid black line).

Figure 13: Monthly hydrogen/aluminium production across different environmental years for 2030



In the daily flex A scenario most months have minimal drop in production. However, during dry years there can be substantial decreases (including no demand whatsoever during the worst month).

The monthly production profile for the hourly version of the "A" scenario looks roughly similar to the daily one. This is perhaps unsurprising as the demand flexibility is offered at identical prices in both scenarios, with the only difference being whether the demand can flex on-and-off on a daily or

[13] As set out in section 2.1, we use historical patterns of hydro inflows, wind and sunshine for 28 historical years to simulate the range of possible renewable flows within years and between years.

hourly basis. This similarity is most apparent during the particularly dry years, as prices here remain elevated for long periods resulting in outcomes arising from daily dispatch which are very similar to those arising from hourly dispatch. There is a higher level of demand response in the hourly scenario during more normal years as the demand is sometimes switched off within a day to respond to shorter duration shortage periods.

Unsurprisingly, the hourly flex B scenario has significantly lower levels of production because 30% of the plant's capacity only operates at times of significant renewable surplus when prices are very low. This results in demand curtailment in all years.

Figure 13 not only shows that some months can have significant drops in production as the plant scales back during dry events, but that these drops in production can be sustained for many months.

If the producer of the hydrogen / aluminium has firm sales commitments, they must either manage these periods of sustained production from:

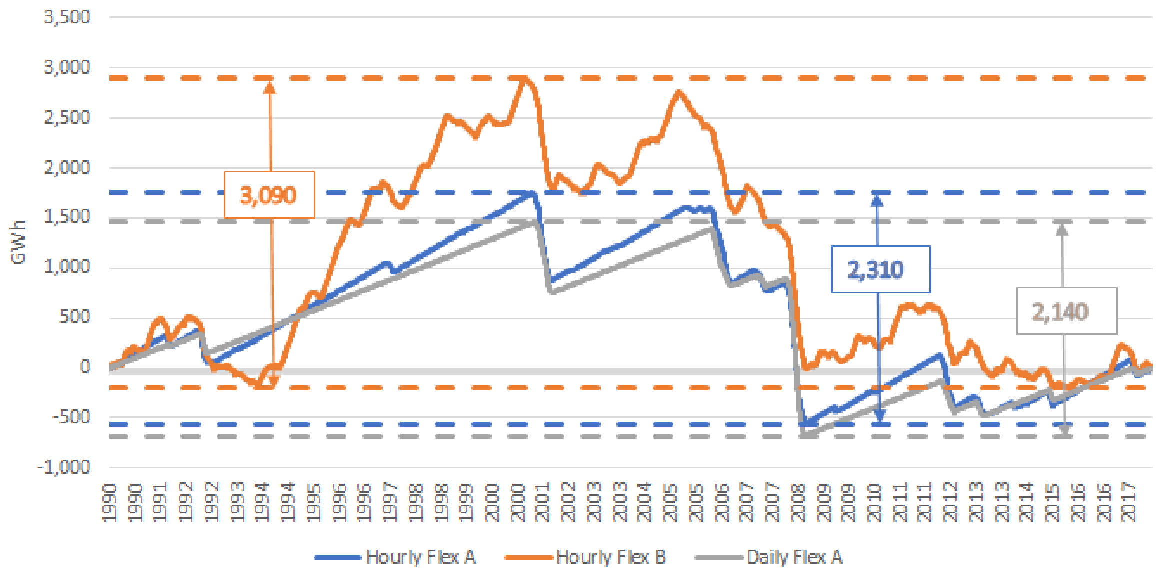
- Sourcing hydrogen / aluminium from an alternative international producer; or
- Using on-site storage / stockpiles which could be built-up during periods of relative renewables surplus and then drawn-down during periods of relative scarcity.

To get a feel for the size of stockpile required if the producer had a firm sales commitment with no within-year variation, and no ability to procure hydrogen / aluminium from international producers, we applied a rolling stock method to the chronological sequence of production produced by our model.

This approach calculates the difference between the average production and the actual production for every period. Any difference between the average production and the actual production will either contribute to, or draw down from, a "stock" of product. The difference between the highest stock level and the lowest stock level is an indication of the maximum size of stockpile required.

Figure 14 shows the results of this analysis for the three different hydrogen/aluminium production scenarios. The units are in GWh of electricity, and the graph shows the cumulative effect of periods of higher consumption relative to the long-term average (as shown by the GWh 'stock' increasing) and lower consumption than average (with the 'stock' decreasing).

Figure 14 - Rolling stock analysis of flexible H2/Al demand for 2030



The maximum size of stockpile required is shown by the difference between the maximum and minimum rolling stock amounts. It shows that the Hourly flex B option will have a significantly greater stockpile size requirement than the Hourly A and Daily A options.

The Hourly B option has an even greater *relative* size of stockpile when compared to average levels of consumption. This is illustrated in Table 3 below.

Table 3: Comparison of stockpile size with average consumption for flexible H2/Al demand for 2030

	Daily A	Hrly A	Hrly B
Maximum 'stockpile' size (GWh)	2,140	2,310	3,090
Average consumption (GWh/yr)	4,860	4,790	3,880
Stockpile size relative to average consumption	44%	48%	80%

H2_Misc_01.xlsm

To get a feel for the rough size of this potential cost, if the plant were to carry a stockpile equivalent to 80% of its average annual production, the carrying cost of this stockpile would increase the opportunity cost of not producing by approximately 10% (assuming the stockpile carrying cost and increased storage vessel costs were recovered over fifteen years using a pre-tax real discount rate of 6%). For carrying a stockpile equivalent to 50% of average annual production, this increase in cost would be only 5.5%.[14]

If the hydrogen / aluminium producer were able to manage some of this variability through procuring alternative overseas production to meet its sales commitments, the size of the stockpile would be less.

Likewise, if the sales commitments had a within-year 'shape', with lower winter sales commitments than summer, this would also reduce the size of the stockpile. This is because, as Figure 13 above illustrated, the periods of greatest renewable scarcity in New Zealand are the winter months, corresponding to dry-year events.

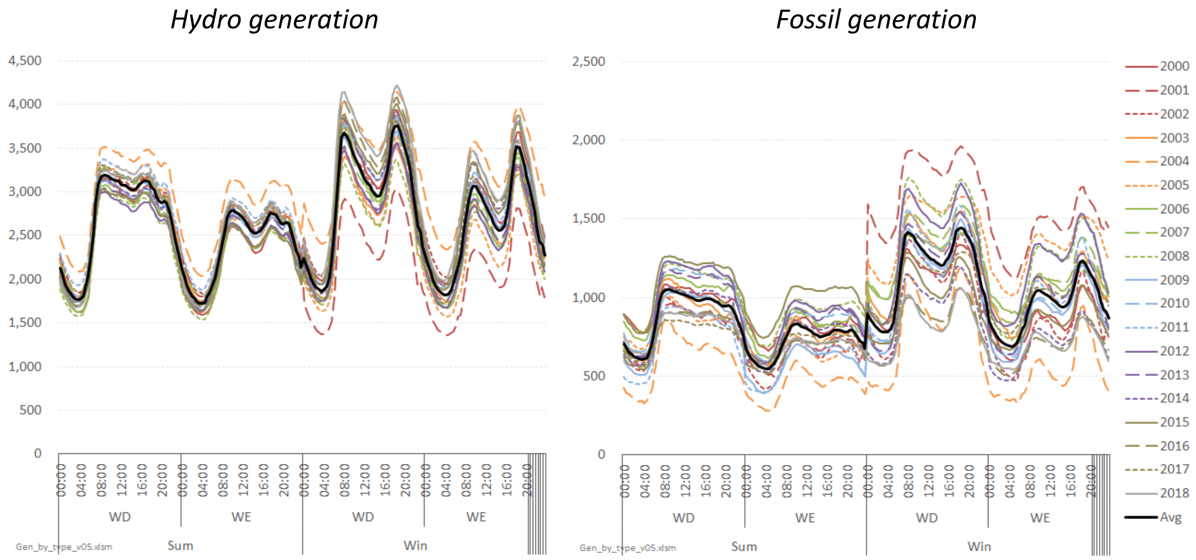
It is beyond the scope of this study to consider the extent to which these real-world effects around the ability to manage sustained reductions in output are consistent with the demand response opportunity costs set out in section 2.3.1. Potentially, this dynamic may result in varying demand response costs according to duration of response, with the costs of response rising for long-duration response. Were this to be the case, it would result in altered benefits (to the system as a whole, and to the owners of the facility) to those modelled here.

3.5 Change in flexibility provision

As set out in detail in Appendix A, hydro and fossil generation currently provide almost all the flexibility required to meet the system's demand for flexibility to balance variations in demand and variations in renewable production. How some of this flexibility is delivered is illustrated in Figure 15 which shows average within-day and within-year patterns of operation for historical years, and the average across all these historical years.

[14] This is not a straightforward comparison, because to some extent the increased opportunity cost associated with increased level of curtailment is captured within the stepped demand-response cost profile set out in section 2.3.1. Nonetheless, this estimate should help give a feel for the scale of cost associated with the storage requirements to enable flexible production of hydrogen / aluminium.

Figure 15: General patterns of historic flexibility provision by hydro and fossil generation (MW)



As can be seen, both hydro and fossil generation have average patterns of operation which match the general patterns of within-day and within-year demand. They also illustrate that fossil generation plays a significant role in balancing year-to-year variations in hydro output. For example, hydro output in winter 2001 was relatively low, causing fossil generation for that year to be relatively high.

What these charts don't show is that there can be significant variation around these average patterns for each year due to variations in demand (significantly due to extremes in weather) and week-to-week variations in hydro inflows and hour-to-hour variations in wind output. This variation in output is greatest for fossil generation.

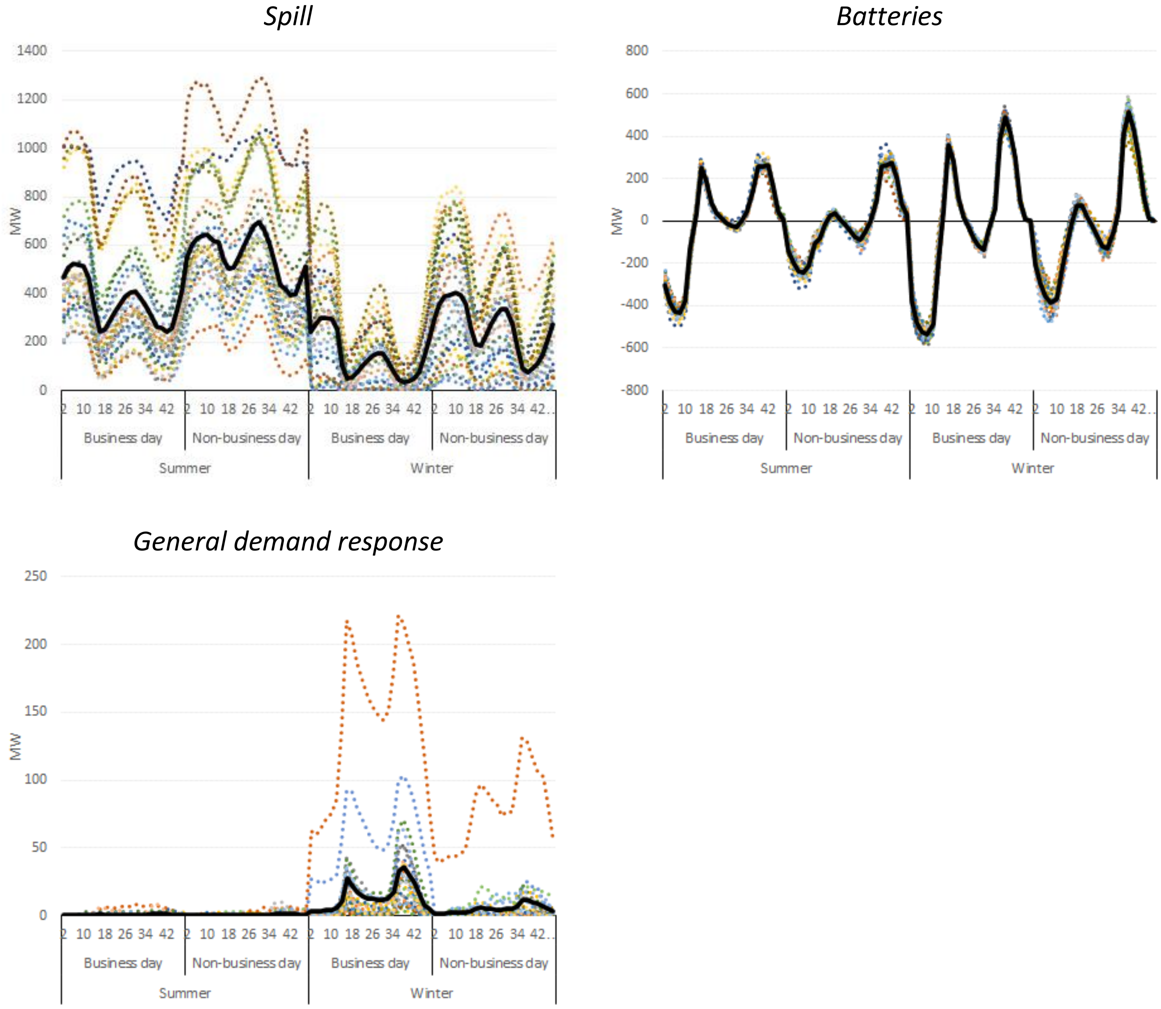
Looking forward, our modelling projects that hydro generation will continue to meet a significant proportion of the flexibility duties required, but with greater variability in hour-to-hour output due to the greater proportions of wind and solar generation and the need to balance their significant variability. It is hard to graphically represent this much greater 'noise' on the system.

In all scenarios, hydro flexibility will be assisted by a combination of spill from renewable overbuild, batteries, and demand-response. The extent to which each of these provide flexible response depends on the extent to which other forms of response are available in each scenario (e.g. pumped storage, peaking thermal generation, hydrogen/aluminium production flexibility.).

The following charts illustrate the typical within-day and within-year patterns of operation of these different forms of response. They are in the same format as Figure 15, with the individual dotted lines representing the patterns of operation for each of the different 28 'environmental years' we modelled, and the solid line representing the average across all environmental years.

The first charts are for the operation of the flexibility resources in the Overbuild scenario.

Figure 16: Patterns of spill, battery operation, and demand response in 2030 for the Overbuild scenario



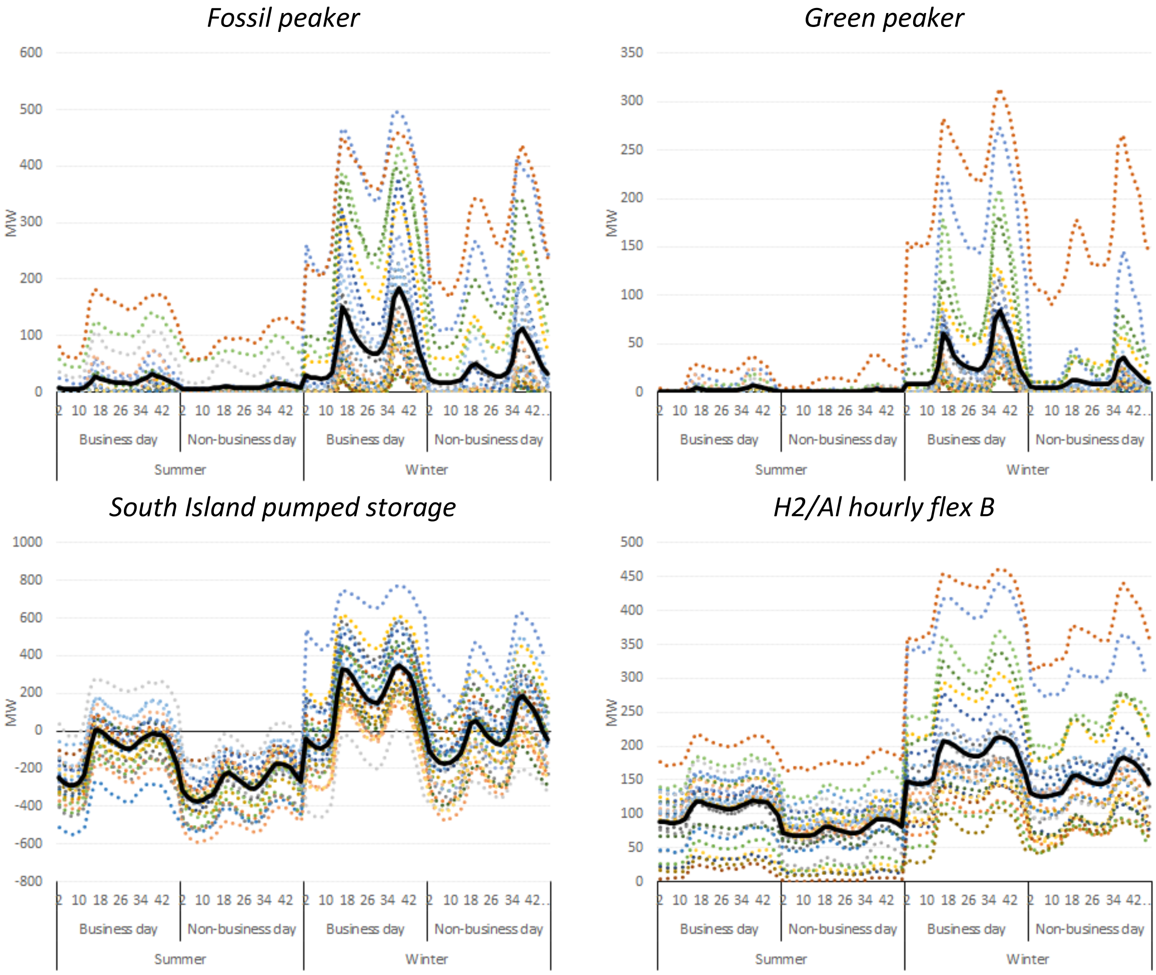
Spill shows a strong within-day shape. It is counter to the typical daily demand profile, showing a drop during morning and evening peaks. Although we have not shown 2050, the mid-day peak is much higher in later years due to increased amounts of solar on the system. In addition to the within-day shape there is significant year-to-year variability. During some environmental years there is minimal spill during winter business days, while in others there is consistently more than 200 MW. However, even in the driest inflow sequences there are significant quantities of spill during summer.

Battery output follows the well-known daily demand shape. The profile is particularly steep at times, with the average output rising from -480 MW at 5am to 410 MW at 8am. Note that the output can be either positive or negative, and that overall “generation” is negative, reflecting that batteries are, on average, a load on the system due to their charging inefficiency. There is minimal difference between different inflow years as the modelled batteries only shift energy within a day, and so seasonal or “dry-year” effects are not directly relevant.

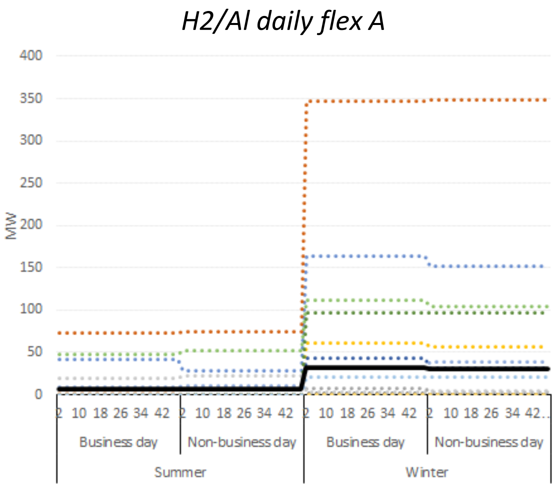
The quantities of demand response are highly variable, both within day and across environmental years. The orange line represents 2008 inflows, while the blue line represents 2001, and these were both dry-years. The model produces an average response of about 150 MW during the winter with 2008 environmental inflows, and this is consistent with the actual response seen during the driest months of 2008.[15] Even during years with higher inflows there is some demand respond during winter peaks. This is due to capacity required that cannot be met even with very high generation from hydro stations.

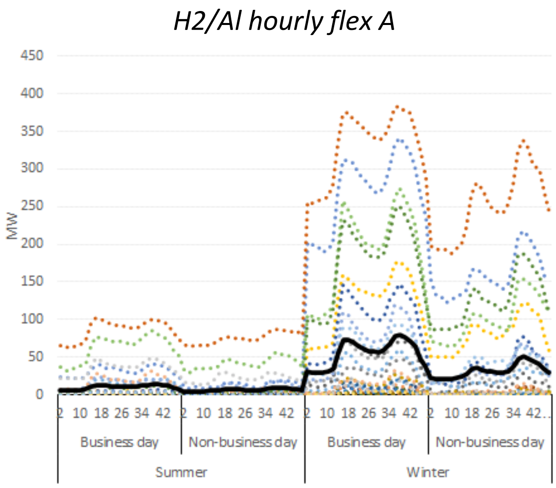
Spill, batteries, and demand response also contribute to meeting flexibility requirements for all our other scenarios, with similar within-day and within-year patterns of operation, but to lesser extents as these other scenarios have other flexibility resources to call upon. Figure 17 shows the general patterns of flexibility provision in 2030 for these other options. (Note the difference in scale for the different options).

Figure 17: General pattern of flexibility provision in 2030 for other flexibility resources modelled



[15] "Review of 2008 Winter" - https://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/security-of-supply/winter-review-2008-archive/





When comparing the projected flexibility operation provided by the different flexibility resources shown in Figure 16 and Figure 17 compared with the current flexibility response provided by fossil generation shown in Figure 15 the following key observations can be made:

- The flexibility provided by spill from renewable overbuild will materially reduce the extent of flexibility response required from other resources.
- Batteries and demand response will provide additional short-term MW capacity flexibility.
- There will still be year-to-year variations in flexibility required driven by hydrology-driven dry/wet year variation, however the magnitude of required variation in output from non-spill resources is significantly less than is currently the case.

While the above charts are useful to understand generally how the different flexibility resources operate, they do not illustrate how the different resources balance the much shorter term (hour-to-hour and day-to-day) variability from demand and variable renewable generation. As Appendix A sets out, the increases of wind and solar on the system are going to significantly increase such short-term volatility, and the need for resources that can balance such volatility.

To help understand the relative contribution of each different flexibility resource across the full range of flexibility requirements (i.e. hourly, weekly, seasonally and year-to-year) we have estimated the flexibility contribution using the approach outline in Appendix A.[16] As this is computationally intense, we have only undertaken this for a subset of the scenarios with the results shown in Figure 18 below.

[16] This approach compares the residual demand for flexibility with and without the contribution of the flexibility resource in question.

Figure 18: Proportions of flexibility response delivered by different resources[17]

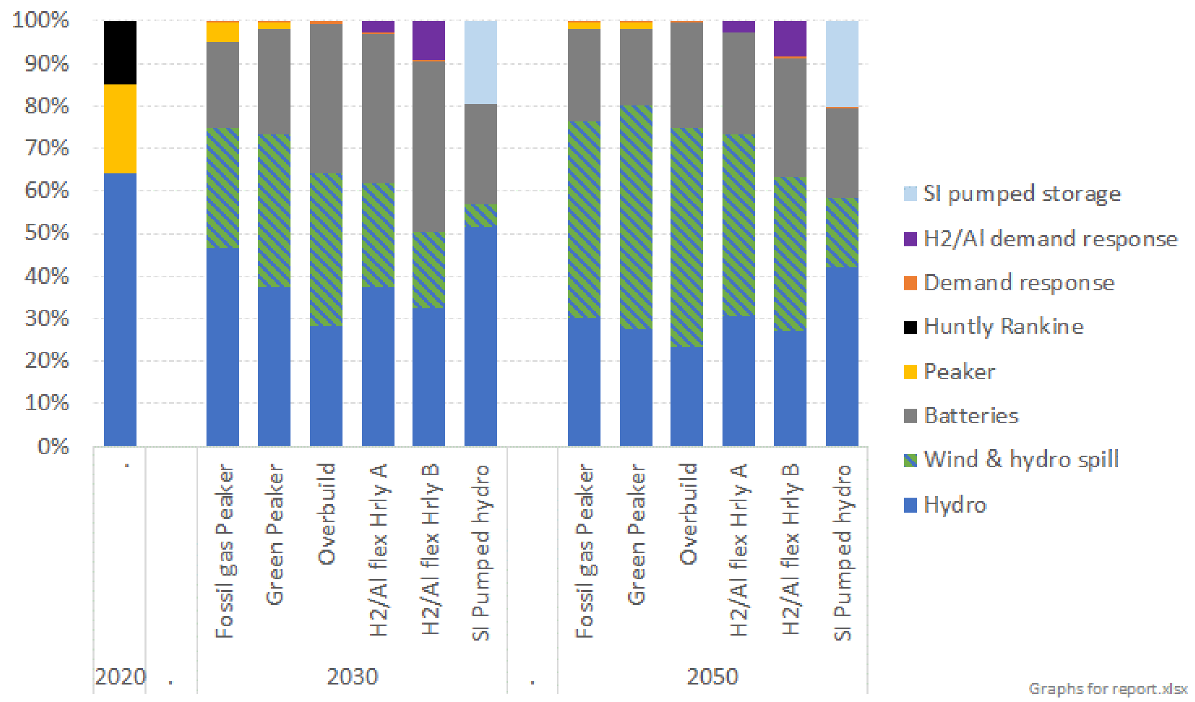


Figure 18 shows how flexibility will be provided by a radically different mix of resources in the future compared to 2020.

The contribution from fossil generation will be radically reduced to be largely replaced by a mix of wind & hydro spill from renewable overbuild, batteries, and (to a much smaller extent) demand response. The proportional contribution from hydro generation will reduce due to increased hydro spill and because the overall need for flexibility is greater (due to increased proportions of variable renewables on the system) while the hydro resource remains unchanged.

The extent of contribution from these different resources will vary according to the extent of response available from other resources such as peakers, H2/Al flex, or pumped hydro.

Scenarios with lower levels of overbuild have correspondingly lower spill, culminating in the SI pumped hydro scenarios which have minimal spill.

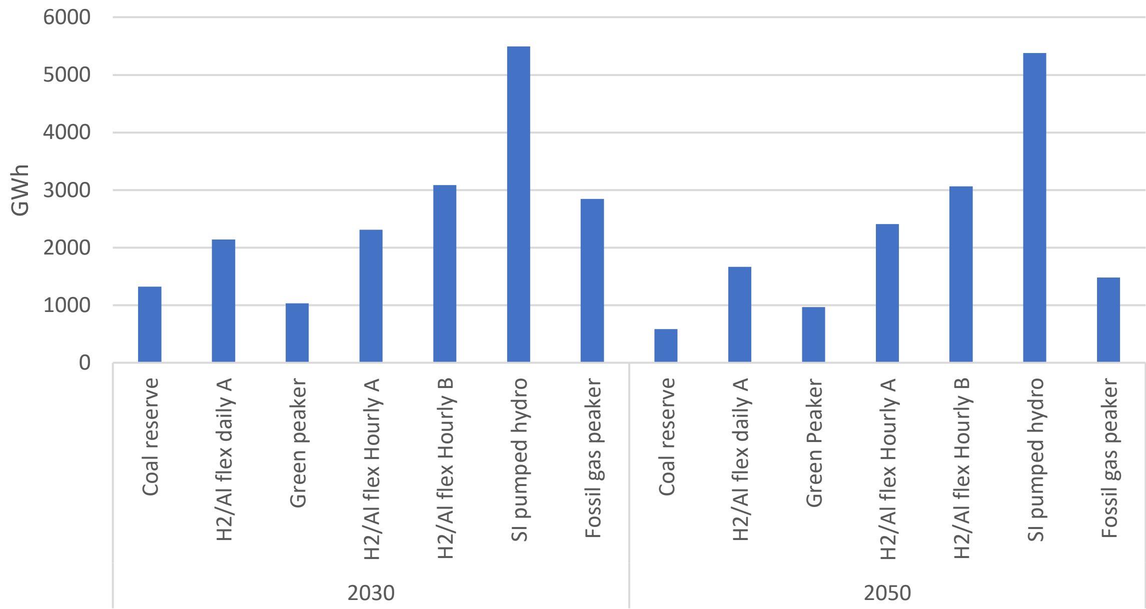
The peaker solutions result in lower levels of battery utilization compared to the other scenarios. In part this is because the peakers capture some of this operation, but it is also because the North Island location of the peakers means there is less need for batteries compared to scenarios which rely on South Island-based flexibility resources (H2/Al flex or pumped storage) as the ability to send capacity northwards over the link is constrained by the capacity of the HVDC.

We have also extended the rolling stock method detailed on page 29 previously for the hydrogen/aluminium flexibility scenarios to consider the other scenarios.

While these don't produce a product that needs to be stockpiled, they often have fuel that needs to be managed in a similar fashion, and this method can highlight the implications of such fuel management. The results are shown in Figure 19.

[17] This graph shows the proportional split of flexibility response. There is also a growing need for flexibility response over time, with 2030 needing more response than 2020, and 2050 even more still.

Figure 19 - Rolling stock for different flexibility resources[18]



The changing nature of the flexibility requirement over time can be seen by the large decrease in coal reserve between 2030 and 2050. Similar, although smaller, decreases can be seen in daily flex A and fossil gas peaker. These decreases reflect the reduced requirement for longer term storage as increased renewable overbuild reduces the size of the residual dry-year flexibility requirement.

The above analysis also provides some insights into the fuel management implications of the options.

- The analysis detailed on page 29 previously outlines the stockpile implications for the hydrogen/aluminium flexibility scenarios.
- For South Island pumped hydro it may seem surprising that the storage requirement has a value of slightly more than 5,000 GWh given that the size of the modelled reservoir is only 5,000 GWh. However, this graph shows the effect on the system, and the inefficiency of the pumped hydro system means that "charging" has a larger effect on the system than it has on the storage reservoir itself. For reference, about 4,000 GWh of total storage is used in the pumped hydro system.
- For the fossil gas peaker option, the storage requirement equates to 27 PJ in 2030, and 14 PJ in 2050. This is less than the levels of flexibility currently delivered by the gas system, delivered by a mix of gas field swing, Methanex demand curtailment, and the Ahuroa underground gas storage facility. For reference, the working volume of the Ahuroa facility is 18 PJ.
- The level of flexibility implied by the coal reserve option is also less than the flexibility currently provided by the combination of the stockpile at Huntly and the ability to top-up with international purchases of coal at 3-4 months' notice.
- For the green peaker option, the stockpile requirement equates to about 9.5 PJ in both 2030 and 2050. This equates to approximately 8 years' worth of average generation.

  This requirement for a stockpile would be reduced if the biodiesel production could be ramped up and down as required, or if biodiesel could be procured from overseas, or if biodiesel could be diverted from other uses.

[18] Overbuild is not shown because there is no scenario-specific flexible resource.

The 155 MW fossil-diesel-fired Whirinaki OCGT currently takes advantage of the latter two dynamics in that it has limited storage tanks on site (equivalent to full operation for just under four days), but has the ability to procure fossil diesel during sustained events given that there is a very large market for fossil diesel for transport and off-road motors. Thus, during the dry year event of 2008, its operation was equivalent to 8.7 times its on-site storage requirement. However, it was able to top-up via procuring diesel from the fuel market. This was feasible because Whirinaki's consumption that year was equivalent to 0.6% of all diesel consumption in New Zealand.

Currently there are no bio-diesel production facilities of anywhere near the scale required for green peaker operation. The Climate Change Commission (CCC) is projecting significant uptake of biodiesel production driven by policies such as the Sustainable Biofuels Mandate that the Government has proposed and is out for consultation.

However, the CCC's projections for biofuel production for transport and off-road machinery are for 5 PJ production in 2030 rising to 9.5 PJ by 2040. As such, the quantities implied by the green peaker analysis (9.5 PJ of stockpile and a maximum yearly offtake of approximately 6.7 PJ) would be very significant in this context. This suggests large-scale storage facilities would be required – potentially equivalent to the full amount indicated in our stockpile analysis.

This would significantly increase the cost of bio-fuel. A rough estimate is that having to store eight years' worth of average fuel consumption would increase the cost of fuel by approximately 60%.[19]

In addition, there are practicality challenges with storing diesel for long periods of time. If it is kept cool and dry, diesel can last for 6 to 12 months before degradation due to microbial activity and water condensation starts to materially impair the quality of the diesel. Biocides and diesel fuel stability treatments can extend the period for which diesel can be stored. However, it is not known whether such treatments could practically extend the life of the diesel for the durations required for green peaker operation.

[19] This assumes the working capital cost of the stockpile is recovered over 30 years with a 6% pre-tax real cost of capital.

4 Summary conclusions and discussion

Our analysis highlights that large-scale flexible demand from a facility such as a hydrogen production plant can potentially deliver significant system flexibility benefits. Coupled with renewable over-build, and assuming the plant could manage significant reductions in output during dry years, such a facility could help New Zealand cost-effectively achieve 100% renewable generation.

New Zealand's changing flexibility challenge

This analysis has also helped shed light on some key issues and opportunities for New Zealand's power sector de-carbonisation challenge, and the extent to which the different options we have considered may help deliver cost-effective whole-of-economy decarbonisation.

The key insights into New Zealand's general power-sector decarbonisation challenge are:

- Reductions in wind & solar costs, combined with increases in carbon prices, mean that it is becoming economic to 'over-build' renewables to the extent that there is systemic spill during periods of renewable surplus in order to have 'just enough' during periods of renewable scarcity. This significantly reduces the need to call upon other flexibility resources to perform the flexibility duty that is currently performed by fossil generation.
- Projected significant increases in wind & solar generation to meet growing demand, combined with this renewable over-build, will radically change the nature of New Zealand's flexibility challenge:
  - Over-build will increasingly reduce the amount of resource required to meet year-to-year variations in hydro generation. i.e. we will still have a dry-year problem, but the size of the dry-year problem will become progressively less over time.
  - The significant increase in wind & solar generation with their much greater short-term volatility will give rise to greater need for flexibility resources that can operate over shorter durations: within-day and within-week. The ability to meet periods of low wind and solar generation that could last days or even weeks – so-called 'dunkelflaute' events[20] – will become steadily more and more a key driver of our flexibility requirements.

    Appendix A sets out the dynamics behind these changes in more detail.
- This reduction in dry-year requirements and increase in dunkelflaute requirements will change the type of response that will most cost-effectively meet our flexibility needs.
  - Our existing hydro fleet will be able to meet much of this challenge with altered within-day and within-week operations, but physical limitations (finite MW capacity, river chain dynamics, finite capacity to transfer South Island generation across the HVDC, and the requirement to maintain minimum river flows) will mean that hydro stations can't meet all this additional demand for short-term flex.
  - Batteries (both static batteries and within electric vehicles) combined with demand-side response will also be able to meet much of the challenge for very short-term duration response. In doing so, they will radically reduce the need for very-infrequently used MW generating capacity, delivering significant economic savings (although not much GWh and associated carbon savings).
  - Flexibility resources located in the North Island will deliver significantly greater benefit than equivalent resources located in the South Island. This is because:
    - there is limited transmission capacity between the North and the South islands, and

[20] "Dunkelflaute" is a German word which literally means "dark doldrums".

  - most of the wind & solar development will be in the North Island due to most of the demand growth occurring in the North Island and the fact that the fossil thermal generation that is due to exit is all located in the North Island.

Relative merits of the options to meet this flexibility challenge

These dynamics explain the relative merits of the different options our modelling has explored:

- Despite being located in the South Island (and thereby having its flexibility contribution to meet North Island dunkelflaute events constrained at times)[21], large-scale flexible demand from a hydrogen production facility or the aluminium smelter could be low-cost options because
  - they don't have any significant capital cost requirements that must be recovered from the electricity market – the cost of the hydrogen production facility or the smelter should be recovered by the sales of hydrogen or aluminium; and
  - the size of their potential response is large relative to the NZ system.

  However, the extent to which these could be lower cost solutions is heavily dependent on their ability to flexibly reduce production without incurring significant costs, including for sustained periods of time. If the opportunity cost of curtailing production of hydrogen or aluminium to deliver electricity flexibility is greater than the assumptions we have used, the scale of benefit we have modelled would be less (and vice versa). We note there is significant uncertainty over this issue of curtailment opportunity costs, and consider this to be a key issue for further analysis.

- North Island peaking thermal generation run infrequently at times of significant scarcity can be a very cost-effective means of meeting the relatively small residual demand for flexibility that isn't provided by renewable over-build.
  - The very high running costs of thermal peakers (either due to fossil gas facing a high carbon price, or biofuel being inherently high cost) is more than outweighed by the benefit of the low capital costs of such options. This is particularly true given that in most cases the peaking plant already exist so their capital costs have been sunk (at least for the next few decades).
  - Further, the North Island location of such peakers will reduce the extent to which high-cost batteries will be needed for periods of extreme scarcity.

  However, we note that the green peaker option faces material uncertainty regarding the cost and practicality of producing and storing sufficient biofuel to provide flexibility.

  The fossil gas peaker option faces far less technical uncertainty. For example, the carbon price required for the cost of electricity to be the same as that assumed for the green peaker is approximately \$550/tCO_2. This price is substantially higher than most projections, and yet it would deliver an equivalent level of benefit to the green peaker option – which, as Figure 9 previously shows is lower cost than the Coal reserve, Overbuild, and SI Pumped Hydro options.

  Another key advantage of the thermal peaking options is that they are more readily deployed incrementally, and thus would not result in the adverse outcomes associated with 'mega projects' detailed below.

[21] Our modelling has been potentially optimistic to South Island options as it assumes the HVDC interconnector between the islands can operate at 1,400 MW in all scenarios. This is materially greater than the currently observed maximum north-flow of about 1,000 MW, and effectively assumes a cable upgrade plus a change to the arrangements for the procurement of instantaneous reserves to cover the risk of the failure of one of the two HVDC 'poles'.

- While a large pumped-storage scheme in the South Island would provide a lot of flexibility for the system, it appears likely that it would come with a significant additional cost. If these costs are recovered from electricity consumers (via a levy or market-mechanism) that could result in higher whole-of-economy emissions, even though this is a 100% renewable option. As noted by the Climate Change Commission, this is because higher electricity prices could frustrate electric vehicle uptake and electrification of space & water heating and industrial process heat.

  As with flexible hydrogen/aluminium production, its South Island location will make it less effective at meeting North Island dunkelflaute events.

  The 25% round-trip efficiency losses associated with pumping will tend to reduce the benefit of its renewable balancing effectiveness.

  Lastly, it is likely that this option would take the longest to develop (most of the other options already exist or, in the case of the hydrogen production facility, could be developed several years earlier than a large-scale South Island pumped hydro scheme), and give rise to the greatest adverse outcomes associated with 'mega projects'.

Potential issues with 'mega projects'

Options which are large relative to the size of the system and cannot be readily broken into smaller components create special challenges in the years leading up to their commissioning. This is because, upon commissioning, the system will suddenly switch into being in a situation of major surplus relative to the period prior to commissioning.

This may tend to suppress investment in renewable generation in the years immediately prior to the mega project's commissioning, as such renewable generation will be less able to cover its costs in a market which is in surplus after the mega project's commissioning.

In the years immediately prior to the mega project's commissioning, the consequences are likely to be:

- Higher prices; and
- Higher levels of fossil generation.

An example of this dynamic is the uncertainty experienced over the last few years as to whether the Tiwai aluminium smelter would exit and cause the system to switch to a situation of major surplus with the loss of 13% of New Zealand's demand. This uncertainty has caused lower investment in new renewable generation over the past few years, resulting in the system being short of generation once the aluminium smelter's contract was extended – albeit for four years and creating a new "will it stay or go?" uncertainty horizon.

The larger and more lumpy the project, the more significant the effect is likely to be on outcomes. Of the options we have considered, the pumped-storage scheme is likely to be most challenging. This is because it is largest in size and because it has the additional challenge of significantly increasing demand in the year or two prior to its commissioning when it is being filled. This filling dynamic will further exacerbate the relative change in the supply/demand balance upon its commissioning.

These adverse effects will vary according to underlying levels of demand growth and associated generation build. If demand growth is high the change in supply/demand balance (and associated adverse outcomes) upon the mega-project's commissioning will not be as great or sustained compared to if demand growth is low. Similarly, if a mega project can be broken into components and staged over time that would reduce the transition challenge.

It was beyond the scope of this study to try and quantify these potential mega-project effects for the different scenarios.

Appendix A. What drives the need for flexibility, and how will this change in a high renewables future?

This appendix provides more analysis detailing:

- what drives the demand for flexible resources;
- how future renewable over-build can cost-effectively and substantially reduce the need for flexible resources; and
- how increased proportions of wind and solar will alter the need for flexible resources.

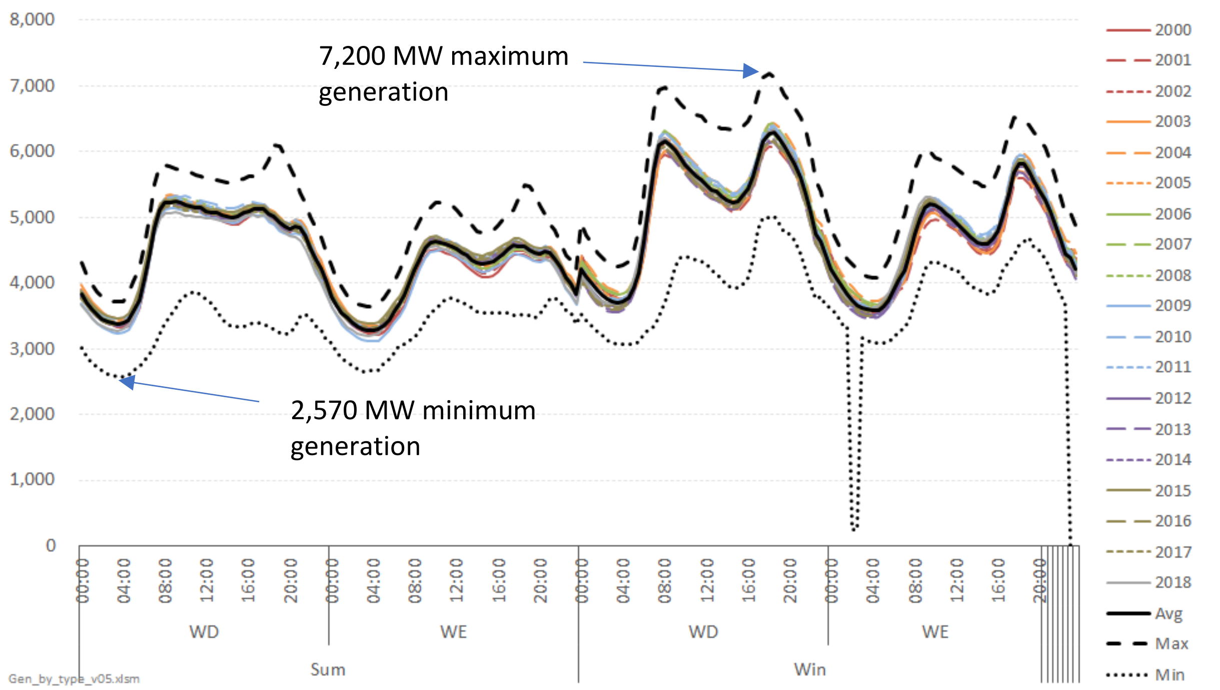
Drivers of the demand for flexibility

Variations in demand drive much of the need for flexibility

Electricity demand varies regularly across the day, week, and year, following the patterns of human activity. In addition to this regular variation, significant random variation can occur across all these timeframes caused by factors such as weather.

This is illustrated by Figure 20 below which shows the average within-day, within-week and within-year demand patterns from 2000 to 2018 – normalised to account for changes in underlying demand during this period[22] – along with the maximum and minimum demands across these historical years for each of these time periods.

Figure 20: Historical patterns in demand for generation (MW)[23]



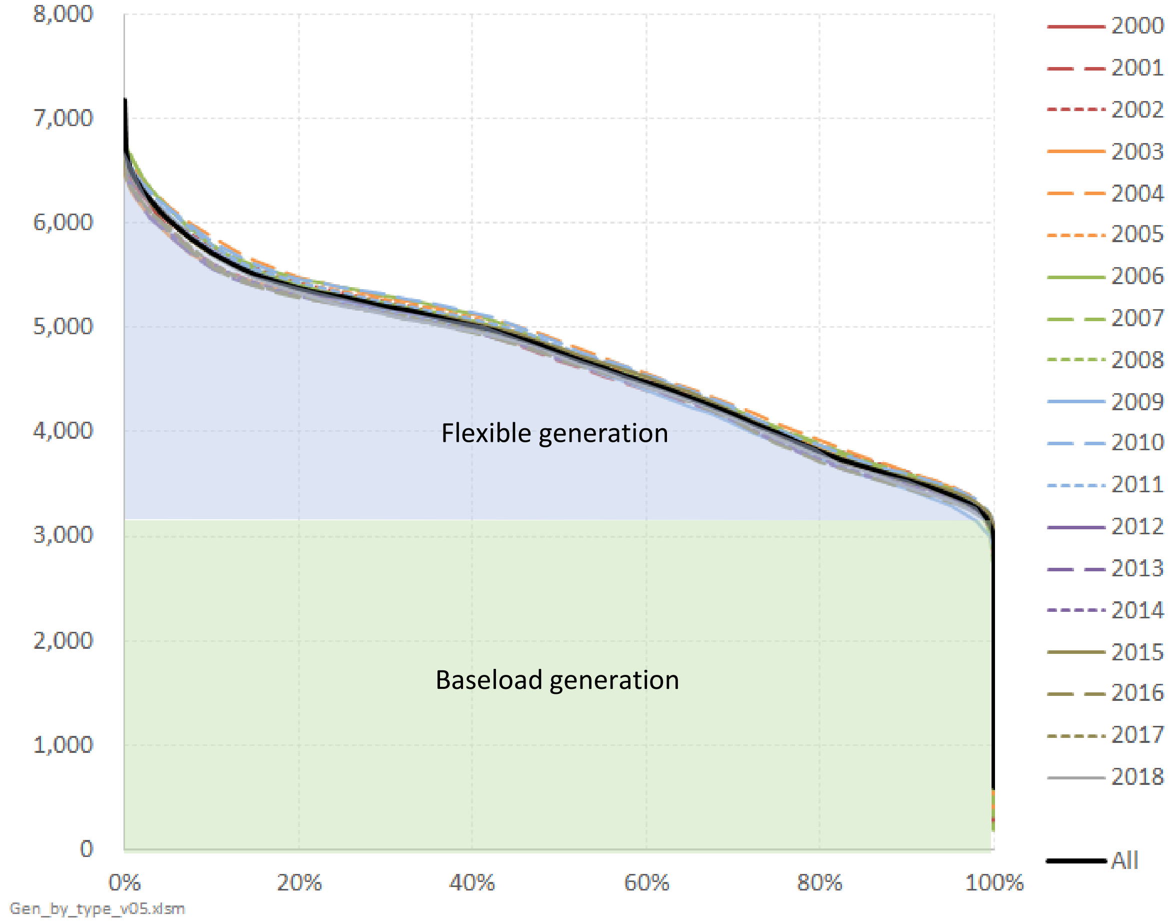
Thus, if the only variation the New Zealand electricity system had to face was from demand, there would be a need for some 2,570 MW of generation that would operate continuously (a.k.a. 'baseload'), and a further 4,630 MW (7,200 minus 2,570) of 'flexible' generation that would only operate for some of the time. Some of this flexible generation would operate almost all the time

[22] Demand has been normalised by increasing or decreasing historical demands to deliver an annual demand for each year that is consistent with 2018 demand.
[23] The couple of incidences of apparent very low minimum demands are due to one instance of missing historical data, and other instances of missing time periods due to the clocks going forward.

and only turn off very infrequently, whilst other generation would be off for most of the time and only turn on very infrequently.

Figure 21 presents the same underlying data as used for Figure 20, but as a duration curve – where each half-hour is ranked according to demand.

Figure 21: Duration curve of historical demand for generation (MW)



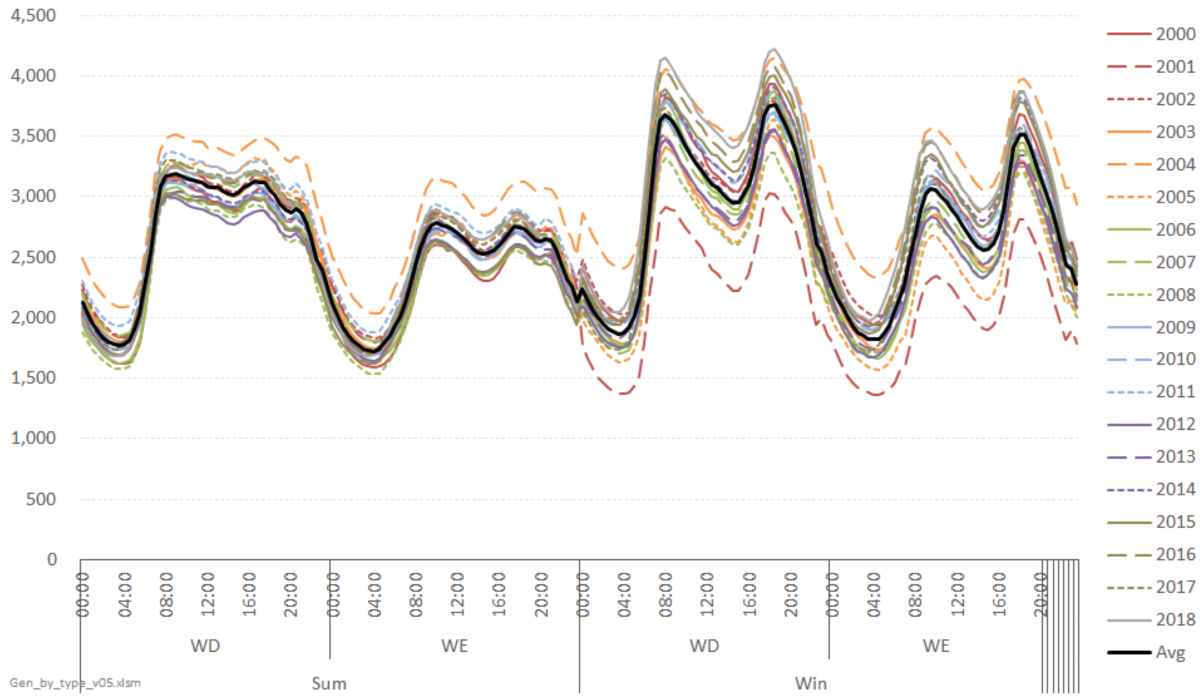
On its own, demand variation currently gives rise to a need for approximately 11,300 GWh of flexible energy – as represented by the blue shaded area in Figure 21. This compares to annual demand for generation (baseload plus flexible) of approximately 41,000 GWh.

Hydro storage meets much of the need for flexibility – but variations in hydro inflows creates a new need for flexibility

Currently, approximately 58% of New Zealand's generation is from hydro power stations. Many of these have storage reservoirs which allow water to be stored during low demand periods to be released during high demand periods.

This storage capability means that New Zealand's hydro schemes can operate to meet a significant proportion of the demand for flexible generation. This can be seen in Figure 22 below which, when compared with Figure 20 previously, shows that the average within-day and within-year pattern of hydro generation closely matches that of demand.

Figure 22: Average historical within-day and within-year patterns of hydro generation (MW)



However, hydro generation is not able to completely meet the within-day and within-year demand for flexible generation. Further, as Figure 22 also shows, there is significant variation in the amount of hydro generation between years, due to variations in whether the weather is 'wet' or 'dry' and associated variations in hydro inflows.

This gives a 'residual demand' for generation after hydro which has some reduced within-day and within-year demand for flexibility, but which now has greater year-to-year variations in the demand for flexibility. This is shown in Figure 23 and Figure 24, below.

Figure 23: Historical average within-year and within-year post-hydro residual demand for generation (MW)

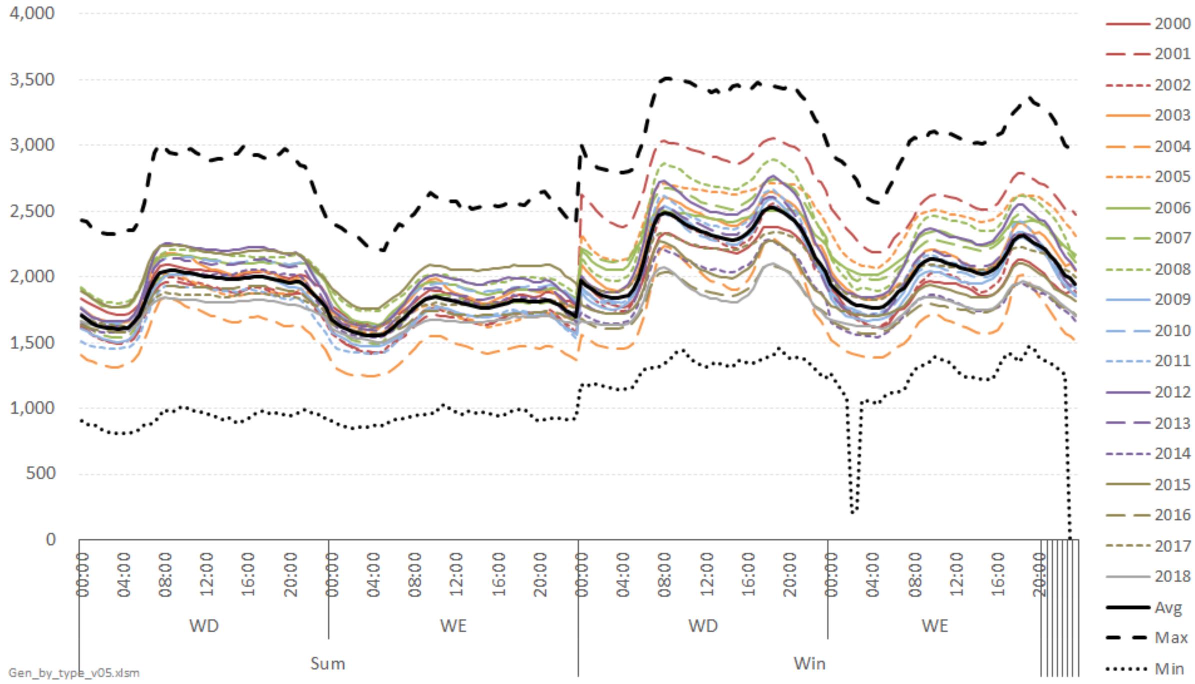
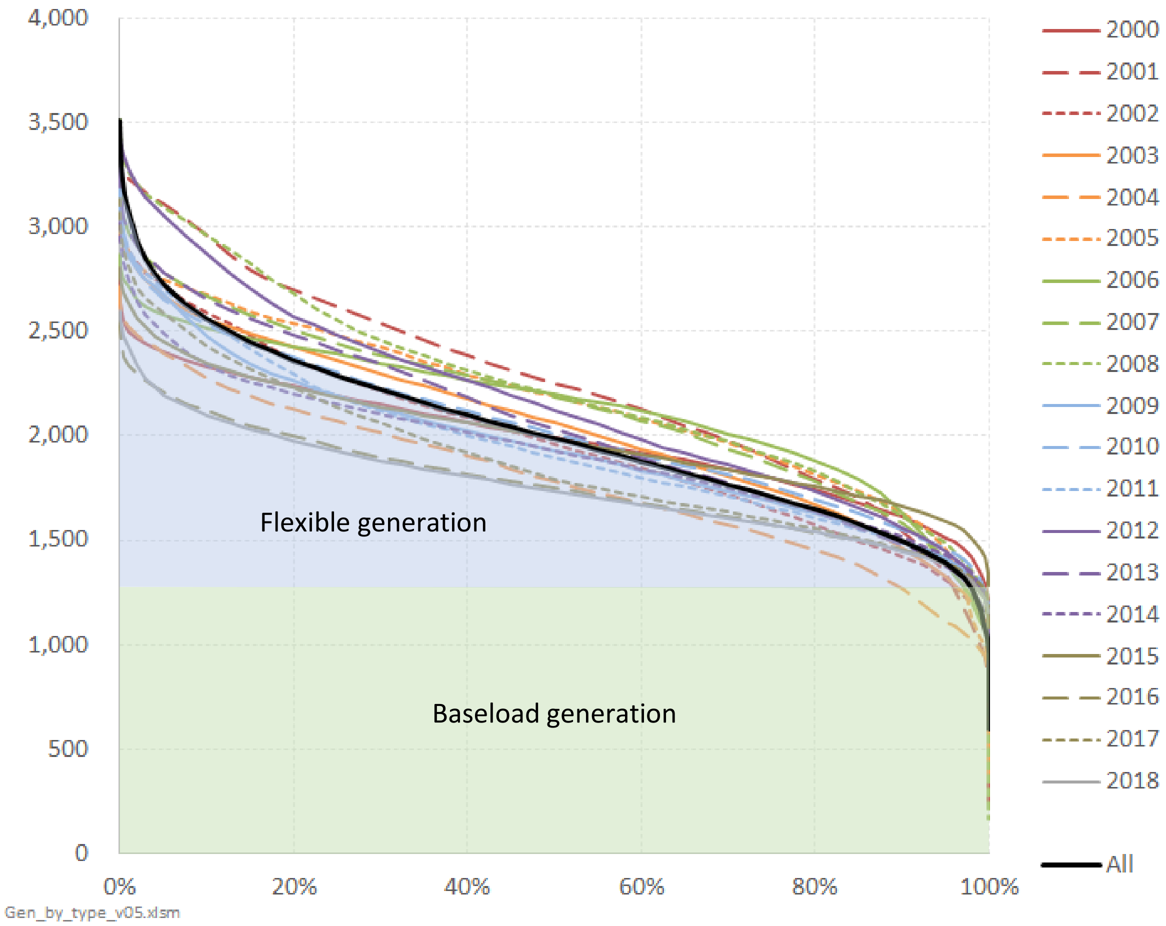


Figure 24: Historical duration curves for post-hydro residual demand for generation (MW)

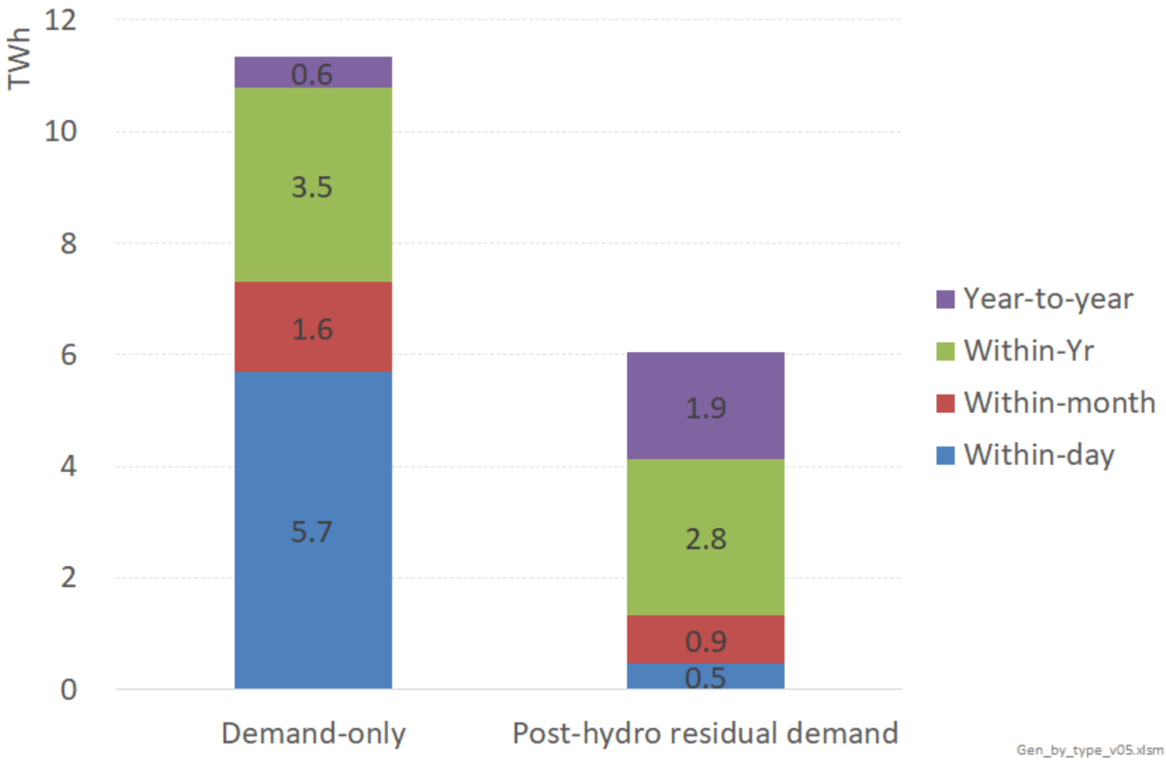


New Zealand's hydro generation has reduced the quantity of flexible generation required from approximately 11,300 GWh to approximately 6,000 GWh. However, the time-frames over which this flexibility has required has changed significantly.

This is illustrated by Figure 25 below. This shows that:

- within-day and within-year variations in demand are the biggest drivers of the demand-only need for flexibility.
- the significant within-day 'sculpting' of hydro generation almost completely meets this demand for within-day flexibility, and reduces the need for within-month and within-year flexibility
- year-to-year variations in hydro generation create a new need for flexible energy resources that can operate over these timescales.

Figure 25: Breakdown of time dimension driving New Zealand's flexible energy requirements[24]



Describing how renewable over-build can meet much of our future flexibility requirements

The development of geothermal and wind generation to-date has largely displaced fossil generation from baseload duties, but fossil generation still almost entirely meets the demand for flexible generation

Over the last decades, New Zealand has made significant investments in wind and geothermal generation. On an *average* within-day and within-year basis the output from these schemes is

[24] The requirement for within-day flexibility has been derived by comparing the total requirement for flexibility, with the requirement for flexibility if each day had completely flat levels of demand or post-hydro demand. Likewise, the requirement for within-month flexibility compares this requirement for flexibility in a 'flat day' world, with that if each month had completely flat levels of demand or post-hydro demand. And so on.

largely flat (although wind has significant random variation – the implications of which are explored more, later).

Thus, Figure 26 below shows that the overall MW demand for post-renewable generation (i.e. demand less hydro, geothermal, and wind) is materially less than the demand for post-hydro generation shown in Figure 23 previously, but the within-day and within-year shape is largely the same.

Figure 26: Within-day and within-year post-renewable demand for generation (MW)

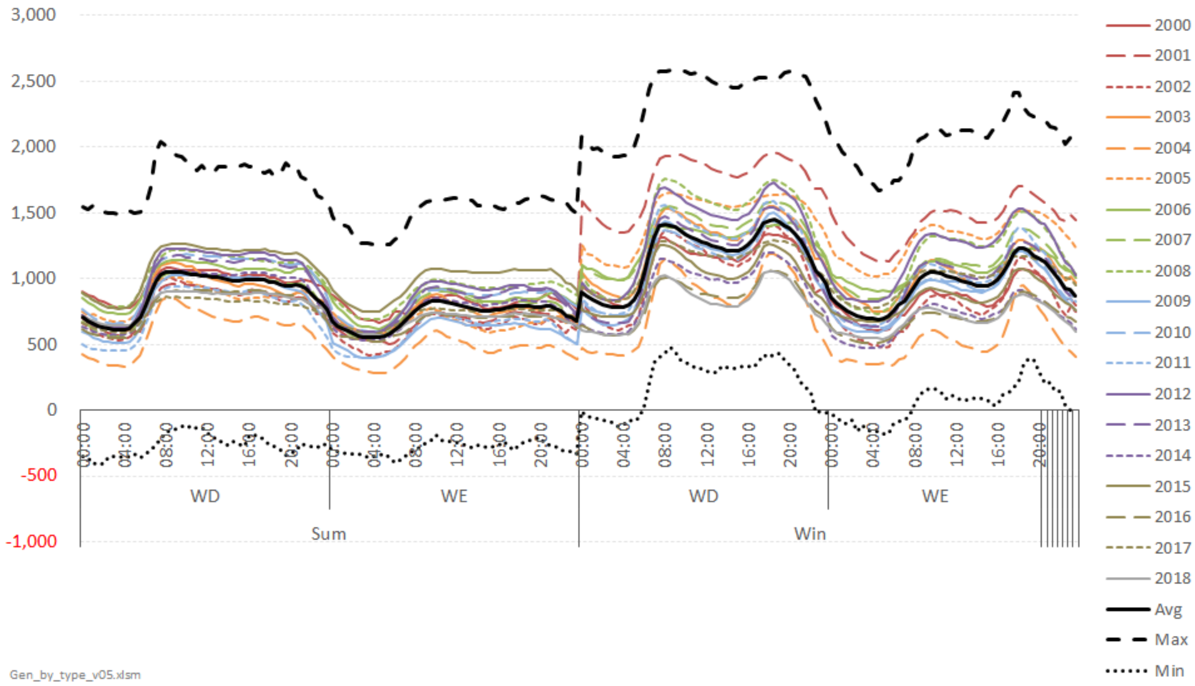
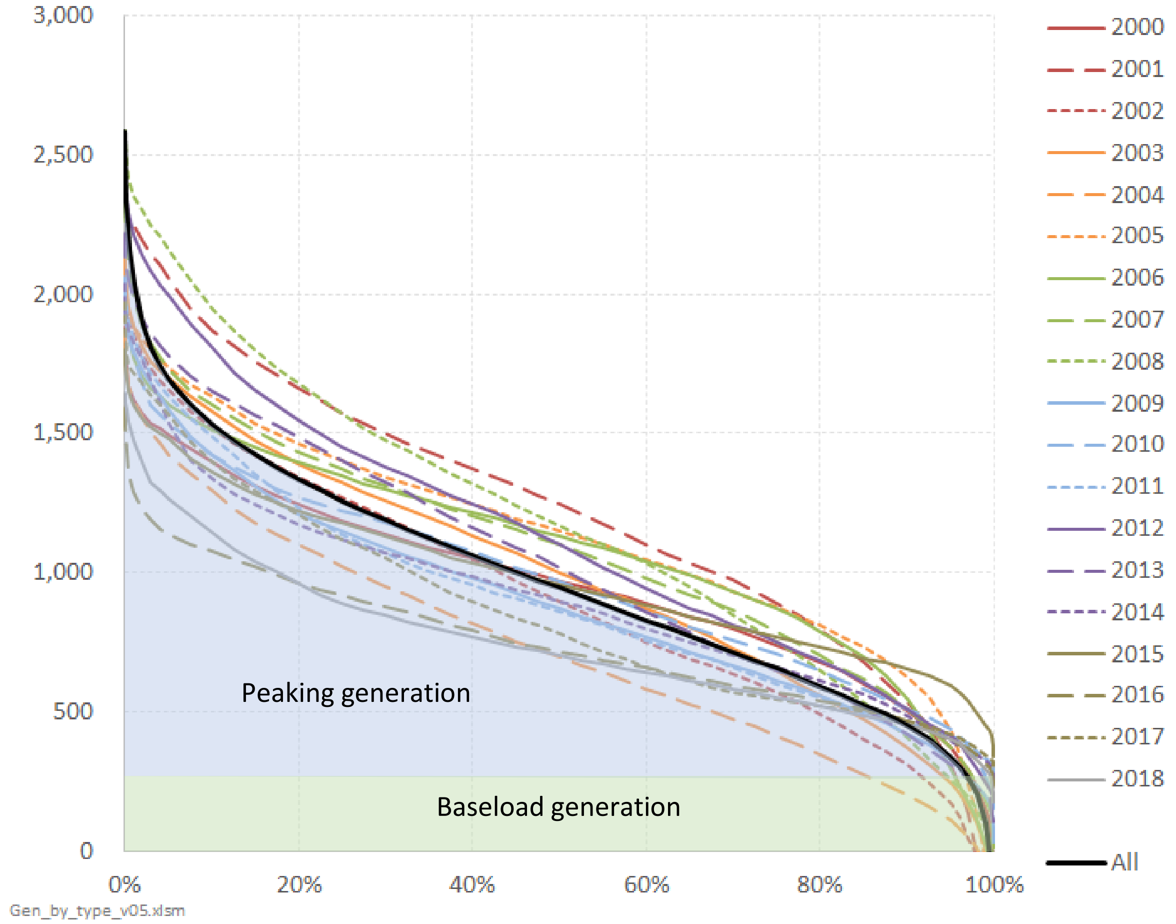


Figure 27 below illustrates that the overall requirement for post-renewable baseload generation is substantially reduced compared to post-hydro generation shown in Figure 24, but the GWh demand for post-renewable flexible generation is largely the same as that for post-hydro generation – albeit with a greater MW requirement for meeting peaks due to wind variability – more on this later.

Figure 27: Duration curve of post-renewable demand for generation



This post-renewable demand for generation is currently met by fossil-fuelled power stations – a mix of: two high-efficiency combined-cycle gas turbine (CCGT) stations; the lower efficiency Huntly Rankine dual-fuel (coal & gas) station; and a handful of lower efficiency open-cycle gas turbine (OCGT) stations.

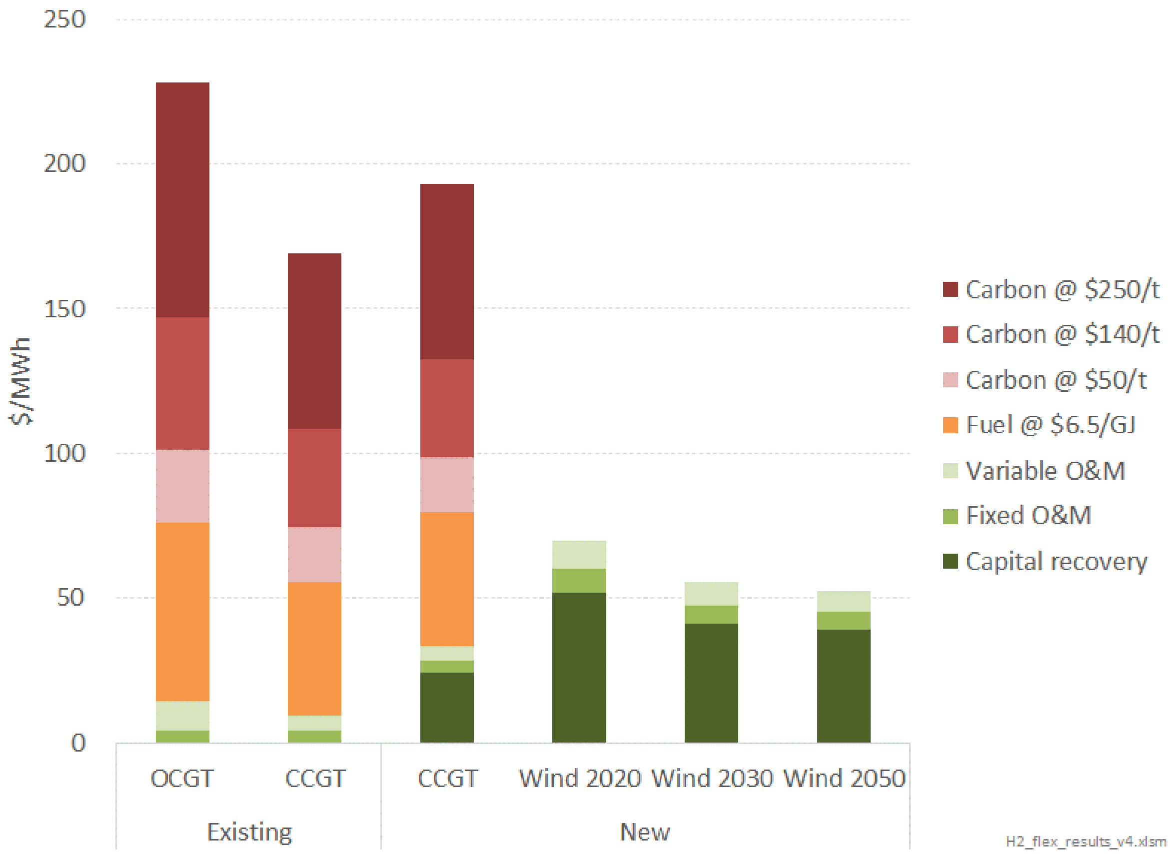
Collectively these stations account for approximately 18% of New Zealand's generation. Of this 18%, approximately 25% performs baseload duties, with the remaining 75% performing peaking duties.

To-date, fossil generation's low capital costs have made it uneconomic to displace from peaking duties, but ongoing reductions in wind & solar costs plus increases in carbon prices, will increasingly change this

Figure 28 shows the levelised cost of electricity (LCOE) for a few different technologies and situations:

- Two types of fossil station
  - High efficiency combined-cycle gas turbine (CCGT) shown for both an existing and a new-build situation
  - Lower-efficiency open-cycle gas turbine (OCGT)
- New-build wind, for three different years (2020, 2030, and 2050)

Figure 28: Levelised-cost-of-energy (LCOE) for baseload operation for different technologies



The key take-aways are that

- By 2020 the cost of wind had dropped to the point where it was already cheaper to build wind to meet baseload demand growth than a new CCGT, even without a cost of carbon, but an existing CCGT which didn't face a cost of carbon would be cheaper to continue to operate rather than build a new wind station to displace it
- The addition of a cost of carbon starts to make it cost-effective to build new wind farms to displace existing CCGTs from baseload operation. The current threshold price for this to be cost-effective is just below $50/t, but as the cost of wind technology reduces this threshold price will also reduce.
- At the carbon prices the Climate Change Commission indicates are likely necessary in 2030 and 2050 ($138 and $250/t$CO_2$, respectively), wind is significantly lower cost than CCGT generation
- Only a very small proportion of the cost of existing fossil plant are fixed costs. All the rest vary with the amount of generation

This would imply that as carbon prices are now reaching $50/t$CO_2$ there should be investment in renewables to the extent that fossil generators are completely displaced from baseload operations. And, indeed, that is indeed the case as a raft of new geothermal, wind and solar generation projects (all of which have LCOEs around the $70/MWh level) are being developed to the extent that the remaining CCGTs will be displaced from baseload duties.

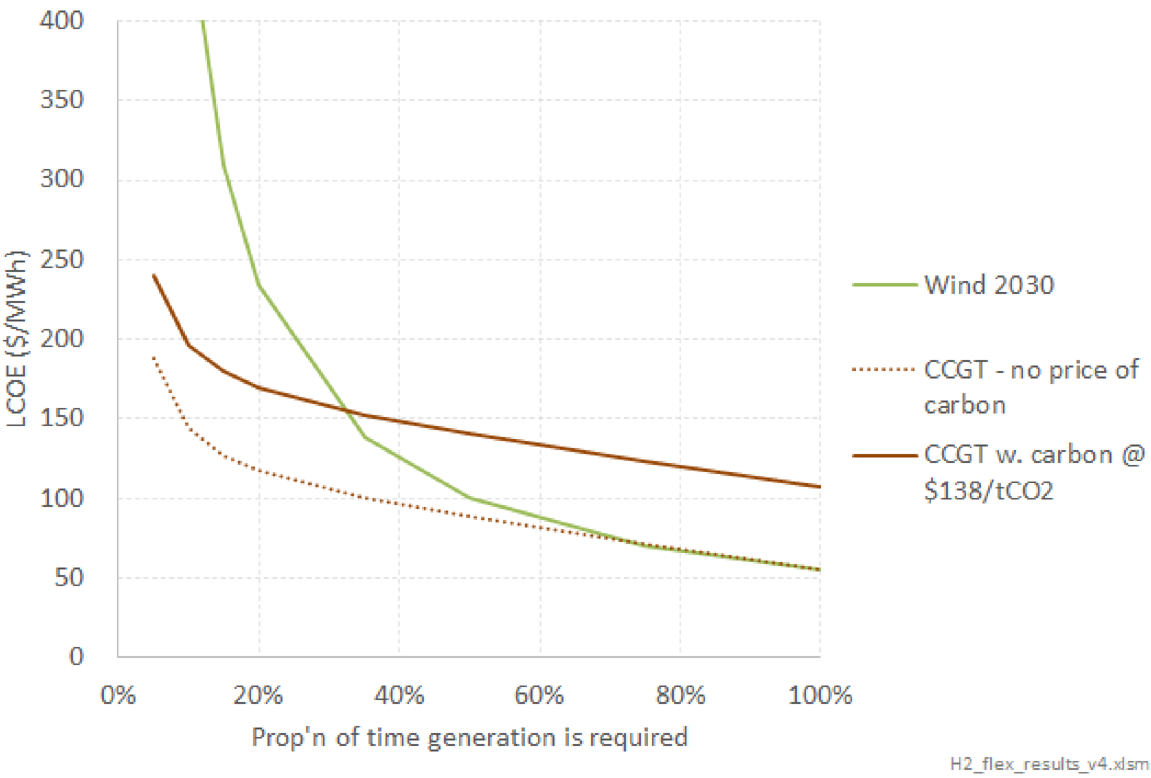
And as carbon prices rise further, and as wind & solar costs drop further, it should become increasingly economic to build new renewables to displace existing CCGTs and OCGTs from lower capacity-factor flexibility duties.

However, there will be limits to how much it will be economic to displace due to the differences in fixed costs between the options.

To illustrate this, consider building a new wind farm to displace peaking fossil generation that is only required 50% of the time. The capital and fixed O&M components of each technology will need to double, as the fixed $ costs are only being recovered over half the kWh of generation. For existing CCGTs and OCGTs this has a relatively small impact on costs because they have no capital to recover (such costs are sunk) and fixed O&M costs are relatively small. In contrast, the costs of wind stations almost double because their LCOE is dominated by capital recovery and fixed O&M costs.

Figure 29 shows the effect of this on the relative costs of building a new wind farm versus continuing to operate an existing CCGT. As can be seen, the cost of a wind farm increases much more significantly at lower capacity factors than the cost of a CCGT. It should be noted that the cost of a CCGT rises with lower capacity factor operations not just because of the recovery of its fixed O&M, but also because the cost of supplying gas at ever lower capacity factors also rises. Thus, we assume that the $/GJ cost of gas for 20% capacity factor operations is double that for baseload operations.

Figure 29: Comparison of LCOE of new wind and existing CCGT in 2030 at differing levels of required operation

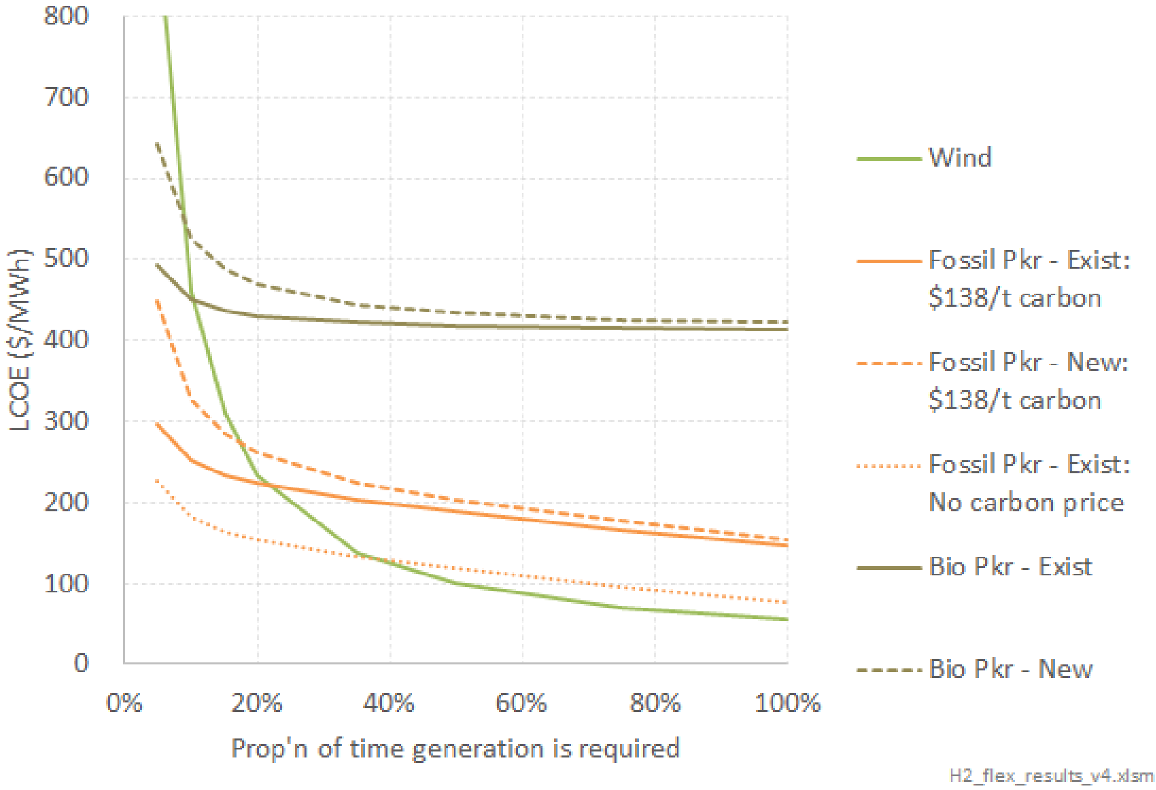


Without a cost of carbon it is finely balanced as to whether it would be cost-effective to build a new wind farm to displace CCGT from operating at anything greater than a 75% capacity factor. However, for CCGT capacity factors below that level it is clear cut that it would not be cost-effective to build new wind.

However, with the cost of carbon for 2030 the CCC indicated was likely necessary to achieve our net-zero transition, it becomes cost-effective to build wind to displace CCGT duties down to capacity factors of just over 30%. Further, at such low capacity factors, the pattern of operation will be very variable with a lot of starting, stopping, and cycling up-and-down. This is not a good pattern of operation for a CCGT which is not a very flexible plant. As such, there would be even greater cost increases for CCGTs at lower capacity factors – something that is not shown on this graph – such that it would start to be more cost-effective to use an OCGT peaker.

Given that OCGTs are likely to be more cost-effective than CCGTs for low-capacity factor operations, Figure 30 below shows the same type of information as in Figure 29, but compares wind with OCGT peakers: Existing and New, and fossil gas and bio-fuelled (with the cost of the gas and bio-fuel as per the assumptions set out in sections 0 and 2.3.5, respectively).

Figure 30: Comparison of LCOE of new wind and OCGT peakers in 2030 at differing levels of required operation

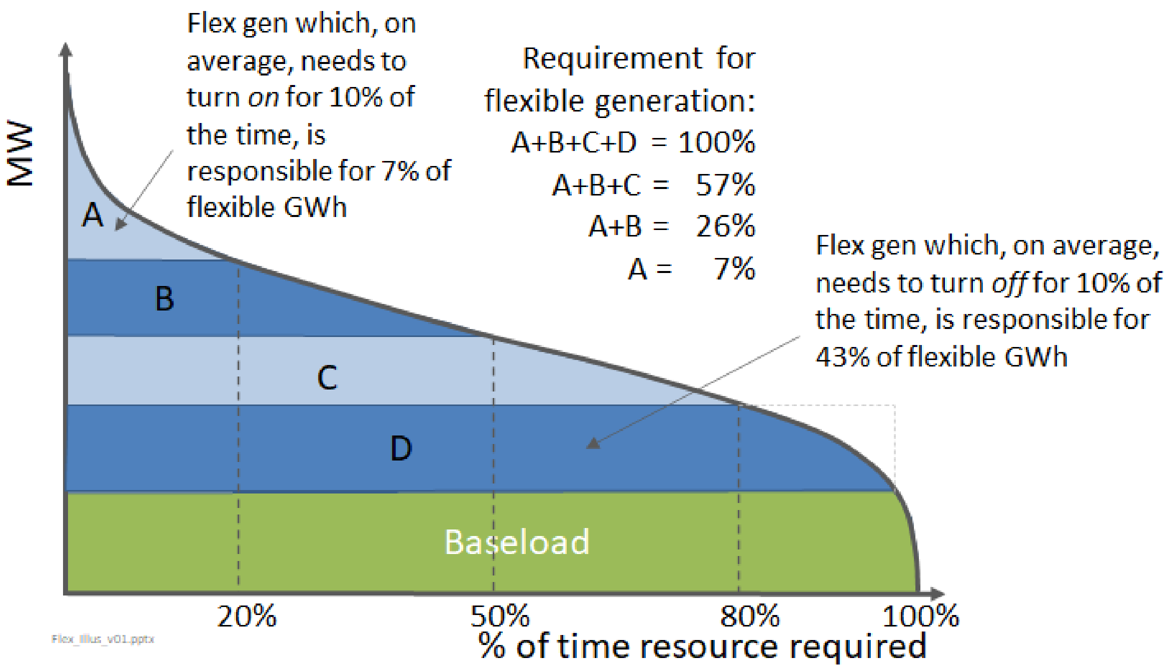


This shows that, at $138/tCO$_2$ carbon prices in 2030, it would be cost-effective to build new wind to displace existing fossil gas peakers down to approximately 20% capacity factor duties (approximately 17.5% to displace new peakers from being built), and for biofueled peakers the cost-effective level of wind development would be to displace bio-peakers down to 10% capacity factors. At this level, the marginal wind plant being developed would only be usefully providing output for 10% of the time.

Cost-effective renewable overbuild can significantly reduce the need for thermal generation

Figure 31 below stylistically represents the post-renewable duration curve for generation shown in Figure 27 previously.

Figure 31: Stylistic representation of the current post-renewable demand for generation



This shows that over-building to a relatively modest extent can significantly reduce the requirement for flexible generation from thermal generation.

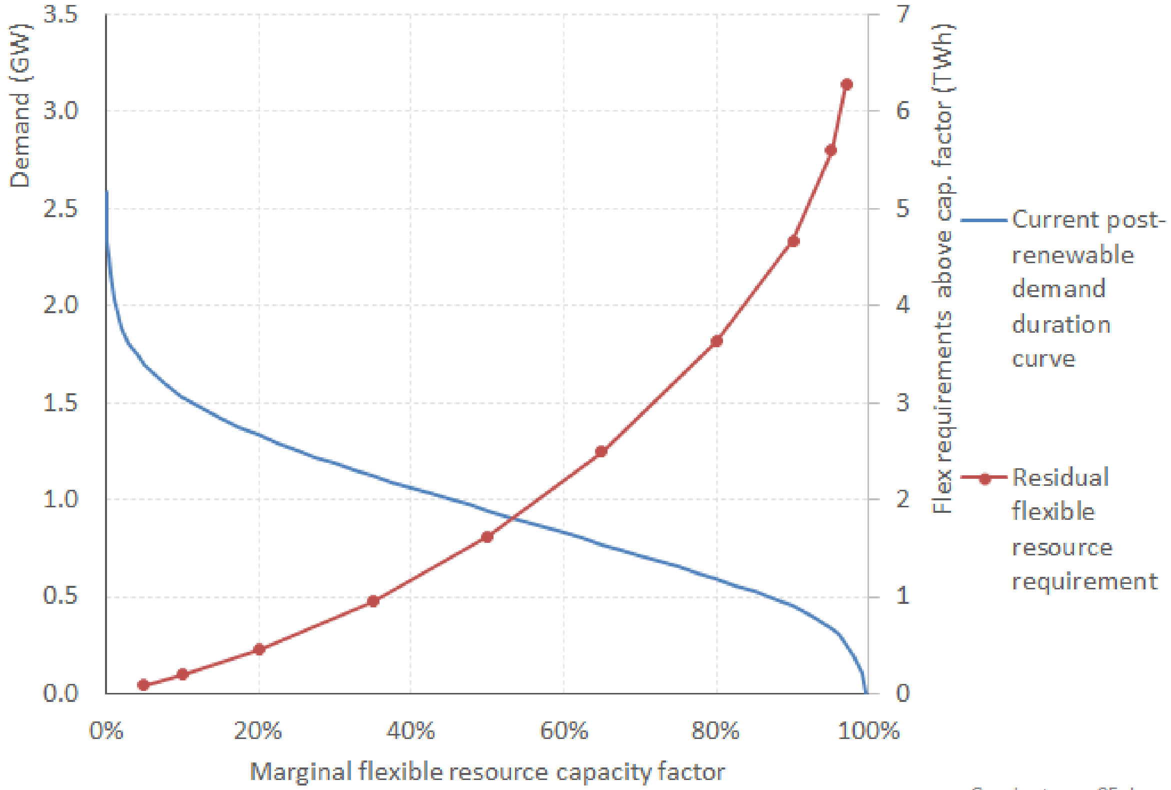
This is shown in Table 4 below which shows how over-building such that the marginal renewable resource is only required for X% of the time (with the remaining (1-X%) of the time resulting in spill) will reduce the requirement for peaking thermal generation by Y%, and result in an overall system renewable % of Z%.

Table 4: Effect of varying degrees of over-build on the requirement for peaking thermal generation and overall renewable generation %

% of time marginal renewable resource is required ('X%')	Reduction in peaking thermal generation ('Y%')	Overall system % of renewables ('Z%')
80%	42.2%	92.1%
50%	74.2%	96.5%
20%	92.8%	99.0%
10%	96.9%	99.6%
5%	98.6%	99.8%

This is further illustrated in Figure 32 below.

Figure 32: Effect of differing capacity factors for the marginal renewable resource on the requirements for flexible generation



Gen_by_type_v05.xlsm

Some of the key take aways from the above analysis are:

- Cost-effectively over-building renewables can significantly reduce the demand for flexibility resources; However
- It starts to become exponentially costly for over-build to displace the last few fractions of a percentage of flexibility requirements which require a lot of capacity that is very infrequently called-upon.

For very low capacity-factor duties, demand response and batteries will limit the need for other forms of flexibility response

Figure 32 shows that for the lowest capacity factor duties (approximately less than 5% of the time), the post-renewable demand duration curve starts to get a lot steeper. In other words, a lot of MW capacity is required but very infrequently.

Some of this requirement will be met by demand response. Typically, demand response is a very expensive resource as it requires the consumer to forego the benefit they would have gained from consuming electricity – e.g. manufacturing steel. However, as Figure 30 previously illustrates, for very low capacity factor duties renewable overbuild and peaker generation options (especially if they are new-build) start to become very expensive options.

We assume a significant amount of demand response is available at $700/MWh: Expensive compared to 'normal' electricity prices of approximately $70-80/MWh on average, but lower-cost for these very low capacity factor duties than overbuilding renewables or building OCGT peakers.

Calling upon demand response will significantly reduce the amount of MW generating capacity that would otherwise have been needed to be built. However, it doesn't result in significant GWh (and associated emissions) savings as this MW capacity would have been used very infrequently.

Most of the extreme peaks in demand for flexibility resources are of short duration – i.e. of the order of a few hours. As such, as batteries are increasingly connected to our system – both static batteries, and batteries within electric vehicles (EVs) – they will increasingly also contribute to meeting these peaks. EVs can contribute through smart-charging which avoids periods of peak demand, and increasingly will also be able to contribute by injecting power back into the grid at times of extreme scarcity – so-called vehicle-to-grid or V2G.

Increased proportions of wind and solar will alter the type of flexible resource required

Cost-effective over-build of renewables will significantly reduce the amount of flexibility resource required to meet dry-year events. Thus, if a large pumped-storage reservoir were to be used to provide flexibility, the size of storage reservoir required to deliver the dry-year energy would be a lot less.

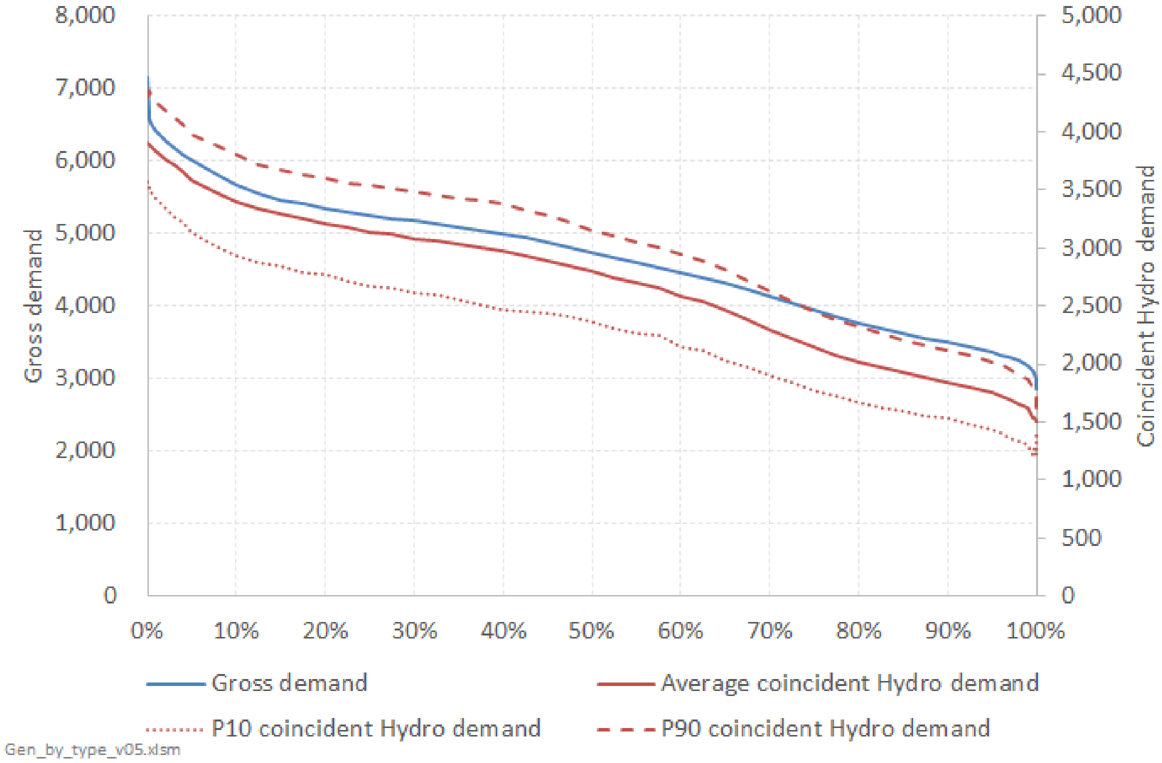
However, while the GWh energy required from flexibility resources may be significantly reduced, there won't be such a significant reduction in the MW capacity required from flexibility resources. This is because a significant proportion of the renewable energy that will be built to meet demand growth and (via overbuild) displace existing fossil stations will be variable generation from wind and solar. This increased variable generation will alter the shape of the post-renewable residual demand curve, making the lowest capacity factor periods have an increased MW requirement relative to the average flexibility requirement.

To help understand this, the following charts step through the historical impact on the demand for flexible resources of hydro generation (which has highly variable inflows, but lots of ability to store such inflows to smooth out such variability) versus wind generation.

The analysis uses actual half-hourly data for the ten-year period 2009 to 2018, inclusive. This period was chosen as it had broadly similar levels of annual demand, and wind and hydro capacity – and thus could be regarded as suitably consistent for the purposes of this illustration.

Figure 33 below plots the half-hourly demand duration curve for this period, and alongside it the average level of hydro output for the different levels of gross demand.

Figure 33: Historical demand duration curve, and average coincident level of hydro output (MW)[25]



It shows that the pattern of hydro generation has, on average, very closely followed that of demand, albeit with material variation – as represented by the P10 and P90 levels of hydro output at these different gross demand levels.

[25] This average hydro output calculation is based on 2.5% bins. i.e. while the 50% level of demand in this graph represents the level of demand exactly at this 50% point in the duration curve, the coincident level of hydro output represents the average hydro output for all half-hours where demand is between the 48.75% and 51.25% marks. For the bottom and top 5% of the curves, the bins are smaller – 1% bins for 1% to 5% and 95% to 99%, and then progressively smaller bins for the very bottom and top 1% of the curves.

Figure 34 looks at the data a different way. It plots the post-hydro residual demand curve (i.e. gross demand minus hydro generation) and the average coincident hydro generation for these different levels of post-hydro residual demand.

Figure 34: Historical post-hydro residual demand duration curve and average coincident hydro demand

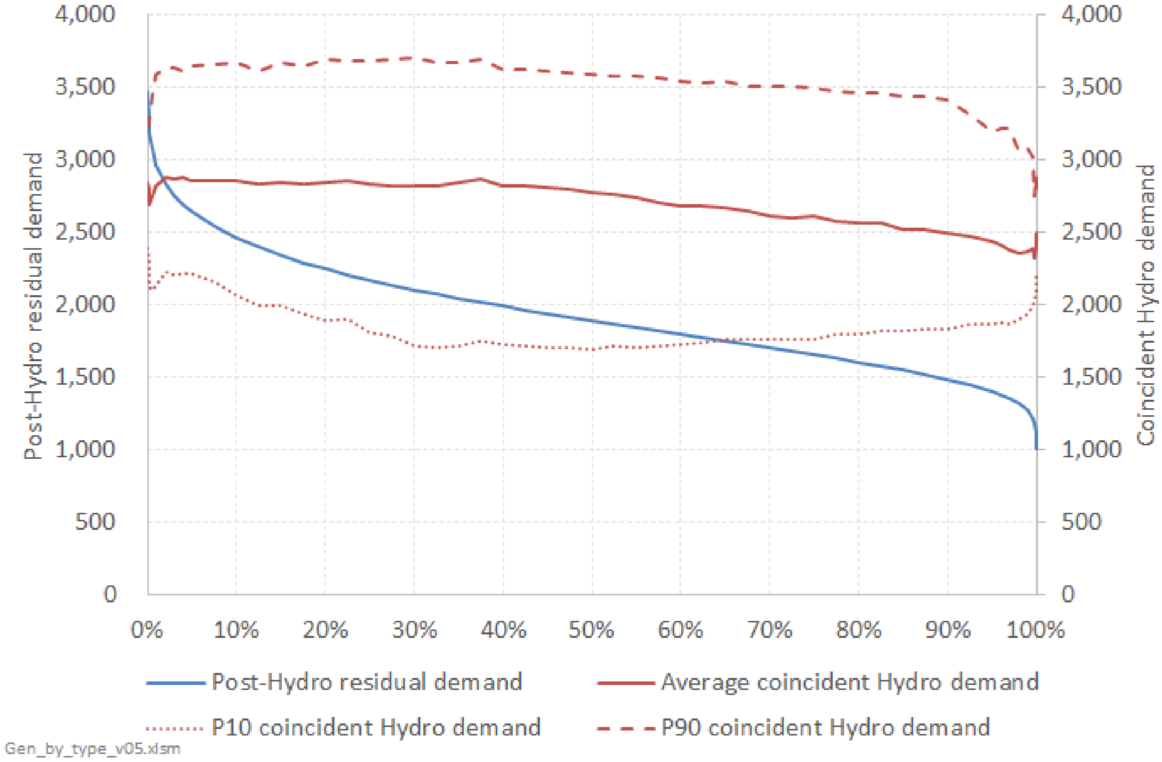


Figure 35 and Figure 36 below plot the same type of data as Figure 33 and Figure 34, but instead show the results for wind rather than hydro.

Figure 35: Historical demand duration curve, and average coincident level of wind output (MW)

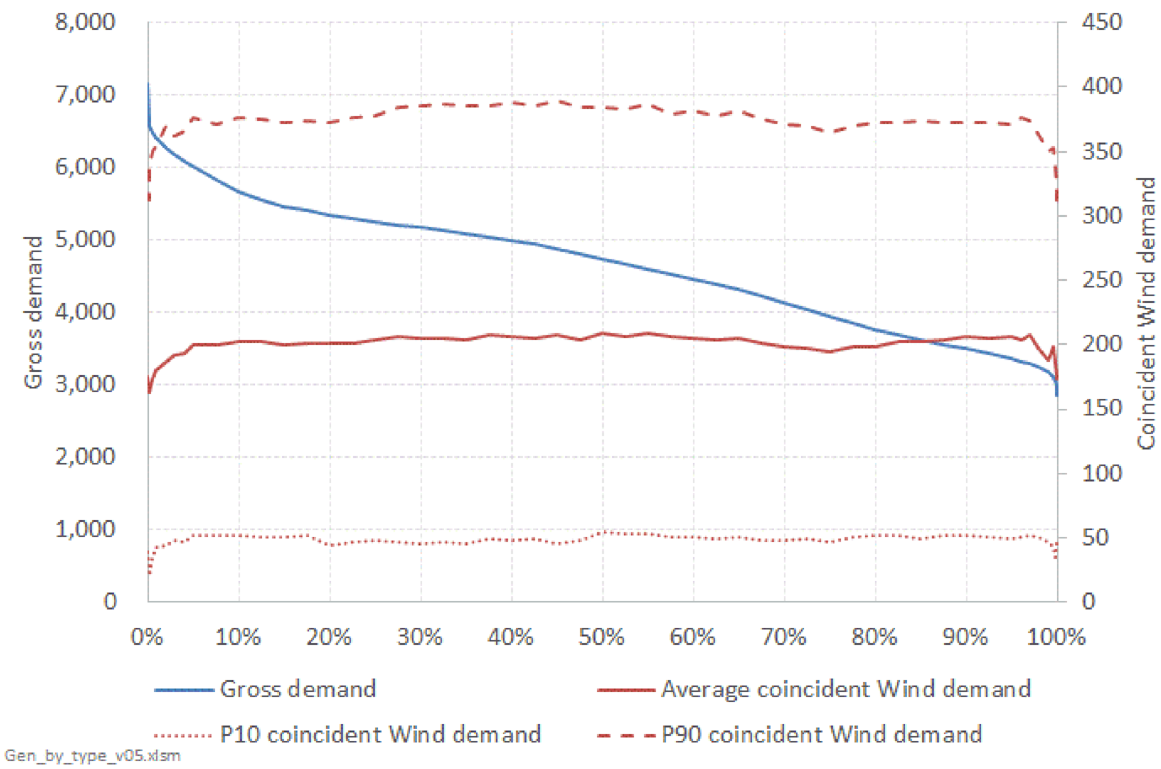


Figure 35 shows that, unlike hydro, there is generally no strong correlation between demand levels and wind output, with the potential for periods of high demand and very low wind output and vice versa.

The exceptions to this lack of correlation between demand and wind is at either end of the demand duration curve:

- During the periods of highest demand, there seems to be an *anti*-correlation with wind. i.e. wind output has on average been lower than normal.
- Wind output also seems to be lower on average at the periods of lowest demand.

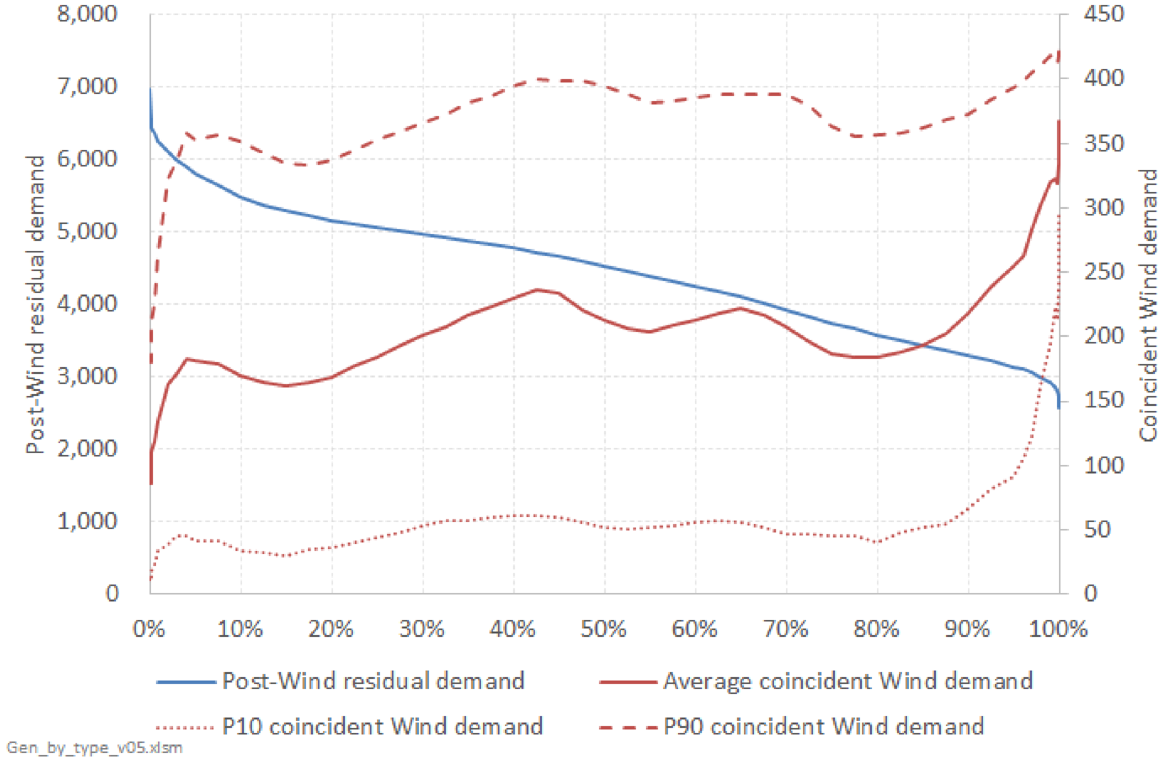
Both phenomena may be due to the type of weather system that affects both demand and wind – potentially a large anti-cyclone sitting over the country in winter and summer, respectively. The impact at times of high demand is particularly significant as it will mean wind is, on average, less able to contribute to meeting peak capacity requirements.

Figure 36 further illustrates that while wind may reduce the demand for energy from other sources, *without overbuild* it actually exacerbates the need for flexible energy due to the coincidence at one end of the duration curve of periods of high demand but low wind and at the other end of the duration curve periods of low demand but high wind. In particular, the periods of high demand and low wind will give an increased requirement for very low capacity factor peaking MW.

This contrasts with other renewable generation sources' contribution to flexibility *without overbuild*:

- hydro actively reduces the requirements for flexible generation from other sources (albeit introducing some year-to-year variability in the process as set out earlier)
- geothermal's completely flat baseload generation profile neither increases or decreases the requirement for flexible generation.

Figure 36: Historical post-wind residual demand duration curve and average coincident wind demand



The italicisation of 'without overbuild' in the preceding paragraphs is to emphasise that renewable overbuild of all types will also contribute to MW capacity requirements, but to varying degrees depending on their variability and correlation with periods of peak demand.

The above analysis has compared hydro and wind. The outcomes for solar will be similar to wind, but even more extreme in that solar output is strongly anti-correlated with periods of peak demand. Thus, the highest demand periods in New Zealand are cold winter evenings – times when there is little or no sunshine.

Appendix B. Resilience of different modelled scenarios to different environmental inputs

Our planted system "solutions" for each scenario are based on historical environmental inputs – i.e. hydrological inflows, wind-speeds, and insolation levels – for the years 1990-2017.

This means our least-cost mix of resources are optimal if future years have environmental inflows whose distribution of outcomes is the same as for 1990-2017. However, they may not be optimal if the pattern of inflows is different to this historical sequence.

To assess whether this may materially alter the relative merits of the different flexibility options, we took each of the fixed system solutions based on 1990-2017 and dispatched them using a random selection of environmental inputs from the full 1935-2017 historical record.[26]

Although there are some inherent limitations with this approach – not least because it is impossible to predict the extent to which climate change may alter environmental inflows – we believe this test provides some useful insights into the ability for different scenarios to respond to years with significantly lower environmental inflows. While much of this is intuitive, some insights may be surprising.

In general, scenarios with a dispatchable energy source fare better than those without. If hydro inflows are lower than expected, then this energy deficit needs to be recovered from somewhere. The H2/Al flex scenarios perform particularly well because they are able to reduce demand for a sustained duration at a relatively low cost.

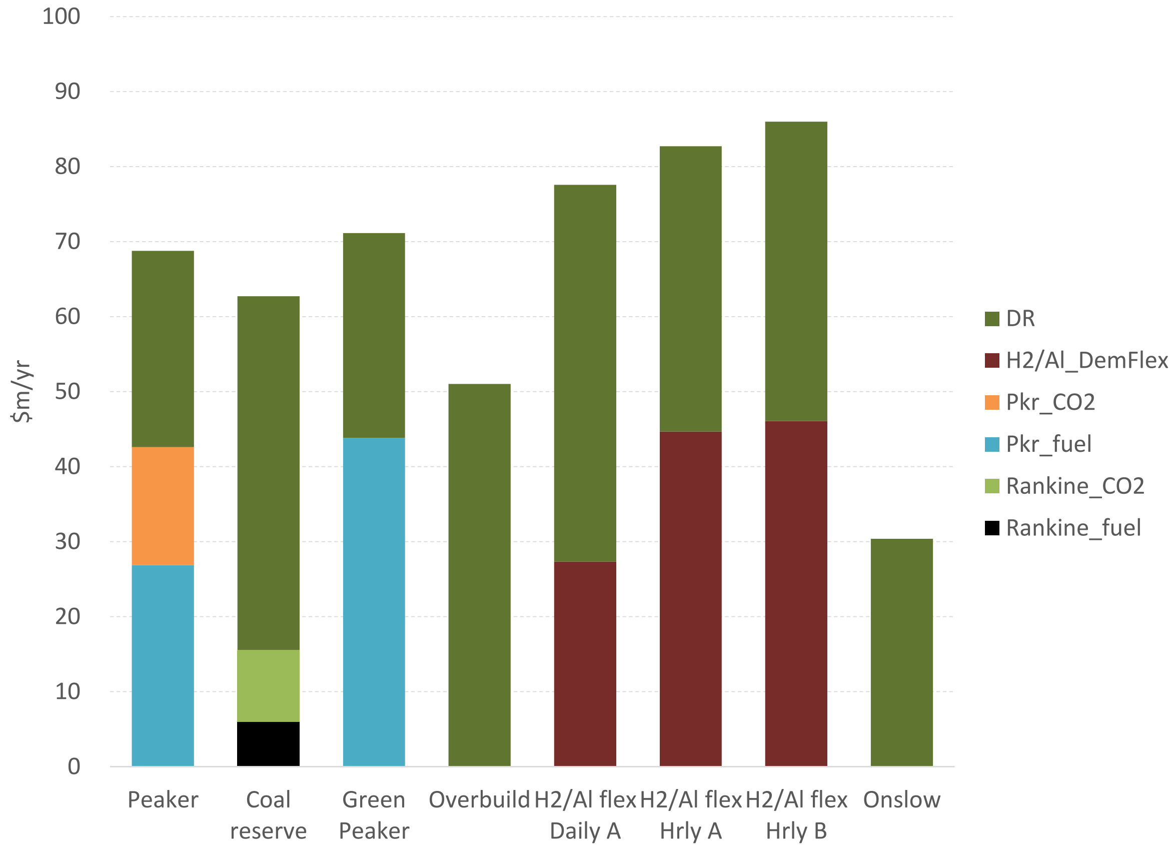
However, spill is also a valuable flexibility resource, and simply spilling less has negligible cost. Systems with peaker generation are tuned "leaner" with less renewable generation and less spill. In certain inflow sequences this can result in higher overall costs because the more expensive peaker generation must be run for longer than anticipated. In other words, the $200/MWh variable cost of fossil peaker generation in 2030 is higher cost than the tranches of the H2/Al flex (which, for the option B scenario is 172 MW at $17.50/MWh then another 100 MW at $150/MWh then a further 100 MW at $200/MWh)

Pumped storage effectively captures both of these downsides, resulting in the worst outcomes. There is no dispatchable source of generation if inflows are lower than expected. And there is minimal spill, because the SI pumped storage scheme performs a very good job at absorbing generation during times of excess capacity.

It's also useful to consider outcomes if inflows are *higher* than expected. Scenarios with dispatchable generation/demand fare better here because less capital is sunk into renewable investment. Or in other words, higher inflows can reduce costs, rather than just leading to higher spill. To quantify this effect, we show the variable costs associated with each scenario that could be reduced if inflows were higher than anticipated.

[26] In practice there is limited wind and solar data for earlier years, meaning this process primarily tests different hydrological inflows.

Figure 37: Variable costs that can be avoided if renewable inflows are greater than expected



Pumped storage again is the worst outcome as there are minimal variable costs that can be avoided.